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Heavy Oil

Controlled Document

Quest CCS Project

Injectivity Risk and Uncertainty Review

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Date	Role	Name	Signature or electronic reference (email)
	Originator	Hein de Groot	
	Reviewer	Doreen Becker	
	Reviewer	Sean McFadden	
	Approver	Syrie Crouch	

Summary

Shell has a mature risk management process which is applied to all projects and provides a rigorous assessment/management of risk that feeds into project decisions. This process has been applied to the QUEST project with the addition of:

- A more formal approach to uncertainty management for the subsurface (Italian Flags /TESLA)
- Project Specific Risk Assessment Matrix (RAM) (See Appendix 1)
- Application of the Bow Tie process to assess barriers that reduce containment risk to ALARP (As Low As Reasonably Practicable) - a key process in the development of a risk based, site specific MMV plan (Only applicable to risks with HSE impact, i.e. Containment).

This document summarizes all injectivity related risks and uncertainties for the Quest integrated Capture and Sequestration project identified up to Q1 2011 and include updates made to incorporate feedback from the Oct 2010 DNV led Independent Project Review, the drilling and testing of well Radway 8-19 and information gathered from 3D seismic campaigns in 2010. This document is an ever green document that will be updated when new data comes available.

Keywords

Quest, CCS, Injectivity, Risks, Uncertainty, TESLA, EasyRisk

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1. Injectivity – Tesla Summary

The injectivity hypothesis is illustrated below for the QUEST project and the evolution of the Italian flag for this hypothesis over the 3 workshops.

INJECTIVITY HYPOTHESIS
Injectivity can be sustained for the full project life cycle

Italian Flag History

Nov. 2008				0.4						
March 2009				0.42						0.01
Sep. 2009						0.6				0.01
Sep. 2010						0.6				
Feb. 2011						0.6				

The key factor driving the reduction of uncertainty in injectivity is the placement and testing of the first Quest development well (Radway 8-19) in the centre of the area of interest. Radway 8-19 has provided updated information on the key parameters that impact injection capacity (permeability, reservoir pore pressure and formation fracture pressure). The offset of Radway 8-19 to the next two nearest development injectors is expected to be 6.8 and 5.5km, for planned injection wells 7-11 and 5-35 respectively. This is much less than the outsteps made from Redwater 3-4 to Radway 8-19 (24.5 km) and from Redwater 11-32 to Redwater 3-4 (15.8 km), although still much larger than the scale of reservoir quality variability expected in the BCS.

From a purely mechanical point of view the drilling of the three Quest appraisal wells has shown that wells can be sited, drilled, completed and stimulated to achieve the required injectivity. The Radway 8-19 injection tests demonstrated high injectivity of 380 m3/d/MPa after initial water quality issues were eventually overcome. N2 backflow and acid stimulation were successful in addressing formation damage incurred due to the injection of contaminated water. It is expected that the Radway 8-19 well, at the injectivity measured during the last stable flow rate, could accommodate more than the total required Quest capacity needs, although some uncertainty about the conversion of water to CO2 injectivity and the sustainability of the injectivity remains. The test results in Radway 8-19 and Quest start-up and integrated system modeling have provided new insights on some of the operational risks to injectivity, whilst also opening up the opportunity of being able to inject the full CO2 stream with less than the planned 5 wells in the D65 regulatory application.

Definition of Injectivity

The relationship between rate and flow in a porous medium is well understood and extensively documented in the public literature based on the Darcy flow equations. The formula provided below defines the pressure differential for a gas in the well bore as a function of rate and a number of other reservoir and fluid parameters.

$$P_{avg}^2 - P_{wf}^2 = 1422\ T\ Q\ \ \mu Z\ /\ kh\ (\ln r_e/r_w - 3/4 + S + DQ)$$

Where P_{avg} and P_{wf} represent the average reservoir pressure and flowing well bore pressure respectively, T represents the reservoir temperature, Q the flow rate, μ the viscosity of the injected CO2, Z the gas factor for the injected CO2 at injection conditions, k the total permeability of the BCS to CO2, h the BCS thickness, r_e/r_w the ratio of radius of investigation to well bore radius, S the skin (well bore formation damage) and DQ the rate dependant skin factor (non-Darcy skin).

This formula controls injectivity as the pressure differential in a well should not exceed the margin between the bottom hole pressure constraint based on fracture gradients and the initial reservoir pressure. From this formula it is apparent that the biggest variable controlling injectivity is kh, the product of permeability and height. The only controllable parameters are the applied pressure differential that Quest proposes to base on fracture pressure constraints and the minimization of formation damage (skin) through good drilling and completion practices.

Injectivity – permeability height

Injectivity estimates in the BCS from injection tests have been hampered by several operational issues. The 1st appraisal well was tested but did not reach radial flow conditions (potential fracture over the minifrac zone) and the 2nd appraisal well could not be tested (liner running tool cemented in hole). The 3rd appraisal well Radway 8-19 required 5 injection tests before water quality issues were overcome and stable injectivity could be established. Only water has been injected into the BCS and a CO2 test is yet to be carried out. The relative injectivity of CO2 versus water is captured in the factor k for permeability, in the formula in the previous section, as part of the relative permeability of the CO2 in brine saturated BCS reservoir. This parameter is based on core analysis and analog studies that have helped to define an appropriate range of uncertainty. Transient pressure test analysis and radial well modeling have suggested that the permeability height product in the BCS varies from around 1000 mD m (Redwater 11-32) to approximately 30,000 in Radway 8-19. Reservoir modeling has indicated that, although there are indications of an improving reservoir quality trend towards the N/NE, there are no reliable predictive correlations that can be used to ensure well placement of future injector wells in high kh area's.

Pressure differential - LMS versus BCS fracture gradients

Although the 32 MPa bottom hole pressure (BHP) constraint will be the design basis for the integrated Quest system and also serve as the basis for the D65 regulatory submission, it is considered prudent to start-up with an additional safety margin to avoid any undesired fracturing in the BCS. The ERCB Directive 51 guidance stipulates a 10% safety factor by constraining maximum injection pressures to 90% of the measured fracture extension pressure of the storage formation, the Basal Cambrian Sand (BCS) in the case of the Quest project. The Quest project team has provided additional safety margin by selecting the fracture extension pressure of the Lower Marine Sands (LMS), the first formation overlying the BCS storage formation with a lower fracture extension pressure, as the basis for injection pressure constraints. The Quest project team felt this was a more appropriate constraint, as the first barrier to loss of containment is the avoidance of fractures propagating into the overburden and the LMS is the first formation above the BCS in that sequence.

This provides an additional 15% (almost 6 MPa) safety margin over and above the 10% mandated by the regulator, as the LMS fracture extension gradient was measured at 17.4°kPa/m, versus 20.6 kPa/m in the BCS. Taking 90% of the LMS fracture extension gradient results in a bottom hole pressure constraint of 32.0°MPa at top BCS in Radway 8-19 against a 37.8 MPa constraint based on BCS fracture extension gradients.

<u>Pressure differential - Reservoir Cooling</u>

Some additional safety margin may be required to protect against the known phenomena that reservoir cooling may result in reduced formation strength and lower fracture gradients. From temperature modelling on the base case pipeline configuration and the vertical well bores it is expected that the temperature of the injected CO_2 may range between 15 and 45degC compared to an initial reservoir temperature of 60 degC. The extent of the reduction in fracture strength due to this 15-45 degC cooling effect in the near wellbore depends on the thermal expansion coefficient, a parameter that can only be acquired through complex specialised core analysis. This analysis is not yet complete for the Quest project and the data from Radway 8-19 core is expected to be available by June 2011 for inclusion in the FDP.
Shell in-house research on the theoretical magnitude of reduction in fracture pressure from injecting cold CO_2, given the uncertainty in the thermal expansion and poro-elastic parameters has indicated that the minimum fracture pressures reduction expected is about 1.4 MPa and the maximum would be about 7.9 MPa. All subsurface scenario modeling was carried out on a BHP constraint of 28 MPa to allow for a 4 MPa margin with interpreted fracture extension gradients measured in the LMS Scotford appraisal well.

<u>Integrated system modeling and operating pressures</u>

Ongoing system modeling has shown that the compression at Scotford can deliver the required bottom hole pressure (BHP). Integrated Production System Modeling (IPSM) was carried out to support compressor and pipeline capacity selection. It was demonstrated that a compressor with 14.5 MPa discharge pressure and a 12" pipeline will provide adequate pressure at the wellheads. The cooling in the pipeline will increase the density of the CO_2 and ensure that bottom hole pressures up to 32 MPa can be achieved at well head pressures of 14 MPa.

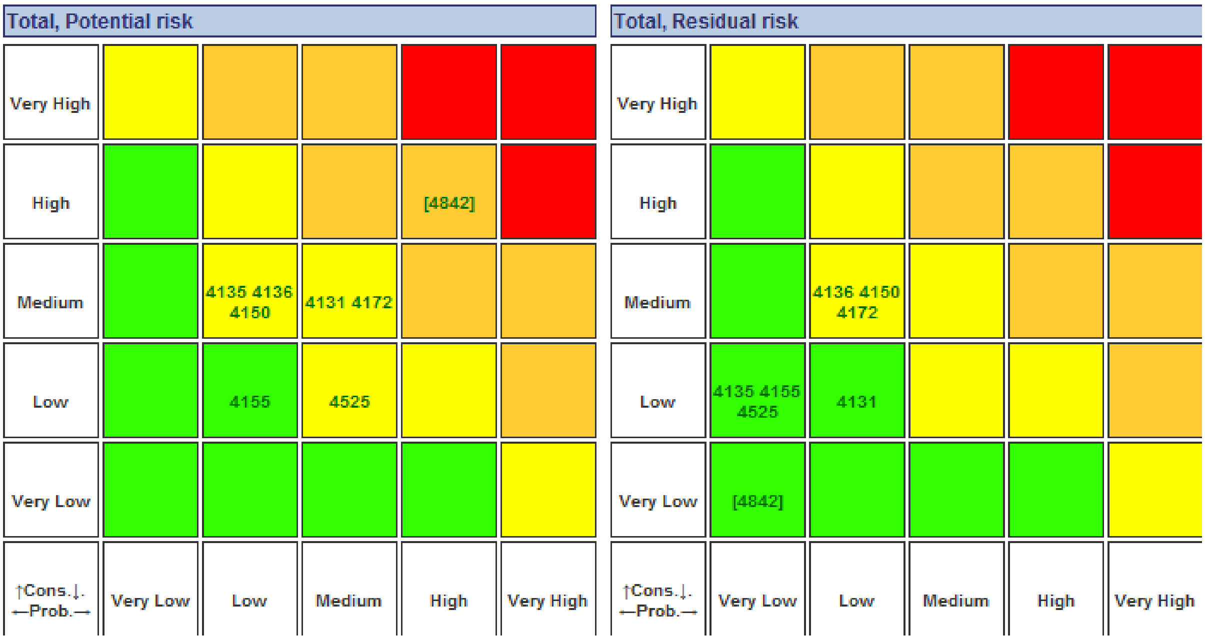
Work is ongoing to further refine the operating window of the integrated system. To avoid inefficient energy usage and compressor recycling it is likely that the compressor will be designed to deliver CO_2 at the well heads between a winter low of 5.6 MPa and a summer high of 10.5 MPa under normal operating conditions, with deviations to 11.5 MPa to cater for temporary upset conditions (i.e. 1 well down). The lower limit of the compressor discharge pressure is likely to be driven by pipeline requirements to keep the CO_2 in the dense state, above critical pressure (7.4 MPa for pure CO_2, higher for CO_2 contaminated with H_2). It is still desirable to have compressor capability to reach well head pressures of 14 MPa to overcome start-up effects (lower rates are acceptable on this short term basis) and as an option to re-wheel the compressor at a the later date (not foreseen within first 3 years) if additional injection data supports the full use of the safety allowance on fracture gradients (increase of the BHP constraint to 32 MPa) should poor reservoir conditions make this change necessary. This provides some additional contingency on injectivity, as all subsurface scenario modeling was carried out on a BHP constraint of 28 MPa.

