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Dynegy: Coal Expansion Poses Risk to Shareholders

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Introduction

In April 2007, Dynegy completed a combination of operating assets and the establishment of a development joint venture with LS Power Group. The transaction increased Dynegy's electricity generation portfolio by approximately 8,000 MW, and created an entity with nearly 20,000 MW of generating capacity comprised of 29 power plants in 13 states. The merger also provided Dynegy with joint ownership of nine greenfield projects under various stages of development by LS Power. Since the merger was completed, three of the proposed projects were abandoned. Dynegy is currently planning to develop six coal-fired power plants in six states with a combined capacity of over 5,800 MW.

Executive Summary

Although Dynegy has abandoned plans to build three coal-fired power plants with a combined capacity of 1,900 MW, the company's current expansion plans present significant risks to shareholders. The completion of Dynegy's proposed 5,800 MW of new coal capacity would increase the company's reliance on coal generation by over 100%. Dynegy's annual CO_2 emissions would subsequently increase by over 41 million tonnes annually or 124% over 2006 levels. Depending on the structure of future legislation on climate change, the proposed expansion could result in annual CO_2 allowance costs of between \$880 million and over \$2 billion, assuming CO_2 costs of between \$21 and \$48/tonne.

Despite the likelihood that Dynegy's proposed coal-fired power plants will face significant CO_2 costs and shifts in consumer demand toward alternative forms of power generation; the company has not demonstrated how it will protect shareholder value and guarantee a return on investment for the development of over 5,800 MW of new coal capacity. This report focuses specifically on the current and emerging CO_2 regulatory landscape, and Dynegy's future exposure to the associated risks.

Finally, this report provides an in depth cost analysis of coal, gas, and wind generation in a carbon constrained economy using Dynegy's proposed Sandy Creek plant in Texas. The findings of this analysis suggest that under most predicted regulatory scenarios, natural gas is more financially viable for the construction of baseload generating capacity.

Carbon Regulation and the Power Sector

Consensus within the utility industry indicates that federal legislation on climate change is impending. Each of the remaining presidential candidates supports a national cap-and-trade system to reduce greenhouse gas (GHG) emissions. In addition, members of the 110th Congress have introduced climate change legislation at a faster pace than any previous Congress. As of March 2008, lawmakers had introduced in excess of 195 bills, resolutions, and amendments that address climate change and GHG emissions.[i]

Increasing momentum toward federal carbon regulation has shifted discussion within the utility industry from whether legislation will occur, to what shape future regulatory structures will take. A majority of the bills proposed and those favored by the remaining presidential candidates each employ a federal cap-and-trade system in which direct costs are assigned to carbon emissions through market mechanisms. Current proposals differ in timeline, scope, and method of permit allocation, but nearly all legislative efforts target the electric power industry for a limit on GHG emissions. In addition, various legislative efforts suggest that proposed coal-fired power plants will not be 'grandfathered' under future regulatory schemes.

In the absence of federal legislation on climate change, regional, state, and local governments continue to develop regulations to address greenhouse gas emissions from the utility sector. Currently, 28 states and the District of Columbia have established standards that require electric utilities to derive a specified amount of electricity from renewable sources. These requirements, which generally take the form of renewable portfolio standards, serve to shift the competitive balance away from coal power plants. Dynegy's proposed power plants in Iowa, Nevada, and Texas will be exposed to changes in the competitive landscape due to existing renewable portfolio standards. In addition, the company's proposed plant in Michigan will likely face similar challenges, as the state is expected to enact a renewable portfolio standard in July.

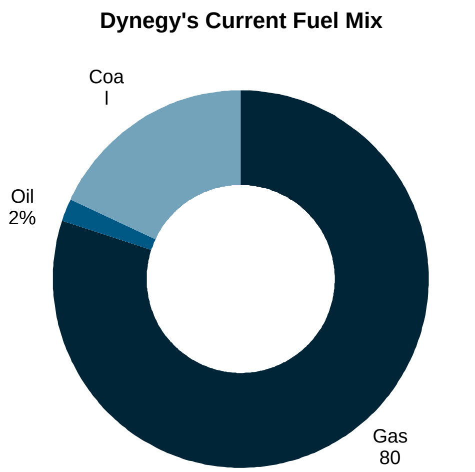
In addition to renewable portfolio standards and other state-level efforts, regional partnerships such as the Regional Greenhouse Gas Initiative, the Western Regional Climate Action Initiative, and Midwestern Regional Greenhouse Gas Reduction Accord have been developed to address climate change. Under these initiatives, member states have agreed to establish regional emissions reduction targets and to develop market-based systems to ensure that these targets are achieved. Both Dynegy's proposed Elk Run Energy Station in Iowa and Midland Power Plant in Michigan could be subject to carbon regulation under the Midwestern Accord.

