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DEPLOYMENT OF LOW AND ZERO EMISSION FOSSIL FUEL POWER GENERATION IN EMERGING NICHE MARKETS

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ABSTRACT

The opportunities for near-term implementation of low and zero-emission fossil fuel power generation using Carbon Capture and Storage (CCS) is emerging in niche markets. This is primarily motivated by regulations following a growing awareness regarding the potential impact of climate-change, and partly the opportunities for use of carbon-dioxide (CO2) with enhanced oil recovery (EOR).

However there remain significant technology, engineering, investment and political barriers that need to be overcome before CCS can be accepted as commercially mature for the power generation industry and the finance community. The risk with early projects is high, while collaboration and trust between government, industry and investors will also be needed to commercialize the technology.

With an emerging sense of urgency regarding a global consensus for tackling climate-change, one also observes that technology pathways are integrated with political agendas and it becomes important to roadmap a commercial strategy for the respective technologies taking account of government requirements for compromise and burden sharing. To some extent this can also impact on comparative choices for the most cost-effective technologies that are supported through to future commercial deployment.

The situation is complicated by the fact that technology choice—be it pre-combustion, post-combustion or oxy-combustion—remains an open question, where parties are probably influenced by their historical expertise, available hardware and near-term perception of future carbon challenge. The fact that energy, materials and engineering costs have been escalating rapidly while there is also a fundamental paradigm change occurring, somewhat undermines the use of historical data and past experience to predict business opportunities for the future.

Within this context the paper considers on-going carbon market evolution in three regions, namely Texas, North Europe and Canada, seen from a technology and project developer perspective. The paper applies updated project engineering costs for capture from natural gas (NG) and coal using post- and oxy-combustion technology. Under all circumstances projects still exhibit poor economic return on invested capital and depend on government participation; they therefore remain unattractive to the investment community.

But perhaps more important is the current perception of technology and market risk which also appears to undermine motivation to make significant commitments when evaluating projects within the old paradigm. However such a situation is not politically sustainable and a new paradigm must emerge.

This will occur through regulation and significant changes in pricing in the energy and commodity market—including valuation of captured and avoided CO2. And this will also impact on the relative merits of various technology options.

For the time being these discussion and results are only indicative of how a new paradigm and evolving technology may become “game-changing”, but the paper does attempt to provide some foresight into future opportunities.

NOMENCLATURE

CER’s	Certified emission reductions
CDM	Clean Development Mechanism
CoE	Cost of electricity
EPC	Engineering, Procurement & Construction
EOR	Enhanced oil recovery
ETS	European Emissions Trading System
IGSC	Integrated Gasification Single Cycle
JI	Joint Implementation
NGCC	Natural Gas Combined Cycle
O&M	Operations & Maintenance (Opex)
TIC	Total Investment Cost (Capex)

TECHNOLOGY AND EMERGING MARKET

The emerging consensus regarding the future impact of climate-change [1], and our own individual experience to date, leads us to presume that;

"The business of carbon cannot be managed using our established ideas, economic practices and vocabulary that has evolved along with our dependence on fossil fuels … therefore there is a paradigm shift currently underway."

By recognizing the above, we are better equipped to understand the early niche market opportunities and implement emerging new technology. This then accelerates introduction of commercial projects within the new regime.

The New Paradigm[1] for Carbon Management

The concept of "paradigm shift" was first introduced in 1962 by Kuhn in his book *The Structure of Scientific Revolutions* [2]. Simplified, he poses the question, which ideas were thinkable at a particular time? And then tries to explain how the "unthinkable" became accepted. In so doing he also creates a non-linear understanding and interpretation of scientific development. Kuhn's terminology has subsequently been applied to many disciplines—not only in the philosophy of science, but also politics, society and business.

Our understanding and reaction to climate-change will probably become categorized by future historians as a classic example of a "paradigm shift".

Already, the period from the *Brundtland Report* [3] in 1987 and through to a post-Kyoto "consensus" for action—that has yet to be achieved—will have extended over at least 25 years. But the development so far appears to be consistent with Kuhn's three phases before a new paradigm has emerged.

In the first phase there is discord regarding observed anomalies. The research is considered scientific in nature but is characterized by incompatible, often conflicting and incomplete scientific explanations. Proponents are polarized but eventually gravitate to a more uniform consensus regarding the problem and suggest revised methodologies while adopting new terminology. This introduces a second phase where normal science prevails, but it is applied in a revised context to further investigate and address the anomalies.

The third phase is a period of revolutionary science and is often associated with a time of crisis when research has fully revealed the fundamental anomalies, identified clear weaknesses of the old paradigm, and new methodology is implemented. This also heralds an opportunity for disruptive technology change, deployment of alternative engineering solutions, while "new truths" evolve into becoming accepted in the revised paradigm. The whole process occurs over time and is often difficult to perceive until after it has occurred.

[1] In the philosophy of science ***paradigm*** is a mode of viewing the world which underlies the theories and methodology of science during a particular period of time (see *Oxford English Dictionary*, Oxford University Press.)

A New Vocabulary and Methodology

An overview of any scientific or current affairs article discussing carbon reveals how the new vocabulary has already infiltrated the old paradigm. Interestingly the text of the Kyoto Protocol [4] signed December 1997 contains no reference to CCS and mentions "carbon sequestration" only once. In fact the concept of capturing and permanently sequestering carbon dioxide, as a methodology for mitigation of GHG emissions to atmosphere, has only truly become mainstay during the past five years. And it has yet to receive formal recognition as a means of avoiding emissions to the atmosphere within the scope of flexible mechanisms envisaged in the Kyoto Protocol[2]. However one assumes that governments will address these issues for the post-Kyoto period currently being negotiated [5].

But there remain some significant challenges regarding measurement, verification, remediation and long-term monitoring that need to be accepted by legal and financial markets before CCS methodology can be implemented for power generation. In this context, we are probably only just moving into Kuhn's phase two where it becomes acceptable to discuss the issue within a revised economic and fiscal framework.

COMMERCIALIZING CCS TECHNOLOGY

The commercial barriers for introducing CCS technology are also significant. Over the past 40 years the gas-turbine Brayton cycle in combination with the Rankine cycle has evolved to completely dominate large-scale and efficient power generation [6]. The latest H-technology has cost manufacturers several billion Euros to develop, but with an ever increasing price for energy, then breaking the 60% barrier for NGCC efficiency should be a sound technology investment to secure future sales into a predicted €8 to €10 billion per year turbine market for the coming decade [7].

The main industry challenge is now improved combustion design to reduce emissions while raising firing temperatures beyond 1,430 °C as this is becoming standard. The focus is also on extended operations between maintenance and further improvements in reliability and availability. Construction costs have risen significantly during the past 36-months but the industry is experiencing growing demand despite longer delivery times; these are welcome signals for a sector that is only now recovering orders following a slump in 2001-04.

