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Eindhoven, January 2009

Value of flexibility in Integrated Gasification Combined Cycle (IGCC) power plants

by
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ABSTRACT

This study analyzes different flexibility scenarios for an Integrated Gasification Combined Cycle (IGCC) power plant with CO2 capture. On the business model side, a dual product model (co-production of hydrogen along with power), and a dual fuel model (natural gas and coal co-firing) have been investigated. Furthermore, impact of forcing an operating schedule restriction on power plant profitability is also explored. On the technology side, a more efficient IGCC and a perfectly flexible IGCC are studied. The approach taken combines economical, operational and technological frameworks. The experiment model is mainly a Monte Carlo simulation with embedded schedule optimization. This model enables analyzing hourly behavior of a power plant under different business environments, without CAPEX considerations. The results around a base plant configuration and 2015 price estimations show that dual fuel and dual product business models might add significant value to profits. Furthermore, forcing the IGCC with load restrictions might have a reduction in profits up to 14%. Finally, a 1% point more efficient plant and a fully flexible plant (instant startup, shutdown, no minimum efficient load restrictions) provide additional 4% and 5% profits respectively. The results show that there might be significant value outside of the known market space for IGCC power plants. On top of trying to provide managerial insights, the study also aims to fill in some of the literature gaps regarding dual fuel dual product schedule optimization models, evaluation of different technology and business model alternatives and integrating of economical and operational perspectives in power plant profitability analysis.

Keywords: IGCC, coal gasification, flexibility, schedule optimization, Monte Carlo simulation, operational flexibility, co-production, co-firing, hydrogen, dual fuel, price volatility

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Gokhan Tekiner
January 2009, Eindhoven

SUMMARY

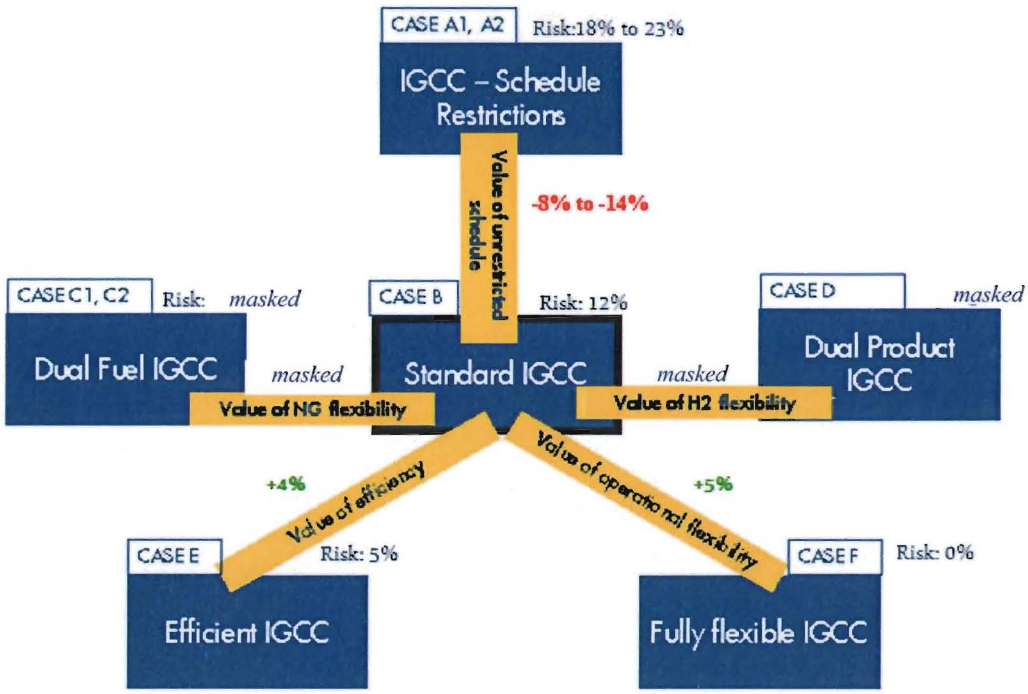
Coal-fired power plants will continue to be one of the key players in the power industry due to abundance of coal, security of supply and relatively cheap feedstock prices. CO2 emission restrictions on the other hand have encouraged the consideration of “cleaner coal” technologies like Integrated Gasification Combined Cycle (IGCC). These plants are designed to run most of the time owing to their relatively high efficiencies compared to traditional coal technologies, and high capital requirements. In the near future however, there might be some critical developments, which might affect their profitability dramatically: stricter CO2 penalties and increasing share of renewables in generation portfolio. While the first one would emphasize their strengths compared to other fossil-fuel options that emit more CO2, the second could compose an economical threat. This future outlook requires investigation of new opportunities.

Overall, there are three main areas that might offer window for new opportunities: new business models, technological improvements, and process optimization. First two dimensions are investigated in this study. In the business model dimension value of dual fuel (coal and natural co-firing), dual product (power and hydrogen co-generation) businesses, and impact of having schedule restrictions (e.g. due to long-term contracts) is investigated. In the technology dimension, value of having a more efficient IGCC (1% point more), and having a fully flexible IGCC (instant start-up, shutdown, no minimum efficient load restrictions, no startup costs) are analyzed. (See table below)

CASE	DESCRIPTION	RELEVANCE
A1	IGCC forced to run at full capacity	SCHEDULE RESTRICTION
A2	IGCC forced to run without allowing shutdown	
B	Standard IGCC (no schedule restrictions)	BASE CASE
C1	Natural gas co-firing: Only as a backup during gasifier outages	DUAL FUEL
C2	Natural gas co-firing: Overall arbitrage opportunity against coal	
D	Hydrogen co-production	DUAL PRODUCT
E	More efficient IGCC	TECHNOLOGY IMPROVEMENT
F	Fully flexible IGCC	

Analysis approach is comprised of a Monte Carlo simulation with embedded hourly plant schedule optimization based on a mixed integer linear program. This model combines several economical (power, feedstock prices, CO2 penalties, operating costs), operational (start-up times, start-up costs, minimum efficient load, ramping rates), and technical (output efficiencies, CO2 emission and capture rates) variables in one framework.

The analysis of different IGCC scenarios provides the following insights depicted in below figure. The value added is calculated as the change in profits compared to base case (case B), without CAPEX considerations. Risk is defined as the probability of having loss at the end of any day.



Summary of findings

Blue figures represent probability of having loss at the end of any day. Green figures are the percentage change in operational profits compared to the base case (Case B).

