Unconventional gas research initiative for clean energy transition in Europe

R. Weijermars*, G. Drijkoningen, T.J. Heimovaara, E.S.J. Rudolph, G.J. Weltje, K.H.A.A. Wolf

UGRI Core Team, Department of Geotechnology, Delft University of Technology, Stevinweg 1, Delft 2628CN, The Netherlands

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ABSTRACT

The clean energy transition and EU 2020 targets require a further shift from coal and oil toward natural gas. As a relatively clean fossil fuel, gas must bridge the transition period required for renewable energy technologies to mature such that larger energy quantities can be economically produced to meet demand. Until then, gas is required in Europe and energy scenarios suggest natural gas consumption will reach 650 bcma in 2020 and 780 bcma in 2030. However, conventional gas production in the EU will decline to 230 bcma in 2020 and 140 bcma in 2030. This means the dependency on intercontinental LNG and pipeline imports will increase further and − by 2030 − must account for up to 80% of total gas supply. Consequently, the development of European unconventional gas resources could reduce the required gas imports and would improve security of supply − and also reduces the risk of price shock. This paper outlines the imminent decline of Europe's conventional gas production, highlights the potential of unconventional gas resources and advocates the key role of R&D to improve the performance of unconventional gas projects. Delft University of Technology has launched the Unconventional Gas Research Initiative (UGRI). The research framework, vision, aims and targets are outlined in this report.

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1. Introduction

Europe's dependency on natural gas is already considerable, with conventional gas accounting for 25% of the primary energy need, and the share of gas in the energy mix is set to grow. Natural gas is a relatively clean fossil fuel. However, Europe's commitment to burn cleaner energy from gas means it has become increasingly vulnerable to supply interruptions and price shock, as nearly half of its natural gas comes from intercontinental imports (pipeline and LNG shipments). Off-setting the decline of Europe's indigenous gas production from conventional fields by the development of indigenous unconventional gas fields could lower its dependency on imports from abroad. The unlocking of Europe's unconventional gas resources therefore would increase the security of gas supply.

Although the prospect of unconventional gas production thus seems attractive, the early success of North America in producing unconventional gas - using a combination of horizontal drilling and hydraulic fracturing, supported by entrepreneurial financing schemes - has recently raised intense scrutiny of worried citizens and concerned investors. The two main themes of this scrutiny are: (1) *citizens' worry about adverse environmental impacts from hydraulic fracturing and slick water injection*, and (2) *investors' concern about the*

dismal operational margins of many unconventional gas producers. Dealing adequately with these two principal concerns is important, not only for sustained success in the more mature North American unconventional gas market, but equally crucial for the success of the emergent, new shale gas plays around the globe.

Addressing environmental issues of new and on-going unconventional gas operations requires a combination of improved technology, monitoring and stakeholder management. Realizing positive margins requires a better validation process for prospect screening, realization of a higher sweet spot count per prospect, and improved well flow rates - all at lower capital and operational expenses.

It is now beyond dispute that North American independents engaged in unconventional gas projects struggle with a steep economic disadvantage as compared to gas production companies operating in conventional gas reservoirs (Berman, 2009a,b; Weijermars, 2010a, 2011a). A variety of benchmarks all reveal − consistently - that the principal unconventional gas operators have produced (over the past few years) their gas at large negative economic margins (Fig. 1). These negative margins are due to the prevailing depressed US gas prices since 2008, and is exacerbated by poor flow rates of the bulk of unconventional gas wells, all in relation to the incurred expenses − which must come down to improve the profit margins.

The poor margins of unconventional gas operations has urged many US independents to move from gas to oil drilling, under the assumption that higher margins may be earned from oil; these

* Corresponding author. Tel.: +31 (0)15 2787801; fax: +31 (0)15 27 81189.
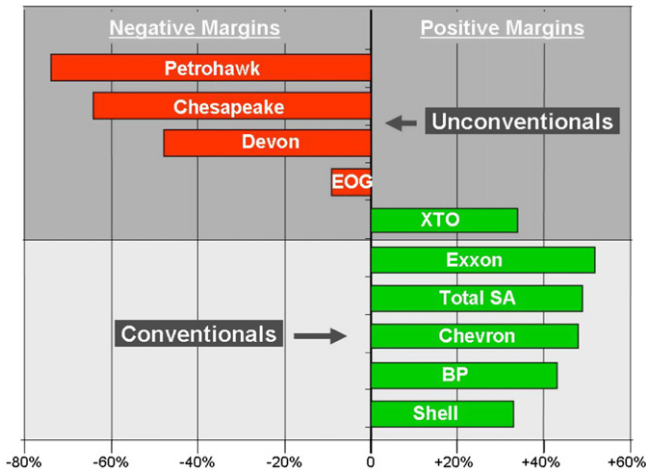*E-mail address:* R.Weijermars@TUDelft.nl (R. Weijermars).

Fig. 1. Pre-tax margins of major unconventional gas producers are negative in 2009 (except for XTO which gained on hedging & derivative trading). In contrast, major producers of conventional gas maintained excellent margins in spite of depressed gas prices [Data source: Weijermars & Watson, in press].

companies are under intense pressure to improve their liquidity positions (Weijermars, 2010b, 2011b). North American investors have maintained a remarkable trust in an eventual improvement of unconventional gas margins, but many analysts continue to question the operational fundamentals. The current wave of leasehold sales by major acreage holders of unconventional gas (e.g., Chesapeake, Petrohawk) increasingly evolves under threat of liquidity shortage. Unconventional asset sales are driven by the need to avert a liquidity crisis that could compound into an imminent insolvency if US well-head prices do not recover over the coming months (Weijermars, 2011b).

The root cause for the economic difficulties faced by unconventional gas operators is that they operate under high uncertainty at every stage of the upstream value chain. For *unconventional* gas projects to eventually rival or outperform *conventional* oil & gas projects, further research is urgently needed to help improve (a) the field development strategy and (b) the reserves maturation process for unconventional gas resources. Well flow rates must increase and cost must come down. Environmental impact must be mitigated and stakeholder issues must be adequately addressed. R&D into these topics must be founded in geoscience (G&G) and technology - all aimed at reducing uncertainty and risks in unconventional field development projects.

Delft University of Technology has launched (early 2011) a dedicated R&D research program named Unconventional Gas Research Initiative (UGRI). The stated UGRI vision is: *to become a leader in unconventional gas R&D by optimizing technology application & enabling value creation.* This program directly contributes to Europe's clean energy transition by enabling the development of further natural gas extraction, which is much needed to continue the replacement of coal-fired power stations in favor of CCGT based electricity generation. For example, coal still accounts for 55% of the primary energy supply in Poland (as compared to 16% OECD Europe's average), and the development of its unconventional gas resources could help the country to meet the EU's GHG reduction targets.

