BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

	)	
AMEREN ENERGY RESOURCES	)	
	)	PCB 12-126
Petitioner,	)	(Variance - Air)
v.	)	
	)	
ILLINOIS ENVIRONMENTAL	)	
PROTECTION AGENCY,	)	
	)	
Respondent.	)	

NOTICE OF ELECTRONIC FILING

To: Attached Service List

PLEASE TAKE NOTICE that on May 16, 2013, I electronically filed with the Clerk of the Pollution Control Board of the State of Illinois **Comments of the Environmental Law & Policy Center, Natural Resources Defense Council, Respiratory Health Association, and Sierra Club**, a copy of which is attached hereto and herewith served upon you.

Respectfully submitted,

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COMMENTS OF ENVIRONMENTAL LAW & POLICY CENTER, NATURAL RESOURCES DEFENSE COUNCIL, RESPIRATORY HEALTH ASSOCIATION, AND SIERRA CLUB

Pursuant to 35 Ill. Adm. Code 104.224(d), Environmental Law & Policy Center, Natural Resources Defense Council, Respiratory Health Association, and Sierra Club (collectively, "Citizens Groups") submit the following comments on the Motion to Reopen Docket and Substitute Parties filed by Ameren Energy Resources ("Ameren") and Illinois Power Holdings, LLC, a subsidiary of Dynegy Inc., ("Dynegy") (collectively, "Dynegy/Ameren") on May 2, 2013. The Board should deny the motion as procedurally improper and substantively unsupported.

I. Introduction

Dynegy/Ameren's motion for substitution cannot be granted. Dynegy/Ameren have not made a legally sufficient demonstration that Ameren's variance from the Illinois Multi-Pollutant Standard's ("MPS") fleet-wide sulfur dioxide ("SO_2") emission limits should be "transferred" to Dynegy. Dynegy/Ameren's motion fails for two reasons. First, the motion is premature, as an entity cannot receive a variance before it legally owns the facilities subject to regulation. Here, Dynegy improperly seeks a prospective variance related to plants that it has not yet purchased.

On this point, Dynegy/Ameren have failed to cite a recent Board decision denying the exact same relief sought here.

Second, the motion fails to demonstrate that the relevant factors of hardship and environmental impact that the Board found supported Ameren's variance last year also would support a variance for Dynegy. Ameren was granted a variance based upon financial hardship, but Dynegy cannot show the same financial hardship. Financial hardship is a very individualized determination that is not sufficiently supported by the motion and attached affidavits. Furthermore, Dynegy/Ameren cannot legitimately claim that Dynegy is in virtually the same financial position as Ameren and therefore would suffer the same financial hardship. Dynegy's own public statements outside of this proceeding indicate that Dynegy believes it will be positioned much differently if takes over the plants in 2014 than Ameren was in 2012. Additionally, financial hardship is self-imposed and does not qualify for a variance where, as will be the case here, the entity seeking the variance voluntarily purchases the subject facilities. Neither can Dynegy/Ameren show that the environmental impact of a variance for Dynegy would be the same as the Board found with respect to Ameren's variance last year. If Dynegy purchases Ameren's plants, there would be at least 27,000 fewer tons of SO_2 emitted if Dynegy were required to comply with the MPS than if it were allowed a variance on terms similar to Ameren's.

For these reasons, Dynegy/Ameren's motion should be denied. The Board should instruct Dynegy to file its own petition for regulatory relief, with full opportunity for public comment, if and when Dynegy purchases the plants at issue. Alternatively, if the Board does not deny this motion outright, Citizens Groups request that the Board allow additional time to respond to the motion, schedule a hearing, and allow a public comment period of at least forty-five days so that this matter of great public interest can be fully vetted and the Board may hear additional comments.

II. The Variance Request is Premature.

Dynegy/Ameren's request to substitute Dynegy for Ameren in the variance docket is essentially a request to transfer the variance to Dynegy. That request to transfer the variance is premature. Under Board precedent and regulations, an entity cannot receive a variance before it legally owns the facilities subject to regulation.

Dynegy/Ameren cite only a handful of Board cases involving adjusted standards, which are distinguishable due to the different standard being applied. Furthermore, they selectively overlook the most relevant Board decision, *The Ensign-Bickford Co. v. IEPA*, PCB 02-159 (Apr. 3, 2003) ("*Ensign-Bickford*"). In *Ensign-Bickford*, the Board denied a motion to transfer a variance from an entity that owned a facility to an entity that was purchasing the facility, and made clear that the purchasing entity should not seek a variance prior to closing on the facility. *Id.*, slip op. at 2.

Like Ameren in this case, the Petitioner in *Ensign-Bickford* filed a motion to transfer its variance from state air regulations to a third party, Dyno Nobel. *Id*., slip op. at 1. Dyno Nobel was in the process of purchasing the facility at issue when the motion was filed, and the Petitioner requested that the variance transfer to Dyno Nobel on the same day that the pending sale was scheduled to close. *Id*.

The Board denied the motion, however, on the grounds that neither the Illinois Environmental Protection Act nor the Board's regulations provide a procedure for the holder of a variance to seek its transfer to a third party. *Id.*, slip op. at 2. Specifically, the Board cited 35 Ill. Adm. Code 104.202(a) ("Filing Requirements), which provides that: "Any person seeking a variance from any rule or regulation, requirement or order of the Board that would otherwise be applicable to that person may file a variance petition." The Board then held that its "procedural rules do not provide for a third party to seek a variance or have a variance transferred on Dyno Nobel's behalf." *Id.*, slip op. at 2. The Board therefore rejected the motion and concluded: "*If in fact [the] closing occurs*, consistent with Section 104.202(a), Dyno Nobel may file a variance petition or other appropriate filing concerning this facility." *Id*. (emphasis added). Therefore, *Ensign-Bickford* demonstrates that there is no legal basis for transferring a variance to the buyer of a facility before the close of the transaction. Instead, the buyer must come before the Board after closing and file its own petition for a variance, pursuant to 35 Ill. Adm. Code 104.202(a).

Dynegy/Ameren's cited case law on substitution of parties is not on point. *See* Mot. at 10-11 (emphasis added; citing *In the Matter of: Petition of the Ensign-Bickford Company for an Adjusted Standard from 35 Ill. Adm. Code 237.102*, AS 00-5 (Jun. 5, 2003) ("*Ensign-Bickford II*"); *In the Matter of: Petition of Commonwealth Edison Company for Adjusted Standard from 35 Ill. Adm. Code 302.211(d) and (e)*, AS 96-10 (Mar. 16, 2000) ("*Com Ed*"); *In the matter of: Petition of Envirite Corp. for a revised Adjusted Standard from 35 Ill. Adm. Code 721 Subpart D*, AS 94-10 (Dec. 19, 1996) ("*Envirite*"). In *ComEd* and *Ensign-Bickford*, there was a sale of assets between two unrelated corporate entities and the adjusted standards were transferred following the closing of the sale of assets. *ComEd* , slip op. at 1 ("ComEd agreed, in March 1999, to sell the Generating Stations to Edison Mission Energy."); *Ensign-Bickford II*, slip op. at 1 ("In the motion, EBCo and Dyno Nobel state that on May 2, 2003, Dyno Nobel became the new operator of the . . . facility."). Consequently, the transfer of the adjusted standard taking place post-closing is of particular importance.

Envirite is distinguishable for a slightly different reason. In *Envirite*, the motion requested that "the Board change the name of the petitioner from Envirite of IL, Inc. to Envirite of Illinois, Inc." because "a determination was made, for consistency with other subsidiaries, to name the new corporation Envirite of Illinois, Inc. and not Envirite of IL, Inc." *Envirite*, slip op. at 1. Consequently, the Envirite Corporation was going through a corporate reorganization and the decision cited by Ameren/Dynegy was a minor administrative correction to the name of the corporation. *Id*.

The reason for the Board's requirement in *Ensign-Bickford* that a transfer of regulatory relief should only occur post-closing is made clear in *Com Ed*—the purchaser of the subject facility needs to have assumed all the obligations, including the obligation to comply with the law, associated with the operation of the facility. *Com Ed*, slip op. at 2 ("Midwest has assumed all rights and obligations associated with the operation of the Generating Stations.").

Stated another way, a variance cannot be provided to an entity that is not "subject" to the relevant regulations. 35 Ill. Adm. Code Part 104, Subtitle B, specifically addresses eligibility for variances. Again, Section 104.202(a) states that "[a]ny person seeking a variance from any rule or regulation, requirement or order of the Board *that would otherwise be applicable to that person* may file a variance petition." 35 Ill. Adm. Code 104.202(a) (emphasis added). Therefore, under this section, only those entities that are subject to a Board regulation can seek a variance from that regulation. Section 104.230 ("Dismissal of Petition") supports this interpretation by stating "[a] petition is subject to dismissal if the Board determines that . . . (d) *[t]he petitioner is not subject to the rule or regulation, requirement, or order of the Board at issue*." 35 Ill. Adm. Code 104.230(d) (emphasis added). However, in the present case Dynegy does not own the facilities yet. Dynegy is not subject to the regulations as they apply to Ameren's fleet of plants, and therefore may not receive a variance.

That Dynegy's request is premature also is demonstrated by 35 Ill. Adm. Code 104.240 ("Certificate of Acceptance"), which provides that:

> The Board's order granting a variance will include a certificate of acceptance. The certificate constitutes acceptance of the variance and its conditions by the petitioner. A variance and its conditions are not binding upon the petitioner until the executed certificate is filed with the Board and served on the Agency. Failure to timely file the executed certificate with the Board and serve the Agency renders the variance void.

If the Board were to grant Dynegy/Ameren's request, Dynegy would be unable to execute a timely certificate of acceptance of the variance. Dynegy would not, in any case, own the subject plants until the end of 2013, well after a Board order on this motion. *See* Mot. at 17 (projecting that the Dynegy/Ameren transaction would close during the fourth quarter of 2013). Dynegy therefore would be unable to accept the responsibility for meeting the variance's conditions at the time the Board issues its order. Dynegy/Ameren try to work around this issue by including as Exhibit D to their motion a proposed "Notice of Closing and Certificate of Acceptance" that would assume legal effect if and when the transaction closes. However, the Board should not be required to make up new legal forms for Dynegy; instead, Dynegy should follow the Board's procedures and file for any desired regulatory relief if and when its transaction closes.

Nor can Ameren seek to transfer the variance to Dynegy on Dynegy's behalf. While Ameren may have couched its motion as one to substitute parties, doing so does not enable it avoid the application of *Ensign-Bickford*'s holding that the Board's procedural rules "do not provide for a third party to seek a variance or have a variance transferred on" a buyer's behalf. *Ensign-Bickford*, PCB 02-159 (Apr. 3, 2003), slip op. at 2. Ameren is barred from seeking a variance on Dynegy's behalf and from asking for its variance to be transferred to Dynegy. Dynegy/Ameren is making a premature, pre-closing request for Ameren's variance to transfer to Dynegy. Dynegy cannot be granted a variance prior to its ownership of the facilities, and Dynegy must come back post-closing with its own petition.[1]

III. Dynegy Cannot Demonstrate the Same Relevant Factors That Ameren Did.

Citing to several Board decisions involving adjusted standards, Dynegy/Ameren contend in their motion that the Board should transfer Ameren's variance to Dynegy because the relevant factors supporting Ameren's variance have remained the same. As discussed above, these decisions are of limited relevance because they all involved a post-purchase substitution of parties and because the showing required to receive an adjusted standard is different from that required to receive a variance. In any case, Dynegy/Ameren have failed to make the showing required by those decisions for the transfer of regulatory relief. The underlying factors of hardship and environmental impact the Board found supported Ameren's variance would be different for a Dynegy variance. Dynegy/Ameren's motion should be denied.

A. Dynegy/Ameren Have Made an Insufficient Showing Regarding the Financial Hardship Factor.

Dynegy/Ameren gloss over how the grant of Ameren's variance was dependent upon factors that were specific to Ameren, and therefore also could not be specific to Dynegy. One of the relevant factors is hardship. Section 35(a) of the Illinois Environmental Protection Act ("Act"), 415 ILCS 5/35(a), provides that the Board may grant a variance when it finds "that compliance with any rule or regulation, requirement or order of the Board would impose an arbitrary or unreasonable hardship." Ameren's 2012 case for a variance focused on financial

[1] Another option, of course, would be for Dynegy/Ameren to seek an amendment to the MPS. Ameren could have attempted to seek such permanent relief last year. Dynegy/Ameren now try to use Ameren's failure to seek that relief as necessitating the Board's bending of its procedural rules for Dynegy. The Board should not allow this attempt.

hardship as the hardship that qualified Ameren for a variance. *See Ameren Energy Resources v. IEPA*, PCB 12-126 (Sept. 20, 2012), slip op. at 13 ("AER claims that it can no longer fund the Newton FGD project in time to comply with the 2015 and 2017 SO_2 emission rates."). The Board has held that "the law is well settled that the financial resources of a petitioner are relevant to a determination of arbitrary or unreasonable hardship." *The Robertson-Ceco Corp.v. IEPA*, PCB 92-90 (Oct. 21, 1993), slip op. at 10.

Financial hardship therefore is an individual determination. Such an individualized determination raises the bar much higher for Dynegy/Ameren's showing that the relevant factors have remained the same. Because a petitioner's financial hardship is an individual determination, the Board must take a hard look at the proposed variance recipient to determine if the financial hardship is comparable. Section 37(a) of the Act, 415 ILCS 5/37(a), places the burden of proof on the person seeking a variance. The burden is on the petitioner to produce information regarding its finances. *Allaert Rendering, Inc. v. IPCB*, 91 Ill. App. 3d 160, 162 (3d Dist. 1980) (upholding Board's rejection of petition when petitioner produced no evidence on its financial condition).

Here, Dynegy/Ameren assert that the hardship facing Ameren last year would remain "unchanged" if Dynegy takes over the plants in 2014. Mot. at 12. This contention is both conclusory and unpersuasive. In granting Ameren's variance, the Board relied on very specific impacts to Ameren's financial condition from declining power prices and regulatory requirements.

Dynegy would not face those same conditions. Rather, Dynegy has engineered a deal that would allow it take over that now-partially controlled fleet and benefit from an expected recovery in energy prices. As discussed below, the economic conditions that would affect

Dynegy beginning in 2014 therefore are quite different from those that Ameren faced in 2012. First, Dynegy's optimistic public account of the deal's "upside" is irreconcilable with Dynegy/Ameren's representations in the motion of declining power prices without a foreseeable end. Second, any hardship faced by Dynegy in complying with the MPS would be entirely self-imposed. Because the factor of hardship would be different for Dynegy in 2014 than it was for Ameren in 2012, the motion must be denied.

1. Dynegy Has Stated Publicly That It Expects Power Prices to Improve and the Ameren Plants to Be Profitable in the Near-Term.

In their motion, Ameren/Dynegy argue that there is no "end in sight" to the depressed power prices that brought Ameren before the Board last year to seek its variance. Mot. at 13. By contrast, Dynegy has stated publicly on multiple occasions that it expects higher power prices, resulting in profitability for the Ameren fleet by 2015. These inconsistent statements demonstrate that the hardship factor underlying Ameren's variance already has changed radically.

According to Ameren/Dynegy's motion, there is "no question that declining power prices continue to erode available operating proceeds generated by the operating energy centers with no certain end in sight." Mot. at 13. In support of this contention, Ameren/Dynegy cite to the affidavit of George W. Bilicic, a third-party consultant at Lazard Frères & Co. LLC who avers that:

> The ongoing decline in power prices has pressured the earnings of AER's primarily coal-fired generation fleet, impairing AER's financial health and access to third-party capital on economic terms supportable by AER's financial condition. *Forecasts of future market conditions suggest that earnings pressure at New AER may continue for the foreseeable future.*

Mot., Bilicic Aff. at 3 (emphasis added). Ameren/Dynegy also attach the affidavit of Mario E. Alonso, a Dynegy Vice President, who states that: "power prices remain depressed and are not expected to improve over the next several years." Mot., Alonso Aff. at 7. Mr. Alonso's affidavit includes a chart of "market expectations" for power prices through 2017 that shows power prices as relative flat for that period (beginning with a price of $34.66 per megawatt hour for 2013, and ending with $35.18 per megawatt hour in 2017). *Id*. at 8.

The motion and affidavits therefore present a dire picture of the Ameren plants' future that Dynegy/Ameren seek to use to justify their contention that Dynegy would need the entire term of Ameren's variance (i.e., though 2019) to comply with the MPS. Yet Dynegy's statements about this transaction outside of this proceeding have been much more optimistic. Indeed, in its March 14, 2013 press release announcing the transaction, Dynegy stated that one of the deal's benefits was to *increase* "Dynegy's exposure to market recovery and Midwest coal plant retirements." See Ex. A, Dynegy, Inc. Form 8-K (March 14, 2013), at Exhibit 99.2 (PDF page 18.[2] Dynegy's President and Chief Executive Officer, Robert C. Flexon, further stated that the transaction was "expected to create significant value for Dynegy shareholders." *Id*. at PDF page 17. Among many other benefits, Dynegy stated that both its existing fleet and Ameren's fleet are compliant with the MATS, going into effect during 2015, and that: "[a]s other noncompliant or uneconomic generation continues to retire, the combined portfolio will be well-positioned to benefit from tightening supply dynamics." *Id*. at PDF page 18. Dynegy concluded:

> The targeted synergies, *along with the current forward market for natural gas prices and Dynegy's associated view on forward power and capacity prices*, are expected to result in AER being accretive to Dynegy's Adjusted EBITDA [Earnings Before Interest, Taxes, Depreciation and Amortization] in 2014 *and to Free Cash Flow by 2015*. In addition, these same forward curves indicate that all three of AER's subsidiaries offer substantial equity value creation for the benefit of Dynegy's shareholders.

Id. (emphasis added). Dynegy defines "Free Cash Flow" as:

[2] This document is available at: http://phx.corporate-ir.net/phoenix.zhtml?c=147906&p=irol-SECText&TEXT=aHR0cDovL2FwaS50ZW5rd2l6YXJkLmNvbS9maWxpbmcueG1sP2lwYWdlPTg3OTY2NzQmRFNFUT0wJlNFUT0wJlNRREVTQz1TRUNUSU9OX0VOVElSRSZzdWJzaWQ9NTc%3d.

> cash flow from operations less maintenance and environmental capital expenditures and debt refinance costs plus restricted cash posted as collateral. The most directly comparable GAAP financial measure to such measure is cash flow from operations.

Id. at PDF page 2. In short, Dynegy expects the Ameren plants to be generating cash by 2015.

Dynegy expanded upon the transaction's benefits during its March 14, 2013 earnings call. (A transcript of the earnings call and the associated slides are attached as Exhibits B and C.)[3] Clint Freeland, Dynegy's Chief Financial Officer and Executive Vice President stated:

> One of the central themes to Dynegy's value proposition is the company's upside exposure to *market recovery* and pool retirements in the Midwest.
>
> Earlier in the presentation, [Dynegy's CEO] walked through the asymmetric risk-return profile of the AER acquisition as it relates to *improvements in natural gas prices*. But as Slide 29 reflects, this is not just a natural gas dynamic. The same asymmetric relationship exists for other market factors as well, *including power prices and capacity prices as coal plant retirements occur over the next several years*. With little to no capital allocated to this transaction upfront and no new shares of common stock issued, the acquisition of AER provides current Dynegy shareholders with substantial additional upside potential and, with the transaction structure as described earlier, significant downside protection.

See Ex. B, Dynegy Earnings Call Transcript, at PDF pages 8-9 (emphasis added). Dynegy's CEO summed up the case that Ameren's fleet would be "economical" for Dynegy to own and operate:

> [C]ertainly, in a post-MATS compliance world, *we certainly expect stronger capacity payments, higher power prices,* so furthering the economic viability of these plants from even what we've built into our base level assumptions.

Id. at PDF page 13 (emphasis added).

Dynegy's public statements that it "certainly", *id*., expects higher power prices cannot be reconciled with the much more negative picture painted in Dynegy/Ameren's motion. Dynegy's

[3] The transcript is available at http://seekingalpha.com/article/1274231-dynegy-management-discusses-q4-2012-results-earnings-call-transcript, and the slides are available at http://www.dynegy.com/investor-relations/presentations-and-webcasts.

inconsistent statements demonstrate Dynegy in 2014 would not face the same sort of economic duress that Ameren faced in 2012. Ameren had been affected by years of declining power prices; by contrast, Dynegy would be taking control of the plants in what is, according to Dynegy's own statements, an upward-trending power market that will result in profitability for the plants. The two companies' situations are not comparable. Dynegy/Ameren's motion should be denied.

2. Dynegy/Ameren Have Failed to Show That Any Hardship is Not Self-Imposed.

Dynegy also is not entitled to a variance because any hardship would be self-imposed. The hardship would be self-imposed because Dynegy is voluntarily entering into an agreement to purchase Ameren's plants knowing of the requirements of the MPS and of the financial hardship that would result from this business decision. *See, e.g.*, *Bravo-Ernst v. IEPA*, PCB 81-62 (Dec. 3, 1981); *Skyway Realty v. IEPA*, PCB 75-249 (Sept. 18, 1975), slip op. at 2. First, Dynegy has knowledge of the MPS and describes itself as "very familiar and experienced with the Illinois MPS requirements." Mot., Thompson Aff. at 3. In fact, Dynegy already owns and operates 4 plants in the State, previously operated 5, and opted its fleet into the MPS. Mot. at 7; Thompson Aff. at 2-3. Dynegy has already invested $1 billion in air pollution controls, including flue gas desulfurization, activated carbon injection systems, and baghouses, at its Illinois facilities to comply with Illinois rules, including the MPS. Mot., Thompson Aff. at 3. Consequently, Dynegy is very much aware of the costs associated with the pollution controls necessary for compliance with the MPS.

Second, because Dynegy is voluntarily entering this transaction and purchasing Ameren's coal-fired power plants, any hardship would be self-imposed. *Cf. Copley Memorial Hospital, Inc. v. City of Aurora*, 99 Ill. App. 3d 217, 222 (2d Dist. 1981) (holding that a hardship was self-imposed when the petitioner "bought the property knowing the restrictions"). Under the proposed transaction, Dynegy would voluntarily take on a staggering amount of Ameren debt, the obligation consisting of approximately $825 million in notes. *See* Ex. 1, Dynegy 8-K, at PDF page 17. This amount of debt would be enough to complete construction of the Newton scrubber project several times over. The annual cost of servicing this debt is almost $60 million, *see* Ex. 3, Dynegy Investor Call Slides, at PDF page 27, and the debt is one of the factors preventing the Dynegy entity that would hold the plants from seeking credit of its own. Mot., Alonso Aff. at 4.

Dynegy's justification for the variance that it will be unable to comply with the MPS because of the terms of the deal that it negotiated ignores the case law that holds that outcomes from business decisions are self-imposed hardships that do not qualify for a variance. *Ekco Glaco v. IEPA*, PCB 87-41 (Dec. 17, 1987), slip op. at 6 (concluding that "any hardship in complying with the . . . regulations is largely self-imposed, in that it results from prior business decisions."). Dynegy claims that, "without the Variance, both near and mid-term capital requirements of the Acquired Merchant Utilities, including the Acquired Plants, would significantly increase, which would make the transaction as negotiated prohibitively uneconomical." Mot., Thompson Aff. at 5. All of the above terms of the deal are "negotiated," though. Once again, this is voluntary and Dynegy was not compelled to purchase the plants for any specific negotiated terms. Dynegy was free to have negotiated different terms for the deal. Since this is a business decision and a voluntary acquisition of the plants, any hardship from complying with the MPS is self-imposed.

Finally, if the variance is not transferred or guaranteed available to Dynegy, it does not have to go through with the deal. Mot., Thompson Aff. at 4. There will be no hardship if the variance is not available because, according to Dynegy, then the deal will not happen. This is the definition of a self-imposed hardship, as Dynegy has options to avoid it.

B. Dynegy/Ameren Have Made an Insufficient Showing on a Dynegy Variance's Environmental Impact.

The variance cannot be transferred to Dynegy because another relevant factor, the variance's environmental impact, is also different. Under a variance transferred to Dynegy, the environmental impact would be worse, and there would not be the same net environmental benefit that the Board found with the Ameren variance. In considering whether to allow a variance, the Board's duty is to consider the "injury to the public or the environment *from a grant of the variance*." *Marathon Oil Co. v. IEPA*, 242 Ill. App. 3d 200, 206 (5th Dist. 1993) (emphasis added). *See also* 35 Ill. Adm. Code 104.204(g)(1) (requiring the comparison of emissions "if the variance is granted . . . to that which would result if immediate compliance is required"). Therefore, determining the environmental impact of the variance under Dynegy requires considering the distinct time period that Dynegy will hold the variance and own the plants. In transferring the variance, the Board should look only at environmental impact of emissions increases and reductions starting in 2014, when the plants are transferred to Dynegy ownership and Dynegy would hold a transferred variance.

The Board should not consider pre-Dynegy emissions reductions because of its previous holding in the Ameren variance decision in 2012. The Board held in that decision that pre-variance emissions are not relevant when assessing a proposed variance's environmental impact. *Ameren Energy Resources v. IEPA*, PCB 12-126 (Sept. 20, 2012), slip op. at 57. Ameren contended that pre-variance emission reductions should be taken into account, but the Board rejected Ameren's perspective. *Id.* Instead, the Board looked at emissions beginning in 2012, because that was when the variance would be granted, and would be the starting point for the variance requirements imposed on Ameren. *Id*. Similarly, Dynegy cannot rely on emissions reductions prior to its ownership of the plants and the transfer of the variance.

In this case, Dynegy and Ameren do not expect to complete the proposed transaction until the end of 2013. *See* Mot. at 17 ("[C]losing on the transaction will occur during the fourth quarter of 2013."). The starting point for addressing the environmental impacts of transferring the variance to Dynegy, therefore, should be calendar year 2014. The 2012 and 2013 emissions that Ameren relied upon to show an environmental benefit from *its* possession of the variance will already be final and on the books by the time that Dynegy would own the plants starting in 2014. Just like Ameren was not given "credit" for its pre-variance reductions of SO_2 emissions, there is no reason that Dynegy should be given "credit" for reductions in emissions that occurred before the beginning of Dynegy's holding the variance and owning the plants.

The chart below compares emissions under the MPS and with emissions under a variance transferred to Dynegy.[4] This chart covers the years 2014 through 2020 when Dynegy will own the plants and would hold the variance:

[4] This is a modified version of the chart that Ameren attached to its August 15, 2012 Post-Hearing Brief as Exhibit 4. The chart in Ameren's Exhibit 4 showed the difference between emissions expected under the MPS to emissions under the Ameren variance—including reductions associated with the retirement of the Meredosia and Hutsonville plants.

Year	Baseline Heat Input MMBtu	MPS SO_2 Rate lb/MMBtu	MPS Baseline SO_2 Tons	Variance SO_2 Rate lb/MMBtu	Variance SO_2 Tons	SO_2 Reduced Tons*	Net Variance SO_2 Tons	Cumulative Reductions in SO_2 Variance Tons
2014	340,446,252	0.43	73,196	0.35	59,578	7,699	51,879	21,317
2015	340,446,252	0.25	42,556	0.35	59,578	7,699	51,879	11,994
2016	340,446,252	0.25	42,556	0.35	59,578	7,699	51,879	2,671
2017	340,446,252	0.23	39,151	0.35	59,578	7,699	51,879	-10,057
2018	340,446,252	0.23	39,151	0.35	59,578	7,699	51,879	-22,785
2019	340,446,252	0.23	39,151	0.35	59,578	7,699	51,879	-35,513
2020	340,446,252	0.23	39,151	0.23	39,151	7,699	31,452	-27,814
Total:			314,912		396,619	53,893	342,726	-27,814
Note for the "Cumulative SO2 Variance Reduced Tons" column, a positive number indicates an emission decrease (benefit).								

The chart shows that fleetwide SO_2 emissions would be at least 27,814 tons higher over the course of the variance under Dynegy's ownership than if Dynegy did not receive a variance and was required to comply with the MPS.[5] In order to determine whether the relevant factor of

[5] The difference in fleet-wide SO_2 emissions would be even higher if Dynegy were not credited with emissions purportedly avoided because of Ameren's 2011 shutdown of its Meredosia and Hutsonville plants. Notably, Dynegy itself previously criticized the use of a shutdown plant to demonstrate an environmental benefit from Midwest Generation's recently granted variance from the Combined Pollutant Standard's fleet-wide SO_2 emissions limits:

> Midwest Gen's proposal not to operate Crawford Station in 2013 and 2014 offers little, if any, benefit to the State. Midwest Gen already ceased operation of Crawford Station on August 28, 2012. While Midwest Gen could legally operate the Crawford units through the end of 2014, those units are not operating due to the poor market conditions that Midwest Gen cites repeatedly in the Petition. To the extent, if any, the Board credits Midwest Gen for purposes of its Petition with reducing emissions from Crawford Station in 2013 and 2014, those reductions should be tied to the plant's anticipated operating levels and not its permitted emission levels or its historic average heat input.

environmental impact is different, these fleetwide SO_2 emissions must be compared to that which the Board found under the Ameren variance. In that variance decision, the Board found that the variance would create "a net benefit to air quality of reducing SO_2 emissions by 33,545 tons from 2012 through 2020." *Ameren Energy Resources v. IEPA*, PCB 12-126 (Sept. 20, 2012), slip op. at 54. In short, a net benefit of 33,545 tons of SO_2 reduced is a different environmental impact that 27,814 additional tons of SO_2. As a result, the environmental impact is different.

In sum, in comparing the environmental impact of emissions increases and reductions starting in 2014, when the plants are transferred to Dynegy ownership and Dynegy would hold a transferred variance, leads to a different and worse environmental impact than under the Ameren variance. The net environmental benefit that the Board found under the Ameren variance would not exist under a Dynegy variance. As a result, the motion should be denied because the relevant factor of environmental impact is different.

IV. CONCLUSION

Dynegy/Ameren have failed to justify the transfer of Ameren's variance to Dynegy. Their motion is procedurally improper, as Dynegy should not be granted any variance related to the Ameren fleet until Dynegy actually owns the plants. The motion also fails on its own terms, because the conditions that supported the Board's decision on Ameren's variance last year are different from the conditions that would confront Dynegy if it took ownership of the Ameren fleet in 2014.

Because this motion is improper, the Board should deny it and keep this docket closed. If Dynegy/Ameren determine to proceed with their transaction, then Dynegy should come back

Midwest Generation v. IEPA, PCB 13-024 (Dec. 31, 2012) (Objection of of Dynegy Midwest Generation, LLC and Dynegy Kendall Energy, LLC) (footnote omitted), at 6. By contrast, Dynegy apparently sees no issue with advocating in this case for an environmental benefit from Ameren's shutdown of the uneconomical Meredosia and Hutsonville plants.

with its own variance request as the plants' owner. Alternatively, if the Board decides not to deny this motion outright, then it should hold Dynegy to provide a fuller account of the alleged hardship it would face as the owner of the Ameren fleet, as well as of a Dynegy variance's environmental impact. To that end, the Board should allow additional time to respond to the motion, schedule a hearing, and allow a public comment period of at least forty-five days.

Respectfully submitted,

Faith E. Bugel

Faith Bugel
Senior Attorney
Environmental Law and Policy Center
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CERTIFICATE OF SERVICE

I, Faith Bugel, hereby certify that I have filed the attached **Comments of the Environmental Law & Policy Center, Natural Resources Defense Council, Respiratory Health Association, and Sierra Club** in PCB 12-126 upon the attached service list by depositing said documents in the United States Mail, postage prepaid, in Chicago, Illinois on May 16, 2013.

Respectfully submitted,

Faith E. Bugel

____

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May 16, 2013

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Exhibit A

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 8-K

CURRENT REPORT
PURSUANT TO SECTION 13 OR 15(d) OF THE
SECURITIES EXCHANGE ACT OF 1934

Date of Report (Date of earliest event reported)
March 14, 2013

DYNEGY INC.

(Exact name of registrant as specified in its charter)

Delaware	**001-33443**	**20-5653152**
(State or Other Jurisdiction of Incorporation)	(Commission File Number)	(I.R.S. Employer Identification No.)

601 Travis, Suite 1400, Houston, Texas	**77002**
(Address of principal executive offices)	(Zip Code)

(713) 507-6400
(Registrant's telephone number, including area code)

N.A.
(Former name or former address, if changed since last report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 2.02 Results of Operations and Financial Condition.

On March 14, 2013, Dynegy Inc. ("Dynegy") issued a press release announcing its fourth quarter and year-end 2012 financial results. A copy of Dynegy's March 14, 2013 press release is furnished herewith as Exhibit 99.1 and is incorporated herein by this reference. Dynegy management will hold an investor call at 9 a.m. ET on Thursday March 14, 2013 to review its fourth quarter and 2012 annual financial results and related information. A live simulcast of the conference call, together with the related presentation materials, will be available as soon as practicable in the Investor Relations section of Dynegy's website (www.dynegy.com) and will remain accessible until the date Dynegy's first quarter 2013 financial results are available.

Pursuant to General Instruction B.2 of Form 8-K and Securities and Exchange Commission (the "SEC") Release No. 33-8176, the information contained in the press release furnished as an exhibit hereto shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, is not subject to the liabilities of that section and is not deemed incorporated by reference in any filing under the Securities Act of 1933, as amended, except as shall be expressly set forth by specific reference in such a filing. In addition, the press release contains statements intended as "forward-looking statements" which are subject to the cautionary statements about forward-looking statements set forth in such press release.

Non-GAAP Financial Information

In analyzing and planning for Dynegy's business, we supplement Dynegy's use of GAAP financial measures with non-GAAP financial measures, including EBITDA, Adjusted EBITDA and Free Cash Flow. These non-GAAP financial measures reflect an additional way of viewing aspects of our business that, when viewed with our GAAP results and the accompanying reconciliations to corresponding GAAP financial measures, may provide a more complete understanding of factors and trends affecting our business. In this Form 8-K, we discuss such non-GAAP financial measures included in the press release, including definitions of such non-GAAP financial information, identification of the most directly comparable GAAP financial measures and the reasons why we believe these measures provide useful information regarding our financial condition, results of operations and cash flows, as applicable, and, to the extent material, the additional purposes, if any, for which these measures are used. Reconciliations of non-GAAP financial measures to the most directly comparable GAAP financial measures, to the extent available without unreasonable effort, are contained in the schedules attached to the press release. These non-GAAP financial measures should not be relied upon to the exclusion of GAAP financial measures and are by definition an incomplete understanding of Dynegy, and must be considered in conjunction with GAAP measures.

EBITDA Measures. We believe EBITDA and Adjusted EBITDA provide meaningful representations of our operating performance. We consider EBITDA as another way to measure financial performance on an ongoing basis. Enterprise-wide Adjusted EBITDA is meant to reflect the operating performance of our entire power generation fleet for the period presented; consequently, it excludes the impact of mark-to-market accounting, impairment charges and gains and losses on sales of assets, and other items that could be considered "non-operating" or "non-core" in nature. Because EBITDA and Adjusted EBITDA are financial measures that management uses to allocate resources, determine our ability to fund capital expenditures, assess performance against our peers and evaluate overall financial performance, we believe they provide useful information for our investors. In addition, many analysts, fund managers and other stakeholders that communicate with us typically request our financial results in an EBITDA and Adjusted EBITDA format presented on an enterprise-wide basis.

"EBITDA" — We define "EBITDA" as earnings (loss) before interest expense, income tax expense (benefit), and depreciation and amortization expense.

"Adjusted EBITDA" —We define "Adjusted EBITDA" as EBITDA adjusted to exclude (i) gains or losses on the sale of assets, (ii) the impacts of mark-to-market changes on economic hedges related to our generation portfolio, (iii) the impact of impairment charges and certain other costs such as those associated with the internal reorganization and bankruptcy proceedings, (iv) amortization of intangible assets and liabilities, (v) income or loss associated with discontinued operations, and (vi) income or expense on up-front premiums received or paid for financial options in periods other than the strike periods.

- As prescribed by the SEC, when Adjusted EBITDA is discussed in reference to performance on a consolidated (or enterprise-wide) basis, the most directly comparable GAAP financial measure to EBITDA and Adjusted EBITDA is Net income (loss).

- Management does not analyze interest expense and income taxes on a segment level; therefore, the most directly comparable GAAP financial measure to Adjusted EBITDA when performance is discussed on a segment level is Operating income (loss).

