ANCHOR REPORT

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India gas: Time to get back in

Correction leaves stocks attractive as LNG makes up for gas production shortfall

May 06, 2011

Research analysts

India Oil & Gas/Chemicals

Anil Sharma
anil.sharma.1@nomura.com
+91 22 4037 4338

Ravi Adukia, CFA
ravikumar.adukia@nomura.com
+91 22 4037 4232

We are raising target prices for most stocks, as we believe LNG is able to fill the breach caused by the KG-D6 production decline.

Petronet LNG (TP: INR180) is the most obvious beneficiary of the LNG boom and is our top pick.

BP-RIL deal underlines long-term sector outlook. BUY RIL (TP: INR1,200).

We also reiterate BUY on GAIL (transmission giant, TP: INR600) and Indraprastha Gas (City Gas in Delhi, TP: INR450).

Key analysis in this anchor report includes:

- Deep dive into LNG dynamics
- India's readiness – terminals and pipelines
- Updates on demand, supply and pricing
- We continue to watch policy carefully and include a detailed analysis on price pooling and upcoming pipelines/CGD networks.

India Gas

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Correction leaves stocks attractive as LNG makes up for domestic production shortfall

Action: Time to get back into the gas story

Despite the underperformance of most gas stocks in reaction to the production decline at the KG-D6 block, we raise our target prices for most stocks under our coverage, as we believe LNG can fill the shortfall. Spare re-gas capacity is filling up fast, and we expect LNG to account for the bulk of gas supply growth in FY12F (fiscal year-end 31 March). New capacity is coming on line and we project LNG re-gas capacity will double by FY14F.

LNG the key catalyst: Petronet LNG is our top pick

Petronet LNG is the obvious beneficiary of the LNG boom and is our top pick, as we think the market has yet to fully value its growth potential. With a projected EPS CAGR of 21% through FY11-FY13F, we believe our implied target P/E of 15x FY13F earnings is undemanding. We reaffirm BUY on Indraprastha Gas (city gas in Delhi) and upgrade Gujarat Gas a notch to NEUTRAL, despite limited market potential. We continue to like transmission giant GAIL and raise our PT to Rs600; we are confident that concerns on KG-D6 and rising subsidies are overdone, while the upside potential from LNG and petrochemicals is not in the price.

BP-RIL deal is a reminder of the long-term outlook

We reaffirm BUY on Reliance Industries and believe its recent partnership with BP will allay concerns over near-term volume decline and delayed ramp-up. We expect the deal to restore confidence in the longer-term E&P outlook, apart from setting a benchmark valuation for the E&P business.

But watch out for regulatory ups and downs

We had previously highlighted that regulatory chaos would take time to be resolved and keep generating short-term noise. The latest example of this can be seen in the continued delays in network authorisation, tariff setting and formal award of three pipelines for Gujarat State Petronet. For these reasons, we cut our PT on the stock to Rs135 but maintain our BUY call.

Fig. 1: India gas: stocks for action

Company	Ticker	Price (INR/sh)	Rating	PT (INR/sh)
Reliance Industries	RIL IN	984	**BUY**	**1,200** ↑
GAIL	GAIL IN	475	**BUY**	**600** ↑
Petronet LNG	PLNG IN	132	**BUY**	**180** ↑
Indraprastha Gas	IGL IN	322	**BUY**	**450** ↑
Gujarat State Petronet	GUJS IN	98	**BUY**	**135** ↓
Gujarat Gas	GGAS IN	367	**NEUTRAL** ↑	**415** ↑

Note: Prices as of 29 April, 2011; ↑ Upgrade from Reduce

Source: Bloomberg, Nomura estimates

Rating: *See report end for details of Nomura's rating system.*

Anchor themes

Even with slowing domestic gas growth in the near term, we see considerable growth potential for gas in the long term. Meanwhile, higher LNG imports should help to drive growth.

Nomura vs consensus

We are more bullish on oil prices and less hopeful of significant near-term reforms.

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India Oil & Gas/Chemicals

Anil Sharma - NFASL
anil.sharma.1@nomura.com
+91 22 4037 4338

Ravi Adukia, CFA - NFASL
ravikumar.adukia@nomura.com
+91 22 4037 4232

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Executive summary

Domestic gas – losing steam

After a decade of low growth (~1.8% CAGR) to March 2009, India's domestic gas production grew by a sharp 45% y-y (even higher 72% y-y on exit rate) in FY10, driven by a sharp ramp-up of gas production to 60mmscmd at the KG-D6 block.

Since starting in April 2009, production at the KG-D6 block had ramped up to ~60mmscmd by end-2009. As Reliance carried out assessment of design capacity of KG-D6 facilities at end-December 2009 (achieved a flow-rate of 80mmscmd), expectations were high for further increases in 2010. However, against our and consensus expectations, production at KG-D6 actually started to decline in 2010 as contractors undertook a study of reservoir characteristics, citing declines in reservoir pressure.

There has been significant investors concern on the KG-D6 block's continued volume decline and non-clarity over likely volume ramp-up. Too much and often conflicting news-flow on likely volumes, quoting different sources, have further exacerbated these concerns, in our view.

Near term – limited domestic production visibility

Apart from the decline in KG-D6 production, efforts on developing existing discoveries and further exploration activities seem to have slowed down for most operators over the past few years, in our view.

Of more than 55 gas discoveries on the East Coast in the New Exploration and Licensing Policy (NELP) blocks, only two gas discoveries (D1/D3 in KG Basin) are currently producing. Despite having large inventories of existing gas discoveries, relatively slow progress on bringing these into development phase for commercial production suggests that India may not see any meaningful increase in domestic gas production in the near term, in our view.

Long term – BP deal restores faith in Indian E&P potential

Although concerns abound in the near term on gas production ramp-up for a variety of reasons – such as technical, regulatory, policy and pricing concerns – the recent announcement of BP taking a 30% stake in the KG-D6 block along with stakes in 22 other blocks is, in our view, clear testimony of the large potential of Reliance's acreage in particular and India's East Coast E&P acreage, in general.

We think this alliance with BP, which has strong deep water expertise, will help resolve the current technical issues at KG-D6. We also believe that BP's large investment could be a harbinger of bringing other big international players to take stakes in other blocks with other operators. Such alliances have been discussed, and even agreed upon, but have not fructified for a variety of reasons until now.

LNG likely the key source of growth in the medium term

With gas volumes at the KG-D6 block unlikely to increase meaningfully in the near term and no visibility of any other significant domestic source, we believe re-gasified liquefied natural gas (RLNG) is the most visible source of gas in the near to medium term. As current spare LNG capacity is fast filling up, we expect LNG to provide the bulk of growth in FY12F. With domestic volumes declining, pipeline constraints easing and short-term LNG prices remaining relatively benign, there has been a series of short-term contracts for LNG by several key players recently.

Also, the fact that a significant amount of new LNG re-gas capacity is under construction (the capacity likely to double by FY14F, on our estimate), and with India trying actively to tie up more long-term LNG supply, we think LNG will continue to be the key source of gas availability for the next three to four years.

Stock selection – favourable risk reward

Gas stocks sharply outperformed the broader market in 2010, as domestic gas availability significantly improved. However, with concerns of declines in KG-D6 volumes and no clear visibility of a ramp-up in the near term, most gas stocks (except Petronet LNG) have corrected in 2011 YTD. We think with higher LNG volumes likely to fill the shortfall, the gas growth story will continue. With risk-reward increasingly favourable, we think it's time to get back into the gas story.

With an increasing focus on LNG, we believe **Petronet LNG** (PLNG, BUY with PT raised to Rs180 from Rs145) is the obvious beneficiary. While the stock has understandably outperformed most other gas names over the past few months, we still think there remains significant potential upside. With projected EPS growth of 28% in FY12F and a further 15% in FY13F, we see the implied 15x FY13F P/E multiple to our PT not demanding. Despite its sharp outperformance to the Sensex (up 19/61% over 6M/12M vs -6/1% for Sensex), **PLNG remains our top mid-cap gas pick.**

We reaffirm BUY on **Reliance Industries** (BUY with PT raised to Rs1,200 from Rs1,140) and believe its recent partnership with BP should allay concerns on volume decline and near-term delays in production ramp-up. We think the deal should restore faith in RIL's longer-term E&P business outlook, apart from setting a benchmark valuation for the E&P business.

We continue to like transmission giant **GAIL** (BUY with PT raised to Rs600 from Rs545 previously), as we are confident that concerns over KG-D6 and higher subsidy are overdone while the upside potential from LNG and petrochemicals is not in the price

Among the mid-cap names, we continue to like **Indraprastha Gas** (BUY, with PT raised to Rs450, from Rs440) a secular CGD story with key advantages of being in Delhi NCR (India's largest metro area) and the CNG business (the emerging fuel of choice). The focus now is also on supplying piped gas to industries, which is currently seeing over 100% y-y growth (volumes were up 112% y-y for 9MFY11).

Gujarat State Petronet (BUY, with PT reduced to Rs135, from Rs150) won all three recently bid long-distance transmission lines. On completion, its network will treble and the company is likely to emerge as a pan-India gas transmission player. However, regulatory concerns remain a key overhang in the near term, as the process of network authorisation (and thus tariff resetting) and the formal award of three pipelines (that it won) have been considerably delayed.

We upgrade **Gujarat Gas** to NEUTRAL (from Reduce) with a revised PT of Rs415 (from Rs385). Still with limited domestic gas availability, it has to source more expensive LNG and is likely to encounter some consumer resistance, in our view. More importantly, cities in which it operates are already mature (networks are over 20 years old), and the company does not seem to be pursuing aggressive growth, in our view.

Reliance Industries (BUY, PT: Rs1,200)
RIL's underperformance (down 17%/35% relative to the Sensex over 1Y/2Y) remains stark. It has pared gains since its deal with BP.

We think its recent partnership with BP is very positive. The valuations were higher than consensus estimates, indicating BP's confidence in the long-term potential of RIL's E&P acreage. With the BP deal returning faith on RIL's long-term E&P potential, it also eases near-term concerns over volume declines and ramp-up delays, in our view.

Fundamentals of RIL's refining (EBIT up by 53% in FY11) and petrochemicals (EBIT up by 8% in FY11) operations have significantly improved and the outlook remains positive, in our view.

Apart from E&P, investors are also concerned about how the company would use its large cash balance (US$10bn as of end-FY11) and the perceived risks of going into unrelated areas. In our opinion, such concerns are overdone and we see risk-reward getting improving.

GAIL (BUY, PT: Rs600)

We attribute GAIL's recent underperformance (down 7% YTD) to concerns over declines in KG-D6 volumes and likely higher subsidies.

In our view, such concerns are overdone. KG-D6 volumes declines are, to a certain extent, offset by higher LNG volumes (which get higher tariffs). In addition, GAIL currently shares subsidies on cooking fuel and not diesel, and the increases in subsidy are largely offset by higher realisation on LPG.

During GAIL's Pata petchem plant shutdown in 2Q/3Q, the plant's capacity was raised by ~20% to 490ktpa. GAIL is working on further expansion at Pata and, according to management, will expand the capacity to 900ktpa (earlier 800ktpa) by FY14.

We continue to like GAIL for its operating upside and potential re-rating from gas growth.

Petronet LNG (BUY, PT: Rs180)

PLNG owns 75% of India's LNG re-gas capacity and will likely be a key beneficiary of the growth spurt in LNG. With limited visibility on domestic growth in the near term, further easing of pipeline constraints and still relatively benign LNG prices, we expect volume growth to continue. From the recent low in 4QFY10, volumes have consistently increased each quarter, with Dahej reaching 100% utilisation in 4QFY11. We expect further growth of 16% in FY13F due to a lower base. PLNG is doubling its capacity by FY14F, and will remain a key gateway for LNG imports, as domestic production struggles.

Besides the existing 7.5mmtpa long-term contract, it also has a 1.5mmtpa long-term contract for Kochi, a major port city located on the west coast of India. It is aggressively scouting to tie-up more long-term LNG, and announcements on any binding contract would be a potential trigger for the stock, in our view. PLNG remains our favourite stock in the mid-cap gas segment.

It has an almost "too good to believe" long-term gas supply and purchase agreement (GSPA) where its re-gas tariffs increase 5% pa. In addition, it keeps making marketing gains on short/spot cargoes that it markets. We think under current regulations, there is little likelihood of regulatory intervention in tariffs.

The stock has outperformed most other gas names over the past few months. We still think there remains a lot more potential upside. With projected EPS growth of 28% in FY12F and further 15% in FY13F, we see the implied 15x FY13F P/E multiple to our PT not demanding. Despite its sharp outperformance to the Sensex, PLNG remains our top mid-cap gas pick.

Indraprastha Gas (BUY, PT: Rs450)

Indraprastha Gas (IGL) continues to enjoy the twin advantages of being in Delhi NCR (India's largest metro area) and marketing CNG (emerging fuel of choice). Despite witnessing a sharp 35% increase in prices over the last one year, CNG continues to be the cheapest transport fuel in Delhi NCR. With wider availability and many car makers now providing factory-fitted CNG cars, CNG is emerging as the fuel of choice in Delhi NCR. We believe availability will further improve when nearly 70 outlets, which are ready and await final approvals, come online in the next few months.

Concerns on its ability to pass-through gas price hikes have diminished, as the company has been able to pass on all cost increases over the past one year (including more than 100% APM increase). Apart from secular CNG growth, the focus is now on the PNG segment (112% growth in 9MFY11) which was untapped earlier due to gas shortages.

Gujarat State Petronet (BUY, PT: Rs135)

GSPL's JV won all three long-distance pipelines in October 2010, but it is still waiting for formal authorisation letters. On completion of these GSPL's network would treble to over 5,500km (present 1700km) and from the present one state network, it will move on to become a pan-India gas transmission company.

While we believe that the three long distance pipelines (that it won through competitive bidding in 3QFY11) would be value accretive, we believe near-term market's concerns would be on timing, capex, funding, source of gas, customer linkage and risk of equity dilution, etc. Although the company has been in operations for over a decade, its current network has yet to be authorised by the Petroleum and Natural Gas Regulatory Board (PNGRB), which is delaying the tariff setting process as per the regulations.

Regulatory delays/concerns have been a key overhang, but clarity may emerge soon as the Supreme Court hears the long pending issue on the PNGRB's powers in early May. We like GSPL as a key long-term gas play, but until near-term uncertainties clear, the stock may remain range-bound, in our view.

Gujarat Gas (Neutral, PT: Rs415)

Even as GGAS' volumes grew 17% in CY10, ending two years of volume decline, limited domestic gas availability is hurting. With an increased share of spot/short-term LNG volumes, the company is moving towards more dynamic price changes, but faces consumer resistance. Despite higher priced RLNG, gas should remain cheaper than liquid fuels, but growth is likely to be limited as current markets are mature.

Since its recent peak in March 2011, the stock has declined 11% (vs the Sensex's gain of 4% during the same period), and we do not see much downside. We upgrade the stock to Neutral with a new PT of Rs415. However, we remain cautious on growth given matured networks, paucity of domestic gas and limited growth opportunities.

Fig. 2: Summary of rating and PT revisions

		Price	Market cap	Rating		PT (INR/sh)		Upsides
Company	Ticker	(INR/sh)	US$bn	New	Old	New	Old	(%)
Upstream								
Reliance Industries	RIL IN	984	72.8	**BUY**	BUY	**1,200**	1,140	22%
Midstream								
GAIL	GAIL IN	475	13.6	**BUY**	BUY	**600**	545	26%
Gujarat State Petronet	GUJS IN	98	1.3	**BUY**	BUY	**135**	150	37%
LNG								
Petronet LNG	PLNG IN	132	2.2	**BUY**	BUY	**180**	145	36%
Downstream								
Indraprastha Gas	IGL IN	322	1.0	**BUY**	BUY	**450**	440	40%
Gujarat Gas	GGAS IN	367	1.1	**NEUTRAL**	REDUCE	**415**	385	13%

Source: Bloomberg, Nomura estimates
Note: Pricing as of 29 April, 2011

Fig. 3: Key market information

Name	Ticker	Rating	Market price	M Cap (US$bn)	Free Float	FII holdings	3M T/O (US$mn)	52W H/L	PT	Upside	Valuation method
Reliance Industries	RIL IN	BUY	984	72.8	55.3	17.6	122.6	1,187 - 841	1,200	22%	SOTP
GAIL	GAIL IN	BUY	475	13.6	42.7	12.5	11.3	536 - 402	600	26%	SOTP
Gujarat State Petronet	GUJS IN	BUY	98	1.3	62.3	11.3	2.8	128 - 88	135	37%	DCF
Petronet LNG	PLNG IN	BUY	132	2.2	50.0	10.8	5.4	141 - 77	180	36%	DCF
Indraprastha Gas	IGL IN	BUY	322	1.0	55.0	17.0	2.1	374 - 215	450	40%	DCF
Gujarat Gas	GGAS IN	NEUTRAL	367	1.1	34.9	15.9	0.3	454 - 260	415	13%	DCF

Source: Bloomberg, National Stock Exchange, Nomura estimates
Note: Pricing as of 29 April, 2011

Fig. 4: WACC rate assumptions

	RIL	GSPL	GGAS	IGL	PLNG
Risk free	7.5%	7.5%	7.5%	7.5%	7.5%
Equity risk premium	5.0%	5.0%	5.0%	5.0%	5.0%
Beta	1.0	1.1	0.7	0.9	1.0
Cost of Equity	13%	13%	11%	12%	13%
Cost of debt (pre-tax)	11%	11%	12%	12%	12%
Tax Rate	20%	33%	33%	33%	33%
Cost of debt (after tax)	9%	7%	8%	8%	8%
Debt/D+E	50%	45%	0%	23%	58%
WACC %	11%	10%	11%	11%	10%

Source: Nomura estimates

Fig. 5: Valuation summary

	P/E (x)				EV/EBITDA (x)				Price/Book (x)				Dividend Yield			
	FY10	FY11F	FY12F	FY13F	FY10	FY11F	FY12F	FY13F	FY10	FY11F	FY12F	FY13F	FY10	FY11F	FY12F	FY13F
Reliance Industries	20.2	15.9	12.6	11.2	12.1	9.2	7.9	7.4	2.3	2.0	1.8	1.6	0.7	0.8	0.8	0.8
GAIL	19.2	16.3	13.6	12.2	12.3	10.9	9.1	8.3	3.6	3.1	2.7	2.4	1.6	1.8	2.2	2.5
GSPL	13.4	11.5	9.8	9.1	7.0	6.7	6.2	5.7	3.5	2.8	2.3	1.9	1.0	1.5	1.5	1.5
Petronet LNG	24.5	16.0	12.5	10.8	14.3	10.6	9.2	8.3	4.4	3.7	3.0	2.5	1.3	1.5	1.5	1.5
Indraprastha Gas	20.9	17.3	14.1	12.1	11.5	9.6	7.8	6.4	5.5	4.4	3.6	2.9	1.4	1.4	1.4	1.4
Gujarat Gas	27.9	18.8	15.9	14.5	17.2	11.6	9.6	8.6	6.2	5.6	4.8	4.0	2.1	3.2	2.7	2.7

Note: December year end for Gujarat Gas. F10/FY11F/FY12F/FY13F corresponds to 2009/2010/2011/2012. Pricing as of 29 April 2011

Source: Company data, Nomura estimates

Fig. 6: Financial summary

	Revenue (INRbn)				EBITDA (INRbn)				PAT (INRbn)				EPS (INR/sh)			
(INRbn)	FY10	FY11F	FY12F	FY13F	FY10	FY11F	FY12F	FY13F	FY10	FY11F	FY12F	FY13F	FY10	FY11F	FY12F	FY13F
Reliance Industries	2,037	2,658	3,267	3,304	309	390	422	437	159	202	259	292	49	62	78	88
GAIL	250	324	388	427	47	56	68	77	31	37	44	49	25	29	35	39
GSPL	10.0	10.6	11.8	12.9	9.4	9.9	11.0	12.0	4.1	4.8	5.7	6.1	7.4	8.6	10.0	10.8
Petronet LNG	106.5	132.0	188.6	250.0	8.5	12.2	15.2	18.3	4.0	6.2	7.9	9.1	5.4	8.3	10.6	12.2
Indraprastha Gas	10.8	17.8	25.1	31.5	3.8	4.9	6.1	7.3	2.2	2.6	3.2	3.7	15.4	18.6	22.8	26.5
Gujarat Gas	14.2	18.5	23.2	25.6	2.8	4.2	4.9	5.3	1.7	2.6	3.0	3.3	13.5	20.0	23.7	25.8

Note: Gujarat Gas has a Dec year end. F10/FY11F/FY12F/FY13F corresponds to 2009/2010/2011/2012.

Source: Company data, Nomura estimates

Fig. 7: Stock performance matrix

	Absolute local (%)						Rel. local market (%)						Rel. MSCI Oil & Gas (%)					
Company	1w	1m	3m	6m	12m	ytd	1w	1m	3m	6m	12m	ytd	1w	1m	3m	6m	12m	ytd
Reliance Industries	(5.5)	(6.2)	7.0	(10.3)	(4.8)	(7.1)	(3.2)	(4.8)	1.2	(4.6)	(12.7)	(0.4)	(7.3)	(7.8)	(1.7)	(28.0)	(20.2)	(17.8)
Gail India	0.3	2.5	1.0	(3.3)	10.8	(7.3)	2.7	4.0	(4.6)	2.8	1.7	(0.6)	(1.6)	0.8	(7.3)	(22.4)	(7.0)	(17.9)
GSPL	(4.5)	(0.6)	(3.6)	(12.5)	3.2	(16.5)	(2.1)	0.9	(8.8)	(7.0)	(5.3)	(10.5)	(6.3)	(2.2)	(11.5)	(29.8)	(13.4)	(26.1)
Petronet LNG	(3.2)	8.4	2.3	18.8	61.1	5.7	(0.9)	10.0	(3.3)	26.3	47.9	13.3	(5.1)	6.6	(6.1)	(4.7)	35.2	(6.5)
Indraprastha Gas	0.0	7.2	3.5	(2.2)	37.7	(6.0)	2.4	8.8	(2.1)	3.9	26.3	0.8	(1.9)	5.4	(4.9)	(21.6)	15.5	(16.8)
Gujrat Gas Company	(3.0)	(4.5)	7.0	(2.5)	29.9	(6.4)	(0.6)	(3.1)	1.1	3.7	19.2	0.3	(4.8)	(6.1)	(1.8)	(21.8)	9.0	(17.2)
Average	**(2.6)**	**1.1**	**2.9**	**(2.0)**	**23.0**	**(6.3)**	**(0.3)**	**2.6**	**(2.8)**	**4.2**	**12.9**	**0.5**	**(4.5)**	**(0.6)**	**(5.6)**	**(21.4)**	**3.2**	**(17.0)**
BSE Sensex	(2.4)	(1.5)	5.8	(5.9)	9.0	(6.7)												
BSE Oil & Gas Index	(2.9)	(1.7)	5.9	(8.2)	0.9	(5.6)												
MSCI Oil and Gas Index	2.0	1.7	8.9	24.7	19.2	13.0												

Source: Bloomberg. Note: Pricing as of 29 April, 2011

Fig. 8: Regional peer group comparison

Company	Ticker	Rating	Price (LC)	Mkt cap (US$bn)	2yrs EPS CAGR	ROE (%)	P/E (x) 10F	P/E (x) 11F	P/E (x) 12F	Yield (%) 10F	Yield (%) 11F	Yield (%) 12F	P/B (x) 10F	P/B (x) 11F	P/B (x) 12F	EV/EBIDTA (x) 10F	EV/EBIDTA (x) 11F	EV/EBIDTA (x) 12F
Asia gas utilities																		
Hong Kong & China Gas	3 HK	Reduce	19	17.7	9%	15%	28.4	25.9	24.0	2.1	2.4	2.6	3.9	3.6	3.4	18.6	17.5	16.4
ENN Energy	2688 HK	Neutral	27	4.4	12%	18%	24.9	20.3	18.4	1.0	1.3	1.7	4.1	3.3	3.0	11.2	8.6	7.2
Towngas China	1083 HK	Neutral	4	1.3	20%	7%	20.5	16.4	14.3	0.7	1.0	1.2	1.2	1.1	1.0	12.4	9.3	8.2
China Resources Gas	1193 HK	BUY	11	2.7	23%	17%	24.6	18.8	16.1	0.7	1.1	1.2	3.4	3.0	2.6	13.1	8.6	7.2
China Gas	384 HK	Reduce	3	1.8	-6%	12%	15.7	22.2	16.4	0.4	0.5	0.6	2.6	1.7	1.6	14.3	9.1	7.1
Beijing Enterprises	392 HK	BUY	42	6.1	16%	10%	18.0	25.1	13.3	1.8	2.1	2.4	1.4	1.3	1.2	8.5	7.8	7.3
Korea Gas	036460 KS	Buy	33,950	2.5	45%	9%	12.1	8.8	5.7	2.5	3.4	5.2	0.6	0.5	0.5	13.4	12.3	11.5
Perusahaan Gas Negara	PGAS IJ	Buy	4,000	11.2	3%	36%	14.1	14.6	13.3	3.9	4.4	4.6	7.0	5.6	4.8	9.2	8.5	7.6
Average					15%	15%	19.8	19.0	15.2	1.6	2.0	2.4	3.0	2.5	2.3	12.6	10.2	9.0
India gas																		
Reliance Industries	RIL IN	Buy	984	72.8	19%	15%	15.9	12.6	11.2	0.8	0.8	0.8	2.0	1.8	1.6	9.2	7.9	7.4
GAIL	GAIL IN	Buy	476	13.6	15%	21%	16.3	13.6	12.2	1.8	2.2	2.5	3.1	2.7	2.4	10.9	9.1	8.3
GSPL	GUJS IN	Buy	99	1.3	12%	23%	11.5	9.8	9.1	1.5	1.5	1.5	2.8	2.3	1.9	6.7	6.2	5.7
Petronet LNG	PLNG IN	Buy	132	2.2	21%	25%	16.0	12.5	10.8	1.5	1.5	1.5	3.7	3.0	2.5	10.6	9.2	8.3
Indraprastha Gas	IGL IN	Buy	322	1.0	19%	26%	17.3	14.1	12.1	1.4	1.4	1.4	4.4	3.6	2.9	9.6	7.8	6.4
Gujarat Gas	GGAS IN	Neutral	367	1.1	14%	28%	18.8	15.9	14.5	3.2	2.7	2.7	5.6	4.8	4.0	11.6	9.6	8.6
					17%	23%	16.0	13.1	11.7	1.7	1.7	1.7	3.6	3.0	2.5	9.8	8.3	7.4

Note: Pricing as of 29 April, 2011; Note: Indian gas companies except Gujarat Gas (Dec year end) have March year end. CY 2010/2011/2012 corresponds to FY11/12/13F

Source: Bloomberg, Nomura estimates

Fig. 9: Nomura vs. Consensus

		Consensus		Nomura		
		PT	FY13F EPS	Rating	PT	FY13F EPS
Reliance Industries	RIL IN	1,144	82	Buy	1,200	88
GAIL	GAIL IN	527	37	Buy	600	39
Gujarat State Petrone	GUJS IN	124	10	Buy	135	11
Petronet LNG	PLNG IN	144	10	Buy	180	12
Indraprastha Gas	IGL IN	357	24	Buy	450	27
Gujarat Gas	GGAS IN	426	25	Neutral	415	26

Note: March year end for Indian gas companies except Gujarat Gas. 2012F corresponds to FY13F

Source: Bloomberg, Company data, Nomura estimates

Domestic gas – losing steam

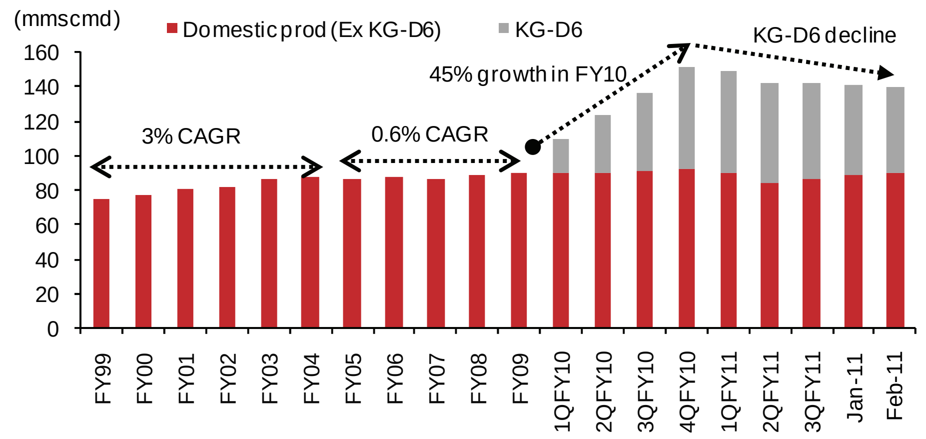
Fizzling domestic volumes in FY11 after sharp growth in FY10

After a decade of low growth (~1.8% CAGR) to March 2009, domestic gas production grew by a sharp 45% y-y (even higher 72% y-y on exit rate) in FY10, driven by a sharp ramp-up of gas production to 60mmscmd at the KG-D6 block.

Since starting in April 2009, production at the KG-D6 block had ramped-up to ~60mmscmd by end-2009. As Reliance carried out the assessment of design capacity of KG-D6 facilities at end-Dec-2009 (achieved a flow-rate of 80mmscmd), expectations were high for further increases in 2010.

However, against our and consensus expectations, KG-D6 production actually started to decline in 2010 as the contractor undertook a study of reservoir characteristics citing a decline in reservoir pressure. Despite additional ~8mmscmd of associated gas production from the D-26 oil field, KG-D6 gas production actually declined from ~60mmsmcmd (from D1/D3 fields) at the start of FY11 to ~50mmscmd currently (~40-41mmscmd from D1/D3 fields and ~8-9mmscmd from D-26 oil field).

Fig. 10: Domestic gas production constrained by slippages at the KG-D6 block



Source: Petroleum Planning & Analysis Cell (PPAC), Nomura research

And confusion abounds on likely KG-D6 volume near term

There has been significant investors concern on the continued volume decline at the KG-D6 block, and non-clarity on the likely ramp-up of KG-D6 volumes. Too much and often conflicting news-flow on likely volumes quoting different sources have further exacerbated these concerns, in our view.

Reliance has shown reluctance in recent months to provide any indication on likely future volumes and ramp-up plans at the KG-D6 block (as well as on exploration efforts in this and other blocks), citing ongoing discussion with governments and regulators.

However, Niko Resource (which owns a 10% stake in KG-D6), announced on 11 Feb 2011 that it had received operator's forecasts for FY12. These forecasts predicted volumes in FY12 to remain flat at current production levels. According to Niko, these forecasts were approved by Niko and Reliance and had been forwarded to the Director General of Hydrocarbons.

Niko's forecast seems to indicated that KG-D6 gas production would likely remain at about 50-52 mmscmd and oil production at 15-17kbpd, the prevailing production levels at that time.

However, in early March, media reported that production at the KG-D6 block could increase to 67-68 mmscmd by April 2011, citing the Director General of Hydrocarbon (Business Standard, 9Mar 2011 *RIL KG basin gas output seen up to 67 mmscmd in April*).

According to the media article, DGH said that 18 wells had been drilled so far and completed out of 22 development or production wells approved in Phase-I of the field development plan (FDP) for the D1 and D3 fields. As per DGH, gas was being produced from 16 wells and two more wells were completed, but not put on production. Another two wells were yet to be connected to production system, and Reliance needed to drill two more wells by April to reach the target of 22 wells.

However, media reported the very next week, citing Reliance's response to DGH's queries (infraline.com, 18 March 2011, *RIL submits D6 production expectations for 2012-13 - I: Average to slip down to 38 MMSCMD'*), that according to Reliance's budgetary figures for FY13, production/sales from the block may reduce to only 38mmscmd in FY13. Reliance later clarified that the figures referred to in the media were purely provisional and indicative and would be subject to such variations as might emerge during the actual operations in the future years.

We assume KG-D6 production at 50/55 mmscmd in FY12/13F

Given the confusion due to wide and conflicting media coverage, and unwillingness of the operator to give any concrete guidance citing ongoing dialogue, there has been significant speculation and concern in the market over likely volumes.

Given the continued decline in production and lack of clear indication of further ramp-up plans, our earlier production assumption of 60 mmscmd in FY12F/13F for the KG-D6 block now looks optimistic.

We now assume that production would remain around current levels of 50mmscmd in FY12F, and would reach 60mmscmd levels only by the end FY13F (avg. of 55mmscmd in FY13F), as Reliance works on its current technical challenges with new partner BP and firms up its plans for further development in the block.

To us, the 38 mmscmd from the D1/D3 fields as reported in the media (total ~47mmsmd including associate gas from the MA-1 oil field at the KG-D6 block) is a scenario that looks rather pessimistic, as it is not building in any upside from further development work in the intervening period.

Fig. 11: KG-D6 production estimates

		FY11		FY12		FY13	
	FY10	New	Old	New	Old	New	Old
Gas production (mmscmd)	39	56	56	50	60	55	60
Oil production (kbpd)	11	24	23	18	25	18	25

Source: Company data, Nomura estimates

Near term – limited domestic production visibility

Apart from the decline in KG-D6 production, efforts on developing existing discoveries and further exploration activities seem to have slowed down for most operators over the past few years, in our view.

Of over 50 gas discoveries on the east coast in NELP blocks, only two gas discoveries (D1/D3 in KG Basin) are currently producing. Despite having large inventories of existing gas discoveries, the relatively slow progress on bringing these commercial into production suggests that India may not see any meaningful increase in domestic gas production near term, in our view.

Apart from operational difficulties (such as the shortage of deep-water rigs), confusing policies on pricing, delays in bringing partners with deep-water and technical expertise, allocation and taxation of domestic gas and slow and overly bureaucratic approval and regulatory process are some of the overhangs limiting near-term domestic gas production.

Despite significant potential resources and existing gas discoveries in key blocks like KG-D6, NEC-25, Deendayal and KG-DWN-98/2, not much significant progress has been made in the past few years to bring these discoveries on production, in our view.

Long term – BP’s deal restores faith in Indian E&P potential

Although concerns abound in the near term on gas production ramp-up on a variety of reasons, such as technical, regulatory, policy and pricing concerns, the recent announcement of BP taking a 30% stake in the KG-D6 block along with stakes in 22 other blocks is, in our view, a clear testimony of the large potential of Reliance’s acreage in particular and India’s East Coast E&P acreage, in general.

We think this alliance with BP, which has significant deep water expertise, will also help resolve the current technical issues at KG-D6. We also believe that BP’s large investment could be a harbinger of bringing other big international players to take stakes in other blocks with other operators. Such alliances have been discussed, and even have been agreed to earlier, but have not fructified for a variety of reasons until now.

The indicative valuation of US$24-US$30bn, apart from early monetization and risk mitigation, set the valuation benchmark for Reliance’s E&P acreages, in our view. More importantly, BP’s investment indicates that BP sees significant value opportunities in Reliance’s E&P assets, and despite so much noise surrounding KG-D6 volume decline, has shown confidence to make a significant upfront investment of US$7.2bn. In addition, BP could pay further future performance payments up to US$1.8bn based on exploration success that results in commercial discovery. BP estimates that including these investments its combined investments could amount to US$20bn.

Fig. 12: BP's India E&P portfolio – 30% stake in 24 blocks

Basin	Type	JV Partners	Area (Sq. Km.)
K-G Offshore			
KG-DWN-98/1(KG-D4)	Deepwater	RIL - 70%	6,700
KG-DWN-98/3 (KG-D6)	Deepwater	RIL - 60%, NIKO - 10%	7,645
KG-DWN-2001/1 (KG-D9)	Deepwater	RIL - 60%, HEPI - 10%	11,605
KG-DWN-2003/1 (KG-D3)	Deepwater	RIL - 60%, HEPI - 10%	3,288
KG-DWN-2004/4	Deepwater	RIL - 70%	11,904
KG-DWN-2004/7	Deepwater	RIL - 70%	11,856
KG-DWN-2005/2*	Deepwater	RIL - 70%	1,949
Cauvery Offshore			
CY-DWN-2001/2	Deepwater	RIL - 70%	14,325
Cauvery-Palar Offshore			
CY-PR-DWN-2001/3	Deepwater	RIL - 70%	8,600
CY-PR-DWN-2001/4	Deepwater	RIL - 70%	10,590
Palar Offshore			
PR-DWN-2001/1	Deepwater	RIL - 70%	8,255
Mahanadi-NEC Offshore			
MN-DWN-98/2	Deepwater	RIL - 70%	7,195
NEC-OSN-97/2	Shallow Water	RIL - 60%, NIKO - 10%	9,461
NEC-DWN-2002/1	Deepwater	RIL - 60%, HEPI - 10%	19,173
MN-DWN-2003/1	Deepwater	RIL - 55%, NIKO - 15%	17,050
MN-DWN-2004/1	Deepwater	RIL - 70%	9,885
MN-DWN-2004/2	Deepwater	RIL - 70%	11,813
MN-DWN-2004/3	Deepwater	RIL - 70%	11,316
MN-DWN-2004/4	Deepwater	RIL - 70%	8,822
MN-DWN-2004/5	Deepwater	RIL - 70%	10,454
Kerala-Konkan Offshore			
KK-DWN-2001/1	Deepwater	RIL - 70%	27,315
KK-DWN-2001/2	Deepwater	RIL - 70%	31,515
Assam-Arakan			
AS-ONN-2000/1	Onshore	RIL - 60%, HEPI - 10%	6,215
Cambay			
CB-ONN-2003/1 (Pt.A&B)	Onshore	RIL - 70%	635

Note: * This block was not the part of recent RIL – BP deal. In other 23 blocks BP has recently acquired 30% stake from RIL, subject to government and other regulatory approvals

Source: Company data

Long term – several potential blocks on the east coast

Apart from KG-D6, there are several other blocks that could provide long-term gas growth, in our view. Post the opening up of upstream exploration with the launch of the new exploration licensing policy (NELP), India's sedimentary basins and in particular, the east coast has seen increased exploration efforts. These have resulted in over 85 discoveries in NELP blocks, of which 56 are gas discoveries.

Most of the success has been in the deep waters off the east coast, and the east coast is being seen as new gas hub.

Of nearly 50 gas discoveries on the east coast, only two have been brought into production, and several other discovered blocks are seen as having large potential. Many of the other discoveries are currently under different phases of further appraisal, commerciality analysis and development phase.

Production from the east coast could significantly increase in the coming years as several of these discoveries are brought into production.

Fig. 13: Of 85+ NELP discoveries 56 are gas discoveries and most of it are on the east coast

Basin	Blocks awarded	Discoveries Oil	Discoveries Gas	Discoveries Oil/gas
Assam & Assam Arakan	20	-	3	-
Cambay	32	21	2	1
Cauvery	14	-	2	1
Krishna - Godavari	32	2	37	6
Mahanadi - NEC	17	-	11	-
Saurashtra	5	-	1	-
Others	82	-	-	-
Total	**202**	**23**	**56**	**8**

Note: These blocks have been awarded in first 8 rounds of NELP and exclude blocks already relinquished by the operator.

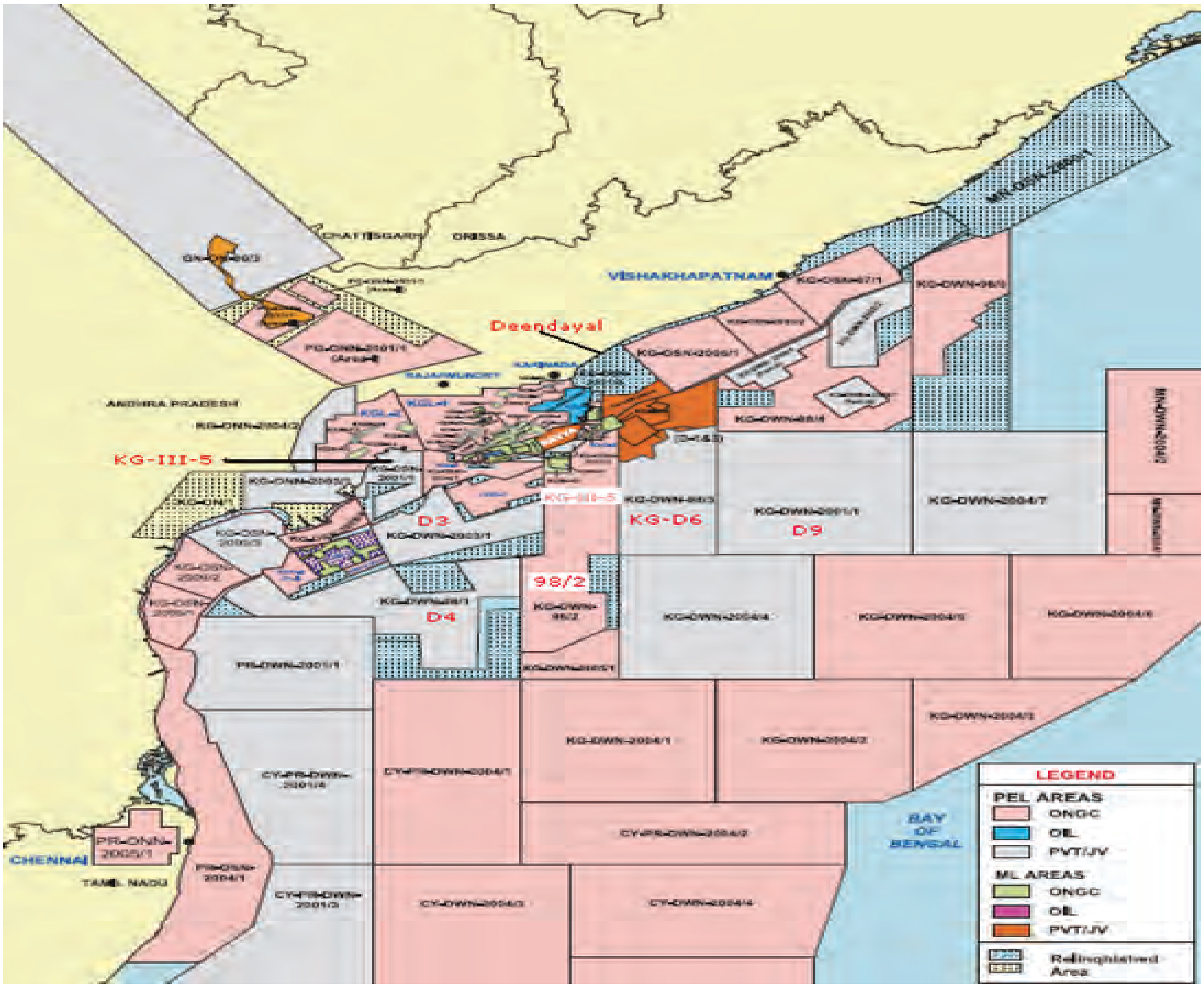
Source: Company data, Directorate General of Hydrocarbons (DGH), Nomura research

Fig. 14: Reliance has 34 gas discoveries

	Discoveries Oil	Discoveries Gas	Discoveries Oil/gas
Reliance Industries	9	34	4
National Oil Company	4	10	0
GSPC	8	6	2
Cairn India	0	1	2
Jubilant Oil & Gas Pvt Ltd	2	3	0
Hardy Exploration	0	2	0
	23	**56**	**8**

Source: Company data, DGH, Nomura research

Fig. 15: Indicative map of KG basin and key blocks



Source: DGH, Nomura research

Fig. 16: Key large discovered / potential NELP blocks

Block	JV partners	Gas finds	Comments
Key blocks			
KG-DWN-98/3 (KG-D6)	RIL 90% (BP to take 30%) NIKO-10% (Option to increase up to 13%)	19	• Two gas (D1/D3) & one oil/gas (MA1) discoveries currently producing • Integrated development being conceptualized. • Satellite fields - amended development plan for 4 discoveries (9 earlier) • Declaration of commerciality (DoC) submitted to DGH for 4 R-series discoveries (D29/D30/D31/D34) in Feb 2010.
NEC-OSN-97/2 (NEC 25)	RIL – 90% (BP to take 30%) NIKO – 10% (Option for up to 13%)	8	• FDP submitted for the first 6 discoveries in 2007 • DoC for the latest 2 discoveries submitted in Feb 2010 • Success in 6 appraisal wells in southern/deeper AJ area – 3 more planned • An integrated development plan being conceptualized
KG-OSN-2001/3 (Deendayal)	GSPC – 80% GGR – 10% Jubilant – 10%	7	• Initial resource estimate of 20tcf • 1P – 0.8tcf, 2P – 1.2tcf, 3P – 1.4tcf (source: GSPC Prospectus) • Gas production now expected from April 2013 (earlier June 2012). • Initial rate likely ~2mmscmd – Peak of 5.7mmscmd (DDW field)
KG-DWN-98/2	National Oil Company – 90% CEIL – 10%	6	• Resource estimates in the range of 5-15tcf. • DoC submitted for Northern and Southern areas • First gas expected during FY2016-17 • Planned farm-out of stake to Petrobras (15%) and Statoil (10%) could not be completed
Other discovered blocks			
KG-DWN-2003/1 (KG-D3)	RIL – 90% (BP to take 30%) HEPI – 10%	4	• Four discoveries - gross risked prospective resources of 4.0tcf. • DoC submitted for three discoveries (D39,41,52) in Feb 2011 • Two more exploration wells planned
KG-DWN-2001/1 (KG-D9)	RIL – 90% (BP to take 30%) HEPI – 10%	0	• First two wells were plugged and abandoned • One more well planned in 2Q2011 • Total gross risked prospective resources of 4.7tcf.
KG-OSN-2001/1	RIL – 100%	3	• Three gas discoveries (Dhirubhai -28, 37, 38) • DoC submitted to DGH in Feb 2010
KG-OSN-2001/2 (KG-III-6)	RIL – 100%	2	• Two oil/gas discoveries (Dhirubhai -24, 25) • DoC submitted to DGH in 2008
MN-DWN-2003/1 (D4 block)	RIL – 90% NIKO – 15%	0	• Niko seems highly optimistic on this block • Seismic for 4400km/3500sq km of 2D/3D complete • 3 wells drilling plan to commence in 2011(earlier 3Q 2010)

Source: Company data, DGH, Infraline, Nomura research

LNG to the rescue

LNG was a key source of gas growth prior to KG-D6

With limited growth in the domestic gas production, RLNG had been the key source of meeting increased gas demand in India before the start of gas production at KG-D6 in April 2009. Beginning with the import of 2.4mmt in 2004, LNG volumes grew to 9mmt (~32mmscmd) in FY10, providing ~22% of Indian gas supplies, on our estimates. Softening spot LNG prices helped imported LNG volumes to reach its peak of ~39mmscmd in 2QFY10.

LNG volumes declined in 2HFY10 due to pipeline constraints...

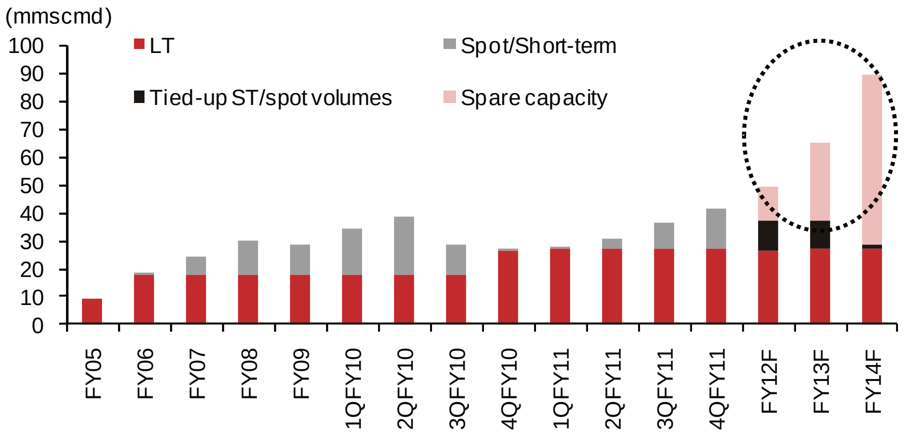
However, with the sharp ramp-up (to 60mmscmd) of gas production at KG-D6, and resultant bottlenecks in GAIL's HVJ pipeline network, spot/short term LNG volumes started to see sharp declines and by 4QFY10, the market for spot LNG nearly dried up in India. Despite receiving ~1.25mtpa of additional long-term LNG cargoes from RasGas, total imported LNG volumes declined by a sharp 21% in 1HFY11.

... but have gradually picked up in FY11

The situation on pipeline availability somewhat eased in 1HFY11, due to a shut-down and resultant reduced production from Panna, Mukta & Tapti fields (PMT) (July-October 2010), as well as a gradual decline in KG-D6 production volumes. This enabled India to import of some spot/short term LNG.

Pipeline bottlenecks have now significantly eased after the installations of compressors at Jhabua and Vijaipur on GAIL's DVPL pipeline on the Hazira-Vijaipur-Jagadishpur (HVJ) network. With the installation, the capacity of this line is now increased to 35mmscmd from 24 mmscmd earlier. The capacity on the HVJ network will further increase when GAIL commissions a new 48" pipeline between Dahej and Vijaipur (DVPL-2). This pipeline, which has been delayed, is now expected by GAIL to be completed by mid-2011, and will further add ~60mmscmd to the HVJ capacity on this key trunk route for taking gas to key markets in north and western India. Once the DVPL-2 is completed, the capacity of the HVJ system will exceed 130mmscmd, on our estimates. This will mark the end of the pipeline constraints in India in the next few years, in our view.

Fig. 17: Given spare capacity, benign global LNG prices and large gas demand spot RLNG imports could jump in the near to medium term



Source: Petroleum Planning & Analysis Cell (PPAC), Nomura estimates

LNG likely to be key source of growth in medium term

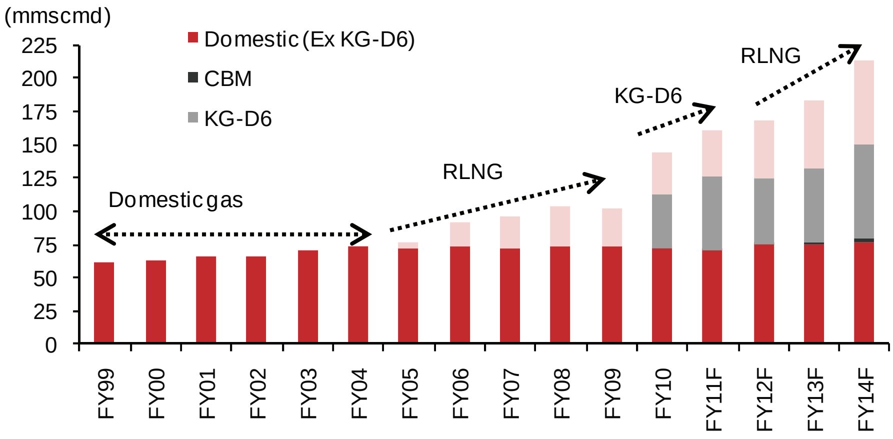
With KG-D6 gas volumes not likely to meaningfully increase in the near term, and no visibility of any other significant domestic source, we believe RLNG is the most visible source of gas in the near to medium term. As the current spare LNG capacity is fast filling up, we expect LNG to provide the bulk of growth in FY12F. Also, as a significant amount of new LNG re-gas capacity is under construction (the capacity likely to double by FY14F, on our estimate), we think that LNG will continue to be the key source of gas availability for the next three to four years.

Significant short-term capacity booked recently

With domestic volumes declining, pipeline constraints easing and short-term LNG prices remaining relatively benign, there has been a series of short-term contracts for LNG by several key players recently:

- Petronet LNG has firmed up contracts for 1.1mmtpa of LNG capacity for two years, and the company indicates that it is looking to tie-up further additional short-term capacity soon.
- GAIL has contracted a three-year deal with Marubeni for importing up to 0.5mmtpa short-term LNG starting Jan 2011.
- Gujarat State Petroleum Corporation Ltd. (GSPC) in January 2011 concluded an agreement with Gazprom Marketing & Trading (GM&T) for about 0.3mmt of LNG capacity for a period of two years commencing 2H 11. Earlier, GSPC had signed a short-term contract for sourcing LNG with Gas Natural (Spain) and also a nine-cargo deal with Repsol (Spain).
- Recently, media (Moneycontrol.com, “Reliance in two-year pact with Hazira LNG” 1 March, 2011, and Petrowatch, “Reliance talks to Marubeni to import term LNG” 24 Feb 2001) reported that RIL was in talks with Marubeni to import between 24 and 35 cargoes over the next two years, and it had signed a two-years contract with Hazira LNG to import these cargoes.
- These short-term deals, in addition to sporadic spot cargoes which keep coming, may enable PLNG’s Dahej and Shell/Total’s Hazira terminal to see near full capacity utilization in FY12F. Thus, compared to total LNG imports of about 9.0-9.2mmt LNG in FY11, India may import nearly 13.5mmt LNG, a y-y increase of nearly 50%, on our estimates.
- Petronet LNG’s Dahej terminal has now already reached full utilisation levels (99% in 4QFY11). Company seems confident that with better optimisation of cargoes the terminal could import even up to 10.5-11mmtpa (105-110% utilisation). Similarly, in an interview to Economic Times (“We are thinking of increasing capacity at Hazira” March 22, 2011) Peter Voser, Shell’s CEO mentioned that the Hazira terminal was running at a full capacity and company was thinking of increasing capacity at the terminal.

