Economic Evaluation of Flexibility in the Design of IGCC Plants with Integrated Membrane Reactor Modules

Juzheng Zhang[1], Michel-Alexandre Cardin[1, 2], Nikolaos Kazantzis[3]

Simon K. K. Ng[1], Y. H. Ma[2], Fellow, AICHE

Abstract

Integrated Gasification Combined Cycle with embedded membrane reactor modules (IGCC-MR) represents a new technology option for the co-production of electricity and pure hydrogen endowed with enhanced environmental performance capacity. It is viewed as an alternative to conventional coal- and gas-fired power generation technologies. An IGCC-MR power plant needs to be techno-economically evaluated in the presence of irreducible regulatory and fuel market uncertainties for the potential deployment of an initial fleet of demonstration plants at the commercial scale. This paper applies a systematic methodological framework to assess the economic value of flexible alternatives in the design and operation of an IGCC-MR plant under the aforementioned sources of uncertainty. The main objective is to demonstrate the potential value enhancements associated with the long-term economic performance of flexible IGCC-MR project investments, by managing the uncertainty associated with future environmental regulations and fuel costs. The paper provides an overview of promising design flexibility concepts for IGCC-MR power plants and focuses on operational and constructional systems flexibility. Operational flexibility is realized through temporary plant shutdown with considerations of regulatory and market uncertainties. Constructional flexibility is realized by considering the installation of a Carbon Capture and Storage (CCS) unit at three strategic periods: 1) installation at the initial construction phase, 2) retrofitting at a later stage and 3) retrofitting at a later stage with pre-investment. Monte Carlo simulations and financial analysis demonstrate that, in the presence of irreducible uncertainty, the most economically advantageous flexibility option is to install CCS in the initial IGCC-MR construction phase.

Keywords: Carbon capture and storage (CCS), Flexibility in Engineering Design, Integrated Gasification Combined Cycle (IGCC), Membrane Reactor Technology, Real Options Analysis.

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[1] Department of Industrial and Systems Engineering, National University of Singapore, Singapore

[2] Corresponding author. Tel.: +65 6516 5387; Fax: +65 67771434; Email: macardin@nus.edu.sg

[3] Center for Inorganic Membranes, Department of Chemical Engineering, Worcester Polytechnic Institute, Massachusetts, USA. Part of this work was performed while N. Kazantzis was at Hughes Hall, University of Cambridge, Cambridge, UK

1 Introduction

Electricity consumption in the United States is expected to increase from 3,877 billion kilowatt-hours (kWh) in 2010 to over 4,716 billion kWh in 2035, a 22% increase [Energy Information Agency, 2012]. Within this context, coal-fired power plants are expected to remain the dominant source of electricity due to their cost advantages and low technology risks. At present, these power plants account for over 28% of global carbon dioxide (CO_2) emissions [International Energy Agency, 2013]. It is well recognized that the increasing amount of CO_2 in the atmosphere represents a major contributor to climate change. To avoid irreversible damage, governments have designed policy responses (e.g. CO_2 emissions permit trading schemes and/or carbon tax regimes [Exxon Mobil, 2012]) to reduce carbon emissions from electric power systems.

A new promising technology option for electric power generation with a lower carbon intensity endowment is the Integrated Gasification Combined Cycle (IGCC) power plant [Rosenberg et al., 2004]. IGCC is a process system that allows the structural integration of a gasification unit with a standard combined cycle power component. After gasification, coal or other solid or liquid feedstock (e.g. biomass, various oils, etc.) are converted into synthetic gas (also known as syngas), which is comprised predominantly of hydrogen (H_2) and carbon monoxide (CO). The combustible syngas is first typically treated for the removal of sulfur dioxide (SO_2), nitric oxide, mercury and particular matter and then used in a gas turbine to produce electricity, whereas the assorted exhaust heat is used to generate steam for a second generation cycle through a steam turbine as shown in [Haslbeck et al., 2010]. It should be emphasized that both major components of IGCC, namely the gasification process system and the combined cycle power block, are associated with mature tested technologies and have been broadly utilized in the petrochemical, chemical processing industries as well as for power generation (electricity production from natural gas).

IGCC power plants display comparable efficiency levels to coal-fired power plants and superior environmental performance (in terms of both CO_2 and pollutant emissions), which can be attained at a lower cost when the integration of a Carbon Capture and Storage (CCS) unit is pursued [Bohm et al., 2007, Rosenberg et al., 2004]. In this paper, the integration of membrane reactor technology into an IGCC power plant (IGCC-MR) is considered. Specifically, Pd-based composite membrane reactor technology [Koc, 2012] offers the option of combining in a single step and on a single process unit (a membrane reactor module serving as the technology platform) the water-gas-shift reaction that plays such a vital role in the enhanced environmental performance of IGCC with the

production of high-purity hydrogen as well as high-quality separation of CO_2 from the reaction products in coal-fired power plants as shown in [Koc, 2012]. The above replacement of multiple process units found in a traditional IGCC setting by a single unit such as the membrane reactor module is obviously advantageous from a process economic standpoint [Koc, 2012, Koc et al., 2012, Scholes et al., 2010]. Furthermore, the high-quality separation of CO_2 from high-purity hydrogen that is co-produced with electricity within the IGCC-MR context renders this option quite attractive [Veziroglu and Barbir, 1998].

However, IGCC power plants require significant capital investment and exhibit more challenging operational characteristics as well as maintenance requirements. Indeed, the Energy Information Agency (EIA) calculates that the overnight capital cost is $2,505/kW for IGCC without CO_2 capture and $3,568/kW for IGCC with CO_2 capture compared to $2,010/kW for advanced pulverized coal plants without CO_2 capture [Energy Information Agency, 2012]. It becomes also evident that given the uncertainty over the future carbon tax regime and rate, as well as electricity price and hydrogen price, it may not be worth operating IGCC-MR systems under some scenarios. Furthermore, in light of the long lifecycle of infrastructure components and significant upfront costs associated with energy projects of such a scale, it is important to carefully assess and simulate the main irreducible uncertainty sources affecting the future economic performance of IGCC-MR power plants, and therefore inform and facilitate the possible deployment of an initial set of demonstration projects of this new advanced energy technology option.

IGCC-MR offers a promising prospect for significant environmental performance enhancement as well as a technological pathway for the co-production of electricity and high-purity hydrogen in a carbon-constrained world. However, this new technology has not been adequately tested and demonstrated at a commercial scale. This lack of accumulated operating experience and assorted data poses significant challenges. Therefore, any preliminary attempt to assess its economic viability and performance-enhancing prospects through various design flexibility options, while methodologically acknowledging irreducible (i.e. regulatory, market, technological) uncertainties, is justified. This effort will stimulate the realization of advanced energy technology demonstration projects at the commercial scale worldwide intensify [Narayanamurti et al., 2011].

One of the primary aims and potential contributions of this study is to employ a generic and powerful methodological, conceptual and analytical framework of engineering system design flexibility in order to: i) draw useful insights, characterize and evaluate a range of economic performance outcomes and prospects of a nascent technology such as IGCC-MR (which has not been demonstrated yet on the commercial scale), ii) identify

potentially value-enhancing flexible design, operating options and decision rules over the lifetime of an IGCC-MR power plant in the presence of irreducible uncertainties, and iii) suggest possible means and inform collective efforts to stimulate the realization of demonstration projects for advanced energy technology in a carbon-constrained world [Narayanamurti et al., 2011].

This design analysis will enable the systems engineering designers and managers to characterize and eventually enhance the IGCC-MR plant's adaptability to the main uncertainty sources such as environmental regulations and fuel costs over its long lifecycle. It is shown that explicitly recognizing flexibility can help improve the economic value of a promising advanced clean energy technology option such as IGCC-MR, as well as provide a sound justification basis to policy and decision-makers for the creative development of the requisite demonstration and adoption incentives.

This paper is organized as follows: Section 2 provides an overview of pertinent literature, and Section 3 provides the framework systematic methodology used to evaluate potentially value-enhancing flexible design options. Section 4 illustrates the application of the methodological framework to the problem of identifying and characterizing flexible design options in IGCC-MR power plants, followed by Section 5 that encompasses the main findings, results of the analysis, a relevant discussion as well as a sensitivity analysis. Finally, conclusions are drawn in Section 6.

2 Literature Review

Uncertainty in techno-economic performance assessment studies of engineering systems has drawn increasing attention from researchers in recent years. de Neufville *et al.* [2004] defined uncertainty as the entire distribution of outcomes including both risks and opportunities. They recognized the limitations in traditional design and project economic performance evaluation approaches in dealing with uncertainties, and underlined that design, rather than aiming at "passively" meeting certain performance criteria with quite wide robustness margins, should explicitly and actively consider uncertainties as a core element. Within such a context, they introduced that the concept of real options developed by economists providing "the right, but not the obligation to change a system in dealing with uncertainties [de Neufville, 2003]" should be considered in engineering systems projects. de Neufville and Scholtes [2011] and Cardin [2014] later provided an overview of the concept and procedures available to systems engineer designers, as they apply to the design of complex engineering systems.

Here, flexibility is used interchangeably with the concept of a real option from the economic and finance literature [Trigeorgis, 1996]. Application of such concepts in engineering is an emerging paradigm that aims to improve lifecycle performance by actively managing risks and uncertainty through design by reducing systems exposure to downside scenarios (e.g. acting like an insurance policy), while pro-actively enhancing potential gains associated with upside opportunities (e.g. like a call option). Examples of real options include staging or phasing capacity deployment over time, allocating resources dynamically to different markets or users, increasing or shutting down operations when needed, or switching between different activity types. Many studies have shown lifecycle performance improvements ranging between 10%-30% as compared to standard design and project evaluation approaches in the aerospace [de Weck et al., 2004, Silver and de Weck, 2007], automotive [Suh et al., 2007], defense [Mikaelian et al., 2012], oil and gas [Lin et al., 2013], water [Zhang and Babovic, 2011], and several other industries [Cardin, 2014].

Since this paper focuses on the IGCC system, a brief account of the pertinent body of literature regarding its economic performance is provided. One should begin with recent insightful reviews as well as survey papers focusing on the traditional IGCC power plant (and its key building blocks such as oxygen production processes, different types of gasifiers, gas cleaning units including CO_2 capture, gas turbines and conventional steam cycle technologies) and a comparative techno-economic assessment against coal- and gas-fired power plants conducted within a deterministic single-point net present value (NPV)-based framework [Department of Mech. & Structural Eng. & Material Science, 2010, Rosenberg et al., 2004, Scholes et al., 2010].

Bohm [2006] conducted a comparison study between IGCC plants with and without pre-investment in CO_2 capture and supercritical pulverized coal plants (SCPC). His study is based on a deterministic discounted cash flow (DCF) model and the comparative evaluation of scenarios generated for different future levels of carbon tax. The author's analysis demonstrated that under low carbon tax scenarios, SCPC appear more economically viable than IGCC plants. However, under a higher future carbon tax trajectory, IGCC plants begin to display economic advantages and their construction seems to be economically justified. In addition, little evidence is found to justify the pre-investment on carbon capture for IGCC plants even under high carbon tax scenarios.

In another comprehensive study, representative IGCC systems using coal as the primary fuel, endowed with CO_2 capture capabilities and relying on various technology options such as membrane reactors (WGS-MR), physical

absorption, chemical looping and stage reactors were comparatively assessed by Rezvani *et al.* [2009]. In particular, it was shown that the IGCC option yields the lowest levelized cost of energy amongst its main competitors.

