Project EVA Case Study 1 Final Report

12 April 2018

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Integrated Planning, Predictive
Modelling and Decision Support

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Glossary

@Risk	–	Risk Analysis Software using Monte Carlo Simulation for Excel.
AIC	–	Akaike Information Criterion; AIC is a measure of the relative quality of statistical models for a given set of data. Given a collection of models for the data, AIC estimates the quality of each model, relative to each of the other models. Hence, AIC provides a means for model selection.
BMA	–	Business Modelling Associates
Chi-square test	–	The Chi-square test is intended to test how likely it is that an observed distribution is due to chance. It is also called a "goodness of fit" statistic, because it measures how well the observed distribution of data fits with the distribution that is expected if the variables are independent.
DCO	–	Development Consent Order
EO	–	Enterprise Optimizer: Advanced prescriptive analytics software that supports visuals, object orientated programming. Used to model the decision trees and calculate the risk-adjusted net present value.
EVA	–	Extreme Value Analysis
Exponential distribution	–	It is the probability distribution that describes the time between events in a Poisson process, i.e. a process in which events occur continuously and independently at a constant average rate. It is a special case of the gamma distribution.
FEED	–	Front End Engineering Design; basic engineering which comes after the Conceptual design or Feasibility study
FES	–	Future Energy Scenarios; document within the System Operator (SO) suite of publications on the future of energy for Great Britain
Geometric distribution	–	The geometric distribution models the number of failures before one success in a series of independent trials, where each trial results in either success or failure, and the probability of success in any individual trial is constant.
GHGe	–	Greenhouse Gas Emission
Green Book	–	Guidance for central government produced by the Treasury on how publicly funded bodies should prepare and analyse proposed policies, programmes, and projects to obtain the best public value and manage risks.
HDD	–	Horizontal Directional Drilling
MWC	–	Main Works Contract
NGGT	–	National Grid Gas Transmission
NIA	–	Network Innovation Allowance
NPV	–	Net Present Value
NPC	–	Net Present Cost
NTS	–	National Transmission System

Ofgem	–	Office of Gas and Electricity Markets
PDF	–	Probability Density Function; A PDF is a function of a continuous random variable, whose integral across an interval gives the probability that the value of the variable lies within the same interval. PDFs are used to represent uncertainty in the form of distributions such as normal, Weibull or exponential distributions.
RIIO	–	Revenue = Incentives + Innovation + Outputs, RIIO is Ofgem's framework for setting price controls for network companies
RIIO-T1	–	The first transmission price control review to reflect the RIIO regulatory framework
ROA	–	Real Options Analysis
ROI	–	Return On Investment
Therm	–	The therm (symbol, thm) is a non-SI unit of heat energy equal to 100,000 British thermal units. It is approximately the energy equivalent of burning 100 cubic feet (2.83 cubic metres) – often referred to as 1 CCF – of natural gas.
TPI	–	Third Party Interference
Triangular Distribution	–	Continuous distribution used in business simulation models, especially involving corporate finance, where little is known or limited data is available about the distribution of a variable other than the minimum and maximum values and, in some cases, the most likely occurrence (mode).
Uniform Distribution	–	Continuous distribution with constant probability over a defined interval. When the model is solved, randomly selected variables have an equal chance of assuming any value in the interval between the user-specified minimum (smallest) and maximum (largest) possible values.
WACC	–	The weighted average cost of capital (WACC) is the rate that a company is expected to pay on average to all its security holders to finance its assets. The WACC is commonly referred to as the firm's cost of capital.

1. Executive Summary

This is the final report on Case Study 1 of National Grid Gas Transmission's (hereinafter abbreviated to National Grid) Network Innovation Allowance (NIA) project examining the application of business and risk analytic methods and tools to investment appraisals subject to extreme value events. This case study examined a range of intervention options, and their net present values, to maintain the integrity and operational capability of the Feeder 9 pipeline.

Feeder 9 transports natural gas from the Easington catchment area to the south and west of the UK via a strategic pipeline traversing the Humber Estuary. The progressive erosion of the supporting river bed led to sections of the pipeline becoming exposed in 2009. In 2010 National Grid implemented remediation activities in the form of gravel bags and concrete frond mattresses that protected the pipeline from further scour. This form of remediation is only expected to be effective for 5-10 years and therefore National Grid has also been pursuing a replacement pipeline option to secure the long-term integrity of the pipeline. A detailed strategic optioneering process was followed which identified a tunnelled pipeline as the preferred replacement option. The Development Consent Order (DCO) for a tunnelled pipeline replacement solution was approved by the Secretary of State in August 2016 and enabling works have now commenced on site.

As part of the RIIO-T1 deal, Ofgem provided National Grid with an allowance of £6.6m (09/10 prices) to achieve planning permission and initial engineering activities for the preferred option. Once planning permissions were obtained National Grid could seek to recover the full cost of the project by submitting a formal re-opener submission May 2018.

In recognition of the challenges associated with quantifying the risks of high impact low probability events, Business Modelling Associates (BMA) were asked to explore the applicability of leading edge business analytics software, together with its risk analytics consultancy expertise, to consolidate and analyse the many and disparate data sources associated with this type of investment appraisal.

The investment decision to replace the Feeder 9 pipeline was used as a case study to test the methodology and model developed through the innovation project. Key aspects of the appraisal were:

I. Building an integrated model of the possible decision routes to mitigating the risk of Feeder 9.

II. Include the hazard and consequence of failure of the current Feeder 9 in the net present value analysis, including the low probability and high consequence of failure events.

III. Varying key input metrics as a method of stress testing results.

IV. Allow uncertainty in input variables where definitive data was not available.

Two fully integrated decision tree-based models of the investment options provided by National Grid were built in the River Logic's proprietary 'Enterprise Optimiser' (EO) platform. They incorporated probability weighted consequences of failure of Feeder 9 valued from a safety, environmental, social, commercial, and reputational perspective. The capital costs of new investments were amortised using a customer bill impact method according to National Grid's regulatory settlement.

All costs were discounted at the 'Green Book' (see: glossary) rate of 3.5% and sensitivity checks were made to understand the relative importance of key cost drivers. The timescale applied to the analysis was 60 years to capture the full extent of the forecast impact on customer bills of the intervention options. A Monte Carlo simulation was used to investigate uncertainty. Microsoft Power BI data visualisation used to assimilate results.

Model results shows the lifetime net present value over 60 years for the scenario where National Grid continues to progress its tunnel-based pipeline replacement method **(Tunnel 2012) at -£214m**. On a comparative basis, the alternative trench-based replacement scenario (**Trench 2012) has a net present value of -£267m**, and the enduring maintenance scenario **(Mitigate 2016) -£292m**. Therefore, the option of progressing with the current Tunnel construction has a benefit of **£53m** over the next best option (**Trench 2012**). Note, these net present values are negative as only costs and risk impacts were considered, therefore they are equal to the net present cost of each option. Key cost drivers were the potential impact on consumer bills of Feeder 9 isolation (minimised in the case where pipeline replacement had already been consented and planned) arising from capacity buy-back costs, the risk of loss of life due to a catastrophic failure, and the impact on the wholesale price of natural gas owing to reduced supply availability in the Easington area. **Across the full range of stress test scenarios, the tunnel-based pipeline replacement projects remained the highest value (lowest cost) solution, indicating that the Tunnel 2012 option is robust and is therefore the preferred approach.**

External appraisal of the methodology, approach and data was carried out by the School of Water, Energy and Environment at Cranfield University. The report supported the quantification of key cost drivers and confirmed the method's conformance with the principles of real option pricing.

2. Introduction

2.1. Business Need

National Grid owns and operates the Feeder 9 pipeline as part of its high-pressure gas transmission network. The 1.039m diameter 70bar pipeline is approximately 5.4km with a 3km crossing of the river Humber Estuary. As the sole transportation route across the river Humber, Feeder 9 is one of the most critical pipelines on the National Transmission System (NTS). It plays a pivotal role in the provision of entry gas from the Easington area to demand centres in the South and East and to the UK gas market as a whole. Network Analysis using FES demonstrated that there is a long-term requirement for the Feeder 9 pipeline to perform this function.

The pipeline was originally laid in 1984 in a trench across the estuary but due to severe estuarine erosion, sections of the pipeline became exposed in 2009/2010; the addition of concrete frond mattresses and gravel filled bags from late 2010 have protected the pipeline from erosion in the short term, but the pipeline remains subject to regular monitoring. Longer term estuarial movements are uncertain, and there is concern about the longevity of the frond mattresses. Significant exposure of the pipeline can lead to free-spanning (and at critical lengths, vortex-induced vibration) and increased risk of Third Party Interference (TPI) from vessels that transit the river. Experience from another National Grid pipeline in the Humber (Feeder 1) showed that pipeline failure is possible in such environments.

In January 2012, National Grid published a Strategic Options Report for the replacement of Feeder 9. It identified direct estuary crossings (approx. 3km) rather than lengthy offshore and onshore routes (together with additional compression requirements), as preferred approaches. Further analysis combined with stakeholder feedback identified a pipeline laid in a bored tunnel as the preferred option because of the large environmental and socio-economic impacts of both Horizontal Directional Drilling (HDD) and trenching techniques. The HDD technique was also discounted because it had never been proven over the distances required for the Feeder 9 crossing and was therefore considered to be unfeasible. As part of the RIIO-T1 submission, National Grid received cost allowances to progress preliminary engineering activities. Planning consent for the bored tunnel option was received in 2016 and a Main Works Contractor (MWC) was appointed.

National Grid will present a formal re-opener submission to Ofgem in May 2018 to seek cost allowances for the construction of a replacement Feeder 9 pipeline. In recognition of the challenges associated with quantifying the risks of high impact low probability events National Grid engaged Business Modelling Associates (BMA) to investigate the innovative application of business analytics software and risk analytics methods to ‘extreme value events’, i.e. events subject to uncertainty and where the risk of asset failure is very low, but consequential impacts are very high. A full comparison of the forward options for managing the integrity risk of Feeder 9 was selected as the first of three case studies to be addressed within the scope of this NIA project commissioned in January 2017.

2.2. Innovation Approach

The challenge addressed in this NIA project was quantifying the value of investments that involve mitigating extreme value risks (low probability, high impact events) – standard approaches often struggle to consider or quantify such risks. The danger is that this places a higher decision threshold on investments that mitigate extreme risk events, increasing the vulnerability of asset infrastructure, and therefore of society and the environment, to such events.

The source of this challenge is twofold:

1. The volume and diversity of data generated by impact assessments – the incorporation of quantitative risk assessments and scenario analysis within a single decision-making framework is challenging.
2. The common approaches to cost benefit and net present value analysis tend to emphasise mean or expected values while undervaluing extreme value risks (low probability, high impact) and ignore uncertainty.

The solution developed and tested in this project addressed both challenges.

2.3. Technology platform

BMA deployed its Enterprise Optimizer (EO) business analytics platform together with expert risk analytics approaches to analyse the net present values of Feeder 9 replacement options over a period of 60 years using a real options analysis approach. EO itself is a 5th generation business modelling application allowing rapid model building, with embedded prescriptive analytics (optimisation) capability. EO was selected for the project since all core functionality required for the solution, such as net present value calculation, mass balance transfer and stochastic distributions, are pre-built within the software. The user therefore is required only to configure the solution to represent the decision to be informed. This enables the rapid model building and moves the model build process from the preserve of IT specialist to business practitioner.

With only 5% of corporations (Gartner Survey) deploying truly prescriptive approaches to business simulation, and the software having been developed originally for operational planning use, the application of EO in this field represents an innovative application of the technology. To aid practicality of use and the interpretation of results, the EO platform can be delivered under Microsoft's Azure cloud platform and data services, and interfaces readily with visualisation tools such as Microsoft's Power BI.

2.4. Solution Approach

This project developed, tested, and implemented a methodology and business modelling platform that encompassed financial, asset and operational modelling to address extreme value events (low probability, high impact asset failures) and facilitated stakeholder engagement in investment decision making. The methodology followed a real options analysis approach and included an extreme risk weighted analysis of Net Present Value (NPV). The solution developed using this methodology supported rapid 'what-if' scenario analysis to support agile decision making. This allowed users to quickly test different assumptions and decision criteria.

2.4.1. Decision Tree Development

The approach taken was to model the range of investment choices, consequential decisions, and consequences thereof, as a decision tree. Where multiple decision options or outcomes occurred, the probability of each occurring, or their frequencies, were assigned and determined from expert elicitation or from historic data where possible (for example in assigning probabilities to the early, on-time or late completion of Feeder 9 replacement). Where there was uncertainty in the probabilities or consequences of decisions or outcomes these were modelled as probability density functions. This minimised the use of average values which underestimate extreme risk (tail end risks). Multiple nested decision trees were built, with the final branch being the assignation of costs arising from each decision consequence. A description of the decision tree modelling methodology can be found in **section 3**. A Full and detailed decision trees can be seen in **Appendix A**.

2.5. Peer Review

Cranfield University were asked to conduct a peer review of the methodology and approach used by BMA to create an Extreme Value Analysis (EVA) model for investment optioneering – a tool to assess investment options for Feeder 9. The aim of the review was to provide an independent assessment of the work done.

The peer review of the NIA project concluded that the use of Enterprise Optimiser was appropriate. It summarised that the use of discounted cash flow as an economic appraisal; decision tree analysis combined with Monte Carlo simulations to implement Real Options Analysis (ROA); modelling uncertainty as Probability Density Functions (PDFs) and as a discrete risk events when PDF could not be obtained were suitable analytical approaches. A number of recommendations were included, ranked in three categories – critical issues (RED), important issues (AMBER), and minor issues (GREEN).

The only critical recommendation related the market risk: as the importance of gas in future UK energy is very uncertain. The review suggested to test the impacts of unsupplied gas using FES scenarios, which has been done accordingly and described in following paragraphs: **5.3.1. Future Energy Scenarios (FES) 5.3.2. Capacity buy-back costs,** and **5.3.3. Wholesale gas prices impact**.

Important recommendations included modelling environmental risks and changes in ecosystem services as well as alternative gas futures (mainly future usage of hydrogen). In response to this the environmental impacts were modelled: GHGe costs due to rupture or controlled venting of the pipeline (covered in **5.3.6. Loss of gas: GHGe costs**), and costs of renting land to offset impact on wetland during trench construction (**5.5.2. Trench (2012) and Trench (2016) scenarios**). Further modelling of environmental impacts was limited due to lack of quantitative data. No environmental costs were considered in terms of Bored Tunnel because it was concluded that it has a minimum impact on habitat. Future of hydrogen gas has not been explored because of significant regulatory uncertainty. Investigation of other alternative gases' future was judged out of scope.

Minor recommendations involved modelling financial risks, namely WACC value used for calculating NPV, value of loss of life due to rupture, and regulatory risks around disruption to supply. Value of WACC used in the model is discussed in paragraph **5.4. Discount factor used and NPV calculation overview**, and stress tests including varying WACC were performed (**6.2. Stress tests**). Value of loss of life has been discussed in paragraph **5.3.10. Casualties due to rupture and cost of a life**. It was concluded that a disruption to supply would not impact National Grid's ability to meet their licence conditions.

Full text of the review has been attached as **Appendix G**.

2.6. Model Overview

Visually, the model represents the branching decision points and possible outcomes of each decision. Within each object, representing the decision points and outcomes, there are data tables representing the probabilities and costs for each of the time periods modelled. This approach allows us to ensure that all possible outcomes of decisions are modelled and appropriately weighted in the NPV calculation. The visual nature of the model also aids validation and communication of the model. The model has 60 time periods corresponding to 60 years at an annual granularity (one time-period is equal to 1 year). This time scale was chosen to allow us to capture the full extent of the forecast impact on customer bills of the intervention options. This allows the user to edit individual probabilities and costs for all time periods or by specific time period.

2.7. Intervention scenarios considered

2.7.1. Stop Tunnel in 2016 and Mitigate

Hereinafter referred to as **Mitigate (2016)**. In this scenario the Main Works Contract (MWC) for the Tunnel option is not awarded in May 2016. Consequently, the tunnel DCO is aborted and the investment decision is made to continue to use the current Feeder 9 pipeline. This results in sunk costs up to end of April 2016 – tunnel DCO and other pre-work costs. Continuing the use of Feeder 9 means mitigating the risk of pipeline failure due to TPI and free spanning using inspection and concrete frond mattresses. Boat and diver inspections are carried out at a frequency of one every two months, these are increased when further erosion of the pipeline silt covering is observed. When the pipeline begins to be uncovered, concrete frond mattresses are lowered over the pipeline. These act as a physical barrier to protect the pipeline and the fronds will help sedimentation and benthic life to recover the pipeline. The frond mattresses need to be periodically replaced. There remains a risk of critical failure (rupture) of the pipeline due to TPI or free spanning. The timeline for the scenario is presented in **Fig. 1**.

2.7.2. Stop Tunnel in 2017 and Mitigate

Hereinafter referred to as **Mitigate (2017)**. As per the Mitigate (2016) scenario, with the difference that MWC on the tunnel is awarded in May 2016 and cancelled in 2017. The tunnel project is subsequently fully demobilised by 2019. This results in sunk costs up to June 2017. The timeline for the scenario is presented in **Fig. 1**.

2.7.3. Tunnel Replacement start in 2012

Hereinafter referred to as **Tunnel (2012)**. In this scenario the decision is made to replace the current Feeder 9 pipeline with a new pipeline contained within a concrete tunnel bored underneath the Humber Estuary. The new pipeline is physically isolated from the estuary bed and shipping, so is not exposed to the two critical failure modes of the current pipeline (rupture due to TPI or free spanning). The current pipeline is decommissioned. This is the scenario with highest Capital Expenditure. The timeline for the scenario is presented in **Fig. 1**.

2.7.4. Trench Replacement start in 2012

Hereinafter referred to as **Trench (2012)**. In this scenario, following the strategic options report in 2012, the investment decision is made to progress with the trenching option (not tunnel option). A trench DCO application is submitted in April 2015, and the DCO is awarded in January/February 2018 (34 months DCO process due to increased environmental constraints associated with this construction method). Construction would begin in 2018 but National Grid couldn't start enabling works over winter months so would need to wait until April 2018. Construction would finish in 2019. Additional cost is required for compensatory land and aftercare for the trenching option. This is the same method by which the current pipeline was placed in the estuary. Therefore, the Trenched Replacement options are exposed to the same failure modes as the current pipeline (rupture due to TPI or free spanning). However, as it will be newly constructed, it will begin life adequately buried in the Humber Estuary bed, with lower vulnerability and therefore probability of failure. The Strategic Options Appraisal carried out by National Grid concluded that reduction in probability of failure can only be assumed for 20 years post construction. The current pipeline is decommissioned. The timeline for the scenario is presented in **Fig. 2**.

2.7.5. Stop Tunnel in 2016 and build Trench

Hereinafter referred to as **Trench (2016)**. As per Trench (2012) scenario, with the difference that the tunnel DCO is applied for but National Grid make the investment decision in April 2016 not go continue with this option. After analysis of the Cost Benefit Analysis (CBA) the leadership team feel that the trench option should be pursued. This would mean that the Trench DCO application was submitted in July 2016 and finishes 34 months[1] later (Apr 2019) Construction would begin in May 2019 and finish 19 months later. This scenario assumes that the MWC for the **Tunnel Option** was not awarded and tunnel that the tunnel DCO was aborted, which results in sunk costs up to 2016. **Fig. 2**. The timeline for the scenario is presented in **Fig. 2**.

[1] This is a relatively conservative view as there may be further requirement for additional surveys which would increase the length of the DCO

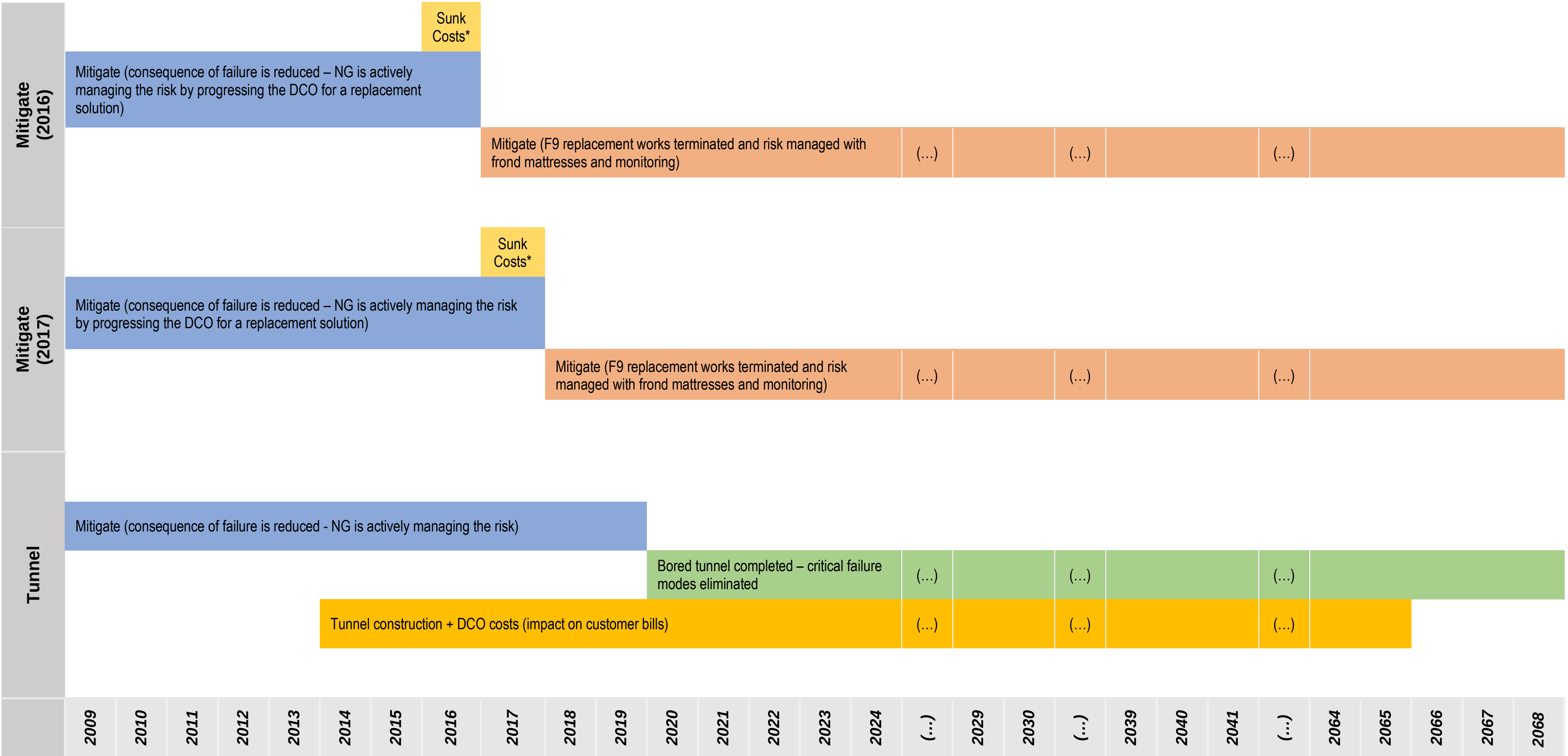

Fig. 1. High level description of Tunnel and Mitigate Scenarios

*Value of the **sunk costs** (described in detail in **paragraph 5.7. Sunk costs**)

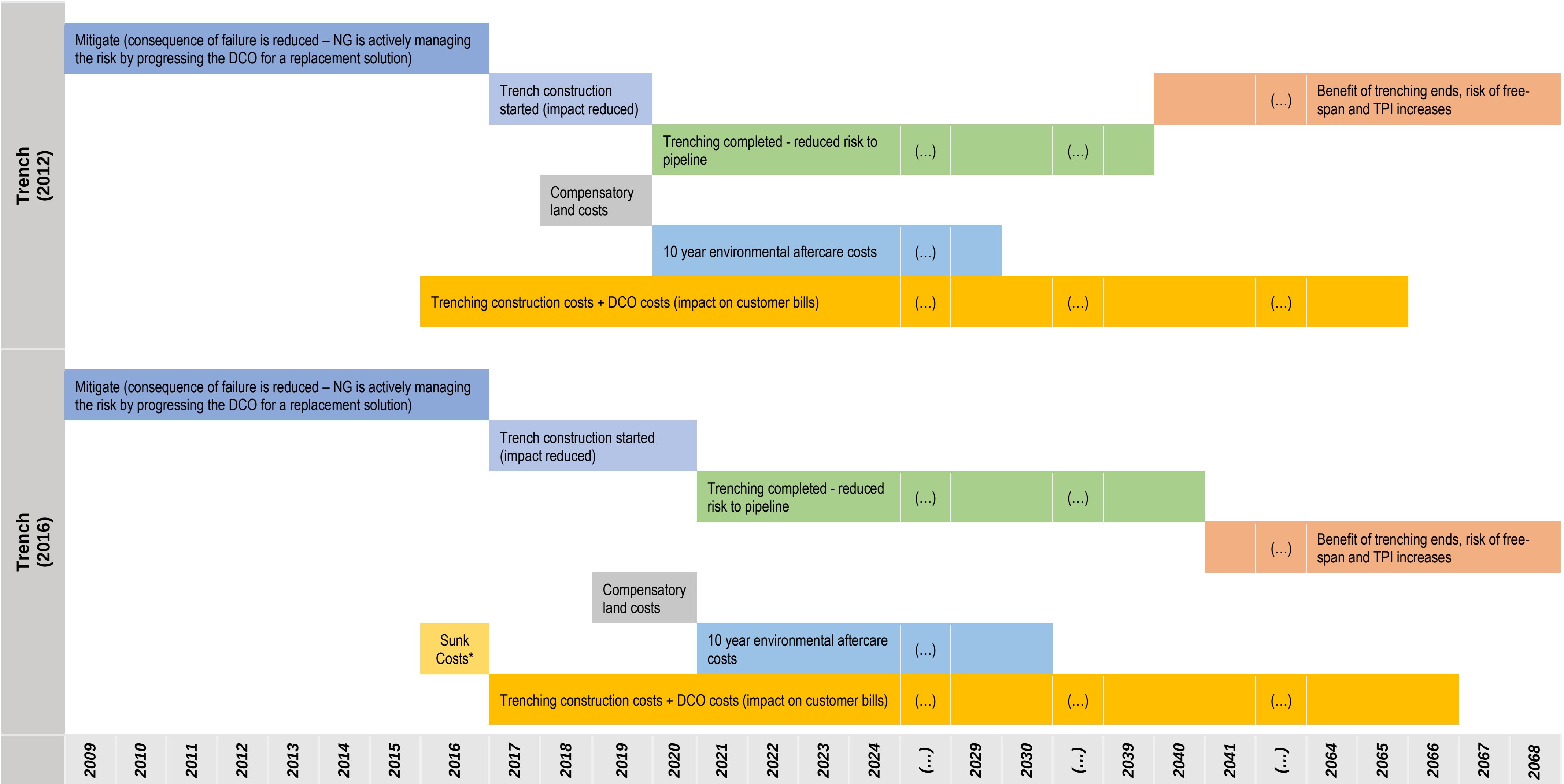

Fig. 2. High level description of Trench Scenarios

*Value of the **sunk costs** (described in detail in **paragraph 5.7. Sunk costs**)

2.8. Relationship with other studies

Decision tree development and data input to the model drew heavily from analysis conducted by National Grid's internal asset management teams (maintenance, inspection and intervention options, and constraint management charges) and National Grid's Strategic Options Report for Feeder 9. The Decision tree was further developed and finalised through a series of facilitated workshops with a wide range of National Grid domain experts.

In assessing the risk of failure and ensuing consequences of failure of Feeder 9, DNV-GL's quantitative risk assessment study[2]

Forward supplies and demand profiles for the Easington area were based on National Grid's four future energy scenarios (FES) published in 2016[2].

The critical span length that will lead to Vortex Induced Vibrations (VIV) was taken from ABPmer Report[3].

Constraint costs and wholesale gas prices impact sections were provided by National Grid and were informed by the Future Energy Scenarios document[4].

Repair methods, estimated time of the repair and associated costs were based on High-Level Emergency Repair Strategy (2016) document issued by Intertek[5].

Cost of recovering and cleaning up a potential shipwreck which may be a consequence of pipeline rupture, ignition, and subsequent sinking of the vessel were based on Safety and Shipping Review by Allianz, 2015[6].

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[2] A Quantified Risk Assessment of the Underwater Section of Feeder F9 in the Humber Estuary, DNV-GL Report 147360-1, A Report For NGT, 11/01/2016

[3] Pipeline Span VIV Assessment: No.9 Feeder, Humber Estuary, ABP mer, ref: R/3924/2, August 2010

[4] Future Energy Scenarios 2016, National Grid

[5] Feeder no. 9 Pipeline - Humber Estuary, High-Level Emergency Repair Strategy, P1816_R3964_Rev1, Intertek, issued 03/02/2016

[6] Safety and Shipping Review, Allianz, 2015

3. Modelling overview

3.1. Decision tree approach

A decision tree approach was chosen as the most suitable approach as it is commensurate with the requirement to align with a ROA approach. In addition, the rigorous process of developing the decision tree ensured that all options and outcomes were considered, even those deemed unlikely. The process of developing the decision tree proved effective in capturing knowledge of the wide range of subject matter experts relevant to this decision. Decision trees were created in collaboration with National Grid through a series of facilitated workshops, as stated in **2.8. Relationship with other studies.** The decision tree was then used to inform the model structure and logic.

A screenshot of the EO model depicting the mitigate and tunnel replacement options is shown in **Fig. 3**. Each branch in the EO represents a branch in the decision tree. For modelling purposes, the following naming conventions were used:

- M1 – refers to the costs and risks associates with mitigating the current Feeder 9 pipeline using concrete front mattresses. This is the primary decision path associates with investment options Mitigate (2016) and Mitigate (2017).
- M1(alt) – refers to the historic costs and risks associates with mitigating the current Feeder 9 pipeline up to and including 2016.
- R1 – refers to the risks and costs associates with the tunnelled replacement pipeline once it is commissioned and operational.

A screenshot of the EO model depicting the trench options is shown in **Fig. 4**. Each branch in the EO represents a branch in the decision tree. For modelling purposes, the following naming conventions were used:

- M1 – refers to the costs and risks associates with mitigating the current Feeder 9 pipeline using concrete front mattresses prior to completion of Trench and after the Trench ceases to actively reduce the risk.
- M1(alt) – refers to the historic costs and risks associates with mitigating the current Feeder 9 pipeline up to and including 2016.
- T1 – refers to the risks and costs associates with the Trench replacement pipeline once it is commissioned and operational.

The full decision tree the EO model is based on is shown in **Appendix A.** The full EO decision tree models are shown in **Appendix B**.

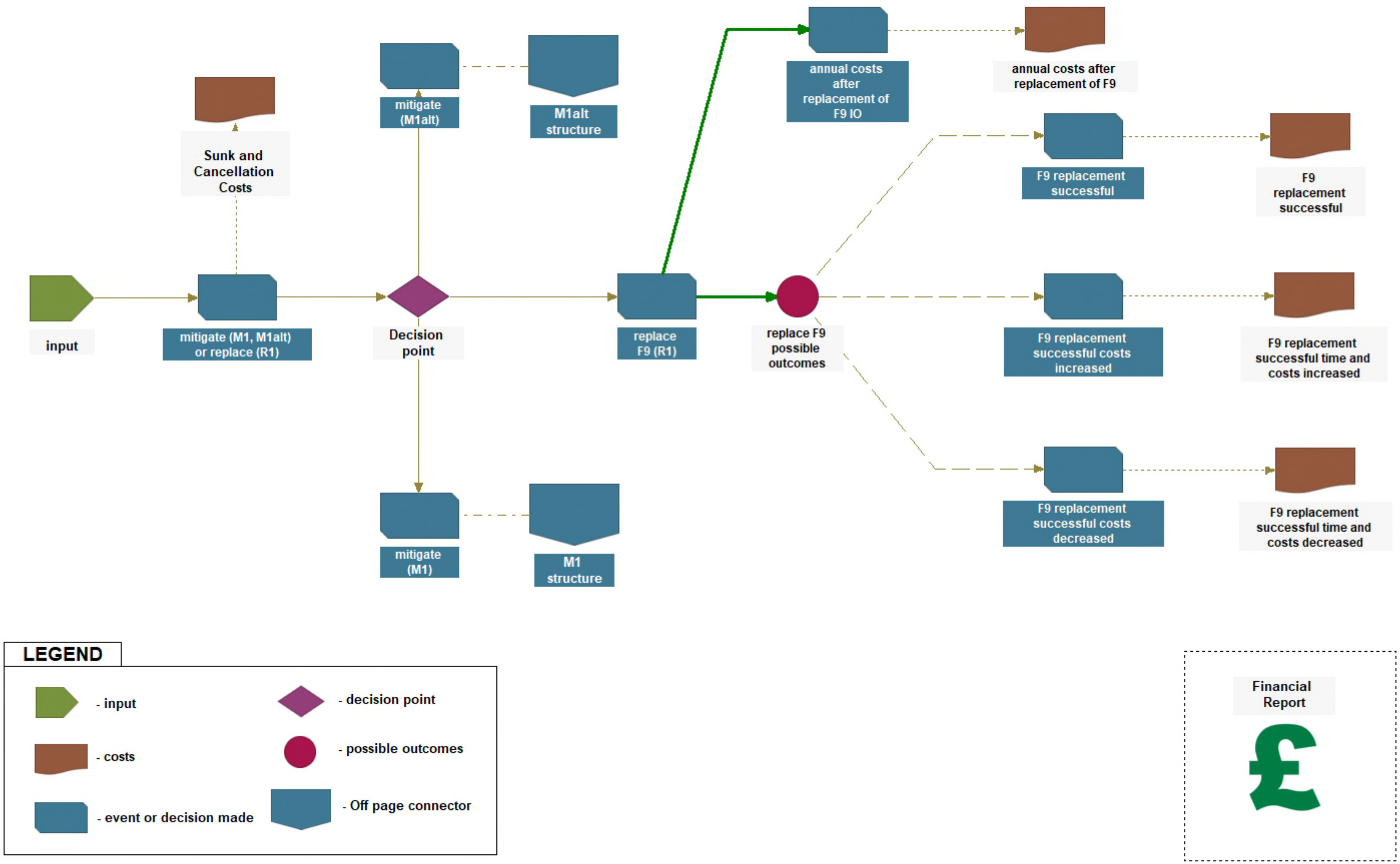


Fig. 3. Screenshot of the EO model showing the top level of the decision tree. Here M1 refers to the mitigation options (mitigating the Feeder 9 risk using frond mattresses) and R1 refers to the tunnelled replacement option (replacing Feeder 9 with a new pipeline encases in a concrete tunnel under the Humber estuary). M1(alt) refers to the historic costs and risks associates with mitigating the current Feeder 9 pipeline up to and including 2016. From this top level of the decision tree the user can drill down to explore the more detailed levels of the decision tree encompassing a large number of decision options and possible outcomes.