This article outlines the need for, and the research framework adopted by, the UGRI program to improve the success of unconventional gas field development projects. Proactively oriented, UGRI's aim is: *to accelerate and foster the environmentally responsible development of unconventional gas resources for play openers in Europe by providing integrated research & knowledge support.* The program's run-time is scheduled for the next 10 years and must

reach the stated goals by 2020. A list of acronyms used is given at the end of this paper.

2. European gas supply Trends

2.1. Conventional gas

Conventional natural gas accounted for 25% of IEA Europe's primary energy supply in 2009, while this was only 10% in 1973 and less than 1% in 1960. The continuous growth of the gas share has diminished the market shares of the two other fossil energy fuels: the combined shares of coal and oil accounted for 85% of the energy mix in 1973, but had reduced to a mere 50% by 2009 (Fig. 2). The introduction of cleaner burning technology and the switch to natural gas has contributed to mitigate the acid rain problem that marred Europe in 1970's.

The rapid growth of European gas consumption has been fed by domestic production, complemented with pipeline and LNG imports (Fig. 3). International gas trading has become a critical component in Europe's energy security (McCredie and Weijermars, in press). As of 2011, international gas trading accounts for nearly half of Europe's gas supply. Foreign gas comes into OECD Europe for 33% by pipeline imports from Russia, Algeria and Azerbaijan, complemented by 12% LNG imports from Algeria, Qatar, Nigeria, Trinidad and Egypt.

The decline in Europe's indigenous conventional gas production continues. Statistics of the International Energy Agency (IEA) show that of the 22 European OECD members, only Norway, Denmark and the Netherlands still have sufficiently large gas reserves to cover domestic demand. All other European OECD members have become net-importers of natural gas by 2009. The future dependency on non-European gas imports is projected to grow further. Over the
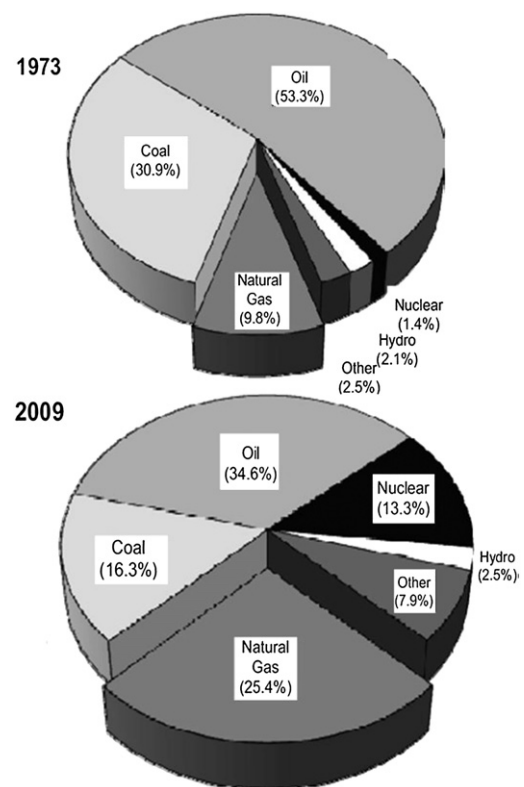

Fig. 2. Share of natural gas in IEA's Europe primary energy supply has increased from ~10% in 1973 to ~25% in 2009. Total energy consumption also increased by 25%, from 1375 Mtoe (1973) to 1721 Mtoe (2009) [Data source: OECD/IEA, 2010].
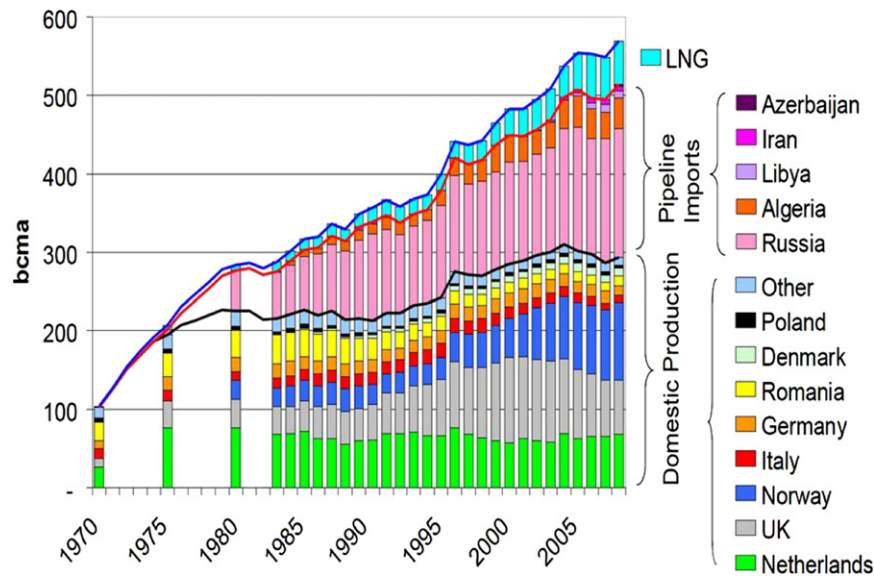
Fig. 3. Supply sources of Europe's conventional gas over the past 40 year period. All domestic sources are in decline, except for Norwegian gas exports. Pipeline and LNG imports account for ~45% of European gas supply in 2010. [Data source: Rogers, 2010].

next two decades, further decline in indigenous gas production from conventional sources means only 20% of the anticipated consumption needs can be covered. European gas demand is projected to grow to 650 bcma by 2020 and 680 bcma by 2030 (Cera, 2010). Consequently, the share of international imports must continue to grow and will need to cover 80% of European gas consumption by 2030 (Fig. 4).

The dependency on natural gas varies considerably throughout Europe. For example, the historic strong production from the North Sea basin has addicted both the UK and the Netherlands to natural gas, which accounts for respectively 40 and 45% of their primary energy supply. In contrast, natural gas consumption remained almost insignificant in Sweden (less than 3%), which relies on an energy mix of hydropower, nuclear power, and oil.

Fig. 4. Share of non-EU gas imports for a panel of 25 EU nations (which excludes Norway) will grow further in order to cover future gas demand. Indigenous production from conventional resources dips below 130 Mtoe (~140 bcm) in 2030 [Data source: SIA Conseil, 2010].

The UK, with its combination of a high population density and high gas percentage in the primary energy mix, ranks - after Germany (93 bcma) - as Europe's 2nd largest gas consumer (91 bcma, or 1/6th of EU's total); it also has the fastest declining indigenous production (Fig. 5). The UK has expanded LNG re-gas facilities (Milford Haven, Isle of Grain and Teeside) over the past decade and now hosts a total re-gas capacity that can cater for half the country's natural gas consumption if needed.

Future gas supplies for Europe from intercontinental pipelines and LNG imports remain vulnerable to price shock when global demand outstrips supply, either due to geopolitical tension or increasing demand from emerging economies. Current world LNG liquefaction capacity is just over 200 bcma and global re-gas facility capacity is well over 700 bcma (Rogers, 2010). This means there will be global competition for LNG shipments, especially when world gas supply tightens. Global liquefaction capacity may have expanded to a total of 550–600 bcma by 2020 (Rogers, 2010). The majority of LNG shipments are under long-term, oil-indexed contracts, and only a fraction is available as spot gas capacity.

