UBS Investment Research

Independent Power Producers

Hopes Deferred as Power Dims

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- **Concerns remain for merchant power; transitioning coverage**

We see several negative themes continuing to affect the Independent Power Producers (IPPs). Despite the modest gas price recovery projected in our natural gas commodity forecast ($6.25/MMBtu in '10 & $7.00/MMBtu in '11 & beyond), hedges priced in '07/'08 are not likely to be replicated, resulting in backwardated EBITDA profiles across much of the sector. Further negatives include a tempered "check-mark"-like recovery in electric sales (0.5-1.5% in '10), basis compression in gas spreads to Henry Hub due to Marcellus shale gas, and depressed capacity auctions results due to demand side mgmt and energy efficiency initiatives.

- **Anticipate little new generation in near term; new regulation looming**

We anticipate relatively little new merchant generation in restructured markets due to both the depressed and highly volatile nature of power prices, markedly higher construction costs, low fixed-capacity payments, siting issues, and uncertain environmental policy. We see emission standards as exacerbating these factors.

- **Downgrading MIR to Sell; Upgrading CPN to Buy; Reiterate DYN as Sell**

Following a complete re-evaluation of our models and valuations, we are downgrading MIR to Sell and lowering our PT to $11 from $15, and upgrading CPN to Buy and raising our PT to $14 from $11.50. We believe the near-year comps for MIR mask the roll-off of its deeply in-the-money hedges, as well as the LT impact of the TRAIL transmission project. We are raising our target on CPN in light of increased confidence in mgmt's ability to grow its EBITDA. However, we remain relatively underweight on the IPPs, and reiterate our Sell rating on DYN.

Table 1: Transferring Lead Coverage of Independent Power Producer (IPP) Universe

		Market Cap.		Price	EBITDA				EV / EBITDA multiple			
2/21/2010	Rating	($ in millions)	Price	Target	2009E	2010E	2011E	2012E	2009E	2010E	2011E	2012E
INDEPENDENT POWER PRODUCERS												
AES Corporation	Not Rated	8,130	12.18	NA	4,557	5,032	4,645	-	5.1	4.6	5.0	
Dynegy, Inc.	Sell (CBE)	1,395	1.65	1.30	774	507	641	617	8.4	12.8	10.2	10.5
Mirant Corp	Sell	1,952	13.45	11.00	874	600	458	343	4.4	6.4	8.3	11.1
Calpine Corporation	Buy	5,021	11.35	14.00	1,734	1,530	1,719	1,723	7.7	8.7	7.7	7.7
NRG Energy Inc.	Neutral	5,949	23.20	24.00	2,649	2,259	1,888	2,095	5.4	6.3	7.5	6.8
RRI Energy Inc.	Neutral (CBE)	1,697	4.81	5.00	78	439	508	314		8.3	7.2	11.6
Average					**1,778**	**1,728**	**1,643**	**849**	**6.2**	**7.9**	**7.7**	**9.6**

Source: FactSet (for AES data) and UBS estimates; averages include entire sectors

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Struggling to Generate a Profit

We are transferring lead coverage of the Independent Power Producers and reiterating our dour outlook on the sector as a whole. We believe weak power prices are likely to persist through 2010 due in large part to weak commodity underlying fundamentals and mild electric sales that have shown only stabilizing or minimally improving QoQ trends recently. A significant takeaway from the ongoing fourth quarter earnings season is the generally tepid outlook presented for 2010, with many utilities anticipating sales to remain flat to modestly up; we expect sales to recover a modest 0.5-1.0% in 2010. Finally, the mandated development of renewables by state renewable portfolio standards (RPS) threatens to continue to undercut power prices and heat rates in many regions, most notably the Midwest. A further headwind is our concern for compressed gas price basis to Henry Hub in the northeast due to Marcellus Shale gas production.

We are transferring lead coverage of select companies within the merchant generation sector, reiterating our dour near term outlook on the sector

Longer term, we anticipate a wave of retirements and a broader lack of new capacity to push power prices higher. Given both the exceptional volatility and low nominal value of natural gas and power in the last several years, we see cash flow uncertainty as an impediment for attracting new, large fixed capital investments in restructured markets. Further, the implementation of carbon regulation (along with other environmental control requirements) could result in widespread switching from coal to gas, pushing both power and gas prices upwards. However, should the EPA pursue carbon regulation prior to the passage of federal legislation, we see litigation and extreme uncertainty significantly limiting any new generation.

Power price fundamentals in the longer term remain robust with a lack of new generation capacity and the threat of tighter environmental controls to likely significantly affect power prices

In this environment, we are upgrading our rating on Calpine to Buy (raising our price target to $14 from $11.50), as we believe those generators that have the greatest ability to weather the downturn in commodity cycle while maintaining exposure to longer term volumetric improvement deserve more than a marginal premium to peers. Even with a recovery in commodities to our long term $7/MMBtu gas, we see EBITDA at many of the IPPs as likely to drop sharply over the next five years.

It's all downhill from here; EBITDA peaked in 2009

CPN offers at least *a flat profile*, while the balance offer sharply declining earnings profiles

We are also downgrading our rating on Mirant to Sell and lowering our price target to $11 from $15. We believe MIR is a clear example of investors looking at peak near year multiples without focus to the sharp declines in EBITDA in 2010 and beyond. With new transmission, a secularly lower power price environment in the Washington, DC area, significant exposure to higher priced NAPP coal, and earnings concentrated to just four units, we see a risk profile not worth a peer multiple. In the near term, we don't anticipate management to deploy its $2 Bn in cash on the balance sheet, likely saving it for rainy days and maturities. Longer term, we see MIR's coal fleet as particularly poorly positioned with respect to carbon legislation given its location in a gas-oriented power market. All of this leads us to ask, why pay so much for a stock with such low normalized EBITDA?

Downgrading MIR to Sell with a $11 PT; we see the name as expensive to peers and likely to disappoint with no further share repurchases

We are also using the opportunity to reiterate our Sell rating and $1.30 price target on Dynegy given its exposure to Midwest power fundamentals, the build out of renewables across the plains states, and carbon legislation. The stock continues to trade at a significant premium to the sector, despite having some of the weakest fundamentals of its IPP peers.

Reiterating Sell rating on DYN and $1.30 PT; why keep paying a premium multiple for eroded fundamentals?

In Summary, we remain underweight the sector relative to its regulated and Competitive Integrated (hybrid) peers. We highlight CPN as our top investment idea in the space, and MIR as our top Sell idea in the space.

Power Prices Could Remain Weak in the Near Term; See Some Improvement with Recovering Gas Price View

Natural gas prices could continue to be pressured in the near term, but our $7 normalized gas forecast builds in expectations for gas production to be scaled back

Given that power prices in many regions tend to be set by the delivered cost of natural gas, we believe potential near term pressure on gas prices should translate into only modest improvements in regional power prices. Near term pressure on gas is driven by four primary factors: 1) record high levels of natural gas storage going into the heating season; 2) gas production has been slow to decline despite a sharp drop in the rig count (improving initial production rates of shale-gas wells coming online); 3) and larger E&P companies targeting double digit production growth rates in 2010; and 4) pressure from an inventory of wells yet to be completed. Our natural gas price forecast does however provide for a glimmer of hope in 2H10, with prices improving to provide an average 2010 NYMEX price of $6.25/MMBtu. We anticipate the significantly depressed rig count to lead to sequential acceleration in gas production, with total US production likely declining by 5%.

Table 2: UBS Natural Gas Price Forecast- NYMEX and Composite ($/MMBtu)

								First Call			Futures Strip		
	1Q09A	2Q09A	3Q09A	4Q09A	2009A	2010E	Normalized	2010E	2011E	2012E	2009E	2010E	2011E
Natural Gas Composite ($/MMBtu	$4.27	$3.49	$3.09	$4.16	$3.78	$6.15	$7.00						
Natural Gas NYMEX ($/MMBtu)	$4.91	$3.51	$3.39	$4.16	$3.99	$6.25	$7.00	$5.69	$6.19	$6.73	$5.48	$5.99	$6.19

Source: First Call and UBS estimates

A gas price concern specific to power producers is the potential for gas price basis compression in the northeast (TETCO M3) relative to Henry Hub

Adding to near term pressure on natural gas, the premium basis to transport gas from the Gulf to the Northeast (TETCO M3 – Henry Hub gas basis) could potentially decline secularly with the increasing development of "local" Pennsylvania-oriented Marcellus Shale gas, impacting a number of IPPs (primarily RRI and MIR). Coal-to-gas switching should buoy both power and gas prices at the $3-4/MMBtu gas level on the low end, even at the most robust of gas production rates. Longer term, we see power prices as delinked from gas as supply/demand fundamentals drive market heat rates and fuel sources. We see a paucity of new generation in restructured (or 'deregulated') electric markets.

Recovery in Coal Prices Should Temper Power Price Improvement

We anticipate a significant increase in Appalachian coal prices should limit margin improvement for Coal IPPs

Despite having an above-market normalized $7/MMBtu natural gas forecast, we forecast significant EBITDA margin compression as coal prices continue to rise for the IPPs (with MIR and RRI affected most dramatically due to their predominant reliance on CAPP/NAPP products). UBS coal analyst Shneur Gershuni projects these products could reach $80/ton in 2011 and $100/ton in

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2012, with a long term view of $75/ton. We note the forward curve for these products is similarly robust. We contrast these in Table 3.

Table 3: UBS CAPP Coal Forecast vs. NYMEX Strip

Coal Product	2010E	2011E	2012E	2013
CAPP-UBSe	$57.00	$80.00	$100.00	$75.00
CAPP-NYMEX Strip	$54.15	$67.18	$75.97	$81.40

Source: FactSet and UBS estimates; *we note Mirant burns (similarly priced) NAPP coal

Price recovery in PRB and repricing of transportation contracts is likely to compress margins

Schner Gershuni also has above strip expectations for PRB, which should crimp even PRB burners such as DYN and NRG. We note that a separate more opaque issue for coal generators remains re-pricing of rail contracts, which contributed significantly in the step down in EBITDA for NRG in 2010 and is likely to contribute to a significant step down for DYN in 2014.

Lack of New Supply, With New Additions Likely Not Keeping Pace With Retirements; Renewables should Fill Most of Gap

Coal plant retirements, organic growth, and flexible generation to meet renewable load variations question whether new additions can keep pace

Longer term, we see power prices as being primarily a function of generation supply and demand dynamics, which we see as setting itself up for another turn in the commodity cycle. Despite the massive buildout in capacity resources during the last decade, a significant portion of the US' small coal plants could face retirements in light of stringent additional environmental control requirements, including NOx, SO_2, mercury, ash pond, once-through cooling, and CO_2 compliance. We anticipate the timing and impact to the sector to become clearer as the EPA elucidates plans on compliance; we anticipate the full impact of EPA actions to be likely several years out, as EPA will only release revised CAIR Phase II/MACT standards later this year and early next year, respectively. We also await EPA's CO_2 Best Available Control Technology (BACT) compliance by mid-2010 which we believe could take the form of a New Source Performance standard, limiting emissions to that of a gas peaker. In aggregate, small coal plants (<400 MW), comprise ~45 GW of generation or ~4% of total US nameplate capacity. We believe larger coal plants without environmental controls also remain at risk, given the rising cost of installing environmental controls. Further, we foresee a continued shift to natural gas, as reliability pricing capacity-markets work to incentivize the construction of low-fixed cost, but higher heat rate, simple-cycle combustion turbines.

Renewables Remain a Key Swing Factor in New Generation Development

As seen this year with a record new build in wind capacity, we believe a key determinant of future market heat rates remains the quantity of renewables being interconnected to the grid. While we now expect a more moderate year in 2010 for wind additions, we see heat rate improvement beyond 2010 as mostly dependent on how aggressive utilities move to meet state and potential federal renewable targets. In particular, we see the MISO region as particularly vulnerable to continued heat rate compression from disproportionate wind development. That said, even under the assumption of a large renewable build we expect gas generation to backup (or "firm" up) these resources, leading to further volatility in both power and gas prices as well as driving up gas prices in the long term.

Next Capacity Auction Likely to Remain Tepid; Constant Evolution in Rules Makes Forecasting Challenging

Auction results in the near term will remain pressured by DSM resource bidding; we see improvements in the longer term, but potential further changes to market design linger

Capacity auctions results from RTOs, namely PJM and NE ISO, are likely to remain tepid in future auctions. We project NE ISO capacity prices to continue declining as the next auction, scheduled for May, potentially no longer has a floor value. For PJM's RPM auction, we project a mild pick-up over last year's low, which cleared at the RTO level at just $16/MW-day, as existing demand response will not be forced to bid zero. In both auctions, we also anticipate the slowed economic recovery to continue to minimize total new needed capacity additions, further suppressing capacity pricing. Beyond the next auction, capacity resources will increasingly need to be priced as a function of the cost of incremental demand response resources. We anticipate a general upward trajectory in capacity prices given likely significant retirements of baseload coal facilities in light of a host of new environmental control requirements. Ultimately, the auction outcomes remain a moving target as modifications to auction rules, and outside influences seemingly remain a reality of each auction.

Initial Utility Indications Point to Mild Recovery in Electric Sales in 2010, as Industrial Sales Expected to See Partial Uptick

Despite large YoY declines, 2010 utility expectations point to mild recovery of +0.5-1.5%

We expect utility sales to experience a longer term shallow "check-mark"-like recovery, in contrast to the broader economic debates of a "U" or "V" shape; our initial 2010 generation forecast is for an uptick of just +0.5-1.5%. We believe most of the pickup will be derived from an industrial upswing ranging from 2.5-4.0% following on UBS economists' expectations for an improvement in Industrial Production of +3.7%. Residential sales could see a 1.0% rebound (albeit clearly primarily weather driven), while commercial sales are likely to remain flat to down -1.0%. UBS' latest *US Construction Update* (see note published Dec. 16, 2009) forecasts another sharp 22.4% drop in non-residential construction in 2010 off a 2009 projected decline of 11.2%. The upper end of our sales range (+1.5%) is just shy of the historic relationship between electric sales and GDP growth at 0.7 times our 2010 UBS GDP growth assumption of + 2.6% (which results in a +1.8% increase).

Table 4: US Generation Forecast - YoY

GWh	Residential	% Δ	Commercial	% Δ	Industrial	% Δ	Total	% Δ
2007A	1,392	3.0%	1,336	2.8%	1,028	1.6%	3,765	2.6%
2008A	1,379	-0.9%	1,352	1.2%	982	-4.4%	3,722	-1.1%
2009E	1,365	-1.1%	1,324	-2.1%	883	-10.1%	3,579	-3.8%
2010E	1,378	1.0%	1,311	-1.0%	914	3.5%	3,610	0.9%
2011E	1,399	1.5%	1,337	2.0%	950	4.0%	3,694	2.3%

Source: EIA and –UBS estimates

Upgrading CPN to Buy; Raising Our Price Target to $14

Despite our more negative view on the sector, we are raising our price target on Calpine to $14 from $11.50 and upgrading the stock to Buy from Neutral. Our revised price target **ascribes a warranted premium to CPN** over the group (8.5x '11E Hedged EBITDA vs. 7.6x for the group), accounting for both CPN's improving risk profile and mitigated exposure to commodity price fluctuations. Calpine has no exposure to rising coal prices and derives significant value from both contracting assets (*e.g.*, Tolls and Purchase Power Agreements) and long term steam contract agreements.

- **EBITDA profile remains intact relative to peers**

Contrasting the company's EBITDA profile with its peers we note CPN's relative ability to maintain cash flow while its peers are experiencing the combination of rolling off above market hedges and higher coal/transportation prices. We actually see 2010 EBITDA as a trough with our EBITDA estimate at roughly $1.55 Bn. We project EBITDA improvement to $1.7 Bn in '11 and beyond; we see Street consensus in '11 & '12 as too pessimistic with consensus at $1.675 Bn and $1.55 Bn, respectively.

- **Free cash flow profile remains attractive; deleveraging is the story**

We believe a primary aspect of the company's story remains its ongoing deleveraging efforts after re-emerging from Chapter 11 reorganization in early 2008. The company has proved thus far, successfully refinanced its expensive CCFC debt and exchanging for par a portion of its Term Loan for a longer dated First Lien Bond. With little to no environmental liabilities to speak of (in sharp contrast to its peers), we see free cash flow remaining relatively robust into the future. We provide our estimate of free cash flow yield (pre-growth capex) but net of major maintenance expense.

Table 5: Free Cash Flow Yield Forecast

	2009E	2010E	2011E	2012E	2013E	2014E
FCF Yield (Pre-growth Capex)	6%	8%	6%	3%	7%	8%

Source: UBS estimates

- **Debt exchange to fixed first lien bonds should allow for eventual share repurchases**

We interpret management's ability to execute its $1.2 Bn debt exchange last October for marginally higher yield as equity positive. We view the less restrictive covenants as likely accelerating the company's ability to begin repurchasing shares and also as a sign that the capital markets are readily able to address CPN's 2014 exit facility maturity. The company has ~$4.5 Bn remaining of its term loan to refinance in the interim.

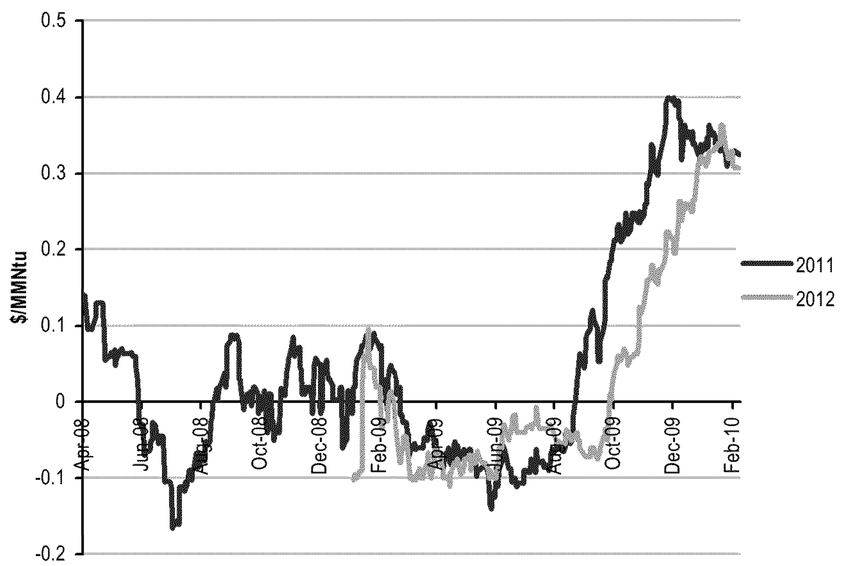
- **Anticipate Geyser announcement on upcoming 4Q Call on (Wed.) 2/25**

We believe management will unveil further details and the timeline of its Geyser expansion project designed to make use of ITC cash grants, taking the installed capital cost down to the $2,500-3,500/kW range. We believe this investment is likely to prove attractive with the promise of robust REC value in tandem with RA capacity, and energy revenues. We have yet to incorporate any new geyser projects in our estimates pending further details.

- **California natural gas basis now positive to Henry Hub**

An added benefit to Calpine is its disproportionate exposure to California (~50% of EBITDA), which has benefitted from improving gas basis to NYMEX Henry Hub. While new shale finds in the East have helped drive down NYMEX gas prices, the distance to California markets should help offset the decline with an improving basis to PG&E Citygate delivery (and consequential support for NP15 power prices). We confirm this basis support examining historic basis trends in Chart 1.

Chart 1: Forward Natural Gas Basis to PG&E Citygate



Source: Platts

Downgrading MIR to Sell; Lowering Our PT to $11

We are downgrading MIR to Sell, as we see estimates as too high and valuation as trading egregiously expensive

We are also downgrading our rating on MIR to Sell (from Neutral) and lowering our price target to $11 from $15. We note the wide discrepancy between our estimates of the company's Open EBITDA at $269 Mn vs. our Hedged EBITDA estimate of $468 Mn. We anticipate investors are failing to take into consideration the roll off and valuing a more "normalized" level of EBITDA of ~$350 Mn. We contrast the fall off in EBITDA among the IPPs in Table 6, with MIR experiencing the most dramatic drop of ~50% from '10 through '13.

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Table 6: Comparison of EBITDA Profiles of IPPs ($ Mn)

EBITDA	2009E	2010E	2011E	2012E	2013E	2014E
INDEPENDENT POWER PRODUCERS						
AES Corporation	4,557	5,032	4,645			
%Δ		10%	-8%			
Dynegy, Inc.	774	507	641	617	616	474
%Δ		-34%	26%	-4%	0%	-23%
Mirant Corp	874	600	458	343	385	336
%Δ		-31%	-24%	-25%	12%	-13%
Calpine Corporation	1,734	1,530	1,719	1,723	1,707	1,698
%Δ		-12%	12%	0%	-1%	-1%
NRG Energy Inc.	2,649	2,259	1,888	2,095	2,005	1,836
%Δ		-15%	-16%	11%	-4%	-8%
RRI Energy Inc.	78	439	508	314	327	291
%Δ		465%	16%	-38%	4%	-11%
Sum	**10,666**	**10,367**	**9,859**	**5,092**	**5,041**	**4,636**
%Δ		-3%	-5%	-48%	-1%	-8%

Source: FactSet (for AES) and UBS estimates

■ Near years multiples comparison hides EBITDA fall off

Despite the robust EBITDA Mirant will likely post in 2009-11, we anticipate a significant decline as the twin effects of above market hedges rolling off and rising coal prices crimp EBITDA. Among its peers, Mirant has the most significant above market hedge value embedded into its EBITDA profile, with fully half of its EBITDA value in 2010 and 2011 derived from above market hedges.

Applying current gas forwards drops EBITDA a further $30-40 Mn

To derive our $11 price target we have applied a healthy ~7.4x EV/EBITDA multiple to MIR's 2011E hedged EBITDA of $458 Mn, despite our expectation for a further 25% drop in EBITDA to normalized levels. Alternatively, stripping away its 2011 hedges, we apply an above cycle 8.5x EV/EBITDA multiple to derive our $11 price target. Substituting further the current market forwards (our UBS forecast has embedded above market assumptions), we apply an 8.3x EV/EBITDA multiple to achieve our $11 price target. This is all in sharp contrast to MIR's 2006-2009 historical 1-year forward average EV/EBITDA multiple of 4.66x. Further to the point, our valuation ascribes robust EV/EBITDA multiples despite MIR's declining EBITDA profile. We contrast the valuation multiples used in our SOP valuations in Table 7.

We ascribe an already healthy 7.4x EV/EBITDA multiple on MIR's '11 EBITDA to derive our $11 PT

Table 7: Comparison of EV/EBITDA SOP Valuation Multiples Across IPPs

	Implied Valuation Multiple		
	2011 Hedged EBITDA	2011 UBS Open EBITDA	2011 Market Forward Open EBITDA
CPN	8.0x	9.5x*	10.5x*
DYN	8.5x	8.1x	8.6x
MIR	6.4x	8.5x	9.1x
NRG	7.9x	6.8x	8.4x
RRI	6.5x	6.5x	7.0x

Source: UBS estimates; *Open are rought ests. for Calpine not comparable given multitude of contract agreements

■ No share repurchases likely in 2010, despite $2 Bn in cash on hand

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We believe a possible disappointment to investors may come as management decides against deploying its $2 Bn in cash into further share repurchases, likely retaining the liquidity in order to potentially pay down near term maturities ($535 Mn in 2011, $1 Bn revolver in 2012, and $850 Mn notes in 2013.) Further, we think Mirant's relatively expensive shares should further temper management's desires to move forward with a share repurchase program. We believe should management become more comfortable with the commodity market and availability of credit, further repurchases could be a 2011+ event.

With shares already expensive and a declining EBITDA profile, we believe a conservative management team would opt to sit tight on liquidity

- **Transmission risk as TRAIL project reaches in-service in June 2011**

We believe a key investment risk is the development of several new transmission projects into the Washington, DC area, reducing wholesale power prices. The most important of which is TRAIL (a joint venture between Dominion and Allegheny), anticipated to be in service in June 2011. Looking further afield we see the even larger PATH project (a JV between AEP and Allegheny) as further minimizing the price premium received in the PEPCO zone. With no actively quoted forward curve for price basis to PEPCO Zone from PJM West Hub, we remain unsure of its impact. However, we believe the basis will likely not recover to its pre-recession level of $11-12/MWh, and is more likely to stay in the $6-7/MWh (recovery to between its average 2009 basis of $4/MWh and its historic level).

We see new transmission projects as pushing power prices down for Mirant, preventing recovery to the historic levels seen pre-recession

- **Anticipated thermal coal price uptick should mitigate EBITDA upside**

Our coal forecast is likely to impinge on the company's ability to grow EBITDA as its above market hedges roll off. Our UBS coal analyst anticipates a pick up in thermal coal exports from the US, bolstering pricing into 2011. We contrast our UBS Thermal coal outlook to the current strip in Table 3, on page 4.

- **Asset concentration— could Potomac River plant be victim to EPA's MACT standards?**

The company is also exposed to substantial asset concentration among four coal plants in the DC area. Three have installed scrubbers to ensure their compliance with the Maryland Healthy Air Act. However, Mirant's Potomac River site does not have sufficient land to incorporate such a scrubber, which could potentially be required under new Maximum Achievable Control Technology (MACT) standards currently under consideration by the EPA. The plant currently implements controls using Solvay's TRONA technology which is likely not to qualify under MACT standards; a potential alternative could include Sodium Bicarbonate (but this remains to be seen).

Reiterating Sell Rating on DYN; Maintaining $1.30 PT

DYN: reiterate Sell rating

We are also reiterating our Sell rating on Dynegy and maintaining our $1.30 price target. The company continues to screen as one of the most expensive companies in the sector despite operating primarily in power markets with arguably the weakest outlook for power demand. We use an 8.5x EV/EBITDA multiple on '11E hedged EBITDA to derive our price target, on par with Calpine.

- **Historical premium to peers no longer warranted**

While Dynegy has historically traded at a premium to the IPP sector, we see its significant leverage, relative decline of Midwest power demand fundamentals, and increasing build out of renewables as all arguments for an erosion of its premium valuation. While the company remains relatively levered, we note its recent asset sale has improved its immediate (2011-12) maturity profile and associated liquidity concerns.

PRB Midwest generator no longer deserves premium valuation; better positioned than MIR & RRI, but question is how much of a premium is warranted?

- **Roll off of rail contract in 2014 should lead to drop in EBITDA**

While the company may fortunately not be exposed to higher CAPP/NAPP pricing, it does have a significantly above market 10-year rail contract expiring in 2014, accounting for a 23% EBITDA drop from $609 Mn to $467 Mn.

We est. the rail roll off is a $140 Mn hit

- **Midwest wind build threatens to undermine heat rates**

We are also concerned with Midwest power fundamentals as further new wind farms and their associated transmission projects aim to deliver Midwest wind energy to the Chicago market. With state RPS standards edging closer and robust capacity factors, we see Exelon's recent estimate of an incremental 3GW into the NI Hub zone by 2012 as a very reasonable figure.

Incremental wind generation likely to offset significant amount of demand improvement

Upcoming Earnings:

NRG Energy – Tuesday, 2/23

We anticipate the company is likely to beat expectations, with the primary swing factor remaining Reliant Retail results. We anticipate 4Q09 EBITDA of $508 Mn, with FY2009 EBITDA of $2,614 Mn. Questions likely to be of particular focus on the call include a discussion of NINA and timeline for reaching agreements with offtakers, etc. Further attention is likely to be focused on

Call to be held at 9 am EST. Dial-in: 866.271.6130 and Passcode: 31069282

Calpine – Thursday, 2/25

At a recent investor conference management already disclosed it will exceed the top end of its 2009 EBITDA guidance of $1.710 – 1.735 Bn. We are maintaining our Adjusted EBITDA estimate at the top end of management's range, implying a 4Q09 EBITDA estimate of $360 Mn (vs. $325 Mn in 4Q08). We believe much of the focus on its earnings call will focus on the outlook for 1) spark spreads in Texas; 2) debt financing plans for 2010; and 3) discussion of its geysers expansion project, including both the size, cost, and timing of the project.

Call to be held at 9 am EST. Dial-in: 888-695-0608 and Passcode: 1737034

Dynegy – Thursday, 2/25

Despite having revised its guidance up already to a range of $730 – 760 Mn, we are raising our '09 estimate to $774 Mn, above its guidance range and implying 4Q09 EBITDA of $64 Mn (vs. $123 Mn last year). We believe this could yet prove conservative. We believe primary points for discussion on its upcoming call will primarily include: 1) a discussion surrounding its pending sale of its development stake in Plum Point and 2) update on environmental regulation including pending new coal combustion byproduct rules from the EPA.

Call to be held at 10 am EST. Dial-in: 1-888-790-0727 and Passcode: Dynegy

RRI Energy – Thursday, 2/25

We believe RRI Energy could exceed its Adjusted EBITDA guidance for 2009 of $56 Mn, with our expectation of $78 Mn; this implies 4Q09 EBITDA of $37 Mn. Primary issues likely to be discussed on the call include: 1) financing plans for 2010; 2) expectations for the upcoming ATSI PJM transition capacity auction; 3) updates the company's PJM coal facilities; and 4) update on exposure to environmental regulation including pending new coal combustion byproduct rules from the EPA.

Call to be held at 11 am EST. Dial-in: 1-888-895-5479; Conference leader is Dennis Barber

Mirant – Friday, 2/26

We believe Mirant could marginally exceed its $860 Mn guidance, posting $874 Mn by our estimate. We see substantially more investor focus on its initiation of 2011 EBITDA guidance which we currently estimate at $458 Mn (assuming our $7/MMBtu NYMEX forecast), or $411 Mn using the current natural gas 2011 strip; consensus remains at $479 Mn. Other issues likely to be brought up on its earnings conference call include: 1) latest thinking on its substantial cash position and debt financing plans (we don't forecast further share repurchases); 2) outlook for this year's PJM capacity auction; and 3) update on exposure to environmental regulation including pending new coal combustion byproduct rules from the EPA.

Call to be held at 9 am EST. Dial-in: 888 637 7719 and Passcode: 7866464

Using This Report

This report is designed to serve as a primer on merchant power, covering both background and current thematic issues facing the sector

We use the balance of this report as a primer on the merchant generation sector. We begin with an overview of the companies within each sector, continue with a background on the underlying commodities and markets merchant generators engage with, address supply and demand fundamentals of power, and conclude with thematic summaries on two issues likely to significantly affect the US utility sector: carbon legislation and renewable generation. We have provided company update notes for the IPPs we are transferring lead coverage of at the back of the report.

Independent Power Producers

Merchant generators are power plants exposed to the underlying economics of power prices and fuel costs

Otherwise known as IPPs, "merchant generators" or "unregulated generators," are companies with power plants that operate in restructured markets in the US and are subject to both "market" prices for their power and the underlying fuel cost of generating the power. In turn, merchant power plants are subject to commodity cycles and volatility, making them significantly more risky investments than traditional utilities. Prior to electric industry restructuring (which is limited to select US states), power plants were subject to cost-of-service rates, under which regulators would ascribe an authorized return on equity and capital structure, allowing companies to pass on their cost of generation to customers and recoup their fixed capital costs.

Listed merchant generators can be broken into two groups: Competitive Integrateds and IPPs

Broadly interpreted, there are two sub-sectors among utility equities with merchant generation exposure: the Independent Power Producers (IPPs) and the Competitive Integrateds. The IPP sector provides investors with the opportunity to invest in purely merchant generation companies, while Competitive Integrated companies have both regulated and unregulated subsidiaries. Generally speaking, the Competitive Integrated sector can be separated into two further groups, those with generation assets divested as a consequence of restructuring and complementary to the regulated business, and those that have acquired power plants independent of their regulated utilities.

Independent Power Producers

There are six publicly traded IPPs, which offer pure exposure to merchant power

Within the US, there are (broadly) six publicly traded IPPs: AES Corp (AES, Not Rated), Calpine (CPN, Buy), Dynegy (DYN, Sell), Mirant (MIR, Sell), NRG Energy (NRG, Neutral), and RRI Energy (RRI, Neutral). A distinguishing characteristic of the IPP space from its utility peers is that all of these companies are non-investment grade credits, given the volatility in the underlying commodity prices (and in turn cash flow) and relatively large amount of leverage employed.

Table 8: IPP Comp Table

		Market Cap.		Price	EBITDA ($ Mn)				EV / EBITDA multiple			
2/21/2010	Rating	($ in millions)	Price	Target	2009E	2010E	2011E	2012E	2009E	2010E	2011E	2012E
INDEPENDENT POWER PRODUCERS												
AES Corporation	Not Rated	8,130	12.18	NA	4,557	5,032	4,645	-	5.1	4.6	5.0	
Dynegy, Inc.	Sell (CBE)	1,395	1.65	1.30	774	507	641	617	8.4	12.8	10.2	10.5
Mirant Corp	Sell	1,952	13.45	11.00	874	600	458	343	4.4	6.4	8.3	11.1
Calpine Corporation	Buy	5,021	11.35	14.00	1,734	1,530	1,719	1,723	7.7	8.7	7.7	7.7
NRG Energy Inc.	Neutral	5,949	23.20	24.00	2,649	2,259	1,888	2,095	5.4	6.3	7.5	6.8
RRI Energy Inc.	Neutral (CBE)	1,697	4.81	5.00	78	439	508	314		8.3	7.2	11.6
Average					**1,778**	**1,728**	**1,643**	**849**	**6.2**	**7.9**	**7.7**	**9.6**

Source: FactSet and UBS estimates

Summary of IPP EBITDA Estimates and Comparison to Consensus

We have provided our EBITDA estimates against those of First Call consensus across all IPPs in Table 9. We note due to the incorporation of our above market gas and coal forecasts our EBITDA estimates are likely to have a tendency to be above consensus for non-Appalachian coal IPPs (*e.g.,* CPN, NRG, and DYN) and inline or below for those that primarily use Appalachian coals (MIR & RRI)'. In turn, we note we are **above** consensus estimates for CPN, while we are notably **below** for MIR, NRG, and RRI. We caution investors on RRI that given its highly sensitive nature to shifts in commodity prices (e.g., power and coal), there are a wide range of possible outcomes depending on one's assumptions embedded. We also note while First Call does not currently have 2014 estimates posted, we anticipate a **significant EBITDA fall off for DYN**.

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Table 9: UBS and Consensus EBITDA Assumptions for IPPs

	Rating	Price Target	2008A	2009E	2010E	2011E	2012E	CAGR
CPN								
UBS EBITDA Estimates	Neutral	$14.00	1,699	1,734	1,530	1,719	1,723	**0%**
UBS EBITDAR Estimates			1,749	1,784	1,580	1,769	1,773	**0%**
First Call EBITDA Estimates			1,699	1,689	1,582	1,678	1,562	**-2%**
Implied EV/EBITDA using Market Value ($11.35)			7.9x	7.7x	8.7x	7.8x	7.8x	
Implied EV/EBITDAR using Market Value			7.7x	7.5x	8.5x	7.6x	7.6x	
Implied EV/EBITDA using Price Target			8.6x	8.4x	9.5x	8.5x	8.5x	
Implied EV/EBITDAR using Price Target			8.3x	8.2x	9.2x	8.2x	8.2x	
DYN								
UBS EBITDA Estimates	Sell (CBE)	$1.30	1,308	774	507	641	617	**-17%**
UBS EBITDAR Estimates			1,358	824	557	691	667	**-16%**
First Call EBITDA Estimates			1,308	760	492	615	611	**-17%**
Implied EV/EBITDA using Market Value ($1.65)			5.0x	8.4x	12.8x	10.1x	10.5x	
Implied EV/EBITDAR using Market Value			4.8x	7.9x	11.7x	9.4x	9.7x	
Implied EV/EBITDA using Price Target			4.7x	8.0x	12.2x	9.7x	10.0x	
Implied EV/EBITDAR using Price Target			4.6x	7.5x	11.1x	9.0x	9.3x	
NRG								
UBS EBITDA Estimates	Neutral	$24.00	2,215	2,649	2,259	1,888	2,095	**-1%**
First Call EBITDA Estimates			2,215	2,648	2,290	2,009	2,134	**-1%**
Implied EV/EBITDA using Market Value ($23.2)			6.2x	5.2x	6.1x	7.3x	6.6x	
Implied EV/EBITDA using Price Target			6.3x	5.3x	6.2x	7.4x	6.7x	
RRI								
UBS EBITDA Estimates	Neutral (CBE)	$5.00	835	78	439	508	314	**-22%**
UBS EBITDAR Estimates			895	138	499	568	374	**-20%**
First Call EBITDA Estimates			835	67	425	501	437	**-15%**
Implied EV/EBITDA using Market Value ($4.81)			4.3x	46.4x	8.2x	7.1x	11.5x	
Implied EV/EBITDAR using Market Value			4.0x	26.2x	7.2x	6.4x	9.7x	
Implied EV/EBITDA using Price Target			4.4x	47.2x	8.4x	7.2x	11.7x	
Implied EV/EBITDAR using Price Target			4.1x	26.7x	7.4x	6.5x	9.8x	
MIR								
UBS EBITDA Estimates	Neutral	$11.00	782	901	617	394	273	**-23%**
UBS EBITDAR Estimates			878	997	713	490	369	**-20%**
First Call EBITDA Estimates			782	869	609	464	346	**-18%**
Implied EV/EBITDA using Market Value ($13.45)			4.9x	4.2x	6.2x	9.7x	14.0x	
Implied EV/EBITDAR using Market Value			4.3x	3.8x	5.3x	7.8x	10.3x	
Implied EV/EBITDA using Price Target			4.4x	3.8x	5.6x	8.8x	12.7x	
Implied EV/EBITDAR using Price Target			3.9x	3.5x	4.8x	7.0x	9.4x	
Group Average								
Implied EV/EBITDA using Market Value			5.7x	14.4x	8.4x	8.4x	10.1x	
Implied EV/EBITDAR using Market Value			5.2x	11.3x	8.2x	7.8x	9.3x	

Source: First Call and UBS estimates; EBITDAR capitalizes operating leases and associated expense; Net Debt includes adjustments for NOLs, Enviro. Liabilities, etc

M&A Opportunities

We see regulators and market power issues as limiting M&A opportunities in the sector; spins such as Entergy's of its merchant nuclear assets are more likely in the near term, in our view

Given the constant M&A discussions in the IPP space, we believe it is worth our while to add our perspective on the potential for consolidation. We believe in the near term, RRI is the most likely takeout candidate, as it seemingly continues to allude to the benefits of consolidation despite the formal end of the evaluation of strategic alternatives. Consolidation of both regulated utilities and competitive integrated utilities (with generation assets and distribution utilities in the same state) is likely to remain difficult as regulators try to extract rate decreases for consumers under stipulations to prove "benefits" to ratepayers as part of the formal regulatory approval process. Alternatively, we believe spins (both of transmission assets and generation assets) remain a much more likely avenue for the utility space. A further consideration of any IPP M&A remains market power limitations within RTOs. We see a variety of M&A combinations being prevented because of this factor. However, market power limitations do leave room for one-off asset acquisitions, which has continued to prove relatively robust. History has also proven that all successful M&A in the sector has been agreeable by both management teams. Longer term, we believe the (increasingly) capital intensive nature of the industry clearly points to consolidation, particularly among regulated utilities.

Risk Factors

We see commodity prices and regulatory risk around new emission requirements as the most significant wildcards for the industry

Our investment thesis is premised on certain commodity, economic, regulatory, and financial assumptions. Should these differ from our assumptions, we see the potential for our investment conclusions to differ materially from those projected. We address each of the primary risk contributors as follow:

- **Commodity:** We use UBS natural gas and coal price deck assumptions in our competitive models; both of which are above the futures curve, respectively. Given this and our near term caution on the commodities, we would highlight the risk of revisions to our price assumptions are more likely to the downside. Should natural gas prices fall further, power prices are likely to be partially offset by improving heat rates due to increased coal to gas switching; declines in power prices in 2009 were approximately ~10% less than gas prices due to this effect. The primary risks to our natural gas price thesis remain higher production from new wells (particularly given indications by the major and independent E&P products of ramped up efforts into year end) and the impact of appropriately gauging the impact of coal to gas switching. We remind investors many generators remain substantially hedged at above market prices in 2010 and beyond. The impact of a lower commodity environment is likely to result in a declining earnings profile, rather than significant near term impacts.

- **Economic:** The economy can impact merchant generators in three primary ways: 1) Natural gas prices are translated into power prices through a conversion ratio known as heat rates representing the supply and demand fundamentals in a given region; 2) through the volumes of power sold from generation units; and 3) for Competitive Integrateds, indirectly through its impact on rate cases and other regulatory outcomes. Again, many of merchant generators are hedged at specific volumes and prices in the near term, limiting the near term impact of any shifts in the economy. Further many merchant generators derive the vast majority of their economics through baseload generation, which is removed for the most part from volumetric downside. We have assumed a minimal recovery in our '10 estimates, with a return to 2008 power volumes for many generators by ~'12.

- **Regulatory:** New regulation and legislation is likely to impact the sector in two ways: 1) through more stringent environmental standards; and 2) derivative regulation, potentially requiring merchant generators to clear more of their trades across exchanges.
  - Financial Reform: Given the current discussion in Washington DC for an exemption for "natural hedgers" such as power producers, we have yet to assume any onerous cost increases associated from complying with financial reform. We anticipate the impact of any such reform is likely to be passed onto consumers in the form of higher power prices and disproportionately impact financial institutions and those who market/trade power without underlying physical assets.
  - Environmental standards: The EPA has been gradually ratcheting up emission standards in the industry over the last three decades. Pending decisions over emissions of SO_2, NOx, mercury ("3P's"), once-through cooling, ash ponds, and carbon could place significant additional required capital expenditures on merchant generators in order for certaint of their plants to continue operating. We have generally assumed minimal incremental capex in our forecasts for power producers beyond what is currently anticipated and believe coal generators are the most at risk given their relative emission profiles.
- **Financial:** Our models are premised on the ability for merchant generators to tap capital markets should they need to refinance or issue new debt. Given the lockup of capital markets over the last year, we believe the sector would clearly face significant difficulties; IPPs would disproportionately face difficulty given their sub-investment grade credit ratings. With a significant portion of the sector's debt anticipated to mature in ~2012, we remain keenly focused on both the cost and ability of the sector to overcome this liquidity event. This is in contrast to the rest of the utility sector, where investment grade credits assure their continued ability to roll debt balances.

Commodity Fundamentals

The IPP and Competitive Integrated utility sector valuations are driven primarily by the outlook for underlying power and fuel commodity prices. Merchant generators source their power primarily from five sources: coal, natural gas, nuclear, hydro, and renewable (wind, solar, and geothermal) resources. They sell their power into power markets whose prices are (mostly) set by the most-costly plant (or cost of the least efficient unit) dispatched to the grid.

Natural Gas Prices Drive Power Prices in Most Regions

During most hours for many regions in the country natural gas tends to set the clearing price of power, generally speaking. Therefore, we use our NYMEX natural gas estimate to forecast power prices across the US. Given this tight relationship between natural gas and power prices, merchant generator valuations tend to trade on shifts in the forward curve. We have included the latest NYMEX forward curve in Table 10 and historical front month contracts in Chart 2.

Table 10: Summary of Historical NYMEX Natural Gas Futures ($/MMBtu)

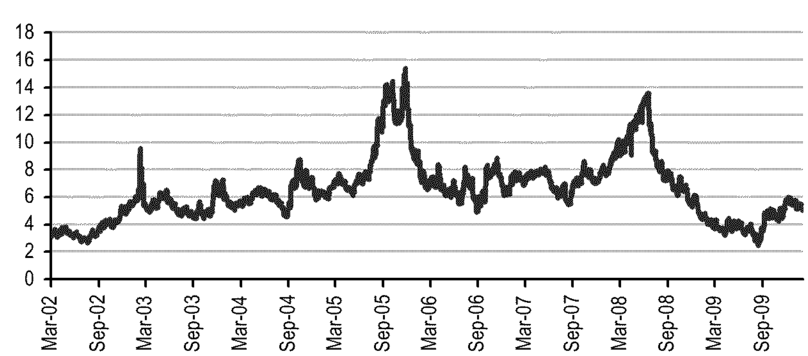
NYMEX Henry Hub Natural Gas Futures

(Dollars per MMBtu; Bold font indicates open contract)

Monthly	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
2000	2.34	2.61	2.60	2.90	3.09	4.41	4.37	3.82	4.62	5.31	4.54	6.02	3.89
2001	9.98	6.29	5.00	5.38	4.89	3.74	3.18	3.17	2.30	1.83	3.20	2.32	4.27
2002	2.56	2.01	2.39	3.47	3.32	3.42	3.28	2.98	3.29	3.69	4.17	4.14	3.22
2003	4.99	5.66	9.13	5.15	5.12	5.94	5.29	4.69	4.93	4.43	4.46	4.86	5.39
2004	6.15	5.78	5.15	5.37	5.94	6.68	6.14	6.05	5.08	5.72	7.63	7.98	6.14
2005	6.21	6.29	6.30	7.32	6.75	6.12	6.98	7.65	9.91	13.91	13.83	11.18	8.54
2006	11.43	8.40	7.11	7.22	7.20	5.93	5.89	7.04	6.82	4.20	7.16	8.32	7.23
2007	5.84	6.92	7.55	7.56	7.51	7.59	6.93	6.11	5.43	6.42	7.27	7.20	6.86
2008	7.17	8.00	8.93	9.03	11.28	11.92	13.11	9.22	8.39	7.47	6.47	6.89	8.99
2009	6.14	4.48	4.06	3.63	3.32	3.54	3.95	3.38	2.84	3.73	4.29	4.49	3.99
2010	5.81	5.27	**5.04**	**5.06**	**5.12**	**5.19**	**5.26**	**5.32**	**5.35**	**5.43**	**5.72**	**6.02**	5.38
2011	**6.24**	**6.20**	**6.03**	**5.59**	**5.57**	**5.61**	**5.67**	**5.73**	**5.76**	**5.86**	**6.13**	**6.43**	5.90
2012	**6.64**	**6.59**	**6.37**	**5.79**	**5.74**	**5.79**	**5.85**	**5.90**	**5.94**	**6.05**	**6.29**	**6.58**	6.13
2013	**6.79**	**6.77**	**6.55**	**5.96**	**5.91**	**5.97**	**6.04**	**6.09**	**6.13**	**6.24**	**6.49**	**6.78**	6.31
2014	**6.98**	**6.96**	**6.74**	**6.15**	**6.11**	**6.17**	**6.25**	**6.31**	**6.34**	**6.46**	**6.71**	**6.99**	6.52

Source: FactSet; as of 2/21/2010

Chart 2: Historical NYMEX Natural Gas Front Month Futures Contracts ($/MMBtu)



Source: FactSet; as of 2/21/10

Our Gas Assumptions Point to a Mild Recovery Off Forward Curves

Using our natural gas analyst's revised assumptions on natural gas prices of **$6.25/MMBtu in 2010** and **$7.00/MMBtu in 2011 & beyond**, we are mildly above the forward curve in the near term, at $5.71/MMBtu in '10 and $6.42/MMBtu in '11; (see Table 2 for details on our price deck). While the forward curve remains in contango (upward sloping) we argue resurging demand and lower rig counts should drive gas prices upwards. However, in the near term gas prices should be pressured by: 1) strong production in natural gas despite the >50% drop in the natural gas rig count, with the expectation for drilling activity actually expected to pickup into the end of the year; 2) waning demand for natural gas for generation (we estimate fuel switching added at a minimum +1.5 bcf/d of incremental demand in 2009, however is more likely in the range of +2.4 bcf/d in demand); 3) entering winter heating season significantly above the historic average (near full); and 4) an inventory of uncompleted, but drill wells that are likely to incrementally pressure upward pricing. For a complete run through of our natural gas price revision, please see our note *Revising NatGas and Oil Price Forecasts, November 17th, 2009.* For further details on coal to gas fuel switching capacity and analysis, see our note, *Powering Down Expectations*, from April 30, 2009.

Our UBS gas price forecast remains $0.54/MMBtu above '10 and $0.74/MMBtu above '11

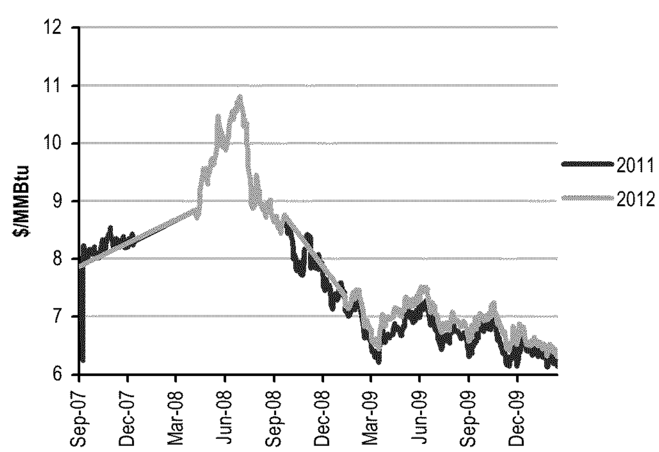
We estimate YTD switching resulted in ~2.4 bcf/d of switching

Gas Basis was Depressed Throughout 2009; We Expect Normalization at a Lower Level

Adding an element of complexity to the derivation of power prices is the basis to NYMEX natural gas futures, which are priced off of Henry Hub in Louisiana. For the PJM market we have lowered our basis assumption to $0.75 from $1.00 in gas basis (on a calendar strip) for delivery to TETCO (Texas Eastern) M3 across our coverage universe. Structurally, we believe there could be further downward pressure on Northeast deliveries as more local Marcellus Shale finds its way to market and additional hydro power is interconnected from Canada. For the Midwest, we quote Chicago Citygate and tend to ascribe no premium to Henry Hub prices.

We have adjusted downwards our TETCO M3 gas basis assumption to $0.75 from $1.00 previously

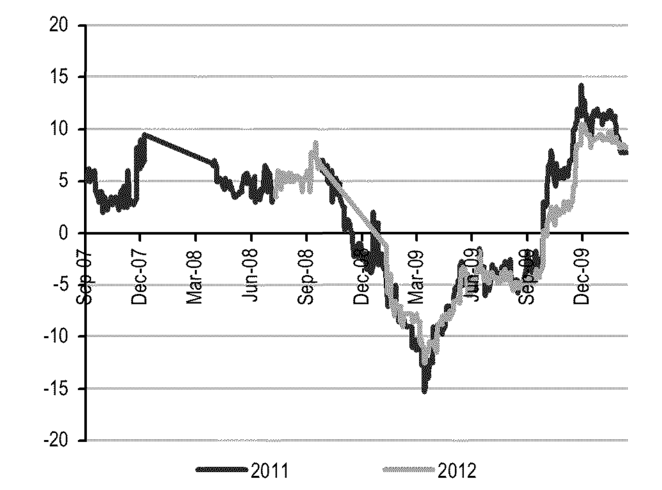
Chart 3: Henry Hub Futures Curve for 2011 and 2012 ($/MMBtu)



Source: Bloomberg

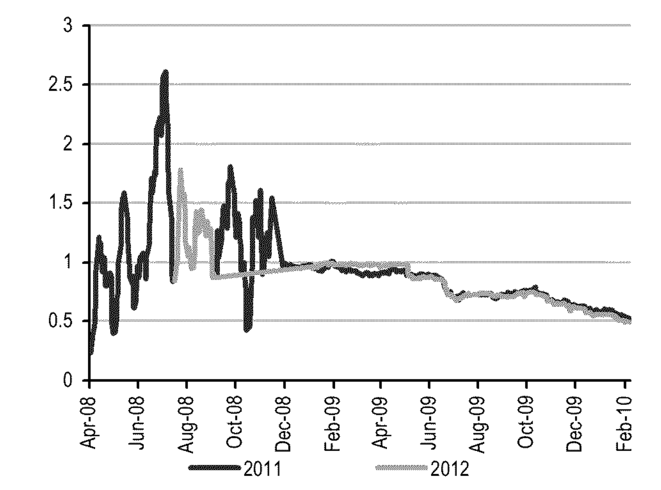
Gas Basis Differentials for Primary US Hubs

Chart 4: Basis for Chicago Citygate (¢/MMBtu)



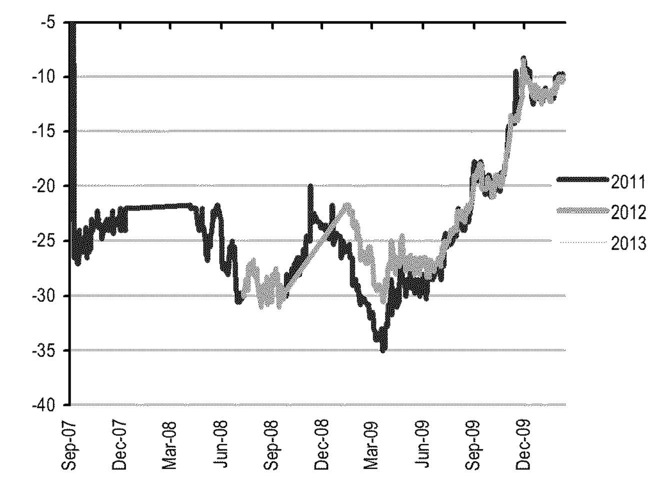
Source: Platts

Chart 5: Basis for TETCO M3 ($/MMBtu)



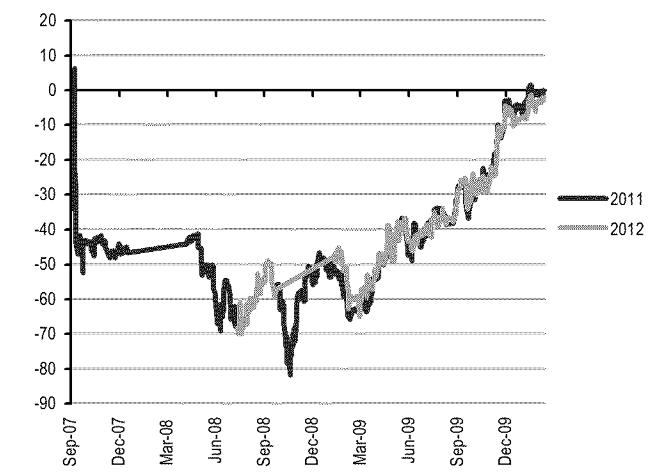
Source: Platts

Chart 6: Basis for Houston Shipping Channel (¢/MMBtu)



Source: Platts

Chart 7: Basis for SoCal (¢/MMBtu)



Source: Platts

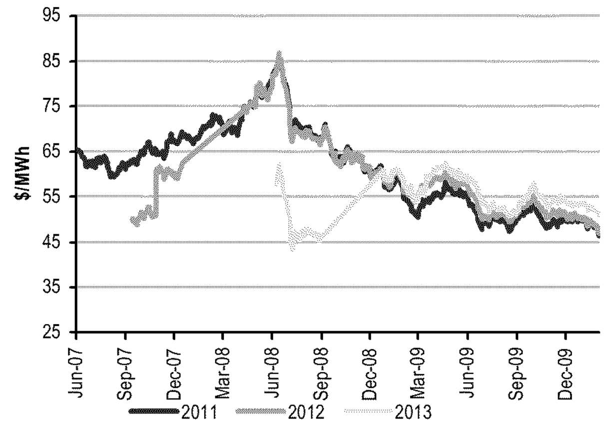
Our takeaway from the gas basis trends tends to favor CPN the most, as it is the most shielded from the impact of eastern shale gas plays (primary exposure is PG&E Citygate gas basis), followed by NRG with its predominant exposure to Houston Shipping channel gas prices. The most negative impacts are for the Northeast coal generators, RRI and MIR.

Power Prices

Power is generally priced on a $/MWh basis and sold in both 'peak' and 'off-peak' blocks

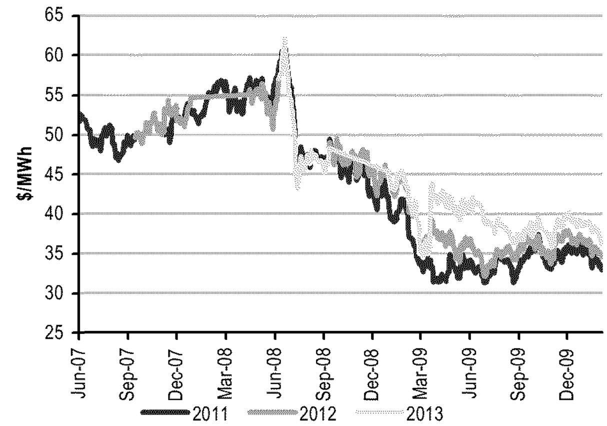
Fundamental to understanding the merchant generation sector is an understanding of the various types and regions in which power is sold. Typically power is quoted in both peak and offpeak "block" products; peak is typically 80 hrs per week (5 weekdays x 16 hrs / day), with the balance of the week's hours (88) off-peak. A block of power is simply a constant amount of electricity provided for the period for a fixed unit price ($/MWh). Around-the-clock (ATC) pricing is the weighted average of the two and is provided below for various regions across the US. We detail ATC market power prices for many frequently quoted hubs around the country in Charts 8-13. All of the charts clearly demonstrate the linkage between gas and power prices.

Chart 8: PJM West ATC Power Prices ($/MWh)



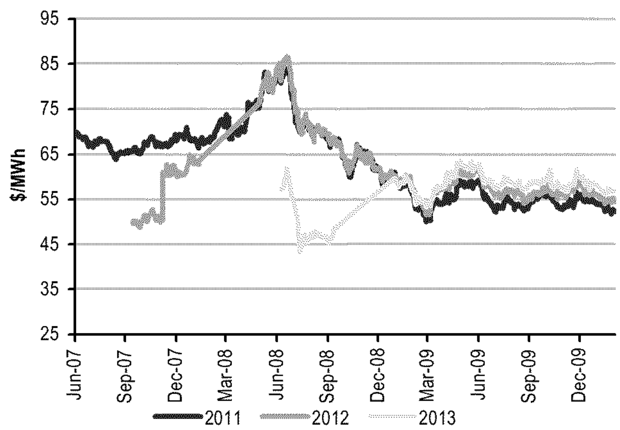
Source: Platts

Chart 9: NI Hub ATC Power Prices ($/MWh)



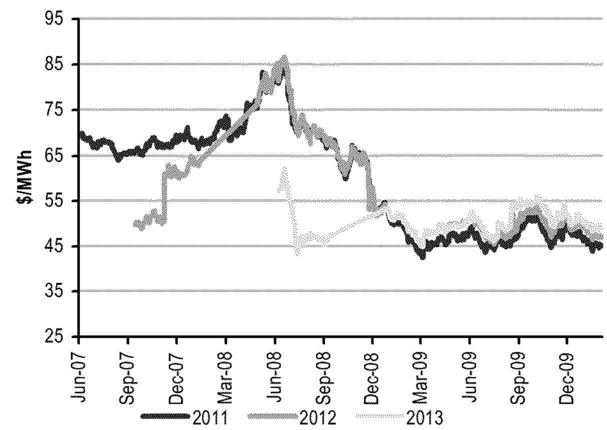
Source: Platts

Chart 10: Mass Hub ATC Power Prices ($/MWh)



Source: Platts

Chart 11: ERCOT-South ATC Power Prices ($/MWh)



Source: Platts

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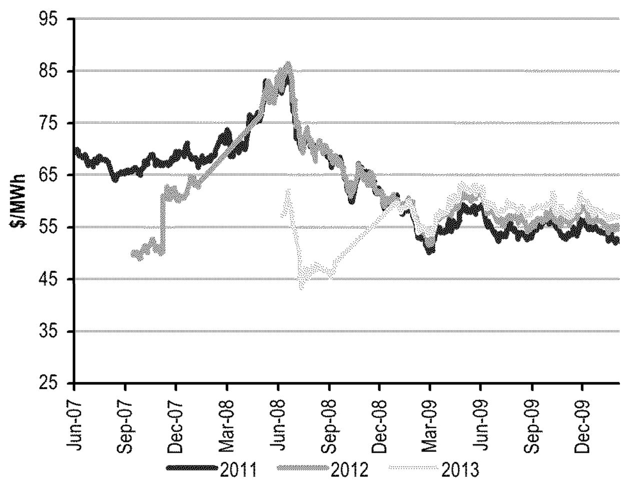
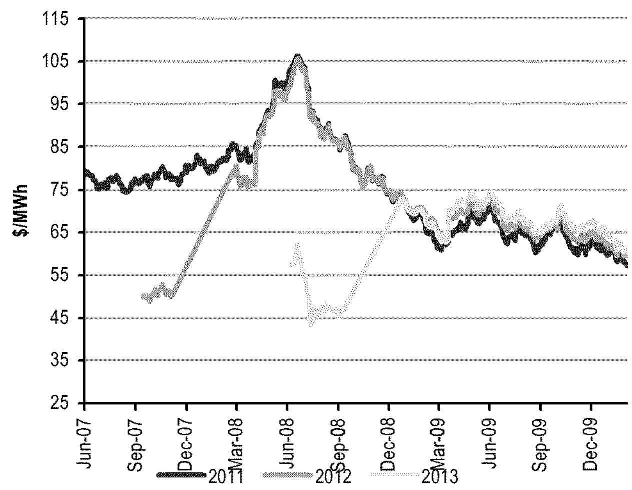
Chart 12: NP15 ATC Power Prices ($/MWh)



Source: Platts

Chart 13: NYISO Zn G ATC Power Prices ($/MWh)



Source: Platts

We note many of these markets remain in contango, with the 2011 and 2012 curves trading closely together above the 2010 curve. We believe in the near term power prices could continue to face pressure primarily due to pressure on natural gas prices. In the long term, we believe power prices are a distinct commodity from natural gas and believe the underlying availability and demand for power drives the commodity price. We remain bullish on the longer term prospects of power, given the potential realities of carbon and new environmental regulations coupled with the lack of new conventional supply to replace retiring units in restructured markets. Mitigating and delaying factors to this view point include US economy's declining energy intensity and mandates on the state (and potential federal level) to procure renewable resources.

