



Private Sector IPPs: Trends & Outlook

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Summary Opinion

The pace of overall capacity addition in the power sector has shown an improvement during the current Plan Period (2007-12) as reflected in the commissioning of 34,461 MW till March'11 which is significantly better than what was achieved in previous plan periods. Based on the current progress, ICRA expects the achievement of overall capacity addition to reach close to 50,000 MW by end March 2012. There has also been a change in the ownership mix of capacities being created with the share of private sector IPPs in the capacity addition during the current Plan Period having increased to 32% (as against less than 10% in the previous Plan Periods). However, despite the improvement, this will result in a slippage w.r.t the target of 78,000 MW set by Government of India (GoI) for the current Plan Period. The shortfall in capacity addition targets has resulted in energy deficits remaining high, with the peak energy deficits remaining high at about 10 % in FY 2011.

Given the existing deficit situation, and likelihood of continued growth in energy requirements, the Indian power sector will require significant incremental capacity addition in the next Plan Period (until March 2017). This requirement amounts to around 130,000 MW assuming energy demand at 7.5 % per annum, testifying to the positive demand outlook for the power generation sector. ICRA also expects that the share of private sector in the total capacity addition increase even further given the large projects being undertaken by various groups.

Notwithstanding the positive demand outlook, ICRA notes that the risk profile of private IPPs have increased appreciably over the last one year period. These include:

Vastly increased fuel supply risks: ICRA observes that about 60% of the thermal capacity under execution by private IPPs is based on domestic coal which remains exposed to fuel supply risks because domestic coal shortages are expected to increase significantly over the long term. This is due to a) CIL's incremental output likely to fall significantly short of the incremental demand, b) overall progress in development of captive coal blocks allotted to both government & private sector companies remaining extremely slow, and c) increased uncertainty on future coal availability due to new initiative by Ministry of Environment & Forest (MoEF) taken during FY 2011 for notifying 'Go and No Go' blocks in which 105 coal blocks are notified as 'No-Go' blocks having high forest cover where mining will not be allowed. Further with the recent amendment (dated June 2011) in the linkage guidelines for supply of coal during XII Plan Period whereby the actual supply of coal will be subject to 85% of power being tied up through long term competitively bid tariff based PPAs with distribution utilities, the merchant power projects remain the worst affected.

Exposure to volatility in merchant tariffs: ICRA observes that about 44% of the capacity under execution by IPPs is either based on short-term PPAs or are untied-up, and therefore, remains exposed to any adverse volatility in the merchant tariffs. Short term tariffs have remained volatile in the last two year period, with demand-supply gap and willingness and ability of state distribution companies (discoms) to purchase higher cost power remaining the key determinants of merchant tariffs in the medium term. The ability and willingness of discoms to purchase merchant power in turn will depend upon the extent of improvement in the commercial viability of state-owned for which adequate tariff revisions and/or allowing periodic recovery of power purchase cost adjustments by State Electricity Regulatory Commissions (SERCs), remains extremely crucial. Based on current trends, ICRA expects average tariffs for short-term contracts (of upto one year maturity) to remain at around Rs. 3.5-4/Unit in the near term.

Preference to Case-I bidding by discoms: Case I bidding route is being preferred over Case II bidding route by the state-owned utilities, since Case I bidding puts the entire onus of land acquisition, seeking clearances and tie-up of fuel on the project developer. However, Case I bidding route is also fraught with issues pertaining mainly to domestic coal availability and rising international coal prices putting upward pressures on tariffs which discoms are reluctant to contract on long term basis, also given the constraints in their paying capacity. This has in turn however affected the competitive bidding process for procurement of power by state-owned discoms. Notwithstanding the same, the sustained progress towards the competitive bidding process by discoms for procurement of power in line with National Tariff Policy - 2007 remains extremely crucial, also given the notification of recent amendment in the coal linkage guidelines for the power projects in XII Plan Period.

Upwards pressure on tariffs that would impact the viability of competitively bid projects: ICRA expects that the rising dependence on coal imports by IPPs as well as likely continuance of high international coal price environment would keep a significant upward pressure on the cost of power generation, going forward. Thus, domestic coal deficit situation is likely to adversely affect the project economics of domestic coal linkage projects having competitively bid based PPAs, essentially due to under-recoveries in fuel cost arising from the actual fuel costs remaining higher than the same through tariff recovery. As a result, the possibilities of renegotiation or dishonouring of PPAs by IPPs having such projects cannot be ruled out, due to increased concerns over their economic viability. Further, the regulatory directions by SERCs in few states for disallowing any amendment requests in the tariff terms of original PPAs by IPPs have increased the financial risk profile of such projects having exposure to fuel price risks.

Exposure to execution, regulatory and geo-political risks in case of coal assets acquired abroad: While a few IPPs have concluded acquisition of overseas coal assets (both operational and green-field) mainly in three countries namely Indonesia, Australia and South Africa so as to ensure reliability in coal supplies, execution risks for development of green-field mine blocks (including the associated infrastructure for port connectivity in some cases) remain quite significant. However, the sharp rise in coal prices during last 18 month period have been accompanied by growing political & regulatory risks. This arises out of the fact that governments have tried to capitalise on high coal prices by keeping high royalty and taxation rates and also protect domestic consumers by stipulating minimum domestic obligation & minimum pricing benchmarks for coal exports. IPPs based on imported coal and having the competitively bid (Case I) PPAs thus remain exposed to significant fuel price risks due to possible mismatches in tariff bid assumptions and actual coal supply terms, which in turn is likely to adversely affect their project economics.

