DOUGLAS-WESTWOOD

PARTNERSHIP
tcs

Atlantic
Ireland
An exciting petroleum province

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An exciting petroleum province

FIELD DEVELOPMENT OPTIONS

t contain a number of proven and
velopments in water depths ranging

tions of the region, we have modelled
ment concepts in each of the four
epths varying from 1,000m to 4,000m,
oth reaches 2,000m, the South
500m and finally the
epth varies from 150m to 1,500m.

ate and experiences some of the
ilar to the extremes experienced in
rill and produce from water depths of
oped to move into even deeper water.

or illustration only and the economic
e considered valid for scoping
udes full details of the assumptions

2B	3A	3B	3C	3D
Porcupine	Slyne/Erris/Donegal			
1,000	500	500	500	500
1tcf gas/cond	1tcf gas/cond	1tcf dry gas	500bcf sweet gas	250bcf sweet gas
subsea wells, manifold	subsea wells, manifold	subsea wells, manifold	subsea wells, manifold	subsea wells, manifold
795	524	524	449	262
9P	9P	9P	8P	4P
43%	61%	61%	56%	33%

P = production   WI = water injection

Field 1A – This was found to meet all the economic hurdles with payback period of approximately seven years across an oil price spread of US $25-45/bbl.

Field 1B – This requires gas prices of around $5.6/mmBtu to be even marginally economic. These fields are candidates for the application of offshore gas to liquid conversion, as yet this is unproven in such conditions, but could significantly reduce the Capex for development and increase IRR from 10% to 27%.

Field 1C – This was found to meet all the economic hurdles with payback period of approximately five years across an oil price spread of US $25-45/bbl.

Field 1D – This requires gas prices above $3.2/mmBtu to be economic.

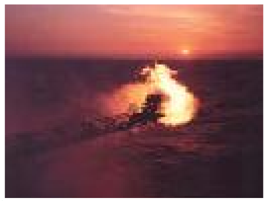
Field 2A – Oil fields of this size in deep water are shown to be uneconomic to marginal as standalone developments across the oil price range of $25-$45/bbl. This example illustrates the lower boundary for deep water stand-alone developments and the opportunities for tying marginal fields into host facilities.

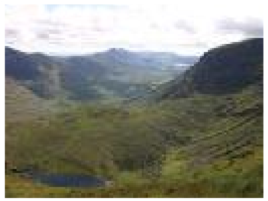
Field 2B – Even with a long tieback and associated cost, the development option was found to be viable under all gas prices above $3.2/mmBtu.

Fields 3A and 3B – These were selected as a dry gas and a gas/condensate field each of 1tcf. Both fields were found to robustly meet the economic indicators at all gas prices above $2.4/mmBtu, but even so, may struggle to match alternate investment opportunities on the basis of stringent payback periods.

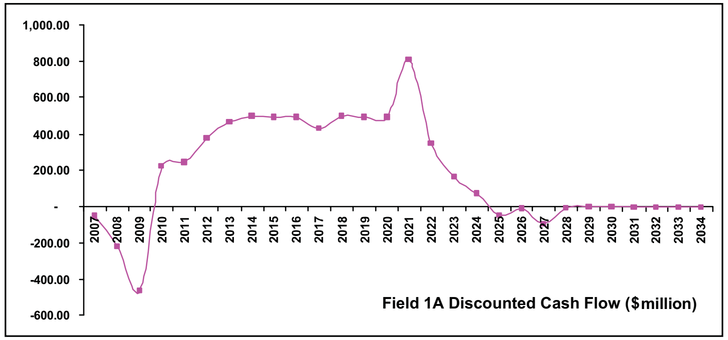
Field 3C – This was found to robustly meet the economic indicators at all gas prices above $3.2/mmBtu.

Field 3D – This was found to be economic as a stand alone development at gas prices above $4/mmBtu based on capital efficiency indicators. Below $4/mmBtu, the Field would be economic if tied back as a satellite development to a Field providing the infrastructure.





Rockall Basin Oil Field 1A



The Rockall Basin is a steep-sided channel with water depths ranging from 1,000-1,500m in the northeast to 3,500-4,000m in the southwest. There is some evidence of seabed geohazards from slope failures that may impact on the foundations of fixed facilities.

The only published data implies the potential for oil & gas shows. No infrastructure exists within the Rockall Basin, but when the Corrib gas field is developed this will include a new onshore gas terminal at Bellanaboy Bridge.