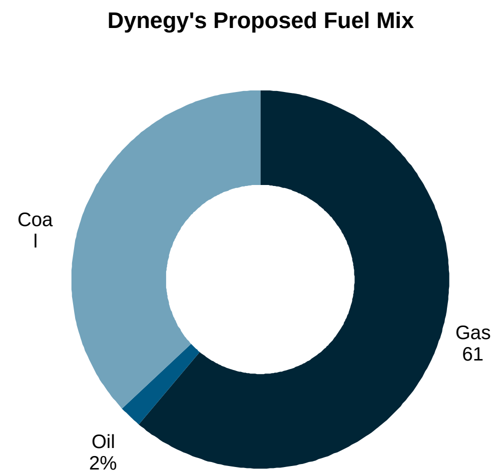
Given, this state and national policy shift toward mandatory greenhouse gas emissions reductions and renewable energy development, there is significant risk associated with Dynegy's strategic decision to pursue six new coal-fired power plants. This risk is intensified by the fact that Dynegy is a provider of merchant power, and is therefore forced to compete for wholesale customers, and has greater exposure to current market trends. As carbon regulations continue to be implemented the cost of coal generation will likely rise. The increased costs of coal generation coupled with renewable portfolio standards will likely cause utilities to seek alternative forms of generation and to limit their exposure to long-term contracts for electricity derived from traditional coal sources. Current and future regulatory constraints could severely limit Dynegy's ability to provide shareholder returns on the six proposed coal-fired power plants.

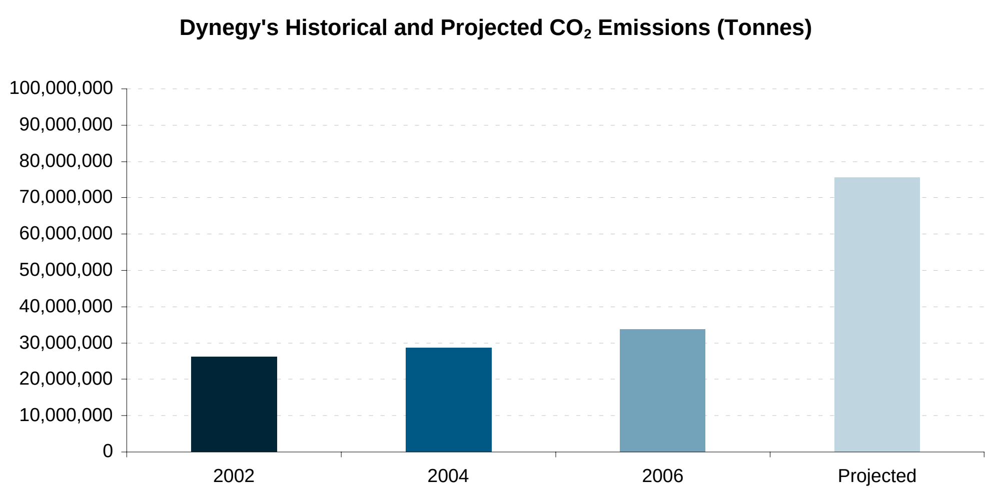
Dynegy's Current and Proposed Carbon Profile

Electric utilities continue to operate without federal limits on greenhouse gas emissions. However, as the previous section indicates, current and future regulatory structures will limit emissions from power plants. As a result, leading utilities have developed proactive strategies to protect shareholder value through voluntary greenhouse gas emissions reductions, improved energy efficiency, and renewable energy development. Dynegy's current expansion plan is in direct contrast to these efforts, and fails to account for the operational and financial risks associated with its plans to develop over 5,800 MW of new coal generating capacity. The company's apparent failure to incorporate the risks and opportunities associated with carbon regulation will likely expose its shareholders to significant risks.