International gas traders must fill Europe's emerging gas gap by securing new gas supplies from remote sources (McCredie & Weijermars, in press). The development of European, hitherto untapped, unconventional gas resources could reduce Europe's growing dependency on imports. If unconventional gas cannot be produced economically and in an environmentally acceptable way, Europe will remain vulnerable to both price shocks and supply interruptions.

2.2. Unconventional gas potential

The map of Fig. 6 shows the current proportion of natural gas in the primary energy mix. A remarkable 14 out of 22 OECD European member states (Luxembourg included but not shown on map of Fig. 6) is totally (100%) dependent on gas imports. Only 3 states are 100% self-sufficient (Norway, Netherlands, and Denmark) and 5 states have domestic production complemented by imports (UK, Germany, Poland, Austria, and Hungary). Clearly, 19 of the OECD Europe member states would directly win on unconventional gas development. Even Denmark and the Netherlands, both with declining production, could benefit from unconventional gas
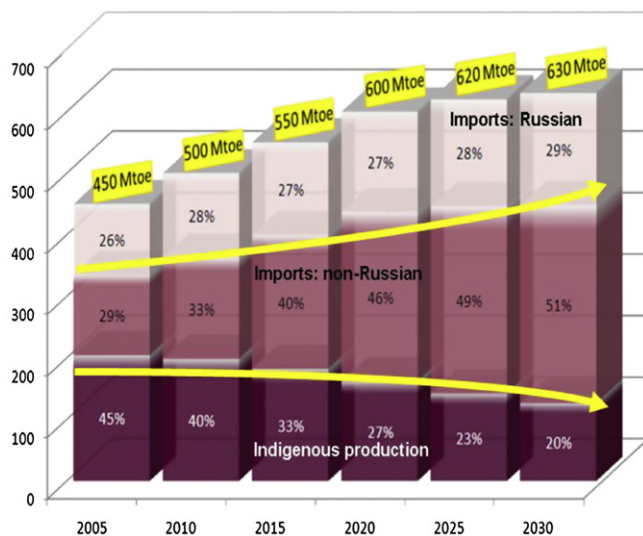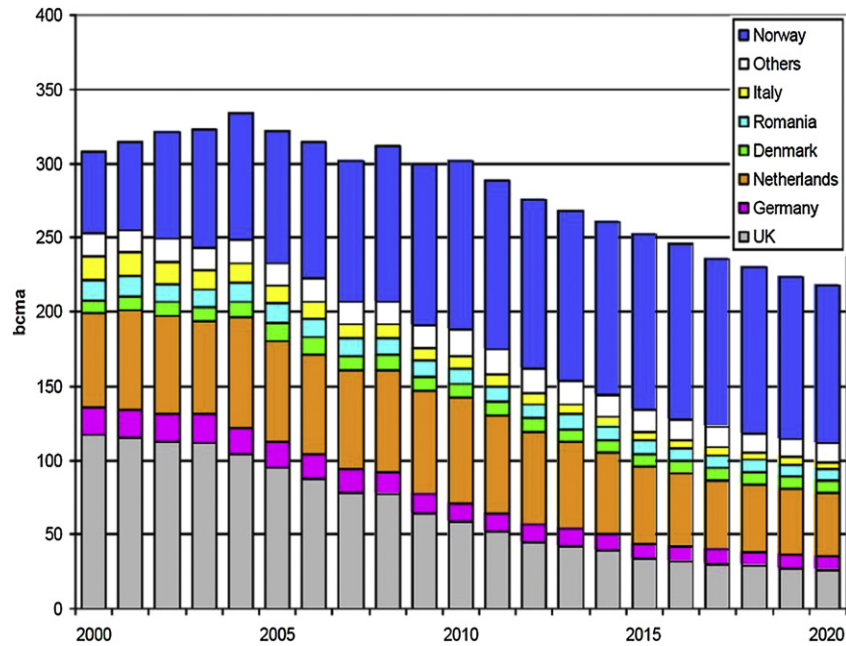
Fig. 5. European indigenous production from conventional sources drops below 230 bcm by 2020 [Data source: Rogers, 2010].
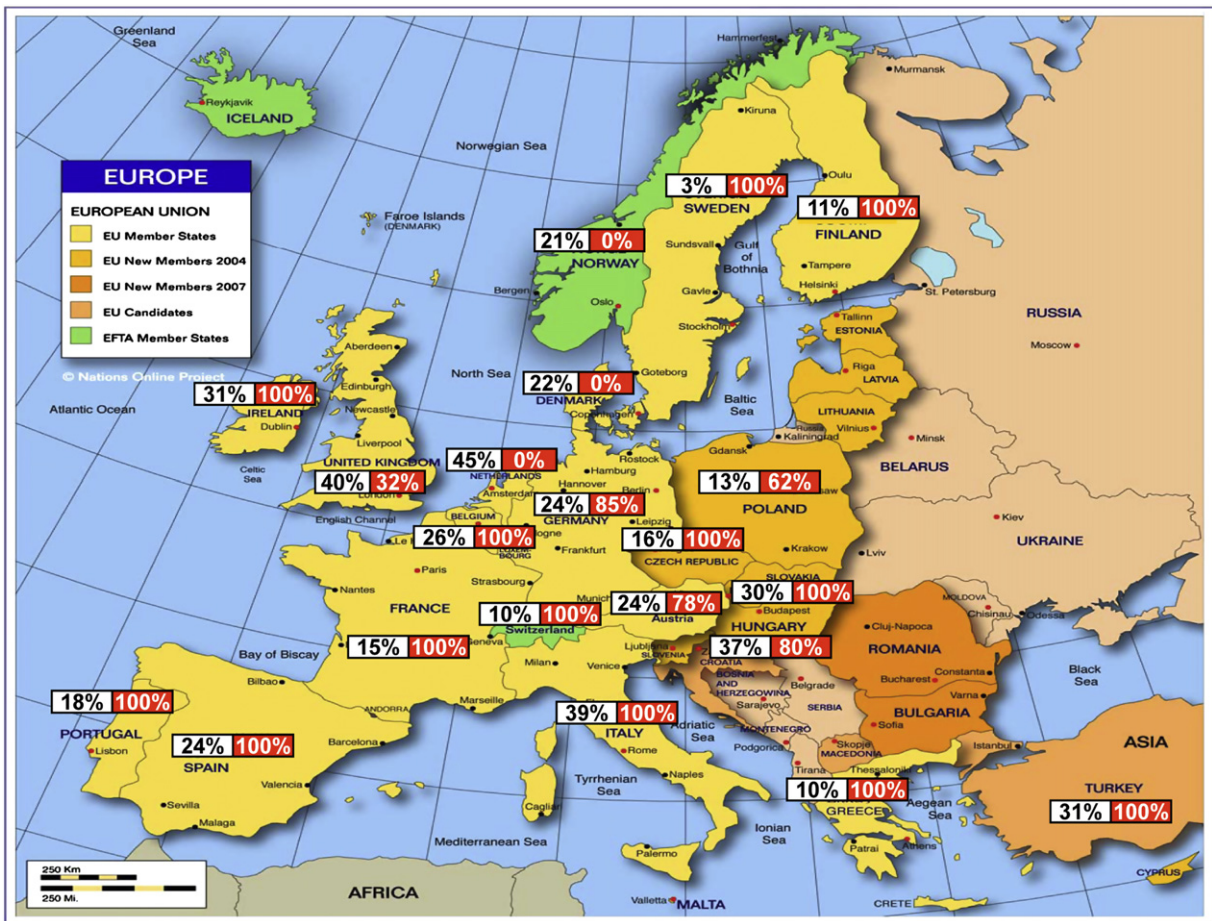

