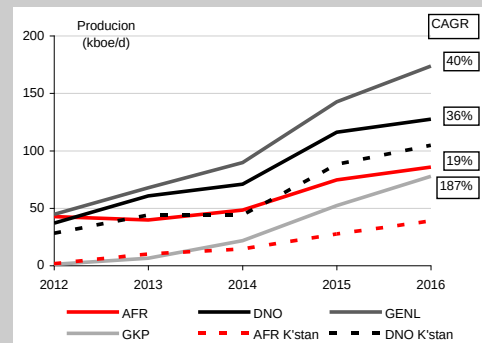




The Equities Research Specialist

EUROPE

Group working interest production (2012e-16e)



Source: Company data, Factset, Macquarie Research, October 2012

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31 October 2012
Macquarie Capital (Europe) Limited

Kurdistan E&P Talking Turkey

Buy DNO for Kurdistan exposure

This report looks at the evolving Oil & Gas climate in Kurdistan. Our stock preference for Kurdistan exposure remains **DNO (Outperform, TP Nkr 12.7)**, as the company has the most attractive valuation and in our view the most straightforward resource base to commercialise.

Within the report, we also initiate on:

Genel Energy (Neutral, TP 785p): Of the European listed E&Ps with leverage to Kurdistan, we forecast Genel to have the highest absolute production rate by 2016 and, at 40%, the second-highest CAGR in production (2012-16). However we remain concerned about the timing of Miran West commercialisation and highlight that African exploration is very early stage. Following a 17% rise in the share price since mid September, we see no reason to chase the shares.

Gulf Keystone (Underperform TP 168p): The need for a dedicated heavy oil pipeline may well make development of Gulf Keystone's Shaikan field a slower reality than is currently envisaged. Trading at a 14% premium to our fair value, the market appears to be ignoring any risk from the ongoing Excalibur litigation case.

Export plans are emerging, but the picture is far from clear

With Turkey looking as if it will provide the export solution if (when) relations between Kurdistan and Baghdad break down, access to export infrastructure is increasingly important. Current plans for a 1mmb/d export line to be operational in 2014 are in train; however, we estimate that by 2015 this capacity will be 80% filled by existing fields, let alone from future discoveries made by the more politically influential IOCs. Our fear is that with such vast quantities of infrastructure required just to develop conventional oil, heavy oil and gas export pipelines – which require additional infrastructure construction on the Turkish side of the border – may take longer to emerge than is currently anticipated.

M&A from the IOCs can support share prices

ExxonMobil, Chevron, Total and Gazprom Neft have all entered the region in the last 12 months and we expect other IOCs to follow as the Kurdistan oil and gas industry matures. With little unlicensed acreage, this is likely to see increasing levels of M&A activity, which we would expect to be at premiums to historic transaction multiples, something that should support share price.

Geological challenges and changing PSC terms

While Kurdistan is widely regarded to have an exploration success rate of ~70%, we show that finding harder to commercialise heavy oil and gas is just as common as finding light/medium crude while sulphur is a common unwanted impurity. In addition, we have looked at the effect of Infrastructure Capacity Payments on \$/boe valuations, concluding that a 30% payment compared to no payment at all can reduce valuations by ~33%.

Kurdistan players in a snap-shot

This document looks at Kurdistan as a region but also at four European E&Ps with material leverage to the region: Afren, DNO International, Genel Energy and Gulf Keystone.

Afren (Neutral, TP 150p, 12% upside)

Kurdistan production is crucial to Afren's medium term production story

Afren entered the Kurdistan region of Iraq in July 2011, taking positions in the Barda Rash and Ain Sifni PSCs for a combined US\$588m entry cost. The reserves and resources attributed to Kurdistan (excluding heavy oil in Barda Rash) account for 60% of the group's total and the assets are the key driver of production growth. Specifically, we forecast Barda Rash to increase in importance from 4% of 2012 WI production to 45% of 2016 WI production. The stock however, trades, in our view, at an unwarranted premium to DNO on an EV/boe basis, and with only limited upside to our Core + Risked NAV of 150p we see no reason to change our current Neutral stance.

DNO International (Outperform, TP Nkr 12.7, 31% upside)

DNO is the value way to play Kurdistan, trading at a 24% discount to Core NAV

DNO's production CAGR of 36% for 2012-16 is driven primarily by the expansion of production capacity at the Tawke field in Kurdistan. The field accounts for 84% of the company's 2P+2C asset base, and in contrast to the other companies looked at in this report DNO is the only one with a greater proportion of 2P reserves relative to 2C resources. The company trades at premium to Genel Energy and Gulf Keystone because of this, in addition to the fact that it is also the only company without Infrastructure Capacity Payments on its PSCs. For us, it is the stand-out value stock, being the only one to trade at a discount to Core NAV (relative to the sector at a 5% premium) and also a 24% discount to Core + Risked NAV of Nkr 12.7. A lack of exploration related leverage is the one draw-back to the investment case.

Genel Energy (Initiate with Neutral, TP 785p, 4% downside)

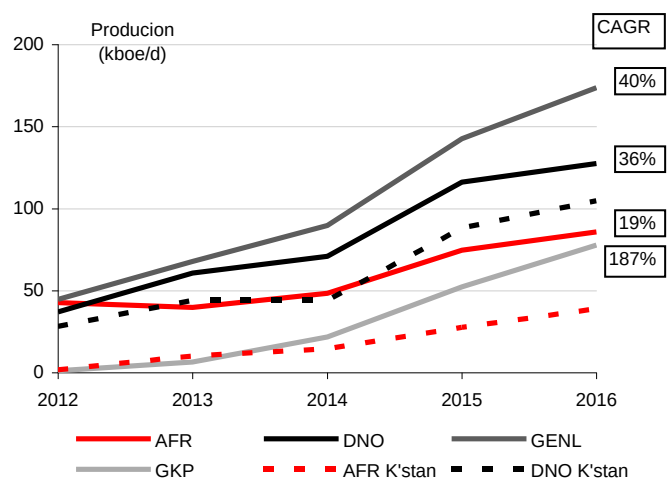
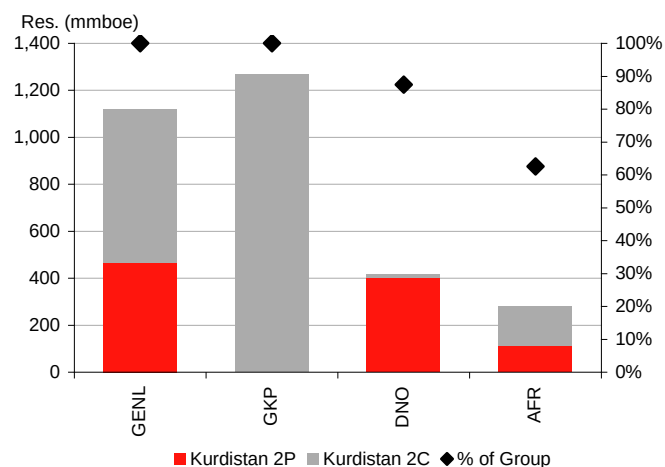
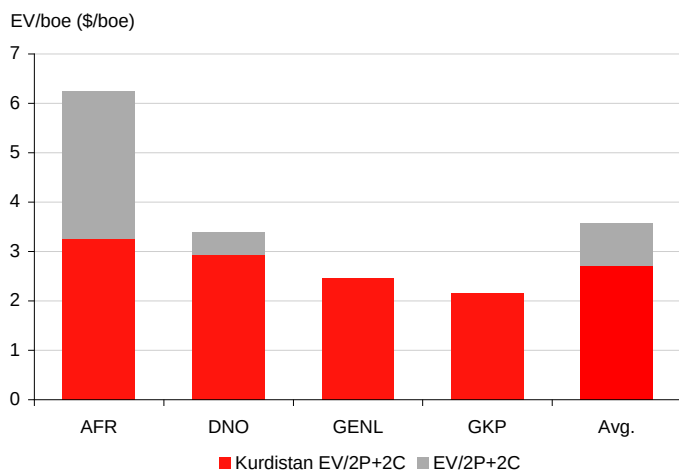
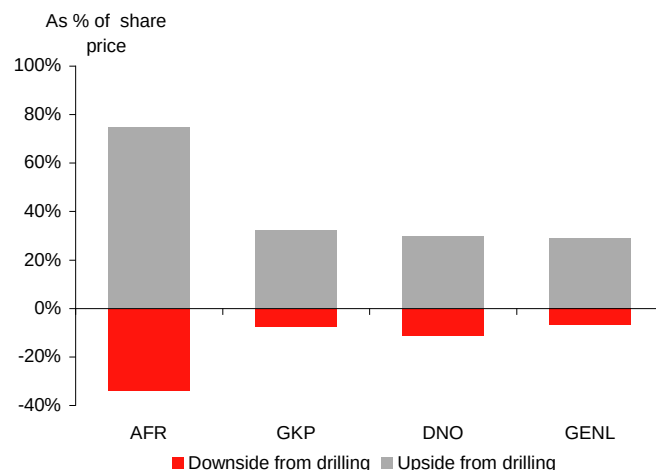
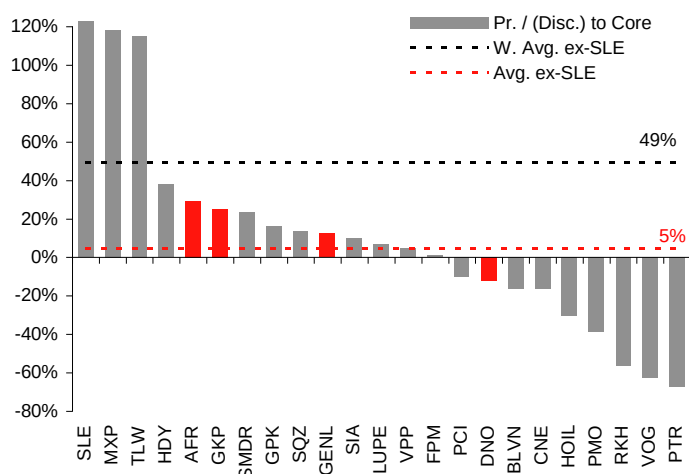
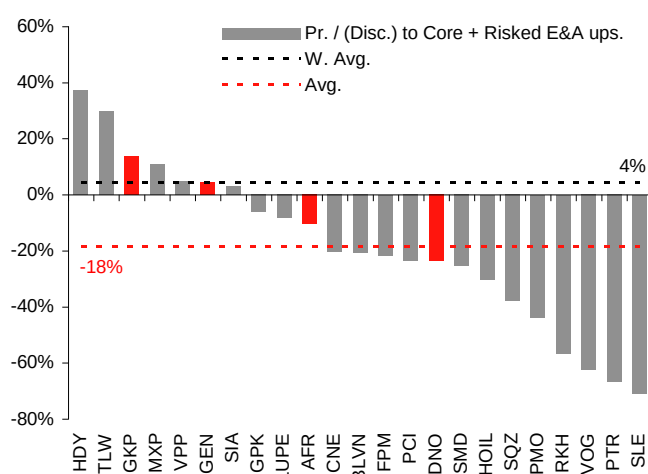
At ~175kboe/d, the company has the potential to have the highest absolute production rate in 2016

Following almost \$1bn of acquisitions over the past 12 months, we estimate the company has ~ 1.1bn boe of reserves and resources, all of which are located in Kurdistan. We forecast that this asset base can lead to Genel Energy having the highest absolute production rate by 2016 of all four companies at ~175kboe/d. In particular, the increase in production will be led by the Tawke and Taq Taq fields reaching plateau rates and the commencement of production from the Bina Bawi and Miran West fields. Trading at US\$2.5/boe on a 2P+2C basis, the company sits below the sector average however this position can be explained by 392mmboe of contingent, lower value, gas resources in the composition. From a valuation stand point, we do not see compelling value at these levels, trading at a 12% premium to Core NAV and marginally above our Core + Risked NAV of 785p.

Gulf Keystone (Initiate with Underperform, 168p, 13% downside)

The only stock trading at a significant premium to Core + Risked NAV

The company is 100%-leveraged to Kurdistan in terms of assets with the company's principal asset, the Shaikan oil discovery, accounting for 97% of our overall 1.23bn bbls estimate for reserves and resources. We still classify these as contingent resources, as a Field Development Plan is not yet agreed and full commercialisation will require a dedicated heavy oil pipeline to be constructed from the field through to the Mediterranean port of Ceyhan in Turkey, something that will require cross-border collaboration. Hence, while the company has the highest CAGR for production for 2012-16 of 187%, our production estimates are also probably the most vulnerable for downwards revision and why we believe the company is correct to trade at the lowest EV/boe multiple. The stock trades at the third-highest premium to Core NAV of all companies that we have under coverage and a 14% premium to our Core + Risked NAV. To us, this suggests that the market is already assuming that the Excalibur litigation charges will be unsuccessful which, in our view, makes the shares more vulnerable to downside risk.

Fig 1 Group working interest production (2012e-16e).**Fig 2 2P+2C Res. In Kurdistan and as % of Group****Fig 3 EV/2P+2C values (Group and Kurdistan)****Fig 4 Leverage to “Visible” exploration drilling****Fig 5 Share prices relative to Core NAV****Fig 6 Share prices relative to Core + Risked NAV**

Source: Company data, Factset, Macquarie Research, October 2012. Note: 2P+2C numbers are based upon what we carry in our Core NAV and therefore may not tally with numbers published by the companies.

Talking Turkey

Switching juniors for super-majors

Continued poor Iraq terms has been a major catalyst in IOCs entering Kurdistan

The oil and gas landscape in Kurdistan is unrecognisable to five years ago. With southern Iraq failing to develop its hydrocarbon industry in an IOC-friendly fashion, and still dogged by political instability, oil and gas companies of ever-increasing size have shifted their attention towards the Kurdistan region. ExxonMobil and Chevron have been by far the largest entrants, but since 2007 we estimate companies with a combined market cap of almost US\$1trillion have entered the region. As a result, the vast majority of Kurdistan is now under license. This means the existing IOCs and any new entrants, will be required to acquire the Kurdistan Regional Government's ("KRG") 3rd party back-in rights, farm-in or make corporate transactions in order to gain or expand footholds. It is our belief that M&A activity in 2013 will continue to support share prices with transaction metrics likely to be at premiums to previous deals.

Confident Turkey will act unilaterally if current agreement falters

Turkey's domestic requirements we believe will drive unilateral trade with Kurdistan if current agreement falters

We are not convinced that the September 2012 agreement between Baghdad and the KRG to continue exports from the region will transpire into a full resolution, given the failure of the two previous attempts, lack of an Iraq Oil & Gas law and a continued refusal to acknowledge Kurdistan PSCs. However, one of the reasons we believe that the super-majors have moved into Kurdistan is that there is increasing confidence that Kurdistan oil and gas can make its way to market directly via Turkey if the current payment agreement between Kurdistan and Baghdad falters. While Turkey has previously said that it would not undertake any activity that contravenes Baghdad, Turkey has one of the fastest growing economies in the EU with limited natural resources meaning that it imports 620kb/d of crude oil and 1.3tcf/annum of gas. Resource-rich Kurdistan is therefore a natural, low cost and hopefully reliable provider of hydrocarbons, and we see it as symbolic that Turkey has already begun to accept trucks of condensate directly from Kurdistan in exchange for refined products.

Existing discoveries can largely fill the planned export pipeline

Competition for export capacity likely to be intense by 2015

Underpinning the improved confidence is a May 2012 Regional Energy and Security Agreement between the KRG and Turkey, which revealed plans to construct a 1mmbbl/day export pipeline directly to Turkey from the Kurdistan region. The pipeline would allow the Kurdistan region to operate independently of Baghdad and put them firmly in the dominant position. As a consequence, operators in Kurdistan are being driven to invest and get fields to plateau production rates and by 2015, we estimate that 80% of the pipeline's capacity can be filled by *existing* discoveries alone, with a corresponding export capacity possibly up to 1.1mmb/d. While this pipeline can link into spare capacity on the Turkish side of the border, planned gas and heavy oil export pipelines twinned alongside the main trunkline would require Turkey to construct matching infrastructure on its side of the border, and it is for this reason we see timing pressure on when these two pipelines will become operational.

Risks remain both in the sub-surface and at the PSC level

Geologies and PSC terms are different!