Fig. 18: RLNG to supply incremental gas in FY12/13



Source: PPAC, Company data, Infraline, Nomura estimates

Fig. 19: LNG supply – near-term forecasts

RLNG supplies (mmscmd)	FY08	FY09	FY10	FY11F	FY12F	FY13F	FY14F
Petronet LNG							
- Long term (RasGas)	18	18	20	27	27	27	27
- Spot/short term (Dahej)	5	5	7	4	9	10	13
- Spot/short term (Kochi)	-	-	-	-	-	2	7
Shell Hazira							
- Spot/short term	7	6	5	3	7	9	12
RGPPL							
- Spot/short term	-	-	-	-	-	4	5
Total	**30**	**28**	**32**	**34**	**43**	**52**	**64**
- Contracted/firmed-up					37	37	29
- spot volumes					6	15	35
Spare capacity (mmtpa)					**1.7**	**3.8**	**7.2**
Spare capacity (mmscmd)					6	14	26

Source: PPAC, Company data, Infraline, Nomura estimates

Seeking to tie-up long-term LNG

Petronet LNG's long-term contract with RasGas (Qatar), under which supplies have began in 2004, is the only source of long-term LNG into India. With the commencement of the second tranche of 2.5mmtpa from January 2010, the volumes under this contract have now increased to 7.5mmtpa. Petronet LNG is RasGas's biggest consumer and accounts for nearly 10% of Qatari output. In addition, in August 2009 Petronet LNG signed a 20-year contract with ExxonMobil to bring 1.5mmtpa of LNG from Gorgon to its upcoming Kochi terminal. The supplies under this contract are likely to begin in end-2014.

Gap between price expectations precluded new contracts

The Indian government and several companies (GAIL and Petronet LNG, in particular) have been making concerted efforts in recent years to bring in more LNG through long-term contracts. However, not much success has been achieved in terms of finalising contracts. The key reason for this, in our view, was not due to any shortage of long-term LNG availability, but due to different price expectations between producers and buyers. With relative lower prices in India (domestic gas between US$2 and US$5.7 per mmbtu), Indian buyers are not willing to agree to high price expectation with a link of ~14-16% to oil prices. Also, as both short-term and spot LNG prices have become far more benign over the last two years, they may have precluded any new firm long-term contracts from being signed.

Increasing willingness to pay higher prices for assured supply

We believe improved gas infrastructure, continued shortage of domestic gas, significant advantage of gas over other alternate fuels, and high volatility of liquid fuel prices are increasing the propensity of Indian buyers to commit to higher prices to assure a long-term supply of LNG. Even with the 14-15% linkage to oil prices, LNG remains far cheaper than other liquid alternative fuels such as naphtha and fuel oils.

Other inherent advantages, such as lower pollution and environment concerns and low working capital needs are also encouraging Indian consumers to agree to higher LNG prices for assured long-term contracts. The significant increase in domestic gas prices (APM prices increased by over 100% last year) has also made domestic consumers realise that the era of very low gas price is over. Added to this is the fact that domestic gas continues be rationed by the government to mainly priority sectors and with limited visibility of increases in domestic supply in the near term, the willingness of Indian consumers to accept higher prices to have long-term LNG supplies is increasing.

Fig. 20: At 15% linkage, and US$100/bbl oil, RLNG is cheaper

	RLNG	Naphtha	Fuel Oil	Diesel
FOB price of Spot LNG (US$/mmbtu)	15			
Delivered price Spot LNG (US$/mmbtu)	20.2			
FOB cost of alternative fuel (US$/bbl)		97	83	117
Delivered cost of alternative fuel (US$/MT)		1,293	884	1,114
Delivered cost of alternative fuel (US$/mmbtu)		28	21	26
RLNG Advantage %		39%	6%	28%

Note: Comparison at Gujarat

Source: Nomura estimates

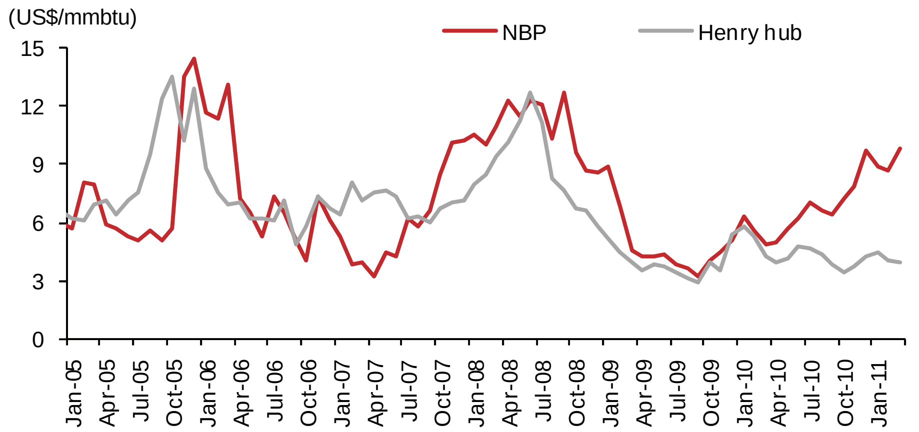
Supply glut moderating price expectations of producers

Over the past two to three years, the dynamics of global LNG markets have dramatically shifted from being a seller's market to a more pronounced buyer's market, in our view. In the past two years, more than 60mmtpa of new LNG liquefaction capacity has been added. Most of this new capacity was targeted to western markets, particularly the US. However, the economic recession and the shale gas revolution in the US have meant that there is much less appetite for far costlier LNG.

Also, as several liquefaction projects which are past final investment decision are unlikely to be called off, the supply-demand gap is likely to increase, in our view.

The supply overhang has meant that both spot and short-term LNG prices have remained far more benign over the last two years. In addition, there has been a clear divergence in global LNG prices. The shale gas glut in North America has meant that Henry Hub prices are capped by shale gas economics, and have remained far subdued. Since 2009, Henry Hub has averaged just US$4.1/mmbtu, versus the previous five-year average of US$7.44, a 45% decline. On the other hand, prices in Europe and Asia-Pacific regions, which are generally indexed to oil or other liquid fuels, are far higher.

Fig. 21: Global gas prices: Sharply declined specially for Henry Hub



Source: Bloomberg, Nomura research

Post nuclear incident – Supply overhang may ease LT

We would expect that post the recent earthquake/tsunami and nuclear incident at Japan's Fukushima nuclear facility, increased preference for gas over nuclear option may lead to absorption of some over-supply in LNG markets.

In the longer term, clean energy, such as wind and solar power, could be replacements, but in the medium term, we believe the more viable source could be gas-fired power plants. With some countries becoming wary of nuclear power, LNG demand could receive a bigger boost over the coming years. Based on our estimates, the LNG market will loosen somewhat and become over supplied in the medium term, offering further incentive for a partial switch from nuclear to LNG.

Prior to the Japanese nuclear crisis, we had estimated that LNG supply would outstrip demand by 69.1mmtpa globally by 2015F. As such, we believe there is enough LNG capacity to compensate for a drop in planned nuclear power expansion.

Fig. 22: LNG global demand and gas supply allocated to LNG

(mmtpa)	2009	2010F	2011F	2012F	2013F	2014F	2015F
Global demand							
North America	13	18	19	20	21	22	23
Europe	51	64	65	66	68	69	71
South America	2	5	5	5	5	6	6
Middle East and Africa	1	2	2	3	3	3	3
Asia-Pacific	127	134	142	145	150	156	163
Total	**193**	**222**	**233**	**239**	**247**	**256**	**266**
Natural gas allocated to LNG							
North America	1	1	0	0	0	0	0
Europe	3	5	5	5	5	5	5
South America	22	24	26	27	27	27	27
Middle East and Africa	104	133	160	174	180	184	189
Asia-Pacific	82	90	97	98	97	100	115
Total	**212**	**252**	**288**	**303**	**308**	**315**	**335**
Surplus LNG available	**19**	**29**	**55**	**65**	**61**	**59**	**69**

Source: BP Statistical Review, Bloomberg, Nomura estimates

For a detailed discussion on impact of nuclear incident and our views on long-term LNG supply/demand please refer to Annexure 1: Long term – LNG as nuclear replacement?

Time for India to tie up LT LNG

As we have mentioned earlier, Indian consumers are now more willing to pay high prices to secure a steady supply of LNG. In addition, with global LNG supply overhang, the expectations of producers have moderated. Globally, as many countries try to assess the nuclear option and the alternate energy source, there is a likelihood that the long-term price expectation of producers would start to move higher again. Thus, we think that now is the time for India to tie up long-term LNG quantities.

In recent months the Indian government and few companies have been talking to several likely sources of long-term LNG providers, such as Qatar, Nigeria, Australia, Russia etc. We believe that it is in the most advanced stage of negotiations with Qatar.

Qatar a most likely source – Formal demand for 15mmtpa

As we have mentioned earlier, India (through Petronet LNG's long-term 7.5mmtpa contract) is RasGas's biggest consumer and accounts for nearly 10% of Qatari LNG output. In addition to the existing 7.5mmtpa contract, Qatar agreed in early 2010 to supply a further up to 5mmtpa LNG on a long term basis, with both parties agreeing to discuss pricing and other aspects.

Now with the commissioning of Qatar's Gas 4 project (Qatar Petroleum 70%, Shell 30%) in December 2010, Qatar has realised its vision of reaching 77mmtpa of LNG liquefaction capacity, and has re-confirmed its position as the world's leading LNG producer. We believe that a significant proportion of Qatar's 77mmtpa capacity is still not tied up and Qatar is aggressively looking for long-term contracts. Talks with Qatar appear to have gathered pace now, and to Qatar, India remains one of the most prospective buyers, in our view.

Incidentally, the first cargo from Qatar Gas 4 was brought to India at Shell's Hazira terminal, during which Qatar's energy minister commented, "I am delighted with the significant accomplishment of the first load-out from Qatar gas 4 to India, which has significant potential as a market for LNG."

India reaffirmed in January 2011 its commitment to secure demand for Qatar's LNG exports and formally put forward an additional demand for 15mn tonnes of LNG, in addition to the existing 7.5mmtpa contract.

Nigeria – GAIL looking to take equity in LNG projects

During the recent (March 2011) Indo-Nigerian Joint commission meeting, the Indian government said that it was interested in tying up LNG imports from Nigeria immediately. Nigerian Foreign Minister indicated that Nigeria LNG was considering dilution of a part of stake, and GAIL was being considered as one of parties.

In addition, GAIL also seems to be keen to take equity stakes in the upcoming Brass LNG and OK LNG projects in Nigeria to source long-term LNG supply. (Source: Government of India Press Release dated 16 Mar 2011)

Russia – talks with Gazprom on swap basis

The Russian government recently indicated that it is in talks with India for long-term LNG. The Russian government seems to be demanding swaps of a possible long-term contract with India's 20% stake in Sakhalin 1 (Source: LNGworldnews.com," Russia: Gazprom in Talks over LNG Supplies to India"). Talks still seem to be preliminary at this stage, in our view.

LNG re-gas capacity to double by FY14F

Current capacity of ~14mtpa at two operational terminals

Imports of LNG began in India in 2004 when Petronet LNG first commissioned its Dahej terminal in April 2004. The Dahej terminal, which operated at 2.5mmtpa in FY05, saw a ramp-up of its capacity first to 6.5mmtpa through debottlenecking in 2006 and later to the current nameplate capacity of 10 mmtpa in July 2009.

India's second LNG terminal was commissioned at Hazira, Gujarat in 2005, in the vicinity of Petronet LNG's Dahej terminal. This terminal was promoted by Hazira LNG Port & Terminal, a JV between Shell (76%) and Total (74%). The initial capacity of 2.5mmtpa was further enhanced to 3.7mmtpa during FY10.

With these two operational LNG re-gasification terminals, India currently has ~14mmtpa (50mmscmd) of import capacity.

Both Dahej and Hazira terminals are expanding capacity

Work on the second jetty at the Dahej terminal has begun and is likely to be completed by mid-2013. With the completion of the jetty, the capacity would increase to ~13mmtpa. With planned additional tank-age and two vaporizers, the company expects the capacity to reach 15mmtpa by the end of FY14 and to further 18mmtpa by FY15-16.

At Hazira terminal, the infrastructure is already laid out for a capacity of 5mmtpa, and with marginal incremental investments the terminal capacity can be enhanced to 5mmpta. The capacity of the terminal is likely to be further expanded to 10mmtpa, with the addition of two cryogenic tanks.

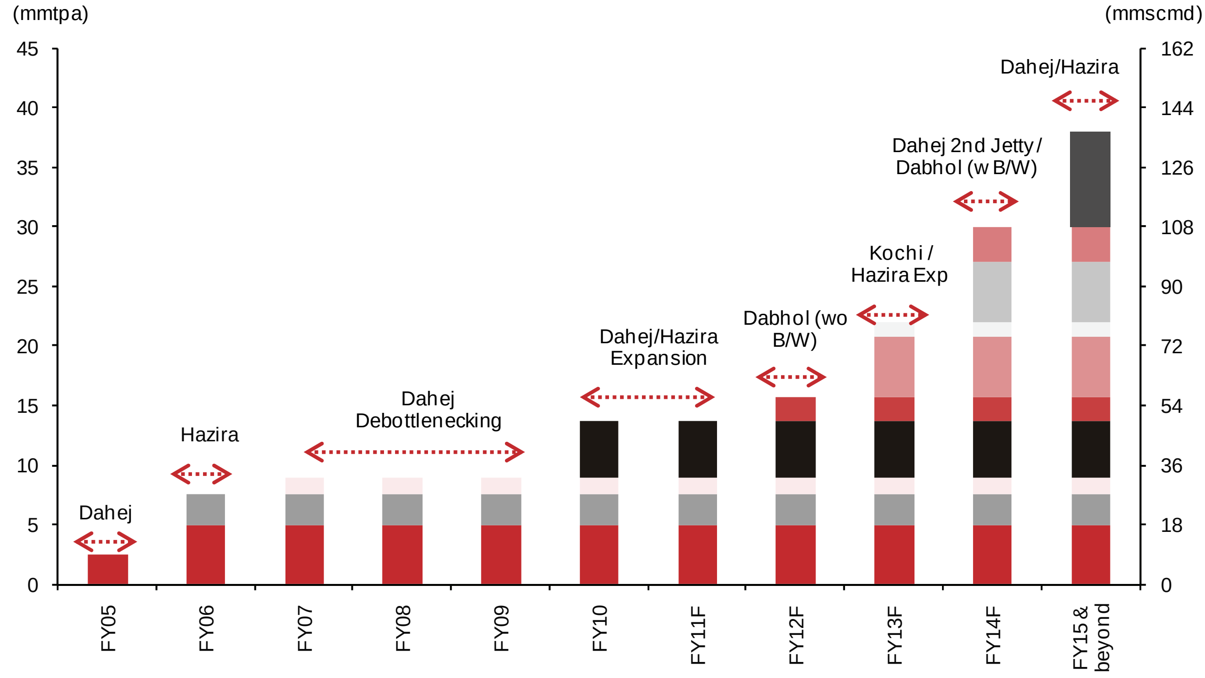
New terminals at Kochi and Dabhol to be operational in 2012

In addition to the existing terminals, construction of two other LNG terminals at Dabhol and Kochi with a 5mmtpa (18mmscmd) capacity each is undergoing.

GAIL-NTPC JV's Dabhol LNG terminal was mechanically completed in end-2008; however, the plant could not be commissioned due to long delays and disputes in completing the dredging and break-water facilities. GAIL expects the tendering process for both dredging and break-water to be completed over the next few months. The dredging is likely to be completed by September-October 2011, and with that the plant is likely to commission by end-2011, according to GAIL. Without a break-water completion (likely by mid-2013), GAIL expects the terminal to operate at a capacity of 2mmtpa and it targets to bring LNG cargoes to this terminal from the start of 2012. Post the break water completion, the capacity of this terminal would increase to 5mmpta, according to GAIL.

At Petronet LNG's Kochi terminal, work is on schedule for the construction of a LNG jetty, storage and re-gas infrastructure. The capacity to import 2.5mmtpa LNG is likely to be commissioned by September 2012, and the full capacity of 5mmtpa is expected by PLNG to be commissioned by March 2013.

Fig. 23: India LNG re-gasification capacity ramp-up



Source: Company data, Infraline, Nomura Research

Several other terminals at drawing board stage

In addition to the existing and currently under-construction LNG terminals, several other LNG terminals have been proposed in recent years. However, most of these have long remained at the drawing board stage, due to earlier expectations of sharp domestic production growth, much higher LNG pricing, and downstream pipeline constraints.

But we are seeing a revival of several proposed terminals, given delays for the KG-D6 block, limited visibility on a ramp-up in domestic gas supplies in the near to medium term, expectations of relatively benign global LNG prices (and reduced gap with domestic gas after price increases), and continued strength in gas demand. Preliminary work has already started at proposed terminals at Ennore (5mmtpa), Mundra (5mmtpa) and Pipavav (4.5mmtpa).

Ennore Terminal (IOC/TIDCO): In August 2010, Indian Oil (IOC) signed an MoU with Tamil Nadu Industrial Development Corporation (TIDCO) to jointly set up an LNG re-gasification terminal and a gas-based power plant for an investment of Rs80bn. The JV plans to set up initially a 2.5mmtpa LNG terminal at capex of Rs30bn. In addition, it intends to set up a 1000MW LNG-based power plant at capex of Rs50bn. On current plans, the LNG terminal is expected to be completed by FY16, and there is provision for capacity to be further expanded to 5mmtpa at a later date.

Mundra Terminal (MPSEZ Ltd): This 5mmtpa LNG terminal (later scalable to 7.5 mmtpa) was earlier to be promoted by GSPC with Adani group. The project saw considerable progress in 2008, including site finalisation, a detailed feasibility report and even the front-end engineering award to Tractable, Belgium. However, the project stalled in 2009, seemingly due to delays in finalisation of the equity structure.

Still, local media (Hindu Business Line, “Adani may start work on Mundra LNG terminal by Jan”, 21 October, 2010) report that Adani group is fast moving to set up this terminal, and has established a wholly owned subsidiary, Mundra LNG Limited, to set up the project. The company received nearly 50 Expressions of Interest for the project construction. Adani group is likely to use a small portion of capacity for its own requirements, and the rest of the infrastructure will be available to users on a take-or-pay basis. It is also likely that GSPC may take equity in the project, in our view.

Pipavav Terminal (Swan Energy): This 4.5mmtpa Floating Storage and Re-gasification unit will be set up by Swan Energy Limited (100% stake), at the APM terminal operated Pipavav Port in Gujarat. Earlier this year (24 January, 2011), Port Pipavav signed an MoU with Swan Energy setting the total investment for this terminal at Rs35bn. Per a presentation by Swan Energy, the in-house feasibility report and a detailed location analysis have been carried out through BMT Consultants, based on which the technical specifications of the FSRU have been frozen, and commissioning is expected in 2012.

Jamnagar Terminal (GVK): Recently (January 2011), GVK Power and Infrastructure signed an agreement with the Gujarat government to set up a new terminal at Okhamadhi in Jamnagar district. As per the MoU, GVK will invest Rs70bn to develop the LNG terminal along with a private coal terminal and a Maritime city.

Terminals on east coast: In recent months both GAIL and Petronet LNG have stated they are working on plans to set up LNG terminals on the east coast of India, with a view to meeting the current deficit and developing gas markets in some of those markets. GAIL has said that the proposed location could be near Haldia, and it is also evaluating the option of having a floating re-gasification unit. Petronet LNG has commissioned a study and short-listed four possible sites for the planned terminal.

Fig. 24: LNG re-gas capacity build-up

LNG terminal	Location	Capacity (mtpa)	(mmscmd)	Promoter	Comments
Existing		13.7	49		
Dahej	Gujarat	10.0	35.8	Petronet LNG	Capacity to increase to: - 13mmtpa with second jetty (Mid-2013 - 15mmtpa by end FY14 - 18mmtpa by FY15-16 7.5 / 2 mmtpa LT/ ST contracts in place
Hazira	Gujarat	3.7	13.2	Shell – 74%, Total – 26%	Capacity can further expand to: - 5mmtpa : Infrastructure already laid, minimal investment needed - 10mmtpa: With addition of oil two tanks and related infrastructure
Under-construction		**10.0**	**36.0**		
Dabhol	Maharashtra	5.0	18.0	RGPPL (GAIL-NTPC JV)	Terminal mechanically ready; Capacity of - 2mmtpa by end2011 post dredging - 5mmtpa post break-water in 2014
Kochi	Kerala	5.0	18.0	Petronet LNG	Under- construction - 2.5mmtpa in 2H2012 and 5mmtpain1Q2013. 1.5mmtpa LT contract with Gorgon, Australia
Proposed terminals		**32.0**	**115.0**		
Ennore	Chennai	5.0	18.0	IOCL	Board approvals in place. Plan of initial capacity of 2.5mmtpa by FY16. Expandable to 5mmtpa.
Mundra LNG	Gujarat	5.0	18.0	Adani Group / GSPC	Capacity expandable to 7.5mmtpa. Tendering for construction expected to start in next few months.
Pipavav LNG	Gujarat	4.5	16.0	Swan Energy	A floating storage and re-gas terminal is planned for completion by 2012.
Jamnagar terminal	Gujarat	5.0	18.0	GVK	MOU signed with state government. Planned investment of INR70bn.
East coast terminal	East Coast	5.0	18.0	Petronet LNG/ GAIL	Feasibility study is ongoing - report is expected by May. Possible location could be anywhere between Kakinada and Haldia.
Mangalore	Mangalore	5.0	18.0	National Oil Company	
Haldia LNG	West Bengal	2.5	9.0	SRM Exploration	

Pipeline: easing bottlenecks; set to grow

Pipeline networks span more than 11,000km currently

India has long-distance natural gas pipeline networks spanning more than 11,000km, including 2,500km of pipeline commissioned over the past two years.

Fig. 25: Key current pipeline system in India

Pipelines	Length (km)	Capacity (mmscmd)	Date	Areas covered
GAIL				
HVJ Network				
HVJ / GREP	3,100	33	1988	Gujarat, Rajasthan, UP, MP, Delhi and Haryana
Dahej - Vijaipur (DVPL)	650	35	2004	Gujarat and MP
Vijaipur - Dadri	458	60	2010	MP, Haryana, Rajasthan, UP
Chainsa - Sultanpur - Neemrama	218	35	2011	Haryana, Delhi
Dadri - Baw ana pipeline	96	35	2010	UP, Haryana
Dahej-Dhabol Section				
Dahej - Uran (DUPL)	474	12	2007	Gujarat, Maharashtra
Dabhol - Panvel (DPPL)	327	12	2007	Maharashtra
Regional Networks				
Gujarat & Rajasthan	1,000	20	2005	Gujarat & Rajasthan
Maharashtra	140	25	-	Maharashtra
KG basin	835	16	-	AP
Cauvery Basin	256	9	-	Tamil Nadu and Pudducherry
Others	424	10	-	
	7,978			
GSPL				
Gujarat netw ork	1,692	50	2000	Dahej, Vadodara, Ahmedabad, Surat & Others
AGCL/OIL				
North East	500	8	1965	Assam
RGTIL				
East West Pipeline	1,400	80	2009	AP, Karnataka, Maharashtra and Gujarat
Total	**11,570**			

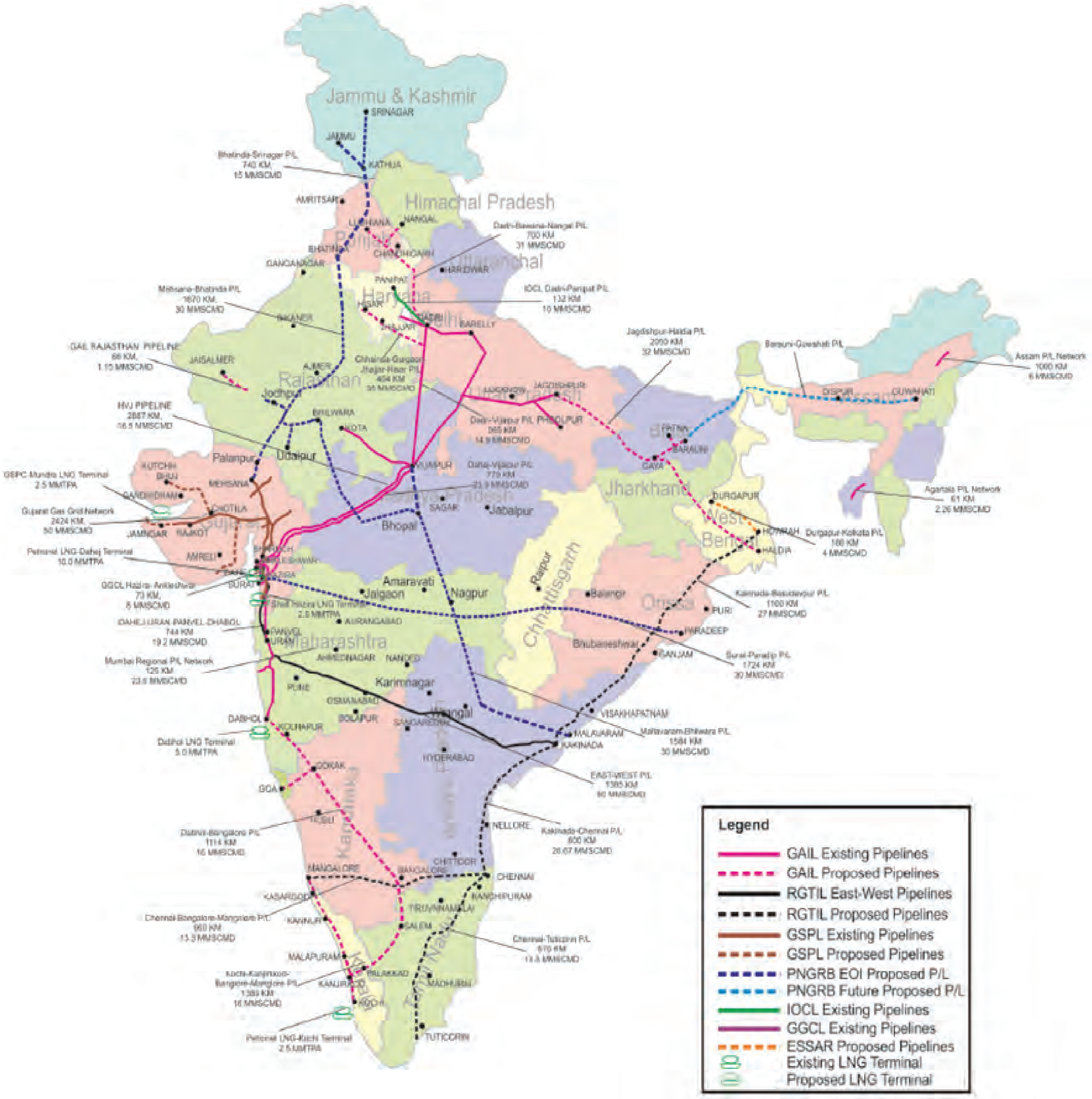
Source: Company data, Infraline, Nomura research

Fig. 26: List of pipelines completed recently

	Length (km)	Cost (INR bn)	Completion Date
GAIL			
Vijaipur - Dadri pipeline	458	28.4	Mar-10
Dadri - Bawana pipeline	96	3.4	Mar-10
Chainsa - Sultanpur - Neemrama	218	7.1	Apr-11
RGTIL			
East west Pipeline	1,400	140.0	Apr-09
GSPL			
Bhadbhut Gana Pipeline	109		Apr-09
Olpad Utran Pipeline	17		Oct-09
Morbi Anjar Pipeline	128		Jan-10
Gana Hadala Pipeline	82		Mar-10

Source: Company data, Ministry of Petroleum & Natural Gas, Nomura research

Fig. 27: Indicative map of gas pipelines: existing and proposed



Source: PNGRB

Easing pipeline bottlenecks

As highlighted earlier, over the past two years, pipeline bottlenecks on the HVJ network were the key impediment to growth in natural gas consumption. Pipeline infrastructure did not keep up with the increase in gas production capacity / LNG import facilities, and India struggled to consume 160mmscmd of gas despite large pent-up gas demand.

Pipeline bottlenecks have significantly eased following installation of compressors at Jhabua and Vijaipur on GAIL's DVPL pipeline. With installation of compression capacity, pipeline capacity has increased to 35mmscmd, from 24 mmscmd.

The capacity of the HVJ system will further increase as GAIL commissions a new 48" pipeline between Dahej and Vijaipur (DVPL -2). This pipeline, which has been delayed, is now scheduled to be completed by mid-2011. Once the DVPL-2 is complete, the capacity of the HVJ system will exceed 130mmscmd, on our estimates. With this, the pipeline constraints that have affected volume growth over the past one year will be well and truly over for the next few years, in our view.

Apart from key HVJ/GREP network, GAIL has commenced work on several key pipelines such as Kochi-Bangalore/Mangalore and Dabhol-Bangalore. These pipelines will link upcoming LNG terminals at Kochi and Dhabol, and will approach largely untapped demand centres in the key southern states of Kerala, Tamil Nadu and Karnataka, apart from Maharashtra. GAIL recently commissioned the 218km long Chainsa-Sultanpur-Neemrana pipeline with capacity of 35mmscmd. This pipeline will serve customers in the industrial areas of Neemrana, Manesar, Dharuhera and Khushkhera.

Fig. 28: Status of key pipelines in work-in-progress stage

	Length (km)	Approved Cost (INRbn)	Capacity (mmscmd)	Likely completion Date
DVPL GREP Upgradation Project				
- Dahej-Vijaipur Phase II (48")	610	51.6	24 to 78	2H 2011
- Vijaipur - Dadri Pipeline (48")	505	56.7	20 to 80	Upto Chainsa - Mar 2010 Compressors at Kailaras/Chainsa - Sept -11
Dadri - Bawana - Nangal	646	23.5	31	Phase I - up to Bawana - March 2010 Phase II - up to Nangal - FY12
Chainsa - Jhajjar - Hissar	349	12.6	35	Phase I - Upto Sultanpur - Mar 2010 Chainsa - Sultanpur - Neemrana - April 2011 Phase II - Upto Hissar - FY12
Jagdishpur - Haldia	2,050	76.0	32	FY14
Dabhol - Bagalore	1,389	50.1	16	Phase I - March 2012 Phase II - Dec 2012
Kochi - Koottanad - Mangalore - Bangalore	1,114	32.6	16	Phase I - March 2012 Phase II - March 2013
	6,663	**303.1**	**244**	

Source: GAIL, Infraline, Nomura research

Slow progress on some authorised pipelines

The government of India notified a pipeline policy (Policy for Development of Natural Gas Pipelines and City or Local Natural Gas Distribution Networks) in December 2006. Post this policy, the government has notified nine trunk-pipelines with a total length of nearly 8,500km.

However, the progress on some of the pipelines authorised in 2007 remains slow, in our view. We believe that meaningful progress on these pipelines will remain contingent upon pipeline developers seeing visibility of gas availability for particular pipelines.

Fig. 29: Pipelines authorised in 2007, where progress seems to be slow

	Length (km)	Capacity (mmscmd)	Developer
Jagdishpur - Haldia	2050	32.0	GAIL
Kakinada-Basudebpur-How rah	1100	26.7	RGTIL*
Kakinada-Nellore-Chennai Pipeline	557	26.7	RGTIL*
Chennai - Bangalore - Mangalore	660	13.3	RGTIL*
Chennai - Tuticorin	670	13.3	RGTIL*

Note: * RGTIL has transferred these pipelines to a SPV Relogistics Infrastructure.
Source: Company data, Ministry of Petroleum & Natural Gas, Nomura research

Bidding process for award of ~6000km of new pipelines

Post the notification of the PNGRB Act, all new trunk pipelines need to be awarded based on principles of competitive bidding. PNGRB can *suo moto* invite bids, or interested companies can file expressions of interest (EOI), and PNGRB can then initiate the bidding process.

PNGRB has so far received EOI on seven pipelines. Of these, the bidding process is nearly completed for three pipelines (Mehsana–Bhatinda, Bhatinda to Jammu and Mallavaram-Bhilwara/Vijaipur). GSPL's JV with oil marketing companies emerged as the winner in all three pipelines when bids were opened in 3QFY11. However, given that the Supreme Court order only allows PNGRB to process the applications, but not issue any final orders, the formal authorisation letters have not been issued yet.

Fig. 30: Expressions of interest process ongoing for 7 pipelines

Pipelines	Capacity (mmscmd)	Length (Km)	Bids (x)	Bidding parties	Likely winners*
Mehsana to Bhatinda	30	1,670	2	GSPL JV and Welspun JV	GSPL JV
Bhatinda to Jammu	15	447	3	GSPL JV, Welspun JV and GAIL	GSPL JV
Mallavaram to Bhilwara /Vijaipur	30	1,585	2	GSPL JV and GAIL JV (with EIL)	GSPL JV
Surat to Paradeep	30	1,600	NA	Technical bid likely by May 2011	
Durgapur to Kolkata	4	160	NA	Last date of bidding is 12 July 2011	
Ennore LNG terminal to Nellore	5	200	NA	EOI submitted by AP Gas Infra Corp	
Kakinada to Srikakulam	20	250	NA	EOI submitted by AP Gas Infra Corp	
	134	**5,912**			

Note: GSPL JV (GSPL – 52%, IOC – 26%, BPC/HPCL – 11% each), Welspun JV – consortium of Welspun Infratech, Adani Energy and ILF&S
Source: PNGRB, Infraline, Nomura research

Demand remains, supply constrained

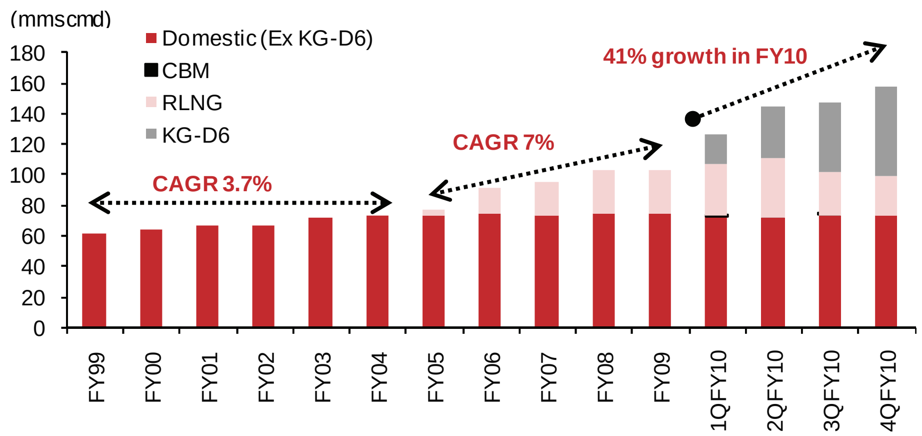
Indian gas markets have since the beginning remained supply constrained, and most of the increase in gas availability has been readily absorbed.

Until 2004, India relied heavily on domestic gas production which remained largely stagnant (1.8% CAGR during the decade to March 2009).

Since 2004, with the start-up of Petronet LNG's Dahej terminal and subsequently Shell/Total's Hazira terminals, the country also started to import LNG – initially through long-term contracts and in recent years also through spot and short-term purchases.

From initial volumes of 2.5mmt in FY05, LNG imports surged sharply to 9.0mmt in FY10, implying a CAGR of 29%. The major push to domestic gas availability came in FY10 when RIL ramped-up KG-D6 gas production to 60mmscmd in a span of just nine months from the start of production in April 2009. Not only was India able to absorb this sharp increase in domestic gas availability in FY10 (~57% increase over FY09 exit rate), consumption growth would have been much more impressive but for pipeline bottlenecks. Despite knowing for many years that supply would increase sharply with KG-D6 coming online and LNG imports increasing, pipeline bottlenecks emerged as regulatory/policy concerns held up investments in mid-stream and downstream facilities.

Fig. 31: Substantial growth in gas availability in FY10…

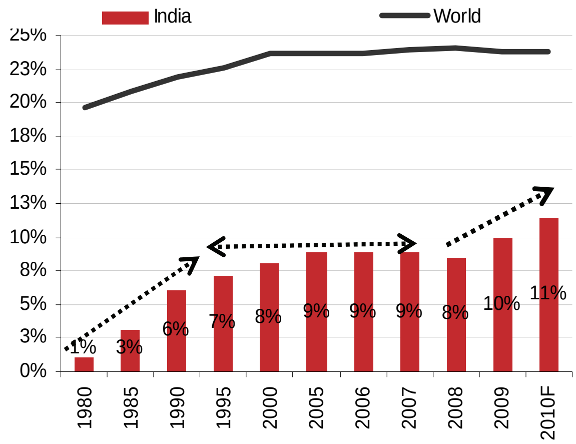


Source: PPAC, MoP&NG, Nomura estimates

While India's industrial GDP grew at an impressive 10% rate over decade to March 2010, despite the big push from the start of KG-D6 production in FY10, India's gas availability grew by modest 8.5%. Stripping out FY10 when it saw a strong one time jump in domestic gas production due to commencement of KG-D6 production, we estimate India's gas availability grew by only 5.3% in the decade to March 2009.

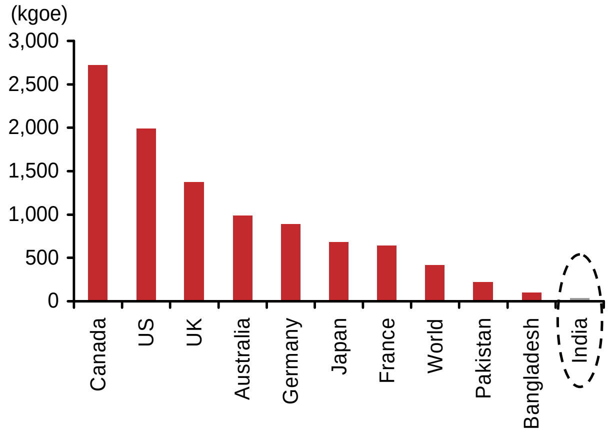
The share of gas in India's energy basket remains low at ~11%, compared with the global average of 24%. On a per-capita basis, gas consumption in India also remains far below global averages.

Fig. 32: … still the share of gas in India's energy basket remains far lower than the global average



Source: BP Statistical Review; Nomura research

Fig. 33: Per-capita gas consumption is also far below global averages as well as rates in neighbouring countries



Source: BP Statistical Review; Nomura research

Given that the share of gas in the energy basket is low and gas infrastructure is still at a nascent stage, the latent potential in India for gas remains very large, in our view.

Fig. 34: Gas demand estimates

	Actual consumption			Current supply	Additional demand		
(mmscmd)	**FY08**	**FY09**	**FY10**	**FY11F**	**Current**	**FY12**	**FY13**
Sector wise consumption / demand							
Fertilizers	28	28	37	40	0	5	22
Power	39	40	60	69	12	10	14
City Gas	9	9	9	10	1	5	5
Refinery + Petchem	8	9	19	21	24	13	12
Steel	4	4	7	8	1	2	5
Captive	0	0	0	0	10	8	8
Others	15	11	11	12	9	9	9
Total consumption / demand	**103**	**102**	**144**	**160**	**58**	**52**	**75**
Gas demand					218	270	345
Gas availability (domestic gas + RLNG)	103	102	144	160	160	168	183
Deficit					(58)	(103)	(162)

Source: Infraline, MoP&NG, Nomura estimates

Government continues to ration domestic gas

Given that gas demand has always far exceeded available domestic supply, the government has since the beginning resorted to virtual rationing of gas by fixing allocation to sectors/consumers. Most of the gas from nominated blocks (termed APM gas) is allocated by the government on this basis, and even the pricing is fixed by the government for most of this gas.

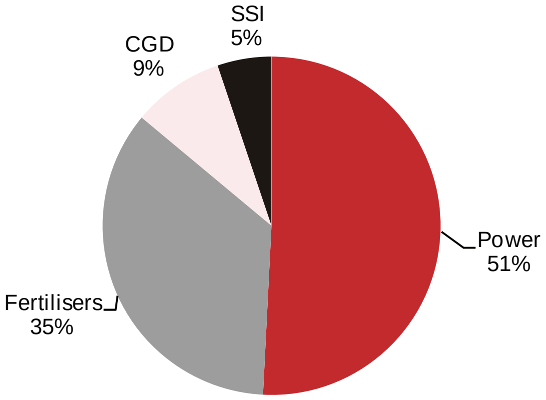
Although the new exploration and licensing policy envisaged that contractors would have marketing freedom for the gas produced, the government allocates even the gas from NELP blocks (eg, KG-D6). Most of this allocation is done largely on an ad-hoc basis, resulting in skewed development of downstream gas industries, in our view.

More than two-thirds of gas still consumed by power/fertiliser sectors

The power and fertiliser sectors have remained the highest priority for allocation of gas. As both of these sectors are perceived as being price sensitive, the effort has also been to ensure that gas is available at minimum price levels.

On our estimates, of the current supply of APM gas, nearly 85% goes to these two sectors. Similarly, of the KG-D6 gas, nearly 75% has been allocated to these two priority sectors. With the increased imports of R-LNG, even as other industries are now taking gas, these two sectors still account for nearly two-thirds of Indian gas consumption.

Fig. 35: Over 85% of APM goes to power and fertiliser…



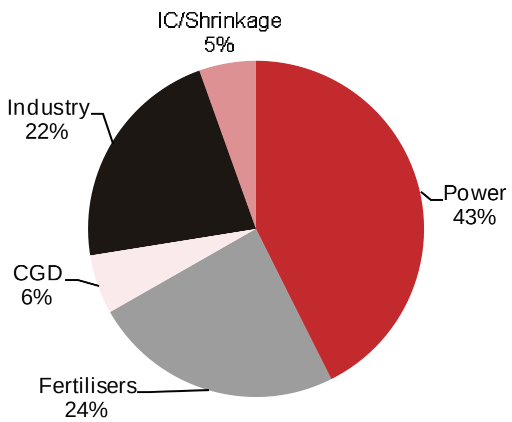
Note: Sep 2010 data, SSI – small-scale industries (volume <50,000scmd)
Source: Ministry of Petroleum & Natural Gas, Infraline, Nomura research

Fig. 36: …nearly three-quarters of KG-D6 allocated to power/fertiliser

	Firm allocation		Firm contracts		Dec-10 avg supply	
Sector	mmscmd	%	mmscmd	%	mmscmd	%
Pow er	33	52%	29.0	51%	26	49%
Fertilisers	16	25%	15.3	27%	14	27%
CGD	1	2%	0.7	1%	1	1%
Steel	4	7%	4.2	7%	3	7%
Refineries	5	8%	4.2	7%	3	6%
Petrochemical	2	3%	1.2	2%	2	3%
LPG	3	4%	2.6	5%	2	4%
RGTIL					1	
Total	**63**		**57.2**		**52**	

Source: MoP&NG, Infraline, Reliance, Nomura research

Fig. 37: Power/fertiliser account for two-thirds of natural gas availability in India (including LNG)



Note: Sep 2010 data
Source: Infraline, Nomura research

Fig. 38: Consumption pattern comparison

	US (2009)	UK (2009)	Australia (2007-08)
Residential	21%	33%	11%
Commercial	14%	3%	4%
Industrial	27%	18%	53%
Vehicle Fuel	0%	0%	0%
Electric Power	30%	35%	31%
Others	8%	10%	2%

Source: EIA, Dept of Energy and Climate Change UK, ABARE, Nomura research

Muted investment in greenfield industry

The fact that gas has been allocated largely on an ad-hoc basis, and if gas supplies were lower (than allocated), gas was further rationed, has meant that most industries have historically gotten much less than what they were allocated. With no clear visibility on how future gas allocations will be determined, there remain concerns on new greenfield investments.

There have been a few instances where several power plants came online on the premise that domestic gas would be made available, but these plants had to remain idle or operate at very low capacity for several years.

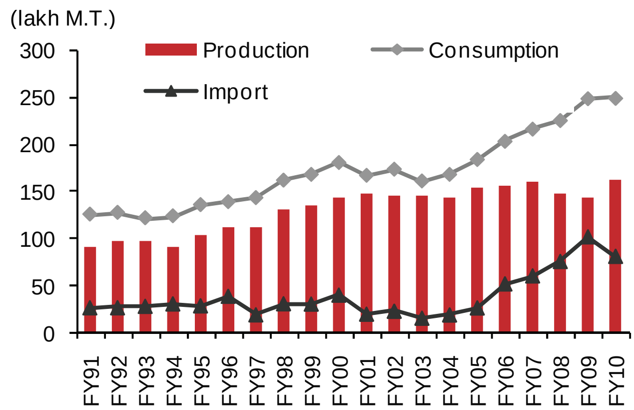
Such concerns have meant that not only was development muted for downstream industries with low allocation priority, but even the priority fertiliser and power sectors saw low growth.

Fig. 39: Total fertiliser capacities remain flat

lakh M.T.	1996-97	2001-02	2006-07	2008-09
Capacity	**127**	**173**	**177**	**177**
Nitrogen	98	121	121	121
Phosphates	29	52	57	57
Production	**112**	**146**	**161**	**143**
Nitrogen	86	108	116	109
Phosphates	26	39	45	35

Source: Ministry of Fertiliser, Nomura research

Fig. 40: Production flat, imports increased



Source: Ministry of Fertiliser, Nomura research

New LT LNG to look beyond power/fertiliser

As we highlight earlier in this report, the price appetite for the Indian consumers has increased in recent years with increases in domestic gas prices and sharp increases in liquid fuel prices. Further, Indian consumers have looked to buy spot/short-term LNG to meet the current shortfall from low domestic gas availability. Even the perceived price-sensitive sectors like fertiliser and power have taken significant quantum of higher-priced short/spot LNG.

However, in our view, the consumers in hitherto non-priority sectors and with large energy requirements (eg, steel, cement, textiles, automobiles) would need long-term volume assurances for switching over to gas. Any new LT LNG contracts would, in our view, would be ideally suited for these other industries and city gas networks, and gas consumption would likely move away from the traditional power/ fertiliser sectors.

The table below shows the likely prices of long-term delivered LNG at a 14.5% slope, assuming long-term oil prices of US$75/bbl and US$100/bbl. At the delivered price of US$15-20/mmbtu, RLNG is likely to be far more expensive than current low domestic gas prices.

Fig. 41: New term LNG may be costliest gas in India

(US$/mmbtu)	Landfall price	Delivered price
APM gas	4.2	5.0
PMT	5.7	6.5
KG-D6 gas	4.2	6.3
LNG prices - At 14.5% linkage to oil price		
- Oil at US$75/bbl	12.5	15.2
- Oil at US$100/bbl	16.3	19.6

Note: Comparison at Gujarat

Source: Nomura estimates

Base power and fertiliser may be priced out

At the delivered price of US$15-20/mmbtu, we think that this gas would be virtually out of reach for price-sensitive fertiliser plants or any base load power generation. However, we believe that the power sector, to meet peaking needs and captive generation, will continue to seek any gas that is cheaper than alternative liquid fuels.

Base power – coal will have price advantage

Coal accounts for ~84% of total thermal power generation capacity in India followed by gas (15%) and liquid fuels (1%). Also, a large chunk of planned new capacity additions in India is also coal-based. India is endowed with substantial reserves of coal and lignite and is the world's third largest producer of coal.

Coal prices in India are largely regulated and substantially lower than international spot prices. If we were to compare the economics of a power plant on domestic coal and RLNG, domestic coal stands out as being very competitive. Even if we compare the economics of a power plant based on RLNG and international coal prices, RLNG is not competitive.

While we estimate that at the current landed cost of ~US$130/tonne, average cost of power in a coal-fired plant is Rs3.26/kwh, the cost of power produced in a RLNG-based power plant is ~30-80% higher (depending upon the landed cost of RLNG).

Thus, in our view, RLNG is not likely to compete with coal for base-load generation.

Fig. 42: RLNG unlikely to compete with coal in base-load generation

		Coal-fired	Gas fired - based on RLNG		
Sourcing		Imported - Spot	US$10/mmbtu	US$12/mmbtu	US$15/mmbtu
PLANT SPECIFICATIONS					
Installed Capacity	MW	660	1,000	1,000	1,000
Auxiliary Consumption	%	6.00%	3.00%	3.00%	3.00%
PLF	%	85.00%	85.00%	85.00%	85.00%
FUEL CONSUMPTION / COST					
Landed cost	US$/ton/mmbtu	130	10	12	15
GCV of coal/LNG	kcal/kg	6,000	8,700	8,700	8,700
Heat Rate	kcal/kWh	2,150	1,900	1,900	1,900
Energy Charge	**Rs/kWh**	**2.23**	**3.5**	**4.2**	**5.25**
FIXED COSTS					
Cost of Plant	US$ mn/MW	1.1	0.8	0.8	0.8
Fixed Cost	**Rs/kWh**	**1.03**	**0.73**	**0.73**	**0.73**
Cost of Power	**Rs/kWh**	**3.26**	**4.22**	**4.92**	**5.97**
Equity IRR at current merchant tariff					
- At Rs3.5/kwh	%	12	Negative	Negative	Negative
- At Rs4.0/kwh	%	21.5	Negative	Negative	Negative
Required tariff at 15% IRR	Rs/kWh	3.66	4.42	5.13	6.17

Note: Based on calculations provided by Nomura India utilities analysts Anirudh Gangahar / Nishit Jalan. Other key assumptions: 75% capital employed taken as debt; interest rate 11%: Rs/US$ of 45; Plant life of 25 years

Source: Nomura estimates

Power sector will still need RLNG for peak/captive needs

Although we argue that base-load generation using RLNG may not compete with coal-fired generation, the power sector will likely continue to seek RLNG, in our view. Rather than the base load, such demand is likely to be to meet the deficit in domestic gas (to reach higher PLF levels), peaking power needs (where plants operate at lower PLF and receive higher premium on power tariff) and for captive generation (which typically pays high tariffs for grid power, and where assured 24X7 availability is also critical).

As we mention earlier, most industries actually get less gas than what they are allocated due to domestic gas shortage. This trend has continued even after domestic gas supply considerably improved with production from KG-D6.

Recent LNG swaps – AP IPPs may pay over US$14/mmbtu

As an example, we show below the gas situation for IPPs in Andhra Pradesh. These power plants have been allocated 13.7mmscmd of domestic gas to reach 75% PLF. However, as APM and KG-D6 quantities are not sufficient, these plants have a shortfall of nearly 4mmscmd. To run these plants at optimum levels and meet rising power deficits in the summer months, the AP government and these plants were seeking to take LNG on a swapping basis.

Fig. 43: Andhra Pradesh power plants - gas requirements, supply and shortages

		Capacity	Gas allocation (mmscmd)			Gas supplies (mmscmd)		Shortfall (mmscmd)
Power Project	Entity	(MW)	Firm	Fall back	Total	APM	KG-D6	
Jegurupadu CCGT	GVK	216	0.9	0.2	1.1	0.6	0.2	0.3
Godavari CCGT	Spectrum	208	0.9	0.2	1.1	0.7	-	0.4
Kondapalli CCGT	Lanco	355	1.5	0.3	1.8	1.1	0.3	0.4
Samalkot CCPP	Reliance Power	220	0.6	0.5	1.2	0.5	0.2	0.5
Vijjeswsram CCGT	AP Gas Power	272	1.3	0.2	1.5	0.9	-	0.7
Vemagiri CCPP	GMR	370	1.6	0.2	1.8	-	1.3	0.5
Jegurupadu CCGT	GVK	220	1.1	0.1	1.2	-	0.8	0.4
Gautami CCPP	GVK	464	2	0.2	2.1	-	1.7	0.5
Konaseema CCPP	Konaseema Gas Power	445	1.6	0.5	2.1	-	1.5	0.6
			11.5	**2.2**	**13.7**	**3.6**	**6.1**	**4.1**

Source: Infraline, Nomura research

In March 2011, these IPPS signed a swapping agreement with RIL, RGTIL and GAIL. As per the agreement, GAIL will divert its entire allocation of 2.594mmscmd of KG-D6 gas (which it gets for shrinkages in its LPG plants) to the IPPs in AP. GAIL will in turn take equivalent quantities of RLNG procured by the IPPs through GAIL (from GAIL's short-term contract with Marubeni).

Apart from the cost of RLNG, the IPPs will pay requisite charges like marketing margin, transportation charges, inter-state and intra-state taxes (whichever is applicable), on account of the proposed swapping. At the indicative price linkage of 9.85% to Brent plus a US$1/mmbtu premium, we estimate that at US$100/bbl of oil, the delivered cost of this swapped LNG would be nearly US$16/mmbtu to IPPs in AP.

Fig. 44: The likely pricing for AP swap customers

US$/mmbtu	Oil price (US$/bbl)		
	75	**100**	**120**
LNG prices (on DES basis)*	8.3	9.9	11.8
Custom duty @ 5.15%	0.4	0.5	0.6
Re-gas charges at Dahej terminal	0.7	0.7	0.7
Ex-terminal price	9.5	11.1	13.2
Marketing Margins	0.2	0.2	0.2
VAT @15%	1.5	1.7	2
LNG price	11.1	13	15.3
Add: Transmission tariff on GAIL's network	1.51	1.51	1.51
Add: Transmission tariff on EWPL	1.28	1.28	1.28
Delivered price of RLNG in AP	**13.9**	**15.7**	**18.1**

Note: LNG prices based on likely pricing in GAIL's 3-yr contract with Marubeni (slope of 9.85%, premium of US$0.95/mmbtu for first year)

Source: Nomura estimates

We note that at delivered RLNG pricing of US$16/mmbtu, the total cost of power would be over Rs6.0/kWh, yet there remains substantial interest in getting more LNG to fill up the deficit. We understand that after seeing the first swap involving KG-D6 gas, other customers are now also queuing up to seek RLNG on swap basis.

Recently, the media has reported that NTPC, Reliance and GAIL will soon enter into an arrangement for further supply of RLNG to AP-based power plants. The deal will involve NTPC getting RLNG for its power plants on GAIL's pipeline, while its quota of KG-D6 gas will be supplied to AP-based power plants. As per the media report, NTPC has in principle agreed to the deal and an agreement is expected soon. (*Business Standard*, 13 April, 2011, NTPC, "RIL join hands to ease Andhra power woes").

We also note that the domestic gas allocation at 75% to IPPs in AP was made as a special case (due to the proximity to KG-D6), and IPPs in other states have been allocated domestic gas of only up to 70% PLF. Similarly, the new gas-based power stations are also likely to be given allocation only in the range of 70-75% of PLF. Thus, we believe that apart from meeting the shortfall in domestic gas, these power plants will also continue to seek imported RLNG to reach higher operating levels of up to 85-90%.