Research work by Dolan *et al.* [2010], also showed that a module with membrane thickness smaller than 20 μm and total area of 13,000 m^2 could drive the plant capital cost to approximately $ 55 million (thus comparable in magnitude to traditional plants using pressure-swing-adsorption for hydrogen separation and amine-based CO_2 capture purposes).

In order to directly cope with the presence of uncertainty, Frey *et al.* [1994] developed a stochastic modeling framework enabling the representation of uncertainties using probability distributions for various types of process systems. Their probabilistic process modeling approach was also applied to a traditional IGCC plant with hot-gas cleanup. More than 20 uncertainty sources related to performance specifications and cost parameters were considered to determine meaningful distributions for total capital cost, the plant net heat rate, as well as the levelized cost of energy (LCOE). These probability distributions were then compared to the deterministic (point-estimate) results. It was found that there is a higher than 75% probability the LCOE of the IGCC system with hot gas clean-up to be higher than the deterministic estimate.

In a recent study by Chen and Rubin [2009] a comprehensive performance and cost analysis of an IGCC system with water-gas-shift reactors and a Selexol unit (i.e. acid gas removal solvent) for CO_2 capture purposes was performed. According to the uncertainty (probabilistic) description and the corresponding distributions considered, the cost of electricity varied from 72 to 144 $/MWh with a 69% likelihood of exceeding the deterministic estimate of 95.8 $/MWh. In addition, the mean value of the cost of energy distribution was found to be 102.8 $/MWh, which was 7 $/MWh higher than the deterministic estimate.

Finally, Koc *et al.* [2012] conducted a comprehensive study on the uncertainties impacting the most the economic performance of IGCC-MR plants. They identified CO_2 tax, CO_2 tax growth rate, nominal discount factor, inflation rate, electricity selling price, Pd price, support price, and membrane life time as key uncertain project/system economic value drivers. The authors explicitly recognized the potential flaws and limitations in using average values for inputs in traditional NPV-based economic analysis. Therefore, more realistic distribution profiles of the plant's economic performance outcomes were generated by a stochastic Monte Carlo simulation model rather than single-point value estimates, similar to the approach followed by Frey *et al.* [1994]. It was shown that future regulatory action on CO_2 emissions could induce appealing NPV-distribution profiles for IGCC-MR in the presence

of uncertainty and technology risks compared to coal-fired power plants as well as the traditional IGCC. The authors also concluded that pre-investments on safety risk-reducing measures confer significant economic advantages in the presence of technology risks and irreducible regulatory uncertainty.

While significant work has been done on model building and testing scenarios of uncertainties in engineering systems techno-economic performance assessment, little attention has been drawn to potentially value-enhancing flexibilities in the plant design and operation of an IGCC-MR power plant. Koc *et al.* [2012] considered sources of uncertainty such as a major and minor leak accident and evaluated the economic value of process safety pre-investments. However, the authors have not considered including flexibility options in the design such as a flexible operation of a CCS unit to mitigate risk associated with uncertain future environmental regulations. Indeed, the plant management team may recognize the need to switch the operating mode of the CCS unit (enabled by flexible design) depending on how conditions in the regulatory environment evolve in order to enhance overall economic performance. Moreover, CCS analysis on other coal-fired power plants such as pulverized coal (PC), SCPC and baseline IGCC is traditionally based on the assumption of a fixed positive growth rate of carbon tax. However, the economic effect of uncertainty in the carbon tax regulatory regime can be further analyzed by explicitly acknowledging the fact that a carbon tax could itself respond to the prevailing macroeconomic conditions.

In addition, fuel prices have displayed very different trends and volatility patterns in different fuel markets over the recent years. Indeed, coal price has been increasing steadily over recent decades while oil and natural gas have experienced highly volatile price trajectories. In light of the above, a flexible-fuel power system may therefore directly benefit from opportunities to optimize its fuel mix with reference and in response to price signals of various types of operationally admissible fuels. Flexible design real options for IGCC-MR power plants and the prospect of enhanced economic performance in the presence of regulatory and market uncertainties become the subject of the next sections.

3 Methodology

To analyze and evaluate the impact of introducing flexibility into the IGCC-MR plant design on its economic performance in the presence of regulatory and market uncertainty, we apply the following four-step methodology. The methodology is inspired from the literature on flexibility in engineering design, and differs from standard/traditional real options analysis since it is based on risk-neutral valuation (key differences are explained by

Wang and de Neufville [2005]). The proposed approach aims to model explicitly the decision rules that systems engineering managers may follow once flexibility is enabled in systems design. This is difficult to do using standard real options techniques relying on Bellman's equations and expected value maximization at each stage and state of the system. Also, this "systems engineering" approach to valuing flexibility does not rely on many assumptions that are necessary in standard real options valuation like path independence, arbitrage-enforced pricing, the idea that a replicating portfolio exists to replicate the project cash flows, etc. The approach focuses here on a valuation metric widely used in industry (i.e. NPV) and transforms it to account for uncertainty (i.e. using expected NPV or ENPV), and other risk tolerance profiles for decision-making (i.e. Value at Risk (VaR) for risk-averse and Value at Gain (VaG) for risk-seeking decision-makers).

3.1 Step 1: Baseline DCF Model

Step 1 involves the development of a base case functional DCF model for each design alternative in order to form a benchmark platform when all flexible options considered in the present study are assessed later in Step 3. However, a set of meaningful cost and revenue drivers for this model needs to be identified first. Within a deterministic framework, these uncertain drivers are fixed at "average/expected" values as are all design parameters, and the deterministic DCF analysis is conducted for all possible design alternatives in order to determine the economically favorable one.

Here, the annual cash flow is calculated by subtracting operating cost and taxes from the electricity selling revenue stream. The lifecycle economic performance of the IGCC-MR plant is evaluated using a standard Net Present Value (NPV) model where future cash flows are discounted as follows:

$$PV = \sum_{t=1}^{n} \frac{C_t}{(1+r)^t} \tag{1}$$

$$NPV = C_0 + PV \tag{2}$$

where *PV* is the present value of cash flows throughout the lifetime; C_t is the annual cash flow at year *t*; *r* is the real discount rate. *NPV* is calculated by summing up the present value of future cash flows and taking into account the initial capital investment represented by C_0 [Brealey et al., 2006].

3.2 Step 2: Uncertainty Analysis

We start with the recognition that the value of the plant/project is inherently uncertain and driven by market/economic, regulatory uncertainties as well as technology risks. Valuation of projects or technology options based on projection forecasts or expected/average values for all uncertainty drivers is not satisfactory since it leads to single project value estimates and often to unsatisfactory investment decision outcomes in an uncertain world (i.e. "Flaw of Averages" [de Neufville and Scholtes, 2011]). Indeed, Koc et al. [2014] demonstrated that a purely deterministic economic performance assessment framework for IGCC-MR overlooking regulatory and fuel market uncertainties may lead to unsatisfactory conclusions, as well as unsound investment decisions for a new and not yet demonstrated technology option when compared to traditional ones. Thus, the sources of uncertainty in an engineering project are explicitly considered in Step 2 and integrated into the lifecycle economic performance assessment framework.

Typically, there is a set of uncertainty drivers, such as various commodity prices, demand patterns, as well as regulatory policies, affecting the project's economic performance and viability. In general, the above uncertainty drivers require reasonable probabilistic descriptions through appropriately selected distribution profiles. Using stochastic Monte Carlo techniques and random sampling from the above distributions, project value driver uncertainty is propagated through the NPV-model, generating a distribution profile for NPV. The full risk-reward profile can then be adequately characterized in a statistical manner. Indeed, to compare a set of economic performance outcomes and risk profiles generated from different design options, standard financial tools and metrics, such as the ENPV, VAR (e.g. P5 or 5^{th} percentile value, quantifying downside potential), VAG (e.g. P95 or 95^{th} percentile, quantifying upside potential), initial capital expenditures (CAPEX), and/or variability (e.g. standard deviation) can be readily used.

3.3 Step 3: Flexibility Analysis

Step 3 applies the concept of flexibility in the design, deployment and operation of the power plant as well as the economic evaluation of the different alternatives. A number of flexible options/strategies are identified in this step to deal with the major uncertainty drivers based on concept generation techniques described in Cardin et al. [2013]. The flexible strategies can be described by two constitutive elements: 1) the set of design variables and 2) the set of decision rules [Cardin, 2014, de Neufville and Scholtes, 2011]. The former is introduced by a technically feasible

design option and operating boundary, whereas the latter is associated with the exercise of flexibility and real options by the plant management team and are mathematically represented by logical statements (e.g. "IF… THEN… ELSE") embedded into the assessment framework developed in Steps 1 and 2. Design variables and decision rules can be jointly adjusted by optimization techniques to further improve the flexible design.

3.4 Step 4: Sensitivity Analysis

A sensitivity analysis is conducted for each flexibility option in order to examine how sensitive the results of the aforementioned analysis are to operating parameters, decision rules, and design variables. Sensitivity analysis can help evaluate the robustness characteristics of the various design alternatives and classify them accordingly. Specifically, the effects of carbon tax and the plant's capacity factor on the IGCC-MR economic performance are considered.

4 Problem Formulation

The four-step methodology is applied to evaluate the economic performance of IGCC-MR under uncertainty and the assorted value-enhancing prospects induced by a set of flexibility options in its design.

4.1 Baseline DCF Model

A DCF model for evaluating the design of IGCC-MR power plants was developed in Excel® based on the following assumptions:

1. The IGCC-MR plant is assumed to be operational for 40 years and configured with an entrained flow gasifier, which is the most common IGCC design option at commercial scale [Koc et al., 2012].
2. This analysis evaluates the costs of equipment based on the cost figures from the General Electric Energy (GEE) IGCC with CO_2 capture (traditional PBR plant 4) in the DOE/NTEL report [Haslbeck et al., 2010]. The costs of equipment are calculated using the Marshal & Swift (M&S) equipment cost index [Marshall And Swift Cost Index, 2010]. Estimates derived from the M&S indexes are accurate for a period of 10 years [Peters and Timmerhaus, 1991].
3. Selling electricity is the only annual revenue stream from operating the IGCC MR plant, calculated as follows:

$$AI_t = \lambda_t^{elec} \cdot CF_t \cdot 24 \cdot 365 \cdot P_t \quad (3)$$

where AI_t is the annual income at year t; λ_t^{elec} is the electricity price at year t; CF_t is the capacity factor at year t; P_t is the hourly energy output at year t.

4. The electricity price is based on historical trends and data and is not altered by the effect of carbon taxes.

5. The total operating costs are the sum of the following costs:

$$OC_t = FC_t + OMC_t + IPT_t + TSC_t \tag{4}$$

where OC_t is the total operating cost at year t; FC_t is the fuel cost at year t; OMC_t is the operating and maintenance cost at year t; IPT_t is the insurance and property tax at year t; TSC_t is the CO_2 transportation and sequestration cost at year t.

6. The fuel cost is given by the following equation:

$$FC_t = \lambda_t^{coal} \cdot CF_t \cdot 24 \cdot 365 \cdot S_t \tag{5}$$

where λ_t^{coal} is the coal price at year t; S_t is the hourly coal feed at year t.

7. A depreciation rate is assumed to follow the declining balance method [Marshall And Swift Cost Index, 2010] as shown below:

$$AV_t = (1 - DR_t)AV_{t-1} \tag{6}$$

$$DV_t = AV_t - AV_{t-1} \tag{7}$$

where AV_t is the asset value at year t; DR_t is the depreciation rate at year t; DV_t is the depreciation value at year t.

8. By considering the depreciated asset value, the insurance and property tax at year t (IPT_t) is computed as:

$$IPT_t = IPTR_t AV_{t-1} \tag{8}$$

where $IPTR_t$ is the insurance and property tax rate at year t.