Power Can Also Be Sold as a "Load-Following" Product

Power can also be sold through load-following deals, which requires generators to match supply needs as they vary throughout the day and seasonally

Power products can also be sold in a load-following or full requirements product, which obligates the seller of the product to deliver a variable amount of power, generally at a pre-specified price. A full requirements product is typically sold through a utility auction or RFP process, and includes energy, capacity, ancillary services, volumetric risk, credit risk, line losses, and any applicable state taxes. Full requirement products generally sell at a 30-50% premium to the underlying energy price, when including all of the aforementioned factors. Premiums for volumetric and credit risk have expanded as the number of brokers participating in commodities marketing and trading has been scaled back over the last two years. Volumetric risk can be further broken into migration risk should customers choose to switch power suppliers and lower volume needs due primarily to typical weather and economic events. Unfortunately, prices for these products are not liquid and single auction results from utilities are typically the best indicators for how these products are priced.

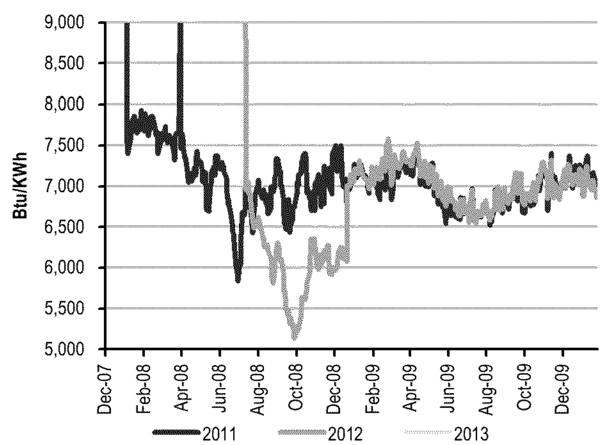
Heat Rates – The Power Guru's Forecasting Tool

Heat rates are defined as the ratio of power prices to delivered natural gas prices

Heat rates are perhaps the most telling of power commodities, as they are an expression of the ratio between delivered gas to a power hub and the price of power at that hub. While the power charts above resemble one another in their curve, the heat rate ratio (measured in Btu/Kwh) communicates the fundamental supply and demand equation in a given region. Generally speaking, the higher the heat rate, the more a less efficient gas plant will run. The heat rate units can be compared to a gas plant's nameplate heat rate, allowing for a quick comparison of whether a plant will operate or not. The most efficient CCGT units have heat rates of 6,500 Btu/Kwh, while peaking units may have heat rates as high as 18,000 Btu/Kwh (but average in the 12,000-14,000 Btu/KWh range).

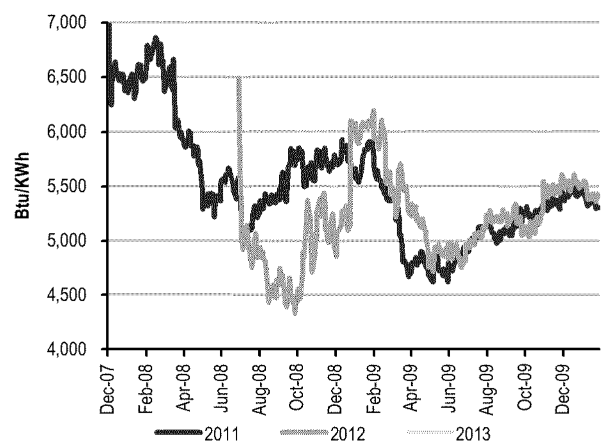
We have provided ATC heat rates for many of the most important power hubs in the US, as well as their corresponding gas hubs in Charts 14-18. The trend in heat rates at each power hub is unique and reflects the supply and demand fundamentals in the region. Noteworthy is the downward trajectory in heat rates in ERCOT South due to a large wind construction program. We further point out the relatively higher heat rates at Mass Hub and NYISO Zone G, where we believe coal to gas switching lifted heat rates this year despite lower aggregate demand for power.

Chart 14: ATC Heat Rate (PJM W – TETCO M3)



Source: Platts and UBS estimates

Chart 15: ATC Heat Rate (NI Hub – Chicago Citygate)



Source: Platts and UBS estimates

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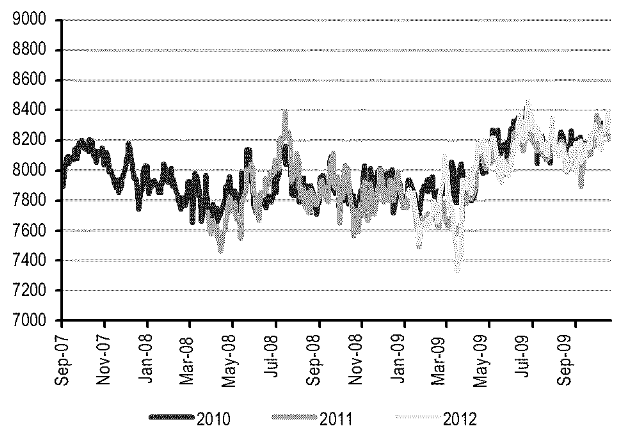
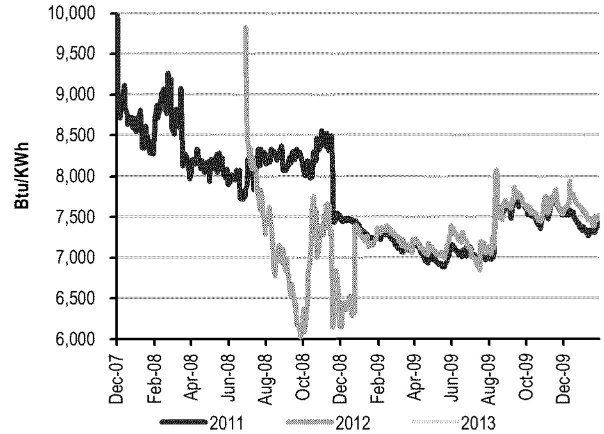
Chart 16: ATC Heat Rate (Mass Hub - Algonquin)



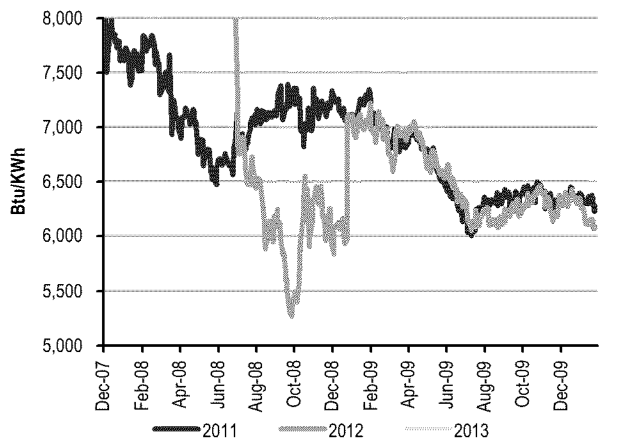
Source: Platts and UBS estimates

Chart 1: ATC Heat Rate (ERCOT South – Houston Shipping)



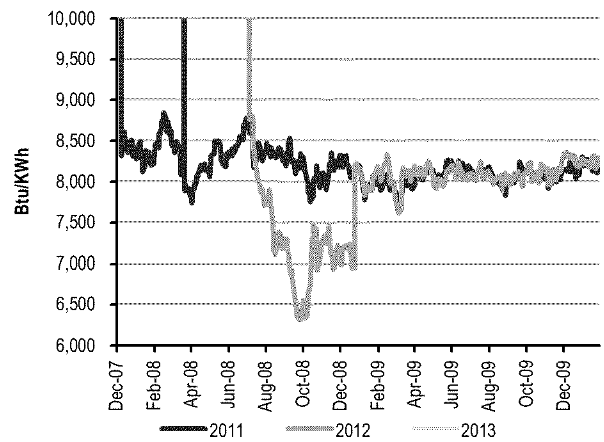
Source: Platts and UBS estimates

Chart 17: ATC Heat Rate (NYISO Zn A – Dawn)



Source: Platts and UBS estimates

Chart 18: ATC Heat Rate (NYISO Zn G – Transco Zn 6)



Source: Platts and UBS estimates

Coal Markets – The Cost Side of the Equation

Coal prices are the most important input costs for the merchant generation sector

Most IPPs and Competitive Integrated generators source a large portion of their generation margin from baseload coal power. The US coal market can be broadly separated into two primary coal markets, Eastern Central Appalachian (CAPP) coal or Western Power River Basin (PRB) coal. CAPP coal tends to cost significantly more than its PRB peer, given its higher heat content (12,500 btu/lb), higher cost structure, and its ability to command a better price in higher priced eastern power markets. CAPP use has remained relatively flat over the last 20 years, whereas PRB coal has been increasingly used by many coal generators to reduce sulfur emissions while avoid ulphure cost of installing backend environmental controls.

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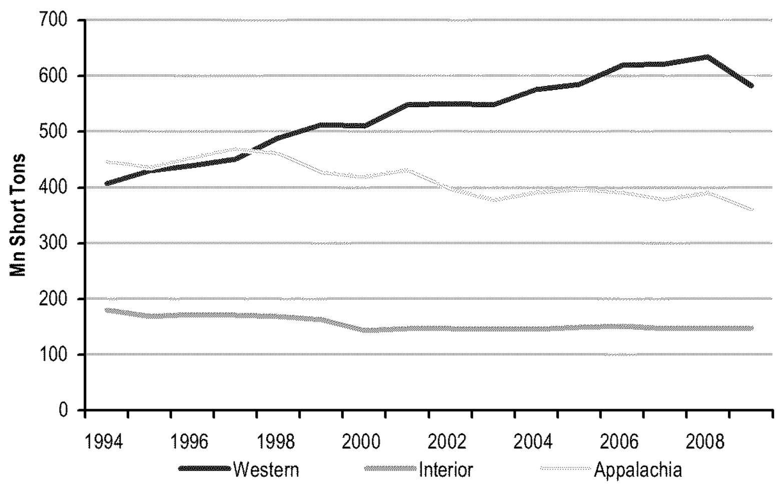
Chart 19: Total US Thermal Coal Production, by Source



Source: EIA and UBS estimates

We note while PRB is considerably cheaper than its eastern peers, the cost of transporting PRB westward (from WY) is typically within a range of $10-15 per-ton per-1000-miles, adding significantly to the ultimate cost of coal consumed. Table 11 summarizes the comparable dispatch economics of PRB and CAPP coal.

Table 11: Summary Dispatch Economics for CAPP and PRB Coal Generation

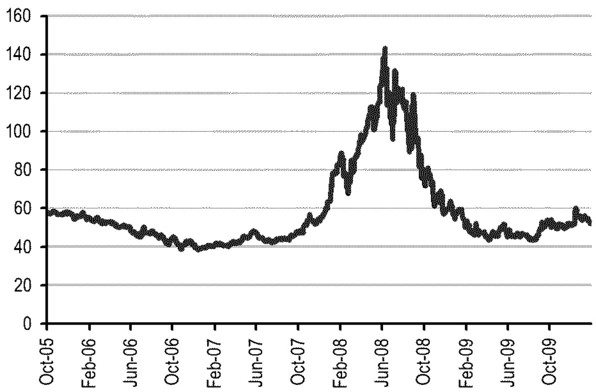
Generic CAPP Generation Cost Calulation		Generic PRB Generation Cost Calulation	
CAPP Coal Assumption ($/ton)	57	PRB Coal Assumption ($/ton)	10.5
Transportation ($/ton)	25	Transportation ($/ton)	30
Total $/ton	82	Total $/ton	40.5
Heat Content (Btu/lb)	12,500	Heat Content (Btu/lb)	8,800
$/MMBtu *(effectively divide by 25)*	3.28	$/MMBtu *(effectively divide by 17.6)*	1.62
Sulfur (lb/MMBtu)	1.50	Sulfur (lb/MMBtu)	0.80
Average Heat Rate (US Aggregate)	10,400		
NOx (lb/MMBtu)	0.20		
NOx CAIR Annual ($/ton)	575		
NOx Seasonal ($/ton)	125		
Sulfur ($/ton)	45		
Dispatch Cost (Ex-O&M), $/MWh	35.19	Dispatch Cost (Ex-O&M), $/MWh	17.76

Source: EIA, Bloomberg, NYMEX, and UBS estimates; assumes 2010 Compliance

Coal Followed Run Up in Gas Prices in 2008

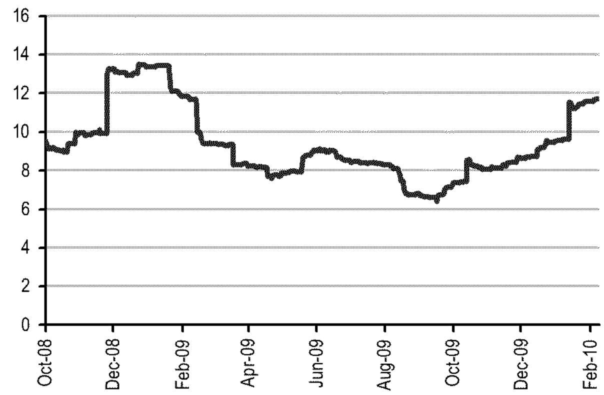
Charts 20 and 21 provide historical front month NYMEX futures for both CAPP and PRB coal. As can be clearly seen, the 2008 commodity boom affected both CAPP and PRB products. We believe the export demand for US thermal coal products in 2008 was likely due to a series of mostly isolated events. Coal prices could reach similar levels should exports to Europe become robust once more, as anticipated in our $100/ton 2012 CAPP coal forecast.

Chart 20: Central App NYMEX Front Month Futures ($/ton)



Source: FactSet

Chart 21: Western PRB NYMEX Front Month Futures ($/ton)



Source: FactSet

UBS Coal Deck Is Above Futures Curve for Coal

In spite of the coal prices now seen in the market, UBS forecasts CAPP products to remain in contango, with prices at $57/ton in 2010 (versus the current NYMEX futures at $55.59/ton), and rising to $80/ton in 2011 and $100/ton in 2012 (vs. respective strip prices of $65.86/ton and $72.70/ton). UBS' forecast is premised on an eventual erosion of relatively high inventories as well as the reflection of higher underlying cost structures. Our $57/ton CAPP forecast specifically targets the middle of the cost curve for producers, assuming a 38 Mn ton reversion in fuel switching demand and an additional 18 Mn tons to account for organic growth (55 Mn net additional tons). Our CAPP and NAPP forecasts are the same as the discount for relatively higher sulfur NAPP to CAPP evaporated in 2008 as scrubbers came online.

Table 12: UBS Thermal Coal Price Deck

Coal Product	2009E	2010E	2011E	2012E	LT Normalized
CAPP	$50.50/st	$57.00/st	$80.00/st	$100.00/st	$75.00/st
NAPP	$50.50/st	$57.00/st	$80.00/st	$100.00/st	$75.00/st
Midwest (2lb)	$36.00/st	$38.00/st	$45.00/st	$60.00/st	$45.00/st
PRB 8800	$10.25/st	$10.50/st	$12.00/st	$16.00/st	$17.00/st
PRB 8400	$8.75/st	$9.25/st	$10.50/st	$13.25/st	$14.00/st

Source: UBS estimates

Dark Spreads Have Contracted Each Quarter; We Anticipate Expansion

Using UBS' NYMEX natural gas and CAPP coal forecasts, we have provided in Chart 22 a historical and forecasted dark spread using our UBS commodity forecasts for both coal and natural gas. We define dark spreads as the margin earned by coal generators in a gas-on-the margin power price environment. In

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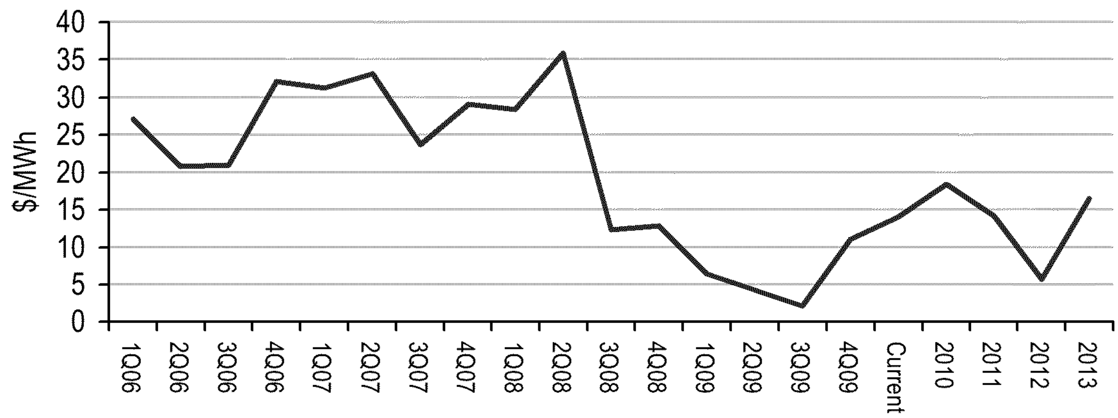
the particular example below, we use a generic 10,700 Btu/KWh coal plant in PJM (7,500 Around-the-Clock market heat rate), burning CAPP coal.

Chart 22: Historical and Projected Dark Spreads ($/MWh)

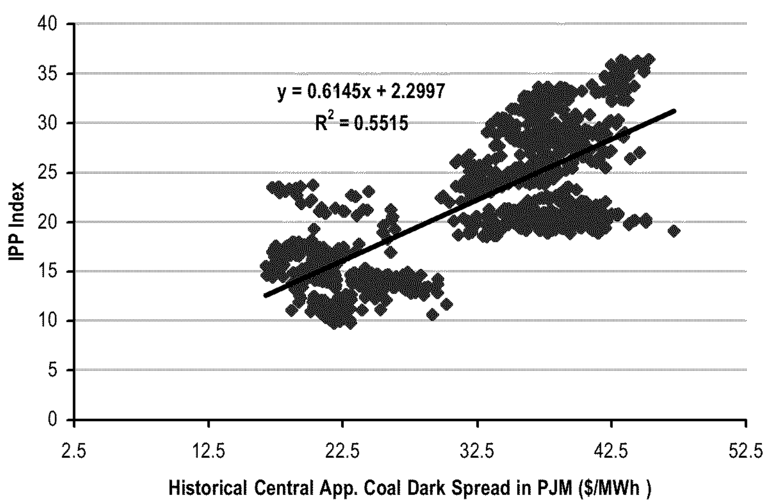


Source: NYMEX, SNL, and UBS estimates

Sector Largely Trades With Dark Spread Movements

From a high level, the IPP sector continues to trade largely with fluctuations in dark spreads, or the margin earned by coal generators. Aggregating the sector we have provided in Chart 23 a scatter plot of our IPP Index against the dark spread earned by a CAPP coal generator at PJM West (the most common profile of merchant generators.) We have applied the log of the relationship to take into account the exponential relationship between IPP valuations and improving margins (due to the sectors relatively high financial leverage). Using this relationship, we note the IPP index could have further downside to 10.92 from 13.69 currently using the linear relationship described below.

Chart 23: Relationship Between IPP Index and PJM Dark Spread



Source: Platts, FactSet, and UBS estimates

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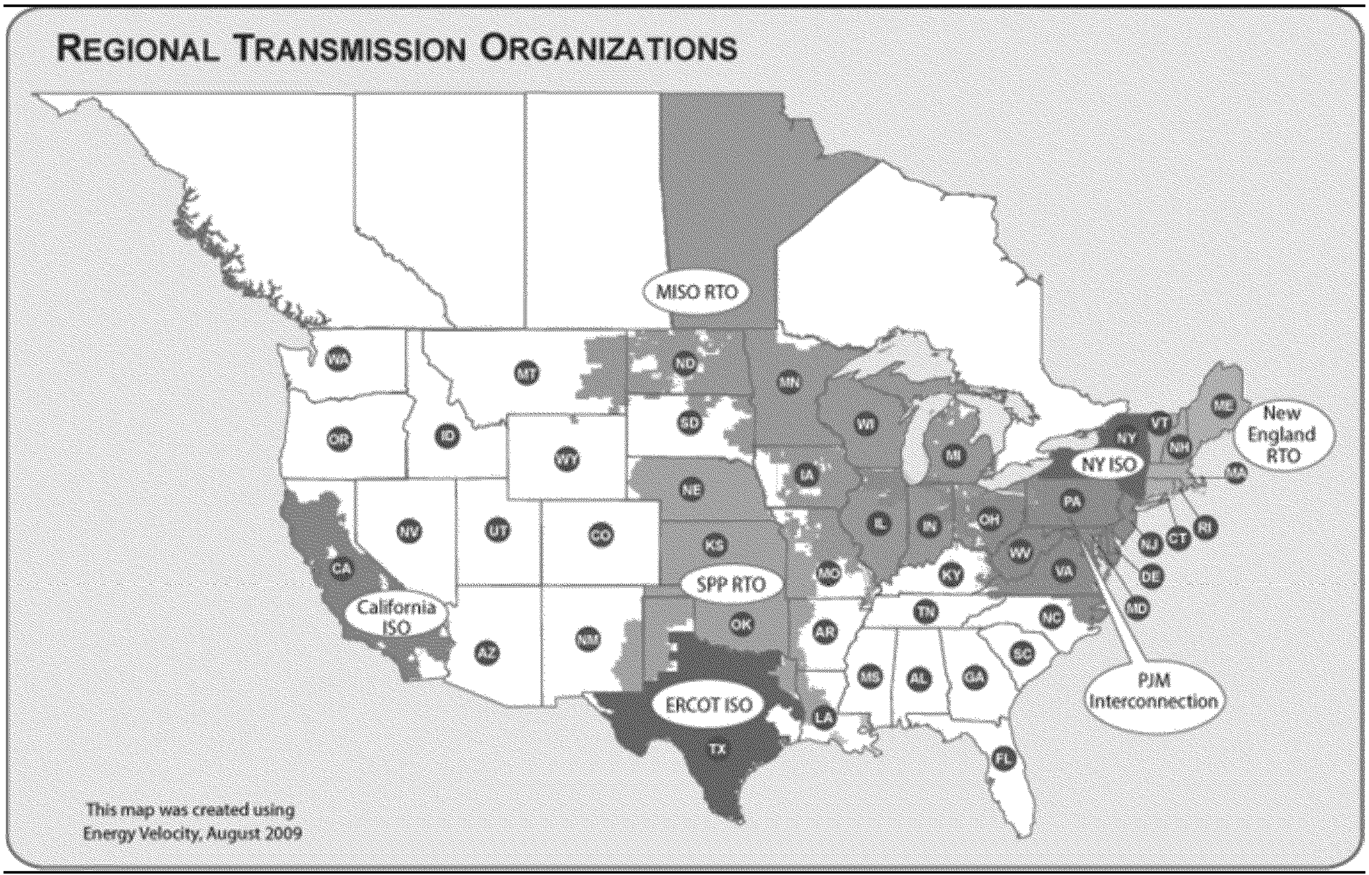
RTO Markets in North America

Power markets in the US are organized under regional transmission operators (RTOs), which provide substantial operational efficiencies in determining the efficient dispatch of resources. As current RTOs mature and the need for coordination increases with the focus on building out transmission, we anticipate unorganized regions will join or form new RTOs. In particular, we highlight the potential entrance of the Entergy system in the Southeast (LA, TX, AR, MS) into SPP.

Figure 1: Regional Transmission Operators in North America



Source: EIA

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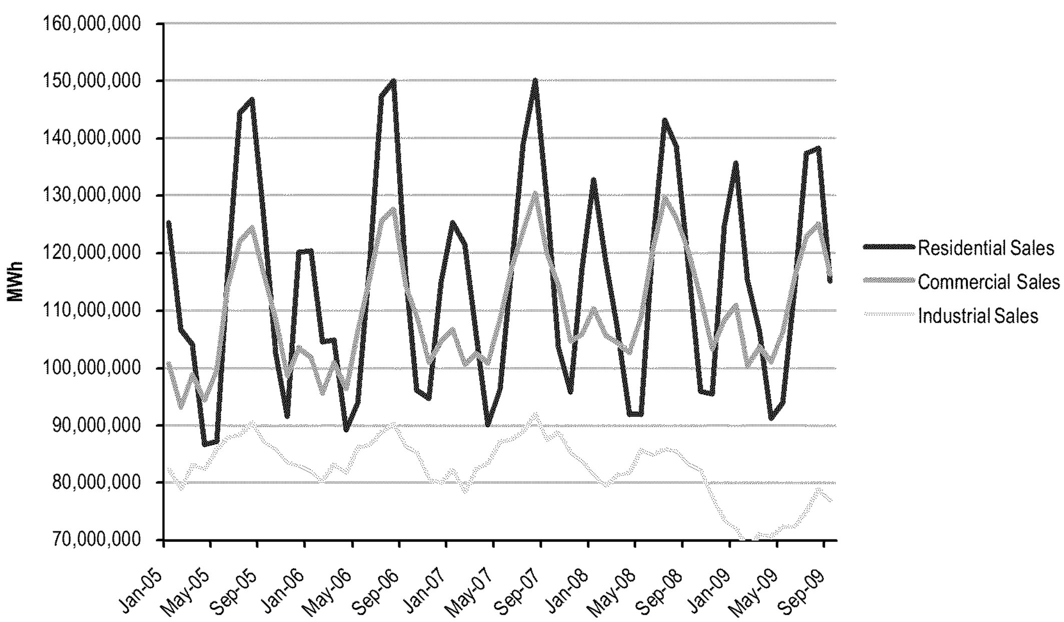
Demand for Power

Industrial sales seem to have bottomed in 2Q09, but commercial sales seem to continue to exhibit a downward trajectory

Power is typically broken down into three primary categories: residential, commercial, and industrial. We also note many utilities may also make additional wholesale or off-system sales directly to aggregators, governments/municipalities, or other utilities. While commercial and industrial sales exhibit relatively little in seasonality, residential sales shift significantly depending on the seasons, with peaks in the height of summer and winter. Given the economic recession, industrial sales were the most affected through October 2009, down 11.6% YoY. In contrast, commercial sales are down 2.4% and residential sales were down just 1.1%. Industrial sales however seem to have bottomed in 2Q09, while commercial sales have seemingly continued to stall into year end. We have provided US power demand broken down by class since 2007 in Chart 24.

Chart 24: Electricity Demand Was Off 4.4% Through Oct-'09, With a Substantial Decline in Industrials



Source: EIA (Sept, 2009); Not weather adjusted data

Utilities nationwide have indicated their initial forecasts for 2010 sales will improve only marginally over 2009, with the majority of the recovery likely due to a partial uptick in industrial sales and a return to normal weather. The summer of 2009 was one of the mildest on record, with cool temperatures and depressed humidity from Kansas through the Midwest, and to the East Coast.

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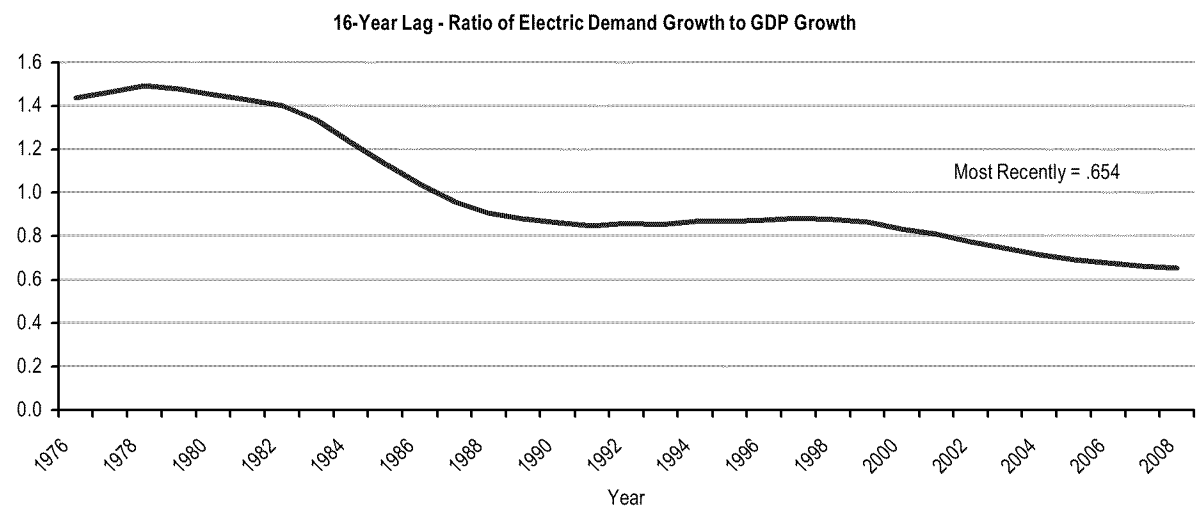
Expect Declining Energy Intensity of Economy

Energy intensity of the US economy has been secularly declining for decades

While we clearly anticipate a prolonged rebound in electric demand through 2011, in tandem with a projected economic recovery, we anticipate a further deceleration in energy intensity per unit of GDP. Chart 26 illustrates how energy intensity has secularly declined through the last three decades. Using a shorter lag of 10- and 5-years the ratio is only 0.576 and 0.599, respectively.

Chart 25: 16-Year Lagged Average Ratio of Electric Demand to GDP Growth



Source: BEA, EIA, and UBS estimates

We anticipate 2010 sales likely in up a mild +0.5 – 1.0% as commercial sale weakness partially offsets a modest uptick in industrial sales

UBS Chief US Economist Maury Harris' expectation for US GDP growth are +2.6% in 2010, +3.0% in 2011, and a trend growth rate of 2.3%. In 2009, our GDP forecast was -2.9% while aggregate US electric volumes outsized the decline with our estimate of -3.8% drop due to the disproportionate downtick in industrial output and below-average weather. We anticipate electric volumes to continue to underperforming GDP, with a partial recovery in industrial sales and a return to normal weather to only leading to total sales improvement in 2010 of ~0.5-1.5%. While we anticipate some industrial pick-up (+2.5-4.0%), we believe this will be significantly offset with a modest decline in commercial sales (-1.0% to flat); we further assume a 1.0% rebound in residential sales. With a substantial portion of 2010 load growth likely filled by incremental renewables (e.g. wind) we anticipate a mild outlook for new fossil generation (outside limited "firming" gas peakers). In 2011 and beyond, we anticipate continued growth in electric generation, albeit at a rate below US GDP growth, likely pointing towards a long term range of +1.3%, prior to the impact of energy efficiency measures. A further distinction is the growth rate of summer peak demand has historically grown at a faster pace (+1.7%) than total demand; a trend that is likely to continue.

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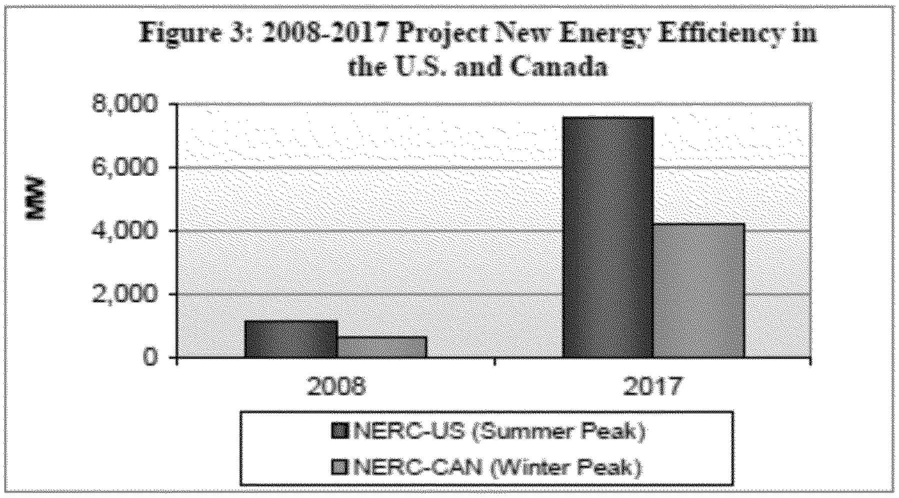
Energy Efficiency Should Decelerate Energy Intensity Further

Mandated energy efficiency measures on both state and federal levels should further reduce the US economy's energy dependence

We believe this trend could further decelerate with the successful passage of a federal RPS (renewable portfolio standard) that tentatively allows energy efficiency measures to qualify as substitutes for renewables. Should the trend towards mandated energy efficiency measures be both enacted and materialize, we anticipate a further deceleration in the underlying energy intensity of the US economy. The Waxman-Markey bill (HR2454) which passed in Congress in June 2009, included a Renewable Energy Standard (RES), allowing states to petition the FERC to meet 40% of the 20% renewables by a 2020 target (or up to 8% of generation) through using energy efficiency measures. We have included in Chart 26 the NERC's projection for energy efficiency additions over the next decade, amounting to an equivalent increase of 0.5% in current capacity (MW).

Chart 26: Significant Increase in Energy Efficiency Further Mitigates Capacity Need



Source: NERC Long Term Reliability Assessment (2008 – 2017)

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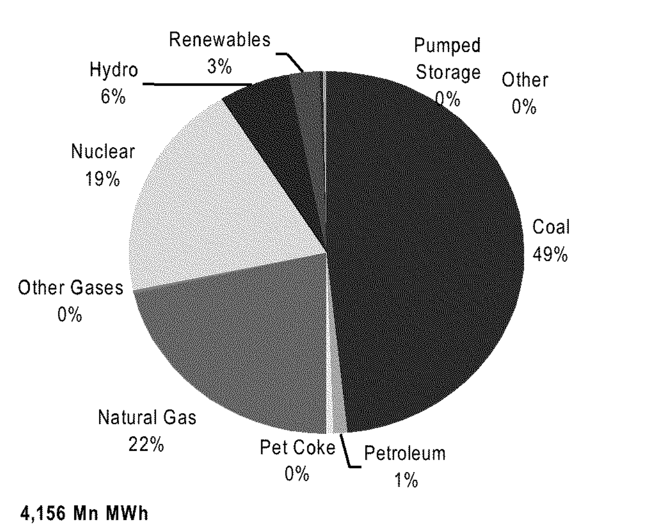
New Generation?

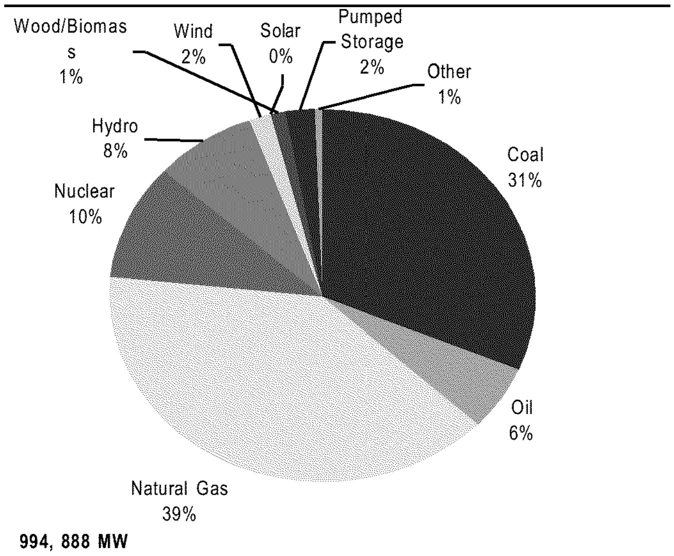
Current US generation is primarily derived from coal (49%) and nuclear (19%) power (see Chart 27 and Chart 28). While natural gas constitutes a large portion of total installed US capacity at 39%, overall capacity factors on these facilities remain relatively low at just 22%.

Chart 27: US Generation by Fuel Source, 2007A



Source: EIA

Chart 28: US Capacity by Fuel Source, 2007A



Source: EIA, Summer Capacity

Parallel with the dour demand picture in the US, we expect relatively little new generation to be built beyond the near term, as excess capacity from the earlier part of this decade is still being absorbed. While the current recession has clearly extended the need for new generation, we remain fundamentally concerned about the ability of unregulated power markets to properly incentivize the addition of new baseload generation. We believe over the next decade, new generation will be primarily added in regulated states where a ratebase structure provides the appropriate risk controls to accommodate such large fixed capital investments. Furthermore, we believe mandated renewable generation development (as part of an effort to meet state and a likely federal Rewewable Portfolio Standard) will likely comprise the vast majority of needed generation additions, in turn requiring its own backup generation to address intermittency issues.

Coal Plant Cancellations Have Increased Sharply in Recent Years

Adding to the lack of anticipated new generation, approximately 62GW of coal generation have been terminated in the last decade (see Table 13), mostly due to both rising costs and difficulty in procuring air pollution permits from state environmental agencies. Currently, very little new coal generation is anticipated to come online beyond 2013.

Table 13: Terminated Coal Plants under Development, by Year and Capacity (MW)

Year	Coal Plants Terminated	Capacity (MW)
2001	4	386
2002	11	4,679
2003	18	9,494
2004	13	4,555
2005	14	6,473
2006	13	3,913
2007	20	13,453
2008	21	7,764
2009	17	11,349
Total	**131**	**62,065**

Source: SNL

Gas Has Become the "Bridge Fuel"

The last decade has seen record additions of new capacity, with 225 GW of gas coming online (~20% of total US generation)

Given the significant citing/permitting issues and high relative fixed costs involved in building new coal, nuclear, and hydro facilities, the next obvious source for incremental baseload generation is gas generation. With significant improvements in gas turbine technology, combined cycle gas turbines (CCGT) units have made natural gas a significantly more competitive fuel source. In the last decade 1999-2008, the US built almost exclusively gas fired generation to meet incremental demand (87% of all new capacity).

Table 14: Aggregate Capacity Additions by Fuel Type, 1949-2008

	Coal	Natural Gas	Nuclear	Petroleum	Hydro	Wind	Solar	Pumped Storage	Geothermal	Wood	Total
1999-2008	4,717	225,947	-	4,317	470	22,188	111	328	202	368	**259,716**
1989-1998	15,115	42,709	8,209	2,968	1,885	729	176	2,248	529	1,813	**78,366**
1979-1988	82,405	14,457	48,494	3,400	8,137	914	211	6,562	1,215	1,888	**169,154**
1969-1978	115,954	60,588	43,562	31,708	13,103	17	-	9,175	298	773	**275,284**
1959-1968	56,974	37,576	-	10,271	21,987	-	-	3,452	-	1,099	**131,520**
1949-1958	36,143	16,690	-	2,938	15,882	-	-	92	-	678	**72,587**

Source: EIA, *May not add to total, due to exclusion of "Other" Category

With natural gas turbines remaining the least expensive, most environmentally friendly, and the greatest dispatch flexibility to operators, we anticipate further investment in new gas generation through the coming decade. We believe the trend towards gas would accelerate should an aggressive cap and trade program for regulating carbon emissions be adopted. We agree with experts terming natural gas fired generation as a "bridge fuel," as it provides the next best alternative to a cost effective, truly carbon-free generation source. In its five-year generation projection outlook (provided in Table 15), the EIA anticipates 52% of new generation to be derived from gas.

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Table 15: EIA Projection for New Generation Additions, by Fuel Type

Energy Source (MW)	2008E	2009E	2010E	2011E	2012E
Coal	1,131	6,082	4,996	4,514	6,624
Petroleum	90	1,045	55	720	--
Natural Gas	9,780	12,334	8,911	6,919	10,156
Nuclear	--	--	--	--	1,270
Hydroelectric Conventional	18	6	6	204	2
Wind	9,821	3,661	1,045	90	--
Solar Thermal and Photovoltaic	23	127	315	1,050	880
Wood and Wood Derived Fuels	32	60	68	14	114
Geothermal	138	30	87	128	--
Other Biomass	173	129	1	122	2
Pumped Storage	--	--	--	--	--
Total	**21,226**	**23,475**	**15,484**	**13,762**	**19,049**

Source: EIA

Breaking Down the Proposed Capacity Additions

Parsing apart the EIA data above, we find restructured and regulated states have proposed capacity additions totalling to 26.16% and 31.17% of current capacity, respectively; we see the ~5% difference as demonstrating the lower amount of generation incentivized by restructured markets. We also find additions in 2008 and 2009 (1.97% and 2.18%) are roughly comparable to the natural depreciation of the fleet (Assuming an average plant life of 50 years is equivalent to 2.0% annual depreciation). We caveat the data was prepared by EIA using 2007 data and is likely to be revised downwards in future updates; particularly for unregulated regions where private developers are finding it particularly challenging to raise the necessary financing in today's market and in light of the significantly lower commodity price environment.

Restructured markets clearly have a smaller pipeline of proposed new power projects

Capacity additions are seemingly slightly more than offsetting current retirements

Examining the proposed generation pipeline from the perspective of fuel mix, we note a significant portion is wind, representing 21% of the pipeline in restructured states and 25% in regulated states. A further 21% and 25% of the pipeline in restructured and regulated states, respectively, are single-cycle gas turbines, disproportionately high relative to its contribution to the current US fuel mix but likely needed to firm unreliable renewable resources.

Contrasting the current generation fuel mix against the pipeline, we see a shift towards single-cycle gas turbines and renewables

... The Bridge Fuel to What?

What will the next fuel source be? Is there a need for a fuel source beyond natural gas? Given the likelihood for legislating significant reductions to carbon emissions, this remains a highly political topic, with two long term fuel sources competing to be the next large capacity source: coal with carbon capture & sequestration (CCS) and nuclear. Given the relative infancy of CCS technology on a commercial scale and the remaining question of where to sequester the CO_2 emissions, we believe for the foreseeable future the US will increasingly become dependent on nuclear generation to both meet CO_2 reduction targets and meet baseload generation demand. We have included our approximations for the cost of new generation units, by fuel type in Table 16.

An increasingly challenging question for the industry is whether to turn to coal with CSS / IGCC or new nuclear as baseload generation?

Table 16: Approximate Cost Ranges for New Generation

Approximate Range of New Build ($/kW)	
Gas CT	500 - 100
Gas CCGT	900 - 1,500
Coal	2,800 - 3,500
IGCC (Coal)	3,700 - 4,500
Nuclear	6,000 - 7,000
Wind (Onshore)	1,800 - 2,500
Solar-PV	3,500 - 6,500

Source: Duke Energy, Progress Energy, Southern Company, PG&E, PSE&G, SNL, and UBS estimates

Reserve Margin Analysis

The NERC (North American Electric Reliability Council) is the governmental agency responsible for assuring sufficient generation capacity in the US and Canada. The agency publishes an authoritative summary of the issues facing reserve margins (the percent of excess capacity available above projected peak load for a given year) as well as projects reserves margins for both a five- and ten-year period; we have included the US summary for the five and ten year scenarios in Table 17 and Table 18, respectively.

Table 17: Estimated 2012 Summer Margins (%), Resources and Demand (MW)

	Net Internal Demand (MW)	Existing Certain and Net Firm Trans-actions (MW)	Net Capacity Resources (MW)	Adjusted Potential Resources (MW)	Total Potential Resources (MW)	Existing Certain and Net Firm Trans-actions Margin (%)	Net Capacity Resources Margin (%)	Adjusted Potential Resources Margin (%)	Total Potential Resources Margin (%)	NERC Reference Margin Level (%)
United States										
ERCOT	68,833	72,486	78,843	86,397	116,615	5.0%	12.7%	20.3%	41.0%	11.1%
FRCC	48,212	52,817	59,979	59,979	59,979	8.7%	19.6%	19.6%	19.6%	13.0%
MRO	44,993	45,221	49,529	54,029	61,324	0.5%	9.2%	16.7%	26.6%	13.0%
NPCC	61,065	69,585	72,923	72,923	84,901	12.2%	16.3%	16.3%	28.1%	
New England	27,541	31,246	31,673	31,673	43,651	11.9%	13.0%	13.0%	36.9%	13.0%
New York	33,524	38,339	41,250	41,250	41,250	12.6%	18.7%	18.7%	18.7%	13.0%
RFC	188,900	213,787	219,492	227,911	255,072	11.6%	13.9%	17.1%	25.9%	
RFC-MISO	65,200	70,076	72,540	74,493	77,322	7.0%	10.1%	12.5%	15.7%	12.8%
RFC-PJM	127,600	141,542	144,783	150,943	175,581	9.9%	11.9%	15.5%	27.3%	12.8%
SERC	214,834	233,581	240,273	268,712	276,703	8.0%	10.6%	20.1%	22.4%	
Central	44,732	48,848	50,304	54,774	56,778	8.4%	11.1%	18.3%	21.2%	13.0%
Delta	30,352	29,655	29,655	41,259	43,391	-2.4%	-2.4%	26.4%	30.1%	13.0%
Gateway	20,000	23,787	24,332	28,839	28,839	15.9%	17.8%	30.6%	30.6%	13.0%
Southeastern	53,896	57,736	59,418	65,218	67,833	6.7%	9.3%	17.4%	20.5%	13.0%
VACAR	65,854	73,556	76,565	78,622	79,862	10.5%	14.0%	16.2%	17.5%	13.0%
SPP	46,248	48,628	54,328	62,975	67,981	4.9%	14.9%	26.6%	32.0%	13.0%
WECC	149,137	166,578	175,431	175,435	184,342	10.5%	15.0%	15.0%	19.1%	12.1%
AZ-NM-SNV	34,802	35,026	37,087	37,091	38,399	0.6%	6.2%	6.2%	9.4%	11.7%
CA-MX US	60,731	64,899	72,021	72,021	77,521	6.4%	15.7%	15.7%	21.7%	13.3%
NWPP	41,004	53,809	52,123	52,123	54,472	23.8%	21.3%	21.3%	24.7%	11.9%
RMPA	13,047	12,852	14,744	14,744	14,744	-1.5%	11.5%	11.5%	11.5%	10.5%
Total - US	**822,222**	**902,683**	**950,798**	**1,008,361**	**1,106,917**	**8.9%**	**13.5%**	**18.5%**	**25.7%**	**13.0%**

Source: NERC 2008 Long Term Reliability Assessment

Table 18: Estimated 2017 Summer Margins (%), Resources and Demand (MW)

	Net Internal Demand (MW)	Existing Certain and Net Firm Trans-actions (MW)	Net Capacity Resources (MW)	Adjusted Potential Resources (MW)	Total Potential Resources (MW)	Existing Certain and Net Firm Trans-actions Margin (%)	Net Capacity Resources Margin (%)	Adjusted Potential Resources Margin (%)	Total Potential Resources Margin (%)	NERC Reference Margin Level (%)
United States										
ERCOT	75,201	72,486	78,843	86,436	116,811	-3.7%	4.6%	13.0%	35.6%	11.1%
FRCC	53,733	51,475	67,434	67,434	67,434	-4.4%	20.3%	20.3%	20.3%	13.0%
MRO	48,625	45,220	50,126	55,984	65,335	-7.5%	3.0%	13.1%	25.6%	13.0%
NPCC	64,145	69,411	72,750	72,750	85,672	7.6%	11.8%	11.8%	25.1%	
New England	28,971	31,246	31,673	31,673	44,596	7.3%	8.5%	8.5%	35.0%	13.0%
New York	35,174	38,165	41,077	41,077	41,077	7.8%	14.4%	14.4%	14.4%	13.0%
RFC	201,700	213,787	219,632	230,875	267,513	5.7%	8.2%	12.6%	24.6%	
RFC-MISO	68,900	70,076	72,540	75,428	80,338	1.7%	5.0%	8.7%	14.2%	12.8%
RFC-PJM	137,000	141,542	144,923	152,940	185,006	3.2%	5.5%	10.4%	25.9%	12.8%
SERC	236,070	234,638	242,498	271,830	302,558	-0.6%	2.7%	13.2%	22.0%	
Central	49,673	47,379	49,983	54,574	67,518	-4.8%	0.6%	9.0%	26.4%	13.0%
Delta	33,144	29,647	29,647	41,251	46,485	-11.8%	-11.8%	19.7%	28.7%	13.0%
Gateway	20,997	23,749	24,314	28,957	28,957	11.6%	13.6%	27.5%	27.5%	13.0%
Southeastern	60,156	61,905	63,587	69,387	78,640	2.8%	5.4%	13.3%	23.5%	13.0%
VACAR	72,100	71,959	74,968	77,661	80,959	-0.2%	3.8%	7.2%	10.9%	13.0%
SPP	49,853	48,390	55,781	64,428	74,354	-3.0%	10.6%	22.6%	33.0%	13.0%
WECC	162,763	166,571	175,838	175,842	187,512	2.3%	7.4%	7.4%	13.2%	12.1%
AZ-NM-SNV	39,442	35,066	37,336	37,340	39,060	-12.5%	-5.6%	-5.6%	-1.0%	11.7%
CA-MX US	64,598	64,515	71,799	71,799	77,976	-0.1%	10.0%	10.0%	17.2%	13.3%
NWPP	44,484	54,127	51,788	51,788	54,861	17.8%	14.1%	14.1%	18.9%	11.9%
RMPA	14,747	12,880	15,418	15,418	16,118	-14.5%	4.4%	4.4%	8.5%	10.5%
Total - US	**892,090**	**901,978**	**962,902**	**1,025,579**	**1,167,189**	**1.1%**	**7.4%**	**13.0%**	**23.6%**	**13.0%**

Source: NERC 2008 Long Term Reliability Assessment

NERC's assessment clearly points to several restructured markets (PJM, New England, and MISO) as having the largest gap between required capacity and anticipated capacity for both 5 & 10

Regions that have the lowest reserve margins by 2012 are New England, MISO, PJM, and the AZ-NM-SNV region of WECC. With the exception of WECC, these regions represent the vast majority of restructured electric markets and seemingly indicate a concern for these markets to incentivize new plant construction. In the case of the AZ-NM-SNV region of WECC, the lack of new generation is likely due to the following two reasons: 1) a moratorium on new utility generation imposed as a consequence of re-regulation through 2014(AZ); and 2) unconstructive regulatory environments, discouraging new investment. From a reserve margin perspective, restructured markets with adequate power outlooks are NYISO and ERCOT.

Capacity Markets

An important and growing earnings component for merchant generators in the Northeast is the availability of capacity payments for incumbent generators in PJM, NYISO, and NE ISO. Conceptually capacity markets should mitigate energy price volatility because peak generation capacity can recover a substantial amount of its associated cost through fixed payments, rather than needing to recoup its entire cost through energy revenues. The fixed capacity revenues further mitigate the commodity and volumetric risk associated with large capital expenditure investments, and aim to incentivize peaking capacity in an attempt to maintain grid reliability. PJM and NE ISO use a forward capacity market, with auctions taking place approximately four years ahead of delivery, allowing for the bidding and development of new generation should the market so require new generation.

Capacity payments are an increasingly important earnings contributor to many merchant generators

PJM's Capacity Market Provides Revenue Bump, but Adds to Backwardated Earnings Profile and Exposure to Political Volatility

PJM's RPM BRA is the most well known capacity auction. Its annual May events have already established prices for the periods 2007-08 through 2012-13. While the capacity auction is seemingly a great idea in concept, the auction process and the ability for incumbent generation to receive capacity payments has attracted political ire from many including a group known as the RPM Buyers. Consequently, we believe there is an inherent political risk associated with these payments and believe the politics of the day can potentially affect the price received by generators. We specifically point to the 2011-12 auction as an example, where all zones cleared at an equal, significantly lower price of $110/MW-day. We have provided a summary of these auctions, by zone, in Table 19.

Table 19: Summary of RPM Base Residual Auction Pricing for PJM (Capacity Payments)

	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13
Resource Clearing Prices ($/MW-day)						
RTO	$40.80	$111.92	$102.04	$174.29	$110.00	$16.59
EMAAC	$197.67	$148.80	$191.32	$174.29	$110.00	$146.87
SWMAAC	$188.54	$210.11	$237.33	$174.29	$110.00	$133.88
DPL-S				$186.12	$110.00	$222.30
PS-N						$146.87
PSEG						$245.25
Reserve Margin	**19.2%**	**17.5%**	**17.8%**	**16.5%**	**18.1%**	**20.9%**
New Capacity Offered	19	93	476	1,028	2,333	1,108
New Capacity from Reactivated	47	131	-	170	181	-
Uprates to Existing Capacity	536	500	796	578	1,063	786
Total	**602**	**724**	**1,272**	**1,776**	**3,576**	**1,894**

Source: PJM

Given the significantly depressed price of the latest PJM auction, we anticipate the next auction to clear at a modestly higher rate (however not at price levels recently seen) for two reasons: 1) while existing energy efficiency resources were required to bid, but were not eligible for payments previously, we understand this will change in the next auction; and 2) demand-side management resources that overwhelmed the latest auction could potentially prove to not be economic at these price levels. The potential addition of the net-short FirstEnergy footprint into PJM could add additional upward pressure.

NE ISO's FCM Market Has Consistently Cleared at the Floor Price

Meanwhile, NE ISO's forward capacity market (FCM) market has cleared at the floor price for each of its auctions held so far (0.6x * cost-of-new-entry prices), as qualifying demand response bids have overwhelmed the need for capacity. We note the next auction to take place is likely to clear at a significantly lower price, given the lack of any floor price relative to CONE. The FCM is modestly newer than its PJM peer, with only three auctions conducted so far. The auctions follow a transition period that began paying incumbent generators in 2007; a summary is provided in Table 20. An important caveat for investors modelling capacity payments are that they are only provided for EFOR (equivalent forced outage rate) adjusted capacity (ie, the amount of capacity multiplied by a reliability factor, typically haircutting payments to conventional generation by 5-10%).

Table 20: NE ISO Forward Capacity Market Summary Auction Results

	2007	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13
Resource Clearing Prices ($/kW-Month)	$3.050	$3.050	$3.750	$4.100	$4.500	$3.600	$2.951
Cleared at Floor?					*Yes*	*Yes*	*Yes*
Net Installed Capacity Requirement (MW)					32,305	32,528	31,965

Source: NE ISO

NYISO Capacity Market is an Auction Process for Near term Capacity

NYISO, in contrast to NYISO and NE ISO, conducts a near term capacity auction for seasonal capacity in both the summer and winter of each year. We note generators are also not obligated to participate and can still negotiate bilateral deals with distribution utilities. The auction process is conducted for just two regions, New York City and Rest of State (ROS), with city pricing significantly higher than ROS.

Potential Remains for Other Markets to Eventually Develop Formalized Capacity Markets as Well

Formal capacity auctions still potentially could be developed in other RTOs

Outside of PJM, NYISO, and NE ISO, several other RTOs are considering the potential to add capacity elements to their systems. In particular, the CA ISO and MISO are exploring the potential. The CA ISO and MISO, among other RTOs, currently engage in bilateral capacity transactions where distribution companies privately negotiate capacity prices with generators.

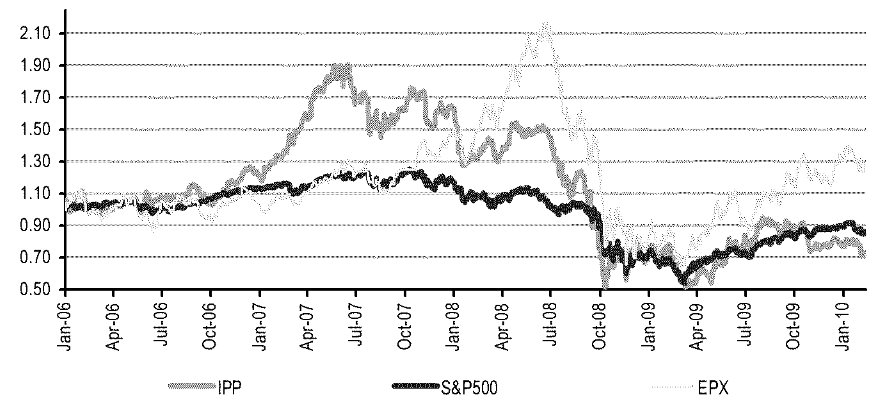
Sector Valuations

Sector Performance Has Outpaced Most Sectors Over Last Decade Due to Underlying Commodity Exposure

The UTY is up 35% since 2000

In line with the dramatic increase in natural gas prices, the utility sector has outpaced the S&P since the start of the decade. The UTY index for the entire electric sector trailed the performance of its E&P-sector index, the EPX, due to its hybrid structure, with much of the utility industry still operating under a cost of service regulatory structure. The utility sector's broader performance throughout the last decade can also be attributed to continued rate base growth at regulated utilities (and a relatively large capital expenditure cycle underway), as well as an improving risk profile as the transition to utility restructuring comes to a close.

Chart 29: Utility Sector compared to E&P Sector and S&P 500 Indices



Source: FactSet

YTD Has Underperformed Market Recovery

However, year to date, the Utility sector has underperformed the market as its relatively lower beta has proved defensive throughout both 2008 and 2009. We believe a key reason why the utility sector was not more defensive during the current downturn was the crises sudden tightening on the availability of credit, the lifeblood of the free cash flow negative sector. We note the more commodity exposed utilities, with their higher betas, experienced a much sharper decline in 2008, as well as a more abrupt recovery this year.

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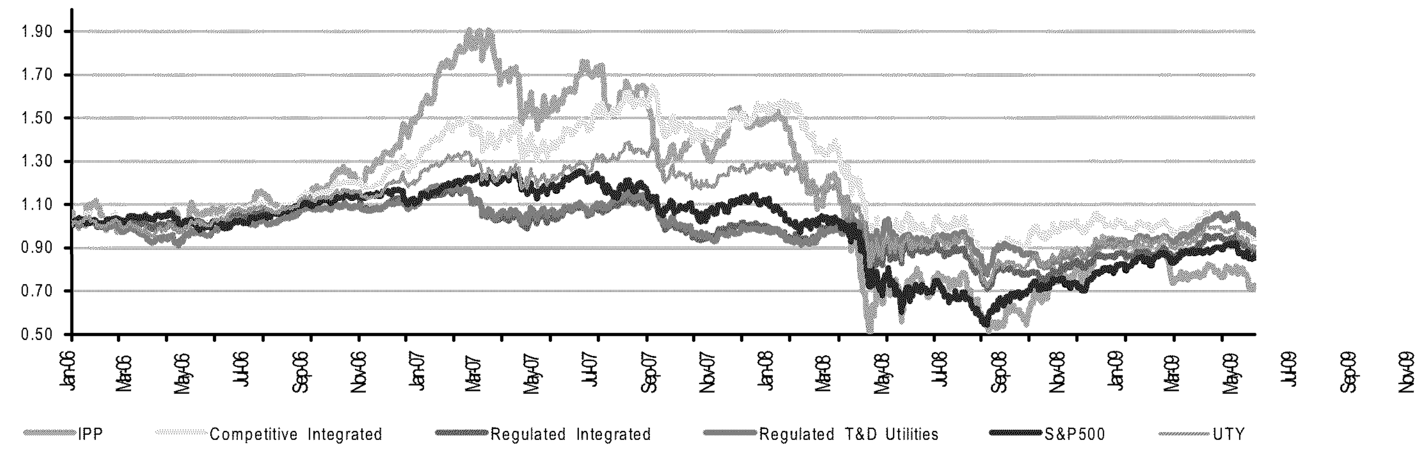
Chart 30: Utility Subsector Share Performance Comparison

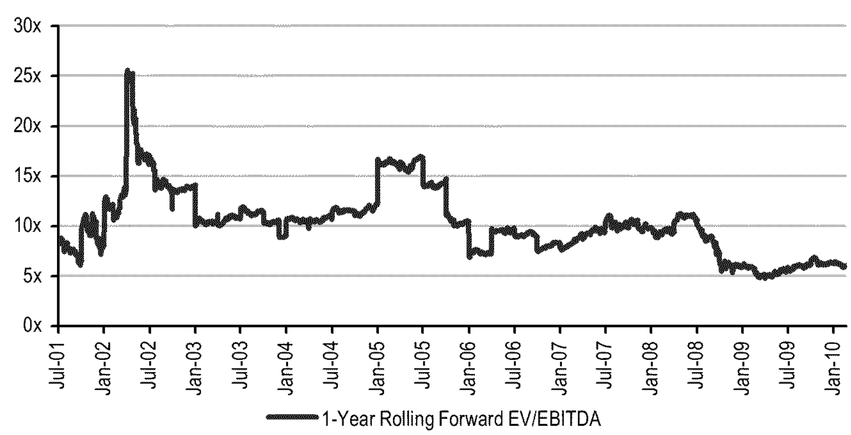


Source: FactSet and UBS estimates

IPP Valuations Premised on EV/EBITDA

Comparing IPP valuations against their long term trend, they are clearly at a low, having reached just 6.0-5.0x on a forward basis in the early part of the year. While there could still be headwinds in the near term for the IPP sector, from a long term perspective, the sector remains undervalued on a purely multiples basis. Alternatively we would interpret the low forward year multiples as a partial pricing in of the significant compression in EBITDA anticipated across the sector.

