Unconventional gas best practice ESG risk management principles and recommendations:

Explanatory document

May 2013

Contents

Executive summary

Regnan recognises the significant investment potential for unconventional gas (UG), but notes that rapid growth elevates risks associated with environmental, social and governance (ESG) failures given the numerous unresolved technical, regulatory and stakeholder issues.

This paper aims to promulgate understanding of UG ESG risks and a set of principles and recommendations to assist listed companies and their associated joint venture partners, including international oil companies (IOCs), to demonstrate sound governance and management of UG ESG risks. Further, enhanced understanding of UG ESG risk management should assist investors to have greater confidence in the allocation of capital to those companies that can demonstrate superior risk-management; offering some protection against downside price volatility.

Specifically, we intend this paper to assist:

- Companies to identify key ESG issues of concern to long term investors, review practices, and develop appropriate risk controls;
- Investors to evaluate current company disclosures by S&P/ASX companies on management of UG ESG risks and provide a basis for company dialogue and engagement.

Following regulatory and other developments, stakeholder, environment, health and safety (SEHS) risks are mainly associated with operational performance and compliance with new regulations, particularly by contractors; and negotiations and implementation of community agreements.

Future investment risks arise from uncertainties that may test existing sentiment about UG. In our view, new scientific research on aquifer connectivity and fugitive methane emissions, as well as reserves and resource estimation reliability concerns, have the potential to materially alter government, investor and community sentiment towards UG and are therefore key ESG-risk management gaps.

Unresolved ESG risks threaten shareholder value through government bans/moratoria, increased regulatory time and costs, increased stakeholder engagement time and costs, exposure to long-tail fines and remediation expenses, litigation and reputation risks, and shareholder actions.

To address this, our UG ESG risk management principles, outlined below, recommend integration of ESG risks within governance structures, evidence of precautionary risk management practices, transparent disclosure about uncertainties and performance measurement and reporting. We further recommend the disclosure of supporting policies and plans on key ESG risks as detailed below, or where these are not disclosed, a rationale to be provided for non-disclosure.

Regnan's UG best practice ESG risk management principles

Aquifer connectivity	**1. Minimise groundwater integrity uncertainties** Publicly disclose baseline groundwater quantity and quality assessments, predict impacts, and include uncertainties. Maintain or improve groundwater integrity through ongoing monitoring, reducing fraccing water requirements, beneficially reusing produced water, and committing to 'make good' water quality and quantity impacts.
Greenhouse gas emissions profile	**2. Reduce greenhouse gas estimation uncertainties and minimise GHG emissions** Disclose inherent greenhouse gas (GHG) estimation uncertainties arising from the use of historic fugitive emission factors, particularly venting and leakage assumptions. Continually improve estimation techniques through the use of direct measurement. Assist with academic/regulatory research into diffuse emissions sources.
Community agreements	**3. Obtain and maintain active and informed community agreement** Facilitate fully informed and timely community participation within SEHS impact assessment prior to exploration drilling, via two-way dialogue to build community trust. Support community decision-making and provide mechanisms for complaint/dispute resolution.
Contractor and partner performance	**4. Ensure best in class contractor, operator and joint venture partner performance** Actively oversee and seek to mitigate UG ESG risks arising from activities performed on behalf of the entity by business partners including contractor, operator, and joint venturer activities.
Reserves estimation and production reliability	**5. Disclose reserves and resource estimation risks** Publicly disclose reserves estimation assumptions, methodology, and uncertainties to provide investors with meaningful information to assess estimation risk, commercial in confidence permitting.
Overarching Governance Controls	**6. Integrate ESG risks associated with UG within strategic decision** Encourage board, executive, and management to integrate UG ESG risks within strategic decision making through formal responsibilities, resource allocation, and ESG-linked performance criteria. **7. Apply precaution in risk management systems** Within the risk management system adopt specific policies on the management of uncertainties and extreme risks, including those that are of very high consequence even where low likelihood. Actively monitor key warning signs and use adaptive risk management processes. **8. Establish policy and plans specific to UG SEHS risks** Publicly disclose policies (preferably in one place) and plans outlining management of technical SEHS risks arising from emerging technology/processes used to extract UG.

Overarching Governance Controls	**9. Measure and publicly report ESG performance indicators** In addition to the specific disclosure recommendations outlined in the sections above, publicly report on indicators that both provide investors with a meaningful measure of the effectiveness of risk mitigation strategies over time and allow for the comparison among industry participants.

IEHN/ICCR Fraccing Guide
Our guidelines are to be used concurrently with the IEHN/ICCR fraccing guide. All goals within the IEHN/ICCR fraccing guide are pertinent for Australian UG operations. See Regnan's Unconventional gas best practice ESG risk management principles and recommendations for further details on the relationship with the IEHN/ICCR fraccing guide.

Purpose and scope

Regnan recognises the significant investment potential for unconventional gas (UG), but notes that rapid growth elevates risks associated with environmental, social and governance failures given the numerous unresolved technical, regulatory and stakeholder issues. This paper aims to promulgate a set of principles and recommendations to assist listed companies and their associated joint venture partners, including international oil companies (IOCs), to demonstrate sound governance and management of UG ESG risks.

Our recommendations draw from current global research, investor initiatives within Australia and overseas, and from initial Regnan dialogue with companies involved in UG activities in Australia. Our recommendations are illustrative of best practice implementation and are not intended to be prescriptive where they do not concur with the specific circumstances of the company. We extend on technical guidance on UG released by an investor coalition in 2011 on hydraulic fracturing risk management (the IEHN/ICCR fraccing guide) that formed part of a collaborative investor engagement initiative led by Boston Common Asset Management.[1] Whilst that guide focuses largely on shale gas in North America, these recommendations remain applicable to companies involved in hydraulic fracturing (fraccing) in Australia and we have extended them to include learnings from CSG. We have also referred to other technical guidance where appropriate.

By articulating such recommendations, we hope to promote corporate development of risk mitigation strategies and so minimise long-tail risks. We also view the successful application of best-practice UG development as an opportunity for UG companies operating within Australia. As with quality execution in other contexts, effective self-regulation can establish license-to-operate and confer commercial advantages, such as achieving joint venture (JV) partner-of-choice status, in the global expansion of UG.

We also aim to ensure that disclosures from companies provide investors with sufficient information to inform their assessments of risk to investee companies and to the sector. Enhanced understanding of ESG risks should assist with effective capital allocation, risk-return expectations, and offer some protection against downside price volatility.

Specifically, we intend this paper to assist:

- Companies to identify key ESG issues of concern to long term investors, review practices, and develop appropriate risk controls;
- Investors to evaluate current company disclosures by S&P/ASX companies on management of UG ESG risks and provide a basis for company dialogue and engagement.

Reference to ESG risk in this document includes all social, environmental, health and safety (SEHS) and reserves and resource estimation risks. Financial risks, such as economic viability of resource recovery, are outside the scope of this paper. Further, while there are many sources of unconventional oil and gas, we have limited our principles and recommendations to coal seam gas (CSG) and shale gas, due to the predominance of these resources within Australia and their advanced stage of exploration and production (E&P).

