NET ZERO IMPACT ON WIDER NETWORK CONTENTS

Impact of Contaminants on the Future Transmission Network

National Gas Transmission

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1 EXECUTIVE SUMMARY

A contaminant is defined as any unwanted component, gas, liquid or solid, that may impact the transportation, material integrity or end use of the bulk gas being transported in the transmission system. This report assesses the impact of natural gas contaminants currently present in the National Transmission System (NTS) on a future repurposed pipeline network carrying hydrogen or carbon dioxide. The possibility of novel contaminants being introduced from the new gases is also considered. The regulatory framework for gas transmission is well established and this has also been borne in mind during this work.

The sources of potential contaminants in repurposed gas pipeline networks are wide and varied. They include:

- Trace components in the gas itself;
- Failure or malfunction of gas processing plant upstream of the injection point;
- Chemical reaction of the gas with other components in the pipeline (solids, liquids or gases);
- Desorption of chemical components from the pipeline surface following repurposing;
- Degradation of material within the pipeline; and
- Introduction of material during construction, operational maintenance, purging and repair.

An extensive list of contaminants has been assembled, and their potential reactivity and impact on the future network assessed. These include the broad classes:

- Corrosion products;
- Aliphatic and aromatic hydrocarbons;
- Glycols;
- Sulfur compounds;
- Acids;
- Metals;
- Minerals; and
- Aldehydes, ketones, alcohols and terpenes.

Contaminants that are derived from natural gas or its processing will clearly decrease with time once no new natural gas is accepted into the pipelines. This includes naturally occurring radioactive material (NORM) derived from radon and radium. Note that hydrogen (even “pink hydrogen” produced from nuclear power) and carbon dioxide contain no radioactive substances and none will form within the pipelines.

Substances such as aliphatic hydrocarbons derived from lubricating oils and greases (e.g. compressor oil and valve sealant) may still be present if used on the future transmission network, but natural gas condensate, aromatic hydrocarbons, glycols etc derived from natural gas will not and these will also reduce.

Some gaps in the current knowledge with respect to future contaminants have been identified although none that were considered serious. In order to generate scientific knowledge on the common contaminants found in the NTS and their interaction with hydrogen or carbon dioxide a campaign of sampling was undertaken by National Gas Transmission to create a snapshot of substances found following pipeline pigging operations. These were analysed in DNV’s laboratory and identified. The table below shows the nine contaminants characterised as part of this project. Samples [redacted] and [redacted] being representative of corrosion products (known as black dust) and aliphatic hydrocarbons were exposed to hydrogen and carbon dioxide in order to confirm the expectation that no significant changes would occur in the future

pipeline network. No significant differences or deleterious compounds were found in these materials from the subsequent analysis carried out by DNV.

DNV ID Number	Sample Type	Sample Description	Principal component(s) identified
[redacted]			Black dust
			Water with aliphatic hydrocarbons
			Castor oil-based grease (e.g. Val-Tex)
			Water with aliphatic hydrocarbons
			Corrosion products and weld spatter
			Weld spatter and black dust
			Black dust (NORM)
			Black dust
			Castor oil-based grease (e.g. Val-Tex)

The following National Gas Transmission management system documents were also reviewed and found to be suitable for continued use:

- Pipeline and Dust NORM Standard (UK/T1/8.7.3/S) and supporting document (UK/T1/8.7.3/SD/1);
- Management procedure: Management of Specific Hazards Associated with Breaking of Containment (T/PM/SMS/4); and
- Work procedure: Breaking Containment and Dealing with NORMs (T/PR/SMS/5).

The work procedures and process equipment are suitable for dealing with liquid and solid contaminants in the future transmission network because they are risk-based and suitable for any solid or liquid contaminant that can be reasonably expected to be present. Moreover the future networks will have gas quality specifications for the conveyed gas (hydrogen or carbon dioxide) that are suitable for the repurposed pipelines, which will minimise the risk of contamination. Factors such as the gas dew point are critical in preventing liquid dropout and in turn the corrosion of the pipelines (forming solid deposits) and these are already being incorporated into the specifications for the new gases by the industry.

It will be important to clean the pipelines and purge them effectively prior to conversion to any new gas to minimise contaminant carry-over. These processes are however either well established or are being investigated by National Gas Transmission's innovation programme and so are not expected to limit the ability of the pipelines to be repurposed.

2 INTRODUCTION

A contaminant is defined as any unwanted component, gas, liquid or solid, that may impact the transportation, material integrity or end use of the bulk gas being transported in the transmission system.

Contaminants may exist as solids, liquids or gases (vapours). The quantity of contaminant present, and its physical state, may cause operational issues, and may also be a challenge for compliance with gas quality specifications.

The sources of potential contaminants in repurposed gas pipeline networks are wide and varied. They include:

- Trace components in the gas itself;
- Flow changes in the pipeline leading to mobilisation of contaminants;
- Failure or malfunction of gas processing plant upstream of the injection point;
- Chemical reaction of the gas with other components in the pipeline (solids, liquids or gases);
- Desorption of chemical components from the pipeline surface following repurposing;
- Degradation of material within the pipeline; and
- Introduction of material during construction, operational maintenance, purging and repair.

The natural gas industry has effective measurement and controls to ensure that routine operations are within the required guidelines, and the relative abundance of expected contaminants are limited through specific regulations (which are discussed further below). This places a legal requirement for the operator to control what is flowing through any point on the network. The operator will agree contractual and operational limits close to or more stringent than this legal requirement to ensure gas entering the network does not impact the overall integrity of the system or on end users' equipment.

In other, less well-established industries this chain of requirements is less clear, and research is ongoing to ensure the specification of such limits is able to balance the purification costs against the need to ensure system longevity. Specifications for hydrogen and carbon dioxide for pipeline transmission (and distribution) are the focus of several research and development activities and form part of major infrastructure projects.

Review studies on hydrogen quality and trace components have been undertaken recently in Germany and for the EU, including work by Busch et al[1], Stohr et al[2] and the EC[3].

A similar recent review on the transport of carbon dioxide has been published highlighting that "the future CO_2 transport pipeline will require intermingling of CO_2 fluids from different sources; monitoring levels of impurity, which may inadvertently lead to corrosion", and the impact of the use of repurposed pipeline networks is an important aspect requiring careful consideration[4].

This report collates potential contaminant information from published literature and other data sources covering natural gas, biomethane, hydrogen and carbon dioxide. A qualitative assessment has been made of the likelihood and consequence of each contaminant causing problems in the future for both gas quality and pipeline integrity/operability, under scenarios of hydrogen blends (up to 20% hydrogen), hydrogen, or carbon dioxide networks.

[1] T. Busch, J. Derichs, T. Klütz, J. Linßen and D. Stolten, *Int. J. Hydrogen Energy*, 2025, **164**, 149367. https://doi.org/10.1016/j.ijhydene.2025.04.532

[2] T. Stöhr, V. Reiter, S. Scheikl, N. Klopčič, S. Brandstätter and A. Trattner, *Int. J. Hydrogen Energy*, 2024, **67**, 1136–1147. https://doi.org/10.1016/j.ijhydene.2023.09.305

[3] M. Zerta, C. Kutz, F. Lust, S. Kettner, J. Knip, M. van Essen, C. Bastiaanse, U. Lubenau, S. Schmidt and J. Dedecca, Study on hydrogen quality in dedicated infrastructure and standardisation, European Commission, 2025. https://op.europa.eu/o/opportal-service/download-handler?identifier=864a9f8a-beb9-11f0-a612-01aa75ed71a1&format=PDF&language=en&productionSystem=cellar

[4] R. Pelton, P. Renzi, K. Supak, R. Kurz, K. Katcher, R. Iyer, J. Bygrave, K. Wygant, J. Wilkes and K. Brun, in *Energy Transport Infrastructure for a Decarbonized Economy*, ed. K. Brun, T. Allison, R. Kurz and K. Wygant, Elsevier, 2025, ch. 8, pp. 329–372. https://doi.org/10.1016/B978-0-443-21893-4.00007-6

The range of potential impurities and contaminants that could have accumulated in pipelines through normal operation and service for natural gas have been identified. These data have been identified through a literature review together with assessment of information in specific reports produced by DNV on pipeline contaminants, and requests to other network operators for details of any data that might be available from wider sources. This report uses the information from the impurity data collected, together with consideration of the impurities from hydrogen production or carbon dioxide capture to identify a wide range of potential contaminants. The report builds on the fundamental chemical properties of these components to assess if there may be an interaction with hydrogen or carbon dioxide and then produce an impact rating.

The report goes on to identify nine contaminant materials recovered from the National Transmission System (NTS). Two representative substances (a black dust and a valve grease) were selected for further testing and were exposed to hydrogen and carbon dioxide to determine whether they are acutely affected by these gases.

Finally the report reviews the procedures for monitoring and remediation of contaminants in the NTS and assesses their suitability for application on the future hydrogen or carbon dioxide networks.

3 NATURAL GAS CONTAMINANTS

Natural gas has been transported in the UK via pipelines since the 1960s and is a mature industry. Much research has been completed on contaminants' reactivity and their impact on transmission pipeline systems.

The UK is supplied with natural gas from the North Sea, from liquefied natural gas (LNG), and through European imports (via interconnecting pipelines). The source of the gas, especially from varying North Sea wells, determines the type and level of contaminants that are likely to be encountered. The gas must be purified to meet the regulatory, contractual and operational requirements. This processing will not remove all traces of contamination, but tightening the gas compositional requirements may incur costs disproportionate to any benefits in, for example, asset integrity. The appropriate balance in this trade-off has been well established for natural gas. As there is not the same level of experience for hydrogen or carbon dioxide pipelines, minor and trace component concentration limits may need to be more constrained to provide confidence in the initial phases of hydrogen or carbon dioxide service.

To ensure safe, reliable and efficient gas use, there are gas quality requirements that must be adhered to.[5] These are encapsulated by a multi-faceted gas quality and compliance framework that includes the following:

- **Legal requirements**: Gas Safety (Management) Regulations (GS(M)R);
- **Contractual requirements**: Network Entry Agreement (NEA); and
- **Operational requirements**: National Gas Transmission policy T/PM/GQ/8 - Assessing the Requirements for Gas Quality, Calorific Value and Flow Measurement Systems (GQ/8).

3.1 Indigenous components

The contaminants found in the gas imports to the UK may vary between each input source.

The majority of natural gas, ca. 80%, feeding the UK transmission system is sourced from the North Sea (United Kingdom Continental Shelf (UKCS) or Norwegian Continental Shelf (NCS) offshore gas fields) or from Morecambe Bay.[6] Gas is received onshore at processing facilities such as St Fergus, Teesside (CATS), Easington, Bacton, and Barrow, where some contaminants are removed to meet the specifications required for pipeline transportation. The network entry limits are provided in Table 1 to Table 4.

Two LNG terminals, at the Isle of Grain and Milford Haven, facilitate import from ocean-going tankers from around the world. At these facilities LNG is vaporised to provide natural gas at the required temperature and pressure for National Transmission System (NTS) injection. Typically, the UK imports 15%[6] of natural gas supply through these terminals.

The NTS is connected to Belgium and the Netherlands through interconnectors (import/export) at the Bacton terminal and to Ireland at Moffat (export only). This, together with withdrawal from storage, accounts for the remaining natural gas demand. The exact supply of the UK's demand varies, and the latest figures can be found at the National Gas Transmission Data Portal.[6]

It is important to understand this range of minor and trace components as they may be present in repurposed pipelines, especially as some components will have adsorbed onto the inner surfaces of the pipes and other mechanical infrastructure.

3.1.1 North Sea

Each of the terminals receiving gas from the North Sea will potentially receive different contaminants at different concentrations. The gas injected into the NTS must meet the entry specifications and these are shown in Table 1 and Table 2.

[5] Unless stated otherwise all volumes are for the real dry gas at ISO standard reference conditions of 15°C and 1.01325 bar.

[6] Gas System Status, https://data.nationalgas.com/gas-system-status, (accessed December 2025).

Table 1 Network entry requirements for injection from UKCS.

Gas Quality Parameter	Bacton – Shell	Bacton – Shell SEAL	Barrow	Easington – Langeled
Hydrogen sulfide	≤3.3 ppm	≤3.3 ppm	≤3.3 ppm	≤5 mg/m^3
Total sulfur	≤15 ppm	≤15 ppm	≤15 ppm	≤30 mg/m^3
Hydrogen content	-	-	≤0.1 mol%	≤0.1 mol%
Oxygen content	≤10 ppm	≤10 ppm	≤0.1 mol%	≤10 ppm
Hydrocarbon dewpoint	≤–1 °C up to 69 barg	≤–2 °C up to 75 barg	≤–2 °C up to 75 barg	≤–2 °C up to 70 barg
Water dewpoint	≤–9 °C at 69 barg .	≤–10 °C at 75 barg	≤–10 °C at 75 barg	≤–10 °C at 70 barg
Wobbe number[7]	48.2 ≤ WN (MJ/m^3) ≤ 51.2	48.1 ≤ WN (MJ/m^3) ≤ 51.4	48.1 ≤ WN (MJ/m^3) ≤ 51.41	47.2 ≤ WN (MJ/m^3) ≤ 51.41
Carbon dioxide	≤2.0 mol%	≤2.5 mol%	≤2.0 mol%	≤2.5 mol%
Total inerts (CO_2 + N_2)	-	-	-	-
Calorific value (real gross dry)	36.9 ≤ CV (MJ/m^3) ≤ 42.3	36.9 ≤ CV (MJ/m^3) ≤ 42.3	36.9 ≤ CV (MJ/m^3) ≤ 42.3	36.9 ≤ CV (MJ/m^3) ≤ 43.7

The entry specification limits provide information on specific gas properties such as Wobbe number (WN) and calorific value (CV) that are important for gas interchangeability requirements and for energy delivery to end users. They also include limits on certain chemical components. These components may be important considerations for repurposed networks and an understanding of the potential gas concentrations that could adsorb onto pipe walls or material in the pipeline and then impact on the quality of the repurposed system.

Table 2 Network entry requirements for injection from UKCS.

Gas Quality Parameter	St Fergus – NSMP	St Fergus – Shell SEGAL	Teesside PX
Hydrogen sulfide	≤3.3 ppm	≤3.3 ppm	≤3.3 ppm
Total sulfur	≤15 ppm	≤35 ppm	≤15 ppm
Hydrogen content	≤0.1 mol%	-	≤0.1 mol%
Oxygen content	≤10 ppm	≤0.1 mol%	≤10 ppm
Hydrocarbon dewpoint	≤–2 °C up to 69 barg	≤–2 °C up to 72.39 barg	≤–2 °C up to 70 barg
Water dewpoint	≤–10 °C at 69 barg	≤–10 °C at 69 barg	≤–10 °C at 70 barg
Wobbe number	47.2 ≤ WN (MJ/m^3) ≤ 51.41	48.2 ≤ WN (MJ/m^3) ≤ 51.2	47.2 ≤ WN (MJ/m^3) ≤ 51.4
Carbon dioxide	≤5.5 mol%	≤2.0 mol%	≤2.9 mol%
Total inerts (CO_2 + N_2)	≤7.0 mol%	-	-
Calorific value (real gross dry	36.9 ≤ CV (MJ/m^3) ≤ 42.3	36.9 ≤ CV (MJ/m^3) ≤ 42.3	36.9 ≤ CV (MJ/m^3) ≤ 42.3

As well as these limits there is also an overarching statement regarding contaminants in GS(M)R, namely that the gas shall not contain solid or liquid material which may interfere with the integrity or operation of pipes or any gas appliance which a consumer could reasonably be expected to operate.

3.1.2 LNG

LNG is produced through a liquefaction process and to avoid issues with the formation of solids and other hazards, the higher boiling fractions of natural gas are removed together with carbon dioxide and oxygen. The resulting LNG is

[7] Note the new lower Wobbe number limit in GS(M)R is 46.5 MJ/m^3 and so this may change in the future.

transported at approximately –160 °C (110 K). The production and purification process for LNG means that its general composition characteristics are typically 95%+ methane, with smaller amounts of ethane, propane and butane.[8] The entry specifications for the LNG entry points to the NTS are shown in Table 3.

Table 3 Network entry requirements for injection from LNG terminals.

Gas Quality Parameter	Isle of Grain 1	Isle of Grain 2	Milford Haven – South Hook
Hydrogen sulfide	≤5 mg/m^3	≤5 mg/m^3	≤3.3 ppm
Total sulfur	≤50 mg/m^3	≤50 mg/m^3	≤50 mg/m^3
Hydrogen content	≤0.1 mol%	≤0.1 mol%	≤0.1 mol%
Oxygen content	≤0.02 mol%	≤0.02 mol%	≤200 ppm
Hydrocarbon dewpoint	≤–2 °C up to 70 barg	≤–2 °C up to 70 barg	≤–2 °C up to 94 barg
Water dewpoint	≤–10 °C at 85 barg .	≤–10 °C at 85 barg	≤–10 °C at 60 barg
Wobbe number	47.2 ≤ WN (MJ/m^3) ≤ 51.41	47.2 ≤ WN (MJ/m^3) ≤ 51.41	47.2 ≤ WN (MJ/m^3) ≤ 51.41
Carbon dioxide	≤2.0 mol%	≤2.0 mol%	≤2.5 mol%
Nitrogen	≤7.0 mol%	-	-
Total inerts	≤7.0 mol%	-	-
Calorific value (real gross dry)	36.9 ≤ CV (MJ/m^3) ≤ 42.3	36.9 ≤ CV (MJ/m^3) ≤ 42.3	36.9 ≤ CV (MJ/m^3) ≤ 42.3
Ethane	≤12 mol%	≤12 mol%	≤12 mol%

The specification limits are similar to pipeline entry points but there is a specific limit for ethane content (<12 mol%) at these sites. This higher limit has been proposed to account for impacts on gas turbine operation and also from consideration of pipeline fracture propagation.

For LNG supplies, the gas properties are typically not within the operational envelope for gas quality as detailed in GS(M)R. To ensure compliance, nitrogen is added to the gas (“nitrogen ballasting”) to ensure that the delivered gas is appropriate. The nitrogen ballasting process may result in additional contaminants, as the nitrogen may contain other components (although this is unlikely), or the amount of nitrogen added may result in over or under content limits. The risks for LNG terminals sending out non-compliant gas is low.

3.1.3 European interconnector

Gas quality limits for network entry from European interconnectors are shown in Table 4. These limits follow a similar structure to the UKCS supply gas entry, but the WN and CV specifications are quoted at a different reference condition. (Note: If the values are converted to UK reference conditions then they are compliant with GS(M)R.)

[8] LNG Operational Information, https://www.nationalgas.com/sites/default/files/documents/28039-LNG%20Technical%20Information.pdf, (accessed December 2025).

Table 4 Network entry requirements for European interconnector sites.

Gas Quality Parameter	Bacton BBL	Bacton – Interconnector
Hydrogen sulfide	≤5.3 mg/m^3	≤3.3 ppm
Total sulfur	≤52.7 mg/m^3	≤30 mg/m^3
Hydrogen content	≤0.1 mol%	≤1000 ppm
Oxygen content	≤200 ppm	≤1000 ppm
Hydrocarbon dewpoint	≤–2 °C up to 70 barg	≤–2 °C up to 69 barg
Water dewpoint	≤–10 °C at 70 barg	≤–10 °C at 69 barg
Wobbe number	49.79 ≤ WN (MJ/m^3) ≤ 54.23	49.75 ≤ WN (MJ/m^3) ≤ 54.19
Carbon Dioxide	≤2.5 mol%	≤2.5 mol%
Calorific value (real gross dry)	38.93 ≤ CV (MJ/m^3) ≤ 44.62	38.9 ≤ CV (MJ/m^3) ≤ 44.6

Note: The reported values for Wobbe number and calorific value are those used in reference source and have not been adjusted. The units used in the table are those used in the reference source.

3.1.4 Storage

Gas quality specifications for the gas storage sites are shown in Table 5 and Table 6. Again, the specifications and limits are similar, though there are some additional constraints on the water content and total inert gas content.

Table 5 Gas quality specification at storage site.

Gas Quality Parameter	Aldborough	Hatfield Moor	Hilltop	Hornsea
Hydrogen sulfide	≤5 mg/m^3	≤5 mg/m^3	≤5 mg/m^3	≤5 mg/m^3
Total sulfur	≤50 mg/m^3	≤50 mg/m^3	≤50 mg/m^3	≤50 mg/m^3
Hydrogen content	≤0.1 mol%	≤0.1 mol%	≤0.1 mol%	≤0.1 mol%
Oxygen content	≤0.2 mol%	≤0.2 mol%	≤0.001 mol%	≤0.01 mol%
Hydrocarbon dewpoint	≤–2 °C up to 85 barg	≤–2 °C up to 70 barg	≤–2 °C up to 70 barg	≤–2 °C up to 70 barg
Water dewpoint	≤–10 °C at 85 barg (≤50 mg/m^3)	≤–10 °C at 70 barg (≤50 mg/m^3)	≤–10 °C at 70 barg (≤50 mg/m^3)	≤–10 °C at 70 barg (≤50 mg/m^3)
Wobbe number	47.2 ≤ WN (MJ/m^3) ≤ 51.41	48.14 ≤ WN (MJ/m^3) ≤ 51.41	47.2 ≤ WN (MJ/m^3) ≤ 51.41	47.2 ≤ WN (MJ/m^3) ≤ 51.41
Carbon dioxide	≤2.0 mol%	≤2.0 mol%	≤2.5 mol%	≤2.5 mol%
Nitrogen	-	≤5.0 mol%	-	
Total Inerts (CO_2 + N_2)	-	≤7.0 mol%	-	-
Calorific value (real gross dry)	36.9 ≤ CV (MJ/m^3) ≤ 42.3	36.9 ≤ CV (MJ/m^3) ≤ 42.3	36.9 ≤ CV (MJ/m^3) ≤ 42.3.	-

Table 6 Gas quality specification at storage site.

Gas Quality Parameter	Humbly Grove	Stublach
Hydrogen sulfide	≤5 mg/m^3	≤5 mg/m^3
Total sulfur	≤50 mg/m^3	≤50 mg/m^3
Hydrogen content	≤0.1 mol%	≤0.1 mol%
Oxygen content	≤0.2 mol%	≤0.001 mol%
Hydrocarbon dewpoint	≤–2 °C up to 85 barg	≤–2 °C up to 70 barg
Water dewpoint	≤–10 °C at 75 barg (≤50 mg/m^3)	≤–10 °C at 70 barg (≤50 mg/m^3)
Wobbe number	47.2 ≤ WN (MJ/m^3) ≤ 51.41	47.2 ≤ WN (MJ/m^3) ≤ 51.41
Carbon dioxide	-	≤2.5 mol%
Nitrogen	-	-
Total inerts (CO_2 + N_2)	≤7.0 mol%	-
Calorific value (real gross dry)	36.9 ≤ CV (MJ/m^3) ≤ 42.3	36.9 ≤ CV (MJ/m^3) ≤ 42.3

3.2 Gas processing

Natural gas may be produced with oil or natural gas condensate together with water. Gas processing involves separating any oil and produced water from the natural gas components. Further processing is required to remove acid gases (carbon dioxide, hydrogen sulfide, and sulfur-compounds such as methyl mercaptan and ethyl mercaptan), nitrogen, helium, mercury, naturally occurring radioactive material (NORM), which is radon gas and radium dissolved in produced water.

The principal processes are:

- **Acid gas removal:** This may be by:
    - Amine treatment with aqueous alkanolamine solvents such as diethanolamine (DEA), monoethanolamine (MEA), methyldiethanolamine (MDEA), diisopropanolamine (DIPA), aminoethoxyethanol (Diglycolamine) (DGA);
    - Sulfinol process using alkanolamine and sulfolane;
    - Benfield process uses activated, inhibited hot potassium carbonate solution;
    - Pressure swing adsorption using molecular sieves; and
    - Polymer membranes.
- **Dehydration:** This may be by:
    - Glycol absorption using monoethylene glycol (MEG), diethylene glycol (DEG), triethylene glycol (TEG) or tetraethylene glycol (TREG). TEG is the most commonly used glycol; and
    - Pressure swing adsorption using molecular sieves.
- **Mercury removal:** This may be by pressure swing adsorption on molecular sieves or activated carbon;
- **Nitrogen rejection:** Typically, a cryogenic process for large volumes and a pressure swing adsorption for smaller volumes; and

- **Natural gas liquids recovery:** Typically, a cryogenic process if it is economic to extract ethane and an absorption process using an oil if it is not.

Process upsets may result in the carryover of contaminants or the solvents used in some of these processes. The most commonly encountered contaminants in transmission pipelines from upstream processing are glycols.

3.3 Gas transportation

Once the gas has been processed it can be injected into the NTS provided it complies with the relevant legal, contractual and operational requirements. This is typically through a Network Entry Agreement (NEA).

An example of a representative and typical NEA is shown in Table 7. This builds on the specifications mentioned in the earlier tables but adds in additional limits for organohalides and radioactivity (from NORM).

Table 7 Network entry specification for natural gas.

Property	Range or limit
Hydrogen sulfide	Less than or equal to 5 mg/m^3
Total sulfur	Less than or equal to 50 mg/m^3
Hydrogen content	Less than or equal to 0.1% (molar)
Oxygen content	Less than or equal to 0.001% (molar)
Hydrocarbon dew point	Not more than –2 °C at any pressure up to 85 barg
Water dew point	Not more than –10 °C at 85 barg
Wobbe number	Shall be between 46.5 to 51.41 MJ/m^3
Gross calorific value (real gross dry)	The Gross Calorific Value (real gross dry) shall be in the range 36.9 to 42.3MJ/m^3, in compliance with the Wobbe Number described above. Subject to gas entry location and volumes, a target for the Calorific Value may be set within this range.
Inerts	Not more than 7.0% (molar) Subject to carbon dioxide (CO_2): Not more than 2.5% (molar)
Contaminants	The gas shall not contain solid, liquid or gaseous material that may interfere with the integrity or operation of pipes or any gas appliance within the meaning of regulation 2(1) of the Gas Safety (Installation and Use) Regulations 1998 that a consumer could reasonably be expected to operate.
Organo halides	Not more than 1.5 mg/m^3
Radioactivity	Not more than 5 Becquerels/g
Odour	Some gas in the NTS is odorised with Odorant NB (80% tertiary-butyl mercaptan, 20% dimethyl sulfide) at an odorant injection rate of 6 mg/SCM. Odorant is added as gas exits the NTS at Moffat (and also at a small number of power stations), and so odorant is not expected to be present on the NTS.
Pressure	The delivery pressure shall be the pressure required to deliver natural gas at the Delivery Point into our Entry Facility at any time taking into account the back pressure of our System at the Delivery Point as the same shall vary from time to time. The entry pressure shall not exceed the Maximum Operating Pressure at the Delivery Point.
Delivery temperature	Between 1 °C and 38 °C

For many gas properties the NEA limit is identical to the GS(M)R limit. Pipeline natural gas is a complex mixture of components (see Table 8), and there is the potential for some trace components or contaminants to be present and for the gas to still remain compliant.

Table 8 Natural gas components (pipeline specification gas).

Substance	Chemical formula	Typical concentration range	Example
Methane	CH_4	85–95 mol%	89.9 mol%
Ethane	C_2H_6	1.0–9.0 mol%	5.4 mol%
Propane	C_3H_8	0.2–3.5 mol%	1.3 mol%
n-Butane	C_4H_{10}	0.005–0.5 mol%	0.2 mol%
iso-Butane	C_4H_{10}	0.01–0.4 mol%	0.2 mol%
n-Pentane	C_5H_{12}	0–0.07 mol%	0.03 mol%
iso-Pentane	C_5H_{12}	0–0.08 mol%	0.04 mol%
neo-Pentane	C_5H_{12}	0–0.003 no	0.001 mol%
Hexanes	C_6H_{14}	0–0.2 mol%	0.04 mol%
Nitrogen	N_2	0.5–4.0 mol%	1.4 mol%
Carbon dioxide	CO_2	0–3.0 mol%	1.5 mol%
Hydrogen sulfide	H_2S	0–1.0 ppm	0.1 ppm
Ethyl mercaptan	C_2H_6S	0–0.11 ppm	0.1 ppm
Methyl ethyl sulfide	C_3H_8S	0–0.15 ppm	0.1 ppm
Diethyl sulfide	$C_4H_{10}S$	0–0.6 ppm	0.1 ppm

Note: Data on sulfur-containing compounds relate to DNV analysis. There is additional information on sulfur concentrations from IGEM/TD/3 Edition 5 July 2015.

The Environment Agency, with support from one shipper, has undertaken a detailed review of natural gas quality focusing on metal content, halogenated components and volatile organic compounds (VOCs).[9]

The natural gas analytical suite was extensive with measurements on the nine selected natural gases for over 260 individual volatile organic compounds (VOCs). The range of VOCs is wide and includes:

- High molecular weight alkanes;
- Branched alkanes;
- Unsaturated compounds (alkenes);
- Aromatic compounds (BTEX);
- Halogenated components;
- Nitrogen-containing compounds;
- Sulfur-containing compounds;
- Alcohols;
- Ketones and aldehydes;
- Cyclic alkanes and alkenes; and
- Terpenes.

Examples of the distribution of component types and their maximum concentrations are shown in Figure 1 and Figure 2. These results are tabulated and can be found in Appendix A.

[9] M. Bains, L. Hill and P. Rossington, *Material comparators for end-of-waste decisions: Fuels: natural gas*, Environment Agency, Report no. SC130040/R15, 2016.

The presence of these components in UK natural gas does not constitute unusual behaviour. This study focused on repurposing infrastructure and considered the likelihood of some components adhering to pipe walls or solids. The degree of pipeline cleaning will reduce the overall inventory of minor and trace components in the pipeline.

Following repurposing, any residual trace components may desorb into the hydrogen or carbon dioxide flow and the potential impacts should be considered. This phenomenon has been observed in natural gas pipeline repurposing to hydrogen operation.[10] The trace components may also interact chemically with hydrogen or carbon dioxide and potentially form other compounds.

These processes essentially reduce the minor and trace component concentrations, and any reaction products or desorbed species concentrations will reduce with time as they will not be replenished if the pipeline has been repurposed to 100% hydrogen or carbon dioxide. (Note: if the repurposing is to a hydrogen/natural gas blend then the minor components will be replenished from the natural gas sources.)

This temporary condition whereby the hydrogen may be impacted by the presence of residual components from the natural gas system has been considered in discussions on hydrogen purity requirements within EN 17977.[11]

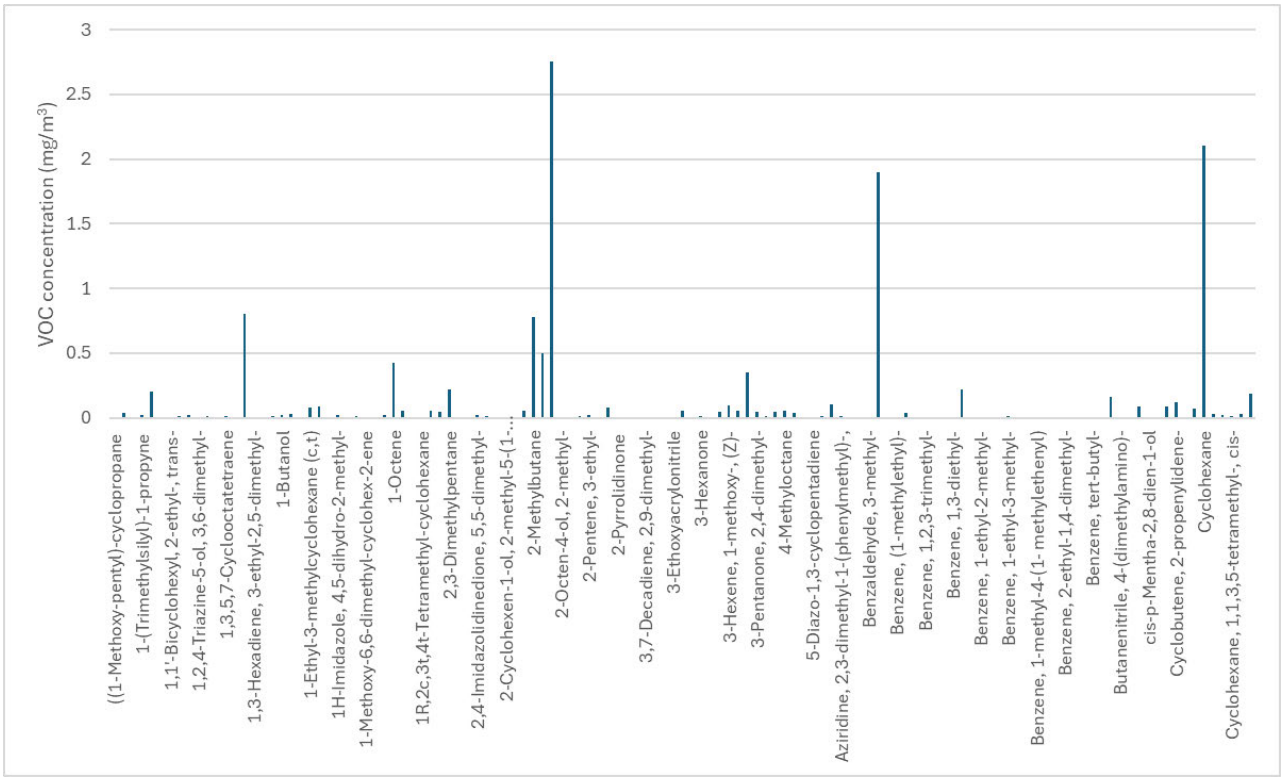


Figure 1 Volatile organic compound screening analysis showing the maximum measured concentration across nine samples of natural gas from one shipper.

[10] Conversion of a natural gas pipeline to hydrogen transport and the effects of impurities on the hydrogen quality, https://www.entsog.eu/sites/default/files/2022-11/4.2%20Conversion%20of%20a%20natural%20gas%20pipeline%20to%20H2%20and%20effects%20of%20impurities%20-%20Henk%20Top%20%28DNV%29.pdf, (accessed December 2025).

[11] CEN, Gas infrastructure – Quality of gas – Hydrogen used in rededicated gas systems, CEN/TS 17977:2024.

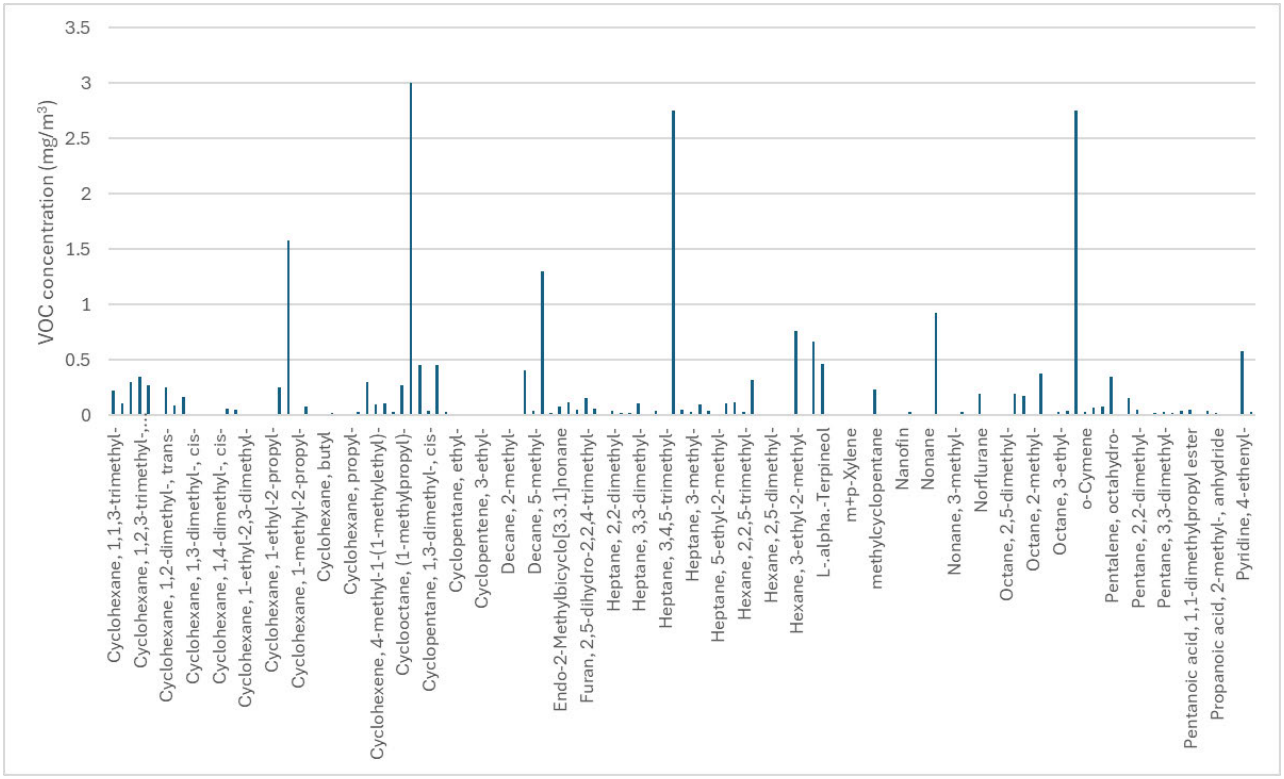


Figure 2 Volatile organic compound screening analysis showing the maximum measured concentration across nine samples of natural gas from one shipper.

Metals were observed across nine natural gases and the data presented in Table 9.

Table 9 Metals (ng/l) found in natural gas analysis.

Sample ID	Sb	Cd	Cr	Co	Cu	Pb	Mn	Hg	Ni	P	Si	Sn	V	Zn
Natural gas 1	<0.3	0.3	2.4	0.2	11.2	8.4	4.9	<0.2	7.9	<12.9	<857.8	4.3	0.2	1415.4
Natural gas 2	<0.3	29.7	1.7	1.1	36.6	17.4	2.7	<0.2	70.5	<12.9	<860.1	2.5	<0.2	283.8
Natural gas 3	0.4	156.3	9.7	3.1	127.0	469.0	8.9	0.3	506.8	21.5	<858.9	9.5	0.3	996.3
Natural gas 4	<0.3	3.1	2.2	0.1	4.4	17.3	0.8	<0.2	8.1	<13.2	<880.2	1.5	<0.2	35.6
Natural gas 5	<0.3	1.1	0.9	7.2	15.3	3.4	0.5	<0.2	5.9	<13.2	<881.9	10.6	<0.2	27.2
Natural gas 6	<0.3	1.7	0.4	0.1	8.6	2.0	2.8	<0.2	5.9	<13.3	<881.6	0.9	<0.2	77.4
Natural gas 7	<0.3	<0.2	1.0	<0.1	3.5	0.6	0.6	<0.2	1.0	<13.8	<917.1	0.7	<0.2	13.8
Natural gas 8	<0.3	0.9	13.3	0.1	8.5	11.9	1.6	<0.2	8.4	<13.8	<920.3	1.7	<0.2	29.4
Natural gas 9	<0.3	0.9	0.7	<0.1	11.6	7.5	0.6	<0.2	8.9	<13.8	<916.8	0.7	<0.2	64.4

As well as the metals listed above, arsenic (As), hexavalent chromium (Cr^{VI}), selenium (Se), thallium (Tl) were analysed for but were present at concentrations lower than the method detection limits and so could not be accurately quantified.

The metal content for the majority of elements is low, but lead (Pb), zinc (Zn), silicon (Si), nickel (Ni), cadmium (Cd) and copper (Cu) are all present in significant quantities and may interact with hydrogen or carbon dioxide following repurposing. Hydrogen may adsorb on to the metals and could result in formation of hydrogen atoms that could interact

with other components. Carbon dioxide can undergo electrochemical reduction on some metals and this could be promoted by cathodic protection.

Benzene, toluene, ethylbenzene and xylenes (BTEX), halogenated hydrocarbons and other volatile organic compounds (VOCs) may interact with hydrogen (and less likely with carbon dioxide) following repurposing of the pipelines, and all were assessed for potential extent of interaction. A summary of the measured concentrations in natural gas for aromatic species and selected halogenated compounds are shown in Table 10 and Table 11.

Table 10 Aromatic compounds (BTEX).

Sample ID	Benzene	Toluene	Ethylbenzene	o-Xylene
Natural gas 1	0.280 mg/m^3	0.370 mg/m^3	0.410 mg/m^3	-
Natural gas 2	0.300 mg/m^3	0.150 mg/m^3	0.390 mg/m^3	0.210 mg/m^3
Natural gas 3	-	-	0.050 mg/m^3	-
Natural gas 4	0.430 mg/m^3	0.180 mg/m^3	0.310 mg/m^3	0.380 mg/m^3
Natural gas 5	0.290 mg/m^3	0.110 mg/m^3	0.110 mg/m^3	0.023 mg/m^3
Natural gas 6	0.280 mg/m^3	0.080 mg/m^3	0.044 mg/m^3	0.030 mg/m^3
Natural gas 7	1.90 mg/m^3	0.550 mg/m^3	0.038 mg/m^3	0.120 mg/m^3
Natural gas 8	1.5 mg/m^3	0.475 mg/m^3	0.075 mg/m^3	0.150 mg/m^3
Natural gas 9	1.5 mg/m^3	0.575 mg/m^3	0.013 mg/m^3	-

Note: "-" means not detected during the VOC screen exercise.

Table 11 Halogenated hydrocarbons.

Sample ID	2,2-difluoro-propane	Bromo-cycloheptane,	Norflurane	1,1,1-Trifluoro-2-propanone
Natural gas 1	0.002 mg/m^3	0.068 mg/m^3	-	-
Natural gas 2	-	-	0.014 mg/m^3	-
Natural gas 3	-	-	-	-
Natural gas 4	-	-	-	-
Natural gas 5	-	-	-	-
Natural gas 6	-	-	-	-
Natural gas 7	-	-	-	-
Natural gas 8	-	-	-	-
Natural gas 9	-	-	-	0.003 mg/m^3

Note: "-" means not detected during the VOC screen exercise.

4 BIOMETHANE CONTAMINANTS

Although biomethane is “out-of-scope” for this study, a brief summary of possible trace components is included as this may impact on certain pipeline networks if reverse compression from the distribution networks to the transmission system is considered.

Biogas is produced through the anaerobic digestion (AD) of organic matter. Biomethane is produced by upgrading biogas by removing carbon dioxide, which typically yields a methane content >96 mol% with minor components of nitrogen, carbon dioxide and oxygen. Before network injection the biomethane is typically enriched with propane to produce a gas with a CV close to that of the network gas. The amount of enrichment depends on the injection location and can range from no propane added (if the relative flows of the biomethane to natural gas are low), up to about 8 mol% propane in some gas distribution networks.

Figure 3 shows an outline of the overall process flow from the biogas production (anaerobic digester) to the network entry point. Most of the potential for trace components and contaminants originates in the biogas production stage, but there is the possibility of compressor oil carryover for higher pressure grid entry.

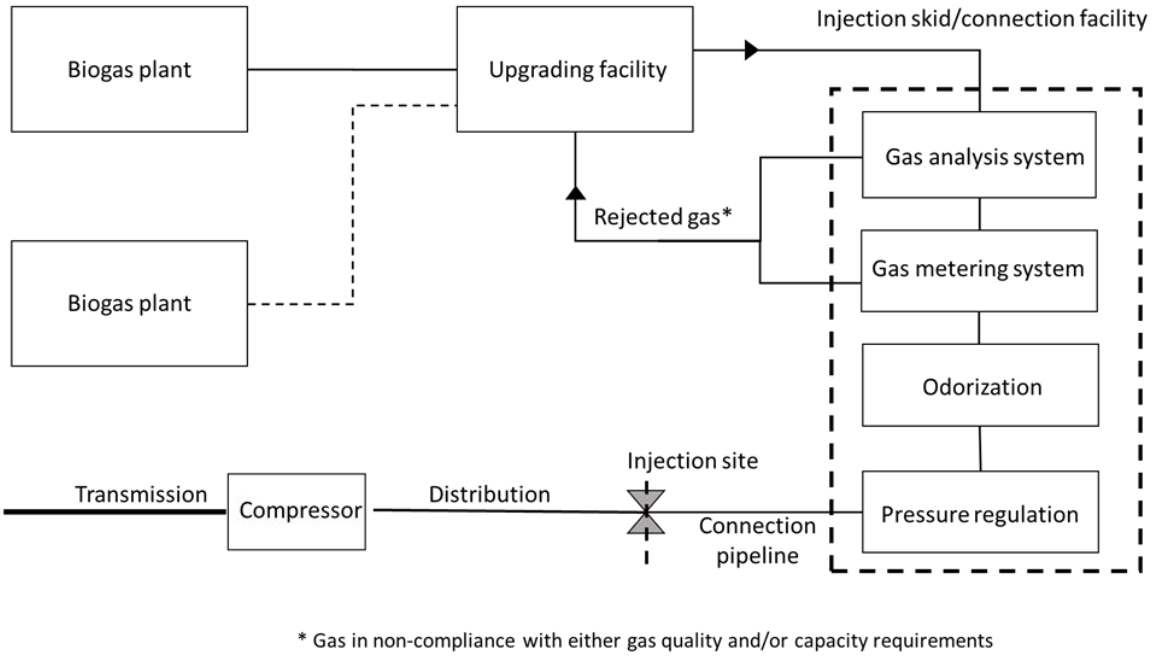


Figure 3 Process flow diagram for biomethane injection.

The biogas production process relies on delivery of organic material, and this could be from a number of sources[12] including:

- Crop residues and agricultural waste;
- Animal manure (e.g. from livestock sources like dairy waste);
- Wastewater (sewage sludge); and
- Food waste and the organic fraction municipal waste.

The different sources present different challenges with regard to biogas upgrading and removal of trace contaminants. Crop residues and food waste tend to be the “cleaner sources” whereas wastewater treatment plants tend to produce a

[12] An introduction to biogas and biomethane, https://www.iea.org/reports/outlook-for-biogas-and-biomethane-prospects-for-organic-growth/an-introduction-to-biogas-and-biomethane (accessed December 2025).

wider range and higher concentration of some trace components, and these need to be removed before network injection.

4.1 Key chemical components

The range of chemical components that are typically considered from the viewpoint of network injection are shown in Table 12.

Table 12 Selected biomethane trace components (and typical concentration limits).

Substance	Typical concentration limit
H_2S	≤5 mg/m^3 (3.3 ppm)
Total Sulfur	≤30 mg/m^3 (EA QP limit), ≤50 mg/m^3 (GS(M)R limit)
Hydrogen	≤0.1 mol% (1,000 ppm) (GS(M)R limit
Organic halides	≤1.5 mg/m^3 (NEA limit)
Hydrogen Chloride	≤1.5 mg/m^3 (EA QP limit)
Hydrogen Fluoride	≤5 mg/m^3 (EA QP limit)
Siloxanes	≤0.23 mg/m^3
Particulates	0
Mercury (metallic)	<10 µg/m^3
Micro-organisms	0
Terpenes	<0.5 mg/m^3
Aldehydes & ketones	<0.5 mg/m^3
Alcohols	<0.5 mg/m^3
Ammonia	20 mg/m^3 (EA QP limit)
Xylene	100 mg/m^3 (EA QP limit)
Arsenic	0.1 mg/m^3 (EA QP limit)
C7 to C12 hydrocarbons	<1 ppm

The concentration limits for the different components mentioned result from different regulations[13] and sources including GS(M)R, the Environment Agency Quality Protocol (EAQP) and NEAs.

The processing of biogas to form biomethane could use upgrading technologies like membranes or water wash, together with specific processing for sulfur removal (often oxygen injection) and water removal (dehydration). To optimise the upgrading process, many trace components are removed and residual concentrations may be low but could still interact with hydrogen or carbon dioxide in a repurposed network.

Odorant (Odorant NB) is also added and propane injected (mainly for gas distribution connected plant), but if there is any reverse compression to the transmission network then these components could be present too.

[13] National Gas Transmission, Gas Quality Parameters at NTS Entry Points, 2022.

5 HYDROGEN CONTAMINANTS

Large scale hydrogen production can be achieved through two major routes. The traditional, most widely used and potentially most economical means is through steam methane reforming (SMR). The second route is through water electrolysis, which is typically more expensive but offers significantly reduced carbon emissions if the electricity is low carbon. Though not expected to be a major production method, hydrogen can also be separated from synthesis gas produced during the gasification of fossil or biogenic fuels, or from pyrolysis of hydrocarbons with solid carbon as a byproduct.

Each production route will lead to different contaminants in the hydrogen product and require different processing steps. The type and nature of the contaminants is dependent upon the purity of the feedstock. Minor or trace components in the natural gas or water can lead to contaminants or minor constituents in the product hydrogen.

Hydrogen purity and composition are typical requirements for the utilisation of the gas. Hydrogen fuel cell (FC) vehicles require very high purity (ISO 14687) whereas pipeline compatible hydrogen could be less pure, meeting a minimum hydrogen content of 98 mol% as developed for EN 17977 and Hy4Heat (IGEM H/4). Both of these standards stipulate limits for select trace components, including water, hydrocarbons, carbon monoxide and sulfur-containing compounds (see Table 13).

Table 13 Example hydrogen pipeline specification.[14]

Parameter	Unit	Value	Reference Standards
Hydrogen	mol	≥98	DIN 51894
Wobbe number	MJ/m^3	42–46	EN 17977
The content and composition of the further quality parameter (e.g. sum of inerts) shall satisfy the Wobbe Number value above.			
Water	µmol/mol	≤250 ≤60[a]	ISO 21087
Hydrocarbon dew point (HCDP)[b]	°C	<–2 °C at 1 < p < 70 bar	ISO 21087
Sum of inerts (N_2, He, Ar)	mol%	≤2	ISO 21087
Gaseous hydrocarbons [b]	mol%	≤2	ISO 21087
Oxygen (O_2)[c]	mol% µmol/mol	≤0.1[d] ≤10	ISO 21087
Carbon monoxide	µmol/mol	≤20	ISO 21087
Carbon dioxide	µmol/mol	≤20	ISO 21087
Total sulfur [b]	µmol/mol	≤7[e]	ISO 21087
Ammonia	µmol/mol	≤13	ISO 21087
Halogenated compounds	µmol/mol	≤0.05	ISO 21087
Max. particulate concentration	mg/kg	Technically free	ISO 21087
Contaminants	The gas shall not contain constituents other than listed in this table at levels that prevent its transportation, storage and/or utilisation without quality adjustment of treatment.		ISO 21087

[a] 250 µmol/mol at MOP less or equal to 10 bar, 60 µmol/mol at MOP over 10 bar.
[b] These components most likely have their source in the previous use of the pipework.
[c] Rolling 24 h average.
[d] Max 0.1 mol-% in grids with no exit point to UGS or to sensitive customers, otherwise max. 10 µmol/mol.
[e] Non-odorised hydrogen.