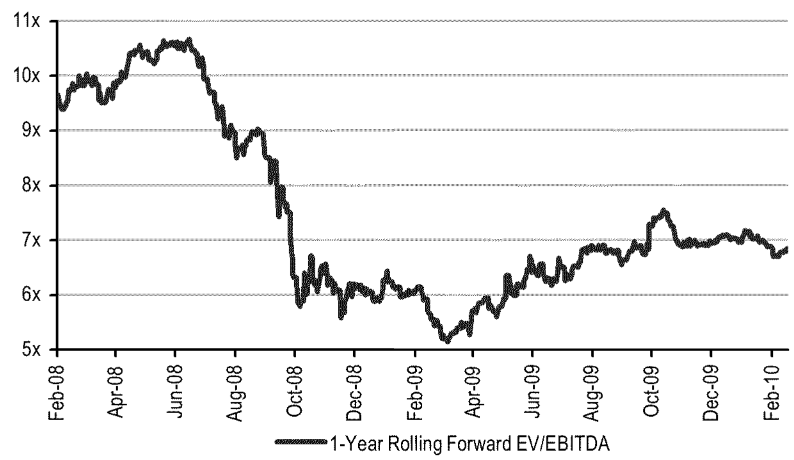
Chart 31: Independent Power Producer 1-Year Rolling EV/EBITDA – Long Term



Source: FactSet, Thomson, and UBS estimates

Examining the IPP sector over the last two years, we see valuations as having reached a trough in March and have recovered only modestly since, on a one-year forward EV/EBITDA basis. While our EBITDA expectations have clearly been compressed due to the lower commodity environment, we see near term pressure leading to a longer term recovery in power equities.

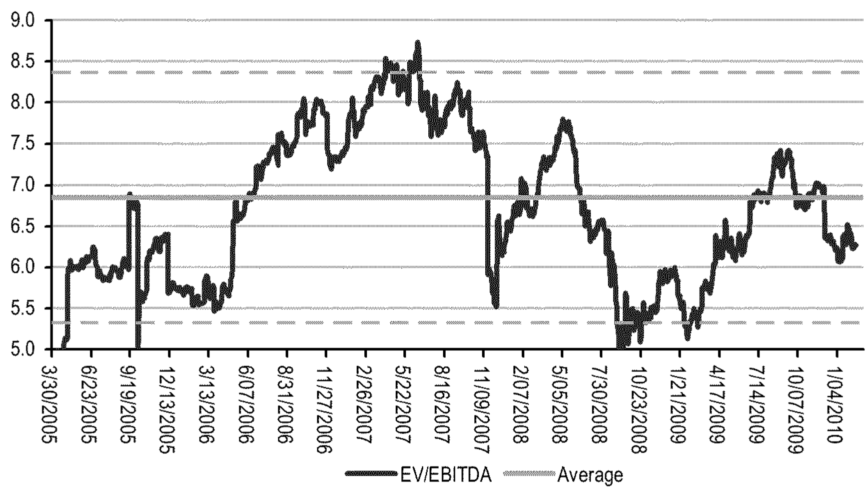
Chart 32: Independent Power Producer 1-Year Rolling EV/EBITDA – Recent Trend



Source: FactSet, Thomson, and UBS estimates

Using FY2 (2 Year Forward) EV/EBITDA consensus expectations, we find IPPs are trading at their recent average.

Chart 33: IPP EV/EBITDA Valuation Using FY2 Consensus Estimates



Source: FactSet

Comparing Implied Capacity Values ($ EV / MW)

While a useful check, we highlight our belief that replacement value of assets remains a relatively uninformative valuation metric

Another "rule-of-thumb" metric used to contrast the IPPs is the implied enterprise value of their underlying generation portfolios. As Chart 34 shows, Calpine and NRG have historically received the most value, while DYN has been in the middle with its primarily low-cost Midwest coal fleet. The two high-cost coal and oil/gas peaking-heavy IPPs, RRI Energy and Mirant, are significantly below the balance.

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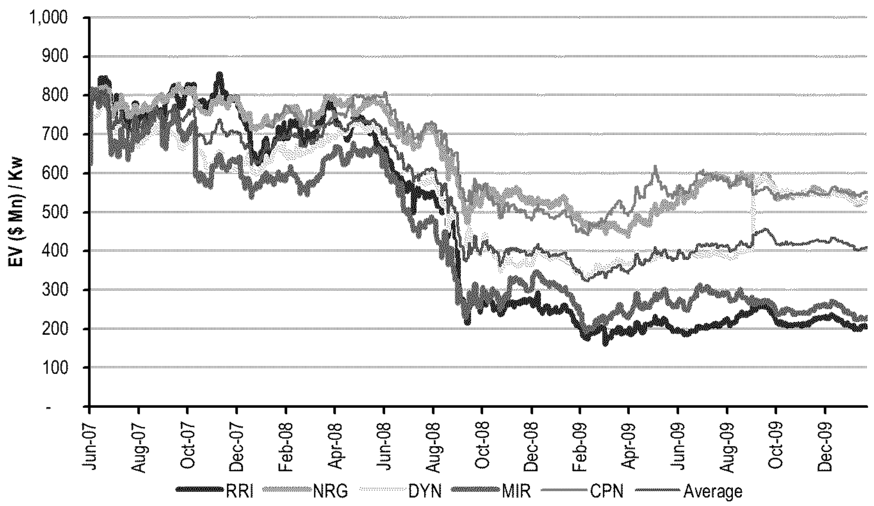
Chart 34: Enterprise Value ($ Mn) / MW



Source: FactSet, Thomson, and UBS estimates

Comparing Our SOP Multiple Valuation

We have included in Table 21 a comparison of the Sum of the Part multiples we use in our valuations for the IPP sector. We note the highest multiple continues to be ascribed to Calpine to account for its relatively flat EBITDA profile (with a trough in 2010); we see the majority of the sector as continuing to show a decline in EBITDA even assuming our above market natural gas forecast of $7/MMBtu. We also note a significant headwind for the sector remains higher coal prices (both for the coal itself and transportation costs), likely actually benefitting Calpine due to the increased competitiveness of its fleet.

Table 21: Comparison of EV/EBITDA SOP Multiples Used in IPP Valuations

	Implied Valuation Multiple		
	2011 Hedged EBITDA	2011 UBS Open EBITDA	2011 Market Forward Open EBITDA
CPN	8.5x		
DYN	8.5x	8.1x	8.6x
MIR	6.3x	8.4x	9.0x
NRG	7.9x	6.8x	8.4x
RRI	6.5x	6.5x	7.0x

Source: UBS estimates; We note for Calpine determining an Open value is not likely indicative given unknown steam, Tolls, and PPA revs.

In a normalized context, we see EV/EBITDA multiples for the IPP group as ranging from 7.0x – 9.0x, with the more stable, contracted assets warranting premium multiples over their commodity-exposed risky peers. We also embed into our multiple assumptions the age of the fleet, potential environmental liabilities, financial leverage, and our view of commodity prices. We note our revised valuation methodology for the IPPs now includes Open EBITDA as one of the three components.

IPPs Remain Relatively Levered Universe

In aggregate, we see the space as broadly being overlevered in the current commodity environment. With leverages reaching over 4.0x Net Debt / EBITDA in several cases, we anticipate general deleveraging will be the priority

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of the day before companies begin considering further share repurchase programs; unique to utilities, IPPs maintain no dividends opting for share repurchase programs when cash flows permit.

Table 22: IPP Net Debt / EBITDA

	Net Debt	Net Debt / EBITDA			
		2009E	2010E	2011E	2012E
Dynegy, Inc.	5,111	6.5x	9.2x	7.5x	7.7x
Mirant Corp	1,860	1.9x	2.7x	3.4x	4.2x
Calpine Corporation	8,292	4.6x	5.2x	4.7x	4.7x
NRG Energy Inc.	8,278	3.2x	3.8x	4.5x	4.1x
RRI Energy Inc.	1,951	14.2x	3.9x	3.4x	5.2x
Sum/Average	**25,492**	**6.1x**	**5.0x**	**4.7x**	**5.2x**
Median		**4.6x**	**3.9x**	**4.5x**	**4.7x**

Source: Company reports and UBS estimates; capitalizes operating leases and other adjustments made

Competitive and IPP Subsectors Operate on a FCF Positive Side

We note a unique aspect of both the Competitive Integrated sector and (more so) the IPP sector is their relative (or potential) positive free cash flows; the regulated utility sector has typically remained in a negative free cash position. While many of the Competitive Integrated utilities have announced programs to reinvest in their associated regulated utilities, (PEG, PPL, CEG, among others), the IPPs have generally decided to pursue share repurchases in recent years, in lieu of investing in new merchant generation. Despite a lower commodity environment, the roll-off of required environmental control capital expenditures should allow for higher free cash flows.

IPP Sector is Entirely High Yield; Financing Risk is Real

In contrast to the balance of the utility sector, the IPPs are generally BB or B credits, with relatively high leverage and volatile cash flows. Despite both operating merchant generation portfolios, there is a discernible difference in strategy between the more hedged portfolios of Competitive Integrateds and the less-hedged IPPs. We anticipate the IPP sector will likely subscribe to a more hedged profile (and overall less risky profile) coming out of the second commodity bust cycle since electric restructuring, having seen a combination of falling commodity prices and freezing credit markets (particularly for HY issuers) nearly bring the sector back into another wave of bankruptcies. While access to debt capital markets for HY issuers has seemingly been restored, we believe refinancing risk and the ability for IPPs to roll or paydown large maturities as a material risk for the sector. We provide in Table 23, a summary of the sector's credit rating from each of three major rating agencies.

Table 23: IPP Credit Rating Summary

	S&P	Moodys	Fitch
CPN	B	B2	
DYN	B	B2*	B-
MIR	B+	B1	B+
NRG	BB-	Ba3	B
RRI	B+	B1	B

Source: Fitch, Moodys, and S&P; *for DHI

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Regulatory Environment

Regulation of utilities is important for both merchant generators and regulated utilities. For regulated utilities, rates must be vetted and approved by state commissions through rate case processes; in this capacity, regulators set both the authorized Returns on Equity (ROEs) in addition to evaluating the prudence of investments and costs for regulated utilities.

Utilities Are Regulated by Both State and Federal Commissions

There have been two recent FERC commissioner changes, with likely impacts on priorities and regulatory ideologies

The primary federal regulator of utilities is the Federal Energy Regulatory Commission (FERC). The FERC has been integral to the design and approval of unregulated power and natural gas markets in the US. The composition of the five member committee has recently changed significantly with the departure of Commissioner Joseph Kelliher in March, the nomination of John Norris by President Obama in June, and the recent announcement by Suedeen Kelly that she will not accept her re-nomination.

Table 24: Current FERC Commissioners

Commissioner	Political Party	State of Origin	Term of Service Began	Term of Service Ends
Jon Wellinghoff (Chairman)	Democrat	Nevada	May-08	Jun-13
Philip Moeller	Republican	Washington	Jul-06	Jun-10
Marc Spitzer	Republican	Arizona	Jun-06	Jun-11
Suedeen Kelly (will step down)	Democrat	New Mexico	Nov-03	Jun-09
John Norris*	Democrat	Iowa		

Source: FERC website; John Norris has not yet been fully approved by the Senate

We anticipate notable subjects the FERC is likely to take up in the coming years include capacity payments, expanding RTO participation, and incentive rate treatment for transmission projects. In particular, we note the departure of Suedeen Kelly is likely to lead to more restrictive definition for transmission projects to qualify for incentive ratemaking.

Pressure on Regulators to Mitigate Cost Increases in Recession

We believe regulators in the near term will be increasingly focused on minimizing rate increases on consumers. While commodity inflation in recent years has pressured rates upwards, we see the recent pullback in gas prices as providing utilities with some headroom to increase distribution rates, offsetting the large volumetric declines in sales this year.

Carbon's Impact on Power

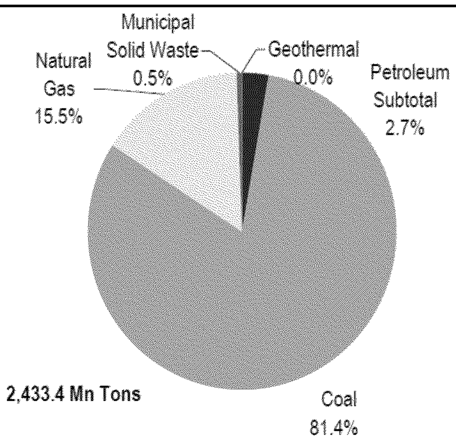
For merchant generators, CO_2 regulation promises to be the most complicated and potentially game-changing environmental regulation yet. With questions over the implementation of a cap and trade system we thought it useful to provide a brief framework on how to think about the impact of Carbon on the merchant power sector under such a scenario. While we do not anticipate cap and trade legislation as a likely 2010 event, we believe some form of implementation of a carbon restricting regime remains on the horizon. As natural gas tends to set the marginal cost of power in many regions in the US, merchant coal generators may see their margins compressed as they are not fully able to pass through their added costs of compliance of procuring CO_2 allowances. In contrast to the uncertain long term scenario for coal generators, we note they stand to be potentially over-allocated in the initial years of the cap and trade, as proposed under the Waxman-Markey bill (HR2454, which passed the House in June, 2009). For a longer explanation and review of the impact of a cap and trade program on US utilities see our note published on *How to Capture the Carbon Opportunity? September 17th, 2009.*

Given the large potential impact any form of carbon regulation would have on the sector, we provide our framework for how to understand its impact

US Electric Sector Remains One of the Top GHG-emitting Sectors

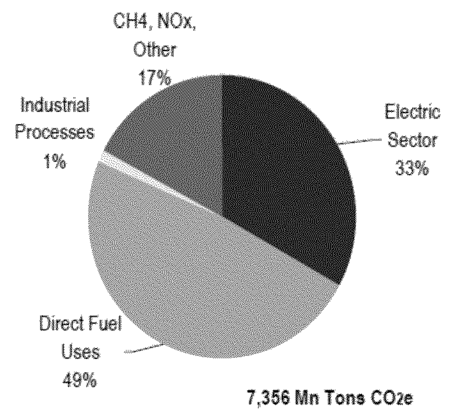
To provide a framework for understanding carbon, we have provided in Chart 236 and Chart 36, aggregate GHG emissions for the US economy (of which, the US utility sector contributes 33%), and within which coal contributes 81%.

Chart 35: US Generation CO_2 Emissions by Fuel Source, 2007P



Source: EIA, Preliminary Data

Chart 36: 2007 US GHG Emissions by Source



Source: EIA, 2007P

Recall that while coal generates only ~50% of electricity in the US, its carbon intensity (CO_2 emissions/MWh) is roughly twice that of natural gas. We have provided approximate carbon intensities for coal, natural gas, and petroleum in Table 25.

Table 25: Conversion Statistics for CO_2 Equivalency

	ton CO2e/MWh	(lb CO2e/KWh)
Natural Gas	0.454	1.001
Coal	0.974	2.147
Oil (Residual No. 6)	0.726	1.601

Source: University of Wisconsin, Kulcinski and UBS estimates

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Using Waxman-Markey to Provide Framework

We provide our framework around carbon using HR 2454 (more commonly referred to as the Waxman-Markey bill) as our benchmark, fully knowing the eventual enactment of any carbon regime is likely to evolve significantly. The bill is the latest in a series introduced in both the House and Senate, and is the first to successfully pass. In addition to tackling climate change, the bill mandates a federal renewable energy standard and comes on the footsteps of the Lieberman-Warner Bill (S.B. 2191) introduced into the full senate in June, 2008. A complementary Senate bill (to HR2454) was introduced in late September 2009 by Senators Boxer & Kerry.

The Waxman-Markey bill provides for an initial reduction in its first year of 3% below 2005 levels (defined as 7,206 Mn tons of CO_2e) by 2012, pacing up to 83% below 2005 levels by 2050 (see Table 26.) These targets are likely to shift as a final bill is prepared for passage. While we anticipate an eventual dilution of the Waxman-Markey targets, the latest Kerry-Boxer bill as initially introduced includes a 20% reduction from 2005 levels by 2020.

Table 26: Waxman-Markey GHG Targets

% Decline	By
3% (below 2005)	2012
17% (below 2005)	2020
42% (below 2005)	2030
83% (below 2005)	2050

Source: HR2454

Allocations Within the Bill Will Mitigate the Impact

The Waxman-Markey bill provides for substantial initial allocations to the US utility sector, limiting the total number of allocations it will need to provide in the early years of the program. The bill is structured such that a pre-defined percentage of free allocations is given to the utility sector. We have provided the total allowances provided under the bill by year, and the associated percentage allocated to the utility sector in Table 27. In turn, we believe the utility's sector allowance should translate to **~85%** of its needs in 2012, taking into account a ~10% drop in CO_2 emissions associated with the recession.

Table 27: Utility Sector Emissions Allocation Under HR 2454

Year	Allowances (Mn Tons)	Electric Allowance (%)	Electric Sector	Year	Allowances (Mn Tons)
2012	4,627	43.75%	2,024	2032	3,283
2013	4,544	43.75%	1,988	2033	3,158
2014	5,099	38.89%	1,983	2034	3,033
2015	5,003	38.89%	1,946	2035	2,908
2016	5,482	35%	1,919	2036	2,784
2017	5,375	35%	1,881	2037	2,659
2018	5,269	35%	1,844	2038	2,534
2019	5,162	35%	1,807	2039	2,409
2020	5,056	35%	1,770	2040	2,284
2021	4,903	35%	1,716	2041	2,159
2022	4,751	35%	1,663	2042	2,034
2023	4,599	35%	1,610	2043	1,910
2024	4,446	35%	1,556	2044	1,785
2025	4,294	35%	1,503	2045	1,660
2026	4,142	28%	1,160	2046	1,535
2027	3,990	21%	838	2047	1,410
2028	3,837	14%	537	2048	1,285
2029	3,685	7%	258	2049	1,160
2030	3,533			2050	1,035
2031	3,408				

Source: HR 2454 and UBS estimates

Merchant Coal Allocation Equates to ~45% of Emissions in 2012

Merchant coal generators would receive ~45% of their annual emissions through allocations in '12, recouping most of the balance of compliance costs through higher power prices

The allocation of 3.5% to the merchant coal generators (or 10% of the 35% allocated to the utility sector) equates to roughly 45% of their average qualifying emissions in 2006-2008; (qualifying emissions are based on the average of historical emissions over 2006-08 and adjusted annually for actual emissions once the program is in place). The 45% allocation makes merchant coal facilities roughly comparable to their gas emitting counterparts, which are 51% as intense (implying it would need to make up 49%). The allocation would also be rateably reduced annually with the annual cap in overall emissions. We believe adopting such an allocation policy would likely temper the increase in overall power costs and the decline in coal generator margins, at least in the near term. However, the bill explicitly states there should be no windfall benefits to merchant generators due to allocation policies. Any extra allocations beyond those needed for the merchant coal sector and PPAs would be credited back to customers through the broader LDC program (which we believe is a material possibility in the early years of the program, albeit difficult to prove given the challenges of proving power price cost recovery). We have included a full summary of merchant coal allocations calculations in Table 28.

Table 28: Merchant Coal Allocations Compared With Gas/Coal Equivalency

Merchant Coal Allocations under HR 2454		
Total Sector Allocation	2,024	Mn CO_2 tons
Merchant Coal Allocation (10%)	202	Mn CO_2 tons
Total US Coal Generation		
2006 Total Coal Generation	1,990,511	GWh
2007 Total Coal Generation	2,016,456	GWh
2008 Total Coal Generation	1,994,385	GWh
Average 2006-08 Coal Generation	*2,000,451*	*GWh*
Merchant Coal Component (23%)	460,104	GWh
Approximate Merchant Coal CO2 Emissions	452	Mn CO_2 tons
Percent of Need Allocated in 2012	45%	
Percent of Coal Emissions Not Recoved w/ Gas-on-Margin	49%	

Source: EIA, Generators for Affordable Power (GAP), and UBS estimates

More Coal to Gas Switching Likely as Economics Shift

We believe between the potential for coal plant retirements and the overall costs of running mid-merit coal facilities, there could be substantial pressure to increase the capacity factors on the existing combined cycle gas turbine (CCGT) fleet, which are highly efficient gas power plants. In particular, we highlight CPN as an explicit beneficiary of this incremental need for gas-fired generation. This trend should be moderated in the early years of the program, as utilities are likely to source a large proportion of their allowances through offset programs (both domestic and international). We provide two scenarios below to demonstrate the large impact of allowances on the overall cost of the program.

Scenario #1:

Policy Taken to Extreme Could Require Up to 170 GW of Switching

Without an effective offset program, the cost of implementing large reductions in carbon quickly could be staggering

To put the required reduction of CO_2 emitted by the utility sector in context, it would be equivalent to 1,025 Mn MWh, or 170 GW of capacity switching from coal to gas, assuming the average coal capacity factor of 69% in the US. In 2008, total installed coal capacity was just 338 GW. The impact on gas demand would in turn be a massive 21.3 Bcf/d increase. While this is clearly an extreme scenario, we include it to highlight the potential cost of achieving CO_2 reductions without an offset program. The EIA recently acknowledged a potential large expansion in gas generation, suggesting the natural gas industry could conceivably deliver the necessary supply under a gas-heavy scenario.

Table 29: Carbon Scenario—Meet Reduction Through Coal to Gas Switching

Mn Metric Ton Reduction Required	(533)	Mn tons CO_2
Coal to Gas Carbon Intensity Differential	520	tons CO_2 /GWh
Total Generation Impact	1.025	Mn GWh
Average US Coal Capacity Factor	69%	
Equivalent Coal Capacity	**170**	**GW**
Equivalent Natural Gas Demand Impact	7.789	Tcf
Equivalent Gas Impact (daily usage)	21.340	Bcf/d

Source: EIA, SNL, and UBS estimates

Scenario #2:

Assuming Credits Are Purchased Leads to 2% Increase in Rates

Using EPA and CBO's cost assumption for carbon prices, we calculate a much more modest 2% increase in rates in 2012 (and rising from there)

Using the EPA's assumption of $13/ton (down from its initial estimates), we calculate the US will likely face a rate increase of roughly 2% in 2012, assuming a complete buyout of the allowances need to meet mandated carbon reductions. Also, funds collected by the government through any auction program would likely be credited back to customers, further mitigating the rate impact. However, many factors drive the cost to consumers (including secondary impacts, such as the increased need for natural gas), making any eventual rate impact too difficult to calculate and likely material under any scenario. We break out our rate increase assumptions under a complete carbon credit purchase scenario in Table 30.

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Table 30: Carbon Scenario—Using Carbon Credits to Meet Reduction in 2012

Mn Metric Ton Reduction Required	-533	Mn tons CO2
Carbon Scenario	$13	/ ton (2015 EPA scenario)
Cost to industry	($6,932)	$ Mn
Total MWh sales	3,756	Mn MWh
Revenue Bill (aggregate)	368,463	$ Mn
Average Increase to US Rates	**1.88%**	
Impact on $/MWh Basis	**1.85**	**$/MWh**

Source: EIA 826, EIA GHG Report, and UBS estimates; Note, we apply the *2015* EPA price estimate

Longer term, estimating the cost of implementing a carbon-reduction regime becomes much less clear; we highlight the large impact potential impact as allocations roll off in the back years of the program

With the more modest price impact associated with purchasing credits, we clearly highlight the importance of developing an effective offset program. We believe a critical aspect of formulating legislation will be allowing the industry sufficient time to find a large number of offset programs. Further to the point, the Scenario #2 imparts the cost difference in creating a multi-sector cap and trade program versus achieving reductions through EPA regulation on a unit by unit basis. While the modest 2% increase is forecast for 2012, we estimate this impact to grow (potentially significantly) over time as allocations are reduced and society's need for energy products continues to grow. The largest increase in cost associated with the Waxman-Markey bill as it stands would occur as the allocations are rolled off from 2025-2030. At this point, the industry would be responsible for procuring credits for all of its emissions, resulting in at least a 19% (but likely much more substantial rate increase) using a CBO cost per ton of $28. We have provided a summary of our rough estimates for carbon cost implications through 2020 in Table 31.

Table 31: Summary of Carbon Cost Impacts under Waxman-Markey (HR2454)

	2012	2013	2014	2015	2016	2017	2018	2019	2020
CBO Estimate ($/ton)	16	17	18	19	21	22	24	26	28
EPA Estimates ($/ton)	*13*			13					16
Industry Needs (assume flat lined), Mn Tons	2,558	2,558	2,558	2,558	2,558	2,558	2,558	2,558	2,558
Allocations	2,024	1,988	1,983	1,946	1,919	1,881	1,844	1,807	1,770
Deficit	533	570	575	612	639	676	713	751	788
Cost of Credits (CBO Scenario), $ Mn	8,532	9,683	10,342	11,626	13,416	14,879	17,122	19,523	22,063
Avg. Impact on Customer Bills* (% Increase)	2%	3%	3%	3%	4%	4%	5%	5%	6%
Impact on $/MWh Basis*	2.27	2.58	2.75	3.10	3.57	3.96	4.56	5.20	5.87
Cost of Credits (EPA Scenario), $ Mn	6,932			7,955					12,607
Avg. Impact on Customer Bills* (% Increase)	2%			2%					3%
Impact on $/MWh Basis*	1.85			2.12					3.36
2008 Baseline									
Total MWh Sales	3,756	Mn MWh							
Total Industry Revenues	368,463	$ Mn							

Source: EPA, CBO, EIA, and UBS estimates; *uses 2008 as baseline for impact

Adding It Up for Merchant Generation

We also provide margin impacts for each merchant generator (IPP and competitive integrated) by contrasting the relative intensities of each merchant generator against the states, RTOs, and NERC regions in which they operate. We provide a breakdown (both by generation by region and by merchant/regulated generation exposure) of every company in our coverage universe. In Table 32, we provide approximate CO_2 intensity per MWh by RTO and NERC region.

Table 32: Approximate Aggregate CO_2 Emissions and Intensity for RTO and NERC Regions, 2008

	Generation (GWh)								CO_2 Output (tons)	CO_2 tons/MWh
	Coal	Gas	Oil	Nuclear	Hydro	Wind	Geothermal	Total		
RTO										
PJM	416,842	54,094	5,277	254,864	-	1,307	-	732,384	434,177,602	0.59
CAISO	4,242	94,878	43	35,792	-	3,780	9,245	147,980	47,246,672	0.32
NE-ISO	20,383	51,158	4,837	36,974	-	11	-	113,363	46,463,918	0.41
MISO	420,056	28,338	169	79,058	-	2,324	-	529,945	422,148,451	0.80
NYISO	21,081	51,511	7,339	42,453	-	833	-	123,217	48,946,204	0.40
SPP	133,263	50,248	8	21,411	-	4,040	-	208,970	152,825,074	0.73
Total / Avg	**1,015,867**	**330,227**	**17,673**	**470,552**	**-**	**12,295**	**9,245**	**1,855,859**	**1,151,807,921**	**0.62**
NERC										
ERCOT	118,942	165,029	-	40,955	-	8,097	-	333,023	191,152,218	0.57
FRCC	63,974	94,216	18,581	29,289	-	-	-	206,060	118,711,902	0.58
MRO	142,886	10,138	229	22,248	-	6,197	-	181,698	143,998,130	0.79
RFC	652,543	65,037	3,856	265,784	-	1,398	-	988,618	670,328,807	0.68
NPCC	42,109	105,992	12,480	79,426	-	943	-	240,950	97,761,141	0.41
SERC	653,124	162,105	1,705	276,628	-	58	-	1,093,620	711,342,235	0.65
WECC	219,594	230,382	98	70,683	-	12,716	14,407	547,880	319,184,801	0.58
Total / Avg	**1,893,172**	**832,899**	**36,949**	**785,013**	**-**	**29,409**	**14,407**	**3,591,849**	**2,252,479,234**	**0.63**

Source: SNL and UBS estimates

Contrasting the IPP and Competitive Integrated universe against the weighted average carbon intensities of the regions in which they operate, we are able to find their relative carbon intensity. For the purposes of our model, we assume the regional carbon intensity will be fully recoverable through market power prices, and the degree to which companies are less or more carbon intensive than their regional average leaves them accordingly positioned to recoup their associated costs of complying with carbon legislation. We summarize this calculation for the IPP and Competitive Integrated universes in Table 33; a positive number in the right column (Δ Company vs. Region) indicates a higher carbon intensity than the region for a particular company, and a likely corresponding negative impact to its economics under a carbon constrained regime. Conversely a negative delta implies a lower carbon intensity than the region.

Table 33: Carbon Model Summary - Merchant Generator vs. Weighted-Average Regional Carbon Intensity

	Avg. Carbon Intensity (CO2 tons/MWh)				Δ Company vs. Region		
	Company	State	RTO	NERC	State	RTO	NERC
AEE	0.83	0.70	0.76	0.71	0.14	0.08	0.13
AYE	0.95	0.83	0.59	0.68	0.12	0.35	0.27
CEG	0.32	0.52	0.52	0.60	(0.19)	(0.20)	(0.26)
D	0.49	0.55	0.58	0.61	(0.06)	(0.09)	(0.13)
EIX	0.58	0.47	0.59	0.68	0.18	0.10	(0.03)
ETR	0.23	0.48	0.62	0.60	(0.25)	(0.39)	(0.37)
EXC	0.05	0.50	0.80	0.79	(0.45)	(0.66)	(0.69)
FE	0.58	0.74	0.59	0.68	(0.16)	(0.01)	(0.10)
FPL	0.32	0.58	0.58	0.59	(0.25)	(0.39)	(0.27)
PPL	0.55	0.29	0.62	0.67	(0.03)	(0.07)	(0.12)
PEG	0.35	0.41	0.57	0.63	(0.05)	(0.22)	(0.29)
SRE	0.38	0.44	0.32	0.58	(0.05)	(0.03)	(0.20)
Total / Avg	**0.47**	**0.54**	**0.59**	**0.65**	**(0.09)**	**(0.13)**	**(0.17)**
AES	0.83	0.64	0.61	0.61	0.19	0.21	0.21
CPN	0.42	0.49	0.49	0.59	(0.06)	(0.07)	(0.16)
DYN	0.74	0.43	0.61	0.66	0.31	0.15	0.08
MIR	0.89	0.59	0.55	0.63	0.30	0.34	0.26
NRG	0.79	0.55	0.58	0.57	0.24	0.22	0.22
RRI	0.85	0.58	0.57	0.66	0.26	0.29	0.19
Total / Avg	**0.75**	**0.55**	**0.57**	**0.62**	**0.21**	**0.19**	**0.13**

Source: SNL and UBS estimates; note: we do not cover AEE, AYE, FE, and AES

IPPs Are Clearly Negatively Affected by Carbon Legislation, While Competitive Integrated Companies Generally Experience Moderate to Favourable Impacts

Given the generally higher intensities for the IPPs (averaging +0.21 CO_2 tons/MWh relative to the states in which they operate), we believe carbon legislation remains a legitimate overhang for the sector. CPN is the sole exception given its positioning as a highly efficient gas turbine operator. In sharp contrast, the Competitive Integrated sector fairs relatively well (with an intensity of -0.09 CO_2 tons/MWh relative to the states in which they operate). Companies particularly well positioned to benefit from a carbon uplift include EXC and ETR.

Carbon Model Approximates Impact; Marginal Fuel Would Be Best Approach; However, Data and Eventual Reality Remain Hard to Model

The marginal unit under a restructured power market will determine the ability for generators to pass through the cost of carbon into power prices

The essence behind understanding the margin impact of carbon legislation to merchant generators is to look at the carbon intensity of the marginal fuel setting the price of power (generally natural gas and coal) against the underlying carbon intensity of the merchant generator. In theory, the marginal unit in a region should bid in its cost to recover the incremental cost of carbon, allowing for full recovery for the marginal unit. However, because of scant data and forecasts for marginal fuels in 2012 and beyond, it is difficult to precisely state what the marginal fuel will be and determine a margin impact for merchant generators. A conservative approach to understand the margin impact of a merchant generator would be to calculate the difference in carbon intensity of a fleet against that of a gas-fired unit, as we believe natural gas units should increasingly set the price of power across the country (however, this clearly remains a very localized phenomenon).

Other Environmental Issues on the Horizon

Despite the focus on climate legislation we see nearer term attention on revised CAIR and MACT standards among other environmental regulations as warranting close attention

While climate legislation clearly remains front and center the most impactful potential regulation of the industry, we anticipate more rigorous standards for a host of other environmental emissions could potentially impact the industry in the nearer term. We see revisions of CAIR (Clean Air Interstate Rule) and MACT (Maximum Achievable Control Technology) rules by the EPA as likely being released in 2H10 and early 2011, respectively, potentially driving significant further control technologies expenditure in the sector to address SO_2, NO_x, and mercury. Further we see regulations requiring once through cooling (already being implemented in California) and ash pond remediation as further adding to utility environmental capex. Finally, we anticipate New Source Review (NSR) investigations to pick up following their suspension, likely leading to new agreements on retrofits. Ultimately regulations around conventional emissions may de facto lead to a significant decline in carbon emissions in the US.

Renewables Are Coming

Given increasing political demand for renewable resources and the associated need to reduce CO_2 emissions, the sector has continued to see a disproportionate amount of new generation derived from renewable resources. In particular, we believe wind generation will contribute a significant amount of new generation to be entered into service in 2009. We refer those interested on US developments in wind to our note, *Capturing the US Wind Opportunity, October 15th, 2009.*

Wind Power Has Seen Exceptional Growth in Recent Years, Which We Anticipate Will Likely Continue

In recent years, wind generation has significantly increased its market share from a base of nearly no installed capacity just a decade ago. We include a summary of US wind capacity and generation from 1995 in Table 34. Despite tremendous growth recently, we anticipate continued strong growth (albeit at a slowed pace) through 2020.

Table 34: US Wind Capacity and Generation, 1995-2009

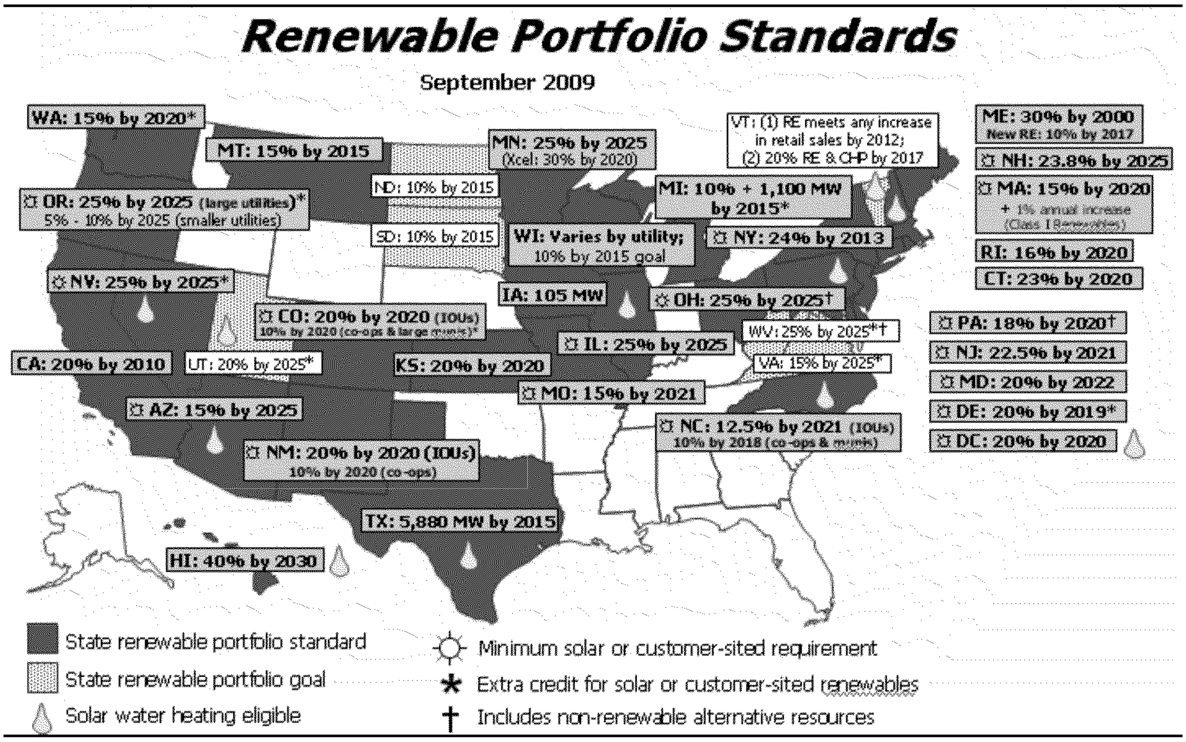
	Cumulative Capacity(MW)	Additions (MW)	% Change	Generation (MWh)	% Change
2009	35,159	9,790	39%		
2008	25,369	8,546	51%	42,772,855	24%
2007	16,823	5,248	45%	34,437,176	30%
2006	11,575	2,426	27%	26,589,146	53%
2005	9,149	2,420	36%	17,410,465	30%
2004	6,729	372	6%	13,366,494	41%
2003	6,357	1,672	36%	9,465,537	-10%
2002	4,685	412	10%	10,483,761	72%
2001	4,273	1,694	66%	6,086,106	15%
2000	2,579	67	3%	5,289,654	23%
1999	2,512	659	36%	4,309,350	50%
1998	1,853	142	8%	2,877,422	
1997	1,711	8	0%		
1996	1,703	-	0%		
1995	1,703				

Source: AWEA and SNL

State Renewable Portfolio Standards (RPS) Drive Demand for Wind

RPS standards mandated in a number of US states set out specific targets for renewable generation by specific dates. While state RPS' generally do not prescribe any specific type of renewable, we anticipate wind, biomass (both coal co-firing and coal repowering), and solar (both PV and thermal) to fill the majority these of targets. We have provided a map with a brief summary by state of each current target in Figure 2.

Figure 2: Renewable Portfolio Standards (RPS), by State



Source: DSIRE (DOE) & North Carolina Solar Center

Renewables Could Be Bolstered With Federal RES

The Waxman-Markey bill (HR2454), which passed Congress in June 2009, provides for a federal renewable energy standard (RES) of 20% by 2020 (see Table 35). The targets would not override state specific targets, but expand a broader target to all states. The RES provides for 25% of the target to be met through energy efficiency (EE), with the potential to petition the FERC to expand the EE component to 40% of the target. The bill also includes a provision for an Alternative Compliance Payment (ACP), exempting utilities from the target at a rate of $25/MWh. In aggregate, we estimate a federal RES could lead to up to ~100GW of wind by 2020.

The Waxman-Markey bill would implement a 20% RES by 2020

Table 35: Waxman-Markey Renewable Energy Standard Targets

Year	Required Annual Percentage
2012	6.0%
2013	6.0%
2014	9.5%
2015	9.5%
2016	13.0%
2107	13.0%
2018	16.5%
2019	16.5%
2020	20.0%
2021-2039	20.0%

Source: HR 2454

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Renewable Impact on Merchants to Be Felt in Midwest

Renewables (and wind in particular), most threaten to undercut heat rates in many power markets, most notably the Midwest

We believe the greatest potential factor undercutting rising power prices over the coming decade is the relative aggressiveness of the RPS targets pursued, and the associated technologies used to arrive at these targets. Given the relatively favorable resource for wind in the Midwest, we anticipate this region may choose to pursue a significant proportion of its RES through wind (as opposed to opting for EE or making use of the ACP). With this anticipated buildout in mind, we remain concerned over the exposure of DYN to eventual erosion in heat rates. Heat rate erosion could be particularly acute for off-peak periods, noting wind in the plains states tends to blow overnight; in turn we anticipate greater volatility between onpeak and offpeak power prices. A well-known example of a region affected by wind has been ERCOT, where forward implied heat rates have exhibited a downward trajectory for some time. While NRG is exposed to these dynamics, we believe the impact of the wind build is visible and has already been priced into expectations for the stock.

Appendix I: Approximate Aggregate CO_2 Emissions and Intensity by State

Table 36: Approximate Aggregate CO_2 Emissions and Intensity by State

	Generation (GWh)								CO_2 Output (tons)	CO_2 tons/MWh
	Coal	Gas	Oil	Nuclear	Hydro	Wind	Other	Total		
VT	-	-	8	4,704	966	11	455	6,143	212,199	0.03
ID	93	1,618	0	-	9,001	172	578	11,464	1,088,327	0.09
WA	8,527	7,556	0	8,109	78,806	2,438	1,608	107,044	12,466,259	0.12
OR	4,355	14,784	0	-	33,656	1,247	1,104	55,147	11,455,281	0.21
CT	3,740	9,748	1,488	16,386	357	-	1,460	33,180	9,811,980	0.30
NJ	10,333	19,064	125	32,010	743	20	1,367	63,662	19,430,410	0.31
CA	4,382	116,489	84	35,792	29,114	5,585	20,465	211,911	66,505,876	0.31
NH	3,932	5,769	326	10,764	955	-	1,184	22,928	7,222,257	0.31
NY	21,680	46,680	7,386	42,453	26,593	833	2,968	148,594	49,019,231	0.33
ME	702	6,652	457	-	3,738	99	4,480	16,129	6,069,479	0.38
SC	41,809	6,017	30	53,200	5,727	-	2,001	108,784	44,383,846	0.41
AK	649	3,868	1,013	-	1,291	1	-	6,821	3,123,089	0.46
SD	2,659	401	9	-	2,917	150	-	6,137	2,778,560	0.45
RI	-	6,853	37	-	4	-	155	7,050	3,208,787	0.46
IL	95,622	7,301	12	95,729	154	664	712	200,194	96,781,961	0.48
VA	35,398	11,266	1,672	27,268	5,083	-	3,345	84,033	42,325,404	0.50
LA	24,954	46,342	0	17,078	827	-	3,344	92,544	46,862,459	0.51
AZ	44,286	38,454	1	26,782	6,863	-	25	116,413	60,605,474	0.52
MA	12,055	25,152	2,779	5,120	2,348	-	1,989	49,443	26,081,411	0.53
NV	7,111	22,413 -	1	-	2,003	-	1,297	32,823	17,689,992	0.54
AR	25,668	8,221	0	15,486	3,266	-	1,954	54,596	29,620,702	0.54
MS	17,423	21,566 -	0	9,359	-	-	1,490	49,838	27,437,779	0.55
PA	123,666	18,527	1,616	77,376	3,809	470	2,951	228,416	131,375,163	0.58
FL	73,456	96,939	18,582	29,289	154	-	7,040	225,461	132,242,819	0.59
TX	148,747	200,999	0	40,955	1,639	9,006	2,824	404,170	237,415,407	0.59
NE	19,698	1,069	5	11,042	347	217	63	32,441	19,703,879	0.61
TN	61,042	683	4	28,700	7,730	50	399	98,608	59,948,802	0.61
AL	77,869	23,390	1	34,325	3,834	-	4,105	143,524	88,327,881	0.62
MN	32,474	4,042	17	13,103	673	2,639	1,548	54,497	34,180,574	0.63
MI	72,237	13,245	3	31,517	4,083	3	2,172	123,259	77,360,115	0.63
NC	80,976	4,529	9	40,045	2,910	-	1,435	129,904	81,585,153	0.63
MD	30,012	1,212	1,728	14,353	1,652	-	1,157	50,114	31,561,309	0.63
MT	18,855	96	0	-	9,364	496	121	28,932	18,463,103	0.64
GA	92,420	15,752	30	32,545	4,943	-	2,568	148,258	98,355,781	0.66
OK	34,464	33,158	0	-	3,333	1,849	450	73,254	48,825,621	0.67
DC	-	-	75	-	-	-	-	75	54,632	0.73
HI	1,541	-	8,875	-	86	238	787	11,527	8,301,424	0.72
WI	41,636	6,284	65	12,910	1,531	109	851	63,386	43,839,540	0.69
KS	36,483	2,088	16	10,369	11	1,153	-	50,119	36,493,939	0.73
CO	36,364	14,608	8	-	2,219	1,284	75	54,557	42,090,225	0.77
IA	38,296	2,924	125	4,519	962	2,757	113	49,697	38,770,274	0.78
DE	5,643	1,644	226	-	-	-	1,021	8,534	6,870,418	0.81
MO	75,246	4,833	7	9,372	1,588	-	22	91,067	75,498,575	0.83
NM	27,668	6,624	0	-	268	1,393	22	35,975	29,965,509	0.83
OH	134,551	3,924	14	15,764	620	15	462	155,349	133,053,582	0.86
UT	37,208	6,611	6	-	542	-	200	44,566	39,336,311	0.88
ND	29,208	0	5	-	1,305	608	86	31,211	28,490,458	0.91
WY	43,207	850	0	-	730	763	92	45,642	42,511,566	0.93
IN	124,042	3,645	17	-	450	-	3,440	131,594	124,045,512	0.94
KY	93,339	1,686	1	-	1,669	-	471	97,166	91,892,133	0.95
WV	92,153	358	0	-	1,178	168	-	93,856	89,919,832	0.96
USA	**2,047,879**	**895,935**	**46,861**	**806,425**	**272,045**	**34,437**	**86,455**	**4,190,037**	**2,474,660,301**	**0.59**

Source: SNL and UBS, 2007A

Appendix II: Total Sales & Average Retail Rates, by US State

Table 37: Total Sales & Average Retail Rates, by US State

	Sales (MWh)				Average Retail Price (c/kWh)			
	Residential	Commercial	Industrial	All Sectors	Residential	Commercial	Industrial	All Sectors
AK	2,125,228	2,837,527	1,350,718	6,313,473	16.35	13.33	14.04	14.50
AL	32,298,384	22,244,168	34,656,698	89,199,251	10.36	9.85	6.18	8.61
AR	17,421,059	11,703,967	17,076,188	46,201,216	9.46	7.76	6.04	7.76
AZ	33,228,805	30,516,295	12,688,987	76,434,088	10.25	8.86	6.60	9.09
CA	91,202,397	124,893,763	50,085,267	267,048,752	14.40	13.05	10.20	12.96
CO	17,599,387	20,562,072	13,161,904	51,371,953	10.15	8.56	6.65	8.61
CT	12,994,088	15,517,443	4,958,137	33,660,101	19.36	15.93	13.90	16.95
DC	1,915,641	9,131,317	257,048	11,616,232	12.68	13.64	11.52	13.49
DE	4,415,829	4,323,188	2,988,534	11,727,551	13.91	12.04	10.09	12.25
FL	114,778,530	93,211,529	18,911,487	226,987,440	11.67	10.20	8.36	10.79
GA	55,678,922	46,870,224	32,513,157	135,243,879	10.06	9.19	6.76	8.96
HI	3,085,180	3,500,539	3,804,287	10,390,008	32.50	29.72	26.05	29.20
IA	13,909,879	11,694,513	19,163,569	44,767,963	9.72	7.28	4.86	7.00
ID	8,508,840	6,077,494	9,324,285	23,910,621	7.01	5.72	4.49	5.70
IL	46,502,455	71,259,711	26,452,326	144,754,607	11.07	8.53	7.83	9.21
IN	33,846,929	24,465,030	48,170,837	106,502,322	8.93	7.81	5.51	7.12
KS	13,458,451	15,021,686	10,170,283	38,650,422	8.98	7.55	5.79	7.59
KY	27,434,486	19,676,784	46,294,603	93,405,876	7.97	7.25	4.81	6.25
LA	28,837,446	22,890,728	26,844,760	78,578,111	10.36	10.16	7.97	9.48
MA	19,702,947	26,582,129	9,037,990	55,682,477	17.50	16.05	14.21	16.22
MD	27,250,418	29,532,916	6,099,065	63,410,981	13.81	12.82	10.40	13.01
ME	4,669,831	4,312,072	3,789,849	12,771,750	15.96	12.95	11.80	13.71
MI	34,263,869	39,265,469	32,149,130	105,683,362	10.93	9.43	6.86	9.14
MN	22,012,735	22,300,314	23,294,825	67,629,743	9.79	7.86	5.96	7.83
MO	35,142,081	31,059,523	17,877,505	84,102,860	8.03	6.59	4.98	6.85
MS	18,431,437	13,293,795	16,376,391	48,101,620	10.30	9.98	6.53	8.93
MT	4,651,806	4,803,796	7,730,918	17,186,521	9.14	8.54	5.73	7.44
NC	55,862,454	46,529,593	27,629,140	130,026,236	9.72	7.67	5.62	8.12
ND	4,275,007	4,451,781	3,811,686	12,538,476	7.48	6.80	5.50	6.64
NE	9,745,395	9,374,614	9,560,482	28,680,489	7.82	6.64	5.05	6.51
NH	4,395,382	4,514,843	2,063,315	10,973,542	15.69	14.28	13.17	14.64
NJ	29,026,261	40,318,253	9,276,991	78,919,628	15.95	14.72	12.42	14.91
NM	6,408,333	9,006,410	6,712,236	22,126,980	10.02	8.56	6.31	8.30
NV	12,060,240	9,344,670	13,810,433	35,223,613	11.93	10.15	7.99	9.91
NY	49,395,059	77,408,250	14,661,018	144,382,513	18.79	16.45	11.97	16.74
OH	53,288,120	47,252,559	58,554,549	159,142,629	10.13	9.26	6.23	8.44
OK	21,747,581	18,766,068	14,923,219	55,436,867	9.25	8.04	6.01	7.97
OR	19,780,216	16,244,349	12,963,957	49,007,565	8.52	7.59	4.91	7.26
PA	54,007,984	47,346,494	48,140,118	150,357,338	11.39	9.42	7.02	9.35
RI	3,042,684	3,665,054	1,076,227	7,783,968	17.57	15.49	14.22	16.13
SC	29,717,888	21,331,362	29,586,732	80,635,984	9.99	8.53	5.42	7.93
SD	4,370,007	4,267,952	2,256,019	10,893,979	8.22	6.83	5.30	7.07
TN	41,876,541	29,386,148	32,941,473	104,206,080	8.81	9.02	6.13	8.02
TX	126,715,278	111,639,935	96,351,284	334,775,042	12.92	10.71	8.86	11.01
UT	8,740,694	10,222,861	9,092,156	28,088,685	8.30	6.72	4.59	6.53
VA	44,764,714	46,847,464	18,410,677	110,216,920	9.69	7.38	5.83	8.06
VT	2,131,050	2,028,312	1,584,252	5,743,614	14.62	12.51	9.00	12.32
WA	36,208,533	29,490,822	24,446,333	90,147,249	7.58	6.79	5.23	6.69
WI	21,906,195	23,349,574	24,752,504	70,008,276	11.60	9.28	6.54	9.04
WV	11,756,109	7,706,240	14,736,530	34,203,311	7.03	6.06	4.20	5.59
WY	2,718,530	4,411,705	9,579,873	16,710,108	8.18	6.70	4.51	5.68
US Total	**1,379,307,315**	**1,352,453,305**	**982,149,952**	**3,721,562,272**	**11.36**	**10.28**	**7.01**	**9.82**

Source: EIA

SB_GT&S_0045723

Appendix III: Carbon Intensities by Company

Table 38: Carbon Intensities by Company

	Fuel Type Output (GWh)							Approximate CO2 Emissions (tons)				CO2 tons/ MWh
	Coal	Gas	Nuclear	Water	Wind	Oil	Total	Coal	Gas	Oil	Total	
	Competitive Integrated											
AEE	67,324	525	9,379	1,752	-	3	78,982	65,573,525	238,344	2,102	65,813,971	0.83
AYE	43,929	116	-	1,188	-	1	45,233	42,786,616	52,513	414	42,839,543	0.95
CEG	16,233	364	32,094	742	-	203	49,731	15,811,306	165,241	147,359	16,123,906	0.32
D	48,920	10,646	45,493	2,329	114	1,005	108,996	47,647,939	4,833,386	729,422	53,210,747	0.49
EIX	36,272	13,185	16,659	2,666	1,110	32	69,924	35,328,729	5,985,964	23,189	41,337,883	0.59
ETR	16,439	26,628	79,691	197	94	0	123,048	16,011,190	12,088,894	16	28,100,100	0.23
EXC	7,805	769	139,366	4,131	-	424	152,723	7,602,012	349,319	307,871	8,259,202	0.05
FE	48,957	57	32,185	1,112	-	0	82,312	47,683,992	25,965	264	47,710,221	0.58
FPL	6,712	76,238	43,740	515	10,681	9,102	147,390	6,537,467	34,612,093	6,608,136	47,757,696	0.32
PPL	26,466	2,230	17,136	3,133	-	343	49,309	25,778,300	1,012,346	249,325	27,039,971	0.55
PEG	13,032	21,023	29,329	364	-	830	64,578	12,693,308	9,544,527	602,459	22,840,295	0.35
SRE	-	17,011	3,078	-	-	-	20,089	-	7,722,917	-	7,722,917	0.38
Total / Avg	332,089	168,792	448,149	18,130	11,999	11,943	992,313	323,454,384	76,631,507	8,670,559	408,756,450	0.47
	Independent Power Producers											
AES	31,326	8,324	-	-	1,643	14	41,308	30,511,994	3,779,264	9,991	34,301,250	0.83
CPN		81,742					87,762	-	37,110,904	-	37,110,904	0.42
DYN	23,283	18,659	-	-	-	477	42,419	22,677,455	8,471,126	346,619	31,495,199	0.74
MIR	14,575	1,957	-	-	-	2,400	18,931	14,195,696	888,483	1,742,067	16,826,247	0.89
NRG	54,653	7,113	9,457	-	39	514	71,776	53,231,816	3,229,517	373,028	56,834,362	0.79
RRI	23,530	7,367	-	-	-	109	31,006	22,917,796	3,344,609	79,408	26,341,813	0.85
Total / Avg	147,369	125,167	9,462	6	1,689	3,522	293,202	143,534,759	56,823,903	2,551,112	202,909,775	0.75
	Regulated Integrated							CO2 Emissions (tons)				
AEP	159,178	10,430	15,036	1,332	959	0	186,935	155,039,416	4,735,032	20	159,774,468	0.85
LNT	17,516	1,025	-	256	30	15	18,857	17,060,453	465,562	10,913	17,536,929	0.93
DPL	15,504	92	-	-	-	0	15,597	15,101,328	41,785	179	15,143,293	0.97
DUK	101,532	4,562	40,903	5,028	73	2	152,100	98,891,863	2,071,318	1,319	100,964,501	0.66
DTE	41,391	405	9,613	1,355	-	- 4	52,935	40,314,823	183,691	- 2,867	40,495,647	0.77
EDE	2,272	1,437	-	33	-	-	3,742	2,212,954	652,588	-	2,865,542	0.77
GXP	19,831	510	3,994	-	419	- 2	24,752	19,315,016	231,673	- 1,157	19,545,533	0.79
PCG	-	504	17,096	8,577	-	15	26,191	-	228,608	10,737	239,344	0.01
PNW	13,166	6,345	8,512	-	-	1	28,034	12,823,413	2,880,836	449	15,704,698	0.56
PGN	42,624	15,379	30,565	429	-	4,325	93,322	41,515,489	6,982,056	3,140,039	51,637,583	0.55
PNM	7,495	2,865	2,986	-	6	0	13,352	7,300,216	1,300,590	2	8,600,808	0.64
SCG	16,270	3,271	4,785	927	-	0	25,794	15,846,976	1,484,919	13	17,331,908	0.67
SRP	5,805	13,735	-	29	-	- 1	19,569	5,654,372	6,235,754	- 817	11,889,310	0.61
SO	133,713	32,971	29,172	3,707	-	10	199,573	130,236,469	14,968,770	7,220	145,212,459	0.73
TE	10,225	7,536	-	-	-	19	17,780	9,959,196	3,421,528	13,456	13,394,181	0.75
WR	22,383	2,151	3,994	-	0	0	28,528	21,801,275	976,731	40	22,778,046	0.80
WEC	18,771	1,846	-	450	207	1	21,275	18,283,016	838,201	436	19,121,653	0.90
XEL	51,440	11,151	12,993	942	85	5	77,101	50,102,587	5,062,703	3,676	55,168,967	0.72
Total / Avg	679,116	116,217	179,650	23,065	1,780	4,385	1,005,438	661,458,863	52,762,344	3,183,660	717,404,868	0.70

Source: SNL and UBS estimates; columns may not add due to other generation sources not listed

Table 39: Entire UBS Electric Utilities Universe Comparables Table

2/21/10	Rating	Market Cap. ($ in millions)	Price	Price Target	Total Return	Dividend Yield	P/E multiple 2009E	P/E multiple 2010E	P/E multiple 2011E	P/E multiple 2012E	Earnings Per Share 2010E	Earnings Per Share 2011E	Earnings Per Share 2012E	Earnings Per Share 2013E	EV / EBITDA multiple 2009E	EV / EBITDA multiple 2010E	EV / EBITDA multiple 2011E	EV / EBITDA multiple 2012E
COMPETITIVE INTEGRATED																		
Ameren Corp.	Not Rated	6,089	25.65	NA	NA	6.0%	9.2	10.8	11.7	nm	2.37	2.19	2.25		6.6	6.4	6.3	
Allegheny Energy Inc.	Not Rated	3,959	23.35	NA	NA	2.6%	10.2	10.2	9.2	9.5	2.29	2.53	2.21	2.47	6.8	6.4	6.2	
Constellation Energy Group	Neutral (CBE)	6,944	34.58	34.00	1.1%	2.8%	10.5	10.3	10.4	11.6	3.36	3.34	2.90	2.97	7.3	7.5	7.4	7.7
Dominion Resources	Neutral	23,394	39.17	38.00	1.7%	4.7%	12.2	12.1	11.9	10.3	3.24	3.30	3.49	3.82	9.0	8.8	8.5	7.5
DTE Energy Co.	Neutral	7,356	44.60	43.00	1.2%	4.8%	13.5	13.1	12.3	10.9	3.40	3.64	3.86	4.10	7.1	6.9	6.6	6.1
Edison International	Not Rated	11,156	34.24	NA	NA	3.7%	11.3	11.3	10.4	11.1	3.03	3.30	3.25	3.08	5.6	5.4	4.8	4.2
Entergy Corp.	Buy	14,893	78.75	88.00	15.7%	4.0%	12.9	12.1	11.6	11.4	6.52	6.81	7.00	6.94	8.8	8.6	8.4	8.4
Exelon Corp.	Buy	29,612	44.88	56.00	29.5%	4.7%	11.1	11.7	9.8	10.1	3.84	4.57	4.12	4.44	6.2	6.3	6.3	6.2
FirstEnergy Corp.	Not Rated	12,102	39.70	NA	NA	5.5%	11.0	11.0	9.7	9.0	3.60	4.08	4.32	4.42	6.8	6.4	6.4	
FPL Group Inc.	Not Rated	19,378	46.88	NA	NA	4.0%	10.7	10.7	10.1	9.3	4.37	4.63	4.93	5.02	7.7	7.2	6.6	5.9
PPL Corporation	Buy	11,246	29.86	37.00	28.6%	4.7%	15.2	8.6	9.2	9.3	3.48	3.24	3.36	3.23	9.6	6.9	7.1	6.8
Public Service Enterprise Group	Neutral	15,777	31.18	35.00	16.6%	4.4%	10.3	9.9	9.7	9.7	3.15	3.21	3.17	3.21	6.3	5.9	5.7	5.7
Sempra Energy	Buy	12,042	48.95	64.00	34.2%	3.5%	10.5	9.6	9.3	8.5	5.11	5.28	5.49	5.79	8.9	6.8	6.5	5.6
Average						**4.3%**	**11.4**	**10.9**	**10.4**	**10.0**	**3.67**	**3.86**	**3.87**	**4.12**	**7.4**	**6.9**	**6.7**	**6.4**
REGULATED INTEGRATED UTILITIES																		
American Electric Power, Inc.	Buy	16,217	33.97	39.00	19.8%	5.0%	11.5	11.0	10.3	9.2	3.10	3.31	3.48	3.70	7.6	7.2	7.0	6.7
Alliant Energy Corp.	Not Rated	3,587	32.42	NA	NA	4.6%	12.7	12.7	11.5	nm	2.55	2.83			6.7	6.2		
CMS Energy	Not Rated	3,546	15.58	NA	NA	3.2%	12.5	12.5	11.5	10.1	1.25	1.35	1.47	1.55	7.2	6.7	6.4	
DPL Inc.	Not Rated	3,245	27.28	NA	NA	4.2%	13.6	11.0	10.5	nm	2.47	2.60	2.43		6.9	6.3		
Duke Energy	Neutral	21,742	16.61	16.50	5.3%	5.9%	14.0	13.1	12.5	11.1	1.27	1.33	1.43	1.49	9.0	8.2	7.6	6.4
Empire District Electric Company	Neutral	671	18.70	18.00	3.1%	6.8%	15.9	14.1	13.0	11.3	1.32	1.44	1.60	1.65	9.2	7.8	7.3	6.8
Great Plains Energy	Not Rated	2,469	18.25	NA	NA	4.5%	15.7	15.7	12.9	9.0	1.16	1.41	1.78	2.03	8.5	7.3	6.1	
Hawaiian Electric Industries	Not Rated	1,843	19.92	NA	NA	6.2%	14.0	14.0	10.0	nm	1.42	2.00			6.4			
OGE Energy	Not Rated	3,628	37.40	NA	NA	3.8%	12.9	12.9	12.3	nm	2.90	3.05			9.6	6.9		
PG&E Corporation	Buy	15,791	42.61	50.00	21.6%	4.2%	13.2	12.6	11.4	10.1	3.39	3.75	3.90	4.21	6.1	5.6	5.1	4.4
Pinnacle West Capital Co.	Neutral	3,791	37.37	37.00	4.6%	5.6%	15.9	12.4	12.6	10.9	3.01	2.97	3.42	3.43	8.0	6.8	6.7	6.1
Progress Energy Inc.	Neutral	10,824	38.52	38.00	5.1%	6.4%	12.8	13.0	12.1	11.6	2.97	3.18	3.23	3.32	7.8	7.6	7.2	6.6
PNM Resources Inc.	Not Rated	1,091	12.59	NA	NA	4.0%	15.5	15.5	18.2	9.7	0.81	0.69	1.04	1.30	8.8	8.6	7.6	
SCANA Corp.	Not Rated	4,464	36.25	NA	NA	5.2%	12.4	12.4	11.0	10.3	2.93	3.31	3.46	3.51				
NV Energy Inc	Not Rated	2,713	11.56	NA	NA	3.8%	11.6	11.6	10.9	8.6	1.00	1.06	1.22	1.35				
Southern Company	Neutral	26,478	32.29	32.00	4.5%	5.4%	14.0	13.6	12.9	11.5	2.38	2.50	2.65	2.81	8.6	7.9	7.2	6.3
TECO Energy Inc.	Neutral	3,342	15.64	15.50	4.2%	5.1%	14.7	11.7	12.8	12.2	1.34	1.23	1.51	1.28	6.2	5.9	6.4	6.4
Westar Energy, Inc.	Neutral	2,415	22.18	22.00	4.9%	5.7%	15.3	12.6	12.0	10.3	1.75	1.85	1.99	2.15	9.0	7.9	7.4	6.5
Wisconsin Energy Corp.	Neutral	5,822	49.80	53.00	9.6%	3.2%	15.9	13.3	12.3	10.6	3.74	4.04	4.50	4.72	11.0	10.8	10.3	8.9
Xcel Energy Inc.	Not Rated	9,618	21.08	NA	NA	4.6%	13.0	13.0	12.2	nm	1.62	1.73	1.83					
Average						**4.9%**	**13.9**	**12.9**	**12.1**	**10.4**	**2.12**	**2.28**	**2.41**	**2.57**	**8.0**	**7.4**	**7.1**	**6.5**
REGULATED T&D UTILITIES																		
CenterPoint Energy Inc.	Buy	5,672	14.53	17.00	22.4%	5.4%	14.2	13.0	12.3	10.9	1.12	1.18	1.28	1.33	9.7	9.2	8.9	8.4
ITC Holdings Corp	Not Rated	2,753	55.06	NA	NA	2.3%	21.5	21.5	20.5	13.1	2.56	2.68	3.35	4.19	11.7	11.7	11.0	9.3
Consolidated Edison	Neutral	11,876	43.13	46.00	12.2%	5.5%	13.4	12.5	12.1	10.8	3.44	3.57	3.79	4.00	7.8	7.8	7.0	6.5
Northeast Utilities	Neutral	4,679	26.67	27.00	5.0%	3.7%	14.3	13.7	12.4	10.7	1.95	2.15	2.39	2.48	7.9	7.9	7.5	7.0
NSTAR, Inc.	Not Rated	3,693	34.58	NA	NA	4.3%	13.7	13.7	13.0	11.3	2.52	2.67	2.83	3.06	7.1	7.1	6.7	6.2
PEPCO Holdings Inc.	Not Rated	3,794	17.12	NA	NA	6.3%	18.2	18.2	13.2	11.6	0.94	1.30	1.38	1.48	8.8	8.8	7.7	7.0
Average						**4.6%**	**15.9**	**15.4**	**13.9**	**11.4**	**2.09**	**2.26**		**2.76**	**8.8**	**8.8**	**8.1**	**7.4**
									Enterprise Value		**EBITDA 2010E**	**EBITDA 2011E**	**EBITDA 2012E**	**EBITDA 2013E**	**2010E**	**2011E**	**2012E**	**2013E**
INDEPENDENT POWER PRODUCERS																		
AES Corporation	Not Rated	8,130	12.18	NA	NA				23,207		5,032	4,645	-	-	5.1	4.6	5.0	
Dynegy, Inc.	Sell (CBE)	1,395	1.65	1.30	-21.2%				6,506		507	641	617	616	8.8	12.8	10.2	10.6
Mirant Corp	Sell	1,952	13.45	15.00	11.5%				3,811		600	458	343	385	4.4	6.4	8.3	9.9
Calpine Corporation	Buy	5,021	11.35	11.50	1.3%				13,313		1,530	1,719	1,723	1,707	7.7	8.7	7.7	7.8
NRG Energy Inc.	Neutral	5,949	23.20	26.00	12.1%				14,227		2,200	1,829	2,036	1,946	5.4	6.5	7.8	7.3
RRI Energy Inc.	Neutral (CBE)	1,697	4.81	6.00	24.7%				3,648		439	508	314	327		8.3	7.2	11.2
Average									**64,712**		**1,718**	**1,633**	**839**	**830**	**6.3**	**7.9**	**7.7**	**9.3**

Source: FactSet (for Not Rated companies) and UBS estimates

Company Pages

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UBS Investment Research

Calpine Corporation

De-Risking Drives Benefits- Upgrade to Buy

■ **Upgrading to Buy as Calpine gets back on its feet**

Following its emergence from Ch.11 in early '08, CPN mgmt has been swift to address paying down debt & refinancing on less onerous terms, focusing on de-risking the business model as it attempts to secure contracts for existing assets. We see the 7.25% covenant-lite exchange in Oct. as exemplifying our confidence in mgmt; despite the positive outcome, CPN shares have traded flat since.