Although IGCC has yet to become as reliable and cost-competitive as NGCC it provides additional multi-fuel flexibility in a market that will continue to experience fluctuating energy costs in the decade to come. And lastly, both power cycles have "capture ready" capability for when the cost of not emitting CO2 can justify upgrading to CCS.

[2] There are currently only two projects within the proposed new category of "Geologic CCS" that are awaiting recognition. These are the *White Tiger Oil Field CCS Project* in Vietnam (NM0167) and *Capture of CO2 from the Petronas LNG Complex* at Bintulu with injection offshore near Sarawak in Malaysia (NM0168). For updated status see Methodologies for CDM Projects at;

http://cdm.unfccc.int/methodologies/PAmethodologies/publicview.html

Is Carbon Capture and Storage Disruptive?

Disruptive technology (and innovation) was originally described in 1995 by Bower and Christensen [8] at Harvard Business School and popularized in 1997 by Christensen in the book *The Innovator's Dilemma* [9]. Subsequently the terminology emerged in diverse disciplines including product development, management strategy and commercialization roadmaps. Danneels [10] critically and succinctly reassesses much of the ensuing debates.

The detailed mechanism varies somewhat, but initially the new technology does not satisfy the minimum requirements of mainstream performance and is considered inappropriate by incumbents in the market having to address the needs of their customers; like renewables CCS has a higher cost of electricity. However there may exist a niche market segment which values other dimensions of performance where the emerging technology excels; initially for CCS it may be EOR, and for oxyfuel in particular, there is also negligible NOx emissions.

Ideally over time, as research and development (R&D) progresses and the technology matures, then performance and market conditions may change to the extent that the technology can satisfy "revised" demand from the mainstream customers. However as the *Stern Report* [11] explains, for power generation the "gap" appears too large for introduction of CCS technology to occur based on conventional market mechanisms. It is only a combination of nurturing technology innovation, regulation and government policy that will change the requirements of the markets and customer expectations.

Indeed, even the current focus on renewable energy (wind and photovoltaic in particular) has only come about following significant government support and favorable fiscal mechanisms providing new entrants with a niche markets. A similar development has yet to happen for wave power [12] while geothermal power generation has only evolved in certain regional markets (e.g. Iceland, Italy and New Zealand) where it is evidently a cost-effective alternative to imported fossil fuel. Similarly in many third world countries biomass remains a primary source of fuel because of its availability.

However all new entrants have faced significant barriers to market entry. And for CCS to be adopted into the power generation sector—with its very long investment periods—it is particularly important to recognize the barriers and possible catalysts that accelerate introduction of the new technologies.

But all these things take time and some believe that the CCS option will only occur in combination with the paradigm shift and a crisis. The paradigm shift is that carbon emitted as CO2 to the atmosphere is harmful to future life on this planet and "Business as Usual" (BAU) will detrimentally impact the global GDP [11]. The crisis is that non-fossil energy (i.e. a combination of new renewable, hydroelectric and nuclear) is nowhere close to providing our energy requirements. At the same time coal (and oil) will continue to be available for several generations to come.

THE COST OF ENERGY FOR POWER GENERATION

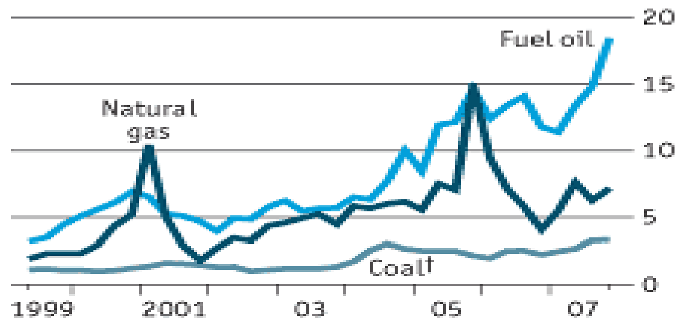


Fig. 1: Cost of Energy in US$ per GJ based upon Fuel Oil, Natural Gas and Coal for period 1999-2007 [13].

Fig. 1 shows energy cost in US$ per GJ over the past 8 years. Both Fuel oil and Natural Gas (NG) have risen while fluctuating considerably since 2004. By comparison coal is cheap—but it has in fact almost trebled in price [13].

The rise in crude price from $15 per barrel in 1999 to ~ $100 during 2008 has meant that much more oil (and tar sands) can now be recovered economically. Over time, with deep-water exploration and advanced production technology, there is probably little shortage of oil—but it will be more expensive and located in geopolitically unstable regions of the world. This however will also strengthen the role of tertiary EOR production from the existing reservoirs.

By comparison the steady increase in the price of coal from ~ $40 in 2004 to around $140 per ton has not been as dramatic but is a clear indication of growing global energy demand. The main challenge appears to be with logistics.

The price for NG is much more regional, and dependent upon fuel-switching strategies. The key point to note is that in the range of $6 to $8 per GJ then transport using LNG tankers becomes economic and so supply (and interim storage) can grow to accommodate varying regional and seasonal demand.

However the relative pricing between oil and coal has already resulted in old collieries reopening in South Wales; utilities like Enel in Italy are fuel-switching from imported oil to coal; China has become a net importer and the United States is now exporting coal to Romania [13].

Certainly, for the time being, a move into coal provides a safer haven from price volatility in the oil and gas markets. By 2012 German RWE plans to have invested €6.2 billion on three conventional plants. Despite coal having a much larger carbon footprint, this is market forces signaling that CCS technology will emerge via coal—but only when political consensus regarding policies for climate-change have been resolved.

Given a future requirement to implement CCS technology, then coal is also a good place to start. However, regarding technology pathways, it may also be sensible to initially prove some of the new technologies using NG before tackling the added complexity of gasification and the cleaning of syngas.

THE COST OF CARBON EMISSION

Many studies have been reported on the cost of carbon management [14], CO2-capture [15] and avoidance, and life-cycle analysis. The NETL [16] study is comprehensive. The author [17] and colleagues have also contributed, but we have not recently conducted a formal review of published material. A general impression based upon our on-going project work is that estimates are escalating due to increased labor, raw materials and energy prices. However comparison between different CCS technology options continues to remain similar.

Typically up until 2005 results quoted in the literature indicated that costs varied roughly from \$35 up to \$75 /tCO2 depending upon the project location and whether one was quoting cost for capture, sequestration, avoidance, etc. Nowadays we suggest that similar numbers apply—but in Euros! Nevertheless, overall spread of current estimates remains large and is also indicative of considerable uncertainty.

