Technical Paper

Integrating Owners' Financial Goals into Boiler Retrofit Considerations

New Opportunities for Economically Improving the Performance and Emissions of Coal-Fired Power Stations

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Presented to:
Power-Gen International
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Summary

This paper inspects the economic impact of installing environmental equipment and simultaneously upgrading an operating coal-fired power plant, as a way to ease the financial cost of environmental improvements.

Using power plant economic modeling software (developed by Competitive Energy Insight, Inc.) and typical plant parameters, this paper shows that boiler upgrades that improve the heat rate, capacity, and capacity factor of a plant can offset the economic cost of environmental upgrades. The resulting increase in sales of electricity — along with savings on SO_2 and NO_x allowances and replacement power — can turn an expense into a revenue booster and into savings for the rate payer.

For an assumed coal-fired power plant burning Powder River Basin (PRB) coal, the net present value (NPV) associated with adding flue gas desulfurization (FGD), selective catalytic reduction (SCR) and representative upgrades over a 20-year life is $188 million ($U.S.) greater than that of an existing facility with no changes. For a similar assumed plant burning Eastern bituminous coal, the NPV difference is $209 million. These numbers reveal that the substantial investment of an environmental retrofit can also earn a profit when combined with de-bottlenecking and boiler upgrades.

Each plant has its own site and unit-specific considerations that will vary in many respects from the assumed plant used in this analysis. Nonetheless, these financial benefits demonstrate the value of power plant upgrades, even when combined with substantial investment in reducing a plant's environmental emissions.

Introduction

A number of power plants are considering new scrubbers for flue gas desulfurization and selective catalytic reduction systems for de-nitrification for a variety of reasons, to meet state requirements or state implementation plan (SIP) calls or for other reasons. For a power plant already updating its environmental permits, there may be an opportunity to offset some of the cost of the environmental investment by also revising the environmental permits to account for upgrades that can improve the plant's efficiency, capacity, and reliability.

Throughout the United States, the fleet of existing coal-fired power plants continues to age. These facilities are a vital part of our power generation infrastructure and represent literally billions of dollars of in-place investment. Moreover, these power plants can be an additional energy resource. The National Coal Council report of June 2001 concluded that, "nationally, approximately 40,000 megawatts of increased electrical production capability is possible now from existing coal-fired power plants." [1]

Many of these facilities are candidates for emission control upgrades, which alone do not add economic value to the utility owner. However, the associated outages provide an opportunity to implement de-bottlenecking and upgrades to existing power generation facilities. To "de-bottleneck" a process plant means to evaluate and remove the most limiting constraints on the output of the equipment. Past experience in the power industry shows that these upgrades can add capacity, improve efficiency, extend service life, and reduce operating and maintenance costs.

In recent years, these types of upgrades have not been undertaken, due to concern that the upgrade would trigger New Source Review (NSR) regulations that will impose more severe environmental mitigation costs than would otherwise be required. Currently, the U.S. Environmental Protection Agency (EPA) is introducing major revisions to the NSR program.[2] This paper does not discuss the changes to the regulations but examines the economic impact of typical past upgrades to coal-fired power plants and presents scenarios that couple these upgrades with the installation of major environmental equipment that conforms to the NSR regulations.

This paper uses the commercially available software EconExpert-LP, developed by Competitive Energy Insight Inc., to model the economic benefits that coal-fired power plants will enjoy from capacity, efficiency, and cost-improving upgrades. These economic benefits are discussed in four ways:

1. Upgrade performed without the addition of environmental equipment.
2. Upgrades made in addition to the installation of an SCR system for NO_x control.
3. Upgrades made in addition to the installation of an FGD system for SO_2 control.
4. Upgrades made in addition to the installation of both SCR and FGD systems.

Additionally, this paper draws an economic comparison between these cases and the action of retiring the existing plant and building a new supercritical coal-fired unit.

Today's Market Conditions

Today's market offers a unique opportunity for power plant upgrades. The recently enacted Jobs and Growth Tax Relief and Reconciliation Act of 2003 "increases to 50% the bonus depreciation deduction for projects that sign firm contracts after May 5, 2003 and before January 1, 2005 and that are placed in service before December 31, 2005."[3] The remaining value of the acquisition must be depreciated using standard IRS modified accelerated cost recovery schedules (MACRS).

The emerging changes in the NSR regulations may make it more practical for the owner of a power plant to arrange for permitting of the modifications to the existing plant to make it more efficient and more productive.

Additionally, new environmental regulations may be imposed in the foreseeable future. These new regulations, such as the proposed Clear Skies Act[4], will impose additional caps on the emissions of sulfur oxides (SO_x), oxides of nitrogen (NO_x) and mercury (Hg), upon industry and utilities.

Typical Environmental Upgrades

Flue Gas Desulfurization System

The first of the two main environmental upgrade options is the addition of an FGD system or scrubber. Wet or dry scrubbing is the most commonly used among coal-fired facilities in the electric utility industry.[5] Scrubbers control the sulfur dioxide (SO_2) emissions from power plants. The average installed cost of a wet FGD system, for our purposes, is assumed to be $150 per kilowatt ($U.S.) of installed capacity. The average installed cost of a dry FGD system is assumed to be $140 per kilowatt.

Selective Catalytic Reduction

The second main environmental upgrade is SCR; these systems remove NO_x from flue gas before it emits into the environment[6]. The injection of ammonia into the flue gas stream in the presence of a catalyst forms N_2 and H_2O. Previously passed federal and state regulations limit the amount of NO_x that a power plant may emit. The SCR system is the most effective, reducing NO_x emission by 70 - 90%. As with the wet FGD, we assume an average installed cost for a new SCR system of $150 per kilowatt of installed capacity.

Typical Plant Upgrades

Before the uncertainty placed on the industry by NSR, many coal-fired plants performed equipment upgrades to their facilities to improve efficiency, add capacity, extend the service life and reduce the operating and maintenance cost. After clarification of the NSR, many upgrades may again become viable options, especially for utilities who are already reducing emissions by adding SCRs or FGDs. By improving plant efficiency, these upgrades may lead to net reductions in the amount of emissions produced by a facility per kilowatt hour (kWh) of energy produced.

The industry has experience with past boiler and de-bottlenecking upgrades. An abbreviated list of typical upgrades follows:

- Total furnace upgrades
- Replacement of components in the convection pass except the economizer
- Superheater surface reduction
- Furnace wingwall installation
- Gas recirculation system elimination
- Secondary superheater outlet header replacement
- Boiler control system replacement
- Conversion of the boiler first pass into a two-pass arrangement
- Furnace floor and furnace wall replacement
- Sootblower and waterlance replacement

Using the generating availability data system (GADS) from the North American Electric Reliability Council (NERC), one can document the availability and capacity increases that these upgrades have provided. According to these data, typical availability improvements from the year prior to the upgrade to the year following the upgrade range from 20 to 30%. Additionally, the units saw a net capacity factor increase of 10 to 15%. These capacity, efficiency, and heat rate improvements provide economic benefits to the utility that, in turn, can offset at least in part the expense of environmental equipment retrofits.

Analysis

This analysis studies two assumed coal-fired powers plants that are typical of the utility industry today. Both are 500 MW Midwestern plants, one burning a high-sulfur Eastern coal and the other burning a low-sulfur PRB coal. For economic analysis, this paper treats both plants as investor-owned utilities (IOU).

Table 1 outlines the assumptions used for the Midwestern IOU burning Eastern, high-sulfur coal. Table 2 outlines the assumptions for the Midwestern plant burning subbituminous low-sulfur PRB coal.