■ **Raising EBITDA ests. to reflect extensive review; LT contracting is focus**

We are also raising our Adj EBITDA ests. to reflect the added confidence we have in the company's ability to maintain its current commodity margin; we believe the wide range in ests should narrow as disclosures on LT margins improve. Further, we believe the company's efforts to engage in LT contracting should bolster the stability of its cash flows and LT margins. While ascribing no value yet, we see merits to its soon to be fleshed-out geothermal expansion at the Geysers.

■ **Volumetric upside is key to long term value; carbon likely the key driver**

With a distinctly different risk/growth profile than its peers, CPN's longer term growth driver is most tightly linked to increasing reliance on natural gas generation (and rising volumes as it takes share from mid-merit coal), as well as rising heat rates. CPN has materially less exposure to gas prices than peers and note the offset of higher capacity factors & delta hedging to a low gas price world.

■ **Valuation: Raising PT to $14, as premium to IPPs warranted**

Our higher PT reflects our newfound confidence in both mgmt's ability to successfully delever/refinance to arrive at situation where it could begin repurchasing shares in 2-3 years times, as well as our higher level of confidence in its ability to maintain its EBITDA profile in outer years.

Highlights (US$m)	12/07	12/08	12/09E	12/10E	12/11E
Revenues	7,970	10,515	7,165	8,324	8,448
EBIT (UBS)	705	1,266	1,217	959	1,129
Net Income (UBS)	2,693	565	240	101	203
EPS (UBS, US$)	5.62	1.16	0.49	0.21	0.42
Net DPS (UBS, US$)	0.00	0.00	0.00	0.00	0.00

Profitability & Valuation	5-yr hist av.	12/08	12/09E	12/10E	12/11E
EBIT margin %	-	12.0	17.0	11.5	13.4
ROIC (EBIT) %	-	10.5	10.3	8.2	9.7
EV/EBITDA (core) x	-	7.8	7.2	7.9	7.0
PE (UBS) x	-	1.8	23.0	54.6	27.1
Net dividend yield %	-	0.0	0.0	0.0	0.0

Source: Company accounts, Thomson Reuters, UBS estimates. (UBS) valuations are stated before goodwill-related charges and other adjustments for abnormal and economic items at the analysts' judgement.

Valuations: based on an average share price that year, (E): based on a share price of US$11.35 on 19 Feb 2010 19:35 EST

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Global Equity Research

Americas

Electric Utilities

12-month rating	**Buy**
	Prior: Neutral
12m price target	**US$14.00**
	Prior: US$11.50
Price	**US$11.35**

RIC: CPN.N BBG: CPN US

Trading data	
52-wk range	US$14.68-4.78
Market cap.	US$5.10bn
Shares o/s	449m (COM)
Free float	70%
Avg. daily volume ('000)	738
Avg. daily value (US$m)	8.3

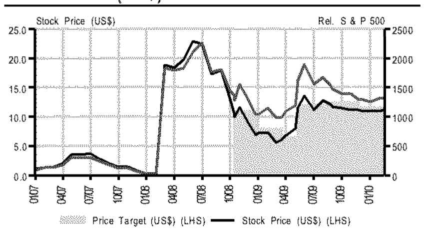
Balance sheet data 12/09E	
Shareholders' equity	US$4.61bn
P/BV (UBS)	1.2x
Net Cash (debt)	(US$8.49bn)

Forecast returns	
Forecast price appreciation	+23.3%
Forecast dividend yield	0.0%
Forecast stock return	+23.3%
Market return assumption	5.9%
Forecast excess return	+17.4%

EPS (UBS, US$)

	12/09E			12/08
	From	To	Cons.	Actual
Q1	0.07	0.07	(0.19)	(0.44)
Q2	(0.16)	(0.16)	0.10	0.41
Q3	0.55	0.55	0.40	0.65
Q4E	0.40	(0.04)	(0.02)	0.55
12/09E	0.93	0.49	*0.28*	
12/10E	0.73	0.21	*0.30*	

Performance (US$)



Source: UBS

www.ubs.com/investmentresearch

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Investment Summary

We are upgrading Calpine shares to Buy from Neutral, and raising our price target to $14 from $11.50 following a thorough re-evaluation of our model and of the company's hedge profile. We now feel more comfortable than previously with the company's hedged margin and do not anticipate any kind of "cliff" in EBITDA beyond its current hedge disclosures (2012+). Alternatively, we see 2010 as a trough year for EBITDA and anticipate growth through 2013 from here (in sharp contrast to many of its IPP peers). Further, we continue to view Calpine as the best positioned IPP in the sector to benefit from the long term conversion to natural gas generation in the US. While the stock looks expensive versus peers, we think it deserves a sizable premium given the long term volumetric upside its fleet is likely to benefit from and due to its stronger than anticipated LT hedge profile; that said, a further unique aspect to Calpine's fleet remains the improved volumetric offset its fleet benefits from in a weak gas price environment (as seen this year in the Southeast with coal to gas switching). Following the company's emergence from bankruptcy in 2008, it has aggressively paid down debt and will likely succeed in refinancing its entire Term loan obligations over the next 24-36 months, providing management with the ability to repurchase shares. We believe the company is attractively positioned, particularly in its sizable California market. Further, Calpine is among a few IPPs with organic growth opportunities to increase EBITDA independent of the commodity cycle, having recently won a contract with PG&E to upgrade an existing site. In the near term, we anticipate the company to detail its intentions to use the 30% ITC cash grants to develop several new geothermal plants at its Geyer fields in Northern California.

We are upgrading CPN to Buy from Neutral, raising our PT to $14

The company benefits from:
- **cont'd EBITDA growth from '10-'13**
- **Volumetric upside on generation**
- **Strong FCF position to de-lever**
- **Organic growth opportunities**

Our new price target of $14 is derived using an average of SOP and DCF analyses, ascribing a peer 8.5x EV/EBITDA multiple on '11E EBITDA. We anticipate the stock to outperform peers as investors focus on 2011 EBITDA growth (10% over 2010's trough) and as a more normalized trading pattern is established following the selling down of Harbinger's (Calpine's largest shareholder) stake in the company, and as the company is able to execute on its continued deleveraging program.

Calpine's business model is unique amongst IPPs, with primary commodity exposure to spark spreads in Texas & California

Calpine benefits from unique exposure to heat rates, gas prices, and volumetric upside

Calpine's unique position as a nearly strictly CCGT (combined cycle) operator gives the company significantly more exposure to recovery in heat rates (e.g., power supply & demand fundamentals) than does its baseload IPP peers. Its positioning as a combined cycle operator leaves Calpine ideally placed to increase capacity utilization (forecast to average 48% in 2009) should power demand experience a recovery out of the recession. Furthermore, its units are new (and therefore have long asset lives remaining), possess limited exposure to environmental regulation (carbon, CAIR, etc.), and are flexibly dispatched to meet varying load in the day (ideal for a volatile commodity environment).

Load recovery elusive in near term; 2010 is a trough EBITDA year

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We do not necessarily anticipate a significant recovery in power demand in our estimates and alternatively believe an improvement in commodity prices will offset Calpine's lower volumes (particularly at its Southeastern fleet) given the lack of a coal-to-gas switching phenomenon. Longer term, we see the value of its CCGT units as most likely being bolstered by the need for backup generation to load follow renewables (wind tends to reach its highest output in offpeak hours) and to meet incremental load growth. Offsetting this trend, however, looms increased energy efficiency mandates and more aggressive implementation of demand side management efforts.

2010 should prove a trough EBITDA year for Calpine as depressed heat rates and lower gas prices moderately depress results

Maintaining a flat EBITDA profile is good in this environment

In contrast to the backwardated EBITDA profiles of many of its IPP peers, we forecast a relatively flat EBITDA profile with a peak in 2012-13 before beginning to fall off marginally. We note management's decision to provide its 2012 hedge profile helps to convey confidence concerning its long term hedge position and price. To further contrast Calpine with its IPP peers, we anticipate EBITDA growth from 2011-13, as both our commodity forecast and current forwards point to a modest recovery in both heat rates and gas prices. We contrast our EBITDA growth rate against the balance of the IPP peers in Table 40 below.

Calpine's relatively limited degree of deep in the money hedges beyond 2010 warrants a premium multiple to peers

Table 40: IPP EBITDA Growth Comparison

	2010	*2011*	*2012*	*2013*	*2014*	*5-year CAGR*
CPN	1,530	1,721	1,723	1,701	1,691	-1%
% Δ	-12%	12%	0%	-1%	-1%	
DYN	507	634	611	609	467	-9%
% Δ	-32%	25%	-4%	0%	-23%	
MIR	600	458	343	385	336	-17%
% Δ	-31%	-24%	-25%	12%	-13%	
NRG	2,200	1,829	2,036	1,946	1,777	-7%
% Δ	-16%	-17%	11%	-4%	-9%	
RRI	439	508	314	327	291	30%
% Δ	465%	16%	-38%	4%	-11%	

Source: UBS estimates

Complicated business model limits transparency, but provides opportunity for investors

We believe Calpine remains the most difficult of its IPP peers to understand, and with disclosures still improving post-bankruptcy, we see possible improvement over time. Fundamentally the company benefits from a portfolio of long-life contracts (for both steam and energy) on a relatively new asset mix, with exposure primarily oriented towards power demand rather than commodity price volatility. We note our estimates embed marginally lower than current forward heat rates, incorporating the current depressed outlook for power. Given the complexity in understanding its steam revenues and ancillary revenues, we see why investors might have difficulty in forecasting revenue streams and alternatively see the lack of clarity as opportunity for the company to improve its disclosures and in turn improve valuations. Specifically we look towards the company to more clearly delineate its long term contracted profile.

We see misunderstanding of its business model by investors as an opportunity to invest

From long term perspective, Calpine is the most defensive position in the sector to environmental regulation and commodities

Minimal environmental liability leaves company very well positioned; could actually benefit from more stringent requirements

We remind investors that from a liability perspective, Calpine is the least exposed to potential required environmental capex with new units, which generally already meet NOx requirements. This is not to mention additional headaches Calpine's coal-oriented IPP peers will need to address regarding sulfur, mercury, and ash pond compliance. Further, Calpine is the lone IPP that could potentially benefit from carbon legislation, given its relatively low carbon intensity CCGT fleet. We believe investors will likely migrate to the name on news of further environmental standards for coal plants, as the slack in generation from older coal units forced into retirement will likely be replaced with incremental gas generation.

Wind – not the threat it represents to baseload generators?

Wind resources do not represent a significant threat to an on-peak spark spread generator like Calpine

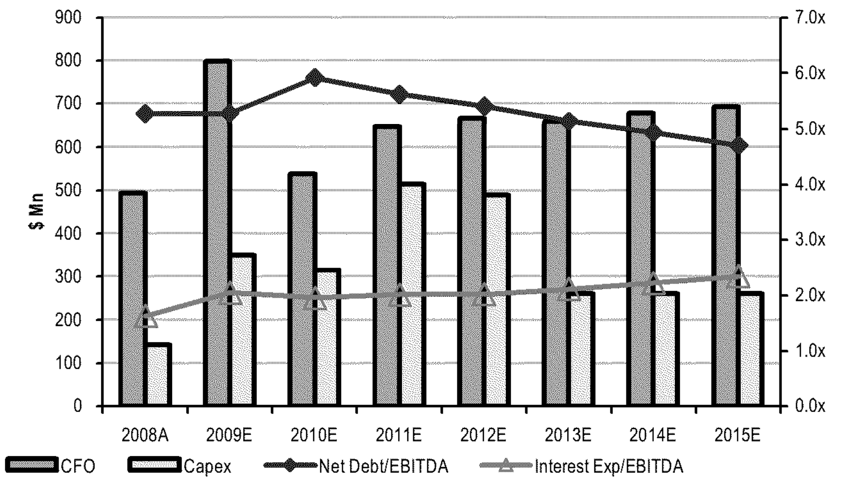
In contrast to Calpine's baseload-heavy IPP peers, we see less of an impact of wind (which tends to blow during both off peak hours and off peak seasons) on Calpine's primarily on-peak spark spreads. Alternatively, we anticipate efforts (particularly in ERCOT) to have wind generators offset the cost of their variability through ancillary and fast revenues as likely proving a further positive offset to the deployment of wind resources. Longer term, we see Calpine's gas fired fleet as the ideal load-following generation to complement the large renewable mandates required by state RPS standards (and likely from an eventual federal standard). A more real concern for us remains several new fossil plants finishing construction in the near term in Texas.

Debt paydown remains management's top priority

We anticipate management will aim to refinance using less restrictive First Lien notes, gradually putting the company in a position to repurchase shares beginning in 2013-14

Management continues to stress it will continue to invest incremental cash flows to pay down debt to arrive at a more manageable Net Debt / EBITDA ratio of ~4.0x (alternatively, it seeks to have an interest coverage ratio of >3.5x). We note the company will likely achieve these metrics by 2014-5, given its hedged position already through 2013 and its inability to dividend or repurchase shares (prior to achieving <2.0x leverage) per its credit agreements. However, we note more importantly the company is likely to refinance its Term Loans with First Lien bonds over the next couple years, removing restrictions from share repurchases. From an equity holder's perspective, the stock therefore remains a strictly capital appreciation story, with the only upside potential coming in the form of organic growth projects and commodity price improvement. We nonetheless believe an improving credit profile and strong free cash flow to support its paydown will prove positive to equity holders. We provide a snapshot of our projected Calpine cash flows in Chart 37.

Chart 37: Projected Calpine Cash Flows and Ratios



Source: UBS estimates

Balancing capital structure and cheap credit

We believe one of management's primary tasks through the coming years will be balancing which debt it chooses to refinance/extend and at what price. We anticipate management will likely opt to continue refinancing its assets at the project finance level (akin to its recent Steamboat & Deer Park financings) as long as it cannot find better terms using its exit facility accordion facility, which is a $2 Bn uncommitted loan that management had negotiated in an attempt to accelerate the collapse of its capital structure.

Recent debt exchange validates our view of lower risk business

October 2009 debt exchange confirms improving outlook for Calpine

Our confidence in Calpine shares was bolstered by the company's ability to perform a debt exchange for First Lien notes against its existing Term loans, exchanging for par $1.2 Bn. The new notes do not encompass the same restrictions on cash flow (e.g., no restriction on share repurchases, no Net Debt/EBITDA test, and no interest coverage ratios) as the exit facility Term Loans did, bringing the company one step closer to returning free cash flow to shareholders as well as locking in a coupon of 7.25%. Despite the impressive terms achieved in the fixed income markets, Calpine shares remain priced at the same level.

Acquisition potential on horizon – PJM is target

CEO Fusco's track record of M&A leaves us wondering what might happen in PJM?

Management continues to highlight its ambitions to acquire PJM assets to diversify the geographic footprint of its generation fleet. While there has been much talk about transactions regarding coal assets in PJM, Calpine management is seemingly sticking with its ambitions to acquire assets with a "green sheen" to them, likely further CCGT units. We also believe Calpine could be a takeout candidate, however believe its outright size coupled with change of control provisions on its bonds should limit buyers to a select few.

Providing Certainty – Aiming to Keep Cash Flow Steady

Two of management's key goals, shifting towards fixed rate debt and contracting assets, are seemingly premised on the same foundation: securing cash flows given the company's relatively leveraged position. In tandem with a focus on collapsing the capital structure and limiting restricted cash, securing cash flows will eventually provide a substantially reduced risk profile. We believe the company is well on its way to emerge as the lowest risk IPP operator and developer in the sector.

Variable Rate exposure is an added risk factor mgmt is addressing

We estimate the company remains weighted towards 70% variable rate financing

While CPN mgmt has engaged in substantial cash flow hedging through interest rate swaps, we note this is perhaps more of a risk factor to CPN's cash flows than peers. Management is acutely aware of its exposure to variable interest rates, and we note the shift from 3Q08 to 3Q09 where interest expense declined to 7.7% from 8.7%. We appreciate the company's exchange of $1.2 Bn of its Term loan to a fixed 7.25% rate First Lien and issuance of new fixed-rate 8% CCFC notes as both a large step in the right direction and at attractive rates. We anticipate the majority of CPN's variable rate exposure to be refinanced as it comes due ($292 Mn of project financing this year and the remaining ~$4.5 Bn of term loans likely by 2013). We anticipate management to likely focus on refinancing its Riverside and Rocky Mountain project financings, maturing in 2011.

Growth Avenues – One of the Few with Real Potential

Given Calpine's restricted ability to repurchase shares or pay dividends, we see organic growth projects as particularly attractive to shareholders

Akin to most of its IPP peers, growth avenues for the sector remain likely limited to the California market. Coupled with the fact that the company is restricted from buying back shares or dividending money, we see organic growth as the near term avenue for delivering real shareholder value. Calpine is already underway developing its Russell City facility in California for which it has a long term PPA agreement with PG&E already (procured through a prior RFO process). This project is anticipated to enter into service in 2012 with 390 MW belonging to Calpine. Calpine is also underway with an upgrade to convert its Los Esteros facility from a 180 CT into a 300 MW CCGT.

More Geysers on the Horizon?

While details are still forthcoming we see incremental investment in Calpine's Geysers field as proving particularly attractive with a 30% ITC cash grant

One unique growth opportunity for the IPP remains its ability to expand its current Geyser field and the longer term potential to open a new geothermal field in extreme northern California. We anticipate details to be forthcoming in the near term on possible expansion opportunities at its existing Geyser field, with the need for 5% of capital expenditures associated with this project to be spent by year end to qualify for the 30% ITC cash grant it anticipates to receive for the project. The company anticipates potentially launching two new fields (totalling a yet unrevealed size).

Glass Mountain project

Glass Mountains is Calpine's potential second geothermal field

Further down the development pike, Calpine is actively litigating a new geothermal field in Northern California where its initial estimates put the potential of the field at 400-500 MW. Calpine currently has two sites permitted for 50 MW each. However, given the litigation the likelihood of those facilities being able to take advantage of 30% cash grant ITCs is unlikely.

EBITDA Estimates

Following a thorough re-examination of our commodity margin methodology, we are significantly increasing our long term EBITDA estimates and profile. We clearly see 2010 EBITDA as a trough year, with a tick-up in 2011 (unique amongst its IPP peers). We forecast long term EBITDA using our current commodity forecast to flatline at approximately $1.7 Bn. A summary by region of our Adjusted EBITDA estimate is included in Table 41.

Table 41: Calpine Adjusted EBITDA Estimates, by Year and Segment

Gross Profit	2007A	2008A	2009E	2010E	2011E	2012E	2013E	2014E
West	841	818	761	735	906	1,013	1,109	1,104
Texas	342	557	551	463	493	475	448	455
Southeast	119	153	350	194	167	133	111	99
North	167	149	124	123	125	103	73	67
Other	(129)	1	(111)	(102)	(105)	(108)	(111)	(115)
Total Gross Profit	**1,340**	**1,678**	**1,676**	**1,413**	**1,586**	**1,616**	**1,629**	**1,611**
Adjustments	105	21	58	117	133	107	78	88
Adjusted EBITDA	**1,445**	**1,699**	**1,734**	**1,530**	**1,719**	**1,723**	**1,707**	**1,698**

Source: Company reports and UBS estimates

EBITDA Sensitivity to Natural Gas Assumptions

In Table 42 we include our estimate of Calpine's Adjusted EBITDA under various natural gas scenarios. We note our above market natural gas deck is the primary contributor to our above consensus EBITDA estimates.

Table 42: Calpine Adjusted EBITDA Sensitivity to Natural Gas Assumption

		Adj. EBITDA - By Year						Price Target
		2010E	2011E	2012E	2013E	2014E	2015E	2011 Hedged EBITDA SOP
	Current	1,530	1,719	1,723	1,707	1,698	1,679	$13.88
	$5.00	$1,530	$1,554	$1,450	$1,370	$1,339	$1,296	$10.9
	$5.50	$1,530	$1,595	$1,518	$1,454	$1,429	$1,392	$11.7
	$6.00	$1,530	$1,637	$1,586	$1,539	$1,519	$1,488	$12.4
	$6.50	$1,530	$1,678	$1,655	$1,623	$1,608	$1,583	$13.1
NYMEX Gas $/MMBtu	**$7.00**	$1,530	$1,719	$1,723	$1,707	$1,698	$1,679	$13.9
	$7.50	$1,530	$1,760	$1,791	$1,792	$1,788	$1,774	$14.6
	$8.00	$1,530	$1,802	$1,860	$1,876	$1,878	$1,870	$15.4
	$8.50	$1,530	$1,843	$1,928	$1,960	$1,968	$1,965	$16.1
	$9.00	$1,530	$1,884	$1,996	$2,044	$2,057	$2,061	$16.8
	$9.50	$1,530	$1,926	$2,065	$2,129	$2,147	$2,156	$17.5
	$10.00	$1,530	$1,967	$2,133	$2,213	$2,237	$2,252	$18.3
Current NYMEX Strip	$5.66	$1,530	$1,658	$1,646	$1,636	$1,653	$1,670	$12.8

Source: NYMEX, UBS estimates

We note our sensitivity to natural gas in 2011 is $93 Mn, in line with management's latest estimate of $88 Mn, and lower than management's 2012 sensitivity of $210 Mn versus our $152 Mn estimate. Our full sensitivities are below:

Table 43: Calpine EBITDA Sensitivity to $1/MMBtu Move in Natural Gas, by Year

$ Mn	2010E	2011E	2012E	2013E	2014E	2015E
Sensitivity to $1 Move	-	83	137	169	180	191

Source: UBS estimates

As part of its hedging strategy, Calpine sells forward gas, leaving open significant heat rate length, particularly in 2010. Should gas prices return to weak levels in 2010, some coal to gas switching could remain, (although unlikely) the associated elevated heat rates could actually improve CPN's margin (e.g. a delta hedging benefit in 2010).

EBITDA Sensitivity to Steam Adjusted Heat Rates

In Table 44 we include our estimate of Calpine's Adjusted EBITDA under various Steam Adjusted Heat Rates. We note steam adjusted heat rates should remain relatively stable assuming the company operates its CCGT units to serve both electric and steam, without use of its auxiliary boilers. Alternatively the sensitivity presented here can be used to determine an approximate impact as well on shifts in the average market heat rate.

Table 44: Calpine Adjusted EBITDA Sensitivity to Steam-Adjusted Heat Rates

		Adj. EBITDA - By Year						Price Target
		2010E	2011E	2012E	2013E	2014E	2015E	2011 Hedged EBITDA SOP
	Current	1,530	1,719	1,723	1,707	1,698	1,679	$13.88
	6.800	$1,530	$1,853	$1,877	$1,886	$1,887	$1,877	$16.3
	6.900	$1,530	$1,823	$1,842	$1,846	$1,844	$1,832	$15.8
	7.000	$1,530	$1,792	$1,807	$1,805	$1,801	$1,787	$15.2
	7.100	$1,530	$1,762	$1,772	$1,765	$1,759	$1,742	$14.7
Steam-Adj Heat Rate	**7.200**	$1,530	$1,732	$1,738	$1,724	$1,716	$1,698	$14.1
	7.300	$1,530	$1,702	$1,703	$1,684	$1,674	$1,653	$13.6
	7.400	$1,530	$1,672	$1,668	$1,644	$1,631	$1,608	$13.0
	7.500	$1,530	$1,641	$1,634	$1,603	$1,588	$1,563	$12.4
	7.600	$1,530	$1,611	$1,599	$1,563	$1,546	$1,518	$11.5
	7.700	$1,530	$1,581	$1,564	$1,522	$1,503	$1,474	$10.7
	7.800	$1,530	$1,551	$1,530	$1,482	$1,461	$1,429	$9.9
		$1,530	$1,232	$1,109	$911	$737	$797	$1.2

Source: UBS estimates

We have also included our sensitivity estimates to changes in steam-adjusted heat rates using Calpine's 172 btu/KWh ($1/MMBtu equivalency factor). We note it is difficult to capture in our model the capacity factor influence of lower market heat rates, which would still be material to Calpine despite its 100% hedged position in 2010; this explains our $0 sensitivity compared with the company's disclosed $33 Mn impact. A full comparison is provided in Table 45.

Table 45: Calpine Heat Rate Sensitivity

$ Mn	2010E	2011E	2012E	2013E	2014E	2015E
Model Sensitivity to .172 HR Δ	-	52	60	70	73	77
Calpine Sensitivity Disclosed	33	66	81			

Source: UBS estimates

Valuation

SOP Valuation

We see Open EBITDA valuation as elusive for Calpine; we stick with DCF and a hedged EBITDA SOP

Our revised $14 12-month price target is derived using an average of DCF and Hedged SOP. We have also provided Open EBITDA valuations of CPN shares using both UBS commodity assumptions and forward curves. However, we believe an Open metric for Calpine remains elusive given its tendency to contract both capacity and energy together for extended periods.

Our SOP ascribes an 8.5x EV/EBITDA multiple on 2011E EBITDA. Despite its above-normalized EBITDA in the year, we ascribe a peer normalized multiple rather than a discount to account for Calpine's volumetric upside potential, lower environmental/carbon risk, and longer remaining asset life to peers. A significant driver of value for the company (similar to several other IPPs) is its relatively large NOL position. Given the large NOL position should commodity markets improve, realization (and the NPV) of these benefits should accelerate with a corresponding impact on valuation. We further believe CPN management is among the best in the industry and anticipate the company's relatively opaque disclosures to improve over time. We further adjust our SOP to account for several operating leases the company has on plants and offices.

Table 46: Calpine SOP Valuation

All figures in US $ million except per share data	2011E Hedged CM/EBITDAR	EV/EBITDA Multiple			Enterprise Value		
		Low	Base	High	Low	Base	High
West	906	7.5x	8.5x	9.5x	$6,797	$7,703	$8,609
Texas	493	7.5x	8.5x	9.5x	3,695	4,188	4,681
North	167	7.5x	8.5x	9.5x	1,250	1,417	1,584
Southeast	125	7.5x	8.5x	9.5x	938	1,063	1,188
Other	(105)	9.5x	8.5x	7.5x	(998)	(893)	(788)
Adj. for Commodity Margin to EBITDA	133	7.5x	8.5x	9.5x	1,001	1,135	1,268
Add Operating Lease Expense	50	7.5x	8.5x	9.5x	375	425	475
Total / Implied	**1,769**	7.4x	8.5x	9.6x	**$13,059**	**$15,038**	**$17,017**
less net debt						(8,396)	
less Operating Leases						(343)	
less Restricted Cash						(505)	
add NPV of NOLs						952	
NPV of Equity					**$4,766**	**$6,746**	**$8,725**
Current Number of Shares outstanding					486	486	486
Equity value per share					**$9.81**	**$13.88**	**$17.95**

Source: UBS estimates

Open EBITDA Valuation

We see Open EBITDA for a company with Calpine's structure as particularly difficult to implement

We have included an Open EBITDA SOP Valuation below for purposes of thoroughness. We note our imputed deep value of Calpine's hedges reflects both the long term nature of its contracts (allowing for new contracts to be priced above market) and the fact it had entered into several of its existing contracts prior to the commodity downturn. Given Calpine's ability to extract seemingly above market value from its longer term hedging program (tolling and PPA contracts for generally ~3-5 years) we believe using an Open EBITDA framework undervalues the EBITDA generation power of the company.

We provide in Table 47 our Open EBITDA framework using UBS Commodity Forward Assumptions.

Table 47: Calpine Open EBITDA SOP Valuation Using UBS Commodity Forward Assumptions

All figures in US $ million except per share data	2011E Open CM/EBITDAR	EV/EBITDA Multiple			Enterprise Value		
		Low	Base	High	Low	Base	High
West	906	8.5x	9.5x	10.5x	$7,703	$8,609	$9,515
Texas	493	8.5x	9.5x	10.5x	4,188	4,681	5,173
North	167	8.5x	9.5x	10.5x	1,417	1,584	1,751
Southeast	125	8.5x	9.5x	10.5x	1,063	1,188	1,313
Other	(105)	10.5x	9.5x	8.5x	(1,103)	(998)	(893)
Adj. from Commodity Margin to EBITDA	133	10.5x	9.5x	8.5x	1,401	1,268	1,135
Add Operating Lease Expense	50	10.5x	9.5x	8.5x	525	475	425
Hedge Impact (Adj. for Steam,etc.)	(294)	8.5x	9.5x	10.5x	(2,500)	(2,794)	(3,088)
Total / Implied	**1,475**	8.6x	9.5x	10.4x	**$12,695**	**$14,013**	**$15,331**
less net debt						(8,396)	
less Operating Leases						(343)	
less Restricted Cash						(505)	
add NPV of NOLs						952	
add Hedge Value NPV						816	
NPV of Equity					**$5,219**	**$6,537**	**$7,855**
Current Number of Shares outstanding					486	486	486
Equity value per share					**$10.74**	**$13.45**	**$16.16**

Source: UBS estimates

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In Table 48 we provide our Open EBITDA SOP valuation using current market forward curves.

Table 48: Calpine Open EBITDA SOP Valuation Using Current Market Forward Assumptions

All figures in US $ million except per share data	2011E Open CM/EBITDAR	EV/EBITDA Multiple			Enterprise Value		
		Low	Base	High	Low	Base	High
West	906	9.5x	10.5x	11.5x	$8,609	$9,515	$10,422
Texas	493	9.5x	10.5x	11.5x	4,681	5,173	5,666
North	167	9.5x	10.5x	11.5x	1,584	1,751	1,917
Southeast	125	9.5x	10.5x	11.5x	1,188	1,313	1,438
Other	(105)	11.5x	10.5x	9.5x	(1,208)	(1,103)	(998)
Adj. from Commodity Margin to EBITDA	133	11.5x	10.5x	9.5x	1,535	1,401	1,268
Hedge Impact	(414)	9.5x	10.5x	11.5x	(3,936)	(4,350)	(4,764)
Total / Implied	**1,305**	9.5x	10.5x	11.5x	**$12,453**	**$13,701**	**$14,949**
less net debt						(8,396)	
less Operating Leases						(343)	
less Restricted Cash						(505)	
add NPV of NOLs						952	
add Hedge Value NPV						748	
NPV of Equity					**$4,908**	**$6,156**	**$7,404**
Current Number of Shares outstanding					486	486	486
Equity value per share					**$10.10**	**$12.66**	**$15.23**

Source: UBS estimates

NOLs, Operating Leases, and Other Valuation Adjustments

We adjust our SOP valuation for Operating Losses, NOLs, and restricted cash

For the purposes of our SOP Valuation, we add back several items to provide a clean valuation. First, we add back Calpine's relatively small Operating Leases (we value its NPV at $344 Mn discounted at our WACC). Second, we take into account its Net Operating Losses (NOLs) and value these using a 40% statutory tax rate and discount this at our WACC to arrive at $1.1 Bn. We further subtract Calpine's restricted cash position against its Net Debt to account for its relatively complicated capital structure, trapping cash at its various subsidiaries and financing vehicles; as of 3Q09, this was $505 Mn.

DCF Valuation

We also use a DCF to derive our $14 price target. We note the company's relatively levered position leaves it more exposed to changes in the cost of issuing debt. We believe as the company leaves behind its bankruptcy legacy and moves towards a more contracted stream of cash flows, the company's Beta should move down (we note MIR has a nominal beta closer to 1.2 and NRG has a 0.85), lowering its WACC and improving its valuation.

Table 49: DCF Valuation for Calpine

All figures in US$ million except per share data	2010E	2011E	2012E	2013E	2014E	2015E
Operating Profit (EBIT)	**1,049**	**1,236**	**1,239**	**1,230**	**1,227**	**1,214**
Taxes	399	470	471	467	466	461
Tax adjusted EBIT	**651**	**766**	**768**	**762**	**761**	**753**
Add: Depreciation & Amortization	454	456	457	451	444	437
Add: deferred taxes	-	-	-	-	-	-
Add: Operating Lease Expense	54	110	47	47	33	30
Less: Incremental Net Working Capital	(16)	(12)	(4)	(34)	(27)	(28)
Less: Capex	(315)	(515)	(490)	(260)	(260)	(260)
Less: Acquisitions / Investments	-	-	-	-	-	-
Unlevered Free Cash Flow	**774**	**695**	**731**	**919**	**918**	**903**
Present Value of Free Cash Flow	713	590	571	661	608	551
Terminal Value						12,938

Cost of debt	
Risk free rate	4.5%
Average debt premium	3.5%
Nominal Cost of Debt	8.0%
Marginal tax rate	38%
Post tax cost of debt	5.0%
Cost of equity	
Risk free rate	4.5%
Equity risk premium (USER INPUT)	6.5%
Equity beta (USER INPUT)	1.6
Cost of equity	14.9%
Cost of preferred stock	6%
Market value of net debt	9,323
Market Value of equity	5,341
Market value of preferred stock	2
Debt weighting	64%
Equity weighting	36%
Preferred stock weighting	0%
WACC	**8.6%**
Growth Rate	**1.5%**
NPV of FCFF	7,365
NPV of TV	7,895
Total NPV	15,259
Less: Net Debt and Preferred Stock	(9,325)
less Operating Leases	(343)
less Restricted Cash	(505)
add NPV of NOLs	952
NPV of Equity	**6,039**
Current Number of Shares outstanding	486
NPV of Equity per share	**$12.4**
Forward value per share	**$13.5**

Source: UBS estimates

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DCF Sensitivities

We have also included sensitivities to our CPN valuation to various changes in drivers to our DCF model. We include a sensitivity table in Table 50 to changes in our WACC and terminal growth rate. Due to the company's relatively high free cash flow position in the near term, its valuation is less sensitive to changes in its WACC.

Table 50: Calpine DCF Valuation Sensitivity to WACC and Terminal Growth Rate

	7.6%	8.1%	**8.6%**	9.1%	9.6%
0.5%	$14.55	$12.75	$11.17	$9.76	$8.49
1.0%	$16.04	$14.02	$12.26	$10.70	$9.32
1.5%	$17.77	$15.48	**$13.50**	$11.77	$10.25
2.0%	$19.82	$17.19	$14.94	$13.00	$11.30
2.5%	$22.26	$19.19	$16.61	$14.41	$12.50

Source: UBS estimates

In Table 51 we include Calpine's DCF sensitivity to changes in Net Debt and cost of debt issuance. We note for a levered company, Calpine enjoyed relatively low costs of capital in 2009 for its large CCFC (8.00%) and First Lien Notes (7.25%, albeit issued at discount).

Table 51: Calpine DCF Valuation Sensitivity to Net Debt / Cap and Nominal Cost of Debt

		Nominal Cost of Debt				
		7.5%	8.0%	**8.5%**	9.0%	9.5%
	48.6%	$9.30	$8.91	$8.53	$8.16	$7.80
	53.6%	$10.75	$10.26	$9.79	$9.34	$8.91
	58.6%	$12.39	$11.78	$11.21	$10.66	$10.13
Net Debt / Cap	**63.6%**	$14.25	$13.50	**$12.79**	$12.12	$11.48
	68.6%	$16.40	$15.47	$14.60	$13.77	$12.99
	73.6%	$18.91	$17.74	$16.66	$15.64	$14.70
	78.6%	$21.88	$20.40	$19.05	$17.79	$16.63

Source: UBS estimates

We have included in Table 52 Calpine's sensitivity to changes in Beta and equity risk premium. We anticipate CPN shares to trade with less volatility as the company reduces operating leverage (e.g., debt), looks to increase its fixed contract positions, and shifts to fixed rate debt. We anticipate CPN's beta could be reduced to near 1.0 in the long term given its asset contracting efforts and delivering targets.

Table 52: Calpine DCF Valuation Sensitivity to Beta and Equity Risk Premium

		Equity Risk Premium				
		5.5%	6.0%	**6.5%**	7.0%	7.5%
	1.30	$18.71	$17.51	$16.40	$15.37	$14.41
	1.40	$17.69	$16.49	$15.37	$14.34	$13.37
	1.50	$16.74	$15.53	$14.41	$13.37	$12.41
Beta	**1.60**	$15.84	$14.62	**$13.50**	$12.47	$11.51
	1.70	$14.99	$13.78	$12.66	$11.62	$10.67
	1.80	$14.19	$12.98	$11.86	$10.83	$9.88
	1.90	$13.44	$12.22	$11.11	$10.08	$9.14

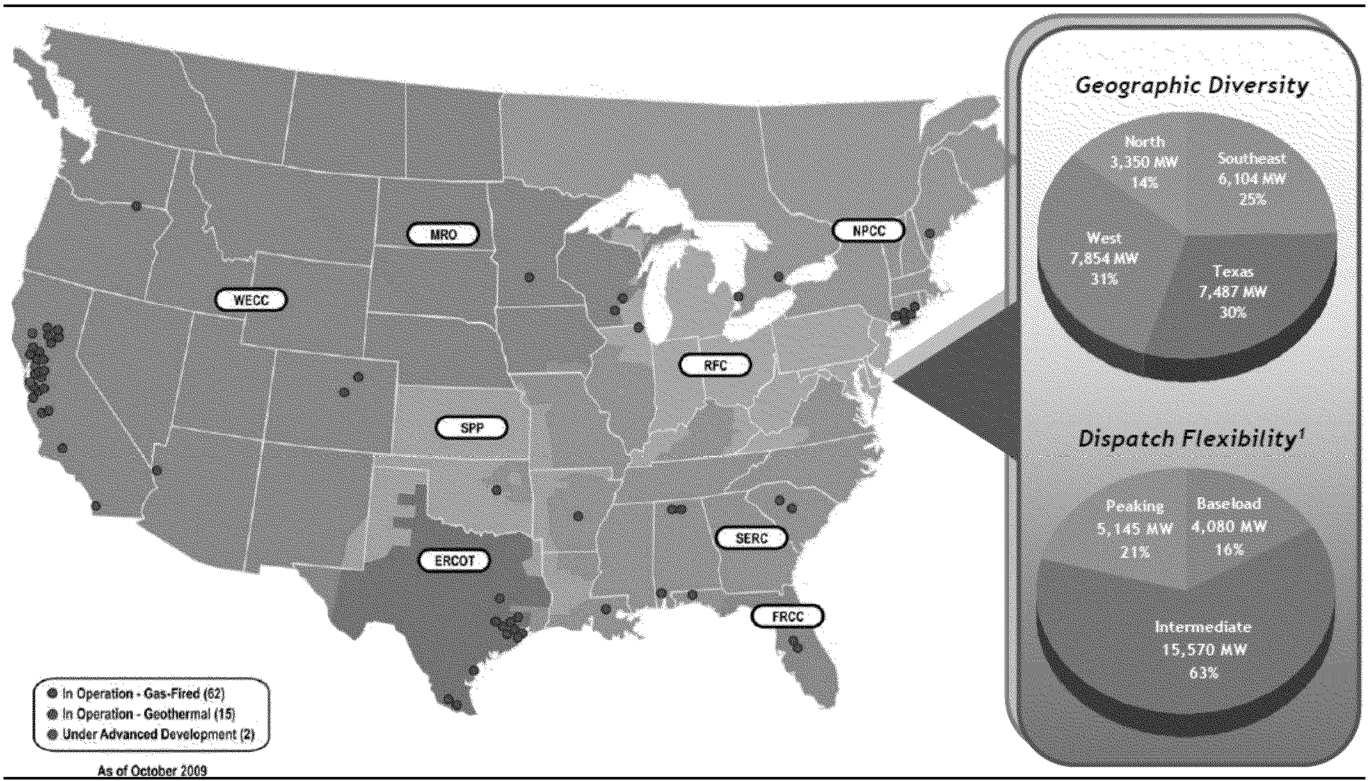
Source: UBS estimates

Company Background

Company Assets

We have provided Calpine's assets plant by region and by asset type (see Figure 3). The vast majority of Calpine's assets are CCGT units, which have a separately reported peaking capacity to them as well. As of Calpine's analyst day (late March 2009), its asset fleet (by MW's) remained ~25% contracted under tolls & PPA's, with a further 34% contracted under combined heating and power agreements. From a contracted energy margin perspective, we estimate CPN has locked in margins of ~$30/MWh for ~35% (and declining) of its fleet in the years beyond its current disclosures.

Figure 3: Calpine Generation Portfolio (MW)



Source: Company reports

Western Region

Calpine's largest region remains its Western fleet, primarily oriented in Northern California. We broke this fleet down between its fossil assets and its geothermal geyser assets. Many of its Western assets receive Local and System Resource Adequacy payments from the CA ISO.

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Table 53: Western Fossil Asset Summary

Plant Name	Location	Type	Capacity (MW)	CCGT	Peaking	08 Gen (GWh)	Implied CF
Agnews Power Plant	San Jose CA	CCGT	28	28	0	234	96%
Delta Energy Center	Pittsburg CA	CCGT	840	818	22	4,826	66%
Greenleaf 1 Power Plant	Yuba City CA	CCGT	50	50	0	231	53%
Greenleaf 2 Power Plant	Yuba City CA	CCGT	49	49	0	229	54%
Hermiston Power Project	Hermiston OR	CCGT	616	547	69	3,720	70%
Los Medanos Energy Center	Pittsburg CA	CCGT	540	512	28	3,172	68%
Metcalf Energy Center	San Jose CA	CCGT	605	564	41	3,219	61%
Pastoria Energy Facility	Lebec CA	CCGT	750	750	0	4,908	75%
Pittsburg Power Plant	Pittsburg CA	CCGT	64	64	0	142	26%
Rocky Mountain Energy Center	Keenesburg CO	CCGT	621	479	142	3,276	61%
South Point Energy Center	Bullhead City AZ	CCGT	520	520	0	2,719	60%
Sutter Energy Center	Yuba City CA	CCGT	578	542	36	2,899	58%
Total CCGT			**5,261**	**4,923**	**338**	**29,574**	
Gilroy Cogeneration Plant	Gilroy CA	Cogen	128	117	11	124	11%
King City Cogeneration Plant	King City CA	Cogen	120	120	0	473	45%
Watsonville (Monterey) Cogeneration Pla	Watsonville CA	Cogen	29	29	0	169	67%
Total Cogen			**277**	**266**	**11**	**766**	
Blue Spruce Energy Center	Aurora CO	Peaker	285			408	16%
Creed Energy Center	Suisun City CA	Peaker	47			16	4%
Feather River Energy Center	Yuba City CA	Peaker	47			27	7%
Gilroy Energy Center	Gilroy CA	Peaker	135			96	8%
Goose Haven Energy Center	Fairfield CA	Peaker	47			15	4%
King City Energy Center	King City CA	Peaker	45			24	6%
Lambie Energy Center	Suisun City CA	Peaker	47			17	4%
Los Esteros Critical Energy Facility	San Jose CA	Peaker	188			83	5%
Riverview Energy Center	Antioch CA	Peaker	47			30	7%
Wolfskill Energy Center	Fairfield CA	Peaker	48			26	6%
Yuba City Energy Center	Yuba City CA	Peaker	47			35	9%
Total Peaking			**983**	**-**	**983**	**776**	
Total Western Fossil			**6,521**	**5,189**	**1,332**	**31,116**	

Source: Company reports and SNL

Calpine has made impressive strides to implement water injection systems to maintain steam pressure through its geothermal turbine fleet. Prior to its majority ownership, the Geysers had experienced declining Net Generation (MW) potential as steam output declined. Calpine reinvests today approximately ~$50 Mn each year to build and maintain the steam resevoirs that are feeding the Geysers. A further benefit of this geothermal power is its ability to generate renewable energy credits (RECs) for which it has long term offtake agreements with several parties, including Pacific Gas & Electric (PG&E) and Southern California Edison (SCE).

Table 54: Western Geyser Assets Summary

Plant Name	Location	Type	Capacity (MW)	CCGT	Peaking	08 Gen (GWh)	Implied CF
Aidlin	Cloverdale CA	Geothermal	17			137	93%
Bear Canyon	Middletown CA	Geothermal	14			116	95%
Big Geysers	Lake County CA	Geothermal	48			436	105%
Calistoga	Lake County CA	Geothermal	66			555	97%
Cobb Creek	Sonoma County CA	Geothermal	52			389	86%
Eagle Rock	Sonoma County CA	Geothermal	66			513	90%
Fumarole #9 & #10 (cold stand-by)	Sonoma County CA	Geothermal	0				
Grant	Sonoma County CA	Geothermal	43			358	96%
Lake View	Sonoma County CA	Geothermal	52			427	95%
McCabe #5 and #6	Sonoma County CA	Geothermal	78			682	101%
Quicksilver	Lake County CA	Geothermal	53			425	92%
Ridge Line #7 and #8	Sonoma County CA	Geothermal	69			601	100%
Socrates	Sonoma County CA	Geothermal	50			406	94%
Sonoma	Sonoma County CA	Geothermal	42			342	94%
Sulphur Springs	Sonoma County CA	Geothermal	51			425	96%
West Ford Flat	Middletown CA	Geothermal	24			210	101%
Total Geysers			**725**			**6,021**	**96%**
Total West (Geysers & Fossil)			**7,246**	**5,189**	**1,332**	**37,137**	**59%**

Source: Company reports and SNL

Texas Region

Calpine's second largest region is in the ERCOT-Houston zone of Texas. For this region, we derive our spark spread off of the gas price from the Houston Shipping Channel. We note ERCOT tends to be a bilateral market with limited opportunity to enter into longer dated PPAs & tolling agreements. Management estimates moving to a nodal market in ERCOT could be a neutral to slightly positive earnings driver.

Table 55: Texas Fossil Asset Summary

Plant Name	Location	Type	Capacity (MW)	CCGT	Peaking	08 Gen (GWh)	Implied CF
Baytown Energy Center	Baytown TX	CCGT	830	742	88	3,797	53%
Brazos Valley Power Plant	Richmond TX	CCGT	594	508	86	2,887	56%
Channel Energy Center	Houston TX	CCGT	593	443	150	2,721	53%
Clear Lake Power Plant	Pasadena TX	CCGT	377	344	33	800	24%
Corpus Christi Energy Center	Corpus Christi TX	CCGT	505	400	105	2,418	55%
Deer Park Energy Center	Deer Park TX	CCGT	1,019	792	227	5,537	63%
Freeport Energy Center	Freeport TX	CCGT	236	210	26	1,274	62%
Freestone Energy Center	Freestone County TX	CCGT	1,036	1,036	-	3,772	42%
Hidalgo Energy Center	Edinburg TX	CCGT	376	373	3	800	25%
Magic Valley Generating Station	Edinburg TX	CCGT	692	662	30	3,230	54%
Pasadena Power Plant	Pasadena TX	CCGT	776	731	45	3,632	54%
Texas City Power Plant	Texas City TX	CCGT	453	400	53	1702	43%
Total Texas			**7,487**	**6,641**	**846**	**32,570**	50%

Source: Company reports and SNL

Northern Region

Calpine's Northeast region is its smallest, and its assets are primarily located in New York state, with individual assets located in a select few other states. It receives capacity payments from NYISO (both RoS and NYC), as well as PJM-RTO for its Zion facility, and from the New England FCM for its Westbrook facility. The company's primary asset in the Northeast is Westbrook in Maine.

Table 56: Northern Fossil Asset Summary

Plant Name	Location	Type	Capacity (MW)	CCGT	Peaking	08 Gen (GWh)	Implied CF
Northeast							
Bethpage Energy Center 3	Hicksville NY	CCGT	80	80	0	304	44%
Bethpage Power Plant	Hicksville NY	CCGT	56	55	1	123	25%
Kennedy International Airport Power Pla	Jamaica NY	CCGT	121	110	11	513	49%
Stony Brook Power Plant	Stony Brook NY	CCGT	47	45	2	269	66%
Westbrook Energy Center	Westbrook ME	CCGT	537	537	0	2,607	56%
Bethpage Peaker	Hicksville NY	Peaker	48	0	48	43	10%
Total Northeast			**889**	**827**	**62**	**3,859**	50%
PJM							
Zion Energy Center	Zion IL	Peaker	503		503	116	3%
Total PJM			**503**	**-**	**503**		
Other							
Greenfield Energy Centre	Courtright Ontario	CCGT	503	388	115	235	5%
Whitby Cogeneration	Ontario		25	-	25	135	62%
Mankato Power Plant	Mankato MN	CCGT	324	280	44	461	16%
Riverside Energy Center	Beloit WI	CCGT	603	518	85	957	18%
RockGen Energy Center	Christiana WI	Peaker	503	0	503	77	2%
			1,958	**1,186**	**772**	**1,865**	11%
Total North			**3,349**	**2,012**	**1,337**	**5,723**	20%

Source: Company reports and SNL

Southern Region

Calpine's southern assets are primarily located in AL, FL, and SC. We use power prices from Entergy and gas prices directly from Henry Hub to derive spark spreads for the group.

Table 57: Southern Fossil Asset Summary

Plant Name	Location	Type	Capacity (MW)	CCGT	Peaking	08 Gen (GWh)	Implied CF
SERC/SPP							
Hog Bayou Energy Center	Mobile AL	CCGT	237	235	2	142	7%
Carville Energy Center	LA	CCGT	501	449	52	1,871	43%
Columbia Energy Center	Calhoun County SC	CCGT	606	455	151	355	7%
Morgan Energy Center	Decatur AL	CCGT	807	720	87	2,321	33%
Decatur Energy Center	Decatur AL	CCGT	792	734	58	1,550	23%
Oneta Energy Center	Coweta OK	CCGT	1134	980	154	2,183	22%
Broad River Energy Center	Gaffney SC	Peaker	847	0	847	603	8%
Total SERC/SPP			**4,924**	**3,573**	**1,351**	9,026	21%
Other							
Auburndale Power Plant	Auburndale FL	CCGT	0	0	-		
Osprey Energy Center	Auburndale FL	CCGT	599	537	62	2,060	40%
Pine Bluff Energy Center	AR		215	184	31	1,247	67%
Santa Rosa Energy Center	Pace FL	CCGT	250	250	-	18	1%
Auburndale Peaking Energy Center	Auburndale FL	Peaker	116	0	116	23	2%
Total Other			**1,180**	**971**	**209**	3,348	33%
Total Southeast			**6,104**	**4,544**	**1,560**	**12,374**	23%

Source: Company reports and SNL

Risks

Risks to our investment thesis include: 1) shifts in the demand for load following natural gas generation, particularly in TX and CA; 2) the threat of depressed heat rates from an extensive renewable build out in regions served by Calpine; 3) actual commodity prices differing significantly from our assumptions; 4) political and regulatory intervention to change the structure of competitive markets in response to high power prices and insufficient new build; 5) the current state of credit markets that has limited the IPP companies' flexibility to return excess cash to shareholders; and 6) the unknown impact from potential carbon legislation (albeit likely a positive). Other investment risks include abrupt changes in weather pattern, sharp slowdown in economic demand, interest rate risks, and disruption of trading activity in power markets.

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Calpine Corporation

Income statement (US$m)	12/04	12/05	12/06	12/07	12/08	12/09E	% ch	12/10E	% ch	12/11E	% ch
Revenues	8,648	10,113	6,706	7,970	10,515	7,165	-31.9	8,324	16.2	8,448	1.5
Operating expenses (ex depn)	(8,150)	(13,977)	(5,763)	(6,802)	(8,816)	(5,431)	-38.4	(6,793)	25.1	(6,729)	-1.0
EBITDA (UBS)	498	(3,865)	943	1,168	1,699	1,734	2.1	1,530	-11.8	1,719	12.3
Depreciation	(446)	(506)	(470)	(463)	(433)	(517)	19.5	(572)	10.5	(590)	3.2
Operating income (EBIT, UBS)	52	(4,371)	472	705	1,266	1,217	-3.9	959	-21.2	1,129	17.8
Other income & associates	86	(4,896)	(986)	3,461	275	(27)	-	(27)	0.0	(27)	0.0
Net interest	(1,041)	(1,313)	(1,183)	(2,019)	(1,024)	(804)	-21.4	(770)	-4.3	(776)	0.7
Abnormal items (pre-tax)	0	0	0	0	0	0	-	0	-	0	-
Profit before tax	(902)	(10,580)	(1,697)	2,147	517	385	-25.4	162	-58.0	327	101.9
Tax	234	741	(64)	546	47	(147)	-	(62)	-57.8	(125)	101.3
Profit after tax	(668)	(9,839)	(1,761)	2,693	564	239	-57.7	100	-58.1	202	102.3
Abnormal items (post-tax)	0	0	0	0	0	0	-	0	-	0	-
Minorities / pref dividends	247	(42)	(5)	0	1	1	0.0	1	0.0	1	0.0
Net income (local GAAP)	(421)	(9,881)	(1,765)	2,693	565	240	-57.6	101	-57.8	203	101.3
Net Income (UBS)	(421)	(9,881)	(1,765)	2,693	565	240	-57.6	101	-57.8	203	101.3
Tax rate (%)	0	0	0	0	0	38	-	38	0.4	38	-0.3
Pre-abnormal tax rate (%)	0	0	0	0	0	38	-	38	0.4	38	-0.3

Per share (US$)	12/04	12/05	12/06	12/07	12/08	12/09E	% ch	12/10E	% ch	12/11E	% ch
EPS (local GAAP)	(0.98)	(21.32)	(3.68)	5.62	1.16	0.49	-57.6	0.21	-57.8	0.42	101.3
EPS (UBS)	(0.98)	(21.32)	(3.68)	5.62	1.16	0.49	-57.6	0.21	-57.8	0.42	101.3
Net DPS	0.00	0.00	0.00	0.00	0.00	0.00	-	0.00	-	0.00	-
Cash EPS	0.06	(20.22)	(2.70)	6.59	2.06	1.56	-24.2	1.38	-11.2	1.63	17.9
BVPS	10.35	(11.88)	(14.93)	(9.71)	9.00	9.48	5.4	9.69	2.2	10.11	4.3

Balance sheet (US$m)	12/04	12/05	12/06	12/07	12/08	12/09E	% ch	12/10E	% ch	12/11E	% ch
Cash and equivalents	-	786	1,077	1,915	1,657	1,556	-6.1	1,060	-31.9	796	-24.9
Other current assets	-	2,642	2,091	2,616	5,843	5,508	-5.7	5,636	2.3	5,644	0.1
Total current assets	-	3,428	3,168	4,531	7,500	7,063	-5.8	6,695	-5.2	6,440	-3.8
Net tangible fixed assets	-	14,119	13,603	12,292	11,908	11,799	-0.9	11,660	-1.2	11,718	0.5
Net intangible fixed assets	-	0	0	0	0	0	-	0	-	0	-
Investments / other assets	0	2,998	1,819	1,659	1,330	1,330	0.0	1,330	0.0	1,330	0.0
Total assets	-	20,545	18,589	18,482	20,738	20,192	-2.6	19,685	-2.5	19,488	-1.0
Trade payables & other ST liabilities	-	1,532	1,083	1,894	4,900	4,665	-4.8	4,777	2.4	4,773	-0.1
Short term debt	-	5,610	4,975	1,710	716	369	-48.5	342	-7.2	328	-4.2
Total current liabilities	-	7,142	6,057	3,604	5,616	5,034	-10.4	5,119	1.7	5,101	-0.4
Long term debt	-	17,072	18,109	18,734	9,756	9,674	-0.8	8,981	-7.2	8,599	-4.2
Other long term liabilities	-	1,563	1,310	793	994	873	-12.2	873	0.0	873	0.0
Total liabilities	-	25,777	25,476	23,131	16,366	15,581	-4.8	14,972	-3.9	14,573	-2.7
Equity & minority interests	-	(5,233)	(6,887)	(4,649)	4,372	4,612	5.5	4,713	2.2	4,916	4.3
Total liabilities & equity	-	20,545	18,589	18,482	20,738	20,192	-2.6	19,685	-2.5	19,488	-1.0

Cash flow (US$m)	12/04	12/05	12/06	12/07	12/08	12/09E	% ch	12/10E	% ch	12/11E	% ch
Net income	(421)	(9,881)	(1,765)	2,693	565	240	-57.6	101	-57.8	203	101.3
Depreciation	446	506	470	463	433	517	19.5	572	10.5	590	3.2
Net change in working capital	(138)	(332)	259	686	(230)	100	-	(16)	-	(12)	-23.4
Other (operating)	121	8,998	1,192	(3,660)	(274)	(58)	-78.7	(117)	101.5	(133)	13.6
Net cash from operations	9	(708)	155	182	494	799	61.7	539	-32.5	647	20.1
Capital expenditure	-	(783)	(212)	(196)	(143)	(350)	144.8	(315)	-10.0	(515)	63.5
Net (acquisitions) / disposals	-	2,103	8	541	492	(121)	-	0	-	0	-
Other changes in investments	-	(402)	218	133	167	0	-	0	-	0	-
Cash from investing activities	-	917	14	478	516	(471)	-	(315)	-33.1	(515)	63.5
Increase/(decrease) in debt	-	248	167	119	(950)	(429)	-	(720)	-	(396)	-
Share issues / (repurchases)	-	0	0	0	0	0	-	0	-	0	-
Dividends paid	-	0	0	0	0	0	-	0	-	0	-
Other cash from financing	-	(408)	(46)	59	(318)	0	-	0	-	0	-
Cash from financing activities	-	(160)	121	178	(1,268)	(429)	-66.2	(720)	67.9	(396)	-45.0
Cash flow chge in cash & equivalents	-	49	291	838	(258)	(101)	-	(496)	-	(264)	-
FX / non cash items	-	-	0	1	0	(1)	-	0	-	0	-
Bal sheet chge in cash & equivalents	-	-	291	839	(258)	(101)	-	(496)	-	(264)	-
Core EBITDA	498	(3,865)	943	1,168	1,699	1,734	2.1	1,530	-11.8	1,719	12.3
Maintenance capital expenditure	-	(783)	(212)	(196)	(143)	(350)	144.8	(315)	-10.0	(515)	63.5
Maintenance net working capital	-	0	0	0	(54)	20	-	(3)	-	(2)	-47.9
Operating free cash flow, pre-tax	-	(4,648)	731	972	1,502	1,404	-6.6	1,212	-13.6	1,203	-0.8

Source: Company accounts, UBS estimates. (UBS) valuations are stated before goodwill-related charges and other adjustments for abnormal and economic items at the analysts' judgement. Note: For some companies, the data represents an extract of the full company accounts.

