MEES RESEARCH

MEES- SINCE 1957

ENERGY & GEOPOLITICAL RISK

MEES RESEARCH SPECIAL REPORT

CONTENTS 3 NOVEMBER 2009

Analysis

Putin's Visit to Ankara And Russian Energy Interests in Southeast Europe

By Theodoros Tsakiris

In the course of a visit to Ankara in early August, Russian Prime Minister Vladimir Putin seems to have partially – but not entirely − revised a major policy decision he took in the immediate aftermath of the orange revolution in Ukraine in December 2004. As the Ukrainian gas corridor became increasingly controversial as the main export route for Russian gas to Europe, Mr Putin understood that the close geopolitical alignment between Turkey and Ukraine, manifested in Ankara's active promotion of Ukraine's NATO candidacy, necessitated the construction of a double bypass that would deny to both Turkey and Ukraine the role of transit states for Russian gas. The South Stream project, and particularly Greece's participation in it, was announced in June 2007 as a means of implementing this strategy. The significance of South Stream's route to Europe was not lost on Turkey, since its effective exclusion from the project was announced by then President Putin and Greek Prime Minister Costas Karamanlis on the sidelines of a Black Sea Cooperation organization summit held in Istanbul.

South Stream followed the same geostrategic logic of lessening Russia's transit dependence on Turkey that led to Moscow's decision to support the implementation of the Burgas-Alexandroupolis oil pipeline. For more than two years no mention was made of a potential Turkish role in the project, until 1 July 2009 when Russian deputy Prime Minister Igor Sechin invited Turkey to participate during a meeting in Moscow with Turkish Energy Minister Taner Yildiz. "We hope that the Turkish side will look at our offer and that we will cooperate further so that our offer is more attractive and clear to our partners," the Turkish daily *Hurriyet* quoted Mr Sechin as saying.

Mr Sechin also told reporters following his meeting with Mr Yildiz that there was no connection between Turkey's stand on Nabucco and his offer on South Stream. He avoided any direct criticism of Nabucco but did comment – when replying to a question on the comparative advantages of Nabucco and South Stream − that "economic accounting…should clearly show which project is the best." Mr Yildiz for his part said that in his view the two projects were complementary and that "neither is being regarded as a competitor." Despite the dearth of official comments from the Kremlin at the time, it was clear that Russia did not envision an extension of the South Stream project to Turkish soil but wanted to secure a "right of way" via parts of Turkey's Exclusive Economic Zone (EEZ) in Black Sea waters.

On 5 August, Yury Ushakov, Mr Putin's deputy chief of staff, told *RIA Novosti* that a protocol regarding the participation of Turkey in the South Stream project would be signed the following day in Ankara by Mr Putrin and Turkish Prime Minister Recep Tayip Erdogan. Mr Ushakov underlined that "Turkey will grant permission for the construction of the South Stream gas pipeline across its Black Sea sector." On 6 August the office of Italian Prime Minister Silvio Berlusconi

Publisher & Editor: Saleh S Jallad, **Consultant to Editorial Board:** Walid Khadduri
Assistant Editor: Theodoros Tsakiris
Editorial Review: Basim Itayim, Charles Snow

announced that Mr Berlusconi would also attend the signing ceremony of the protocol on South Stream that grants permission to Russia's Gazprom and Italy's Saipem to explore Turkey's Black Sea bed for the potential routing of the pipeline.

It should be emphasized that this is not a done deal as far as either side is concerned, being neither a finalized agreement nor a permit to transit the Turkish EEZ. *Hurriyet* quoted an unnamed senior energy official as saying on 4 August that Ankara is examining "its legal options" and questioning whether Turkey has the right to say no to the Russians or is obliged by international law to let the pipeline transit its economic zone.

The Russian Rationale

From the strategic point of view two major factors may be behind the Russian move:

(a) The need to prolong the deadlock between Turkey, Azerbaijan and the Nabucco consortium, a development that can only make the Russian offer over Shah Deniz 2 increasingly attractive. Despite a series of public statements suggesting that a resolution of the Azeri-Turkish impasse is imminent, the gap between Baku and Ankara remains as wide as ever, regardless of the Intergovernmental agreement on Nabucco which was also signed in Ankara on 13 July. The Nabucco IGA has created a framework and a timetable for the resolution of the Turkish-Azeri dispute, but it has yet to offer any real incentive to either side to move towards resolving the impasse.

