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The conference organised by the Oxford Institute for Energy Studies on issues of oil price volatility and price swings was held on 9 October at St Catherine's College. It brought together participants from governments, oil companies, academia, and banks. It was an important event. We are happy to publish here a summary minutes of the discussions (without attributions) written by Bassam Fattouh and Paul Segal; and an article by Robert Mabro where he attempts to classify views on this complex subject under a number of 'streams of thought'. The conference was so interesting that the organisers could not keep Asinus, this stubborn, intrusive but charming beast away from it. In this issue of *Forum* Asinus muses exclusively on the themes of the conference.

The longstanding debate on whether 'speculation' or 'fundamentals' drive oil prices in the futures exchanges of New York and London was only resolved by arguing that speculation cannot be clearly defined (which is surprising) and by the more cogent observation that speculators also hedge and hedgers are implicitly speculating by taking a view on a particular price.

The fundamentals of supply and demand are not available in real time. This is inevitable. There are delays in the production and distribution of reliable data. Traders do not know what the state of the fundamentals is at the time when they operate on derivatives markets. They try to guess using proxies or non-oil variables about which information is immediately available. It seems that in the absence of solid information about current fundamentals, views about their likely state in the medium or long term are an important oil price determinant. Not the only one of course, otherwise the oil price will not move. Views about the long term do not change from day to day.

Notwithstanding all that, views expressed by participants were sometimes so different as to induce some scepticism about the prospects of a consensus on ways to prevent the future reoccurrence of a huge oil price swing. Such a consensus between the main parties with interests on the world oil scene is the necessary condition for designing and implementing remedial action.

In the previous issue of Forum

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OXFORD INSTITUTE FOR ENERGY STUDIES

we included articles on wind energy. This inaugurated a series on renewable energy and technological developments that may affect world demand for oil. We continue with a review of a book detailing the extraordinary achievement of William Kamkwamba, a young Malawi boy, who managed to build a small windmill and obtain electricity in his dark room, then his home, then his village.

In this issue of *Forum* we have two articles on solar power, a source so abundant that it could cover a high multiple of current world energy requirements, but so expensive to harness as to drastically constrain its development. Malcolm Keay assesses with his renowned objectivity the challenges facing solar and its prospects by asking the question: Will solar energy find its place under the sun? The answer is yes but only if costs can be significantly brought down. Despite considerable efforts and some progress this objective has not yet been achieved.

Till Stenzel describes in an interesting contribution the Desertec initiative, a plan to develop solar energy production in North Africa to supply the electricity needs of the region and export the surplus to Southern Europe. The difficulties are assessed. But the author ends with an optimistic note pointing out that many academics, policymakers and private companies are working hard to solve the economic problems involved. They will 'make Desertec a reality, not in the distant future but much sooner than many skeptics may think.' Let us very much hope that the initiative will succeed.

The problems of oil production are catching media headlines. The decline in Norway's production together with decline in the UK Continental Shelf, Mexico and other countries are providing ammunition to the proponents of the peak oil theory. The Norwegian situation is authoritatively discussed by Lars Erik Aamot, a high official of the Ministry of Petroleum and Energy. Another headline that caused some excitement was about an increase in Russian oil exports that put that country ahead of Saudi Arabia. Shamil Yenikeyeff argues that this apparent achievement is more of a glitch than the beginning of a trend. He points to the many factors that hinder investments in the oil sector, mainly but not exclusively the fiscal regime.

Finally, another important topic addressed in this issue is the pricing of natural gas. In this respect there is a fundamental difference between the pricing of oil and gas in international trade.

There is greater consistency in the pricing of oil than in gas where there are different pricing systems resulting in significant differentials not only between different regions of the world (the USA, Europe, and the Far East) but within the same region. This is the case in Europe. Howard Rogers, noting that the same gas in Europe is priced at $8 per million Btu if imported from Russia or Algeria, and only $3 per million Btu while spot gas in the UK is selling at about $3 per million Btu, asks: Why? And more importantly: is this structure sustainable.

All the topics in this issue are subject to debate because of fundamental differences of views. Surely readers have much to say about this or that subject that happens to interest them. They are warmly invited to put pen to paper and send a letter to the Editor expressing their opinions. We will be publishing them to foster debates.

Contributors to this issue

LARS ERIK AAMOT is Director General, Oil & Gas Department, Ministry of Petroleum and Energy, Norway

BASSAM FATTOUH is Director of the Oil and Middle East Programme, OIES

MALCOLM KEAY is Senior Research Fellow, OIES

JUDITH MABRO is an editor and author

ROBERT MABRO is Fellow of St Catherine's College, Oxford

HOWARD ROGERS is Senior Research Fellow, OIES

PAUL SEGAL is Research Fellow, OIES

TILL STENZEL is at NUR Energy, London

SHAMIL MIDKHATOVICH YENIKEYEFF is Research Fellow, OIES

Oil Price Volatility

Bassam Fattouh and Paul Segal consider causes and mitigation strategies

On 9 October 2009, the Oxford Institute for Energy Studies held a one-day conference in Oxford on '**Oil Price Volatility: Causes and Measures of Mitigation Strategies'.** The conference focused on three themes: the role of fundamentals and financial factors in explaining the recent sharp swings in oil prices and the marked increase in price volatility; an assessment of the plans and strategies currently pursued to dampen oil price volatility; and the potential measures that could be adopted to mitigate the impact of sharp swings in the oil price on the energy industry. The group of participants included key senior figures from government, oil companies, the financial industry, and academia. The conference was conducted under the Chatham House Rule of non-attribution. This note contains a summary of the proceedings.

Oil Prices: Speculation or Fundamentals?

The sharp swings in oil prices in the last two years have polarised views about the drivers of these movements: some believe that prices are driven by fundamental determinants, and others argue that 'speculation' has contributed significantly to price movements. Many participants agreed that this dichotomy between fundamentals and speculation is unhelpful: there is no clear definition of 'speculation' as all actors in the market are, in fact, taking a view on future prices, and one cannot distinguish between 'speculators' and 'hedgers'. While one can distinguish between financial and industry players, there are no consistent differences in their behaviour – witness the huge forward sales for 2009 that Mexico made in 2008. Moreover, financial players do not operate in isolation of the physical parameters and are often driven by oil market fundamentals.

On the other hand, there clearly are traders who do not pay any attention to oil fundamentals, and to whom the oil price is just a number on a screen, to be predicted using short-run computer models. Such people have a stake in oil price volatility because their trading profits depend upon it. Whether they have any substantial impact on the oil price, however, is a different question. A problem will only arise if their trading distorts prices away from a 'correct' level that would give appropriate signals to producers and consumers.

It was broadly agreed that the idea that the oil price can be 'sliced' into components – e.g. that $X of the price are explained by fundamentals and a further $Y by speculators – is confused.

Oil must be understood as both a physical good and a financial commodity, and it is expectations of future fundamentals that drive the price at the far end of the curve. One striking feature of the market during the price rise that occurred until mid-2008 was that the far end of the curve rose with the prompt price, implying that expectations of future fundamentals were changing with the prompt oil price.

The key question is whether the oil market is a helpful contributor to price discovery, or whether the large fluctuations in the oil price are inefficient and destructive. Short-term price fluctuations such as occur on a daily or weekly basis were agreed to be of little importance for policy makers. Views differed, however, on the big price swings. Some argued that very high oil prices reflect a genuine demand for more oil, which is helpful because it incentivises a supply response through investment. Others, on the contrary, said that they were not helpful and merely caused uncertainty and disruption, noting that the large movements of mid-term futures prices implied that the market was evidently failing to correctly predict future prices, and therefore failing to aid price discovery. On the other hand, future fundamentals are extremely uncertain and it would be wrong to pretend that anyone really knows what the correct price will be in the future.

Further complications in the oil market include the following. First, the market has a large cartel. Second, prices are not determined by marginal costs, because the supply curve is not smooth but very lumpy. If anything, costs follow prices through demand for inputs rather than the other way around. Third, the market is extremely opaque. Physical trades outside financial markets in particular are very un-transparent. Moreover, producers' reluctance to share information about their reserves means that no one really knows how much oil there is underground.

> "futures prices implied that the market was … failing to aid price discovery"

The question of the oil majors' behaviour on futures markets was raised. It was noted that they typically have a policy of not selling forward, on the basis that investors bought their shares because they wanted exposure to the oil price. Some questioned this logic, observing that investors can get direct exposure to the oil price through appropriate securities and futures contracts, and that buying shares in a company necessarily involves taking a view on the management of that company as well.

It was noted that there is lack of liquidity further along the futures price curve, and that the market performance would improve if there were more liquidity. There were concerns that new regulatory measures could further decrease liquidity at the back end of the futures curve.

Mitigating Oil Price Volatility: Issues and Current Proposals

The motivation for regulating the oil market is to reduce the incidence of big oil price swings, the view being that they are unhelpful to both producers and consumers. Widespread concern was expressed at the possibility that regulation of energy markets, aimed ostensibly at reducing undesirable volatility, may in fact hinder legitimate and useful activity. Many energy producers use financial products in order to finance investment, and if such products were regulated away then these producers would be unable to get financing. There is a lot of political pressure on the US government to be seen to be doing something to stabilise markets and this may lead to poorly thought out action. The G20 position is to increase transparency and data collection rather than regulate which financial products are to be allowed.

Regulation of banks more generally should not be conflated with regulation of energy markets. There may be too little competition in the banking sector, and there was an under-pricing of risk.

Most activity on oil markets is by consumers and producers of oil, as opposed to financial actors. As already mentioned, the largest IOCs typically do not buy or sell forwards, but most other oil companies do.

Financial actors can be divided into four broad camps. Macro hedge funds trade in a range of markets, not just commodities. They have a top-down approach and take a view on macroeconomic issues. Specialist commodity hedge funds are more bottom-up, using large quantities of data and taking a strong view of fundamentals of supply and demand. ‘Black box’ hedge funds have a view of the oil price based on calculations known only to them. Finally, institutional investors typically put between 0.5 and 8 percent of their funds into commodities for the sake of portfolio diversification. They tend to sell when prices are high and buy when they are low, stabilising the market, owing to (price-weighted) limits in their portfolios. It is rare now for institutional investors to want aggregated standard commodity indices; they usually prefer more bespoke products.

Banks have been the largest traders of oil since 1985. What has changed is that banks have become more involved in physical trade, e.g. bridging the gaps between producer and consumer clients.

It was argued that the real problem for ‘price discovery’ on the basis of ‘medium-term fundamentals’ is that such fundamentals do not exist: there are too many unknown variables, including supply, oil technology, alternative technologies, demand and so on. Given these facts, transparency may help a bit, but not a lot. Perhaps we have to live with this uncertainty, in which case regulating markets won’t solve the problem.

This view was disputed on the basis that a range of fundamentals such as OPEC decisions and changes in global demand do have the expected effect on the oil price.

From the point of view of energy demand, subsidies are a large problem as they distort the market by increasing demand. The Middle East is a major subsidiser, and China used to be, but no longer. Fiscal difficulties in the face of the rising oil price led to a number of countries reducing subsidies.

Oil Price Volatility: Potential Policy Responses

ENI have a proposal to stabilise the large swings in the oil market because high prices hinder global growth, while low prices reduce investment both in oil production and in alternative energies. The proposal is based on two pillars: the first is the establishment of a global energy agency to represent both producers and consumers, and to present transparent, timely and complete information on the oil market; the second is the introduction of some tools to stabilise the oil market, which would involve both spare capacity and global oil inventories. At present spare capacity is not remunerated, so it needs to be.

An alternative proposal by Robert Mabro is to establish a committee that could be given the role of determining reference oil prices, based on as objective a view as possible on market fundamentals. It was suggested that there might be analogies with the delegation of interest rate determination to the Monetary Policy Committee of the Bank of England. International agreement would be required to allow the committee to operate.

Two major problems were discussed. First, agreeing on the right price for oil. Second, operationalising any proposed regulation, which is problematic given that commodity price agreements historically have not worked well. It was also suggested that a stable price might even be undesirable if it meant a failure to change when fundamentals changed, and thus a loss of useful price signals. On this basis a crawling price band might be appropriate.

“regulation of energy markets … may in fact hinder legitimate and useful activity”

Some thought that merely publicising a ‘reference price’ or ‘focal point’ for oil, even in the absence of formal mechanisms to enforce it, might act to stabilise the market. The recent relative stability of price between about $60 and $80 was seen by several participants as the results of comments by King Abdullah to the effect that $75 was a reasonable price. If the USA were to make a similar statement then the effect may be even more robust.

One of the major consequences of oil price changes is the distributional impact. Even if we decide that the price of petroleum products to consumers should be high, e.g. in order to incentivise energy efficiency, the question still remains whether this is to be achieved through taxes in rich countries or through a high oil price. The former benefits consumer countries, the latter producer countries. Even if no reference price or stabilisation mechanism is agreed, we should look to ameliorate the negative consequences of high oil prices for poor oil importers.