[14] U. Lubenau, H. Bültemeier, C. Marrune, J. Hüttenrauch, P. Pietsch, M. Janssen and M. Reger, *H_2 short study: Hydrogen quality in an overall German hydrogen network*, DBI Gas-und Umwelttechnik, 2022. https://www.get-h2.de/wp-content/uploads/220801_Report_Study_H2-Purity_EN_Original-DBI.pdf

5.1 Indigenous components

5.1.1 Steam methane reforming

In the near term, hydrogen production through SMR is likely to be the most appropriate and significant route for large scale hydrogen production. This is a very established process, essentially mixing natural gas and steam to produce a synthesis gas that has a high hydrogen content.

The reforming process is often coupled to a water–gas shift reaction that converts the carbon monoxide byproduct (together with water) to form carbon dioxide and hydrogen. As a final stage, the produced gas can be purified using a pressure swing absorption process and this results in a hydrogen stream that has low levels of contaminants. To ensure optimum performance of the SMR the feed gas can undergo a preforming to “crack” the higher hydrocarbon content and also a desulfurisation stage to protect the reforming catalyst. The result of the overall process is hydrogen with low levels of contaminants, that may be nitrogen, water and low concentrations of carbon monoxide and carbon dioxide.

5.1.2 Electrolysis

Hydrogen production via electrolysis has the potential to be carbon neutral. This makes an attractive option from an environmental perspective but is as yet limited by the scaling of technology and elevated capital and operational expenditure. Hydrogen is produced by using electricity to split water molecules into hydrogen and oxygen. There are various techniques for achieving this, each with a slightly different operating principle.

5.1.2.1 Proton exchange membrane

Proton exchange membrane (PEM) electrolysis is a well-established technique. An ionically conductive solid polymer membrane separates electrodes over which a voltage can be applied. Purified water is fed to the anode, where the oxygen ions are oxidised to oxygen atoms and the remaining hydrogen ions travel through the membrane to the cathode where they are reduced to hydrogen atoms. This process yields a high hydrogen purity at the cathode and due to the solid membrane technology can be operated with hydrogen outlet pressures up to 40 barg.

5.1.2.2 Alkaline water

Alkaline water electrolysis (AWE) works by applying a voltage over two electrodes separated by a diaphragm in an alkaline electrolyte solution, for example 30 wt% potassium hydroxide (KOH). In this method, hydrogen molecules and hydroxide ions are produced at the cathode and hydroxide ions are transported through the diaphragm to the anode. The hydrogen is then separated from the KOH solution in a vapour–liquid separation vessel. The nature of the diaphragm limits the differential pressure that the cell can withstand, and the design of the system is such that there is a small chance of KOH carryover into the hydrogen stream.

5.1.2.3 Anion exchange membrane

Anion exchange membrane (AEM) technology is the least mature of the methods discussed and works in a similar fashion to PEM electrolysis. A solid polymer electrolyte separates the anode and cathode over which a voltage is applied and as such can operate at greater differential pressures. Water is fed to the cathode (instead of to the anode as with PEM) where the current splits water into hydrogen molecules and hydroxide ions. The hydroxide ions are conducted through the membrane and form water and oxygen at the anode. The commercially available AEM electrolysers currently use a 1 wt% KOH solution rather than pure water at the cathode. This requires the same separation vessel and chance of KOH carryover into the hydrogen stream as for AWE.

5.1.2.4 Solid oxide

Solid oxide electrolysis cells (SOEC) are less well established than PEM and AWE and operate at a far higher temperature than the other technologies discussed. This lowers the electrical input required to separate the water molecules into hydrogen and oxygen. In this case, steam is fed to the cathode and is split into hydrogen molecules and oxygen ions. Oxygen ions travel through the ceramic membrane to the anode, and the hydrogen stream is a mixture of steam and hydrogen.

5.1.3 Contaminants from hydrogen production

Table 14 summarises the potential contaminants from steam methane reforming and each electrolysis technique.

Table 14 Hydrogen components, electrolysis.

Production Technique	Substance	Chemical formula	Typical concentration	Footnote
SMR	Hydrogen	H_2	70 vol%	15 (assumed dry, pre-water-gas shift reaction)
	Water	H_2O	-	
	Carbon monoxide	CO	16.5 vol%	
	Carbon dioxide	CO_2	6 vol%	
	Methane	CH_4	7.5 vol%	
PEM	Hydrogen	H_2	99.998 %	16
	Water	H_2O	Dew point: -75 °C @ 1 bara	
	Oxygen	O_2	< 2 ppm	
	Nitrogen	N_2	< 12 ppm	
AWE	Hydrogen	H_2	99.998 %	17
	Water	H_2O	Dew point: -75 °C @ 1 bara	
	Oxygen	O_2	< 2 ppm	
	Potassium hydroxide	KOH	< 12 ppm	
AEM	Hydrogen	H_2	99.9 %	18
	Water	H_2O	< 1 000 ppm	
	Oxygen	O_2	< 5 ppm	
SOEC	Hydrogen	H_2	Limited public information available but expected to be similar to PEM due to solid electrolyte, though will depend on level of post-production drying.	
	Water	H_2O		
	Oxygen	O_2		
	Carbon dioxide	CO_2	May be present if contained within feedstock	

There are several purification techniques that can be used to remove impurities before a hydrogen stream is exported from a plant. These are most commonly used with SMR due to the concentration of the impurities however specialist applications may require very high purity hydrogen and so can also be found on electrolysis hydrogen production facilities.

These include pressure swing adsorption (PSA), membrane separation and electrochemical compression. For hydrogen produced through SMR (blue hydrogen if carbon dioxide is captured and sequestered), PSA is the most common method of purification. Hydrogen can be produced at high purity and high pressure at large flow rates.[19]

[15] S. Jallais and A. Gavrikov, Syngas explosion reactivity in steam methane reforming process, https://h2tools.org/sites/default/files/2019-08/paper_197.pdf, (accessed December 2025).

[16] HyLZER Water Electrolysers, https://mart.cummins.com/imagelibrary/data/assetfiles/0070332.pdf, (accessed December 2025).

[17] AE Electrolyser EL 4.0, https://handbook.enapter.com/electrolyser/el40/downloads/Enapter_Datasheet_EL40_EN.pdf, (accessed December 2025).

[18] HySTAT Alkaline Electrolyzers, https://mart.cummins.com/imagelibrary/data/assetfiles/0070333.pdf, (accessed December 2025).

[19] M. Shah, Hydrogen purification technologies overview, ARPA-E Methane Pyrolysis Annual Program Review Virtual Meeting, 2021. https://arpa-e.energy.gov/events/methane-pyrolysis-annual-program-review, (accessed December 2025).

Where higher outlet pressures are not required or hydrogen production rate is low, membranes offer an economic alternative. Membrane separation generally utilises hollow fibres of small diameter through the walls of which hydrogen permeates and is hence separated from the mixture.[20]

Electrochemical compression is less well established in the market but can offer a high purity and high-pressure hydrogen outlet. The principle of this technology is to electrochemically separate hydrogen from the mixture by oxidising hydrogen in the inlet gas, transporting protons across the membrane and reducing back to hydrogen gas at the outlet. This is a highly selective process.

5.2 Gas transportation and persistence of contaminants

Hydrogen may be introduced into pipelines by three routes:

1. The first is through blending with natural gas. In this scenario, the addition of hydrogen (and any contaminants) must not contravene the current gas quality specifications;
2. In the second, existing natural gas infrastructure may be repurposed for 100% hydrogen transmission. In this event, any contaminants remaining within the pipe, for example adsorbed onto inner walls, may desorb into the hydrogen flow; and
3. The third option is to lay new pipeline. In each case the processes required during transmission, for example compression, will be similar to those discussed in section 3.3 but may differ for example in terms of the specific lubricant oil used and therefore the potential contaminants.

System operations can also introduce other contaminants especially from hydrogen storage systems and from reverse compression from a distribution network to the transmission system. These contaminant sources have been considered in the data collation exercise and presented in Table 17 (see section 7.1).

The persistence of contaminants in pipelines that are repurposed from natural gas use to hydrogen depends on the chemical functionality and physical nature of the trace component. Solids will tend to remain, but their concentration will be significantly reduced following extensive cleaning of the pipeline. Liquids may adhere to the pipe walls and also persist in traps and filters. The entrainment of liquids into the gas phase will be dependent on the vapour pressure of the liquid, the flow rate of the gas over the liquid, the “solubility” of the liquid vapour in hydrogen and the operating pressure of the pipeline.

Adsorbed gases are expected to desorb into the hydrogen and be removed from the pipeline surfaces through displacement by hydrogen, or possibly reaction.

The range of “persistence times” is wide. Solids will tend to remain for longest. Some lighter molecular weight liquids may be entrained in the hydrogen flow and have relatively short persistence times, but other components like water or glycol could persist for longer times, and this has been observed in existing natural gas pipelines. For adsorbed species the persistence is influenced by the chemical nature of the contaminant. For instance alkanes will desorb rapidly, BTEX will persist for longer times and odorant or sulfur-containing species will persist for greater times.

[20] European Industrial Gases Association, *Best Available Techniques for Hydrogen Production by Steam Methane Reforming*, EIGA, Brussels. https://www.eiga.eu/uploads/documents/DOC155.pdf

6 CARBON DIOXIDE CONTAMINANTS

Carbon dioxide capture and storage as means of reducing industrial carbon footprints will rely on the transportation of the captured CO_2 to the storage location. There are many permutations between projects looking to capture and store carbon dioxide, with transportation being by pipeline or non-pipeline means (such as by rail or by ship) and with carbon dioxide being transported either in the gaseous or dense phase. The production source, phase and method of transport greatly impact the contaminants present and their allowable concentrations.

6.1 Indigenous components

The components indigenous to a carbon dioxide stream depend on the source of the carbon dioxide and the method of capture. Industries utilising carbon capture include electricity generation (combined cycle gas turbine and energy from waste plants) and oil and gas refineries and may rely on common transportation infrastructure. The sharing of infrastructure will mean all emitters be expected to meet the specifications of operation. Table 15 shows potential contaminants from a range of industrial producers.

Table 15 Carbon dioxide components by industry using post carbon capture.[22]

Substance (unit)		Chemical formula	Typical concentration by industry				
			O&G Refinery [MEA]	Cement plant [MEA]	Cement kiln	Coke production	Lime production
Carbon dioxide	(%v/v)	CO_2	99.6	99.8	99.00	99.4	99.52
Nitrogen	(%v/v)	N_2	0.29	0.0893	-	-	-
Carbon monoxide	(ppmv)	CO	1.2	1.2	1620	701	2000
Argon	(ppmv)	Ar	11	11	-	-	-
Water	(ppmv)	H_2O	640	640	-	-	-
Nitrogen oxides	(ppmv)	NO_x	2.5 (NO_2)	0.86 (NO_2)	3330	1690	1100
Sulfur oxides	(ppmv)	SO_x	1.3 (SO_2)	<0.1 (SO_2)	4410	3030	1800
Oxygen	(ppmv)	O_2	35	35	-	-	-
Methane	(ppmv)	CH_4	-	-	-	206	-
Chlorine	(ppmv)	Cl	0.41	0.41	65.7	26.8	-
Ash	(ppm)	-	-	5.7			
Mercury	(ppmv)	Hg	-	0.00073	0.1	-	-
Arsenic	(ppmv)	As	0.29	0.0029	-	-	-
Selenium	(ppmv)	Se	1.2	0.0088	-	-	-
VOC	(ppmv)	-	-	-	-	96.9	-
Total organic carbon (TOC)	(ppmv)	-	-	-	81	-	-

Some of the component concentrations may be challenging for injection and pipeline network operations. For example, a water content of 640 ppmv would give rise to water dewpoint issues and lower concentrations would be better to prevent liquid drop-out. Also high concentrations of NO_x and SO_x as these acid gases can give rise to increased pipeline corrosion rates.

6.2 Gas processing

Several technologies are used to capture and purify carbon dioxide from industrial emitters. These include removal from the fuel pre-combustion (by gasification and CO_2 separation), by capture post-combustion (adsorption/absorption, e.g.

using amine solvents, membrane separation, cryogenic distillation or calcium looping) or through oxy-fuel combustion (combustion using pure oxygen to minimise the presence of other contaminants and simplify separation).[21] Each processing technique will influence the contaminants found in the carbon dioxide.

6.2.1 Capture technologies

6.2.1.1 Pre-combustion capture

Pre-combustion capture can occur during a gasification process before the fuel is burnt. Both anthropogenic and biogenic carbon-based fuel sources can be gasified, where heat is added to break the feedstocks down into hydrogen (or steam), carbon monoxide and carbon dioxide without combusting the fuel. The carbon monoxide and carbon dioxide can then be removed before burning the hydrogen to produce heat, reducing the carbon content entering and therefore exiting the combustion process.

Pre-combustion capture is suited to separation techniques requiring an elevated CO_2 partial pressure, such as liquid or solid absorption.

6.2.1.2 Post-combustion capture

Post-combustion capture is the technique of separating carbon dioxide from the exhaust gas of an industrial process. At this point, the fuel has been combusted, and the exhaust stream contains a range of components including nitrogen oxides, air and carbon monoxide.

This is the technique often retrofitted to industrial emitters, requiring very little modification to existing plant operations. The process however is energy intensive, and exhaust gases are often at near atmospheric pressure and may contain a lower carbon dioxide mass fractions reducing the overall energy efficiency of the separation.

Post-combustion capture can occur through several mechanisms: chemical absorption using solvents or sorbents, membranes and cryogenic liquefaction.

6.2.1.3 Oxyfuel combustion

Oxyfuel combustion is the process of burning the fuel in pure oxygen. This process can be more efficient than traditional fuel combustion due to a higher operating temperature and produces a less complex mixture in the exhaust gas subsequently simplifying the carbon dioxide separation steps. This process is less mature than other capture techniques and can be expensive to implement on an industrial scale.[22]

6.2.1.4 Contaminants from carbon dioxide capture

Table 16 summarises the potential contaminants from carbon dioxide production and capture.

Other purification steps can be employed to further reduce the concentration of contaminants, for example through flashing or distillation, with the remaining levels of contaminant varying between plant design and equipment manufacture.

[21] A. Nema, A. Kumar and V. Warudkar, *Energy Convers. Manage.*, 2024, **323**, A, 119244. https://doi.org/10.1016/j.enconman.2024.119244

[22] R.T.J. Porter, M. Fairweather, M. Pourkashanian, R.M. Woolley, *Int. J. Greenhouse Gas Control*, 2015, **36**, 161–174. http://dx.doi.org/10.1016/j.ijggc.2015.02.016

Table 16 Carbon dioxide components by capture technology.[22]

Substance (unit)		Chemical formula	Carbon capture technology				
			Oxyfuel combustion			Pre-combustion	Post-combustion
			Raw/ Dehumidified	Double flashing	Distillation		
Carbon dioxide	(%v/v)	CO_2	74.8–87.0	95.84–96.7	99.3–99.95+	95–99	99.6–99.8
Oxygen	(%v/v)	O_2	3.21–6.0	1.05–1.2	0.0001–0.4	0	0.015–0.0035
Nitrogen	(%v/v)	N_2	4.0–16.6	1.6–2.03	Trace–0.2	0.0195–1	0.045 –0.29
Argon	(%v/v)	Ar	2.3–4.47	0.4–0.61	Trace–0.1	0.0001–0.15	0.0011– 0.021
Nitrogen oxides	(ppmv)	NO_x	100–709	0–150	3–100	400	20–38.8
Sulfur dioxide	(ppmv)	SO_2	36–800	0–4500	0.1–50	25	0–67.1
Sulfur trioxide	(ppmv)	SO_3	20	-	0.1–20	-	N.I.
Water	(ppmv)	H_2O	100–1000	0	0–100	0.1–600	100–640
Carbon monoxide	(ppmv)	CO	50–162	-	<2–50	0–2000	1.2–10
Hydrogen / Carbonyl sulfide	(ppmv)	H_2S / COS	-	-	-	0.2–34,000	-
Hydrogen	(ppmv)	H_2	-	-	-	20–30 000	-
Methane	(ppmv)	CH_4	-	-	-	0–112	-

6.2.2 Purification technologies

6.2.2.1 Chemical absorption

Chemical absorption involves flowing flue gas through a column and washing it with a solvent such as an amine, ammonia or salt solution. The carbon dioxide from the flue reacts with the solvent, which travels to a separator downstream in which solvent is regenerated and the carbon dioxide removed. The efficiency of the solvent is determined by its chemical nature together with the composition of the carbon dioxide stream, operational conditions and the desired outlet specification.[23]

Contaminants such as SO_x and NO_x can impact the capture process through reactions with the solvent. These compounds reduce the amount of solvent available for capture and requires greater effort in the solvent recovery stage. Failure to manage aerosols and particulates entering the process can result in an increase in amine emissions to atmosphere over time.

6.2.2.2 Physical absorption

Physical absorption relies on the absorption of carbon dioxide from a flue gas stream into a solvent at a given pressure and temperature. The carbon dioxide-rich solution is then transported to a low-pressure column in which the carbon dioxide is separated and removed. The solvent is regenerated and reused. Physical absorption is similar to chemical absorption but requires lower heating and cooling utility duties and is therefore preferred at higher partial pressures of carbon dioxide. For this reason, physical absorption is more common in pre-combustion capture where inlet gas pressure is greater than outlet flue pressure.

6.2.2.3 Sorbent capture

Sorbent capture systems rely on carbon dioxide adsorption onto solids and can be fixed, moving or fluidised beds offering a reduction in regeneration and energy requirements compared to liquid absorption techniques. For the carbon

[23] T. Evans-Gavhure, R. Laing and J. Woods, Industry Guidelines for Setting the CO_2 Specification in CCUS Chains, Wood, 2023. https://www.woodplc.com/insights/reports/Industry-Guidelines-for-Setting-the-CO2-Specification-in-CCUS-Chains

dioxide stream (e.g. flue gas) to flow over the solid sorbent it is often necessary to pressurise the input. The method of regeneration depends on the form of the sorbent bed. It may flow continuously into a regeneration vessel or may be discretely removed and replaced to maintain continuous operation. The regeneration of sorbent beds often employs steam for heat, releasing the carbon dioxide.

6.2.2.4 Membranes

Membrane separation works by introducing a physical barrier through which different components in the source gas diffuse at different rates. The design of the membrane depends on the composition of the source gas and is more efficient at higher source gas pressures. Separation systems often require two or more stages to reach the required carbon dioxide purity. Membranes can be susceptible to high temperatures and easily become fouled or damaged during cleaning. Careful membrane material selection can resolve these problems but at present pose significant increases in capital expenditure.

6.2.2.5 Cryogenic liquefaction

Cryogenic liquefaction is the process of reducing the temperature of the gas stream such that carbon dioxide condenses or precipitates and can be removed as a liquid or solid.

6.2.2.6 Chemical looping

Chemical looping, for example using calcium, which is known as calcium looping, is the process of removing carbon dioxide from a stream through reaction with a metal oxide. This technique is particularly useful in the cement industry, where an abundance of calcium oxide is present.

6.3 Gas transportation

Transportation of carbon dioxide can be divided into pipeline and non-pipeline transport means and may be in either the gaseous or dense phase. The most appropriate method depends largely on project economics, production rate and transportation distances. The impact of the contaminants depends on the materials being used and the processes involved in transportation. Components such as alcohols and glycols can significantly shift the phase boundary of a carbon dioxide stream, while acidic gases (e.g. SO_x, NO_x) can dissolve in liquid water to initiate severe corrosion. Some contaminants are known to initiate or modify crack development, including hydrogen sulfide, hydrogen, oxygen and carbon monoxide[24] as summarised below:

- Water (H_2O), hydrogen sulfide (H_2S), sulfur oxides (SO_x), and oxygen (O_2) are common;
- H_2S and O_2 significantly accelerate internal corrosion, especially in the presence of water;
- Contaminants also alter carbon dioxide phase behaviour, raising the risk of two-phase flow;
- Water-induced corrosion:
    - CO_2 and H_2O form carbonic acid (H_2CO_3), which is highly corrosive to carbon steel; and
    - Can cause erosion–corrosion, pitting, and rapid wall loss, especially at pre-existing defects.
- Hydrate formation: Under certain conditions, hydrates can block flow or damage the pipeline; and
- Material compatibility: Some steel grades are not compatible with wet or impure carbon dioxide, requiring stringent purity control and dehydration before transport.

Where pipelines are planned to be repurposed, there is potential for a range of substances to contaminate the carbon dioxide stream. Some components of natural gas, such as sulfur-containing compounds, water or high molecular weight hydrocarbons are known to adhere to the pipeline walls and may persist despite the pipeline being purged.

[24] J. Sonke, B.H. Morland, G. Moulie and M.S. Franke, *Int. J. Greenhouse Gas Control*, 2024, **133**, 104075. https://doi.org/10.1016/j.ijggc.2024.104075

Purging a pipeline from natural gas to carbon dioxide may be undertaken directly or indirectly using a different medium such as nitrogen or air. In these cases, residual gas, nitrogen or air may remain within the pipeline. As it is anticipated that repurposing would require major works on some pipeline components (like meters and compressors), it is likely that indirect purging via nitrogen will be the main approach.

For new pipelines, residual air may lead to trace contamination of the carbon dioxide with nitrogen, oxygen, argon and water vapour. The use of new pipelines can also lead to debris in the line resultant from welding or other installation processes. Any scale, moisture or residue from previous pressure testing may also contribute to contaminant concentration. The concentration of these contaminants can be reduced if pipeline cleaning is undertaken prior to full commissioning.

7 SUMMARY OF POTENTIAL CONTAMINANTS IN REPURPOSED NETWORKS FROM PUBLISHED INFORMATION AND DATA COLLECTION EXERCISE

The sources of potential contaminants in repurposed gas pipeline networks are wide and varied. They include:

- Trace components in the gas itself;
- Failure or malfunction of gas processing plant upstream of the injection point;
- Chemical reaction of the gas with other components in the pipeline (solids, liquids or gases);
- Desorption of components that were adsorbed onto the pipe walls when in natural gas operation;
- Degradation of material within the pipeline; and
- Introduction of material during construction, operational maintenance, purging and repair.

However, some of the processes are also present for existing natural gas pipeline operations which assists in understanding the overall contamination mechanisms that might be present if the pipeline is repurposed to either hydrogen or carbon dioxide.

7.1 Risk from contaminants when repurposing for hydrogen

Table 17 shows potential contaminants and the interactions that may occur in the presence of hydrogen. Further details are contained in the Contaminants Register but this table provides a summary of the impact based on likelihood and severity. In Table 17, a qualitative Red-Amber-Green (RAG) assessment is made based on engineering judgement to provide a visual summary of the assessed impacts.

Table 17 Potential interaction of highlighted contaminants in hydrogen transmission.

Substance	Interaction with Hydrogen	RAG
Aldehyde, various	Aldehydes (present in biomethane or a partially oxidised product from hydrocarbons) will probably be chemically reduced in the presence of hydrogen. This can yield alcohols or possibly alkanes. Hydrogen interactions with these compounds is expected to be minor.	
Ammonia	No interaction anticipated. Ammonia proposed as a hydrogen carrier and decomposition will yield hydrogen.	
Arsenic	There is no direct reaction of arsenic with hydrogen at ambient temperature.	
Benzene	There are two processes to consider: entrainment and reaction. Benzene may be entrained into hydrogen. Reaction of hydrogen and benzene typically requires a catalyst (nickel or platinum used mostly). If this did occur the benzene is converted to cyclohexane and this will have a similar impact to other low boiling hydrocarbons.	
Black dust	Mixed solids can interact with hydrogen. Oxides and sulfides can potentially react with hydrogen to form water or hydrogen sulfide. Data are scarce. Some black dusts are pyrophoric.	
Calcium carbonate	Possible hydrogenation reaction to reduce the carbonate to calcium oxide. Rate of this process is expected to be low at ambient temperature.	
Carbon dioxide	No direct reaction anticipated but carbon dioxide will adsorb onto pipe walls and may desorb into the hydrogen after repurposing.	
Carbon disulfide	CS_2 can form from bacterial action in underground storage facilities. CS_2 can react with hydrogen to form methane and H_2S. Need to check on the rates of the conversion reactions.	
Carbon monoxide	Syngas contains mixtures of carbon monoxide and hydrogen. Carbon monoxide proposed as an inhibitor for stress corrosion cracking and hydrogen embrittlement.	
Carbonic acid	No direct reaction anticipated.	

Substance	Interaction with Hydrogen	RAG
Formaldehyde	Formaldehyde is a by-product of some hydrogen production processes and has a limit in ISO 14687 for hydrogen purity. It is unlikely to be present in high concentration and is also unlikely to have a significant impact on hydrogen properties.	
Formic Acid	Formic acid is a by-product of some hydrogen production processes and has a limit in ISO 14687 for hydrogen purity. It is unlikely to be present in high concentration and is also unlikely to have a significant impact on hydrogen properties	
Fusion bonded epoxy	Epoxy resin is quoted as a promising sealing liner for hydrogen. No significant chemical interaction.	
Glycol, diethylene	DEG is a liquid and could be present in hydrogen once pipeline is repurposed. Low volatility so gas phase concentration expected to be low, and of the order of that in natural gas under similar physical conditions	
Glycol, monethylene	MEG is a liquid and could be present in hydrogen once pipeline is repurposed. Low volatility so gas phase concentration expected to be low, and of the order of that in natural gas under similar physical conditions	
Glycol, triethylene	TEG is a liquid and could be present in hydrogen once pipeline is repurposed. Low volatility so gas phase concentration expected to be low, and of the order of that in natural gas under similar physical conditions	
Graphite	Seals tend to be able to operate in hydrogen environments, and a main cause of damage is through rapid decompression that tends to result in physical damage.	
Grease	Reactivity between greases and hydrogen expected to be very low. Some hardening may happen.	
Hydrocarbons, high boiling aliphatic	Reactivity between aliphatic hydrocarbons and hydrogen expected to be very low. Some cyclic species may react. Some components may desorb but concentrations expected to be low.	
Hydrogen sulfide	No direct chemical interaction expected.	
Ketone, various	Ketones (present in biomethane) will probably be reduced in the presence of hydrogen. This can yield alcohols or possibly alkanes. Hydrogen interactions with these compounds is expected to be minor.	
Mercaptan, methyl	Methyl mercaptan can form in underground storage facility for hydrogen. This could impact on the sulfur content of the hydrogen gas. Direct reaction of mercaptan with hydrogen is not thought to be significant, based on the suitability studies of Odorant NB in hydrogen.	
Mercury	No direct chemical interaction of mercury with hydrogen expected. Mercury is volatile and may be entrained in the hydrogen flow.	
Methanol	Recent research suggests that methanol may be useful in acting as an agent to reduce hydrogen embrittlement. No significant reaction of methanol with hydrogen expected.	
Mill scale	Mill scale is generally a combination of iron oxides such as FeO, Fe_3O_4, and Fe_2O_3. Hydrogen could potentially react to reduce the oxides and form water but this is not thought to be a rapid process at pipeline conditions. As oxide layers tend to protect steel pipelines from hydrogen entry, this benefit may be lost.	
Natural gas	Included as a potential source of contamination in repurposed networks. Expected in low concentration as it desorbs from pipe walls and deposits. Purging management should decrease concentration.	
Natural gas condensate	Condensate not anticipated to react with hydrogen under pipeline operating conditions, but there is a possibility that some hydrocarbon species could desorb and be entrained into the hydrogen.	
Naturally occurring radioactive material	Hydrogen is not expected to interact with NORM.	
Neoprene	Seals tend to be able to operate in hydrogen environments, and a main cause of damage is through rapid decompression that tends to result in physical damage.	
Nitrile	Seals tend to be able to operate in hydrogen environments, and a main cause of damage is through rapid decompression that tends to result in physical damage.	
Nitrogen	No direct chemical interaction expected. Nitrogen may desorb from internal pipeline surface and debris during a repurposing procedure. Experiments have shown that nitrogen can be entrained into the hydrogen flow. Any impacts expected to be short-term, and for the impact to decrease with use after repurposing has started.	

Substance	Interaction with Hydrogen	RAG
Nylon	Seals tend to be able to operate in hydrogen environments, and a main cause of damage is through rapid decompression that tends to result in physical damage.	
Oil, compressor	Reactivity between oil hydrocarbons and hydrogen expected to be very low. Some components may desorb but concentrations expected to be low. Experience in refineries handling hydrogen show that hydrogen compressor oil is established. Residual compressor oils that originate from natural gas systems are not expected to have a significant reaction with hydrogen, or be present.at concentrations above hydrogen purity specification requirements.	
Organohalides, various	Current network entry limits for organohalide give a maximum of 1.5 mg/m^3. Reaction with hydrogen may produce hydrocarbon and acidic HX (where X is the halide). Possible interaction if there is water present.	
Oxygen	Oxygen is present in natural gas and biomethane and can adsorb onto the pipe walls and onto debris within the pipe. Reaction of hydrogen and oxygen is possible and will form water, but at ambient temperature the rate of this is low. Oxygen could desorb from the pipe walls in any repurposing and could result in the gas phase. The oxygen content could be higher risk if the concentration is increased to allow biomethane entry or if oxygen is deliberately added as an inhibitor of facture growth/embrittlement.	
Perlite (expanded)	Perlite sources tend to be related to LNG. No significant impact.	
Polymer pipeline liner	Hydrogen may be able to permeate through the liner. This permeation will work both ways and it is not expected to an issue, unless there is rapid depressurisation and then the liner could be damaged.	
Polytetrafluoroethylene	Seals tend to be able to operate in hydrogen environments, and a main cause of damage is through rapid decompression that tends to result in physical damage.	
Polyurethane	Seals tend to be able to operate in hydrogen environments, and a main cause of damage is through rapid decompression that tends to result in physical damage.	
Pyrophoric dust	H21 project considered the interaction of pyrophoric dusts and hydrogen following repurposing. The risk is anticipated to be the same as for natural gas.	
Radon	No direct interaction of radon with hydrogen is anticipated.	
Rust	Iron oxide can potentially react with hydrogen to form water in a reduction process.	
Sand / soil	See silica entry.	
Sealant (e.g. Val-Tex)	Castor oil-based sealants for block valves. Information on sealant interaction with hydrogen is not readily available but if chemical functionality of the oil is considered then this has been considered in other components and the impact is anticipated to be small.	
Silica	Silica or sand is sometimes observed in pipeline solids. The source is thought to be entry during construction. Hydrogen is not expected to interact with silica.	
Silicone	Seals tend to be able to operate in hydrogen environments, and a main cause of damage is through rapid decompression that tends to result in physical damage.	
Siloxane, various	Limited data on siloxane interaction with hydrogen. Compounds may be reduced forming hydrocarbons and silica.	
Sodium chloride	Hydrogen embrittlement may be enhanced due to the presence of sodium chloride.	
Sulfur dioxide	SO_2 can form in some underground storage installations for hydrogen. Hydrogen can react with SO_2 but the rate of reaction at pipeline pressures is not known.	
Sulfur, elemental	Elemental sulfur can form and deposit in some natural gases. Once present it may interact with hydrogen and produce H_2S.	
Terpene, various	Terpenes are unsaturated hydrocarbons and may be hydrogenated by hydrogen (although this may require a catalyst). Any products from this process are likely to be aliphatic hydrocarbons and not anticipated to cause significant problems.	
Toluene	There are two processes to consider—entrainment and reaction. Toluene may be entrained into hydrogen. Reaction of hydrogen and toluene typically requires a catalyst (nickel or platinum used mostly). If this did occur the toluene is converted to methyl-cyclohexane and this will have a similar impact to other low boiling hydrocarbons.	

Substance	Interaction with Hydrogen	RAG
Water	No direct interaction of hydrogen and water.	
Waxes	Reactivity between waxes and hydrogen expected to be very low. Some hardening may happen.	
Welding rod	Welding rod occasionally found in solid debris in pipelines left over from the construction process. No significant interaction of hydrogen with welding rods.	
Xylene (mixed isomers)	Similar to toluene.	

7.2 Risk from contaminants when repurposing for carbon dioxide

Table 18 shows potential contaminants and the interactions that may occur in the presence of hydrogen.

Table 18 Potential interaction of highlighted contaminants in carbon dioxide transmission.

Substance	Interaction with Carbon Dioxide	RAG
Aldehyde, various	Carbon dioxide can act as a solvent for aldehydes and they may desorb into the carbon dioxide flow. Reaction is possible but this typically requires a catalyst.	
Ammonia	Ammonia can react with carbon dioxide in the presence of water. This can form new carbamate species and potentially urea. Ammonia can also impact on the phase behaviour of carbon dioxide.	
Arsenic	Arsenic does not react with carbon dioxide, and if it is present it will be in low concentrations.	
Benzene	Benzene may be entrained into carbon dioxide. Benzene does impact on the phase behaviour of carbon dioxide but the likely concentration in a repurposed pipeline is low. Reaction of carbon dioxide and benzene typically requires a catalyst and probably occurs at a slow rate at ambient temperature. Any entrainment is expected to be at concentrations lower than specification limits.	
Black dust	Black dust is a general term for mixed solids and the oxides may be able to interact with carbon dioxide.	
Calcium carbonate	No direct chemical interaction of calcium carbonate with carbon dioxide expected.	
Carbon disulfide	CS_2 can form from bacterial action in underground storage facilities. CS_2 does not directly react with carbon dioxide.	
Carbon monoxide	Carbon monoxide not expected to interact with carbon dioxide, although small effects of the phase behaviour may occur	
Elemental sulfur	Elemental sulfur can form and deposit in some natural gases. Once present in a pipeline it may interact with carbon dioxide but information is scarce, and water may also be needed in the reaction process	
Formaldehyde	Formaldehyde is a by-product of some processes. It is unlikely to be present in high concentration and is also unlikely to have a significant impact on carbon dioxide properties. Formaldehyde does not react with carbon dioxide.	
Formic Acid	Formic acid is a by-product of some processes. It is unlikely to be present in high concentration and is also unlikely to have a significant impact on carbon dioxide properties. Formic acid does not react with carbon dioxide.	
Fusion bonded epoxy	Epoxy resin is a possible liner for carbon dioxide pipelines. No significant chemical interaction.	
Glycol, diethylene	DEG is a liquid and could be present in hydrogen once pipeline is repurposed. Low volatility so gas phase concentration expected to be low.	
Glycol, monethylene	MEG is a liquid and could be present in carbon dioxide once pipeline is repurposed. Low volatility so gas phase concentration expected to be low	
Glycol, triethylene	TEG is a liquid and could be present in carbon dioxide once pipeline is repurposed. Low volatility so gas phase concentration expected to be low	
Graphite	Seals tend to be able to operate in carbon dioxide environments, and a main cause of damage is through rapid decompression that tends to result in physical damage.	
Grease	Reactivity between greases and carbon dioxide are expected to be very low.	

Substance	Interaction with Carbon Dioxide	RAG
Hydrocarbons, high boiling aliphatic	Reactivity between aliphatic hydrocarbons and carbon dioxide expected to be very low. Some components may desorb (see comment on condensate) but concentrations expected to be low.	
Hydrogen	Hydrogen does not react with carbon dioxide at ambient temperature. Hydrogen can impact on the carbon dioxide phase but with the expected concentration of hydrogen as a minor component this impact is not expected to be significant.	
Hydrogen sulfide	Hydrogen sulfide can react with carbon dioxide to form carbonyl sulfide (COS). Hydrogen sulfide can also impact on the phase behaviour of carbon dioxide. Concentration of these components is anticipated to be low.	
Ketone, various	Carbon dioxide can act as a solvent for ketones and they may desorb into the carbon dioxide flow. Reaction is possible but this typically requires a catalyst.	
Mercury	No direct chemical interaction of mercury with carbon dioxide expected. Mercury is volatile and may be entrained in the carbon dioxide flow.	
Methanol	No significant reaction of methanol with carbon dioxide expected at pipeline conditions. Some reaction is possible but usually requires a catalyst.	
Methyl mercaptan	Methyl mercaptan can form in underground storage facilities. There is no direct reaction chemistry with carbon dioxide but it could impact on the phase behaviour.	
Mill scale	Mill scale is generally a combination of iron oxides such as FeO, Fe_3O_4, and Fe_2O_3. Carbon dioxide reaction with these solids could produce carbonates, but the trace components in the captured carbon dioxide (e.g. NO_x and SO_x) could react to form acids.	
Natural gas	Included as a potential source of contamination in repurposed networks. Expected in low concentration as it desorbs from pipe walls and deposits. Purging management should decrease concentration.	
Natural gas condensate	Condensate not anticipated to react with carbon dioxide under pipeline operating conditions. Some hydrocarbon species could desorb and be entrained into the carbon dioxide.	
Naturally occurring radioactive material	No interaction expected.	
Neoprene	Seals tend to be able to operate in carbon dioxide environments, and a main cause of damage is through rapid decompression that tends to result in physical damage.	
Nitrile	Seals tend to be able to operate in carbon dioxide environments, and a main cause of damage is through rapid decompression that tends to result in physical damage.	
Nitrogen	No direct chemical interaction expected, though nitrogen can impact on phase behaviour of carbon dioxide. The low concentrations of nitrogen that could be present in carbon dioxide pipelines means that any impact will be expected to be small.	
Nylon	Seals tend to be able to operate in carbon dioxide environments, and a main cause of damage is through rapid decompression that tends to result in physical damage.	
Oil, compressor oil	Reactivity between oil hydrocarbons and carbon dioxide expected to be very low. But possible influence of minor components in the CO_2, including NO_x, SO_x, etc. Some components may desorb but concentrations from the oil but concentrations expected to be very low. Residual compressor oils that originate from natural gas systems are not expected to have a significant reaction with carbon dioxide.	
Organohalides, various	Current network entry limits for organohalide give a maximum of 1.5 mg/m³. Organohalides are not expected to react with carbon dioxide at ambient temperature. Possible interaction if there is water present. Organohalides may impact on the phase behaviour of carbon dioxide but impact should be small as the organohalide concentration is low.	
Oxygen	No direct chemical interaction expected, though oxygen can impact on phase behaviour of carbon dioxide. The low concentrations of oxygen that could be present in carbon dioxide pipelines means that any impact will be expected to be small.	
Perlite (expanded)	Perlite sources tend to be related to LNG. No significant impact.	
Polymer pipeline liner	Carbon dioxide is not expected to interact or react with polymer pipeline liner. Any absorption into the liner may cause problems if there is rapid decompression.	

Substance	Interaction with Carbon Dioxide	RAG
Polytetrafluoroethylene	Seals tend to be able to operate in carbon dioxide environments, and a main cause of damage is through rapid decompression that tends to result in physical damage. Specific details on PTFE suitability needs to be included.	
Polyurethane	Seals tend to be able to operate in carbon dioxide environments, and a main cause of damage is through rapid decompression that tends to result in physical damage.	
Pyrophoric dust	Although carbon dioxide can react with some pyrophoric materials, metals, organolithium agents and others, it is unlikely for these components to be present in the pipeline dusts. It is possible that the pyrophoric material is iron sulfide and this does not react with carbon dioxide. Further investigation required.	
Radon	No interaction of Radon with carbon dioxide expected. Further investigation required.	
Rust	Iron oxide could potentially react with carbon dioxide to form carbonates.	
Sand / soil	See silica entry.	
Sealant (e.g. Val-Tex)	Seals tend to be able to operate in carbon dioxide environments, and a main cause of damage is through rapid decompression that tends to result in physical damage.	
Silica	Silica or sand is sometimes observed in pipeline solids. The source is thought to be entry during construction. Carbon dioxide is not expected to interact with silica.	
Silicone	Seals tend to be able to operate in carbon dioxide environments, and a main cause of damage is through rapid decompression that tends to result in physical damage.	
Siloxane, various	Limited data on siloxane interaction with carbon dioxide, but it anticipated to be low.	
Sodium chloride	No direct chemical interaction of sodium chloride with carbon dioxide expected.	
Sulfur dioxide	SO_2 can form in some underground storage installations for hydrogen. Carbon dioxide does not react with SO_2 directly, but in the presence of water an acid solution can form. Sulfur dioxide can impact on carbon dioxide phase behaviour.	
Terpene, various	Carbon dioxide can act as a solvent for terpenes and they may desorb into the carbon dioxide flow. Reaction is possible but this typically requires a catalyst.	
Toluene	Toluene may be entrained into carbon dioxide. Benzene does impact on the phase behaviour of carbon dioxide but the likely concentration in a repurposed pipeline is low. Reaction of carbon dioxide and Toluene typically requires a catalyst (and probably occurs at a slow rate at ambient temperature.	
Water	Water can react with carbon dioxide to form carbonic acid. Water can also influence the phase behaviour of carbon dioxide.	
Waxes	Reactivity between waxes and carbon dioxide expected to be very low. Some hardening may happen.	
Welding rod	Welding rod occasionally found in solid debris in pipelines left over from the construction process. No significant interaction of carbon dioxide with welding rods.	
Xylene (mixed isomers)	Similar to toluene.	

8 IDENTIFICATION AND TESTING OF CONTAMINANTS RECOVERED FROM THE NATIONAL TRANSMISSION SYSTEM

National Gas Transmission has undertaken a campaign of solid and liquid contaminant sampling following pigging operations on the National Transmission System during early 2026. This generated nine substances that were supplied to DNV for testing and analysis. These contaminants were all complex mixtures of compounds but were not novel contaminants and were considered representative of the substances found most commonly. Testing with hydrogen and carbon dioxide was therefore undertaken to confirm that these contaminants would not interact adversely.

8.1 Testing methodology

8.1.1 Material identification

To identify the contaminant materials and attempt to identify their origin, the following scope of work was carried out:

1. On receipt, the materials were entered into DNV's Loughborough laboratory sample register and given unique identification numbers to ensure traceability throughout the lab process.
2. The samples were subject to a thorough naked eye visual inspection to determine any unique or distinguishable features that may aid in the identification of the material and where it originated. Any areas of interest were photographed.
3. The materials were further examined using a stereo optical microscope capable of up to 80× magnification. Again, any areas of interest were photographed.
4. Representative sub-samples were examined with a Hitachi S-3400N scanning electron microscope (SEM) equipped with a tungsten filament (15 kV) and Oxford Instruments energy dispersive X-ray (EDX) analyser.
5. Materials that could not be subjected to electron microscopy (i.e. liquids or organics) were instead investigated using a Thermo Scientific Nicolet Is5 Fourier transform infrared (FTIR) spectrometer and the spectra were compared to known compounds to aid identification of the compounds present.

8.1.2 Exposure testing

Following the material characterisation two representative samples (a black dust and a grease) were exposed separately to both hydrogen or carbon dioxide, and chemical analysis repeated to identify any changes. These were:

1. Sample [redacted]; and
2. Sample [redacted]ludge.

Hydrogen was generated in a conical flask through the reaction of zinc and hydrochloric acid while gaseous carbon dioxide was produced from the sublimation of dry ice. The gases were allowed to contact replicate contaminated materials placed in a connected conical flask equipped with an air lock for four hours. The equipment setup is shown in Figure 4.

These tests were sufficient to identify contaminants that would readily react adversely with hydrogen or carbon dioxide.

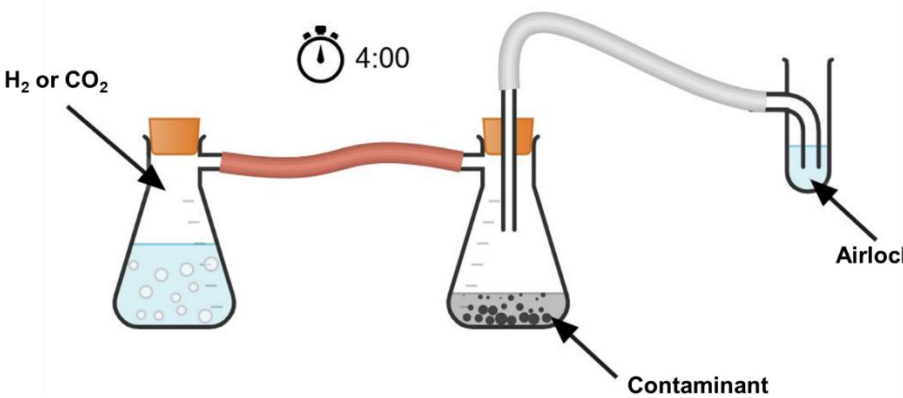


Figure 4 Schematic diagram showing the apparatus for performing the hydrogen and carbon dioxide exposure tests.

8.2 Material identification

8.2.1 General

DNV's Loughborough laboratory received nine samples from National Gas Transmission on 10th October 2025. They were entered into the sample register and given unique identification numbers to maintain traceability throughout the laboratory process. Details of the samples are shown in Table 19 below.

Table 19 Samples received.

DNV ID Number	Sample Type	Sample Description	Image
[redacted]			

[1] The provided sample description implied "sludge" however solid debris was found.
[2] Naturally occurring radioactive material (NORM) identified.
[3] Not photographed due to the radiation hazard.

All materials were tested for the presence of naturally occurring radioactive material (NORM) on receipt. Sample [redacted] was found to be radioactive (19.9 Bq/g). All samples except this one were photographed.

DNV requested information from National Gas Transmission on the presence of asbestos in the solid samples on 10th October 2025. No information was available since an asbestos screen had not taken place and so the solid samples (except sample [redacted] were sent for asbestos analysis by a specialist laboratory on 31st October 2025, and results were received on 14th November 2025 (see Appendix A). This analysis confirmed that asbestos was not present in any of the samples tested. (It should be noted that fibrous material was observed in sample [redacted] that is potentially asbestos.)

Figure 5 Sample [redacted] (representative sample).

Figure 6 Sample [redacted] (representative sample).

Figure 7 Sample [redacted] (representative sample).

Figure 8 Sample [redacted] (representative sample).

Figure 9 Sample [redacted] (representative samples).

Figure 10 Sample [redacted] (representative samples).

Figure 11 Sample [redacted] (representative samples).

Figure 12 Sample [redacted] (representative sample).

8.2.2 Sample [redacted]

8.2.2.1 Visual examination

Sample [redacted] weighed approximately 606 g. From this a representative selection of sub-samples were taken. This included solid material of varying sizes (possibly inorganic and organic material) (Figure 13 and Figure 14) and polymeric material, approximately 48 mm in length (Figure 15). All of the selected sub-samples were heavily contaminated with black dust.

A portion of the material was examined using the stereomicroscope capable of up to 80× magnification. From this, the sample could be seen to be contain varying sizes of metallic material (Figure 16), as well non-metallics, for example, specks of red paint or coating could be seen throughout the sample (Figure 17). Smaller particles, likely the same metallic material, could also be seen under the stereomicroscope (Figure 18).

Figure 13 Sample [redacted] solid material of varying size with black heavy black dust-like contamination.

Figure 14 Sample [redacted] solid material with black dust-like contamination.

Figure 15 Sample [redacted] polymeric material.

Figure 16 Sample [redacted] stereo microscopic image showing varying sizes of metallic particles.

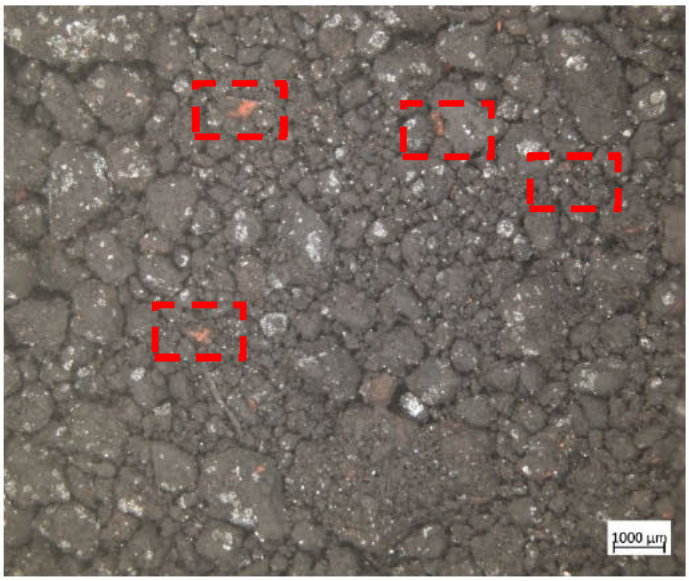


Figure 17 Sample [redacted] stereo microscopic image showing metallic material and red paint or coating specks distributed throughout (outlined in red).

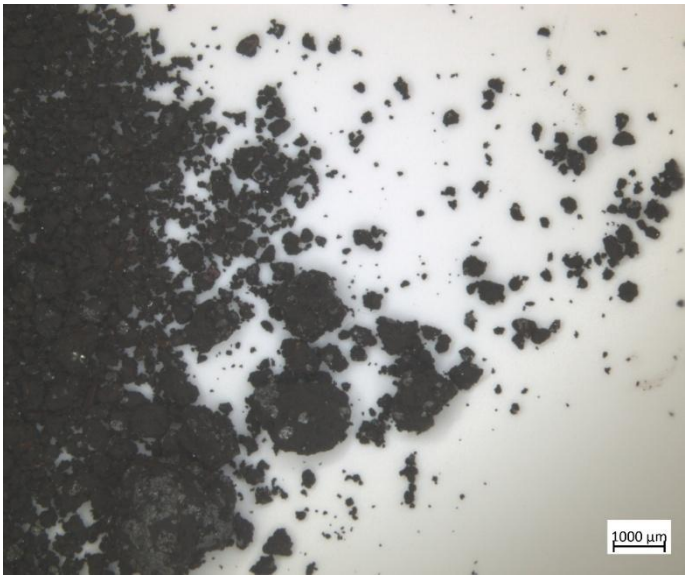


Figure 18 Sample [redacted] stereo microscopic image showing smaller particles of metallic material.

8.2.2.2 FTIR

FTIR spectroscopy is an analytical technique used to aid the identification of organic and polymeric materials. The different chemical bonds within a material absorb different amounts of infrared light, hence providing a spectrum of different types and abundance of bonds, which can act as a “fingerprint” to identify the material.