Field 1A is assumed to be an oil field with Standard Tank Oil Initially In Place (STOIIP) of 650mmbls. The recovery rate is assumed to be 40% with peak production rate of 110,000bopd. It is assumed that the oil is similar to that tested on Connemara, i.e. 32-38° API crude. It is noted that in geologically-similar Eastern Canada, some oil is heavy, e.g. Ben Nevis is 19-21° API; if this were repeated in Field 1A, then flow assurance issues would need to be fully assessed. Water depth at the field is 2,500m.

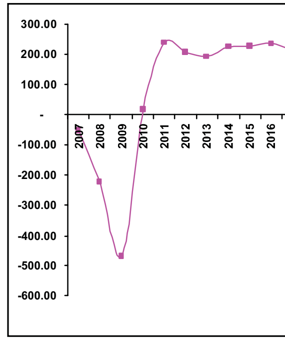
This development scenario was found to meet all the economic hurdles with payback period of approximately seven years across an oil price spread of $25-45/bbl. (The 'spike' in discounted net cash flow in 2021 is due to the drilling of water injection wells.)

Development Parameter	
Field	Oil
Reserves	425mmbls recoverable 35° - API
Production	121,000bopd
Field life	17 years
Wells	Up to 18 producing wells + 7 WI
Water Depth	2,500m
Facilities	Subsea wells tied back to production manifold, flexible line to riser base, hybrid risers to FPSO which has 10 days production storage, offloading by dedicated shuttle tanker.

Element	Capex
Subtotal	$1,168,413,000
Contingency	$220,040,000
Total	$1,388,453,000
Tanker	$185,312,000
Floater	$150,072,000
Drilling 1	$295,507,000
Drilling 2	$322,538,000
Subsea 1	$220,395,000
Subsea 2	$214,629,000
Total	$1,388,453,000

Oil Price at Start Production	$45/bbl	$35/bbl	$25/bbl
NPV @10% - $million	1846	1712	1577
IRR	38%	36%	35%
NPV/NPCe	3.0	2.8	2.5
Payback - years	6.7	6.51	6.35

Rockall Basin Gas Fiel



Field 1B is a dry gas field with ini
70% and condensate of 1bbls/mr
allowing flexibility in the event of
assumed booster compression w
adequate flow pressures.

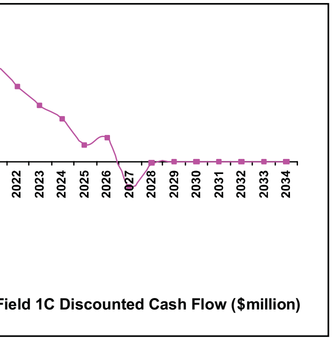
In this case, the field developmen
prices below $5.6/mmBtu and wo
opportunities.

Development Parameter	
Field	Gas
Reserves	1tcf sweet gas
Production	264 mmscf/d
Field life	18 years
Wells	Up to 8 producing wells
Water Depth	2,500m
Facilities	Subsea wells tied back to p manifold, pipeline to a new form built in < 500m water scf/d 24" 320 km export pip an onshore terminal adjace

Gas Price at Start Production	$5.6/mn
NPV @10% - $million	
IRR	
NPV/NPCe	
Payback - years	

The capital cost of the facility and
An alternate to the pipeline would
converting the produced gas and
plant capable of handling 200mm
estimated costs as $541m. This r
$316m, which would significantly
process technology is still unprov
would be required before commit
option results are:

Gas Price at Start Production	$5.6/mn
NPV @10% - $million	1
IRR	
NPV/NPCe	
Payback - years	



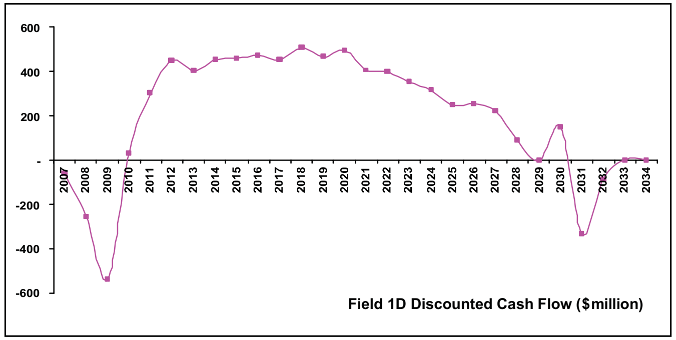
assumed to be an oil field but with over 1,000mmbbl. The recovery rate is of 750mmbbl and peak production is similar to that tested on Connemara

oduction and injection wells, tied back e manifold is connected to a riser base through the turret of a FPSO fitted out provides storage for up to ten days one of a number of reception facilities