The producer–consumer dialogue can be an informal mechanism for dampening price movements. However, doubt was expressed over the possibility of any real understanding between producers and consumers, whose points of view are too opposed to reach any such agreement.

General Discussion and Summing-up

The discussion in the conference illustrated the complexity of oil markets, and it should come as no surprise that deriving an efficient price that accurately reflects market fundamentals may not always be feasible. This has been compounded by the fact that factors outside the market such as macroeconomic news could influence the price formation process. Although the sharp swing in oil price was mainly an oil story, the big collapse and the recent behaviour of oil prices were less related to oil market developments. It was also recognised that investment upstream involves two marginal costs: high costs where IOCs operate and low marginal costs in some OPEC countries. Any price within this wide band could equilibrate the market. Some participants also raised the issue of depletion rates, which imply a premium above long-run marginal cost. This factor is likely to become more important in the future. Others pointed out that fiscal issues in oil-exporting countries are likely to be fundamental for pricing in the future.

There was more-or-less an agreement that lack of regulation in the oil market was not the major cause of the oil price swings witnessed in the last few years, and that some proposals for regulation now may have limited effects or even be potentially problematic.

It was also accepted that while the futures markets are key for price discovery, the links between spot (physical benchmarks) and futures prices remain unclear. In private, IOCs and NOCs always complain about the lack of transparency in the price formation process in the physical markets, but they are reluctant to raise the issue in public. One of the participants argued that allowing some of the crudes with large underlying physical supply to be re-traded in the market would create a very liquid and transparent market, and would cause the imperfect WTI benchmark to wither away. However, such an argument did not receive wide support.

It was recognised that a serious problem in understanding the oil market is the discourse itself. Terms such as ‘transparency’, ‘price discovery’, ‘speculation’, and so on, which are not clearly defined by those who use them, just add to confusion. A second problem is the lack of serious efforts to look for alternatives to the current system. If parties are disturbed by big swings then they have to think seriously about alternative pricing regimes. There are different possibilities with advantages and disadvantages, but they must be discussed and studied.

One of the participants considered that such radical actions are not necessary as it is not obvious that the high volatility is in fact a big problem. It has not derailed investment and the industry can cope with it. The wider political and economic effects should be dealt with in the context of macroeconomic policy. In fact, it could be argued that counter-cyclicality in the global economy has played a stabilising role. In contrast, some argued that the reason the oil market witnessed volatility in the first place is related to the fact that the world economy did not react in the way one would have anticipated – the high oil price did not lead to a slow down when expected, so the feedbacks from the world economy were muted. However, not everyone agreed, and some pointed out that feedbacks were present – especially through the squeeze on real incomes in oil-importing countries.

It has been suggested that, in some instances, when there is great uncertainty, the market can coordinate on public signals. Although such signals don’t carry much information, they are particularly relevant because of the beauty-contest nature of the market – people care more about what other people think than about the reality.

This led to an interesting idea relating to the role of the producer–consumer dialogue. The distribution of the rent between producers and consumers cannot be part of any agreement because it is a zero sum game. But the dialogue does not have to be about rents. If, for example, it is assumed that production cannot go beyond 95mb/d, it is clear that there is a future need to increase efficiency and/or develop more non-conventional energy. Then it might be possible to get consensus on how to achieve the level of 95mb/d – for example by funding marginal projects. There was a general agreement that in the current market circumstances, this would require something like a price of $60–80. Such signals concerning price preferences, supported both by producers and consumers, could help stabilise market expectations, with positive effects on reducing oil price volatility.

Robert Mabro looks at oil price swings

The big oil price swing that occurred in 2007–9 has worried governments from oil-exporting and -importing countries. The main fact is well known. The price of WTI as it arises in the New York futures exchange (NYMEX) increased to an unprecedented height of more than $140 per barrel in early July 2008, and then collapsed in a free fall to a low of $32.40 per barrel in December 2008, less than six months later.

Regulators were asked whether their lax approach to the working of the derivatives market was responsible for this destabilising swing. Some US senators want to revamp the regulatory system. The UK approach is to seek the solution in an enhanced oil producer–consumer dialogue and to seek more transparency rather than new regulations.

Prime Minister Gordon Brown went to Jeddah in search of a joint solution with Saudi Arabia. President Sarkozy and PM Brown published a joint article in the *Wall Street Journal* (8 July 2009) arguing that the problem of oil market volatility must be urgently addressed. Interestingly, they claim that 'governments can no longer stand idle'. But no concrete measures were specified other than a call for greater transparency and for greater co-operation between producers and consumers in the context of the International Energy Forum.

Different views about the oil price swings and possible remedies are being expressed in numerous articles and other publications, and in many seminars. The purpose of this article is to report on, and assess, these views by classifying them in relation to different streams of thought.

Views Related to the Economic Theory of Finance

The efficient market hypothesis is central to this approach. The main propositions are that prices reflect all the available information. The market is a mechanism for price discovery, and the prices discovered carry useful information. Market concentration (cartels, big players and so on) and lack of transparency distort prices. In the absence of such distorting factors prices follow a random walk. This is essential for 'efficiency' as it makes predictions impossible, and ensures that no participant enjoys advantages over others.

All economists recognise that markets suffer from imperfections, but the thinking of some is wedded to the essential features of the 'efficient market' paradigm. It is remarkable that nobody in this context has mentioned the late Professor Dornbush's article on the inherent tendency of financial markets (foreign exchange in his article) to over-shoot. Interestingly, some empirical studies appear to show that price behaviour in futures oil markets does not correlate with any variable that characterises activity in these markets. No correlation seems to exist between price movements and changes in the volume of transactions, the volume of open interest, the composition of participants, trading in index funds and so on. The question, of course, is whether the methodologies used are sharp enough to identify *marginal* changes instead of changes in averages that hide critical margins through a smoothing effect.

Assuming that the results of these studies are correct, two questions arise. To which variable, outside the activity of the market, do prices correlate? If the answer to this question is found regulators will have to focus on that variable, and radically change their thinking. The second question is: if no correlation is found, will this mean that prices move in a random walk? Some will argue that the answer, then, is probably yes. In that case we should ask: is it appropriate to use prices in a random walk in a market of a financial instrument, *efficient for its participants and nobody else,* as references in pricing formulae for some 45 or 50 million barrels per day of physical oil in international trade? If I became lost in some unfamiliar street would I ask a person walking in a strange random way for directions?

The Practitioners

For sure, many of them know how the futures market works, and some understand it very well. But they will never tell us the full story. A long on-going debate on whether 'speculators' or 'the economic fundamentals of supply and demand' determine the price is poisoned by the vested interests of those who promote this or the opposite view. Spokespersons from the financial sector will often argue that it is all about fundamentals. One may suspect that this is meant to keep regulators at bay. Those who have reservations about the role of financial players argue that it is all about speculation. It would help if they bothered to define 'speculation' with some clarity and rigor.

There is no way through which a futures market that operates in real time could get data on oil supply and demand instantaneously. There are data collection and distribution lags. The call for more transparency, admirable as it is, may improve the reliability of data (albeit up to a point) that only become available after a lag. One may argue, however, that reliable data arriving a month late on a regular basis will improve the market judgment on today's situation. This is correct. The problem, however, is to ensure reliability when OPEC's production is reported by journalists, the so-called 'secondary sources', commercial inventories by busy company staff who often delegate the job to inexperienced juniors, and when double-checking is too onerous and rarely, if ever, performed. And I am always intrigued by those who insist that reserves estimates have to become transparent and reliable as if the size of reserves in exporting countries is relevant to the determination of oil prices other than in the very long run.

"Presently, there is no reason why views about current fundamentals should be changing"

It is evident that the market cannot relate closely to the state of short-term fundamentals. It may rely on proxies, for example, weekly changes in US commercial oil inventories. These are simplistically interpreted as to mean that supplies are tight when the inventory level has fallen, and that supplies are abundant when the level has risen. This is a *non-sequitur* because a weekly change in inventory levels may be due to a host of logistical factors such as a delay in tanker arrivals or a bunching of arrivals, or to planning errors causing some companies to order when they nominate liftings more (less) than they will actually need when tankers arrive to destination.

Some argue that the market is moved by perceptions of the long/medium term (six or eight years ahead) supply-demand balance. These perceptions are influenced by proponents of the peak oil theory, as well as by statements considered authoritative made by the IEA, some major banks and some important consultancies. All those often expect that the oil market will be increasingly tight in the future because of demand growth in emerging countries (China and India) and failure of upstream investments to keep pace. In effect, those who hold these views, whether intentionally or otherwise, talk the price up.

Do not blame the bulls, therefore, who bid the price high; but just hope that those who are less bullish can create resistance before the price levels attained are too dramatically high.

Perceptions about the long term do not change rapidly. For this reason one would expect the back end of the forward price curve to display some stability. This is the Gabillon 'cantilever theorem' developed in an OIES publication many years ago. Recently this has not been the case. The back end of the curve has been moving despite the absence of news changing long-term perceptions.

The short term seems to rule. Presently, there is no reason why views about current fundamentals should be changing. Supplies are available even when demand rises because of the existence of significant surplus capacity in Saudi Arabia, Kuwait and Abu Dhabi. Furthermore, the term futures price structure is still in contango, meaning that the front market is well supplied. In the absence of significant oil news the market needs to look at changes in other variables. It seeks them in the financial realm: the exchange value of the dollar that leads traders to go long on oil when the dollar depreciates and short when it appreciates, and other financial indicators such as equity indices. Financial indices are interpreted as predictors of an imminent recovery. The implications for oil are obvious. Economic recovery leads to an increase in oil demand and to future price rises, which the futures market then anticipates.

The futures oil market is at all times a financial market but never as much as when there are no significant changes in oil news. Those who emphasise its importance as a mechanism for price discovery would be right if they specify their statement as 'the discovery of the price of a *financial instrument'*. The physical barrel of oil is a different commodity.

It is important to identify clearly the functions of the oil futures market. The first is that this market is the place where some agents hedge by buying or selling a futures contract (or taking a put or a call option) at a prevailing price that they wish to lock in. Speculators are those who have participated in bidding this price. The hedger/speculator paradigm means that one of the functions of futures and other derivatives is akin to an insurance system. The hedgers are in effect buying an insurance policy. If the market has no other function than this first one, the demand for hedging will determine its size. There can be no 'exuberant speculation' because hedging determines the volume of transactions.

> "It is in the use of futures prices as references for pricing oil in international trade that big swings matter"

The second function is to serve players (often called investors) who bet on prices when they form a view about future movements. They will sell when they think prices will fall, and buy when they believe that they will rise. Their counterparts are players who either take a different view or who wish to realise profits on earlier transactions. In this context, the market is a betting casino.

The third function of the futures market is that it generates prices that exporters use directly or indirectly as references in their pricing formulae.

Hedging (the first function) as an insurance policy is as meaningful as other insurances. One may pay too much in premia in relation to the risks involved, or secure a good bargain. Mounting a big hedging operation as the Mexican Central Bank did on more than one occasion may enable the hedger to obtain a higher price at a future date than obtained otherwise; usually, however, such large-scale operations bring prices down involving costs to those who had gone long.

Betting on prices (the second function) is akin to casino gambling. There are laws and regulations that apply to casinos. But how can they be applied to the derivatives markets without affecting other more useful functions?

Of course, gamblers usually hedge their bets. Hence, the prevalence of spread trading observed in futures markets. A spread trade involves two transactions. It generates therefore two flat price data by somebody who is not trading the flat price and is totally uninterested in its level.

It is in the use of futures prices as references for pricing oil in international trade that big swings matter. Big rises in international oil prices have an impact on most consumers. Big falls in prices cause delays in the implementation of projects, their postponement, and sometimes their abandonment. They affect the economies of oil importers when prices reach the sky, and the economies of exporting countries when they fall to abysmal levels. Low oil prices also worry OECD importing nations concerned about future supply security. (These worries may partly bridge the gap between prices preferred by producers and importers). Oil companies are also affected despite frequent public denials. Of course they are not going bankrupt but employees made redundant are entitled to feel badly affected.

It is difficult to say whether the oil price increases of 2007–8 were, together with the bursting of financial bubbles, the collapse of Lehman, the accumulation of toxic assets and the ensuing credit crunch, one of the causes of the economic recession. Yet, only a brave person would argue that future increases in oil prices above the current $80 per barrel level will be neutral in respect of the recovery of the world economy.

The Denying Game

We have already mentioned that some deny that speculation has anything to do with oil price movements on the grounds that it is impossible to define the term convincingly or because empirical studies failed to discover a correlation between activities in futures markets and changes in oil prices.