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Global Equity Research

Americas

Electric Utilities

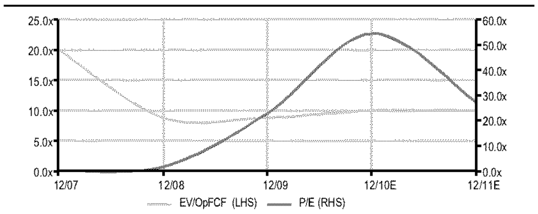
12-month rating	**Buy**
12m price target	**US$14.00**

Calpine Corporation

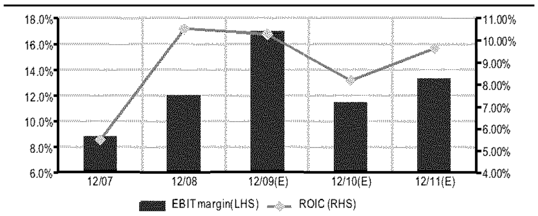
Company profile

Calpine is an Independent Power Producer (IPP) that operates power generation facilities across North America. Calpine's generation fleet consists of approximately 24,000 MW of capacity, making it one of the largest wholesale power generators in the country. Its portfolio is composed of two power generation technologies: natural gas-fired combustion (primarily combined-cycle) facilities and renewable geothermal facilities. Its facilities are primarily oriented in Northern California and Eastern Texas.

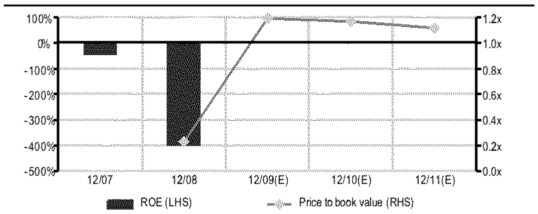
Value (EV/OpFCF & P/E)



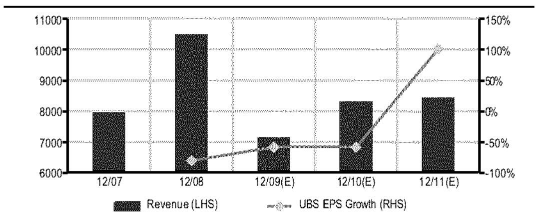
Profitability



ROE v Price to book value



Growth (UBS EPS)



Valuation (x)	5Yr Avg	12/07	12/08	12/09E	12/10E	12/11E
P/E (local GAAP)	-	0.4	1.8	23.0	54.6	27.1
P/E (UBS)	-	0.4	1.8	23.0	54.6	27.1
P/CEPS	-	0.3	1.0	7.3	8.2	7.0
Net dividend yield (%)	-	0.0	0.0	0.0	0.0	0.0
P/BV	-	NM	0.2	1.2	1.2	1.1
EV/revenue (core)	-	2.5	1.3	1.7	1.5	1.4
EV/EBITDA (core)	-	16.7	7.8	7.2	7.9	7.0
EV/EBIT (core)	-	27.7	10.5	10.2	12.7	10.6
EV/OpFCF (core)	-	20.1	8.8	8.8	10.0	10.0
EV/op. invested capital	-	1.5	1.1	1.1	1.0	1.0

Enterprise value (US$m)	12/07	12/08	12/09E	12/10E	12/11E
Average market cap	939	939	5,098	5,098	5,098
+ minority interests	3	2	2	2	2
+ average net debt (cash)	20,268	13,672	8,651	8,375	8,197
+ pension obligations and other	0	0	0	0	0
- non-core asset value	(1,659)	(1,330)	(1,330)	(1,330)	(1,330)
Core enterprise value	19,551	13,283	12,421	12,146	11,967

Growth (%)	5Yr Avg	12/07	12/08	12/09E	12/10E	12/11E
Revenue	-	18.9	31.9	-31.9	16.2	1.5
EBITDA (UBS)	-	23.9	45.5	2.1	-11.8	12.3
EBIT (UBS)	-	49.3	79.6	-3.9	-21.2	17.8
EPS (UBS)	-	-	-79.3	-57.6	-57.8	101.3
Cash EPS	-	-	-68.8	-24.2	-11.2	17.9
Net DPS	-	-	-	-	-	-
BVPS	-	-35.0	-	5.4	2.2	4.3

Margins (%)	5Yr Avg	12/07	12/08	12/09E	12/10E	12/11E
EBITDA / revenue	-	14.7	16.2	24.2	18.4	20.4
EBIT / revenue	-	8.8	12.0	17.0	11.5	13.4
Net profit (UBS) / revenue	-	33.8	5.4	3.3	1.2	2.4

Return on capital (%)	5Yr Avg	12/07	12/08	12/09E	12/10E	12/11E
EBIT ROIC (UBS)	-	5.5	10.5	10.3	8.2	9.7
ROIC post tax	-	5.5	10.5	6.4	5.1	6.0
Net ROE	-	(45.6)	(400.0)	5.3	2.2	4.2

Coverage ratios (x)	5Yr Avg	12/07	12/08	12/09E	12/10E	12/11E
EBIT / net interest	-	0.3	1.2	1.5	1.2	1.5
Dividend cover (UBS EPS)	-	-	-	-	-	-
Div. payout ratio (%, UBS EPS)	-	-	-	-	-	-
Net debt / EBITDA	-	NM	5.2	4.9	5.4	4.7

Efficiency ratios (x)	5Yr Avg	12/07	12/08	12/09E	12/10E	12/11E
Revenue / op. invested capital	-	0.6	0.9	0.6	0.7	0.7
Revenue / fixed assets	-	0.6	0.9	0.6	0.7	0.7
Revenue / net working capital	-	9.2	12.6	8.0	9.8	9.8

Investment ratios (x)	5Yr Avg	12/07	12/08	12/09E	12/10E	12/11E
OpFCF / EBIT	-	1.4	1.2	1.2	1.3	1.1
Capex / revenue (%)	-	2.5	1.4	4.9	3.8	6.1
Capex / depreciation	-	0.4	0.3	0.7	0.6	0.9

Capital structure (%)	5Yr Avg	12/07	12/08	12/09E	12/10E	12/11E
Net debt / total equity	-	NM	NM	NM	NM	NM
Net debt / (net debt + equity)	-	NM	66.9	64.8	63.7	62.3
Net debt (core) / EV	-	NM	NM	69.6	69.0	68.5

Source: Company accounts, UBS estimates. (UBS) valuations are stated before goodwill-related charges and other adjustments for abnormal and economic items at the analysts' judgement.

Valuations: based on an average share price that year, (E): based on a share price of US$11.35 on 19 Feb 2010 19:35 EST Market cap(E) may include forecast share issues/buybacks.

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UBS Investment Research

Dynegy, Inc.

Global Equity Research

Americas

Electric Utilities

12-month rating	Sell * *Unchanged*
12m price target	US$1.30 *Unchanged*
Price	US$1.65

RIC: DYN.N BBG: DYN US

Overvalued Despite Trough 2010 EBITDA

- **DYN is a highly-levered Midwest merchant generator**

DYN operates ~13GW of generation across the Midwest, Northeast, and California. Its main economics are driven by several large PRB-fired coal plants in Illinois, exposing the company to declining (off-peak) heat rates as transmission across the Midwest is set to transport significant wind power to the state.

- **2010 should prove a trough year in EBITDA; secular headwinds remain**

Despite the trough year of EBITDA in '10 (due to bottom ticked hedges), we see flat EBITDA in '11-'13. We anticipate higher coal prices and under market rail contracts to erode EBITDA growth thereafter. Further, with less leverage to a recovery in natural gas prices & limited heat rate improvement, we don't anticipate a significant improvement in power prices.

- **Executing on liability mgmt strategy, DYN mgmt pays down $812 Mn**

As part of DYN's debt reduction strategy (it remains the most levered IPP), mgmt bought back $812 Mn of its '11/'12 maturities, effectively pushing out its large maturities to 2013. While the asset sale to LS Power improved DYN's liquidity situation, we believe it signals underlying issues in that its largest shareholder is opting to sell down its stake; LS went as far as to re-market the $235 Mn note it was issued by DYN following the deal's completion.

- **Valuation: Continue to see more than fair value; Reiterate Sell rating**

Despite mgmt's superior disclosures, we believe the company's risk profile is not commensurate with a 12% premium to its IPP peers on '11E. With renewables, carbon, and basis risk (NI Hub – Cin Hub) increasingly factoring into DYN's risk profile, we think many investors have fail to recognize an evolving power market in the Midwest in continuing to ascribe DYN's historic premium to the group.

Highlights (US$m)	12/07	12/08	12/09E	12/10E	12/11E
Revenues	3,103	3,354	1,830	1,417	1,601
EBIT (UBS)	591	937	417	181	321
Net Income (UBS)	85	435	14	(186)	(17)
EPS (UBS, US$)	0.11	0.52	0.02	(0.31)	(0.03)
Net DPS (UBS, US$)	0.00	0.00	0.00	0.00	0.00

Profitability & Valuation	5-yr hist av.	12/08	12/09E	12/10E	12/11E
EBIT margin %	-	27.9	22.8	12.8	20.0
ROIC (EBIT) %	-	9.6	4.3	2.0	3.7
EV/EBITDA (core) x	-	8.1	8.5	12.1	9.0
PE (UBS) x	-	12.0	NM	NM	NM
Net dividend yield %	-	0.0	0.0	0.0	0.0

Source: Company accounts, Thomson Reuters, UBS estimates. (UBS) valuations are stated before goodwill-related charges and other adjustments for abnormal and economic items at the analysts' judgement.

Valuations: based on an average share price that year, (E): based on a share price of US$1.65 on 19 Feb 2010 19:35 EST

Trading data	
52-wk range	US$2.63-1.04
Market cap.	US$1.38bn
Shares o/s	838m (COM)
Free float	100%
Avg. daily volume ('000)	2,702
Avg. daily value (US$m)	5.0

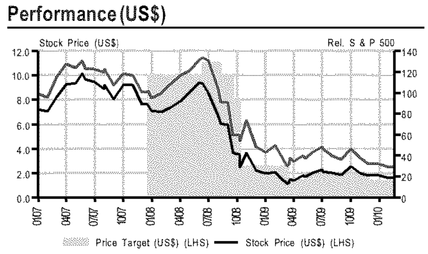
Balance sheet data 12/09E	
Shareholders' equity	US$4.60bn
P/BV (UBS)	0.3x
Net Cash (debt)	(US$5.32bn)

Forecast returns	
Forecast price appreciation	-21.2%
Forecast dividend yield	0.0%
Forecast stock return	-21.2%
Market return assumption	5.9%
Forecast excess return	-27.1%

EPS (UBS, US$)

	12/09E From	12/09E To	12/09E Cons.	12/08 Actual
Q1	0.26	0.26	(0.01)	0.16
Q2	0.07	0.07	(0.06)	0.14
Q3	0.21	0.21	0.27	0.11
Q4E	(0.14)	(0.06)	(0.13)	0.11
12/09E	(0.06)	0.02	*0.00*	
12/10E	(0.40)	(0.31)	*(0.23)*	

Performance (US$)



Source: UBS

www.ubs.com/investmentresearch

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*** Exception to core rating bands; See page150**

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Investment Summary

We continue to view DYN as the most overvalued name among the merchant generation sector. Having reassessed Dynegy's financial profile, we firmly believe Dynegy remains overvalued to peers, with investors seemingly looking past Dynegy's deep in the money hedges for rail contracts. Unlike commodity prices, which clearly can fluctuate substantially prior to needing to lock in new hedges, we anticipate there is little chance for downward pressure on rail rates. While downside to power prices remains somewhat mitigated for Dynegy given both the lower degree to which gas is on the margin and bottoming out in Midwest industrial sales, we view these positives as being more than sufficiently baked into current share price valuations. Alternatively, we see continued secular pressure on power prices as renewables are aggressively developed in the Midwest; EXC's latest estimate is for 3GW of new wind at NI Hub by 2012. Further, we believe anticipations for a strong Midwest recovery in load led by industrials are overdone with ComEd's latest 2010 update to sales expectations envisioning +1.5% in Large C&I load growth and +0.8% load growth in Small C&I. In the longer term, we see DYN as particularly affected by any eventual carbon legislation, competing in IL against EXC's substantial nuclear fleet. We interpret the recently completed asset sale to LS Power, DYN's largest single shareholder, as confirming our concerns over the company's outlook with the transaction resulting in LS Power's effective retirement of half its equity stake in exchange for a $235 Mn note, which it proceeded to immediately re-market. We reiterate our Sell rating and $1.30 12-month price target; given the relatively open position on power prices in 2011 & beyond, we anticipate near term pressures on commodity prices will affect DYN's share price disproportionately.

We continue to rate DYN Sell with a $1.30 price target:

- Rail contract value underappreciated

- ComEd load recovery in '10 is limited

- See limited recovery in power prices as 3GW of wind and limited uplift from natural gas prices

- Carbon remains LT concern in IL, competing with low-cost nuclear

- LS Power stake selldown remains important signal by largest holder

Fundamentals of Regional Power Markets Remain in Question With Increased Wind Likely Oriented Towards Illinois

However, we remain concerned over the company's long term prospects, given its exposure to carbon legislation. DYN operates a relatively carbon-intensive fleet in IL, a state with a relatively low footprint due to the large size of EXC's nuclear fleet in the state. A further concern of ours is DYN's exposure to significant new wind capacity being constructed across the Plains states; these projects largely intend to bring the power to Chicago and IL. We believe heat rates at NI-Hub could compress as transmission projects progress, particularly for off-peak hours. This is of particular concern for DYN as it hedges itself against Cinergy hub, further East, which is less exposed to renewables coming from the West. Should heat rates become depressed and the basis between NI-Hub and Cinergy expand, DYN's hedges against its coal fleet could become partially ineffective.

Where Is the Industrial Recovery?

A further concern of ours remains industrial recovery in the Midwest. While Dynegy's fleet is not necessarily in ComEd's service territory, the initial 2010 outlook for a sales recovery in its service territory provides less than stellar expectations (+1.5% for Large C&I and +0.8% for Small C&I). While Ameren's utilities have yet to disclose their anticipated recovery for 2010, we do not anticipate a sizable recovery.

Forward Curve Seemingly Does Not anticipate Heat Rates Recovering to Pre-industrial Sales Collapse Levels

Examining the current implied forward curve for NI Hub – Chicago Citygate, we see the curve below a 6.0x heat rate through. For 2011, we incorporate a 6.0x heat rate 2014 (which we nominally see as roughly the pre-collapse level) into our power price assumptions, providing a more conservative upward bias to our estimate. In 2012 & beyond, we use a heat rate of 5.75x to account for the impact of added wind to the Midwest grid. We believe this added generation is a significant reason behind why the current implied forward heat for NI Hub-Citygate is in relatively less contango than its regional peers.

A combination of lost sales and wind keep market heat rates below pre-recession levels through its entire duration

Management Dealt Difficult Hand; Pursuing the Right Steps

We do believe management has clearly taken to heart the difficulties the company faces and is actively pursuing its "liability management" strategy, its euphemism for paying down debt and pushing out maturities. We see the recent asset sale and associated paydown of $830 Mn of its 2011/12 bonds ($420 Mn of 2011's and $410 Mn of 2012's) as a clear step in the right direction. We anticipate DYN to continue focusing on reducing leverage and addressing near term maturities as needed. We do not forecast further reinvestment in the business or organic growth projects at this time, outside of required environmental control projects underway. A potential near term catalyst would be the sale of its remaining ownership in Plum Point; a positive for liquidity.

Mgmt's efforts to paydown debt through its liability management initiative are the right steps in a difficult situation

EBITDA Estimates

We have provided our latest Adjusted EBITDA estimates below. 2009 and 2010 have a declining EBITDA profile, as Dynegy entered into a significant number of hedges for both years while it struggled to lock in minimal cash flows during the bottom of the commodity cycle. We see relatively stable EBITDA in '11-'13 before falling off in 2014 with the roll-off of its in-the-money rail contract.

Table 58: Dynegy Adjusted EBITDA Estimates, by Year and Segment

$ Mn	2007A	2008A	2009E	2010E	2011E	2012E	2013E	2014E
EBITDA	**966**	**814**	**774**	**507**	**641**	**617**	**616**	**474**
Midwest	677	646	629	435	534	499	502	364
West	199	168	187	125	115	122	125	125
Northeast	209	116	108	81	117	112	105	101
CRM	(2)	-	-	-	-	-	-	-
Other	(117)	(116)	(150)	(135)	(125)	(115)	(115)	(115)

Source: Company reports and UBS estimates

EBITDA Sensitivity to Changes in Natural Gas Assumption

We have also provided sensitivities to our EBITDA under a variety of natural gas assumptions. Although natural gas prices generally do not drive NI Hub or Cinergy power prices during most hours, we derive our power assumptions for all of Dynegy's regions using market heat rate assumption. Due to this relationship, our sensitivities to shifts in natural gas are particularly uncertain in the case of Dynegy.

Table 59: Dynegy Sensitivity to Shifts in Natural Gas Price Assumption ($/MMbtu)

		Adj. EBITDA - By Year					Price Target
		2010E	2011E	2012E	2013E	2014E	2011 Open EBITDA SOP
	Current	507	641	617	616	474	$1.29
	$5.00	$478	$445	$307	$295	$153	($2.7)
	$5.50	$490	$492	$383	$374	$232	($1.8)
	$6.00	$501	$539	$459	$452	$310	($0.8)
	$6.50	$513	$587	$535	$531	$389	$0.2
NYMEX Gas Assumption	**$7.00**	$524	$634	$611	$609	$467	$1.2
	$7.50	$536	$681	$686	$688	$546	$2.2
	$8.00	$547	$728	$762	$767	$625	$3.2
	$8.50	$559	$776	$838	$845	$703	$4.1
	$9.00	$570	$823	$914	$924	$782	$5.1
	$9.50	$582	$870	$989	$1,002	$860	$6.1
	$10.00	$593	$917	$1,065	$1,081	$939	$7.1
Current NYMEX Strip	$5.66	$496	$571	$539	$558	$443	($0.1)

Source: NYMEX, UBS estimates

However, using market forwards for natural gas, our EBITDA scenarios are significantly lower, resulting in a compressed price target SOP multiple.

EBITDA Sensitivity to Changes in Coal Price Assumption

We have also provided sensitivities to our EBITDA under a variety of delivered PRB assumptions (in $/ton), including current market forwards. Due to the confidential and relatively uncertain price of delivery costs of PRB to Dynegy's plants, our assumption of market transportation rates (particularly in future years) is a challenging process.

Table 60: Dynegy Sensitivity to Shifts in Delivered PRB Assumption ($/ton)

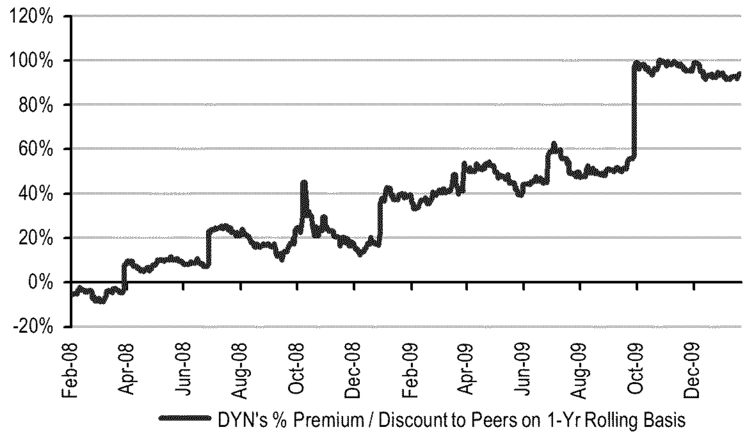
		Adj. EBITDA - By Year					Price Target
		2010E	2011E	2012E	2013E	2014E	2011 Open EBITDA SOP
	Current	507	641	617	616	474	1.29
	$15.0	$656	$801	$801	$802	$798	($2.7)
	$17.5	$625	$768	$768	$769	$765	($1.8)
	$20.0	$593	$735	$735	$736	$732	($0.9)
	$22.5	$561	$702	$702	$703	$699	$0.1
Delivered PRB Coal ($/ton)	**$25.0**	$529	$669	$668	$670	$666	$1.0
	$27.5	$497	$635	$635	$636	$632	$2.0
	$30.0	$466	$602	$602	$603	$599	$2.9
	$32.5	$434	$569	$569	$570	$566	$3.8
	$35.0	$402	$536	$535	$537	$533	$4.8
	$37.5	$370	$503	$502	$504	$500	$5.7
	$40.0	$338	$469	$469	$470	$466	$6.7
NYMEX Delivered PRB Strip	$35.39	$418	$523	$522	$524	$520	($0.23)

Source: NYMEX, UBS estimates

Valuation

We derive our $1.30 price target using an average of DCF, and a SOP combination of Open and Hedged 2011E EBITDA. We have included below a 1-Year Forward Rolling EV/EBITDA valuation of DYN against the peer group; while we note 2010 is particularly low for DYN, the premium to peers now nears 100% on this basis; we think too high for EBITDA that should improve by just 29% in 2011 and decline thereafter.

Chart 38: Dynegy Premium to Peers on 1-Year Forward Rolling EV/EBITDA Basis



Source: FactSet and UBS estimates

SOP Valuation

We have included in Table 61 our SOP valuation for Dynegy's merchant portfolio. We use a marginally higher multiple for DYN's coal assets compared with RRI and MIR to account for their lower cost PRB dispatch profile. The premium multiples for the balance of the fleet account for the higher level of transparency and disclosures. Further adjustments made include adding back the Central Hudson lease PV (we calculate $709 Mn), removing all but its share of the non-recourse debt associated with Plum Point ($533 Mn), netting out its restricted cash posted against its synthetic L/C ($850 Mn), and adding back the PV of its (IL consent decree) environmental capex program.

Table 61: Dynegy Hedged 2011E EBITDA SOP Valuation

All figures in US $ million except per share data	2011E Hedged EBITDA	EV/EBITDA Multiple			Enterprise Value		
		Low	Base	High	Low	Base	High
Midwest	534	7.0x	8.0x	9.0x	$3,739	$4,273	$4,807
West	115	7.0x	8.0x	9.0x	804	919	1,033
Northeast	117	7.0x	8.0x	9.0x	817	934	1,051
Central Hudson Lease	50	7.0x	8.0x	9.0x	350	400	450
Other	(125)	6.0x	5.0x	4.0x	(750)	(625)	(500)
Total / Implied	**691**	7.2x	8.5x	9.9x	**$4,960**	**$5,901**	**$6,842**
less net debt						(5,334)	
less lease Central Hudson lease (PV)						(709)	
add adjust net recourse project debt for PPEA minority interest						533	
add Restricted Cash against L/C						850	
add NPV of NOLs						-	
less PV of environmental capex						(451)	
NPV of Equity					**($151)**	**$790**	**$1,731**
Current Number of Shares outstanding					600	600	600
Equity value per share					**-$0.25**	**$1.32**	**$2.89**

Source: Company reports and UBS estimates

As a second part of our SOP valuation, we include an Open EBITDA valuation to more appropriately triangulate our valuation against its hedge value. We have included in Table 62 our best estimate of Dynegy's Open position using UBS' commodity view (above market for both natural gas and PRB), as well as its Open position using current commodity forwards in Table 63. We use a lower multiple on our Open EBITDA position in 2011 to account for the underwater nature of its hedges in the Midwest.

Table 62: Dynegy Open 2011E EBITDA SOP Valuation – Using UBS Commodity Forecast

All figures in US $ million except per share data	2011E Open EBITDA	EV/EBITDA Multiple			Enterprise Value		
		Low	Base	High	Low	Base	High
Midwest	534	6.5x	7.5x	8.5x	$3,472	$4,006	$4,540
Power Hedge	92	6.5x	7.5x	8.5x	598	690	782
Coal Hedge	(71)	6.5x	7.5x	8.5x	(465)	(536)	(608)
West	115	7.0x	8.0x	9.0x	804	919	1,033
Northeast	117	7.0x	8.0x	9.0x	817	934	1,051
Central Hudson Lease	50	9.0x	8.0x	7.0x	450	400	350
Other	(125)	7.0x	5.0x	9.0x	(875)	(625)	(1,125)
Total / Implied	**711**	6.8x	8.1x	8.5x	**4,802**	**5,788**	**6,024**
less net debt						(5,334)	
less lease Central Hudson lease (PV)						(709)	
add adjust net recourse project debt for PPEA minority interest						533	
add Restricted Cash against L/C						850	
add NPV of NOLs						-	
less PV of environmental capex						(451)	
add Hedge Value NPV						94	
NPV of Equity					**($215)**	**$771**	**$1,008**
Current Number of Shares outstanding					600	600	600
Equity value per share					**-$0.36**	**$1.29**	**$1.68**

Source: UBS estimates

Table 63: Dynegy Open 2011E EBITDA SOP Valuation – Using Current Market Forwards

All figures in US $ million except per share data	2011E Open EBITDA	EV/EBITDA Multiple			Enterprise Value		
		Low	Base	High	Low	Base	High
Midwest	534	8.5x	9.5x	10.5x	$4,540	$5,074	$5,609
Power Hedge	2	8.5x	9.5x	10.5x	17	19	21
Coal Hedge	(129)	8.5x	9.5x	10.5x	(1,094)	(1,223)	(1,351)
West	115	7.0x	8.0x	9.0x	804	919	1,033
Northeast	117	7.0x	8.0x	9.0x	817	934	1,051
Central Hudson Lease	50	9.0x	8.0x	7.0x	450	400	350
Other	(125)	4.0x	5.0x	6.0x	(500)	(625)	(750)
Total / Implied	**639**	7.9x	8.6x	9.3x	**$5,034**	**$5,499**	**$5,963**
less net debt						(5,334)	
less lease Central Hudson lease (PV)						(709)	
add adjust net recourse project debt for PPEA minority interest						533	
add Restricted Cash against L/C						850	
add NPV of NOLs						-	
less PV of environmental capex						(451)	
add Hedge Value NPV						354	
NPV of Equity					**$374**	**$838**	**$1,303**
Current Number of Shares outstanding					600	600	600
Equity value per share					**$0.62**	**$1.40**	**$2.17**

Source: UBS estimates

DCF Valuation

Our DCF yields a price target of $1.30 (WACC of 8.1% and long term growth rate of 0.5%). We note a primary difference between our DCF and SOP valuations is the incorporation into our terminal cash flow, Dynegy's free cash flow under a market rail contract. We believe many investors frequently overlook the likely $4-7/MWh increase in the cost of delivered PRB when Dynegy's rail contracts go to market in 2014.

Investors are likely to increasingly focus on the roll-off of DYN's transportation contract in 2014, with an estimated cost increase of PRB of $4-7/MWh

Table 64: DCF Valuation for Dynegy

All numbers in US$ million except the per share data	2009E	2010E	2011E	2012E	2013E	2014E
Operating Profit (EBIT)	**407**	**166**	**306**	**284**	**287**	**150**
Taxes	142	58	107	99	100	52
Tax adjusted EBIT	**264**	**108**	**199**	**184**	**187**	**97**
Add: Depreciation & Amortization	357	326	320	319	314	310
Add: deferred taxes	0	0	0	0	0	0
Less: Incremental Net Working Capital	117	(55)	(26)	(2)	5	(1)
Less: Capex	(530)	(345)	(295)	(205)	(200)	(100)
Less: Sale of assets / (Acquisitions)	105	1,025	0	0	0	0
add Imputed principal for Central Hudson Lease	50	50	50	50	50	50
Unlevered Free Cash Flow	**364**	**1,109**	**248**	**346**	**356**	**356**
Present Value of Free Cash Flow	357	1,007	208	269	256	237
Terminal Value						4,718
Implied Terminal Multiple (EV/EBITDA)						10.3x
Cost of debt						
Risk free rate (bond yield updated throu	4.0%					
Average debt premium	6.0%					
Nominal cost of debt	10.0%					
Marginal tax rate	35%					
Post tax cost of debt	6.5%					
Cost of equity						
Risk free rate	4.0%					
Equity risk premium (USER INPUT)	6.5%					
Equity beta (USER INPUT)	1.4					
Cost of equity	13.1%					
Capital Structure						
Total net debt	4,289					
Net Debt	5,315					
Central Hudson Lease	(709)					
PPEA Consolidation Adjustment	533					
Restricted Cash against L/C	(850)					
Market Value of equity	1,347					
Debt weighting	76%					
Equity weighting	24%					
WACC	**8.1%**					
Growth Rate	**0.5%**					
NPV of FCFF	2,332					
NPV of TV	3,138					
Total NPV	5,470					
Less: Net Debt and Preferred Stock	(4,289)					
less PV of environmental capex	(451)					
NPV of Equity	730					
Current Number of Shares outstanding	600					
NPV of Equity per share	**$1.2**					
Forward value per share	**$1.38**					

Source: UBS estimates

DCF Sensitivities

To provide context to our DCF valuation we have provided scenario analysis for several factors in the tables below. The first adjusts our WACC and Terminal

Growth Rate, pointing to the relative sensitivity to both of these assumptions. We note we use a relatively low terminal growth rate of 0.5% in our valuation, reflecting the poor long term growth prospects for the IPP industry and particularly for Dynegy (its long term capex remains significantly below its depreciation level).

Table 65: DCF Valuation Sensitivity to Changes in WACC and Terminal Growth Rate

		Terminal Growth Rate				
		0.0%	0.3%	**0.5%**	0.8%	1.0%
	7.1%	$2.16	$2.42	$2.70	$3.00	$3.33
	7.6%	$1.53	$1.76	$1.99	$2.25	$2.52
WACC	**8.1%**	$0.99	$1.18	**$1.38**	$1.60	$1.83
	8.6%	$0.51	$0.67	$0.85	$1.04	$1.24
	9.1%	$0.08	$0.22	$0.38	$0.54	$0.71

Source: UBS estimates

A second sensitivity we include is Dynegy's sensitivity to the cost of debt and its leverage. We note amongst the IPPs, we ascribe the highest cost of incremental debt to Dynegy (at 10%), due to its relatively levered position and declining EBITDA profile.

Table 66: DCF Valuation Sensitivity to Changes in Net Debt to Cap and Cost of Debt

		Nominal Cost of Debt				
		9.0%	9.5%	**10.0%**	10.5%	11.0%
	61.2%	$0.76	$0.57	$0.38	$0.21	$0.05
	66.2%	$1.13	$0.90	$0.69	$0.49	$0.30
	71.2%	$1.54	$1.27	$1.02	$0.79	$0.57
Net Debt	**76.2%**	$1.99	$1.68	**$1.38**	$1.11	$0.85
/ Cap	81.2%	$2.49	$2.12	$1.78	$1.46	$1.16
	86.2%	$3.04	$2.61	$2.21	$1.84	$1.50
	91.2%	$3.67	$3.15	$2.68	$2.25	$1.86

Source: UBS estimates

Finally, we include Dynegy's sensitivity to equity risk premium and Beta. Due to Dynegy's relatively levered position, we find changes to these two variables have the least impact on DYN shares.

Table 67: DCF Valuation Sensitivity to Beta and Equity Risk Premium

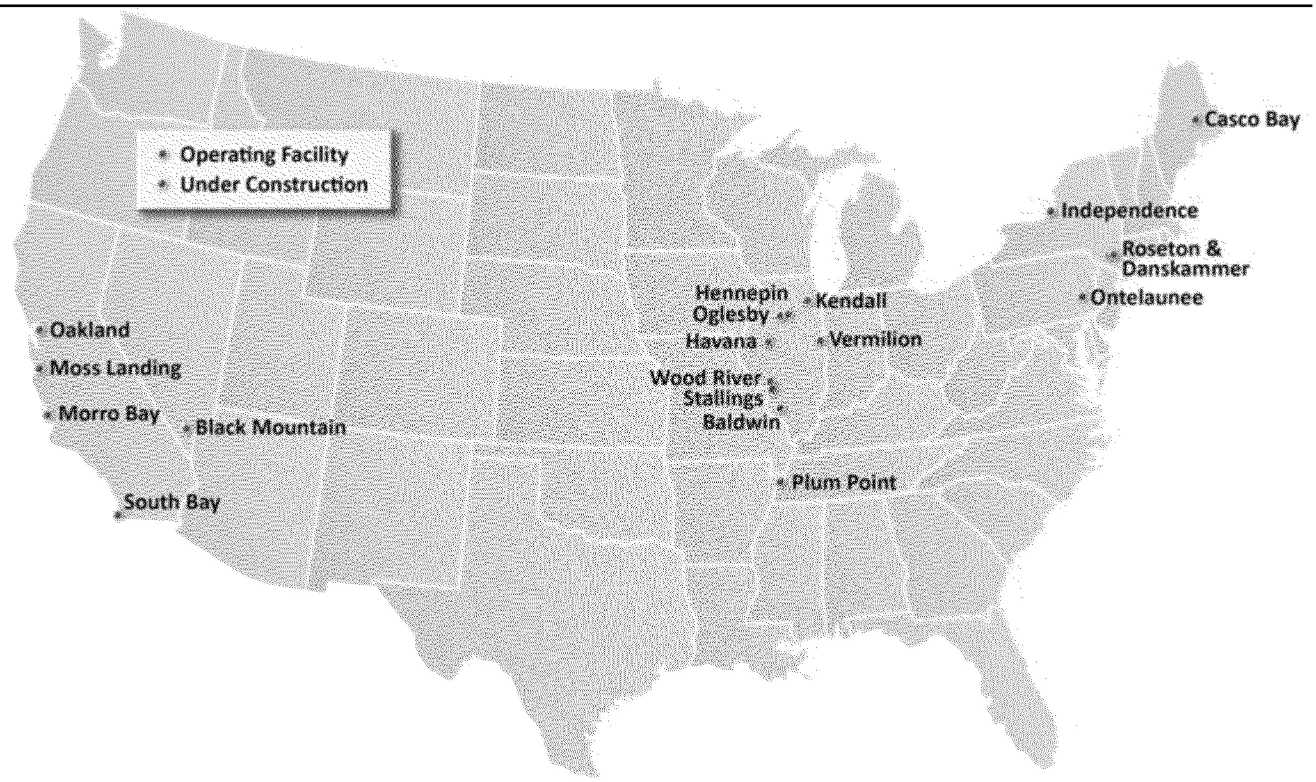
		Equity Risk Premium				
		5.5%	6.0%	**6.5%**	7.0%	7.5%
	1.10	$2.23	$2.07	$1.91	$1.75	$1.60
	1.20	$2.07	$1.90	$1.73	$1.56	$1.40
	1.30	$1.91	$1.73	$1.55	$1.38	$1.21
Beta	**1.40**	$1.75	$1.56	**$1.38**	$1.20	$1.02
	1.50	$1.60	$1.40	$1.21	$1.02	$0.85
	1.60	$1.46	$1.25	$1.05	$0.86	$0.67
	1.70	$1.31	$1.10	$0.89	$0.69	$0.50

Source: UBS estimates

Company Description

Dynegy provides wholesale power, capacity, and ancillary services to utilities, cooperatives, municipalities, and other energy companies in 15 states in our key US regions of the Midwest, the Northeast and the West Coast. The company's power generation portfolio consists of approximately 13,000 megawatts of baseload, intermediate, and peaking power plants fueled by a mix of coal, fuel oil, and natural gas.

Figure 4: DYN's Generation Portfolio



Source: Company presentation

Assets by Region

Dynegy's primary assets are located in the Midwest. It also maintains assets in the West (primarily CA ISO) and the Northeast (primarily NYISO).

Midwest Fleet

Dynegy's primary assets in the Midwest consist of its large Baldwin, Havana, Hennepin, and Wood River coal facilities. We note its Kendall CCGT unit benefits from a long term PPA. The company is currently constructing scrubbers at its Baldwin units (all three) and recently put in place a scrubber at its Havana unit under its Illinois EPA consent decree. Its Hennepin and Vermilion facilities will have only baghouses installed once its current environmental capital expenditures are complete, a potential long term liability under MACT requirements. DYN chooses to hedge its coal fleet in the Midwest at Cinergy Hub. We also note of its gas fleet, only two have in the money heat rates, Kendall and Ontenlaunee.

Table 68: Midwest Fleet Summary, 2010

	Capacity (MW)	Fuel	Dispatch	Location	Region	2008 Stats		
						Output (MWh)	Heat Rate (btu/KWh)	CF (%)
Baldwin	1,800	Coal	Baseload	Baldwin, IL	MISO	13,073,751	10,248	83
Havana - Unit 6	441	Coal	Baseload	Havana, IL	MISO	0	0	0
Hennepin	293	Coal	Baseload	Hennepin, IL	MISO	1,609,505	10,647	63
Vermilion	164	Coal/Gas	Baseload	Oakwood, IL	MISO	NA	NA	NA
Wood River - Units 4-5	446	Coal		Alton, IL	MISO	3,248,072	10,405	83
Plum Point	-	Coal	Baseload			0	0	0
Total Midwest Coal	3,144							
Oglesby	63	Gas	Peaking	Oglesby, IL	MISO	NA	NA	NA
Stallings	89	Gas	Peaking	Stallings, IL	MISO	NA	NA	NA
Tilton	-	Gas	Peaking	Tilton, IL	MISO	NA	NA	NA
Wood River - Units 1-3	119	Gas	Peaking	Alton, IL	MISO	2,695	10,420	0
Kendall	1,200	Gas	Intermediate	Minooka, IL	PJM	1,038,147	7,489	9
Ontelaunee	580	Gas	Intermediate	Ontelaunee, PA	PJM	1,393,523	7,154	26
Rocky Road	-	Gas	Peaking	East Dundee, IL	PJM	39,151	12,832	1
Riverside/Foothills	-	Gas	Peaking	Louisa, KY	PJM	56,166	11,221	1
Renaissance	-	Gas	Peaking	Carson City, MI	MISO	276,459	10,878	4
Bluegrass	-	Gas	Peaking	Oldham County, KY	SERC	57,959	11,064	1
Total Midwest Gas	2,051							
Vermilion - Unit 3	12	Oil	Peaking	Oakwood, IL	MISO	NA	NA	NA
Havanna - Units 1-5	228	Oil	Peaking	Havana, IL	MISO	739	11,503	0
Total Midwest Oil	240							
Midwest Total (MW)	**5,435**							

Source: Company reports, SNL, and UBS estimates

Western Fleet

Dynegy's Western fleet is primarily oriented in California. The majority of its assets in this region are contracted with IOU utilities, creating a relatively stable source of cash flow for the company.

Table 69: West Fleet Summary, 2010

	Capacity (MW)	Fuel	Dispatch	Location	Region	2008 Stats		
						Output (MWh)	Heat Rate (btu/KWh)	CF (%)
Moss Landing - Units 1-2	1,020	Gas	Intermediate	Monterrey County, CA	CAISO	5,835,971	7,265	65
Arlington Valley	-	Gas	Intermediate	Arlington, AZ	Southwest	1,045,936	7,218	20
Griffith	-	Gas	Intermediate	Golden Valley, AZ	WAPA	1,609,044	7,387	32
Total West CCGT	1,020							
Moss Land - Units 6-7	1,509	Gas	Peaking	Monterrey County, CA	CAISO	1,449,624	9,970	11
Morro Bay	650	Gas	Peaking	Morro Bay, CA	CAISO	83,386	9,874	1
South Bay	706	Gas	Peaking	Chula Vista, CA	CAISO	1,015,240	11,551	17
Heard County	-	Gas	Peaking	Heard County, GA	SERC	1	NA	0
Black Mountain	43	Gas	Baseload	Las Vegas, NV	WECC	NA	NA	NA
Total West Gas Peaking	2,908							
Sandy Creek (Coal)	-	Coal	Baseload		ERCOT	0	0	0
Oakland (Oil)	165	Oil	Peaking		CAISO	8,996	14,669	1
Total West (MW)	**4,093**							

Source: Company reports, SNL, and UBS estimates

Northeastern Fleet

Dynegy's smallest fleet is its Northeastern assets. Dynegy's largest source of EBITDA in this segment is from its Danskammer coal facility. Dynegy benefits from a long term toll agreement on its Independence facility with Con Edison.

Table 70: Northeastern Fleet Summary, 2010

	Capacity (MW)	Fuel	Dispatch	Location	Region	2008 Stats		
						Output (MWh)	Heat Rate (btu/KWh)	CF (%)
Moss Landing - Units 1-2	1,020	Gas	Intermediate	Monterrey County, C	CAISO	5,835,971	7,265	65
Arlington Valley	-	Gas	Intermediate	Arlington, AZ	Southwest	1,045,936	7,218	20
Griffith	-	Gas	Intermediate	Golden Valley, AZ	WAPA	1,609,044	7,387	32
Independence	1,064	Gas	Intermediate	Scriba, NY	NYISO	1,190,767	10,255	12
Bridgeport	-	Gas	Intermediate	Bridgeport, CT	ISO-NE	1,869,388	7,604	41
Casco Bay / Maine Indep.	540	Gas	Intermediate	Veazie, ME	ISO-NE	1,656,642	7,341	35
Total Northeast CCGT	1,604							
	-							
Roseton	1,185	Gas/Oil	Peaking	Newburgh, NY	NYISO	446,584	10,827	4
Danskammer - Units 1-2	123	Gas/Oil	Peaking	Newburgh, NY	NYISO	20,554	10,293	2
Total Northeast (Dual) Peaking	1,308							
	-							
Danskammer Units 3-4 (Coal/Gas)	370	Coal/Gas	Baseload	Newburgh, NY	NYISO	2,661,548	10,255	83
Total Northeast (MW)	**3,282**							
Net Capacity (MW)	**12,810**							

Source: Company reports, SNL, and UBS estimates

Risks

Risks to our investment thesis include: 1) actual commodity prices differing significantly from our assumptions; 2) political and regulatory intervention to change the structure of competitive markets in response to high power prices and insufficient new build; 3) the current state of credit markets that has limited the companies' flexibility to return excess cash to shareholders; and 4) unknown impact from a potential carbon legislation. Other investment risks include abrupt changes in weather pattern, sharp slowdown in economic demand, interest rate risks, and disruption of trading activity in power markets.

Dynegy, Inc.

Income statement (US$m)	-	12/05	12/06	12/07	12/08	12/09E	% ch	12/10E	% ch	12/11E	% ch
Revenues	-	**2,313**	**2,017**	**3,103**	**3,354**	**1,830**	*-45.4*	**1,417**	*-22.6*	**1,601**	*13.0*
Operating expenses (ex depn)	-	(1,620)	(1,530)	(2,187)	(2,046)	(1,056)	*-48.4*	(910)	*-13.9*	(961)	*5.6*
EBITDA (UBS)	-	**693**	**487**	**916**	**1,308**	**774**	*-40.8*	**507**	*-34.5*	**641**	*26.4*
Depreciation	-	(220)	(230)	(325)	(371)	(357)	*-3.7*	(326)	*-8.8*	(320)	*-1.9*
Operating income (EBIT, UBS)	-	**473**	**257**	**591**	**937**	**417**	*-55.5*	**181**	*-56.6*	**321**	*77.4*
Other income & associates	-	0	0	0	0	0	-	0	-	0	-
Net interest	-	(411)	(391)	(384)	(427)	(395)	*-7.4*	(362)	*-8.4*	(338)	*-6.7*
Abnormal items (pre-tax)	-	0	0	0	0	0	-	0	-	0	-
Profit before tax	-	**62**	**(134)**	**207**	**510**	**21**	*-95.8*	**(181)**	-	**(17)**	*-90.6*
Tax	-	(42)	28	(122)	(75)	(7)	*-90.1*	(5)	*-32.6*	0	-
Profit after tax	-	**20**	**(106)**	**85**	**435**	**14**	*-96.8*	**(186)**	-	**(17)**	*-90.9*
Abnormal items (post-tax)	-	0	0	0	0	0	-	0	-	0	-
Minorities / pref dividends	-	0	0	0	0	0	-	0	-	0	-
Net income (local GAAP)	-	**20**	**(106)**	**85**	**435**	**14**	*-96.8*	**(186)**	-	**(17)**	*-90.9*
Net Income (UBS)	-	**20**	**(106)**	**85**	**435**	**14**	*-96.8*	**(186)**	-	**(17)**	*-90.9*
Tax rate (%)	-	*68*	*0*	*59*	*15*	*35*	*138.0*	*0*	-	*0*	-
Pre-abnormal tax rate (%)	-	*68*	*0*	*59*	*15*	*35*	*138.0*	*0*	-	*0*	-

Per share (US$)	-	12/05	12/06	12/07	12/08	12/09E	% ch	12/10E	% ch	12/11E	% ch
EPS (local GAAP)	-	0.04	(0.21)	0.11	0.52	0.02	*-96.8*	(0.31)	-	(0.03)	*-90.9*
EPS (UBS)	-	0.04	(0.21)	0.11	0.52	0.02	*-96.8*	(0.31)	-	(0.03)	*-90.9*
Net DPS	-	0.00	0.00	0.00	0.00	0.00	-	0.00	-	0.00	-
Cash EPS	-	0.47	0.24	0.55	0.96	0.44	*-54.1*	0.23	*-47.0*	0.50	*116.9*
BVPS	-	10.92	7.57	5.49	5.47	5.44	*-0.5*	7.35	*35.1*	7.33	*-0.4*

Balance sheet (US$m)	-	12/05	12/06	12/07	12/08	12/09E	% ch	12/10E	% ch	12/11E	% ch
Cash and equivalents	-	1,636	407	292	757	663	*-12.4*	562	*-15.3*	572	*1.7*
Other current assets	-	1,702	1,376	1,322	2,023	1,772	*-12.4*	1,756	*-0.9*	1,787	*1.7*
Total current assets	-	**3,338**	**1,783**	**1,614**	**2,780**	**2,435**	*-12.4*	**2,318**	*-4.8*	**2,358**	*1.7*
Net tangible fixed assets	-	4,979	4,614	9,017	8,934	9,002	*0.8*	7,996	*-11.2*	7,971	*-0.3*
Net intangible fixed assets	-	3	12	438	433	433	*0.0*	433	*0.0*	433	*0.0*
Investments / other assets	-	1,299	1,221	2,038	2,027	2,027	*0.0*	2,027	*0.0*	2,027	*0.0*
Total assets	-	**9,619**	**7,630**	**13,107**	**14,174**	**13,897**	*-2.0*	**12,774**	*-8.1*	**12,789**	*0.1*
Trade payables & other ST liabilities	-	1,974	1,173	948	1,617	1,484	*-8.2*	1,413	*-4.8*	1,417	*0.3*
Short term debt	-	149	2	51	64	61	*-3.9*	53	*-14.5*	53	*0.5*
Total current liabilities	-	**2,123**	**1,175**	**999**	**1,681**	**1,545**	*-8.1*	**1,466**	*-5.2*	**1,470**	*0.3*
Long term debt	-	3,287	2,776	5,939	6,072	5,917	*-2.6*	5,060	*-14.5*	5,088	*0.5*
Other long term liabilities	-	880	647	1,572	1,838	1,838	*0.0*	1,838	*0.0*	1,838	*0.0*
Total liabilities	-	**6,290**	**4,598**	**8,510**	**9,591**	**9,300**	*-3.0*	**8,363**	*-10.1*	**8,396**	*0.4*
Equity & minority interests	-	3,329	3,032	4,597	4,583	4,597	*0.3*	4,410	*-4.1*	4,393	*-0.4*
Total liabilities & equity	-	**9,619**	**7,630**	**13,107**	**14,174**	**13,897**	*-2.0*	**12,774**	*-8.1*	**12,789**	*0.1*

Cash flow (US$m)	-	12/05	12/06	12/07	12/08	12/09E	% ch	12/10E	% ch	12/11E	% ch
Net income	-	20	(106)	85	435	14	*-96.8*	(186)	-	(17)	*-90.9*
Depreciation	-	220	230	325	371	357	*-3.7*	326	*-8.8*	320	*-1.9*
Net change in working capital	-	(81)	(357)	(179)	(48)	117	-	(55)	-	(26)	*-52.2*
Other (operating)	-	(479)	153	(77)	(217)	0	-	0	-	0	-
Net cash from operations	-	**(320)**	**(80)**	**154**	**541**	**489**	*-9.7*	**85**	*-82.6*	**277**	*225.6*
Capital expenditure	-	(193)	(153)	(379)	(611)	(530)	*-13.3*	(345)	*-34.9*	(295)	*-14.5*
Net (acquisitions) / disposals	-	2,393	224	558	451	105	*-76.7*	1,025	*876.2*	0	-
Other changes in investments	-	(384)	310	(996)	73	0	-	0	-	0	-
Cash from investing activities	-	**1,816**	**381**	**(817)**	**(87)**	**(425)**	*388.5*	**680**	-	**(295)**	-
Increase/(decrease) in debt	-	(798)	(1,045)	438	147	(157)	-	(866)	-	28	-
Share issues / (repurchases)	-	0	0	4	0	0	-	0	-	0	-
Dividends paid	-	0	0	0	0	0	-	0	-	0	-
Other cash from financing	-	0	0	0	0	0	-	0	-	0	-
Cash from financing activities	-	**(798)**	**(1,045)**	**442**	**147**	**(157)**	-	**(866)**	*450.4*	**28**	-
Cash flow chge in cash & equivalents	-	**698**	**(744)**	**(221)**	**601**	**(94)**	-	**(101)**	-	**10**	-
FX / non cash items	-	-	(485)	106	(136)	0	-	0	-	0	-
Bal sheet chge in cash & equivalents	-	**-**	**(1,229)**	**(115)**	**465**	**(94)**	-	**(101)**	-	**10**	-
Core EBITDA	-	693	487	916	1,308	774	*-40.8*	507	*-34.5*	641	*26.4*
Maintenance capital expenditure	-	(193)	(153)	(379)	(611)	(530)	*-13.3*	(345)	*-34.9*	(295)	*-14.5*
Maintenance net working capital	-	0	0	0	0	0	-	0	-	0	-
Operating free cash flow, pre-tax	-	**500**	**334**	**537**	**697**	**244**	*-65.0*	**162**	*-33.6*	**346**	*113.5*

Source: Company accounts, UBS estimates. (UBS) valuations are stated before goodwill-related charges and other adjustments for abnormal and economic items at the analysts' judgement. Note: For some companies, the data represents an extract of the full company accounts.

Global Equity Research

Americas

Electric Utilities

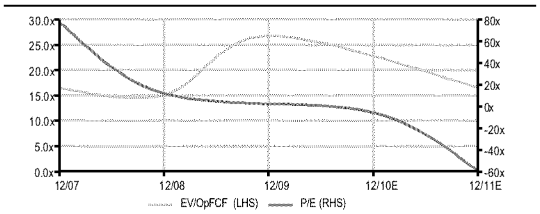
Dynegy, Inc.

12-month rating	**Sell ***
12m price target	**US$1.30**

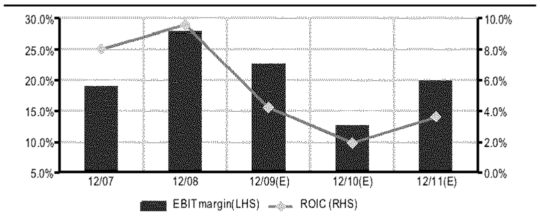
Company profile

Dynegy provides wholesale power, capacity, and ancillary services to utilities, cooperatives, municipalities, and other energy companies in 15 states in key US regions of the Midwest, the Northeast, and the West Coast. The company's power generation portfolio consists of approximately 20,000 megawatts of baseload, intermediate, and peaking power plants fueled by a mix of coal, fuel oil, and natural gas.

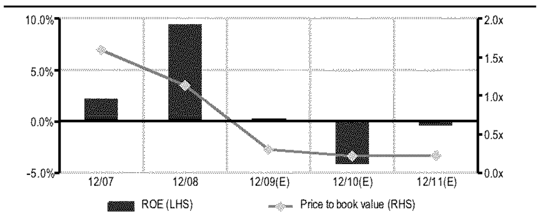
Value (EV/OpFCF & P/E)



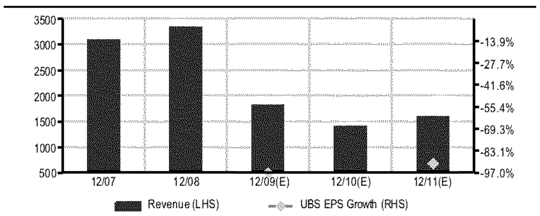
Profitability



ROE v Price to book value



Growth (UBS EPS)



*** Exception to core rating bands; See page150**

Valuation (x)	5Yr Avg	12/07	12/08	12/09E	12/10E	12/11E
P/E (local GAAP)	-	NM	12.0	NM	NM	NM
P/E (UBS)	-	NM	12.0	NM	NM	NM
P/CEPS	-	16.0	6.5	3.8	7.1	3.3
Net dividend yield (%)	-	0.0	0.0	0.0	0.0	0.0
P/BV	-	1.6	1.1	0.3	0.2	0.2
EV/revenue (core)	-	2.8	3.1	3.6	4.3	3.6
EV/EBITDA (core)	-	9.6	8.1	8.5	12.1	9.0
EV/EBIT (core)	-	14.9	11.3	15.7	NM	17.9
EV/OpFCF (core)	-	16.4	15.1	26.8	NM	16.6
EV/op. invested capital	-	1.2	1.1	0.7	0.7	0.7

Enterprise value (US$m)	12/07	12/08	12/09E	12/10E	12/11E
Average market cap	5,216	5,205	1,383	1,383	1,383
+ minority interests	0	0	0	0	0
+ average net debt (cash)	4,035	5,539	5,347	4,933	4,560
+ pension obligations and other	1,572	1,838	1,838	1,838	1,838
- non-core asset value	(2,038)	(2,027)	(2,027)	(2,027)	(2,027)
Core enterprise value	8,785	10,555	6,541	6,127	5,753

Growth (%)	5Yr Avg	12/07	12/08	12/09E	12/10E	12/11E
Revenue	-	53.8	8.1	-45.4	-22.6	13.0
EBITDA (UBS)	-	88.0	42.8	-40.8	-34.5	26.4
EBIT (UBS)	-	129.8	58.6	-55.5	-56.6	77.4
EPS (UBS)	-	-	NM	-96.8	-	-90.9
Cash EPS	-	124.4	75.6	-54.1	-47.0	116.9
Net DPS	-	-	-	-	-	-
BVPS	-	-27.5	-0.3	-0.5	35.1	-0.4

Margins (%)	5Yr Avg	12/07	12/08	12/09E	12/10E	12/11E
EBITDA / revenue	-	29.5	39.0	42.3	35.8	40.0
EBIT / revenue	-	19.0	27.9	22.8	12.8	20.0
Net profit (UBS) / revenue	-	2.7	13.0	0.8	NM	NM

Return on capital (%)	5Yr Avg	12/07	12/08	12/09E	12/10E	12/11E
EBIT ROIC (UBS)	-	8.1	9.6	4.3	2.0	3.7
ROIC post tax	-	3.3	8.2	2.8	2.0	3.7
Net ROE	-	2.2	9.5	0.3	(4.1)	(0.4)

Coverage ratios (x)	5Yr Avg	12/07	12/08	12/09E	12/10E	12/11E
EBIT / net interest	-	1.5	2.2	1.1	0.5	0.9
Dividend cover (UBS EPS)	-	-	-	-	-	-
Div. payout ratio (%, UBS EPS)	-	-	-	-	-	-
Net debt / EBITDA	-	6.2	4.1	6.9	9.0	7.1

Efficiency ratios (x)	5Yr Avg	12/07	12/08	12/09E	12/10E	12/11E
Revenue / op. invested capital	-	0.4	0.3	0.2	0.2	0.2
Revenue / fixed assets	-	0.4	0.4	0.2	0.2	0.2
Revenue / net working capital	-	10.8	8.6	5.3	4.5	4.5

Investment ratios (x)	5Yr Avg	12/07	12/08	12/09E	12/10E	12/11E
OpFCF / EBIT	-	0.9	0.7	0.6	0.9	1.1
Capex / revenue (%)	-	12.2	18.2	29.0	24.4	18.4
Capex / depreciation	-	1.2	1.6	1.5	1.1	0.9

Capital structure (%)	5Yr Avg	12/07	12/08	12/09E	12/10E	12/11E
Net debt / total equity	-	NM	NM	NM	NM	NM
Net debt / (net debt + equity)	-	55.3	54.0	53.6	50.8	51.0
Net debt (core) / EV	-	45.9	52.5	81.8	80.5	79.3

Source: Company accounts, UBS estimates. (UBS) valuations are stated before goodwill-related charges and other adjustments for abnormal and economic items at the analysts' judgement.

Valuations: based on an average share price that year, (E): based on a share price of US$1.65 on 19 Feb 2010 19:35 EST Market cap(E) may include forecast share issues/buybacks.

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UBS Investment Research

RRI Energy Inc.

Global Equity Research

Americas

Electric Utilities

12-month rating	Neutral *
	Unchanged
12m price target	US$5.00
	Prior: US$6.00
Price	US$4.81

RIC: RRI.N BBG: RRI US

Waiting for the Return

■ **RRI Energy provides the best leverage to rising nat gas & power prices**

RRI Energy (formerly Reliant Energy) provides investors with the least hedged recovery to gas & power prices, while conversely expressing a short position on CAPP coal. RRI's fleet is primarily oriented in PA (PJM West), with 6,952 MW of its aggregate 14,563 MW capacity located in the state. Further, the company's primary economics are derived from 8.6GW of merchant (CAPP) coal generation.