Cash Flow Measure. Our non-GAAP Cash Flow measure may not be representative of the amount of residual cash flow that is available to us for discretionary expenditures, since it may not include deductions for mandatory debt service requirements and other non-discretionary expenditures. We believe, however, that our non-GAAP Cash Flow measure is useful because it measures the cash generating

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ability of our operating asset-based energy business relative to our capital expenditure obligations and financial performance. However, this non-GAAP Cash Flow measure does not have a standardized definition; therefore, it may not be possible to compare this financial measure with other companies' cash flow measures having the same or similar names.

"Free Cash Flow" — We define "Free Cash Flow" as cash flow from operations less maintenance and environmental capital expenditures and debt refinance costs plus restricted cash posted as collateral. The most directly comparable GAAP financial measure to such measure is cash flow from operations.

We believe that the historical non-GAAP measures and forward-looking non-GAAP measures disclosed in our filings are only useful as an additional tool to help management and investors make informed decisions about Dynegy's financial and operating performance. Further there can be no assurance that the assumptions made in preparing forward-looking non-GAAP numbers will prove accurate, and actual results may be materially less or greater than those contained in the forward-looking non-GAAP numbers. By definition, non-GAAP measures do not give a full understanding of Dynegy; therefore, to be truly valuable, they must be used in conjunction with the comparable GAAP measures. In addition, non-GAAP financial measures are not standardized; therefore, it may not be possible to compare these financial measures with other companies' non-GAAP financial measures having the same or similar names. We strongly encourage investors to review our consolidated financial statements and publicly filed reports in their entirety and not rely on any single financial measure.

Item 7.01 Regulation FD Disclosure.

Also on March 14, 2013, Dynegy issued a press release announcing the signing of a definitive agreement with Ameren Corporation "Ameren"), pursuant to which Dynegy's subsidiary, Illinois Power Holdings, LLC, will acquire Ameren's subsidiary, Ameren Energy Resources, and its subsidiaries Ameren Energy Generating Company, AmerenEnergy Resources Generating Company, and Ameren Energy Marketing Company, as a result of which Dynegy will own more than 8,000 megawatts of generating capacity in Illinois, and nearly 14,000 megawatts nationally. The transaction is expected to close during the fourth quarter of 2013 and is subject to customary closing conditions, including approval from the Federal Energy Regulatory Commission. A copy of Dynegy's March 14, 2013 press release is furnished herewith as Exhibit 99.2 and is incorporated herein by this reference.

Pursuant to General Instruction B.2 of Form 8-K and Securities and Exchange Commission (the "SEC") Release No. 33-8176, the information contained in the press release furnished as an exhibit hereto shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, is not subject to the liabilities of that section and is not deemed incorporated by reference in any filing under the Securities Act of 1933, as amended, except as shall be expressly set forth by specific reference in such a filing. In addition, the press release contains statements intended as "forward-looking statements" which are subject to the cautionary statements about forward-looking statements set forth in such press release.

The information set forth in Item 2.02 above is incorporated herein by reference.

This Current Report on Form 8-K and the press releases contain statements intended as "forward-looking statements" which are subject to the cautionary statements about forward-looking statements set forth therein.

Item 9.01 Financial Statements and Exhibits.

(d) Exhibits:

Exhibit No.	Document
99.1	Press release dated March 14, 2013, announcing results of operations
99.2	Press release dated March 14, 2013, announcing definitive agreement with Ameren

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

DYNEGY INC.
(Registrant)

Dated: March 14, 2013

By: /s/ Catherine B. Callaway
Name: Catherine B. Callaway
Title: Executive Vice President, Chief Compliance Officer and General Counsel

EXHIBIT INDEX

Exhibit No.	Document
99.1	Press release dated March 14, 2013, announcing results of operations
99.2	Press release dated March 14, 2013, announcing definitive agreement with Ameren

Exhibit 99.1

NEWS RELEASE

Dynegy Inc. • 601 Travis Street • Suite 1400 • Houston, Texas • 77002 • www.dynegy.com

FOR IMMEDIATE RELEASE **NR13-05**

Dynegy Announces Full-Year 2012 Results

Full-year 2012 summary:

- $57 million in Enterprise-wide Adjusted EBITDA, a decrease of $224 million compared to 2011
- $(81) million in combined Cash Flow from Operations, $215 million in Free Cash Flow
- $592 million in liquidity at March 8, 2013, including $370 million in cash on hand and $153 million in revolver and letter of credit availability
- PRIDE results exceeded targets with $44 million in operating margin and cost improvements and $148 million in incremental liquidity from balance sheet improvements

Fourth quarter 2012 summary:

- $(42) million in Enterprise-wide Adjusted EBITDA, a decrease of $28 million compared to the fourth quarter 2011
- Repaid $325 million of the Dynegy Power, LLC (GasCo) and Dynegy Midwest Generation, LLC (CoalCo) term loans
- Completed the Baldwin Unit 2 planned outage marking the Company's completion of the environmental compliance capital obligations under our Consent Decree
- Completed the Chapter 11 process and emerged from bankruptcy on October 1, 2012

Recent Developments and Capital Allocation:

- Today, Dynegy announced, in a separate news release, that it has entered into a definitive agreement to acquire Ameren Energy Resources (AER), comprised of 4,119 MW of generating capacity and the associated retail and marketing businesses
- On January 16, 2013, GasCo entered into a new $150 million revolving credit agreement, improving our corporate liquidity profile. The revolver is available for working capital requirements and general corporate purposes within GasCo.

HOUSTON (March 14, 2013) — Dynegy Inc. (NYSE:DYN) reported full-year 2012 Enterprise-wide Adjusted EBITDA of $57 million compared to $281 million for the same period in 2011. Lower realized prices for the Coal segment, lower revenues from the termination of certain California contracts, and the settlement of legacy financial positions reduced Adjusted EBITDA for the Coal and Gas segments by $305 million. Partially offsetting these items were an $18 million improvement in Coal and Gas segments operating and maintenance expenses, a $27 million improvement in spark spreads, net of hedges and basis, in the Gas segment, and a $38 million positive adjustment for non-cash amortization related to the Gas segment's Independence contract. The Company's operating loss was $99 million for the full-year 2012 compared to an operating loss of $189 million for the same period in 2011.

"2012 was a transformative year for Dynegy. We completed the majority of our financial and organizational restructuring during the year and now have one of the strongest balance sheets in the merchant generation sector. Both our coal and gas fleets had strong operational performance in 2012 despite pressure on power prices from low natural gas prices," said Robert C. Flexon, Dynegy President and Chief Executive Officer. "Our work in 2012 allows us to further focus on executing daily operations, strategic priorities including capital allocation, successfully closing the AER acquisition and completing a corporate-level refinancing. We are committed to maintaining and building upon our financial strength and affirm the 2013 Adjusted EBITDA and cash flow guidance that we provided during our January 2013 investor meeting."

Fourth quarter 2012 Enterprise-wide Adjusted EBITDA was $(42) million compared to $(14) million for the same period in 2011. The weaker financial results were primarily driven by lower realized power prices for the Coal segment, due to lower hedge prices and increased basis differentials, which decreased energy margins by $62 million. Unfavorable financial settlements of $29 million related to legacy financial positions for the Gas segment were more than offset by a $34 million increase in operating margin due to improved spark spreads, net of hedges and basis, and the absence of a $34 million loss on commercial activities which occurred in 2011. The 2012 fourth quarter operating loss was $104 million compared to an operating loss of $105 million for the same period in 2011.

Full-Year Comparative Results

The non-GAAP financial measures of EBITDA and Adjusted EBITDA are used by management to evaluate Dynegy's business on an ongoing basis. For comparative purposes, the Adjusted EBITDA results below include the results of Dynegy Inc. for the full-years 2012 and 2011 and the three months ending December 31, 2012 and 2011. As a result of the application of fresh-start accounting as of the Plan Effective Date, the financial statements on or prior to October 1, 2012 are not comparable with the financial statements after October 1, 2012. Please refer to our 2012 Form 10-K (when filed) for greater discussion of the accounting impacts of the Dynegy Inc. and DH merger, our emergence from Chapter 11 and fresh-start accounting on our GAAP financial statements. The following table presents a reconciliation of operating income (loss) to Adjusted EBITDA and combines the results of the period from January 1, 2012 through October 1, 2012 (the 2012 Predecessor Period) and the period from October 2, 2012 through December 31, 2012 (the Successor Period). We believe a combined presentation provides a more meaningful comparison to 2011 results. For convenience purposes, the Successor Period is referred to as the three months ended December 31, 2012 throughout. General and administrative expenses are not allocated to each segment. Management does not analyze interest expense and income taxes on a segment level and therefore uses operating income (loss) as the most directly comparable GAAP measure to Adjusted EBITDA when performance is evaluated on a segment level.

	Combined			
	Twelve Months Ended December 31, 2012 (in millions)			
	Coal	Gas	Other	Total
Operating Income / (Loss)	$ (112)	$ 97	$ (84)	$ (99)
Plus / (Less):				
Impairment of Undertaking receivable, affiliate	—	—	(832)	(832)
Bankruptcy reorganization items, net	—	—	1,034	1,034
Depreciation and amortization expense	21	127	7	155
Earnings from unconsolidated investment	—	2	—	2
Other items, net	5	2	32	39
EBITDA from continuing operations	(86)	228	157	299
Plus / (Less):				
Impairment of Undertaking receivable, affiliate	—	—	832	832
Bankruptcy reorganization items, net	—	—	(1,034)	(1,034)
Interest income on Undertaking receivable	—	—	(24)	(24)
Restructuring costs and other expense	—	—	3	3
Mark-to-market (income) losses, net	7	(166)	—	(159)
Amortization of intangible assets and liabilities (1)	78	61	—	139
Premium adjustment	1	(1)	—	—
Changes in fair value of warrants	—	—	(8)	(8)
Adjusted EBITDA	$ —	$ 122	$ (74)	$ 48
Adjusted EBITDA from Legacy Dynegy (2)	20	—	(11)	9
Enterprise-wide Adjusted EBITDA	$ 20	$ 122	$ (85)	$ 57

(1) The amount in the Coal segment in the 2012 Predecessor Period relates to intangible assets and liabilities related to rail transportation and coal contracts, respectively, recorded in connection with the DMG Acquisition. The amount in the Gas segment in the 2012 Predecessor Period is related to the intangible assets related to the 2005 Sithe acquisition. The amounts in the Successor Period relate to intangible assets and liabilities related to rail transportation, coal contracts, gas revenue contracts and gas transportation contracts recorded in connection with the application of fresh-start accounting.

(2) Our 2012 consolidated results reflect the results of our accounting predecessor, DH, which was our wholly-owned subsidiary until the Merger on September 30, 2012. Therefore, certain results related to Legacy Dynegy are not included in our consolidated results for the 2012 Predecessor Period. Additionally, effective June 5, 2012, we completed the DMG Acquisition. As a result, the results of our Coal segment, as well as certain items in the Other segment, are not included in our consolidated results for the period from January 1, 2012 through June 5, 2012. However, we have included the Adjusted EBITDA related to Legacy Dynegy for the 2012 Predecessor Period and the Coal segment for the period from January 1, 2012 through June 5, 2012 in this adjustment because management uses enterprise-wide Adjusted EBITDA to evaluate the operating performance of our entire power generation fleet.

	Predecessor			
	Twelve Months Ended December 31, 2011 (in millions)			
	Coal	Gas	Other	Total
Operating Loss	$ (38)	$ (37)	$ (114)	$ (189)
Plus / (Less):				
Bankruptcy reorganization items, net	—	—	(52)	(52)
Depreciation and amortization expense	156	132	7	295
Other items, net	2	2	31	35
EBITDA from continuing operations	120	97	(128)	89
Plus / (Less):				
Merger termination fee, restructuring costs and other expenses	(1)	7	25	31
Bankruptcy reorganization items, net	—	—	52	52
Mark-to-market loss, net	76	51	4	131
Adjusted EBITDA from continuing operations	$ 195	$ 155	$ (47)	$ 303
Adjusted EBITDA from Legacy Dynegy (1)	48	—	(51)	(3)
Adjusted EBITDA	$ 243	$ 155	$ (98)	$ 300
Adjusted EBITDA from discontinued operations				(19)
Enterprise-wide Adjusted EBITDA				$ 281

(1) Our 2011 consolidated results reflect the results of our accounting predecessor, DH, which was our wholly-owned subsidiary until the Merger on September 30, 2012. Therefore, certain results related to Legacy Dynegy are not included in our consolidated results for the twelve months ended December 31, 2011. Additionally, effective September 1, 2011, we completed the DMG Transfer. As a result, the results of our Coal segment, as well as certain items in the Other segment, are not included in our consolidated results for the period from September 1, 2011 through December 31, 2011. However, we have included the Adjusted EBITDA related to Legacy Dynegy for the twelve months ended December 31, 2011 and the Coal segment for the period from September 1, 2011 through December 31, 2011 in this adjustment because management uses enterprise-wide Adjusted EBITDA to evaluate the operating performance of our entire power generation fleet.

Segment Review of Results Year-Over-Year

Coal — The full-year 2012 operating loss was $112 million, compared to a full-year 2011 operating loss of $38 million. Adjusted EBITDA, before the allocation of corporate general and administrative expense, totaled $20 million during 2012 compared to $243 million in 2011. Lower energy margins due to lower realized power prices partially from higher basis differentials were responsible for $191 million of the negative variance. An increase in year-over-year outages and lower off-peak generation volumes in response to market pricing resulted in an additional $29 million decrease in Coal segment results.

Gas — Full-year 2012 operating income was $97 million, compared to a full-year 2011 operating loss of $37 million. Adjusted EBITDA, before the allocation of corporate general and administrative expense, totaled $122 million during 2012 compared to $155 million in 2011. While Gas segment generation increased 71% primarily due to improved spark spreads, the $27 million in higher energy margins, net of hedges and basis, was more than offset by $37 million in lower tolling and capacity revenues due to the early cancellation of agreements in California. Further, the settlement of $77 million in legacy put options together with a $20 million reduction in option premium revenue led to lower 2012 Adjusted EBITDA despite a $38 million positive adjustment for non-cash amortization related to the Independence contract and the absence of a $34 million commercial loss incurred in 2011.

Fourth Quarter Comparative Results

	Successor Three Months Ended December 31, 2012 (in millions)			
	Coal	Gas	Other	Total
Operating Loss	$ (49)	$ (31)	$ (24)	$ (104)
Plus / (Less):				
Bankruptcy reorganization items, net	—	—	(3)	(3)
Depreciation and amortization expense	8	36	1	45
Earnings from unconsolidated investment	—	2	—	2
Other items, net	—	—	8	8
EBITDA from continuing operations	(41)	7	(18)	(52)
Plus / (Less):				
Bankruptcy reorganization items, net	—	—	3	3
Mark-to-market income, net	(6)	(39)	—	(45)
Amortization of intangible assets (1)	29	32	—	61
Premium adjustment	1	(2)	—	(1)
Changes in fair value of warrants	—	—	(8)	(8)
Enterprise-wide Adjusted EBITDA	$ (17)	$ (2)	$ (23)	$ (42)

(1) The amounts within the Coal and Gas segments relate to intangible assets and liabilities related to rail transportation, coal contracts, gas revenue contracts and transportation contracts recorded in connection with the application of fresh-start accounting.

	Predecessor Three Months Ended December 31, 2011 (in millions)			
	Coal	Gas	Other	Total
Operating Loss	$ —	$ (88)	$ (17)	$ (105)
Plus / (Less):				
Bankruptcy reorganization items, net	—	—	(52)	(52)
Depreciation and amortization expense	—	32	2	34
Other items, net	—	1	23	24
EBITDA from continuing operations	—	(55)	(44)	(99)
Plus / (Less):				
Merger termination fee, restructuring costs and other expenses	—	(5)	19	14
Bankruptcy reorganization items, net	—	—	52	52

Mark-to-market (income) loss, net	—	38	(1)	37
Adjusted EBITDA from continuing operations	$ —	$ (22)	$ 26	$ 4
Adjusted EBITDA from Legacy Dynegy (1)	37	—	(45)	(8)
Adjusted EBITDA	$ 37	$ (22)	$ (19)	$ (4)
Adjusted EBITDA from discontinued operations				(10)
Enterprise-wide Adjusted EBITDA				$ (14)

(1) Our 2011 consolidated results reflect the results of our accounting predecessor, DH, which was our wholly-owned subsidiary until the Merger on September 30, 2012. Therefore, certain results related to Legacy Dynegy are not included in our consolidated results for the three months ended December 31, 2011. Additionally, effective September 1, 2011, we completed the DMG Transfer. As a result, the results of our Coal segment, as well as certain items in the Other segment, are not included in our consolidated results for the three months ended December 31, 2011. However, we have included the Adjusted EBITDA related to Legacy Dynegy and the Coal segment for the three months ended December 31, 2011 in this adjustment because management uses enterprise-wide Adjusted EBITDA to evaluate the operating performance of our entire power generation fleet.

Segment Review of Results Quarter-Over-Quarter

Coal — The fourth quarter 2012 operating loss was $49 million compared to a fourth quarter 2011 operating loss of zero. Legacy Dynegy had an operating loss of $14 million related to Coal for the fourth quarter 2012. Adjusted EBITDA, before the allocation of corporate general and administrative expense, totaled $(17) million during the fourth quarter 2012 compared to $37 million during the same period in 2011. Lower energy margins because of lower realized power prices, due to lower hedge prices and higher basis differentials, were responsible for $62 million of the negative Adjusted EBITDA variance. This was partially offset by a $7 million improvement in operating and maintenance expense.

Gas — The fourth quarter operating loss was $31 million compared to a fourth quarter 2011 operating loss of $88 million. Adjusted EBITDA, before the allocation of corporate general and administrative expense, totaled $(2) million during the fourth quarter 2012 compared to $(22) million during the same period in 2011. Improved spark spreads, net of hedges and basis, contributed an additional $34 million in 2012, and together with the absence of the $34 million commercial loss incurred in 2011, more than

offset $29 million in legacy put option settlements, $9 million in lower capacity revenues and $7 million in lower California tolling and resource adequacy payments.

Liquidity

As of March 8, 2013, Dynegy's available liquidity was $592 million, which included $370 million in unrestricted cash and cash equivalents, $153 million in letter of credit availability and $69 million in restricted cash available for collateral posting purposes.

	March 8, 2013	December 31, 2012
LC capacity, inclusive of required reserves	249	262
Required reserves	(7)	(8)
Outstanding letters of credit	(239)	(252)
LC availability	3	2
Revolver	150	—
Cash and cash equivalents	370	348
Collateral posting account	69	71
Total available liquidity	$ 592	$ 421

Consolidated Cash Flow

Cash flow used in operations for the Successor Period was $44 million and for the 2012 Predecessor Period was $37 million for a full-year 2012 total of $81 million. During the year, the power generation business used $71 million primarily due to losses incurred during the year. Corporate and other operations used cash of approximately $58 million primarily due to payments to advisors, employee related payments and other general and administrative expense. These uses of cash were partially offset by $48 million in positive changes in working capital, which includes $6 million related to increased collateral postings, net of return of collateral. Cash flow used in operations totaled $1 million for the year ended December 31, 2011.

Cash flow provided by investing activities for the Successor Period was $265 million and for the 2012 Predecessor Period was $278 million for a full-year 2012 total of $543 million compared to cash flow used in investing activities of $229 million in 2011. During 2012, capital expenditures totaled $109 million, including $76 million in maintenance capital expenditures and $33 million in environmental capital expenditures, the latter of which reflects the Company's continuing investment in environmental upgrades under the Consent Decree. During 2011, capital expenditures totaled $196 million, with $88 million in maintenance capital expenditures and $108 million in environmental capital expenditures. During 2012, there was a $256 million cash inflow due to the Dynegy Midwest Generation acquisition by DH from Legacy Dynegy compared to a $441 million cash outflow in 2011 related to the Dynegy Midwest Generation transfer to Legacy Dynegy from DH. During 2012, there was a $399 million net cash inflow related to restricted cash balances compared to a $222 million net cash inflow in 2011. During 2011, there was a $419 million cash inflow related to maturities of short-term investments offset by a $244 million cash outflow related to purchases of short-term investments.

Cash flow used in financing activities for the Successor Period was $328 million and for the 2012 Predecessor Period was $184 million for a full-year 2012 total of $512 million compared to cash flow provided by financing activities of $375 million during 2011. During 2012, the Company repaid $339 million of borrowings and made a $200 million payment to unsecured creditors under the terms of its

Plan of Reorganization, offset by an increase of $27 million in connection with the recapitalization of Legacy Dynegy. In 2011, proceeds from long-term borrowings of $2 billion were partially offset by $1.6 billion in repayments of other debt instruments.

PRIDE Update

During 2012, we continued to benefit from our cost and performance improvement initiative, known as PRIDE, driving recurring cash flow benefits by optimizing our cost structure, implementing company-wide process and operating improvements, and improving balance sheet efficiency. For 2012, we recognized $44 million in operating margin and cost improvements and $148 million in incremental liquidity from balance sheet improvements due to PRIDE initiatives. In 2013, we are targeting additional margin and cost improvements of $42 million, and additional balance sheet improvements of $83 million. We will continue to use the PRIDE initiative to improve our operating performance, cost structure and balance sheet.

Ameren Energy Resources Acquisition

Dynegy Inc. and Ameren announced today they have signed a definitive agreement under which Dynegy's subsidiary Illinois Power Holdings, LLC (IPH) will acquire Ameren's subsidiary, Ameren Energy Resources (AER) and its subsidiaries Ameren Energy Generating Company, Ameren Energy Resources Generating, and Ameren Energy Marketing Company. Upon closing, Dynegy will own more than 8,000 megawatts (MW) of generating capacity in Illinois, and nearly 14,000 MW nationally. The AER retail and marketing businesses and the following plants are included in the transaction: Duck Creek, Coffeen, E.D. Edwards, Newton, and Joppa.

Investor Conference Call/Webcast

Dynegy will discuss its 2012 financial results and the Ameren Energy Resources acquisition during an investor conference call and webcast today, March 14, 2013, at 9 a.m. ET/8 a.m. CT. Participants may access the webcast and the related presentation materials in the "Investor Relations" section of www.dynegy.com.

ABOUT DYNEGY

Dynegy's subsidiaries produce and sell electric energy, capacity and ancillary services in key U.S. markets. The Dynegy Power, LLC power generation portfolio consists of approximately 6,771 megawatts of primarily natural gas-fired intermediate and peaking power generation facilities. The Dynegy Midwest Generation, LLC portfolio consists of approximately 2,980 megawatts of primarily coal-fired baseload power plants.

This press release contains statements reflecting assumptions, expectations, projections, intentions or beliefs about future events that are intended as "forward-looking statements," particularly those statements concerning: the strength of Dynegy's balance sheet in the merchant generation sector; Dynegy's execution of its daily operations, strategic priorities and capital allocation; Dynegy's successful close of the AER acquisition; Dynegy's commitment to its financial strength; anticipated earnings and cash flows and 2013 Adjusted EBITDA and cash flow guidance. Historically, Dynegy's performance has deviated, in some cases materially, from its cash flow and earnings guidance. Discussion of risks and uncertainties that could cause actual results to differ materially from current projections, forecasts, estimates and expectations of Dynegy is contained in Dynegy's filings with the Securities and Exchange Commission (the "SEC"). Specifically, Dynegy makes reference to, and incorporates herein by reference, the section entitled "Risk Factors" in its 2012 Form 10-K, when filed. In addition to the risks and uncertainties set forth in Dynegy's SEC filings, the forward-looking statements described in this press release could be affected by, among other things, (i) Dynegy's ability to consummate the Roseton and Danskammer facilities sale transactions in accordance with the Settlement Agreement, the Dynegy Northeast Generation, Inc. Chapter 11 Joint Plan of Liquidation and the Danskammer and Roseton Asset Purchase Agreements; (ii) lack of comparable financial data due to the application of fresh-start accounting; (iii) beliefs and assumptions relating to Dynegy's liquidity, available borrowing capacity and capital resources generally, including the extent to which such liquidity could be affected by poor economic and financial market conditions or new regulations and any resulting impacts on financial institutions and other current and potential counterparties; (iv) limitations on Dynegy's ability to utilize previously incurred federal net operating losses or alternative minimum tax credits; (v) expectations regarding Dynegy's compliance with the DMG and DPC Credit

Agreements and DPC's Revolving Credit Agreement, including collateral demands, interest expense, financial ratios and other payments; (vi) the timing and anticipated benefits of any refinancing of the DMG and DPC Credit Agreements; (vii) efforts to secure retail sales and the timing of such sales; (viii) the timing and anticipated benefits to be achieved through Dynegy's company-wide cost savings programs, including its PRIDE initiative; (ix) efforts to identify opportunities to reduce congestion and improve busbar power prices; (x) expectations regarding environmental matters, including costs of compliance, availability and adequacy of emission credits, and the impact of ongoing proceedings and potential regulations or changes to current regulations, including those relating to climate change, air emissions, cooling water intake structures, coal combustion byproducts, and other laws and regulations to which Dynegy is, or could become, subject; (xi) beliefs, assumptions and projections regarding the demand for power, generation volumes and commodity pricing, including natural gas prices and the impact on such prices from shale gas proliferation and the timing of a recovery in natural gas prices, if any; (xii) sufficiency of, access to and costs associated with coal, fuel oil and natural gas inventories and transportation thereof; (xiii) beliefs and assumptions about market competition, generation capacity and regional supply and demand characteristics of the wholesale power generation market, including the anticipation of higher market pricing over the longer term; (xiv) the effectiveness of Dynegy's strategies to capture opportunities presented by changes in commodity prices and to manage Dynegy's exposure to energy price volatility; (xv) beliefs and assumptions about weather and general economic conditions; (xvi) projected operating or financial results, including anticipated cash flows from operations, revenues and profitability; (xvii) Dynegy's focus on safety and its ability to efficiently operate its assets so as to capture revenue generating opportunities and operating margins; (xviii) beliefs about the costs and scope of the ongoing demolition and site remediation efforts at the South Bay and Vermilion facilities; (xix) beliefs and assumptions regarding the outcome of the SCE contract terminations dispute and the impact of such terminations on the timing and amount of future cash flows; (xx) ability to mitigate impacts associated with expiring RMR and/or capacity contracts; (xxi) beliefs about the outcome of legal, administrative, legislative and regulatory matters, including the impact of final rules regarding derivatives issued by the CFTC under the Dodd-Frank Act; and (xxii) expectations and estimates regarding capital and maintenance expenditures. Any or all of Dynegy's forward-looking statements may turn out to be wrong. They can be affected by inaccurate assumptions or by known or unknown risks, uncertainties and other factors, many of which are beyond Dynegy's control.

Dynegy Inc. Contacts: Media: Katy Sullivan, 713.767.5800; Analysts: 713.507.6466

DYNEGY INC.
REPORTED CONSOLIDATED STATEMENTS OF OPERATIONS
(IN MILLIONS, EXCEPT PER SHARE DATA)

	Successor	Predecessor	Combined	Predecessor
	October 2 Through December 31, 2012	January 1 Through October 1, 2012	Year Ended December 31, 2012	Year Ended December 31, 2011
Revenues	$ 312	$ 981	$ 1,293	$ 1,333
Cost of sales	(268)	(662)	(930)	(866)
Gross margin, exclusive of depreciation shown separately below	44	319	363	467
Operating and maintenance expense, exclusive of depreciation shown separately below	(81)	(148)	(229)	(254)
Depreciation and amortization expense	(45)	(110)	(155)	(295)
Impairment and other charges	—	—	—	(5)
General and administrative expense	(22)	(56)	(78)	(102)
Operating income (loss)	(104)	5	(99)	(189)
Earnings from unconsolidated investment	2	—	2	—
Bankruptcy reorganization items, net	(3)	1,037	1,034	(52)
Interest expense	(16)	(120)	(136)	(348)
Debt extinguishment costs	—	—	—	(21)
Impairment of Undertaking receivable, affiliate	—	(832)	(832)	—
Other income and expense, net	8	31	39	35
Income (loss) from continuing operations before income taxes	(113)	121	8	(575)
Income tax benefit	—	9	9	144
Income (loss) from continuing operations	(113)	130	17	(431)
Income (loss) from discontinued operations, net of taxes	6	(162)	(156)	(509)
Net loss	$ (107)	$ (32)	$ (139)	$ (940)
Basic loss per share: (3)				
Loss from continuing operations (1)	$ (1.13)	N/A	N/A	N/A
Income from discontinued operations	0.06	N/A	N/A	N/A
Basic loss per share (3)	$ (1.07)	N/A	N/A	N/A
Diluted loss per share: (3)				
Loss from continuing operations (1)	$ (1.13)	N/A	N/A	N/A
Income from discontinued operations	0.06	N/A	N/A	N/A
Diluted loss per share (3)	$ (1.07)	N/A	N/A	N/A
Basic shares outstanding	100	N/A	N/A	N/A
Diluted shares outstanding	100	N/A	N/A	N/A

(1) For the Successor Period, a reconciliation of basic loss per share from continuing operations to diluted

loss per share from continuing operations is presented below:

Loss from continuing operations for basic and diluted loss per share	$ (113)

Basic weighted-average shares		100
Effect of dilutive securities-stock options and restricted stock		—
Diluted weighted-average shares		100
Loss per share from continuing operations		
Basic	$	(1.13)
Diluted (2)	$	(1.13)

(2) Entities with a net loss from continuing operations are prohibited from including potential common shares in the computation of diluted per share amounts. Accordingly, we have utilized the basic shares outstanding amount to calculate both basic and diluted loss per share for all periods presented.

(3) Prior to the Merger, DH was organized as a limited liability company and the capital structure of DH did not change until September 30, 2012. Although Legacy Dynegy's shares were publicly traded, DH did not have any publicly traded shares during the Predecessor periods; therefore, no loss per share is presented for (i) the three and twelve months ended December 31, 2011 and (ii) the twelve months ended December 31, 2012.

DYNEGY INC.
UNAUDITED CONSOLIDATED STATEMENTS OF OPERATIONS
(IN MILLIONS)

	Successor	Predecessor
	Three Months Ended December 31,	
	2012	2011
Revenues	$ 312	$ 130
Cost of sales	(268)	(148)
Gross margin, exclusive of depreciation shown separately below	44	(18)
Operating and maintenance expense, exclusive of depreciation expense shown separately below	(81)	(37)
Depreciation and amortization expense	(45)	(34)
Impairments and other charges	—	(1)
General and administrative expense	(22)	(15)
Operating loss	(104)	(105)
Earnings from unconsolidated investment	2	—
Bankruptcy reorganization items, net	(3)	(52)
Interest expense	(16)	(65)
Debt extinguishment costs	—	—
Impairment of Undertaking receivable, affiliate	—	—
Other income and expense, net	8	24
Loss from continuing operations before income taxes	(113)	(198)
Income tax benefit	—	50
Loss from continuing operations	(113)	(148)
Income/(loss) from discontinued operations, net of taxes	6	(468)
Net loss	$ (107)	$ (616)

DYNEGY INC.
REPORTED SEGMENTED RESULTS OF OPERATIONS
TWELVE MONTHS ENDED DECEMBER 31, 2012
(UNAUDITED) (IN MILLIONS)

The following table provides summary financial data regarding our enterprise-wide Adjusted EBITDA for the twelve months ended December 31, 2012:

	Combined			
	Twelve Months Ended December 31, 2012			
	Coal	Gas	Other	Total
Net loss				$ (139)
Plus / (Less):				
Loss from discontinued operations, net of taxes				156
Income tax benefit (1)				(9)
Interest expense				136
Depreciation and amortization expense				155
EBITDA from continuing operations (2)	$ (86)	$ 228	$ 157	$ 299
Plus / (Less):				
Impairment of Undertaking receivable, affiliate	—	—	832	832
Bankruptcy reorganization items, net	—	—	(1,034)	(1,034)

Interest income on Undertaking receivable	—	—	(24)	(24)
Restructuring costs and other expense	—	—	3	3
Mark-to-market (income) loss, net	7	(166)	—	(159)
Amortization of intangible assets and liabilities (3)	78	61	—	139
Premium adjustment	1	(1)	—	—
Changes in fair value of warrants	—	—	(8)	(8)
Adjusted EBITDA (2)	—	122	(74)	48
Adjusted EBITDA from Legacy Dynegy (4)	20	—	(11)	9
Enterprise-wide Adjusted EBITDA (2)	$ 20	$ 122	$ (85)	$ 57

(1) For the twelve months ended December 31, 2012, the difference between the effective income tax rate of 113 percent and the statutory federal rate of 35 percent resulted primarily from a valuation allowance to eliminate our net deferred tax assets partially offset by the impact of state taxes. As of December 31, 2012, we do not believe we will produce sufficient future taxable income, nor are there tax strategies available, to realize our net deferred tax assets not otherwise realized by reversing temporary differences.

(2) EBITDA and Adjusted EBITDA are non-GAAP financial measures. Please refer to Item 2.02 of our Form 8-K filed on March 14, 2013, for definitions, utility and uses of such non-GAAP financial measures. A reconciliation of EBITDA to Operating income (loss) is presented below. Management does not allocate interest expense and income taxes on a segment level and therefore uses Operating income (loss) as the most directly comparable GAAP measure.

(3) The amount in the Coal segment in the 2012 Predecessor Period relates to intangible assets and liabilities related to rail transportation and coal contracts, respectively, recorded in connection with the DMG

Acquisition. The amount in the Gas segment in the 2012 Predecessor Period is related to the intangible assets related to the 2005 Sithe acquisition. The amounts in the Successor Period relate to intangible assets and liabilities related to rail transportation, coal contracts, gas revenue contracts and gas transportation contracts recorded in connection with the application of fresh-start accounting.

	Combined			
	Twelve Months Ended December 31, 2012			
	Coal	Gas	Other	Total
Operating income (loss)	$ (112)	$ 97	$ (84)	$ (99)
Impairment of Undertaking receivable, affiliate	—	—	(832)	(832)
Bankruptcy reorganization items, net	—	—	1,034	1,034
Depreciation and amortization expense	21	127	7	155
Earnings from unconsolidated investment	—	2	—	2
Other items, net	5	2	32	39
EBITDA from continuing operations	$ (86)	$ 228	$ 157	$ 299

(4) Our 2012 consolidated results reflect the results of our accounting predecessor, DH, which was our wholly-owned subsidiary until the Merger on September 30, 2012. Therefore, certain results related to Legacy Dynegy are not included in our consolidated results for the 2012 Predecessor Period. Additionally, effective June 5, 2012, we completed the DMG Acquisition. As a result, the results of our Coal segment, as well as certain items in the Other segment, are not included in our consolidated results for the period from January 1, 2012 through June 5, 2012. However, we have included the Adjusted EBITDA related to Legacy Dynegy for the 2012 Predecessor Period and the Coal segment for the period from January 1, 2012 through June 5, 2012 in this adjustment because management uses enterprise-wide Adjusted EBITDA to evaluate the operating performance of our entire power generation fleet. The following table presents a reconciliation of Legacy Dynegy Adjusted EBITDA to Operating income (loss):

	Combined			
	Twelve Months Ended December 31, 2012			
	Coal	Gas	Other	Total
Operating income (loss)	$ (2,702)	$ —	$ 1,670	$ (1,032)
Depreciation and amortization expense	78	—	—	78
Bankruptcy reorganization items, net	—	—	(8)	(8)
Loss from unconsolidated investment	—	—	(1)	(1)
EBITDA	(2,624)	—	1,661	(963)
Loss (gain) on Coal Holdco Transfer	2,652	—	(1,711)	941
Bankruptcy reorganization items, net	—	—	8	8
Restructuring costs and other expense	—	—	30	30
Mark-to-market income, net	(8)	—	—	(8)
Loss from unconsolidated investment	—	—	1	1
Adjusted EBITDA from Legacy Dynegy	$ 20	$ —	$ (11)	$ 9

DYNEGY INC.
REPORTED SEGMENTED RESULTS OF OPERATIONS
TWELVE MONTHS ENDED DECEMBER 31, 2011
(UNAUDITED) (IN MILLIONS)

The following table provides summary financial data regarding our enterprise-wide Adjusted EBITDA by segment for the twelve months ended December 31, 2011:

	Predecessor			
	Twelve Months Ended December 31, 2011			
	Coal	Gas	Other	Total
Net loss				$ (940)
Plus / (Less):				
Loss from discontinued operations, net of taxes				509
Income tax benefit from continuing operations (1)				(144)
Interest expense and debt extinguishment costs				369
Depreciation and amortization expense				295
EBITDA from continuing operations (2)	$ 120	$ 97	$ (128)	$ 89
Plus / (Less):				
Bankruptcy reorganization items, net	—	—	52	52
Merger agreement termination fee, restructuring costs and other expenses	(1)	7	25	31
Mark-to-market loss, net	76	51	4	131
Adjusted EBITDA from continuing operations (2)	195	155	(47)	303
Adjusted EBITDA from Legacy Dynegy (3)	48	—	(51)	(3)
Adjusted EBITDA	$ 243	$ 155	$ (98)	$ 300
Adjusted EBITDA from discontinued operations				(19)
Enterprise-wide Adjusted EBITDA				$ 281

(1) For the twelve months ended December 31, 2011, the difference between the effective income tax rate of 25 percent and the statutory federal rate of 35 percent resulted primarily due to the impact of state taxes partially offset by a change in our valuation allowance.