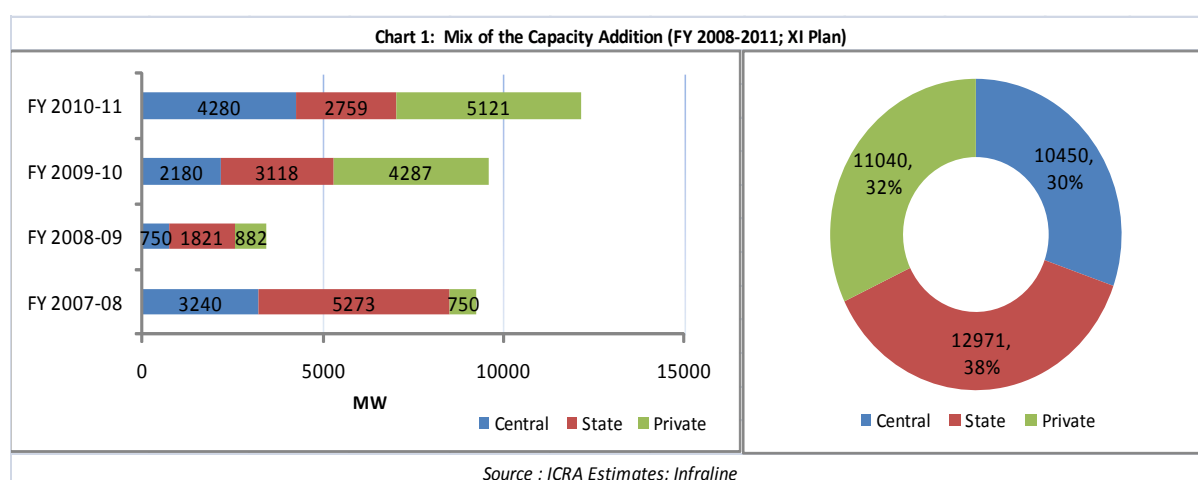
Financial position of state distribution companies (discoms) remains weak resulting in counterparty credit risks remaining high: Overall the operating and financial position of state-owned distribution companies continues to remain weak. While T&D losses remain high at between 20-45% for most states the aggregate book losses even after government subsidy in 14 key states stood at about Rs. 21,000 Cr during FY 2009-10 exposing IPPs to significant counter-party credit risks. The losses are a result of factors such as a) shortfalls in meeting distribution loss level target as set by SERCs leading to disallowance of power purchase cost, b) higher operating overheads than allowed, c) inadequacy of tariff subsidy booked, c) absence or inadequacy of tariff revision by SERCs and d) under-recovery of fuel & power purchase cost adjustment (FPPCA). With these losses being largely funded by bank loans, leveraging levels of discoms has remained high and shown an increasing trend.

Leveraging levels for many of private IPPs to remain high due to investment phase: Given that many of private sector IPPs are in investment phase with large-sized plans in capacity addition as well as for acquisition of coal mining assets in overseas countries, overall funding requirements remain quite significant which will keep their leveraging levels high at least over the next 3-5 year period. The prevailing volatility in the equity markets since November 2010 as well as increasingly cautious approach of lenders (w.r.t. ensuring fuel linkage and/or certain portion of the capacity to be tied-up through long term PPA route) may thus affect the financial closures of some of the projects. Given the inherently high execution risks involved & concerns over the coal availability, there could be an increased instance of amendment requests by the IPPs for the revision in project implementation schedule and in turn, the debt repayment schedule going forward thus reflecting the increased risk profile for IPPs mainly for projects having either competitively bid and/or merchant PPAs. Notwithstanding the exposure to interest rate and forex risks, ICRA notes that debt servicing ability of IPPs would be crucially dependent upon stabilisation of operations with adequate fuel availability and extent of fuel price pass-through/escalation provision in tariff so as to keep the actual variable costs in line with tariff levels.

Update on Key Issues

Slippages in capacity addition during the XI Plan period results in continued supply-demand imbalances

The Government of India had planned a capacity addition of 78,000 MW during the XI Plan Period. However as against this, the actual capacity addition in the four-year period till end of March 2011 remained muted at 34,461 MW- although this is a significant improvement over what has been achieved previously (the maximum achieved in any plan period was 21,180 MW during the X Plan Period). Of this capacity, about 85% was thermal based, 12% hydro based and the balance nuclear. Kindly refer **Chart 1** which illustrates the mix of capacity addition by central, state and private sector during XI Plan Period as on March 2011. Based on the current progress, ICRA expects cumulative capacity addition of about 50,000 MW by March 2012. Another noteworthy feature is that the share of private sector in the capacity addition has significantly improved to 32%, as against 9% in the previous plan period (FY 2003-2007). With capacity additions having shown a significant slippage w.r.t. targets, this has led to continued power deficit levels. During FY 2011 peak deficit & energy deficit in India stood at 9.8% and 8.5% respectively, as against that of 15.4% and 11.6% respectively for FY 2009-10.



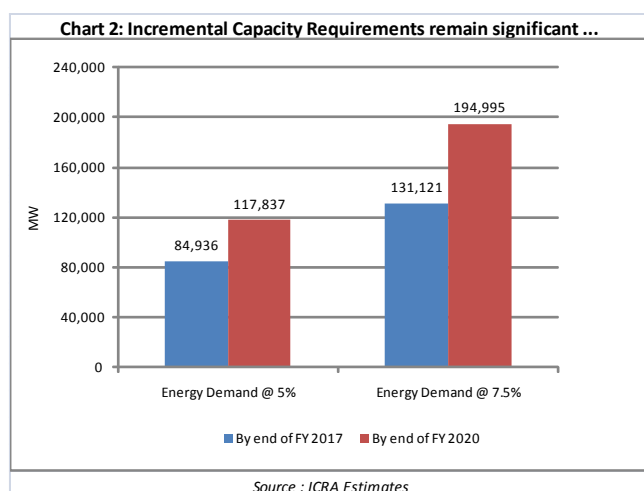
Incremental capacity additions required till end of XII Plan Period would be 1,30,000 MW assuming historical growth rates of 7.5%

The existing power deficit level and low per capita consumption¹ implies significant growth potential in electricity consumption requirements in future. Even assuming a conservative average growth rate of 5% in energy demand and improvement in transmission & distribution loss levels from the current level of 32% to 23%², ICRA estimates that the country would require additional power generation capacity of around 85,000 MW by FY 2017 (which is around 75% of the existing installed capacity based on conventional sources). This

¹ Also significantly lower than world average by about 70%

² Assuming loss reduction of 1% on YoY basis by 2020

implies capacity addition requirement of about 17,000 MW per year. By contrast, if energy demand growth were to be higher at 7.5% (which is in fact in line with actuals over FY 2002–2010), incremental capacity requirements in the same period would be much higher at around 1,30,000 MW by FY 2017 (Refer **Chart 2**).