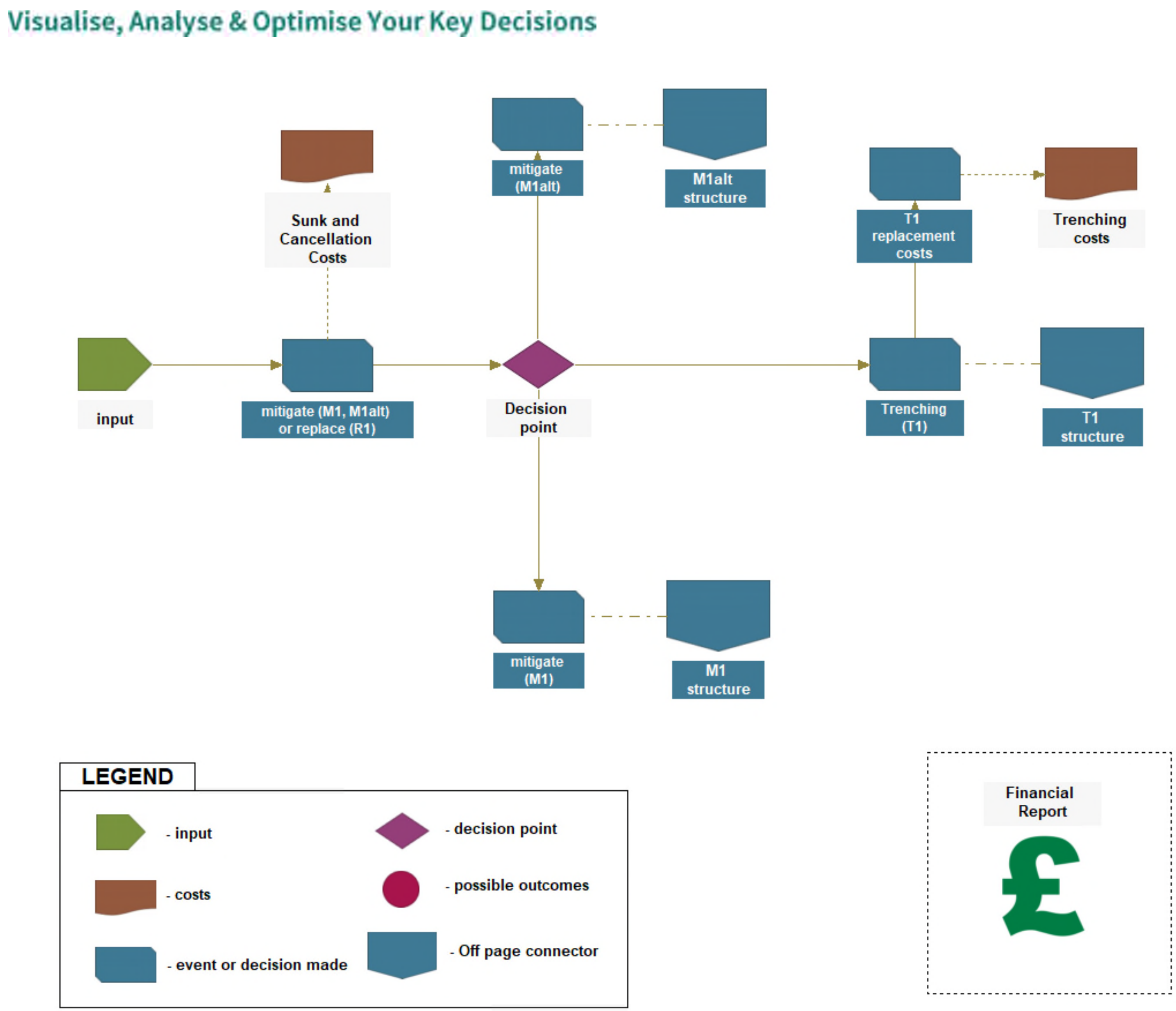


Fig. 4. Screenshot of the EO model showing the top level of the decision tree. Here M1 refers to the mitigation options (mitigating the Feeder 9 risk using frond mattresses) and T1 refers to the trench replacement option (replacing Feeder 9 with a new pipeline in a trench across the Humber estuary). M1(alt) refers to the historic costs and risks associates with mitigating the current Feeder 9 pipeline up to and including 2016. From this top level of the decision tree the user can drill down to explore the more detailed levels of the decision tree encompassing a large number of decision options and possible outcomes.

3.2. Brief introduction to modelling with the use of Enterprise Optimiser Software

3.2.1. Software capabilities

Enterprise Optimizer® (EO) is an optimization-based modelling and analysis environment designed for strategic, tactical, and operational planning in any industry. EO includes a complete set of automated financial reporting and analysis features including fully customizable Income Statement, Balance Sheet, Cash Flow Statement, Financial Ratio, and Present Value Analysis reports. EO solves to optimize enterprise-wide Net Income across all time periods. EO can also be configured to optimize other performance measures such as Net Present Value, Return on Investment, and Cost minimisation.

3.2.2. Principles of modelling in EO

EO is material driven and constrained based software. In the context of this project materials are used to represent decisions and decision consequences. That means that materials (decisions and their consequences) defined in the model are "flowing" from one object to another. Each object has unique capabilities to restrict the flow (impose constraints) or transform one material into another material. A generic EO model is presented in **Fig. 5.** The legend describing icons used for EVA model presents **Fig. 6**. Representation of material flow depicts **Fig. 7**. A brief explanation of the EO objects and their capabilities, along with specific use in the EVA model, are presented below.

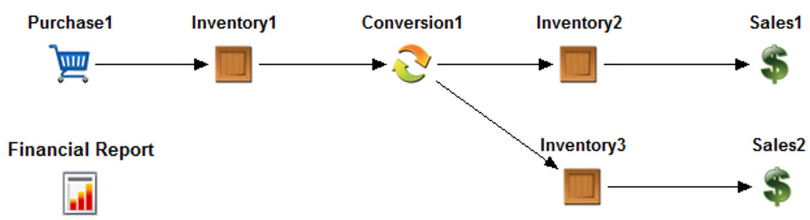


Fig. 5. Generic EO model

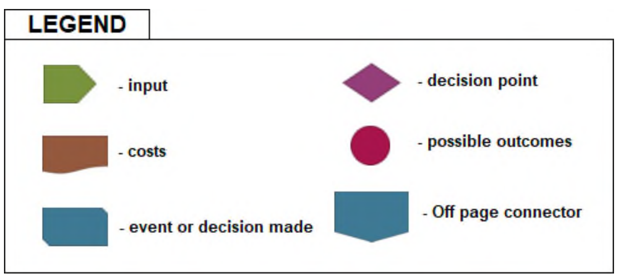


Fig. 6. Legend for the EO model

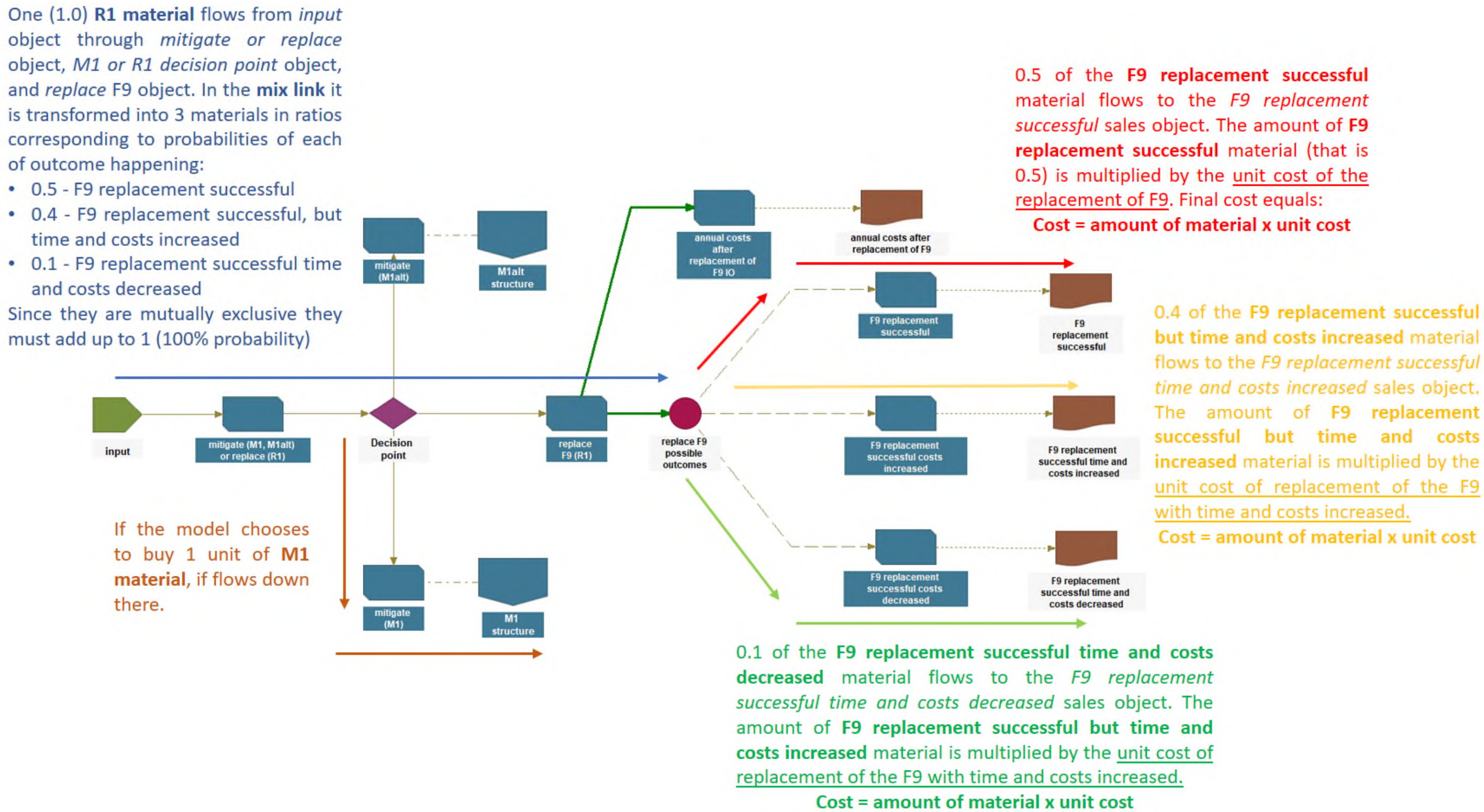


Fig. 7. Illustration of model logic – flow of materials triggering certain costs and risks

Purchase Object (shopping trolley symbol) creates input to the model – generate materials. Material can represent physical materials or options, decision, events etc. Materials are then transported via "link" objects to other objects. Yields, probabilities and frequencies or other conversions are applied in the "link" objects. In the EVA model, the purchase object generates M1 and/or R1 materials, representing the maintenance and replacement decisions. Default icon was changed to green arrow.

Fig. 8. EO's purchase object and EVA's representation

Inventory Objects (wooden crate symbol) are essential objects in EO and must be created between any two other objects. They are places where materials are defined and can also be accumulated ("inventory" storage capability). In the EVA model, they are used to define materials but they don't accumulate them – materials "flow" through them and end up in sales objects. In the EVA model Inventory Objects model decision points, possible outcomes nodes, events, or decisions.

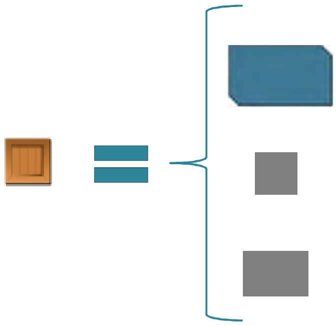


Fig. 9. EO's purchase object and EVA's representation

Meta groups model "Off page connectors"" – sub-models that grouped certain costs and risk together for clarity that are "triggered" at specified time period.

Fig. 10. EO's meta-groups and EVA's representation

Link Objects connect all EO Objects. There are two types of links:

1. Sort Links - enable the flow of the material from one object to another (arrow head shows the direction of the flow). In **the EVA model,** they are <u>brown coloured</u>.

2. Mix Links - give the possibility to transform one material into other materials in arbitrary ratios. In **the EVA model,** they are thick and green coloured.

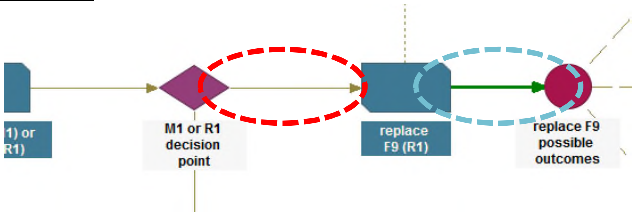


Fig. 11. EO's links objects and EVA's representation

Sales Objects (dollar sign) **are** points of output of materials from the system. They generate revenue for sales and may incur costs. In the **EVA model**, they incur costs associated with events that take place or decisions made.

Fig. 12. EO's sales object and EVA's representation

Financial Report Objects (chart symbol) store the Chart of Accounts and all financial reporting information for each facility including budgets, tax rates, asset information, financial ratio calculations and financial transaction accounting information. In the **EVA model**, it is used for calculating NPV of the model.

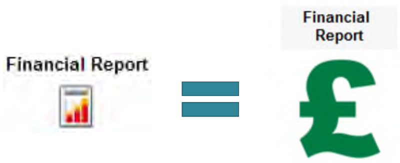


Fig. 13. EO's financial report object and EVA's representation

Conversion Objects (circular arrows symbol) convert input materials into output materials in arbitrary configurations. They are much more sophisticated than mix links since they allow modelling resources and processes that take place in them. They are computational heavy and, since mix links functionality was sufficient for EVA model, they were not used.

Fig. 14. EO's conversion object

4. Monte Carlo simulation overview

4.1. Definition and Assumptions

Definition: Monte Carlo simulations are used to model the probability of different outcomes in a process that cannot easily be predicted due to the intervention of random variables. They rely on repeated random sampling to obtain numerical results. Their essential idea is using randomness to solve problems that might be deterministic in principle.

Each Monte Carlo simulation consisted of 1,000 iterations. In each iteration, a value was randomly selected from each stochastic function (probability density function), input into the relevant model field, the model solved and the results exported to the results database. 1,000 iterations were considered appropriate, weighing of the benefits of a greater number of iterations and model solve time.

EO offers modelling uncertainty with the use of probability distribution functions for a range of variables. In the EVA model, they were used to model uncertainty in:

- Costs
- Probabilities of events happening

Two types of distributions were used: uniform and triangular distributions. Below are the definitions of usage in the EVA model.

a) Triangular distribution

Definition: A triangular distribution is a continuous probability distribution with a probability density function shaped like a triangle. It is defined by three values: the minimum value a, the maximum value b, and the mode value c. This is useful as in a real-life situation we can often estimate the maximum and minimum values, and the most likely outcome, even if we don't know the mean and standard deviation. The triangular distribution has a definite upper and lower limit, so we avoid unwanted extreme values.

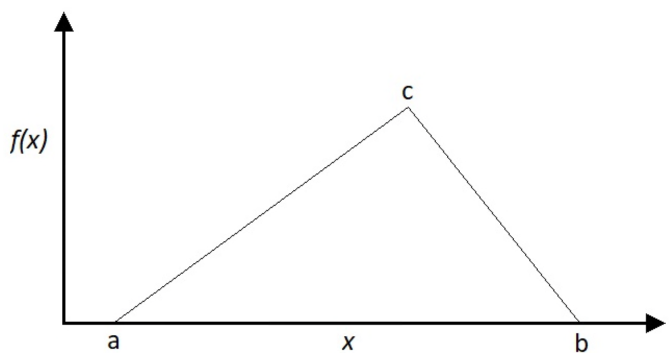


Fig. 15. Triangular probability density function. Minimum = a, maximum = b, mode = c

Usage: A Triangular distribution was used as most relevant whenever minimum, maximum, and most likely values of the variable were provided by National Grid.

b) Uniform distribution

Definition: Uniform distribution is a continuous distribution with constant probability over a defined interval. When the model is solved, randomly selected variables have an equal chance of assuming any value in the interval between the user-specified minimum (smallest) and maximum (largest) possible values.

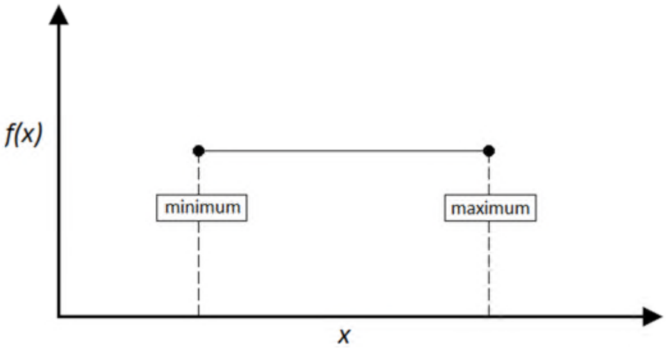


Fig. 16. Uniform probability density function. Minimum and maximum values shown.

Usage: Uniform distribution was used whenever minimum and maximum values of the variable were provided by National Grid or assumptions were made by BMA, but no certain probability could have been assigned to variable values.

4.2. Uncertainty around costs

Where uncertain costs values were provided as a minimum, maximum and most likely value (mode) these were represented using triangular distributions in the model. See **Table 1** for examples.

Table 1. Examples of Triangular and Uniform Distributions for modelling costs.

Cost of:	Distribution	Min	Mode	Max
Continuing to use/re-instate F9 replacement of frond mattresses	Triangular	£102,900.00	£235,320.00	£765,000.00
Repeating installation and replacing every 1-10 years	Triangular	£1,131,900.00	£1,264,320.00	£1,794,000.00
clearing up (after vessel sunk)	Triangular	£0.00	£300,000,000.00	£425,000,000.00
F9 stabilization or decommissioning	Uniform	£0.00	£3,770,000.00	£0.00
Cost of:	**Distribution**	**Min**	**Max**	
F9 stabilization or decommissioning	Uniform	£0.00	£3,770,000.00	

4.3. Uncertainty around probabilities

Where model variables were provided as a minimum and maximum only, these were represented as a uniform distribution. See **Table 2** for examples.

Table 2. Example of uniform distribution used for modelling probability.

Probability of:	Distribution	Min	Max
Notice given on lease to operate pipeline across Humber	Uniform	0.0001	0.1
Sediment erosion approaching F9	Uniform	0.000548149	0.05481485
<20m section of free span developing	Uniform	0.002528625	0.25286251
=>55m section of free span developing	Uniform	0.000007142	0.0007142
=>20m section of free span developing	Uniform	0.000487084	0.04870844
Gas ignition	Uniform	0.1169	0.8197
Probability of:	**Distribution**	**Min**	**Max**
high constraint	Uniform	£83,300,000.00	£83,300,000.00
low constraint	Uniform	£24,500,000.00	£24,500,000.00
mod high	Uniform	£390,300,000.00	£894,600,000.00
mod low	Uniform	£2,700,000.00	£6,300,000.00
mod med	Uniform	£190,500,000.00	£425,700,000.00

5. Model inputs and assumptions

The underlying principle of this case study was to use the best available data and to not unnecessarily exclude any data. Therefore, data of different format and granularities were included, some derived from quantitative studies (such as the DNV GL quantitative risk assessment of TPI risk to Feeder 9), while others were based on domain experts in National Grid (for example probability of licence to operate a pipeline across the Humber Estuary bed being revoked by ABP).

5.1. Third Party Interference

One of the main risks that apply to Feeder 9 is Third Party Interference (TPI) – a failure mode that may lead to critical failure of the pipeline. TPI involves a vessel impact or anchor strike on the pipeline. This can then result in damage to the pipeline and, in the most extreme case, sudden and catastrophic rupture of the pipeline. In the later scenario, significant volumes of gas escape which may ignite causing casualties in any ships passing above. The worst-case scenario involves a large passenger ferry being exposed to the fire caused by the ruptured pipeline.

Assumptions:

Summed frequencies of both vessel impact and anchor strike were taken directly from the DNV GL report (*DNV GL: PP147360-1 Feeder 9 QRA Issue 1.0*). The study considered the number of vessels crossing the pipeline as well as the size of the vessel. In the case of 'no rupture TPI suspected' scenario the pipeline has suffered a TPI incident but has not immediately ruptured. The extent of the potential damage is then modelled from minor to severe. In the case of 'rupture' the pipeline immediately ruptures.

Table 3: Aggregated frequencies of vessel impact and anchor strike

Scenario description	Probability of the scenario
No rupture occurs, but TPI is suspected	3.13E-04
Rupture occurs	1.22E-04

5.2. Further loss of sediment around Feeder 9

Further loss of sedimentation can also result in the pipeline rupturing. In this case, where sedimentation erosion results in a free spanning section of pipeline (section of pipeline uncovered and unsupported by estuary substrata) of 55 meters or greater, there is a possibility that vortex induced vibration (VIV) can cause the pipeline to sheer catastrophically. Through the development of the decision tree the following critical decision points were identified (**Table 4. Critical decision points driven by erosion of estuary substrata around Feeder 9**).

Table 4. Critical decision points driven by erosion of estuary substrata around Feeder 9

Scouring / Free spanning observed:	National Grid Response	Additional risks
Any scouring observed near or on pipeline	Increase survey frequency to monthly	
1-20-metre free span	Install additional concrete frond mattresses in at risk areas	
20-55-metre free span	Isolate and inspect with divers, then install additional concrete frond mattresses	There is a risk the frond mattress mitigation does not work and the free span grows
55-metre or greater free span	If not yet ruptured, isolate and inspect with divers: repair, replace or permanently isolate as appropriate	When a free spanning section reaches 55 metres or more, there is also a risk of catastrophic rupture caused by vortex induced vibration.

In order to determine a reasonable probability of further loss of sedimentation around Feeder 9 the available historic data was used. The available and relevant historical data used included Bathymetric surveys of Feeder 9 carried out between 2008 and 2016 (presented in **Table 5**) and historical frond mattress interventions (presented in Table 6). The Bathymetric surveys covers data on a number of exposed sections caused by scouring and their length. This provided a small data set covering 9 years.

Table 5: Bathymetric surveys of Feeder 9

Year	Number of new scouring events	Scouring event ID				Notes
2008	0					
2009	1	2009-1				
2010	3	2010-1	2010-2	2010-3	2010-4	First frond mattresses deployed on Feeder 9. 2010-4 is a growth of event 2009-1.
2011	1	2011-1				
2012	0					
2013	1	2013-1				frond mattresses re-installed on existing scour
2014	0					
2015	0					
2016	0					

Table 6: Historical frond mattress interventions

Scour event	Length of scours [m]	KP-1 [km]*	KP-2 [km]*	Notes
2009-1	33.2	0.955	0.988	-
2010-1	14.7	0.89	0.904	-
2010-2	5.4	0.907	0.913	-
2010-3	16.2	0.917	0.933	-
2009-1; 2010-4	38.4	0.955	0.994	2009-1 and 2010-4 are the same scour which grows from 2009 to 2010
2011-1	6.9	1.056	1.063	
2013-1	-	-	-	Re-installed frond mattresses

*KP stands for Kilometre Point and indicates the location along the length of the Feeder 9 pipeline.

The @Risk software was used to fit a Probability Density Function (PDF) such as a triangular or normal distribution to the data on:

1. Number of new scour events
2. The length of scour

This was used to create a predictive model that would predict the probability of a scour event and the probability it would be of a defined size range.

The PDF that best fit the historic number of scouring events was a discrete Geometric distribution (p=0.64286) (**Fig. 18**). A geometric distribution describes the probability of a number of discrete events, therefore is appropriate for modelled whether something happens or not. Therefore, it is a good fit to model the probability of scouring events happening or not. The Geometric distribution was the highest ranked by @Risk by the Akaike Information Criterion (AIC) goodness of fit metric (**Fig. 17**). AIC is a measure of the relative quality of a statistical model given a set of data. A comparison of the empirical and simulated annual scour events can be seen in **Table 7**.

Fig. 17. On left, the geometric distribution of number of scouring events per year had the highest goodness of fit score based on the Akaike Information Criterion (AIC).

Rank By: AIC

	Fit	Value
☑	Geomet	22.7618
☐	Poisson	23.0205
☐	NegBin	26.0606
☐	IntUniform	30.9533
☐	*Binomial*	*N/A*

Table 7. On right, tabular comparison of best fit Geometric distribution (red) and historic data (blue) for number of scouring events per year

Statistics Grid

	Input	Geomet
Minimum	0.0000	0.0000
Maximum	3.0000	+∞
Mean	0.5556	0.5555
Mode	0.0000	0.0000
Median	0.0000	0.0000
Std Dev	1.0138	0.9296
Skewness	2.1213	2.2709
Kurtosis	7.6470	10.1572
Left X	0.000	0.000
Left P	5.0%	64.3%
Right X	3.000	3.000
Right P	95.0%	98.4%
Dif. X	3.0000	3.0000
Dif. P	90.0%	34.1%
1%	0.0000	0.0000
5%	0.0000	0.0000
10%	0.0000	0.0000
15%	0.0000	0.0000
20%	0.0000	0.0000
25%	0.0000	0.0000
30%	0.0000	0.0000
35%	0.0000	0.0000
40%	0.0000	0.0000
45%	0.0000	0.0000
50%	0.0000	0.0000
55%	0.0000	0.0000
60%	0.0000	0.0000
65%	0.0000	1.0000
70%	1.0000	1.0000
75%	1.0000	1.0000
80%	1.0000	1.0000
85%	1.0000	1.0000
90%	3.0000	2.0000
95%	3.0000	2.0000
99%	3.0000	4.0000

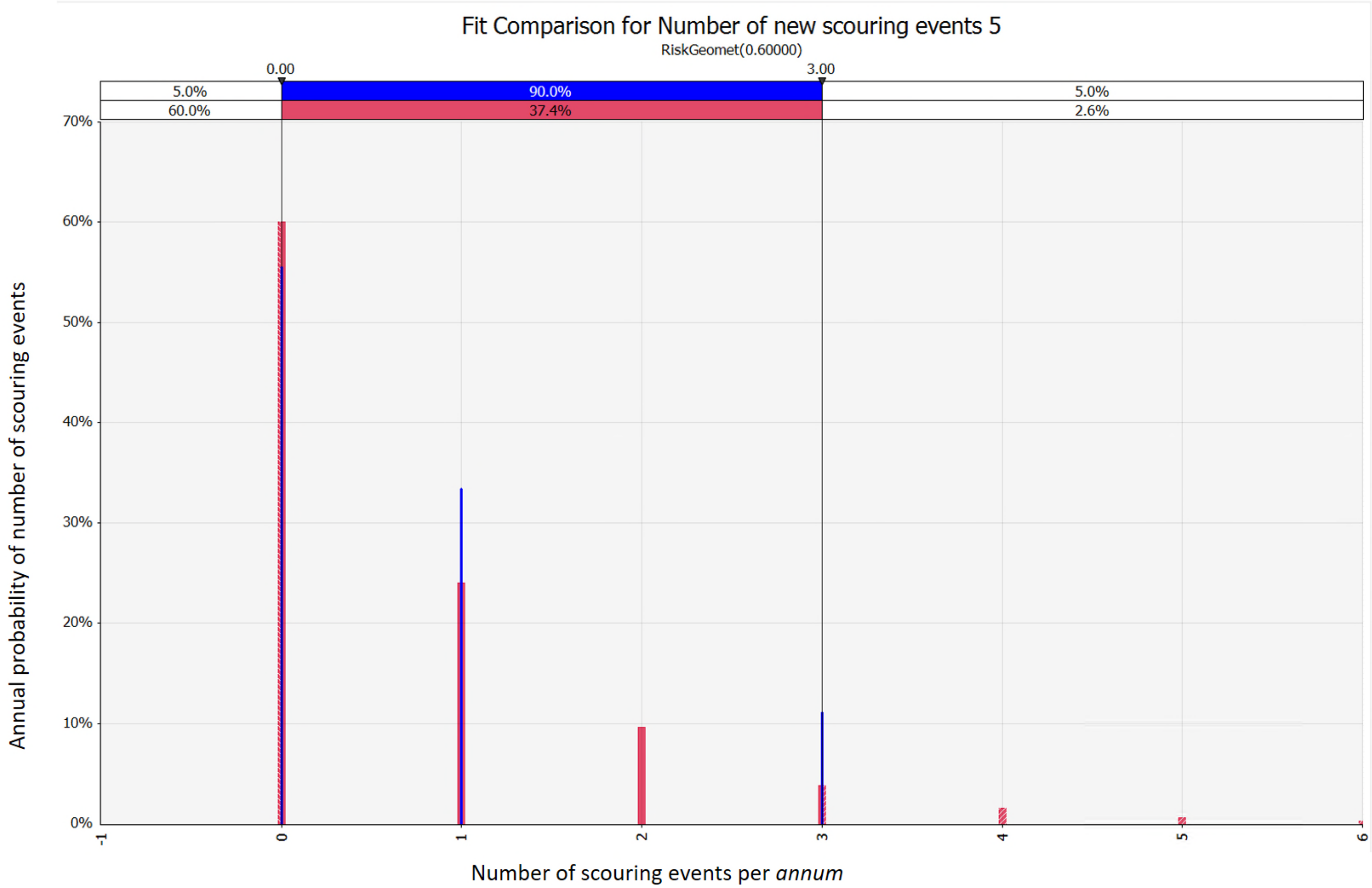


Fig. 18. Graphical comparison of best fit Geometric distribution (red) and historic data (blue) for number of scouring events per year

The PDF that best fit the length of scouring event was a determined to be an Exponential distribution (8.2833, RiskShift (3.6194)) (presented in **Fig. 19**).

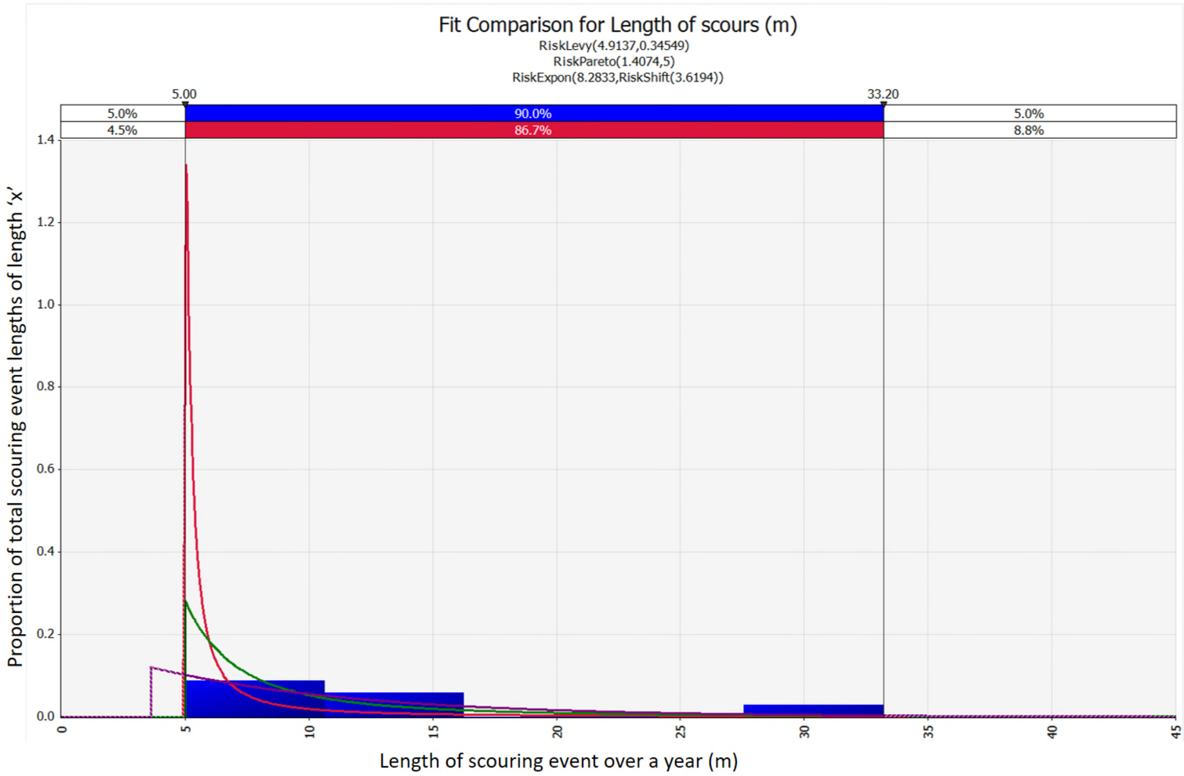


Fig. 19. Exponential PDF in purple, Pareto in green and Levy in red

An exponential distribution is a probability distribution that describes rapid growth or decline in a variable. It is useful for describing variables where there are many small values but only a few large values (or conversely where there are many large values buy only a few small values).

The exponential distribution reflected the length of scouring events well, where most scouring only growing to a small (or moderate) size and only a few reaching a large size. This PDF was not the highest ranked AIC PDF (as shown in **Fig. 20**), however the two higher ranked PDFs overestimate the likelihood of shorter scour lengths (presented in **Table 8**). Further Exponential PDF had a closer mean value to the empirical data than the other two distributions. This is reflected in a better Chi-Squared score (as shown in **Fig. 20**). A comparison of the empirical and three highest ranking PDFs (by AIC score) can be found in **Table 8**.

Rank By: AIC

	Fit	Value
☑	Levy	42.2788
☑	Pareto	43.7392
☑	Expon	47.3709
☐	ExtValue	50.6694
☐	Pearson5	51.6839
☐	Invgauss	52.0130
☐	Uniform	52.1095
☐	Logistic	52.6730
☐	Normal	52.7850
☐	Laplace	53.3954
☐	ExtValueMin	54.8898
☐	Triang	57.0403
☐	BetaGeneral	---
☐	*Gamma*	*N/A*
☐	*Kumaraswamy*	*N/A*
☐	*Loglogistic*	*N/A*
☐	*Lognorm*	*N/A*
☐	*Pearson6*	*N/A*
☐	*Weibull*	*N/A*

Rank By: Chi-Sq

	Fit	Value
☑	Expon	0.0000
☐	ExtValue	0.0000
☐	ExtValueMin	0.0000
☐	Laplace	0.0000
☑	Levy	0.0000
☐	Logistic	0.0000
☐	Normal	0.0000
☑	Pareto	0.0000
☐	Invgauss	0.0000
☐	Triang	0.3333
☐	BetaGeneral	0.3333
☐	Pearson5	0.6667
☐	Uniform	2.6667
☐	*Gamma*	*N/A*
☐	*Kumaraswamy*	*N/A*
☐	*Loglogistic*	*N/A*
☐	*Lognorm*	*N/A*
☐	*Pearson6*	*N/A*
☐	*Weibull*	*N/A*

Fig. 20. AIC and Chi-Squared score rankings of best fit distributions for the length of scouring events

Table 8: Tabular comparison of best fit distributions for the length of scouring events

Statistics Grid

	Input	Levy	Pareto	Expon
Minimum	5.000	4.9137	5.000	3.619
Maximum	33.200	+∞	+∞	+∞
Mean	13.283	N/A	17.273	11.903
Mode	≈5.705	5.0289	5.000	3.619
Median	5.400	5.6731	8.182	9.361
Std Dev	10.984	N/A	N/A	8.283
Skewness	1.4355	N/A	N/A	2.0000
Kurtosis	4.9368	N/A	N/A	9.0000
Left X	5.00	5.00	5.00	5.00
Left P	5.0%	4.5%	0.0%	15.4%
Right X	33.20	33.20	33.20	33.20
Right P	95.0%	91.2%	93.0%	97.2%
Dif. X	28.200	28.2000	28.200	28.200
Dif. P	90.0%	86.7%	93.0%	81.8%
1%	5.000	4.9658	5.036	3.703
5%	5.000	5.0036	5.186	4.044
10%	5.000	5.0414	5.389	4.492
15%	5.000	5.0804	5.612	4.966
20%	5.200	5.1241	5.859	5.468
25%	5.200	5.1748	6.134	6.002
30%	5.200	5.2353	6.442	6.574
35%	5.400	5.3092	6.790	7.188
40%	5.400	5.4015	7.188	7.851
45%	5.400	5.5191	7.646	8.571
50%	5.400	5.6731	8.182	9.361
55%	14.700	5.8806	8.818	10.234
60%	14.700	6.1700	9.588	11.209
65%	14.700	6.5916	10.542	12.315
70%	16.200	7.2407	11.762	13.592
75%	16.200	8.3165	13.389	15.102
80%	16.200	10.2964	15.690	16.951
85%	33.200	14.5735	19.248	19.334
90%	33.200	26.7929	25.674	22.692
95%	33.200	92.7768	42.014	28.434
99%	33.200	2,204.2562	131.835	41.765

These two distributions (geometric for number of scouring events per year, and exponential for the length of scouring events) were combined into a statistical model that forecast the probability of a scour event of defined lengths on Feeder 9 each year (as in **Table 9**).

Table 9: Annual probability of scouring event occurring

Scouring event	Annual probability
Any scouring event	35.71%
Once scouring has occurred, probability that scour is length:	
<20m scour	70.81%
=>55m scour	0.20%
=>20m scour	13.64%

The data model provided a representation of the probability and severity of scouring based on the historic scouring activity observed on Feeder 9 between 2009 and 2012. It cannot predict whether scouring will become more, or less, likely in the future. Nor can it predict the rate at which these scouring events will develop into free spanning events. An analysis of the relationship between free spanning and scouring was undertaken for Feeder 1 which also crosses the Humber estuary using the results of the Intertek Metoc bathymetric surveys of Feeder 1 from 2010 to 2016 (**Table 10**). The history of scouring and free spanning on Feeder 1 indicates a highly dynamic and uncertain picture, where the ratio of free spanning events to exposed sections ranges from 0.6 to 3.5. Further, free spans events were observed to be both much smaller than the parent scouring event to almost the same size (**Figure 1**).