The upgrades to each of these units are identical (except for the FGD type) and are modeled on the example upgrades described earlier. In their own way, each of the upgrades will affect the heat rate, capacity, or capacity factor of the plant. This study assumes

Table 1. Assumptions, Midwest IOU burning Eastern, high-sulfur coal

Ownership	*IOU/Publicly Traded*
Location	*Midwest*
Coal Type	*High Sulfur Bituminous*
Delivered Coal Price	*$1.20/MBtu*
Fuel Heating Value	*11,500 Btu/lb*
% Ash in Fuel by weight	*10%*
% Sulfur in Fuel by weight	*2.5%*
Plant Capacity	*500 MW*
Net Heat Rate	*10,250 Btu/kWh*
Capacity Factor	*65%*
Pressure	*2400 psig*
Temperature	*1000 F*
Reheat Temperature	*1000 F*

Table 2. Assumptions, Midwest plant burning subbituminous, low-sulfur PRB coal

Ownership	*IOU/Publicly Traded*
Location	*Midwest*
Coal Type	*Low Sulfur PRB*
Delivered Coal Price	*$1.00/MBtu*
Fuel Heating Value	*8,500 Btu/lb*
% Ash in Fuel by weight	*5%*
% Sulfur in Fuel by weight	*0.50%*
Plant Capacity	*500 MW*
Net Heat Rate	*10,500 Btu/kWh*
Capacity Factor	*65%*
Pressure	*2400 psig*
Temperature	*1000 F*
Reheat Temperature	*1000 F*

that the capacity increases 10 %, from 500 to 550 MW. This study also assumes that the capacity factor improves 10 percentage points, from 65% to 75%. It is assumed the heat rate improves 1% for both cases. Other important items taken into consideration are:

- Cost of upgrades
- Cost of fuel
- Raw material costs
- Waste disposal costs
- Reagent use
- Major maintenance costs and periodic maintenance frequency
- Spare parts expense and savings
- Catalyst use and replacement
- Cost of replacement electricity
- Value of electricity sold
- Emissions credits
- Other revenues (sales of ash and gypsum)

The Cases

Table 3 lays out the cases that were considered in the model. All cases were studied for both Eastern an PRB coals.

As mentioned earlier, it is assumed that the upgrade will increase the base plant's capacity factor by 10%, in our case from 65% to 75%, as a result of the combination of improved reliability and more competitive economic dispatch. The upgrades were also assumed to increase the capacity from 500 MW to 550 MW and to improve the heat rate by 1.0% for both base plants. Adding SCR and FGD penalizes both the heat rate and the capacity of the plant, while the capacity factor remains constant.

A major factor influencing the potential economic benefits of plant upgrades is the capital cost associated with the upgrade and the capital costs for the SCR and scrubber retrofits. For both cases, the upgrade cost was estimated to be $50/kW with the SCR cost at $150/kW. The model values the wet and dry scrubbers at different costs. The cost of the dry scrubber was valued at $140/kW while the wet scrubber was valued at $150/kW. The estimated cost of building a new supercritical plant, burning either Eastern or PRB coal, is $1,200/kW. Finally NO_x and SO_2 allowances were valued at $2,500 and $200 respectively and were not escalated.

The main assumptions for the 12 additional cases, which include the new supercritical plants, are outlined in the tables (Tables 4 through 15).

The life expectancy of the upgrades and the environmental equipment were premised to be 20 years. The new supercritical plant was also premised to have a life expectancy of 20 years. The construction term for the upgraded plant was assumed to be one year, while the SCR and scrubber's terms were assumed to be 18 and 24 months respectively. The estimated construction term for the upgrade with SCR and scrubber was 24 months.

To put all of the analyses in a common time frame and to remove any inflation effects when comparing options, all cases were assumed to have a start-up date of December 1, 2005. Recognizing that this schedule might not realistically be achievable for some applications (e.g. a new supercritical boiler), any special benefits, such as the bonus depreciation allowances, were not applied to cases that might not realistically be achievable in this time frame. It was assumed that standard plant upgrades and environmental upgrades could meet this schedule and therefore would be eligible for the federal bonus depreciation. Readers are instructed to consult their tax advisors to confirm this assumption in their specific circumstances. It was also assumed that the bonus depreciation would not apply for state tax purposes, though in some states this could provide an additional economic benefit.

Results of Different Cases

Based on the above inputs and assumptions the EconExpert-LP financial model calculated after-tax NPV for each case using an unleveraged discount rate of 6% for Case #1 and a leveraged discount rate of 8% for Cases #2 through #7. Net present value was selected as the metric to compare the impact of the different courses

Table 3. Cases considered in model

	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7
Operate Existing Base Plant	Yes	No	Yes	Yes	Yes	Yes	Yes
Build New, Supercritical Plant	No	Yes	No	No	No	No	No
Upgrade and De-bottleneck Steam Path	No	N/A	Yes	Yes	Yes	Yes	No
Add Retrofit SCR	No	N/A	No	Yes	No	Yes	Yes
Add Retrofit FGD	No	N/A	No	No	Yes	Yes	Yes
FGD Type for Eastern Coal	N/A	N/A	N/A	N/A	Wet	Wet	Wet
FGD Type for Powder River Basin (PRB) Coal	N/A	N/A	N/A	N/A	Dry	Dry	Dry

N/A = Not Applicable

Table 4. New supercritical plant burning Eastern coal, Case 2

Ownership	*IOU/Publicly Traded*
Location	*Midwest*
Coal Type	*High Sulfur Bituminous*
Fuel Heating Value	*11,500 Btu/lb*
% Ash in Fuel by weight	*10%*
% Sulfur in Fuel by weight	*2.5%*
Plant Capacity	*550 MW*
Net Heat Rate	*8,786 Btu/kWh*
Capacity Factor	*80.0%*
Capital Investment	*$1,200kW*
Fixed O&M (1000$/year)	*$10,500*
Variable O&M (mils/kWh)	*1.24*

Table 5. New supercritical plant burning PRB coal, Case 2

Ownership	*IOU/Publicly Traded*
Location	*Midwest*
Coal Type	*Low Sulfur PRB*
Fuel Heating Value	*8,500 Btu/lb*
% Ash in Fuel by weight	*5%*
% Sulfur in Fuel by weight	*0.50%*
Plant Capacity	*550 MW*
Net Heat Rate	*9,000 Btu/kWh*
Capacity Factor	*80.0%*
Capital Investment	*$1,200kW*
Fixed O&M (1000$/year)	*$10,500*
Variable O&M (mils/kWh)	*1.24*

Table 6. Eastern coal, Case 3, base plant with upgrade

Ownership	*IOU/Publicly Traded*
Location	*Midwest*
Coal Type	*High Sulfur Bituminous*
Fuel Heating Value	*11,500 Btu/lb*
% Ash in Fuel by weight	*10%*
% Sulfur in Fuel by weight	*2.5%*
Plant Capacity	*550 MW*
Net Heat Rate	*10,148 Btu/kWh*
Capacity Factor	*75%*
Capital Investment	*$50/kW*
Fixed O&M (1000$/year)	*$9,300*
Variable O&M (mils/kWh)	*1.11*

Table 7. PRB coal, Case 3, base plant with upgrade

Ownership	*IOU/Publicly Traded*
Location	*Midwest*
Coal Type	*Low Sulfur PRB*
Fuel Heating Value	*8,500 Btu/lb*
% Ash in Fuel by weight	*5%*
% Sulfur in Fuel by weight	*0.50%*
Plant Capacity	*550 MW*
Net Heat Rate	*10,395 Btu/kWh*
Capacity Factor	*75%*
Capital Investment	*$50/kW*
Fixed O&M (1000$/year)	*$9,300*
Variable O&M (mils/kWh)	*1.11*

Table 8. Eastern coal, Case 4, base plant with upgrade and SCR

Ownership	*IOU/Publicly Traded*
Location	*Midwest*
Coal Type	*High Sulfur Bituminous*
Fuel Heating Value	*11,500 Btu/lb*
% Ash in Fuel by weight	*10%*
% Sulfur in Fuel by weight	*2.5%*
Plant Capacity	*540 MW*
Net Heat Rate	*10,198 Btu/kWh*
Capacity Factor	*75.0%*
Capital Investment	*$200/kW*
Fixed O&M (1000$/year)	*$9,800*
Variable O&M (mils/kWh)	*1.21*

Table 9. PRB coal, Case 4, base plant with upgrade and SCR

Ownership	*IOU/Publicly Traded*
Location	*Midwest*
Coal Type	*Low Sulfur PRB*
Fuel Heating Value	*8,500 Btu/lb*
% Ash in Fuel by weight	*5%*
% Sulfur in Fuel by weight	*0.50%*
Plant Capacity	*540 MW*
Net Heat Rate	*10,447 Btu/kWh*
Capacity Factor	*75.0%*
Capital Investment	*$200/kW*
Fixed O&M (1000$/year)	*$9,800*
Variable O&M (mils/kWh)	*1.21*