Private IPP segment to play a key role in capacity addition; Large-sized investment plans in place with thermal capacity of over 70,000 MW proposed to be implemented over FY 2012-2017

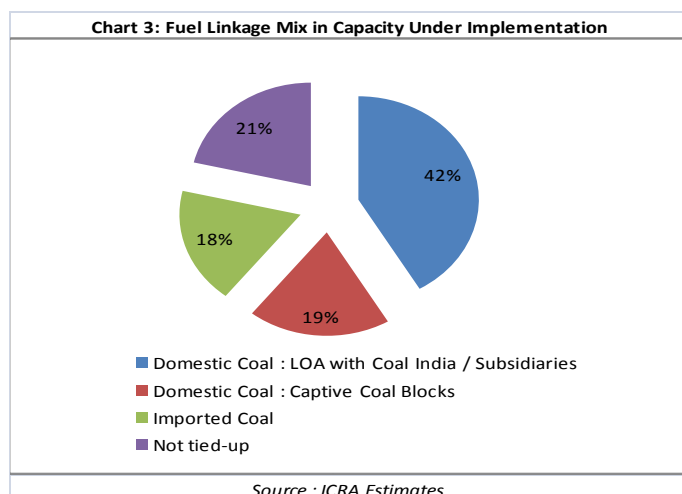
Figures in MW	Operational Capacity As on March 31,	Yearwise Thermal Capacity Additions Expected						Expected As on end of FY 2017
		FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017	
Reliance Power	1,033	-	3,060	3,840	1,320	1,980	1,320	12,553
Essar Energy	1,515	1,800	1,500	1,920	1,260	600	-	8,595
Adani Power	1,980	1,320	2,640	1,320	660	660	660	9,240
Lanco Infratech	3,292	1,332	-	1,320	1,980	660	-	8,584
Tata Power	2,956	2,650	2,400	-	-	-	-	8,006
Jaypee Power	700	500	-	660	1,980	2,640	-	6,480
JSW Energy	1,730	1,410	-	-	-	600	1,980	5,720
Indiabulls Power	-	-	-	1,620	1,620	1,620	540	5,400
KSK Energy	684	-	135	600	1,800	1,200	-	4,419
Sterlite Energy	1,200	1,200	660	1,320	-	-	-	4,380
CESC	1,225	-	-	-	1,200	660	660	3,745
Torrent Power	1,647	-	-	782	400	400	-	3,229
GMR Energy	791	-	1,368	350	700	-	-	3,209
GVK Energy	905	-	-	1,340	800	-	-	3,045
Avantha Group	191	-	1,200	1,200	-	-	-	2,591
Athena Energy	-	-	-	660	1,260	600	-	2,520
Ind-Bharat Energy	290	-	1,000	660	-	-	-	1,950
								-
Sub-Total	20,139	10212	13963	17592	14980	11620	5160	93,666

Source : ICRA Estimates; Company Presentations

Based on the current status of thermal-based projects under implementation (where reasonable progress has been made in terms of statutory approvals, land acquisition, fuel linkage & construction activities) by major IPPs, overall capacity addition of over 70,000 MW is under implementation and is likely to be completed over the next six year period until March 2017, as can be seen from **Table 1**. In addition, thermal capacity addition by both i.e. the central and state sector owned generating companies is expected to be about 25,000-30,000 MW during XII Plan Period. For the assessment of the capacity under implementation by the private sector, only thermal based capacity³ has been considered. Hydro-electric projects, being of long gestation period due to significant uncertainties arising from geological risks and resettlement & rehabilitation (R & R) issues, have not been considered. Despite the positive demand outlook, ICRA notes that overall risk profile of IPPs have increased significantly; some of these risk factors are being discussed as below:

³ Coal occupies a dominant share i.e. about 90% of the capacity under implementation, and the remaining by gas.

Significant fuel supply risks due to domestic coal shortages expected to continue until end of XII Plan Period



As seen from **Chart 3**, about 60% of the thermal capacity under execution by private IPPs is based on domestic coal (i.e. either through linkage⁴ from CIL/its subsidiaries or from captive coal blocks allotted). While India ranks fourth in the world in terms of coal reserves worldwide, the growing coal demand has outpaced production levels and has gradually resulted in an increase in imports over the period. The dependence on imports is expected to increase further going forward. While CIL estimates its incremental coal production by end of FY 2017 at around 120 MMT, its commitment under various LOAs signed to power projects (likely to be implemented by 2014) under various LOAs

amounts to around 325 MMT, which implies that serious shortages are expected to continue until the end of XII Plan Period. Further, ICRA notes further that CIL and its subsidiaries are yet to sign FSAs in many cases for the old linkages granted prior to National Coal Distribution Policy (NCDP-2007) as well as for coal linkages post NCDP where the milestones have been met and in some plants have started commercial operations as well. Pending FSAs, coal supplies have been continuing through MOU route as per the assessed quantity by the Central Electricity Authority (CEA). However, the same have remained lower for many power stations i.e. varying in the range of 40~60% of the normative linkage quantity. The model FSA⁵ as per NCDP is also in favour of CIL which stipulates that no compensation is payable by CIL in case of any shortfall in the coal delivery of upto 50% of annual contracted quantity (ACQ). Thus, the risk of coal shortfall would be borne by the IPPs, and the cost of imported coal, if sourced by CIL to meet the ACQ, would be passed on to IPPs. Further with the recent amendment (dated June 2011) in the linkage guidelines for supply of coal during XII Plan Period whereby the actual supply of coal will be subject to 85% of power being tied up through long term competitively bid tariff based PPAs with distribution utilities (except for PSU projects where PPAs were signed before 5.01.2011), the merchant power projects remain the worst affected.