Fig. 6. Percentage of natural gas in the primary energy mix (white box, left) and percentage of net gas imports (red box, right) in OECD Europe as of 200. The three countries with 0% net imports are net exporters. [Data source: OECD/IEA, 2010]. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

development to offset the decline of conventional gas production. Norway is the only OECD Europe member that can maintain a robust production from conventional reservoirs (Fig. 5), and it does not stand to gain much from non-conventional gas development. Nonetheless, Statoil has been very active to enter joint ventures to develop unconventional gas fields in the US.

Europe's unconventional gas resources in place were first ranked in global perspective by Rogner (1997), who estimated some 1255 Tcf GIP (shale gas: 549 Tcf; tight sands: 431 Tcf; CBM: 275 Tcf). The technically recoverable resource base was for Europe estimated to range between 150 and 200 Tcf by Wood MacKenzie (2009). CERA (2009) considered technically recoverable shale gas to range between 106 and 423 Tcf (3000 to 12,000 bcm). Fig. 7 places these resource estimates in perspective by comparison to Europe's three major conventional gas production fields (Groningen in Netherlands; Troll and Ormen Lange on Norway's Continental Shelf). Europe ranks at the lower end of global unconventional resource potential, with only 4% of the worldwide total (Asia and North America lead, with respectively 30% and 25% of GIP). This is partly due to the exclusion of Poland, Hungary and Romania in Rogner's (1997) assessment; appraisals for these countries were not available at that time. The inset of Fig. 7 shows that the estimates of recoverable resource potential differ greatly per country; Ukraine, Poland and Hungary host the larger estimates.

Meanwhile, more detailed unconventional GIP inventories and estimates of technically recoverable resources are underway at nation level in most European countries. For example, technically recoverable unconventional gas resources for the Netherlands were estimated to amount up to 100 times the Groningen Field (TNO, 2009), but this view has been dismissed as overly optimistic by Shell geologists (Herber and De Jager, 2010) who arrive at a recoverable volume of about a tenth of Groningen's equivalent.

The inventory of Europe's unconventional gas potential continues. Improving security of gas supply by upgrading prospective unconventional gas resources into securely proved reserves is becoming reality. The on-going and planned exploration activities for the unconventional gas resource development in Europe have been reviewed by Geny (2010) and Bernstein (2010). Typical targets are tight sandstones of the Rotliegendes, Posidonia shales (Jurassic), Alum Shale (Lower Paleozoic), and Silurian, Carbonifeorus and Cambrian shales in Poland. The largest total acreage licensed lie in Poland, France and Germany (Geny, 2010, p. 55). Europe also has already seen its first bankruptcies among junior players that lack the financial resources to develop an unconventional high-risk exploration target into a cash flow asset: Gold Point Energy, Galaxy Energy, and Island Gas all failed between 2009 and 2010.

3. Unconventional gas research role & Strategic position

The accelerated development of Europe's unconventional gas requires improved development strategies for unconventional gas fields. A much more R&D focused and sweet spot intensity driven approach is needed (Geny, 2010). The US provided a technology proving ground and Europe can benefit from the broad principles, but knowledge—building must be tailored to the specific subsurface conditions of European basins — every geological play is full of its own surprises.

Accelerating and fostering the environmentally responsible development of unconventional gas resources for play openers in Europe is but one aim of the UGRI research program. The reserves maturation process must be further stabilized, as current volatility in reserve reporting may herald future impairments of gas reserves, which is counter to investor expectations on security of reserves. Well flow rates must increase and cost must come down. Environmental impact must be mitigated and stakeholder issues must be addressed at the same time. R&D into these topics must be founded in advanced geoscience (G&G) and technology expertise using state-of-the-art laboratory facilities. Unconventional gas research initiated in several research centers around the world has been reviewed elsewhere (see Weijermars and Luthi, in press).

The approach of Delft University of Technology benefits from its unique access to multi-disciplinary expertise, upstream field data (from non-conventional prototype fields in North America and European subsurface data from conventional fields) as well as advanced laboratory facilities. Our track record in controlled laboratory experiments on hydraulic fracturing and petrophysical behavior is already well established. Further environmental engineering and geophysical monitoring are necessary for responsible solutions in
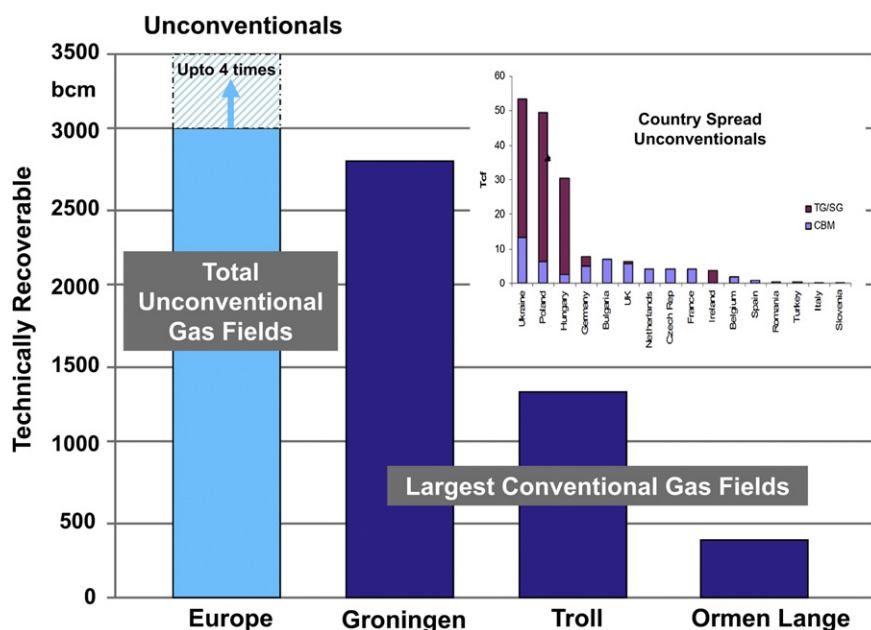

Fig. 7. Relative sizes of Groningen, Troll and Ormen Lange Gas Fields, and early estimates of Europe's total recoverable unconventional gas resources [Data source: unconventionals, Wood MacKenzie, 2009].

development of unconventional gas fields. Fig. 8 provides an overview of selected laboratory facilities for applied unconventional gas research; a dozen more dedicated rock test apparatuses, including two tomography scanners, are available in the Dietz Laboratory of TU Delft, supported by academically trained staff and technicians.