(2) EBITDA and Adjusted EBITDA are non-GAAP financial measures. Please refer to Item 2.02 of our Form 8-K filed on March 14, 2013, for definitions, utility and uses of such non-GAAP financial measures. A reconciliation of Operating loss to EBITDA from continuing operations is presented below. Management does not allocate interest expense and income taxes on a segment level and therefore uses Operating loss as the most directly comparable GAAP measure.

	Predecessor			
	Twelve Months Ended December 31, 2011			
	Coal	Gas	Other	Total
Operating loss	$ (38)	$ (37)	$ (114)	$ (189)
Bankruptcy reorganization items, net	—	—	(52)	(52)
Other items, net	2	2	31	35
Depreciation and amortization expense	156	132	7	295
EBITDA from continuing operations	$ 120	$ 97	$ (128)	$ 89

(3) Our 2011 consolidated results reflect the results of our accounting predecessor, DH, which was a wholly-owned subsidiary until the Merger on September 30, 2012. Therefore, certain results related to Legacy Dynegy are not included in our consolidated results for the twelve months ended December 31, 2011. Additionally, effective September 1, 2011, we completed the DMG Transfer. As a result, the results of our Coal segment, as well as certain items in the Other segment, are not included in our consolidated results for the period from September 1, 2011 through December 31, 2011. However, we have included the Adjusted EBITDA related to Legacy Dynegy for the twelve months ended December 31, 2011 and the Coal segment for the period from September 1, 2011 through December 31, 2011 in this adjustment because management

uses Enterprise-wide Adjusted EBITDA to evaluate the operating performance of our entire power generation fleet. The following table presents a reconciliation of Legacy Dynegy Adjusted EBITDA to Operating loss:

Predecessor			
Twelve Months Ended December 31, 2011			
Coal	Gas	Other	Total

Operating loss	$ (18)	$ —	$ (40)	$ (58)
Depreciation and amortization expense	50	—	(1)	49
Other items, net	(1)	—	(39)	(40)
EBITDA	31	—	(80)	(49)
Restructuring charges and other expenses	2	—	19	21
Impairment and other charges	—	—	10	10
Mark-to-market loss, net	15	—	—	15
Adjusted EBITDA from Legacy Dynegy	$ 48	$ —	$ (51)	$ (3)

DYNEGY INC.
REPORTED SEGMENTED RESULTS OF OPERATIONS
THREE MONTHS ENDED DECEMBER 31, 2012
(UNAUDITED) (IN MILLIONS)

The following table provides summary financial information data regarding our enterprise-wide Adjusted EBITDA for the three months ended December 31, 2012:

	Successor			
	Three Months Ended December 31, 2012			
	Coal	Gas	Other	Total
Net loss				$ (107)
Plus / (Less):				
Discontinued operations, net of taxes				(6)
Income tax benefit (1)				—
Interest expense				16
Depreciation and amortization expense				45
EBITDA from continuing operations (2)	$ (41)	$ 7	$ (18)	$ (52)
Plus / (Less):				
Bankruptcy reorganization items, net	—	—	3	3
Mark-to-market income, net	(6)	(39)	—	(45)
Amortization of intangible assets and liabilities (3)	29	32	—	61
Premium adjustment	1	(2)	—	(1)
Changes in fair value of warrants	—	—	(8)	(8)
Enterprise-wide Adjusted EBITDA (2)	$ (17)	$ (2)	$ (23)	$ (42)

(1) For the three months ended December 31, 2012, our overall effective tax rate on continuing operations was different than the federal statutory rate of 35 percent as a result of a valuation allowance to eliminate our deferred tax assets.

(2) EBITDA and Adjusted EBITDA are non-GAAP financial measures. Please refer to Item 2.02 of our Form 8-K filed on March 14, 2013, for definitions, utility and uses of such non-GAAP financial measures. A reconciliation of EBITDA to Operating loss is presented below. Management does not allocate interest expense and income taxes on a segment level and therefore uses Operating loss as the most directly

comparable GAAP measure.

(3) The amounts within the Coal and Gas segments relate to intangible assets and liabilities related to rail transportation, coal contracts, gas revenue contracts and transportation contracts recorded in connection with the application of fresh-start accounting.

	Successor			
	Three Months Ended December 31, 2012			
	Coal	Gas	Other	Total
Operating loss	$ (49)	$ (31)	$ (24)	$ (104)
Bankruptcy reorganization items, net	—	—	(3)	(3)
Depreciation and amortization expense	8	36	1	45
Earnings from unconsolidated investment	—	2	—	2
Other items, net	—	—	8	8
EBITDA from continuing operations	$ (41)	$ 7	$ (18)	$ (52)

DYNEGY INC.
REPORTED SEGMENTED RESULTS OF OPERATIONS
THREE MONTHS ENDED DECEMBER 31, 2011
(UNAUDITED) (IN MILLIONS)

The following table provides summary financial information data regarding our enterprise-wide Adjusted EBITDA by segment for the three months ended

December 31, 2011:

	Predecessor			
	Three Months Ended December 31, 2011			
	Coal	Gas	Other	Total
Net loss				$ (616)
Plus / (Less):				
Discontinued operations				468
Income tax benefit (1)				(50)
Interest expense				65
Depreciation and amortization expense				34
EBITDA from continuing operations (2)	$ —	$ (55)	$ (44)	$ (99)
Plus / (Less):				
Bankruptcy reorganization items, net	—	—	52	52
Merger agreement termination fee, restructuring costs and other expenses	—	(5)	19	14
Mark-to-market (income) loss, net	—	38	(1)	37
Adjusted EBITDA from continuing operations (2)	$ —	$ (22)	$ 26	$ 4
Adjusted EBITDA from Legacy Dynegy (3)	37	—	(45)	(8)
Adjusted EBITDA	$ 37	$ (22)	$ (19)	$ (4)
Adjusted EBITDA from discontinued operations				(10)
Enterprise-wide Adjusted EBITDA				$ (14)

(1) For the three months ended December 31, 2011, the difference between the effective tax rate of 25 percent and the federal statutory tax rate of 35 percent resulted primarily from a valuation allowance to eliminate our net deferred tax assets partially offset by the impact of state taxes.

(2) EBITDA and Adjusted EBITDA are non-GAAP financial measures. Please refer to Item 2.02 of our Form 8-K filed on March 14, 2013, for definitions, utility and uses of such non-GAAP financial measures. A reconciliation of EBITDA to Operating loss is presented below. Management does not allocate interest expense and income taxes on a segment level and therefore uses Operating income (loss) as the most directly comparable GAAP measure.

	Predecessor			
	Three Months Ended December 31, 2011			
	Coal	Gas	Other	Total
Operating loss	$ —	$ (88)	$ (17)	$ (105)
Bankruptcy reorganization items, net	—	—	(52)	(52)
Other items, net	—	1	23	24
Depreciation and amortization expense	—	32	2	34
EBITDA from continuing operations	$ —	$ (55)	$ (44)	$ (99)

(3) Our 2011 consolidated results reflect the results of our accounting predecessor, DH, which was our wholly-owned subsidiary until the Merger on September 30, 2012. Therefore, certain results related to Legacy Dynegy are not included in our consolidated results for the three months ended December 31, 2011. Additionally, effective September 1, 2011, we completed the DMG Transfer. As a result, the results of our Coal segment, as well as certain items in the Other segment, are not included in our consolidated results for the three months ended December 31, 2011. However, we have included the Adjusted EBITDA related to Legacy Dynegy and the Coal segment for the three months ended December 31, 2011 in this adjustment because management uses enterprise-wide Adjusted EBITDA to evaluate the operating performance of our entire power generation fleet. The following table presents a reconciliation of Legacy Dynegy Adjusted EBITDA to Operating loss:

	Predecessor			
	Three Months Ended December 31, 2011			
	Coal	Gas	Other	Total
Operating loss	$ (14)	$ —	$ (34)	$ (48)
Depreciation and amortization expense	37	—	(1)	36
Other items, net	1	—	(34)	(33)
EBITDA	24	—	(69)	(45)
Restructuring charges and other expenses	(3)	—	14	11
Impairment and other charges	—	—	10	10
Mark-to-market loss, net	16	—	—	16
Adjusted EBITDA from Legacy Dynegy	$ 37	$ —	$ (45)	$ (8)

DYNEGY INC.
SUMMARY CASH FLOW INFORMATION (1)

TWELVE MONTHS ENDED DECEMBER 31, 2012 and 2011
(UNAUDITED) (IN MILLIONS)

	Combined			Predecessor
	Twelve Months Ended December 31,			
	2012			2011
	Dynegy Inc. (as reported)	Other (3)	Total	Total
Adjusted EBITDA (2)	$ 48	$ 9	$ 57	$ 281
Interest payments	(135)	(19)	(154)	(256)
Cash taxes	7	—	7	2
Collateral	(6)	(3)	(9)	(54)
Working capital / non-cash adjustments / other changes	5	(93)	(88)	62
Cash Flow from Operations	(81)	(106)	(187)	35
Maintenance capital expenditures	(76)	(9)	(85)	(106)
Environmental capital expenditures	(27)	(28)	(55)	(159)
Return of cash collateral, net (investing)	399	55	454	—
Free Cash Flow	$ 215	$ (88)	$ 127	$ (230)

(1) This presentation is intended to demonstrate the relationship between the performance measure of Adjusted EBITDA and the liquidity measure of Free Cash Flow. We believe it is useful to our analysts and investors to understand this relationship because it demonstrates how the cash generated by our operations is used to satisfy various liquidity requirements. A reconciliation of Free Cash Flow to Cash Flow from Operations is presented above. Please refer to Item 2.02 of our Form 8-K filed on March 14, 2013, for definitions, utility and uses of such non-GAAP financial measures.

(2) Adjusted EBITDA is a non-GAAP financial measure. Please refer to Item 2.02 of our Form 8-K filed on March 14, 2013, for definitions, utility and uses of such non-GAAP financial measures. Please see Reported Segmented Results of Operations for the twelve months ended December 31, 2012 and 2011 for a reconciliation of Adjusted EBITDA to Net loss.

(3) Other includes the cash flows from Legacy Dynegy for the twelve months ended December 31, 2012 which included the Coal segment for the period from January 1, 2012 through June 5, 2012.

DYNEGY INC.
OPERATING DATA

The following table provides summary financial data regarding our Coal and Gas segment results of operations for the three and twelve months ended December 31, 2012 and 2011, respectively. As a result of the DMG Transfer, 2011 results only include the results of the Coal segment through August 31, 2011. As a result of the DMG Acquisition, 2012 results only include the results of the Coal segment for the period of June 6, 2012 through December 31, 2012. Additionally, as a result of the DMG Transfer, 2011 results only include the results of the Coal segment for the period from January 1, 2011 through August 31, 2011.

	Successor	Predecessor	Combined	Predecessor
	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2012	2011	2012	2011
Coal				
Million Megawatt Hours Generated (1)	4.7	N/A	11.3	15.6
In-Market Availability for Coal Fired Facilities (2)	86%	N/A	91%	92%
Average Quoted On-Peak Market Power Prices ($/MWh) (3):				
Indiana (Indy Hub) (4)	$ 35	N/A	$ 38	$ 45
Gas				
Million Megawatt Hours Generated (5):	3.5	2.7	20.4	12.3
Average Capacity Factor for Combined Cycle Facilities (6)	36%	27%	52%	21%
Average Market On-Peak Spark Spreads ($/MWh) (7):				
Commonwealth Edison (NI Hub)	$ 9	$ 9	$ 14	$ 12
PJM West	$ 15	$ 15	$ 19	$ 19
North of Path 15 (NP 15)	$ 9	$ 7	$ 8	$ 4
New York - Zone A	$ 10	$ 9	$ 13	$ 9
Mass Hub	$ 23	$ 17	$ 19	$ 18
Average Market Off-Peak Spark Spreads ($/MWh) (7):				
Commonwealth Edison (NI Hub)	$ (1)	$ (3)	$ 4	$ (3)
PJM West	$ 6	$ 8	$ 8	$ 5
North of Path 15 (NP 15)	$ 1	$ (1)	$ (1)	$ (10)
New York - Zone A	$ 2	$ 2	$ 4	$ 2
Mass Hub	$ (3)	$ 9	$ 4	$ 6

Average Natural Gas Price - Henry Hub ($/MMBtu) (8)	$ 3.39	$ 3.31	$ 2.75	$ 3.99

(1) Reflects production volumes in million MWh generated during the periods Coal was included in our consolidated results. Generation volumes were 5.3 million MWh for the full three months ended December 31, 2011. Generation volumes were 19.9 million MWh and 22.2 million MWh for the full twelve months ended December 31, 2012 and 2011, respectively.

(2) Reflects the percentage of generation available during periods when market prices were such that these units could be profitably dispatched during the periods Coal was included in our consolidated results. In-Market Availability for Coal Fired Facilities was 89 percent for the full three months ended December 31, 2011. In-Market Availability for Coal Fired Facilities was 92 percent for the full twelve months ended December 31, 2012 and 2011, respectively.

(3) Reflects the average of day-ahead quoted prices for the periods Coal was included in our consolidated results and does not necessarily reflect prices we realized. The average of day-ahead quoted prices was $34 for the full three months ended December 31, 2011. The average of day-ahead quoted prices were $35 and $41 for the full twelve months ended December 31, 2012 and 2011, respectively.

(4) The market reference for 2011 was Cinergy (Cin Hub). At the end of 2011, the Cin Hub pricing point in MISO ceased to exist when the Ohio portion of the market point became part of PJM. Beginning in 2012, Indy Hub became MISO's major market point and is considered a direct correlation to the old Cin Hub and has been accepted as a replacement for Cin Hub in commercial contracts.

(5) Includes our ownership percentage in the MWh generated by our investment in the Black Mountain power generation facility for the three and twelve months ended December 31, 2012 and 2011, respectively.

(6) Reflects actual production as a percentage of available capacity.

(7) Reflects the simple average of the spark spread available to a 7.0 MMBtu/MWh heat rate generator selling power at day-ahead prices and buying delivered natural gas at a daily cash market price and does not reflect spark spreads available to us.

(8) Reflects the average of daily quoted prices for the periods presented and does not reflect costs incurred by us.

Exhibit 99.2

NEWS RELEASE

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FOR IMMEDIATE RELEASE **NR13-06**

Dynegy to Acquire Ameren Energy Resources, Expanding Illinois Portfolio

Transaction highlights:

- Dynegy to acquire 4,119 MW of generation and AER's marketing and Homefield Energy retail businesses through Illinois Power Holdings, a newly formed, non-recourse subsidiary (with the exception of a $25 million limited guarantee)
- Ameren, through the Genco put option, to purchase 1,166 MW of gas-fired generation from Genco prior to closing for a minimum of $133 million
- No cash consideration for the acquisition of AER and its consolidated subsidiaries; $825 million in existing Genco debt remains a Genco obligation
- AER and consolidated subsidiaries to be transferred at closing with $226 million in cash, $160 million in working capital, and two years of credit support from Ameren
- More than $60 million of expected annual synergies by 2015
- Existing transmission rights to PJM to remain in place
- Expected to be accretive to Adjusted EBITDA in 2014 and Free Cash Flow by 2015

HOUSTON, TX (March 14, 2013) — Dynegy Inc. (NYSE:DYN) and Ameren (NYSE: AEE) announced today they have signed a definitive agreement under which Dynegy's subsidiary Illinois Power Holdings, LLC (IPH) will acquire Ameren's subsidiary, Ameren Energy Resources (AER) and its subsidiaries Ameren Energy Generating Company (Genco), AmerenEnergy Resources Generating Company (AERG), and Ameren Energy Marketing Company (AEM). Upon closing, Dynegy will own more than 8,000 megawatts (MW) of generating capacity in Illinois, and nearly 14,000 MW nationally. The AER retail and marketing businesses and the following plants are included in the transaction: Duck Creek, Coffeen, E.D. Edwards, Newton, and Joppa.

"The acquisition of AER is expected to create significant value for Dynegy shareholders by building upon our existing scale in one of our key markets with assets similar to our Illinois-based CoalCo portfolio. We are uniquely positioned to create significant synergies that will benefit AER *and* our CoalCo and GasCo businesses. AEM also brings to Dynegy an established retail business with significant scale that complements both portfolios," said Robert C. Flexon, Dynegy President and Chief Executive Officer. "Additionally, the financial terms of the acquisition and the transaction structure ensure that very limited capital support, if any, will be needed or provided by the Company to AER thereby preserving Dynegy's capital allocation flexibility."

Transaction Structure

Dynegy will acquire AER and its subsidiaries through a wholly-owned special purpose entity — IPH — that will maintain corporate separateness from current Dynegy entities. Obligations under the signed Transaction Agreement (TA) include:

Ameren:

- Prior to closing, Ameren, or its designated subsidiary, will purchase Genco's Elgin, Grand Tower and Gibson City natural gas-fired generation plants for a guaranteed minimum price of $133 million. Appraisals will be obtained for these plants prior to settlement, and if the average value of the appraisals exceeds $133 million, any excess amount will be remitted to Genco. If Ameren subsequently sells these plants within two years of closing, all after-tax proceeds in excess of the $133 million, or the higher appraised value if applicable, will be remitted to Genco.
- In addition to the gas plant sale proceeds, Ameren will ensure a minimum of $93 million of cash at AER and its subsidiaries of which approximately $70 million will be held at Genco.
- For 24 months following closing, Ameren is to provide post-closing credit support to IPH for its existing commercial obligations. IPH's reimbursement obligation for that support would be secured by a lien on certain IPH assets.
- AER will have consolidated net working capital at closing, excluding cash, of $160 million.
- Post closing, Ameren will offer transition support services to IPH, as needed, and billable to IPH for services provided in excess of $5 million.

Dynegy:

- Dynegy has provided a $25 million guarantee to Ameren at TA signing of certain IPH obligations under the TA for a period of 24 months beyond the transaction closing.

IPH:

- IPH will assume existing business and on-site environmental obligations of the five acquired plants but will not assume any potential liabilities associated with previously owned facilities and the Duck Creek rail embankment.
- IPH will indemnify Ameren for up to $25 million for certain offsite liabilities associated with the beneficial reuse and disposal of coal combustion residuals from the acquired operating sites.

Transaction Benefits

AER's coal generation and retail marketing business is a natural fit with CoalCo, Dynegy's existing coal generation fleet. Both portfolios are compliant with the EPA's Mercury and Air Toxic Standards which goes into effect during 2015. As other noncompliant or uneconomic generation continues to retire, the combined portfolio will be well positioned to benefit from tightening supply dynamics. Transaction benefits include:

- The transaction more than doubles Dynegy's exposure to market recovery and Midwest coal plant retirements.
- AER has recently obtained additional transmission rights which, when confirmed by AER, will increase the total available transmission capacity from their Illinois assets into PJM to approximately 900 MW. These rights will be available for the 2016/2017 PJM capacity auction.
- AER and its subsidiaries will have sufficient liquidity and collateral support at closing to meet expected operating obligations.
- Operational synergies are expected to exceed $60 million per year by 2015. Cost synergies, such as lower delivered fuel cost and other procurement opportunities, result from the combined portfolio's increased scale in Illinois. Other savings, such as reductions in operating and general and administrative expenses, result from the similar asset profile of CoalCo and by leveraging Dynegy's existing infrastructure. As part of the integration, Dynegy will expand its highly

successful PRIDE (Producing Results through Innovation by Dynegy Employees) program to AER's business.

- Dynegy's existing business is also anticipated to benefit through lower allocation of existing infrastructure costs across the broader asset base.
- AEM has established marketing and retail businesses which provide 15 million megawatt-hours of electricity annually to municipals, co-ops, and commercial and industrial customers in MISO and PJM. The Homefield Energy retail brand, which serves nearly 500,000 homes and small businesses in Illinois, is included in this total. Dynegy's PJM-based generation facilities will provide support for growth in that market. These businesses will also provide basis management opportunities for the entire coal fleet.

The targeted synergies, along with the current forward market for natural gas prices and Dynegy's associated view on forward power and capacity prices, are expected to result in AER being accretive to Dynegy's Adjusted EBITDA in 2014 and to Free Cash Flow by 2015. In addition, these same forward curves indicate that all three of AER's subsidiaries offer substantial equity value creation for the benefit of Dynegy's shareholders.

Combined Portfolio Profile

Dynegy continues to support environmentally compliant coal and gas-fired generation as a responsible way to support America's future energy needs. Dynegy remains committed to working with local communities, state and federal regulators, and legislators to ensure that affordable, reliable, responsible and environmentally compliant electricity is provided to the communities which the Company serves.

Approvals and Time to Close

Dynegy and Ameren expect to close the transaction during the fourth quarter of 2013. The transaction is subject to customary closing conditions, including approval from the Federal Energy Regulatory Commission.

Advisors

Dynegy's financial advisor for this transaction is Lazard.

Investor Conference Call/Webcast

Dynegy will discuss its 2012 financial results and the Ameren Energy Resources acquisition during an investor conference call and webcast today, March 14, 2013, at 9 a.m. ET/8 a.m. CT. Participants may access the webcast and the related presentation materials in the "Investor Relations" section of www.dynegy.com.

ABOUT DYNEGY

Dynegy's subsidiaries produce and sell electric energy, capacity and ancillary services in key U.S. markets. The Dynegy Power, LLC (GasCo) power generation portfolio consists of approximately 6,771 megawatts of primarily natural gas-fired intermediate and peaking power generation facilities. The Dynegy Midwest Generation, LLC (CoalCo) portfolio consists of approximately 2,980 megawatts of primarily coal-fired baseload power plants.

Adjusted EBITDA and Free Cash Flow are non-GAAP financial measures. Please refer to Item 2.02 of our Form 8-K filed on March 14, 2013, for definitions, utility and uses of such non-GAAP financial measures.

This press release contains statements reflecting assumptions, expectations, projections, intentions or beliefs about future events that are intended as “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. These forward-looking statements include statements regarding benefits of the proposed transaction, including significant value for Dynegy shareholders, expected synergies and anticipated future financial operating performance and results, AEM’s established retail business, preservation of Dynegy’s capital allocation flexibility, obligations under the TA, AER’s consolidated net working capital at closing, sufficiency of AER’s liquidity and collateral support, and ability to close the transaction during the fourth quarter of 2013. These statements are based on the current expectations of Dynegy’s management. Discussion of risks and uncertainties that could cause actual results to differ materially from current projections, forecasts, estimates and expectations of Dynegy is contained in Dynegy’s filings with the Securities and Exchange Commission (the “SEC”). Specifically, Dynegy makes reference to, and incorporates herein by reference, the section entitled “Risk Factors” in its 2012 Form 10-K, when filed. In addition to the risks and uncertainties set forth in Dynegy’s SEC filings, the forward-looking statements described in this press release could be affected by, among other things, (i) conditions to the closing of the transaction may not be satisfied; (ii) problems may arise in successfully integrating AER’s coal generation and retail marketing business into Dynegy’s current portfolio, which may result in Dynegy not operating as effectively and efficiently as expected; (iii) Dynegy may be unable to achieve expected synergies or it may take longer than expected to achieve such synergies; (iv) the transaction may involve unexpected costs or unexpected liabilities; (v) Dynegy may be unable to obtain regulatory approvals required for the transaction or required regulatory approvals may delay the transaction or result in the imposition of conditions that could have a material adverse effect on Dynegy or cause Dynegy to abandon the transaction; (vi) the business of Dynegy may suffer as a result of uncertainty surrounding the transaction; (vii) the industry may be subject to future regulatory or legislative actions, including environmental, that could adversely affect Dynegy; and (viii) Dynegy may be adversely affected by other economic, business, and/or competitive factors. Any or all of Dynegy’s forward-looking statements may turn out to be wrong. They can be affected by inaccurate assumptions or by known or unknown risks, uncertainties and other factors, many of which are beyond Dynegy’s control.

Dynegy Inc. Contacts: Media: Katy Sullivan, 713.767.5800; Analysts: 713.507.6466

Exhibit B

Dynegy Management Discusses Q4 2012 Results - Earnings Call Transcript

Executives

Laura Hrehor

Robert C. Flexon - Chief Executive Officer, President and Director

Clint Freeland - Chief Financial Officer and Executive Vice President

Carolyn J. Burke - Former Principal Accounting Officer, Vice President and Controller

Catherine B. Callaway - Chief Compliance Officer, Executive Vice President and General Counsel

Brian Despard

Lynn A. Lednicky - Executive Vice President of Operations

Daniel Thompson

Analysts

Brandon Blossman - Tudor, Pickering, Holt & Co. Securities, Inc., Research Division

Jonathan Cohen - ISI Group Inc., Research Division

Brian Chin - Citigroup Inc, Research Division

Julien Dumoulin-Smith - UBS Investment Bank, Research Division

Stephen Byrd - Morgan Stanley, Research Division

Terran Miller

Lance Ettus

Jason Mandel

Amer Tiwana - CRT Capital Group LLC

Dynegy (DYN) Q4 2012 Earnings Call March 14, 2013 9:00 AM ET

Operator

Hello, and welcome to the Dynegy Inc. 2012 Financial Results Teleconference. At the request of Dynegy, the conference is being recorded for instant replay purposes. [Operator Instructions] I'd now like to turn the conference over to Ms. Laura Hrehor, Managing Director, Investor Relations. Ma'am, you may begin.

Laura Hrehor

Good morning, everyone, and welcome to Dynegy's investor conference call and webcast covering the company's annual and fourth quarter 2012 results, and Dynegy's proposed transaction with Ameren Corp.

As is our customary practice, before we begin this morning, I would like to remind you that our call will include statements reflecting assumptions, expectations, projections, intentions or beliefs about future events and views of market dynamics. These and other statements not relating strictly to historical or current facts are intended as forward-looking statements. Actual results though may vary materially from those expressed or implied in any forward-looking statements. For a description of the factors that may cause such a variance, I would direct you to the forward-looking statements legend contained in today's news release and in our SEC filings, which are available free of charge through our website at dynegy.com.

With that, I will now turn it over to our President and CEO, Bob Flexon.

Robert C. Flexon

Good morning, and thank you for joining us this morning. Here with me this morning are several members of Dynegy's management team, including Clint Freeland, our Chief Financial Officer; Catherine Callaway, our General Counsel; and Carolyn Burke, our Chief Administrative Officer. As we announced in January, Kevin Howell, our Chief Operating Officer, stepped down from the COO role, but continues to support us in advisory capacity. He will also aid in the transition of his commercial responsibilities over to Hank Jones, who will be coming on board as Chief Commercial Officer at the end of this month.

Our agenda for today's call is located on Slide 3. We'll follow our traditional agenda with a somewhat scaled back discussion of our 2012 annual and fourth quarter highlights in order to spend time reviewing the Ameren transaction. I'll cover 2012 operational and commercial results, including recent events affecting our California assets. Clint will review the fourth quarter and full year financial performance, as well as provide an update on our PRIDE results for the year. Our final and main topic this morning is our proposed acquisition of Ameren Corp.'s merchant generation and retail businesses, Ameren Energy Resources or AER. This transaction builds upon our investment thesis of creating significant upside opportunities for our shareholders while carefully managing downside risk. Due to the amount of material to be covered this morning, we will extend this call by an extra half-hour, if necessary, to allow ample time for the Q&A discussion.

Highlighted on Slide 4 are several of the significant accomplishments during 2012 that will benefit the company for years to come. Dan Thompson, our Vice President of CoalCo Operations, and his team successfully completed the 7-year $1 billion Consent Decree program that positions our coal fleet to be in full compliance with all current environmental standards and requirements. Our commercial team successfully executed the new long-term rail contract during the third quarter at rates significantly below what had been forecasted. By repaying $325 million of GasCo's and CoalCo's term loan debt, we reduced the annual cash interest cost by $30 million and expect to generate further savings through a full refinancing of our term loans during 2013. Across the company, we continued our emphasis on improving the company through our PRIDE initiative, with the priority on improving fixed cash costs and gross margin and implementing balance sheet efficiencies.

Finally, on October 1, 2012, Dynegy successfully completed its restructuring effort, reducing our net debt by approximately $4 billion and providing a strong foundation to meet today's challenges associated with the current low power and capacity price environment.

It has been a significant and busy year for the company. Each of these accomplishments by our team along with many others has strengthened the company and set the stage for Dynegy's next chapter.

Slide 5 highlights our operational and financial performance. Production volumes for the year were up approximately 20% over the prior year driven by the 70% increase in generation from our gas fleet as a result of improved spark spreads experienced throughout the year. Volumes for the coal fleet declined 10% primarily due to lower off peak pricing in the region and an increase in planned outages period-over-period. Despite these changes in production levels, both the coal and gas fleet maintained the reliable track record, achieving in-market availability of over 90%.

Our fourth quarter and full year 2012 financial performance is in line with our Analyst Day guidance provided in January. Clint will provide additional detail, but the variance to the prior year's principally driven by lower realized power prices for the Coal segment. The annual results were also impacted by lower financial settlements due to the legacy gas put option liabilities.

Our PRIDE efforts met and exceeded our targets established for 2012, and our 2013 guidance remains on track. Clint will cover both of these topics in his prepared remarks.

Coal production on Slide 7 decreased 10% due to lower on- and off-peak pricing in the region and an increase in planned outages, while gas production increased approximately 70% and is attributable to higher on-peak spark spreads for Kendall and Independence, and higher off-peak spark spreads for Ontelaunee. IMA and EAF results for both segments were relatively flat period over period.

While our 2012 safety performance has yet to reflect the improvements made during the course of the year, such as reestablishing plant safety council as well as increasing emphasis on job safety analysis, our year-to-date 2013 performance has shown substantial improvement with only 1 employee recordable [ph]. Safety continues to be a top priority in 2013 as we continue to strive each and every day for an injury-free environment.

Our current hedge positions are shown on Slide 8. As market prices and spark spreads improved, our commercial team layered in more hedges and will continue to do so opportunistically. We continued to maintain a fairly open portfolio in 2014 for the Coal and Gas segments in order to capitalize on what we anticipate will be improved power prices in spark spreads compared to trading values today. Throughout the year, we've updated investors on capacity factors by a facility due to the significant increase in run hours the gas units are experiencing in this gas price environment.

Slide 9 shows the capacity factors for the Gas segment continued to be higher than prior periods, merely due to improved spark spreads in the on- and off-peak hours. Plans for the largest spark spread improvement are Kendall's off-peak spark spreads improved almost $7 per megawatt hour and Moss Landing's on- and off-peak spreads which improved approximately $5 and $10, respectively. Casco Bay's plant spark spreads continued to compress period over period due to localized gas supply constraints. The Coal segment capacity factors were reduced from prior period primarily due to planned outages in addition to lower power prices. However, when removing the impact of outages, the fleet average capacity factor would have been above 85%.

Recent developments impacting our California assets are highlighted on Slide 10. In February, a settlement [ph] was held by the California Public Utilities Commission, California ISO and the California Energy Commission to discuss the need for forward RA procurement as well as operational flexibility necessary to integrate and mitigate the intermittency caused by renewable resources. As we covered at our January Analyst Meeting, the unreliable nature of wind and solar generation requires support from fast-ramping gas-fired resources.

The current Cal ISO market design does not provide the compensation needed either to incent new generation or prevent the retirement of existing facilities that have these desired capabilities. Without quick ramping resources, integrating the growing supply of renewable generation becomes more challenging for the state. The meeting concluded with the California ISO volunteering to implement a stakeholder process to design a framework necessary to create a viable capacity market. We intend to be a proactive participant in this process and the design. Jason Cox from our Regulatory Affairs team sits on the board of Western Power Trading Forum, much has been actively engaged in the development of a forward capacity proposal and we are fully supportive of that proposal.

Key items we would like to be addressed include a forward resource adequacy market that is 3 to 5 years forward of the delivery year; incremental capacity options held once a year to allow for additional capacity to be bought or sold as needed due to changes in load forecasts; the RA market should be centrally administered and allow for bilateral agreement and self-supply with all resources being put into the market; finally, but equally importantly, a centralized auction should place a premium on flexible capacity to accommodate demand swings, and should provide additional compensation compared to non-flexible or intermittent capacity. There is broadening support for these market changes, and we currently anticipate these market design changes could be operational by the 2015, 2016 time frame. With these changes, Moss Landing and Morro Bay facilities, with their fast-ramping and low-turndown capabilities and Oakland with its black start [ph] capabilities will continue to play a key role in meeting the energy needs of California.

In connection with our Morro Bay and Moss Landing contractual dispute with Southern Cal Edison, we initiated an arbitration to settle the Morro Bay tolling agreement and expect to have a resolution during the first quarter of 2014. In connection with the Moss Landing RA capacity dispute, we initiated litigation to resolve the matter. The litigation schedule is expected to be set during a hearing in the second quarter of 2013.

I'll now ask Clint to address the financial results.

Clint Freeland

Thank you, Bob. As outlined on Slide 12, the company had a disappointing finish to 2012, generating consolidated adjusted EBITDA of negative $42 million during the fourth quarter compared to negative $14 million for the same period last year. As in the first 3 quarters of 2012, lower prices net of hedges at the Coal segment and the settlement of legacy option positions negatively impacted results. However, in the fourth quarter, there was additional downward pressure on Coal segment earnings as a result of higher basis differentials between our plants and their nearest liquid trading hubs. These 3 factors reduced gross margin by $91 million compared to last year. However, this was somewhat offset by higher Gas segment net energy margin and a lack of a fourth quarter commercial losses experienced in 2011.

Year-to-date, consolidated adjusted EBITDA totaled $57 million within the $50 million to $60 million range provided at Dynegy's Analyst Day in January compared to $281 million in 2011. The year-over-year decline in results was primarily driven by 3 factors: lower realized prices at the Coal segment, settlement of legacy put options at the Gas segment, and the cancellation of tolling and resource adequacy contracts at our Morro Bay and Moss Landing facilities. Together, these items reduced gross margin by $305 million and were only partially offset by higher net energy margin at the Gas segment, the site amortization add back and lower O&M expenses.

Total available liquidity at March 8, 2013, excluding DNE, stood at $592 million, including $370 million in unrestricted cash, $69 million of restricted cash in our unused collateral accounts and $153 million in the revolver and letter of credit capacity. As previously disclosed, GasCo entered into a new 364-day $150 million revolver in early January, and as of today, remains undrawn and fully available.

Looking to Slide 13, adjusted EBITDA for the Coal and Gas segments before the allocation of corporate G&A expense totaled negative $19 million during the fourth quarter, down from a positive $15 million during the same period last year. As you can see from the segment breakout, the quarter-over-quarter decline was due to weakness at the Coal segment, primarily due to a $12.65 per megawatt hour decline in realized prices, which led to a $62 million reduction in gross margin.

While average INDY Hub day-ahead prices remained relatively flat between the periods, 2 factors contributed to the weakness in realized prices: a significant decline in the average hedge price realized during the period, and a further reduction in the price of power received as a result of basis differentials between the liquid hubs and our plants.

During the fourth quarter of 2011, hedge settlements added on average $7.41 per megawatt hour to the Coal segment's earnings as most of the hedges settled during the quarter were initiated during 2010 and the first half of 2011 when prices were considerably higher. Conversely, a majority of the hedges, which settled during the fourth quarter of 2012, were initiated during the first half of 2012 when power prices were much weaker, locking in average prices which were $4.24 per megawatt hour lower than market during the quarter. The change in average hedge prices alone accounted for a $51 million decline in segment results.

Additionally, the average basis differentials between the liquid hubs and our plants increased by $3.41 per megawatt hour from $5.02 during the fourth quarter of 2011 to $8.43 during the same period in 2012, negatively impacting results by $11 million. These gross margin impacts were partially offset during the quarter by a $7 million reduction in O&M expense.

Gas segment adjusted EBITDA before corporate G&A allocations total negative $2 million during the fourth quarter of 2012 compared to negative $22 million during the fourth quarter of 2011. As previously disclosed, results for the fourth quarter of 2012 were negatively impacted by $29 million in legacy put option settlements. Excluding these settlements, adjusted EBITDA for the quarter would have been positive $27 million or $49 million higher than the fourth quarter of 2011. Higher spark spreads, improved hedge prices, the add back of site amortization and the absence of a fourth quarter commercial loss more than offset lower capacity revenues at our Kendall facility and the loss of tolling and resource adequacy revenues at our Morro Bay and Moss Landing facilities.