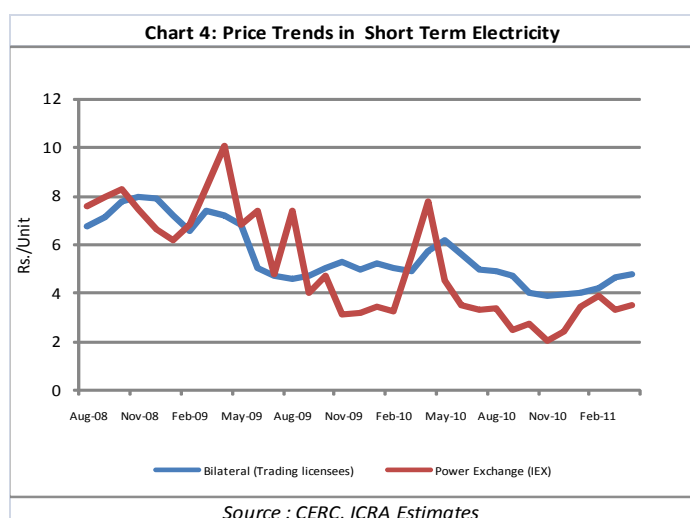
While IPPs with captive coal blocks are theoretically better placed than IPPs dependent on CIL, the ground reality is that progress on captive coal mining has been very slow. While 207 captive coal blocks have been allotted so far (both government & private companies), the overall progress has been extremely slow and only 26 blocks (all of which were allocated prior to 2003) have commenced production until June 2010. Between 2004 and June 2010, 168 blocks were allotted to public sector units and private companies. However progress has remained unsatisfactory in most cases and as of now, 84 show cause notices for cancellation of coal block allotment have now been sent by the Ministry of Coal, GoI during FY 2011. In another setback to the coal mining plans, the Ministry of Environment & Forest (MoEF) during the last financial year has notified several coal blocks⁶ as 'No-Go' blocks having high forest cover. The development has also led to an increased uncertainty over the coal availability going forward.

⁴ These coal linkages as per New Coal Distribution Policy (NCDP,2007) granted by CIL/its Subsidiaries are in the form of letter of assurances (LOA) with a validity period of 24 months and subject to achievement of the stipulated milestones as mentioned therein, LOA holders remain eligible to sign Fuel Supply Agreement (FSA).

⁵ Model FSA between the [Name of Coal India Ltd's Subsidiary Company] and [Name of New Private Power Utility through LOA Route*] *Also, applicable for LOAs issued prior to NCDP and units to be commissioned after introduction of NCDP against the old linkages.

⁶ The Ministries of Coal and Ministry of Environment & Forest, GoI had jointly undertaken an exercise to mark 'go' and 'no-go' areas for mining in nine coal fields in June 2010. As per the parameters set by the Ministries, of the 582 coal blocks over 600,000 hectares, 49 per cent were declared no-go zone, where mining could be carried out in compliance with the environment and forest laws. Subsequently, MoEF re-examined the classification of coal blocks whereby 23.27 per cent of the area, now comprising 105 blocks, was declared as no-go zone. While these blocks under no-go zone include some of the blocks already allotted to private developers for captive mining; prospective blocks yet to be allotted; as well as the coal blocks of Coal India & its subsidiaries, details of the same are not available.

Sizeable capacity under execution is still either based on short-term PPAs or not tied-up, resulting into its exposure towards possible volatility in merchant power tariffs



As about 44% of the overall capacity under execution by IPPs is either based on short-term PPAs or untied-up, the IPPs remain exposed towards any adverse volatility in the merchant tariffs. As seen in Chart 3, the merchant electricity tariffs particularly on power exchange have shown a significant volatility⁷ while, bilateral traded prices have remained relatively less volatile although with a declining trend too. The volatility is dependent on several factors such as seasonal fluctuations, level of energy deficits, availability of hydel power, regulatory intervention by the Central Electricity Regulatory Commission (CERC) to check spikes in the prices of short term/merchant electricity & control

unscheduled interchange (UI) volumes of electricity, as well as, the constraints arising out of the paying capacity of the distribution companies.

With domestic coal shortages to continue for the coal-based capacity (for existing capacities as well as those under implementation) resulting in higher dependence on costlier coal and likely increase in domestic coal prices, the overall cost of power generation is expected to increase and put an upward cost pressure on merchant tariffs. Notwithstanding this, merchant tariffs may not increase proportionately, due to constraints in the paying capacity of state-owned distribution companies. This was observed during the second half of FY 2011 as the state-owned distribution utilities preferred to adopt load-shedding instead of purchase of costlier power from the merchant/short term market – thus restraining the load mainly from agricultural & rural areas. However, the preference of such load-shedding by distribution licensees (who are obligated to supply the electricity in license area) even when the prices in the merchant market remained lower than the long term average power purchase cost, may invite regulatory attention in order to prevent such situation, in the future.

Units Input	MU	85000		
Units Sold	MU	64000		
T&D Loss		25%		
Extent of Short Term Power Purchase (by volume)		10%		
Long Term Power Purchase Cost	Rs./Unit Input	2.5		
			I	II
				III
Cost of Short Term Power	Rs./Unit	4	5	6
Blended Power Purchase Cost (PPC)	Rs./Unit Input	2.7	2.75	2.85
Increase in PPC	Rs./Unit Input	6%	10%	14%
Increase in PPC	Rs. Cr.	1275	2125	2975
Base Tariff	Rs./Unit Sold	4.28	4.28	4.28
Revised Tariff	Rs./Unit Sold	4.43	4.53	4.63
Tariff Increase through FAC		4%	6%	8%

