

A Compact Gas-To-Methanol Process and its Application to Improved Oil Recovery

James Banister and Svend Rumbold

Heatric division of Meggitt (UK) Ltd, Poole, Dorset, UK

Abstract

As North Sea Continental Shelf oil production peaks, operating companies must evaluate options for economic life-extension and improved oil recovery (IOR). Water flooding and gas injection are clear possibilities, and increasing interest is also being shown in CO₂ injection – no doubt motivated at least in part by government commitments to reduce CO₂ emissions, and perceived arising opportunities for CO₂ sequestration. The likely subsequent appearance of significant CO₂ in associated produced gas - at some stage during late field life – presents a significant challenge, with scope for additional processing facilities on existing offshore facilities severely restricted by space and weight considerations.

The problem posed by periods of high CO₂ content in associated gas is one that already faces certain North American operators who make extensive use of CO₂ well fracturing as an IOR technique. The well fracturing procedure is followed by a “flowback” well clean-up period, during which produced gas exhibits high CO₂ levels, well beyond the upper limit for export via pipeline, resulting in undesirable periods of gas flaring that can last up to several weeks.

Both scenarios call for a cost-effective technique for processing gas with high CO₂ levels, maximizing the produced gas value, without excessive capital or operating costs. Heatric is endeavoring to address this challenge with a compact Gas-to-Methanol process package. In the Heatric process natural gas, including quite high concentrations of CO₂, is steam reformed and then converted to methanol in a unique once-through reactor design, with hydrogen-rich tail gas being combusted to heat the reformer..

Heatric’s steam reformer has been demonstrated both in-house and at the University of Sydney, and lies at the heart of a commercial prototype Hydrogen Production Unit supplied to an industrial user in California. The methanol converter is currently the subject of a demonstration project. Sanction for an integrated Gas-to-Methanol commercial prototype is expected towards the end of this year.

The unique and innovative reactor designs constitute the enabling technology for a commercially viable packaged plant, and are derived from Heatric’s proven Printed Circuit Heat Exchanger technology. Recent breakthrough advances in manufacturing techniques enable us to substantially enhance the commercial viability that has historically characterised such processes.

Introduction

The scope for IOR in the North Sea

The first North Sea gas field was brought on stream in 1967 (West Sole), and the first oil field followed in 1975 (Argyll, closely followed by Forties). Thus the North Sea is now a mature area, with many of the largest fields producing below their early production plateau rates.

Further development is now principally focused on smaller or more technically challenging North Sea fields, making use of the existing infrastructure, and deeper (500-1500m), harsher climate areas on the Atlantic Margin.

However, techniques for Improved Oil Recovery (IOR), including water flood and gas reinjection, and technical advances in reservoir management, drilling and well technology during recent decades have also enabled significant increases in the hydrocarbon recovery from mature fields - well beyond levels that were initially thought economically recoverable. [Note: the authors do not profess any understanding of reservoir engineering, and have adopted the expression "Improved Oil Recovery" to encompass any technique or operation that enables oil or gas recovery above the level initially considered economically and technically recoverable.]

Water flooding – either by water injection or aquifer influx – has been a feature of many or most North Sea field developments, right from early life. This has resulted in very good recovery factors: the volume averaged recovery factor for Central and Northern North Sea oilfields is predicted to be 45%, with up to 70% using water flooding alone, in some cases. However, with over half the oil remaining in place, there is clear scope for further IOR programs. Carbon dioxide injection is technically feasible where reservoirs are above the minimum miscibility pressure: many UK continental shelf fields are estimated to fulfill this criterion, with reservoir conditions that compare well with successful CO₂ injection projects in the United States ⁽¹⁾.

Statoil's Sleipner West natural gas field contains 9% CO₂ in the reservoir, and this is separated offshore and reinjected into the Utsira aquifer formation 800-1000 meters below the seabed. The offshore separation and reinjection concept was an integral part of the field's development plan, prompted by the introduction of a Norwegian CO₂ tax ⁽⁴⁾. BP's Algerian In-Salah project also features separation of CO₂ and reinjection into a saline aquifer. However, to date there have been no CO₂ IOR projects in the North Sea (or any other offshore location). The challenge of capturing CO₂ from an onshore location, transporting it offshore, and reinjecting through new or existing installations, has not hitherto been considered commercially viable.

A recent study indicates approximately 76% of the total cost for a North Sea CO₂ capture/IOR project can be attributed to onshore capture of CO₂ and transport offshore ⁽³⁾. The reuse of existing pipelines for CO₂ transport would have a substantial impact on project economics.

North American Experience of CO₂ IOR

Most experience of CO₂ injection tertiary IOR projects to date has been in North America, principally the Permian Basin area of west Texas. In total there are some 75 miscible CO₂ injection projects in the United States and Canada. Incremental oil recovery is reported to be in the range 4-12% of original oil in place ⁽³⁾. Interestingly, although the first projects made use of CO₂ separated from natural gas, the success of CO₂ injection projects led to such high demand that the large majority of North American projects use naturally occurring geological sources of CO₂ supplied via an extensive pipeline network – principally the McElmo Dome (Colorado), Sheep Mountain (Colorado), and Bravo Dome (New Mexico) ⁽²⁾. Thus the most significant difference between North America and the North Sea is the vastly different cost of supplying CO₂ for IOR.