For full year 2012, adjusted EBITDA for the Coal and Gas segments before corporate G&A allocations totaled $142 million, down from $398 million in 2011. The $256 million reduction in results was primarily driven by the same factors that impacted the fourth quarter.

Coal segment adjusted EBITDA declined by $223 million, as an $8.70 per megawatt hour decline in average realized prices led to a $191 million year-over-year change in adjusted EBITDA.

Additionally, generation volumes were down 10% as a result of 2 large planned outages at our Havana and Wood River facilities, and lower off-peak generation in response to market pricing, leading to an additional $29 million decline in year-over-year adjusted EBITDA.

Gas segment adjusted EBITDA declined by $33 million during the year ended 2012 compared to the same period in 2011, primarily as a result of $77 million in legacy put option settlements and $58 million in lower capacity, tolling and resource adequacy revenues. These items more than offset a $27 million improvement in net energy margin, $38 million in site amortization add backs, $20 million in lower hedging costs and $10 million in lower operating expenses.

Slide 14 details the company's continued progress in driving both cash flow and balance sheet improvements in its business. During 2012, the company met or exceeded its stated targets for the year, with $31 million in incremental fixed cost reductions through various efforts, including a reduction in the use of activated carbon injections at Baldwin, various procurement initiatives throughout the company and, of course, our headquarters relocation.

We also realized $13 million in gross margin enhancements, primarily through modest improvements in our in-market availability and gas resourcing at Independence, while generating an additional $148 million in balance sheet efficiencies with reductions in cash collateral, improvements in our days payable and successful inventory management. We will continue to focus on improving how we do business to increase the company's cash flow in 2013, and remain committed to delivering an additional $42 million in cash cost savings and gross margin improvements, along with an incremental $83 million in balance sheet efficiency.

In January of this year, we initiated segment and consolidated adjusted EBITDA and free cash flow guidance for 2013, and as outlined on Slide 15, we are reaffirming that guidance today. While we have seen some downward pressure at our Coal segment due to higher-than-forecasted basis differentials in February and the first part of March, this has been partially offset by higher-than-forecasted balance of the year INDY Hub prices. The Gas segment, on the other hand, has benefited from stronger-than-anticipated pricing for our Independence facility. Taking these factors into consideration, we remain comfortable with the adjusted EBITDA and free cash flow guidance ranges provided both at the segment and consolidated levels. However, I would note that our current guidance does not incorporate any impact from the transaction announced today. Any updates related to this will be evaluated at the time of closing.

With that, I'll turn it back over to you, Bob.

Robert C. Flexon

Turning to Slide 17, I'll address today's announcement of our planned purchase of Ameren Energy Resources or AER. This acquisition process occurred over several months, and required thoughtful and careful structuring decisions by both parties to ensure all stakeholder interests were considered and appropriately addressed. I want to thank Tom Voss and his team at Ameren for their dedication and hard work to consummate this transaction and for fostering a very professional and productive relationship between our 2 companies. Dynegy's CoalCo and Ameren's AER coal portfolios are interconnected through the Ameren Illinois transmission system, and building and strengthening our relationship with Ameren is very beneficial for Dynegy.

The portfolio we are acquiring includes all coal generation plants held by AER subsidiaries, Ameren Energy Generating Company or Genco, and Ameren Energy Resources Generating or AERG. In addition, Ameren Energy Marketing or AEM is part of the transaction and includes Ameren Energy Marketing and Homefield Energy. AEM provides Dynegy with an immediate and substantial retail and commercial and industrial business, a strategic goal we have previously established for ourselves. The addition and fit of this acquisition to our current portfolio is also compelling due to the operating synergies and the risk adjusted rate of return profile of this opportunity.

The acquisition of AER is being accomplished through a newly created subsidiary of Dynegy, Illinois Power Holdings or IPH, which will be a ring-fenced, nonrecourse subsidiary other than a $25 million Dynegy guarantee that will observe corporate separateness formalities. In structuring the transition, we established and followed these principles: IPH must stand on its own and be a viable self-sustaining business; Dynegy cannot and will not put its balance sheet at risk; and there is no intent, no plans and no reason to engage in any type of financial restructuring of Genco's public debt.

Prior to covering the transaction details on Slide 18, I'd like to demonstrate the investment thesis for our shareholders. As we covered in our January 2013 Analyst Meeting, the upside embedded in our equity is primarily through our coal portfolio. This transaction requiring minimal to no capital from Dynegy dramatically magnifies our upside leverage for the same fundamental value drivers to which our investors want exposure, tightening reserve margins resulting from retirement, higher power prices, increasing capacity payments and a strengthening national gas curve.

I've illustrated the risk/reward profile point using our sensitivity to natural gas as an example. The chart on the left depicts this asymmetric risk. A $1 move in natural gas for the combined portfolio is 2.2x more leveraging than stand-alone Dynegy, whereas there is no incremental downside due to the ring-fence structure and minimal or no capital being deployed by Dynegy.

To further illustrate the point, a positive $1 per million BTU move in natural gas prices increases annual EBITDA by $150 million or $1.50 per share for Dynegy's stand-alone portfolio. Adding AER to the portfolio more than doubles the uplift to $332 million or from $1.50 to $3.32 per share. This upside leverage cannot be replicated on a stand-alone basis. Theoretically, to obtain this leverage, our outstanding share count would have to be reduced by 55 million shares from 100 million to 45 million shares outstanding, which would require over $1 billion of capital, which obviously is impractical, and you would still retain an equal amount of downside risk. Creating this asymmetric risk return profile while protecting our balance sheet and maintaining our capital allocation flexibility is what makes this opportunity so compelling.

Slide 19 shows a side-by-side comparison of the 2 coal fleets. And as you can see, the portfolios are geographically in the same region, are similar in technology, utilized Powder River Basin coal as the main fuel and will be compliant with the Mercury and Air Toxics Standards in 2015.

In addition, both portfolios have maintained high-capacity factors throughout the recent low natural gas price environment. One difference between the fleets, however, is the gen-weighted average dispatch cost, which is primarily attributable to the difference in the cost of delivered coal. I would note, however, that AER's more favorable base position partially offsets this economic impact.

Slide 20 lists the steps that will occur prior to closing. First, Genco and Ameren will exercise the existing put option agreement that enables Genco to sell their natural gas plants, including Elgin, Grand Tower and Gibson City, to a subsidiary of Ameren. Ameren's purchase of these 3 gas facilities will be at a minimal price of $133 million, which is calculated using the average of 3 appraisals for these assets. These appraisals are required to be updated prior to exercising the put option. And any change in the updated average valuation results in the following treatments: as the updated valuation is less than $133 million, Genco will receive $133 million at closing. If it is greater than $133 million, Genco will receive the higher amount at closing. Furthermore, if Ameren subsequently sells these assets within 2 years after closing, any after-tax proceeds in excess of what Genco received from the appraisal process will be remitted to Genco. Dynegy's newly formed subsidiary, IPH, will then acquire AER.

Slide 21 highlights several of the key transaction terms by counterparty. In addition to the put option agreement just discussed, an additional incremental $60 million in cash will be funded by Ameren to AER and subsidiaries for general corporate purposes. AER and its subsidiaries will also retain $25 million in existing cash, plus $8 million from expected land sale proceeds. Of this total $93 million in incremental cash, $70 million will be at Genco and the remaining $23 million, shared by AERG and AEM. Ameren has also agreed to provide collateral support to these entities for all outstanding contracts and hedges for a 2-year period from the date of closing.

In addition to the cash and 2 years of collateral support to AER from Ameren, AER's consolidated net working capital at closing will be approximately $160 million, which has been determined using historical operating needs and practices. With $226 million in cash, $160 million of working capital and 2 years of collateral support, we believe that AER and its subsidiaries will have the financial resources they need to operate successfully and independently from Dynegy.

Regarding environmental issues, the general principle followed with some exception is that Ameren retained responsibility for all inactive sites and risks outside of the operating plant locations, while the IPH subsidiaries retain responsibility for everything on site of the operating locations. The 2 exceptions to this principle are first, IPH will provide Ameren an indemnity for a potential off-site liabilities associated with coal combustion byproducts up to a maximum of $25 million; and second, Ameren will provide an indemnity to IPH associated with the Dove Creek rail embankment exposure. Dynegy, for its part is providing a $25 million guarantee extending for 2 years beyond the closing date for certain pre-closing payment obligations of IPH and certain post-closing indemnification and reimbursement obligations of IPH.

The transaction benefits are highlighted on Slide 22. Carolyn Burke, our CAO, will lead our integration team, and momentarily will review in more detail the operational benefits and synergies targeted at a $60 million run rate in 2014 with significant upside potential thereafter. Our experience with our PRIDE initiative over the past 18-plus months combined with the diligence we performed gives us the confidence that these synergies are obtainable. Furthermore, this transaction spreads our current general administrative costs as well as additional operations support costs, over a much larger base benefiting our existing business.

Prior to the synergies discussion, I want to highlight the excellent work Ameren has done on moving a substantial portion of its generation from MISO to PJM on Slide 23. Ameren has previously disclosed that Ameren Energy is in the process of expanding its transmission position into PJM. There is approximately 800 megawatts of transmission available to Ameren with no upgrade cost. This newly available capacity, along with the existing 150-megawatt of transmission capacity from the Edwards facility in the PJM, results in Ameren's ability to deliver over 900 megawatts into the PJM energy markets and the ability to participate in the upcoming 2016, 2017 base residual auction. With this capacity potentially leaving Miso for the PJM market, the Ameren coal fleet will benefit from the higher price markets for both energy and capacity, improving earnings and providing greater visibility of capacity payments available in the PJM market. The estimated impact of energy delivered into the PJM market through this transmission is approximately $1.25 per megawatt hour, improvement in busbar prices based on a comparison to busbar LMP pricing during 2011 and 2012. This uplift, assuming full utilization, equates to approximately $10 million per year for the megawatts delivered in the PJM.

The approved unit contingent capacity after adjustment for historical average [ph] rates associated with this available transmission is about 840 megawatts for planning year 2016, 2017. This capacity is eligible to be offered into PJM capacity options. The estimated uplift for capacity payments in 2016 and 2017 versus what the facilities received today would be approximately $35 million based on the 2015, 2016 PJM auction clearing price of $4.14 per kW a month. In addition, the departure of these megawatts from MISO would further tighten reserve margins within MISO.

A significant benefit of this transaction, Ameren's retail business covered on Slide 24. In AEM, we are acquiring an established retail marketing platform that currently reaches customers of MISO, as well as PJM. The customer base is diversified, including municipals, co-ops, commercial, industrial, small business and residential sectors. The Homefield energy brand markets to residual and small business customers and serves 141 communities and nearly 500,000 homes and small businesses.

AEM provides much of what we are seeking to accomplish through our own grassroots retail offering but on a much larger and established scale, something we cannot replicate. Not only does retail realize the benefits from competitively priced retail products backed by owned generation that provides the ability to better manage basis exposure across the Illinois coal assets.

We see growth opportunities in residential sales as the Ameren Illinois market has only seen 20% of residential customers switching to retail providers through 2012, leaving a large pool of available customers. We also see retail growth opportunities in PJM with our existing generation presence in PJM plus additional MISO capacity we'll be placing in PJM, we'll be able to offer very competitive pricing in the combined [ph] territory to grow our presence there.

Carolyn Burke will now address the synergies of the transaction.

Carolyn J. Burke

Thanks, Bob. One of the significant value drivers of this transaction is simply the combination of 2 exceptional coal fleets. Benefits increase exponentially when you combine 2 of the strongest portfolios in the MISO region.

On the Dynegy side, we are able to leverage our very scalable infrastructure across another set of assets and gain an established retail business. As you know, we only just announced our intention to enter into the Illinois retail space in January. This transaction not only saves us the time and costs of building a new business, but we gain a high-quality seasoned team that will be able to take advantage of its new larger portfolios of AER and Dynegy assets.

The AER business, on the other hand, will benefit from our relentless focus on continuous improvement through our PRIDE program. We have a proven track record of driving margin and cost improvements. As Clint discussed, PRIDE has driven over $82 million of fixed cash cost improvement and $25 million in gross margin improvements in just its first 2 years.

We are committed to delivering similar results at AER. Together, our combined operational expertise in safety, environmental and engineering will deliver real value to shareholders.

On Slide 26, we have laid out that real value and what we expect to deliver in year 1. $60 million in total EBITDA run rate improvements through margin, O&M and G&A enhancements. We will be driving increased margin through EFOR improvement as we have with our end market availability improvement programs at Dynegy. We will also look at fuel procurement practices and bring our success and expertise at CoalCo to AER.

On the O&M side, we expect significant synergies through the combination of our engineering, maintenance and outage planning expertise. Our vendor optimization program, successful here at Dynegy, will be rolled out to AER.

Finally, G&A. Our existing infrastructure has managed 20,000 megawatts in the past. It can easily support an additional 4,100 megawatts now. Real programs, real initiatives and real savings. And as is our practice, these are conservative estimates. Once we close the transaction, we expect our combined teams will identify further improvements.

And with that, I'll turn it over to Clint.

Clint Freeland

Thanks, Carolyn. As reflected on Slide 27, AER's 3 subsidiaries have separate and distinct financial profiles. Of the 3 businesses, Genco is the only one with third-party debt, which today totals $825 million and requires annual interest payments of $59 million. With the earliest maturity date being 2018, Genco has 5 years before any refinancing will be required. Maintenance CapEx requirements for the Genco fleet are relatively modest. However, we do expect an uptick in 2016 and 2017 as certain projects previously deferred are pursued.

On the environmental side, most of Genco's CapEx requirements relate to the installation of a scrubber at the Newton facility, which requires an investment of $15 million to $20 million per year through 2017, then ramping up in 2018 and 2019 as major construction takes place. With the debt and CapEx requirements at Genco, liquidity is at a premium, so the transaction has been structured to ensure that the company has over $200 million in cash and sufficient working capital deployed to support the ongoing financial requirements of the business. With only 2 plants, minimal CapEx requirements and no debt outstanding, AERG's liquidity needs are more modest and will be supported with existing working capital deployed in the business at closing and cash balances currently estimated at $23 million, which will be shared between AERG and AEM in an intercompany money pool. With a significant portion of the working capital volatility at AERG and AEM tied to purchases and sales of power between the 2 entities, the money pool arrangement should help even out and reduce intra-month liquidity needs between the companies. We continue to evaluate the need for additional working capital for AERG and AEM, and should additional financing be required, we will consider putting in place a secured working capital line either through a third-party financial institution or, perhaps, by DI.

As Bob mentioned earlier, we expect this transaction to be accretive to adjusted EBITDA in 2014 and free cash flow in 2015 based on what we view to be very reasonable assumptions, as outlined on Slide 28. In addition to using the current NYMEX natural gas curve, our analysis uses heat rates in line with current market implied levels; synergies of $60 million per year, with 80% realized in 2014 and 100% realized in 2015; and CapEx levels outlined on the previous slide. We also assume that MISO capacity prices converge with PJM capacity prices over the medium to long term, but I would note that a majority of that convergence is assumed to take place post 2015 and is not instrumental in achieving our free cash flow accretion target. And with up to 900 megawatts of the AER fleet moving to PJM by 2016, our expectation for MISO capacity price recovery to levels comparable to PJM are at least partially hedged for this fleet.

One of the central themes to Dynegy's value proposition is the company's upside exposure to market recovery and pool retirements in the Midwest.

Earlier in the presentation, Bob walked through the asymmetric risk-return profile of the AER acquisition as it relates to improvements in natural gas prices. But as Slide 29 reflects, this is not just a natural gas dynamic. The same asymmetric relationship exists for other market factors as well, including power prices and capacity prices as coal plant retirements occur over the next several years. With little to no capital allocated to this transaction upfront and no new shares of common stock issued, the acquisition of AER provides current Dynegy shareholders with substantial additional upside potential and, with the transaction structure as described earlier, significant downside protection.

Bob, I'll turn it back to you.

Robert C. Flexon

Thanks, Clint. Slide 31 summarized how we approach this transaction: protect our equity against downside risks, strengthen both portfolios to create upside leverage for our shareholders and preserve Dynegy's balance sheet and capital allocation opportunities.

At this point, Wendy, I'd like to open the line for Q&A.

Question-and-Answer Session

Operator

[Operator Instructions] Our first question today is from Brandon Blossman with Tudor.

Brandon Blossman - Tudor, Pickering, Holt & Co. Securities, Inc., Research Division

Let's see. Just touching on the AER debt a little bit, any covenants that should be of concern over the next 2 or 3 years, and any -- and I assume it's not amortizing debt, correct?

Clint Freeland

That's correct. They're bullet maturities. As it relates to covenants, there really are no financial covenants. The only ratios that are in there really deal with debt incurrence, as well as the ability to make restricted payments out of the entity. But as far as financial covenants that could be triggered, there are none.

Brandon Blossman - Tudor, Pickering, Holt & Co. Securities, Inc., Research Division

Great. And then I guess also just from the purchase and sale agreement perspective, the $25 million guarantee, is that the absolute limit to Dynegy parent liabilities here?

Clint Freeland

That's correct, and that expires 2 years after closing.

Brandon Blossman - Tudor, Pickering, Holt & Co. Securities, Inc., Research Division

Okay, great. And then just one more, and I'll get back in the queue. As far as the hedge profile at AER, I assume it's a fairly big hedge book right now. Do you intend to roll that off as the guarantee from Ameren rolls off?

Clint Freeland

Well, it's roughly 50% hedged for 2014, I guess about 20% hedged in 2015. Our plan would be to, as those roll off, to look to see if there's a way for us to provide -- if there's available credit in the marketplace, do a first-lien type structure. We'll work through that as time goes on. Also, their retail book offers some level of hedge protection for the portfolio as well.

Operator

Our next question is from Jon Cohen with ISI Group.

Jonathan Cohen - ISI Group Inc., Research Division

A couple of questions. First of all, does -- on your conditions to close, does the Illinois Commerce Commission have any ability to review the deal?

Robert C. Flexon

No.

Jonathan Cohen - ISI Group Inc., Research Division

And how do you think FERC will look at market power issues? It looks like 7,000 megawatts of merchant generation in MISO Illinois. I mean, that's a pretty big chunk of that market, right?

Robert C. Flexon

Yes, and we've looked at it with our internal experts, as well as 2 external experts, and all of our analysis shows that this should not come close to creating a market power issue. Actually, we'll ask Catherine Callaway to comment, on our General Counsel.

Catherine B. Callaway

Yes. We've looked at it preliminarily and done as much analysis we can. We intend to make our filings very quickly. We expect the transaction to meet FERC's Section 203 market power test and that we can maintain market-based rate authority.

Jonathan Cohen - ISI Group Inc., Research Division

Okay. And then one other question on the synergies. So the $60 million, does that -- can you break down a little bit of what that includes? Does that include some upside on the rail contracts to Ameren's facilities in line with what you guys were able to get? And does it also include the capacity revenue from that increased sales into PJM?

Clint Freeland

The $60 million is all cost-based synergies. There's no revenue synergies included in that. A good portion of that number is the corporate allocation that comes from Ameren, so that will go away rather swiftly. There is some level of rail procurement synergy in there. There is one contract, one rail contract expiring in the near future. So that's included in there, and then the rest are generally more traditional operating and overhead-type G&A synergies.

Jonathan Cohen - ISI Group Inc., Research Division

Okay. And then I guess one last question on the retail business that you bought. Have you looked at what the retail price that Illinois customers in MISO are paying, the generation component of that relative to what your plant LMPs are? And how much of an uplift is there?

Robert C. Flexon

I'm going to ask Brian Despard, who manages our coal portfolio, to comment on that.

Brian Despard

Yes. Without going into detail about what is included in the Ameren portfolio, what we're seeing in Illinois is C&I rates that are roughly $2 in margin, and residential, we expect is a bit higher than that. So it's fairly competitive in the state, but we're looking at margins probably in the $2 to $3 range.

Jonathan Cohen - ISI Group Inc., Research Division

But is that to INDY Hub, or is that to plant busbar [ph]?

Brian Despard

Plant.

Operator

Our next question is from Brian Chin with Citigroup.

Brian Chin - Citigroup Inc, Research Division

On the competitive retail component, can you give us a sense of what the margin is per megawatt hour and retail sales is?

Brian Despard

Yes. As I just mentioned, looking at the market, not necessarily at the Ameren portfolio but just what we're seeing out in the market, $2 to $3 depending on customer class. The C&I usually has tighter margins. Residential will have a little bit higher margins, so $2 to $3.

Brian Chin - Citigroup Inc, Research Division

Okay. And what is the level of volume that the retail business is selling at current level?

Brian Despard

The Ameren volume is about 50 million megawatt hours a year.

Brian Chin - Citigroup Inc, Research Division

And then just to be clear in case I might have missed this earlier. For the PJM RPM uplift, the $35 million, that uplift is relative to what those plants are currently capturing and whatever bilateral and capacity contracts are in place right now, so that's a net uplift?

Clint Freeland

Yes, that's correct.

Brian Chin - Citigroup Inc, Research Division

And then as part of the deal, do you have any commitments to keep any of the plants in operation for a period -- for a certain period of time, or do you have maximum degree of flexibility to...

Robert C. Flexon

We have [indiscernible].

Operator

Our next question is from Julien Dumoulin-Smith with UBS.

Julien Dumoulin-Smith - UBS Investment Bank, Research Division

First question here on environmental. Just with respect to Illinois MPS averaging policies, do you expect to be able to realize some of the uplift, if you will, from your existing portfolio over to Ameren? And how does that impact the need to pursue environmental retrofits on the Ameren side?

Robert C. Flexon

Julien, all of our assumptions and our planning is that each of the portfolios are standing on their own. There is no ability to do that. Ameren has their existing variance with the Illinois PCB and will continue to operate under that variance assumption.

Julien Dumoulin-Smith - UBS Investment Bank, Research Division

Okay, fair enough. And then you mentioned that the EBITDA is only accretive in '14. Is that meant to suggest that EBITDA is negative in '13 and is comparably for free cash flow in '15? How do you think about that? What are the year-on-year drivers that we should just be aware of that might not necessarily be intuitive?

Robert C. Flexon

Yes. The only reason we started with '14 is just we're assuming this transaction takes pretty much through the end of the year, so we haven't even thought of it in the context of '13. So when we think about first full year of operation, which would be '14, that's where we view EBITDA will be accretive.

Julien Dumoulin-Smith - UBS Investment Bank, Research Division

Got you. And then with respect to the PJM capacity revenues, just to be clear, how much cleared the last auction, if you will? I think it was only about 100 in change, if you will, or about 100 megawatts, and so incrementally, we're going to see up to 840 in this next auction. Is that the right way to think about it?

Robert C. Flexon

That's correct. I mean, the capacity has been granted and offered, if you will, by MISO at PJM, and it's subject only to Ameren's confirmation of the capacity.

Julien Dumoulin-Smith - UBS Investment Bank, Research Division

And so from your perspective, is there any opportunity for further exports? I mean, this is arguably the second or third time this has happened. What's that maximum theoretical, if you can kind of provide some -- quantify?

Robert C. Flexon

We haven't reached beyond that number in terms of looking at the growth. There is, I think, a larger volume than that available on the MISO side. But it would require basically a restart on the PJM side of the entire analysis and modeling process to look for additional capacity at PJM.

Clint Freeland

But Julien, I would add that there are requests both that Ameren has in as well Dynegy has in the queue to try to find those opportunities, and both companies are waiting to hear the results of that work and what, if any, capital would be required to expand that number to something greater than the 900 megawatts. So that's under review as we speak.

Julien Dumoulin-Smith - UBS Investment Bank, Research Division

Great. And then something a little bit further field, California, going back to that for a quick second, what's the latest as it relates to Moss and Morro here? As you look at the portfolio, how much have you been able to contract on Moss 1 and 2 for this year and then your re-contracting efforts in '14 on both VO [ph] units?

Robert C. Flexon

Well, for Morro, at this point, we actually have been dispatched. We're operating under CPM at the moment, and Moss Landing continues under its existing contract, but we have not re-contracted that capacity beyond the expiration of the contract at this point in time.

Lynn A. Lednicky

Not in terms of the toll, but there is -- RFO just came out for summer [ph] capacity, RA capacity, and we'll be participating in that.

Julien Dumoulin-Smith - UBS Investment Bank, Research Division

How long is the existing Morro Bay CPM commitment? I will assume you're getting the full price CPM, but for how long should we be modeling that this year?

Lynn A. Lednicky

It was just through -- it's 60-day CPM, and we've got for 50 megawatts, it's going in the -- here, I believe about mid-April.

Operator

Our next question is from Stephen Byrd with Morgan Stanley.

Stephen Byrd - Morgan Stanley, Research Division

As you look at the fleet of Ameren's assets, you've laid out the environmental spend. Is there a potential for us to be thinking about some asset retirements within the Ameren fleet over time? I think you had a general question on it before, but I just want to understand this. As you assess the fleet here, is there anything that strikes you that you might change in terms of how you approach it versus how Ameren approached it?

Robert C. Flexon

I think when we look at the forward curves and the economics right now at our planning -- and I would say in our planning, we also assumed incremental CapEx to work on increased reliability in EFOR rates and made some assumptions around potential future capital associated with even coal handling and issues such as that, but when we layer all of that in and look at the existing natural gas curve that exists out there using market implied heat rates and our view around capacity, for the foreseeable future, we see all plants as being economic to run. And that decision, obviously, will continuously be evaluated, and we'd make the right decision at that point in time. The real ramp-up in capital spend really starts in the 2017 time frame. So I think what we'll see as a company is that we'll certainly continue on with the assets as long as they're economical, which, again, we see that being the case. And certainly, in a post-MATS compliance world, we certainly expect stronger capacity payments, higher power prices, so furthering the economic viability of these plants from even what we've built into our base level assumptions.

Stephen Byrd - Morgan Stanley, Research Division

Understood, great. And then just thinking about the put option, the minimum is $133 million. Given those assets, there certainly seems to be a reasonably good chance that the price is higher than that, potentially significantly higher. What would your -- assuming that it were higher, what should we be thinking about in terms of the usage of that cash? Or would that just basically stay within the Genco for liquidity purposes? Or if it were significantly higher, would you think about other uses for that capital?

Robert C. Flexon

No, that cash goes into Genco for Genco operating needs.

Operator

Our next question is from Terran Miller with Cantor Fitzgerald.

Terran Miller

I might have missed this, but in terms of the $60 million of synergies, what is the breakdown between what's going to be realized at the individual businesses? Does the bulk of that accrete to Ameren gen, or does a significant portion of that go to Dynegy?

Clint Freeland

Well, those synergies, the $60 million within AER and its subsidiaries, now some of that, again, relates to a fairly substantial corporate overhead charge that will be replaced with a Dynegy overhead charge, if you will. So that will be spread amongst the entities. How that $60 million ultimately breaks down between the various subsidiaries at this point in time, we don't want to get that granular until we spent a lot more time around specific identification and how we want to organize things as we go forward. That's as close as I can get for you, Terran, on that.

Terran Miller

Okay. Just a follow-up then. They have talked about $30 million to $35 million of corporate allocation, so are you saying that the $60 million includes that going away and it will be replaced by an allocation from Dynegy? Or is the $60 million net of that savings for what the Dynegy allocation will be?

Clint Freeland

The allocation that we've done our planning around is not quite as high as that number, but that -- but your statement is correct that that number would go away. And then as Dynegy looks to reallocate its corporate overhead to GasCo, CoalCo and now AER, we need to come up with the right fair arms-length methodology in all 3 of those units.

Terran Miller

Okay. So that is gross before the Dynegy allocation, so that will be an offset to that $60 million?

Clint Freeland

Yes, that's correct.

Operator

Our next question is from Lance Ettus with Tuohy Brothers.

Lance Ettus

Obviously, I think you'll be up to close to 14 gigawatts of capacity, but you have a decent amount of that in the Midwest, obviously. So does this preclude you? And there's tremendous synergy opportunities, sorry about the long-winded question here. But can you guys do more deals potentially in the Midwest after this? I know that Mission Energy is bankrupt, so maybe that's in play. I guess comments on that, and also, I have one follow-up question.

Robert C. Flexon

Lance, I actually don't know the answer to that question. I presume it depends on the specific market as to what level of market power would exist there, so that would have be an analysis to an asset-by-asset basis, and I -- we haven't looked at that, so I don't really know the answer to that. I have to say that right now, particularly after spending the last 3 months working on this, I can't even think about another one at this point in time. I mean, the priority for us is to run and execute the Dynegy businesses really, really well and integrate this acquisition quickly, efficiently and run it very, very well. And to even think about anything, I mean, I'm speaking from my perspective, for us to think about anything beyond that at this point in time, I just haven't even begun to think that because these 2 priorities are so significant to make sure we get this done right and we have the successful enterprise is where my priority is completely focused on from this point forward.

Lance Ettus

Okay. And is there -- obviously, the synergies, the larger you get in merchant generation, but is there increased synergies to be more concentrated in more fuel types in more coal plants versus a diverse mix, or does it not matter?

Robert C. Flexon

I think it absolutely matters. I mean, you've got the skill set. You've got similar technologies, your central engineering units, your scale on working with coal providers or coal transport companies, so it makes a big difference. The one other thing to your earlier question that we haven't really spoke about yet on this call, when we think about priorities for 2013, we talked about, obviously, running Dynegy well and being very successful on integrating this transaction. Doing our corporate level refinancing is a priority that immediately takes center stage now. We've been delaying that because of this acquisition. Now that this acquisition is announced, we're prepared now to move forward very quickly on our refinancing, which is a critical priority as we go forward. Substantial value creation is on the table by getting that done quickly.

Operator

Our next question is from Jason Mandel with RBC Capital Markets.

Jason Mandel

I just want to make sure I clarify and understand best what the cash is going to look like at Genco and AERG. I realize you've provided some good information, but there's some bits and pieces floating around. Can you talk about -- you guys have mentioned the $70 million of cash in Genco. I presume that's in addition to the $133 million that comes in from the asset sale? And as a separate comments about the $60 million contribution, and then of course, there is the $60 million expected from tax sharing during 2013 from Ameren, and given this isn't going to close until the end of the year, just curious how all those play into sort of pro forma year end.

Robert C. Flexon

Yes, Jason, let me just -- because we did throw a lot of numbers out there. So total cash at AER and subsidiaries will be $226 million. Of that $226 million, $203 million would be at Genco, and then $23 million would be shared between AERG and AEM.

Jason Mandel

Okay, perfect. And just to clarify, for any differences that occur throughout the year, that would just be sort of settled up at the end of the year, and those are going to be the balances for the purchase and sale agreement.

Robert C. Flexon

That's correct.

Operator

Our next question is from Jon Cohen with ISI Group.

Jonathan Cohen - ISI Group Inc., Research Division

I just had a follow-up on the dispatch costs. I think your fleet was $17 a megawatt hour, and you're saying Ameren's is $23. Can you give us a sense of what the differences are? Is it just rail transportation? And if you were able to renegotiate...

Robert C. Flexon

The $17, we're still operating under our legacy coal transportation contract that goes back quite a few years. Theirs have been more recently priced to market in the past several years, so that's the primary difference. Also, the coal commodity cost for Ameren's fleet tend to be higher because they do more longer-term purchasing. We've done more -- we tend to do our pricing in the prompt year. PRB coal has the history of having the contango that disappears each time they get towards the prompt year. So it's really when you think about coal transportation and coal commodity costs, that's the difference. When our new rail contract starts in '14, that will take our number from $17 upwards to between $19 and $20, so then the difference narrows. But then the other point that I made, even though that our dispatch costs would be still a few dollars lower, their basis is lower than ours, so they have an economic advantage there where their plant, in general, dispatch at a differential to the hub of $2 to $3, where we're right now, $4 to $5 to $6, depending on what month you're talking about. So when you take all of those factors into consideration, 2014 and moving forward, that difference on a kind of a gross margin basis really flattens out pretty close.

Jonathan Cohen - ISI Group Inc., Research Division

Okay. And to the extent that some of that $60 million is for rail transportation cost synergies, that will reduce their dispatch cost and presumably increase their capacity factors?

Robert C. Flexon

That's our goal.

Operator

[Operator Instructions] Our next question is from Stephen Byrd with Morgan Stanley.

Stephen Byrd - Morgan Stanley, Research Division

Just one follow-up. Just thinking about that gas asset, could you just talk to the rationale for not acquiring the gas assets?

Robert C. Flexon

Sure. From the Dynegy perspective, the one thing that we found very difficult to address was the put option structure that was embedded between Genco and affiliated companies. And to try to work through that put option structure and getting in the middle of that is not something that we felt comfortable doing. So the arrangement that we worked out with the Ameren team is that they would handle the put option, so that was really the driver between separating the gas and coal. And also, what we're really interested in here, too, was obviously taking a coal fleet that's almost identical to our coal fleet and realize the benefits of the scale of putting those 2 together. So it made for a cleaner, more easily executed contract.

Operator

Our next question is from Terran Miller with Cantor Fitzgerald.

Terran Miller

Just a separate question. On Newton, do you have an updated estimate of what you think the scrubber is going to cost going forward?

Robert C. Flexon

I think our estimates around that is that the absolute cost is about $500 million, of which about $200 million has been spent. I have Dan Thompson from CoalCo here, who can comment on that.

Daniel Thompson

Yes. Bob, the total direct cost is right there at -- you figure $500 million -- excuse me, $450 million. And then you have another $50 million of other costs. And then on top of that, you got the AFUDC [ph], so our modeling reflected the Ameren estimates.

Robert C. Flexon

And of that amount, approximately $200 million has been...

Daniel Thompson

Yes. Bob, about $230 million, $240 million has been spent and maybe north of that at this point, but about $240 million has been spent to date.

Terran Miller

Okay. And you’re comfortable at this point that that number doesn't go up if you continue to spend the $15 million to $20 million a year through 2017?

Daniel Thompson

That $15 million to $20 million that Clint referred to is in the plan, and that's consistent with our view and what Ameren's plan is.

Terran Miller

Okay. And those numbers were as of year-end '12, I assume, right, the $200 million spent?

Daniel Thompson

Yes.

Robert C. Flexon

Fairly close to that. I'm not sure if some of that...

Terran Miller

Okay. But that's the approximate date for the number?

Robert C. Flexon

Yes.

Operator

Our next question is from Amer Tiwana with CRT Capital.

Amer Tiwana - CRT Capital Group LLC

I wanted to sort of confirm that you're still planning on refinancing at the DI level, and you had given an estimate for additional liquidity that would come onto the balance sheet from the restricted cash becoming unrestricted, if that's still true.

Clint Freeland

Yes. I think this transaction really does not change our thinking around the refinancing. So I think at this point, our plan would be to still target refinancing at the DI level. And as you said, our plan is to refinance it in a way that does free up the restricted cash that's currently on our balance sheet and make that unrestricted and available at the DI level. So from my perspective, nothing really has changed on that front.

Operator

Thank you. And I'm currently showing no questions.

Clint Freeland

Okay. Well, I'd like to thank everybody for dialing in, and that this point, I'll conclude the call. Thank you, Wendy.

Operator

Thank you. This does conclude today's conference. Thank you very much for joining. You may disconnect at this time.

Executives

Laura Hrehor

Robert C. Flexon - Chief Executive Officer, President and Director

Clint Freeland - Chief Financial Officer and Executive Vice President

Carolyn J. Burke - Former Principal Accounting Officer, Vice President and Controller

Catherine B. Callaway - Chief Compliance Officer, Executive Vice President and General Counsel

Brian Despard

Lynn A. Lednicky - Executive Vice President of Operations

Daniel Thompson

Analysts

Brandon Blossman - Tudor, Pickering, Holt & Co. Securities, Inc., Research Division

Jonathan Cohen - ISI Group Inc., Research Division

Brian Chin - Citigroup Inc, Research Division

Julien Dumoulin-Smith - UBS Investment Bank, Research Division

Stephen Byrd - Morgan Stanley, Research Division

Terran Miller

Lance Ettus

Jason Mandel

Amer Tiwana - CRT Capital Group LLC

Dynegy (DYN) Q4 2012 Earnings Call March 14, 2013 9:00 AM ET

Operator

Hello, and welcome to the Dynegy Inc. 2012 Financial Results Teleconference. At the request of Dynegy, the conference is being recorded for instant replay purposes. [Operator Instructions] I'd now like to turn the conference over to Ms. Laura Hrehor, Managing Director, Investor Relations. Ma'am, you may begin.