FTIR analysis was conducted on the polymeric material (sample [redacted] Figure 15). These results can be seen in Figure 19 below.

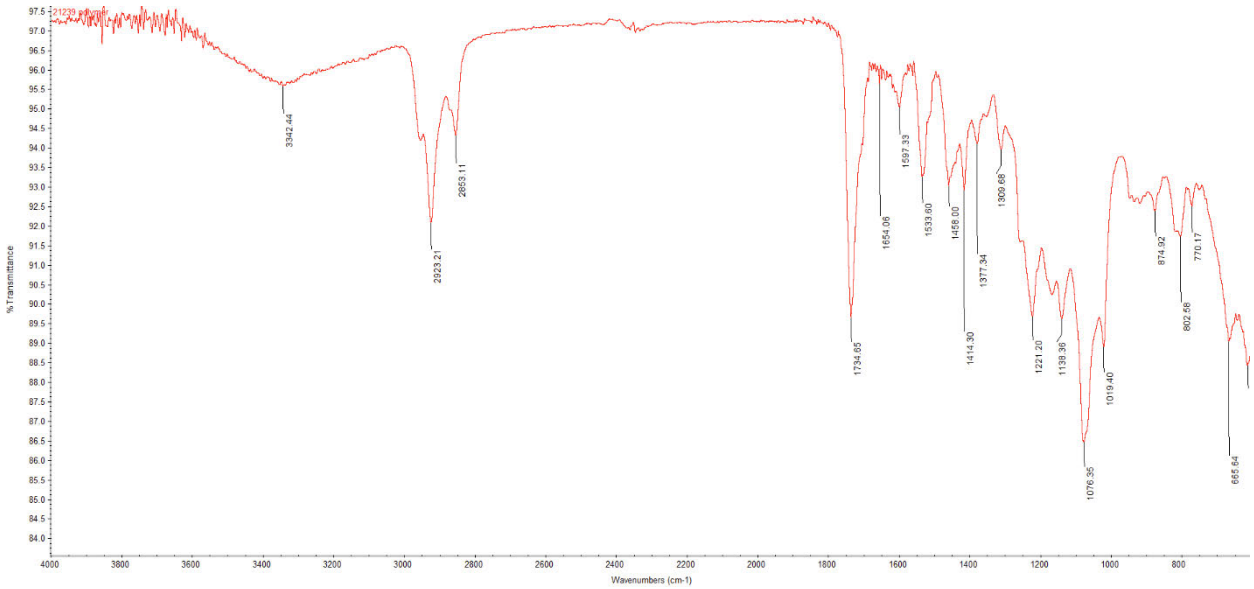


Figure 19 Sample [redacted] FTIR spectrum of the polymeric material.

A list of the characteristic spectrum peaks (in wavenumbers) and their representative chemical bonds is shown in Table 20 below.

Table 20 Sample [redacted] polymeric material spectrum and representative chemical bonds.

Chemical bond	Wave number (cm^{-1})	
	Typical FTIR chemical bond range	Sample [redacted]
O–H or N–H stretch	3200–3550	3342
C–H stretch (CH_3 or CH_2)	2850–2960	2931
		2832
C=O stretch (ester or urethane)	1720–1750	1735
C=C	1640–1680	1654
N–H bend and C–N stretch	1510–1560	1534
C–N or C–O stretch (ester or urethane)	1260–1320	1309
C–O stretch (ether)	1020–1240	1221
		1139
		1076
		1019
Aromatic C–H bend	680–900	875
		802
		770
		687

Based on the strong C=O peak seen at 1735 cm^{-1} along with the C–O peaks and the aromatic C–H bend peaks in the fingerprint region, this polymeric material may be polyethylene terephthalate (PET). On the NTS elastomeric materials are more commonly used in functional components such as valves compared to thermoplastics such as PET and so it is unclear where this fragment may have originated from.

8.2.2.3 SEM imaging and EDX analysis

The SEM was used to visualise small areas of the sample at magnifications up to 2000×. The EDX analysis unit attached to the SEM was used to acquire the chemical composition of the samples. This was carried out in order to identify the chemical elements present. In Figure 20, for example, the top image shows the sample magnified, and other images show the location of particular chemical elements, i.e. sulfur, carbon, chlorine, iron, oxygen, silicon, sodium, and calcium.

The smaller solid contaminant material (sample [redacted] Figure 13) was examined under the SEM and EDX. The high level of carbon present in the polymeric material (sample [redacted] Figure 15) made it unsuitable for EDX analysis.

There was a high concentration of iron and oxygen in several locations which indicated an iron oxide component with aluminium, calcium and silicon, as well as sodium and chlorine (likely sodium chloride), indicative of environmental contamination. This was the case at several locations as indicated in Figure 20 and Figure 21.

A small concentration of mercury was also observed within the sample along with the typical metallic elements and environmental contamination (Figure 22).

It is likely that the iron oxides represent the majority of the metallic material in the sample tested and the lighter elements correspond to a mixture of mineral compounds together often referred to as black dust, together with specks of paint identified during the stereomicroscopic examination.

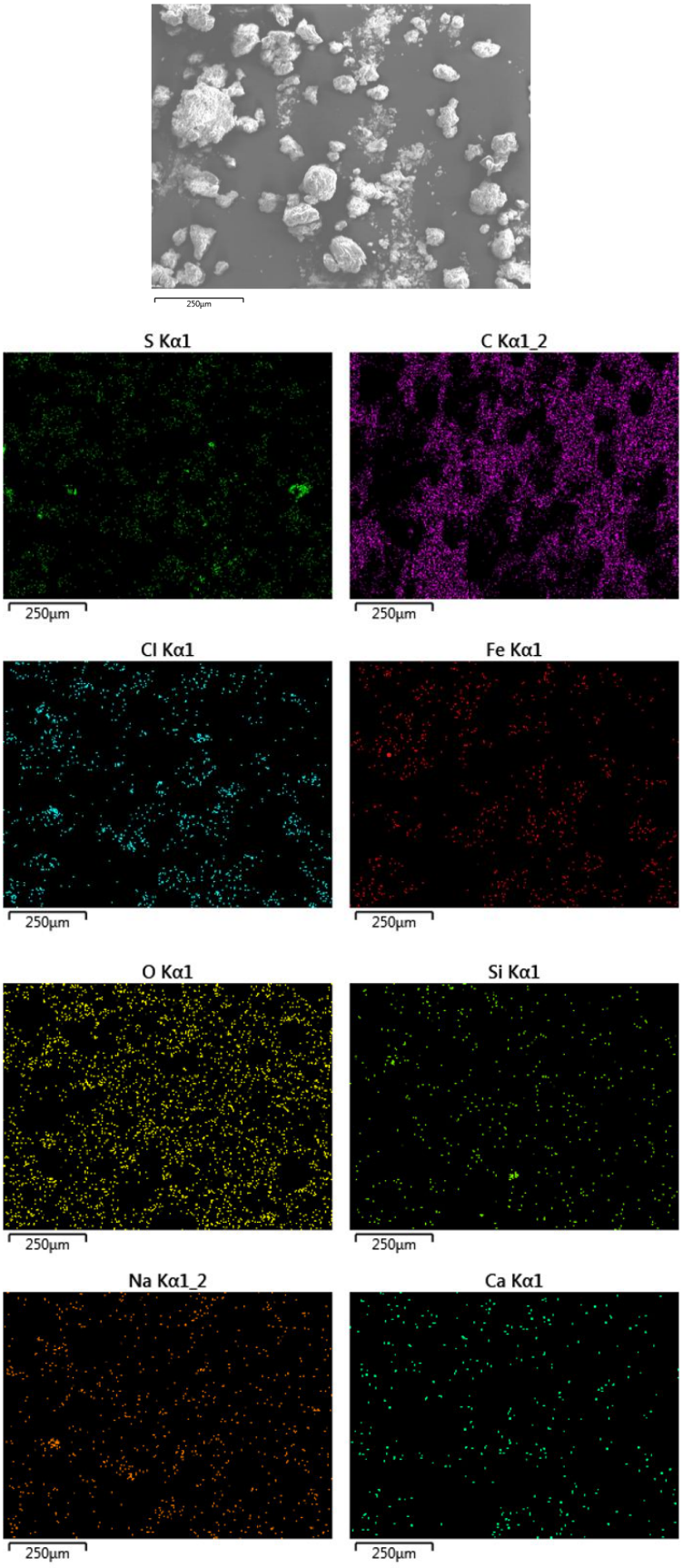
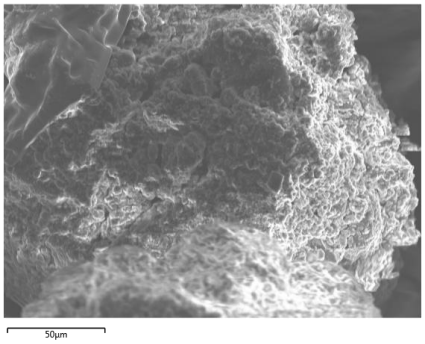
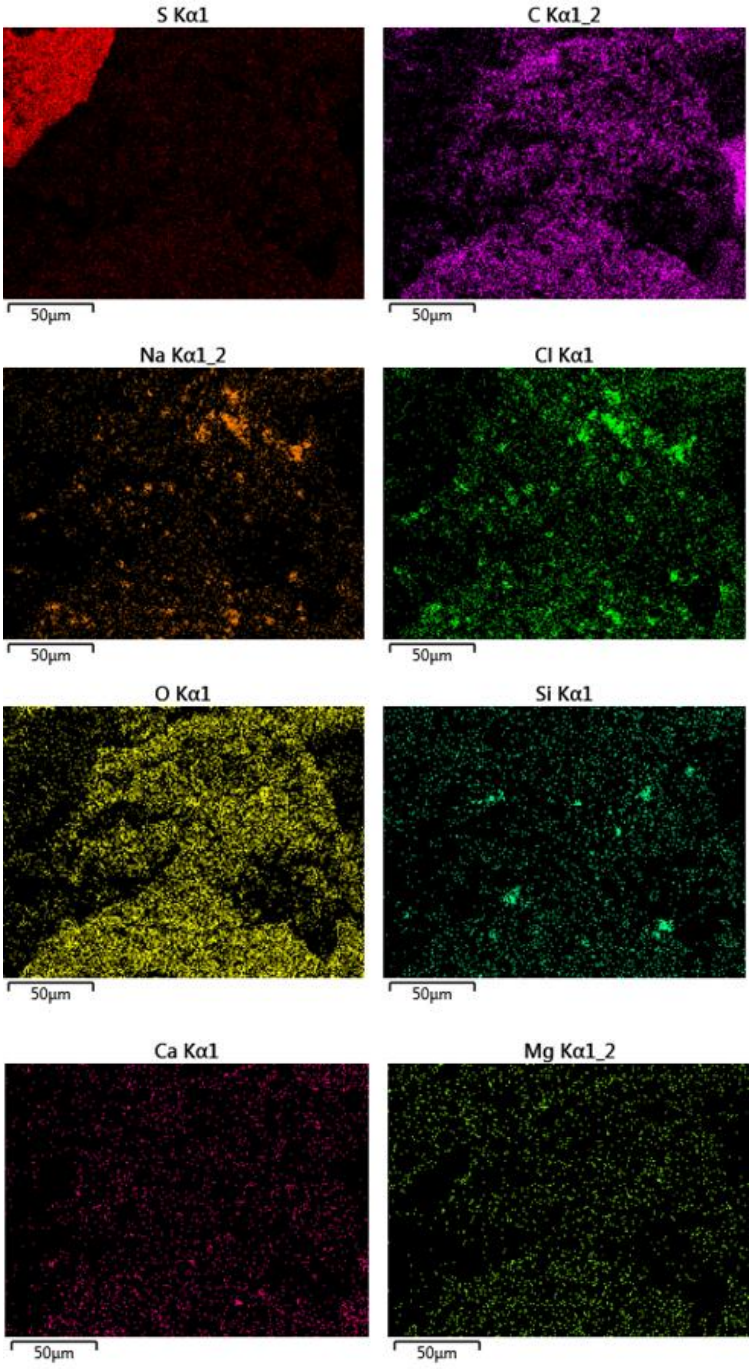


Figure 20 SEM imaging and EDX mapping of sample [redacted] black dust-like material.


50µm


S Kα1
C Kα1_2
Na Kα1_2
Cl Kα1
O Kα1
Si Kα1
Ca Kα1
Mg Kα1_2
50µm

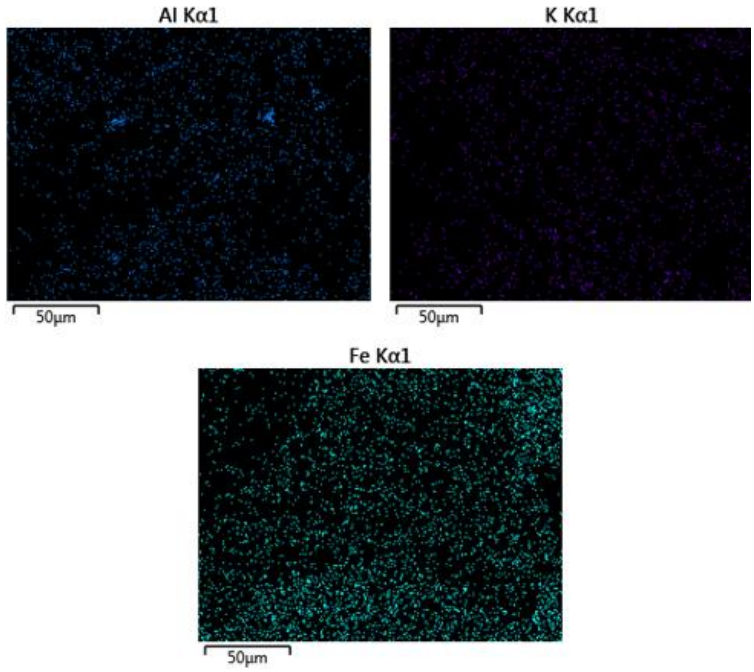
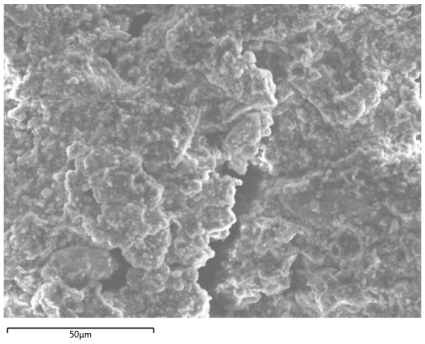
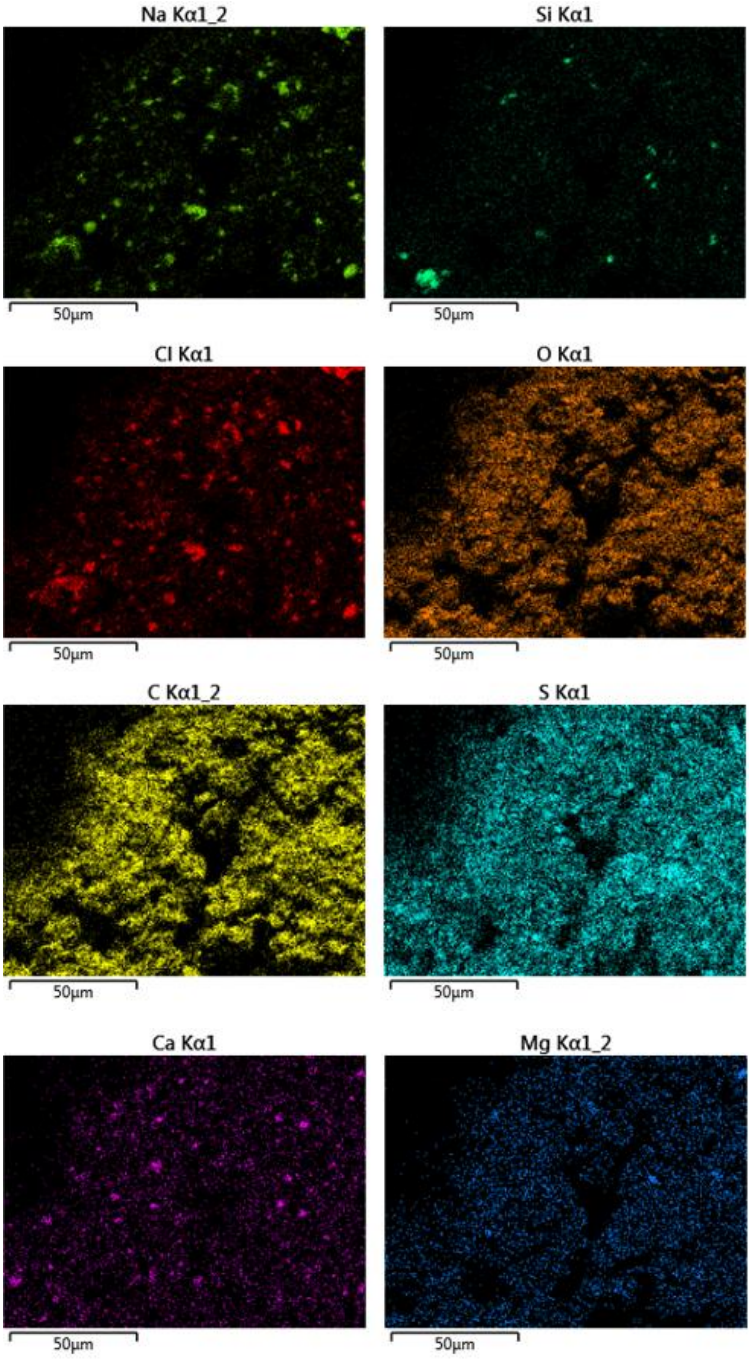


Figure 21 SEM imaging and EDX mapping of sample [redacted] black dust-like material.


50µm


Na Kα1_2
50µm
Si Kα1
50µm
Cl Kα1
50µm
O Kα1
50µm
C Kα1_2
50µm
S Kα1
50µm
Ca Kα1
50µm
Mg Kα1_2
50µm

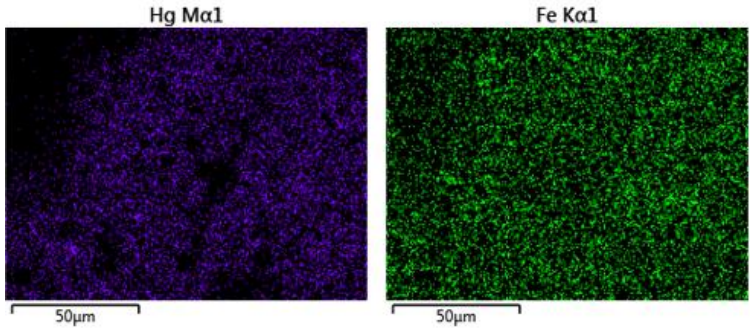


Figure 22 SEM imaging and EDX mapping of sample [redacted] black dust-like material showing the presence of mercury.

8.2.2.4 Summary of findings

The solid debris contained both metallic and non-metallic material, including polymeric material. The EDX analysis showed that the metallic component of the sample consisted mostly of iron oxide together with elements associated with environmental contamination (e.g. salts and minerals). The FTIR analysis indicated the possibility of a PET polymer being present, its origin is unknown. This sample is typical of a black dust pipeline deposit.

8.2.3 Sample [redacted]

8.2.3.1 Visual examination

Sample [redacted] consisted mostly of 645 ml of pale yellow liquid with small amounts of darker yellow liquid suspended within it (sample [redacted] Figure 23). Within this sample there was a small amount of viscous brown liquid with some black contamination. It was extremely difficult to pour and adhered to the surfaces it contacted (sample [redacted] Figure 24).

Stereo microscopic examination would not reveal further information about the liquids and so was not carried out.

Figure 23 Sample [redacted] liquid solution.

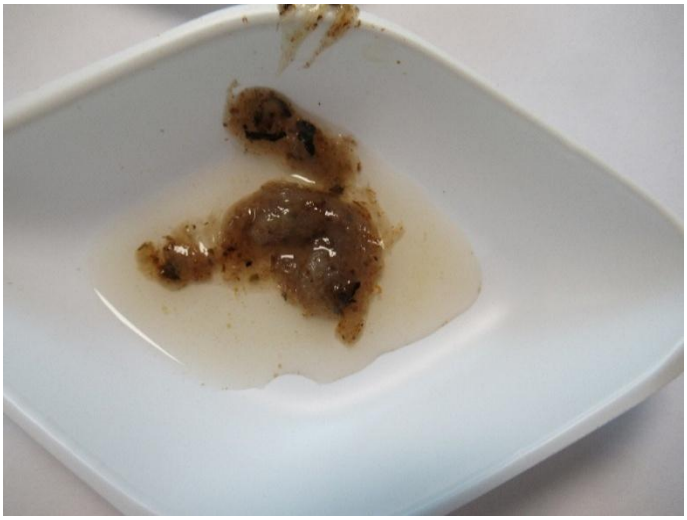


Figure 24 Sample [redacted] suspension product within the liquid solution.

8.2.3.2 FTIR

FTIR was carried out on both the pale yellow liquid (sample [redacted] and the viscous brown liquid (sample [redacted]

Figure 25 below shows the FTIR spectrum of the pale yellow liquid.

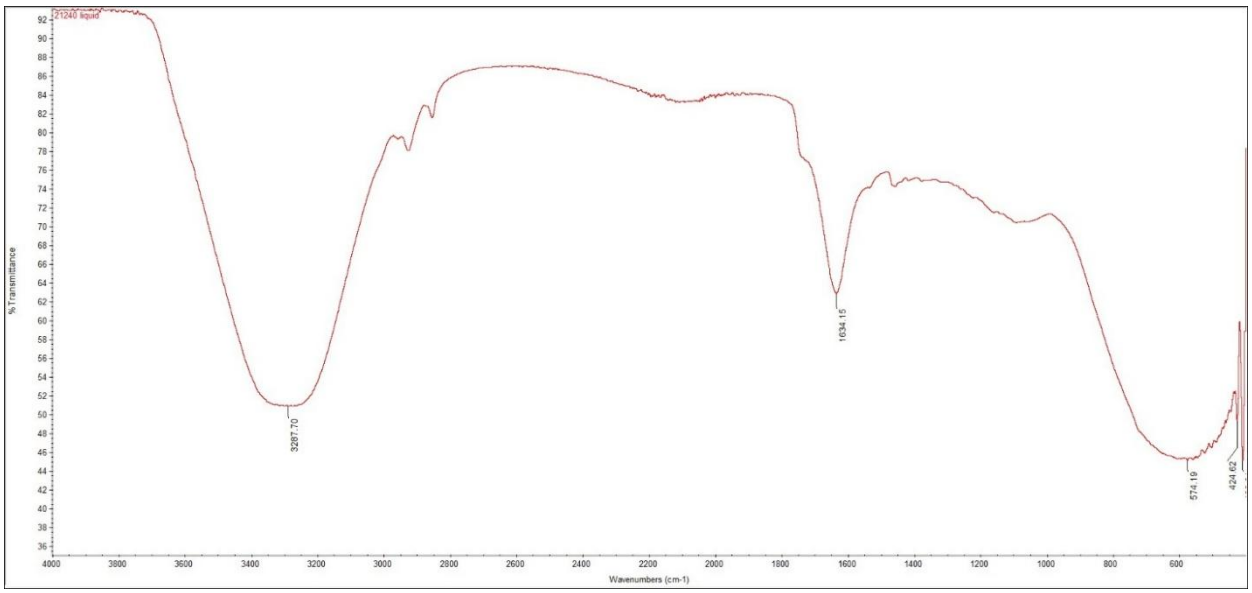


Figure 25 Sample [redacted] FTIR spectrum of the pale yellow liquid component.

A list of the characteristic spectrum peaks (in wavenumbers) and their representative chemical bonds is shown in Table 21.

Table 21 Sample [redacted] pale yellow liquid wavenumber locations and their representative chemical bonds.

Chemical bond	Wave number (cm^{-1})	
	Typical FTIR chemical bond range	Sample [redacted]
O–H or N–H stretch	3200–3550	3287
C=O stretch or H–O–H bend	1650–1750	1634
C–C, C–O bending	500–600	574

Figure 26 below shows the FTIR spectrum of the viscous brown liquid.

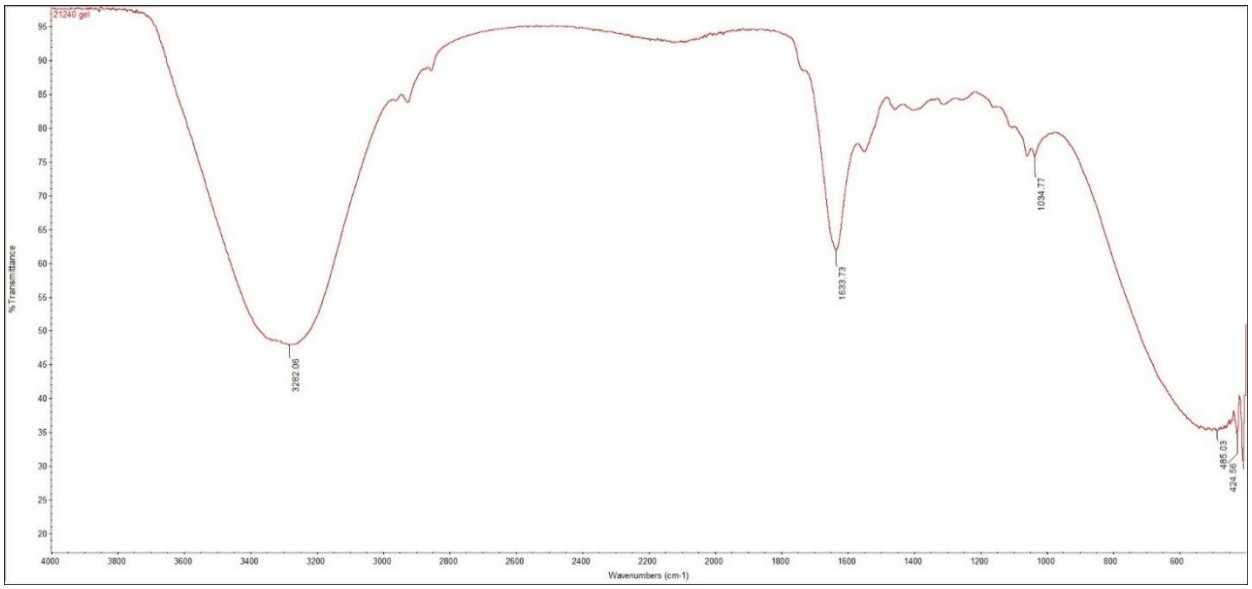


Figure 26 Sample [redacted] FTIR spectrum of the viscous brown liquid.

A list of the characteristic spectrum peaks (in wavenumbers) and their representative chemical bonds is shown in Table 22.

Table 22 Sample [redacted] viscous brown liquid spectrum and representative chemical bonds.

Chemical bond	Wave number (cm^{-1})	
	Typical FTIR chemical bond range	Sample [redacted]
O–H or N–H stretch	3200–3550	3282
C=O stretch or H–O–H bend	1650–1750	1634
C–O stretch (alcohol, ester)	1000–1300	1034

The analysis of both samples [redacted] and [redacted] show similar chemical compositions and peak strengths. The strong O–H and H–O–H peaks indicates high levels of water, together with smaller quantities of an aliphatic hydrocarbon oil.

8.2.3.3 SEM imaging and EDX analysis

SEM imaging and EDX analysis are techniques which require the samples to be in a solid, vacuum-compatible state. Liquid samples cannot be subjected to SEM/EDX analysis due to their inability to withstand the high vacuum

environment within the microscope chamber. Exposing the equipment to liquid may result in damage or sample loss. Additionally, the SEM/EDX requires a conductive surface to produce accurate imaging and elemental analysis, this cannot be provided by liquid-phase materials. Additionally, the FTIR results indicate a high carbon content for sample [redacted] the EDX cannot accurately determine carbon concentration and therefore no further testing was conducted.

8.2.3.4 Summary of findings

Sample [redacted] contained mostly a pale liquid (sample [redacted] with some viscous brown suspension material (sample [redacted] The FTIR analysis showed the chemical composition of the two substances to be very similar with strong O–H stretches, indicating it is likely a mixture of water and lubricating oil, although the presence of natural gas condensate could not be ruled out.

8.2.4 Sample [redacted]

8.2.4.1 Visual examination

Sample [redacted] was a viscous black substance. It was grainy in texture and adhered to all surfaces during transfer, during this process it also appeared non-elastic and broke away into several small pieces (Figure 7). It was uniformly black with a sheen across the sample surface and approximately 375 g was provided for testing. It emitted a strong natural gas odorant smell.

Stereo microscopic examination would reveal no further information about the viscous contaminant or its composition and therefore was not carried out for sample [redacted]

8.2.4.2 FTIR

FTIR analysis was conducted on a representative quantity of sample [redacted] the results of which can be seen in Figure 27 below.

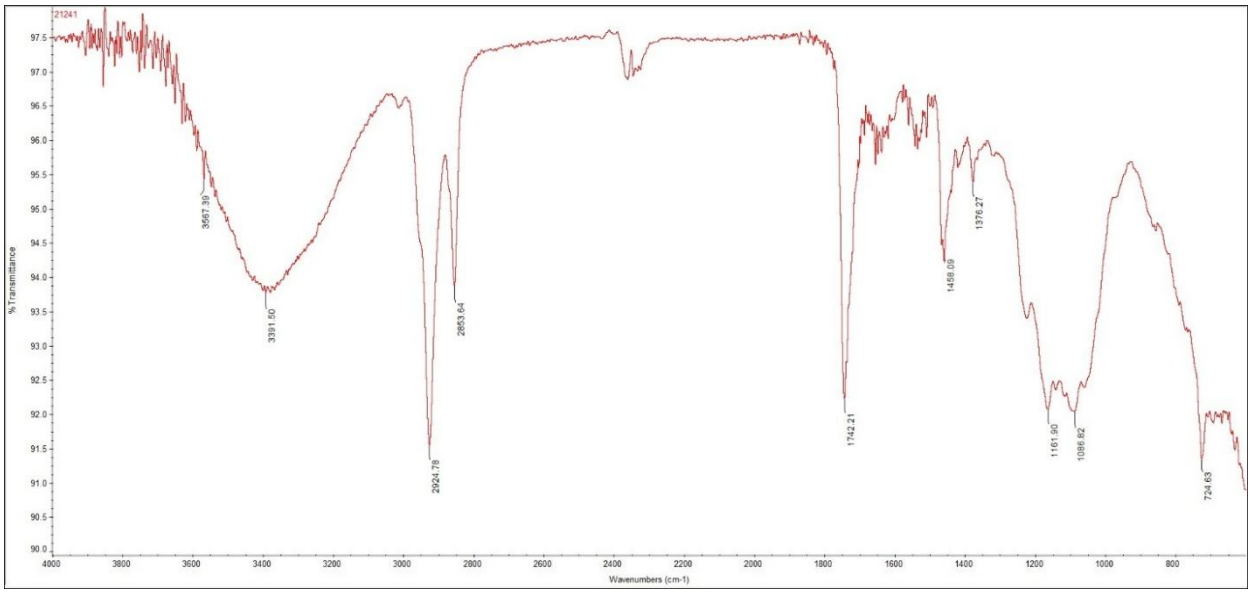


Figure 27 Sample [redacted] FTIR spectrum of the viscous black substance.

A list of the characteristic spectrum peaks (in wavenumbers) and their representative chemical bonds is shown in Table 23.

Table 23 Sample [redacted] viscous black substance spectrum and representative chemical bonds.

Chemical bond	Wave number (cm^{-1})	
	Typical FTIR chemical bond range	Sample [redacted]
O–H stretch (alcohol)	3200–3700	3391
C–H stretch	2850–2960	2924
		2855
C=O stretch (esters)	1650–1750	1742
C–H bending	1465–1420	1458
CH_3 bending	1000–1300	1161
		1086

The FTIR spectrum indicates the presence of aliphatic hydrocarbons, potentially a grease emulsified with traces of water. The metal soap-based grease used by National Gas Transmission has a diagnostic absorption band between 1500–1600 cm^{-1}, which is not seen in this spectrum.[25] It is more likely to be a castor oil-based grease (see Figure 28) such as Val-Tex valve sealant[25], which shows strong similarities in peak position and peak transmission strengths, particularly at 2925, 2854 and 172 cm^{-1}.

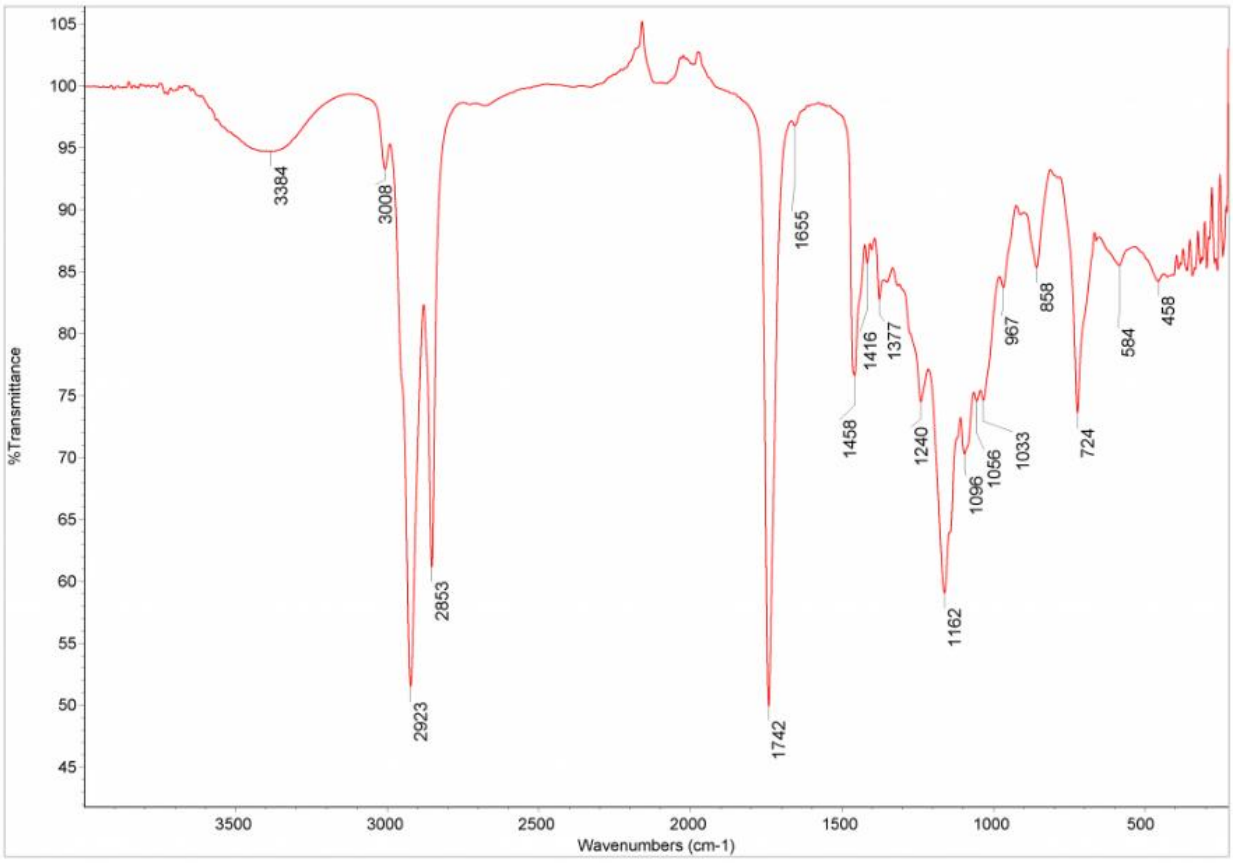


Figure 28 FTIR reference spectrum of castor oil.

[25] A. Brealey, D. Robson and A. Wood, 42" Nuovo Pignone Valve Sealant Investigation, DNV report no. 10230, 2010.

8.2.4.3 SEM imaging and EDX analysis

SEM imaging and EDX analysis are techniques which require the samples to be in a solid, vacuum-compatible state. Liquid samples cannot be subjected to SEM/EDX analysis due to their inability to withstand the high vacuum environment within the microscope chamber. Exposing the equipment to liquid may result in damage or sample loss. Additionally, the SEM/EDX require a conductive surface to produce accurate imaging and elemental analysis, this cannot be provided by liquid-phase materials. Additionally, the FTIR results indicate a high carbon content for sample [redacted] the EDX cannot accurately determine carbon concentration and therefore no further testing was conducted.

8.2.4.4 Summary of findings

Sample [redacted] was a black viscous substance. It is most likely to be a valve sealant emulsified with water and contaminated with corrosion products.

8.2.5 Sample [redacted]

8.2.5.1 Visual examination

Sample [redacted] was a clear to yellow liquid with a small amount of suspended debris within it (Figure 29). This was the consistent composition throughout the 459 ml supplied.

Stereo microscopic examination would reveal no further information about the liquid contaminant or its composition.

Figure 29 Sample [redacted] liquid solution with some debris present.

8.2.5.2 FTIR

FTIR analysis was conducted on a representative quantity of sample [redacted] the results of which can be seen in Figure 30 below.

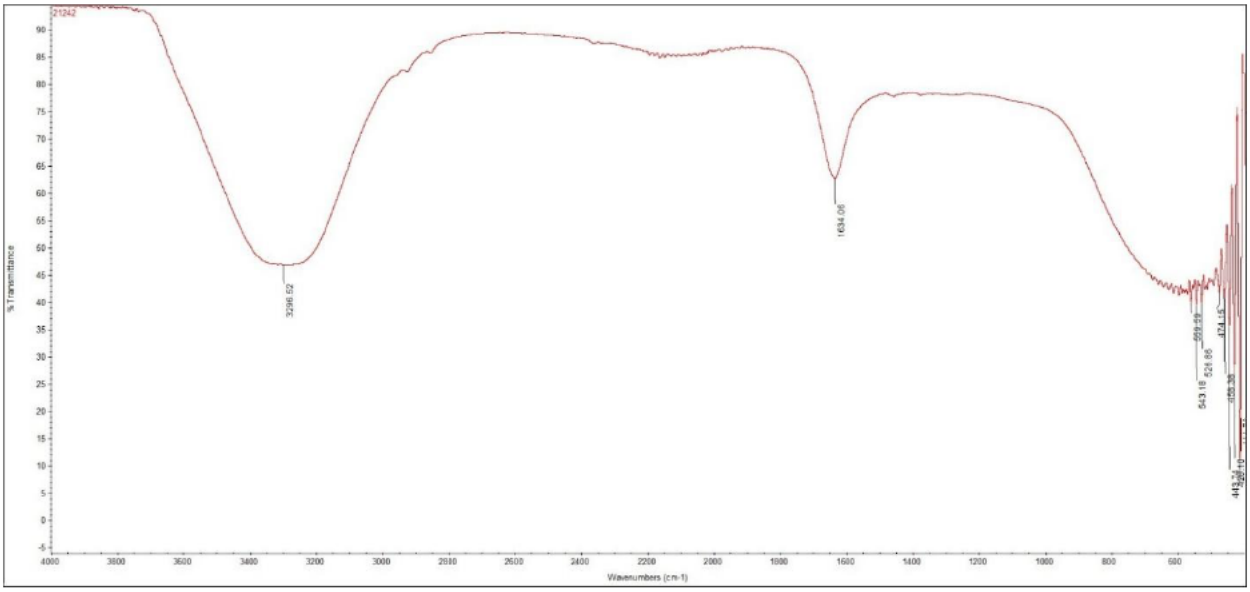


Figure 30 Sample [redacted] FTIR spectra for the liquid component.

A list of the characteristic spectrum peaks (in wavenumbers) and their representative chemical bonds is shown in Table 24. The peaks of a wavenumber greater than 600 cm^{-1} have been excluded from the table as a result of high noise in the signal during testing.

Table 24 Sample [redacted] liquid component spectrum and their representative chemical bonds.

Chemical bond	Wave number (cm^{-1})	
	Typical FTIR chemical bond range	Sample [redacted]
O–H stretch (alcohol)	3200–3700	3296
C=O stretch (esters)	1650–1750	1634

The FTIR analysis of sample [redacted] shows it is likely a water together with a small amount of aliphatic hydrocarbons.

8.2.5.3 SEM imaging and EDX analysis

SEM imaging and EDX analysis are techniques which require the samples to be in a solid, vacuum-compatible state. Liquid samples cannot be subjected to SEM/EDX analysis due to their inability to withstand the high vacuum environment within the microscope chamber. Exposing the equipment to liquid may result in damage or sample loss. Additionally, the SEM/EDX require a conductive surface to produce accurate imaging and elemental analysis, this cannot be provided by liquid-phase materials. Additionally, the FTIR results indicate a high carbon content for sample [redacted] the EDX cannot accurately determine carbon concentration and therefore no further testing was conducted.

8.2.5.4 Summary of findings

Sample [redacted] is a liquid component, likely water with some aliphatic hydrocarbons (i.e. lubricating oil or natural gas condensate).

8.2.6 Sample [redacted]

8.2.6.1 Visual examination

Sample [redacted] weighed approximately 165 g. From this a representative selection of sub-samples were taken. The bulk of the sample consisted of a series of irregularly shaped orange-brown thin and brittle material ranging from

approximately 1 cm to 4 cm in size (Figure 9). This is likely to be iron oxide pipe scale as per the sample description provided in Table 19. There was additionally some finer particulate debris and fibrous material (Figure 9).

The pipe scale and smaller debris samples were examined using the stereomicroscope capable of up to 80× magnification. From this, similarly to the visual examination the pipe scale could be seen to have a rough surface and edges and further showed the iron oxide-like orange to brown colour (sample [redacted] Figure 31).

The smaller debris showed varying particulate sizes and shapes, often ranging between 500 and 3000 microns (sample [redacted] Figure 32). Some of the debris was spherical in shape suggesting weld spatter or shotblasting material. The inconsistent size is more suggestive of weld spatter. This was often grey in colour or contaminated with an orange surface (Figure 32). The weld spatter was widely present in the sample and was evenly distributed throughout the sample.

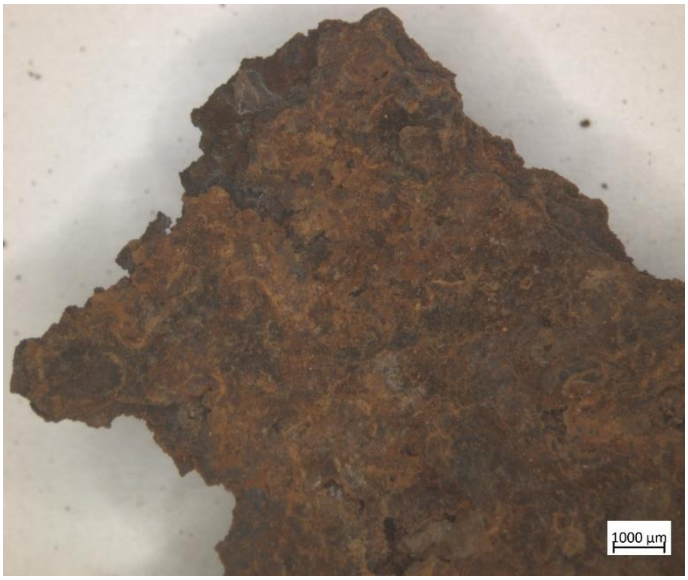


Figure 31 Sample [redacted] stereo microscope image of pipe scale.

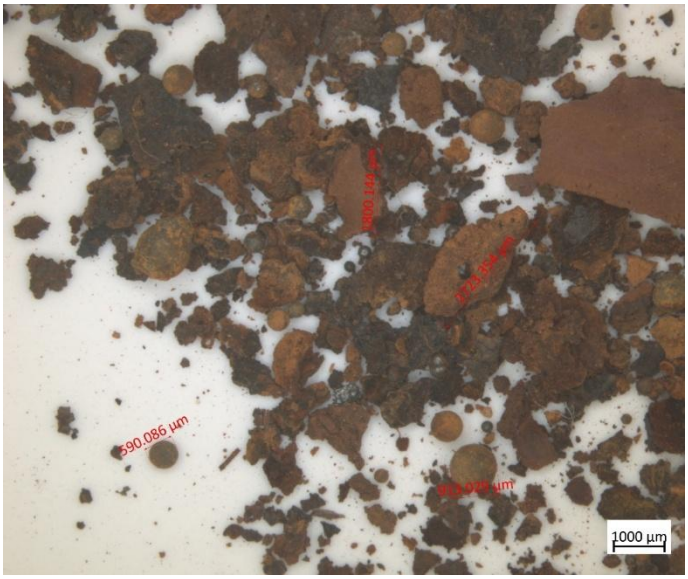


Figure 32 Sample [redacted] stereo microscope image of smaller particles including spherical particles likely to be weld spatter or shotblasting material.

8.2.6.2 SEM imaging and EDX analysis

A cross-section of the pipe scale (sample [redacted] was taken and subjected to SEM imaging and EDX analysis that confirmed its chemical composition consisted of both iron and oxygen (Figure 33).

Smaller debris from sample [redacted] also had high levels of iron and oxygen present in its composition (Figure 34 and Figure 35). The weld spatter was spherical and was of similar composition to the other debris in the sample (Figure 36). The presence of sulfur and sodium indicated general contamination.

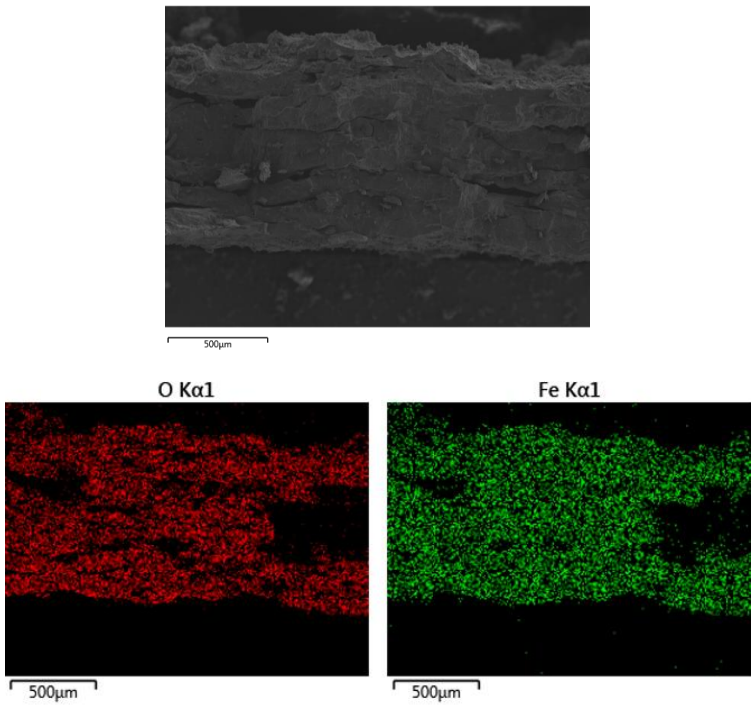


Figure 33 Sample [redacted] SEM imaging and EDX mapping of pipe scale cross section.

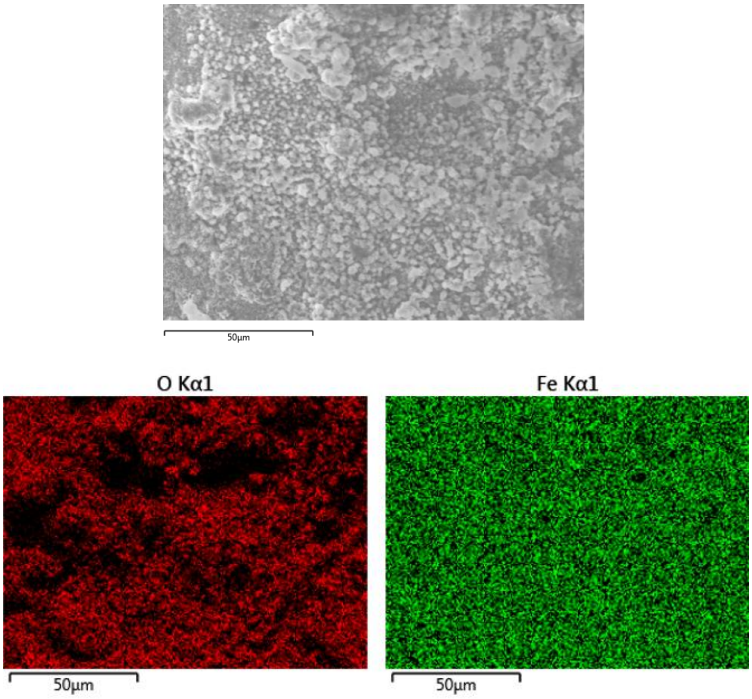
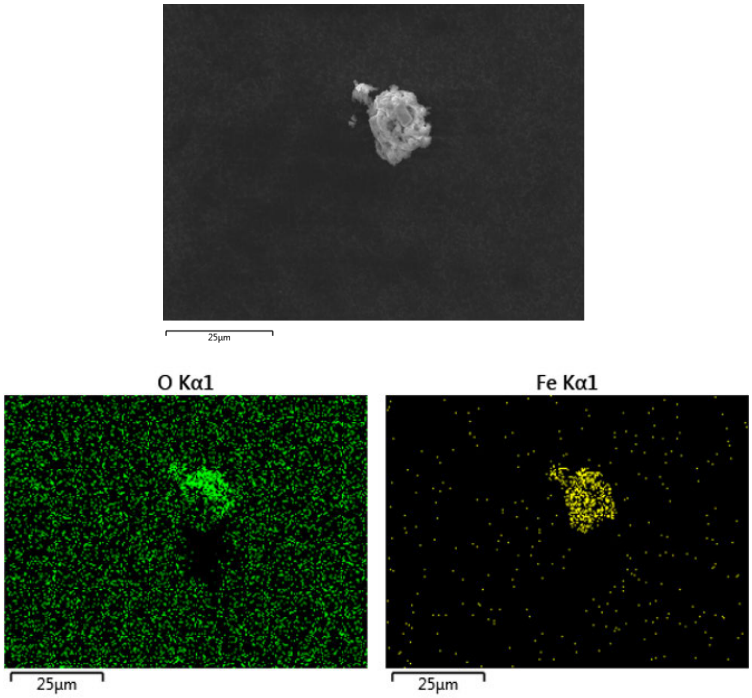


Figure 34 Sample [redacted] SEM imaging and EDX mapping of small particulates.