Fertiliser – RLNG unlikely to compete with direct imports

Fertiliser sector has been accorded the highest priority in the allocation of natural gas in India. As the existing requirements of all gas-based fertiliser plants are largely met and new fertiliser plants would likely receive preferential allocation of cheap domestic gas, the scope of RLNG in the fertiliser sector is rather limited, in our view.

India imports ~40% of its total fertiliser requirements. A question arises whether setting up greenfield fertiliser capacity based on RLNG is economically feasible. On our estimates, based on the delivered RLNG prices of US$10-15/mmbtu, the cost of producing one tonne of urea would be ~US$338-443/tonne. At current international urea prices of ~US$300/tonne, domestic greenfield capacity based on RLNG is not competitive, in our view.

However, similar to the power sector, an existing fertiliser plant which is partly using liquid fuels like naphtha and fuel oils due to shortage of domestic gas could switch to RLNG given the better economics of RLNG compared to these liquid fuels.

Fig. 45: Cost of production of urea at various RLNG prices

RLNG Price US$/mmbtu	Fixed Cost US$/MT	Variable cost US$/MT	Total Cost US$/MT
10	128	210	338
12	128	252	380
15	128	315	443

Note: Calculation is based on a presentation by Fertiliser Department

Source: Nomura estimates

Most other industries would find RLNG attractive

In our view, most industries that currently use liquid fuels would find RLNG attractive, given its price advantage and environmental benefits. We estimate that even at high 15% linkage to oil, the delivered cost of gas to customers would be US$20/mmbtu at US$100/bbl oil price. Even at this price, we estimate that RLNG would be cheaper than liquid alternatives by 28-44%.

Fig. 46: At 15% linkage and US$100/bbl, RLNG is cheaper

	RLNG	Naphtha	Fuel Oil	Diesel
FOB price of Spot LNG (US$/mmbtu)	15.0			
Delivered price Spot LNG (US$/mmbtu)	20.2			
FOB cost of alternative fuel (US$/bbl)		97	83	117
Delivered cost of alternative fuel (US$/MT)		1,293	884	1114
Delivered cost of alternative fuel (US$/mmbtu)		28	21	26
RLNG Advantage %		39%	6%	28%

Note: Comparison at Gujarat

Source: Nomura estimates

Fig. 47: RLNG advantage at different oil prices

Oil price (US$/bbl)	60	70	80	90	100	120
Delivered RLNG price (US$/mmbtu)	12.9	14.7	16.5	18.4	20.2	23.8
Naphtha(US$/mmbtu)	17.6	20.2	23.2	25.8	27.9	31.9
Saving over naphtha (%)	36%	37%	40%	41%	39%	34%
FO (US$/mmbtu)	12.9	15.6	17.7	19.7	21.3	25.2
Saving over fuel oil (%)	0%	6%	7%	7%	6%	6%
Diesel(US$/mmbtu)	22	22	23.9	25.8	25.8	25.8
Saving over diesel (%)	70%	49%	44%	41%	28%	9%

Note: Assume RLNG prices at 15% linkage to crude price. Calculation is based on duties and taxes as applicable in Gujarat, and historical average crack margins for diesel/ fuel oil / naphtha

Source: Nomura estimates

Fig. 48: Potential demand driver of RLNG

Key demand drivers	Uses	Can substitute
Captive power	Fuel	Naphtha / Diesel/ FO
Peaking power	Fuel	Naphtha / Fuel Oil
Steel	Fuel/Feedstock	Coal / Liquid Fuels / commercial power
Refining	fuels	Fuel oil
Textiles & Ceramics	fuel	Liquid fuel / commercial power
Automobiles	fuel	Liquid fuel / commercial power
Other industries	fuel	Liquid fuel / electricity
City Gas Distribution		
- CNG	Fuel	Petrol/Diesel/Auto LPG
- Commercial PNG	Fuel / CHP	Commercial LPG / Power, Diesel
- Industrial PNG	Fuel / Feedstock	Naphtha/ FO/Diesel/Commercial power

Source: Nomura research

Fig. 49: FO and naphtha off-take – new gas has substituted a lot of naphtha and fuel oil, but much more potential still left

'000 MT	9MFY11	FY10	FY09
FO/LSHS			
Power	674	1,563	1,975
Fertiliser	1,198	1,636	1,664
Petrochemicals	356	489	600
Steel	184	226	141
Others	1,320	1,540	1,405
General Trade	4,156	5,635	5,890
Total	**7,888**	**11,088**	**11,675**
y-y growth	**-7%**	**-5%**	**-1%**
Equivalent gas (mmscmd)	**33**	**35**	**37**
Naphtha			
Power	392		1,912
Fertiliser	613		2,217
Petrochemicals	5,792		5,293
Steel	26		155
Others	28		26
Total	6,851	9,014	9,603
y-y growth	**-1%**	**-6%**	**-8%**
Equivalent gas (mmscmd)	**32**	**32**	**34**
Total Gas equivalent (mmscmd)	**65**	**67**	**71**

Source: Petroleum Industry Performance Review, Nomura research

RLNG would also be competitive for CGD applications

Taking gas to cities will be the cornerstone of gas growth in India, in our view. With increased gas availability in the country, city gas distribution (CGD – comprising CNG for vehicles, piped gas for residential use, and piped gas up to 50,000cm/day for industrial/commercial uses) is seen as an area with significant growth potential.

The scope for the development of CGD networks in urban areas is large, and with increased visibility on gas availability, several new players have started to prepare to participate in this opportunity. The regulator itself has talked of developing 330 additional urban areas, by putting eight to 10 cities up for auction each month over the next two to three years.

Fig. 50: The large potential of city gas distribution in India

		2009-14	2015-20	2021-25
No. of potential cities	x	298	117	69
Investments reqd.	INRbn	372	82	52
Gas demand	mmscmd	74	16	10
Potential households	x million	15	-	-
Potential vehicles	x million	4	-	-

Source: GAIL Gas, Nomura research

CGD gets priority – significant advantage over alternate fuels

In the prevailing pecking order, CGD for supply to domestic and transport sector has high priority. With significant benefits of reducing environmental pollution in India's cities, apart from cutting down large fuel under-recoveries, we believe that the city gas sector will continue to be accorded high priority for any allocation from any domestic cheaper gas.

CNG – likely to retain advantages even if RLNG is used as input

Compressed natural gas (CNG) is primarily methane compressed at high pressure of 200-250kg/sq cm to increase on-board vehicle storage capacities. In cities where it is widely available, it soon emerges as the fuel of choice mainly due to its better economy. The fact that this is a "green" fuel with significantly lower emission levels compared to liquid fuels is an added advantage.

At current price levels in Delhi, we estimate that operating costs for CNG-run vehicles are 36-62% cheaper than liquid fuels like gasoline, diesel and auto LPG.

Fig. 51: CNG is the cheapest transportation fuel

		Petrol	Diesel	Auto LPG	CNG
Retail Price	INR/litre	58.4	37.7	35	
	INR/kg	78.8	45.6	59.5	29.3
Calorific value	Kcal/kg	11,200	10,860	11,020	10,923
Equivalent price	INR/10,000kcal	70.4	42	54	26.8
Advantage	**%**	**62%**	**36%**	**50%**	

Note : Comparison at Delhi prices

Source: PPAC, Nomura estimates

Fig. 52: Favourable CNG conversion economics

Vehicle	Fuel	Avg use (kms)	Conversion cost (INR)	Payback period (months)
Private Car	Petrol	50	40,000	12
Taxi	Diesel	100	40,000	13
Auto	Diesel	100	23,000	11
Bus	Diesel	150	400,000	26

Note: Comparison at Delhi prices

Source: Nomura estimates

Even in a few cities where cheap domestic gas is not available for CNG vehicles and RLNG is used to meet the entire or a substantial part of the requirements, CNG remains quiet competitive vs alternative fuels. However, the advantage reduces when compared to diesel.

For Delhi, Indraprastha Gas gets nearly its entire requirement for CNG usage from APM (2.2mmscmd) and KG-D6 (0.15mmscmd) gas, with a basic price of US$4.2/mmbtu. In the next table, we analyse that if the basic cost were to progressively increase, and both petrol / diesel prices were to remain at current levels, CNG would remain cheaper than petrol and diesel even if gas prices were to double.

Fig. 53: CNG advantage continues even at higher gas prices

	Base				
Gas price (US$/mmbtu)	4.2	6.0	8.0	10.0	12.0
Likely CNG prices (INR/kg)	29.3	34.5	39.3	44.5	49.7
Advantage over					
- Petrol	62%	55%	49%	42%	35%
- Diesel	36%	25%	14%	3%	-8%
- Auto LPG	50%	42%	33%	25%	16%

Note: Comparison at Delhi prices, Assume no hikes in the prices of petrol, diesel and auto LPG
Source: Nomura estimates

Residential piped gas — subsidised domestic LPG makes even US$4.2 expensive

Piped natural gas (PNG), which is primarily methane supplied at low pressure directly to kitchens through PE pipes, has several advantages, such as un-interrupted supply, cleaner burning thus lower pollution, and better safety compared to conventional LPG cylinders used in most of urban India.

However, as retail LPG is also heavily subsidised (we estimate the subsidy at ~Rs400/cylinder at Delhi prices), the economic advantage to LPG is significantly lower.

Also, as prices of piped gas need to be kept close to domestic LPG prices to encourage customers to convert, this has meant that domestic PNG margins are significantly lower.

This, in our view, has been the key reason why domestic PNG has not seen similar growth as CNG in big cities such as Mumbai and Delhi. Thus, compared to over 400,000 CNG vehicles, Delhi has only about 200,000 piped gas connections.

Fig. 54: Subsidised domestic LPG results in low advantage for PNG for domestic use

Domestic LPG		
Price (14.2kg Cylinder)	INR	345
Price	INR/kg	24
Calorific value	Kcal/kg	11,007
Price	INR/10,000kcal	22
PNG		
Price	INR/scm	19
Calorific value	Kcal/scm	8,300
Price	INR/10,000kcal	23
Price advantage	**%**	**-3%**

Source: Nomura estimates

Commercial piped gas — can easily afford higher priced gas

Wider availability of gas in cities would likely lead to large-scale switching by industrial/commercial customers, who currently use liquid fuels such as fuel oil, diesel, naphtha or commercial LPG. Similar to other liquid fuels, we estimate that a higher priced RLNG would be quite affordable compared to commercial LPG which is not subsidised in India. At current prices in Delhi, we estimate that switching from commercial LPG to piped gas would lead to a price advantage of 54%. Thus even if piped commercial gas prices were raised by 35% to Rs46/scm (US$28/mmbtu), it would still remain competitive to commercial LPG at current prices.

Fig. 55: PNG is competitive vs commercial LPG…

Commercial LPG		
Price (19kg Cylinder)	INR	1,160
Price	INR/kg	61
Calorific value	Kcal/kg	11,007
Price	INR/10,000kcal	56
PNG		
Price	INR/scm	30
Calorific value	Kcal/scm	8,300
Price	INR/10,000kcal	36
Price advantage	**%**	**54%**

Source: Nomura estimates

Fig. 56: … and would likely remain so even after a 50% price hike

Commercial LPG		
Price (19kg Cylinder)	INR	1,160
Price	INR/kg	61
Calorific value	Kcal/kg	11,007
Price	INR/10,000kcal	56
PNG		
Price	INR/scm	**46**
Calorific value	Kcal/scm	8,300
Price	INR/10,000kcal	55
Price advantage	**%**	**0%**

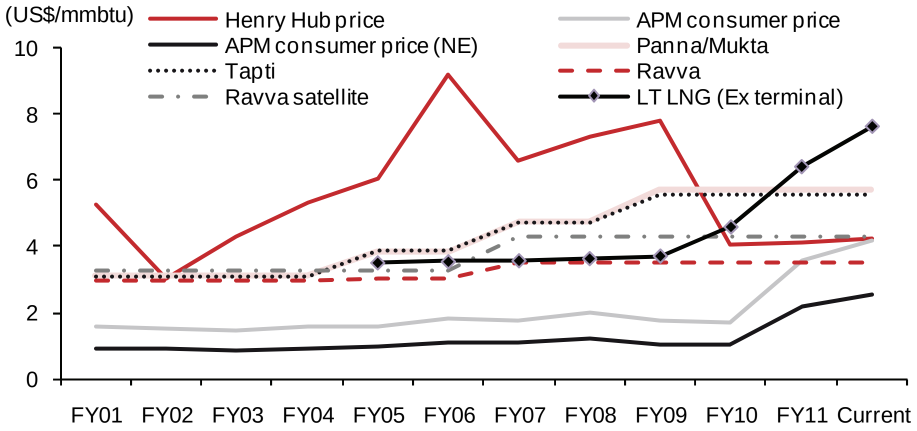
Source: Nomura estimates

Gas pricing – increased but in shackles

Historically, gas pricing in India has remained controlled and generally low compared with international benchmarks, such as Henry Hub in US and NBP in EU, and below alternative fuel prices such as fuel oil / naphtha / crude / diesel. In recent years, as new players have entered the exploration and production (E&P) business, pricing has become even more complex and heterogeneous.

Although the blocks awarded under pre-NELP/NELP allowed producers to charge market-determined prices, even here, the government has intervened in terms of price/formula determinations, and prices have typically remained lower than comparative global prices.

Fig. 57: Historically, gas prices have remained low and controlled in India



Source: MoP&NG, Infraline, Nomura research

Also, different regions/sectors demand different preferential prices, meaning that even within the APM, several different prices prevailed. Until last year, before the price revision within the APM there were 9 different prices – six for consumers and three for producers.

The prices under different types of blocks to new entrants in the form of marginal blocks, pre-NELP, NELP and CBM, have further added to the complexity. We estimate that there exist at least 25 different domestic gas prices, and the pricing for most of these has been done generally on an ad-hoc basis, with not much linkage to alternative fuels / or parity with international gas pricing.

Fig. 58: Multiple domestic prices, most fixed on an ad-hoc basis

Category	(US$/mmbtu)	Category	(US$/mmbtu)
APM price		**CB/OS-2 - Cairn**	
- Customers o/s North - East	4.2	- to GTCL	4.6
- Customers in North - East	2.5	- to GPEC	4.8
APM gas at Market prices		- to GSPC	5.5
- Western/Northern Zone	5.3	Oplad (NSA) NIKO	5.5
- Southern Zone-KG Basin	4.5	Hazira NIKO	4.6
- Southern Zone-Cauvery Basin	4.8	**HOEC**	
- North East	4.2	- North Balol	2.7
- Rajasthan, South Gujarat	5.0	- Palej	3.5
Panna & Mukta		Dhoika	1.8
- to RRVUNL	4.6	**Amguri fields**	
- to Torrent	4.8	- AGCL	2.2
- to GAIL	5.7	- GAIL	1.3
Tapti	5.6	**CBM**	
KG-D6	4.2	Raniganj	5.5
Rava Main	3.5		
Rava Satellite	4.3		

Note: Above prices exclude marketing margins
Source: MoP&NG, Infraline, Nomura research

Last year's APM price increase was sharp and surprising

Last year, with effect from 1June 2010, the government increased APM producer prices for the national oil companies (NOCs) by more than 100% from the prevailing US$1.8/mmbtu to US$4.2/mmbtu (including a 10% royalty).

Though the NOCs had demanded price increase for a long time and the prices had not changed meaningfully for nearly a decade, the 100%-plus increase in one go was clearly a surprising and positive decision, in our view. It was also surprising considering that a government appointed Tariff Commission (appointed in 2005, and final recommendation in 2007) itself had recommended for a modest hike of ~17% in 2007, and even this was not implemented for nearly 3 years, pending the issue of relevant orders.

Along with gas price increases, the government had also allowed marketing margins of Rs200/mscm (~11cent/mmbtu) on APM gas. GAIL, which markets nearly all of its ~50mmscmd of gas, was the key beneficiary of this marketing margin decision, in our view.

Yet, APM increase was ad-hoc – static and with no time frame

Although, the APM price increase was sharp and a step in the right direction, the final price of US$4.2/mmbtu was decided on quite an ad-hoc basis, in our view. There was no rationale provided for choosing US$4.2/mmbtu and perhaps this was just chosen on the basis of the prevailing price as arrived from the KG-D6 pricing formula. However, unlike KG-D6 pricing, this APM price was not linked to any fuel, and thus was too static a price for a commodity which generally has a dynamic pricing scenario.

More importantly and critically, there was no indication in the government order of when will this price will be reviewed. We note that this price hike happened after nearly a decade, and when the next hike will come is a big unknown.

To us, a formula linked to international alternative fuels (crude, fuel oil or coal) would have been more appropriate, as apart from providing dynamic pricing (in line with international prices of alternate fuels) such a pricing formula would obviate the need for such scant but sharp revisions.

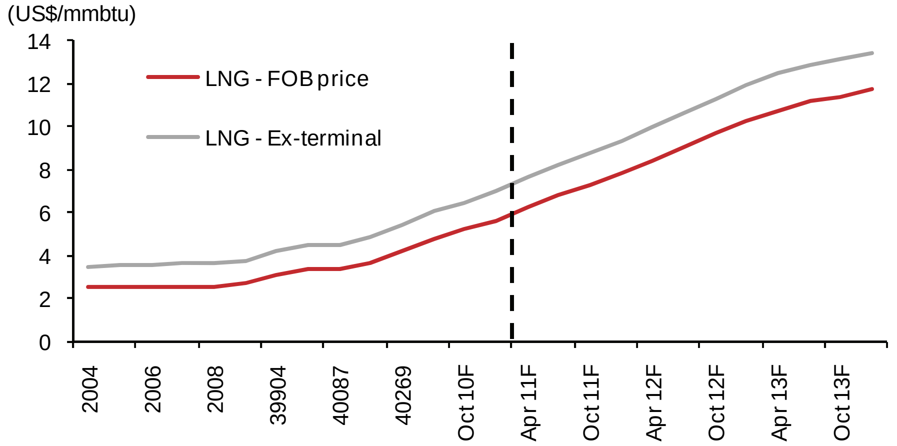
Only LNG price has been truly market linked, in our view

In our view, true market linked/formula based pricing has prevailed only for LNG pricing in India. The LT LNG from RasGas comes based on a formula linking it to crude prices, and similarly the new contract for Kochi terminal from Gorgon will also link prices to oil price. Spot and short-term LNG imports are also priced similar to prevailing international prices/formula.

The pricing formula, under the RasGas LNG contract, links LNG prices to JCC (Japanese Crude Cocktail). However, for the initial five-year period (2004-2008), to develop the then-evolving gas markets in India, prices were kept frozen at the FOB price of US$2.53/mmbtu (based on US$20/bbl of oil prices).

The formula-based pricing commenced in January 2009. The formula would progressively (every month for 60 months) link LNG price to the average of 12-month trailing JCC price, subject to a ceiling and floor provided based on the previous 60-month JCC average price.

Fig. 59: LT RLNG price for Ras Gas contract is increasing each month and by end-2013 will be fully linked to JCC (at ~13% linkage)



Source: MoPN&G, Infraline, Nomura research

With the application of the formula with progressive links to JCC, ex-terminal prices (gross calorific value [GCV] basis), which were below US$3.7/mmbtu until 2008, have increased to US$7.5/mmbtu, on our estimates. We expect the ex-terminal price to increase to nearly US$9/mmbtu by end-2011.

We estimate that at our oil price forecasts, the pricing of LT LNG could increase ex-terminal to US$11.5/mmbtu by December 2012 and US$13.5 by December 2013 — when prices will be completely linked to JCC prices.

Government actively considering pooling of prices

As prices of LT LNG for PLNG's long-term contract increase every month, several customers, especially in the price-sensitive fertilizer and power sectors, have been raising concerns and are seeking replacement of term LNG with increased allocation of domestic gas (APM or KG-D6). With not a very positive outlook on domestic volume growth in the near to medium term, the Indian government is looking to tie-up even more quantities of long-term LNG, and pricing of this LNG at a likely 14-15% slope could be even higher than PLNG's current pricing.

For some time, the Petroleum Ministry (and a few companies like GAIL) have talked of pooling of gas prices as a solution. GAIL had commissioned a study by Mercados Energy to look at the possibility of pooling of gas prices as well as gas transportation tariffs. The report was submitted in January 2010.

The key highlights/recommendations of the Mercados report (Source: Mercados Energy report as available on Petroleum Ministry website):

- It analysed the option but did not recommend cost-based pooling of all consuming sectors and suppliers (excluding spot LNG). This would be difficult and need legislative mandate, as PSC provisions regarding price discovery would be affected.
- It suggested more limited sectoral pooling covering only the price sensitive power and fertiliser segments. Also, it recommended separate pools for the two sectors to avoid cross subsidies and administration issues.
- The pools should be notified consequent to a policy issued by the government. The notification should spell out the guidelines for pool operation in sufficient detail including its tenure, and recommended a 4-5 year term for the pool;
- It believed that sectoral pool would be facilitative of an eventual migration to competitive markets.
- The report recommended the creation of a roadmap for migration to competitive wholesale markets for gas, which would typically be through bid based pools, and feature a large number of independent shippers.
- It recommended against the pooling of transportation tariffs and found this to inefficient and distortionary. This can also result in stranded assets that would prevent efficient gas market development.

To move further on gas price pooling, the Indian government recently set up a new inter-ministerial committee for pooling of gas prices. The terms of reference for this committee include formulating a policy for pooling of natural gas and devising pool operating guidelines to make the policy operational. The committee will also work out a mechanism of gas price pooling of natural gas from different domestic sources and other sources (including spot/short term LNG imports). The committee is also likely to examine the zonal transportation tariffs and suggest mechanism for uniform gas pipeline transportation tariff.

We still believe that pooling would be a retrograde step

On the face of it, pooled pricing would appear to be a right step as it would remove many different prices currently prevailing in the domestic markets. Also, it may make the relative prices of incremental LNG lower and affordable to price sensitive sectors, due to averaging.

However, we think pooling of gas prices would be taking a big step backward from the eventual plan of going towards market-determined pricing.

To us, with the government currently controlling gas allocation and domestic prices, there is already effective pooling. The priority sectors such as power and fertiliser have been given up to 75% allocation of cheaper domestic gas. Hence, even if these sectors use some imported LNG, their average costs for these sectors remains lower.

If the pooling of prices were to be applied today, we estimate that average prices (including spot/short term LNG, as government is considering) would be about US$6.1/6.8mmbtu in mmbtu. With most of current domestic gas being available at US$4.2/mmbtu to the power / fertiliser sectors, the increase would be a sharp 45-60% for these sectors in FY12/FY13F, on our estimates. We believe that the power sector itself is opposing price pooling of gas prices.

Fig. 60: Pooling of prices – pooled price scenario

	FY11		FY12		FY13	
	Supply (mmscmd)	Price (US$/mmbtu)	supply (mmscmd)	Price (US$/mmbtu)	supply (mmscmd)	Price (US$/mmbtu)
National Oil Companies	56	4.2	56	4.2	56	4.2
RIL	55	4.2	50	4.2	55	4.2
PMT/Ravva/Ravva sat	15	5.3	17	5.3	16	5.3
Others domestic	0	5.3	2	5.3	5	5.3
LT LNG	27	6.4	27	8.7	27	11.1
Spot LNG	7	12.0	16	15.0	24	15.0
Weighted avg price	160	**5.0**	167	**6.1**	182	**6.8**

Source: Nomura estimates

On the supply side, since most PSC under the NELP require market-determined price discovery mechanisms, price pooling could lead to legal complications, in our view. We also highlight here that a similar pooling mechanism was tried when short-term spot LNG was being brought to Ratnagiri Power Plant a few years ago. Several consumers/ aggregators of gas had challenged the government directive dated 3 March 2007 to pool RLNG prices. Despite the end of short-term contracts of LNG import for Ratnagiri Power Plant in 2009 and an end to that pooling, the matter remains under litigation.

Litigation and legal issues aside, our big concern against the pooling mechanism is be the apparent reluctance of government to increase prices for a variety of reasons.
This has been seen in petroleum product pricing, where prices do not change in line with market realities, leading to large problems of under-recoveries. Similarly, despite the recommendation of government-appointed tariff commissions, and general agreement by most stake-holders for the urgent need to revise APM prices, price hikes took nearly a decade. We are concerned that the pooling of gas prices now, and the later reluctance to change prices for consumers, could lead to gas under-recovery problems, in line with the current petroleum fuel under-recovery problems.

Time's ripe to re-visit domestic gas pricing, in our view

Instead of working out modalities and looking at ways to make the price of imported LNG look lower at the consumer end through price pooling, we think perhaps it is time to look to further increase and rationalise domestic prices, in line with international prices / alternate fuel prices.

Even though domestic APM prices were increased by over 100% less than a year ago, we believe it is time to again look at the domestic pricing formula. As we mentioned earlier, the revised price of US$4.2/mmbtu was decided more on an ad-hoc basis, and was just chosen on the basis of prevailing price as arrived from the KG-D6 pricing formula. Here, we also highlight that even though the APM prices were increased by more than 100% in one go, there has been no decline in gas demand from either the power or fertiliser sectors.

Also, although the pricing formula for KG-D6 is valid until March-2014 (five years since commercial commencement in April 2009), we think it is time to re-visit that formula.

We note that the KG-D6 pricing formula (links gas price to previous year's Brent average price) was decided in September 2007, and capped the price of crude in the variable portion of the formula to just US$60/bbl (against the proposed price of US$65/bbl by contractors).

Moreover, since the KG-D6 price formula was fixed in September 2007, we note that international oil prices have sharply increased, and had touched an all-time high of US$147/bbl in 2008. Also, apart from a few months post the financial crisis and subsequent demand destruction due to the global recession for most of the period, oil prices have remained significantly higher than the price cap of US$60/bbl. Thus, in our view, although the current formula applies until March 2014, the relevance of cap pricing US$60/bbl is all but lost.

Fig. 61: KG-D6 gas price formula approved by Empowered Group of Ministers (EGoM)

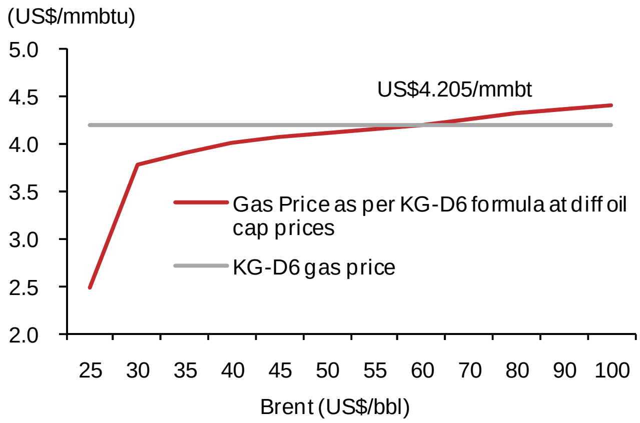
Price (US$/mmbtu) = 2.5 + (CP-25)^0.15 + C

CP is the average Brent price for the previous year, with a cap of US$60/bbl and floor of US$25/bbl

C is assigned a value of Zero (0)

Source: Company data, MoP&NG, Nomura research

Fig. 62: KG-D6 gas price at different oil price caps



Source: Company data, MoP&NG, Nomura research

Fig. 63: Time to revisit?: Except for a brief period when KG-D6 production commenced, crude has remained far higher that cap of US$60/bbl

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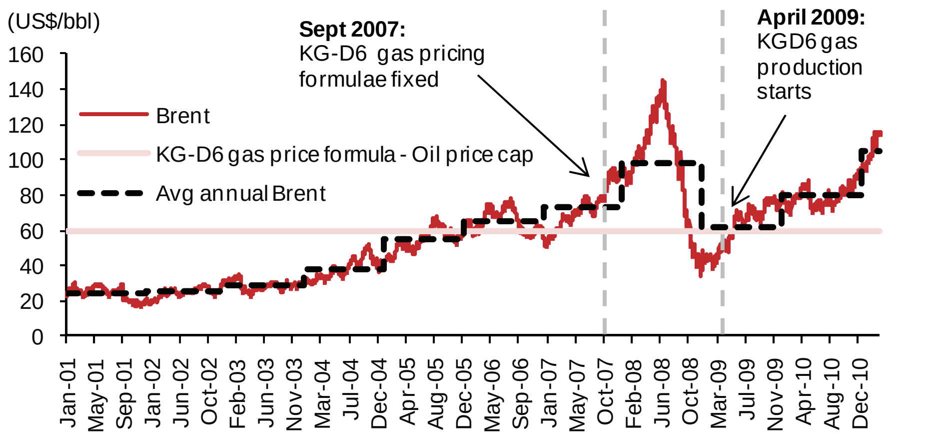


Source: Bloomberg, MoP&NG, Nomura research

Also, as we have highlighted earlier, post the opening up of upstream exploration with the launch of NELP, India's sedimentary basin and in particular, its east coast has seen significantly increased exploration efforts. These efforts have resulted in nearly over 85 discoveries in NELP blocks, of which 55 are gas discoveries. Most of the success has been in the deep waters off the east coast, and the east coast is being seen as a new gas hub. However, apart from two discoveries in the KG-D6 block, the development of most other gas discoveries has been significantly delayed. In our view, apart from concerns on regulatory/policy/taxation issues, the uncertainty and concerns on pricing have been one of key reasons for these delays.

With significantly increased capital costs due to sharply increased commodity prices, rigs rated, construction and engineering cost, most developers find that the price of US$4.2/mmbtu too low to justify new investments, and thus have been seeking higher prices. For example, in March 2010, Gujarat State Petroleum Corporation (GSPC, unlisted) in its draft red-herring prospectus mentioned that it used a price of US$5.7/mscf (net of royalty & taxes) for the field development plan (FDP) of its Deen Dayal West (DDW) field in its KG block. This price was approved by the management committee of the block. Including royalties and taxes, this price would be ~ US$6/mmbtu, significantly higher than the price of US$4.2/mmbtu. The pricing formula for this block is not yet approved by the government, we believe.

We also highlight here that India continues to highly rely on oil & gas imports to meet its energy needs. For oil & petroleum products, the import dependency is nearly 80%. Despite recent increases in domestic gas volumes, LNG imports comprise nearly 25% of current consumption. With limited visibility on domestic gas volume growth, and likely higher incremental LNG imports, the share of imported gas is likely to grow further.

In terms of energy equivalence at 1/6th (~16%) of oil prices, gas prices typically are always cheaper than oil prices. Over the past few years, short/spot LNG prices have typically ranged between 8% and 12% of oil prices, and the global LNG producers' price expectation for long-term contracts continue to remain around 14-15% of oil prices. In comparison, at current oil prices of US$100+/bbl, the prevailing domestic price for 85% of gas at US$4.2/mmbtu is just 4%.

With over 50 gas discoveries already in place and significant potential seen, we believe if Indian gas prices are increased and made to align with global gas prices / prices of alternate liquid fuels, investments to increase production could accelerate. Thus, rather than looking for near-term myopic solutions in terms of price pooling, we think the time is ripe to free up domestic gas pricing.

Regulatory/ policy chaos continues...

In our anchor report "Growth in Chaos" dated 11th May 2010, we had highlighted that the Indian gas market is in early stages of potentially remarkable growth. We also highlighted several regulatory/ policy concerns that seemed transient and teething problems in a fast changing landscape.

There have been few positive developments over the last one year, which include: 1) a more than 100% increase in APM gas prices (and companies being allowed to pass-on these hikes); 2) notification of section 16 of PNGRB Act (empowering the regulator to authorise pipelines / city gas distribution networks); 3) MoPNG's authorisation to Indraprastha Gas to operate CGD network in Ghaziabad (virtually ending long-drawn legal battle between regulator and CGD operator); 4) completion of bidding for three long-distance pipelines (Mehsana to Bhatinda, Bhatinda to Jammu and Mallavaram to Bhilwara / Vijaipur); and 5) tariff setting for some of key pipeline networks as per the new regulations for GAIL's HVJ/GREP and DUPL/DPPL networks, and for RGTIL's East West pipeline.

However, several issues persist, which continue to hinder further progress on development of gas markets. The key among these, in our view, is that despite the notification of section 16, the regulator is still not able to completely exercise its power to authorise pipelines.

We highlight below key issues, clarity/action which could further ease the current regulatory chaos.

Empowering of PNGRB with authorisation powers

Post the notification of section 16 of PNGRB Act (effective 15th July 2010) by the government, the regulator finally got the much needed powers to authorise pipeline/CGD networks. However, as the issue is still pending in Supreme Courts (PNGRB had appealed against the Jan 2010 Delhi High Court order denying PNGRB with power to issue authorisations), the progress on authorisation of pipelines / CGD networks is still stalled. Pending the final decision in this case, the Supreme Court of India, in its order in March 2010, allowed PNGRB to process all pending application, but not to issue any final orders.

The Supreme Court hearings in this case have been postponed several times, and in December 2010, the next hearing on the case was put for August 2011. However, in March 2011, the Supreme Court moved up the next hearing to 5 May 2011, on which date the issue is listed for final disposal.

The early decision on this issue, in our view, would be very positive and would accelerate the process of authorisation and issuance of new licenses for new pipelines and CGD networks. As we have mention earlier in the report, despite completion of bidding for three long-distance pipelines in 3QFY11, winners are yet to be formally announced and issued letters of authorisations. Similarly, the progress made on the third and fourth CGD licensing rounds has also been delayed. Under the third CGD licensing, the PNGRB invited bids for CGD network in eight cities in July 2010 and the process was to be completed in Dec 2010. CGD-4 also faced similar delays.

Bidding process – near zero bidding for tariff continues

Apart from the regulatory concern regarding the regulator's powers to conduct bids and award pipeline / CGD networks, the bidding process, which has commenced, is also being marred by controversies / confusion related to near zero tariff bidding. This was seen earlier in the first two rounds of CGD bids, and recently for cross-country pipelines, where winners bid apparently very low tariffs.

The bidding criteria for both CGD networks and pipelines are highly mathematical, requiring bidders to give projections for each of the next 25 years. The strategy of bidders has been seemingly (and perhaps rightly so) to take advantage of the mathematical formula, win cities / networks, and worry about tariffs / returns later. Also, since natural gas under the current regulation is not notified commodity, the regulator does not have power to control the end product pricing at the pump / burner tip. Apart from regulated network tariffs/compression charges, the operators are free to charge any marketing margin, which is beyond the PNGRB control in the current form of regulations, in our view.

The result has been that the losing bidders are protesting / appealing, and this could further delay the entire process, raising more uncertainties/concerns.

Fig. 64: Bidding criteria for CGD networks

Bidding Criteria	Weightage
Overall unit network tariff for each year	40%
Number of domestic PNG customers	30%
Inch-km of steel pipelines for each year	20%
Compression charge for each year	10%

Note: The financial bid may vary by a maximum of +/- 20% from the year-wise numbers from feasibility report
Source: PNGRB, Nomura research

Fig. 65: Bidding criteria for pipeline networks

	Bidding criterion	Weightage	Comments
A	Lowness of the PV* Zone - I tariff	40%	- Bid shall be for each year of the economic life. - Weightage of 70% if length of pipeline is <=300kms
B	Lowness of % increase in tariff from Zone 1 to 2	20%	- a single number to be bid (No max limit) - Zero weightage if pipeline is <=300kms. - 30% weightage if length between 300 to 600kms.
C	Lowness of % increase in tariff from zone 2 to 3	10%	- a single number (but it should be less than 100%)
D	Highness of the PV* of gas volumes (in mmscmd)	30%	- volumes bid shall be for each year of the economic life.

Note: * PV to be calculated using a discount rate of 12%
Source: PNGRB, Nomura research

The bidding process for CGD networks, which commenced in end-2008, has remained controversial. In the first round, GAIL's 100% subsidiary won four cities out of the six cities on very low tariff bidding. The second round, which commenced in February 2009, was sent into disarray as some bidders bid "zero" for the network tariff, which was one of key bidding criteria. Nearly two years have elapsed and the winners of the second round are not finalised yet.

Fig. 66: First CGD round – GAIL and its subsidiary Bhagyanagar Gas won 5 of 6 cities

Cities	Winners
Kakinada	Bhagyanagar Gas
Dewas	GAIL Gas
Kota	GAIL Gas
Sonipat	GAIL Gas
Meerut	GAIL Gas
Mathura	DSM Infratech

Source: PNGRB, Company, Nomura research

Fig. 67: Second CGD round – Final winners not yet decided

Cities	Bids	Bidders *
Allahabad	2	IOC & Adani JV / GAIL Gas
Chandigarh	4	IOC & Adani JV/ HPCL/ GAIL Gas/ GSPL
Ghaziabad	6	IOC & Adani JV/HPCL/ GAIL Gas/ IGL / Siti Energy/ GSPL
Jhansi	1	GAIL Gas
Rajahmundry	3	IOC & Adani JV/ Reliance Gas/ Bhagyanagar Gas
Shahdol	1	Reliance Gas
Yanam	1	Reliance Gas

* First (or only bidders) were provisional winners
Source: PNGRB, Company, Nomura research

To avoid zero bidding in future rounds, regulations now require bidders to prepare a detailed feasibility report, which should result in a IRR of not less than 6% (pre-tax) on capital employed from the cash inflows and from regulated tariffs (network charges and compression tariffs). The quoted numbers in the financial bids are required to be within 20% compared to the feasibility report. We believe this should not result in zero tariffs, but it remains possible that a few bidders may still bid for quite low tariffs.

Even though bidding for the third and fourth rounds is currently in progress, there has been significantly increased interest. In our view, concern remains on the likelihood of low tariff bidding. This perhaps is due to several large players, who were earlier keen on bidding for city gas distribution (like Reliance which had expressed interest for nearly 50 cities), not seen in the bidding process in recent rounds. For example, among the existing listed players in the CGD segment, IGL (only two bids) and Gujarat Gas (only one bid) have bid for very few areas in the third round.

Fig. 68: Third CGD round: increased interest

Geographical Area (GA)	State	Bids
Asansol-Durgapur	West Bengal	7
Bhavnagar District	Gujarat	2
Kutch(East)	Gujarat	8
Kutch (West)	Gujarat	4
Jamnagar District	Gujarat	2
Ludhiana	Punjab	16
Jalandhar	Punjab	12
Panipat **	Haryana	

** bidding deferred for revising area coverage in Panipat GA

Source: PNGRB, Nomura research

Fig. 69: Fourth CGD round: list of cities**

Geographical Area (GA)	State
Ernakulam District	Kerala
Rangareddy & Medak District	AP
Nalgonda District	AP
Khammam District	AP
Alibag/Pen	Maharashtra
Lonavala/Khopoli	Maharashtra
Guna	MP
Shahjahanpur	UP

** technical bids to open on 25 May 2011

Source: PNGRB, Nomura research

Similar to the CGD bidding, the three cross country pipelines for which bids were opened in 3QFY11, the winner seemingly took advantage of the mathematical formula by bidding overly low in Zone-1, which had the highest weighting of 40%.

For all the three long distance pipelines (Mehsana–Bhatinda, Bhatinda to Jammu and Mallavaram-Bhilwara/Vijaipur), the GSPL JV with oil marketing companies (GSPL: 52%; IOC: 26%; BPCL and HPCL: 11% each) emerged as a winner. Even as the regulator had indicated that it would not allow zero tariff bids, the GSPL JV seemingly quoted a very low tariff just above zero in Zone-1.

Our analysis (using hypothetical scenarios) suggests that despite a very low bid, the winner could still have the highest average tariff. In the following exhibit, we show three hypothetical scenarios for tariffs. We assume volume would be at similar levels. We show that despite quoting a very low Zone-1 tariff, the winner could still have the highest average tariff and thus make the highest profits.

Fig. 70: Bidding scenario analysis on hypothetical bidding assumption – winner can still make good returns, despite low Zone – 1

	Bidding Criterias	Weight	Bidders I	Bidders II	Bidders III	Comments
A	PV of Tariff in zone 1 (INR/mmbtu)	**40%**	**0.10**	4.00	5.00	- Assume that bidder I opts for very low Zone-1 tariff, and very high subsequent tariff increases
B	% increase for Zone 1 to 2	20%	5000%	20%	3%	- Bidder II goes for moderate initial tarifs and escalations;
C	% increase for Zone 2 to 3	10%	50%	10%	2%	
D	PV of gas volumes (mmscmd)	30%	30	30	30	- Bidder III goes for high zone 1 tariff and low escalations
	Criteria scores					
	PV of Tariff in zone 1 (INR/mmbtu)		100%	3%	2%	Bidder I gets very high score on Zone 1 tariffs
	% increase for Zone 1 to 2		0%	15%	100%	
	% increase for Zone 2 to 3		4%	20%	100%	
	PV of gas volumes (mmscmd)		100%	100%	100%	Assume same volume for all three
	Weighted scores					
	PV of Tariff in zone 1 (INR/mmbtu)		0.40	0.01	0.01	Very high weight to Zone 1 tariff ensures that despite getting zero weighted avg scores in tariff escalation criteria;
	% increase for Zone 1 to 2		0.00	0.03	0.20	
	% increase for Zone 2 to 3		0.00	0.02	0.10	
	PV of gas volumes (mmscmd)		0.30	0.30	0.30	
	Composite score		**0.70**	**0.36**	**0.61**	**Bidder 1 wins on highest composite score**
	Implied Zonal Tariff (INR/mmbtu)					
	Zone 1 { A }		0.10	4.00	5.00	Bidder I - has very low tariff
	Zone 2 { A * (1+B) }		5.10	4.80	5.15	Nearly same number for all
	Zone 3 { A * (1 + B + B*C) }		7.60	4.88	5.15	Bidder 1 far ahead in tariffs in zone 3 & 4
	Zone 4 { A * (1 + B + B*C + B*C*C) }		8.85	4.89	5.15	
	Average tariff		**5.41**	4.64	5.11	**Yet bidder 1 could get the highest tariffs !!**

Source: Petroleum and Natural Gas Regulatory Board (PNGRB), Nomura research

Several industry participants, including gas transmission companies, have favoured single postalised tariffs. Although the zonal structure may have its merits, in our view, the emphasis should have been on a gradual escalation when moving from one zone to another. Even in the zonal apportioned tariffs for HVJ and RGTIL pipelines, which were decided few months ago, there were sharp jumps when moving from one zone to another.

In our view, these kind of bidding process aid to uncertainty and confusion as the other players (who lost the bidding) could seek judicial remedy to stall/delay the entire process.

Inclusion of natural gas in GST regime / declared goods status

The varied tax policies and tax rates in different states are, in our view, an impediment to the development of natural gas markets in the country. Not only do tax rates vary from 4% to as high as over 20% in different states, policies on the availability of input tax credit also vary significantly. In our view, to bring an orderly taxation structure and develop a nation-wide market for natural gas, it is necessary that natural gas forms part of the new Goods and Service Tax regime, which is currently under the process of being implemented. Once included in the GST regime, distortions created due to huge differences in CST and local VAT regimes for the same category of consumers and the cascading effect of taxes would be eliminated, in our view.

Unlike coal and crude oil, natural gas is not conferred with the declared goods status (Goods of Special Importance in Inter-state Trade or Commerce) and levied different VAT rates in different states, whereas coal and crude are being declared as goods and enjoy a ceiling of 4% VAT rate. In our view, natural gas, being an emerging fuel of choice, should be considered at par with other fossil fuels like coal and crude, and should also be given declared as goods status. This will not only reduce the regional disparity in gas usage, but would help bring down the overall cost of natural gas to end-users.

Seven-year income tax holiday for natural gas

The NELP provided an income tax holiday for seven years from the start of commercial production. The intent, in our view, was to give tax benefits to hydrocarbon discoveries — either oil or gas. However, the Income Tax department has interpreted these benefits to be available only to mineral oil production, as it argues that the mineral oil definition does not include gas. However, the union budget 2009 provides the tax benefits will be extended to undertakings engaged in commercial production of gas from blocks awarded under the eighth round of NELP. Confusion and litigation continues for blocks awarded prior to the eighth round of NELP.

Confusion over definition of undertaking

A tax holiday is available for a period of seven consecutive years, starting from the year in which the undertaking begins commercial production of mineral oil. Earlier, several companies interpreted this to mean “undertaking” as a single well to prolong the holiday period. However, the Finance Act 2009, by an explanation, has broadened the “undertaking” to include all blocks (awarded under NELP rounds) licensed under a single contract. This new explanation is being challenged by several contractors and could limit the tax benefits if implemented.

Gas allocation as per the government’s gas utilisation policy impinges on marketing freedom given in PSCs, in our view

Utilisation policy takes away marketing freedom

NELP provided the contactor freedom of marketing of gas in domestic markets. However, in 2008 the government framed a gas utilisation policy which requires contractors to sell gas produced from NELP blocks to consumers engaged in industry sectors as per the priority in the policy. This takes away the marketing freedom, in our view. This restriction may also prevent contractors from selling gas to other non-priority consumers that are willing to pay higher prices as compared to the price paid by priority consumers.

Pipeline taxation benefits under section 80IA

In the FY09 Union Budget, the Indian government had proposed an investment-linked incentive scheme by introducing a new section 35AD to the Income Tax Act. This regime allows a 100% deduction of capex for long-distance pipelines that commence operation on or after April 2007. However, along with the introduction of this new section, the government has withdrawn section 80-IA benefits, which provided for ten years of tax holiday (in a block of 15 years) for new gas pipelines.

Although the withdrawal of the ten-year tax holiday was a negative, we believe that the allowance of 100% capex deduction is likely to result in a lower tax liability for companies that have existing earnings from the gas transmission business and have large capex plans, such as GAIL. There remains a lack of clarity on the definition of specified business. Under the tax proposal, the 100% capex deduction is only for specified business, and it is not yet completely clear that deductions could be made for existing earnings from old pipelines.

Annexure 1: Long term – LNG as nuclear replacement?

We would expect that post the recent earthquake/tsunami and nuclear incident at Japan's Fukushima nuclear facility, increased preference for gas over nuclear option may lead to absorption of some of over-supply in LNG markets.

As a result of the earthquake, we note that around 9,700MW of electricity generating capacity of nuclear plants has been shut. A further 3,768MW of capacity of nuclear plants were already shut down for regular maintenance.

We believe that the bulk of this 9700 MW capacity that was shut may not restart soon. The plants that are undergoing maintenance may be required to undergo additional inspections by national/local governments to ascertain the earthquake impact.

Fig. 71: Nuclear plant shutdown in Japan

Nuclear Power Plant	Units	(MW)	Comments
Fukushima No 1	1 - 3	2,028	Shut after quake
Fukushima No 2	1 - 4	4,400	Shut after quake
Onagawa	1 - 3	2,174	Shut after quake
Tokai	2	1,100	Shut after quake
Total		**9,702**	
Fukushima No 1	4 - 6	2,668	Regular maintenance
Higashidori	1	1,100	Regular maintenance
Total		**3,768**	

Source: Nomura Research

Loss of nuclear power similar to 2007

In order to estimate the impact of earthquakes on oil demand in Japan, our Asian oil team looked at oil demand scenarios in the aftermath of the Kobe earthquake of January 1995 and the Niigata-ken chuetsu-oki earthquake in July 2007. While in terms of economic damage, the earthquake of 11 March looks similar to the Kobe earthquake of 1995, the nuclear power outage of 2007 is more comparable to the current power crisis.

The Niigata-ken chuetsu-oki earthquake in July 2007 led to a shutdown of the Kashiwazaki-kariwa nuclear power plant in Japan. As a result, nuclear power production went down by 39.6TWh (-13.1% y-y) in Japan. In order to cope with power generation lost and the increase in power demand in 2007, fuel was used as a substitute to make up for the differences. Thermal (coal, LNG and oil) power production in the country increased by 9,521 MW in 2007, up 14.4% y-y. This is comparable to the current 9,702 MW of nuclear power capacity that is currently shut down due to the recent earthquake.

Nuclear power shutdown could increase near-term LNG demand

The aftermath of the tragedy, along with fears regarding possible radiation leaks, increases the likelihood that Japan will need to depend on alternative sources, such as coal, LNG and oil, for producing power lost in the affected nuclear power plants. Based on the efficiency of power plants, calculated based on historical data, our regional oil team estimates that Japan would need an extra 17.2mmtpa of coal or 14mmtpa of LNG or 248kbbl/d of oil to offset the power outage.

We note that the maximum surplus capacity in the country is available in oil-fired power plants, but owing to the cost differential as well as environmental impact, the country would try to run the coal and LNG plants at full capacity and balance the remaining outage by burning oil. With coal-fired power plants already running close to capacity, we expect the bulk of the power outage to be replaced by LNG and oil.

Fig. 72: Earthquake impact on power demand

2007		2011F	
Increase in thermal power generation	9,521 MW	Nuclear power generation lost	9,702 MW
Max individual alternate fuel requirement		**Max individual alternate fuel requirement**	
Coal	17.0 mmtpa	Coal	17.2 mmtpa
LNG	13 mmtpa	LNG	14 mmtpa
Oil	246 kbbl/d	Oil	248 kbbl/d
Actual demand increase by fuel (%age of total)		**Potential increase by fuel (based on 2007 %age)**	
Coal	16.1 TWh (18.8%) / 2.1mmtpa	Coal	2.2 mmtpa
LNG	24.4 TWh (28.5%) / 3.9mmtpa	LNG	4.0 mmtpa
Oil	45.0 TWh (52.6%) / 168 kbbl/d	Oil	171 kbbl/d
Total	**85.5 TWh (100.0%)**		

Note: 'Max individual alternate fuel requirement' refers to the individual additional requirement of each alternative source to generate the total additional power required. 'Actual demand increase by source' for 2011F is calculated at the same percentage of total as 2007.

Source: FEPC, JNES, Nomura estimates

Long term – LNG as nuclear replacement?

Following the earthquake in Japan on 11 March and the nuclear crisis thereafter, some countries are re-thinking their nuclear strategies and looking towards alternative sources to meet their electricity demand. Being more environment-friendly as well as economical, natural gas is the most sought after alternative for countries looking to build new power plants to meet their increasing power demand in the near term. With natural gas being the preferred fuel, we believe that LNG demand could rise over the coming few years.

Several countries have already announced immediate audit/review of safety aspects of their existing plants. Also, several countries are also re-visiting their strategy to build new nuclear power plants for future energy requirement.

Europe: As an immediate reaction to Japanese earthquake, as per a Reuters's report (Reuters.com, *Germany to shut down pre-1980 nuclear plants*, 15 March, 2011), Germany announced a three-month moratorium on extending the operation periods for its nuclear power plants, which accounted for 23% of the nation's power. Under the moratorium, seven plants that began operating before 1980 will be shut down, leaving 10 plants still operational. This move is a reversal of last year's decision to keep these plants running until the mid-2030s. Similarly, Switzerland also suspended its nuclear plans pending a safety review. European Union called for an emergency meeting of energy ministers to assess, among other points, the idea of running stress tests on the EU's 143 nuclear plants.

China: We believe China's rapid nuclear plant construction could be affected, as China will likely scale back its plant construction plans under a new policy that stresses safety instead of rapid development. Beijing's earlier plans had called for nuclear plants to supply up to 5% of China's power by 2020, but this could now be closer to 3% in our view.

According to our utilities team, China had about 10.8 GW of nuclear capacity at the end of 2010, which could go up to 80 GW by 2020F. This will be achieved by building 77 nuclear reactors with a total capacity of 87.6 GW. Out of the planned 77 reactors, 27 are under construction, with a total capacity of 29.9 GW, all of which are planned to be completed by 2015F. In addition, 10 more plants with a total capacity of 10.6 GW also planned, but not currently under construction, are to be completed by 2015F.

With the China State Council calling for suspension of new nuclear project approvals and safety assessment of plants under construction, we estimate an additional 13.3mmtpa of additional LNG would be required by China by 2015F if all the 10 planned plants, on which construction has not yet begun, get shelved and are replaced by gas-fired power plants.

India: The Indian government has ordered a thorough review of nuclear strategy following the Japanese earthquake. Although we do not believe that construction of nuclear power plants will grind to a halt, any scale back could have implications on alternative fuel.

India's nuclear power plant capacity is planned to rise to 20 GW by 2020F from the current 4.78 GW, according to Reuters (15 March 2011). Our utilities team expects India's nuclear capacity to be at 5.9 GW by the end of FY15F with no growth in capacity between FY12F and FY15F. If we were to assume a 20% drop in planned capacity expansion and that generation capacity will be replaced by gas-fired power plants, India would require an additional 3.8mmtpa of LNG by 2020F.

Japan: Argus (Argusmedia.com, Japanese *utilities shelve more nuclear power projects*; 18 March 2011) reported that Tokyo Electric Power (Tepco) has decided to indefinitely shelve the 1385MW No.1 reactor at Higashidori in Aomori prefecture. The construction at this plant was to commence in December 2011, with commissioning targeted in March 2017. Similarly, Argus has reported that Japanese electricity and wholesale producer J-power has temporarily suspended its 1,383 MW Ohma nuclear power plant. Earlier, Chugoki Electric Power had decided to put on hold its 2746 MW Kaminoseki nuclear power plant.

Enough LNG to compensate drop in nuclear capacity

In the longer term, clean energy such as wind and solar power could be potential replacements, but in the medium term, we believe the more viable source could be gas-fired power plants. With some countries becoming wary of nuclear power, LNG demand could receive a bigger boost over the coming years. Based on our estimates, LNG market will loosen and become oversupplied in the medium term, offering further incentive for a partial switch from nuclear to LNG.

Prior to the Japanese nuclear crisis, we had estimated that LNG supply would outstrip demand by 69.1mmtpa globally by 2015F. As such, we believe there is enough LNG capacity to compensate for a drop in planned nuclear power expansion in India and China.