Table 10. Eastern coal, Case 5, base plant with upgrade and wet scrubber

Ownership	*IOU/Publicly Traded*
Location	*Midwest*
Coal Type	*High Sulfur Bituminous*
Fuel Heating Value	*11,500 Btu/lb*
% Ash in Fuel by weight	*10%*
% Sulfur in Fuel by weight	*2.5%*
Plant Capacity	*535 MW*
Net Heat Rate	*10,274 Btu/kWh*
Capacity Factor	*75.0%*
Capital Investment	*$200/kW*
Fixed O&M (1000$/year)	*$10,800*
Variable O&M (mils/kWh)	*1.16*

Table 11. PRB coal, Case 5, base plant with upgrade and dry scrubber

Ownership	*IOU/Publicly Traded*
Location	*Midwest*
Coal Type	*Low Sulfur PRB*
Fuel Heating Value	*8,500 Btu/lb*
% Ash in Fuel by weight	*5%*
% Sulfur in Fuel by weight	*0.50%*
Plant Capacity	*535 MW*
Net Heat Rate	*10,525 Btu/kWh*
Capacity Factor	*75.0%*
Capital Investment	*$190/kW*
Fixed O&M (1000$/year)	*$10,800*
Variable O&M (mils/kWh)	*1.16*

Table 12. Eastern coal, Case 6, base plant with upgrade, SCR, and wet scrubber

Ownership	*IOU/Publicly Traded*
Location	*Midwest*
Coal Type	*High Sulfur Bituminous*
Fuel Heating Value	*11,500 Btu/lb*
% Ash in Fuel by weight	*10%*
% Sulfur in Fuel by weight	*2.5%*
Plant Capacity	*528 MW*
Net Heat Rate	*10,327 Btu/kWh*
Capacity Factor	*75.0%*
Capital Investment	*$350/kW*
Fixed O&M (1000$/year)	*$11,300*
Variable O&M (mils/kWh)	*1.26*

Table 13. PRB coal, Case 6, base plant with upgrade, SCR, and dry scrubber

Ownership	*IOU/Publicly Traded*
Location	*Midwest*
Coal Type	*Low Sulfur PRB*
Fuel Heating Value	*8,500 Btu/lb*
% Ash in Fuel by weight	*5%*
% Sulfur in Fuel by weight	*0.50%*
Plant Capacity	*528 MW*
Net Heat Rate	*10,579 Btu/kWh*
Capacity Factor	*75.0%*
Capital Investment	*$340kW*
Fixed O&M (1000$/year)	*$11,300*
Variable O&M (mils/kWh)	*1.26*

Table 14. Eastern coal, Case 7, base plant with SCR, wet scrubber, and NO upgrade

Ownership	*IOU/Publicly Traded*
Location	*Midwest*
Coal Type	*High Sulfur Bituminous*
Fuel Heating Value	*11,500 Btu/lb*
% Ash in Fuel by weight	*10%*
% Sulfur in Fuel by weight	*2.5%*
Plant Capacity	*478 MW*
Net Heat Rate	*10,429 Btu/kWh*
Capacity Factor	*65.0%*
Capital Investment	*$300kW*
Fixed O&M (1000$/year)	*$12,000*
Variable O&M (mils/kWh)	*1.27*

Table 15. PRB coal, Case 7, base plant with SCR and dry scrubber, and NO upgrade

Ownership	*IOU/Publicly Traded*
Location	*Midwest*
Coal Type	*Low Sulfur PRB*
Fuel Heating Value	*8,500 Btu/lb*
% Ash in Fuel by weight	*5%*
% Sulfur in Fuel by weight	*0.50%*
Plant Capacity	*478 MW*
Net Heat Rate	*10,684 Btu/kWh*
Capacity Factor	*65.0%*
Capital Investment	*$300kW*
Fixed O&M (1000$/year)	*$12,000*
Variable O&M (mils/kWh)	*1.27*

Table 16. Eastern coal plant NPV results

Case #	**Description**	**NPV (1000$)**	**Difference from Base Plant**	***Rank***
1	Base Plant	$292,793	--	*6*
2	New Super-Critical Plant	$316,854	$24,061	*5*
3	Base Plant with Upgrade	$513,481	$220,688	*2*
4	Base Plant with Upgrade & SCR	$573,574	$280,781	*1*
5	Base Plant with Upgrade & FGD	$443,096	$150,303	*4*
6	Base Plant with Upgrade, SCR & FGD	$502,299	$209,506	*3*
7	Base Plant with SCR & FGD, NO Upgrade	$235,697	($57,096)	*7*

Table 17. PRB coal plant NPV results

Case #	**Description**	**NPV (1000$)**	**Difference from Base Plant**	***Rank***
1	Base Plant	$333,933	--	*5*
2	New Super-Critical Plant	$318,145	($15,788)	*6*
3	Base Plant with Upgrade	$561,138	$227,205	*2*
4	Base Plant with Upgrade & SCR	$632,960	$299,027	*1*
5	Base Plant with Upgrade & FGD	$452,021	$118,088	*4*
6	Base Plant with Upgrade, SCR & FGD	$522,391	$188,458	*3*
7	Base Plant with SCR & FGD, NO Upgrade	$252,662	($81,271)	*7*

of action, because it measures the financial impact of changes in operations over time through discounted cash flow (DCF) analysis. Then it compares the results of changes in operation with the cost of the investments required to achieve those changes. The results for the Eastern and PRB coals are shown in Tables 16 and 17.

As can be seen from the tables, boiler upgrades provide the opportunity to realize significant NPV benefits. What is most important to notice is that the upgrade, in addition to installing environmental equipment, turns what would be a negative return project into one that returns a considerably higher NPV than running the base plant with no changes.

To show what variables factor into this NPV value, Figures 1 through 12 were developed. Figures 1 through 6, for the Eastern coal cases, show the factors that contribute the most to the difference between the base case and the five upgraded cases.

For Case #2, the new supercritical plant, we see that the large capital expense and decommissioning costs may cancel any benefits gained by an increased capacity factor, increased capacity, replacement power savings, and emission allowances.

For Case #3, the base plant plus upgrade only, we see that the biggest factors attributing to the NPV are the increased capacity factor, the increased capacity, and the savings in replacement power.

Case #4 shows the same gains as Case #3, except that this is a new addition to the NPV, which comes from the savings on NO_x allowances due to adding the SCR.

In Case #5, the SCR is removed and a scrubber is installed.