The completion of Dynegy's proposed 5,865 MW of coal-fired capacity will increase the company's coal capacity by over 160% and its annual CO_2 emissions by over 120% relative to 2006 levels. Since, approximately 62% of Dynegy's installed gas generating capacity is peaking, the company's reliance on coal generation would likely increase significantly as these peaking plants are too expensive to run as baseload capacity. The addition of this new coal capacity, which would emit an estimated 41 million tonnes of CO_2 would move Dynegy from the US power sector's 18th largest emitter of CO_2 to the 5th.[ii,iii]







Assuming a federal cap-and-trade system in which 100% of emissions allocations are auctioned, and CO_2 prices of between \$21 and \$48/tonne, the completion of Dynegy's six proposed power plants could result in annual CO_2 costs of between \$880 million and over \$2 billion. Given Dynegy's role as a provider of merchant power, it will likely be more difficult to pass future CO_2 costs to consumers, as these consumers will likely seek less costly power purchase agreements.

Dynegy recognizes that the adoption of regulatory programs that mandate a substantial reduction in CO_2 emissions will have a significant impact on its business. However, the company's strategic expansion plan does not account for current regulatory trends that continue to shift the competitive balance away from coal-fired generation. These factors raise uncertainties about Dynegy's ability to provide a return on its investment and to protect shareholder value in light of impending carbon legislation.

Stakeholder Opposition to the Development of New Coal Capacity

Although numerous utilities continue to pursue new coal generating capacity, recent trends indicate that this strategy is facing increased opposition throughout the country. In 2007, stakeholder opposition coupled with rising construction costs resulted in the delay or cancellation of more than 50 power plants in 20 states. Since Dynegy completed its merger with LS Power in April, 2007, the company abandoned plans to develop coal-fired power plants in Colorado, New Jersey, and Virginia with proposed capacities of 600 MW, 500 MW, and 800 MW respectively. Although the remaining six plants are in various stages of development, none have been able to avoid stakeholder opposition, which is likely to cause significant delays and could potentially force Dynegy to abandon specific plants.

Traditional opposition to new coal power plants centered around concern over air emissions and the associated effects on public health. These concerns continue to be relevant, and are increasingly coupled with apprehension over the contribution of greenhouse gas emissions from new coal-fired power plants to climate change. As a result, regulators across the country are beginning to favor alternative forms of power generation and increased energy efficiency initiatives over new coal capacity. The following provides examples of some of the key regulatory developments regarding the development of new coal that have occurred during the last year.

In March 2008, the Rural Utility Service announced that it would not fund new coal plants in 2008 and 2009. Since 2001, the Rural Utility Service has issued more than $1.3 billion in low-cost financing to rural electric cooperatives for new power plant construction. The decision to suspend the funding of new coal fired power plants was a response to pending litigation and concern that the Rural Utilities Service was putting taxpayers at risk and undermining efforts to address global climate change. This decision will affect at least six proposed coal plants in Montana, Kentucky, Illinois, Arkansas, Texas, and Missouri.

PacifiCorp recently cancelled plans to develop 950 MW of new coal capacity at its existing Intermountain Power station. The company sited concern over climate change after six California cities that rely on the plant refused to support the proposed expansion. PacifiCorp will subsequently focus on developing new natural gas or wind generating capacity.

In October 2007, Sunflower Electric Power was denied an air permit for its proposed 1,400 MW of new coal generating capacity in Holcomb, Kansas. In denying the permit, the Kansas Department of Health and Environment became the first government agency in the United States to cite CO_2 emissions as the reason for refusing an air permit for a coal-fired power plant. The Kansas legislature recently failed to overturn this decision.

Finally, the US EPA Environmental Appeals Board in Washington is currently hearing a case brought by the Sierra Club involving a waste-coal-fired plant proposed in Utah by Bonanza Power. The issue before the Board is whether the Supreme Court's Massachusetts v. EPA ruling that CO_2 is a pollutant requires power plant developers to establish emission limits for CO_2. The Board has determined that this is an issue of national significance, and has scheduled oral arguments for May 19th in Washington, DC, with a decision expected to follow within two to three months. The national implications of this case would be significant as a ruling in favor of CO_2 limits would require all coal power plant projects to determine methods to reduce their CO_2 emissions.

