CO_2 EOR and storage in the North Sea: A developer's perspective

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Commercial drivers for CO_2 storage deployment

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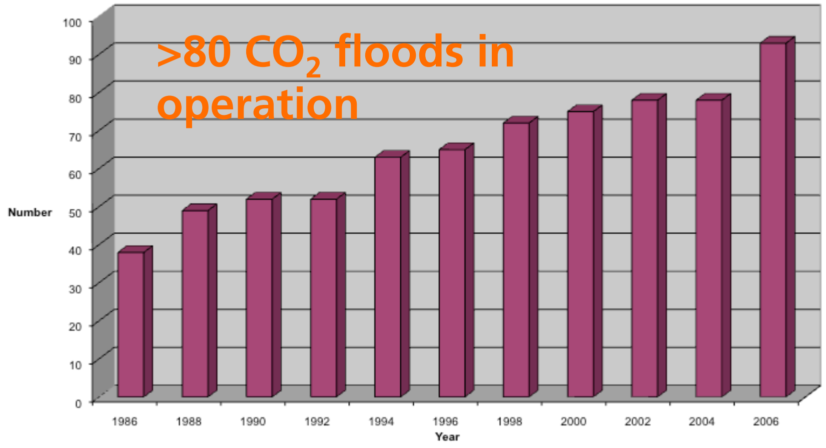
Well integrity risk	Highest More wells, some re-used, corrosive fluids	Intermediate Re-use of wells, large pressure gradients	Lowest Fewer purpose-built wells

CO_2 EOR – established technology with improving performance



- Business built in North America on low-cost natural CO_2 at low oil prices
- Today ~60 Mtpa CO_2 injected, >300 mstbd
- 4 decades of field experience and technology development

CO_2 EOR trends

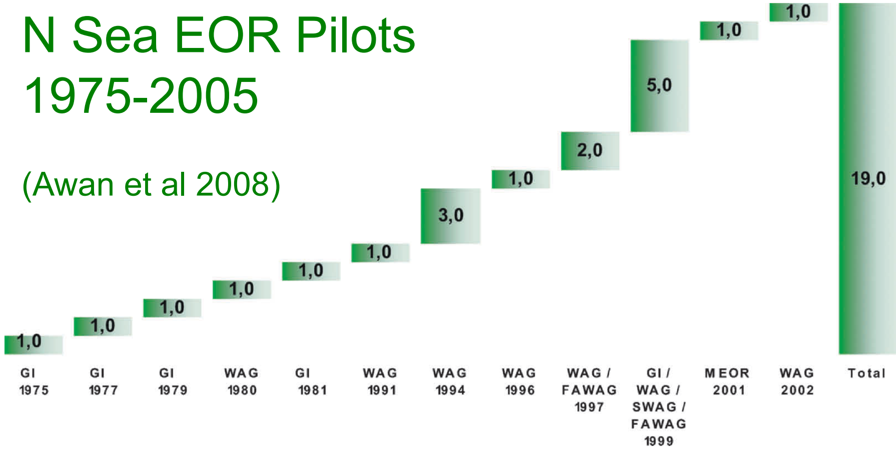
- Higher incremental recovery (>15% STOIP or more) as floods mature, techniques improve and oil price rises
- Higher oil/CO_2 price drives tradeoff of CO_2 utilisation for higher throughput (>1 HCPV) and higher ultimate recovery
- Tapered WAG or no WAG
- Better surveillance enables better control of volumetric sweep
- Higher oil price enables directional/horizontal drilling, better completions to target unswept oil

CO_2 EOR has been considered in the North Sea for more than 30 years

1979 Heriot Watt study for UK Dept of Energy
- Technically attractive, many potential targets
- CO_2 capture from power plants - too expensive

Numerous CO_2 EOR studies since:
- Forties, Miller, Gullfaks, etc.
- BP, Shell, Statoil, Apache, ConocoPhillips, etc.