Element	Capex
Subtotal	$1,798,656,000
Contingency	$338,840,000
Total	$2,137,496,000
Tanker	$187,611,200
Floater	$229,803,200
Drilling 1	$525,640,000
Drilling 2	$552,702,400
Subsea 1	$345,356,800
Subsea 2	$296,382,400
Total	$2,137,496,000

l	$25/bbl
3	2,700
%	39%
1	2.92
3	6.78

South Porcupine/Goban Basin Gas Field 1D



Field 1D is a variation of Field 1B and similarly assumed to be a dry gas field but with initial gas in place of in excess of 2tcf with recovery rate of 70% and condensate of 5bbls/mmscf. We assume a 24 inch pipeline to shore with a capacity of 450mmscf/d. This option maintains pipeline sizing from Field 1B and hence field life increases with larger reserve quantities. The pipeline length is estimated to be 320km to be routed allowing flexibility in the event of seafloor geohazards and slope instability. The pipeline will land adjacent to the existing Corrib terminal. It is assumed booster compression will be required early in the field life to ensure adequate flow pressures.

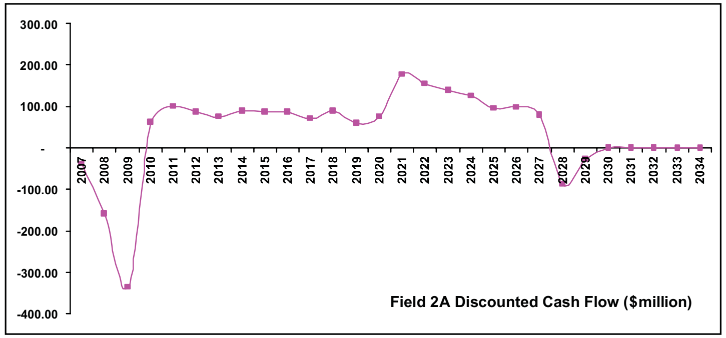
The optimum solution would appear to be a combination of subsea wells tied back to a central production manifold. The manifold would be connected via a pipe-in-pipe to a fixed platform some 150-200km from the field and in shallower water. The fixed platform would act as a booster platform to control pipeline temperature and pressure and chemical injection to control hydrate formation. The fixed platform would then be connected by pipeline to a land based gas terminal.

Development Parameter	
Field	Gas
Reserves	2tcf sweet gas
Production	490 mmscf/d
Field life	21 years
Wells	Up to 13 producing wells
Water Depth	2,500m
Facilities	Subsea wells tied back to production manifold, pipeline to a new booster platform built in <500m water with export pipeline back to an onshore terminal

Element	Capex
Subtotal	$1,261,840,000
Contingency	$186,756,800
Total	$1,448,596,800
Jacket	$121,366,400
Topside	$271,571,200
Pipeline	$687,464,000
Drilling	$217,860,800
Subsea	$150,334,400
Total	$1,448,596,800

Gas Price at Start Production	$5.6/mmBtu	$4/mmBtu	$3.2/mmBtu
NPV @10% - $million	1,864	938	475
IRR	32%	23%	17%
NPV/NPCe	2.6	1.29	0.64
Payback - years	6.1	8.4	10.52

North Porcupine Basin Oil Field 2A



The North Porcupine is a north-south trending deep water area with water depths ranging from 350m to 1,700m. There is no evidence of specific seabed geohazards that may impact on the foundations of facilities.

There is potential for sulphur-free sweet light crudes with API gravities of 32-41° API. Additionally the potential for gas exists.

No significant infrastructure exists, but when the Corrib gas field is developed in the nearby Slyne/Erris/Donegal region, this will include an export pipeline to a new gas terminal at Bellanaboy Bridge.

Field 2A is an oil field with STOIIP of 250mmbbls and recovery of 50% oil. Individual well flow rates are taken as 1,500-5,000bopd. The distance to shore is 240km. Water depth at the field is 1,000m.

There are a number of feasible options for this field, one of which is to utilise a Spar or Semi-submersible with a pipeline tied back to a storage facility at Bantry Bay, from which the crude could be transferred to VLCC for transport to processing plants. If Bantry Bay could not be utilised, an FPSO option with shuttle tanker would be an alternative.

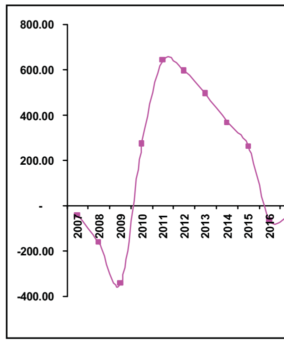
In this case, the field development would not pass the hurdle rates at the high oil price. To be economic it would require a tieback to an existing facility which would reduce the Capex from $1,078m to around $474m although there would be additional operating tariffs added into the Opex. Alternately, increasing the minimum recoverable reserves above 250mmbbls may significantly improve the financial assessment.

