Prices holding steady, despite massive planned capacity additions

Petroleum Review *regularly updates its listing of the upcoming so-called 'megaprojects'. The aim of the listing is to attempt to answer the question as to whether sufficient oil is being developed to meet likely requirements going forward, writes* Chris Skrebowski.

This latest update of the megaprojects database shows that both Canada and the Opec producers plan major significant new capacity additions by the end of the decade.

The *Petroleum Review* database – based on public sources of information – now identifies some 21.3mn b/d of new capacity due onstream by 2010. Of this total, some 10.3mn b/d is to come from Opec producers and nearly 11mn b/d from non-Opec producers.

The significant increase in the planned future capacity in the database is the result of Opec publishing a comprehensive listing of its future projects (see **www.opec.org**) and of a number of Canadian tar sands projects being announced, as well as the inclusion of the smaller projects down to peak flows of 50,000 b/d.

In overall terms, the outlook for future supply appears somewhat brighter than even six months ago – possibly as a result of high prices being sustained and triggering investment decisions.

However, before concluding that the pressure is off and oil prices will now ease back, it is worth examining what happened in 2005.

The projects that actually come onstream in 2005 had a notional capacity of around 2.6mn b/d. [Capacity additions are allocated by year and time of start-up – so this total includes increments from fields that started up in earlier years, and the amount of new capacity added in 2005 adjusted for start-up date.] However, the actual increase in 2005 supply was just 1.05mn b/d (according to IEA's *Oil Market Report*, Febuary 2006). The explanation is the loss of capacity through depletion and the loss of capacity caused by the Gulf of Mexico hurricanes.

For the Opec producers, the gross capacity addition in 2005 was 1.16mn b/d and the net addition was 1.02mn b/d. The 140,000 b/d difference is mainly due to the loss of capacity in the various Opec states that was not covered by the normal infill drilling and well workovers. It is assumed that, with most Opec producers operating flat out, there has been little or no change to the spare capacity largely held by Saudi Arabia.

In the case of the non-Opec producers, which all operate at capacity, the gross addition in 2005 of 1.42mn b/d yielded a net addition of just 30,000 b/d (IEA *Oil Market Report*, February 2006). The Gulf of Mexico hurricanes cost the system the equivalent of 278,000 b/d on an annualised basis. The remaining 1.1mn b/d is accounted for by the erosion of non-Opec capacity (see *Petroleum Review*, August 2005). Virtually all of the capacity erosion occurred in the OECD countries. According to the IEA's figures, in 2005 all the itemised OECD producers had a lower production in 2005 than in 2004. Collectively, OECD output fell by 0.95mn b/d in 2005.

Looking forward to the 2006–2010 period, the situation should improve, as in each year over 3mn b/d of gross new capacity is due onstream. However, this total will be eroded by four possibly predictable and one unpredictable factors.

- Project slippage – over recent years project slippage has averaged around two to three months, although some projects have seen delays running into years. Even two to three months equates to around a 20% shortfall in any one year. The capacity is not lost, but moves forward. This has the effect of smearing out the new capacity so the increment in any one year is lower, but

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	2005	2006	2007	2008	2009	2010
Opec new capacity	1,160	1,520*	1,420*	1,320*	2,240*	2,235*
Non-Opec capacity	1,416	1,865*	2,320*	1,886*	1,710*	1,035*
Total new capacity	**2,576**	**3,385***	**3,740***	**3,206***	**3,950***	**3,270***
Capacity erosion	1,226	1,400	1,600	1,750	1,800	1,850
Net new capacity	**1,350**	**1,985**	**2,140**	**1,456**	**2,150**	**1,420**
Gulf of Mexico loss	300					
Net Net	**1,050**	**1,037****	**1,300****	**1,866****	**1,622****	**1,189****

**assumes no slippage and no capacity shortfall; **assumes 20% slippage and 10% capacity shortfall* — *All calculations* Petroleum Review