Other areas of uncertainty that have not seen significant reductions in uncertainty and could impact injectivity over the life cycle are:

- Reservoir heterogeneity has now been fully incorporated (e.g. depositional environment studies, the integration of core and FMI data from the appraisal wells) in Gen-3 modelling and shown to have limited impact on pressure distribution around the well. Reservoir heterogeneity does however, introduce an additional level of uncertainty as large local permeability variation is seen in the model that is currently driven by stochastic modeling parameters and can not be accurately predicted from wells or seismic.
- The issue of far field pressures would benefit from further clarification of the hypothesis. In our most recent interpretation the uncertainty of this issue has been much reduced with evidence for regional connectivity of our target unit. 3D surface seismic now covers approximately 415 km2 or about 11% of the AOI and the latest processed data, available since April 2011, indicates increased frequency content of the data (up to 100Hz) which for the first time allows for an interpretation of an event near the top BCS. The absence of interpreted faults continuing from top Precambrian interval to top of BCS on the 3D seismic dataset has reduced the probability of the presence of large scale flow boundaries across the BCS reservoir that could cause compartmentalisation.
- The issue of well impairment by scaling, or mineral precipitation and transport. The impact of Halite precipitation has been investigated and still needs to be fully documented before it can be closed out. A preliminary review of scaling shows the probability to be low. As there is no analogue history of injection in the BCS further work is needed in this area to reduce the uncertainty around impairment over the project lifecycle.

2. Injectivity – EasyRisk Summary

Seven risks and one opportunity are captured in the EasyRisk database for Injectivity.



The project and HSE Risk Assessment Matrix (RAM) and its definitions are provided in Appendix 1.

Probability pre mitigation High (50-80% occurs in most projects, more likely than not)

4842 – High Injectivity due to higher than expected near well bore properties (kh and skin) (H/H ➔ VL/VL)

Probability pre mitigation Medium (20-50% occurs in projects, fairly likely)

4172 – Loss of Injectivity due to pressure build-up (M/M ➔ L/M)
4135 – Low Injectivity due to poorer than expected near well bore properties (kh and skin) (L/M ➔ VL/L)
4131 – Loss of Injectivity due to Operational upsets (M/M ➔ L/L)
4525 – Loss of Injectivity due to well interventions (MMV/integrity) (M/L ➔ VL/L)

Probability pre mitigation Low (5-20% occurs in some projects, low but not impossible)

4136 – Loss of Injectivity due to dropping BHP constraints (L/M ➔ L/M)
4150 – CO_2 injectivity overestimated from H_2O test (relperm & Non-Darcy skin) (L/M ➔ L/M)
4155 – Loss of Injectivity due to geochemical alteration of the reservoir / Halite precipitation (L/L ➔ VL/L)

TESLA buckets:

Wells – R-4135 (low kh/high skin), R4842 (high kh), R-4150 (gas vs water)
Heterogeneity (reactive flow), Far field Aquifer – R-4172 (pressure build-up)
Near well bore impairment – R-4155 (geochem/halite), R-4131 (ops), R-4525 (MMV)
Compression, BHP – R-4136 (dropping BHP constraint)

Comments/ recent changes from Discussion on Friday 3 Sept 2010:

A new risk was introduced (R-4842) to capture the opportunity to drill less than 5 injectors
Well interventions required for well integrity issues are now included in risk of MMV interventions (R-4525)
Sand failure risk captured in R4131 (Ops upsets), fines migration risks are captured in R4155

3. Feedback from the Oct 2010 External Performance Review

The below paragraph is quoted from the final close out report of the DNV facilitated Independent Project Review [07-3-AA-0706-0001, Nov. 2010]

QUOTE:
The Panel agrees that ample evidence has been provided to support the hypothesis for injectivity: ***Injectivity can be sustained for the full project life-cycle***. There was some confusion about what time-frame that should be applied to injectivity assessments. The injectivity risks relate to the ability to meet their contractual "obligation" under the funding agreement with the Albertan government, which requires 10 years of injection. The TESLA hypotheses that relate to injectivity, on the other hand, refer to sustained injectivity for the full life cycle, i.e., 25 years. The Panel recommends that the time-frames for risks (risk register) and uncertainties (TESLA database) be made consistent.

The Panel further agrees that the injectivity risks are generally accurately assessed, but has the following additional remarks and/or recommendations for modifications:

- HSSE impacts (post-mitigation) for all injectivity risks should be recorded as minor effect. HSSE impacts are currently assessed as either minor effect or slight effect. The implication of operational upsets due to injectivity problems is generally the same for all risks. The HSSE impact should therefore be ranked consistently across the range of injectivity risks.
- CO_2 injectivity overestimated from water injectivity test (rel-perm and non-Darcy skin). Post mitigation probability is currently assessed to be "Extremely unlikely". This should be raised to Low, but not impossible. Conducting relative permeability measurements for expected temperature and pressure ranges for CO_2-brine systems could reduce assessed risk.
- Loss of injectivity due to pressure build-up. Assessment ok, but there was some ambiguity about the density (salinity) of the BCS brine that should be clarified.
- Loss of injectivity due to geochemical alteration of the reservoir / Halite precipitation. Post mitigation probability may be higher than current assessment ("Extremely unlikely"). Additional geochemical modelling studies should be conducted to support conclusions.
- Loss of injectivity due to dropping BHP constraints. Assessment ok, but subsurface pressure and pressure gradient should be carefully stated and used. Text in risk register should be revised.

UNQUOTE

Actions and Comments on IPR feedback from Quest Storage Team

HSSE Impacts

The Quest project team had defined two groups of injectivity risks, one group likely to require the drilling of additional injectors wells (rated with a minor HSE impact) and one group likely to mitigate loss of injectivity through workover operations of existing injectors (rated with a slight HSE impact). The Quest project team has reviewed whether all mitigations should be rated to have a minor HSE impact, regardless whether the likely activity involves only well services or also well drilling activities. However, the Quest team concluded that drilling additional wells should be rated to have a potentially higher HSE impact, both through the operations involved in drilling the injector, the requirement for additional well sites (and pipeline connections) for injection and MMV purposes and the addition of penetrations in to a potentially pressurised location within the storage complex.

R4150 - CO2 injectivity overestimated from water injectivity test *(rel-perm and non-Darcy skin)*

The Quest project team has carried out further assessment of the relative injectivity of CO2 versus water in small scale numerical radial well models. Relative permeability datasets from Quest mineral oil-water core experiments and existing CO2 analog data were used to define a range of uncertainty. Capillary pressure endpoints were revised to capture a range of uncertainty in irreducible water saturations (not captured in Gen-3). The models indicate a relative injectivity ratio between CO2 and water of between 1.2 to 1.5 with the base case sitting close to the low end of the range at 1.25. This is considered to be conservative in view of the viscosity contrast of close to 10 that we expect between CO2 and BCS brine at reservoir conditions. The Quest team has also committed to carry out some end point permeability measurements with CO2 by June 2011 to confirm validity of the endpoints measured in previous mineral oil-brine SCAL experiments.

The limited value gain perceived to be achievable from CO2 testing and the long regulatory timeline relative to the timing of major project decisions, resulted in a decision not to pursue a CO2 test prior to FID (project sanction). Given the enhanced clarity of no early CO2 testing we agree with the panel that the post mitigation probability of this risk could be elevated from “very unlikely” to “low, but not impossible”. Work is now focused on reducing the impact of water to CO2 conversion issues by adequately defining the residual range of uncertainty, through selective core measurements and radial well modeling and recognizing the opportunity provided by an early start-up following the turnaround of HMU3 and the commissioning of 40% of total system capacity by Q4 2014.

R4172 – Loss of Injectivity due to pressure build-up

We believe the panel’s comment relates to the inconsistent use of BCS aquifer salinity in some of the Quest documentation (i.e. the use of kppm NaCl vs use of mg/l and the use of TDS). This will be addressed by issuing some internal guidelines on the correct units to be used in reference to brine salinity/density. It is not believed that this issue will impact in any material way the pressure build-up that may result from compartmentalisation, the underlying mechanism that is targeted by this risk.

The issue of aquifer density gradients and how these may affect aquifer flow and CO2 migration inside the BCS storage complex will be captured as a risk to conformance, more specifically risk R4163, Unexpected plume migration.

R4155 - Loss of Injectivity due to geochemical alteration of the reservoir and/or Halite precipitation

Awaiting conclusions of further modeling studies (e.g. Gen-4 TOUGHREACT model) before able to make an assessment whether post-mitigation risk probability should be increased from VLO to LO.

R4136 - Loss of Injectivity due to dropping BHP constraints

We believe the panel feedback refers to the inconsistent use of the term “hydrostatic” in the evidence sections for some of the TESLA hypotheses, in combination with various different pressure gradients quoted in the document. These descriptions will be clarified.

Clarification or alignment of life cycle in TESLA being 25 years and System Capacity in RAM being 10 years.

Review whether the system capacity definition in the RAM needs to be clarified to align it with the project description as carried in the FDP being clearly stated as:

- Store up to 27 mln tonnes of CO_2 over 25 years

4. Changes implemented from Rev. 01

R4135: Low Injectivity due to poorer than expected near well bore properties (kh, skin)
The drilling and testing of Radway 8-19 has moved the pre-mitigation probability of this risk down from MED (20-50%) to LO (5-20%), as Radway 8-19 was tested to provide approximately 80% of the required system capacity. The chance that more than 5 injection wells are required has now become considerably less likely.
As this risk is all about initial injectivity, a closure date of 1.1.2015 was defined. By this date all wells should have been drilled and tested and the post mitigation probability (i.e. uncertainty on this risk) should have disappeared. The post-mitigation probability of this risk has been reduced from LO to VLO as after drilling of the development wells the uncertainty on injectivity will be much reduced and the residual probability of this risk virtually reduced to zero. Residual injectivity risks still exist but are captured elsewhere (e.g. R4131, R4136, R4172 and R4155).
The action to consider drilling of the 4th appraisal /2nd development well has now been tied to this risk and is also used to support a NEW Opportunity to drill less than 5 wells (R4842). This action has further matured and a change management proposal is currently in progress to accelerate the drilling of two injection wells to mid 2012, straight after FID, and test them in time to support the decision whether or not additional injection wells and a pipeline extension are required. This decision would be required by November 2012 to allow the pipeline to be completed before start-up in 2014, whilst the extra wells would be drilled in the winter of 2013/2014 should more than 3 injection wells be required.