Figure 1: Feeder 1 exposure (scouring) and free spanning bathymetric overview (2016 Intertek Metoc survey)

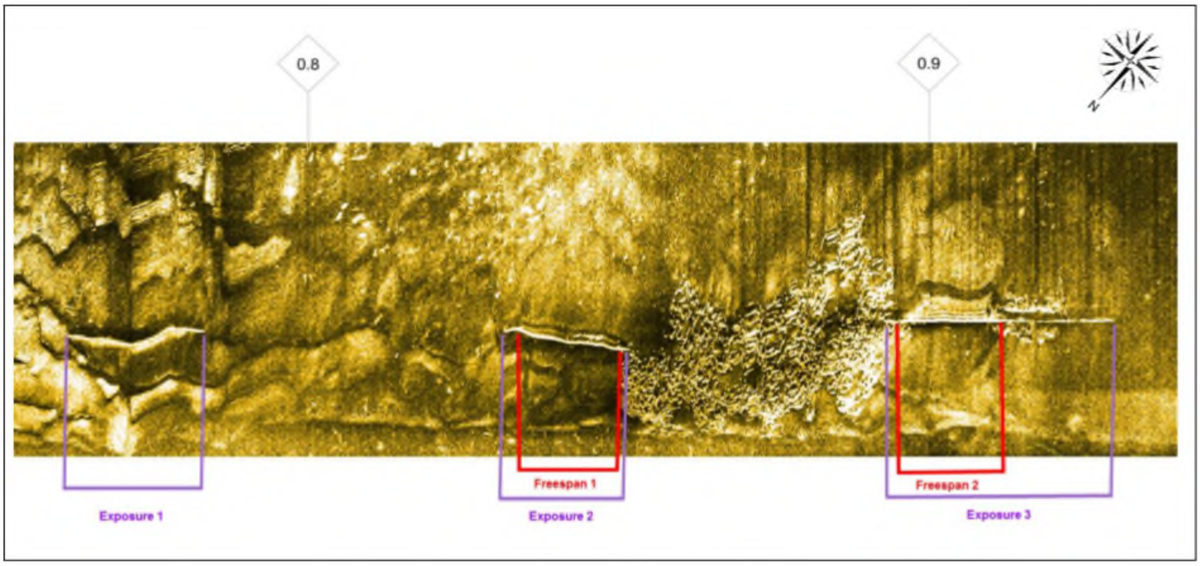


FIGURE 7: NO.1 FEEDER PIPELINE OVERVIEW (SSS)

SSS RECORD OF EXPOSED AND FREESPANNING SECTIONS. SSS SET AT 445KHZ WITH A 50M RANGE

Table 10: Feeder 1 scouring and free spanning history

Feeder 1 scouring and free spanning history					
Year	Number discrete exposures	Total exposure	Min free spans	Max free spans	Comment
2010	3	227.4	3	4	
2011	2	233.7	6	7	2 exposures combined
2012	3	200.6	6	7	
2013	2	159.8	4	5	2 exposures combined
2014	2	130.2	4	6	
2015	2	166.4	5	6	
2016	3	97.8	2	3	

Due to the small data set available and high uncertainty associated with forecasting scouring and free spanning in a dynamic and changing environment (Humber estuary) a wide range of future free spanning rates were modelled on Feeder 9. The range modelled assumes that observed scouring frequency between 2009 and 2013 is the maximum rate of free spanning that might occur over the following 53 years and at a minimum only 1 in 100 sourcing events would result in free spanning. We believe this is a reasonable range of values that reflects both the high rate of free spanning observed on Feeder 1 and the fact that to date no scouring event on Feeder 9 has resulted in free spanning. The probabilities of free spanning on Feeder 9 were therefore modelled as a range from 100 times less than the observed rate scouring up to the observed rate of scouring (as a maximum) (**Table 11**).

Table 11: Range of probabilities by free span length once a scouring event has occurred

Probability of:	Distribution*	Min probability	Max probability
<20m section of free span developing	Uniform	0.7081%	70.81%
=>55m section of free span developing	Uniform	0.0020%	0.20%
=>20m section of free span developing	Uniform	0.1364%	13.64%

*a uniform distribution assumed an equal likelihood of values between the minimum and maximum values.

Given the high level of uncertainty involved in modelling Feeder 9 scouring and free spanning a number of stress tests were run to test the model sensitivity to the impacts of free spanning. The impact of free spanning in the model are primarily:

- Loss of life
- Constraint costs due to supply interruptions/constraints
- Impact on wholesale cost of gas due to sudden supply constraint (market shock)

These impacts where reduced by 50 and 90 per cent individually and in combination (for loss of life the value of a life was tested at £3.2m, £4.8m and £6.4m).

5.3. Rupture of the pipeline

Rupture of the pipeline may be caused by both TPI events (as in paragraph **5.1. Third Party Interference**) and free spanning events (**0.**
Further loss of sediment around Feeder 9). Rupture events due to TPI and free spanning were modelled independently in the model. Whenever rupture takes place in the model, it results in:

- Capacity buy-back costs (described below in **5.3.2**)
- Wholesale gas prices impact (described below in **5.3.3**)
- Gas release impact (described below in **5.3.4**)
- Loss of gas: market value (described below in **5.3.5**)
- Loss of gas: GHGE (Greenhouse Gas Emissions) costs (**5.3.6**)
- Potential clear up costs of vessel destroyed (described below in **5.3.7**)
- Shipping lane closure after rupture (described below in **5.3.8**)
- Feeder 9 stabilisation or decommissioning (described below in **5.3.9**)
- Potential loss of life (described below in **5.3.10**)

5.3.1. Future Energy Scenarios (FES)

Future Energy Scenarios

Future Energy Scenarios are a range of credible pathways for the future of energy out to 2050. They reflect the possible sources of, and demands for, gas and electricity in the future, and the implications of this for the energy industry. The scenarios are used within National Grid for network and operability planning and developing other forward-looking views such as charging projections. They are also used across the energy industry, driving debate and decision making.

In the case of Feeder 9 isolation, Future Energy Scenarios have a significant impact on Capacity buy-back costs (**5.3.2**) as well as wholesale gas prices impact **(5.3.3**). The colour bands are used to depict the variance in Capacity buy back and wholesale cost of gas costs depending on FES scenario (presented in **Table 12**). Colour bands describing capacity buy back costs and wholesale gas prices impacts are presented in **Table 13**.

<u>There are four scenarios considered (brief description in **Fig. 21**)</u>

- Consumer Power (CP)
- Two Degrees (TG) – previously Gone Green (GG)
- Steady State (SS) – previously No Progression (NP)
- Slow Progression (SP)

		2009	2010	2011	2012	(...)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	(...)	2065	2066	2067	2068
Base Case Scenario: with Rough storage	NP*					(...)																		(...)				
	CP*					(...)																		(...)				
	GG*					(...)																		(...)				
	SP*					(...)																		(...)				

Table 12. Capacity buy-back costs depending on scenario type and time period

- (CP) - Consumer Power
- (GG) - Gone Green; in *Future Energy Scenarios July 2017* renamed to Two Degrees (TG)
- (NP) - No Progression; in *Future Energy Scenarios July 2017* renamed Steady State (SS)
- (SP) - Slow Progression

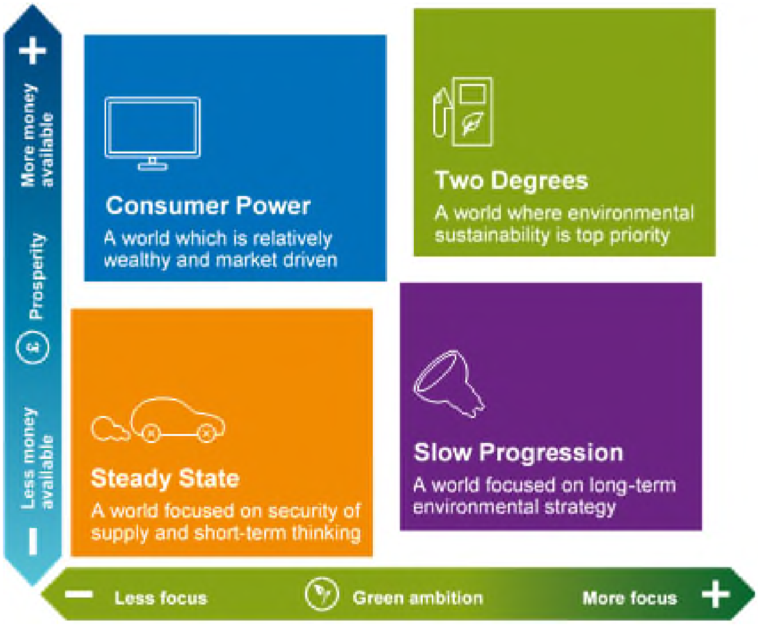


Fig. 21. Future Energy Scenarios Diagram

Full description of the scenarios can be found in *Future Energy Scenarios July 2017* document.

Table 13. Capacity buy-back costs and whole sale gas prices impact depending on scenario type

	Scenarios	Constraint buyback Cost - Mod agreed in 3 days	Constraint buyback Cost - Mod agreed in 7 days	Mod Costs	Mod Probabilities	Gas price impact
Winter	Amber	£0.00	£0.00	As per constraint decision tree	75% low case 25% mid case	£0.00
Summer	Amber	£0.00	£0.00	As per constraint decision tree	75% low case 25% mid case	£0.00
Winter	Green	3-day prompt buyback Day 1 @ 1p p/kWh Day 2 @ 5 p/kWh Day 3 @ 10 p/kWh = £44.8m	7 day prompt buyback Day 1 @ 1 p/kWh Day 2 @ 5 p/kWh Day 3-7 @ 10 p/kWh = £156.8 m	As per constraint decision tree	25% low case 65% mid case 10% High Case	25p/thm increase for 1 month 2p/thm increase for the remainder of the F9 outage
Summer	Green	£0.00	1-day prompt at 1p/kwh = £2.8m	As per constraint decision tree	25% low case 65% mid case 10% High Case	2 p/thm increase for remainder of F9 outage

5.3.2. Capacity buy-back costs

Isolation of the pipeline due to rupture or severe damage results in capacity buy-back costs. General rules for calculating the costs are presented in diagrams and assumptions provided by National Grid and included in **Appendix C**. As described in paragraph **5.3.1. Future Energy Scenarios (FES)** , **Table 13** presents Capacity buy back costs grouped into colour bands. **Table 12** uses the aforementioned colour bands to depict costs depending on FES scenarios. Assumption was made that each of the FES scenario is equally likely, therefore average costs were used in the models.

5.3.3. Wholesale gas prices impact

National Grid provided the impact of losing Feeder 9 on UK wholesale gas prices. The wholesale gas price increases were based on analysis of historic supply loss events and are presented in **Table 13** (impacts were grouped into colour bands indirectly representing different FES scenarios). As per **5.3.3**, the assumption was made that each of the FES scenarios is equally likely, therefore average costs were used in the models, **Table 12** was used as a timing reference. Example of the impact depicts **Fig. 22**. below. The length of outage was determined by the expected time for a replacement or a repair to be complete. When construction of a replacement was under way the remaining construction time was used, when no construction of a replacement was under way then the best case construction plus DCO time was used. The time to repair was as per **paragraph 5.8**.

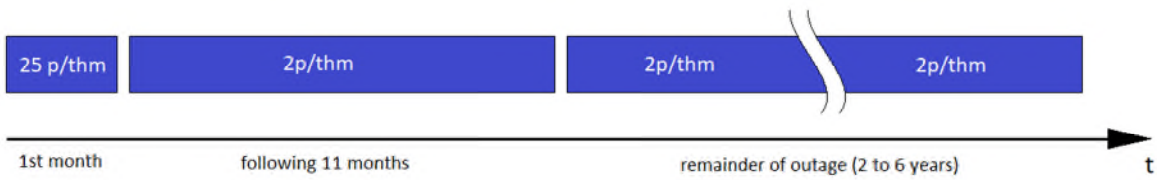


Fig. 22. Example of wholesale gas price impact

Table 14 presents calculated averages of unit costs per Therm,

Table 15 presents total sums of the wholesale gas prices impact for each of the scenario for given years. These costs were then incorporated into the models as per **Table 16** (Mitigate 2016 and Mitigate 2017 scenarios) and **Table 17** (Trench (2012), Trench (2016), Tunnel (2012) scenarios). Note that the costs were spread over the appropriate number of years to ensure that the correct cost of capital was applied. For example, a risk event in year 1 triggers costs representing the increase in wholesale cost of gas in years 1 through 6.

Table 14. Wholesale gas prices impact (unit prices per duration)

Time range	Duration		
	1st month	next 11 months	Remainder of outage
2009-2024	25.0p/thm	2.0p/thm	2.0p/thm
2025-2033	18.75p/thm	1.5p/thm	1.5p/thm
2034-2068	18.75p/thm	1.5p/thm	1.5p/thm

Table 15. Wholesale gas prices impact (total sums per duration)

Time range	Total Duration of Outage		
	2.4 years	3 years	6 years
2009-2024	£689,380,896.00	£829,249,202.00	£1,563,190,840.00
2025-2033	£517,035,672.00	£621,936,901.50	£1,172,393,130.00
2034-2068	£517,035,672.00	£621,936,901.50	£1,172,393,130.00

Table 16. Wholesale Gas Prices Impact for Mitigate Scenarios – EO input for Mitigate scenarios

	Mitigate (2016)		Mitigate (2017)	
year	cost	Incurred for:	cost	Incurred for:
2009	260,531,806.67	6 years	260,531,806.67	6 years
2010	260,531,806.67	6 years	260,531,806.67	6 years
(…)	260,531,806.67	6 years	260,531,806.67	6 years
2015	260,531,806.67	6 years	260,531,806.67	6 years
2016	260,531,806.67	6 years	276,416,400.67	3 years
2017	260,531,806.67	6 years	344,690,448.00	2 years
2018	260,531,806.67	6 years	344,690,448.00	2 years
2019	260,531,806.67	6 years	276,416,400.67	3 years
2020	260,531,806.67	6 years	260,531,806.67	6 years
2021	260,531,806.67	6 years	260,531,806.67	6 years
(…)	260,531,806.67	6 years	260,531,806.67	6 years
2024	260,531,806.67	6 years	260,531,806.67	6 years
2025	195,398,855.00	6 years	195,398,855.00	6 years
2026	195,398,855.00	6 years	195,398,855.00	6 years
(…)	195,398,855.00	6 years	195,398,855.00	6 years
2033	195,398,855.00	6 years	195,398,855.00	6 years
2034	195,398,855.00	6 years	195,398,855.00	6 years
2035	195,398,855.00	6 years	195,398,855.00	6 years
(…)	195,398,855.00	6 years	195,398,855.00	6 years
2068	195,398,855.00	6 years	195,398,855.00	6 years

Table 17. Wholesale Gas Prices Impact for Trench and Tunnel Scenarios – EO input for Trench and Tunnel scenarios

	Trench (2012)		Trench (2016)		Tunnel (2012)	
year	cost	Incurred for:	cost	Incurred for:	cost	Incurred for:
2009	260,531,806.67	6 years	260,531,806.67	6 years	260,531,806.67	6 years
2010	260,531,806.67	6 years	260,531,806.67	6 years	260,531,806.67	6 years
(...)	260,531,806.67	6 years	260,531,806.67	6 years	260,531,806.67	6 years
2015	260,531,806.67	6 years	260,531,806.67	6 years	260,531,806.67	6 years
2016	276,416,400.67	3 years	260,531,806.67	6 years	276,416,400.67	3 years
2017	344,690,448.00	2 years	276,416,400.67	3 years	344,690,448.00	2 years
2018	402,138,856.00	1 year	344,690,448.00	2 years	402,138,856.00	1 year
2019	114,896,816.00	<1 year	402,138,856.00	1 year	114,896,816.00	<1 year
2020	260,531,806.67	6 years	114,896,816.00	<1 year	0	–
2021	260,531,806.67	6 years	260,531,806.67	6 years	0	–
(...)	260,531,806.67	6 years	260,531,806.67	6 years	0	–
2024	260,531,806.67	6 years	260,531,806.67	6 years	0	–
2025	195,398,855.00	6 years	195,398,855.00	6 years	0	–
2026	195,398,855.00	6 years	195,398,855.00	6 years	0	–
(...)	195,398,855.00	6 years	195,398,855.00	6 years	0	–
2033	195,398,855.00	6 years	195,398,855.00	6 years	0	–
2034	195,398,855.00	6 years	195,398,855.00	6 years	0	–
2035	195,398,855.00	6 years	195,398,855.00	6 years	0	–
(...)	195,398,855.00	6 years	195,398,855.00	6 years	0	–
2068	195,398,855.00	6 years	195,398,855.00	6 years	0	–

5.3.4. Gas release impact

Gas release was associated with two significant types of costs. The first cost was associated with a monetised market value of the lost gas. The second cost was associated with gas released into atmosphere and its effect on the environment – Greenhouse Gas Emissions (GHGe).

Two scenarios of gas release were modelled:

1. Due to pipe rupture (caused by either a TPI event or free spanning and subsequent vortex-induced vibration)
2. Due to controlled venting of the pipeline (should the need for repair and emptying the pipeline arise).

5.3.5. Loss of gas: market value

Costs associated with loss of gas market value for three possible scenarios of gas release are presented in **Table 18**.

Assumptions:

1. Summer and winter scenarios are equally likely – simple averages were used.
2. Pipe rupture scenario assumes that each of the three scenarios relating to valve closure times are equally likely due to unknown response time when rupture occurs – simple averages were used.
3. Controlled venting scenario assumes **Valves closed in 5 min** scenario.

Final averages used in the model are presented in **Table 19**.

Table 18. Costs of gas market value loss

		Valves closed in 5 min	Valves Closed in 30 min	Valves closed in 120 min
Volume	mcm	0.3485	2.0410	8.1680
CV	MJ/m3	39.6000	39.6000	39.6000
Energy	kWh	3833500.0000	22451000.0000	89848000.0000
Energy	thm	130804.0000	766060.0000	3065742.0000
Summer 17 Price	p/thm	37.5940	37.5940	37.5940
Winter 17 Price	p/thm	45.9250	45.9250	45.9250
Summer Cost		**£49,175.00**	**£287,993.00**	**£1,152,535.00**
Winter Cost		**£60,072.00**	**£351,813.00**	**£1,407,942.00**

Table 19. Loss of gas market value used in EO

	Pipe Rupture	Vented pipeline
Valves closed in 5 min (summer)	£49,175.00	£49,175.00
Valves Closed in 30 min (summer)	£287,993.00	–
Valves closed in 120 min (summer)	£1,152,535.00	–
Valves closed in 5 min (winter)	£60,072.00	£60,072.00
Valves Closed in 30 min (winter)	£351,813.00	–
Valves closed in 120 min (winter)	£1,407,942.00	–
Sum:	**£3,309,530.00**	**£109,247.00**
Total Average:	**£551,588.33**	**£54,623.50**

5.3.6. Loss of gas: GHGe costs

The below summarises the assumptions and calculations for both scenarios. Final values used in the model are presented in **Table 20**.

Assumptions:

1. Average release of gas (5min, 30min and 120min valve closures) = 3.519 mcm (10e6 m3)
2. Density of natural gas = 0.73 kg/m3
3. Density of CO_2 = 1.98 kg/m3
4. Minimum release of gas = 0.3485 mcm
5. Multiplier for GHG impact of methane, relative to CO_2 = 25 (te/te)
6. Pipe Rupture scenario – it was assumed that the gas always combusts therefore $C0_2$ is released to atmosphere
7. Controlled venting scenario – methane is released to atmosphere

Calculations:

1. Pipe rupture scenario: 3.519 mcm of CO2 (density 1.96 kg/m3), or 6.897 10e6 kg (6,897 te). At £59/te, cost impact is **£0.407m**
2. Vented pipeline – 0.3485 mcm or 0.254 10e6 kg or 254 te of methane is released to atmosphere. This has an equivalent GHGe of 25 x 254 = 6,350 te CO2e. Cost is 59 x 6350 = **£0.375m**

Table 20. GHGe costs used in the model

Costs	Pipe Rupture	Vented pipeline
Loss of Gas: GHGe costs	£407,000.00	£375,000.00
	Assumption: gas always combusts, we only consider CO2 release	*Assumption: gas does not combust, methane is released to atmosphere*

5.3.7. Clear up costs

'Clear up costs' represented the cost of recovering and cleaning up a potential shipwreck which may be a consequence of pipeline rupture, ignition, and subsequent sinking of the vessel. Clear up costs were taken from publicly available costs for vessels of a similar size to those using the Humber.

Assumption:
Mean value of clear up costs = £241,666,667 (based on Safety and Shipping Review, Allianz, 2015)

5.3.8. Shipping lane closure

If rupture occurred, an exclusion zone that would prevent vessels from navigating the Humber would need to be placed around the pipeline. It's likely that the closure of the shipping lane would be relatively short. However, if there was uncertainty around the integrity of the pipeline, e.g. part of the pipeline or frond mattresses had broken free, the harbour master may see fit to leave the exclusion zone in place until the pipeline can be made safe.

Assumption:

Shipping lane closure = £8,500,000.00 (based on costs provided by the Humber Harbour Master, as agreed with National Grid)

5.3.9. F9 stabilisation or decommissioning

Assumption:

Pipeline decommissioning costs were provided by National Grid. For more details on different options and detailed costs please see the Feeder 1 Decommissioning Report.

Feeder 9 decommissioning costs = £ 1,885,000.00 (As per the Humber Estuary pipeline Decommissioning Study (2011))

5.3.10. Casualties due to rupture and cost of a life

Where rupture is caused by a ship or anchor strike (TPI) there is a possibility that the resulting release of gas will reach the surface where it will ignite potentially causing causalities in any ship passing overhead. The number of expected casualties resulting from such an event was provided by the DNV GL Quantitative Risk Assessment (QRA). The QRA considered both the likelihood of the pipeline rupturing due to TPI and the likelihood of ships of different sizes passing overhead based on historic vessel traffic on the Humber. The report defined a best and worst-case scenario based on ships carrying 155 and 1506 crew and passengers respectively. The number and probability of casualties derived from the DNV GL report are show in **Table 21**. The probability of gas ignition derived from the DNV GL report is between 0.1169 and 0.8197.

Table 21: Number, frequency and probability of possible casualties from catastrophic rupture of pipeline.

Probability and Number of Casualties for Base and Worst Cases			
Number of Casualties as a range	Probability	Expected number of casualties (base case)	Expected number of casualties (worst case)
1<N<8	0.00007028	0.00028112	0.00028112
8<N<20	0.00000255	0.00002040	0.00002040
20<N<70	0.00000845	0.00016900	0.00016900
70<N<100	0.00000281	0.00019670	0.00019670
100<N<190	0.00000020	0.00002000	0.00002000
190<N<300	0.00000012	0.00002280	0.00002280
300<N<1000	0.00001397	0.00216535	0.00216535
1000<N<	0.00001397	0.00000000	0.01397000

To monetise the impact of life lost due to pipeline rupture, a **disproportionate factor of 10** was used taking the base value of a life, **£1.6m**, to **£16m**. This is in line with the monetised asset risk methodology developed for gas distribution and electrical transmission (**Table 22**). This reflects lower public willingness to accept the risk of death due to gas distribution and electrical transmission. However, as the latest Network Output Measures (NOMs) methodology is still being developed and a disproportionate factor of 3-4 is being consider, a range of lower values of life were tested in the stress test scenarios.

Table 22: Disproportionate factors for cost of life

Industry	Disproportionate Factor
Electricity Transmission / Gas Distribution Networks	10
Electricity Distribution	6.25
Water industry	1
Highways / Rail	1

5.4. Discount factor used and NPV calculation overview

All costs calculated by the model were discounted using Net Present Value approach across 60 years. Discount factor was derived from the Green Book.

Assumptions:

A discount factor of 3.5% was used to represent the time value of money in the model and to derive a NPV for each scenario. This was chosen as it is the value suggested by the UK Treasury Green Book. The Green Book outlines UK central government advice and recommendations on project and scheme appraisal and informs other government departments such as Ofgem.

Calculations:

The EO's NPV Analysis tables were used to calculate NPV. NPV was calculated from "Free Cash Flow" consisting of cash flow from operations minus net investments (purchases less proceeds from the sale of assets). All costs and monetised risk impacts where debited from the "Free Cash Flow" account and therefore included in the NPV calculation. The "Free Cash Flow" in each time period was discounted back to the present value in the appropriate discount rate. The horizon value of each scenario (net present value of cash in last time period) was calculated using the perpetuity method. The perpetuity method takes the free cash flow from the last time period of a model and assumes that it continues in perpetuity beyond the time horizon of the model. There is also a provision for specifying a growth rate for the last period free cash flow. The horizon value is then discounted back to present value using the appropriate discount rate.

5.5. Construction costs

5.5.1. Tunnel (2012) scenario construction costs

Total costs for replacing Feeder 9 (including DCO, MWC and construction costs) were spread across 52 years. All costs were set at 2015/2016 price base. Discrete values for each year (modelled as separate time period in EO) were provided by National Grid. However, values were given only for the base case scenario, that is Feeder 9 replacement is successful and costs have neither increased not decreased. For two other agreed scenarios (Feeder 9 replacement is successful and costs increased and Feeder 9 replacement is successful and costs decreased) the costs were calculated as a ratio to base case provided by National Grid. The rationale was based on initial costs provided by National Grid (P50, P20 and P80 values taken from Sanction Paper *GTIC0264 - PAC2260 - Feeder 9 signed* document). The likelihood of the project being under, on or over budget was based on National Grid past performance on delivering large construction and engineering projects. All costs used in the model are presented in **Appendix D.**

Table 23. Ratios applied to calculate F9 replacement costs

Initial Costs		
F9 Replacement Successful (P50 value)	**F9 replacement successful costs increased (P80 value)**	**F9 replacement successful costs decreased (P20 value)**
£181,717,000.00	£192,500,000.00	£177,500,000.00
Ratio with reference to previous base case		
F9 Replacement Successful (P50 value)	**F9 replacement successful costs increased (P80 value)**	**F9 replacement successful costs decreased (P20 value)**
1.0000	1.0593	0.9768

5.5.2. Trench (2012) and Trench (2016) scenarios construction costs

Construction cost

Construction cost equals £96.5m (2013 price base) based on figure provided in Route Corridor Investigation Study.

Construction duration:

- 90 days enabling works
- 112 days trench crossing
- 390 days commissioning, decommissioning and physical close out

Total duration: 592 days or 1.62 years (19 months)

Total construction cost: £102,320,698 (2015/16 price base)

DCO costs

DCO cost was approx. £5m for tunnel option & 16 months duration. The trench option would take approx. an additional 18 months of DCO duration so 34 months in total. The trench DCO costs would be approx.:

- £5m for 16 months DCO work (April 15 to August 16 – 2015/16 price base as per tunnel DCO application costs)
- £0.5m for additional boat surveys associated with the trench option
- An additional 18 months of DCO costs pro rata from the £5m 16 months tunnel DCO cost

In total: £11,125,000in 2015/16 price base (same price base as £181m tunnel sanctioned P50 value)

Total cost of trenching and DCO was provided by National Grid in tabular format (*Summary of MAR impact for Feeder 9 Options* excel spreadsheet). Due to the costs being from 2009/2010, they were multiplied by 1.228 factor to account for the inflation. Value of the factor was agreed with National Grid. **Appendix E** depicts the costs used for Tunnel (2012) and Tunnel (2016) scenarios.

Compensatory land costs:

In order to offset the environmental impact of trench construction on the estuary shoreline we have assumed that an equivalent area of land will need to be rented during the construction phase. This assumption was based on the DCO requirements concerning compensatory land for the Able Logistics Park development on the Humber Estuary which was granted a DCO in December 2013. The model assumed the leased land will cost £1.25m2 (£12.35k per hectare), so working on a notional 20.23 acres, compensatory land costs of **£250k/year** were applied. This would be paid as an annual rent to the relevant land owner out of the project cost code.

5.6. Maintenance costs

5.6.1. Tunnel (2012) scenario maintenance costs

Prior to completion of the Bored Tunnel, the existing Feeder 9 would continue to undergo regular Pipeline Inspection Gauge monitoring (PIGing) and bi-monthly boat inspections. Cost of PIGing equals £249000 for 1 in 15 years. Annualized cost of PIGing and boat inspection costs are presented below in **Table 24**.

Table 24. Maintenance costs of existing Feeder 9

remediation	cost per annum
regular PIGing	£16,600.00
bi-monthly inspection	£351,240.00

After completion of the Bored Tunnel, the new tunnel would undergo regular PIGing and other maintenance, while existing Feeder 9 (after decommissioning) would undergo regular inspections. Annual maintenance costs of new Tunnel and Feeder 9 inspections, both provided by National Grid, presents **Table 25**.

Table 25. Maintenance costs after completion of Bored Tunnel

remediation	cost per annum
Tunnel pipeline annual maintenance	£55,750.00
F9 ongoing inspection	£17,625.00

5.6.2. Trench (2012) and Trench (2016) scenarios maintenance costs

Prior to completion of the Bored Tunnel, the existing Feeder 9 would continue to undergo regular PIGing and bi-monthly boat inspections. Costs of these are presented in **Table 24** above (paragraph **5.6.1**). After completion of the Trench, the new pipeline must also undergo regular PIGing and quarterly boat inspections. Cost of PIGing equals £249000 for 1 in 15 years. Annualized cost of PIGing and boat inspections are presented in **Table 26**.

Table 26. Maintenance costs after completion of Trench

remediation	cost per annum
Regular PIGing	£16,600.00
Quarterly inspection of new Trenched Pipeline	£175,620.00
F9 ongoing inspection	£17,625.00

It was assumed that environmental aftercare costs would last 10 years after completion of the Trench. The costs were estimated based on previous costs paid on National Grid projects:

- Milford Haven (300km, working width 41m = 1230 hectares) - £14.5M aftercare costs
- Sapperton (40km, working width 35m = 140 hectares) - £0.5M aftercare costs

Midpoint between the two above schemes is £7.6k per hectare. The Feeder 9 construction area is approx. 20 hectares (based on crossing options report).

20 hectares x £7.6k = **£152k for the 10 years** or **£15.2k a year** in aftercare costs

5.7. Sunk costs

Sunk costs were modelled in scenarios that included abortive costs, for example where an option was abandoned for another option after investment was incurred.

5.7.1. Trench (2016) scenario

In this scenario sunk costs up to the end of April 2016 were modelled and equal **£15,539,819.07**. They consist of tunnel DCO and pre- works costs for the tunnel option.

5.7.2. Mitigate (2016) scenario

In this scenario sunk costs up to the end of April 2016 were modelled and equal **£15,539,819.07**. They consist of tunnel DCO and pre- works costs for the tunnel option.

5.7.3. Mitigate (2017) scenario

In this scenario sunk costs to the end of June 2017 were modelled. They consist of:

- Costs incurred with regards to construction works at the end of June 2017 = £44,324,116.60
- Cancellation costs (TBM, STP, Pipe = £729,562.77, £1,803,940.09, £1,616,906.44 = £4,150,409.30
- Reinstatement (between £1.5m & £2m –depending on how far the project has progressed and the works carried out – this is an estimate)

<u>Total sunk costs up to June 2017</u> = **£50,474,524.9 (£50m)**

5.8. Repair options

The study by Intertek *(Emergency Repair Report_Feeder 9_P1816_R3964_Rev1* document) determined the response time and cost for affecting a repair to the pipeline in the estuary crossing using a hinged half-shell clamp for the repair of localised damage and mechanically connected replacement spool for more extensive damage. Probabilities of remediation depending on damage type were agreed with National Grid.

<u>Assumptions:</u>

1. Remediation and costs for corresponding types of damage are presented below in **Table 27**.

Table 27. Damage types, costs, and remediation

Damage	Repair	Cost (£M)	Total duration (weeks)
Localised mechanical/impact damage	Repair clamp	**2.61**	**48**
Localised failure	Short replacement spool	**12.60**	**69**
Extensive failure over pipeline span	Long replacement spool	**18.14**	**75**

2. Probabilities of remediation depending on damage type are presented below in **Table 28**.

Table 28. Probabilities of remediation depending on damage type

Scenario	Remediation / Damage	Probability
isolate F9 and repair (after **MINOR DEFECT** found)	Repair clamp (Localised mechanical/impact damage)	**0.90**
	Short replacement spool (Localised failure)	**0.05**
	Long replacement spool (Extensive failure over pipeline span)	**0.05**
isolate F9 and repair (after **MAJOR DEFECT** found)	Repair clamp (Localised mechanical/impact damage)	**0.60**
	Short replacement spool (Localised failure)	**0.30**
	Long replacement spool (Extensive failure over pipeline span)	**0.10**

5.9. Loss of lease

If the harbour port authority removed the licence to operate a pipeline across the Humber the process would be slow and subject to legal challenge. Therefore, it was assumed that gas markets would have time to adjust and there would be no impact on the wholesale cost of gas. The impact of loss of lease would be a requirement to decommission the current pipeline and then either replace with a tunnelled pipeline or operate the network without a pipeline crossing the Humber.

The probability of the Humber Ports Authority removing the licence to operate a pipeline across the Humber was provided by NGGT based on their expert opinion. The probability was estimated to be between 0.01% and 10% per year. This was modelled as a uniform distribution in the model (**Table 28**), therefore in each iteration of the Monte Carlo a random probability between 0.01% and 10% is selected.

Table 29: Probability of loss of lease

Probability of:	Distribution	Min	Max
Notice given on lease to operate pipeline across Humber	Uniform	0.0001	0.1

5.10. Frond mattresses installation

Routine replacement costs:

Costs and their corresponding probabilities of the Frond Mattresses equals (as agreed with National Grid):

- Minimum Frond Mattresses cost = £1,029,000 (80% probability)
- Maximum Front Mattresses cost = £7,650,000 (20% probability)

Therefore, the weighted average (80-20) of the cost equals:

- **Routine Frond mattresses installation** = (1,029,000 *0.8 + 7,650,000 * 0.2) = £2,353,200

Routine replacement frequency:

There is an uncertainty around frequency of replacing the frond mattresses. It was assumed that front mattresses require replacing once in 1 to 10 years.

Costs of re-instating frond mattresses after they have moved

After boat survey and/or diver inspection finds that front mattress requires re-instatement due to movement, a cost of re-instating them is incurred in the model (described below).

Cost of re-instating frond mattresses: £1,029,000.00 - as agreed with National Grid, based on value for previous remediation of 50m

5.11. Increased survey costs

After routine boat survey confirms that further loss of sediment around Feeder 9 happened, this would result in increased frequency of the surveys and would cost:

increase survey frequency cost= **£351,240**

6. Results

6.1. Monte Carlo results

All modelled scenarios were as described in paragraph **2.7. Intervention scenarios considered**. In addition, models were run as Monte Carlo simulation as described in paragraph **4. Monte Carlo simulation overview**.

The results are presented in various formats. Total average NPV values for all five Monte Carlo Simulations, as well as Tunnel Scenario benefit in relation to other options modelled, are represented in tabular form (**Table 30**).

Table 30. Total averaged NPV values for all scenarios

Scenario Full Name	Scenario Name	Average of Total Net Present Value	Tunnel benefit vs Option:
Tunnel Replacement start in 2012	Tunnel (2012)	-£214,029,081.78	£0.00
Trench Replacement start in 2012	Trench (2012)	-£266,646,930.94	£52,617,849.16
Stop Tunnel 2016 and Build Trench	Trench (2016)	-£279,824,004.06	£65,794,922.28
Stop Tunnel 2016 and Mitigate	Mitigate (2016)	-£291,646,132.97	£77,617,051.19
Stop Tunnel and Mitigate from 2017	Mitigate (2017)	-£312,480,545.52	£98,451,463.74

Average NPV of each individual year by scenario type and year are shown in **Fig. 23** (with description) and **Fig. 24** (without description). The annual NPV of the top 3 options is shown on **Fig. 25**. The Average Cumulative NPV by scenario type and year, presented in a form of a line graph, is shown on **Fig. 26**.

For a better representation of the Monte Carlo simulations results box plots were created. These visualise the range of uncertainty modelled for each of the scenarios, description of the box plot depicts **Fig. 27**. Collectively, they are represented in **Fig. 28**.

Aggregated costs and monetised risk (grouped into cost areas) modelled over the 60 years are presented as a column chart in **Fig. 29**. The cost areas' components are presented in **Table 32**. Cost areas split into detailed costs and monetised risk (Cost Centres) are presented in **Fig. 29**, **Fig. 30** and **Fig. 31**. The Cost Centre' components are presented in **Table 31**.

Fig. 32 provides an indication of how the costs might be split between those that would directly affect National Grid customers (UK tax payers and consumers of gas are included as an indirect customer here) and costs that would be incurred directly by National Grid without pass-through to customers or UK tax payers. All the values are presented in tabular form as **Appendix F**. Note that values are not adjusted for time.

To compare results side-by-side tornado charts are used. Comparison between Tunnel (2012) and Mitigate (2016) scenarios was presented on **Fig. 33**, while **Fig. 34** presents differences between Tunnel (2012) and Trench (2012) scenarios.