It remains difficult to predict exactly what impact stakeholder opposition will have on each of Dynegy's proposed coal-fired power plants. However, national trends suggest that the current challenges to each of the six proposed plants will likely cause significant delays, and may ultimately force Dynegy to reconsider specific facilities. Shareholders should recognize these risks and the potential for cost overruns as a result of the associated delays.

Rising Coal Costs Pose Additional Challenges

In addition to regulatory challenges and potential shifts in demand for new coal capacity, the profitability of Dynegy's proposed expansion will also likely be affected by rising coal prices. Over the last year, a rise in global demand for coal has lead to a sharp increase in coal prices that is expected to continue through at least 2009. This trend is exemplified by a 90% increase in spot prices for central Appalachia coal and a 65% increase in Powder River Basin coal in Wyoming in the last year. [iv]

Dynegy's strategic decision to pursue new coal capacity as a source of less expensive baseload power appears to neglect the recent and predicted increase in coal prices. This coupled with future CO_2 costs will further shift the competitive balance away from coal-fired electricity generation, and challenge the profitability of the company's proposed expansion.

Cost Comparison of Coal, Gas, and Wind Generation

Dynegy's decision to expand its generation using coal-fired plants occurs at a time of conflicting pressures on the electric power sector: from one side continuing increases in demand, and from the other looming legislation on climate change that will likely establish a federal cap-and-trade system limiting the amount of GHG emissions that power plants can emit and putting a price on these emissions.

In this context, it is critical that stakeholders of new power plants projects consider the potential costs of compliance coupled with emissions regulations and a range of non-financial 'carbon risks' alongside traditional financial considerations. Using data from Dynegy's proposed Sandy Creek plant in Texas, this analysis reviews the relative risks of three power plant scenarios in a carbon-constrained operating environment:

1. **Super-critical black coal (referred to herein as SC coal or coal-fired)**
2. **Combined cycle gas turbine (CCGT or gas-fired)**
3. **Wind turbine**

Constructions costs for the Sandy Creek project were initially estimated in $2,300 per kW.[v] Although construction costs have likely increased from these original price estimates to between $2,600 per kW and $3,000 per kW as a result of rising global demand for construction materials and services, the following analysis is based on the original cost projections to present a more conservative scenario.[vi]

The following table shows some of the key cost considerations for a new power plant of each type. [vii]

	(1)	(2)	(3)
	SC Coal	CCGT	Wind*
Construction costs for 900MW project ($ million)	2075	783	1620
Fuel costs ($/MWh)	6.15	20.50	0
GHG emissions per MWh (tonnes CO_2e)	0.96	0.59	0

* Note that wind projects are also eligible for a 2cent/kWh Production Tax Credit nationally, and in Texas are eligible to earn Renewable Energy Certificates, which have recently traded at around $5/MWh. These policy incentives for renewable energy are not included in the remainder of this analysis.

A critical determining factor of the fuel chosen under a carbon constrained economy is its relative GHG intensity. A new coal-fired power plant has emissions almost 50% higher than that of a comparable gas-fired plant. This analysis considers a number of factors that are pivotal to a utility's choice between developing coal-fired, gas-fired or wind power plants under a carbon cap-and-trade system:

- **First, a model was developed a to assess cash flows over ten years for each, varying key parameters to quantify their effect on the plant's profitability, a key indicator of the project's credit risk**
- **Second, cost functions were derived for each option in order to quantify a 'switching price' for the price of carbon, above which gas or wind provides cheaper base-load electricity than coal.**

1. CREDIT RISK IMPLICATIONS OF EMISSIONS TRADING

The relative financial positions of new power plants under any carbon legislation are highly dependent on two key factors:

- **The market price of GHG emissions**
- **The degree to which emissions permits are auctioned versus freely allocated.**

The EU ETS provides perhaps the best available indication of the market price for emissions, though it is a young and still evolving market. Futures contracts on emissions permits expiring in 2010 have averaged $27 (€20) per tonne of CO_2e over time, and have recently traded at around these levels. From what can be surmised from the experience to date in the EU ETS, and from legislative proposals circulating in the Congress, electric utilities can expect to have to purchase a majority or all of their emissions permits via the market in the medium and long term.