Table 1: Capacity additions and capacity erosion, 2005–2010

Project	Location	Operator	Oil peak flows (kb/d)	Gas peak flows (mn cf/d)	Reserves (mn b)	Partners and shareholdings
Onstream 2006						
Opec countries						
AOR-E Delta	Nigeria	ExxonMobil	110			
Asab upgrading	Abu Dhabi	ADNOC	100			
Bu Hasa, Sahil project	Abu Dhabi	ADNOC	180			ADCO 100%
Darkhovin Ph2	Iran	Eni/Naftiran	+110			Eni 60% (on behalf of NIOC), Naftiran Intertrade (NICO) 40%
Dolphin, Al Khalij	Qatar	QP/Total	100			
EA	Nigeria	Shell	+50			
Erha	Nigeria (OPL 209)	ExxonMobil	150		500	ExxonMobil 56.25%, Shell 43.75%
Ghawar Haradh Ph3 (33° API)	S Arabia onshore	Saudi Aramco	+300 (2Q2006)			Saudi Aramco 100%
In Amenas (cond)	Algeria	BP/Statoil	50			
NEB Ph1 project****	NE Abu Dhabi	ADNOC	+110			ADNOC 100%?
South Pars Ph6 and 8 (cond)		Statoil	120			
South Pars oil layer (Ahwaz)		NIOC	250			
Non-Opec countries						
ACG Ph2 West Azeri	Azerbaijan	BP	+300 (2007)		5800	BP 34.14%, Unocal 10.28%, Socar 10%, Inpex 10%, Statoil 8.56%, ExxonMobil 8%
ACG (cont)						TPAO 6.75%, Devon 5.62%, Itochu 3.92%, Delta Hess 2.72%
Albacora Leste (P50)	Brazil	Petrobras	180 (2006)		700mn boe	Petrobras 90%, Repsol 10%
Atlantis	Gulf of Mexico	BP	150		675 boe	BP 56%, BHP 44%
Benguela-Belize (BBLT1)	Angola	Chevron	100 (2007)		400	Chevron 31%, Agip 20%,Total 20%,Sonangol 20%, Galp 9%
Buzzard	UKCS	Nexen	100 (2007/2008)		550	Encana 43%, Intrepid Energy 30%, BG Group 22%, Edinburgh Oil & Gas 5%
Cachalote	Brazil	Petrobras			800	
Chinguetti Ph1	Mauritania offshore	Woodside	75		123	Woodside 47.39%, Hardmn Res 19%, SMdH 12%, BG 10.23%, Premier 8.13%, Roc Oil 3.25%
Dalia	Angola	Total	240		1,600	Total 40%, BP 16.67 %, Statoil 13.33%, ExxonMobil 20%
Enfield (+Laverda/Vincent)	Australia NW Shelf	Woodside	100		363	Woodside Petroleum 60%, Mitsui 40%
Foster Creek	Canada Northern Alberta		115 (2015)			
Golfinho Module I (28-40°API)	Brazil (Espirito Santo)	Petrobras	100 (2007)		450	Petrobras 100%
Jubarte 1 Ph1 (P34)	Brazil B60 Santos	Petrobras	60 (2006)		540	Petrobras 100%?
Surmont (heavy oil by SAGD)	Canada Northern Alberta	ConocoPhillips	100 (2012)			ConocoPhillips 50%, Total 50%
Syncrude Ph3	Athabasca, Canada	Canadian Oil Sands	100			Canadian Oil Sands 32%, Imperial Oil 25%, Petro-Canada 12%, Nexen ?%, others ?%
Tengiz/Kololev expansion*	Kazakhstan	Chevron	+150	100	7,000	Chevron 50%, ExxonMobil 25%, KazMunaiGaz 20%, LukArco 5%
Thunder Horse (inc North)	Gulf of Mexico	BP	250 (2008)	200	1,500 boe	BP 75%, ExxonMobil 25%
Upper Salym, Vadelyp	Khanty-Mansiisk	Shell/Evikhon	60 (2009)		800	Salym Petroleum Development (SPD): 50% Shell, 50% Evikhon
Onstream 2007						
Opec countries						
Abu Hadriya/Khursaniyah/Fadhili	S Arabia onshore	Saudi Aramco	+500	250	4,500, 500, 950	Saudi Aramco 100%