First of all, the analysis shows that there is a cost of forcing the power plant to run with minimum shutdowns. As discussed earlier, there might be several reasons for utilities to adopt such an operating model, especially related to long-term supply contracts and extending the lifetime of the equipment. Results show however that this operating mode, if used in power spot market operations could decrease the operational profits by 8%. Secondly, the study shows that apart from traditional mono-fuel mono-product IGCC business model, there might be other opportunities, which IGCC is technically capable to exploit. A dual fuel model in which natural gas used together with coal can increase operational profits by *masked* if used during gasifier outages, and by *masked* more profits if used whenever it is more profitable than coal. IGCC's are capable of producing syngas out of coal, which can be used in many different applications apart from power. Our analysis with a hydrogen co-production case shows that there might be significant added value in this business model, depending on the negotiated hydrogen price, future of Steam Methane Reformation (SMR) utilities in CO2 framework and finally the power price volatility. Currently SMR's are not part of CO2 framework however they are the dominant players in determining the hydrogen price. A case in which power price volatility is 25% higher than that of 2007, SMR's are part of CO2 framework and 50% of their cost passes through to the hydrogen price, and hydrogen could be sold at market price results in about *masked* increase in plant profitability.

From R&D perspective, our analysis also illustrates the value of two improvement options: efficiency and operational flexibility. Results show there could be important value in both options, in terms of risk elimination and profit maximization. According to results a 1% efficiency increase, although it is not a very easy target to achieve, adds value to profits almost equal to that of a perfectly flexible power plant (which is virtually impossible to achieve). However, a further research is necessary to explore the value of these options under more dramatic efficiency increase / decreases, and different availability and start-up times.

Apart from the findings related to different IGCC options that are presented here, we believe that the approach itself might also add value to assessment of different subjects in power generation industry. First of all, compared to solely economic (simple yearly average calculation, spark spread analysis, real option analysis ...etc) and solely operational (unit commitment, economic dispatch ...etc) techniques, the model represented here combines numerous economic, operational and technical variables in one simulation framework. This results in a more accurate calculation of profits. Secondly, the real strength of this model becomes evident during investigation of more exotic cases. Examples are valuation of dual fuel and dual product business models, impact of different operating schedules, and operational flexibility, all of which are difficult to analyze in either solely economical or solely operational models.

Ultimately, the study offers insights about the value of integrating operations management elements into strategic planning level decisions in power industry.

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SECTION 1: INTRODUCTION

Coal-fired power plants will continue to be one of the key players in the power industry due to abundance of coal, security of supply and relatively cheap feedstock prices. CO2 emission restrictions on the other hand has encouraged the consideration of "cleaner coal" technologies like Integrated Gasification Combined Cycle (IGCC) or post-capture super critical plants in investment portfolio. These plants are designed to run most of the time owing to their relatively high efficiencies compared to traditional coal technologies, and high capital requirements. In the near future however, there might be some critical developments, which might affect their profitability dramatically: stricter CO2 penalties and increasing share of renewables in generation portfolio. While the first one would emphasize their strengths compared to other fossil-fuel plants that emit more CO2, the second could compose an economical threat. This future outlook requires investigation of new opportunities.

This study analyzes the value of different scenarios for Integrated Gasification Combined Cycle (IGCC) power plants with CO2 capture capability (CCS) under a simulated market environment of 2015. These cases are then compared with each other in order to quantify the value of different business models and technology improvements. On the business model side, a dual product model (co-production of hydrogen along with power), and a dual fuel model (natural gas and coal co-firing) have been investigated. Furthermore, impact of forcing an operating schedule restriction on power plant profitability is also explored. On the technology side, a more efficient plant and a perfectly flexible power plant cases are analyzed.

In order to investigate these research questions from a combined economical, technological and operational framework, a Monte Carlo simulation with embedded schedule optimization module has been developed. This model makes it possible to analyze the hourly behavior of a power plant under different business environments.

The flow of the documents is as following; in the next section a short background regarding market, technology and related literature review is introduced. Subsequently the project and research questions are identified. Then the design choices and the details of the experiment model are discussed. A short section explains the data collection process, followed by the results. A discussion of the results, considering the academic and managerial insights is provided in the succeeding section. The discussion is closed with consideration of further research areas.

SECTION 2: BACKGROUND & MOTIVATIONS

2.1. Decentralized power markets

Two aspects of power makes it distinct compared to other commodities; significantly high price volatility and non-storability. To illustrate the magnitude of this volatility Giaier suggests that California power prices have demonstrated two times more volatility than that of Dutch tulips (between years 1634-1637), one of the most volatile commodities ever in the economic history. [Giaier, 2001] Non-storability on the other hand makes the "secure" supply and transmission of power as vital as the "economical" functioning of the system. Security implies that all power demand at any time is met successfully without experiencing any blackouts. Apart from these natural attributes of power as a commodity, the recent decentralization of power markets also changed the rules of game. As an example, the deregulation of the European Union (EU) power market further increased the volatility of power prices and other market uncertainties compared to prior monopolistic market structure. [Blaesig, 2007]

Thus it is important to discuss briefly how decentralized power markets function before moving further into our analysis. The main actors in a power market can be classified under five roles: independent system operators (ISO), generation companies (GENCO), transmission companies (TRANSCO), distribution companies (DISTCO), and retail companies (RETAILCO) [Shadiahpour et al, 2002]. The overall power pool is coordinated by ISO, who is responsible for secure and economic functioning of the overall power system. GENCO's are the generation companies, which constitute the supply portfolio of the market with diverse capacity and technology profiles. [Shadiahpour et al, 2002]

Functioning of a generic decentralized power market can be summarized in five steps. First, ISO's develop forecasts about overall power demand for both the short-term and medium-term. Then, GENCO's make their bids to pool, by ensuring that the generation would be economical and feasible. Thirdly, the bids are accepted by ISO starting with the lowest marginal cost option. This results in a hierarchical order of different power generation utilities, which is called a merit order curve. As depicted in Figure 1, the lowest marginal cost options like nuclear and renewables are accepted first, followed by other fossil fuel options. The allocation continues until the last KWh hour of power forecasted demand is met. The actual market price is then determined automatically being equal to the marginal cost of the latest offer accepted. Fourthly, GENCO's commit their units in the agreed hours to fulfill their pool contracts, and transmit the power to the transmission lines. TRANSCO's coordinate the safe and economic functioning of the grid lines. Finally, DISTCO's or RETAILCO's sell this electricity to numerous customers like households or industry utilities. [Shadiahpour et al, 2002]

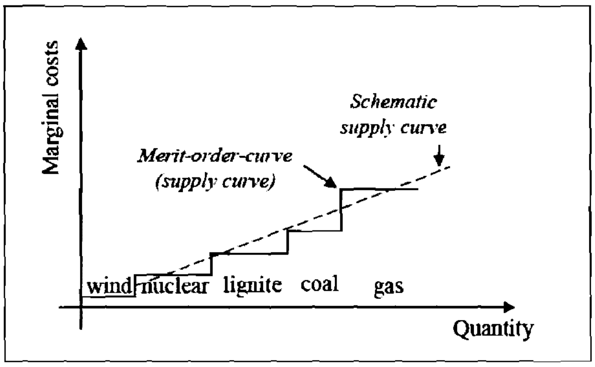

Figure 1 Example merit curve. [Bode, 2006]

Each unit is committed to generation with an ascending order of marginal costs. The allocation stops when the power demand is fully met. The generation assets that are positioned in the lower parts of the curve are called "base load" plants, since they run most of the time. The units that are close to the top line are called "peaking plants" (or peak-shaving plants), since they operate only when there is a peak in power demand. The region in-between is called "mid-merit" region.