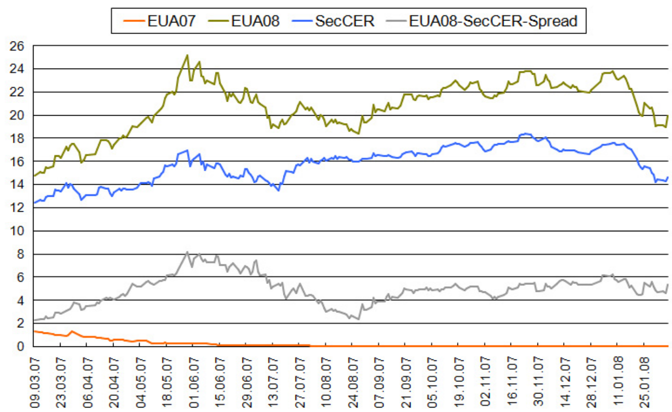


Fig. 2: Cost in € /tCO2 for EU Allowances from Mar-07 to Jan-08. The EUA07 were valid 2005-07 while EUA08 are valid for 2008. The Secondary CER's are created with CDM projects and valid throughout the 2008-12 period.

In the near-term, it is politicians and regulators that will determine the cost of carbon and can stimulate technology. An example of this has been the Norwegian CO2-tax for offshore installations that was introduced in 1991 and has varied in the range €20 to €35 /tCO2. This has not been sufficient to trigger major investments in new capture technology offshore. But was sufficient to justify nearly one million ton per year (mtCO2/yr) injection into Sleipner, which is now a well documented pilot project for CO2 sequestration, verification and monitoring [18].

Another example of how regulators can intervene is shown in Fig. 2 for the ETS. In May 2007 the price of EU Allowances (EUA) for Phase I ending in Dec 2007 slumped to below €0.05 /tCO2 and never recovered because the National Allocation Plans [19] had been too lenient—this obviously impacted on the credibility of the early market [20].

However allowances for Phase II from 2008 have remained above €20 /tCO2 while the cost of CER's from CDM projects is now ~ €15 /tCO2. Furthermore, after Jan 2008 non-compliance by a member state will suffer a fine of €100 /tCO2!

A sensible strategy for credit allocation combined with "carrot-and-stick" are just examples of a portfolio of mechanisms that regulators will gradually introduce to stimulate growth of a well functioning market in the future. And despite the early Phase I price failure, the ETS is becoming a more robust market that is starting to evolve—many participants have seen similar behavior before in other tradable markets such as energy, electricity, SOx and NOx.

But there is still some way to go before carbon traders can operate in a fully mature financial market. In particular the ETS still appears to be fraught with risk associated with recognition of CDM and JI projects, as well as the registration and issuance of resulting CER's. There is also risk associated with the transfer of credits to national carbon registry accounts and there is general pricing uncertainty inherent in building and trading a carbon portfolio. Neither is it clear regarding the extent to which countries will be permitted to supplement their national efforts with CDM projects abroad. One does not truly expect these issues to be resolved until after completion of Phase II in 2012 at earliest.

At the same time the World Bank estimated [21] that the global value of carbon transaction grew from \$11 in 2005 to \$30 billion in 2006. Point Carbon, a leading market analysts, recently predicted [22] that transactions in 2008 will be 4.2 GtCO2 having an estimated market value of \$90 billion. With growth the market is also developing carbon specific derivatives designed to protect against volume and price exposure, thereby mirroring developments that have already occurred in, for example, weather derivatives.

And What Role for CO2 – EOR?

The use of naturally occurring (underground) CO2 for tertiary enhanced oil recovery (EOR) has been standard industry practice in North America for more than 25 years. In the Permian Basin, West Texas ~ 220,000 bpd incremental oil is now being produced with over 30 mtCO2/yr. It is also estimated that from 2000 to 2005 the contract price for commodity

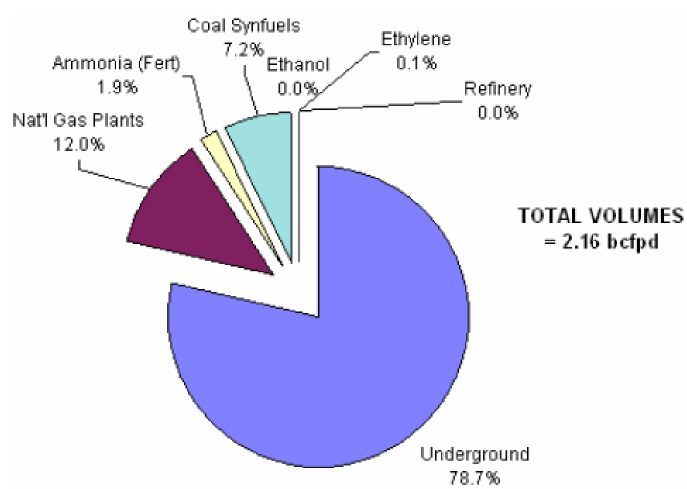


Fig. 3: Over 42 mtCO2/yr is currently used for CO2-EOR in the United States. Nearly 80% is from underground sources.

CO_2 rose fourfold to above $30 per ton, driven by higher oil prices and more open market trading. During the past 3 years the U.S. market for CO_2 has grown ~ 15% to more than 40 mtCO_2/yr (2.16 bcfpd) as shown by Fig. 3. But with a constrained supply-side the proportion of underground CO_2 has actually reduced from 81 to 78.7% indicating that over 2.2 mt anthropogenic CO_2 has also come onto the market.

This trend will now no doubt accelerate because there is already an estimated shortfall of up to 10 mtCO_2/yr into the Permian Basin [23]. And during 4Q-2007 contracts for additional CO_2 to on-going CO_2-floods were made at above $40 per ton. A "rule-of-thumb" has been that CO_2 value in $ per ton can be up to three-quarter the $ cost for a barrel of oil [24].

With rising demand for oil, CO_2 and power (for compression), the Permian Basin is now a recognized niche market for early deployment of CCS technology.

CCS Incentives, Legislation and Liability

Furthermore in Texas there has since 1989 been in place an *EOR Severance Tax Incentive* scheme ensuring reduced tax rate of 2.3% on the market value of oil for the first 10 years of CO_2-EOR production. This is at one-half of the standard rate.

In Jan 2008 the Legislature also adopted an *Advanced Clean Energy and EOR Tax Reduction Bill* which reduced the effective tax rate for use of anthropogenic CO_2 to 1.15% for the first 7 years of CO_2-EOR production [31].

Also to encourage the development of CCS technology the State is establishing joint industry grant awards and loan guarantees through to 2020. And as part of the *FutureGen Texas* consortium the *Railroad Commission* has set a precedence that the State may also take on long-term ownership and liability[3] of the CO_2. To our knowledge, there is currently no other arena (in the world) that has available such a comprehensive package of market incentives, legislative measures and policies helping to clear the pathway for investment decisions and implementation of CCS with EOR projects.

In Europe the scope of CO_2-EOR is not so advanced: there are a few smaller onshore CO_2-floods in Hungary [25], but offshore has so far only been studied [26], [27] by many [28]. In North Norway Statoil have recently extended their experience at Sleipner and constructed an 8-inch pipeline to inject 0.8 mtCO_2/yr from the LNG plant on Melkøya into a deep saline aquifer formation 160 km offshore at Snøhvit.