Laura Hrehor

Good morning, everyone, and welcome to Dynegy's investor conference call and webcast covering the company's annual and fourth quarter 2012 results, and Dynegy's proposed transaction with Ameren Corp.

As is our customary practice, before we begin this morning, I would like to remind you that our call will include statements reflecting assumptions, expectations, projections, intentions or beliefs about future events and views of market dynamics. These and other statements not relating strictly to historical or current facts are intended as forward-looking statements. Actual results though may vary materially from those expressed or implied in any forward-looking statements. For a description of the factors that may cause such a variance, I would direct you to the forward-looking statements legend contained in today's news release and in our SEC filings, which are available free of charge through our website at dynegy.com.

With that, I will now turn it over to our President and CEO, Bob Flexon.

Robert C. Flexon - Chief Executive Officer, President and Director

Good morning, and thank you for joining us this morning. Here with me this morning are several members of Dynegy's management team, including Clint Freeland, our Chief Financial Officer; Catherine Callaway, our General Counsel; and Carolyn Burke, our Chief Administrative Officer. As we announced in January, Kevin Howell, our Chief Operating Officer, stepped down from the COO role, but continues to support us in advisory capacity. He will also aid in the transition of his commercial responsibilities over to Hank Jones, who will be coming on board as Chief Commercial Officer at the end of this month.

Our agenda for today's call is located on Slide 3. We'll follow our traditional agenda with a somewhat scaled back discussion of our 2012 annual and fourth quarter highlights in order to spend time reviewing the Ameren transaction. I'll cover 2012 operational and commercial results, including recent events affecting our California assets. Clint will review the fourth quarter and full year financial performance, as well as provide an update on our PRIDE results for the year. Our final and main topic this morning is our proposed acquisition of Ameren Corp.'s merchant generation and retail businesses, Ameren Energy Resources or AER. This transaction builds upon our investment thesis of creating significant upside opportunities for our shareholders while carefully managing downside risk. Due to the amount of material to be covered this morning, we will extend this call by an extra half-hour, if necessary, to allow ample time for the Q&A discussion.

Highlighted on Slide 4 are several of the significant accomplishments during 2012 that will benefit the company for years to come. Dan Thompson, our Vice President of CoalCo Operations, and his team successfully completed the 7-year $1 billion Consent Decree program that positions our coal fleet to be in full compliance with all current environmental standards and requirements. Our commercial team successfully executed the new long-term rail contract during the third quarter at rates significantly below what had been forecasted. By repaying $325 million of GasCo's and CoalCo's term loan debt, we reduced the annual cash interest cost by $30 million and expect to generate further savings through a full refinancing of our term loans during 2013. Across the company, we continued our emphasis on improving the company through our PRIDE initiative, with the priority on improving fixed cash costs and gross margin and implementing balance sheet efficiencies.

Finally, on October 1, 2012, Dynegy successfully completed its restructuring effort, reducing our net debt by approximately $4 billion and providing a strong foundation to meet today's challenges associated with the current low power and capacity price environment.

It has been a significant and busy year for the company. Each of these accomplishments by our team along with many others has strengthened the company and set the stage for Dynegy's next chapter.

Slide 5 highlights our operational and financial performance. Production volumes for the year were up approximately 20% over the prior year driven by the 70% increase in generation from our gas fleet as a result of improved spark spreads experienced throughout the year. Volumes for the coal fleet declined 10% primarily due to lower off peak pricing in the region and an increase in planned outages period-over-period. Despite these changes in production levels, both the coal and gas fleet maintained the reliable track record, achieving in-market availability of over 90%.

Our fourth quarter and full year 2012 financial performance is in line with our Analyst Day guidance provided in January. Clint will provide additional detail, but the variance to the prior year's principally driven by lower realized power prices for the Coal segment. The annual results were also impacted by lower financial settlements due to the legacy gas put option liabilities.

Our PRIDE efforts met and exceeded our targets established for 2012, and our 2013 guidance remains on track. Clint will cover both of these topics in his prepared remarks.

Coal production on Slide 7 decreased 10% due to lower on- and off-peak pricing in the region and an increase in planned outages, while gas production increased approximately 70% and is attributable to higher on-peak spark spreads for Kendall and Independence, and higher off-peak spark spreads for Ontelaunee. IMA and EAF results for both segments were relatively flat period over period.

While our 2012 safety performance has yet to reflect the improvements made during the course of the year, such as reestablishing plant safety council as well as increasing emphasis on job safety analysis, our year-to-date 2013 performance has shown substantial improvement with only 1 employee recordable [ph]. Safety continues to be a top priority in 2013 as we continue to strive each and every day for an injury-free environment.

Our current hedge positions are shown on Slide 8. As market prices and spark spreads improved, our commercial team layered in more hedges and will continue to do so opportunistically. We continued to maintain a fairly open portfolio in 2014 for the Coal and Gas segments in order to capitalize on what we anticipate will be improved power prices in spark spreads compared to trading values today. Throughout the year, we've updated investors on capacity factors by a facility due to the significant increase in run hours the gas units are experiencing in this gas price environment.

Slide 9 shows the capacity factors for the Gas segment continued to be higher than prior periods, merely due to improved spark spreads in the on- and off-peak hours. Plans for the largest spark spread improvement are Kendall's off-peak spark spreads improved almost $7 per megawatt hour and Moss Landing's on- and off-peak spreads which improved approximately $5 and $10, respectively. Casco Bay's plant spark spreads continued to compress period over period due to localized gas supply constraints. The Coal segment capacity factors were reduced from prior period primarily due to planned outages in addition to lower power prices. However, when removing the impact of outages, the fleet average capacity factor would have been above 85%.

Recent developments impacting our California assets are highlighted on Slide 10. In February, a settlement [ph] was held by the California Public Utilities Commission, California ISO and the California Energy Commission to discuss the need for forward RA procurement as well as operational flexibility necessary to integrate and mitigate the intermittency caused by renewable resources. As we covered at our January Analyst Meeting, the unreliable nature of wind and solar generation requires support from fast-ramping gas-fired resources.

The current Cal ISO market design does not provide the compensation needed either to incent new generation or prevent the retirement of existing facilities that have these desired capabilities. Without quick ramping resources, integrating the growing supply of renewable generation becomes more challenging for the state. The meeting concluded with the California ISO volunteering to implement a stakeholder process to design a framework necessary to create a viable capacity market. We intend to be a proactive participant in this process and the design. Jason Cox from our Regulatory Affairs team sits on the board of Western Power Trading Forum, much has been actively engaged in the development of a forward capacity proposal and we are fully supportive of that proposal.

Key items we would like to be addressed include a forward resource adequacy market that is 3 to 5 years forward of the delivery year; incremental capacity options held once a year to allow for additional capacity to be bought or sold as needed due to changes in load forecasts; the RA market should be centrally administered and allow for bilateral agreement and self-supply with all resources being put into the market; finally, but equally importantly, a centralized auction should place a premium on flexible capacity to accommodate demand swings, and should provide additional compensation compared to non-flexible or intermittent capacity. There is broadening support for these market changes, and we currently anticipate these market design changes could be operational by the 2015, 2016 time frame. With these changes, Moss Landing and Morro Bay facilities, with their fast-ramping and low-turndown capabilities and Oakland with its black start [ph] capabilities will continue to play a key role in meeting the energy needs of California.

In connection with our Morro Bay and Moss Landing contractual dispute with Southern Cal Edison, we initiated an arbitration to settle the Morro Bay tolling agreement and expect to have a resolution during the first quarter of 2014. In connection with the Moss Landing RA capacity dispute, we initiated litigation to resolve the matter. The litigation schedule is expected to be set during a hearing in the second quarter of 2013.

I'll now ask Clint to address the financial results.

Clint Freeland - Chief Financial Officer and Executive Vice President

Thank you, Bob. As outlined on Slide 12, the company had a disappointing finish to 2012, generating consolidated adjusted EBITDA of negative $42 million during the fourth quarter compared to negative $14 million for the same period last year. As in the first 3 quarters of 2012, lower prices net of hedges at the Coal segment and the settlement of legacy option positions negatively impacted results. However, in the fourth quarter, there was additional downward pressure on Coal segment earnings as a result of higher basis differentials between our plants and their nearest liquid trading hubs. These 3 factors reduced gross margin by $91 million compared to last year. However, this was somewhat offset by higher Gas segment net energy margin and a lack of a fourth quarter commercial losses experienced in 2011.

Year-to-date, consolidated adjusted EBITDA totaled $57 million within the $50 million to $60 million range provided at Dynegy's Analyst Day in January compared to $281 million in 2011. The year-over-year decline in results was primarily driven by 3 factors: lower realized prices at the Coal segment, settlement of legacy put options at the Gas segment, and the cancellation of tolling and resource adequacy contracts at our Morro Bay and Moss Landing facilities. Together, these items reduced gross margin by $305 million and were only partially offset by higher net energy margin at the Gas segment, the site amortization add back and lower O&M expenses.

Total available liquidity at March 8, 2013, excluding DNE, stood at $592 million, including $370 million in unrestricted cash, $69 million of restricted cash in our unused collateral accounts and $153 million in the revolver and letter of credit capacity. As previously disclosed, GasCo entered into a new 364-day $150 million revolver in early January, and as of today, remains undrawn and fully available.

Looking to Slide 13, adjusted EBITDA for the Coal and Gas segments before the allocation of corporate G&A expense totaled negative $19 million during the fourth quarter, down from a positive $15 million during the same period last year. As you can see from the segment breakout, the quarter-over-quarter decline was due to weakness at the Coal segment, primarily due to a $12.65 per megawatt hour decline in realized prices, which led to a $62 million reduction in gross margin.

While average INDY Hub day-ahead prices remained relatively flat between the periods, 2 factors contributed to the weakness in realized prices: a significant decline in the average hedge price realized during the period, and a further reduction in the price of power received as a result of basis differentials between the liquid hubs and our plants.

During the fourth quarter of 2011, hedge settlements added on average $7.41 per megawatt hour to the Coal segment's earnings as most of the hedges settled during the quarter were initiated during 2010 and the first half of 2011 when prices were considerably higher. Conversely, a majority of the hedges, which settled during the fourth quarter of 2012, were initiated during the first half of 2012 when power prices were much weaker, locking in average prices which were $4.24 per megawatt hour lower than market during the quarter. The change in average hedge prices alone accounted for a $51 million decline in segment results.

Additionally, the average basis differentials between the liquid hubs and our plants increased by $3.41 per megawatt hour from $5.02 during the fourth quarter of 2011 to $8.43 during the same period in 2012, negatively impacting results by $11 million. These gross margin impacts were partially offset during the quarter by a $7 million reduction in O&M expense.

Gas segment adjusted EBITDA before corporate G&A allocations total negative $2 million during the fourth quarter of 2012 compared to negative $22 million during the fourth quarter of 2011. As previously disclosed, results for the fourth quarter of 2012 were negatively impacted by $29 million in legacy put option settlements. Excluding these settlements, adjusted EBITDA for the quarter would have been positive $27 million or $49 million higher than the fourth quarter of 2011. Higher spark spreads, improved hedge prices, the add back of site amortization and the absence of a fourth quarter commercial loss more than offset lower capacity revenues at our Kendall facility and the loss of tolling and resource adequacy revenues at our Morro Bay and Moss Landing facilities.

For full year 2012, adjusted EBITDA for the Coal and Gas segments before corporate G&A allocations totaled $142 million, down from $398 million in 2011. The $256 million reduction in results was primarily driven by the same factors that impacted the fourth quarter.

Coal segment adjusted EBITDA declined by $223 million, as an $8.70 per megawatt hour decline in average realized prices led to a $191 million year-over-year change in adjusted EBITDA.

Additionally, generation volumes were down 10% as a result of 2 large planned outages at our Havana and Wood River facilities, and lower off-peak generation in response to market pricing, leading to an additional $29 million decline in year-over-year adjusted EBITDA.

Gas segment adjusted EBITDA declined by $33 million during the year ended 2012 compared to the same period in 2011, primarily as a result of $77 million in legacy put option settlements and $58 million in lower capacity, tolling and resource adequacy revenues. These items more than offset a $27 million improvement in net energy margin, $38 million in site amortization add backs, $20 million in lower hedging costs and $10 million in lower operating expenses.

Slide 14 details the company's continued progress in driving both cash flow and balance sheet improvements in its business. During 2012, the company met or exceeded its stated targets for the year, with $31 million in incremental fixed cost reductions through various efforts, including a reduction in the use of activated carbon injections at Baldwin, various procurement initiatives throughout the company and, of course, our headquarters relocation.

We also realized $13 million in gross margin enhancements, primarily through modest improvements in our in-market availability and gas resourcing at Independence, while generating an additional $148 million in balance sheet efficiencies with reductions in cash collateral, improvements in our days payable and successful inventory management. We will continue to focus on improving how we do business to increase the company's cash flow in

2013, and remain committed to delivering an additional $42 million in cash cost savings and gross margin improvements, along with an incremental $83 million in balance sheet efficiency.

In January of this year, we initiated segment and consolidated adjusted EBITDA and free cash flow guidance for 2013, and as outlined on Slide 15, we are reaffirming that guidance today. While we have seen some downward pressure at our Coal segment due to higher-than-forecasted basis differentials in February and the first part of March, this has been partially offset by higher-than-forecasted balance of the year INDY Hub prices. The Gas segment, on the other hand, has benefited from stronger-than-anticipated pricing for our Independence facility. Taking these factors into consideration, we remain comfortable with the adjusted EBITDA and free cash flow guidance ranges provided both at the segment and consolidated levels. However, I would note that our current guidance does not incorporate any impact from the transaction announced today. Any updates related to this will be evaluated at the time of closing.

With that, I'll turn it back over to you, Bob.

Robert C. Flexon - Chief Executive Officer, President and Director

Turning to Slide 17, I'll address today's announcement of our planned purchase of Ameren Energy Resources or AER. This acquisition process occurred over several months, and required thoughtful and careful structuring decisions by both parties to ensure all stakeholder interests were considered and appropriately addressed. I want to thank Tom Voss and his team at Ameren for their dedication and hard work to consummate this transaction and for fostering a very professional and productive relationship between our 2 companies. Dynegy's CoalCo and Ameren's AER coal portfolios are interconnected through the Ameren Illinois transmission system, and building and strengthening our relationship with Ameren is very beneficial for Dynegy.

The portfolio we are acquiring includes all coal generation plants held by AER subsidiaries, Ameren Energy Generating Company or Genco, and Ameren Energy Resources Generating or AERG. In addition, Ameren Energy Marketing or AEM is part of the transaction and includes Ameren Energy Marketing and Homefield Energy. AEM provides Dynegy with an immediate and substantial retail and commercial and industrial business, a strategic goal we have previously established for ourselves. The addition and fit of this acquisition to our current portfolio is also compelling due to the operating synergies and the risk adjusted rate of return profile of this opportunity.

The acquisition of AER is being accomplished through a newly created subsidiary of Dynegy, Illinois Power Holdings or IPH, which will be a ring-fenced, nonrecourse subsidiary other than a $25 million Dynegy guarantee that will observe corporate separateness formalities. In structuring the transition, we established and followed these principles: IPH must stand on its own and be a viable self-sustaining business; Dynegy cannot and will not put its balance sheet at risk; and there is no intent, no plans and no reason to engage in any type of financial restructuring of Genco's public debt.

Prior to covering the transaction details on Slide 18, I'd like to demonstrate the investment thesis for our shareholders. As we covered in our January 2013 Analyst Meeting, the upside embedded in our equity is primarily through our coal portfolio. This transaction requiring minimal to no capital from Dynegy dramatically magnifies our upside leverage for the same fundamental value drivers to which our investors want exposure, tightening reserve margins resulting from retirement, higher power prices, increasing capacity payments and a strengthening national gas curve.

I've illustrated the risk/reward profile point using our sensitivity to natural gas as an example. The chart on the left depicts this asymmetric risk. A $1 move in natural gas for the combined portfolio is 2.2x more leveraging than stand-alone Dynegy, whereas there is no incremental downside due to the ring-fence structure and minimal or no capital being deployed by Dynegy.

To further illustrate the point, a positive $1 per million BTU move in natural gas prices increases annual EBITDA by $150 million or $1.50 per share for Dynegy's stand-alone portfolio. Adding AER to the portfolio more than doubles the uplift to $332 million or from $1.50 to $3.32 per share. This upside leverage cannot be replicated on a stand-alone basis. Theoretically, to obtain this leverage, our outstanding share count would have to be reduced by 55 million shares from 100 million to 45 million shares outstanding, which would require over $1 billion of capital, which obviously is impractical, and you would still retain an equal amount of downside risk. Creating this asymmetric risk return profile while protecting our balance sheet and maintaining our capital allocation flexibility is what makes this opportunity so compelling.

Slide 19 shows a side-by-side comparison of the 2 coal fleets. And as you can see, the portfolios are geographically in the same region, are similar in technology, utilized Powder River Basin coal as the main fuel and will be compliant with the Mercury and Air Toxics Standards in 2015.

In addition, both portfolios have maintained high-capacity factors throughout the recent low natural gas price environment. One difference between the fleets, however, is the gen-weighted average dispatch cost, which is primarily attributable to the difference in the cost of delivered coal. I would note, however, that AER's more favorable base position partially offsets this economic impact.

Slide 20 lists the steps that will occur prior to closing. First, Genco and Ameren will exercise the existing put option agreement that enables Genco to sell their natural gas plants, including Elgin, Grand Tower and Gibson City, to a subsidiary of Ameren. Ameren's purchase of these 3 gas facilities will be at a minimal price of $133 million, which is calculated using the average of 3 appraisals for these assets. These appraisals are required to be updated prior to exercising the put option. And any change in the updated average valuation results in the following treatments: as the updated valuation is less than $133 million, Genco will receive $133 million at closing. If it is greater than $133 million, Genco will receive the higher amount at closing. Furthermore, if Ameren subsequently sells these assets within 2 years after closing, any after-tax proceeds in excess of what Genco received from the appraisal process will be remitted to Genco. Dynegy's newly formed subsidiary, IPH, will then acquire AER.

Slide 21 highlights several of the key transaction terms by counterparty. In addition to the put option agreement just discussed, an additional incremental $60 million in cash will be funded by Ameren to AER and subsidiaries for general corporate purposes. AER and its subsidiaries will also retain $25 million in existing cash, plus $8 million from expected land sale proceeds. Of this total $93 million in incremental cash, $70 million will be at Genco and the remaining $23 million, shared by AERG and AEM. Ameren has also agreed to provide collateral support to these entities for all outstanding contracts and hedges for a 2-year period from the date of closing.

In addition to the cash and 2 years of collateral support to AER from Ameren, AER's consolidated net working capital at closing will be approximately $160 million, which has been determined using historical operating needs and practices. With $226 million in cash, $160 million of working capital and 2 years of collateral support, we believe that AER and its subsidiaries will have the financial resources they need to operate successfully and independently from Dynegy.

Regarding environmental issues, the general principle followed with some exception is that Ameren retained responsibility for all inactive sites and risks outside of the operating plant locations, while the IPH subsidiaries retain responsibility for everything on site of the operating locations. The 2 exceptions to this principle are first, IPH will provide Ameren an indemnity for a potential off-site liabilities associated with coal combustion byproducts up to a maximum of $25 million; and second, Ameren will provide an indemnity to IPH associated with the Dove Creek rail embankment exposure. Dynegy, for its part is providing a $25 million guarantee extending for 2 years beyond the closing date for certain pre-closing payment obligations of IPH and certain post-closing indemnification and reimbursement obligations of IPH.

The transaction benefits are highlighted on Slide 22. Carolyn Burke, our CAO, will lead our integration team, and momentarily will review in more detail the operational benefits and synergies targeted at a $60 million run rate in 2014 with significant upside potential thereafter. Our experience with our PRIDE initiative over the past 18-plus months combined with the diligence we performed gives us the confidence that these synergies are obtainable. Furthermore, this transaction spreads our current general administrative costs as well as additional operations support costs, over a much larger base benefiting our existing business.

Prior to the synergies discussion, I want to highlight the excellent work Ameren has done on moving a substantial portion of its generation from MISO to PJM on Slide 23. Ameren has previously disclosed that Ameren Energy is in the process of expanding its transmission position into PJM. There is approximately 800 megawatts of transmission available to Ameren with no upgrade cost. This newly available capacity, along with the existing 150-megawatt of transmission capacity from the Edwards facility in the PJM, results in Ameren's ability to deliver over 900 megawatts into the PJM energy markets and the ability to participate in the upcoming 2016, 2017 base residual auction. With this capacity potentially leaving Miso for the PJM market, the Ameren coal fleet will benefit from the higher price markets for both energy and capacity, improving earnings and providing greater visibility of capacity payments available in the PJM market. The estimated impact of energy delivered into the PJM market through this transmission is approximately $1.25 per megawatt hour, improvement in busbar prices based on a comparison to busbar LMP pricing during 2011 and 2012. This uplift, assuming full utilization, equates to approximately $10 million per year for the megawatts delivered in the PJM.

The approved unit contingent capacity after adjustment for historical average [ph] rates associated with this available transmission is about 840 megawatts for planning year 2016, 2017. This capacity is eligible to be offered into PJM capacity options. The estimated uplift for capacity payments in 2016 and 2017 versus what the facilities received today would be approximately $35 million based on the 2015, 2016 PJM auction clearing price of $4.14 per kW a month. In addition, the departure of these megawatts from MISO would further tighten reserve margins within MISO.

A significant benefit of this transaction, Ameren's retail business covered on Slide 24. In AEM, we are acquiring an established retail marketing platform that currently reaches customers of MISO, as well as PJM. The customer base is diversified, including municipals, co-ops, commercial, industrial, small business and residential sectors. The Homefield energy brand markets to residual and small business customers and serves 141 communities and nearly 500,000 homes and small businesses.

AEM provides much of what we are seeking to accomplish through our own grassroots retail offering but on a much larger and established scale, something we cannot replicate. Not only does retail realize the benefits from competitively priced retail products backed by owned generation that provides the ability to better manage basis exposure across the Illinois coal assets.

We see growth opportunities in residential sales as the Ameren Illinois market has only seen 20% of residential customers switching to retail providers through 2012, leaving a large pool of available customers. We also see retail growth opportunities in PJM with our existing generation presence in PJM plus additional MISO capacity we'll be placing in PJM, we'll be able to offer very competitive pricing in the combined [ph] territory to grow our presence there.

Carolyn Burke will now address the synergies of the transaction.

Carolyn J. Burke - Former Principal Accounting Officer, Vice President and Controller

Thanks, Bob. One of the significant value drivers of this transaction is simply the combination of 2 exceptional coal fleets. Benefits increase exponentially when you combine 2 of the strongest portfolios in the MISO region.

On the Dynegy side, we are able to leverage our very scalable infrastructure across another set of assets and gain an established retail business. As you know, we only just announced our intention to enter into the Illinois retail space in January. This transaction not only saves us the time and costs of building a new business, but we gain a high-quality seasoned team that will be able to take advantage of its new larger portfolios of AER and Dynegy assets.

The AER business, on the other hand, will benefit from our relentless focus on continuous improvement through our PRIDE program. We have a proven track record of driving margin and cost improvements. As Clint discussed, PRIDE has driven over $82 million of fixed cash cost improvement and $25 million in gross margin improvements in just its first 2 years.

We are committed to delivering similar results at AER. Together, our combined operational expertise in safety, environmental and engineering will deliver real value to shareholders.

On Slide 26, we have laid out that real value and what we expect to deliver in year 1. $60 million in total EBITDA run rate improvements through margin, O&M and G&A enhancements. We will be driving increased margin through EFOR improvement as we have with our end market availability improvement programs at Dynegy. We will also look at fuel procurement practices and bring our success and expertise at CoalCo to AER.

On the O&M side, we expect significant synergies through the combination of our engineering, maintenance and outage planning expertise. Our vendor optimization program, successful here at Dynegy, will be rolled out to AER.

Finally, G&A. Our existing infrastructure has managed 20,000 megawatts in the past. It can easily support an additional 4,100 megawatts now. Real programs, real initiatives and real savings. And as is our practice, these are conservative estimates. Once we close the transaction, we expect our combined teams will identify further improvements.

And with that, I'll turn it over to Clint.

Clint Freeland - Chief Financial Officer and Executive Vice President

Thanks, Carolyn. As reflected on Slide 27, AER's 3 subsidiaries have separate and distinct financial profiles. Of the 3 businesses, Genco is the only one with third-party debt, which today totals $825 million and requires annual interest payments of $59 million. With the earliest maturity date being 2018, Genco has 5 years before any refinancing will be required. Maintenance CapEx requirements for the Genco fleet are relatively modest. However, we do expect an uptick in 2016 and 2017 as certain projects previously deferred are pursued.

On the environmental side, most of Genco's CapEx requirements relate to the installation of a scrubber at the Newton facility, which requires an investment of $15 million to $20 million per year through 2017, then ramping up in 2018 and 2019 as major construction takes place. With the debt and CapEx requirements at Genco, liquidity is at a premium, so the transaction has been structured to ensure that the company has over $200 million in cash and sufficient working capital deployed to support the ongoing financial requirements of the business. With only 2 plants, minimal CapEx requirements and no debt outstanding, AERG's liquidity needs are more modest and will be supported with existing working capital deployed in the business at closing and cash balances currently estimated at $23 million, which will be shared between AERG and AEM in an intercompany money pool. With a significant portion of the working capital volatility at AERG and AEM tied to purchases and sales of power between the 2 entities, the money pool arrangement should help even out and reduce intra-month liquidity needs between the companies. We continue to evaluate the need for additional working capital for AERG and AEM, and should additional financing be required, we will consider putting in place a secured working capital line either through a third-party financial institution or, perhaps, by DI.

As Bob mentioned earlier, we expect this transaction to be accretive to adjusted EBITDA in 2014 and free cash flow in 2015 based on what we view to be very reasonable assumptions, as outlined on Slide 28. In addition to using the current NYMEX natural gas curve, our analysis uses heat rates in line with current market implied levels; synergies of $60 million per year, with 80% realized in 2014 and 100% realized in 2015; and CapEx levels outlined on the previous slide. We also assume that MISO capacity prices converge with PJM capacity prices over the medium to long term, but I would note that a majority of that convergence is assumed to take place post 2015 and is not instrumental in achieving our free cash flow accretion target. And with up to 900 megawatts of the AER fleet moving to PJM by 2016, our expectation for MISO capacity price recovery to levels comparable to PJM are at least partially hedged for this fleet.

One of the central themes to Dynegy's value proposition is the company's upside exposure to market recovery and pool retirements in the Midwest.

Earlier in the presentation, Bob walked through the asymmetric risk-return profile of the AER acquisition as it relates to improvements in natural gas prices. But as Slide 29 reflects, this is not just a natural gas dynamic. The same asymmetric relationship exists for other market factors as well, including power prices and capacity prices as coal plant retirements occur over the next several years. With little to no capital allocated to this transaction upfront and no new shares of common stock issued, the acquisition of AER provides current Dynegy shareholders with substantial additional upside potential and, with the transaction structure as described earlier, significant downside protection.

Bob, I'll turn it back to you.

Robert C. Flexon - Chief Executive Officer, President and Director

Thanks, Clint. Slide 31 summarized how we approach this transaction: protect our equity against downside risks, strengthen both portfolios to create upside leverage for our shareholders and preserve Dynegy's balance sheet and capital allocation opportunities.

At this point, Wendy, I'd like to open the line for Q&A.

Question-and-Answer Session

Operator

[Operator Instructions] Our first question today is from Brandon Blossman with Tudor.

Brandon Blossman - Tudor, Pickering, Holt & Co. Securities, Inc., Research Division

Let's see. Just touching on the AER debt a little bit, any covenants that should be of concern over the next 2 or 3 years, and any -- and I assume it's not amortizing debt, correct?

Clint Freeland - Chief Financial Officer and Executive Vice President

That's correct. They're bullet maturities. As it relates to covenants, there really are no financial covenants. The only ratios that are in there really deal with debt incurrence, as well as the ability to make restricted payments out of the entity. But as far as financial covenants that could be triggered, there are none.

Brandon Blossman - Tudor, Pickering, Holt & Co. Securities, Inc., Research Division

Great. And then I guess also just from the purchase and sale agreement perspective, the $25 million guarantee, is that the absolute limit to Dynegy parent liabilities here?

Clint Freeland - Chief Financial Officer and Executive Vice President

That's correct, and that expires 2 years after closing.

Brandon Blossman - Tudor, Pickering, Holt & Co. Securities, Inc., Research Division

Okay, great. And then just one more, and I'll get back in the queue. As far as the hedge profile at AER, I assume it's a fairly big hedge book right now. Do you intend to roll that off as the guarantee from Ameren rolls off?

Clint Freeland - Chief Financial Officer and Executive Vice President

Well, it's roughly 50% hedged for 2014, I guess about 20% hedged in 2015. Our plan would be to, as those roll off, to look to see if there's a way for us to provide -- if there's available credit in the marketplace, do a first-lien type structure. We'll work through that as time goes on. Also, their retail book offers some level of hedge protection for the portfolio as well.

Operator

Our next question is from Jon Cohen with ISI Group.

Jonathan Cohen - ISI Group Inc., Research Division

A couple of questions. First of all, does -- on your conditions to close, does the Illinois Commerce Commission have any ability to review the deal?

Robert C. Flexon - Chief Executive Officer, President and Director

No.

Jonathan Cohen - ISI Group Inc., Research Division

And how do you think FERC will look at market power issues? It looks like 7,000 megawatts of merchant generation in MISO Illinois. I mean, that's a pretty big chunk of that market, right?

Robert C. Flexon - Chief Executive Officer, President and Director

Yes, and we've looked at it with our internal experts, as well as 2 external experts, and all of our analysis shows that this should not come close to creating a market power issue. Actually, we'll ask Catherine Callaway to comment, on our General Counsel.

Catherine B. Callaway - Chief Compliance Officer, Executive Vice President and General Counsel

Yes. We've looked at it preliminarily and done as much analysis we can. We intend to make our filings very quickly. We expect the transaction to meet FERC's Section 203 market power test and that we can maintain market-based rate authority.

Jonathan Cohen - ISI Group Inc., Research Division

Okay. And then one other question on the synergies. So the $60 million, does that -- can you break down a little bit of what that includes? Does that include some upside on the rail contracts to Ameren's facilities in line with what you guys were able to get? And does it also include the capacity revenue from that increased sales into PJM?

Clint Freeland - Chief Financial Officer and Executive Vice President

The $60 million is all cost-based synergies. There's no revenue synergies included in that. A good portion of that number is the corporate allocation that comes from Ameren, so that will go away rather swiftly. There is some level of rail procurement synergy in there. There is one contract, one rail contract expiring in the near future. So that's included in there, and then the rest are generally more traditional operating and overhead-type G&A synergies.

Jonathan Cohen - ISI Group Inc., Research Division

Okay. And then I guess one last question on the retail business that you bought. Have you looked at what the retail price that Illinois customers in MISO are paying, the generation component of that relative to what your plant LMPs are? And how much of an uplift is there?

Robert C. Flexon - Chief Executive Officer, President and Director

I'm going to ask Brian Despard, who manages our coal portfolio, to comment on that.

Brian Despard

Yes. Without going into detail about what is included in the Ameren portfolio, what we're seeing in Illinois is C&I rates that are roughly $2 in margin, and residential, we expect is a bit higher than that. So it's fairly competitive in the state, but we're looking at margins probably in the $2 to $3 range.

Jonathan Cohen - ISI Group Inc., Research Division

But is that to INDY Hub, or is that to plant busbar [ph]?

Brian Despard

Plant.

Operator

Our next question is from Brian Chin with Citigroup.

Brian Chin - Citigroup Inc, Research Division

On the competitive retail component, can you give us a sense of what the margin is per megawatt hour and retail sales is?

Brian Despard

Yes. As I just mentioned, looking at the market, not necessarily at the Ameren portfolio but just what we're seeing out in the market, $2 to $3 depending on customer class. The C&I usually has tighter margins. Residential will have a little bit higher margins, so $2 to $3.

Brian Chin - Citigroup Inc, Research Division

Okay. And what is the level of volume that the retail business is selling at current level?

Brian Despard

The Ameren volume is about 50 million megawatt hours a year.

Brian Chin - Citigroup Inc, Research Division

And then just to be clear in case I might have missed this earlier. For the PJM RPM uplift, the $35 million, that uplift is relative to what those plants are currently capturing and whatever bilateral and capacity contracts are in place right now, so that's a net uplift?

Clint Freeland - Chief Financial Officer and Executive Vice President

Yes, that's correct.

Brian Chin - Citigroup Inc, Research Division

And then as part of the deal, do you have any commitments to keep any of the plants in operation for a period -- for a certain period of time, or do you have maximum degree of flexibility to...

Robert C. Flexon - Chief Executive Officer, President and Director

We have [indiscernible].

Operator

Our next question is from Julien Dumoulin-Smith with UBS.

Julien Dumoulin-Smith - UBS Investment Bank, Research Division

First question here on environmental. Just with respect to Illinois MPS averaging policies, do you expect to be able to realize some of the uplift, if you will, from your existing portfolio over to Ameren? And how does that impact the need to pursue environmental retrofits on the Ameren side?

Robert C. Flexon - Chief Executive Officer, President and Director

Julien, all of our assumptions and our planning is that each of the portfolios are standing on their own. There is no ability to do that. Ameren has their existing variance with the Illinois PCB and will continue to operate under that variance assumption.

Julien Dumoulin-Smith - UBS Investment Bank, Research Division

Okay, fair enough. And then you mentioned that the EBITDA is only accretive in '14. Is that meant to suggest that EBITDA is negative in '13 and is comparably for free cash flow in '15? How do you think about that? What are the year-on-year drivers that we should just be aware of that might not necessarily be intuitive?

Robert C. Flexon - Chief Executive Officer, President and Director

Yes. The only reason we started with '14 is just we're assuming this transaction takes pretty much through the end of the year, so we haven't even thought of it in the context of '13. So when we think about first full year of operation, which would be '14, that's where we view EBITDA will be accretive.

Julien Dumoulin-Smith - UBS Investment Bank, Research Division

Got you. And then with respect to the PJM capacity revenues, just to be clear, how much cleared the last auction, if you will? I think it was only about 100 in change, if you will, or about 100 megawatts, and so incrementally, we're going to see up to 840 in this next auction. Is that the right way to think about it?

Robert C. Flexon - Chief Executive Officer, President and Director

That's correct. I mean, the capacity has been granted and offered, if you will, by MISO at PJM, and it's subject only to Ameren's confirmation of the capacity.

Julien Dumoulin-Smith - UBS Investment Bank, Research Division

And so from your perspective, is there any opportunity for further exports? I mean, this is arguably the second or third time this has happened. What's that maximum theoretical, if you can kind of provide some -- quantify?

Robert C. Flexon - Chief Executive Officer, President and Director

We haven't reached beyond that number in terms of looking at the growth. There is, I think, a larger volume than that available on the MISO side. But it would require basically a restart on the PJM side of the entire analysis and modeling process to look for additional capacity at PJM.

Clint Freeland - Chief Financial Officer and Executive Vice President

But Julien, I would add that there are requests both that Ameren has in as well Dynegy has in the queue to try to find those opportunities, and both companies are waiting to hear the results of that work and what, if any, capital would be required to expand that number to something greater than the 900 megawatts. So that's under review as we speak.

Julien Dumoulin-Smith - UBS Investment Bank, Research Division

Great. And then something a little bit further field, California, going back to that for a quick second, what's the latest as it relates to Moss and Morro here? As you look at the portfolio, how much have you been able to contract on Moss 1 and 2 for this year and then your re-contracting efforts in '14 on both VO [ph] units?

Robert C. Flexon - Chief Executive Officer, President and Director

Well, for Morro, at this point, we actually have been dispatched. We're operating under CPM at the moment, and Moss Landing continues under its existing contract, but we have not re-contracted that capacity beyond the expiration of the contract at this point in time.

Lynn A. Lednicky - Executive Vice President of Operations

Not in terms of the toll, but there is -- RFO just came out for summer [ph] capacity, RA capacity, and we'll be participating in that.

Julien Dumoulin-Smith - UBS Investment Bank, Research Division

How long is the existing Morro Bay CPM commitment? I will assume you're getting the full price CPM, but for how long should we be modeling that this year?

Lynn A. Lednicky - Executive Vice President of Operations

It was just through -- it's 60-day CPM, and we've got for 50 megawatts, it's going in the -- here, I believe about mid-April.

Operator

Our next question is from Stephen Byrd with Morgan Stanley.