(b) The need to avoid a confrontation with Ukraine over the route of the pipeline through the latter's EEZ in the Black Sea. Given the presence of Russia's Black Sea fleet and a majority of ethnic Russians in Crimea, a confrontation between Kiev and Moscow over the route of South Stream could easily escalate. Russia wants to finish the pipeline before a 1997 lend-lease agreement over the basing of its Black Sea fleet in Crimea comes up for renewal in 2017.

The Kremlin wants to be in as strong a position as possible on the energy front when the time comes to pressure Kiev to renew the leasing of the Crimean bases. If Kiev resists, Crimea's Russian population could conceivably demand the peninsula's separation from Ukraine, igniting a serious crisis. Moscow wants to be prepared to deal with this possibility without endangering the flow of gas to Europe.

It is important to note, though, that Russia is not yet fully committed to build the pipeline through the Turkish EEZ and could change its mind if a more pro-Moscow government comes to power in Kiev after the January 2010 presidential elections. Nonetheless Russia's Turkish option signals to the politicians in Kiev that they could lose yet more leverage in their complex relationship with the Kremlin, although a "right of way" via a country's EEZ is not as difficult to obtain from a legal and practical point of view as securing a transit agreement via a state's territory. According to international maritime law a state cannot refuse the passage of a major infrastructure project through its EEZ unless it has verifiably substantiated proof that the project under consideration would pose a serious environmental threat or obstruct the security of navigation.

In South Stream's case neither condition applies, as Turkey proved by agreeing to the construction of the underwater Blue Stream line through which it imported almost 10 bcm of gas last year. Technically Blue Stream and South Stream are identical, and Turkey is so confident of the environmental safety standards of Blue Stream that it has been lobbying Russia for the construction of a second parallel line, Blue Stream 2, that would be used to export Russian gas to Cyprus, Lebanon, Syria, Jordan and Israel.

Once the underwater pipeline is built the "transit" state has no technical ability to interfere with the flow of gas. There are no underwater metering stations, turbines and pressure points that could provide Turkey (or for that matter Ukraine) with the physical capacity to manipulate the flow of gas through South Stream. There will be no joint venture agreement to regulate the Turkish component of the South Stream project, which is why the strategic significance of Turkey's EEZ is somewhat limited. Routing the pipeline through Ukraine's EEZ could delay Russia's timetable for the implementation of South Stream**.** Russia's Energy Minister, Sergei Shmatko, told Prime-Tass news agency on 6 August that the geological surveys of Turkey's EEZ would start over the next few months – even during August 2009 according to some sources − so that the construction of the underwater section can begin no latter than November 2010. This is the second time Russia has moved up the date for the start-up of the project, since originally work on the Black Sea route was not due to begin before late 2011 or early 2012.

Ankara's Compensation

The addition of a re-export clause to existing gas import contracts, the construction of Turkey's first nuclear power plant at Akkuyu and potential exports of crude oil via the Samsun-Ceyhan oil pipeline constitute credible incentives to secure Ankara's agreement to South Stream's Black Sea transit. On the other hand, the construction of a second Blue Stream line to export Russian gas to the Middle East could be of limited importance after Israel's discovery of the offshore Tamar gas field. With Israel out of the picture as a potential gas consumer, there appears to be little interest from the Arab states of the eastern Mediterranean in a long-term import arrangement with Russia. The Arab Gas Pipeline (AGP) from Egypt to Syria and Turkey makes such a long-term commitment even less desirable.

Ankara is also eager to extend by 15-25 years a 6 bcm/year contract with Gazprom that expires in 2011 – but on condition that Gazprom allows it to re-export part of the volume. Gazprom has rejected all of Ankara's earlier requests to permit the resale of its gas, but might agree to a joint marketing arrangement for customers such as Syria and Lebanon for at least a limited period of time.

Turkish Energy Minister Taner Yildiz and Syrian Petroleum Minister Sufian 'Alaw on 14 July announced the signature of a final agreement on the construction of a 153km pipeline to connect the two national gas systems The 28-inch pipeline is designed to have an initial throughput capacity of 2 bcm/y with the ultimate purpose of linking up to the 10 bcm/y AGP. By adding more compressors the line's export capacity is expected to double to around 4 bcm/y, but it will be initially utilized in a reverse flow capacity so as to allow for Syrian imports of 1-2 bcm/y of gas.

