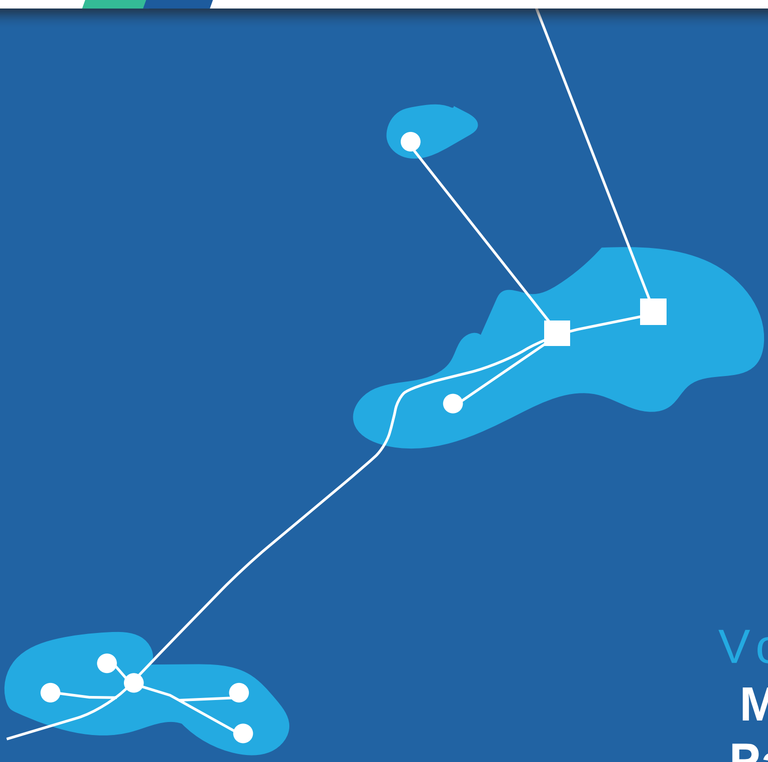
Kinsale Area Decommissioning Project

Environmental Impact Assessment Report



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Main Text
Part 1 of 3

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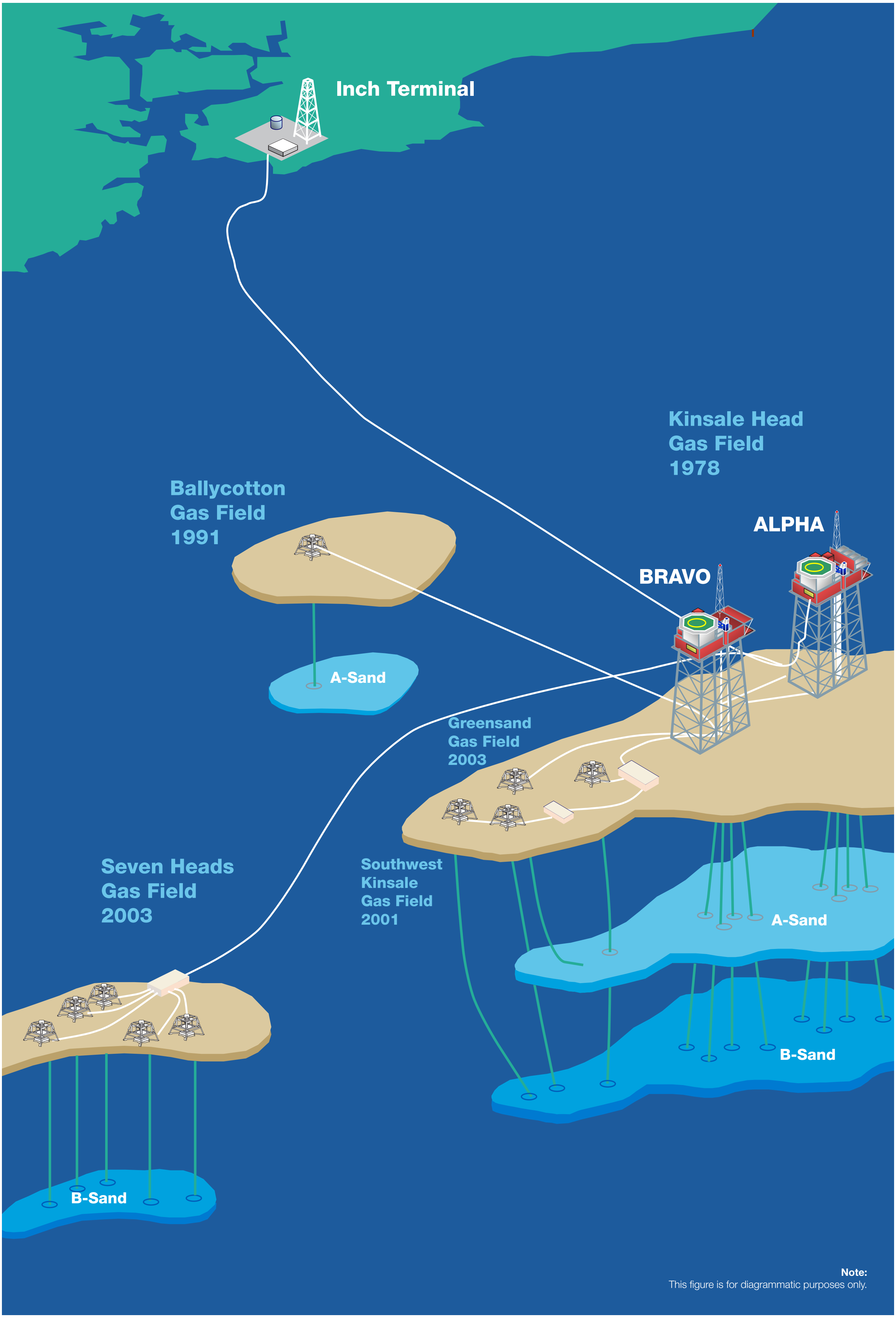
Glossary of Terms

Hartley Anderson

ARUP



Inch Terminal
Kinsale Head
Gas Field
1978
Ballycotton
Gas Field
1991
ALPHA
BRAVO
A-Sand
Greensand
Gas Field
2003
Seven Heads
Gas Field
2003
Southwest
Kinsale
Gas Field
2001
A-Sand
B-Sand
B-Sand
Note:
This figure is for diagrammatic purposes only.

Glossary of Terms

Term	Explanation
AA	Appropriate Assessment
AIS	Automatic Identification System
ALARP	As Low As Reasonably Practicable
Bathymetry	Measurement of depth of water in oceans, seas, or lakes
Benthic Zone	Ecological region at the lowest level of a body of water such as an ocean or a lake, including the sediment surface and some sub-surface layers
Biotope	Region of a habitat associated with a particular ecological community
Buoyancy tank	An enclosed air-filled section of a boat, ship or hovercraft designed to keep it afloat and prevent it from sinking
Bunker	Fill the fuel containers of a ship (refuel)
Bunkering	Supply of fuel for use by ships in a seaport
CA	Comparative Assessment
Cantilever	Structural element anchored at only one end to a support from which it is protruding
Caprock	Harder or more resistant rock type overlying a weaker or less resistant rock type
CCS	Carbon Capture and Storage
CRU	Commission for Regulation of Utilities Water and Energy
Cephalopods	Any member of the molluscan class Cephalopoda such as a squid, octopus or nautilus
CFP	Common Fisheries Policy
CH_4	Methane
CITES	Convention on International Trade in Endangered Species of Wild Fauna and Flora
CLC	CORINE Land Cover
CO	Carbon Monoxide
CO_2	Carbon Dioxide
Concrete mattress	A series of concrete blocks usually connected by polypropylene ropes resembling a rectangular mattress, used for the weighting and/or protection of seabed structures including pipelines
CoP	Cessation of Production: the stage at which, after all economic development opportunities have been pursued, hydrocarbon production ceases.
CORINE	Co-Ordinated Information on the Environment
CSO	Central Statistics Office
CSV	Construction Support Vessel
DCCAE	Department of Communications, Climate Action and Environment
DCENR	Department of Communications, Energy and Natural Resources
DECC	Department of Energy & Climate Change (UK)

Term	Explanation
Decommissioning	Planned shut-down or removal of a building, equipment, plant, offshore installation etc.., from operation or usage offshore.
Demersal	Living close to the floor of the sea or a lake
Diesel	A low viscosity distillate fuel
DP	Dynamic Positioning: the use of thrusters and real time positional information to maintain the location of a vessel
Drill cuttings	Rock from the wellbore resulting from the mechanical action of the drill bit
DTTAS	Department of Transport, Tourism and Sport
DSV	Diving Support Vessel
ED	Electoral Division
EEMS	Environmental and Emissions Monitoring System
EIA	Environmental Impact Assessment
EIAR	Environmental Impact Assessment Report
EPA	Environmental Protection Agency
Epifauna	Animals living on the surface of the seabed or a riverbed, or attached to submerged objects or aquatic animals or plants.
EU28	Denotes the 28 member countries which make up the European Union
EUNIS	European Nature Information System
FBE	Fusion Bonded Epoxy
Flowline	Pipeline carrying unprocessed oil/gas within the oil or gas field area
Freespan	A free span on a pipeline is where the seabed sediments have been eroded, or scoured away leaving a void under the pipeline so that the pipeline is no longer supported on the seabed
GHG	Greenhouse gas
GNI	Gas Network Ireland
Grout	Particularly fluid form of concrete used to fill gaps, generally a mixture of water, cement, and sand
GWP	Global warming potential
HES	Health, Environment and Safety
HGV	Heavy Goods Vehicle
HFCs	Hydrofluorocarbons
HLV	Heavy-Lift Vessel
ICES	International Council for the Exploration of the Sea
IEMA	Institue of Environmental Management and Assessment
IMO	International Maritime Organisation
INFOMAR	Integrated Mapping for the Sustainable Development of Ireland's marine Resource, joint venture between the Geological Survey of Ireland and the Marine Institute.
In-Situ	In the original place.
Interconnector	Structure which enables energy to flow between networks, refers to international connections between electricity and natural gas networks

Term	Explanation
IOSEA	Irish Offshore Strategic Environmental Assessment
IPCC	Intergovernmental Panel on Climate Change
IRPA	Individual Risk Per Annum
Jacket	The structure comprising the "legs" of the offshore platform connected together by horizontal and diagonal trusses and usually made of welded tubular steel. The jacket is typically secured to the seabed by piles
Jack-up rig	A mobile floating drilling rig typically with three long triangular truss legs which can be lowered to the seabed to provide stability once on location
KA	Kinsale Alpha platform
KADP	Kinsale Area Decommissioning Project
KB	Kinsale Bravo platform
KPIs	Key Performance Indicators
km	Kilometre: 1,000m, equivalent to 0.54 nautical miles
L_{Aeq}	Sound levels that vary over time which results in a single decibel value which takes into account the total sound energy over the period of time of interest
LAT	Lowest Astronomical Tide
LCA	Life cycle assessment
Likelihood – Remote	Unlikely to occur
Likelihood – Unlikely	Once during decommissioning activity
Likelihood – Possible	Foreseeable possibly once a year
Likelihood – Likely	Once a month or regular short term events
Likelihood - Definite	Continuous or regular planned activity
LPP	Layer polypropylene
LULUCF	Land Use, Land Use Change and Forestry
LWIV	Light Well Intervention Vessel
Major Effect	• Change in ecosystem leading to medium term (2+ year) damage with recovery likely within 2 - 10 years to an offshore area 100 hectares or more or 2 hectares of a benthic fish spawning ground or coastal habitat, or to internationally or nationally protected populations, habitats or sites • Transboundary effects expected • Moderate contribution to cumulative effects • Issue of public concern • Possible effect on human health • Possible medium term loss to private users or public finance
Manifold	A pipe or chamber branching into several openings.
MARPOL	The International Convention for the Prevention of Pollution from Ships
Megaripple	An extensive undulation of the surface of a sandy beach or sea bed

Term	Explanation
Moderate Effect	• Change in ecosystem leading to short term damage with likelihood for recovery within 2 years to an offshore area less than 100 hectares or less than 2 hectares of a benthic fish spawning ground • Possible but unlikely effect on human health • Possible transboundary effects • Possible contribution to cumulative effects • Issue of limited public concern • May cause nuisance • Possible short term minor loss to private users or public finance
MODU	Mobile Offshore Drilling Unit
MPA	Marine Protected Area
MRCC	Marine Rescue Co-ordination Centres
Natura 2000 sites	Natura 2000 is a network of nature protection areas in the territory of the European Union. It is made up of Special Areas of Conservation (SACs) and Special Protection Areas (SPAs) designated respectively under the Habitats Directive and Birds Directive.
Negligible Effect	Change is within scope of existing variability but potentially detectable.
Nephrops	Genus of lobsters comprising a single extant species
NIAH	National Inventory of Architectural Heritage
NIS	Natura Impact Statement
nm	Nautical Mile (1852m = 1 minute of latitude = 1/60 degree of latitude)
NMVOCs	Non-methane volatile organic compounds
None Foreseen (Effect)	No detectable effects.
NOx	Nitrogen Oxides
NPWS	National Parks and Wildlife Service
NTM	Notice to Mariners
NUI	Normally Unmanned Installation: an installation with minimal facilities which is not permanently crewed and is controlled from a remote location (e.g. other platform or shore)
OBMs	Oil Based Mud
OCNS	Offshore Chemical Notification Scheme
OECD	Organisation for Economic Co-Operation and Development
OGUK	Oil & Gas UK
OSPAR	Oslo and Paris Convention
OWF	Offshore Wind Farm
P&A	Plug and Abandon (wells)
PAD	Petroleum Affairs Division of the Department of Communications, Climate Action and Environment
Pelagic (fish)	Fish which live in the pelagic zone. The pelagic zone is any water in sea or lake which is neither close to the bottom nor near the shore.
PETRONAS	Petroliam Nasional Berhad

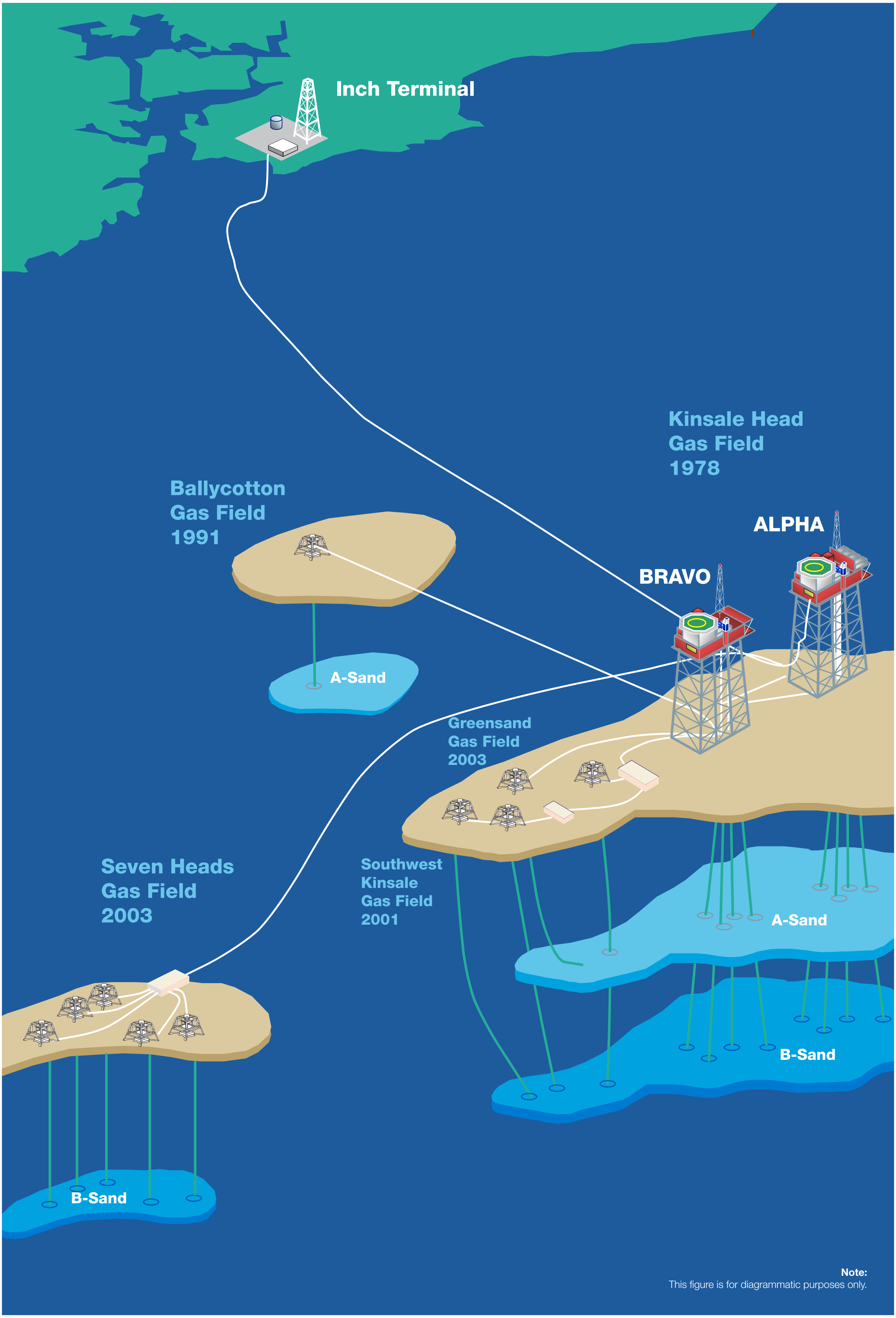
Term	Explanation
PFCs	Perfluorocarbons
Phytoplankton bloom	Plankton consisting of microscopic plants.
Piece Medium	Method of decommissioning the topside structures which involves the separating of the topsides into a number of medium size pieces for removal with a heavy lift vessel and transported to shore for further dismantling. Also known as 'reverse installation'.
Plankton	Small and microscopic organisms drifting or floating in the sea or fresh water
PLEM	Pipeline End Manifold
PLL	Potential Loss of Life
PLONOR	Pose Little or No Risk
PM_{10}	Particulate matter and smaller particulate matter of diameter less than or equal to 10 micrometers
Positive Effect	• Activity may contribute to recovery of habitats • Positive benefits to local, regional or national economy
PSV	Platform supply vessel
PUDAC	Permit to Use or Discharge Added Chemicals
Quaternary	The most recent major geological subdivision, encompassing the past ~2.6 million years up to and including the present day
RAMSAR	Intergovernmental treaty that provides the framework for the conservation and wise use of wetlands and their resources
RF	Recovery Factor
Rigless intervention	A well-intervention operation conducted with equipment and support facilities that precludes the requirement for a rig over the wellbore
RMP	Record of Monuments and Places
ROV	Remotely Operated Vehicle: a small, unmanned submersible used for inspection and the carrying out of some activities such as valve manipulation
SAC	Special Area of Conservation: established under the Habitats Directive
SCANS	Small Cetaceans in European Atlantic waters and the North Sea
SEA	Strategic Environmental Assessment
Seafastening	Action of fastening/securing cargoes on ship with the aim of preventing them from movement while the ship is in transit
Semi-submersible rig	A floating mobile drilling rig supported on a number of pontoons, and typically anchored to the seabed while on station
Severe Effect	• Change in ecosystem leading to long term (10+ year) damage with poor potential for recovery to an offshore area 100 hectares or more or 2 hectares of a benthic fish spawning ground or coastal habitat, or to internationally or nationally protected populations, habitats or sites • Major transboundary effects expected • Major contribution to cumulative effects • Issue of acute public concern • Likely effect on human health • Long term, substantial loss to private users or public finance
SF	Sulphur hexafluoride

Term	Explanation
SFPA	Sea Fisheries Protection Authority
Shears	Cutting instrument in which two blades move past each other
Shelter	Place giving temporary protection from bad weather or danger
Shingle	a mass of small rounded pebbles
Shut-in	to close off a well so that it stops producing
Sidescan sonar	category of sonar system that is used to efficiently create an image of large areas of the sea floor
SO_2	Sulphur Dioxide
SOPEP	Shipboard Oil Pollution Emergency Plan
SOSI	Seabird Oil Sensitivity Index
SPA	Special Protection Area: established under the Birds Directive
Steel jackets	Structural sections made of tubular steel members, and are usually attached to the seabed using piles
Subcrop	Part of a geological formation that is close to the surface but is not a visible exposing of bedrock
Subsea manifold	Large metal piece of equipment made up of pipes and valves, designed to transfer oil or gas
SWK	South West Kinsale
TEG	Triethylene Glycol
Tidal Channel	Protion of a stream that is affected by ebb and flow of ocean tides, in the case that the subject stream discharges to an ocean, sea or strait
Tie-backs	Link between a satellite field and an existing production facility
TII	Transport Infrastructure Ireland
Topsides	The collective name for the many drilling, processing, accommodation and other modules which when connected together make up the upper section of the platform which rests on the installation jacket
TVD	Total Vertical Depth
UHO	Underwater Heritage Order
UKCS	United Kingdom Continental Shelf
UKHO	United Kingdom Hydrographic Office
UKOOA	UK Offshore Operators Association
UNCLOS	UN Convention on the Law of the Sea
Umbilical	Cable and/or hose which supplies required consumables to an apparatus
VMS	Vessel Monitoring System
WDC	Western Drill Centre
WEEE	Waste Electrical and Electrical Equipment
Wet Gas	Any gas with a small amount of liquid present
WFD	Water Framework Directive

Kinsale Area Decommissioning Project

Section 1

Introduction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1 Introduction

1.1 Introduction

PSE Kinsale Energy Limited (Kinsale Energy) is preparing for the decommissioning of the Kinsale Area gas fields and facilities, which are coming to the end of their productive life, having been in production since 1978. The Kinsale Area gas fields and facilities are located in the Celtic Sea, between approximately 40 and 70km off the County Cork coast as well as onshore at Inch, Co. Cork (**Figure 1.1**).

1.2 Project Background

Pursuant to section 13 of the Petroleum and Other Minerals Development Act 1960 as amended (1960 Act), two petroleum leases have been granted in respect of the Kinsale Area gas fields and facilities: one for the Kinsale Head Gas Fields dated 7 May 1970 and one for the Seven Heads Gas Field dated 13 November 2002. Pursuant to the terms of these Petroleum Leases, a plan of development was submitted and agreed with the then Minister for Industry and Commerce in respect of Kinsale Head and the then Minister for Communications, Marine and Natural Resources in respect of Seven Heads.

The Kinsale Area gas fields and facilities are coming to the end of their productive life and PSE Kinsale Energy is now preparing Decommissioning Plans setting out the proposals for the decommissioning of the Kinsale Area facilities. Pursuant to Section 13 of the 1960 Act Kinsale Energy intends to submit these Decommissioning Plans as an addendum to the existing plans of development, which were submitted to and agreed with the then Minister under the terms of the Petroleum Leases under section 13 of the 1960 Act. In accordance with section 13A of the 1960 Act, this Environmental Impact Assessment Report (EIAR) has been prepared to accompany the Decommissioning Plans.

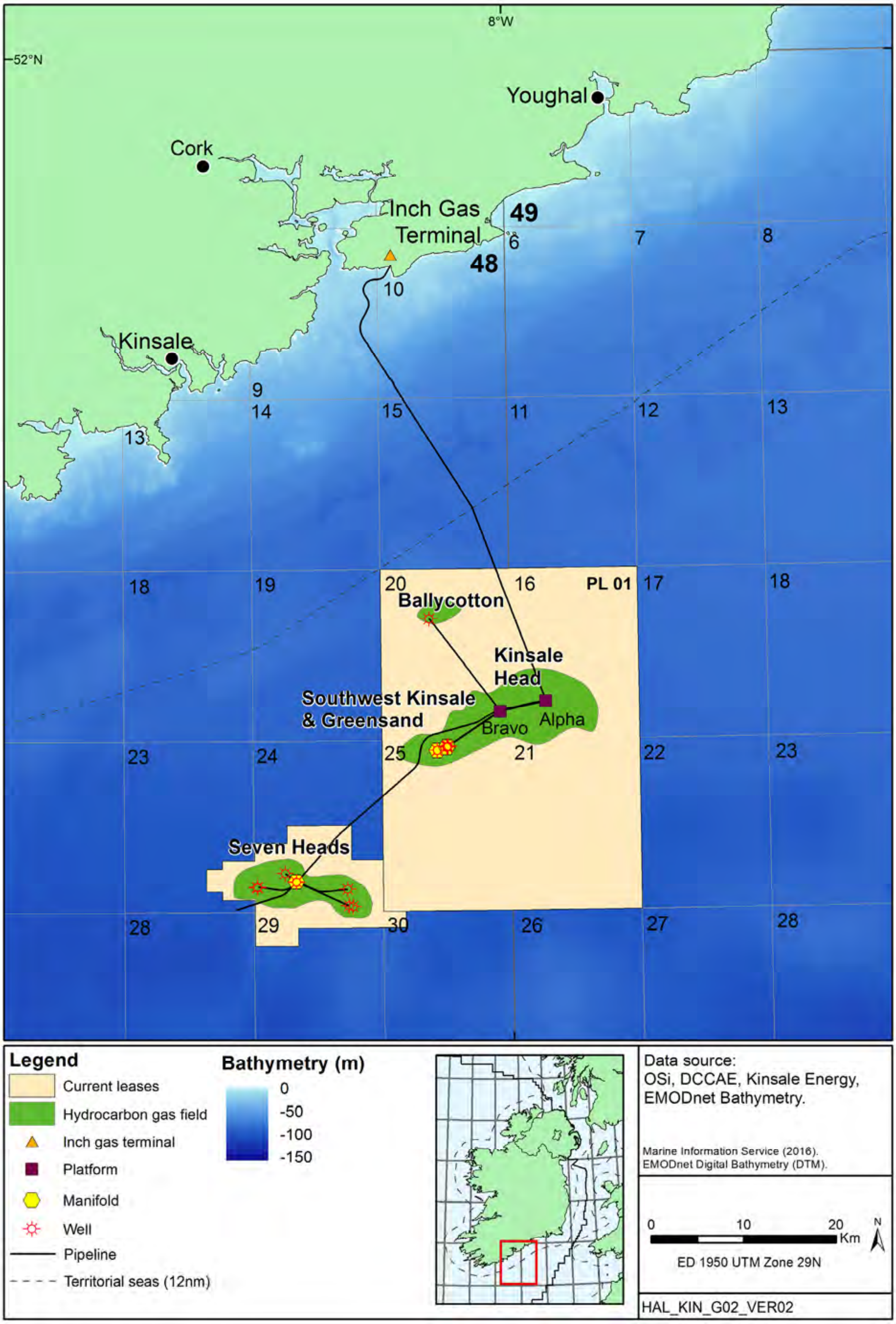
This EIAR provides an assessment of all likely significant environmental impacts of the decommissioning of the Kinsale Area gas fields to enable the Minister for Communications, Climate Action & Environment to undertake an Environmental Impact Assessment to determine whether the proposed decommissioning of the offshore and onshore facilities associated with the Kinsale Area fields would or would not be likely to have significant effects on the environment.

The facilities subject to the Decommissioning Plans are:

- The Kinsale Alpha (KA) and Kinsale Bravo (KB) platforms, which includes both their topsides and jackets,
- All subsea and platform wells including the wellhead structures,
- All infield subsea infrastructure associated with the wider Kinsale Area fields (Kinsale Head, South West Kinsale, Greensand, Ballycotton and Seven Heads), including manifolds,
- All infield subsea pipelines, umbilicals and protection materials, and
- The main export pipeline between KA and the Inch Terminal on the Co. Cork coastline.

The Decommissioning Plans do not include the Kinsale Area onshore gas terminal at Inch, Co. Cork, the decommissioning of which is covered by planning permission granted by Cork County Council (planning reference no. 2929/76). This EIAR, however, assesses the environmental impact of the entirety of the proposed Kinsale Area facilities decommissioning project including the decommissioning of the Inch onshore gas terminal.

Figure 1.1: Location of the Kinsale Area and its related fields and infrastructure



1.3 EIAR

Directive 2011/92/EU[1] on the assessment of the effects of certain public and private projects on the environment sets out the requirements in relation to Environmental Impact Assessments (EIAs). Directive 2014/52/EU[2] amends Directive 2011/92/EU (together the "EIA Directive") and replaces the requirement to prepare an Environmental Impact Statement (EIS) with the requirement to produce an Environmental Impact Report (EIAR). Sections 13A and 13B of the 1960 Act transposed the provisions of Directive 2011/92/EU in relation to the development of petroleum, however, at the time of publication of this EIAR, Directive 2014/52/EU has not been transposed into Irish law, despite the passing of the transposition date.

This EIAR has been prepared in compliance with both Directive 2014/52/EU and Directive 2011/92/EU.