9. The plant was assumed to be built in 2013 and the carbon tax will be levied starting from \$10 in 2017 with an expected annual growth rate of 3% afterwards. The carbon tax at year t is calculated as follows:

$$CT_t = CTR_t \cdot E_t^{CO2} \tag{9}$$

where CT_t is the carbon tax at year t; CTR_t is the carbon tax rate at year t; E_t^{CO2} is the emission of carbon dioxide at year t.

10. Taking into account income tax and the above set of equations (3)-(9), the annual cash flow (ACF_t) is calculated as follows:

$$ACF_t = (AI_t - OC_t)(1 - IT_t) + DV_t - CT_t \quad (10)$$

where IT_t is the income tax at year *t*.

11. With the formula for annual cash flow constructed, the present value is calculated in (11) and subsequently the net present value is computed in (12), where C_0 refers to the capital expenditure.

$$PV = \sum_{t=1}^{n} \frac{ACF_t}{(1+r)^t} \quad (11)$$

$$NPV = C_0 + \sum_{t=1}^{n} \frac{ACF_t}{(1+r)^t} \quad (12)$$

12. In view of the higher risk associated with novel IGCC-MR technology, the assorted higher maintenance requirements and technical complexities, we use 9% as a nominal discount rate in the DCF analysis. This discount rate is comparable to the one used for IGCC baseline plants.

13. Given the pertinent technical specifications [Koc et al., 2012], a 98% CO_2 separation quality level is considered.

14. The input parameters of this DCF model are given in Table A1, Appendix A.

4.2 Uncertainty Analysis

There are a number of uncertain parameters associated with the IGCC-MR plant's economic performance (e.g. CO_2 tax, CO_2 tax growth rate, plant capacity factor, inflation rate, electricity demand, electricity price, hydrogen price, hourly wage, Pd-price, coal price, membrane life time and etc.). Carbon taxes and coal prices are the most consequential ones and will be described as follows:

Carbon taxes

To generate a realistic CO_2 tax scenario, the model considers the body of literature pertaining to CO_2 emission permit trading schemes in the United States and Europe. In general, there are two key variables considered in this scenario, namely, the initial CO_2 tax and its growth rate.

In the United States, the Regional Greenhouse Gas Initiative (RGGI) is the first market-based regulatory program aiming at reducing greenhouse gas (GHG) emissions, which involves the states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont. These states engage in

cooperative efforts in capping CO_2 emissions and aspire to reduce CO_2 emissions from the power generation sector by 10 percent by 2018. In the RGGI auction that took place in December, 2012, CO_2 allowances were sold at a clearing price of \$1.93/tCO_2 [Regional Greenhouse Gas Initiative (RGGI), 2012] Furthermore, RGGI forecasts that the carbon permit trading price will remain at approximately \$2/tCO_2 until 2030 [Regional Greenhouse Gas Initiative, 2010)].

In the European Union, CO_2 emission permits have been traded under the Emissions Trading Scheme (ETS) since 2005 with satisfactory participation from the energy sector. The carbon price was at an average of \$10.80/tCO_2 from September 2011 to September 2012. Considering the impact of the financial crisis and the discrepancy between the European Union and U.S. carbon prices, it is assumed that the most likely value of a future carbon tax is \$10/tCO_2. The maximum value is assumed to be \$50/tCO_2, which is the pre-crisis peak of carbon price in the European Union. The minimum value is assumed at \$1/tCO_2.

The uncertain initial carbon tax is modeled using a triangular distribution based on the above values. It is used to capture the range of reasonable estimates reported in the literature (see [Koc et al., 2014]), as well as based on expert opinion. Indeed, there is only a dearth of reliable data available since only a limited number of countries and regions have adopted such a tax (or a comprehensive well-functioning cap-and-trade system). Available data were used from references and bibliographical sources pertinent to the European Union Emissions Trading Scheme (ETS) and U.S. emission trading schemes. The average trading price was used as the most likely – or central – estimate. Considering the impact of the financial crisis on the carbon emissions price, the pre-crisis price was used as the maximum value of the distribution. Since the U.S. carbon price is significantly lower than the ETS price, it was used as the distribution's minimum value.

For the carbon tax growth rate, a stochastic Geometric Brownian Motion (GBM) model is adopted:

$$CTGR_t = \mu \cdot \Delta t + \sigma \cdot \varepsilon \cdot \sqrt{\Delta t} \tag{13}$$

Variable $CTGR_t$ is the carbon tax growth rate at year t; μ is the drift (assumed to be 3% [Bohm, 2006]); σ is the volatility (assumed to be 3% by taking into account the existing historical data of CO_2 emission permits [Regional Greenhouse Gas Initiative (RGGI), 2012]); ε captures the Wiener process based on a standard normal distribution; Δt is the time step (equal to 1 year in this study).

Coal Prices

According to DOE [Haslbeck et al., 2010], Illinois #6 coal represents the favored feed for IGCC plants, although its price history is not released by the EIA for IP protection. Here, annual coal prices from EIA are considered [Energy Information Agency, 2012]. The analysis conducted could be easily modified if the Illinois #6 coal price history were made available. By using regression analysis, the drift and volatility of annual coal prices from years 2001 to 2011 were found at 8.52% and 4.85%, respectively. The uncertain annual coal price growth rate was modeled using the same GBM assumptions as captured in [de Neufville, 2003].

The Monte Carlo simulation consists of 2,000 samples (or scenarios) generated from the stochastic version of the DCF model described in step 1 (i.e. including random variables for carbon taxes and coal prices described above). The rationale for using 2,000 samples is to balance statistical significance of the simulation results, while ensuring computational tractability of the model so it runs within seconds. The simulation model used here is relatively inexpensive to run, hence such a large number was selected. The standard error of the sample mean then becomes negligible, hence providing a good assessment for the mean of the simulated performance (e.g. NPV) distribution.

4.3 Flexibility Analysis

In general, flexibility options can be classified as options "on" or "in" engineering systems [Wang and de Neufville, 2005]. Flexibility "on" systems refers to managerial flexibility such as abandoning operation, deferring investment until favorable market conditions develop, etc. Flexibility "in" systems refers to the change of design components to enable flexibility. In this paper, we describe three flexibility options, namely: 1) a fuel-related, 2) an operational and 3) a constructional one, to improve the economic performance of an IGCC-MR power plant in an uncertain regulatory and market environment. The fuel-related and operational options are actually classified as flexibility "on" the system, whereas the constructional option is considered as flexibility "in" the system. These options resulted from an effort to elicit expert advice and input, explore the pertinent IGCC literature, use systematic concept generation techniques, and also consider standard strategies from the literature on real options and flexibility in engineering design [Cardin et al., 2013, de Neufville and Scholtes, 2011, Trigeorgis, 1996]**.**

Fuel Flexibility

IGCC has the potential to handle a wide range of primary fuels such as coal, biomass, waste, petroleum coke, refinery residues as well as a blend of these fuels. Furthermore, IGCC possesses a proven ability to co-fire syngas from primary fuels with secondary fuels such as natural gas. Indeed, the co-firing option was first adopted in 1996

by the Texaco El Dorado IGCC plant in Kansas. It should be also noted that syngas provides one third of the thermal input while natural gas provides the remaining two thirds. In addition, power availability of 97% has been achieved during the plant operation. By 2000, there were 19 General Electric gas turbines operating on a mix of coal, petroleum coke and other low heating value fuels [Brdar and Jones, 2000]. Fuel flexibility ensures that an IGCC power plant can selectively use a few types of fuels depending on their prices (and developments in their respective markets) to effectively manage the uncertainty of fuel prices and availability.

Operational Flexibility

The operational flexibility option is motivated by uncertain power demand patterns and the future state of environmental regulations. To reduce GHG emissions, renewable energy sources are expected to gradually replace a percentage of the current fossil fuel used in power generation. However, renewable energy sources such as wind and solar cannot produce stable output due to the intermittency induced by changes in weather conditions. Within such context, IGCC power plants would still be needed to reliably compensate for the intermittent energy output of renewables.

Two flexible operating modes are considered. The first one is operating the plant under partial load (i.e. producing a fraction of the full load output), and the second one is to shutdown and start-up periodically in response to changing operational conditions. The partial load operation is deemed impractical because it imposes a penalty on plant efficiency and results in a relatively high GHG emission rate per unit of electricity generated. The periodic shutdown and start-up (involving particularly the operation of the CCS component unit) option is deemed a more meaningful one. Indeed, when emission permit or carbon tax prices are high or renewables produce high outputs, the plant may be dormant. When the above conditions evolve in opposite directions, plant operations may become favorable.

The main concerns regarding the periodic shutdown and start-up modes are the operation reliability and the relatively high operating cost of start-up. The start-up time is also a key factor. A shorter start-up time implies lower fuel consumption rates during start-up and higher start-up efficiency, resulting in significant savings in fuel and CO_2 emissions costs. It has been convincingly demonstrated that Siemens FACYTM provides an economic and technically viable solution for fast shutdown and start-up [Pickard and Meinecke, 2011]: de-loading from 100% to 55% is achieved within 6 seconds and start-up takes less than 30 minutes. Siemens demonstrated that nightly shut

downs saved 360 ton CO_2 per night and therefore mitigated the risk of a high carbon tax [Pickard and Meinecke, 2011].

Constructional Flexibility

The phased construction concept can be applied to an IGCC-MR plant [Cardin, 2014, de Neufville and Scholtes, 2011]. For instance, the plant may initially be built starting with a natural gas combined cycle and allowing space for future development. Later, if coal prices are competitive or production of by-products from syngas becomes economically attractive, coal gasification and syngas treatment components can be added. If a carbon tax is levied, CCS could be installed to remove CO_2. Flexible phased construction requires pre-investment to minimize operation disruption and capital expenditures when future development will be carried out.

There are currently two main concepts of technology for CO_2 capture, namely pre-combustion capture and post-combustion capture. Pre-combustion capture removes CO_2 before the syngas is combusted in the gas turbine. Therefore, the combusted syngas contains mainly hydrogen, generating also an opportunity for extra-purity hydrogen production. As most CO_2 and carbon composites are removed, the gas turbine does not need to be designed to accommodate different compositions of CO_2, CO and H_2. Thus, the plant could use a wide range of fuels. Due to the relative small volume of syngas for CO_2 cleaning, the capture level is guaranteed at more than 90% [International Energy Agency, 2013].

CCS operation takes place at the expense of energy that could be used for electricity generation. Due to the operation of CCS, the capacity factor is assumed to drop from 80% to 75%. The cost estimates of fuel, O&M, CO_2 emissions and CO_2 transportation and sequestration are summarized in Table B4, Appendix B**.** These assumptions are based on accumulated operating experience related to existing IGCC plants suggesting that they typically reach availability factor levels of 70%-85%, which can be further enhanced by introducing a spare gasifier (the IGCC component unit with lower reliability characteristics) and made comparable to the ones exhibited by conventional natural gas-fired combined cycle power plants (85%-90%). The integration of membrane reactor modules into the conventional IGCC structure (IGCC-MR) considered here represents a new technology that may potentially offer enhanced techno-economic and environmental performance, but has not yet been demonstrated at commercial scale.

This realization inevitably introduces potentially higher technology risks and uncertainty when IGCC-MR is compared to traditional technology options. Therefore, in light of the associated lack of any pertinent operating experience and dearth of data, the above eventuality (performance outcome) is captured through a lower availability

factor. In a recently published paper the aforementioned availability factor was considered as an uncertain model input variable (random variable) explicitly integrated into a Monte Carlo-based economic performance assessment framework as well as a comparative evaluation of IGCC-MR against the conventional technology options in the presence of uncertainty [Koc et al., 2014].