[1] 'Investor Environmental Health Network and Interfaith Centre on Corporate Responsibility, 2011, Extracting the Facts: An Investor Guide to Disclosing Risks from Hydraulic Fracturing Operations', http://www.iehn.org/publications.reports.frackguidance.php. Regnan confirmed its support for the IEHN/ICCR fraccing guide in 2012.

About Regnan

Regnan – Governance Engagement & Research Pty Ltd was established to investigate and address environmental, social, and corporate governance related sources of risk and value for long term shareholders in Australian companies.

Its research is used by institutional investors for investment decision-making, and also used in directing the company engagement and advocacy it undertakes on behalf of long term investors with $47 billion invested in S&P/ASX200 companies (at December 2012), including: ACT Treasury; BT Investment Management; Catholic Super; Commonwealth Superannuation Corporation (formerly ARIA); Hermes (UK); HESTA Super Fund; (NSW) Local Government Super; Vanguard Australia; VicSuper; and the Victorian Funds Management Corporation. This approximates 4.5% of of investment within the S&P/ASX200 index.

Unconventional gas potential

High demand and declining access to traditional oil and gas reserves have led the energy industry into the exploration and development of unconventional reserves across the globe, including coal seam gas (CSG), tight, and shale. In Australia, the development of UG is emerging as a major source of economic development and is considered a significant growth opportunity for UG companies operating within Australia.

UG resources in Australia

UG has been labelled the energy game changer for good reason; IEA estimates that UG makes up half of known gas resources.[2] Australia is understood to have one of the larger recoverable regions of emerging unconventional gas resources. Australia's total recoverable gas resources are estimated to be 396 tcf of shale gas and 235 tcf of CSG compared with 167 tcf of conventional gas.[3]

CSG resources are more extensively developed than other UG resources in Australia. Since commencing production in Queensland in 1996, CSG now supplies 90% of Queensland gas. Should planned developments in NSW go ahead, CSG will also become a significant contributor to energy production in that state as well. 2P reserves (proven plus probable) of CSG in Australia were estimated at 33 tcf, ~160 years of supply at current rates of extraction.[4][5]

The first shale gas well began producing in October 2012, after a shale vertical test well flowed successfully and was tied in to existing production facilities.[6] While current 2C contingent resources stand at 2 tcf (with no 2P), shale gas is expected to dominate Australian production over the next decade, if proven economic.[7]

Known Australian UG basins are outlined in Table 1.

2 International Energy Agency (IEA), 2011, World Energy Outlook 2011: Are we entering a golden age of gas? Special report, France, November 2011, p49.
3 SCER, 2012, The Draft National Harmonised Regulatory Framework: Coal Seam Gas, accessed at: http://www.scer.gov.au/workstreams/land-access/coal-seam-gas/
4 ibid
5 http://www.australianminesatlas.gov.au/education/fact_sheets/coal_seam_gas.html
6 http://www.santos.com/Archive/NewsDetail.aspx?id=1347
7 U.S. Energy Information Administration (EIA), 2011, World Shale Gas Resources: An Initial Assessment of 14 Regions Outside the USA, 2011 April.

Demand drivers of unconventional gas

The UG industry in Australia is driven by both domestic and international demand. Underpinning demand growth is the lower carbon emissions profile of gas-fired power generation over brown and black coal to meet future energy demand, although these claims are now being challenged (see GHG section below) and rising concern over energy security. Drivers of domestic demand vary across states however. We note for example, that the mandatory gas-fired electricity target in Queensland is driving demand in that state. In NSW, where only 6% of gas supply is sourced from within the state, security of supply is a key driver of UG.

Growing international energy demand, particularly in Asia, is driving Australian LNG development. The rising cost environment in Australia, coupled with increased global LNG-competition, has meant that further investment in unsanctioned greenfield LNG plants is less sure however. Nevertheless, LNG export opportunities will underpin the bulk of UG development and brownfield expansion in Australia over the next decade.

Increasing LNG exports are expected to continue to drive up domestic gas prices. High export-driven gas prices are expected to result in the development of UG resources which might otherwise be marginal for domestic-only markets.

Australian company activities – CSG and shale

Outlined in Table 1, S&P/ASX200 listed entities play an important role in advancing UG E&P globally.

Table 1 Major unconventional gas players in Australia

Region	Type	Stage	S&P/ASX200	IOCs JVs/farm-ins
Gladstone, QLD	CSG-LNG	C	ORG, STO	APLNG - ORG (37.5%), ConocoPhillips (37.5%) and Sinopec (25%) GLNG - STO (30%), Petronas (27.5%), Total (27.5%) and KOGAS (15%) QC LNG - QGC - BG (100%)
Gladstone, QLD	CSG-LNG	D		Arrow LNG - Arrow Energy - Royal Dutch Shell (50%) PetroChina (50%)
Galilee, Bowen and Surat Basins in QLD (CSG)	CSG	D, P	ORG, STO, AGK	Galilee JV - CNOOC (50%), EXE (50%) Arrow Energy - Royal Dutch Shell (50%), PetroChina (50%) QC LNG - QGC - BG (100%)
Clarence Moreton basin, NSW/QLD	CSG			
Sydney, Gunnedah and Gloucester Basins, NSW	CSG	D, P	AGK, STO	
Canning Basin, WA	Shale/ tight	E	BRU	BRU farm-in: Mitsubishi (37.5%), BRU (37.5%, operator), Rey (25%)

Region	Type	Stage	S&P/ASX200	IOCs JVs/farm-ins
				NSE farm-in: ConocoPhillips (75%), NSE (25%, operator)
Carnarvon Basin, WA	Shale/ tight			
Onshore Perth Basin, WA	Shale/ tight	E	AWE, ORG	AWE farm-in: Bharat Petro Resources Ltd (27.8%), NWE (27.9%), AWE (44.3%)
Cooper Basin, SA	Shale/ tight	E/P	BPT, STO, ORG, SXY, DLS	BPT farm-in: Chevron (up to 60%) DLS farm-in: QGC (60%)
Maryborough Basin, QLD	Shale			
Gippsland Basin, VIC	Tight			
Southern Georgina Basin, NT	Shale	E		BKP farm-in: PetroFrontier Corp, Statoil CTP farm-in: Total
Beetaloo Basin, NT	Shale	E		Falcon Australia farm-in: Hess
Eagle Ford Shale, Texas, USA	Shale/ liquids	P	AUT, AWE, and BHP	
Fayetteville Shale, Arkansas, USA	Shale	P	BHP	
Haynesville/Bossier Shale, Louisiana, USA	Shale	P	BHP	
Permian Basin Shale, Texas, USA	Shale/ liquids	P	BHP	

Sources: company resources and APPEA,[8] PESA,[9] and EIA[10]
KEY: C = construction D = development E = exploration P = production

Key ESG risks for investors

While processes to extract UG are not new (there are over 700 fracced wells in the Cooper Basin, in SA/QLD alone), application of UG extraction technology in new hydro/geological conditions increases technical risk. Further, deployment of these technologies at the scale anticipated raises additional risk factors, including cumulative and long-term effects, such as impacts on groundwater supplies.