Article 5(2) of the EIA Directive outlines the information to be included in an EIAR:

1. Where an environmental impact assessment is required, the developer shall prepare and submit an environmental impact assessment report. The information to be provided by the developer shall include at least:

(a) a description of the project comprising information on the site, design, size and other relevant features of the project;

(b) a description of the likely significant effects of the project on the environment;

(c) a description of the features of the project and/or measures envisaged in order to avoid, prevent or reduce and, if possible, offset likely significant adverse effects on the environment;

(d) a description of the reasonable alternatives studied by the developer, which are relevant to the project and its specific characteristics, and an indication of the main reasons for the option chosen, taking into account the effects of the project on the environment;

(e) a non-technical summary of the information referred to in points (a) to (d); and

(f) any additional information specified in Annex IV relevant to the specific characteristics of a particular project or type of project and to the environmental features likely to be affected.

Following consultation with the Department of Communications, Climate Action and Environment, Kinsale Energy is submitting an EIAR to accompany the Decommissioning Plans pursuant to section 13A of the 1960 Act.

This EIAR assesses the impact of the entirety of the proposed Kinsale Area facilities decommissioning project and includes an assessment of all likely significant environmental impacts for decommissioning of the onshore gas terminal at Inch.

1.4 Consent Application Process

A two stage consent application process is proposed for both the Kinsale Head Gas Fields and Seven Heads Gas Field Decommissioning Plans. The reasoning for this approach is to reflect project scheduling requirements and to facilitate studies on the potential for any re-use options for the Kinsale Area facilities (see **Section 3.3**). It is anticipated that both staged consent applications, for the Kinsale Head Gas Fields and Seven Heads Gas Field, will be submitted before cessation of production. The scope of work involved in decommissioning the Kinsale Area facilities, covered by each consent application, is outlined as follows:

- **Works covered in consent application 1:**
    - **Facilities preparation**: disconnect and degas process plant and pipelines (Pipelines displaced with seawater, and inhibited seawater in the case of the 24" export pipeline and the 18" Seven Heads pipeline).

[1] Directive 2011/92/EU of the European Parliament and of the Council of 13 December 2011 on the assessment of the effects of certain public and private projects on the environment (codification).
[2] Directive 2014/52/EU of the European Parliament and of the Council of 16 April 2014 amending Directive 2011/92/EU on the assessment of the effects of certain public and private projects on the environment.

  - **Wells**: plug and abandon all platform and subsea wells and removal of any surface component of these wells, including wellhead structures and platform conductors.
  - **Platform topsides**: complete removal in accordance with OSPAR Decision 98/3.
  - **Subsea structures**: (e.g. manifolds, wellhead protection structures): full removal in accordance with OSPAR Decision 98/3, including the removal of connecting spool pieces, umbilical jumpers and protection materials.
- **Works covered in consent application 2:**
  - **Platform jackets:** complete removal in accordance with OSPAR Decision 98/3.
  - **Offshore pipelines and umbilicals**: rock cover of freespans and/or remaining exposed sections and remaining *in situ* protection materials.
  - **Export pipeline (offshore and onshore section)**: fill onshore section with grout (if a viable re-use option is not identified) and rock cover of freespans and/or remaining exposed sections in offshore section.

Decommissioning the Inch Terminal will involve full removal and reinstatement to agricultural use, as per the terms of the site planning permission (Cork County Council planning reference 2929/76). As noted above, this scope of work will not be included in the Decommissioning Plan consent applications, but this EIAR assesses the impact of the entirety of the proposed Kinsale Area facilities decommissioning project and includes an assessment of all likely significant environmental impacts for decommissioning of the onshore gas terminal at Inch.

The project to decommission all of the above facilities is hereinafter referenced as the Kinsale Area Decommissioning Project (KADP). This EIAR has been prepared to provide information on the potential environmental impacts of the proposed project and to propose mitigation measures to reduce the residual impacts of the project.

1.5 Environmental Assessment Process

The environmental assessment process has been initiated at an early stage in project planning. Information was collected on the natural environment and other users of the sea relevant to the Kinsale Area, using both desk-based and field-based techniques, including a four week offshore pre-decommissioning environmental survey carried out in May 2017. A range of decommissioning options (alternatives) were identified through a series of engineering and environmental studies. These have formed the environmental assessment process.

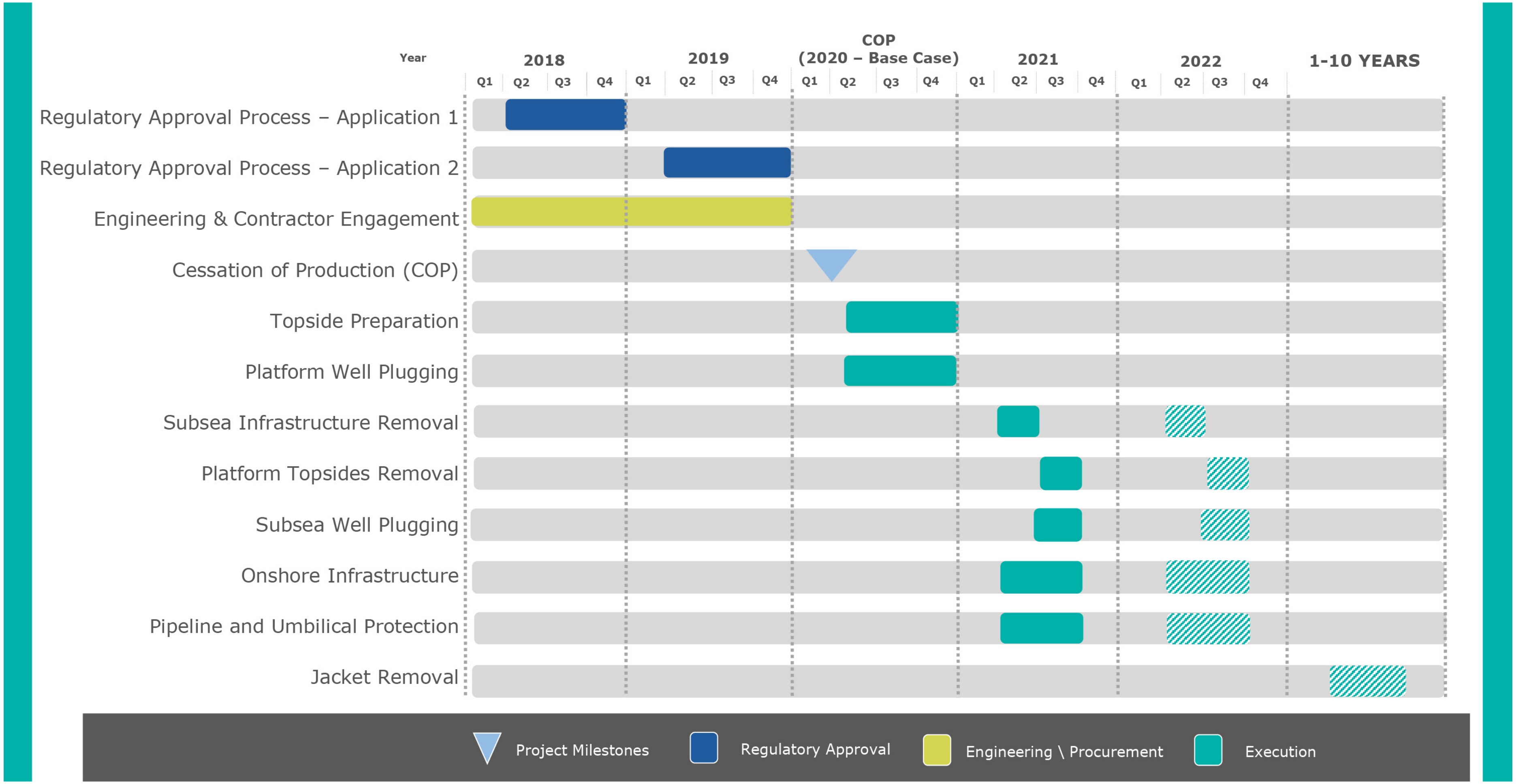
This Environmental Impact Assessment Report (EIAR) has been prepared in compliance with the requirements of the EIA Directive and implementing legislation.

This EIAR has also been prepared in accordance with the guidelines published by the Environmental Protection Agency (EPA) entitled *Guidelines on the information to be contained in Environmental Impact Assessment Reports DRAFT* published August 2017.

1.6 Overall Project Schedule

The final detailed decommissioning project schedule will be developed once all decommissioning contractors and services have been appointed. However, a conservative overall project schedule is detailed in **Figure 1.2** below which has been used for the basis of the environmental assessment.

Figure 1.2: Indicative Project Schedule



Note: The actual timing of Cessation of Production will depend on field economics (gas prices) and facilities performance, currently anticipated between 2020 and 2021. The timing of activities may also vary depending on company strategy and availability of specialised marine vessels.

1.7 Structure of the EIAR

The EIAR comprises nine sections, a non-technical summary and appendices, as summarised in **Table 1.1** below. Figures and tables are interspersed throughout the document.

The EIAR is in accordance with the requirements of Article 3 of the EIA Directive as follows:

'1 'The environmental impact assessment shall identify, describe and assess in an appropriate manner, in the light of each individual case, the direct and indirect significant effects of a project on the following factors:

- *a. Population and human health;*
- *b. Biodiversity, with particular attention to species and habitats protected under Directive 92/43/EEC and Directive 2009/147/EC,*
- *c. Land, soil, water, air and climate;*
- *d. Material assets, cultural heritage and the landscape;*
- *e. The interaction between the factors referred to in points (a) to (d).*

2 The effects referred to in paragraph 1 on the factors set out therein shall include the expected effects deriving from the vulnerability of the project to risks of major accidents and/or disasters that are relevant to the project concerned.'

Effects likely to arise from the activities associated with the KADP (relevant to those factors within the meaning of Article 3(1), above) have been identified on the basis of the nature of the project as described in **Section 3**, considered against the description of the environment as described in **Sections 4** and **5** and the understanding of impact pathways. The process of identifying those environmental factors likely to be significantly affected by the KADP and associated results are documented in **Section 6**. The major sources of potentially significant effect have been grouped against those decommissioning activities identified to likely directly or indirectly affect one or more relevant environmental factors (and interactions between these), and are described and assessed in detail in **Section 7**. **Appendix D** includes a summary description and assessment of those activities/sources of potential effect which are identified in **Section 6** to have potential minor and negligible effects positive or negative effects. Environmental management actions (including proposed mitigation measures) and residual effects for the decommissioning activities are identified throughout the **Section 7** assessment and are summarised in **Section 8**.

Table 1.1: Report section content summaries

Section	Content Summary
Non-Technical Summary	Intended as a comprehensive stand-alone summary of the EIAR, its findings and conclusions.
Glossary of Terms	Abbreviations and technical terms
Section 1: Introduction	Provides a background to the KADP, the scope and structure of the Environmental Impact Assessment Report, progress to date on the environmental assessment process.
Section 2: Legal & Policy Framework	Provides an overview of the legislative and policy context of relevance to the decommissioning of the offshore and onshore Kinsale facilities.
Section 3: Project Description	Describes the facilities of the Kinsale Area of relevance to the KADP and the proposed approach to decommissioning these, including a consideration of alternatives considered.
Section 4: Characteristics of the Marine Environment	Provides an overview of the ecological, physical and socio-economic character of the offshore area of relevance to the KADP.
Section 5: Characteristics of the Terrestrial Environment	Provides an overview of the ecological, physical and socio-economic character of the terrestrial area of relevance to the KADP.

Section	Content Summary
Section 6: Environmental Assessment Methodology and Identification of Potentially Significant Effects	Identifies effects likely to arise from the activities associated with the KADP, as described in Section 3, on the environment, as described in Section 4 and 5. Those activities identified as being sources of potentially significant effects are tabulated and summarised before being described and assessed further in Section 7.
Section 7: Consideration of Potential Significant Effects	Provides a description and assessment, including of cumulative effects, of those activities identified as being sources of potentially significant effects in Section 6.
Section 8: Management of Residual Effects and Conclusion	Summary of legal standards and controls, environmental management commitments which form standard practice, and any proposed mitigation and residual risks as identified in the EIAR.
Section 9: References	A list of all references cited in the text.
Appendix A: International and European Legislation	International and European legislation and conventions forming the legal framework within which the decommissioning of offshore facilities must be undertaken in Ireland.
Appendix B1: Seabed Features & Habitats	An overview of the seabed topography, sediments and fauna from mapping, sampling and photography.
Appendix B2: Archaeological Assessments	List of archaeological assessment records and external pipeline survey records of the Kinsale Area
Appendix C: Characteristics of the Terrestrial Environment – Biodiversity	Further details of the terrestrial biodiversity background to the Kinsale Area
Appendix C2: Characteristics of the Terrestrial Environment - Archaeology	Further details of the terrestrial archaeological and historical background to the Kinsale Area
Appendix D: Positive, minor or negligible issues	Assessment of potential positive, minor or negligible impacts
Appendix E: Comparative Assessment	Report detailing the pipeline, umbilical and protective materials comparative assessment of alternatives
Appendix F: List of Consultees	List of statutory, non-statutory bodies and other interested parties consulted during the preparation of this EIAR.
Appendix G: Consultation material	Copies of the public consultation newspaper advert and an information leaflet prepared for the KADP.

1.8 Consultation

During the preparation of this EIAR, discussions were had and/or correspondence made with statutory and non-statutory bodies and other interested parties in order to ensure that issues relating to the proposed KADP were addressed. The parties consulted include the following:

- Petroleum Affairs Division (PAD) - Department of Communications, Climate Action and Environment
- Commission for Regulation of Utilities (CRU),
- Marine Planning and Foreshore Unit – Department of Housing, Planning and Local Government
- Cork County Council
- National TFS (TransFrontier Shipments) Office, Dublin City Council
- National Parks and Wildlife Service (NPWS)
- National Monuments (NM)
- Ervia
- Gas Networks Ireland (GNI)
- ESB
- Cork Port Operations
- Naval Operations (Cork)
- South West Regional Fisheries Forum
- South East Regional Fisheries Forum
- Birdwatch Ireland
- Irish Whale and Dolphin Group (IWDG)
- Cork City Council
- TDs and local councillors

For a full list of consultees, please refer to **Appendix F.**

A consultation response was received from the Irish Whale and Dolphin Group (IWDG) noting the need to ensure that the decommissioning works will not disturb or degrade the marine habitat for cetaceans.

The proposed decommissioning scope of work and the environmental assessment has had due regard to the concerns regarding the protection of cetaceans and ensures that potential adverse effects are minimised.

A written response was also received from Dublin Airport Authority (DAA) stating that DAA has no observations to make on the KADP.

A meeting was held between Kinsale Energy, Arup/Hartley Anderson and NPWS during the consultation process. At this meeting Kinsale Energy outlined the proposed decommissioning project as well as detailing the methodology being used to assess ecological impacts and impacts on Natura 2000 sites. NPWS requested that the following was also considered:

- To consult with the IWDG for data on cetaceans.
- To consider the Marine Institute's Fisheries Ecosystems Advisory Services (FEAS) survey data, in particular marine mammal and seabird observations made during the Celtic Sea herring and ground fish surveys.

Subsequent to the meeting, useful information was obtained from both the IWDG and FEAS publications which has been reflected in the KADP EIAR.

A response was also received from the National Monuments Service of the Department of Culture, Heritage and the Gaeltacht regarding the underwater archaeology assessment. The environmental assessment has had due regard to underwater archaeology.

In addition to the above, two public consultation sessions were undertaken with invitations made to all key stakeholders and interested members of the local community. The first information session took place at the Clayton Hotel, Cork City On 18th April 2018. An advertisement was placed in the local newspapers and letters sent to key stakeholders. The second public information session was hosted in the Aghada Community Centre, East Cork on 19th April 2018. This was arranged to facilitate residents living in the area of the onshore Inch terminal. Letters of invitation were individually delivered to residents in the Inch area in advance of the information session.

Both public information sessions were well received, with a total attendance of 45 people across both sessions. Feedback received from stakeholders has been positive and will be monitored and managed for the duration of the project.

Copies of the newspaper advert and an information leaflet giving an overview of the project are provided in **Appendix G.**

1.9 List of Contributors

The environmental appraisal was undertaken, and EIAR prepared, by a team of competent experts on behalf of Kinsale Energy.

The compilation and editing of the document was supervised by Sheila O'Sullivan. Sheila holds a BEng in Civil and Environmental Engineering and is a chartered member of Engineers Ireland. She has worked full time as a consultant engineer for over 11 years, in the Designer and Project Manager role for numerous major infrastructure projects.

The following experts have undertaken the environmental appraisal and prepared the EIAR:

Name	Qualification	Relevant Experience	Contribution to EIAR
Hartley Anderson Limited – Offshore/marine environmental consultants			
Dr JP Hartley	BSc (Hons) Zoology with Marine Zoology, PhD	Dr JP Hartley is a marine environmental consultant scientist with over 35 years of environmental assessment (EIA, SEA, HRA), applied marine research and environmental management experience in Ireland, the UK and internationally.	Section 4, 6, 7, 8, Appendix B, Appendix D - Characteristics of marine

Name	Qualification	Relevant Experience	Contribution to EIAR
		He is technical Director of the independent environmental consultancy Hartley Anderson Ltd, which he co-founded. He is joint project director for the UK Offshore Energy Strategic Environmental Assessment programme from 1999 to date. He is a regular contributor to university Masters programmes. He has served on a range of marine scientific research and management steering groups for Renewables, Aggregate, Climate Change and Environmental Monitoring.	environment and appraisal; Review of entire EIAR.
Dr DM Borthwick	MA (Hons) Geography, PhD	Dr DM Borthwick has over ten years of experience in environmental assessment for offshore energy involving work at the strategic (SEA) and project (EIA) levels, including screening and Appropriate Assessment under the Habitats Directive. He has led or participated in Environmental Impact Assessments for offshore projects (oil and gas and carbon dioxide transport and storage) in the North Sea. He has technical expertise in geology, substrates and coastal processes, seascape, marine archaeology and climate, Geographic Information Systems (GIS) marine spatial data and analysis.	Section 3, 4, 6, 7, 8, Appendix D – project description, Characteristics of marine environment and appraisal
Dr RJ Trueman	BSc (Hons) Environmental Biology, PhD	Dr RJ Trueman has over 15 years of relevant experience, worked on EIAs for offshore projects in the North and Irish Seas, for oil and gas production and carbon dioxide transport and storage. He has also been involved in Strategic Environmental Assessment (SEA) for energy related plans and programmes in the marine and terrestrial environment, and related Appropriate Assessments.	Section 4, 7, Appendix D - Characteristics of marine environment and appraisal
Dr F Marubini	BSc (Hons.) Biology, PhD	Dr F Marubinin has two decades of experience in marine ecology research and its application to sustainable environmental management. He held several advisory roles to the UK Government including on marine biodiversity, marine species, fisheries policy, marine mammals, marine turtles and coral reef ecology within UK waters and internationally. He is a technical expert in noise and marine mammals for strategic and project level environmental assessments of offshore energy projects.	Section 4, 7 - Characteristics of marine environment and appraisal
Mr DA Vale	BSc (Hons.) Biology, MSc Marine and Fisheries Science	Mr DA Vale has ten years of experience in SEA and EIA for offshore energy. He has been involved in project level EIA and related activity permitting for a range of marine energy projects and for a number of oil and gas operators in the North Sea. He is a technical expert in fish and fisheries for strategic and project level environmental assessments of offshore energy projects.	Section 4 - characteristic of marine environment
Mrs SK Hartley	BSc (Special Hons.) Applied Zoology, PGCE	Mrs SK Hartley is an environmental consultant with more than 25 years of environmental practice and project management in Ireland the UK and internationally. She is Managing Director of the independent environmental consultancy Hartley Anderson Ltd, which she co-founded. She is joint project director for the UK Offshore Energy Strategic Environmental Assessment programme from 1999 to date. Establishment of assessment criteria and documented procedures, stakeholder engagement, technical input on policy and legislation, technical challenge and quality review, interpretation and communication of technical issues to lay audiences.	NTS, Section 6, 7, 8 – Marine environment appraisal
Dr AM Brown	BSc Marine Geography, MRes Marine and	Dr AM Brown is a marine scientist with a broad knowledge-base and strong research background, including specialisations in environmental assessment, GIS, offshore energy, marine mammals and fisheries. He has worked on EIA, SEA, Habitat Regulation	Section 7, Appendix D – Marine

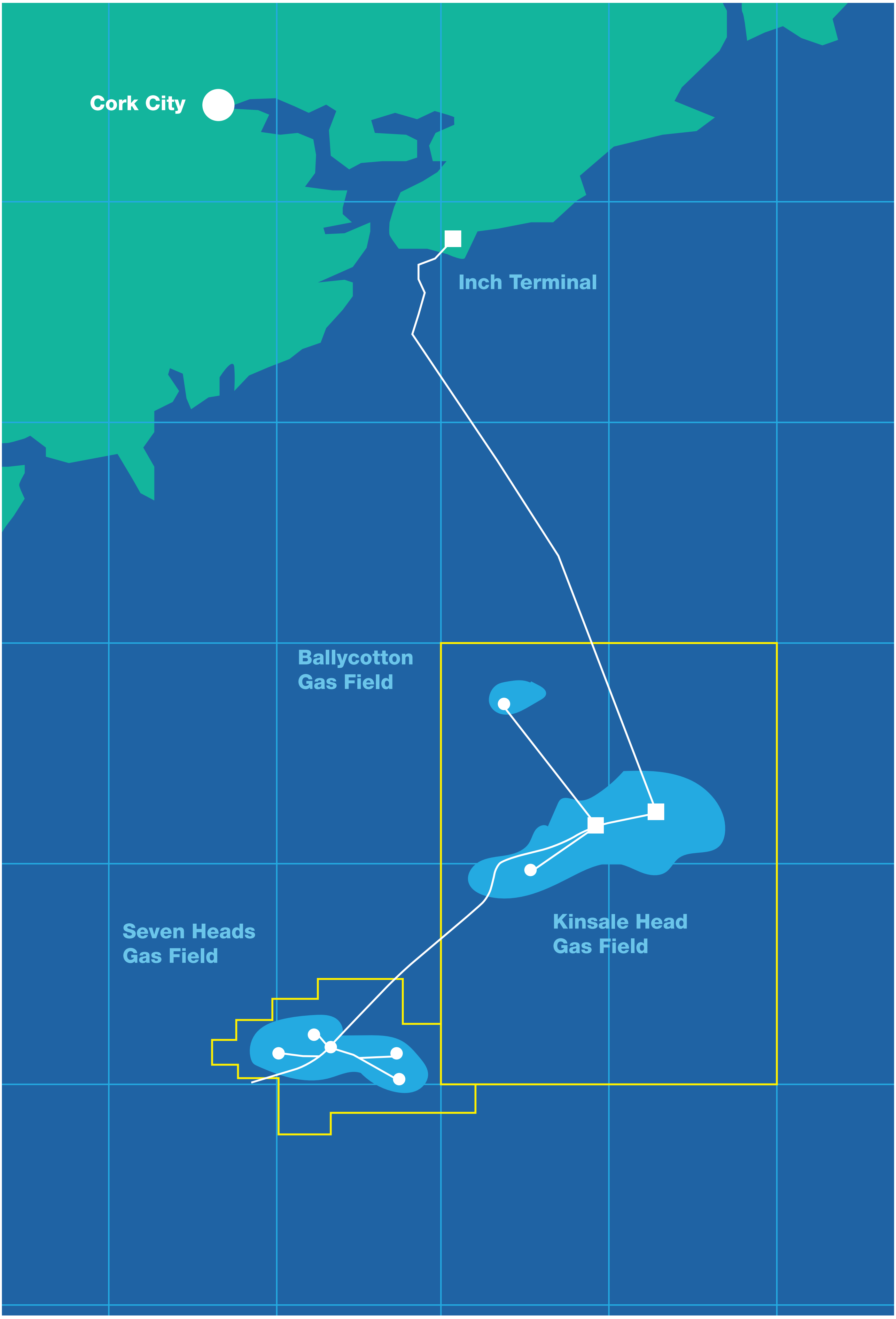
Name	Qualification	Relevant Experience	Contribution to EIAR
	Fisheries Science, PhD	Assessment and conducted noise assessments for several projects.	environment appraisal
Dr GM Bishop	BSc (Hons.) Biological Sciences, PhD	Dr GM Bishop has over 30 years marine research and environmental management experience and has been continuously involved in marine environmental management and environmental assessments (as team member, team coordinator or client), primarily for the offshore energy industry covering a wide range of activities from exploration drilling in environmentally sensitive waters, oil and gas field platform and subsea developments and subsea infrastructure decommissioning.	Section 4 - Characteristics of marine environment
Mr KM Carey	BSc Zoology, MSc Applied Geospatial Information Systems	KM Carey has five years Geographic Information System (GIS) applied experience in map production and data management for a range of marine environmental assessments, including national scale SEA and project specific EIA and permit applications.	Maps used in Sections 1, 3, 4 and Appendix B
Arup – Onshore/terrestrial environmental consultants			
Clodagh O'Donovan	BE, MEngSc, CEng, FIEI, FConsEI, MCIWEM, C.WEM	Clodagh O'Donovan is a chartered civil engineer, with over 20 years' experience in the consultancy business in Ireland. As Environmental Team Leader for Arup Ireland, Clodagh has direct responsibility for both the team and the projects that it undertakes. Over her career, Clodagh has led the preparation of EIA and AA documentation for a wide range of projects, including in particular, the energy sector, where she has specialist knowledge.	Review of EIAR
Ria Lyden	BE, MBA, CEng, FIEI, MIStructE	Ria Lyden has a Bachelor of Engineering degree in civil engineering and a Master of Business Administration degree. She is a fellow of the Institution of Engineers of Ireland and has over 20 years' experience as an environmental consultant. Ria has prepared or supervised the preparation of sixty environmental impact statements for a wide range of industrial, commercial, energy and infrastructure projects.	Section 2 - Legal and Policy Framework
Olivia Holmes	BSc, MSc, CEng MIEI, MCIWEM, C.WEM	Olivia Holmes has eighteen years' experience in Environmental Engineering focussing primarily on Appropriate Assessment (AA) and Environmental Impact Assessment (EIA) and planning and waste management. She has led the preparation of a number of large-scale multi-disciplinary EIA projects and planning and other consent applications.	Section 5, 6, 7, Appendix D - Characteristics of terrestrial environment and appraisal
Dixon Brosnan Environmental Consultants – Onshore ecological consultants			
Carl Dixon	BSc (Applied Ecology), MSc (Ecological Monitoring)	Carl Dixon has 18 years experience in environmental and ecological consultancy. During that time he has worked on a range of small and large scale infrastructural projects including roads, gas pipelines, quarries, energy projects, wind farms and quarries. He has particular expertise in preparing Appropriate Assessment (AA) Screening Reports, Natura Impact Statements (NIS) and Ecological Impact Assessments and coordinating detailed ecological assessments for complex projects.	Section 5 - Onshore biodiversity

PSE Kinsale Energy Limited, the project client also contributed to the EIAR.

Kinsale Area Decommissioning Project

Section 2

Legal and Policy Framework


Cork City
Inch Terminal
Ballycotton
Gas Field
Seven Heads
Gas Field
Kinsale Head
Gas Field

2 Legal and Policy Framework

2.1 Legislative Framework

2.1.1 Introduction

This section sets out the relevant National and European legislation in relation to the statutory consent application process, particularly in respect of the EIA process.

A key international convention, relevant to the KADP (the OSPAR Convention) is also outlined in Section 2.1.4, with other relevant European legislation and international conventions outlined in Appendix A.

2.1.2 Relevant National Legislation

Petroleum and Other Minerals Development Act, 1960, as amended

The Petroleum and Other Minerals Development Act, no 7 of 1960, as amended, ("1960 Act") regulates offshore petroleum (including gas) exploration and production activities in Ireland. The Minister for Communications, Climate Action and Environment is the competent authority under the 1960 Act.

A petroleum lease is the authorisation, issued under Section 13 of the1960 Act, to allow the exploitation of a commercial petroleum discovery. The Kinsale Area facilities operate under two petroleum leases.

- Petroleum Lease No 1 (OPL 1 - 1970): Kinsale Head, Southwest Kinsale and Ballycotton Gas Fields, and
- Seven Heads Petroleum Lease (2002): Seven Heads Gas Field.

The 1992 Licensing Terms address the surrender of a petroleum lease in Section 33[3]. The abandonment of wells is covered in Section 57[4]. The abandonment of fixed facilities is covered in Section 71[5].

Under Section 28 of the 1992 Licensing Terms, Kinsale Energy must apply for the Minister's approval under Section 13/13A of the 1960 Act, as amended, for the KADP.

The requirements of the 1992 Licensing Terms can be summarised as follows:

- The Minister must be given at least 12 months' notice of the intention to determine the petroleum leases,
- An abandonment plan must be submitted in writing to the Minister,
- The plan must contain information on the abandonment and removal of any facilities,
- The plan must contain technical, economic and financial information, as will enable the Minister to evaluate the proposals fully and to assess their economic, social, safety and environmental implications.