Fig. 73: LNG global demand and gas supply allocated to LNG

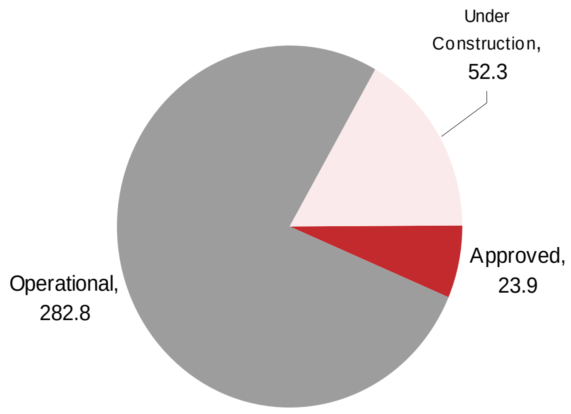
(mmtpa)	2009	2010F	2011F	2012F	2013F	2014F	2015F
Global demand							
North America	13	18	19	20	21	22	23
Europe	51	64	65	66	68	69	71
South America	2	5	5	5	5	6	6
Middle East and Africa	1	2	2	3	3	3	3
Asia-Pacific	127	134	142	145	150	156	163
Total	**193**	**222**	**233**	**239**	**247**	**256**	**266**
Natural gas allocated to LNG							
North America	1	1	0	0	0	0	0
Europe	3	5	5	5	5	5	5
South America	22	24	26	27	27	27	27
Middle East and Africa	104	133	160	174	180	184	189
Asia-Pacific	82	90	97	98	97	100	115
Total	**212**	**252**	**288**	**303**	**308**	**315**	**335**
Surplus LNG available	**19**	**29**	**55**	**65**	**61**	**59**	**69**

Source: BP Statistical Review, Bloomberg, Nomura estimates

LNG market to loosen with 30% increase in supply in five years

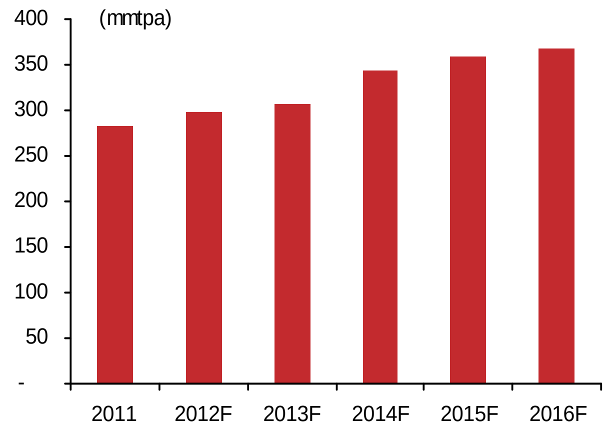
Looking at the approved and under-construction projects, we estimate the global LNG capacity will increase by about 30% to 367.6mmtpa by 2016F. As a result, we estimate that LNG exports could double from their 2009 levels to over 350mmtpa by 2016F.

Fig. 74: Current LNG capacity by status of project (mmtpa)



Source: Oil & Gas Journal, Nomura research

Fig. 75: Estimated global LNG production capacity till 2016F



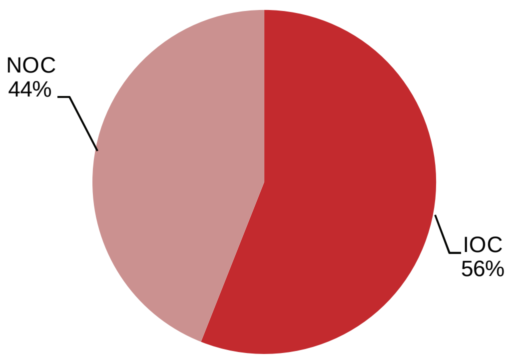
Source: Oil & Gas Journal, Nomura research

IOCs and NOCs have nearly equal production capacity

While the Algerian and Libyan governments own 100% of the LNG capacity in these countries, most countries have allowed international oil companies (IOCs) to participate in LNG plants. As a result, IOCs account for about 56% of the total projected LNG liquefaction capacity till 2016, with NOCs accounting for only 44%.

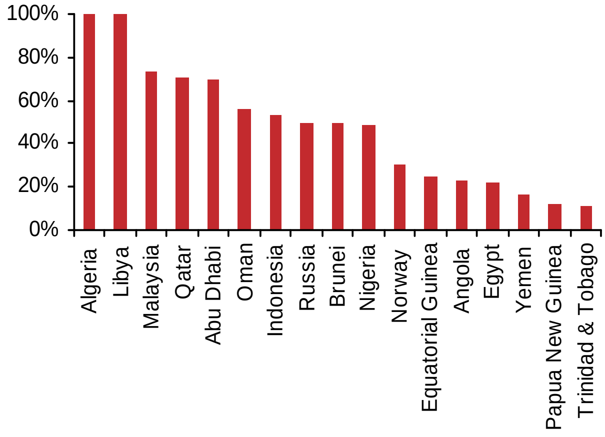
Among the national oil companies (NOCs), the largest exposure to LNG is in the Middle Eastern and North African (MENA) countries, with Qatar Petroleum and Sonatrach in Algeria having the largest exposure.

Fig. 76: LNG production capacity breakdown by type of company (till 2016F)



Source: Company data, Oil & Gas Journal, Nomura research

Fig. 77: LNG production capacity of NOCs as percentage of country's total LNG capacity (till 2016F)

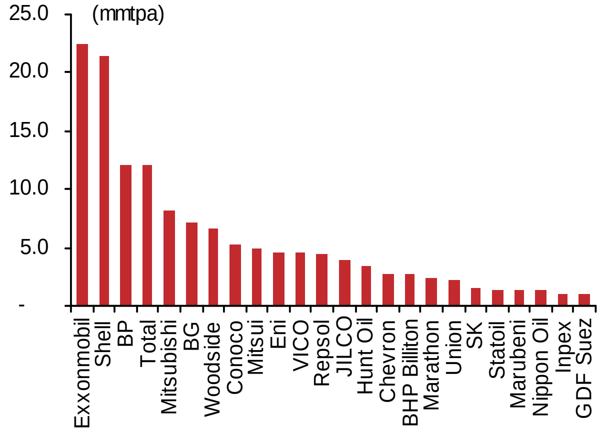


Source: Company data, Oil & Gas Journal, Nomura research

Royal Dutch Shell and ExxonMobil have largest capacity

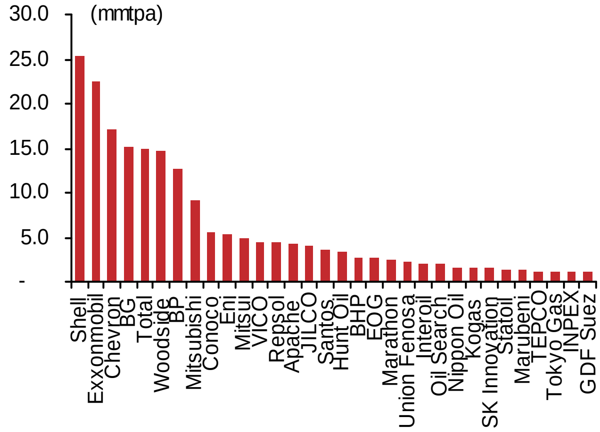
Among the major oil companies, ExxonMobil currently has the largest production capacity of 22.4mmtpa. However, by 2016, we estimate that Royal Dutch Shell could overtake ExxonMobil with the largest LNG capacity of 25.4mmtpa, as its Australian LNG projects begin operation. In terms of growth, we expect Chevron and BG to have the largest capacity increase between now and 2016F as their LNG projects in Australia come on-stream.

Fig. 78: Current LNG production capacity at IOCs



Source: Company data, Oil & Gas Journal, Nomura Research

Fig. 79: LNG production capacity at IOCs by 2016F

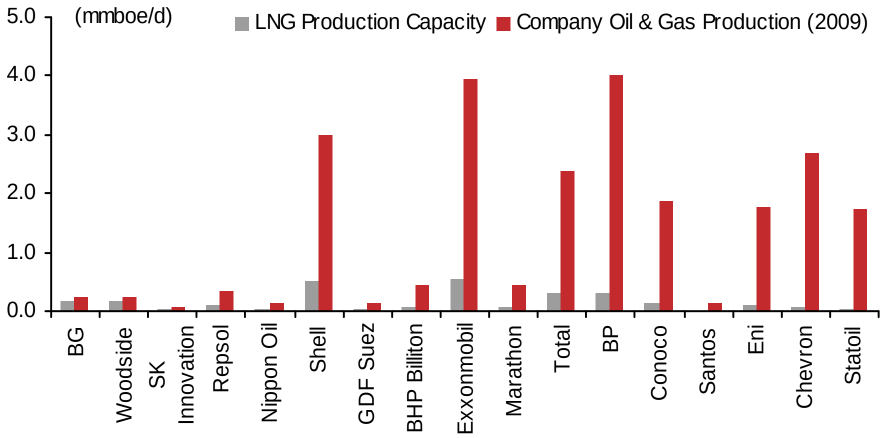


Source: Company data, Oil & Gas Journal, Nomura Research

BG and Woodside – largest exposure to LNG as % of global production

Among the large oil companies, BG and Woodside appear to have the highest exposure to LNG as a percentage of their global production in 2009. While BG's current LNG liquefaction capacity is located in Trinidad and Tobago and Egypt, all of its planned capacity expansion is coming from Australia. Woodside has its total exposure to LNG in Australia.

Fig. 80: LNG production capacity versus company's global oil & gas production (ranked by exposure)



Note: Companies are ranked by ratio of LNG production capacity and Company's global oil & gas production (2009)

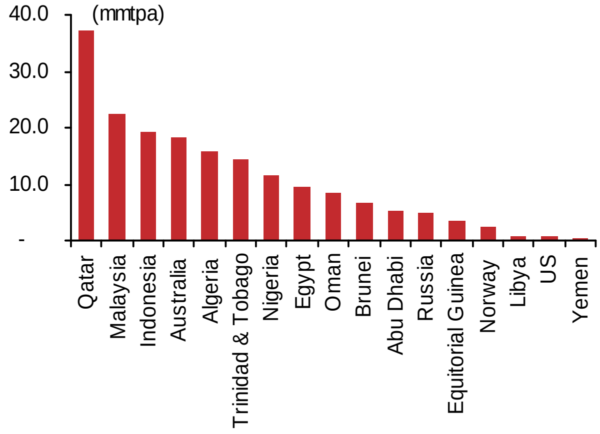
Source: Company data, Oil & Gas Journal, Nomura research

LNG export dominated by MENA and Asia-Pacific

According to the Oil and Gas Journal, a total of 181.2mn tonnes of LNG were exported globally in 2009. Qatar and Malaysia were the largest exporters, exporting 37.3mn tonnes and 22.6mn tonnes, respectively.

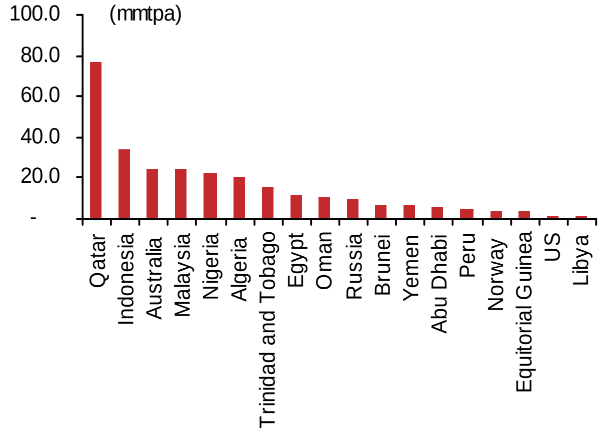
LNG export in 2009 was dominated by the MENA region (Qatar, Algeria, Egypt, Oman, UAE, Libya and Yemen) and the Asia-Pacific region (Malaysia, Indonesia, Australia and Brunei) with the two regions accounting for nearly 80% of the world export. Of the total current operational capacity, of 282.8mmtpa, the two regions account for 222.7mmtpa. Qatar has the largest operational capacity of 76.8mmtpa.

Fig. 81: LNG exports by country (2009)



Source: Company data, Oil & Gas Journal, Nomura research

Fig. 82: Current LNG capacity by country



Source: Company data, Oil & Gas Journal, Nomura research

Majority of MENA production from non-troubled countries

We believe that while the current MENA crisis could have a short-term impact on LNG supply, there is no major threat to LNG infrastructure so far. Majority of the MENA production capacity is located in Qatar, which remains isolated from the threats so far.

Among the countries which have been impacted by the ongoing protests, the maximum capacity is located in Algeria. We estimate that a total of 30% of the current MENA production capacity is retrograde instability.

Fig. 83: LNG production capacity in MENA region

Country	Company	Operational mmtpa	Total mmtpa
Yemen	Total	2.7	2.7
	Yemen Govt	1.1	1.1
	Hunt Oil	1.2	1.2
	SK Innovation	0.6	0.6
	Kogas	0.4	0.4
	Hyundai	0.4	0.4
	GASSP	0.3	0.3
	Total	**6.7**	**6.7**
Libya	Sirte Oil (NOC)	0.6	0.6
	Total	**0.6**	**0.6**
Algeria	Sonatrach (NOC)	20.7	29.9
	Total	**20.7**	**29.9**
Egypt	EGPC, EGAS (NOC)	2.7	2.7
	Union Fenosa	1.9	1.9
	Eni	1.9	1.9
	BG	2.7	2.7
	Petronas	2.7	2.7
	GDF Suez	0.2	0.2
	Total	**12.0**	**12.0**
Affected regions		**40.0**	**49.2**
Qatar	Qatar Petroleum (NOC)	53.0	53.0
	ExxonMobil	15.4	15.4
	Total	2.2	2.2
	Marubeni	0.7	0.7
	Mitsui	0.8	0.8
	ConocoPhillips	2.3	2.3
	Royal Dutch Shell	2.3	2.3
	Total	**76.8**	**76.8**
Oman	Oman Govt	6.2	6.2
	Royal Dutch Shell	2.6	2.6
	Total	0.5	0.5
	Mitsubishi	0.4	0.4
	Mitsui	0.2	0.2
	Partex	0.2	0.2
	Itochu	0.2	0.2
	Korea LNG	0.4	0.4
	Union Fenosa	0.3	0.3
	Osaka Gas	0.1	0.1
	Total	**11.0**	**11.0**
UAE	ADNOC	4.0	4.0
	BP	0.6	0.6
	Total	0.3	0.3
	Mitsui	0.9	0.9
	Total	**5.7**	**5.7**
Unaffected regions		**93.5**	**93.5**
Total MENA region		**133.5**	**142.7**

Source: Company data, Oil & Gas Journal, Nomura research

Reliance Industries RELI.BO RIL IN

OIL & GAS/CHEMICALS

NOMURA
EQUITY RESEARCH

Risk reward keeps getting better

Refining and petchem strength continues; BP deal restores faith in LT E&P potential

May 6, 2011

Rating Remains	**Buy**
Target price Increased from 1140	INR 1200
Closing price April 29, 2011	INR 984
Potential upside	+22%

Action: Marked underperformance despite several positives

RIL's underperformance remains stark (13/35% over 1Y/2Y vs Sensex). FY11 earnings were up 27% y-y, driven by strength in refining (EBIT +53% y-y), petchem (+8% y-y) and higher E&P volumes (EBIT up 24%). Although some near-term concerns remain on KG-D6, we think the E&P deal with BP allays a lot of these and restores faith in the LT E&P potential, apart from setting a valuation benchmark for the E&P segment. The stock seems to ignore these positives and remains range-bound.

Catalyst: Further strength in refining/petchem; clarity on E&P/cash

Refining strength has surpassed all expectations. Our regional team expects strength to continue near term and has raised its Singapore complex forecast to USD7.5/7.0 per barrel for 2011/2012F. Our team also believes the petchem sector is entering a "Golden Age" and expects more upside from polyester. Apart from strength in refining/petchem, clarity on E&P plans to monetise large inventory of discoveries would be positive. With nearly USD10bn cash, investor focus is also likely to remain on cash usage plans. Beyond petchem/E&P/shale gas, RIL, in our view, will keep looking for M&A in the energy chain. However, diversification in non-energy areas would likely be seen as negative in the market.

Raising earnings and target price; valuation more compelling

We raise RIL's FY12/13F refining margin by 17%/5% to USD11.1/10.7 per barrel. We raise FY12/13F petchem EBIT by 8%/13%. We also adjust E&P for the BP deal. Our FY12/13F EPS increases by 8-9% to INR78/88, lifting our target price by 5% to INR1,200. BUY reaffirmed.

31 Mar	FY10	FY11F		FY12F		FY13F	
Currency (INR)	Actual	Old	New	Old	New	Old	New
Revenue (bn)	2,037	2,564	2,658	3,191	3,267	3,237	3,304
Reported net profit (bn)	245	208	193	240	259	268	292
Normalised net profit (bn)	159	208	202	240	259	268	292
Normalised EPS	48.6	63.4	61.8	72.5	78.4	80.3	87.6
Norm. EPS growth (%)	2.2	30.3	27.0	14.4	26.9	10.7	11.8
Norm. P/E (x)	20.2	N/A	15.9	N/A	12.6	N/A	11.2
EV/EBITDA	12.1	N/A	9.2	N/A	7.9	N/A	7.4
Price/book (x)	2.3	N/A	2.0	N/A	1.8	N/A	1.6
Dividend yield (%)	0.7	N/A	0.8	N/A	0.8	N/A	0.8
ROE (%)	18.7	13.8	12.9	14.0	15.1	13.7	14.8
Net debt/equity (%)	36.0	26.0	22.4	15.1	5.8	6.1	1.3

Source: Nomura estimates

Key company data: *See page 2 for company data, and detailed price/index chart.*
Rating: *See report end for details of Nomura's rating system.*

Anchor themes

While earnings momentum will likely continue on improving fundamentals in refining and petchem, markets are likely to await newsflow and progress on the E&P front.

Nomura vs consensus

We are more positive on both refining and petchem. Our FY12/13F earnings are 7% higher and PT 6% higher than consensus.

Research analysts

India Oil & Gas/Chemicals

Anil Sharma - NFASL
anil.sharma.1@nomura.com
+91 22 4037 4338

Ravi Adukia, CFA - NFASL
ravikumar.adukia@nomura.com
+91 22 4037 4232

Key data on Reliance Industries

Income statement (INRbn)

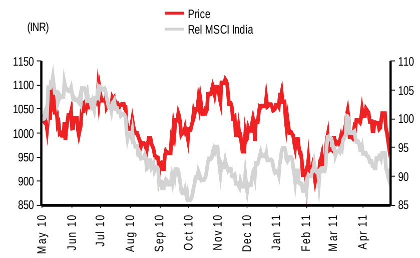
Year-end 31 Mar	FY09	FY10	FY11F	FY12F	FY13F
Revenue	**1,512**	**2,037**	**2,658**	**3,267**	**3,304**
Cost of goods sold	-1,244	-1,684	-2,220	-2,793	-2,813
Gross profit	**268**	**353**	**438**	**473**	**490**
SG&A	-90	-154	-190	-165	-162
Employee share expense	0	0	0	0	0
Operating profit	**178**	**199**	**248**	**308**	**328**
EBITDA	**234**	**309**	**390**	**422**	**437**
Depreciation	-57	-109	-141	-114	-109
Amortisation	0	0	0	0	0
EBIT	178	199	248	308	328
Net interest expense	-18	-21	-24	-25	-25
Associates & JCEs	0	0	0	0	0
Other income	19	22	25	48	70
Earnings before tax	**179**	**201**	**250**	**331**	**373**
Income tax	-29	-43	-48	-70	-79
Net profit after tax	**150**	**158**	**202**	**260**	**294**
Minority interests	0	1	0	-1	-1
Other items	0	0	0	0	0
Preferred dividends	0	0	0	0	0
Normalised NPAT	**150**	**159**	**202**	**259**	**292**
Extraordinary items	0	86	-9	0	0
Reported NPAT	**150**	**245**	**193**	**259**	**292**
Dividends	-22	-24	-31	-31	-31
Transfer to reserves	**127**	**221**	**162**	**229**	**261**
Valuation and ratio analysis					
FD normalised P/E (x)	20.7	20.2	15.9	12.6	11.2
FD normalised P/E at price target (x)	25.2	24.7	19.4	15.3	13.7
Reported P/E (x)	20.7	13.1	16.7	12.6	11.2
Dividend yield (%)	0.7	0.7	0.8	0.8	0.8
Price/cashflow (x)	19.0	15.7	8.0	10.2	8.1
Price/book (x)	2.6	2.3	2.0	1.8	1.6
EV/EBITDA (x)	16.0	12.1	9.2	7.9	7.4
EV/EBIT (x)	21.1	18.7	14.4	10.8	9.9
Gross margin (%)	17.7	17.3	16.5	14.5	14.8
EBITDA margin (%)	15.5	15.2	14.7	12.9	13.2
EBIT margin (%)	11.8	9.8	9.3	9.4	9.9
Net margin (%)	9.9	12.0	7.3	7.9	8.8
Effective tax rate (%)	16.3	21.2	19.2	21.2	21.3
Dividend payout (%)	14.8	9.9	15.9	11.9	10.7
Capex to sales (%)	18.3	11.3	6.0	7.6	8.3
Capex to depreciation (x)	4.9	2.1	1.1	2.2	2.5
ROE (%)	14.8	18.7	12.9	15.1	14.8
ROA (pretax %)	9.6	8.5	9.8	11.9	12.3
Growth (%)					
Revenue	13.3	34.7	30.5	22.9	1.1
EBITDA	0.5	31.9	26.1	8.3	3.6
EBIT	-3.7	12.2	24.5	24.0	6.6
Normalised EPS	-9.7	2.2	27.0	26.9	11.8
Normalised FDEPS	-9.7	2.2	27.0	26.9	11.8
Per share					
Reported EPS (INR)	47.56	74.93	58.95	78.38	87.63
Norm EPS (INR)	47.56	48.61	61.75	78.38	87.63
Fully diluted norm EPS (INR)	47.55	48.62	61.75	78.38	87.63
Book value per share (INR)	385.22	431.15	486.58	554.54	633.41
DPS (INR)	6.50	7.00	8.00	8.00	8.00

Source: Nomura estimates

Notes

Even after sharp 27% EPS growth in FY11, we expect further 27% growth in FY12F

Price and price relative chart (one year)



(%)	1M	3M	12M
Absolute (INR)	-3.8	7.7	-5.0
Absolute (USD)	-2.6	11.5	-4.3
Relative to index	-3.8	4.1	-10.2
Market cap (USDmn)	72,830.1		
Estimated free float (%)	56.0		
52-week range (INR)	1187/840.55		
3-mth avg daily turnover (USDmn)	120.39		
Major shareholders (%)			
Promoter Group	44.8		
FIIs	17.6		

Cashflow (INRbn)

Year-end 31 Mar	FY09	FY10	FY11F	FY12F	FY13F
EBITDA	234	309	390	422	437
Change in working capital	174	-155	135	-159	-17
Other operating cashflow	-246	51	-122	55	-17
Cashflow from operations	**163**	**205**	**402**	**318**	**404**
Capital expenditure	-277	-230	-160	-248	-275
Free cashflow	**-114**	**-25**	**242**	**70**	**129**
Reduction in investments	156	-67	-154	-35	-35
Net acquisitions	0	0	0	0	0
Reduction in other LT assets	-508	568	-64	-142	-181
Addition in other LT liabilities	17	11	6	13	18
Adjustments	382	-465	140	361	163
Cashflow after investing acts	**-68**	**23**	**170**	**267**	**94**
Cash dividends	-19	-22	-31	-31	-31
Equity issue	152	5	11	15	15
Debt issue	118	-94	100	0	0
Convertible debt issue	0	0	0	0	0
Others	2	0	0	0	0
Cashflow from financial acts	**252**	**-111**	**80**	**-16**	**-16**
Net cashflow	**184**	**-89**	**250**	**251**	**77**
Beginning cash	43	227	139	389	640
Ending cash	227	139	389	640	718
Ending net debt	535	507	357	106	28

Source: Nomura estimates

Notes

Nearly USD10bn of cash on books, net debt expected to decline sharply

Balance sheet (INRbn)

As at 31 Mar	FY09	FY10	FY11F	FY12F	FY13F
Cash & equivalents	227	139	389	640	718
Marketable securities	29	29	29	29	29
Accounts receivable	48	101	105	132	142
Inventories	201	344	317	376	402
Other current assets	110	107	115	115	115
Total current assets	**616**	**720**	**956**	**1,293**	**1,406**
LT investments	36	102	256	291	326
Fixed assets	1,070	1,602	1,557	1,227	1,212
Goodwill	0	0	0	0	0
Other intangible assets	0	0	0	0	0
Other LT assets	738	170	235	376	557
Total assets	**2,461**	**2,594**	**3,003**	**3,187**	**3,501**
Short-term debt	62	45	45	45	45
Accounts payable	316	361	340	343	358
Other current liabilities	73	65	206	129	134
Total current liabilities	**451**	**471**	**591**	**518**	**537**
Long-term debt	701	601	701	701	701
Convertible debt	0	0	0	0	0
Other LT liabilities	96	107	113	126	144
Total liabilities	**1,247**	**1,179**	**1,405**	**1,345**	**1,382**
Minority interest	1	6	6	6	8
Preferred stock	0	0	0	0	0
Common stock	14	30	30	30	30
Retained earnings	566	785	957	1,185	1,446
Proposed dividends	0	0	0	0	0
Other equity and reserves	632	595	606	620	635
Total shareholders' equity	**1,213**	**1,410**	**1,593**	**1,836**	**2,112**
Total equity & liabilities	**2,461**	**2,594**	**3,003**	**3,187**	**3,501**
Liquidity (x)					
Current ratio	1.37	1.53	1.62	2.50	2.62
Interest cover	9.8	9.7	10.3	12.3	13.1
Leverage					
Net debt/EBITDA (x)	2.28	1.64	0.92	0.25	0.06
Net debt/equity (%)	44.1	36.0	22.4	5.8	1.3
Activity (days)					
Days receivable	13.4	13.4	14.1	13.3	15.1
Days inventory	50.4	59.1	54.4	45.4	50.5
Days payable	76.5	73.3	57.6	44.7	45.5
Cash cycle	-12.8	-0.9	10.9	13.9	20.1

Source: Nomura estimates

Notes

Balance sheet remains very strong; we think a big-ticket acquisition remains quite likely

Stark stock underperformance

Reliance Industries (RIL) has significantly underperformed the broad Indian stock market over the past two years. It has underperformed the Sensex by 13% over the past one year (RIL down 5%, Sensex up 9%), and a sharp 35% over the past two years (RIL up 9%, Sensex up 68%).

We believe the underperformance in FY10 can be attributed to several negative developments during the period, which include: 1) an adverse High Court judgment in June 2009 on its gas litigation, and the subsequent litigation in the Supreme Court; 2) RIL's preliminary bid for LyondellBassel; and 3) and, more importantly, a weak refining margin environment, which resulted in refining EBIT declining by ~38% in FY10, despite its new refinery coming on line.

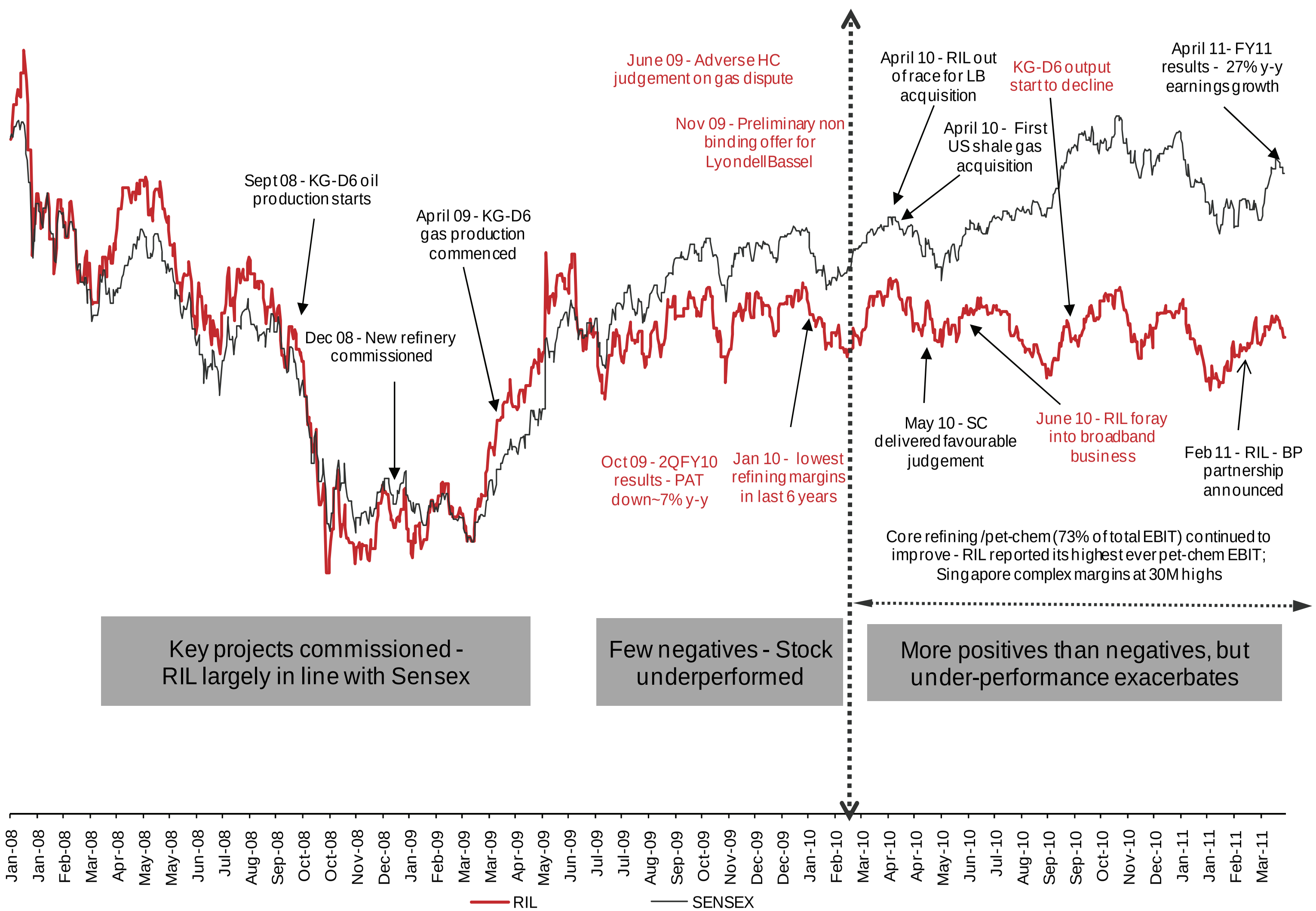
However, underperformance over the past one year has come as a surprise to us, as we have seen several key positives, such as:

- A favourable Supreme Court Judgment, ending its long litigation, and its subsequent agreement to cancel all earlier non-compete arrangements with Reliance ADAG group, replacing these with simpler non-compete agreements limited only to gas-based power generation;
- RIL opting out of acquiring LyondellBassel.
- Investment to acquire significant US shale gas acreages, including: 1) a 40% stake in a JV with Atlas Energy adding net 5.3tcf of resources; 2) a 45% stake in a JV with Pioneer adding 4.5tcf of resources; and 3) a 60% stake in its JV Carrizo.
- A sharp improvement in refining margins. Singapore complex margins improved from a low of USD1.9 in 3QFY10 to USD7.4/bbl in 4QFY11. Average Singapore complex margins in FY11 rose nearly 50% to USD5.2/bbl. Reliance's reported GRM for FY11 rose 29% to USD8.4/bbl; EBIT of the refining business increased a sharp 53% to INR92bn during the same period.
- Petrochemical margins, driven by strength in the aromatic chain and continued resilience in the ethylene chain, increased in FY11. This enabled RIL to report its highest-ever quarterly EBIT in 3Q, which it again exceeded in 4Q. Overall petchem EBIT in FY11 increased by 8% to INR93bn.
- Even as oil and gas production volumes have started to decline since the beginning of FY11, RIL's overall E&P EBIT increased a sharp 24% y-y, driven by higher average volumes compared with FY10.
- Strength in core refining/petchem margins, and higher y-y oil & gas production have enabled Reliance's earnings to grow significantly – in FY11, EBITDA grew by 26% and PAT 27% y-y.

In the past year, there have also been a few concerns, such as: 1) a sharp decline in E&P production and management's subsequent reluctance to indicate plans for future ramp-up; and 2) the announcement of plans to invest in a few areas unrelated to the energy business, such as telecom, hotels and aviation, along with recent plans to invest in financial services.

However, we believe the positives far outweigh the concerns. Even though there remain concerns in the near term on declines in the KG-D6 block, we think its recent partnership with BP is very positive. Valuations were higher than consensus estimates, and we think indicate BP's confidence in the long-term potential of RIL's E&P acreage. With the BP deal restoring faith in RIL's long-term E&P potential, near-term concerns on volume decline and ramp-up delays should also be assuaged. Similarly, even as concerns remain on investments in unrelated areas, the likely investments (apart from telecom) are minor given the size of RIL, we believe.

Fig. 84: Despite more positives than negatives, RIL's underperformance to Sensex has been stark



Source: Bloomberg, Nomura research

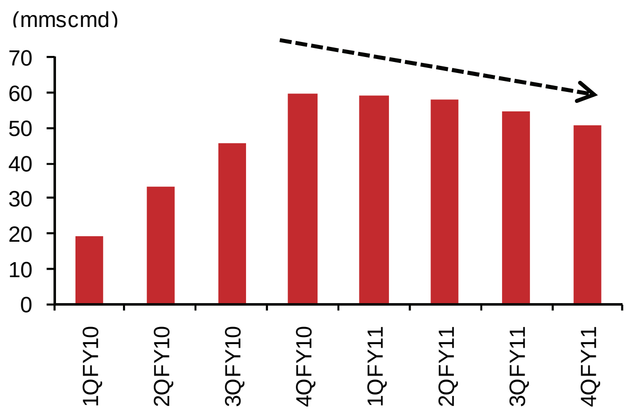
E&P: BP deal should restore faith

Too much noise around KG-D6 in the past one year

After starting production in April 2009, KG-D6 production ramped-up to ~60mmscmd by end-2009. RIL assessed the design capacity of KG-D6 facilities at end-Dec-2009 (achieved a flow-rate of 80mmscmd), and expectations were set high for further increases in 2010.

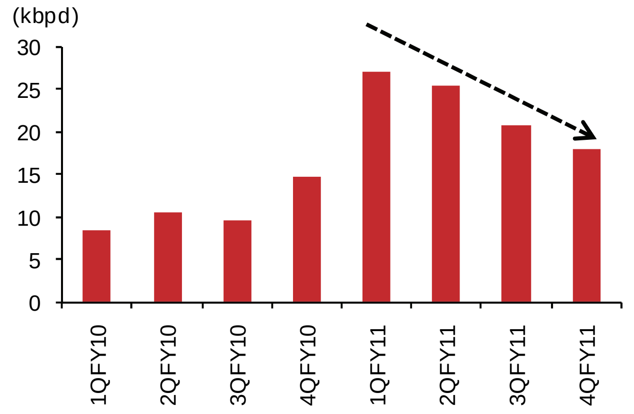
However, against Nomura and consensus expectations, KG-D6 production started to decline in 2010; the contractors undertook a study of reservoir characteristics, citing a decline in reservoir pressure. Despite an additional ~8mmscmd of associated gas production from the D-26 oil field, KG-D6 gas production has actually declined from ~60mmsmcmd (from the D1/D3 fields) in early FY11 to ~50mmscmd currently (~41-42mmscmd from the D1/D3 fields and ~8-9mmscmd from the D-26 oil field).

Fig. 85: KG-D6 gas volumes declining since 4Q



Source: Company data, Nomura research

Fig. 86: KG-D6 oil production has also disappointed



Source: Company data, Nomura research

Significant investor concerns have been expressed on the continuing decline in KG-D6 volumes, and non-clarity on likely ramp-up of volumes. Often conflicting newsflow on likely volumes quoting different sources has exacerbated these concerns, in our view.

RIL itself has been reluctant, in recent months, to provide any indication on likely future volumes and ramp-up plans for KG-D6 block (as well as on exploration efforts in this and other blocks), citing ongoing discussions with the government and the regulator. However, Niko Resources (which owns a 10% stake in the KG-D6 block), in an announcement made on February 11, 2011, mentioned that it has received the operator's forecasts for FY12. These predict volumes in FY12 will be flat at current production levels. According to Niko, these forecasts were approved by Niko and RIL, and have been forwarded to the Director General of Hydrocarbons.

BP deal takes attention away from near-term noise/concerns

Though near-term concerns abound on gas production ramp-up due to many reasons (such as technical, regulatory, policy and pricing concerns), the February 21 announcement that BP would take up a 30% stake in the KG-D6 block, along with stakes in 22 other blocks, is clear testimony, in our view, to the significant potential of RIL's E&P acreage.

We think this alliance with BP, which has significant deep water expertise, should also help resolve the current technical issues at KG-D6.

The indicative valuation of USD24-30bn, apart from early monetization and risk mitigation, provides a valuation benchmark for RIL's E&P business, in our view. More importantly, we believe BP's investment indicates that it sees significant value opportunities in RIL's E&P assets, and despite there being so much noise around the decline in KG-D6 volumes, it has shown confidence by making a significant upfront investment of USD7.2bn.

Fig. 87: Post BP taking a 30% stake – Reliance's stake would vary from 60-70% in key blocks

Basin	Type	Area (Sq. Km.)	RIL's stake - Current	RIL's stake - Post BP deal
K-G Offshore				
KG-DWN-98/1(KG-D4)	Deepwater	6,700	100%	70%
KG-DWN-98/3 (KG-D6)	Deepwater	7,645	90%	60%
KG-DWN-2001/1 (KG-D9)	Deepwater	11,605	90%	60%
KG-DWN-2003/1 (KG-D3)	Deepwater	3,288	90%	60%
KG-DWN-2004/4	Deepwater	11,904	100%	70%
KG-DWN-2004/7	Deepwater	11,856	100%	70%
Cauvery Offshore				
CY-DWN-2001/2	Deepwater	14,325	100%	70%
Cauvery-Palar Offshore				
CY-PR-DWN-2001/3	Deepwater	8,600	100%	70%
CY-PR-DWN-2001/4	Deepwater	10,590	100%	70%
Palar Offshore				
PR-DWN-2001/1	Deepwater	8,255	100%	70%
Mahanadi-NEC Offshore				
MN-DWN-98/2	Deepwater	7,195	100%	70%
NEC-OSN-97/2	Shallow Water	9,461	90%	60%
NEC-DWN-2002/1	Deepwater	19,173	90%	60%
MN-DWN-2003/1	Deepwater	17,050	85%	55%
MN-DWN-2004/1	Deepwater	9,885	100%	70%
MN-DWN-2004/2	Deepwater	11,813	100%	70%
MN-DWN-2004/3	Deepwater	11,316	100%	70%
MN-DWN-2004/4	Deepwater	8,822	100%	70%
MN-DWN-2004/5	Deepwater	10,454	100%	70%
Kerala-Konkan Offshore				
KK-DWN-2001/1	Deepwater	27,315	100%	70%
KK-DWN-2001/2	Deepwater	31,515	100%	70%
Assam-Arakan				
AS-ONN-2000/1	Onshore	6,215	90%	60%
Cambay				
CB-ONN-2003/1 (Pt.A&B)	Onshore	635	100%	70%

Source: Company data, Nomura research

Deal sets near-term benchmark for E&P valuation

For its 30% interest in RIL's 23 E&P production-sharing contracts, BP will pay an aggregate consideration of USD7.2bn. (It has already paid USD2bn as a deposit, and we think the rest is likely to be paid in tranches in FY12.) In addition, BP could pay future performance payments of up to USD1.8bn based on exploration success that results in development of commercial discoveries. BP estimates that, including these investments, its combined investments could amount to USD20bn.

After giving out a 30% stake in these 23 blocks, RIL's stake will decline to 70% in 17 blocks, 60% in five blocks and 55% in one block, as shown above. Post this deal, Niko Resources, which has a partnership with RIL in three blocks, can also increase its stake in these blocks by 30%. If Niko were to exercise this right, its stake could increase to 13% (from 10%) in KG-D6 and the NEC-25 blocks and to 19.5% in the D4 block. We believe that the valuation that Niko would pay (if it decides to increase its stake) would be similar to what BP has agreed.

Based on BP's 30% stake, we estimate the deal assigns a base valuation of USD24bn, which could increase to USD30bn (if BP pays out all performance payments totalling USD1.8bn). Post the deal, we estimate the value for RIL's balance stake in these acreages could range from USD14.4bn to USD21bn, in addition to it receiving cash of USD7.2bn, which could further increase by up to USD1.8bn.

In our valuation, we assume RIL receives only USD7.2bn, and our valuation for RIL's stake in these blocks, at USD16bn, is towards the lower range of the implied valuation.

Fig. 88: We value RIL's remaining stake in 23 blocks at USD16bn (at lower range of implied valuation)

(US$bn)	Base Valuation	Base + Future performance payment
BP's 30% stake in 23 blocks	7.2	9.0
Implied value of RIL's remaining stakes		
- At balance 60% stake	14.4	18.0
- At balance 70% stake	16.8	21.0
Incl Cash value of E&P (part of BP deal)		
- At balance 60% stake	21.6	27.0
- At balance 70% stake	24.0	30.0

Source: Nomura estimates

Deal likely to be tax-neutral, minimum impact on earnings

In our view, the upfront receipt of USD7.2bn in FY12 will be largely tax-free for RIL, as it would be able to claim deduction for past exploration and development expenditure, which is not permitted in income tax calculations under current income tax laws.

RIL follows the full-cost method of accounting.

The company also indicated that the entire sale consideration of USD7.2bn is likely to be adjusted against the carried value of capitalised costs and no gains on the farm-out of this 30% interest in 23 blocks would be recognised. This would mean that gross blocks for the E&P segment would be significantly reduced by the adjustment of this USD7.2bn, which would result in lower future charges on account of depreciation/depletion.

We think this transaction would largely be tax-neutral for RIL

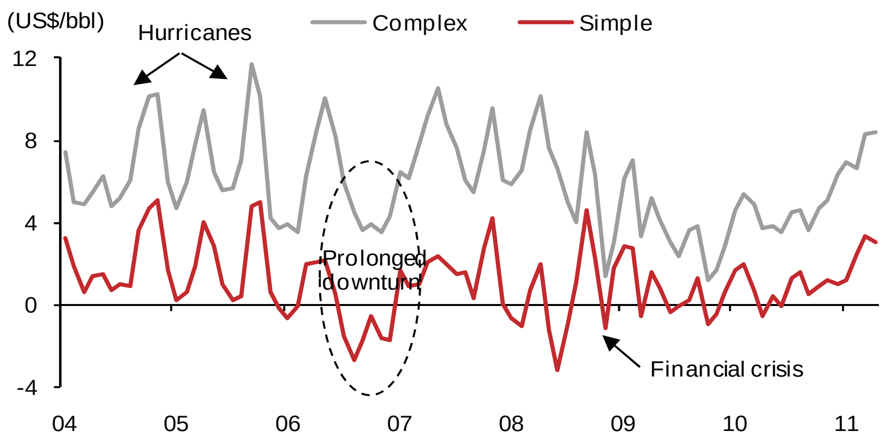
Assuming nominal interest rates on cash receipt, we estimate the stake sale will likely have a very minimal impact on earnings in the near term.

Minimum impact on earnings as lower DD&A offset lower share of KG-D6 earnings.

Refining: surpassing all expectations

Singapore complex margins have improved significantly from the beginning of this year, from an average of USD6.9/bbl in January 2011 to an average of USD8.4/bbl in April 2011. The current level of margins is the highest achieved since the financial crisis of September 2008, and marks the fifth straight quarter of improving refining margins from the trough in 4Q09.

Fig. 89: Singapore refining margin trend



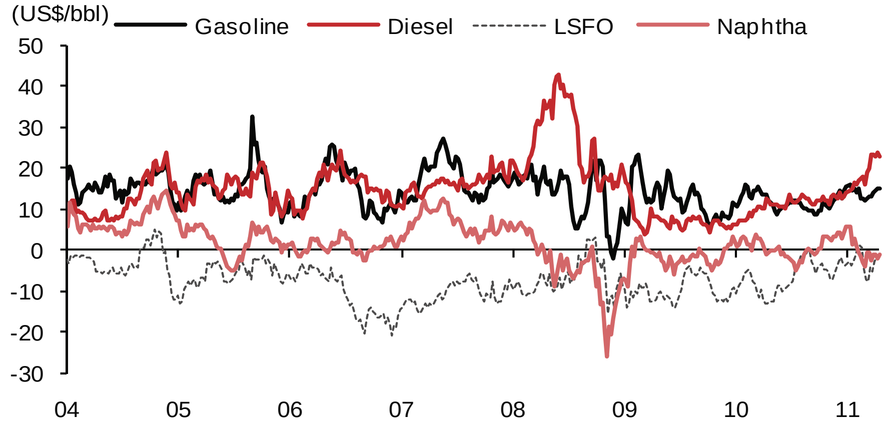
Source: Reuters

The significant improvement in refining margins has been primarily driven by higher diesel spreads, which have risen to USD23/bbl, from USD16/bbl in January and an average of USD11/bbl in 2010.

Fuel oil spreads have seen a wide divergence between high sulphur fuel oil (HSFO) and low sulphur fuel oil (LSFO) spreads. HSFO spreads have worsened to –ve USD11/bbl at present, compared with an average of –ve USD6.7/bbl in 2010. Conversely, LSFO spreads have improved to –ve USD1.7/bbl compared with an average of –ve USD6.5/bbl in 2010.

Gasoline and naphtha margins have been largely stable. Gasoline margins have been range-bound between USD13/bbl and USD15/bbl this year, similar to 1Q10. Naphtha margins have been weak since the beginning of the year, averaging -ve USD0.4/bbl YTD, as of April 11.

Fig. 90: Key product crack spreads (vs Dubai)



Source: Bloomberg

Raising refining margins forecasts

To take into account the shortage of sweet crude, continued strong oil demand growth and resulting tighter refining supply/demand balance, our regional oil and gas team has raised its forecasts for Singapore complex refining margins, as detailed in the Figure below. (R*efer to our note,* Asia Refining – *The Sweet Spot*, 6 May 2011*.*) The upgrades are most significant for 2011 and 2012, where our team has raised its forecasts by USD1.9/bbl and USD1.4/bbl, respectively.

Despite forecasting that the supply/demand balance will tighten next year, we forecast refining margins will drop in 2012 from 2011 levels, as we expect the loss of Libyan crude to be partially restored in 2012, while Japan may be able to switch towards more LNG burning by then. In any case, we believe that a refining margin of USD7/bbl is still high and only surpassed by the USD7.6/bbl margin in 2007.

We expect refining margins to decline in 2013 from 2012 levels, as we expect full restoration of Libyan crude and a loosening supply/demand balance as we expect supply to exceed demand by 229kb/d. However, we are raising our forecasts to USD6/bbl (from USD5/bbl) to take into account stronger middle distillate and naphtha spreads.

Fig. 91: Key changes to refining margin assumptions

(US$/bbl)		**Old**			**New**	
Products	**2011F**	**2012F**	**2013F**	**2011F**	**2012F**	**2013F**
Gasoline	12.0	11.5	10.5	13.5	13.0	12.0
Jet	13.5	14.0	13.5	21.0	19.0	16.0
Diesel	13.0	14.0	13.0	20.0	18.0	15.5
Fuel oil	-5.0	-6.0	-6.0	-8.0	-8.0	-7.0
Naphtha	1.5	1.0	0.8	0.2	1.0	1.5
LPG	-14.0	-16.0	-16.0	-22.0	-20.0	-20.0
Singapore complex	**5.6**	**5.6**	**5.0**	**7.5**	**7.0**	**6.0**
Singapore simple	**1.2**	**1.5**	**1.1**	**2.0**	**2.0**	**1.5**

Source: Nomura estimates

Fig. 92: Singapore refining margin trend & forecasts

US$/bbl	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011F**	**2012F**	**2013F**
Gasoline	7.6	6.1	4.5	7.7	15.7	0.0	13.5	17.0	13.7	12.5	12.0	13.5	13.0	12.0
Jet	8.3	5.6	0.0	6.0	13.5	17.4	18.4	18.5	27.7	8.2	12.0	21.0	19.0	16.0
Diesel	6.4	4.7	0.0	5.4	11.6	14.2	15.3	16.7	25.9	7.3	11.3	20.0	18.0	15.5
Fuel oil	-1.2	-1.8	-1.8	-1.0	-3.8	-6.2	-11.2	-8.3	-14.7	-7.5	-6.4	-8.0	-8.0	-7.0
Naphtha	2.2	1.3	0.0	2.5	7.0	0.0	0.8	6.2	-4.2	-1.6	0.9	0.2	1.0	1.5
LPG	1.4	-0.2	-1.8	0.0	0.0	0.0	-14.6	-14.0	-27.2	-15.3	-14.0	-22.0	-20.0	-20.0
Singapore complex	**3.2**	**2.1**	**0.2**	**3.4**	**6.7**	**2.1**	**5.5**	**7.6**	**6.2**	**3.7**	**4.6**	**7.5**	**7.0**	**6.0**
Singapore simple	**1.2**	**0.2**	**-1.3**	**1.4**	**2.1**	**0.4**	**-0.3**	**1.7**	**0.4**	**0.7**	**0.9**	**2.0**	**2.0**	**1.5**

Source: Reuters, Nomura estimates

We raise our margin assumptions for RIL

We are aligning our FY12/13F Singapore complex margins assumption with our regional forecasts, and hence are raising our refining margins assumptions for RIL by 17%/5% for FY12F/13F. We now estimate RIL's GRM at USD11.1/10.7/bbl in FY12F/13F.

Fig. 93: Change in RIL's GRM estimates

			FY12F		FY13F	
(US$/bbl)	**FY10**	**FY11**	**New**	**Old**	**New**	**Old**
Singapore Complex	3.5	5.2	7.5	4.9	6.8	4.4
Premium over Singapore GRM	3.0	3.2	3.6	4.6	3.9	5.7
RIL's GRM	6.5	8.4	11.1	9.5	10.7	10.1
Change %			17%		5%	

Source: Reuters, Company data, Nomura estimates

Petchem – from strength to strength

Petrochemical margins, particularly in the aromatics chain and downstream polyester (POY/PSF margins are significantly above their five-year average), continue to be strong.

In our opinion, the key reason has been strengthening end-demand, as we observe that production of a wide range of goods, such as appliances, automobiles and garments, has been rising strongly.

We continue to believe that the chemical sector is poised to enter a Golden Age, benefiting from rising demand and restrained capacity additions over the next two years.

We believe chemicals demand could continue to be strong in the backdrop of global economic recovery. In terms of supply, we believe we are close to passing the peak of new cracker start-ups. Meanwhile, we forecast slowing capacity growth over the next two years across major mid- and downstream products, which we attribute to the effects of the global financial crisis of 2008.