More vocally, many are now arguing that regulation is broadly irrelevant. They warn against the introduction of new measures that may cause collateral damage, or reduce liquidity, or induce traders to move their business from more to less regulated jurisdictions. In any case, they would say, regulation is more political than technical in nature.

Yet, hedgers need to be protected from any malfunctioning of the 'insurance' market. Regulators may want to protect the gamblers, politely referred to as investors, from manipulations and other malpractices. Although I have little sympathy for gamblers, the belief that they play a role in price discovery requires regulators to ensure that the game is clean.

For public relation reasons, we hear claims sometimes that oil price swings do not cause much damage. Even if this was true for private oil companies said to know how to adjust to adverse price movements, it may not be true for national economies.

Although I do not like to be associated with this group I must admit that I also do deny that the futures market is the right market to determine the reference prices for oil in international trade.

The Reformists

Dissatisfaction with the current price regime has led to the call by Sarkozy and Brown (as mentioned before) for governments to cease being idle. The CEO of ENI, Paolo Scaroni, made a presentation to a G8 Energy Summit meeting in Rome on a Blue Print for a Quest for Stability. This involves eight propositions introducing various ideas about institutions and policies. The scheme is complex but deserves thorough study and debate. Russia has ideas similar in one respect to the ENI proposal for a Global Energy Agency. I have also offered a contribution to the reform agenda (*Forum* no 74) which is based on the creation of an independent commission backed by a big research apparatus and an international convention that will set a reference price for oil once a month. This will take into account the state of the oil industry, spot and futures prices and other relevant parameters.

My call is for serious research on oil price regime alternatives. There are many other ideas that deserve evaluation. The argument that there are no alternatives to the current regime, made before any research is seriously done to assess the merits and drawbacks of other systems in relation to one another, is also a denial that thinly veils the powerful vested interests that either gain from the current situation or fear the possibility of unfamiliar changes.

Nothing needs to be done if everyone is comfortable with the current oil price regime. But in that case why do influential authorities worry, angst and complain about price swings?

The conclusion involves two simple propositions:

1. If something is to be done it should be done now when the oil market is relatively stable, not when we will be going through some new crisis.
2. Policy makers and regulators should focus on the real issue, which is the search for a new oil price regime. A less imperfect system than the current one may after all exist. All the talk and search for measures to improve the performance of the oil futures market through greater transparency, caps on the volume of transactions and so on is nothing but tinkering, necessary perhaps for other objectives than minimising the risks of destabilising price swings. Tinkering will fail to address effectively the issue of dynamic stability.

Problems of Oil Production

Lars Erik Aamot discusses the challenges facing Norway's oil production

Forty years ago the giant Ekofisk field was discovered on the Norwegian Continental Shelf (NCS). For Norway this was an event of historical proportions, which marks the beginning of the country's oil era. Oil production on the NCS commenced a couple of years after the discovery of Ekofisk. Production increased rather slowly in the first years, and as late as 1980 it stood at 0.5 million barrels per day (mbd) only.

From 1980 and onwards, production growth was much stronger, due to the build-up of production from several giant oil fields that had been discovered in the years between 1975 and 1985.

Generally, recovery from the oil fields proved to be higher than was expected by the geologists before the fields were developed. Particularly during the 1990s, Norwegian oil production increased quickly – and by more than was forecasted by the authorities. Advances in upstream technology, such as horizontal drilling, partly explain why production growth was so strong. Liquid production (crude oil and NGLs) in Norway peaked in 2001 at a level of 3.4 mbd. This ranked Norway the second largest oil exporter after Saudi Arabia at that time. From the start, no one had ever expected Norway to become an oil producer of this size.

Since the start of this century, we have seen a steady decline in production. The decline has occurred despite increasing oil prices and the industry investing more than ever on the Norwegian Continental Shelf.

In 2009 liquids production is estimated to be around 2.3 mbd or some 30 percent lower than the plateau level. For crude, the drop is almost 40 percent from the peak.

The decline in production since 2001 has been much steeper than Norwegian petroleum planners forecasted. We do not have a single good explanation as to why our projections for oil production in this period ended up to be too optimistic. But, as many other countries and companies have experienced, it is a demanding task to be correct when it comes to important issues like project slippage, production build-up and decline rates. Seen in hindsight, in Norway we underestimated the growth in production when we were in the build-up phase and underestimated the decline in production after 2001.

Despite the fall in production, Norway is still a significant supplier of oil. Our domestic consumption is small, so only a handful of countries export more oil than Norway today. And it has been of some comfort to us that gas production has continued to grow to the extent that total petroleum from Norway has remained fairly stable for more than ten years.

So, what is the outlook for Norway as an oil producer today?

The future depends to a significant degree on conditions that are beyond the control of the authorities, such as the geology of the NCS, available technology and crude prices. But it is also determined by the government and its resource management policies.

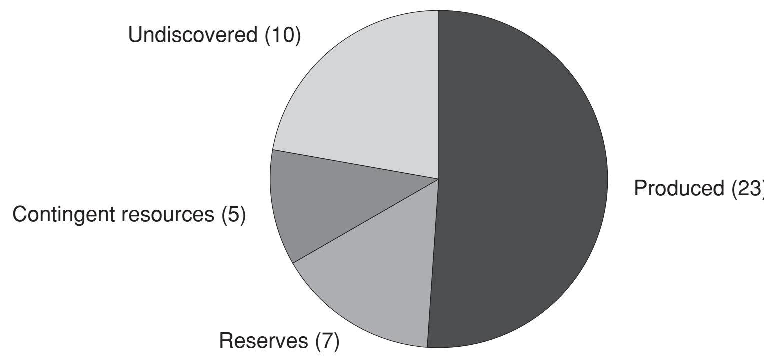
Even though recent production trends have not been positive, the prospects are by no means entirely bleak for Norway's oil sector. As we view it, some important issues for the country's future oil supply are:

- How much of the remaining resource potential will we be able to discover and produce profitably?
- Will we continue to see strong interest from the industry to explore for, develop and produce petroleum in Norwegian waters?
- Will we be able to find solutions so that petroleum activities can co-exist with other industries (fisheries, tourism) in all areas not yet opened for petroleum activities?
- Will the operators on our shelf be able to improve oil recovery rates even further?

Regarding the remaining resource potential on the NCS, it is quite considerable. The NCS is vast, its size amounts to 2.2 million square kilometres, of which half has bedrock in which petroleum may be found, and only half of that has been opened for petroleum activity.

on the NCS. In order to stimulate the entry of newcomers, the government adjusted the tax system so it no longer discriminates between incumbents and newcomers when it comes to treatment of exploration costs. The newcomers have brought more dynamism and competition into Norway's oil sector. This has been particularly important in the wake of the big oil mergers at the end of the last century and the increasing maturity of NCS as an oil province. To address all the different opportunities in our oil sector, we need both the contribution from the 'oil' players and the companies recently.

Figure 1: Distribution of total recoverable, liquids resources, bboe



Source: Norwegian Petroleum Directorate

Total resources on the NCS are estimated by The Norwegian Petroleum Directorate (NPD) to be 85 billion barrels of oil equivalent (bboe). Total recoverable quantities of liquids, including undiscovered resources, are estimated to be around 45 bboe (Figure 1), of which 50 percent is not produced yet. Half of the expected, remaining resources is yet to be found. These estimates are obviously uncertain, as large areas have few seismic data and no exploration wells. But clearly, there is a good potential left.

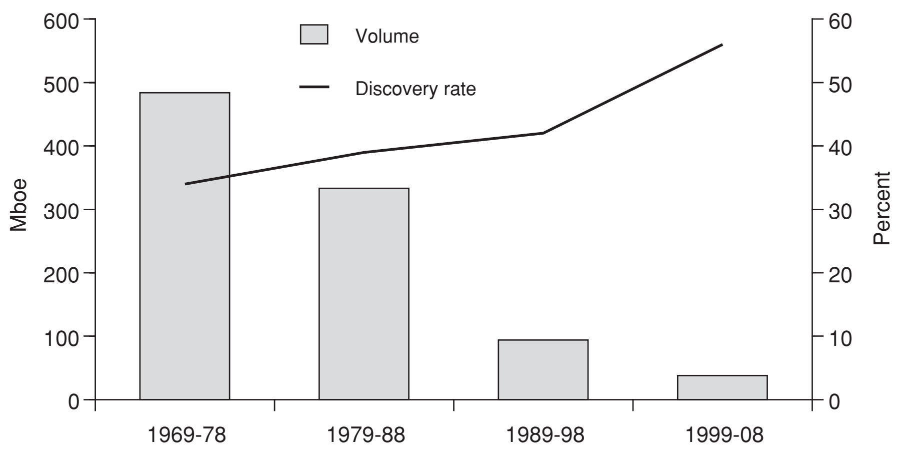
Only drilling can confirm what is in the ground. In the past years we have seen a strong interest from the industry to explore for and develop petroleum in Norway. This is encouraging.

In the course of the last ten years, 50 to 60 new companies have been prequalified as operators or licensees

Exploration activity has been quite good for many years. Last year saw a total of 56 exploration wells being drilled, the highest number ever. Field investments are also at an all time high, but this reflects the general cost inflation in the oil industry, and not merely the level of activity. The high level of activity indicates that the NCS remains an attractive place to invest for the oil industry. Although the resource potential might be higher in other places, fiscal conditions are reasonably attractive and have been stable for many years; in addition, the political risks are low.

However, exploration results have been somewhat mixed. Although the number of discoveries has remained high, field size has declined and more gas than oil has been found. (Figure 2) These results reflect the combination of a positive trend in the mature areas and a few disappointments in frontier

Figure 2: The average size of discoveries and the discovery rate



Source: Norwegian Petroleum Directorate

areas. Since 1994 no giant oil field has been discovered on the NCS. In 2000, eleven fields on NCS produced more than 100,000 barrels/day. Today the number is five.

But it is still possible to make large discoveries on the NCS, such as in deep waters in the Norwegian Sea, in the Barents Sea and areas not yet open.

The government recognises that the industry needs new attractive acreage if exploration activity is to be upheld and new reserves proven. In recent years the government has aimed at awarding licences close to existing infrastructure to be able to produce resources before the infrastructure ceases to be used. The government has also streamlined the policies for third party use of existing infrastructure.

Looking ahead, frontier areas are expected to hold the lion's share of undiscovered resources, although recent drilling results have not come up to the expectations of the authorities and the companies.

A fundamental precondition for petroleum activities on the NCS is the coexistence of the oil industry and other users of the sea and land areas affected by such activities. We have been successful in this regard for 40 years.

Earlier this year the Parliament decided to start an impact assessment for the waters around Jan Mayen. A decision on whether or not to license acreage in this area will be made when the impact assessment is finalised. Next year, a decision on how to go forward in our northernmost areas, including the prospective areas in the vicinity of the Lofoten archipelago north of the Arctic Circle, is expected. This decision will be taken in connection with the update of the so-called integrated management plan for the Barents Sea and the sea areas off the Lofoten Islands.

Increased recovery activities on producing fields are important for our short- and medium-term production outlook. Increased recovery from producing fields is likely to be a significant source of new oil supplies from the NCS. For a long time, improved oil recovery has been a high priority for the Norwegian authorities. On average, fields on NCS have an oil recovery factor of 46 percent. This is respectable compared with oil provinces in other parts of the world. However, it is probably possible to arrange for significantly higher recovery based on profitable production in the longer-term perspective. A small rise in the recovery factor may give substantial volumes of additional oil.

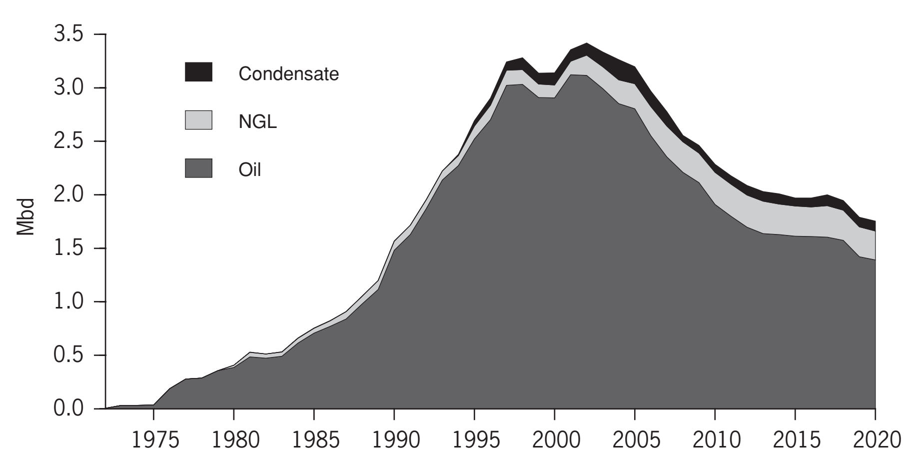
All fields on the NCS contain both oil and gas. Their recovery therefore cannot be viewed independently of each other. Injection of gas has in many instances been an effective technology to improve oil recovery on the NCS. As much as 30–40 bcm of gas – equal to one-third of total gas export – is injected into oil fields every year to maintain reservoir pressure and to stimulate oil production. Whether used for injection or export, the government will promote the use of gas that maximises the value to the society.