Section 13A of the 1960 Act, as amended, requires an applicant, submitting a plan to the Minister for approval, to submit an environmental impact statement (EIS) (or EIAR under the latest EU Directive) and requires the Minister to undertake an environmental impact assessment (EIA) in certain circumstances. Further detail in this regard is set out in Section 2.2 below.

Continental Shelf Act

The Continental Shelf Acts, 1968 to 1995 ("1968 Act, as amended") is the legislative regime applying to the Continental Shelf. The Continental Shelf is the area of sea and seabed between the 12 nautical mile limit and the 200 nautical mile limit.

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[3] DMNR (1992), page 28.
[4] DMNR (1992), page 41.
[5] DMNR (1992), page 38.

Section 5 of the 1968 Act, as amended, imposes the requirement to obtain consent from the Minister to "*construct, alter or improve any structure or works in or remove any object or material from a designated area.*"

The Continental Shelf Designated Areas Order 1993 SI 92 of 1993, Section 2, defines the "*designated area*" as the "*The area set out in paragraph 1 of the Schedule to this Order is hereby designated as an area within which the rights of the State outside the territorial seas over the sea bed and subsoil for the purpose of exploring such sea bed and subsoil and exploiting their natural resources are exercisable*." The Schedule provides a list of points specified by latitude and longitude to define the Continental Shelf.

The Minister can require the applicant for consent under the Continental Shelf Act, as amended, to provide plans and particulars and may require the applicant to publish a notice of the application[6]. The Minister can refuse consent or can attach conditions to the consent, either at the time of giving consent or any time thereafter[7]. The Minister can hold an inquiry into granting consent[8].

The Minister for Communications, Climate Action and Environment is the competent authority under the Continental Shelf Act, as amended.

Apart from the Inch Terminal and the parts of the export pipeline on land and on the Foreshore, the Kinsale Area facilities are located on the Continental Shelf. The KADP will involve altering or removing objects or material from the seabed of the Continental Shelf. Consequently, consent under the Continental Shelf Act will be required for the KADP.

Foreshore Acts

The Foreshore Acts 1933 to 2014 ("Foreshore Acts"), regulate development on the foreshore.

The Foreshore is defined as the land and seabed between the high water of ordinary or medium tides (shown as 'HWM' on Ordnance Survey Maps) and the outer limit of the foreshore. The outer limit of the foreshore is taken to be coterminous with the seaward limit of the territorial seas of the state. This is typically taken to mean the twelve-mile limit. Twelve nautical miles is approximately 22.24 kilometres. The Foreshore Acts require that a lease or licence must be obtained from the Department of Housing, Planning, Community and Local Government for undertaking any works or placing structures or material on, or for the occupation of, or removal of material from, State-owned foreshore. The Marine Planning and Foreshore Section of the Department of Housing, Planning, and Local Government is the competent authority under the Foreshore Acts.

Part of the Kinsale Area export pipeline is located on the Foreshore. A Foreshore Licence MS 51/8/584 was granted in 1978 for the part of the Kinsale Area export pipeline on the Foreshore, as the Foreshore was defined in 1978. In 1978 the Foreshore extended from the high water mark to a 3 mile limit, rather than the current 12 mile limit. The licence MS 51/8/584was amended in 1997 to take account of the 12 mile limit. The 1997 amendment provided for the licence to be surrendered by notification to the Minister and payment of a fee. A new Foreshore Licence would be required for any additional works, to be undertaken on the Foreshore as part of the KADP.

[6] 1968 Act, as amended, Section 5(3)
[7] 1968 Act, as amended, Section 5(4), 5(5) and 5(6)
[8] 1968 Act, as amended, Section 5(7) and 5(8)

2.1.3 Relevant European Legislation

Environmental Impact Assessment Directive 2011/92/EU amended by Directive 2014/52/EU

A directive requiring the assessment of the impacts of certain projects on the environment (EIA) has been in force since 1985, following the adoption of Council Directive 85/337/EEC on the assessment of the effects of certain public and private projects on the environment. The EIA Directive of 1985 was amended three times by Directive 97/11/EC, Directive 2003/35/EC and 2009/31/EC. It was ultimately codified and repealed by Directive 2011/92/EU, EU (2011). Directive 2011/97/EU was amended in 2014 by Directive 2014/52/EU, EU (2014a).

The Directive applies to a wide range of public and private projects, which are defined in Annex I and II. For the projects listed in Annex I of the Directive, EIA is mandatory. For projects listed in Annex II, Member States have the option of requiring EIA for projects, which meet defined thresholds or criteria, or for projects subject to a case by case examination. Member State competent authorities are required to consider the criteria laid down in Annex III as part of this process.

The Directive is implemented in Ireland through a number of measures, as discussed in more detail in **Section 2.2** below.

Habitats Directive (92/43/EEC) and Birds Directive (79/409/EEC and 2009/147/EC)

The Habitats Directive, EEC (1992), was adopted in 1992. The Habitats Directive provides for the conservation of biodiversity in Europe. The main aim of the Habitats Directive is to achieve and maintain favourable conservation status for habitats and species within the Natura 2000 network.

The Birds Directive, EEC (1979) and EC (2009), seeks to protect, manage and regulate all bird species naturally living in the wild, including their eggs, nests and habitats, and to regulate the exploitation of these species. Special measures are to be implemented for the protection of the habitats of certain bird species, identified in the Birds Directive, and for migratory species. The Birds Directive establishes a network of Special Protection Areas (SPAs) to protect migratory species and species, which are rare, vulnerable, in danger of extinction, or otherwise require special attention.

Special Areas of Conservation (SACs), Candidate Special Areas of Conservation (cSACs) and Special Protection Areas (SPAs) form a pan-European network of protected sites known as Natura 2000 sites. The Habitats Directive sets out a unified system for the protection and management of SACs and SPAs. Article 6(3) and 6(4) of the Directive set out key elements of the system of protection, including the requirement for Appropriate Assessment of plans and projects as follows:

- Article 6(3): *"Any plan or project not directly connected with or necessary to the management of the site but likely to have a significant effect thereon, either individually or in combination with other plans or projects, shall be subject to appropriate assessment of its implications for the site in view of the site's conservation objectives. In the light of the conclusions of the assessment of the implications for the site and subject to the provisions of paragraph 4, the competent national authorities shall agree to the plan or project only after having ascertained that it will not adversely affect the integrity of the site concerned and, if appropriate, after having obtained the opinion of the general public."*
- Article 6 (4): *"If, in spite of a negative assessment of the implications for the site and in the absence of alternative solutions, a plan or project must nevertheless be carried out for imperative reasons of overriding public interest, including those of a social or economic nature, the Member State shall take all compensatory measures necessary to ensure that the* overall coherence of Natura 2000 is protected. It shall inform the Commission of the *compensatory measures adopted".*

The Habitats Directive and the Birds Directive are enacted into Irish law by the *Wildlife Acts 1976 – 2010*, the *European Communities (Birds and Natural Habitats) Regulations, 2011 (S.I. No. 477 of 2011), (as amended),* and *the Planning and Development Acts 2000 to 2017*. These pieces of national legislation provide the legislative framework for the establishment of Natura 2000 sites in Ireland.

The KADP will be subject to the requirements of the Habitats and Birds Directives. Kinsale Energy has prepared a screening report for Appropriate Assessment in respect of the KADP (reference, 253993-00-REP-14). This screening report provides the information required to allow the competent authority to conclude, on the basis of the best scientific knowledge and in view of the conservation objectives of the relevant SACs, cSACs and SPAs, that the KADP, individually or in combination with other plans or projects, is not likely to have a significant effect on any SAC, cSAC or SPA.

Article 12 of the Habitats Directive is aimed at the establishment and implementation of a strict protection regime for species listed in Annex IV within the whole territory of the Member States (i.e. in locations outside protected areas as well as inside their boundaries).

Article 12 of the Directive states:

"1. Member States shall take the requisite measures to establish a system of strict protection for the animal species listed in Annex IV (a) in their natural range, prohibiting:

(a) all forms of deliberate capture or killing of specimens of these species in the wild;

(b) deliberate disturbance of these species, particularly during the period of breeding, rearing, hibernation and migration;

(c) deliberate destruction or taking of eggs from the wild;

(d) deterioration or destruction of breeding sites or resting places.

2. For these species, Member States shall prohibit the keeping, transport and sale or exchange, and offering for sale or exchange, of specimens taken from the wild, except for those taken legally before this Directive is implemented.

3. The prohibition referred to in paragraph 1 (a) and (b) and paragraph 2 shall apply to all stages of life of the animals to which this Article applies.

4. Member States shall establish a system to monitor the incidental capture and killing of the animal species listed in Annex IV (a). In the light of the information gathered, Member States shall take further research or conservation measures as required to ensure that incidental capture and killing does not have a significant negative impact on the species concerned."

Under Article 12 of the Habitats Directive, all species listed in Annex IV are afforded strict protection, prohibiting deliberate capture, disturbance and destruction of all life stages and deterioration or destruction of breeding sites or resting places. In addition, species listed in Annex II are afforded the same protection, even when not present in numbers which result in the designation of a Natura 2000 site.

The Report for the Purposes of Appropriate Assessment Screening and Article 12 Assessment Screening (reference, 253993-00-REP-14) also provides the information required to allow the competent authority to determine whether or not the proposed decommissioning works will result in the deliberate disturbance or destruction of any of the species listed in Annex IV (a) of the Habitats Directive that may be present in the study area. The assessment takes into account the status and sensitivities of relevant Annex IV species to potential impacts associated with decommissioning activities.

2.1.4 Relevant International Conventions

The OSPAR Convention, OSPAR (1992), is the current legislative instrument regulating international cooperation on environmental protection in the North-East Atlantic. It replaces the 1972 Oslo Convention on dumping waste at sea and the 1974 Paris Convention on land-based sources of marine pollution. Ireland has ratified the Convention.

The Convention applies to the internal waters and the territorial seas of the Contracting Parties, the sea beyond and adjacent to the territorial sea under the jurisdiction of the coastal State to the extent recognised by international law, and to the high seas, including the bed of all those waters and its subsoil, situated within specified limits of the Atlantic and Arctic Oceans.

Under paragraph 2 of the OSPAR Decision 98/3, the dumping, and leaving wholly or partly in place, of disused offshore installations is prohibited within the OSPAR maritime area. The conditions that would allow for a derogation from these Decision 98/3 requirements do not apply to the Kinsale Area facilities.

See **Appendix A** for further information on the OSPAR Convention and other international conventions relevant to the KADP.

2.1.5 Summary of key relevant National and European legislation

Table 2.1 below summarises the relevant key National, European and International legislation and the associated consents and requirements for decommissioning of infrastructure relevant to the KADP.

Table 2.1: Key National, European and International legislation relevant to the KADP

Relevant Legislation	Consents / requirements for Decommissioning
Section 13 of The Petroleum & Other Minerals Development Act 1960	Application will be made pursuant to Section 13 for decommissioning.
Section 5 of The Continental Shelf Act 1968	Application for the consent to “alter/construct/improve” works or structure in ‘or remove any object or material from’ the Continental Shelf designated area.
Section 3 of the Petroleum (Exploration and Extraction) Safety Act 2010	Part IIA of the Electricity Regulation Act 1999 - Section 13D renders the decommissioning of petroleum infrastructure and the abandoning of any well as a “designated petroleum activity”. Section 13E requires a safety permit to carry out designated petroleum activity. Kinsale Energy’s current safety permit does not include decommissioning. Approval of Safety Case required for decommissioning.
Energy (Miscellaneous Provisions) Act 1995, Section 17	The Minister (for Transport, Energy and Communications) shall not approve abandonment without consent of the Minister for the Marine.
European Communities (Birds and Natural Habitats) Regulations 2011 – 2015	Screening to be undertaken by competent authority to determine whether actions will affect European sites and species. Screening appraisal report to be submitted to competent authority.
	Transposes Habitats Directive (92/43/EEC) and Birds Directive (2009/147/EC) into Irish law.
Environmental Impact Assessment Directive 2011/92/EU amended by Directive 2014/52/EU	EIA Screening, and EIA if required, to be undertaken by competent authority.
Decisions 98/3, OSPAR (1998)	The dumping, and leaving wholly or partly in place, of disused offshore installations is prohibited within the OSPAR maritime area.

2.2 Legislative basis for EIA and EIAR

As detailed in **Section 2.1.2** above, pursuant to Section 13A of the Petroleum and other Minerals Development Act 1960 (as amended) (“1960 Act”), Kinsale Energy is seeking the consent of the Minister for Communications, Climate Action and Environment for the decommissioning of the Kinsale Area gas fields and facilities (Kinsale Area Decommissioning Project - KADP). Pursuant to Section 13B of the 1960 Act, the Minister will consider whether the proposed plan of decommissioning would be likely to have significant effects on the environment.

Based on information submitted on the characteristics of the project and its likely significant effects on the environment, the Minister determined that having regard to Annex III of the EIA Directive and given the potential for significant adverse environmental effects by virtue, inter alia , of the nature, size and location of the project, an Environmental Impact Assessment Report would be required to support the consent applications.

2.3 EIAR Guidance and Methodology

In preparing this EIAR, in addition to the requirements of the Directive, consideration was given to the guidance provided in the following documents:

- Environmental Impact Assessment of Projects Guidance on Scoping (Directive 2011/92/EU as amended by 2014/52/EU), EU 2017a
- Environmental Impact Assessment of Projects Guidance on the preparation of the Environmental Impact Assessment Report (Directive 2011/92/EU as amended by 2014/52/EU), EU 2017b
- Guidelines for Planning Authorities and An Bord Pleanála on carrying out Environmental Impact Assessment (Department of the Environment, Community and Local Government (DoECLG), 2013).
- Guidelines on the information to be contained in Environmental Impact Assessment Reports draft August 2017 (EPA, 2017a).
- Advice Notes for Preparing Environmental Impact Statements draft September 2015 (EPA, 2015b)

2.4 Policy Framework – Kinsale Energy Environmental Management System Overview

In addition to the legislative basis set out above, and adhering to the OSPAR Convention requirement to protect the maritime area against the adverse effects of human activities, Kinsale Energy (as a wholly owned subsidiary of PETRONAS) operates a Health, Safety and Environment Management System (HSEMS) based on the requirements of internationally accepted standards for Environmental Management (ISO14001) and for Occupational Health and Safety (OHSAS18001).

Kinsale Energy's Health, Environment and Safety (HES) policy commits the company to take all reasonable and practical steps to prevent and eliminate risks of injuries, occupational illness, damage to property and the conservation of the environment. This policy is applicable to Kinsale Energy's activities and those of its contractors. All contractors must adhere to all Kinsale Energy HES policies and procedures.

The Kinsale Energy HSEMS is structured around 8 elements which are summarised below:

Leadership and Commitment: addresses top-down commitment and company culture necessary for success in the systematic management of HES.

Policy & Strategic Objectives: a written HES Policy is required as a minimum. In setting strategic objectives and developing a HES Plan, management is required to consider the overall risk levels of its business activities taking into consideration the legal requirements, technological change, emerging issues and key stakeholders expectations.

Organisation, Responsibilities, Resources, Standards & Documents: addresses the organisation of people within Kinsale Energy, and the resources and documentation for sound and sustainable HES performance. Requires that the organisation and resources are adequate for its purpose, and that responsibilities for safety critical positions at all levels are clearly described, communicated and understood. It requires that staff based offshore are developed following structured competency assessment and training systems.

Hazards and Effects Management Process (HEMP): describes the identification of hazards and evaluation of HES risks for all activities, products and services, and the development of control and recovery measures to reduce HES risks to as low as reasonably practicable (ALARP).

Planning and Procedures: addresses asset integrity, procedures and work instructions, work permit system, management of change, contingency and emergency planning expectations, legislation compliance, process safety management, purchasing and procurement.

Implementation and Monitoring: addresses how activities are performed and monitored, and how corrective action is taken when necessary.

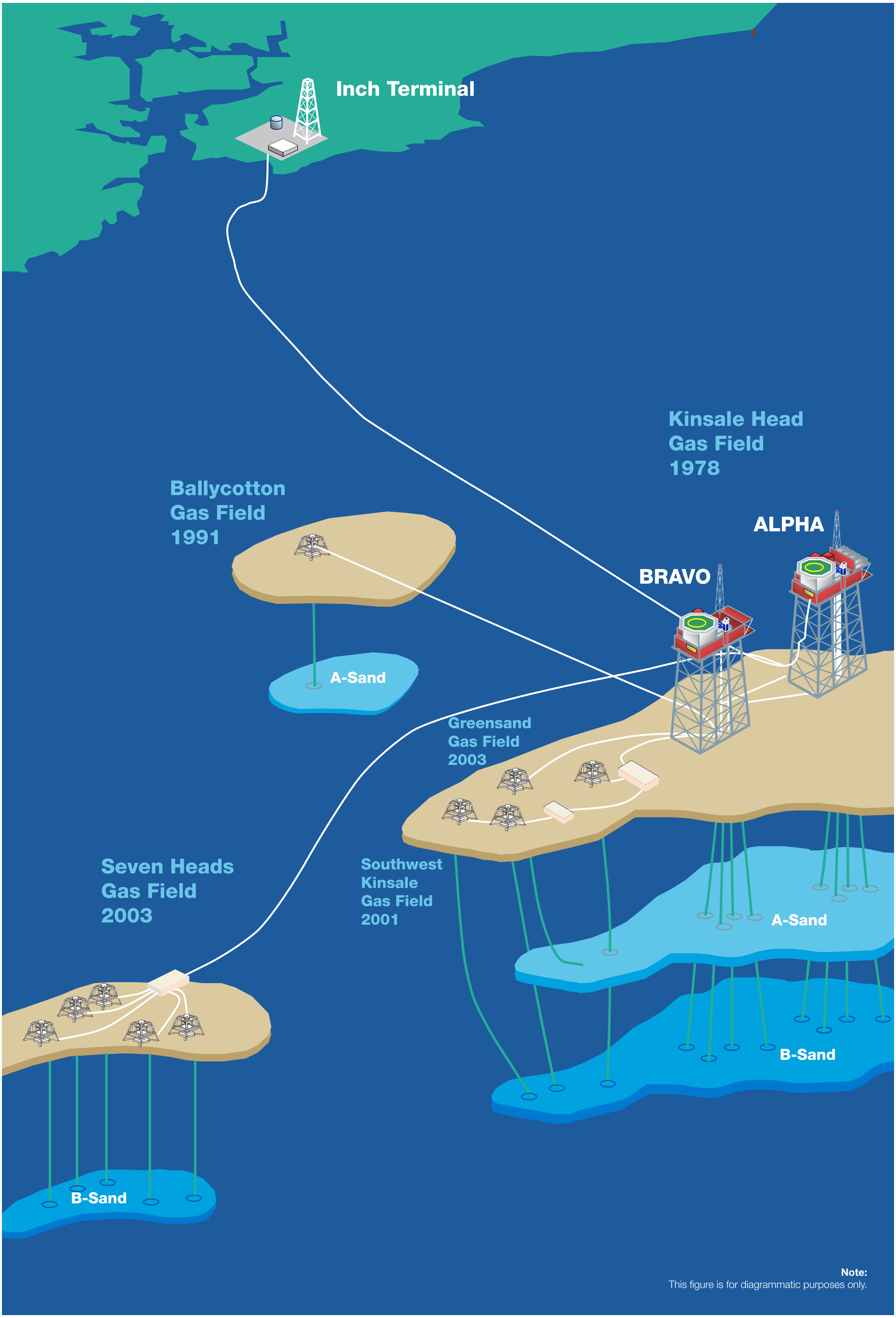
Audits: puts in place a programme to review and verify the effectiveness of the management system. It includes audits by independent auditors of processes or facilities.

Management Review: a formal process for management to review the effectiveness and suitability of the Management System in managing HES risks and ensuring continual improvements in HES performance. A management review occurs every 2 months at the HES Management Committee meeting.

Kinsale Area Decommissioning Project

Section 3

Project Description


Inch Terminal
Kinsale Head
Gas Field
1978
Ballycotton
Gas Field
1991
ALPHA
BRAVO
A-Sand
Greensand
Gas Field
2003
Seven Heads
Gas Field
2003
Southwest
Kinsale
Gas Field
2001
A-Sand
B-Sand
B-Sand
Note:
This figure is for diagrammatic purposes only.

3 Project Description

3.1 Introduction

This section provides an inventory and description of the Kinsale Area infrastructure and the decommissioning options identified, including consideration of alternatives discounted. This information is used along with the description of the environment in **Section 4** and **Section 5** as the basis for the assessment in **Sections 6** and **Section 7**. See **Glossary** for abbreviations and technical terms.

3.1.1 History of the Kinsale Area

The Kinsale Head Gas Field was discovered in 1971 and was brought on-stream in 1978 under a Plan of Development approved by the then Dept. of Industry and Commerce. The Kinsale Head field was developed with two fixed steel platforms (Kinsale Alpha and Kinsale Bravo) with gas exported by pipeline from Kinsale Alpha to the onshore Inch Terminal. The discovery of the field was the basis for the development of the natural gas industry in Ireland and Kinsale Head was Ireland's only source of gas until the installation of an interconnector pipeline from Scotland in 1993.

Following the Kinsale Head discovery, there was extensive exploration of the Celtic Sea with ~90 wells drilled, the last was the Midleton well in Block 49/11 drilled by Kinsale Energy in 2015. However, despite the intensive exploration effort, no other large fields have been discovered, although a number of smaller gas fields have been commercially exploited as subsea tie-backs to Kinsale Head.

The development of the smaller gas fields, which would not have been economic on a stand-alone basis, and technical modifications to the Kinsale Head facilities (e.g. installation of compression), have prolonged the life of the main field which is currently expected to remain viable for a further 2-3 years even at current low production rates and pressures.

The Kinsale Area fields, infrastructure and production status are summarised in **Table 3.1**.

Table 3.1: Summary of Development History for the Kinsale Area Fields

Lease	Field	No. of Wells	Facilities	Date/First Production	Status (2018)
OPL-01	Kinsale Head	14	Kinsale Alpha (Manned Platform with production, drilling & accommodation) 7 x Platform Wells	1978	Producing
			Compression added	1992	
			Kinsale Bravo (Manned Platform with production, drilling & accommodation) 7 x Platform Wells	1979	Producing (1 Well Shut-In)
			Compression added	1993	
			Kinsale Bravo Converted to Normally Unmanned Installation	2001	
	Ballycotton	1	1 x Subsea Well	1991	Shut-In
	Southwest Kinsale	3	3 x Subsea Wells	1999 – 2001	Producing
	Greensand	1	1 x Subsea Well	2003	Producing
Seven Heads	Seven Heads	5	1 x Subsea Manifold 5 x Subsea Wells	2003	Producing (1 Well Shut-In)

Notes:

*Associated pipeline and umbilical details are found in **Table 3.4** and **Table 3.5**.*

In 2001 Southwest Kinsale was redeveloped to enable gas from the adjacent offshore gas fields to be stored in the reservoir. In 2006, further modifications were made to convert the field into an offshore storage facility for gas from the onshore network. The last of the storage gas was withdrawn from Southwest Kinsale reservoir in March 2017 and the field currently operates as a gas production reservoir only.

In addition to those wells numbered above, there are four previously abandoned exploration wells which require removal of their redundant wellheads as part of the KADP.

3.1.2 Rationale for Decommissioning

The Kinsale Area gas fields have been in production since 1978 (Kinsale Head) and it is expected that the economic extraction of gas will no longer be viable by approximately 2020/2021, whereupon the fields will be shut-in, the wells plugged and abandoned and the associated facilities decommissioned as described below.

The main producing reservoirs have been drawn down to extremely low pressures and are expected to be in the order of 50 - 100 psia at cessation of production (CoP), such that there are no further cost-effective production technology modifications that can be applied to extend field life. The offshore production wells and Kinsale Alpha export compressor pressures are also approaching a technical limit (offshore production wells bottom-hole pressures (sub-hydrostatic) and the Kinsale Alpha export compressor suction pressure (less than 5psig)), for offshore natural gas fields operation.

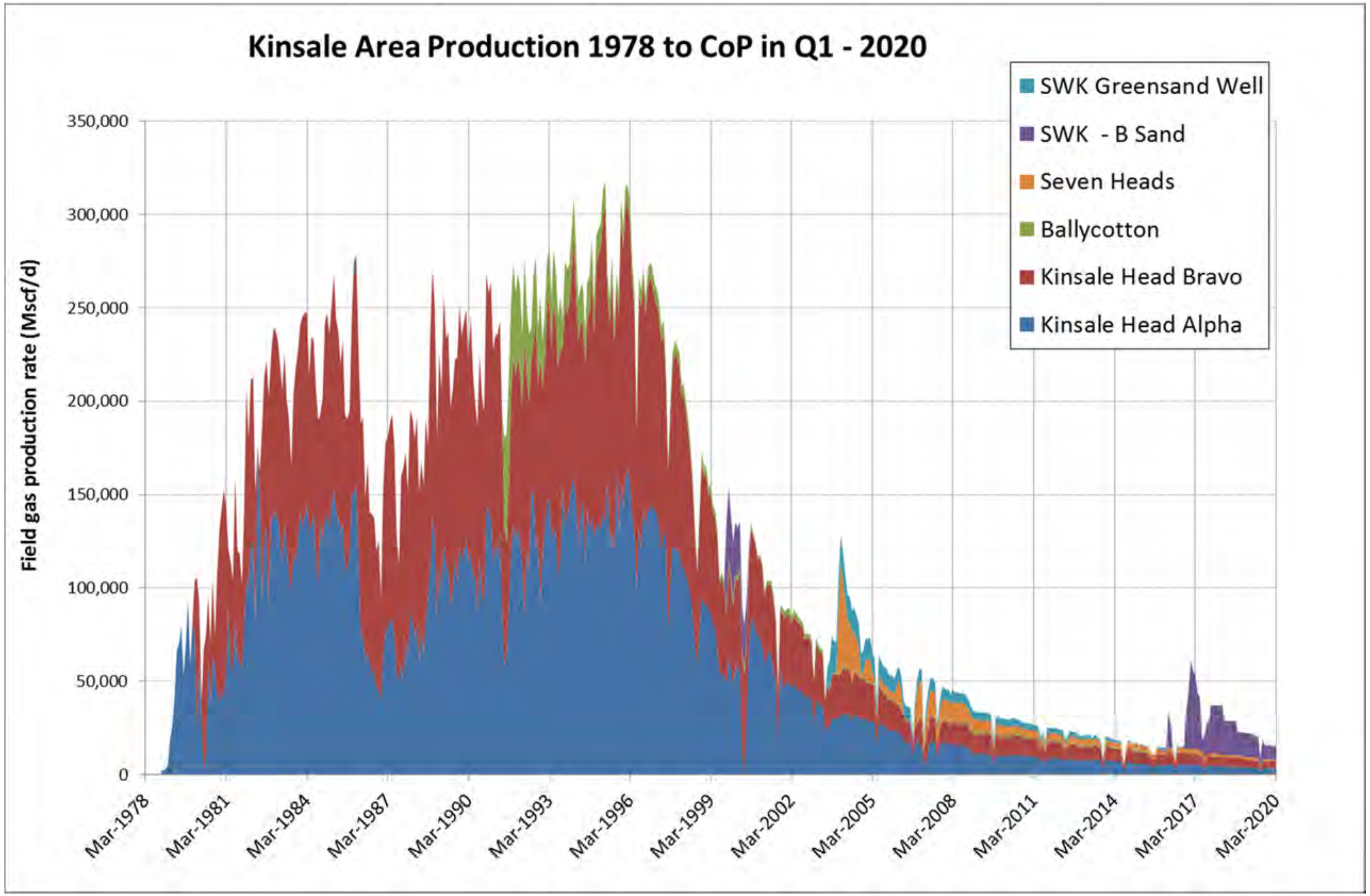
Production History

The original Kinsale Head Field Development Plan envisaged a 20 year production profile with a total ultimate recovery of 0.915 trillion cubic feet (TCF) of gas, corresponding to a Recovery Factor (RF) of ~70%.

In fact, the Kinsale Head Gas Field has produced ~1.76TCF of gas since start up to the end of 2017 and is ultimately expected to produce ~1.77TCF or approx. 96% of the estimated Gas in Place in the reservoir. High recovery factors are also expected for the other fields which have been developed via the Kinsale Head facilities.

Peak production levels were achieved in the mid-1990's and since then gas production levels have decreased significantly – with current (2018) daily average rates being less than 5% of peak rates. **Figure 3.1** is a graph showing daily average gas production from the fields to date. Field and facility performance have been carefully and pro-actively managed to maximise and extend economic production. However, given the continuing declines in gas rates, no economically sustainable investment program or technical improvements can be implemented to further extend economic production.