Block 208 El Merk fields	Algeria	Anadarko	125			Anadarko 100%?
Idd al Shargi N and S Dome	Qatar	Occidental	65			
Khursaniyah NGLs	S Arabia onshore	Saudi Aramco	300			
Corocoro Ph1	Venezuela offshore	ConocoPhillips	75		450	ConocoPhillips 32.5%, PdVSA 35%, Eni 26%, Opic 6.5%
Rag e Safid-Bangestan	Iran onshore	Qeshm	150			
Ras Gas (cond)	Qatar	ExxonMobil	50			
Sabriya	Kuwait onshore	KOC	50			
Salman, Faroozan, Daroud	Iran onshore	Total, Petro Iran	150			
Non-Opec countries						
ACG Ph2 East Azeri	Azerbaijan	BP	+300 (2007/2008)		5,800	TPAO 6.75%, Devon 5.62%, Itochu 3.92%, Delta Hess 2.72%
Espadarte RJS-409	Brazil	Petrobras	100			
Golfinho Module II (28-40°API)	Brazil (Espirito Santo)	Petrobras	100 (2007/2008)		450	Petrobras 100%
Greater Plutonio (6 fields)	Angola block 18	BP	240		800	BP 50%, Shell 50%
Kikeh	Malaysia offshore Sabah	Murphy Oil	120 (2009)		530	Murphy 80%, Petronas Carigali 20%
Lobito-Tombuco (BBLT 2)	Angola	Chevron	+100 (2008)	400+		Chevron 31%, Agip 20%,Total 20%,Sonangol 20%, Galp 9%
Long Lake (tar sands)	Canada, N Alberta	Nexen	70		1,900	Nexen 50%, OPTI Canada 50%
Mangala and Aishwariya	India onshore Rajastan	Cairn Energy	80–100	600		Cairn Energy 70%, ONGC 30%
Peng Lai Ph2	China Bohai Bay PL19-3	ConocoPhillips	190 (2009)	800		CNOOC 51%, ConocoPhillips 49%
Polvo (BM-C-8)	Brazil, Campos basin	Devon Energy	50	50mn b+		Devon Energy 60%, SK Corporation 40%
Roncador II (FPU P52)	Brazil	Petrobras	180 (2008)		2,700 (tot)	Petrobras 100%
Roncador III (P54)	Brazil	Petrobras	180 (2008)		2,700 (tot)	Petrobras 100%
Rosa (tieback to Girassol)	Angola block 17	Total	250, net+40		300	Total 40%, Esso 20%, BP 16.67%, Statoil 13.33%, Norsk Hydro 10%
Sakhalin 2	Russian Far East	Shell	+120			
Vankorskoye 2 fields	Russia Siberia	Shell/TFE PSA	216		1,700 boe	
Onstream 2008						
Opec countries						
Agbami	Nigeria OPL 216, 217	Chevron	230	800		Chevron 68.15%, Petrobras 13%, Statoil 18.85%
Akpo	Nigeria OML 130	Elf Nigeria (Total)	180		590	Total 24%, NNPC ?%, Petrobras ?%, Sapetro ?%
AKG later phases (cond)	Qatar	ExxonMobil	90			
Al Rayyan	Qatar	Occidental	50			
Berkine block 405b (cond)	Algeria	First Calgary	50			
Bosi Oil	Nigeria	ExxonMobil	110			
Hawiyah NGLs	S Arabia onshore	Saudi Aramco	370			Saudi Aramco 100%
Jeruk	Indonesia, offshore Java	Santos	50	170 boe		Sampang PSC: Santos 45%, Singapore Petroleum Co (SPC) 40%, Cue Energy 15%
Nuayyim (Arab Super Light 50°)	S Arabia onshore	Saudi Aramco	100		1,000	Saudi Aramco 100%
Qatargas II (cond)	Qatar	ExxonMobil	160			
Ras Gas (cond/LPG)	Qatar	ExxonMobil	150			
Shaybah and Central fields expn	S Arabia onshore	Saudi Aramco	+300			Saudi Aramco 100%
Non-Opec countries						
ACG Ph3 (Gunashli)	Azerbaijan	BP	+200 (2009)		5,800	See under Ph1 in 2006
Horizon Ph1 (tar sand)	Canada, N Alberta	CNR	240		3,300	CNR ???