What conclusions about Norway's oil prospects can be derived from the considerations above?

It is clear that after 40 years of petroleum activities, Norway has moved well into the harvesting phase of its petroleum era. Nevertheless, its oil fields have many years left to produce.

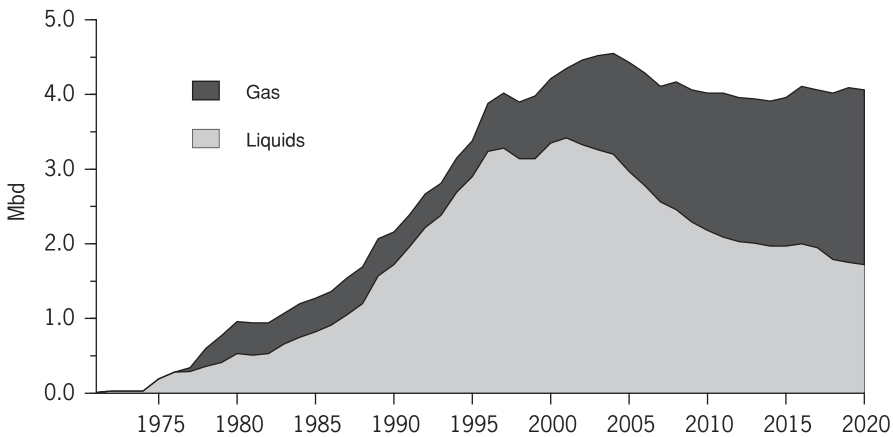
Future production levels are uncertain, but a continued fall in oil production is probably not possible to avoid. If our projections are right, Norwegian

Figure 3: Norwegian liquids production



Source: Norwegian Petroleum Directorate

Figure 4: Production of liquids and natural gas



Source: Norwegian Petroleum Directorate

liquids supply in 2020 will be around 1.7 million barrels per day (Figure 3), with a further decline thereafter. Supportive oil prices, use of new technology and government policies can moderate the rate of decline, but not stop it. Whatever oil prices and whatever measures the government takes, the geological realities of the NCS are the same.

But as natural gas production is expected to grow for some more years, total petroleum production from Norway could stay at the current level of about 4 million barrels of oil equivalent per day well into the coming decade. (Figure 4)

For the industry investment opportunities on the NCS should be plentiful, but they will be different from the past. And they will be more diverse – from 'easy' tie-ins to existing fields, to challenging green field developments in the high north. Fields will on average be smaller and gas developments more frequent than oil developments.

Thus, in spite of decreasing oil supply, Norway will remain an attractive area for energy investment and a large energy exporter for many years to come.

Shamil Midkhatovich Yenikeyeff looks at Russian oil output

In September–October 2009, Russia made headlines when its oil exports in the second quarter of 2009 surpassed that of the world's largest oil supplier, Saudi Arabia. In April–June 2009, Russia exported 7.4 million barrels of oil per day compared to Saudi Arabia's oil exports of 7 million barrels. In addition, in the middle of 2009 Russian oil output reached a ten-year record of 9.91 million barrels per day.

At first glance, it may appear that the global financial meltdown has not made a severe impact on the Russian oil industry. However, the Russian reality is rather different if not complex. First, it can be argued that the recent increase in Russian oil exports was primarily driven by external market conditions rather than domestic policies. In fact, Russian government policies of the past eight years promoted the stagnation rather than the development of the oil sector. Secondly, although according to official data for the second quarter of 2009 Russia surpassed the other top oil-producing nation, Saudi Arabia, in terms of oil exports, it actually was placed worst amongst all G20 countries in terms of economic performance during the crisis of 2009. Quite notably, in April–June 2009 in comparison to Saudi Arabia's GDP decline of 0.9 percent, Russia's GDP fell by as much as 10.9 percent. Poor economic performance in Russia is linked not only to the sudden fall of oil prices within the second half of 2008, but also to the manner in which the government's fiscal policies and taxation of the domestic oil sector were implemented from 2004 through 2008. However, before these issues are examined further in this brief study it is essential to establish the actual factors behind Russia's rise to its status as a leading oil exporter in the second quarter of 2009.

Russia and Saudi Arabia

There is nothing new about the fact that Russia surpassed Saudi Arabia in terms of oil production. Throughout the 2000s, these two countries have been producing similar volumes of oil, with Russian output occupying the top position from time to time. This first occurred in early 2002, when Russia produced 7.28 million barrels per day compared to the Saudi daily output of 7.19 million barrels. Subsequently, Russia managed to surpass Saudi oil production again a few additional times. However, what differed in this instance is the fact that Russia for the entire second quarter of 2009 exported more oil than Saudi Arabia, a mark which Russia had never managed to reach since the disintegration of the Soviet Union in 1991.

It is important to note that Russia's historic achievement as a leading oil exporter was possible not so much because of domestic policies towards the oil sector, but mainly because of oil output cuts of 4.2 million barrels a day agreed to by OPEC in the fall of 2008. Saudi Arabia, as OPEC's key supplier, has been especially stringent in implementing oil output cuts in order to stabilise oil prices. OPEC's decision was based on the widely shared assumption that a sudden collapse of oil prices could hurt upstream investments leading to future shortages of oil supplies vital for global economic growth. Russia, as a non-OPEC member, often benefits from oil supply cuts implemented by OPEC. As in the past, Russian oil producers rallied to export more oil abroad to generate extra revenues while the Saudi-backed OPEC cuts were maintained.

By mid-2009, Russian oil exports experienced a 1.5 times increase in comparison to November 2008 when oil prices fell to their lowest levels in many years. Thus, despite additional export volumes, revenues generated by Russian oil exporters from January through July 2009 were only half of what they were in the same period in 2008 due to oil price dynamics: $45.8 billion and $96.5 billion respectively.

Crucial Issues

The issue of oil (and oil price-linked gas) revenues are of paramount importance not only to the Russian budget but also to the future socio-economic stability of this resource-rich nation. In the past five years, Russia's economy (despite earlier proclamations of diversification) became more dependent on oil revenues due to the government's fiscal policies, and will remain so for at least a decade. Therefore, in order to ensure political and economic stability in the country, the Russian government will be required either to diversify the economy (which is unlikely) or to boost future Russian hydrocarbon production and exports.

In this respect, three interconnected issues are important: taxation of the oil sector, availability of investments, and oil price dynamics. While the latter factor is well beyond the Russian government's control, policy-makers in Moscow will face serious challenges in relation to the first two issues.[1]

From 2000 through mid-2008, Russian economic development was predominately driven by rising oil prices. Currently, the hydrocarbon sector accounts for 60 percent of Russian export revenues and contributes to over 45 percent of the federal budget. In March 2009, the Russian Minister of Finance Alexey Kudrin stated that during the period of high oil prices, the government chose to spend extra revenues instead of diversifying the national economy. However, the government's departure from its previous stance on economic diversification was not merely a result of its decision to spend additional revenues on day-to-day needs, but was a part of its policy of transferring extra revenues to the Stabilisation Fund. The significant exposure of the Russian economy and financial system to price fluctuations in the global hydrocarbon markets was the core reason behind the formation of the Stabilisation Fund. From 2004 to 2007 the Russian government used the Fund to accumulate revenues from oil prices which exceeded the cut-off price set at $20 per barrel (and increased to $27 per barrel in 2006) in order to balance the federal budget should oil prices fall below the cut-off level. The Fund's resources were then invested into foreign assets, converted into foreign currency or deposited into foreign banks. In January 2008, the Ministry of Finance split the Stabilisation Fund into the Reserve Fund and the National Welfare Fund.

"From 2000 through mid-2008, Russian economic development was predominately driven by rising oil prices"

It is important to note that there has not been a drastic decline of world oil prices in comparison to the 2003–2004 period (when the Russian Stabilisation Fund was formed). Although external market conditions have not changed, the domestic budgetary situation has altered dramatically: for instance, instead of a budget surplus, the government now has limited financial resources at its disposal. A decline in Reserve Fund resources and growing budgetary expenditures are likely to lead to a situation whereby Russia will utilise its accumulated hydrocarbon revenues faster than previously envisioned. The Reserve Fund could be spent almost entirely by 2010 – a prediction which Russian government officials concur with.

The current situation with the Russian budget evolved out of the 2004–2009 period when the government expanded the scope of budgetary expenditures. The influx of oil and gas revenues, associated with high hydrocarbon prices in external markets, was used by the government to solve pressing social problems mainly by increasing levels of pension payments and basic salaries. From 2000 through 2006, the per capita income of Russian citizens increased four-fold from 2,280 to 10,000 roubles, whereas the standard pension level tripled from 690 to 2,500 roubles. In the 2000s the dependence of the Russian economy and the society on the domestic oil and gas sector increased dramatically. This could explain why, in the second half of 2008 through the first half of 2009, Russia surprisingly showed the biggest decline in GDP and industrial production amongst all the countries of the former Soviet Union.

Astoundingly, over the past eight years, gross revenues of Russian oil companies surpassed $1 trillion, whereas their net income reached $150 billion, of which $50–$70 billion were invested. During this period, the state received over $700 billion in hydrocarbon and corporate taxes and duties. However, these large oil and gas revenues did not increase the workforce employed in the Russian economy: if in 2006 the Russian workforce was estimated at 51 million, by 2008 this figure fell to 48 million. As a result, the Russian government completely withheld funds that could have been used for the provision of extra credits to Russian companies and for the development of vital infrastructure projects.

If in 2003 the share of taxes within revenues of Russian oil companies comprised 35 percent, by 2005 these companies had to transfer nearly 60 percent of their revenues to the budget. This sudden change was due to tax reforms initiated by the government in the 2000s when the taxation of the oil and gas sector was substantially increased.

1 This section is partially based on the forthcoming working paper, 'Natural Resource Management in Russia' by Valery Kryukov, Anatoly Tokarev and Shamil Yenikeyeff.

Naturally, one would assume that companies, having paid their tax dues, would use a substantial portion of remnant revenues for investment into the sector whereas the state would use the collected taxes as a means of ensuring socio-economic stability and for paying off any external debts. However, in the Russian case, such assumptions are accurate only to a certain degree. The reality was that the largest portion of oil revenues (and a smaller portion of gas revenues) was transferred abroad. The remaining amount was used by Russian oil and gas companies for direct investments, as well as for acquisition of other domestic oil and gas companies. At the same time, the volume of direct investments into the industry never reached a level adequate for the maintenance of oil and gas output and the development of new oil and gas fields.

> "The key challenge for the Russian government now is how to meet budgetary obligations while boosting domestic oil production and exports or diversifying the economy"

In 2002, the Russian Accounts (Audit) Chamber highlighted that prior to 2000 the investment situation in the oil and gas sector had been unsatisfactory and in a state of crisis. If in 1990 investment levels in the Russian hydrocarbon sector reached 112 billion roubles, by 1999 it had decreased to 51.3 billion roubles. Equipment depreciation levels reached 50 percent for oil production and 80 percent for oil refining. More than half of the domestic oil trunk pipelines have been in operation for over 25 years, while their average working life is 30 years.

There are several reasons for the lack of investment activities within the oil and gas sector:

- An unstable investment climate, including high tax burdens imposed onto companies;
- A pre-existing industrial infrastructure (developed in Soviet times), which has been advantageous for most Russian oil companies in the post-Soviet era. However, these same companies failed to re-invest financial resources into the maintenance and refurbishment of the aged infrastructure and to meet compliance with technological rules and standards of the industry. Instead, some companies went so far as to use equipment and infrastructure depreciation payments as an additional source of revenue generation;
- A lack of financial resources, particularly for the implementation of key projects essential for reproducing existing assets and resources as well as for developing resources in new oil and gas fields.

It may be argued that a heavy tax burden levied by the government upon the oil and gas sector led to declining investment flows. Yet it is also important to note that from 2000 to 2005, Russian oil companies (such as Sibneft, Yukos, TNK-BP, Lukoil) paid very high dividends to their shareholders, which often exceeded their corporate annual revenues. Simultaneously, these companies transferred most of their financial assets abroad as part of a widespread capital flight. For example, according to the Central Bank of Russia estimates, by 2003 the Russian private sector had invested around $66 billion abroad. Even still, a number of experts assert that the real figure of Russian capital invested abroad reached over $300 billion. The Central Bank of Russia is unable to provide accurate figures on the Russian capital flight due to the fact that most of these funds were transferred abroad without the required registration procedure nor with any governmental permission.