The principle behind miscible CO₂ injection is that CO₂ fully dissolves into the oil, resulting in a reduction in viscosity, facilitating the flow of oil through the formation to the producing well. (The specific volume of the reservoir fluids also increases, creating a further driving force.) Thus one consequence of CO₂ IOR is the flowrate and concentration of CO₂ in associated gas will increase substantially throughout the lifetime of the project. The rate of increase can vary considerably, depending on a range of geological factors and the field development history: typical changes in total flow and CO₂ content are shown in Figure 1.

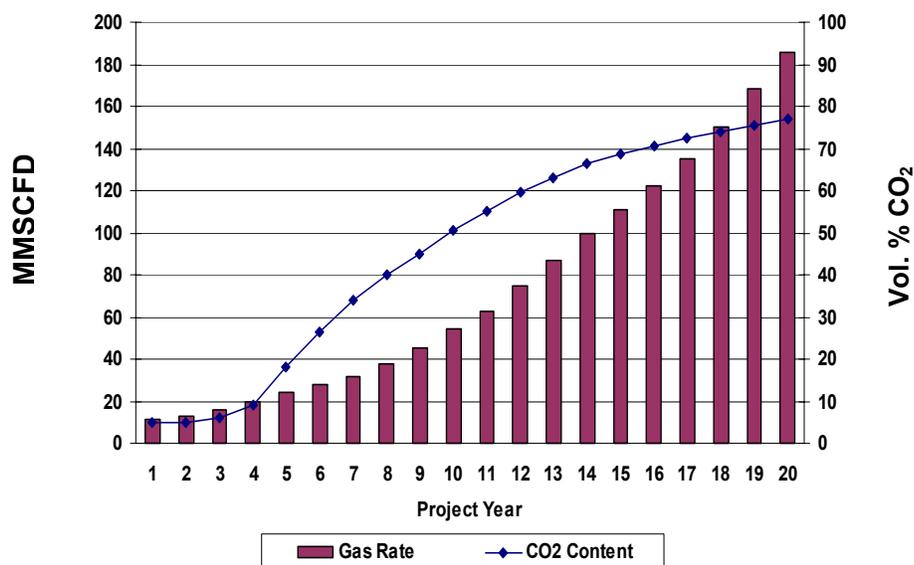


Figure 1. Typical Produced Gas Flow and CO₂ Concentration During CO₂ IOR Project ⁽²⁾

A further consideration is corrosion: high concentrations of moist CO₂ can give rise to significant corrosion problems, both in the well assembly and downstream processing equipment. Corrosion considerations are often the primary influence in design of the associated gas processing configuration – the further upstream CO₂ is removed, the less impact on materials of construction.

Typical options for gas processing include:

- **No CO₂ recovery from associated gas**, most appropriate when only a small proportion of gas processed is from CO₂ IOR:
- **Total recycle and reinjection of associated gas**, only suitable if the hydrocarbon content is low, to avoid the minimum miscibility pressure exceeding reservoir pressure:
- **Separation and recycle of CO₂ rich gas**, either by membrane or absorption.

These options are outside the scope of this paper, and are discussed in more detail elsewhere ⁽²⁾.

In any event the associated gas processing facilities must provide the flexibility to handle both increasing throughput and substantial compositional changes, and minimize the potential impact of corrosion.

Tight Gas Well CO₂ Fracture-Stimulation

It has been estimated that, in the United States alone, so called “tight gas” sands and shales may contain almost three times the currently proved U.S. gas reserves⁽⁵⁾. These reserves are gas-bearing sandstones and carbonates with a very low *in situ* permeability – sometimes as low as 0.001 millidarcy. Generally operators seek to drill in areas where natural rock fractures abound. Except where microfractures are present, tight gas formations must be fracture-stimulated, giving the gas an easier pathway to the well, to achieve economic production rates. Techniques for fracturing wells involve the high pressure injection of water-based fluids, emulsions, oil-based fluids, or liquid CO₂. Great care is needed in selecting the appropriate fracture fluid, since the very small rock pores are easily obstructed by liquids – held in place by surface tension forces. Most wells deteriorate over time, giving rise to an ongoing need for refracturing to restore or further improve production: some wells have been refractured more than 15 times. Given there are around 50,000 tight gas wells in the U.S., the number of fracturing operations each year is clearly very large.

In the clean-up period following fracture-stimulation, once the well is back in production, fracture fluids and proppant (solid material intended to hold open the newly created fractures) “flowback” with the produced gas. In the case of CO₂ fracturing, this results in a period lasting up to several weeks, during which the produced gas contains elevated CO₂ levels. The fracture-stimulation procedure is applied to an individual well, but gas is collected and processed from a large number of wells in a wide geographical area and exported via pipeline with minimal processing. Therefore, it is expedient to simply flare the high-CO₂ gas rather than provide special processing facilities that would not be needed for the normal produced gas composition. Illustrative gas compositions illustrative of normal and “flowback” conditions are shown in Table 1.