In addition to the pool bidding system described above, in some cases GENCO's might prefer to bypass the pool and arrange bilateral power contracts with customers like big industry utilities. [Shadiahpour et al, 2002] [Harris, 2006] Furthermore, on top of spot market (i.e. day-ahead market) operations, there are two other market operations that GENCO's perform. First they can sell their slack capacities as an ancillary service, which acts as an insurance against realization of demand over forecasted figures. In such cases ancillary capacity that has been committed by GENCO's can be put into action within seconds or minutes to avoid blackouts. Secondly, GENCO's can also operate financially in derivate power markets, which is highly influenced by future and forward prices. This opens a wide array of opportunities for increasing profits, and hedging against market risks. [Harris, 2006]

Finally, another element that has affected the business dynamics in power industry is the climate change policies. In 2005 European Union Emissions Trading Scheme (EU ETS) has been established. [EU, 2006] It has affected the cost structure of several industries along with the players in their supply chain. [Tekiner, 2008]Power industry is also covered within the CO2 framework, implying that utilities are restricted in terms of their CO2 emissions. The scheme started with a warm-up phase in which CO2 prices were rather low. [Worldbank, 2007] Currently the scheme is in its Phase II, with a cap& trade mechanism and an active emissions allowances market. With the introduction of the third phase of the EU ETS in 2013, CO2 prices are expected to rise, the allocation mechanism is expected shift to auctioning and the number of included sectors is expected to increase. [EU, 2006]

2.2. IGCC and coal gasification technology

In this study, we are investigating a GENCO with Integrated Gasification Combined Cycle (IGCC) technology with CO_2 capture, mainly operating in a day-ahead power spot market. Here a short description of IGCC and coal gasification technology is introduced.

2.2.1 Coal gasification technology

In a regular combustion reaction, fuel is burned completely with oxygen to generate heat, by emitting CO_2. [Higman and Burgt, 2003]

$$2CH_4 + 4\ O_2 \rightarrow 2CO_2 + 4\ H_2O \text{ (Combustion)}$$

$$2CH_4 + O_2 \rightarrow 2CO + 4H_2 \text{ (Gasification)}$$

In gasification, however feedstock is combusted 'partially' and the reaction produces CO and H_2 instead of CO_2 and H_2O. This mixture is called syngas (or synthesis gas). If CO is further reacted with hot water steam, it can be captured as CO_2 and produce more H_2. This second reaction is called water gas shift, and enables the capture of CO_2 in different ratios (rate can be controlled with the composition of inputs). Then this H_2 rich syngas can be sent into power units to generate electricity, or purified to sell to industrial customers, or can be used to produce various other chemicals like alcohols, ammonia ...etc. Since CO_2 is captured prior to combustion in the turbines, this technology is also called "pre-combustion capture" of CO_2, as opposed to "post-combustion capture", which captures CO_2 from flue gas after combustion. [Higman and Burgt, 2003]

Although gasification is indeed an old technology that was frequently used in 18th century to produce lamp gas (or town gas) since the last decade it has attracted attention as a power generation alternative in a carbon-constrained world. This is owing to coal's advantages over natural gas in terms of price and security and gasification technology's advantage of burning coal with less CO_2 emissions. [Higman and Burgt, 2003] [MIT, 2007]

2.2.2 Integrated Gasification Combined Cycle (IGCC)

An Integrated Gasification Combined Cycle Power (IGCC) power plant contains a gasifier, which transforms coal or other feedstocks like biomass into synthetic gas (syngas). Subsequently syngas can be combusted in combined cycle turbines to generate power by using a gas turbine along with a steam turbine. Furthermore, if the additional facilities are implemented, syngas can also be used for other products like hydrogen, methanol, synthetic natural gas, mixed alcohols and so on. Figure 2 gives an overview of process flow in a typical poly-generation IGCC. In our analysis we consider an IGCC as a combination of three sub-units. The value chain from coal feed to shifted syngas production is grouped under "gasification island", value chain from syngas to power generation is analyzed under the name "power island (i.e. CCGT)". Finally, the value chain from syngas to industrial hydrogen is studied under "Hydrogen purification unit" (i.e. PSA: Pressure Swing Adsorption).

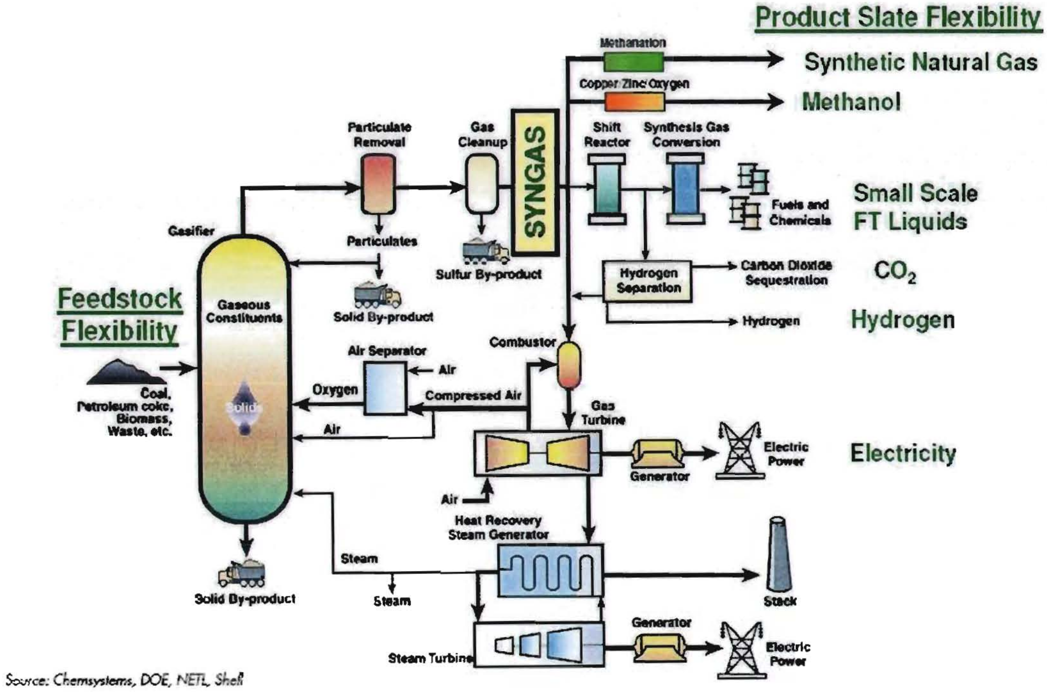

Figure 2 Overview of IGCC and poly-generation based on coal gasification

2.3. Future outlook

Several developments might be expected in the near future, which might play significant role in the profitability of a GENCO with IGCC technology.