To illustrate relative contribution of certain costs waterfall charts are sued. Main costs and monetised risks across all scenarios are presented on waterfall chart in **Fig. 35**, and for top 3 scenarios in **Fig. 36**.

Events of very low annual frequency and high impact are presented as an average annual frequency, impact per unit and average Total Expected Value (over 60 years) in the form on bar chart (**Fig. 37**).

<u>To sum up, across all scenarios modelled Tunnel Replacement in 2012 Scenario appears the most optimal option in terms of NPV value, i.e. has the lowest negative value of NPV.</u>

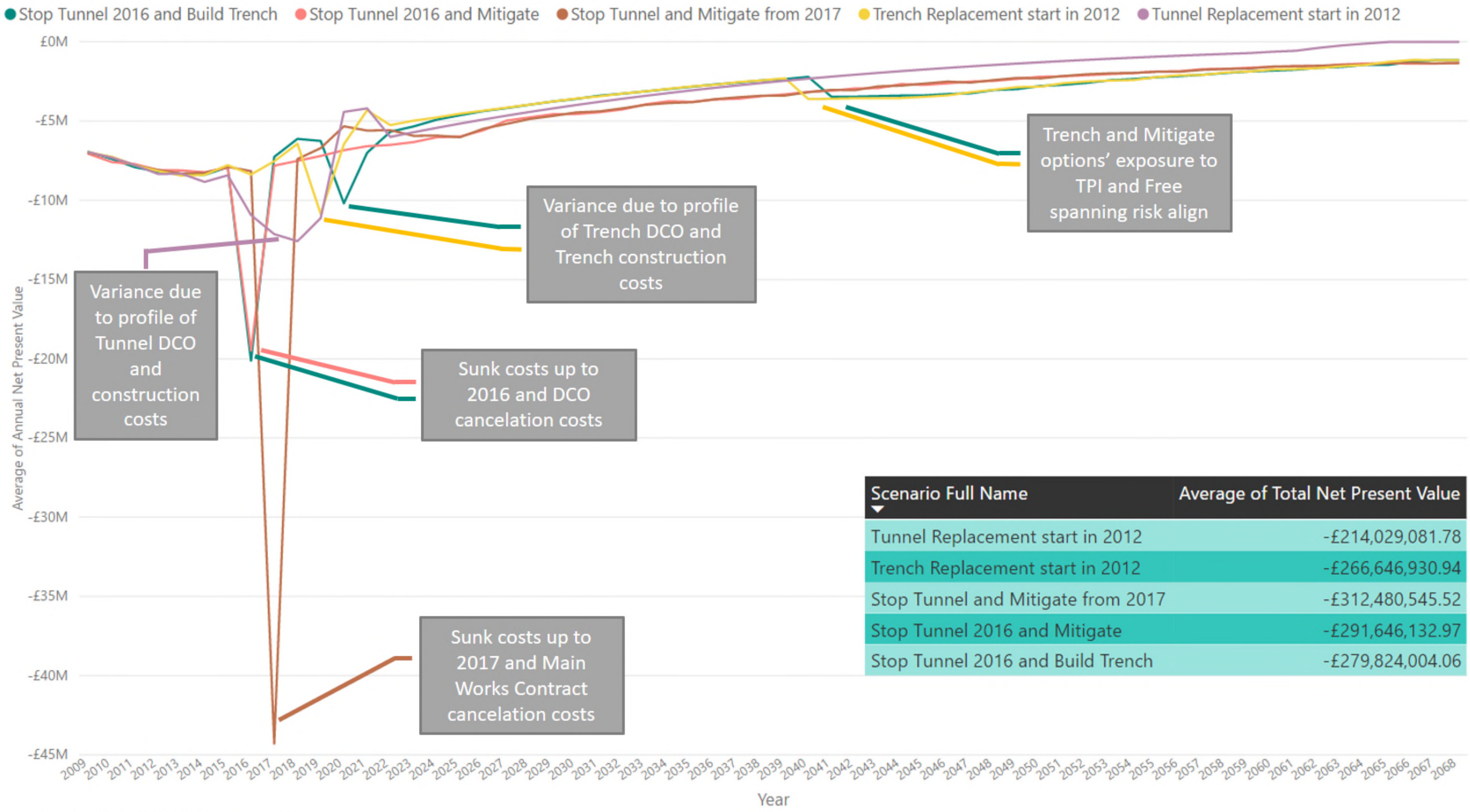
Table 31: Cost Centre Components and Costs

<table>
<tr><th>Cost Centre</th><th>Cost Centre Component Costs</th></tr>
<tr><td rowspan="2">Capacity buy-back</td><td>Short term capacity buy-back</td></tr>
<tr><td>Long term capacity buy-back</td></tr>
<tr><td rowspan="2">Construction costs</td><td>Bored Tunnel construction costs</td></tr>
<tr><td>Trench construction costs</td></tr>
<tr><td>Damage due to TPI or Freespanning</td><td>Costs of repairs due to TPI or Freespanning</td></tr>
<tr><td rowspan="6">Direct Impacts of Rupture (loss of life etc.)</td><td>Damage to ships and life</td></tr>
<tr><td>Damaged ship clear up costs</td></tr>
<tr><td>incident management costs</td></tr>
<tr><td>reputational damage</td></tr>
<tr><td>share price reduction</td></tr>
<tr><td>shipping lane closure</td></tr>
<tr><td>Emergency isolation and replacement</td><td>costs of emergency isolation and building a replacement</td></tr>
<tr><td>F9 stabilisation or decommissioning</td><td>Feeder 9 stabilisation or decommissioning costs</td></tr>
<tr><td>Increase in wholesale gas prices</td><td>Increase in wholesale gas prices</td></tr>
<tr><td rowspan="4">Loss of gas</td><td>Loss of vented gas (GHGe) due to repair of F9</td></tr>
<tr><td>Loss of vented gas market value due to repair of F9</td></tr>
<tr><td>Loss of ruptured Gas (GHGe) due to rupture of F9</td></tr>
<tr><td>Loss of ruptured gas market value due to rupture of F9</td></tr>
<tr><td rowspan="10">Operational and Maintenance Costs</td><td>Feeder 9 ongoing inspection after completion of Bored Tunnel</td></tr>
<tr><td>Annual maintenance costs of Bored Tunnel</td></tr>
<tr><td>Annualized cost of replacing frond mattresses</td></tr>
<tr><td>Diver inspection and boat survey costs</td></tr>
<tr><td>Increased survey frequency costs</td></tr>
<tr><td>Ad hoc diver inspections</td></tr>
<tr><td>Costs of installing additional mattresses and gravel bags</td></tr>
<tr><td>Routine bi-monthly inspection of Feeder 9</td></tr>
<tr><td>Annualized costs of Regular PIGGING</td></tr>
<tr><td>Cost of additional PIG inspection</td></tr>
<tr><td>Sunk Costs and Cancellation Costs</td><td>Sunk Costs and Cancellation Costs</td></tr>
<tr><td rowspan="2">Trench Environmental Costs</td><td>Aftercare costs</td></tr>
<tr><td>Compensatory land costs</td></tr>
</table>

Table 32: Cost Area Components and Costs

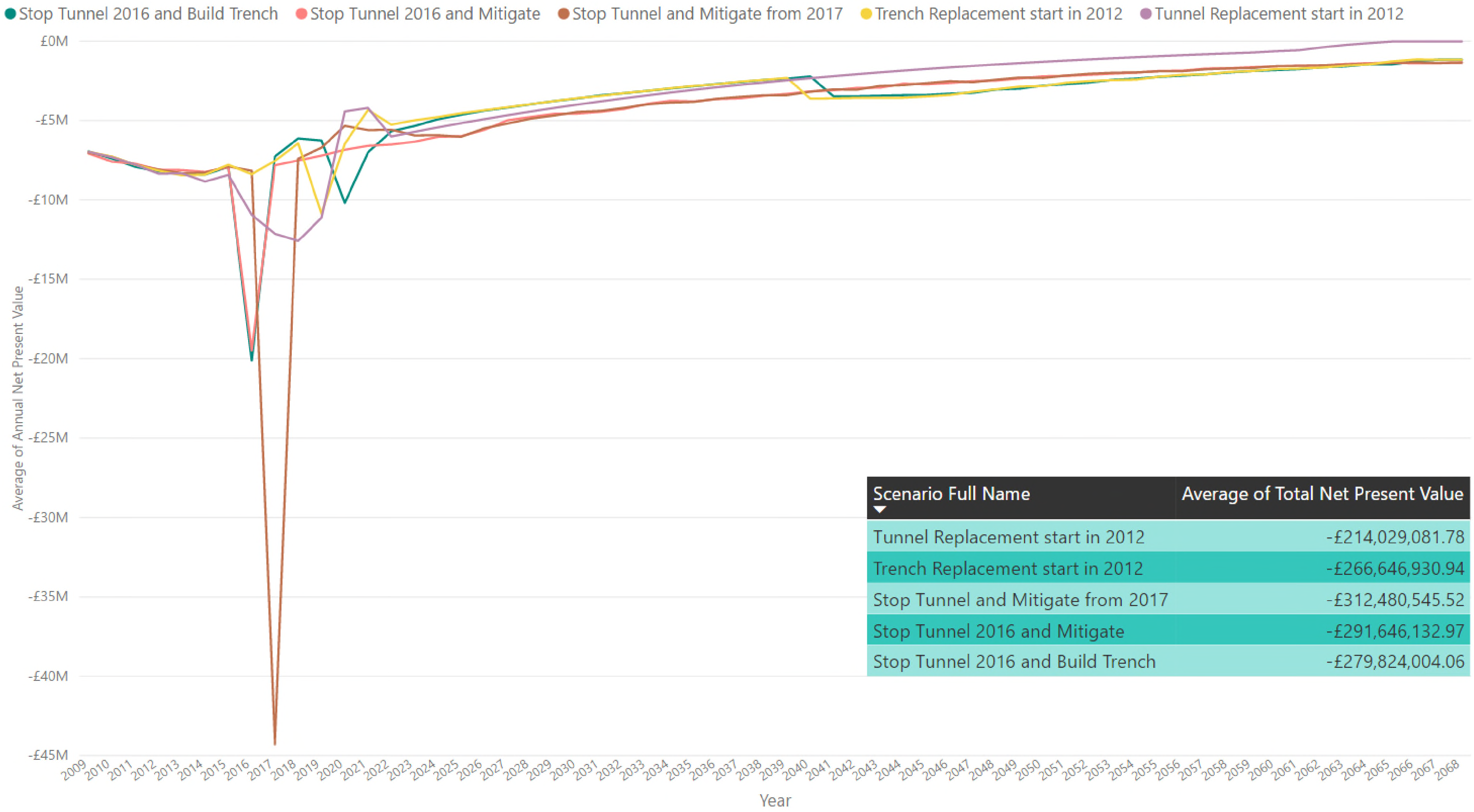
Cost Area	Level 1 Description of Cost Area Component Costs	Level 2 Description of Cost Area Component Costs
Construction costs	Bored Tunnel Construction Costs	Bored Tunnel Construction Costs
	Trench replacement costs	Trench replacement costs
Frond Mattresses Installation and Maintenance	Regular frond mattresses replacement costs	Regular frond mattresses replacement costs
	Cost of re-instating mattresses after they have moved or have not been deployed correctly	Cost of re-instating mattresses after they have moved or have not been deployed correctly
lose lease to operate pipeline	Consequences of losing lease to operate F9	Costs of replacement of Feeder 9
		Costs of isolation of Feeder 9
		Costs of repairs, weighted by probability of type of damage
Routine Pipeline Maintenance	Costs of Routine Pipeline Maintenance	Costs of regular PIGing
		Costs of boat inspections
Sunk and Cancellation Costs	Sunk and Cancellation Costs	Sunk and Cancellation Costs
Risk Adjusted Impact of Freespanning	After major/minor defect was found after F9 examination	Costs of Diver Inspection
		Costs of PIGing
		Costs of repairs, weighted by probability of type of damage
		Consequence of network operating without F9
		Costs of isolation of Feeder 9
		Costs of replacement of Feeder 9
		Impact on wholesale gas prices, taking into account two scenarios: winter and summer
	After rupture of Feeder 9 was found	Costs of isolation of Feeder 9
		Costs of repairs, weighted by probability of type of damage
		Consequence of network operating without F9
		Costs of replacement of Feeder 9
		Impact on wholesale gas prices, taking into account two scenarios: winter and summer
		Costs of damage to ships and life
		Damaged ship clear up costs
		shipping lane closure costs
		Impact on wholesale gas prices, taking into account two scenarios: winter and summer
	After no damage was found after F9 examination	Costs of Diver Inspection and PIGing
		Costs of increasing survey frequency
		Costs of installing additional Frond Mattresses and gravel bags

Risk Adjusted Impact of TPI	After major/minor defect was found after F9 examination	Costs of Diver Inspection
		Costs of PIGing
		Costs of repairs, weighted by probability of type of damage
		Consequence of network operating without F9
		Costs of isolation of Feeder 9
		Costs of replacement of Feeder 9
		Impact on wholesale gas prices, taking into account two scenarios: winter and summer
	After rupture of Feeder 9 was found	Costs of isolation of Feeder 9
		Costs of repairs, weighted by probability of type of damage
		Consequence of network operating without F9
		Costs of replacement of Feeder 9
		Impact on wholesale gas prices, taking into account two scenarios: winter and summer
		Costs of damage to ships and life
		Damaged ship clear up costs
		shipping lane closure costs
		Impact on wholesale gas prices, taking into account two scenarios: winter and summer
	After no damage was found after F9 examination	Costs of Diver Inspection
		Costs of installing additional Frond Mattresses and gravel bags if they have moved
		Costs of PIGing if the damage is unclear



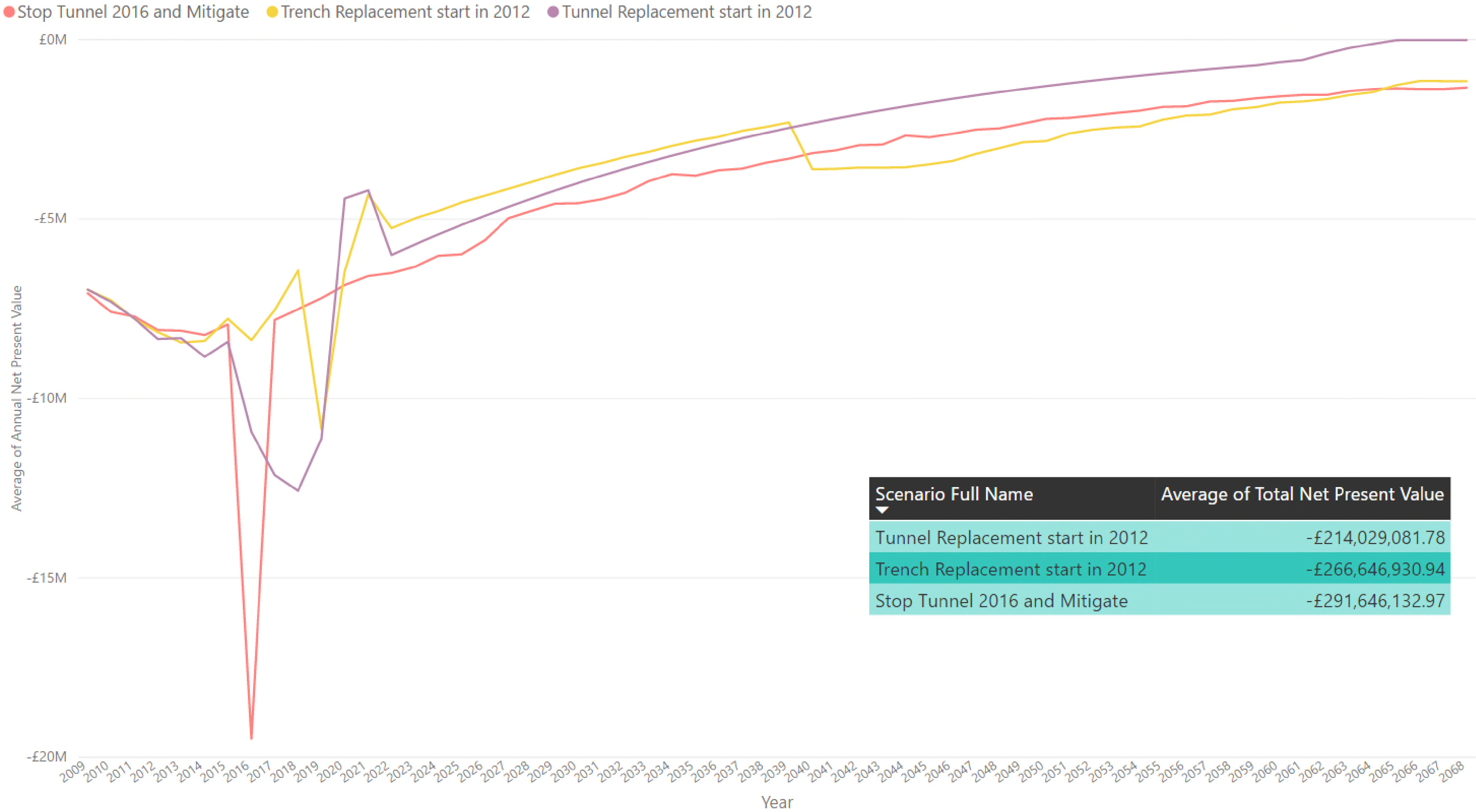
Scenario Full Name	Average of Total Net Present Value
Tunnel Replacement start in 2012	-£214,029,081.78
Trench Replacement start in 2012	-£266,646,930.94
Stop Tunnel and Mitigate from 2017	-£312,480,545.52
Stop Tunnel 2016 and Mitigate	-£291,646,132.97
Stop Tunnel 2016 and Build Trench	-£279,824,004.06

Fig. 23 Average NPV of each individual year by scenario type and year – with explanation



Scenario Full Name	Average of Total Net Present Value
Tunnel Replacement start in 2012	-£214,029,081.78
Trench Replacement start in 2012	-£266,646,930.94
Stop Tunnel and Mitigate from 2017	-£312,480,545.52
Stop Tunnel 2016 and Mitigate	-£291,646,132.97
Stop Tunnel 2016 and Build Trench	-£279,824,004.06

Fig. 24 Average NPV of each individual year by scenario type and year – without explanation



Scenario Full Name	Average of Total Net Present Value
Tunnel Replacement start in 2012	-£214,029,081.78
Trench Replacement start in 2012	-£266,646,930.94
Stop Tunnel 2016 and Mitigate	-£291,646,132.97

Fig. 25 Average NPV of each individual year – Top 3 Scenarios shown

Visualise, Analyse & Optimise Your Key Decisions

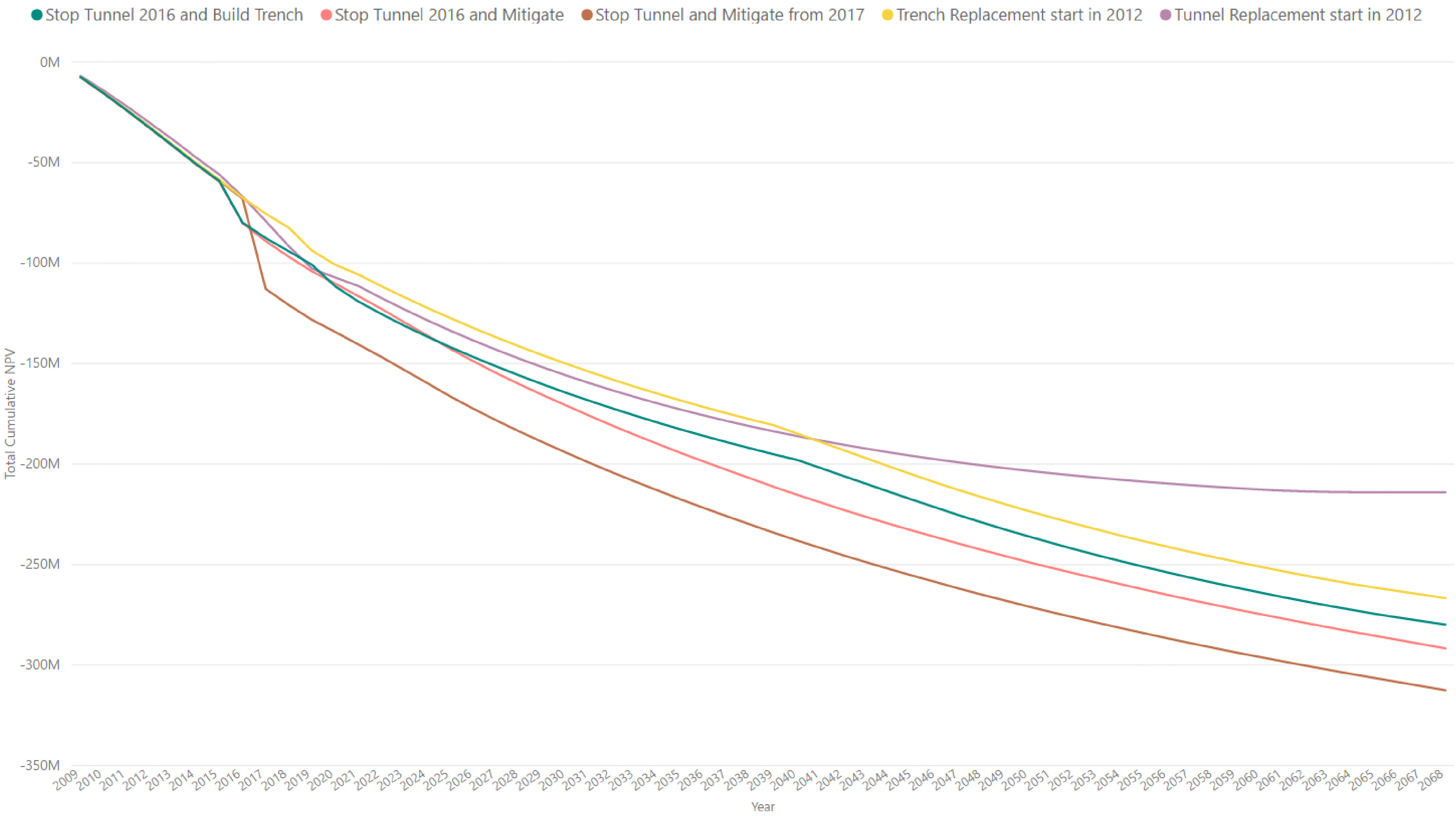


Fig. 26 Cumulative NPV line graph by scenario type and year

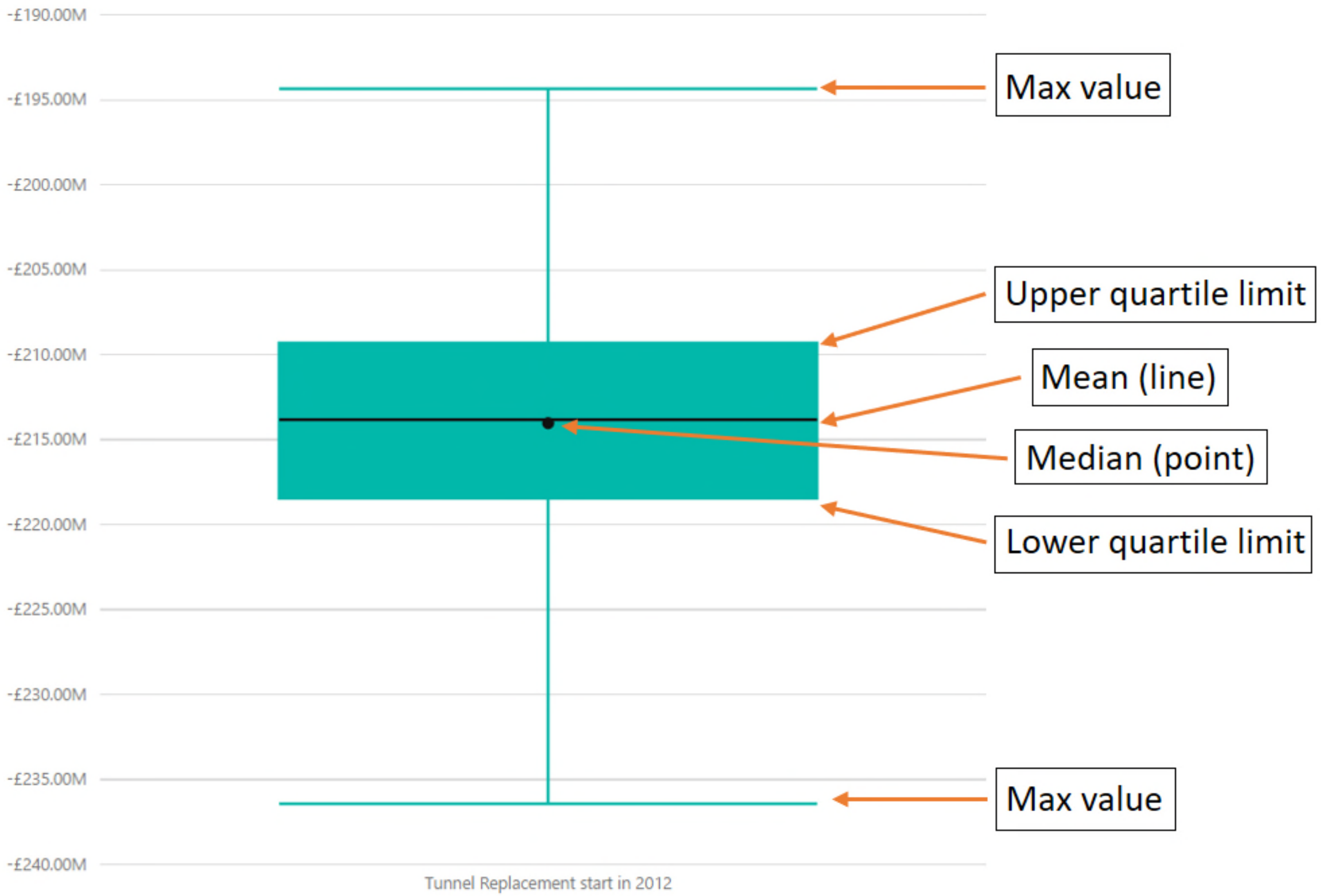


Fig. 27 NPV box plot with explanation

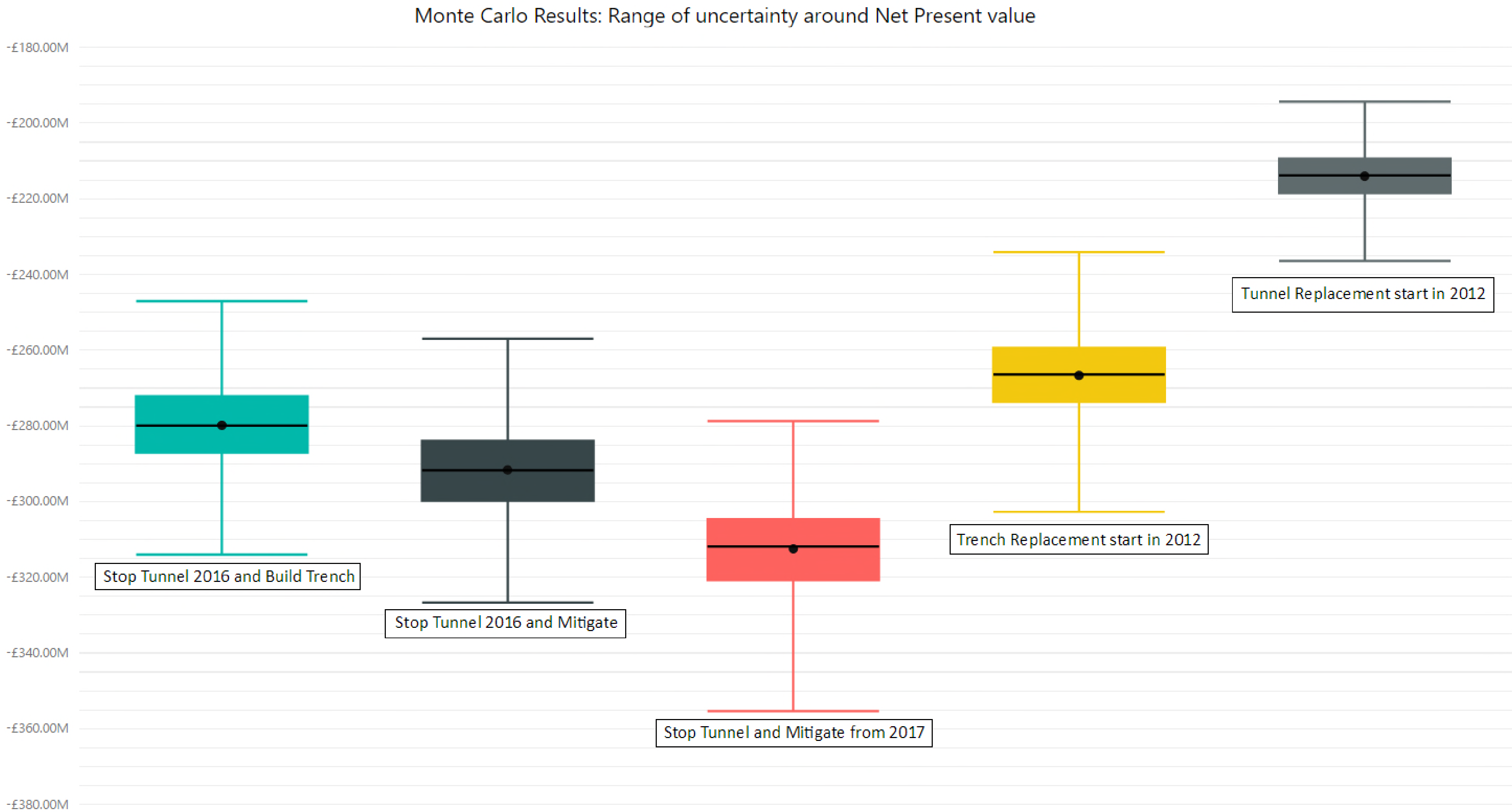


Fig. 28 NPV box plots by scenario type

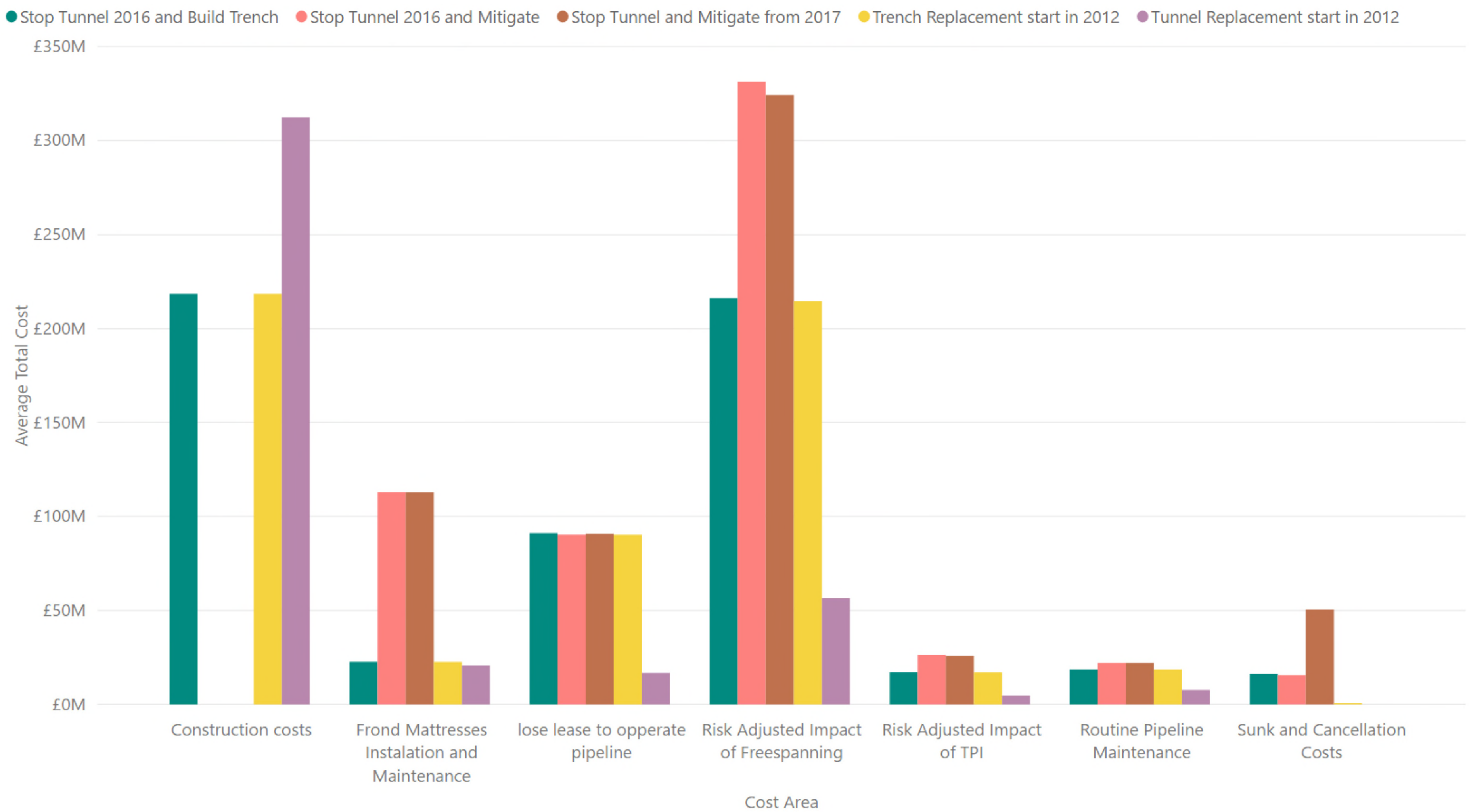


Fig. 29 Aggregated costs and monetised risk over the 60 years modelled. Not adjusted for time.

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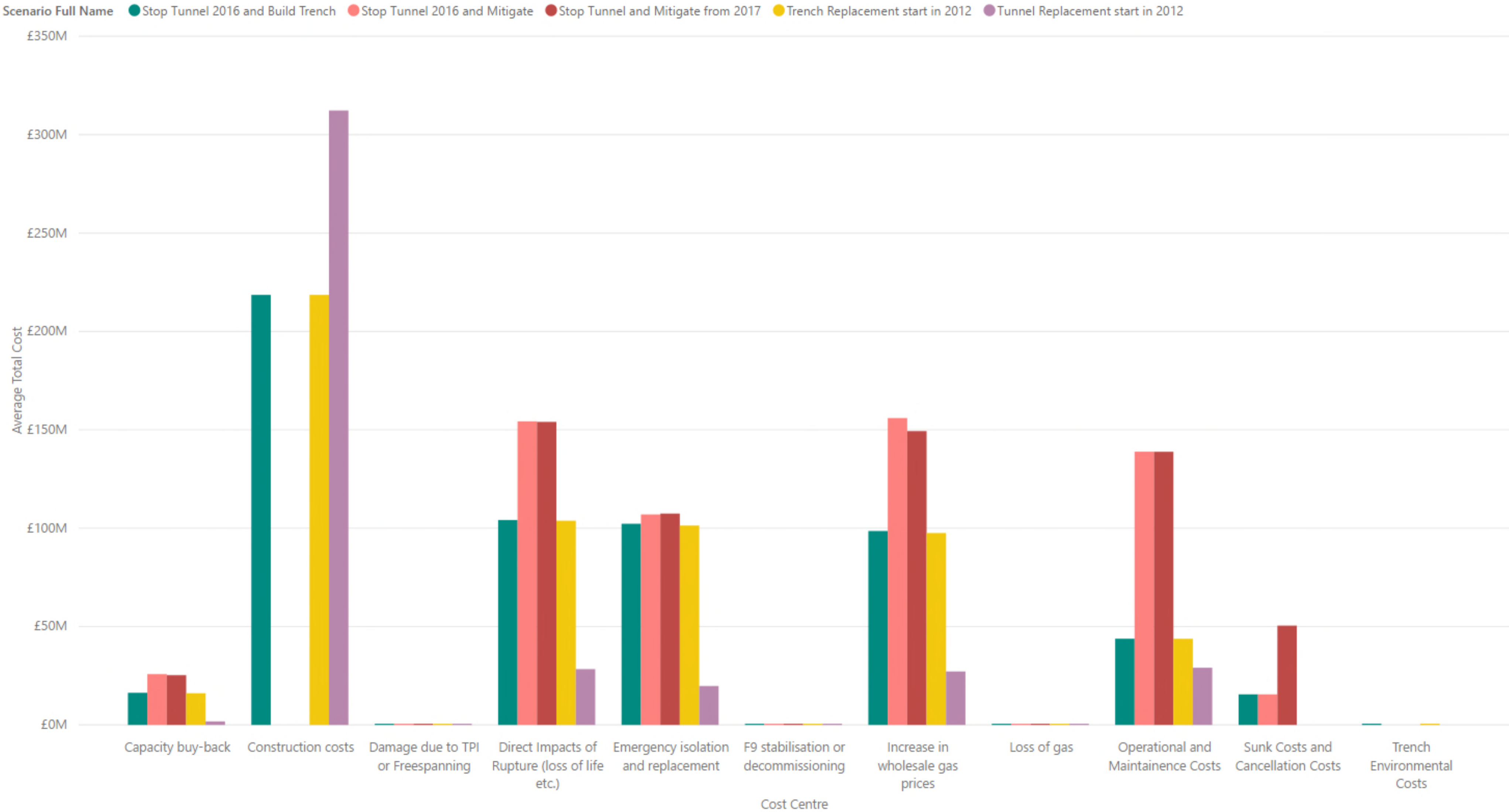


Fig. 30 Detailed aggregated costs and monetised risk over the 60 years modelled. Not adjusted for time.