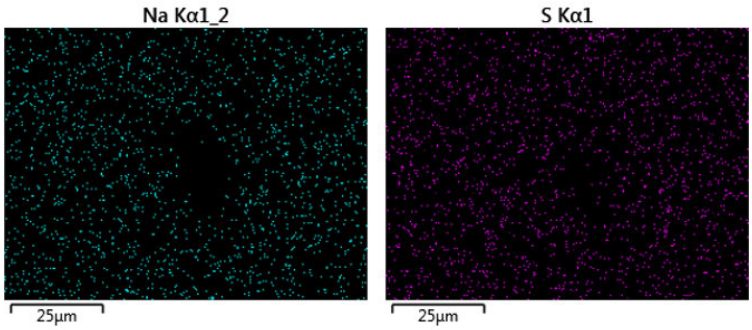


Figure 35 Sample [redacted] SEM imaging and EDX mapping of small particulates.

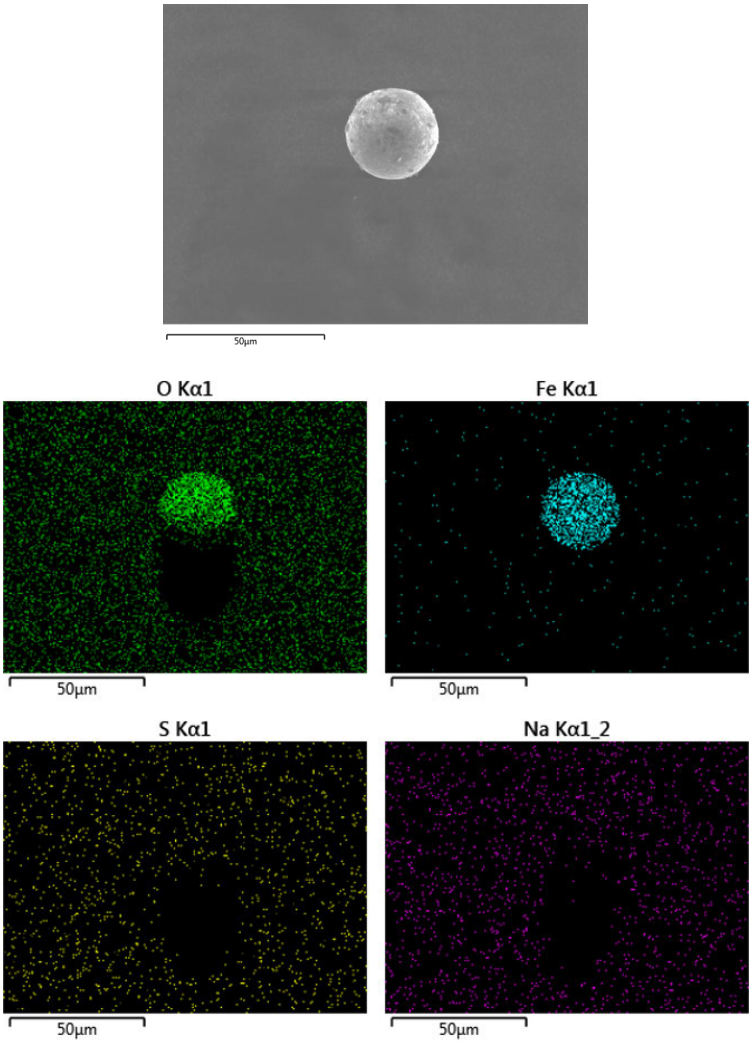


Figure 36 Sample [redacted] SEM imaging and EDX mapping of weld spatter.

8.2.6.3 Summary of findings

The bulk of Sample [redacted] consisted of orange-brown brittle material with an iron oxide chemical composition; it is likely this is a corrosion product pipe scale. There was additionally some smaller debris that was spherical in shape indicating either weld spatter or shotblasting material, both of which have a similar chemistry and physical appearance, although the variable particle size is more suggestive of weld spatter.

8.2.7 Sample [redacted]

8.2.7.1 Visual examination

Sample [redacted] contained 303g of apparent weld spatter of various sizes and shapes from small particulate matter and spherical debris up to larger sections up to 4 cm in size (Figure 10 and Figure 37). It is possible some of the more spherical debris may be shotblasting material as opposed to weld spatter. The larger irregularly shaped material, which is most likely weld spatter is all dark grey in colour with varying levels of orange-brown oxide contamination (Figure 38).

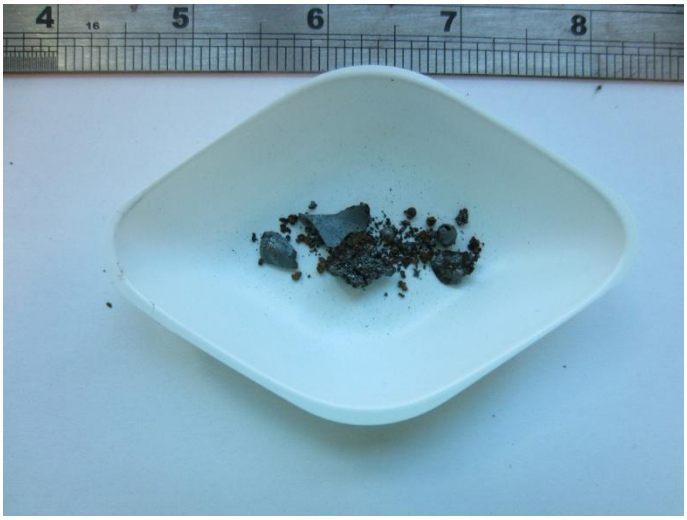


Figure 37 Sample [redacted] smaller weld spatter.

Figure 38 Sample [redacted] weld spatter showing varying levels of contamination.

8.2.7.2 SEM imaging and EDX analysis

All of the SEM imaging and EDX analysis showed the presence of both iron and oxygen in the composition only (Figure 39, Figure 40 and Figure 41). One area sampled contained manganese which is often present in mild steels (either weld by-product or shotblasting material) (Figure 42).

Some of the spherical particles have then been subjected to further hot weld spatter which has caused spherical indentations (Figure 39).

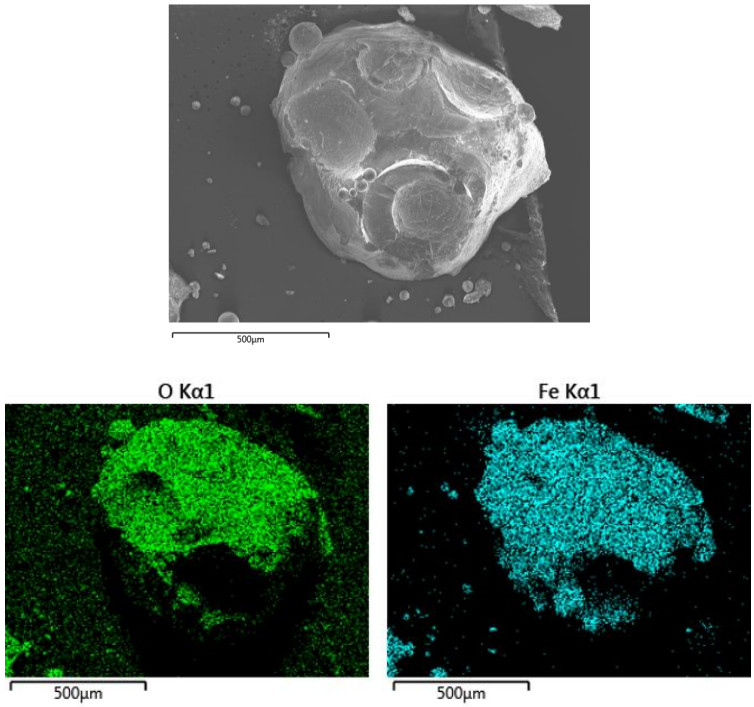


Figure 39 SEM imaging and EDX mapping of weld spatter from Sample [redacted]

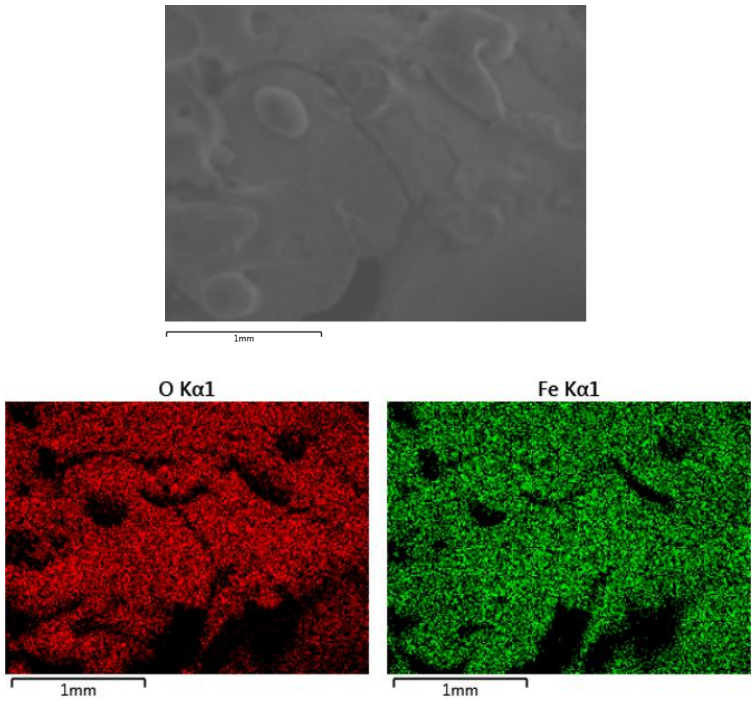


Figure 40 SEM imaging and EDX mapping of weld spatter from Sample [redacted]

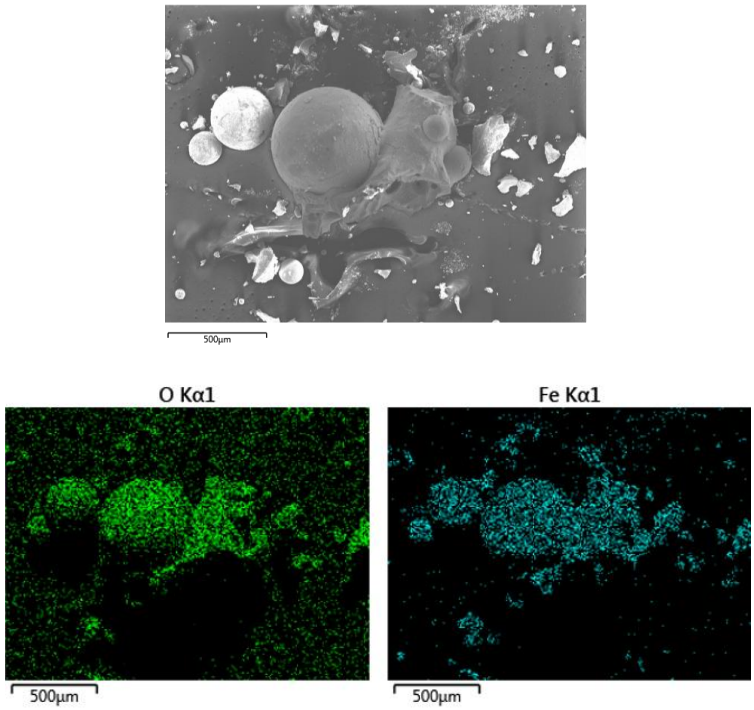


Figure 41 SEM imaging and EDX mapping of weld spatter from Sample [redacted]

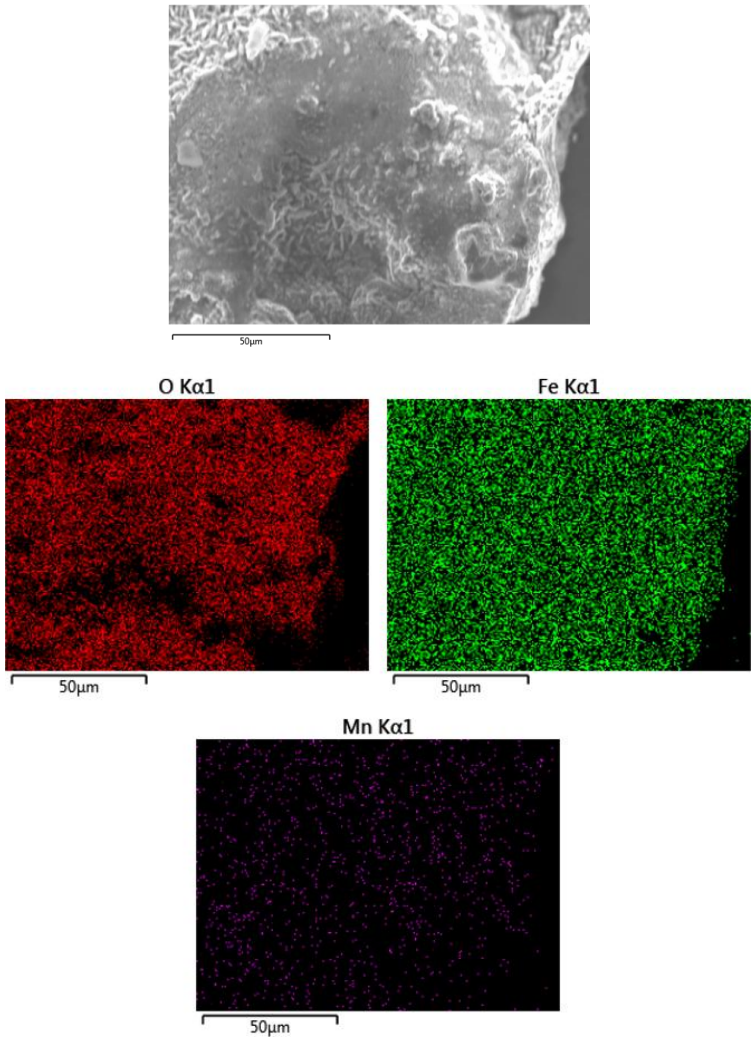


Figure 42 SEM imaging and EDX mapping of weld spatter from Sample [redacted] containing manganese.

8.2.7.3 Summary of findings

Sample [redacted] consisted of weld spatter material of various sizes and shapes. Some spherical debris may be shotblast material as opposed to weld, but this could not be distinguished from the chemical composition as both were identified as iron oxide.

8.2.8 Sample [redacted]

8.2.8.1 Visual examination

Sample [redacted] weighed approximately 195 g. From this, a representative selection of sub-samples were taken. The bulk of the sample consisted of weld spatter with the possibility of smaller spherical components being shotblasting material, together with black dust (Figure 11).

8.2.8.2 SEM imaging and EDX analysis

All of the SEM imaging and EDX analysis showed the presence of both iron and oxide in the composition. Additional elements could also be seen such as, silicon and sulfur (Figure 43 and Figure 44) which are trace elements often found in mild steel products. Titanium, silicon, manganese, sulfur and aluminium were also found in areas (Figure 45) which indicate environmental contamination as well as mild steel elements.

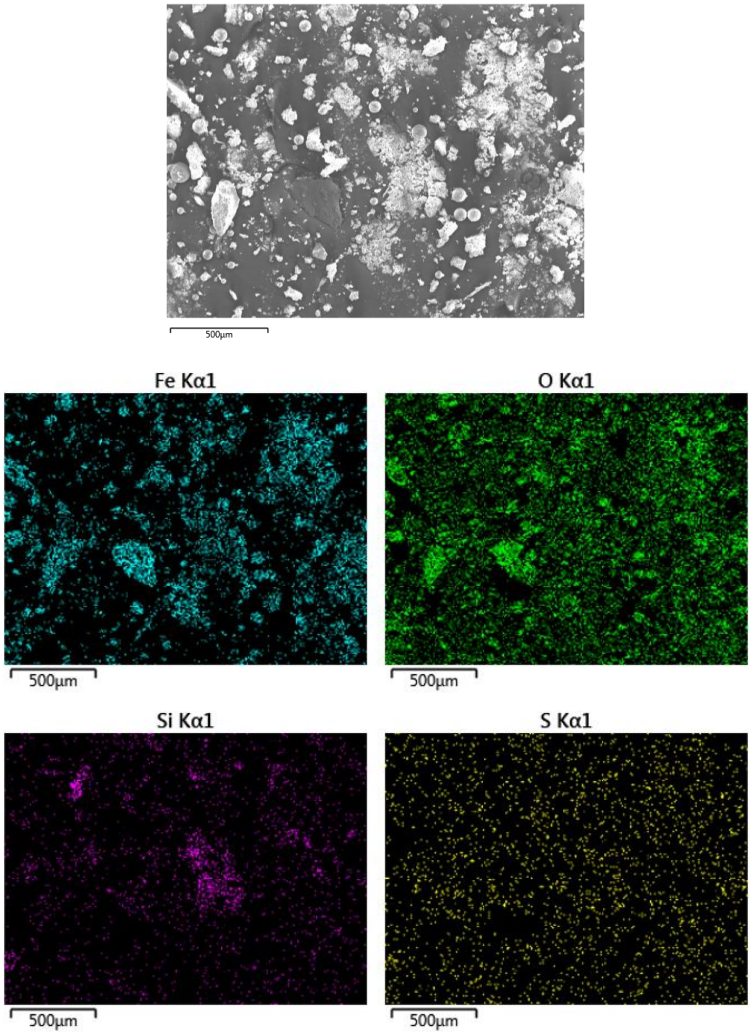


Figure 43 Sample [redacted] SEM imaging and EDX mapping of weld spatter and shotblasting material.

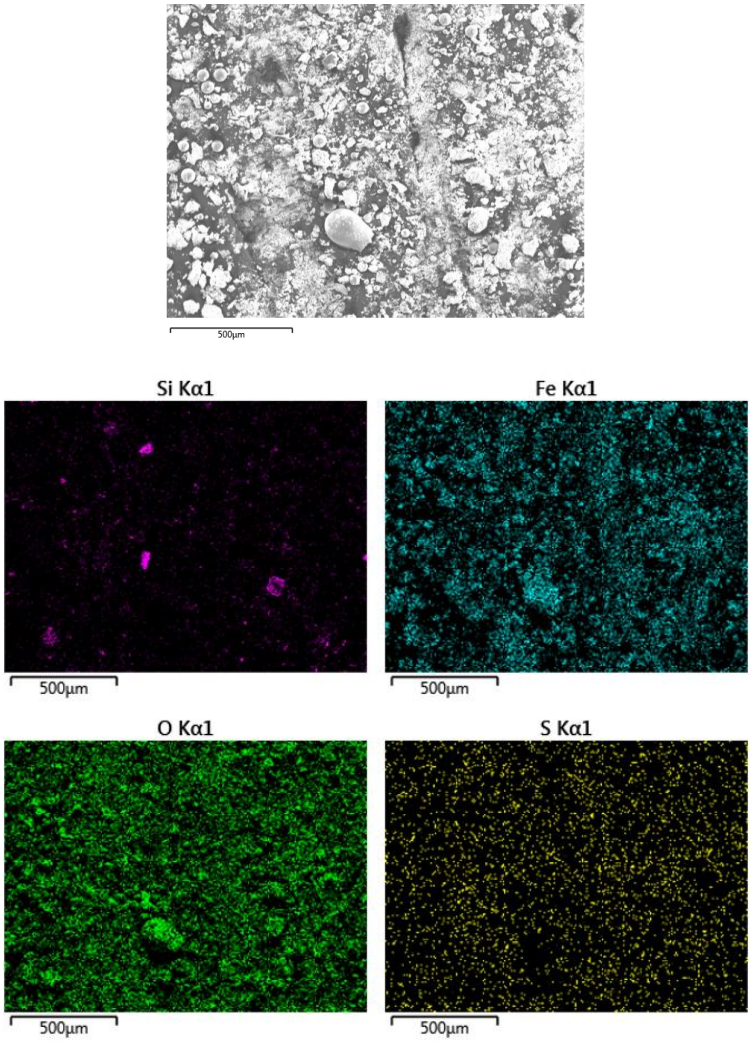


Figure 44 Sample [redacted] SEM imaging and EDX mapping of weld spatter and shotblasting material.

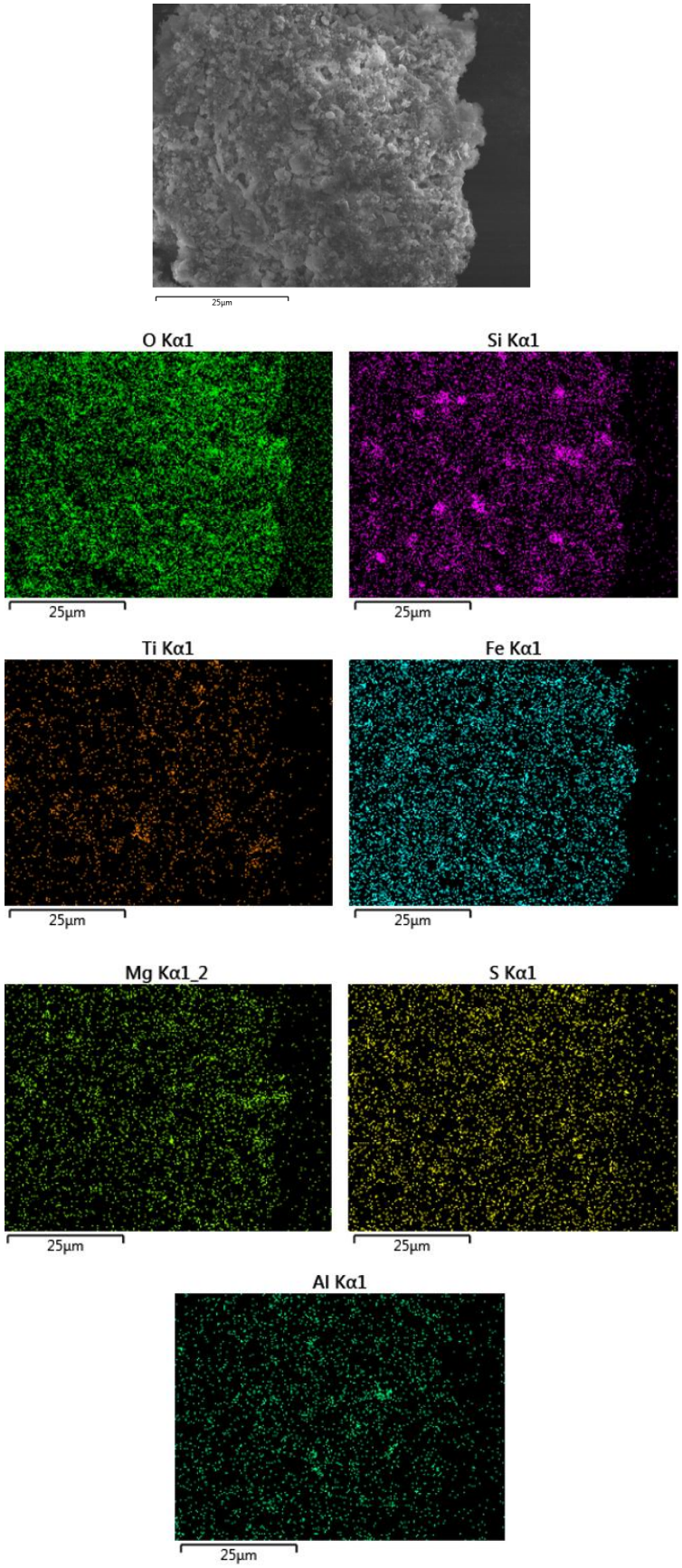


Figure 45 Sample [redacted] SEM imaging and EDX mapping of weld spatter and shotblasting material.

8.2.8.3 Summary of findings

This sample consisted of iron oxides from weld spatter with possible traces of shotblasting material. There was a significant number of lighter elements also present indicating environmental contamination which likely corresponds to the black dust seen during the visual examination.

8.2.9 Sample [redacted]

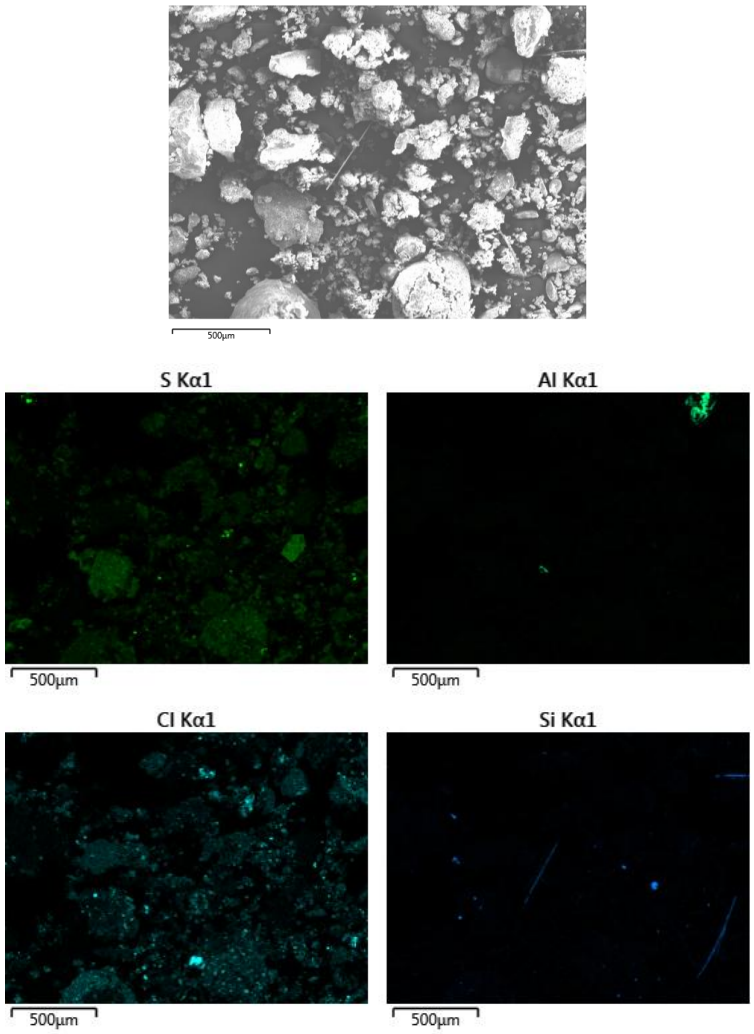
8.2.9.1 Visual Examination

This sample was found to be radioactive during the NORM screening, with a reading of 19.9 Bq/g. Gas from Bacton is known to contain NORM and so this is not unexpected. However in order to minimise the radiation exposure the visual examination was not conducted. Instead, the material was prepared for the SEM in a fume cupboard and transferred immediately. During this process it was observed that the material was dark grey in colour and composed of small particles, approximately 0.5 mm and smaller.

8.2.9.2 SEM imaging and EDX analysis

The SEM imaging showed that the representative sample taken from sample [redacted] was particulate matter of varying shapes and sizes, with most material between 0.1 and 0.4 mm in length (Figure 46). Also present in the sample were long, thin, fibrous strands (Figure 46). These could be asbestos, or glass fibres from pipeline insulation.

Sample [redacted] contained various elements including sulfur, aluminium, silicon, chlorine, sodium, calcium, magnesium and potassium along with iron and oxygen (Figure 46). In one area mercury was also identified (Figure 47).



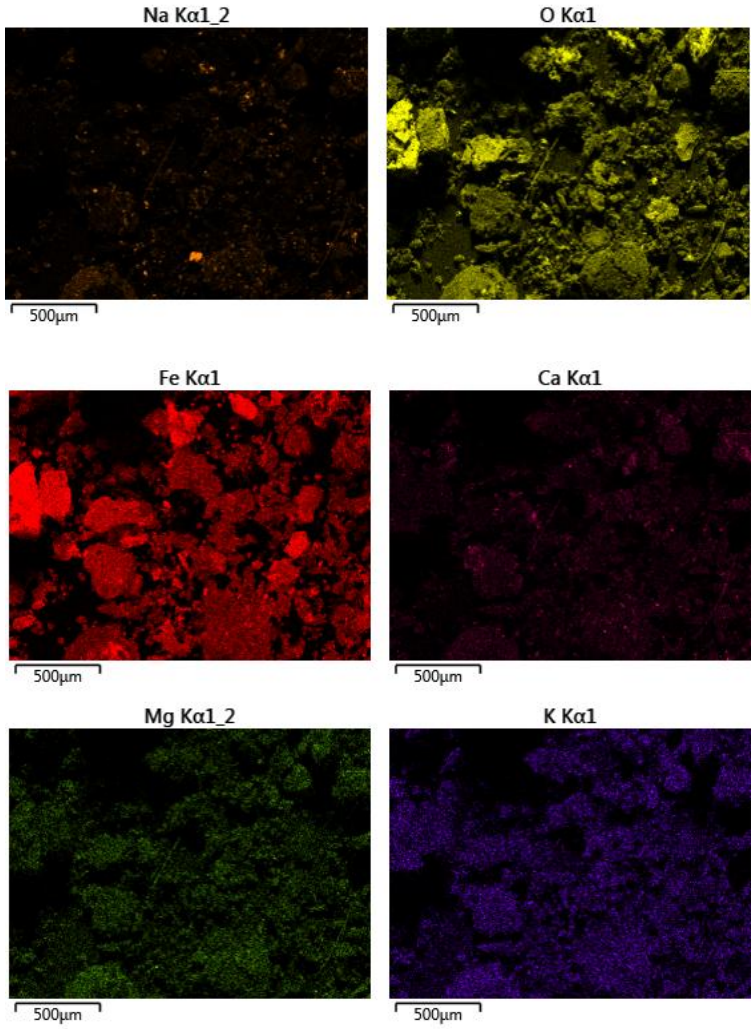


Figure 46 Sample [redacted] SEM imaging and EDX mapping.

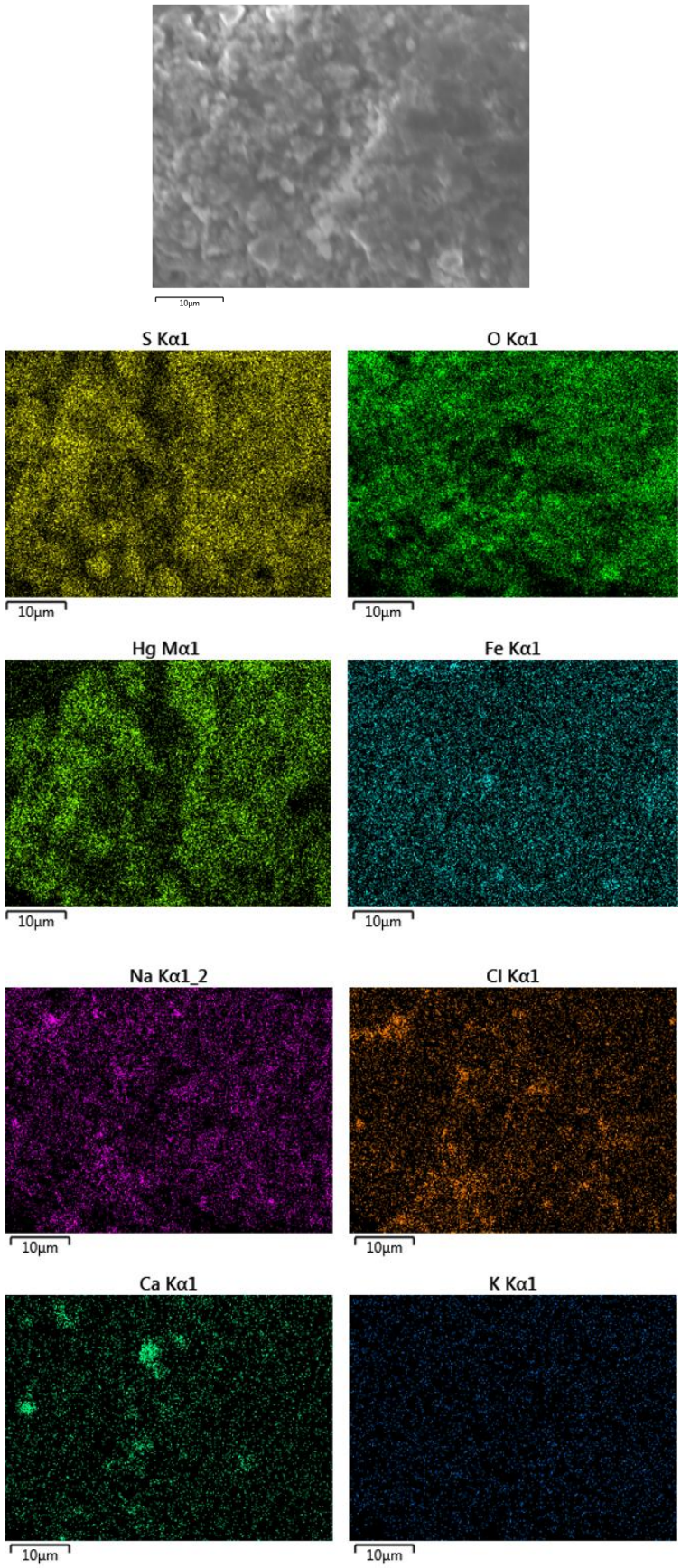


Figure 47 Sample [redacted] SEM imaging and EDX mapping.

8.2.9.3 Summary of findings

This sample contained mostly iron oxide corrosion products together with various light elements indicative of environmental contamination. This sample is classified as black dust.

8.2.10 Sample [redacted]

8.2.10.1 Visual examination

Sample [redacted] was a viscous brown liquid with some solid contamination distributed throughout (Figure 12). It was extremely difficult to pour and adhered to all surfaces it contacted.

Stereo microscopic examination would reveal no further information about the liquid contaminant or its composition.

8.2.10.2 FTIR

FTIR analysis was conducted on a representative portion of sample [redacted] the results of which can be seen in Figure 48 below.

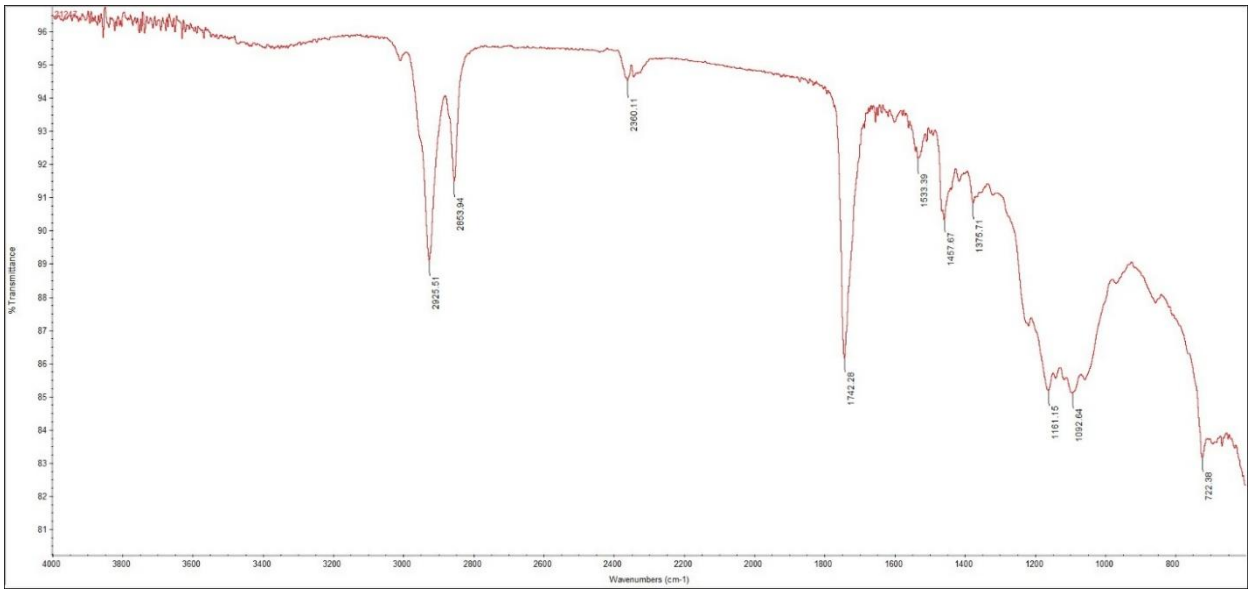


Figure 48 Sample [redacted] FTIR spectrum for the viscous brown liquid.

A list of the characteristic spectrum peaks (in wavenumbers) and their representative chemical bonds is shown in Table 25.

Table 25 Sample [redacted] viscous brown liquid spectrum and representative chemical bonds.

Chemical bond	Wave number (cm^{-1})	
	Typical FTIR chemical bond range	Sample [redacted]
C–H stretch (alkanes)	2850–2960	2925
		2854
C=O stretch (esters)	1650–1750	1742
Conjugated C=C	1500–1550	1533
C–H bending (alkanes)	1465–1420	1457
CH_3 bending	1375–1380	1375

The peak at 1360 cm^{-1} is indicative of CO_2 from the laboratory atmosphere that was not completely removed by the instrument's background subtraction and has therefore been excluded from the table.

The FTIR spectrum indicates the presence of aliphatic hydrocarbons most likely from a castor oil-derived grease.

8.2.10.3 SEM imaging and EDX analysis

SEM imaging and EDX analysis are techniques which require the samples to be in a solid, vacuum-compatible state. Liquid samples cannot be subjected to SEM/EDX analysis due to their inability to withstand the high vacuum environment within the microscope chamber. Exposing the equipment to liquid may result in damage or sample loss. Additionally, the SEM/EDX require a conductive surface to produce accurate imaging and elemental analysis, this cannot be provided by liquid-phase materials. Additionally, the FTIR results indicate a high carbon content for sample [redacted] the EDX cannot accurately determine carbon concentration and therefore no further testing was conducted.

8.2.10.4 Summary of findings

Sample [redacted] was a brown viscous liquid, the FTIR spectrum showing strong similarities to a castor oil-derived grease such as Val-Tex valve sealant.

8.3 Hydrogen exposure testing

The results of the hydrogen exposure testing are shown in Table 26. No significant physical or chemical changes were observed in either of the contaminants tested. Details of the testing procedure and results can be found in Appendix C.

Table 26 Reaction of contaminants with hydrogen.

DNV ID Number	Principal component(s)	Run	Impact of Hydrogen Exposure
[redacted]	Black dust	1	No noticeable differences or deleterious compounds observed
		2	No noticeable differences or deleterious compounds observed
		3	No noticeable differences or deleterious compounds observed
[redacted]	Castor oil-based grease	1	No noticeable differences or deleterious compounds observed
		2	No noticeable differences or deleterious compounds observed
		3	Slight dehydration observed via FTIR analysis but no deleterious compounds

8.4 Carbon dioxide exposure testing

The results of the carbon dioxide exposure testing are shown in Table 26. No significant physical or chemical changes were observed in either of the contaminants tested. Details of the testing procedure and results can be found in Appendix C.

Table 27 Reaction of contaminants with carbon dioxide.

DNV ID Number	Principal component(s)	Run	Impact of Carbon Dioxide Exposure
[redacted]	Black dust	1	No noticeable differences or deleterious compounds observed
		2	No noticeable differences or deleterious compounds observed
		3	No noticeable differences or deleterious compounds observed
[redacted]	Castor oil-based grease	1	Slight dehydration observed via FTIR analysis but no deleterious compounds of visual effects
		2	Slight dehydration observed via FTIR analysis but no deleterious compounds
		3	Slight dehydration observed via FTIR analysis and peak absence but no deleterious compounds

8.5 Discussion

Table 28 provides a summary of the materials supplied for chemical analysis. These form four main groups:

1. Pipeline corrosion products (either black dust or corrosion scale);
2. Water with trace amounts of aliphatic hydrocarbons (lubricating oil or natural gas condensate);
3. Grease (mostly likely to be castor oil-derived rather than a metal soap); and
4. Weld spatter.

These materials are considered to be representative of the contaminants that are most commonly found in the NTS.

Table 28 Summary of sample characterisation.

DNV ID Number	Sample Type	Sample Description	Principal component(s)
[redacted]			

Two representative samples (a black dust and a grease) were exposed separately to both hydrogen or carbon dioxide, and chemical analysis repeated to identify any changes. These were:

1. [redacted]

[redacted]

These tests showed that neither hydrogen nor carbon dioxide exposure produced observable changes to the black dust (corrosion products) or grease (aliphatic hydrocarbons). It can therefore be tentatively concluded that these contaminants will not transform into secondary products in the future network, although more extensive testing at

representative pressures, temperatures and over a longer duration would be required to be certain. In any case the management processes currently in place will likely remain suitable.

9 DESIGN PHILOSOPHIES FOR CONTAMINANT MANAGEMENT

9.1 Applicable contaminants

Table 29 provides a list of all the contaminants identified from the literature search and the testing undertaken together with their means of detection and management in the pipeline network. Control is typically achieved by imposing limits within gas quality specifications in Network Entry Agreements following a GQ/8 risk assessment[26] (for new connections). Monitoring may be either by online instruments (e.g. process gas chromatographs) or through sampling for laboratory analysis at prescribed frequencies. Many contaminants are not routinely monitored and will only be detected incidentally when process upsets occur. Following this project, it is not expected that this approach will need to change in the future network (see section 9.2 for further details).

Quantitative laboratory analysis is considered to be “definitive” where the method used is validated under an ISO 17025 approved laboratory management system. Other methods may be used in the field (for gases), for example Dräger tubes[27] or various sensor systems. Both these and similar methods may be subject to cross-sensitivity to other compounds and so new techniques will require careful validation.

Where solids, liquids or mixtures of substances are collected in large volumes (typically in filters or pig traps) then removal is required. The processes for this are discussed in section 9.3.

Table 29 List of contaminants and the means of detection and management.

Substance	Detection (Definitive)	Management (Mitigation/Removal)
Aldehyde, various	Gas chromatography (laboratory).	Controlled through limits.
Ammonia	Ion chromatography (laboratory).	Controlled through limits.
Arsenic	Laboratory analysis (ICP-OES).	Controlled through limits.
Benzene	Gas chromatography (laboratory).	Controlled by hydrocarbon dewpoint.
Black dust	Powder X-ray diffraction, scanning electron microscopy.	Removed during pigging and/or at filters.
Calcium carbonate	Powder X-ray diffraction, scanning electron microscopy.	Not normally remediated. Incidental finds.
Carbon dioxide	Gas chromatography (online).	Controlled through limits.
Carbon disulfide	Gas chromatography (laboratory).	Controlled through limits.
Carbon monoxide	Gas chromatography (laboratory).	Controlled through limits.
Carbonic acid	Ion chromatography (laboratory).	Controlled through limits.
Compressor oil	Gas chromatography (laboratory).	Remediation not normally required.
Diethylene glycol	Gas chromatography (laboratory).	Typically found in filters. This may require multiple site visits and can impact large users (e.g. power stations) connected to the NTS. The low vapour pressure means glycol will not enter the gas phase in significant quantities. Combustion will not lead to harmful substances.
Formaldehyde	Gas chromatography (laboratory).	Controlled through limits.
Formic Acid	Ion chromatography (laboratory).	Controlled through limits.
Fusion bonded epoxy	Infrared spectroscopy (laboratory).	Not normally remediated. Incidental finds.
Graphite	Infrared spectroscopy (laboratory).	Not normally remediated. Incidental finds.
Grease	Gas chromatography (laboratory).	Remediation not normally required.

[26] National Gas Transmission, Management Procedure for Assessing the Requirements for Gas Quality, Calorific Value and Flow Measurement Systems, T/PM/GQ/8, 2006.

[27] Dräger short term tubes, https://www.draeger.com/en_uk/Products/Short-term-Tubes, (accessed December 2025).

Substance	Detection (Definitive)	Management (Mitigation/Removal)
High boiling aliphatic hydrocarbons	Gas chromatography (laboratory).	Controlled by hydrocarbon dewpoint.
Hydrogen sulfide	Gas chromatography (online).	Controlled through limits.
Ketone, various	Gas chromatography (laboratory).	Controlled through limits.
Mercury	Laboratory analysis (ICP-OES).	Controlled through limits.
Methanol	Gas chromatography (laboratory).	Typically found in filters. This may require multiple site visits and can impact large users (e.g. power stations) connected to the NTS. Also removed by pigging. Combustion will not lead to harmful substances.
Methyl mercaptan	Gas chromatography (laboratory).	Controlled through limits.
Mill scale	Powder X-ray diffraction, scanning electron microscopy.	Removed during pigging and/or at filters.
Monoethylene glycol	Gas chromatography (laboratory).	Typically found in filters. This may require multiple site visits and can impact large users (e.g. power stations) connected to the NTS. The low vapour pressure means glycol will not enter the gas phase in significant quantities. Also removed by pigging. Combustion will not lead to harmful substances.
Natural gas	Gas chromatography (online).	N/A
Natural gas condensate	Gas chromatography (laboratory).	Controlled by hydrocarbon dewpoint.
Naturally occurring radioactive material	Radioactivity screening (laboratory)	Removed during pigging and/or at filters.
Neoprene	Infrared spectroscopy (laboratory).	Not normally remediated. Incidental finds.
Nitrile	Infrared spectroscopy (laboratory).	Not normally remediated. Incidental finds.
Nitrogen	Gas chromatography (online).	Controlled through limits.
Nylon	Infrared spectroscopy (laboratory).	Not normally remediated. Incidental finds.
Organohalides, various	Gas chromatography (laboratory).	Controlled through limits.
Oxygen	Gas chromatography (online).	Controlled through limits.
Perlite (expanded)	Powder X-ray diffraction, scanning electron microscopy.	Typically found in filters. Also removed by pigging.
Polymer pipeline liner	Infrared spectroscopy.	Not normally remediated. Incidental finds.
Polytetrafluoroethylene	Infrared spectroscopy (laboratory).	Not normally remediated. Incidental finds.
Polyurethane	Infrared spectroscopy (laboratory).	Not normally remediated. Incidental finds.
Pyrophoric dust	Powder X-ray diffraction, scanning electron microscopy.	Removed during pigging or when emptying filters.
Radon	Alpha spectrometry (on-site or laboratory).	Controlled through limits.
Rust	Powder X-ray diffraction, scanning electron microscopy.	Removed during pigging and/or at filters.
Sand / soil	Powder X-ray diffraction, scanning electron microscopy.	Not normally remediated. Incidental finds.
Sealant e.g Val-Tex	Infrared spectroscopy (laboratory).	Not normally remediated. Incidental finds.
Silica	Powder X-ray diffraction, scanning electron microscopy.	Not normally remediated. Incidental finds.
Silicone	Infrared spectroscopy (laboratory).	Not normally remediated. Incidental finds.
Siloxane, various	Gas chromatography (laboratory).	Controlled through limits.
Sodium chloride	Powder X-ray diffraction, scanning electron microscopy.	Not normally remediated. Incidental finds.
Sulfur	Gas chromatography (laboratory). Sampling and analysis technique is complex.	Not usually remediated.
Sulfur dioxide	Gas chromatography (laboratory).	Controlled through limits.

Substance	Detection (Definitive)	Management (Mitigation/Removal)
Terpene, various	Gas chromatography (laboratory).	Controlled through limits.
Toluene	Gas chromatography (laboratory).	Controlled by hydrocarbon dewpoint.
Triethylene glycol	Gas chromatography (laboratory).	Typically found in filters. This may require multiple site visits and can impact large users (e.g. power stations) connected to the NTS. The low vapour pressure means glycol will not enter the gas phase in significant quantities. Combustion will not lead to harmful substances.
Water	Laboratory analysis.	Controlled by water dewpoint.
Waxes	Infrared spectroscopy (laboratory).	Not normally remediated. Incidental finds.
Welding rod	Visual inspection. Powder X-ray diffraction, scanning electron microscopy.	Not normally remediated. Incidental finds.
Xylene (mixed isomers)	Gas chromatography (laboratory).	Controlled by hydrocarbon dewpoint.

9.2 Contaminant monitoring

9.2.1 Risk assessment

National Gas Transmission has obligations for the management of the quality and quantity of gas conveyed on its networks, and commercial arrangements at the relevant connections to its networks. It is not anticipated that this requirement would change in a future hydrogen network given that the Ofgem regulatory framework will have the same aims, although for carbon dioxide this may be different depending upon the business model selected.

The *Management Procedure for Assessing the Requirements for Gas Quality, Calorific Value and Flow Measurement Systems* (T/PM/GQ/8)[26] is used to ensure that:

a. Gas measurement provisions are included in new or amended Network Connection Agreements; and

b. These provisions are sufficient to manage the quality and quantity of gas delivered to National Gas Transmission networks so as to ensure both compliance with statutory obligations, and satisfaction of any additional commercial requirements agreed between National Gas Transmission and third parties connected to the network.

The relevance to contaminant management is that it covers the Gas Transporter's requirements for the content and characteristics of gas. Parameters and limit values against which the GQ/8 risk assessment should be performed are given in the Network Entry Conditions published in either the National Gas Transmission Ten Year Statement or the UK Distribution Long Term Development Plan (as appropriate) prevailing at the time of the risk assessment. Clearly these do not currently include parameters relevant to hydrogen or carbon dioxide and so the discussion below is based on the work done during this project.

9.2.2 Methodology

GQ/8 risk assessments should be carried out by a team in a workshop setting. Irrespective of the risk assessment being carried out in-person or online the methodology follows the same essential steps:

1. An introduction of the nature and requirements of the risk assessment will be given by the appointed coordinator/chair to the Connecting Party and associated participants;

2. The coordinator/chair and National Gas Transmission will agree on the information required to enable the risk assessment along with the key gas quality parameters against which risk ratings will be applied;

3. The requirements will be forwarded to the Connecting Party and responses coordinated initially by National Gas Transmission prior to forward to the coordinator/chair;

4. The coordinator/chair will determine if the information is sufficient to carry out the risk assessment or if more is required;
5. Once sufficient information has been received the coordinator/chair will assign risk ratings against the key parameters using the National Gas Transmission risk matrix;
6. The risk ratings will be recorded as per a standard template, which will be forwarded to all parties for comment;
7. The need for and nature of any corrective actions in the case of parameters for which high risk ratings are assigned will be discussed by all parties. Actions will be assigned as necessary. The risk ratings may then be revised on completion of corrective action; and
8. The risk assessment will be issued with final risk ratings to all parties for agreement.

9.2.3 Documentation

9.2.3.1 Required for risk assessment

Documentation and information required for the GQ/8 risk assessment is summarised below:

- P&IDs (overall gas production and flow process);
- Basis of process plant/storage design, and process operation descriptions;
- Details and locations of all gas quality measurement instrumentation;
- Operation, calibration, maintenance details of gas measurement instrumentation;
- Expected/target composition (chemical and physical properties) of the product gas; and
- Relevant gas quality specification and limits for network entry.