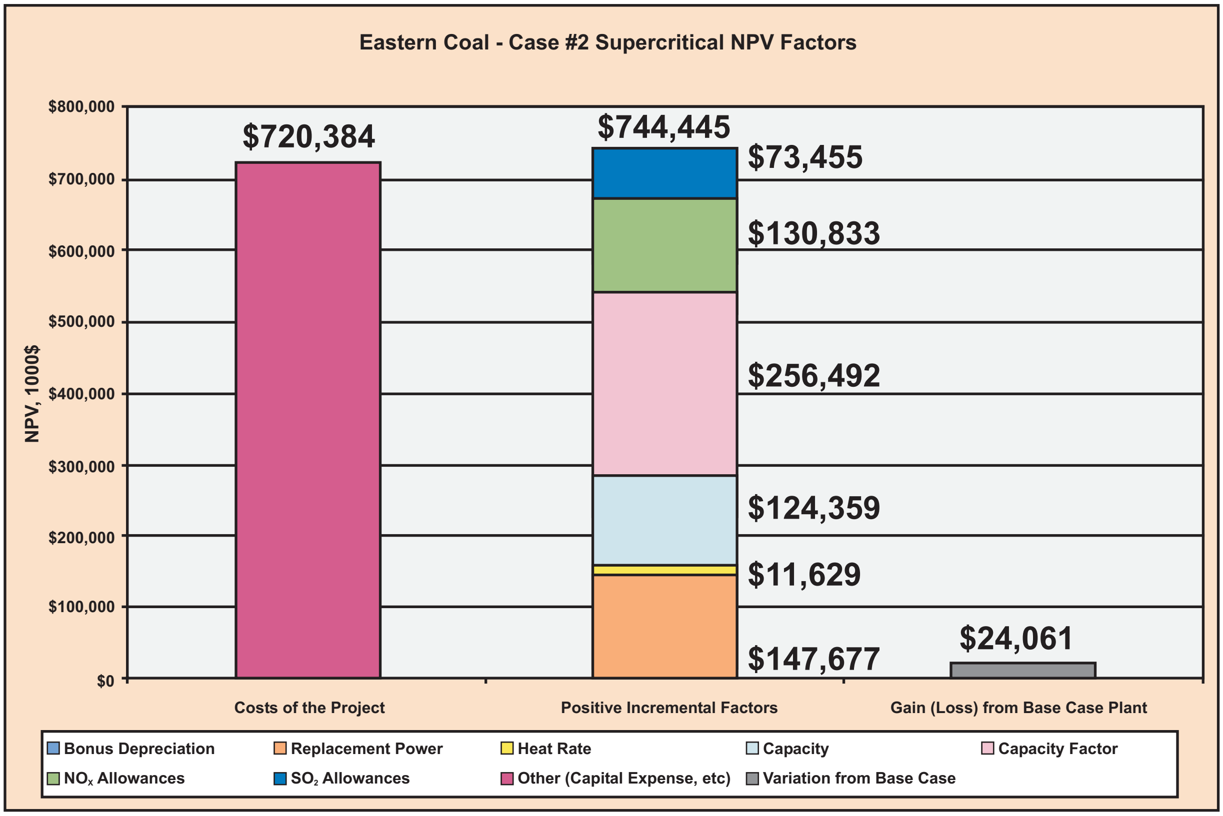

Fig. 1 Eastern coal, Case 2, supercritical NPV factors

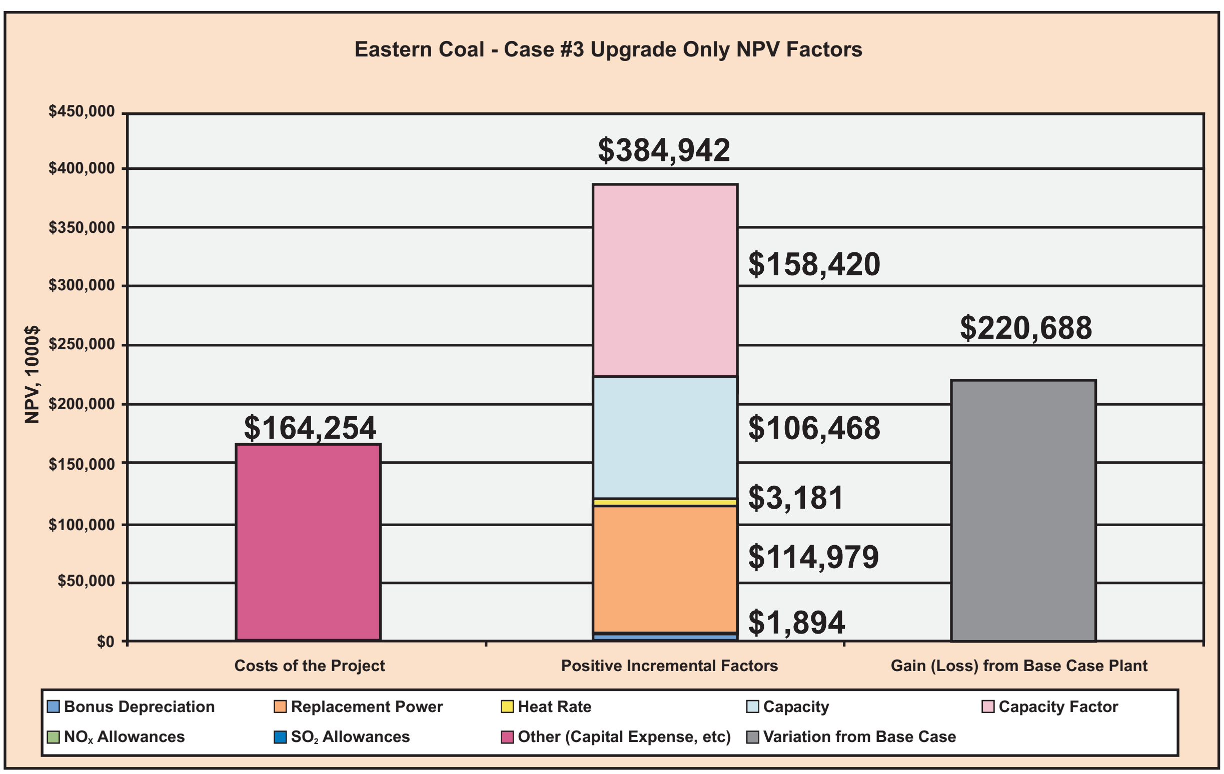

Fig. 2 Eastern coal, Case 3, upgrade only of NPV factors.