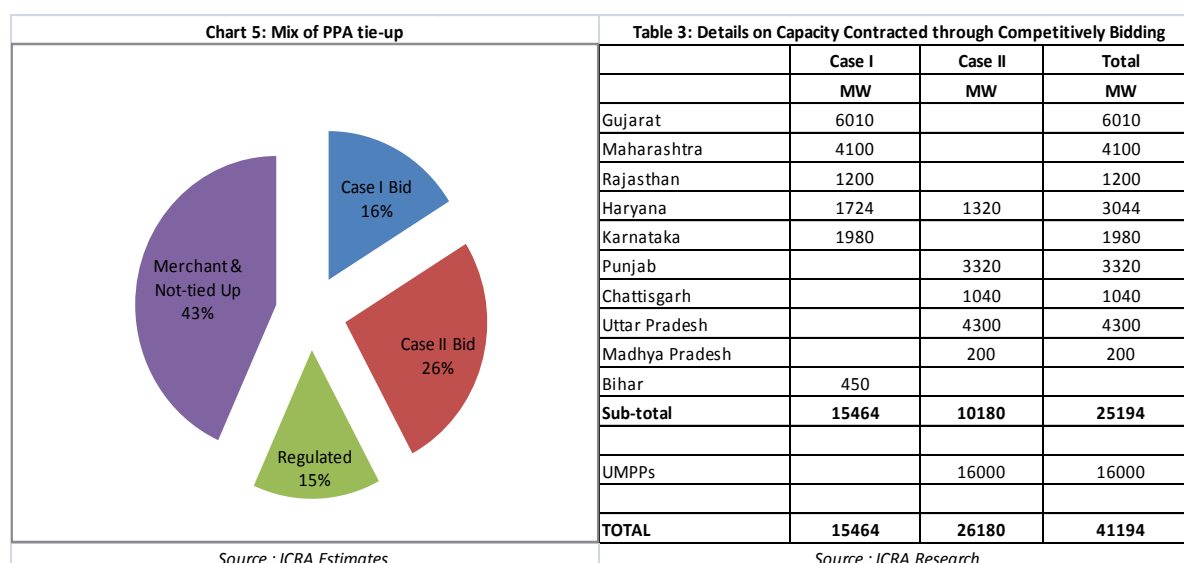
Source : ICRA Estimates

ICRA expects average short-term tariffs (for contracts of upto 1 year) to remain at around Rs. 3.5-4/Unit in the medium term which may increase further in case of any significant widening demand-supply gap from the current levels and also due to inflationary pressures. However, the sustainability of such tariff levels would depend upon the extent of improvement in the commercial viability of discoms for which adequate tariff revisions and/or allowing periodic recovery of power purchase cost adjustments by SERCs, remains extremely crucial. Our analysis of a large state-owned utility in the western region on the basis of certain assumptions (as highlighted in the **table**

2), shows that additional burden on power purchase cost in absolute terms would remain significant for short-term power purchases at the cost of Rs. 6 /unit & Rs. 4/unit respectively, though the tariff increase required through Fuel & Power Purchase Cost Adjustment (FPPCA) is modest and ranges between 4 % and 8%.

⁷ Volatility is reflected through a decline from average high price of 10 Rs./Unit in April 2009 (i.e. just prior to elections for Central Government) to average low price of 2/Unit in November 2010

Shift towards Case I bids which is being preferred by discoms; Higher prices revealed in Case-I bids



As can be seen from **Chart 5**, about 40% of the aforementioned capacity under execution is proposed to be sold through competitively bid (Case I & II) PPAs. Also, switch in composition of competitive bids (excluding the bidding for UMPPs) with Case I bidding route is preferred over Case II bidding route by utilities since Case I bidding puts the entire onus of land acquisition, seeking clearances and tie-up of fuel on the project developer. Another noteworthy feature has been that there have been significant upward movement in tariffs quoted under Case I bids. As against tariff levels observed in the range of Rs. 2.6 – 3.2 /Unit in Case I bidding until FY 2010, bid levels quoted (where PPAs are yet to be signed) during FY 2011 remained much higher at upto 4.8 Rs./unit, with rising coal prices internationally. Further, in case of the developers with projects outside the procuring state (which has invited bidding) and based on imported coal, the quoted Case I bid tariffs⁸ have remained on higher side due to build-up of costs associated with the applicable transmission charges and loss level in kind. Further given the spiralling tariffs quoted, ICRA foresees resistance from the distribution utilities for signing PPAs at such high rates, especially when the financial health of the utilities still remains a concern.

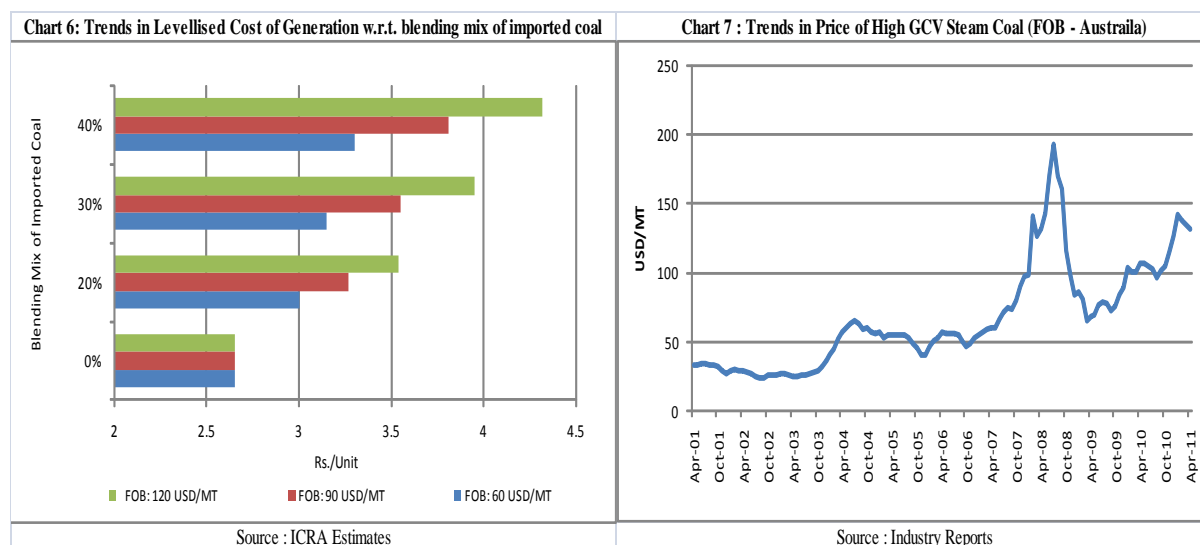
It may also be noted here that there has been modest progress so far observed in ten states⁹, where discoms have concluded PPAs based on competitively bidding with private developers for the cumulative capacity of 25,000 MW. Further, it may be noted here that during the last 18 months, no projects have been awarded or PPAs signed based on Case II bidding¹⁰, as Case I bidding is preferred. The recent tie-up for about 35,000 MW capacity through regulated (cost-plus) based PPAs by Central sector generation utilities with state distribution utilities prior to January 6, 2011 (i.e. the expiry date of five year exemption period given to CPSUs from the competitive bidding as per National Tariff Policy dated January 2006) may have further affected the competitive bidding process for procurement of electricity. Notwithstanding the same, the sustained progress towards the competitive bidding process by discoms for procurement of power in line with National Tariff Policy - 2007 remains extremely crucial, also given the recent amendment notified in June 2011 by Ministry of Power, GoI in the coal linkage guidelines for the power projects in XII Plan Period.