Fig. 94: Asian spot chemical prices

US$/tonne US$/bbl	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011F	2012F	2013F
Brent	24.5	25.0	28.9	38.2	54.0	65.6	73.1	97.7	62.0	80.0	110.0	110.0	110.0
Naphtha	204	236	284	388	487	582	701	858	558	727	990	1,000	1,010
Ethylene	445	413	470	900	906	1,136	1,153	1,204	845	1,114	1,350	1,420	1,490
LDPE	615	587	677	1,106	1,118	1,227	1,434	1,598	1,142	1,421	1,650	1,740	1,820
HDPE	571	521	609	943	1,022	1,211	1,304	1,440	1,079	1,173	1,360	1,480	1,570
Propylene	405	455	563	822	943	1,100	1,093	1,229	901	1,201	1,470	1,500	1,540
PP	522	567	698	958	1,055	1,223	1,317	1,451	1,039	1,288	1,530	1,590	1,660
AN	664	634	857	1,123	1,344	1,505	1,763	1,862	1,237	2,174	2,570	2,650	2,530
Butadiene	367	560	707	954	1,220	1,352	1,068	2,132	1,003	1,913	2,490	2,600	2,630
Benzene	296	350	455	833	825	885	1,038	1,025	694	927	1,190	1,220	1,250
SM	494	613	699	1,048	1,133	1,192	1,279	1,327	954	1,194	1,510	1,560	1,610
PS	605	676	793	1,186	1,172	1,248	1,435	1,421	1,051	1,337	1,610	1,670	1,720
ABS	849	799	928	1,291	1,409	1,528	1,703	1,872	1,354	1,961	2,140	2,080	2,150
Phenol	513	568	693	1,140	1,046	1,179	1,570	1,416	858	1,586	1,840	1,860	1,560
BPA	1,028	795	963	1,365	1,571	1,414	1,748	1,698	1,276	1,918	2,280	2,235	1,980
PVC	497	544	617	882	815	814	936	1,030	777	962	1,135	1,150	1,175
MEG	441	424	656	920	862	851	1,113	975	632	880	1,140	1,212	1,284
PX	432	422	620	819	906	1,159	1,141	1,198	990	1,056	1,540	1,600	1,570
PTA	450	488	577	776	812	899	883	913	833	968	1,390	1,360	1,270

Source: Thomson Reuters DataStream, Nomura estimates

Fig. 95: Asian spot chemical spreads

US$/tonne	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011F	2012F	2013F
Ethylene-Naphtha	242	177	186	512	419	554	452	346	287	387	360	420	480
LDPE-Naphtha	412	351	393	718	631	645	733	740	584	694	660	740	810
LDPE-Ethylene	170	174	207	206	212	91	281	394	297	307	300	320	330
HDPE-Naphtha	368	285	325	555	535	629	603	582	521	446	370	480	560
HDPE-Ethylene	126	108	139	43	116	75	151	236	234	59	10	60	80
Propylene-Naphtha	201	219	279	434	456	518	392	371	343	474	480	500	530
PP-Naphtha	319	331	414	570	568	641	616	593	481	561	540	590	650
PP-Propylene	117	112	135	136	112	123	224	222	138	87	60	90	120
AN-Propylene	259	179	294	301	401	405	670	633	336	973	1,100	1,150	990
Butadiene-Naphtha	164	324	423	566	733	770	367	1,274	445	1,186	1,500	1,600	1,620
Benzene-Naphtha	93	114	171	445	338	303	337	167	136	200	200	220	240
SM-Naphtha	291	377	415	660	646	610	578	469	396	467	520	560	600
PS-SM	111	63	94	138	39	56	156	94	97	143	100	110	110
ABS-Naphtha	645	563	644	903	922	946	1,002	1,014	796	1,234	1,150	1,080	1,140
Phenol-Naphtha	310	332	409	752	559	597	869	558	300	859	850	860	550
BPA-Phenol	515	227	270	225	525	235	178	282	418	332	440	375	420
PVC-Ethylene	274	338	382	432	362	246	360	428	355	405	460	440	430
MEG-Ethylene	174	176	374	380	318	169	421	252	125	212	330	360	390
PX-Naphtha	228	186	336	431	419	577	440	340	432	329	550	600	560
PTA - Naphtha	247	252	293	388	325	317	182	55	275	241	400	360	260

Source: Thomson Reuters DataStream, Nomura estimates

Price and margin trends

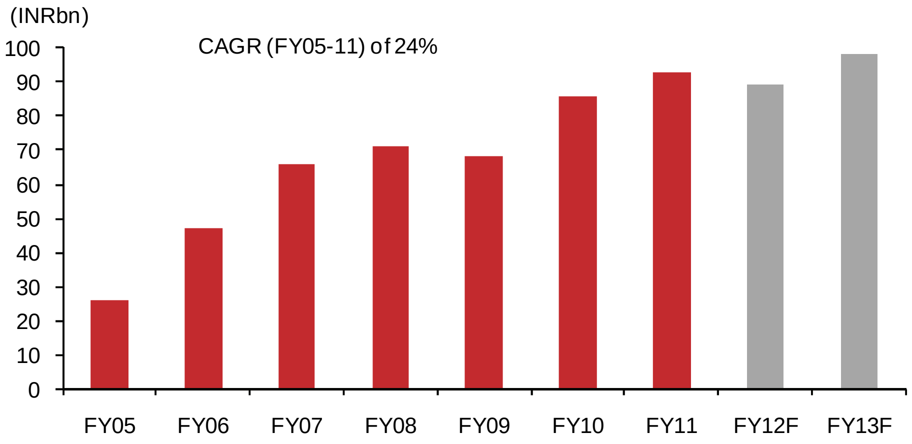
Fig. 96: Price trend of major chemicals

US$/t	1Q09	2Q09	3Q09	4Q09	1Q10	2Q10	3Q10	4Q10	1Q11	2Q11
Naphtha	417	517	611	687	723	711	666	807	918	1,037
Ethylene	645	764	969	1,013	1,273	1,143	942	1,099	1,283	1,356
HDPE	899	1,102	1,164	1,147	1,242	1,164	1,065	1,221	1,306	1,350
LDPE	936	1,112	1,224	1,292	1,459	1,370	1,288	1,568	1,699	1,683
LLDPE	943	1,112	1,230	1,232	1,370	1,258	1,141	1,335	1,416	1,405
MEG	490	550	699	788	965	822	757	976	1,206	1,121
PVC	646	729	884	858	990	964	917	976	1,040	1,211
Caustic soda	770	267	92	190	193	227	248	389	367	371
Propylene	658	846	1,044	1,059	1,226	1,205	1,133	1,239	1,430	1,562
PP	840	1,060	1,130	1,127	1,273	1,278	1,214	1,386	1,558	1,641
AN	854	1,155	1,337	1,610	2,104	2,406	2,053	2,134	2,505	2,744
2-EH	861	1,023	1,189	1,235	1,616	1,775	1,601	1,783	1,914	1,932
ECH	1,002	1,303	1,421	1,522	2,180	2,207	1,856	2,251	2,285	2,356
Butyl acrylate	1,474	1,571	1,661	1,894	2,250	2,720	2,661	3,174	3,336	3,313
Butadiene	476	701	1,408	1,458	1,868	2,107	1,739	1,939	2,359	2,893
ABS	1,111	1,378	1,441	1,493	1,804	1,975	1,927	2,138	2,318	2,317
SBR	1,535	1,704	1,901	1,985	2,520	2,339	2,439	3,068	3,670	3,959
Benzene	413	668	837	862	970	923	846	971	1,153	1,187
SM	711	956	1,075	1,064	1,282	1,163	1,067	1,265	1,421	1,407
PS	803	1,029	1,193	1,184	1,399	1,354	1,211	1,385	1,522	1,553
Phenol	558	799	957	1,118	1,337	1,547	1,694	1,751	1,770	1,960
BPA	919	1,202	1,525	1,458	1,643	1,868	1,945	2,217	2,352	2,500
PC	1,850	2,050	2,167	2,317	2,683	2,983	3,025	3,043	3,040	3,075
Epoxy resin	2,637	2,087	2,065	2,087	2,563	3,260	3,370	3,267	3,443	3,678
Acetone	721	870	850	1,033	1,276	1,111	900	1,070	1,193	1,313
MMA	1,767	1,610	1,667	1,700	1,883	2,160	2,400	2,400	2,393	2,420
Paraxylene	848	1,074	1,027	1,011	1,052	988	928	1,255	1,626	1,637
PTA	715	854	878	891	959	910	880	1,124	1,446	1,433
Polyester (PSF)	959	1,071	1,145	1,188	1,304	1,323	1,290	1,783	2,083	2,060
Orthoxylene	936	1,045	1,040	1,101	1,320	1,248	1,106	1,331	1,459	1,496
Caprolactam	1,230	1,626	2,037	1,999	2,330	2,563	2,470	2,763	3,384	3,550
Nylon	1,923	2,355	2,738	2,817	3,153	3,423	3,363	3,763	4,528	4,750
Methanol	184	209	242	274	309	261	261	355	350	338
Acetic acid	373	415	383	386	405	380	377	455	420	547
Urea	281	246	271	279	311	259	299	365	367	320

Source: Thomson Reuters DataStream

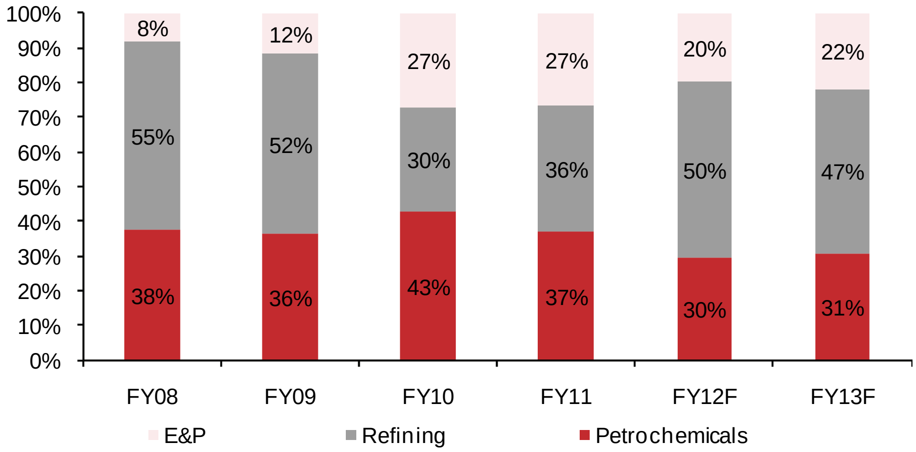
Continued resilience in petrochemicals enabled RIL to report its highest-ever quarterly EBIT in 3QFY11, which it again exceeded in 4QFY11. Overall petchem EBIT in FY11 increased by 8% to INR93bn, after strong growth in FY10 (EBIT was up 25%).

Fig. 97: Trend of RIL's petchem EBIT



Source: Company data, Nomura

Fig. 98: Refining and petchem contributes ~75% to RIL's EBIT



Source: Company data, Nomura research

Rising cash – a ticket to big M&A?

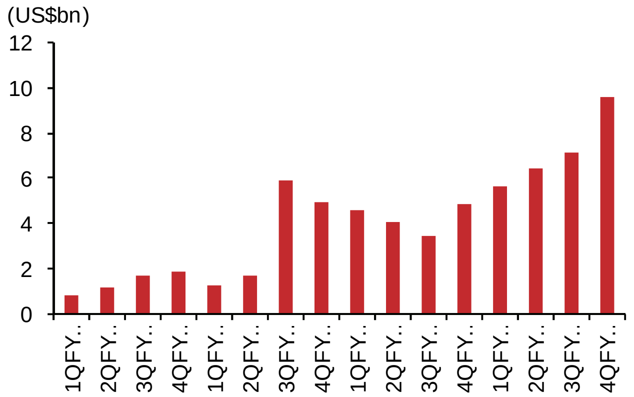
USD10bn of cash on hand and counting…

Over the past two years, RIL's key ongoing projects such as its new refinery & the KG-D6 block have been completed, and capex has slowed for further E&P development, and also in earlier planned areas such as retail, SEZ and petroleum downstream marketing. Similarly, with new capacities coming on line in refining, petchem and E&P, as well as margins improving in the refining and petchem segments, Reliance's cash profits have increased significantly.

As at end FY11, Reliance had cash and equivalents of more than USD10bn (including USD2bn received from BP as deposit for the E&P transaction). Most has been kept in fixed deposits, certificates of deposit with banks, mutual funds and government securities / bonds. In addition, annually it generates cash profit of ~USD7-8bn. The cash pile should further increase as BP pays an additional nearly USD5.2bn this year for its 30% stake in 23 E&P blocks.

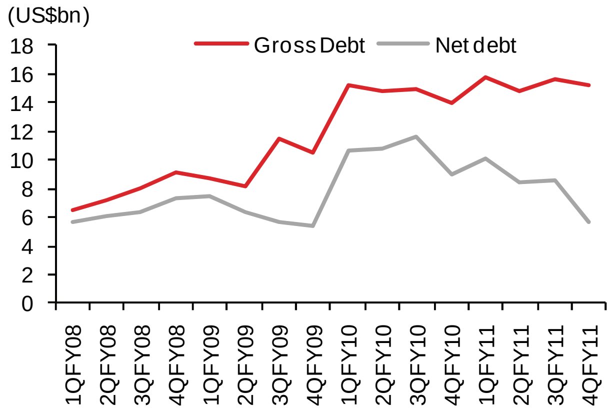
We estimate that RIL will have ~USD30bn of investible cash over next two years for making new investments and debt repayments.

Fig. 99: Cash levels have increased sharply



Source: Company data, Nomura research

Fig. 100: And net debt on the decline



Source: Company data, Nomura research

Also, even as RIL's cash position looks relatively large compared with its historical cash levels; we note that for a company of its size, such a cash position is not any exception. Several global companies of equivalent size have significantly larger cash levels.

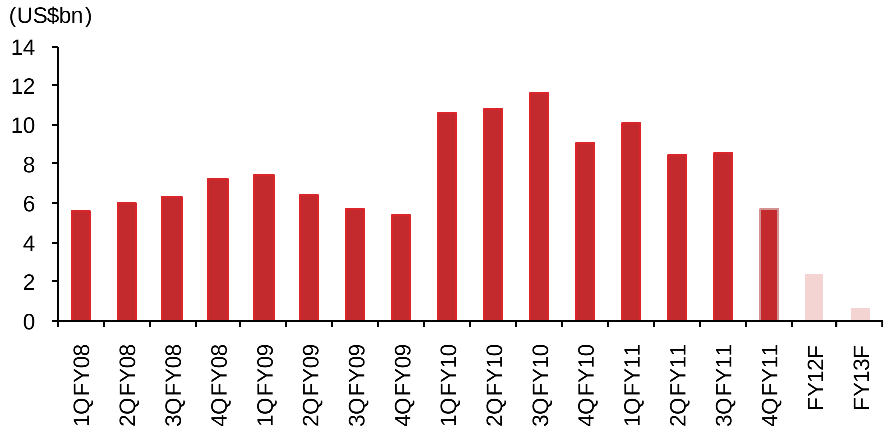
Fig. 101: Cash position of RIL vs other global companies

	S&P 500 *		Global oil & gas companies	
Market cap (US$bn)	**No of companies**	**Cash (US$bn)**	**No of companies**	**Cash (US$bn)**
Over 100bn	22	23.3	12	12.7
Over 75bn	29	20.2	18	10
Over 50bn	44	15.8	23	8.4
Over 25bn	113	9.5	52	5

Note: Cash and cash equivalents as of last balance sheet date. * S&P 500 excluding banks and financial institutions

Source: Bloomberg, Nomura research

Fig. 102: We expect net debt levels to decline significantly



Source: Company data, Nomura research

Investments in polyesters resumed; olefins likely soon

Over the past few years, Reliance has announced plans to further consolidate its position as the world's largest polyester producer. In addition, it has planned several other petrochemical projects, such as off-gas crackers and related downstream poly-olefin projects, as well as pet-coke gasification.

The total planned investment in petrochemicals is nearly USD10bn over the next 4-5 years. Work on several projects in the polyester chain, with a total investment of USD3bn, is under way. The company indicates that most fibre/yarn capacity is likely to be commissioned by end-2012, and polyester intermediate capacity by end-2013.

We would expect work on the olefin project, as well as the coal-gasification project, to commence soon.

Fig. 103: New petchem capacities planned over next 3-5 years

Product	Location	Capacity	Further Options
Work in progress - US$3bn investment		(mmtpa)	(mmtpa)
PX	Jamnagar	1.4	
PTA	Dahej	2.3	1.15
PET	Gandhar	0.54	0.54
PFY/PTY	Silvassa	0.54	
PSF	Dahej	0.29	
Planned projects - ~US$7bn investments			
Off-gas cracker	Jamnagar		
- Olefins capacity		1.5	
- downstream		1.5	
Coal gasification project			
Butyl Rubber (JV with SIBUR)		0.1	

Source: Company data

Although current investments in E&P have slowed due to regulatory hurdles, we would expect that eventually focus will turn to monetising several of Reliance's over 50 discoveries in India.

Apart from these investments, we expect Reliance will keep investing in areas such as shale gas, telecom and retail. In FY11, Reliance invested USD1.77bn in four shale gas JVs (three production ventures and one mid-stream) and has committed capex of nearly USD3.5bn over the next two years. Two shale gas JVs already started production last year, and the third is likely to commence production in 2Q FY12. The company indicates an aggressive three-year target of achieving USD2bn EBITDA from shale gas.

Fig. 104: US Shale Gas: RIL's net resources of 12tcfe; USD1.8bn invested in FY11, commitment of USD3.5bn over next two years

	Atlas JV*	Pioneer JV **	Carrizo JV	Total
Announcement date	9-Apr-10	24-Jun-10	5-Aug-10	
Shale play	Marcellus	Eagle Ford	Marcellus	
Operator	Atlas Energy	Pioneer	Carrizo	
Gross Acreages in JV(acres)	343,000	263,000	104,400	710,400
RIL's share (%)	40%	45%	60%	
RIL's share of resources (tcf)	5.3	4.5	2.0	11.8
Drilling programme (No of w ells)	3,000	1,750	1,000	5,750
FY11 exit production (mmscfed)	55	86	starts 2QFY12	
Total Acquisition cost (US$mn)	1,699	1,315	392	3,406
- Upfront payment	339	263	340	942
- Drilling Carry	1,360	1,052	52	2,464
FY11 Investment (incl upfront)	607	788	370	1,765
Capex commitment next 2 years				3,500
RIL's planned investment - 10yrs	4,400	4,000	2250	10,650

Notes: * Chevron now JV partner post its acquisition of Atlas; ** 70% JV acreage in condensate window
Source: Company data, Nomura estimates

RIL sees the power sector as a big opportunity

Last year, RIL indicated that it saw an unbound opportunity in the whole value chain of the power business – spanning generation, transmission and distribution. It also stated that it was drawing specific plans for mega-investments in clean coal-based power generation projects, hydel projects as well as nuclear power (as and when it is opened up). Thus, the power business continues to be a likely avenue for big-ticket capex, in our view.

Big-ticket M&As continue to be very likely

Even as RIL invests in petrochemicals, announces plans for further large-scale investments in E&P, and keeps making investments in new areas such as shale gas, telecom, and power, we think the company will continue to actively scout for big-ticket M&As, globally. Apart from its large cash holdings, the company still has significant treasury stock (~US$7bn at current prices), which could come handy for making such investments, in our view.

Although the market's view on M&As would depend on several factors, such as valuation, the business and synergies, we believe that any investment in the energy-related business would be seen positively. However, any further investments in areas unrelated to the energy chain, such as telecom, hotels, aviation, or the recent financial services, would not be liked by the market, in our view.

Earnings revisions

We are raising RIL's refining margin assumptions by 17/ 5% to USD11.1/10.7 per bbl for FY12F/13F. We are raising our petchem assumptions, and our petchem EBIT is 8/13% higher for FY12F/13F. We are also adjusting E&P for the BP deal. Our EPS increases by 8-9% to INR78/88 in FY12F/13F.

Below are the key changes to our assumptions:

Increase in refining margins: We align our FY12F/13F Singapore complex margins assumption with our regional forecasts; we have raised our refining margins assumptions for RIL by 17% /5% for FY12F/13F. We now estimate RIL's GRM at USD11.1/10.7/bbl in FY12F/13F (earlier USD9.5/10.1/bbl). With this change, our refining EBIT increases a sharp 31% in FY12F and 9% in FY13F.

Increase in petchem assumptions: We are also raising our petchem prices/margins assumption in line with our regional team's new forecasts. Our petchem EBIT increases by 8% /13% in FY12/13F.

Cut near-term KG-D6 estimates: We now assume that production would remain at around the current level of 50mmscmd in FY12F, and would reach 60mmscmd only by end-FY13F (average of 55mmscmd in FY13).Thus our KG-D6 gas production assumption is lower by 10/5mmscmd in FY12F/13F to 50/55mmscmd. We have also trimmed our KG-D6 oil (including condensate) production forecast. We now assume 18kbpd of oil production in FY12F/13F (lower from 25kbpd earlier).

Incorporate the BP deal: Management has indicated that the RIL-BP deal is effective from January 1, 2011, subject to various regulatory approvals and other conditions. On our estimates, we assume the deal will receive all necessary approvals and be completed in FY12. RIL has already received USD2bn as a deposit from BP and the balance USD5.2bn is to be received in tranches in FY12. As discussed earlier, on our estimates, this deal is likely to be tax-neutral for RIL, with a minimal impact on earnings.

Minor changes to our exchange rate assumptions: We have also fine-tuned our exchange rate assumptions to INR43.7/43.5USD in FY12F/13F (from INR43.4/USD).

Fig. 105: RIL - key modelling assumptions

			FY12		FY13	
	FY10	FY11	New	Old	New	Old
Refining Margins (US$/bbl)						
Singapore Complex	3.5	5.2	**7.5**	4.9	**6.8**	4.4
Premium over Singapore GRM	3	3.1	**3.6**	4.6	**3.9**	5.7
Avg GRM of RIL	6.5	8.4	**11.1**	9.5	**10.7**	10.1
Exchange Rate (INR / US$)	47.5	45.6	**43.7**	43.4	**43.5**	43.4
KG-D6 gas production (mmscmd)	39	56	**50**	60	**55**	60
KG-D6 Oil production (kbpd)	11	24	**18**	25	**18**	25

Source: Company data, Nomura estimates

Fig. 106: EBIT breakdown by segment

	FY10	FY11	FY12F		FY13F	
EBIT breakdown (INRbn)			New	Change	New	Change
E&P	54	67	59	-34%	69	-22%
Refining	60	92	129	31%	147	9%
Petrochemicals	86	93	92	8%	95	13%
EBIT change (%)						
E&P and others	27%	27%	20%		22%	
Refining	30%	36%	50%		47%	
Petrochemicals	43%	37%	30%		31%	

Source: Company data, Nomura estimates

Fig. 107: Earnings sensitivity to key variables

	FY12F		FY13F	
Base EPS	78		88	
EPS change	**INR/shr**	**%**	**INR/shr**	**%**
Refining GRM				
Base Case (US$/bbl)	11.1		10.7	
+1 US$/bbl	5.2	6.7%	5.6	6.4%
KG-D6 gas production				
Base Case (mmscmd)	50		55	
+ 5 mmscmd	1.4	1.7%	1.5	1.7%
KG-D6 gas prices				
Base Case (US$/mmbtu)	4.34		4.34	
+1 US$/mmbtu	3.7	4.7%	4.3	4.9%
KG-D6 Oil Production				
Base Case (kbpd)	18		18	
+ 5 kbpd	1.0	1.3%	1.2	1.3%
Exchange Rate				
Base Case (INR/US$)	43.7		43.5	
INR 1 depreciation	3.1	4.0%	3.4	3.9%

Source: Nomura estimates

Sum-of-the-parts valuation

Our revised TP of INR1,200 (from INR1,140) is based on a sum-of-the-parts valuation. In our valuation, we assume that RIL receives only USD7.2bn from BP for a 30% stake in 23 blocks. We value RIL's balance stake in these blocks at USD16bn, towards the lower range of the implied valuation. For the refining and petchem business, we continue to assign a 7x FY13F EV/EBITDA multiple.

Fig. 108: RIL's SOTP valuation

		INR Bn	$ bn	INR / Share	Comments	INR /share (old)
1	**Refining**	**1,319**	**30.2**	**445**	7x FY13 EBITDA	416
2	**Petrochemicals**	**873**	**20.0**	**295**	7x FY13 EBITDA	272
3	**E&P**	**1,039**	**24.1**	**351**		403
	Part of BP deal	**699**	**16.0**	**236**	BP to take 30% stake	
	KG-D6 Gas	393	9.0	133	DCF	202
	KG-D6 Oil	56	1.3	19	DCF	34
	Exploration assets	249	5.7	84		53
	Not part of BP deal	**340**	**8.1**	**115**		114
	PMT	199	4.6	67	7x FY13 EBITDA	67
	CBM Blocks	47	1.1	16		16
	Shale gas	88	2	30		29
	Others	6	0	2		2
4	**Investments**	**413**	**10.5**	**139**		139
	Enterprise Value	**3,645**	**84.7**	**1,230**		1,231
	Less: Net Debt	106	2.4	36	FY12E end	93
	Equity Value	**3,539**	**82.3**	**1,195**	Ex-treasury shares of 2962mn	1,138
	Target Price			**1,200**		1,140

Source: Nomura estimates

Valuation methodology and investment risks

We use the SOTP method to value RIL's different businesses. For its core businesses, we use EV/EBITDA multiples. We use a 7x FY13F EV/EBITDA multiple for its refining and petrochemical business. We use DCF to value the company's new E&P business. Our TP is INR1, 200/share.

Key downside risks:

Deterioration in refining and petchem margins.

Further delays in the ramp-up of KG-D6 volumes.

Delays in government approvals for the E&P deal with BP.

Sharper rupee appreciation vs. the US dollar than our assumptions.

Concerns look overdone

LNG offsets domestic declines; subsidy impact least on GAIL; petchem upcycle continues

May 6, 2011

Rating Remains	**Buy**
Target price Increased from 545	INR 600
Closing price April 29, 2011	INR 475
Potential upside	+26.3%

Action: Overdone concerns on gas volume decline

Even as we cut our transmission volume est by 7-10% (lower KG-D6, offset by LNG), we are not overly concerned. As GAIL's contracts include ship-or-pay provisions, the revenue decline is likely lower. Also, on additional LNG, it charges tariff for new HVJ (over 100% of old HVJ). Our tariff assumptions are 7-8% higher; thus we see transmission revenue being largely flat.

Action: Subsidy a concern, but GAIL least impacted among oil PSUs

Subsidy is a concern. But the consoling fact is that unlike other upstream companies, GAIL shares burden only on cooking fuels (~13% of upstream's one-third share). As the price of oil rises, the bulk of incremental under-recoveries are due to diesel that GAIL does not share. In the current mechanism, most of the subsidy increase is offset by higher realisation on LPG, on our estimates.

Catalysts: Petchem prices strong, capacity on increase

During its recent shut-down in 2Q/3Q, GAIL raised its petchem capacity by ~20% to 490ktpa. We expect GAIL's polymers sales to increase nearly 42% q-q in 4Q, as 3Q sales were affected by shut-down and stock-built up. GAIL is further expanding capacity to 900ktpa (earlier 800ktpa) by FY14F. PE prices are strong, and we expect strength to continue with supply/demand balance getting tighter.

Valuations: Raising earnings by 4%; Raising TP to INR600

We adjust our model for lower gas volumes, higher tariffs, higher petchem /LPG prices and higher tax rates. Our FY12/13F earnings increase is mainly due to higher petchem prices. We roll forward our valuations to FY13F and raise our target price by 10% to INR600.

31 Mar	FY10	FY11F		FY12F		FY13F	
Currency (INR)	Actual	Old	New	Old	New	Old	New
Revenue (bn)	250	323	324	397	388	442	427
Reported net profit (bn)	31	37	37	43	44	47	49
Normalised net profit (bn)	31	37	37	43	44	47	49
Normalised EPS	24.8	28.9	29.2	33.7	35.0	37.4	38.8
Norm. EPS growth (%)	12.0	16.9	17.8	16.5	20.0	10.9	11.0
Norm. P/E (x)	19.2	N/A	16.3	N/A	13.6	N/A	12.2
EV/EBITDA	12.3	N/A	10.9	N/A	9.1	N/A	8.3
Price/book (x)	3.6	N/A	3.1	N/A	2.7	N/A	2.4
Dividend yield (%)	1.6	N/A	1.8	N/A	2.2	N/A	2.5
ROE (%)	19.9	20.5	20.5	21.1	21.5	20.7	20.8
Net debt/equity (%)	net cash	7.0	5.5	13.1	10.1	17.0	12.6

Source: Nomura estimates

Key company data: *See page 2 for company data, and detailed price/index chart.*
Rating: *See report end for details of Nomura's rating system.*

Anchor themes

We continue to like GAIL for its potential operating upside and re-rating from gas growth.

Nomura vs consensus

Our FY13F EPS estimate (6% higher) and PT (13% higher)are higher than consensus, as we are more positive on LNG and petchem upside.

Research analysts

India Oil & Gas/Chemicals

Anil Sharma - NFASL
anil.sharma.1@nomura.com
+91 22 4037 4338

Ravi Adukia, CFA - NFASL
ravikumar.adukia@nomura.com
+91 22 4037 4232

Key data on GAIL

Income statement (INRbn)

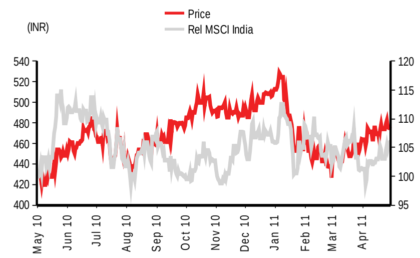
Year-end 31 Mar	FY09	FY10	FY11F	FY12F	FY13F
Revenue	**238**	**250**	**324**	**388**	**427**
Cost of goods sold	-186	-191	-257	-306	-336
Gross profit	**51**	**59**	**67**	**82**	**90**
SG&A	-16	-18	-18	-22	-22
Employee share expense	0	0	0	0	0
Operating profit	**35**	**41**	**50**	**61**	**68**
EBITDA	**41**	**47**	**56**	**68**	**77**
Depreciation	-6	-6	-6	-8	-9
Amortisation	0	0	0	0	0
EBIT	35	41	50	61	68
Net interest expense	-1	-1	-1	-1	-2
Associates & JCEs	0	0	0	0	0
Other income	8	5	6	6	7
Earnings before tax	**42**	**46**	**55**	**65**	**72**
Income tax	-14	-14	-18	-21	-23
Net profit after tax	**28**	**31**	**37**	**44**	**49**
Minority interests	0	0	0	0	0
Other items	0	0	0	0	0
Preferred dividends	0	0	0	0	0
Normalised NPAT	**28**	**31**	**37**	**44**	**49**
Extraordinary items	0	0	0	0	0
Reported NPAT	**28**	**31**	**37**	**44**	**49**
Dividends	-10	-11	-13	-16	-17
Transfer to reserves	**18**	**20**	**24**	**29**	**32**
Valuation and ratio analysis					
FD normalised P/E (x)	21.5	19.2	16.3	13.6	12.2
FD normalised P/E at price target (x)	27.1	24.2	20.6	17.1	15.4
Reported P/E (x)	21.5	19.2	16.3	13.6	12.2
Dividend yield (%)	1.5	1.6	1.8	2.2	2.5
Price/cashflow (x)	23.4	12.9	19.8	10.2	9.6
Price/book (x)	4.1	3.6	3.1	2.7	2.4
EV/EBITDA (x)	14.3	12.3	10.9	9.1	8.3
EV/EBIT (x)	16.6	14.0	12.4	10.3	9.4
Gross margin (%)	21.6	23.6	20.8	21.2	21.1
EBITDA margin (%)	17.1	18.7	17.3	17.6	18.0
EBIT margin (%)	14.7	16.4	15.3	15.6	15.9
Net margin (%)	11.8	12.6	11.4	11.4	11.6
Effective tax rate (%)	33.3	31.4	32.6	32.0	32.0
Dividend payout (%)	37.1	35.4	35.0	35.0	35.0
Capex to sales (%)	10.7	14.3	15.4	12.9	11.7
Capex to depreciation (x)	4.6	6.4	7.7	6.5	5.7
ROE (%)	20.2	19.9	20.5	21.5	20.8
ROA (pretax %)	17.8	17.2	17.4	18.0	17.5
Growth (%)					
Revenue	32.0	5.1	29.7	19.8	9.8
EBITDA	2.7	15.2	20.1	22.0	12.1
EBIT	3.4	17.5	20.7	22.3	11.8
Normalised EPS	7.8	12.0	17.8	20.0	11.0
Normalised FDEPS	7.8	12.0	17.8	20.0	11.0
Per share					
Reported EPS (INR)	22.10	24.75	29.16	35.00	38.85
Norm EPS (INR)	22.10	24.75	29.16	35.00	38.85
Fully diluted norm EPS (INR)	22.10	24.75	29.16	35.00	38.85
Book value per share (INR)	116.44	132.43	151.38	174.13	199.37
DPS (INR)	7.00	7.50	8.75	10.50	11.65

Source: Nomura estimates

Notes

We expect earnings growth of 20% / 10% in FY12/13F driven by gas transmission and petchem

Price and price relative chart (one year)



(%)	1M	3M	12M
Absolute (INR)	4.8	4.6	14.2
Absolute (USD)	6.1	8.2	15.1
Relative to index	4.8	0.9	9.0
Market cap (USDmn)	13,640.1		
Estimated free float (%)	42.7		
52-week range (INR)	537.75/402.05		
3-mth avg daily turnover (USDmn)	11.14		
Major shareholders (%)			
Government of India	57.3		
LIC	7.4		

Cashflow (INRbn)

Year-end 31 Mar	FY09	FY10	FY11F	FY12F	FY13F
EBITDA	41	47	56	68	77
Change in working capital	-7	15	-13	7	4
Other operating cashflow	-7	-15	-13	-16	-19
Cashflow from operations	**26**	**47**	**30**	**59**	**63**
Capital expenditure	-26	-36	-50	-50	-50
Free cashflow	**0**	**11**	**-20**	**9**	**13**
Reduction in investments	-2	-3	-5	-5	-5
Net acquisitions	0	0	0	0	0
Reduction in other LT assets	0	0	0	0	0
Addition in other LT liabilities	0	1	0	0	0
Adjustments	5	4	0	0	0
Cashflow after investing acts	**3**	**13**	**-25**	**4**	**8**
Cash dividends	-12	-7	-13	-16	-17
Equity issue	0	0	0	0	0
Debt issue	-1	3	8	10	10
Convertible debt issue	0	0	0	0	0
Others	-1	-1	0	0	0
Cashflow from financial acts	**-13**	**-5**	**-5**	**-6**	**-7**
Net cashflow	**-10**	**7**	**-30**	**-2**	**0**
Beginning cash	45	35	42	12	10
Ending cash	35	42	12	10	10
Ending net debt	-23	-27	11	22	32

Source: Nomura estimates

Notes

We assume capex of INR50bn for each of the next three years

Balance sheet (INRbn)

As at 31 Mar	FY09	FY10	FY11F	FY12F	FY13F
Cash & equivalents	35	42	12	10	10
Marketable securities	0	0	0	0	0
Accounts receivable	15	13	17	20	22
Inventories	6	6	7	8	8
Other current assets	67	76	76	77	77
Total current assets	**123**	**137**	**112**	**115**	**118**
LT investments	17	21	26	31	36
Fixed assets	115	143	186	228	270
Goodwill	0	0	0	0	0
Other intangible assets	0	0	0	0	0
Other LT assets	0	0	0	0	0
Total assets	**255**	**300**	**324**	**374**	**423**
Short-term debt	0	0	0	0	0
Accounts payable	20	20	29	34	38
Other current liabilities	62	83	67	72	76
Total current liabilities	**82**	**104**	**95**	**107**	**114**
Long-term debt	12	15	22	32	42
Convertible debt	0	0	0	0	0
Other LT liabilities	13	14	14	14	14
Total liabilities	**107**	**132**	**132**	**153**	**170**
Minority interest	0	0	0	0	0
Preferred stock	0	0	0	0	0
Common stock	13	13	13	13	13
Retained earnings	133	153	177	206	238
Proposed dividends	0	0	0	0	0
Other equity and reserves	2	2	2	2	2
Total shareholders' equity	**148**	**168**	**192**	**221**	**253**
Total equity & liabilities	**255**	**300**	**324**	**374**	**423**
Liquidity (x)					
Current ratio	1.50	1.32	1.17	1.08	1.03
Interest cover	40.2	58.7	72.1	44.4	36.4
Leverage					
Net debt/EBITDA (x)	net cash	net cash	0.19	0.32	0.42
Net debt/equity (%)	net cash	net cash	5.5	10.1	12.6
Activity (days)					
Days receivable	19.8	20.4	16.7	17.4	18.1
Days inventory	11.5	11.8	9.4	8.7	8.6
Days payable	36.9	38.3	34.8	37.6	39.0
Cash cycle	-5.7	-6.0	-8.7	-11.6	-12.3

Source: Nomura estimates

Notes

Strong balance sheet with very low debt

LNG likely to offset KG-D6 decline

Cut transmission volume assumption by 7%/10% for FY12/13

As India's domestic gas production grew sharply in FY10, GAIL -- as the country's key long distance gas transmission company -- was a key beneficiary. With likely further growth in KG-D6, GAIL was likely to benefit further.

As KG-D6 volumes have continued to disappoint, and with no clear indication on further ramp-up plans, we are now more cautious on our KG-D6 volume numbers. We now assume that production will remain around current levels of 50mmscmd in FY12, and reach 60mmscmd levels only by end FY13 (average of 55mmscmd in FY13).

The lower KG-D6 volumes imply lower gas availability for GAIL versus our earlier expectation. However, as we highlight earlier in the report, we expect LNG imports volume to significantly increase near term, and to some extent offset domestic volume declines.

Fig. 109: Volume decline largely offset by likely tariff increases

	FY10	FY11F		FY12F		FY13F	
mmscmd		**New**	**Old**	**New**	**Old**	**New**	**Old**
Transmission volume	107	**119**	120	**130**	140	**140**	155
Change %		**-1%**		**-7%**		**-10%**	

Source: Company data, Nomura estimates

Tariff increases likely to offset volume declines

We highlight that most of GAIL's existing contracts have 'ship or pay' provisions, and typically if volumes drop below 90-95% daily contracted quantities (DCQ), the contracts require customers to keep paying the capacity charges. This means that typically GAIL's revenue decline would be far lower than the actual volume decline.

However, recently media outlets ("Small relief for RIL gas users", *The Telegraph*, 11 April, 2011) have reported that after protest from some customers, the ministry has directed GAIL not to charge additional tariffs if customers bring some LNG to make up for the KG-D6 gas shortfall. But, as not all customers will bring LNG (and even those that do may not make up the full extent of domestic volume decline), this benefit could continue to accrue to GAIL, in our view.

Last year, PNGRB, while deciding tariffs for GAIL's HVJ/GREP pipeline, cut GAIL's provisional average tariff for the extant HVJ/GREP network (this pipeline accounts for ~50% of GAIL's transmission volumes) customers by ~11% with retroactive effect from November 2008. However, for GAIL's new expansion of HVJ/GREP, the regulator had set a tariff of INR53.7/mmbtu, which was more than double the tariff approved for old HVJ/GREP of INR25.5/mmbtu. As capacity of the old HVJ/GREP network is fully utilised, GAIL gets the higher tariff for all incremental gas such as additional LNG imports.

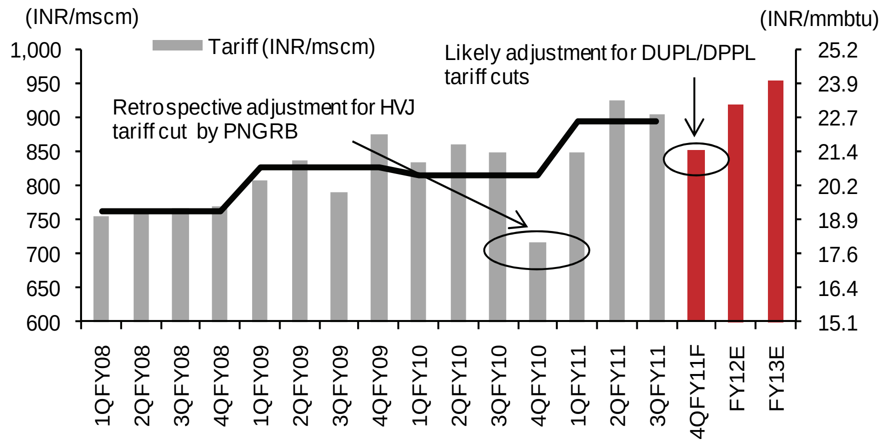
The result of this has been that despite cuts in tariffs. GAIL's average tariff realized have kept on increasing over last few years, with average annual increase of ~5% every year since FY08. With most of additional gas likely to flow on the expansion HVJ/GREP network, the trend of higher tariff is likely to continue, in our view.

Fig. 110: GAIL's tariff have been cut by PNGRB

Pipeline Network	Order Date	Applied from	Old Tariff	New tariff	Change
HVJ - GREP - DVPL	Apr-10	Nov-08	28.5	25.5	-11%
DVPL / GREP upgradation	Apr-10	Apr-10	NA	53.7	
DUPL / DPPL	Feb-11	Nov-08	26.1	24.5	-6%

Source: PNGRB, Nomura research

Fig. 111: Yet, average tariff realised have kept on increasing



Source: Company data, Nomura estimates

Gas swapping likely to further increase average tariffs

In March 2011, few Independent power plants (IPPs) in Andhra Pradesh signed a swapping agreement with RIL, RGTIL and GAIL. As per this agreement, GAIL will divert its entire allocation (2.594mmscmd) of KG-D6 (which GAIL gets for shrinkages in its LPG plants) to IPPs in Andhra Pradesh. GAIL will in turn take equivalent quantities of RLNG procured by IPPs (from GAIL's short-term contract with Marubeni) to its LPG plants.

On such swapped volumes, apart from getting the tariff for the RGTIL pipeline, GAIL also gets the tariff for actual delivery of imported LNG to its own LPG plants (HVJ tariffs) and also charges these customers handsome marketing margins, in our view

Despite the much higher price of RLNG compared with domestic gas, there is still more demand for this LNG on a swapping basis. Recently, media outlets reported that NTPC, Reliance, and GAIL will soon enter into an arrangement for further supply of RLNG to Andhra Pradesh based power plants. The deal will involve NTPC getting RLNG for its power plants on GAIL's pipeline, while its quota of KG-D6 gas would be supplied to Andhra Pradesh based power plants. ("NTPC, RIL join hands to ease Andhra power woes," *Business Standard*, 13 April 2011). This arrangement would be positive for GAIL, in our view.

Fig. 112: Volume decline largely offset by likely tariff increases

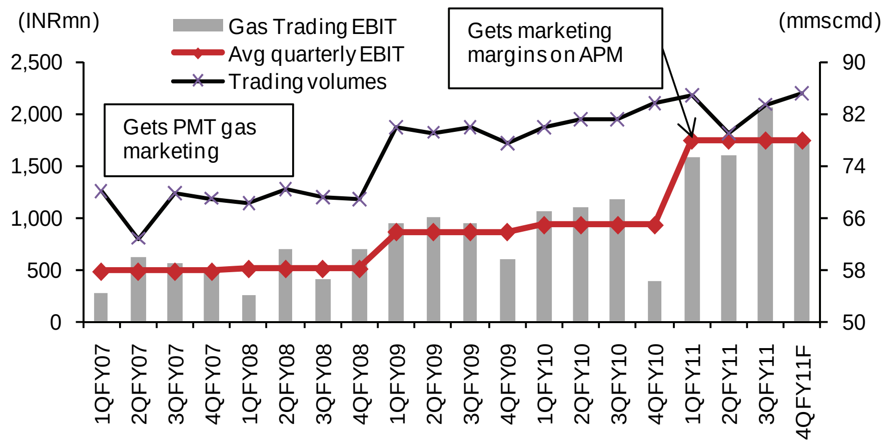
	FY10	FY11F		FY12F		FY13F	
Gas Transmission		**New**	**Old**	**New**	**Old**	**New**	**Old**
Volume (mmscmd)	107	**119**	120	**130**	140	**140**	155
Change %		**-1%**		**-7%**		**-10%**	
Avg Tariff (INR/mscm)	813	**883**	843	**920**	859	**953**	886
Change %		**5%**		**7%**		**8%**	
Transmission Revenue (INR bn)	31.7	**38.3**	37	**43.8**	43.9	**48.7**	50.1
Change %		**4%**		**0%**		**-3%**	

Source: Company data, Nomura estimates

Gas trading – APM marketing margin boosted earnings

Last year, along with the price increases on APM gas, the government allowed marketing margins of INR200/mscm (~11cent/mmbtu) on APM gas. The decision, which has been applied since 1 June 2010, was a positive for GAIL, which markets nearly all of its ~50mmscmd of APM gas.

Fig. 113: Marketing margins on APM gas have boosted trading gains



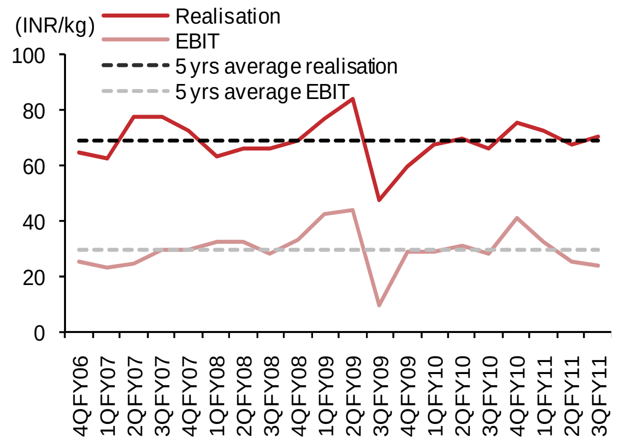
Source: Company data, Nomura estimates

Petchem resilient – volume growth continues

Over the past few years, GAIL has been increasing the capacity of its gas-based petrochemical plants. From an initial capacity of 310ktpa, capacity was raised by 32% to 410ktpa in FY08. During a shutdown in 2H10, GAIL commissioned its sixth furnace, which increased PE capacity by a further 20% to 490ktpa. GAIL is further working on increasing the capacity in stages to reach 900ktpa (earlier plan was for 800ktpa) by end-FY14. We expect GAIL's polymers sales to increase nearly 42% q-q in 4Q, as sales in 3Q were affected by shutdowns and built-up stock.

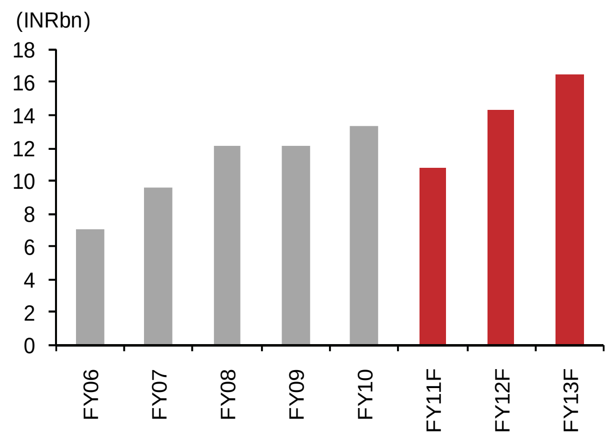
Overall, as shown in the exhibit below, right, PE prices have continued to be resilient over the past few years. Even as GAIL's gas costs have increased substantially over these years, profitability has been resilient, with gains in EBIT largely coming with volume increases.

Fig. 114: Polymer realisations remain resilient, but margins declined due to increased gas costs



Source: Company data, Nomura research

Fig. 115: Petchem EBIT increases driven by creeping capacity increases from 320 to 490ktpa now



Source: Company data, Nomura estimates

Fig. 116: Increase in the feedstock cost of GAIL

Price $/mmbtu	FY04	FY05	FY06	FY07	FY08	FY09	FY10	FY11F
Avg purchase price	1.7	1.8	2.4	2.8	3.2	3.6	3.5	
Avg. price for internal consumption	1.9	1.9	3.2	4.4	4.1	4.8	4.9	
Avg. price for gas as feedstock	2.2	2.3	3.3	4.5	4.8	4.9	4.7	5.3
Feedstock cost - yoy growth %	6%	6%	45%	37%	7%	1%	-3%	11%

Source: Company data, Nomura estimates

Beyond 2012 – the possibility of a 'supercycle'?

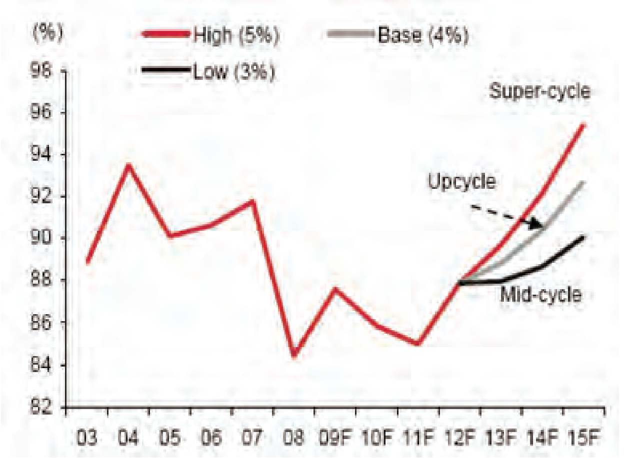
Our regional team remains very positive in its outlook, and believes that the chemicals sector is poised to enter a Golden Age, benefiting from rising demand and restrained capacity additions over the next two years. In the case of ethylene, we forecast a steady up-cycle from end-2011 onwards through 2015.

Our team believes that prospects for ethylene should gradually improve over the next few years given slowing capacity growth and longer construction lead times (three to four years per cracker versus two to three years per downstream plant).

An ethylene 'supercycle' could take place if crude prices remain benign and annual demand grows uninterruptedly at 5% pa throughout the period.

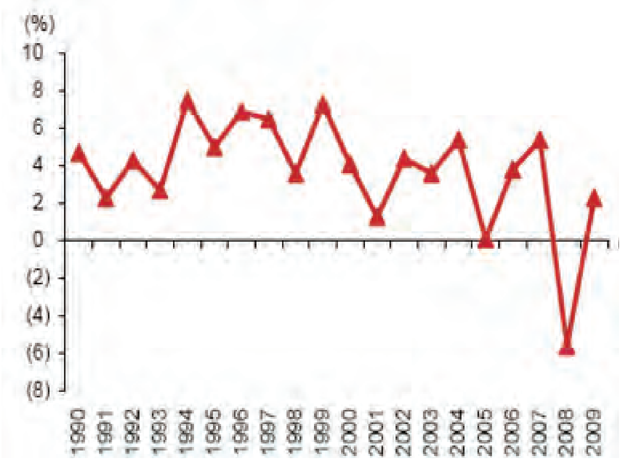
Currently, our base case assumes 4.8% pa growth rates for 2011-12F and 4% pa growth rates for 2013-15F. Under this scenario, we forecast global ethylene operating rates to rise to 89% by 2013, 90% by 2014 and 93% by 2015. We therefore believe it may be premature to price in a full upcycle for ethylene, as it is still two years away, in our view.

Fig. 117: Global ethylene operating rate sensitivity to demand growth



Source: CMAI, Nomura estimates

Fig. 118: Historical global ethylene demand growth



Source: CMAI, Nomura research

Fig. 119: Global ethylene supply and demand (annualised capacity)

	02	03	04	05	06	07	08	09	10F	11F	12F	13F	14F	15F
Global														
Capacity (LHS)	109.8	110.8	111.4	115.8	120.3	125.1	130.2	132.5	140.9	148.9	151.1	155.4	159.3	162.3
Demand (LHS)	95.6	98.4	104.1	104.4	109	114.8	108.3	111.6	119.5	126.5	132.8	138.2	143.7	149.4
Operating rate (RHS)	87.1	88.9	93.5	90.1	90.6	91.8	83.2	84.2	84.8	85	87.9	88.9	90.2	92.1
Capacity grow th	5.3%	0.9%	0.6%	4.0%	3.9%	4.0%	4.1%	1.8%	6.3%	5.7%	1.5%	2.9%	2.5%	1.9%
Demand grow th	4.2%	2.9%	5.8%	0.2%	4.5%	5.3%	-5.7%	3.1%	7.1%	5.8%	5.0%	4.0%	4.0%	4.0%
Capacity grow th	5.5	1.0	0.6	4.4	4.5	4.8	5.1	2.3	8.4	8.0	2.2	4.3	3.9	3.1
Demand grow th	3.8	2.8	5.7	0.2	4.7	5.7	-6.5	3.4	7.9	7.0	6.3	5.3	5.5	5.7

Source: CMAI, Nomura estimates

For more details please see our 3 November 2010 Anchor Report: *Asian Chemicals – A Golden Age* http://www.nomura.com/research/getpub.aspx?pid=400306, authored by Yong Liang Por, Cindy Park and Cheng Khoo.

LPG — subsidy a concern, but GAIL looks least impacted

GAIL has seven gas processing plants that produce LPG and other liquid hydrocarbons (LHC) such as propane, pentane and naphtha. The combined LPG capacity (including other liquid hydrocarbons) of these plants is 1.4mtpa.

Even though GAIL is not an upstream producer (and gets limited upside from increased LHC prices with increases in oil prices), it has been made to a bear subsidy burden with upstream companies in the ratio of their profits. The entire under-recovery /subsidy mechanism has largely remained ad-hoc and non-transparent over the years, and has been a key overhang and concern over the past few years, in our view. However, we believe that among oil PSUs that incur under-recoveries (PSU oil marketing companies) or are made to bear these (PSU upstream companies), GAIL is least impacted.

Now GAIL does not share subsidies on auto fuels

Even though subsidy sharing has been ad-hoc and non-transparent, the one redeeming factor has been that the upstream's share has generally been limited to one-third (except in FY07).

Since GAIL was brought into a subsidy-sharing mechanism (and until FY09 end), GAIL was sharing under-recoveries only on cooking fuels (Domestic LPG and PDS kerosene). GAIL shared these losses in the ratio of previous year's reported profits of upstream companies, as per the earlier formula.

However, as the government rejigged the sharing mechanism in early 2010, and decided that upstream companies (including GAIL) would share only auto fuel (diesel & petrol) losses and not cooking fuel losses. This again was in the ratio of last year's profits of upstream companies.

However, this new sharing mechanism was detrimental to GAIL as unlike other upstream companies (with natural hedge from increased oil prices) GAIL only had limited upsides from higher oil prices (only on LPG production). GAIL's subsidy outgo shot up substantially in 1HFY10.

We believe GAIL raised this issue with the government and the subsidy-sharing formulae were apparently reworked to perhaps reduce the burden on GAIL. We understand that now GAIL again shares subsidy burden only in cooking fuel.

Now as per the new formula, for the upstream share of one-third of cooking fuel losses, GAIL shares in the ratio of average profits of upstream companies for the past three years. With this method, GAIL's share works out at 12.6% for FY10 and 13.2% for FY11.

The next exhibit shows a detailed calculation for subsidy working. And, based on the above methodology, the calculated numbers for GAIL's subsidy mechanism are in line with actual reported subsidy numbers for full fiscal FY10, and for each of the three quarters reported in FY11.

Fig. 120: Subsidy sharing mechanism for GAIL

Reported Profit INRbn	FY07	FY08	FY09	FY10	vg (FY07-09)	vg (FY08-10)
Upstream Companies	172	185	184	194	180	187
GAIL	24	26	28	31	26	28
	196	211	212	225	206	216
Ratio for sharing of cooking fuel losses					FY10	FY11
Upstream Companies					87.4%	86.8%
GAIL					12.6%	13.2%

		FY10	1QFY11	2QFY11	3QFY11	9MFY11	4QFY11E
GAIL's share	A	12.6%	13.2%	13.2%	13.2%	13.2%	13.2%
Under-recoveries							
Auto fuels	B	144	97	37	61	195	170
Cooking fuels	C	316	105	75	95	275	141
Total	**D=B+C**	**461**	**201**	**113**	**156**	**470**	**310**
1/3rd of cooking	E=C/3	105	35	25	32	92	47
GAIL's share	F=A*E	13.3	4.6	3.3	4.2	12.1	6.2
GAIL's Actual	G	13.3	4.5	3.5	4.2	12.1	6.2
Difference	H=G-F	0.0	(0.1)	0.1	-	0.0	0.0

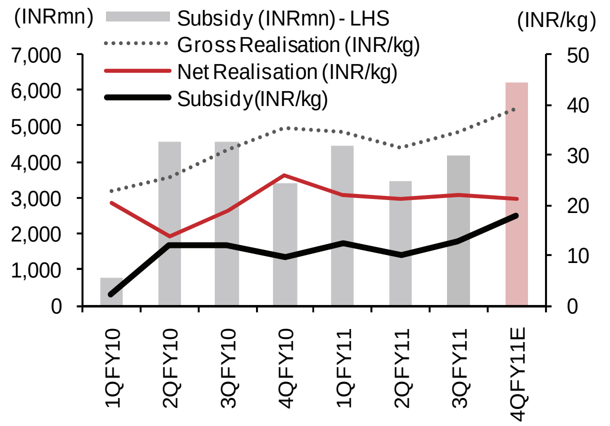
Source: PPAC, Company data, Infraline, Nomura estimates

At one-third of cooking fuels, subsidy is largely revenue neutral

In our estimates, as oil prices increase, even though the subsidy burden on cooking fuel share also increases, this is largely offset by GAIL's higher realisation on LPG (it gets import parity price). In our estimates, as oil prices move beyond US$75-80/bbl, when diesel under-recoveries start to build up, the bulk of the incremental increase is due to diesel, which GAIL does not share. Thus, as the previous exhibit shows, GAIL's net revenue realisations (ex-subsidy) remained resilient. Therefore, we believe if current subsidy mechanism were to continue, even as GAIL's subsidy outgo increases with higher oil prices, its LPG revenues would remain largely resilient. As such, we are not overly concerned about GAIL's subsidy sharing.