	Normal Operation	“Flowback” following CO ₂ Fracture
Composition, Vol%		
CH ₄	94	60
C ₂ H ₆	2	1
C ₃ H ₈	trace	-
CO ₂	4	39

Table 1. Effect of CO₂ Flowback on Produced Gas Composition

Whilst flaring high CO₂ gas has been expedient, there is increasing pressure on operating companies to eliminate venting and flaring of hydrocarbons. Consequently there is genuine market interest and commercial opportunity in ways of processing this gas at the wellhead.

Compact Methanol Process

Heatric Technology Background

High integrity and effectiveness heat exchange, derived from Heatric's Printed Circuit Heat Exchanger (PCHE), lies at the heart of the compact methanol process. The PCHE is an established compact heat exchanger technology, originally invented as a result of post-doctoral research performed at the University of Sydney in the early 1980s. Following Heatric's move from Australia to the UK in 1989, PCHEs rapidly gained acceptance in the offshore industry. Other applications include LNG, ethylene oxide, sulphuric acid, naphtha reforming, and caustic soda plants. A total of over 600 PCHEs have entered service around the world.

The compact core of a PCHE is constructed by forming flow passages in flat metal plates, and then stacking and diffusion bonding the plates together into a single block. The chemical milling technique typically used to form the flow passages is analogous to that used for the manufacture of electronic printed circuit boards, and this gave rise to the "Printed Circuit" exchanger name. Diffusion bonding is a high temperature solid state joining process that promotes grain growth across the metal boundaries, resulting in a join exhibiting parent metal strength and ductility. If necessary, multiple diffusion bonded blocks may be welded together to form larger units, before headers and nozzles are welded on to complete the exchanger. Alternatively, instead of welded-on headers, it is also possible to incorporate flow distribution channels within the diffusion bonded block, in a so-called "ported" design.

PCHEs can be up to 85% smaller and lighter than an equivalent shell-and-tube exchanger, as a result of the very high surface area density, high heat transfer coefficient, and potentially near-perfect counter current flow. PCHE cores can be designed for extreme temperatures and pressures: units are in operation at over 500 bar and temperatures ranging from cryogenic up to more than 800°C. They can be designed for very low pressure drops, even when handling highly viscous liquids or hot gas.

The potential for using a PCHE as a plug flow reactor was recognised by Heatric at an early stage⁽⁶⁾. However, it was not until 2002 that Heatric designed and constructed the first embodiment of PCHE technology into a chemical reactor – the so-called Printed Circuit Reactor (PCR). The chosen demonstration process was the steam reforming of methane⁽⁷⁾.

Process Selection

Process options for bringing gas to market have been the topic of frequent discussion, including the 2004 GPAE Annual Conference⁽⁸⁾.

For Heatric the choice was initially simplified by having previously identified steam reforming as a process well suited to the application of our PCR technology, and having started development of a compact steam reforming technology.

When it comes to choosing between Fischer-Tropsch (FT) liquids or methanol, for world scale on-shore gas utilisation projects, there are several drivers that make FT the favoured technology: ease of integrating the product into the current energy (fuels) market; no restrictive space limitations at remote sites; and a strong pricing link with the current energy market. At least in the eyes of established technology providers who are also project

investors, these considerations outweigh the technical challenges and investment risk associated with constructing a world scale plant.

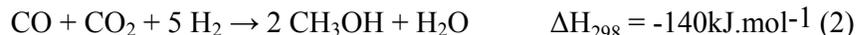
However, when considering smaller volume gas streams with variable composition and perhaps limited feed availability, a flexible, compact and (in order to maximise product life and return on investment) relocatable approach is called for. The FT catalyst, operating within a complex three-phase reactor environment (synthesis gas, hydrocarbons, and water), has a lower specific productivity than a methanol catalyst. Even with high shear reactors the catalyst productivity cannot approach that of a methanol reactor, and a larger reactor inevitably results. The exothermic and equilibrium limited nature of the methanol reaction also means it is possible to drive productivity up, and size down, through clever thermal management. Simply put, FT reactors are large, and likely to stay that way, whilst methanol reactors are small, with potential to get smaller.

Methanol from Natural Gas

Methanol is produced from natural gas in two steps. The first step is the endothermic high temperature reforming of natural gas over a catalyst into synthesis gas – a mix of principally carbon monoxide (CO) and hydrogen (H₂), plus carbon dioxide (CO₂), and water (H₂O). The steam reforming reactions are:



The second step is the exothermic equilibrium synthesis of methanol from the synthesis gas by the hydrogenation of carbon oxides over a catalyst. :



The water gas shift equilibrium reaction also occurs in parallel in both the reforming and methanol synthesis reactions:



Compact Reforming

Heatric started work on compact chemical reactors in 2000, and embarked on a self-funded steam reforming program in 2001. The decision to focus on steam reforming was based on a number of synergistic considerations, including:

- significant and growing interest in small scale hydrogen production, including fuel cell applications;
- opportunities in a wide range of other synthesis gas based chemistries, including
 - methanol,
 - Fischer-Tropsch liquids,
 - DME,
 - ammonia;
- substantial overlap with our materials development program in support of high temperature heat exchangers for the next generation of nuclear power applications.