But for the mature North Sea fields CO_2-EOR remains a challenge for the operators who still need to have guaranteed supply[29] and incentives[30] to develop a CO_2-flood industry.

The Political Path Forward for CCS

The idea that carbon as a commodity becomes for the 21st century what oil was for the previous century is not wholly unreasonable. And it is evident that the future role of politicians for determining the price of carbon in the next decade can be as influential—if not more—than was the role of OPEC for fixing the price of oil in the past three decades. One difference appears to be that OPEC could control the supply side, while regulators effectively can control the demand for carbon reduction.

At the same time, as the *Stern Report* [11] concludes, it is being recognized that despite niche opportunities, market forces alone will not guide the transition process successfully so that one overcomes the initial barriers to introducing CCS technology. The main reasons are as follows;

- The power sector has very long lead-times for invested capital. There is therefore significant "lock-in" to existing technology and infrastructure.
- The political signals and path forward is still not being clearly presented to the business community in a trustworthy manner and carbon storage has yet to be adopted as a recognized GHG mitigation measure.
- There remains serious discussion regarding alternative pathways that would favors renewable energy or nuclear power. The EU Commission is developing a policy strategy for CCS [32] but this needs the full support of the EU Parliament, and will only get a first-hearing in 2010 with ratification later.
- Commercial-size demonstrations will be expensive, but are required to prove the complete CCS value chain [33]. However in the mean time, industry is also fully occupied with the business constructing new plants under the old paradigm.
- There are significant legislative and commercial aspects that also need to come into place alongside investments in CO_2-handling, transportation, storage, monitoring and remediation.

Despite the cost of electricity (CoE) with CCS increasing, it remains the only meaningful alternative to "Business as Usual" and it appears that the technology will inevitably be deployed.

And with high energy costs and depleting production reserves, it is probably a combination of government, oil prices and the stock market that can best decide if, and how soon, CO_2 will also become part of the final North Sea hydrocarbon era [34].

UPDATED ECONOMICS FOR CARBON CAPTURE

From 2000 to 2007 the *Power Capital Cost Index (PCCI)*[4] had risen 131% overall and, most notably, by 27% compared with the previous 12-months as is shown in *Fig. 4*. Furthermore since 2005, delivery of most equipment has increased[5] by ~50%. In combination with volatile energy costs and regional

[3] The question of liability is very important for anyone wanting to be an early mover in the CCS arena. And in most markets this is still not resolved to an extent that major investment decisions can or should be made!

[4] The PCCI tracks the costs of equipment, facilities, materials and personnel (both skilled and unskilled) used in the construction of a geographically diversified portfolio of more than 30 power generation construction project throughout North America. It is similar to the consumer price index (CPI).

[5] CO_2 compressors, for example, now have a lead-time of 36-months.

market differences, it is therefore important to understand prevailing limitations of on-going cost-estimate studies.

Despite such introductory caution, we present results from two recent engineering studies for a standalone amine CO2 capture plant at the newly commissioned 420 MW_e NGCC plant at Kårstø, on the West Coast of Norway shown in Fig. 5.

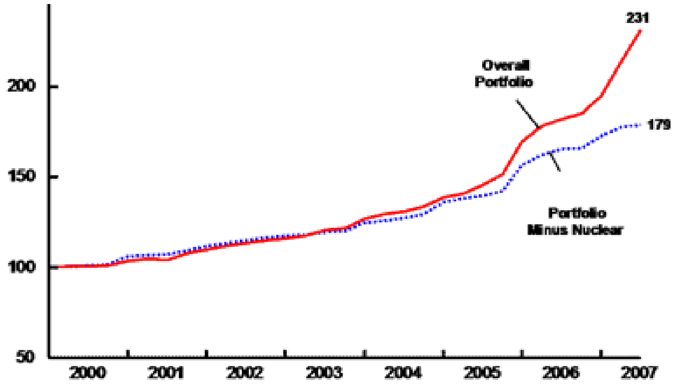


Fig. 4: Engineering costs index for the North American market since 2000. (Source: www.ihsindexes.com)

We use a standard net present value (NPV) analysis with an initial Capex investment followed by annual income and operating expenditure over a 25-year project duration.

- Plant efficiency is 59% (LHV) with 92% availability.
- Construction is over 2 years with equal split for TIC.
- All O&M costs are 5% of TIC unless stated otherwise.
- Analysis is before tax with 10% discount rate.
- Fuel gas Gross heating value is 39.0 MJ/Nm^3.
- Currency is 5.50 NOK / US$ and 8.00 NOK / €.

Scenario-I assumes (from Fig. 1) that cost of NG stabilizes at $10 /GJ which is ~ €25 /MWh of gross energy input. From Fig. 2 one may also infer that the EUA settles at €25 /tCO2.

In Scenario-II it is assumed that carbon becomes a more critical issue and that carbon credits are difficult to generate. Legislation tightens and the EUA rises to €50 /tCO2. This results in some fuel-switching to cleaner NG which also rises to €50 /MWh. Historically this would be a high gas price, but reflects tighter EU supply from Norway, Russia and North Africa in combination with some LNG import. We also assume that oil prices stimulate CO2-EOR and tax incentives can guarantee a floor price at €25 /tCO2. The scheme is self-funding through increased tertiary oil production [35], while market price-restructuring also could open a new and lucrative "high-priced" offshore electricity market. (This is despite the somewhat subdued conclusions based upon analysis using the existing paradigm [36].)

The Base Case NGCC Power Plant

Norsk Hydro has been owners engineer during construction of the Kårstø NGCC power plant and they have indicated a TIC of €250 million (€595 /kW) for the turnkey plant supplied by Siemens as originally negotiated in 2004. Recent cost escalations suggest that a new plant in the same area would cost around €700 /kW.

Fig. 5: The NGCC Power Plant at Kårstø, West Norway.

The calculated basic CoE is €62 /MWh of which 76% covers energy and remainder is capacity charges (i.e. all other non-energy costs). The CoE assuming that EUA's must be purchased at €25 /tCO2 then becomes €70 /MWh.

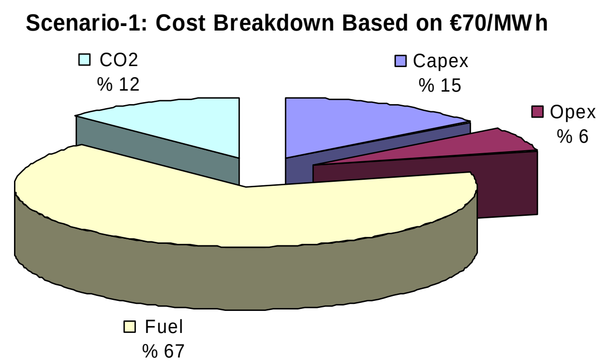


Fig. 6: CoE breakdown for a conventional NGCC power plant assuming energy at €25 /MWh and EUA at €25 /tCO2.