Table 2: Future oil field projects with a peak production capacity of over 50,000 b/d

Project	Location	Operator	Oil peak flows (kb/d)	Gas peak flows (mn cf/d)	Reserves (mn b)	Partners and shareholdings
Jackpine Mine Ph1	Canada, N Alberta		200 (10)			
Joslyn Ph1 & 2	Canada, N Alberta		100 (14)			
Kashagan Ph1	Kazakh Caspian	Agip (Eni)	450 (2009/2010)	1,500	13,000 (tot)	Eni/Total/ExxonMobil/Shell 18.52% each, ConocoPhillips 9.26%, Inspex 8.33%,KMG 8.33%
Kizomba C	Angola	ExxonMobil	200		1,000	ExxonMobil 40%, BP 26.66%, Eni 20%, Statoil 13.33%
Marlim Leste (P53)	Brazil, Campos Basin	Petrobras	140 (2008)	6mn cm/d	150	Petrobras 100%
Marlim Sul Module 2 (P51)	Brazil	Petrobras	180		2,679 boe (tot)	Petrobras 100%
Moho-Bilondo	Congo (Haute Mer permit)	Total	90			Total 53.5%, Chevron 31.5%, Societe Nationale de Petroles du Congo (SNPC) 15%
Sunrise Thermal project	Canada, N Alberta		200			
Su Tu Trang (White Lion)15-1	Vietnam Cuu Long Bas	ConocoPhillips	100?	220		Petrovietnam 50%, ConocoPhillips 23.25%, KNOC 14.25%, SK Corp 9%, Geopetrol 3.5%
Shenzi	Gulf of Mexico	BHP Billiton		100		BHP Billiton ?%, BP ?%
Stybarrow	Australia offshore	BHP Billiton	80		60–90	BHP Billiton 50%, Woodside Petroleum 50%
Tahiti	Gulf of Mexico	Chevron	125	70	400–500mn boe	Chevron 58%, Statoil 25%,Shell 17%
Onstream 2009						
Opec countries						
Al Shaheen expansion	Qatar offshore	Maersk Oil	+225			Maersk Oil, QPC
Azadegan (southern part)***	onshore Iran	Inspex, NIOC	125		2,500–3,000	Pedco 25%, Japanese interests 75% (Inspex ?%, Japex ?%, JNOC ?%, Tomen ?%)
Corocoro Ph2	Venezuela offshore	ConocoPhillips	+45		450	ConocoPhillips 50%, PdVSA 24%, Eni 26%
Khurais	S Arabia onshore	Saudi Aramco	1,200		3,000	Saudi Aramco 100%
Qatar GTL (Ph1)	Qatar	Qatar Shell Gas	165 (cond)	800		Qatar Petroleum ?%, Shell ?%
Rhourde El Baguel	Algeria	Sonatrach	100			
South Pars Ph9 and 10 (cond)	Iran	NIOC, LG	80 (cond)			
Upper Zakum redevelopment	Abu Dhabi	ExxonMobil	+200			ExxonMobil to 28%
Non-Opec countries						
BC10 Block 74	Brazil Espirito Santo	Shell? Petrobras?	80		400	Petrobras 35%, Shell 35%, ExxonMobil 30%
Frade	Brazil	Chevron	100 (2010)		300	Chevron 42.5%, Petrobras,?%, Nissho Iwai ?%
Karachaganak Ph3 and 4	Kazakhstan	Eni and BG	+200?			Eni 32.5%, British Gas 32.5%, Chevron 20%, Lukoil 15%
Kearl project Ph1	Canada, N Alberta	Imperial Oil	100			Imperial Oil ?%, ExxonMobil ?%
Muskeg River	Canada, N Alberta		140			
Onstream 2010						
Opec countries						
Al-Shaheen expansion	Qatar	Maersk Oil	+300			
Cepu block (Banyu Urip)	Indonesia Offshore	ExxonMobil (TBC)	170	20	700 in block	ExxonMobil 45%, Pertamina 45%, Indonesian government 10%