Figure 3.1: Kinsale Area gas fields – production rates



3.2 Kinsale Area Facilities

The Kinsale Area facilities to be decommissioned are detailed in **Section 3.2.1** to **Section 3.2.6** and summarised in the tables shown in **Section 3.2.7**.The facilities are described under the following headings:

- Kinsale Head Development
- Ballycotton Subsea Development
- Southwest Kinsale and Greensand Subsea Developments
- Seven Heads Subsea Development
- Wells
- Onshore Pipeline and Terminal

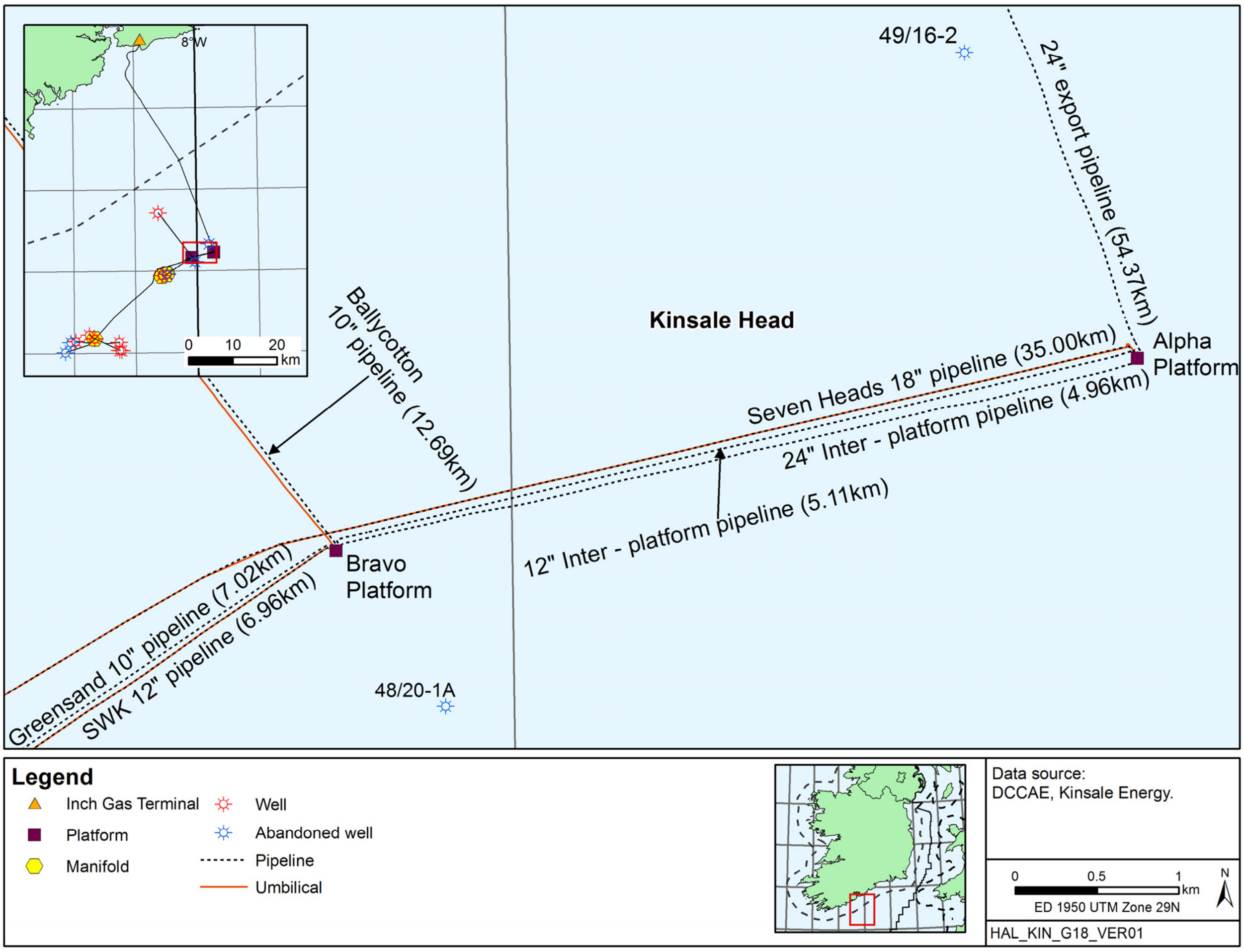
The original Kinsale Head field development was undertaken using fixed steel platforms, as described below. All subsequent developments (Ballycotton, Southwest Kinsale, Greensand and Seven Heads) used subsea well technology whereby underwater wellheads are controlled from a host platform (Kinsale Alpha or Kinsale Bravo) by means of an electro hydraulic control umbilical.

It should be noted that hydrocarbons produced in the Kinsale Area are dry natural gas with small amounts of condensate from Seven Heads field (e.g. no sludges, solid naturally occurring radioactive materials (NORM), liquid hydrocarbons or H2S are present). The reservoirs producing to the Kinsale Area platforms do not produce sand, and the water associated with the gas is "water of saturation" and is fresh water. No solid sample taken from the Kinsale Area platforms or associated wells, has ever been classed as positive for low specific activity (LSA) or Naturally Occurring Radioactive Material (NORM). This demonstrates that there is no LSA or NORM associated with the Kinsale Area platforms.

It should also be noted that oil based muds were only used in the drilling of one well in the Kinsale Area (the cuttings of which were not discharged to sea, with all material being returned to shore). Any resulting well cutting piles are now non-existent in the Kinsale Area with the 2017 seabed survey confirming all such piles have dispersed.

3.2.1 Kinsale Head Development

Figure 3.2: Overview of the Kinsale Head Facilities



Kinsale Alpha Platform

The Kinsale Alpha (KA) platform was installed in 1977. It incorporated drilling, production and accommodation facilities (**Figure 3.3**). KA comprises an eight-leg piled steel jacket with a total weight in air of ca. 8,100 tonnes. It supports an integrated deck module support frame and topsides of some 4,700 tonnes, which was installed in seven sections. Maximum accommodation is 43 persons, with present routine manning levels around 15-20 persons. The platform has 9 well slots, of which 7 have been used. The drilling facilities were installed as an integrated package which was removed following completion of the KA wells and transferred to Kinsale Bravo (KB). Subsequent modifications have included cantilever additions in 1991-1992 (the Eastern Compression Cantilever), 2001 (the Injection Compression Cantilever) and 2003 (the Seven Heads Cantilever). Processing of gas for all of the fields in the Kinsale Area is undertaken at KA. The gas is exported from KA to the Inch Terminal on the Co. Cork coastline, approximately 50km to the north.

There is an exclusion zone, (ref S.I. No. 285/1977) for other sea users, bounded by a line which is 500m at all points from a straight line joining the KA and KB platforms. This results in an elongated 500m exclusion zone around the KA, KB platforms and the entire stretch between them.

Figure 3.3: Kinsale Alpha

Kinsale Bravo Platform

The Kinsale Bravo (KB) platform (**Figure 3.4**) was installed in 1977 and was originally almost identical to KA. An eight-leg piled steel jacket with a total weight in air of some 7,600 tonnes supports an integrated deck module support frame and topsides of about 3,700 tonnes, which was installed in seven sections. The platform has 9 well slots, of which 7 have been used. The wells were completed using the drilling package transferred from KA, which was subsequently removed. Production from KB, which includes produced gas from the Kinsale Head, SW Kinsale, Greensand and Ballycotton fields, is routed to KA for processing and export. Accommodation on KB was originally for 46 persons but it was converted to a Normally Unmanned Installation (NUI) in 2001, with emergency accommodation for 9 persons. The compression modules and control room which were added in 1993 have been removed.

As noted above there is an elongated 500m exclusion zone around the KB platform and the entire stretch between the KA and KB platforms.

Figure 3.4: Kinsale Bravo

Export pipeline

The main export pipeline from KA to the Inch Terminal consists of a 55.57km, 24” concrete coated pipeline installed in 1977. The pipeline is mainly surface laid but with some buried sections and rock placement at strategic locations. The pipeline is buried from 2km seaward of the landfall to the landfall and for the 1.2km inland from the landfall as far as the Inch Terminal.

KA to KB pipelines

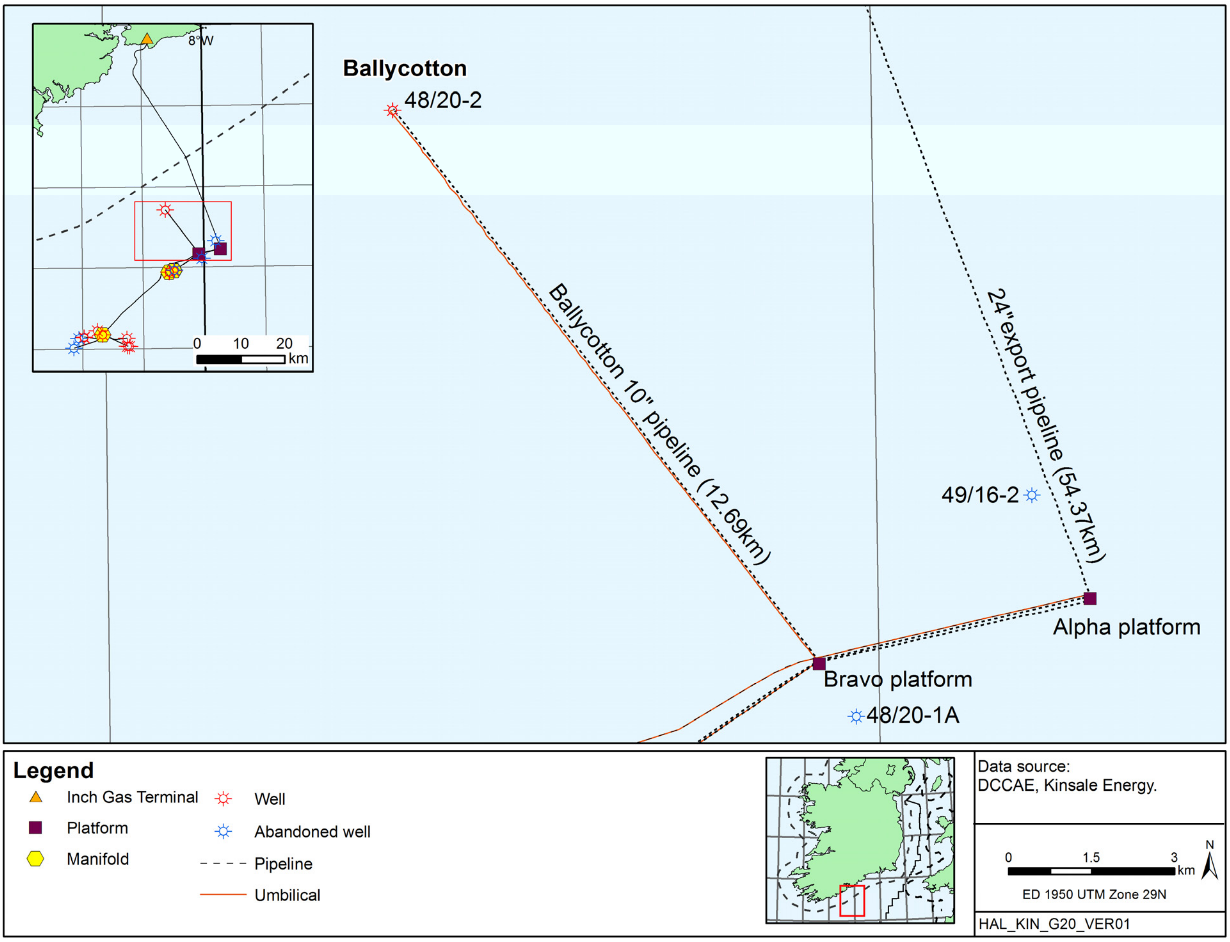
Two pipelines connect the KA and KB platforms, a 24” concrete coated pipeline (4.96km) and a 12” three layer polypropylene (PPL) coated pipeline (5.11km). The pipelines were installed in 1977 and 2001 respectively and are both surface laid, with rock having been placed at strategic locations along the 24” pipeline.

3.2.2 Ballycotton Subsea Development

The 12.69km 10” Ballycotton pipeline was installed in 1991, and connects well 48/20-2 to KB and is trenched and buried throughout most of its length though with some exposed sections, and mattress protection, particularly at the wellhead end, which is extensively protected. The umbilical (control cable) is trenched separately to the pipeline and is of similar length (13.00km). There are two infield crossings of the Ballycotton pipeline close to KB (**Figure 3.2**) by the Seven Heads pipeline and umbilical, each of which is protected with concrete mattresses.

There is a 500m exclusion zone, for other sea users, around the Ballycotton well 48/20-2 (ref S.I. No. 226/1991).

Figure 3.5: Ballycotton Facilities



3.2.3 Southwest Kinsale and Greensand Subsea Developments

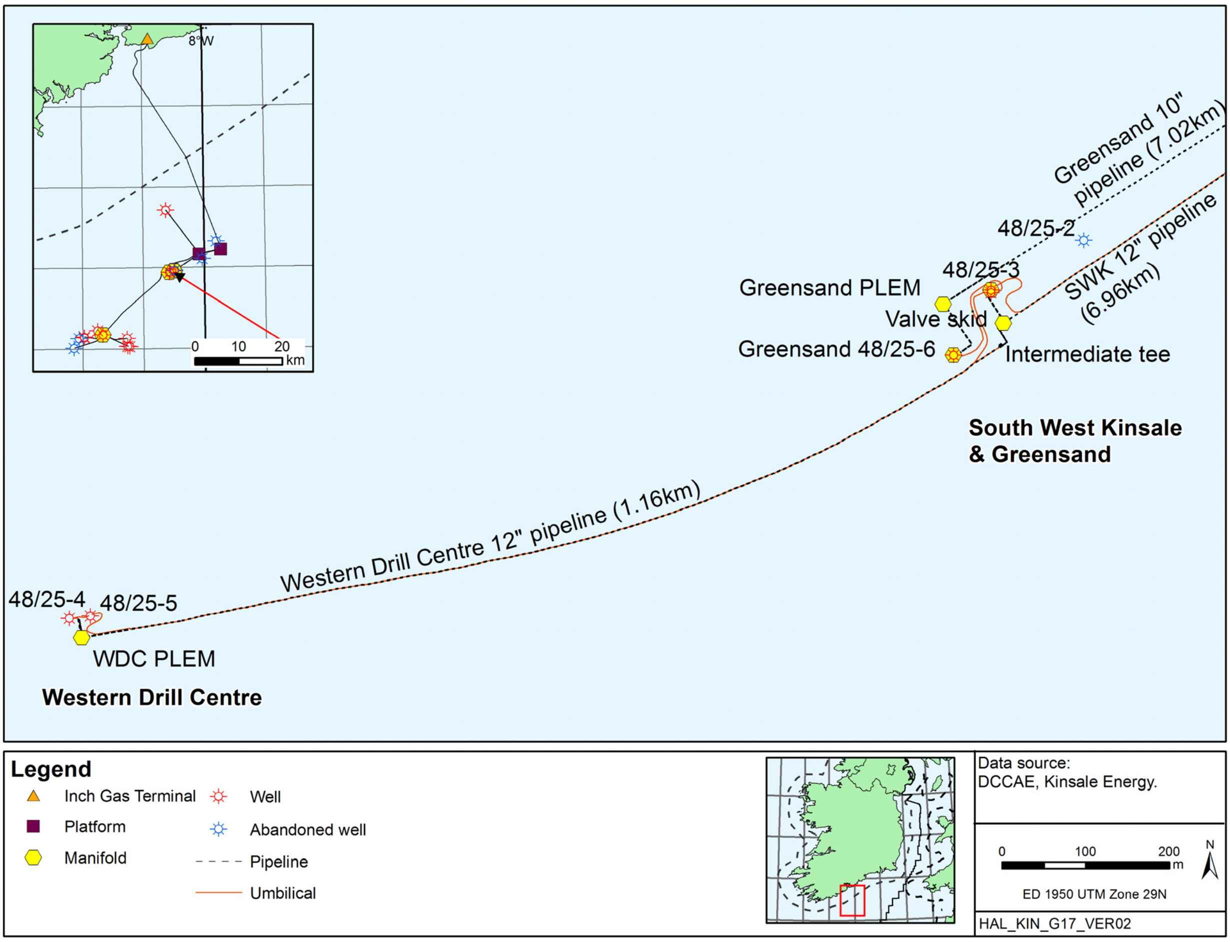
The Southwest Kinsale (SW Kinsale) development is connected to the KB platform via a 6.96km, 12" pipeline installed in 1999, which is partially trenched and buried, and rock covered where required trenching depths could not be reached. Concrete protective mattresses cover both ends of the pipeline, on its approach to the SW Kinsale valve skid and at its connection with KB. The SW Kinsale valve skid is tied into well 48/25-3 and an intermediate tee skid which connects the Western Drill Centre (WDC) extension.

The WDC extension is a similar 12" pipeline 1.16km in length installed in 2001, which is rock-covered along its length. The WDC pipeline terminates at the WDC Pipeline End Manifold (PLEM) and is connected via spool pieces to the 48/25-4 and 48/25-5 wells.

A subsea well completion (Greensand) in the "A" sand zone of SW Kinsale was installed in 2003 and the infrastructure is immediately adjacent to that of SW Kinsale. The 7.02km 10" pipeline is rock-covered along its length to KB with the exception of a short section approaching the Greensand PLEM. Spool pieces connect the Greensand PLEM to well 48/25-6.

There is an exclusion zone, for other sea users (ref S.I. No. 6/2003), bounded by a line which is 500m at all points from a straight line joining the SW Kinsale well 48/25-3 and a point at the WDC wells. This results in an elongated 500m exclusion zone around the Southwest Kinsale, Western Drill Centre and Greensand wells.

Figure 3.6: Southwest Kinsale and Greensand



A common umbilical serves the SW Kinsale and Greensand infrastructure and runs parallel with the SW Kinsale pipeline and under the same protection materials. In the immediate vicinity of the SW Kinsale and Greensand wells/subsea infrastructure there are control umbilicals which are under concrete protection mattresses.

3.2.4 Seven Heads Subsea Development

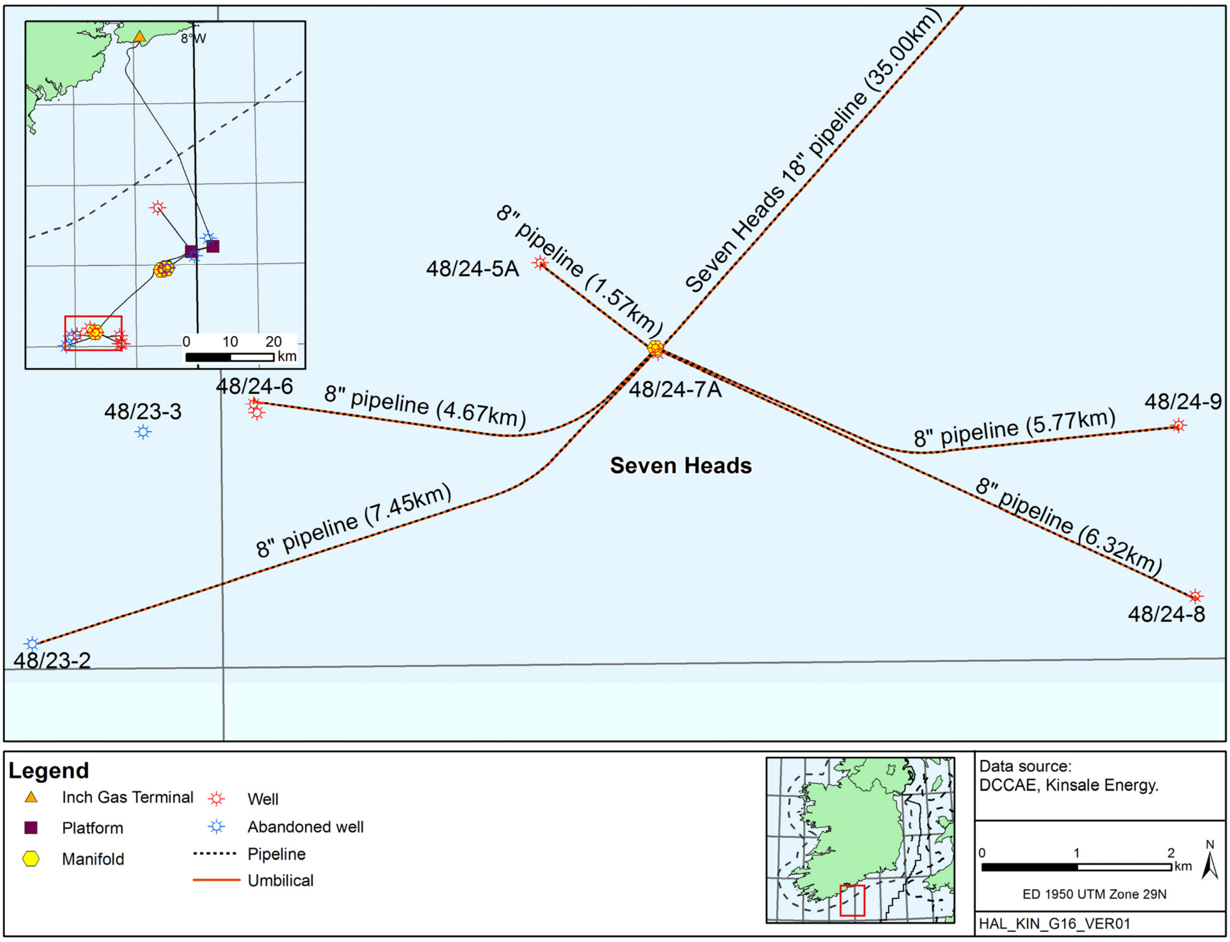
The Seven Heads field was developed by a group led by Ramco Energy in 2003; Ramco's interest (86.5%) was subsequently acquired in 2006 and is now operated by PSE Seven Heads Ltd, a subsidiary of PSE Kinsale Energy Limited.

Seven Heads is connected to KA via a 35.00km concrete coated 18" pipeline installed in 2003, which is variously buried, exposed or rock covered. The control umbilical is laid alongside the pipeline with the same protection. The 18" pipeline terminates at the Seven Heads manifold, which connects the export line to six separate 8" flowlines and umbilicals of various lengths (0.06-7.45km). Only five of the infield pipelines and umbilicals are connected to active subsea wells (48/24-5A, 48/24-6, 48/24-7A, 48/24-8 and 48/24-9), but all have rock cover and concrete mattress protection.

The Seven Heads pipeline and umbilical cross the active Hibernia Atlantic "D" and the disused PTAT telecommunications cables. A separate telecommunications cable (Hibernia Express, installed in 2015) crosses over the Seven Heads pipeline and umbilical to the south of these. These are separated by concrete mattresses.

There is a 500m exclusion zone, for other sea users, around the Seven Heads manifold and each of the Seven Heads active subsea wells (ref S.I. No. 685/2003).

Figure 3.7: Seven Heads Facilities



3.2.5 Wells

There are a total of 28 wells to be decommissioned, 14 associated with the KA and KB platforms and the remaining 14 made up of 10 subsea development wells in satellite fields and 4 previously abandoned exploration wells in the Kinsale Area which require their wellheads to be removed.

All development wells are completed with a Xmas Tree structure, located on the seabed for the subsea development wells (see **Figure 3.8**) and on the platform cellar deck for the platform wells.

Figure 3.8 Typical subsea Xmas Tree structure

3.2.6 Onshore Pipeline and Terminal

The gas produced from the Kinsale Head field and subsea tie backs is transported to shore in the 24” export pipeline to an onshore terminal at Inch, approximately 1.20km inland from the landfall at Inch. The terminal was constructed in 1978.

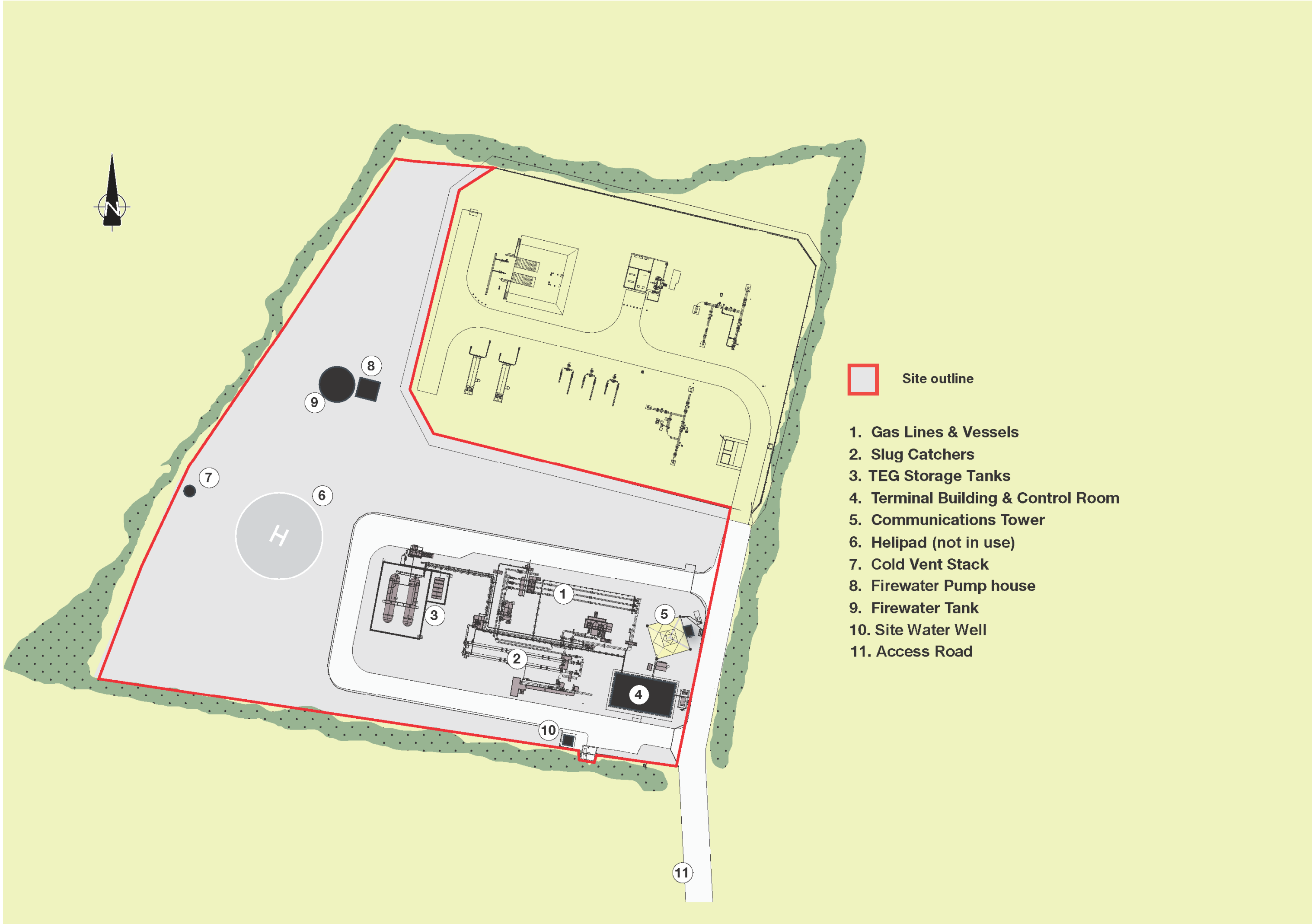
The aerial photograph in **Figure 3.9** below shows the Inch terminal layout. The onshore section of the Kinsale Area facilities are located on the southern portion of the site and include the communications tower as shown in the photograph. The facilities outlined in red are part of the Irish gas transmission system owned by Gas Networks Ireland and do not form part of the KADP.

Figure 3.9: Inch Terminal

The Kinsale Energy equipment and structures on the terminal site are shown in **Figure 3.10**. The Inch Terminal site comprises a site area of 2.3 Ha, some 220m^2 (9.7%) of which is occupied by buildings, a 20m high vent stack, 98m high communications tower with concrete foundations, and access road.

The onshore Inch Terminal is a small sized onshore terminal used for metering and does not include any gas processing as all gas leaving KA platform already meets the Commission for Regulation of Utilities (CRU) Gas Quality Specification for export to the Gas Networks Ireland onshore grid.

Figure 3.10: Inch Onshore Terminal layout plan



Not to scale

3.2.7 Summary of Kinsale Area Facilities

Tables 3.2 to 3.7 summarise the Kinsale Area facilities to be decommissioned.