In this note we have also looked back at available information on previous discoveries within the region. While we have found nothing to contravene the notion that there ~70% exploration success rate, we do note that there is just as much chance as finding harder to commercialise gas and heavy oil as there is light/medium quality crude oil. Furthermore, we also note that high sulphur content and low levels of natural (matrix) porosity are two sub-surface challenges that have emerged. Both can be overcome but will require the service sector to mature and additional capex and opex. Finally, we show that PSC terms have, as perhaps may have been anticipated, been altered in favour of the KRG via the introduction of "Infrastructure Capacity Payments". These payments see operators forgo a proportion of their profit oil and are company-/PSC-specific. Our modelling shows that for a typical 500mmb field the impact of having a 30% payment over a 0% payment may be to reduce NPV/bbl valuations by ~33%.

What a difference five years makes

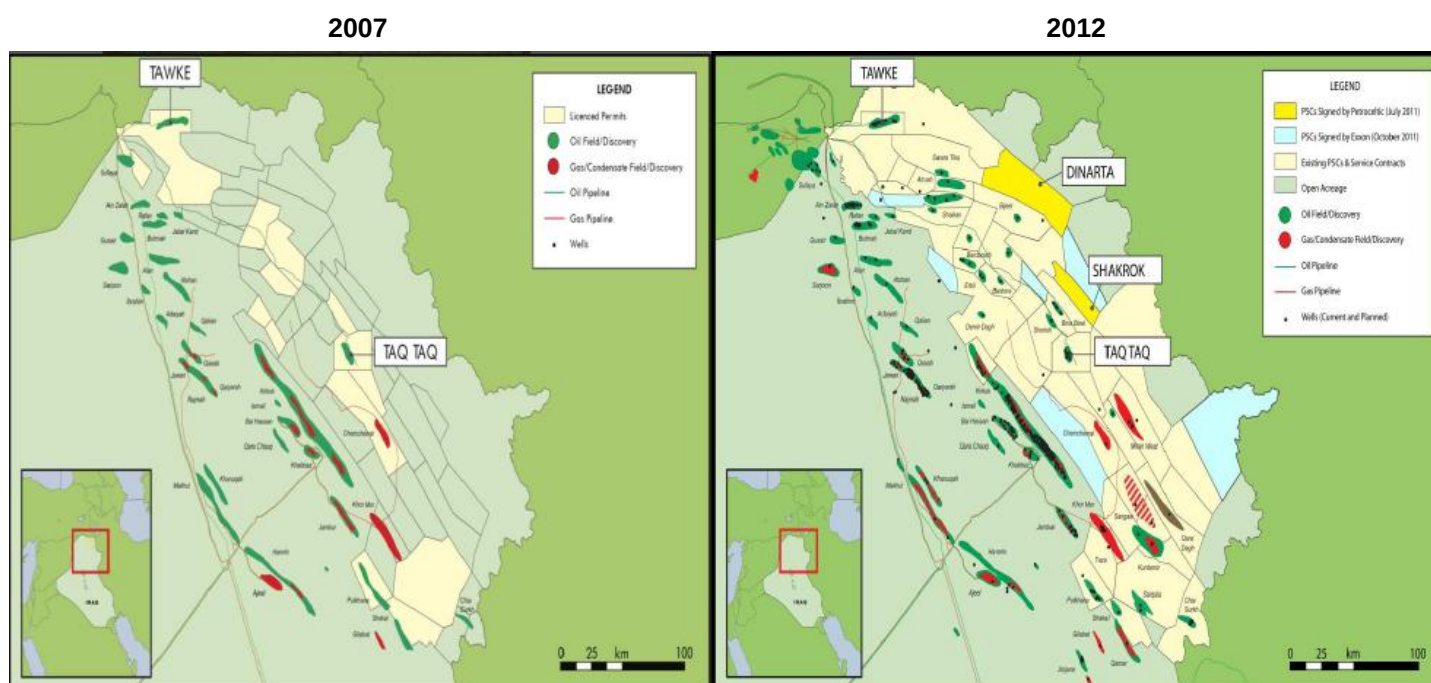
Kurdistan operators are bigger than ever before

Kurdistan was the domain of the small cap, southern Iraq the domain of the super- majors

Kurdistan's oil & gas development has been driven by small entrepreneurial E&P companies, with both Genel Energy and DNO amongst the early pioneers. Political considerations, the unexplored nature of Kurdistan and the draw of much larger reserves in southern Iraq caused the majors to hold off entering the region.

However, rapid exploration success in Kurdistan by these small cap companies, together with continued poor contract terms in southern Iraq and ongoing security risks, has altered the perception and draw of region. This is demonstrated in Fig 7 below where we show how the Kurdistan oil & gas licensing map has changed since 2007 to present day. From a sparsely licensed region in 2007, the region is now largely licensed out, with remaining acreage largely high up in the Zagros mountains.

Fig 7 The proliferation of licensed areas (cream) means that only acreage in the mountains is now available



Source: Petroceltic International, Macquarie Research, October 2012

Fig 8 on the following page re-iterates the point that new entrants into the Kurdistan region since 2007 have been of ever-increasing size.

Arrival of super-majors driven by increasing confidence in ability to commercialise discoveries

The early years after 2007 were predominantly defined by the entrance of medium-sized “independents” such as Talisman and Marathon, companies unlikely to play a prominent position in the development of southern Iraq. In the past year, though, the size of companies signing contracts with the KRG has moved on again with the entrance of the “super-majors”, led by ExxonMobil in November 2011. In total, since 2007, we believe that companies with an aggregated market cap of almost US\$1 trillion have been awarded contracts in Kurdistan.

The recent wave on transactions, which has seen Chevron, Total and Gazprom Neft enter the region since the start of July, is, we believe, in part due to better visibility on the ability to commercialise resources in the region, with direct exports to Turkey a solution if no permanent resolution is found with Baghdad (see next section)

Of the companies set out in Fig 8 it is worth highlighting Exxon, Gazprom Neft and Total in particular. This is because all three have existing Technical Service Agreements with Baghdad to develop fields in southern Iraq. And, while Baghdad has never endorsed Kurdistan PSCs, it has explicitly said that any company operating in Kurdistan will be black-listed from operating in southern Iraq.

Fig 8 Major entrants into the Kurdistan Region of Iraq since 2007

Date	Company	Mkt Cap (US\$m)	PSCs awarded
Aug-12	Gazprom Neft	23.2	Gamian (40%); Shakal (80%)
Jul-12	Total	118.9	Harir; Safen (35%), Taza (20%)
Jul-12	Chevron	218.2	Rovi; Sarta (80%; op)
Oct-11	ExxonMobil	418.3	Baeshiq; Al Qush; Pirmam; Betwata; Penjwin; Qara Hanjeer (all 100%; op)
Aug-11	A.P. Moller-Maersk	30.6	Sarsang (15%)
Jul-11	Repsol	24.5	Qala Dze; Pirmagrun (both 100%; op)
Jul-11	Hess	18.2	Shakrok (64%, op); Dinarta (64%, op)
Jul-11	Afren	2.3	Ain Sifni (20%); Barda Rash (60%; op)
Jul-11	Petroceltic	0.3	Shakrok (16%); Dinarta (16%)
Nov-10	Murphy Oil	11.6	Central Dohuk (50%, op)
Oct-10	Marathon	21.1	Harir (80%, op); Safen (80%, op) Atrush (20%); Sarsang (25%)
Aug-09	Sinopec	89.7	Taq Taq (36%); Sangaw North (26.66%) – acquisition of Addax Petroleum
Jun-08	Talisman	12.5	K39 (60%); Kurdamir (40%); Baranan (60%, op)
Nov-07	MOL	8.9	Akri Bijel (64%, op), Shaikan (20%)
Total		998.3	

Source: Company data, Macquarie Research, October 2012

Super-majors now willing to jeopardize southern Iraq contracts for Kurdistan exposure

Hence, the move into Kurdistan by these three companies suggests a deliberate and commercial decision has been taken by Boards and management teams. Following three licensing rounds in southern Iraq since 2009 and despite progress of Iraq exports hitting their highest level in three decades, it would appear that the more attractive commercial terms and better security in Kurdistan are winning out in the draw for super-majors' balance sheets and expertise. Indeed, the most obvious evidence of this is recent media speculation that ExxonMobil has told the US State Department that it is looking to sell its 60% stake in the West Qurna-1 development in order to focus on Kurdistan.

Fig 9 below shows the major oil companies operating in southern Iraq and their position with respect to Kurdistan. Of the companies listed below, it is widely believed that ENI, Lukoil and Statoil are the most likely to move into Kurdistan. Additionally, ConocoPhillips is notable in its absence from both regions, while BG has recently been reported in the press to be looking at the Chemchemal field. Interestingly, we have not heard of any disputes by Baghdad regarding NOCs which have different entities operating in both regions such as China (CNPC/ Sinopec) and South Korea (KoGas/KNOC).

Fig 9 Oil companies operating in S. Iraq and positions vis a vis Kurdistan

Company	Nationality	Field	Comment
BP	UK	Rumaila (38%)	Unknown
CNPC	China	Halfaya (38%), Rumaila (37%)	Kurdistan operations undertaken through Sinopec
ENI	Italy	Zubair (33%)	CEO said in August 2012 that the company would not do anything to jeopardise Zubair contract however ENI often linked in media to Kurdistan
ExxonMobil	US	West Qurna (60%)	Reportedly looking to exit West Qurna to focus on Kurdistan where it will spend US\$250m on exploration drilling from mid 2013
Gazprom Neft	Russia	Badra (30%)	Media reports said it had withdrawn from Kurdistan however subsequently rejected. Further activity likely driven by Russian stance
Japex	Japan	Garraf (30%)	Unknown
Kogas	S. Korean	Akkas (75%); Zubair (19%), Badra (23%), Mansuriya (20%)	Kurdistan operations undertaken through KNOC
Kuwait Energy	Kuwait	Mansuriya (30%) Siba (60%)	Unknown
Lukoil	Russia	West Qurna 2 (56%)	Media reports it is looking at Kurdistan
Oxy	US	Zubair (23%)	Unknown
Petronas	Malaysia	Halfaya (19%), Majnoon (30%), Badra (15%), Garraf (45%)	Unknown
Shell	Netherlands /UK	Majnoon (45%), West Qurna (15%)	Recently denied reports it was negotiating with Kurdistan. Operating Southern Iraq gas project means it has more to lose.
Sonangol	Angola	Qayara (75%), Najmah (75%),	Unknown
Statoil	Norway	West Qurna 2 (19%)	Media reports it is looking at Kurdistan
Total	France	Halfaya (19%)	Active in Kurdistan, we believe may well look to increase footprint
TPAO	Turkey	Mansuriya (50%); Siba (40%), Badra (8%)	Positions may come under threat if Kurdish exports made directly to Turkey

Source: Company data, Macquarie Research, October 2012

We expect the super-majors to take up from Genel Energy as the lead protagonist of M&A

M&A to be increasingly super-major led

As Fig 7 showed previously, the majority of Kurdistan has now been licensed out. Corporate transactions have therefore become an increasingly frequent way by which companies have gained additional exposure. While Genel Energy has been the most active company in the M&A space this year, we believe it has now reached a critical mass and going forward we expect the under represented super-majors to be amongst the most active M&A protagonists. These companies in turn are likely to be challenged by companies not yet active in the region and therefore, we are confident that transaction metrics will remain strong and even possibly increase.

Below we show that the market has, in general, paid relatively consistent multiples for 2P and 2C barrels.

- **2P reserves valued at \$5.1/bbl:** In our view, the DNO/RAK Petroleum merger and Vallares/Genel Energy merger need to be looked at in isolation to other transactions, as these are the only ones to include well defined fields (Taq Taq and Tawke) capable of producing significant volumes. As these were corporate rather than asset-specific deals, though, it is hard to know what exactly was being ascribed value. However, with an average \$5.1/bbl transaction metric against our asset models valuations of ~\$4.5/bbl, we believe that reserve upgrades (subsequently delivered) were discounted in the price.

Fig 10 Historical transaction multiples based upon what we believe should be considered 2P reserves

Date	Buyer	Seller	Asset	Value (\$m)	2C Res. (mmboe)	EV/2C (\$/bbl)	Comment
Sep-11	DNO	RAK Petroleum	Tawke (55% WI)	1,520	342	4.5	Implied value given merger terms, we have removed our estimate for EMV and reserves ex-Kurdistan
Sep-11	Vallares	Genel Energy	Taq Taq (44% WI), Tawke 25% WI)	2,100	356	5.9	Based upon the Vallares CPR reserve estimate for Tawke.
Sep-11	Vallares	Genel Energy	Taq Taq (44% WI), Tawke 25% WI)	2,100	412	5.1	Based upon operator DNO's reserve estimate for Tawke
Average						5.1	

Source: Company data, Macquarie Research, October 2012

- **Contingent resources valued at \$2.2/boe:** Licence transactions which involve discovered fields which are not yet ready to deliver material volumes have seen multiples average \$2.2/boe. This average, though, is brought up by the recent Gazprom Neft transaction, which we estimate was valued at between \$3.7/bbl - US\$5.7/bbl.

Fig 11 Historical transaction multiples based upon contingent resources

Date	Buyer	Seller	Asset	Value (\$m)	2C Res. (mmboe)	EV/2C (\$/bbl)	Comment
Aug-12	Genel Energy	Heritage Oil	Miran (56% WI)	450	341	1.3	83% of resources are gas. Heritage had no Infrastructure Capacity Payments.
Aug-12	Genel Energy	Hawler Energy	Bina Bawi (21% WI)	240	158	1.5	Hawler had no Infrastructure Capacity Payments, hence premium to AT&T transaction
Aug-12	Gazprom Neft	WesternZagros, KRG	Garmian (40% WI), Shakal (80% WI)	260	46	5.7	Based upon 45mmb gross at Shakal and 21mmb at Garmian. Including recent Mil Qasim success at Garmian (63mmb gross) would drop multiple to \$3.7/bbl
Jul-12	Total	Marathon Petroleum	Hareer (35% WI), Safen (35% WI)	Not disclosed			
Jul-12	Chevron	Reliance Industries	Rovi (80% WI), Sarta (80%)	Not disclosed			
Jan-12	Genel Energy	AT&T Petroleum	Bina Bawi (23% WI)	175	175	1.0	Based upon Genel current estimate of 750mmboe (60% oil, 40% gas).
Jul-11	Afren	Komet Group	Barda Rash (60% WI)	419	304	1.4	Excludes 578mmb heavy oil
Average						2.2	Would fall to \$1.8/bbl if Mil Qasim included for Gazprom Neft transaction

Source: Company data, Macquarie Research, October 2012

Turkey as the grand solution

As we have previously alluded to, we believe that the move of super-majors into Kurdistan is being driven by increasing confidence that the region's oil and gas reserves can be commercialised directly into Turkey if a long-term resolution with Baghdad is not found. In this section, we look at Kurdistan's current infrastructure plans and Turkey's economic development.

Kurdistan is having a third attempt at exports

There have been false dawns before for Kurdistan oil exports

Kurdistan's position as a land-locked region has meant that gaining access to international crude markets has required the use of Iraq operated Kirkuk-Ceyhan export pipeline that runs from the giant Kirkuk oil field in Iraq to the Turkish port of Ceyhan on the Mediterranean. However, Baghdad's failure to endorse KRG PSCs has meant that two periods of significant oil exports since the Iraq constitution was signed in 2006 (June 2009 – October 2009 and February 2011 – March 2012) that operated under temporary payment agreements have eventually been stopped due to the failure of Kurdistan operators to receive payments. The most recent attempt, which lasted over a year, resulted in operators receiving only two payments and leaving an estimated US\$1.5bn of payment receivables outstanding.

Operators are still waiting for money from the KRG

Despite this, Kurdistan resumed exports in August 2012 and on 13th September both Baghdad and Kurdistan agreed to the resumption of payments to Kurdistan operators with the agreement subsequently ratified by the Iraqi Cabinet. While the precise details of the agreement remain unknown, industry press and operators are fairly consistent on the following details:

- Kurdistan has received an initial US\$559m payment for historical production, which should be transferred to operators imminently once accounts have been approved. A second US\$301m payment is also expected in the near term.
- Kurdistan has agreed to expand exports to 200kb/d for the remainder of the year, with 2013 export volumes preliminarily agreed at 250kb/d. Exports are to be paid for on a quarterly basis in arrears.
- Importantly, Genel Energy says that Kurdistan producers are expected to receive "full contractor entitlement" which, to us, suggests that they will receive both cost AND profit oil payments, in line with the PSCs signed with the KRG.