9.2.3.2 Reporting

In addition to the reporting of risk ratings the overall risk assessment will be recorded in a formal report. This will detail all information provided, all findings, corrective actions required and final risk ratings.

9.2.3.3 Other relevant documentation

Reference will also be made to the following in the risk assessment process:

- The Gas Safety (Management) (Amendment) Regulations (2023) formerly the Gas Safety (Management) Regulations (1996);
- PAS 4444:2020+A1:2021 Hydrogen-fired gas appliances:
- National Gas Transmission, Gas Quality Measurement Systems Connected to the NTS which are used for Regulatory and Commercial Compliance, T/SP/GQ/9, 2022;
- General requirements for the competence of testing and calibration laboratories, ISO/IEC 17025:2017
- ‘Natural gas — Performance evaluation for analytical systems, ISO 10723:2012.

9.2.4 Controls required for the future network

The limits set in the gas quality specifications for hydrogen and carbon dioxide will form the foundation of the required controls for the future network. Many of these are not directly relevant to contaminants in the transmission network and are set to protect end users of hydrogen or the integrity of the pipeline network. It should be noted that trace components in carbon dioxide greatly affect the phase behaviour but these are the subject of other work commissioned by National Gas Transmission.[28]

[28] R. Cartwright, Hydrogen and Carbon Dryness Management: Summary Report, DNV report no. 10504613/4, 2024.

Notwithstanding the fact that gas quality specifications are still in development, the compounds that are most likely to be found in bulk in the transmission system are unlikely to change significantly from the natural gas network since the repurposed network already contains them. They will however reduce over time as no new compounds are added from natural gas. Compounds will be added from hydrogen and carbon dioxide but the trace components are unlikely to pose a risk of pipeline contamination. The natural gas derived contaminants of particular interest are NORM, volatile organic compounds (aliphatic and aromatic hydrocarbons), corrosion products (iron oxides and sulfides) and heavy metals. These are managed through careful control of hydrocarbon and water dew points together with the oxygen limit. Mitigation methods are discussed in section 9.3.

9.3 Contaminant Management

9.3.1 Review of procedures

The following National Gas Transmission management system documents have been reviewed:

- Pipeline and Dust NORM Standard (UK/T1/8.7.3/S) and supporting document (UK/T1/8.7.3/SD/1);
- Management procedure: Management of Specific Hazards Associated with Breaking of Containment (T/PM/SMS/4); and
- Work procedure: Breaking Containment and Dealing with NORMs (T/PR/SMS/5).

The aim of the review is to assess the documents for applicability and completeness to a future network carrying pure hydrogen or carbon dioxide.

9.3.1.1 Pipeline and dust NORM standard (UK/T1/8.7.3/S) and supporting document (UK/T1/8.7.3/SD/1)

The Pipeline and Dust NORM Standard (UK/T1/8.7.3/S) defines the minimum standards for protection of employees from risks relating to work with pipeline dust and NORM that are above the “out of scope” levels as defined in Environmental Permitting legislation or within the levels scoped by the Ionising Radiations Regulations 2017, i.e. 5 Bq/g for lead, Pb^{210} and 1 Bq/g for radium, Ra^{226}, with the value of 5 Bq/g listed in the NTS Network Entry Agreement[29] Unless there is evidence to the contrary, all pipeline dust is considered as potentially containing NORM and falls within the requirements of this standard. It would be expected that NORM will reduce over time in a future network not transporting natural gas since new lead and radium species will not be being introduced. As such this overarching requirement remains applicable, but it may be possible to withdraw the standard once no more NORM is being produced.

The standard defines roles and responsibilities of personnel and these will remain appropriate under a future network.

The Pipeline Dust and NORM Supporting Document (UK/T1/8.7.3/SD/1) is applicable only to pipeline dust and NORM that is present as loose powder or sludge from operations on the high, intermediate and medium pressure gas pipes. It sets out the detailed requirements for National Gas to collect, store, weigh, assess and record, in a controlled manner, all pipeline dusts and analyse for potentially NORM contaminated residues prior to disposal or transfer to a waste recipient. Again, these requirements remain applicable to a future network, but it may be possible to withdraw the document once no more NORM is being produced. Until that time, unless legislation changes, it remains applicable.

9.3.1.2 Management procedure: Management of specific hazards associated with breaking of containment (T/PM/SMS/4)

The Management of Specific Hazards Associated with Breaking of Containment (T/PM/SMS/4) document is primarily to outline the management activities associated with specific hazards related to breaking containment of high pressure gas

[29] For information on the National Gas Transmission Network Entry Agreement proforma see: https://www.nationalgas.com/sites/default/files/documents/Network-Entry-Agreement-NEA.pdf, (accessed 19 December 2025).

plant and equipment (including pipelines, terminals, compressors, and above ground installations) where there is a need to ensure the management of pipeline dust/sludge/liquids/oily residue etc containing NORM.

The management procedure aims to ensure that harmful elements that may be disturbed during breaking of containment activity are appropriately controlled, and that the control of activities where NORM may be encountered, which are covered by the Ionising Radiations Regulations 2017, are appropriately managed. Relevant activities include:

- Filter changes and maintenance;
- Inline inspection (ILI) operations;
- Valve cut outs; and
- Scrubber maintenance.

In addition to NORM, materials may also contain other substances that are hazardous to health through absorption through the skin, inhalation and ingestion, including:

- Benzene, toluene, ethyl benzene, xylenes (BTEX);
- Lead;
- Mercury;
- Arsenic; and
- Cadmium.

The management procedure defines roles and responsibilities of personnel managing and carrying out this work and these will remain appropriate under a future network. The overarching requirements remains applicable, but it may be possible to modify the procedure once no more NORM are being produced (i.e. once dusts are below the “out of scope” level of radiation these parts of the document can be removed). It is likely that the risk of chemical hazard will persist into the future and so these parts of the management procedure will remain. The procedure is largely goal setting (e.g. requiring a risk assessment) or signposts other documents and so it is not envisaged that these parts of the document will need to change.

9.3.1.3 Work procedure: Breaking containment and dealing with NORMs (T/PR/SMS/5)

The Breaking containment and dealing with NORMs (T/PR/SMS/5) document is primarily to fulfil the obligations defined in the Ionising Radiations Regulations 2017 (specifically Regulation 18 (1)-(2) constituting the “Local Rules”) and to assist those undertaking breaking containment activities to minimise the risk of harm to people or the environment.

The requirements of the work procedure are applicable to all breaking containment activities. This includes those where radiation has not been detected. The control measures detailed are stated in the documents to be appropriate for managing the risks associated with the heavy metals and/or volatile organic compounds detected within the arisings, and this will not change in a future network.

Relevant activities include:

- Filter changes and maintenance;
- Inline inspection (ILI) operations;
- Valve cut outs;
- Scrubber maintenance; and
- Activities which require breaking containment where pipeline arisings are present (dust/sludge/liquids).

The materials considered by the document result from chemical and radiochemical sampling and testing of pipeline and asset arisings, the results of which confirmed that NORM and chemical contaminants such as heavy metals and volatile organic compounds (VOCs) are present across the National Transmission System (NTS) in varying orders of magnitude, with no obvious distribution pattern.

The work procedure is currently suitable for tasks involving breaking containment where chemical contaminants are encountered and this is expected to remain applicable in a future network. Both NORM and chemical contaminants could be present in pipeline dusts, sludges, liquids and waste wash-waters generated from cleaning filter baskets or pipeline inspection gauges for example.

The primary hazards identified in the work procedure from NORM dust and/or NORM-contaminated residues are internal radiation exposure (tissue damage) due to inhalation and ingestion. Residues may also contain other chemical contaminants which are hazardous to health due to exposure through absorption through the skin, inhalation and ingestion, including, but not limited to:

- Benzene, toluene, ethyl benzene, xylenes (BTEX);
- Lead;
- Mercury;
- Arsenic; and
- Cadmium.

The risk assessments required together with the control measures described remain applicable to a future network. The overarching requirements remains applicable, but it may be possible to modify the procedure once no more NORM are being produced (i.e. once dusts are below the “out of scope” level of radiation these parts of the document can be removed). It is likely that the risk of chemical hazard will persist into the future and so these parts of the work procedure will remain.

10 CONCLUSIONS

The contaminants from natural gas transmission pipelines have been listed comprehensively in this report and their impact on future networks transporting hydrogen or carbon dioxide have been assessed. Some testing has been undertaken on representative samples from the NTS and these did not show concerning results. The risk from natural gas contaminants is generally considered to be low in the future network, and best controlled through cleaning and purging prior to conversion, by setting appropriate gas quality specifications, and through management and mitigation in a similar way to the natural gas network. Selected contaminants of particular interest to National Gas Transmission are discussed below.

The repurposing of pipelines from natural gas to hydrogen or carbon dioxide is not expected to result in greater quantities of particulates, liquids, or sealing agent residues. It is suggested that the process of repurposing will significantly reduce the overall contaminant loading as some cleaning and purging processes will be required. As data are scarce on the potential impacts, it is proposed that a plan is developed for ongoing monitoring of particulates, liquids, or sealing agent residues and data recorded on amounts and trends to enable the overall repurposing schemes to be optimised.

NORM content will be reduced by the cessation of natural gas transportation and further by cleaning pipelines prior to being repurposed. Tritium (a form of hydrogen) is produced naturally from interactions of cosmic rays with gases in the upper atmosphere and is also a by-product of nuclear reactors. It will not form from decay of NORM found in gas transmission systems, or be formed during hydrogen production, transportation or end use.[30] Hydrogen can lead to embrittlement and cracking of some grades of pipeline steel. An extensive programme of testing and research in ongoing by National Gas Transmission to demonstrate that pipelines can be safely repurposed to transport hydrogen. Tritium poses no greater risk than “normal hydrogen” in this respect.

Hydrogenation reactions are likely to be slow at ambient temperatures. The potential end product from hydrogenation of, for example, benzene is cycloalkane, and this does not constitute a significant integrity or gas quality risk. No significant impacts are expected.

As the pyrophoric dusts form in gas transmission systems from sulfur-containing species, it is likely that formation will decrease in pipelines that are repurposed to hydrogen. Good, effective cleaning during the repurposing process should result in much lower inventories of pyrophoric materials, but there is still a possibility of spontaneous ignition during pigging and filter maintenance. As this is a gap in the available data, it is proposed that a research project is considered to quantify the overall risk and also develop strategies to minimise the likelihood of problems with pyrophoric dust in hydrogen pipelines.

The risk of gas hydrate formation in transmission pipelines is likely to be hydrogen < natural gas < carbon dioxide, although this may be influenced by the contaminants present. Some contaminants within repurposed pipelines are likely to be promoters of hydrate formation (e.g. methane, propane, butane, hydrogen sulfide). This indicates that effective purging will be required to reduce the risk. However other contaminants (e.g. monethylene glycol, methanol) are hydrate inhibitors. Although hydrates have always to be considered in pipeline design and operation, the impact of contaminants in repurposed systems for hydrogen and carbon dioxide are likely to be relatively small. The gas itself (hydrogen or carbon dioxide) and the degree of dehydration are more important than the contaminants present.

Hexavalent chromium compounds are carcinogenic. Chromic acid and some hexavalent chromium salts are soluble in water and could react to form other compounds. The risk of this is best controlled through dew point control to avoid liquid water formation, which is required in hydrogen and carbon dioxide pipelines in any case for corrosion control.

[30] M. Brown and M. Maple, *HAZID Actions Discussion – Technical Detail*, DNV technical note no. 10577716/1, 2026.

11 RECOMMENDATIONS

Although the issue of contaminants in repurposed natural gas pipelines has been addressed and evaluated from a technical viewpoint, it is apparent that the underlying technical information on selected topics is rather limited. The following recommendations have been proposed for consideration during the operational phase of the future network:

1. **Particulate monitoring and overall risk assessment**: The response identified that the overall content of particulate, liquids, or sealing agent residues within the pipeline is expected to reduce. This is a result of the twofold activities of pipeline cleaning and that the input of these contaminants is expected to be lower in hydrogen and carbon dioxide systems.
   It is proposed that a monitoring programme is introduced following repurposing with the concentrations of particulate, liquids, or sealing agent residues measured in filters and from any pipeline pigging operations that are undertaken. This evidence should support the view of the change in contaminant loading following repurposing.

2. **Pyrophoric dust management in repurposing natural gas pipelines for hydrogen operation**: It is proposed that a project is developed to endeavour to quantify the overall risk associated with pyrophoric dusts. This should initially be based on a test programme comparing the impacts for natural gas compared to hydrogen or carbon dioxide to gauge if there is a measurable difference in the likelihood of ignition.
   The outcomes from the technical project will identify any changes required to management and operational procedures to ensure that the impacts of with pyrophoric dust in hydrogen pipelines are minimised.

APPENDIX A
Summary of EA VOC screening exercise

Table 30 shows a list of VOCs in screening analysis.

Table 30 VOCs from, screening analysis.

Chemical Species	Present in number of samples	Peak concentration (mg/m^3)
(1-Methoxy-pentyl)-cyclopropane	1	0.006
1-Propoxy-pentyl)-cyclopropane	1	0.037
α-Methylstyrene	1	0.002
1-(Trimethylsilyl)-1-propyne	1	0.019
1,1,4-Trimethylcyclohexane	5	0.203
1,1'-Bicycloheptyl	1	0.001
1,1'-Bicyclohexyl, 2-ethyl-, trans-	1	0.007
1,2,4,5-Tetrazin-3-amine	1	0.010
1,2,4,5-Tetrazin-3-amine, 6-methyl-	1	0.019
1,2,4-Triazine-5-ol, 3,6-dimethyl-	1	0.005
1,2-Dipropylcyclopropene	1	0.017
1,2-Ethanediamine, N,N'-diethyl-	1	0.004
1,3,5,7-Cyclooctatetraene	1	0.010
1,3-Cyclopentadiene, 5-(1-methylpentylidene)-	1	0.001
1,3-Dimethyl cyclopentane	5	0.800
1,3-Hexadiene, 3-ethyl-2,5-dimethyl-	1	0.003
1,4-Benzenedicarboxylic acid, dimethyl ester	1	0.002
1-Butanamine, 2-methyl-N-(2-methylbutylidene)-	1	0.013
1-Butanol	1	0.025
1-Butanol, 2-ethyl-	1	0.032
1-Ethyl-2,2,6-trimethylcyclohexane	1	0.001
1-Ethyl-3-methylcyclohexane (c,t)	3	0.083
1-Ethyl-4-methylcyclohexane	1	0.090
1-Hexanol, 2-ethyl-	3	0.004
1H-Imidazole, 4,5-dihydro-2-methyl-	1	0.025
1H-Imidazole-4-carboxamide, 5-amino-	1	0.004
1H-Indene, octahydro-, cis-	3	0.011
1-Methoxy-6,6-dimethyl-cyclohex-2-ene	1	0.002
1-Methyl-2-methylenecyclohexane	2	0.003
1-Methylcyclooctene	4	0.021
1-Octene	2	0.425
1-Penten-3-one	1	0.055
1-Pyrrolidinecarboxaldehyde	1	0.006

Chemical Species	Present in number of samples	Peak concentration (mg/m^3)
1R,2c,3t,4t-Tetramethyl-cyclohexane	1	0.005
2(3H)-Furanone, 5-ethyldihydro-	1	0.055
2(5H)-Furanone, 5-(1-methylethyl)-	1	0.048
2,3-Dimethylpentane	1	0.220
2,4,6-Octatriene, 2,6-dimethyl-	1	0.001
2,4,6-Trimethyl-1,5-diazabicyclo[3.1.0]hexane	1	0.002
2,4-Imidazolidinedione, 5,5-dimethyl-	1	0.019
2-Aminocyanoacetamide	1	0.015
2-Butanone, 4-(dimethylamino)-	1	0.001
2-Cyclohexen-1-ol, 2-methyl-5-(1- methylethenyl)-, acetate	1	0.003
2-Cyclohexen-1-one, 3,5-dimethyl-	1	0.001
2-Heptene	1	0.052
2-Methylbutane	4	0.775
2-Methylpentane	3	0.50
2-Methylheptane	7	2.750
2-Octen-4-ol, 2-methyl-	1	0.008
2-Pentene, 3,4,4-trimethyl-	1	0.008
2-Pentene, 2,4,4-trimethyl-	1	0.017
2-Pentene, 3-ethyl-	1	0.023
2-Propanone, 1,1,1-trifluoro-	1	0.003
2-Pyrazoline, 1-isopropyl-5-methyl-	3	0.083
2-Pyrrolidinone	1	0.005
2-Undecen-4-ol	1	0.001
3-(1'-pyrrolidinyl)-2-butanone	1	0.007
3,7-Decadiene, 2,9-dimethyl-	1	0.004
3-Butene-1,2-diol, 1-(2-furanyl)-	1	0.001
3-Carene	1	0.003
3-Ethoxyacrylonitrile	1	0.002
3H-1,2,4-Triazol-3-one, 1,2-dihydro-	1	0.058
3-Heptyne, 5-methyl-	1	0.002
3-Hexanone	1	0.013
3-Hexanone, 2,5-dimethyl-	1	0.003
3-Hexanone, 2-methyl-	1	0.046
3-Hexene, 1-methoxy-, (Z)-	1	0.095
3-Hexene-2,5-dione	1	0.055
3-Methyl heptane	1	0.350
3-Pentanone, 2,4-dimethyl-	1	0.048
4,4'-Bi-1,3,2-dioxaborolane, 2,2'-diethyl-	1	0.015

Chemical Species	Present in number of samples	Peak concentration (mg/m^3)
4-Methoxy-3-buten-2-one	2	0.045
4-Methyloctane	1	0.058
4-Octen-3-one	2	0.040
4-Piperidinamine, N,1-dimethyl-	1	0.003
5-Diazo-1,3-cyclopentadiene	1	0.002
Acetone	2	0.010
Aziridine, 2,2-dimethyl-	1	0.100
Aziridine, 2,3-dimethyl-1-(phenylmethyl)-,	1	0.017
Benzaldehyde, 2-methyl-	2	0.002
Benzaldehyde, 4-methyl-	1	0.002
Benzaldehyde, 3-methyl-	1	0.001
Benzene	8	1.900
Benzene, (1,1-dimethylpropyl)-	1	0.001
Benzene, (1-methylethyl)-	1	0.001
Benzene, (1-methylbutyl)-		0.039
Benzene, 1,2,4-trimethyl-	6	0.009
Benzene, 1,2,3-trimethyl-	5	0.005
Benzene, 1,2-diethyl-	2	0.002
Benzene, 1,3,5-trimethyl-	1	0.008
Benzene, 1,3-diethyl-	1	0.003
Benzene, 1,3-dimethyl-	2	0.220
Benzene, 1-ethyl-2,4-dimethyl-	1	0.002
Benzene, 1-ethyl-2-methyl-	5	0.004
Benzene, 1-ethyl-3,5-dimethyl-	1	0.002
Benzene, 1-ethyl-4-methyl-	1	0.001
Benzene, 1-ethyl-3-methyl-	6	0.010
Benzene, 1-methyl-3-(1- methylethyl)-	3	0.002
Benzene, 1-methyl-3-propyl-	1	0.005
Benzene, 1-methyl-4-(1- methylethenyl)	1	0.004
Benzene, 1-methyl-4-(1-methylpropyl)-	1	0.003
Benzene, 1-methyl-4-propyl-	3	0.004
Benzene, 2-ethyl-1,4-dimethyl-	1	0.002
Benzene, 4-ethenyl-1,2-dimethyl-	2	0.002
Benzene, propyl-	5	0.008
Benzene, tert-butyl-	9	0.008
Bicyclo[2.2.2]octane, 2-methyl-	1	0.001
Butane, 2-methyl-	2	0.160
Butanenitrile, 4-(dimethylamino)-	1	0.003

Chemical Species	Present in number of samples	Peak concentration (mg/m^3)
Camphene	1	0.008
cis-1-Ethyl-3-methyl-cyclohexane	1	0.088
cis-p-Mentha-2,8-dien-1-ol	1	0.002
Creatinine	1	0.003
Cyclobutane, methyl-	1	0.087
Cyclobutene, 2-propenylidene-	2	0.120
Cyclobutanone, 2,2,3-trimethyl-	1	0.001
Cycloheptane, bromo-	1	0.068
Cyclohexane	8	2.100
Cyclohexane, (1-methylethyl)-	3	0.033
Cyclohexane, 1,1,2,3-tetramethyl-	5	0.020
Cyclohexane, 1,1,3,5-tetramethyl-, cis-	4	0.012
Cyclohexane, 1,1,3-trimethyl-	1	0.028
Cyclohexane, 1,1-dimethyl-	3	0.188
Cyclohexane, 1,2,3-trimethyl-	3	0.022
Cyclohexane, 1,2,3-trimethyl-, (1.alpha.,2.beta.,3.alpha.)-	2	0.038
Cyclohexane, 1,2,4-trimethyl-, (1.alpha.,2.beta.,4.beta.)-	2	0.30
Cyclohexane, 1,2-diethyl-, cis-	1	0.002
Cyclohexane, 1,2-dimethyl-, trans-	1	0.225
Cyclohexane, 1,3,5-trimethyl-	3	0.104
Cyclohexane, 1,3-dimethyl-	2	0.300
Cyclohexane, 1,3-dimethyl-, cis-	2	0.350
Cyclohexane, 1,3-dimethyl-, trans-	3	0.275
Cyclohexane, 1,4-dimethyl-	1	0.013
Cyclohexane, 1,4-dimethyl-, cis-	4	0.248
Cyclohexane, 1,4-dimethyl-, trans-	2	0.087
Cyclohexane, 1-ethyl-1-methyl-	2	0.168
Cyclohexane, 1-ethyl-2,3-dimethyl-	1	0.002
Cyclohexane, 1-ethyl-2-methyl-	1	0.005
Cyclohexane, 1-ethyl-2-methyl-, cis-	2	0.006
Cyclohexane, 1-ethyl-2-propyl-	1	0.011
Cyclohexane, 1-ethyl-4-methyl-, cis-	3	0.057
Cyclohexane, 1-ethyl-4-methyl-, trans-	3	0.054
Cyclohexane, 1-methyl-2-propyl-	2	0.003
Cyclohexane, 1-methyl-4-(1-methylethenyl)-, cis-	3	0.011
Cyclohexane, 1-methyl-4-(2-hydroxyethyl)-	1	0.010
Cyclohexane, butyl	4	0.005
Cyclohexane, ethyl--	6	0.253

Chemical Species	Present in number of samples	Peak concentration (mg/m^3)
Cyclohexane, pentyl-	5	1.575
Cyclohexane, propyl-	1	0.002
Cyclohexane, methyl-	9	0.080
Cyclohexene	1	0.003
Cyclohexene, 4-methyl-1-(1-methylethyl)-	4	0.008
Cyclohexene,1-propyl-	2	0.018
Cyclohexene,3-propyl-	1	0.003
Cyclooctane, (1-methylpropyl)-	1	0.003
Cyclopentane, (1,1-dimethylethyl)-	1	0.026
Cyclopentane, 1,2,4-trimethyl-	2	0.300
Cyclopentane, 1,3-dimethyl-, cis-	2	0.100
Cyclopentane, 1,3-dimethyl-, trans-	1	0.110
Cyclopentane, 1-ethyl-2-methyl-, cis-	1	0.031
Cyclopentane, ethyl-	6	0.275
Cyclopentane, methyl-	3	3.000
Cyclopentene, 1,5-dimethyl-	1	0.450
Cyclopentene, 3-ethyl-	1	0.035
Cyclopentene, 4,4-dimethyl-	2	0.450
Decane	7	0.033
Decane, 2-methyl-	2	0.003
Decane, 3-methyl-	1	0.001
Decane, 4-methyl-	4	0.003
Decane, 5-methyl-	1	0.003
D-Limonene	6	0.007
Dodecane	6	0.004
Endo-2-Methylbicyclo[3.3.1]nonane	1	0.005
Ethanone, 1-(1-methylcyclohexyl)-	2	0.009
Ethylbenzene	9	0.410
Furan, 2,5-dihydro-2,2,4-trimethyl-	1	0.043
Heptane	7	1.300
Heptane, 2,2,4-trimethyl-	2	0.016
Heptane, 2,2-dimethyl-	5	0.083
Heptane, 2,3-dimethyl-	5	0.120
Heptane, 2,4,6-trimethyl-	5	0.045
Heptane, 3,3-dimethyl-	5	0.160
Heptane, 2,6-dimethyl-	1	0.062
Heptane, 2,5-dimethyl-	2	0.008
Heptane, 3,4,5-trimethyl-	1	0.041

Chemical Species	Present in number of samples	Peak concentration (mg/m^3)
Heptane, 3-ethyl-	1	0.025
Heptane, 3-ethyl-2-methyl-	4	0.019
Heptane, 3-methyl-	1	0.110
Heptane, 4-(1-methylethyl)-	1	0.002
Heptane, 4-ethyl-	2	0.043
Heptane, 5-ethyl-2-methyl-	1	0.008
Hexane	8	2.750
Hexane, 2,2,4-trimethyl-	1	0.053
Hexane, 2,2,5-trimethyl-	1	0.031
Hexane, 2,2-dimethyl-	3	0.100
Hexane, 2,4,4-trimethyl-	3	0.038
Hexane, 2,5-dimethyl-	1	0.003
Hexane, 3,3-dimethyl-	3	0.105
Hexane, 3-ethyl-	1	0.113
Hexane, 3-ethyl-2-methyl-	1	0.028
Hexane, 3-methyl-	2	0.320
Isobutane	1	0.004
L-.alpha.-Terpineol	6	0.005
Limonene	1	0.003
Longifolene	3	0.002
m+p-Xylene	6	0.760
Mesitylene	4	0.005
Methylcyclohexane	3	0.670
methylcyclopentane	3	0.460
m-Menthane, (1S,3S)-(+)-	1	0.007
m-Menthane, (1S,3R)-(+)-	2	0.005
Nanofin	1	0.013
Naphthalene, 1,2,3,4-tetrahydro-	2	0.002
Naphthalene, decahydro-, trans-	2	0.003
Nonane	6	0.228
Nonane, 2,6-dimethyl-	2	0.007
Nonane, 2-methyl-	1	0.002
Nonane, 3-methyl-	5	0.010
Nonane, 4-methyl-	6	0.026
Nonane, 5-methyl-	3	0.004
Norflurane	1	0.014
Octane	6	0.925
Octane, 2,3-dimethyl-	1	0.002

Chemical Species	Present in number of samples	Peak concentration (mg/m^3)
Octane, 2,5-dimethyl-	1	0.003
Octane, 2,6-dimethyl-	4	0.026
Octane, 2,7-dimethyl-	2	0.007
Octane, 2-methyl-	3	0.198
Octane, 3,3-dimethyl-	7	0.012
Octane, 3,5-dimethyl-	1	0.002
Octane, 3-ethyl-	1	0.009
Octane, 3-methyl-	4	0.190
Octane, 4-methyl-	6	0.170
o-Cymene	3	0.008
o-Xylene	6	0.380
p-Cymene	1	0.003
Pentalene, octahydro-	1	0.033
Pentalene, octahydro-, cis-	2	0.035
Pentane	6	2.750
Pentane, 2,2-dimethyl-	1	0.026
Pentane, 2,3,3,4-tetramethyl-	1	0.065
Pentane, 2,3-dimethyl-	1	0.074
Pentane, 3,3-dimethyl-	4	0.350
Pentane, 3-ethyl-	1	0.008
Pentane, 3-ethyl-2,2-dimethyl-	1	0.154
Pentanoic acid, 1,1-dimethylpropyl ester	1	0.054
Piperidine, 1-(1-methylpentyl)-	1	0.005
Propane, 2,2-difluoro-	1	0.022
Propanoic acid, 2-methyl-, anhydride	1	0.033
Propionaldehyde, diethylhydrazone	1	0.019
p-Xylene	1	0.044
Pyridine, 4-ethenyl-	1	0.048
Pyrimidine, 4-amino-2-methoxy-	1	0.002
Pyrrolidine	2	0.043
Succinimide	1	0.018
Sulfur dioxide	2	0.006
Thiazole, 2-methyl-	1	0.002
Toluene	8	0.575
trans-1,2-Diethyl cyclopentane	1	0.029
Trans-1,4-diethylcyclohexane	1	0.002
Tridecane	3	0.004
Undecane	9	0.011

Chemical Species	Present in number of samples	Peak concentration (mg/m^3)
Uracil, 1-methyl-	1	0.011
Vinyl butyrate	1	0.003

CERTIFICATE OF ANALYSIS

Element Materials Technology Environmental UK LTD. (Registration No: 11371415) Registered Office: 5 Southampton Street, London, United Kingdom, WC2E 7HA | 0203 540 1820 | www.element.com | asbestos@element.com

Client: ??DNV Services UK Ltd? (Stockport), Ashby Road, Holywell Park, Loughborough

These samples were provided by ??DNV Services UK Ltd? (Stockport)

Sampling Location: Gas Pipes

Samples analysed by polarised light microscopy (PLM) in accordance with documented in-house procedures and the method defined in HSG248 'Asbestos: The analysts' guide for sampling, analysis and clearance procedures' Element Materials Technology Environmental UK Limited is accredited to ISO/IEC 17025 for asbestos sampling and identification by PLM. The results shown in this table relate only to the samples tested.

Item Number	Date sample taken/received	Date sample analysed	Analyst	Lab	Sample Number	Client Reference or Location of Sample Point	Analyst result	Report Sample Notes
1	14/11/2025	14/11/2025	Crystal Davies	Stockport	BS000337	Pig Trap Debris, 21239	No Asbestos Detected	n/a
2	14/11/2025	14/11/2025	Crystal Davies	Stockport	BS000338	Pipe Scale, 21243	No Asbestos Detected	n/a
3	14/11/2025	14/11/2025	Crystal Davies	Stockport	BS000339	Pipe Scale, 21244	No Asbestos Detected	n/a
4	14/11/2025	14/11/2025	Crystal Davies	Stockport	BS000340	Pipe Scale, 21245	No Asbestos Detected	n/a

Analysed & authorised by:

Crystal Davies

Date of issue:

14 Nov 2025

Issued by:

Stockport

Sampling and analysis of solid (bulk) samples taken by Element Materials Technology Environmental UK Limited: Where asbestos is not positively identified the result is quoted as "none detected" | Sampling of suspected asbestos containing materials is in accordance with in-house documented methods, complying with HSG264: 'Asbestos: The survey guide' | Samples not taken by Element Materials Technology Environmental UK Limited: Results are given in good faith based on the information supplied by the client | No responsibility can be accepted for incorrect information, interpretations, actions or errors or omissions by persons other than Element Materials Technology Environmental UK Limited's staff | Opinions and interpretations expressed herein, including the description of the material are outside the scope of UKAS accreditation | Lab identifiers used in table above indicate location of analysis: CX: Chapelcross • WF: (Flexible scope) Wylfa • SW: (Flexible scope) Sizewell • EK: (Flexible scope) East Kilbride • TW: Trawsfynydd • SP: Stockport | Refer to current UKAS schedules at www.ukas.org for lab address details. | Records of analysis are retained for a period of 6 years | Samples are held within the laboratory location for a minimum of 12 months.

J021141

APPENDIX C
Exposure testing

Following the material characterisation two representative samples (a black dust and a grease) were exposed separately to both hydrogen or carbon dioxide, and chemical analysis repeated to identify any changes. These were:

- [redacted]
- [redacted]

Hydrogen was generated in a conical flask through the reaction of zinc and hydrochloric acid while gaseous carbon dioxide was produced from the sublimation of dry ice. The gases were allowed to contact replicate contaminated materials placed in a connected conical flask equipped with an air lock for four hours. The equipment setup is shown in Figure 4.

These tests were sufficient to identify contaminants that would readily react adversely with hydrogen or carbon dioxide.

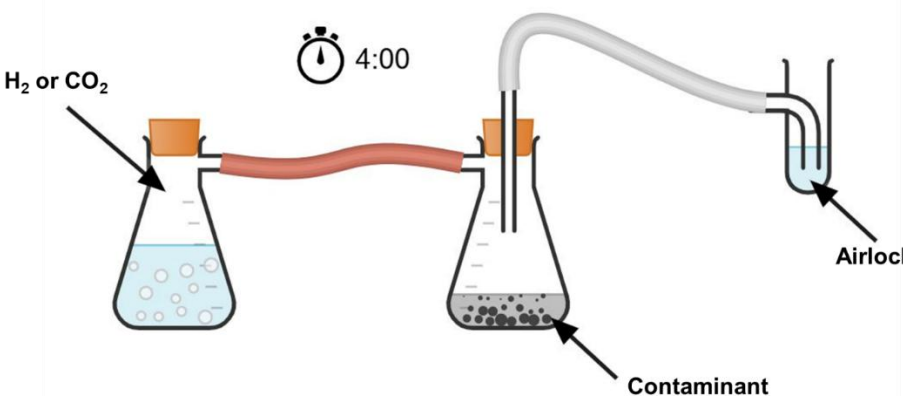


Figure 49 Schematic diagram showing the apparatus for performing the hydrogen and carbon dioxide exposure tests.

Hydrogen exposure testing

Sample [redacted] – Test 1

Observations during testing

The initial reaction between the zinc and the hydrochloric acid proceeded slowly, however the first signs of gas evolution were observed within the first minute, as seen in Figure 50 below. The reaction became more active after approximately 5 minutes.

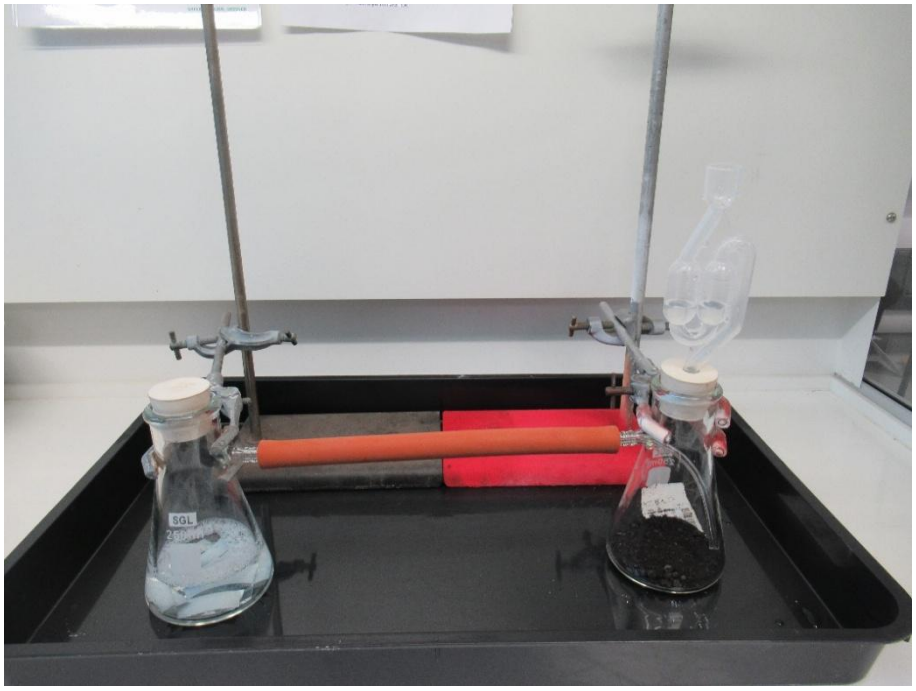


Figure 50 Initial observations.

After 10 minutes, a pressure differential could be observed in the air lock implying a hydrogen environment had been created in the flask containing the contaminants (Figure 51).

Figure 51 Pressure differential in the air lock.

Halfway through the experiment, the consumption of zinc could start to be seen but the reaction was steadily ongoing. There were no visual signs of change to the contaminants at this time (Figure 52).

Figure 52 Sample [redacted] halfway through the hydrogen exposure testing.

3-hours into the experiment, the reaction producing the hydrogen was beginning to slow but the hydrogen environment was still established. There were no visual signs of change to the contaminant at this time (Figure 53).

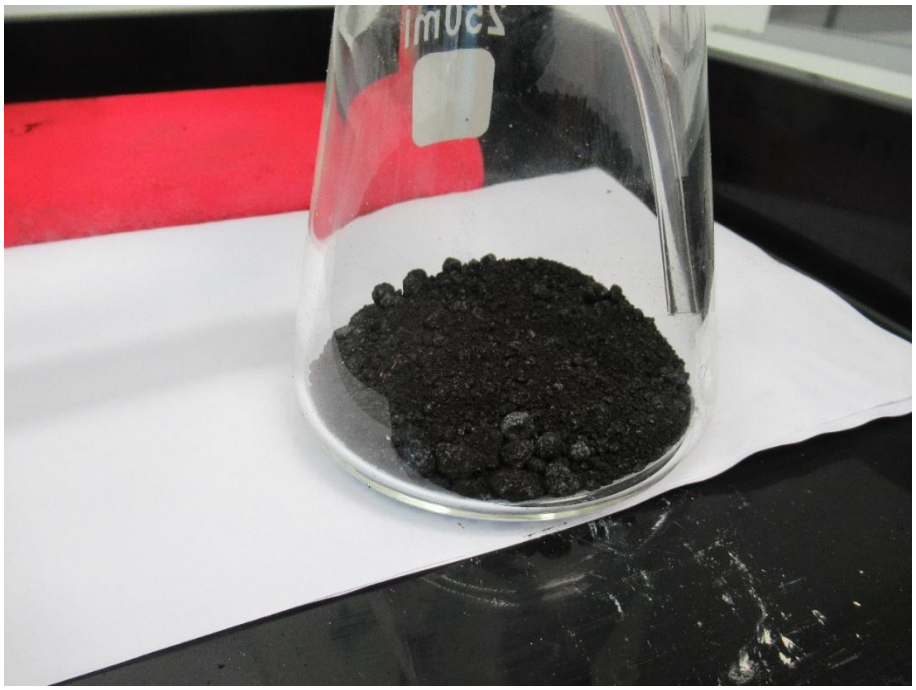


Figure 53 Sample [redacted] three hours into the hydrogen exposure testing.

After four hours the experiment was stopped. Final observations showed no visual change to the contaminants (Figure 54).

Figure 54 Sample [redacted] at the end of the hydrogen exposure testing.

Post-test SEM/EDX examination

Immediately after the hydrogen exposure testing, the sample of [redacted] was subjected to SEM examination and EDX analysis.

Prior to the testing, sample [redacted] contained high concentration of iron oxide in several locations which indicated a metallic presence of aluminium, calcium and silicates, as well as other light element, indicative of environmental contamination. Similar observations were made subsequent to the hydrogen exposure testing as seen in Figure 55, Figure 56 and Figure 57.

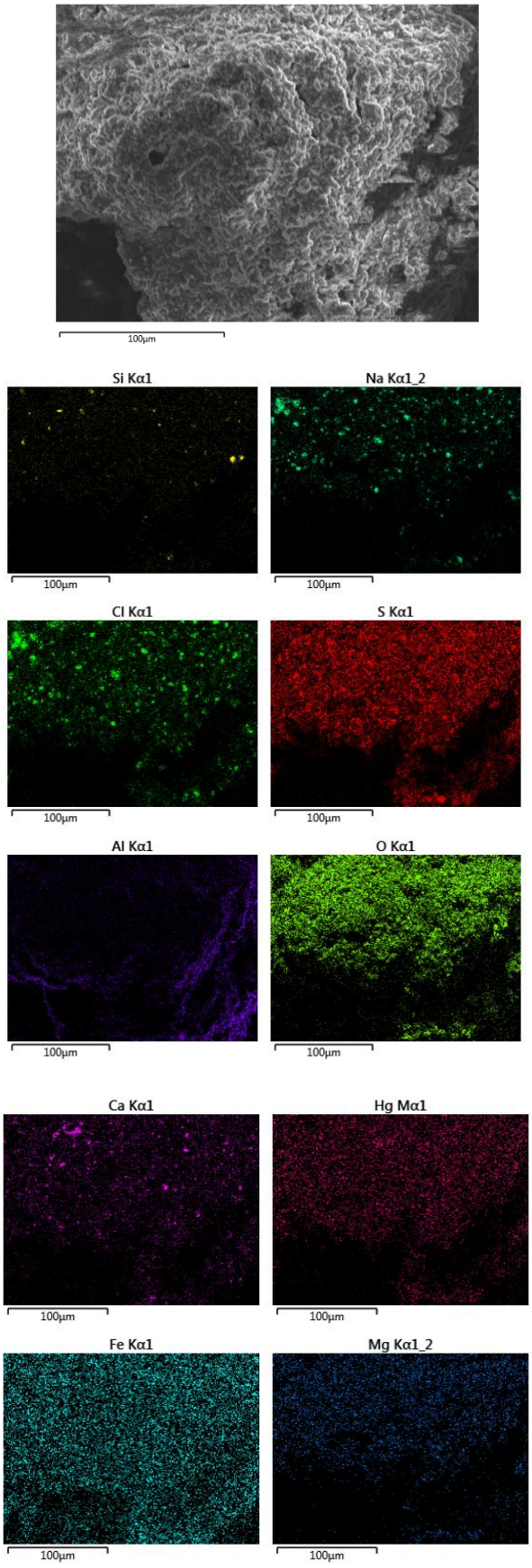


Figure 55 SEM imaging and EDX mapping sample [redacted] after hydrogen exposure testing.

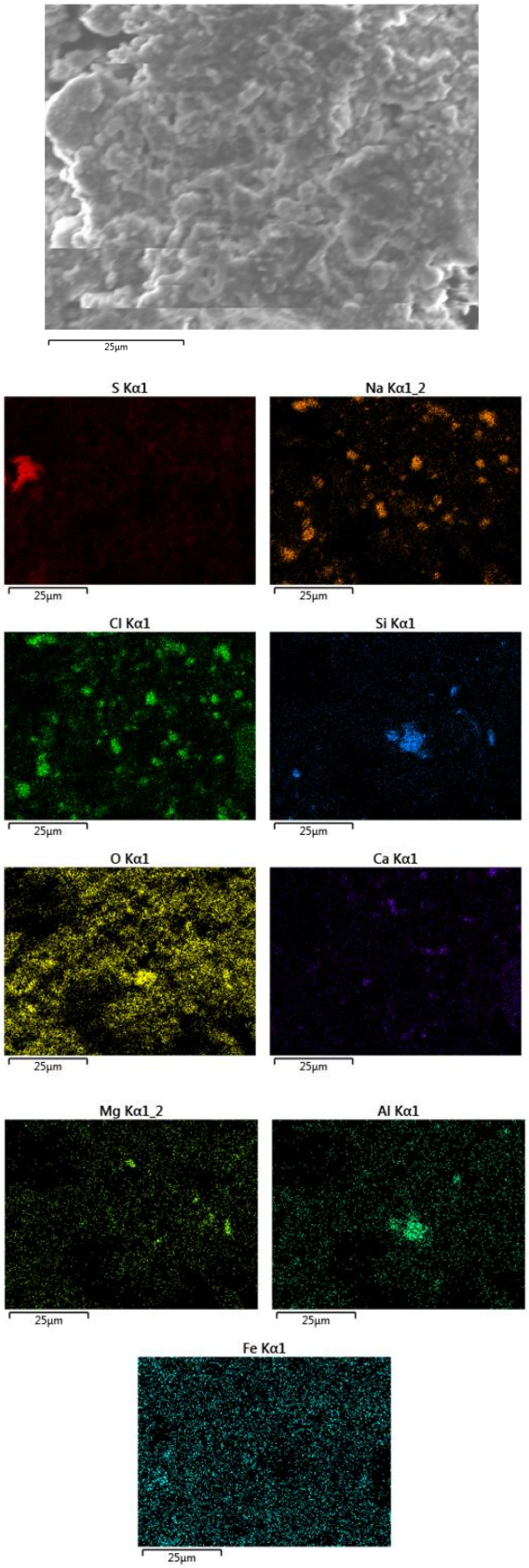


Figure 56 SEM imaging and EDX mapping Sample [redacted] after hydrogen exposure testing.

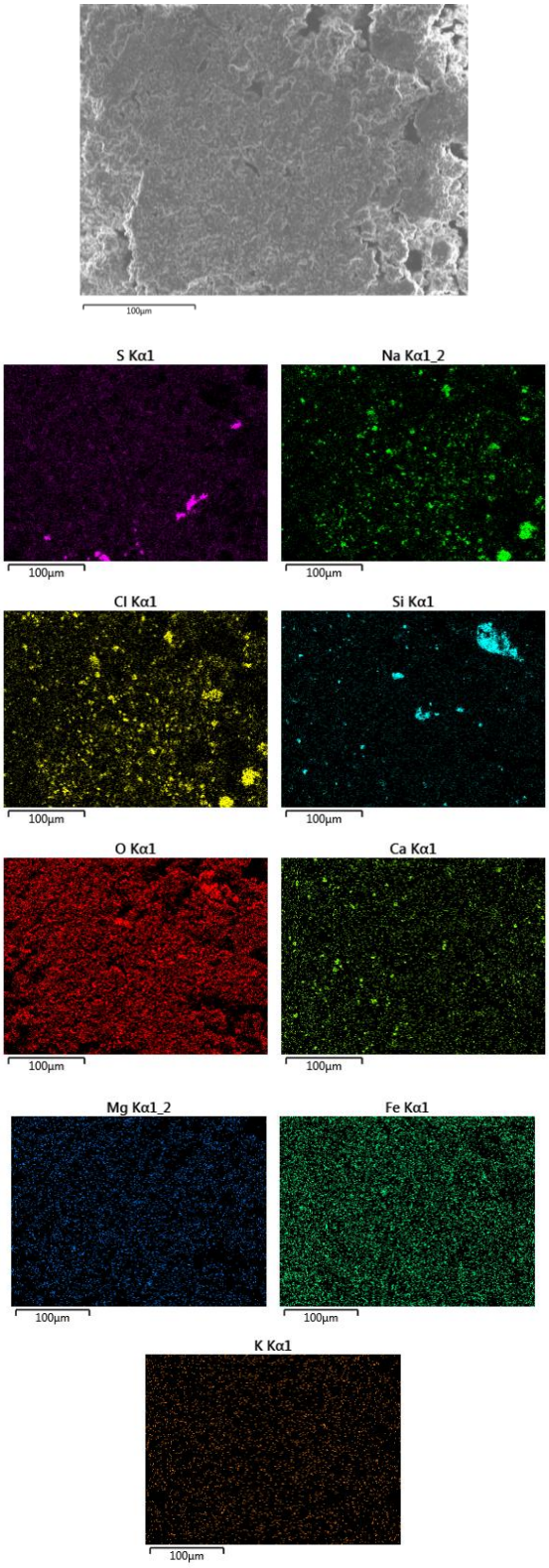


Figure 57 SEM imaging and EDX mapping Sample [redacted] after hydrogen exposure testing.

Conclusion

No notable differences or development of deleterious compounds were observed after the exposure testing.

Sample [redacted] – Test 2

Observations during testing

The initial reaction can be seen in Figure 58 below. The reaction was steady and a hydrogen environment was established as can be seen by the pressure differential and bubble generation in the airlock.

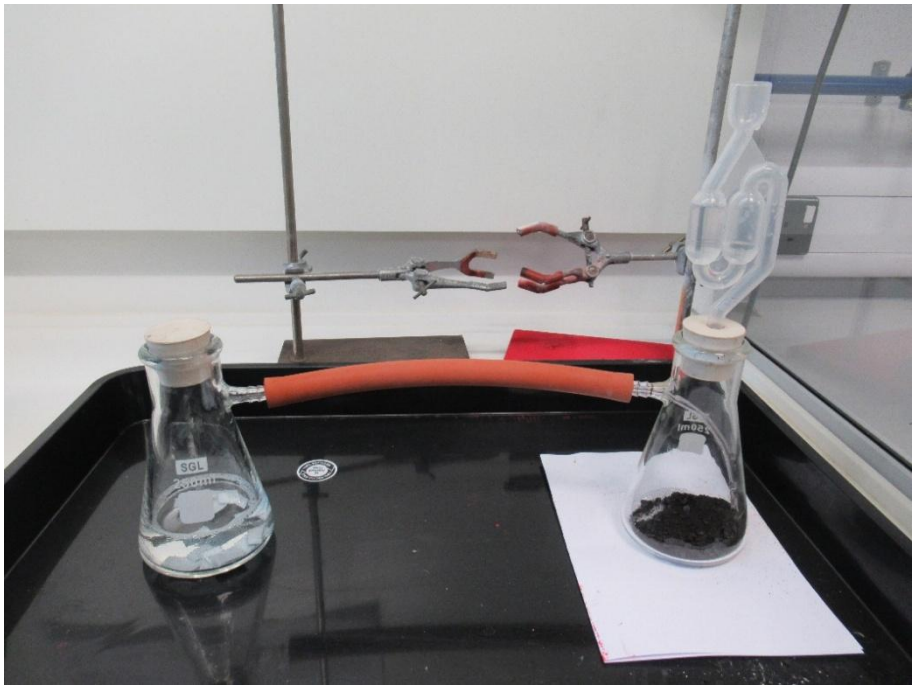


Figure 58 Initial observations.

The representative sample of [redacted] can be seen in Figure 59 at the beginning of the test period.