Furthermore, IGCC efficiency is a function of the specific fuel type (coal rank), gasifier and gas turbine technology as well as the degree of integration between the gas turbine and the air separation unit. To enhance plant efficiency, bituminous coal was considered, a GE entrained-flow gasifier and new generation F-class gas turbines with air-integration [Maurstad, 2005]. The integration of a carbon capture unit into the IGCC structure results in an output de-rating and efficiency loss due primarily to the operating performance requirements of the CO_2 separation unit and CO_2 compression costs. Also, the integration and structural configuration of membrane reactor modules into IGCC-MR power plants was performed in a way that further enhances net plant efficiency [Gray and Tomlinson, 2002, Haslbeck et al., 2010, Koc et al., 2014]. The integration of the membrane reactor into the IGCC plant induces an energy penalty at the gas turbine inlet [Haslbeck et al., 2010, Koc et al., 2014] due to the associated H_2 compression costs. However, the separation of CO2 under high pressure in IGCC-MR results in significant energy savings in terms of CO_2 compression costs when compared to traditional IGCC with carbon capture [Koc et al., 2014]. In particular, the auxiliary power load needed in the IGCC-MR case was determined by including the energy requirements related to reheating the feed steam for the membrane reactor, cooling the retentate stream before CO_2 compression, the H_2 compression of the module's permeate stream before the gas turbine and finally CO_2 compression [Koc et al., 2014].

The power requirements for the H_2 compression were calculated by assuming a multi-stage intercooled compressor. The energy requirement for isothermal H_2 compression before directing the H_2 flow to the gas turbine represented 40% of the total auxiliary power requirement [Koc et al., 2014]. Innovative design options are essential in reducing the total H_2 compression costs such as membrane reactor modules in series: one operating at a higher permeate side pressure and the next one at a lower permeate side pressure to remove as much H_2 as possible. If the H_2 compression costs could be reduced, the size of the IGCC-MR would be smaller while attaining the same level of net power output. Finally, in the above analysis, the energy requirements and gains for the heating and cooling steps were determined by assuming 40% efficiency to convert thermal energy to electric power, and vice versa (for more details see: [Koc et al., 2014]).

If the carbon tax rate is high or grows fast, it may be economical to install and operate a CCS unit. Apart from the initial capital investment on carbon capture, each ton of CO_2 incurs a transportation and sequestration cost of $10 [Holt, 2007]. Moreover, capturing CO_2 takes place at the expense of generating electricity, and therefore the net electricity output will be smaller for an IGCC-MR power plant with carbon capture than that without carbon capture. For comparison purposes, costs and revenues in the economic performance assessment framework are corrected for a common net output figure of 550 MWe amongst all operating modes and design possibilities (through plant component re-sizing) considered in the present study.

5 Main Results and Discussions

The simulation results of the operational and constructional flexible alternatives are presented and discussed. Our analysis focuses on the quantitative evaluation of two flexible options to provide better guidance for decision-making. In particular, there are two cases corresponding to the above flexible options. For each case, several sub-options are introduced, such as base case (BC), decision rules (DR), investment at later stage (LS), and with pre-investment (PI). For better readability, the cases are listed as follows:

Case 1: Operational Flexibility (i.e. "ON" flexibility)

- Case 1-a (denoted by ON_BC) is a base case for an IGCC-MR plant without considering operational flexibility and CCS technology; and
- Case 1-b (denoted by ON_DR) introduces the operational flexibility mentioned earlier with the consideration of operating decision rules.

Case 2: Constructional Flexibility (i.e. "IN" flexibility)

- Case 2-a (denoted by IN_BC) introduces CCS in the initial construction phase and assumes that it remains operational all the time throughout the plant's economic life;
- Case 2-b (denoted by IN_DR) introduces CCS in the initial construction phase and assumes that its operation is governed by decision rules in response to the state of the uncertain regulatory environment;
- Case 2-c (denoted by IN_DR_LS) introduces the option of plant retrofitting with a CCS unit at a later stage until favorable economic conditions arise in response to developments in the regulatory environment; and

- Case 2-d (denoted by IN_DR_LS_PI) introduces the option of plant retrofitting with a CCS unit at a later stage when pre-investment took place for such a design accommodation until favorable economic conditions arise in response to developments in the regulatory and market environment.

5.1 Operational Flexibility

Operational flexibility has been comprehensively discussed in the previous section and shown to be technically viable. Since this analysis focuses on a year-to-year operation, the formulated operational flexible option is to temporarily shut down the plant for one year in case of continuing economic loss, and this is referred to as ON_DR (Case 1-b) thereafter. The characterization of the IGCC power plant's dynamic response during start-up, shutdown as well as step or ramp-like changes in the set-point variables to meet electricity demand requirements has been recently the focus of many studies [Bhattacharyya et al., 2011, Casella and Colonna, 2012, Glover et al., 2007, Mahapatra and Zitney, 2012]. These studies also emphasize potential gains to be realized through the employment of advanced process monitoring and automated control systems that can further enhance system operational flexibility and robustness by inducing the desirable dynamic response characteristics as well as meeting key system performance requirements during the start-up, shut-down and set-point tracking stages.

Furthermore, it has been observed [Jones et al., 2011, Maurstad, 2005] that the IGCC power plant's dynamic response is critically related to the degree of integration between the gas turbine (GT) in the combined cycle power block and the air separation unit (ASU). In particular, an interesting performance trade-off arises [Maurstad, 2005]: a high degree of integration between GT-ASU leads to high plant efficiencies but lower operational flexibility during the above stages (sluggish responses), whereas lower degrees of integration between GT-ASU lead to lower plant efficiencies but enhanced operational flexibility. The above studies focus on the traditional IGCC power plant structure and, to the best of our knowledge, there is no research analogue in the literature for the IGCC-MR case (a worthwhile future research direction). Here, all of the plants' dynamic response characteristics and "time-constants" considered in our arguments conform to the aforementioned studies and their findings.

The decision rule is to temporarily shut down the plant for a year if the cash flows for the previous two years are negative. The same decision rule will be applied for the remaining years. If any one of the two previous years displays non-negative cash flow, the plant remains open. The plant will be re-opened if the forecasted cash flows in

any one of two previous years are positive. When the plant is closed in year *t*-1 and reopens in year *t*, an extra O&M cost of $4.3 million [Bohm, 2006] will be incurred for starting up the plant in year *t*.

In a year when the plant is not operating, no revenue stream is generated. Therefore, any depreciation and the assorted depreciation tax shield will be delayed until the next operating year. Furthermore, the land rental is most likely to be specified in a long-term contract, and thus it represents a sunk cost. According to a corporate finance principle, this sunk cost should not affect short-term operation decisions [Chen and Rubin, 2009]. The plant is assumed to dismiss its labor force during the shutdown period and not purchase any raw materials. Hence, no operating cost will be incurred. As a result, the plant generates a zero cash flow in a non-operating year. There are limitations on the zero operating cost assumption. The plant owners may still need to pay for worker layoff compensation and recruitment. Given the intractable complexities of labor relations and pertinent market issues, the associated costs are omitted in the present study.

The simulation results are summarized in Table I. The best result for each criterion is highlighted in bold. The CDF plots are shown in Figure 1. The flexible case dominates the base case in all evaluation metrics except for maximum value and VAG P95, for which both designs appear to exhibit similar economic behavior. ENPV changes from negative to positive by incorporating the operational flexibility option. Furthermore, the NPV profile becomes less spread in the flexible design case. ON_DR (Case 1-b) produces a 21% increase in VAR P5, suggesting the possibility of a better management of downside risk.

Table I: Simulation results for operational flexibility

	Case 1-a (ON_BC)	Case 1-b (ON_DR)
Mean ($ M)	-67.5	**241.1**
Max ($ M)	**2,022.3**	1,953.4
Min ($ M)	-5,230.7	**-4,173.3**
VAG P95 ($ M)	**1,659.7**	1,647.1
VAR P5 ($ M)	-4,868.0	**-3,866.9**
Standard Deviation ($ M)	992.0	**783.5**
Probability of Loss ($ M)	47%	**34%**

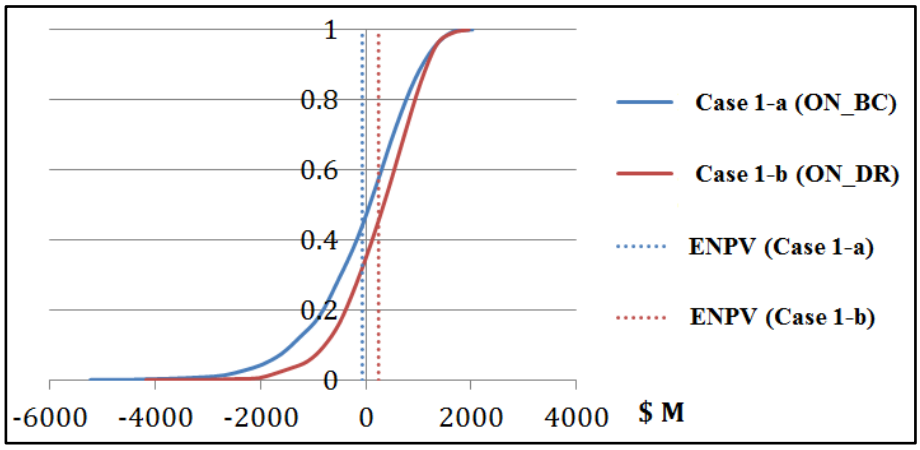


Figure 1: CDF plots for ON_BC (Case 1-a) and ON_DR (Case 1-b)

The pie chart in Figure 2 shows the distribution of outcomes generated by 2,000 simulations when the plant is temporarily shut down. In most simulation runs, the operational flexibility option is exercised 4-8 times over the plant's lifetime, accounting for over 80% of the runs.

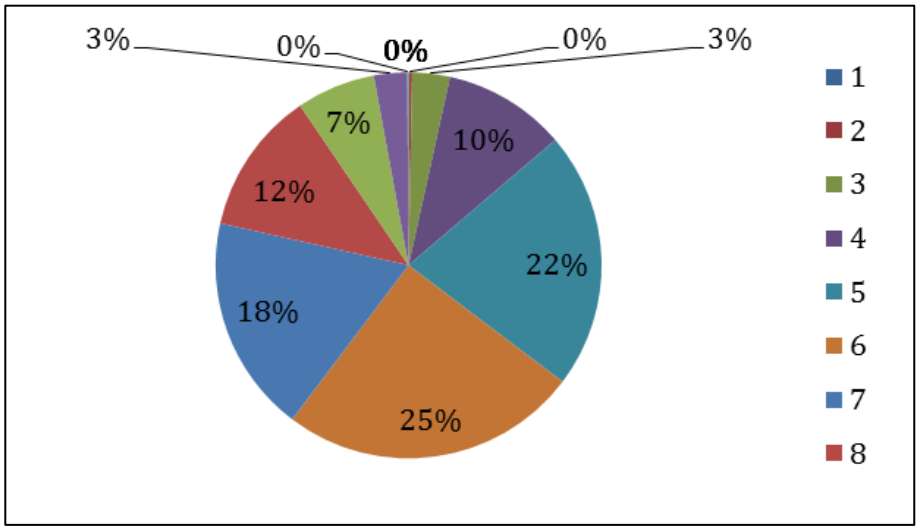


Figure 2: Percentage of samples where the operational flexibility option is exercised 1-8 times, out of 2,000 samples

5.2 Constructional Flexibility – Inclusion of CCS Unit in the Design Phase

Two flexible options, IN_BC (Case 2-a) and IN_DR (Case 2-b) are introduced in this section. Case 2-a introduces CCS in the initial construction phase and assumes that it remains operational all the time throughout the plant's economic life. Case 2-b introduces the inclusion of the CCS unit in the design phase of the plant and the opportunity to be operational only when cost effective. Cost-effective means that the CCS-relevant cost is lower

than the amount paid for CO_2 emission taxes in the previous two years (i.e. decision rule associated with exercising the constructional flexibility option). Within the above context, the CCS-relevant cost refers to the after-tax cost of the additional consumption of fuel, operation and maintenance cost, the CO_2 transport and sequestration cost and the forgone electricity revenue due to the inevitable drop in the plant's capacity factor.