8As mentioned in Competitive Bidding Guidelines, for the purposes of standardisation in the process of bid evaluation for Case I bidding, the tariffs shall be compared at the delivery point, i.e., the interface with the STU network in the procurer's state where power is delivered to the procurers. Bid evaluation shall duly consider normative transmission charges, if any, from the injection point, i.e. CTU interface point, to the delivery point with respective escalations provided by the CERC/SERC. Transmission losses from the interconnection point to the delivery point, as specified by the Appropriate Commission shall also be considered for evaluation and reflected in the final levelised tariff. Actual transmission charges, as specified by the Appropriate Commission, from the injection point to the delivery point shall be borne by the procurers. Charges up to the injection point shall be borne by the bidder.

⁹ namely Gujarat, Maharashtra, Karnataka, Madhya Pradesh, Haryana, Punjab, Chhattisgarh, Uttar-Pradesh, Bihar & Rajasthan (excluding UMPPs which were awarded by Central Government)

¹⁰ Case II bidding: Location, technology & fuel is specified by the procurer & significant project planning work is required to be done upfront before the start of bidding process and award of project to the winning bidder.

With increased dependence on imported coal, the cost of power generation is likely to increase further; possibilities of renegotiation or dishonouring of competitively bid PPAs, where fuel price risk is not covered, cannot be ruled out.



The international price level of coal (gross calorific value (GCV) of 6600 Kcal/kg) has shown a significant volatility with a rising trend for the last ten-year period as seen in **Chart 7** mainly attributable to the growing coal demand from India and China. By contrast, the present domestic steam coal prices¹¹ offered by CIL are much cheaper - varying in the range of about Rs. 1000/MT for average GCV of 4500 Kcal/Kg to about Rs.600/MT for average GCV of 2800 Kcal/Kg. Adjusted for calorific value, domestic coal prices are about 60% cheaper than international coal prices. As domestic coal shortages are expected to continue, the dependence of IPPs on coal imports is bound to increase and this along with, any upward revision in domestic steam coal prices¹² (of Grade E & F) by CIL so as to realign towards international market prices in the future will result in a significant upward pressure on the cost of power generation.

To illustrate a scenario, if an IPP were to meet its coal requirement of upto 40% through imports, the levelled total cost of generation (without the return on equity) would show an increase of 63% to Rs. 4.3 /Unit at current prices over the cost of generation of Rs. 2.7/Unit based on 100% domestic coal, as seen below in **Chart 6**. Thus for IPPs based on domestic coal linkage and with competitively bid PPAs, non-recovery of the actual cost escalation due to blending of imported coal is likely to have an adverse impact on the returns of IPPs. In such scenario, the power project could be forced to operate on lower PLF level depending upon domestic coal availability which will in turn lead to under-recovery of fixed capacity charges (which is due to lower plant availability than normative) further affecting the project economics further. Else, there could be possibilities of renegotiation/dishonouring of PPAs by IPPs. Also, such risks exist for the competitively bid PPAs without any escalable provision in energy charges and assuming fuel linkage through domestic captive coal blocks, if there are significant delays in development of the captive coal blocks or coal blocks are cancelled out of regulatory uncertainties. Similarly, for IPPs based on imported coal and having the competitively bid PPAs, which are exposed to fuel price risk fully (due to mismatch in bid assumptions and actual coal supply terms), any sharp increases and volatility in steam coal prices would have an adverse impact on the project economics & could also result in renegotiation/dishonouring of PPAs. While coal based projects that have competitively bid based PPAs with energy charges quoted on the basis of 'Net Heat Rate' and 'cost-plus' based PPAs, would remain insulated from the fuel price risk, although the cost-competitiveness of such projects would be affected due to increase in cost of generation. Should the quantum of cost increases be very high, this may result in greater resistance on part of utilities to offtake such expensive power. As observed, the regulatory directions taken by the State Electricity Regulatory Commission (SERCs) have been favourable for the procuring discoms in few cases related to requests for tariff amendment/cancellation of PPAs by IPPs (such as Lanco Amarkantak Power

¹¹ The steam coal prices as notified by CIL are last revised in October 2009 which was subsequently followed by the revision in February 2011 for the prices of specific grades of coal i.e. high calorific value coal of Grade A and B with GCV of 6200 Kcal/Kg and above.

¹² For average increase of 10% in steam coal prices, average increase in tariff required is about 4%.

Pvt. Ltd¹³ and Adani Power Ltd). As a result, there has been a significant increase in the financial risk profile of such IPPs with an exposure to fuel price risk.

Increasingly, IPPs have opted for acquisition of overseas mining assets, however, they remain exposed to volatility in coal prices as well as political & regulatory risks; further, execution challenges remain significant for coal mine development, given the limited track record of domestic players

With a strategy of providing long-term fuel security and control over coal costs, many IPPs have been looking at acquisition of overseas coal assets. Some of the leading private sector IPPs (as mentioned in **Table 4**) have acquired substantial coal assets predominantly in three countries namely, Indonesia, Australia and South Africa. The preference towards these countries has been on account of adequacy of deposits in these countries with surplus coal availability for exports, logistical advantages of proximity to India and availability of low ash coal (that is below 10%) with high calorific value.

Name of IPP	Location	Particulars on Acquired Coal Assets/Mining Company	Period	Reserves	Acquisition Cost
				MMT	Million USD
Lanco Infratech Ltd	Australia	Acquisition of Griffin Coal Mining Ltd, Australia	Dec-10	1100	730
Adani Enterprises Ltd	Australia	100% interest in the Galilee Coal block in Queensland	Sep-10	7800	500+ Royalty
Essar Power Ltd	Indonesia	Aries Coal Mines	Apr-10	64	118
JSW Energy Ltd	South Africa	Majority Stake in South African Coal Mining Holding Company Ltd	Apr-10	22	NA
GMR Energy Ltd	Indonesia	PT Barasentosa Lestari, Indonesia	Mar-09	110	80
GMR Energy Ltd	South Africa	56% stake in Homeland Energy, South Africa	Feb-09	300	NA
TATA Power Company Ltd	Indonesia	30% Stake in KPC & Artumin	May-08	2900	1200
Reliance Power Ltd	Indonesia	3 Coal Mines in South Sumatra, Indonesia	Mar-08	2000	1600
Adani Enterprises Ltd	Indonesia	Acquisition of Mining Rights	2005	140	NA