4. Research framework

UGRI themes are organized in a novel framework for the unconventional gas development lifecycle. The need for a revised framework is explained here by first presenting the established workflow architecture for conventional gas projects (Section 4.1) as a basis for our new framework for unconventional gas development projects (Section 4.2).

4.1. Conventional gas field development lifecycle

The conventional oil & gas business has optimized its field development workflow over the past few decades. The mature workflow model commonly used by the industry facilitates project selection, validation and execution. Each significant step forward in the project's lifecycle path is thoroughly reviewed for present value in periodic reviews (so-called value assurance reviews). The adopted gate-stage structure enables gatekeepers and decision-makers to ease the communication on the project status (Fig. 9). The workflow can be grouped according to six attribute groups: (1) decision gate aims, (2) strategy options, (3) workflow sections, (4) decision gate stops, (5) workflow process focus, and (6) motto.

The result of the conventional value assurance process is that field development projects, that make it through the successive gate-stages, have been thoroughly validated. The process is rigorously executed and reduces any undue uncertainty about present value. All projects for which a Final Investment Decision (FID) is taken have validated and risked NPVs that generously pass the corporate hurdle rate. This value assurance process also is the very reason why conventional E&P companies consistently book excellent corporate profit margins (ref. Fig. 1). The problem with unconventional field development projects is that the traditional workflow architecture of Fig. 9 is, in fact, unsuitable for such projects.

4.2. Unconventional gas field development lifecycle framework

One of the principal reasons why development of unconventional fields remains economically risky is that the estimated ultimate recovery (EUR) of gas remains poorly constrained, due to uncertainty in GIP estimates and recovery factors. Both GIP and recovery factors may vary widely per well, due to intrinsic petrophysical variations as well as due to variations in fracture density & penetration. The lifecycle and flow rates of adjacent wells may steeply or gradually decline within the leased acreage. Appraisal wells are all meant to produce. The lack of gas interconnectivity between wells in unconventional gas fields means GIP and EUR estimates for overall acreage of leasehold remains speculative. Borehole integrity and flow rates may be compromised even within the first decade of a well's existence. The high degree of uncertainty about GIP and recovery rates lead to poorly constrained EUR gas volumes. Combined with added volatility of gas prices in regions of unconventional gas growth, NPV estimates may be right out wrong. Similarly, even 'proved' reserves may be volatile due to risk of impairment when so-called asset carrying value evaporates due sub-economic performance.

We advocate a new unconventional gas field development concept which contains several iterative and concatenated feedback loops, which define a prospect-specific learning cycle (Fig. 10). Present value becomes better constrained as subsurface uncertainty reduces over time, based on value of information accumulated by monitoring, analysis and modeling. Our concept includes extra feedback loops in the 'explore & screen' stage, since one well is not representative for a whole field in the case of an unconventional gas play. Individual well completion and field development architecture are monitored *real-time,* such that NPV is progressively optimized. The new field development concept is central in our multidisciplinary research program and integrates information flows to extract maximum value for companies venturing into unconventional field assets.

5. Challenges Ahead

5.1. Environmental Challenges

The environmental footprint of unconventional gas operations is greater than for conventional gas plays, because well density is
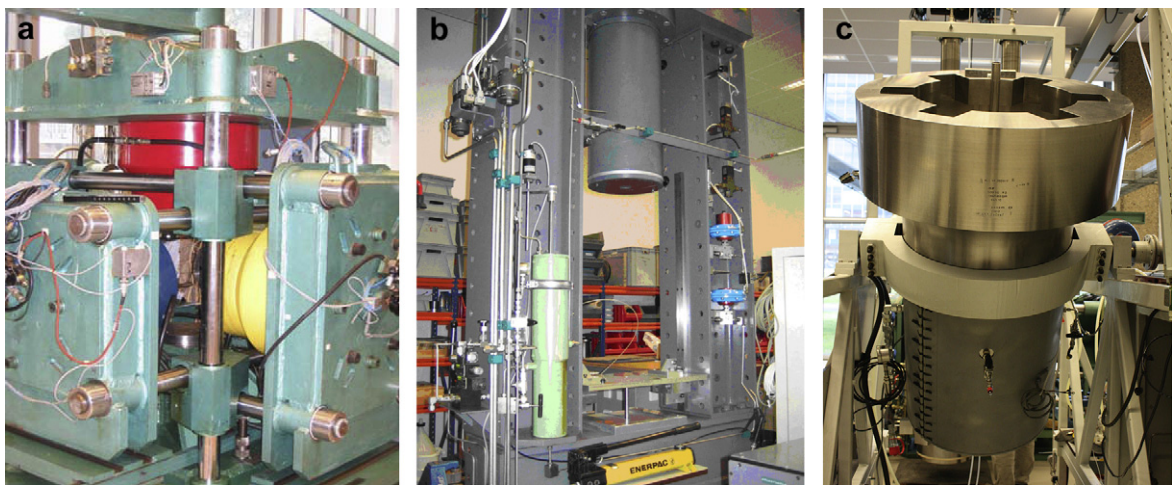