ON_BC (Case 1-a), IN_BC (Case 2-a) and IN_DR (Case 2-b) are "normalized" to account for the same electricity output of 550 MWe (through appropriate component re-sizing in the respective designs and cost/revenue re-calculation) in order to ensure fair comparison. In the analysis of Case 2-a and Case 2-b, the capital investments are the same. This analysis assumes no additional capital cost associated with activating or cancelling the operation of the CCS unit because this is likely to be included into most plant designs for reliability, availability and maintenance purposes [Chalmers et al., 2009]. The zero cost assumption is in accordance with the assumption in Patino-Echeverri *et al.* [2012].

The analytical framework enables explicit calculation of the value of the specific CCS operational flexibility option. If relevant cost estimates for the CCS operational flexibility option are available, the plant operator can weigh the value of flexibility against the above costs. Simulation results for ON_BC (Case 1-a), ON_DR (Case 1-b), IN_BC (Case 2-a), and IN_DR (Case 2-b) are summarized in Table II.

Table II: Simulation Results Summary for Cases 1-a, 1-b, 2-a and 2-b

	Case 1-a (ON_BC)	Case 1-b (ON_DR)	Case 2-a (IN_BC)	Case 2-b (IN_DR)
Mean ($ M)	-67.5	241.1	254.1	**541.8**
Max ($ M)	**2,022.3**	1,953.4	1,358.0	1,940.8
Min ($ M)	-5,230.7	-4,173.3	**-2,206.8**	-2,731.6
VAG P95 ($ M)	**1,659.7**	1,647.1	1,179.8	1,707.2
VAR P5 ($ M)	-4,868.0	-3,866.9	**-2,028.5**	-2,497.9
Standard Deviation ($ M)	992.0	783.5	**461.0**	489.9
Probability of Loss	47%	34%	26%	**13%**
Capex ($ M)	**1,514**	**1,514**	1,576	1,576

The analysis introduces one degree of flexibility at a time to show how flexibility adds value incrementally. This approach reveals potential biases of the model more effectively than solely comparing the highly flexible case with the base case. Finally, all flexible cases are comparatively assessed against the base case as well.

Constructional Flexibility vs Operational Flexibility

First, ON_BC (Case 1-a) and IN_BC (Case 2-a) are compared to reveal how CCS affects the economic performance of the plant (see Table II and Figure 3). It is found that CCS greatly improves the ENPV and reduces the spread of the NPV profile. The downside risk is cut down by 58%.

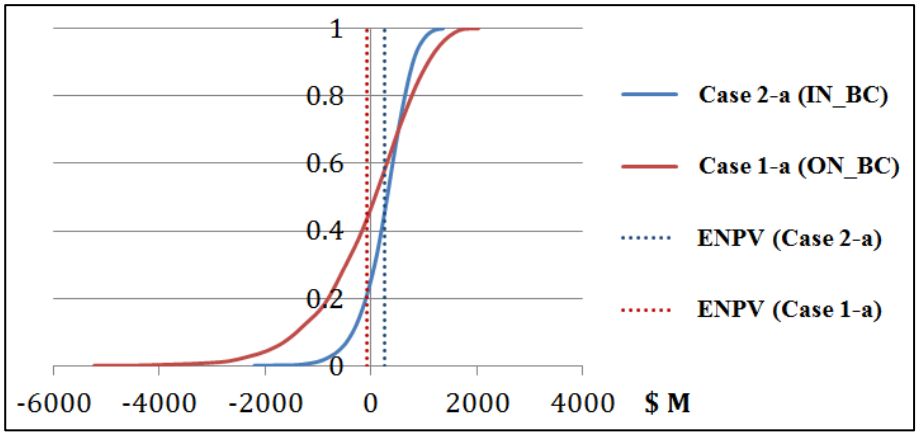


Figure 3: CDF plots for ON_BC (Case 1-a) and IN_BC (Case 2-a)

This suggests that CCS provides IGCC-MR Plant with insurance over a potentially aggressive carbon tax policy regime. In the event of a high initial carbon tax being levied or carbon tax growing on a fast track, CCS protects the plant from operating while inducing continuous losses. Although a moderate carbon tax policy is more likely than an aggressive one, the risk should not be ignored. In fact, the Australian government set an ambitious carbon tax plan by imposing an initial tax of $23 and an annual growth rate of 5%, much higher than the carbon-trading price in Europe and the United States [Regional Greenhouse Gas Initiative, 2010)]. The probability of loss also decreases from 47% to 26%.

The operation of the CCS unit, however, reduces the upside opportunity, the value at gain (VAG) or 95th percentile (P95), by 29%. The upside opportunity corresponds to low carbon tax scenarios and/or high coal price scenarios. In these cases, the savings on carbon tax are outweighed by the additional cost of fuel stemming from the inclusion of the CCS unit. In view of the slow progress of international efforts to impose a transparent globally meaningful tax on CO_2 emissions and the increase in coal price over the past decade, the plant designer and management team may want to carefully think of the possibility of an upside opportunity loss.

A difference curve is plotted in Figure 4 to assess the value of the CCS inclusion. CCS indeed delivers an expected gain on NPV of $286 million, and an IGCC-MR plant with CCS has a 60% chance of performing better

than the base case as well as a 55% chance of outperforming the base case by $62 million (which is comparable to the additional investment in the installation of the CCS unit).

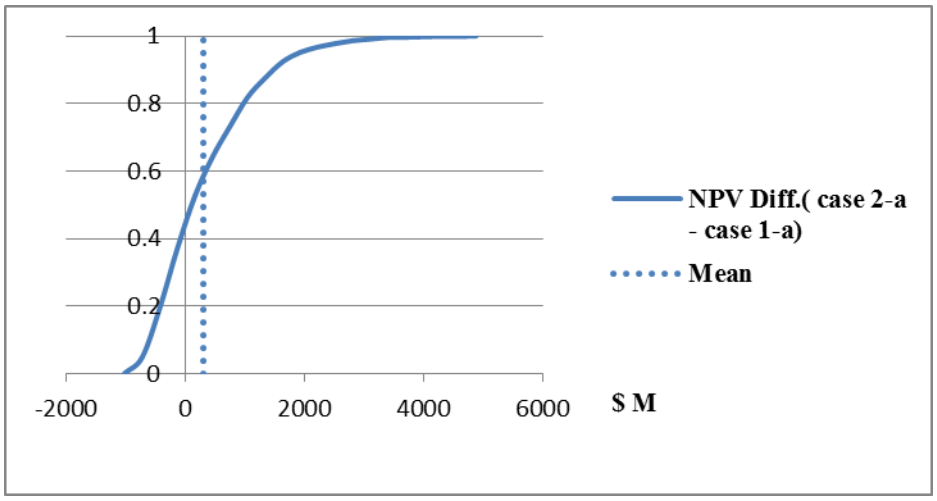


Figure 4: CDF plot for NPV difference between IN_BC (Case 2-a) and ON_BC (Case 1-a)

A regret plot is shown in Figure 5. The vertical axis corresponds to the value of the preferred design (IN_BC) while the horizontal axis depicts the value by which the CCS option boosts overall economic performance, i.e. NPV (Case 2-a) - NPV (Case 1-a). Case 2-a (IN_BC) generally outperforms Case 1-a (ON_BC) as most points in Figure 5 are located to the right of the vertical split. In many instances, IN_BC can deliver positive value even when outperformed by ON_BC; these scenarios correspond to the points above the horizontal split and to the left of the vertical axis.

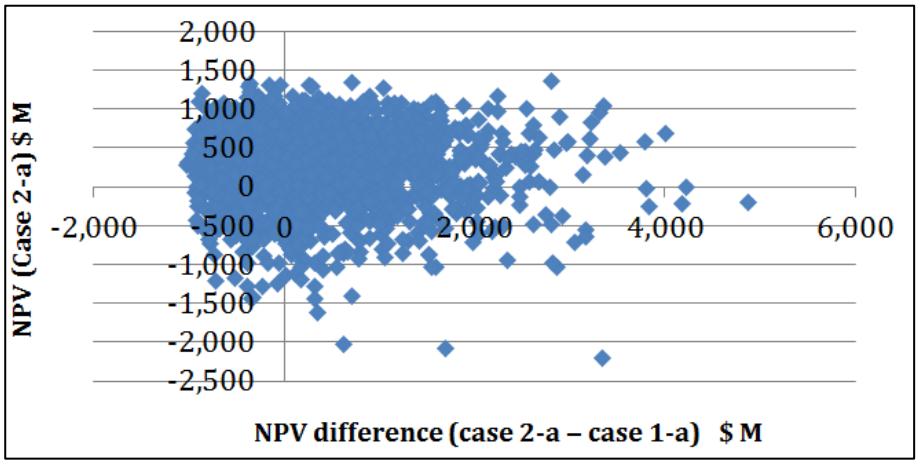


Figure 5: Regret plot for ON_BC (Case 1-a) and IN_BC (Case 2-a)

To sum up, in these scenarios, IN_BC (Case 2-a) represents a better choice than ON_BC (Case 1-a). The inclusion of CCS leads to a significant improvement on the ENPV-metric level, reduces the dispersion of the NPV profiles and mitigates the downside risk. For 60% of the simulated scenarios the design with CCS inclusion outperforms the one without CCS. The plant owner, however, needs to make a tradeoff between the gains and the penalty on upside opportunities.

The Importance of Decision Rules in Constructional Flexibility

IN_BC (Case 2-a) and IN_DR (Case 2-b) are now compared to show how the operational flexibility of CCS adds economic value to the plant operations (see Table II and Figure 6). Indeed, it can be inferred that the operational flexibility option increases the ENPV by 113% and the standard deviation by 6.3%. However, as seen in Figure 6, the increase in standard deviation is mainly due to the fact that the CDF profile in IN_BC (Case 2-a) stretches out to the positive side – arguably a good thing. IN_DR (Case 2-b) significantly decreases the probability of loss from 26% to 13%. However, VAR for IN_DR is 24% lower than for IN_BC.