Source : ICRA Research; Company Presentations

The sharp rise in coal prices has, however, been accompanied by growing political and regulatory risks. The rise could be mainly attributed to the fact that governments have tried to capitalise on high coal prices by keeping high royalty and taxation rates and also protect domestic consumers by stipulating minimum domestic obligation and minimum pricing benchmarks for coal exports. As a result, the IPPs having imported coal-based projects remain exposed to the risk of higher coal prices (in line with prevailing market pricing) than that assumed in tariff bids, due to sharp increase in the international steam coal prices over the last two year period & possibilities of the amendments in coal supply terms complying the regulatory requirements of coal exporting countries. In Indonesia, after introduction of the New Mining Law in December 2008, key implementing regulations related to domestic market obligations (DMO)¹⁴ and benchmark coal pricing norms¹⁵ for domestic and export sales are put in place during CY 2010. The Government of Australia has proposed a

13 Lanco Amarkantak Power Ltd (LAPL) has signed PPA with PTC India Ltd (PTC) at a levelled (Case I) tariff of Rs. 2.32/unit and in turn, PTC has signed the PSA with Haryana Power Generation Company Ltd (HPGCL). Pending the commencement of the supplies as per the PSA, the petition was filed by PTC for amendment in PPA signed by PTC with HPGCL (also with reference to back to back PPA between PTC and LAPPL) on the grounds which include occurrence of Force Majeure event i.e. Earthquake in China and Change in VISA policy of India resulting into increase in capital cost and shortages in domestic coal due to New Coal Distribution Policy resulting into dependence on costlier coal options. The commission however has directed vide order dated February 2, 2011 that PPA as earlier signed cannot be revised; 300 MW of contracted power should go to HPGCL and LAPPL is restrained to sell the power (300 MW) to any third party/merchant market.

14 DMO: The Regulation requires coal and mineral producing companies to allocate a certain minimum percentage of its total production to the domestic market, where DMO percentage will be as approved by the Ministry. The DMO can be implemented through sale of coal or minerals to a domestic trading company which holds a valid marketing and transportation license from the Ministry, Governor or the relevant head of region, as applicable. If the mining company fails to meet its minimum DMO in any particular quarter, they are required to make up any shortfall in the following quarter. The regulation contains strict sanctions for failure to comply with the DMO requirement, including a cut of up to 50% in quotas for mining production (for the mining company). The Regulation provides that DMO pricing should be based on the benchmark price applicable in the international market for the relevant mineral.

15 The Regulation requires that mineral and coal producers are obliged to sell minerals and coal based on a regulated benchmark price, whether for domestic or export sales. The benchmark pricing obligation applies to all minerals and coal sales to third parties, including to any affiliate of the mineral and coal producer. For spot contracts, the price used for the spot sale must be based on the benchmark price for the month the relevant mineral or coal is delivered. For coal and mineral "term" sales (defined as sales of minerals or coal for a period of 12 months or longer), the sale price must refer to the average benchmark price for the last three months before the signing of the relevant sales contract. Holders of Production Operation IUPs/IUPKs for minerals and coal are obliged to adjust their prices for term-based sales every 12 months. Benchmark Coal Reference Price for May 2011 for thermal coal is set at US\$ 117.61 per ton for GCV of 6322 Kcal/Kg.

Mineral Resource Rent Tax (MRRT)¹⁶ for the coal & iron ore sector to be implemented with effect from July 2012.

The overall execution challenges for mine development (including associated infrastructure development such as port connectivity) remain significant in case of acquisitions of mining blocks, where the development period could be about 4-5 years for start of production. While many of these IPPs have no track record in execution of such mining projects, the same risk can be minimised through third party appointment of Mine Developer-cum-Operator (MDO). Such risks would also be relatively lower in case of stake acquisitions in mining companies having operational mining assets; however, stake acquisition is relatively costly and the ability to ramp-up the production levels remains crucial.

Strengthening of transmission network by central and state sector transmission utilities remain crucial; Acquiring right of way and statutory clearances often results into delays in transmission connectivity projects

While the present inter-regional transmission capacity of PGCIL stands at 22,000 MW as on March 2011, the same is expected to increase to about 57,000 MW by 2015 and 75,000 MW by 2017 as per the estimates of CEA. Further, the responsibility of network planning in conjunction with the growing demand rests with PGCIL and State Transmission Utilities¹⁷, as clearly stated in National Electricity Policy, also given that these transmission utilities are expected to remain dominant players. With respect to the large-sized network expansion planned by PGCIL, regulatory approval was granted by CERC vide its order dated May 2010, approving the plan of PGCIL to set up nine high capacity power transmission corridors costing at about Rs 58,000 crore for power evacuation from various projects planned by several independent power producers (IPPs) particularly in coal-rich regions such as Orissa, Jharkhand, Madhya Pradesh & Chhattisgarh.

The average execution period of such transmission projects vary in the range of 24 to 36 months. Despite relatively low technical complexities, such transmission projects face significant execution challenges that arise out of stiff resistance faced from land owners in acquiring right of ways and several necessary clearances (including forest clearance which is a time-consuming process, in case the line passes through the forest zone) from government/statutory authorities. As for the competitively bid power projects, where the state transmission utilities/PGCIL take the responsibility of laying the evacuation responsibility¹⁸, any delays in execution by state transmission utilities/PGCIL could cause delay in the commissioning of such generation projects. In case of stranded capacity due to such delays by procurer, the impact on the cash flows of IPPs could only be offset if IPPs are able to claim over the fixed capacity charges linked to deemed generation.

It may be noted that the participation by the private sector in transmission projects has been limited so far, though improving. Six Ultra Mega Transmission Projects (UMTPs) entailing overall investments of about Rs. 7000 Cr. for inter-region system strengthening schemes have been awarded by Power Finance Corporation (PFC) /Rural Electrification Corporation (REC) being a nodal agency, over the last two year period to private players. In addition to UMTPs, private participation has also been through JVs with PGCIL & State Transmission Utilities for implementation of the transmission projects, which are mainly generation project specific. PGCIL has formed 5 JVs¹⁹ as of now with the private IPPs namely Essar Power Ltd, Torrent Power Ltd, Teesta Urja Ltd, Jaypee Group and ONGC Tripura Power Ltd, while state transmission utilities in states of Maharashtra, Karnataka, Haryana & Rajasthan have so far formed JVs with private IPPs.