Table 3.2: Kinsale Area wells to be decommissioned

Well no.	Drill date	Location/associated development	Present status
Platform Wells			
49/16-A1	08/07/1978	Kinsale Head (KA)	Gas Producer
49/16-A3	24/12/1978	Kinsale Head (KA)	Gas Producer
49/16-A4	08/08/1978	Kinsale Head (KA)	Gas Producer
49/16-A5	09/04/1978	Kinsale Head (KA)	Gas Producer
49/16-A6	15/11/1978	Kinsale Head (KA)	Gas Producer
49/16-A7	19/01/1979	Kinsale Head (KA)	Gas Producer
49/16-A9	22/05/1978	Kinsale Head (KA)	Gas Producer
49/16-B1	07/06/1979	Kinsale Head (KB)	Gas Producer
49/16-B3	26/09/1979	Kinsale Head (KB)	Gas Producer
49/16-B4	27/06/1979	Kinsale Head (KB)	Gas Producer
49/16-B5	13/05/1979	Kinsale Head (KB)	Gas Producer
49/16-B6	30/06/1979	Kinsale Head (KB)	Gas Producer
49/16-B7	18/07/1979	Kinsale Head (KB)	Gas Producer
49/16-B9	10/08/1979	Kinsale Head (KB)	Gas Producer, shut in.
Subsea Wells			
48/20-2	01/03/1989	Ballycotton	Gas Producer; shut-in
48/25-3	30/07/1995	SW Kinsale	Gas Producer
48/25-4	25/04/2001	SW Kinsale (WDC)	Gas Producer
48/25-5	28/04/2001	SW Kinsale (WDC)	Gas Producer
48/25-6	22/04/2003	Greensand	Gas Producer
48/24-5A	05/08/2001	Seven Heads	Gas Producer; shut-in
48/24-6	15/03/2003	Seven Heads	Gas Producer
48/24-7A	16/05/2003	Seven Heads	Gas Producer
48/24-8	12/06/2003	Seven Heads	Gas Producer
48/24-9	24/06/2003	Seven Heads	Gas Producer
Plugged and Abandoned Wells			
48/25-2	13/09/1971	Kinsale Head	Plugged and abandoned.
49/16-2	04/07/1973	Kinsale Head	Plugged and abandoned.
48/20-1A	06/05/1972	Kinsale Head	Plugged and abandoned.
48/23-3	03/05/2006	Seven Heads	Plugged and abandoned.

Table 3.3: Platforms (Topsides & Jackets) to be decommissioned

Structure	Description	Dimensions	Weight (in air)
Kinsale Alpha	Manned platform – Topsides & Jacket standing in approximately 89.9m of water. Topside details: • Cellar deck – equipment and wellheads • Main deck - accommodation on the west side with 43 beds • Vent stack on the north west side of the platform • Helideck on south west side of the platform Jacket details: • 8-legged piled steel lattice structure, with piles driven to an approximate depth of 50m below the seabed • 9 conductor slots (7 conductors) • Risers / J-tubes:	Topside: Main Deck area 165 x 83 ft (50.3 m x 25.3 m) Cellar Deck area 152 x 83 ft (46.3 m x 25.3 m) Jacket: Base 70m x 44m, Height 98m, 7 plan bracing levels	Topside: 4,700Te approx. Jacket: 8,100Te approx. (including main members, risers, caissons, marine growth, piles to seabed level, grout, mudmats & anodes)
Kinsale Bravo	Normally unmanned platform – Topsides & Jacket standing in approximately 90.5m of water KB Topside details: • Cellar Deck – Equipment and wellheads • Main Deck - Temporary accommodation only Jacket details: • 8-legged piled steel lattice structure, with piles driven to an approximately depth of 50m below the seabed • 9 conductor slots (7 conductors) • Risers / J-tubes	Topside: Main Deck area 165 x 83 ft (50.3 m x 25.3 m) Cellar Deck area 152 x 83 ft (46.3 m x 25.3 m) Jacket: Base 70m x 44m, Height 98m, 7 plan bracing levels	Topside: 3,700Te approx. Jacket: 7,600Te approx. (including main members, risers, caissons, marine growth, piles to seabed level, grout, mudmats & anodes)

Source: Genesis (2011), Xodus (2016a)

Table 3.4: Pipelines to be decommissioned

Pipeline	Length (km)	Description	Year installed	Status	Tie-in spools pieces	Protection materials	Comments
	Onshore						
Inch Terminal to Inch Beach landfall export pipeline	1.20km	24″ X60 steel, coal-tar epoxy	1977	Active	Inch Terminal pipeline entry buried with Inlet Stop Valve P149 in pit	25mm concrete coated section from the vegetation zone above the beach to 150m from Lowest Astronomical Tide (LAT)	
	Kinsale Head, Southwest Kinsale, Greensand & Ballycotton						
Inch Beach landfall to Kinsale Alpha export pipeline	54.37km	24″, X60 steel, coal-tar epoxy and concrete coated	1977	Active	50mm concrete coated tie-in at KA.	Intermittent grout bag supports at 11 locations. Rock cover totals 5.8km, covering a number of strategic locations.	Number of non-critical freespans detected. Cumulative freespan length 1,822m
Kinsale Alpha (KA) to Kinsale Bravo (KB) export pipeline	4.96km	24″ X52 steel, coal-tar epoxy and concrete coated	1977	Active	50mm concrete coated tie-in at KA and KB.	Rock cover totals 96m, covering a number of strategic locations.	12 non-critical freespans detected. Cumulative freespan length 205m
KA to KB pipeline	5.11km	12″ X52 steel, 3LPP coated	2001	Active	25m spool underneath each jacket, 40m spool connecting pipeline at KA end.	No pipeline protection. 2 support ramps of grout bags at KA and KB tie-in spools. 34 mattresses (6x3x0.15m) used at each tie-in location at KA and KB.	8 non-critical freespans detected. Cumulative freespan length 188m

Pipeline	Length (km)	Description	Year installed	Status	Tie-in spools pieces	Protection materials	Comments
Southwest Kinsale pipeline	6.96km	12″ X52 steel, 3LPP coated	1999	Active	36m spool at KB, vertical leg to riser end. Single spool between valve skid and 48/25-3 tree.	Rock cover totals 2.6km. 4 mattresses (5x3x0.15m) at SWK end and 20 mattresses (5x2.2x0.15m) at the KB end. Tie-in spools include 6 mattresses (5x2.2x0.15m) at KB and 8 mattresses (6x3x0.15m) at SWK.	No freespans identified
Extension pipeline to Western Drill Centre	1.16km	12″ X52 steel, 3LPP coated	2001	Active	2 x 6" spools to WDC 48/25-4 and 48/25-5 trees. 34m long spool between skids at SWK.	Rock cover along entire length. 8 mattresses (5x3x0.15m) at WDC on PLEM to tree spools. 6 mattresses (5x3x0.15m) on spool between skids at SWK. 4 mattresses (5x3x0.15m) at SWK on pipeline end. 4 mattresses (5x3x0.15m) at WDC on pipeline end.	No freespans identified
Greensand pipeline	7.02km	10″ X52 steel, 3LPP coated	2003	Active	Two 10″ spools at KB. Two 6″ spools between the Greensand well (48/25-6) and PLEM and one 10″ spool connecting the PLEM to the greensand pipeline.	Rock cover along entire length. 10 mattresses (6x3x0.15m) at Greensand pipeline end and 13 mattresses at KB pipeline end. Spools with groutbag support at KB. KB spool protection includes 9 mattresses (6x3x0.15m). Well spool protection includes 13 mattresses (6x3x0.15m).	No freespans identified

Pipeline	Length (km)	Description	Year installed	Status	Tie-in spools pieces	Protection materials	Comments
Ballycotton pipeline	12.69km	10″ X52 steel, 0.5mm FBE coated	1991	Not active, well shut in	30m tie-in spool to 48/20-2 tree and 20m tie-in spool at KB.	44 mattresses used for pipeline protection. Groutbag support at Ballycotton tree and KB spools. Grout bag berm 8m long at tee spool. 4 kennel-type protection tunnel for 20m on tree tie-in spool along with 3 mattresses (5x3x0.15m). 105 mattresses on pipeline end at tree. 9 stabilisation mattresses (2.5x1.5x0.15m) on pipeline end at KB.	8m freespan identified.
	Seven Heads						
Seven Heads export pipeline	35.00km	18″ X52 steel, 3LPP and concrete coated	2003	Active	Two 14″ tie-in spools, 44m and 36m in length at the manifold end. Two 14″ tie-in spools, 42m and 39m in length at the KA end.	10 mattresses (6x2x0.15m) and 25 mattresses (5x3x0.15m) at the manifold end. 41 mattresses (5x3x0.15m) on the pipeline end at KA. 3 mattresses (5x3x0.15m) at each of the two crossings over the Ballycotton pipeline and umbilical.	There are 3 communication cable crossings. The Seven Heads pipeline crosses over the Hibernia Atlantic “D” and the disused PTAT cable, while the Hibernia Express cable installed in 2015 crosses over the Seven Heads pipeline.
Seven Heads well 48/24-5A pipeline	1.57km	8″ X52 steel, 3LPP coated	2003	Active	8” spool, 44m long at the manifold.	22 mattresses (6x3x0.15m) and 4 mattresses (6x2x0.15m) at the manifold. 13 mattresses (6x3x0.15m) at the well.	No freespans identified

Pipeline	Length (km)	Description	Year installed	Status	Tie-in spools pieces	Protection materials	Comments
Seven Heads well 48/24-6 pipeline	4.67km	8″ X52 steel, 3LPP coated	2003	Active	Two 8" spools, 23m and 27m long at the manifold.	24 mattresses (6x3x0.15m) and 16 mattresses (6x2x0.15m) at the manifold. 27 mattresses (6x3x0.15m) at the well.	No freespans identified
Seven Heads well 48/24-7A pipeline	0.06km	8″ X52 steel, 3LPP coated	2003	Active	8" spool, 60m long at the manifold.	12 mattresses (6x3x0.15m) and 3 mattresses (6x2x0.15m) at the manifold.	No freespans identified
Seven Heads well 48/24-8 pipeline	6.32km	8″ X52 steel, 3LPP coated	2003	Active	Two 8" spools, 39m and 35m long at the manifold.	16 mattresses (6x3x0.15m) and 5 mattresses (6x2x0.15m) at the manifold. 37 mattresses (6x3x0.15m) at the well.	No freespans identified
Seven Heads well 48/24-9 pipeline	5.77km	8″ X52 steel, 3LPP coated	2003	Active	Two 8" spools, 51m and 34m long at the manifold.	24 mattresses (6x3x0.15m) and 4 mattresses (6x2x0.15m) at the manifold. 12 mattresses (6x3x0.15m) at the well.	No freespans identified
Seven Heads well 48/23-2 (abandoned) pipeline	7.45km	8″ X52 steel, 3LPP coated	2003	Not active	Two 8" spools, 33m and 25m long at the manifold.	26 mattresses (6x3x0.15m) and 19 mattresses (6x2x0.15m) at the manifold. 8 mattresses (6x3x0.15m) at the well.	No freespans identified. Well F flowline is inactive and was never used; filled with seawater since installation; well not tied-in

Source: Genesis (2011), Xodus (2016c), Anatec (2017) Kinsale Energy's as-built data for Seven Heads

Table 3.5: Umbilicals to be decommissioned

Umbilical	Diameter	Length	Current Burial Status / Installation Method	Protection materials	Comments
Southwest Kinsale umbilical	82mm	6.96km	Partially trenched. Laid alongside 12" South West Kinsale pipeline, sharing the same protection materials.	8 mattresses (6x3x0.15m) at KB end and 20 mattresses at the SWK tree end. Grout bags used to support a crossing with the SWK pipeline near KB.	
Western drill centre umbilical	82mm	1.16km	Laid alongside 12" South West Kinsale extension to Western Drill Centre, sharing the same protection materials.	Rock cover along majority of length. 8 mattresses (5x3x0.15m) and 6 mattresses (5x2x0.15m) cover the umbilicals to the trees. 24 mattresses (6x2x0.15m) cover the umbilical between the SWK tree and the pipeline rock placement.	
Greensand umbilical jumper	101mm	-	Laid on seabed and covered in concrete mattresses.	23 mattresses (6x2x0.15m) between Greensand and SWK wells.	
Ballycotton umbilical	98.2mm	13.00km	Trenched	The Seven Heads pipeline and umbilical cross over the Ballycotton umbilical. Crossing includes 3 mattresses (5x3x0.15m). 12 mattresses cover the umbilical to the tree and 3 mattresses cover the umbilical to KB.	9m freespan identified
Seven Heads Umbilical	123.5mm	35.00km	Laid alongside Seven Heads 18" pipeline, sharing the same protection materials.	Protection materials are the same as those listed in Table 4 for the Seven Heads pipeline cable crossings and tie-in to the platform and the manifold, along with 18 additional mattresses (6x2x0.15m) covering the umbilical tie-in to the platform.	Two 3rd party crossings of communication cables under the pipeline & umbilical: PTAT (Mercury) and 360 Atlantic "D" (360 Networks Inc.). One 3rd party crossing (Hibernia Express) over the pipeline & umbilical.
Seven Heads well umbilicals	93.2mm	0.06 to 7.45km	All laid alongside 8" pipelines and rock covered.	Protection materials are the same as those listed in Table 4 for the tie-in pipes, with 45 additional mattresses (6x2x0.15m) covering the umbilicals to the trees.	Well 48/23-2 (Well F) umbilical inactive and never used.

Source: Genesis (2011), Xodus (2016c), Anatec (2017), Kinsale Energy's as-built data

Table 3.6: Subsea infrastructure to be removed

South West Kinsale Valve Skid	
Manifold contains a 12” branch to tie-in the SWK well spool and a further 12” connection to tie-in the pipeline.	
Main structure: Protection blocks:	4.4x2.2x1.2m, 10.5Te 10x2.4x1.8m, weight 65Te (x2) 7.7x 2.4x1.8m, weight 45Te (x2)
South West Kinsale Intermediary Tee	
Located approximately 30m from the SW Kinsale valve skid. Connects the Western Extension pipeline to the SW Kinsale infrastructure in a daisy chain configuration.	
Main structure: Protection blocks:	6.5x3.2x1.4m, 8.4Te 8.75x 2.4x1.765m, weight 43Te (x3) 8.75x2.4x1.765m, weight 47Te (x1)
Greensands Pipeline End Manifold (PLEM)	
Manifold includes a 6” branch to tie-in the Greensand well spool and a 10” pipeline end flange.	
Main structure: Protection blocks:	4.7x2.3x1.7m, 9.2Te 10x2.4x1.8m, weight 65Te (x2) 7.7x2.4x1.8m, weight 45Te (x2)
Western Drill Centre PLEM	
Manifold has two 6” branches to tie-in the well spools and a 12” branch to tie-in the extension pipeline spool	
Main structure: Protection blocks:	4.7x2.2x1.7m, 9.2Te 10x2.4x1.8m, weight 65Te (x2) 7.7x2.4x1.8m, weight 45Te (x2)

Seven Heads Manifold	
Manifold housed within a rectangular steel protection frame with diagonal rakers at the corner members. Drop-in ballast weight inserts in the corner tubular members.	
Main structure: Manifold module: Corner weights: Total:	17x12mx6m (to end of diagonal rakers), 66.1Te 36.7Te 19.5Te (x4) 190Te
Well Head Protection Structures	
Four structures placed over SWK Wells 48/25-3, 4, 5 and Greensand Well 48/25-6. Steel tubular frame with concrete foundation blocks on two sides.	
Steel frame: Concrete blocks:	12x13m base, 4.3x4.35m top, 7m high, 25Te 133.3Te (6 concrete blocks of max individual weight 25Te)

Source: Genesis (2011), Xodus (2016c)

Table 3.7: Inch Onshore Terminal to be decommissioned

Terminal	Description	Dimensions
Inch Terminal	Onshore gas terminal equipment: • Gas lines, vessels & associated equipment, pipework, instrumentation & cabling • Tri-Ethylene Glycol (TEG) Storage Tanks Buildings: • Terminal Building; a single storey concrete building with precast concrete roof, containing rooms including a battery room, gas chromatograph room, control room, canteen and toilet • Firewater Pump house Other • Internal Roadway • Communications Tower • Helipad (not used) • Cold Vent Stack • Firewater Tank • Foul sewer drain and septic tank • Surface water drains and soakaways • Site water well • Three phase mains (ESB) supply	Site area: 1.66ha (excluding main access road – 0.64ha) Buildings: 223m^2 (Terminal Building – 215m^2, Firewater Pump House – 8m^2) Communications Tower: 98m high with concrete foundations Vent Stack: 20m high 16” vent

Source: Genesis (2011), Xodus (2016a)

3.3 Consideration of Potential Re-Uses

The Kinsale Area facilities have been designed for dry gas production and processing, and the majority of the facilities are now close to or beyond their original design lives. Nevertheless, parts of the facilities may be suitable for re-use, depending on the service, particularly the main Kinsale and Seven Heads export pipelines and the platform jackets.

Three potential re-uses have been considered at a high level. These are hydrocarbon production, carbon capture and storage (CCS) and offshore wind energy production.

Hydrocarbon Production

The Kinsale Area facilities are not designed for liquid hydrocarbon or wet gas production and are unlikely to be suitable for such use. Some of the facilities could potentially be re-used for a future dry gas development as host infrastructure. However, there are currently no known commercial dry gas discoveries in the vicinity nor is Kinsale Energy aware of any firm drilling plans for dry gas prospects within tieback distance of any of the facilities. There are a number of appraisal wells planned in the Barryroe field and the 18” pipeline from Seven Heads to Kinsale Alpha, could be used for export of associated gas from a potential development of that field

Carbon Capture and Storage

Kinsale Energy has carried out technical studies which would indicate that the main Kinsale Head reservoir may be suitable for CCS and also that some of the Kinsale Area facilities may be suitable for CO_2 transportation, particularly the 24” export pipeline and the jackets.

There is currently no commercial case for a merchant CCS service as CO_2 prices are too low to justify the required investment, however, this may change in the coming years. It is also noted that there is a proposal in Ireland’s current National Mitigation Plan (July 2017) for DCCAE to explore the feasibility of utilising suitable reservoirs for CO_2 storage within the next 5 years. A feasibility study into the use of the Kinsale Head reservoir for CCS is being undertaken by Ervia.

Offshore Wind Energy Production

The main 24” export pipeline and landfall could possibly have a use as a cable conduit, for either fibre optic or high-voltage direct current (HVDC) cables (for example as part of a windfarm). The platform jackets could be used to support HV convertor stations. Kinsale Energy is not aware of any wind farm development being considered for the vicinity of any of the Kinsale Area facilities, so no proposal currently exists at this time.

Conclusion

No other re-use options have been identified at present. Should future circumstances change with respect to the potential for any of the re-use options identified above, then a leave *in situ* option, particularly with regard to the 18” Seven Heads export pipeline and the main 24” export pipeline and landfall, could facilitate the re-use of that infrastructure in the future. Additionally, the platform jacket removal campaign may be scheduled over a number of years (1-10 years), depending on vessel availability, cost efficiency and company strategy, which could extend the period over which an alternative use may be identified.

The above considerations inform a staged approach to the consent application process for the project, such that the wells, platform topsides, and subsea structures comprise the first consent application, and the pipelines and platform jackets comprise the second consent application.

Should any of the potential re-use proposals be taken forward, they would be subject to the requisite environmental assessments and consents at the appropriate time, which would also include a cumulative assessment of the decommissioning of the Kinsale Area facilities.

3.4 Decommissioning Alternatives Considered

3.4.1 Do Nothing Alternative

The do nothing scenario should be considered in the assessment of alternatives, in accordance with the EIA Directive.

As outlined in Section 1, the Kinsale Area facilities are operated in accordance with two petroleum leases:

- Petroleum Lease No 1 (OPL 1 - 1970): Kinsale Head, Southwest Kinsale and Ballycotton Gas Fields, and
- Seven Heads Petroleum Lease (2002): Seven Heads Gas Field.

It is a requirement of both leases that the facilities are decommissioned and decommissioning plans must be submitted to the Minister for approval, under the terms of the leases. In the context of the KADP therefore, the do nothing alternative is not an alternative which can be brought forward for assessment.

3.4.2 Other Decommissioning Alternatives Considered

This section describes a range of alternatives for the decommissioning of the facilities (alternatives within the meaning of the EIA Directive). Some of these alternatives, having been considered (in accordance with the EIA Directive), were discounted, for the reasons described herein. Other alternatives have been taken forward into the full environmental assessment. The impacts of the decommissioning options taken forward into the full assessment, on the environmental receptors relevant to the Kinsale Area (which are identified in **Section 4** and **Section 5)**, are assessed in **Section 6** and **Section 7**.

Table 3.8 sets out a summary of the decommissioning alternatives considered, with **Section 3.4.3** to **Section 3.4.6** providing further detail.

Table 3.8: Summary of decommissioning alternatives initially considered

Section Ref.	Facility	Decommissioning Alternatives Initially Considered	Comment
n/a	Platform and Subsea Wells	• Plug & Abandon	No technically recognised alternative
3.4.7	Platform Topsides	• Full Removal • Leave *in situ*	Leave *in situ* was initially considered as an alternative for the platform topsides, however, as no potential re-uses have been identified and due to legal obligations for the complete removal of structures (OSPAR Decision 98/3 – refer to **Section 2.1.4 and Appendix A**) the leave in situ alternative was not considered further.
3.4.4	Platform Jackets	• Full Removal • Partial Removal • Leave *in situ* • Toppling in current location	Partial removal, leave *in situ* or toppling in current location were initially considered as alternatives for the platform jackets but due to legal obligations for the complete removal of structures (OSPAR Decision 98/3 – refer to **Section 2.1.4 and Appendix A**) no alternative other than full removal was not considered further.

Section Ref.	Facility	Decommissioning Alternatives Initially Considered	Comment
3.3.5	Subsea structures	• Full Removal • Leave *in situ*	Leave *in situ* was initially considered as an alternative for the other subsea structures but due to legal obligations for the complete removal of structures (OSPAR Decision 98/3 – refer to **Section 2.1.4 and Appendix A**) the leave in situ alternative was not considered further.
3.3.6	Pipelines, Umbilicals and protection materials	• Full Removal • Partial Removal • Leave *in situ*	Full removal and partial removal were initially considered as alternatives for pipelines, umbilicals and protection materials. Refer to **Section 3.4.6** and **Appendix E** for details of a comparative assessment which considered the safety, environmental, technical, social and cost aspects of the various alternatives and which identified leave *in situ* as the optimal option.
3.3.7	Inch Terminal	• Full Removal	Pursuant to the conditions imposed under the original planning permission for the Inch Terminal, it is required to be fully removed upon the permanent cessation of its function and therefore no alternative options were considered.

3.4.3 Platform Topsides Decommissioning Alternatives

As indicated in **Table 3.8,** no re-use options have currently been identified for the Kinsale Area platforms (refer to **Section 3.3**) such that the platform topsides could be left *in situ*. As a consequence and to ensure compliance with OSPAR Decision 98/3, both KA and KB topsides will be completely removed and returned to shore for reuse, recycling and/or disposal.

3.4.4 Platform Jackets Decommissioning Alternatives

As indicated in **Table 3.8**, the Kinsale Area platforms will be removed in line with OSPAR Decision 98/3. However, Kinsale Energy initially considered a number of alternatives for the decommissioning of both KA and KB jackets including:

- Full removal
- Partial removal
- Toppling of jackets *in situ*
- Leave *in situ*

These decommissioning alternatives were considered to identify the preferred decommissioning option for the Kinsale Area platforms. Several studies have previously been carried out to inform the options selection for the decommissioning of the KA and KB platforms (Genesis 2011, Allseas 2012a, Xodus 2016d).

Partial removal of the jackets down to the top of footings or removal to -55m below sea level in accordance with the International Maritime Organisation (IMO) guidelines relevant to maritime security were considered as technically feasible, for example. However, both these options would not be in accordance with OSPAR Decision 98/3 and therefore were not considered further.

Toppling of the jackets is technically feasible, but due to the depth of water and size of structures 55m clear draught between the top of the structures and the water surface would not be provided in accordance with the IMO guidelines. Therefore, this alternative was also not considered further.

Similar to the platform topsides, no re-use options have currently been identified for the platform jackets (refer to **Section 3.3**), such that they could be left *in situ* but there remains the potential for re-use. If a re-use option is not identified in the decommissioning timescale (up to 10 years, see **Section 3.5.2.3**), the jackets will also be removed. Project execution phasing allows for the consideration of the removal of the topsides and jackets separately, not only in terms of maximising the potential for re-use of the jackets, but also in relation to vessel availability and cost efficiency. The possible alternatives in terms of phasing have been considered in the full assessment herein.

3.4.5 Subsea Structures Decommissioning Alternatives

Similar to the Kinsale Area platforms, all subsea structures (manifolds, valve skids and tee structures) will be removed, as they are interpreted to fall within the category "disused offshore installation" under OSPAR Decision 98/3, which may only be left in place, "when exceptional and unforeseen circumstances resulting from structural damage or deterioration, or from some other cause presenting equivalent difficulties, can be demonstrated." This is not the case with the Kinsale Area subsea facilities and so all such facilities will be removed.

3.4.6 Pipelines and Umbilicals Decommissioning Alternatives

There are a number of alternative approaches to decommissioning of the Kinsale Area pipelines and umbilicals. In order to decide on the best approach, a Comparative Assessment (CA) of different options has been undertaken. The CA followed a systematic process, in which the safety, environmental, technical, social aspects and cost of the various options were evaluated. The process is documented in a CA report (refer to **Appendix E**) which includes the scoring methodology and scoring matrices for each of the options, and also narrative expanding upon the implications of each of the options.

3.4.6.1 Comparative Assessment

The framework for the CA drew on OSPAR 98/3 and Oil and Gas UK (OGUK) (2015) guidance, with a scoring system to assess each of the proposed decommissioning options covering safety, environment, technical, societal and economic criteria. The technical feasibility of any option was also considered in relation to industry experience to date, including from proposed approaches to the decommissioning of pipelines for fields in the North Sea, and related summary reports of experience to date (e.g. OGUK 2013).

Initially a set of 45 individual option considerations relating to each individual pipeline and umbilical were evaluated as part of the CA process, including various combinations of full removal, partial removal and leave *in situ*. On review of the initial results from this CA process it was considered that certain pipelines and umbilicals could be grouped and assessed together in view of their similarity (e.g. type and burial status). Additionally, as indicated in **Section 3.2**, with the exception of Ballycotton all umbilicals are laid next to their associated pipelines and share the same protection materials (e.g. rock or concrete mattresses). In practice, it is unlikely that the decommissioning of the umbilicals would take place separately and it was regarded that these could be assessed alongside their respective pipelines. Moreover, the similarity in the decommissioning options for each pipeline or umbilical resulted in initial CA scoring which was either not significantly different or the same for multiple options. For these reasons, umbilicals and pipelines were considered together.

The grouping resulted in two types of offshore pipeline/umbilical being defined along with their associated options:

- pipelines which are surface laid or exposed along much of their length and,
- pipelines and umbilicals which are largely under protective materials or buried.

In addition to refining the process by grouping similar pipelines/umbilicals, the initial consideration also allowed for the further definition of options for these groups.

For example the consideration of partial removal for those pipelines largely under protective materials or buried was not considered to be appropriate (e.g. as the results would not be appreciably different to the full removal option), and the results from the initial consideration also noted that the additional safety, technical and environmental risks from partial removal did not result in significant risk reduction, for example, compared to the equivalent option using rock cover. The following options were taken forward for further consideration in the final CA:

For surface laid pipelines and those exposed along much of their length:

- fully remove,
- leave in situ and rock cover those sections which are >50% exposed as well as pipe ends,
- leave in situ and rock cover pipe ends and any freespans

For pipelines and umbilicals largely under protective materials or buried:

- fully remove,
- leave in situ and rock cover pipe ends and any freespans (where applicable)

Criteria for evaluating the potential impact of the various options were developed for safety, environment, technical feasibility, society and cost categories. The CA used a scoring matrix (see OGUK 2015). For each of these categories, a number of sub-categories were incorporated. The sub-categories were scored using a five point classification based on the relative risk or expected magnitude of effect from each option. The criteria and scoring matrix is shown in **Table 3.9.**

The sub-criteria were scored on a five point scale ranging from 1 (Very Low) through to 5 (Very High), where 1 represents best performance/least significant impact/lowest risk and 5 worst performance/largest significant impact/highest risk. Scores for the sub-criteria were then weighted according to the level of definition and understanding of methods, equipment and hazards ("uncertainty").