The results in Fig. 6 reveal that for the NGCC plant, fuel would represent 67% of the overall CoE while carbon credits would be 12% of the total electricity production cost.

A similar analysis for Scenario-II—where the fuel and carbon costs have doubled—results in CoE of €126 /MWh with fuel representing 75% and carbon credits now 14% of the CoE.

Depending upon how rapidly this scenario impacted the price of coal, then some utilities might feel forced to adopt post-combustion CCS technology to remove CO2 from existing and new-build pulverized coal-fired power plants because the technology could be implemented with lower risk than for a new IGCC requiring CCS. Such early market driven stimulus would also create additional opportunities and further lower the cost of post-combustion CCS technology.

The NVE Amine CO2 Capture Plant at Kårstø

The Norwegian government has indicated a strong commitment to early deployment of CCS technology and in March 2006 the Norwegian Water and Energy Authorities (NVE) were charged with the task of assessing a complete CO2 value chain that would sequester 85% of the CO2 emitted from the Kårstø NGCC power plant.

The NVE Report [37] was published in Dec 2006 (in Norwegian) and indicated a total overall investment cost of NOK 5 billion (€625 million) for the standalone amine CO2 capture plant, together with a pipeline infrastructure and offshore injection into aquifer storage as shown in Fig. 7.

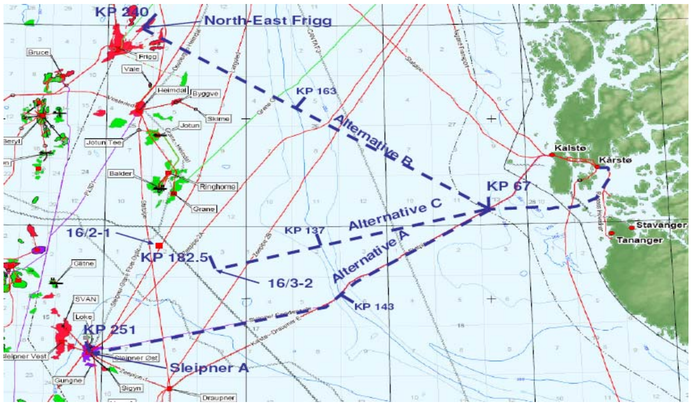


Fig. 7: Overview of alternative pipeline routes for transportation and saline aquifer storage of ~ 1.2 mtCO2/yr from the Kårstø NGCC power plant, in West Norway and out into the Norwegian sector of the North Sea. The existing injection of CO2 at Sleipner is shown near bottom left of the image.

The Report concluded that cost for capture and storage was ~ €90 /tCO2. This was based upon a detailed engineering cost analysis and pipeline estimates from several major equipment suppliers. As such it qualifies as an important update regarding engineering costs for a complete CCS value chain.

Although the Report used some different assumptions compared with our own economic analysis methodology it is possible to reuse their cost-estimates (± 40%) for the amine CO2 capture plant and deduce direct comparison with our own work. The main differences are as follows;

- We do not include pipeline transportation and offshore injection as this is too project site-dependent and outside the scope for comparison of the capture technologies.
- The NVE used discount rate of 5% while we use a more standard value of 10% for comparative analysis.
- We assume market price for electricity is €70 /MWh as calculated in Scenario-I; NVE assumed €45 based upon the then prevailing onshore electricity tariff.
- The amine plant captures 85% of the CO2 produced. We assume the remaining 15% is emitted to atmosphere and must be offset through purchase of EUA's.

We have applied the same cost-breakdown for amine plant annual operating expenses; variable cost was €5.75 million while maintenance was a fixed 2.5% of TIC.

These revised assumptions resulted in a TIC of €727 million for the combined NGCC and amine capture plant at Kårstø. The net electricity production is 354 MW_e yielding a specific cost of €2 050 per kW installed. This is almost three times compared with the standalone NGCC power plant (but includes 15% contingency). It is still significantly greater than what has been published in earlier feasibility studies, but is based upon cost-estimates from the OEM's that are in line with price escalations reported by others.

Notably, although the main cost-driver was project TIC, only ~ 45% of this was directly attributable to the EPC contract for the amine capture plant. And nearly one half of this was already determined by material and labor costs.

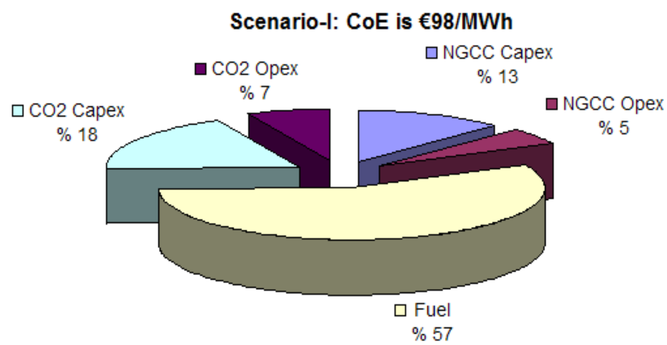


Fig. 8: CoE breakdown for the NVE Amine CO2 Capture Plant assuming energy at €25 /MWh and EUA at €25 /tCO2.

In Scenario-I the resulting CoE is €98 /MWh, which is €28 higher than the Base Case of €70 /MWh. This equates to €102 /tCO2 captured.

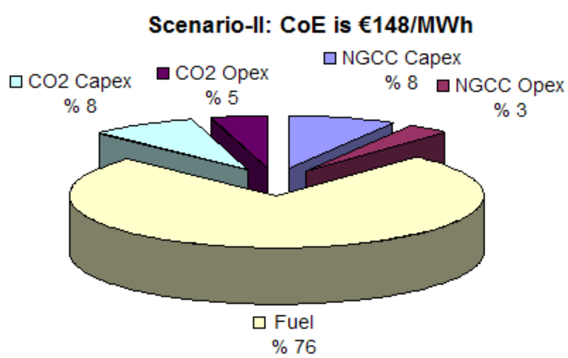


Fig. 9: CoE breakdown for NVE Amine CO2 Capture Plant assuming energy at €50 /MWh and EUA at €50 /tCO2.

In Scenario-II the CoE is €148 /MWh but the comparative cost for CO2 has reduced from 25% to 13% because CO2 is also sold at €25 /t for EOR thereby creating some (but not sufficient) additional income for the cost of capture is €111 /tCO2 compared with cost of the EUA at €50 /tCO2

Norsk Hydro Study for Amine Capture at Kårstø

The Norsk Hydro project organization also conducted an independent assessment of the cost for amine capture plant at Kårstø, given similar operating conditions as the NVE Report.