While the current tone from operators is unsurprisingly positive, we remain concerned that history is on the side of the agreement again faltering. Indeed we believe there is already some nervousness, given that the second US\$301m payment has not yet arrived and that there appears to be no provision in the 2013 Iraqi budget for payments to Kurdistan operators. Our view is that it will take a number of on-time payment receipts to operators for the market to get comfortable with the fact that the current agreement is in any way permanent. Longer term, the broader Iraq Oil & Gas Law, which governs the operation and regulation of the entire Iraq oil and gas industry, needs to be agreed and ratified for a permanent export and payment solution to be in place.

A blueprint to get to 1mmbbls of export capacity

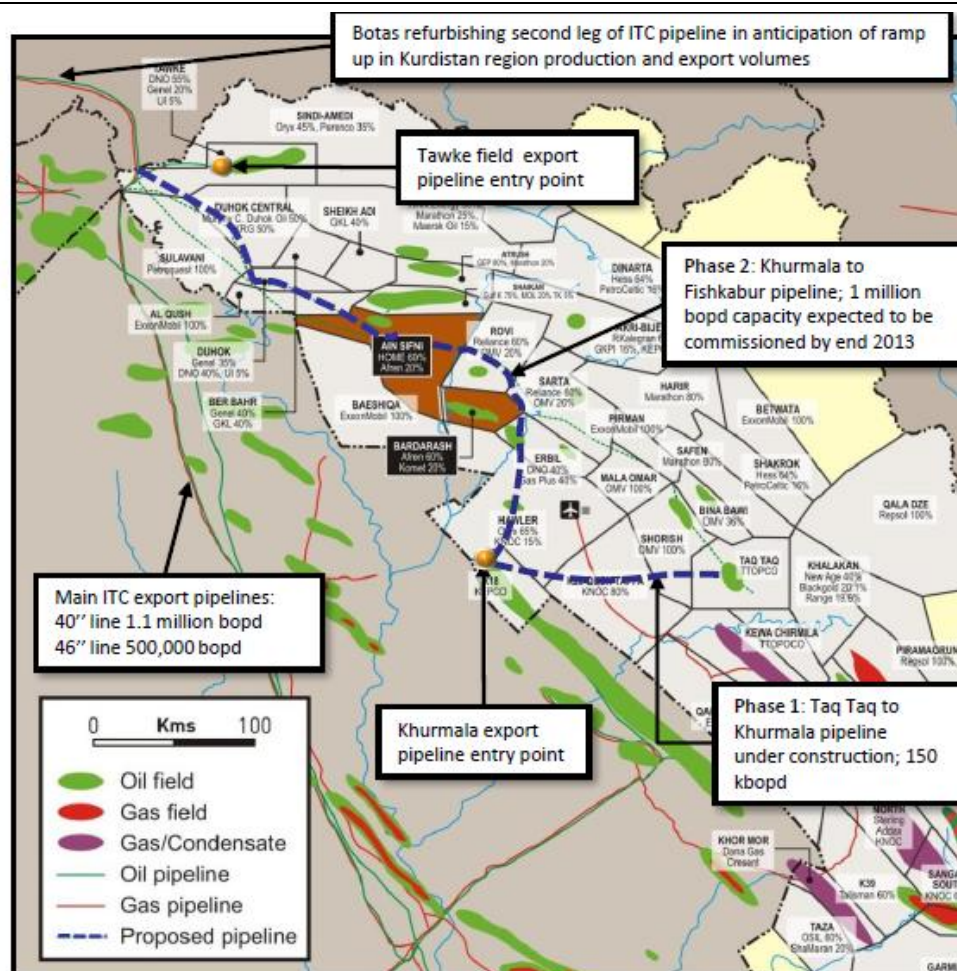
Turkey/Kurdistan Energy and Security Agreement driving Baghdad's reconciliation

From a Baghdad perspective, we believe that one of the key drivers for attempting a third period of exports was the May 2012 Regional Energy and Security Agreement between Kurdistan and Turkey. This agreement, made at an Energy Conference in Erbil by Turkey's Energy Minister, Taner Yildiz, and Ashti Hawrami the KRG's Minister for Natural Resources, provided for Kurdistan to export hydrocarbons directly to Turkey, thus circumventing any existing Iraqi infrastructure and therefore Baghdad control. That said, the KRG is at pains to say (at least publically) that it is developing the region's oil and gas industry inline with the Iraqi constitution, thus trying to dampen concerns that it is trying to push through greater independence.

According to various media articles and operator understandings, the main features of the Regional Energy and Security Agreement relating to hydrocarbon exports are:

- A 1mmb/day pipeline that would run from the Khurmala Dome processing facilities through the centre of Kurdistan and up towards Turkey (Fig 12). The pipeline would then connect to the principal Kirkuk-Ceyhan export line, which consists of a currently operational 40" pipeline that has capacity of 1.1mmb/d and a redundant 46" pipeline with a capacity of 500kb/d that has been shut in since 1990 but which Turkey has committed to refurbishing.

Fig 12 The blueprint for Kurdistan exports



Source: Afren, Macquarie Research, October 2012

- What is not presently clear is where the two pipelines would connect. In light of the current Kurdistan/Baghdad agreement we believe that the tie-in point is likely to be at the State Oil Marketing Organisation (SOMO)-operated Fishkabur pumping station on the Iraq/Turkey border. While tying in here would effectively give Baghdad control of the throughput we believe that an alternative option if Baghdad/KRG relations again soured could be to tie into the pipelines somewhere in Turkey, a strategy that would afford the KRG greater control of volumes.
- Volumes into the pipeline would initially come from the KAR-operated Khurmala Dome field and the Genel Energy-operated Taq Taq field. A 150kb/d capacity pipeline to Khurmala Dome from Taq Taq should be commissioned by the end of 2012, with capacity increasing to 200kb/d by the end of 2014. Additional fields along the pipeline's route, such as Barda Rash and Bina Bawi, could also be tied in while a second phase development would extend the pipeline towards the tertiary light oil discoveries in the south-east of the region. Ultimately the KRG envisage 70% of the region's crude production being exported, with the rest refined domestically.
- A heavy oil pipeline, with capacity of 500kb/d, is also planned. The pipeline would spur at Gulf Keystone's Shaikan discovery, allowing commercialisation of the field which is estimated to have a plateau production of ~400kb/d. This would see 100kb/d of spare capacity to be filled by other heavy oil fields in the vicinity such as Sheikh Adi, Bekhme and Bijel.

- In addition, Genel Energy's Miran West gas discovery is due to feed an export gas pipeline to run alongside the main 1mmbbl/d crude export line. The gas pipeline would feed both a planned gas fuelled power plant in Ceyhan as well as potentially an LNG export facility. Other gas discoveries would also be commercialised through this route.

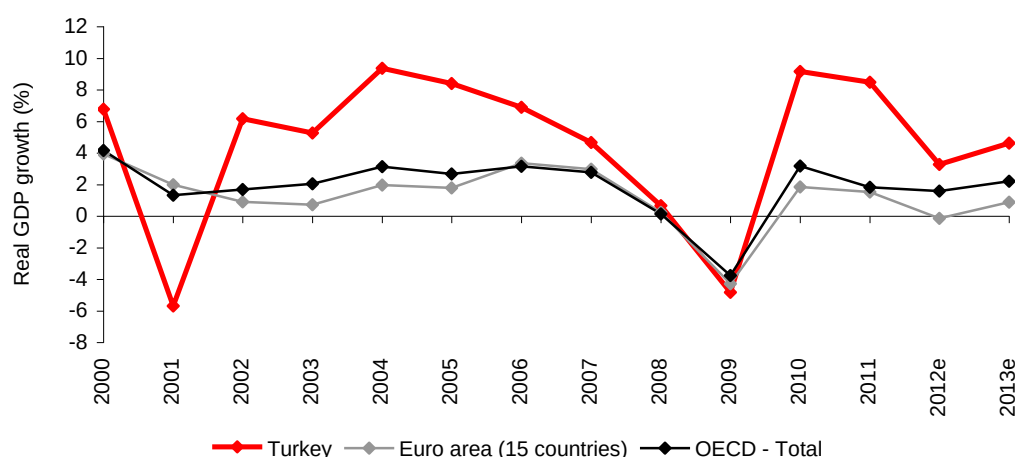
Economic growth is driving Turkey's demand for energy

**Turkey's economy
is vastly
outperforming the
EU area**

Successful economies within Europe are hard to find currently, but Turkey's economy has rebounded strongly since slipping in to recession in 2009 and, crucially, is forecast by the OECD to continue expansion through 2012 and 2013. This is fuelling a demand for energy which, given limited domestic production, has led the country to expand its sources of supply.

- Following a 4.8% contraction in GDP in 2009, Turkey's economy has demonstrated an impressive rebound, growing 9.2% and 8.5% in 2010 and 2011 respectively.
- Importantly, economic growth is forecast by the OECD to continue, with the economy due to grow 3.3% in 2012 and a larger 4.6% in 2013. These rates are significantly above those recorded by the Euro area and the OECD.

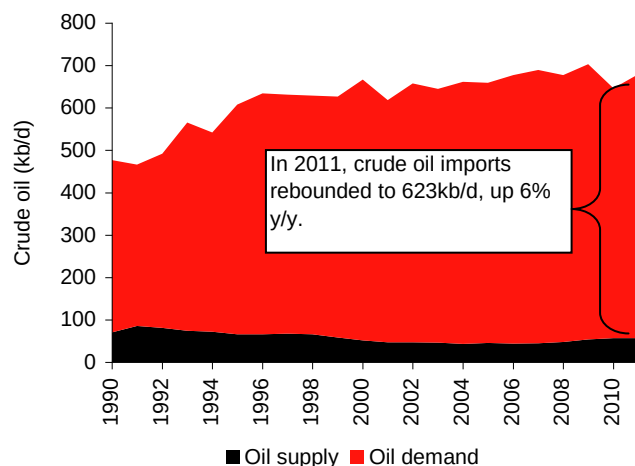
Fig 13 Turkey's economy has rebounded strongly since its recession in 2009



Source: OECD, Macquarie Research, October 2012

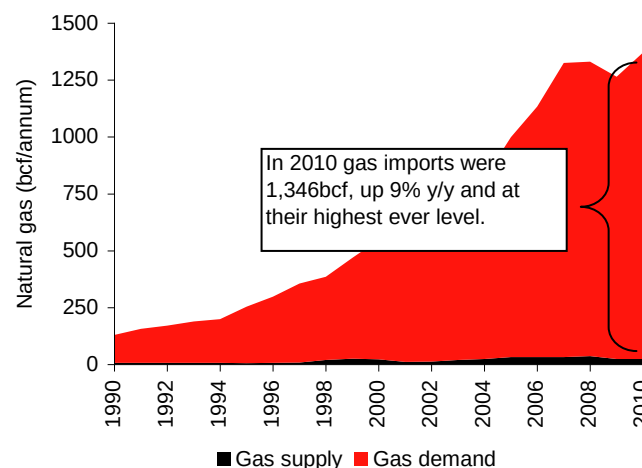
The GDP expansion has brought with it a growing demand for energy. As Figs 14 and 15 below show, given low levels of domestic hydrocarbon production the vast majority of this energy demand needs to be met by costly imports.

Fig 14 Turkey's oil demand has been stabilising...



Source: EIA, Macquarie Research, October 2012

Fig 15 ...but natural gas demand continues to grow



Source: EIA, Macquarie Research, October 2012

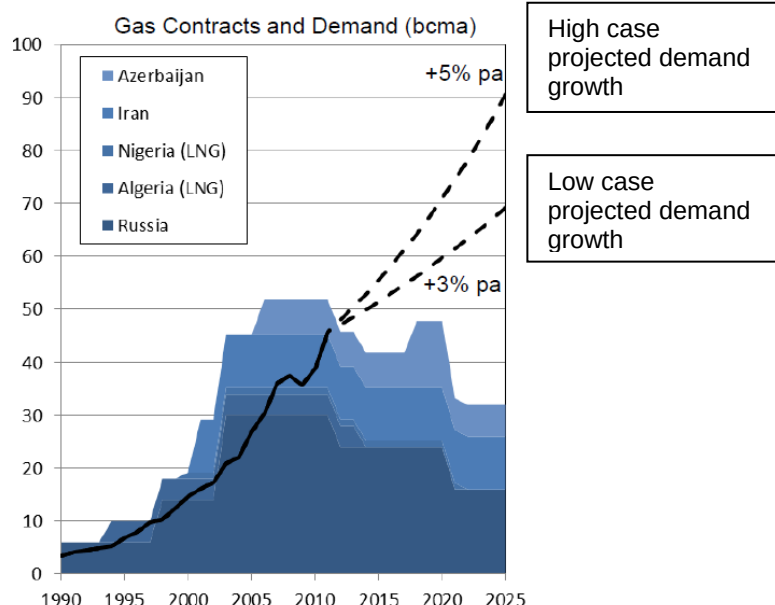
**Confident on Turkey
providing the
solution, not
confident on timing**

Kurdistan is the logical solution, however there are hurdles

From a geographic point of view Kurdistan provides the obvious solution to Turkey's increasing hydrocarbon demand. However, there are issues that will need to be overcome in order to make it a reality. Ultimately, though, we do not see any of these as insurmountable, and we are confident that direct exports to Turkey would occur if relations with Baghdad deteriorate, albeit they may be later than currently envisaged.

- **Contract not yet awarded for 1mmbbl/d pipeline:** The KAR Group should complete construction of the 150kb/d pipeline between the Taq Taq field and Khurmala Dome processing facilities by year end. Beyond this, however, we are not aware that the KRG has yet awarded an EPC contract for the main 1mmbbl/d trunkline, something that may mean its original aim of having it commissioned by the end of 2013 is missed.
- **Heavy oil and gas pipelines require Turkish infrastructure as well:** While the 1mmb/d pipeline can tie into existing infrastructure, both the heavy oil and gas pipelines will also require Turkey to construct corresponding capacity on their side of the border. While we expect the pipelines would follow the existing Kirkuk-Ceyhan pipeline, environmental permitting and funding are both aspects which amongst others may delay the project.
- **Conflicting statements from Turkey itself:** Despite the Energy and Security agreement, Turkey has previously said it would not take exports from Kurdistan without Baghdad's approval. It is significant therefore that Turkey is currently receiving condensate trucks directly from Kurdistan and sending back refined product, something that has required written permit from within Turkey. From an economic standpoint, we also argue that while Iraq is Turkey's second-largest trading partner with annual trade of US\$11bn, over 70% of this is with the Kurdistan region, so a vast majority of trade would persist even if ties with Baghdad broke down.
- **Take or pay gas contracts in place already:** One of our concerns had been that existing take or pay gas contracts with Iran, Azerbaijan and Russia which account for 58% of Turkey's current gas supply may limit the addressable market for Kurdistan. However, as Fig 16 from Genel's Capital Market Day below shows, these contracts are rolling off and supply shortfalls are likely to be met by more expensive spot LNG cargos and other solutions. Although planned pipelines such as ITE (Iran-Turkey-Europe) and TAP (Trans Adriatic Pipeline) may offer alternative sources of gas, we believe that Kurdistan gas will be available sooner, with ITE construction in doubt given the sanctions against Iran and TAP unlikely to begin construction before 2015. In addition, we expect that Kurdistan will provide a relatively low cost option relative to current spot LNG cargo prices of US\$12/mcf.