Gazprom's construction subsidiary Stroytransgaz is contracted to complete the pipeline on the Syrian part of the border. Mr 'Alaw said that Syria needs to import gas from both Egypt and Turkey for a period of over 5-6 years before an expected rise in domestic production would be sufficient to meet its domestic needs.

The Oil Factor

Turkey is also trying to expand its role as a potential transit state for Russian oil exports. Mr Yildiz said during a press conference with his Russian counterpart on 5 August that Gazprom's oil subsidiary Gazpromneft would be interested in joining the Samsun-Ceyhan oil pipeline project or TAPCO, the Trans Anatolian Pipeline Company. The $1.5bn pipeline, which is being built by the owners of TAPCO, Calik Energy of Turkey and Italy's ENI, will extend 700 km (435 miles) through Turkey from the Black Sea port of Samsun to the port of Ceyhan, the terminal point of the Baku-Tbilisi-Ceyhan (BTC) oil pipeline. According to the *Ihlas News Agency*, Mr Yildiz said that Russia may supply oil for the planned 1.0-1.5 mn b/d Samsun-Ceyhan pipeline.

Prime Minister Putin's deputy chief of staff, Yury Ushakov, told *RIA Novosti* on the same day that the two sides "would set up a working group on the Samsun-Ceyhan." Last month Gazprom's Deputy CEO said in an interview with Bloomberg that Gazpromneft would be interested in joining the project. Last April, ENI said it would fully finance the project's engineering phase, to be completed by the end of 2010, and would take a final investment decision after that. The cost of the project could be some $4bn (€2.8bn), but its prospects appear to be rather doubtful.

Despite the fact that ENI is a major (32.5%) shareholder in the consortium developing the onshore Karachaganak field in north-western Kazakhstan, it has very little influence over Karachaganak oil's destination once it is linked to the Russian-controlled Caspian Pipeline Consortium (CPC) pipeline to the Black Sea port of Novorossiysk. ENI holds, via Agip International NV, a mere 2% of CPC's shares. Shell, which appeared interested in participating in TAPCO in June 2008, could add another 3.75% through its participation in CPC via the Caspian Ventures Ltd Company with Rosneft. Yet it is far from certain that the Russian state company – or any other Russian controlled company for that matter − would agree to support a Turkish oil pipeline as long as the Burgas-Alexandroupolis line remains incomplete.

That rules out just about all of Kazakhstan's output from currently operating fields in Karachaganak and Tengiz. Shell is no more able than ENI to divert a significant share of the current CPC capacity throughput of 750,000 b/d towards TAPCO. In reality it is very unlikely that the Russians would seriously consider any commitment of crude to TAPCO before Burgas-Alexandroupolis is operating at a capacity of 700,000 b/d. In addition to that, since February 2006 Russia has made the near doubling of CPC's capacity a precondition for the future expansion of Burgas-Alexandroupolis to a capacity of 1-1.2mn b/d or – at the very least – the completion of the project's first phase.

The Greek-Bulgarian pipeline would still need a commitment of about 300,000-350,000 b/d of CPC crude in order to reach its initial transit capacity of 700,000 b/d. If a portion of Kashagan's oil were to find its way into Novorossiysk via an expanded CPC, Moscow would be more likely to feed it into an already operational Burgas-Alexandroupolis rather than underwriting yet another Turkish-dominated project, even though it is possible that Russia could offer some support to TAPCO after Burgas-Alexandroupolis is up and running.

TAPCO partners are also targeting additional crude commitments from Azerbaijan, which do not appear to be a realistic prospect. The only producer whose geopolitical interests are completely aligned with a pipeline project that would further decrease Russia's geo-strategic standing in the region, is none other than Azerbaijan. The basic problem with Azerbaijan is that the near entirety of its 5.4bn barrels of petroleum reserves are committed to the Baku-Tbilisi-Ceyhan line. Even that commitment does not appear to be enough to ensure the sustainability of the project, given the fact that Azerbaijan is desperately seeking Kazakhstan's assistance in order to safeguard BTC's long-term profitability. At the end of the day that is the backbone of the Kazakhstan Caspian Transport System (KCTS) project that envisions feeding up to 500,000 b/d of Kazakh crude into the BTC line before the middle of the next decade.