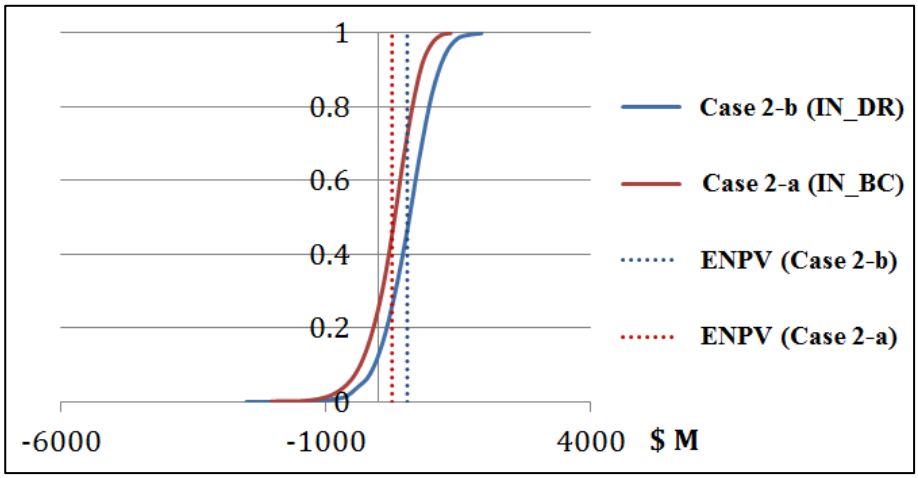


Figure 6: CDF plots for IN_BC (Cases 2-a) and IN_DR (Case 2-b)

Downside NPVs may correspond to high carbon tax scenarios. Since 100% carbon capture cannot be realized, the plant management needs to pay for carbon taxes even when CCS is running. High carbon taxes add burden to the plant and thus lead to smaller NPV values. In high carbon tax scenarios, Case 2-b appears to be disadvantageous compared to Case 2-a because the CCS unit should be operated immediately, however its operation is delayed by two years according to the aforementioned decision rule. Consequently, high costs are inevitably incurred.

IN_DR also produces a 45% higher VAG than IN_BC, showing the strength of CCS operational flexibility in terms of capitalizing on upside opportunities. The upside NPVs may correspond to the low fuel cost scenarios in favor of CCS operation. Still IN_DR provides a smarter managerial decision-making option to achieve a higher possible gain.

The NPV difference curve in Figure 7 demonstrates that IN_DR delivers an expected gain on NPV of $249 million and outperforms IN_BC in almost all scenarios. Here $249 million represents the expected value of the CCS operational flexibility option. The underlying assumption of zero cost is associated with "turning on or off" the CCS unit. This assumption may of course not hold true (however it might be a good approximant when the associated costs are quite low). Finally, the plant operator and the whole management team may compare the cost of obtaining CCS operational flexibility with the its value $249 million to determine whether it is a good investment decision.

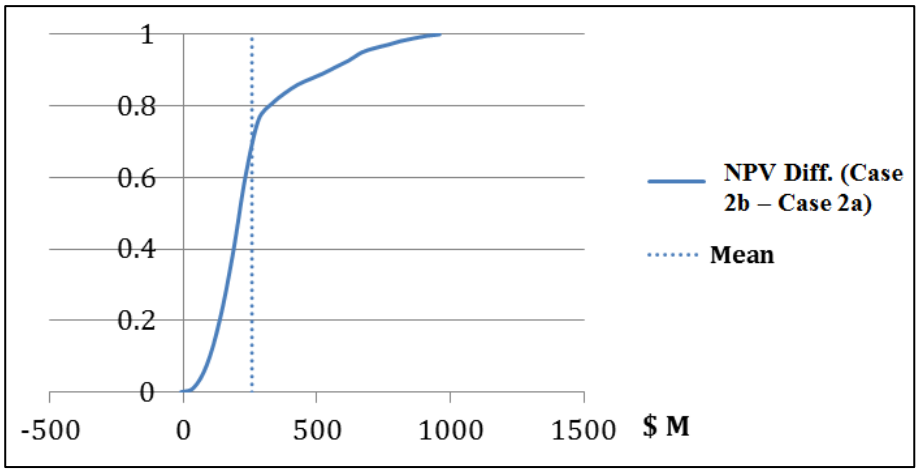


Figure 7: CDF plot for NPV difference between IN_BC (Cases 2-a) and IN_DR (Case 2-b)

5.3 Constructional Flexibility – Inclusion of CCS Unit at a Later Stage

In this study, retrofitting an IGCC-MR plant means the integration of a CCS unit into the plant's structure at a later stage rather than at the initial design phase. It is motivated by the irreducible uncertainty in the regulatory regime involving CO_2 emissions. The cost of retrofitting an IGCC-MR plant for CO_2 capture is higher than the difference in the total plant costs between a green-field (i.e. not constrained by prior work) no-capture and capture plant for the following reasons:

- There are two separate construction phases, which require additional planning and contracting requirements.

- The layout of the plant may have to be modified to accommodate the CO_2 conditioning and compression unit.
- The components of the plant may be mismatched after the retrofit, increasing the output de-rating of the plant after retrofit relative to a green-field capture plant.

However, an IGCC-MR Plant exhibits economic advantages over other traditional IGCC designs due to the replacement of equipment that is no longer required due to the embedded membrane reactor module (the reader is referred to the Introductory Section).

In this last subsection, three cases are examined. All cases are endowed with the operational flexibility option for the CCS unit. IN_DR (Case 2-b) includes a CCS unit in the initial construction phase, the same as in the previous subsection. IN_DR_LS (Case 2-c) involves the CCS-based retrofitting of the plant as described above. Finally, IN_DR_LS_PI (Case 2-d) considers plant retrofitting with pre-investment enabling more easily the later accommodation of the CCS-unit into the IGCC-MR structure. One should note that pre-investment could reduce the output de-rating occurring after retrofit. Within this context, both MIT [Bohm, 2006] and EPRI [Electric Power Research Institute, 2012] presented a bundle of pre-investment options for CCS retrofit. The studies advocate pre-investment strategies focused on the air separation unit and gasifier, which are designed with approximately 10% more capacity. The pre-investment cost figure was taken from the MIT study [Bohm, 2006], and is $66.44/kWe in 2012. The economic performance characteristics before and after retrofit are presented in Table III for IN_DR_LS (Case 2-c) and IN_DR_LS_PI (Case 2-d). The output de-rating and net efficiency figures are also taken from the MIT study [Bohm, 2006] and by using the comprehensive simulation model developed by Koc *et al.* [2012]. Details are shown in Table B1, Appendix B.

Retrofit investment includes the retrofit cost and output de-rating cost. Furthermore, retrofit costs are associated with the addition of the CO_2 compression and conditioning units. The specific cost figures are taken from the U.S. Department of Energy (DOE) [Haslbeck et al., 2010]. The output de-rating cost is estimated by considering the building cost of a makeup plant to compensate for the output de-rating. Therefore, it is equal to the product of the output de-rating and the overnight capital cost of a green-field IGCC plant with CO_2 capture. The overnight capital cost estimates are also taken from the U.S. DOE [Haslbeck et al., 2010]. Details are summarized in Table B2, Appendix B. Comprehensive cost and performance summaries are presented in Table B3 and B4, respectively. For both IN_DR_LS and IN_DR_LS_PI, the decision rule is that retrofit is pursued if during the previous two years the

benefit of operating the plant with a CCS unit outweighs the assorted total cost (i.e. if the following inequality holds true):

*Savings on carbon tax > (1-tax rate) *(CO_2 transportation and sequestration costs + additional fuel costs + foregone electricity revenue due to capacity factor penalty + additional O&M costs)*

Table III: Simulation Results Summary for Cases 2-b, 2-c and 2-d

	Case 2-b (IN_DR)	Case 2-c (IN_DR_LS)	Case 2-d (IN_DR_LS_PI)	Improvement by pre-investment
Mean ($ M)	**541.4**	338.0	357.6	6%
Max ($ M)	1,895.3	**1,928.3**	1,868.5	-3%
Min ($ M)	**-1,370.4**	-1,992.1	-1,492.3	25%
Value at Gain 95% ($ M)	**1,732.0**	**1,732.3**	1,700.5	-2%
Value at Risk 5% ($ M)	**-1,207.1**	-1,796.1	-1,324.3	26%
Standard Deviation ($ M)	**486.2**	502.9	500.1	-1%
Probability of Loss	**14%**	24%	23%	-1%
Capex ($ M)	1,576	1,**514**	1,551	3%
PV(Capital investment)	**1,576**	1776.0	1,738.8	-2%
Year of Retrofit	N/A	12	12	N/A

Once the retrofit is complete, the retrofit cost will be counted in the IGCC's asset and entitled to depreciation from the next year on. Finally, the present value of total investment is the sum of initial investment and the present value of retrofit investment. The plots of the CDF profiles for these three cases are shown in Figure 8. The simulation results are summarized in Table III.

IN_DR (Case 2-b) generates the highest ENPV, significantly larger than the retrofit cases. IN_DR also results in a less spread NPV profile and a smaller probability of loss. Although the initial capital investment in IN_DR is higher than that in IN_DR_LS (Case 2-c) and IN_DR_LS_PI (Case 2-d), IN_DR has a smaller PV (Capital investment). Furthermore, it can be deduced that IN_DR_LS outperforms the other two cases in terms of maximum value and VAG. This corresponds to the scenarios where CCS is undesirable or only desired when the plant approaches the end of its lifetime. The present value of retrofitting is either zero or very small after heavy discount. In these scenarios, IN_DR_LS appears clearly more favorable than IN_DR and IN_DR_LS_PI, both of which encompass some investment in the design phase. However, the NPV profile for IN_DR_LS is the most spread-out and the ENPV for IN_DR_LS is the smallest. Thus the overall performance of IN_DR_LS is not satisfactory. Moreover, IN_DR_LS_PI is not the best performer in terms of any evaluation metric. However, if a plant owner

decides to delay the integration of the CCS unit, then the pre-investment option boosts expected performance and provides insurance over unfavorable scenarios.

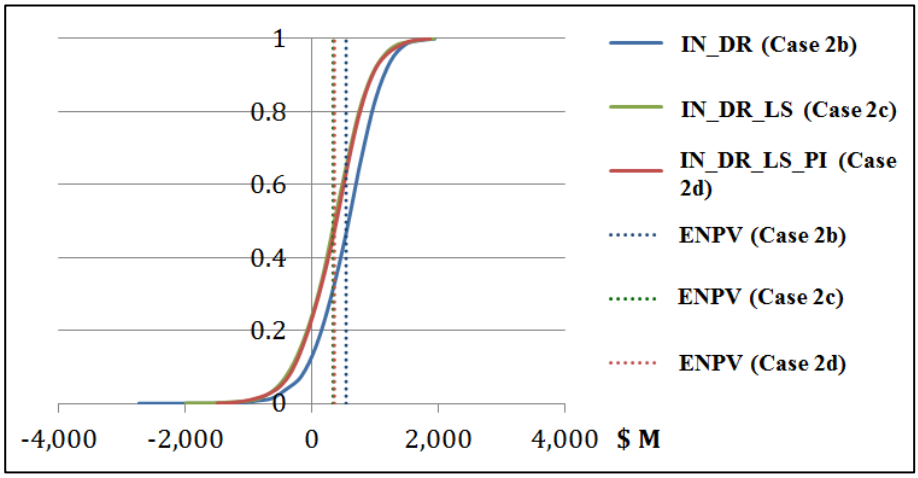


Figure 8: CDF plots for IN_DR (Cases 2-b), IN_DR_LS (Case 2-c) and IN_DR_LS_PI (Case 2-d)

The present research study holds a conservative stance on the carbon tax forecast and the stringency of the associated regulatory regime. This consideration should favor delaying the installation of the CCS unit in an IGCC-MR power plant. However, the results derived still show that IN_DR represents the best option. For a more aggressive/stringent carbon tax policy, IN_DR would have an even more appealing NPV profile most likely outperforming IN_DR_LS and IN_DR_LS_PI by a considerable margin.

5.4 Sensitivity Analysis

The carbon tax may never be levied throughout the lifetime of the plant. Figure 9 plots the CDF curves of NPV for all six cases under the zero carbon tax scenarios. The expectation is that investments in CCS are not economically justified and CCS should not be operated. Therefore, case 2-a (IN_BC) should be dominated by all other cases, which either do not have CCS or can operate CCS flexibly.