Development Parameter	
Field	Oil
Reserves	125mmbls – 35°API
Production	26,400 bopd
Field life	18 years
Wells	Up to 8 producing wells + 3 WI
Water Depth	1,000m
Facilities	Subsea wells tied back to production manifold, flexible risers tied back to a semi-submersible/spar production unit with tanker offloading or pipeline to Bantry Bay

Element	Capex
Subtotal	$844,064,000
Contingency	$156,490,000
Total	$1,000,554,000
Semi sub	$413,552,000
Floater	$53,013,000
Pipeline	$172,575,000
Drilling 1	$109,634,000
Drilling 2	$137,289,000
Subsea 1	$46,247,000
Subsea 2	$68,245,000
Total	$1,000,554,000

Oil Price at Start Production	$45/bbl	$35/bbl	$25/bbl
NPV @10% - $million	181	62	-8.8
IRR	14%	11%	9%
NPV/NPCe	0.4	0.1	0
Payback - years	14.6	15.7	20.0

North Porcupine Basin



Field 2B is a gas/condensate field and condensate rates of 1bbl/mm exported by a 24 inch pipeline; ca back to the existing Corrib termin

The selected option is a series of manifold and control centre and a assurance will need to be fully as booster pumps and possibly a m

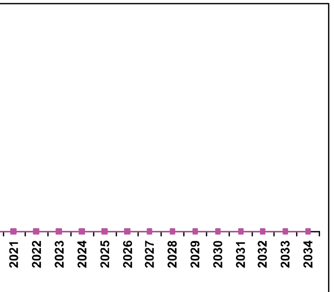
If pipeline flow assurance proves be the use of subsea wells tied ba Mini-TLP. An export pipeline wou reception terminal.

In this case, the field developmen above $4/mmBtu, but may strugg ties on the basis of payback perio

Development Parameter	
Field	Gas
Reserves	1tcf sour gas 70% recover
Production	550mmscf/d
Field life	6 years
Wells	Up to 9 producing wells
Water Depth	1,000m
Facilities	Subsea wells tied back to manifold, with export pipel back to onshore terminal – to incorporate subsea boo

Gas Price at Start Production	$5.6/mn
NPV @10% - $million	
IRR	
NPV/NPCe	
Payback - years	

ondensate Fields 3A & 3B



3A & 3B Discounted Cash Flow ($million)

erves of 1tcf and a recovery rate of
densate rate is assumed to be
s. Export of gas is by a 24 inch pipeline
20km tying back to the Corrib onshore

wells tied back to a manifold from
s terminal or an adjacent facility.
e advantageous to incorporate a High
ate the use of a lower rated pipeline.

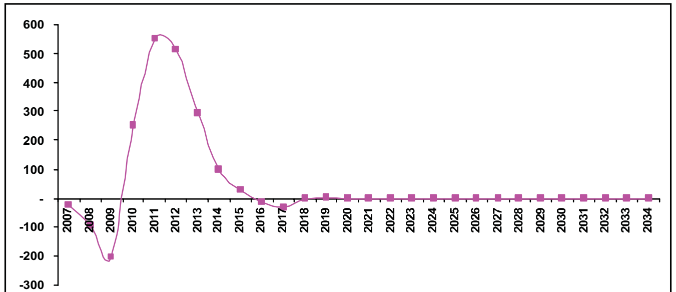
ditional Capex of $256m to cover a
rib terminal and its operating costs.
easible to add an additional two
sting terminal (depending on tariffs
e total Capex for this option of $224m,
0m, compared to the estimated total
0m.

he same as that for wet gas and
ices down to below $2.4/mmBtu, but
tment opportunities on the basis of

Element	Capex
Subtotal	$444,845,000
Contingency	$79,253,000
Total	$524,098,000
Drilling	$223,443,000
Pipeline	$154,165,000
Subsea	$146,490,000
Total	$524,098,000

$3.2/mmBtu
620
53%
1.8
5.6

Slyne/Erris/Donegal Basin Gas/Condensate Field 3C



Field 3C Discounted Cash Flow ($million)

Field 3C is a variation of Field 3A and similarly assumed to be a gas/condensate field with smaller initial reserves of 500bcf, 70% recovery, condensate rates of 5 bbl/mmscf. There is no H2S but 0.3% CO2. A 24-inch pipeline exports gas; capacity of 450mmscf/d and a length of 120km back to the existing Corrib terminal. Cost savings could be realised if instead of running the pipeline directly to the onshore terminal it ran to a tie-in point on the main Corrib export line.