R4136: Loss of Injectivity due to dropping BHP constraints
Additional clarification on fracture pressures and gradients is provided as the Radway 8-19 BCS minifrac data is now available and is supported by log based analysis of minimum horizontal formation strengths in the various formations of the storage complex. The Radway°8-19 minifrac test in the BCS confirmed the data acquired earlier at Redwater 11-32. Also, the 9 5/8" casing shoe leak off test in the LMS confirmed LMS minifrac results from the Redwater 11-32 well. A D65 application with fracture data and a D51 approval to inject have been prepared and submitted to the ERCB, whilst the pressure operating envelope has also been documented in the basis for design document that Quest issued in January 2011.
The outstanding piece of work, currently in progress, that would provide additional information on the risk of reducing fracture gradients is the measurement of the thermal expansion coefficient on Radway 8-19 core. This will help determine whether the 4MPa margin that the project has already incorporated to buffer the effect that reservoir cooling may have on fracture gradients is adequate to help prevent loss of containment issues due the fracturing of the seals in the storage complex.

R4150: CO_2 injectivity overestimated from water injectivity test *(rel-perm and non-Darcy skin)*
Risk rating and description are updated to reflect latest plans to NOT test CO_2 prior to FID. Testing may still be beneficial to address start-up and operational issues but will bring little benefit to reduce remaining uncertainty on injectivity. Also, there now appears to be an opportunity to use the phased start-up of HMU's (HMU3 starting in 2014, followed by the

remaining HMU's in 2015) to have a prolonged start-up period which may negate the need for CO_2 testing prior to 1st injection in 2014. The post–mitigation probability was adjusted from VLO to LO in line with the feedback from the external panel.
Opportunity to reduce the post-mitigation impact from MED to LO should be reviewed, as SCAL and radial well modeling could help demonstrate impact to be small, and prolonged start-up period may also help reduce uncertainty by 2015 to insignificant levels.

R4172: Loss of Injectivity due to pressure build-up

Limited new data has become available on this risk, as the planned long water injection test in Radway 8-19 failed to provide any interpretable indication for the presence or absence of flow barriers in the reservoir, due to operational test issues. However, new 3D surface seismic provides evidence for the absence of large scale faults extending from top Precambrian to top BCS and have reduced the likelihood of compartmentalization.
Options are being considered to incorporate a pulse test in the injection test of a 2nd development well should plans to accelerate this well materialize. Both Radway 8-19 and Redwater 3-4 (if converted to an BCS observation well) are considered candidates to be used for monitoring the pressure response from injection into the new well. A pulse test is also considered, as part of the start-up strategy, as wells will be started up sequentially and downhole gauges can be monitored for interference in adjacent shut-in injection wells
This risk is now cross-referenced with new capacity risk (R4130) on compartmentalisation.

R4131: Loss of injectivity due to operational upsets

Radway 8-19 testing has demonstrated the vulnerability of injectivity to fluid contamination issues. Other acid gas operations within Shell also experienced injectivity issues and partner feedback from CO_2 injection in EOR operations also indicated a high potential for injectivity issues following operational upsets. Although injectivity is the above cases appear to have been successfully restored through stimulation and workovers, higher than anticipated well down time (i.e. well intervention and stimulation frequencies) could result in a larger system injectivity consequence of this risk, especially if not adequately mitigated. The pre-mitigation impact of this risk was hence increased from LO (10-15% downtime) to MED (15-20% downtime), whilst mitigation measures currently under consideration will still ensure post-mitigation impact level to remain LO. Pre and Post-mitigation probabilities of MED and LO respectively are still considered adequate.

R4155: Loss of Injectivity due to geochemical alteration of the reservoir and/or Halite precipitation

Needs further review and documentation.
Check for post-mitigation probability, **panel suggested upgrade from VLO to LO.**

R4525: Loss of injectivity due to injection well interventions (required by MMV)

Minimal update required, MMV strategy remains to be based on minimal intervention. Interventions required for well integrity reasons are now also included in this risk as these were not yet captured elsewhere in the database.

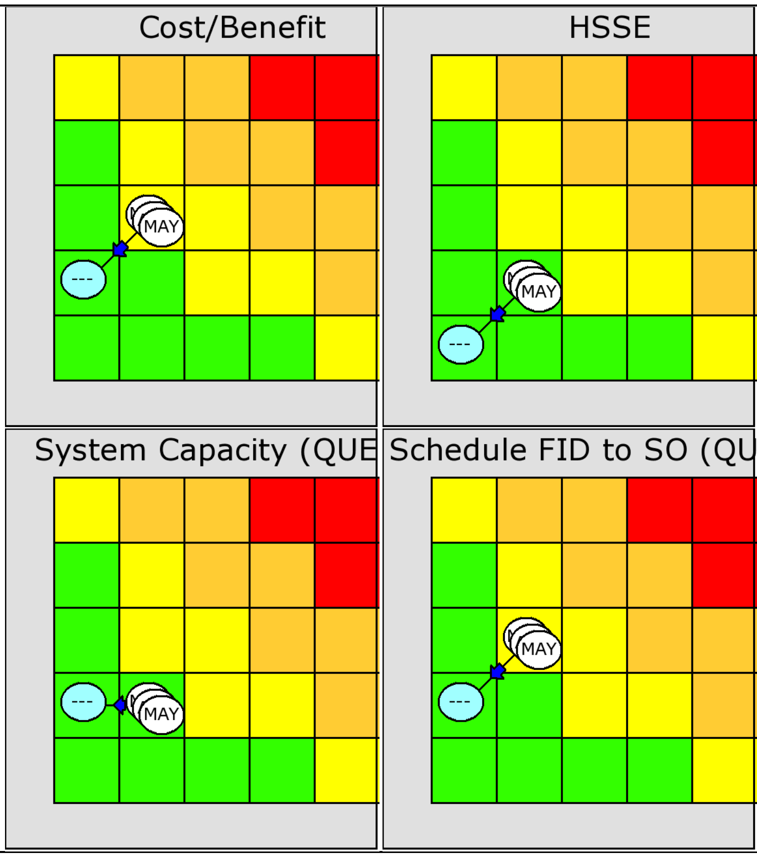
R4842: OPPORTUNITY High Injectivity due to better than expected near well bore properties (kh, skin)

This new risk was created to capture the opportunity that less than 5 wells can potentially be drilled in the base case development whilst still meeting the required system capacity of 1.2°mtpa. The probability of requiring less than 5 wells is currently assessed as High (50-80%) with a cost impact that is also High (25-50 mln CAD), representing the opportunity to save two injectors, two deep MMV wells and 13 km of pipeline.

Post-mitigation this risk disappears and the closure date for this Opportunity is set for December 2012, as most of the potential cost savings will evaporate after this date when commitments for the length of the pipeline need to be made.

5. All Injectivity Risks in Easyrisk and Tesla Databases

Risk 4135: Low Injectivity due to poorer than expected near well bore properties (kh, skin)

ID	R-4135
Name	QUEST: Low Injectivity due to poorer than expected near well bore properties (kh, skin)
Description	CAUSE: BCS reservoir permeability or thickness come in below expected range of uncertainty based on all available data or skin is higher than anticipated RISK EVENT: Initial Injectivity may be lower than expected, requiring more than 5 wells to meet contractual injection capacity. CONSEQUENCE: Increased cost (more wells) and potentially more time required to meet sustained injection at contractual injection capacity.
Notes	1 Sep 2010 (HdG) This risk also to include risk of high skin to align risk better with TESLA 1 Mar 2010 (HdG) Risk description updated after subsurface framing workshop
Mitigations Assumed or In Place	1) Radway 8-19 has been drilled and completed and was tested to have a water injectivity of 380 m3/d/MPa, calculated to be sufficient to cover 80% of Quest CO2 injection capacity needs. 2) The operation philosophy will include a 'spare' well so that system capacity can be reached with total number of wells minus 1. 3) Owner approvals for 8 confirmed locations in place and submitted as part of the regulatory submission update.
Owner	Crouch, Syrie
(Sub)Project	Injectivity (Quest)
Status	In Progress
Review Date	2011-02-25
Planned Finish	2015-01-01
	
Before actions	Probability: Low The 3rd appraisal well was drilled and logged within the expected propertye range and was tested well above expectation injectivity and can be retained as a keeper well. The scope for capacity shortage in the 5 well base case now substantially reduced.

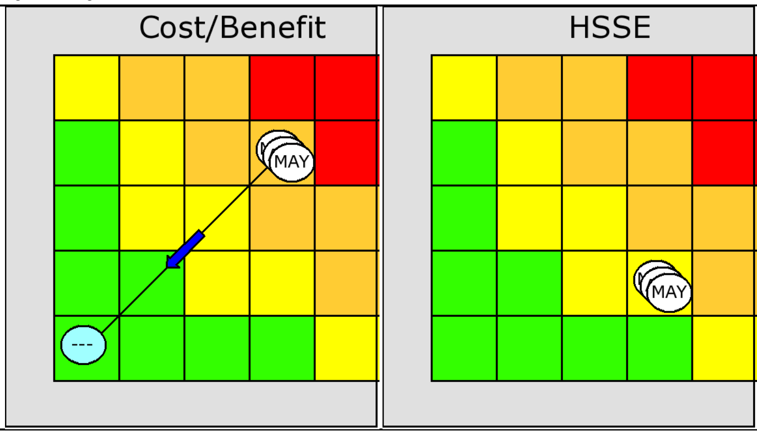
	Cost/Benefit [C&B]	Medium	Additional 1-3 injection well(s) and associated MMV required
	HSSE [HSSE]	Low	Additional exposure from well operations if workovers or extra wells are required.
	Reputation [REP]		No impact
	System Capacity (QUEST)	Low	Potential for 30% system capacity shortage at start-up but can be remedied in 3-6 months by drilling off additional well. Impact over 10 yr contract period reduced to 10-15% downtime
	Schedule to FID (QUEST)		No Impact
	Schedule FID to SO (QUEST)	Medium	If development wells come in with low injectivity a last minute decision will be required to drill more wells to meet contractual system capacity
After actions	Probability:	Very Low	This risk relates predominantly to low initial injectivity. Once all wells are drilled and tested sometime end 2014 the uncertainty on injectivity will be much reduced and the residual probability of this risk virtually reduced to zero.
	Cost/Benefit [C&B]	Low	at most 1 extra injection well + MMV required if Radway 8-19 proves high injectivity and covers >30% of capacity requirement.
	HSSE [HSSE]	Very Low	Additional exposure from well operations if stimulation, workover or extra well is required.
	Reputation [REP]		No impact
	System Capacity (QUEST)	Low	Potential for 30% system capacity shortage at start-up but can be remedied in 3-6 months by drilling off additional well. Impact over 10 yr contract period reduced to 10-15% downtime
	Schedule to FID (QUEST)		No Impact
	Schedule FID to SO (QUEST)	Low	If development wells are drilled early and tested prior to SO, mitigating measures like drilling more wells can be well on the way to limit impact on SO
Action Party	Sequestration Team		

Associated actions:

ID	*Name*	*Status*	*Owner*	*Start Date*	*Planned Finish*
A-2617	QUEST: Evaluate merits of horizontal well design to enhance injectivity in low permeability scenario's.	Closed	Clark, Christa	2010-08-02	2011-01-31
A-2623	QUEST: Drill and test a third appraisal well within the commercial area.	Closed	Crouch, Syrie	2010-01-01	2010-12-04
A-2627	QUEST: Assess CO2/water injectivity ratio's and CO2/brine displacement through radial well models	In Progress	De Groot, Hein	2010-09-01	2011-04-29
A-2634	QUEST: Comprehensive core data gathering and analysis	In Progress	Winkler, Mario	2009-02-01	2011-06-30
A-2635	QUEST: Model multiple subsurface realizations dynamically for pressure response.	In Progress	Huang, Hongmei	2009-01-01	2011-06-30
A-2692	QUEST: Assess feasibility of seismic QI to map variations in BCS thickness and porosity	Closed	Bourne, Stephen	2010-11-01	2011-05-13
A-2704	QUEST: Conduct and Evaluate Well Test on Radway 8-19	In Progress	De Groot, Hein	2010-09-01	2011-02-25
A-2707	QUEST: Accelerate drilling of 2nd development injector and evaluate options for pulse test	In Progress	Crouch, Syrie	2009-07-01	2011-12-30
A-2715	QUEST: Minimise induced formation damage in injectors	In Progress	Hugonet, Vincent	2010-04-01	2011-06-30
A-3275	QUEST: Enhance reservoir characterization of BCS and LMS (incorp. Radway data)	In Progress	Abernethy, Ross	2010-08-20	2011-05-13
A-3277	QUEST: Establish credible range of uncertainty for all reservoir parameters	In Progress	Abernethy, Ross	2010-07-01	2011-06-30

Opportunity 4842: High Injectivity due to better than expected near well bore properties (kh, skin)

ID	R-4842
Name	QUEST: OPPORTUNITY Reduce number of injection wells due to high injectivity
Description	CAUSE: BCS reservoir permeability and/or thickness come in above expected range of uncertainty based on all available data and skin from formation damage is minimal (i.e. better than expected near well bore properties like kh and skin) RISK EVENT: Initial Injectivity may be higher than expected, requiring less than 5 wells to meet contractual injection capacity. CONSEQUENCE: Reduced cost as less injection and monitoring wells are required, providing an opportunity to save on pipeline cost by shortening the D65 pipeline route by approx. 13 km.
Notes	Generated on 11 Feb'11 by HdG following injectivity risk review by team 18 Apr '11 (HdG) name updated to capture duplicate risk 4903 in visual risk matrix (now deleted)
Mitigations Assumed or In Place	
Owner	Crouch, Syrie
(Sub)Project	Injectivity (Quest)
Status	Proposed
Review Date	2011-02-25
Planned Finish	2012-12-01



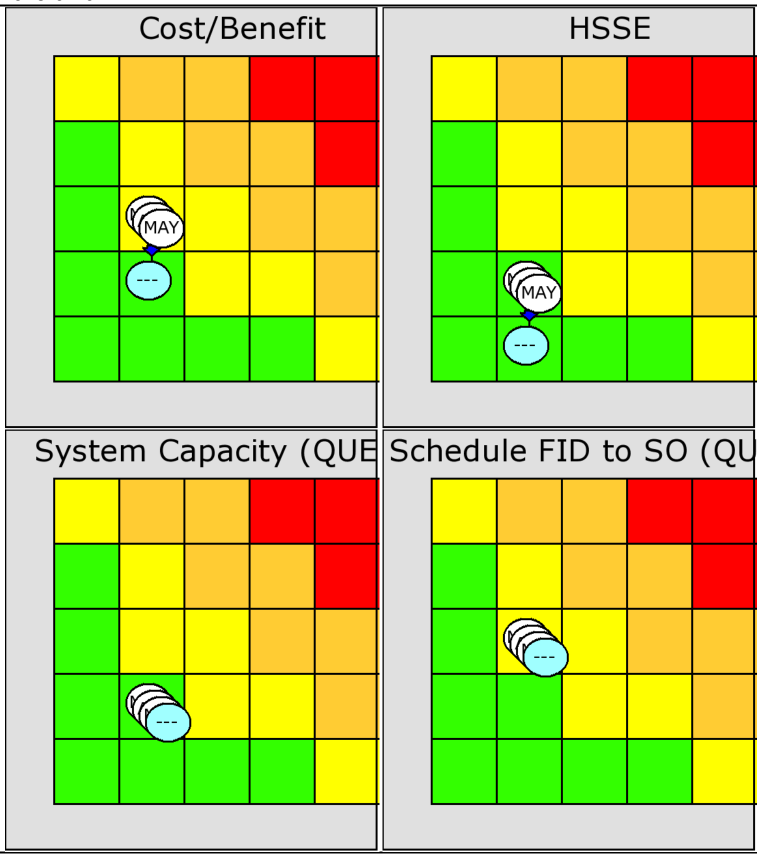
Before actions	Probability:	High	The probability that drilling the next development well could prove a development concept with less than 5 wells is currently assessed to be >50%.
	Cost/Benefit [C&B]	[High]	Potential to save 1-2 injectors and corresponding saving on MMV program (less MMV wells, fewer VSP's etc) and potential 13 mln CAD pipeline savings
	HSSE [HSSE]	[Low]	Reduced HSE exposure if fewer wells need to be drilled
	Reputation [REP]	[]	No impact
	System Capacity (QUEST)		No impact
	Schedule to FID (QUEST)		No impact
	Schedule FID to SO (QUEST)		No impact
After actions	Probability:	Very Low	Once this opportunity has been captured by adopting a base case development with less wells, this Opportunity can be closed and the probability set to zero.
	Cost/Benefit [C&B]	[Very Low]	
	HSSE [HSSE]		
	Reputation [REP]		
	System Capacity (QUEST)		
	Schedule to FID (QUEST)		
	Schedule FID to SO (QUEST)		
Likelihood			
Cost Estimate			

Schedule Estimate	
Production Estimate	
Action Party	Sequestration Team
Prefix - risk number	

Associated actions:

ID	Name	Status	Owner	Start Date	Planned Finish
A-2627	QUEST: Assess CO2/water injectivity ratio's and CO2/brine displacement through radial well models	In Progress	De Groot, Hein	2010-09-01	2011-04-29
A-2635	QUEST: Model multiple subsurface realizations dynamically for pressure response.	In Progress	Huang, Hongmei	2009-01-01	2011-06-30
A-2707	QUEST: Accelerate drilling of 2nd development injector and evaluate options for pulse test	In Progress	Crouch, Syrie	2009-07-01	2011-12-30
A-2715	QUEST: Minimise induced formation damage in injectors	In Progress	Hugonet, Vincent	2010-04-01	2011-06-30
A-3275	QUEST: Enhance reservoir characterization of BCS and LMS (incorp. Radway data)	In Progress	Abernethy, Ross	2010-08-20	2011-05-13
A-3277	QUEST: Establish credible range of uncertainty for all reservoir parameters	In Progress	Abernethy, Ross	2010-07-01	2011-06-30

Risk 4150: CO2 injectivity over-estimated from water injectivity test (relperms & non-Darcy skin)

ID	R-4150
Name	QUEST: CO2 injectivity over-estimated from water injectivity test (relperms & non-Darcy skin)
Description	CAUSE: Water injectivity test may not provide accurate estimate of CO2 Injectivity due to uncertainties around relative permeability and non-Darcy skin. CONDITION/EVENT: CO2 Injectivity may be lower than expected, requiring more wells to meet contractual injection capacity. CONSEQUENCE: Increased cost (more wells) and potentially more time required to meet sustained injection at contractual injection capacity.
Notes	4 Feb'11 (HdG) Post mitigation probability moved from VLO to LO in line with panel feedback 1 Sep 2010 (HdG) Non-Darcy skin is now rolled into this risk, separate from R-4135 (near wellbore risks) 1 Mar 2010 (HdG) Risk description updated after subsurface framing workshop
Mitigations Assumed or In Place	1) Literature review of field cases that injected both CO2 and water and review of NW Canada Acid gas injection history has shown little to no evidence for poor CO2 to water injection ratio's. 2) Review done by Shell core specialists show that interfacial tension between CO2 and brine behaves very much like a mineral oil water system and SCAL work on BCS core shows relatively small range of uncertainty of relative permeability curves (i.e well defined CO2 vs water injection ratio) 3) A study was conducted to review the expected impact of non-Darcy flow and found to have a minimal effect at the expected Quest injection rates per well. 4) The operation philosophy will include a 'spare' well so that system capacity can be reached with total number of wells minus 1.
Owner	Crouch, Syrie
(Sub)Project	Injectivity (Quest)
Status	In Progress
Review Date	2011-02-11
Planned Finish	2015-01-01
	

Before actions	Probability:	Low	
	Cost/Benefit [C&B]	Medium	Additional 1-3 injection well(s) and associated MMV required
	HSSE [HSSE]	Low	Additional exposure from well operations if workovers or extra wells are required.
	Reputation [REP]		No impact
	System Capacity (QUEST)	Low	Potential for 30% system capacity shortage at start-up but can be remedied in 3-6 months by drilling off additional well. Impact over 10 yr contract period reduced to 10-15% downtime
	Schedule to FID (QUEST)		No impact
	Schedule FID to SO (QUEST)	Medium	Relative flow of CO2 in formation brine can effect start-up and extend the period required to reach stable flow by 1-3 months.
After actions	Probability:	Low	There is little scope to reduce the probability of this riks as no firm plans are in place to conduct CO2 tests in the field. However, a prolonged start-up period (Expansion HMU on-line in 2014) provides scope for mitigation by drilling more wells in 2015
	Cost/Benefit [C&B]	Low	The impact of mis-interpreting the water injection test will be reduced through literature review, SCAL work and radial well modeling to at worst 1 extra well + MMV requirements.
	HSSE [HSSE]	Very Low	Additional exposure from well operations if stimulation, workover or extra well is required.
	Reputation [REP]		No impact
	System Capacity (QUEST)	Low	Potential for 30% system capacity shortage at start-up but can be remedied in 3-6 months by drilling off additional well. Impact over 10 yr contract period reduced to 10-15% downtime
	Schedule to FID (QUEST)		No impact
	Schedule FID to SO (QUEST)	Medium	Relative flow of CO2 in formation brine can effect start-up and extend the period required to reach stable flow by 1-3 months.
Likelihood			
Cost Estimate			
Schedule Estimate			
Production Estimate			
Action Party	Sequestration Team		
Prefix - risk number			

Associated actions:

ID	***Name***	***Status***	***Owner***	***Start Date***	***Planned Finish***
A-2623	QUEST: Drill and test a third appraisal well within the commercial area.	Closed	Crouch, Syrie	2010-01-01	2010-12-04
A-2627	QUEST: Assess CO2/water injectivity ratio's and CO2/brine displacement through radial well models	In Progress	De Groot, Hein	2010-09-01	2011-04-29
A-2634	QUEST: Comprehensive core data gathering and analysis	In Progress	Winkler, Mario	2009-02-01	2011-06-30
A-2719	QUEST: Develop early testing and monitoring plan for CO2 injectivity (test vs early start-up)	In Progress	De Groot, Hein	2010-04-16	2011-06-30
A-3016	QUEST: Literature review on CO2 pilots and tests	Closed	De Groot, Hein	2010-02-01	2010-09-17
A-3065	QUEST: Decide on need for a CO2 test on the 3rd appraisal well	Proposed Closed	De Groot, Hein	2010-04-21	2011-03-31
A-3300	QUEST: Review impact of non-Darcy skin on injectivity	Closed	De Groot, Hein	2010-01-01	2010-05-27
A-3591	QUEST: Quantify the radius of cooling around an injector	In Progress	Huang, Hongmei	2011-01-05	2011-06-30

TESLA - WELLS (FLC): Can be sited, drilled, completed and stimulated to achieve sufficient injectivity

Root Hypothesis -Impact Rank	23

Italian Flag History

Nov. 2008			0.35							0.05
March 2009						0.6				
Sep. 2009										
July 2010						0.6				
Feb. 2011								0.8		

Evidence FOR

1) The development area appears to be sited in a conducive geological setting
2) The appraisal well campaign demonstrated that vertical wells can be drilled to the BCS with the required well integrity.
3) 3D Seismic will control siting of wells to avoid "bald" Precambrian highs.
4) Core and log data provide evidence of moderate to good permeability in the BCS.
5) Scotford water injection test proves water injectivity in the BCS. Current well test analysis supports a ~20-50mD average permeability.
6) Radway 8-19 water injection test suggest injectivity of 380 m3/d/MPa, approx. 80% of required system injection capacity (kh~30,000 mD m)
7) A consistent set of minifrac data is available to support a deltaP sufficient to reach injectivity without fracturing the BCS
8) Well test activities at Scotford have demonstrated that a well can be completed with moderate skin of ~7. Optimisations on perforation strategy (shot density, reduced overbalance, etc.) were identified that could help reduce skin in future wells. A reduced skin was unfortunately not achieved Radway 8-19 due to water quality issues, but the well did demonstrate that injectivity could successfully be restored through N2 lifting and acid stimulation.
9) N2 lifting and acid stimulation have been demonstrated as feasible stimulation techniques.
10) Dynamic sensitivity modeling has demonstrated that even in a low connectivity, base case reservoir property scenario, sufficient injectivity can be achieved with 10 wells (as carried as the maximum in the D65 Regulatory Submission).
11) Same as 10) for low case reservoir property and base connectivity model.