Firstly, coal is still expected to be an indispensable feedstock in power generation due to its high availability, supply security and relatively cheap price. [MIT, 2007] In order for coal to meet the increasing energy demand of world with the lowest environmental cost, technologies enabling the capture of CO2 will be indispensable. [MIT, 2007] Higher CO2 prices and more strict environmental regulations could position IGCC's as more profitable coal-fired power generation options compared to traditional pulverized coal plants, which don't have the capability to capture CO2. [MIT, 2007]

Secondly, the share of renewables (i.e. solar, wind and hydro power) in the European power generation portfolio is expected to increase. [Bode, 2006] [Quaschning, 2001] Such an increase in renewable share would have two major impacts in the power market. First, due to their relatively lower marginal costs, renewables would constitute more of the base load generation. Secondly, since the renewable power generation is by its nature has very high supply volatility, this would inflate the overall power price volatility.[Starr et al, 2005] Typically three operating modes are observed for power plants: base load mode in which plant run most of the time in full load, shifting mode in which plant run during daytime and shuts down during night, and peak-shaving mode where plant only runs during power price peaks. The operating mode is primarily determined by the merit curve allocation as discussed earlier. Most of the existing IGCC plants are designed before deregulation and therefore aimed to run on base load mode. However, increased CO2 restrictions and growing renewable portfolio may force coal-fired power plants out of base load to either two shift operating mode or peak-shaving operating mode [Starr et al, 2005].

2.4. Need for identifying new opportunities

The possible increase in power price volatility, increasing competition among fossil fuel options, and threat of being forced away from base load operating mode requires identification of new opportunities to maintain the profitability of an IGCC. Overall, there are three main areas that might offer window for new opportunities: new business models, technological improvements, and process optimization.

2.4.1. Business models

Firstly, exploring different business models might assist not only in protecting against the aforementioned risks, and but also in exploiting the emerging opportunities. Two types of business model might be especially promising: using multi fuel and producing multi products. Typical power plants are designed to work in a mono-fuel mono-product business model. For instance, typical CCGT power plants run on natural gas to generate power. IGCC power plants technologically have the flexibility to run on multiple fuels (e.g. different coal types, biomass, natural gas) and produce multiple products (e.g. power, hydrogen, methanol, synthetic natural gas ...etc). A multi fuel-multi product business model might have many advantages over a traditional mono fuel – mono product business model. Firstly, from an economical perspective it provides a better portfolio flexibility, fuel and product arbitrage possibilities. (See Figure3)

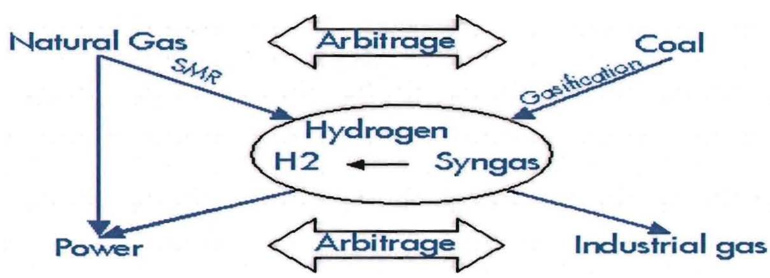

Figure 3 A dual fuel, dual product business model from arbitrage perspective

Secondly, from an operational perspective, such business models allow the decoupling of gasification island, power island and hydrogen purification units. In a typical IGCC, which operates with a mono-fuel mono-product business model gasification island has to follow load of power island[1]. Conversely, power island is also constrained by the syngas supply of gasification island to generate power. Two consequences of this model are that during a gasifier outage, power-island also needs to shutdown and secondly during power price dips power island might be forced to run if the opportunity cost of shutting down the gasifier is higher. This opportunity cost is mainly determined by the start-up times and cost of gasification island. In Figure 4 one can see the distinction between load responses of two IGCC's under a generic power price curve.

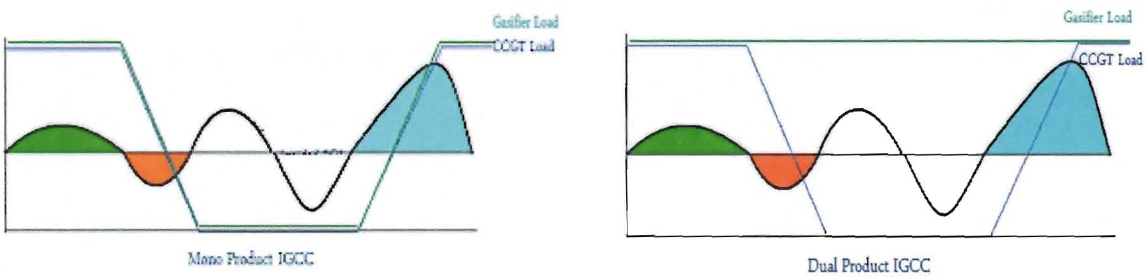

Figure 4 Generic load curves for gasifier and CCGT under different business models

Assuming a flat marginal cost curve and a generic power price curve, a standard IGCC and a dual product IGCC would react differently. In the first one gasifier and CCGT have to follow each other's load. In the second one they can be decoupled.

First case on the left side of the figure is running with a traditional mono fuel, mono product model. The other IGCC is running with a dual fuel dual product business model (e.g. power and hydrogen co-production). In the first case gasifier and power island have to follow each other's load. In the second case on the right gasification island and power island is decoupled from each other. If natural gas can be accessed as a backup fuel, during periods in which it is more economical to run on natural gas, or when the gasification island is not able to supply to needed syngas power island can switch to natural gas. Conversely, when generating power is not profitable, for instance during nights, gasification island can still run and divert its syngas output to other options like hydrogen or methanol production.

[1] Assuming no syngas storage is available, due to high investment costs.

2.4.2. Technological improvements

Second type of opportunity lies in the R&D side. A technological improvement might provide an increase in efficiency or operational flexibility. Efficiency increase might be driven by several achievements like higher coal to syngas transformation efficiency, less oxygen usage, better heat efficiency in the power turbines and so on. [Descamps et al, 2008] Regardless of the type of achievement, the ultimate effect would be a reduction in the marginal production costs, and therefore an opportunity to run in base load mode more often. Operational flexibility improvements can be achieved through a reduction of start-up times and costs, ramping and minimum stable generation requirements and an increase in availability of the units. To explain, minimum stable load (or minimum efficient load) is the smallest load that unit can run economically and technically. [Weber, 2005] Thus it is better to shut down the unit rather than running it in lower loads than this threshold. Start-up times are required for the plant to warm up and reach the minimum efficient load before start with production. Ramping constraints restricts the consecutive load changes between periods. Availability is the percentage of the time in which the unit can produce the demanded quantity, and mainly determined by the reliability of the units. [Weber, 2005] Overall, a technological advancement related to these operational parameters would imply less plant outage and higher responsiveness to market conditions.