Fig. 8. Geomechanical facilities for testing rock behavior in response to wellbore loading and hydraulic fracturing moved to a dedicated, new Dietz Laboratory in 2007: (a) Tri-axial cell allows in-situ hydraulic fracture initiation and propagation from a synthetic borehole under loads of up to 3 MNewton, fracture growth is simultaneously monitored by acoustic sensors, (b) TerraTek load cell with axial pressures up to 70 MPa (c) Borehole Simulator for hydraulic fracture test under reservoir temperatures and with axial pressures up to 40 MPa; radial pressure up to 20 MPa.
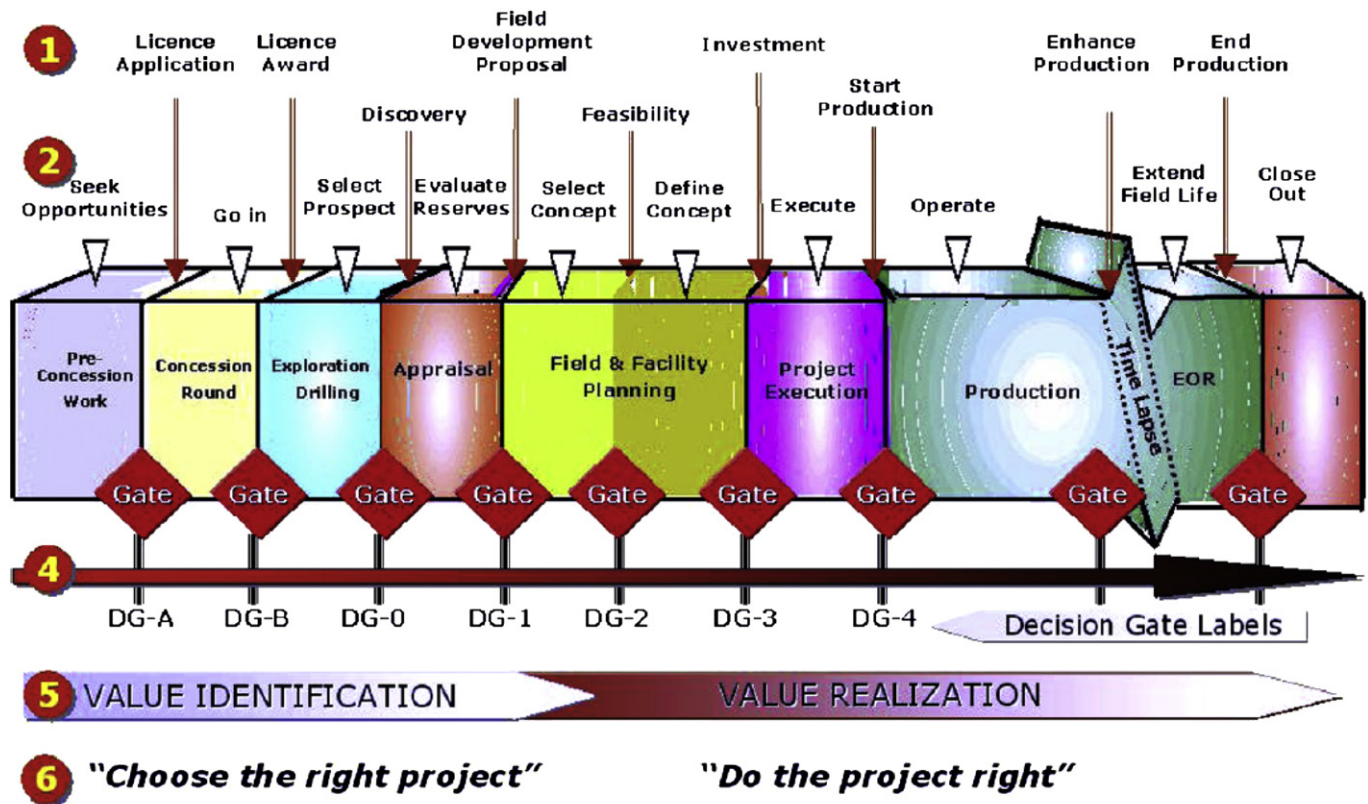
Fig. 9. 'Traditional' E&P Workflow architecture for development of conventional upstream oil & gas projects. [Data source: Weijermars, 2009].

inherently higher and above-ground infrastructure denser to produce the gas at economic rates (PTAC, 2006). The hydraulic fracturing job uses fluids (mostly water, sometimes acidized to dissolve carbonate matrix) and proppants (mostly sand), with nitrogen-foamed fracturing fluid being common for shallow shale with low reservoir pressure. The pumped fluid reaches pressure of 8000 psi (55 MPa), and may crack a shale formation as much as 3000 feet (~1 km) in lateral directions. Section 322 of the US
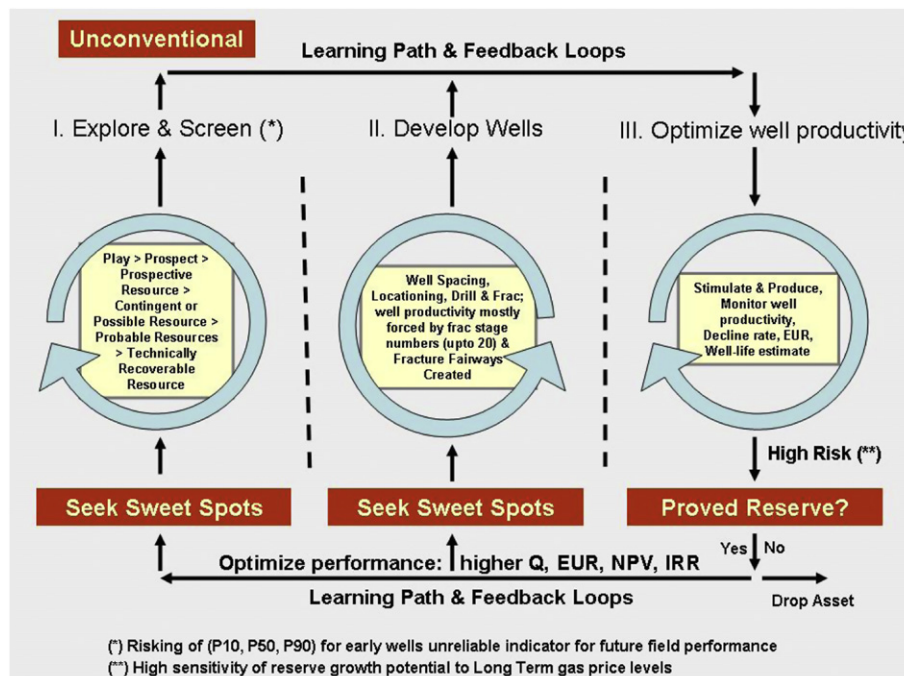

Fig. 10. Unconventional gas field development concept [Source: UGRI Group].

Energy Policy Act of 2005 provides regulation for hydraulic fracturing operations. Service companies adjust the proportion of frac fluid additives to the unique conditions of each well. The Occupational Safety and Hazard Administration (OSHA) requires that material safety data sheets (MSDS) accompany each chemical used on the drill site, but the proportion of each chemical additive may be kept proprietary (29 C F R §§ 1910 Subpart Z, Toxic and hazardous substances). New US legislation is aimed at the disclosure of any propriety formula to the state, EPA Administrator, or treating physician or nurse if required in the case of a medical emergency.

The need for groundwater resources is high in gas shale plays: the amount of water consumed in hydraulic fracturing ranges between 1.2 and 3.5 billion gallons/well depending on well type (Bene et al., 2007). Unconventional gas development typically uses a combination of 40 acre spacing vertical wells, 20 acre spacing vertical wells, 80 acre spacing horizontal wells (Forest Oil, 2009). Given a Barnett Shale gas development area of 7000 Acre Feet (AF) in 2005, and typical 4 to 11 AF development area per well, overall water consumption accumulates to over 1 trillion gallons, with 60% coming from groundwater (Trinity and Woodbine aquifers, Bene et al., 2007). These gravel aquifer resulting from valley-fill deposits are susceptible to leaky surface impoundments and contamination from well operations is subject to state legislation and federal law (Clean Water Act), but currently exempted from the federal Safe Drinking Water Act. The so-called flowback water that is pumped out of the well by the frac job contractor before production starts commonly contains dissolved salts and frac chemicals and requires treatment before disposal or injection into suitable subsurface formations.