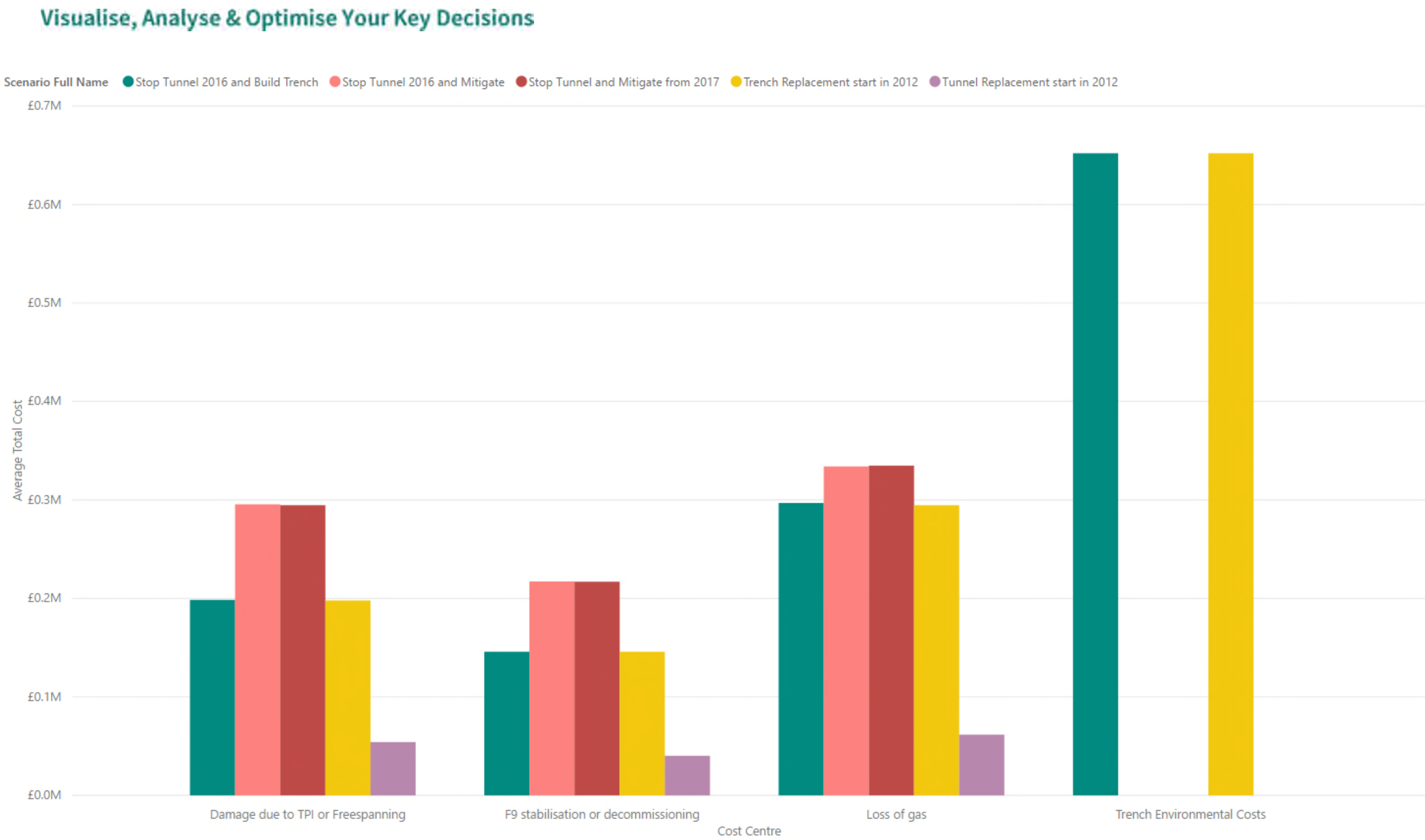


Fig. 31 Detailed aggregated costs and monetised risk over the 60 years modelled. Not adjusted for time – the lowest values

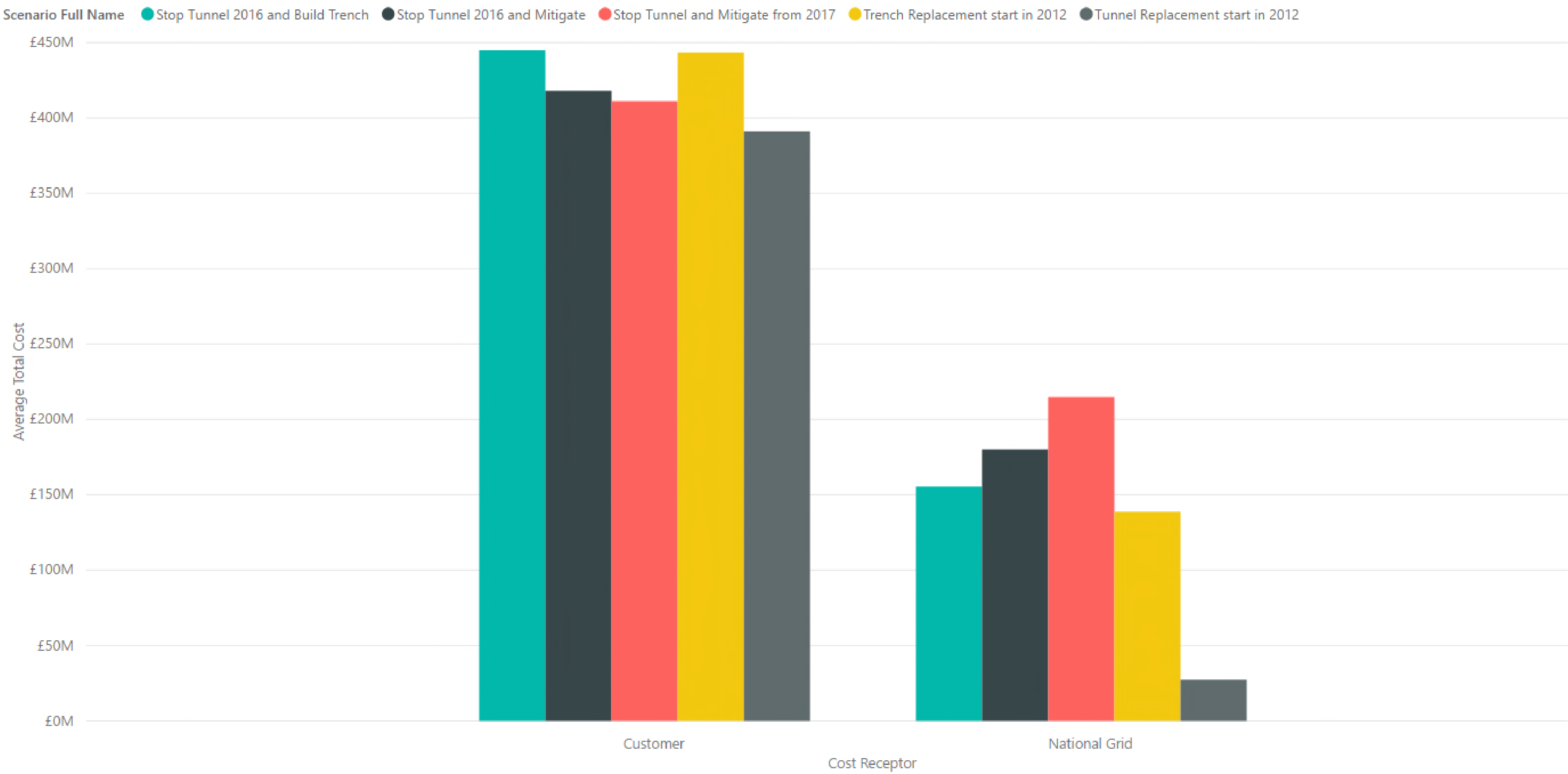


Fig. 32 Analysis of costs that would be directly incurred by customers or born by National Grid without direct pass through to customers.

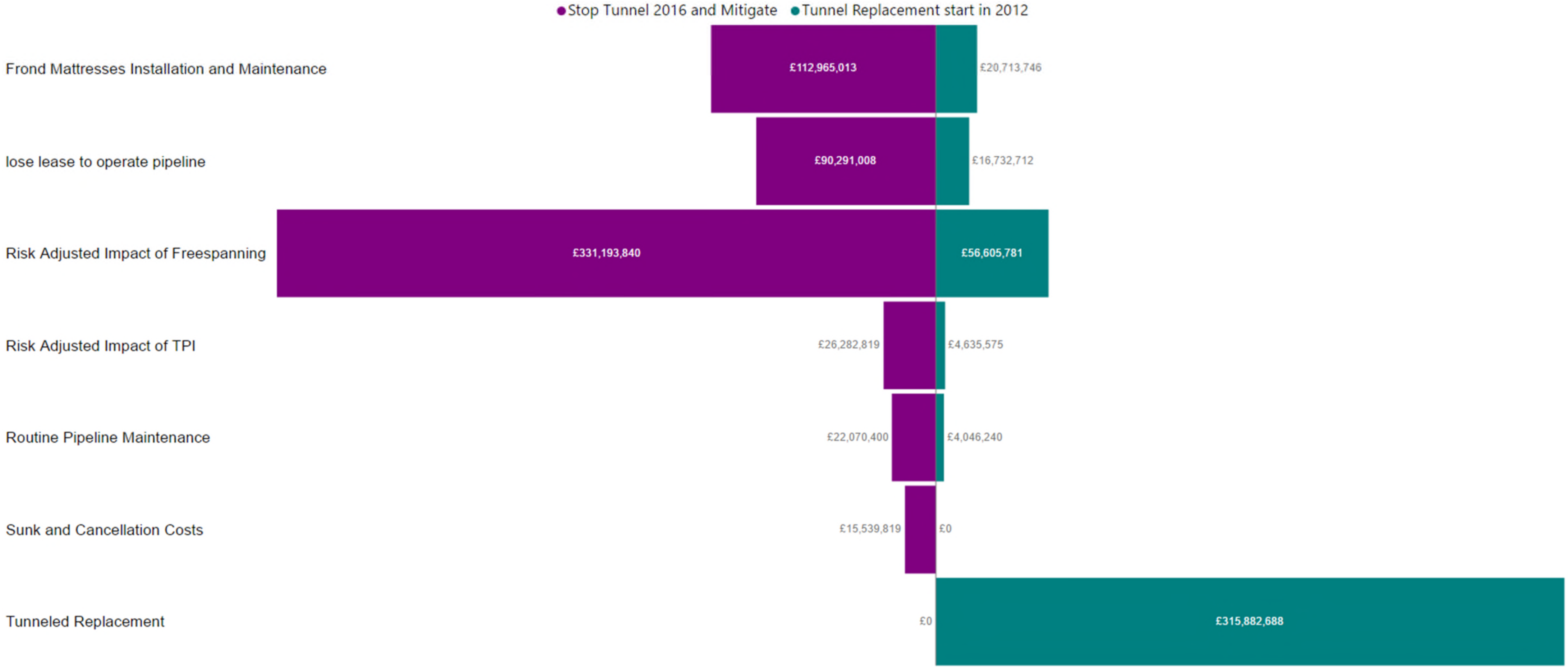


Fig. 33 Tornado chart comparison: Tunnel (2012) and Mitigate (2016) scenarios

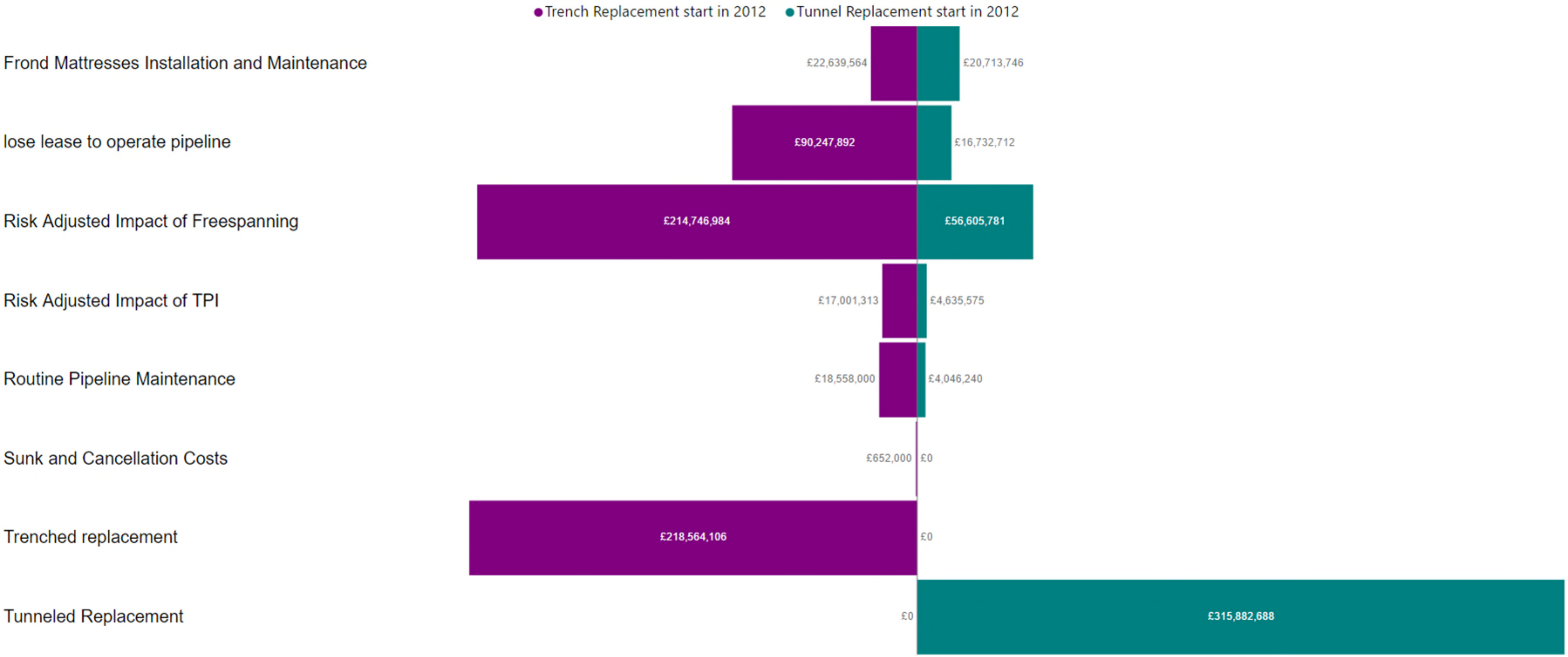


Fig. 34 Tornado chart comparison: Tunnel (2012) and Trench (2012) scenarios

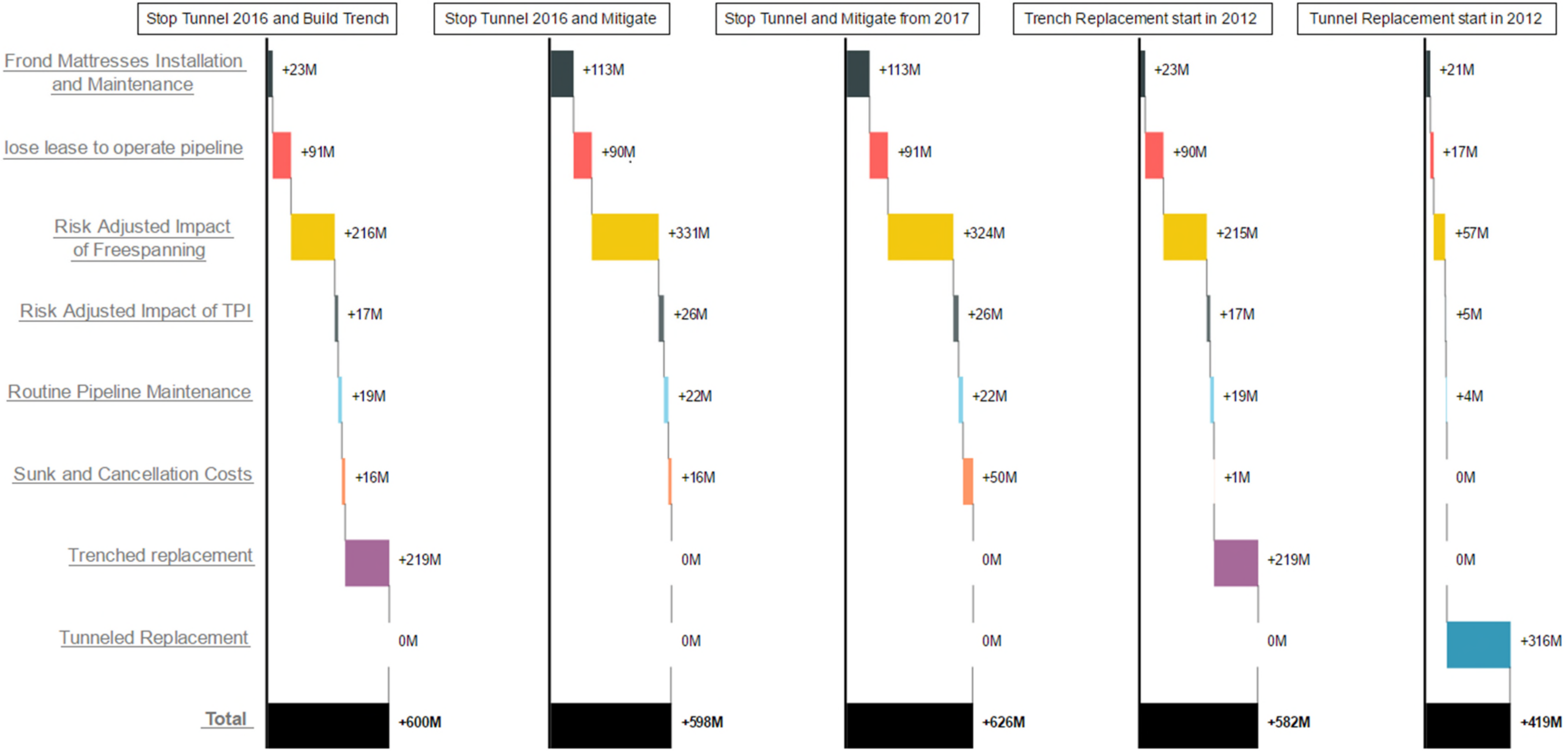


Fig. 35 Waterfall chart with main costs and monetised risks across all scenarios

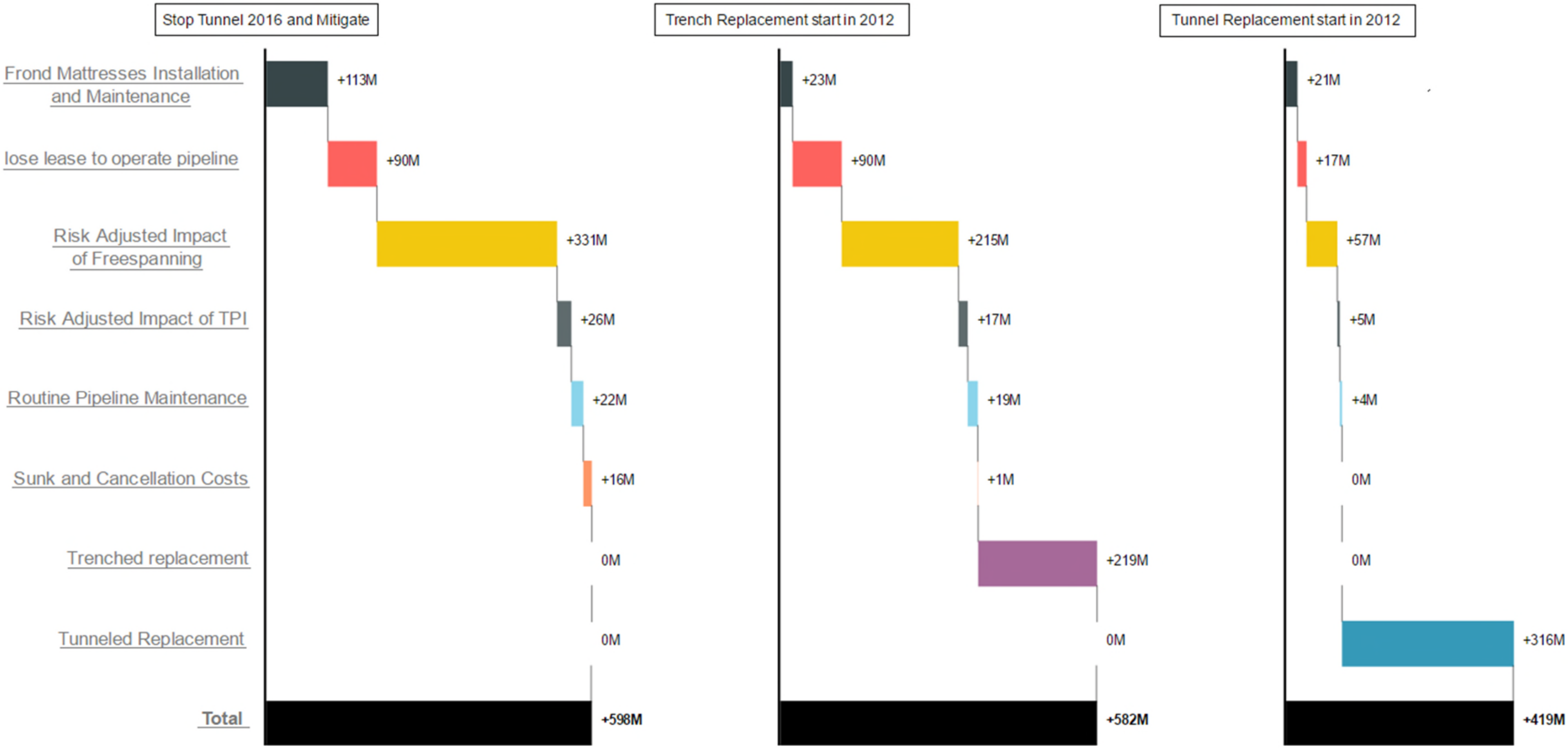


Fig. 36 Waterfall chart with main costs and monetised risks – top 3 scenarios

Visualise, Analyse & Optimise Your Key Decisions

Fig. 37 Low–frequency–high–impact events summary

6.2. Stress tests performed with results

6.2.1. Parameters chosen

Several stress test scenarios were run to investigate how the key parameters influence the model's output (NPV value). They were run for Top 3 Scenarios, i.e. Tunnel 2012, Mitigate 2016 and Trench 2012 options. It is important to highlight that stress tests that could potentially change the preferred option, i.e. Bored Tunnel, were chosen rather those that would favour it. The aim was to show that the Tunnel option was robust to uncertainty around some of the biggest potential cost increases.

Impacts of following variables were tested:

1) Clear up costs of vessel destroyed by rupture of Feeder 9
2) Constraint Costs following isolation of Feeder 9
3) Wholesale cost of gas price increase due to rupture of Feeder 9
4) Cost of Capital used to calculate NPV value
5) The value of a life lost as a result of rupture of Feeder 9
6) Constraint Costs and wholesale cost of gas price increase combined
7) Constraint Costs, wholesale cost of gas price increase and clear up costs of ship destroyed by rupture combined

6.2.2. Impact of Rough Storage availability

At the time when decision to choose Tunnel Option was made little was known about Rough Storage's future availability. In June 2017 Centrica announced that it would shut the site altogether, warning that the 32-year-old facility was at the end of its design life and could no longer be operated safely. As another stress test, to better accommodate possible future scenarios, models were run as both With-Rough Storage Facility and No-Rough Storage Facility.

Rough Storage Facility is a long-range natural gas storage facility on the national transmission system, situated off the Yorkshire coast. It is operated by Centrica Storage Ltd, a wholly owned subsidiary of Centrica. It has a storage capacity of 3.31 billion cubic metres which is approximately 70% of the UK's gas storage capacity (approx. 9 days' supply). Rough can supply 10% of the UK's peak gas demand and as such is an important part of the UK's gas infrastructure.

Rough's availability has an impact on Capacity buy-back costs (**paragraph 5.3.2**) as well as wholesale gas prices impact **(paragraph 5.3.3**). Capacity buy back costs and wholesale gas prices impacts were grouped into colour bands (**Table 13)**, which were used to depict the variance in capacity buy back and wholesale cost of gas costs depending on FES scenario and Rough's availability (
Table 33). Colour bands describing capacity buy back costs and wholesale gas prices impacts are presented in **Table 34**. Wholesale gas prices impact for No Rough scenarios (total sums per duration) are presented in **Table 35**. EO input for Mitigate scenarios (Wholesale Gas Prices Impact) presents **Table 36**. EO input for Trench and Tunnel scenarios (Wholesale Gas Prices Impact) presents **Table 37**.

Since Rough Storage will be operational up until 2025, Tunnel build will have been completed by that date. As a result, availability of Rough Storage has no effect on Tunnel Scenario's NPV value.

Table 33. Capacity buy-back costs depending on scenario type and time period – no Rough scenarios

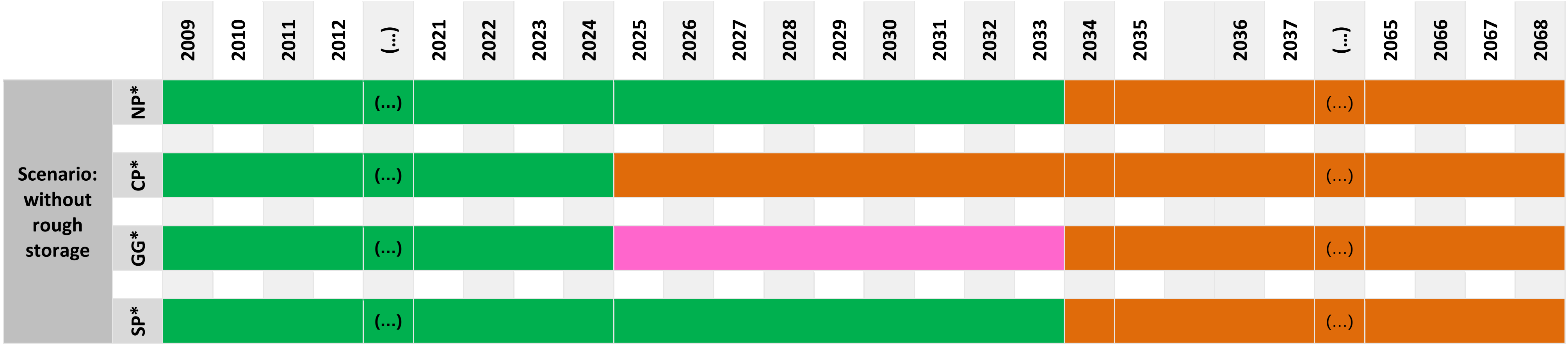


Table 34. Capacity buy-back costs and whole sale gas prices impact depending on scenario type

	Scenarios	Constraint buyback Cost - Mod agreed in 3 days	Constraint buyback Cost - Mod agreed in 7 days	Mod Costs	Mod Probabilities	Gas price impact
Winter	Pink	3-day Prompt buyback @1 p/kwh =£8.4 m	7-day Prompt buyback @1 p/kwh £19.6 m	As per constraint decision tree	45% low case 45% mid case 10% high case	10 p/thm increase for 1 month 2 p/thm increase for remainder of F9 outage
Summer	Pink	£0.00	1 day prompt at 1p/kwh = £2.8m	As per constraint decision tree	45% low case 45% mid case 10% high case	2 p/thm increase for remainder of F9 outage
Winter	Amber	£0.00	£0.00	As per constraint decision tree	75% low case 25% mid case	£0.00
Summer	Amber	£0.00	£0.00	As per constraint decision tree	75% low case 25% mid case	£0.00
Winter	Green	3-day prompt buyback Day 1 @ 1p p/kWh Day 2 @ 5 p/kWh Day 3 @ 10 p/kWh = £44.8m	7 day prompt buyback Day 1 @ 1 p/kWh Day 2 @ 5 p/kWh Day 3-7 @ 10 p/kWh = £156.8 m	As per constraint decision tree	25% low case 65% mid case 10% High Case	25p/thm increase for 1 month 2p/thm increase for the remainder of the F9 outage
Summer	Green	£0.00	1-day prompt at 1p/kwh = £2.8m	As per constraint decision tree	25% low case 65% mid case 10% High Case	2 p/thm increase for remainder of F9 outage

Table 35. Wholesale gas prices impact for No Rough scenarios (total sums per duration)

Scenario Type	Total Duration of Outage		
	2.4 years	3 years	6 years
without Rough (2009-2024)	£689,380,896.00	£829,249,202.00	£1,563,190,840.00
without Rough (2025-2033)	£484,401,481.00	£589,302,710.75	£1,139,758,939.25
without Rough (2034-2068)	£0.00	£0.00	£0.00

Table 36. Wholesale Gas Prices Impact No Rough scenarios – EO input for Mitigate scenarios

	Mitigate (2016) - without Rough Storage		Mitigate (2017) - without Rough Storage	
year	cost	Incurred for:	cost	Incurred for:
2009	260,531,806.67	6 years	260,531,806.67	6 years
2010	260,531,806.67	6 years	260,531,806.67	6 years
(…)	260,531,806.67	6 years	260,531,806.67	6 years
2015	260,531,806.67	6 years	260,531,806.67	6 years
2016	260,531,806.67	6 years	276,416,400.67	3 years
2017	260,531,806.67	6 years	344,690,448.00	2 years
2018	260,531,806.67	6 years	344,690,448.00	2 years
2019	260,531,806.67	6 years	276,416,400.67	3 years
2020	260,531,806.67	6 years	260,531,806.67	6 years
2021	260,531,806.67	6 years	260,531,806.67	6 years
(…)	260,531,806.67	6 years	260,531,806.67	6 years
2024	260,531,806.67	6 years	260,531,806.67	6 years
2025	189,959,823.21	6 years	189,959,823.21	6 years
2026	189,959,823.21	6 years	189,959,823.21	6 years
(…)	189,959,823.21	6 years	189,959,823.21	6 years
2033	189,959,823.21	6 years	189,959,823.21	6 years
2034	0.00	6 years	0.00	6 years
2035	0.00	6 years	0.00	6 years
(…)	0.00	6 years	0.00	6 years
2068	0.00	6 years	0.00	6 years

Table 37. Wholesale Gas Prices Impact for No Rough scenarios – EO input for Trench and Tunnel scenarios

	Trench (2012) - without Rough Storage		Trench (2016) - without Rough Storage		Tunnel - without Rough Storage	
year	cost	Incurred for:	cost	Incurred for:	cost	Incurred for:
2009	260,531,806.67	6 years	260,531,806.67	6 years	260,531,806.67	6 years
2010	260,531,806.67	6 years	260,531,806.67	6 years	260,531,806.67	6 years
(…)	260,531,806.67	6 years	260,531,806.67	6 years	260,531,806.67	6 years
2015	260,531,806.67	6 years	260,531,806.67	6 years	260,531,806.67	6 years
2016	276,416,400.67	3 years	260,531,806.67	6 years	276,416,400.67	3 years
2017	344,690,448.00	2 years	276,416,400.67	3 years	344,690,448.00	2 years
2018	402,138,856.00	1 year	344,690,448.00	2 years	402,138,856.00	1 year
2019	114,896,816.00	<1 year	402,138,856.00	1 year	114,896,816.00	<1 year
2020	260,531,806.67	6 years	114,896,816.00	<1 year	0	–
2021	260,531,806.67	6 years	260,531,806.67	6 years	0	–
(…)	260,531,806.67	6 years	260,531,806.67	6 years	0	–
2024	260,531,806.67	6 years	260,531,806.67	6 years	0	–
2025	189,959,823.21	6 years	189,959,823.21	6 years	0	–
2026	189,959,823.21	6 years	189,959,823.21	6 years	0	–
(…)	189,959,823.21	6 years	189,959,823.21	6 years	0	–
2033	189,959,823.21	6 years	189,959,823.21	6 years	0	–
2034	0.00	6 years	0.00	6 years	0	–
2035	0.00	6 years	0.00	6 years	0	–
(…)	0.00	6 years	0.00	6 years	0	–
2068	0.00	6 years	0.00	6 years	0	–

Below, **Table 38** depicts the average values of total NPV results and benefit of the Tunnel Option vs other options without Rough Storage. On the next page, **Table 39** presents the summary of the results of all stress tests performed. The first column “Stress Test Description” describes what variable(s) were put to the test and whether the value was fixed or increased/decreased in relation to the base value. The following columns shows values of the stress tests for given scenarios as well as benefit of the Tunnel scenarios vs Trench 2012 and vs Mitigate 2016 options.

Table 38. Total averaged NPV values for all No–Rough scenarios

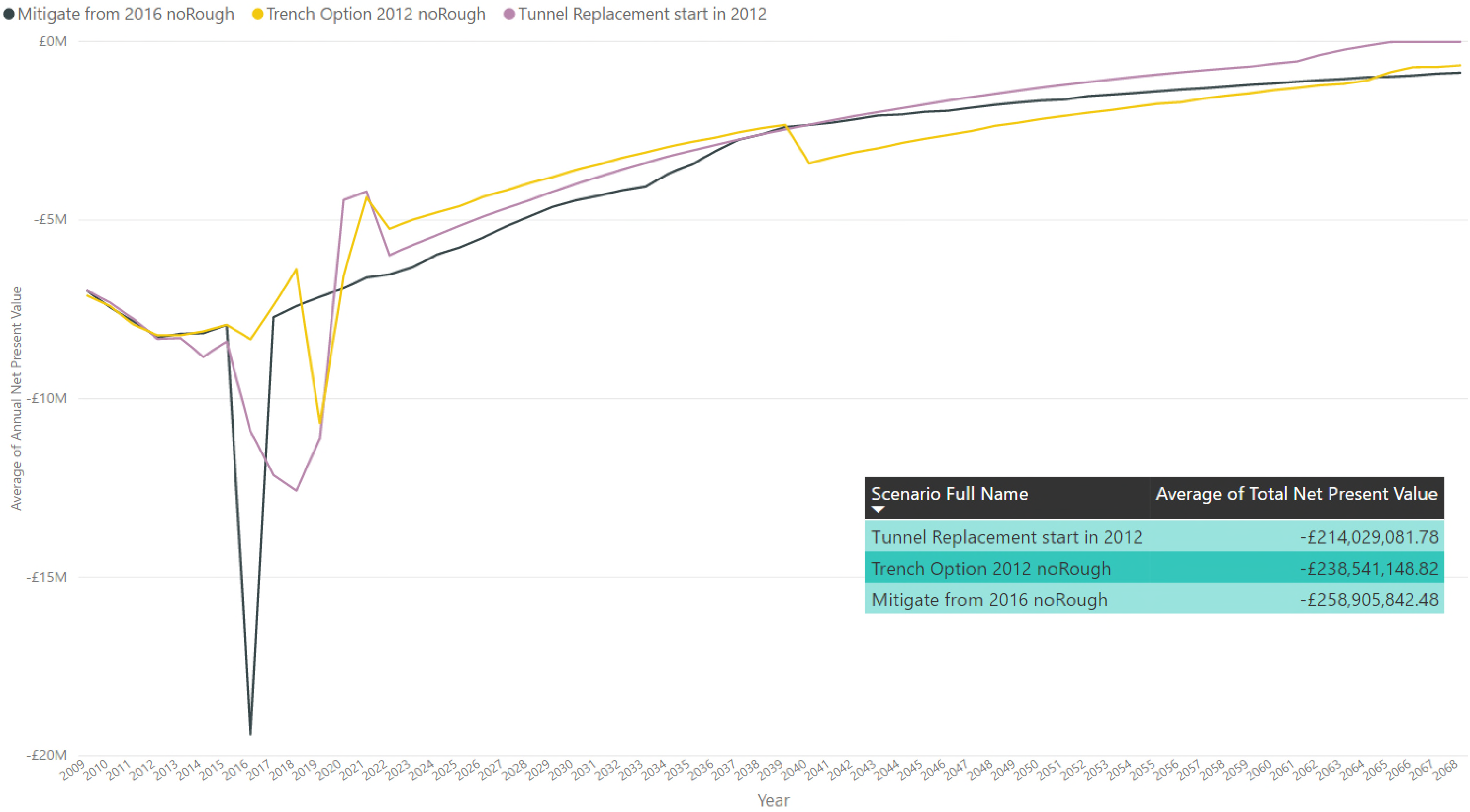
Scenario Full Name	Scenario Name	Average of Total Net Present Value	Tunnel benefit vs option (noRough)
Mitigate from 2016 (no Rough)	M1_2016_noRough	-£258,905,842.48	£44,855,770.11
Stop Tunnel 2016 and Build Trench (no Rough)	T1_2016_noRough	-£290,898,251.14	£76,848,178.77
Stop Tunnel and Mitigate from 2017 (no Rough)	M1_2017_noRough	-£279,824,327.30	£65,774,254.93
Trench Option 2012 (no Rough)	T1_2012_noRough	-£238,541,148.82	£24,491,076.45
Tunnel Option noRough (no Rough)	R1_noRough	-£214,050,072.37	£0.00

To illustrate the impact of No-Rough, a series of graphs were created: **Fig. 38** shows average NPV of each individual year for Top 3 No-Rough Scenarios. **Fig. 39** compares with-Rough and no-Rough scenarios for Trench 2012 scenario, **Fig. 40** shows the difference between with-Rough and no-Rough scenarios for Mitigate 2016 scenario. There is no difference between with-Rough and no-Rough variants for Tunnel 2012 scenario, therefore there is no need for such a comparison.