The Hydro Study [38] was undertaken during 2007 and drew upon site experience from the organization that participated in construction and commissioning of the NGCC power plant. Their ± 40% cost-estimate for a "First Build" Amine CO2 Capture Plant assumes equipment cost to be €60 million while TIC lies in the range of €450 to €640 million as shown for their "high" cost-estimate in Fig. 10. This includes 17% contingency, but can be compared with €430 million for the similar plant described in the NVE Report from 2006.

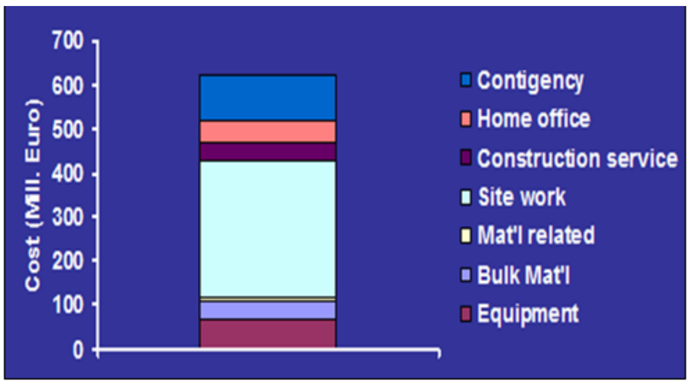


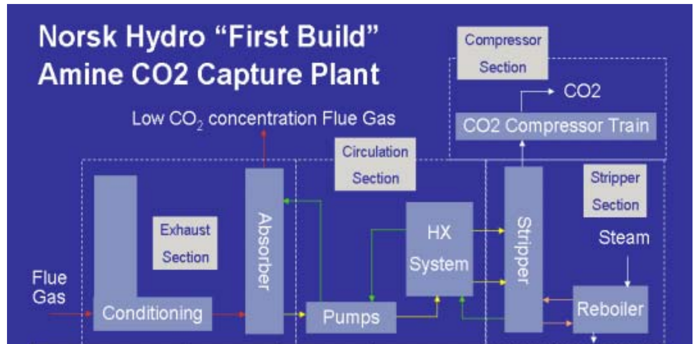
Fig. 10: Breakdown of Total Investment Cost (TIC) for Amine CO2 Capture Plant based on the "high" cost-estimate.

The two studies are based upon reasonably consistent equipment lists and costs provided by *Mitsubishi Heavy Industries, Fluor, Bechtel* and *AkerKvaerner*. However equipment and materials only represent one-sixth of TIC. By contrast, on-site work, construction services and project administration represents over two-thirds—this is one major distinguishing feature between the two studies. As such the Norsk Hydro Study may include a useful indication of cost escalation when moving into FEED and construction.

Power consumption for the capture plant reduces overall efficiency by 11.5%-point. Furthermore there will be CO2 emissions associated with transportation, injection and storage. Although Norsk Hydro does not include pipeline transportation and offshore injection, they do suggest that avoided CO2 is only equivalent to 75% of the captured CO2; despite capturing one million ton per annum only three-quarter of this would eventually be recognized as a reduction in emissions to atmosphere and thereby be converted to a carbon credit.

The question regarding how such a "new build" plant may generate credits is also a complicated issue that is subject to the methodology governments chose to distribute, auction or sell credits within their respective allocation schemes—this too needs to be addressed in future CCS methodologies.

The Norsk Hydro Study also documents the potential for technology innovation and cost-reductions for a future optimized plant. Fig. 11 shows the breakdown of overall power consumption for the "First Build" plant to be 83.5 MW. This compares with 66 MW in the earlier NVE Report.



Plant Section ==>	Exhaust	Circulation	Compression	Stripper (Steam)	Total
Power Consumed	19.0	1.8	16.7	46.0	83.5 MW_e
Efficiency Loss	2.6%	0.2%	2.3%	6.3%	11.5%-pt
Equipment Cost	60%	4%	28%	8%	€ 60 mill.

Fig. 11: Overview of energy consumption and cost for a "First Build" full-scale Amine CO2 Capture Plant at Kårstø.

The NVE had originally assumed a power consumption of 27-30 MW_e for fans, pumps and CO2 compression while Norsk Hydro indicates it may be higher at 37.5 MW_e. The difference is primarily because of more detailed estimates for pressure losses throughout the capture plant. In both studies CO2 compression is similar at 0.11 kWh /kg CO2 which we note is also in good agreement with our own studies.

Plant Section ==>	Exhaust	Circulation	Compression	Stripper (Steam)	Total
Power Consumed	19.0	3.5	15.7	32.4	70.6 MW_e
Efficiency Loss	2.6%	0.5%	2.2%	4.4%	9.7%-pt
Equipment Cost	53%	5%	34%	8%	€ 46 mill.

Fig. 12: Overview of energy consumption and cost for a "Future" optimized full-scale Amine CO2 Capture Plant.

For steam supply to the absorber / stripper both studies considered supplementary heating but concluded with having a reduced power output from the HRSG section of the main power plant. The NVE assumed the equivalent of 36 MW_e parasitic loss, while Norsk Hydro on the basis of having done a more detailed assessment of issues regarding integration with the NGCC power plant, concluded 46 MW_e for "First Build".

However with future optimization this could be reduced to 32 MW_e as indicated from Fig. 12. Overall the amine capture plant would still constitute a 10%-point reduction in overall power plant thermal efficiency. Any further reductions will most probably be due to future improvements in solvents to be tested at the new *European CO2 Test Centre Mongstad* [39].

Lastly, it was indicated that equipment cost could reduce significantly from the "First Build" with €60 million down to €46 million as additional plants are deployed commercially.

Discussion for NG Post Combustion Capture

The results presented for the Amine CO2 Capture Plant at Kårstø[6] are summarized in Table 1 below. Compared with earlier studies these results are important because they are based upon recent work by OEM's and engineering project organizations that have conducted detailed engineering studies with the intention of also making future investment decisions.

SCENARIO-I 2006 (±40%)	NGCC Power Plant	NVE CO2 Amine Plant	Norsk Hydro Study	
			First	Future
Capex (€ mill)	294	727	934	744
Opex (€ mill)	14.7	33.9	46.7	37.2
Load (MW_e)		66.0	83.5	70.6
Exhst & Circlt^{n}		13.0	20.8	22.7
Compression		17.0	16.7	15.7
Stripper		36.0	46.0	32.2
Output (MW_e)	420.0	354.0	336.5	349.4
Capex (€/ kW)	700	2 052	2 774	2 129
LHV Efficiency	59.0%	49.7%	47.3%	49.1%
CoE (€/ MWh)	61.6	97.6	115	101
CO_2 (kg/ MWh)	349	62.1	65.3	62.9
CO_2 (€/ tCO_2)	**25.0**	**102**	**146**	**110**

Table 1: Summary of results presented for the NGCC Power Plant at Kårstø with proposed Amine CO2 Capture based upon recent studies by NVE [37] and Norsk Hydro [38]. Results are for Scenario-I that assumes Natural Gas energy cost at €25 /MWh and EUA at €25 /tCO2.