There is no commercial reason for Baku to send its oil to Ceyhan via a major detour passing though either Supsa or Novorossiysk. If Kazakh, and more particularly Kashagan, oil gets as far as Baku, there is no reason why should it reach Ceyhan in any other way than via the BTC. The only scenario in which such a detour would make any sense is a complete shut-down of the BTC due to a new round of Azeri-Armenian clashes in Nagorno-Karabakh or the potential re-ignition of Georgia's ethnic conflicts with Abkhazia and South Ossetia. In this case though, Kazakhstan is almost certain either to utilize the CPC line or increase its swap-deals with Iran. Baku may also be tempted to use the Baku-Novorossisk line in order to bypass a war torn Georgia.

That is why it is still unclear if the Russian-Turkish "joint working group" has any real practical value. Russia has already committed around 350,000-400,000 b/d to the Burgas-Alexandroupolis pipeline and would have to divert its oil shipments via the Bosporus in order to contribute crude volumes to TAPCO. Russia and Kazakhstan have stated that they would use up to 300,000-350,000 b/d from CPC's expansion to feedstock the completion of the 700,000 b/d Burgas-Alexandroupolis project. That would leave almost 300,000-350,000 b/d for a potential Russian-Kazakh contribution to the TAPCO project before Kashagan's production comes on stream. TAPCO would still need up to 1mn b/d in order to operate at full capacity and it would have to compete not only with Burgas-Alexandroupolis (in its second development phase to 1mn b/d) but also with BTC for a share of Kashagan's output.

Report

The following report on Peak Oil, published in October 2009 by the UK Energy Research Centre, is based on a review of over 500 studies and the analysis of industry databases and global supply forecasts.

Abundant supplies of cheap liquid fuels form the foundation of modern industrial economies and at present the vast majority of these fuels are obtained from 'conventional' oil. But a growing number of commentators are forecasting a near-term peak and subsequent terminal decline in the production of conventional oil as a result of the physical depletion of the resource. Many believe that this could lead to substantial economic dislocation, with alternative sources being unable to 'fill the gap' on the timescale required. In contrast, other commentators argue that liquid fuels production will be sufficient to meet global demand well into the 21st century, as rising oil prices stimulate exploration and discovery, the enhanced recovery of conventional oil and the development of 'non-conventional' resources such as oil sands. The first group claims that physical depletion will have a dominant influence on future oil supply, while the latter emphasise how depletion can be mitigated by investment and new technology. A concern for both is whether the relevant organisations will have the incentive and ability to invest.

Despite much popular attention, the growing debate on 'peak oil' has had relatively little influence on energy and climate policy. Most governments exhibit little concern about oil depletion, several oil companies have been publicly dismissive and the majority of energy analysts remain sceptical. But beginning in 2003, a combination of strong demand growth, rising prices, declining production in key regions and ominous warnings from market analysts has increased concerns about oil security. While the global economic recession has brought oil prices down from their record high of July 2008, the International Energy Agency (IEA) is warning of a near-term 'supply crunch' owing to the cancellation and delay of many upstream investment projects. There is a growing consensus that the age of cheap oil is coming to an end.

Without sufficient investment in demand reduction and substitute sources of energy, a decline in the production of conventional oil could have a major impact on the global economy. In addition, the transition away from conventional oil will have important economic, environmental and security implications which need to be anticipated if the appropriate investments are to be made. While the timing of a future peak (or plateau) in conventional oil production has been a focus of debate, what appears equally important is the rate at which production may be expected to decline following the peak and hence the rate at which demand reduction and alternative sources of supply may be required. In addition, there are uncertainties over the extent to which the market may be relied upon to signal oil depletion in a sufficiently timely fashion.

Overview

This report addresses the following question:

What evidence is there to support the proposition that the global supply of 'conventional oil' will be constrained by physical depletion before 2030?