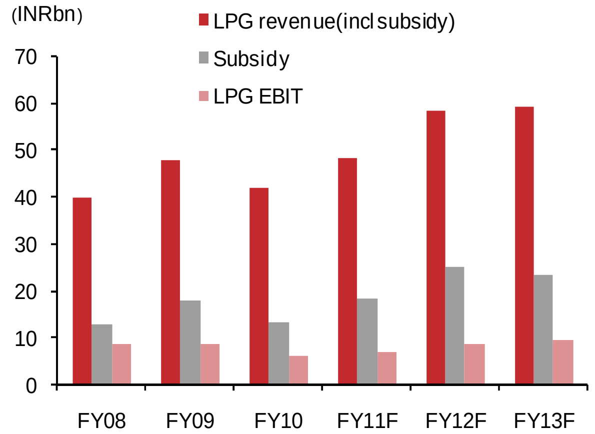
We believe that even though the company may keep arguing its case for being kept out of the subsidy-sharing mechanism (this was also suggested by the Kirit Parikh Committee), we think that looks unlikely, as the subsidy problem continues to be quite large. Similarly, as we highlight that overall the entire mechanism has remained very ad-hoc and non-transparent, and the government may again change the mechanism to the detriment of GAIL, we do not build that scenario in our current numbers. And even though the likelihood looks low to us, nevertheless such a scenario would be negative for GAIL

Fig. 121: Despite volatile subsidy burden, GAIL's net LPG realisation (ex subsidy) remains resilient



Source: Company date, Nomura estimates

Fig. 122: Higher LPG prices offset incremental subsidy burden and LPG EBIT remains largely unimpacted



Source: Company date, Nomura estimates

Earning changes

We adjust our model for lower gas volumes, higher tariffs, higher petchem/LPG prices and higher tax rates. Our FY12/13F earnings increase by 4% for FY12/13F, mainly due to higher petchem price/margins assumptions.

Fig. 123: Key modelling assumptions

	FY10	FY11F		FY12F		FY13F	
Gas Transmission		New	Old	New	Old	New	Old
Volume (mmscmd)	107	119	120	130	140	140	155
Avg. Tariff (INR/mscm)	813	883	843	920	859	953	886
Petrochemicals							
Polymers production (KT)	417	414	426	475	475	480	475
Avg. realisation (INR/kg)	71	71	61	72	61	77	67
LPG & Other liquid HC							
LPG sales (KT)	1,101	1,081	1,135	1,157	1,160	1,180	1,185
Other HC sales (KT)	343	298	349	320	353	328	356
LPG prices (US$/MT)	610	766	684	905	766	899	882
Subsidy (INR mn)	13,267	18,277	14,170	25,207	19,110	23,317	27,710
Tax rate (%)	31	33	30	32	30	32	30

Source: Company data, Nomura estimates

Fig. 124: EBIT breakdown by segment

Gas business contributed nearly two-thirds to EBIT

	FY09	FY10	FY11F	FY12F	FY13F
EBIT breakdown (INRbn)					
Transmission & trading	21.7	28.9	36.9	41.6	46.0
Petrochemicals	12.1	13.3	10.8	14.3	16.4
LPG & Liquid HC	8.6	6.1	7.2	8.7	9.4
EBIT breakdown (%)					
Transmission & trading	51	60	67	64	64
Petrochemicals	29	28	20	22	23
LPG & liquid HC	20	13	13	13	13

Source: Company data and Nomura estimate

Fig. 125: Earnings sensitivity to key variables

	FY12F		FY13F	
Base case EPS (INR/share)	35.0		38.9	
EPS Change	**INR/Share**	**%**	**INR/Share**	**%**
Gas transmission volume				
Base volumes (mmscmd)	130		140	
+10 mmscmd	1.2	3.6%	1.3	3.3%
Gas transmission tariffs				
Base avg tariff (Rs/'000 SCM)	920		953	
5% higher tariff	1.2	3.4%	1.3	3.4%
Polymer prices				
Base case ($/MT)	1650		1760	
10% higher prices	1.8	5.2%	2.0	5.1%
Subsidy burden				
Base (INRbn)	25.2		23.3	
10% higher subsidy	-1.4	-3.9%	-1.3	-3.2%

Source: Nomura estimates

Valuation – favorable risk reward

We roll forward our sum-of-the-parts valuation for GAIL to FY13-end and continue to assign 10x FY13F EV/EBITDA multiple to gas transmission business (including gas trading), 7x FY13F EV/EBITDA multiple for petrochemical and 6x FY13F EV/EBITDA multiple for LPG business. We continue to value E&P upside at a conservative INR15/share. Our revised SOTP-based target price for GAIL is INR600/share (from INR545).

Compared with 8-12x 2012F EV/EBITDA multiples for regional gas and utilities stocks, and 11x FY13F EV/EBITDA for Indian PSU power utilities, GAIL currently trades at 8.3 x FY13F EV/EBITDA multiple. We continue to like GAIL for its potential operating upside and re-rating from gas growth. We reiterate BUY.

Fig. 126: GAIL — SOTP valuation

	(INRbn)	(US$bn)	INR / Share	INR /Share (Old)	Comments
Gas transmission	521	11.4	411	377	10x FY13F EBITDA
Petrochemicals	127	2.8	100	71	7x FY13F EBITDA
LPG & liquid HC	62	1.4	49	47	6x FY13F EBITDA
E&P upside	19	0.4	15	15	
Investments	58	1.3	46	54	
Enterprise value	**787**	**17.3**	**621**	**564**	
Less: net debt	22	0.5	18	22	FY12F
Equity value	**765**	**16.8**	**603**	**542**	
Price target			**600**	**545**	

Source: Nomura estimates

Fig. 127: Comparative valuation matrix of Indian and Regional gas and power utilities

Company	Ticker	Rating	Price (LC)	M Cap (US$bn)	P/E 2010	P/E 2011F	P/E 2012F	EV/EBITDA 2010	EV/EBITDA 2011F	EV/EBITDA 2012F
India Power Utilities										
NTPC	NATP IN	BUY	187.8	34.8	19.4	18.0	16.4	14.3	13.6	11.9
Power Grid	PWGR IN	BUY	105.3	10.9	20.7	17.4	15.4	13.6	11.3	10.0
Average					**20.1**	**17.7**	**15.9**	**14.0**	**12.4**	**10.9**
China Gas Utilities										
ENN Energy	2688 HK	Neutral	26.9	4.3	24.8	20.2	18.3	11.2	8.5	7.2
Towngas China	1083 HK	Neutral	4.0	1.3	20.1	16.1	14.0	12.2	9.2	8.1
China Resources Gas	1193 HK	BUY	11.7	2.8	25.5	19.4	16.7	13.6	9.0	7.5
China Gas	384 HK	Reduce	3.4	1.9	16.8	23.8	17.6	15.0	9.6	7.5
Beijing Enterprises	392 HK	BUY	42.3	6.2	18.4	15.4	13.5	8.7	8.0	7.4
Average					**21.1**	**19.0**	**16.0**	**12.1**	**8.8**	**7.5**
HK Utilities										
Power Assets Holdings L	6 HK	BUY	53.6	14.7	15.7	13.4	12.9	14.0	11.7	11.1
CLP Holdings	2 HK	Neutral	63.9	19.8	15.3	15.9	14.8	10.2	9.5	8.9
Hong Kong & China Gas	3 HK	Reduce	18.9	17.5	28.1	25.7	23.7	18.5	17.4	16.2
CKI	1038 HK	Neutral	36.9	10.7	16.4	11.1	10.7	17.2	11.8	11.5
Average					**18.9**	**16.5**	**15.5**	**15.0**	**12.6**	**11.9**

Source: Bloomberg, Nomura estimates

Valuation methodology and risks to our investment view

We have used sum-of-the-parts as our primary tool to value GAIL's diversified business. We have valued its gas transmission business (including gas trading) at 10x its FY13F EBITDA. We have assigned a multiple of 7x FY13F EBITDA for petrochemical and 6x FY12F estimated EBITDA for the LPG business. We also value E&P upside at a conservative INR15/share. Our target price is INR600.

Key downside risks: Lower transmission volume growth, a sharp cut in overall tariffs by the regulator (we do not assume any cut), a sharper polymer price decline than our assumption and higher subsidy burden than our assumptions.

Petronet LNG PLNG.BO PLNG IN

OIL & GAS/CHEMICALS

NOMURA
EQUITY RESEARCH

Pure LNG upside play

Keeps surprising on volumes; geared for further growth -- capacity to double by FY14

May 6, 2011

Rating Remains	**Buy**
Target price Increased from 145	INR 180
Closing price April 29, 2011	INR 132
Potential upside	+36.4%

Action: Key beneficiary of LNG spurt

PLNG owns 75% of India's LNG re-gas capacity, and has benefited from a spurt in LNG demand. From a recent low in 4QFY10, volumes have consistently increased each quarter, with Dahej reaching 100% utilisation in 4QFY11. We expect further growth of 16% in FY13 due to a lower base. It is doubling capacity by FY14, and we believe it will remain a key gateway for LNG imports. It has a "too good to believe" LT GSPA, with the re-gas tariff increasing 5% pa. Apart from getting the same tariff on short/spot cargoes, the company keeps surprising on marketing gains on cargo that it markets. Yet, in the current framework, there is not much risk of regulatory intervention in tariffs, in our view.

Catalysts: New LT contracts for new capacity

Near-term capacity is all booked with short-term contracts, yet few spot cargoes could keep surprising. PLNG is set to double its capacity to 20mmtpa as it adds new 5mmt terminal at Kochi (starts in FY13) and expands at Dahej (15mmt by FY14, and eventually 18mmt). In addition to the current 7.5mmtpa LT contract (valid until 2029), it also has a 20-year 1.5mmtpa contract for Kochi (starts in 2014). As it increases capacity, it is looking to tie more LT LNG; early contracts would be positive.

Valuation: Stock has done well; we see more upside

We are now even more confident on PLNG's volume outlook near term, and expect volumes of 10.1/10.4mmt in FY12/13F (earlier 9.3/9.6 mmt). We increase our earnings estimates by sharp 27/35% in FY12/13F. We also roll forward our DCF valuation to FY13 and raise our PT by 24% to INR180/share. PLNG remains our favourite in mid-cap gas space.

31 Mar	FY10	FY11F		FY12F		FY13F	
Currency (INR)	Actual	Old	New	Old	New	Old	New
Revenue (mn)	106,491	128,852	131,973	180,616	188,569	238,905	250,012
Reported net profit (mn)	4,045	5,480	6,196	6,225	7,914	6,770	9,137
Normalised net profit (mn)	4,045	5,480	6,196	6,225	7,914	6,770	9,137
Normalised EPS	5.4	7.3	8.3	8.3	10.6	9.0	12.2
Norm. EPS growth (%)	-22.0	35.5	53.2	13.6	27.7	8.8	15.5
Norm. P/E (x)	24.5	N/A	16.0	N/A	12.5	N/A	10.8
EV/EBITDA	14.3	N/A	10.6	N/A	9.2	N/A	8.3
Price/book (x)	4.4	N/A	3.7	N/A	3.0	N/A	2.5
Dividend yield (%)	1.3	N/A	1.5	N/A	1.5	N/A	1.5
ROE (%)	19.2	22.6	25.2	22.0	26.5	20.5	24.9
Net debt/equity (%)	96.6	122.9	110.7	140.5	125.0	145.2	130.4

Source: Nomura estimates

Key company data: *See page 2 for company data, and detailed price/index chart.*
Rating: *See report end for details of Nomura's rating system.*

Anchor themes

As domestic gas production struggles, and limited visibility on ramp-up , R-LNG is most likely source for meeting India's gas appetite, in near to medium term.

Nomura vs consensus

Consensus estimates seem to be builiding in a pessimistic scenario on volume and tarrifs. Our FY13 EPS/PT are 20/25% higher than consensus.

Research analysts

India Oil & Gas/Chemicals

Anil Sharma - NFASL
anil.sharma.1@nomura.com
+91 22 4037 4338

Ravi Adukia, CFA - NFASL
ravikumar.adukia@nomura.com
+91 22 4037 4232

Key data on Petronet LNG

Income statement (INRmn)

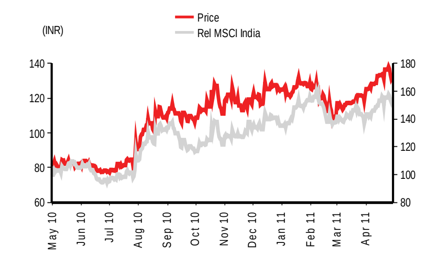
Year-end 31 Mar	FY09	FY10	FY11F	FY12F	FY13F
Revenue	**84,287**	**106,491**	**131,973**	**188,569**	**250,012**
Cost of goods sold	-73,756	-96,648	-118,012	-171,501	-229,361
Gross profit	**10,531**	**9,843**	**13,961**	**17,069**	**20,651**
SG&A	-2,543	-2,987	-3,645	-3,856	-5,191
Employee share expense	0	0	0	0	0
Operating profit	**7,988**	**6,856**	**10,316**	**13,213**	**15,460**
EBITDA	**9,013**	**8,465**	**12,163**	**15,165**	**18,330**
Depreciation	-1,025	-1,609	-1,847	-1,952	-2,870
Amortisation	0	0	0	0	0
EBIT	7,988	6,856	10,316	13,213	15,460
Net interest expense	-1,012	-1,839	-1,931	-2,008	-2,468
Associates & JCEs					
Other income	765	978	680	642	687
Earnings before tax	**7,740**	**5,995**	**9,064**	**11,847**	**13,679**
Income tax	-2,556	-1,950	-2,868	-3,933	-4,541
Net profit after tax	**5,184**	**4,045**	**6,196**	**7,914**	**9,137**
Minority interests	0	0	0	0	0
Other items	0	0	0	0	0
Preferred dividends	0	0	0	0	0
Normalised NPAT	**5,184**	**4,045**	**6,196**	**7,914**	**9,137**
Extraordinary items	0	0	0	0	0
Reported NPAT	**5,184**	**4,045**	**6,196**	**7,914**	**9,137**
Dividends	-1,536	-1,531	-1,755	-1,755	-1,755
Transfer to reserves	**3,649**	**2,514**	**4,441**	**6,159**	**7,382**
Valuation and ratio analysis					
FD normalised P/E (x)	19.1	24.5	16.0	12.5	10.8
FD normalised P/E at price target (x)	26.0	33.4	21.8	17.1	14.8
Reported P/E (x)	19.1	24.5	16.0	12.5	10.8
Dividend yield (%)	1.3	1.3	1.5	1.5	1.5
Price/cashflow (x)	34.5	9.6	11.3	9.7	7.0
Price/book (x)	5.0	4.4	3.7	3.0	2.5
EV/EBITDA (x)	12.8	14.3	10.6	9.2	8.3
EV/EBIT (x)	14.4	17.6	12.5	10.6	9.8
Gross margin (%)	12.5	9.2	10.6	9.1	8.3
EBITDA margin (%)	10.7	7.9	9.2	8.0	7.3
EBIT margin (%)	9.5	6.4	7.8	7.0	6.2
Net margin (%)	6.2	3.8	4.7	4.2	3.7
Effective tax rate (%)	33.0	32.5	31.6	33.2	33.2
Dividend payout (%)	29.6	37.8	28.3	22.2	19.2
Capex to sales (%)	9.4	9.8	10.7	10.4	9.1
Capex to depreciation (x)	7.7	6.5	7.6	10.0	8.0
ROE (%)	28.8	19.2	25.2	26.5	24.9
ROA (pretax %)	18.9	13.2	16.3	16.6	15.5
Growth (%)					
Revenue	28.6	26.3	23.9	42.9	32.6
EBITDA	4.1	-6.1	43.7	24.7	20.9
EBIT	4.6	-14.2	50.5	28.1	17.0
Normalised EPS	9.2	-22.0	53.2	27.7	15.5
Normalised FDEPS	9.2	-22.0	53.2	27.7	15.5
Per share					
Reported EPS (INR)	6.91	5.39	8.26	10.55	12.18
Norm EPS (INR)	6.91	5.39	8.26	10.55	12.18
Fully diluted norm EPS (INR)	6.91	5.39	8.26	10.55	12.18
Book value per share (INR)	26.45	29.80	35.72	43.93	53.78
DPS (INR)	1.75	1.75	2.00	2.00	2.00

Source: Nomura estimates

Notes

We expect next two year EPS CAGR of 21%

Price and price relative chart (one year)



(%)	1M	3M	12M
Absolute (INR)	9.0	4.0	68.2
Absolute (USD)	10.4	7.6	69.4
Relative to index	9.0	0.4	63.0
Market cap (USDmn)	2,239.9		
Estimated free float (%)	50.0		
52-week range (INR)	141.5/76.6		
3-mth avg daily turnover (USDmn)	5.55		
Major shareholders (%)			
Gail(India) Ltd	12.5		
BPCL	12.5		

Cashflow (INRmn)

Year-end 31 Mar	FY09	FY10	FY11F	FY12F	FY13F
EBITDA	9,013	8,465	12,163	15,165	18,330
Change in working capital	-3,295	2,791	-953	-1,107	215
Other operating cashflow	-2,844	-977	-2,443	-3,825	-4,433
Cashflow from operations	**2,874**	**10,279**	**8,767**	**10,233**	**14,111**
Capital expenditure	-7,894	-10,472	-14,105	-19,545	-22,855
Free cashflow	**-5,021**	**-193**	**-5,338**	**-9,312**	**-8,744**
Reduction in investments	2,431	-2,344	500	1,000	1,000
Net acquisitions	0	0	0	0	0
Reduction in other LT assets	0	0	0	0	0
Addition in other LT liabilities	30	540	218	0	0
Adjustments	708	-82	254	534	579
Cashflow after investing acts	**-1,853**	**-2,079**	**-4,366**	**-7,778**	**-7,165**
Cash dividends	-1,316	-1,536	-1,755	-1,755	-1,755
Equity issue	0	0	0	0	0
Debt issue	7,041	2,181	9,100	12,135	14,000
Convertible debt issue					
Others	-879	-1,739	-1,931	-2,008	-2,468
Cashflow from financial acts	**4,845**	**-1,094**	**5,414**	**8,372**	**9,777**
Net cashflow	**2,992**	**-3,173**	**1,048**	**594**	**2,612**
Beginning cash	3,586	6,578	3,405	4,453	5,047
Ending cash	6,578	3,405	4,453	5,047	7,658
Ending net debt	16,239	21,593	29,645	41,187	52,575

Source: Nomura estimates

Notes

Negative free cash flow owing to ongoing capex at Kochi and expansion at Dahej

Balance sheet (INRmn)

As at 31 Mar	FY09	FY10	FY11F	FY12F	FY13F
Cash & equivalents	6,578	3,405	4,453	5,047	7,658
Marketable securities	2,722	4,709	4,209	3,209	2,209
Accounts receivable	6,712	5,035	6,223	7,481	9,935
Inventories	3,856	2,223	3,276	3,740	4,140
Other current assets	952	1,554	1,709	1,880	2,068
Total current assets	**20,819**	**16,925**	**19,871**	**21,357**	**26,011**
LT investments	321	677	677	677	677
Fixed assets	33,156	42,012	54,270	71,863	91,848
Goodwill	0	0	0	0	0
Other intangible assets	0	0	0	0	0
Other LT assets	0	0	0	0	0
Total assets	**54,295**	**59,614**	**74,818**	**93,897**	**118,536**
Short-term debt	0	0	0	0	0
Accounts payable	7,365	7,449	8,737	9,351	12,419
Other current liabilities	1,557	1,557	1,712	1,884	2,072
Total current liabilities	**8,922**	**9,006**	**10,450**	**11,235**	**14,491**
Long-term debt	22,817	24,998	34,098	46,234	60,234
Convertible debt	0	0	0	0	0
Other LT liabilities	2,722	3,262	3,480	3,480	3,480
Total liabilities	**34,461**	**37,266**	**48,028**	**60,948**	**78,205**
Minority interest	0	0	0	0	0
Preferred stock	0	0	0	0	0
Common stock	7,500	7,500	7,500	7,500	7,500
Retained earnings	10,780	13,294	17,735	23,894	31,277
Proposed dividends	0	0	0	0	0
Other equity and reserves	1,555	1,555	1,555	1,555	1,555
Total shareholders' equity	**19,834**	**22,349**	**26,790**	**32,949**	**40,331**
Total equity & liabilities	**54,295**	**59,614**	**74,818**	**93,897**	**118,536**
Liquidity (x)					
Current ratio	2.33	1.88	1.90	1.90	1.79
Interest cover	7.9	3.7	5.3	6.6	6.3
Leverage					
Net debt/EBITDA (x)	1.80	2.55	2.44	2.72	2.87
Net debt/equity (%)	81.9	96.6	110.7	125.0	130.4
Activity (days)					
Days receivable	21.7	20.1	15.6	13.3	12.7
Days inventory	11.8	11.5	8.5	7.5	6.3
Days payable	28.8	28.0	25.0	19.3	17.3
Cash cycle	4.7	3.6	-1.0	1.5	1.7

Source: Nomura estimates

Notes

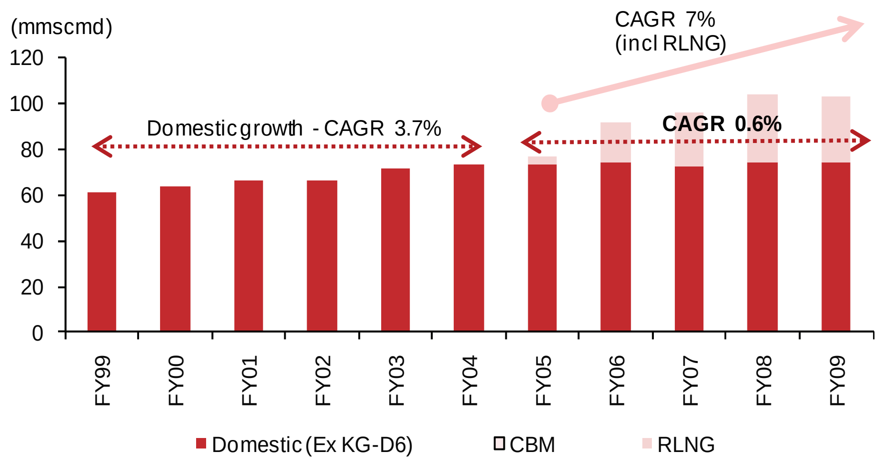
Net debt levels expected to increase in near term

PLNG – The key play on LNG story

Between FY05 and FY09, when domestic gas volume growth was a meagre 0.6% CAGR, re-gassified liquefied natural gas (R-LNG) had emerged as the key source of meeting India's increasing gas demand. Beginning with imports of 2.4mmt in 2004, imported volume grew to 8mmt (29mmscmd) in FY09, providing nearly 28% of Indian gas supplies.

Large LNG imports enabled gas availability to improve 7% CAGR between FY05 and FY09. Petronet LNG played the key role in these LNG imports – it had nearly 75% of LNG re-gas capacity and accounted for over 85% of LNG imports.

Fig. 128: R-LNG was the key source of growth between FY05 and FY09



Source: Petroleum Planning & Analysis Cell (PPAC), Nomura research

RLNG vols declined in 2HFY10 due to pipeline constraints

Even as the domestic supply situation dramatically improved with the KG-D6 block starting production in April-2009, RLNG volumes continued to grow in 1HFY10, in part due to considerably softened global spot LNG price. The import volumes of LNG peaked at ~39mmscmd in 2QFY10.

However, as KG-D6 volumes further ramped-up in 2HFY10 (reaching a peak of 60mmscmd in 4QFY10), the pipeline infrastructure did not come up in line with increasing gas availability, became a key bottleneck. Both spot and short-term LNG volumes took a big hit and nearly dried up by 4QFY10. Even as Petronet LNG's LT contract imports increased by 50% to 7.5mmtpa from January 2010, India's total LNG imports bottomed at ~26 mmscmd in 4QFY10 (quarter ending March 2010).

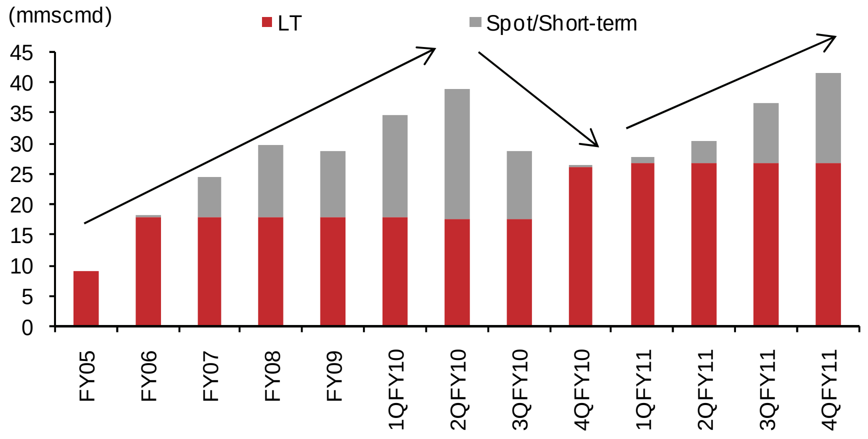
Volumes gradually but surely picked up in FY11

The situation on pipeline availability somewhat eased in 1HFY11, due to an accident and the resultant reduced production from PMT fields (July to October 2010) and also due to gradual declines that began in KG-D6 block. This enabled the import of some spot/short-term volumes.

Pipeline bottlenecks have now significantly eased after installation of compressors at Jhabua and Vijaipur on GAIL's DVPL (Dahej Vijaipur pipeline). With the installation of compression capacity, the pipeline capacity has now increased to 35mmscmd from 24 mmscmd earlier.

After virtually drying out in 4QFY10, spot/short term volumes grew at rapid pace in FY11

Fig. 129: Spot LNG volumes gradually picked up in FY11F



Source: PPAC, Nomura estimates

Next LNG wave – most capacity tied-up for FY12/13F

The capacity on the HVJ system will further increase as GAIL commissions a new 48" pipeline between Dahej & Vijaipur (DVPL -2). This pipeline, which has been delayed, is now expected to be completed by mid-2011. The commissioning of this new pipeline will further add ~60mmscmd to HVJ capacity on this key trunk route for taking gas to key markets in North and Western India. Once the DVPL-2 is complete, the capacity of HVJ system would exceed 130mmscmd, on our estimates. With this, the pipeline constraints that had affected volume growth over the past year should abate for the next few years, in our view.

We believe visibility on domestic supply will remain poor for the near to medium term. In our view, KG-D6 gas volumes are not likely to meaningfully increase near term, and there is no visibility of any other significant domestic source. Thus, RLNG to us is the most visible near- to medium-term source of gas.

As the current spare LNG capacity is fast filling up, LNG will provide the bulk of growth in FY12F, in our view. Also, the fact that significant new LNG re-gas capacity is under construction (capacity likely to double by FY14), we think that LNG will continue to be the key source of gas availability for next 3-4 years.

Significant short-term capacity booked recently

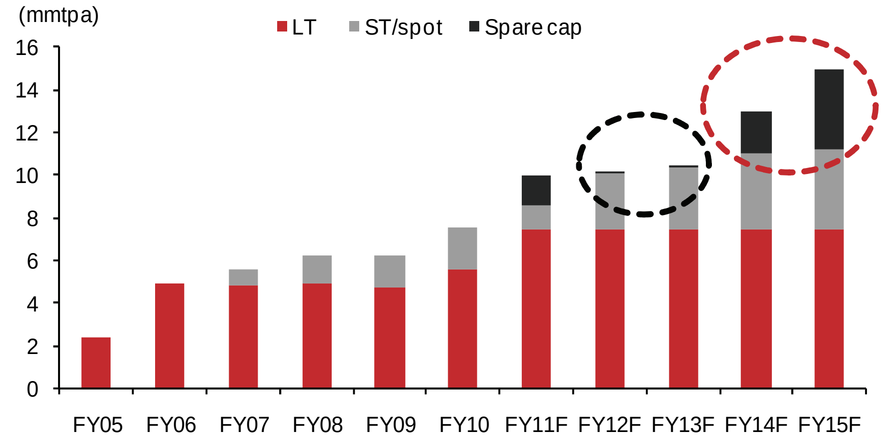
As domestic volumes declined, pipeline constraints eased, and short-term LNG prices remained relatively benign, there has been a spurt of several short-term contracts for LNG recently, by several key players. These have included:

- Petronet LNG firming up contracts for 1.1mmtpa for two years, and the company indicating that it is looking to tie-up further additional short-term capacity soon.
- GAIL has done a three-year deal with Marubeni for importing upto 0.5mmtpa short term LNG starting Jan 2011.
- Gujarat State Petroleum Corporation Ltd. (GSPC) has in January 2011 concluded an agreement with GM&T (Gazprom Marketing & Trading) for about 0.3mmt for a period of two years commencing 2H11. Earlier, GSPC had signed a short-term contract for sourcing LNG with Gas Natural (Spain) and also a nine cargo deal with Repsol (Spain).
- Recently, media outlets (Moneycontrol.com, "Reliance in 2-year pact with Hazira LNG" dated 1 March, 2011, and Petrowatch, "Reliance talks to Marubeni to import term LNG" 24 February, 2001) reported that RIL is in talks with Marubeni to import 24-35 cargoes over the next two years, and that it has signed a two-year contract with Hazira LNG to import these cargoes.

Owing to these short-term deals, in addition to a few spot cargoes that keep coming in, we expect that both Petronet LNG's Dahej terminal and Shell & Total's Hazira terminal may see full capacity utilisation in FY12 and FY13. Thus, compared to total LNG imports of about 9.0–9.2mmt LNG in FY11, India may import nearly 13.5mmt LNG, a y-y increase of nearly 50%.

Petronet LNG's Dahej terminal has now already reached full utilisation levels (99% in 4QFY11). Company seems confident that with better optimisation of cargoes the terminal could import even upto 10.5-11mmt (105-110% utilisation). Similarly, recently in an interview with *Economic Times* ("We are thinking of increasing capacity at Hazira" 22 March, 2011), Peter Voser, Shell's CEO, mentioned that the Hazira terminal is now running at full capacity and the company is thinking of increasing capacity there.

Fig. 130: We expect near full utilisation of Dahej terminal in FY12/13

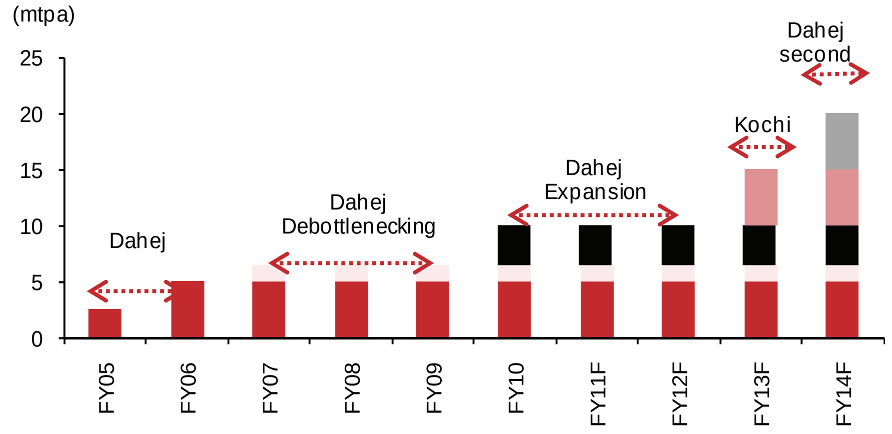


Source: Company data, Nomura estimates

PLNG expecting to double its capacity by FY14-end

PLNG is set to double its capacity to 20mmtpa by FY14 end. It is adding a new 5mmtpa terminal at Kochi (commissions in FY13), and a second jetty and other infrastructure at existing Dahej terminal (capacity to reach 15mmtpa in FY14, and eventually to 18mmtpa). In addition to the existing 7.5mmtpa LT contract, it also has a 1.5mmtpa LT contract for Kochi. The company is aggressively scouting to tie-up more LT LNG, and in the interim has booked significant short-term volumes.

Fig. 131: PLNG import capacity likely to double by FY14 end



Source: Company data, Nomura estimates

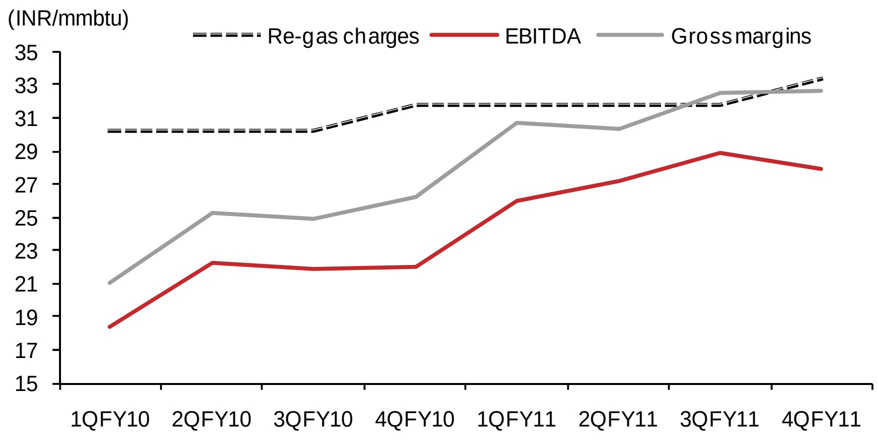
Almost "too good to believe" GSPA with off-takers

PLNG has a distinctive and almost "too good to believe" gas supply purchase agreement with its off-takers (GAIL 60%, IOC 30%, and BPCL 10%), who also happen to be its promoters. It passes all the commodity price risk, and gets 5% annual escalation in re-gasification charges.

The company has been able to increase the escalation rate by 5% over the past six years, from INR23.7/mmbtu in 2004 to the current INR33.4/mmbtu, an increase of nearly 41%.

Moreover, compared to current long term contract of 7.5mmtpa, the company now has design capacity of 10mmtpa at Dahej terminal. It utilises the balance capacity to bring in spot/short-term cargoes, on which it charges the same re-gas tariff as applicable on the LT RasGas contract. In addition, the company is now targeting to get incrementally more spot/short-term cargo, which it itself markets (compared to its earlier scheme of making additional capacity for third-party volumes). On the quantities the company that the markets itself, it makes significant marketing margins, which in recent quarters have surprised on the positive side.

Fig. 132: Marketing gain leading to higher gross & EBITDA margin per unit



Source: Company data; Nomura research

We believe regulatory risk for tariff control is low

The current regulatory environment continues to remain chaotic. Also, the way the regulatory environment will evolve remains a grey area and of concern. However, we believe that the PNGRB Act and regulations in their current form indicate that PNGRB is not likely to monitor and regulate re-gasification tariffs.

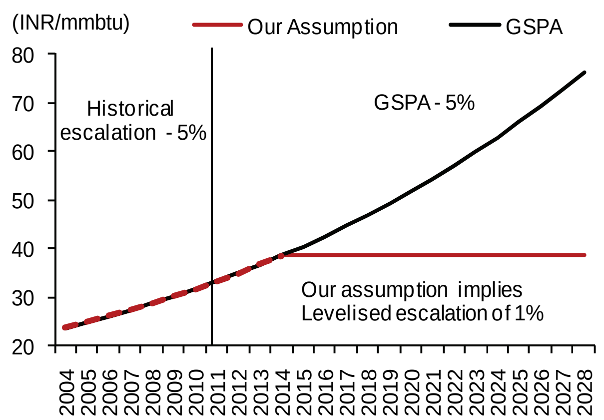
Currently the PNGRB Act requires the entities establishing or operating LNG terminals to seek registration. However, LNG terminals are out of the purview of entities that would be regulated for tariffs or third-party access. The existing terminal operators have argued that as these terminals were developed before the PNGRB Act came into force, and were developed on the premise that these would not come under third-party open access. The terminal operators have also argued that rather than equating these terminals with infrastructure (such as pipelines or storage terminals), they should be seen as production facilities for producing gas, which are outside the purview of the regulator.

However, we are conservative on our tariff assumptions

Even as we believe that the likelihood of tariff regulation by regulators is low, and PLNG has “too good to believe” off-take agreements, including a 5% escalation clause, we believe some consumers will start raising concerns on rising tariffs, which in turn increase delivered gas costs. Even though re-gas tariffs now are less than 10% of delivered LNG price, the pressure to revisit the tariffs could emerge, in our view. Also, as India’s re-gas capacity increases, and new operators enter the current seemingly very lucrative business model, competitive pressure could also increase.

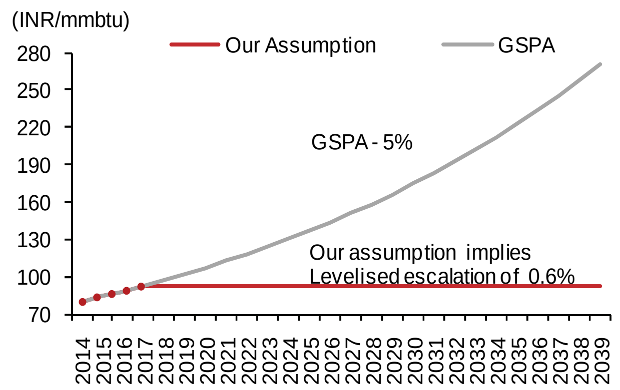
In our current assumptions, compared to a 5% escalation for the entire period of GSPAs, we assume that PLNG will increase tariffs only for next three years by 5% and thereafter tariffs would remain flat. We think this is a rather conservative assumption, and PLNG could surprise on the upside.

Fig. 133: Dahej – GSPA for 5% pa tariff increase; we assume levelised escalation of only 1%



Source: Company data; Nomura estimates

Fig. 134: Kochi – Our levelised tariff increase of only 0.6% pa vs. 5% as per GSPA



Source: Company data; Nomura estimates

Raise near-term volume assumption, remain conservative LT

With capacity nearly all booked, and the management remaining confident of achieving 105% utilisation (10.5mmtpa) near term, we have increased our volume assumption by 7%/5% for FY12F/13F and now assume throughput volume of 10/10.1mmtpa for FY12F/13F.

Even though, we remain confident that R-LNG is likely to remain a key source of increased domestic availability, and PLNG would be the key beneficiary if India were to sign any LT contract, discussions on which continue, as mentioned earlier in this report. However, as any new LT agreements are not in place, our volume assumption for our DCF are quiet conservative, in our view.

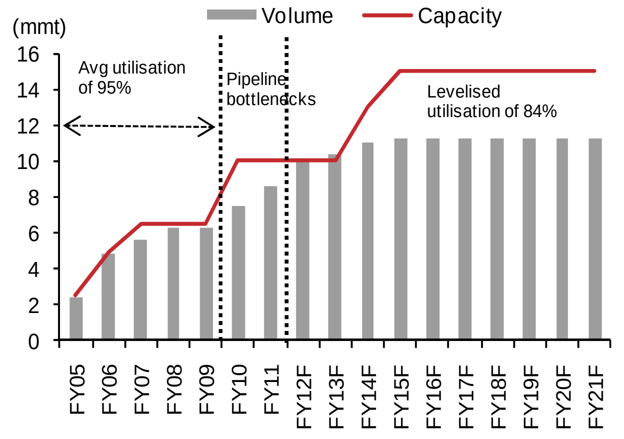
Compared to historical capacity utilisation of nearly 95% since the Dahej terminal has been operational; our levelised capacity utilization forecasts based on our DCF volume assumptions are only 80% for Dahej and 40% for Kochi.

Fig. 135: Key changes to our volumes assumption

	FY10	FY11	FY12F		FY13F	
			New	Old	New	Old
Dahej's volume(mmt)						
- Long term	5.6	7.5	7.5	7.5	7.5	7.5
- Short term/spot	1.9	1.1	2.6	1.8	2.9	2.1
- Total	**7.6**	**8.6**	**10.1**	**9.3**	**10.4**	**9.6**
Change %				8%		8%

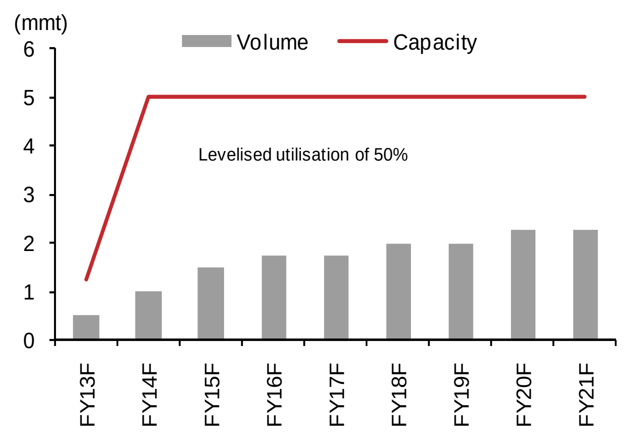
Source: Company data and Nomura estimates

Fig. 136: Historical capacity utilisation at 95% -- we assume 84% levelised utilisation at Dahej



Source: Company data, Nomura estimates

Fig. 137: …and 50% levelised utilisation at Kochi terminal



Source: Company data, Nomura estimates

Our revised DCF based PT is INR180/share

We are now even more confident in PLNG's volume outlook near term, and expect volumes of 10.1/10.4mmt in FY12/13F (earlier 9.3/9.6 mmt). Our earnings estimates increase by a sharp 27/35% in FY12/13F. We also roll forward our DCF valuation to FY13 and raise our PT by 24% to INR180/share.

Below are our key assumptions:

Dahej Terminal

- We assume throughput volume of 10.0/10.1/11.0mmtpa for FY12F/13F/14F. Our volume assumptions are conservative, as our numbers imply only 84% levelised utilization compared to average capacity utilization of 95%, between FY05 and FY09. The utilisation levels were lower in FY10 and FY11, mainly due to downstream pipeline constraints.
- We conservatively assume that PLNG will increase its tariff only for next three years by 5% pa and there-after tariff would remain flat, even as per GSPA tariffs can be increased by 5% pa for entire duration of GSPAs until 2029.
- We assume WACC of 10% and terminal growth rate of 1%.

Kochi Terminal

- The Kochi terminal is expected to be commissioned in FY13 – an initial 2.5mtpa capacity is likely by September 2012 and full capacity of 5mtpa is expected by 13 March. The Kochi terminal currently has 1.5mtpa of long-term LNG contracts tied-up with Gorgon LNG Australia, which is expected to start operations by 2014/15. In the mean time, the Kochi terminal can resort to spot cargoes. We are very conservative in our assumptions of LNG volume at the Kochi terminal and only assume volume of 0.5/1.0mtpa in FY13F/14F. Our DCF valuation implies levelised utilisation of only 50% at the Kochi terminal.
- Management has indicated that the off-take agreement for the long-term LNG contract for the Kochi terminal provides for initial re-gas charges of INR80/mmbtu and 5% annual escalation, similar to the Dahej off-take agreement. We conservatively assume 5% escalation for the first three years of the contract and flat tariffs thereafter.
- We assume total capex of INR40bn at Kochi (for 5mtpa capacity) and 70% debt financing.

Fig. 138: PLNG – DCF valuation

Key assumptions and Valuation	FY13 end
Terminal Growth rate	1%
WACC	10%
Valuation (INRmn)	
Discounted FCFF	70,692
Terminal cash flow	99,896
Enterprise Valuation	**170,588**
Net Debt (FY12end)	37,301
Implied Mcap	**133,288**
Value per share (INR)	179
Price Target (INR)	**180**

	FY11F	FY12F	FY13F	FY14F	FY15F	FY16F	FY17F	FY18F	FY19F	FY20F	FY21F
LNG Volumes (MMT)											
- Dahej	8.6	10.1	10.4	11.0	11.3	11.3	11.3	11.3	11.3	11.3	11.3
- Kochi	0.0	0.0	0.5	2.0	2.0	2.0	2.0	2.0	2.5	2.5	2.5
Net back Margins (INR/mmbtu)											
- Dahej	31.9	33.2	35.1	37.8	37.8	37.8	37.8	37.8	37.8	37.8	37.8
- Kochi	-	-	80.0	84.0	80.0	84.0	88.2	92.6	92.6	92.6	92.6
EBIT	**10,432**	**13,213**	**15,460**	**20,851**	**19,157**	**19,338**	**19,544**	**19,768**	**21,617**	**21,459**	**21,300**
FCFF			-9,658	2,339	16,570	16,857	17,153	17,461	18,854	18,907	18,959
Discounted FCFF			**-9,658**	**2,127**	**13,703**	**12,677**	**11,730**	**10,859**	**10,663**	**9,724**	**8,867**

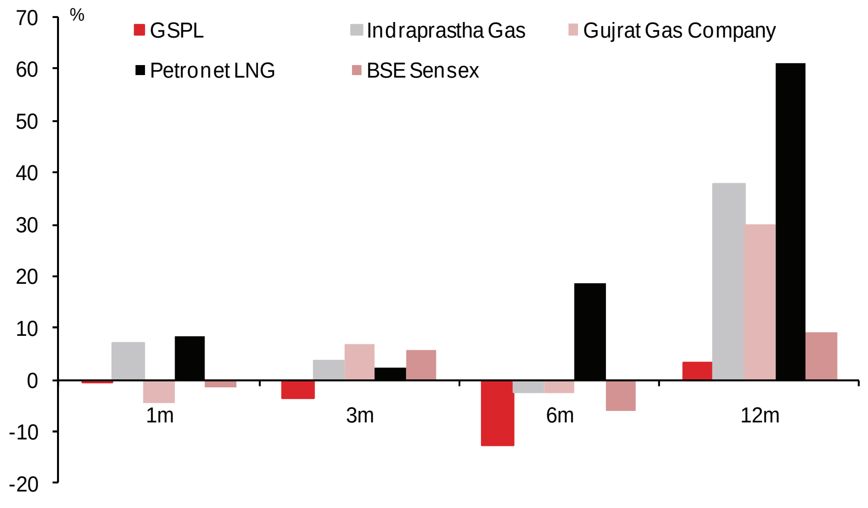
Source: Nomura estimates

Despite run-up, valuations still attractive

With diminishing volumes and a more negative outlook on near-term domestic gas supplies, and improving LNG outlook and rising LNG volumes, PLNG has seen a sharp run-up over last few months, outperforming the broader market and also other mid-cap gas names such as GSPL, Indraprastha Gas, and Gujarat Gas.

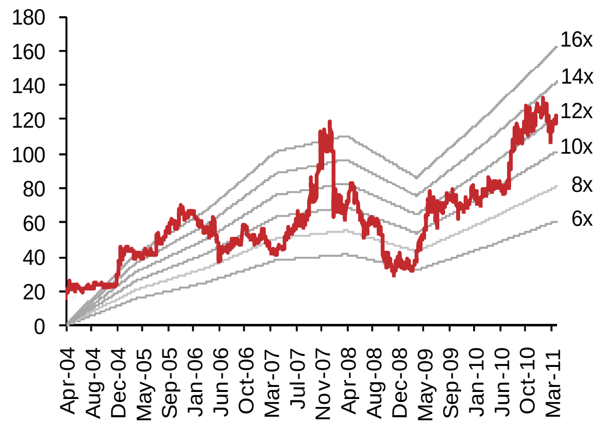
Despite such outperformance, we still think that a lot of potential upside remains. Our assumption on LNG volumes and tariff (vs historical levels) are conservative, and yet our PT of INR180 implies upside of ~36% at current levels.

Fig. 139: PLNG has outperformed its peer mid-cap gas names and also Sensex over the past 1/3/6/12M



Source: Bloomberg, Nomura research

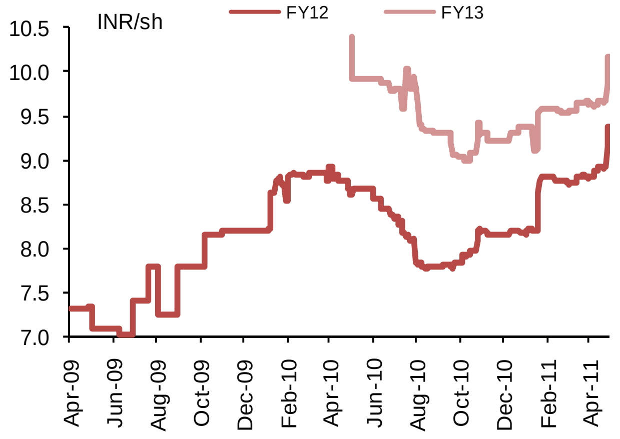
Fig. 140: PLNG - 1yr fwd P/E band chart



Source: Add Source Here

Fig. 141: Street earnings estimates on the rise

With improving LNG volumes, Street is upgrading estimates



Source: Add Source Here

Key earnings and valuation sensitivities

Fig. 142: Market seems to be building in no tariff growth and only 75% utilisation

Levelised tariff	Levelised utilisation rate at Dahej: 70%	75%	80%	84%	90%	100%
0%	119	**135**	152	164	184	216
1%	130	148	165	**179**	200	234
2%	143	162	181	195	217	253
3%	157	177	197	212	236	274
4%	172	193	214	231	256	297
5%	188	211	233	251	278	322

Source: Nomura estimates

Fig. 143: Sensitivity of DCF valuation to WACC and Terminal growth rate

Terminal Growth Rate	WACC (%): 8%	9%	10%	11%	12%
0%	226	191	164	141	122
1%	252	210	**179**	152	131
2%	287	235	197	165	141
3%	336	268	220	182	154
4%	410	314	251	204	170
5%	533	383	295	233	190

Source: Nomura estimates

Fig. 144: Earnings sensitivity to key variables

	FY12		FY13	
Base EPS	10.6		12.2	
EPS change				
LNG volume				
Base case (mmtpa)	10.1		10.4	
+ Increase of 1.0MT	1.3	12.6%	1.5	11.9%
Regas Charges				
Base case (INR/mmbtu)	33.8		35.5	
-Cut by 5%	-0.8	-7.3%	-0.9	-7.2%
Marketing Margins (INR/mmbtu)				
Base case (INR/mmbtu)	18		18	
+ Increase of INR5	0.4	3.9%	0.5	4.1%

Source: Nomura estimates

Valuation methodology and investment risks

We use a DCF methodology to value Petronet LNG. Based on WACC of 10% and terminal growth of 1%, our DCF-based price target is INR180.

Key downside risks: 1) Lower-than-expected spot volumes could result in downside to our numbers. 2) The Dahej off-take agreement provides for 5% annual rises in the regasification charges. Although we believe we are conservative in our assumptions on re-gasification charges, a sharp cut could have a negative impact on profitability and valuations. 3) PLNG's Kochi terminal is under construction and execution delays and cost overruns could hurt our valuation of the Kochi terminal.

Indraprastha Gas IGAS.BO IGL IN

OIL & GAS/CHEMICALS

NOMURA
EQUITY RESEARCH

A secular CGD story

Advantage Delhi & CNG continues; focus now on industrial piped gas

May 6, 2011

Rating Remains	**Buy**
Target price Increased from 440	INR 450
Closing price April 29, 2011	INR 322
Potential upside	+39.8%

Action: Secular CGD story with consistent ability to pass costs

IGL enjoys twin advantages of being in Delhi NCR (India's largest metro) and marketing CNG (emerging fuel of choice). In our view, concerns on its ability to pass along gas costs have been reduced by the ease with which it has passed on all cost increases over the past year (including a more than 100% APM increase) to raise CNG prices by 35%. Yet IGL's prices remain the lowest in India, and the cheapest for transport fuel. The company's advantage has further increased as most key car makers now provide factory-fitted CNG vehicles, and availability should further improve as it commissions ~70 new outlets over the next few months.

Catalysts: Growth in NCR areas, industrial segment, more allocation

Focus is now on taking CNG to big NCR areas like Noida, Greater Noida and Ghaziabad. With current domestic allocation for CNG/domestic piped gas being fully utilised, IGL is seeking more allocation. We believe that, given the priority for CGD, more availability should soon be forthcoming. Industrial piped gas, a hitherto untapped industrial segment due to earlier gas shortages, is seeing sharp y-y growth of over 100%. The industrial pie can be very large, as the industrial segment still accounts for less than 10% of volume, compared to over 80% in the case of Gujarat Gas.

Valuation: Recent correction a buying opportunity

Even though the shares have done very well (outperforming the Sensex by 26%/62% over 1Y/2Y) on improved gas availability, we still see significant upside, and our estimates remain conservative. We think the recent correction (6% YTD) provides a good opportunity to enter this secular downstream CGD story. Reiterate BUY with revised PT of INR450.