The indicated cost for CO2 capture is above €100 /tCO2 and considerably higher than has been previously published for similar engineering studies. At the same time the results provide a reasonable assessment of the challenges for developing NG-based post-combustion CCS technology in Norway and (probably) the North Sea rim countries.

Our main conclusion regarding this North European scenario is that for investors the "technology gap" and risk remains too large to compete with their other investment opportunities. As such it may only be bridged through additional market incentives (or regulations). A market could emerge if government were to integrate its policies for climate-change together with fiscal incentives, offshore electrification and CO2-EOR—but that is also a complex challenge!

[6] The Kårstø NGCC Power Plant completed commissioning 3Q-2007 and is somewhat unique in that the owner Naturkraft AS received permits in 2001 to emit CO2 (against purchase of emission reduction credits). However subsequently the Norwegian government has for political reasons established an independent project organization (Gassnova SF) that is now charged with capturing CO2 from the flue gas without essentially interfering with power plant operations. The exact commercial implication for such an arrangement is not self-evident, but the situation has resulted in the two engineering case studies (described here) having been conducted. Gassnova indicate that full FEED will be completed during 2009.

UPDATED ASSESSMENT OF STATUS FOR OXYFUEL

In this context introducing oxyfuel as an alternative technology options for CCS is also challenging and complicated by the fact that it still needs to commercially demonstrate a "new" process cycle.

With extensive development work [40] oxyfuel is also diverging along two different paths and one now distinguishes between the atmospheric oxy-boiler (or "indirect") combustion cycle, as shown in Fig. 13, and the "direct" high-pressure (HP) "oxy-burn" cycle that specifically benefits through development of more advanced oxy-turbines.

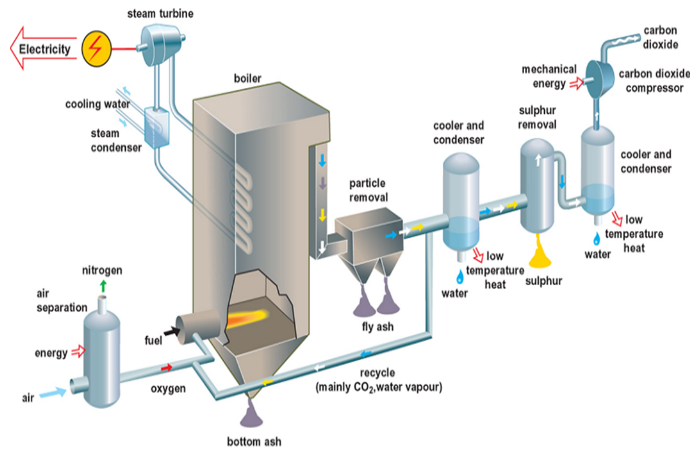


Fig. 13: Schematic of the Doosan Babcock atmospheric oxyfuel boiler process cycle.

Oxy-boiler technology is being pursued by among others, Vattenfall [41] and the consortium led by Doosan Babcock [42] which recently completed a very detailed cost-comparison between amine-based CO2 Capture and oxyfuel for the Canada market [43]. The results in Table 2 are "partly" comparable with those from the Norwegian study presented in Table 1.

Canadian Market 4Q-2006 (±30%)	ASC Ref. Plant	New Build		Retrofit	
		Oxy	MEA	Oxy	MEA
Capex (€ mill)	1 172	1 632	1 547	1 892	1 554
Opex (€ mill)	9.1	9.6	14.0	10.5	15.3
Gross (MW_e)	542.0	570.5	480.5	568.7	484.1
Output (MW_e)	503.4	400.2	391.3	392.3	394.1
Capex (€/ kW)	2 330	4 080	3 956	4 826	3 944
LHV Efficiency	45.6%	36.2%	35.4%	35.5%	35.7%
CoE (€/ MWh)	43.2	65.7	65.7	74.3	66.1
CO_2 (kg/ MWh)	790	80	100	90	100
CO_2 (€/ tCO_2)	—	**31.8**	**32.5**	**44.5**	**33.4**

Table 2: Summary of results for sub-bituminous Advanced Supercritical coal-fired power plant as reported by Doosan Babcock et al. comparing Amine CO2 Capture with Oxyfuel in the 2006 Canadian Market. (Coal price used was €9.3 /ton.)

Although the Canadian study did not include a credit penalty for emitted CO2, the cost-estimates are applicable for the prevailing North American market as of 4Q-2006.

Not surprisingly comparison between the two Tables confirms that it will be significantly cheaper to extract CO2 from coal in North America than from NG in North Europe (see also recent work by NETL [44]).

More pertinently Table 2 underlines an emerging consensus that "New Build" oxyfuel may now be considered to have similar costs as the amine-based CO2 capture technology. Given that both *Air Products* and *Mitsubishi Heavy Industries* participated in the study consortium—they are major stakeholders of respective technologies—then this is a clear signal to the market that there is still a technology comercialization roadmap that remains to be unfolded.

Brief Overview of High-Pressure "Direct" Oxy-Cycle

The high-pressure "direct" oxyfuel cycle is presumed to originate with the pioneering work of Werner von Braun during the 1930's using oxygen and hydrogen for auxiliary power generation in the emerging field of rocketry. Historically it is worth noting that after the Second World War the technology seems to have dispersed along with the German scientists to evolve comparatively independently with work in the Soviet Union [45], [46], Austria [47] and the United States [48], [49]. For further historical details see also [50].

Many attributes of the cycle are currently being developed by different organizations among which are the US-DOE[51], *Clean Energy Systems* [52], Siemens Power Generation [53], *Graz University* [54], the Norwegian company *ZENG AS* [55] and recently Jacobs Engineering [56] in the UK.

But why is using (expensive) oxygen and developing new oxy-turbines also one of the paths forward for carbon capture?

The Case for Oxygen-Based CCS Technology

There are some good reasons why oxyfuel is emerging as a competitive and cost-effective technology for CCS. One of these is associated with the difference between our Scenario-I and II. Specifically if emission of carbon becomes expensive—which it eventually will do—then a direct oxy-cycle has a zero-emission capability and should inevitably be more competitive than a low-emission option that continues to emit ~ 15% of the carbon in the fossil fuel—NOx will be costly too!

Furthermore with increasing oil price CO2-EOR should become more accepted for tertiary recovery in maturing oil regions. Sales revenue on that final 15% of CO2, in contrast with having to purchase allowances for the same CO2, will also have an impact on the resulting overall cost for capture.

It is also important to note that oxyfuel is net water positive and fully condensing process cycle that utilizes the gross heating value of the fuel in contrast to the open Brayton cycle which is limited to the lower heating value. For NG the difference in available thermal input is effectively over 10%.