Jeruk	Indonesia, offshore Java	Santos	100		170 boe	Sampang PSC: Santos 45%, Singapore Petroleum Co (SPC) 40%, Cue Energy 15%
Kushk-Hosseineh	Iran onshore		300		1,500+	
'Project Kuwait' (Northern fields)	Kuwait onshore	KPC/ Oilco group	+450			Fields involved: Raudhatain, Ratqa, Abdali and Sabriyah
Shaybah (Ph2)	S Arabia onshore	Saudi Aramco	+200			Saudi Aramco 100%
Usan/Ukot/Tongo	Nigeria (OPL 222)	Elf Nigeria (Total)	175		480+	Elf Nigeria 20%, Chevron 30%, ExxonMobil 30%, Nexen 20%
Non-Opec countries						
Albacora (complementary)	Brazil	Petrobras	100			
Golfinho (FPSO 3)	Brazil	Petrobras	100?			
Jubarte Ph2 (P57)	Brazil B60 Santos	Petrobras	60 (2010)		540	Petrobras 100%?
Kashagan Ph2	Kazakh Caspian	Agip (Eni)	+450 (2012)	1,500	10,000 (tot)	Eni/Total/ExxonMobil/Shell 18.52% each, ConocoPhillips 9.26%, Inspex 8.33%, KMG 8.33%
Roncador IV (FPSO P55)	Brazil	Petrobras	150			
Uvatskoye	Russia Siberia	TNK-BP	200			
Onstream 2011						
Opec countries						
Bonga SW + Aparo	Nigeria (OML 118)	Shell+Chevron	175		1,000	Shell 55%, ExxonMobil 20%, Total 12.5%, Eni 12.5%
Manifa (Arab Heavy 28° API) Ph1	S Arabia offshore	Saudi Aramco	300			Saudi Aramco 100%
Qatar GTL Ph2	Qatar	Qatar Shell Gas	100 (cond)			Qatar Petroleum ?%, Shell ?%
Yadavaran	Iran onshore	NIOC/CNPC?	300		3,000	NIOC 80%, ONGC 20%
Non-Opec countries						
Marlim Sul III (FPSO P56)	Brazil	Petrobras	100			
Marlim Sul IV (semi, tba)	Brazil	Petrobras	100			
Papa Terra (DC-20) (14°-17° API)	Brazil	Petrobras	200?		700–1000	Petrobras 62.5%, Chevron 37.5%
Onstream 2012						
Opec countries						
Azadegan Ph2 (Northern part)***	onshore Iran	NIOC/Japan	110		2,500–3,000	NIOC, Japanese interests
Non-Opec countries						
Horizon Ph3 (tar sand)	Canada, N Alberta	CNR	+122		3,300	CNR ???
Kashagan Ph3	Kazakh Caspian	Agip (Eni)	+300(2016)	1,500	10,000 (tot)	Agip/Total/ ExxonMobil/Shell 20.37%, ConocoPhillips 10.19%, Inspex 8.33%
Onstream 2013						
Opec countries						
Manifa (Arab Heavy 28° API) Ph2	S Arabia offshore	Saudi Aramco	+300			Saudi Aramco 100%
Manifa (Arab Heavy 28° API) Ph3	S Arabia offshore	Saudi Aramco	+400			Saudi Aramco 100%
Potential Projects						
Opec countries						
Anaran block (4 fields)	onshore Iran	Norsk Hydro	100		1,000	Norsk Hydro 75%, Lukoil 25% (PSA?)
Arash	Iran in Gulf	NIOC			683 boe	
Hamrin	Iraq onshore (South)	SOC	60			
Khurmala Dome	Iraq onshore (Kirkuk area)	NOC	100			
Majnoon	Iraq onshore	SOC	360		12,100	
Minagish EOR project	Kuwait onshore	KOC	100			
Neutral Zone expansion	Saudi/Kuwaiti on/offshore		+150			