Table 3.9: Comparative Assessment Relative Risk and Impact Criteria Scoring

Criteria	Sub criteria	Very Low	Low	Medium	High	Very High
		1	2	3	4	5
Safety	Risk to personnel offshore during decommissioning operations (Potential Loss of Life)	>0.00001	>0.0001	>0.001	>0.01	>0.1
Safety	Risk to personnel onshore during decommissioning operations	No risk. No onshore disposal elements	Minor/first aid. Handling <500 tonnes of material	Medical aid/lost time injury. Handling >500 tonnes of material.	Permanent disability/fatality	Multiple fatalities
Safety	Risk to divers during decommissioning operations (PLL)	>0.00001	>0.0001	>0.001	>0.01	>0.1
Safety	Risk to 3rd parties and assets during decommissioning operations	No risk	Loss of access to operational area	Interference with 3rd party operations altering safety risk	Damage to 3rd party asset/damage to vessel	Damage to 3rd party asset requiring remediation/loss of vessel
Safety	Residual risk to 3rd parties	No risk	Potential snagging risk	Damage/loss of fishing gear	Damage to vessel	Loss of vessel

Criteria	Sub criteria	Very Low 1	Low 2	Medium 3	High 4	Very High 5
Environment	Chemical discharge	None	PLONOR chemicals only	No warnings or substitution labels RQ<1	Warning labels RQ>1	Warnings and substitution labels RQ>1
Environment	Seabed disturbance and/or habitat alteration including cumulative impact	0 - 1% of existing footprint	1 - 10% of existing footprint	10% - 50% of existing footprint	>50% - 100% of existing footprint	>100% of existing footprint
Environment	Total CO_2 Emissions (resulting from energy consumption associated with vessels, treatment of recovered material and rock cover)	<1000t	1,000-5,000t	>5,000-10,000t	>10,000-25,000t	>25,000t
Environment	Proportion of potential recyclable material returned	>80%	50% - 80%	30% - <50%	10% - <30%	<10%
Environment	Proportion of total landfill material returned	<10%	10% - <30%	30% - <50%	50% - 80%	>80%
Environment	Conservation sites and species (including noise effects)	No impact	Potential effects but unlikely to be detectable as within normal variability	Minor detectable effects with rapid recovery	Effects detectable, not affecting site integrity or species population	Significant effects on site integrity or population
Environment	Loss of containment to the environment of chemicals, hydrocarbons	None	Slight Impact Reportable spill	Minor Impact/ Localised Impact Spill requiring Tier 1 response	Major Impact Spill requiring Tier 2 response	Massive Impact Spill requiring Tier 3 response
Technical	Technical feasibility	Routine operations with high confidence of outcomes Very low risk of failure. Low technical complexity	Routine operations with good confidence of outcomes Low risk of failure.	Non-routine operations but with good experience base Low risk of failure. Medium technical complexity	Non-routine operations with limited experience base Moderate risk of failure.	Untried technique Higher risk of failure. High technical complexity

Criteria	Sub criteria	Very Low	Low	Medium	High	Very High
		1	2	3	4	5
Technical	Weather sensitivity	Operations not weather sensitive	Operations are little affected by weather	Requires good weather window	Requires typical summer good weather window	Requires long good weather window
Societal	Residual effect on fishing, navigation or other access (including cumulative)	No effect	Access to area unrestricted	Access to area with charted obstructions	Access to area with uncharted debris and obstructions	Closed access to area
Societal	Coastal communities	No impact	Impacts within normal variability of onshore operations	Short term nuisance during onshore operations	Medium term nuisance during onshore operations	Long term nuisance during onshore operations
Economic	Total cost	<€2million	€2-5 million	€5-10 million	€10-20 million	>€20 million
Economic	Residual liability including monitoring and remediation if necessary	No residual liability	Surveys and remediation unlikely to be required	Survey requirement anticipated but at declining frequency	Surveys and remediation likely to be required in each 5 year period	Annual survey and potential for remedial work

The overarching conclusion of the CA process was that the full removal options have the highest potential impact (reflected in these scoring worst using the CA criteria, particularly in respect of environment and health and safety, but also in technical and economic criteria) and are therefore least preferable with key findings summarised as follows:

- The full removal option represented the highest safety risk to personnel involved in the removal and recycling of the infrastructure and greatest technical risk due to relatively limited experience to date, particularly in the removal of large pipelines.
- While the methods for removing pipelines are transferrable from standard procedure elsewhere in the oil and gas industry, their implementation at the scale proposed by the option is not, and therefore it entails greater technical and safety risks.
- The snagging risks to fisheries have been assessed as being very low for the leave in situ options (Anatec 2017; even though it is noted that these risks would be removed by the complete removal of the facilities which could represent a long-term snagging hazard to fisheries).
- The environmental risks were highest for full removal as this option would generate an area of seabed disturbance greater than that occupied by the pipeline, and at least as great as that which would have been associated with installation. There would also be greater volumes of CO_2 emissions from longer vessel times in the field for the full removal option.
- Though full removal provides substantial returns to shore of recyclable material which could offset future emissions from products using the recycling materials, this was largely counteracted by emissions from vessels involved in removal, and the uncertainty relating to the recyclability of the concrete, in addition to greater onshore risks of material handling.

Whilst the same scores were achieved for residual societal risks (e.g. to fisheries) for both leave in situ options, the results of the fisheries study (Anatec 2017) indicate that risk could be reduced further through the adoption of rock cover on 50% exposed pipeline in addition to freespans, or a modified version of this which applies rock cover to all exposed sections.

- The costs of full removal options were significantly greater than for any other option considered.

Figures 3.11a-f below, taken from the CA report (refer to **Appendix E** for full report) summarise the average option scoring of the CA.

Figure 3.11a-f: The average option scoring of the Comparative Assessment for all pipelines and umbilicals

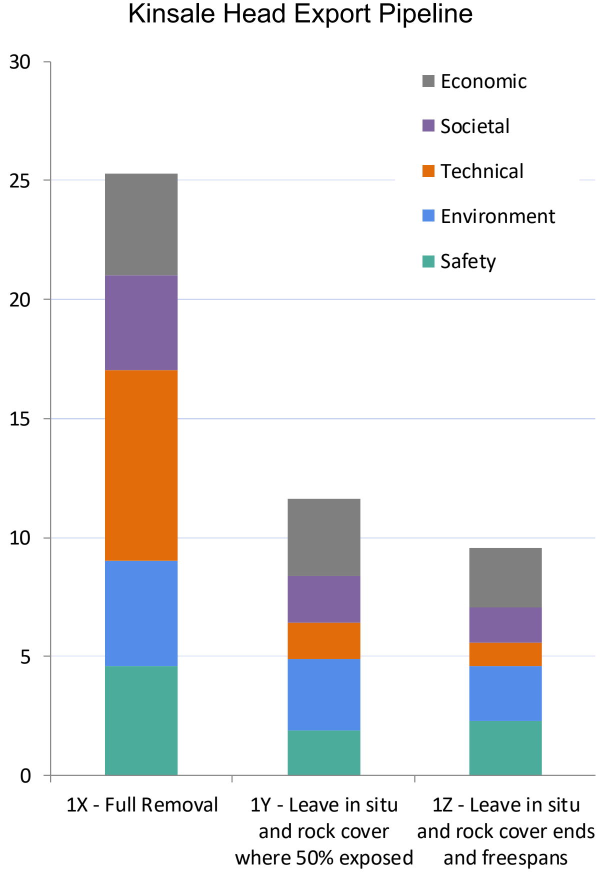


Figure 3.11a

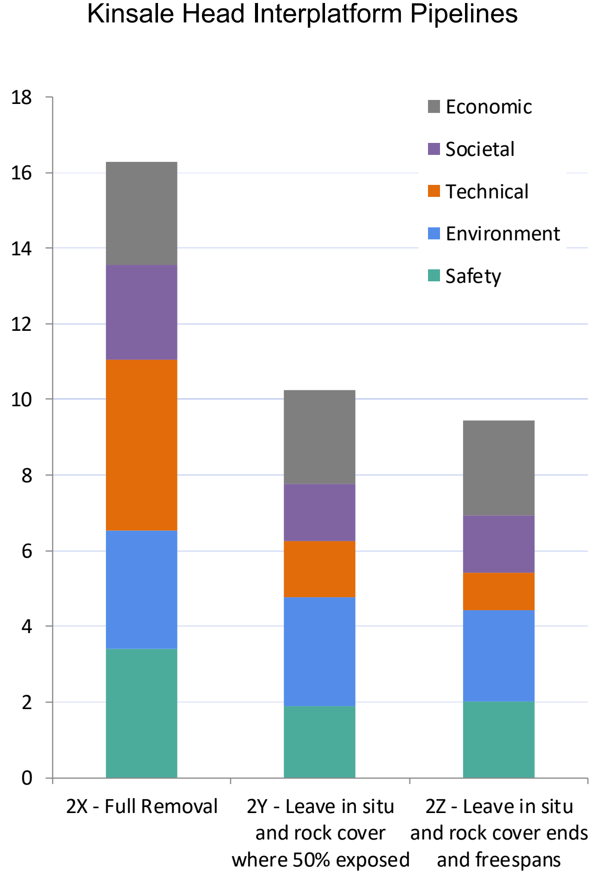


Figure 3.11b

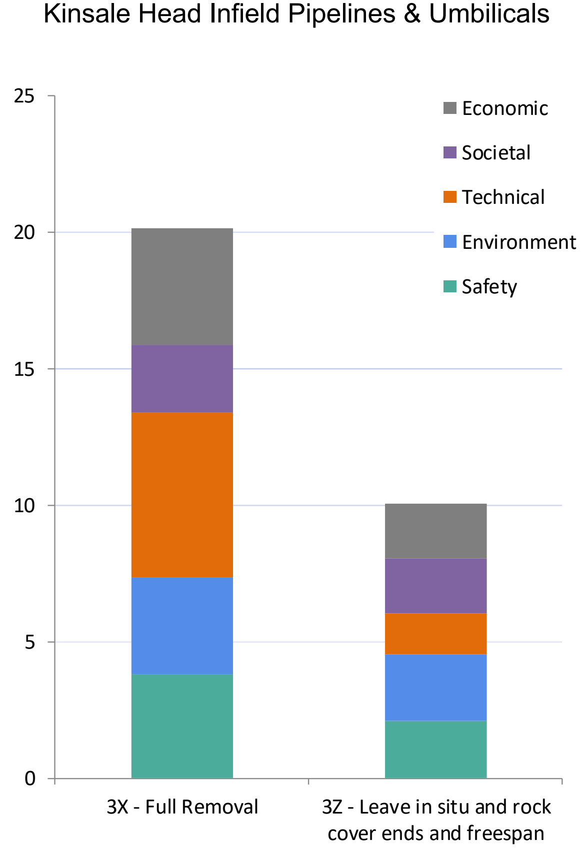


Figure 3.11c

Seven Heads Export Pipeline & Umbilical	Seven Heads Infield Pipelines & Umbilicals	Onshore Pipeline

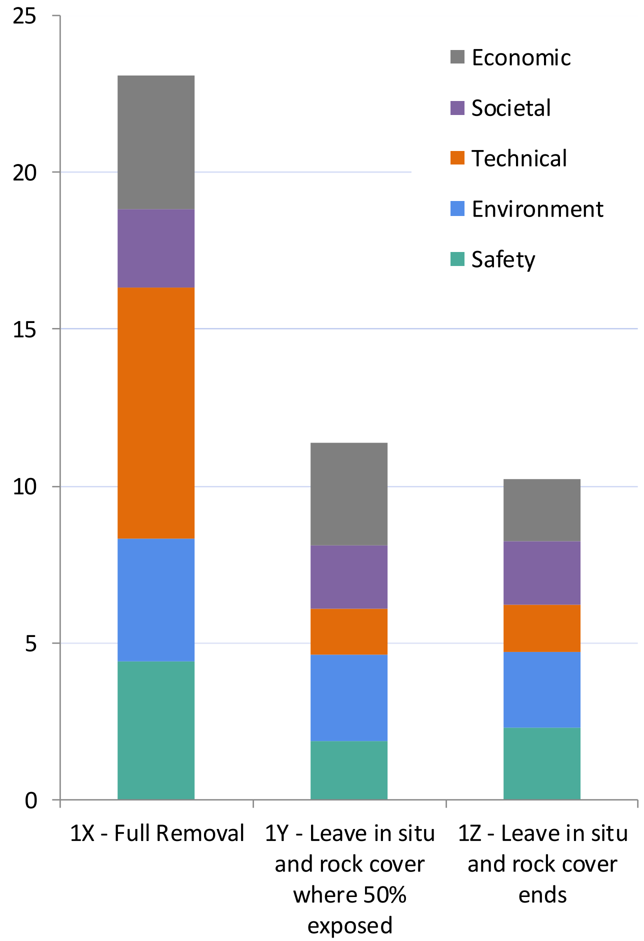


Figure 3.11d

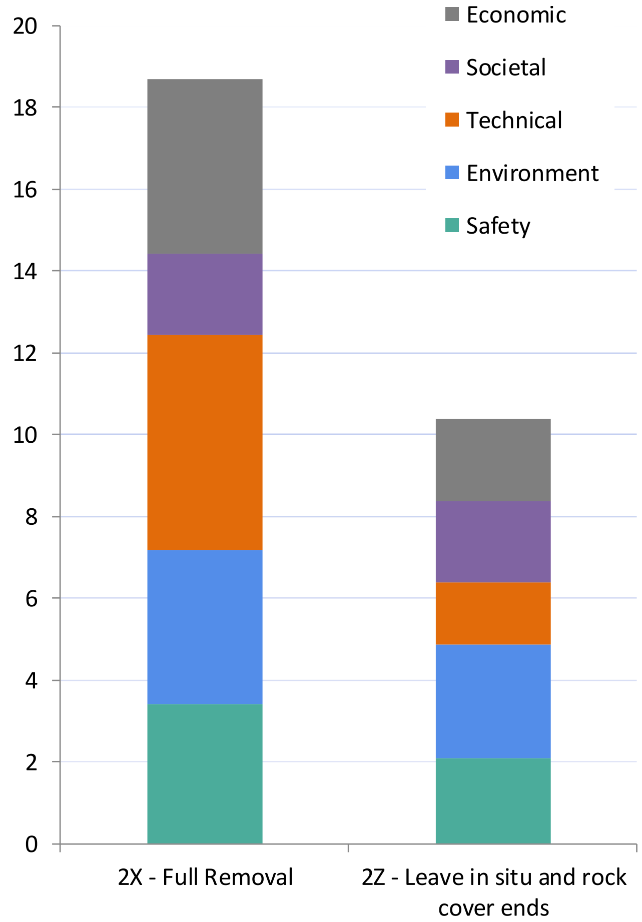


Figure 3.11e

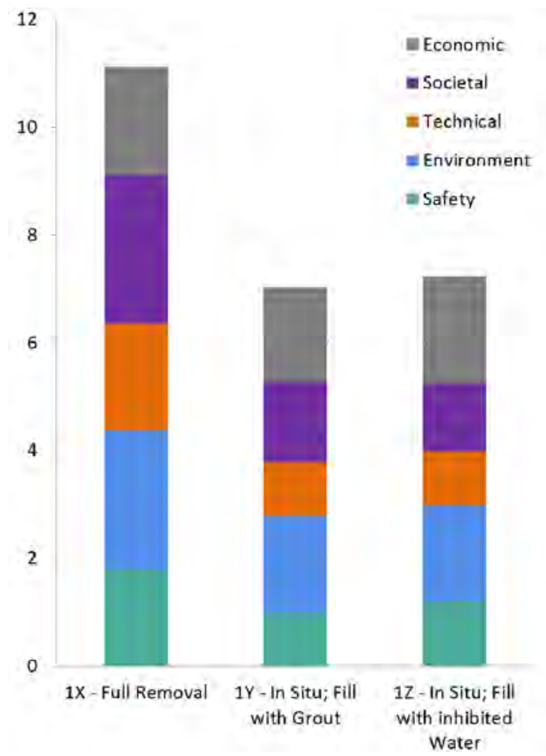


Figure 3.11f

Note: Lower score = lowest risk (best scoring option); higher score = highest risk (worst scoring option).

Based on the results of the CA, the most favourable options for the offshore pipeline infrastructure is to leave the pipelines and umbilicals *in situ* and to remediate freespans and cover the ends, using rock cover, to reduce future risks to 3rd parties. This option scores favourably for all the categories assessed, and the majority of sub-categories, including being the preferred option in terms of the environmental criteria considered. While additional rock placement may reduce 3rd party risk even further, this did not change the overall results of the CA. Nevertheless, in order to ensure a conservative assessment of possible impacts, two *in situ* decommissioning options have been assessed in this EIAR:

- rock cover remediation of pipe ends and freespans only (CA preferred option)
- rock cover the full length of pipelines, which are currently not buried or under protective material

3.4.6.2 Onshore Pipeline

The Comparative Assessment (refer to **Appendix E** for full report) also included the onshore section of the 24" export pipeline from Inch Terminal to the high water mark (HWM) at Inch beach. The options analysed within the CA were:

- Removal and disposal of the pipeline in its entirety,
- Leave pipeline in situ and fill with grout
- Leave pipeline in situ and fill with inhibited water

Similar to the offshore pipelines and umbilicals the overarching conclusion of the CA process is that the full removal option for the onshore pipeline has the worst scores across all the categories assessed and is therefore least preferable (see **Figure 3.11f**).

The two options to leave the onshore pipeline *in situ* (and fill with grout or fill with inhibited water) scored similarly and therefore, **both leave *in situ* options** have been considered for the purposes of assessment in this EIAR to provide a reasonable assessment of the associated impact.

The option to leave the pipeline *in situ* and fill with inhibited water would provide for future alternative re-use of the pipeline, while minimising impacts. This option would only be progressed if an alternative use and operator is identified prior to commencing pipeline decommissioning. In the event that no such re-use option is identified, the pipeline will be filled with grout.

3.4.6.3 Summary

For the purposes of this environmental assessment, the options to leave offshore pipelines and umbilicals *in situ* and rock cover freespans only, or to rock cover the full length of pipelines, which are currently not buried or under protective material (i.e. any exposed lengths), have both been brought forward for assessment in the EIAR, to ensure, in the event that more/less rock cover may be required during the decommissioning process, that the reasonable worst case has been identified and all likely impacts are assessed.

3.4.7 Onshore Terminal

The extant planning permission for the onshore terminal (Cork County Council reference no. 2929/76) requires the full removal of all infrastructure and the reinstatement of the site to agricultural use to the original contours. No alternative re-use has been identified for this facility and the full removal of all facilities on the site was considered the reasonable worst case alternative and was carried forward to the full environmental assessment.

3.4.8 Decommissioning Alternatives and Methodologies brought forward for full assessment

Table 3.10 sets out a summary of the selected decommissioning alternatives included in the full environmental assessment for each facility.

It also includes alternative methodologies which can be used to achieve each decommissioning alternative. The final decommissioning methodology for each facility will be determined in conjunction with the selected removal contractor, however, where alternative methodologies are available, these have been included for the purposes of environmental assessment as detailed in the following sections to provide an assessment of the reasonable worst case scenario of the potential associated impact. These will also inform the decommissioning plans.

The KA and KB platforms are comparable in design, but they have been modified since their original installation with both the removal and addition of modules. Consequently, they now have different overall topside weights and configurations. Despite these differences, the methods considered feasible to remove the platform topsides and jackets are essentially the same.

Section 3.5 describes the proposed decommissioning project, including the various alternative decommissioning options and alternative methodologies brought forward for full assessment in the EIAR.

Table 3.10: Summary of decommissioning alternatives (and associated alternative methodologies) progressed to full environmental assessment

Section Ref.	Facility	Chosen Decommissioning Alternative	Alternative Methodologies identified and considered for each chosen Decommissioning Alternative	
			Method	Vessel Type[9]
3.5.1	Platform Wells	Plug & Abandon	1. “Thru-tubing”	n/a – wells abandoned “rigless”
	Subsea Wells			a. Semi-submersible rig
				b. Light well intervention vessel / semi-submersible rig
3.5.2.2	Platform Topsides	Full Removal	1. Single Lift	a. Specialist HLV
				b. Conventional HLV
			2. Piece-medium (reverse installation)	a. Conventional HLV
3.5.2.3	Platform Jackets	Full Removal	1. Single Lift	a. Specialist HLV
				b. Conventional HLV
				c. Flotation
			2. Multiple Lift	a. Conventional HLV
3.5.3	Subsea structures	Full Removal	1. Single Lift	a. DSV

[9] Note that only the principal vessels involved are listed in this table, however other vessels, for example construction support (CSV), anchor handling (AHV), platform support (PSV) and guard vessels may also be used and are listed in full in relevant sections below.

Section Ref.	Facility	Chosen Decommissioning Alternative	Alternative Methodologies identified and considered for each chosen Decommissioning Alternative	
			Method	Vessel Type[9]
3.5.4	Pipelines, Umbilicals and protection materials	Leave *in situ*	Offshore: 1. Rock cover pipe ends and free spans 2. Rock cover pipe ends and all exposed sections • Note export pipeline will be filled with inhibited water if re-use identified Onshore: 1. Fill with inhibited water, followed by grout if no re-use option identified (see **Section 3.3**)	a. Rock placement vessel with remotely operated vehicle (ROV) supervision n/a
3.5.6	Inch Terminal	Full Removal	Demolition and removal of all above ground facilities on site and reinstatement of the site to original ground condition	

3.5 Description of the Proposed Decommissioning Scope of Work

The broad scope of work involved in decommissioning the Kinsale Area facilities, including all decommissioning alternatives and methodologies which have been taken forward into the full environmental assessment as decommissioning options (refer to **Table 3.10**) are outlined below. More detail is provided in **Sections 3.5.1-3.5.7**.

- Facilities preparation: disconnect and degas process plant and pipelines (pipelines displaced with seawater, and inhibited seawater in the case of the 24” export pipeline).
- Wells: plug and abandon all platform and subsea wells and removal of any surface component of these wells, including wellhead protection structures and platform conductors.
- Platform topsides: complete removal of topsides either by single lift using a conventional or specialist heavy-lift vessel (HLV), or multiple lifts using a smaller HLV after cutting the topsides into sections, in accordance with OSPAR Decision 98/3.
- Subsea structures: (e.g. manifolds, wellhead protection structures): full removal in accordance with OSPAR decision 98/3 including the removal of connecting spool pieces and umbilical jumpers, and associated protection measures, for recycling/disposal.
- Platform jackets: complete removal by single lift using a conventional or specialist HLV, flotation, or multiple lift by smaller HLV by cutting the jacket into sections in accordance with OSPAR Decision 98/3.
- Offshore pipelines, umbilicals and protection materials: leave *in situ,* rock cover of freespans only or all exposed sections, and rock cover remaining *in situ* protection materials.

- Export pipeline (offshore and onshore section): leave *in situ,* fill onshore section with grout (if a viable re-use option is not identified) and rock cover of freespans only or all exposed sections in offshore section.
- Inch Terminal: full removal of facilities and reinstatement of site to the original contours and agricultural use, as per the terms of the site planning permission (Cork County Council planning reference 2929/76).
- Post-decommissioning survey: A debris clearance and pipeline route survey will be undertaken to confirm the completion of the decommissioning operations.

As indicated in Section 3.4.5, the final decommissioning methodology for each facility will be determined in conjunction with the selected removal contractor. The durations of each decommissioning option selected for the purposes of assessment have been chosen to be conservative; the actual durations are expected to be less.

Note that where durations of vessels, engaged in decommissioning activities, are provided, a contingency of 25% has been added to allow for weather or technical issues that could lead to activities taking longer than planned. This again ensures a conservative assessment.

3.5.1 Well Decommissioning

The Kinsale Area wells are drilled in the Cretaceous age “A” (Greensand) and/or “B” (Wealden) sands, which are overlain by a regional clay caprock seal (Gault Clay). Each platform well targets both intervals and production is comingled in the well, whereas the subsea wells variously target either the “A” sand (Ballycotton, Greensand) or “B” sand intervals (Southwest Kinsale, Seven Heads).

Reservoir pressures in the various fields, which were initially around 1500 psia, have substantially depleted through field life, with estimated pressures at time of cessation of production (CoP) in the order of 50-100 psia. Although well pressures will be sub-hydrostatic at the time of abandonment, the design of the permanent well barriers (plugs) conservatively accounts for the possibility of reservoir re-charge occurring and pressures regaining the original level over geological time. Permanent barriers (cement plugs) will be set at suitable depths in each well to isolate both the “A” and “B” sand formations from the surface.

The proposed approach to decommissioning each of the Kinsale Area wells (see **Table 3.11** & **Table 3.12**) was determined by studies undertaken by AGR (2016a, b) based on Oil and Gas UK (2015) well abandonment guidelines.

Whilst a mobile offshore drilling unit (MODU) may be used as part of the well decommissioning campaign for the subsea wells, no drilling operations will take place.

3.5.1.1 Platform wells

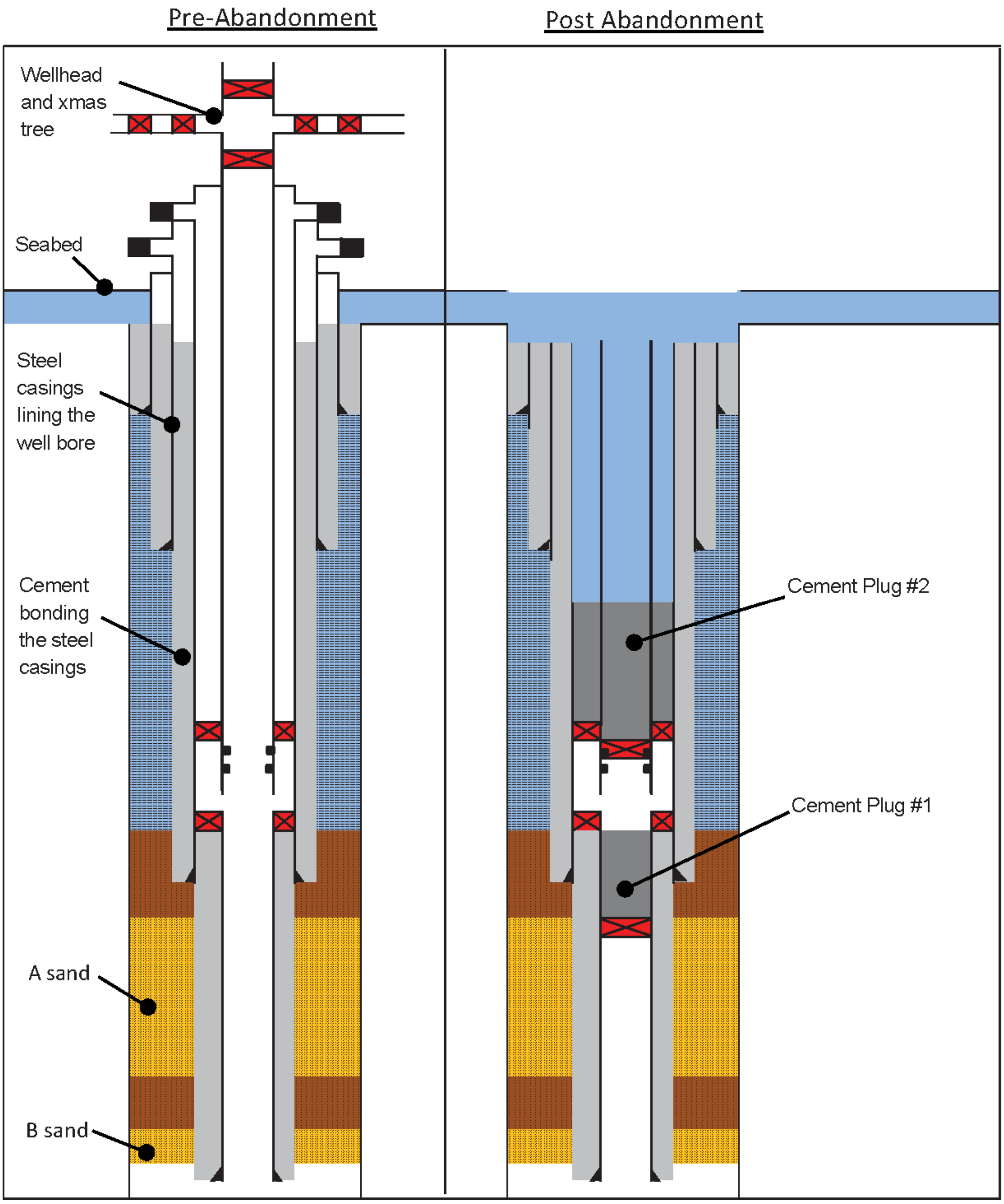
There are seven production wells on each platform all of which have a similar design, with a 20” conductor followed by 13⅜” and 9⅝” on 7” casings with wells reaching a total vertical depth (TVD) below seabed of ~3,000ft. All wells are completed with 7” production tubing and a Xmas Tree located on the platform cellar deck.

Due to the shallow well depth and the relatively simple completion design, a “thru-tubing” abandonment can be undertaken for the KA and KB platform wells using either “slickline” well intervention where tools are deployed into the well by wireline or coil tubing techniques. This approach minimises recovery of the 7” production tubing (which would otherwise significantly increase equipment requirements).

The use of a Jack-up or MODU beside the platform for well plug and abandonment (P&A) activities was discounted at an early stage of the study due to technical feasibility factors. A rigless intervention approach was determined to be the most suitable method for well P&A activities on both the Alpha and Bravo platform, utilising existing infrastructure and mobilising skid-mounted intervention equipment as required.

The proposed platform well abandonment methodology is summarised in **Table 3.11** and illustrated in **Figure 3.12.**

Figure 3.12: Typical Well Abandonment Diagram



Source: based on AGR (2017b).

