



JOINT TRANSPORT RESEARCH CENTRE

*Discussion Paper No. 2007-19
December 2007*

Medium-term Oil Market Uncertainties

**Lawrence EAGLES
International Energy Agency
Paris, France**

The views expressed in this paper are those of the author and do not necessarily represent positions of the International Energy Agency, the OECD or the International Transport Forum.

Medium Term Oil Market Uncertainties

Lawrence Eagles
Head, Oil Industry & Markets Division
IEA

OVERVIEW	4
Demand Methodology	4
Forecasting Uncertainties	5
Prices	5
Substitution.....	7
Subsidies.....	9
Economic growth.....	9
Data	10
Biofuels.....	11
SUPPLY-SIDE UNCERTAINTIES.....	12
Project slippage.....	13
Decline Rates	13
INVESTMENT	15
Prices	15
Operating environment and constraints.....	15
OPEC Supply	17
CONCLUSION.....	18

Paris, Revised January 2008

OVERVIEW

The oil market has changed dramatically over the past 8 years, with prices rising from \$10 to over \$90/barrel. The dynamics of the industry have changed, but there is still considerable debate over whether this represents a paradigmatic shift of supply and demand conditions or is simply a result of longer term cyclical factors. Non-OECD oil demand growth is running three times faster than in the OECD, and is set to surpass the OECD in volumetric terms in the middle of the next decade. Non-OPEC supplies have plateaued over the past five years and look set to remain at such levels for the coming five years. Understanding the drivers behind these shifts gives an insight into the prospects for the coming years. However, even looking five years forward, there are many variables which could affect the outcome. These forecasts therefore provide a guide to the future, but should not be expected to project supply and demand with pinpoint accuracy. Equally important is the need to understand the uncertainties which lie behind any forecast that could change the final outcome.

This paper derives from the extensive work undertaken by the International Energy Agency for its Medium Term Oil Market Report, and looks at the variables and forecasting uncertainties that could alter the forecast path.

Demand Methodology

Our econometric demand model is primarily driven by the GDP assumptions provided by the IMF's World Economic Outlook, combined with a price assumption of IEA import prices (derived from the prevailing ICE¹ Brent futures curve). Using historical data, this model is adjusted to account for short-term factors (unseasonable weather variations, retail tax changes, etc.) and longer-term structural shifts (such as interfuel substitution, changes in the vehicle fleet or petrochemical expansions, and policy changes etc), in order to determine an underlying demand trend by product and country.

This 'top-down' approach implies calculating income and price elasticities for every major product group for all countries in the world. This allows us to assess the global trends for each individual product market – which can often be very different from an assessment based on total oil demand. For example, transportation fuels tend to be more income-sensitive, while fuel oil, which is more readily substitutable, is more price sensitive.

1. The New York Stock Exchange's Intercontinental Exchange. ICE's energy futures business is run by its London based subsidiary, ICE Futures Europe.

Our demand analysis is complemented by ‘bottom-up’ sectoral analysis, which focus on changes in end-user demand – for example, the impact of the switch from gasoline to diesel vehicles in Europe, the effects of the rapid expansion of petrochemical capacity in Asia and the Middle East, or the growing use of natural gas and coal for power generation in Europe. Although this approach provides a valuable comparison with the main ‘top-down’ assessment, its results must be interpreted with caution. For example, will there be sufficient feedstock supply (predominantly naphtha) to sustain China’s petrochemical expansion plans? Will this expansion result in a regional petrochemical surplus, leading to the closure of less efficient plants?

Forecasting Uncertainties

Global demand is predominantly driven by two primary forces, price and income. If the assumptions underlying those variables are wrong, then the output of the model will be affected. Similarly, the robustness of the historical data underpinning the model is important. Finally, substitution issues can work in many ways, leading to additional modelling complications.