Stephen Byrd - Morgan Stanley, Research Division

As you look at the fleet of Ameren's assets, you've laid out the environmental spend. Is there a potential for us to be thinking about some asset retirements within the Ameren fleet over time? I think you had a general question on it before, but I just want to understand this. As you assess the fleet here, is there anything that strikes you that you might change in terms of how you approach it versus how Ameren approached it?

Robert C. Flexon - Chief Executive Officer, President and Director

I think when we look at the forward curves and the economics right now at our planning -- and I would say in our planning, we also assumed incremental CapEx to work on increased reliability in EFOR rates and made some assumptions around potential future capital associated with even coal handling and issues such as that, but when we layer all of that in and look at the existing natural gas curve that exists out there using market implied heat rates and our view around capacity, for the foreseeable future, we see all plants as being economic to run. And that decision, obviously, will continuously be evaluated, and we'd make the right decision at that point in time. The real ramp-up in capital spend really starts in the 2017 time frame. So I think what we'll see as a company is that we'll certainly continue on with the assets as long as they're economical, which, again, we see that being the case. And certainly, in a post-MATS compliance world, we certainly expect stronger capacity payments, higher power prices, so furthering the economic viability of these plants from even what we've built into our base level assumptions.

Stephen Byrd - Morgan Stanley, Research Division

Understood, great. And then just thinking about the put option, the minimum is $133 million. Given those assets, there certainly seems to be a reasonably good chance that the price is higher than that, potentially significantly higher. What would your -- assuming that it were higher, what should we be thinking about in terms of the usage of that cash? Or would that just basically stay within the Genco for liquidity purposes? Or if it were significantly higher, would you think about other uses for that capital?

Robert C. Flexon - Chief Executive Officer, President and Director

No, that cash goes into Genco for Genco operating needs.

Operator

Our next question is from Terran Miller with Cantor Fitzgerald.

Terran Miller

I might have missed this, but in terms of the $60 million of synergies, what is the breakdown between what's going to be realized at the individual businesses? Does the bulk of that accrete to Ameren gen, or does a significant portion of that go to Dynegy?

Clint Freeland - Chief Financial Officer and Executive Vice President

Well, those synergies, the $60 million within AER and its subsidiaries, now some of that, again, relates to a fairly substantial corporate overhead charge that will be replaced with a Dynegy overhead charge, if you will. So that will be spread amongst the entities. How that $60 million ultimately breaks down between the various subsidiaries at this point in time, we don't want to get that granular until we spent a lot more time around specific identification and how we want to organize things as we go forward. That's as close as I can get for you, Terran, on that.

Terran Miller

Okay. Just a follow-up then. They have talked about $30 million to $35 million of corporate allocation, so are you saying that the $60 million includes that going away and it will be replaced by an allocation from Dynegy? Or is the $60 million net of that savings for what the Dynegy allocation will be?

Clint Freeland - Chief Financial Officer and Executive Vice President

The allocation that we've done our planning around is not quite as high as that number, but that -- but your statement is correct that that number would go away. And then as Dynegy looks to reallocate its corporate overhead to GasCo, CoalCo and now AER, we need to come up with the right fair arms-length methodology in all 3 of those units.

Terran Miller

Okay. So that is gross before the Dynegy allocation, so that will be an offset to that $60 million?

Clint Freeland - Chief Financial Officer and Executive Vice President

Yes, that's correct.

Operator

Our next question is from Lance Ettus with Tuohy Brothers.

Lance Ettus

Obviously, I think you'll be up to close to 14 gigawatts of capacity, but you have a decent amount of that in the Midwest, obviously. So does this preclude you? And there's tremendous synergy opportunities, sorry about the long-winded question here. But can you guys do more deals potentially in the Midwest after this? I know that Mission

Energy is bankrupt, so maybe that's in play. I guess comments on that, and also, I have one follow-up question.

Robert C. Flexon - Chief Executive Officer, President and Director

Lance, I actually don't know the answer to that question. I presume it depends on the specific market as to what level of market power would exist there, so that would have be an analysis to an asset-by-asset basis, and I -- we haven't looked at that, so I don't really know the answer to that. I have to say that right now, particularly after spending the last 3 months working on this, I can't even think about another one at this point in time. I mean, the priority for us is to run and execute the Dynegy businesses really, really well and integrate this acquisition quickly, efficiently and run it very, very well. And to even think about anything, I mean, I'm speaking from my perspective, for us to think about anything beyond that at this point in time, I just haven't even begun to think that because these 2 priorities are so significant to make sure we get this done right and we have the successful enterprise is where my priority is completely focused on from this point forward.

Lance Ettus

Okay. And is there -- obviously, the synergies, the larger you get in merchant generation, but is there increased synergies to be more concentrated in more fuel types in more coal plants versus a diverse mix, or does it not matter?

Robert C. Flexon - Chief Executive Officer, President and Director

I think it absolutely matters. I mean, you've got the skill set. You've got similar technologies, your central engineering units, your scale on working with coal providers or coal transport companies, so it makes a big difference. The one other thing to your earlier question that we haven't really spoke about yet on this call, when we think about priorities for 2013, we talked about, obviously, running Dynegy well and being very successful on integrating this transaction. Doing our corporate level refinancing is a priority that immediately takes center stage now. We've been delaying that because of this acquisition. Now that this acquisition is announced, we're prepared now to move forward very quickly on our refinancing, which is a critical priority as we go forward. Substantial value creation is on the table by getting that done quickly.

Operator

Our next question is from Jason Mandel with RBC Capital Markets.

Jason Mandel

I just want to make sure I clarify and understand best what the cash is going to look like at Genco and AERG. I realize you've provided some good information, but there's some bits and pieces floating around. Can you talk about -- you guys have mentioned the $70 million of cash in Genco. I presume that's in addition to the $133 million that comes in from the asset sale? And as a separate comments about the $60 million contribution, and then of course, there is the $60 million expected from tax sharing during 2013 from Ameren, and given this isn't going to close until the end of the year, just curious how all those play into sort of pro forma year end.

Robert C. Flexon - Chief Executive Officer, President and Director

Yes, Jason, let me just -- because we did throw a lot of numbers out there. So total cash at AER and subsidiaries will be $226 million. Of that $226 million, $203 million would be at Genco, and then $23 million would be shared between AERG and AEM.

Jason Mandel

Okay, perfect. And just to clarify, for any differences that occur throughout the year, that would just be sort of settled up at the end of the year, and those are going to be the balances for the purchase and sale agreement.

Robert C. Flexon - Chief Executive Officer, President and Director

That's correct.

Operator

Our next question is from Jon Cohen with ISI Group.

Jonathan Cohen - ISI Group Inc., Research Division

I just had a follow-up on the dispatch costs. I think your fleet was $17 a megawatt hour, and you're saying Ameren's is $23. Can you give us a sense of what the differences are? Is it just rail transportation? And if you were able to renegotiate...

Robert C. Flexon - Chief Executive Officer, President and Director

The $17, we're still operating under our legacy coal transportation contract that goes back quite a few years. Theirs have been more recently priced to market in the past several years, so that's the primary difference. Also, the coal commodity cost for Ameren's fleet tend to be higher because they do more longer-term purchasing. We've done more -- we tend to do our pricing in the prompt year. PRB coal has the history of having the contango that disappears each time they get towards the prompt year. So it's really when you think about coal transportation and coal commodity costs, that's the difference. When our new rail contract starts in '14, that will take our number from $17 upwards to between $19 and $20, so then the difference narrows. But then the other point that I made, even though that our dispatch costs would be still a few dollars lower, their basis is lower than ours, so they have an economic advantage there where their plant, in general, dispatch at a differential to the hub of $2 to $3, where we're right now, $4 to $5 to $6, depending on what month you're talking about. So when you take all of those factors into consideration, 2014 and moving forward, that difference on a kind of a gross margin basis really flattens out pretty close.

Jonathan Cohen - ISI Group Inc., Research Division

Okay. And to the extent that some of that $60 million is for rail transportation cost synergies, that will reduce their dispatch cost and presumably increase their capacity factors?

Robert C. Flexon - Chief Executive Officer, President and Director

That's our goal.

Operator

[Operator Instructions] Our next question is from Stephen Byrd with Morgan Stanley.

Stephen Byrd - Morgan Stanley, Research Division

Just one follow-up. Just thinking about that gas asset, could you just talk to the rationale for not acquiring the gas assets?

Robert C. Flexon - Chief Executive Officer, President and Director

Sure. From the Dynegy perspective, the one thing that we found very difficult to address was the put option structure that was embedded between Genco and affiliated companies. And to try to work through that put option structure and getting in the middle of that is not something that we felt comfortable doing. So the arrangement that we worked out with the Ameren team is that they would handle the put option, so that was really the driver between separating the gas and coal. And also, what we're really interested in here, too, was obviously taking a coal fleet that's almost identical to our coal fleet and realize the benefits of the scale of putting those 2 together. So it made for a cleaner, more easily executed contract.

Operator

Our next question is from Terran Miller with Cantor Fitzgerald.

Terran Miller

Just a separate question. On Newton, do you have an updated estimate of what you think the scrubber is going to cost going forward?

Robert C. Flexon - Chief Executive Officer, President and Director

I think our estimates around that is that the absolute cost is about $500 million, of which about $200 million has been spent. I have Dan Thompson from CoalCo here, who can comment on that.

Daniel Thompson

Yes. Bob, the total direct cost is right there at -- you figure $500 million -- excuse me, $450 million. And then you have another $50 million of other costs. And then on top of that, you got the AFUDC [ph], so our modeling reflected the Ameren estimates.

Robert C. Flexon - Chief Executive Officer, President and Director

And of that amount, approximately $200 million has been...

Daniel Thompson

Yes. Bob, about $230 million, $240 million has been spent and maybe north of that at this point, but about $240 million has been spent to date.

Terran Miller

Okay. And you're comfortable at this point that that number doesn't go up if you continue to spend the $15 million to $20 million a year through 2017?

Daniel Thompson

That $15 million to $20 million that Clint referred to is in the plan, and that's consistent with our view and what Ameren's plan is.

Terran Miller

Okay. And those numbers were as of year-end '12, I assume, right, the $200 million spent?

Daniel Thompson

Yes.

Robert C. Flexon - Chief Executive Officer, President and Director

Fairly close to that. I'm not sure if some of that...

Terran Miller

Okay. But that's the approximate date for the number?

Robert C. Flexon - Chief Executive Officer, President and Director

Yes.

Operator

Our next question is from Amer Tiwana with CRT Capital.

Amer Tiwana - CRT Capital Group LLC

I wanted to sort of confirm that you're still planning on refinancing at the DI level, and you had given an estimate for additional liquidity that would come onto the balance sheet from the restricted cash becoming unrestricted, if that's still true.

Clint Freeland - Chief Financial Officer and Executive Vice President

Yes. I think this transaction really does not change our thinking around the refinancing. So I think at this point, our plan would be to still target refinancing at the DI level. And as you said, our plan is to refinance it in a way that does free up the restricted cash that's currently on our balance sheet and make that unrestricted and available at the DI level. So from my perspective, nothing really has changed on that front.

Operator

Thank you. And I'm currently showing no questions.

Clint Freeland - Chief Financial Officer and Executive Vice President

Okay. Well, I'd like to thank everybody for dialing in, and that this point, I'll conclude the call. Thank you, Wendy.

Operator

Thank you. This does conclude today's conference. Thank you very much for joining. You may disconnect at this time.

Exhibit C

DYNEGY

Dynegy to Acquire Ameren Energy Resources; 2012 Annual and 4th Quarter Results

March 14, 2013

Energizing you, powering our communities.

Forward-Looking Statements

Cautionary Statement Regarding Forward-Looking Statements

This presentation contains statements reflecting assumptions, expectations, projections, intentions or beliefs about future events that are intended as “forward looking statements.” You can identify these statements by the fact that they do not relate strictly to historical or current facts. Management cautions that any or all of Dynegy’s forward-looking statements may turn out to be wrong. Please read Dynegy’s annual, quarterly and current reports filed under the Securities Exchange Act of 1934, including its 2012 Form 10-K, when filed, for additional information about the risks, uncertainties and other factors affecting these forward-looking statements and Dynegy generally. Dynegy’s actual future results may vary materially from those expressed or implied in any forward-looking statements. All of Dynegy’s forward-looking statements, whether written or oral, are expressly qualified by these cautionary statements and any other cautionary statements that may accompany such forward-looking statements. In addition, Dynegy disclaims any obligation to update any forward-looking statements to reflect events or circumstances after the date hereof.

Non-GAAP Financial Measures

This presentation contains non-GAAP financial measures including EBITDA, Adjusted EBITDA and Free Cash Flow. Reconciliations of these measures to the most directly comparable GAAP financial measures to the extent available without unreasonable effort are contained herein. To the extent required, statements disclosing the definitions utility and purposes of these measures are set forth in Item 2.02 to our current report on Form 8-K filed with the SEC on March 14, 2013, which is available on our website free of charge, www.dynegy.com.

Agenda

I. 2012 Annual and 4th Quarter Highlights

II. Operations and Commercial Review

III. Financial Results and Guidance Update

IV. Dynegy to Acquire Ameren Energy Resources

V. Summary and Q&A

DYNEGY

2012 – Strengthening Dynegy for the Future

- ✓ **Ensured environmental compliance through completion of Consent Decree work in 4Q 2012**
- ✓ **Met 2012 PRIDE targets for reduced OpEx and gross margin improvements**
- ✓ **Successfully completed restructuring on October 1, 2012**
- ✓ **Drove 2012 PRIDE results by meeting targets for G&A cost reductions**

- ✓ **Entered into a long-term rail contract at prices below market expectations in 3Q 2012**
- ✓ **Reduced future interest expense by repaying $325 million of term loan debt in 4Q 2012**
- ✓ **Exceeded 2012 PRIDE target to create balance sheet efficiency**

DYNEGY

2012 Annual and 4th Quarter Highlights

- Operational Performance
  - Annual production volumes increased period-over-period by ~20%
    - Annual production volumes for Gas segment increased ~70% period-over-period primarily due to increased spark spreads
    - Annual production volumes for Coal segment decreased 10% period-over-period due to lower power pricing and an increase in planned outages
  - Strong operational performance with overall in-market-availability of ~93% during 2012
  - Safety performance continues to be a priority

- Financial Performance
  - 4Q12 Adjusted EBITDA of $(42) million, down $28 million primarily due to lower realized prices at the Coal segment and legacy financial settlements at the Gas segment
  - Annual Adjusted EBITDA of $57 million, down $224 million primarily due to lower realized prices at the Coal segment and legacy financial settlements
  - Liquidity of ~$590 million as of 3/8/2013
  - PRIDE achieves 2012 targets to contribute ~$45 million in Fixed Cash Savings and Gross Margin improvements and ~$150 million in Balance Sheet Efficiency
  - Reaffirming Adjusted EBITDA and Cash Flow Guidance for 2013

Note: Production volumes excludes DNE and Vermilion. DNE's 4th quarter and 2011 Adjusted EBITDA was $(10) million and $(19) million, respectively. Effective October 1, 2012, DNE was deconsolidated from Dynegy's 2012 financials statements and historical amounts for that year were reclassified as discontinued operations.

DYNEGY

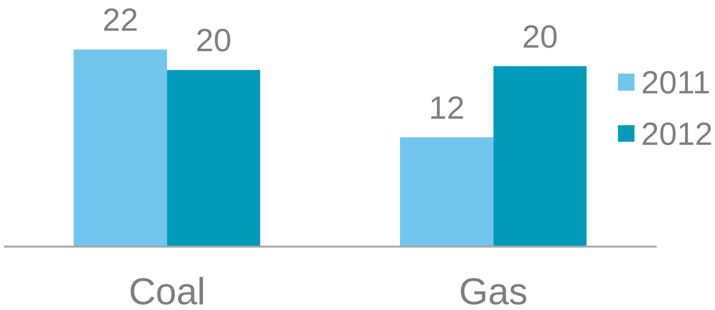
Operations and Commercial Review

Robert C. Flexon, President and CEO

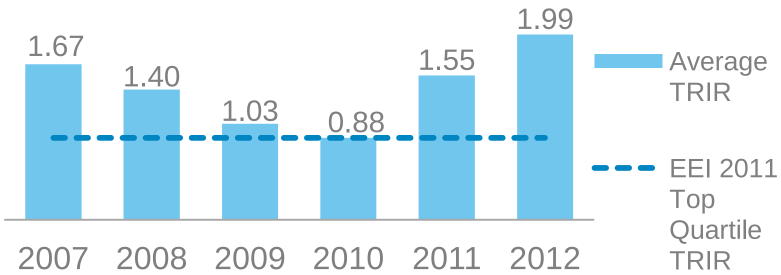
DYNEGY

Operations Highlights – Annual Results

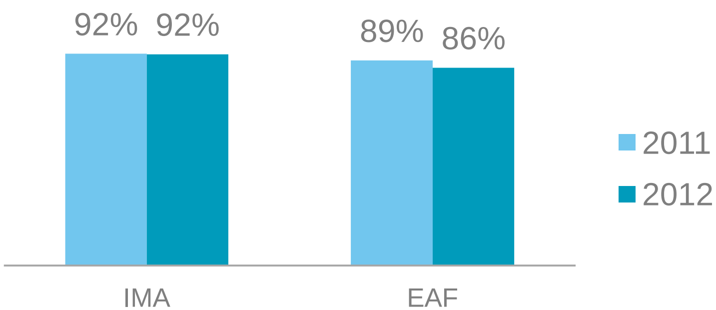
Volumes by Segment 2011 v 2012
(MM MWh)



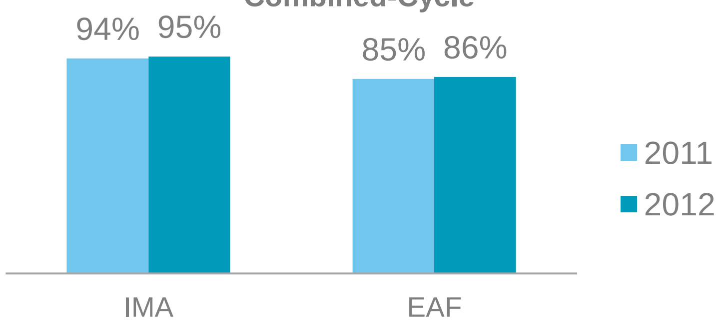
Safety Performance
Total Recordable Incident Rates (TRIR)



IMA and EAF for Coal Segment
Baseload



IMA and EAF for Gas Segment
Combined-Cycle

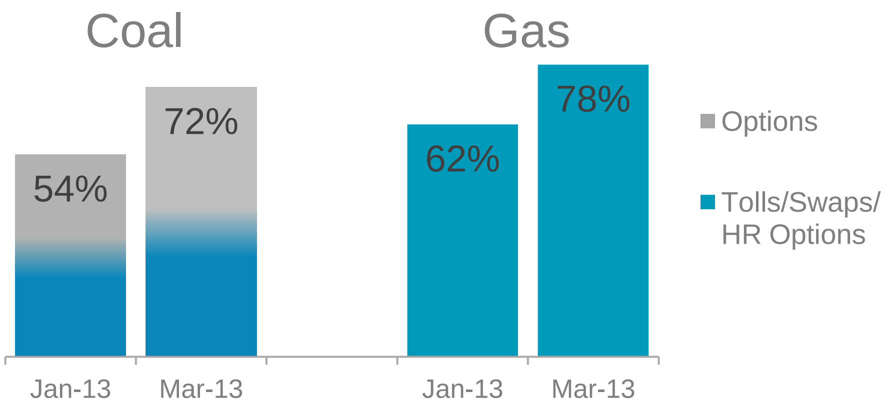


- Total production volumes increased ~20% period-over- period
  - Coal volumes decreased 10% primarily due to lower energy prices
  - Gas volumes increased ~70% due to improved spark spreads
- IMA and EAF results were relatively flat period-over-period for both baseload coal and combined-cycle fleets
  - EAF for coal segment decreased slightly due to greater unplanned outages in 2012
- Management and employees continue to emphasize improved safety expectations

DYNEGY

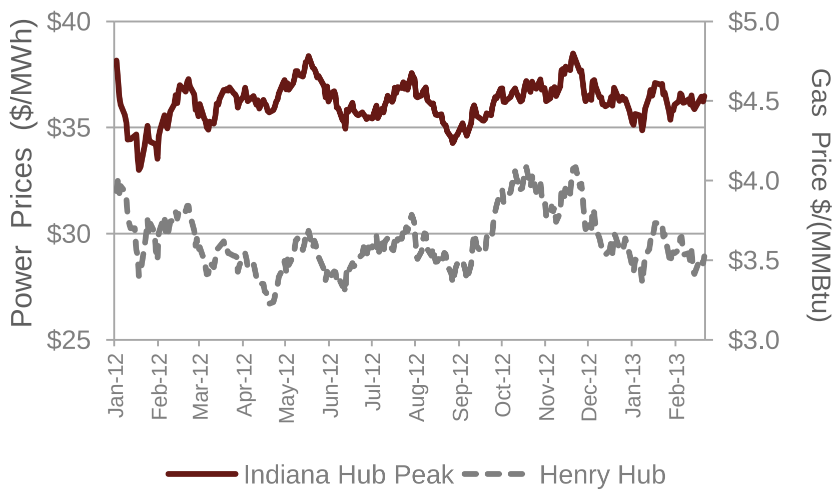
Commercial Update - 2013

2013 Generation Volumes Hedged by Segment

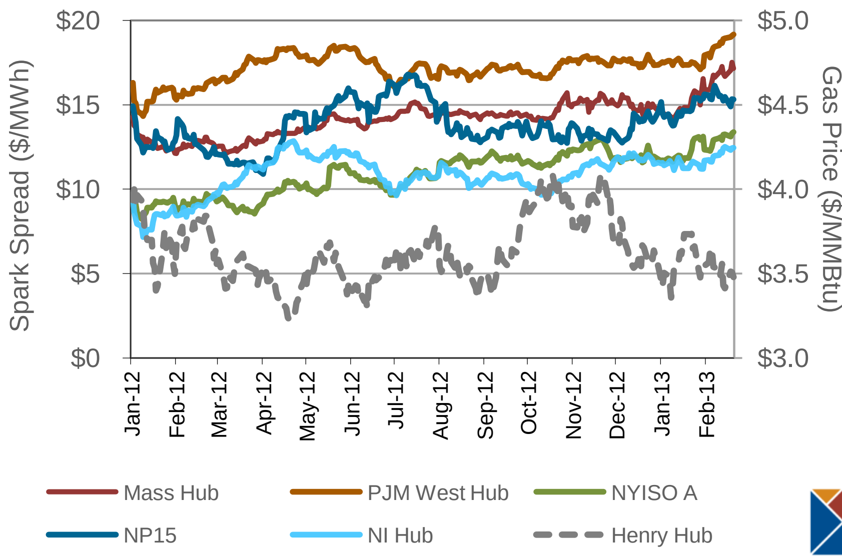


- Coal segment hedges added as market price and trading liquidity improved
  - Indy Hub continues to trade in a narrow range
- Gas segment hedges added primarily in response to improving NP-15 spark spreads
  - Spark spreads across our fleet generally remained healthy and continued to improve
- 2014 Coal and Gas segment hedges increased to 16% and 15%, respectively, as price targets were met

Balance 2013 Forward Power and Gas

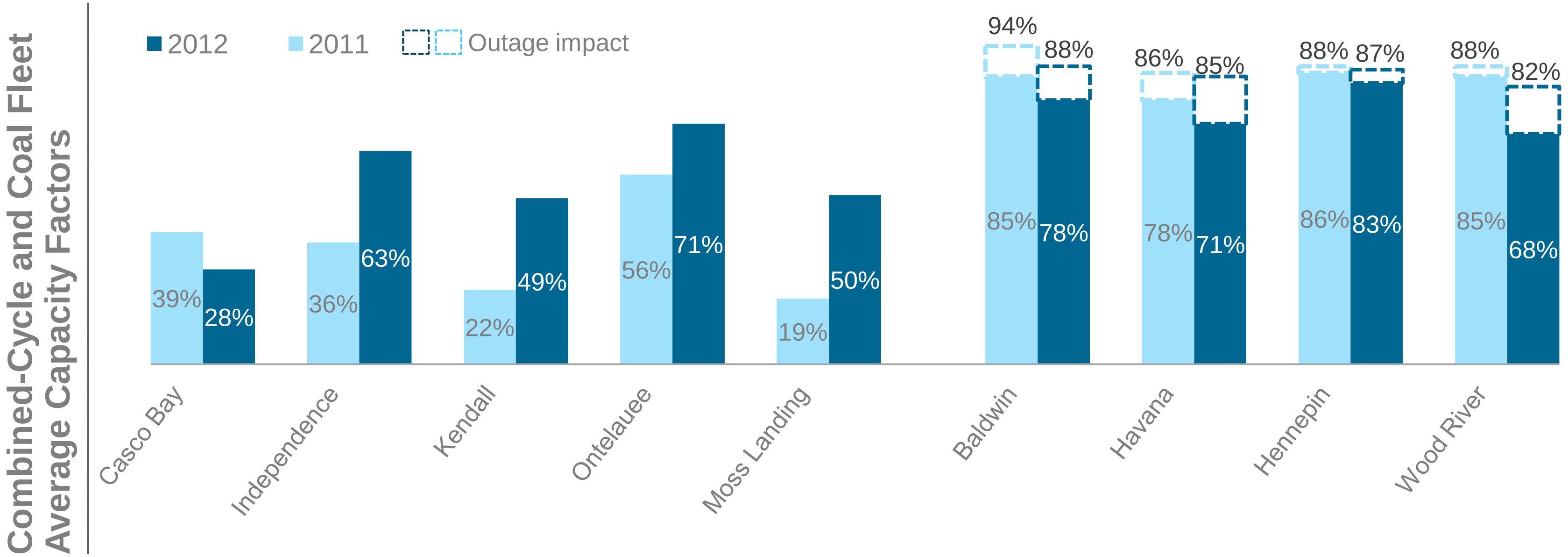


Balance 2013 Forward Sparks and Gas



DYNEGY

Capacity factors continue to be strong for Gas fleet; outages impacting Coal fleet



- Improved capacity factors for combined-cycle fleet primarily due to increased on and off-peak spark spreads as a result of lower gas prices
  - Ontelaunee experienced greater off-peak spark spreads
  - Independence and Kendall saw improved spark spreads around-the-clock
  - Moss Landing on-peak spark spreads improved by ~$4 on average
  - Casco Bay saw decreased on and off-peak spark spreads
- Coal fleet capacity factors decreased due to increased planned outages in 2012 at Wood River and Havana, in addition to lower prices in MISO

DYNEGY

Recent developments for California assets

Resource Adequacy Market

- CAISO will begin stakeholder process to develop framework for a Resource Adequacy market
- Key discussion items should include:
  - Defining "flexible capacity" for different unit capabilities
  - Restrictions or requirements for various characteristics or technologies
  - 3-5 year forward looking market
  - Anticipate market to be operational by 2015-2016
- Dynegy will be proactive in process
  - Efforts to highlight the flexibility of our portfolio
    - Fast ramping and low turndown (Moss Landing / Morro Bay)
    - Blackstart / quickstart (Oakland)

SCE Dispute

- Morro Bay Tolling Agreement
  - Dynegy initiated arbitration; arbitration scheduled for 1Q 2014
- Moss Landing RA Capacity
  - Dynegy initiated litigation; hearing during 2Q 2013 to establish litigation schedule

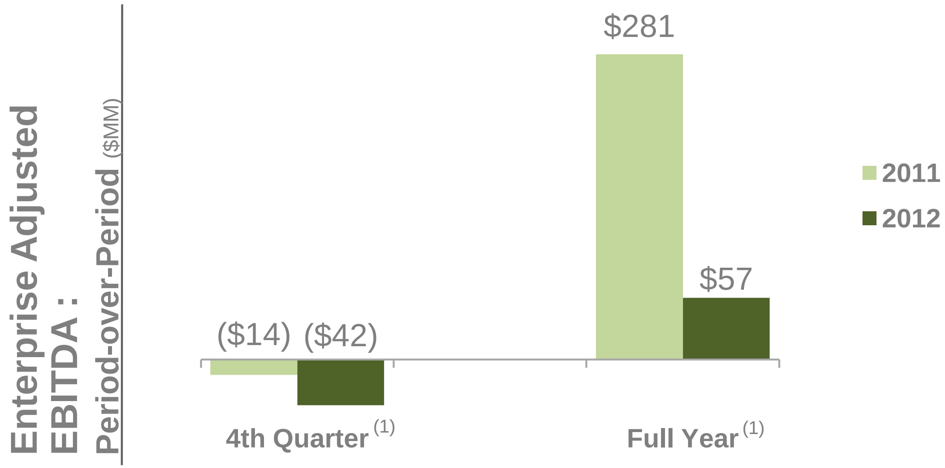
DYNEGY

Financial Results

Clint C. Freeland, CFO

DYNEGY

Financial Summary



Q4 2012

- Lower hedged power prices and higher basis differentials at Coal segment
- Settlement of legacy puts at Gas segment

Full Year 2012

- In-line with previously disclosed earnings estimate range of $50-$60 MM
- Lower realized prices at Coal segment
- Settlement of legacy puts at Gas segment
- Cancellation of California contracts

Liquidity

- 9/30/12 to 12/31/12:
  - $325MM term loan repayment
  - $200MM payment to creditors at bankruptcy exit
- 12/31/12 to 3/8/13:
  - New $150MM GasCo revolver closed January 2013

(1) 2011 full year and 4th quarter results include $(19) million and $(10) million, respectively, for the DNE segment; DNE is excluded from 2012 Adj. EBITDA due to deconsolidation and reclassification to discontinued operations

DYNEGY

Adjusted EBITDA Period-over-Period Segment Performance Drivers

4Q 2012: Period-over-Period ($MM)

Coal Segment

- Lower energy margin due to lower realized prices including increased basis
- Partially offset due to lower O&M expenses

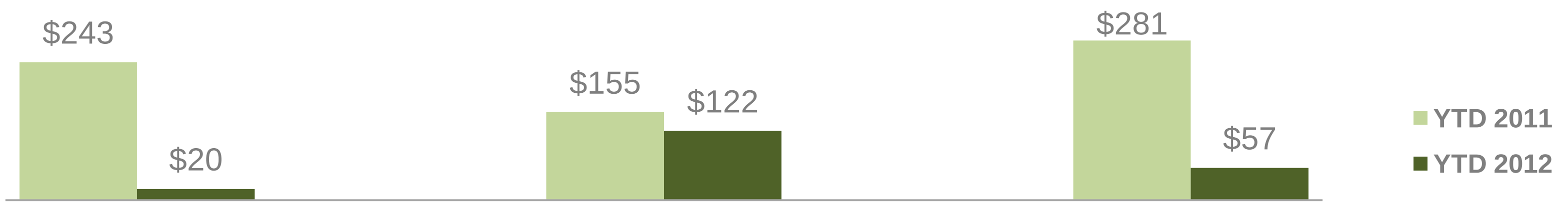
Gas Segment

- Increased energy margin due to improved spark spreads and hedge prices
- Partially offset by legacy put option settlements and lower capacity/tolling revenues

Enterprise

- Includes Corporate G&A expense
- $10 million benefit from deconsolidation of DNE in 2012 ($10 million loss in Q4 2011 vs $0 in Q4 2012)

FY 2012: Period-over-Period ($MM)



Coal Segment

- Lower energy margin primarily due to lower realized prices
- Additional decrease due to increased outages and off-peak economics

Gas Segment

- Lower revenues from legacy put option settlements
- Lower capacity and tolling revenues
- Partially offset by higher spark spreads

Enterprise

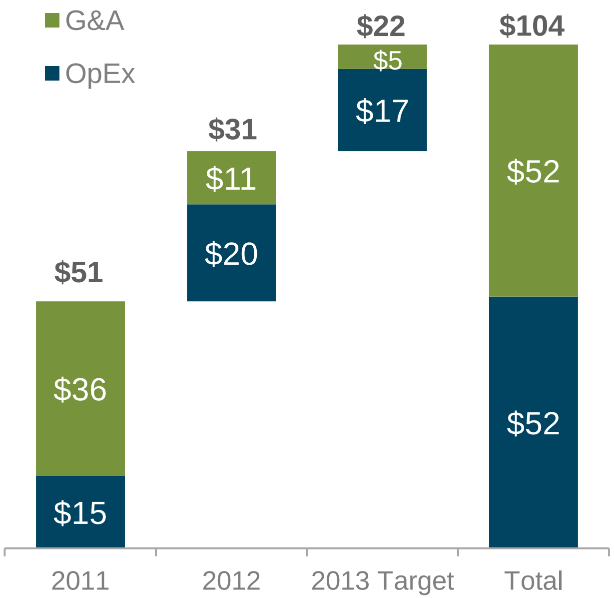
- Includes Corporate G&A expense
- $19 million benefit from deconsolidation of DNE in 2012 ($19 million loss in 2011 vs $0 in 2012)

DYNEGY

PRIDE delivered $44MM of Fixed Cash Savings and Gross Margin improvement in 2012 with an additional $42MM targeted for 2013

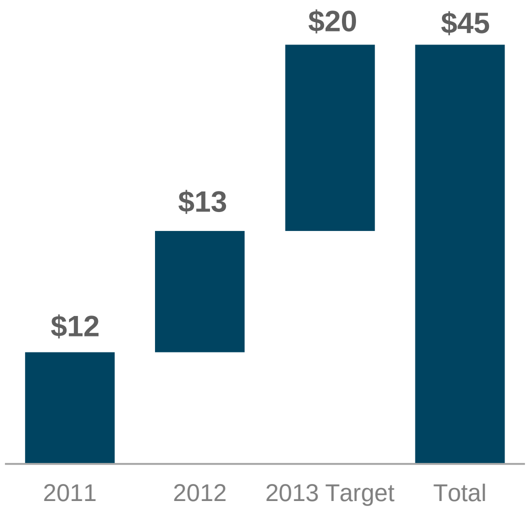
Producing **R**esults through **I**nnovation by **D**ynegy **E**mployees

Fixed Cash Savings
$ MM



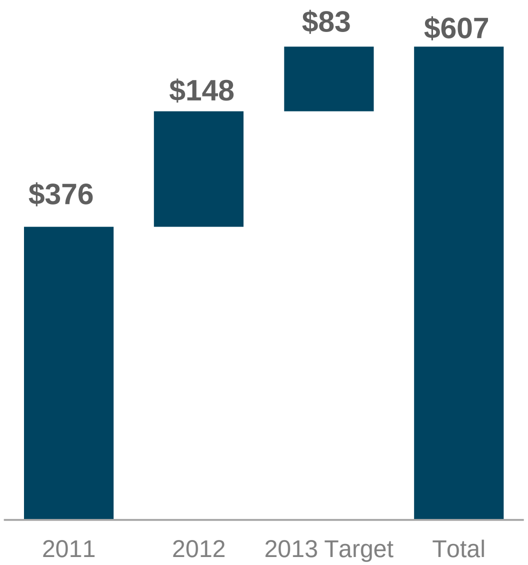
Exceeded 2012 PRIDE Fixed Cash target by $6 million, achieving a $31 million improvement over 2011 actuals

Gross Margin Improvements
$ MM



Met Gross Margin Improvement target, a $13 million increase over 2011 actuals

Balance Sheet Efficiency
$ MM



Exceeded 2012 PRIDE target of $100 million by ~50%, a $148 million improvement over 2011 actuals

DYNEGY

Reaffirming 2013 Consolidated Adjusted EBITDA and FCF Guidance[1]

Coal Segment	
Segment Adjusted EBITDA (excluding G&A)	$60 - $85
CapEx	$(43)
	$17 - $42

Gas Segment [2]	
Segment Adjusted EBITDA (excluding G&A)	$255 - $280
CapEx	$(63)
	$192 - $217

Consolidated	
Segment Adjusted EBITDA (excluding G&A)	**$340 - $365**
Corporate G&A and other	$(90)
Adjusted EBITDA	**$250 - $275**
Cash Interest	$(120)
CapEx	$(110)
Restricted Cash Release/Other	$120
Free Cash Flow	**$140 -$165**

(1) Segment Adjusted EBITDA, Adjusted EBITDA and Free Cash Flow are non-GAAP measures; for definitions and uses of Segment Adjusted EBITDA and reconciliations to GAAP, please see the Appendix;; (2) Impact of potential settlement for the Morro Bay tolling and Moss Landing capacity contracts is excluded from Gas Segment and Consolidated 2013 Adjusted EBITDA Guidance