■ **Debt reduction program ongoing, as aims for takeout bid**

Mgmt's top priority in the near term remains focused on repaying debt, targeting a \$1.5 Bn reduction through 2011. RRI has earmarked \$400 Mn to pay down its Orion 2010 maturity, and has ~\$90 Mn remaining of its initial \$250 Mn commitment for further reductions (mgmt tended for \$160 Mn of debt in the quarter). We believe the de-leveraging is an attempt by the company to make it more palatable to a bid, mindful of maintaining any likely suitor's investment grade balance sheet.

■ **Environmental controls and carbon loom large for RRI as well**

We believe the most significant risk to RRI remains its exposure to potential environmental regulation on SO_2, NOx, mercury, and carbon. While the company does not anticipate retiring any units prior to 2012, we believe both existing facilities will likely face significant capex requirements and its MISO coal fleet could be at risk; we have added an (inclusive) imputed liability of \$821 Mn.

■ **Valuation: \$5.00 12-month price target fully reflect current strip prices**

Our \$5.00 PT (from \$6.00) is derived using an average of a DCF and an EV/EBITDA SOP multiples approach. Given the company's high exposure to dark spreads and our less than favorable outlook, we believe the stock will likely trade sideways.

Highlights (US$m)	12/07	12/08	12/09E	12/10E	12/11E
Revenues	10,764	12,553	1,714	2,031	2,319
EBIT (UBS)	450	498	(200)	189	266
Net Income (UBS)	128	256	(295)	48	102
EPS (UBS, US$)	0.36	0.74	(0.84)	0.14	0.29
Net DPS (UBS, US$)	0.00	0.00	0.00	0.00	0.00

Profitability & Valuation	5-yr hist av.	12/08	12/09E	12/10E	12/11E
EBIT margin %	-	4.0	-11.7	9.3	11.5
ROIC (EBIT) %	-	9.4	(5.0)	5.7	7.1
EV/EBITDA (core) x	-	8.4	25.4	4.4	3.7
PE (UBS) x	-	23.5	NM	35.3	16.5
Net dividend yield %	-	0.0	0.0	0.0	0.0

Source: Company accounts, Thomson Reuters, UBS estimates. (UBS) valuations are stated before goodwill-related charges and other adjustments for abnormal and economic items at the analysts' judgement.

Valuations: based on an average share price that year, (E): based on a share price of US$4.81 on 19 Feb 2010 19:35 EST

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Trading data

52-wk range	US$7.24-2.23
Market cap.	US$1.66bn
Shares o/s	344m (COM)
Free float	99%
Avg. daily volume ('000)	1,370
Avg. daily value (US$m)	7.2

Balance sheet data 12/09E

Shareholders' equity	US$3.48bn
P/BV (UBS)	0.5x
Net Cash (debt)	(US$0.92bn)

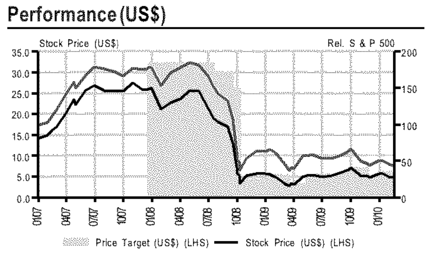
Forecast returns

Forecast price appreciation	+4.0%
Forecast dividend yield	0.0%
Forecast stock return	+4.0%
Market return assumption	5.9%
Forecast excess return	-1.9%

EPS (UBS, US$)

	12/09E			12/08
	From	To	Cons.	Actual
Q1	(0.17)	(0.14)	(0.30)	0.08
Q2	(0.30)	(0.30)	(0.30)	(0.03)
Q3	0.11	(0.06)	(0.05)	1.89
Q4E	(0.27)	(0.38)	(0.18)	(1.20)
12/09E	(0.82)	(0.84)	*(0.83)*	
12/10E	0.14	0.14	*(0.06)*	

Performance (US$)



Source: UBS

www.ubs.com/investmentresearch

*** Exception to core rating bands; See page150**

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Investment Summary

We continue to view RRI Energy cautiously in what we anticipate to prove a difficult ride for the entire power sector. We believe the stock is likely to lead the IPP sector due to its relatively unhedged strategy, bearing the brunt of what we anticipate is likely to prove a challenging commodity environment in the near term. Conversely, we anticipate many investors will flock back to RRI's stock in the eventuality of a recovery in commodity prices. A further overhang for the company remains environmental compliance, as the EPA promulgation of new rules over conventional emissions (CAIR & MACT standards) and further discussions regarding carbon regulation lead to large variability in the terminal value of its fleet. Finally, while RRI's EBITDA profile is not impacted by the roll off of above market hedges like many of its peers, we forecast EBITDA to decline beyond 2011 nonetheless due to our anticipation of a recovery in CAPP coal prices. Offsetting this outlook is the very real potential for a takeout bid, as management has clearly indicated an interest in seeing further consolidation. We believe our price target appropriately values RRI using a discounted 6.5x multiple to account for the relatively weak power price outlook and its disproportionate impact on RRI. While on a $/EV basis, the company appears relatively inexpensive (significantly below replacement cost), we anticipate power markets will likely never in the medium term reach close to new entrant economics, nor will bidders ascribe significant value to the fleet, given the uncertainty of projected cash flows in the face of future environmental regulation.

We see RRI as the ideal investment for investors willing to make a play on PJM Dark spreads (e.g. - the spread between natural gas and coal), environmental policy, and M&A in the sector

First and Foremost, RRI Remains the #1 M&A Target

In our view, RRI continues to welcome bids; we see the stock as benefitting from any market discussion of M&A activity

Despite management's declaration with 1Q09 results that RRI had formally concluded its evaluation of strategic alternatives with the sale of its Reliant Retail business to NRG, we see RRI Energy as the most likely takeout candidate in the utility sector. We firmly believe the utility space could benefit from continued consolidation and with the sale of the retail business, its pure merchant generation portfolio provides an acquisition target for those looking for assets. We believe the name should continue to benefit from a takeout premium and will likely trade up on any market mentions of potential M&A in the sector. While we anticipate appetite for further M&A in the near term is likely limited from merchant generators due to balance sheet and credit considerations, we see share for share inter-IPP M&A remaining the most likely option in the near term. Many Competitive Integrateds have faced pressure from credit rating agencies to limit/balance their commodity vs. regulated earnings mix to maintain their investment grade credit ratings. We do however find it interesting that FE opted to bid for AYE instead of RRI.

Potentially Benefitting From Transition of FE to PJM RTO

FirstEnergy's transition to PJM from MISO could benefit RRI's capacity in the region

RRI Energy stands to potentially benefit from the migration of the FE system into PJM and the ensuing ability for its MISO-oriented plants (ex-Shelby) to participate in PJM's BRA capacity auction, likely leading to higher capacity payments to the units. Should all go forth as planned (FE has already received FERC approval), RRI will participate in a special transition auction in March 2010 for the planning years 2011-12 and 2012-13; the auction is tentatively scheduled for March 15th – 19th, with results posted on March 26th. Further, these plants should also participate in the standard RPM auction held every May (this year for 2013-14).

A special auction will be held in March to establish capacity prices for '11-'13

Continued Debt Paydown Remains the Name of the Game

In step with many of its peer IPPs, RRI Energy is also pursuing a debt reduction strategy aimed at reducing its gross debt to a target of $1.7 Bn (from its current $2.5 Bn level). The reduction, promised as part of RRI's strategy last summer at its latest analyst day, is to deploy its cash to ensure survivability in the latest downturn. RRI Energy recently completed both a tender offer and completed open market purchases of its 2014 Senior Secured notes and aims to payoff the Orion Power Holdings notes when they come due in 2010, at a cost of $400 Mn. The company aims to maintain a minimal long term cash balance of $250 Mn.

Likely targets for a further $400 Mn in debt reduction over the next couple years include:

- $279 Mn remaining of Secured 2014 Notes
- $575 Mn remaining of Unsecured 2014 Notes
- $406 Mn PEDFA Tax-exempt notes

In Tandem With Reducing Cash Liquidity, Looking at Collateral Structure to Maintain Hedges

A further aspect of RRI's goal to pay down debt remains its hope to put in place a collateral structure to mitigate the liquidity impact of commodity hedges, anticipating in effect to replace cash liquidity with a $1 Bn collateral hedge facility. Likely structures include a First Lien asset collateralization for hedges or a commodity-linked revolver. At the time of its analyst day, management was still evaluating its ability to establish a further First Lien against its assets; while it believes it has the authority to do so, management seemingly indicated it would approach bondholders ahead of any final decisions. RRI will likely unveil any such structure in tandem with a renegotiation and extension of its revolver and L/C facility (its $500 Mn revolver matures in 2012).

Future Environmental Liabilities Cloud Earnings Power

Of central concern to RRI's future remains the fate of further emissions regulation on conventional pollutants/permitting constraints (e.g. SO_2, NOx, Hg, and once-through cooling) before any concerns over CO_2 constraints. We calculate the PV environmental liability of the future plants at ~$800 Mn for those plants detailed in its potential investments bucket. We note the Mandalay facility was the only unit included that had negative projected plant margin in 2010. In contrast, Niles, New Castle, El Rama, and Indian River (which represent ~5% of economic margin in 2010) were highlighted by the company as likely not warranting further investment (implying retirement within the decade). Facilities included for potential investments are included Table 71. We note a further potential risk to investment particular to PA coal generators is the state's mandated Phase II rules for a 90% reduction in mercury emissions by 2015 (vs. its 80% by 2010 Phase I requirement); RRI would likely incur additional capex requirements (albeit uncertain) in order to achieve these higher standard.

Table 71: RRI Imputed Environmental Liability NPV

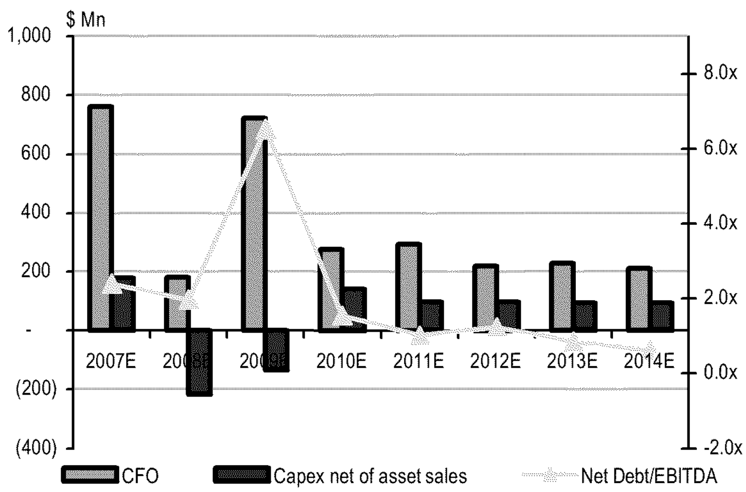
Candidates for Potential Investment		Technology ($ Mn to install)				
	Capacity (MW)	NOx	SO2	Cooling	Decision	Spending
NJ Gas	1,132	140			2012	2013
Portland	570	100	240		2013+	
Shawville	350	90	150	70	2013+	
Titus	274	80	170		2013+	
Avon Lake	745	110	260		2013+	
Ormond	1,516			130	2016	2020
Mandalay	560			70	2016	2020
Total		520	820	270		
Totals (by year)						
Discount Rate (WACC)	10.6%					
Gross Total	1,610					
NPV of Total	**821**					

Source: Company reports and UBS estimates

In interim, RRI Should Remain Modestly Free Cash Flow Positive

We forecast RRI to generate modestly positive free cash flow by 2011, with gradual erosion as we forecast coal price inflation eating away at margins in the long term. We note our capex forecast included in Chart 39 does not include the potential future environmental expenditures discussed above.

Chart 39: RRI Should Outspend Capex in Near Term



Source: UBS estimates

Exposure to CAPP coal price recovery remains material risk

Despite providing investors with the most leverage to a recovery in power prices, the stock is also exposed to a run up in CAPP coal prices. In 2009, RRI management had the unfortunate luck of locking in coal CAPP prices at $3.92/MMBtu (or $98/ton delivered) at the height of the commodity run. We believe should prices run up once more as indicated by our forecast of $100/ton coal in 2012, margins could be significantly impaired. We note we use a 1-year delayed CAPP coal price in our model as the company tends to contract on a rolling basis; due to this factor, should RRI contract at our CAPP coal forecast, our estimates could be revised downwards. Our forecast and current market strip price is included in the sector section of the report in Table 3: UBS CAPP Coal Forecast vs. NYMEX Strip.

EBITDA Estimates

2009 EBITDA represents near-trough earnings power for RRI, as its ill-timed coal hedges topped the coal run-up in 2008 and compressed dark spreads when management failed to lock in power prices in tandem. We expect a significant recovery in EBITDA margins in 2010, as market power prices improve and its former 2009 coal contracts rolloff. We forecast peak EBITDA in 2011, with gas prices levelling at $7.00/MMBtu while our coal price forecast jumps significantly in 2011 & 2012.

Table 72: RRI Energy Adjusted EBITDA Estimates, by Year and Segment

	2006A	2007A	2008A	2009E	2010E	2011E	2012E
Generation Volume (TWh)	33.7	33.7	27.1	26.1	27.8	28.0	28.2
Unit Margin ($/MWh)	**20.8**	**25.7**	**29.8**	**5.4**	**22.2**	**25.5**	**20.5**
Open Energy Gross Margin ($ million)	700	864	807	140	615	713	577
Other Margin ($ million)	**410**	**453**	**486**	**517**	**535**	**444**	**453**
Total Open Gross Margin ($ million)	**1,110**	**1,317**	**1,293**	**657**	**1,151**	**1,157**	**1,030**
EBITDA	**224**	**848**	**835**	**(6)**	**494**	**489**	**351**

Source: Company reports and UBS estimates

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Adjusted EBITDA Under Various Natural Gas Scenarios

We have provided in Table 73 our estimate of RRI's Adjusted EBITDA under various natural gas scenarios, including the current forward curve. This does not dynamically reflect changes to capacity factors, which could in theory moderate the impacts. We further make the assumption that our power prices are related to natural gas prices, reflecting a constant heat rate relationship, which would not necessarily be the market reality.

Table 73: RRI Adjusted EBITDA Scenarios

		Adj. EBITDA - By Year					Price Target
		2010E	2011E	2012E	2013E	2014E	2011 Open EBITDA SOP
	Current	451	510	314	327	291	$5.01
	$5.00	$451	$222	($100)	($91)	($132)	($2.1)
	$5.50	$451	$293	$4	$13	($27)	($0.3)
	$6.00	$451	$363	$107	$118	$79	$1.4
	$6.50	$451	$434	$210	$222	$185	$3.2
NYMEX Gas Assumption	**$7.00**	$451	$510	$314	$327	$291	$5.0
	$7.50	$451	$593	$417	$432	$397	$6.8
	$8.00	$451	$676	$520	$536	$503	$8.7
	$8.50	$451	$758	$624	$641	$609	$10.5
	$9.00	$451	$841	$727	$746	$715	$12.3
	$9.50	$451	$924	$830	$850	$821	$14.1
	$10.00	$451	$1,006	$934	$955	$927	$16.0
Current NYMEX Strip	$5.66	$451	$400	$197	$239	$238	$2.3

Source: NYMEX (for future prices) and UBS estimates

Summarizing the above EBITDA sensitivity, we contrast our Adj. EBITDA estimates against applying the current NYMEX gas strip in Table 74.

Table 74: RRI Comparison of Adj. EBITDA Estimates Using UBS Commodity View and Current NYMEX Gas Strip

	2010E	2011E	2012E	2013E	2014E	Price Target 2011 Open EBITDA SOP
UBS Gas Forecast	**$4.00**	**$6.25**	**$7.00**	**$7.00**	**$7.00**	**$6.25**
Adj EBITDA Est. / PT	451	510	314	327	291	$5.01
Current NYMEX Gas Strip	**$5.66**	**$6.26**	**$6.44**	**$6.58**	**$6.75**	**$6.26**
Adj. EBITDA Est. / PT	451	400	197	239	238	$2.34

Source: UBS estimates

Power & Gas Hedge Position

RRI is distinctive among its utility and IPP peers to the degree it does not hedge. Management's formal hedging policy remains to lock in a minimum $1/MMBtu gas-coal spread in depressed commodity environments. Given the relatively low gas (and, in turn, power prices) seen in the current downturn, management has entered into a renewed hedging program utilizing both gas swaps and power swaps (selling both AD Hub and PJM West), as well as natural gas put options.

RRI uses a combination of gas and power swaps as well as gas put options to lock in revenue

Adjusted EBITDA Under Various CAPP Coal Scenarios

We have provided in Table 75 our estimate of RRI's Adjusted EBITDA under various CAPP coal scenarios, including the current forward curve. This does not dynamically reflect changes to capacity factors, which could in theory moderate the impacts. We further make the assumption that our power prices are related to natural gas prices, reflecting a constant heat rate relationship, which would not necessarily be the market reality. A rough rule of thumb for the company's high degree of exposure to coal prices is a $1/ton move in coal prices equates to ~$10 Mn in EBITDA in 2011 & beyond.

A relatively unique quality is also RRI's large leverage to falling CAPP coal prices

Δ of $1/ton in CAPP coal costs equates to $10 Mn in EBITDA

Table 75: RRI Adjusted EBITDA Scenarios for CAPP Coal

		Adj. EBITDA - By Year					Price Target
		2010E	2011E	2012E	2013E	2014E	2011 Open EBITDA SOP
	Current	451	510	314	327	291	$5.01
	$15	$696	$940	$945	$960	$954	$13.6
	$25	$638	$838	$848	$855	$844	$11.5
	$35	$579	$736	$751	$749	$733	$9.5
	$45	$521	$633	$654	$644	$623	$7.5
CAPP Coal ($/ton)	**$55**	$463	$531	$556	$538	$512	$5.4
	$65	$405	$429	$459	$433	$402	$3.4
	$75	$346	$326	$362	$327	$291	$1.4
	$85	$288	$224	$265	$222	$181	($0.6)
	$95	$230	$121	$168	$116	$71	($2.5)
	$105	$172	$19	$71	$11	($40)	($4.5)
	$115	$113	($83)	($26)	($95)	($150)	($6.4)
Current NYMEX Coal Strip	$55.59	$459	$420	$385	$307	$270	$3.2

Source: NYMEX (for future prices) and UBS estimates

Summarizing the above EBITDA sensitivity, we contrast our Adj. EBITDA estimates against applying the current NYMEX gas strip in Table 76. We assume RRI contracts at prior year pricing (1-year ahead).

Table 76: RRI Comparison of Adj. EBITDA estimates using UBS Commodity View and Current NYMEX Gas Strip

	2010E	2011E	2012E	2013E	2014E	Price Target 2011 Open EBITDA SOP
UBS Coal Forecast ($/ton)	**$57.00**	**$80.00**	**$100.00**	**$75.00**	**$75.00**	**$80.00**
Adj EBITDA Est. / PT	451	510	314	327	291	$5.01
Current NYMEX CAPP Coal Strip	**$55.59**	**$65.86**	**$72.70**	**$76.90**	**$76.90**	**$65.86**
Adj. EBITDA Est. / PT	459	420	385	307	270	$3.20

Source: UBS estimates

CAPP Coal Hedges

In light of the run-up in CAPP coal prices in 2008 and RRI's consequential huge underwater coal hedge in 2009, management has decided to try improve the purchases of CAPP coal and power sales. To this end, management indicated at the time of its latest analyst day to pursue a more appropriate "just-in-time" contracting pricing arrangement with its coal providers. Mgmt has yet to elaborate since on its plans to implement such a program. We include our estimate of the value of these hedges in Table 77.

Table 77: RRI Coal Hedge Position

Coal Hedges	2010E	2011E
Coal Hedges (Mn MMBtu)	91	46
Avg. Hedged Cost - UN-delivered $/ton	2.83	2.31
Market Cost ($/ton)		
UBS Forecast	57	80
Current Market Forecast	54	67
Market Cost ($/MMBtu)		
UBS Forecast	2.28	3.20
Current Market Forecast	2.17	2.69
Other Hedge Value (WACOG, LCG, etc)	4	0
Total Coal Hedge value		
UBS Forecast	(46)	40
Current Market Forecast	(56)	17

Source: Company reports and UBS estimates

Valuation

SOP Valuation

Our $5.00 ($6.00 previously) 12-month price target is derived using the average of our DCF and EV/EBITDA SOP multiples approach. Our EV/EBITDA multiple of 8.0x is below peers, but appropriate given the peak nature of EBITDA in 2011E. Our forecast projects a significant uptick in coal prices, significantly depressing EBITDA in later years. We further believe RRI's assets represent a more risky profile to peers with intermediate coal assets representing the bulk of the company's economics, significantly exposing the company to environmental regulation. In our SOP, we make the following adjustments to our EBITDA to derive equity value:

1) We add back the REMA (Reliant Energy Mid-Atlantic Power Holdings, LLC) lease expense and subtract our PV of the REMA lease;

2) we add the NPV of its remaining Net Operating Losses (NOLs), which could accelerate valuation improvement in the case of a move upwards in commodities;

3) we subtract our PV of the environmental liabilities associated with compliance at several of its potential sites for upgrades; and

4) for the Open EBITDA analyses, we add back the hedge value for RRI's 2011 coal and power contracts, adding back the NPV of the hedges for 2010 and 2011 using our WACC.

Our Hedged EBITDA SOP is provided in Table 78, our Open EBITDA SOP using our UBS commodity view is provided in Table 79, and our Open EBITDA SOP using the current market forwards is provided in Table 80. We note in the case of RRI with relatively few hedges, there is a minimal difference between the valuation between the hedged and open SOP valuations. Given our above market expectations for natural gas prices (which outweigh our above market expectations for coal prices) our SOP valuation based on current market forward yields a lower price target.

Table 78: RRI Energy Hedged EBITDA SOP Valuation

All figures in US $ million except per share data	2011E HedgedEBITDA	EV/EBITDA Multiple			Enterprise Value		
		Low	Base	High	Low	Base	High
Wholesale Contribution Margin	510	5.5x	6.5x	7.5x	2,807	3,318	3,828
REMA Lease Payment	60	5.5x	6.5x	7.5x	330	390	450
Total / Implied	**570**	5.5x	6.5x	7.5x	**3,137**	**3,708**	**4,278**
less net debt						(784)	
less PV of REMA Lease						(435)	
less PV of environment capex						(795)	
add NPV of NOLs						62	
NPV of Equity					**1,186**	**1,756**	**2,327**
Current Number of Shares outstanding					351	351	351
Equity value per share					**$3.38**	**$5.00**	**$6.63**

Source: Company reports and UBS estimates

Table 79: RRI Open EBITDA SOP Valuation Using UBS Commodity Forecast

All figures in US $ million except per share data	2011E Open EBITDA	EV/EBITDA Multiple			Enterprise Value		
		Low	Base	High	Low	Base	High
Wholesale Contribution Margin	510	5.5x	6.5x	7.5x	2,807	3,318	3,828
REMA Lease Payment	60	5.5x	6.5x	7.5x	330	390	450
Power Hedges	45	5.5x	6.5x	7.5x	247	291	336
Coal Hedges	(40)	5.5x	6.5x	7.5x	(223)	(263)	(304)
Total / Implied	**575**	5.5x	6.5x	7.5x	**3,161**	**3,736**	**4,311**
less net debt						(784)	
less PV of REMA Lease						(435)	
less PV of environment capex						(795)	
add NPV of NOLs						62	
add NPV of Power Hedges						(22)	
add NPV of Coal Hedges						(6)	
NPV of Equity					**1,182**	**1,757**	**2,331**
Current Number of Shares outstanding					351	351	351
Equity value per share					**$3.37**	**$5.01**	**$6.64**

Source: Company reports and UBS estimates

Table 80: RRI Open EBITDA SOP Valuation using Current Market Forwards

All figures in US $ million except per share data	2011E Open EBITDA	EV/EBITDA Multiple			Enterprise Value		
		Low	Base	High	Low	Base	High
Wholesale Contribution Margin	510	6.0x	7.0x	8.0x	3,063	3,573	4,084
REMA Lease Payment	60	6.0x	7.0x	8.0x	360	420	480
Power Hedges	(33)	6.0x	7.0x	8.0x	(200)	(233)	(267)
Coal Hedges	(15)	6.0x	7.0x	8.0x	(89)	(103)	(118)
Total / Implied	**522**	6.0x	7.0x	8.0x	**3,134**	**3,657**	**4,179**
less net debt						(784)	
less PV of REMA Lease						(435)	
less PV of environment capex						(795)	
add NPV of NOLs						62	
add NPV of Power Hedges						96	
add NPV of Coal Hedges						(36)	
NPV of Equity					**1,242**	**1,765**	**2,287**
Current Number of Shares outstanding					351	351	351
Equity value per share					**$3.54**	**$5.03**	**$6.52**

Source: Company reports and UBS estimates

DCF Valuation

Verifying our SOP valuation, we use also run a DCF on RRI's future cash flows to derive our price target. Applying an 11.2% WACC and 2.0% terminal growth rate we find the name screens as relatively expensive, with our assumptions proving more generous than peers. We note the DCF is particularly vulnerable to RRI's high equity beta largely due in part to its unhedged open model. We have included a summary of our DCF in Table 81.

Table 81: RRI DCF Valuation

All numbers in US$ million except per share data	2009E	2010E	2011E	2012E	2013E	2014E
EBIT	(195)	206	274	88	111	85
taxes	(68)	72	96	31	39	30
EBIT (1-T)	**(127)**	**134**	**178**	**57**	**72**	**55**
add depreciation	278	251	242	231	221	211
add lease payment	63	52	63	56	64	62
less capex	(186)	(93)	(55)	(55)	(55)	(55)
less acquisitions/sale of assets	388	-	-	-	-	-
less emission allowances	(69)	(48)	(44)	(42)	(41)	(40)
less change in working capital	676	(31)	(50)	(7)	(8)	(8)
FCF	**1,022**	**265**	**333**	**239**	**253**	**225**
PV of FCF	1,022	238	270	174	166	133
Terminal value						2,508
Risk free rate	4.0%					
Debt spread	5.5%					
pre-tax cost of debt	9.5%					
Statuory tax rate	35%					
Post-tax cost of debt	6.2%					
Beta	1.50					
equity risk premium	6.0%					
Cost of equity	13.0%					
market value of equity	2,117					
Net Debt	784					
equity ratio	73%					
debt ratio	27%					
WACC	**11.2%**					
terminal growth rate	**2.0%**					
NPV of FCF	2,003					
NPV of Terminal Value	1,478					
Enterprise Value	3,481					
less debt	(784)					
less REMA Lease	(435)					
add PV of NOLs	62					
add PV of Environmental Liabilities	(795)					
Equity Value	**1,530**					
shares outstanding	351					
Equity Value per share	**$4.36**					
Forward value per share	**$4.84**					

Source: UBS estimates

Scenario Analysis around DCF Assumptions

We provide in the following tables scenario analysis around shifts in WACC, the terminal growth rate, the cost of debt and its capital structure. The company's ongoing deleveraging efforts should not affect its DCF valuation, given the deployment of existing cash on its balance sheet (already recognized in our net debt calculation). A 10 basis point shift in RRI's Beta is a 0.4% impact on its WACC.

Table 82: RRI DCF Sensitivity: WACC vs. Terminal Growth Rate

		WACC				
		10.2%	10.7%	11.2%	11.7%	12.2%
Terminal	1.0%	$4.82	$4.57	$4.34	$4.14	$3.97
Growth Rate	1.5%	$5.13	$4.83	$4.58	$4.36	$4.16
	2.0%	$5.46	$5.13	**$4.84**	$4.59	$4.37
	2.5%	$5.85	$5.47	$5.14	$4.85	$4.60
	3.0%	$6.29	$5.85	$5.47	$5.14	$4.86

Source: UBS estimates

Table 83: RRI DCF Sensitivity: Net Debt / Cap vs. Pre-tax Cost of Debt

		Cost of Debt				
		7.5%	8.5%	**9.5%**	10.5%	11.5%
	17.0%	$4.61	$4.56	$4.51	$4.46	$4.41
	22.0%	$4.82	$4.74	$4.67	$4.60	$4.53
Net Debt / Cap	**27.0%**	$5.04	$4.94	**$4.84**	$4.75	$4.66
	32.0%	$5.30	$5.16	$5.04	$4.92	$4.80
	37.0%	$5.58	$5.41	$5.25	$5.10	$4.96

Source: UBS estimates

Table 84: RRI DCF Sensitivity: Beta vs. Equity Risk Premium

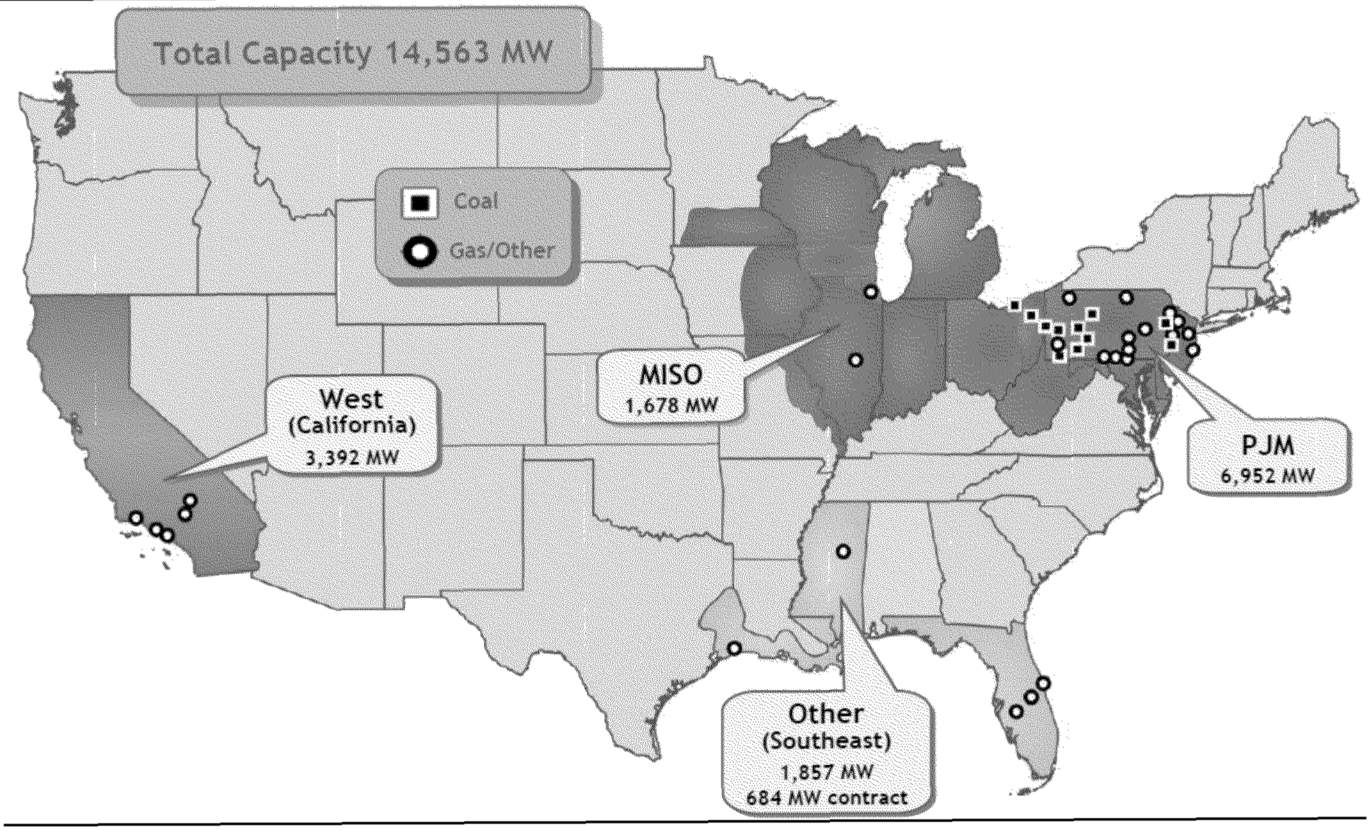
		Equity Risk Premium				
		4.0%	5.0%	**6.0%**	7.0%	8.0%
	1.3	$7.73	$6.50	$5.57	$4.83	$4.25
	1.4	$7.31	$6.11	$5.21	$4.50	$3.95
Beta	**1.5**	$6.93	$5.76	**$4.88**	$4.21	$3.68
	1.6	$6.58	$5.44	$4.59	$3.95	$3.44
	1.7	$6.26	$5.15	$4.33	$3.71	$3.23

Source: UBS estimates

Company Description

RRI owns and contracts 14,563 MW (684 MW contracted) of generation across the US. The majority of the company's EBITDA margin is derived from its eastern baseload/intermediate coal fleet.

Figure 5: RRI's Generation Fleet



Source: Company presentation

We have provided our estimates for RRI Energy's volumes in 2009 and beyond; while we anticipate a decline from 2008 levels, we see this a trough year with volumes likely recovering to greater than 30 GWh by 2012.

Table 85: RRI Energy estimated Generation Volumes (GWh)

Generation Volume (GWh)	2007A	2008A	2009E	2010E	2011E	2012E
PJM Coal	19,677	18,438	16,333	17,681	19,155	20,039
MISO Coal	5,518	4,988	3,985	4,433	4,765	5,097
PJM/MISO Gas	1,444	1,235	1,937	1,456	1,456	1,456
West	3,544	2,393	2,992	3,320	3,320	3,320
Other	3,494	62	827	871	871	871
Total	**33,677**	**27,116**	**26,073**	**27,761**	**29,567**	**30,784**

Source: Company reports and UBS estimates

Table 86: RRI Energy estimated Generation Volumes (GWh)

Generation Volume (GWh)	2007A	2008A	2009E	2010E	2011E	2012E
PJM Coal	19,677	18,438	16,333	17,681	19,155	20,039
MISO Coal	5,518	4,988	3,985	4,433	4,765	5,097
PJM/MISO Gas	1,444	1,235	1,937	1,456	1,456	1,456
West	3,544	2,393	2,992	3,320	3,320	3,320
Other	3,494	62	827	871	871	871
Total	**33,677**	**27,116**	**26,073**	**27,761**	**29,567**	**30,784**

Source: Company reports and UBS estimates

The generation volumes translate to the following capacity factors:

Table 87: RRI Energy Generation Capacity Factors (%)

Overall Capacity Factor	2007A	2008A	2009E	2010E	2011E	2012E
PJM Coal	68%	63%	55%	60%	65%	68%
MISO Coal	50%	45%	36%	40%	43%	46%
PJM/MISO Gas	5%	4%	6%	4%	4%	4%
West	12%	9%	9%	10%	10%	10%
Other	44%	1%	4%	4%	4%	4%
Total	**32%**	**26%**	**20%**	**21%**	**23%**	**24%**

Source: Company reports and UBS estimates

The primary contributor to the YoY decline in EBITDA is related to the collapse in the PJM West dark spread, as can be seen clearly in our 2009 Unit Open margin estimates.

Table 88: RRI Energy Open Margin ($/MWn)

Unit Open Margin ($/MWH)	2007A	2008A	2009E	2010E	2011E	2012E
PJM Coal	31	33	4	28	31	21
MISO Coal	29	22	2	14	19	12
PJM/MISO Gas	35	34	11	24	27	27
West	6	(0)	15	3	3	3
Other	7	16	0	0	0	0
Weighted Average	**25.7**	**29.8**	**9**	**21**	**25**	**17**

Source: Company reports and UBS estimates

RRI Energy Generation Facilities, by Region

We have included in the following tables lists of generation units that make up each of RRI's segments. Included within each table is its weighted average heat rate, useful in making broader characterizations as to the fuel costs of its segments. Should FirstEnergy succeed in transitioning its ATSI transmission grid to PJM, Shelby will be RRI's only remaining MISO asset.

RRI's PJM coal assets form the bulk of its existing commodity margin, providing the company with large leverage to PJM West – CAPP coal dark spreads.

Table 89: PJM Coal Assets

PJM Coal	Location	Primary Fuel	Capacity	Heat Rates	SO_2 Control	NO_x Control	Commercial CF 2006	2007	2008
Cheswick	PA	Coal	560	10.0	Wet FGD (2010)	SNCR, LNB, OFA	76.2%	82.3%	94.0%
Conemaugh 1 & 2	PA	Coal	281	9.4	Wet FGD	LNB, OFA	97.2%	88.9%	81.7%
Elrama 1, 2, 3	PA	Coal	289	11.5-12.6	Wet FGD	SNCR, LNB, OFA	72.2%	64.3/60.0/ 75.1%	81.8%
Elrama 4	PA	Coal	171	10.4	Wet FGD	SNCR, LNB, OFA	74.2%	71.1%	84.2%
Keystone 1 & 2	PA	Coal	284	9.5	Wet FGD (2009)	SNCR, LNB, OFA	90.3%	96.3/ 75.1%	97.9%
Portland 1	PA	Coal	158	10.0	-	LNB, OFA	88.2%	85.8%	62.5%
Portland 2	PA	Coal	243	9.6	-	LNB, OFA	86.9%	81.0%	90.8%
Seward	PA	Coal	525	9.7	Limestone Injection	-	74.6%	82.4%	86.4%
Shawville 1 & 2	PA	Coal	247	10.1	-	SNCR (2009), LNB, OFA	80.8%	88/86.7%	84.4%
Shawville 3 & 4	PA	Coal	350	10.4	-	SNCR (2009), LNB, OFA	92.4%	73/88.8%	84.3%
Titus 1, 2, 3	PA	Coal	243	10.8	-	LNB, OFA	91.4%	96.5/91.8/ 80.6%	87.3%
Total / Weighted Avg			**3,351**	**9.1**					

Source: Company reports

RRI's MISO coal assets remain its second tier facilities, likely facing retirement over the next decade should commodity prices remain lackluster. These units in particular should form the bulk of RRI's benefit in the shift from MISO to PJM.

Table 90: MISO Coal Units

MISO Coal	Location	Primary Fuel	Capacity	Heat Rates	SO_2 Control	NO_x Control	CCF 2006	2007	2008
Avon Lake 7	OH	Coal	96	15.1	-	SNCR (temp), LNB, OFA	86.4%	76.2%	78.5%
Avon Lake 9	OH	Coal	625	9.0	-	SNCR (temp), LNB, OFA	88.9%	60.7%	86.8%
Avon Lake 10	OH	Nat. Gas	24	17.4	-	-	100.0%	100.0%	-
New Castle 3, 4	PA	Coal	193	10.9	-	SNCR (temp), LNB, OFA	78.2/ 84.9%	80.0/ 87.5%	89.1%
New Castle 5	PA	Coal	135	10.3	-	SNCR (temp), LNB, OFA	84.8%	68.4%	92.3%
New Castle IC	PA	Fuel Oil	6	10.0	-	-	100.0%	100.0%	-
Niles 1	OH	Coal	108	10.6	Wet FGD	SNCR (temp), LNB, OFA	74.8%	76.1%	80.1%
Niles 2	OH	Coal	108	10.5	-	SNCR (temp), LNB, OFA	81.9%	85.6%	72.0%
Niles GT	OH	Fuel Oil	28	21.3	-	-	100.0%	0.0%	-
Total			**1,323**						

Source: Company reports

Offsetting the company's large coal fleet is a robust fleet of natural gas and oil units in the Mid-Atlantic. We see the economics of this fleet as largely being determined by capacity revenues received through PJM's BRA auction.

Table 91: PJM/MISO Gas Units

MISO Coal	Location	Primary Fuel	Capacity	Heat Rates	SO_2 Control	NO_x Control	CCF 2006	CCF 2007	CCF 2008
Avon Lake 7	OH	Coal	96	15.1	-	SNCR (temp), LNB, OFA	86.4%	76.2%	78.5%
Avon Lake 9	OH	Coal	625	9.0	-	SNCR (temp), LNB, OFA	88.9%	60.7%	86.8%
Avon Lake 10	OH	Nat. Gas	24	17.4	-	-	100.0%	100.0%	-
New Castle 3, 4	PA	Coal	193	10.9	-	SNCR (temp), LNB, OFA	78.2/ 84.9%	80.0/ 87.5%	89.1%
New Castle 5	PA	Coal	135	10.3	-	SNCR (temp), LNB, OFA	84.8%	68.4%	92.3%
New Castle IC	PA	Fuel Oil	6	10.0	-	-	100.0%	100.0%	-
Niles 1	OH	Coal	108	10.6	Wet FGD	SNCR (temp), LNB, OFA	74.8%	76.1%	80.1%
Niles 2	OH	Coal	108	10.5	-	SNCR (temp), LNB, OFA	81.9%	85.6%	72.0%
Niles GT	OH	Fuel Oil	28	21.3	-	-	100.0%	0.0%	-
Total / Weighted Avg			**1,323**	**10.5**					

Source: Company reports

RRI's Western segment largely remains a contracted market, with little direct commodity exposure from the segment.

Table 92: CAISO West Units

West	Location	Primary Fuel	Capacity	Heat Rates	SO_2 Control	NO_x Control	CCF 2006	CCF 2007	CCF 2008
Coolwater	CA	Nat. Gas	622	10.1	-	IFGR	96.1%	96.5%	92.9%
Ellwood	CA	Nat. Gas	54	13.3	-	Water Ing.	100.0%	0.0%	0.0%
Etiwanda	CA	Nat. Gas	640	10.0	-	SCR, FGR	0.0%	0.0%	0.0%
Mandalay	CA	Nat. Gas	560	10.9	-	SCR, FGR, LNB, OFA	97.2%	85.6%	97.0%
Ormond Beach	CA	Nat. Gas	1516	9.6	-	SCR, FGR, LNB	56.9%	93.5%	91.1%
Total / Weighted Avg			**3,392**	**10.0**					

Source: Company reports

RRI's Southeast portfolio is also relatively focused on contracted opportunities given the relatively opaque market dynamics in the region.

Table 93: Southeast Units

Southeast	Location	Primary Fuel	Capacity	Heat Rates	SO_2 Control	NO_x Control	CCF 2006	CCF 2007	CCF 2008
Indian River	FL	Dual	587	10.5	-	-	0.0%	0.0%	0.0%
Osceola	FL	Dual	470	11.0	-	Water Inj./ LPM	0.0%	100.0%	100.0%
Choctaw	MS	Nat. Gas	800	-	-	SCR, LPM	0.0%	72.9%	81.8%
Vandolah (Tolling)	FL	Tolling	630	-	-	SCR, LPM	-	-	-
Sabine (Equity Investment)	TX	Nat. Gas	54	-	-	SCR, LPM	-	-	-
Total / Weighted Avg			**2,541**						

Source: Company reports

Risks

Risks to our investment thesis include: 1) actual commodity prices differing significantly from our assumptions, with large exposure to wholesale power prices in PJM and corresponding cost of coal, due its limited hedging program; 2) political and regulatory intervention to change the structure of competitive markets in response to high power prices and insufficient new build; 3) the current state of credit markets that has limited the companies' flexibility to return excess cash to shareholders; and 4) unknown impact from a potential carbon legislation (likely a significant negative). Other investment risks include abrupt changes in weather pattern, sharp slowdown in economic demand, interest rate risks, and disruption of trading activity in power markets.

RRI Energy Inc.

Income statement (US$m)	12/04	12/05	12/06	12/07	12/08	12/09E	% ch	12/10E	% ch	12/11E	% ch
Revenues	-	9,712	10,877	10,764	12,553	1,714	-86.3	2,031	18.5	2,319	14.2
Operating expenses (ex depn)	-	(9,587)	(10,560)	(9,890)	(11,718)	(1,636)	-86.0	(1,591)	-2.7	(1,811)	13.8
EBITDA (UBS)	-	125	318	874	835	78	-90.7	439	464.7	508	15.7
Depreciation	-	(446)	(373)	(424)	(337)	(278)	-17.4	(251)	-9.8	(242)	-3.6
Operating income (EBIT, UBS)	-	(321)	(55)	450	498	(200)	-	189	-	266	41.3
Other income & associates	-	25	0	5	5	5	0.0	5	0.0	5	0.0
Net interest	-	(399)	(394)	(314)	(219)	(174)	-20.6	(120)	-31.0	(103)	-13.9
Abnormal items (pre-tax)	-	0	0	0	0	0	-	0	-	0	-
Profit before tax	-	(694)	(449)	140	285	(369)	-	74	-	168	128.4
Tax	-	253	122	(12)	(28)	74	-	(26)	-	(66)	155.8
Profit after tax	-	(441)	(327)	128	256	(295)	-	48	-	102	113.6
Abnormal items (post-tax)	-	0	0	0	0	0	-	0	-	0	-
Minorities / pref dividends	-	0	0	0	0	0	-	0	-	0	-
Net income (local GAAP)	-	(441)	(327)	128	256	(295)	-	48	-	102	113.6
Net Income (UBS)	-	(441)	(327)	128	256	(295)	-	48	-	102	113.6
Tax rate (%)	-	0	0	9	10	0	-	35	-	39	12.0
Pre-abnormal tax rate (%)	-	0	0	9	10	0	-	35	-	39	12.0

Per share (US$)	12/04	12/05	12/06	12/07	12/08	12/09E	% ch	12/10E	% ch	12/11E	% ch
EPS (local GAAP)	-	(1.46)	(1.06)	0.36	0.74	(0.84)	-	0.14	-	0.29	113.6
EPS (UBS)	-	(1.46)	(1.06)	0.36	0.74	(0.84)	-	0.14	-	0.29	113.6
Net DPS	-	0.00	0.00	0.00	0.00	0.00	-	0.00	-	0.00	-
Cash EPS	-	0.02	0.15	1.62	1.74	(0.05)	-	0.85	-	0.98	15.2
BVPS	-	13.23	12.81	13.12	11.06	9.92	-10.3	10.06	1.4	10.35	2.9

Balance sheet (US$m)	12/04	12/05	12/06	12/07	12/08	12/09E	% ch	12/10E	% ch	12/11E	% ch
Cash and equivalents	-	88	464	755	1,109	799	-28.0	608	-23.9	627	3.1
Other current assets	-	4,642	2,709	2,030	3,252	1,999	-38.5	2,026	1.4	2,090	3.1
Total current assets	-	4,730	3,173	2,785	4,361	2,798	-35.8	2,634	-5.9	2,717	3.1
Net tangible fixed assets	-	5,934	5,742	5,222	4,877	4,397	-9.8	4,239	-3.6	4,052	-4.4
Net intangible fixed assets	-	897	805	785	440	440	0.0	440	0.0	440	0.0
Investments / other assets	0	2,007	847	665	957	1,027	7.2	1,074	4.7	1,118	4.1
Total assets	-	13,569	10,567	9,457	10,635	8,661	-18.6	8,387	-3.2	8,327	-0.7
Trade payables & other ST liabilities	-	2,617	2,338	1,551	2,933	2,355	-19.7	2,352	-0.1	2,365	0.5
Short term debt	-	789	355	53	13	7	-40.7	6	-18.6	5	-12.5
Total current liabilities	-	3,406	2,693	1,603	2,945	2,362	-19.8	2,358	-0.2	2,370	0.5
Long term debt	-	4,317	3,178	2,902	2,871	1,711	-40.4	1,393	-18.6	2,325	66.9
Other long term liabilities	-	1,981	745	469	1,041	1,106	6.2	1,106	0.0	0	-
Total liabilities	-	9,705	6,616	4,975	6,858	5,179	-24.5	4,857	-6.2	4,695	-3.3
Equity & minority interests	-	3,864	3,952	4,482	3,778	3,482	-7.8	3,530	1.4	3,632	2.9
Total liabilities & equity	-	13,569	10,567	9,457	10,635	8,661	-18.6	8,387	-3.2	8,327	-0.7

Cash flow (US$m)	12/04	12/05	12/06	12/07	12/08	12/09E	% ch	12/10E	% ch	12/11E	% ch
Net income	-	(441)	(327)	128	256	(295)	-	48	-	102	113.6
Depreciation	-	446	373	424	337	278	-17.4	251	-9.8	242	-3.6
Net change in working capital	(349)	(1,237)	1,169	127	(239)	676	-	(29)	-	(51)	73.8
Other (operating)	140	483	215	(267)	1,005	65	-93.5	0	-	0	-
Net cash from operations	-	(749)	1,429	413	1,359	723	-46.8	269	-62.8	293	8.8
Capital expenditure	(160)	(82)	(97)	(189)	(310)	(186)	-40.1	(93)	-50.0	(55)	-40.9
Net (acquisitions) / disposals	(53)	238	184	(3)	520	319	-38.7	(48)	-	(44)	-7.9
Other changes in investments	1,114	150	969	13	7	0	-	0	-	0	-
Cash from investing activities	901	306	1,057	(179)	217	133	-38.7	(141)	-	(99)	-29.7
Increase/(decrease) in debt	(169)	596	(1,267)	(188)	(45)	(1,166)	-	(319)	-	(174)	-
Share issues / (repurchases)	0	0	0	0	0	0	-	0	-	0	-
Dividends paid	0	0	0	0	0	0	-	0	-	0	-
Other cash from financing	(879)	(1)	(691)	(104)	0	0	-	0	-	0	-
Cash from financing activities	(1,048)	594	(1,957)	(292)	(45)	(1,166)	2481.7	(319)	-72.6	(174)	-45.4
Cash flow chge in cash & equivalents	-	152	529	(58)	1,530	(310)	-	(191)	-	19	-
FX / non cash items	-	-	(153)	350	(1,176)	0	-100.0	0	-	0	-
Bal sheet chge in cash & equivalents	-	-	376	291	354	(310)	-	(191)	-	19	-
Core EBITDA	-	125	318	874	835	78	-90.7	439	464.7	508	15.7
Maintenance capital expenditure	-	-	(69)	(98)	(90)	(55)	-38.9	(55)	0.0	(55)	0.0
Maintenance net working capital	-	-	0	0	0	0	-	0	-	0	-
Operating free cash flow, pre-tax	-	-	249	776	745	23	-96.9	384	1587.6	453	17.9

Source: Company accounts, UBS estimates. (UBS) valuations are stated before goodwill-related charges and other adjustments for abnormal and economic items at the analysts' judgement. Note: For some companies, the data represents an extract of the full company accounts.

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Global Equity Research

Americas

Electric Utilities

RRI Energy Inc.

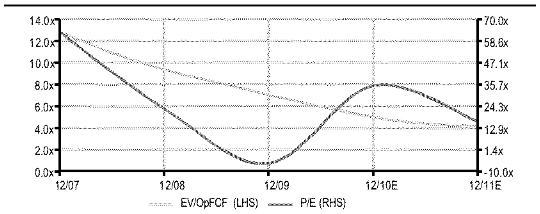
12-month rating **Neutral ***

12m price target **US$5.00**

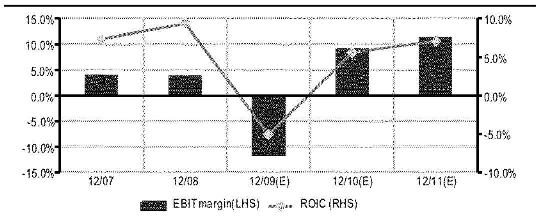
Company profile

RRI Energy, Inc., based in Houston, is one of the largest independent power producers in the nation, with approximately 14,000 megawatts of power generation capacity in operation across the US.

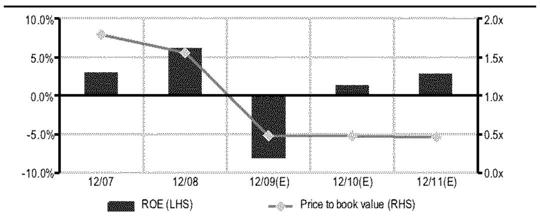
Value (EV/OpFCF & P/E)



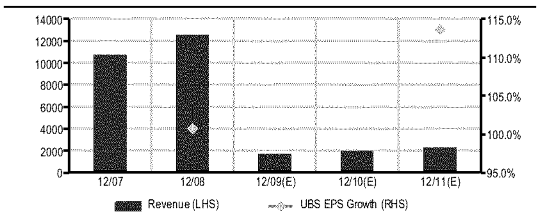
Profitability



ROE v Price to book value



Growth (UBS EPS)



*** Exception to core rating bands; See page150**

Valuation (x)	5Yr Avg	12/07	12/08	12/09E	12/10E	12/11E
P/E (local GAAP)	-	65.2	23.5	NM	35.3	16.5
P/E (UBS)	-	65.2	23.5	NM	35.3	16.5
P/CEPS	-	14.6	10.0	NM	5.7	4.9
Net dividend yield (%)	-	0.0	0.0	0.0	0.0	0.0
P/BV	-	1.8	1.6	0.5	0.5	0.5
EV/revenue (core)	-	0.9	0.6	1.2	0.9	0.8
EV/EBITDA (core)	-	11.4	8.4	25.4	4.4	3.7
EV/EBIT (core)	-	22.2	14.0	NM	10.2	7.1
EV/OpFCF (core)	-	12.8	9.4	NM	5.0	4.2
EV/op. invested capital	-	1.6	1.3	0.5	0.6	0.5

Enterprise value (US$m)	12/07	12/08	12/09E	12/10E	12/11E
Average market cap	7,997	5,958	1,656	1,656	1,656
+ minority interests	0	0	0	0	0
+ average net debt (cash)	2,634	1,987	1,347	1,347	1,347
+ pension obligations and other	0	0	0	0	0
- non-core asset value	(665)	(957)	(1,027)	(1,074)	(1,118)
Core enterprise value	9,967	6,988	1,977	1,929	1,885

Growth (%)	5Yr Avg	12/07	12/08	12/09E	12/10E	12/11E
Revenue	-	-1.0	16.6	-86.3	18.5	14.2
EBITDA (UBS)	-	175.2	-4.5	-90.7	NM	15.7
EBIT (UBS)	-	-	10.9	-	-	41.3
EPS (UBS)	-	-	100.8	-	-	113.6
Cash EPS	-	NM	7.4	-	-	15.2
Net DPS	-	-	-	-	-	-
BVPS	-	2.4	-15.7	-10.3	1.4	2.9

Margins (%)	5Yr Avg	12/07	12/08	12/09E	12/10E	12/11E
EBITDA / revenue	-	8.1	6.7	4.5	21.6	21.9
EBIT / revenue	-	4.2	4.0	-11.7	9.3	11.5
Net profit (UBS) / revenue	-	1.2	2.0	NM	2.4	4.4

Return on capital (%)	5Yr Avg	12/07	12/08	12/09E	12/10E	12/11E
EBIT ROIC (UBS)	-	7.4	9.4	NM	5.7	7.1
ROIC post tax	-	6.7	8.5	NM	3.7	4.3
Net ROE	-	3.0	6.2	(8.1)	1.4	2.9

Coverage ratios (x)	5Yr Avg	12/07	12/08	12/09E	12/10E	12/11E
EBIT / net interest	-	1.4	2.3	-	1.6	2.6
Dividend cover (UBS EPS)	-	-	-	-	-	-
Div. payout ratio (%, UBS EPS)	-	-	-	-	-	-
Net debt / EBITDA	-	2.5	2.1	NM	1.8	3.4

Efficiency ratios (x)	5Yr Avg	12/07	12/08	12/09E	12/10E	12/11E
Revenue / op. invested capital	-	1.8	2.4	0.4	0.6	0.6
Revenue / fixed assets	-	1.7	2.2	0.3	0.4	0.5
Revenue / net working capital	-	25.3	31.4	NM	NM	NM

Investment ratios (x)	5Yr Avg	12/07	12/08	12/09E	12/10E	12/11E
OpFCF / EBIT	-	1.7	1.5	NM	2.0	1.7
Capex / revenue (%)	-	1.8	2.5	10.9	4.6	2.4
Capex / depreciation	-	0.4	0.9	0.7	0.4	0.2

Capital structure (%)	5Yr Avg	12/07	12/08	12/09E	12/10E	12/11E
Net debt / total equity	-	49.1	47.0	26.4	22.4	46.9
Net debt / (net debt + equity)	-	32.9	32.0	20.9	18.3	31.9
Net debt (core) / EV	-	26.4	28.4	68.1	69.8	71.5

Source: Company accounts, UBS estimates. (UBS) valuations are stated before goodwill-related charges and other adjustments for abnormal and economic items at the analysts' judgement.

Valuations: based on an average share price that year, (E): based on a share price of US$4.81 on 19 Feb 2010 19:35 EST Market cap(E) may include forecast share issues/buybacks.

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UBS Investment Research

Mirant Corp

Global Equity Research

Americas

Electric Utilities

12-month rating	Sell
	Prior: Neutral
12m price target	US$11.00
	Prior: US$15.00
Price	US$13.45

RIC: MIR.N BBG: MIR US

Looking Past the Hype: Downgrade to Sell

■ **We are downgrading MIR as EBITDA fall off hidden in near-year comps**

We are downgrading MIR to Sell despite the company's apparent cheap near-year multiple to account for its fundamentally declining EBITDA profile. Trading at a 5% discount on near term hedged EBITDA multiples, the company is likely experiencing the most dramatic fall-off in EBITDA in the IPP sector. We anticipate the premium price it receives for its power to be eroded as new transmission (TRAIL in 2011, and less so PATH in 2015+) comes online.

■ **We see no share repurchase program announced; not out of the woods**

Despite the company's substantial cash balance (~$2.0 Bn) and the completion of its environmental compliance program by mid-year 2010, we do not anticipate mgmt to announce any new share repurchase programs. Alternatively, we believe mgmt will conserve liquidity as $2.5 Bn in debt/facilities matures through '13.

■ **Premium price to PJM West potentially at risk; is it gone for good?**

Although Mirant has historically enjoyed a premium basis to PJM West power prices of $11-12/MWh, we find the avg. 2009 basis at just $3.86/MWh due to lower demand and congestion. While we forecast a recovery to the $6-7/MWh level in '11 & beyond, we are doubtful of a full recovery. Finally, given the fact that mgmt hedges basis only up to 18 months ahead, we are uncertain as to what nearer term impacts the lower basis could have on our estimates.

■ **Valuation: Downgrading to Sell, as see too much risk for the price**

Our lowered $11 PT is derived using DCF and SOP (both hedged & open EV/EBITDA) analysis. While MIR does not face the same secular headwinds as DYN, it trades at a pricey 9.4x EV/EBITDA to our calculated Open '11 EBITDA est. We apply a generous 6.5x EV/EBITDA multiple to its hedged EBITDA to arrive at our $11 PT, despite a 25% decline in EBITDA in '12+.

Highlights (US$m)	12/07	12/08	12/09E	12/10E	12/11E
Revenues	2,353	2,331	2,226	2,168	2,139
EBIT (UBS)	859	638	730	431	277
Net Income (UBS)	603	447	587	320	170
EPS (UBS, US$)	2.18	2.25	4.04	2.20	1.17
Net DPS (UBS, US$)	0.00	0.00	0.00	0.00	0.00

Profitability & Valuation	5-yr hist av.	12/08	12/09E	12/10E	12/11E
EBIT margin %	-	27.4	32.8	19.9	12.9
ROIC (EBIT) %	-	15.8	14.9	8.1	5.0
EV/EBITDA (core) x	-	7.6	3.2	4.7	6.0
PE (UBS) x	-	13.6	3.3	6.1	11.5
Net dividend yield %	-	0.0	0.0	0.0	0.0

Source: Company accounts, Thomson Reuters, UBS estimates. (UBS) valuations are stated before goodwill-related charges and other adjustments for abnormal and economic items at the analysts' judgement.

Valuations: based on an average share price that year, (E): based on a share price of US$13.45 on 19 Feb 2010 19:35 EST

Trading data

52-wk range	US$18.72-9.25
Market cap.	US$1.95bn
Shares o/s	145m (ORD)
Free float	100%
Avg. daily volume ('000)	449
Avg. daily value (US$m)	6.5

Balance sheet data 12/09E

Shareholders' equity	US$4.35bn
P/BV (UBS)	0.4x
Net Cash (debt)	(US$0.81bn)

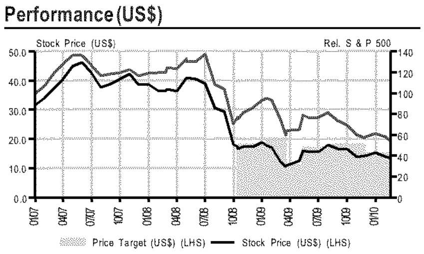
Forecast returns

Forecast price appreciation	-18.2%
Forecast dividend yield	0.0%
Forecast stock return	-18.2%
Market return assumption	5.9%
Forecast excess return	-24.1%

EPS (UBS, US$)

	12/09E			12/08
	From	To	Cons.	Actual
Q1	0.77	0.77	0.79	0.53
Q2	1.21	1.21	0.90	0.24
Q3	1.63	1.63	1.63	1.09
Q4E	0.63	0.43	0.54	0.46
12/09E	4.23	4.04	*3.62*	
12/10E	2.03	2.20	*1.65*	

Performance (US$)



Source: UBS

www.ubs.com/investmentresearch

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Investment Summary

We are downgrading MIR to Sell from Neutral and lowering our price target to $11 from $15. We the see shares as significantly overvalued to peers and believe the name could disappoint investors mid-year if no share repurchase program is announced following the completion of its large capex spend. However, we believe management will likely prove more conservative and choose not to proceed with a further repurchase program. Alternatively, with $600 Mn of cash trapped at subsidiaries, a $545 Mn maturity in 2011, and further $850 Mn in 2013, we believe MIR's (conservative) management will sit on its $2 Bn in cash for the moment.