Fig 16 Gas contracts with existing suppliers are rolling over



Source: Genel Energy, Macquarie Research, October 2012

Vying for space in the export pipeline

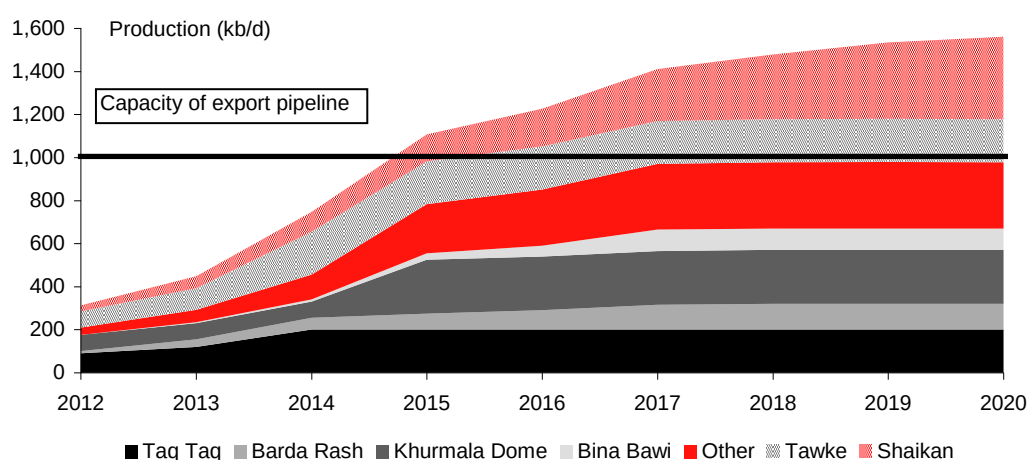
In this section we have used what publically available information there is, together with our own forecasts, to look at how production from Kurdistan may ramp up over the coming years.

On course for Kurdistan production of 1.1mmbbls/day in 2015

Our best guess is that Kurdistan will be able to produce 1.1mmb/d by 2015

Fig 17 below shows what we believe year end production capacity will be for the Kurdistan for the 2012-20 timeframe based upon existing discoveries alone. By 2015 we estimate the region will be able to supply ~ 1.1mmb/d of crude, with the planned 1mmb/d pipeline carrying about 0.8mmb/d. Looking further out, we believe that existing discoveries alone could see the pipeline more or less filled by 2017 and by 2020 the region could be producing ~1.5mmb/d of crude oil.

Fig 17 Kurdistan's oil production capacity through to 2020 (best guess!)



Source: Company presentations, Macquarie Research, August 2012

The ramp-up in production is being led by the following fields, which will feed directly into the 1mmbb/day export pipeline.

- **Taq Taq:** Current field capacity of 120kb/d is being expanded and should reach 200kb/d by 2014. Taq Taq, together with Khurmala Dome, underpins volumes into the planned export pipeline.
- **Barda Rash:** Phase 1 development should see 10-15kb/d produced by the end of 2012. Phase II, to be achieved in 2013, should see capacity increase to 35kb/d, while Phase III is for a full field development and delivery of 120kb/d plateau in 2017. A final Phase IV would see ~950mmb of heavy oil developed; however, this some distance off, and not modelled in this analysis.
- **Khurmala Dome:** The field, which is in fact the part of the giant Kirkuk field that lies within the Kurdistan region, is currently capable of producing 75kb/d. We understand that operator KAR Group intends to expand the field's production capability to 250kb/d capacity by 2015.
- **Bina Bawi:** An Extended Well Test should be operational in 1Q13, producing at 5kb/d which could rise to 10kb/d. Genel Energy has spoken of a phased development from 2014 onwards with an ultimate production plateau of 100kb/d envisaged.
- **Others:** At this stage we model only modest production from Khor Mor, Bijel, Sarsang, Garmian, Kurdamir, Atrush, Miran West and Topkhana fields, pending more detailed production profiles from the companies. Nor do we model any production from future discoveries. In total, by 2015, our "other" fields account for ~230kb/d of production.

In addition, both the Tawke and Shaikan fields combined should be providing ~325kb/d by the end of 2015; however, Tawke crude volumes will be exported using its existing pipeline to Fishkabur, while Shaikan crude will utilise the planned heavy oil pipeline.

- **Tawke:** DNO is currently in the process of expanding field capacity from 75kb/d to 100kb/d by the end of 2012. By the end of 2014 the plans are to have doubled this capacity again to 200kb/d.
- **Shaikan:** The field's ramp-up has been delayed by the requirement to bring in better gas handling equipment, given a higher than anticipated gas to oil ratio. Current production is therefore shut in; however, when these facilities are installed later in 2012, production capacity should increase to 20kb/d before a second Extended Well Test facility is installed in 2013, taking capacity to 40kb/d. Medium-term capacity is forecast to be 150kb/d in 2015, with field plateau of 400kb/d expected in 2020.

The above analysis shows that there will be increasing competition for export capacity as new discoveries are made and brought through into production. This will put pressure on the KRG to expand the pipeline and ultimately provide some form of mechanism for allocating capacity within the pipeline. We do not however believe it will be on a first-come, first-served basis, as we believe the KRG is likely to accommodate the super-majors who are yet to make commercial discoveries.

Domestic oil market not there if exports fails

With the KRG needing to demonstrate that it can provide significant volumes of crude in order to pressure Baghdad into a permanent export and payment resolution/encourage Turkey to build required infrastructure, we believe that capex plans are not as flexible as perhaps operators try and convey. This means that if exports do not persist, then the local market would be saturated with supply.

However, domestic refining capacity may just be 190kb/d

There is no official figure for the amount of refining capacity within Kurdistan, in part due to the existence of "topping plants", small garage-based operations capable of refining the lighter end of crude oil. However, we estimate that by the end of 2012 domestic refining demand will be ~190kb/d, rising to ~300kb/d by 2014. Of the current 190kb/d capacity, we estimate that roughly 120kb/d is from official government refineries and the rest is from topping plants.

- **Kalak refinery, Erbil:** The KAR Group recently announced plans for a further upgrade, taking total capacity from 80kb/d currently up to 185kb/d.
- **Baizan refinery, Sulimaniya:** Current capacity 17kb/d rising to 35kb/d by the end of 2012 and then 50kb/d at some point thereafter.
- **Tawke refinery, Tawke PSC:** Current capacity of 6kb/d. We are not aware of any plans to expand; however, should exports falter, then increasing capacity would be an option to allow the Tawke field to produce at higher rates.
- **Taq Taq refinery, Taq Taq:** Previous plans envisaged a 60kb/d refinery by 2015 however there is no firm commitment to construct this as yet.

Looking at the ability to monetise gas domestically, the future looks relatively optimistic with the KRG in the process of expanding the regions' power plant capacity from their current levels of 2000MW to over 7500MW. Major projects include:

- The expansion of the Mass Global Investments operated Erbil and Sulaymaniyah (Chemchemical) power plants from their current levels of 750MW to 1000MW. In April 2012 Abu Dhabi National Energy Company (TAQA) bought a 50% stake in the Sulaymaniyah Power Plant. These power plants are currently fed by 300mscf/d of gas production from the Crescent Petroleum/DanaGas-operated KhorMor field.
- Construction of additional power plants at Erbil, Sulaymaniyah(Chemchemical) and Dohuk, which will add a total of 5000MW of capacity, equivalent to an additional ~800-900mmscf/day of gas production.
- In 2008 the KRG announced that Gas Cities LLC, a JV between Crescent Petroleum and Dana GAS, planned to construct a 461m sq foot Kurdistan Gas City near Sulaymaniyah. The site is expected to cost a total of US\$40bn and would be home to a number of world scale petrochemical, heavy manufacturing and other gas intensive industries. We believe that this development has for the time being, at least, been mothballed.

Sub surface challenges

**11bn bbls and
Kurdistan lies within
the prolific Zagros**

Kurdistan lies within the prolific Zagros Basin Fold and Thrust belt. The 2011 Preliminary Reserve and Resource Survey results released by the KRG estimated that recoverable resources of 11bn bbls of oil and 40TCF of gas had been discovered to date, while other estimates suggest there is a further 40bn bbls of oil and 100TCF of gas to be discovered. The prospectivity of the region is not therefore in doubt; however, we believe that the geological understanding is still at a relatively early stage with subsurface geology and hydrocarbon phase/impurities still providing surprises and challenges to development.

Many potential reservoirs but well deliverability remains a challenge

**Kurdistan has a
number of
prospective
horizons**

As set out in Fig 18 below, drilling has encountered hydrocarbon pay across a significant number of intervals, ranging from the Tertiary all the way through to the Triassic, with deeper Permian to be tested for the first time in-country by Gulf Keystone's Shaikan-7 well early in 2013.

Fig 18 Some of the major hydrocarbon bearing formations in Kurdistan

Age of formation	Example formations
Tertiary	Pliocene Not a known hydrocarbon producing formation
	Miocene Upper Fars, Lower Fars, Jeribe, Euphrates
	Oligocene Kirkuk Group
	Eocene Pila Spi, Jaddala
	Paleocene Aaliji, Kolosh
Cretaceous	Upper Shiranish/Aqra, Bekhme, Kometan, Dokan
	Lower Qamchuqa, Sarmord, Balambo
Jurassic	Upper Gotnia/Barsarin, Naoklelekan
	Middle Sargelu, Sekhanlyan
	Lower Alan, Mus, Adalyah, Sakri/Butmah
Triassic	Upper Kurra Chine A, Kurra Chine C, Kurra Chine D
	Middle To be tested with Shaikan-7
	Lower To be tested with Shaikan-7
Permian	To be tested with Shaikan-7, known producing interval in Syria

Source: Company data, Macquarie Research, June 2012

**Intersecting
pervasive fractures
a key determinant of
well deliverability**

While there are clearly an abundant number of prospective horizons, the bigger challenge has come from a lack of natural (matrix) porosity within the reservoirs which has affected the ability of wells to flow at commercial rates. Well deliverability is more determined by the ability to intersect pervasive fracture networks which vary across discoveries and has therefore lead to uncertainty about recovery factors despite significant Oil in Place estimates. For example, both the Sheikh Adi and Bekhme exploration wells encountered oil but failed to flow oil to surface due to a lack of fracturing.

Wide azimuth, high fold, 3D seismic is one way that operators are identifying zones with higher fracturing, while deviated wells ensure that more of the well bore is exposed to the fractures. Early indications are that this method of well design is successful; for example Heritage Oil obtained its first meaningful flow rates from the Miran West structure (up to 75mmscf/d from the Jurassic) by drilling a deviated well into fractures observed on 3D seismic.

A bi-product of this greater seismic coverage is that it is allowing the next phase of exploration prospects to be matured. In particular, we expect to see a move away from obvious structural traps towards more subtle stratigraphic traps.

The above in mind, when only In Place Oil estimates have been given, we have applied in our analysis a 15% recovery factor for heavy oil (22 API or below) and a 25% recovery factor for medium/light oil and condensate to account the uncertainties surrounding reservoir quality.

Heavy oil and gas as common as light crude

Another feature of Kurdistan is the variability of hydrocarbon phase across the various horizons with less valuable heavy oil¹, gas and condensate as prevalent as medium crudes.

Hydrocarbon phase shifts from heavy oil in the north-west to condensate/gas in the south-east

This is demonstrated in the table below which shows API gravity across a number of discoveries, listed by geographic location (northwest to southeast). The results show that in the northwest of the region the major risk is encountering heavy oil rather than medium crude, whereas to the southeast the risk is that the source rock is overly mature due to a deeper burial depth and gas/condensate is discovered. It is also worth noting the emergence of the light oil Tertiary play in the southeast of the region which is successfully being exploited by Talisman and WesternZagros.

Fig 19 Hydrocarbon phase and quality at known discoveries

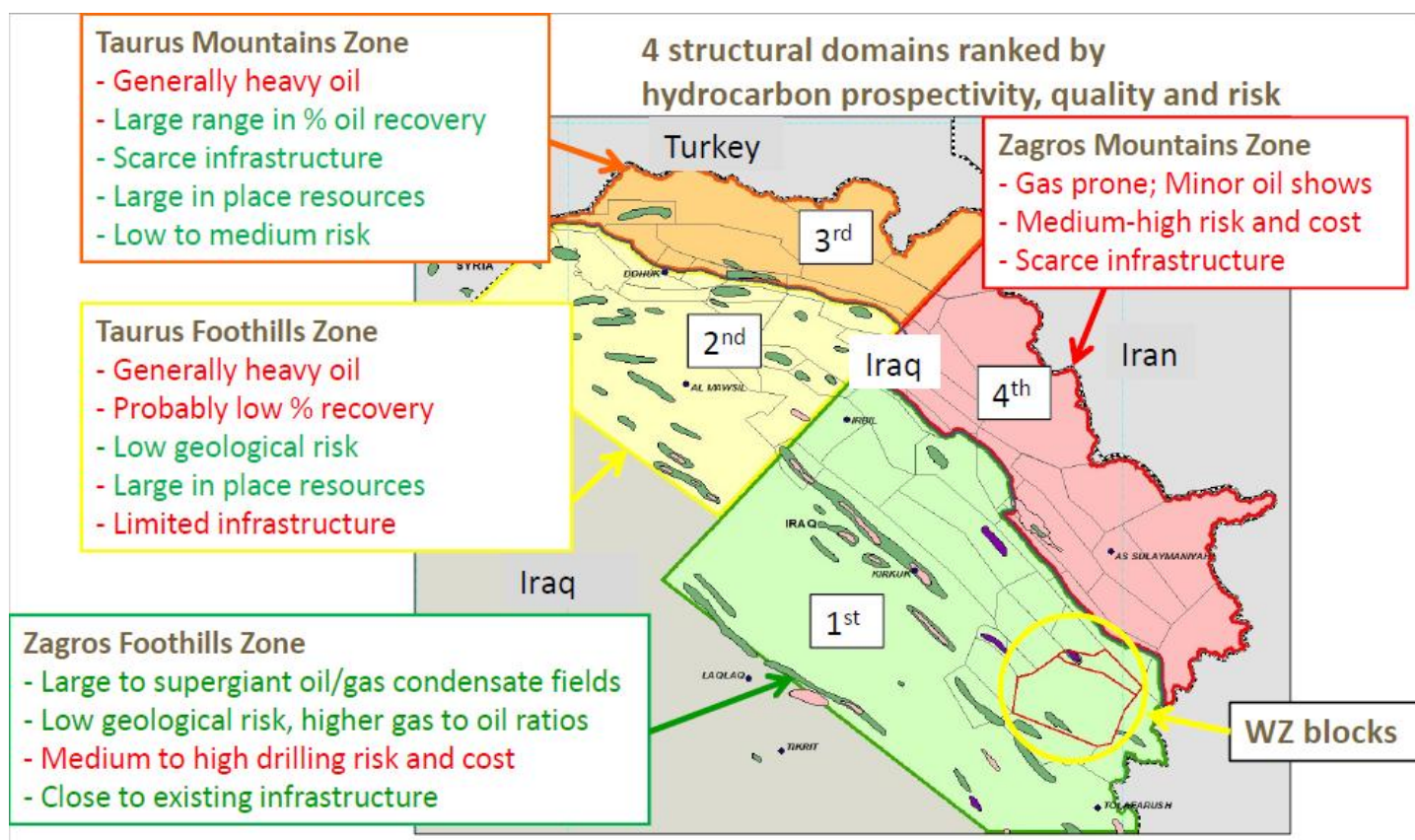
Field	PSC	Operator	Reservoir age			
			Tertiary	Cretaceous	Jurassic	Triassic
Tawke	Tawke	DNO	24 API	26 API		
Peshkabir	Tawke	DNO			27-29 API	
Ber Bahr	Ber Bahr	Genel Energy			10-15 API	
Sheikh Adi	Sheikh Adi	Gulf Keystone		Heavy oil	17-22 API	
Shaikan	Shaikan	Gulf Keystone		Heavy oil	18-26 API	Light oil/cond
Atrush	Atrush	GEP			26.5 API	
Swara Tika	Sarsang	HKN Energy				Light oil/gas
Bijeel	Akri-Bijeel	MOL			12-18 API	
Bekhme	Akri-Bijeel	MOL			Heavy oil	
Simrit	Ain Sifni	Hunt Oil		Testing	Testing	39 API
Barda Rash	Barda Rash	Afren		16 API	30-32 API	
Summail	Duhok	DNO		Gas	Heavy oil	
Bastora	Erbil	DNO		16-18 API		
Benenen	Erbil	DNO			25-34 API	
Demir Dag	Hawler	Oryx	15 API	22 API	8 API	
Bina Bawi	Bina Bawi	OMV		35 API	44-47 API	Gas
Taq Taq	Taq Taq	TTOPCO	24 API	48 API		
Miran West	Miran West	Heritage Oil		15 API	Gas/Cond	
Chemchemical	Chemchemical	Dana Gas Crescent		Gas		
Sangaw North	Sangaw North	Sterling Energy		Gas	Gas	Gas
Qara Dag	Qara Dag	Niko Resources		48 API		
Khor Mor	Khor Mor	Dana Gas Crescent	Gas/Cond			
Kurdamir	Kurdamir	Talisman	38-42 Oil/Cond	39-40 API		
Pulkhana	Pulkhana	Open	33-35 API	27-36 API		
Sarqala	Garmian	WesternZagros	40-44 API			
Mil Qasim	Garmian	WesternZagros	43-44 API			
Chia Surkh	Chia Surkh	Genel Energy	41 API	Gas		
Shakal	Shakal	Open	26-35 API			
Key		Heavy oil				
		Medium/light oil				
		Gas/Condensate				

Source: Company data, Macquarie Research, October 2012

In Fig 20 below, we show how WesternZagros has subdivided the Kurdistan region into four distinct hydrocarbon plays. The result provides a similar picture to the analysis above, suggesting a shifting hydrocarbon phase from heavy oil to light oil, condensate and gas from the northwest to the southeast. It also suggests that wells to the southeast will be more expensive. We disagree, however, with the notion that the southeast is close to existing infrastructure, as the planned export pipeline to Turkey will initially run from only the centre of the region.