2.4.3. Process optimization

Finally, there might be opportunities related to process optimization in power plants. The process here stands for planning activities related to demand forecasting, manufacturing activities of plant, portfolio management. The main decision making activities for a power plant is the operating schedule optimization in the short run, derivative and commodity portfolio optimization in the medium run and capacity decisions in the long run. [Yu and Sheble, 2003] A better forecast of fuel and power prices, combined with more effective management of the asset portfolio could result in higher profits.

Table 1 summarizes the different opportunities for an IGCC. In this study, we focus on first two dimensions namely the value of different business models (including the restrictions on operating schedules) and value of different technological advancement options. Motivations are explained in more detail in section 3, while discussing project definition.

Business model	Technology improvement	Process optimization
Dual fuel	Better efficiency	Forecasting optimization
Dual product	Better operational flexibility	Manufacturing optimization
Restricted vs. Unrestricted schedule	Better availability	Portfolio management optimization

Table 1 Overview of different IGCC options (Grey shaded points are investigated in this study)

2. 5. Overview of power industry literature

Academic literature in power industry can be classified under four main categories: technological, economical, operational and hybrid studies.

First set of studies focus on technology of power generation alternatives. The main objectives of this type of studies are either to describe an existing technology, or suggest a new technology or an improvement in the existing technologies. As an example in this field Descamps et al discusses the efficiency of IGCC's with CCS. [Descamps et al, 2008] Beèr on the other hand compares different fossil fuel power generation options from a technical efficiency point of view [Beèr, 2007].

Second set of studies investigates power industry from an economic perspective. Some of the research areas that have been popular in this literature are; power generation investment analysis, climate policy analysis, market price forecasting and game theoretical pool bidding. Especially generation asset valuation field covers a wide range of studies that differ in depth of analysis and ease of use. To begin with the simplest case, net operational profit of a power plant can be calculated[2] as $q*(P^e-h*P^f)$, where q is power yield, P^e is power price, h is heat efficiency rate of the plant and P^f is fuel price. The term (P^e-h*P^f) is often called "spark spread". [Gardener and Zhuang, 2000]. Spark spread analysis has been popular in both academia and practice thanks to its simplicity. It can be used as a building block to calculate profitability of a power plant as discounted cash flow. Nevertheless, discounted cash flow methodology is criticized due to the fact that it does not account for the irreversibility of the investment (i.e. part of investment is always sunk cost), uncertainty of cash flows (i.e. volatility of input and output prices), and timing flexibility of investments. [Dixit and Pindyck, 1994]. A further step that builds upon spark spreads is "real options valuation'', which is comprised of applying financial derivative pricing theory to valuation of real assets. [Dixit and Pindyck, 1994]. As an example in power industry applications, Deng et al applies real options methodology based on spark spreads that follow log normal distributions in order to evaluate different generation assets. [Deng et al, 1998]. Real options framework is also used in studies like [Tseng and Barz, 2002], [Hlouskova, 2005] for short term planning, and [De Jong et al, 2004], [Reedman et al, 2006] for investigating impact of climate policy on power sector. In another study, Abadie and Chamarro compare coal and natural gas fired power plants with each other by using real options and stochastic price simulation. [Abadie and Chamarro, 2006]. However simple spark spread based models do not account for important plant operating characteristics like, start-up times, start-up costs, ramping rates, random outages and minimum load constraints.

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[2] Ignoring the capital and non-fuel operating costs

Third set of studies is aimed to explore operational aspects of power industry, mainly operations management of power plants. Major topics in this type of literature is power plant schedule optimization, maintenance planning and transmission grid line optimization. As example, Weber and Shahidehpour et al investigates optimization of power plant operations by using mixed integer linear programming techniques. [Weber, 2005] [Shahidehpour, 2002] The schedule optimization literature is discussed in more detail in section 4, where the design choices are presented.

Finally, literature research shows that there have been attempts to combine some of these frameworks in hybrid studies. As an example to techno-economical hybrid study, Chiesa et al, and Damen et al compares different fossil fuel options from a technical and economical perspective [Chiesa et al, 2005], [Damen et al, 2006]. However their economical perspective is solely cost driven, therefore rather simplistic, since this approach does not capture the volatility of power and feedstock prices, and associated response of power plant to those. Another type of hybrid studies merges economical and operational frameworks together. In reality power plants are not only exposed to economical and technical but also to operational constraints. [Shadiahpour et al, 2002] The existence of such variables makes the problem of generation asset valuation a state-dependent problem, meaning that actual performance of a plant depends on the current operational state of the unit. [Gardener and Zhuang, 2000] For instance, a power plant that is just restarting after an outage is unable to harvest any profits from the market, although spark spread for the time being is positive. This would necessitate the integration of economical and operational frameworks. Blake and Miranda reports that a solely economic analysis without considering operational boundaries like start-up, ramping and minimum generation restrictions could result in significantly inaccurate generation asset valuation. However, they don't address a detailed model to remedy this gap. [Blake and Miranda, 2003] In another economical-operational hybrid study, Gardner and Zhuang applies a real options valuation framework to power plant valuation by using a dynamic programming to calculate value of plant based on an optimized schedule subjected to the operational boundaries [Gardener and Zhuang, 2000]. However, this model is only applicable to a traditional mono fuel and mono product business model. Therefore it is not suitable for investigating any other business models like dual fired power plants, or hydrogen co-production cases. Probably the closest example of our study in the available literature is a study of German power producer e.ON [EON, 2001], which compares the cost of having a traditional IGCC to a having a perfectly flexible IGCC. However, instead of using a price simulation to account for uncertainty, the study uses a static set of historical prices (i.e. 1998 UK spot market prices). Furthermore, other IGCC options like schedule restrictions, or fuel flexibility are not investigated in this study.

To sum up this section, a couple of gaps have been identified in the literature. First there are relatively few economical-operational hybrid studies compared to solely economical and solely operational researches and there is a clear impetus to integrate operational aspects to the analysis. Secondly, most of the research is carried around traditional business model of power generation on coal. Dual product business model is mainly investigated for combined heat and power plants. Dual fuel business models are primarily investigated from a solely economical spark-spread approach. Cost of having schedule restrictions (for instance due to long term power supply contracts) is not investigated comprehensively. Thirdly, the cost of having an inflexible power plant (i.e. long startup times, ramping rates...etc) is another promising area for research. Finally, no substantial efforts have been made to develop a common basis to evaluate and compare various IGCC opportunities. Table 2 summarizes the gaps in the literature.

KEY GAPS IN THE LITERATURE	
1	Few number of economical-operational hybrid studies, which investigate value of power plants subjected to operational constraints as well as hourly power market volatility.
2	Hydrogen-Power dual product business model is under-investigated
3	Coal-Natural gas dual fuel business model is under-investigated
4	Impact of schedule restrictions (e.g. no shutdown is allowed …etc) on plant profitability is under-investigated
5	Impact of physical boundaries (i.e. startup times, minimum stable generation constraints …etc) is under-investigated
6	No combined framework for comparing different IGCC options (i.e. Business models, R&D advancements)

Table 2 Key gaps in the literature

2.6. Positioning of the study

Within this framework, our study fits into the "economical-operational hybrid" classification and contributes in fulfilling all of the mentioned gaps in the literature. Economical side of this study is related to modelling of power, hydrogen and feedstock markets, as well as CO2 framework. On the operational side, hourly operations scheduling, as well as basic reliability simulation is embedded into the study. Technological variables are integrated to study as simplified linear efficiency functions derived from heat balance equations. Furthermore, the study investigates hydrogen co-production along with power generation, and natural gas fuel arbitrage against coal. Finally, effect of schedule restrictions, operational flexibility and efficiency is also investigated.