The design of Heatric's first **"proof-of-concept" steam reformer** has been well described elsewhere⁽⁷⁾, but it is helpful to identify the key elements:

- high efficiency (design ~95% of theoretical maximum);
- stand-alone system, no import or export of steam;
- 3 barg design pressure on the process side;
- multiple adiabatic bed arrangement, with
 - 5 stages of pre-reforming, heated by flue gas and synthesis gas,
 - 9 stages of reforming, heated by catalytic combustion,
 - 9 stages of catalytic combustion;
- passive control, by careful design of heat transfer elements;
- design to avoid carbon formation;
- comparable manufacturing cost to a simple PCHE of similar size and weight.

The passively controlled reforming temperature profile is illustrated in Figure 2. One of the plate designs incorporated within the main reformer block is shown in Figure 3, together with a view of the test bed installation in Figure 4.

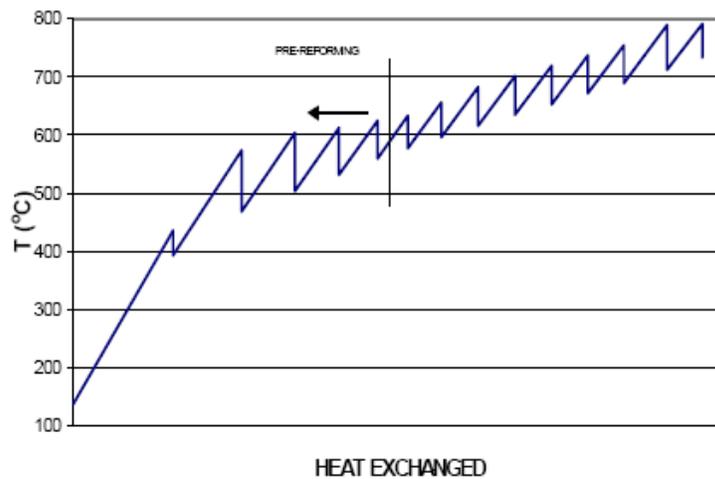


Figure 2. Reforming Temperature Profile⁽⁷⁾

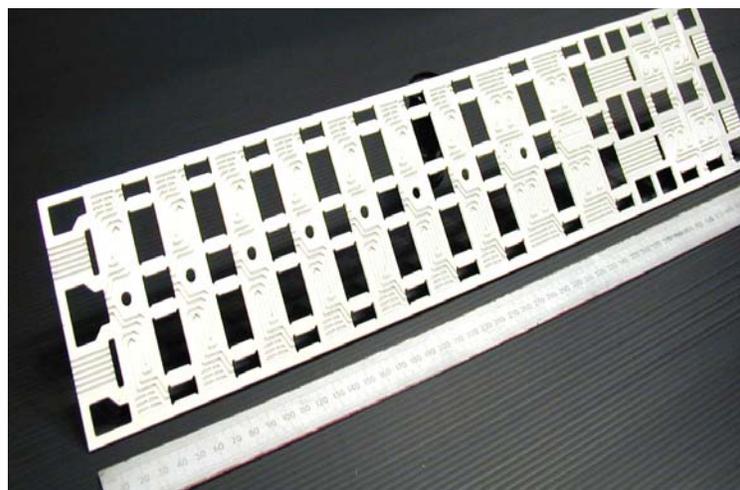


Figure 3. Reformer Plate, Proof-of-Concept Heatric Reformer

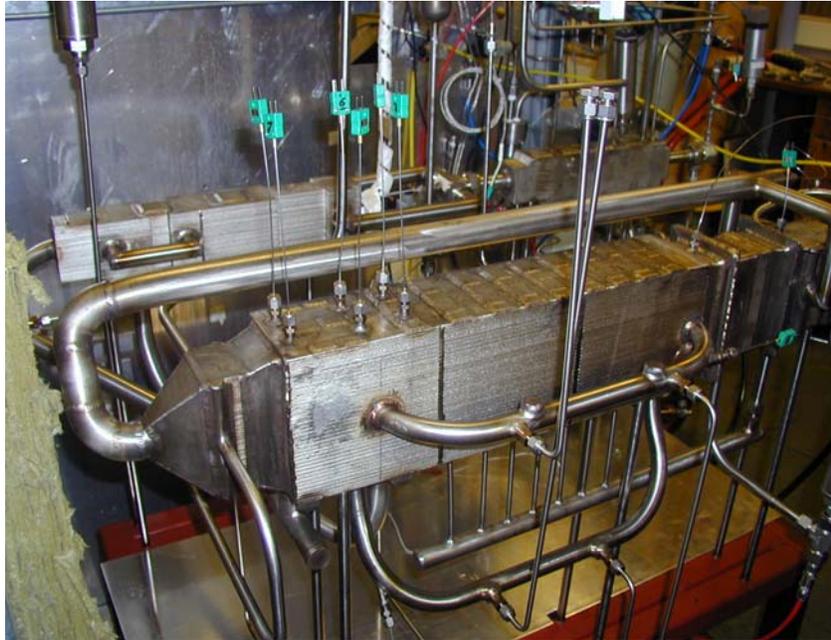


Figure 4. Proof-of-Concept Heatric Reformer

Subsequent to the successful proof-of-concept, a **fully instrumented prototype** was constructed, and installed in a specially equipped laboratory at The University of Sydney. This unit has operated well, with a remarkably close match between measured performance and Heatric's design ⁽⁹⁾. Figure 5 compares the measured and calculated reforming profile. Figure 6 shows the prototype installation.