¹ There is no set definition of heavy oil although it is generally considered to have an API <22.3 and typically has a viscosity in excess of 100 centipoise. The oil is "heavier" as it contains a higher proportion of non-paraffinic, higher molecular weight, compounds. When refined, heavy oil produces a high proportion of less valuable "bottom of the barrel" products such as bitumen and asphalt and therefore tends to trade at a discount to medium/light oils. Heavy oil is a result of biodegradation that occurs when poorly sealed reservoirs allow algae to degrade the lighter hydrocarbons compounds.

Fig 20 WesternZagros' interpretation of likely hydrocarbon phase



Source: WesternZagros, Macquarie Research, October 2012

Sulphur is an unwanted impurity that requires greater opex and capex costs

Sulphur is an unwanted impurity that is found in both crude oil and natural gas and is prevalent in the Kurdistan region. As such, many of the hydrocarbons found in Kurdistan are classified as “sour,” ie containing a sulphur content in excess of 0.5%.

The sulphur needs to be removed from the crude before it is exported, as it can corrode processing and refining equipment, while burning refined products containing sulphur causes sulphur dioxide, which is a key cause of acid rain. Special de-sulphurisation equipment therefore has to be installed which removes sulphur through the addition of amines which react with the sulphur to form non toxic products.

In the ground, the sulphur can also react with hydrogen atoms to form hydrogen sulphide, a toxic and potentially fatal gas which, like sulphur dioxide, has corrosive qualities and can erode production lining etc.

Ultimately, while sulphur content can be overcome, it all results in higher capex and opex costs, especially given the nascent stage of Kurdistan hydrocarbon development. Indeed, one of the issues that has prevented Gulf Keystone from ramping up production at the Shaikan EWT-1 facility to its maximum throughput of 20kb/d has been the 8.9% H₂S found in the crude oil produced from the Sargelu formation. While the company has been able to desulphur the crude by injecting chemicals, this can only be done on a relatively small scale. “Scavenger” units needed to be imported to allow for larger-scale production

Infrastructure Capacity Payments

Fiscal creep by the KRG is evidenced by the introduction of Infrastructure Capacity Payments which require operators to cede a proportion of profit oil back to the KRG.

Varying rates mean that the same barrel can be worth more to one company than another

The KRG has published PSCs and amendments on its website

In an attempt to improve transparency the KRG has published signed PSC terms, along with amendments, on its website ([link](#))

Looking at these PSC terms, one thing that stands out is the amendments to the PSCs surrounding *Infrastructure Capacity Payments* ("ICPs"). These payments, which require a percentage of a contractor's profit oil to be paid into a separate Capacity Building Account, were first highlighted when Gulf Keystone agreed to give up 40% of its profit oil across all its licences in return for assuming ETAMIC's 50% interest in the Gulf Keystone Petroleum International JV.

The table below shows the ICPs made by each of the operators that we detail in this report as well as Petroceltic. Interestingly, these payments can vary by operator across the same licence. In particular, it is worth pointing out that DNO is not required to make these payments on any of its three PSCs, while OMV's 45% ICP at Bina Bawi was the highest of any that we came across whilst going through the PSC documents. Going forwards, we believe it probable that the KRG will try and harmonize PSCs and will impose ICPs on those PSCs where they are not currently present.

Fig 21 Overview of Infrastructure Capacity Payments by PSC and company

PSC	Company										
	Afren	DNO	Genel	GKP	Petroceltic	Hess	Hunt	MOL	OMV	Petoil	Sinopec
Ain Sifni	20%						20%				
Akri-Bijeeel				40%				40%			
Barda Rash	20%										
Ber Bahr			30%	40%							
Bina Bawi			30%						45%		
Chia Surkh			30%							40%	
Dinarta					20%	20%					
Duhok		0%	30%								
Erbil		0%									
Miran West			8%								
Shaikan				40%				0%			
Shakrok					20%	20%					
Sheikh Adi				40%							
Taq Taq			30%								0%
Tawke		0%	30%								

Source: Macquarie Research, October 2012

The impact of these payments on NPV/boe economics

We estimate that a 30% Capacity Payment deducts 33% of value from a discovered barrel at US\$100/bbl

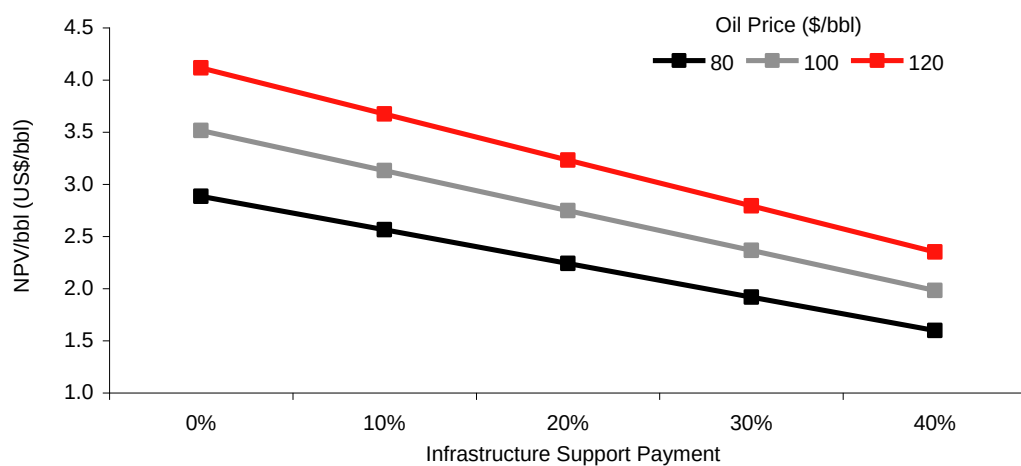
We have, as part of our valuations, constructed a generic Kurdistan PSC based upon a 500mmb development. Development assumes first oil in 2015 with a five-year plateau at ~100kb/d from 2019. Overall capex costs amount to \$2/bbl while opex costs are estimated at \$3/bbl.

Using this model as our basis, we show in the chart on the next page that there is a straight relationship between Infrastructure Capacity Payments and NPV/bbl economics. The absolute change in value is largest under the highest oil price assumption, hence the convergence of the NPV/bbl economics as the payment level increases.

To put hard and fast numbers to the analysis, in a \$100/bbl oil price environment we calculate that a barrel of discovered undeveloped oil would be worth \$3.51/bbl for a company with no Infrastructure Capacity Payments whereas it would be worth \$2.37/bbl, some 33% less, for a company with a 30% Infrastructure Capacity Payment.

So, while the market (and analysts) may well compare company valuations relative to resources, we believe that it is always worth bearing in mind that **the same** resources in Kurdistan can have differing values.

Fig 22 Value of discovered undeveloped barrels of oil dependent upon Infrastructure Capacity Payment and Oil Price



Source: Macquarie Research, October 2012

Valuations

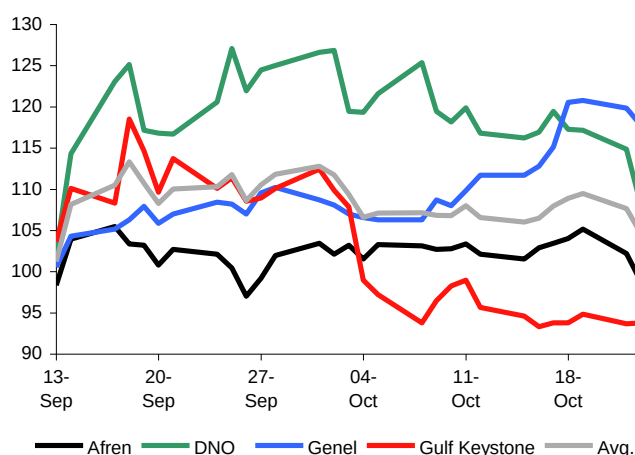
In this section we look at the relative valuations of the Afren, DNO, Genel Energy and Gulf Keystone against each other and relative to our broader E&P universe. Although DNO is more expensive on EV/boe metrics than Genel Energy and Gulf Keystone, we believe there are reasons to justify this. However, we see no reason to justify DNO being the only company to trade at a discount to Core NAV. Hence we recommend that investors gain Kurdistan exposure through this name.

Recent share price performance

The share prices of Genel and DNO are factoring in at least a period of continued exports

Figure 23 below shows Kurdistan operators unsurprisingly responded well to the 13th September agreement between the KRG and Baghdad to continue exports. For DNO and Genel Energy, share prices have remained elevated, suggesting that the market believes that the agreement will last, at least for a period of time. Gulf Keystone's underperformance is exacerbated by a recent US\$300m convertible bond issue.

Fig 23 We believe that share prices are now factoring in exports and payments, at least for a while



Source: Factset, Macquarie Research, October 2012

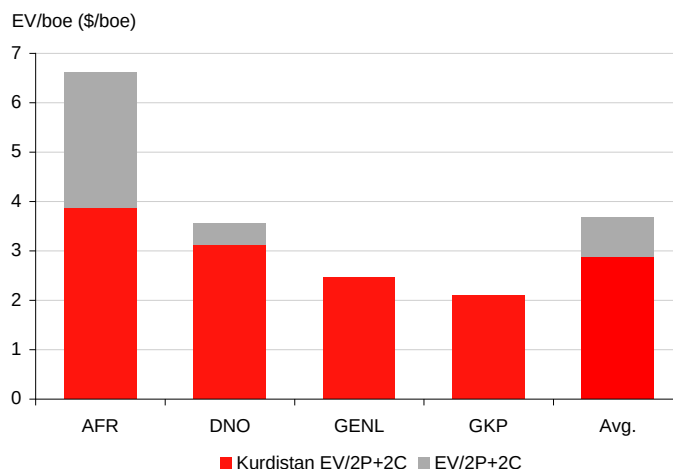
Comparative valuations are only a good starting point

Comparative valuations ignore underlying asset development and Infrastructure Capacity Payments

Given the geographic concentration of assets in Kurdistan, it is only natural that investors look at Afren, DNO, Genel Energy and Gulf Keystone on an EV/boe relative basis. However, trying to compare companies on this basis is complicated by Afren and DNO, which own assets outside of Kurdistan that operate under different (generally more favourable) fiscal regimes, Kurdistan assets being of at different stages of development and subject to differing Infrastructure Capacity Payment rates and finally, Genel Energy having gas as well as oil exposure.

That said, we do believe that the analysis can be useful. Not so much because investors should buy the cheapest and sell the more expensive, but in so far as it should highlight any clear anomalies. For the four companies mentioned above, Fig 24 below show where we believe the stocks trade at relative to: i) Group 2P+2C Reserves and Resource and ii) Kurdistan 2P+2C Reserves and Resources, calculated by backing out reserves and resources outside of Kurdistan along with their EMV.

Note that our estimates for 2P reserves and 2C resources are derived from our Core NAV analysis and therefore do not necessarily match the 2P and 2C numbers published by the companies themselves.

Fig 24 EV/boe comparison across Kurdistan E&Ps

Source: Factset, Macquarie Research, October 2012

The results are, largely as we would have expected:

- DNO rightly trades at a premium to Genel Energy given that it has a higher proportion of 2P reserves within the 2P+2C mix and is also 100% oil focused.
- Gulf Keystone trades at the cheapest metric, which is explained by the fact it has only contingent resources and the timing of plateau at Shaikan is even more uncertain than for other fields in Kurdistan, given the need for the heavy oil pipeline. We suggest that Gulf Keystone also trades at a discount given the uncertainty regarding recoverable resources at Shaikan.
- However, Afren's valuation relative to DNO is hard to rationalise, given that DNO has no Infrastructure Capacity Payments on its PSCs compared to Afren, which has 20% payments. In addition, DNO has a higher proportion of 2P reserves within its 2P+2C mix.

Premium/(discounts) to NAVs are a better stock selection method

We continue to believe that the best method of stock selection is looking at companies from a bottom-up NAV approach using our EMVs, with our target prices formed from a combination of Core NAV and Visible Risked exploration upside.

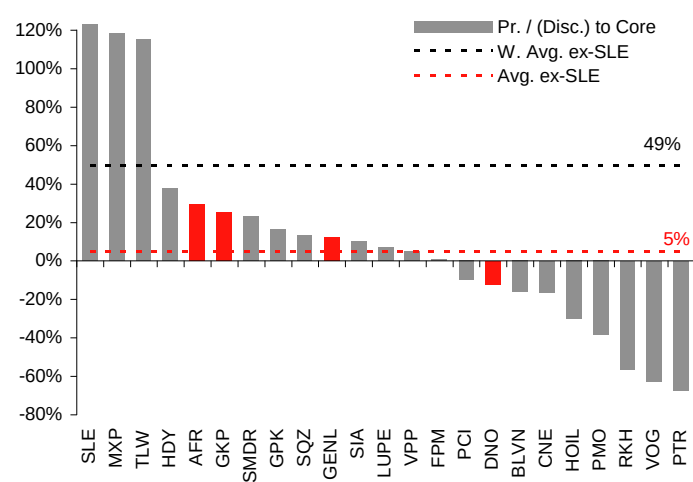
Of course this approach means that riskings play a part in valuation, but here we have tried to be consistent across the board, imposing a maximum 85% CoS for any field in Kurdistan whilst the export payment mechanism remains unresolved.

Fig 25 and 26 on the following page show where we believe stocks are trading at relative to Core NAVs and Core + Risked NAVs and how that compares to our E&P universe as a whole.

- Gulf Keystone and Afren both trade at significant ~30% premiums to Core NAV, with Genel also trading above the sector average premium of 5%. DNO is the only Kurdistan-focused company to trade at a discount (12%).
- On a Core + Risked NAV view, Gulf Keystone trades at a 14% premium, which in our view means that a favourable outcome from the Excalibur litigation case is already discounted into the share price. DNO again stands out as offering attractive value, trading at a 24% discount to Core + Risked NAV, which is a larger discount than the sector average of 18%.