Apart from this hybrid framework, from a solely operational perspective the study also introduces a dual fuel, dual product IGCC schedule optimization mixed integer linear program during the journey. To our knowledge such a model was not studied in the literature before.

SECTION 3: PROJECT DEFINITION

As discussed in the previous section a more competitive future outlook of power industry with higher uncertainty and price volatility results in an impetus to explore new opportunities in the power industry. An interesting question is what could be the potential value added of these different options as compared to a base business case. As mentioned earlier, in this study we investigate the value of the first two dimensions namely new business models and technological improvements. The scenarios are primarily shaped by Shell's business interests and availability of data. In the business model dimension, restricted vs. unrestricted schedules, dual fuel and dual product cases are investigated. On the technology side, value of efficiency increase, and value of operational flexibility cases are analyzed. Related to process optimization dimension, an optimization model for a dual fuel and dual product IGCC is described. However detailed analysis of this dimension is left out of scope of this work, since there is already substantial amount of work related this dimension in the literature

3.1. Scenarios Investigated

In order to investigate the value of different business models and technological advancements, following IGCC cases have been defined:

CASE	DESCRIPTION	RELEVANCE
A1	IGCC forced to run at full capacity	SCHEDULE RESTRICTION
A2	IGCC forced to run without allowing shutdown	
B	Standard IGCC (no schedule restrictions)	BASE CASE
C1	Natural gas co-firing: Only as a backup during gasifier outages	DUAL FUEL
C2	Natural gas co-firing: Overall arbitrage opportunity against coal	
D	Hydrogen co-production	DUAL PRODUCT
E	More efficient IGCC	TECHNOLIOGY IMPROVEMENT
F	Fully flexible IGCC	

Table 3 Overview of investigated IGCC cases

A. IGCC with schedule restrictions

A.1.Standard IGCC – Always run at full capacity

This is an extreme case, in which IGCC is forced to run on full load all the time. This probably does not make much sense from practical business perspective; however it is used as stepping stone to identify the full impact of schedule restrictions. . By "Standard IGCC" we imply a mono fuel mono product business model (i.e. only power generation on coal).

A.2. Standard IGCC – No shutdown allowed (except outages)

The second schedule restriction case does not force the IGCC to run at full load all the time, but does not allow a complete shutdown either. Thus during times in which power is unprofitable IGCC can only respond by decreasing load. IGCC has to shutdown only if there is an outage in gasification or power islands. This case resembles the operating mode of IGCC's, which runs with long-term power supply contracts. Another motivation to run on this operating mode could be trying to extend the lifetime of the equipment by avoiding frequent restarts. The Buggenum IGCC in the NL is an example of this case most of the time. Thus it is noteworthy to evaluate the cost of running in this mode in order to be able to compare it with benefits.

B. Standard IGCC – No schedule restrictions (BASE CASE):

This is the base case to compare all the other scenarios, and evaluate the corresponding values. This is a typical mono fuel, mono product IGCC which runs without any schedule restrictions.

C. Dual fuel IGCC – Natural gas

C.1. Dual Fuel IGCC – Natural gas backup during gasifier outages

In this scenario, the IGCC is allowed to access natural gas grid in order to be able to backup power generation during gasifier outages. Such a connection to natural gas grid requires additional investment, thus it is important to quantify the associated value added.

C.2. Dual Fuel IGCC – Coal vs. Fuel arbitrage any time

This second dual fuel scenario allows the IGCC to choose between coal and natural gas any time based on their profitability as a power generation feedstock. Thus it creates an arbitrage possibility in addition to the traditional coal to power value chain. Note that this case also covers case C1.

D. IGCC with dual product – Hydrogen co-production

In this case power plant can use syngas in industrial hydrogen production as well as power generation. This requires a unit called PSA (Pressure Swing Adsorption) to achieve high purity of industrial hydrogen. The selection between power and hydrogen should be decided dynamically in order to maximize plant profitability. This business model has two advantages over a standard mono fuel mono product model. From economical perspective it adds an additional arbitrage opportunity between product types. From operational perspective it decouples power island from gasification island. Typical example of this would be keeping a steady load on gasifier, using syngas to generate power during daytime, and divert it to H2 production during night while power island could be shutdown.

E. More Efficient IGCC

As discussed in the previous section, another room for improvement in the future of IGCC's could be in the technology dimension. In this case, the impact of 1% point efficiency increase on profitability of the plant is investigated. This gives a snapshot of the relative value of an efficiency improvement compared to other options.

F. Fully flexible IGCC:

Second technological improvement case is the reduction of start-up times, costs and minimum efficient load requirement for the power plant. For this purpose a perfectly flexible IGCC that has instant start-up times, no start-up costs and zero minimum efficient load requirements is analyzed. This is actually a utopian case, which is used to identify the value of high responsiveness to market conditions.

Figure below demonstrates a generic example to distinguish cases A1, A2, B and F.

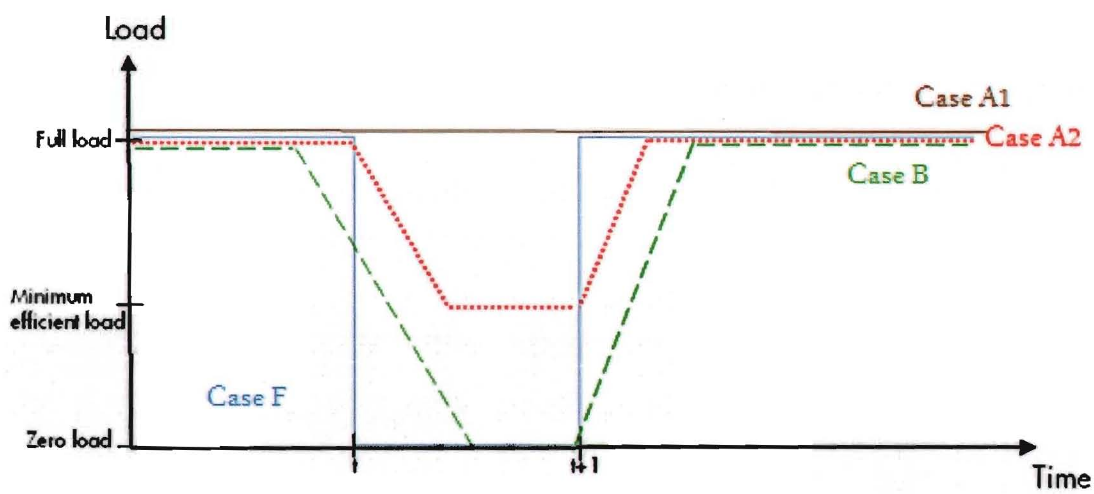

Figure 5 Demonstration of forced run, allowing shutdown and fully flexible cases

Assume that power generation is not profitable between periods t and t+1. IGCC- Forced to run at full load (Case A1) will not be able to response the price dip and lose money. IGCC-without shutdown case (Case A2) would decrease the load to minimum stable generation level, and will protect against some of the losses. Base case (Case B) uses its option to shutdown and restart, incurring less loss. A fully flexible plant (Case F) also shuts down and restarts, but instantly.