<u>In all stress tests performed Tunnel Replacement in 2012 Scenario remained the most optimal in terms of NPV value, i.e. has the lowest negative value of NPV.</u>

Table 39. Summary of all stress tests

Stress Test Description	Tunnel 2012 NPV	Trench 2012 NPV	Mitigate 2016 NPV	Tunnel benefit versus Trench	Tunnel benefit versus Mitigate
Base case scenario	-£214,029,081.78	-£266,646,930.94	-£291,646,132.97	£52,617,849.16	£77,617,051.19
Rough Storage facility use stops in 2025	-£214,050,072.37	-£238,541,148.82	-£258,905,842.48	£24,491,076.45	£44,855,770.11
Clear up costs of vessel destroyed by rupture reduced by 50 per cent	-£212,196,870.27	-£263,775,051.40	-£285,998,040.34	£51,578,181.13	£73,801,170.07
Clear up costs of vessel destroyed by rupture reduced by 90 per cent	-£210,608,267.53	-£260,433,551.10	-£280,955,726.01	£49,825,283.57	£70,347,458.48
Constraint Costs, wholesale cost of gas price increase and clear up costs of ship destroyed by rupture reduced by 90 per cent	-£189,709,255.65	-£208,310,665.88	-£201,029,016.91	£18,601,410.23	£11,319,761.26
Constraint Costs following isolation of Feeder 9 reduced by 50 per cent	-£213,452,595.41	-£264,544,281.30	-£286,475,126.41	£51,091,685.89	£73,022,531.00
Constraint Costs following isolation of Feeder 9 reduced by 90 per cent	-£212,868,572.78	-£261,818,164.91	-£281,814,480.92	£48,949,592.13	£68,945,908.14
Constraint Costs and wholesale cost of gas price increase reduced by 50 per cent	-£202,785,685.51	-£239,399,324.69	-£249,544,260.14	£36,613,639.18	£46,758,574.63
Constraint Costs and wholesale cost of gas price increase reduced by 90 per cent	-£193,283,611.83	-£215,829,041.57	-£212,374,224.16	£22,545,429.74	£19,090,612.33
Cost of Capital Increased to 4.8 per cent	-£176,283,896.43	-£193,953,414.38	-£214,248,231.61	£17,669,517.95	£37,964,335.18
Cost of Capital Increased to 6.0 per cent	-£150,350,667.80	-£154,340,116.03	-£172,091,385.35	£3,989,448.23	£21,740,717.55
The value of a life lost set at £3.2m	-£198,913,841.83	-£235,835,251.00	-£243,836,962.01	£36,921,409.17	£44,923,120.18
The value of a life lost set at £4.8m	-£200,822,439.56	-£239,849,835.48	-£249,894,958.41	£39,027,395.92	£49,072,518.85
The value of a life lost set at £6.4m	-£202,731,037.30	-£243,864,419.95	-£255,952,954.82	£41,133,382.65	£53,221,917.52
Wholesale cost of gas price increase reduced by 50 per cent	-£203,515,713.80	-£242,806,970.17	-£255,370,067.00	£39,291,256.37	£51,854,353.20
Wholesale cost of gas price increase reduced by 90 per cent	-£194,597,662.76	-£221,962,803.44	-£222,860,676.50	£27,365,140.68	£28,263,013.74



Scenario Full Name	Average of Total Net Present Value
Tunnel Replacement start in 2012	-£214,029,081.78
Trench Option 2012 noRough	-£238,541,148.82
Mitigate from 2016 noRough	-£258,905,842.48

Fig. 38 Average NPV of each individual year – Top 3 No-Rough Scenarios shown

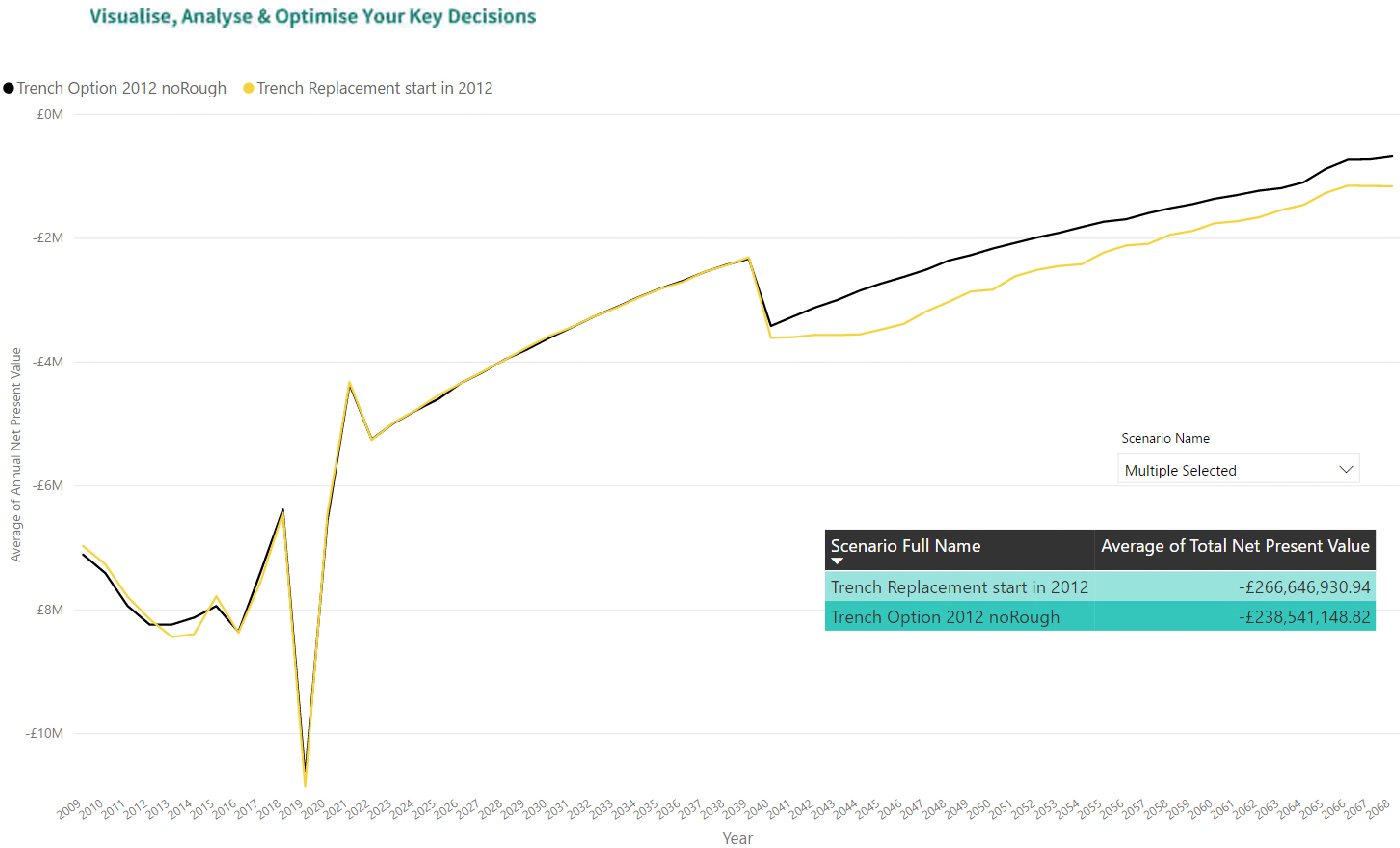


Fig. 39 Average NPV of each individual year – Trench 2012 with–Rough and no–Rough scenarios compared

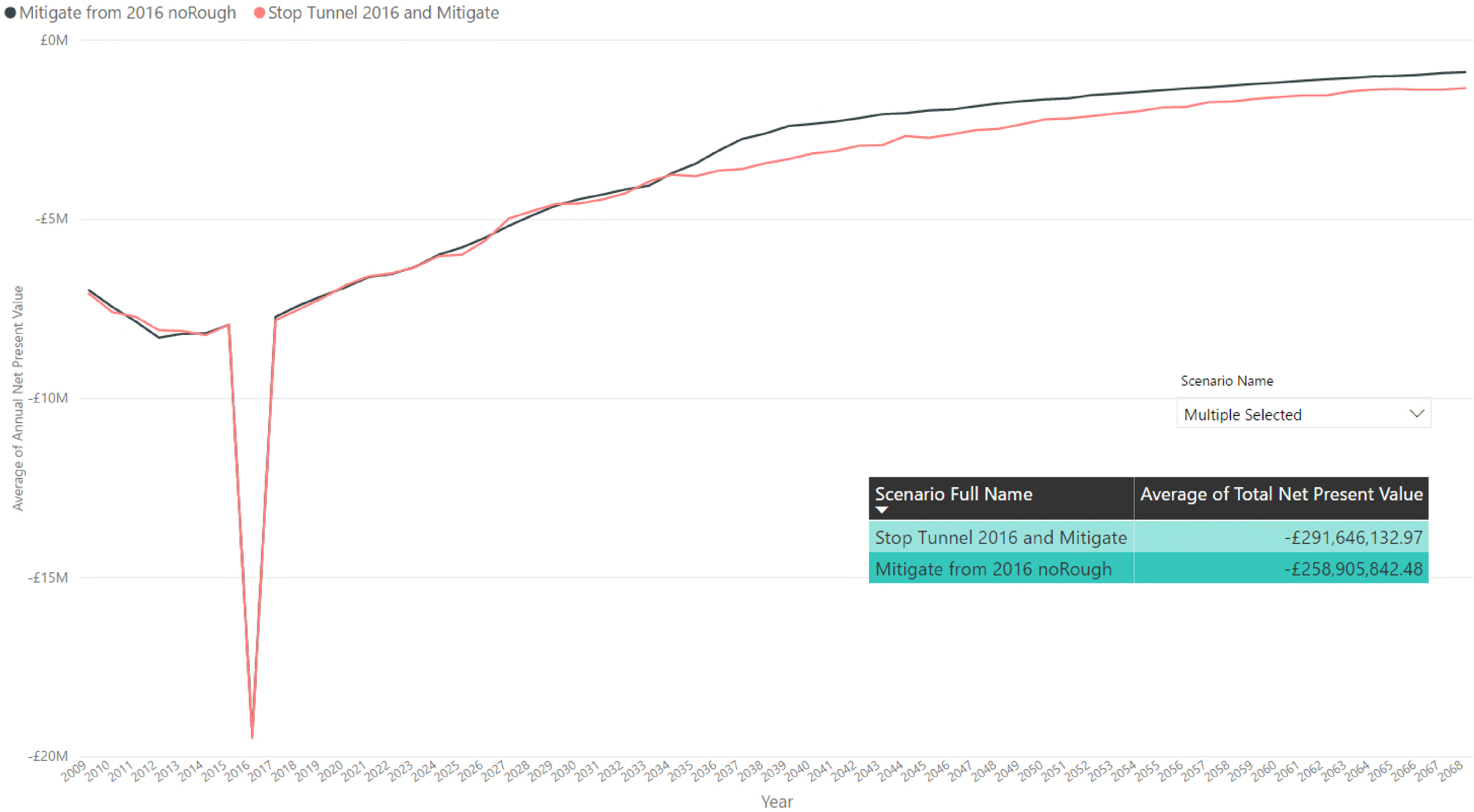


Fig. 40 Average NPV of each individual year – Mitigate 2016 with–Rough and no-Rough scenarios compared

7. Summary and Conclusion

In summary, the EO models developed were successfully able to compare the risk adjusted NPV of constructing a new pipeline (via both a tunnelled and trenched construction method) with an enduring maintenance regime of the existing Feeder 9 (Mitigate 2016 and Mitigate 2017 scenarios). The model integrated a broad range of costs and risks to provide a robust analysis drawing on a wide body of data. Risk was represented both as probability and frequency to capture both low probability and high frequency risk events, including extreme risks (low probability, high impact risks). The risk to safety, environmental, social, commercial, and reputational outcomes were effectively considered in the model. Where input data was uncertain, that uncertainty was directly represented in the model.

In addition to successfully delivering an extreme risk-adjusted analysis of the NPV of the main options to manage the risk associated with Feeder 9, the solution also demonstrated some of the core modelling capabilities the wider NIA project is to develop with the additional case studies.

The solution effectively tested and demonstrated the following functionalities:

- Ability to incorporate a wide range of data from multiple sources into an integrated net present value model.
- Ability to directly represent uncertainty, avoiding reliance on average values and associated loss of information on tail end events.
- Ability to represent extreme risk events, low probability and high impact events, in the analysis.
- Ability to support rapid scenario analysis and stress testing.

Model results show the lifetime net present value over 60 years for the scenario where National Grid continues to progress its tunnel-based pipeline replacement method **(Tunnel 2012) at -£214m**. On a comparative basis, the alternative trench-based replacement scenario (**Trench 2012) has a net present value of -£267m**, and the enduring maintenance scenario **(Mitigate 2016) -£292m**. Therefore, the option of progressing with the current Tunnel construction has a benefit of **£53m** over the next best option (**Trench 2012**). Note, these net present values are negative as only costs and risk impacts are considered, therefore they are equal to the net present cost of each option. Key cost drivers are the potential impact on consumer bills of Feeder 9 isolation (minimised in the case where pipeline replacement has already been consented and planned) arising from capacity buy-back costs, the risk of loss of life due to a catastrophic failure, and the impact on the wholesale price of natural gas owing to reduced supply availability in the Easington area. **Across the full range of stress test scenarios, the tunnel-based pipeline replacement project remains the highest value (lowest cost) solution, indicating that the tunnel option is robust and is therefore the preferred approach.**

Our recommendations are that based on the positive progress demonstrated in case study 1, the methodology is further developed through a further two case studies. These will also allow National Grid to further evaluate this technology and the benefits it could bring.

Appendix A

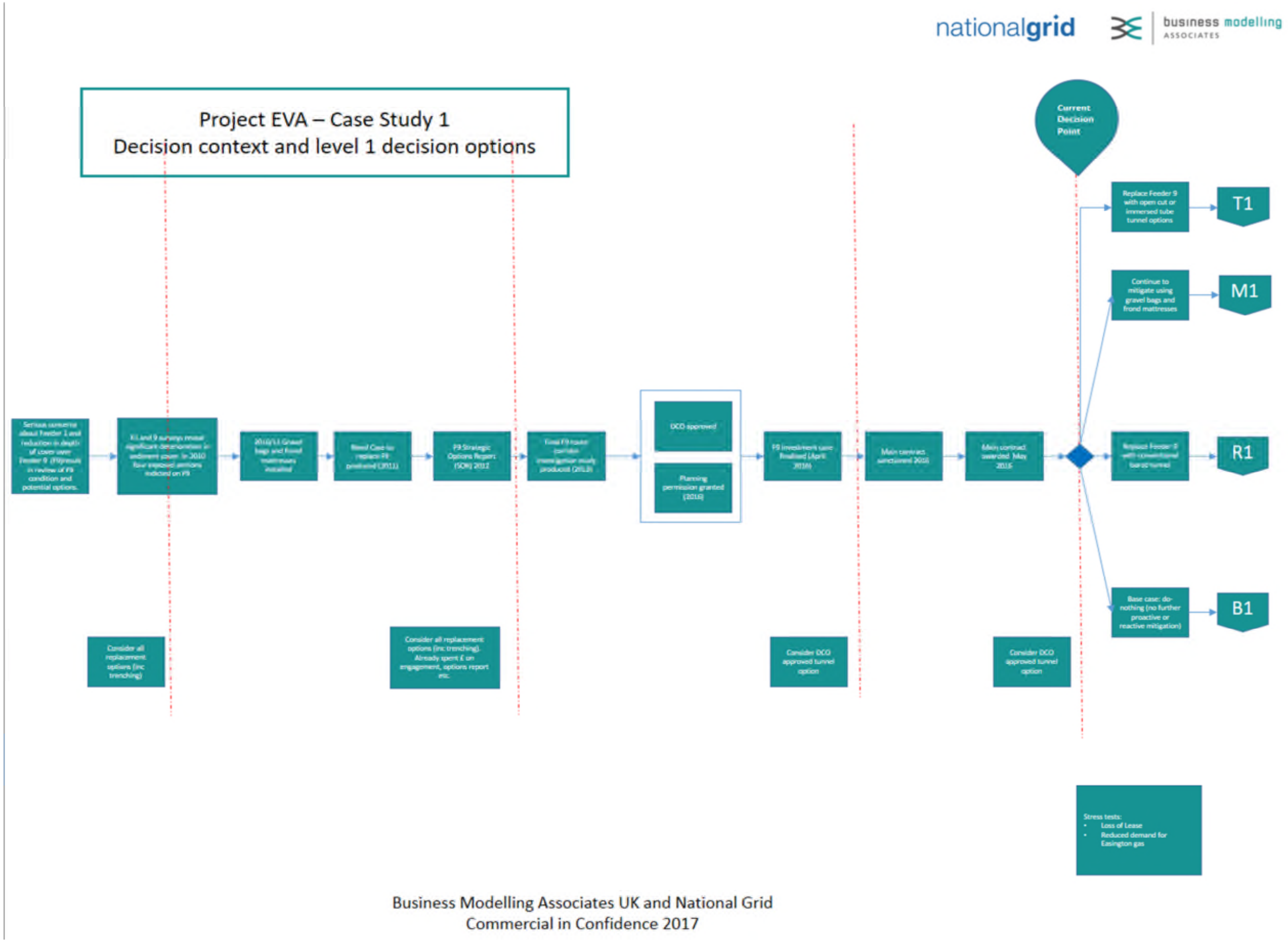


Fig. 41: High level decision tree showing historic decisions made and current decisions being evaluated. M1 represents the option to continue to maintain the current Feeder 9 pipeline, R1 represents the option to replace the current feeder with a new tunnelled feeder, T1 represents the options to replace the current feeder with a new trenched pipeline, B1 refers to a hypothetical do nothing scenario.

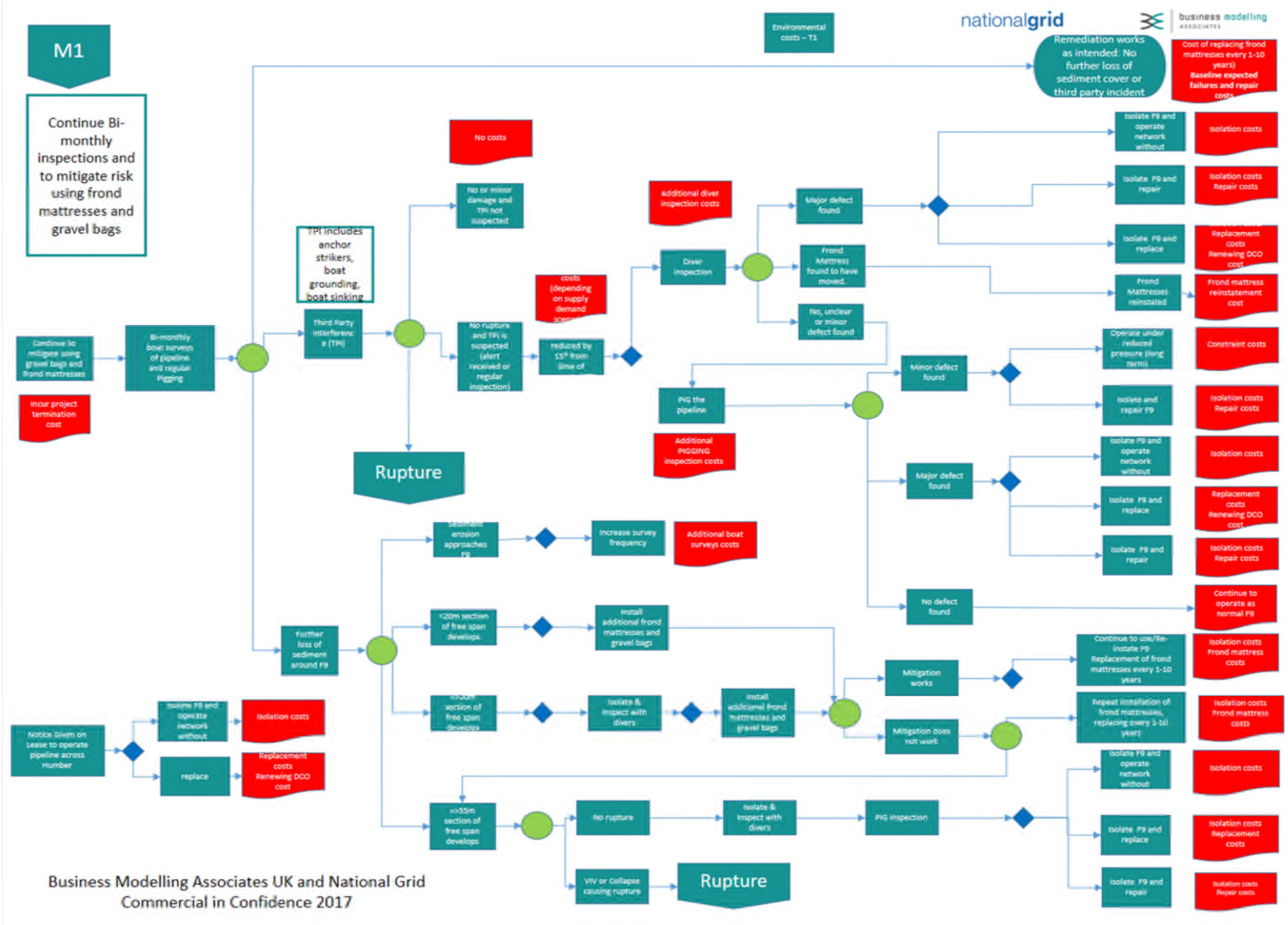


Fig. 42: This figure shows the detailed decision tree for the M1, maintain current feeder 9, option with all associated possible consequences and kn0ck-on decisions.

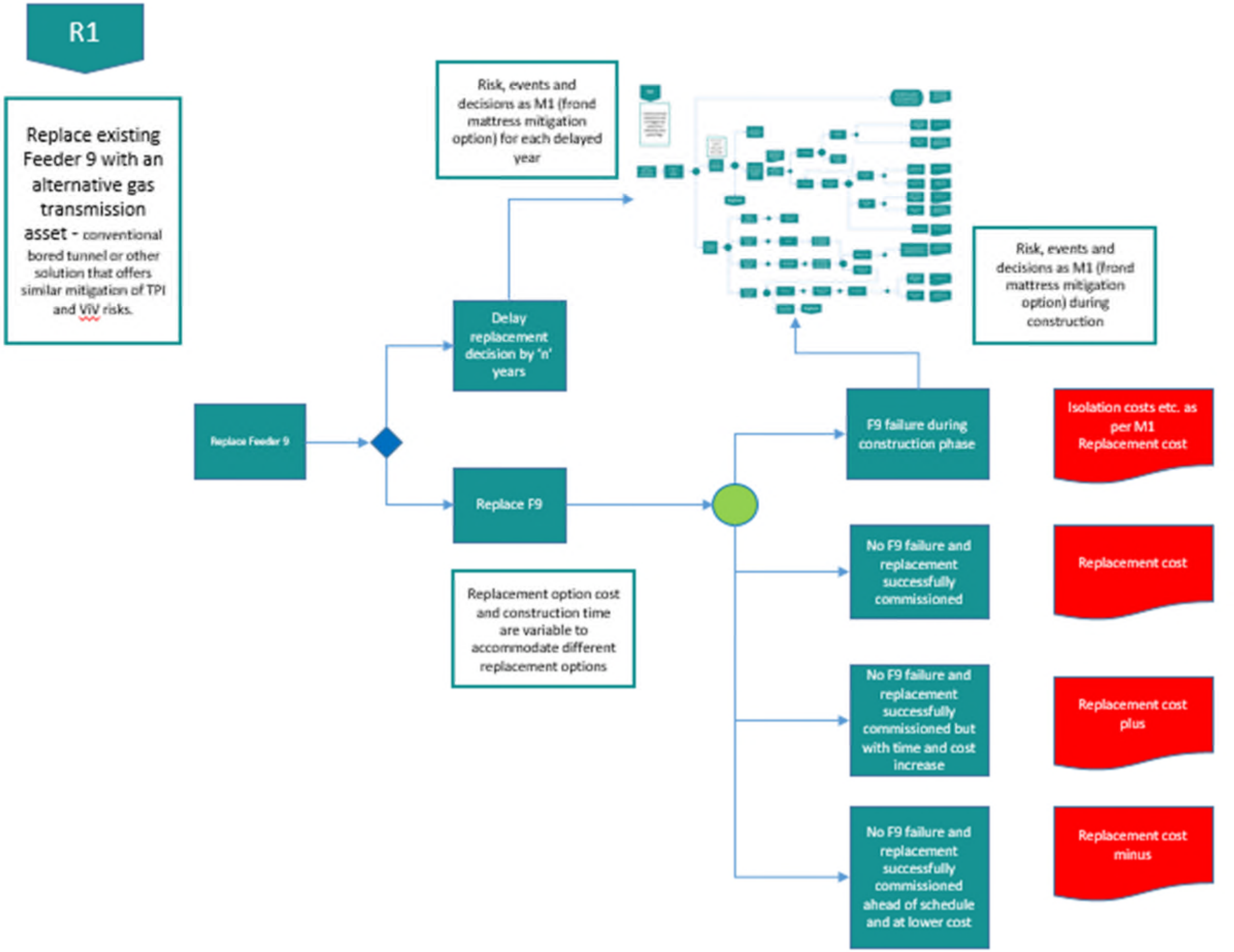


Fig. 43: This figure shows the detailed R1, Tunnel Replacement, decision tree which details the consequences and knock-on decisions of the R1 option.

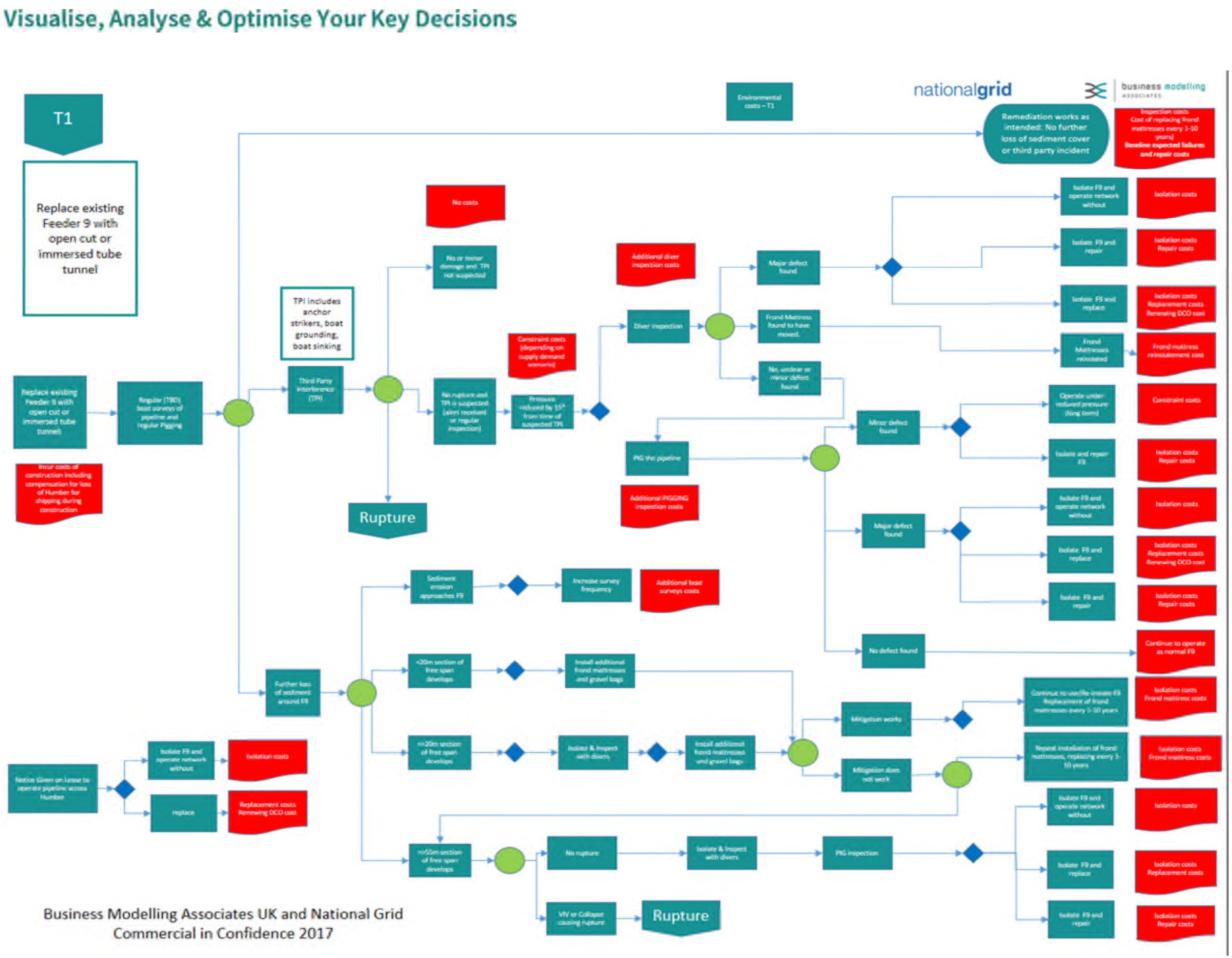


Fig. 44: This figure shows the detailed T1, Trenched Replacement, decision tree which details the consequences and knock-on decisions of the T1 option. Note T1 is very similar to M1 as the same failure modes exist, however the probabilities of failure are judged to be reduced.

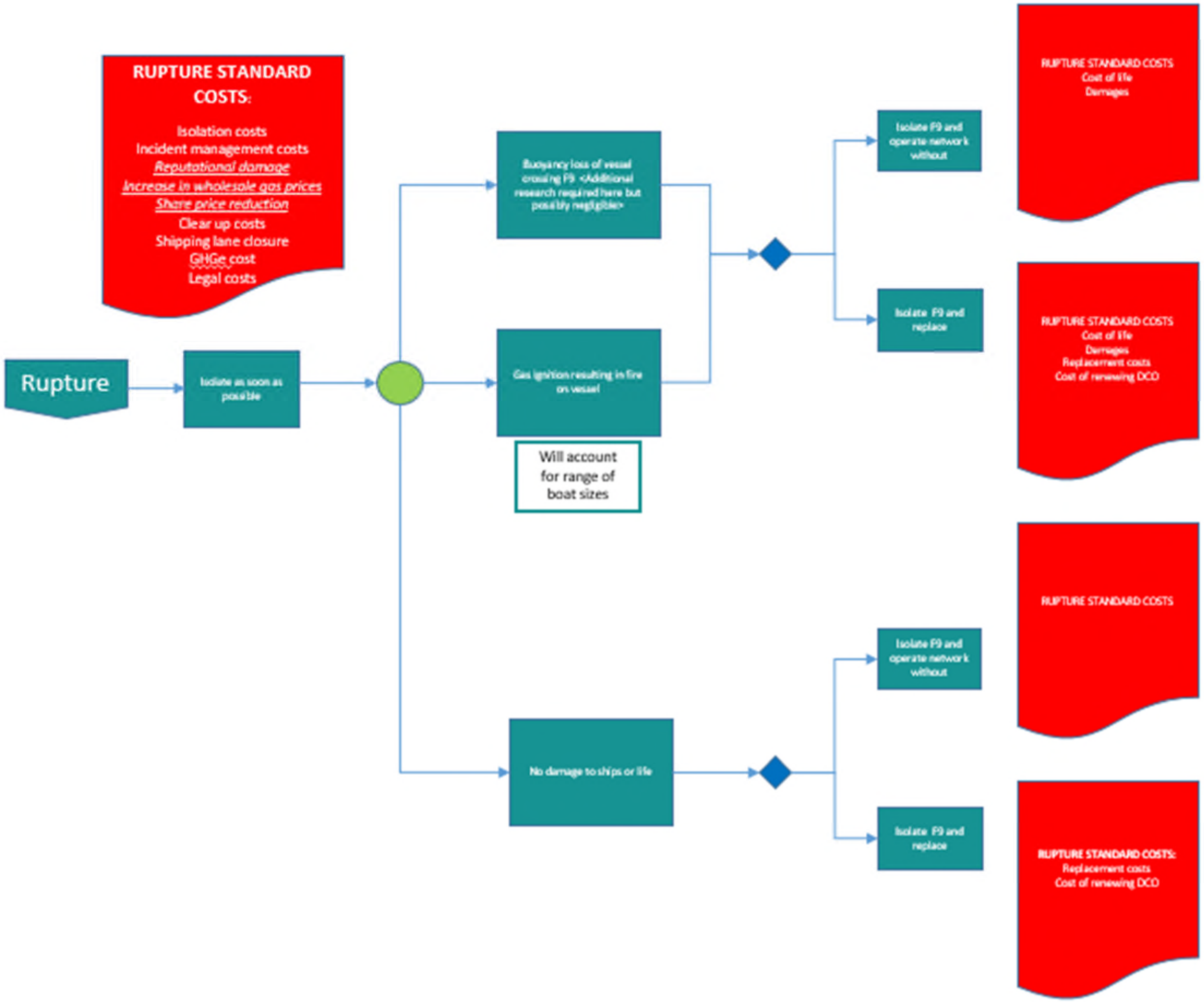


Fig. 45. Shows the consequences and resulting decisions in the event of the Feeder 9 pipeline rupturing, this is references in the M1, R1 and T1 decision trees.