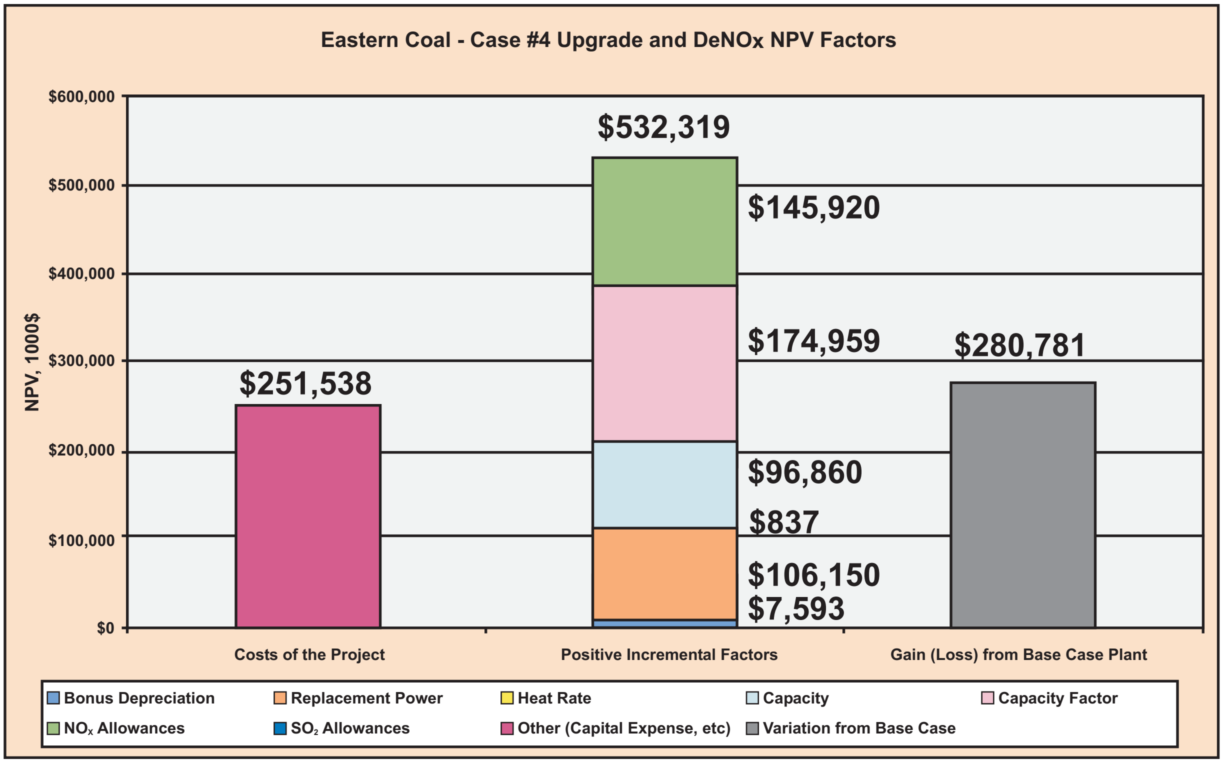

Fig. 3 Eastern coal, Case 4, upgrade and DeNOx NPV factors

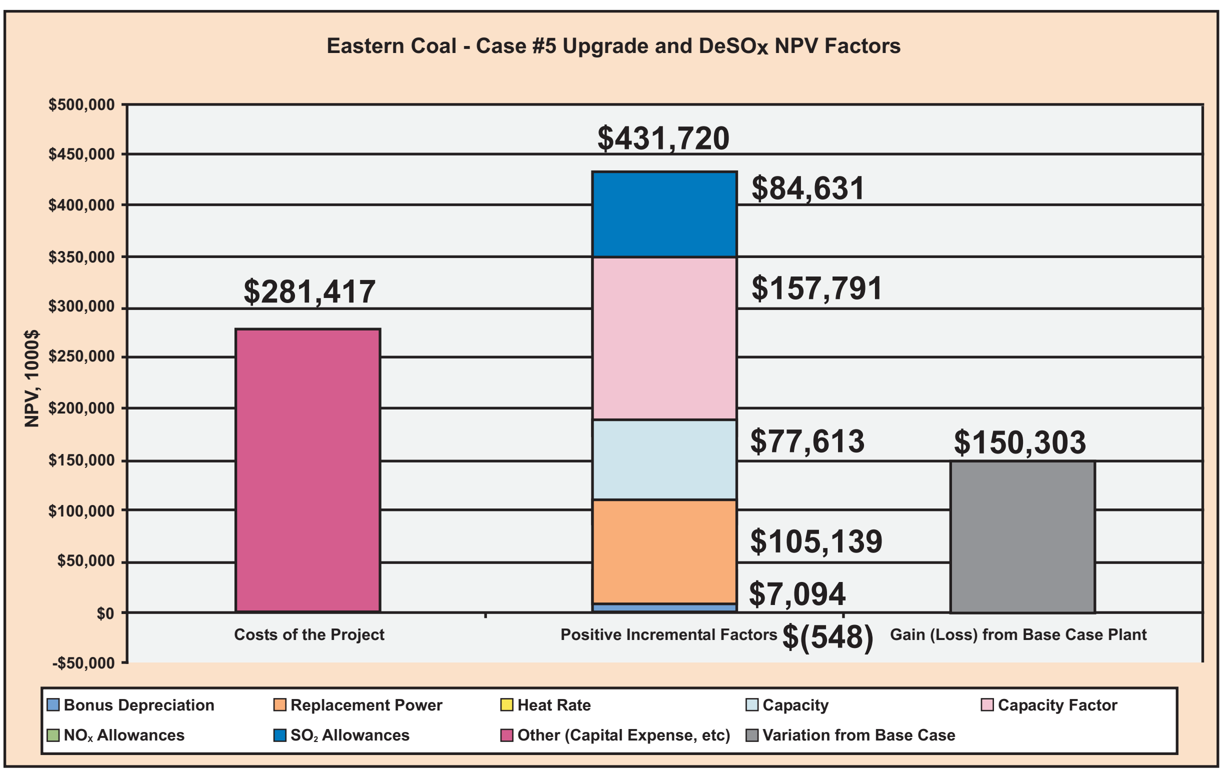

Fig. 4 Eastern coal, Case 5, upgrade and DeSOx NPV factors

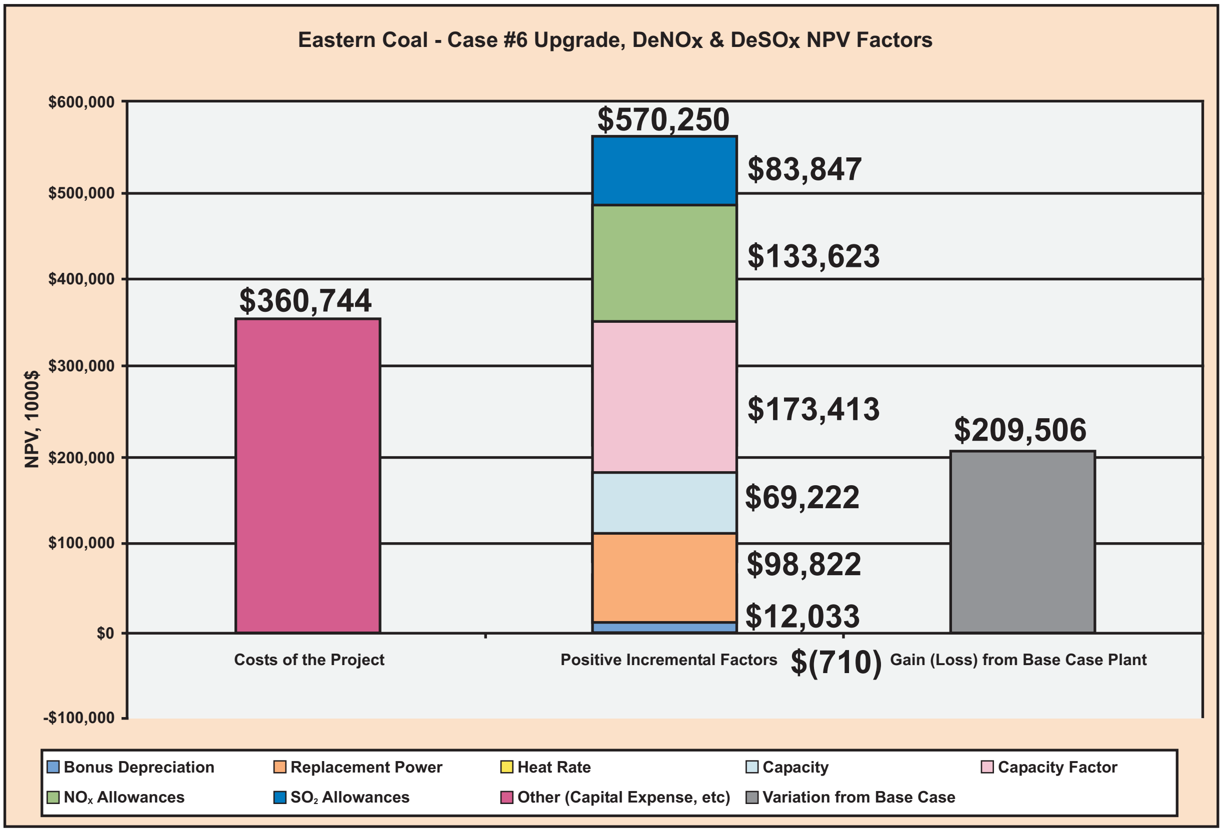

Fig. 5 Eastern coal, Case 6, upgrade, $DeNO_X$ and $DeSO_X$ NPV factors