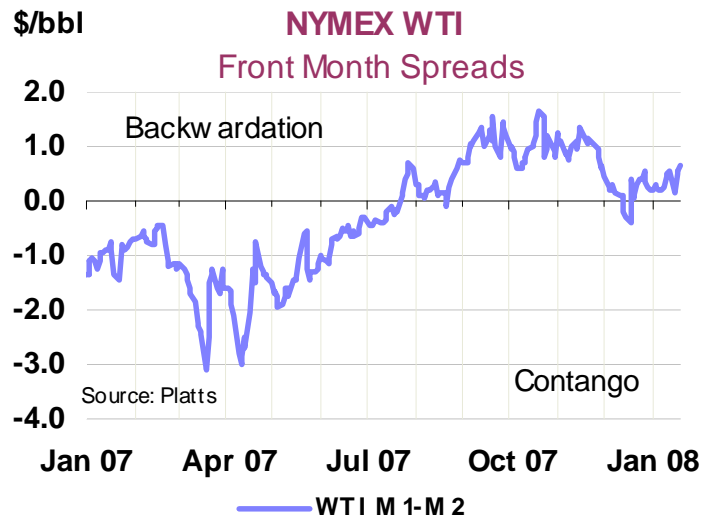
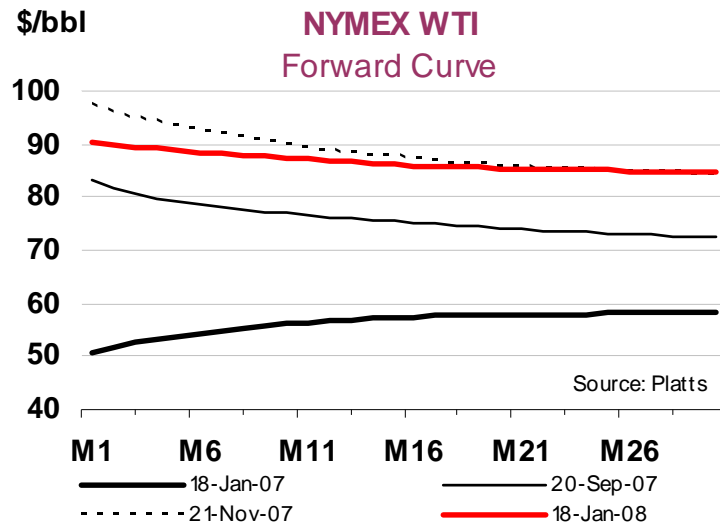
Prices

When constructing our medium-term forecasting model, a price assumption was one of the harder concepts to incorporate. The dynamics of the oil market have changed considerably over the past five years and we are unaware of any formal price model that predicted a rise in the oil price from \$25 to \$90/bbl over the past four years. The seemingly robust relationship between oil stocks in the OECD and prices appeared to break down. Additional inputs such as refining capacity, spare upstream capacity, investment flows, natural gas prices and the term structure changes between spot and forward prices have all had an impact.

Ultimately, the decision was taken to use a price assumption derived from average IEA import prices and the futures curve. This provided the opportunity to look at future developments under current market assumptions. By definition, this also means that the rest of the model is assessed under the same conditions – i.e., it is a static model designed to highlight where current market forecasts potentially lead to imbalances. These imbalances, in our opinion, offer the greatest insight into the medium term market direction. The medium term forecasts are therefore not the outcome of a dynamic equilibrium model of oil supply and demand.

There is a lively academic debate over the usefulness of the futures curve in predicting market prices. Although a market derived price allows consumers and producers to fix prices up to seven years in the future (by effectively purchasing the right to buy or sell oil in the future at a price fixed today), the only portion of the futures curve that has a strong predictive record is the refining margin derived from NYMEX crude, gasoline and heating oil futures curves, as evidenced by empirical studies. Under tight market conditions, the spot oil price tends to trade above forward months to form a “backwardated” price structure. The steepness of the curve

tends to reflect the relative scarcity of spot material, and the formation is therefore generally associated with rising prices. As such, while cyclically prices may be expected to fall once a bull market has finished, a backwardated market curve shows limited explanatory insight during the rising price trend.



The opposite situation is a “contango” structure, generally seen when the oil market is amply supplied and the spot price is below forward prices. Market theory shows that there should be an upper limit to the forward price rise representing the cost of storage, finance and insurance at the point of pricing. Typically, a contango structure

is associated with falling prices, which again is of limited value except at the bottom of a bear market, where prices are expected to rise. However, over the course of the past four years, the average rise in oil prices has been over \$12 per year, with intra-year volatility sometimes being over \$20/barrel both up and down. Atypically, this rise in prices has also been associated with a contango structure for the past two years.

However, while the traditional relationship of a contango market and falling prices has been turned on its head, there remains a strong link between the spot and forward price differential and stock levels. Unusually, crude prices have been rising, despite rising stockpiles. This has led to considerable debate between analysts: has the rising crude price been a reflection of anticipated longer term oil market tightness and the need for more investment and energy conservation? Is it a complex interaction reflecting the mismatch between the structure of crude product demand and spare refining capacity, or merely a distortion relating to the large inflows of passive investment money into commodities?