3.2. Research Questions

An overview of the flexibility options to be investigated is given in below figure.

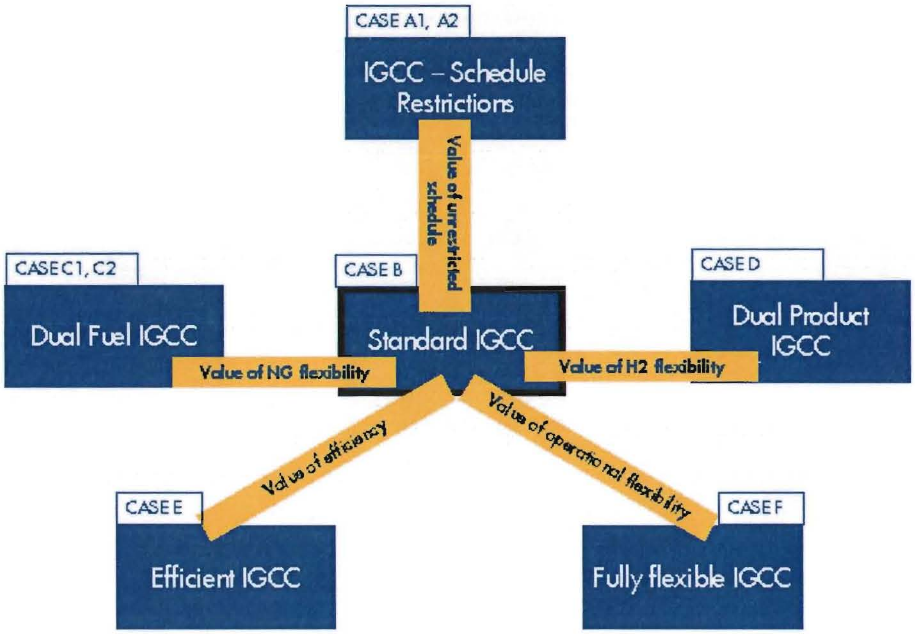

Figure 6 Links between different flexibility options

As can be clearly seen, comparing different options with the base case gives the value of associated flexibilities. Identifying the links between the cases explains the value of different flexibilities that are depicted in yellow rectangles in Figure 6. These relationships answer the following research questions:

Schedule Restrictions:

- What is the cost of forcing an IGCC always to run on full load? (By comparing cases A1 and B)
- What is the cost of forcing an IGCC to run without shutdowns? (By comparing cases A2 and B)

Business models:

- What is the value of natural gas backup during gasifier outages? (By comparing cases C1 and B)
- What is the overall arbitrage value of using dual fuel? (By comparing cases C2 and B)
- What is the value of co-production of hydrogen along with power? What market conditions make this business model more or less profitable? (By comparing cases D and B)

Technology improvements:

- What is the value of one point efficiency increase? (By comparing cases E and B)
- What is the value of perfect operational flexibility? (By comparing cases F and B)

Ultimately, the combined framework of these questions gives a big picture of relative value of different IGCC options.

SECTION 4: DESIGN OF EXPERIMENT

In order to be able to investigate the research questions introduced in the previous section, an experiment has been designed. This section starts with discussing the design choices that have been made, the other alternatives and motivations of choice. It is followed by the description of detailed model in detail.

4.1. Design Choices

An overview of the design choices is given in below table.

Analysis technique	Monte Carlo simulation with an integrated schedule optimization
Scheduling decisions	Given based on a Mixed Integer Linear Programming (MILP), which optimizes the hourl schedule of the power plant by deciding on load of gasification island, power island (CCGT and hydrogen purification unit (PSA)
Power plant type	Power plant type: IGCC with CCS (i.e. CO2 capture)
Analysis time bucket	Hours
Price set	Adjusted historical data with stochastic noise. Simulation year is 2015
Variables within scope	Market (Feedstock and product prices, CO2 emission cost, CO2 transportation cost, unit star up costs), technical (Production and CO2 capture/emission efficiencies), and operational (star up times, ramping rates, minimum efficient load)
Variable out of scope	CAPEX, financial inputs (tax, inflation, depreciation), revenue from additional CO2 subsidie and cost of sequestrating CO2.
Value chain scope	From feedstock spot market to generation in the plant to power and H2 grid.
Power market scope	Only spot market operations, no long term contracts or ancillary services
Operations planning horizon	96 hours rolling horizon, solution for the first 24 hours is fixed
Optimization model type	Mixed Integer Linear programming with deterministic price and availability set.
Regional scope	Europe
Product focus	Power and industrial Hydrogen
Fuel focus	Bituminous coal and natural gas
Performance measures	Average profit from goods sold. Risk of having loss at the end of any day, which is derived from daily profit distribution curv

Table 4 Overview of design choices for the analysis

The experiment is principally a Monte Carlo simulation, with an embedded schedule optimization module. A simulation approach is preferred over an analysis solely based on a single set of historical or forecasted data, since it better accounts for the stochastic behavior of power and feedstock prices and occurrence of unplanned outages. Thus the resulting measure is not only an average value of different options but also the associated risk achieving profit targets.

4.1.1. Market simulation

Having a consistent set of hourly power prices and daily feedstock prices for target year (2015) is probably one of the biggest challenges in this study. Therefore price set used in the analysis is calculated based on three elements: historical volatility and seasonality pattern of 2007 spot market prices, target year (i.e. 2015) forecasted averages, and a stochastic noise. The motivation behind using volatility and seasonality patterns from the past data is to have a consistent relationship between power and feedstock prices. 2007 is chosen due to the fact that it was the most recent and complete data series available. Using an average of a set of years was not favored since it would smooth out the actual price volatility effect. Forecasted values are based on a third party publication, and chosen particularly since it provided a consistent set of forecasts for feedstock and power prices for 2015. Finally, for the stochastic process, a "Mean Reverting Geometric Brownian Motion" (MRGBM) is used. Although there are various types of stochastic processes [Stirzaker, 2005], a few of them have found wide applications in power generation analysis. [Schwartz, 1997] The simplest of them is a random walk process (i.e. Brownian motion), in which the series follow a zigzag-like random pattern. This process was used extensively in derivative and commodity pricing, building upon the seminal works of Black and Scholes, and Dixit and Pindyck . [Black and Scholes, 1976] [Dixit and Pindyck, 1994]. "Geometric Brownian Motion" on the other hand fits better in commodity pricing owing to its ability to restrict the simulated prices from falling below zero due its lognormal distribution [Blanco and Soronow, 2001]. Two further extensions could be made on top of Geometric Brownian Motion: a mean reversion effect and a jumping behavior [Blanco and Soronow, 2001]. Ronn and Pilipovic reports that spot prices for feedstock and power markets in reality demonstrate this mean reverting behavior. [Ronn, 2002], [Pilipovic, 1998] In other words, power and feedstock prices are inclined to converge to a mean value in the long term. The speed of reversion and the long-term mean are two additional parameters for this stochastic process on top of the volatility pattern.