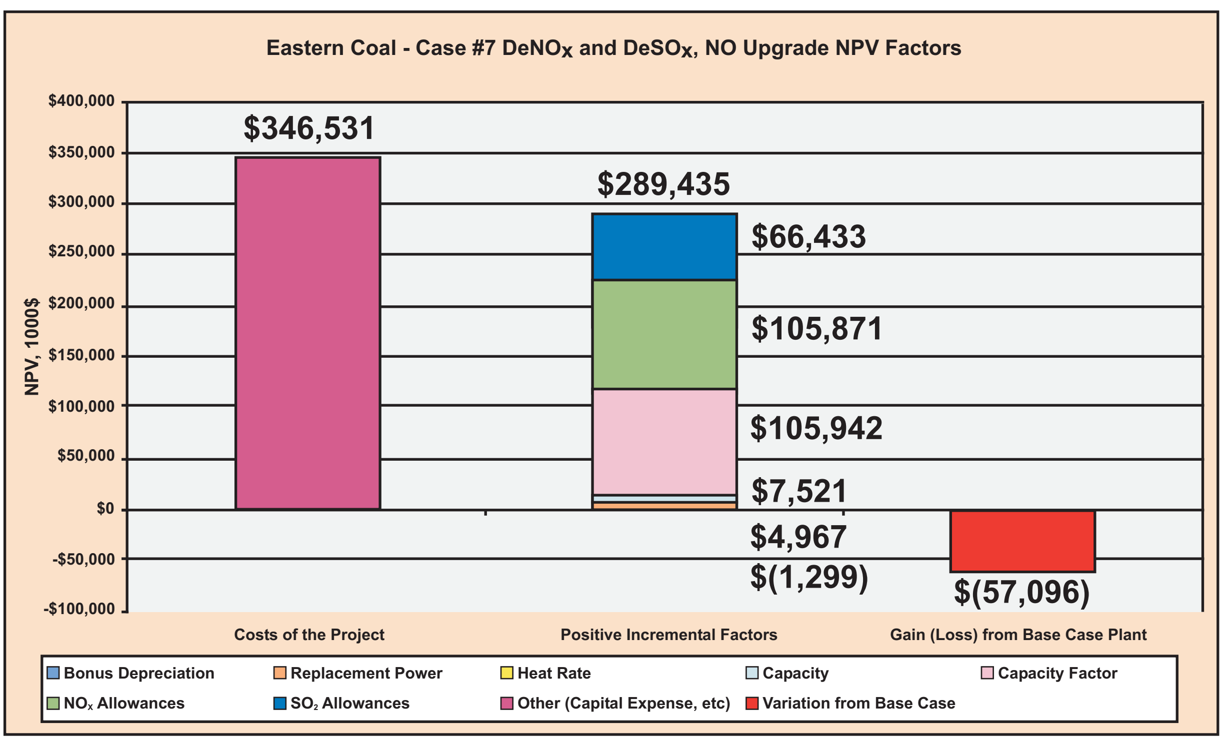

Fig. 6 Eastern coal, Case 7, $DeNO_X$ and $DeSO_X$, NO upgrade NPV factors

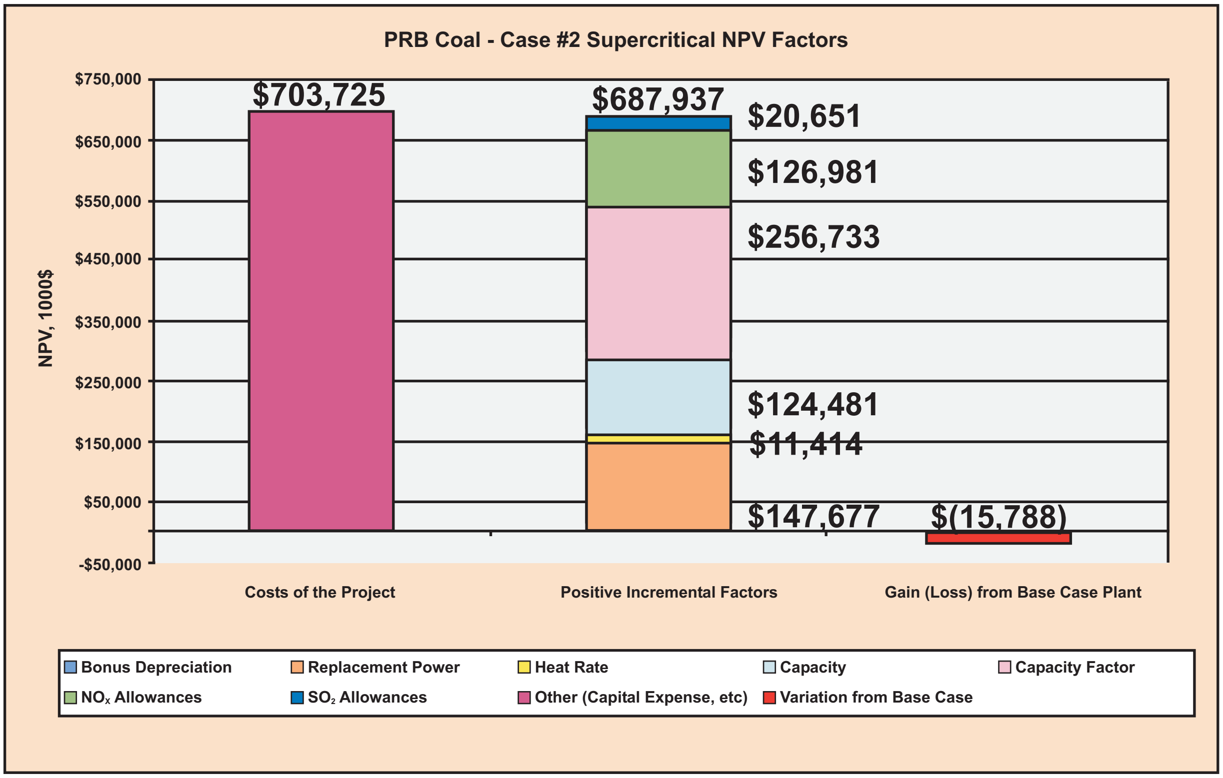

Fig. 7 PRB Coal - Case 2, supercritical NPV factors

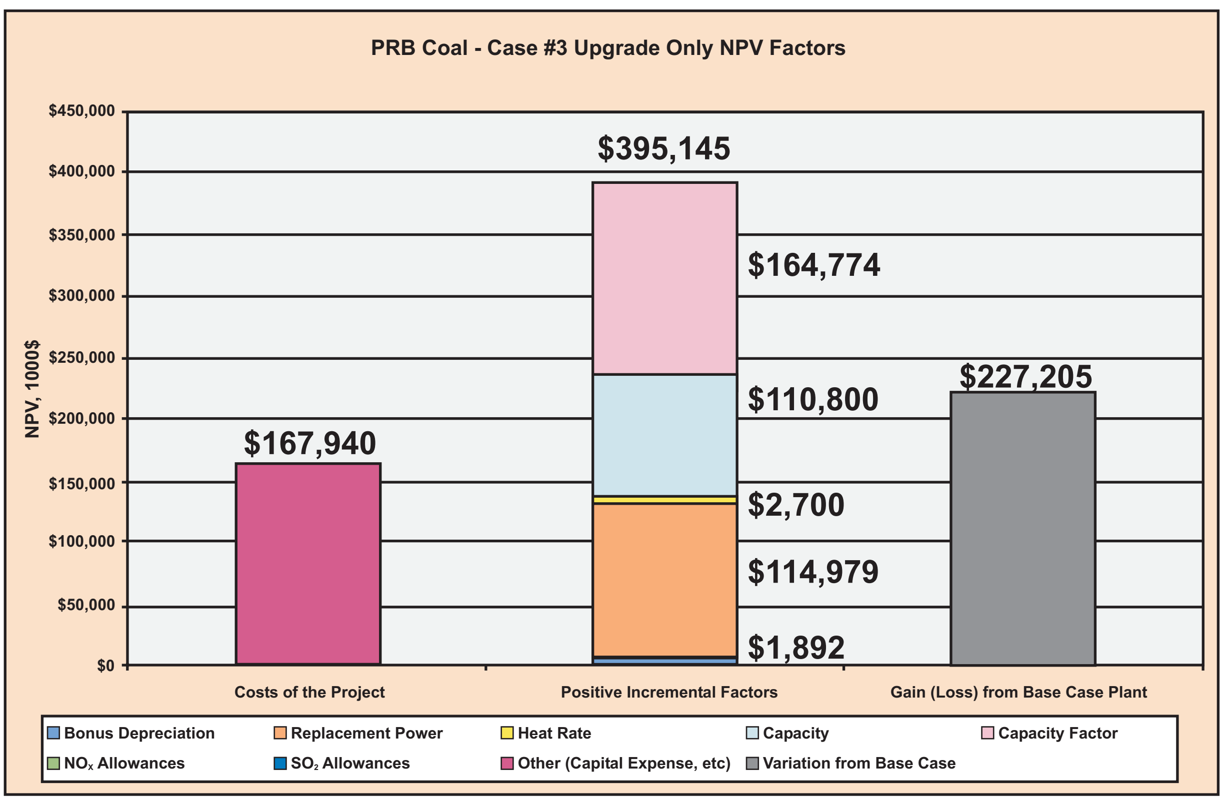

Fig. 8 PRB coal, Case 3, upgrade only of NPV factors.