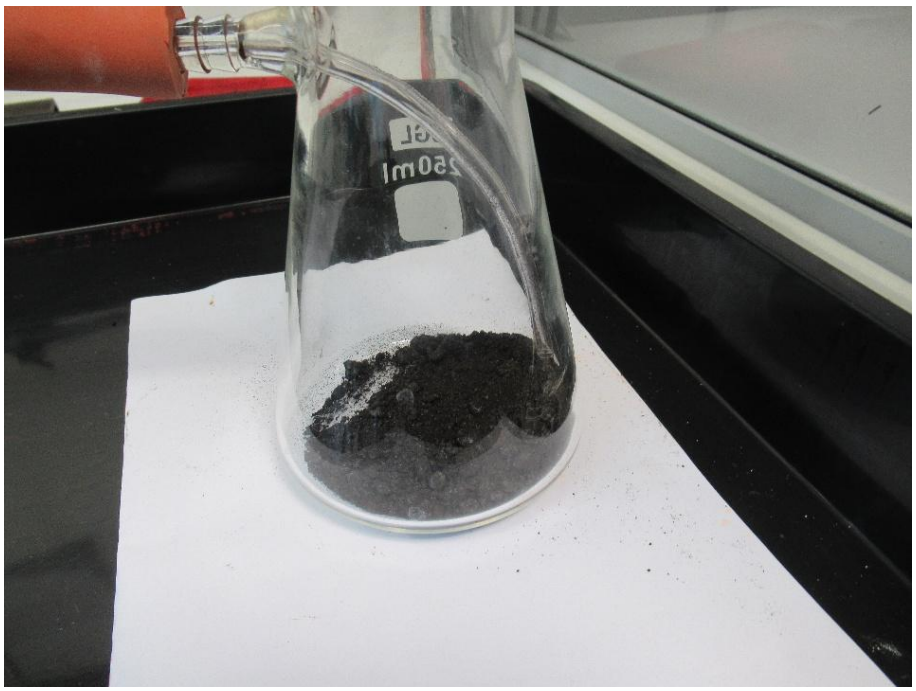


Figure 59 Initial observation of sample [redacted] representative sample tested.

After one hour, the contaminants showed no change as can be seen in Figure 60 below.

Figure 60 Sample [redacted] after one hour of hydrogen exposure testing.

Halfway through the experiment, the consumption of zinc could start to be seen but the reaction was steadily ongoing. There were no visual signs of change to the contaminants at this time (Figure 61 and Figure 62).

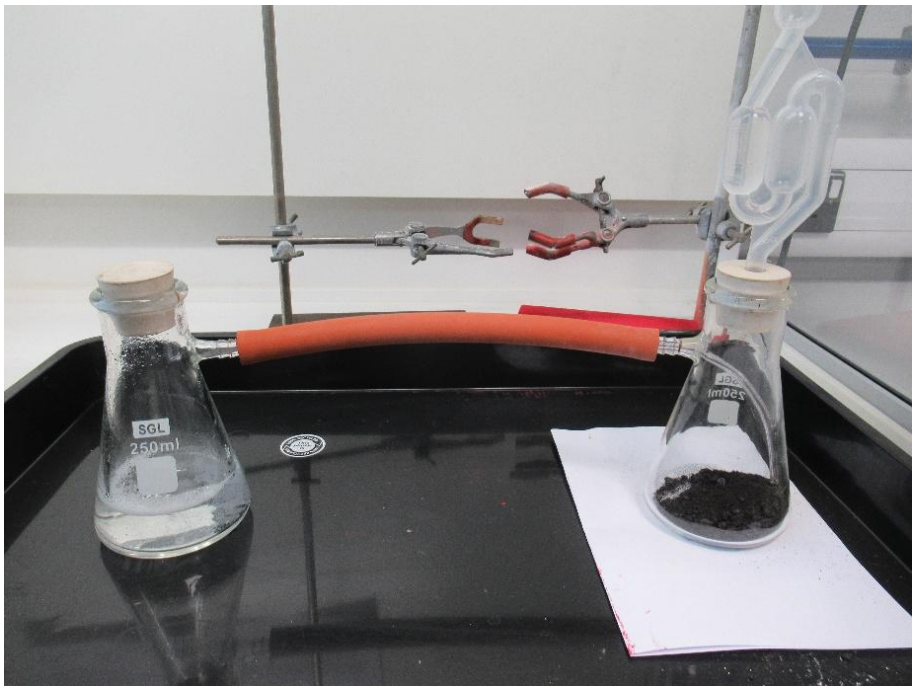


Figure 61 The reaction of hydrochloric acid and zinc halfway through the experiment.

Figure 62 Sample [redacted] halfway through the hydrogen exposure testing.

Three hours into the experiment, the reaction producing the hydrogen was beginning to slow but the hydrogen environment was still established. There were no visual signs of change to the contaminant at this time (Figure 63).

Figure 63 Sample [redacted] three hours into the hydrogen exposure testing.

After four hours the experiment was stopped. Final observations showed no visual change to the contaminants (Figure 64).

Figure 64 Sample [redacted] at the end of the hydrogen exposure testing.

Post-test SEM/EDX examination

Immediately after the hydrogen exposure testing, the sample of [redacted] was subjected to SEM examination and EDX analysis.

Prior to the testing, sample [redacted] contained high concentration of iron oxide in several locations, indicative of a metallic material with the presence of aluminium, calcium and silicates, as well as other light elements, which was likely environmental contamination. Elements such as mercury were initially identified prior to exposure testing and their presence remained. There were some additional elements present that were not initially identified however this is the result of representative sampling and the small measurement area of the SEM. Overall, similar observations were made subsequent to the hydrogen exposure testing as seen in Figure 65, Figure 66 and Figure 67.

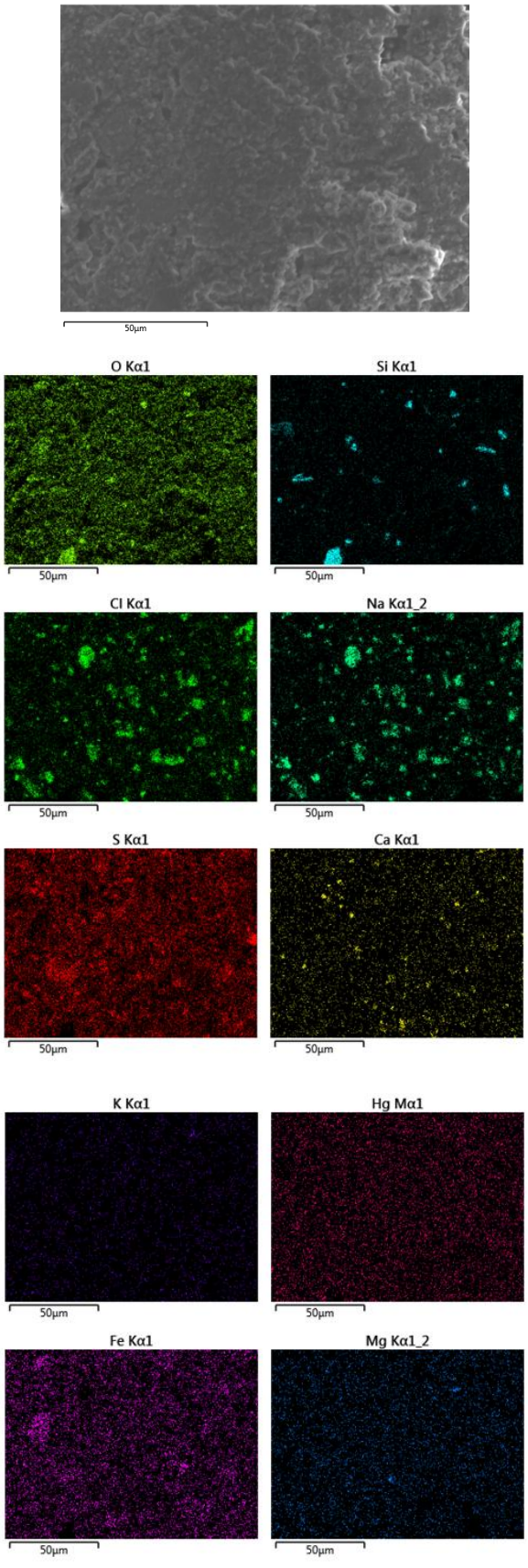


Figure 65 SEM imaging and EDX mapping sample [redacted] after hydrogen exposure testing.

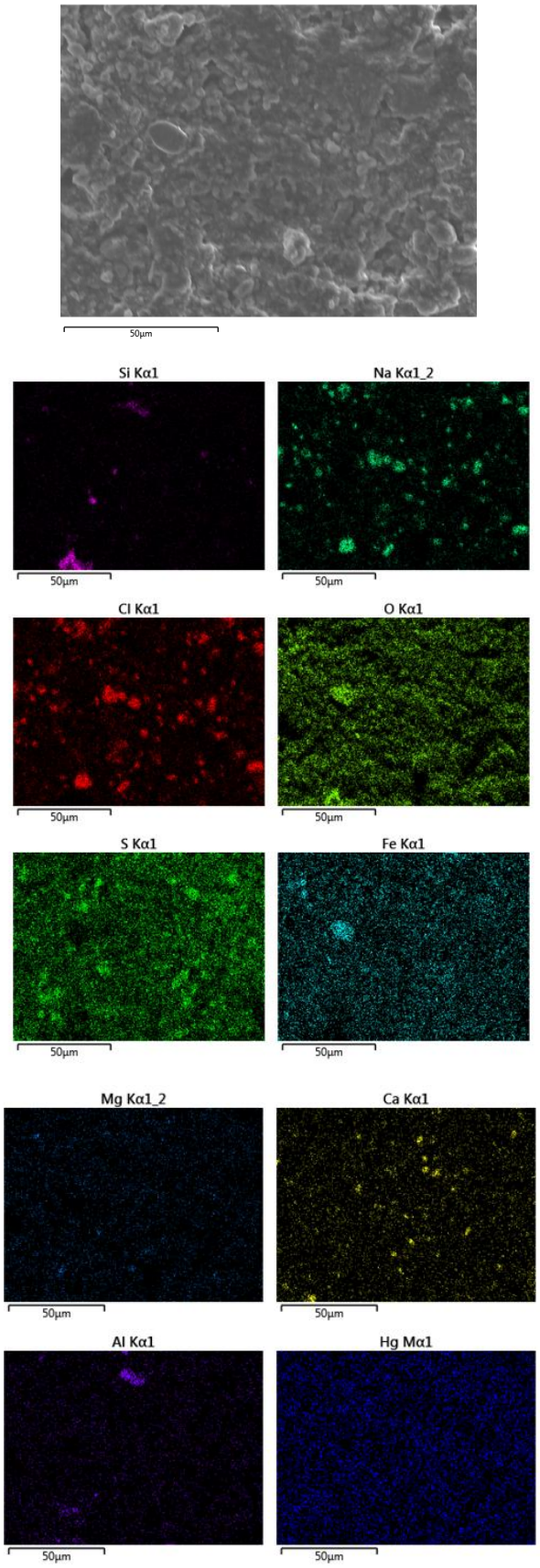


Figure 66 SEM imaging and EDX mapping sample [redacted] after hydrogen exposure testing.

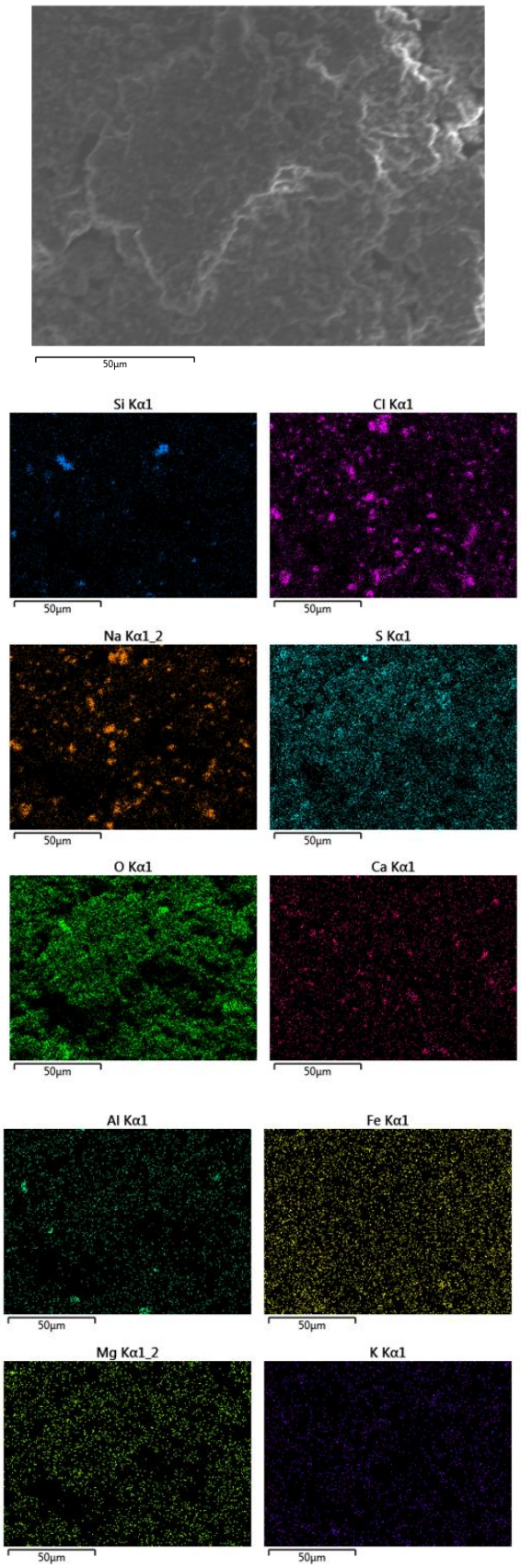


Figure 67 SEM imaging and EDX mapping sample [redacted] after hydrogen exposure testing.

Conclusion

No notable differences or deleterious compounds were observed after the exposure testing.

Sample [redacted] – Test 3

Observations during testing

The initial reaction can be seen in Figure 68 below. The reaction was steady and a hydrogen environment was established as can be seen by the pressure differential and bubble generation in the airlock.

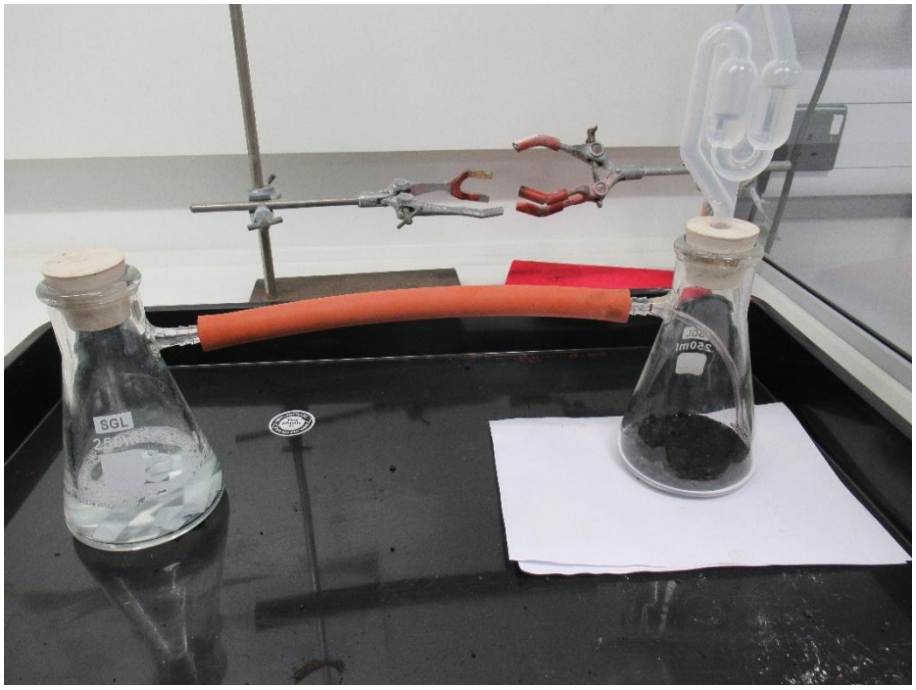


Figure 68 Initial observations.

The representative sample of [redacted] can be seen in Figure 69 at the beginning of the test period.

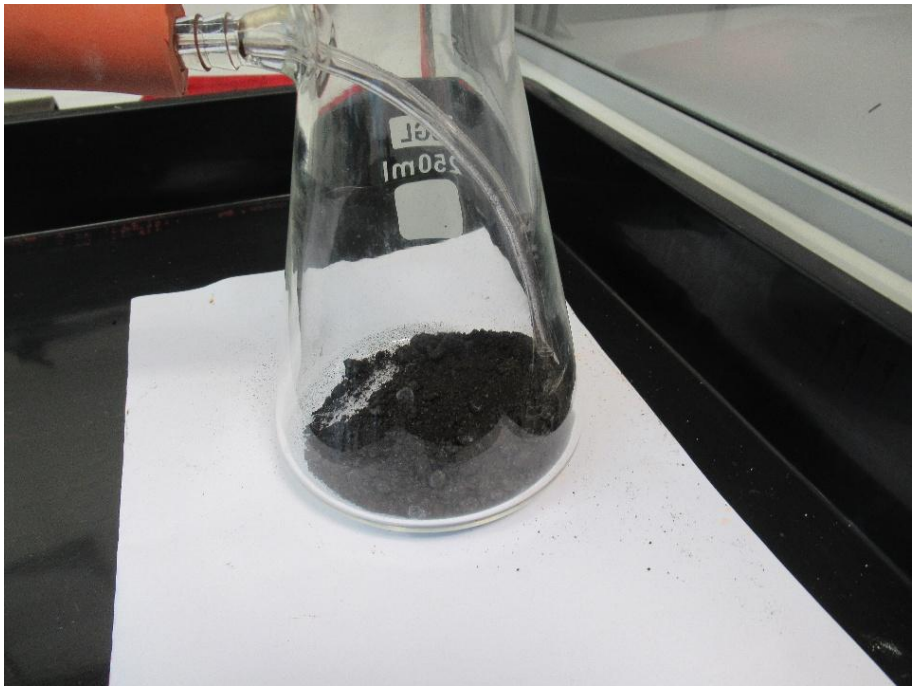


Figure 69 Initial observation of sample [redacted] representative sample tested.

After one hour, the contaminants showed no change (see Figure 70).

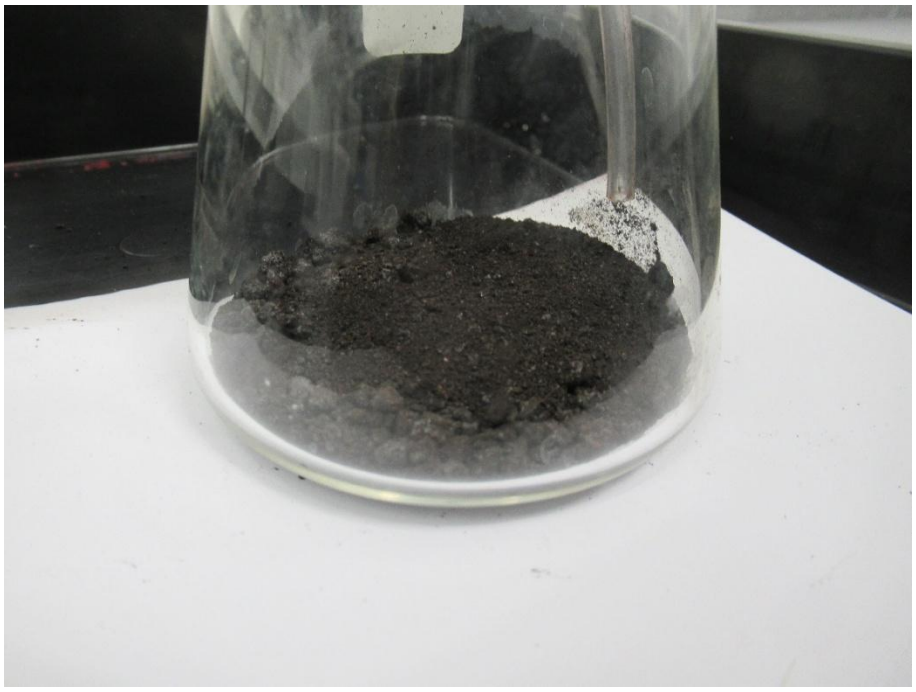


Figure 70 Sample [redacted] after one hour of hydrogen exposure testing.

Halfway through the experiment, there were no visual signs of change to the representative sample of contaminants and zinc consumption was ongoing. The consumption of zinc could start to be seen but the reaction was steadily ongoing. There were no visual signs of change to the contaminants at this time (Figure 71).

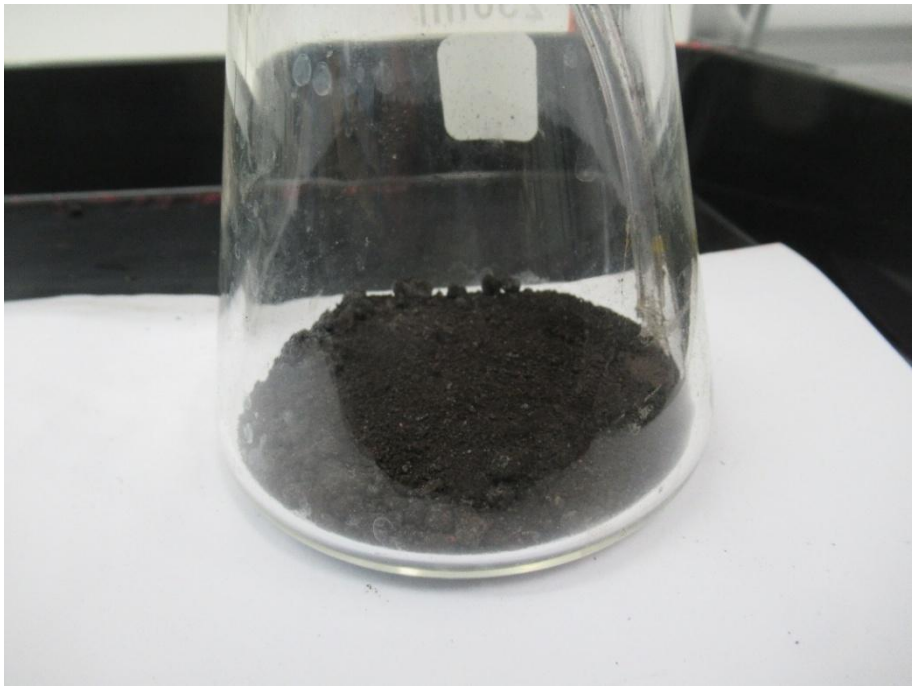


Figure 71 Sample [redacted] halfway through the hydrogen exposure testing.

At the three hour mark, the reaction producing the hydrogen was beginning to slow but the hydrogen environment was still established. There were no visual signs of change to the contaminant at this time (Figure 72).

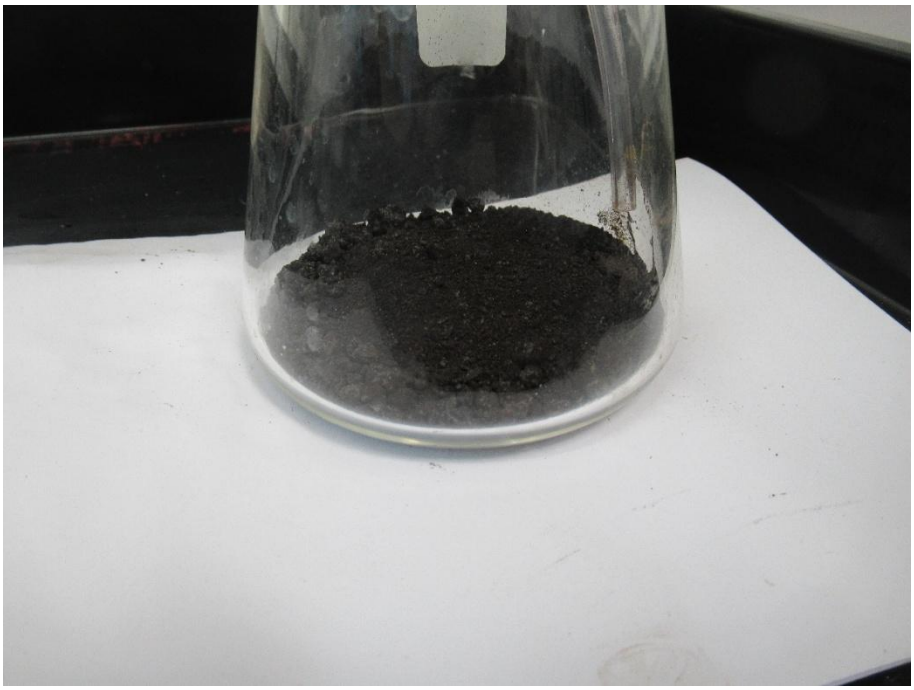


Figure 72 Sample [redacted] three hours into the hydrogen exposure testing.

At the end of the experiment, after four hours, final observations showed no visual change to the contaminants (Figure 73).

Figure 73 Sample [redacted] at the end of the hydrogen exposure testing.

Post-test SEM/EDX examination

Immediately after the hydrogen exposure testing, the sample of [redacted] was subjected to SEM examination and EDX analysis.

Prior to the testing, sample [redacted] contained high concentration of iron oxide in several locations, indicative of a metallic material with the presence of aluminium, calcium and silicates, as well as other light elements, which was likely environmental contamination. Elements such as mercury were initially identified prior to exposure testing and their presence remains. There are some additional elements present that were not initially identified however this is the result of representative sampling and the small measurement area of the SEM. Overall, similar observations were made subsequent to the hydrogen exposure testing as seen in Figure 74, Figure 75 and Figure 76.

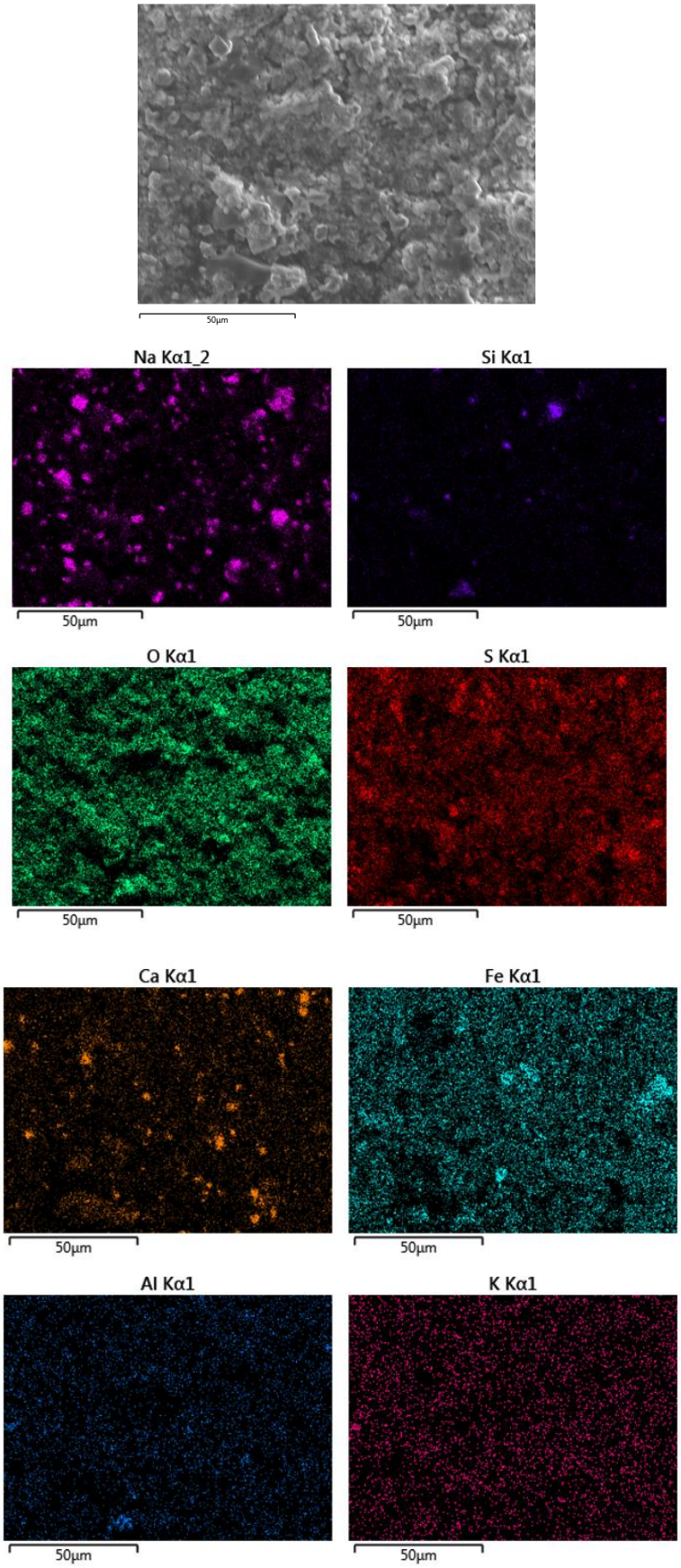


Figure 74 SEM imaging and EDX mapping sample [redacted] after hydrogen exposure testing.

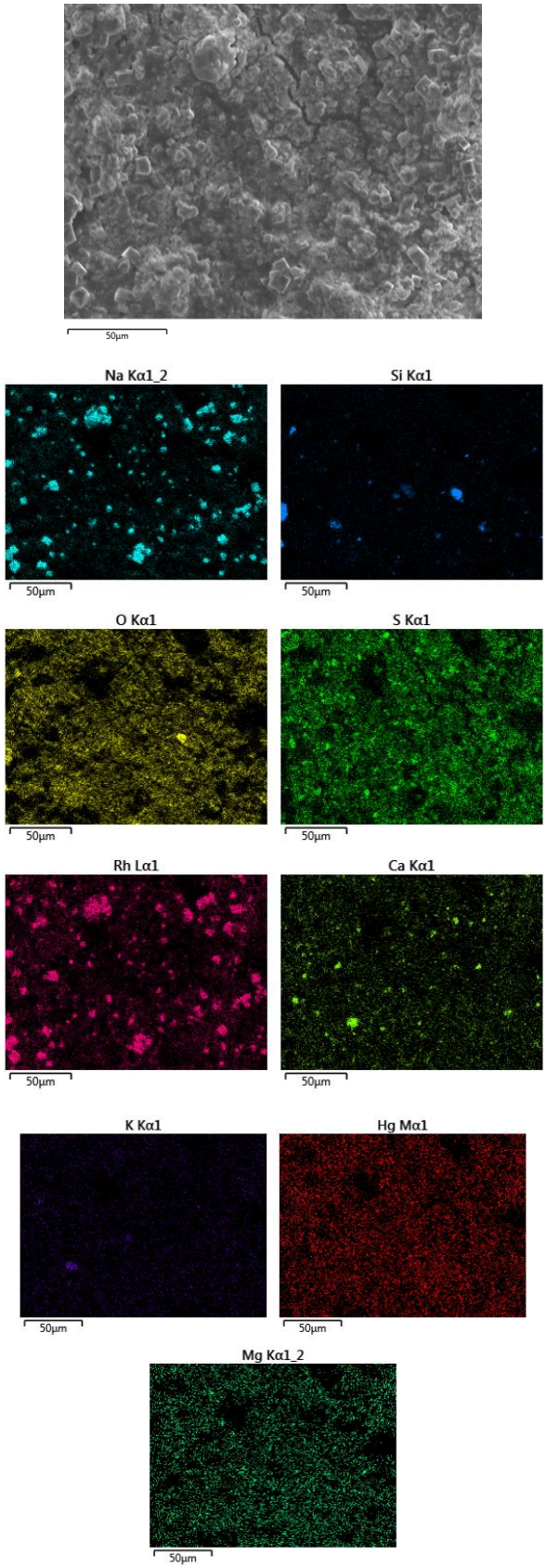


Figure 75 SEM imaging and EDX mapping sample [redacted] after hydrogen exposure testing.

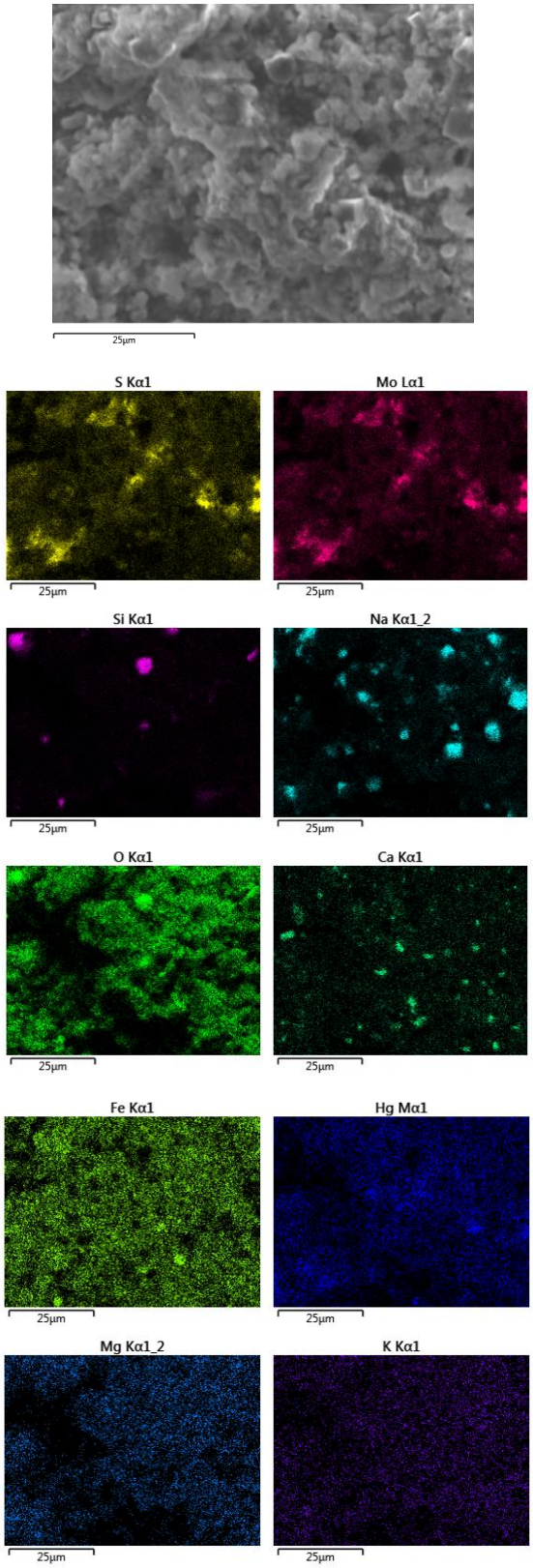


Figure 76 SEM imaging and EDX mapping sample [redacted] after hydrogen exposure testing.

Conclusion

No notable differences or deleterious compounds were observed after the exposure testing.

Sample [redacted] – Test 1

Observations during testing

The initial reaction between the zinc and the hydrochloric acid proceeded slowly, however the first signs of gas evolution were observed within the first minute, as seen in Figure 77 below. The reaction became more active after approximately 5 minutes.

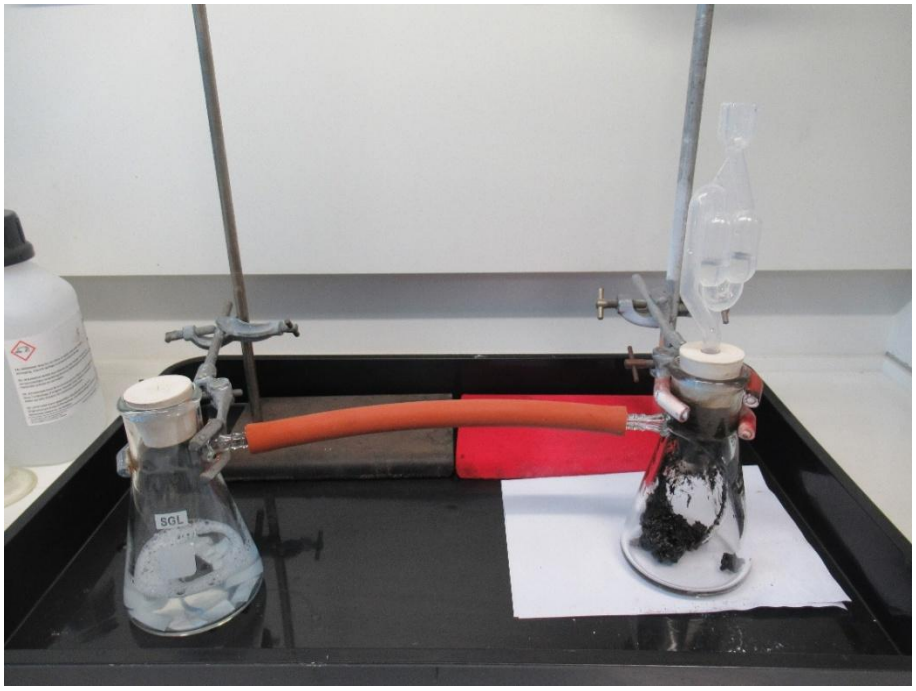


Figure 77 Initial Observations.

Halfway through the experiment, the consumption of zinc could start to be seen but the reaction was steadily ongoing. There were no visual signs of change to the contaminants at this time (Figure 78).

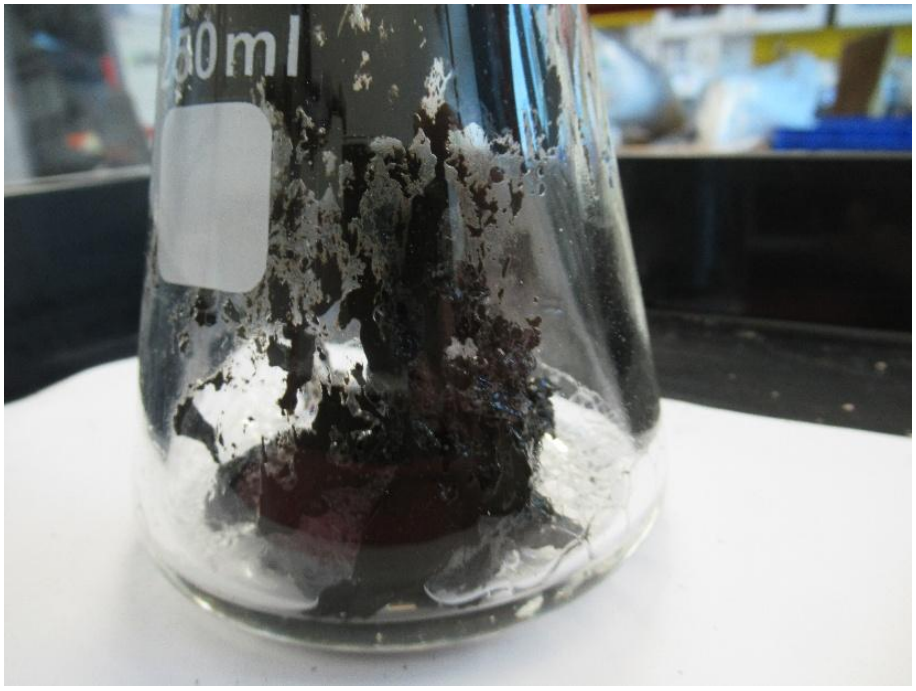


Figure 78 Sample [redacted] halfway through the hydrogen exposure testing.

Three hours into the experiment, the reaction producing the hydrogen was beginning to slow but the hydrogen environment was still established. There were no visual signs of change to the contaminant at this time (Figure 79).

Figure 79 Sample [redacted] three hours into the hydrogen exposure testing.

After four hours the experiment was stopped. Final observations showed no visual change to the contaminants (Figure 80).

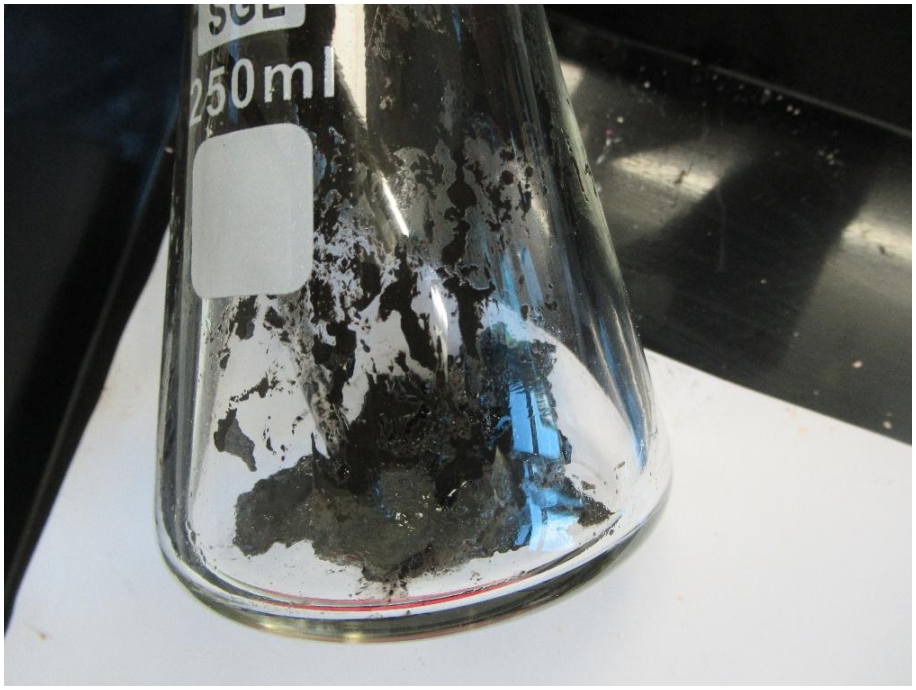


Figure 80 Sample [redacted] at the end of the hydrogen exposure testing.

Post-test FTIR Analysis

Immediately after the hydrogen exposure testing, the sample of [redacted] was subjected to FTIR analysis.

Prior to the testing, the FTIR spectrum for sample [redacted] showed the presence of aliphatic hydrocarbons, potentially a grease emulsified with traces of water. Similar observations were made subsequent to the hydrogen exposure testing. The FTIR spectrum of sample [redacted] after the exposure testing can be seen Figure 81 and a comparison to the non-exposed sample can be seen in Figure 82. The FTIR spectrum of sample [redacted] prior to testing has stronger peaks in several locations, this is only a margin increase in intensity, up to a maximum of 3% and is likely the result of general variation between tests. No notable difference between the FTIR spectra before and after exposure testing can be seen.

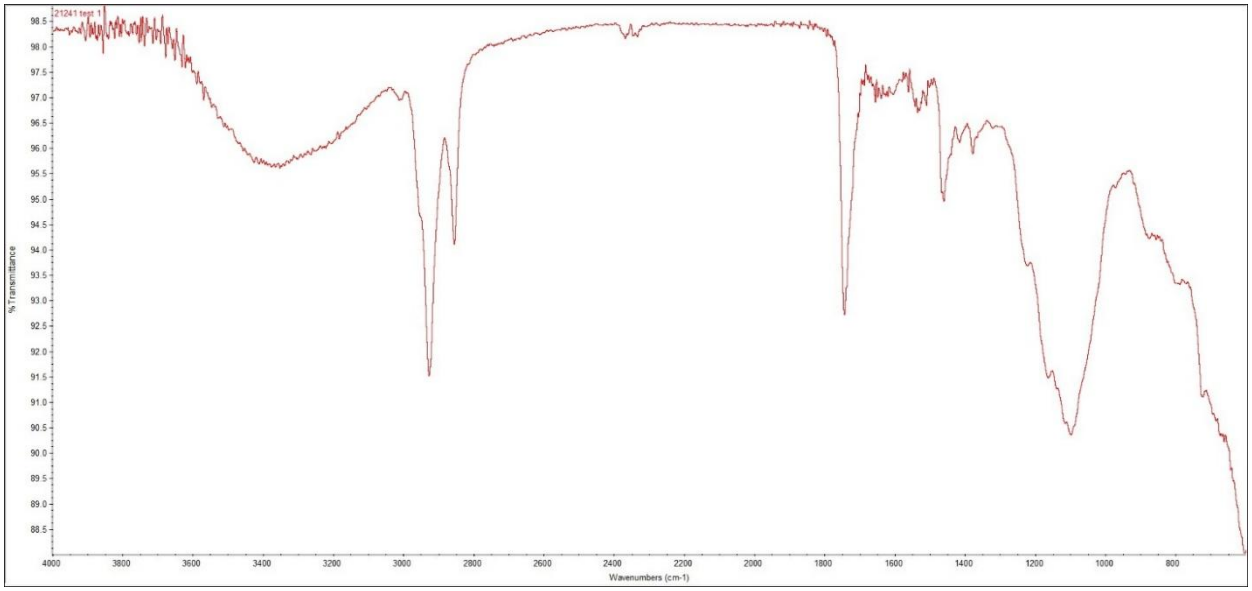


Figure 81 FTIR spectrum of sample [redacted] after hydrogen exposure test 1.

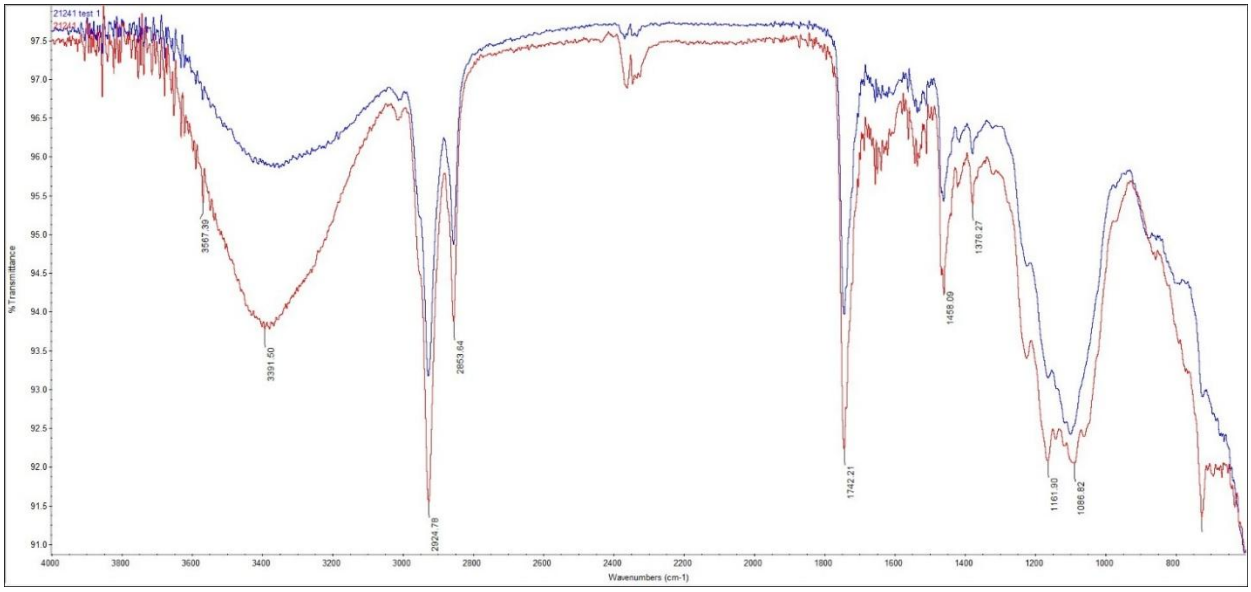


Figure 82 FTIR spectra comparing sample [redacted] before testing (red) and after hydrogen exposure testing (blue).

Conclusion

No notable differences or deleterious compounds were observed after the exposure testing.

Sample [redacted] – Test 2

Observations during testing

The initial reaction producing the hydrogen proceeded slowly to begin with, however gas evolution was observed, this can be seen in Figure 83 below.

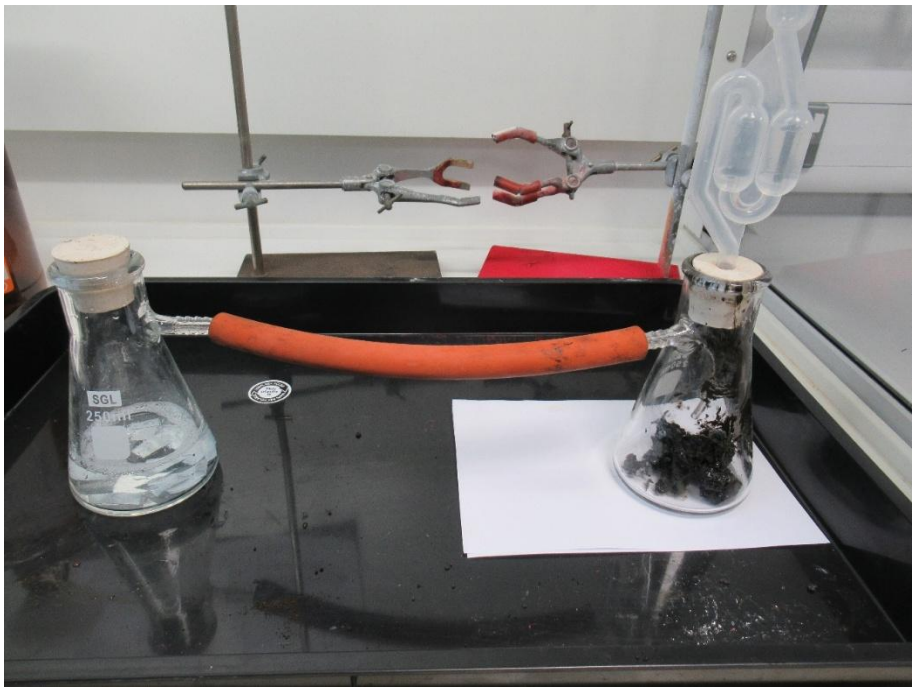


Figure 83 Initial observations.

Initial observations of the sample show no visual changes (Figure 84).

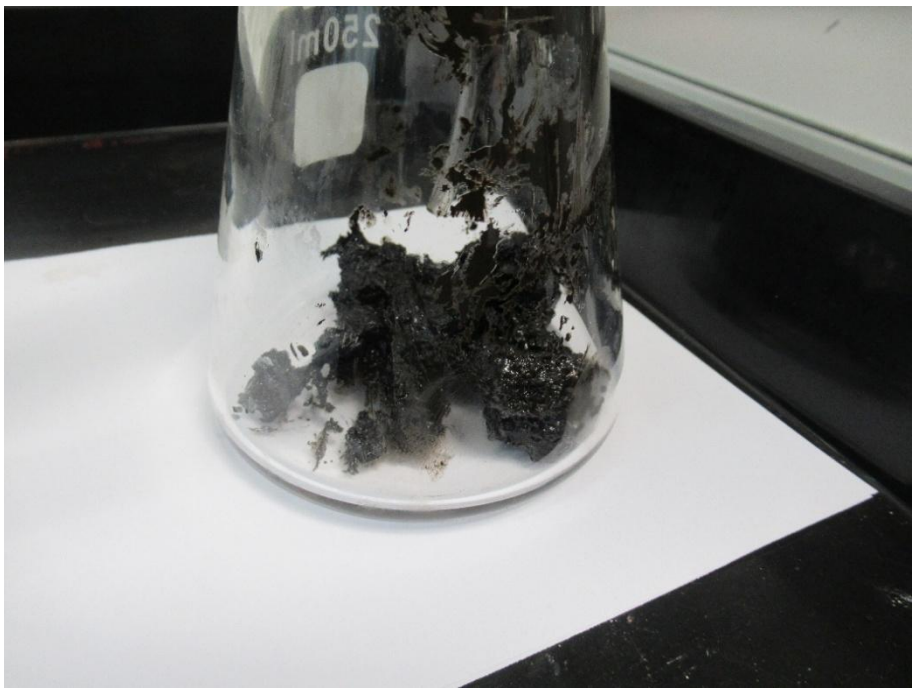


Figure 84 Sample [redacted] initial observations.