Appendix B

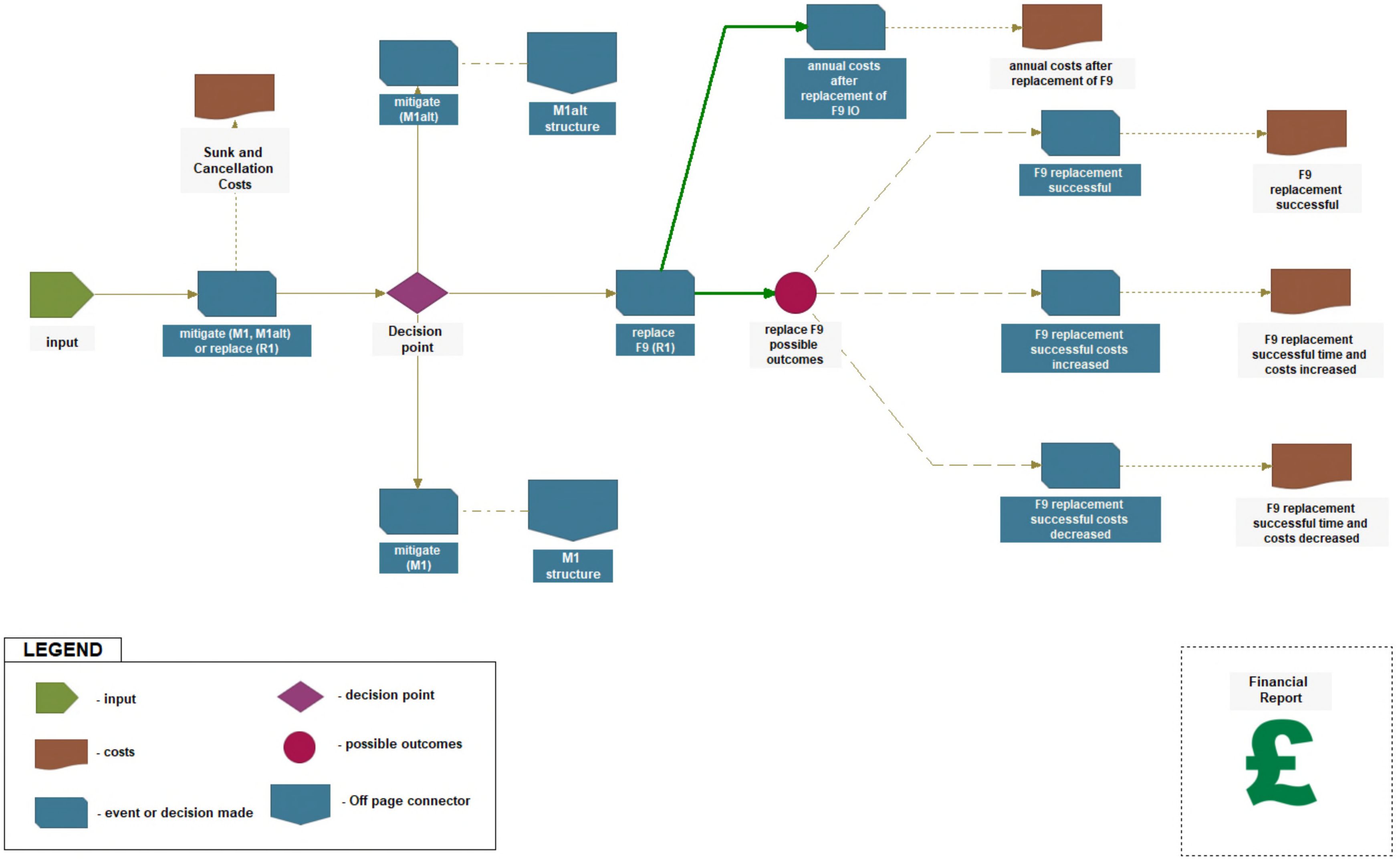


Fig. 46 High level view of Mitigate/Tunnel scenarios EO model. The "M1" refers to the mitigation options (mitigating the Feeder 9 risk using frond mattresses) and R1 refers to the tunnelled replacement option (replacing Feeder 9 with a new pipeline encases in a concrete tunnel under the Humber estuary). M1(alt) refers to the historic costs and risks associates with mitigating the current Feeder 9 pipeline up to and including 2016. From this top level of the decision tree the user can drill down to explore the more detailed levels of the decision tree encompassing a large number of decision options and possible outcomes.

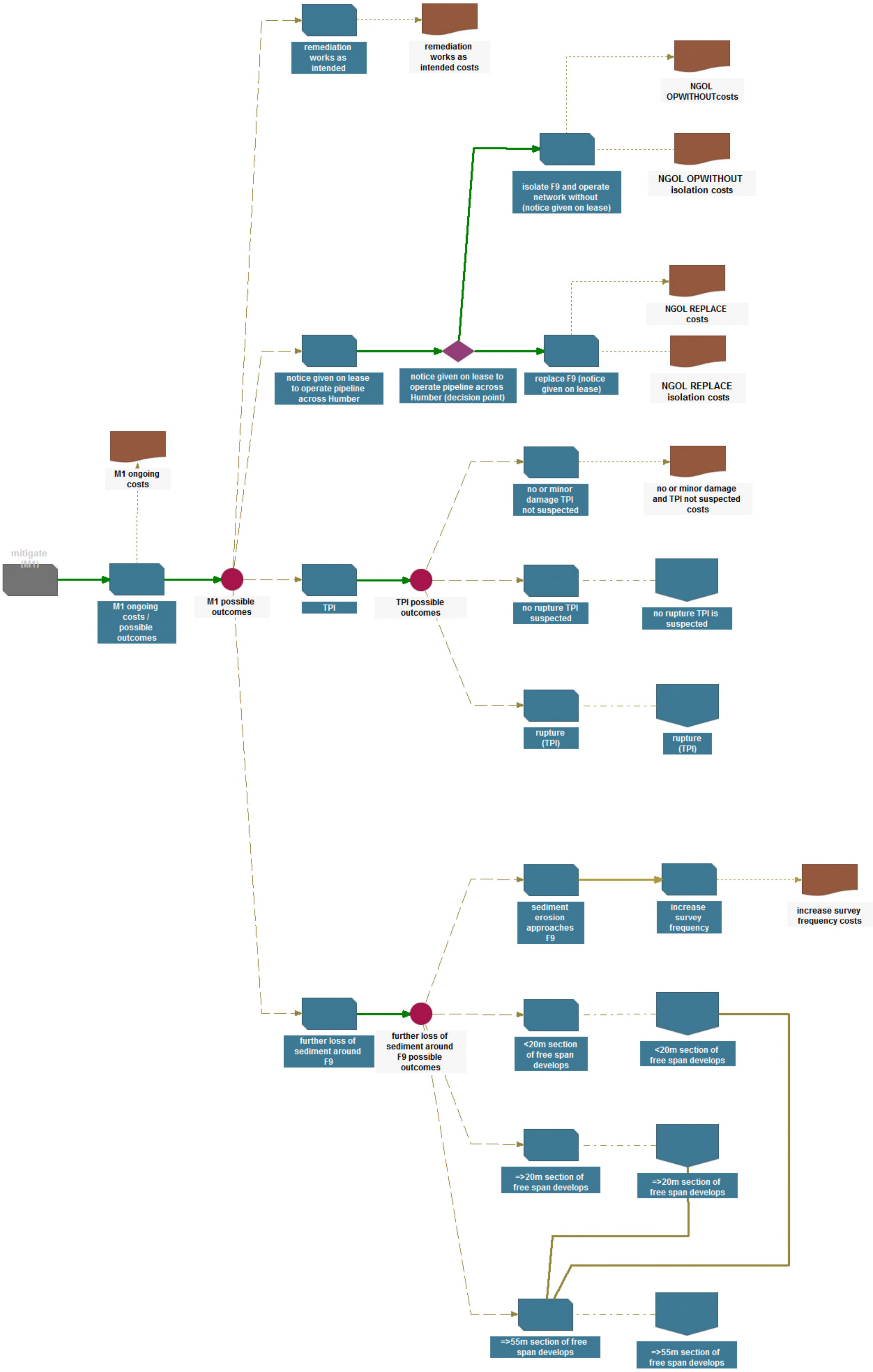


Fig. 47 M1 sub-layer view

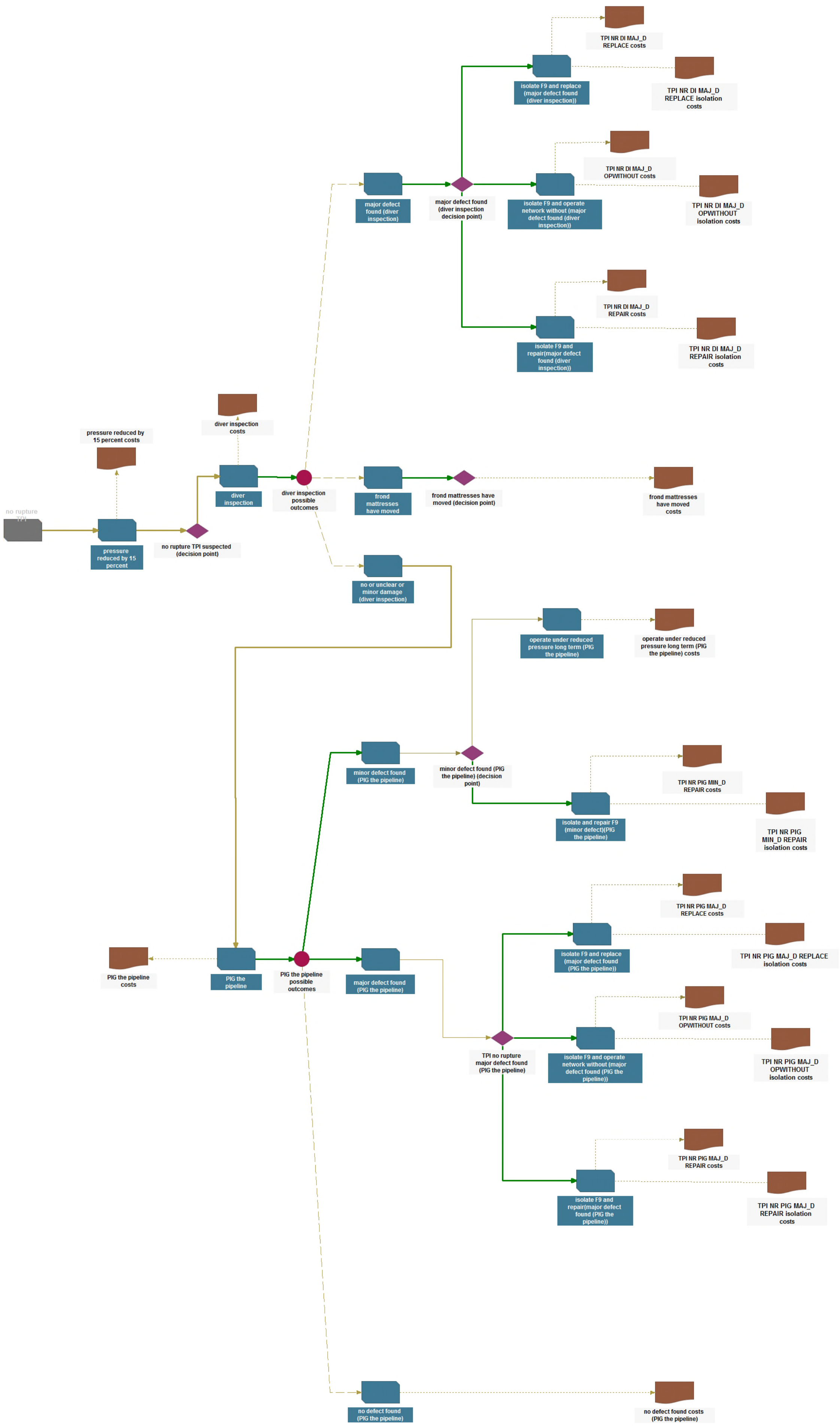


Fig. 48 M1 -> no rupture after TPI event sub-layer

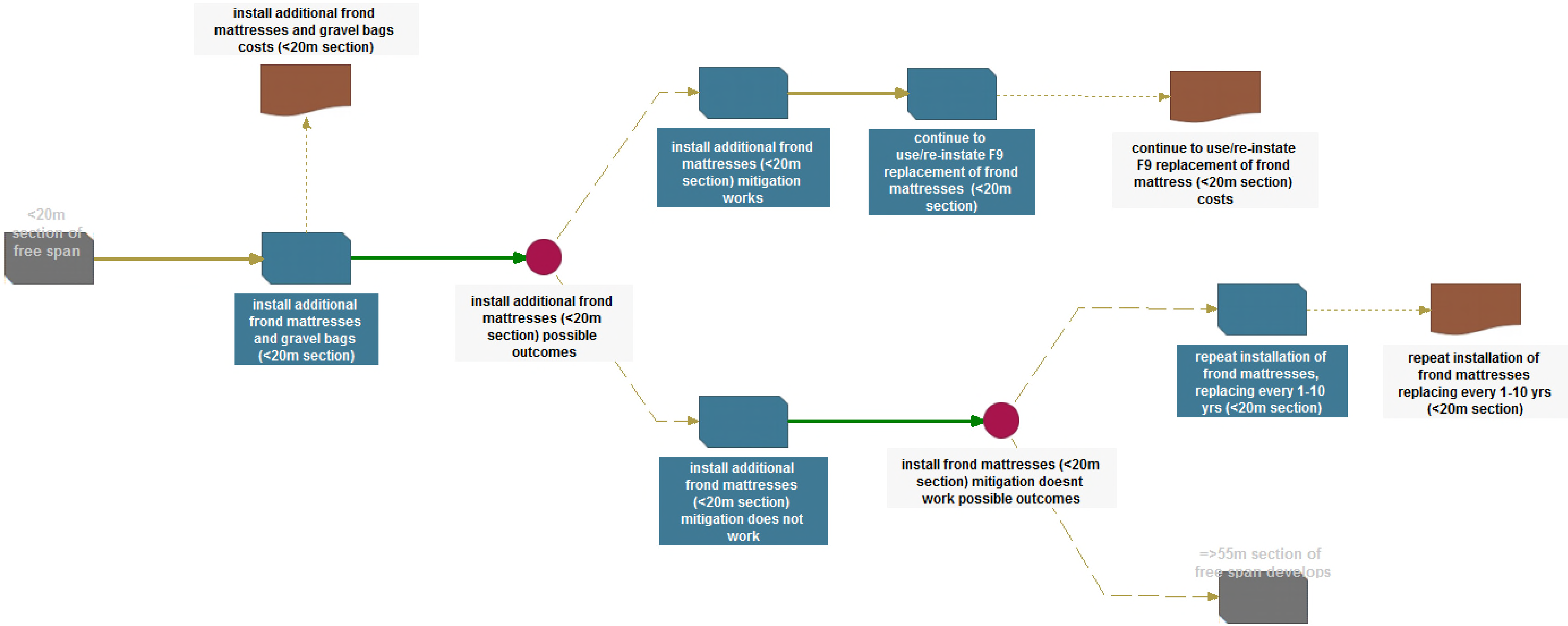


Fig. 49 M1 -> Further loss of sediment, <20m free span develops

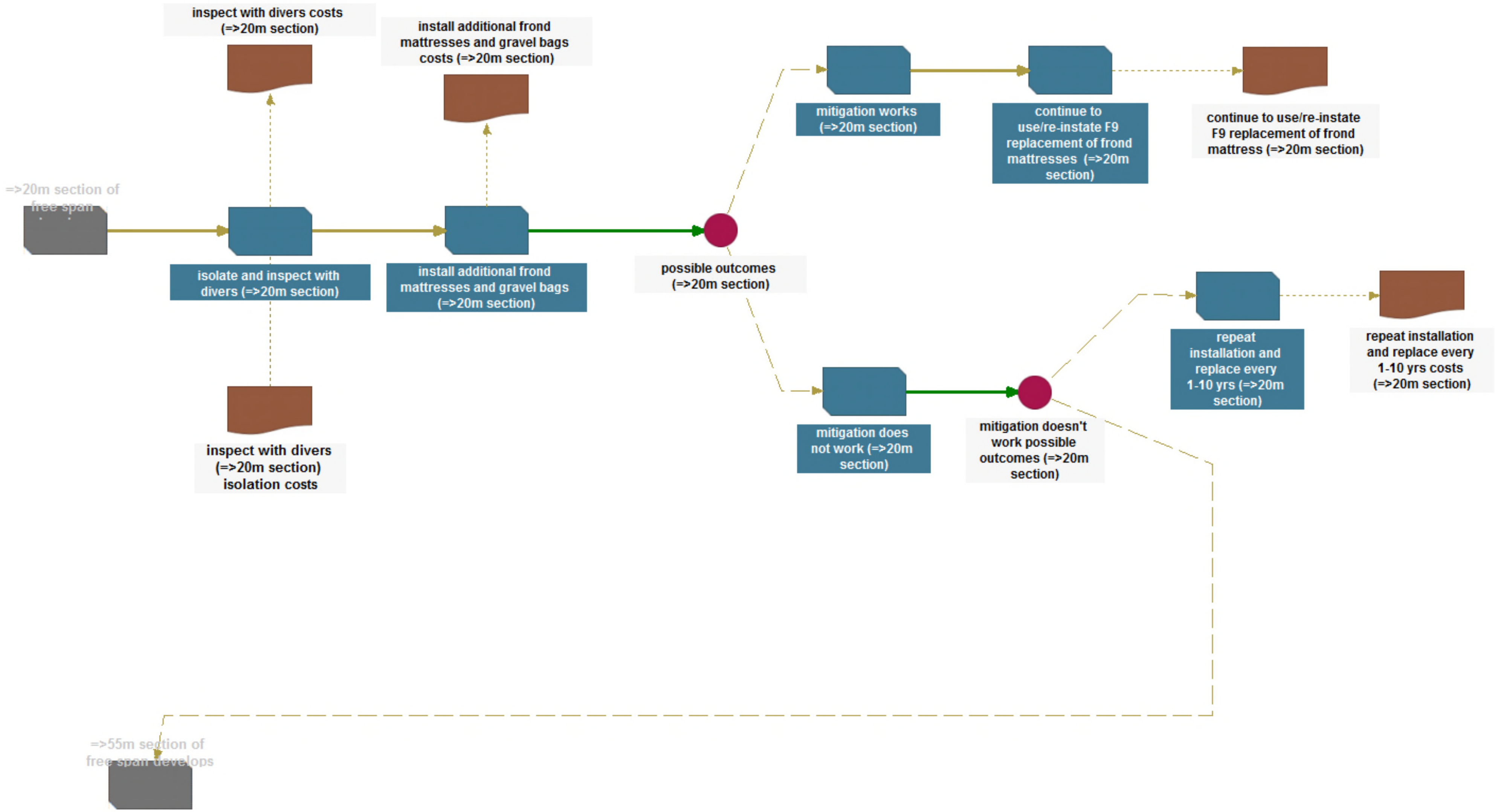


Fig. 50 M1 -> Further loss of sediment, =>20m free span develops

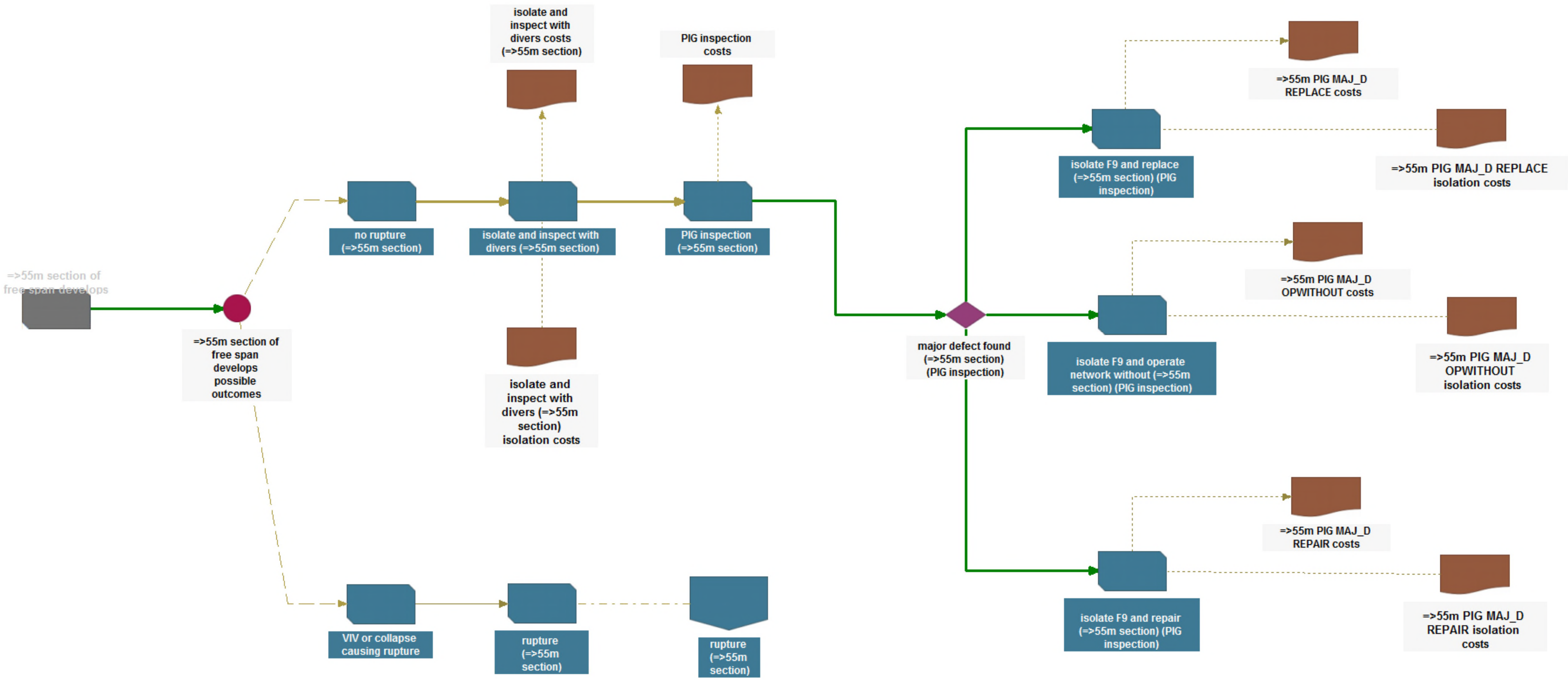


Fig. 51 M1 -> Further loss of sediment, =>55m free span develops

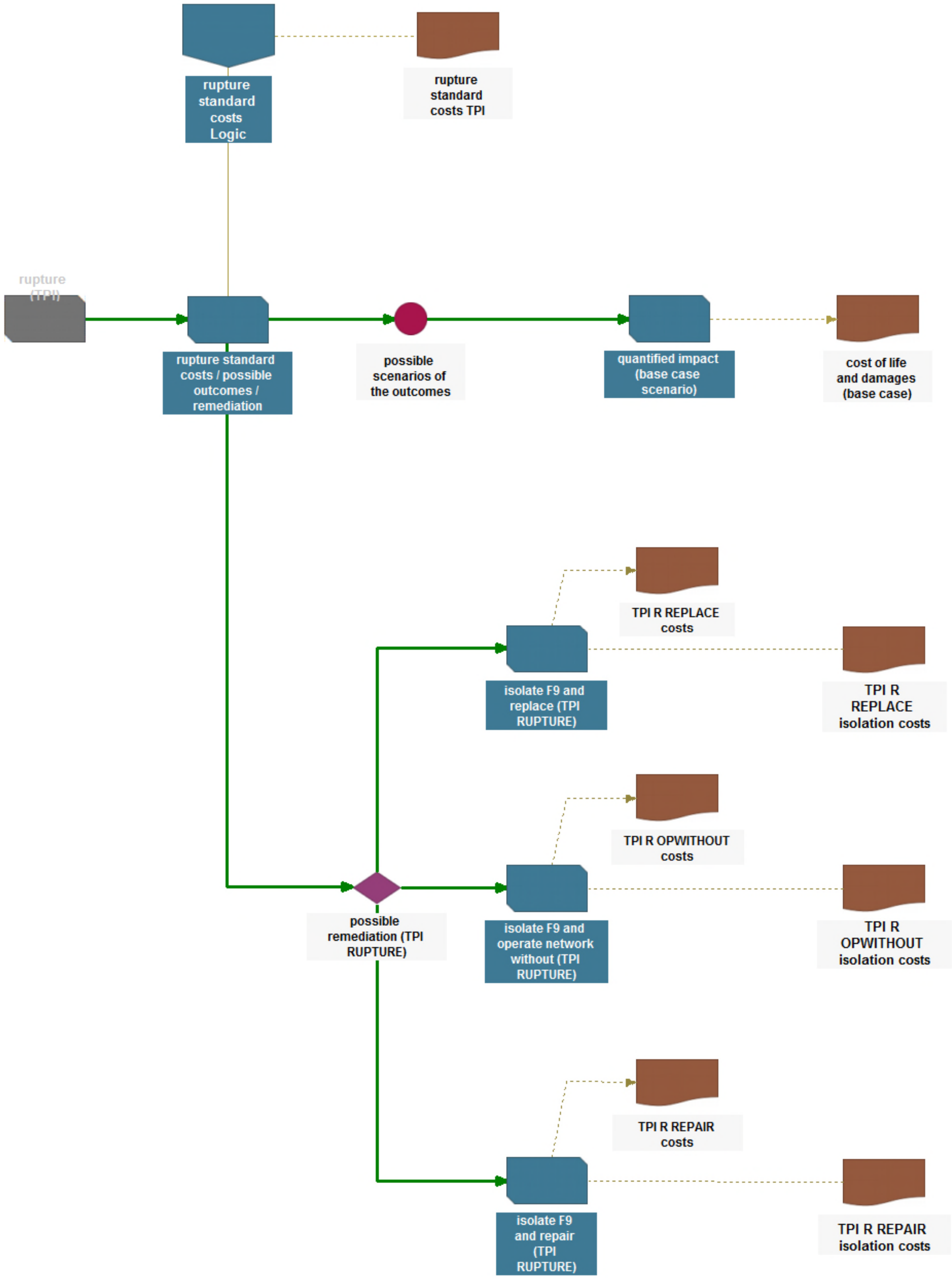


Fig. 52 M1 -> rupture view

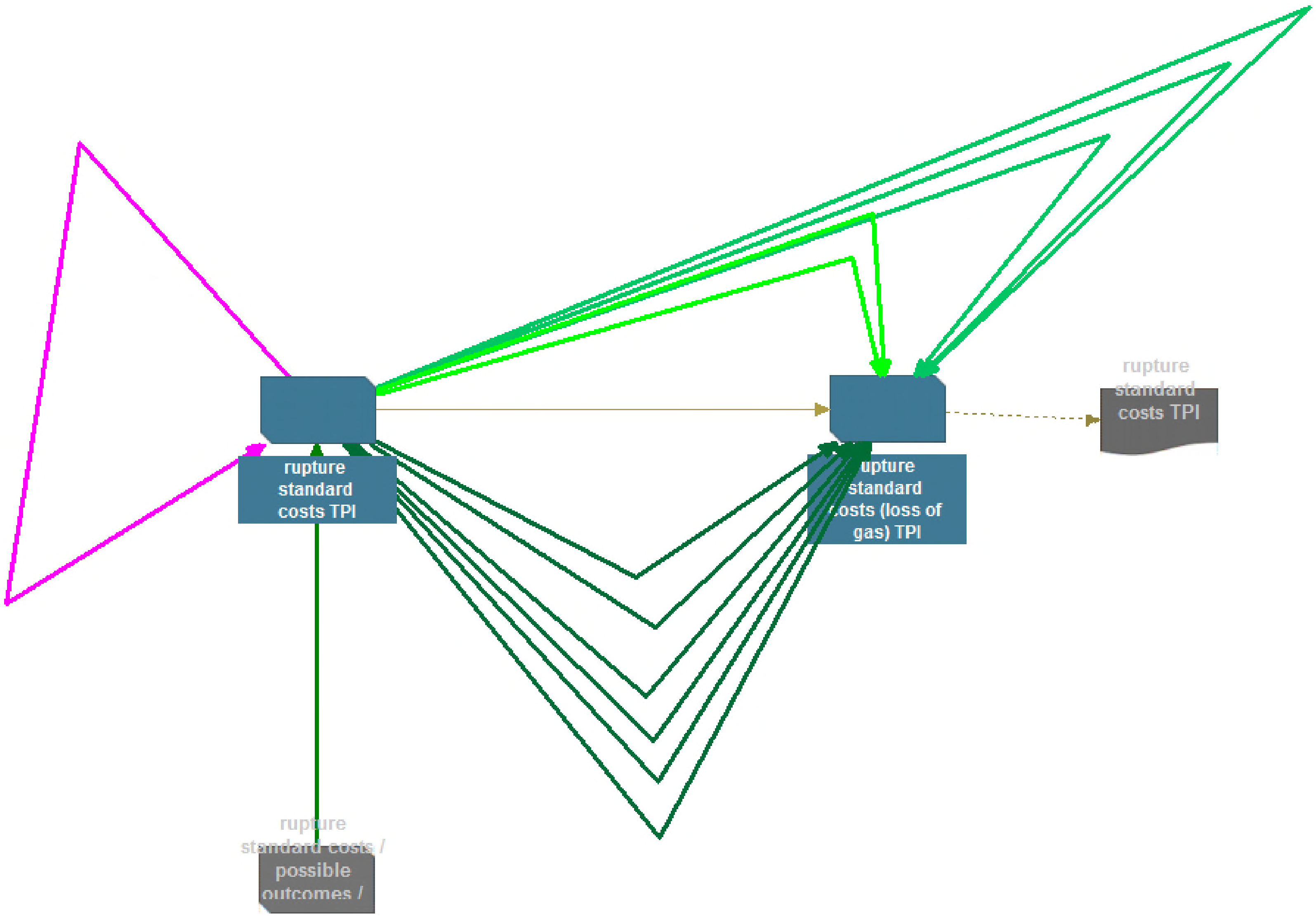


Fig. 53 M1 -> rupture wholesale gas impact logic

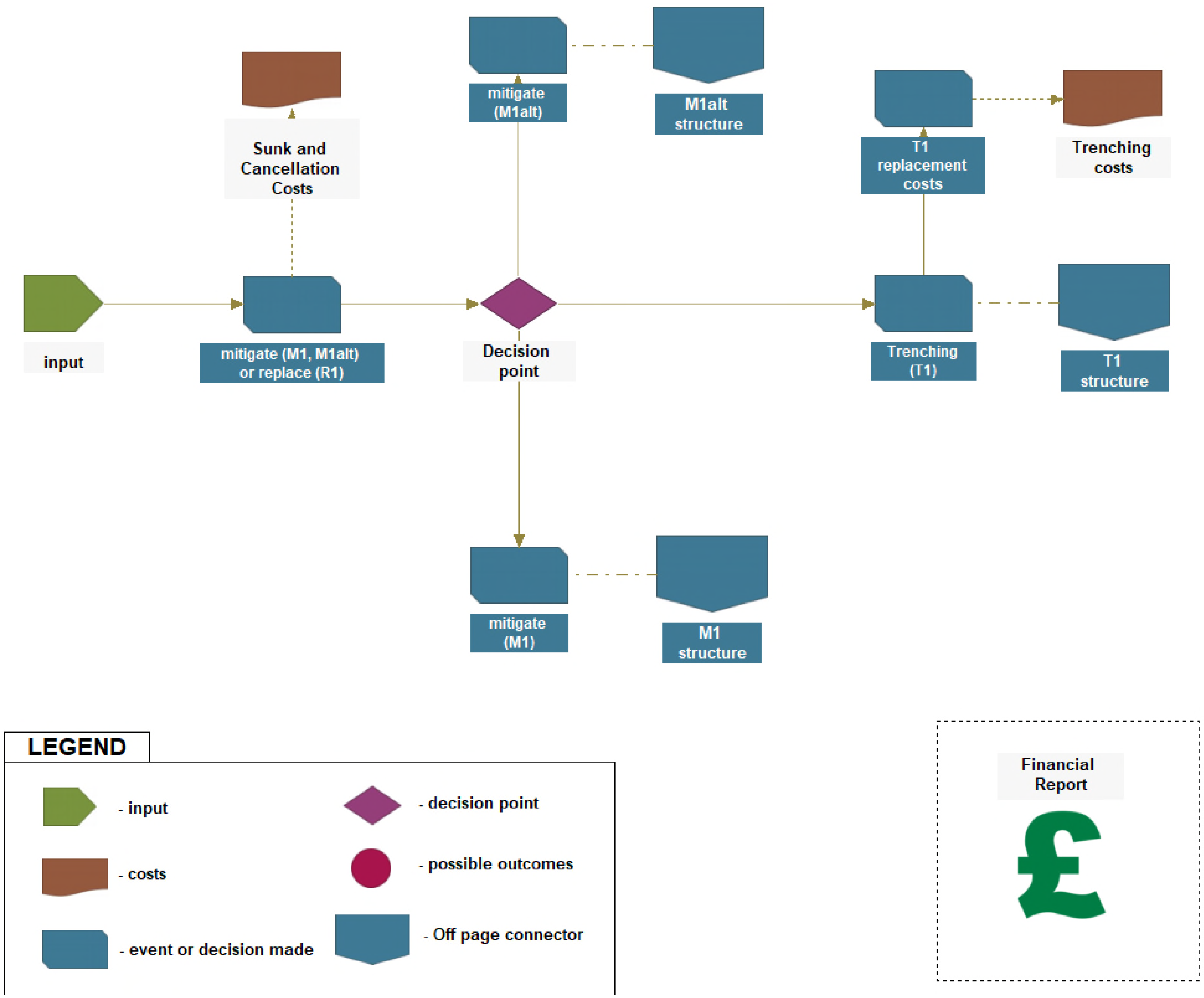
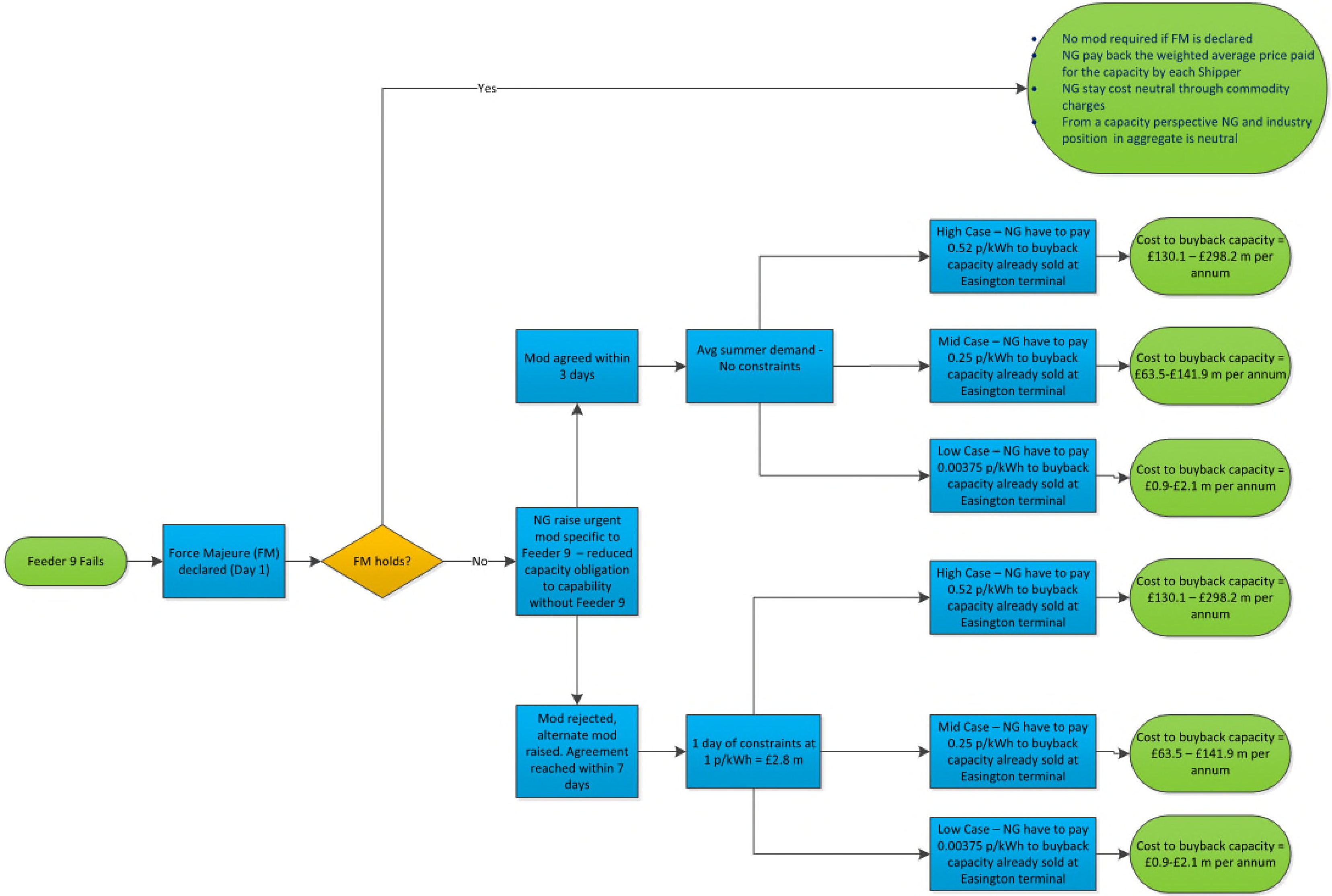


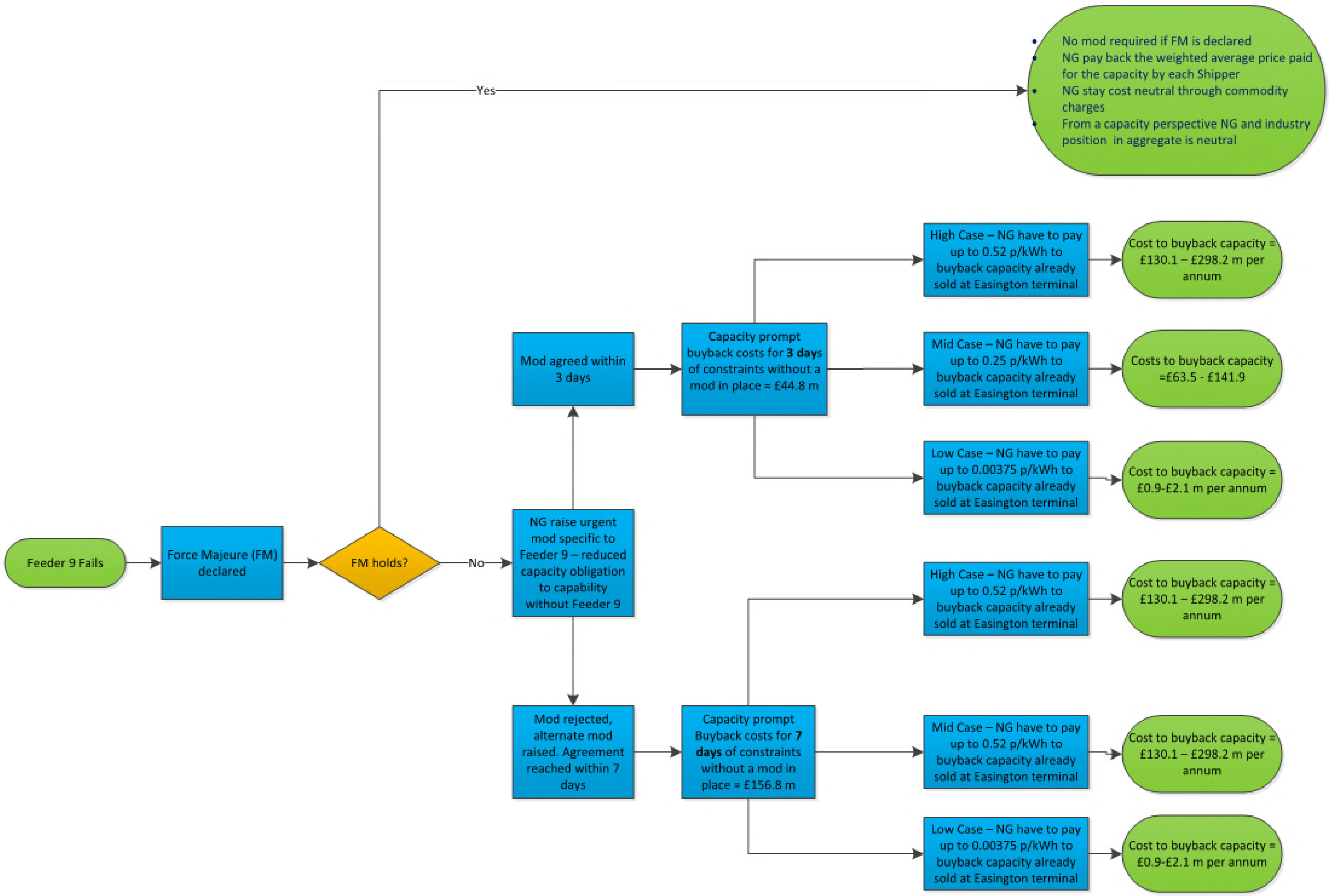
Fig. 54 High level view of Trench scenarios EO model. Here M1 refers to the mitigation options (mitigating the Feeder 9 risk using frond mattresses) and T1 refers to the trench replacement option (replacing Feeder 9 with a new pipeline in a trench across the Humber estuary). M1(alt) refers to the historic costs and risks associates with mitigating the current Feeder 9 pipeline up to and including 2016. From this top level of the decision tree the user can drill down to explore the more detailed levels of the decision tree encompassing a large number of decision options and possible outcomes.