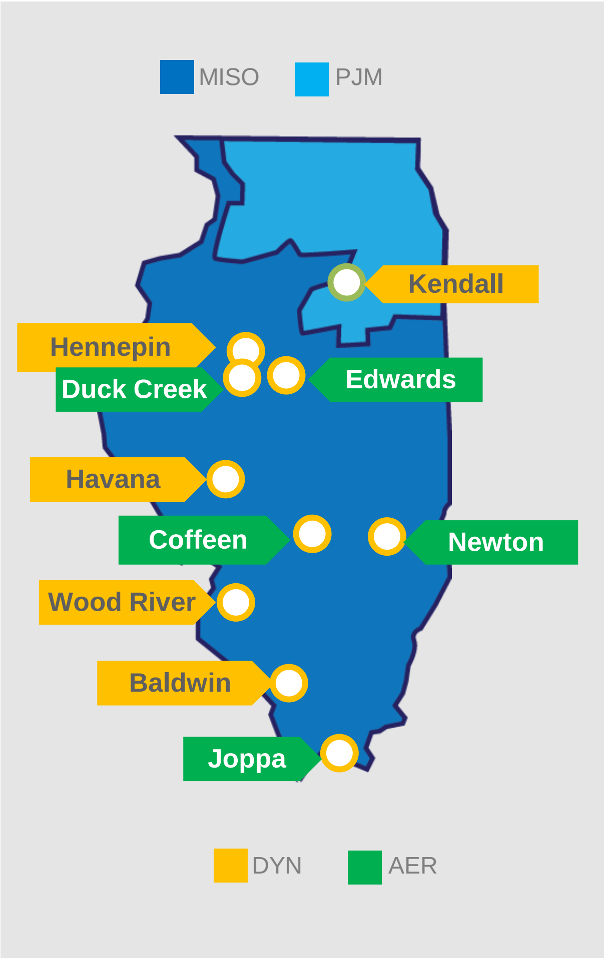
DYNEGY

Dynegy to Acquire Ameren Energy Resources

Robert C. Flexon, President and CEO
Carolyn J. Burke, CAO
Clint C. Freeland, CFO

DYNEGY

AER's coal generation and retail marketing business is a natural fit with CoalCo



Portfolio Overview

- ~4,100 MW of environmentally compliant, baseload coal generation in MISO and PJM
  - ~900 MW in PJM by 2016
- Ameren Energy Marketing and Homefield Energy – established retail and commercial energy providers

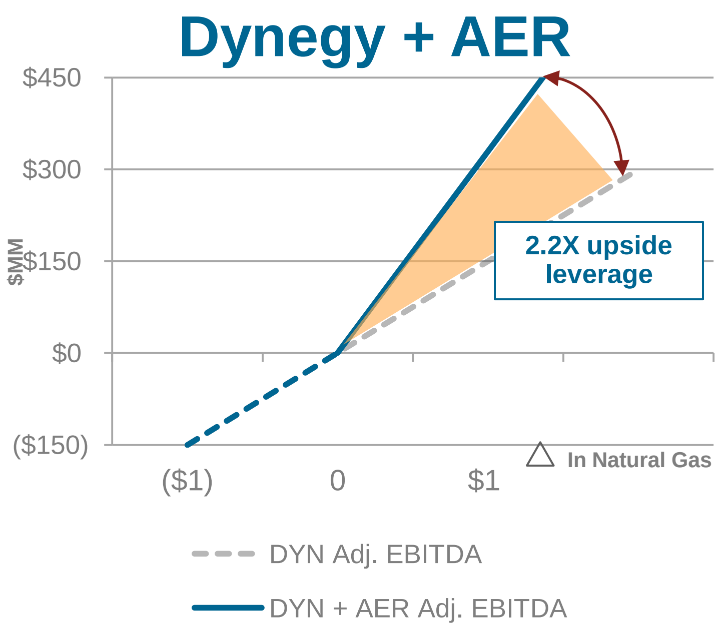
Transaction Summary

- Dynegy's newly created, non-recourse subsidiary(1), Illinois Power Holdings, acquires AER equity for no cash consideration
- At closing, AER and its subsidiaries will have $226 million in cash, $160 million in working capital and 2 years of collateral support from Ameren
- Synergy run-rate in 2014, targeted to exceed ~$60 million; further synergy run-rate increases for 2015
- Accretive to Adj. EBITDA in 2014 and Free Cash Flow by 2015(2)
- Regulatory approvals include FERC, FCC and Illinois Pollution Control Board
- Estimated close during 4th quarter 2013

(1) Excluding a $25 million Dynegy guarantee to Ameren Corp. (2) Definitions of Adjusted EBITDA and Free Cash Flow are set forth in Item 2.02 to our current report on Form 8-K filed with the SEC on March 14, 2013

DYNEGY

Asymmetric Risk/Reward Profile: Enhances shareholder upside in most capital-efficient manner



Impact of $1/MMBtu increase in natural gas

	Stand Alone		With AER
Annual Adj. EBITDA Impact [1]	$150MM	$182MM	$332MM
Shares Outstanding	100MM		100MM
Impact/Share[3]	**$1.50**	121% Increase	**$3.32**

To achieve this upside leverage on a standalone basis would require repurchasing **55** million shares with more than $1 billion of capital – not a feasible option[2]

Providing significantly greater upside leverage for Dynegy shareholders without compromising the balance sheet or consuming significant Dynegy capital

(1) Definitions of Adjusted EBITDA is set forth in Item 2.02 to our current report on Form 8-K filed with the SEC on March 14, 2013 (2) Assuming a $150 million standalone Adj. EBITDA sensitivity, remaining shares of 45 million after a 55million share repurchase in order to achieve the $3.32 /share Adj. EBITDA enhancement resulting from a $1/MMBtu increase in natural gas; $1 billion based illustratively on current share prices (3) Assumes any resulting income taxes would be offset by Dynegy's NOL Carryfoward.

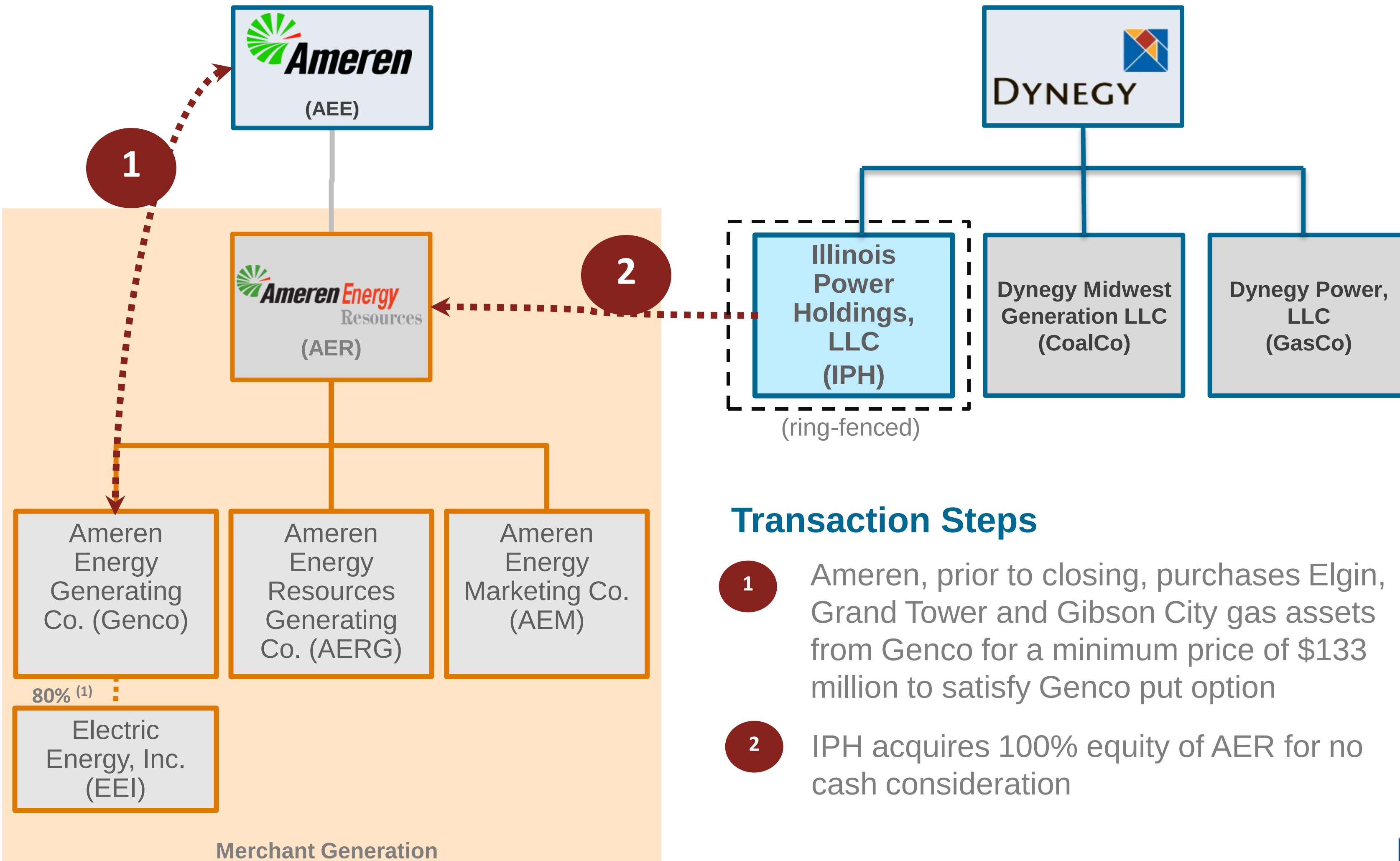
DYNEGY

AER's coal assets are highly complementary with Dynegy's existing coal fleet

	Ameren Energy Resources	Dynegy CoalCo
Number of Plants	6	4
Total Capacity	~4,100 MW	~3,000 MW
Fuel Type	PRB 8800	PRB 8800
ISO	MISO/PJM	MISO
Dispatch	Baseload	Baseload
Avg. Weighted 2013 Dispatch Cost	$23/MWh	$17/MWh
MATS Compliant	Yes	Yes

- ✓ Baseload PRB Coal
- ✓ Low Cost
- ✓ Environmentally Compliant
- ✓ Long-term Assets

The transaction has been structured to mitigate risk and ensure liquidity



Transaction Steps

1. Ameren, prior to closing, purchases Elgin, Grand Tower and Gibson City gas assets from Genco for a minimum price of $133 million to satisfy Genco put option
2. IPH acquires 100% equity of AER for no cash consideration

(1) Genco owns an 80% interest in EEI, which owns Joppa Steam and MEPI Joppa 6B

DYNEGY

The terms of the acquisition require minimal capital commitment from Dynegy

Ameren

- Prior to closing, Ameren to satisfy Genco Put Agreement for a minimum of $133 million
- Cash contribution of $60 million to AERG and Genco for general corporate purposes
  - AER subsidiaries also retaining $25 million in existing cash balances and ~$8 million in proceeds from sale of property
- AER net working capital at closing of $160 million, excluding cash, and two years of collateral support to AER
- Retention of non-operating locations and offsite environmental responsibilities subject to limited indemnification from IPH

DYNEGY

- $25 million guarantee at signing, that extends for 2 years from closing for certain payment obligations of IPH prior to closing and certain indemnifications and reimbursement obligations of IPH post-closing

Illinois Power Holdings, LLC

- AER and subsidiaries to retain the on-site environmental and business obligations, excluding the Duck Creek rail embankment
  - Genco's debt of $825 million remains outstanding
- Indemnify Ameren for future potential offsite liabilities associated with beneficial re-use and disposal of coal ash as follows:
  - Up to $10 million – 50/50 AEE/IPH
  - >$10-$30 million – 100% IPH
  - >$30 million – 100% AEE

DYNEGY

AER acquisition offers Dynegy shareholders significant upside potential with limited downside risk

Transaction Benefits

Operational

$60MM+ Synergies Year 1

- ✓ Lower fuel cost and other procurement opportunities due to increased scale
- ✓ G&A and operating cost reductions by leveraging Dynegy's existing infrastructure

PRIDE

- ✓ Dynegy will expand successful PRIDE program to AER's business

Lower Allocation

- ✓ Sharing infrastructure costs across a broader asset base will benefit Dynegy's business by ~$20 million per year

Commercial

PJM Export

- ✓ ~900 MW of fleet capacity available for the 2016/17 PJM capacity auction, pending MISO approval

Retail Business

- ✓ Established marketing business with expertise in MISO and PJM
- ✓ Opportunities for growth potential, which aligns with Dynegy's retail initiative
- ✓ Provides basis management opportunities for the entire coal fleet

MISO Market Recovery Upside

- ✓ Entire fleet MATS compliant
- ✓ As noncompliant or uneconomic generation retires, tightening supply dynamics should improve power and capacity pricing
- ✓ **Transaction more than doubles Dynegy's upside leverage to natural gas prices and MISO market recovery**

Financial

Ample Liquidity

- ✓ Sufficient liquidity and collateral support provided at closing to meet expected operating needs

Earnings Accretive

- ✓ Targeted synergies, along with the current forward market for natural gas prices and Dynegy's view of forward power and capacity prices, are expected to result in AER being accretive to Adjusted EBITDA in 2014 and Free Cash Flow in 2015 (1)

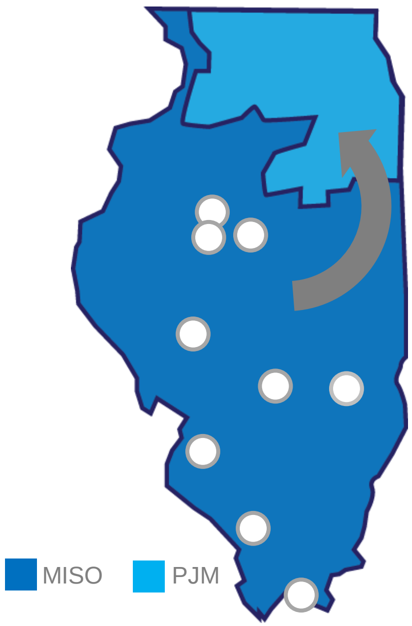
Equity Value Creation

- ✓ **These same forward curves indicate that all three of AER's subsidiaries offer substantial equity value creation for the benefit of Dynegy's shareholders**

(1) Definitions of Adjusted EBITDA and Free Cash Flow are set forth in Item 2.02 to our current report on Form 8-K filed with the SEC on March 14, 2013

DYNEGY

Access to the PJM market offers further upside



~900 MW transmission from AER assets to PJM(1)

Energy Sales

~650 MW of energy available for sale at PJM's MISO interface price effective June 2013

✓ ~Approximate uplift of ~$10 million/yr (2)

~250 MW remaining will be eligible for delivery into PJM effective June 2015

Capacity Sales

~840 MW(3) available for sale into PJM's 2016/2017 capacity auction

✓ 2015/16 PJM RTO Auction cleared $4.14/kW-mo

✓ Uplift of ~$35 million/yr assuming MISO capacity price of $0.50/kW-mo

Capacity prior to 2016/17 auction will be offered into various PJM incremental auctions or marketed under bi-lateral capacity sales

Reserve Margins

~900 MW of MISO capacity exported to PJM will further tighten reserve margins in MISO and benefit energy and capacity sales in the MISO market

(1) ~800 MW Pending acceptance by Ameren (2) Assumes $1.25/MWh uplift and 100% utilization (3) Includes EFOR derate

DYNEGY

Adding an established retail business enhances growth opportunities, efficiency and risk management

Ameren Energy Marketing

What is it?

- Customer focused business supplying munis, co-ops, commercial, industrial and small business customers in MISO and PJM
- As Homefield Energy, serves 141 communities and supplies electricity to nearly 500,000 homes and small businesses

How does it fit with Dynegy?

- Meets Dynegy's previously expressed objective to establish a retail business, but immediately and on a larger scale
- Provides positive financial contribution
- Allows for portfolio effects when supplying load with local generation
- Results in the effective management of basis risk around plant LMPs

Opportunities?

- Local generation throughout Illinois allows for high rate of customer retention
- ~80% of residential market has not yet switched to alternative retail suppliers
- Existing and new capacity in PJM will support competitive pricing which may lead to increased PJM sales

DYNEGY

Both fleets will benefit from significant synergies driven by increased scale and shared capabilities

Synergies Benefiting Dynegy Fleet

- Reduction of corporate cost allocation burden across both coal and gas fleets
- Retail expertise to address CoalCo basis issues

Synergies Benefiting AER Fleet

- PRIDE program to achieve benefits of scale
  - Process efficiencies
  - Cost improvements
  - Operational opportunities
  - Working capital efficiencies

Synergies with Joint Benefits

- Safety and Environmental programs
- Procurement savings
- Centralized engineering expertise
- Best practices between fleets

DYNEGY

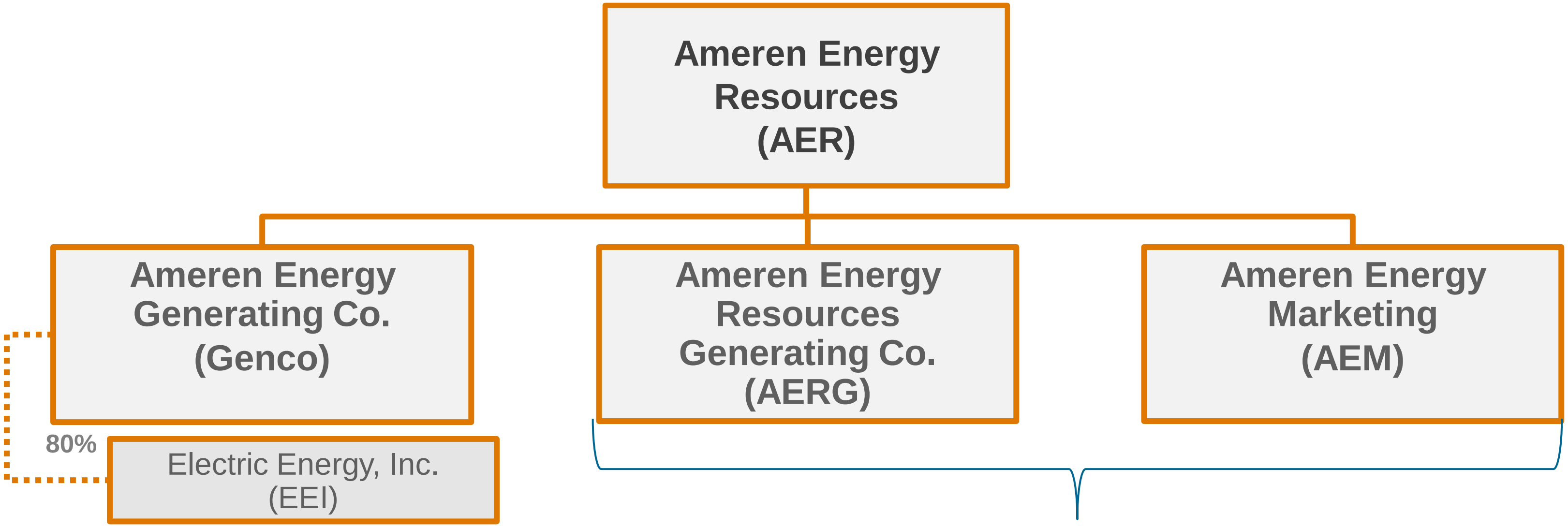
Synergies targeted to capture an annual run rate of $60 million in savings in 2014 with potential for upside in future years

			Year 1	Year 2+
Synergies	Margin Improvements	• Combination of various initiatives at the facilities including fuel supply, EFOR improvement and other reliability initiatives	$15MM	Operational Synergies
	O&M Enhancements	• Operational synergies through combining engineering and maintenance programs, outage management • Purchasing initiatives, contractor reviews and real estate optimization	$25MM	
	G&A Reduction	• Leveraging Dynegy's existing infrastructure	$20MM	
Total PRIDE improvements			$60MM	Additional synergies anticipated

Natural synergies between portfolios will create significant value for AER fleet

DYNEGY

Financial Profile Post-Closing



- <u>Available Liquidity at Closing:</u> $203MM in cash
- <u>Total Debt at Closing:</u> $825MM
  - $300MM due 2018
  - $250MM due 2020
  - $275MM due 2032
  - Interest exp.: $59MM/yr
- <u>Maintenance CAPEX:</u> $10-15MM/yr; higher in 2016 and 2017
- <u>Environmental CAPEX:</u> Primarily Newton scrubber; $15-20MM/yr through 2017; higher in 2018/19

- <u>Available Liquidity at Closing:</u> ~$23MM in cash + additional working capital facility, if needed; AERG and AEM liquidity to be managed together through money pool
- <u>Total Debt at Closing:</u> None
- <u>Maintenance CAPEX</u>: $5-10MM/yr at AERG
- <u>Environmental CAPEX:</u> $5-15MM/yr at AERG

DYNEGY

Transaction is Adjusted EBITDA accretive in 2014 and FCF Accretive in 2015 using reasonable assumptions

Natural Gas — Existing NYMEX gas curve

Heat Rates — In line with current market implied heat rates

Synergies — Target synergies achieved ($60 million/year)

Capacity Prices — Dynegy expects MISO capacity prices to converge with PJM over time due to retirements

- >20% hedged with up to 900 MW of fleet moving to PJM by 2016

CAPEX — Assuming reasonable maintenance and environmental capital expenditures necessary to meet all known regulations

Note: Definitions of Adjusted EBITDA is set forth in Item 2.02 to our current report on Form 8-K filed with the SEC on March 14, 2013

DYNEGY

Dynegy's upside leverage to market recovery and MISO retirements more than doubles with little to no capital deployed upfront…

CoalCo Stand Alone	
Capacity Pricing Uplift to $2/kW-mo	~$60
Power Pricing with 2.7 GW MISO Central Retirements	~$90
Natural Gas Recovery (+$1/MMBtu)	~$150

(in $MM)

Dynegy Coal Assets Post Transaction	
Capacity Pricing Uplift to $2/kW-mo	~$150
Power Pricing with 2.7 GW MISO Central Retirements	~$190
Natural Gas Recovery (+1/MMBtu)	~$330

(in $MM)

… and downside market risk remains unchanged

DYNEGY

Summary and Q&A

Robert C. Flexon, President and CEO

In summary, the portfolio acquisition enhances Dynegy's fundamental investment thesis

Dynegy Investment Thesis

- ✓ **Limited Downside Risk**
- ✓ **Multiple Avenues for Substantial Upside**
- ✓ **Capital Allocation Opportunities**

AER Acquisition

- ✓ **Minimal financial exposure with downside risk ring-fenced**
- ✓ **Natural synergies and market recovery benefits**
- ✓ **Preserves future capital allocation opportunities**

Increasing shareholder value while protecting and preserving Dynegy's balance sheet

DYNEGY

Appendix
2012 and 4Q Earnings

DYNEGY

Segment Adjusted EBITDA Definition

Segment Adjusted EBITDA is a non-GAAP measure which is utilized to more clearly demonstrate the financial results of each business segment. The measure reflects segment gross margin less operating expenses. Corporate allocations such as general and administrative expenses and the financial structure are not included in order to demonstrate the cash amount each business segment contributes towards the corporate cost and capital structures.

DYNEGY

Dynegy Generation Facilities

Portfolio/Facility[1]	Location	Net Capacity[2]	Primary Fuel	Dispatch Type	Market Region
Coal					
Baldwin	Baldwin, IL	1,800	Coal	Baseload	MISO
Havana	Havana, IL	441	Coal	Baseload	MISO
Hennepin	Hennepin, IL	293	Coal	Baseload	MISO
Wood River Units 4-5	Alton, IL	446	Coal	Baseload	MISO
CoalCo TOTAL		**2,980**			
Gas					
Casco Bay	Veazie, ME	540	Gas - CCGT	Intermediate	ISO-NE
Independence	Scriba, NY	1,064	Gas - CCGT	Intermediate	NYISO
Kendall	Minooka, IL	1,200	Gas - CCGT	Intermediate	PJM
Ontelaunee	Ontelaunee Township, PA	580	Gas - CCGT	Intermediate	PJM
Moss Landing	Monterey County, CA				
Units 1-2		1,020	Gas - CCGT	Intermediate	CAISO
Units 6-7		1,509	Gas	Peaking	CAISO
Morro Bay	Morro Bay, CA	650	Gas	Peaking	CAISO
Oakland	Oakland, CA	165	Oil	Peaking	CAISO
Black Mountain	Las Vegas, NV	43	Gas	Baseload	WECC
GasCo TOTAL		**6,771**			
TOTAL GENERATION		**9,751**			

NOTES:

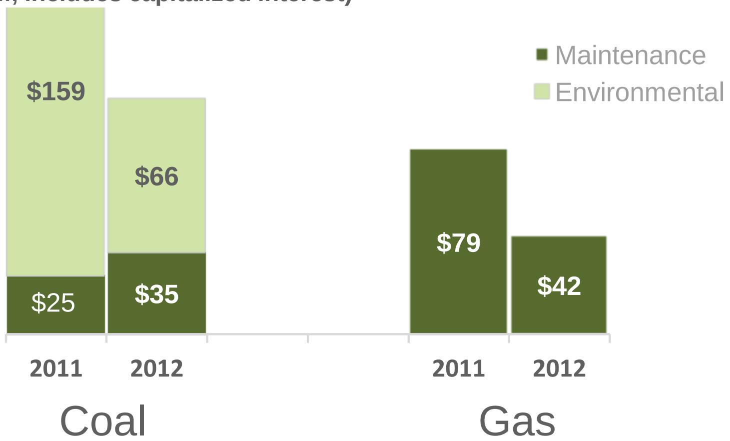
1) Dynegy owns 100% of each unit listed, except that it owns a 50% interest in the Black Mountain facility. Total Net Capacity set forth in this table for Black Mountain includes only Dynegy's proportionate share of such unit's gross generating capacity. The list also does not include several facilities that are retired or in agreement to be sold. Those facilities include Havana 1-5 and Wood River 1-3 which are retired and out of operation; Morro Bay 1-2 which are in mothball status and out of operation; and Danskammer and Roseton, which were deconsolidated effective October 1, 2012 and are under agreement to be sold.

2) Unit capabilities are based on winter capacity.

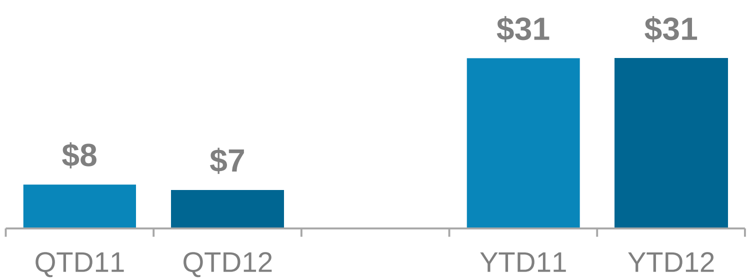
DYNEGY

Capital and Major Maintenance O&M Expenditures Period-Over Period

Capital Expenditures by Segment
($MM; includes capitalized interest)



Total Major Maintenance Expense for Gas and Coal Segments ($MM)



Coal Segment

– 2012 Environmental CapEx decreased period-over-period due to declining Consent Decree spending

– 2012 Maintenance CapEx increased period-over-period due to increased planned outages

Gas Segment

– 2012 CapEx decreased period-over-period due to less maintenance outages scheduled period-over-period

Gas and Coal Segments

– QTD 2012 Major Maintenance Expense decreased slightly period-over-period due to fewer maintenance outages

– YTD 2012 Major Maintenance Expense was flat period-over-period

Capital and Liquidity Summary (as of 12/31/2012)

(in $MM)

Dynegy Inc.[1]	
Cash & Cash Equivalents	$317
L/C Capacity[1]	$28
L/C Outstanding[1]	$(27)
Total Liquidity	**$318**

GasCo	
1st Lien Term Loan	**$837**
Cash & Cash Equivalents	$21
Collateral Posting Account[3]	$63
L/C Capacity[2]	$220
L/C Outstanding[2]	$(219)
Total Liquidity	**$85**

CoalCo	
1st Lien Term Loan	**$517**
Cash & Cash Equivalents	$10
Collateral Posting Account[3]	$8
L/C Capacity[2]	$14
L/C Outstanding[2]	$(14)
Total Liquidity	**$18**

Total Enterprise Liquidity and Net Debt		
	Cash & Cash Equivalents	$348
	Collateral Posting Account[3]	$71
	L/C Capacity[2]	$262
	L/C Outstanding[2]	$(260)
Total Liquidity		**$421**
	Total Obligations	$1,354
Less:	Cash & Cash Equivalents	$348
Less:	Restricted Cash	$333
Total Net Debt		**$673**

Note: Above chart represents an abbreviated organizational structure. (1) Includes various subsidiaries of Dynegy Inc. (2) Letters of credit are cash collateralized. Amount includes a required reserve of 3%. (3) Restricted Cash as part of the Term Loan Facility.

DYNEGY

Capital and Liquidity Summary (as of 3/8/2013)

(in $MM)

Dynegy Inc.[1]

Cash & Cash Equivalents	$301
L/C Capacity[1]	$28
L/C Outstanding[1]	$(28)
Total Liquidity	**$301**

GasCo

1st Lien Term Loan	**$837**
Cash & Cash Equivalents	$56
Collateral Posting Account[3]	$58
Revolver Capacity	$150
L/C Capacity[2]	$210
L/C & Revolver Outstanding[2]	$(207)
Total Liquidity	**$267**

CoalCo

1st Lien Term Loan	**$517**
Cash & Cash Equivalents	$13
Collateral Posting Account[3]	$11
L/C Capacity[2]	$11
L/C Outstanding[2]	$(11)
Total Liquidity	**$24**

Total Enterprise Liquidity and Net Debt

	Cash & Cash Equivalents	$370
	Collateral Posting Account[3]	$69
	Revolver Capacity	$150
	L/C Capacity[2]	$249
	L/C & Revolver Outstanding[2]	$(246)
Total Liquidity		**$592**
	Total Obligations	$1,354
Less:	Cash & Cash Equivalents	$370
Less:	Restricted Cash	$318
Total Net Debt		**$666**

Note: Above chart represents an abbreviated organizational structure. (1) Includes various subsidiaries of Dynegy Inc. (2) Letters of credit are cash collateralized. Amount includes a required reserve of 3%. (3) Restricted Cash is part of the Term Loan Facility.

DYNEGY

Operational Statistics

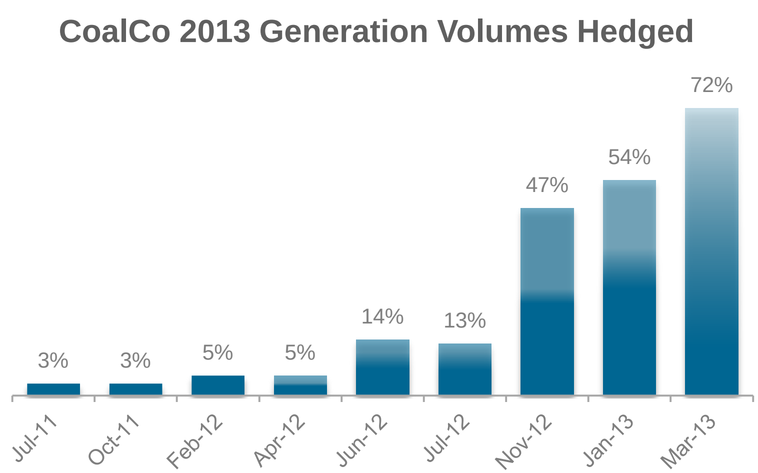
Gas - Combined Cycles	4Q11	4Q12	FY11	FY12
Total Generation (MM MWh)				
California	0.5	1.3	1.7	4.4
NY/NE	1.3	1.1	4.9	6.8
PJM-W	0.8	1.1	4.9	8.4
In-Market-Availability				
California	71.4%	93.9%	89.4%	97.0%
NY/NE	98.3%	85.0%	94.2%	95.8%
PJM-W	99.6%	70.3%	96.1%	94.2%
Average Capacity Factor				
California	23.4%	56.0%	19.4%	49.5%
NY/NE	37.0%	32.3%	36.9%	50.9%
PJM-W	19.9%	28.1%	33.1%	56.4%

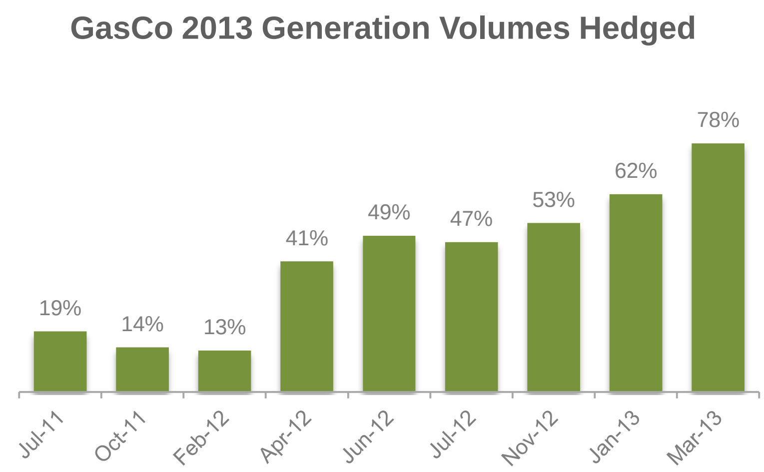
Coal – Coal-Fired Units	4Q11	4Q12	FY11	FY12
Total Generation (MM MWh)	5.3	4.7	22.0	19.9
In-Market-Availability	88.9%	86.3%	92.2%	92.0%
Average Capacity Factor	79.0%	71.5%	84.0%	75.9%

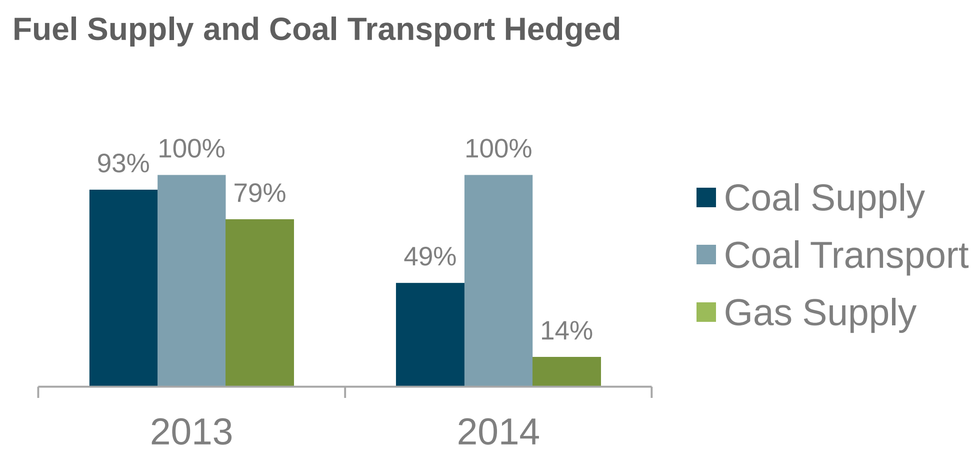
Note: 2011 excludes Vermilion volumes; Unit was retired during 2011

DYNEGY

Commercial Activity (as of 3/8/2013)





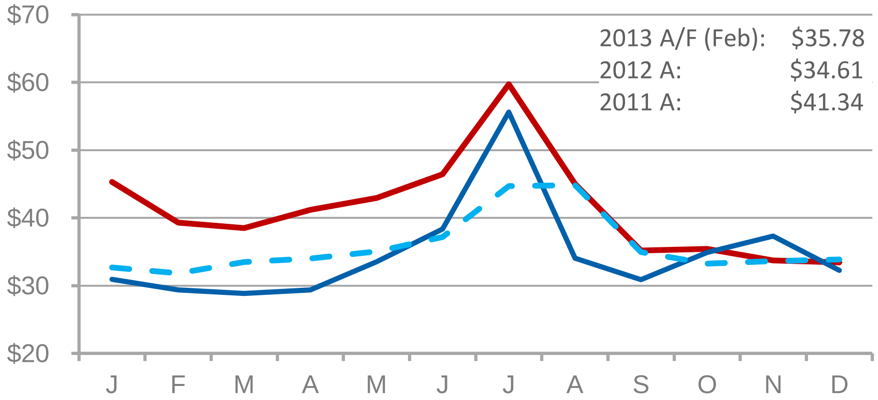


DYNEGY

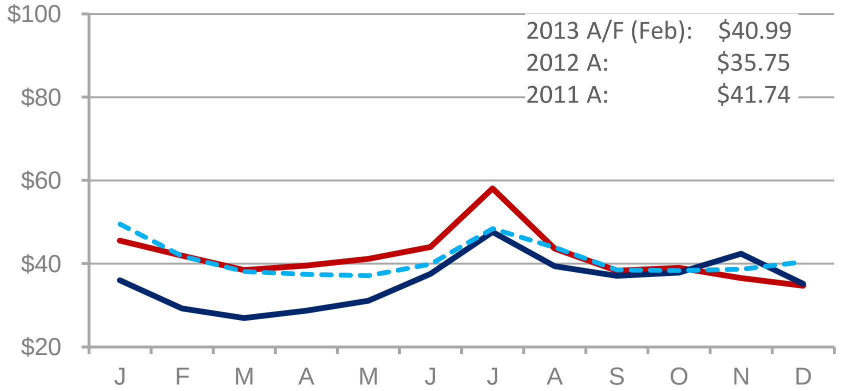
Commodity Pricing (on-peak power)