A number of skid-mounted equipment modules will be required on the platforms to support abandonment operations including additional diesel power generators which will be needed to provide a minimum of 500kVa of dedicated power, along with pumping and cementing equipment and jacking units to recover the conductor and surface casing sections. For the purposes of estimating emissions associated with platform well decommissioning, it is considered that doubling the capacity of existing diesel generators will adequately cover the required loads.

The platform well abandonment activities are estimated to take approximately 155 days to complete (including a 25% contingency)[10]. This excludes mobilisation of the equipment to the platforms from Cork, which would involve up to 3 platform support vessel (PSV) trips.

Table 3.11: Platform well abandonment main steps

Item	Operation
1	Re-enter well and displace wellbore to sea-water
2	Install cement plugs downhole
3	Cut and recover 7" tubing ~150ft below seabed
4	Remove Xmas Tree
5	Recover conductor and casings

3.5.1.2 Subsea wells

All subsea wells will be decommissioned from a semi-submersible MODU (see **Figure 3.13**), and/or a light well intervention vessel (LWIV).

Figure 3.13: Typical semi-submersible drilling rig (MODU)

Normally two anchor handling vessels tow such a rig to the well location. On reaching the location, a third anchor handler is generally brought in to run and deploy the rig anchors.

[10] Based on AGR (2017b)

Mooring is achieved via the deployment of 8-12 anchors weighing approximately 12 tonnes each, connected to the rig by chain, a proportion of which will lie on the seabed (catenary contact) when the anchor is deployed. Minor adjustments to the rig position can be made by hauling or paying out the anchor chain. The precise arrangement of anchors around the rig will be defined by a mooring analysis which takes account of the local water depth, tidal and other currents, winds and seabed features. Due to the presence of subcropping chalk bedrock, with a thin sediment cover, it may be effective to pre-lay the MODU anchors in advance of the MODU's arrival at each well location. The MODU would normally move and re-anchor between each subsea well but the rig may be repositioned without lifting anchors between some closely spaced wells, such as the Southwest Kinsale wells.

The rig would have facilities for drilling (or in this case well plugging and abandonment), power generation, supporting utilities and accommodation. The rig will require refuelling (bunkering) during the abandonment programme which will be undertaken in calm seas and in accordance with procedures agreed with Department of Transport, Tourism and Sport (DTTAS). Helifuel supplies are replenished when necessary by replacing an empty with a full tank. Approximately 2 crew change helicopter trips per week will be made to and from Cork during the well abandonment campaign.

An alternative approach is to use a LWIV which can perform simple well plug and abandonment procedures such as those required for the majority of the subsea wells. A LWIV has the advantage of faster mobilisation and transit between wells and negates the requirement for anchor handling vessels or the deployment of anchors. However, a LWIV's limited deck space necessitates returns to port to replenish supplies of cement and there is a smaller operational weather window compared to the MODU. Such vessels are also not currently well equipped to deal with tubing recovery, which will be required for one of the Seven Heads wells (48/24-8) and therefore a MODU will need to be mobilised to abandon this well. The deployment of either a MODU or LWIV will be subject to vessel availability, schedule and detailed technical assessment. A construction support vessel (CSV) could be used to cut and retrieve the wellheads and casings following abandonment, whichever option is selected.

The subsea production wells (though with small variation in design and target formations) will be abandoned using the same "thru-tubing" approach outlined above for the platform wells, irrespective of whether a MODU or LWIV is used (see **Figure 3.12**). The Ballycotton well has a vertical Xmas Tree which requires different equipment to allow intervention, but the abandonment process is fundamentally the same as for all the other wells. The main steps for the abandonment of the subsea wells are set out in **Table 3.12**.

The four exploration wells (49/16-2, 48/20-1A, 48/25-2, 48/23-3) have already been abandoned to a standard suitable for permanent decommissioning such that the only remaining work required is to remove the wellhead and to sever the casings to 10ft below the seabed and recover these to shore. This can be completed from a CSV.

Though all of the subsea wells have a surface component in the form of subsea Xmas Trees, four have additional wellhead protection structures comprising a gravity based foundation of four concrete blocks over which sits a truncated triangular steel frame (see **Section 3.5.3** for more details). These will be removed prior to the well abandonment to allow access to the subsea wellheads. A LWIV and/or MODU rig would accommodate a crew in the order of 100 persons.

Table 3.12: Subsea well abandonment main steps

Item	Operation
1	Re-enter well and displace well bore to seawater
2	Slickline thru-tubing cementing and cutting and recovery of tubing ~400-600ft below seabed
3	Recover 4½" tubing and perform remedial cementing of 9⅝" section (*well 48/24-8 only)*
4	Remove Xmas Tree
5	Recover conductor and casings

The overall schedule to abandon the subsea wells is estimated at approximately 99 or 159 days (including a 25% contingency) depending on the chosen option outlined above. The estimation is based on the PSV duration which is required for the duration of the works for each option. A high level vessel breakdown for each of the two options is summarised in **Tables 3.13 and 3.14**.

These include mobilisation/demobilisation and infield rig/vessel moves and a 25% contingency. For the purposes of this environmental assessment, the vessel durations associated with the MODU option have been used, in **Section 7** as the worst case scenario.

Table 3.13: Subsea well abandonment timing (days) using a MODU

Vessel	Activity	Mob/ Demob	Transit	Operational	Total Duration	Total with Contingency
MODU	Well intervention and abandonment	11	32	84	127	159
AHV	Anchor handling for MODU	-	6	25	31	39
CSV	Wellhead and casing removal	4	6	25	35	43
PSV	Supply/standby during abandonment	-	-	84	127	159

Source: based on AGR (2017a)

Table 3.14: Subsea well abandonment timing (days) using a LWIV and MODU

Vessel	Activity	Mob/ Demob	Transit	Operational	Total Duration	Total with Contingency
LWIV	Well intervention and abandonment	1.5	10	46	57	72
MODU	Well intervention and abandonment of well requiring remedial cementing (48/24-8)	16	20	33	69	86
AHV	Anchor handling for MODU	-	6	7.5	14	17
CSV	Wellhead and casing removal	4	6	25	35	43
PSV	Supply/standby during abandonment	-	-	79	79	99

Source: based on AGR (2017b)

3.5.2 Kinsale Area Platforms Decommissioning

3.5.2.1 Offshore Facilities Preparation Works

Prior to decommissioning of the platforms, preparation works, such as cleaning and topsides preparation and disconnecting and degassing all process plant and pipelines is required. All of these works will be undertaken from the Kinsale Area platforms.

Topsides Preparatory Works

Cleaning and topsides preparation, following Cessation of Production (CoP), is the work required on all systems, plant and equipment to ensure that the platforms are free of hydrocarbon fuels, gases and removable hazardous materials. This ensures that during preparations and final removal of the topsides, no hazards from the production, operating or cleaning elements remain and that the topsides are handed over in a clearly defined and documented condition to facilitate topsides removal.

Initially, pipework and vessels on the topsides will be isolated from the wells, purged with nitrogen gas and vented to the atmosphere to ensure they are free of any residual natural gas.

Volumes of waste (water and corrosion debris (iron)) from the topsides cleaning are expected to be small as the hydrocarbons produced are dry natural gas (e.g. no sludges or solid naturally occurring radioactive materials (NORM) material are present).

These wastes will not be discharged to sea and along with any residual inventories of diesel, chemicals, condensate or aviation fuel, will be collected for onshore disposal under Kinsale Energy's existing waste management procedures.

Asbestos identified on the platforms (mainly building cladding material) will remain on the topsides and be taken away during the topsides removal. Asbestos and other hazardous waste will be handled and disposed of at appropriately licensed facilities in accordance with all relevant legislation. Contractors will be required to strictly adhere to all relevant legislation and guidelines in this regard.

An overview of the waste generated in cleaning the topsides, prior to the overall removal of the topsides to shore, is summarised in **Table 3.15**.

Table 3.15: Overview of topside cleaning waste generated

Waste Type	Composition of Waste	Disposal Route
On-board hydrocarbons	fuels and lubricants: • Diesel • Heli-fuel (Jet A1) • Lubricating Oils	Fuels and lubricants will be transported onshore for re-use/disposal within Ireland
Other hazardous materials & Waste Chemicals	Hazardous waste such as: • Batteries • Fluorescent tubes (containing mercury) • Fire Detectors (radioactive waste) • Fire extinguishants • Refrigerant gases • Tri-Ethylene Glycol (TEG) Hydraulic fluid • Hydraulic Fluid HW540 v2 • BOP fluid (Erifon HD856) (1% concentration).	Waste chemicals, and other hazardous materials will be transported ashore for re-use/disposal within Ireland or Europe Inventories of spare operating chemicals used e.g. (Tri-Ethylene Glycol (TEG) will be run down to minimum levels prior to Cessation of Production)
Original paint coating	The potential presence of lead based paints	May give off toxic fumes / dust if cutting is used so appropriate safety measures will be taken. Painted items will be disposed of appropriately onshore with consideration given to any toxic components

Pipeline Degassing and Umbilicals Contents Displacement

It is planned to remove gas from the pipelines shortly after cessation of production (CoP) by displacing the contents of the pipelines into the subsea wells by pumping seawater from the platforms. Surfactants may also be used prior to the final seawater displacement procedure to clean the pipelines (excluding the export pipeline) and ensure there is no residual hydrocarbons present (though note it is highly unlikely for there to be residual hydrocarbons in the pipelines in view of the production history). All infield pipeline contents will be displaced into the subsea wells and there will be no marine discharges from this activity.

The 24" export pipeline between Kinsale Alpha and the Inch Terminal (offshore and onshore sections) will be displaced from Kinsale Alpha into the terminal site where the seawater will be collected and stored in sealed containers. The seawater will then be disposed during the Inch Terminal decommissioning works (approximately 425m^3 of seawater transported for waste disposal to an appropriately licensed facility via 22HGV movements over 2 days). During the displacement of the export pipeline the majority of gas will be displaced into the gas network but small volumes of gas will be vented at the terminal site intermittently over a period of 2.5 days.

Following the initial displacement of the 24” export pipeline and the Seven Heads 18” export pipeline with seawater, inhibited seawater (approximately 15,800m^3 and 5,700m^3 respectively) will be placed into both export pipelines with both ends of the pipelines mechanically capped.

This will allow for the preservation of the export pipelines for a possible re-use, with a decision being made on the fate of the pipelines when the pipeline decommissioning works are undertaken (i.e. if no re-use option is identified at that time, the onshore section of the 24” export pipeline will be grout filled, and the inhibited water will be discharged at the seaward end (see **Section 3.5.4.2**)).

Similarly to the offshore pipelines the umbilical chemical line contents will also be displaced by seawater into the subsea wells. The umbilical hydraulic line contents will not be displaced prior to decommissioning of the subsea facilities. These hydraulic lines consist of water based hydraulic fluid (approximately 29.5m^3 in total across all umbilicals) and will be released to sea during the umbilical jumper cutting for the jackets and subsea structures decommissioning or during degradation of the umbilicals over the following decades/centuries.

3.5.2.2 Topsides Removal

Removal – Single lift

The removal of the KA and KB topsides in a single lift may be undertaken by a specialist lift vessel such as a twin hulled ship shape heavy-lift vessel (HLV), or alternatively using a more conventional semi submersible HLV, with barge transport to a suitable disposal yard.

Single lift using specialist HLV

The following describes the procedure for a single lift based on a study by Allseas (2012a), with additional information provided on the use of a standard HLV from Genesis (2011). Engineering work required in advance of the lifting procedure may include the addition of module reinforcement and seafastenings, estimated to be between 22t and 43t (based on an assumed 0.5-1.0% of topside weight). The topsides will be separated from the jacket at a suitable point above sea level, using diamond-wire or hydraulic cutting tools, and transferred to a barge using support stools and a skid system. A combination of ballasting the HLV and deballasting the cargo barge will bring the topsides and stools together in a controlled manner. Once all of the topside weight has been transferred to the barge, the lifting system will be disconnected, allowing the barge to be unmoored and towed away.

On arrival at the disposal yard, the barge will be moored and ballasted to match the height of the quayside, and link beams run and connected to the barge to allow for the topsides to skid from the barge, during which ballasting of the barge will maintain its level with the quay.

The overall schedule for the lift of both topsides using a specialist HLV and their transport to the disposal yard is approximately 88 days (including a 25% contingency). This is based on the platform supply vessel (PSV) which is required for the longest duration as a worst case scenario. A high level breakdown of the vessel durations is provided in **Table 3.16**.

It should be noted that the vessel durations associated with this methodology are not the worst case scenario in terms of topsides removal methodology options. For the purposes of this environmental assessment, the vessel durations for the piece medium removal option below are considered the worst case scenario and it is these durations which have been used in **Section 7,** for the environmental assessment.

Table 3.16: Estimated removal duration (days) of KA and KB topsides in a single lift using a specialist HLV

Vessel	Mob/ Demob	Transit	Working	Total Duration	Total with Contingency
HLV	8	6	17	31	39
Barge	7	6	7	20	25
PSV	8	24	38	70	88
Tugs (4no.)	8	24	28	60	75
Guard Vessel	6	3	55	64	80

Source: based on Allseas (2012a & b)

Single Lift using conventional HLV

A more conventional HLV, a semi-submersible crane vessel or similar, could also be used to lift the topsides (see **Figure 3.14**). The removal would be analogous to that outlined above in terms of preparatory works e.g. module strengthening and cutting of the topsides from the jackets. The topsides would then be lifted onto a barge and transported to shore for recycling/disposal. A conventional HLV may require to be moored, using anchors. For example a 12 anchor mooring system analogous to that of a semi-submersible drilling rig would be required.

Figure 3.14: Conventional HLV, in this case Saipem 7000, lifting a topsides module

Source: worldmaritimenews.com; Courtesy of Saipem

Detailed structural analysis will be required to determine the extent of strengthening of the topside structure and provision of lifting points, required to perform a single lift in this way. Similar to the other removal options, it is assumed that the existing accommodation on KA will be utilised to support the preparation works to the topsides, for as long as possible, until the arrival of the HLV. On the KB platform, temporary accommodation will be used to facilitate the preparation works.

The overall schedule for the lift of both topsides using a conventional HLV and their transport to the disposal yard is approximately 88 days (including a 25% contingency). This is based on the estimated guard vessel duration which is assumed to be required for the duration of the HLV and PSV infield works as a worst case scenario. A high level breakdown of the vessel timings is provided in **Table 3.17**.

As detailed above, the vessel durations associated with this methodology are not considered to be the worst case scenario in terms of topsides removal methodology options. For the purposes of this environmental assessment, the vessel durations for the piece medium removal option below are considered the worst case scenario and it is these durations which have been used in **Section 7,** for the environmental assessment.

However, the potential use of anchors with the conventional HLV for this option has been assessed in **Section 7.**

Table 3.17: Estimated removal timing (days) of KA and KB topsides in a single lift using conventional HLV

Vessel	Mob/ Demob	Transit	Working	Total Duration	Total with Contingency
HLV	8	6	21	35	44
Barge	7	6	7	20	25
PSV	8	24	28	70	88
Tugs (4no.)	8	24	28	60	75
AHV	8	6	21	35	44
Guard Vessel	8	3	59	70	88

Source: based on vessels and durations provided by Kinsale Energy

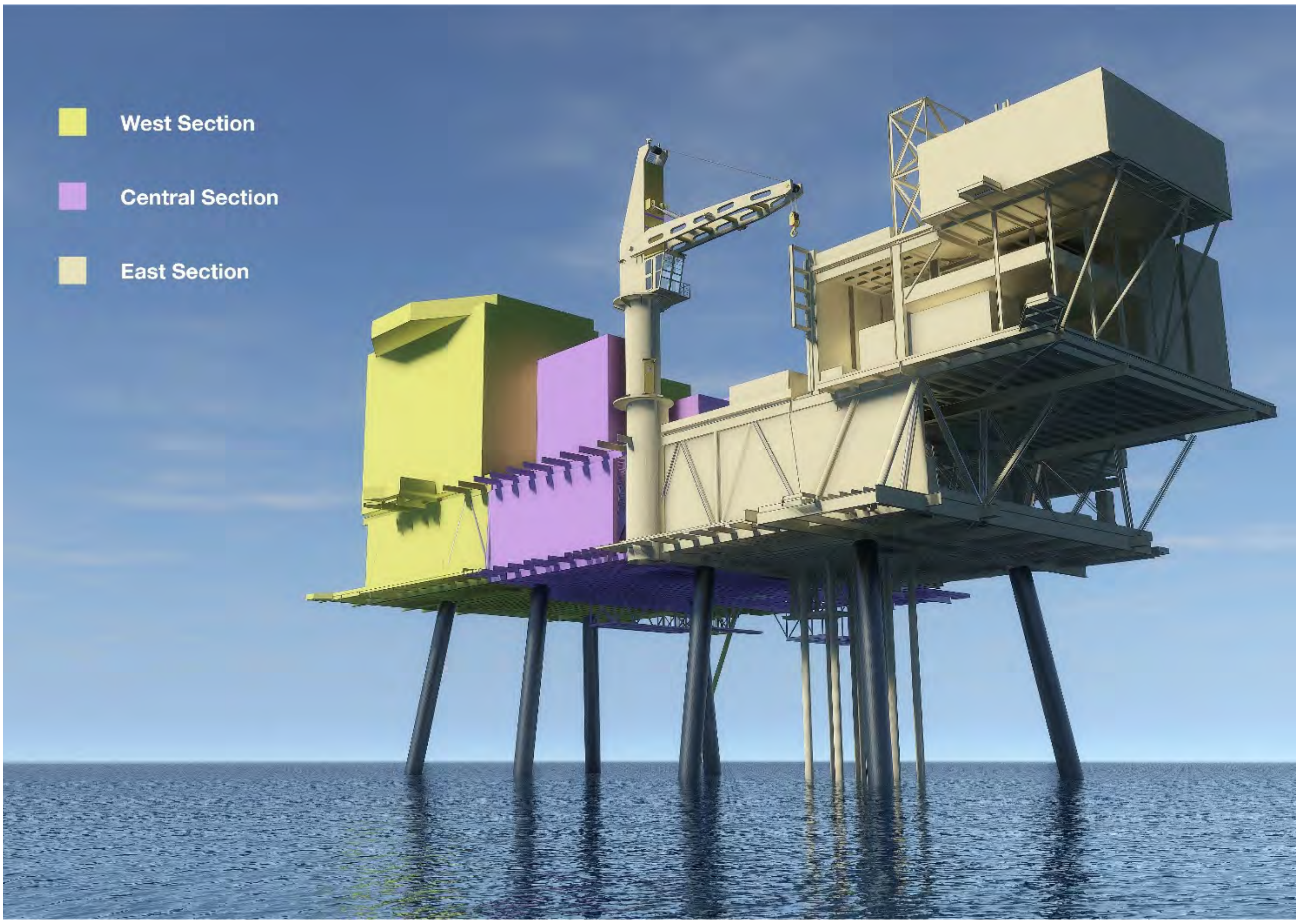
Removal – Piece-medium (reverse installation)

The reverse installation approach as a potential methodology option for topsides removal incorporates a combination of piece small and piece medium in which the equipment, secondary structures, modules and module support frame are removed in separate lifting operations.

See **Figure 3.15** for a schematic showing a view of the KA topsides module sections. The approach shown for the KA topsides will essentially be repeated for the KB platform.

It is assumed that the existing accommodation on KA will be used to support the preparatory and piece small work until arrival of the HLV, on which the workforce could be accommodated. On the KB platform, temporary accommodation will be installed to facilitate the piece medium and preparation works.

Figure 3.15: Kinsale Alpha topsides schematic showing the topside module sections



The overall schedule for the lift of both topsides and their transport to the disposal yard using the piece medium approach is estimated to be approximately 169 days (including a 25% contingency). This is based on the estimated guard vessel duration (vessel which is required for the longest duration) which is assumed to be required for the duration of the infield works being undertaken by the crane vessel, HLV, PSV and CSV, as a worst case scenario in the environmental assessment. A high level breakdown of the vessel timings for the entire schedule of works for the piece medium approach is provided in **Table 3.18.** There is the opportunity for simultaneous operations and resource sharing with the KA facility activities, which has been taken into account when estimating the total vessel durations to complete both KA and KB topsides decommissioning by reverse installation. As with all decommissioning options the ultimate lift strategy will depend on vessel availability, technical assessment, safety and commercial factors. For the purposes of this environmental assessment, the vessel durations associated with the piece medium remove option for the topsides have been used in **Section 7** as the worst case scenario.

Table 3.18: Estimated removal timing (days) of KA and KB topsides using reverse installation

Vessel	Mob/ Demob	Transit	Working	Total Duration	Total with Contingency
HLV	4	6	31	41	51
PSV	8	24	57	89	111
CSV	3	6	48	57	71
Cargo Barges (2no.)	36	24	69	129	161
Tugs (2no.)	8	24	11	43	54
Supply Boat	16	8	8	32	40

Vessel	Mob/ Demob	Transit	Working	Total Duration	Total with Contingency
AHV	8	24	31	63	79
Guard Vessel	6	3	126	135	169

Source: based on Xodus (2016d) and vessels and durations provided by Kinsale Energy

3.5.2.3 Jacket Removal

The separation of the jacket structures from pipelines and umbilicals on the seabed will be undertaken by ROV tooling wherever possible, or using divers and a DSV where required. It will not be necessary to uncouple at flanges as the pipelines and jackets have no future use, and so they will be cut using an external cutting tool, e.g. hydraulic shears. Spool pieces will be cut into recoverable sections of approximately 24m in length and lifted by a suitably equipped support vessel and transported to shore for recycling or disposal.

For a conservative assessment of the associated impact it is assumed that approximately 100m of spool pieces will be recovered at all platform tie-ins. In total, it is estimated that some 0.85km of spool pieces will be recovered during the jacket decommissioning, taking into account all pipeline connection points to the KA and KB jackets.

Protection materials covering these spool pieces will also be removed where required for access (134no. mattresses with each mattress assumed to be approximately 10Te). The method of removal for these items may include speed loaders or cargo nets. A number of other novel methods are also emerging in the market, as decommissioning activity increases (see Jee Ltd. 2015).

Once removed, the concrete mattresses will be returned to shore, where they will either be recycled or disposed of in landfill if recycling is not possible. In keeping with a waste-hierarchy approach, where possible, this material will be recycled as aggregate, but it may be necessary for some/all to be disposed of in landfill. For the purposes of this assessment it is assumed that all concrete mattresses returned to shore will be disposed of in landfill as this represents the worst case scenario for assessment purposes.

The removal of protection materials and the cutting and lifting of spool pieces will involve the use of a number of vessels including a CSV and PSV. The number of vessel days associated with these operations as part of the jacket decommissioning are included in **Table 3.19,** with the overall schedule for the removal of spool pieces and protection material and their transport to the disposal yard estimated at 71 days (including a 25% contingency).

Table 3.19: Estimated timing (days) for removal of spool pieces, umbilical jumpers and protection materials at the platform jackets

Vessel	Mob/ Demob/ Transit	Removal of protection material	Cut spool pieces & umbilical jumpers	Recover spool pieces	Total Duration	Total with Contingency
CSV	32	9	10	6	57	71
PSV	16	-	-	2	18	23

Source: Based on CA method statements (modified after Ramboll 2017a,b)

Regardless of the lift technique to be employed the jackets will be cut from the pile foundations at, or close to, seabed level using either an internal or external pile cutting tool. Internal leg surveys have been undertaken to confirm access for an internal pile cutting tool if they are to be cut internally. External cuts of the legs and piles could be made using diamond wire cutting tools, using remote tooling as far as possible, or diver intervention only if necessary.

The cutting tool will cut the legs at seabed level, as future exposure is not expected due to the hard strata at seabed level. In the worst case, it may not be possible to cut a leg at seabed level. If this situation arises, a short (~1m) section may be left exposed, and rock cover would be applied as part of the wider seabed remediation campaign.

Due to the high recyclability of steel (the dominant jacket material) the jackets will be recycled. The jackets will be removed to a dismantling yard, and recycling and waste facilities, which will be fully licensed for the relevant activities, will be selected by the removal contractor.

Marine growth comprising of a variety of hard- and soft-bodied organisms are present on the platform jackets, and it is proposed that the marine growth will be removed onshore following the removal and transport of the jackets to the disposal yard. A proportion of the marine growth will be removed offshore at cut locations, or will fall off in transit.

Following removal of the jackets, all significant debris on the seabed, which has accumulated around the jackets following years of operations, will be confirmed by the post-decommissioning survey (as detailed in **Section 3.5.5**) and will be removed using an ROV and grab. Larger items will be removed using a crane on a construction support vessel. Existing items known to be on the seabed include scaffolding boards and tubes, deck grating and miscellaneous construction debris, with no hazardous materials known to be present.

Removal – Single lift

Three options are potentially available to remove the jackets in a single lift. Two involve the use of specialist heavy lift vessels such as a twin hulled ship shape heavy-lift vessel (HLV) or a more conventional semi submersible HLV to lift the jackets, in a manner similar to topside removal, and transport them to a barge in sheltered water, prior to onward transport to a disposal yard. The third option is the use of a system involving attaching buoyancy caissons to the jacket, such that it can be floated and towed away using tugs.

Single Lift using specialist HLV

The following describes the procedure for a single lift based on a study by AllSeas (2012c & 2012d) using a specialist HLV, such as a twin hulled ship shape heavy-lift vessel (HLV). The HLV uses a Jacket Lift System (JLS), comprising a hoist and tilting lift beams with skids, which are used to rotate the jacket on removal onto its side, and manoeuvre it onto the vessel deck. **Figure 3.16** illustrates the HLV lifting a jacket from the seabed and aligning and tilting it onto the vessel deck for removal. Weight will be minimised by ensuring that as much water as possible from flooded jacket members is allowed to escape, which can be facilitated by the drilling of holes in these members.

Analogous to the transport of the topsides to the disposal yard described above, the barge with the jacket will be towed to the disposal yard and moored at the disposal yard quayside. It will be ballasted to the appropriate elevation, and the jacket will be skidded onto the quayside.

Figure 3.16: Specialist HLV, in this case, *Pioneering Spirit,* with jacket lifted from the seabed and tilted towards the vessel deck

Source: https://allseas.com

The overall schedule for the lift of both jackets together and their transport to the disposal yard is estimated at approximately 110 days (including a 25% contingency). This is based on the estimated guard vessel duration which is assumed to be required for the duration of the HLV and CSV infield works as a worst case scenario. A high level estimate of the vessel timings is provided in **Table 3.20**. For the purposes of this environmental assessment, the vessel durations associated with this option are not the worst case scenario for the removal option for the jackets. See vessel durations for the multiple lift option below which have been used in **Section 7,** for the environmental assessment worst case scenario.

Table 3.20: Estimated removal timing (days) of KA and KB jackets in a single lift using a specialist HLV

Vessel	Mob/ Demob	Transit	Work	Total Duration	Total with Contingency
HLV	3	6	22	31	39
Barge	7	6	11	24	30
CSV	2	6	57	65	81
Tugs (4no.)	8	24	44	76	95
Guard Vessel	6	3	79	88	110

Source: based on Allseas (2012c & d), and vessels and durations provided by Kinsale Energy

Single lift using conventional HLV

Similar to the topsides removal a conventional HLV could also be used for the removal of the jackets in a single lift. The overall schedule for the lift of both jackets and their transport to the disposal yard using this method is also estimated at 118 days (including a 25% contingency). This is based on the estimated guard vessel duration which is assumed to be required for the duration of the HLV and CSV infield works as a worst case scenario. A high level estimate of the vessel timings is provided in **Table 3.21**.

For the purposes of this environmental assessment, the vessel durations associated with the single lift option using a conventional HLV for the jackets are not the worst case scenario for the removal option for the jackets. See vessel durations for the multiple lift option below which have been used in **Section 7** as the worst case scenario. However, the potential use of anchors with the conventional HLV for this option have been assessed in **Section 7.**

Table 3.21: Estimated removal timing (days) of KA and KB jackets in a single lift using conventional HLV

Vessel	Mob/ Demob	Transit	Work	Total Duration	Total with Contingency
HLV	3	6	28	37	46
Barge	7	6	11	24	30
CSV	2	6	57	65	81
Tugs (4no.)	8	24	44	76	95
Guard Vessel	6	3	85	94	118
AHV	8	6	28	37	46

Source: based on vessels and durations provided by Kinsale Energy

Single lift using flotation

An alternative approach to jacket removal in a single lift is to use buoyancy tanks to float the jacket into a vertical mid-water position, in which it is towed to a sheltered location close to the disposal yard using tug vessels. On arrival, the ballast of the tanks is adjusted to rotate and lift the jacket to a horizontal position at the water surface where to can be towed and lifted onto the disposal yard quayside. A high level estimate of the vessel timings is provided in **Table 3.22,** with an overall schedule of 109 days for both jackets**.** This is based on the estimated guard vessel duration which is assumed to be required for the duration of the CSV and tug infield works as a worst case scenario.