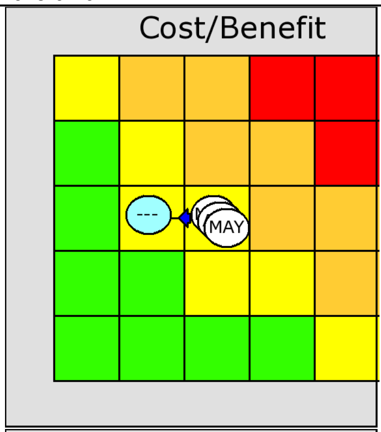
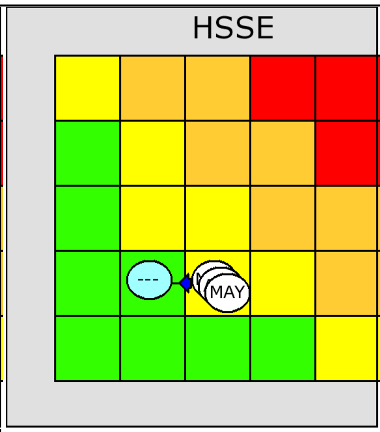
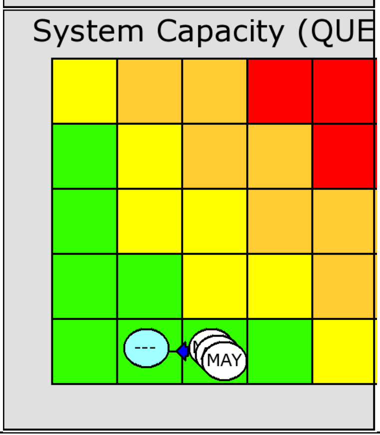
Evidence AGAINST

None

Uncertainties:

1) Nature of Precambrian faults seen on 3D
2) Residual uncertainty from Redwater 11-32 (no radial flow, fracture in minifrac zone ?) and Radway 8-19 (water quality issues, unstable pressures) water injection tests
3) Residual uncertainty on converting water injectivity to CO2 injectivity

Risk 4172: Loss of injectivity due to pressure build-up

ID	R-4172
Name	QUEST: Loss of injectivity due to pressure build-up
Description	CAUSE: Limited connectivity through reservoir heterogeneity and/or fault baffles cause a faster than expected build-up of pressures in and around the well . CONDITION/EVENT: Gradually declining Injectivity, requiring infill wells to continue to meet contractual injection capacity. CONSEQUENCE: Increased post start-up cost (infill wells and associated MMV) as new injectors need to be drilled to maintain field injection capacity (no impact on schedule).
Notes	3 Sep 2010 (HdG) Risk reopened and renamed from "Loss of injectivity due to geochemical alteration of reservoir" to "Loss of injectivity due to pressure build-up" to align with TESLA hypotheses on Far-Field Aquifer and Heterogeneity. Baffles and tortuous flow paths from faulting are also considered in this risk. 1 Sep 2010 (HdG) geochemical risks transferred to R-4155 on Halite precipitation. Containment risks of geochemistry captured in R-4167, Injectivity risks in R-4155. Relevant comments and actions copied across to those risks
Mitigations Assumed or In Place	1) Reservoir heterogeneity has been introduced in Gen-3 models and FDP needs to ensure that development is robust against the modelled reservoir quality variations. 2) The operation philosophy will include a 'spare' well so that system capacity can be reached with total number of wells minus 1.
Owner	Crouch, Syrie
(Sub)Project	Injectivity (Quest)
Status	In Progress
Review Date	2011-02-11
Planned Finish	2025-01-01
	  
Before actions	Probability: Medium — Reservoir heterogeneity and fault baffles are known to have limited connected volume around injectors in multiple projects around the world. All available data however suggests the BCS to be fairly continuous.

	Cost/Benefit [C&B]	Medium	Additional 1-3 injection well(s) and associated MMV required
	HSSE [HSSE]	Low	Limited additional exposure from drilling extra wells if required
	Reputation [REP]		No impact
	System Capacity (QUEST)	Very Low	Loss of injectivity will be gradual, if at all, and not manifest itself until years after SO. Sufficient indicators will be available to drill new wells when required resulting in minimal capacity loss
	Schedule to FID (QUEST)		No impact
	Schedule FID to SO (QUEST)		No impact, loss of injectivity from pressure build-up will not take place at start-up
After actions	Probability:	Low	Well Test of Radway 8-19 will evaluate the potential presence and nature of faults associated with faults seen in the top Precambrian on 3D seismic
	Cost/Benefit [C&B]	Medium	Additional 1-3 injection well(s) and associated MMV required
	HSSE [HSSE]	Low	Limited additional exposure from drilling extra well if required
	Reputation [REP]		No impact
	System Capacity (QUEST)	Very Low	Loss of injectivity will be gradual, if at all, and not manifest itself until years after SO. Sufficient indicators will be available to drill new wells when required resulting in minimal capacity loss
	Schedule to FID (QUEST)		No impact
	Schedule FID to SO (QUEST)		No impact, loss of injectivity from pressure build-up will not take place at start-up
Action Party	Sequestration Team		

Associated actions:

ID	***Name***	***Status***	***Owner***	***Start Date***	***Planned Finish***
A-2595	QUEST: Build a framework geological model to base Prairie evaporites (Gen-3)	Closed	Abernethy, Ross	2010-01-01	2010-11-23
A-2623	QUEST: Drill and test a third appraisal well within the commercial area.	Closed	Crouch, Syrie	2010-01-01	2010-12-04
A-2624	QUEST: Acquire additional seismic in the commercial area.	Closed	Bourne, Stephen	2009-12-01	2010-12-24
A-2628	QUEST: Map faults using seismic	In Progress	Bourne, Stephen	2010-01-01	2011-06-30
A-2629	QUEST: Develop adaptive MMV plan	In Progress	Bourne, Stephen	2010-01-01	2011-07-29
A-2632	QUEST: Define well based monitoring (MMV) requirements	In Progress	Malik, Satinder	2010-04-01	2011-06-30
A-2635	QUEST: Model multiple subsurface realizations dynamically for pressure response.	In Progress	Huang, Hongmei	2009-01-01	2011-06-30
A-2704	QUEST: Conduct and Evaluate Well Test on Radway 8-19	In Progress	De Groot, Hein	2010-09-01	2011-02-25
A-3275	QUEST: Enhance reservoir characterization of BCS and LMS (incorp. Radway data)	In Progress	Abernethy, Ross	2010-08-20	2011-05-13
A-3301	QUEST: Document work done on Sedimentology and Petrography	In Progress	Smith, Mauri	2010-09-01	2011-06-24
A-3308	QUEST: Review and document BCS waste disposal well locations and volumes NE of AOI	Proposed Closed	Smith, Mauri	2010-06-01	2010-11-30
A-3309	QUEST: Document IPSM work on integrated disposal system (pipelines and wells)	In Progress	Clark, Christa	2010-03-29	2011-06-30
A-3599	QUEST: Evaluate impact of concurrent CCS schemes adjacent to Quest AOI	In Progress	Huang, Hongmei	2009-04-29	2011-05-27

TESLA - HETEROGENEITY (FLC): Of the primary reservoir, is sufficiently understood to be confident of maintaining FLC injectivity under reactive flow conditions

Root Hypothesis -Impact Rank	12

Italian Flag History

Nov. 2008				0.4						
March 2009		0.2								
Sep. 2009					0.5					
July 2010						0.6				
Feb. 2011						0.6				

Comment: **Only reservoir heterogeneity aspects of this hypothesis are captured here, the issue of reactive flow conditions is captured under the near well bore impairment hypothesis. Is it not more relevant to capture the effect of fault baffles in sustained injectivity?**

Evidence FOR

1) High N/G clastic system free of carbonates and interstitial clays as supported by core description
2) Well control indicates a significant degree of *large scale* homogeneity from well to well. This shows itself in terms of continuity (sand bodies) and lack of diagenesis.
3) There is a feasible development solution for all reservoir realizations :
    a. including models with high structural heterogeneity assuming all faults are sealing. In reality the fault throw is less than BCS thickness.
    b. including models that incorporate FMI calibrated Kv/Kh and facies based modelling (i.e. low kv/kh, poorly connected LMS)
    c. Reservoir heterogeneity is at a scale no smaller than the fault densities modelled.
4) Top BCS pick from new 3D surface seismic provides further evidence that the BCS is laterally continuous and unfaulted although thinning towards the NE due to a rise of the Precambrian basement.

Evidence AGAINST

None

Uncertainties:

Large scale reservoir heterogeneities associated with the depositional environment of a TDBM setting

TESLA - FAR-FIELD AQUIFER (FLC): The aquifer boundary conditions (geography, flow conditions) are sufficiently understood and analysis is supportive of FLC safe injection with no significant impact on BHP or sensitive domains elsewhere.

Root Hypothesis -Impact Rank	18

Italian Flag History

Nov. 2008				0.4						
March 2009	0.1									0.1
Sep. 2009										
July 2010							0.7			
Feb. 2011							0.7			

Evidence FOR

1) The geological framework is well understood (Western Canadian Sedimentary Basin) and the BCS is a basin scale aquifer that is penetrated by ~100 regional wells.
2) The hydrodynamic system (incl. Salinity maps) is well understood, fluid flow in the basin is known to be very low (1 - 10 cm/yr) and regional flow maps have been created that are consistent with previous publications.
3) Waste disposal sites E-NE of our AOI have not seen reduction of injectivity due to an increase in reservoir pressure and are located approx. 90km to the NE.
4) Dynamic sensitivity modeling has demonstrated that even in a low connectivity scenario with limited connected aquifers, sufficient injectivity can be achieved with 10 wells (as carried as the maximum in the D65 Regulatory Submission).
5) The likelihood of a *Low Connectivity and Low Property* Model is further reduced with the interpretation of the new 3D surface seismic (no faulting across BCS) and the well results of Radway 8-19 (avg porosity increased to 16%).