The report is based upon a thorough review of the current state of knowledge on oil depletion, supplemented by data analysis and guided by an Expert Group. A total of seven supporting reports have been produced and are available to download from the UKERC website. This synthesis report clarifies the concepts and definitions relevant to the 'peak oil' debate, identifies the strengths and weaknesses of different methods for estimating the size of oil resources and for

forecasting future supply, highlights the degree of uncertainty associated with key issues, compares contemporary forecasts of oil supply and assesses the risk of a near-term peak in oil production.

The report focuses on 'conventional oil', defined here to include crude oil, condensate and natural gas liquids (NGLs) but to exclude liquid fuels derived from oil sands, oil shale, coal, natural gas and biomass. Conventional oil is anticipated to provide the bulk of the global supply of liquid fuels in the period to 2030 and its resource base is comparatively depleted. A peak in conventional oil production will only be associated with a peak in liquid fuels supply if 'non-conventional' sources are unable to substitute in a sufficiently timely fashion. While the economic potential of non-conventional fuels is of critical importance, it is beyond the scope of this report.

The report also focuses on the broadly 'physical' factors that may restrict the rate at which conventional oil can be produced, including the production profile of individual fields and the distribution of resources between different sizes of field. While these are invariably mediated by economic, technical and political factors, the extent to which increased investment can overcome these physical constraints is contested. Global oil supply is also influenced by a much wider range of economic, political and geopolitical factors (e.g. resource nationalism) and several of these may pose a significant challenge to energy security, even in the absence of 'below-ground' constraints. What is disputed, however, is whether physical depletion is *also* likely to constrain global production in the near-term, even if economic and political conditions prove more favourable. In practice, these 'above ground' and 'below ground' risks are interdependent and difficult to separate. Nevertheless, this report focuses primarily on the latter since they are the focus of the peak oil debate.

The report does not investigate the potential consequences of supply shortages or the feasibility of different approaches to mitigating such shortages, although both are priorities for future research.

Key Conclusions

The main conclusions of the report are as follows:

1. *The mechanisms leading to a 'peaking' of conventional oil production are well understood and provide identifiable constraints on its future supply at both the regional and global level.*

- Oil supply is determined by a complex and interdependent mix of 'above-ground' and 'below-ground' factors and little is to be gained by emphasising one set of variables over the other. Nevertheless, fundamental features of the conventional oil resource make it inevitable that production in a region will rise to a peak or plateau and ultimately decline. These features include the production profile of individual fields, the concentration of resources in a small number of large fields and the tendency to discover and produce these fields relatively early. This process can be modelled and the peaking of conventional oil production can be observed in an increasing number of regions around the world.

- Given the complex mix of geological, technical, economic and political factors that affect conventional oil production, anticipating a forthcoming peak is far from straightforward. However, supply forecasting becomes more reliable once access is available to the appropriate data and the range of 'possible futures' becomes more constrained once the resource is substantially depleted. This is increasingly the case at the global level.

2. *Despite large uncertainties in the available data, sufficient information is available to allow the status and risk of global oil depletion to be adequately assessed.*

- Publicly available data sources are poorly suited to studying oil depletion and their limitations are insufficiently appreciated. The databases available from commercial sources are better in this regard, but are also expensive, confidential and not necessarily reliable for all regions. In the absence of audited reserve estimates, supply forecasts must rely upon assumptions whose level of confidence is inversely proportional to their importance – being lowest for those countries, including key OPEC members that hold the majority of the world's reserves.

- Data uncertainties are compounded by errors in interpretation and the slow progress towards standardisation in reserve reporting. For example, it is statistically incorrect to simply add the estimates of 'proved' reserves from different oil fields to obtain a regional total. Doing so may lead to an underestimation of reserves at the regional and global level which could potentially offset any overestimation of those reserves by key producing countries. Hence, the debate on oil depletion would benefit from improved understanding of the nature and limitations of the available data.

3. *There is potential for improving consensus on important and long-standing controversies such as the source and magnitude of 'reserves growth'.*

- The distribution of conventional oil resources between different sizes of field is increasingly well understood. Although there are around 70,000 oil fields in the world, approximately 25 fields account for one quarter of the global production of crude oil, 100 fields account for half of production and up to 500 fields account for two thirds of cumulative discoveries. Most of these 'giant' fields are relatively old, many are well past their peak of production, most of the rest will begin to decline within the next decade or so and few new giant fields are expected to be found. The remaining reserves at these fields, their future production profile and the potential for reserve growth are therefore of critical importance for future supply.

