Migration from the primary store - a cross network challenge -

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- RESOURCES: Our use of the term “resources” in this presentation includes quantities of oil and gas not yet classified as SEC proved oil and gas reserves or SEC proven mining reserves. Resources are consistent with the Society of Petroleum Engineers 2P and 2C definitions.

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Problem statement

- How do we determine if we can detect migration from the primary store?
  - Where is it likely to occur – via what flow paths?
  - When can it occur?
  - At what rates can it occur?
  - What volumes can we detect?
This work was done as part of the Longannet to Goldeneye Project

CO₂ extracted from flue gas at Scottish Power’s 2.4 GW coal-fired Longannet Power Station

Carbon capture technology provided by Aker Clean Carbon, already tested on site with mobile pilot plant

CO₂ piped to St Fergus Gas Terminal using existing National Grid gas pipeline

CO₂ transported to Goldeneye field using existing 101 km offshore pipeline

20 Mt CO₂ stored in the depleted Goldeneye gas reservoir, injecting via existing platform wells
Storage complex

210 mD, $S_{sat}$ 25%, 1500 tonnes/day injection.
Cross section of store and complex

- Cross section showing reservoirs, Caprock, Back-up Containment, Upper Chalk Gp, Lista Mst (Complex Seal), Dornoch Mst (Complex Seal).

- The diagram highlights the complex seal and reservoir areas.
Risk assessment

Where is it likely to occur – via what flow paths?
A full bow-tie analysis was performed to identify and assess containment risk.

Legend
- **Passive** safeguards; these are always present
- **Active** safeguards, these are only present when a decision to intervene is made triggered by monitoring information

Numbers
- 34 Preventative safeguards
- 31 Corrective safeguards
Bow tie results lead to identification of threats and potential migration paths

**Acidic fluids react with minerals ...**
- And perforate primary seal
- In fault / fracture cement making them conductive
- In reservoir weakening the formation and causing failure
- In the fault / fracture cement allowing fault to reactivate

**Diffusion**
- Pure diffusion of CO₂ through primary seal (Rodby)

**Stress of injection**
- Fault opening or formation of new open fault in seal
- Fracture opening or formation of new open fractures in primary seal

**Existing faults**
- Existing faults crossing primary seal (migration in complex)
- Faults / features crossing 1st & 2nd seals (migration from complex)

**Lateral migration**
- Lateral migration along the Captain fairway beyond the storage complex.

**Abandoned wells**
- Flow up abandoned E&A wellbores to near surface
- Abandoned injection wells create leak path

**Injection wells**
- Injection well tubing leak to
- Behind production casing cross flow

1. CO₂ leakage through Plugged and Abandoned Wells
2. CO₂ leakage through injectors
3. CO₂ leakage through faults/fractures
4. CO₂ leakage laterally to Captain Fairway Aquifer
5. CO₂ leakage to Mey Sandstone via caprock or wells
Timing of migration

When do the conditions to drive migration occur?
During the injection of CO$_2$ the field is sub-hydrostatic in all but two cases until the end of injection.

- Regional modelling of hydraulically connected volumes and other fields.
Maximum volume

What is the volume at risk
Take each well and calculate the mobile CO$_2$.

- Figure shows the volume at risk below each well within the store after the system has reached gravity equilibrium in 2050 after injection of 20Mt.
- The chart separates CO$_2$ into mobile and immobile CO$_2$. 
Rate of migration

What are the likely rates for a leak up a well
13Mt can migrate, but at what rate (if re-pressured)?

- Significant modelling required looking at realistic micro annulus scenarios
- Constrained by cement plug tests and experiments
- Rates
  - 1500 Tones per day. Total CO$_2$ migration is 10Mt. This represent a total failure of all barriers.
  - 100 tonnes/d based on cement shrinkage factor of 0.7%.
  - Most realistic leak rate 2.1 tonnes/d
Detection

What volumes can we detect?
Multiple simulations of the secondary store were created with different cross flow rates

- 1000 year migration

- 14/29a3
  - 1500 tonnes/d

- 14/29a3
  - 100 tonnes/d

- 14/29a3
  - 2.1 tonnes/d
Synthetic 4D seismic was generated

- Strong CO2 softening signal at top reservoir
- Strong CO2 signal at base saturation
- Dim amplitudes corresponding to low saturation and thickness
- Time delay due to CO2 saturation
This was also done for lateral migration from the store

- Synthetic seismic at Captain level
- Can see CO2 in lateral aquifer even when noise superimposed

Fairly good match between seismic and modeled synthetic using SSM rock model and Mores saturation/structure grids

Minimum 4D amplitude around Top Captain horizon (+/- 15 ms)

4D “softening” signal above the noise level indicating CO2 presence in the aquifer, CO2 plume a km away from the spill point
Captain CO₂ plume tip at end injection – Detectability

Around original contact, Plume thickness is ~15-30m (50-100 ft)

Tip of plume thickness Is ~2 m (~7 ft) (~3 sim layers)

Estimated Seismic Detection Limits

<table>
<thead>
<tr>
<th></th>
<th>3D resolution Vertical Z (top-base CO₂ column)</th>
<th>4D resolution Vertical Z (height CO₂ column)</th>
<th>4D resolution Lateral X x Y</th>
<th>CO₂ injection detection limit in tonnes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Near surface (0-500 m)</td>
<td>12-25 m (40-80 ft)</td>
<td>5 m (15 ft)</td>
<td>50m x 50m</td>
<td>15-500</td>
</tr>
<tr>
<td>Mey (1200-1500m)</td>
<td>14-28 m (45-90ft)</td>
<td>10 m (30 ft)</td>
<td>100m x100m</td>
<td>500-12,000</td>
</tr>
<tr>
<td>Reservoir (2500-2750m)</td>
<td>17-36 m (55-120ft)</td>
<td>13 m (50 ft)</td>
<td>200m x 200m</td>
<td>3,000-30,000</td>
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Dietz Tongue
Conclusion

- Even in this simple example we have seen integrated network approach:
  - Risk assessment
  - Wells
  - Modelling
  - Monitoring
  - Environmental

- All working together to show that potential migration can be detected.

- Some areas for improving understanding – input for tomorrow R&D sessions: migration though overburden, migration up microannuli in wells, quantitative measurement of CO2 migration.

Many thanks to the team:

- Over 30 staff who worked for 9 months to deliver this as part of a larger team who spent 70,000 hours on this end to end project

- Message to governments and organisations – 90/10 rule
Goldeneye full field model: some water invaded
CO₂ injected at existing well locations

Year +2
CO$_2$ displaces water and mixes with remaining gas

Year +4
CO₂ filling the original structure

Year +6
CO$_2$ driven below original contacts by force of injection

Year +8

CO$_2$ override

CO$_2$ override
CO₂ maximum extent at end of injection

Year +10
CO$_2$ moves back into gas leg driven by buoyancy

Year +20

Capillary trapping in water leg
Trapping is structural with capillary and dissolution.

Year +50

Capillary trapping in water leg