Figure 5. Comparison of Measured and Calculated Reforming Profile⁽⁹⁾

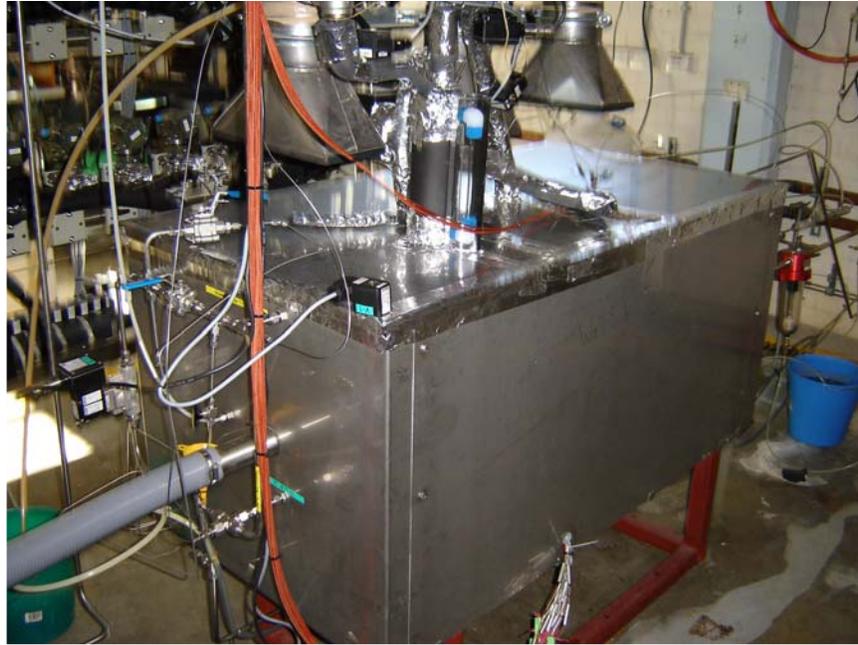


Figure 6. Prototype Heatric Reformer, University of Sydney

Following hard on the heels of these laboratory programs is the first **industrial installation** of a prototype hydrogen production unit. This fully skid mounted unit incorporates the following features:

- natural gas desulphurization,
- natural gas compression,
- feed water purification,
- combustion air blower,
- multiple adiabatic bed reformer system (15 bar design pressure), with water gas shift,
- PSA hydrogen purification to 99.99% purity,
- catalytic combustion of PSA off-gas,
- fully automated start-up, normal operation and shut-down,
- automated emergency shutdown system (SIL 2).

The unit was fully engineered by Heatric in Poole, and is currently being assembled at a Meggitt group affiliate site in Los Angeles. Figure 7 shows the CAD design and a comparable view of the unit part way through assembly.

Successful operation of this first industrial unit will validate the manufacturability, simplicity of operation, and reliability of Heatric's compact reformer technology. However, the project goes much further, since it will provide a sound benchmark for demonstrating size, weight, manufacturing cost, operating cost and maintainability of both reforming-based hydrogen units and similar skid-mounted units comprising similar equipment and functionality.

Thus we consider Heatric's compact reforming technology provides improved simplicity of control and operation, very large size savings, cost advantages, and is close to being industrially proven.

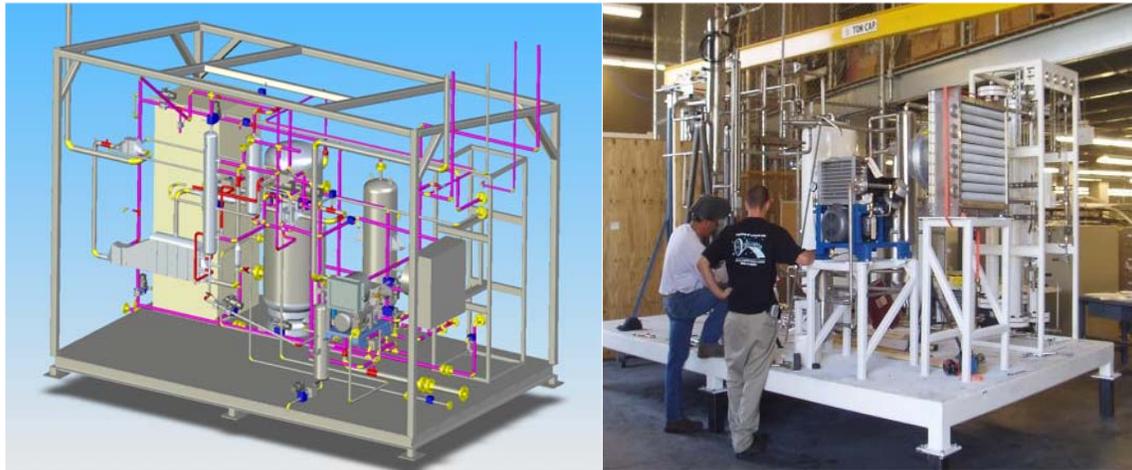


Figure 7. Heatric Industrial Hydrogen Production Unit, Los Angeles.