Despite differing estimates, it is generally agreed that the Russian capital flight after the collapse of the Soviet Union was substantial. From 1992 through 1995, large disparities between domestic and global oil prices as well as other mineral, metal and chemical products, enabled Russian trading houses to accumulate tremendous profits. An absence of any state control over such trading activities, as well as high income taxes, also contributed to the capital flight. Thus, the main reasons for Russian capital flight included:

- Macroeconomic instability, linked to political instability, making investors nervous about future revenue prospects in Russia.
- The unstable and confiscatory nature of the domestic tax system, which facilitated tax evasion and the transfer of funds abroad hence away from Russian tax authorities.
- A lack of trust in the domestic banking system, boosting transfer of individual savings to foreign banks.
- Institutional weakness of property protection measures and widespread corruption, discouraging companies and individuals from retaining their financial assets in Russia.

Since 2003 the situation with capital flight has changed: if in the late 1990s 'pure' capital outflow was widespread, by 2008 it appeared to take on a new form. For example, the volume of resources used by Russian companies to acquire assets abroad increased threefold, from approximately 23 billion USD in 1999 up to 73.4 billion in 2005.

According to the Central Bank of Russia, in 2008 the 'pure' outflow of private capital from the country sharply increased reaching $130 billion, including the banking sector ($57.5 billion) and other sectors of the economy ($72.5 billion). In the first quarter of 2009, capital flight was estimated at $23.1 billion.

This dynamic of capital outflow has been directly connected with the government's policy on the taxation of the Russian hydrocarbon sector, as well as the aspiration of the state to accumulate main tax revenues from the oil and gas industry into the Stabilisation Fund.

The key challenge for the Russian government now is how to meet budgetary obligations while boosting domestic oil production and exports or diversifying the economy. One of the ways to achieve this is by borrowing financial resources through external markets. Another way is to lower taxes imposed on the Russian oil sector, which could promote development of existing and new fields. At the same time, substantial reduction of this tax burden could lead to even greater budgetary deficit and could jeopardise socio-economic stability in Russia. Hence, today the Russian oil sector faces serious obstacles including:

- Increasingly challenging conditions for the exploration and development of new hydrocarbon fields located in difficult-to-reach territories with severe climates and complex geology;
- Lack of incentives for private investors (both foreign and domestic) to develop new fields under the existing legal framework, in a sector dominated by state-controlled companies (which determine whether a given independent company gains access to vital infrastructure and key export routes);
- The substantial tax burden recently imposed on the hydrocarbon sector, coupled with the dominance of state-controlled oil and gas companies, impedes the facilitation of exploration and development of new oil and gas fields. Various tax exemptions and privileges granted by the government in 2008–2009 to companies operating in new fields could not compensate for the high expenditures incurred during their industrial development; for example, in the first half of 2009, Russian oil companies reduced their exploration drilling by over 40 percent in comparison to the same period in 2008.

Despite all the media hype surrounding a recent increase in Russia's oil output and exports, fundamental problems within this sector and the Russian economy at large imply that this is a glitch rather than a trend. Therefore, it is unsurprising that the Russian government forecast indicates the stagnation of the annual domestic oil production (from 492 million tonnes in 2008 down to 483 million tonnes in 2011) as well as a decline of oil exports (from 245.4 million in 2009 to 238 million tonnes in 2012). Despite this rather pessimistic short-term forecast, the government's long-term forecast for the oil sector sees its gradual recovery by 2030. According to the draft *Russian Energy Strategy* discussed by the government in August 2009, in 2030 Russia's annual oil output is projected to increase to 530–535 million tonnes (with annual oil exports reaching 329 million tonnes).

In order to achieve these targets, the *Russian Energy Strategy* envisages that the domestic hydrocarbon sector will require up to $2.5 trillion in investment. It is highly unlikely that these financial volumes could be secured through a different system of taxation of the domestic oil sector. Russian oil companies are also unlikely candidates for reinvesting adequate levels of their profits back into the sector. In fact, oil companies have shown a pattern of using extra financial resources primarily for the benefit of their shareholders instead of investing in exploration and production in new fields. It appears that the only way forward for the Russian oil sector is to secure these vital financial resources through a formation of legal mechanisms conducive to foreign investment.

Successful transformation of the Russian economy from resource dependent into hi-tech and innovative will depend on a successful promotion of incentives for investors and greater opportunities for entrepreneurs, not only in the hydrocarbon sector but also in other sectors of the economy (thus facilitating economic growth and additional budgetary revenues). In the 2000s, the growing tax burden forced Russian companies to compensate their diminishing revenues by borrowing in external markets. This resulted in an accelerated economic decline in Russia during the crisis period.

European Natural Gas Prices

Howard V Rogers

Introduction

There are two types of gas sold in Europe. Their appearance and physical characteristics are identical; the only difference is the way in which they are priced. This summer, pipeline gas from Russia and North Africa was selling at around $8/mmbtu, while traded or 'spot' gas in the UK was selling for around $3/mmbtu. The fact that the same commodity should be the subject of such extreme price variation raises three questions:

- How has the market architecture developed to allow such disparities to arise?
- What are the forces currently applying stresses to this structure?
- Is such a system sustainable?

The Evolution of the European Gas Market's Structure

The structure of the continental European natural gas market was initially shaped and subsequently heavily influenced by the seemingly simple question of how to formulate the price of gas from the Groningen Field discovered in Holland. Given the low cost base of this relatively shallow onshore reservoir, gas from Groningen, after lengthy consideration, was priced, not on the basis of its underlying cost of supply but on the basis of competitiveness with the final consumer's alternative non-gas fuels. This is often termed the 'market value principle' or alternatively the 'netback market approach'.

This same approach was subsequently adopted for contracted pipeline imports to continental Europe from Russia and North Africa. Contracts for European pipeline imports initiated from the 1970s, were typically 20 to 25 years in duration. The buyer had the right to nominate up to an annual amount (the Annual Contract Quantity – or 'ACQ') but had to take or, in any case, pay for a quantity equal to the 'Take-or-Pay' level ('TOP'), which is typically some 80–85 percent of the ACQ on a contract year basis. Additional flexibility was applied at the monthly or daily level provided that, in the course of a gas contract year, an amount at least equal to the TOP was paid for.

Pricing of long-term contracted gas imports is generally linked by formula to gas oil and fuel oil, by a formula negotiated and defined in the contract:

$$P_n = P_0 \times (a \times \mathrm{av}\,(F(n\text{-}x) + \ldots + F(n\text{-}1)) + b \times \mathrm{av}\,(G(n\text{-}x) + \ldots + G(n\text{-}1)) + c)$$

The price in month n equals the initial contract price multiplied by:

A constant **a** multiplied by the average of the last x months Fuel oil (F) prices,

A constant **b** multiplied by the average of the last x months Gas oil (G) prices plus

A constant **c**.

The values of the key variables are confidential to the parties to the contract, however they have over time been inferred, in aggregate, from border price data. These contracts also provide for periodic price re-negotiation or 'price re-openers' if market conditions change significantly. For this reason, in continental Europe there is a significant level of price similarity in contract gas from different sources. This was not historically the case in the UK, where contracts did not provide for price re-opener negotiations.

In the UK, cost-based pricing was the main principle used in the negotiation of contracts between the state monopoly buyer British Gas and upstream producers in the pre-liberalisation era (pre-1996). This led to a wide range of contract prices depending on the cost base and gas/liquids production ratio of field-specific contracts negotiated. During the 1990s, successive legislative acts served to progressively undermine this position, critically enabling upstream producers to sell gas directly to the large power users. This catalysed the monetisation of the 'backlog' of undeveloped discoveries, which subsequently competed aggressively for customers in the power and industrial sectors. British Gas's market share loss was such that it was unable to sell on its Take-or-Pay levels under field-specific long-term contracts that were priced 'out of the market'.

Facing significant financial exposure British Gas was forced to re-negotiate many of these contracts at lower price levels and to transform them to non-field specific long-term supply contracts. The UK market now comprises a mixture of these old 'legacy' contracts and spot gas which is sold at the National Balancing Point (NBP) – the UK's only hub. Although possibly some 25 percent of UK production is still sold under 'legacy' supply contracts the disparate pricing formulae have resulted in a significant degree of scatter and, as a result, these do not noticeably influence the traded UK gas price. The UK market became effectively liberalised in the mid 1990s with the NBP becoming a virtual hub.

Despite the moves to liberalise the continental European gas market it is still, in the author's opinion, in a state of 'semi-suspended animation': held back by the interests of its gas market incumbents who have little incentive to change and whose long-term contractual arrangements with suppliers in Russia and North Africa are difficult to reconcile with the liberalised gas market model epitomised by the UK and North America. Since the liberalisation of the UK gas market, Europe has had what can best be described as a 'Hybrid' market. In the UK, gas prices at the NBP are primarily determined by supply and demand. Across the Channel, in continental Europe, the territory is dominated by traditional long-term pipeline supply contracts with gas prices determined by formulae incorporating a 6 to 9 month rolling average of gas oil and fuel oil prices.

A crucial development in recent years has been the establishment of trading hubs in northern continental Europe in Zebrugge, (at the end of the UK–Belgium Interconnector pipeline), and in France, The Netherlands and Germany. Initially it is arguable that such hubs were created in the early 2000s solely by the 'overflow' of excess UK domestic production during the summer months when (as a consequence of its low provision of seasonal storage capacity and a liberalised market), the UK found willing buyers for summer spot gas. As the UK's domestic production began to decline (post 2001), it was to be expected that these 'satellite' hubs would literally 'dry-up', starved of spot gas supply.

This outcome has been averted by the development of the Norwegian Ormen Lange field and the associated Langeled pipeline to the UK. This provides Norway with an alternative to selling oil-indexed gas at the Continental European 'beach'; specifically the option to sell Ormen Lange, and any gas not nominated by Continental European buyers, into the UK traded market at prevailing spot prices. However, this may well result in Norwegian gas 'at the margin' overflowing through the interconnector into the Continental market via Belgium. Similarly the BBL (Balgzand Bacton Line) from the Netherlands is 'at the margin' flowing gas from the Netherlands into the UK and then back out again to Belgium.

Contrary to the 'Old School' logic that long-term contracts are a pre-requisite to the construction of significant import infrastructure, the UK with a good track record on pragmatic, limited Third Party Access exemption, has succeeded in building sufficient pipeline and LNG import capacity to see it through the medium term. LNG imports into the UK will also become a major source of spot gas supply for trading hubs in northern Continental Europe.

So far so good. The European Market 'hybrid' system can remain 'stable' and a liberalised UK market and satellite hubs can co-exist with the long-term contract paradigm as long as the following 'rules of engagement' hold:

- Continental European pipeline gas import contract prices adhere to the contractual formulae based on a time-averaged relationship to gas oil and fuel oil (as asserted by supplier countries to Europe).

- Continental buyers/midstream players can engage in hub trading and LNG diversions as long as they honour their Take-or-Pay commitments under the long-term pipeline gas contracts.

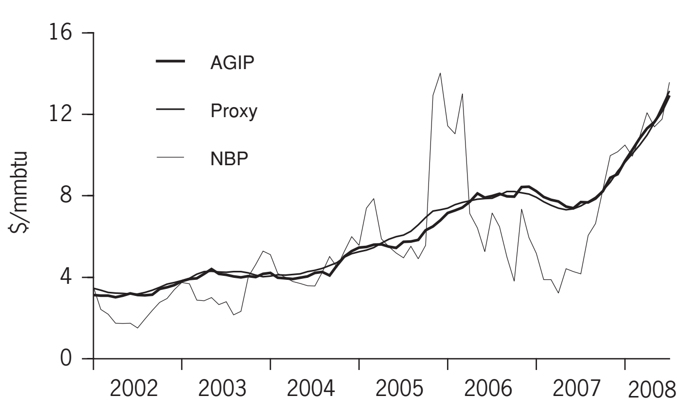
Clearly the greater the absolute price of oil-indexed gas and the size of the differential between this price and that of UK/Continental hub spot gas prices, the more these 'rules of engagement' are in conflict with the temptation for 'enlightened self interest' for key players i.e. end consumers seeking to purchase cheaper 'spot gas' in preference to oil-indexed supplies.

With the high oil prices in the second half of 2008 and the economic-recession driven low demand (and hence low spot gas prices) prevailing in 2009 the strains on the 'rules of engagement' have never been so severe. Will they prevail? Here are two reasons that suggest the edifice is beginning to crumble.