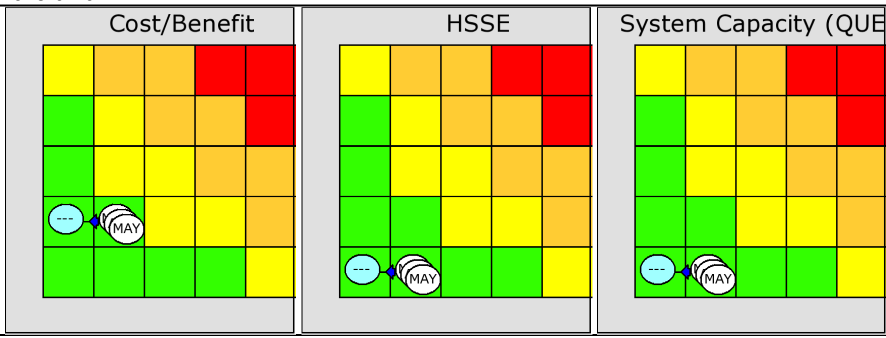
Evidence AGAINST

None

Uncertainties:

Do basement boundaries seen as lineaments on HRAM represent constraints on aquifer connectivity?

Risk 4155: Loss of Injectivity due to geochemical alteration of the reservoir and/or Halite precipitation

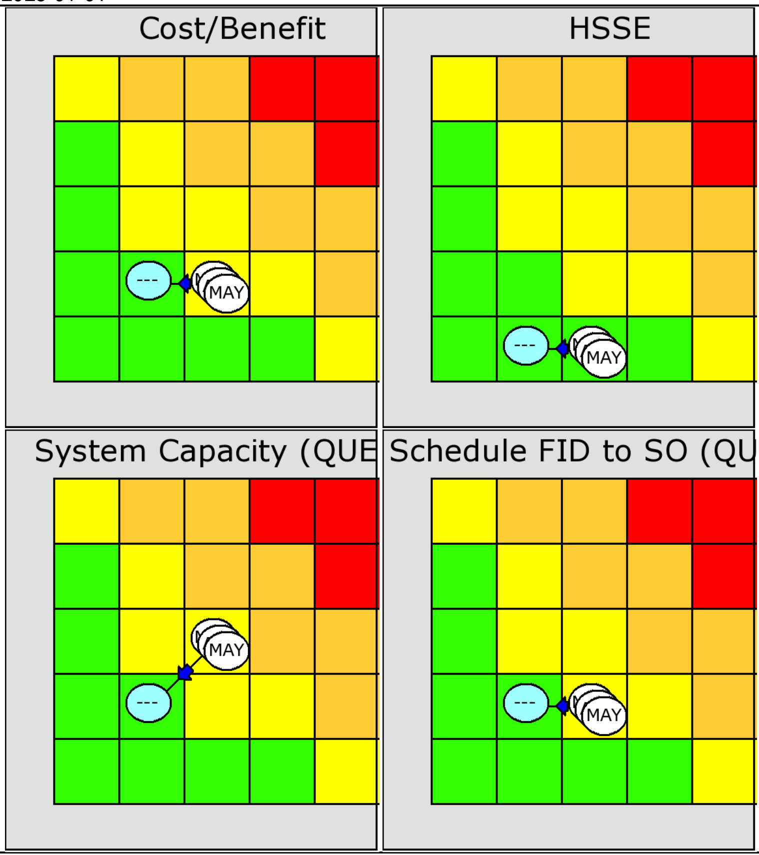
ID	R-4155
Name	QUEST: Loss of Injectivity due to geochemical alteration of the reservoir, halite precipitation or fines migration
Description	CAUSE: Geochemical alteration of reservoir could decrease porosity and permeability, the drying effect of CO2 in the highly saline brine in BCS and/or reservoir fines could plug pore throats in the near well bore (salts precipitated in the drying zone and/or fines may be remobilised by the velocity of the injected CO2, resulting in reduction in permeability via plugging of pore throats) EVENT: Injectivity may gradually drop with time, requiring more wells or more frequent well intervention to meet contractual injection capacity. CONSEQUENCE: Increased operating cost as wells will require more frequent intervention (stimulation or fresh water flushing) and an additional back-up well may be required.
Notes	11 Feb 2011 (HdG) Description adjusted to incorporate fines migration, previously in R4131 1 Sep 2010 (HdG) Geochemical risks from R-4172 have been incorporated in this risk. Sand failure risk will be transferred to R-4131
Mitigations Assumed or In Place	1) Geochemistry: Current data suggests a low likelihood of occurrence as the only reactive component identified in the BCS is K-feldspar (5% vol) which is expected to continue to dissolve in the low pH flushed zone. The absence of mineral trapping will help sustained injectivity. 2) Halite precipitation: No reports of halite precipitation causing loss of injectivity exist in available literature. Modeling in TOUGHREACT suggested the dry-out zone around injectors to be limited to 65m after 25 years of injection, whilst injection of low temperature CO2 could reduce the dry out zone further by a factor 2. Halite precipitation the dry-out zone should be dissolvable by fresh or low salinity water. 3) Fines migration. No evidence for fines or dispersed clays in the connected pore structure of the rock matrix have been found in thin sections that were cut to review possible causes of formation damage following the Radway 8-19 injection test. 4) The operation philosophy will include a 'spare' well so that system capacity can be reached with total number of wells minus 1.
Owner	Crouch, Syrie
(Sub)Project	Injectivity (Quest)
Status	In Progress
Review Date	2011-02-11
Planned Finish	2025-01-01
	
Before actions	Probability: — Low — Geochemical reactions (other than halite precipitation) are unlikely to occur based on already available rock-fluid interaction studies. The reservoir consists of clean quartz with no scope for calcite deposits. Cost/Benefit [C&B] — Low — Cost impact was assumed to be limited to occasional low salinity water flush of the injectors or at worst a requirement for 1 extra well. HSSE [HSSE] — Very Low — Limited additional exposure from well services/drilling when fresh water flushing or extra well is required. Reputation [REP] — No impact System Capacity (QUEST) — Very Low — Loss of injectivity will be gradual, if at all, and not manifest itself until years after SO. Sufficient indicators will be available to drill new wells when required resulting in minimal capacity loss

	Schedule to FID (QUEST) Schedule FID to SO (QUEST)		No impact No impact, loss of injectivity from geochemical alteration of the reservoir or halites will not take place until long after start-up
After actions	Probability:	Very Low	Further core studies and the development of a halite mitigation plan should further reduce the probability of this risk occurring.
	Cost/Benefit [C&B]	Low	Cost impact was assumed to be limited to occasional low salinity water flush of the injectors or at worst a requirement for 1 extra well.
	HSSE [HSSE]	Very Low	Limited additional exposure from well services/drilling when fresh water flushing or extra well is required.
	Reputation [REP]		No impact
	System Capacity (QUEST)	Very Low	Loss of injectivity will be gradual, if at all, and not manifest itself until years after SO. Sufficient indicators will be available to drill new wells when required resulting in minimal capacity loss
	Schedule to FID (QUEST) Schedule FID to SO (QUEST)		No impact No impact, loss of injectivity from geochemical alteration of the reservoir or halites will not take place until long after start-up
Likelihood			
Cost Estimate			
Schedule Estimate			
Production Estimate			
Action Party	Sequestration Team		
Prefix - risk number			

Associated actions:

ID	*Name*	*Status*	*Owner*	*Start Date*	*Planned Finish*
A-2615	QUEST: Prepare conceptual workover strategy for wells with dropping injectivity or well integrity issues	In Progress	Malik, Satinder	2009-07-01	2011-06-30
A-2619	QUEST: Evaluate need for a 'spare' well	In Progress	Malik, Satinder	2009-03-02	2011-07-29
A-2623	QUEST: Drill and test a third appraisal well within the commercial area.	Closed	Crouch, Syrie	2010-01-01	2010-12-04
A-2629	QUEST: Develop adaptive MMV plan	In Progress	Bourne, Stephen	2010-01-01	2011-07-29
A-2634	QUEST: Comprehensive core data gathering and analysis	In Progress	Winkler, Mario	2009-02-01	2011-06-30
A-2637	QUEST: Halite Core Experiments	Proposed Closed	Winkler, Mario	2009-02-01	2011-02-11
A-2701	QUEST: Model Rock-Fluid interactions (BCS and seal Geochemistry/halite precipitation)	In Progress	Winkler, Mario	2010-01-01	2011-06-30
A-2715	QUEST: Minimise induced formation damage in injectors	In Progress	Hugonet, Vincent	2010-04-01	2011-06-30
A-2718	QUEST: Create halite mitigation plan.	In Progress	Hugonet, Vincent	2010-07-01	2011-06-30
A-2719	QUEST: Develop early testing and monitoring plan for CO2 injectivity (test vs early start-up)	In Progress	De Groot, Hein	2010-04-16	2011-06-30
A-3016	QUEST: Literature review on CO2 pilots and tests	Closed	De Groot, Hein	2010-02-01	2010-09-17
A-3301	QUEST: Document work done on Sedimentology and Petrography	In Progress	Smith, Mauri	2010-09-01	2011-06-24

Risk 4131: Loss of injectivity due to operational upsets

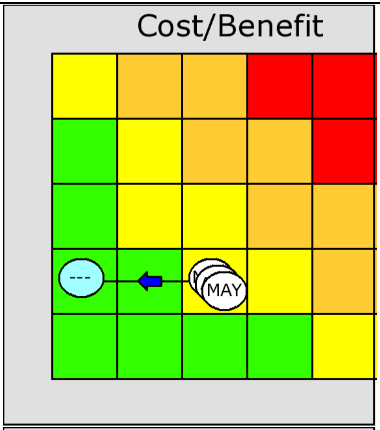
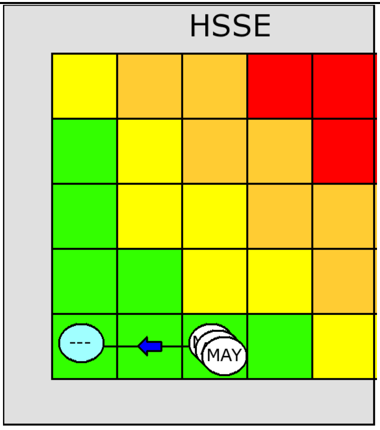
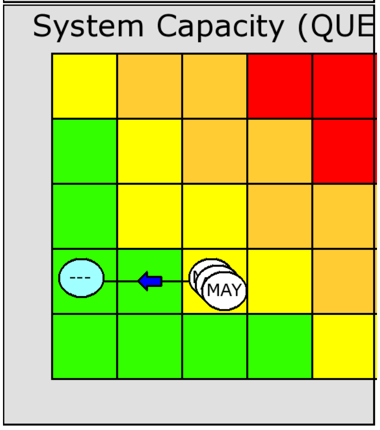
ID	R-4131
Name	QUEST: Loss of injectivity due to operational upsets
Description	CAUSE: Frequent system shutdowns will require injectors to be shut-in and could potentially lead to sand failure in the well bore due to pressure shocks and/or back flow. Solids or fluids in the injectant (from pigging, inhibitors, glycol or operational upsets) could plug the pore throats in the near well bore. Finally a leak of completion fluids into the near well bore could also cause impairment. EVENT: Plugging of the completion resulting in gradual loss of injectivity or inability to restart injection after a well shut-in. CONSEQUENCE: Increased costs as injectors may require remedial work (workover/stimulation) and system capacity may be temporarily reduced whilst waiting for the workover or the addition of new wells to restore injection capacity.
Notes	4 Feb '11: New information suggests glycol may continuously spill over in the injectant stream (2m3/month). The CO2 tream was previously assumed to be clean so this is a change that is currently routed through MOC. This risk is to be re-evaluated after MOC process is concluded. 1 Sep 2010 (HdG): Risk renamed from "Frequent system shutdowns have detrimental impact on injectivity, particularly at start-up" to "Loss of inj due to operational upsets" to incorporate all operational related issues. The issue of solids in the injectant was moved across from R-4155.
Mitigations Assumed or In Place	1) In-line filters will be in place at the wellsite upstream of wellhead (in BoD) 2) Length of pipeline will provide linepack to buffer pressure effects of short system upsets. 3) Pipeline valves will be shut-in in event of system upsets to maintain pressure in pipeline to ensure CO2 stays single phase. 4) The operation philosophy will include a 'spare' well so that system capacity can be reached with total number of wells minus 1.
Owner	Crouch, Syrie
(Sub)Project	Injectivity (Quest)
Status	In Progress
Review Date	2011-02-04
Planned Finish	2025-01-01
	