High profile contamination events in the USA associated with shale gas fraccing, and controversy surrounding CSG developments in Queensland and NSW, have negatively influenced public perception of UG. While the process to extract UG varies between resource types (e.g. fraccing vs. dewatering), these technology distinctions (and consequent SEHS issues) may not be recognised by community stakeholders or policy makers,

8 http://www.appea.com.au/industry/csg.html.
9 PESA, 2009, An Overview Of Tight Gas Resources In Australia, http://www.pesa.com.au/publications/pesa_news/june_july_09/images/pn100_95-100.pdf
10 U.S. Energy Information Administration (EIA), 2011, World Shale Gas Resources: An Initial Assessment of 14 Regions Outside the USA, 2011 April.

hence raising further challenges for operators to overcome negative sentiment. Lack of scientific certainty over the long term SEHS effects of UG operations adds to stakeholder management challenges.

Authorities have responded with new risk-based regulation. Operators maintain that best-practice technological implementation can reduce or fully mitigate key ESG concerns. However, stakeholder opposition to UG development persists. In this section we provide a high-level outline of the regulatory and corporate response to key UG regulation of ESG risks, as well as our analysis of key ESG risks, summarised in Table 2.

Regulatory response

Australian state and federal governments introduced amendments to CSG regulatory approvals and compliance requirements over 2010-13,[11] including a National Partnership Agreement to create a national independent expert scientific committee (IIESC) to oversee CSG approvals (and we presume shale).[12] A Draft National Harmonised Regulatory Framework: CSG (national CSG framework) has also been developed via the Standing Council on Energy and Resources (SCER), which aims for consistency in regulation across states.[13] We are not aware of any plans to harmonise shale gas regulation between states.

Prior to regulatory amendments, the NSW Government imposed a 17-month moratorium on fraccing in NSW (lifted in September 2012), which effectively halted CSG-related cash flow generation for companies operating in that state until its strategic regional land use (SRLU) policy was finalised.[14] The Queensland Government chose not to halt the considerable CSG development, instead drip-feeding regulatory amendments to address SEHS concerns.[15] The Victorian Government imposed a moratorium on CSG and fraccing approvals in August 2012, as well as banning benzene, toluene, ethylbenzene, and xylenes (BTEX), until the national CSG framework is completed.[16] Statements made by regulatory authorities in WA, SA and NT suggest that moratoria will not be issued in these states at this stage, although persistent community opposition could influence this.

The national CSG framework, which is awaiting confirmation following closure of the stakeholder consultation period, sets out 18 leading practices for CSG ESG risk management. These were mainly drawn from amendments introduced by NSW and QLD to address SEHS issues, and include practices such as:

- strengthened well construction and testing;
- water drawdown protections, which can include water accounting and requirement for cumulative water modelling as part of impact assessment;
- baseline and ongoing water monitoring; beneficial water treatment and use etc.

Not all state best practices were adopted however, e.g. ‘make good’ commitments, evaporation pond and BTEX bans. Consequently, Regnan questions how leading these practices are. The SCER is also drafting a Multiple Land Use Framework to assist with land access/use concerns.

A recent NSW development has altered the tone of regulatory changes, which up until now has facilitated CSG development and has not significantly impacted company CSG strategy. In February 2013, the NSW government amended its SRLU policy to include a 2km buffer around residential areas and exclude CSG

11 http://www.herbertsmithfreehills.com/insights/legal-briefings/shale-gas-in-australia-to-follow-the-us
12 http://www.environment.gov.au/coal-seam-gas-mining/index.html
13 SCER, 2012, The Draft National Harmonised Regulatory Framework: Coal Seam Gas, accessed at: http://www.scer.gov.au/workstreams/land-access/coal-seam-gas/
14 http://www.resources.nsw.gov.au/community-information/coal-seam-gas/what-is-the-government-doing
15 http://www.ehp.qld.gov.au/management/coal-seam-gas/index.html
16 http://www.premier.vic.gov.au/media-centre/media-releases/4710-reforms-to-strengthen-victorias-coal-seam-gas-regulation-and-protect-communities-.html

activities in viticulture and equine industry clusters.[17] The NSW CSG exclusion zones have effectively halted CSG development in some regions, the Clarence Moreton basin being the most affected.

More stringent environmental regulatory requirements and landowner equity requirements in NSW and QLD have increased development approval time and costs (although these costs are small relative to escalating costs affecting the industry) and halted development in some regions. Media reporting of landowner disputes has been less prominent since the announcement of regulatory changes, however localised stakeholder protests continue. Continued community protests may result in further SEHS regulatory requirements, a source of further uncertainty, particularly given the appointment of state-government Commissioners tasked with improving landowner relations; the recent NSW exclusion zones are an example of this.

Corporate response

Australian companies have partially responded to community concerns and pre-empted further regulation by contributing to the development of industry standards such as the WA APPEA fraccing code[18], as well as strengthening individual company responses, which include:

- reverse osmosis treatment and beneficial reuse of produced water (now regulated);
- baseline and ongoing water monitoring (now regulated);
- local community consultation committees;
- use of multi-well pads and horizontal directional drilling to place wells in lower risk locations;
- agricultural/CSG co-existence demonstration sites;
- reserves and resources reporting split between conventional and unconventional (now regulated); and
- increasing compensation payments in response to landowner concerns.

In Regnan's view, corporate responses fall short of international investor expectations as outlined in the IEHN/ICCR fraccing guide. For example, holding ponds remain uncovered despite community concerns (as opposed to closed and vented) and an absence of public reporting on fraccing chemical use remains despite various industry participants' commitment to work with regulators on public chemical reporting over the last year(s).

Table 2 assessment of key unconventional gas ESG risks

ESG risk	Likelihood; Consequence	Risk drivers and mitigation
Fraccing and/or dewatering impacts aquifer connectivity, hydro-geological pressure and subsidence: leading to material water contamination, water drawdown and/or methane leaks and further bans/moratoria.	L;VH	• Current understanding of permeability of barriers is based on engineering assumptions rather than conclusive scientific research. • IIESC intend to address gaps in water research in the long term. • Lack of legacy baseline studies prohibits conclusive studies. • QLD based water modelling provides some certainty through 3-yearly estimates of 'make good' requirements, albeit subject to model limitations. • Increased risk for projects sited near communities or high agricultural/environmental value land.