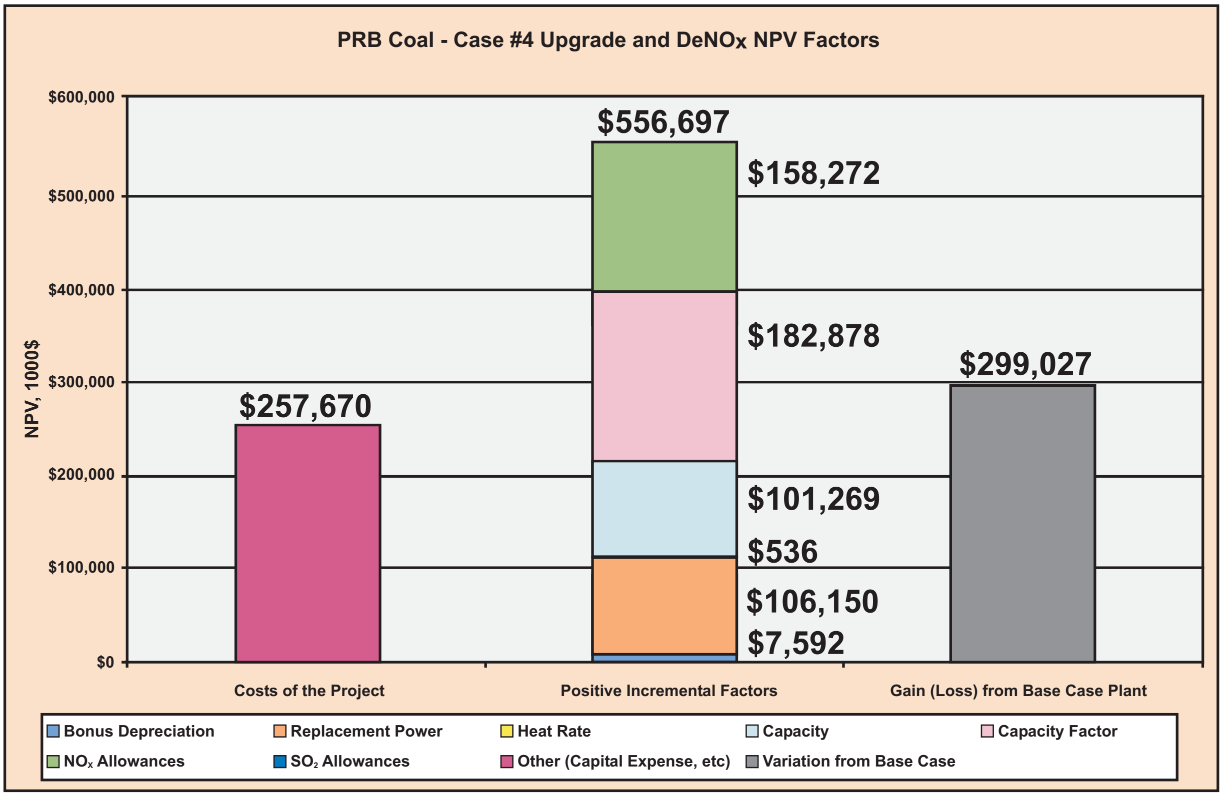

Fig. 9 PRB coal, Case 4, upgrade and DeNO$_x$ NPV factors

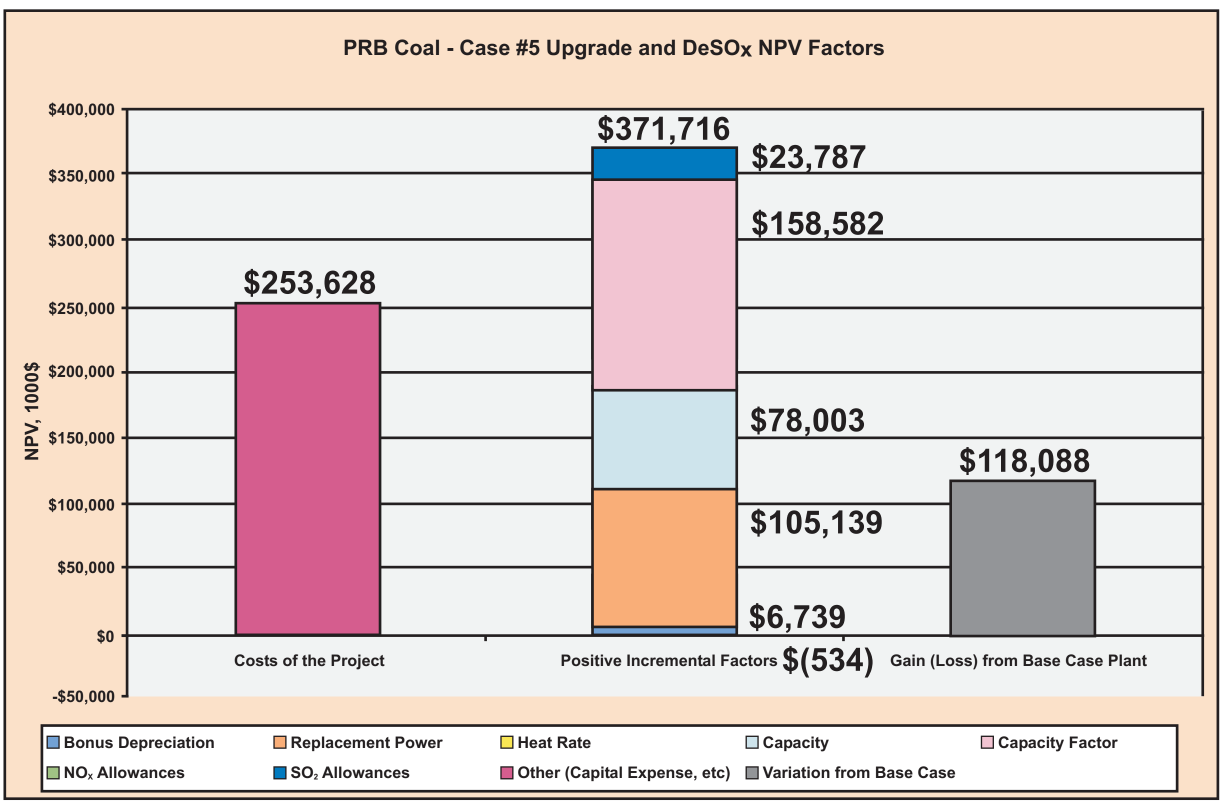

Fig. 10 PRB coal, Case 5, upgrade and DeSO$_x$ NPV factors

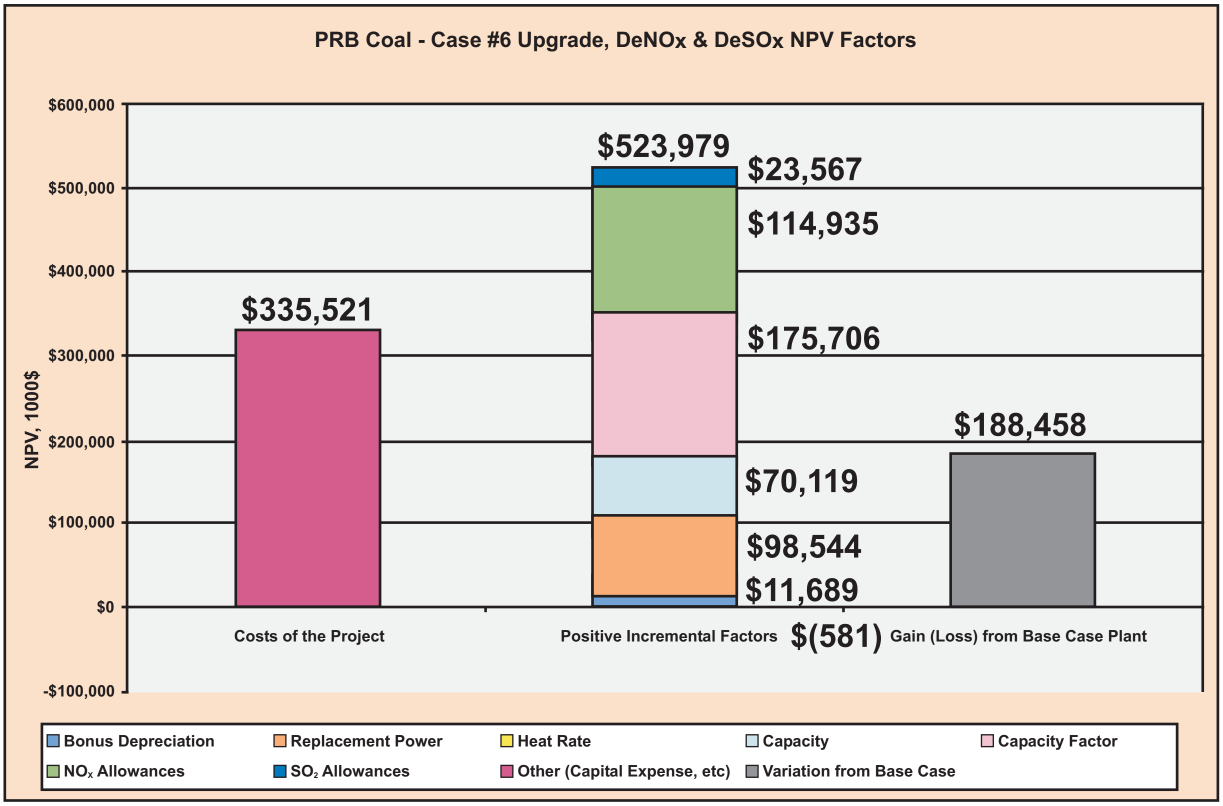

Fig. 11 PRB coal, Case 6, upgrade, $DeNO_X$ and $DeSO_X$ NPV factors

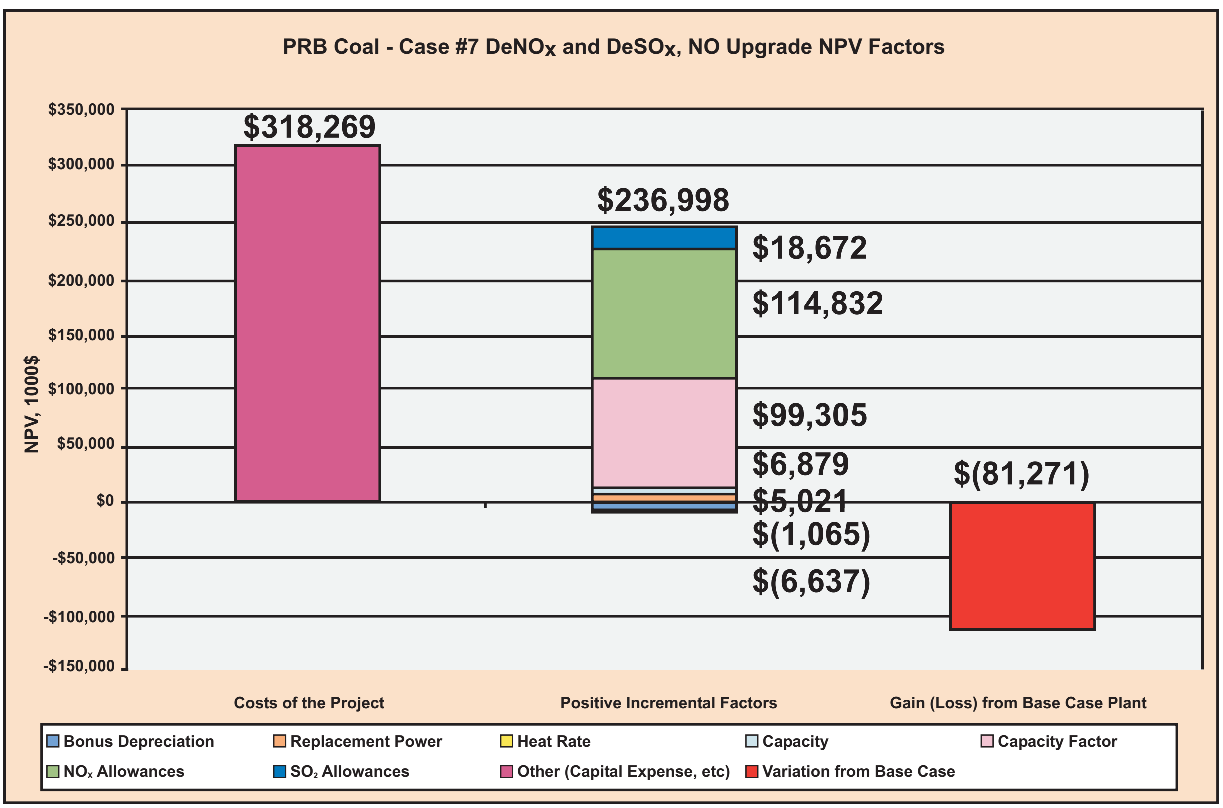

Fig. 12 PRB coal, Case 7, $DeNO_X$ and $DeSO_X$, NO upgrade NPV factors

There is a slight decrease in the gains from the capacity factor and capacity itself, but there are additional savings on SO_2 allowances because of the assumed 98% SO_2 removal rate of the scrubber.

For Case #6, upgrade plus SCR plus scrubber, we have approximately the same NPV gains from increased capacity, increased capacity factor, and replacement power savings. The difference in this case is that both the SCR and scrubber are additions to the plant; therefore it can realize the savings on both NO_x and SO_2 allowances.

Figures 7 through 12 essentially show the same variables acting in the same capacity for the PRB coal cases. The biggest difference is that the effects of the SO_2 allowance saving are not as great due to the previous low-sulfur content of PRB coal. The differences in total values between the Eastern and PRB coal cases are due mainly to coal characteristics such as heating value, delivered price, heat rate, ash and moisture content, and the sorbent and catalysts needed for emission control.

Sensitivity of Results

A sensitivity analysis was performed for the five factors that are felt to most greatly influence the NPV of the options studied. Three likely scenarios were selected for this analysis, Eastern Coal Case #6 (upgrade, SCR, scrubber), PRB Coal Case #6 (upgrade, SCR, scrubber), and PRB Coal Case #4 (upgrade and SCR). Table 18 shows the minimum, mid-range, and maximum values used for each case and variable.

As can be seen in Table 19, the most influential factor to the NPV sensitivity analysis for all three cases is the price of energy as sold by the utility. The $40/MWH value used conveys the nationwide year-round average.

The second most sensitive variable is the NO_x allowance price. Although $2,500/ton is a conservative value, this price is volatile and subject to change.

One can see that the SO_2 allowance sensitivity changes rank from case to case. This is due to the fact that PRB is a low-sulfur coal. The SO_2 allowances do not apply to PRB Coal Case #4 because a scrubber is not installed. These allowances are also subject to the same change and volatility as the NO_x allowances.

It is also noted that a plus or minus change in the capacity factor of 13.3% increases or decrease the plants NPV by an average of $200 million across the three cases.

The heat rate does not play as large a part in the NPV for these cases due to the heat rate penalty that the environmental equipment places on the power plant.