31 Mar	FY10		FY11F		FY12F		FY13F
Currency (INR)	Actual	Old	New	Old	New	Old	New
Revenue (mn)	10,781	17,035	17,753	20,783	25,133	24,253	31,546
Reported net profit (mn)	2,155	2,753	2,609	3,194	3,187	3,692	3,711
Normalised net profit (mn)	2,155	2,753	2,609	3,194	3,187	3,692	3,711
Normalised EPS	15.4	19.7	18.6	22.8	22.8	26.4	26.5
Norm. EPS growth (%)	24.9	27.7	21.1	16.0	22.2	15.6	16.4
Norm. P/E (x)	20.9	N/A	17.3	N/A	14.1	N/A	12.1
EV/EBITDA	11.5	N/A	9.6	N/A	7.8	N/A	6.4
Price/book (x)	5.5	N/A	4.4	N/A	3.6	N/A	2.9
Dividend yield (%)	1.4	N/A	1.4	N/A	1.4	N/A	1.4
ROE (%)	28.6	29.7	28.4	27.8	28.1	26.0	26.4
Net debt/equity (%)	net cash	net cash	23.0	net cash	22.8	net cash	11.7

Source: Nomura estimates

Key company data: *See page 2 for company data, and detailed price/index chart.*
Rating: *See report end for details of Nomura's rating system.*

Anchor themes

CNG business in Delhi NCR is a secular growth story. Increased gas availability provides growth opportunites in industrial segments and newer markets.

Nomura vs consensus

We are more optimistic on volume growth both in CNG and PNG. Street seems to be cautious. Our FY13F EPS and price target is 12% and 25%, respectively, ahead of consensus estimates.

Research analysts

India Oil & Gas/Chemicals

Anil Sharma - NFASL
anil.sharma.1@nomura.com
+91 22 4037 4338

Ravi Adukia, CFA - NFASL
ravikumar.adukia@nomura.com
+91 22 4037 4232

Key data on Indraprastha Gas

Income statement (INRmn)

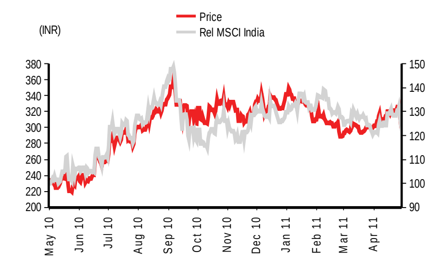
Year-end 31 Mar	FY09	FY10	FY11F	FY12F	FY13F
Revenue	**8,528**	**10,781**	**17,753**	**25,133**	**31,546**
Cost of goods sold	-4,108	-4,949	-10,159	-15,672	-20,298
Gross profit	**4,420**	**5,833**	**7,594**	**9,461**	**11,249**
SG&A	-2,071	-2,799	-3,686	-4,578	-5,601
Employee share expense	0	0	0	0	0
Operating profit	**2,349**	**3,033**	**3,908**	**4,883**	**5,648**
EBITDA	**3,024**	**3,808**	**4,913**	**6,149**	**7,309**
Depreciation	-674	-775	-1,005	-1,266	-1,661
Amortisation	0	0	0	0	0
EBIT	2,349	3,033	3,908	4,883	5,648
Net interest expense	-23	0	-109	-288	-267
Associates & JCEs	0	0	0	0	0
Other income	262	211	107	177	174
Earnings before tax	**2,589**	**3,244**	**3,905**	**4,772**	**5,555**
Income tax	-864	-1,089	-1,297	-1,584	-1,844
Net profit after tax	**1,725**	**2,155**	**2,609**	**3,187**	**3,711**
Minority interests	0	0	0	0	0
Other items	0	0	0	0	0
Preferred dividends	0	0	0	0	0
Normalised NPAT	**1,725**	**2,155**	**2,609**	**3,187**	**3,711**
Extraordinary items	0	0	0	0	0
Reported NPAT	**1,725**	**2,155**	**2,609**	**3,187**	**3,711**
Dividends	-655	-735	-737	-737	-737
Transfer to reserves	**1,070**	**1,420**	**1,872**	**2,450**	**2,974**
Valuation and ratio analysis					
FD normalised P/E (x)	26.1	20.9	17.3	14.1	12.1
FD normalised P/E at price target (x)	36.5	29.2	24.2	19.8	17.0
Reported P/E (x)	26.1	20.9	17.3	14.1	12.1
Dividend yield (%)	1.2	1.4	1.4	1.4	1.4
Price/cashflow (x)	20.6	13.8	11.8	9.1	7.6
Price/book (x)	6.6	5.5	4.4	3.6	2.9
EV/EBITDA (x)	14.4	11.5	9.6	7.8	6.4
EV/EBIT (x)	18.5	14.4	12.1	9.8	8.3
Gross margin (%)	51.8	54.1	42.8	37.6	35.7
EBITDA margin (%)	35.5	35.3	27.7	24.5	23.2
EBIT margin (%)	27.5	28.1	22.0	19.4	17.9
Net margin (%)	20.2	20.0	14.7	12.7	11.8
Effective tax rate (%)	33.4	33.6	33.2	33.2	33.2
Dividend payout (%)	38.0	34.1	28.3	23.1	19.9
Capex to sales (%)	20.2	36.2	37.9	19.3	13.4
Capex to depreciation (x)	2.6	5.0	6.7	3.8	2.6
ROE (%)	27.4	28.6	28.4	28.1	26.4
ROA (pretax %)	34.8	35.2	30.4	27.5	26.8
Growth (%)					
Revenue	20.8	26.4	64.7	41.6	25.5
EBITDA	0.4	25.9	29.0	25.2	18.9
EBIT	-1.5	29.1	28.8	25.0	15.7
Normalised EPS	-1.1	24.9	21.1	22.2	16.4
Normalised FDEPS	-1.1	24.9	21.1	22.2	16.4
Per share					
Reported EPS (INR)	12.32	15.39	18.63	22.77	26.50
Norm EPS (INR)	12.32	15.39	18.63	22.77	26.50
Fully diluted norm EPS (INR)	12.32	15.39	18.63	22.77	26.50
Book value per share (INR)	48.82	58.96	72.33	89.83	111.07
DPS (INR)	4.00	4.50	4.50	4.50	4.50

Source: Nomura estimates

Notes

We expect near 20% annual EPS growth to continue, driven by CNG, expansion in NCR towns and sharp growth in the PNG segment

Price and price relative chart (one year)



(%)	1M	3M	12M
Absolute (INR)	7.4	4.2	37.4
Absolute (USD)	8.8	7.8	38.4
Relative to index	7.5	0.6	32.2
Market cap (USDmn)	1,018.0		
Estimated free float (%)	55.0		
52-week range (INR)	374/215.1		
3-mth avg daily turnover (USDmn)	2.13		
Major shareholders (%)			
GAIL (India)Ltd	22.5		
Bharat Petroleum Corporation Ltd	22.5		

Cashflow (INRmn)

Year-end 31 Mar	FY09	FY10	FY11F	FY12F	FY13F
EBITDA	3,024	3,808	4,913	6,149	7,309
Change in working capital	-175	272	112	233	256
Other operating cashflow	-662	-807	-1,197	-1,440	-1,643
Cashflow from operations	**2,186**	**3,273**	**3,827**	**4,942**	**5,922**
Capital expenditure	-1,720	-3,905	-6,728	-4,840	-4,237
Free cashflow	**466**	**-632**	**-2,901**	**102**	**1,685**
Reduction in investments	47	872	0	0	0
Net acquisitions					
Reduction in other LT assets	0	0	0	0	0
Addition in other LT liabilities	167	316	201	352	385
Adjustments	38	-149	-104	-256	-294
Cashflow after investing acts	**718**	**406**	**-2,804**	**199**	**1,776**
Cash dividends	-655	-655	-735	-737	-737
Equity issue	0	0	0	0	0
Debt issue	0	0	3,364	468	-1,000
Convertible debt issue	0	0	0	0	0
Others	0	0	0	0	0
Cashflow from financial acts	**-655**	**-655**	**2,629**	**-269**	**-1,737**
Net cashflow	**63**	**-249**	**-175**	**-71**	**39**
Beginning cash	1,399	1,462	1,213	1,038	967
Ending cash	1,462	1,213	1,038	967	1,006
Ending net debt	-1,462	-1,213	2,326	2,865	1,826

Source: Nomura estimates

Notes

Debt/equity levels are moderate and likely to decline, even after the company raised debt last year for capex needed to grow its network

Balance sheet (INRmn)

As at 31 Mar	FY09	FY10	FY11F	FY12F	FY13F
Cash & equivalents	1,462	1,213	1,038	967	1,006
Marketable securities	1,042	170	170	170	170
Accounts receivable	319	335	434	534	668
Inventories	237	278	326	419	525
Other current assets	574	747	815	891	974
Total current assets	**3,634**	**2,742**	**2,783**	**2,981**	**3,344**
LT investments	0	0	0	0	0
Fixed assets	5,211	8,340	14,064	17,638	20,214
Goodwill	0	0	0	0	0
Other intangible assets	0	0	0	0	0
Other LT assets	0	0	0	0	0
Total assets	**8,845**	**11,083**	**16,847**	**20,619**	**23,557**
Short-term debt	0	0	0	0	0
Accounts payable	857	1,262	1,583	2,080	2,656
Other current liabilities	679	776	782	786	790
Total current liabilities	**1,536**	**2,038**	**2,365**	**2,867**	**3,447**
Long-term debt	0	0	3,364	3,832	2,832
Convertible debt					
Other LT liabilities	474	790	991	1,343	1,728
Total liabilities	**2,011**	**2,828**	**6,721**	**8,042**	**8,007**
Minority interest	0	0	0	0	0
Preferred stock	0	0	0	0	0
Common stock	1,400	1,400	1,400	1,400	1,400
Retained earnings	5,434	6,854	8,726	11,176	14,150
Proposed dividends	0	0	0	0	0
Other equity and reserves	0	0	0	0	0
Total shareholders' equity	**6,834**	**8,254**	**10,126**	**12,576**	**15,550**
Total equity & liabilities	**8,845**	**11,083**	**16,847**	**20,619**	**23,557**
Liquidity (x)					
Current ratio	2.37	1.35	1.18	1.04	0.97
Interest cover	103.2	na	35.7	17.0	21.2
Leverage					
Net debt/EBITDA (x)	net cash	net cash	0.47	0.47	0.25
Net debt/equity (%)	net cash	net cash	23.0	22.8	11.7
Activity (days)					
Days receivable	11.7	11.1	7.9	7.0	7.0
Days inventory	20.7	19.0	10.8	8.7	8.5
Days payable	73.1	78.2	51.1	42.8	42.6
Cash cycle	-40.7	-48.1	-32.3	-27.0	-27.1

Source: Nomura estimates

Notes

Strong balance sheet with conservative financing

Advantage CNG continues

Despite price increase, CNG remains cheapest fuel

Compressed natural gas, besides being a cleaner and more environmentally friendly “green” fuel, is much cheaper than liquid transportation fuels. Despite raising prices by nearly 35% over the past one year, and compared to lower price increases for petrol (23%) and diesel (6%), CNG remains far cheaper than both.

Conversion economics remain very favourable, and at nominal daily use of 50km, a CNG-driven vehicle can recoup the CNG kit cost in just about a year.

With several key car makers now making the choice available to purchase factory-fitted CNG cars, the CNG growth is likely to see further momentum, in our view.

Fig. 145: Continued ability to raise prices

Prices up 8x in the past three years, 4x in the past year alone

	CNG price	Change	
Date	**INR/kg**	**INR/kg**	**%**
Mar-08	18.9	-0.3	-2%
Jun-09	21.2	2.3	12%
Mar-10	21.7	0.5	2%
May-10	21.9	0.2	1%
Jun-10	**27.5**	**5.6**	**26%**
Oct-10	27.8	0.3	1%
Jan-11	29.0	1.3	5%
Apr-11	29.3	0.3	1%
Price hikes in last 1 year		7.6	35%

Source: Company data, Nomura research

Fig. 146: Still, IGL's CNG prices are among the lowest in India

Company	Area of operations	Price (INR/kg)	Diff (INR/kg)
Bhagyanagar Gas	Hyderabad	40.0	10.7
Green Gas	Agra, Lucknow	39.0	9.7
Aavantika Gas	Ujjain	37.0	7.7
Adani Energy	Ahmedabad, Vadodara	36.7	7.4
Gujarat Gas	Surat, Bharuch, Ankleshwar	35.3	6.0
Central UP Gas	Kanpur, Bareilly	35.0	5.7
Bhagyanagar Gas	Rajahmundery	35.0	5.7
GAIL	Vadodara	32.1	2.8
GSPC Gas	Gujarat	31.6	2.3
Mahanagar Gas	Mumbai	31.5	2.2
Indraprastha Gas	**Delhi**	**29.3**	
	Noida, Greater Noida, Ghazia	**32.9**	

Note: Comparison based on latest available prices

Source: Infraline, Nomura research

Fig. 147: CNG remains cheapest transport fuel

		Petrol	Diesel	Auto LPG	CNG
Retail Price	INR/litre	58.4	37.7	35.0	
	INR/kg	78.8	45.6	59.5	29.3
Calorific value	Kcal/kg	11,200	10,860	11,020	10,923
Equivalent price	INR / 10,000kcal	70.4	42.0	54.0	26.8
Advantage	**%**	**62%**	**36%**	**50%**	

Source: PPAC, Nomura estimates

Fig. 148: Conversion economics remain very favourable

Vehicle	Fuel	Avg use	Conversion cost	Payback period
		(kms)	**(INR)**	**(months)**
Private Car	Petrol	50	40,000	12
Taxi	Diesel	100	40,000	13
Auto	Diesel	100	23,000	11
Bus	Diesel	150	400,000	26

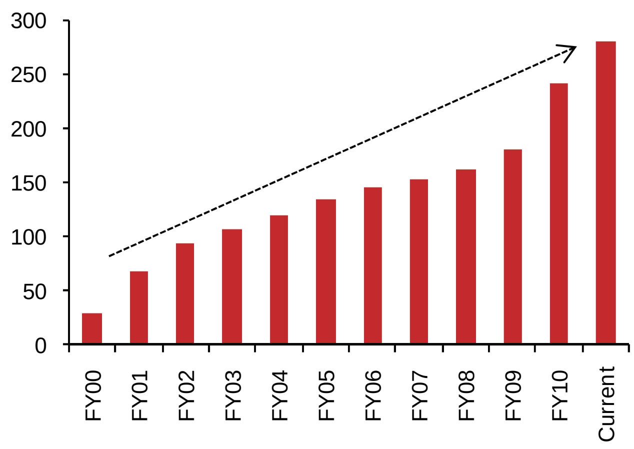
Source: Nomura estimates

Fig. 149: Factory-fitted CNG models likely to increase discretionary conversion

Manufacturer	Car Models
Maruti Suzuki	SX4, Eeco, Wagon R, Estilo and Alto
Toyota	Innova, Corolla Altis
General Motors	Chevrolet Aveo

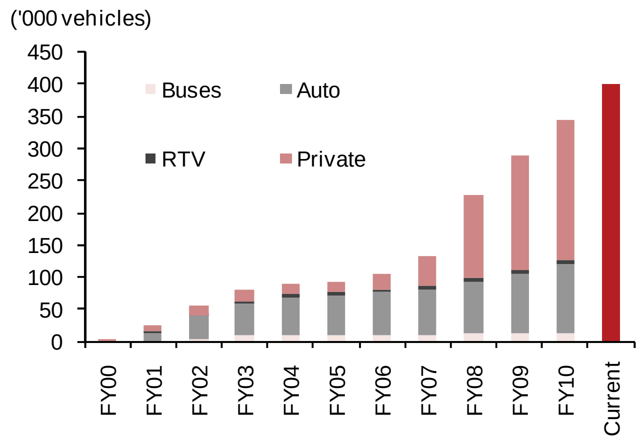
Source: Company data, Nomura research

Fig. 150: Availability improving with rising CNG outlets



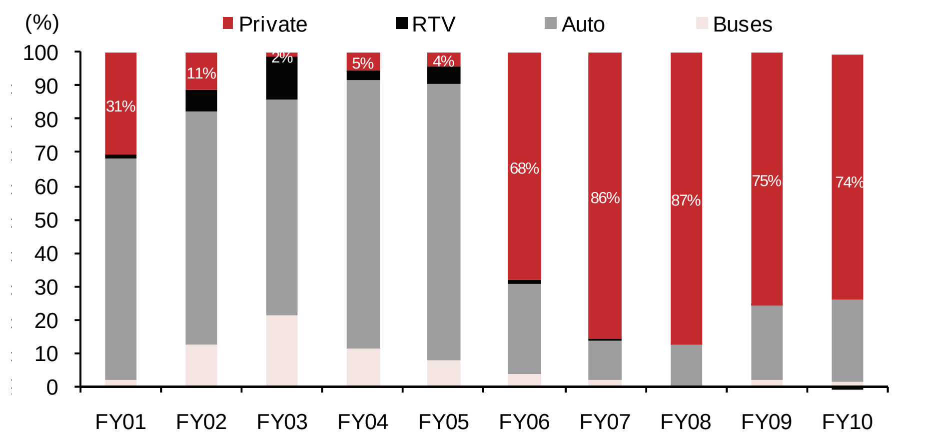
Source: Company data, Nomura research

Fig. 151: Sharp growth in CNG fleet continues



Source: Company data, Nomura research

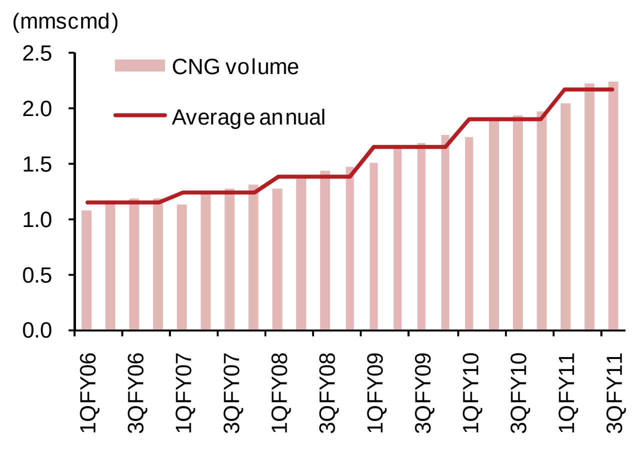
Fig. 152: Private vehicles make up ~80% of CNG vehicle growth in past five years



Source: Company data, Nomura research

Fig. 153: CNG volume growth remains robust

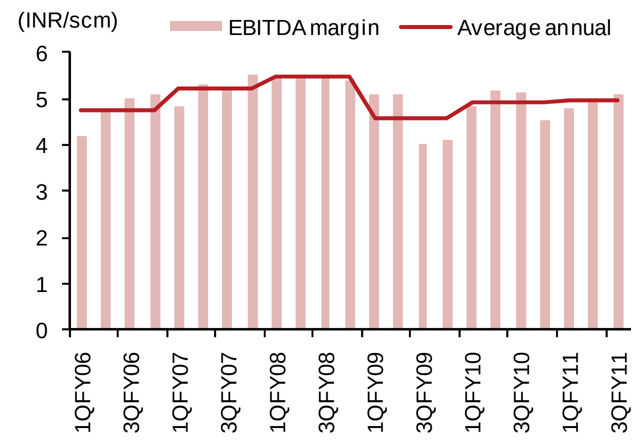
CAGR of 15% over past four years; 16% y-y growth in 9MFY11



Sourc : Company data, Nomura research

Fig. 154: Ability to pass on cost increase prices

Per unit margin remains resilient



Source: Company data, Nomura research

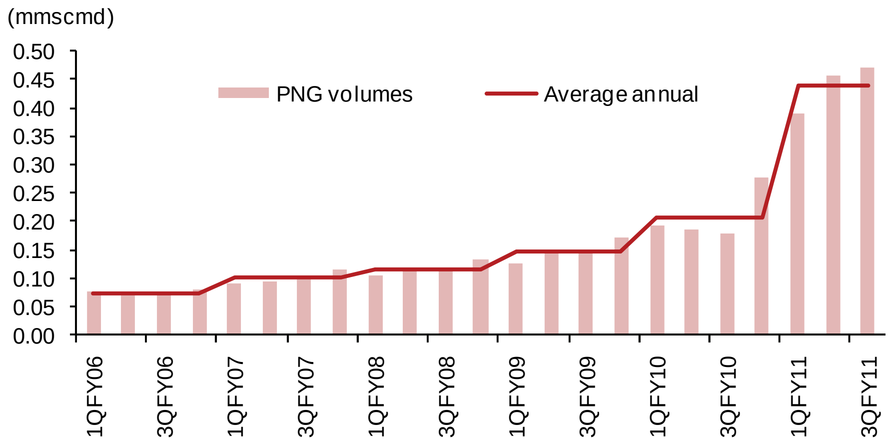
Thrust in industrial segment growth

IGL was born primarily to implement Supreme Court directives on compulsory conversion of city bus fleets, auto-rickshaws and LGVs (except vehicles plying on a national permit) to CNG. As a result, until recently, IGL had been concentrating on building CNG infrastructure and providing PNG connections. As much as 90% of its gas allocation was only for CNG in Delhi. Thus, IGL could not grow beyond Delhi and was unable to tap the large potential demand in the industrial/commercial segments in Delhi and the NCR areas.

As gas availability has increased over the past two years, IGL has started to focus on industrial segments, focusing on industrial areas in Delhi NCR. To meet the growing industrial demand, it has tied up for RLNG with both BPCL and GAIL.

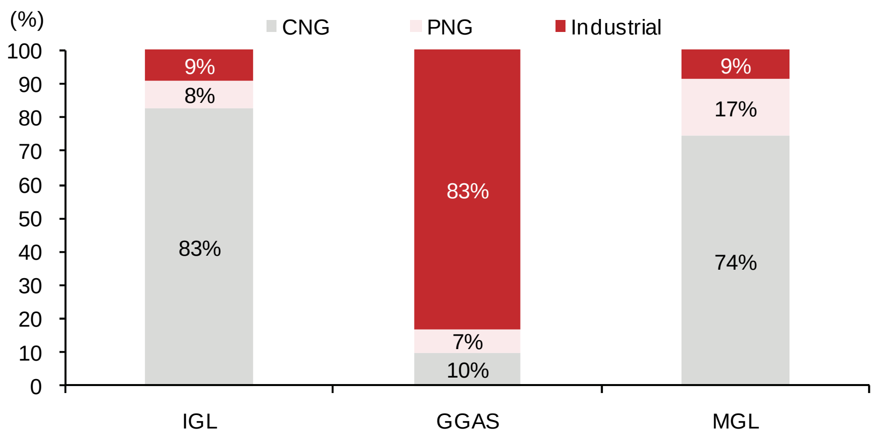
Driven by sharp growth in industrial volume, the piped natural gas segment (comprising domestic, commercial and industrial customers) has seen robust growth of more than 100% y-y over the past few quarters. Despite the sharp growth, we estimate the share of industrial volume is still below 10% for IGL, compared to over 80% for Gujarat Gas which has a more mature industrial market, given that the availability of gas was much better historically.

Fig. 155: PNG segment has seen over 100% y-y growth over past few quarters



Source: Company data, Nomura estimates

Fig. 156: Share of industrial volume still remains below 10% for IGL



Source: Company data, Nomura research

More APM allocation likely

Currently, IGL has a total of 2mmscmd of APM gas for Delhi and 0.2 mmscmd for the Noida/Greater Noida region. Of this, 90% is to be utilised for CNG usage and the balance for piped gas for domestic usage.

In addition, IGL had been given an allocation of 0.3mmcmd of KG-D6 in 2009. However, given that time demand back then was lower, and to avoid take-or-pay provisions, IGL had decided to lower the gas quantities in its agreement to only 0.15mmscmd.

Over the past two years, as CNG has grown, IGL has utilised its entire availability of domestic gas. To avoid mixing higher-cost RLNG to meet the CNG demand (this would lead to a further increase in CNG prices), IGL has been requesting higher domestic gas allocations. The demands include:

- Allocation of about 0.25mmscmd for the Ghaziabad region, which currently has none and is a fast-growing market;
- Asking for pooling of all the gas allocation for the Delhi NCR area. This would enable IGL to use a currently unutilised allocation of ~0.3 mmscmd in the Faridabad/Gurgaon regions (allocation of 0.5mmscmd, but consumption of only 0.2mmsmcd) in other deficit areas.

In our view, given that CNG is a high priority area in current gas allocation policy, and also the political sensitivity of raising CNG prices (which IGL would do if it has to use RLNG for CNG purposes), we view higher allocation of domestic gas as quite likely.

In addition, we note that as per the gas allocation by Empowered Group of Ministers for KG-D6 gas, the CGD sector has a high priority and was allocated 3.22mmsmcd of gas (1.22mmsmcd on a firm basis and 2.0mmsmcd on fall-back), as against this only 0.68mmscmd has been contracted with all CGD players, of which IGL's share is 0.15mmscmd. Thus, even as KG-D6 volumes decline, we believe if the government prioritises allocation to priority areas, by cutting gas supplies to non-priority areas (against current mechanism of pro-rata cuts), IGL and other CGD players could get increase KG-D6 gas allocation.

Minor adjustments to earnings estimates

We have marginally adjusted our earnings estimates for FY12/13F. We have raised our volumes estimates for FY12/13F by 5.0-7.5% and made minor adjustments to our EBITDA margin assumptions. However, our earnings estimates for FY12/13F remain largely unchanged, as higher interest costs on borrowed debt offset the positive impact of our higher volume estimates.

Our earnings forecasts remain largely unchanged – higher interest costs offset the positive impact of our higher volume estimates

Fig. 157: Key modelling assumption

	FY07	FY08	FY09	FY10	FY11F	FY12F	FY13F
Volumes (mmscmd)							
CNG	1.2	1.4	1.7	1.9	2.2	2.6	3.0
PNG	0.1	0.1	0.1	0.2	0.5	0.7	0.9
Total	**1.3**	**1.5**	**1.8**	**2.1**	**2.7**	**3.3**	**3.9**
Revision%					0.4%	5.0%	7.5%
Volumes (% break-down)							
CNG	93%	92%	92%	89%	83%	80%	78%
PNG	7%	8%	8%	11%	17%	20%	22%
Blended Revenue (INR/scm)	12.6	12.9	13.0	13.8	18.3	21.1	22.3
Blended EBITDA (INR/scm)	5.2	5.5	4.6	4.9	5.1	5.2	5.2
Revision (%)					-1.5%	0.8%	1.0%

Source: Company data; Nomura estimates

IGL remains our preferred CGD pick

We have made minor adjustments to our DCF valuation of IGL and raise our PT marginally to INR450, from INR440. We raise our capex estimate for FY11-15F to INR22.6bn, from INR15.9bn, as we expect IGL to aggressively expand its network in Delhi NCR. However, as we also roll forward our valuation to FY13F, the impact of the higher capex is largely neutralised.

Key DCF assumptions:

- We assume a WACC of 11% and long-term growth rate of 2.5%.
- We assume CNG volume growth of 15-18% pa over the next three years and 5.0-7.5% pa longer term.
- We assume strong 32-43% pa volume growth in the PNG segment (mainly due to industrial volume growth) over the next three years and very conservative 3-5% pa growth thereafter.
- We conservatively assume EBITDA margins will fall gradually as more industrial volume is added and the share of market-priced natural gas increases in the gas supply portfolio.

IGL is our preferred CGD pick. IGL trades at FY13F P/E of 12.1x, while its closest peer, Gujarat Gas, trades at a higher multiple of 14.5x for 2012F, even as expected volume growth is likely to be muted for Gujarat Gas. Given our expectation of a three-year (FY10-13F) earnings CAGR of 20%, we think IGL deserves a premium.

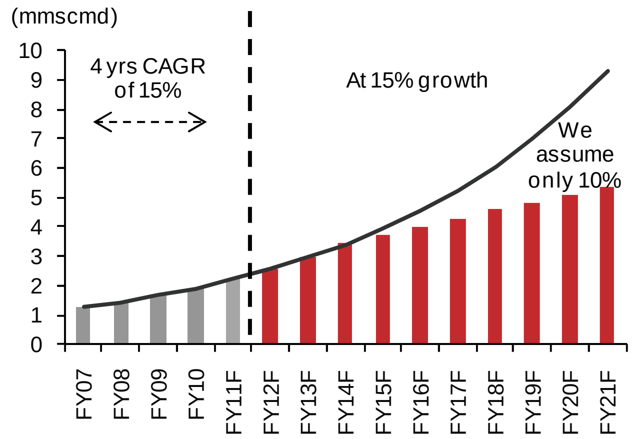
Fig. 158: IGL – DCF valuation

(INRmn)	FY10	FY11F	FY12F	FY13F	FY14F	FY15F	FY16F	FY17F	FY18F	FY19F	FY20F	FY21F
Total Volume (mmscmd)	**2.1**	**2.7**	**3.3**	**3.9**	**4.6**	**4.9**	**5.3**	**5.6**	**6.0**	**6.3**	**6.6**	**6.9**
CNG (mmscmd)	1.9	2.2	2.6	3.0	3.5	3.7	4.0	4.3	4.6	4.8	5.1	5.3
PNG (mmscmd)	0.2	0.5	0.7	0.9	1.1	1.2	1.3	1.3	1.4	1.4	1.5	1.5
EBITDA (INR/scm)	**4.9**	**5.1**	**5.2**	**5.2**	**5.0**	**4.9**	**4.8**	**4.7**	**4.5**	**4.4**	**4.3**	**4.2**
EBITDA	**3,808**	**4,913**	**6,149**	**7,309**	**8,464**	**8,815**	**9,174**	**9,549**	**9,940**	**10,120**	**10,304**	**10,492**
EBIT	3,033	3,908	4,883	5,648	6,575	6,747	7,058	7,385	7,728	7,860	7,996	8,136
FCFF	(1,105)	(3,113)	(312)	1,197	2,494	3,575	6,031	6,297	6,574	6,711	6,850	6,991
Discounted FCFF				1,197	2,249	2,906	4,420	4,161	3,917	3,605	3,318	3,053

DCF Summary (INRmn)	FY13 End
Assumptions	
Terminal Growth rate	2.5%
WACC	11%
Valuation summary	
Discounted free cash flow	28,826
Terminal valuation	37,204
Enterprise Value	**66,030**
Net Debt / (Cash) incl investments	2,695
Implied Mcap	**63,335**
Value per share	453
Target price	**450**

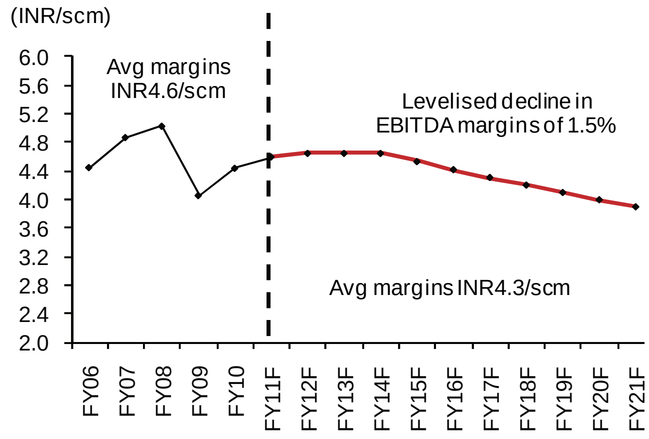
Source: Company data, Nomura estimates

Fig. 159: Still conservative on LT CNG with a CAGR forecast of 10% vs the historical 15% over the past four years



Source: Company data, Nomura estimates

Fig. 160: Although we do not expect CNG margins to decline, we assume a levelised cut of 1.5%.



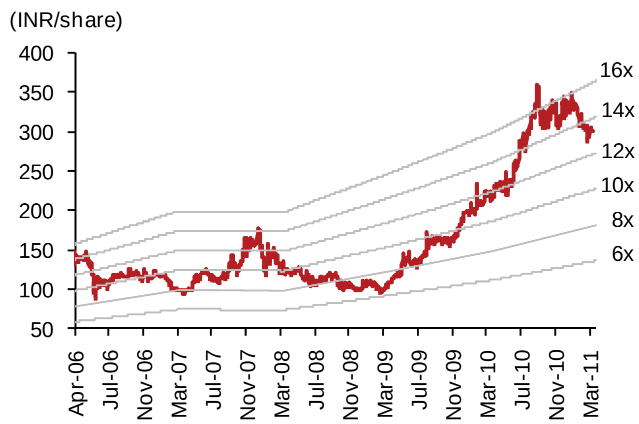
Source: Company data, Nomura estimates

Fig. 161: Our assumptions are still conservative, presenting possible upside

		Levelised CNG volume growth				
Levelised decline in CNG margins		8.0%	9.0%	10.0%	11.0%	12.0%
	0.0%	441	470	503	535	571
	1.0%	412	438	469	498	531
	1.5%	398	423	**453**	480	512
	2.0%	385	409	437	463	494
	3.0%	360	382	408	432	459

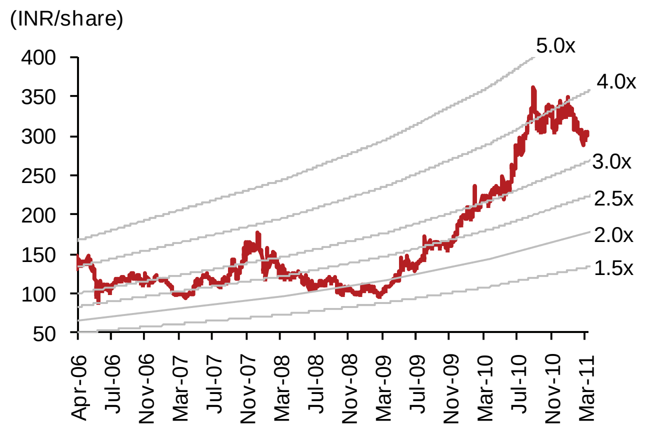
Source: Nomura estimates

Fig. 162: IGL – 1-year forward P/E band



Source: Bloomberg, Nomura estimates

Fig. 163: IGL – 1-year forward P/B band



Source: Bloomberg, Nomura estimates

Key downside risks: 1) Under the new PNGRB regulations, the regulator can only control network tariff (based on 14% post tax ROCE principle) and not end-product pricing. Therefore, we do not expect any major risk to IGL's margins. However, any sharp cut in the overall tariff would negatively impact our valuations. 2) Any slowdown in CNG conversions and new PNG connections could also present downside risk.

Gujarat State Petronet GSPT.BO GUJS IN

OIL & GAS/CHEMICALS

NOMURA
EQUITY RESEARCH

Emerging pan-India gas transmission play

Near-term concerns remain on regulatory chaos – tariff setting and pipeline award delayed

May 6, 2011

Rating Remains	**Buy**
Target price Reduced from 150	INR 135
Closing price April 29, 2011	INR 98
Potential upside	+37.8%

Action: From Gujarat to now pan-India focus

While GSPL's current network is limited to only one state, it has seen the sharpest volume growth and now has 25+% of the gas transmission market. In 3QFY11, GSPL's JV (GSPL owns 52%), emerged as the winner in all three long-distance pipelines for which bids were opened. On completion, its network will treble to over 5,500km (vs 1,700km now), and GSPL will emerge as a pan-India transmission company.

Catalysts: Regulatory delays are a pain; Early resolution a positive

Although GSPL is operating for over a decade, and the regulator was appointed in 2007, surprisingly in the current scheme of things, GSPL's network is not yet authorised. The earlier delay was due to non-notification of Section 16 of the PNGRB Act and later Delhi High Court deciding that without this notification, PNGRB has no powers to authorise. The matter is now pending for over a year in the Supreme Court (next hearing on 5 May). The Supreme Court has allowed PNGRB to process applications, but not to issue any final orders; delaying tariff setting and issuing letters of award for new pipelines. An early decision would be positive.

Volume growth moderating; Cutting PT to INR135; Maintain Buy

Near term growth will come from Gujarat, but at a far more moderate pace as existing demand is met and new demand is contingent on adding new customers/pipelines. We now assume lower volumes of 41/47mmscmd in FY12/13 (44/48 earlier). However, our EPS estimates increase by 13/18% in FY12/13F, due to a now lower depreciation rate (3.17% vs. 8.5%). Our DCF-based PT is now lower at INR135 (earlier INR150).

31 Mar	FY10	FY11F		FY12F		FY13F	
Currency (INR)	Actual	Old	New	Old	New	Old	New
Revenue (mn)	10,009	11,290	10,586	12,452	11,758	13,197	12,871
Reported net profit (mn)	4,138	4,841	4,835	5,002	5,651	5,136	6,054
Normalised net profit (mn)	4,138	4,841	4,835	5,002	5,651	5,136	6,054
Normalised EPS	7.4	8.6	8.6	8.9	10.0	9.1	10.8
Norm. EPS growth (%)	234.0	16.9	16.8	3.3	16.9	2.7	7.1
Norm. P/E (x)	13.4	N/A	11.5	N/A	9.8	N/A	9.1
EV/EBITDA	7.0	N/A	6.7	N/A	6.2	N/A	5.7
Price/book (x)	3.5	N/A	2.8	N/A	2.3	N/A	1.9
Dividend yield (%)	1.0	N/A	1.5	N/A	1.5	N/A	1.5
ROE (%)	29.8	27.6	27.5	23.3	25.9	20.1	22.7
Net debt/equity (%)	69.4	56.8	57.5	49.1	52.9	38.2	43.2

Source: Nomura estimates

Key company data: *See page 2 for company data, and detailed price/index chart.*
Rating: *See report end for details of Nomura's rating system.*

Anchor themes

Domestic gas supplies are likely to remain stagnant near term, but RLNG is likely to provide near term gas growth.

Nomura vs consensus

Our numbers are adjusted for the recent cut in depreciation rate, and thus appear higher.

Research analysts

India Oil & Gas/Chemicals

Anil Sharma - NFASL
anil.sharma.1@nomura.com
+91 22 4037 4338

Ravi Adukia, CFA - NFASL
ravikumar.adukia@nomura.com
+91 22 4037 4232

Key data on Gujarat State Petronet

Income statement (INRmn)

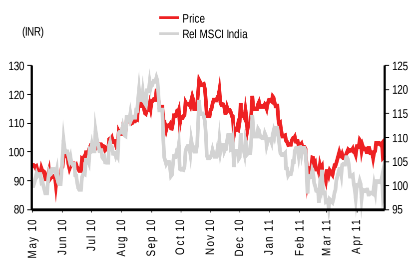
Year-end 31 Mar	FY09	FY10	FY11F	FY12F	FY13F
Revenue	**4,875**	**10,009**	**10,586**	**11,758**	**12,871**
Cost of goods sold	-225	-283	-362	-398	-416
Gross profit	**4,650**	**9,726**	**10,224**	**11,360**	**12,455**
SG&A	-2,105	-2,677	-2,188	-1,913	-2,182
Employee share expense	0	0	0	0	0
Operating profit	**2,544**	**7,049**	**8,036**	**9,447**	**10,273**
EBITDA	**4,249**	**9,414**	**9,866**	**10,962**	**12,019**
Depreciation	-1,705	-2,365	-1,830	-1,515	-1,746
Amortisation	0	0	0	0	0
EBIT	2,544	7,049	8,036	9,447	10,273
Net interest expense	-870	-938	-988	-1,197	-1,429
Associates & JCEs	0	0	0	0	0
Other income	243	159	190	209	220
Earnings before tax	**1,918**	**6,269**	**7,238**	**8,459**	**9,063**
Income tax	-679	-2,131	-2,402	-2,808	-3,009
Net profit after tax	**1,238**	**4,138**	**4,835**	**5,651**	**6,054**
Minority interests	0	0	0	0	0
Other items	0	0	0	0	0
Preferred dividends	0	0	0	0	0
Normalised NPAT	**1,238**	**4,138**	**4,835**	**5,651**	**6,054**
Extraordinary items	-4	0	0	0	0
Reported NPAT	**1,234**	**4,138**	**4,835**	**5,651**	**6,054**
Dividends	-493	-656	-987	-987	-987
Transfer to reserves	**741**	**3,482**	**3,848**	**4,663**	**5,067**
Valuation and ratio analysis					
FD normalised P/E (x)	44.7	13.4	11.5	9.8	9.1
FD normalised P/E at price target (x)	61.4	18.4	15.7	13.4	12.5
Reported P/E (x)	44.8	13.4	11.5	9.8	9.1
Dividend yield (%)	0.8	1.0	1.5	1.5	1.5
Price/cashflow (x)	27.2	6.3	6.6	6.8	6.0
Price/book (x)	4.6	3.5	2.8	2.3	1.9
EV/EBITDA (x)	15.5	7.0	6.7	6.2	5.7
EV/EBIT (x)	25.9	9.4	8.3	7.2	6.6
Gross margin (%)	95.4	97.2	96.6	96.6	96.8
EBITDA margin (%)	87.2	94.1	93.2	93.2	93.4
EBIT margin (%)	52.2	70.4	75.9	80.3	79.8
Net margin (%)	25.3	41.3	45.7	48.1	47.0
Effective tax rate (%)	35.4	34.0	33.2	33.2	33.2
Dividend payout (%)	40.0	15.9	20.4	17.5	16.3
Capex to sales (%)	93.9	77.7	65.4	66.1	53.4
Capex to depreciation (x)	2.7	3.3	3.8	5.1	3.9
ROE (%)	10.5	29.8	27.5	25.9	22.7
ROA (pretax %)	9.5	21.6	20.7	21.2	20.3
Growth (%)					
Revenue	16.7	105.3	5.8	11.1	9.5
EBITDA	16.6	121.5	4.8	11.1	9.6
EBIT	26.4	177.0	14.0	17.6	8.7
Normalised EPS	21.8	234.0	16.8	16.9	7.1
Normalised FDEPS	21.8	234.3	16.9	16.9	7.1
Per share					
Reported EPS (INR)	2.20	7.36	8.60	10.05	10.76
Norm EPS (INR)	2.20	7.36	8.60	10.05	10.76
Fully diluted norm EPS (INR)	2.20	7.35	8.60	10.05	10.76
Book value per share (INR)	21.56	27.80	34.64	42.94	51.95
DPS (INR)	0.75	1.00	1.50	1.50	1.50

Source: Nomura estimates

Notes

After sharp over 100% growth in FY10, EBITDA growth has moderated

Price and price relative chart (one year)



(%)	1M	3M	12M
Absolute (INR)	-1.6	-5.1	3.0
Absolute (USD)	-0.4	-1.8	3.7
Relative to index	-1.6	-8.8	-2.3
Market cap (USDmn)	1,252.7		
Estimated free float (%)	62.3		
52-week range (INR)	128.25/87		
3-mth avg daily turnover (USDmn)	2.75		
Major shareholders (%)			
Gujarat State Petroleum Corporation Ltd	37.8		
Gujarat Maritime Board	6.6		

Cashflow (INRmn)

Year-end 31 Mar	FY09	FY10	FY11F	FY12F	FY13F
EBITDA	4,249	9,414	9,866	10,962	12,019
Change in working capital	-1,488	1,836	-69	4	221
Other operating cashflow	-725	-2,387	-1,405	-2,773	-2,976
Cashflow from operations	**2,036**	**8,862**	**8,392**	**8,193**	**9,265**
Capital expenditure	-4,579	-7,774	-6,923	-7,767	-6,876
Free cashflow	**-2,543**	**1,088**	**1,469**	**426**	**2,388**
Reduction in investments	0	-310	0	0	0
Net acquisitions	0	0	0	0	0
Reduction in other LT assets	3	0	0	0	0
Addition in other LT liabilities	142	261	962	0	0
Adjustments	152	205	-805	176	186
Cashflow after investing acts	**-2,246**	**1,245**	**1,626**	**602**	**2,575**
Cash dividends	-329	-493	-987	-987	-987
Equity issue	2	5	0	0	0
Debt issue	1,849	1,086	3,297	3,684	3,200
Convertible debt issue	0	0	0	0	0
Others	-870	-1,075	-988	-1,197	-1,429
Cashflow from financial acts	**652**	**-478**	**1,321**	**1,500**	**784**
Net cashflow	**-1,595**	**767**	**2,947**	**2,102**	**3,358**
Beginning cash	2,569	975	1,742	4,689	6,791
Ending cash	975	1,742	4,689	6,791	10,149
Ending net debt	10,535	10,854	11,203	12,785	12,627

Source: Nomura estimates

Notes

Our current numbers do not build in the new pipelines that GSPL has won

Balance sheet (INRmn)

As at 31 Mar	FY09	FY10	FY11F	FY12F	FY13F
Cash & equivalents	975	1,742	4,689	6,791	10,149
Marketable securities	0	0	0	0	0
Accounts receivable	544	753	865	961	1,053
Inventories	926	1,327	1,297	1,442	1,579
Other current assets	3,171	3,728	3,736	3,744	3,752
Total current assets	**5,615**	**7,549**	**10,587**	**12,939**	**16,534**
LT investments	356	666	666	666	666
Fixed assets	24,132	29,755	34,847	41,099	46,229
Goodwill	0	0	0	0	0
Other intangible assets	0	0	0	0	0
Other LT assets	0	0	0	0	0
Total assets	**30,103**	**37,970**	**46,100**	**54,703**	**63,428**
Short-term debt	0	0	0	0	0
Accounts payable	3,742	4,848	4,554	4,807	5,265
Other current liabilities	1,590	3,486	3,802	3,802	3,803
Total current liabilities	**5,331**	**8,334**	**8,356**	**8,610**	**9,068**
Long-term debt	11,509	12,595	15,892	19,576	22,776
Convertible debt	0	0	0	0	0
Other LT liabilities	1,144	1,405	2,367	2,367	2,367
Total liabilities	**17,985**	**22,335**	**26,615**	**30,553**	**34,211**
Minority interest	0	0	0	0	0
Preferred stock	0	0	0	0	0
Common stock	5,621	5,624	5,624	5,624	5,624
Retained earnings	2,478	5,990	9,840	14,505	19,572
Proposed dividends	0	0	0	0	0
Other equity and reserves	4,019	4,021	4,021	4,021	4,021
Total shareholders' equity	**12,119**	**15,635**	**19,485**	**24,150**	**29,217**
Total equity & liabilities	**30,103**	**37,970**	**46,100**	**54,703**	**63,428**
Liquidity (x)					
Current ratio	1.05	0.91	1.27	1.50	1.82
Interest cover	2.9	7.5	8.1	7.9	7.2
Leverage					
Net debt/EBITDA (x)	2.48	1.15	1.14	1.17	1.05
Net debt/equity (%)	86.9	69.4	57.5	52.9	43.2
Activity (days)					
Days receivable	35.9	23.6	27.9	28.4	28.6
Days inventory	1,071.8	1,452.8	1,323.0	1,260.4	1,324.5
Days payable	6,434.2	5,541.0	4,741.5	4,307.3	4,414.9
Cash cycle	-5,326.4	-4,064.5	-3,390.6	-3,018.5	-3,061.8

Source: Nomura estimates

Notes

Net debt/equity is currently conservative, but may increase as funding plans are announced for new pipelines

From Gujarat to now pan-India focus

GSPL's JV with oil marketing companies (GSPL: 52%; IOC: 26%; BPCL and HPCL: 11% each) emerged as a winner in all three long-distance pipelines where it bid, and bids for which were opened in 3QFY11. On completion of these pipelines, GSPL's network will treble to over 5,500km (present: 1,700km), and from the current one state network, it will move on to become a pan-India gas transmission company.

Fig. 164: GSPL's JV has emerged as the winner for all three trunk gas pipelines

On completion, GSPL will emerge as a pan-India player

Pipelines	Capacity (mmscmd)	Length (Km)	Bids (x)	Bidding parties
Mehsana to Bhatinda	30	1,670	2	GSPL JV and Welspun JV
Bhatinda to Jammu	15	447	3	GSPL JV, Welspun JV and GAIL
Mallavaram to Bhilwara /Vijaipur	30	1,585	2	GSPL JV and GAIL JV (with EIL)

Note – GSPL JV is still awaiting a formal authorisation letter from regulator PNGRB

Source: Petroleum and Natural Gas Regulatory Board (PNGRB), Nomura research

Fig. 165: Indicative map of GSPL's existing and new pipelines network

Source: Company data

Despite low zone-1 tariff, may still make good returns

The key reason for GSPL's JV winning all three pipelines in our view was the very low bid it put in for the first zone tariff. The JV's strategy seems to have been to win first to gain pan-India coverage (perhaps rightly so) and worry about tariffs later.

The winner, in our view, took advantage of the complex bidding criteria. The GSPL JV bid very low in zone -1, which as per the bidding criteria, had the highest weighting of 40%. Though the actual tariff numbers are yet to be announced, the regulatory board chairman had been quoted in the media (Hindu Business Line: "GAIL loses Kakinada, Bhilwara pipeline project to GSPC-led team" dated 20 Oct 2010) as saying that the GSPL JV bid a tariff of only paisa 1 for the zone-1 of the Mallavaram pipeline.

Our analysis (using hypothetical scenarios) shows that despite a very low bid, the winner could still have the highest average tariff. In the exhibit below, we show three hypothetical scenarios for tariffs. We assume volume at similar levels. We show that despite quoting a very low zone-1 tariff, the winner could still have the highest average tariffs — and thus make the highest profits.

Fig. 166: Scenario analysis on hypothetical bidding assumption – winner can make good returns, despite low Zone – 1 tariff

				Bidders		
	Bidding criterias	**Weight**	**I**	**II**	**III**	**Comments**
A	PV of Tariff in zone 1 (INR/mmbtu)	**40%**	**0.10**	4.00	5.00	- Assume that bidder I opts for very low Zone-1 tariff, and very high subsequent tariff increases
B	% increase for Zone 1 to 2	20%	5000%	20%	3%	- Bidder II goes for moderate initial tarifs and escalations;
C	% increase for Zone 2 to 3	10%	50%	10%	2%	- Bidder III goes for high zone 1 tariff and low escalations
D	PV of gas volumes (mmscmd)	30%	30	30	30	
	Criteria scores					
	PV of Tariff in zone 1 (INR/mmbtu)		100%	3%	2%	Bidder I gets very high score on Zone 1 tariffs
	% increase for Zone 1 to 2		0%	15%	100%	
	% increase for Zone 2 to 3		4%	20%	100%	
	PV of gas volumes (mmscmd)		100%	100%	100%	Assume same volume for all three
	Weighted scores					
	PV of Tariff in zone 1 (INR/mmbtu)		0.40	0.01	0.01	
	% increase for Zone 1 to 2		0.00	0.03	0.20	Very high weight to Zone 1 tariff ensures that despite getting zero weighted avg scores in tariff escalation criteria;
	% increase for Zone 2 to 3		0.00	0.02	0.10	
	PV of gas volumes (mmscmd)		0.30	0.30	0.30	
	Composite score		**0.70**	**0.36**	**0.61**	**Bidder 1 wins on highest composite score**
	Implied Zonal Tariff (INR/mmbtu)					
	Zone 1 { A }		0.10	4.00	5.00	Bidder I - has very low tariff
	Zone 2 { A * (1+B) }		5.10	4.80	5.15	Nearly same number for all
	Zone 3 { A * (1 + B + B*C) }		7.60	4.88	5.15	Bidder 1 far ahead in tariffs in zone 3 & 4
	Zone 4 { A * (1 + B + B*C + B*C*C) }		8.85	4.89	5.15	
	Average tariff		**5.41**	4.64	5.11	**Yet bidder 1 could get the highest tariffs !!**

Source: Petroleum and Natural Gas Regulatory Board (PNGRB), Nomura research

Fig. 167: Bidding criteria for natural gas pipelines as per PNGRB regulations

	Bidding criterion	Weightage	Comments
A	Lowness of the PV* Zone - I tariff	40%	- Bid shall be for each year of the economic life. - Weightage of 70% if length of pipeline is <=300kms
B	Lowness of % increase in tariff from Zone 1 to 2	20%	- a single number to be bid (No max limit) - Zero weightage if pipeline is <=300kms. - 30% weightage if length between 300 to 600kms.
C	Lowness of % increase in tariff from zone 2 to 3	10%	- a single number (but it should be less than 100%)
D	Highness of the PV* of gas volumes (in mmscmd)	30%	- volumes bid shall be for each year of the economic life.

Source: Petroleum and Natural Gas Regulatory Board (PNGRB), Nomura research

Capex, funding, timing add to near term concerns

We are not worried on low tariffs in zone – 1 for new pipelines as such. We believe, with India lacking the key pipeline infrastructure for long term growth, the gas pipelines will continue to be value accretive.

However, by winning three pipelines, GSPL's network would virtually treble from the current 1700km, as it adds the new 3800km from these three pipelines. Such large growth raises questions about large capex, the source of funding and risk of equity dilution.

As per the regulations, these pipelines would need to be completed within 36 months of the letter of authorisation being given by PNGRB. In our view, even as regulations call for 36-month completion, the eventual completion would take far longer and would depend on many other factors such as tie-up of gas both on supply and customer sides, long right of acquisition process for laying of pipelines etc.

Also, companies may not need to do entire pipelines at one stretch, and may do it in steps. This may result in the entire build-out taking up to a decade. Historically, also there have been many instances when pipelines have been delayed for far longer than originally planned and not much action being taken in terms of taking authorisation away from pipeline operators.

However, we believe that clarity on build-out plans, capex etc would start coming only after the final letters of authorisation are made.

We do not expect sharp tariff cuts, yet remain conservative

The tariff determination process as per PNGRB has also got delayed due to non-clarity and delays in decisions on PNGRB's powers to authorise networks. We expect that the tariff setting process would be the highest priority once the Supreme Court allows decision making to go ahead. We believe that groundwork for an early decision on tariff setting has been done by both the company & PNGRB.

Apart from regulatory delays, the markets' other concern on GSPL has been likely cuts in its tariffs, as new tariffs are determined by PNGRB. The company expects that its overall tariffs would remain at similar levels to existing tariffs. We note that while deciding the tariffs for GAIL' HVJ network, RGTIL's East West Pipelines, and also GAIL's recent DUPL/DPPL tariffs, the regulator has reduced tariffs by marginally 6-11%. We also note that despite tariff cuts, GAIL's overall average tariffs realised have increased.