The AGIP Price Mystery

The Average German Import Price (AGIP) is disclosed by the German Federal Ministry of Economics and Technology. It is the average price of gas purchased under bundles of contracts with Russia, Norway, The Netherlands and an 'Other' category – primarily Denmark and the UK (which may well be spot-priced gas). The AGIP 'actual' price is reported typically 2 to 3 months 'old'. In order to try to predict future oil-indexed prices, analysts have used 'proxy' formulae to derive indicative future values, based on the format described at the beginning of this article. Figure 1 shows the actual NPB and AGIP prices and also the 'Proxy' values produced by 'tuning' an approximate formula.

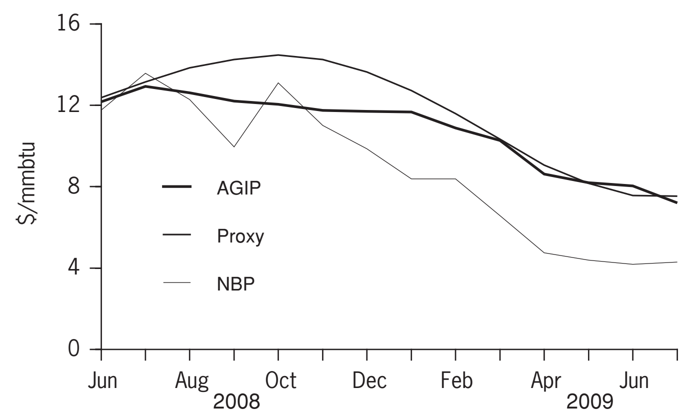
Figure 1: UK, German and Proxy Prices 2002–2008



For much of the period the Proxy price has a reasonable 'fit' to the Actual AGIP price. Also of note is the periodic convergence of UK (NBP) price to AGIP – due to arbitrage at the trading hubs with oil-indexed gas. Periods of extreme high NBP prices in late 2005/early 2006 were due to a combination of a generally tight market for spot gas and LNG combined with the subsequent operational problems with the UK's main seasonal storage facility. The period of low NBP prices in 2006 and 2007 coincided with the advent of new supplies of Norwegian gas via the Langeled pipeline. In the first half of 2008, arbitrage kept NBP very close to AGIP, which in turn was being driven by the rapid rise in oil and oil product prices.

Now let's take this on to the period June 2008 to the present (Figure 2). From August 2008 to March 2009 AGIP tracked a path that was at times some $2/mmbtu lower than the Proxy prediction would suggest. From March 2009 onwards the previous relationship appears to have re-established itself.

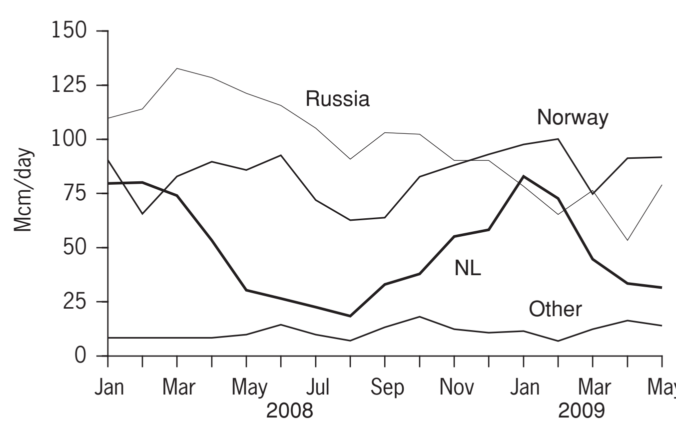
Figure 2: UK, German and Proxy Prices 2008–2009



Looking at the relative scale of gas imports from different supplier countries shown in Figure 3 provides no explanation. The relatively low scale of gas imports in the 'other' category is insufficient to cause this price dip, even if this was all UK spot gas. Gas imports from the Netherlands were high during this period – but on a par with those of a year earlier when no such discrepancy between AGIP and the Proxy prediction was evident.

In the absence of further clues one can only assume that one or more of Russia, Norway and the Netherlands in the period August 2008 to February 2009 reduced its gas sales price substantially below contractually agreed levels.

Figure 3: German Gas Imports



The Take or Pay Conundrum

There have been widespread media stories concerning the apparent failure of European buyers to have met their Take-or-Pay volume purchases of Russian oil-indexed pipeline gas imports for the contract year ending on 30 September 2009. Estimates, based on inferred actual imports for Russia, Algeria, Libya, Azerbaijan and Iran in aggregate to June 2009 and best estimates to September, imply that for the contract year 2008/2009 importers will collectively have imported around 10 percent less than their Take-or-Pay obligation (this adjusted for the gas which was not available due to the Russia–Ukraine dispute in January 2009).

Clearly the stakes are high and involve more than just payment for the under-lifted volumes. As the earlier gas price graph showed (Figure 2) oil indexed prices are around twice the level of UK spot prices. If Russia were to make major concessions on Take-or-Pay levels this would, subject to infrastructure constraints, increase the scope for penetration into the European market of LNG pricing off Henry Hub and/or NBP.

The two developments described above represent either a ‘hiccup’ or signs of major structural subsidence in the long-standing European oil-indexed contract paradigm. Without a sudden resurgence in demand in Asia or Europe to levels above those of 2008, the additional LNG supply coming on-stream in the next two years will continue to exert severe ‘stress testing’ of Europe’s ‘Hybrid’ natural gas market.

The Story of William Kamkwamba

Judith Mabro

‘The people who walk in darkness will see a great light.’ Isiah 9:2

Once known as the dark continent by Westerners who had no knowledge of it and saw it as obscure, Africa is still sometimes referred to as dark but for a different reason. According to *The Economist* in 2007,

> Seen from space, Africa at night is largely unlit, as dark as all-but empty Siberia. With nearly 1 billion people, Africa accounts for over a sixth of the world’s population, but generates only 4% of global electricity.

Various estimates state that between 2 percent and 8 percent of the population of Malawi have electricity at home. Recently I read the book, *The Boy who Harnessed the Wind: Creating Currents of Electricity and Hope* by William Kamkwamba and Bryan Mealer. William Kamkwamba lived in a village in Malawi at a time when the country was suffering from drought and famine; he was forced to leave school aged fourteen because his family could not afford the fees and he was needed to work on the farm. Like most Malawians he had to go to sleep at about 7.00 pm because there was no light in the house. He was curious about how things worked and wanted to improve life for his family. He began by taking broken radios apart to discover how they worked; he found a bicycle dynamo and worked out how the light came on and ultimately put his mind to how he could create his own electricity.

A book called *Using Energy* borrowed one day from a primary school library changed his life. ‘Energy is all around you every day’, it said. ‘Sometimes energy needs to be converted to another form before it is useful to us. How can we convert forms of energy? Read on and you’ll see.’ He did, he saw photos of windmills and understood how they could be used to generate power. He collected scrap metal, PVC pipe, a broken bicycle and wooden poles and managed to construct a windmill that powered a light for his room and later he extended it to all the family’s rooms. He was called mad, lazy, crazy by the people of his village until the windmill was finally assembled and producing light. Eventually he was discovered by some education officials touring the region, quickly followed by the media rushing in, then he was taken to conferences in Africa and America and even met Al Gore and appeared on the Jon Stewart Daily Show when the book came out. Bryan Mealer, his co-author and a journalist who had covered the war in the Democratic Republic of the Congo, befriended him and was determined to share his powerful and uplifting story with the world and to finally go home from Africa ‘with some good news to tell’.

When William Kamkwamba first saw the photos of windmills in the book from the primary school library, what he saw were ‘giant beautiful machines that towered into the sky, so powerful that they made the photo itself appear to be in motion’. When he was taken to California years later to visit a wind farm he was amazed at the miles of windmills, more than six thousand of them. Looking up, he saw ‘the hundred-foot blades twirling slowly like the toys of God.’ In total, the wind farm produced over six hundred megawatts of electricity, which was enough to power the whole of Malawi. ESCOM, the almost totally government-owned electricity supply corporation of Malawi produced only 224 megawatts at the time. As he watched them, he wondered whether he would return to Malawi and plant a forest of windmills along the green fields; or would he teach others to build more simple windmills to power their own homes and villages? He has travelled an extraordinary journey to date and will no doubt continue to do so.

Although he is lauded by environmentalists at international technology conferences, to people in Malawi, William Kamkwamba said in a recent interview, wind power is not talked about as a way of helping climate change. ‘We talk about wind and solar power because it’s a simpler and safer way to give us electricity and irrigation. Clean water and power is our right as humans on this earth, and for too long our governments in Africa have failed to provide these things.’

When his story was reported by the BBC, many comments were posted from readers in Africa praising William Kamkwamba and hoping that other young Africans will be inspired. One came from a reader in The Gambia:

'It is indeed a great joy to see a talented young African brother having a big dream to modernise his community with water and electrical supply. Africa has a lot of talented youths but there are no resources to work on. The intelligent poor children have no seats in the classroom and our greedy politicians are only looking after their own interests. Job well done my brother, I hope many will take your steps in the love of our own people.'

Solar energy

Malcolm Keay asks whether solar power will find its place in the sun

> "In an 1878 letter, Ericsson concluded that 'the fact is … that although the heat is obtained for nothing, so extensive, costly, and complex is the concentration apparatus that solar steam is many times more costly than steam produced by burning coal.'"
>
> Wilson Clark, *Energy for Survival: The Alternative to Extinction* (Garden City, NY: Anchor Books, 1974), p. 364.

For more than a century, solar power has faced the problem highlighted above – that despite the almost universal availability of solar power, the cost of transforming it into useful energy has prevented it from playing any significant part in the world's energy supplies. The purpose of this article is to explore whether this might now be changing – could solar power be the energy of the future, or at least a significant component of future energy systems?

Solar Power Comes in Many Varieties

In fact, the comments in the paragraph above need to be qualified almost immediately. Just as renewable energy is not one source, but many, so there are many varieties of solar power – too many to be covered in a short article. It is possible only to identify certain broad categories of solar power, each of which in its turn embraces many technologies and approaches.

The first, and most important (but usually ignored as an energy source) is **passive solar** power (referring essentially to building design and orientation to make the maximum use of natural sunlight for heating and cooling). This is of course something which has been practised for millennia and remains probably the main use of solar power in this country (it is estimated that it provides 15–20 percent of the heating in an average home during the heating season – a proportion which can be increased to perhaps 40 percent by careful design and better insulation). However, it is of its nature difficult to measure and is normally classed as energy efficiency rather than supply.

The second broad class is of **solar thermal** applications which use sunlight to heat water or some other liquid, which is then circulated to provide hot water or heating (or even cooling) to a building (the heat is normally at too low a temperature for process use). This technology is also fairly widespread. The country making most use of it is (perhaps surprisingly) China, which has over half of global capacity of the technology, with some 50 million square metres of collecting panels.

Both the above technologies will continue to be of importance in the future but for a step change in the penetration of solar power, we probably need to look at solar electricity generation, which in turn comes in various different forms. The best known is probably **solar photovoltaics** which uses solar power to generate electricity directly via photoelectric cells. The technology has been developing rapidly. Traditionally, crystalline silicon cells were used; newer 'thin film' technologies are lighter and cheaper and offer greater flexibility (in a literal as well as a metaphorical sense – some varieties can be folded and shaped at will).

A second class of solar-based electricity generating technologies, which is now receiving increasing attention, is **concentrated solar power** (CSP). Once again, this comes in a variety of forms, including parabolic troughs (using curved mirrors, sometimes raised) or Fresnel lenses to concentrate the rays of the sun onto a target, usually on the ground, where electricity is generated, using a conventional steam turbine, sometimes with a heat carrying fluid such as oil as an intermediate stage. An alternative, now being investigated more intensively, is the 'power tower' which normally uses flat mirrors to focus the sun onto a raised generating system on a tower. There are some advantages to this approach (discussed further in the accompanying article on the prospects for the so-called Desertec project): for instance, the mirrors are generally easier to manufacture and maintain than curved mirrors or lenses, less pipework is required and the need for water cooling is reduced – an important feature in the hot desert areas where solar systems are generally most effective.

A different approach is the use of Stirling engines – a form of external combustion engine that uses a closed internal circulation system. Although invented as long ago as 1816, Stirling engines have so far failed to find a significant place in energy or industry but they may nonetheless have potential – they can use almost any heat source and do not require water for steam raising.