Table 2: Future oil field projects with a peak production capacity of over 50,000 b/d

Project	Location	Operator	Oil peak flows (kb/d)	Gas peak flows (mn cf/d)	Reserves (mn b)	Partners and shareholdings
Ramin	Iran near Ahwaz	NIOC			1,500	
Sincor II	Venezuela	Total	180			
Subbah-Luhais	Iraq onshore (South)	SOC	80			
Tomoporo (23° API)	Venezuela	PdVSA	250?		1,000	PdVSA, but private investors to 49%
West Qurna Ph2	Iraq onshore	SOC	650		11,300	
Non-Opec countries						
BC-2	Brazil Campos basin	Total				
BS-4	Brazil offshore	Shell				
Block 09-03	Vietnam Cuu Long bas	Petrovietnam	100+?		300–400	
Block 18 West (3 fields)	Angola block 18	BP			250–300	
Block 31 North E – Plutao+3 dev	Angola block 31	BP			500 in block 31	BP 26.67%, ExxonMobil 25%, Sonangol 20%, Statoil 13.33%, Marathon 10%, Total 5%
Block 31 S-Ceres/Palas/Juno	Angola block 31	BP			500 in block 31	BP 26.67%, ExxonMobil 25%, Sonangol 20%, Statoil 13.33%, Marathon 10%, Total 5%
Block 32- Perpetua et al	Angola block 32	Total			4 discoveries	Total 30%, Marathon 30%, Sonangol 20%, ExxonMobil 15% and Petrogal 5%
Borealis	Canada, N Alberta		100			
Christina Lake	Canada, N Alberta		250			
Chinook BM-C-7	Brazil Campos basin	Kerr McGee			250–450 boe	Kerr-McGee 50% Petrobras 50%
Filanov	Caspian, Russian sector	Lukoil	100+		600	Lukoil 100%
Fort Hills oilsands	Canada, N Alberta	Petro-Canada	190		2,800	Petro-Canada 55%, UTS Energy Corp 30%, Teck Cominco 15%
Great White	Gulf of Mexico	Shell			500–1000 boe	Shell ?%
Jackpine Mine Ph2	Canada, N Alberta					
Kearl project Ph2 and 3	Athabasca, Canada	Imperial Oil	200			Imperial Oil ?%, ExxonMobil ?%
Kebabangan	Malaysia Blk J off Sabah	ConocoPhillips			200–300	Block J: Petronas Carigali 20%, ConocoPhillips 40%,Shell 40%
Kharampur	Russia	Rosneft			4,900 boe	
Kharyaga	Russia Siberia	Total PSA			5,200	
Khvalynskoye	Russian Caspian	Lukoil/KazMgaz			17(c)36mn t (o)	
Kizomba D	Angola block 15	ExxonMobil				
Kurmangazy	N Caspian (Russ/Kaz)	Rosneft/KMG	600?		7,000	Rosneft 25%, other Russian 25%, KazMunaiGaz 25%, Total 25% (tbc)
Lungu	China Tarim basin	Petrochina			500	
Marimba Leste (FPS-Semi)	Brazil Campos basin	Petrobras				
Marimba Leste (FSO)	Brazil Campos basin	Petrobras				
Northern Lights oil sands project	Canada Northern Alberta	Synenco	100			Synenco 60%, Sinopec 40%
Northern Territories 4flds	Russia, Timan-Pechora	Lukoil, ConocoPhillips			990	
Stybarrow	Australia Exmouth basin	BHP Billiton	100		90	BHP Billiton 50%, Woodside Petroleum 50%
Su Tu Vang (Golden Lion) 15-1	Vietnam Cuu Long basin	ConocoPhillips	100?		400?	Petrovietnam 50%, ConocoPhillips 23.25%, KNOC 14.25%, SK Corp 9%, Geopetrol 3.5%
Suncor (tarsands) expansion	Canada		100			
Talanskoye	Russia Siberia	Surgutneftegas			832	
Tiof	Mauretania	Woodside			298	
Tsentralnoye block	Russia/Kazakh Caspian	Lukoil/Kazakhoil			3,800	TsentrKaspneftegaz JV: Kazakhoil 50%, Lukoil and Gazprom 50%
Val Gamburtsev	Russia Siberia	Yukos/Sibneft			600	
Verkhnechonsknoye	Eastern Siberia	TNK-BP?			1,500	
Voyageur	Canada, N Alberta		250			
Yalamo-Samur	Russia/Azeri Caspian	Lukoil			3,750 boe	
Yuri Korchagin	Russian Caspian	Lukoil			879 boe	
Yuzhno-Shapinskoye	Russia Siberia	SeverTek			500	Lukoil Fortum
Su Tu Nau (Brown Lion)	Vietnam Block 15-1	ConocoPhillips				PetroVietnam 50%, ConocoPhillips 23.3%, KNOC 14.2%, SK Corp 9%, Geopetrol 3.5%