Compact Methanol Synthesis

In a conventional methanol plant the majority of the capital cost (and plot area) is attributable to steam reforming. However, methanol synthesis is far from simple, either. The reaction is strongly exothermic and equilibrium limited, taking place over a catalyst bed, and thus conventionally a low conversion-per-pass reactor is used, with a large gas recycle. Catalyst use is optimised by stepwise addition of cold feed (“cold shot”), steam rising to cool the reactor tubes, or cooling by flowing cold inlet gas over the reactor tubes. However, the large gas recycle compressor is both costly and operationally burdensome at smaller plant sizes.

The experience gained from the successful steam reformer design has enabled us to confidently predict the performance alternative methanol synthesis reactors, based principally on published kinetic data ⁽¹⁰⁾. By making good use of compact heat transfer surface, and achieving close temperature approaches, Heatric has been able to devise a reactor arrangement that achieves both high carbon to methanol conversion and elimination of the recycle compressor. Thermal integration with the reformer is achieved by a medium pressure steam loop. Passive control of temperature and flow is maximised, thus requiring active control of outlet gas pressure, outlet methanol flow, and two heat transfer streams only – see Figure 8. The result is a unit that is robust to changing compositions of gas, changing reformer conditions but that operates reliably with minimal intervention.

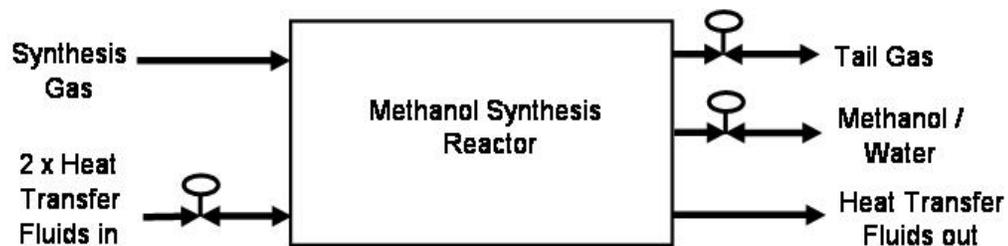


Figure 8. Heatric Methanol Synthesis Reactor Schematic.

Certain catalyst operating conditions (but not temperature) are beyond the envelope of conventional reactor designs and published literature. Therefore, we will conduct catalyst performance trials to confirm our reactor design during the last part of 2005. We are confident that, having demonstrated the multiple adiabatic bed PCR as part of our reformer program, we will then be able to move straight to a commercial demonstration scale methanol unit.

Thus, by the end of 2005 we expect to be able to confidently design a modular methanol synthesis reactor, requiring minimal active control, that enables the recycle gas compressor to be eliminated.

Integrated Gas-to-Methanol Process

Feed conditioning, feed compression, synthesis gas compression, and utility systems are required to complete the methanol process. Optionally, to make maximum use of available energy, we can also include raw methanol distillation.

Feed conditioning requirements will be dependent on site-specific considerations. However, typical requirements might include some or all of the following:

Sulphur removal: both H₂S and organic sulphur species may be present, and would rapidly poison the reforming catalyst. In its simplest form a zinc oxide bed may be sufficient, but in the case of high organic sulphur levels a hydrogenation pre-treatment may be necessary.

Chloride removal: chlorides are an acute poison to methanol synthesis catalysts, and must therefore also be removed. The principal source is likely to be carry-over of produced brine into the gas stream. A sacrificial bed is typically used.

Mercury removal: although less common, some natural gas sources contain significant quantities of mercury. Whilst the gas-to-methanol process does not suffer the corrosion-related problems associated with LNG, mercury is another potential catalyst poison. Removal may be either by regenerable molecular sieve, or a sacrificial sulphur-impregnated carbon bed.

Compression requirements will depend on wellhead gas pressure. There is also a trade-off between compressing the natural gas feed versus compressing the synthesis gas. From examination of the reforming stoichiometry (equation 1), and considering the process steam requirement, it is clear that natural gas feed compression is generally advantageous. Typically we would aim for a circa 30 bar feed pressure to the reformer, and then go through a single stage of synthesis gas compression to circa 80 bar prior to entering the methanol synthesis reactor. Compressor drivers can be either electrical or direct diesel driven.

Process steam is raised using synthesis gas heat recovery (at the reformer operating pressure), and further utility steam is raised within the methanol synthesis reactor; the utility steam may be conveniently matched to the raw methanol distillation reboiler duty. A suitable water treatment system, to provide feedwater, will be needed. The sizing of the feedwater treatment system is significantly influenced by the disposition of both process water condensate knocked out downstream of the reformer and methanol distillation bottoms. If a water

injection well is available, it may be expedient to reinject process water condensate, rather than clean-up the water for re-use.

Notwithstanding the extensive thermal integration in the process, the highly endothermic high temperature reforming reaction and exothermic lower temperature methanol synthesis reaction inevitably result in substantial surplus low grade heat. Unless there is a conveniently situated and well matched energy consumer, this surplus energy will either be rejected to atmosphere in reformer flue gas, or through the use of air coolers or cooling water.