Ultimately, by using a futures curve, the MTOMR produces a forecast that displays potential imbalances in the future that could necessitate further price shifts to achieve the necessary equilibrium outcome, rather than trying to adjust the price to induce market balancing shifts in supply or demand. Arguably, as the market has shown over the past few years, stock shifts, which are of little relevance in long term projections, can considerably influence medium term outcomes.

Substitution

Interfuel substitution is in essence a further price effect, but one much harder to model. The most obvious fuel shift both to and away from oil involves the usage of natural gas in the power generation sector. Unfortunately, there is no global natural gas price through which these effects can be easily modelled. As planning and construction of gas-fired power generation takes years, the structural shift away from oil is derived from an expected long term running cost advantage for natural gas. However, as long as there is fuel switching capacity or idled capacity that can quickly be brought back into service, there can be shorter-term substitutions.

While the expansion of LNG trade may lead to a convergence of prices around the world, a large number of natural gas supply contracts (in Europe and Asia) are related to oil prices. This can lead to shifts in power generation demand for natural gas that are unrelated to economic trends in gas supply and demand. Where natural gas prices are derived from a long-term moving average of oil prices, volatility in the oil price can lead to periods where there are significant differences between oil and natural gas prices. Ultimately, in these instances, US natural gas futures prices can be used as a barometer for fuel switching potential. Nevertheless, increased fuel oil demand is either related to natural gas generating capacity constraints, supply issues, or weather-related demand surges, rather than outright price shifts.

Therefore, the price elasticities for fuel oil are extremely difficult to calculate and are often nonsensical, so a judgemental approach to power demand is usually required.

Emissions regulations are likely to further complicate oil demand projections, and particularly those of fuel oil use. The IEA's Medium Term Gas Market Review indicated the potential for gas market tightness in key areas beyond 2010, as natural gas-fired power generation capacity expands at a level that may be incompatible with regional supply growth. Typically, short-term power generation issues are often resolved by turning to fuel oil as a temporary fuel source. Beyond 2010, however, considerable investment in refinery upgrading capacity may lead to a tightening of the fuel oil market.

With emissions regulations making it difficult to restart old coal power generation plants, there is the potential for sharp upward price pressures in both fuel oil and natural gas prices, which would be felt across the petroleum sector. With the refining industry effectively converting fuel oil into transportation fuels at that point, any increase in fuel oil demand would lead to a decrease in the supply of transportation fuels. Ultimately, tightness in natural gas supplies could lead to a tightening gasoline balance. The question that arises, therefore, is at what point (if at all) would governments decide that it is better to suspend emissions constraints to allow idled coal generation capacity if the alternative were sharply rising oil and gas prices or power shortages.

The petrochemicals industry is another area where there can be significant inter-fuel substitution. While there are some instances where natural gas and biofuels have substituted oil product inputs into petrochemicals, substitution generally occurs between different petroleum products. LPG, naphtha, gasoil, NGLs and condensates can all be largely interchangeable. The demand for these products will be related not only to their relative price, but also to their availability, which in turn can be related to the demand for other products, available capacity and natural gas investments. Again, these differences mean that price elasticities for these products require an in-depth understanding of the sector, together with a necessarily judgemental approach to demand.

Substitution, however, is not simply an input effect. For example, significant shifts have been seen away from base metals to plastics in recent years in two key areas – construction and beverages. The popularity of the PET bottle has displaced aluminium demand from the canning industry. Pet bottles have the twin advantage of lower weight and resealability – benefits for consumer, distributor and marketer. Similarly, in the construction industry the rampant rise of copper prices in recent years has led to significant market penetration of plastics in domestic and industrial plumbing. Both examples are areas where innovation, availability and price could significantly affect oil demand patterns in years to come – particularly in the petrochemical sector. Similarly, waste management in many OECD countries is putting pressures on the use plastics in packaging and other areas – again, an area where substitution may be induced in a relatively short period of time.

Subsidies

A further area of forecast uncertainty is fuel subsidies. Price and income effects tend to be larger in developing economies, but with state administered prices prevalent in a large number of populous non-OECD consuming countries, the spot price is not necessarily reflective of local market conditions. Indonesia provides a good example of the impact and uncertainty caused by heavy oil subsidies, which at current prices are expected to cost in excess of \$5bn/year. An attempt to raise oil prices in 2005 led to significant social unrest, and had to be partially undone shortly afterwards. As prices rose, there were significant swings in local demand, but with smuggling in the region commonplace, it was difficult to determine how much of the demand swing was related to pre-emptive local stockpiling and reduced smuggling and how much final consumption was lowered. The rapid rise in oil prices in 2006 meant that subsidies were effectively re-introduced. Indonesia is perhaps a micro-study of regional uncertainty, and the prevalence of (lesser) subsidies in China and India mean that price effects could be much larger at some point in the future, therefore distorting demand growth. The Middle East is a further key demand growth area where fuel prices are heavily subsidised. Again, although domestic pressures to liberalise prices are less (due to rising oil incomes), the policy shifts could alter the path of demand via price effects.