limited production from 12/2004, Vadelyp 2006; ** 250,000 b/d 2007–2009; * 5,000mn barrels for field; **** Al Dhabiya, Rumaitha, Shanaget*

Table 2: Future oil field projects with a peak production capacity of over 50,000 b/d

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growth extends further forwards.

In tight and inflationary markets, for virtually everything to do with oil field development projects, delays are more likely to increase than decrease. Canadian tar sands projects are particularly vulnerable as gas supply, water supply, carbon dioxide emissions and manpower issues are not fully resolved. Some of the Opec new capacity targets also look aggressive.

- Supply shortfalls – peak production levels will be decreased by normal maintenance and operational factors. Some fields will disappoint and a few will give pleasant surprises. Some industry insiders suggest that total peak flows should be reduced by around 10% to reflect these realities.
- Capacity erosion or depletion will increase as more countries reach the point where their production declines year-on-year. Over the next few years China, Mexico, Malaysia, India and Brunei will move into decline. All the evidence shows that depletion tends to speed up rather than slow down – the North Sea being a good example.
- After the exceptional demand growth seen in 2004, the general view is that it will be slower as continuing high prices restrict demand. The latest IEA estimates for 2006 demand growth have been revised down from 1.78mn b/d to 1.49mn b/d (IEA *Oil Market Report*, March 2006). It is virtually impossible to predict demand growth, but for the purpose of analysis, around 1.5mn b/d could be used.
- Wars, revolutions and hurricanes are all likely to reduce supply, but are quite unpredictable. The effects can also be surprisingly long-lived. The IEA does not envisage 2004 production levels in the Gulf of Mexico being reattained before 2007 or even 2008. And this assumes there won't be significant further hurricane damage.

If all the factors reducing new capacity come into play, makets will remain tight and prices high. Only if new capacity flows into the system rather more rapidly than of late, will there be any chance of rebuilding spare capacity and softening prices. (See **Table 1**.)

Petroleum Review *is always pleased to receive comments and corrections on the megaprojects analysis. The subject is both contentious and productive of strong emotions, but the compilation of a viable analysis is important to both the oil industry and the wider oil using community. Any help or comments on the analysis would be gratefully received. Furthermore, in filling our role as reporters on the industry, we would be pleased to print other analyses. We would also welcome letters to the Editor.*