17 http://www.planning.nsw.gov.au/srlup
18 APPEA, 2012, Western Australian Onshore Gas Code of Practice, accessed at http://www.appea.com.au/images/stories/Policy_-_Environment/wa%20fraccing%20code%20of%20practice_final%20november.pdf

ESG risk	Likelihood; Consequence	Risk drivers and mitigation
Increased greenhouse gas emissions intensity estimates vs. coal: leading to reduced demand for UG and reallocation of capital/divestment of assets.	M;H	• Actual measurement of site specific UG GHG emissions in infancy. • Methane emission mitigation available at low cost. However, some methane migration may not be easily captured i.e. diffuse sources. • Energy demand and security considerations mitigate risk.
Material surface spills of produced water, flow-back water, and/ or frac fluid/chemicals: leading to water contamination and loss of community trust.	M;M	• Risk dependent on operational performance and compliance, particularly contractors. • Closed loop fraccing systems available, which reuse frac water, to reduce risk of spills. • Increased risk for projects sited near communities or high agricultural/environmental value land. • National CSG framework includes leading practices to reduce chemical risk.
Production forecasts / reserves estimates downgrades: leading to investor uncertainty and increased volatility in share price.	M;M	• ASX released new reporting requirements in 2012, however assumption uncertainty was not covered.
Poor well integrity: leading to water contamination, water drawdown, methane leaks, and ultimately loss of community trust.	M;M	• Regulatory bodies oversee well integrity requirements and there are currently low incident rates in Australia. • National CSG framework includes geological assessments prior to fraccing and monitoring prior/during frac. • Risk dependent on long-term aquifer connectivity and operational performance and compliance, particularly contractors.
Produced/flow-back water management: produced water treatment and waste management requirements, including salt, brine, and radioactive waste, lead to prohibitive compliance costs.	M;M	• Evaporation ponds have been banned in QLD/NSW. • Closed loop fraccing systems / water treatment tanks available to treat and reuse water, reduce total amount of water extracted and chemicals required, and reduce risk of spills. • Beneficial reuse of CSG produced water now recognised as leading practice in the national CSG framework. • Disposal of salt and radioactive waste least progressed.
Insufficient water availability for fraccing, from either scarcity or water competition: leading to delays/disruptions to operations or increased operational costs.	H;M	• Closed loop fraccing systems available, which reuse frac water, to reduce total amount of water extracted. • Increased risk for projects sited near communities or high agricultural/environmental value land.

ESG risk	Likelihood; Consequence	Risk drivers and mitigation
Community disruption from high transportation requirements (water, frac chemicals, sand, fuel, and waste): leads to further community protests and regulation.	H;M	• Water directly extracted from environment or reused which reduces transportation requirements although transportation for other inputs/outputs is significant. • Outcome depends on community agreement negotiations.
Continuing concerns regarding community agreements (consent and benefits distribution): leads to further community protests and regulation.	M;M	• Developments in landowner agreements and appointment of commissioners tasked with improving community relations. • Long term local community acceptance however is driven by aquifer connectivity and operational performance and compliance.
Lack of agreement on co-existence of agricultural and UG resource development: limiting land use availability.	M;M	• Developments in landowner agreements and the establishment of commissioners to improve co-existence may improve community acceptance. • Multi Land Use Framework under development. • UG industry has been supported by government to date. Risk dependent on proximity to communities and high agricultural/environmental value land. • Long term agricultural community acceptance is based on aquifer connectivity and operational performance and compliance.
Cumulative footprint impacts on the community, biodiversity, and ecosystem: leading to regulation on well density and hence ultimate resource recovery rates.	M;M	• Use of multi-well pads and horizontal directional drilling to reduce number of wells required; locate wells away from existing communities or areas with significant environmental value, although total quantum of wells remains a concern. • Limited flexibility of water treatment infrastructure location also remains a concern.
Seismic tremors from produced/flow-back water injection and to a lesser extent, fraccing: leading to further bans/moratoria on reinjection and/or fraccing.	L;M	• Water reinjection is allowed in some states. • National CSG framework includes geological assessments prior to fraccing. • Closed loop fraccing systems can reduce water reinjection requirements. • USA/UK investigations have led to increased knowledge on risk management, e.g. avoiding drilling/injecting on fault lines and reinjection into deep wells the most significant risk. • Increased risk for projects sited near communities in high seismic activity regions.
Air/noise pollution: impacting community health and leading to increased regulation.	M;L	• Use of multi-well pads and horizontal directional drilling to reduce number of wells required and locate wells away from existing properties/communities.

ESG risk-management gap analysis

The majority of *technical* SEHS risks appear to have been at least partially addressed via regulation and/or industry response. Remaining SEHS risks arise from operational performance and compliance with new regulations, particularly from contractors and operators, and negotiation and implementation of community agreements.

Future investment risks arise from uncertainties that may test existing sentiment about UG. In our view, new scientific research on aquifer connectivity and fugitive methane emissions, as well as reserves and resource estimation reliability concerns, have the potential to materially alter government, investor and community sentiment towards UG and are therefore key risk management gaps. We outline these key risks drivers and our corresponding draft best practice controls in the section below.

ESG risk management

Aquifer connectivity

1. Minimise groundwater integrity uncertainties:

Publicly disclose baseline groundwater quantity and quality assessments, predict impacts, and include uncertainties. Maintain or improve groundwater integrity through ongoing monitoring, reducing fraccing water requirements, beneficially reusing produced water, and committing to 'make good' water quality and quantity impacts. The potential for contamination of drinking-water supplies from upward migration of methane and fraccing fluids remains the most significant unresolved concern for CSG and shale developments. It is generally believed that the majority of drinking water contamination in the USA/Australia to date has been caused by faulty well design and construction. The potential for fraccing to connect resource formations and previously unconnected aquifers is still unknown however, due to limited academic research in this area.[19]

Further, the Surat Underground Water Impact Report confirmed that CSG extraction can lower bore water levels due to water pressure changes arising from the dewatering process. The degree of interconnection between the coal formations and surrounding aquifers determines the water level changes.[20] We note that the Namoi Catchment Water Study suggests that more monitoring is required to enable more accurate analysis of hydraulic connections between water systems to examine potential impacts to water quality.[21] A further uncertainty is whether dewatering can lead to water contamination from the upward migration of methane due to hydro-geological pressure changes via cracks and fissures in the ground (which could be exacerbated by fraccing).

Research findings which link groundwater contamination to migration of methane/fraccing fluids remain heavily contested, as do the causes.[22] [23] Industry geological engineers claim that the presence of impervious geological barriers (aquitards) prevents upward migration. Where baseline studies have not been conducted, establishing causality is problematic due to the fact that methane and other chemicals

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[19] Recent research released out of Duke University indicates potential pathways for connectivity of shallow drinking water resources and deeper formations in the Marcellus Shale in Pennsylvania, unrelated to shale gas drilling, although these findings are early stage and it is not known over what timeframe nor whether the findings are transferable to other regions. Warner, NR et al., 2012, Geochemical evidence for possible natural migration of Marcellus Formation brine to shallow aquifers in Pennsylvania, PNAS, vol. 109 no. 30, July 24 2012.

20 Queensland Water Commission (QWC) Surat Underground Water Impact Report

21 http://www.namoicatchmentwaterstudy.com.au/site/index.cfm?display=243752

[22] Osborn, S.G, et al., 2011, Methane Contamination of drinking water accompanying gas-well drilling and hydraulic fracturing, PNAS, vol. 108 no.20, May 17 2011, accessed at: http://www.pnas.org/content/108/20/8172

[23] G.E. King, 2012, Estimating frac risk and improving frac performance in UG and oil wells, http://www.gekengineering.com/id6.html.

commonly used in fraccing are already present in the water supply due to naturally-occurring seepage, particularly where significant hydrocarbon resources are present. [24]

We expect that a comprehensive US EPA study into the impacts of fraccing on drinking and ground water, due end 2014, will inform stakeholder debate.[25] In Australia, in addition to overseeing project approvals, the IIESC has been tasked with improving understanding on aquifer integrity, including developing water modelling guidelines.[26] We expect decision-making for approvals will be more dependent on upfront prediction of aquifer impacts.