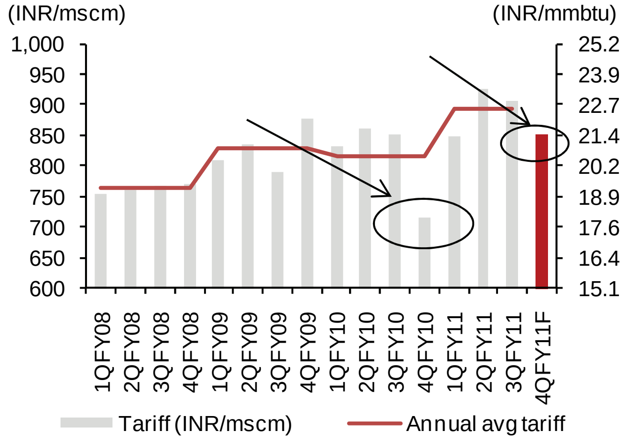
Over the last two years, GSPL's tariffs have averaged about INR830/mscm, and conservatively we assume a tariff decline of 10% by FY13F. We assume a flat tariff of INR750/mscm in our DCF model.

Fig. 168: PNGRB tariffs cuts only marginal for existing players

Date	Pipelines	Old	Expected	New	Chg
19-Apr-10	HVJ - GREP - DVPL	28.5	35.4	25.46	-11%
19-Apr-10	East - West Pipeline	55.9	53.6	52.23	-7%
25-Feb-11	DUPL/DPPL	26.1	40.2	24.49	-6%

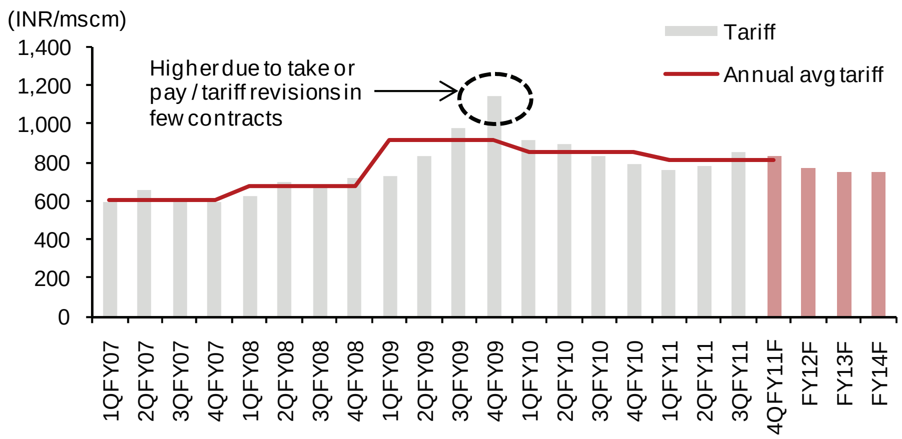
Source: PNGRB, Nomura research

Fig. 169: Despite cuts, GAIL's overall average tariff has actually increased



Source: Company data, Nomura research

Fig. 170: We conservatively assume 10% tariff decline by FY13, from average of ~INR830/mscm over the last two years



Source: Company data, Nomura estimates

Gujarat story is intact, but volume growth to moderate

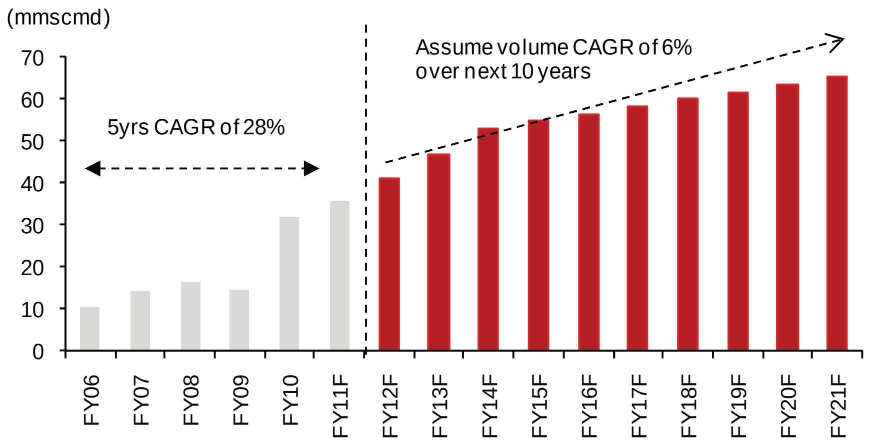
GSPL is present in 16 of 26 districts of Gujarat with ~1,700kms of gas grids. It plans to expand further by constructing ~1,100kms of pipelines in the next two to three years. Near term growth will come from Gujarat, but at a far more moderate pace, as all the existing demand is met and incremental demand will come as new pipelines are completed and new customers (especially power plants) are added.

We have toned down our volume expectations, and assume volumes of 41/47 mmscmd in FY12/13 (earlier 44/48).

Fig. 171: GSPL's network in Gujarat

Source: Company data

Fig. 172: We assume 6% levelised volume growth compared with past 5 year 32% CAGR



Source: Company data, Nomura estimates

Upgrade FY12/13F earnings estimates by 13-18%

We upgrade our earnings estimates for FY12/13F by ~13/18%, mainly due to a lower depreciation rate (3.17% vs 8.5% earlier) offset by lower transmission volumes. We have toned down our volume expectations, and assume volumes of 41/47 mmscmd in FY12/13 (earlier 44/48mmscmd).

During 3QFY11, the company had lowered the rate of depreciation on gas transmission pipelines to 4.75% (from 8.33%), in line with the rates as prescribed in the Companies Act 1956. Even the revised rate of 4.75% is higher than the SLM rate of 3.17% used by GAIL for depreciation on its gas transmission pipelines, and the company had indicated that it would approach the Ministry of Company Affairs to seek the necessary approval before adopting a rate similar to that of GAIL.

In our FY11F estimates we assume a depreciation rate of 4.75% on gas transmission pipelines. If the company receives necessary approvals for the lower 3.17% depreciation rate before the 4Q results, lower depreciation (if provided for in 4Q with retrospective effect) would give upside risks to our numbers.

In our estimates for FY12 and onwards, we assume a lower depreciation rate of 3.17% (SLM) on gas transmission pipelines.

Earning upgrades are largely due to lower depreciation rate on gas pipelines.

Fig. 173: GSPL - Key modelling assumptions

		FY11F		FY12F		FY13F	
	FY10	New	Old	New	Old	New	Old
Transmission volume (mmscmd)	32	36	39	41	44	47	48
Change (%)			-7%		-6%		-3%
Transmission Tariff (INR/mscm)	850	807	800	775	775	750	750
Change (%)			1%		0%		0%
EPS (INR/share)	7.4	8.6	8.6	10.0	8.9	10.8	9.1
Change (%)			0%		13%		18%

Source: Company data, Nomura estimates

Cut PT to INR135/share, maintain BUY

We like GSPL as a key long term gas play, but till near term uncertainties clear, the stock may remain range-bound. We reduce our PT to INR135/sh (150/sh earlier) for higher capex assumptions apart from lower near term cash earnings.

Our key DCF assumptions are as follows.

- We use a WACC of 10.5% and terminal growth rate of 2.5%.
- We now assume moderate volume growth of 13-15% in the next three years compared to the volume CAGR over the past 5 years of 28%. Our long term volume growth assumption is only 3%. Our DCF valuation implies conservative levelised volume growth of 6%.
- We do not expect a sharp cut in overall tariff post the application of new PNGRB regulations. However on a conservative basis, we assume a tariff decline of ~10% from the average tariff of INR830/mscm over the last two years.

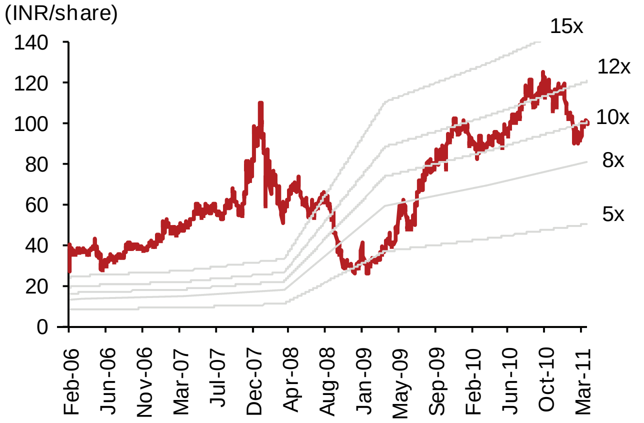
Fig. 174: GSPL – DCF valuation

DCF Summary (INRmn)	FY13 end
Discounted FCFF	37,507
Terminal valuation	50,866
Terminal Growth rate	2.5%
WACC	10.4%
Enterprise Value of core business	**88,373**
Investment	866
Enterprise Valuation	**89,239**
Net Debt (FY12 - Rsm)	12,785
Implied Mcap (Rsm)	76,454
Per share Value	136
Target price	**135**

(INRmn)	FY10	FY11F	FY12F	FY13F	FY14F	FY15F	FY16F	FY17F	FY18F	FY19F	FY20F	FY21F
Gas Volumes (mmscmd)	32.0	35.7	41.2	46.8	53.2	54.8	56.5	58.1	59.9	61.7	63.5	65.4
Tariffs (Rs/MSCM)	850	807	775	750	750	750	750	750	750	750	750	750
EBIT (Rsm)	**7,049**	**8,036**	**9,447**	**10,273**	**11,682**	**11,304**	**11,608**	**11,923**	**12,251**	**12,592**	**12,947**	**13,314**
FCFF (Rsm)				1,732	3,133	6,750	7,055	7,367	7,688	8,018	8,356	8,703
Discounted FCFF (Rsm)				1,732	2,837	5,535	5,239	4,954	4,681	4,421	4,172	3,935

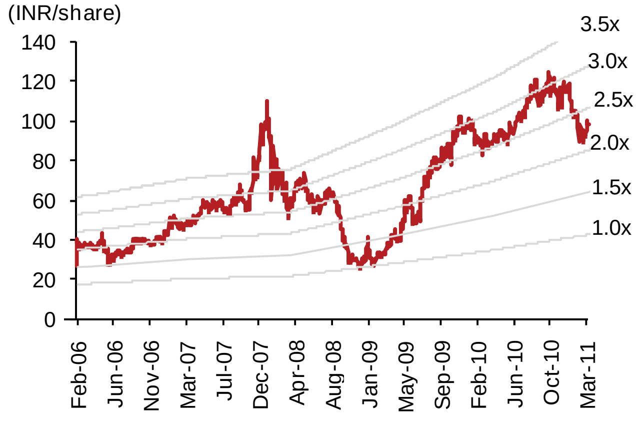
Source: Nomura estimates

Fig. 175: GUJS – 1 yr forward P/E band chart



Source: Bloomberg, Nomura estimates

Fig. 176: GUJS – 1 yr forward P/B band chart



Source: Bloomberg, Nomura estimates

Valuation methodology and risks to our investment view

We use DCF methodology to value GSPL. We use a WACC of 10.4% and terminal growth rate of 2.5%. Our DCF-based price target is INR135.

Key downside risks: lower-than-expected growth in transmission volumes, a sharp cut in the transmission tariff by the PNGRB post application of new regulations, and an eventually higher social contribution as per the directives of the Gujarat government (in our estimates, we do not factor any outgoing here).

Gujarat Gas GGAS.BO GGAS IN

OIL & GAS/CHEMICALS

NOMURA
EQUITY RESEARCH

Limited growth visibility

Raising prices to pass RLNG cost; Sacrificing volume growth in already mature markets

May 6, 2011

Rating Up from Reduce	**Neutral**
Target price Increased from 385	INR 415
Closing price April 29, 2011	INR 367
Potential upside	+13.1%

Action: Low domestic allocation; Rising RLNG share hurting growth

As PMT volumes decline and not much domestic gas is allocated to GGAS, the company is increasingly relying on higher spot/short-term RLNG. As RLNG prices fluctuate, the company is now resorting to more frequent pricing change, but is facing some consumer resistance. After a sharp 16% increase in December 2010, it has further raised prices for the industrial segment by a sharp 25% from April 2011. Volume growth in already mature markets is slowing with rising prices.

Catalysts: More domestic allocation; expansion into new areas

CGD is a priority area for APM and KG-D6 gas allocation. Yet, compared to current need of ~0.5mmscmd for CNG and domestic piped gas, GGAS' allocation is limited to 0.15mmscmd of APM gas. It does not get any KG-D6. It has been seeking more gas, and any allocation would be positive. Its current operating areas are already mature markets, and industrial volume growth is further slowing due to rising RLNG prices. To further grow, GGAS needs to expand, but seems not to be pursuing aggressive growth strategy. Even as regulator has invited bids for 29 cities in first 4 CGD rounds (4 in Gujarat), GGAS has bid only for one area.

Valuation: Limited downsides; upgrade to Neutral

Since its recent peak in March 2011, the stock has declined 11% (Sensex up 4%). We do not see much downside. However, the focus does not seem to be on aggressive growth, as reflected by the 70% dividend payout over the past 2 years. We roll forward our DCF value to CY12F, and upgrade to NEUTRAL with revised TP of INR415 (earlier 385).

31 Dec	FY10		FY11F		FY12F		FY13F
Currency (INR)	Actual	Old	New	Old	New	Old	New
Revenue (mn)	18,493	20,034	23,243	22,424	25,575		28,336
Reported net profit (mn)	2,565	2,592	3,036	2,859	3,311		3,658
Normalised net profit (mn)	2,565	2,592	3,036	2,859	3,311		3,658
Normalised EPS	20.0	20.2	23.7	22.3	25.8		28.5
Norm. EPS growth (%)	48.3	10.6	18.4	10.3	9.1		10.5
Norm. P/E (x)	18.8	N/A	15.9	N/A	14.5	N/A	13.2
EV/EBITDA	11.6	N/A	9.6	N/A	8.6	N/A	7.6
Price/book (x)	5.6	N/A	4.8	N/A	4.0	N/A	3.4
Dividend yield (%)	3.2	N/A	2.7	N/A	2.7	N/A	3.1
ROE (%)	31.9	24.5	32.9	22.2	30.4		28.4
Net debt/equity (%)	net cash	net cash	net cash	net cash	net cash		net cash

Source: Nomura estimates

Key company data: *See page 2 for company data, and detailed price/index chart.*
Rating: *See report end for details of Nomura's rating system.*

Anchor themes

With limited visibility on ramp-up in domestic gas production near term, RLNG is most likely source of incremental gas. Higher share and cost of RLNG prices are hurting volume growth in already matured markets where GGAS operates.

Nomura vs consensus

Our CY12F EPS and PT are largely in line with Street estimates.

Research analysts

India Oil & Gas/Chemicals

Anil Sharma - NFASL
anil.sharma.1@nomura.com
+91 22 4037 4338

Ravi Adukia, CFA - NFASL
ravikumar.adukia@nomura.com
+91 22 4037 4232

Key data on Gujarat Gas

Income statement (INRmn)

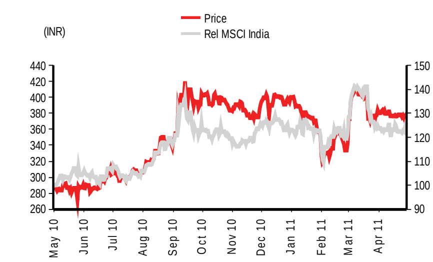
Year-end 31 Dec	FY09	FY10	FY11F	FY12F	FY13F
Revenue	**14,197**	**18,493**	**23,243**	**25,575**	**28,336**
Cost of goods sold	-10,031	-12,865	-16,717	-18,538	-20,736
Gross profit	**4,166**	**5,629**	**6,525**	**7,037**	**7,600**
SG&A	-1,844	-2,015	-2,253	-2,420	-2,598
Employee share expense	0	0	0	0	0
Operating profit	**2,321**	**3,614**	**4,272**	**4,617**	**5,001**
EBITDA	**2,795**	**4,156**	**4,880**	**5,281**	**5,725**
Depreciation	-474	-542	-608	-664	-723
Amortisation	0	0	0	0	0
EBIT	2,321	3,614	4,272	4,617	5,001
Net interest expense	-1	-5	-5	-5	-5
Associates & JCEs	0	0	0	0	0
Other income	266	224	319	388	526
Earnings before tax	**2,586**	**3,833**	**4,586**	**5,001**	**5,523**
Income tax	-836	-1,243	-1,523	-1,660	-1,833
Net profit after tax	**1,750**	**2,590**	**3,064**	**3,340**	**3,689**
Minority interests	-9	-13	-15	-16	-18
Other items	0	0	0	0	0
Preferred dividends	-13	-13	-13	-13	-13
Normalised NPAT	**1,729**	**2,565**	**3,036**	**3,311**	**3,658**
Extraordinary items	0	0	0	0	0
Reported NPAT	**1,729**	**2,565**	**3,036**	**3,311**	**3,658**
Dividends	-1,209	-1,802	-1,513	-1,513	-1,513
Transfer to reserves	**520**	**763**	**1,523**	**1,798**	**2,145**
Valuation and ratio analysis					
FD normalised P/E (x)	27.9	18.8	15.9	14.5	13.2
FD normalised P/E at price target (x)	30.8	20.8	17.5	16.1	14.5
Reported P/E (x)	27.9	18.8	15.9	14.5	13.2
Dividend yield (%)	2.1	3.2	2.7	2.7	3.1
Price/cashflow (x)	27.0	16.8	13.5	12.2	11.0
Price/book (x)	6.2	5.6	4.8	4.0	3.4
EV/EBITDA (x)	17.2	11.6	9.6	8.6	7.6
EV/EBIT (x)	20.7	13.3	11.0	9.9	8.7
Gross margin (%)	29.3	30.4	28.1	27.5	26.8
EBITDA margin (%)	19.7	22.5	21.0	20.6	20.2
EBIT margin (%)	16.4	19.5	18.4	18.1	17.7
Net margin (%)	12.2	13.9	13.1	12.9	12.9
Effective tax rate (%)	32.3	32.4	33.2	33.2	33.2
Dividend payout (%)	69.9	70.2	49.8	45.7	41.4
Capex to sales (%)	10.9	6.2	4.9	5.0	4.6
Capex to depreciation (x)	3.3	2.1	1.9	1.9	1.8
ROE (%)	23.4	31.9	32.9	30.4	28.4
ROA (pretax %)	18.7	25.2	27.0	27.6	28.5
Growth (%)					
Revenue	9.1	30.3	25.7	10.0	10.8
EBITDA	18.8	48.7	17.4	8.2	8.4
EBIT	20.0	55.7	18.2	8.1	8.3
Normalised EPS	8.5	48.3	18.4	9.1	10.5
Normalised FDEPS	8.5	48.3	18.4	9.1	10.5
Per share					
Reported EPS (INR)	13.48	20.00	23.67	25.82	28.53
Norm EPS (INR)	13.48	20.00	23.67	25.82	28.53
Fully diluted norm EPS (INR)	13.48	20.00	23.67	25.82	28.53
Book value per share (INR)	60.79	66.99	78.96	93.08	109.91
DPS (INR)	8.00	12.00	10.00	10.00	11.80

Source: Nomura estimates

Notes

One of largest dividend payouts in oil and gas space. We expect earnings growth to slow down.

Price and price relative chart (one year)



(%)	1M	3M	12M
Absolute (INR)	-0.3	1.3	33.1
Absolute (USD)	0.1	4.1	32.9
Relative to index	-3.6	-0.9	26.6
Market cap (USDmn)	1,082.8		
Estimated free float (%)	34.9		
52-week range (INR)	444.84/254.75		
3-mth avg daily turnover (USDmn)	0.31		
Major shareholders (%)			
BG Asia Pacific Holdings Pte. Ltd	65.1		
Aberdeen Asset Managers Limited	12.0		

Cashflow (INRmn)

Year-end 31 Dec	FY09	FY10	FY11F	FY12F	FY13F
EBITDA	2,795	4,156	4,880	5,281	5,725
Change in working capital	645	322	-252	71	88
Other operating cashflow	-1,659	-1,604	-1,053	-1,405	-1,436
Cashflow from operations	**1,782**	**2,874**	**3,576**	**3,947**	**4,377**
Capital expenditure	-1,553	-1,151	-1,150	-1,290	-1,300
Free cashflow	**229**	**1,722**	**2,426**	**2,657**	**3,077**
Reduction in investments	-692	-1,250	0	0	0
Net acquisitions	0	0	0	0	0
Reduction in other LT assets	0	0	0	0	0
Addition in other LT liabilities	342	629	240	195	201
Adjustments	-63	-391	-61	-17	-22
Cashflow after investing acts	**-184**	**709**	**2,605**	**2,835**	**3,256**
Cash dividends	-240	-1,210	-1,802	-1,513	-1,513
Equity issue					
Debt issue	0	0	0	0	0
Convertible debt issue					
Others	278	515	194	145	145
Cashflow from financial acts	**39**	**-695**	**-1,608**	**-1,368**	**-1,368**
Net cashflow	**-146**	**14**	**997**	**1,467**	**1,888**
Beginning cash	225	79	94	1,090	2,558
Ending cash	79	94	1,090	2,558	4,446
Ending net debt	-79	-94	-1,090	-2,558	-4,446

Source: Nomura estimates

Notes

Increasing free cash flows

Balance sheet (INRmn)

As at 31 Dec	FY09	FY10	FY11F	FY12F	FY13F
Cash & equivalents	79	94	1,090	2,558	4,446
Marketable securities	4,218	5,478	5,478	5,478	5,478
Accounts receivable	1,139	1,411	1,783	1,962	2,174
Inventories	211	189	255	280	311
Other current assets	606	609	609	609	609
Total current assets	**6,254**	**7,781**	**9,215**	**10,887**	**13,017**
LT investments	20	10	10	10	10
Fixed assets	7,165	7,657	8,199	8,825	9,402
Goodwill	0	0	0	0	0
Other intangible assets	0	0	0	0	0
Other LT assets	0	0	0	0	0
Total assets	**13,438**	**15,448**	**17,424**	**19,722**	**22,428**
Short-term debt	0	0	0	0	0
Accounts payable	2,152	2,141	2,616	2,891	3,221
Other current liabilities	1,324	1,909	1,621	1,621	1,621
Total current liabilities	**3,476**	**4,051**	**4,237**	**4,512**	**4,842**
Long-term debt	0	0	0	0	0
Convertible debt	0	0	0	0	0
Other LT liabilities	2,114	2,743	2,982	3,178	3,378
Total liabilities	**5,590**	**6,793**	**7,219**	**7,690**	**8,220**
Minority interest	52	63	78	94	112
Preferred stock	144	144	144	144	144
Common stock	278	294	294	294	294
Retained earnings	7,374	8,153	9,688	11,499	13,657
Proposed dividends	0	0	0	0	0
Other equity and reserves	0	0	0	0	
Total shareholders' equity	**7,796**	**8,591**	**10,127**	**11,938**	**14,095**
Total equity & liabilities	**13,438**	**15,448**	**17,424**	**19,722**	**22,428**
Liquidity (x)					
Current ratio	1.80	1.92	2.17	2.41	2.69
Interest cover	1,701.9	782.3	924.7	999.3	1,082.5
Leverage					
Net debt/EBITDA (x)	net cash	net cash	net cash	net cash	net cash
Net debt/equity (%)	net cash	net cash	net cash	net cash	net cash
Activity (days)					
Days receivable	30.6	25.2	25.1	26.8	26.6
Days inventory	7.1	5.7	4.8	5.3	5.2
Days payable	82.1	60.9	51.9	54.4	53.8
Cash cycle	-44.4	-30.1	-22.0	-22.3	-22.0

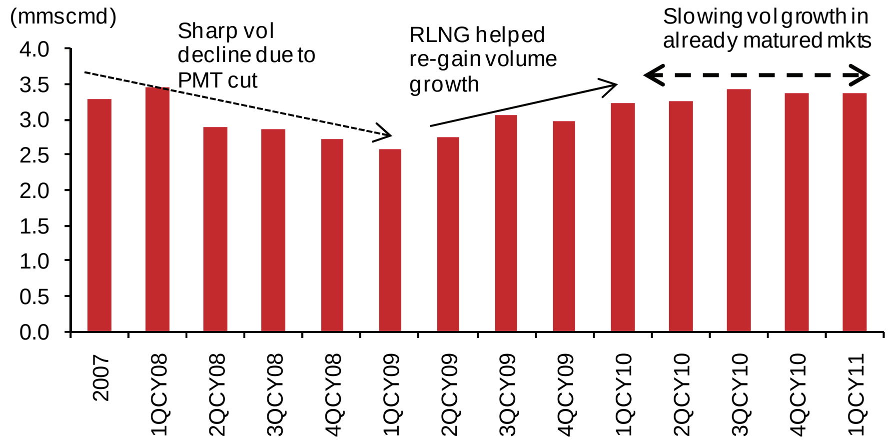
Source: Nomura estimates

Notes

Company remains debt free

Volume growth to remain muted

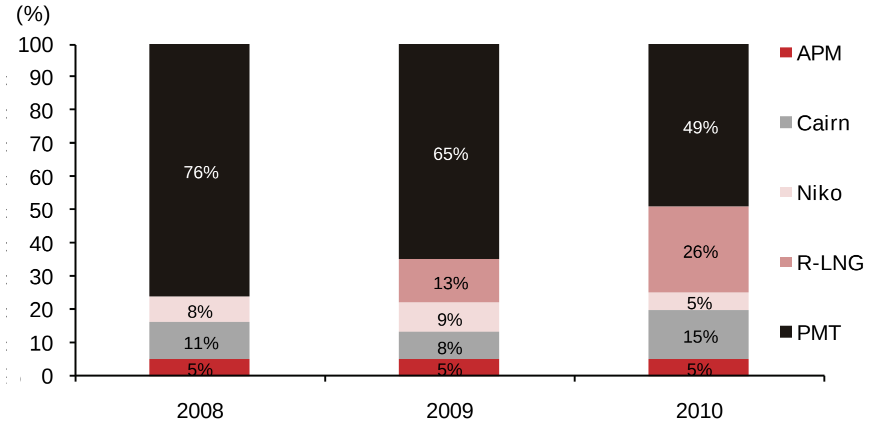
Fig. 177: Slowing volume growth in already matured markets



Source: Company data, Nomura research

Fig. 178: Rising share of RLNG in gas sourcing mix is actually hurting volume growth

Share of RLNG has increased to over 1/4th in total gas availability



Source: Company data, Nomura research

Fig. 179: Key assumptions

We have toned down our volume estimates and now assume moderate 7-8% volume growth in 2011/12F

	2009	2010	2011F		2012F	
			New	Old	New	Old
Total volumes (mmscmd)	2.8	3.3	3.6	3.7	3.8	4.0
Change %				-4%		-5%
Blended EBITDA (INR/scm	2.7	3.4	3.8	3.1	3.8	3.1
Change %				20%		21%
EPS (INR/share)	13.5	20.0	23.7	20.2	25.8	22.3
Change %				17%		16%

Source: Add Source Here

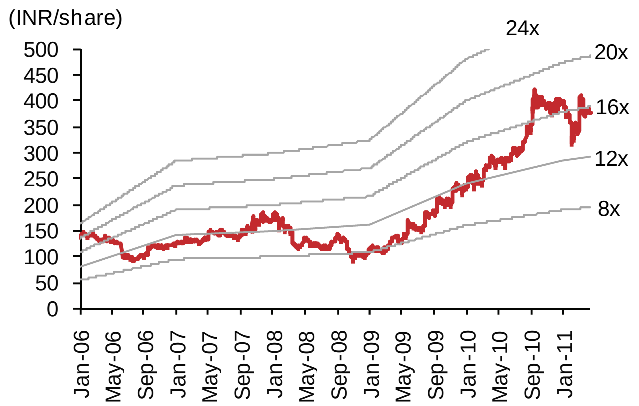
Fig. 180: GGAS - DCF valuation

(INRmn)	2010	2011F	2012F	2013F	2014F	2015F	2016F	2017F	2018F	2019F
Gas Sales (mmscmd)	3.32	3.56	3.84	4.17	4.50	4.77	5.04	5.36	5.68	6.02
EBITDA (INR/scm)	3.43	3.76	3.76	3.76	3.51	3.51	3.51	3.51	3.51	3.51
EBIT(INRmn)	**3,614**	**4,272**	**4,617**	**5,001**	**4,984**	**5,288**	**5,613**	**5,960**	**6,330**	**6,725**
FCFF	1,832	2,312	2,458	2,764	2,812	3,657	3,916	4,190	4,479	4,785
Discounted FCFF			2,458	2,488	2,277	2,665	2,569	2,473	2,379	2,287

DCF Summary	CY12end
Discounted free cash flow	19,596
Terminal Growth rate	2.5%
WACC	11%
Terminal valuation	27,197
Enterprise Value of core business	**46,794**
Investments	5,488
Enterprise valuation	**52,282**
Net Debt / (Cash) - CY11F	(1,090)
Preference shares	144
Implied Mcap (Rsm)	**53,228**
Per share Value	415
Target price	**415**

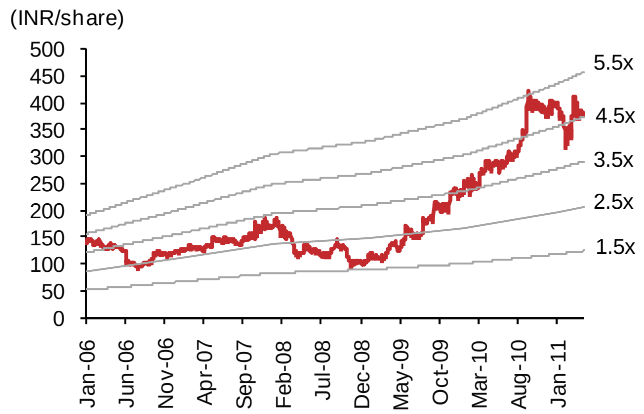
Source: Add Source Here

Fig. 181: GGAS - 1yr fwd P/E band chart



Source: Bloomberg, Nomura estimates

Fig. 182: GGAS - 1yr fwd P/B band chart



Source: Bloomberg, Nomura estimates

Valuation methodology and risks to our investment view

We use DCF methodology to value Gujarat Gas. We use a WACC of 11% and a terminal growth rate of 2.5%. Our DCF-based price target is INR415/share.

Key upside risks include: 1) an increase in domestic gas availability; 2) success in winning new cities in currently ongoing city gas bidding process; and 3) rupee appreciation.

Key downside risks include: 1) Lower than expected volume growth 2) Sharp increase in RLNG costs.

Appendix A-1

Analyst Certification

We, Anil Sharma and Ravikumar Adukia, hereby certify (1) that the views expressed in this Research report accurately reflect our personal views about any or all of the subject securities or issuers referred to in this Research report, (2) no part of our compensation was, is or will be directly or indirectly related to the specific recommendations or views expressed in this Research report and (3) no part of our compensation is tied to any specific investment banking transactions performed by Nomura Securities International, Inc., Nomura International plc or any other Nomura Group company.

Issuer Specific Regulatory Disclosures

Mentioned companies

Issuer name	Ticker	Price	Price date	Stock rating	Sector rating	Disclosures
GAIL	GAIL IN	446 INR	03-May-2011	Buy	Not rated	
Gujarat Gas	GGAS IN	362 INR	03-May-2011	Neutral	Not rated	
Gujarat State Petronet	GUJS IN	100 INR	03-May-2011	Buy	Not rated	
Indraprastha Gas	IGL IN	316 INR	03-May-2011	Buy	Not rated	
Petronet LNG	PLNG IN	134 INR	03-May-2011	Buy	Not rated	
Reliance Industries	RIL IN	944 INR	03-May-2011	Buy	Not rated	

Previous Rating

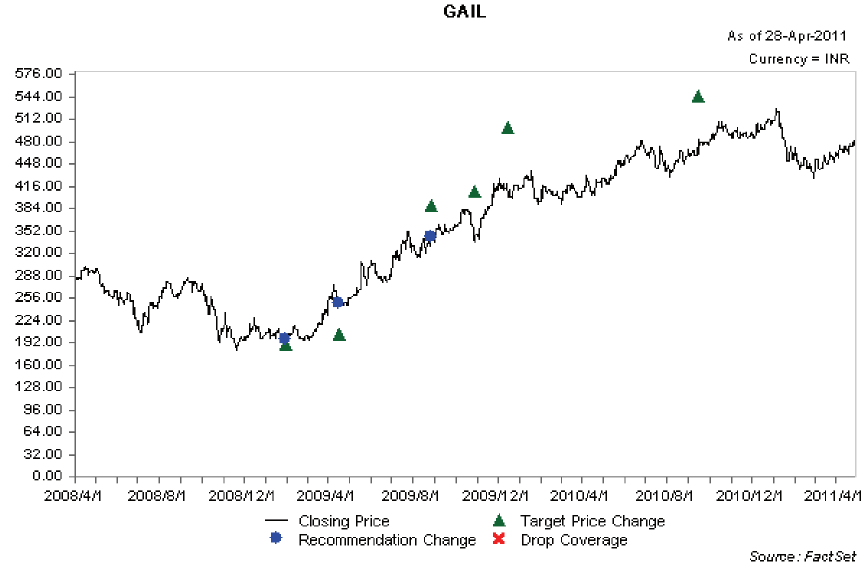
Issuer name	Previous Rating	Date of change
GAIL	Reduce	27-Aug-2009
Gujarat Gas	Reduce	05-May-2011
Gujarat State Petronet	Not Rated	11-May-2010
Indraprastha Gas	Not Rated	11-May-2010
Petronet LNG	Not Rated	11-May-2010
Reliance Industries	Neutral	05-Apr-2010

Rating and target price changes

	Ticker	Old stock rating	New stock rating	Old target price	New target price
GAIL	GAIL IN	Buy	Buy	545	600
Gujarat Gas	GGAS IN	Reduce	Neutral	385	415
Gujarat State Petronet	GUJS IN	Buy	Buy	150	135
Indraprastha Gas	IGL IN	Buy	Buy	440	450
Petronet LNG	PLNG IN	Buy	Buy	145	180
Reliance Industries	RIL IN	Buy	Buy	1140	1200

GAIL (GAIL IN) **446 (03-May-2011)** Buy (Sector rating: Not rated)

Rating and target price chart (three year history)



Date	Rating	Target price	Closing price
15-Sep-2010		545.00	483.30
16-Dec-2009		500.00	409.30
29-Oct-2009		410.00	343.05
27-Aug-2009		390.00	343.15
27-Aug-2009	Buy		343.15
16-Apr-2009		205.00	249.35
16-Apr-2009	Reduce		249.35
29-Jan-2009		190.00	196.80
29-Jan-2009	Neutral		196.80

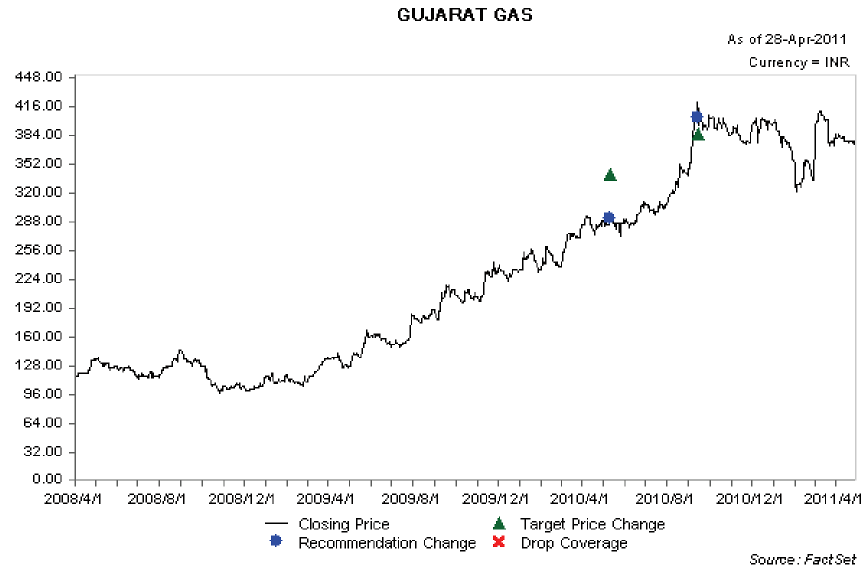
For explanation of ratings refer to the stock rating keys located after chart(s)

Valuation Methodology We have used sum-of-the-parts as our primary tool to value GAIL's diversified business. We have valued its gas transmission business (including gas trading) at 10x its FY13F EBITDA. We have assigned a multiple of 7x FY13F EBITDA for petrochemical and 6x FY12F estimated EBITDA for the LPG business. We also value E&P upside at a conservative INR15/share. Our target price is INR600.

Risks that may impede the achievement of the target price Key downside risks: lower transmission volume growth, a sharp cut in overall tariffs by the regulator (we do not assume any cut), a sharper polymer price decline than our assumption and higher subsidy burden than our assumption.

Gujarat Gas (GGAS IN) **362 (03-May-2011)** Neutral (Sector rating: Not rated)

Rating and target price chart (three year history)



Date	Rating	Target price	Closing price
15-Sep-2010		385.00	402.35
15-Sep-2010	Reduce		402.35
11-May-2010		340.00	290.45
11-May-2010	Buy		290.45

For explanation of ratings refer to the stock rating keys located after chart(s)

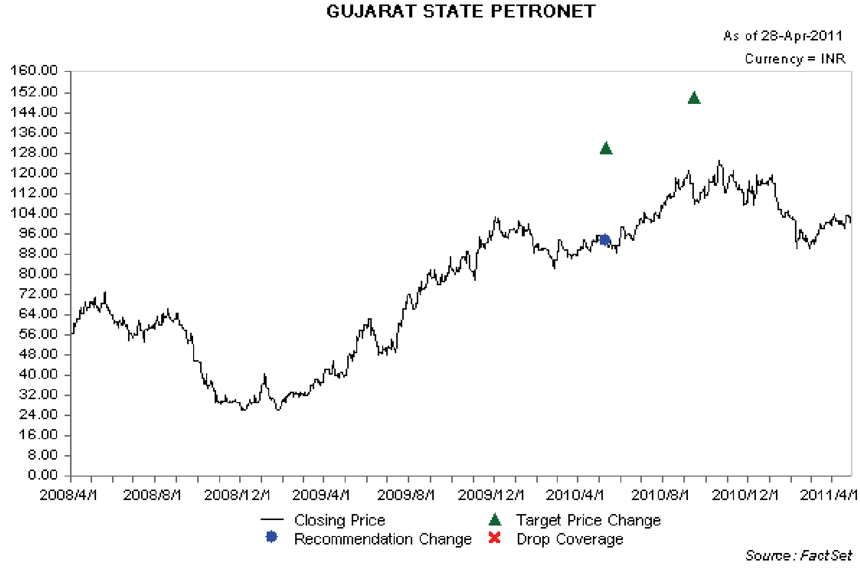
Valuation Methodology We use DCF methodology to value Gujarat Gas. We use a WACC of 11% and a terminal growth rate of 2.5%. Our DCF-based price target is INR415/share.

Risks that may impede the achievement of the target price Key upside risks include: 1) an increase in domestic gas availability; 2) success in winning new cities in the ongoing city gas bidding process; and 3) rupee appreciation. Key downside risks include: 1) lower-than-expected volume growth; and 2) a sharp increase in RLNG costs.

Gujarat State Petronet (GUJS IN)

100 (03-May-2011) Buy (Sector rating: Not rated)

Rating and target price chart (three year history)



Date	Rating	Target price	Closing price
15-Sep-2010		150.00	109.30
11-May-2010		130.00	93.35
11-May-2010	Buy		93.35

For explanation of ratings refer to the stock rating keys located after chart(s)

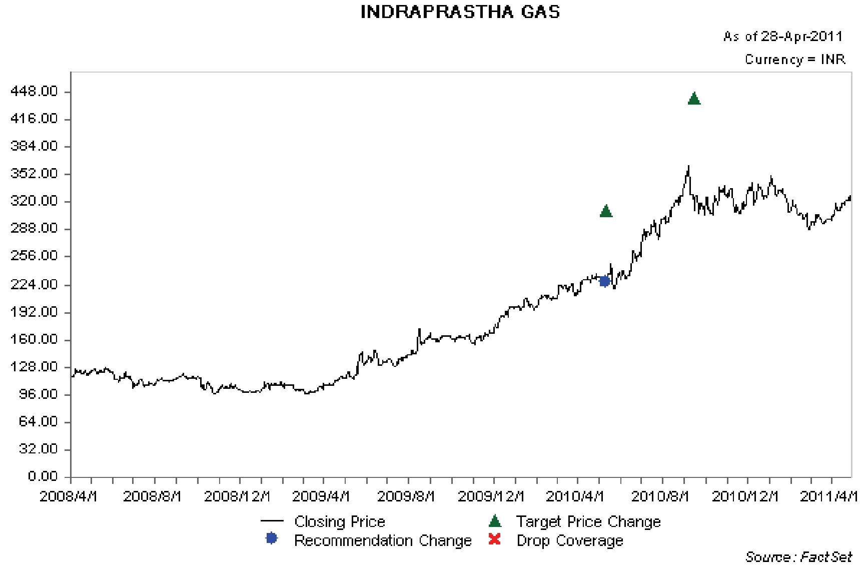
Valuation Methodology We use DCF methodology to value GSPL. We use a WACC of 10.4% and terminal growth rate of 2.5%. Our DCF-based price target is INR135.

Risks that may impede the achievement of the target price Key downside risks: Lower-than-expected growth in transmission volumes, a sharp cut in transmission tariffs by PNGRB post application of tariff regulations, and any actual social contribution as per the directive of the Gujarat Governement (we do not factor any outgoing).

Indraprastha Gas (IGL IN)

316 (03-May-2011) Buy (Sector rating: Not rated)

Rating and target price chart (three year history)



Date	Rating	Target price	Closing price
15-Sep-2010		440.00	310.15
11-May-2010		310.00	226.65
11-May-2010	Buy		226.65

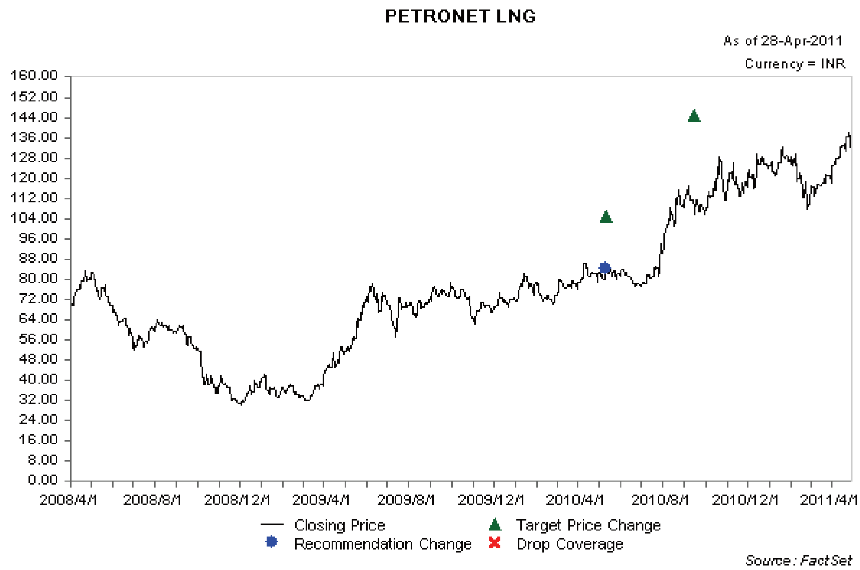
For explanation of ratings refer to the stock rating keys located after chart(s)

Valuation Methodology We use DCF methodology to value IGL, assuming a WACC of 11% and a terminal growth rate of 2.5%. This derives a target price of INR450/share.

Risks that may impede the achievement of the target price Under the new PNGRB regulations, the regulator can only control network tariff (based on 14% post tax ROCE principle) and not end-product pricing. Therefore, we do not expect any major risk to IGL's margins. However, any sharp cut in the overall tariff would negatively impact our valuations. Any slowdown in CNG conversions and new PNG connections could also present downside risk.

Petronet LNG (PLNG IN) **134 (03-May-2011)** Buy (Sector rating: Not rated)

Rating and target price chart (three year history)



Date	Rating	Target price	Closing price
15-Sep-2010		145.00	107.10
11-May-2010		105.00	84.25
11-May-2010	Buy		84.25

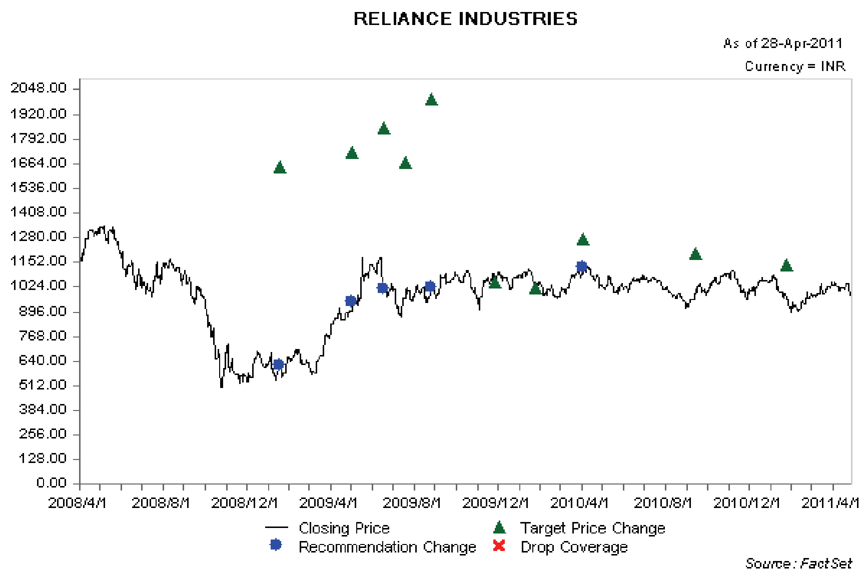
For explanation of ratings refer to the stock rating keys located after chart(s)

Valuation Methodology We use DCF methodology to value Petronet LNG. Based on WACC of 10% and terminal growth of 1%, our DCF-based price target is INR180.

Risks that may impede the achievement of the target price Key downside risks: 1) Lower-than-expected spot volumes could result in downside to our numbers. 2) The Dahej off-take agreement provides for 5% annual rises in the re-gasification charges. Although we believe we are conservative in our assumptions on re-gasification charges, a sharp cut could have a negative impact on profitability and valuations. 3) PLNG's Kochi terminal is under construction and execution delays and cost overruns could hurt our valuation of the Kochi terminal.

Reliance Industries (RIL IN) **944 (03-May-2011)** Buy (Sector rating: Not rated)

Rating and target price chart (three year history)



Date	Rating	Target price	Closing price
24-Jan-2011		1140.00	971.05
15-Sep-2010		1200.00	1010.45
05-Apr-2010		1275.00	1125.15
05-Apr-2010	Buy		1125.15
25-Jan-2010		1020.00	1041.70
27-Nov-2009		1050.00	1048.90
27-Aug-2009		2000.00	1020.12
27-Aug-2009	Neutral		1020.12
20-Jul-2009		1670.00	1015.33
18-Jun-2009		1850.00	1012.48
18-Jun-2009	Reduce		1012.48
04-May-2009		1725.00	942.67
04-May-2009	Neutral		942.67
19-Jan-2009		1650.00	614.83
19-Jan-2009	Buy		614.83

For explanation of ratings refer to the stock rating keys located after chart(s)

Valuation Methodology We use the SOTP method to value RIL's different businesses. For its core businesses, we use EV/EBITDA multiples. We use a 7x FY13F EV/EBITDA multiple for its refining and petrochemical business. We use DCF to value the company's new E&P business. Our TP is INR1,200/share.

Risks that may impede the achievement of the target price Key downside risks: 1) Deterioration in refining margins and petrochemical margins. 2) Further delays in ramp-up of KG-D6 volume. 3) Delays in government approvals to E&P deal with BP. 4) Sharper rupee appreciation vs the US dollar than our assumption.

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As at 31 March 2011.
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11% have been assigned a Reduce rating which, for purposes of mandatory disclosures, are classified as a Sell rating; 16% of companies with this rating are investment banking clients of the Nomura Group*.
As at 31 March 2011.
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Explanation of Nomura's equity research rating system in Europe, Middle East and Africa, US and Latin America for ratings published from 27 October 2008

The rating system is a relative system indicating expected performance against a specific benchmark identified for each individual stock. Analysts may also indicate absolute upside to target price defined as (fair value - current price)/current price, subject to limited management discretion. In most cases, the fair value will equal the analyst's assessment of the current intrinsic fair value of the stock using an appropriate valuation methodology such as discounted cash flow or multiple analysis, etc.

STOCKS

A rating of '**Buy'**, indicates that the analyst expects the stock to outperform the Benchmark over the next 12 months.
A rating of '**Neutral'**, indicates that the analyst expects the stock to perform in line with the Benchmark over the next 12 months.
A rating of '**Reduce'**, indicates that the analyst expects the stock to underperform the Benchmark over the next 12 months.
A rating of '**Suspended'**, indicates that the rating and target price have been suspended temporarily to comply with applicable regulations and/or firm policies in certain circumstances including when Nomura is acting in an advisory capacity in a merger or strategic transaction involving the company.
Benchmarks are as follows: **United States/Europe**: Please see valuation methodologies for explanations of relevant benchmarks for stocks (accessible through the left hand side of the Nomura Disclosure web page: http://www.nomura.com/research);**Global Emerging Markets (ex-Asia):** MSCI Emerging Markets ex-Asia, unless otherwise stated in the valuation methodology.

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Explanation of Nomura's equity research rating system for Asian companies under coverage ex Japan published from 30 October 2008 and in Japan from 6 January 2009

STOCKS

Stock recommendations are based on absolute valuation upside (downside), which is defined as (Target Price - Current Price) / Current Price, subject to limited management discretion. In most cases, the Target Price will equal the analyst's 12-month intrinsic valuation of the stock, based on an appropriate valuation methodology such as discounted cash flow, multiple analysis, etc.

A '**Buy'** recommendation indicates that potential upside is 15% or more.

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A '**Reduce'** recommendation indicates that potential downside is 5% or more.

A rating of '**Suspended'** indicates that the rating and target price have been suspended temporarily to comply with applicable regulations and/or firm policies in certain circumstances including when Nomura is acting in an advisory capacity in a merger or strategic transaction involving the subject company.

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Explanation of Nomura's equity research rating system in Japan published prior to 6 January 2009 (and ratings in Europe, Middle East and Africa, US and Latin America published prior to 27 October 2008)

STOCKS

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A rating of '2' or '**Buy'**, indicates that the analyst expects the stock to outperform the Benchmark by 5% or more but less than 15% over the next six months.

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Explanation of Nomura's equity research rating system for Asian companies under coverage ex Japan published prior to 30 October 2008

STOCKS

Stock recommendations are based on absolute valuation upside (downside), which is defined as (Fair Value - Current Price)/Current Price, subject to limited management discretion. In most cases, the Fair Value will equal the analyst's assessment of the current intrinsic fair value of the stock using an appropriate valuation methodology such as Discounted Cash Flow or Multiple analysis etc. However, if the analyst doesn't think the market will revalue the stock over the specified time horizon due to a lack of events or catalysts, then the fair value may differ from the intrinsic fair value. In most cases, therefore, our recommendation is an assessment of the difference between current market price and our estimate of current intrinsic fair value. Recommendations are set with a 6-12 month horizon unless specified otherwise. Accordingly, within this horizon, price volatility may cause the actual upside or downside based on the prevailing market price to differ from the upside or downside implied by the recommendation.

A '**Strong buy'** recommendation indicates that upside is more than 20%.

A '**Buy'** recommendation indicates that upside is between 10% and 20%.

A '**Neutral'** recommendation indicates that upside or downside is less than 10%.

A '**Reduce'** recommendation indicates that downside is between 10% and 20%.

A '**Sell'** recommendation indicates that downside is more than 20%.

SECTORS

A '**Bullish'** rating means most stocks in the sector have (or the weighted average recommendation of the stocks under coverage is) a positive absolute recommendation.

A '**Neutral'** rating means most stocks in the sector have (or the weighted average recommendation of the stocks under coverage is) a neutral absolute recommendation.

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Nomura Asian Equity Research Group

Hong Kong	Nomura International (Hong Kong) Limited 30/F Two International Finance Centre, 8 Finance Street, Central, Hong Kong Tel: +852 2536 1111 Fax: +852 2536 1820
Singapore	Nomura Singapore Limited 5 Temasek Boulevard #11-01, Suntec Tower Five, Singapore 038985, Singapore Tel: +65 6433 6288 Fax: +65 6433 6169
Taipei	Nomura International (Hong Kong) Limited, Taipei Branch 17th Floor, Walsin Lihwa Xinyi Building, No.1, Songzhi Road, Taipei 11047, Taiwan, R.O.C. Tel: +886 2 2176 9999 Fax: +886 2 2176 9900
Seoul	Nomura Financial Investment (Korea) Co., Ltd. 17th floor, Seoul Finance Center, 84 Taepyeongno 1-ga, Jung-gu, Seoul 100-768, Korea Tel: +82 2 3783 2000 Fax: +82 2 3783 2500
Kuala Lumpur	Nomura Securities Malaysia Sdn. Bhd. Suite No 16.5, Level 16, Menara IMC, 8 Jalan Sultan Ismail, 50250 Kuala Lumpur, Malaysia Tel: +60 3 2027 6811 Fax: +60 3 2027 6888
India	Nomura Financial Advisory and Securities (India) Private Limited Ceejay House, Level 11, Plot F, Shivsagar Estate, Dr. Annie Besant Road, Worli, Mumbai- 400 018, India Tel: +91 22 4037 4037 Fax: +91 22 4037 4111
Indonesia	PT Nomura Indonesia Suite 209A, 9th Floor, Sentral Senayan II Building Jl. Asia Afrika No. 8, Gelora Bung Karno, Jakarta 10270, Indonesia Tel: +62 21 2991 3300 Fax: +62 21 2991 3333
Sydney	Nomura Australia Ltd. Level 25, Governor Phillip Tower, 1 Farrer Place, Sydney NSW 2000 Tel: +61 2 8062 8000 Fax: +61 2 8062 8362
Tokyo	Equity Research Department Financial & Economic Research Center Nomura Securities Co., Ltd. 17/F Urbannet Building, 2-2, Otemachi 2-chome Chiyoda-ku, Tokyo 100-8130, Japan Tel: +81 3 5255 1658 Fax: +81 3 5255 1747, 3272 0869

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