Economic growth

The IEA demand forecasts are based on GDP projections derived from work undertaken by the IMF and OECD. These they are subject to forecast uncertainty that has been covered extensively by the agencies themselves. At the present time, both agencies warn there are considerable uncertainties to the downside, which confer similar downside risks to oil demand. From a longer-term perspective, unless the trend in GDP growth alters dramatically from the projection, cyclical swings are likely to even out. In a five-year time horizon, a recession or boom could considerably alter the projected outcome.

Immigration is a further issue to consider. The expansion of the EU has led to widespread worker migration, leading to rapid population expansions in wealthier countries. With oil income elasticities being driven by income per capita changes, shifts in migration could have an important impact. In the UK, for example, our assumption of relatively static population growth may be too low. Migrant worker growth may have added several million to the UK population over the past few years, while one study group projected that the higher birth rates of migrant workers could lead to a significant population increase in the next 20 years. Such shifts in worker migration could raise per capita GDP, and could distort growth rates. Similarly, some studies have attributed recent growth in US gasoline demand to shifts in migrant workers. Ultimately, though, in the case of many countries we may have to wait 10 years for accurate census data on the population to provide a benchmarking snapshot.

Data

Turning to forecasting uncertainties, in addition to those surrounding future economic growth and oil price evolution (notably at the retail level), the predictive power of any demand forecast is largely dependent upon the availability and quality of the historical data underlying the projections. In countries where the collection of detailed oil statistics is still in its early stages, both data (and revisions) may be inaccurate. This may lead to an over- or understatement of demand, thus distorting the calculation of income and price elasticities upon which the forecasting model is based. In the case of Asia, for example, revisions have tended historically to be upward, suggesting that current demand may be understated. Moreover, many non-OECD countries do not include stock data, obliging analysts to estimate demand on an ‘apparent’ basis.

Supply-side data is far from perfect, but historically, the larger revisions have come from the demand side. This is partly due to the fact that in many areas, national supply-side data can be double-checked with results from oil companies. In many cases in non-OPEC countries, supplies can be aggregated independently on a field-by-field basis. However, that is not the case for all countries. A lack of field data and a lack of detailed and consistent methodology for reserve reporting makes estimates for rates of decline in production difficult in many regions.

Similarly, it is clear that at times, politics have played a role in reserve estimation in some OPEC countries. During the late 1980s and early 1990s reserve levels within the producer group had an influence on daily production targets. At that time, there seemed to be an increase in proven reserve levels more to maintain market share than through technological innovation or discovery.

Demand however typically relies on accurate reporting from the refining, distribution, stock holding and import/export sectors to central government data collection. The Joint Oil Data Initiative (JODI) is a welcome attempt to improve data availability and quality. Nevertheless, despite the efforts of its members (IEA, OPEC, APEC, UNSD, OLADE and Eurostat), the statistical balancing item in the Oil Market Report (‘miscellaneous-to-balance’) has been rising in recent years. There is clearly some way to go – the more so if the miscellaneous-to-balance item turns out to be due to under-reported demand.

Understandably, therefore, much of the data uncertainty focuses on non-OECD countries, and in particular, the major growth regions of Asia and the Middle East. Given China’s status as the world’s second largest oil consumer and rapid oil demand growth, the fact that its energy balance are subject to close scrutiny is only natural. While data has improved – quality is significantly better than many other countries with a similar level of GDP per capita – China still needs to take several key steps: 1) release primary (refinery level) commercial and strategic stock data; 2) survey ‘teapot’ refinery activity; 3) revise data, particularly that pertaining to trade

figures; and 4) explain why Chinese refiners achieve a volumetric processing loss, while European and US refiners with similar equipment achieve refinery gains.

These data inconsistencies – probably due to the lack of free-market pricing throughout the supply chain, which provides incentives to distort data reports – make it difficult to assess China's oil demand. For example, news reports suggest that teapot refiners are supplied with domestic crude, which is unreported on both the supply and demand side – possibly amounting to around 150-250 kb/d in 1H07. Similarly, customs data has sometimes shown no crude exports in a particular month, despite evidence of effective loading and sailing of cargoes.