Investors face both upside and downside risks from science-based approvals, depending on whether research identifies long-term impacts on surrounding water resources. While difficulties attributing aquifer contamination causality may limit short-term litigation exposure, long-term reputation and litigation risks will accrue until conclusive research/evidence becomes available. This potentially exposes entities to larger liabilities due to delays in remedial action.

Although much of SEHS risk has crystallised, we expect that greater scientific understanding of water impacts may lead to further regulatory changes. Incremental increases in long-term regulatory and compliance costs may be material to project economics, particularly for marginal developments post-final investment decision (FID). Further, we see the potential for additional moratoria in the event that new research confirms a higher level of permeability between aquifers and formations than assumed.

If GHG risks can be managed (see below), we expect shale gas to benefit from its relatively deep geology compared with CSG, which may limit aquifer connectivity risks.

Our groundwater integrity best practice controls have been drawn from leading regulatory practice within Australia and extended to include precaution.

Best practice recommendations:

- Assess risk by preparing regional scale water modelling for key underground water resources, which predict anticipated impacts to water resources due to dewatering/fraccing and include cumulative impacts and state uncertainties that may influence model outcomes;
- Update water modelling when material new information arises affecting modelling outcomes;
- Develop baseline and ongoing water monitoring for all groundwater resources;
- Assess and monitor water extraction amounts;
- Commit to 'make good' impacts to surrounding water resources;
- Reduce fraccing water requirements through the use of closed loop fraccing systems;
- Treat produced water to enable beneficial reuse wherever possible, including aquifer recharge and virtual reinjection;
- Publicly state uncertainties regarding understanding of aquifer connectivity potential from fraccing and dewatering, and outline respective company, government and/or academic responsibilities and plans, including timelines and funding, to address these knowledge gaps within a reasonable time;
- Assist with investigations into unexplainable contamination events by providing access to wells, data, and any other assistance required.

[24] ibid
[25] http://www.epa.gov/hfstudy/
26 http://www.environment.gov.au/coal-seam-gas-mining/research-projects/aquifers.html

Greenhouse gas emissions profile

2. Reduce greenhouse gas estimation uncertainties and minimise GHG emissions:

Disclose inherent greenhouse gas (GHG) estimation uncertainties arising from the use of historic fugitive emission factors, particularly venting and leakage assumptions. Continually improve estimation techniques through the use of direct measurement. Assist with academic/regulatory research into diffuse emissions sources.

Uncertainty surrounding fugitive methane emission is an emerging area of risk for UG.[27] [28] Risks relate to two areas of uncertainty which would increase the overall GHG emission profile for UG developments:

1. Potential for direct measurement of fugitive methane emissions (venting, leakage, and, more recently, diffuse) to result in significantly different emission values than those given by current estimation techniques; and
2. Likely adjustment of the global warming potential (GWP) for methane.

UG is sensitive to changes in greenhouse gas (GHG) emissions measurement methodology, particularly methane due to its high GWP. Current estimates indicate that ~50% of direct CSG-LNG emissions occur at the extraction stage, which includes a significant quantity of methane emissions.[29] By comparison, about 6% of direct emissions for conventional LNG occur at the extraction stage, of which only a small portion is fugitive methane.[30]

The US EPA's recent revision of fugitive emissions factors for gas production, and recent published academic research using direct measurement of UG production site emissions in the USA, indicate that, while these results may not be representative of Australia UG emissions profiles, leakage assumptions from processing and production equipment, as well as venting from well work overs, completions and dewatering, may be higher than previously thought. [31]

Following a review of CSG GHG estimation methodology, the Commonwealth Government has proposed the development of Australian specific emissions factors for CSG well leakage, and the mandating of direct measurement of vented fugitive emissions for well work overs and completions with fraccing.[32] In 2013, CSIRO commenced field measurements of methane emissions from a sample of CSG production facilities within NSW and QLD. It is expected that the outcomes will support the development of Australian-specific emissions factors.[33] It is proposed that companies will transition to revised emission factors based on actual measurement of methane emissions in 2015; public disclosure of NGER data will not be available until March 2017 however. Until then, the information available to investors on emissions to inform their assessments of risk is undermined by a lack of comparability.

Emerging research also indicates the greater potential for fugitive emissions to the surrounding atmosphere and water sources, not just via CSG infrastructure but from more diffuse sources, such as directional drilling and hydro-geological pressure changes via cracks and fissures in the ground. Preliminary research conducted by Southern Cross University shows methane concentrations collected around the Tara gas fields in Southern QLD are ~3.5 times higher than surrounding areas where there is

27 See SWIP, 2012, Sustainability Research Series: Shale gas: the fugitive methane problem and IIGCC, IGCC and INCR, 2012, Controlling fugitive methane emissions in the oil and gas sector, accessed at http://www.igcc.org.au/Resources/Documents/Fugitive%20Methane-Consultation-Draft.pdf
28 http://www.climatechange.gov.au/government/submissions/coal-seam-gas-discussion-paper.aspx
29 Higher energy intensities associated with the number of wells required to achieve equivalent production as well as the use of energy-intensive fraccing are thought to add to GHG emissions profiles for UG. Shale gas operations utilise fraccing to unlock the resource where as CSG and conventional O&G utilise fraccing to extend the life/recovery rate of wells.
30 WorleyParsons, 2012, Lifecycle GHG emissions from electricity generation: A comparative analysis of Australian energy sources, accessed via energies open access.
31 http://www.climatechange.gov.au/government/submissions/~/media/government/submissions/nger/coal-seam-gas-methods-review-2012.pdf
32 http://www.climatechange.gov.au/government/submissions/coal-seam-gas-discussion-paper.aspx
33 http://www.csiro.au/en/Outcomes/Energy/Fugitive-emissions-from-coal-seam-gas.aspx

no CSG infrastructure.[34] Diffuse fugitive emissions are not included within the current GHG estimation framework, although the Commonwealth government has proposed a scoping study to inform the development of field methodologies for estimating diffuse emissions.

An additional risk factor is the increase in the methane GWP value due to revision of assumptions relating to climate forcing. Australia agreed for the second commitment period of the Kyoto Protocol (2013 – 2020) to calculate its targets using the IPCC fourth assessment report (4AR) GWPs.[35] For methane this means an increase in GWP from 21 to 25 resulting in a 19% increase in Australian country (and presumably corporate) methane emissions, which will have flow-on effects to emissions reductions trajectories.[36]

Any international agreement from 2020 will use the most recent science.[37] The IPCC fifth assessment report (5AR) will update radiative forcing science in September 2013, which will provide an indication of long-term estimation risk; Published academic research suggests the 100 year GWP for methane could increase to 33.[38] If a 33 methane GWP was negotiated methane emissions would increase by a further 32% (57% on 2012 GHG data).[39] Additionally, if calls to amend the time horizon of radiative forcing from 100 years to 20 years were accepted, Australian industry methane emissions would increase by 500% on 2012 estimates.[40] Resolution of the GWP timeframe remains uncertain and politically charged however.