In addition to the carbon tax, a sensitivity analysis has been conducted with respect to other key parameters. Table IV summarizes the low, base and high input values for each parameter. For cases with CCS operational flexibility, a general term “capacity factor” (CF) is displayed in the Tornado charts. When CCS is operated, the case of CF with CCS applies. When CCS is not operated, the case of CF without CCS applies. The Tornado diagram of ENPV for Case 2-b (IN_DR) is shown in Figure 10 as a representative example.

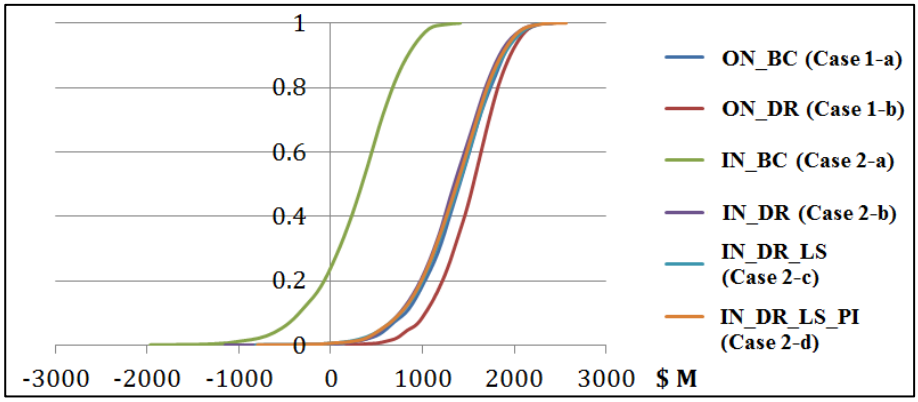


Figure 9: CDF plots for case 1-6 under zero carbon tax scenarios

Table IV: Inputs for Sensitivity Analysis

Parameter	Low	Base	High
Expected growth rate of carbon tax	0	3%	6%
Volatility of carbon tax	0	0.1	0.2
Year of introducing carbon tax	2	5	8
Capacity factor without CCS	70%	80%	90%
Capacity factor with CCS	65%	75%	85%

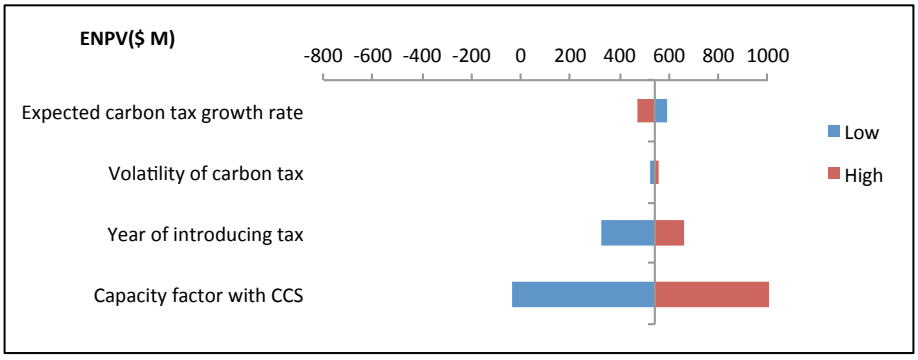


Figure 10: Tornado diagram for ENPV of IN_DR (Case 2-b)

The Tornado diagrams of ENPV for all cases except Case 2-b (IN_DR) are presented in Appendix C. The sensitivity plots for the plant designs with CCS (Cases 2-a, 2-b, 2-c, and 2-d) are not as sensitive to the choice of expected carbon tax growth rate and year of introduction as for the plant designs without CCS (Cases 1-a and 1-b). This conforms to the expectation that CCS can mitigate the regulatory risk associated with a future carbon tax regime. All cases are also robust to the volatility of the carbon tax compared to other carbon tax parameters. This

finding helps validate the carbon tax modeling framework suggesting that the volatility of carbon tax only adds to the randomness of carbon tax growth and does not overly bias the model. Lastly, the plant's capacity factor seems to be affecting all design alternatives in similar ways implying that risks related to this new and still untested technology at the commercial scale appear to be manageable.

Finally, the authors also consider as in Frey *et al.* [1994] a type of probabilistic sensitivity analysis that blends with Tornado analysis in terms of identifying the most consequential sources of uncertainty on IGCC-MR plant economic performance outcomes under "flexible-design". A probability of (10%, 80%, 10%) is assigned to the low, most likely, and high scenarios respectively. ENPV is calculated for each parameter under the scenario probability assignment. In particular, the following three parameters are considered because the model was shown to display the highest sensitivity to these three parameters on the Tornado charts. Table V shows the ENPV of each case for each parameter considered. The analysis shows that even under uncertainty in expected carbon tax growth rate and capacity factor parameter estimation, Case 2-b (IN_DR) remains best in terms of ENPV performance. The conclusion shifts, however, to Case 2-d (IN_DR_LS_PI) when there is higher variability in assessing the year of introduction of the tax. Retrofitting to CCS with pre-investment in such case may be a better strategy on average.

Table V Probabilistic Sensitivity Analysis

	Case 1-a	**Case 1-b**	**Case 2-a**	**Case 2-b**	**Case 2-c**	**Case 2-d**
Expected Carbon Tax Growth Rate	-100.2	223.5	254.6	**540.0**	340.7	360.3
Year of Introducing Tax	-64.8	239.1	255.4	99.3	334.6	**353.6**
Capacity Factor	-68.6	244.5	272.3	**547.2**	346.6	370.0

6 Conclusions

In a world with growing uncertainty including environmental regulations on greenhouse gas emissions and volatile fuel prices, a comprehensive framework enabling a smart management of uncertainty is increasingly important to the primary decision-makers, designers, and operators of a power plant system. This is especially the case for the Integrated Gasification Combined Cycle power plant with integrated membrane reactors modules (IGCC-MR), since the underlying technology has not been demonstrated yet at the commercial scale, and no experience has been accumulated in dealing with the uncertainties encountered in everyday plant operation.

This paper identifies, proposes and evaluates flexible design alternatives for an IGCC-MR power plant that enhance overall economic performance by minimizing downside risks while enabling the system to capitalize on upside opportunities, and thus advantageously adapting to uncertain CO_2 emission regulations and fuel prices. A systematic methodology is used to evaluate variants of two flexibility options, an operational and a constructional one for the design of an IGCC-MR power plant.

One objective of this study is to provide more insights, help plant managers and operators to incorporate more policies and technological flexibility options in their planning stages, and determine the best planning and operating strategies in the presence of irreducible uncertainty for this nascent technology. To achieve this, the study contributes to the advancement by considering and proposing the installation of a CCS system as well as examining the proper timing of its installation. The results show that installing a Carbon Capture and Storage (CCS) unit at the early design phase (Case 2-b) is the most flexible and economical option by exhibiting the lowest downside risk (at least 70% improvement compared to the base case) and the highest expected net present value (ENPV).

The second objective is to assess different design alternatives, operating options, and decision rules to improve lifecycle performance of IGCC-MR technology in the face of uncertainty, as compared to standard design and evaluation methods. For instance, regarding the timing of installing an CCS unit, the following decision rule was evaluated first for only the previous year, then for the two previous consecutive years and onwards:

*Savings on carbon tax > (1-tax rate) *(CO_2 transportation and sequestration costs + additional fuel costs + foregone electricity revenue due to capacity factor penalty + additional O&M costs)*

Our analysis shows that when the above rule focuses on the previous two consecutive years, the best outcome emerges. Table VI provides a quantitative summary of the results based on multiple performance criteria. It shows that Case 2-b is the best option in terms of Mean, Min, Value at Risk 5%, standard deviation, and probability of loss. Even using 95% VAG as an evaluation metric where Case 2-b is not the best, still it does not fall much behind the "best alternative" (i.e. Case 2-c). Notice that the value of the Max-criterion/metric for Case 2-b is small compared to all other solutions. However, any comprehensive assessment should account for multiple criteria, since decision-makers often exhibit risk preference as counteracting objectives (e.g. minimize risk while maximizing return).

The study contributes towards a third objective, which is to provide a sound scientific framework to inform and contribute to potential policy initiatives towards the realization of demonstration projects on the commercial scale of

an advanced technology option such as IGCC-MR. To this end, Table VII provides a qualitative summary of the findings, useful to support policy-making discussions.

Table VI: Quantitative Summary of the Analysis Outcomes

Performance Metrics - Indicators	Case 1-a (ON_BC)	Case 1-b (ON_DR)	Case 2-a (IN_BC)	Case 2-b (IN_DR)	Case 2-c (IN_DR_LS)	Case 2-d (IN_DR_LS_PI)
Mean ($ M)	-67.5	241.1	254.1	**541.4**	338.0	357.6
Max ($ M)	**2,022.3**	1,953.4	1,358.0	1,895.3	1,928.3	1,868.5
Min ($ M)	-5230.7	-4,173.3	-2,206.8	**-1,370.4**	-1,992.1	-1,492.3
VAG 95% ($ M)	1,659.7	1,647.1	1,179.8	1,732.0	**1,732.3**	1,700.5
VAR 5% ($ M)	-4,868.0	-3,866.9	-2,028.5	**-1,207.1**	-1,796.1	-1,324.3
STD ($ M)	992.0	783.5	**461.0**	486.2	502.9	500.1
Probability of Loss	47%	34%	26%	**14%**	24%	23%
CAPEX ($ M)	**1,514**	**1,514**	1,576	1,576	**1,514**	1,551
PV(Capital investment)	**1,514**	**1,514**	1,576	1,576	1776.0	1,738.8
Year of Retrofit	N/A	N/A	N/A	N/A	12	12

Table VII: Qualitative Summary of the Analysis Outcomes

Case	Case Explanation	Qualitative Summary of Performance
Case 1-a (ON_BC)	Base case	The largest NPV in the best scenario; the smallest capital expenditure
Case 1-b (ON_DR)	Operational flexibility	The smallest capital expenditure
Case 2-a (IN_BC)	Introduce CCS in the initial construction phase; CCS remains operational all the time throughout the plant's economic life	The smallest standard deviation of NPV
Case 2-b (IN_DR)	Introduces CCS in the initial construction phase; CCS operation is governed by decision rules	The largest ENPV; largest NPV in the worst case scenario; largest NPV at risk; the smallest probability of loss
Case 2-c (IN_DR_LS)	Retrofit the plant with a CCS unit in a later stage	The largest NPV at gain; smallest capital expenditure
Case 2-d (IN_DR_LS_PI)	Retrofit the plant with a CCS unit in a later stage and make pre-investment for the retrofitting	The second largest ENPV; second largest NPV and at risk; second smallest probability of loss

The four-step methodology is generalizable to the analysis of other engineering systems, since variants have been used in many other studies [Cardin, 2014, de Neufville and Scholtes, 2011]. The results obtained here, however, are lifecycle performance improvement observed when analyzing complex systems for flexibility. Hence, one of the contributions of the paper is the development and application of a sound decision-support framework that allows valuable insights to be generated for the first time in the literature into value-enhancing prospects for IGCC-MR

technology, through flexible system design and operational decision-making. The paper not only provides new and valuable design strategies, but also a quantitative evaluation of their expected performance, and a set of managerial decision rules to manage them in system/plant operations. These capabilities are certainly needed as this new technology option might be called to expand in the future.