The US Energy Policy Act ('Cheny Act') of 2005 (P.L. 109-58 in Section 322 Hydraulic Fracturing) amended the Safe Drinking Water Act (42 U.S.C. 300 h/d/1) to exclude the fluids or propping agents (other than diesel fuels) used in hydraulic fracturing operations related to oil, gas, or geothermal production activities from the definition of the term "underground injection." Several pending policy bills address the current exemption of hydraulic fracturing under SDWA; and this may put further cost pressure on unconventional natural gas production.

Within Europe, groundwater reserves are strongly protected with the European Water Framework Directive. As a result we may expect that the license to operate an unconventional gas play will be stricter than is currently the case in the United States. In order to operate more cost-effectively, a European gas play will need to have environmental protection engrained in the core of its operating procedures instead of being an issue of compliance.

5.2. Technology Challenges

In order to have positive netback on their invested capital, natural gas companies need to beat breakeven cost. Technology progress is needed to bring down breakeven cost of unconventional gas wells, as breakeven cost is above prevailing wellhead prices for many unconventional gas wells, so operating efficiencies must be improved. The per well performance cycle benefits from (Reeves et al., 2007):

- Detection of sweet spots, by being able to identify in advance where naturally fractured fairways exist.
- Better delineation of productive pay interval, mechanical stratigraphy (fraccability) and existing stress field in reservoir characterization
- Establish the threshold reservoir quality required for justifying the use of well stimulation technology and meeting corporate hurdle rates
- Enhance production by improving recovery technology (CO_2 sequestration in CBM, Nitrogen-stripping etc.)

Well productivity is poorly constrained and history matching is not widely publicized and mostly kept proprietary. We need better models to predict production potential prior to commercial development. Play-based analysis is needed with an emphasis on detailed reservoir characterization (PTAC, 2006): depositional environment, diagenetic history, drainage area size and shape, continuity of beds or layers within production zones, long-term recovery factors,
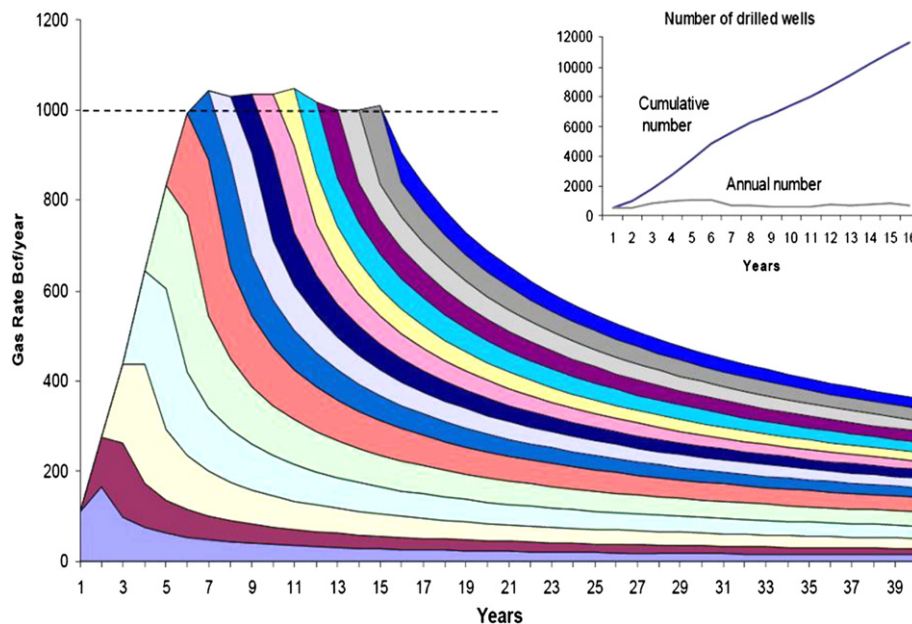

Fig. 11. Scenario for European shale gas production, assuming rig roll-out at just below 1000 wells per year and US Fayetteville play well productivity rate. Each color band represents production volume from 1000 wells drilled annually. Drilling stops after 16 years in this hypothetical example, but this is only a model constraint. [Data source: Geny, 2010, p. 65]. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)
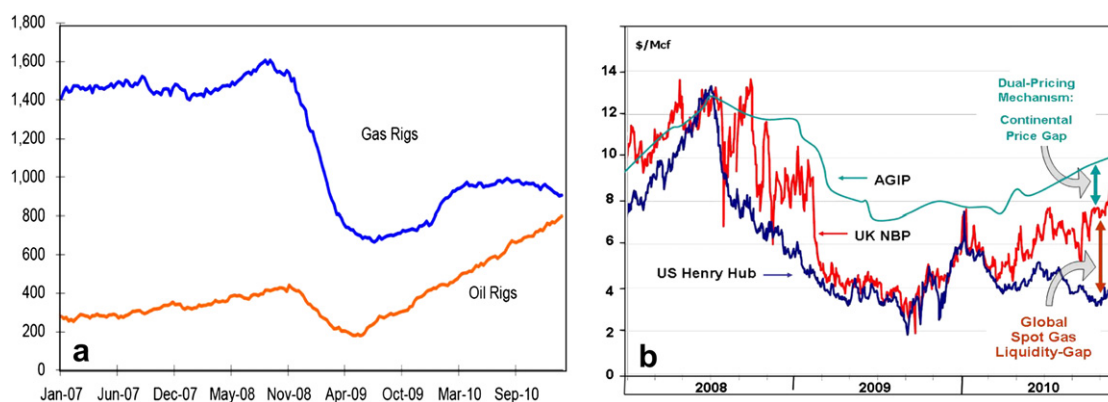
Fig. 12. (a) US Rig Counts for gas are declining and oil rig counts steadily gained ground as 2009/2010 oil margins are better than US gas margins (Data source: Baker Hughes]. (b) Continental European gas prices (AGIP) are buffered by oil-indexing, and commonly higher than US and UK spot gas prices (after Weijermars and McCredie, 2011).

recovery rates over time, natural fracture orientations, down-hole pressure, temperatures, and smart well development.

5.3. Economic Challenges

Typical well cost for well completion is build up as follows: 20–25% drilling rig, 30–35% frac job, 10–15% tubulars (Godec et al., 2007). Slim hole technology using 53/4 inch (or even micro-holes diameters ranging from 1.25 to 2.38 inches, instead of 83/4 inch conventional completion size (PTAC, 2006) and cheaper horizontal drilling, geo-steering and coiled tubing help bring down well costs. Some unconventional shale plays (e.g., Marcellus shale) may even be produced without expensive well stimulation techniques (Engelder and Lash, 2008).