For the purposes of this environmental assessment, the vessel durations associated with this option are not the worst case scenario for the removal option for the jackets. See vessel durations for the multiple lift option below which have been used in **Section 7,** for the environmental assessment worst case scenario.

Table 3.22: Estimated removal timing (days) of KA and KB jackets in a single lift using flotation

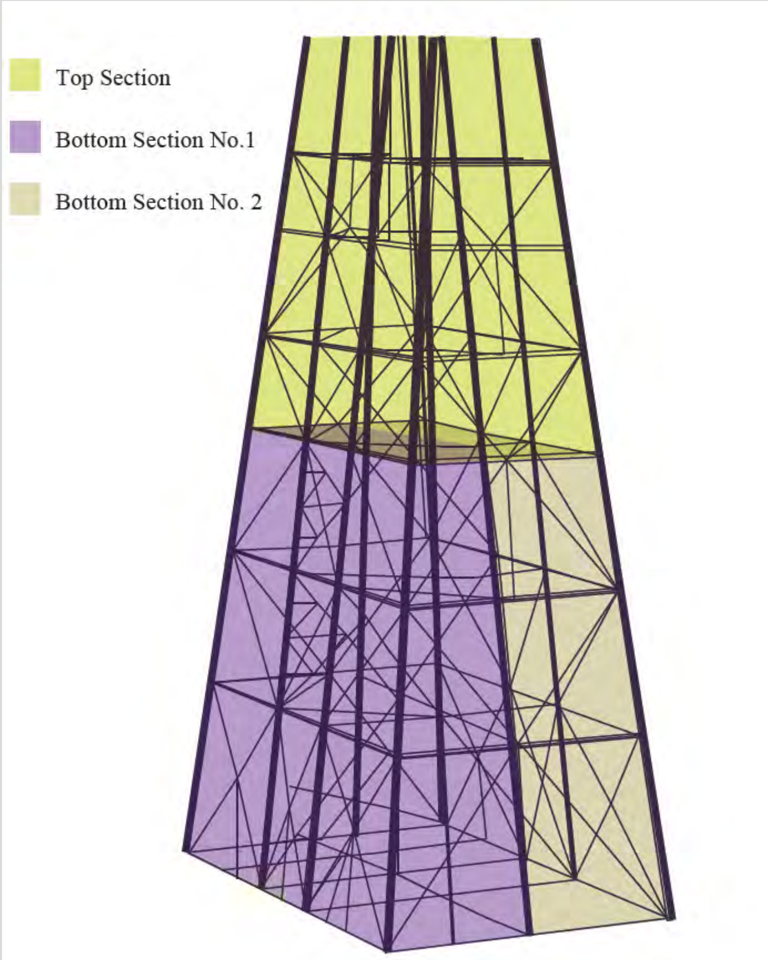
Vessel	Mob/ Demob	Transit	Work	Total Duration	Total with Contingency
CSV	2	6	57	65	81
Tugs (4no.)	8	12	84	104	130
Guard Vessel	6	3	78	87	109

Source: based on vessels and durations provided by Kinsale Energy

Removal – Multiple lift

If this methodology for removal was used, the KA and KB jackets would be cut into approximately 3 sections (see **Figure 3.17**) and removed in separate lifts, using a HLV, onto a waiting barge before being transferred to shore. Jacket members (legs and braces) will be cut using a combination of hydraulic shears for smaller cuts and abrasive water jet or diamond wire cutting for larger cuts.

Figure 3.17: Kinsale Alpha jacket schematic showing possible jacket sections



Preparatory work to lift the jackets will involve the same steps as for the single lift (above) with the drilling of holes into flooded members to allow water drainage to minimise weight, plus the installation of lifting points on the upper jacket section and the cutting of the jacket legs. The upper section would then be cut from the lower jacket sections, prior to these being separated and lifted using an internal lifting tool, which will be deployed into the jacket legs and secured.

For this environmental assessment, it is assumed the preparatory works will be undertaken from the HLV and a DSV, however, a PSV and/or CSV may be used for some of the preparatory works rather than the HLV depending on availability of vessels.

Each jacket section will be backloaded onto the HLV before being transferred to a barge where it will be seafastened for transport to the disposal yard.

The estimated vessel times for the multiple lift jacket removal procedure are indicated in **Table 3.23**, with the overall schedule for the lift of both jackets and their transport to the disposal yard using the multiple lift option estimated at 149 days (including a 25% contingency). This is based on the estimated guard vessel duration (vessel which is working for the longest duration) which is assumed to be required for the duration of the infield works being undertaken by the HLV, DSV and survey vessel as a worst case scenario.

For the purposes of this environmental assessment, the vessel durations associated with this option are the worst case scenario for the removal option for the jackets, which have been used in **Section 7,** for the environmental assessment worst case scenario. The potential use of anchors with the HLV for this option have also been assessed in **Section 7.**

Table 3.23: Estimated removal timing (days) of KA and KB platform jackets using the multiple lift jacket procedure

Vessel	Mob/ Demob	Transit	Working	Yard	Total Duration	Total with Contingency
HLV	4	6	58		68	85
DSV	3	6	40		49	61
Cargo Barges (3no.)	54	36	76	14	180	225 (75 per barge)
Tugs (3no.)	12	36	15		74	93
Supply Boat	8	4			12	15
AHV	8	24	58		90	113
Survey Vessel	2	6	12		20	25
Guard Vessel	6	3	110		119	149

Source: Based on Xodus (2016d) and vessels and durations provided by Kinsale Energy

Jacket Removal Deferral

As shown in **Figure 1.2**, the platform removal campaign may be scheduled over a number of years (1-10 years), depending on vessel availability and cost efficiency. It is possible that jacket removal may not take place immediately after topsides removal, in which case the jacket structures will be equipped with additional navigation aids and markers to ensure they do not form a hazard to other marine users and the surface safety zones will remain in place. Offshore platform jackets left in this way are commonly referred to as being in "lighthouse mode".

If jacket removal is scheduled to occur significantly later than the other facilities, this would allow further consideration of possible other uses for the jacket structure(s) for example, for hydrocarbon exploitation (with new topsides), carbon capture and storage or as part of a renewables development e.g. as a power hub.

If however, no re-use has been identified within this time period, the jackets will then be removed.

Lighting and Marking of the Platforms

Throughout the operational phase the Kinsale platforms have been marked with Aids to Navigation (AtoN) as agreed with the Commissioners of Irish Lights. Kinsale Energy will provide continuity of navigational safety from CoP through the removal of the topsides and jackets, although this will require changes to the specific Navigation Aids used. Before the start of decommissioning of the platform topsides Kinsale Energy will agree a lighting and marking plan as directed by the Commissioners for Irish Lights for the decommissioning phase of the project. This applies to establishment of new AtoN as well as disestablishment or changes to existing AtoN.

- All applications will be accompanied by an up to date Navigational Risk Assessment, with traffic analysis to inform the Commissioners of Irish Lights to set the Aids to Navigation requirements
- All Lighting and Marking proposals will comply with International Association of Marine Aids to Navigation and Lighthouse Authorities (IALA) Recommendation 0-139 on the Marking of Man-Made Offshore Structures (2013)
- Notices to Mariners will be issued highlighting the new marking arrangements

Kinsale Energy will provide solar powered Aids to Navigation (AtoN) marking on the jacket structures, after topsides removal, during the extended decommissioning phase (units will be self-contained with the ability to be monitored by satellite, if required).

3.5.3 Subsea Structures

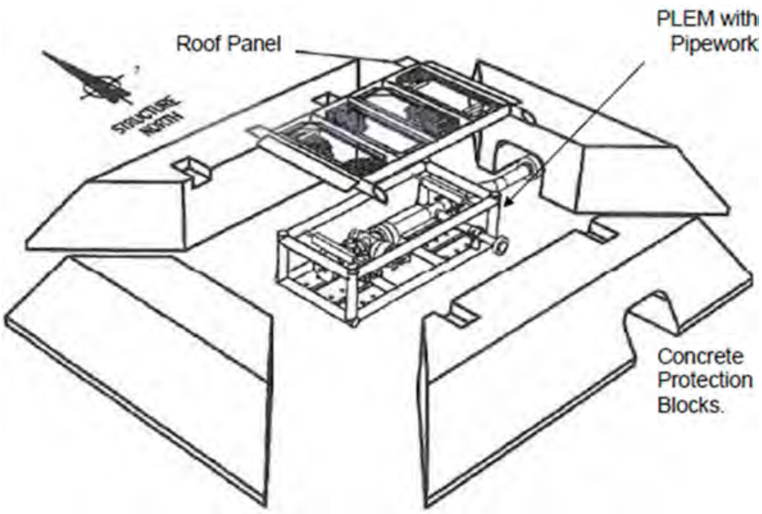
OSPAR Decision 98/3 states that, unless in exceptional circumstances, all subsea structures are to be removed during decommissioning, unless they are to remain *in situ* for an alternative use.

With no alternative use identified for the Kinsale Area subsea structures Kinsale Energy proposes to remove all subsea structures. The subsea structures in the Kinsale Area are as described in **Table 3.6** and are illustrated in **Figure 3.18**.

Figure 3.18: Subsea infrastructure

a) Wellhead protection structure

b) Typical Kinsale Area PLEM



c) Seven Heads manifold

3.5.3.1 Removal of Protection Materials

The concrete mattress and grout bag materials will be removed only when necessary to allow access to the tie-in facilities underneath, as indicated for the jacket removal in **Section 3.5.2.3**. **Table 3.24** details the number of mattresses to be removed to allow the removal of the spool pieces and umbilical jumpers at all subsea structures, with each mattress assumed to be approximately 10Te. Refer to **Table 3.25** for a conservative estimate of vessel days to complete the removal of these protection materials.

Table 3.24: Concrete mattresses to be removed at Subsea Structures

Pipelines and umbilicals	Estimated number of mattresses to be removed
12" SW Kinsale Pipeline & 12" Western Drill Centre & 10" Greensand & 10" Ballycotton & all associated umbilicals	196
Seven Heads 18" export pipeline and main control umbilical	8
Seven Heads 8" flowlines & umbilicals to wells	107
Total	**311**

Source: Based on CA method statements (modified after Ramboll 2017a,b)

3.5.3.2 Cutting and Removal of Spools and Umbilical Jumpers

The separation of subsea structures from pipelines and umbilicals will be undertaken by ROV tooling wherever possible, or using divers and a DSV where required, also as indicated for the jacket removal in **Section 3.5.2.3**.

For a conservative assessment of the associated impact it is assumed that approximately 50m of spool pieces will be recovered at all subsea structure tie-ins. In total, this amounts to an estimated 0.7km of spool pieces, taking into account all pipeline connection points.

The removal of protection materials and the cutting and lifting of spool pieces will involve the use of a number of vessels including a CSV and PSV. The number of vessel days associated with these operations are included in **Table 3.25**.

3.5.3.3 Removal of Wellhead Protection Structures

The wellhead protection structures need to be removed to allow access to the subsea trees and wellhead, for decommissioning. The steel structures will need to be cut/disconnected from the concrete foundation blocks, which anchor them to the seabed, and then the structures can be lifted to a vessel for onshore recycling/disposal. The foundation blocks will also be recovered individually, with each block having two lifting points. It is anticipated that existing lifting eyes will not be used and new lifting straps will be used for lifting structures to the vessel. An ROV will be used where possible, but a DSV with divers may also be used. For the purposes of this environmental assessment, the DSV methodology is included as a worst case scenario for the decommissioning of the subsea structures.

3.5.3.4 Removal of Valve skid, Intermediary Tee, PLEMS and Seven Heads Manifold

Initially all tie-ins (spool pieces and umbilical jumpers), will be disconnected and removed as detailed above. The concrete protection blocks, surrounding each structure will also be removed and recovered.

Once all disconnections are made, the structures will be recovered to a vessel for onshore recycling/disposal. Similar to the wellhead protection structures, lifting straps will be used for lifting to the vessel. The lifting straps will be put in place using an ROV, where possible, but a DSV with divers may be used. Similar to the removal of the wellhead protection structures, for the purposes of this environmental assessment, the DSV methodology is included as a worst case scenario for the decommissioning of the subsea structures.

3.5.3.5 Vessels & Durations

The estimated vessel times for the subsea structures removal, as detailed for each structure type above assuming a DSV is required for the structure removal (conservative assumption), is indicated in **Table 3.25**, with the overall schedule for the removal of spool pieces and protection materials, and the lift of all structures and their transport to the disposal yard estimated at 110 days (including a 25% contingency). This is based on works not being undertaken in parallel as a worst case scenario. For the purposes of this environmental assessment, the vessel durations associated with this methodology are the worst case scenario for the decommissioning of the subsea structures, and as such, this methodology has been used in **Section 7,** which assesses the potential environmental impacts of the proposed project.

Table 3.25: Estimated removal timing (days) of the subsea structures

Vessel	Mob/ Demob/ Transit	Removal of protection material	Cut spool pieces & umbilical sections	Recover spool pieces	Removal of Structures	Total Duration	Total with Contingency
CSV	24	17	10	9	-	60	75
PSV	8	-	-	1	-	9	11
DSV	11	-	-	-	8	19	24

Source: Based on CA method statements (modified after Ramboll 2017a,b)

3.5.4 Pipelines and Umbilicals

The Kinsale Area pipelines and umbilicals to be decommissioned are detailed in **Table 3.4** and **Table 3.5**.

As noted in **Section 3.5.2.1** as part of the overall facilities preparatory works the pipeline contents and umbilical chemical line contents will be displaced with seawater in preparation for the pipeline decommissioning. The chosen decommissioning options for pipelines and umbilicals included in the full environmental assessment are as summarised in **Table 3.10** and detailed below.

3.5.4.1 Offshore Pipelines and Umbilicals

Both *in situ* decommissioning options involve rock cover remediation of pipe ends and rock cover of either freespans only, or the full length of pipelines, which are currently not buried or under protective material. Additionally, some mattresses or grout bags may be retained in place, where they are associated with sections of pipeline ends beyond the tie-in spools which are proposed to be recovered as part of the subsea structures removal. These will also be subject to rock placement.

For the purposes of this assessment, it is assumed that rock cover, on exposed pipe (including pipe ends), mattresses remaining *in situ* and freespans will be placed such that at least 0.2m cover will be provided at all points. The rock berm is calculated with a 1m wide berm over the pipe and mattresses (where present) and 1:2.5 slopes on either side. Similarly, rock cover at identified freespans will be placed with a 1m wide berm and 1:2.5 slopes on either side. These rock cover dimensions have been considered in order to provide a conservative yet reasonable assessment of the potential associated impact.

Table 3.26 provides estimates of the rock placement required for the two *in situ* options and the vessel days required to complete the required rock placement operations. The rock placement vessel used for this assessment is assumed to have an approximate rock carrying capacity of 9,260m^3 (25,000Te), with the capability of placing approximately 1,666m^3 (4,500Te) of rock per day.

Graded rock will be used similar to existing rock material specifications (1”-5”), with all rock being placed in a controlled manner using a dedicated dynamically positioned fall pipe vessel and monitored by an ROV during placement. The rock will be sourced onshore, most likely from a UK or Norwegian quarry, because currently there are no Irish quarries with high capacity facilities for loading ships.

Table 3.26: Estimated rock placement requirements for *in situ* decommissioning options

Pipeline	Pipe ends & freespans		Pipe ends & all exposed sections	
	Length of rock placement	Quantity	Length of rock placement	Quantity
Inch Beach landfall to Kinsale Alpha 24" pipeline	2,288m	3,790m^3 / 10,234Te	38,234m	56,542m^3 / 152,662Te
24" KA to KB Pipeline & 12" KA to KB Pipeline	573m	910m^3 / 2,456Te	9,344m	12,947m^3 / 34,958Te
12" SW Kinsale Pipeline & 12" western drill centre & 10" Greensand & 10" Ballycotton & all associated umbilicals	627m	714m^3 / 1,927Te	2,450m	1,866m^3 / 5,037Te
Seven Heads 18" export pipeline and main control umbilical	350m	626m^3 / 1,691Te	13,830	12,243m^3 / 33,057Te
Seven Heads 8" flowlines & umbilicals to wells	1,360m	1,247m^3 / 3,368Te	1,402m	1,282m^3 / 3,461Te
Total		19,676Te		229,175Te

Source: Based on CA method statements (modified after Ramboll 2017a, b) and length of pipeline exposure in Xodus (2016c)

The estimated vessel times for the pipeline, umbilical and protective material decommissioning is indicated in **Table 3.27**, with the overall schedule estimated between 16 and 104 days (including a 25% contingency) depending on the selected option. We have considered the more conservative requirement of rock covering the pipe ends and all exposed sections in Section 7, which assesses the worst case scenario likely environmental impacts associated with the decommissioning project.

Table 3.27: Estimated vessel timings (days) for pipeline and umbilical decommissioning

Vessel	Mob/ Demob/ Transit	Rock Placement	Total Duration	Total with contingency
Rock Placement Vessel (pipe ends & freespans)	8	5	13	16
Rock Placement Vessel (pipe ends & all exposed sections)	32	51	83	104

Source: Based on CA method statements (modified after Ramboll 2017a, b) and additional vessel timings for rock placement vessel based on indicative mob/demob timings: vessel rock capacity (25,000Te) and placement rates (4,500Te/day).

3.5.4.2 Onshore Pipeline

The onshore pipeline section will be filled with inhibited seawater pumped through the pipeline from Kinsale Alpha as part of the facilities preparatory works (detailed in **Section 3.5.2.1**). In the event that no re-use option is identified, the onshore pipeline is to be filled with grout. A plug will be inserted in to the pipeline and run down the pipe internally to the required location, and the onshore pipeline will then be filled from within the terminal site, with the grout transported in via road. The inhibited seawater within the offshore pipeline will also be discharged at its seaward end at this time. It is estimated that approximately 500m^3 of grout will be required to fill 2km of pipe. At no stage will intrusive or disturbance works occur along the length of the onshore pipeline, as all activities will either occur from the platform or the onshore terminal.

3.5.5 Post-Decommissioning Survey

A completion survey will be carried out to confirm the completion of the decommissioning work scope and enable debris clearance (existing operational debris or debris deemed to have arisen from the decommissioning operations) to be undertaken.

The pipelines and umbilicals decommissioned *in situ* will be surveyed post-decommissioning to accurately record their location and status. This information will be included in navigational charts and also passed on to representatives of the fishing community.

As a minimum, the area covered for debris clearance will include a 500m radius around any installation and up to a 100m wide corridor along the length of any pipelines and umbilicals (50m either side of pipelines). The offshore survey will be undertaken over approximately 5 days. Identification of debris would normally be conducted by side scan sonar and/or multi-beam echo sounder (MBES) with an ROV deployed to investigate and recover any potential hazards. Larger items of debris would be recovered by crane or grab from a construction support vessel. A seabed clearance certificate will be issued by the survey contractor to confirm completion of the works.

Standard overtrawling surveys will also be undertaken where wellheads, spool pieces etc., are removed to confirm the area is clear of debris and snagging hazards.

The offshore survey of the export pipeline will end at some 3km offshore of the landfall at Powerhead. A separate inshore survey involving a smaller vessel will also be undertaken.

3.5.6 Inch Terminal

The scope of work for the Inch Terminal decommissioning comprises the demolition and removal of all above ground facilities on site and reinstatement of the site to original ground condition (grassland), in accordance with the extant planning permission.

Prior to demolition and following Cessation of Production (CoP), Kinsale Energy will disconnect the terminal from the gas grid, purge the plant to render it hydrocarbon free, and all chemicals will be removed from site. Similar to the offshore topsides, volumes of waste (water and corrosion debris (iron)) are expected to be small as the hydrocarbons produced are dry natural gas (e.g. no sludges or solid NORM material are present). These wastes, along with any residual inventories of chemicals (TEG) will be collected for onshore disposal under Kinsale Energy's existing waste management procedures.

The terminal facility will be disconnected from the power grid (three-phase ESB mains supply) and the telecommunications network (EIR telecommunications cable) prior to mobilisation of the demolition contractor.

Demolition works will be carried out by a suitably experienced contractor, who will operate in accordance with a construction Health and Safety Plan, Demolition Resource Plan and a Waste Management Plan.

The terminal demolition works will have a duration of approximately 16 weeks.

All buildings, above ground structures, roads and services (excluding the main access road which serves the adjacent Gas Networks Ireland above ground installation), vessels and above and below ground pipework (excluding the main export pipeline) will be fully demolished and the site reinstated to original ground condition (grassland).

The demolition methodology will be as follows:

Area of work	Demolition methodology
Pipe and Vessels	1. Cut all above ground pipework into sizes which can easily be handled and transported off site. 2. Remove all vessels/tanks/vent stack (cut from foundations) using a mobile crane and transport off site. 3. Excavate and remove all below ground pipework and transport off site (except for the main export pipeline – refer to Section 3.5.4.2 for decommissioning options). 4. Excavate/break out all pipework and vessel bases and remove off site. 5. Backfill all trenches with excavated material. 6. The materials will be removed from site using light and heavy goods vehicles.
Terminal Building	1. Soft Strip: strip out and removal of non-structural elements such as internal fittings and fixtures will be undertaken using small plant. 2. Any identified hazardous materials, such as asbestos will be removed in accordance with the relevant legislation and disposed of by specialist contractors to an appropriately licensed facility. 3. Deconstruct the concrete building walls, roof and floor 4. The materials will be removed from site using light and heavy goods vehicles. 5. Remove foundations down to concrete footings.
Site Services	1. Excavate and remove all underground utilities, including foul drains, firewater and electricity. 2. Road drains will be removed. 3. Plug and cap site water well approximately 1m below finished ground level.
Telecommunication mast	1. The removal of the telecommunication mast will require a mobile crane on site. 2. The mast will be cut in sections and removed from site. 3. Excavate/break out the foundations of the mast and break on site. 4. Remove the foundation material down to concrete footings.

Area of work	Demolition methodology
Access roads/hardstanding	1. The main access road (connecting to the local road network) will remain in situ for use as the Gas Networks Ireland installation site access. 2. The internal access roads and hardstanding areas will be excavated and removed off site. 3. The helipad tarmac area will be excavated and transported off site.
Fences	1. Remove all fences and associated foundations.
Reinstatement	1. On completion of the demolition, it is likely that subsoil and topsoil will need to be imported to site (estimated at approximately 12,000Te). 2. The subsoil/topsoil will be spread and seeded.

It is estimated that an average of approximately 11HGV movements per day (over 16 weeks) will be generated by the works based on the waste quantities to be removed, as detailed in **Table 3.28**, and the subsoil and topsoil to be imported.

3.5.7 Material Generated

Table 3.28 below summarises the estimated material generated from the KADP to be either recycled or disposed of onshore at licensed waste facilities.

The final disposal route and destination for items removed from the field, whether for recycling or disposal, is yet to be confirmed. A number of licensed sites within Ireland, UK, Norway and the Netherlands have currently been identified for recycling or disposal of the various items removed from the field. For the purposes of assessment, the final destination is assumed to be a site within Europe at a distance of 700nm from the Kinsale Area, which is the farthest distance within which the disposal route is realistically likely to be selected. This is to allow the assessment of the worst case scenario for the disposal route. The selection of the recycling and disposal sites will be made when the decommissioning contractor is appointed, with the selected sites at a distance of 700nm as a worst case scenario. The selected destination site will be an appropriately licensed site under the relevant legislation.

Table 3.28: Material Generated

Material Type	Wells	Platforms	Subsea Structures including spools, umbilical jumpers and protection materials	Inch Terminal
Steel	Total - 1,500Te for all wells, assuming recovery of casings to 3m below seabed and relevant sections of production tubing.	Alpha Total - 9134Te 4544Te - Topsides (695Te Piping, 179Te Deck Plate, 2457Te Equipment, 1396Te Structure less 183Te Asbestos) 4590Te Jacket Bravo Total - 7977Te 3594Te – Topsides (552Te Piping, 147Te Deck Plate, 1900 Equipment, 1128Te Structure less 133Te Asbestos) 4383Te Jacket	KH Total - 293Te (4x25 Te wellhead protection structures, 10.2 Te SWK Intermediate Tee, 12.3Te SWK Valve Skid, 11.1Te Greensand PLEM, 11.1Te WDC PLEM; 148Te spools) SH Total - 249Te (SH Manifold and spools)	Total - 110Te (Process Equipment)
Concrete	N/A	Alpha Total - 1567Te Grout (including grout in mudmats, grouted members & grout between pile and jacket legs) Bravo Total -1383Te Grout (including grout in mudmats, grouted members & grout between pile and jacket legs)	KH Total - 4452Te (4x134Te wellhead protection structures, 2x65Te and 2x45Te for SWK Valve Skid, Greensand PLEM and WDC PLEM; 3x43Te and 1x47Te for SWK Intermediate Tee	Total - 5339Te (4980Te - approx. depth of 0.15m across full site [1.66ha] requires removal, consisting of concrete foundations, gravel, hardcore, helipad, internal access tracks etc.; 20Te – 2.9mx2.9mx3m Pumphouse [200mm solid block walls and 225mm precast slab roof];

Material Type	Wells	Platforms	Subsea Structures including spools, umbilical jumpers and protection materials	Inch Terminal
			80Te Pipe spool Concrete Coating & 3000Te Concrete Mattresses) SH – 1452Te (42Te Pipe spool Concrete Coating and 1410Te Concrete Mattresses)	339Te – 11mx19.5mx3.5m Office Building [250mm cavity block walls and 225mm precast slab roof])
Non-ferrous Metals	N/A	Alpha - 108Te Anodes Bravo - 108Te Anodes	SH 0.12Te Anode	N/A
Asbestos	N/A	Alpha 183Te Bravo 133Te	N/A	N/A
Other Hazardous Waste	Small quantities of: • Excess cement ; minimised through effective planning to only make required quantity (likely discharged offshore) • Cement and steel millings (likely discharged offshore)	Small quantities of: • Fluorescent tubes (Mercury) • F&G Detectors (radioactive waste) • Fire Extinguishants • HFCs • TEG • Diesel • Heli-fuel • Lubricating Oils Hydraulic fluids • HW540 v2 • BOP fluid (Erifon HD856) (1% concentration). Other miscellaneous hazardous items such as: • Paint and Varnish • Batteries • Aerosols • Coolants	N/A	Small quantities of: • Fluorescent tubes (Mercury) • F&G Detectors (radioactive waste) • Fire Extinguishants • TEG • Diesel • Lubricating Oils • Hydraulic fluids Other miscellaneous hazardous items such as: • Paint and Varnish • Batteries • Aerosols • Coolants

Material Type	Wells	Platforms	Subsea Structures including spools, umbilical jumpers and protection materials	Inch Terminal
Other Non-hazardous Wastes*	N/A	Alpha Cabling 222Te (copper and plastics) Bravo Cabling 176Te (copper and plastics) Alpha Marine Growth 1450Te Bravo Marine Growth 1450Te	Umbilical quantities negligible (copper and plastics)	N/A
Total	**1,500Te**	**23,493Te**	**6,445Te**	**5,449Te**

Source: Genesis (2011), Xodus (2016a), Xodus (2016c), OHSS (2012), OHSS (2016), Ramboll (2017a), Ramboll (2017b), John O'Donovan & Associates (1976), well steel calculated on the bases of AGR (2017a), and assuming 43kg/m tubing on each production well.

3.5.8 Activity Scheduling

An indicative project programme is shown in **Figure 1.2** of this report. As detailed in **Section 1.6,** the final decommissioning project removal schedule will be completed once all decommissioning contracts have been awarded. The timing of platform removal and subsea well abandonments may vary depending on availability of specialised marine construction and drilling vessels (crane barges, MODUs etc.).

Post Cessation of Production (CoP), the platform well plug and abandonment (P&A) will be commenced and the pipelines connecting the platforms to the subsea wells will be displaced with seawater into the wells, in order to achieve hydrocarbon free status on the Kinsale Alpha and Bravo platforms. The 24" pipeline from KA to Inch Terminal, including the onshore pipeline, will also be filled with inhibited seawater at the start of the decommissioning programme. All of these offshore project activities up to the point where the platforms are hydrocarbon free will be carried out within the existing Kinsale Energy operations framework.

Upon completion of platform well P&A and subsea pipeline displacement activities, both Alpha and Bravo platforms will be de-manned and are then available for removal operations. The platform topsides will be removed within 1-2 years depending on vessel scheduling, and the jackets will be left *in situ* for a period of up to 10 years (see **Section 3.5.2.3**).

A subsea programme of works to remove subsea structures and protection materials and to disconnect spool pieces and umbilical jumpers will be completed in advance of subsea well plug and abandonment activities, which may be carried out by a rig or an intervention vessel, or a combination thereof. This may be completed before, after or during the removal of the platforms. The pipeline, umbilical and protective material rock placement works will be undertaken following the removal of the spool pieces and the umbilical jumpers.

The onshore terminal decommissioning which is of relatively short duration will be carried out at a suitable time within the overall project schedule. The onshore pipeline section will be grout filled at this stage, if no further use of the pipeline is anticipated.