- Estimates of the recoverable resources of individual fields are commonly observed to grow over time as a result of improved geological knowledge, better technology, changes in economic conditions and revisions to initially conservative estimates of recoverable reserves. This process appears to have added more to global reserves over the past decade than the discovery of new fields and it seems likely to continue to do so in the future. While the contribution of different factors varies widely between different fields and regions, 'reserve growth' does not appear to be primarily the result of conservative reporting.

- Reserve growth tends to be greater for larger, older and onshore fields, so as global production shifts towards newer, smaller and offshore fields the rate of reserve growth may decrease in both percentage and absolute terms. At the same time, higher oil prices may stimulate the more widespread use of enhanced oil recovery techniques. The suitability of these techniques for different sizes and types of field and the rate at which they may be applied remain key areas of uncertainty.

- The oil industry must continually invest to replace the decline in production from existing fields. The average rate of decline from fields that are past their peak of production is at least 6.5%/year globally, while the corresponding rate of decline from all currently-producing fields is at least 4%/year. This implies that approximately 3mn b/d of new capacity must be added each year, simply to maintain production at current levels - equivalent to a new Saudi Arabia coming on stream every three years.

- Decline rates are on an upward trend as more giant fields enter decline, as production shifts towards smaller, younger and offshore fields and as changing production methods lead to more rapid post-peak decline. As a result, more than two thirds of current crude oil production capacity may need to be replaced by 2030, simply to prevent production from falling. At best, this is likely to prove extremely challenging.

- Oil reserves cannot be produced at arbitrarily high rates. There are physical, engineering and economic constraints upon both the rate of depletion of a field or region and the pattern of production over time. For example, the annual production from a region has rarely exceeded 5% of the remaining recoverable resources and most regions have reached their peak well before half of their recoverable resources have been produced. Supply forecasts that assume or imply significant departures from this historical experience are likely to require careful justification.

4. *Methods for estimating resource size and forecasting future supply have important limitations that need to be acknowledged.*

- The ultimately recoverable resources (URR) of a region depend upon economic and technical factors as much as geology and can only be estimated to a reasonable degree of confidence when exploration is well advanced. Although widely criticised, simple 'curve-fitting' techniques for estimating URR have an important role to play when fieldlevel data is not available and also have much in common with more sophisticated methods such as 'discovery process modelling'. But they are best applied to well-explored and geologically homogeneous areas with a consistent exploration history. Since many regions do not meet these criteria, errors are likely to result.

- Many analysts have paid insufficient attention to the limitations of curve-fitting techniques, such as the sensitivity of the estimates to the choice of functional form, the frequent neglect of future reserve growth and the inability to anticipate future cycles of production or discovery. This has led to underestimates of regional and global URR and has contributed to excessively pessimistic forecasts of future supply.

- Methods of forecasting future oil supply vary widely in terms of their theoretical basis, their inclusion of different variables and their level of aggregation and complexity. Each approach has its strengths and weaknesses and no single approach should be favoured in all circumstances. Bottom-up models using field or project data provide a fairly reliable basis for near to medium-term forecasts, but many existing models are hampered by their reliance on proprietary datasets, lack of transparency, neglect of economic variables and requirement for multiple assumptions. Sensitivity testing and the presentation of uncertainties remain the exception rather than the rule.

- The timing of a global peak (or plateau) in conventional oil production may be estimated to within decadal accuracy assuming a particular value for the global URR and no significant disruptions to the oil market. But given the potential for political, economic, or technological disruptions, no model can provide estimates of great precision. Increasing model complexity does little to address this problem and is subject to rapidly diminishing returns.

5. *Large resources of conventional oil may be available, but these are unlikely to be accessed quickly and may make little difference to the timing of the global peak.*

- Although estimates of the global URR of conventional oil have been trending upwards for the last 50 years, the most recent estimates from the US Geological Survey (USGS) represent a substantial departure from the historical trend. Contemporary estimates now fall within the range 2,000-4,300 billion barrels (Gb), compared to cumulative production through to 2007 of 1,128 Gb. This wide range leads to a corresponding uncertainty in global supply forecasts. But despite their apparent optimism, assertions that the USGS estimates are 'discredited' are at best premature. Global reserve growth appears to be matching the USGS assumptions and although the rate of new discoveries is lower than implied by the USGS, the size of these discoveries may have been underestimated and there are continuing restrictions on exploration in some of the most promising areas.