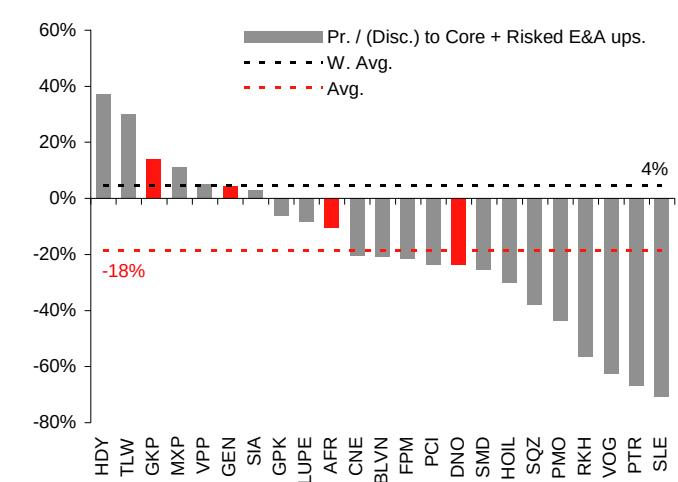
**A bottom up
approach suggests
DNO is the stock to
own**

Fig 25 Share prices relative to Core NAV



Source: Company data, Macquarie Research, October 2012

Fig 26 Share prices relative to Core + Risked NAV



Source: Company data, Macquarie Research, October 2012

UNITED KINGDOM

AFR LN Neutral

Price (at 15:35, 26 Oct 2012 GMT) £1.34

12-month target	£	1.50
12-month TSR	%	+11.8
Valuation	£	2.81

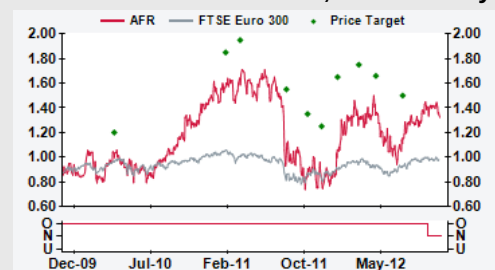
- Sum of Parts methodology

GICS sector		Energy
Market cap	£m	1,458
30-day avg turnover	£m	4.8
Market cap	US\$m	2,337
Number shares on issue	m	1,087

Investment fundamentals

Year end 31 Dec		2011A	2012E	2013E	2014E
Revenue	m	596.7	1,438.2	1,098.7	1,481.8
EBITDA	m	438.0	1,014.7	755.2	1,063.5
EBIT	m	277.9	645.4	485.9	753.1
Reported profit	m	121.7	205.6	169.6	314.5
EPS adj	US\$	0.12	0.18	0.15	0.28
EPS adj growth	%	133.0	57.8	-17.5	85.4

AFR LN vs FTSE Euro 300, & rec history



Note: Recommendation timeline - if not a continuous line, then there was no Macquarie coverage at the time or there was an embargo period.

Source: FactSet, Macquarie Research, October 2012
(all figures in USD unless noted)

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31 October 2012

Macquarie Capital (Europe) Limited

Afren

Kurdistan deal still looking smart

Event

- We review Afren's Kurdistan assets as part of our wider note on the region.

Impact

- Kurdistan will be a key driver for production growth.** Barda Rash first oil achieved on 7 July 2012 (and announced on 21-Aug) was the first milestone in Afren's ambitious plan to bring Kurdistan gross production to 120kb/d by 2019 (~72kb/d on a WI basis). This is a key driver to allow the company to reach its long term total WI production target of 100kboe/d by 2017. In our analysis we highlight how Kurdistan will play an important role in growing production: we estimate that Kurdistan production will be only 4% of 2012 production, growing to 26% in 2013, 30% in 2014 and 37% in 2015.
- Jebel Simrit volumes likely to be revised.** Afren is currently testing the Jebel Simrit-2 exploration well (Ain Sifni PSC, 20% WI) following the 460m net oil pay discoveries announced on 17-Apr. The company has already tested 3 (out of up to 12) intervals, flowing 39°API oil at 13,584b/d cumulatively (plus 23.5mmcf/d of associated gas). No information of test duration was released. In the same block, Afren is about to spud the Jebel Simrit-3 exploration well that will be targeting the East Simrit prospect. RPS pre-drill estimates were 42mmb 2C resources and 227mmb P50 prospective resources. We believe that results to date from Jebel Simrit-2 support an upward revision case – we already carry P10 volumes of 482mmb (7.8p/sh, 13.4p/sh unrisked).
- Financing in place to support capex plan.** Our liquidity analysis to 2015 suggests that the company will be able to pay for its capex plan through 2015 and generate free cash flow. Kurdistan US\$609m spend (net to Afren) to 2015 will be more than 30% of total spend from 2013 onwards.

Earnings and target price revision

- No change in EPS and TP

Price catalyst

- 12-month price target: £1.50 based on a Sum of Parts methodology.
- Catalyst: Jebel Simrit-2 testing update, Jebel Simrit-3 well updates, Pai-Pai well results (Kenya), IMS (13-Nov)

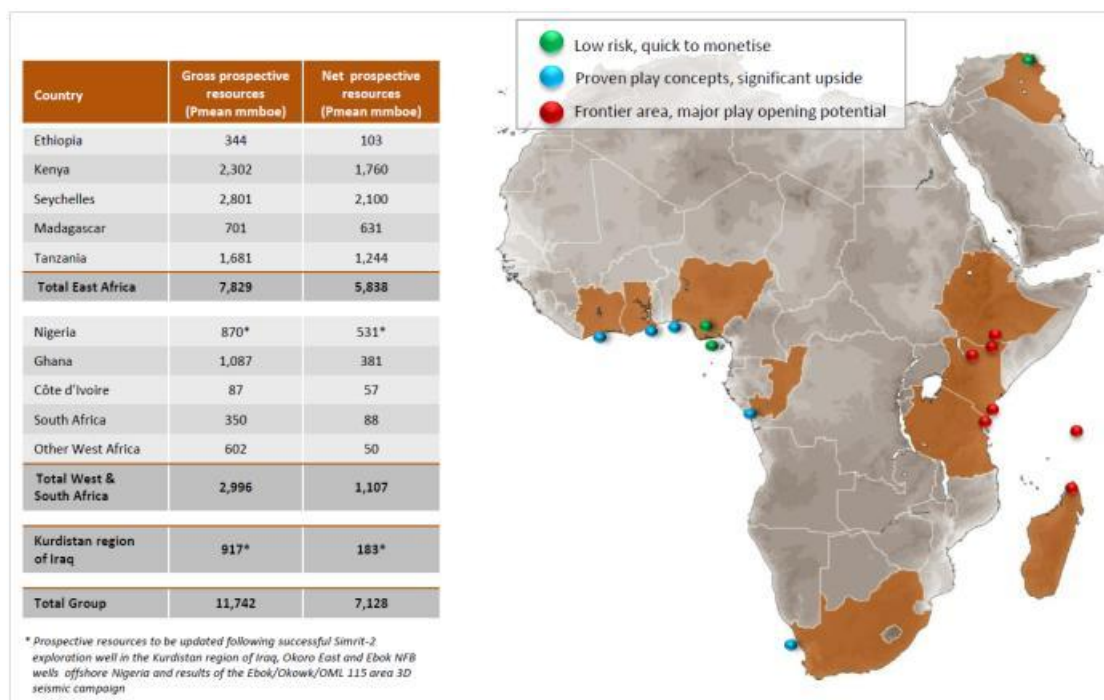
Action and recommendation

- We confirm our Neutral rating and 150p TP, as we see much of the value now captured in our target price, which includes, in our view, much of the medium term material exploration upside.
- Overall, we continue to have a positive view on Afren's long term value proposition, particularly the leverage to exploration exposure within its portfolio over the next few years (Unrisked Total NAV is £14.48/sh or 10.8x the current share price). Additionally, this exploration exposure is fully funded out to 2015 even on our conservative production assumptions for Kurdistan.

Company overview

- **From Nigeria to Kurdistan through East Africa.** Kurdistan has been the latest addition to Afren's asset portfolio, the first one outside Africa and part of a broader diversification strategy started with the entry into East Africa through the acquisition of Black Marlin in 2010. We believe that 2013 production from Kurdistan will represent 26% of Afren's total production of 40kboe/d, growing to 30% in 2014 (of 48kboe/d total) and to 37% in 2015 (of 75kboe/d total). On a valuation basis, Kurdistan represents ~23% of the assets included in our Core NAV and 19% of the assets included in our Total NAV.

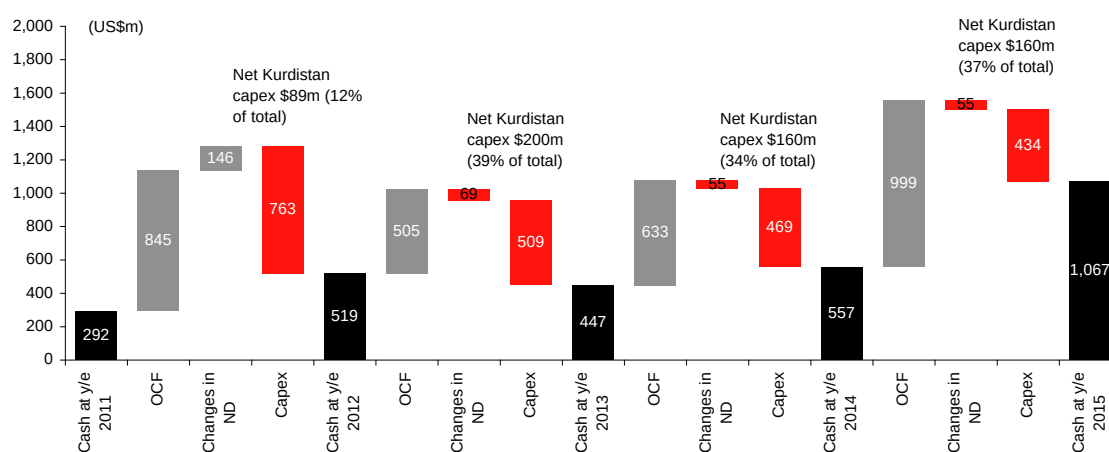
Fig 1 Afren's asset portfolio – an African focused company with Kurdistan exposure



Source: Afren 1H12 presentation, Macquarie Research, October 2012

- **~US\$610m Kurdistan capex to 2015.** Our liquidity analysis suggests that Afren is well funded to support its capex plan to 2015 (of which, as showed in Fig 2, Kurdistan's US\$609m represents a sizeable part). We believe Afren will be free cash flow positive through to 2015.

Fig 2 Free cash flow generation to 2015 supports Afren capex plan



1 – Assuming Brent price of \$107.51/bbl in 2012; \$106.25/bbl in 2013; \$115.54/bbl in 2014; \$117.52/bbl in 2015

Source: Company data, Macquarie Research, October 2012

Kurdistan assets

- Afren entered into Kurdistan on 27 July 2011, announcing the acquisition of a 60% operating WI in the Barda Rash PSC from Komet Group (Private) and of a 20% WI in the Ain Sifni PSC from the KRG. Both Barda Rash and Ain Sifni are located in the Zagros Fold and Thrust Belt in the eastern part of Kurdistan just to the south of Gulf Keystone's "Shaikan" block.
- We illustrate the transaction metrics of the headline US\$588m deal in Fig 3 below.

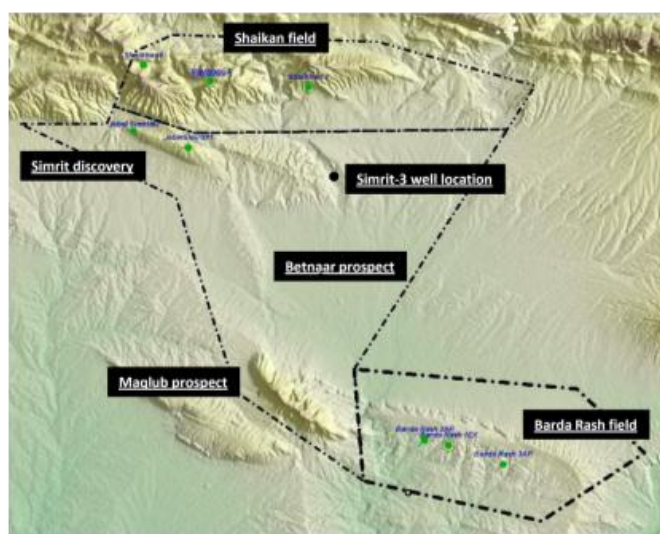
Fig 3 Kurdistan acquisition – resource breakdown (at the time of the acquisition)

	Acquisition price	2C net resources (light oil)	2C net resources (heavy oil)	2C net resources (total)	Net prospective resources	Total net resources
	US\$m	mmb	mmb	mmb	mmb	mmb
Barda Rash PSC (60%)	419	304	578	882		882
Price multiple (US\$/Bbl)		1.38	0.72	0.47		0.47
Ain Sifni PSC (20%)	170			8	183	192
Price multiple (US\$/Bbl)				20.18	0.92	0.88
Combined PSC	588	304	578	890	183	1074
Price multiple (US\$/Bbl)		1.94	1.02	0.66	3.21	0.55

Source: Company data, Macquarie Research, October 2012

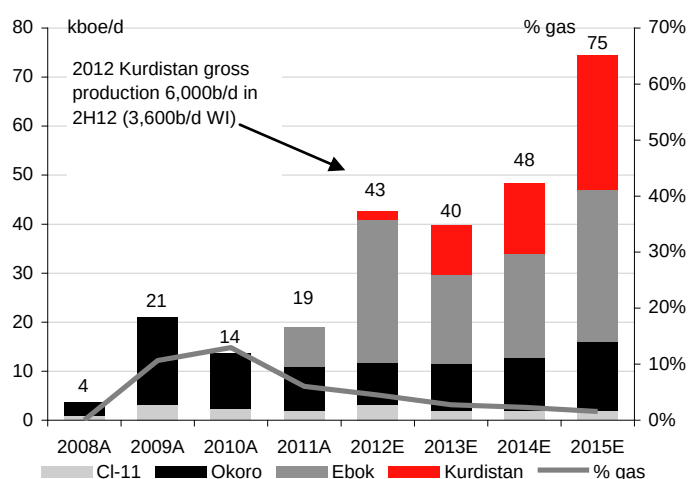
- During its 1H12 results on 21 Aug 2012, Afren announced that on 7 Jul 2012 Barda Rash achieved first oil and it was "filling tanks" and would commence selling crude after Eid holiday ended (25 Aug). However, although we are assuming sales have started, Afren has not yet provided any update to confirm these sales have commenced.
- At Afren's update on 21 Aug 2012, the Barda Rash field was producing at 6kb/d with the aim to bring overall production to 10-15kb/d by the end of 2012 (~6-9kb/d on a WI basis). We are currently assuming Afren will produce 3.0kb/d in 2012 (1.8kb/d on a WI basis), 17kb/d in 2013 (10.2kb/d on a WI basis) and 24kb/d in 2014 (14.4kb/d on a WI basis). According to Afren's development plan the company plans to reach 24kb/d in 2014 (14.4kb/d on a WI basis) and peak production at 120kb/d in 2019 (72kb/d on WI basis).

Fig 4 Barda Rash and Ain Sifni PSCs



Source: Afren Presentation, October 2012

Fig 5 Kurdistan contribution to Afren production (Macq. Est.)

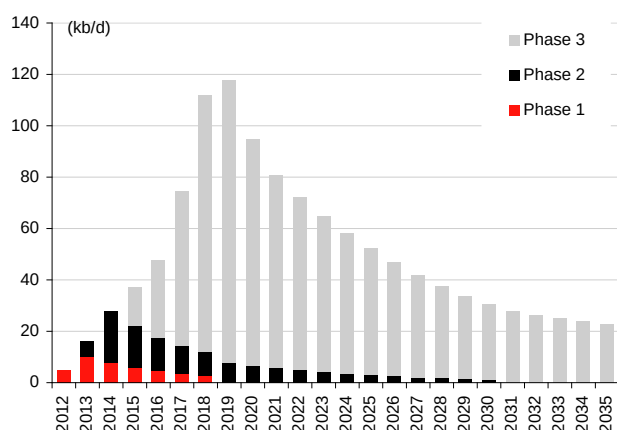


Source: Company data, Macquarie Research, October 2012

Barda Rash – 60% WI (op) (Komet 20%; KRG 20%)

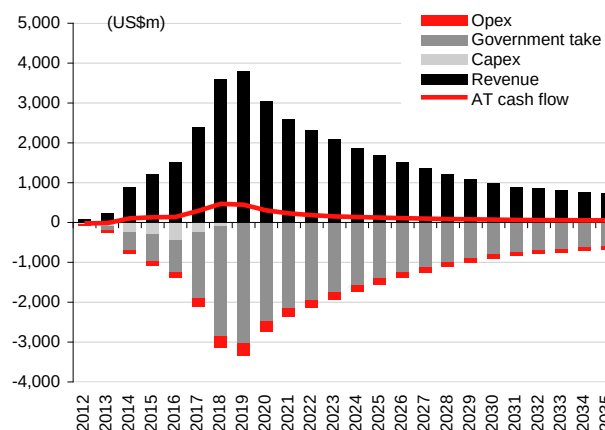
- When Afren farmed into the Barda Rash PSC, three previously drilled E&A wells were already present (BR-1, 2 and 3, green spot in Fig 4 above). The discovery well BR-1 was drilled in the crestal position to 3,743m MD and encountered heavy oil (14-17°API) shows throughout the Cretaceous and the Upper and Middle Jurassic. The well also flowed light oil (30-32° API) from the Mus and Adaiya Formations (Lower Jurassic). Appraisal well BR-2 was drilled within the hanging wall, while BR-3 was drilled to the south penetrating the southern bounding fault. A limited number of flow tests were conducted and only mud with traces of oil was reported.
- However, according to RPS Energy's Letter of Opinion (19 Apr 2011), "this may be due to the very short nature of the tests, which are of poor quality, where the test interval has not 'cleaned up' and hence cannot be considered definitive of the flow potential of the reservoir".
- For the light oil resources (506mmb gross recoverable contingent resources) Afren is planning a 3-phase development. In Phase 1 (currently ongoing), the company will re-enter the existing wells BR-1, BR-2 and BR-2 aiming to achieve 10-15kb/d gross production by y/e 2012. In Phase 2, Afren is planning to drill sufficient wells to increase production to 35kb/d. According to Afren's plan this will be achieved throughout the course of 2013. In our analysis, we assume the company will reach 35kb/d sometime in 2015. In Phase 3, Afren is planning to reach 120kb/d gross production by 2019 (we have 118kb/d in 2019). Overall planned capex spent (net to Afren) is estimated at US\$1,059m.