Regardless of GWP changes, verification of GHG intensity claims appear to be years away, which creates long term investment uncertainty as to the sustainability of the industry. Under Australia's current clean energy futures legislation package and carbon pollution mechanism (CPM) concessions, if improved scientific understanding of fugitive emissions leads to an increase in GHG emissions estimates UG companies may face rising carbon liabilities.[41] The ready availability of low cost fugitive emissions abatement options is a key mitigating factor however, particularly given enhanced estimation methodology will presumably increase GHG mitigation incentives.[42] Due to the nascency of research, the potential cost impacts of diffuse emissions are less clear.

More generally, we expect greater scrutiny of industry claims regarding the GHG benefits of gas as a transition fuel relative to coal,[43] which may have flow-on effects to community acceptance of UG relative to alternative energy technologies, hence affecting project approvals.

Improved scientific understanding of fugitive emissions and improved data would provide the constructive evidence needed to address fugitive emissions uncertainty and incentivise emissions abatement, thereby reducing risks to the industry and its investors. Our best practice GHG controls focus on moving industry up the GHG estimation hierarchy as well as best practice emissions reduction guidance.

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34 http://www.climatechange.gov.au/en/government/submissions/closed- consultations/~/media/government/submissions/csg/CSG-20121109- CentreForCoastalBiogeochemistrySCU.pdf

35 http://climatechangeauthority.gov.au/sites/climatechangeauthority.gov.au/files/files/caps/13-030-CATRIP.pdf and http://www.ipcc.ch/publications_and_data/ar4/wg1/en/ch2s2-10-2.html

36 It is not clear whether NGERs methods will be updated to reflect new GWPs, the revised NGA is out in July 2013. http://www.climatechange.gov.au/~/media/publications/nga

37 http://climatechangeauthority.gov.au/sites/climatechangeauthority.gov.au/files/files/caps/13-030-CATRIP.pdf

38 Shindell DT, et. al.,2009, Improved attribution of climate forcing to emissions. Science 326: 716-718.

39 25 to 33 GWP = 32%. 21 to 33 GWP = 57%

40 Estimates of 20-year GWP range from 56 in the Kyoto Protocol to 72 in IPCC 4AR and more recent academic research (Shindell DT, et. al., 2009) support 105, versus 2012 Kyoto Protocol 100-year GWP of 21.

41 Australia's CPM came into effect 1 July 2012 commencing with a transitional fixed carbon price of $23/tCO2-e for three years before transitioning into a cap and trade market-based system by 2015. All direct and indirect oil and gas GHG emissions will be captured under the CPM, although LNG producers will receive an effective compensation rate of ~50% of all related extraction and production emissions. Liable entities in Australia will still be able to meet up to 50 per cent of their liabilities through purchasing eligible international units including the EU ETS, although only 12.5 per cent of their liabilities will be able to be met by Kyoto units. http://www.climatechange.gov.au/en/government/clean-energy-future/legislation.aspx

42 IIGCC, IGCC and INCR, 2012, Controlling fugitive methane emissions in the oil and gas sector, accessed at http://www.igcc.org.au/Resources/Documents/Fugitive%20Methane-Consultation-Draft.pdf

43 Research indicates that if higher venting and leakage assumptions are applied, UG would still compare favourably to coal combustion and coal thermal power although the benefits become more marginal. However, if a 20-year adjusted GWP methane factor is applied, UG combustion may be less-efficient than coal.

Best practice recommendations:

- Include within GHG estimate disclosure:
  - GHG measurement risks and uncertainties: including those arising from the use of historic emissions factors based on conventional gas production;
  - Methane emissions: estimate risks and uncertainties arising from the use of historic methane global warming potentials (GWP), e.g., IPCC fourth assessment report (4AR) vs. Kyoto Protocol; 20-year vs. 100-year.
- Commence the direct measurement of actual greenhouse gas emissions for key emissions activities where it is uncertain whether direct emissions monitoring would result in emissions profiles that are materially different from estimates using historic conventional emissions factors;
- Assist with academic/regulatory research into diffuse methane emissions by providing access to land, data and any other assistance required, preferably prior to well drilling;
- Reduce GHG emissions as per **IIGCC, IGCC, and INCR** fugitive methane emission disclosure guidance.[44]

Community agreements

3. Obtain and maintain active and informed community agreement:

Facilitate fully informed and timely community participation within SEHS impact assessment prior to exploration drilling, via two-way dialogue to build community trust. Support community decision making and provide mechanisms for complaint/dispute resolution.

The high-profile 'Lock the Gate' campaign led by a variety of increasingly well-organised stakeholders in NSW and QLD has resulted in CSG development companies being denied access to permits by landowners.[45] [46]

Stakeholder opposition to UG developments has stemmed from different issues in Australia compared to the USA. To date, there is no evidence of significant contamination events in Australia from UG, nevertheless minor incidents caused by poor implementation have resulted in reputation damage e.g. pipe/well leaks, spills, unauthorised water discharges etc.[47]

Key stakeholder concern has focused on co-existence between communities, agricultural production, and UG developments. Concerns relate primarily to the large number of wells required for CSG development in predominantly agricultural regions and the potential for CSG dewatering activities to drawdown and/or contaminate surrounding ground and surface waters.[48]

Differing landowner rights in the USA and Australia have influenced landowner responses to UG. In Australia, rights to petroleum resources under the land are owned by government regardless of land ownership, whereas landowners retain that right in the USA.[49] This has led to differences in landowner

44 IIGCC, IGCC and INCR, 2012, Controlling fugitive methane emissions in the oil and gas sector, accessed at http://www.igcc.org.au/Resources/Documents/Fugitive%20Methane-Consultation-Draft.pdf
45 Stakeholder groups include landholders, environment groups, local government, farmers' associations, and political parties
46 http://lockthegate.org.au/
47 http://coalseamgasnews.org/wp-content/uploads/2012/10/Contaminated-sites-and-accidents-related-specifically-to-CSG-in-Australia.pdf
48 Regnan, 2011, Coal Seam Gas in Australia – ESG risks and opportunities.
49 http://www.crikey.com.au/2012/02/20/land-use-and-csg-what-rights-do-property-owners-have/

consent requirements and benefit distribution. American landowners have right of veto over resource development within their land and may receive a share of royalties; Australian landowners only have the right to negotiate access arrangements, but do not have power to refuse resource development and receive compensation rather than share in the profits.[50]

Landowner equity issues, which include both access consent and benefits distribution, have been partially addressed through standardised land access agreements and regional community funds and the public reporting of compensation agreed (NSW), as well as appointment of Commissioners in both NSW and QLD to oversee landowner concerns.[51] [52] However, these initiatives fall short of providing landowners with a right-of-veto.