- The timing of the global peak for conventional oil production is relatively insensitive to assumptions about the size of the global resource. For a wide range of assumptions about the global URR of conventional oil and the shape of the future production cycle, the date of peak production can be estimated to lie between 2009 and 2031. Although this range appears wide in the light of forecasts of an imminent peak, it may be a relatively narrow window in terms of the lead time to develop substitute fuels. In this model, increasing the global URR by one billion barrels delays the date of peak production by only a few days (for comparison, the cumulative production from the UK is approximately 24 Gb). Delaying the peak beyond 2030 requires optimistic assumptions about the size of the recoverable resource combined with a slow rate of demand growth prior to the peak and/or a relatively steep decline in production following the peak. These considerations constrain the range of plausible global supply forecasts.

- Although more optimistic estimates of the global URR of conventional oil appear plausible, much of this is located in smaller fields in less accessible locations. If (as seems likely) these resources can only be produced relatively slowly at high cost, supply constraints may inhibit demand growth at a relatively early stage. Demand growth may also be constrained if the national oil companies that control much of these resources lack the incentive or ability to invest.

6. *The risks presented by global oil depletion deserve much more serious attention by the research and policy communities.*

- Much existing research focuses upon the economic and political threats to oil supply security and fails to either assess or to effectively integrate the risks presented by physical depletion. This has meant that the probability and consequences of different outcomes has not been adequately assessed.

- The short term future of oil production capacity, to about 2016, is relatively inflexible, because the projects which will raise supply are already committed. Reasonable short-term forecasts for any region can be constructed using widely available public data. The primary issue for the short term is the cancellation and delay of these projects as a result of the 2008 economic recession and the consequent risk of supply shortages when demand recovers.

- For medium to long-term forecasting, the number and scale of uncertainties multiply making precise forecasts of the timing of peak production unwarranted. Nevertheless, we consider that forecasts that delay the peak of conventional oil production until after 2030 rest upon several assumptions that are at best optimistic and at worst implausible. Such forecasts need to either demonstrate how these assumptions can be met or why the constraints identified in this report do not apply. On the basis of current evidence we suggest that a peak of conventional oil production before 2030 appears likely and there is a significant risk of a peak before 2020. Given the lead times required to both develop substitute fuels and improve energy efficiency, this risk needs to be given serious consideration.

Policy Implications

The evaluation of different mitigation options is beyond the scope of this report. However, three general comments may be made.

- First, it seems likely that mitigation will prove challenging owing to both the scale of investment required and the associated lead times. For example, a report for the US Department of Energy argues that large-scale programmes of substitution and demand reduction need to be initiated at least 20 years before the peak if serious shortfalls in liquid fuels supply are to be avoided (Hirsch, et al, 2005). While this report overlooks many important mitigation options (e.g. public transport, electric vehicles) it also assumes a relatively modest post-peak decline rate (2%/year) and ignores environmental constraints. Hence, even 2030 may not be a distant date in terms of developing an appropriate policy response.

- Second, although many measures associated with climate change policy will help to mitigate the effects of oil depletion, there will be strong incentives to exploit high carbon non-conventional fuels. Converting one third of the world's proved coal reserves into liquid fuels would result in emissions of more than 800 billion tonnes of carbon dioxide (CO2), with less than half of these emissions being potentially avoidable through carbon capture and storage. This compares to recommendations that total future emissions should be less than 1,800 billion tonnes if the most likely global warming is to be kept to 2˚C (Allen, et al, 2009). Hence, early investment in low-carbon alternatives to conventional oil is of considerable importance.

- Third, investment in large-scale mitigation efforts will be inhibited by oil price uncertainty and volatility and seems unlikely to occur without significant policy support. This investment can be encouraged by measures comparable to those being established within national climate programmes. But greater and more rapid change than is currently envisaged could potentially be required. For this to become politically feasible requires both improved understanding and much greater awareness of the risks presented by global oil depletion.