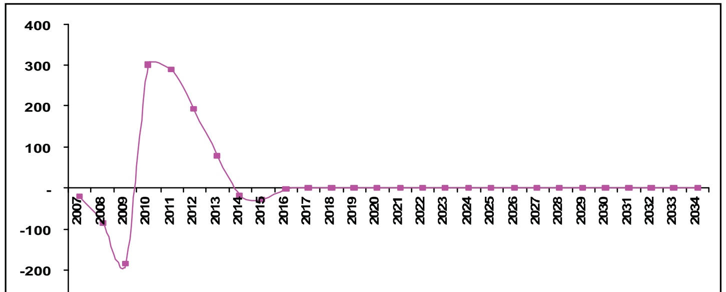
No specific option screening has been undertaken for Field 3A and similarly it is assumed the optimum solution for Field 3C is a series of subsea wells tied back to a manifold from which an export pipeline runs to the Corrib onshore gas terminal or adjacent facility. Depending on well shut-in pressures it may be necessary to incorporate a High Pressure Integrity Protection System (HIPPS) to facilitate the use of a lower rated pipeline.

Development Parameter	
Field	Gas
Reserves	500 bcf gas condensate
Production	400 mmscf/d
Field life	6 years
Wells	Up to 8 producing wells
Water Depth	500m
Facilities	Subsea wells tied back to production manifold, with export pipeline 120km back to an onshore terminal

Element	Amount
Subtotal	$382,550,400
Contingency	$66,793,600
Total	$449,344,000
Drilling	$223,441,600
Pipeline	$163,278,400
Subsea	62,624,000
Total	$449,344,000

Gas Price at Start Production	$5.6/mmBtu	$4/mmBtu	$3.2/mmBtu
NPV @10% - $million	827	495	329
IRR	77%	56%	43%
NPV/NPCe	3.1	1.82	1.21
Payback - years	4.19	4.46	4.77

Slyne/Erris/Donegal Basin Gas/Condensate Fields 3D



Field 3D Discounted Cash Flow ($million)

Field 3D is a variation of Field 3A and similarly assumed to be a gas/condensate field with smaller initial reserves of 250bcf, 70% recovery, condensate rates of 5 bbl/mmscf. There is no H2S but 0.3% CO2. A 24-inch pipeline exports gas; capacity of 450mmscf/d and a length of 120km back to the existing Corrib terminal. Cost savings could be realised if instead of running the pipeline directly to the onshore terminal it ran to a tie in point on the main Corrib export line.

No specific option screening has been undertaken for Field 3A and similarly it is assumed the optimum solution for Field 3D is a series of subsea wells tied back to a manifold from which an export pipeline runs to the Corrib onshore gas terminal or adjacent facility. Depending on well shut-in pressures it may be necessary to incorporate a High Pressure Integrity Protection System (HIPPS) to facilitate the use of a lower rated pipeline.

Development Parameter	
Field	Gas
Reserves	250 bcf gas condensate
Production	232 mmscf/d
Field life	4 years
Wells	Up to 4 producing wells
Water Depth	500m
Facilities	Subsea wells tied back to production manifold, with export pipeline 120km back to an onshore terminal

Element	Capex
Subtotal	$223,703,000
Contingency	$38,669,000
Total	$262,372,000
Drilling	$139,651,000
Pipeline	$96,353,000
Subsea	$26,368,000
Total	$262,372,000

Gas Price at Start Production	$5.6/mmBtu	$4/mmBtu	$3.2/mmBtu
NPV @10% - $million	313	139	53
IRR	56%	33%	19%
NPV/NPCe	1.28	0.57	0.22
Payback - years	4.34	4.88	5.77

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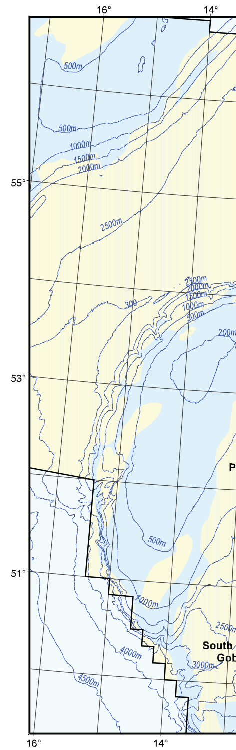

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