Conclusion

As New Source Review modifications are enacted, the opportunity for utilities to upgrade power plant boilers is the best since the 1980s. Environmental retrofits are becoming a fact of life for many utilities throughout the nation. The likelihood of the passage of additional environmental regulations, such as the Clear Skies Act, is growing and almost imminent. The environmental upgrades that new legislation will require place a heavy burden on the pocket books of utilities. This expense can be recovered by completing boiler upgrades that increase the capacity and capacity factor of the plant while decreasing its heat rate. The additional revenue from these benefits along with savings on SO_2 and NO_x allowances, provided by the SCR and FGD installation, turn what was once a money losing scenario into a profitable investment for the owner.

Table 18. Variable values used for sensitivity analysis

	Eastern Coal - Case 6		
Sensitivity	Min Value	Mid-Range	Max Value
NOx Allowances ($/ton)	0	2,500	5,000
SO2 Allowances ($/ton)	0	200	400
Price of Power (sold) ($/MWH)	20	40	60
Capacity Factor	58.1%	71.4%	84.8%
Heat Rate (Btu/kwh)	9,128	10,327	11,526
	PRB Coal - Case 6		
Sensitivity	Min Value	Mid-Range	Max Value
NOx Allowances ($/ton)	0	2,500	5,000
SO2 Allowances ($/ton)	0	200	400
Price of Power (sold) ($/MWH)	20	40	60
Capacity Factor	58.1%	71.4%	84.8%
Heat Rate (Btu/kwh)	9,380	10,579	11,778
	PRB Coal - Case 4		
Sensitivity	Min Value	Mid-Range	Max Value
NOx Allowances ($/ton)	0	2,500	5,000
SO2 Allowances ($/ton)	n/a	n/a	n/a
Price of Power (sold) ($/MWH)	20	40	60
Capacity Factor	58.1%	71.4%	84.8%
Heat Rate (Btu/kwh)	9,248	10,447	11,646

Table 19. Sensitivity of NPV to selected factors ($000, Leveraged)

	Eastern Coal - Case 6				
Sensitivity	Min Value	Mid-Range	Max Value	Difference	*Rank*
NOx Allowances	358,926	502,299	645,673	*286,747*	*2*
SO2 Allowances	406,472	502,299	598,126	*191,654*	*3*
Price of Power (sold)	66,881	502,299	937,718	*870,837*	*1*
Capacity Factor	417,614	502,299	589,223	*171,609*	*4*
Heat Rate	541,140	502,299	463,459	*77,681*	*5*
	PRB Coal - Case 6				
Sensitivity	Min Value	Mid-Range	Max Value	Difference	*Rank*
NOx Allowances	366,881	522,391	677,901	*311,020*	*2*
SO2 Allowances	496,913	522,391	547,869	*50,956*	*5*
Price of Power (sold)	86,972	522,391	957,809	*870,837*	*1*
Capacity Factor	421,198	522,391	625,494	*204,296*	*3*
Heat Rate	551,760	522,391	493,021	*58,739*	*4*
	PRB Coal - Case 4				
Sensitivity	Min Value	Mid-Range	Max Value	Difference	*Rank*
NOx Allowances	463,140	632,960	802,780	*339,640*	*2*
SO2 Allowances	n/a	n/a	n/a	n/a	*n/a*
Price of Power (sold)	151,476	632,960	1,114,444	*962,968*	*1*
Capacity Factor	518,747	632,960	749,259	*230,512*	*3*
Heat Rate	664,563	632,960	601,357	*63,206*	*4*

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