After one hour, there was no visual changes to Sample [redacted] as seen in Figure 85.

Figure 85 Sample [redacted] one hour into the hydrogen exposure testing.

Halfway through the experiment, the consumption of zinc could start to be seen but the reaction was steadily ongoing. There were no visual signs of change to the contaminants at this time (Figure 86).

Figure 86 Sample [redacted] halfway through the hydrogen exposure testing.

After three hours there were no visual signs of change to the contaminant at this time (Figure 87).

Figure 87 Sample [redacted] three hours into the hydrogen exposure testing.

The experiment ended after four hours, and the final observations showed no visual change to the contaminants (Figure 88).

Figure 88 Sample [redacted] at the end of the hydrogen exposure testing.

Post-test FTIR analysis

Immediately after the hydrogen exposure testing, this representative sample of [redacted] was subjected to FTIR analysis (Figure 89).

Prior to the testing, the FTIR spectrum of sample [redacted] showed the presence of aliphatic hydrocarbons, potentially a grease emulsified with traces of water. Similar observations were made subsequent to the hydrogen exposure testing. The FTIR spectrum of sample [redacted] after the exposure testing can be seen Figure 89 and a comparison to the un-exposed sample can be seen in Figure 90. The FTIR spectrum of sample [redacted] prior to testing has stronger peaks in several locations, this is only a marginal increase in intensity, up to a maximum of 5% and is likely the result of general variation between tests. No notable difference between the FTIR spectra before and after exposure testing can be seen. An inverted peak could be seen at 2400 cm^{-1} for the sample after hydrogen testing, this is an outlier in the data.

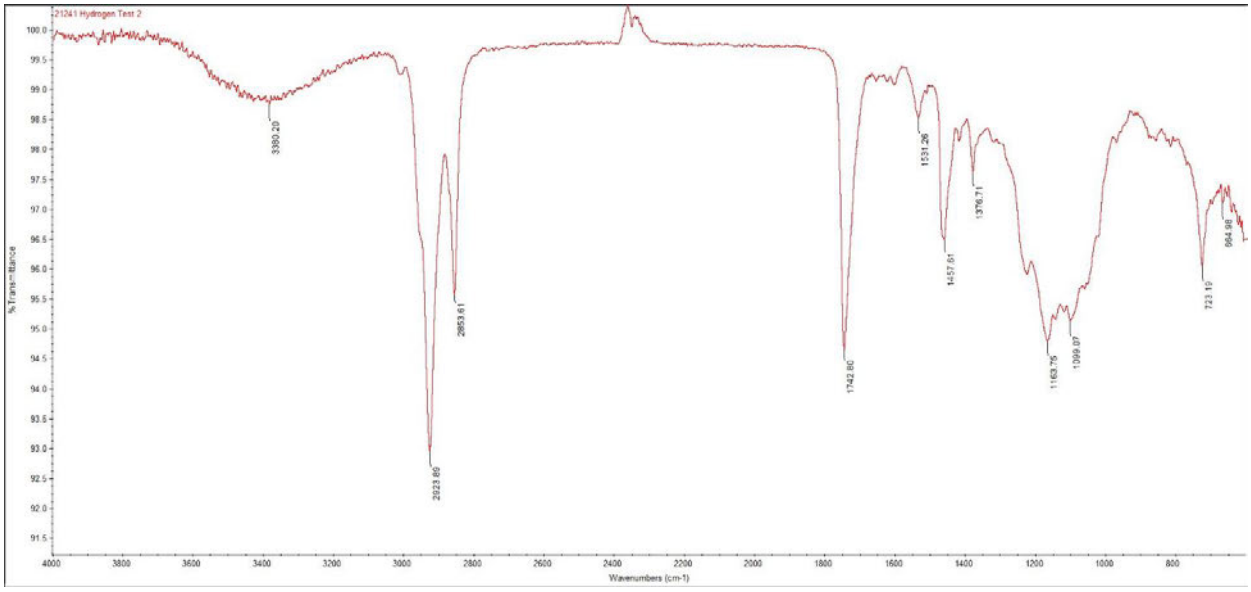


Figure 89 FTIR spectrum pf sample [redacted] after hydrogen exposure test 2.

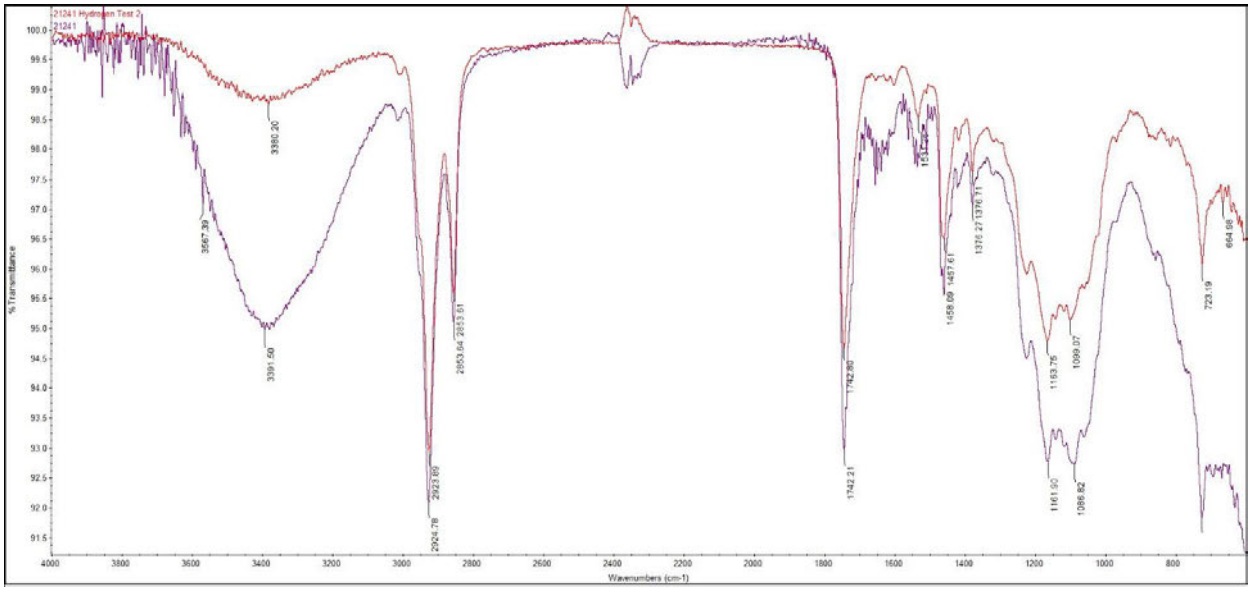


Figure 90 FTIR spectra comparing sample [redacted] before testing (purple) and after hydrogen exposure testing (red).

Conclusion

No notable differences or deleterious compounds were observed after the exposure testing.

Sample [redacted] – Test 3

Observations during testing

The initial reaction producing the hydrogen proceeded slowly to begin with, however gas evolution was observed, this can be seen in Figure 91 below.

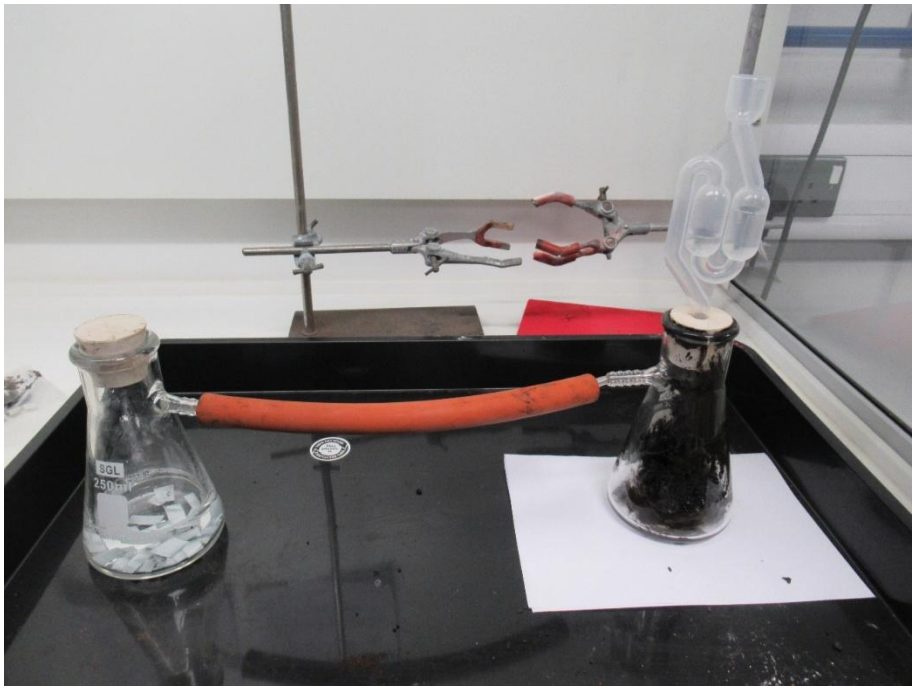


Figure 91 Initial observations.

Initial observations of the sample show no visual changes (Figure 92).

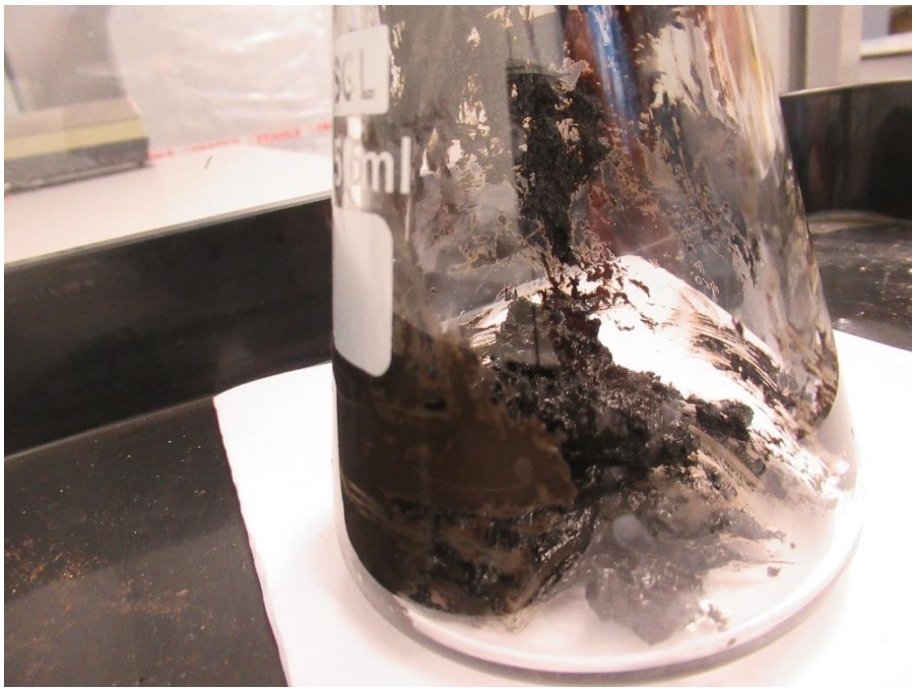


Figure 92 Sample [redacted] initial observations.

Halfway through the experiment, the consumption of zinc could start to be seen but the reaction was steadily ongoing. There were no visual signs of change to the contaminants at this time (Figure 93).

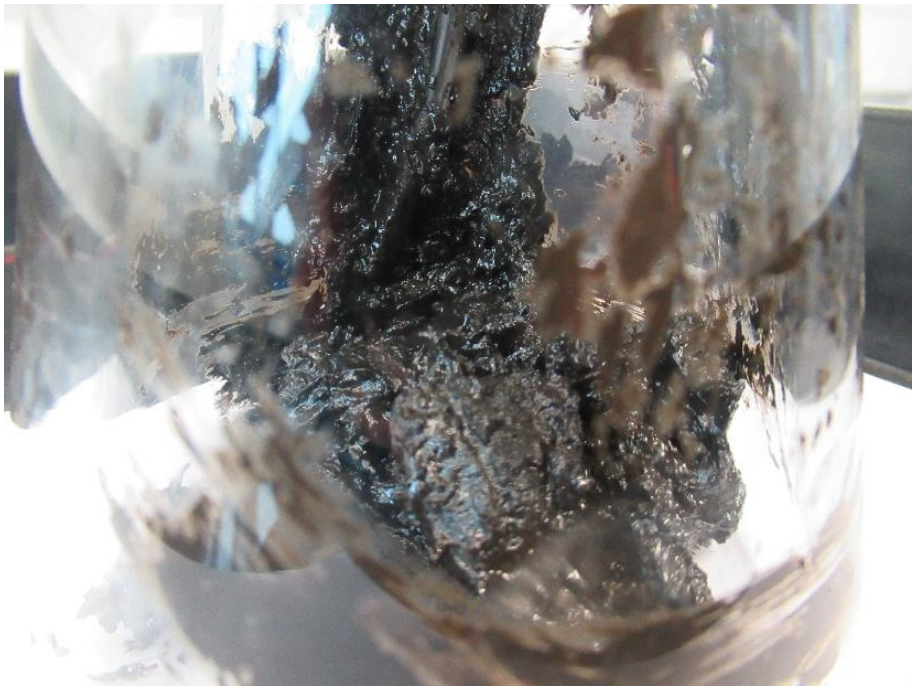


Figure 93 Sample [redacted] halfway through the hydrogen exposure testing.

The experiment ended after four hours, and the final observations showed no visual change to the contaminants (Figure 94).

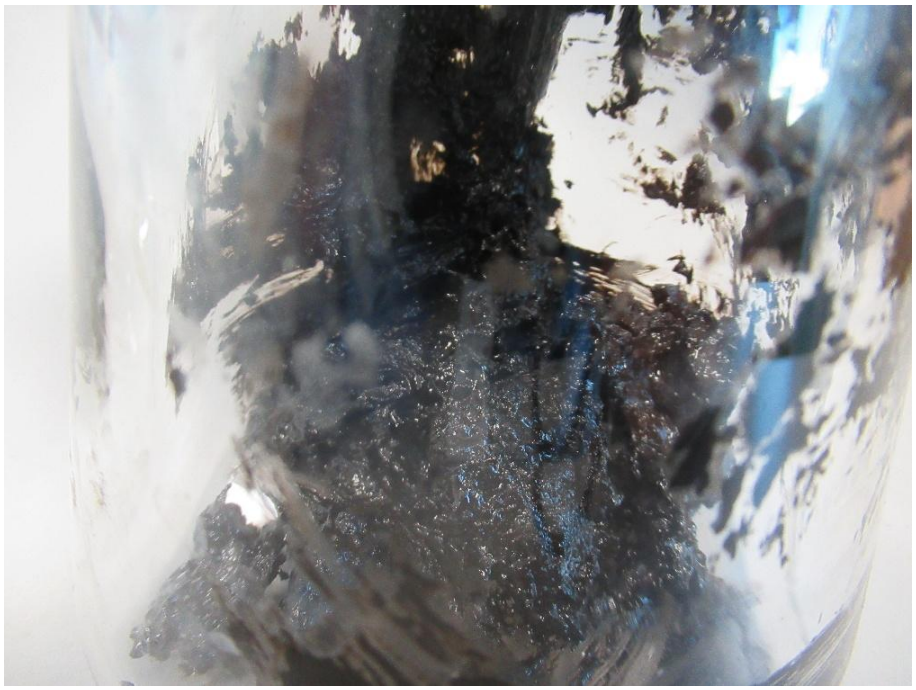


Figure 94 Sample [redacted] at the end of the hydrogen exposure testing.

Post-test FTIR analysis

Immediately after the hydrogen exposure testing, this representative sample of [redacted] was subjected to FTIR analysis (Figure 95).

Prior to the testing, the FTIR spectrum of sample [redacted] showed the presence of aliphatic hydrocarbons, potentially a grease emulsified with traces of water. Similar observations were made subsequent to the hydrogen exposure testing. The FTIR spectrum of sample [redacted] after the exposure testing can be seen Figure 95 and a comparison to the un-exposed sample can be seen in Figure 96. The FTIR spectrum of sample [redacted] prior to testing has stronger peaks in several locations, after the third hydrogen exposure test, the peak at approximately 3400 cm^{-1} was much less than that prior to testing. This trend was also seen after the previous two hydrogen exposure tests but to a lesser extent. This is likely the result of general variation which is common between FTIR measurements. It is additionally possible that hydrogen exposure may have resulted in a slight dehydration of the sample, that was un-noticeable visually but could be seen through the FTIR peak intensity. No further differences between the FTIR spectra before and after exposure testing can be seen.

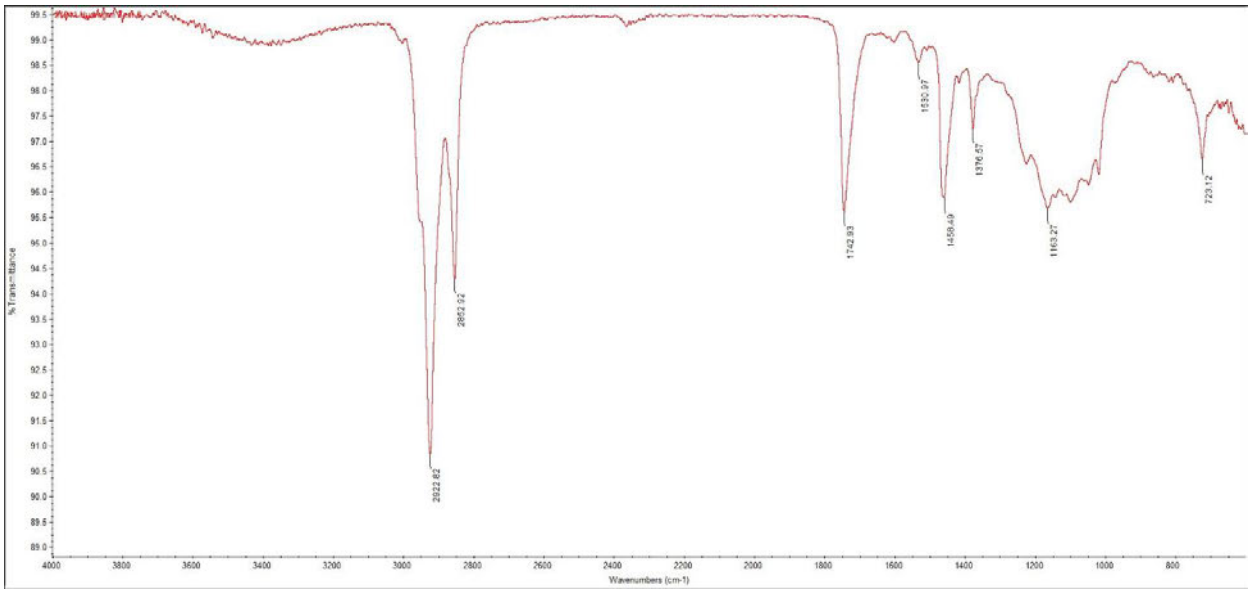


Figure 95 FTIR spectrum of sample [redacted] after hydrogen exposure test 3.

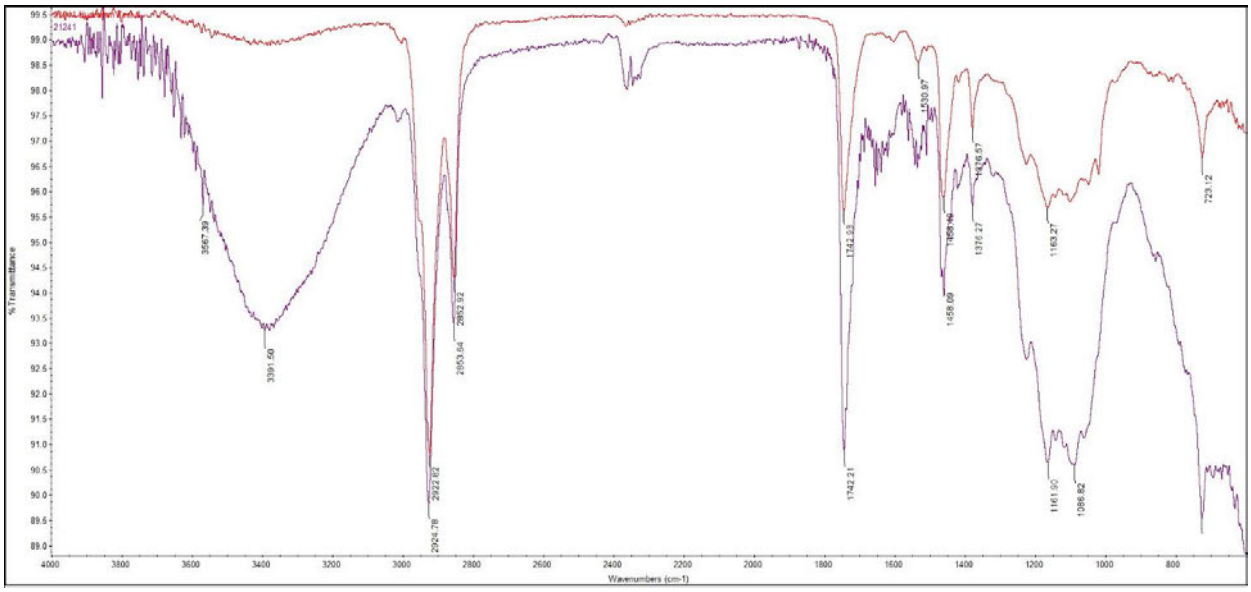


Figure 96 FTIR spectra comparing Sample [redacted] before testing (purple) and after hydrogen exposure testing (red).

Conclusion

No significant differences or deleterious compounds were observed after the exposure testing. However, a significantly smaller peak was observed at approximately 3400 cm^{-1} after the exposure testing compared to before for sample [redacted] It is possible that this was a general variation in results or the result of a dehydration effect caused by the hydrogen exposure.

Carbon dioxide exposure testing

Sample [redacted] – Test 1

Observations during testing

In order to produce a CO_2 environment, dry ice was used and the experimental set up remained similar to that of the hydrogen exposure testing otherwise. This set up can be seen in Figure 97 below. Gas evolution was observed immediately.

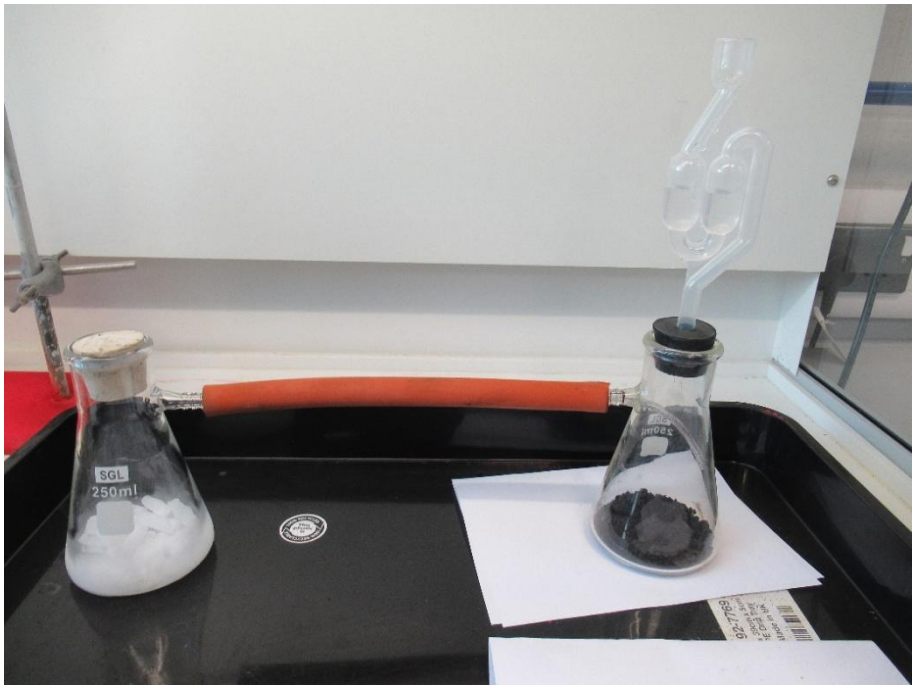


Figure 97 Initial observations.

No visual changes could be seen to the representative sample after 1 hour, 2 hours or 3 hours, as seen respectively in Figure 98, Figure 99 and Figure 100.

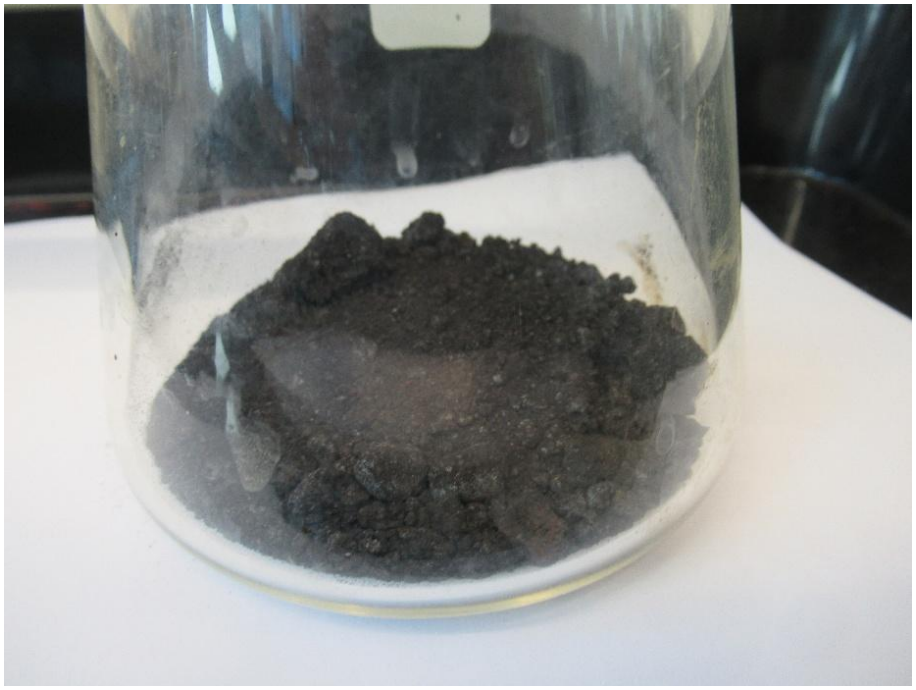


Figure 98 Sample [redacted] after one hour of CO_2 exposure testing.

Figure 99 Sample [redacted] halfway through CO_2 exposure testing.

Figure 100 Sample [redacted] three hours into CO_2 exposure testing.

After four hours the experiment was stopped. Final observations showed no visual change to the contaminants (Figure 101).

Figure 101 Sample [redacted] at the end of the CO_2 exposure testing.

Post-test SEM/EDX examination

Immediately after the CO_2 exposure testing, the sample of [redacted] was subjected to SEM examination and EDX analysis.

Prior to testing, sample [redacted] displayed several areas with high concentrations of iron oxide, indicating the presence of metallic material containing aluminium, calcium, silicates, and other light elements consistent with environmental contamination. A small number of additional elements were detected only after exposure to CO_2; however, this is expected given the representative sampling approach and limited surface area analysed during each SEM measurement and is not indicative of CO_2 effects. Overall, the observations made after CO_2 exposure testing remained consistent with the initial findings, as shown in Figure 102, Figure 103 and Figure 104.

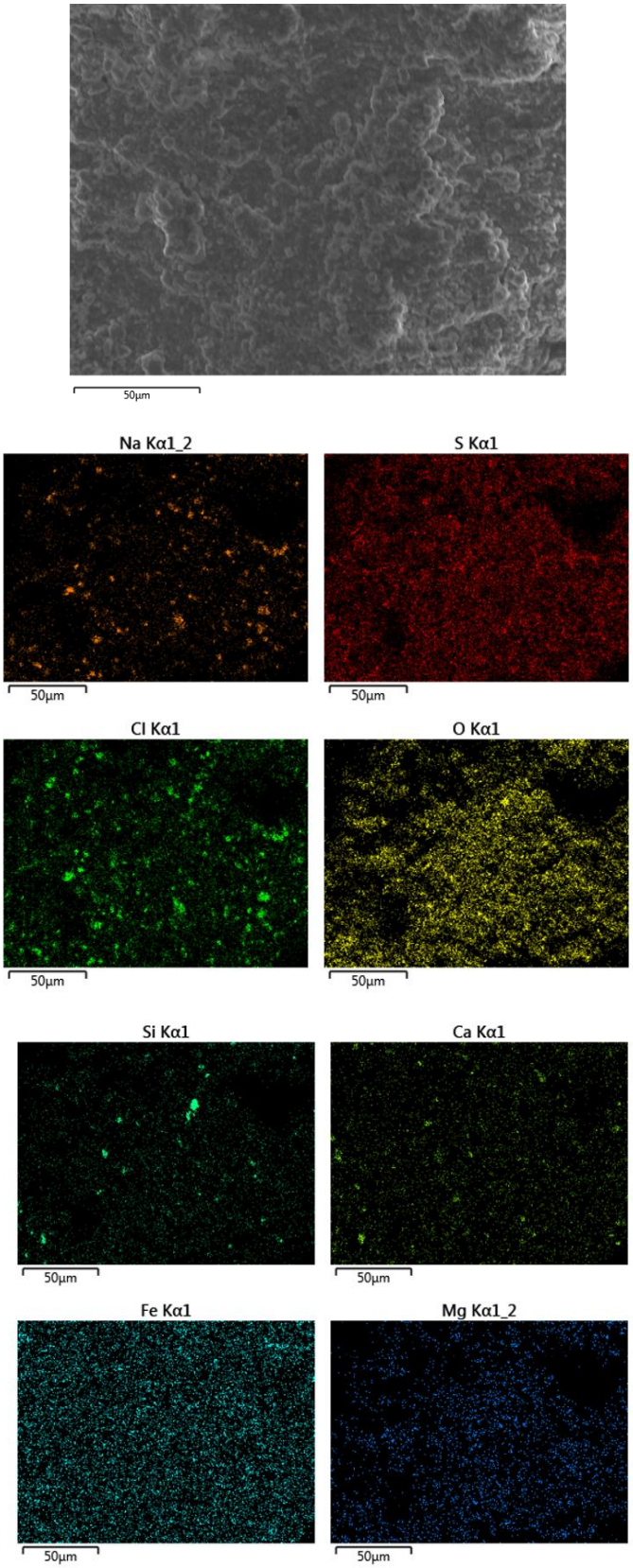


Figure 102 SEM imaging and EDX mapping sample [redacted] after CO_2 exposure testing.

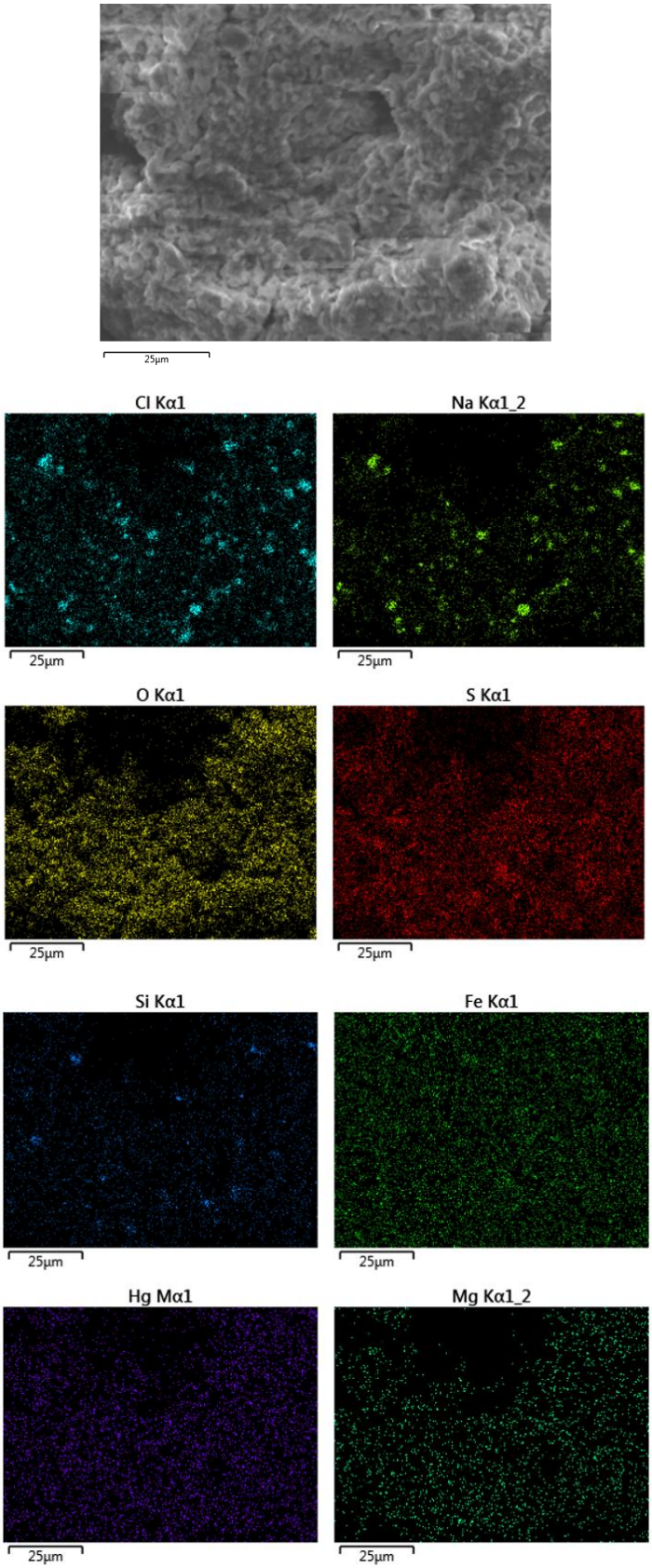


Figure 103 SEM imaging and EDX mapping sample [redacted] after CO_2 exposure testing.

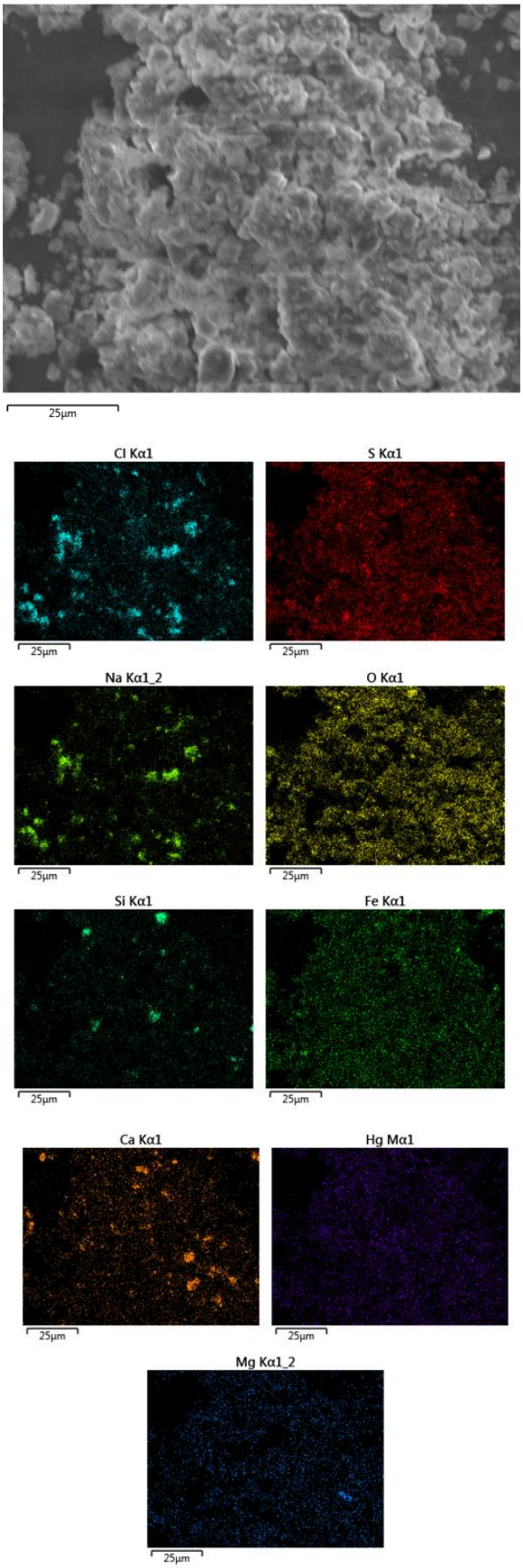


Figure 104 SEM imaging and EDX mapping sample [redacted] after CO_2 exposure testing.

Conclusion

No notable differences or deleterious compounds were observed after the exposure testing.

Sample [redacted] – Test 2

Observations during testing

In order to produce a CO_2 environment, dry ice was used and the experimental set up remained similar to that of the hydrogen exposure testing otherwise. This set up can be seen in Figure 105 below. Gas evolution was observed immediately.

Figure 105 Initial observations.

No visual changes could be seen to the representative sample after 1 hour, 2 hours or 3 hours, as seen respectively in Figure 106, Figure 107 and Figure 108.

Figure 106 Sample [redacted] after one hour of CO_2 exposure testing.

Figure 107 Sample [redacted] halfway through CO_2 exposure testing.

Figure 108 Sample [redacted] three hours into CO_2 exposure testing.

After four hours the experiment was stopped. Final observations showed no visual change to the contaminants (Figure 109).

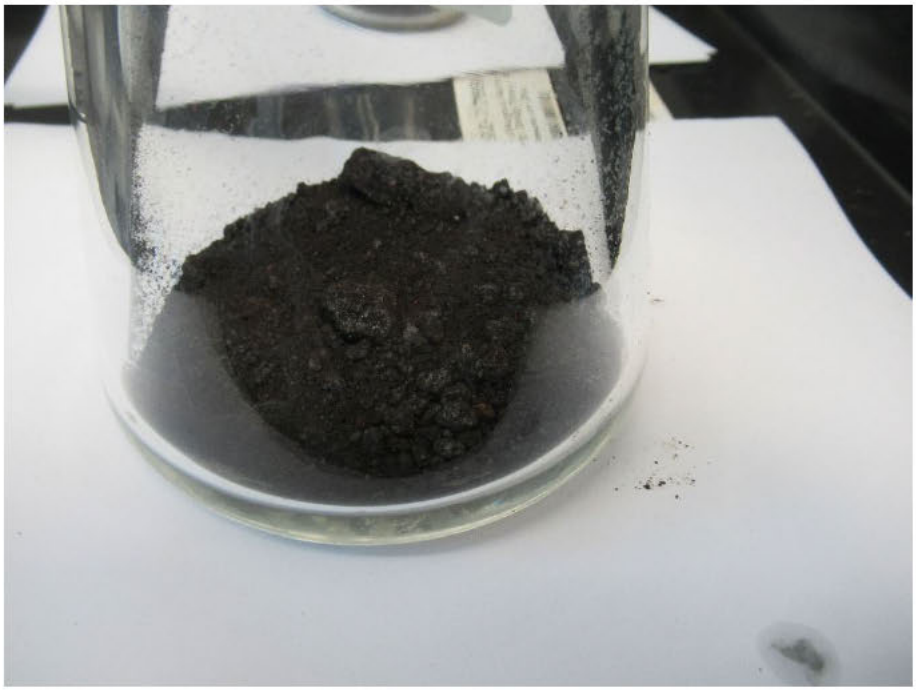


Figure 109 Sample [redacted] at the end of the CO_2 exposure testing.

Post-test SEM/EDX examination

Immediately after the CO_2 exposure testing, the sample of [redacted] was subjected to SEM examination and EDX analysis.

Prior to testing, sample [redacted] displayed several areas with high concentrations of iron oxide, indicating the presence of metallic material with aluminium, calcium, silicates, and other light elements consistent with environmental contamination. A small number of additional elements were detected only after exposure to carbon dioxide; however, this is expected given the representative sampling approach and limited surface area analysed during each SEM measurement and is not indicative of CO_2 effects. Overall, the observations made after CO_2 exposure testing remained consistent with the initial findings, as shown in Figure 110, Figure 111 and Figure 112.

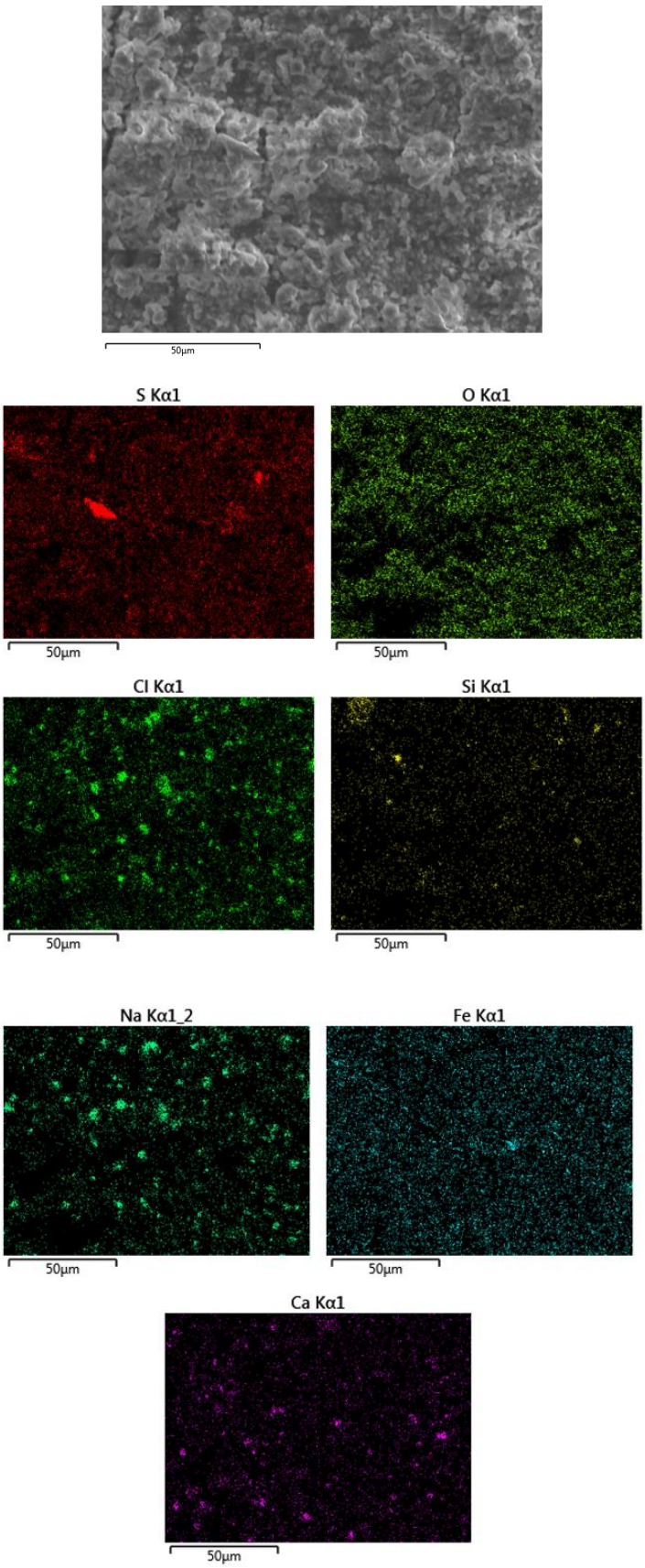


Figure 110 SEM imaging and EDX mapping sample [redacted] after CO_2 exposure testing.

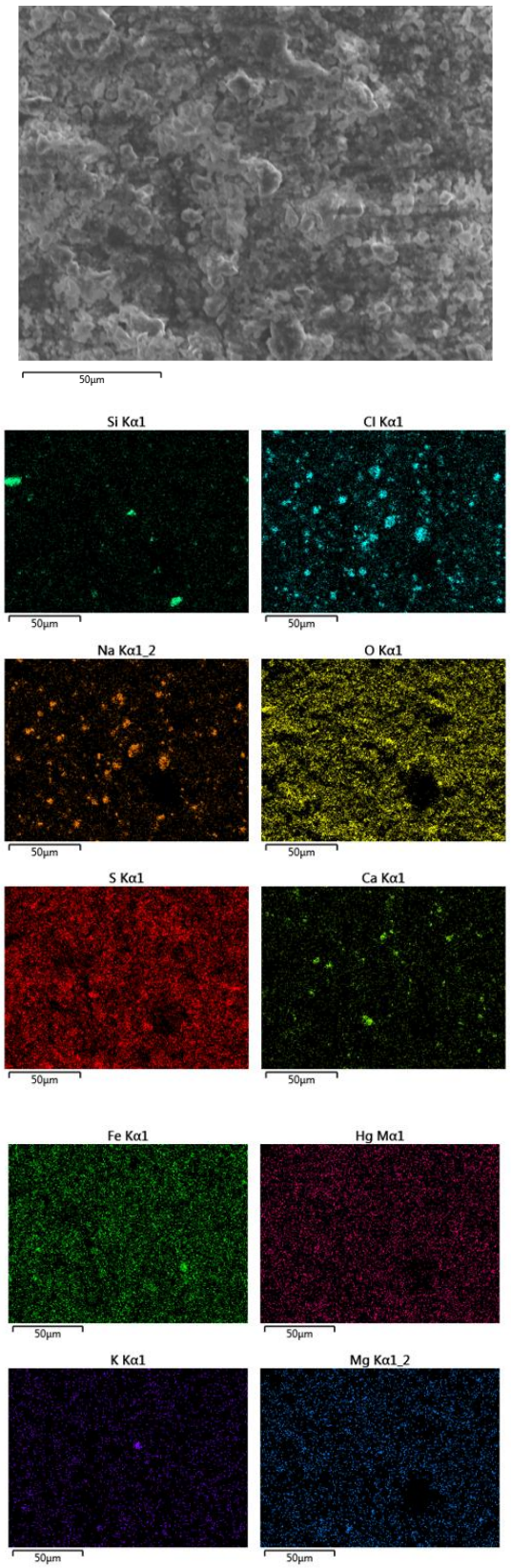


Figure 111 SEM imaging and EDX mapping sample [redacted] after CO_2 exposure testing.

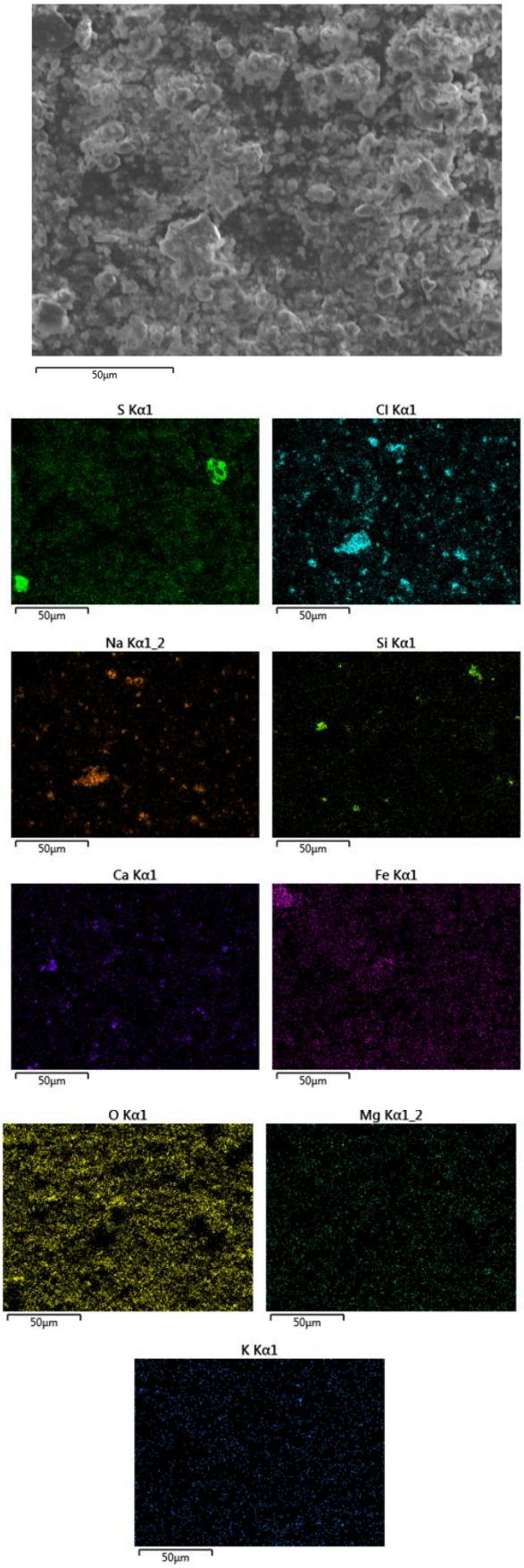


Figure 112 SEM imaging and EDX mapping sample [redacted] after CO2 exposure testing.

Conclusion

No notable differences or deleterious compounds were observed after the exposure testing.

Sample [redacted] – Test 3

Observations during testing

In order to produce a CO_2 environment, dry ice was used and the experimental set up remained similar to that of the hydrogen exposure testing otherwise. This set up can be seen in Figure 113 below. Gas evolution was observed immediately.

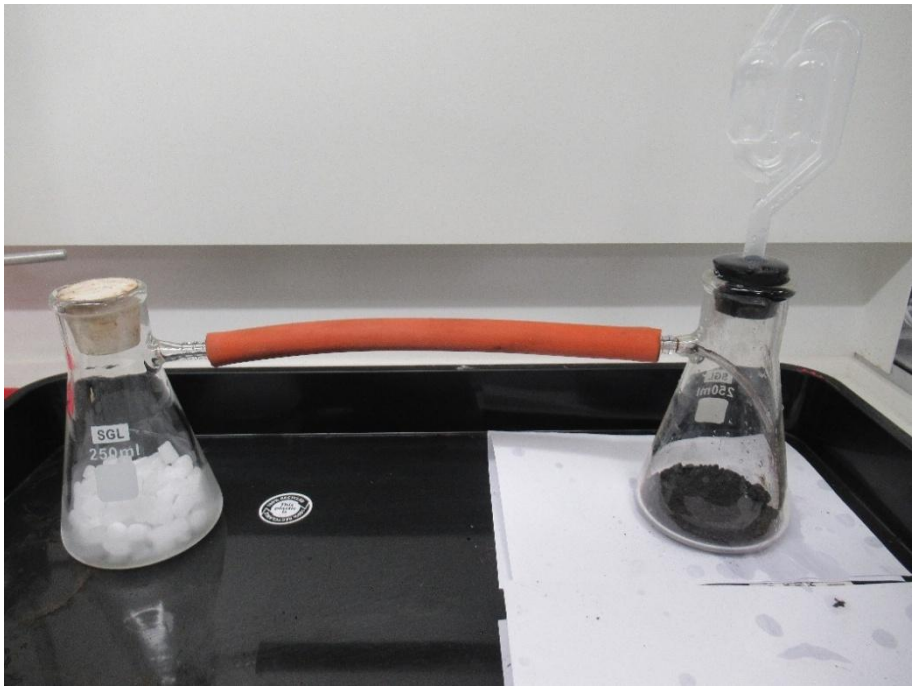


Figure 113 Initial observations.