The proposed analysis can be used as a demonstration to assist plant and systems engineering managers consider more options into the design and operational planning stages, and systematically determine and evaluate value-enhancing flexible design and operating strategies in the presence of irreducible uncertainty. The development and evaluation of a set of decision rules (e.g. pertaining to the design accommodation and also the operating mode of the carbon capture and storage (CCS) system) pertains to each manager, and may differ from one system to another. In any case, it should help plant managers adopt design flexibility and advantageously exercise it in a world fraught with uncertainty, as it relates to the particular system under their purview. This flexible design analysis specifically focuses on enhancing the IGCC-MR plant's adaptability to uncertainty sources such as environmental regulations and fuel costs over its lifecycle, but others may be considered in the analytical framework.

The most significant finding is that the installation of a CCS unit at an early design stage provides the best economic performance, as it directly addresses the uncertainty of a future carbon tax, significantly reduces the amount of carbon dioxide emissions, and therefore, the carbon tax and regulatory compliance cost incurred. On the other hand, operating the CCS unit requires additional fuel consumption and energy expenditure, the price of which represents another source of uncertainty included in the analysis. If the price is high, there is a disincentive to operate the CCS system. If the benefit of operating the plant with a CCS unit (tax savings) outweighs the cost, then an incentive to operate the CCS unit emerges. Thus, there is a tradeoff between savings on carbon tax and the additional cost of operating the CCS unit (the overall CCS-relevant cost refers to the after-tax cost of the additional consumption of fuel, operation and maintenance cost, the CO_2 transport and sequestration cost and the forgone electricity sales revenue). Also, timing of CCS installation introduces another important tradeoff. If a CCS unit can be installed later in the plant's life, the plant manager has access to more information about the trends in the carbon tax and fuel cost profiles (as uncertainties get progressively resolved), which enables him/her to make a better decision. However, the installation of a CCS unit after the plant construction is more costly than performing it during the construction stage. Therefore, the flexible options considered in the paper are not better than the baseline

design option on an *ad hoc* basis. As amply demonstrated, each flexible option has its pros and cons, merits and limitations, reminding the importance of meticulous risk management at the infrastructure level.

The present work is constrained by certain limitations whose identification and acknowledgement could trace future research directions, although out of scope for the current study. First, a stochastic demand model for electricity could be developed as a modification of the proposed analytical framework to allow pure hydrogen sales in pertinent markets concurrently with sales of electricity. Second, the effect of a carbon tax (or a cap-and-trade scheme) on electricity price could be also studied, offering an opportunity to better understand its effects, and incorporate into the proposed framework as an uncertainty driver. Third, more analysis can be conducted to analyze other decision rules, and the parameters that characterize them. Not all possible variations of the decision rules were considered in this analysis , and therefore opportunities for future improvements and further refinement exist. All decision rules considered here were associated with the best outcomes amongst all possible variations considered in our analysis.

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8 Appendix

A. DCF model formulation

Table A1: Economic Parameters in DCF Model Formulation

Parameter	Mathematic Expression	Value
Plant life [years]	L	40
Tax rate	T	40%
Depreciation accelerator	DA	30%
Insurance and property tax rate	IPT	1.78%
CO2 tax ($/ tonnes CO2, starts in the fifth operating year)	CT	10
Expected CO2 tax growth rate [Bohm et al., 2007]	μ^{CT}	3%
CO2 transportation & sequestration cost ($/t CO2) [Holt, 2007]	TSC	10
Nominal discount rate	R	9%
Inflation rate	π	2.5%
Electricity selling price [cents/kWh]	λ_t^{elec}	16.8
Plant capacity factor	CF	80%

B. Retrofit Performance and Cost Estimates

Table B1: Performance characteristics of evaluated cases before and after retrofit

Parameters	IGCC MR Plant	IGCC MR Plant with Pre-investment
Before retrofit		
Output(MWe)	550	550
Efficiency (% HHV)	33.5%	33.5%
CO2 emission (t/MWh)	0.89	0.89
After retrofit		
Output de-rating (%)	17%	12.3%
Output(MWe)	457	482
Efficiency (%, HHV)	30.1%	30.1%
CO2 emissions (t/MWh)	0.02	0.02
CO2 captured (t/MWh)	0.98	0.98

Table B2: Costs and performance of greenfield makeup plants

Case	IGCC MR Plant	IGCC MR Plant with pre-investment
Net output (MWe)	93	68
Efficiency	30.1%	30.1%
Total plant cost ($/kWe)	3576.8	3576.8
Total plant cost (M $)	333	243
O&M costs ($/MWh)	29.7	29.7

Table B3 Costs and performance of greenfield makeup plants

Case	IGCC MR	IGCC MR with pre-investment
Before retrofit		
Net output(MWe)	550	550
Total plant cost (M$)	1514	1551
Total plant cost ($/kWe)	2753	2838
After retrofit		
Net output(MWe)	457	482
Retrofit total plant cost (M$)	45	45
Total plant cost after retrofit ($/kWe)	3411	3311

Table B4 Model Inputs

Parameters	IGCC MR Plant	IGCC MR Plant with pre-investment
Investment costs		
Initial investment (M $)	1514	1551
Retrofit and makeup investment (M $)	378	288
Before retrofit		
Fuel Consumption (M ton)	1.53	1.53
O & M costs (M $/yr) (excludes carbon tax)	88	88
CO2 emissions (MT/yr)	4.3	4.3
After retrofit		
Fuel Consumption (M ton)	1.60	1.60
O&M costs (M$/yr)	107	107
CO2 emissions (MT/yr)	0.1	0.1
CO2 sequestered (MT/yr)	4.7	4.7

C. Tornado diagram of ENPV for all cases except Case 2-b (IN_DR)

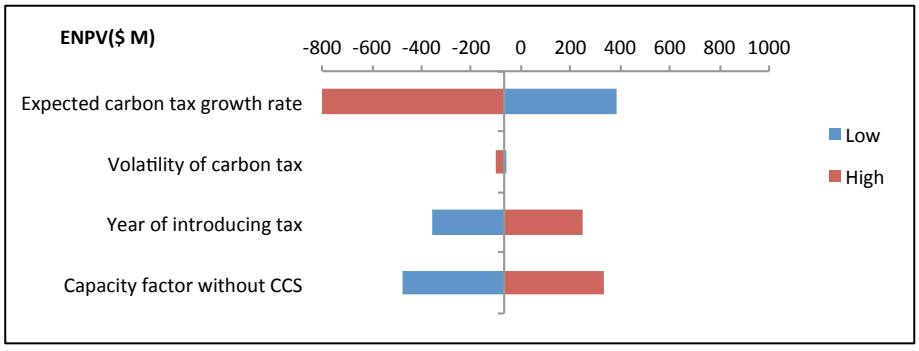


Fig. C1 Tornado diagram for ENPV of Case 1-a (ON_BC)

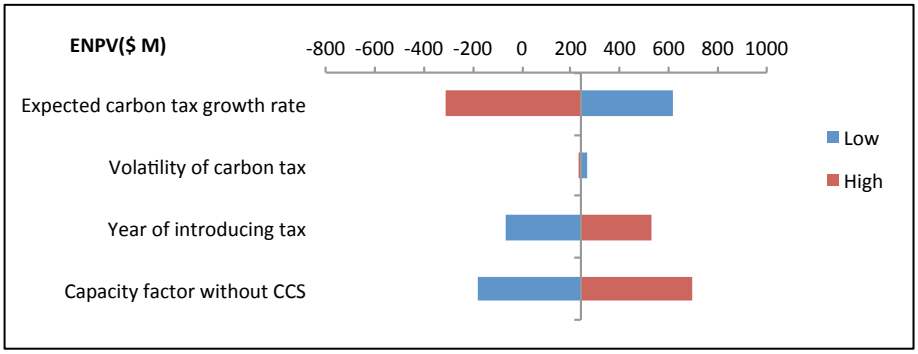


Fig. C2 Tornado diagram for ENPV of Case 1-b (ON_DR)

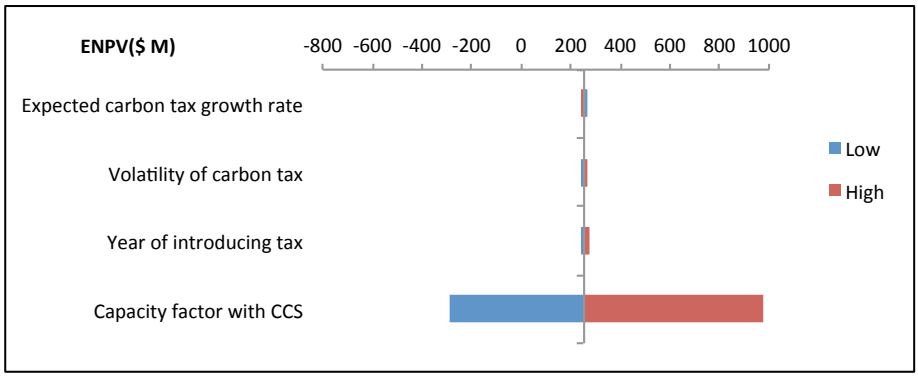


Fig. C3 Tornado diagram for ENPV of Case 2-a (IN_BC)

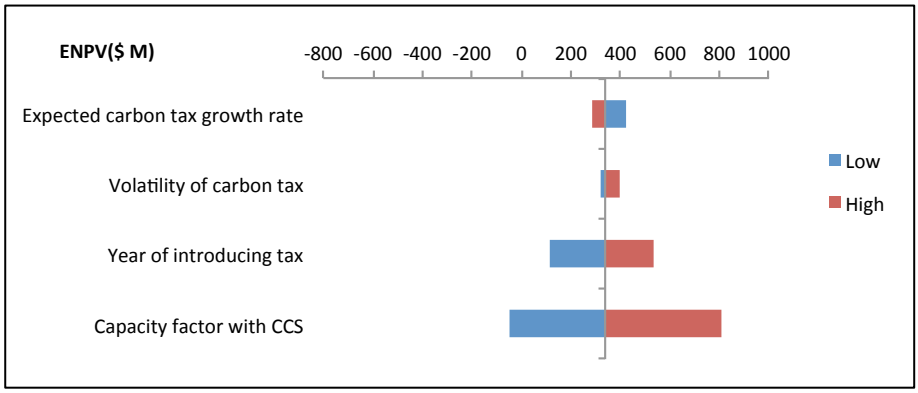


Fig. C4 Tornado diagram for ENPV of Case 2-c (IN_DR_LS)

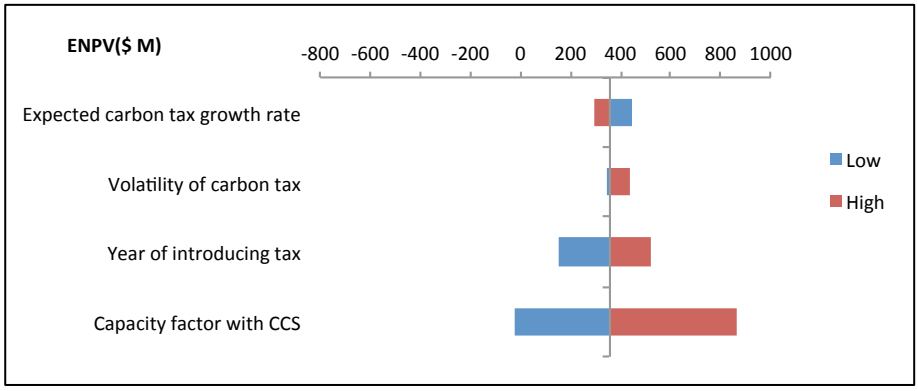


Fig. C5 Tornado diagram for ENPV of Case 2-d (IN_DR_LS_PI)

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