We are downgrading MIR to Sell from Neutral, lowering our price target to $11 from $15

We do NOT anticipate share repurchases later this year; this could be a disappointment and perceived as risky to others with $2 Bn on the B/S

As for the underlying business, we believe the name remains misunderstood with ***significantly*** *above market hedges deluding investors looking at pure multiples even out to 2012. Our Open EBITDA SOP valuation uses a trough multiple of 10.0x EV/EBITDA to arrive at our $11 price target. While the name does benefit from a relatively advantaged environmental profile (given the completion of SO_2 reducing scrubbers at its three MD coal facilities last year), we see the premium power price earned by these plants in a congested pocket of the Mid-Atlantic as likely being dissipated by future transmission build. We remind investors that while several transmission projects have been delayed, the TRAIL project (D-AYE Partnership) remains targeted for a June 1, 2011 in-service, likely depressing power prices for Mirant's coal fleet further.*

The company's cheap appearance on the FY1 and FY2 multiples basis conceals above market value of its hedges

While a takeout risk remains a clear concern for our Sell rating, we believe at current valuations and with overhang remaining regarding future environmental regulations (for ash ponds, mercury, and carbon) we anticipate buyers will remain on the sidelines. Further, we see no clear combinations for Corporate M&A in the space (one-off asset acquisitions do remain in the cards).

Takeout risk is real, but unlikely given current landscape in sector, risk over environmental regulation, and pricey shares; RRI is a more likely target

Our $11 price target for MIR is derived using an average of our DCF, and both Open and Hedged SOP EV/EBITDA on 2011E. We see the stock as likely underperforming through the year given the macro headwinds for the sector, investors looking past low FY1 and FY2 multiples, and disappointment regarding a share repurchase program. We see its Mid-Atlantic peer, RRI as a comparably much more attractive, albeit risky investment.

At a cheaper valuation, we see RRI's (relatively comparably) share as relatively more attractive

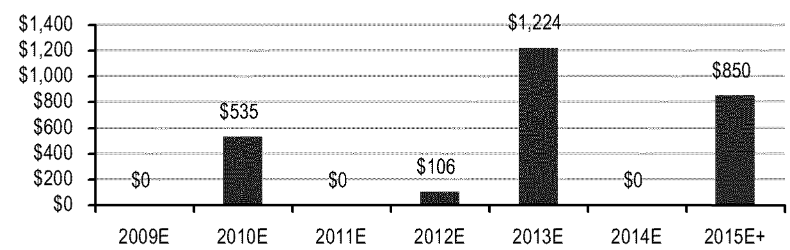
Capital Redeployment Could Disappointment Some; no Share Repo

While management has discussed re-evaluating its cash position following the outcome of PG&E's California RFO and conclusion of its environmental expenditures related to Maryland Healthy Air Act compliance, we anticipate no new announcements regarding its capital deployment ambitions this year. We believe despite having a long term goal of achieving a 4.0x Net Debt / EBITDAR goal (on '12 trough EBITDA they are at just 1.7x), a more conservative mantra (and rightly so) will prevail with management likely announcing its intentions to pay down debt either pre-emptively or as they mature (Table 94 includes its maturity profile). We see such an announcement as likely being perceived as a disappointment to the market, and more importantly as the last of the potential positive catalysts for 2010. Should MIR be successful in refinancing its 2013 $850 Mn Mirant NA note and its 2012 $1 Bn revolving credit facility (of which only $106 Mn is drawn), we believe there

We believe a shrewd management will choose not to redeploy cash in the face of little free cash flow forecast in the future and several maturities looming

is a substantially better chance management would feel comfortable enough with a share repurchase program at that time.

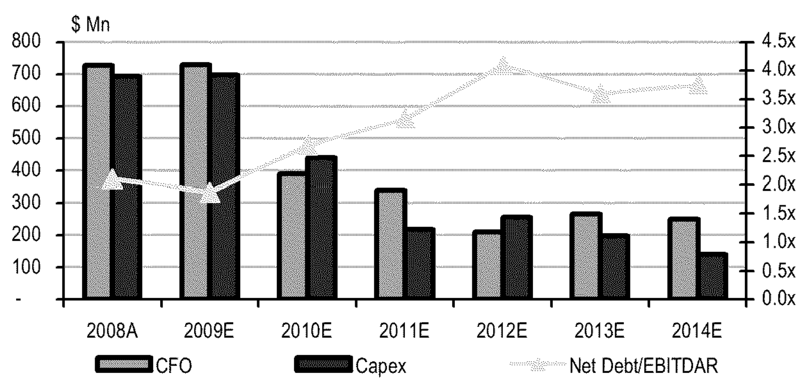
Table 94: MIR Maturity Profile



Source: UBS estimates

Looking longer term at the company's cash flows, we do not project significant free cash flow. In fact, we project the company to continue to be relatively FCF neutral despite the significant ramp down in spend on environmental controls. We have provided a snapshot of our cash flow projections in Chart 40.

Chart 40: Mirant Cash Flow Profile – Capex Roughly Offsets CFO Generation



Source: UBS estimates

Backwardated EBITDA Profile Should Persist Through 2014

EBITDA to continue to trend downward, reaching a trough in 2012E and a lower trough in 2015E

Even assuming our above market natural gas price, we see the stock as continuing to post declining EBITDA, with declines likely even beyond our forecast period of 2014. Further, with plants facing retirement, the higher cost of running advanced environmental controls, and the potential for further regulatory requirements on emissions, likely revisions to EBITDA point downwards. We have included our EBITDA estimates (both ours and applying the natural gas curve) below.

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Table 95: Comparison of Adjusted EBITDA Estimates for UBS and Using Current NYMEX Gas Strip

	2010E	2011E	2012E	2013E	2014E	Price Target 2011 Open EBITDA SOP
UBS Gas Forecast	**$6.25**	**$7.00**	**$7.00**	**$7.00**	**$7.00**	**$7.00**
Adj EBITDA Est. / PT	600	458	343	385	336	$10.96
Current NYMEX Gas Strip	**$5.66**	**$6.26**	**$6.44**	**$6.58**	**$6.75**	**$6.26**
Adj. EBITDA Est. / PT	590	416	312	354	319	$5.29

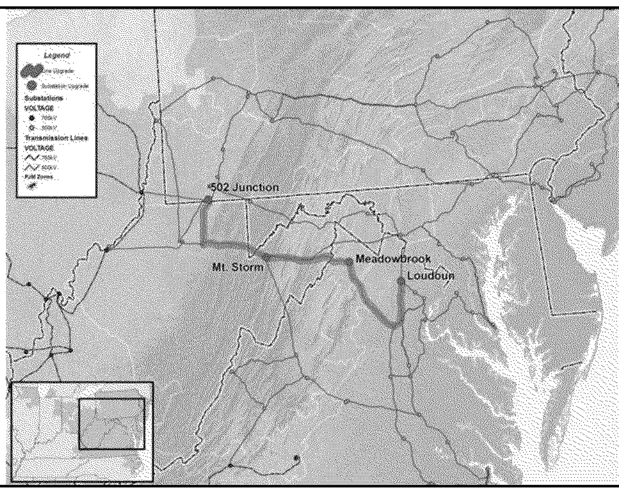
Source: UBS estimates

PJM East Power Prices Still Face Transmission Threat; TRAIL Remains on Track to Reach In-Service by June 2011, Depressing Basis to West

Several new transmission projects, most notably TRAIL threaten to mitigate the premium received by generators in the constrained PEPCO Zone of PJM

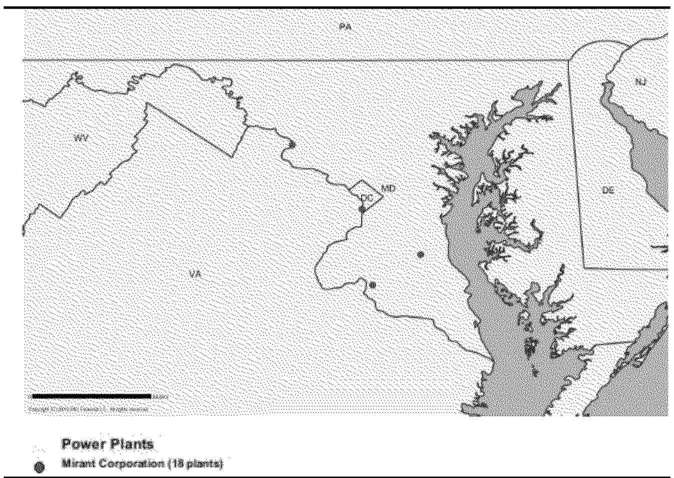
Mirant has historically been situated in an ideal power-constrained corridor of the Mid-Atlantic coast (more formally known as the PEPCO Zone of PJM). This advantage has dissipated as congestion has eased with the large declines in power demand in 2009. Even with an economic recovery, we see limited improvements in power prices delivered to PEPCO zone as the TRAIL (not yet delayed and still on track for an in-service date for June 1, 2011) and PATH transmission projects (originally scheduled for June 1, 2014, but delayed pending further PJM's analysis of power demand to the region) will likely limit upside to power prices in the region. Both the PATH and TRAIL projects aim to bring cheaper power from the Western side of PJM to Eastern Maryland (PATH from WV and TRAIL from Western PA), alleviating significant transmission constraints. This would also affect future PJM RPM auctions, limiting the premium prices the SW-MAAC zone has historically received (among the highest clearing prices of all regions).

Figure 6: Map of TRAIL Route – In-Service Expected June, '11



Source: SNL

Figure 7: Map of MIR's Mid-Atlantic Fleet



Source: SNL

Historic premium basis is already gone; will it ever come back?

Even without the impact of the transmission lines in service yet the basis to PJM West Hub declined from $11-12/MWh historically to a realized average of $3.86/MWh in 2009. While this is likely to improve as demand improves, we see this as a potential nearer term headwind to EBITDA as the company tends to hedge basis up to ~18 months out; in turn we fear revising down our hedged power price assumptions given the relatively healthy premium already baked into our power price assumptions. For Mirant's unhedged power, we assume a PEPCO basis recovery to $6-7/MWh in '11 and beyond.

MD Healthy Air Act Compliance Mitigates Environmental Liabilities; CO_2 Regulation Remains the White Elephant in the Room

While compliant for the moment, the stock remains among the most exposed to CO_2 regulation

One of the brightest points for MIR is the recent completion of scrubbers at all three of its Maryland coal facilities (Chalk Point, Dickerson, and Morgantown). Further, the company operates under a consent decree with Virginia for its Potomac River where it implements its TRONA technology. While this is a clear positive for the company to ensure the viability over its generation facilities through the next five years, we see concern over CO_2 regulation as putting into question the terminal value of this company. With the vast majority of the company's economics coming from its four coal facilities, the undiversified operational risk of these units remains material. We further anticipate scrutiny on coal ash byproducts to receive heightened scrutiny.

EBITDA Estimates

We have provided our latest Adjusted EBITDA estimates in Table 96. 2009 benefits from a significant fuel oil management and proprietary trading backlog, which gradually returns to normal in '10 & beyond; management estimates the normalized run rate of these businesses at $50 Mn for prop trading and a $5 Mn benefit from fuel oil management. A second substantial drag is the significantly above-market hedges the company was able to lock in during 2Q08; these hedges remain substantial through 2012, with a roll off through 2014. A final headwind is capacity prices in New England, which we anticipate to clear at the floor price once more in the next FCM auction (at $1.5/kW-month for 2013-14).

Table 96: Mirant Adjusted EBITDA Estimates, by Year and Segment

	2006A	2007A	2008A	2009E	2010E	2011E	2012E	2013E	2014E
Adjusted EBITDA Estimates									
Mid Atlantic	502	727	645	695	463	330	224	264	228
Northeast	101	123	65	26	29	37	24	5	-5
California	45	61	59	53	57	41	44	65	63
Other	0	77	13	100	50	50	50	50	50
Consolidated	648	988	782	874	600	458	343	385	336
Guidance				860	617				

Source: Company reports and UBS estimates

Adjusted EBITDA Sensitivity to Changes in Natural Gas Prices

We have provided our best approximation as to the impact of shifting natural gas prices on Mirant's Adjust EBITDA in Table 97. The impact to Mirant's EBITDA in the near term remains significantly mitigated by its relatively robust hedging program, while the impact on longer dated EBITDA (2014 & beyond) remains modest. We also provide our EBITDA estimates assuming the current natural gas strip and implicit price target. We note the sensitivities neither adjust for multiple compression / appreciation nor do they take into account varying capacity factors resulting from more or less economic generation opportunities.

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Table 97: Mirant Adjusted EBITDA Sensitivity to Changes in Natural Gas

		Adj. EBITDA - By Year					Price Target
		2010E	2011E	2012E	2013E	2014E	2011 Open EBITDA SOP
	Current	600	458	343	385	336	$10.96
	$5.00	$572	$332	$213	$201	$121	($6.1)
	$5.50	$583	$363	$246	$247	$175	($1.8)
	$6.00	$594	$395	$278	$293	$229	$2.4
	$6.50	$605	$426	$310	$339	$283	$6.7
NYMEX Gas Assumption	**$7.00**	$616	$458	$343	$385	$336	$11.0
	$7.50	$627	$489	$375	$431	$390	$15.2
	$8.00	$638	$521	$407	$477	$444	$19.5
	$8.50	$649	$552	$440	$523	$498	$23.8
	$9.00	$660	$584	$472	$569	$551	$28.0
	$9.50	$671	$615	$504	$615	$605	$32.3
	$10.00	$681	$647	$537	$661	$659	$36.6
Current NYMEX Strip	$5.66	$590	$416	$312	$354	$319	$5.3

Source: UBS estimates

Adjusted EBITDA Sensitivity to Changes in NAPP Coal Prices

In turn, we have also included a sensitivity table to shifts in our NAPP coal price assumptions (which fuels the majority of Mirant's Mid-Atlantic coal needs).

Table 98: Mirant Adjusted EBITDA Sensitivity to Changes in NAPP Coal

		Adj. EBITDA - By Year					Price Target
		2010E	2011E	2012E	2013E	2014E	2011 Open EBITDA SOP
	Current	600	458	343	385	336	$10.96
	$15	$635	$539	$600	$737	$743	$35.9
	$25	$626	$519	$561	$678	$676	$32.0
	$35	$618	$500	$521	$619	$608	$28.2
	$45	$610	$481	$481	$561	$540	$24.4
NAPP Coal ($/ton)	**$55**	$601	$462	$442	$502	$472	$20.5
	$65	$593	$443	$402	$443	$404	$16.7
	$75	$585	$423	$363	$385	$336	$12.9
	$85	$576	$404	$323	$326	$268	$9.0
	$95	$568	$385	$283	$268	$201	$5.2
	$105	$559	$366	$244	$209	$133	$1.4
	$115	$551	$347	$204	$150	$65	($2.3)
Current NYMEX Coal Strip	$55.59	$602	$438	$359	$347	$293	$15.9

Source: UBS estimates

Hedge Price – Backing Into Them From Disclosures

We back into MIR's hedge price by year using their disclosures on power hedges from slide 24 of their quarterly presentation. We note they now provide their hedged fuel cost in their quarterly releases. Using this we find on average their hedges in 2011-14 remain at an $11/MWh premium to market prices, leading to further EBITDA declines in later years. Mirant maintains relatively robust hedge levels even in these outer years, with 57% in 2012, 37% in 2013, and 27% in 2014. We have included our hedge value derivations in Table 99.

Table 99: Mirant Hedge Price Derivation

Nominal Value Claimed (2010) - 3Q09	**251**
Premium to Market for 2010	14.85
Premium from Slides	16.32
ATC Price for PJM East ($/MWh)	57
Hedged Price ($/MWh)	72
Nominal Value Claimed (2011-2014) - 3Q09	**357**
Premium to Market for 2011-14	10.1
ATC Price for PJM East - 2011	60
ATC Price for PJM East - 2012-13	62
Hedged Price - 2011	70
Hedged Price - 2012-14	72

Source: Company reports, Platts, and UBS estimates

Valuation

SOP Valuation

We derive our $11 price target for MIR using an average of DCF and SOP (both hedged and open EBITDA scenarios). We have included below our latest SOP valuation for Mirant's merchant portfolios. We include a slightly below average group low multiple of 6.5x on the Mid-Atlantic fleet to account for the backwardated EBITDA profile, carbon risk, and the relatively lower/concentrated quality of Mirant's assets.

Table 100: Mirant Hedged EBITDA SOP Valuation

All figures in US $ million except per share data	**2011E HedgedEBITDA**	**EV/EBITDA Multiple**			**Enterprise Value**		
		Low	**Base**	**High**	**Low**	**Base**	**High**
MidAtlantic	330	5.5x	6.5x	7.5x	1,814	2,144	2,473
Mid-Atlantic Lease	96	5.5x	6.5x	7.5x	528	624	720
Northeast	37	6.0x	7.0x	8.0x	223	261	298
West	41	6.0x	7.0x	8.0x	246	287	328
Other	50	3.0x	4.0x	5.0x	150	200	250
Total / Implied	**554**	5.3x	6.3x	7.3x	**2,961**	**3,515**	**4,069**
less net debt						(865)	
add NPV of NOLs						203	
less PV of environment capex						(193)	
add NPV of Lease Payments						(1,006)	
NPV of Equity					**1,101**	**1,655**	**2,209**
Current Number of Shares outstanding					146	146	146
Equity value per share					**$7.6**	**$11.4**	**$15.2**

Source: Company reports and UBS estimates

We have also applied an Open EBITDA SOP calculation for Mirant using both current commodity forwards as well as UBS' commodity views. We find that open analyses under both scenarios yield significantly lower EBITDA expectations for 2011 (with the UBS EBITDA forecast lower than the open expectation primarily associated to our higher coal cost assumptions). In turn we apply significantly higher EV/EBITDA multiples to account for what appears to be a relatively trough year from an open perspective, particularly for the Mid-

Atlantic fleet. Applying such high multiples (peak multiples) and reaching valuations still significantly lower than the current valuation backs our Sell rating. Our Open EBITDA SOPs are provided in Table 101 and Table 102.

Table 101: Mirant Open EBITDA SOP Valuation – Using UBS Commodity View

All figures in US $ million except per share data	2011E Open EBITDA	EV/EBITDA Multiple			Enterprise Value		
		Low	**Base**	**High**	**Low**	**Base**	**High**
MidAtlantic	330	9.0x	10.0x	11.0x	2,968	3,298	3,628
Mid-Atlantic Lease	96	9.0x	10.0x	11.0x	864	960	1,056
Northeast	37	6.0x	7.0x	8.0x	223	261	298
West	41	6.0x	7.0x	8.0x	246	287	328
Other	50	3.0x	4.0x	5.0x	150	200	250
Hedge Value	(216)	9.0x	10.0x	11.0x	(1,946)	(2,162)	(2,378)
Total / Implied	**338**	7.4x	8.4x	9.4x	**2,505**	**2,843**	**3,181**
less net debt						(865)	
add NPV of Hedges						611	
add NPV of NOLs						203	
less PV of environment capex						(193)	
add NPV of Lease Payments						(1,006)	
NPV of Equity					**1,256**	**1,594**	**1,932**
Current Number of Shares outstanding					146	146	146
Equity value per share					**$8.6**	**$11.0**	**$13.3**

Source: Company reports and UBS estimates

UBS' coal and power forecasts are higher than current market expectations, with coal pricing significantly higher than the current market forward (outpacing the impact of our higher power price expectations).

Table 102: Mirant Open EBITDA SOP Valuation – Using Current Market Forwards

All figures in US $ million except per share data	2011E Open EBITDA	EV/EBITDA Multiple			Enterprise Value		
		Low	**Base**	**High**	**Low**	**Base**	**High**
MidAtlantic	330	11.0x	12.0x	13.0x	3,628	3,957	4,287
Mid-Atlantic Lease	96	11.0x	12.0x	13.0x	1,056	1,152	1,248
Northeast	37	6.0x	7.0x	8.0x	223	261	298
West	41	6.0x	7.0x	8.0x	246	287	328
Other	50	3.0x	4.0x	5.0x	150	200	250
Hedge Value	(287)	11.0x	12.0x	13.0x	(3,162)	(3,450)	(3,737)
Total / Implied	**266**	8.0x	9.0x	10.0x	**2,140**	**2,407**	**2,673**
less net debt						(865)	
add NPV of Hedges						1,010	
add NPV of NOLs						203	
less PV of environment capex						(193)	
add NPV of Lease Payments						(1,006)	
NPV of Equity					**1,290**	**1,557**	**1,823**
Current Number of Shares outstanding					146	146	146
Equity value per share					**$8.9**	**$10.7**	**$12.5**

Source: Company reports and UBS estimates

DCF Valuation

Our DCF derives a price target of $10 and is derived using a WACC of 8.5% and a terminal growth rate of 1.5%. The company's WACC is relatively high due to its relatively low net debt/cap (just 35%), low for peers. Its cost of equity does benefit from a relatively low Beta for an IPP given its relatively long-dated hedge profile. We note our DCF remains generous given we include the PV of its leases in our WACC calculation (a benefit we do not ascribe to MIR's peers). We include our full DCF valuation in the table below.

Table 103: NRG Energy Summary DCF Valuation

All figures in US $ million except per share data	2009E	2010E	2011E	2012E	2013E	2014E
EBIT	730	431	277	160	199	150
taxes	292	172	111	64	80	60
EBIT (1-T)	**438**	**259**	**166**	**96**	**119**	**90**
add depreciation	144	169	181	183	186	186
less capex	(698)	(441)	(218)	(255)	(198)	(100)
less acquisitions/sale of assets	-	-	-	-	-	-
less emission allowances						
less change in working capital	(53)	(130)	(10)	(30)	(16)	15
FCF	**(169)**	**(143)**	**119**	**(7)**	**91**	**191**
PV of FCF	(169)	(132)	101	(5)	66	127
Terminal value						2,781
Risk free rate	4.0%					
debt spread	4.0%					
Nominal cost of debt	8.0%					
tax rate	40%					
post-tax cost of debt	4.8%					
beta	1.10					
equity risk premium	6.5%					
cost of equity	11.2%					
Market value of equity	2,587					
Total Net Debt & Debt-Like	1,870					
Net Debt	865					
NPV of Lease Payments	1,006					
Equity Ratio	58%					
Debt Ratio	42%					
WACC	**8.5%**					
Terminal Growth Rate	**1.5%**					
NPV of FCF	157					
NPV of Terminal Value	1,851					
Enterprise Value	2,008					
less Net debt	865					
less NPV of Lease Payments	1,006					
add NPV of NOLs	203					
less PV of environment capex	193					
Equity Value	1,347					
shares outstanding	146					
Equity Value per share	**$9.3**					
Equity Value per share rolled 12-months forward	**$10.3**					

Source: Company reports and UBS estimates

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Discounted Cash Flow Scenarios

We have provided in the tables below scenario analysis around our DCF valuation above. Table 123 provides a comparison of our WACC and our terminal growth rate, which is important to the company, as ~92% of its DCF valuation is reflected in the Terminal Value (beyond 2014).

Table 104: MIR Energy WACC vs. Terminal Growth Rate

		WACC				
		7.5%	8.0%	**8.5%**	9.0%	9.
Terminal Growth Rate	0.5%	$10.9	$9.6	$8.4	$7.4	$
	1.0%	$12.1	$10.6	$9.3	$8.1	$
	1.5%	$13.5	$11.8	**$10.3**	$9.0	$
	2.0%	$15.2	$13.2	$11.5	$10.0	$
	2.5%	$17.2	$14.8	$12.8	$11.1	$

Source: UBS estimates

In Table 124, we provide a comparison of MIR's cost of debt (used in our WACC calculation) against the debt capitalization of the company. We note our cost of debt (at 8.00%) is lower than peers to reflect the relatively low leverage the company maintains and robust hedging program.

Table 105: MIR Energy Cost of Debt vs. Debt Capitalization

		Equity Risk Premium				
		4.5%	5.5%	**6.5%**	7.5%	8.5%
	0.9	$16.6	$14.4	$12.5	$10.9	$9.6
	1.0	$15.4	$13.2	$11.3	$9.8	$8.4
Beta	**1.1**	$14.4	$12.1	**$10.3**	$8.7	$7.4
	1.2	$13.4	$11.2	$9.3	$7.8	$6.5
	1.3	$12.5	$10.3	$8.5	$7.0	$5.7

Source: UBS estimates

Finally, we examine MIR's DCF sensitivity to Beta and Equity Risk Premium in Table 106 below. We note the relatively high sensitivity to MIR's Beta given its relatively high equity composition. We anticipate the company to lever up going into the back half of 2010, mitigating its sensitivity.

Table 106: MIR Beta and Equity Risk Premium

		Equity Risk Premium				
		4.5%	5.5%	**6.5%**	7.5%	8.5%
	0.9	$18.7	$16.1	$13.9	$12.0	$10.5
	1.0	$17.3	$14.7	$12.5	$10.7	$9.2
Beta	**1.1**	$16.1	$13.4	**$11.3**	$9.6	$8.1
	1.2	$14.9	$12.3	$10.3	$8.6	$7.1
	1.3	$13.9	$11.3	$9.3	$7.6	$6.3

Source: UBS estimates

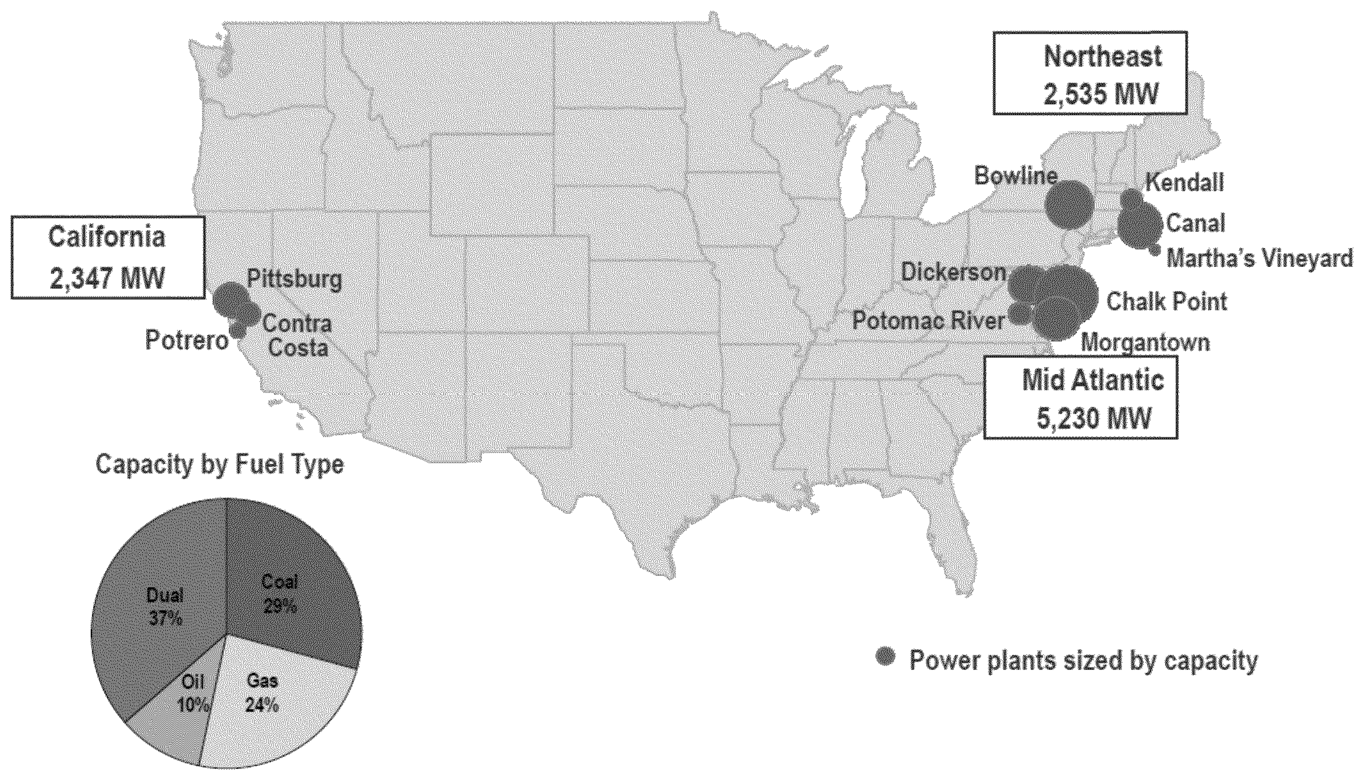
NOLs Remain Important Aspect of Valuation

We interpret the relatively large quantity of Net Operating Losses recorded by Mirant ($3.1 Bn) as accelerating both improvements and declines in its earnings profile. We believe this is a particularly acute concern, as we anticipate further pressure on earnings from lower commodity prices could have an intensified impact with delayed NOL realization.

Company Description

Mirant Corporation is an independent power producer involved in the production and sale of energy, capacity, and transmission-related services. It owns or leases over 10,000 MW of electric generating capacity across the Northeast, Mid-Atlantic, and California. Mirant's customers include independent system operators (ISOs), utilities, municipal systems, aggregators, electric cooperative utilities, producers, generators, marketers, and large industrial customers. We have provided in Figure 8 a map of Mirant's generation fleet.

Figure 8: MIR's Generation Portfolio (MW)



Source: Company presentation

We also provide in Figure 9 Mirant's latest corporate structure. We note the fact a large portion of its fleet (the Mid Atlantic coal assets) are structured as leveraged leases.

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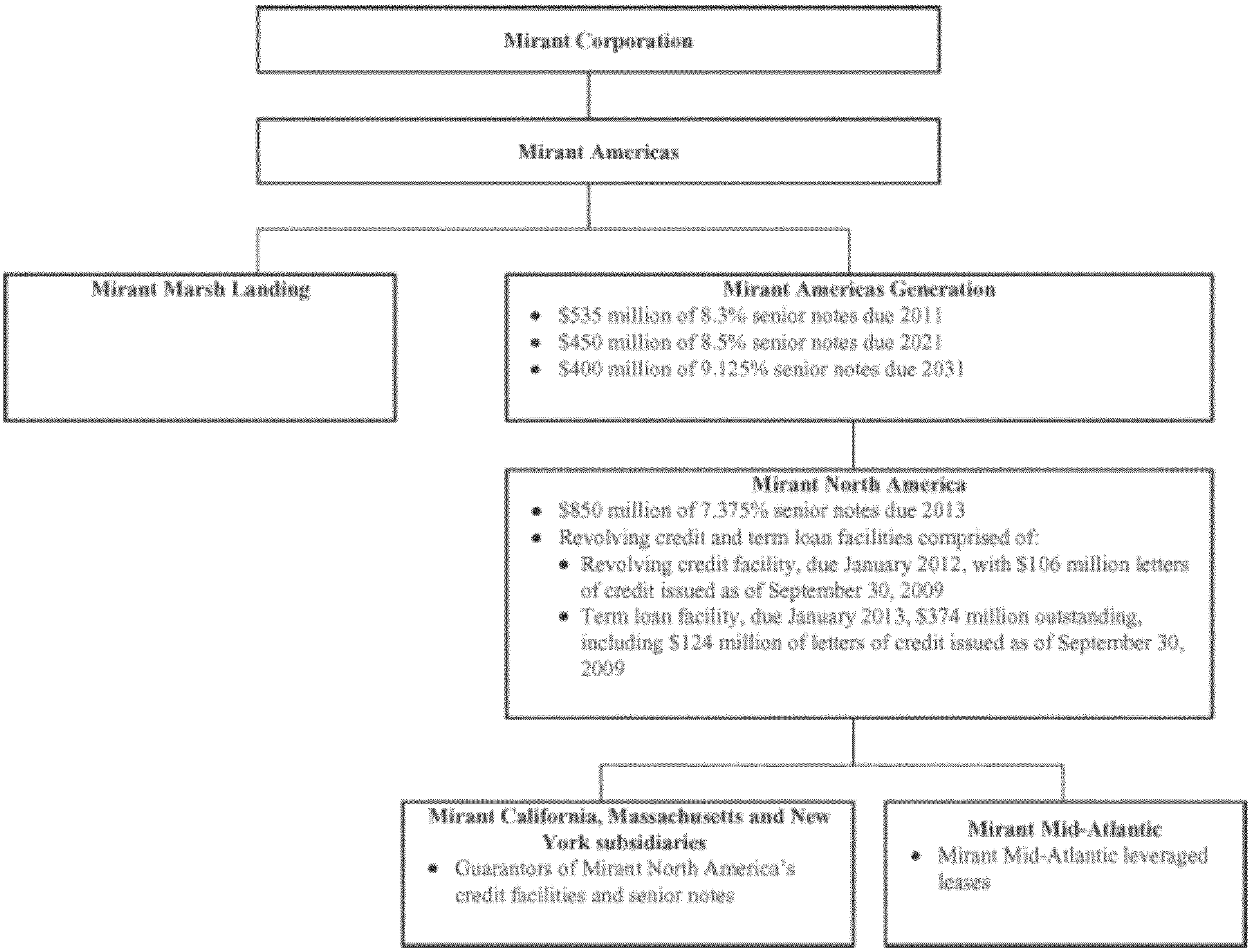
Figure 9: Mirant Corporate Structure



Source: Mirant Third Quarter 2009 10Q Filing

Income Statements by Region

Mirant operates in three primary regions: the Northeast, California, and the Mid-Atlantic. We have provided individual summary income statements for each of the regions as well as their accompany generation portfolios below.

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Table 107: Mid-Atlantic Segment Summary Income Statement

Mid-Atlantic Income Statement	2007A	2008A	2009E	2010E	2011E	2012E
Revenue		1,594	1,579	1,402	1,338	1,367
Energy Revenues		1,254	1,225	1,088	1,123	1,173
Contracted & Capacity Revenues	269	340	354	314	214	194
Energy Costs		556	483	518	579	705
Realized Gross Margin		**1,038**	**1,095**	**884**	**758**	**661**
Energy	686	517	741	570	544	467
Contracted & Capacity	196	340	354	314	214	194
Realized value of hedges	202	181	-	-	-	-
Realized Gross Margin	**1,084**	**1,038**	**1,095**	**884**	**758**	**661**
Operating costs	357	393	400	420	429	437
Adjusted EBITDA	**727**	**645**	**695**	**463**	**330**	**224**
Interest	(5)	-	-	-	-	-
Depreciation & Amortization	81	92	92	94	94	94
Income taxes		-	-	-	-	-
Net Income	**651**	**553**	**603**	**369**	**236**	**130**

Source: Company reports and UBS estimates

Table 108: Mid-Atlantic Generation Portfolio

Mid-Atlantic	Location	Primary Fuel	Total MW
Chalk Point 1 and 2	Maryland	Coal	2,413
Chalk Point 3 and 4		Oil	
Dickerson	Maryland	Coal	849
Dickerson CT		Natgas	
Morgantown	Maryland	Coal	1,486
Morgantown CT		Oil	
Potomac River	Virginia	Coal	482
Total Mid-Atlantic			**5,256**

Source: Company reports

The company's California segment remains a primarily contracted market, with long term contracts signed with IOUs in California. We believe the company's recent win of a 760 MW peaking facility (Marsh Landing at Contra Costa) through PG&E's RFO process should help offset its declining EBITDA profile in 2013. Marsh Landing is anticipated to be in service by May 2013, and is likely to be project financed at either the Mirant Americas Inc. or Mirant North America subsidiaries; the RFO process is for a 10-year tolling agreement with PG&E.

Table 109: California Segment Summary Income Statement

California Income Statement	2007A	2008A	2009E	2010E	2011E	2012E
Revenue		186	148	169	153	159
Energy Revenues		63	29	44	42	42
Contracted & Capacity		123	119	125	111	117
Energy Costs		59	25	40	38	38
Realized Gross Margin		**127**	**123**	**129**	**115**	**121**
Energy	3	4	4	4	4	4
Contracted & Capacity	132	123	119	125	111	117
Realized value of hedges	-	-	-	-	-	-
Realized Gross Margin	**135**	**127**	**123**	**129**	**115**	**121**
Operating Costs	74	68	70	72	74	77
Adjusted EBITDA	**61**	**59**	**53**	**57**	**41**	**44**
Interest	(5)	1	-	-	-	-
Depreciation & Amortization	13	23	20	20	20	20
Income taxes	-	-	-	-	-	-
Net Income	**53**	**35**	**33**	**37**	**21**	**24**

Source: Company reports and UBS estimates

Table 110: California Generation Portfolio

California	Location	Primary Fuel	Total MW
Contra Costa	California	Natgas	674
Pittsburg	California	Natgas	1,311
Potrero	California	Natgas	362
Potrero CT		Oil	
Total California			**2,347**

Source: Company reports

The company's northeast segment is primarily driven by a CCGT unit in Boston, Kendall which operates as a baseload unit. The segment is also bolstered by its fuel oil management logistic and trading benefits.

Table 111: Northeast Segment Summary Income Statement

Northeast Income Statement	2007A	2008A	2009E	2010E	2011E	2012E
Revenue		582	308	476	508	495
Energy Revenues		492	210	375	407	407
Contracted & Capacity		90	98	101	101	88
Energy Costs		393	195	310	342	342
Realized Gross Margin		**189**	**113**	**166**	**166**	**153**
Energy	128	73	24	71	79	79
Contracted & Capacity	87	90	98	101	101	88
Realized value of hedges	65	26	40	-	-	-
Realized Gross Margin	**280**	**189**	**162**	**172**	**180**	**168**
Operating costs	157	124	136	143	143	143
Adjusted EBITDA	**123**	**65**	**26**	**29**	**37**	**24**
Interest	(7)	(1)	-	-	-	-
Depreciation & Amortization	25	19	20	20	20	20
Income taxes		-	-	-	-	-
Net Income	**105**	**47**	**6**	**9**	**17**	**4**

Source: Company reports and UBS estimates

Table 112: Northeast Generation Portfolio

Northeast	Location	Primary Fuel	Total MW
Bowline	New York	Natgas/Oil	1,139
Canal	Massachusettes	Natgas/Oil	1,126
Kendall	Massachusettes	Natgas	256
Martha's Vineyard	Massachusettes	Diesel	14
Oak Bluffs Generating Facility	Massachusettes	Oil	8
West Tisbury Generating Facility	Massachusettes	Oil	5
Total Northeast			**2,549**

Source: Company reports

Risks

Risks to our investment thesis include: 1) actual commodity prices differing significantly from our assumptions, including a contraction in basis to PJM West Hub which is not hedged more than 18 months ahead; 2) political and regulatory intervention to change the structure of competitive markets in response to high power prices and insufficient new build, particularly with regard to Maryland regulation and evolving PJM RPM capacity auction rules; 3) the current state of credit markets that has limited the companies' flexibility to return excess cash to shareholders; and 4) unknown impact from a potential carbon legislation (likely a significant negative for MIR) and other potential environmental remediation . Other investment risks include abrupt changes in weather pattern, sharp slowdown in economic demand, interest rate risks, and disruption of trading activity in power markets.

Mirant Corp

Income statement (US$m)	12/04	12/05	12/06	12/07	12/08	12/09E	% ch	12/10E	% ch	12/11E	% ch
Revenues	-	3,286	2,343	2,353	2,331	2,226	-4.5	2,168	-2.6	2,139	-1.4
Operating expenses (ex depn)	-	(2,507)	(1,695)	(1,365)	(1,549)	(1,352)	-12.7	(1,569)	16.1	(1,681)	7.1
EBITDA (UBS)	-	779	648	988	782	874	11.8	600	-31.4	458	-23.6
Depreciation	-	(135)	(137)	(129)	(144)	(144)	0.0	(169)	17.2	(181)	7.2
Operating income (EBIT, UBS)	-	644	511	859	638	730	14.4	431	-41.0	277	-35.7
Other income & associates	-	0	0	0	0	0	-	0	-	0	-
Net interest	-	(1,404)	(289)	(247)	(189)	(131)	-30.9	(104)	-20.3	(103)	-0.9
Abnormal items (pre-tax)	-	0	0	0	0	0	-	0	-	0	-
Profit before tax	-	(760)	222	612	449	599	33.5	327	-45.5	174	-46.8
Tax	-	18	(2)	(9)	(2)	(12)	499.3	(7)	-45.5	(3)	-46.8
Profit after tax	-	(742)	220	603	447	587	31.4	320	-45.5	170	-46.8
Abnormal items (post-tax)	-	0	0	0	0	0	-	0	-	0	-
Minorities / pref dividends	-	0	0	0	0	0	-	0	-	0	-
Net income (local GAAP)	-	(742)	220	603	447	587	31.4	320	-45.5	170	-46.8
Net Income (UBS)	-	(742)	220	603	447	587	31.4	320	-45.5	170	-46.8
Tax rate (%)	-	0	1	1	0	2	349.0	2	0.0	2	0.0
Pre-abnormal tax rate (%)	-	0	1	1	0	2	349.0	2	0.0	2	0.0

Per share (US$)	12/04	12/05	12/06	12/07	12/08	12/09E	% ch	12/10E	% ch	12/11E	% ch
EPS (local GAAP)	-	(2.43)	0.74	2.18	2.25	4.04	79.7	2.20	-45.5	1.17	-46.8
EPS (UBS)	-	(2.43)	0.74	2.18	2.25	4.04	79.7	2.20	-45.5	1.17	-46.8
Net DPS	-	0.00	0.00	0.00	0.00	0.00	-	0.00	-	0.00	-
Cash EPS	-	(1.99)	1.20	2.64	2.97	5.03	69.2	3.36	-33.1	2.41	-28.2
BVPS	-	12.40	17.36	20.74	20.26	29.89	47.5	32.09	7.4	33.26	3.6

Balance sheet (US$m)	12/04	12/05	12/06	12/07	12/08	12/09E	% ch	12/10E	% ch	12/11E	% ch
Cash and equivalents	-	-	-	4,961	1,831	1,856	1.4	1,299	-30.0	1,313	1.1
Other current assets	-	8,764	6,843	1,273	3,917	3,773	-3.7	3,916	3.8	3,957	1.0
Total current assets	-	-	-	6,234	5,748	5,629	-2.1	5,215	-7.4	5,270	1.1
Net tangible fixed assets	-	2,328	2,212	2,590	3,215	3,769	17.2	4,041	7.2	4,078	0.9
Net intangible fixed assets	-	225	214	205	196	196	0.0	196	0.0	196	0.0
Investments / other assets	0	527	1,125	423	1,529	1,529	0.0	1,499	-2.0	1,499	0.0
Total assets	-	-	-	9,452	10,688	11,123	4.1	10,951	-1.6	11,043	0.8
Trade payables & other ST liabilities	-	5,743	3,117	717	3,738	3,593	-3.9	3,606	0.4	3,637	0.9
Short term debt	-	3	142	142	46	45	-1.4	37	-18.9	35	-5.0
Total current liabilities	-	5,746	3,259	859	3,784	3,638	-3.9	3,642	0.1	3,672	0.8
Long term debt	-	2,579	3,133	2,953	2,630	2,624	-0.2	2,127	-18.9	2,020	-5.0
Other long term liabilities	-	731	701	330	512	512	0.0	512	0.0	512	0.0
Total liabilities	-	9,056	7,093	4,142	6,926	6,774	-2.2	6,281	-7.3	6,204	-1.2
Equity & minority interests	-	-	-	5,310	3,762	4,349	15.6	4,669	7.4	4,840	3.6
Total liabilities & equity	-	-	-	9,452	10,688	11,123	4.1	10,951	-1.6	11,043	0.8

Cash flow (US$m)	12/04	12/05	12/06	12/07	12/08	12/09E	% ch	12/10E	% ch	12/11E	% ch
Net income	-	(742)	220	603	447	587	31.4	320	-45.5	170	-46.8
Depreciation	-	135	137	129	144	144	0.0	169	17.2	181	7.2
Net change in working capital	-	(269)	(473)	(105)	(538)	(53)	-90.2	(130)	146.4	(10)	-92.4
Other (operating)	-	909	679	337	674	51	-92.4	30	-41.2	0	-
Net cash from operations	-	33	563	964	727	730	0.4	389	-46.6	341	-12.3
Capital expenditure	0	(101)	(133)	(588)	(731)	(698)	-4.5	(441)	-36.8	(218)	-50.6
Net (acquisitions) / disposals	0	165	143	5,338	42	0	-	0	-	0	-
Other changes in investments	0	15	(162)	7	(5)	0	-	0	-	0	-
Cash from investing activities	0	79	(152)	4,757	(694)	(698)	0.6	(441)	-36.8	(218)	-50.6
Increase/(decrease) in debt	-	98	1,542	(180)	(420)	(7)	-	(505)	-	(109)	-
Share issues / (repurchases)	-	0	(1,261)	(1,297)	(2,761)	0	-	0	-	0	-
Dividends paid	-	0	0	0	0	0	-	0	-	0	-
Other cash from financing	-	(144)	(807)	(668)	18	0	-	0	-	0	-
Cash from financing activities	-	(46)	(526)	(2,145)	(3,163)	(7)	-99.8	(505)	7482.7	(109)	-78.4
Cash flow chge in cash & equivalents	-	66	(115)	3,576	(3,130)	25	-	(557)	-	14	-
FX / non cash items	-	-	189	243	0	0	-	0	-	0	-
Bal sheet chge in cash & equivalents	-	-	74	3,819	(3,130)	25	-	(557)	-	14	-
Core EBITDA	-	779	648	988	782	874	11.8	600	-31.4	458	-23.6
Maintenance capital expenditure	-	(101)	(133)	(588)	(731)	(698)	-4.5	(441)	-36.8	(218)	-50.6
Maintenance net working capital	-	0	0	0	0	0	-	0	-	0	-
Operating free cash flow, pre-tax	-	678	515	400	51	176	245.0	159	-9.8	240	51.2

Source: Company accounts, UBS estimates. (UBS) valuations are stated before goodwill-related charges and other adjustments for abnormal and economic items at the analysts' judgement. Note: For some companies, the data represents an extract of the full company accounts.

Global Equity Research

Americas

Electric Utilities

12-month rating **Sell**

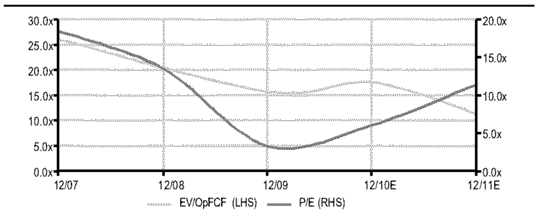
12m price target **US$11.00**

Mirant Corp

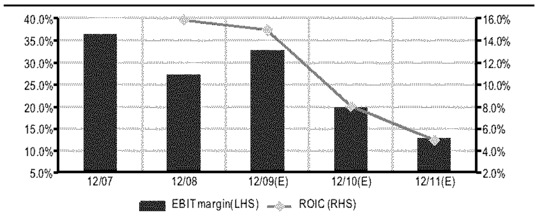
Company profile

Mirant Corporation is an independent power producer involved in the production and sale of energy, capacity, and transmission-related services. It owns or leases over 10,000 MW of electric generating capacity across the Northeast, Mid-Atlantic, and California. Mirant's customers include independent system operators (ISOs), utilities, municipal systems, aggregators, electric cooperative utilities, producers, generators, marketers, and large industrial customers.

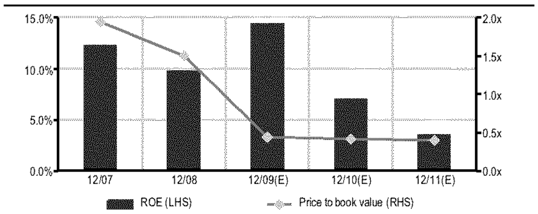
Value (EV/OpFCF & P/E)



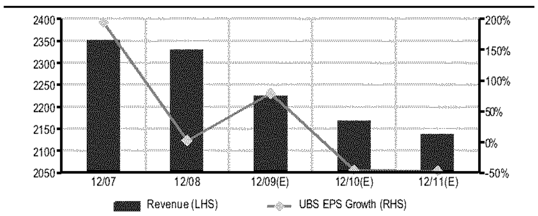
Profitability



ROE v Price to book value



Growth (UBS EPS)



Valuation (x)	5Yr Avg	12/07	12/08	12/09E	12/10E	12/11E
P/E (local GAAP)	-	18.5	13.6	3.3	6.1	11.5
P/E (UBS)	-	18.5	13.6	3.3	6.1	11.5
P/CEPS	-	15.2	10.3	2.7	4.0	5.6
Net dividend yield (%)	-	0.0	0.0	0.0	0.0	0.0
P/BV	-	1.9	1.5	0.4	0.4	0.4
EV/revenue (core)	-	4.4	2.5	1.2	1.3	1.3
EV/EBITDA (core)	-	10.6	7.6	3.2	4.7	6.0
EV/EBIT (core)	-	12.2	9.3	3.8	6.5	9.9
EV/OpFCF (core)	-	26.1	NM	15.8	17.6	11.5
EV/op. invested capital	-	-	1.5	0.6	0.5	0.5

Enterprise value (US$m)	12/07	12/08	12/09E	12/10E	12/11E
Average market cap	10,309	6,435	1,950	1,950	1,950
+ minority interests	0	0	0	0	0
+ average net debt (cash)	134	(511)	829	839	803
+ pension obligations and other	0	0	0	0	0
- non-core asset value	0	0	0	0	0
Core enterprise value	10,442	5,925	2,779	2,789	2,753

Growth (%)	5Yr Avg	12/07	12/08	12/09E	12/10E	12/11E
Revenue	-	0.4	-0.9	-4.5	-2.6	-1.4
EBITDA (UBS)	-	52.5	-20.9	11.8	-31.4	-23.6
EBIT (UBS)	-	68.1	-25.7	14.4	-41.0	-35.7
EPS (UBS)	-	193.9	3.2	79.7	-45.5	-46.8
Cash EPS	-	119.8	12.4	69.2	-33.1	-28.2
Net DPS	-	-	-	-	-	-
BVPS	-	19.5	-2.3	47.5	7.4	3.6

Margins (%)	5Yr Avg	12/07	12/08	12/09E	12/10E	12/11E
EBITDA / revenue	-	42.0	33.5	39.3	27.7	21.4
EBIT / revenue	-	36.5	27.4	32.8	19.9	12.9
Net profit (UBS) / revenue	-	25.6	19.2	26.4	14.8	8.0

Return on capital (%)	5Yr Avg	12/07	12/08	12/09E	12/10E	12/11E
EBIT ROIC (UBS)	-	-	15.8	14.9	8.1	5.0
ROIC post tax	-	-	15.8	14.6	7.9	4.9
Net ROE	-	12.4	9.9	14.5	7.1	3.6

Coverage ratios (x)	5Yr Avg	12/07	12/08	12/09E	12/10E	12/11E
EBIT / net interest	-	3.5	3.4	5.6	4.1	2.7
Dividend cover (UBS EPS)	-	-	-	-	-	-
Div. payout ratio (%, UBS EPS)	-	-	-	-	-	-
Net debt / EBITDA	-	NM	1.1	0.9	1.4	1.6

Efficiency ratios (x)	5Yr Avg	12/07	12/08	12/09E	12/10E	12/11E
Revenue / op. invested capital	-	-	0.6	0.5	0.4	0.4
Revenue / fixed assets	-	0.9	0.8	0.6	0.5	0.5
Revenue / net working capital	-	-	6.3	12.4	8.8	6.8

Investment ratios (x)	5Yr Avg	12/07	12/08	12/09E	12/10E	12/11E
OpFCF / EBIT	-	0.5	0.1	0.2	0.4	0.9
Capex / revenue (%)	-	25.0	NM	NM	20.3	10.2
Capex / depreciation	-	4.6	5.1	4.8	2.6	1.2

Capital structure (%)	5Yr Avg	12/07	12/08	12/09E	12/10E	12/11E
Net debt / total equity	-	(35.1)	22.5	18.7	18.5	15.3
Net debt / (net debt + equity)	-	(54.2)	18.3	15.8	15.6	13.3
Net debt (core) / EV	-	1.3	(8.6)	29.8	30.1	29.2

Source: Company accounts, UBS estimates. (UBS) valuations are stated before goodwill-related charges and other adjustments for abnormal and economic items at the analysts' judgement.

Valuations: based on an average share price that year, (E): based on a share price of US$13.45 on 19 Feb 2010 19:35 EST Market cap(E) may include forecast share issues/buybacks.

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UBS Investment Research

NRG Energy Inc.

Leaders Without the Premium

- **NRG's fleet boasts large array of assets, primarily baseload TX**

NRG operates 23,120 MW of plants oriented in TX, the Northeast, South Central, California, and abroad. However, the economics of the portfolio are derived primarily from baseload nuclear/coal assets in TX. In the last year NRG also acquired a retail business Reliant Energy, in TX from RRI Energy, which has contributed significantly to EBITDA in 2009.

- **Continuing to deliver value; NRG deserves premium to peers**

We believe NRG's diversified generation portfolio and several organic growth projects deserve at least a peer multiple (NRG shares trades at a 25% discount). We see mgmt's target of 3% in annual share repurchases (~$200-300 Mn) as both conceivable given current FCF projections and a clear advantage over NRG's IPP peers. Even at this level we anticipate mgmt should have the flexibility to continue growing organically (at a modest pace) and paying down debt.

- **Reliant Retail proves cunning; see focus on developing contracted gen.**

Mgmt's latest focus has been on incorporating its $285 Mn acquisition of Reliant retail, which is expected to post $900 Mn of EBITDA in '09. At its recent analyst day(s), mgmt described a focus on lowering its carbon intensity through contracted investments in renewables and new nuclear, laying out a set of pre-approved PPA renewable projects as well as tangible roadmap for developing its STP 3&4 units.

- **Maintaining Neutral rating and lowering price target to $24**

While we anticipate headwinds for the IPP group as a whole, we believe NRG should outperform its peers as it continues to execute on its capital redeployment strategy. Further, we remain concerned over '11 FC estimates at ~$2.3 Bn today vs. our $1.9 Bn est. Our $24 price target may be conservative and implies a 6.9x multiple to NRG's '11E Open EBITDA.

Highlights (US$m)	12/07	12/08	12/09E	12/10E	12/11E
Revenues	5,824	6,178	5,038	5,292	5,044
EBIT (UBS)	1,378	1,566	2,011	1,605	1,234
Net Income (UBS)	332	254	873	641	439
EPS (UBS, US$)	1.15	0.92	3.22	2.48	1.75
Net DPS (UBS, US$)	0.00	0.00	0.00	0.00	0.00

Profitability & Valuation	5-yr hist av.	12/08	12/09E	12/10E	12/11E
EBIT margin %	-	25.3	39.9	30.3	24.5
ROIC (EBIT) %	-	16.9	20.7	16.4	12.8
EV/EBITDA (core) x	-	4.7	3.0	3.3	3.8
PE (UBS) x	-	37.5	7.2	9.4	13.3
Net dividend yield %	-	0.0	0.0	0.0	0.0

Source: Company accounts, Thomson Reuters, UBS estimates. (UBS) valuations are stated before goodwill-related charges and other adjustments for abnormal and economic items at the analysts' judgement.

Valuations: based on an average share price that year, (E): based on a share price of US$23.20 on 19 Feb 2010 19:35 EST

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Global Equity Research

Americas

Electric Utilities

12-month rating	Neutral
	Unchanged
12m price target	US$24.00
	Prior: US$26.00
Price	US$23.20

RIC: NRG.N BBG: NRG US

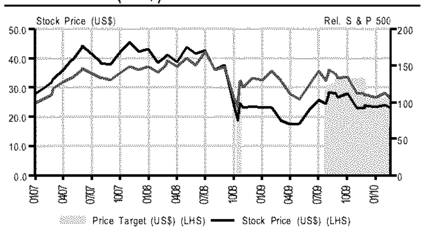
Trading data	
52-wk range	US$29.13-16.34
Market cap.	US$5.50bn
Shares o/s	237m (COM)
Free float	100%
Avg. daily volume ('000)	1,458
Avg. daily value (US$m)	35.1

Balance sheet data 12/09E	
Shareholders' equity	US$6.72bn
P/BV (UBS)	0.9x
Net Cash (debt)	(US$7.33bn)

Forecast returns	
Forecast price appreciation	+3.4%
Forecast dividend yield	0.0%
Forecast stock return	+3.4%
Market return assumption	5.9%
Forecast excess return	-2.5%

EPS (UBS, US$)	12/09E			12/08
	From	To	Cons.	Actual
Q1	(0.54)	(0.52)	0.70	0.25
Q2	0.99	0.79	1.56	1.52
Q3	0.99	1.29	1.02	(0.41)
Q4E	1.87	1.71	0.45	(0.42)
12/09E	3.25	3.22	*2.74*	
12/10E	2.56	2.48	*2.13*	

Performance (US$)



Source: UBS

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Investment Summary

Opportunities Abound in a Mild Outlook

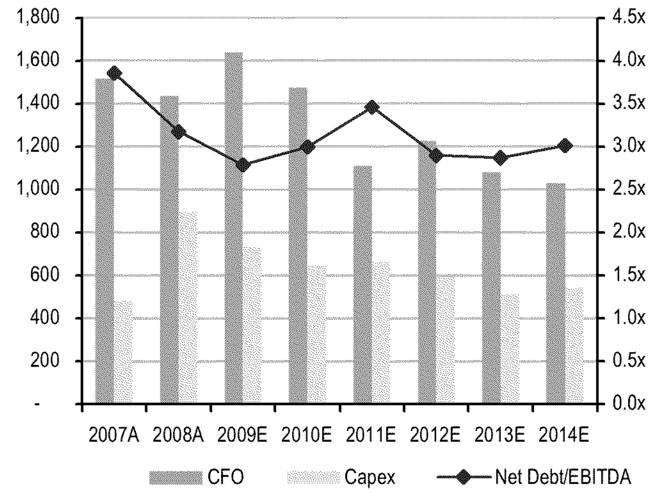
We are maintaining our Neutral rating on NRG and lowering our price target to $24 (from $26). Despite remaining our favourite baseload IPP (not withstanding CPN), we believe broader sector headwinds and power recovery should cloud the entire sector's recovery. Trading at a 25% discount to peers, we believe (the real) concerns over compressed heat rates are sufficient. Alternatively while consensus EBITDA estimates remain too high for 2011 & beyond, we believe the company is well positioned to weather the downturn and grow organically on the margin. We believe 2010 could prove relatively attractive for shareholders, as NRG's initial guidance seems conservative ($2.2 Bn seems like a very attainable level) and as it is able to negotiate an RP amendment with bondholders to allow for dividends back to the parent.

Despite our caution on the sector, this is our favourite baseload IPP – we believe a company with strong management, an organic growth platform, and decent assets deserves a premium multiple on its generation portfolio

Anticipate Continued Debt Paydown and Share Repurchases

Part of NRG management's mantra remains the continued return of capital to debt and equity holders. Using our projections, we anticipate NRG will be able to continue to meet its share repurchase target of 3% of outstanding shares (which management earmarks ~$300 Mn/yr, implying a fair value of $39/sh). For our share repurchase assumptions, we use 3% of existing share count, equating to roughly $200 Mn. For 2010, we have assumed just $125 Mn, offsetting the impact of the accelerated $500 Mn repurchase program announced in early 2009. Further, we anticipate management to be able to continue to use its excess free cash flow both to meet its required cash sweep under its Term Loan and continue addressing maturities (e.g., – CSF facility, 2014 Senior notes). We do note its maturity of its Term Loan B, revolver, and credit facility in 2013 could pose a liquidity event should the company have refinancing risk (not off the table for what remains a BB credit, but a subsiding risk). We believe share repurchases could be curtailed should some of its pipeline of growth projects pan out. Chart 41 provides our estimate for NRG's cash flows in the near term.

Chart 41: NRG Cash Flows and Net Debt / EBITDA Projection



Source: UBS estimates

Is the Texas Wind Build Over? Yes, but Look Out for Coal

Several new coal plants in Texas will likely temper any heat rate improvement in the near term

Arguably yes; however, we anticipate new coal and fossil fired generation to remain a downward drag on heat rates in Texas over the next few years. We include in Table 113 the EIA's current pipeline of announced projects in the state; With sizable above market hedges remaining, we forecast significant headwinds in NRG's ability to grow Adjusted EBITDA from current levels. Alternatively, NRG management's best hope will be to make the best use of existing cash flow from above market hedges in hopes of pursuing accretive investments to offset the backwardation in its earnings profile akin to its investment earlier this year in Reliant Retail.