To date, shale gas has not achieved the same public profile as CSG in Australia, although the industry is at early stages of exploration. There have been calls for similar lock-the-gate campaigns which have not yet gained traction within local communities. Currently the majority of shale gas exploration is concentrated within the Cooper Basin which benefits from a low population density; other shale gas regions, such as Onshore Perth Basin, will be more exposed to community risks.

Company stakeholder engagement has been central to resolving conflicts in Australia due largely to the limited control of landowners over development decision-making. Consequently, stakeholder engagement time and costs have contributed to rising project costs not only in access agreement negotiation time and costs but also legal costs where companies are obliged to apply for access through the courts. To mitigate the risk of landowner court action, some operators have increased compensation and improved land access arrangements.[53]

Protracted access negotiation can also result in the loss of goodwill from landowners with whom companies must do business for the life of the operation. Furthermore, widespread protests over SEHS, and land access issues have resulted in industry-wide reputational damage for both CSG and shale gas, with consequent reputational-threats to the retail businesses of vertically integrated energy companies and those entities hoping to benefit from JV 'partner of choice' status globally.

Guidance on community consultation has evolved in the last few years, moving from an engagement focus to one that concentrates on the development of an ongoing and mutually beneficial relationship and more participatory processes. Our recommendations draw from recent industry guidance to establish best practice for companies negotiating agreements with local communities.[54]

Best practice recommendations:

- Fully identify relevant stakeholders within the community;
- Identify SEHS impacts;
- Ensure that key stakeholders are fully informed of all relevant risks and uncertainties in a timely manner by providing needs-appropriate, two-way dialogue;
- Support the community through relevant knowledge gathering/decision-making processes, by allowing sufficient time and resources for decisions/consultation, including the nomination of representatives (if required);

50 BHP Billiton, 2011, Transcript: Investor Briefing – Onshore US Assets, November 14 2011.
51 http://www.gasfieldscommissionqld.org.au/gasfields
52 http://www.trade.nsw.gov.au/__data/assets/pdf_file/0020/443126/Government-unveils-new-protections-for-agricultural-land.pdf
53 For example STO's new NSW landowner compensation scheme provides landowners with a farm management plan; ongoing service payment of $30k pa; an initial land value payment during exploration and first year of production; followed by landholder incentive funds equal to 5% of royalties paid and a regional community benefit fund effectively equalling 10% of royalties paid post-production commencement.http://www.santos.com/Archive/NewsDetail.aspx?id=1336
54 IPIECA, 2012, Human rights due diligence process: A practical guide to implementation for oil and gas companies and Operational level grievance mechanisms: IPIECA good practice survey, accessed at http://www.ipieca.org/library. Also see RIO's Community Agreement Guidance 2012, http://www.riotinto.com/documents/Community_agreements_guidance_2012_2014.pdf.

- Where stakeholder concerns are not sufficiently addressed via regulatory processes, extend participatory processes to protect the integrity of community decision-making;
- Publicly disclose stakeholder concerns and consultation outcomes within corporate/project strategy, policies and plans;
- Periodically monitor performance against agreed outcomes and include learnings within management plans;
- Provide appropriate mechanisms for complaint/dispute reporting and resolution, including independent third-party mediation if required.[55]

Contractor and partner performance

4. Ensure best in class contractor, operator, and joint venture partner performance:

Actively oversee and seek to mitigate UG ESG risks arising from activities performed on behalf of the entity by business partners including contractor, operator, and joint venturer activities.

SEHS operational performance and compliance is important to prevent contamination events from well integrity issues and spills and is a key driver of community acceptance. Thousands of wells are required for UG industry development which results in substantial ongoing monitoring and compliance responsibilities for both operational and abandoned wells. Given the infancy of this industry, it is not clear whether industry and regulators have the capacity to ensure compliance.

Further, the majority of well integrity and fraccing risks occur at the drilling /fraccing stage, usually performed by contractors. The boundaries between operator, contractor, and JV partner responsibilities may not be clearly defined, although larger partners are often held publicly accountable, if not legally, for actions performed by contractor/operator organisations. Oversight of operator and contractor operational performance is therefore a key risk for owners. Regnan has concerns that risk management standards applying to operator / contractor and JV partner responsibilities may not be sufficient given long-tail reputation and litigation risk.

Companies are exposed to potential fines and remediation expense if operational performance standards are not maintained to prevent contamination. Companies may also be exposed to fines/litigation/remediation costs via business partner activities or from legacy incidents via acquired sites. Regulatory costs alone are unlikely to be material, although remediation costs are more substantial (e.g. STO-owned Eastern Star Gas was fined $3k for a produced water spill in NSW although remediation costs are estimated to be ~$20m).[56] We also see material risk from potential class actions if contamination of key water resources were to occur in major aquifers.

Regnan's best practice partner controls are based on international best practice and have been extended to include all business partners.

Best practice recommendations:

- Manage contractor and operator performance in line with **IEHN/ICCR fraccing guide**.

55 ibid
56 http://www.santos.com/exploration-acreage/nsw-csg/pilliga-rehabilitation.aspx

Reserves estimation and production reliability

5. Disclose reserves and resource estimation risks:

Publicly disclose reserves estimation assumptions, methodology, and uncertainties to provide investors with meaningful information to assess estimation risk, commercial in confidence permitting.

Resource estimation for UG reserves presents challenges to investment decision-making due to the absence of historical data and production variance both within and between UG formations. Further, current production rates may not be indicative of long-term production performance due to the fact that more productive areas ('sweet spots') within formations are typically developed first. Production rates generally decline over the life of each well, hence reliance on early-stage production rates may lead to overestimation of reserves.[57]

The reliability of UG reserves estimates is an emerging issue in the USA. It is not yet clear if reserve estimates will become an issue for Australia investors but the consequences appear to be of sufficient magnitude to warrant further corporate disclosure on risk mitigation. In the USA, the Securities Exchange Commission and the New York State Attorney General issued subpoenas to 6 shale gas companies in 2011 following media reports that proven reserves estimates were being over-stated.[58] [59]

The ASX issued an updated consultation paper in September 2012 regarding reserves and resources disclosure rules, requiring reserves to be split between conventional and unconventional. Under rule changes, first reporting of unconventional reserves must include the number of wells and the land area involved.[60] The ASX also requires first (or substantially updated) reporting of reserves to include a brief description of analytical procedures used to estimate reserves. At this stage, there are no specific requirements in relation to uncertainties regarding UG reserves estimation.

We note media reports suggesting that production rates from CSG wells in QLD may not have been as high as anticipated.[61] Whilst there is no conclusive evidence that UG reserve estimates in Australia are unreliable to date, we highlight potential risks due to limited differentiation between disclosure on conventional and unconventional reserves estimation methods. The extent to which Australian listed companies have processes in place to improve estimation methods and verify reserve estimates remains unclear.

Our best practice controls focus on improving disclosure to assist investment risk assessment.