The IEA estimates Chinese demand on the basis of refinery output plus net product imports, adjusted for direct crude burn and the use of teapot refineries. However, it could also be calculated by adding domestic crude production, net crude and net product imports. This latter methodology, though, does not enable the disaggregation of demand on a product-by-product basis and tends to overestimate demand if stock building is significant. Having to choose between both methodologies – which by definition include some arbitrary assumptions and hence can lead to different results – we believe the first one, during a period where China is building strategic oil stocks, is perhaps more accurate, since it allows us to track each product.

India, meanwhile, has the potential to see a surge in energy demand and also presents data reporting issues which complicate the understanding of regional energy balances. Indeed, local analysts suggest that coastal imports outside of main consuming areas may be under-reported, therefore leading to a lower recorded demand. In addition, the widespread adulteration of diesel-based fuels can lead to distortions of inter-product demand. Last but not least, there is no reliable of commercial stock data.

In the Middle East, reporting qualities vary. While data from certain countries, Saudi Arabia in particular, is very comprehensive on the demand side, in others, demand data collection is in its infancy. Large price subsidies lead to extensive smuggling.

Biofuels

Automotive biofuels represent a further uncertainty, although it is rather contentious whether or not they should be regarded as a demand-side uncertainty. From the perspective of demand forecasting, biofuels are only significant in that the lower volumetric energy content of ethanol and biodiesel supplies need to be accommodated in our projections. However, biofuels are important with regards to the petroleum-liquids they displace.

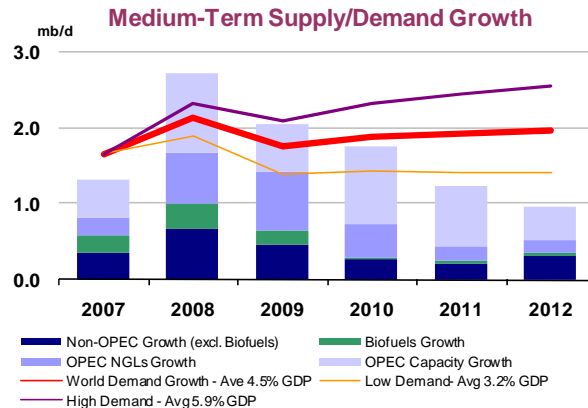
Over the medium-term, biofuels supply and demand will broadly match, but this is not necessarily the case over the short-term. Automotive biofuels production capacity is expanding rapidly, sometimes at a rate faster than the mandated level refiners are

required to blend. This could lead to short-term imbalances. In addition, the rapid expansion of biofuels production capacity is tightening feedstock markets and therefore raising their price, posing questions over whether sufficient feedstocks will be available at an economic rate to meet capacity growth projections. Given these caveats, our biofuel supply projections are around 1 mb/d below planned capacity expansions by 2012.

SUPPLY-SIDE UNCERTAINTIES

The MTOMR projects strong non-OPEC liquids (crude, condensate, NGLs and biofuels) supply growth in 2007-2009 appearing to recede thereafter as the slate of verifiable investment projects diminishes. Total non-OPEC liquids supply growth to 2012 is pegged at 2.6 mb/d. The report estimates that around 3 mb/d of new production is needed each year to offset the effects of decline. This equates to net oilfield decline rates averaging 4.6% annually for non-OPEC and 3.2% per year for OPEC crude. Aggregate levels mask much sharper declines in a 15-20% per annum range for mature producing areas and for many recent deepwater developments. Further, our supply-side estimates incorporate a new 0.4 mb/d contingency factor, reflecting a tendency for unscheduled field outages.

Supply-side uncertainty is further exacerbated by increasing instances of resource nationalism and geopolitical risk, constraining the ability of the industry to expand output. Upstream construction, drilling and service capacity will remain stretched for some time, leaving forecasts prone to slippage due to cost over-runs and project delays. On balance, these above-ground risks are seen as greater than those posed by resource depletion and other below-ground factors. Overall, this leads to average non-OPEC supply growth of 1.0% between 2007 and 2012, 0.4% below the growth seen in the previous seven years and roughly half the rate of global demand growth projections.



Ultimately there are the natural resources to boost output in the medium term, but there are considerable questions whether the above ground access, service sector resources and IOC investment plans will deliver. With this in mind, substantially

higher cash returns to shareholders stand in curious contrast to growing upstream supply tightness and essentially unchanged exploration and production (E&P) effort. Nominal E&P expenditures are up, but higher costs have eroded their purchasing power commensurately. However, it is clear that there are other issues at work.