2011 Actual — 2012 Actual — 2013 Actual/Forward as of 2/22/2013(1)

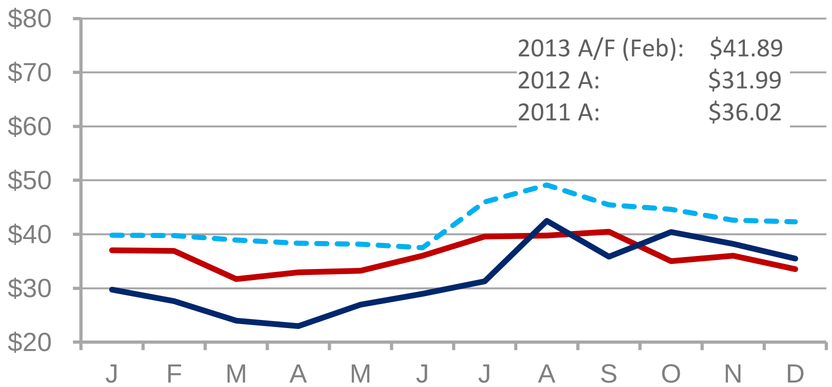
Indiana Hub (2) ($/MWh)



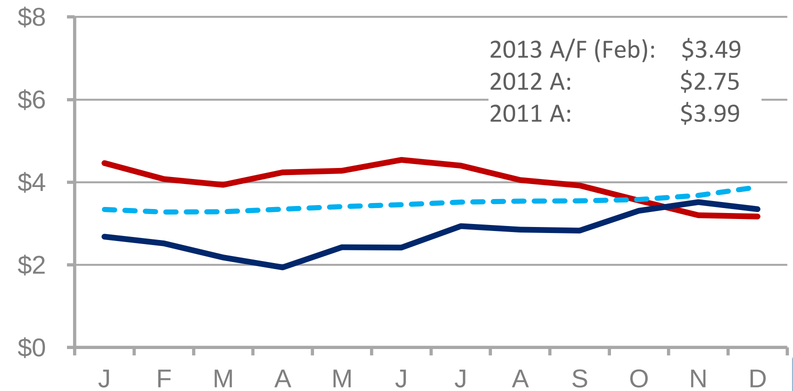
New York Zone A ($/MWh)



NP-15 ($/MWh)



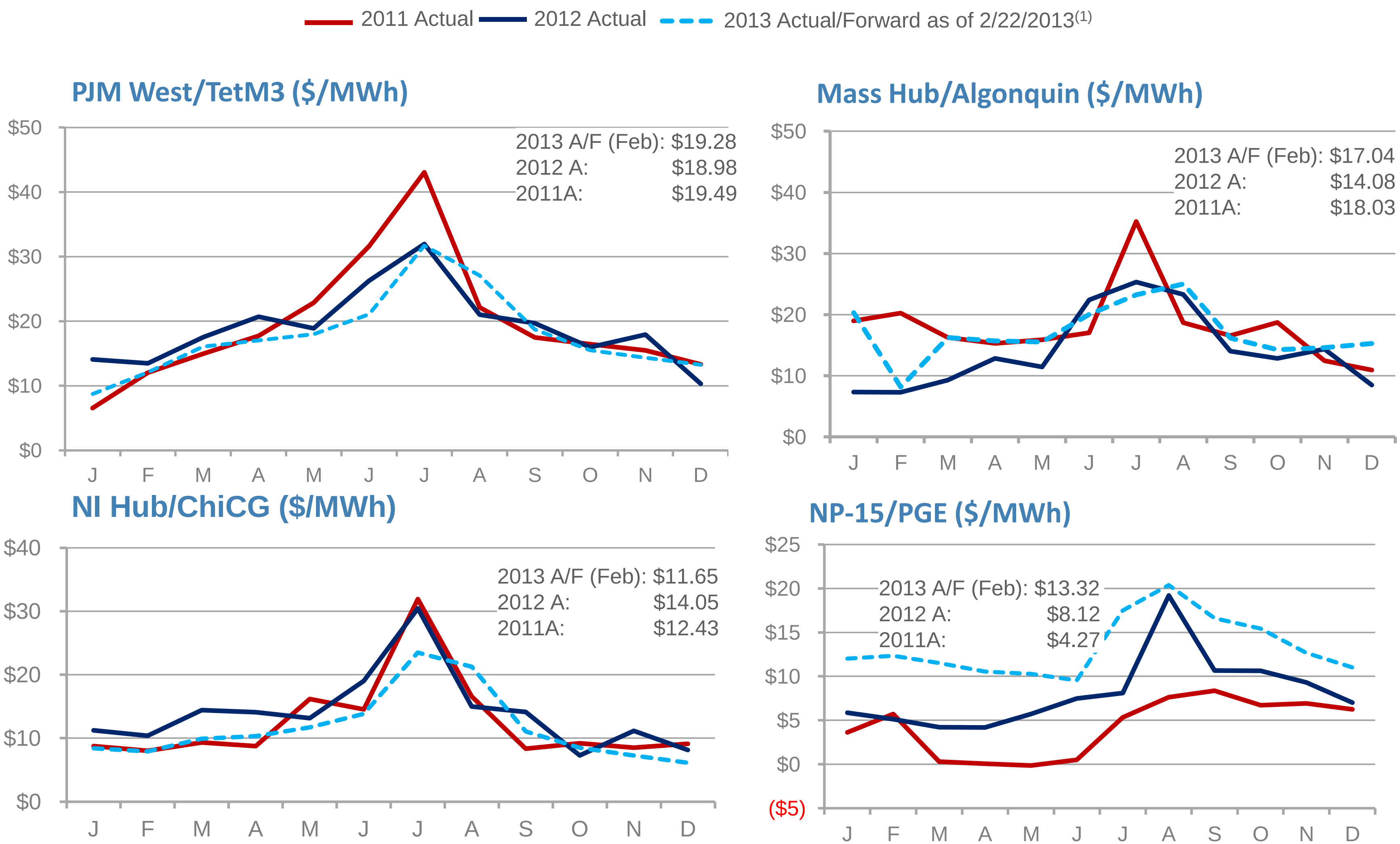
Natural Gas ($/MMBtu)



(1) Prices reflect actual day ahead on-peak settlement prices for 1/1/2013 – 2/22/2013 and quoted forward on-peak monthly prices for 2/23/2013-12/31/2013 (2) Cin Hub pricing data for 2011; Indiana Hub data starting 1/1/2012.

DYNEGY

Spark Spreads (on-peak)



(1) Prices reflect actual day ahead on-peak settlement prices for 1/1/13 – 2/22/13 and quoted forward on-peak monthly prices for 2/23/13 - 12/31/13

DYNEGY

Adjusted EBITDA Sensitivities

$ mm

		2013		Unhedged Year	
		Gas	Coal	Gas	Coal
Market Implied Heat Rate Movement (Btu/KWh)	+ 500 HR[(1)]	$9	$18	$30	$ 39
Change in Cost of Natural Gas ($/MMBtu)	+ $1 Gas[(2)]	$(14)	$69	$(4)	$153
	Additional impact to Natural Gas Sensitivity assuming current market heat rates	$6	$14	$46	$33
	+$1/MWh increase in basis				$22

Shows impact of a change in market implied heat rates on earnings, **holding gas prices and expected generation levels constant**

Shows impact of a change in gas prices on earnings , **where power prices are adjusted by holding spark spreads constant for a 7,000 Btu/kWh heat rate and expected generation levels are held constant**

(1) Sensitivities based on power price changes and full-year estimates; Assumes constant natural gas price of $3.46/MMBtu and heat rate changes are for a full year

(2) Sensitivities based on full-year estimates and assume natural gas price change occurs for the entire year and entire portfolio; power prices are adjusted by holding the spark spread constant for a 7,000 Btu/KWh heat rate

DYNEGY

Market Pricing

Average Actual Power/Gas Prices ($/MWh)

	4Q11		4Q12		FY11		FY12	
	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak
Henry Hub ($/MMBtu)	$3.3	$3.3	$3.4	$3.4	$4.0	$4.0	$2.7	$2.7
INDY Hub	$34	$27	$35	$26	$41	$29	$35	$25
Mass Hub	$42	$34	$50	$41	$53	$41	$42	$31
NP15	$35	$27	$38	$30	$36	$22	$32	$23
NY – Zone A	$37	$31	$38	$30	$42	$34	$36	$27
PJM-W	$40	$32	$40	$32	$51	$37	$40	$29

Average Plant Spark Spreads ($/MWh)

	4Q11		4Q12		FY11		FY12	
	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak
PJM West/ TetM3	$15	$8	$15	$6	$19	$5	$19	$8
Ni Hub/ChiCG	$9	$(3)	$9	$(1)	$12	$(3)	$14	$4
NP-15/PGE	$9	$1	$10	$2	$4	$(7)	$8	$3
NY – Zone A/ Dominion	$13	$7	$15	$7	$13	$6	$16	$8
Mass Hub/Algonquin	$14	$7	$12	$3	$18	$6	$14	$4

DYNEGY

Gas Segment: Tolling, Capacity and Other

Tolling Agreements

Plant	Contract Type	Size (MW)	Tenor
Moss Landing 6&7	Tolling Agreement	1,509	Through 2013
Oakland	RMR	165	Through Dec-2013
Independence	Steam & Energy	44	Through Jan-2017
Kendall	Tolling Agreement	50-85	Through Sep-2017

Capacity / Resource Adequacy

Plant	Contract Type	Clearing Price (1)	Size (MW)	Tenor
Casco Bay	ISO-NE Capacity Auction	$2.95/kw-mo	410	Jun-2012 to May-2013
		$2.34/kw-mo	488	Jun-2013 to May-2014
		$3.21/kw-mo	435	Jun-2014 to May-2015
		$3.43/kw-mo	445	Jun-2015 to May-2016
Kendall	PJM Capacity Auction	$16.46/MW-day	1,019	Jun-2012 to May-2013
		$27.73/MW-day	1,008	Jun-2013 to May-2014
		$125.99/MW-day	1,016	Jun-2014 to May-2015
		$136.00/MW-day	1,033	Jun-2015 to May 2016
Ontelaunee	PJM Capacity Auction	$133.37/MW-day	503	Jun-2012 to May-2013
		$226.15/MW-day	504	Jun-2013 to May-2014
		$136.50/MW-day	492	Jun-2014 to May-2015
		$167.46/MW-day	503	Jun -2015 to May 2016
Moss Landing 1&2	RA Capacity		321	Avg Bilateral Sold 2013
			25	Avg Bilateral Sold 2014
Independence	ICAP - Con Ed		740	Through Oct-2014

(1) Publicly disclosed clearing prices have been added where applicable

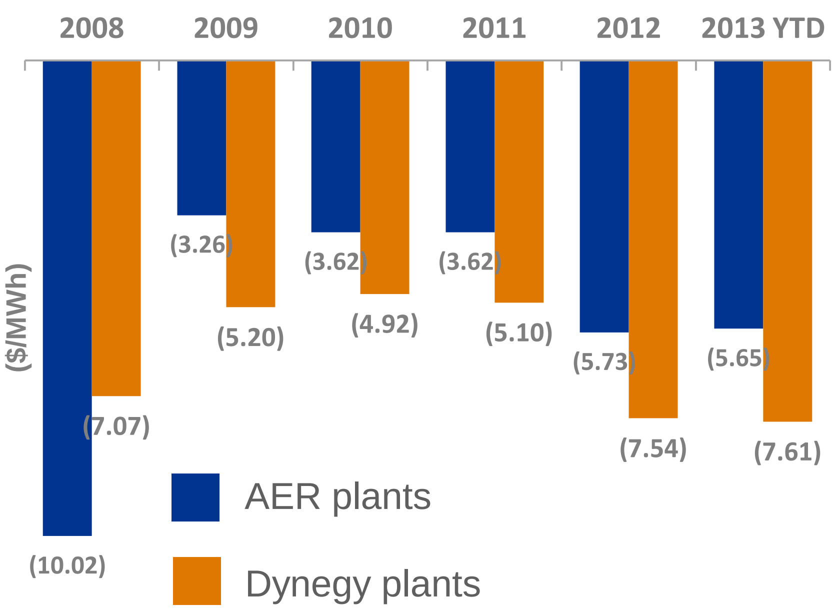
DYNEGY

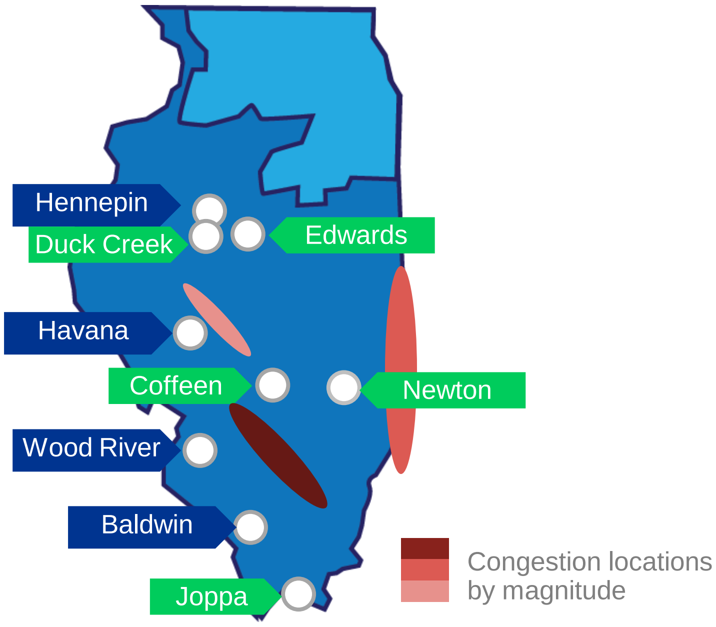
Appendix
AER Coal Fleet Information

DYNEGY

AER's fleet experiences lower and less volatile basis issues than Dynegy

Average On-Peak Generation-Weighted Basis





– E.D. Edwards, Duck Creek, Coffeen and Newton are located North of a major congestion point and experience lower basis, similar to Havana and Hennepin

– Joppa has ~1,000 MW of firm transmission into Illinois that aids in managing basis

Compliance Profiles: Environmental Control Technologies

DI Plant	Acid Gases (SO2)	Mercury (Hg)	NOx	Particulates
Baldwin 1	Dry FGD	CaBr	Overfire Air, SCR	ESP, FF
Baldwin 2	Dry FGD	CaBr	Overfire Air, SCR	ESP, FF
Baldwin 3	Dry FGD	ACI & CaBr	Low NOx burners, Overfire Air	ESP, FF
Havana 6	Dry FGD	ACI	Low NOx burners, Overfire Air, SCR	ESP, FF
Hennepin 1-2	Ultra low sulfur coal	ACI & CaBr	Low NOx burners, Overfire Air	ESP, FF
Wood River 4	Ultra low sulfur coal	ACI & CaBr	Low NOx burners, Overfire Air	ESP
Wood River 5	Ultra low sulfur coal	ACI & CaBr	Low NOx burners, Overfire Air	ESP

AER Plant	Acid Gases (SO2)	Mercury (Hg)	NOx	Particulates (Nox)
Coffeen 1	Wet FGD		Overfire Air, SCR	ESP
Coffeen 2	Wet FGD		Overfire Air, SCR	ESP
Joppa Steam 1-6		ACI	Low NOx burners, Separated Overfire Air except Unit 2	ESP
Newton 1-2 (1)	Scrubbers under construction	ACI & CaBr	Low NOx burners, Overfire Air	ESP
Duck Creek 1	Wet FGD		Low NOx burners, SCR	ESP
E. D. Edwards 1		ACI	Low NOx burners, Overfire Air	ESP -upgrades planned 2014
E. D. Edwards 2		ACI	Low NOx burners, Overfire Air	ESP
E.D. Edwards 3		ACI	Low NOx burners, Overfire Air, SCR	ESP

Abbreviations

FGD – Flue Gas Desulphurization ("scrubber")
CaBr – Calcium Bromide
ACI – Activated Charcoal Injection

ESP – Electrostatic Precipitator
FF – Fabric Filter
SCR – Selective Catalytic Reduction

(1) In order to comply with the Multi-Pollutant Standard, Ameren Energy Resources has retired two of its facilities, Meredosia and Hutsonville, and has spent $237 million on scrubbers at Newton to date, which must be completed by December 31, 2019.

DYNEGY

Appendix
Reg G Reconciliations

DYNEGY

Reg G Reconciliation – 4th Quarter 2012 Adjusted EBITDA

DYNEGY

DYNEGY INC.
REPORTED SEGMENTED RESULTS OF OPERATIONS
THREE MONTHS ENDED DECEMBER 31, 2012
(UNAUDITED) (IN MILLIONS)

The following table provides summary financial information data regarding our enterprise-wide Adjusted EBITDA for the three months ended December 31, 2012:

	Successor			
	Three Months Ended December 31, 2012			
	Coal	Gas	Other	Total
Net loss				$ (107)
Plus / (Less):				
Discontinued operations, net of taxes				(6)
Income tax benefit (1)				-
Interest expense				16
Depreciation and amortization expense				45
EBITDA from continuing operations (2)	$ (41)	$ 7	$ (18)	$ (52)
Plus / (Less):				
Bankruptcy reorganization items, net	-	-	3	3
Mark-to-market income, net	(6)	(39)	-	(45)
Amortization of intangible assets and liabilities (3)	29	32	-	61
Premium adjustment	1	(2)	-	(1)
Change in fair value of warrants	-	-	(8)	(8)
Enterprise-wide Adjusted EBITDA (2)	$ (17)	$ (2)	$ (23)	$ (42)
Less:				
Other Adjusted EBITDA				(23)
4Q 2012 Adjusted EBITDA Gas and Coal Segments				$ (19)
Plus / (Less):				
Option premiums				(4)
Legacy put options				29
4Q 2012 Adjusted EBITDA Gas and Coal Segments Excluding Option Activity				$ 6

(1) For the three months ended December 31, 2012, our overall effective tax rate on continuing operations was different than the federal statutory rate of 35 percent as a result of a valuation allowance to eliminate our deferred tax assets.

(2) EBITDA and Adjusted EBITDA are non-GAAP financial measures. Please refer to Item 2.02 of our Form 8-K filed on March 14, 2013, for definitions, utility and uses of such non-GAAP financial measures. A reconciliation of EBITDA to Operating loss is presented below. Management does not allocate interest expense and income taxes on a segment level and therefore uses Operating loss as the most directly comparable GAAP measure.

(3) The amounts within the Coal and Gas segments relate to intangible assets and liabilities related to rail transportation, coal contracts, gas revenue contracts and transportation contracts recorded in connection with the application of fresh-start accounting.

	Successor			
	Three Months Ended December 31, 2012			
	Coal	Gas	Other	Total
Operating loss	$ (49)	$ (31)	$ (24)	$ (104)
Bankruptcy reorganization items, net	-	-	(3)	(3)
Depreciation and amortization expense	8	36	1	45
Earnings from unconsolidated investment	-	2	-	2
Other items, net	-	-	8	8
EBITDA from continuing operations	$ (41)	$ 7	$ (18)	$ (52)

Reg G Reconciliation – 4th Quarter 2011 Adjusted EBITDA

DYNEGY INC.
REPORTED SEGMENTED RESULTS OF OPERATIONS
THREE MONTHS ENDED DECEMBER 31, 2011
(UNAUDITED) (IN MILLIONS)

The following table provides summary financial information data regarding our enterprise-wide Adjusted EBITDA by segment for the three months ended December 31, 2011:

	Predecessor			
	Three Months Ended December 31, 2011			
	Coal	Gas	Other	Total
Net loss				$ (616)
Plus / (Less):				
Discontinued operations				468
Income tax benefit (1)				(50)
Interest expense				65
Depreciation and amortization expense				34
EBITDA from continuing operations (2)	$ -	$ (55)	$ (44)	$ (99)
Plus / (Less):				
Bankruptcy reorganization items, net	-	-	52	52
Merger agreement termination fee, restructuring costs and other expenses	-	(5)	19	14
Mark-to-market (income) loss, net	-	38	(1)	37
Adjusted EBITDA from continuing operations (2)	$ -	$ (22)	$ 26	$ 4
Adjusted EBITDA from Legacy Dynegy (3)	37	-	(45)	(8)
Adjusted EBITDA	$ 37	$ (22)	$ (19)	$ (4)
Adjusted EBITDA from discontinuing operations				(10)
Enterprise-wide Adjusted EBITDA				$ (14)
Less:				
DNE Adjusted EBITDA				(10)
Other Adjusted EBITDA				(19)
4Q 2011 Adjusted EBITDA Gas and Coal Segments				$ 15
Plus / (Less):				
Option premiums				9
4Q 2011 Adjusted EBITDA Gas and Coal Segments Excluding Option Activity				$ 24

(1) For the three months ended December 31, 2011, the difference between the effective tax rate of 25 percent and the federal statutory tax rate of 35 percent resulted primarily from a valuation allowance to eliminate our net deferred tax assets partially offset by the impact of state taxes.

(2) EBITDA and Adjusted EBITDA are non-GAAP financial measures. Please refer to Item 2.02 of our Form 8-K filed on March 14, 2013, for definitions, utility and uses of such non-GAAP financial measures. A reconciliation of EBITDA to Operating loss is presented below. Management does not allocate interest expense and income taxes on a segment level and therefore uses Operating loss as the most directly comparable GAAP measure.

	Predecessor			
	Three Months Ended December 31, 2011			
	Coal	Gas	Other	Total
Operating loss	$ -	$ (88)	$ (17)	$ (105)
Bankruptcy reorganization items, net	-	-	(52)	(52)
Other items, net	-	1	23	24
Depreciation and amortization expense	-	32	2	34
EBITDA from continuing operations	$ -	$ (55)	$ (44)	$ (99)

(3) Our 2011 consolidated results reflect the results of our accounting predecessor, DH, which was our wholly-owned subsidiary until the Merger on September 30, 2012. Therefore, certain results related to Legacy Dynegy are not included in our consolidated results for the three months ended December 31, 2011. Additionally, effective September 1, 2011, we completed the DMG Transfer. As a result, the results of our Coal segment, as well as certain items in the Other segment, are not included in our consolidated results for the three months ended December 31, 2011. However, we have included the Adjusted EBITDA related to Legacy Dynegy and the Coal segment for the three months ended December 31, 2011 in this adjustment because management uses enterprise-wide Adjusted EBITDA to evaluate the operating performance of our entire power generation fleet. The following table presents a reconciliation of Legacy Dynegy Adjusted EBITDA to Operating loss:

	Predecessor			
	Three Months Ended December 31, 2011			
	Coal	Gas	Other	Total
Operating loss	$ (14)	$ -	$ (34)	$ (48)
Depreciation and amortization expense	37	-	(1)	36
Other items, net	1	-	(34)	(33)
EBITDA	24	-	(69)	(45)
Restructuring charges and other expenses	(3)	-	14	11
Impairment and other charges	-	-	10	10
Mark-to-market loss, net	16	-	-	16
Adjusted EBITDA from Legacy Dynegy	$ 37	$ -	$ (45)	$ (8)

DYNEGY

Reg G Reconciliation – FY 2012 Adjusted EBITDA

DYNEGY

DYNEGY INC.
REPORTED SEGMENTED RESULTS OF OPERATIONS
TWELVE MONTHS ENDED DECEMBER 31, 2012
(UNAUDITED) (IN MILLIONS)

The following table provides summary financial data regarding our enterprise-wide Adjusted EBITDA for the twelve months ended December 31, 2012:

	Combined			
	Twelve Months Ended December 31, 2012			
	Coal	Gas	Other	Total
Net loss				$ (139)
Plus / (Less):				
Loss from discontinued operations, net of taxes				156
Income tax benefit (1)				(9)
Interest expense				136
Depreciation and amortization expense				155
EBITDA from continuing operations (2)	$ (86)	$ 228	$ 157	$ 299
Plus / (Less):				
Impairment of Undertaking receivable, affiliate	-	-	832	832
Bankruptcy reorganization items, net	-	-	(1,034)	(1,034)
Interest income on Undertaking receivable	-	-	(24)	(24)
Restructuring costs and other expense	-	-	3	3
Mark-to-market (income) loss, net	7	(166)	-	(159)
Amortization of intangible assets and liabilities (3)	78	61	-	139
Premium Adjustment	1	(1)	-	-
Change in fair value of warrants	-	-	(8)	(8)
Adjusted EBITDA (2)	-	122	(74)	48
Adjusted EBITDA from Legacy Dynegy (4)	20	-	(11)	9
Enterprise-wide Adjusted EBITDA (2)	$ 20	$ 122	$ (85)	$ 57
Less:				
Other Adjusted EBITDA				(85)
YTD 2012 Adjusted EBITDA Gas and Coal Segments				$ 142
Plus / (Less):				
Option premiums				(9)
Legacy put options				77
YTD 2012 Adjusted EBITDA Gas and Coal Segments Excluding Option Activity				$ 210

(1) For the twelve months ended December 31, 2012, the difference between the effective income tax rate of 113 percent and the statutory federal rate of 35 percent resulted primarily from a valuation allowance to eliminate our net deferred tax assets partially offset by the impact of state taxes. As of December 31, 2012, we do not believe we will produce sufficient future taxable income, nor are there tax strategies available, to realize our net deferred tax assets not otherwise realized by reversing temporary differences.

(2) EBITDA and Adjusted EBITDA are non-GAAP financial measures. Please refer to Item 2.02 of our Form 8-K filed on March 14, 2013, for definitions, utility and uses of such non-GAAP financial measures. A reconciliation of EBITDA to Operating income (loss) is presented below. Management does not allocate interest expense and income taxes on a segment level and therefore uses Operating income (loss) as the most directly comparable GAAP measure.

(3) The amount in the Coal segment in the 2012 Predecessor Period relates to intangible assets and liabilities related to rail transportation and coal contracts, respectively, recorded in connection with the DMG Acquisition. The amount in the Gas segment in the 2012 Predecessor Period is related to the intangible assets related to the 2005 Sithe acquisition. The amounts in the Successor Period related to intangible assets and liabilities related to rail transportation, coal contracts, gas revenue contracts and gas transportation contracts recorded in connection with the application of fresh-start accounting.

	Combined			
	Twelve Months Ended December 31, 2012			
	Coal	Gas	Other	Total
Operating income (loss)	$ (112)	$ 97	$ (84)	$ (99)
Impairment of Undertaking receivable, affiliate	-	-	(832)	(832)
Bankruptcy reorganization items, net	-	-	1,034	1,034
Depreciation and amortization expense	21	127	7	155
Earnings from unconsolidated investment	-	2	-	2
Other items, net	5	2	32	39
EBITDA from continuing operations	$ (86)	$ 228	$ 157	$ 299

(4) Our 2012 consolidated results reflect the results of our accounting predecessor, DH, which was our wholly-owned subsidiary until the Merger on September 30, 2012. Therefore, certain results related to Legacy Dynegy are not included in our consolidated results for the 2012 Predecessor Period. Additionally, effective June 5, 2012, we completed the DMG Acquisition. As a result, the results of our Coal segment, as well as certain items in the Other segment, are not included in our consolidated results for the period from January 1, 2012 through June 5, 2012. However, we have included the Adjusted EBITDA related to Legacy Dynegy for the 2012 Predecessor Period and the Coal segment for the period from January 1, 2012 through June 5, 2012 in this adjustment because management uses enterprise-wide Adjusted EBITDA to evaluate the operating performance of our entire power generation fleet. The following table presents a reconciliation of Legacy Dynegy Adjusted EBITDA to Operating income (loss):

	Combined			
	Twelve Months Ended December 31, 2012			
	Coal	Gas	Other	Total
Operating income (loss)	$ (2,702)	$ -	$ 1,670	$ (1,032)
Depreciation and amortization expense	78	-	-	78
Bankruptcy reorganization items, net	-	-	(8)	(8)
Loss from unconsolidated investment	-	-	(1)	(1)
EBITDA	(2,624)	-	1,661	(963)
Loss (gain) on Coal Holdco Transfer	2,652	-	(1,711)	941
Bankruptcy reorganization items, net	-	-	8	8
Restructuring costs and other expense	-	-	30	30
Mark-to-market income, net	(8)	-	-	(8)
Loss from unconsolidated investment	-	-	1	1
Adjusted EBITDA from Legacy Dynegy	$ 20	$ -	$ (11)	$ 9

Reg G Reconciliation – FY 2011 Adjusted EBITDA

DYNEGY INC.
REPORTED SEGMENTED RESULTS OF OPERATIONS
TWELVE MONTHS ENDED DECEMBER 31, 2011
(UNAUDITED) (IN MILLIONS)

The following table provides summary financial data regarding our enterprise-wide Adjusted EBITDA by segment for the twelve months ended December 31, 2011:

	Predecessor			
	Twelve Months Ended December 31, 2011			
	Coal	Gas	Other	Total
Net loss				$ (940)
Plus / (Less):				
Loss from discontinued operations, net of taxes				509
Income tax benefit (1)				(144)
Interest expense and debt extinguishment costs				369
Depreciation and amortization expense				295
EBITDA from continuing operations (2)	$ 120	$ 97	$ (128)	$ 89
Plus / (Less):				
Bankruptcy reorganization items, net	-	-	52	52
Merger agreement termination fee, restructuring costs and other expenses	(1)	7	25	31
Mark-to-market loss, net	76	51	4	131
Adjusted EBITDA from continuing operations (2)	195	155	(47)	303
Adjusted EBITDA from Legacy Dynegy (3)	48	-	(51)	(3)
Adjusted EBITDA	$ 243	$ 155	$ (98)	$ 300
Adjusted EBITDA from discontinuing operations				(19)
Enterprise-wide Adjusted EBITDA				$ 281
Less:				
DNE Adjusted EBITDA				(19)
Other Adjusted EBITDA				(98)
YTD 2011 Adjusted EBITDA Gas and Coal Segments				$ 398
Plus / (Less):				
Option premiums				(27)
YTD 2011 Adjusted EBITDA Gas and Coal Segments \Excluding Option Activity				$ 371

(1) For the twelve months ended December 31, 2011, the difference between the effective tax rate of 25 percent and the statutory federal rate of 35 percent resulted primarily due to the impact of state taxes partially offset by a change in our valuation allowance. We do not believe we will produce sufficient taxable income, nor are there tax planning strategies available to realize the tax benefit.

(2) EBITDA and Adjusted EBITDA are non-GAAP financial measures. Please refer to Item 2.02 of our Form 8-K filed on March 14, 2013, for definitions, utility and uses of such non-GAAP financial measures. A reconciliation of Operating loss to EBITDA from continuing operations is presented below. Management does not allocate interest expense and income taxes on a segment level and therefore uses Operating loss as the most directly comparable GAAP measure.

	Predecessor			
	Twelve Months Ended December 31, 2011			
	Coal	Gas	Other	Total
Operating loss	$ (38)	$ (37)	$ (114)	$ (189)
Bankruptcy reorganization items, net	-	-	(52)	(52)
Other items, net	2	2	31	35
Depreciation and amortization expense	156	132	7	295
EBITDA from continuing operations	$ 120	$ 97	$ (128)	$ 89

(3) Our 2011 consolidated results reflect the results of our accounting predecessor, DH, which was a wholly-owned subsidiary until the Merger on September 30, 2012. Therefore, certain results related to Legacy Dynegy are not included in our consolidated results for the twelve months ended December 31, 2011. Additionally, effective September 1, 2011, we completed the DMG Transfer. As a result, the results of our Coal segment, as well as certain items in the Other segment, are not included in our consolidated results for the period from September 1, 2011 through December 31, 2011. However, we have included the Adjusted EBITDA related to Legacy Dynegy for the twelve months ended December 31, 2011 and the Coal segment for the period from September 1, 2011 through December 31, 2011 in this adjustment because management uses enterprise-wide Adjusted EBITDA to evaluate the operating performance of our entire power generation fleet. The following table presents a reconciliation of Legacy Dynegy Adjusted EBITDA to Operating loss:

	Predecessor			
	Twelve Months Ended December 31, 2011			
	Coal	Gas	Other	Total
Operating loss	$ (18)	$ -	$ (40)	$ (58)
Depreciation and amortization expense	50	-	(1)	49
Other items, net	(1)	-	(39)	(40)
EBITDA	31	-	(80)	(49)
Restructuring charges and other expenses	2	-	19	21
Impairment and other charges	-	-	10	10
Mark-to-market loss, net	15	-	-	15
Adjusted EBITDA from Legacy Dynegy	$ 48	$ -	$ (51)	$ (3)

Reg G Reconciliation – 2013 Guidance

Regulation G Reconciliation
DYNEGY INC.
2013 Guidance
(IN MILLIONS)

	CoalCo		GasCo		Corporate and Other		Dynegy Consolidated	
	Low	High	Low	High	Low	High	Low	High
Gross Margin	$ 92	$ 131	$ 252	$ 277	$ -	$ -	$ 369	$ 408
Plus:								
Amortization of Intangibles	120	130	120	132	-	-	240	262
Adjusted Gross Margin	212	261	372	409	-	-	609	670
Operating Expenses	(152)	(176)	(118)	(129)	-	-	(270)	(305)
Adjusted EBITDA excluding General and Administrative Expenses	60	85	255	280	-	-	340	365
General and Administrative Expenses	-	-	-	-	(90)	(90)	(90)	(90)
Adjusted EBITDA	$ 60	$ 85	$ 255	$ 280	$ (90)	$ (90)	$ 250	$ 275

	CoalCo		GasCo		Corporate		Dynegy Consolidated	
	Low	High	Low	High	Low	High	Low	High
Adjusted Gross Margin	$ 212	$ 261	$ 372	$ 409	$ -	$ -	$ 609	$ 670
Amortization of Intangibles	(120)	(130)	(120)	(132)	-	-	(240)	(262)
Operating Expenses	(152)	(176)	(118)	(129)	-	-	(270)	(305)
Depreciation Expense	(33)	(47)	(137)	(151)	(2)	(2)	(172)	(200)
General and Administrative Expenses	-	-	-	-	(90)	(90)	(90)	(90)
Operating Income (Loss)	$ (93)	$ (92)	$ (2)	$ (3)	$ (92)	$ (92)	$ (162)	$ (187)

	CoalCo		GasCo		Corporate		Dynegy Consolidated	
	Low	High	Low	High	Low	High	Low	High
Net Income (Loss)							$ (306)	$ (332)
Add Back:								
Interest Expense							145	145
Operating Income (Loss)	$ (93)	$ (92)	$ (2)	$ (3)	$ (92)	$ (92)	$ (162)	$ (187)
Depreciation Expense	33	47	137	151	2	2	172	200
EBITDA (1)	(60)	(45)	135	148	(90)	(90)	10	13
Plus:								
Amortization of Intangibles	120	130	120	132	-	-	240	262
Adjusted EBITDA (1)	$ 60	$ 85	$ 255	$ 280	$ (90)	$ (90)	$ 250	$ 275

(1) EBITDA and Adjusted EBITDA are non-GAAP Measures. Management does not allocate interest expenses and income taxes on a segment level and therefore uses Operating Income (Loss) as the most directly comparable GAAP measure.

Free Cash Flow Guidance - Regulation G Reconciliation
(IN MILLIONS)

	Dynegy Consolidated	
	Low	High
Adjusted EBITDA	$ 250	$ 275
Cash Interest Payments	(120)	(120)
Cash Tax Payments	-	-
Collateral	20	20
Other Changes	20	20
Cash Flow from Operations	170	195
Maintenance Capital Expenditures	(100)	(100)
Environmental Capital Expenditures	(10)	(10)
Costs to refinance debt	(45)	(45)
Return of restricted cash posted as collateral, net (2)	125	125
Free Cash Flow	$ 140	$ 165

(2) Amount represents the return of restricted cash posted as collateral net of $150 million used to repay existing debt.

DYNEGY