Recent Developments

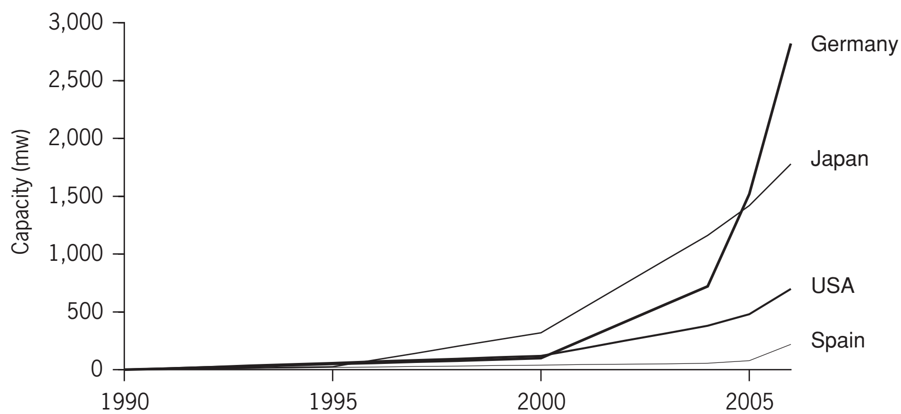
The recent growth of solar power is primarily driven by policy support, which has been substantial. For instance, in Germany the 'feed-in' tariffs offer prices of 30–40 €cents per kWh, about eight times the normal wholesale electricity price and much higher than the price on offer for other renewable sources (e.g. wind and biomass get about 9c; hydro 6–7c). Germany has probably had the world's most ambitious solar programme, despite not being the world's sunniest country – best known perhaps is the so-called 100,000 roofs programme which offered grants and low interest loans for installing solar photovoltaic panels on household roofs (and over-achieved its target – well over 100,000 roofs were equipped with solar panels during the currency of the programme).

Globally, photovoltaics have been growing particularly fast, as shown in Figure 1, particularly in Europe, where about 4GW was installed in 2008, making this the third largest source of new capacity (behind wind and natural gas, but ahead of coal and nuclear). Photovoltaic capacity has doubled every few years this decade, though total capacity, at around 15GW, remains a small proportion of global electricity supply.

This exponential growth has, however, recently faced a setback. Excess capacity has emerged in Europe, because of a combination of over-rapid expansion in production, lower growth in demand for electricity as a result of the recession, and the impact of the credit crunch on a capital-intensive industry. In addition, as in many other sectors, Asian companies are now able to produce at much lower cost than their European counterparts – many of which are now contracting production out to Asia. China alone is thought to have around 8 GW a year of production capacity – as compared with global demand currently standing at around 7 GW.

Photovoltaics are not of course the only version of the technology receiving support in Europe. Solar thermal is supported in many countries and concentrated solar power has been under development for some years, particularly in Spain, which opened the world's first commercial CSP plant near Seville in 2007.

Figure 1: Cumulative Installed PV Capacity by Country, 1990–2006



Japan and the USA have also been active in installing various forms of solar power. In the USA, unsurprisingly, it is the Western states, particularly California and Nevada, which have the most capacity, aided by their high levels of sunshine and land availability. Solar capacity in US utilities grew about 25 percent in 2008 – to 882MW – driven by renewable portfolio standards and expectations of future carbon regulation. A range of technologies is being developed, including Stirling engines. Stirling Energy Systems of Phoenix, Arizona has two large projects in planning – a 750MW plant in the Imperial Valley to sell electricity to San Diego and a huge 850MW project in the Mojave Desert destined for Southern California Edison.

Resource Availability and Economics

As regards longer-term potential, solar power is of course ubiquitous and abundant. Indeed it is the most abundant permanent energy resource in the world; the question is how much of it can be captured for human use and how efficiently. The constraint is unlikely to be the resource itself. For instance, the World Energy Council estimates that 'Even if only 0.1% of this energy could be converted at an efficiency of only 10% it would be four times the world's total generating capacity of about 3,000 GW. Looking at it another way, the total annual solar radiation falling on the earth is more than 7,500 times the world's total annual primary energy consumption of 450 EJ.' Even taking account of such issues as land availability and efficiency, the IEA suggests that the potential could be 3 to 100 times current world energy consumption.

Question marks over the future of solar arise not from issues of availability but from economics. Solar power remains expensive, even as compared with other renewables, as the figures above from Germany indicate. The capital costs for most forms of solar start at about $5,000 per kW or more (about ten times the cost of a combined cycle gas turbine plant) and installation and land costs are high. Efficiencies are also currently fairly low (typically below 20 percent, though best available technology achieves higher efficiencies and prototypes with efficiencies of over 40 percent have been developed).

However, the capital costs are coming down and efficiencies increasing; costs are also lower in areas such as North Africa and the Middle East (where solar resources are high and land often has few alternative uses), than they are in Europe or Japan, where most existing plants are located. Overall, the cost of photovoltaics has been declining at 3–4 percent p.a. for many years and the cost of solar thermal plant is also falling fast – the IEA thinks it could fall to around $1,250 per kW in 2030, which would bring generating costs on suitable sites to about 5c per kWh. This would be competitive with gas at $6.5 per MBtu or above; it should also be broadly competitive with nuclear or other renewables.

Characteristics of Solar Power

Assuming that the cost can be brought down as suggested above, solar power would have a number of additional attractions, which could well make it the renewable source of choice:

Generation pattern: With many renewable sources, such as wind, generation is variable, unpredictable (except in the very short term) and not well matched with demand. Solar power by contrast is stable and predictable. In the hot countries where it is likely to be sited and where air conditioning is the main component of electricity load, generation coincides fairly well with demand. Back-up of some sort would of course be needed for the hours of darkness. Cloudiness can also be a problem in northern Europe, but it can largely be avoided at sites in desert areas away from the coast and in any event it reduces output only partially (unlike, say, the absence of wind for a wind farm). Furthermore, concentrated solar systems can, at least in principle, store solar power in the form of a hot liquid, which is easier than storing electricity.

Siting: For many of the new renewables, siting is a problem. Good resources of wind and hydropower are only available at suitable sites, which may be remote or environmentally sensitive. Solar power by contrast tends to be relatively homogeneous over a country or even a whole region, so sites can be chosen with fewer constraints.

Land use: While solar power is relatively low density in energy terms as compared with fossil fuels, it compares favourably with many other renewables, even those which ultimately also rely on solar energy. For instance, supplying the UK's energy needs with biomass would – according to the calculations of David Mackay, the Government's scientific adviser for climate change and energy – take many times the agricultural land area of the UK. His simple conclusion: 'biofuels can't add up'. Solar power can provide much more energy for a given land area – concentrated solar power production over an area the size of Lake Nasser (the lake behind the Aswan Dam) could produce more energy than the whole of Middle Eastern oil production; an area the size of Austria could provide the whole of the world's energy needs.

Furthermore, solar power is easier to reconcile with existing land uses. Photovoltaics can be installed on the roofs of buildings – even potentially in future on the roofs of vehicles – in crowded developed countries. In many sparsely populated developing countries, like much of North Africa, the Middle East and Southern Africa, there is an ideal combination of abundant solar resource and low pressure on land use.

> "Solar power remains highly attractive in principle: the resource is free and widely available. But the question of cost remains"

Off-grid applications: Because of its ubiquity, solar power is also particularly suitable for off-grid applications. Whereas wind, hydro, geothermal and so on are often found far from any electricity consumption areas, solar power is available everywhere (at least in the developing countries where electricity grids are not yet fully developed) and can be used to provide electricity in places the grid does not yet reach – this is often the cheapest way of providing power for dispersed communities.

Scalability: Finally, solar power should offer scalability – that is, it should be possible to produce it in whatever quantities are required. It is suitable for small-scale applications such as the off-grid uses discussed above or the solar panels on road-side emergency telephones, but can also be scaled up, more or less without limit. This is partly because of the size of the resource, discussed above, but also because of the lack of a major siting problem. Most forms of renewable face two different, and contrasting, cost trends – over time, technical costs tend to go down as the technology improves; however, site costs tend to go up, since the cost of generating, say, wind power, depends very much on the site concerned (wind characteristics; location; closeness to grid connections and so on). As the best sites tend naturally to be used first, the increasing scarcity of good sites pushes up costs over time. (We are currently seeing this in the UK as production is being moved offshore, where it is much more expensive, because of the difficulty of gaining environmental approvals for suitable onshore sites). In addition, with intermittent sources like wind, the costs of integration into the electricity system increase as the proportion of wind on the system increases. These factors tend to cap the maximum contribution feasible from sources like wind.

With solar, these problems should be much less significant. The siting issue is less acute, so should not lead to a rising cost curve; meanwhile, in addition to the technology advances expected, there should be significant economies of scale both in manufacturing the generating equipment and in installation (e.g. in the costs of transmission from a large site). So as solar penetration increases, the costs should tend to go down over time.

The Future – Big Projects?

It is factors such as those discussed above which have led to the elaboration of ambitious plans for solar. The basic idea is simple – Europe wants to increase its use of renewable electricity, mainly for environmental reasons, but is finding it difficult to scale up its own production to match its ambitions – both the UK in particular and the EU in general (and most individual countries in the EU) are falling well short of their renewables targets.

Meanwhile, the countries round the Mediterranean Basin offer one of the most attractive places in the world for solar power development – the combination of a high solar resource; few pressures on land; and closeness to a huge body of demand. For the countries of the Middle East and North Africa, there are additional motivations for an interest in solar.

Many of them face a similar combination of problems:

- a need to diversify their economies away from hydrocarbon revenues which, in many countries, provide virtually all of exports and tax revenues and account for the bulk of GDP;
- rapidly growing populations and economies which are consuming ever larger amounts of domestically produced oil and gas, often at artificially low prices, and therefore limiting quantities available for export – in many cases there are also significant plans for desalination plant required to supply their growing water needs, with additional impact on energy demand;
- the potential decline of their hydrocarbon exports in the future either because of reserve exhaustion or because the world moves away from fossil fuels.

Against this background, developing alternative energy resources of a more sustainable nature, especially if it can be done with outside help, makes good sense.

Plans for cooperation on such projects across the Mediterranean Basin are therefore developing fast. The most prominent is the so-called Desertec project, discussed in more detail in another article in this issue. The project is highly ambitious – it would involve building some 6,500 square miles of concentrated solar power plants in North Africa, along with a super-grid of high voltage transmission lines, to supply countries in Europe and Africa with electricity. Ultimately, the project is expected to cost €400 billon and generate up to 100GW, though in practice it would build up over time. Whether it ever gets off the ground, of course, remains highly uncertain – there are major political and institutional issues to overcome in addition to the basic challenge of economic viability.

Conclusion

Over a century and a quarter have passed since the passage at the head of this article was written, but in many ways not a lot has changed. Solar power remains highly attractive in principle: the resource is free and widely available. But the question of cost remains – can it be converted to useful energy at low enough cost to make it attractive to users? Despite all the technological changes that have taken place, all the innovative new techniques that have been developed, and the increasingly pressing environmental concerns, this fundamental question has not yet been answered. But it is clear that if it can be answered successfully, the future for solar is very positive – of all the renewable energy sources, solar has the strongest claim to be the only one that can potentially form the cornerstone of a post-fossil energy system.

Till Stenzel assesses exports of solar energy from North Africa

There is no doubt today that solar electricity export from the deserts of Northern Africa to Europe is technically feasible. While it is clear that such 'Desertec' projects are technically, institutionally and financially complex, the picture that emerges after piecing together the individual pieces of this jigsaw is one of utilising proven components and technology to serve a mature market with a clear need for increased supply of electricity from carbon-free sources. Recent initiatives such as the German-led 'Desertec Industrial Initiative' (DII) and the World Bank's $750m Clean Technology Fund (CTF) programme for scaling-up concentrating solar power (CSP) technology in the Middle-East/North Africa (MENA) region merely serve to highlight that industry and policy-makers have increasingly realised its overwhelming potential.

What Technology can deliver Today...

What are the individual components of such export projects and what do they entail? Lets start with CSP technology, which is most often mentioned in the context of the DII. CSP technology has a track-record at least as long as photovoltaic (PV) and wind technologies, with over 20 years of operating history from 354MW of power plants that were built in the 1980s and early 1990s in the Mojave Desert in California. These plants have been operating reliably, in fact exceeding design capacity, and have answered many basic questions such as the rate of breakage of glass mirrors and the impact of frequent on-off cycles on the steam turbines used. While there was a dearth of new plants during the period of cheap oil and fading policy interest in the 1990s, several new plants have now been built, mainly in the USA and Spain and many more announced.

What makes CSP technology so attractive in the context of solar export projects is the fact that they can deliver dispatchable power, a feature that their intermittent PV and wind cousins cannot offer in the absence of economic electricity storage options. CSP plants can either store the heat generated for release 'on-demand' or they can be co-fired with natural gas (as the Mojave Desert plants are) to extend operating hours and smoothen the production profile during cloudy days.

HVDC cables are proposed to transport the electricity from the North African deserts to the demand centres both locally as well as in Europe. These cables have been utilised in over-ground and sub-marine applications for over 50 years, increasing in distance and voltage over time. Only this year, the new 'NorNed' HVDC connection started transporting electricity through the North Sea between Holland and Norway on a 580km long, 700MW capacity cable.