In particular:

- Access and contractual conditions (even in OECD countries) are deteriorating.
- Hurdle rates for upstream investment may be too conservative (development costs have moved higher, albeit there are indications that cost inflation, may be stabilising)
- Labour, equipment and service sector constraints may reduce the potential for expansion of the project base, at least through 2012.
- The rise of consumer-country NOCs and independent exploration companies is eroding the market share of more risk-averse IOCs, which endured years of lower returns after the oil price collapsed in the mid-1980s.

Project slippage

Project slippage is a major issue for supply-side projections. In the 5 months between the publication of the February MTOMR update and the 2007 MTOMR in July, over 3.2 mb/d of new projects in the 2007 to 2011 period saw their timing slip, emphasising the scale of the problem. Slippage varies between two and 36 months, but is typically around six months. Given the scale of the problem project timing assessments have been dealt with more aggressively, particularly with those where delay is most likely. Nonetheless, shortages of labour, raw materials, fabrication and drilling capacity and transport infrastructure may continue to undermine output growth for some time.

Decline Rates

An average global decline rate is a useful rule of thumb, but one which can be over-used. From a field by field forecast, it is clear that decline rates can vary hugely even between fields in similar locations. There is a constant ebb and flow of fields entering decline, offset by others where decline is reversed by the application of EOR or satellite developments.

A proxy can be calculated by comparing net change in non-OPEC supply for 2007-2012 and gross capacity additions. The implied net non-OPEC decline rate for baseload production is around 4.6% per year. This covers not only fields in decline, but also older supply which is at or approaching plateau. With net decline from OPEC assumed at 3.2% per year, this gives a global annual decline of 4%, suggesting that 3.2 mb/d of new production must be found each year just to stand still. Moreover, this net global decline for existing assets masks fairly aggressive

assumptions for parts of the OECD and for deepwater projects elsewhere. Development schedules for the latter can show rapid ramp-up followed by abrupt annual decline in a 15-20%-plus range.

Decline rates clearly hold the potential for significant oil supply forecast uncertainty. Our derived net decline of 4.6% per year results in non-OPEC oil supply (excluding biofuels and processing gain) in 2012 of 48.8 mb/d. Increasing that decline rate to 5% would net 875 kb/d off the total, and a range of decline rates from 2% to 7% swings 2012 non-OPEC supply by 11 mb/d in total.

Without minimising the importance of this variable, particularly given a shortage of comprehensive field-specific production and reserves data, our analysis suggests that variance from the original non-OPEC forecast in recent years has not primarily been due to understatement of field decline rates. Rather, we believe that project slippage, weather, and unplanned production stoppages for technical, economic and geopolitical reasons, have been, and will continue to be in the next five years, the main risk factors. Put another way, while we continue to monitor and actively adjust for shifts in field and aggregate decline, we see above-ground risks more prevalent, for now, than below-ground risks.

The concept of peak oil production and its timing are emotive subjects which raise intense debate. Much rests on the definition of which segment of global oil production is deemed to be at or approaching peak. Certainly our forecast suggests that the non-OPEC, conventional crude component of global production appears, for now, to have reached an effective plateau, rather than a peak. Having attained 40 mb/d back in 2003, conventional crude supply has remained unchanged since and could do so through 2012. While significant increases are expected from the FSU, Brazil and sub-Saharan Africa, these are only sufficient to offset declines in crude supply elsewhere. Put another way, all of the growth in non-OPEC supply over 2007-2012 comes from gas liquids, extra heavy oil, biofuels (and, by 2012, 145 kb/d of coal-to-liquids from China). As overall non-OPEC liquids capacity increases, this plateau reduces the share of non-OPEC conventional crude supply from 77% in 2000, to 74% in 2006 and 67% in 2012.

While there might be a temptation to extrapolate this trend, citing a peak in conventional oil output, a degree of caution is in order. Firstly, the concept of 'conventional' oil changes with time, technology and economics. In the early 1970s, much offshore production was deemed unconventional, but this portion of global supply has since grown to account for 30% of the total. Evolving economies of scale and infrastructure development could do the same for GTL, oil sands and ultra-deepwater reserves in the future, shifting today's unconventional resource into tomorrow's conventional supply category. Moreover, rapidly-growing condensate and NGL supply is scarcely 'non-conventional' in a technical sense now.

We also note that for certain regions, notably the FSU and West Africa, the turn of the current decade is likely to mark a hiatus in crude supply growth. Strong growth is

expected to resume here towards the middle of the next decade. Whether this will be sufficient to offset the declines expected for mature OECD crude supply, preventing overall decline for non-OPEC, is less easy to predict.