No visual changes could be seen to the representative sample after 1 hour, 2 hours or 3 hours, as seen respectively in Figure 114, Figure 115 and Figure 116.

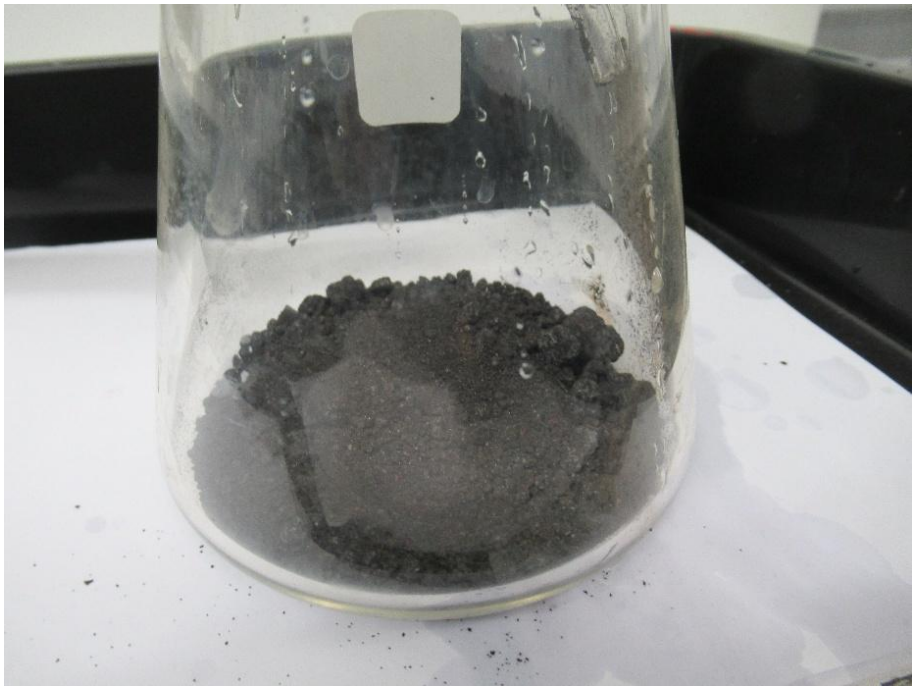


Figure 114 Sample [redacted] after one hour of CO_2 exposure testing.

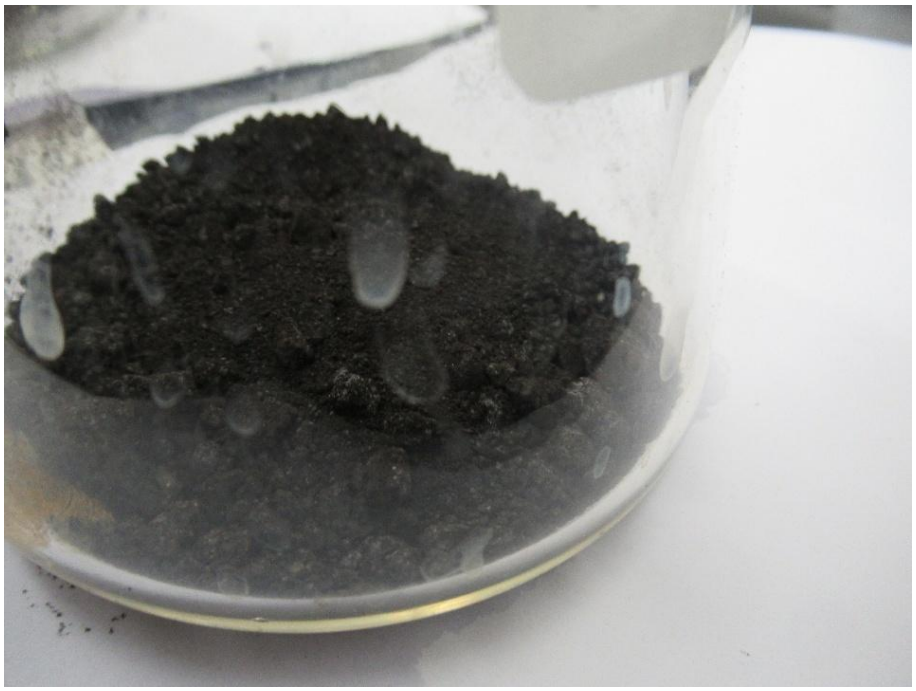


Figure 115 Sample [redacted] halfway through CO_2 exposure testing.

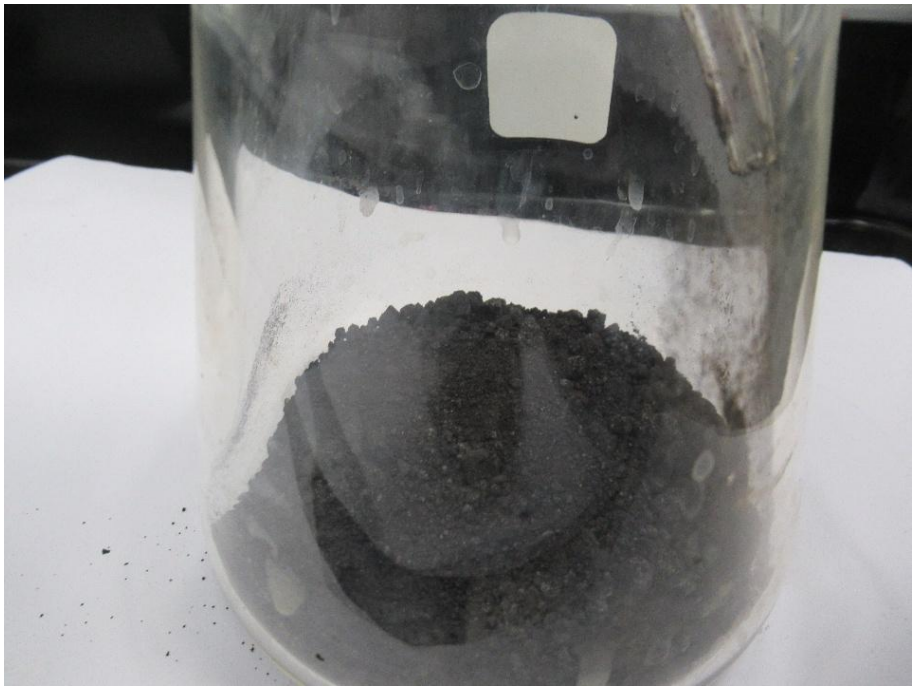


Figure 116 Sample [redacted] three hours into CO_2 exposure testing.

After four hours the experiment was stopped. Final observations showed no visual change to the contaminants (Figure 117).

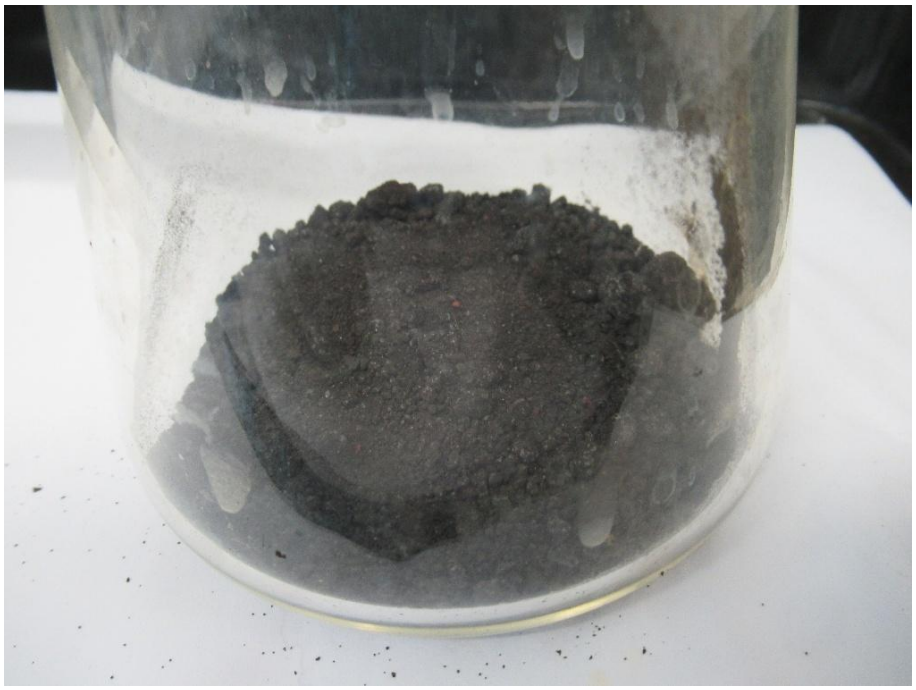


Figure 117 Sample [redacted] at the end of the CO_2 exposure testing.

Post-test SEM/EDX examination

Immediately after the CO_2 exposure testing, the sample of [redacted] was subjected to SEM examination and EDX analysis.

Prior to testing, Sample [redacted] displayed several areas with high concentrations of iron oxide, indicating the presence of metallic material with aluminium, calcium, silicates, and other light elements consistent with environmental contamination. A small number of additional elements were detected only after exposure to carbon dioxide; however, this is expected given the representative sampling approach and limited surface area analysed during each SEM measurement and is not indicative of CO_2 effects. Overall, the observations made after CO_2 exposure testing remained consistent with the initial findings, as shown in Figure 118, Figure 119 and Figure 120.

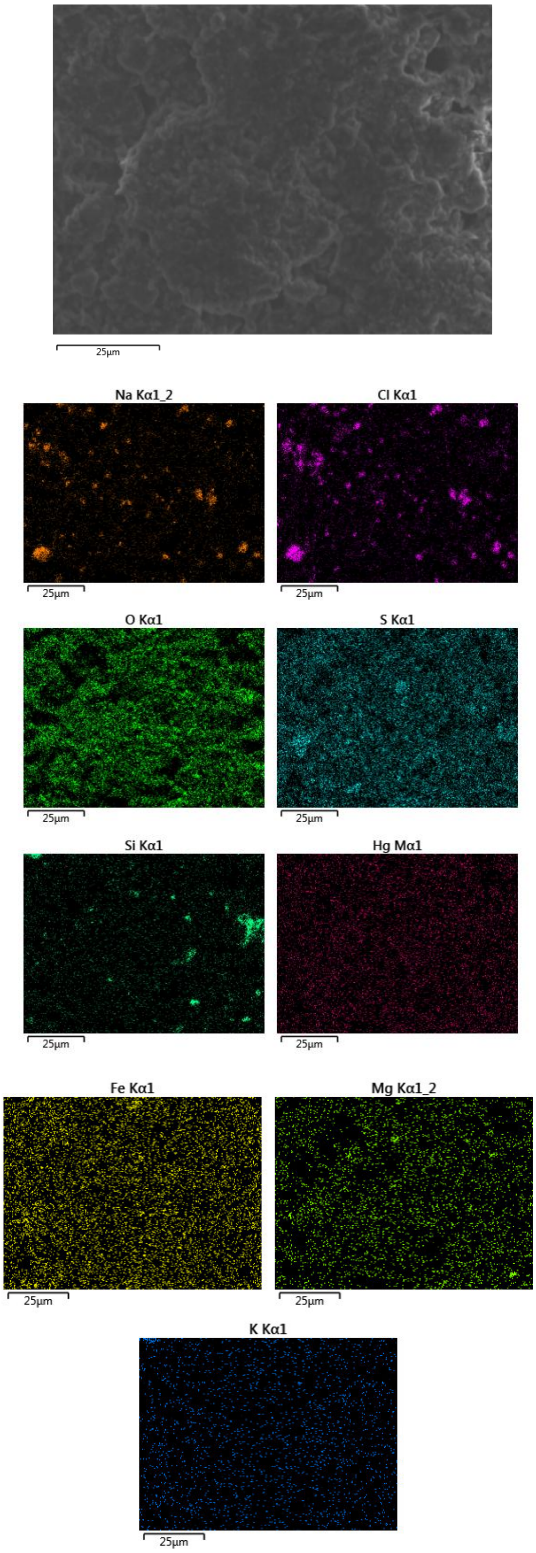


Figure 118 SEM imaging and EDX mapping sample [redacted] after CO2 exposure testing.

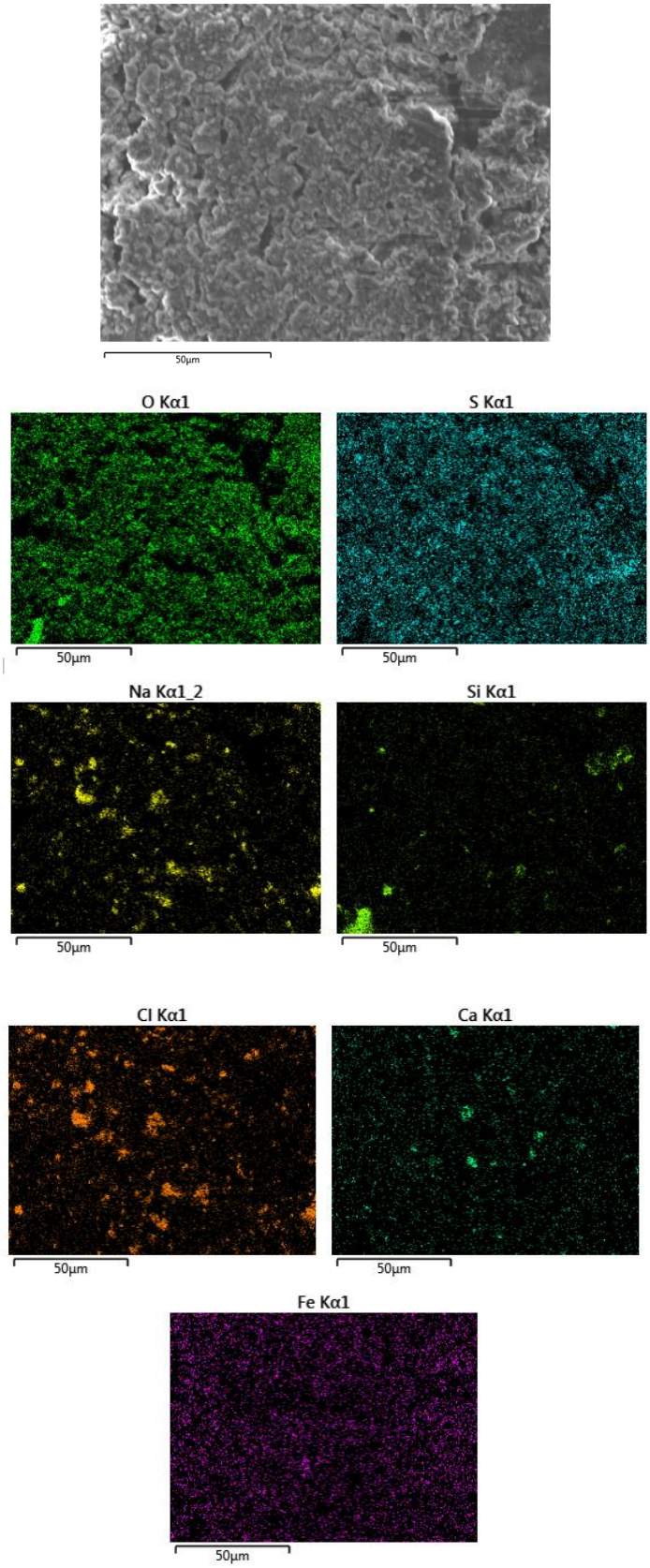


Figure 119 SEM imaging and EDX mapping sample [redacted] after CO2 exposure testing.

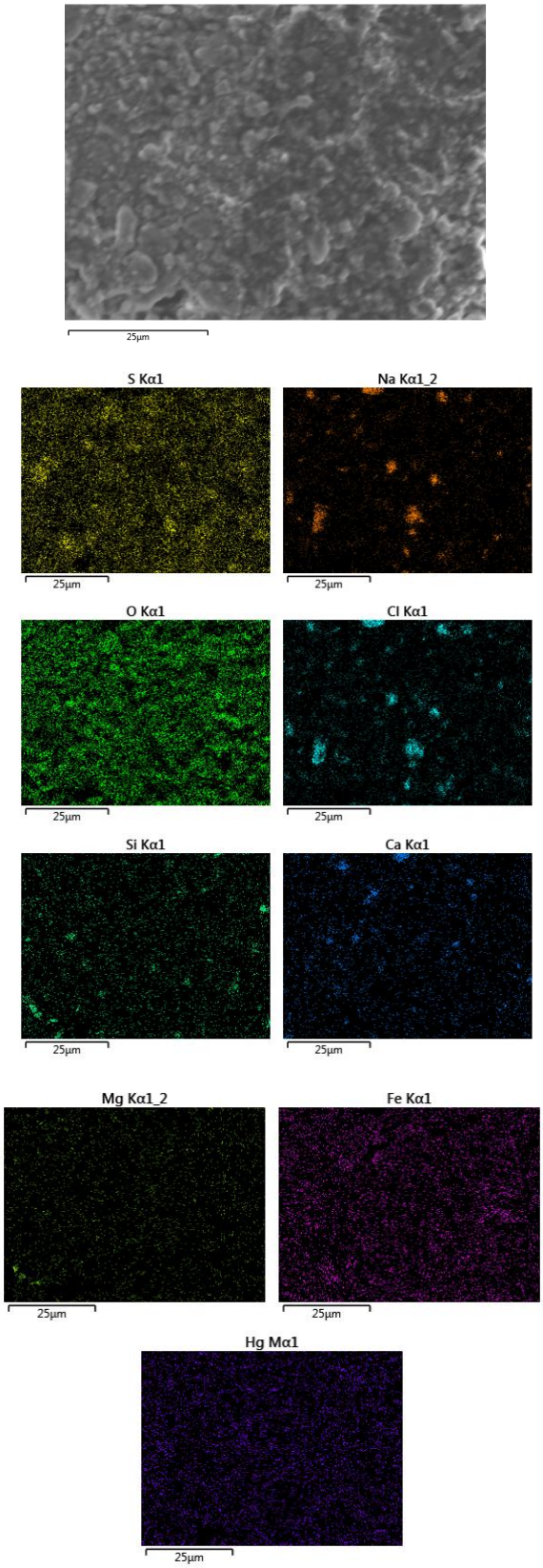


Figure 120 SEM imaging and EDX mapping sample [redacted] after CO2 exposure testing.

Conclusion

No notable differences or deleterious compounds were observed after the exposure testing.

Sample [redacted] – Test 1

Observations during testing

In order to produce a CO_2 environment, dry ice was used and the experimental set up remained similar to that of the hydrogen exposure testing otherwise. This set up can be seen in Figure 121 below. Gas evolution was observed immediately.

Figure 121 Initial observations.

Initial observations of the sample show no visual changes (Figure 122).

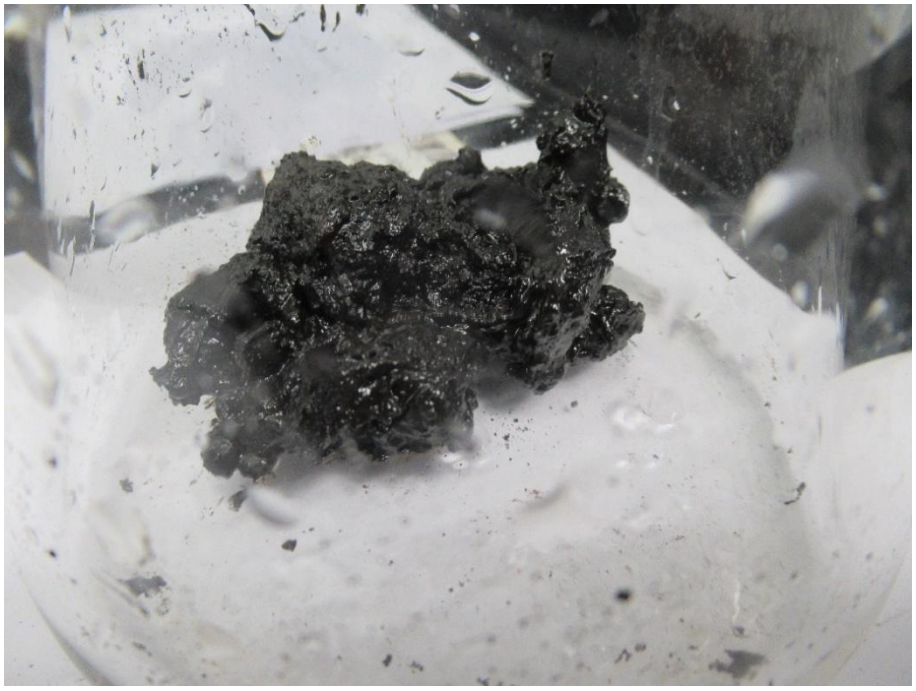


Figure 122 Sample [redacted] initial observations.

Halfway through the experiment, there were no visual signs of change to the contaminants (Figure 123).

Figure 123 Sample [redacted] halfway through the CO_2 exposure testing.

The experiment ended after four hours, and the final observations showed no visual change to the contaminants (Figure 124).

Figure 124 Sample [redacted] at the end of the CO_2 exposure testing.

Post-test FTIR analysis

Immediately subsequent to the CO_2 exposure testing, this representative sample of [redacted] was subjected to FTIR analysis (Figure 125).

Prior to the testing, the FTIR spectrum of sample [redacted] showed the presence of aliphatic hydrocarbons, potentially a grease emulsified with traces of water. Similar observations were made subsequent to the CO_2 exposure testing. The FTIR spectrum of sample [redacted] after the exposure testing can be seen Figure 125 and a comparison to the sample not subjected to exposure testing can be seen in Figure 126. The FTIR spectrum of sample [redacted] prior to testing has stronger peaks in several locations. Similar to test 3 of the hydrogen exposure testing, the first CO_2 exposure test also showed that the peak at approximately 3400 cm^{-1} was much less than the sample tested prior to exposure. This is likely the result of general variation which is common between FTIR measurements. It is additionally possible that CO_2 exposure may have resulted in a slight dehydration of the sample, that was un-noticeable visually but could be seen through the FTIR peak intensity. No further differences between the FTIR spectra before and after exposure testing can be seen.

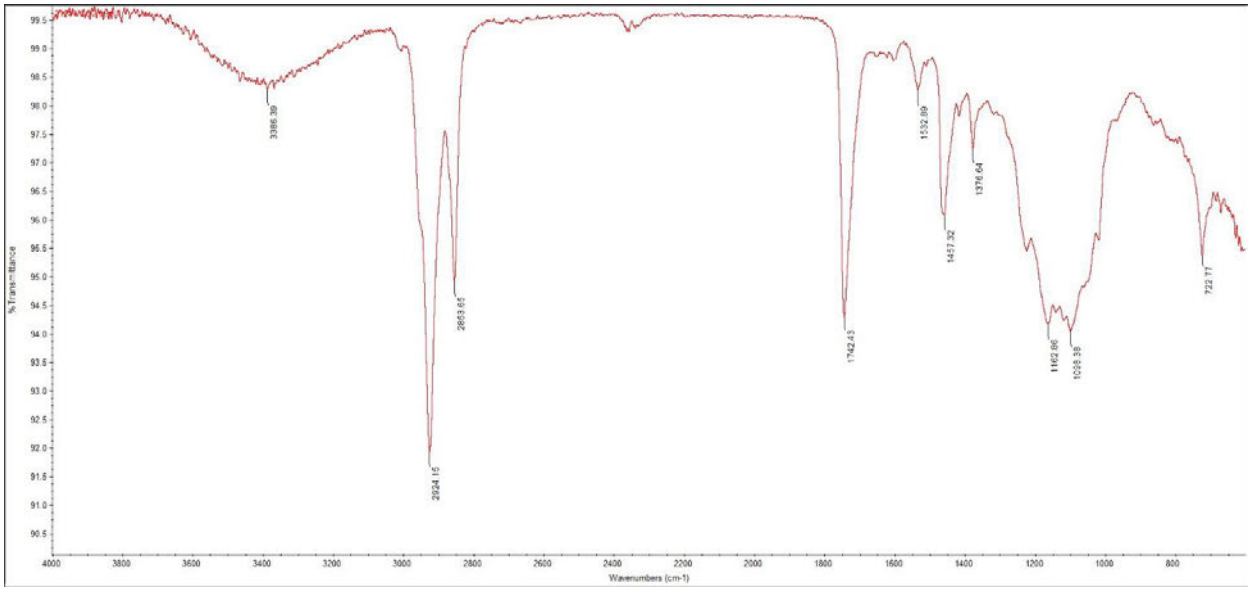


Figure 125 FTIR spectra for sample [redacted] after CO_2 exposure test 1.

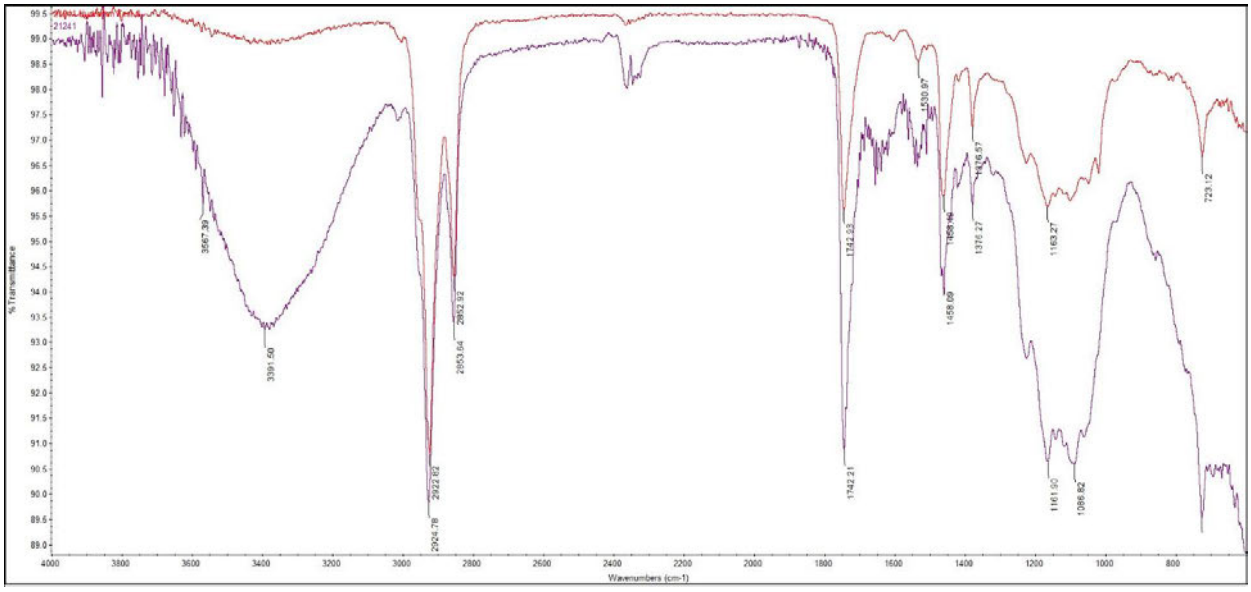


Figure 126 FTIR spectra comparing sample [redacted] before (purple) and after (red) CO_2 exposure testing.

Conclusion

No notable differences or deleterious compounds were observed after the exposure testing.

Sample [redacted] – Test 2

Observations during testing

In order to produce a CO_2 environment, dry ice was used and the experimental set up remained similar to that of the hydrogen exposure testing otherwise. This set up can be seen in Figure 127 below. Gas evolution was observed immediately.

Figure 127 Initial observations.

Initial observations of the sample show no visual changes (Figure 128).

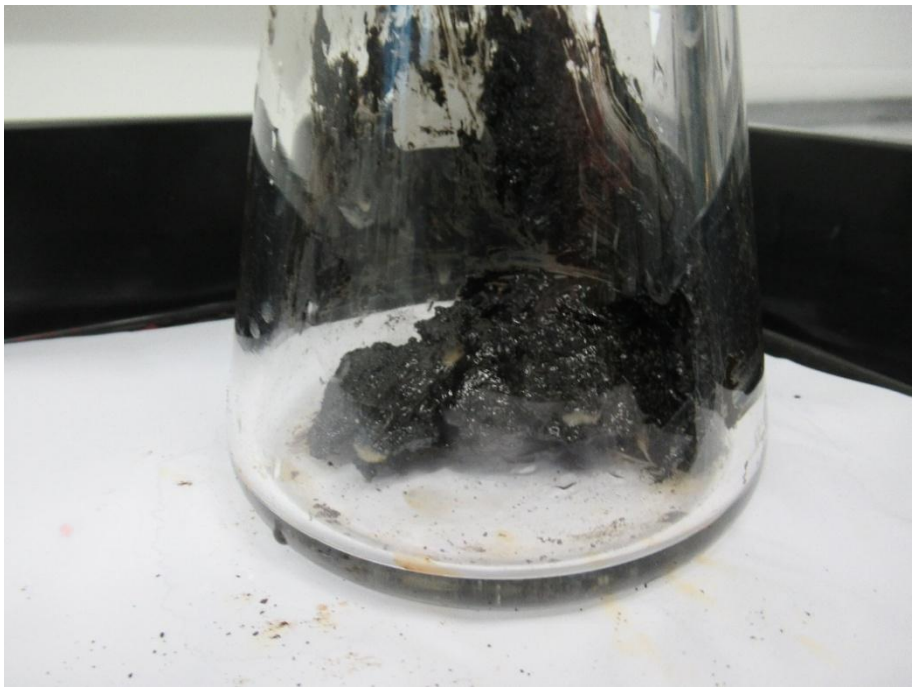


Figure 128 Sample [redacted] initial observations.

Halfway through the experiment, there were no visual signs of change to the contaminants (Figure 129).

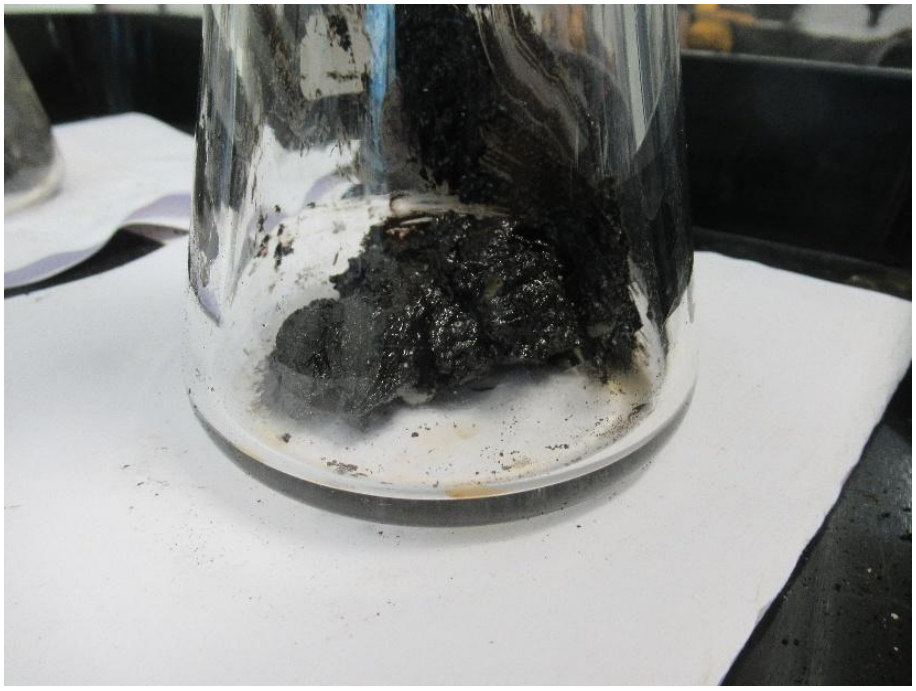


Figure 129 Sample [redacted] halfway through the CO_2 exposure testing.

The experiment ended after four hours, and the final observations showed no visual change to the contaminants (Figure 130).

Figure 130 Sample [redacted] at the end of the CO_2 exposure testing.

Post-test FTIR analysis

Immediately after the CO_2 exposure testing, this representative sample of [redacted] was subjected to FTIR analysis (Figure 131).

Prior to the testing, the FTIR spectrum of sample [redacted] showed the presence of aliphatic hydrocarbons, potentially a grease emulsified with traces of water. Similar observations were made subsequent to the CO_2 exposure testing. The FTIR spectrum of sample [redacted] after the exposure testing can be seen Figure 131 and a comparison to the sample not subjected to exposure testing can be seen in Figure 132. The FTIR spectrum of sample [redacted] prior to testing has stronger peaks in several locations. Similar to the first CO_2 exposure test also showed that the peak at approximately 3400 cm^{-1} was much less than the sample tested prior to exposure. This is likely the result of general variation which is common between FTIR measurements. It is additionally possible that CO_2 exposure may have resulted in a slight dehydration of the sample, that was un-noticeable visually but could be seen through the FTIR peak intensity. No further differences between the FTIR spectra before and after exposure testing can be seen.

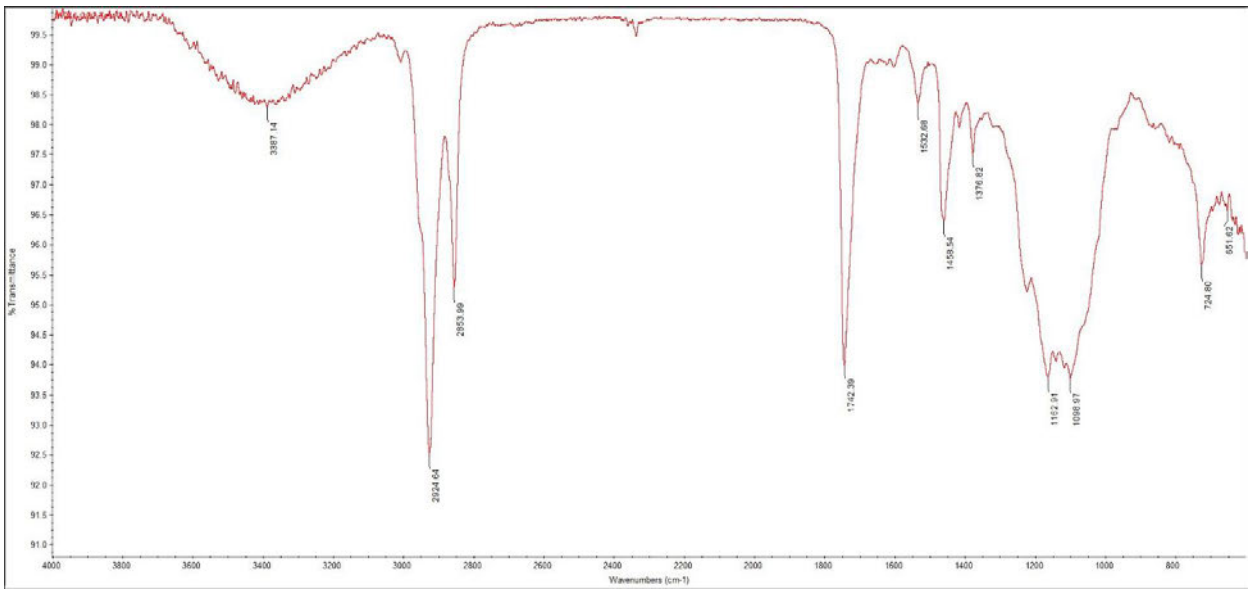


Figure 131 FTIR spectrum of sample [redacted] after CO_2 exposure test 2.

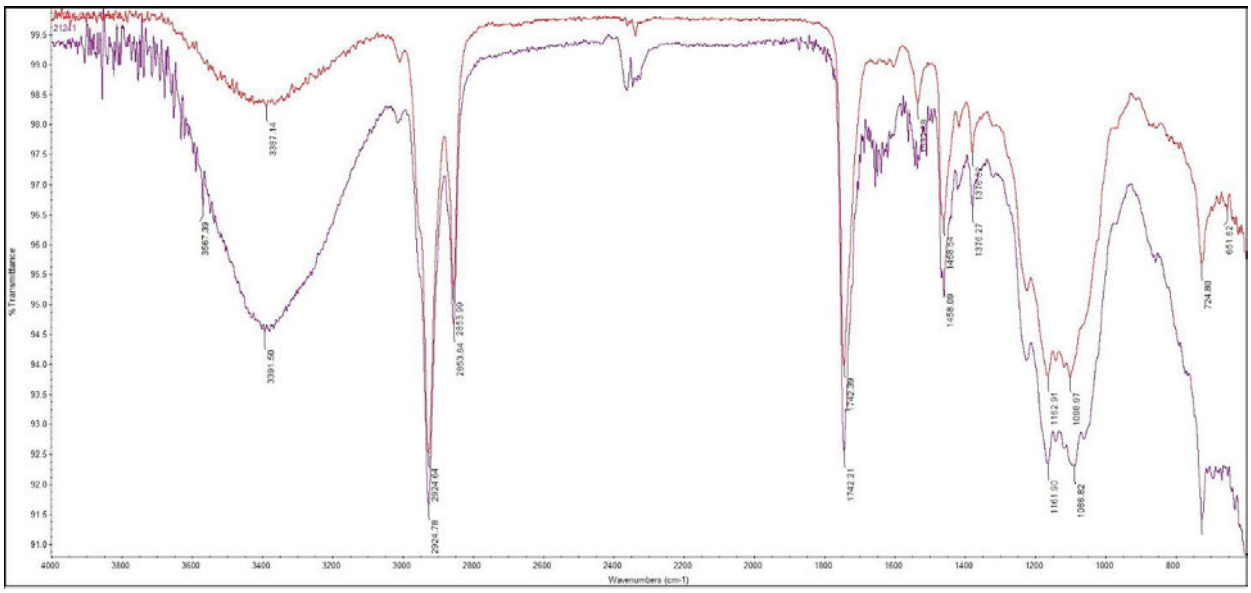


Figure 132 FTIR spectra comparing sample [redacted] before (purple) and after (red) CO_2 exposure testing.

Conclusion

No notable differences or deleterious compounds were observed after the exposure testing.

Sample [redacted] – Test 3

Observations during testing

In order to produce a CO_2 environment, dry ice was used and the experimental set up remained similar to that of the hydrogen exposure testing otherwise. This set up can be seen in Figure 133 below. Gas evolution was observed immediately.

Figure 133 Initial observations.

Initial observations of the sample show no visual changes (Figure 134).

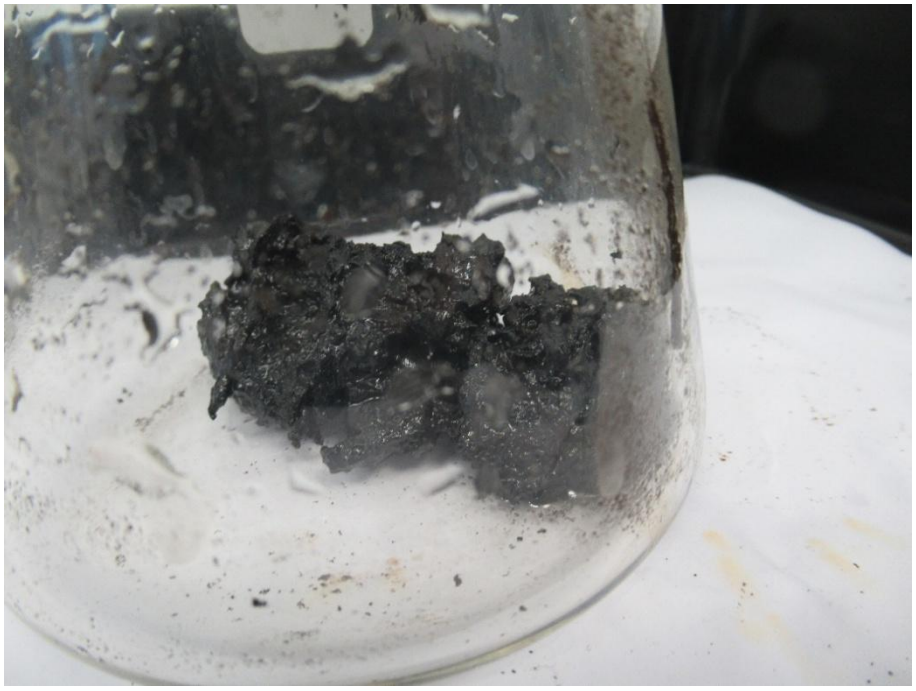


Figure 134 Sample [redacted] initial observations.

Halfway through the experiment, there were no visual signs of change to the contaminants (Figure 135).

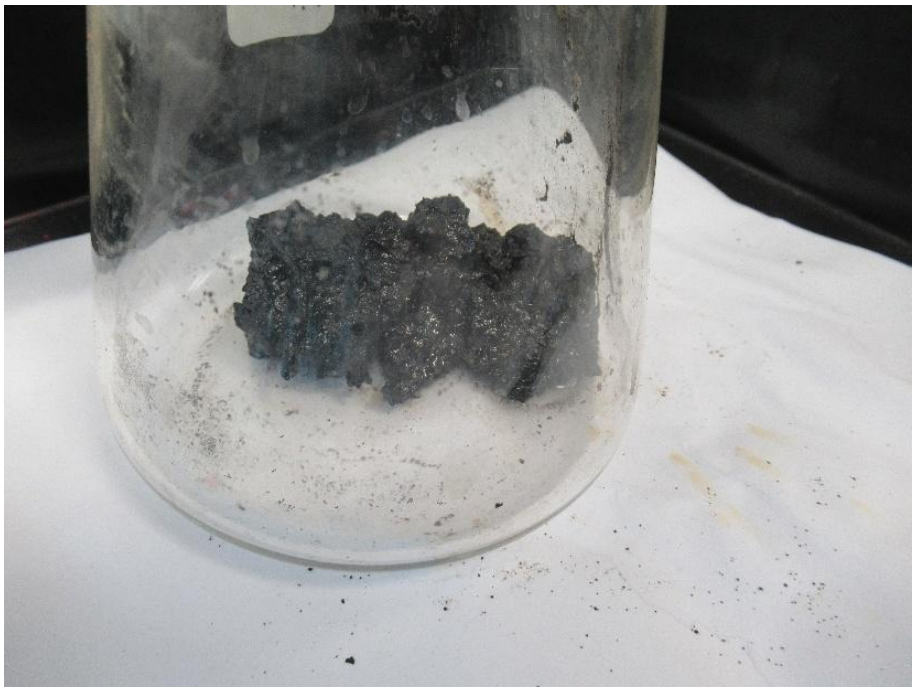


Figure 135 Sample [redacted] halfway through the CO_2 exposure testing.

The experiment ended after four hours, and the final observations showed no visual change to the contaminants (Figure 136).

Figure 136 Sample [redacted] at the end of the CO_2 exposure testing.

Post-test FTIR analysis

Immediately subsequent to the CO_2 exposure testing, this representative sample of [redacted] was subjected to FTIR analysis (Figure 137).

Prior to the testing, the FTIR spectrum of sample [redacted] showed the presence of aliphatic hydrocarbons, potentially a grease emulsified with traces of water. Similar observations were made subsequent to the CO_2 exposure testing. The FTIR spectrum of sample [redacted] after the exposure testing can be seen Figure 137 and a comparison to the sample not subjected to exposure testing can be seen in Figure 138. The FTIR spectrum of sample [redacted] prior to testing has stronger peaks in several locations. Similar to the first CO_2 exposure test also showed that the peak at approximately 3400 cm^{-1} was much less than the sample tested prior to exposure. This is likely the result of general variation which is common between FTIR measurements. It is additionally possible that CO_2 exposure may have resulted in a slight dehydration of the sample, that was un-noticeable visually but could be seen through the FTIR peak intensity. It can also be seen in Figure 138 that the peaks in the fingerprint region of the FTIR spectra are significantly lower intensity after exposure testing, especially at 1161 and 1085 cm^{-1} which represent CH_3 bending. CO_2 peaks would likely influence in the region between 800 and 600 cm^{-1} and therefore it is assumed that this is not related to the exposure.

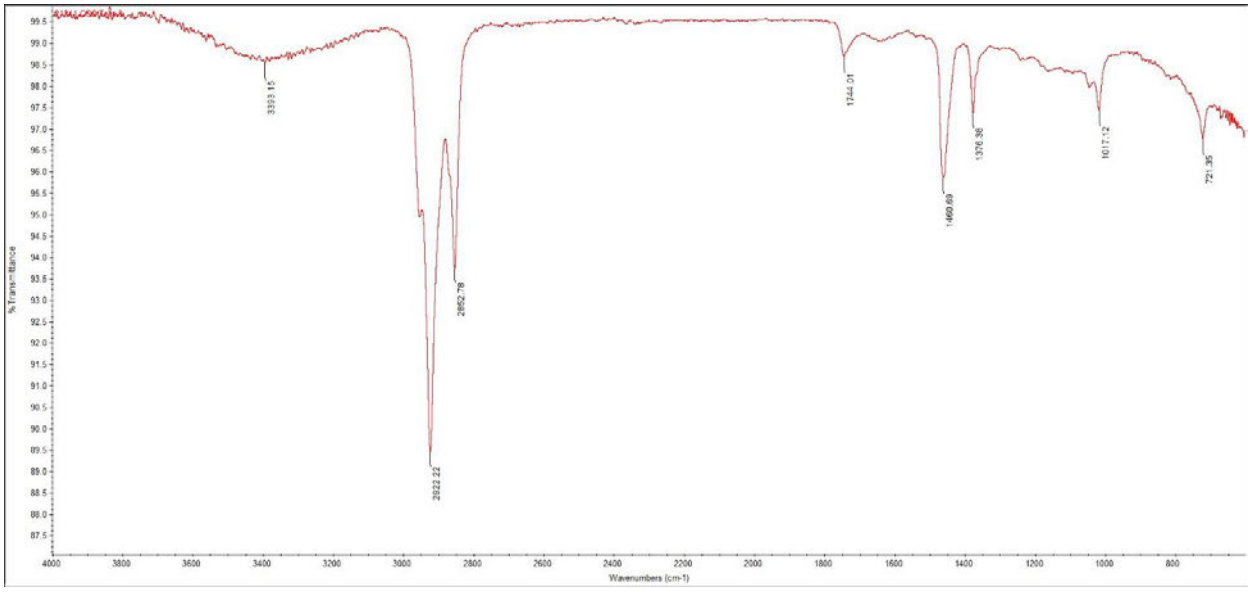


Figure 137 FTIR spectra for sample [redacted] after CO_2 exposure test 2.

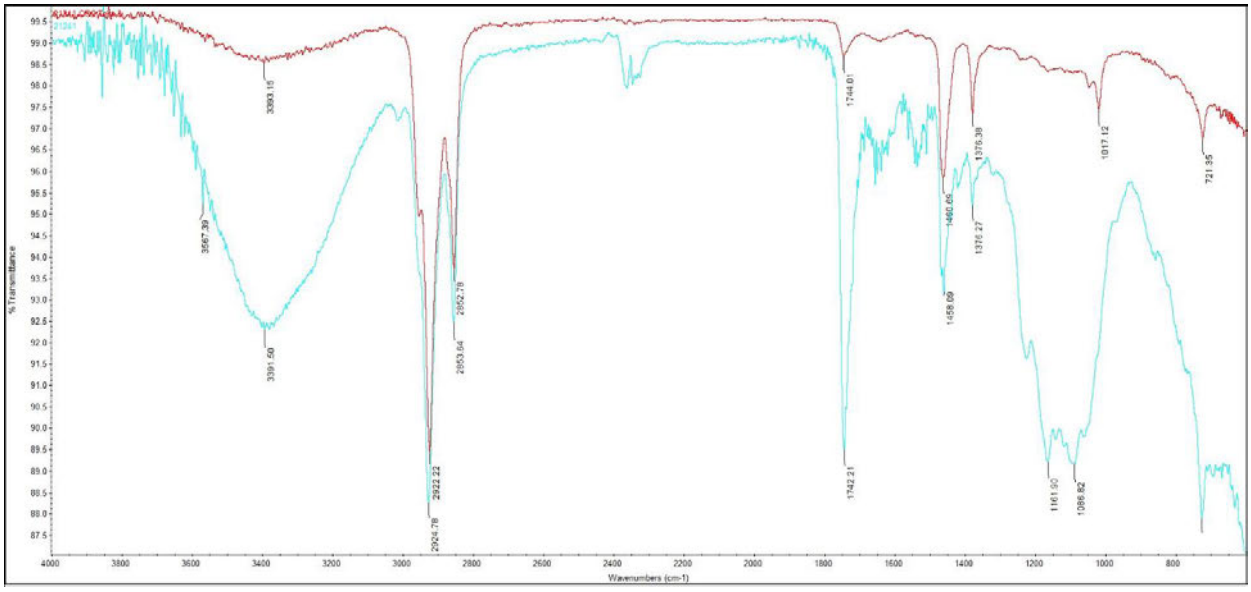


Figure 138 FTIR spectra comparing sample [redacted] before (purple) and after (red) CO_2 exposure testing.

Conclusion

No notable differences or deleterious compounds were observed after the exposure testing.

About DNV

DNV is the independent expert in risk management and assurance, operating in more than 100 countries. Through its broad experience and deep expertise DNV advances safety and sustainable performance, sets industry benchmarks, and inspires and invents solutions.

Whether assessing a new ship design, optimizing the performance of a wind farm, analyzing sensor data from a gas pipeline or certifying a food company's supply chain, DNV enables its customers and their stakeholders to make critical decisions with confidence.

Driven by its purpose, to safeguard life, property, and the environment, DNV helps tackle the challenges and global transformations facing its customers and the world today and is a trusted voice for many of the world's most successful and forward-thinking companies.