For example, the Lieberman-Warner: America's Climate Security Act establishes that 20% of the National Emission Allowance Account will be allocated to the electric power sector. To put this figure in context, the electric power sector was responsible for more than 50% of the increase in GHG emissions between 2000 and 2006, and will remain the largest source of CO_2 emissions in the next 20 years. The bill also mandates that a 20% allocation will remain constant for the first five years and then it will transition to 0% by 2035. [viii]

To demonstrate the impact of a cap-and-trade scheme on an electric utility's financial position, three different price scenarios for three auctioning cases were considered. The pricing scenarios included an expected maximum of $48, a minimum of $21, and a most likely case of $30 per tonne of CO_2e. [ix] With regards to the auctioning, the following scenarios were modeled: 100% of permits allocated for free; 50% of permits allocated free; and 0% of permits allocated free (full auctioning). [x]

The model assumes a steady three percent per annum increase in prices, costs, and revenues to reflect inflation so that the impacts of varying carbon prices and allocation/auctioning scenarios can be more clearly observed. Additionally, the economic viability of the project is assessed for the investment as a whole in order to further isolate the effect of carbon regulations in the decision to construct a power plant. The following summarizes the effect of varying carbon prices and the level of free permit allocation on a power plant's financial performance, measured by pre-tax profit margin.

	Level of free permit allocation		
Pricing scenario	**100%**	**50%**	**0%**
Min. Case \$21.00 per tCO_2e	coal	gas	gas
Exp. Case \$30.00 per tCO_2e	coal	gas	gas
Max. Case \$48.00 per tCO_2e	coal	gas	wind

For a price of \$30 per tonne of CO_2e where all allowances are allocated up to the reduction target, SC coal provides higher profitability. The pre-tax profit margin averages two percentage points higher for coal compared with gas. With 100% auctioning, gas provides a significantly higher profitability than coal. The pre-tax profit margin is 12 percentage points higher for gas compared with coal. With 50% auctioning, gas provides a somewhat higher profitability than coal. The pre-tax profit margin is six percentage points higher for gas compared with coal.[xi]

The following table summarizes the magnitude of carbon costs at the different price scenarios investigated, assuming full auctioning:

Carbon Costs in 2020 at Different Permit Prices

	\$ million		Percentage of EBIT	
Pricing scenario	**SC coal**	**CCGT**	**SC coal**	**CCGT**
Min. Case \$21.00 per tCO_2e	154.5	95.9	38.6	30.0
Exp. Case \$30.00 per tCO_2e	213.3	132.4	53.3	41.5
Max. Case \$48.00 per tCO_2e	335.3	208.1	83.8	65.2

In general, this analysis demonstrates that gas is a more financially sound choice for the construction of baseload generating capacity than coal in all scenarios except 100% free allocation of carbon allowances.