Finally, we note that focussing on non-OPEC crude alone is a rather selective way of considering the sustainability of global oil production. Peak or plateau production is frequently taken as shorthand for impending resource exhaustion. While hydrocarbon resources are finite, nonetheless issues of access to reserves, prevailing investment regime and availability of upstream infrastructure and capital seem greater barriers to medium-term growth than limits to the resource base itself. Critically, our belief that above-ground factors rather than resource constraints are the key impediment to capacity expansion holds out the possibility that the recent slowing of capacity growth could be reversible.

INVESTMENT

Prices

Over the very long term, the economic threshold at which oil companies invest in upstream projects is likely to reflect prevailing oil prices. However, the extreme constraints in the oil services sector has led to rampant cost inflation. E&P budgets, while expanding rapidly, have therefore failed to deliver a proportional increase in E&P activity. While we believe that this is a cyclical phenomenon, related to labour and equipment shortages and rising commodity prices, it is not a situation that leads itself open to modelling. Therefore, on the supply side, our forecasts are based on the premise that the spot oil price remains above the marginal cost of production for the medium term, therefore encouraging the recent increase in E&P activity from the low levels seen for much of the previous 15 years. However, while it is clear that strong investment will be required over the longer term, medium-term investment decisions may be subject to cyclical industry and economic effects.

Operating environment and constraints

Net supply projections are the result of push and pull between various factors, which clearly vary over time and often require subjective judgement. The MTOMR characterises the upstream operating and investment environment for 2006-2011 as follows:

1. Rising crude oil price assumptions employed by operating companies;
2. Increasing spending and activity levels;
3. The expanding reach of consumer country NOCs;
4. A declining trend in exploration expenditure as a share of IOC total spending;
5. High costs and tightness in construction, drilling and service capacity;
6. Correspondingly, a tendency for new upstream project delays;
7. A compounding impact of delays to new pipeline and gas processing capacity;
8. Proliferating geopolitical risks and barriers to oil company access.

Arguably, the first three factors could accelerate the pace of expansion in non-OPEC and OPEC supply. However, the balance of risks deriving from factors 4-8 lies heavily on the downside and would seem to argue for slower growth in global production capacity relative to historical trends.

These trends are clearly changing. For example, NOCs and governments are broadly budgeting for an average economic threshold of \$45/bbl (versus \$35/bbl a year ago), with international company and independent producer price assumptions levelling off close to \$55/bbl. However, in some cases, new projects are still being tested at prices down to as low as \$35/bbl. Clearly this leaves room for a growing portfolio of feasible projects with current oil prices over \$90/bbl.

With rising prices, spending levels have increased. Industry spending surveys by Lehman Brothers and Citigroup suggest ongoing growth in upstream activity, notably outside of North America. Increases in expected capital spend in 2007 lie in a 10-15% range, with similar growth for 2008. However, many of these spending increases have been mitigated by rising upstream development and service sector costs.

In many ways parts of the current supply cycle stretch back to OPEC supply management in the 1970s and 1980s, which led to a sharp increase in OPEC spare capacity as market share was eroded by expanding non-OPEC supplies. The resultant supply overhang helped to keep prices relatively low, cyclically prompting IOCs to curb exploration, outsource service-sector roles and cutting research and development. OPEC spare capacity was reduced, which meant that when the 2004 demand surge hit, the industry was left with few resources with which to respond.

It takes time to rebuild such capacity, and while high wage rates are attracting more engineers into the field, labour constraints are unlikely to ease significantly into the next decade. But it has to be recognised that this is not simply an oil related issue. Production expansions of many natural resources are being constrained by similar factors. Equipment tightness is prevalent in many industries, and particularly in other energy sectors. Silicone shortages are limiting the expansion of solar panels, wind power generators are suffering from turbine shortages, and base metal prices are at record highs.

Cost inflation for raw materials, service and drilling capacity shows some signs of moderating, although industry consensus points to a levelling in upstream costs rather than a substantial fall. Healthy spending increases have therefore largely been absorbed by double-digit inflation, limiting any automatic feed-through of high prices into incremental discoveries and production. The rise in exploration's share of upstream spending has been modest, and company reserve replacement rates remain weak, despite sustained high prices. This can be partly explained by access and regulatory uncertainty, in turn, partly related to a spate of resource nationalism.