In the US, cost of operations and reserve replacement may rise faster than gains in efficiency. Reserve replacement cost have risen steeply over the past decade: land leasing cost involves signing bonuses for new acreage, which has inflated to about 3000 $/acre near the close of the decade (100 fold price increase as compared to the start of this decade), with royalty rates now commonly ranging between 12.5% and 28% (Andrews et al., 2009).

Geny (2010) and Oswald (2010) separately undertook a European scenario exercise assuming first production to start in 2015 and reaching some 800 Tcfa by 2020 (Fig. 11), which corresponds to 4% of European demand. Clearly, gas imports will still be needed to complement Europe's indigenous gas production, unless drilling rates can rival the rig counts and nearly 20,000 unconventional wells drilled in the US each year.

The prevailing gas prices are an important factor in determining which unconventional gas resources can eventually be economically developed. In the US, new unconventional gas field development has slowed down as is reflected in the decline of gas rig counts (Fig. 12a), due to the low US wellhead gas prices. It is rarely realized that the traditionally oil-indexed gas prices of Continental Europe set a favorable hurdle rate for unconventional gas development. Continental European gas prices are commonly much higher than − and throughout 2009 and 2010 traded at over twice − US Henry Hub spot gas prices (Fig. 12b).

Unlike gas in Britain, the Continental gas prices, subject to the oil-indexed pricing-mechanisms of long-term gas contracts, are largely insensitive to short-term supply and demand swings that dominate spot gas prices. Continental Europe may see its oil-indexed gas prices firm up still further when the price of oil continues to rise. AGIP (Average German Import Price) has already risen above 10 $/Mcf, in step with crude oil prices above 100$/barrel (as of early 2011). The marginal cost of European production

from unconventional gas ranges between 8 and 12 $/Mcf (Geny, 2010; Bernstein, 2010).

6. UGRI 2020 Roadmap

Europe needs a strong regionally leveraged development of its unconventional gas resources. We forge research alliances with academic institutions based on supplementary capabilities, interface with industry to abstract tacit knowledge from practitioner's perspective and bring this knowledge into the codified, explicit knowledge domain. We work with government institutions to optimize national resource development.

UGRI's research agenda is set in close collaboration with our allied upstream knowledge partners. Our TU Delft knowledge network includes academic partners (ISES, CSM, TAMU, BEG, Stanford, MIT, IFP, CSIRO, GFZ), industry partners (IRO, NOGEPA, KIVI/NIRIA, Exxon, Shell, Statoil, Northern Petroleum, Schlumberger, Halliburton, Baker Hughes, etc.) and governmental organizations (EBN, TNO, MELI). Many of these partners may become part of the UGRI initiative.

Our research policy and collaborative network are driven by geographical spread, supplementary capabilities and collective bargaining power. We believe in the benefit of sharing open source systems versus the development of proprietary systems. UGRI will act as a regional European coordinator of industry concerns and
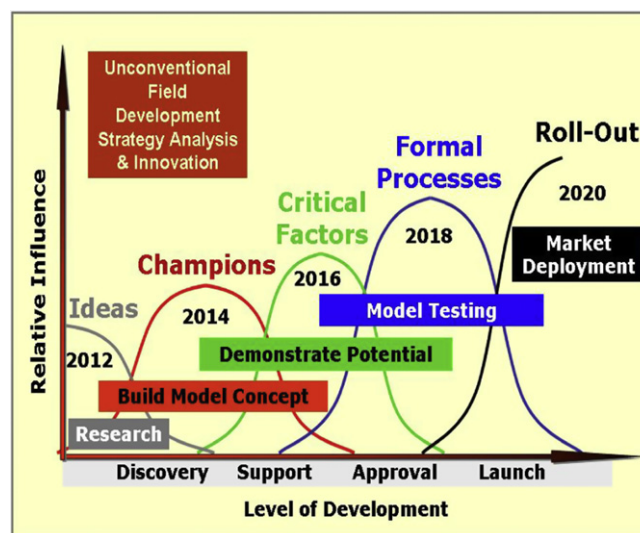

Fig. 13. Roadmap for UGRI results focuses on practical roll-out of the Integrated Field Development Optimization Model (IFDOM) for unconventional gas resources.

includes practitioners' requirements in the field development model for process optimization. The innovated unconventional field development strategy will be formalized in an Integrated Field Development Optimization Model (IFDOM) for unconventional gas resources. UGRI follows a game-changer philosophy (Schilling, 2008) and the road map ahead for model discovery, design and delivery is scheduled in Fig. 13.

7. Conclusions

Europe can mitigate decline in indigenous gas production by developing unconventional gas resources. Early estimates indicate recovery of unconventional gas at Continental European wholesale gas prices and current production cost level make unconventional field development a marginal activity. However, economic recovery of such fields becomes realistically possible when oil-linked gas prices continue to rise and when cost of technology comes down, aided by improved field development strategy and workflow. Geological surveys and petroleum directorates continue their efforts to improve estimates of the national gas resource base. Industry must move in to develop and unlock the gas resource potential to bring it to market. Reserve development and maturation speed will benefit from a dedicated research program that integrates the global knowledge base for practical application and improved performance of unconventional gas assets. Delft University of Technology has launched UGRI to accelerate the development of unconventional gas resources for play openers in Europe by providing integrated research & knowledge support.

Acknowledgements

List of Acronyms Used

AF	Acre Feet
AGIP	Average German Import Price (BAFA)
Bcf	billion cubic feet
Bcma	billion cubic meter per annum
BEG	Bureau of Economic Geology (University of Texas at Austin)
CBM	Coal Bed Methane
CERA	Cambridge Energy Research Associates
CSM	Colorado School of Mines
CSIRO	Commonwealth Scientific and Industrial Research Organisation (Australia)
CCGT	Combined Cycle Gas Turbine
EBN	Energie Beheer Nederland
E&P	Exploration & Production
EPA	Environmental Protection Agency
EU	European Union
EUR	Estimated Ultimate Recovery
GFZ	Geoforschungs Zentrum (Potsdam, Germany)
G&G	Geology & Geophysics
GHG	Greenhouse Gas
GIP	Gas in Place
IEA	International Energy Agency
IFDOM	Integrated Field Development Optimization Model
IFP	Institut Français du Pétrole (Paris)
IRO	The Association of Dutch Suppliers in the Oil and Gas Industry
IRR	Internal Rate of Return

ISES	The Netherlands Research Centre for Integrated Solid Earth Science
KIVI/NIRIA	The Royal Institute of Engineers in the Netherlands
LNG	Liquefied Natural Gas
Mcf	1000 cubic feet
MELI	Ministry of Economic Affairs, Agriculture ('Landbouw') and Innovation
MIT	Massachusetts Institute of Technology
NOGEPA	Netherlands Oil and Gas Exploration and Production Association
NPV	Net Present Value
OECD	Organisation for Economic Cooperation and Development
Q	well flux
R&D	Research & Development
SDWA	Safe Drinking Water Act
TAMU	Texas Agricultural and Technical University
TNO	Netherlands Organization for Applied Scientific Research
UGRI	Unconventional Gas Research Initiative

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