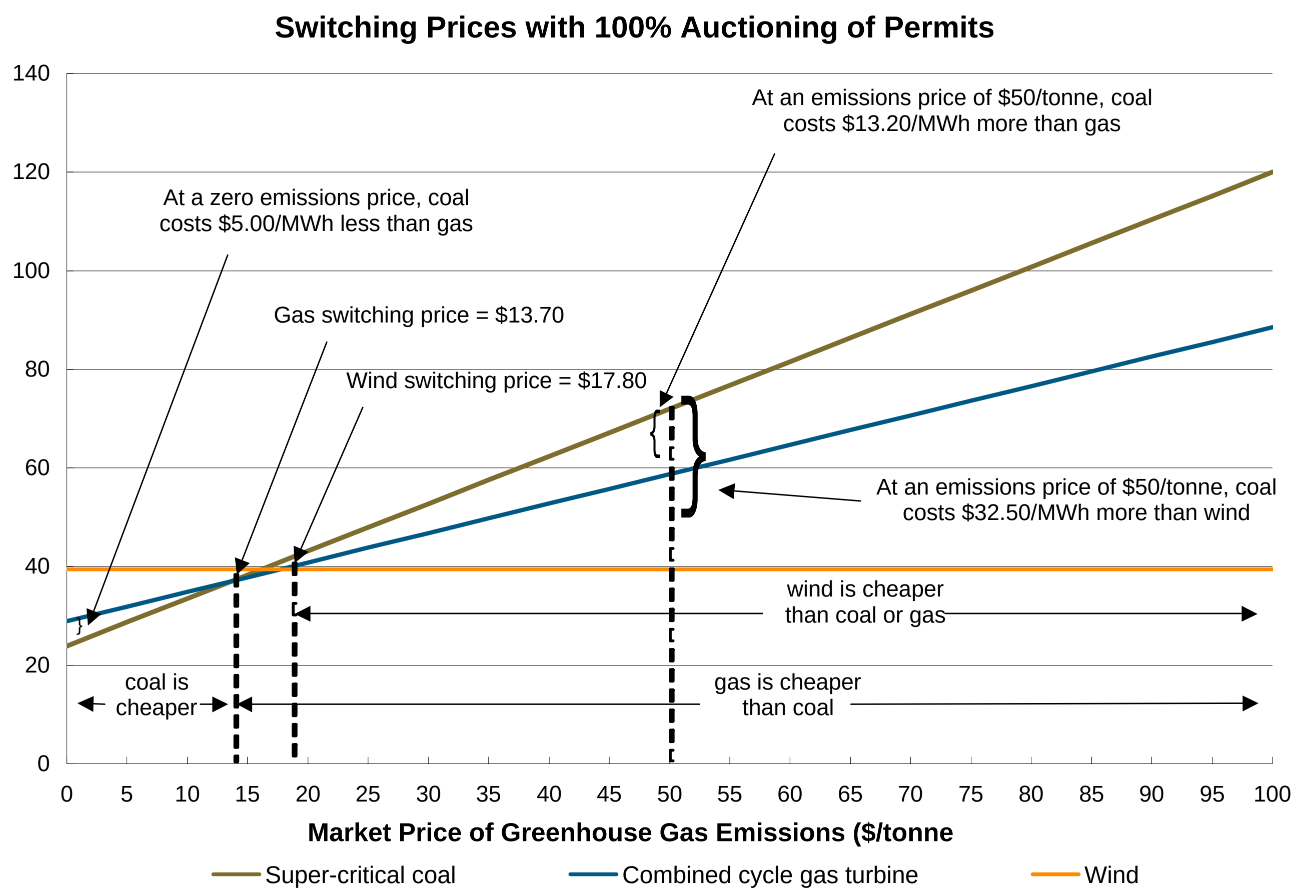
2. THE SWITCHING PRICE FOR GAS

The choice to develop less carbon-intensive generating capacity such as gas or wind can provide a natural hedge against uncertainty in carbon prices and allocation systems. By choosing coal over gas or wind, electric utilities must count on low carbon prices or high allocation of free permits. It should be noted that carbon prices do not represent a symmetric risk though, as prices are bounded by zero from below but unbounded above.

The asymmetric nature of carbon price risks can be measured using a simple cost model. Solving the cost functions for various carbon price levels demonstrates the advantage of gas from the perspective of asymmetric carbon price risks.

For low carbon prices, coal becomes the lower cost generation option, and when there is no price on carbon, coal has a cost advantage of \$5.00/MWh. This is the largest cost advantage attainable for coal. For gas on the other hand, the cost advantage rises continuously for higher carbon prices, reaching higher levels as the carbon price rises. For a \$50/tonne carbon price, gas is $13.20/MWh cheaper than coal, and for a $100/tonne carbon price gas is $31.50/MWh cheaper. At a carbon price of around $13.70, CCGT is able to provide base-load power at an equivalent cost to SC coal in the scenario where carbon permits are 100% auctioned. For carbon prices above this level, CCGT becomes the lower cost option for base-load electricity capacity. The following graph illustrates the switching price for gas.

Similarly, for higher carbon prices, wind is able to provide cheaper electricity than either coal or gas. At a carbon price of around $17.80, wind is equivalent in cost to gas, and at emissions prices above this level becomes a cheaper source of power than gas. Because of issues with intermittency in wind resource though, gas still has a large role to play for baseload and as a quick-start backup for wind at carbon prices at or above this level.