¹⁶ The proposed tax (MRRT) will be levied on 30% of MRRT assessable profit, where assessable profit is defined as assessable receipts minus deductible expenditure (including an MRRT allowance). The MRRT allowance is proposed to be set at the long term government bond rate plus 7% (700 basis points). Projects will also be eligible for a 25% extraction allowance, which reduces the effective statutory tax rate to 22.5%. State royalties will be deductible for MRRT purposes, and MRRT payments will be deductible for company income tax purposes.

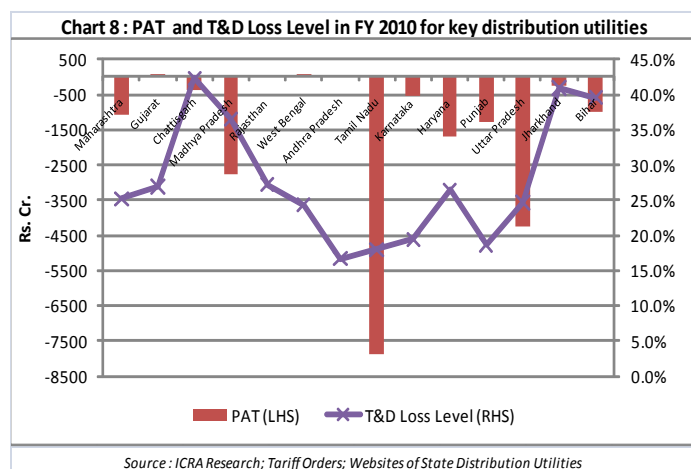
¹⁷ NEP-2005 states that "network expansion should be planned and implemented by CTU/STUs keeping in view the anticipated transmission needs that would be incident on the system in the open access regime. Prior agreements with the beneficiaries would not be a precondition for network expansion. CTU/STU should undertake network expansion after identifying the requirements in consonance with the National Electricity Plan and in consultation with stakeholders, and after due regulatory approvals."

¹⁸ As part of PPA, the procurer/STU assumes the responsibility for putting up transmission lines from the switch yard of the generating station to the nearest sub-station of the utility.

¹⁹ In each of the five JVs formed so far, PGCIL holds 26 per cent equity stake while the private sector entity holds a controlling 74 per cent.

Financial position of state-owned distribution utilities continues to remain weak resulting in high counterparty credit risks for IPPs

As observed from **Chart 8**, the aggregate book losses including booked subsidy for the state-owned distribution utilities in 14 states²⁰ which account for about 80% of the overall electricity consumption on All-



India basis, were high and at about Rs. 21000 Crore. However, ICRA is of the opinion that cash losses for these utilities (based on cash collections from consumers and subsidy received basis) are estimated to be much higher than Rs. 21,000 Crore. The transmission & distribution loss levels too remain high and range between 20% and 45% across the states. Overall, the high losses can be attributed to a mix of factors such as a) shortfalls in meeting distribution loss level target as set by SERCs, leading to disallowance of power purchase cost (which forms about 80% of cost of supply of power for any distribution utility), b) higher

operating overheads than allowed, c) inadequacy of tariff subsidy booked, c) absence or inadequacy of tariff revision by SERCs and d) under-recovery of fuel & power purchase cost adjustment (FPPCA). With the continued book losses, the leveraging levels (Total Debt/TNW) of utilities in many of the states remain high due to their dependence on short-term borrowings arising out of liquidity constraints to fund cash losses in addition to debt required for their ongoing capital expenditure plans. ICRA further notes that with rising fuel & power purchase cost and growing agriculture consumption which is largely unmetered and enjoys heavily subsidised power, the subsidy requirements have been rising for distribution utilities²¹, and remains a key credit concern. This is observed in many states with populist policies such as either free power policy or tariff compensation/subsidy to certain sections of the society. Though a payment security mechanism in PPA comprising a) letter of credit, b) escrow account and c) right of sale to third party may partially offset such counterparty credit risk. Fundamentally an improvement in the commercial viability of the state-owned distribution utilities remains crucial.

With many of IPPs being in their investment phase, leveraging levels would remain high along with significant execution risks

Given that many of private sector IPPs are in their investment phase with large-sized plans in capacity addition as well as backward integration with respect to acquisition of coal mining assets in overseas countries, overall funding requirements will remain quite significant²² and keep their leverage levels high at least over the next three to five year period. Also, with 'green-field nature' of most of these projects that involve implementation related challenges, the risks of time overrun and cost overrun persist. Besides time overrun, the cost overrun could also arise out of foreign currency variation risks during construction, given that many of the private IPPs are relying on imported BTG sets, and hence, hedging plan to offset such risks post CoD remains crucial. The prevailing volatility in the equity markets since November 2010 as well as increasingly cautious approach of lenders (with respect to ensuring fuel linkage and/or a certain portion of the capacity to be tied-up through long-term PPA route) may thus affect the financial closures of some of the projects. Given the inherently high execution risks involved and the concerns over the coal availability, there could be an increased instance of amendment requests by the IPPs for revision in the project implementation schedule and the debt repayment schedule going forward – thus reflecting the increased risk profile for IPPs mainly for projects with either competitively bid and/or merchant PPAs. ICRA notes that debt servicing ability of IPPs would depend mainly on stabilisation of operations with adequate fuel availability and extent of fuel price pass-through/escalation provision so as to keep the actual variable costs in line with bid levels.

20 The financials for discoms in the states of Uttar Pradesh, Bihar and Jharkhand for FY 2010 are not available, and hence, PAT for FY 2009-10 is assumed to remain at same level as observed for FY 2009.

21 Kindly refer note on "State-owned Distribution Utilities : Key Trends & Credit Perspective " dated January 2011 published by ICRA

22 Based on the assessment of the financial closures achieved for various thermal power projects, average capital cost is observed in the range of Rs. 4.5 ~ 5.5 Cr./MW with debt : equity funding mix of 3 times.



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