Table 113: Texas Capacity Additions, EIA

	2008E	2009E	2010E	2011E	2012E	Total Capacity / Additions
Capacity Additions (MW)	3,800.6	6,150.4	1,057.7	500.0	1,939.0	13,448
% of Existing Capacity	3.42%	5.53%	0.95%	0.45%	1.74%	111,226

Source: EIA estimates

Continued Integration of Reliant Retail

Having acquired the business at a bargain price, we look to management to prove it can successfully negotiate the associated risks of this business

We think the successful acquisition of Reliant Retail from RRI Energy at a distressed price earlier in the year (~0.3x EV/EBITDA) speaks to the capabilities of the current management team. Having successfully unwound its credit sleeve with Merrill Lynch, we now look towards the company's ability to successfully operate the business and prove the effectiveness of once more re-integrating the business model between Retail and Generation. With the company's 2010 EBITDA guidance at $500 Mn and a long run EBITDA forecast (albeit likely conservative) at $300 Mn, management will struggle to grow the business from current levels.

One of Few Companies With Tangible Organic Growth Avenue

One of NRG's unique features remains its pipeline of organic growth avenues to grow EBITDA independent of the commodity cycle. While NRG's latest

Analyst Day could be perceived as light in nearer term content, it effectively conveyed the company's future potential investment opportunities and financial profile post the Retail acquisition. We mention a few longer term growth opportunities we think show relative promise:

– **New Nuclear Units 3 & 4 at the South Texas Project:**

We continue to see the contracted merchant approach taken by NRG to constructing units 3 & 4 at STP using the ABWR technology as the second most promising project behind Southern. Given its strategy of pursuing a contracted approach to new nuclear in a merchant context, we look to how NRG will choose to sell down or contract down its enlarged ownership in the project (following its recent agreement with CPS). We are particularly interested in the company's ability to build risk sharing provisions into its offtake agreements.

– **Exploring Offshore Wind in Delaware With Bluewater Acquisition**

Following on NRG's construction of three wind farms in Texas (Sherbino, Elbow Creek, and Langford most recently), NRG is looking to construct its first offshore wind project off the coast of Delaware. We see the project as particularly promising given its 25-year 200 MW PPA already in hand with Delmarva Light & Power. While its timing remains far out and is likely to be project financed at 70%, this could prove an attractive project when completed (likely in the 2013-2014 time frame).

– **Cofiring and Repowering With Biomass**

Specifically, we point to the Montville repowering of unit 5 from an 80 MW dual-fuel unit into a 40 MW biomass unit in Connecticut as particularly attractive. This project is scheduled to be online by mid-2011.

First Lien Hedging Structure Unique in Space; CSF Structure Also Speaks to Financial Innovation by Management

Adding to our relative appreciation for the company to peers we note its ability to piece together attractive financial options. We see its First Lien hedging structure (adopted from Texas Genco's earlier 2nd lien program) as the most impressive financial structure among the IPPs. With no maturity profile to this structure and with the value (and hence size of the facility) expanding as energy prices increase (which is when IPPs are in need of the most liquidity), we see this as one of the most important risk mitigating mechanisms the company can lean on. We wonder whether NRG will be able to make use of this facility to hedge the value of its Retail business now.

We also see the CSF structure as an innovative mechanism introduced to repurchase shares in an unrestricted subsidiary in exchange for issuing a structured note to Credit Suisse. Despite proving to be both a costly mechanism and potentially limiting upside to share price beyond $40.80 (due to embedded call options), we are encouraged by management's willingness to address shareholder return. In its first tranche (CSF I) management repurchased $220 Mn and in its second, management repurchased an additional $180.

Credit Profile and Capital Deployment

Restricted Payments and Mandatory Debt Retirement

NRG's term loan facility includes a mandatory debt retirement offer as defined as a percentage of free cash flow. Lenders must choose to accept at least 50% of this amount. For the year ended 2008, NRG's lenders accepted a total $197 Mn in retirements. A primary focus of the management team in 2010 will likely prove a renegotiation of the bondholder's current restricted payments basket definition, allowing NRG additional flexibility to return cash to shareholders. While previous attempts have proved unfruitful, a simple adjustment likely amenable to all parties is the removal of mark-to-market impacts.

Management Committed to 3% Annual Share Repurchase

At its recent analyst day, management committed itself to a long term return of capital roughly equivalent to 3% of its market capitalization, with an anticipated purchase cash layout of $300 Mn (roughly twice the stock's current value). Given its current capital expenditures plan, we believe this share repurchase program appears viable.

EBITDA Estimates

We have summarized our EBITDA results by region in Table 114. We see a substantial decline in EBITDA in 2011 associated with significantly lower hedge prices. We see the company's 2010 guidance of $2.2 – 2.3 Bn is manageable. We however anticipate continued EBITDA declines beyond its peak year in 2012. We look to the company's 2009 10K filing later this month to update the hedge prices and percentages across its fleet.

Table 114: NRG Energy Adjusted EBITDA Estimates, by Year and Segment

Summary of Assumptions	2007A	2008A	2009E	2010E	2011E	2012E	2013E	2014E
NYMEX Assumption	*5.96*	*9.05*	*4.00*	*6.25*	*7.00*	*7.00*	*7.00*	*7.00*
Texas	1,319	1,543	1,363	1,114	925	1,147	1,084	923
Northeast	544	475	445	476	371	414	368	348
South Central	101	145	73	76	109	132	146	153
West	41	68	57	68	68	68	68	68
Reliant Retail	-	-	641	491	381	300	305	309
Other	140	60	35	35	35	35	35	35
Total	**2,145**	**2,291**	**2,614**	**2,259**	**1,888**	**2,095**	**2,005**	**1,836**
FC EBITDA Est.			2,658	2,285	2,051	2,218	2,011	

Source: Company reports and UBS estimates

Adjusted EBITDA Under Various Natural Gas Scenarios

We have provided in Table 115 our estimate of NRG's Adjusted EBITDA under various EBITDA scenarios including the current forward curve. We note this does not dynamically reflect changes to capacity factors, which could in theory moderate the impacts. We further make the assumption that our power prices are related to natural gas prices, reflecting a constant heat rate relationship, which would not necessarily be the market reality. Nonetheless, the various scenarios demonstrate the large degree to which NRG's hedges remain above market through 2012. We believe its next 10K is likely to incorporate new hedges for 2010-2013, with a lower average hedge price reflecting the reality of hedges added in the 2009 time frame.

Table 115: NRG Adjusted EBITDA Scenarios Using Various Natural Gas Scenarios

		Adj. EBITDA - By Year					Price Target
		2010E	2011E	2012E	2013E	2014E	2011 Open EBITDA SOP
	Current	2,259	1,888	2,095	2,005	1,836	$24.14
	$5.00	$2,241	$1,645	$1,676	$1,411	$1,001	$4.8
	$5.50	$2,248	$1,706	$1,781	$1,560	$1,209	$10.3
	$6.00	$2,255	$1,767	$1,886	$1,708	$1,418	$15.9
	$6.50	$2,262	$1,828	$1,990	$1,857	$1,627	$21.4
NYMEX Gas Assumption	**$7.00**	$2,269	$1,888	$2,095	$2,005	$1,836	$27.0
	$7.50	$2,276	$1,949	$2,200	$2,153	$2,045	$32.5
	$8.00	$2,283	$2,010	$2,304	$2,302	$2,253	$38.1
	$8.50	$2,290	$2,071	$2,409	$2,450	$2,462	$43.6
	$9.00	$2,297	$2,132	$2,514	$2,599	$2,671	$49.2
	$9.50	$2,304	$2,193	$2,618	$2,747	$2,880	$54.7
	$10.00	$2,311	$2,253	$2,723	$2,896	$3,088	$60.3
Current NYMEX Strip	$5.79	$2,253	$1,808	$1,996	$1,907	$1,770	$19.6

Source: NYMEX (for future prices) and UBS estimates

Summarizing the above EBITDA sensitivity, we contrast our Adj. EBITDA estimates against applying the current NYMEX gas strip in Table 116.

Table 116: Comparison of Adj. EBITDA Estimates Using UBS Commodity View and Current NYMEX Gas Strip

	2010E	2011E	2012E	2013E	2014E	Price Target 2011 Open EBITDA SOP
UBS Gas Forecast	**$6.25**	**$7.00**	**$7.00**	**$7.00**	**$7.00**	**$7.00**
Adj EBITDA Est. / PT	2,259	1,888	2,095	2,005	1,836	$24.14
Current NYMEX Gas Strip	**$5.79**	**$6.34**	**$6.53**	**$6.67**	**$6.84**	**$6.34**
Adj. EBITDA Est. / PT	2,253	1,808	1,996	1,907	1,770	$19.60

Source: UBS estimates

Adjusted EBITDA Under Various Texas Coal Price Assumptions

We have included below our model's sensitivity to changes in delivered coal prices to Texas (blended mix of PRB and Lignite). We assume for the purposes of our model approximately ¾ of NRG's load in Texas is served with PRB and the balance with local Lignite. Given the lack of transparency around transportation costs, we assume $25.50 as a market rate for transportation this year (per Argus Coal Transportation Weekly), and increase this by $0.50/ton annually to account for marginal cost inflation. We use our PRB 8,400 btu/lb. forecast and assume a weighted average heat content of 7,800 btu/lb for its Texas portfolio.

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Table 117: NRG Adjusted EBITDA Scenarios Under Various Texas Coal Cost Scenarios

		Adj. EBITDA - By Year					Price Target
		2010E	2011E	2012E	2013E	2014E	2011 Open EBITDA SOP
	Current	2,259	1,888	2,095	2,005	1,836	$24.14
	$20	$2,466	$2,115	$2,335	$2,258	$2,103	$27.7
	$22	$2,423	$2,071	$2,291	$2,215	$2,059	$27.6
	$24	$2,379	$2,028	$2,248	$2,171	$2,016	$27.4
	$26	$2,336	$1,985	$2,204	$2,128	$1,972	$27.3
Delivered Coal Cost ($/ton)	**$28**	$2,293	$1,941	$2,161	$2,085	$1,929	$27.1
	$30	$2,249	$1,898	$2,118	$2,041	$1,886	$27.0
	$32	$2,206	$1,854	$2,074	$1,998	$1,842	$26.9
	$34	$2,162	$1,811	$2,031	$1,954	$1,799	$26.7
	$36	$2,119	$1,768	$1,988	$1,911	$1,755	$26.6
	$38	$2,076	$1,724	$1,944	$1,868	$1,712	$26.4
	$40	$2,032	$1,681	$1,901	$1,824	$1,669	$26.3
Forwards for Delivered Coal	$28.28	$2,286	$1,879	$2,091	$2,006	$1,843	$26.9

Source: NYMEX and UBS estimates; we note the Forward curve applied here is not static and uses the price for that particular year

A summary of our EBITDA estimates against the current commodity forwards is included below in Table 118.

Table 118: Summary of NRG estimates Under Various Texas Coal Cost Scenarios

	2010E	2011E	2012E	2013E	2014E	Price Target 2011 Open EBITDA SOP
UBS Deliverd Coal Cost Forecast ($/ton)	**$29.55**	**$30.06**	**$30.06**	**$30.67**	**$30.67**	**$30.06**
Adj EBITDA Est. / PT	2,259	1,888	2,095	2,005	1,836	$24.14
Forward Price for Delivered Coal ($/ton)	**$28.28**	**$30.86**	**$31.23**	**$31.60**	**$31.97**	**$30.86**
Adj. EBITDA Est. / PT	2,286	1,879	2,091	2,006	1,843	$26.94

Source: UBS estimates

Valuation

Our lowered $24 12-month price target is derived using the average of our DCF and SOP approaches. Our SOP approach ascribes an 8.0x multiple across the Merchant portfolio to our 2011E hedged EBITDA. We ascribe a 4.0x multiple to NRG's Reliant Retail business, due to the higher risk and more volatile earnings profile of this business. This multiple is in line with the multiple we ascribe to NRG's peers with similar businesses. While 2011 is even further depressed due to the relatively low hedges locked against its baseload for the year, 2012 should prove a significant uptick. We further note in outer years, the EBITDA contribution of the generation portfolio grows relative to the size of the Retail business, magnifying the uptick on NRG's valuation.

Table 119: NRG Energy SOP Valuation – Hedged EBITDA

All figures in US $ million except per share data	2011E HedgedEBITDA	EV/EBITDA Multiple			Enterprise Value		
		Low	Base	High	Low	Base	High
Texas	925	7.0x	8.0x	9.0x	6,474	7,399	8,323
Northeast	371	7.0x	8.0x	9.0x	2,597	2,968	3,339
South Central	109	7.0x	8.0x	9.0x	763	871	980
West	68	7.0x	8.0x	9.0x	473	540	608
Reliant Retail	381	3.0x	4.0x	5.0x	1,144	1,525	1,906
Other	35	5.0x	4.0x	3.0x	175	140	105
Total / Implied	**1,888**	6.2x	7.1x	8.1x	**11,624**	**13,443**	**15,261**
less net debt						(6,066)	
less Preferred Shares						(534)	
less PV of environment capex						(838)	
NPV of Equity					**4,186**	**6,005**	**7,823**
Current Number of Shares outstanding					262	262	262
Equity value per share					**$15.98**	**$22.92**	**$29.86**

Source: Company reports and UBS estimates

Using Open EBITDA Approach Similarly Yields Upside

We have provided Open EBITDA valuations for NRG in the tables below. Given the range of scenarios investors approach IPP equities from, we have provided Open calculations off of UBS' Commodity Forecast and off of the current Platts Power Forwards.

Table 120: NRG SOP Valuation – Using Open Analysis and UBS Commodity Forecast

All figures in US $ million except per share data	2011E Open EBITDA	EV/EBITDA Multiple			Enterprise Value		
		Low	Base	High	Low	Base	High
Texas	925	6.0x	7.0x	8.0x	5,549	6,474	7,399
Northeast	371	6.0x	7.0x	8.0x	2,226	2,597	2,968
South Central	109	6.0x	7.0x	8.0x	654	763	871
West	68	6.0x	7.0x	8.0x	405	473	540
Power Hedges	100	6.0x	7.0x	8.0x	601	701	801
Coal Hedges	92	6.0x	7.0x	8.0x	554	646	739
Reliant Retail	381	3.0x	4.0x	5.0x	1,144	1,525	1,906
Other	35	5.0x	4.0x	3.0x	175	140	105
Total / Implied	**2,081**	5.4x	6.4x	7.4x	**11,307**	**13,318**	**15,329**
less net debt						(6,066)	
less Preferred Shares						(534)	
less NPV of environment capex						(838)	
add NPV of Power Hedges						592	
add NPV of Coal Hedges						(149)	
NPV of Equity					**4,312**	**6,323**	**8,334**
Current Number of Shares outstanding					262	262	262
Equity value per share					**$16.46**	**$24.14**	**$31.81**

Source: UBS estimates

Valuing NRG using Platts power forwards on an Open Basis yields a marginally lower outlook.

Table 121: NRG SOP Valuation – Using Open Analysis and Platts Power Forwards

All figures in US $ million except per share data	2011E Open EBITDA	EV/EBITDA Multiple			Enterprise Value		
		Low	Base	High	Low	Base	High
Texas	925	8.0x	9.0x	10.0x	7,399	8,323	9,248
Northeast	371	8.0x	9.0x	10.0x	2,968	3,339	3,710
South Central	109	8.0x	9.0x	10.0x	871	980	1,089
West	68	8.0x	9.0x	10.0x	540	608	675
Power Hedges	(321)	8.0x	9.0x	10.0x	(2,568)	(2,889)	(3,210)
Coal Hedges	(118)	8.0x	9.0x	10.0x	(941)	(1,058)	(1,176)
Reliant Retail	381	3.0x	4.0x	5.0x	1,144	1,525	1,906
Other	35	5.0x	4.0x	3.0x	175	140	105
Total / Implied	**1,450**	6.5x	7.6x	8.4x	**9,413**	**10,968**	**12,243**
less net debt						(6,066)	
less Preferred Shares						(534)	
less NPV of environment capex						(838)	
add NPV of Power Hedges						1,521	
add NPV of Coal Hedges						447	
NPV of Equity					**3,944**	**5,499**	**6,773**
Current Number of Shares outstanding					262	262	262
Equity value per share					**$15.05**	**$20.99**	**$25.85**

Source: UBS estimates

Approaching NRG through DCF yields an attractive FCF profile

Valuing NRG using DCF yields a premium valuation to the SOP, given the company's relatively strong FCF metrics. We have enclosed a summary of our DCF below. We incorporate an 7.2% WACC (consistent with its IPP peers), as well as a 1.0% terminal growth rate. We believe the 1.0% terminal growth rate could be punitive given the numerous growth opportunities (including a minority stake in a new unit at STP 3 & 4) management has discussed.

Table 122: NRG Energy Summary DCF Valuation

All figures in US$ million except per share data		2009E	2010E	2011E	2012E	2013E	2014E
Operating Profit (EBIT)		**2,035**	**1,605**	**1,234**	**1,444**	**1,361**	**1,197**
Taxes		773	610	469	549	517	455
Tax adjusted EBIT		**1,262**	**995**	**765**	**895**	**844**	**742**
Add: Depreciation & Amortization		638	654	654	651	644	639
Add: deferred taxes		400	200	-	-	-	-
Less: Incremental Net Working Capital		112	(23)	18	(18)	(119)	(71)
Less: Capex		(732)	(647)	(662)	(594)	(512)	(544)
Less: Acquisitions / Investments		(28)	-	-	-	-	-
Unlevered Free Cash Flow		**1,652**	**1,179**	**775**	**935**	**857**	**765**
Present Value of Free Cash Flow		1,652	1,100	674	758	649	540
Terminal Value							12,454
Implied Terminal EV/EBITDA							6.8x
Cost of debt							
Risk free rate	4.0%						
Average debt premium	4.5%						
Nominal cost of debt	8.5%						
Marginal tax rate	38%						
Post tax cost of debt	5.3%						
Cost of equity							
Risk free rate	4.0%						
Equity risk premium (USER INPUT)	6.5%						
Equity beta (USER INPUT)	0.85						
Cost of equity	9.5%						
Cost of preferred stock	4.5%						
Market value of net debt	6,066						
Market Value of equity	5,695						
Market value of preferred stock	534						
Debt weighting	49.3%						
Equity weighting	46.3%						
Preferred stock weighting	4.3%						
WACC	**7.2%**						
Growth Rate	**1.0%**						
NPV of FCFF	3,722						
NPV of TV	8,794						
Total NPV	12,516						
Less: Net Debt and Preferred Stock	(6,600)						
NPV of Equity	5,916						
Current Number of Shares outstanding	259						
NPV of Equity per share	**$22.85**						
Forward value per share	**$25.03**						

Source: Company reports and UBS estimates

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Discounted Cash Flow Scenarios

We have provided in the tables below scenario analysis around our DCF valuation above. Table 123 provides a comparison of our WACC and our terminal growth rate, which is important to the company as ~70% of its DCF valuation is reflected in the Terminal Value (beyond 2014).

Table 123: NRG Energy DCF Sensitivity to WACC and Terminal Growth Rate

		WACC				
		6.4%	6.9%	**7.4%**	7.9%	8.4%
Terminal Growth Rate	0.5%	$34.33	$29.59	$25.54	$22.03	$18.97
	1.0%	$38.77	$33.28	$28.64	$24.66	$21.22
	1.5%	$44.11	$37.64	**$32.25**	$27.70	$23.80
	2.0%	$50.66	$42.88	$36.53	$31.25	$26.79
	2.5%	$58.86	$49.31	$41.68	$35.45	$30.27

Source: UBS estimates

In Table 124, we provide a comparison of NRG's cost of debt (used in our WACC calculation) against the debt capitalization of the company. Our cost of debt (at 9.00%) is marginally above the $700 Mn senior secured note NRG issued in 2009 at 8.75% (8.5% coupon). We note the relative sensitivity this relatively levered company has to higher yield spreads.

Table 124: NRG Energy DCF Sensitivity to Cost of Debt and Debt Capitalization

		Cost of Debt Financing				
		7.0%	8.0%	**9.0%**	10.0%	11.0%
	40.1%	$30.48	$28.29	$26.27	$24.38	$22.63
	45.1%	$32.96	$30.30	$27.86	$25.63	$23.57
Net Debt / Cap	**50.1%**	$35.65	$32.45	**$29.55**	$26.93	$24.54
	55.1%	$38.61	$34.77	$31.36	$28.30	$25.55
	60.1%	$41.86	$37.28	$33.28	$29.75	$26.61

Source: UBS estimates

We provide in Table 125 the sensitivity of our DCF to changes in our beta and equity risk premium. NRG is the only IPP to have an equity beta below 1.0 (at just 0.84).

Table 125: NRG Energy DCF Sensitivity to Beta and Equity Risk Premium

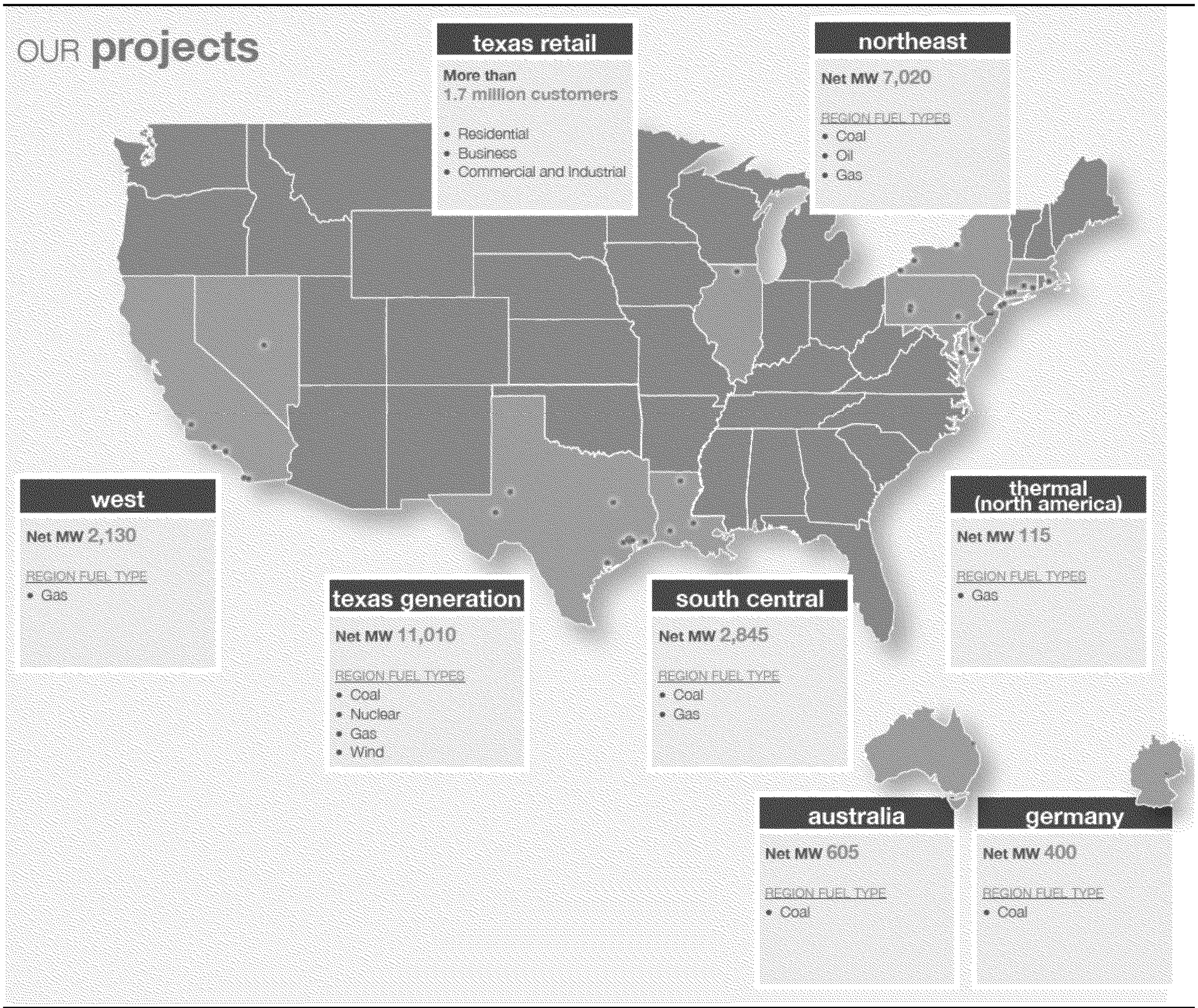
		Equity Risk Premium				
		5.5%	6.0%	**6.5%**	7.0%	7.5%
	0.54	$42.66	$41.03	$39.48	$38.01	$36.60
	0.64	$39.43	$37.69	$36.04	$34.48	$32.99
	0.74	$36.50	$34.67	$32.94	$31.32	$29.77
Beta	**0.84**	$33.82	$31.92	**$30.14**	$28.47	$26.89
	0.94	$31.36	$29.41	$27.59	$25.89	$24.28
	1.04	$29.09	$27.11	$25.26	$23.53	$21.92
	1.14	$27.00	$24.99	$23.12	$21.38	$19.75

Source: UBS estimates

Company Description

NRG Energy, Inc. is a wholesale power generation company engaged in the ownership, development, construction, and operation of power generation facilities, the transacting in and trading of fuel and transportation services, and the trading of energy, capacity and related products in the US and internationally. The company has an aggregate power generation capacity of over 23,000 MW. The majority of these assets lie in the US, with approximately net equity interest in 585 MW of generation capacity overseas. In the Texas region the Langford wind project is not included but accounts for 150 MW of incremental capacity, due in operation by year-end 2009. We have provided a summary map of NRG's assets in **Error! Reference source not found.**.

Figure 10: NRG Asset Portfolio



Source: Company reports

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Table 126: Texas Generation Portfolio

Texas	Location	Primary Fuel	% Owned	ERCOT Zone
Baseload				
W.A Parish	Thompsons, TX	Coal	100%	Houston
Limestone	Jewett, TX	Lignite/Coal	100%	Houston
South Texas Project	Bay City, TX	Nuclear	44%	South
Total				
Natural-Gas Fired Units				
Cedar Bayou	Baytown, TX	Natural Gas	100%	Houston
T.H. Wharton	Houston, TX	Natural Gas	100%	Houston
W.A. Parish	Thompsons, TX	Natural Gas	100%	Houston
S.R. Bertron	Deer Park, TX	Natural Gas	100%	Houston
Greens Bayou	Houston, TX	Natural Gas	100%	Houston
San Jacinto	LaPorte, TX	Natural Gas	100%	Houston
Total				
Intermittent				
Elbow Creek	Howard County	Wind	100%	West
Sherbino	Pecos County	Wind	50%	West
Total				

Source: Company reports

We note in the Northeast Region, NRG will be mothballing Units 1 and 2 of Indian River in 2011 and 2010, respectively, as part of a settlement agreement with the Delaware Dept. of Natural Resources and Environmental Control, totalling ~180 MW. More recently, NRG agreed to Mothball Indian River Unit 3 (165MW) by the end of 2013. NRG plans to retire its 125 MW Somerset coal unit in Massachusetts late this year per an agreement with the state DEP. Substantial environmental retrofits remain under way for its Dunkirk, Huntley, and Indian River Unit 4 coal plants in the Northeast.

Table 127: Northeast Region Generation Portfolio

Northeast	Location	Primary Fuel	% Owned	Net Generation Interest (MW)
Oswego	NY	Oil	100%	1,635
Arthur Kill	NY	Natgas	100%	865
Middleton	CT	Oil	100%	770
Indian River	DE	Coal	100%	740
Astoria Gas turbines	NY	Natgas	100%	550
Huntley	NY	Coal	100%	380
Dunkirk	NY	Coal	100%	530
Montville	CT	Oil	100%	500
Norwalk Harbor	CT	Oil	100%	340
Devon	CT	Natgas	100%	140
Vienna	MD	Oil	100%	170
Somerset Power	MA	Coal	100%	125
Connecticut Remote Turbines	CT	Oil	100%	145
Conemaugh	PA	Coal	3.7%	65
Keystone	PA	Coal	3.7%	65
Total Northeast Region				**7,020**

Source: Company reports

In the South Central region NRG operates its portfolio primarily meet to the full load obligations of 11 Louisiana distribution cooperates, SWEPCO, CLECO, and municipalities in MS.

Table 128: South Central Region Generation Portfolio

South Central	Location	Primary Fuel	% Owned	Net Generation Interest (MW)
Big Cajun II	LA	Coal	86%	1,490
Bayou Cove	LA	Natgas	100%	300
Big Cajun I 3 & 4 (pkrs)	LA	Natgas	100%	210
Big Cajun I Units 1 and 2	LA	Natgas/Oil	100%	220
Rockford I	IL	Natgas	100%	300
Rockford II	IL	Natgas	100%	150
Sterlington	LA	Natgas	100%	175
Total South Central				**2,845**

Source: Company reports

In the Western region, NRG operates a fleet of natural gas units primarily in the CA ISO with the exception of Sagauro. These units primarily derive their value from Reliability Must Run (RMR) and Resource Adequacy (RA) capacity payments.

Table 129: Western Region Generation Portfolio

West Region	Location	Primary Fuel	% Owned	Net Generation Interest (MW)
Encina	CA	Natgas	100%	965
El Segundo	CA	Natgas	100%	670
Long Beach	CA	Natgas	100%	260
Cabrillo II	CA	Natgas	100%	190
Saguaro	Nevada	Natgas	50%	45
Total West Region				**2,130**

Source: Company reports

NRG also owns minority stakes in generation interests abroad; we anticipate management will continue to sell down these stakes as it did with MIBRAG earlier this year.

Table 130: International Generation Portfolio

International Region	Location	Primary Fuel	% Owned	Net Equity Interest
Gladstone	Australia	Coal	37.5%	605
Schkopau	Germany	Lignite	41.9%	400
MIBRAG	Germany	Lignite	50.0%	75
Total International				**1,080**

Source: Company reports

Risks

Risks to our investment thesis include: 1) actual commodity prices differing significantly from our assumptions, particularly for the ERCOT region; 2) political and regulatory intervention to change the structure of competitive markets in response to high power prices and insufficient new build; 3) credit markets and the (in)ability to refinance high yield maturities; and 4) unknown impact from a potential carbon legislation (likely a modest negative) and other environmental legislation (CAIR/MACT standards). We note NRG could potentially be required to install scrubbers at its Big Cajun and Parish units. Other investment risks include abrupt changes in weather patterns, sharp slowdown in economic demand, interest rate risks, large renewable/transmission buildout across TX, and disruption of trading activity in power markets.

NRG Energy Inc.

Income statement (US$m)	12/04	12/05	12/06	12/07	12/08	12/09E	% ch	12/10E	% ch	12/11E	% ch
Revenues	**2,348**	**2,430**	**5,623**	**5,824**	**6,178**	**5,038**	*-18.5*	**5,292**	*5.0*	**5,044**	*-4.7*
Operating expenses (ex depn)	(1,747)	(2,031)	(3,592)	(3,788)	(3,963)	(2,424)	*-38.8*	(3,068)	*26.6*	(3,190)	*4.0*
EBITDA (UBS)	**601**	**399**	**2,031**	**2,036**	**2,215**	**2,649**	*19.6*	**2,259**	*-14.7*	**1,888**	*-16.4*
Depreciation	(208)	(162)	(593)	(658)	(649)	(638)	*-1.6*	(654)	*2.4*	(654)	*0.1*
Operating income (EBIT, UBS)	**393**	**237**	**1,438**	**1,378**	**1,566**	**2,011**	*28.4*	**1,605**	*-20.2*	**1,234**	*-23.1*
Other income & associates	99	66	41	75	76	0	-	0	-	0	-
Net interest	(266)	(204)	(649)	(744)	(675)	(599)	*-11.3*	(575)	*-4.0*	(540)	*-6.1*
Abnormal items (pre-tax)	0	0	0	0	0	0	-	0	-	0	-
Profit before tax	**226**	**99**	**830**	**709**	**967**	**1,412**	*46.0*	**1,030**	*-27.0*	**694**	*-32.6*
Tax	(65)	(47)	(325)	(377)	(713)	(539)	*-24.3*	(389)	*-27.8*	(255)	*-34.4*
Profit after tax	**161**	**52**	**505**	**332**	**254**	**873**	*243.6*	**641**	*-26.6*	**439**	*-31.5*
Abnormal items (post-tax)	0	0	0	0	0	0	-	0	-	0	-
Minorities / pref dividends	0	0	0	0	0	0	-	0	-	0	-
Net income (local GAAP)	**161**	**52**	**505**	**332**	**254**	**873**	*243.6*	**641**	*-26.6*	**439**	*-31.5*
Net Income (UBS)	**161**	**52**	**505**	**332**	**254**	**873**	*243.6*	**641**	*-26.6*	**439**	*-31.5*
Tax rate (%)	*29*	*47*	*39*	*53*	*74*	*38*	*-48.2*	*38*	*-1.0*	*37*	*-2.6*
Pre-abnormal tax rate (%)	*29*	*47*	*39*	*53*	*74*	*38*	*-48.2*	*38*	*-1.0*	*37*	*-2.6*

Per share (US$)	12/04	12/05	12/06	12/07	12/08	12/09E	% ch	12/10E	% ch	12/11E	% ch
EPS (local GAAP)	0.80	0.31	1.68	1.15	0.92	3.22	*248.7*	2.48	*-23.1*	1.75	*-29.5*
EPS (UBS)	0.80	0.31	1.68	1.15	0.92	3.22	*248.7*	2.48	*-23.1*	1.75	*-29.5*
Net DPS	0.00	0.00	0.00	0.00	0.00	0.00	-	0.00	-	0.00	-
Cash EPS	1.84	1.26	3.66	3.44	3.28	5.58	*69.8*	5.00	*-10.3*	4.35	*-13.1*
BVPS	8.34	6.66	18.85	19.23	26.46	24.81	*-6.2*	27.96	*12.7*	29.80	*6.6*

Balance sheet (US$m)	12/04	12/05	12/06	12/07	12/08	12/09E	% ch	12/10E	% ch	12/11E	% ch
Cash and equivalents	1,104	493	795	1,132	1,494	1,000	*-33.1*	1,000	*0.0*	1,000	*0.0*
Other current assets	1,015	1,703	2,288	2,430	6,998	6,714	*-4.1*	6,813	*1.5*	6,808	*-0.1*
Total current assets	**2,119**	**2,196**	**3,083**	**3,562**	**8,492**	**7,714**	*-9.2*	**7,813**	*1.3*	**7,808**	*-0.1*
Net tangible fixed assets	3,158	2,609	11,600	11,320	11,545	11,927	*3.3*	11,920	*-0.1*	11,928	*0.1*
Net intangible fixed assets	0	0	0	0	0	0	-	0	-	0	-
Investments / other assets	2,587	2,661	4,752	4,392	4,771	4,511	*-5.4*	4,511	*0.0*	4,511	*0.0*
Total assets	**7,864**	**7,466**	**19,435**	**19,274**	**24,808**	**24,151**	*-2.6*	**24,244**	*0.4*	**24,247**	*0.0*
Trade payables & other ST liabilities	576	1,262	1,902	1,811	6,117	5,934	*-3.0*	6,007	*1.2*	6,021	*0.2*
Short term debt	511	95	130	466	464	388	*-16.3*	355	*-8.6*	344	*-3.2*
Total current liabilities	**1,087**	**1,357**	**2,032**	**2,277**	**6,581**	**6,322**	*-3.9*	**6,362**	*0.6*	**6,365**	*0.0*
Long term debt	2,973	2,410	8,647	7,895	7,704	7,372	*-4.3*	6,741	*-8.6*	6,524	*-3.2*
Other long term liabilities	1,111	1,221	2,850	3,351	3,160	3,160	*0.0*	3,360	*6.3*	3,360	*0.0*
Total liabilities	**5,171**	**4,988**	**13,529**	**13,523**	**17,445**	**16,854**	*-3.4*	**16,464**	*-2.3*	**16,249**	*-1.3*
Equity & minority interests	2,693	2,478	5,906	5,751	7,363	7,297	*-0.9*	7,780	*6.6*	7,998	*2.8*
Total liabilities & equity	**7,864**	**7,466**	**19,435**	**19,274**	**24,808**	**24,151**	*-2.6*	**24,244**	*0.4*	**24,247**	*0.0*

Cash flow (US$m)	12/04	12/05	12/06	12/07	12/08	12/09E	% ch	12/10E	% ch	12/11E	% ch
Net income	161	52	505	332	254	873	*243.6*	641	*-26.6*	439	*-31.5*
Depreciation	208	162	593	658	649	638	*-1.6*	654	*2.4*	654	*0.1*
Net change in working capital	41	(16)	140	9	198	101	*-48.8*	(26)	-	18	-
Other (operating)	235	(130)	(832)	518	333	0	-	200	-	0	-
Net cash from operations	**645**	**68**	**406**	**1,517**	**1,434**	**1,613**	*12.4*	**1,469**	*-8.9*	**1,111**	*-24.3*
Capital expenditure	(119)	(106)	(221)	(481)	(899)	(732)	*-18.6*	(647)	*-11.6*	(662)	*2.3*
Net (acquisitions) / disposals	55	74	(4,247)	32	81	(28)	-	0	-	0	-
Other changes in investments	248	190	292	122	146	0	-	0	-	0	-
Cash from investing activities	**184**	**158**	**(4,176)**	**(327)**	**(672)**	**(760)**	*13.1*	**(647)**	*-14.9*	**(662)**	*2.3*
Increase/(decrease) in debt	147	(510)	4,344	(468)	(273)	(441)	-	(697)	-	(262)	-
Share issues / (repurchases)	(405)	(250)	254	(346)	(176)	(906)	-	(125)	-	(188)	-
Dividends paid	0	0	0	0	0	0	-	0	-	0	-
Other cash from financing	(26)	(70)	(545)	0	7	0	-	0	-	0	-
Cash from financing activities	**(284)**	**(830)**	**4,053**	**(814)**	**(442)**	**(1,347)**	*204.6*	**(822)**	*-39.0*	**(449)**	*-45.3*
Cash flow chge in cash & equivalents	**545**	**(604)**	**283**	**376**	**320**	**(494)**	-	**0**	-	**0**	-
FX / non cash items	-	(7)	19	(39)	42	0	*49900.0*	0	-	0	-
Bal sheet chge in cash & equivalents	**-**	**(611)**	**302**	**337**	**362**	**(494)**	-	**0**	-	**0**	-
Core EBITDA	601	399	2,031	2,036	2,215	2,649	*19.6*	2,259	*-14.7*	1,888	*-16.4*
Maintenance capital expenditure	(119)	(106)	(221)	(481)	(899)	(732)	*-18.6*	(647)	*-11.6*	(662)	*2.3*
Maintenance net working capital	41	(16)	140	6	39	38	*-1.0*	(11)	-	7	-
Operating free cash flow, pre-tax	**523**	**277**	**1,950**	**1,561**	**1,355**	**1,956**	*44.3*	**1,601**	*-18.1*	**1,233**	*-23.0*

Source: Company accounts, UBS estimates. (UBS) valuations are stated before goodwill-related charges and other adjustments for abnormal and economic items at the analysts' judgement. Note: For some companies, the data represents an extract of the full company accounts.

NRG Energy Inc.

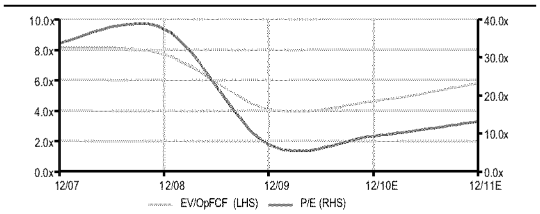
12-month rating **Neutral**

12m price target **US$24.00**

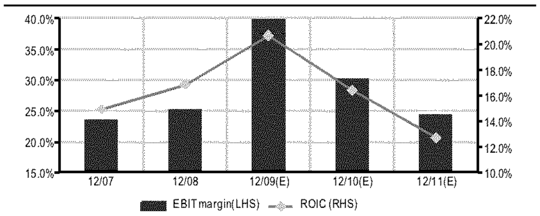
Company profile

NRG Energy, Inc. is a wholesale power generation company engaged in the ownership, development, construction, and operation of power generation facilities, the transacting in and trading of fuel and transportation services, and the trading of energy, capacity and related products in the US and internationally. The company has an aggregate power generation capacity of over 23,000 MW. The majority of these assets lie in the US, with approximately net equity interest in 585 MW of generation capacity overseas.

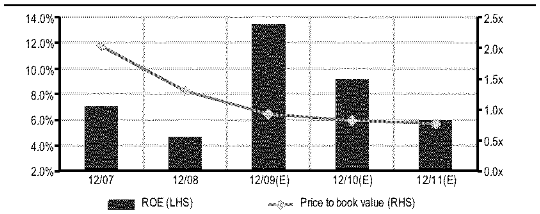
Value (EV/OpFCF & P/E)



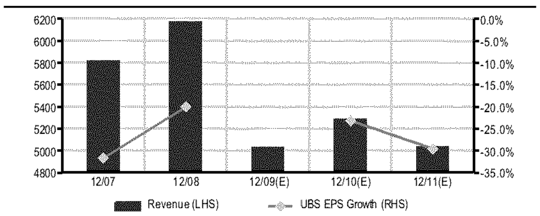
Profitability



ROE v Price to book value



Growth (UBS EPS)



Valuation (x)	5Yr Avg	12/07	12/08	12/09E	12/10E	12/11E
P/E (local GAAP)	-	33.9	37.5	7.2	9.4	13.3
P/E (UBS)	-	33.9	37.5	7.2	9.4	13.3
P/CEPS	-	11.4	10.5	4.2	4.6	5.3
Net dividend yield (%)	-	0.0	0.0	0.0	0.0	0.0
P/BV	-	2.0	1.3	0.9	0.8	0.8
EV/revenue (core)	-	2.2	1.7	1.6	1.4	1.4
EV/EBITDA (core)	-	6.2	4.7	3.0	3.3	3.8
EV/EBIT (core)	-	9.2	6.7	4.0	4.6	5.8
EV/OpFCF (core)	-	8.1	7.7	4.1	4.6	5.8
EV/op. invested capital	-	1.4	1.1	0.8	0.8	0.7

Enterprise value (US$m)	12/07	12/08	12/09E	12/10E	12/11E
Average market cap	9,493	8,205	5,498	5,498	5,498
+ minority interests	0	7	7	7	7
+ average net debt (cash)	7,229	6,674	6,760	6,097	5,868
+ pension obligations and other	0	0	0	0	0
- non-core asset value	(4,008)	(4,468)	(4,208)	(4,208)	(4,208)
Core enterprise value	12,714	10,418	8,058	7,394	7,165

Growth (%)	5Yr Avg	12/07	12/08	12/09E	12/10E	12/11E
Revenue	-	3.6	6.1	-18.5	5.0	-4.7
EBITDA (UBS)	-	0.2	8.8	19.6	-14.7	-16.4
EBIT (UBS)	-	-4.2	13.6	28.4	-20.2	-23.1
EPS (UBS)	-	-31.5	-19.9	NM	-23.1	-29.5
Cash EPS	-	-6.1	-4.5	69.8	-10.3	-13.1
Net DPS	-	-	-	-	-	-
BVPS	-	2.0	37.6	-6.2	12.7	6.6

Margins (%)	5Yr Avg	12/07	12/08	12/09E	12/10E	12/11E
EBITDA / revenue	-	35.0	35.9	52.6	42.7	37.4
EBIT / revenue	-	23.7	25.3	39.9	30.3	24.5
Net profit (UBS) / revenue	-	5.7	4.1	17.3	12.1	8.7

Return on capital (%)	5Yr Avg	12/07	12/08	12/09E	12/10E	12/11E
EBIT ROIC (UBS)	-	14.9	16.9	20.7	16.4	12.8
ROIC post tax	-	7.0	4.4	12.8	10.2	8.1
Net ROE	-	7.1	4.7	13.4	9.2	6.0

Coverage ratios (x)	5Yr Avg	12/07	12/08	12/09E	12/10E	12/11E
EBIT / net interest	-	2.0	2.4	3.4	2.8	2.3
Dividend cover (UBS EPS)	-	-	-	-	-	-
Div. payout ratio (%, UBS EPS)	-	-	-	-	-	-
Net debt / EBITDA	-	4.1	3.5	2.8	2.9	3.4

Efficiency ratios (x)	5Yr Avg	12/07	12/08	12/09E	12/10E	12/11E
Revenue / op. invested capital	-	0.6	0.7	0.5	0.5	0.5
Revenue / fixed assets	-	0.5	0.5	0.4	0.4	0.4
Revenue / net working capital	-	11.6	8.2	6.1	6.7	6.3

Investment ratios (x)	5Yr Avg	12/07	12/08	12/09E	12/10E	12/11E
OpFCF / EBIT	-	1.1	0.9	1.0	1.0	1.0
Capex / revenue (%)	-	8.3	14.6	14.5	12.2	13.1
Capex / depreciation	-	0.7	1.4	1.1	1.0	1.0

Capital structure (%)	5Yr Avg	12/07	12/08	12/09E	12/10E	12/11E
Net debt / total equity	-	NM	NM	NM	91.7	85.1
Net debt / (net debt + equity)	-	64.5	55.4	52.2	47.8	46.0
Net debt (core) / EV	-	56.9	64.1	83.9	82.5	81.9

Source: Company accounts, UBS estimates. (UBS) valuations are stated before goodwill-related charges and other adjustments for abnormal and economic items at the analysts' judgement.

Valuations: based on an average share price that year, (E): based on a share price of US$23.20 on 19 Feb 2010 19:35 EST Market cap(E) may include forecast share issues/buybacks.

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Statement of Risk

Risks for regulated utilities include the uncertainty around the composition of state regulatory Commissions, adverse regulatory changes, unfavorable weather conditions, variance from normal population growth, and changes in the customer mix. Changes in macroeconomic factors will affect customer additions/subtractions and usage patterns. Corporate risk also stems from commodity, load variability, and operational risk attributed to non-regulated operations at utilities. Rising coal and, to a certain extent, uranium prices could pressure margins as the fuel hedges roll off merchant generators. Other non-regulated risks include weather and foreign currency risk, which again must be diligently accounted in the company's risk management operations. Major external factors, which affect our valuation, are environmental risks. Environmental capex could escalate if stricter emission standards are implemented. We believe a nuclear accident or a change in the Nuclear Regulatory Commission/Environment Protection Agency regulations could have a negative impact on our estimates. Also see Company sections within the report for company-specific risks.

Analyst Certification

Each research analyst primarily responsible for the content of this research report, in whole or in part, certifies that with respect to each security or issuer that the analyst covered in this report: (1) all of the views expressed accurately reflect his or her personal views about those securities or issuers; and (2) no part of his or her compensation was, is, or will be, directly or indirectly, related to the specific recommendations or views expressed by that research analyst in the research report.

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UBS Investment Research: Global Equity Rating Allocations

UBS 12-Month Rating	Rating Category	Coverage[1]	IB Services[2]
Buy	**Buy**	48%	40%
Neutral	**Hold/Neutral**	40%	35%
Sell	**Sell**	13%	26%
UBS Short-Term Rating	**Rating Category**	**Coverage[3]**	**IB Services[4]**
Buy	**Buy**	less than 1%	17%
Sell	**Sell**	less than 1%	67%

1:Percentage of companies under coverage globally within the 12-month rating category.
2:Percentage of companies within the 12-month rating category for which investment banking (IB) services were provided within the past 12 months.
3:Percentage of companies under coverage globally within the Short-Term rating category.
4:Percentage of companies within the Short-Term rating category for which investment banking (IB) services were provided within the past 12 months.

Source: UBS. Rating allocations are as of 31 December 2009.

UBS Investment Research: Global Equity Rating Definitions

UBS 12-Month Rating	Definition
Buy	FSR is > 6% above the MRA.
Neutral	FSR is between -6% and 6% of the MRA.
Sell	FSR is > 6% below the MRA.
UBS Short-Term Rating	**Definition**
Buy	Buy: Stock price expected to rise within three months from the time the rating was assigned because of a specific catalyst or event.
Sell	Sell: Stock price expected to fall within three months from the time the rating was assigned because of a specific catalyst or event.

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KEY DEFINITIONS

Forecast Stock Return (FSR) is defined as expected percentage price appreciation plus gross dividend yield over the next 12 months.
Market Return Assumption (MRA) is defined as the one-year local market interest rate plus 5% (a proxy for, and not a forecast of, the equity risk premium).
Under Review (UR) Stocks may be flagged as UR by the analyst, indicating that the stock's price target and/or rating are subject to possible change in the near term, usually in response to an event that may affect the investment case or valuation.
Short-Term Ratings reflect the expected near-term (up to three months) performance of the stock and do not reflect any change in the fundamental view or investment case.
Equity Price Targets have an investment horizon of 12 months.

EXCEPTIONS AND SPECIAL CASES

UK and European Investment Fund ratings and definitions are: Buy: Positive on factors such as structure, management, performance record, discount; Neutral: Neutral on factors such as structure, management, performance record, discount; Sell: Negative on factors such as structure, management, performance record, discount.
Core Banding Exceptions (CBE): Exceptions to the standard +/-6% bands may be granted by the Investment Review Committee (IRC). Factors considered by the IRC include the stock's volatility and the credit spread of the respective company's debt. As a result, stocks deemed to be very high or low risk may be subject to higher or lower bands as they relate to the rating. When such exceptions apply, they will be identified in the Company Disclosures table in the relevant research piece.

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UBS Securities LLC: Julien Dumoulin-Smith; Ronald J. Barone; Kevin M. Anderson, CFA.

Company Disclosures

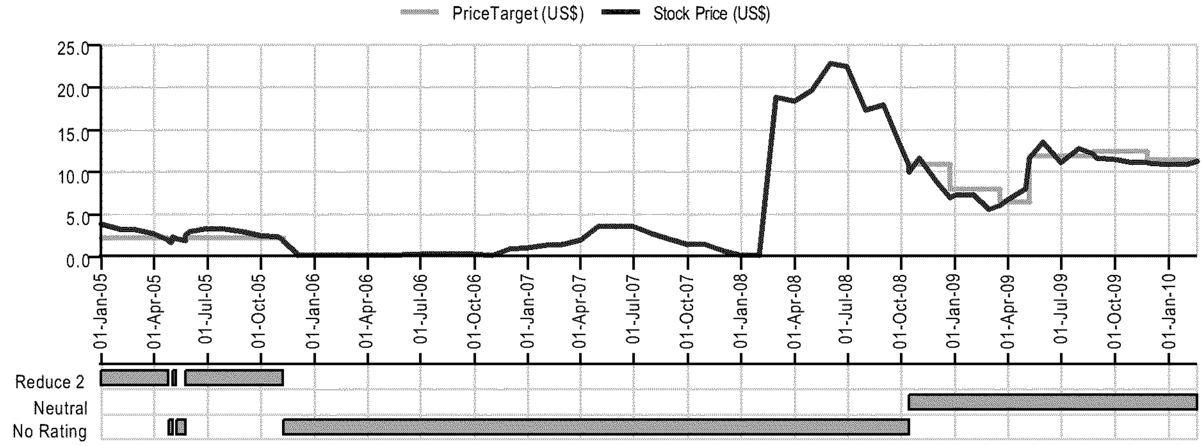
Company Name	Reuters	12-mo rating	Short-term rating	Price	Price date
Calpine Corporation[6, 7, 16]	CPN.N	Neutral	N/A	US$11.35	19 Feb 2010
Dynegy, Inc.[16, 20]	DYN.N	Sell (CBE)	N/A	US$1.65	19 Feb 2010
Mirant Corp[16]	MIR.N	Neutral	N/A	US$13.45	19 Feb 2010
NRG Energy Inc.[16]	NRG.N	Neutral	N/A	US$23.20	19 Feb 2010
RRI Energy Inc.[6, 7, 16, 20]	RRI.N	Neutral (CBE)	N/A	US$4.81	19 Feb 2010

Source: UBS. All prices as of local market close.
Ratings in this table are the most current published ratings prior to this report. They may be more recent than the stock pricing date

6. This company/entity is, or within the past 12 months has been, a client of UBS Securities LLC, and non-investment banking securities-related services are being, or have been, provided.
7. Within the past 12 months, UBS Securities LLC has received compensation for products and services other than investment banking services from this company/entity.
16. UBS Securities LLC makes a market in the securities and/or ADRs of this company.
20. Because UBS believes this security presents significantly higher-than-normal risk, its rating is deemed Buy if the FSR exceeds the MRA by 10% (compared with 6% under the normal rating system).

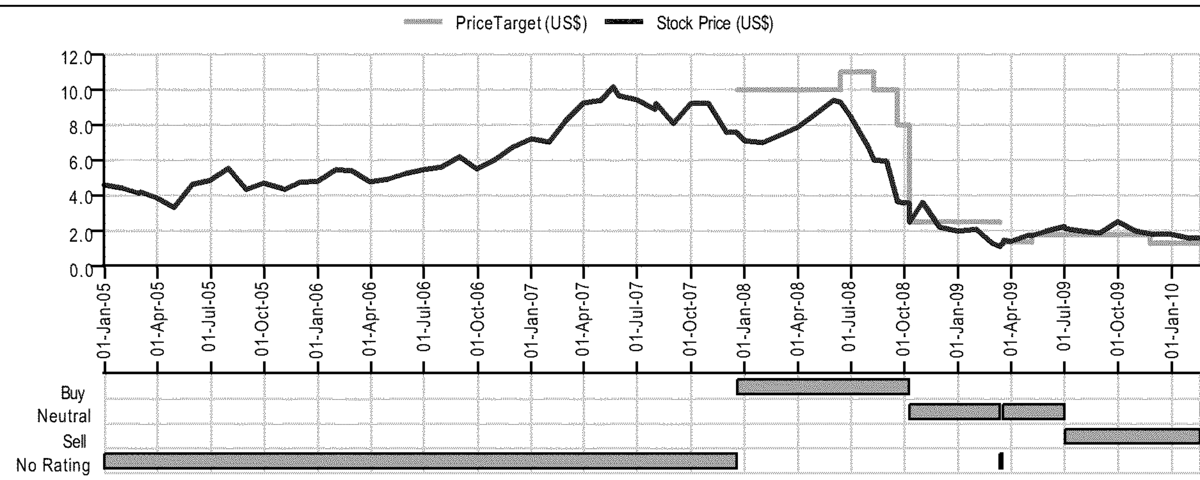
Unless otherwise indicated, please refer to the Valuation and Risk sections within the body of this report.

Calpine Corporation (US$)



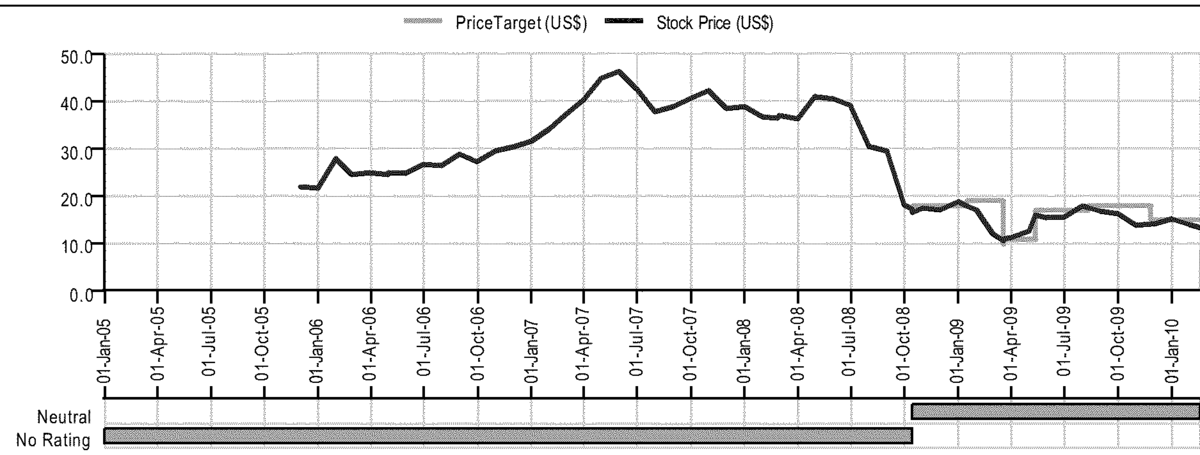
Source: UBS; as of 19 Feb 2010

Dynegy, Inc. (US$)



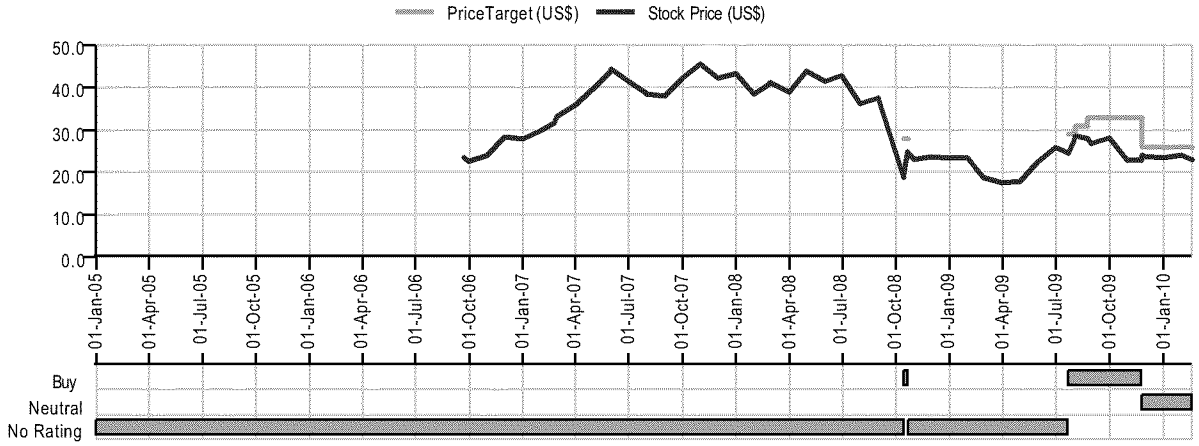
Source: UBS; as of 19 Feb 2010

Mirant Corp (US$)



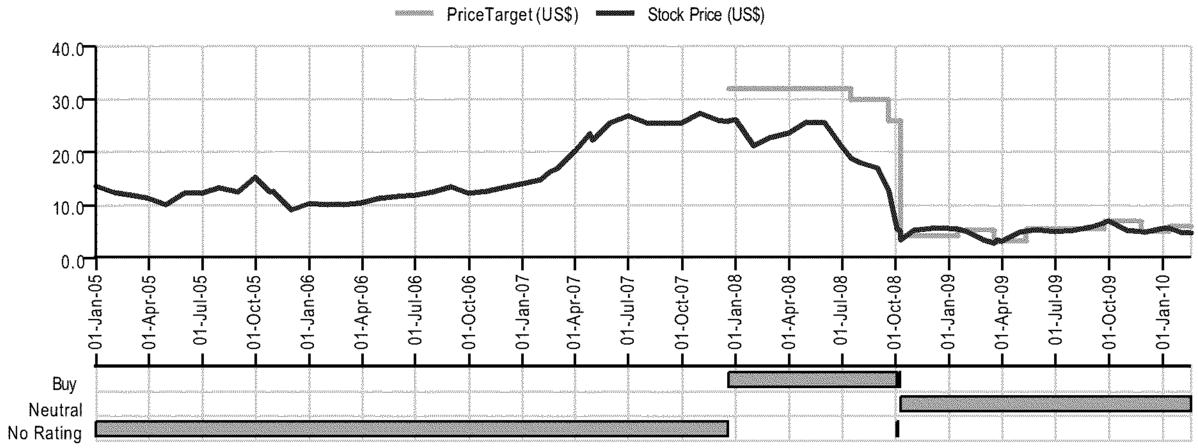
Source: UBS; as of 19 Feb 2010

NRG Energy Inc. (US$)



Source: UBS; as of 19 Feb 2010

RRI Energy Inc. (US$)



Source: UBS; as of 19 Feb 2010

Note: On August 4, 2007 UBS revised its rating system. (See 'UBS Investment Research: Global Equity Rating Definitions' table for details). From September 9, 2006 through August 3, 2007 the UBS ratings and their definitions were: Buy 1 = FSR is > 6% above the MRA, higher degree of predictability; Buy 2 = FSR is > 6% above the MRA, lower degree of predictability; Neutral 1 = FSR is between -6% and 6% of the MRA, higher degree of predictability; Neutral 2 = FSR is between -6% and 6% of the MRA, lower degree of predictability; Reduce 1 = FSR is > 6% below the MRA, higher degree of predictability; Reduce 2 = FSR is > 6% below the MRA, lower degree of predictability. The predictability level indicates an analyst's conviction in the FSR. A predictability level of '1' means that the analyst's estimate of FSR is in the middle of a narrower, or smaller, range of possibilities. A predictability level of '2' means that the analyst's estimate of FSR is in the middle of a broader, or larger, range of possibilities. From October 13, 2003 through September 8, 2006 the percentage band criteria used in the rating system was 10%.

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