The above figure shows that the cost advantage of gas and wind continues to rise unbounded for higher carbon prices. Therefore, investing in gas and wind generation acts as a natural hedge against higher carbon prices, while investing in coal generation takes on price risk equivalent to selling a 30-40 year call option on rising carbon prices.

Conclusion

The addition of over 5,800 MW of new coal capacity is intended to provide Dynegy and its shareholders with a significant growth opportunity. However, the company's expansion plan does not adequately account for current state and federal policy trends that continue to shift the competitive balance away from coal fired generation. An analysis of the current and future regulatory environment and the associated costs of developing and operating coal-fired power plants indicates that the risks of Dynegy's proposed expansion could prevent it from achieving a profitable return on its investment. As a result, Dynegy's shareholders will likely be exposed to significant risks.

ABOUT INNOVEST

Innovest Strategic Value Advisors was founded in 1995 with the mission of integrating sustainability and finance by identifying non-traditional sources of risk and value potential for investors. Our analysis is designed to assist our clients in constructing and managing portfolios that out-perform the market. We do this by tracking company performance and strategic positioning on over 120 factors that are not captured or explained by the traditional, accounting-driven securities analysis. **To learn more about Innovest please see the contact information listed below, or visit us online at www.innovestgroup.com. We look forward to assisting you.**

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[i] Pew Center on Global Climate Change: http://pewclimate.org/what_s_being_done/in_the_congress/110thcongress.cfm
[ii] Assuming greenhouse gas emissions of 0.96 tonnes/MWh
[iii] NRDC Benchmarking Air Emissions: http://www.nrdc.org/air/pollution/benchmarking/
[iv] The New York Times 'An Export in Solid Supply' 19 March 2008: http://www.nytimes.com/2008/03/19/business/19coal.html?pagewanted=1
[v] According to Moody's Investors Service the capital structure description for this project has a $1 billion of 8-year senior secured first lien term and construction loans to be issued by Sandy Creek Energy Associates, L.P. (SCEA or OpCo), which is owned 50/50 by LS Power Associates and Dynegy Inc. (the Sponsors) through an intermediate holding company. Combined with $647 million of equity, the proceeds from the issuance of the loans will be used to fund SCEA's 75% share in the construction of a 900 MW coal-fired power plant in Texas, and to pay an upfront hedge premium and financing costs. A $75 million liquidity facility will be in place six months prior to commercial operations to support a permanent six-month debt service reserve and provide for working capital needs. (Text released by Moody's. See http://uk.reuters.com/article/oilRpt/idUKWNA923820070814).
[vi] See Innovest's Sunflower report. $3,000 USD per kW is still a conservative figure as construction costs continue to escalate.
[vii] For the comparative CCGT construction costs, American Electric Power's plans to build a new gas plant, at a cost $787,500 per MW was used. Additionally, we assumed that a similar $75 million liquidity facility that the coal case will have, will be in place six months prior to commercial operations. For the comparative wind scenario we assumed a cost of $1,800 per kW. For fuel costs data from the Electric Power Research Institute cited in The New York Times on 2007/11/07 was used. Finally, the source for the emissions factor tCO_2e/MWh is the Department of Energy and the Environmental Protection Agency report on CO_2 emissions from the US Electric Power sector.
[viii] A 10 year scenario was modeled based on the Lieberman-Warner's S-2191 Act.
[ix] These prices reflect the expected value of tCO_2e using EU ETS data.
[x] Other assumptions for this analysis were: annual utilization (load factor) of 85%; weighed average cost of capital of 6.1% for the electric sector; interest rate of 4%; the average wholesale electricity for Texas for the last three years of $61.94 per MWh; and, a 100 percent in level of borrowings on capital costs. The cost of carbon capture and storage (CSS) is not modeled given the uncertainties regarding the future cost and viability of CCS. An example of this, is the recent withdrawal of US Federal funding of the FutureGen CCS project last month. Indicatively, including the cost of CCS would have imposed greater carbon costs on the SC based load model.
[xi] For a price of $48 per tonne of CO_2e and 100% auctioning, the wind option provides higher profitability. The pre-tax profit margin averages 10 percentage points higher for wind compared with gas.