Miscible gas EOR with enriched hydrocarbon gas:
- 18 field tests 1975-2005; 17 successful
- Successful full field development at Magnus



Historical barriers to CO_2 EOR

- Competition for capital with lower-cost barrels (satellites, green field, other basins)
- CO_2 supply for pilots
- Facilities availability, retrofit
- Lack of large scale, long-term CO_2 supplies at competitive cost

CCS projects create new opportunities for EOR

UK Applicants for NER300 Funding

Peterhead, SSE
400 MW, 1.5 Mtpa

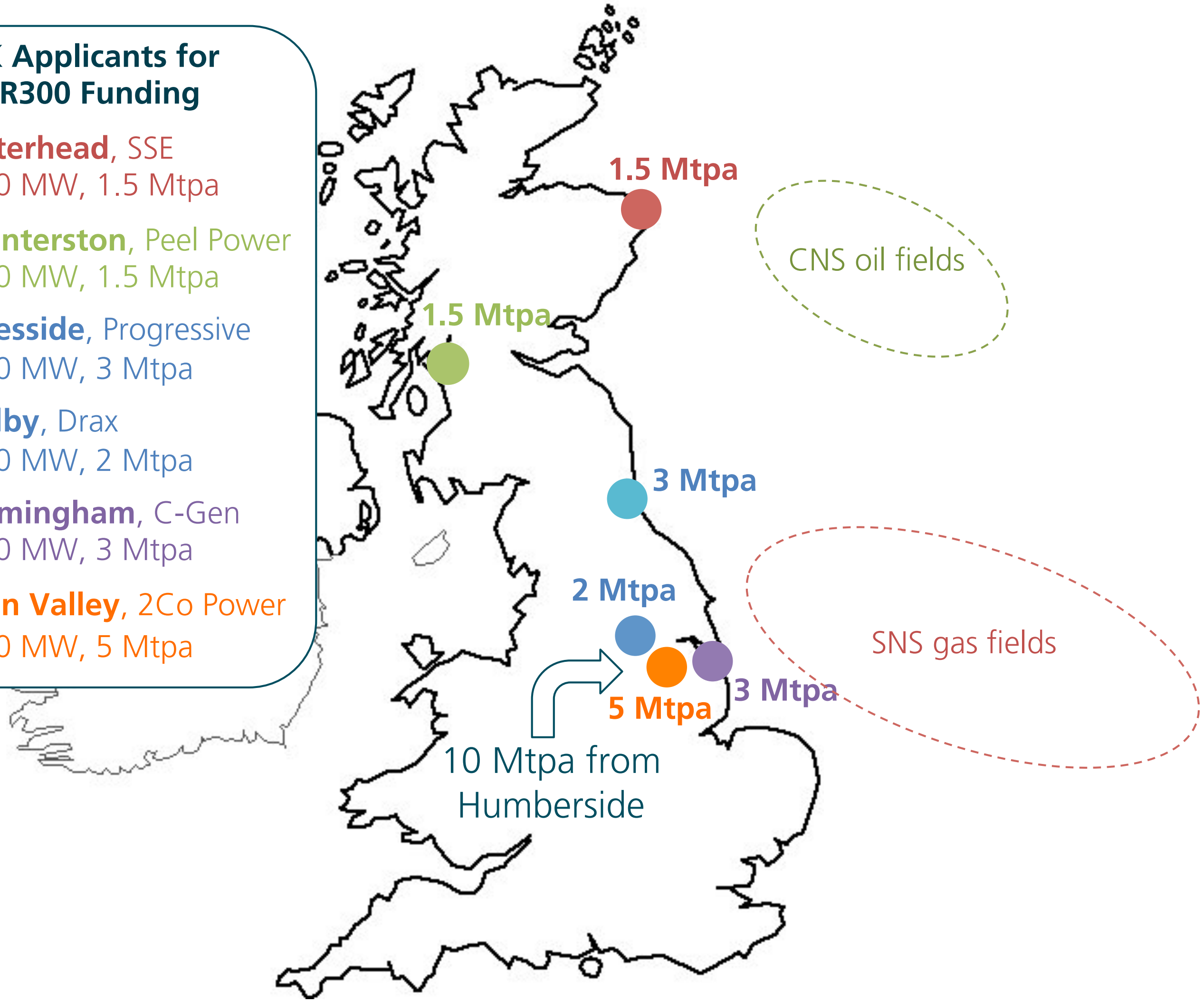
Hunterston, Peel Power
300 MW, 1.5 Mtpa

Teesside, Progressive
450 MW, 3 Mtpa

Selby, Drax
300 MW, 2 Mtpa

Immingham, C-Gen
450 MW, 3 Mtpa

Don Valley, 2Co Power
650 MW, 5 Mtpa



NER300 applicants to be selected in 2012; commercial operation by 2016-17

UK CCS demonstration programme is expected to support up to 4 projects

Potential CO_2 supply 5 – 11 Mtpa by 2020

Moving offshore – challenges and opportunities

	Onshore	Offshore
Well Cost	Lower – closer spacing, pattern water floods	Higher – large spacing, peripheral water floods
Facilities Capex and Opex	Lower – lesser reservoirs are economic, longer field life	Higher – only large, high quality reservoirs, shorter life
Logistics	Pilots and phased developments	No pilots, limited ability to phase
CO_2 supply	Competitive market for limited supplies	Low cost storage alternative -> low commodity cost; higher transportation?

Prospects for North Sea CO_2 EOR:

- High costs for wells and facilities offset against higher reservoir quality (and lower CO_2 costs?)
- Higher development risks due to limited phasing
- Generally lower recovery factors due to shorter field life and larger well spacing

Generic North Sea development for CO_2 EOR and storage

Project size

- Assume ultimate recovery of 1.5 - 3 stb/t of imported CO_2 and 8 - 15% of STOIP (cf 3 stb/t and 12% onshore*)
- 80 Mt CO_2 (4 Mtpa for 20 years) yields 120 - 240 mmstb
- Field size needed: 800 – 1,500 mmstb STOIP
- 25 – 60 wells for 25 - 30 mmstb/well

New facilities capex £500 - £1,000 m

- CO_2 import & injection – riser, metering, manifolds, vent, (pumps)
- Produced gas recycling >300 mmscfd – compression and power