The Air Separation Unit

With the Brayton cycle, nitrogen (in air) acts as a diluent during combustion, but also absorbs work[7] and reduces the partial pressure of emitted CO2 thereby increasing the size of apparatus for flue gas desulfurization, selective catalytic reduction and CO2 capture.

For oxyfuel cycles the Air Separation Unit (ASU) is the largest additional cost-factor. It typically represents about one-third of total Capex and consumes ~ 0.25 kWh/kg O_2 representing 8 to 10%-point on overall efficiency. However, once accounted for, the ASU also permits considerable simplification for the remainder of the process cycle, which now becomes more "comparable" with a conventional steam cycle and can be based upon "available" power plant technology.

Furthermore the ASU is still being considered as stand-alone and is based upon mature cryogenic technology. There are recognized opportunities for integrating the ASU with the oxy-power cycle and possibly the CO2 compression, cleanup and drying process—these have yet to be seriously evaluated. However development efforts are targeting reduction of Capex by one-third and energy by one-quarter in the 2015-2020 timeframe [57].

Stoichiometric Oxy-Combustion

A significant development for oxyfuel technology has been demonstration and deployment of the Gas Generator developed by *Clean Energy Systems (CES)* based in Sacramento, Ca.[58]. The company has since 2002 tested and proven [59] their 20 MW_t Gas Generator and have since 2005 deployed it for oxy-power generation [60] at their Kimberlina Power Plant, near Bakersfield, Ca. The company will during 2Q-2008 also be testing their latest 170 MW_t Gas Generator.

In addition to the Gas Generator the core commercializing technology for power generation is the turbine expander. At Kimberlina CES have to date used an existing steam turbine as a first generation proof-of-concept machine, but are now deploying more advanced turbines for power generation [61].

Advanced Cycle Development and Design

The unique feature of the Gas Generator is that it enables high-pressure and high temperature stoichiometric combustion creating a drive gas comprising of steam with some CO2 that is then delivered to a suitable turbine expander at any desired pressure and temperature within a design envelope of 40 to 240 bar and 600 to 1,600 °C.

Thermodynamically this also permits new process designs [62], [63], [64] and allows for integration of the best features of the Brayton and the Rankine cycle into what will become "advanced" oxyfuel cycles which can also be uniquely adapted for CCS.

These cycles tend to distinguish between the high-pressure (HP), intermediary pressure (IP) and a low-

[7] We sometimes note that oxyfuel is not so much about oxygen, but more about there being no nitrogen in the main process!

pressure (LP) section, while obviously targeting different turbine inlet temperatures at each pressure level.

The HP section is typically “Rankine-based” and currently limited to a maximum temperature of ~ 565 °C in line with available steam turbine technology. The challenge here is upgrading existing blade material to be compatible with also permitting ~ 10%-mol CO2 in the modified process fluid. In future one will target temperatures up to 700 °C as this also becomes available for advanced supercritical steam turbines.

The IP section is “Brayton-like” and where oxy-turbine development and testing is currently being focused. The operating pressure is typically ~ 40 bar, but this also depends somewhat on cycle design. It is justifiably the IP firing temperature that is the most important design parameter for achieving higher efficiencies in the advanced cycles.

With commercial deployment of near-term projects then this could increase rapidly from 760 °C that CES is currently testing on a modified LMA 1500 (also termed GE J79) at Kimberlina (using un-cooled turbine blades) up to ~ 1 050 °C (with blade-cooling) as is being studied for a Westinghouse 251B turbine (now SGT900) together with *Florida Turbine Technology* and *Siemens Power Generation* in Orlando [61]. Meanwhile above 1 240 °C is currently being targeted for the ZENG Demonstration Plant at Risavika around 2012 using state-of-the-art materials and blade-cooling [55].

Such continuous proof-of-concept along with commercial demonstration will be pre-requisite technology steps towards deployment of advanced oxy-turbines targeting CET of ~ 1400 °C in the 2015+ timeframe [51]. This should also make possible cycle efficiencies around ~55% (LHV, inclusive of oxygen supply and CO2 treatment) thereby creating competitive opportunities for zero emission power generation within a decade. Such a development Roadmap for the HP oxyfuel cycle is currently being proposed by multiple partners in the United States, Norway, Netherlands and the UK.

Finally, to mention that it is probably in the LP section that cycle designers can, with careful attention to thermal management and the thermodynamics of condensing binary phase fluids contribute significantly to overall cycle performance.

CONCLUSIONS

This paper presents an overview of a new market that is evolving very rapidly. The complexity of understanding commercial aspects combined with technology and political considerations regarding climate-change and carbon capture and storage (CCS) is challenging.

This is because the arena is evolving within a paradigm change where valuation of technology, projects and business opportunities remains difficult to quantify while there is no recognized “level-playing field” or price on the main product which is clean power. This statement is valid independent of how the power is produced, be it renewable, fossil or nuclear.

Because of the continued dominance of fossil fuels the situation will remain diffuse until the true cost of “avoided” carbon emission to the atmosphere can be quantified much more precisely than is presently the case.

Furthermore, it is the opinion of the author that the whole market will continue to be volatile at least until after the Kyoto period ends in 2012 and there comes a political consensus as to how the global community shall value its efforts.

In the mean time there will continue to be significant opportunities for new investments, but these will be combined with high risk. For this specific reason the development of pre-requisite technology demonstration and infrastructure investment projects will remain limited to government supported activities combined with R&D funding from the major industrial companies.

Financially this is already creating an investment bottle-neck with capital being available at a time when global carbon emissions are rising due to growth in the developing countries. However the investments are not being made because investors remain uncertain as to the direction and depth political commitment and where to invest.

Our own experience as project developers, suggest that it is not so much details of the technology nor the initial costs that will in the longer-term be recognized as having been the main barriers, but instead alleviation of liability, risk and access to loan-guarantees in order to initiate the first-mover full-size projects [65].

In this context, to get things in perspective, it is pertinent to note that sometimes simply the impact of depreciation modeling or tax incentives can have a significantly greater influence on project net present value than early introduction of advanced technology or improved project cost optimization schemes.

And in the present economic situation one of the greatest challenges has also been simply acquiring the use of engineering resources in an industry that is already struggling to keep abreast with orders while doing business as usual.

ACKNOWLEDGEMENTS

CO2-Global is currently developing CCS projects using both post-combustion and oxyfuel technology similar to that described in the present paper.

The author and colleagues in CO2-Global are also indebted to on-going collaboration with many individuals, groups and companies that are currently promoting CCS and are mentioned in this paper.

We also acknowledge that the information presented here is probably an incomplete overview based upon information from many parties, including some that through limitation of space have not been mentioned.

However the paper is intended to inform about status and overall opportunities for more rapid deployment of CCS technology. Many thanks to all that have contributed to date.

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