Drilling indicators for oil remain positive. While there was a sharp decline in drilling activity in 2Q07 this was largely due to a collapse in Canadian natural gas drilling due to weaker gas prices. It is estimated that deepwater drilling capacity will remain constrained for another 18-24 months before substantial new capacity is activated. However, given that much of the projected increases in production are seen coming from the likes of Brazil, GOM, northern Russia, the Caspian and West Africa, the potential for additional slippage clearly compounds supply-side risks.

Delays in natural gas expansion are another factor that can be added to the list of potential forecast risks. For the Middle East and Russia, the IEA's Natural Gas Market Review has identified insufficient upstream investment. This undermines not only natural gas liquids (NGL) supply, but also oilfield reinjection of associated gas, potentially impeding crude oil production rates. That said, as producers recognise potential future shortages in gas for domestic or export markets, so efforts to boost supply by cutting gas flaring and transmission losses should intensify.

The price signals are there but service sector capacity will take time to expand, and until it does, the market will be slow to respond. Even when this cycle has ended, there needs to be sufficient access to reserves to prompt a supply response. Further, the price incentives need to be high to persuade oil companies to take the significantly higher risks of exploration.

OPEC Supply

In the MTOMR, OPEC producers are expected to add a net 4.0 mb/d to installed crude capacity during 2007-2012. The years 2008 and 2010 see particularly strong growth, when new project start-ups drive OPEC capacity higher by over 1.0 mb/d in both years. The forecast takes account of new capacity investments and net decline from older fields (decline rates are assumed to range from 1-5% pa for onshore fields in the Mideast Gulf, through to 12-15% pa for deepwater fields). Overall, net decline for the group as a whole averages 3.2% annually, lower than the 4.6% evident from the non-OPEC forecast. This reflects in part the predominance of lower-decline onshore and shallow water production in the total (albeit deepwater production from Angola and Nigeria is taking on greater importance). OPEC therefore faces the task of replacing some 1.1 mb/d each year just to sustain capacity at existing levels.

Political and security issues also confer considerable risk to the supply forecast. The MTOMR assumes limited growth in Venezuela, Iran, Iraq, while in Nigeria, a portion of long term outages have been assumed to continue to reduce effective spare capacity. Changes to current conditions are difficult to predict, but it is fair to argue that a resolution of security issues in Iraq and Nigeria could result in a significant expansion in OPEC capacity.

Looking at OPEC crude additions for 2006-2012 tells only half the story for potential capacity growth. Gas liquids (ethane, propane, butane and pentanes from gas processing plants plus field gas condensates) are expected to rise by +2.2 mb/d (+7.8% pa) and take potential OPEC NGL supply to 7.1 mb/d by 2012. The rate of increase matches growth evident during 2001-2006, as attempts to boost natural gas utilisation and to reduce flaring continue.

While there is considerable uncertainty over the level of OPEC reserves and decline rates, as great an issue for projected oil market balances in the coming decade is how OPEC countries choose to manage their reserves. What will a country decide is its optimum production rate? There have been suggestions that Saudi Arabia for example, will limit its crude supply expansion to a maximum of 15 mb/d. Regardless of how China or India's future car pool is calculated, and what level of demand growth is implied, quite simply, it will not, materialise if the supply is not there in the short-to medium-term.

CONCLUSION

Considerable forecasting risks remain on both oil supply and demand. Some of these risks can be better understood by improvements to data quality and coverage. Improved transparency will not augment supply, but it can help to improve the robustness of supply-side projections. However, arguably some of the largest uncertainties facing the oil world stem from non-oil data issues.

On the demand side, the rate of growth of oil consumption depends heavily on the rate of economic growth in highly populous developing countries such as China, India, Indonesia and Brazil. There would a considerable difference to outcomes if Chinese economic growth were to stall, rather than continue growing at its current 10% annual rate. Similarly, these countries at some point will reach a point where growth rates moderate, thus slowing demand-side pressures. Demand may also be constrained by an accelerated policy effort to reduce emissions. Policy and prices can alter the speed at which technological innovations occur and are incorporated.

But demand projections can only be realised if there is the supply there to meet them. National resource management policy is perhaps the hardest area to forecast. At what point a country decides its extraction rate is optimised will depend upon many factors, including prevailing price levels and the resource base. Security and political shifts can result in this factor becoming a moving target. Ultimately, though, even if supply constraints are less than envisaged, the demand potential from emerging economies is very significant, and in the foreseeable future there is little prospect of a significant shift away from petroleum-based fuels in the transportation sector. Whether constraints are derived from the supply or demand side of the equation, environmental considerations are a further reason to justify the need to prepare for a constrained transportation fuel market – even if the fuel is there, there are reasons we may not wish to use it.