Fig 6 Barda Rash production (Macq. Est.)



Source: Company data, Macquarie Research, October 2012

Fig 7 Barda Rash cash flow generation (Macq. Est)



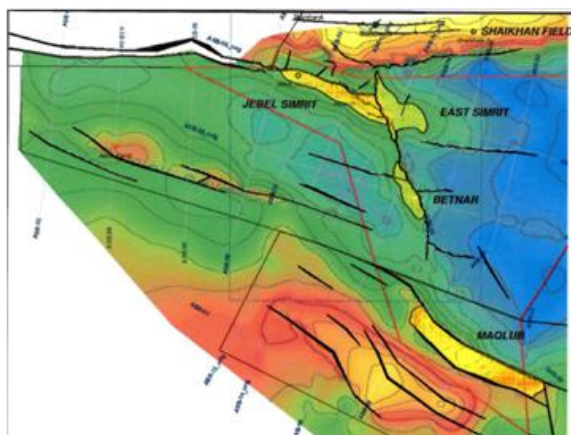
Source: Company data, Macquarie Research, October 2012

- The heavy oil component (964mmb gross recoverable contingent resources) is located in the shallower reservoirs, although in the neighbouring Shaikan discovery the Kurra Chine has flowed light oil from similar depths. Afren has not yet discussed a development plan but is planning to try different recovery techniques and pilot testing throughout the initial development phases to establish the most appropriate production solutions

Ain Sifni – 20% WI (Hunt Oil 60% (op); KRG 20%)

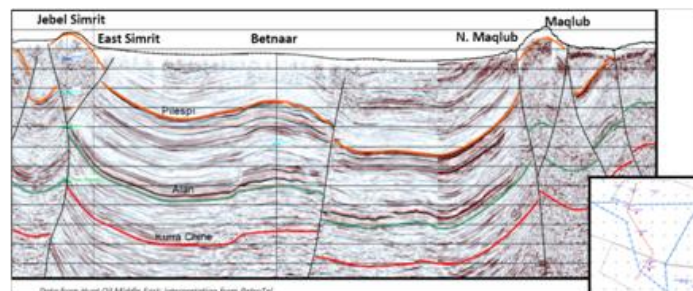
- In the Ain Sifni block, three structures have been identified (Fig 8 and 9). In the north of the block is the Jebel Simrit discovery (42mmb gross contingent resources and 227mmb gross Pmean prospective resources, pre Jebel Simrit-2 well results), the only one of the three to have been penetrated, located south west of the neighbouring Shaikan Field. To the south of Jebel Simrit is the Betnar structure (28mmb gross Pmean prospective resources). The third structure is the Maqlub (661mmb gross Pmean prospective resources), located in the south of the block up dip of the Barda Rash field.

Fig 8 Ain Sifni overview



Source: Afren presentation, July 2012

Fig 9 Ain Sifni cross section



Source: Afren presentation, July 2012

- Jebel Simrit was discovered by the operator Hunt Oil in 2010 with the JS-1 well. Hunt Oil found oil bearing reservoirs in both the Cretaceous and in the Jurassic sections (Triassic section was not penetrated because the well was suspended due to drilling issues). The JS-1 well penetrated the fault in the Cretaceous section passing into the footwall where the Cretaceous was repeated. Heavy asphaltic oil shows were recorded in the footwall from 1,110m to TD.

Jebel Simrit-2 volumes likely to be revised...up

- Jebel Simrit-2 was spudded in Oct 2011 and reached TD (~3,800m) on 17 Apr 2012, finding 460m net oil pay throughout the Cretaceous, Jurassic and Triassic age reservoirs and establishing no oil water contact (OWC). On 19-Jul-12 Afren announced it flowed 39°API oil from 3 zones in the Triassic section (Kurra Chine formation, accounting for 199m of net pay) at a cumulative rate of 13,584b/d (plus 23.5mmcf/d of associated gas). Testing further (up to) 9 intervals is currently ongoing and we look forward further clarity on the OWC (not established yet) and confirmation of oil quality and sulphur content, although at this stage the data collected is very encouraging
- In the RPS Energy Letter of Opinion dated 9 Jun 2011, 2C resources for the Jebel Simrit-1 well were estimated at 42mmmb across 12 Cretaceous and Jurassic horizons (75mmmb P10). Mid case Prospective resources for the Jebel Simrit and East Simrit prospects were estimated at 227mmmb across 12 horizons including the Triassic Kurra Chine formation (440mmmb P10). The reservoirs encountered to date suggest that a revised resource update should be expected.
- In our valuation, we carry the 2C resources and the P10 prospective resources for Jebel Simrit at a combined 482mmmb in our target price (8p/sh / 13p/sh unrisks) and look forward to revised resource estimates following the apparent success so far at Jebel Simrit-2.
- On 12 Sep 2012 the Viking-11 drilling rig spudded the Simrit-3 well that will test the eastern side of the Simrit anticline structure, 10km East of the Simrit-2 discovery well, with the "objective to extend known oil out to the eastern extent of the Simrit anticline".
- The CPR report has also estimated 28mmmb mid case prospective resources for the Betnar structure (51mmmb in the P10 case) and for the Maqlub 661mmmb mid case prospective resources (1,092mmmb in the P10 case). These additional prospects will probably be targeted after the Simrit-3 well.

Valuation

- We make no changes to our Afren valuation. Our Target Price of 150p/sh is made up of 104p/sh of Core NAV and 46p/sh of Risked E&A upside.

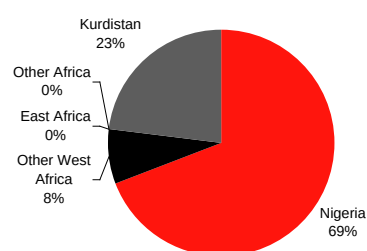
Fig 10 Afren's Core and Total NAV; components of target price highlighted

Afren					Previous published		
	Riskd resources (mmboe)	Unit Value (US\$/boe)	EMV (US\$m)	Value (p/sh)	Change	Value (p/sh)	Comments
Assets (NPV10)							
Producing Assets	50.7	22.7	1,151.0	65p	0p	0%	65p
Cash/(Net Debt)			-582.5	-33p	0p	0%	-33p
Undeveloped Assets	215.0	6.1	1,320.2	74p	0p	0%	74p
Other assets less G&A			-39.1	-2p	0p	0%	-2p
Core NAV	265.6	7.0	1,849.5	104p	0p	0%	104p No change
Option Proceeds			27.3	2p	0p	0%	2p
Riskd E&A upside	736.8	4.2	3,117.9	175p	0p	0%	175p
Total NAV	1002.5	5.0	4,994.8	281p	0p	0%	281p
Riskd E&A upside included in TP				46p	0p	0%	46p No change
Unriskd value of above				146p	0p	0%	146p
Target price				150p	0p	0%	150p No change

Source: Company data, Macquarie Research, October 2012

- In Fig 11 and 12 we show Kurdistan's relative importance to our Afren valuation.

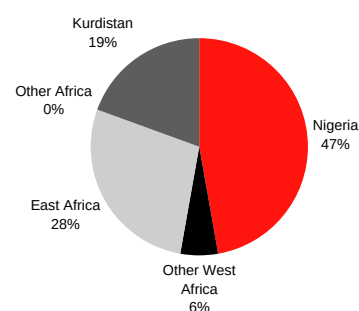
Fig 11 Kurdistan is 23% of assets in 104p Core NAV



1 – Kurdistan (32p/sh is 25% of the 139p/sh assets included in our Core NAV). Net Core NAV of 104p/sh is calculated as the asset value in Core NAV (139p/sh) minus net debt and G&A (35p/sh)

Source: Company data, Macquarie Research, October 2012

Fig 12 Kurdistan is 19% of asset in Total NAV of 281p



1 – Kurdistan (61p/sh is 20% of the 313p assets included in our Total NAV). Net Total NAV of 281p/sh is calculated as the asset value in Total NAV (313p/sh) minus net debt and G&A (35p/sh) plus proceeds from options (1.5p/sh)

Source: Company data, Macquarie Research, October 2012

Fig 13 Afren's asset breakdown EMV (E&A upside included in TP highlighted)

Country	Project/Prospect	Gross Res. Potential (mmboe)	Working Interest (%)	C.O.S. (%)1	Discounted Value (US\$/boe)2	Net Risked (mmboe)	EMV (US\$m)3	Risked Value (p/sh)	Unrisked Value (p/sh)4
Producing Assets									
Nigeria	OML 67 - Ebok Central fault block	32.6	40.0%		\$42.6	13.0	556	31.2	31.2
Nigeria	OML 67 - Ebok West fault block	24.0	40.0%		\$27.6	9.6	265	14.9	14.9
Nigeria	OML112 - Okoro	14.7	50.0%		\$26.6	7.4	195	11.0	11.0
Cote d'Ivoire	Block CI-11 Lion & Panthere	4.4	48.0%		\$13.0	2.1	28	1.5	1.5
Cote d'Ivoire	Lion LPG Plant	3.0	100.0%		\$20.5	3.0	62	3.5	3.5
Nigeria	OML 26 - Oginini & Isoko	40.7	20.3%		\$1.0	8.2	8	0.5	0.5
Kurdistan	Barda Rash (light oil) - phase 1	14.4	60.0%	85%	\$5.0	7.3	37	2.1	2.4
		133.8				50.7	1,151	64.7	65.0
Undeveloped assets									
Nigeria	OML 67 - Ebok North Fault block	35.0	40.0%	60%	\$19.1	8.4	161	9.0	15.1
Nigeria	OML 67 - Ebok further phase	25.0	40.0%	50%	\$11.6	5.0	58	3.3	6.5
Nigeria	OML 67 - Ebok Southern Lobe	20.7	40.0%	50%	\$11.0	4.1	46	2.6	5.1
Kurdistan	Barda Rash (light oil) - phase 2	43.8	60.0%	70%	\$4.6	18.4	85	4.8	6.8
Kurdistan	Barda Rash (light oil) - phase 3	412.7	60.0%	50%	\$3.6	123.8	446	25.0	50.1
Cote d'Ivoire	Block CI-01	37.0	65.0%	50%	\$3.9	12.0	47	2.6	5.2
Cote d'Ivoire	Block CI-11 infill	12.4	48.0%	50%	\$20.7	3.0	61	3.5	6.9
Nigeria	OML 67 - Okwok	26.3	28.0%	60%	\$16.5	4.4	73	4.1	6.8
Nigeria	OML 26 - Oginini & Isoko (2C upside)	142.3	20.3%	60%	\$0.8	17.4	14	0.8	1.3
Nigeria	OML112 - Okoro East (2 wells pilot)	18.0	50.0%	80%	\$20.4	7.2	147	8.3	10.3
Nigeria	OML112 - Okoro East (Full field dev upside)	37.0	50.0%	60%	\$16.3	11.2	182	10.2	16.9
		810.1				215.0	1,320	74.2	131.1
Risked Upside									
JDZ	Block 1 - Obo #2	193.0	4.4%	50%	\$9.6	4.3	40.8	2.3	4.6
Kurdistan	Ain Sifni - Jebel Simrit (2C resources)	42.1	20.0%	90%	\$2.5	7.6	18.8	1.1	1.2
Kurdistan	Ain Sifni - (Jebel Simrit & East Simrit) Pmean	227.1	20.0%	60%	\$2.5	27.3	67.5	3.8	6.3
Kurdistan	Ain Sifni - (Jebel Simrit & East Simrit) P10 ups.	213.1	20.0%	50%	\$2.5	21.3	52.8	3.0	5.9
Kenya	Block 10A - Paipai P50	115.0	20.0%	20%	\$6.2	4.6	27.7	1.6	8.0
Kenya	Block 10A - Paipai P10	175.0	20.0%	15%	\$6.2	5.3	31.7	1.8	12.2
Nigeria	OML115 (S of Ebok) Ufon	60.0	40.0%	40%	\$11.0	9.6	101.0	5.7	14.9
Nigeria	OPL310	250.0	40.0%	20%	\$8.5	20.0	160.2	9.0	47.7
Nigeria	OML 67 - Ebok FBW upside	15.0	40.0%	50%	\$11.0	3.0	33.1	1.9	3.7
Nigeria	Okwok contingent upside	43.7	28.0%	50%	\$17.3	6.1	105.8	5.9	11.9
Nigeria	OML 67 - Ebok Qua Iboe (deep)	45.0	40.0%	33%	\$11.0	6.0	66.2	3.7	11.2
Nigeria	OML 67 - Ebok D2 Upside Case	12.0	40.0%	33%	\$11.0	1.6	17.6	1.0	3.0
Nigeria	Okoro East upside to P10	34.4	50.0%	33%	\$16.3	5.7	93.6	5.3	15.7
Kenya	L17/18 - Wasin prospect**	197.0	50.0%	15%	\$5.6	14.8	78.9	4.4	31.2
Tanzania	Tanga Block - Orpheus (Upper Miocene)*	198.0	40.0%	15%	\$3.8	11.9	43.6	2.4	17.1
Tanzania	Tanga Block - Orpheus (Palaeocene)*	255.0	40.0%	10%	\$3.8	10.2	38.6	2.2	22.0
Tanzania	Tanga Block - Orpheus (Cretaceous)*	265.0	40.0%	10%	\$3.8	10.6	40.2	2.3	22.9
Kenya	Block 1	270.0	80.0%	20%	\$9.1	43.2	391.3	22.0	110.8
Madagascar	Block 1101	150.0	40.0%	10%	\$12.3	6.0	64.8	3.6	41.5
Ethiopia	Blocks 2 & 6	85.0	30.0%	20%	\$9.0	5.1	43.7	2.5	13.0
Nigeria	OML 26 - Aboh, Ozoro, Ovo oil	23.0	20.3%	60%	\$0.8	2.8	2.3	0.1	0.2
Nigeria	OML 26 - A/O/O gas	118.8	20.3%	40%	\$0.8	9.6	7.9	0.4	1.1
Kurdistan	Barda Rash (heavy oil)	944.5	60.0%	25%	\$2.0	141.7	282.5	15.9	65.0
Kurdistan	Ain Sifni (Betnar)	28.4	20.0%	33%	\$2.2	1.9	2.2	0.1	0.7
Kurdistan	Ain Sifni (Maqlub)	661.3	20.0%	33%	\$2.2	44.1	96.5	5.4	16.6
Nigeria	Okwok Upside Qua Iboe level	114.0	28.0%	20%	\$9.8	6.4	56.7	3.2	17.5
Nigeria	OML115 Upside Qua Iboe level	50.0	40.0%	10%	\$26.3	2.0	52.5	2.9	29.5
Nigeria	OML115 prospective	96.0	40.0%	8%	\$26.3	3.1	80.6	4.5	56.6
Nigeria	OML 26 prospective	615.0	20.3%	8%	\$5.2	10.0	51.5	2.9	36.2
Nigeria	OPL907/917	40.0	41.5%	20%	\$5.6	3.3	18.8	1.1	5.3
Nigeria	OML30 - Ofa	10.0	32.5%	10%	\$5.6	0.3	1.8	0.1	1.0
Nigeria	OML 26 - prospective oil	615.0	20.3%	33%	\$0.6	41.1	15.5	0.9	3.9
Ghana	Keta Block - further Upside	543.5	35.0%	5%	\$6.8	9.5	45.2	2.5	73.2
Seychelles	Blocks A,B, C (Offshore)	240.0	75.0%	10%	\$3.5	18.0	42.9	2.4	35.5
Ethiopia	Blocks 2, 6, 7 & 8	50.0	30.0%	20%	\$4.1	3.0	9.9	0.6	3.4
Cote d'Ivoire	Block CI-01 Upside	0.3	65.0%	50%	-\$3.0	0.1	0.0	0.0	0.0
Cote d'Ivoire	Lion LPG Plant Upside	5.3	100.0%	40%	\$20.5	2.1	43.6	2.4	6.1
Cote d'Ivoire	Block CI-11 Upside	5.0	48.0%	30%	\$20.7	0.7	14.9	0.8	2.8
Gabon	Ibekelia - Prospect 1	25.0	20.0%	20%	\$19.2	1.0	17.1	1.0	5.4
JDZ	Block 1 - Kainji & Kainji W	157.0	4.4%	25%	\$8.7	1.7	13.4	0.8	3.4
JDZ	Block 1 - Osun	144.0	4.4%	25%	\$8.7	1.6	12.2	0.7	3.1
Kenya	L17/18 - Wasin prospect upside**	258.0	50.0%	5%	\$3.8	6.5	24.8	1.4	27.9
Kenya	L17/18 - Other prospects**	891.0	50.0%	15%	\$3.8	66.8	252.7	14.2	96.2
Kenya	L17/18 - Other prospects upside**	1272.0	50.0%	5%	\$3.8	31.8	117.5	6.6	137.4
Tanzania	Tanga Block - Orpheus upside*	1000.0	40.0%	5%	\$3.8	20.0	74.0	4.2	86.3
Tanzania	Tanga Block - Other prospects*	963.0	40.0%	15%	\$3.2	57.8	180.9	10.2	68.7
Tanzania	Tanga Block - Other prospects upside*	1248.0	40.0%	5%	\$3.2	25.0	76.4	4.3	89.0
South Africa	Block 2B	50.0	25.0%	5%	\$5.6	0.6	2.3	0.1	4.0
Congo	La Noubi - further prospect	40.0	14.0%	5%	\$15.0	0.3	3.5	0.2	4.7
		13,053.5				736.8	3,118	175.1	1285.2
Total Asset Value		13,997.4				1,002.5	5,589	313.9	1481.3