Best practice recommendations:

Publicly report at least annually on the following indicators:

- Resource type by geographic breakdown (e.g., cooper basin shale etc.);
- Estimate assumptions and/or methodology for each resource type, commercial in confidence permitting; and
- Resource estimation risk and uncertainties for UG.

57 Sustainable Investments Institute, 2012; Discovering shale gas: An investor guide to hydraulic fracturing.
58 As far as we are aware, nothing has come of the subpoenas to date; only one company's investigation has reportedly closed, with no enforcement action. http://www.ryderscott.com/pdfs/presentations/2011/01-%202011%20RSC%20Conference_Subpoenas%20to%20Shale%20Producers_Elkin.pdf
59 http://www.marketwatch.com/story/sec-ends-probe-into-shale-gas-reserves-gdp-chk-xom-bhp-rrc-cog-2012-09-24
60 http://www.asxgroup.com.au/media/Reserves_and_Resources_Reporting_Mining_Oil_Gas_Coys.pdf
61 http://www.smh.com.au/business/origin-inks-gas-sale-deal-with-rival-20120502-1xy61.html

Overarching Governance Controls

In addition to the guidance addressing specific ESG risks outlined above, Regnan also recognises the evolving nature of UG and the need for general governance processes to ensure ESG risks are continually monitored and reassessed and responded to with precaution. We have therefore included four overarching ESG risk management controls to address unspecified ESG risks (the unknown unknowns).

6. Integrate within strategic decision making ESG risks specific to UG:

Encourage board, executive, and management to integrate UG ESG risks within strategic decision making through formal responsibilities, resource allocation, and ESG-linked performance criteria.

Best practice recommendations:

- Board responsibilities include oversight of ESG risks specific to UG, either at board level or through board sub-committee(s);
- At least one executive's responsibilities include management of ESG risks specific to UG, dependent on organisational structure;
- Resource internal controls and reporting to assist board and executive(s) in fulfilling their responsibilities for ESG risks; and
- Link executive and management KPIs to ESG performance.

7. Apply precaution in risk management systems:

Within the risk management system, adopt specific policies on the management of uncertainties and extreme risks, including those that are of very high consequence even where low likelihood. Actively monitor key warning signs and use adaptive risk management processes.

Best practice recommendations:

- Identify and assess uncertainties associated with UG ESG risks;
- Adopt specific risk management strategies for extreme risks including very high consequence but low likelihood risks;
- Establish baselines for reasonably anticipated key impacts/warning signs;
- Publicly disclose key uncertainties and outline plans, including timelines and funding, for either the company or academic/regulatory bodies to address knowledge gaps within a reasonable time; and
- Assist with academic/regulatory research into uncertainties by providing access to wells, data, and any other assistance required.

8. Establish policy and plans specific to UG SEHS risks:

Publicly disclose policies (preferably in one place) and plans outlining management of technical SEHS risks arising from emerging technology/processes used to extract UG.

Best practice recommendations:

- Policy statements in line with IEHN/ICCR fraccing guide and Regnan's principles and recommendations (as stated above).

9. Measure and publicly report ESG performance indicators:

In addition to the specific disclosure recommendations outlined in the sections above, publicly report on indicators that both provide investors with a meaningful measure of the effectiveness of risk mitigation strategies over time and allow for the comparison among industry participants.

Best practice recommendations:

Publicly report at least annually on the following indicators:

- Baseline and ongoing groundwater level and quality monitoring results;
- Produced/flow back water volumes and reuse;
- Details of fraccing operations and fraccing fluid ingredients; and
- Stakeholder complaints, disputes, and resolutions during the reporting period.

- **Dewatering –** the process of removing water from coal formations which reduces the pressure within the coal seam and releases (desorbs) the gas trapped inside the seams.
    - **Produced water** – the water removed from the coal seams during dewatering. The water is usually very salty and may contain chemicals from the fraccing process, if used, as well as those naturally present in the coal seam.

- **Emissions factors** – A cost effective way of determining GHG emissions for an activity, expressed as the amount of CO_2-e equivalent per unit of activity e.g. per quantity of fuel consumed. Emissions factors are usually national average factors determined by the Department of Climate Change and Energy Efficiency, although in some instances they can be adjusted to take into account facility specifics e.g. coal carbon content. If there are no suitable emissions factors available for a particular activity e.g. underground coal then emissions may be directly measured, either continuously or intermittently. Direct measurement is considered to be further up the estimation hierarchy due to its degree of accuracy.[62]

- **Global warming potential (GWP) -** An index, based upon radiative properties of greenhouse gases, measuring the radiative forcing of a unit mass of a given greenhouse gas in today's atmosphere integrated over a chosen time horizon relative to that of carbon dioxide. The Kyoto Protocol is based on GWPs from pulse emissions over a 100 year time frame. The GWP represents the combined effect of the differing times these gases remain in the atmosphere and their relative effectiveness in absorbing outgoing thermal infrared radiation.[63]

- **Hydraulic fracturing (fraccing)** - is the stimulation of fractures (tiny cracks) in a rock layer by pumping water and fraccing fluid down a well at high pressure in order to increase the flow of gas from a reservoir/formation.
    - **Flowback water** - recovered fraccing fluid and associated water. The fluid is made up of water and chemicals from the fracturing process as well as those naturally present in the reservoir.

- **Risk** – the effect of uncertainty on objectives.
    - **Uncertainty** – deficiency of information related to understanding or knowledge of an event, its consequence, or likelihood.

- **Unconventional gas** - Unconventional gas refers to a part of the gas resource base that has traditionally been considered difficult or costly to produce.
    - **Coal seam gas** (CSG) - natural gas contained in coal beds now typically produced from non-mineable coal seams.
    - **Shale gas** - natural gas contained within a commonly occurring rock classified as shale. Shale formations are characterised by low permeability, with more limited ability of gas to flow through the rock than is the case with a conventional reservoir.
    - **Tight gas** – a general term for natural gas found in low permeability formations that cannot produce economically without the use of technologies to stimulate flow of the gas towards the well, such as fraccing.

[62] http://www.climatechange.gov.au/en/government/initiatives/national-greenhouse-energy-reporting/publications/~/media/government/initiatives/nger/publications/nger-technical-guidelines-2012-13-PDF.pdf
[63] http://www.ipcc.ch/pdf/assessment-report/ar4/syr/ar4_syr_appendix.pdf

Useful investor resources and initiatives

- Regnan, 2011, *Coal Seam Gas in Australia – ESG risks and opportunities*.
- Investor Environmental Health Network and Interfaith Centre on Corporate Responsibility, 2011, *Extracting the Facts: An Investor Guide to Disclosing Risks from Hydraulic Fracturing Operations*.
- Sustainable Investments Institute, 2012, *Discovering shale gas: An investor guide to hydraulic fracturing*.
- Sustainalytics, 2011, *Fracking Under Pressure: The Environmental and Social impacts and Risks of Shale Gas Development*.
- IEA, 2012, World Energy Outlook: Golden Rules for a Golden Age of Gas.
- PRI Australian Network Unconventional Gas Working Group.
- PRI collaborative engagement on fracking.