Illustrative Performance

We have chosen the wellhead processing of CO₂ fracture-stimulation flowback gas as the basis for illustrating the performance of the compact methanol process. Key points are:

- 1 x 10⁶ SCFD gas feed (dry basis)
- natural gas composition comprising methane and CO₂ only
- nominal 3 barg wellhead pressure (probably not realistic in practice)
- reforming at 27 barg
- methanol synthesis at 79 barg
- raw methanol distillation to nominal 99.5% purity

The process performance of a unit processing feed gas with varying CO₂ content is shown in Table 2.

Case	1	2	3	4	5
Feed Composition, Vol%					
CH ₄	100	96	85	75	62
CO ₂	-	4	15-	25	38
Feed Flow, SM³/h (10⁶SCFD)	1180 (1.0)				
Methanol Production, kg/h (bbl/day)	1311 (267)	1290 (263)	1186 (242)	1052 (215)	853 (174)
Process Water Make-up, kg/h	916	826	604	465	344
Process Water Recycle, kg/h	4792	4327	3182	2508	2133
Synthesis Gas Compression, kW	263	249	213	185	153
Carbon Efficiency, mole % (includes CO₂ in feed)	81.7	80.4	73.9	65.6	56.9
Incremental CO₂, kg/kg Methanol	0.272	0.233	0.175	0.165	0.251

Table 2. Illustrative Heatric Compact Methanol Process Performance, varying Feed CO₂ Content

Perhaps the most important observation to make is reflected in the last line of Table 2, that incremental CO₂ per kg of methanol produced passes through a minimum at around 25 vol.% CO₂ in the feed, since CO₂ is needed in the methanol synthesis reaction (reaction

(2) above). 25 vol.% CO₂ in the feed provides a roughly stoichiometric composition for methanol synthesis.

Case	1	2	3	4	5	
Feed Gas Composition, component kg/h	CH ₄	801	769	680	600	464
	CO ₂	-	88	329	549	779
Methanol Reactor Tail Gas Composition, component kg/h	CH ₄	106	115	139	143	132
	CO ₂	32	42	116	269	541
	CO	20	20	25	30	57
	H ₂	97	80	44	26	15

Table 3. Comparison of Methanol Synthesis Reactor Tail Gas Composition, varying Feed Gas Composition (mass flow basis)

Table 3 shows the methanol synthesis reactor tail gas composition for the feed cases studied. It is important to remember that the tail gas is delivered at circa 79 barg, and in the process scheme studied it is let down in pressure and burned using catalytic combustion to provide heat to the reforming process. Whilst we have not considered CO₂ recovery in the flowback gas processing scenario, there is a clear opportunity to apply membrane technology to sequester the CO₂ at this point in the process.

Conceptual Layout

A preliminary conceptual layout indicates, depending on feed processing requirements, that it might be feasible to incorporate the core process units into a single vehicle semitrailer, with perhaps another unit for utility, control and ancillary equipment.

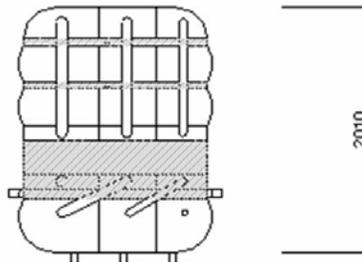


Figure 9. Methanol Synthesis Reactor, Side Elevation (dimensions in mm)

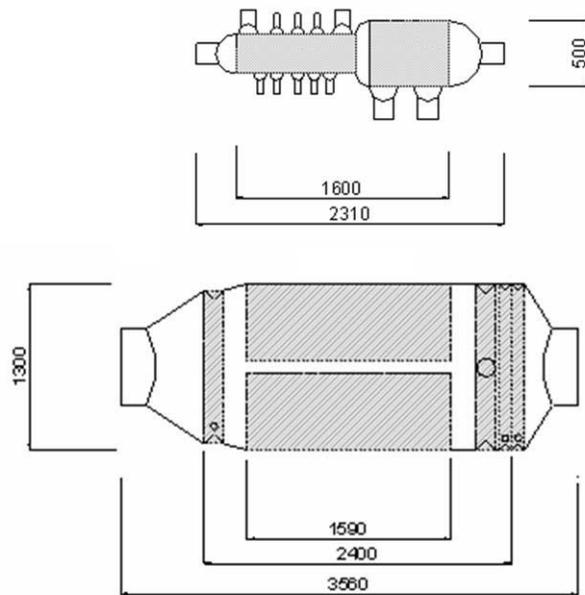


Figure 10. Pre-reformer and Reformer System, Side Elevation (dimensions in mm)

Summary of Heatric Compact Methanol Process Status

The key points we would like to highlight from the foregoing process description are as follows.

1. Heatric believe methanol is the most appropriate conversion route for small quantities of natural gas.
2. We have devised a highly compact, cost effective, and easy-to-operate steam reformer, which is close to being industrially demonstrated.
3. We have devised a compact, simple and easy-to-operate methanol synthesis concept, which enables the elimination of the conventional synthesis loop compressor.
4. We have demonstrated the compact methanol process is able to process a wide range of CO₂ levels in the natural gas feed.
5. The compact methanol process is well suited to the sequestration of a significant proportion of CO₂ in the feed, for high CO₂ cases.
6. It appears entirely feasible to mount a small (1-5 x 10⁶ SCFD) compact methanol unit on vehicle semitrailers.