Before actions	Probability: Medium

	Cost/Benefit [C&B]	Low	Additional well services cost to workover or stimulate the wells more than planned and at worst 1 well to be re-drilled (due to eg. sand failure, etc.)
	HSSE [HSSE]	Very Low	Additional exposure from well operations if workovers or extra wells are required.
	Reputation [REP]		No Impact
	System Capacity (QUEST)	Medium	Well remediation work after operational upsets could result in a reduction of 15-20% system capacity, as Radway 8-19 has demonstrated considerable vulnarability of injectivity to contamination of injection fluids.
	Schedule to FID (QUEST)		No Impact
	Schedule FID to SO (QUEST)	Low	If injection starts before clean and stable CO2 injection can be guaranteed, well impairment could result in delays in reaching injection capacity
After actions	Probability:	Low	Further pre-FID work will resolve the need for sand control and the definition of an operation strategy that minimises system upsets. Also, design of consistent dry CO2 injection will eliminate/minimize need for injection of inhibitors.
	Cost/Benefit [C&B]	Low	Additional well services cost to workover or stimulate the wells more than planned and at worst 1 well to be re-drilled (due to eg. sand failure, etc.)
	HSSE [HSSE]	Very Low	Additional exposure from well operations if stimulation, workover or extra well is required.
	Reputation [REP]		No Impact
	System Capacity (QUEST)	Low	Impact of operational upsets can be reduced through definition of and ensure adherence to strict specifications on contaminants in injected CO2 and installations of filters on the well site.
	Schedule to FID (QUEST)		No Impact
	Schedule FID to SO (QUEST)	Low	If injection starts before clean and stable CO2 injection can be guaranteed, well impairment could result in delays in reaching injection capacity
Likelihood			
Action Party	Sequestration Team		
Prefix - risk number			

Associated actions:

ID	*Name*	*Status*	*Owner*	*Start Date*	*Planned Finish*
A-2600	QUEST: Deliver consistent CO2 purity	Closed	Leontowich, Jeffrey	2009-10-01	2011-01-25
A-2615	QUEST: Prepare conceptual workover strategy for wells with dropping injectivity or well integrity issues	In Progress	Malik, Satinder	2009-07-01	2011-06-30
A-2618	QUEST: Evaluate need for sand control	In Progress	Hugonet, Vincent	2010-01-01	2011-06-30
A-2619	QUEST: Evaluate need for a 'spare' well	In Progress	Malik, Satinder	2009-03-02	2011-07-29
A-2622	QUEST: Develop Operating guidelines	In Progress	Malik, Satinder	2010-04-01	2011-06-30
A-2634	QUEST: Comprehensive core data gathering and analysis	In Progress	Winkler, Mario	2009-02-01	2011-06-30
A-2715	QUEST: Minimise induced formation damage in injectors	In Progress	Hugonet, Vincent	2010-04-01	2011-06-30
A-3309	QUEST: Document IPSM work on integrated disposal system (pipelines and wells)	In Progress	Clark, Christa	2010-03-29	2011-06-30

Risk 4525: Loss of injectivity due to injection well interventions (required for MMV or well integrity purposes)

ID	R-4525
Name	QUEST: Loss of injectivity due to injection well interventions (required for MMV or well integrity purposes)
Description	CAUSE: Well interventions in injector wells (e.g. wireline logging for MMV purposes or re-entries to address well integrity issues) may require these wells to be killed prior to re-entry, potentially introducing near well bore formation damage. EVENT: Injectivity may drop with every well intervention, requiring more wells to meet contractual injection capacity. CONSEQUENCE: Increased operating cost as wells will require remedial action (stimulation) or increased Capex (extra wells) as wells eventually lose too much injectivity and need to be replaced.
Notes	11 Feb 2011 (HdG) This risk now also includes loss of injectivity due to interventions required to address well integrity issues 2 Mar 2010 (HdG) Introduced based on feedback from the Subsurface framing workshop end February 2010.
Mitigations Assumed or In Place	MMV plan will try to maximise introduction of non-intrusive monitoring techniques (DTS, downhole gauges, etc.) in order to minimise well entries. Completion design will allow for killing the well on packers (no kill fluid over the formation required) if tubing retrieval is required The operation philosophy will include a 'spare' well so that system capacity can be reached with total number of wells minus 1.
Owner	Crouch, Syrie
(Sub)Project	Injectivity (Quest)
Status	In Progress
Review Date	2011-02-11
Planned Finish	2025-01-01
	  

Before actions	Probability:	Medium	Annual interventions to run 3D VSP's on the injectors are part of the base MMV plan.
	Cost/Benefit [C&B]	Low	Additional well services cost to workover or stimulate the wells more than planned and at worst 1 well to be re-drilled (due to irreversible loss of injectivity)
	HSSE [HSSE]	Very Low	Additional exposure from well operations if workovers or extra wells are required.
	Reputation [REP]		No impact
	System Capacity (QUEST)	Low	Well remediation work after MMV interventions could result in a reduction of 10-15% system capacity.
	Schedule to FID (QUEST)		No impact
	Schedule FID to SO (QUEST)		No impact, injectivity loss if any will only become apparent after a few years (i.e. a number of interventions)
After actions	Probability:	Very Low	Critically review the MMV plan for well intervention requirements and try to eliminate well entries through introduction of non-intrusive monitoring techniques (DTS, downhole gauges, etc.).
	Cost/Benefit [C&B]	Low	Extra (1-2) wells or more frequent well workovers (stimulations) required to maintain field injectivity
	HSSE [HSSE]	Very Low	Additional exposure from well operations if stimulation, workover or extra well is required.
	Reputation [REP]		No impact
	System Capacity (QUEST)	Low	Well remediation work after MMV interventions could result in a reduction of 10-15% system capacity.
	Schedule to FID (QUEST)		No impact
	Schedule FID to SO (QUEST)		No impact, injectivity loss if any will only become apparent after a few years (i.e. a number of interventions)
Likelihood			
Cost Estimate			
Schedule Estimate			
Production Estimate			
Action Party	Sequestration Team		
Prefix - risk number			

Associated actions:

ID	***Name***	***Status***	***Owner***	***Start Date***	***Planned Finish***
A-2603	QUEST: Ensure robust well design (incl. material selection, cement quality, completion)	In Progress	Malik, Satinder	2009-07-01	2011-06-30
A-2615	QUEST: Prepare conceptual workover strategy for wells with dropping injectivity or well integrity issues	In Progress	Malik, Satinder	2009-07-01	2011-06-30
A-2629	QUEST: Develop adaptive MMV plan	In Progress	Bourne, Stephen	2010-01-01	2011-07-29
A-2632	QUEST: Define well based monitoring (MMV) requirements	In Progress	Malik, Satinder	2010-04-01	2011-06-30
A-3111	QUEST: Define Well intervention strategy	In Progress	Malik, Satinder	2010-06-10	2011-06-30

TESLA - NEAR WELL-BORE SCALING & IMPAIRMENT (FLC): Scaling, mineral precipitation and mineral transport are sufficiently understood to support FLC injectivity.

Root Hypothesis -Impact Rank	11

Italian Flag History

Nov. 2008				0.4						
March 2009			0.3							
Sep. 2009					0.5					
July 2010						0.6				
Feb. 2011						0.6				

Comment: **The reactive flow aspects from the Reservoir Heterogeneity hypothesis are captured here along with other near well bore impairment issues.**

Evidence FOR

1) Initial review of rock-fluid interactions shows no mineral trapping and continued dissolution of K-feldspars.
2) Thin section analysis has not shown any evidence for mobile fines in the pore matrix.
3) Porosity reduction due to halite precipitation is expected to be small~2% and this is within current uncertainty range carried for porosity in 3D reservoir models and development is robust for low porosity scenario.
4) Only two of 52 AGI projects have suffered decrease in injectivity (but injection formations are not the BCS).
5) Mineralogy appears to be suitable (clay content ~4% and of this < 20% smectite) for water injection to mitigate potential halite precipitation.
6) CO2 sink analogue (Ketzin, Germany) indicates no impairment after 1 year injection into single well (also high salinity at ~220kppm).
7) Risk of scaling not apparent (no free water, water content of CO2 < 6 lbs/MMscf)
8) Stimulation with HCl acid appeared to be effective in Redwater 11-32 and Radway 8-19. N2 backflow is now proven as a clean-up methodology after completion.

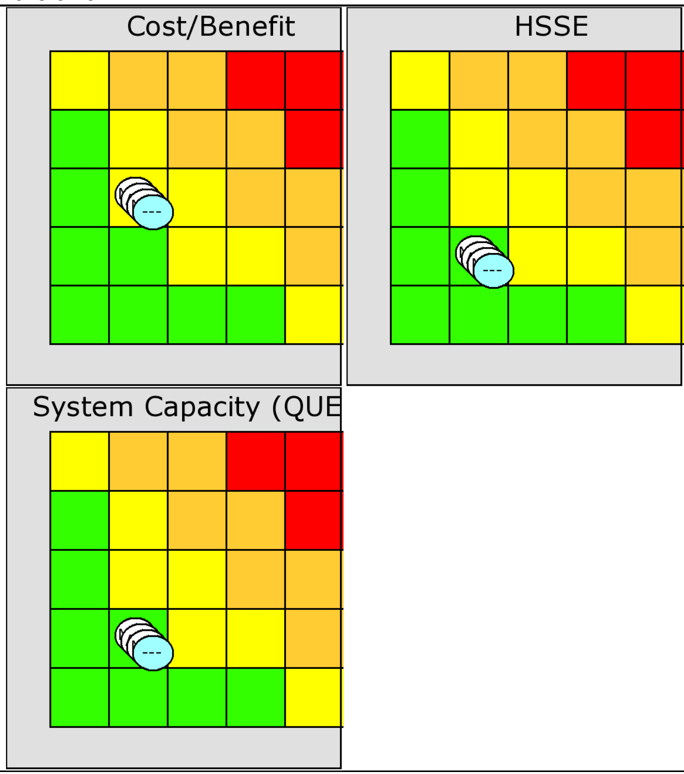
Evidence AGAINST

1) Under dry CO2 injection conditions there will be halite precipitation with an unknown effect on permeability that can however be mitigated by low salinity KCL brine flushing.