- New steel jacket and platform (bridge-linked to existing)
- Platform life extension
- Installation, hook-up & commissioning

*history-matched forecasts for sandstone reservoirs in OGJ EOR Survey 2008

Generic North Sea development for CO_2 EOR and storage (cont'd)

Well capex £150 - £700 m

- Workovers to equip for CO_2 service
- New drilling for improved well placement and spacing
- Abandonments for CO_2 storage integrity

Opex £70 – 90 m/yr

- Operations, maintenance, inspection and corrosion control
- CO_2 storage monitoring, CO_2 Storage Permit and CO_2 Storage Lease

Illustrative costs & revenues (£ billion)		
Capex	0.7	1.7
Opex	1.4	1.8
CO_2 transport (purchase)	0.8	2.5
CO_2 storage fees	0	1.5
Oil revenue ($75/bbl)	6	12
Production Taxes	3	9

N Sea EOR is potentially economic with conservative assumptions on oil recovery and price

Large fields and a large CO_2 supply ($\geq$4 Mtpa) are required to recover costs of field re-development and CO_2 pipeline

Don Valley CCS chain with EOR

~2 Mtpa coal

~920 Mwe gross power generation

~630 Mwe net power export

~4.6 Mtpa net CO_2 export

~100 km onshore pipeline

~300 km offshore pipeline

Central N Sea

Oil field re-development for CO_2 EOR

CO_2 EOR and storage – a developer's perspective

- EOR is the most cost-effective option for commercial CO_2 storage
- CO_2 EOR is well established onshore; miscible gas EOR successfully deployed in the North Sea
- Lack of a suitable CO_2 supply has been the principal barrier to deployment in the North Sea
- Industrial scale CCS demonstrations will create large CO_2 supplies for EOR in the next 5 years
- Compared to onshore developments, offshore EOR will involve higher costs and capital exposure, set against superior reservoir quality and low commodity cost for CO_2
- Estimated costs for a large offshore development are manageable, assuming modest EOR performance (compared to onshore averages) and conservative oil prices
- The proposed Don Valley CCS chain would demonstrate technical and commercial viability of North Sea CO_2 EOR and storage, anchoring further developments for cost-effective storage and CCS

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