Further developments include:

- the introduction of substantially lower cost manufacturing techniques, especially suited to high temperature alloys required for reformer processes;
- the commercial application of protective coatings, principally based on aluminium, to assure commercially acceptable equipment operating life;
- collaboration with other Meggitt group companies, aimed at reducing the cost of instrumentation and control systems.

We believe the next 12-18 months will be an exciting time, with a very real prospect of commercializing our compact methanol process for selected niche applications.

Conclusions

We have reviewed the gas processing issues faced in two distinct IOR scenarios:

- miscible CO₂ injection for tertiary oil recovery, and
- CO₂ fracture-stimulation of tight gas wells.

North Sea Miscible CO₂ Injection IOR

In the case of miscible CO₂ injection, it is clear that North Sea opportunities are hampered by the cost of supplying CO₂. This represents a fundamental difference between Europe and North America. Indeed, in Europe forecast project costs are dominated by the collection (sequestration) and transmission of CO₂ offshore, and hence the reuse of existing pipelines for CO₂ transport would have a substantial impact on project economics.

We have considered the requirements for the associated gas processing facilities. These must offer the flexibility to handle both increasing throughput and substantial compositional changes. Further, to minimize the potential extent of corrosion problems, it is desirable to process gas as close to the wellhead as practicable.

A compact, simple-to-operate gas-to-methanol process fulfills many of the criteria for gas processing. By converting gas to liquid, existing gas export pipeline infrastructure could conceivably be used for CO₂ supply. Whilst the issue of CO₂ recovery is far from resolved, we nevertheless believe our compact methanol process has the potential to enable a significant step towards the viability of miscible CO₂ injection IOR and CO₂ sequestration.

Processing of Flowback Gas from CO₂ Fracture-Stimulation

We have found genuine market interest and commercial opportunity in ways of processing flowback gas at the wellhead. We have developed a technically feasible concept for a mobile compact methanol plant, to process gas that has hitherto been flared.

We believe it is through relatively small niche opportunities, such as this, that broader industry skepticism towards gas-to-liquids processing can be overcome. Heatric is proactively developing a demonstration project to achieve this.

Outlook

With up to 3% of world gas production estimated to be either flared or vented ⁽¹¹⁾, the opportunity for getting relatively small flows of natural gas to market is large and well known. The focus of this paper has been on processing natural gas streams associated with IOR projects. However, other opportunities include offshore production of methanol for hydrate suppression; recovery of purge streams from worldscale methanol plant; co-production of methanol and urea for the onsite production of urea-formaldehyde resins. We are confident that compact methanol technology will be demonstrated and gain acceptance in the not-too-distant future.

Acknowledgements

The steam reforming and methanol processes and reactor concepts that lie at the heart of this paper are the result of a collaborative effort between Dr. Tony Johnston and Prof. Brian Haynes. Dr. Johnston is the inventor of PCHE technology, a founder and past-MD of Heatric, and currently principal of Optint Pty Ltd, a Sydney company closely collaborating with Heatric on the further development of micro-structured devices and associated processes. Prof. Haynes of the University of Sydney has collaborated with Heatric for 20 years in the development of various aspects of micro-structured technology, and heads the Applied Microstructures Research Group within the Department of Chemical Engineering. Without their efforts and imagination this paper would not have been possible.

References:

1. Jayasekera, A.J., Goodyear, S.G., "Improved Hydrocarbon Recovery in the United Kingdom Continental Shelf: Past, Present and Future", SPE75171 prepared for SPE/DOE 13th Symposium on Improved Oil Recovery, Tulsa, 13-17 April 2002.
2. Freidman, B.M., Wissbaum, R.J., "CO₂ Enhanced Oil Recovery – Supply Options, Treatment Facilities and Effect on Existing Downstream Processing", GPA Annual Convention, New Orleans, March 2004
3. Gozalpour, F., "CO₂ Injection for IOR and Storage: Opportunities and Challenges for the North Sea", DTI Oil & Gas Maximising Recovery Programme (formerly SHARP) IOR Views, Issue 10, June 2005.
4. Kaarstad, O., "Investor/end user Experience with and Perspective on CO₂ Sequestration; Future, Gaps and Collaboration", IEA ZETS Workshop, Oslo, 14th January 2002.
5. "Tight Gas" Supplement to Oil and Gas Investor, March 2005.
6. Johnston, A.M. (Tony), "Miniaturized Heat Exchangers for Chemical Processing", *The Chemical Engineer*, December 1986, pp36-38
7. Johnston, A.M., Haynes, B., "Heatric Reforming Technology", presented at the AIChE 2002 Spring National Meeting 2nd Topical Conference on Natural Gas Utilisation, New Orleans, 10th-14th March 2002.
8. Font Freide, J., "Methanol: A Gas Processing Option", GPAE Annual Conference, Sainte-Cyr sur Mer, 29th September – 1st October 2004.
9. Seris, E., Abramowitz, G., Haynes, B., Johnston, A. M., "Demonstration Plant for Distributed Production of Hydrogen from Steam Reforming of Methane", 7th World Congress of Chemical Engineering, Glasgow, 11th-14th July 2005.
10. Vanden Bussche, K., Froment, G. M., *J. Catal.* **161**, pp1-10 (1996).
11. US Energy Information Agency Natural Gas Statistics, www.eia.doe.gov/emeu/international/gas.html