Uncertainties:

1) Halite precipitation will occur in the dry out zone. There is uncertainty whether halites will migrate and accumulate in pore throats or at grain contacts and also whether its impact on permeability may be more than offset by the added porespace that becomes available for flow by evaporating the irreducible water saturation.
2) Glycol and lubrication may be carried over at low concentrations from the capture facility.

Risk 4136: Loss of Injectivity due to dropping BHP constraints

ID	R-4136
Name	QUEST: Loss of Injectivity due to dropping BHP constraints
Description	CAUSE: Formation stresses and resulting fracture gradients could drop with reducing reservoir temperatures from CO2 injection and/or micro seismic monitoring could indicate unexpected fracturing in the BCS, both could result in a reduction of the BHP constraint. Alternatively, regulations could change requiring BHP constraint below 90% of fracture pressure. RISK EVENT: A drop of the BHP constraint would result in reduced well injectivity CONSEQUENCE: Increased costs (infill wells and associated MMV) would be required to maintain injection at contractual injection capacity. Some CO2 credits could be lost awaiting completion of new wells following the implementation of more stringent BHP constraints.
Notes	8 Sep 2010 (HdG) A duplicate risk description ("Unexpected relative permeability and residual saturation = >Severely reduced injection performance => impact on system capacity and cost") was recycled to capture a new risk around changing BHP constraints. Relperm effects are captured in R-4150, residual saturation in R-4166.
Mitigations Assumed or In Place	1) All dynamic modelling is carried out using a conservative BHP constraint of 28 MPa, the D65 will be submitted using fracture propagation pressure gradient in the LMS (17.4 kPa/m) , estimating a BHP constraint at Radway 8-19 of 32,210 kPa. This provides sufficient margin to be robust against this risk. 2) Geomechanics will further define the expected impact (including uncertainty range) of low temperature CO2 injection on formation stress and fracture gradients. 3) Micro seismic monitoring requirements and response plan will be incorporated in the adaptive MMV plan. 4) Changing Regulations usually have a grandfather clause leaving sufficient time (5 yrs) to respond and implement mitigation measures. 5) Thermal modelling indicates a limited lateral extent of the temperature drop away from the injector (~200m in 10 years) and this will limit the lateral extent of any thermal induced fractures. 6) The operation philosophy will include a 'spare' well so that system capacity can be reached with total number of wells minus 1.
Owner	Crouch, Syrie
(Sub)Project	Injectivity (Quest)
Status	In Progress
Review Date	2011-02-04
Planned Finish	2025-01-01
	

Before actions	Probability:	Low	The safety margin both internal (28 vs 32 MPa) and through regulations (max BHP 90% frac press.) should minimize the prob. of this risk occurring. Also, regulations are not known to change with immediate effect for ongoing projects (grandfathering).
	Cost/Benefit [C&B]	Medium	Additional 1-3 injection well(s) and associated MMV required
	HSSE [HSSE]	Low	Additional exposure from well operations if workovers or extra wells are required.
	Reputation [REP]		No impact
	System Capacity (QUEST)	Low	Potential for sudden system capacity shortage if BHP constraints but can be remedied in 3-6 months by drilling off additional well. Impact over 10 yr contract period reduced to 10-15% downtime
	Schedule to FID (QUEST)		No impact
	Schedule FID to SO (QUEST)		No impact, risk will not be active until after SO
After actions	Probability:	Low	Not expected to change much although geomechanical understanding of temperature effect on fracture pressures may improve
	Cost/Benefit [C&B]	Medium	Additional 1-3 injection well(s) and associated MMV required
	HSSE [HSSE]	Low	Additional exposure from well operations if workovers or extra wells are required.
	Reputation [REP]		No impact
	System Capacity (QUEST)	Low	Potential for sudden system capacity shortage if BHP constraints but can be remedied in 3-6 months by drilling off additional well. Impact over 10 yr contract period reduced to 10-15% downtime
	Schedule to FID (QUEST)		No impact
	Schedule FID to SO (QUEST)		No impact, risk will not be active until after SO
Likelihood			
Cost Estimate			
Schedule Estimate			
Production Estimate			
Action Party	Sequestration Team		
Prefix - risk number			

Associated actions:

ID	***Name***	***Status***	***Owner***	***Start Date***	***Planned Finish***
A-2620	QUEST: Evaluate possible temperature change that wellbore could experience	In Progress	Clark, Christa	2010-04-01	2011-06-30
A-2622	QUEST: Develop Operating guidelines	In Progress	Malik, Satinder	2010-04-01	2011-06-30
A-2629	QUEST: Develop adaptive MMV plan	In Progress	Bourne, Stephen	2010-01-01	2011-07-29
A-2632	QUEST: Define well based monitoring (MMV) requirements	In Progress	Malik, Satinder	2010-04-01	2011-06-30
A-2634	QUEST: Comprehensive core data gathering and analysis	In Progress	Winkler, Mario	2009-02-01	2011-06-30
A-2635	QUEST: Model multiple subsurface realizations dynamically for pressure response.	In Progress	Huang, Hongmei	2009-01-01	2011-06-30
A-2716	QUEST: Dynamic Fracture Modeling	In Progress	Clark, Christa	2010-01-01	2011-06-30
A-3591	QUEST: Quantify the radius of cooling around an injector	In Progress	Huang, Hongmei	2011-01-05	2011-06-30

TESLA - BHP (FLC): Bottom hole pressures can be sufficiently quantified and managed to maintain injectivity

Root Hypothesis -Impact Rank	9

Italian Flag History

Nov. 2008				0.4						
March 2009						0.6				
Sep. 2009						0.6				
July 2010						0.6				
Feb. 2011						0.6				

Evidence FOR

1) There is a consistent dataset of MDT pressure points in the BCS that suggest pressures in the three Shell appraisal wells are on a single pressure trend. The data supports that:
   a. The initial reservoir pressure is well understood with minimal uncertainty
   b. There is no evidence for BCS pressure compartments within the AOI.
2) Fracture extension pressure data is available from minifrac tests in two wells:
   a. 20.7 kPa/m BCS fracture gradient in Redwater 11-32 (45.4 MPa @ 2190 mTVD)
   b. 20.6 kPa/m BCS fracture gradient in Radway 8-19 (42.4 MPa @ 2049 mTVD)
   c. LMS microfrac data for Redwater 11-32 indicates a lower fracture propagation pressure gradient of 17.4 kPa/m
3) ERCB regulations restrict injection to 90% of fracture pressure in injection zone
4) The proposed D65 BHP constraint based on 90% of LMS fracture gradient provides 10 MPa margin to the Radway 8-19 BCS fracture extension pressure.
5) Dynamic models are run on a BHP constraint of 28 MPa (well within ERCB requirements) and support FLC injection requirements under the full range of reservoir realizations.
6) Current MMV plan includes continuous BHP pressure measurements in all injectors and selected micro seismic monitoring near at least one injector to confirm the absence of fracturing.

Evidence AGAINST

None

UNCERTAINTY

Behavior of fracture pressure gradient and in-situ stresses over time (as function of Pressure and Temperature changes)

TESLA - COMPRESSION (FLC): Can be achieved and sustained

Root Hypothesis -Impact Rank	22

Italian Flag History

Nov. 2008				0.4						
March 2009					0.5					
Sep. 2009							0.7			
July 2010									0.9	
Feb. 2011									0.9	

Evidence FOR

1) Design discharge pressure of the compressor has been selected at 14.5 MPa.
    a. Operating pressures for normal well head operating conditions are estimated between 5.6 and 10.5 MPa, for low and high CO_2 arrival temperatures respectively.
    b. 14.5 MPa discharge pressure is required for max. BHP of 32 MPA whilst start-up is planned at 28 MPa and will require lower discharge pressures.
2) An IPSM model has been built to validate injectivity in the well bore can be achieved with this compressor configuration and a 12" pipeline covering all subsurface scenario's
3) Length of buried pipeline (~85 km) ensures low arrival temperatures (0-10 degC) at well head and contributes to high CO_2 density and stable BHP.
4) Similar compressors have already been in use at Dakota Gasification in North Dakota for ~10yrs. Dakota Gasification has been consulted by Quest on design criteria and operating experience. Dakota is currently considering purchasing additional 2 compressors for an expansion
5) Compressor vendor selected and FEED started on compressor design.

Evidence AGAINST

Uncertainty

1) Limited operating experience available on this size compressor in a CO_2 environment (Specifically only one vendor has experience at our flowrate at the higher pressure)
2) Ratio of pressure drop in line and across well bore (i.e. use of hydrostatic head) may be different than in North Dakota / Weyburn

APPENDIX 1 Quest Risk Assessment Matrix (RAM)

Last Update: April 22, 2010

PROBABILITY →

Risk Category: Cost/Benefit in CDN $[1]	Schedule delay to FID[2]	Schedule delay to SO[3]	System Capacity[4]	HSE[5]	Reputation	IMPACT ↑	1 VLO 0-5% Occurs in almost no Projects (Extremely Unlikely)	2 LO 5-20% Occurs in some Projects (Low but Not Impossible)	3 MED 20-50% Occurs in Projects (Fairly Likely)	4 HI 50-80% Occurs in most Projects (More Likely than Not)	5 VHI 80-100% Expected to Occur in Every Project (Almost Certain)	Score	Assessment
> 50 mln	> 6 mos	> 6 mos	>25% downtime	Refer to HSE RAM	International impact		5	10	15	20	25	5	VHI
25-50 mln	3 - 6 mos	3 - 6 mos	20% - 25% downtime		National impact		4	8	12	16	20	4	HI
10-25 mln	1 - 3 mos	1 - 3 mos	15% - 20% downtime		Considerable (Regional) impact		3	6	9	12	15	3	MED
5-10 mln	0.5 - 1 mos	0.5 - 1 mos	10% - 15% downtime		Limited impact (public concern/ local media)		2	4	6	8	10	2	LO
< 5 mln	< 0.5 mos	< 0.5 mos	< 10% downtime		Slight impact (some public awareness)		1	2	3	4	5	1	VLO

IMPACT ↑

1) Cost/ Benefit in Operations is measured by cumulative impact during project Funding Period (first 10 years of operation)
2) Schedule delay to Final Investment Decision (between now and ~Q1 2012)
3) Schedule delay to Sustained Operations (incremental delay from FID to meeting contractual disposal requirement
4) System Capacity refers to the cumulative impact on the combined Capture, PL and Sequestration capacity during project Funding Period (first 10 years of operation)
5) The Risk Assessment matrix is project specific, with the exception of HSE where a global RAM is applied

Shell Global HSE Risk Matrix

Last Update: March 3rd, 2010

PROBABILITY →

Category: People	Environment	IMPACT ↓	A Never Heard of in Industry	B Heard of in Industry	C Has happened in Organization or >1/yr in Industry	D Has happened in Location or >1/yr in Organization	E Has happened >1 /yr in Location	Score
No injury or health affect	No effect							0
Slight injury or health effect	Slight effect							1
Minor injury or health effect	Minor effect							2
Major injury or health effect	Moderate effect							3
PTD* or up to 3 fatalities	Major effect							4
More than 3 fatalities	Massive effect							5

IMPACT ↓