Appendix C

Summer



Winter



Feeder 9 Fails
Force Majeure (FM) declared
FM holds?
Yes
No
No mod required if FM is declared
NG pay back the weighted average price paid for the capacity by each Shipper
NG stay cost neutral through commodity charges
From a capacity perspective NG and industry position in aggregate is neutral
NG raise urgent mod specific to Feeder 9 – reduced capacity obligation to capability without Feeder 9
Mod agreed within 3 days
Capacity prompt buyback costs for 3 days of constraints without a mod in place = £44.8 m
High Case – NG have to pay up to 0.52 p/kWh to buyback capacity already sold at Easington terminal
Cost to buyback capacity = £130.1 – £298.2 m per annum
Mid Case – NG have to pay up to 0.25 p/kWh to buyback capacity already sold at Easington terminal
Costs to buyback capacity =£63.5 - £141.9
Low Case – NG have to pay up to 0.00375 p/kWh to buyback capacity already sold at Easington terminal
Cost to buyback capacity = £0.9-£2.1 m per annum
Mod rejected, alternate mod raised. Agreement reached within 7 days
Capacity prompt Buyback costs for 7 days of constraints without a mod in place = £156.8 m
High Case – NG have to pay up to 0.52 p/kWh to buyback capacity already sold at Easington terminal
Cost to buyback capacity = £130.1 – £298.2 m per annum
Mid Case – NG have to pay up to 0.52 p/kWh to buyback capacity already sold at Easington terminal
Cost to buyback capacity = £130.1 – £298.2 m per annum
Low Case – NG have to pay up to 0.00375 p/kWh to buyback capacity already sold at Easington terminal
Cost to buyback capacity = £0.9-£2.1 m per annum

Appendix D

Appendix DTime Period (years)	Costs of building Bored Tunnel (Feeder 9 replacement)		
	Replacement successful (£)	Replacement successful costs increased (£)	Replacement successful costs decreased (£)
2014	693,266.04	734,404.11	677,177.81
2015	703,680.78	745,436.86	687,350.87
2016	3,549,009.56	3,759,606.09	3,466,649.77
2017	6,446,745.29	6,829,292.08	6,297,139.45
2018	6,935,706.72	7,347,268.24	6,774,753.84
2019	8,278,809.29	8,770,069.88	8,086,687.82
2020	6,252,450.23	6,623,467.64	6,107,353.28
2021	6,362,420.98	6,739,964.01	6,214,772.01
2022	9,438,720.29	9,998,809.46	9,219,681.44
2023	9,291,163.81	9,842,497.04	9,075,549.21
2024	9,143,607.33	9,686,184.63	8,931,416.99
2025	8,996,050.85	9,529,872.22	8,787,284.76
2026	8,848,494.37	9,373,559.80	8,643,152.54
2027	8,700,937.88	9,217,247.39	8,499,020.31
2028	8,553,381.40	9,060,934.97	8,354,888.08
2029	8,405,824.92	8,904,622.56	8,210,755.87
2030	8,258,268.44	8,748,310.14	8,066,623.64
2031	8,110,711.95	8,591,997.73	7,922,491.41
2032	7,963,155.47	8,435,685.31	7,778,359.19
2033	7,815,598.99	8,279,372.90	7,634,226.96
2034	7,668,042.51	8,123,060.48	7,490,094.74
2035	7,520,486.02	7,966,748.07	7,345,962.51
2036	7,372,929.54	7,810,435.65	7,201,830.28
2037	7,225,373.06	7,654,123.24	7,057,698.06
2038	7,077,816.58	7,497,810.82	6,913,565.83
2039	6,930,260.10	7,341,498.41	6,769,433.60
2040	6,782,703.60	7,185,186.01	6,625,301.38
2041	6,635,147.12	7,028,873.59	6,481,169.15
2042	6,487,590.64	6,872,561.18	6,337,036.92
2043	6,340,034.16	6,716,248.76	6,192,904.70
2044	6,192,477.67	6,559,936.35	6,048,772.47
2045	6,044,921.19	6,403,623.93	5,904,640.24
2046	5,897,364.71	6,247,311.52	5,760,508.02
2047	5,749,808.23	6,090,999.10	5,616,375.79
2048	5,602,251.74	5,934,686.69	5,472,243.58
2049	5,454,695.26	5,778,374.27	5,328,111.35
2050	5,307,138.78	5,622,061.86	5,183,979.12
2051	5,159,582.30	5,465,749.44	5,039,846.90
2052	5,012,025.82	5,309,437.03	4,895,714.67
2053	4,864,469.33	5,153,124.62	4,751,582.44
2054	4,716,912.85	4,996,812.20	4,607,450.22
2055	4,569,356.37	4,840,499.79	4,463,317.99
2056	4,421,799.89	4,684,187.37	4,319,185.76
2057	4,274,243.39	4,527,874.96	4,175,053.54
2058	4,126,686.91	4,371,562.55	4,030,921.31
2059	3,979,130.43	4,215,250.14	3,886,789.08
2060	3,631,457.02	3,846,945.95	3,547,183.93
2061	3,383,028.30	3,583,775.58	3,304,520.33
2062	2,349,326.92	2,488,734.85	2,294,807.46
2063	1,439,276.55	1,524,682.53	1,405,876.09
2064	735,016.71	778,632.25	717,959.61
2065	40,485.20	42,887.57	39,545.69
2066	0.00	0.00	0.00
2067	0.00	0.00	0.00
2068	0.00	0.00	0.00

Appendix E

Time Period (years)	Costs of trenching + DCO (Trench 2012)	Costs of trenching + DCO (Trench 2016)
2014	0.00	0.00
2015	0.00	0.00
2016	413,222.00	0.00
2017	570,406.00	307,000.00
2018	656,366.00	524,724.40
2019	7,567,672.80	691,118.40
2020	7,373,280.40	7,754,820.00
2021	4,507,005.60	8,186,216.40
2022	6,723,914.00	6,710,406.00
2023	6,621,990.00	6,610,324.00
2024	6,520,066.00	6,510,242.00
2025	6,418,264.80	6,410,160.00
2026	6,316,340.80	6,310,078.00
2027	6,214,416.80	6,209,996.00
2028	6,112,492.80	6,109,914.00
2029	6,010,691.60	6,009,954.80
2030	5,908,767.60	5,909,872.80
2031	5,806,843.60	5,809,790.80
2032	5,704,919.60	5,709,708.80
2033	5,603,118.40	5,609,626.80
2034	5,501,194.40	5,509,544.80
2035	5,399,270.40	5,409,462.80
2036	5,297,346.40	5,309,380.80
2037	5,195,545.20	5,209,298.80
2038	5,093,621.20	5,109,339.60
2039	4,991,697.20	5,009,257.60
2040	4,889,773.20	4,909,175.60
2041	4,787,972.00	4,809,093.60
2042	4,686,048.00	4,709,011.60
2043	4,584,124.00	4,608,929.60
2044	4,482,200.00	4,508,847.60
2045	4,380,398.80	4,408,765.60
2046	4,278,474.80	4,308,683.60
2047	4,176,550.80	4,208,724.40
2048	4,074,749.60	4,108,642.40
2049	3,972,825.60	4,008,560.40
2050	3,870,901.60	3,908,478.40
2051	3,768,977.60	3,808,396.40
2052	3,667,176.40	3,708,314.40
2053	3,565,252.40	3,608,232.40
2054	3,463,328.40	3,508,150.40
2055	3,361,404.40	3,408,068.40
2056	3,259,603.20	3,308,109.20
2057	3,157,679.20	3,208,027.20
2058	3,055,755.20	3,107,945.20
2059	2,953,831.20	3,007,863.20
2060	2,852,030.00	2,907,781.20
2061	2,750,106.00	2,807,699.20
2062	2,571,186.40	2,707,617.20
2063	2,391,161.60	2,550,924.40
2064	2,226,364.00	2,374,829.20
2065	807,778.40	2,198,365.60
2066	0.00	906,632.40
2067	0.00	0.00
2068	0.00	0.00

Appendix F

Scenario Full Name	High Level Cost Area	Average Total Cost
Stop Tunnel 2016 and Build Trench	Frond Mattresses Installation and Maintenance	£22,691,661.74
Stop Tunnel 2016 and Mitigate	Frond Mattresses Installation and Maintenance	£112,965,013.21
Stop Tunnel and Mitigate from 2017	Frond Mattresses Installation and Maintenance	£112,919,419.11
Trench Replacement start in 2012	Frond Mattresses Installation and Maintenance	£22,639,563.75
Tunnel Replacement start in 2012	Frond Mattresses Installation and Maintenance	£20,713,746.30
Stop Tunnel 2016 and Build Trench	lose lease to operate pipeline	£91,105,994.38
Stop Tunnel 2016 and Mitigate	lose lease to operate pipeline	£90,291,007.81
Stop Tunnel and Mitigate from 2017	lose lease to operate pipeline	£90,791,966.01
Trench Replacement start in 2012	lose lease to operate pipeline	£90,247,892.44
Tunnel Replacement start in 2012	lose lease to operate pipeline	£16,732,711.82
Stop Tunnel 2016 and Build Trench	Risk Adjusted Impact of Freespanning	£216,331,369.68
Stop Tunnel 2016 and Mitigate	Risk Adjusted Impact of Freespanning	£331,193,839.71
Stop Tunnel and Mitigate from 2017	Risk Adjusted Impact of Freespanning	£324,181,278.95
Trench Replacement start in 2012	Risk Adjusted Impact of Freespanning	£214,746,984.20
Tunnel Replacement start in 2012	Risk Adjusted Impact of Freespanning	£56,605,780.69
Stop Tunnel 2016 and Build Trench	Risk Adjusted Impact of TPI	£17,055,800.06
Stop Tunnel 2016 and Mitigate	Risk Adjusted Impact of TPI	£26,282,818.63
Stop Tunnel and Mitigate from 2017	Risk Adjusted Impact of TPI	£25,803,984.03
Trench Replacement start in 2012	Risk Adjusted Impact of TPI	£17,001,313.34
Tunnel Replacement start in 2012	Risk Adjusted Impact of TPI	£4,635,574.65
Stop Tunnel 2016 and Build Trench	Routine Pipeline Maintenance	£18,558,000.00
Stop Tunnel 2016 and Mitigate	Routine Pipeline Maintenance	£22,070,400.00
Stop Tunnel and Mitigate from 2017	Routine Pipeline Maintenance	£22,070,400.00
Trench Replacement start in 2012	Routine Pipeline Maintenance	£18,558,000.00
Tunnel Replacement start in 2012	Routine Pipeline Maintenance	£4,046,240.00
Stop Tunnel 2016 and Build Trench	Sunk and Cancellation Costs	£16,191,819.07
Stop Tunnel 2016 and Mitigate	Sunk and Cancellation Costs	£15,539,819.07
Stop Tunnel and Mitigate from 2017	Sunk and Cancellation Costs	£50,474,524.90
Trench Replacement start in 2012	Sunk and Cancellation Costs	£652,000.00
Stop Tunnel 2016 and Build Trench	Trenched replacement	£218,564,106.40
Trench Replacement start in 2012	Trenched replacement	£218,564,106.40
Stop Tunnel 2016 and Mitigate	Tunnelled Replacement	£0.00
Stop Tunnel and Mitigate from 2017	Tunnelled Replacement	£0.00
Tunnel Replacement start in 2012	Tunnelled Replacement	£315,882,688.47

Scenario Full Name	Detailed Cost Centre	Average Total Cost
Stop Tunnel 2016 and Build Trench	Capacity buy-back	£16,333,122.39
Stop Tunnel 2016 and Mitigate	Capacity buy-back	£25,830,299.93
Stop Tunnel and Mitigate from 2017	Capacity buy-back	£25,299,931.11
Trench Replacement start in 2012	Capacity buy-back	£16,104,408.92
Tunnel Replacement start in 2012	Capacity buy-back	£1,785,394.33
Stop Tunnel 2016 and Build Trench	Construction costs	£218,564,106.40
Trench Replacement start in 2012	Construction costs	£218,564,106.40
Tunnel Replacement start in 2012	Construction costs	£312,287,313.47
Stop Tunnel 2016 and Build Trench	Damage due to TPI or Freespanning	£198,521.50
Stop Tunnel 2016 and Mitigate	Damage due to TPI or Freespanning	£295,510.39
Stop Tunnel and Mitigate from 2017	Damage due to TPI or Freespanning	£294,641.77
Trench Replacement start in 2012	Damage due to TPI or Freespanning	£197,897.07
Tunnel Replacement start in 2012	Damage due to TPI or Freespanning	£54,130.28
Stop Tunnel 2016 and Build Trench	Direct Impacts of Rupture (loss of life etc.)	£104,143,402.09
Stop Tunnel 2016 and Mitigate	Direct Impacts of Rupture (loss of life etc.)	£154,298,322.07
Stop Tunnel and Mitigate from 2017	Direct Impacts of Rupture (loss of life etc.)	£154,029,371.06
Trench Replacement start in 2012	Direct Impacts of Rupture (loss of life etc.)	£103,786,828.74
Tunnel Replacement start in 2012	Direct Impacts of Rupture (loss of life etc.)	£28,361,946.65
Stop Tunnel 2016 and Build Trench	Emergency isolation and replacement	£102,241,915.94
Stop Tunnel 2016 and Mitigate	Emergency isolation and replacement	£106,972,596.89
Stop Tunnel and Mitigate from 2017	Emergency isolation and replacement	£107,419,566.64
Trench Replacement start in 2012	Emergency isolation and replacement	£101,347,905.44
Tunnel Replacement start in 2012	Emergency isolation and replacement	£19,787,741.72
Stop Tunnel 2016 and Build Trench	F9 stabilisation or decommissioning	£145,882.02
Stop Tunnel 2016 and Mitigate	F9 stabilisation or decommissioning	£217,218.61
Stop Tunnel and Mitigate from 2017	F9 stabilisation or decommissioning	£216,981.79
Trench Replacement start in 2012	F9 stabilisation or decommissioning	£145,859.40
Tunnel Replacement start in 2012	F9 stabilisation or decommissioning	£40,212.20
Stop Tunnel 2016 and Build Trench	Increase in wholesale gas prices	£98,561,221.72
Stop Tunnel 2016 and Mitigate	Increase in wholesale gas prices	£155,969,335.18
Stop Tunnel and Mitigate from 2017	Increase in wholesale gas prices	£149,333,037.57
Trench Replacement start in 2012	Increase in wholesale gas prices	£97,533,677.26
Tunnel Replacement start in 2012	Increase in wholesale gas prices	£27,170,620.68
Stop Tunnel 2016 and Build Trench	Loss of gas	£296,933.84
Stop Tunnel 2016 and Mitigate	Loss of gas	£333,999.38
Stop Tunnel and Mitigate from 2017	Loss of gas	£334,823.08
Trench Replacement start in 2012	Loss of gas	£294,623.63
Tunnel Replacement start in 2012	Loss of gas	£61,640.68
Stop Tunnel 2016 and Build Trench	Operational and Maintenance Costs	£43,821,826.36
Stop Tunnel 2016 and Mitigate	Operational and Maintenance Costs	£138,885,796.92
Stop Tunnel and Mitigate from 2017	Operational and Maintenance Costs	£138,838,695.09
Trench Replacement start in 2012	Operational and Maintenance Costs	£43,782,553.25
Tunnel Replacement start in 2012	Operational and Maintenance Costs	£29,067,741.91
Stop Tunnel 2016 and Build Trench	Sunk Costs and Cancellation Costs	£15,539,819.07
Stop Tunnel 2016 and Mitigate	Sunk Costs and Cancellation Costs	£15,539,819.07
Stop Tunnel and Mitigate from 2017	Sunk Costs and Cancellation Costs	£50,474,524.90
Stop Tunnel 2016 and Build Trench	Trench Environmental Costs	£652,000.00
Trench Replacement start in 2012	Trench Environmental Costs	£652,000.00

Appendix G*

*Please note that document uses the previous naming conventions of the early version of the EO model. T1 corresponds to Trench Scenarios, M1 to Mitigate Scenarios, and R1 to Tunnel Replacement Scenario.

Peer review of NIA project:

An extreme value analysis model for investment optioneering by Business Modelling Associates

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Date: 30/06/2017

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NIA Project: Peer review report

Business Modelling Associates is commissioned by National Grid to develop a tool to assess investment options for Feeder 9. This peer review report is aimed to provide an independent assessment of this work and is structured around four sections as follows: a brief summary of on economic appraisal of investment options, application of real options analysis for the alternative remediation options for Feeder 9, review of recent academic studies on impact of shocks on gas prices and commentary on the study.

1. Economic appraisal of investment options

Pay-back period and/or discounted cash flow (DCF) methods are conventional approaches used in economic appraisals. The former would aim to estimate the number of years it would take for the income from a particular investment to pay back the costs of the investment. However the focus on the time horizon to recoup the investment means that benefits that might emerge after the payback period are overlooked. Also, the timing of returns to investment is not reflected in this method which might be really important for investments with long lead periods. In DCF method, the present value of future cash flows are determined by discounting them using an appropriate cost of capital (or discount rate). Whilst DCF addresses the shortcoming of pay-back period method by capturing time cost of money, it is limited in capturing the impact of uncertainty on investment decisions when management actions can be timed flexibly. These uncertainties might arise from a number of factors ranging from political, economic to social, legal, environmental and technological risks. Ioannou et al. (2017) offer a comprehensive list of these different factors specifically for renewable energy sector most of which are relevant for gas networks as well (Table 40).

Table 40. Risks for gas networks

Risk category	Sub-category	Risk factors/ events
Political	Country	Changes in the national economy Political stability
	Regulatory	Changes in policy support schemes (for example changes in levels of tax credit or RPS targets) Liability to third parties Contracting risk
	Bureaucracy	Complex approval processes/Delay of permits
Economic	Market	Variability of revenue due to electricity price Demand fluctuations
	Financial/Fiscal	Generating costs (CAPEX, fixed and variable OPEX, pre-development costs) Interest rate swings Financing risks (insufficient access to investment and operating capital) Taxation regime Transaction costs
	Strategic/business	Damage to reputation
Social	Lack of public acceptance	Delays in the licence acquisition
	Health risks	Accidents, acute diseases
Technological	Project development	Revenue loss due to project delay for the commercial operation date (COD) Failure to obtain all required licences
	Construction	Damage during transport or construction Damages due to natural hazards Unreliability of components or materials Unavailability of skilled labour
	Operation/maintenance	Damages due to natural hazards Technological/innovation risk Higher OPEX due to critical failures of components Sabotage, terrorism and theft risk
	Resource risk	Revenue loss due to interruptions to supply
	Infrastructure	Variability of revenue due to grid availability
	Decommission	Decommissioning costs
Legal	Energy and climate change policy	Changes in the national energy and climate change policy
Environmental		Risk of environmental damage Carbon footprint and life cycle assessment

Source: Adapted from (Ioannou et al., 2017)

Real options analysis (ROA) focuses on the timing of the decision by taking into account the values of alternative options at each time period. Other methods focus on a binary decision making process, i.e. whether to undertake the project or not. ROA takes into account the effects of different sources of uncertainty on the cash-flow explicitly. In this sense it recognises that decision maker have the right but not the obligation to invest until positive market signals emerge (Cheng 2017).

Martins et al. (2013) identify five alternative methods to implement ROA: the Black-Scholes Option pricing model, the Binomial option pricing model, the risk-adjusted decision trees, the Monte Carlo simulation and hybrid real options. The project has used decision tree analysis combined with Monte Carlo simulations.

2. Application of ROA to appraise the replacement of Feeder F9

This review focuses solely on the implementation of the ROA to appraise the benefit/cost impact of the alternative remediation options – a sub-riverbed new pipeline - for Feeder Number9 replacement.

The use of Enterprise Optimiser seems to be appropriate, based on my view of the outputs provided by the project team. The project team provided powerpoint slides outlining the decision points and relevant alternative options. This was complemented with a tool to analyse and visualise the numerical outputs of the model. The finalised set of outputs refers to the modelling of three alternative options: maintenance (M1), replacement (R1) and Trenching (T1).

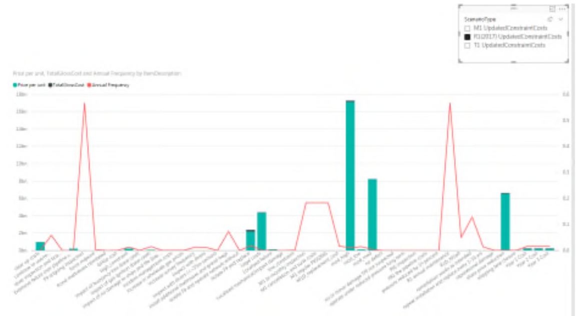
2.1. Modelling uncertainty

The scope identifies that when risks can't be represented as PDFs, then a discrete risk event modelling approach will be followed to analyse a best, worst and an expected case. Indeed, this seems to have been done in the modelling M1, TPI rupture standard costs or M1, remediation works as planned. One suggestion here is provision of a summary table of cases where this discrete event modelling approach has been followed, along with their justifications.

2.2. Overall comments

Overall approach is sound. As evident in the graphs provided by the project team (Figure 2), the events with high costs have low probabilities across three scenarios.

Option: M1



Option: R1

Option: T1

Figure 2. Review of costs and frequencies across three options

3. Impact of shocks on gas prices

A review of shocks to gas networks is provided in a recent study by Skea et al. (2012). They note that there have been no massive global gas supply disruptions in the last 20 years. As gas networks are spatial, most shocks occurred in specific locations (Table 41). The aging of transmission infrastructure or extreme weather events are common causes. They analyse economic impacts of a supply shock by multiplying the energy unserved (which depends on the magnitude and duration of the shortfall) by the value of lost load (assuming £10/kWH).

Table 41. Review of gas supply crises and accidents

Date	Place	Duration	Cause	Loss
September 2010–January 2011	Norway's Kollsnes gas plant	Several months	Technical problems related to recovering natural gas liquids from two fields	The operation of Kollsnes was reduced dramatically
April–June 2010	UK	Several months	Qatari liquefied natural gas (LNG) producers ran an extensive summer maintenance programmes reducing global supplies	Forward British gas prices for the following winter 2010/11 rose significantly as a result
Several occasions in 2004, 2007 and June 2010	Belarus	Several days	Russian companies cut off natural gas supplies to the Belarus to force payment of debts	The gas supplies in many European countries which depend on Russian natural gas were curtailed or threatened
Several times in 2002, 2006 and January 2009	Ukraine	1 to several days	Russian companies cut off natural gas supplies to the Ukraine and Georgia to force payment of debts	The gas supplies in many European countries depending on Russian natural gas were curtailed or threatened
28 February 2008–3 March 2008	UK Bacton terminal	4 days	The terminal was shut down due to a fire breaking out at a waste water treatment plant	An instantaneous reduction in supply of around 30 mcm
July 1, 2007–mid September 2007	UK CATS pipeline	About 2 months	The pipeline's protective casing was damaged by the anchor of a large vessel in June 2007	Some oil and gas fields, such as J-block and Armada, had to stop producing
February 16, 2006	The Bravo rig, in Centrica's Rough field, UK	About 4 months	There was an apparent failure of a cooler unit in one of four dehydration units and an explosion occurred in that vicinity	Two people were injured. The main consequence of the Rough incident was higher prices after the event
September–December 2005	US	4 months	Hurricanes	10% of US gas production was reduced during the last four months of 2005
November 2005	UK interconnector	Early part of the winter 2005/2006	Possible reasons include infrastructure bottlenecks, legal restrictions and lack of transparency about gas movements in the EU and Norwegian markets	The UK failed to attract gas from continental Europe through the Interconnector even though UK prices were higher than those in Europe
17 and 18 June 2003	Bacton, UK	2 days	A number of localised system balancing actions taken to address a supply deficit in the south of Great Britain failed to result in a sufficient physical response	National Grid Transco (NGT) interrupted 10.5 mcm of National Transmission System (NTS) load on 17 June and 11 mcm of NTS and Local Distribution Zones (LDZ) loads on 18 June, as well as flows to the Belgian interconnector
15 December, 1999	Easington terminal, UK		Easington terminal was struck by lightning, limiting the operation of the Rough subterminal and other facilities	This reduction in flows contributed to a sharp increase in prices
September 25–October 14 1998	Victoria, Australia	19 days	A vessel in a natural gas processing plant fractured, releasing hydrocarbon vapours and liquid	1.3 million households and 89,000 businesses were affected. The commercial/ industrial cost was AUD $1.3 bn. Two people were killed

Source: Skea et al. (2012)

A common approach used in analysing the determinants of volatility of gas prices is vector autoregressive (econometric) methods. Nick and Thoenes (2014) analyse the effects of natural gas supply interruptions in German gas market which is heavily dependent on gas imports via pipelines. The analysis focus on three recent supply interruptions: the Russian–Ukrainian gas dispute of January 2009, the Libyan civil war in 2011 and the withheld Russian exports in February 2012. They find that shortfall of natural gas supplies accounts for an increase in the gas price of more than 30% in the short term (Figure 2). Unusually low temperatures make up 10% of the price increases. The actual increase in the gas price was less than what would have been implied by the sudden supply shortfall and extreme temperature when setting all other influences to zero as this event has occurred during the financial crisis where the natural gas price was already following a negative trend.

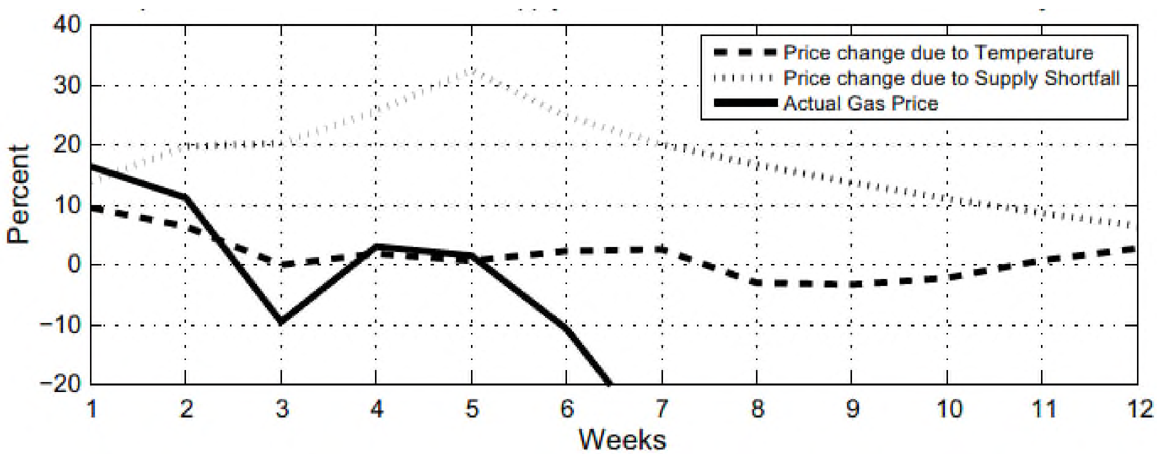


Figure 3. Historical decomposition of structural influences during the Russian–Ukrainian gas dispute of January 2009 on German gas market

Source: Nick and Thoenes (2014), p.525

They also analyse the impact of supply interruptions of Russian natural gas deliveries in February 2012. In early 2012, unusually low temperatures across Central and Western Europe, coupled with higher domestic gas demand in Russia resulted in Russia not being able to meet its export commitments and thereby induced supply shortages. In this instance, they report that the abnormally low temperatures can explain a bigger share of the actual price increase than the relatively small amount of supply shortfall. In other words, price increase was driven by a positive demand shock than by the temporary cut in gas supplies (Figure 4).

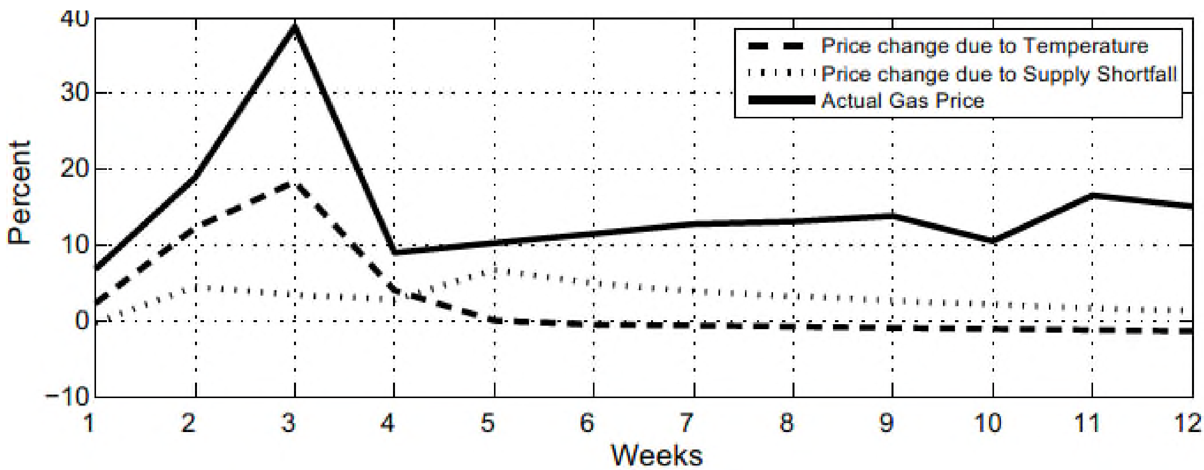


Figure 4. Historical decomposition of structural influences during the Russian supply shortfall in February 2012 on German gas market

Source: Nick and Thoenes (2014), p.525

For the UK, Misund and Oglend (2016) analyse the impacts of changes in supply or demand on gas prices. The analysis is carried out using disaggregated daily U.K. natural gas demand and supply at the U.K. National Balancing Point (NBP) system, collected from National Grid. They find that deviations in one or more of the supply or demand elements are compensated by opposite deviations in the other elements. For example, positive deviations in aggregate demand (at local distribution zone level) on time t-1 is positively associated with positive and significant deviations in pipeline imports, LNG imports, and storage withdrawals at time t. This mitigation of shocks in single demand or supply elements by the optimization of flexible assets such as storage or interconnectors point to flexibility of UK gas system, confirming the strong link between volatility and natural gas storages.

A more recent, long-term analysis is carried out for the U.S. gas market. Wiggins and Etienne (2017) find that during 1993-2015, the relative contribution of supply disruptions to the total variance of the natural gas price forecast error has been consistently above 25%. Another factor that affects price fluctuations with a similar magnitude is aggregate economic demand, though after 2009 this influence has declined to about 20%.

Overall, the academic studies reveal that shocks in supply account for around 25-30% of gas price volatility. However, as gas networks are spatial, the inherent characteristics of the gas networks in terms of its storage capacity, interconnections and LNG imports will play a key role on the magnitude of these shocks.

4. Commentary on the model

This section includes a discussion of key issues that need to be taken into account in the study. These issues have been grouped into three categories as follows:

- Red – The model does not take into account something critical / serious flaw in methodology
- Amber – The model does not completely take something important into account / moderate flow in methodology
- Green – no or minor omission/flaw

4.1. Critical issues (RED)

Market risk is a critical issue as the importance of gas in future UK energy is very uncertain. Marginal cost of one extra unit of unsupplied gas (e.g. mcm) will depend on whether gas has a central role in the UK energy system. The impacts will be more severe in a scenario where gas plays a prominent role in balancing intermittent resources compared to the case alternative options (e.g. storage, demand side response or interconnectors) are used. This is one of the key uncertainties that will influence the benefit/cost impact of alternative investment options. Would the results be tested using FES scenarios? How do these scenarios compare against DECC or other academic scenarios (e.g. UKERC)?

4.2. Important issues (AMBER)

Environmental risks and changes in ecosystem services: Are environmental risks taken into account across three scenarios? For example, if there was a gas ignition/ rupture, what would be the impact on the values stakeholders attach for recreational use of the area? In R1 or T1 scenarios, do the values associated with the destruction of seabed are taken into account?

Market risks: If some of the gas network were to be used to deliver hydrogen at a later stage, would it have any effects on the design of F9?

4.3. Minor issues (GREEN)

Financial risks: How would the availability and cost of capital influence the results (in a post-Brexit world)? Is it realistic to assume WACC=4.38? Should it be changed as going far into the future?

Value of loss life: An initial literature review reveals a value of between US$1.5-4.5M (a mid point value of US$3M, as at 2005; Clough et al., 2015) whereas the project uses £16M.

Regulatory risks: Does the model include the value of a severe (low probability/ high impact) disruption to supply? Also, would such an incident affect NG's meeting their licence conditions?

Political risks: The project team notes differences on environmental impacts and planning procedures across three scenarios. Would all costs related to design and preliminary work preparation be captured within a 3-year design period? How realistic is that? Would availability of skilled labour an issue?

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