Given the large scale of the projects

currently being discussed, how will this electricity be integrated into European grids? This is a question that Nur Energie has been studying for some time now, first with power system engineers from Imperial College in London and now with CESI, the Italian electricity network research institute. Utility-scale CSP plants are expected to deliver electricity in multiples of gigawatts to different interconnection points, so individual grid connection points might quickly be saturated. After having identified a feasible route through the Mediterranean to connect a utility-scale CSP plant from Tunisia, we have identified several potential interconnection points and are currently in the process of ranking them in terms of suitability, timing and ease of interconnection. An advantage here is that CSP plants can incrementally expand their capacity to co-incide with grid reinforcements. Optimal sizes are between 100MW and 200MW for an individual plant, and economies of scale will be achieved by building a series of plants at the same site. Thus, the roll-out of new CSP plants in the desert can coincide with the provision of adequate interconnection capacity on the European side.

...and where it is heading

Ah, the critics will retort, this is all very well, but what about the economics of all this? Feed-in tariffs for CSP plants in Spain are currently in the order of €0.27/kWh, so this will be a very expensive adventure in the desert.

While it cannot be denied that CSP technology is currently not cost competitive in most locations without support schemes, it also has to be pointed out that despite its long operating history, global investment in CSP has been very limited to date. Recent figures produced by the World Bank highlight this:

Global Cumulative Investment to-date:

Wind Energy	\$200bn
Solar PV	\$100bn
Solar CSP	\$2.5bn

This suggests that the learning rate of CSP is likely to follow a steep reduction curve, as the installed base is low and each doubling of capacity can be achieved in relatively small increments. Furthermore, to use the jargon of the ‘technological innovation’ literature, no single ‘technological paradigm’ has yet emerged in the CSP industry. If anything, the traditionally dominant design of ‘trough’ technology is increasingly being challenged by the emerging ‘tower’ technology.

Tower technology holds several advantages. In order to understand the differences between the two, a short technical background is required: trough technology is installed in long rows of round-shaped (parabolic) mirrors, which reflect sunlight onto a tube in the centre of the mirrors. This heats a ‘heat-transfer-fluid’ (HTF), often oil, which runs through the tubes, collecting the heat and delivering it to a heat-exchanger in an adjacent power block, which transforms the heat into steam, thus driving a conventional steam turbine. These configurations currently have performance characteristics of 400C heat and 100bar pressured steam, with conversion efficiencies from solar to electricity of between 12–14 percent.

In contrast, solar towers produce steam directly, by reflecting sunlight onto a single receiver area at the top of a tower, which is surrounded by a field of thousands of mirrors. This removes the need for HTFs, as a solar boiler, placed at the top of the tower, absorbs directly the heat from the receiver area and heats the water inside to generate steam. This is fed into the turbine situated at the foot of the tower, further removing the need for kilometers of piping and reducing the losses and parasitic power consumption associated with this. BrightSource Energy, a solar tower technology provider with several advanced CSP projects in the USA, consequently aims for operating temperatures of 550C and 140–160bar pressures, thus vastly increasing the operating efficiency of the whole plant to >20 percent.

Together with the reduced need for specialist components and piping, this is set to deliver a step-change in costs. With both Siemens providing the turbines for BrightSource’s 440MW Ivanpah site in California, and Bechtel leading the EPC consortium, major industrial companies in the power and construction business are backing this concept. Among BrightSource’s equity investors, both venture capital companies such as Vantage Point and DFJ, as well as traditional energy companies such as BP and Chevron Technology Ventures provide equally strong backing.

Another major advantage of tower technology is that the higher operating temperature allows the plants to switch to a dry-cooling approach of the power block, which reduces water requirements by 90 percent compared to the water-cooled standard in trough technology. This is particularly pertinent for solar export projects in the desert environments of North Africa where water is a major bottleneck.

> “no attempts have yet been made to formalise an investment framework that would govern the installation of numerous electricity cables across the Mediterranean”

Nur Energie’s models show that utilising BrightSource’s technology in the North African deserts and assuming moderate learning curves will deliver levelised costs of electricity (LCOE) that will be cost competitive with European wholesale prices much sooner than the timeframe of 2020, which is the current reference point for the EU’s renewable energy, as well as various carbon reduction targets. A timeframe of 2015 certainly seems realistic.

Desertec – The Major Challenges

So what is holding back the advent of large solar export projects? Three issues will be highlighted here:

1. Novel Regulatory Environment

As much as the technology is proven and costs are on the brink of becoming competitive, such projects would be placed into a novel regulatory environment, which does not exist today. Gas export pipelines have been typically regulated by special treaties and laws, both within the exporting and importing nations, as well as between them. Neither of those exist for electricity export cables between North Africa and Europe today.

While the EU has given priority to energy infrastructure investments and operates a neighbourhood investment programme with Northern Africa, no attempts have yet been made to formalise an investment framework that would govern the installation of numerous electricity cables across the Mediterranean, either on a merchant-basis or in cooperation between national grid operators. However, a first interconnection project between Italy and Tunisia has now commenced with agreements on a bilateral basis.

Furthermore, besides novel South–North electricity cables, an expanding base of large-scale solar plants in Northern Africa will require reinforcements of electricity links between Northern African countries as well. Such links could be an important co-benefit of increased South–North electricity trade and increase intra-African trade of electricity and associated developments such as the provision of fresh-water through desalination.

2) 'First-of-a-kind' Risks

As much as the opportunity of solar export plants is enormous, the complexity of the task and the risks involved are significant hurdles in forming an industrial consortium to match them. The Desertec Industrial Initiative is an expression of the recognition of these complexities, with no one member firm willing to explore a solar export project on its own.

Agreements are needed to mitigate such issues as sovereign and electricity offtake risks, at least for the first plants. A model could be the loan guarantees currently provided for renewable energy projects in the USA, as well as precedents from the USA's nuclear policy. The 2005 Energy Policy Act provides financial guarantees against cost-overruns and construction delays of the first six nuclear reactors, as well as production tax credits for the first 6000MWh of annual production for the first eight years of operation of new nuclear power plants. Feed-in tariffs for imported electricity could be an alternative approach.

Our conversations with banks indicate that the arrangement of project finance will not be a major hurdle if these issues are addressed. CSP technologies have been project financed in the past and lending into Northern African countries is frequently occuring, often in syndications with multi-lateral financing institutions or development banks. The offtake in a mature electricity market such as the European adds to create a stable investment framework.

3) Scepticism in North African Countries

Currently, the increasing euphoria over Desertec in Europe is unmatched in the North African region. National development plans are often unambitious and lack clarity and detail with respect to crucial questions over finance and regulatory certainty. Furthermore, there is an aversion by North African countries to implement a perceived 'black box' technology from Europe or the USA, without deriving any local benefits in the form of technology transfer and know-how.

For Desertec to succeed clear commitments from European countries along those lines are required. In fact, one of the rationales for the World Bank's CTF programme is the recognition that the MENA region hosts one of the most promising solar radiation levels for the large-scale implementation of CSP projects, in contrast to the total potential in Europe itself. Decomposing solar tower CSP technology, and to a lesser extent trough technology, it can quickly be seen that most individual components are amenable to mass manufacturing by light industry clusters, precisely matching current industrial structures in North African countries such as Tunisia and Algeria. In fact, most of the know-how in solar tower technology is in the design, control and operations of the solar field. This can be transferred through technology collaboration and training in the actual implementation of CSP projects, which is precisely the objective of the Desertec initiative.

Recent policy developments are promising. The new EU Renewables Directive explicitly opens the door for member countries to support export projects and allows them to count towards their national renewable energy targets, subject to certain conditions. Initiatives such as the Mediterranean Solar Plan of the Mediterranean Union, the World Bank's $750m CSP lending facility for the MENA region and the DII are mobilising private and public sector actors on both sides of the Mediterranean Basin. Hence, a policy and investment framework for solar export projects has never been closer.

In summary, it is easy to see why advocates of the Desertec initiative have called for an 'Apollo'-programme to turn the vision of large-scale solar-export projects into reality. Several political, techno-economic and financial hurdles have to be overcome in order to create the conditions in which significant investments will flow into such projects. Still, the scale of the solution that Desertec offers can pay back these initial efforts many times over. Just 0.3 percent of the North African deserts' surface area would theoretically be required to serve the electricity and desalinated water needs of the entire MENA–EU region. A small fraction of this would already allow a significant percentage of Europe's electricity demand and renewable energy targets to be met. This is the backdrop to the energy devoted by many academics, policy-makers and private companies to solve this jigsaw and make Desertec a reality, not in the distant future but much sooner than many sceptics might think.

Asinus Muses

Asinus has been musing on oil markets. Or more accurately, Asinus has been listening to better-informed people meditate, deliberate and pontificate about oil markets at the Oxford Institute for Energy Studies' first *Oil Day*. Do speculators spoil an otherwise-honourable institution? Would regulation ruin legitimate businesses? Are the dramatic ups and downs even a problem in the first place? The well-groomed look of the great and good who attended was evidence enough that the vagaries of the oil price have not forced too much belt-tightening in their personal cases. But then a criterion for being great and good is the ability to look beyond the demands of one's own paunch to the larger needs of society – the topic of the day.

And what are those needs? With oil bouncing from \$147 to \$33 to \$80 in 15 months, it was widely agreed that less pronounced swings would be desirable. Widely, but not universally: Asinus spotted a loose but positive correlation between the amount of economics training a participant had and his or her equanimity with respect to oil's volatility. In Asinus's opinion this belies the mythic status of economics as a dismal science. At times it seems that economists, in fact, are bothered by very little, on the basis that everything has a perfectly good explanation even if we haven't spotted it yet. They seem to share the view that the Lord moves in mysterious ways, although the chap in question would be our friend the rationally optimising and forward-looking representative agent, rather than the big guy with the beard.

Why, on this view, might the grumbling be an over-reaction? Well, the oil price was high because the world and its demand for oil were growing fast. The oil price was low when it looked like the financial services sector had just delivered us back to the stone age. Now that confidence has returned, it is surely correct that oil is up again. Indeed, the futures curve has been rising, collapsing and recovering along with the prompt, suggesting that all was being driven by our friends the fundamentals.

But was it really the fundamentals? As after every great crash, certain observers have decried the shadowy figure of the speculator plying his evil trade at our expense. This shifty wretch allegedly fills his pockets with gold by betting against the side of the market composed of decent commercial producers or purchasers of petroleum, trying to make a living on the basis of true demand and supply fundamentals. (Asinus is interested to note that the financial market is perhaps the only arena in which fundamentalism is supposed to be the more honourable position.) Fortunately, it was unanimously agreed that this popular dichotomy is a confusion. If you enter the futures market you take a view on the price. If you are right you make money; if not, not. This simple logic determines the behaviour of all participants, commercial or financial, whether their core business is pumping oil, burning hydrocarbons, or shuffling bits of high-value paper. And those who have no more than little black boxes, betting simply on the numbers and the patterns they trace, or the positions of the stars, add no more than harmless daily noise.

Even if speculators are not the problem, many participants were not so content with the large swings in price. What should be done about them was a more difficult question. It seems there is one theme on which economists are reliably gloomy, and that is any attempt to try to do something about the imperfections that most of us perceive in the world. But in this case the economists were not alone: even if oil price swings are undesirable, many believed that attempts to regulate the price would be futile, disastrous or both. If energy markets are swept up in the anti-finance fervour of today's regulators, repentant at their former negligence, then smaller energy producers may find it impossible to raise money for legitimate investments. The sins of the banks should not be visited on the rest of us.

But on attempts to stabilise the oil price per se, a few radical voices stood out against the sceptics. Asinus has previously mentioned Robert Mabro's scheme, in which an Oil Price Committee, along the lines of the Monetary Policy Committee of the Bank of England, would manage the price with the support of the USA, Japan and Saudi Arabia. ENI have also come up with a scheme for stabilisation. Noting that spare capacity is required to manage the price, but that spare capacity does not pay, their plan involves all oil market participants paying a small tax to those who hold it to make it profitable. The thought of subsidising the Saudis may not have universal appeal – do they really need more 25-foot-long SUVs? But it can hardly be more galling than million-dollar bonuses to bankers in thanks for breaking the global economy.

Asinus, at least, (despite his economics training) can see the argument against the more sanguine view of the oil price. Indeed, it can be argued that the future's following of the prompt price makes a mockery of the notion that the market is engaged in 'price discovery'. In such circumstances allowing the futures price to guide our actions is like taking comfort in the fact that, when you turn to the right, your broken compass turns with you. The usual outcome in these circumstances is to walk in circles. As the more trigonometrically-minded will know, walking in circles on a moving path results in a sine wave. Throw in a couple of large whiskies and you get the oil price.

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