Notes:

1. C.O.S. - Chances of Success - Includes all risk factors such as geological, political, project delivery, commercial, etc.

2. Value/boe - Includes proximity to established infrastructure, development capex required, oil quality, discount rate (10%), etc.

3. EMV - Expected Monetary Value - a risk weighted value. EMV = (Reward*C.O.S.) - [Capital at Risk*(1-C.O.S.)]

4. Unrisked Value - Refers to the value that could potentially be realized if success was achieved on prospect and commercial production realized.

* Assumes 2:1 farm-down

** Assumes non-promote farm-down

Source: Company data, Macquarie Research, October 2012

Afren outstanding shares (fd)
GBP/USD 1112.7
1.60

AFREN (AFR LN, Neutral, Target price: 150p)

Price Assumption		2011A	2012E	2013E	2014E	2015E
Oil-Brent	\$/b	111.34	107.51	106.25	115.54	117.52
Gas-UK	US\$/mmbtu	9.28	8.53	8.50	9.24	9.40
US\$/£ (per end)	\$	1.60	1.58	1.60	1.60	1.60
US\$/£ (per end)	\$	1.38	1.35	1.40	1.40	1.40

Income Statement		2011A	2012E	2013E	2014E	2015E
Oil & Liquids	kb/d	18.1	40.8	38.8	47.4	73.6
Natural Gas	mmcf/d	7.0	11.5	6.0	6.0	6.0
Total Production	kboe/d (@ 6:1)	19.2	42.7	39.8	48.4	74.6
Gas Production Ratio	%	6.0	4.5	2.5	2.1	1.3
Production per Share Growth YoY	%	0.2	1.1	-0.2	0.2	0.5

Gross Revenue (pre-royalty)	m	691.9	1,635.6	1,242.4	1,671.8	2,426.3
Royalties	m	-95.3	-203.1	-143.8	-190.0	-265.6
Net Revenue	m	596.7	1,432.5	1,098.7	1,481.8	2,160.7
Operating Costs	m	-134.2	-384.1	-282.7	-328.7	-468.7
G&A Costs	m	-19.6	-20.0	-22.9	-24.1	-25.3
Other operating expenses	m	-4.9	-18.0	-37.8	-65.6	-87.7
EBITDA	m	438.0	1,010.4	755.2	1,063.5	1,579.0
DD&A	m	-160.1	-368.8	-269.3	-310.4	-435.9
EBIT	m	277.9	641.6	485.9	753.1	1,143.1
Interest Costs	m	-56.6	-96.6	-88.8	-87.0	-78.3
Back-in rights and other fin. costs	m	-3.7	0.0	0.0	0.0	0.0
Taxes	m	-96.0	-342.1	-225.6	-349.7	-504.7
Net Income	m	121.7	202.8	171.5	316.4	560.1
EPS (basic)	cts/sh	12.0	18.8	15.8	29.1	51.6
EPS (diluted)	cts/sh	11.5	18.2	15.4	28.4	50.3
Revenue per Share Growth YoY	%	65.8	127.6	-23.3	34.9	45.8
EBITDA per Share Growth YoY	%	116.6	128.0	-25.3	40.8	48.5
Basic WA Shares OS	m	1,016.7	1,077.4	1,086.4	1,086.4	1,086.4
Diluted WA Shares OS	m	1,056.0	1,113.7	1,113.8	1,113.8	1,113.8

Balance Sheet		2011A	2012E	2013E	2014E	2015E
Cash (including Restricted)	m	291.7	515.5	444.7	556.3	1,068.8
Debt	m	957.4	1,110.4	1,041.3	986.8	932.3
Net Debt (Cash)	m	1,054.4	747.1	748.8	582.7	15.7
Bank Lines	m	493.0	188.0	188.0	140.0	0.0
Net Debt as % of Bank Lines	%	213.9	397.4	398.3	416.2	na
Total Assets	m	2,930.5	3,355.4	3,523.9	3,793.8	4,303.9
Total Liabilities	m	1,723.2	1,932.2	1,921.2	1,866.7	1,812.2
Total S/H Equity	m	1,207.4	1,423.2	1,602.7	1,927.1	2,491.7

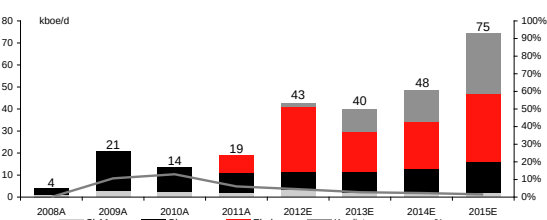
Ratios Analysis		2011A	2012E	2013E	2014E	2015E
ROA	%	5.6	6.5	5.0	8.6	13.8
ROCE	%	17.4	27.3	18.8	27.1	36.1
ROE	%	11.8	15.4	11.3	17.9	25.4
Net Debt/Equity	%	87.3	52.5	46.7	30.2	0.6
Net Debt/CF	x	2.4	0.8	1.3	0.8	0.0
Price/Book	x	0.0	1.7	1.5	1.3	1.0
Book Value	\$/sh	1.1	1.3	1.5	1.8	2.3

Valuation		2011A	2012E	2013E	2014E	2015E
P/E	x	16.1	12.7	15.0	8.1	4.6
P/CF	x	4.5	2.7	4.3	3.6	2.4
Dividend Yield	%	0.0	0.0	0.0	0.0	0.0
Enterprise Value	m	3,017.2	3,322.0	3,324.0	3,157.8	2,590.8
EV/DACF	x	3.5	3.5	4.5	5.3	4.3
EV/Reserves ²	\$/boe	16.3	18.0			
EV/2P + 2C	\$/boe	3.0	3.3			
EV/Production	\$/boe/d	157.0	77.8	83.4	65.3	34.7
Reserve/Production (2P)	years	26.4	11.9			
Core Net Asset Value (PV10AT) ³	p/sh	103.9				
P/CoreNAV	x	2.2				
Core NAV + Risked Resource Upside ³	p/sh	280.6				
P/RENAV	x	0.8				

Half-yearly Forecast		H2/11A	H1/12E	H2/12E	H1/13E	H2/13E
Oil-Brent	\$/b	111.11	113.52	101.50	104.00	108.50
Gas-UK	US\$/mmbtu	9.2	9.0	8.1	8.3	8.7
Oil & Liquids	kb/d	24.4	38.5	43.1	43.1	34.7
Natural Gas	mmcf/d	6.1	11.5	11.5	6.0	6.0
Total Production	kboe/d (@ 6:1)	25.4	40.4	45.0	44.1	35.7

Revenue	m	435.7	771.7	660.7	584.8	513.8
EBITDA	m	316.8	545.2	465.2	393.5	361.6
Net Income	m	101.0	100.2	102.6	79.6	91.9
Adjusted EPS (diluted)	cts/sh	9.36	8.96	9.27	7.14	8.25
Net Cash Flow from Operations	m	320.9	536.7	406.1	339.4	256.3

Production profile		2011A	2012E	2013E	2014E	2015E
Ebok	kboe/d	8.0	29.3	18.2	21.3	31.1
Okoro	kboe/d	9.0	8.5	9.5	10.7	14.0
CI-11	kboe/d	1.9	3.1	2.0	1.9	1.9
Kurdistan (domestic sales)	kboe/d	0.0	1.8	10.2	14.4	27.5
Total	kboe/d	18.9	42.7	39.8	48.4	74.6
% gas		6%	4%	3%	2%	2%



Cashflow Analysis		2011A	2012E	2013E	2014E	2015E
Cash Flow from Operations	m	439.9	957.5	595.7	721.7	1,078.8
Chgs in Working Cap	m	-102.3	-14.7	0.0	0.0	0.0
Net Cash Flow from Operations	m	337.5	942.8	595.7	721.7	1,078.8
Cash Flow from Investing	m	-876.8	-761.7	-508.6	-468.6	-433.5
Cash Flow from Financing	m	690.7	42.7	-157.9	-141.5	-132.8
Increase in Cash	m	151.5	223.8	-70.8	111.6	512.5

Free Cash Flow ¹	m	-541.9	196.8	87.1	253.1	645.3
Debt Adjusted Cash Flow (DACF)	m	874.2	957.5	745.5	595.7	595.7

CFPS	cts/sh	41.7	86.0	53.5	64.8	96.9
Capital Expenditures	m	879.5	746.0	508.6	468.6	433.5
Capex/Cash Flow	x	2.0	0.8	0.9	0.6	0.4

Per Boe Statistics		2011A	2012E	2013E	2014E	2015E
Revenue/boe	\$/boe	98.66	105.11	93.02	105.16	101.82
Royalties/boe	\$/boe	-13.58	-13.05	-10.76	-11.95	-11.14
Operating costs/boe	\$/boe	-19.13	-24.68	-21.17	-20.68	-19.67
Operating Netback/boe	\$/boe	65.94	67.37	61.09	72.53	71.00
G&A/boe	\$/boe	-2.79	-1.29	-1.72	-1.51	-1.06
Interest/boe	\$/boe	-8.06	-6.21	-6.65	-5.47	-3.29
Capital Tax/boe	\$/boe	3.39	0.00	-3.59	-4.87	-4.75
Cash Netback/boe	\$/boe	58.48	59.88	49.13	60.67	61.91
Depletion and Depreciation/boe	\$/boe	-22.83	-23.70	-20.16	-19.52	-18.29
Stock based compensation/boe	\$/boe	-1.04	-0.53	-0.60	-0.50	-0.19
Other Non-cash/boe	\$/boe	-3.93	-1.37	0.00	0.00	0.00
Cash Taxes/boe	\$/boe	-2.99	-4.06	-12.54	-22.00	-21.18
Deferred Taxes/boe	\$/boe	-10.70	-17.93	-4.35	0.00	0.00
Earnings Netback/boe	\$/boe	16.98	12.29	11.48	18.65	22.25

All figures US\$ unless noted and production and reserve figures are gross of royalties

1) Cash flow from Operations (before chg in WC) Less Capex

2) Excludes non-producing assets

3) Risked resource upside based on LT price of US\$8.8/mmbtu HH, US\$115/b Brent, and GBP/USD 1.6

Source: Company Data, Macquarie Research, October 2012

NORWAY

DNO NO Outperform

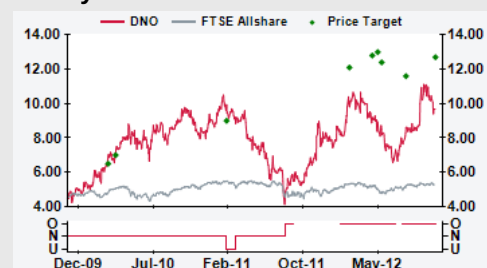
Price (at 14:25, 26 Oct 2012 GMT) kr9.69

12-month target	kr	12.70
12-month TSR	%	+31.1
Valuation	kr	13.39
- Sum of Parts methodology		
GICS sector		Energy
Market cap	krm	9,916
30-day avg turnover	krm	40.3
Market cap	US\$m	1,721
Number shares on issue	m	1,023

Investment fundamentals

Year end 31 Dec		2011A	2012E	2013E	2014E
Revenue	m	2,070.2	2,105.7	3,741.7	4,919.9
EBITDA	m	1,420.2	1,483.5	3,056.3	3,921.8
Adjusted profit	m	653.1	850.5	2,324.4	2,570.8
EPS adj	kr	0.69	0.84	2.27	2.51
EPS adj growth	%	nmf	22.5	169.7	10.6
Total DPS	kr	0.00	0.00	0.00	0.00
Total div yield	%	0.0	0.0	0.0	0.0

DNO NO vs FTSE Allshare, & rec history



Note: Recommendation timeline - if not a continuous line, then there was no Macquarie coverage at the time or there was an embargo period.

Source: FactSet, Macquarie Research, October 2012
(all figures in NOK unless noted)

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31 October 2012

Macquarie Capital (Europe) Limited

DNO International

Ready to deliver

Event

- As part of our Kurdistan E&P note issued today we review DNO's Kurdistan asset base.

Impact

- Tawke field driving 36% CAGR in production:** DNO's Tawke field is ideally positioned close to the Turkish border and unlike other fields in Kurdistan it already has a direct connection to the Fishkabur tie-in point. Increasing volumes is therefore less dependent upon the construction of the planned 1mmb/d export pipeline and we believe the field's ramp up towards a 200kb/d plateau can help DNO deliver production of ~128kboe/d in 2016, a 36% CAGR over the 2012-16 period.
- Aiming to add more reserves at Tawke:** DNO is drilling more laterally extensive development wells at Tawke, which together with improved recovery factors, has led to a reserve estimate increase from ~200mmb in 2009 to 734mmb presently. The 2012-13 development wells we believe are targeting some of the 142mmb upside on the field and we believe further reserve improvements are possible. Additionally, DNO is currently drilling the 213mmb Tawke Deep prospects, targeting as yet untested horizons below the main field.
- Ex Kurdistan assets yet to hit full stride:** We think one of the attractions of DNO though is that it is not 100% geared to Kurdistan. Assets acquired with the RAK Petroleum merger in 2012 are yet to sparkle due to operational difficulties. However, combined with Yemen, we expect production ex-Kurdistan in 2Q12e of just 6.0kboe/d to rebound to 16.8kboe/d in 2013 as operational issues are resolved and new production wells brought on stream.

Earnings and target price revision

- We raise our target price to Nkr 12.7 (from Nkr 11.6). Our FY12e EPS increases by 50% to Nkr 0.84 (from Nkr 0.56) while our FY13 EPS increases by 166% to Nkr 2.27.

Price catalyst

- 12-month price target: kr12.70 based on a Sum of Parts methodology.
- Catalyst: 3Q12 results (14th Nov); Tawke Deep results (1Q13, Nkr 0.6/Nkr 2.8)

Action and recommendation

- DNO's share price has risen 11% since the Baghdad/KRG announcement on exports in September; however the shares still trade at a 12% discount to our Core NAV, meaning it is the only European listed E&P with significant Kurdistan leverage which has a value proposition.