Johnson and Barz compared the performance of different Brownian and Geometric Brownian motion processes in simulation of power prices [Johnson and Barz, 1999] For this purpose, they generated price series by using different stochastic processes, and compare them with the realized prices. Their conclusion is that the best performance is achieved via a Geometric Brownian Motion with mean reversion and jumping behavior. [Johnson and Barz, 1999].

In our analysis, a slightly different approach is used. The price series are not generated solely based on a single stochastic process from scratch. Instead a blueprint derived from historical data was used as a starting point. This blueprint captures seasonality, volatility and correlation patterns within and between feedstock and power price series, and makes sure that they are consistent. The series is then further adjusted with the target year expected averages. Finally a mean reverting Geometric Brownian Motion is injected to system in order to either distort the seasonality pattern intentionally, or to add additional volatility. The jumping behavior is already captured in the blueprint, therefore is not included in the stochastic process once more.

Hydrogen prices and CO2 prices does not follow this method. Hydrogen price is calculated dynamically based on daily natural gas and power prices. The formula is provided by Shell's Contracting and Procurement Industrial Gas Department. For CO2 price a constant yearly price is used. Such decision was driven by the difficulty of predicting an accurate daily seasonality and volatility pattern for CO2 market for 2015 solely based on the short history of EU Emissions Trading Scheme.

4.1.2. Power plant operations scheduling

As discussed earlier, the main strength of the approach in this study compared to simple spark-spread analysis models is the consideration of operational boundaries. Therefore based on the market conditions and current operational state of the units, in each hour model needs to decide on the load, type of product to produce and type of fuel to use.

The power plant operations scheduling is a complex problem due to its high dimensionality [Salam, 2007]. There are various methods for modeling and solving this problem in the literature. First, several heuristics have been suggested for achieving approximate practical solutions. As example, Kerr et al proposes one which starts with a feasible solution and improves it by trying to reduce starting costs [Kerr et al, 1966] while Baldwin et al suggests another heuristic based on a fixed priority order [Baldwin et al, 1997]. However, most of these heuristic approaches are significantly sub-optimal. [Salam, 2007] Secondly, a more complex yet rigorous approach is dynamic programming. In this method, scheduling problem is solved in a step-by-step manner by using different branch and bound procedures. The foremost advantage of dynamic programming is its reasonably high solving speed. On the other hand it suffers from high dimensionality as the size of problem increases, and therefore might require pre-processing of data by truncation or fixed-ordering [Salam, 2007]. Thirdly, a Lagrangian relaxation approach is more powerful in this sense. However it has a sensitivity problem related to unnecessary commitments of generation units [Salam, 2007]. Just like heuristics, neither dynamic programming nor Lagrangian relaxation approach is guaranteed to give an optimal solution [Salam, 2007] [Padhy, 2004]. Fourthly, mixed integer linear programming (MILP) offers the best optimality and rigor for a cost of increased need with an expense of high solving power requirement. [Salam, 2007] [Padhy, 2004] Apart from its strengths in finding an optimal solution, it is also easily scalable (i.e. size of problem might be modified easily). Finally there have been also various efforts to apply more exotic methods (e.g. fuzzy logic, neural networks, artificial networks...etc) to scheduling problem [Padhy, 2004]. Although there have been impressive progress in this field, MILP approach still offers the most rigorous solution [Padhy, 2004]. Therefore, in our study the scheduling optimization problem is modeled with MILP technique and solved by a powerful commercial solver for the sake of accuracy.

Several examples of MILP power plant scheduling models could be found in the literature. To mention some of them, Weber explains a deterministic MILP schedule optimization model, which takes into account startup and ramping restrictions. [Weber, 2005] Shahidehpour et al goes one step further and discusses schedule optimization models with stochastic prices, and security constraints for a generic power producer. [Shahidehpour et al, 2002] Ko and Chang solve the problem for a dual fuel (biomass and refuse-derived fuel) by using a nonlinear mixed integer approach. [Ko and Chang, 2007]. Yusta et al study a MILP model for solving combined heat and power problem. [Yusta et al, 2008]

However, none of the existing MILP models were found suitable for solving a dual fuel (coal vs. natural gas), and dual product (power vs. hydrogen) problem. Therefore a new optimization model had to be developed for this study for several reasons. The core motive is that all of the above mentioned MILP models consider IGCC as a single entity composed of a single production unit. This makes sense from a traditional mono fuel, mono product business model, since gasification island and power island (i.e. CCGT) have to follow each other's load. In other words, if CCGT needs to generate power, gasification island also needs to run in order to supply the required syngas, and vice versa. However in order to investigate different scenarios facilitating the dual fuel and dual product models, these units should be decoupled. Therefore in this study a different approach is adopted for modeling power plant schedule optimization. First, gasification island, power island (i.e. CCGT), and hydrogen purification unit (i.e. PSA) are considered as separate entities. Therefore separate scheduling decisions are given for each of these units. This complicates the problem but on the other hand also enables the decoupling of gasification island, power island and hydrogen purification unit from each other whenever the business model allows that. Secondly, a syngas balance constraint makes sure that gasification island, CCGT and PSA are linked, implying that syngas demand from CCGT and PSA cannot exceed the supply from the gasification island. Thirdly, in dual fuel business model, the single load variable is substituted with two variables; namely load on syngas and load on natural gas. The detailed explanation of the scheduling model is provided in Appendix 1. We believe that this model might provide a different perspective for the power plant scheduling problem due to its "decoupling" approach and also should contribute in filling the gap of dual fuel, dual product IGCC's schedule optimization models.

The time bucket of the analysis is chosen as hours, since power prices show significant volatility between hours of the day, and operational boundaries are also described in hours. Using such a deep scale makes it possible to identify the changes in market conditions and associated response of the power plant more realistically.

The optimization model is deterministic, which implies that price series and condition of the units are perfectly known within the planning period. In order to be able to address the consequences of a deterministic versus a stochastic modelling approach, the distinction between the "environment" that they assume and "type of control" that they require should be discussed. A deterministic environment for power industry in this analysis implies that the price developments and occurrence of outages within the planning period are perfectly known to the planner. On the other hand a stochastic environment would indicate that the forecasts of these variables would involve an amount of error from the realizations. However, the difference between two environments is more complex than simply "the forecasting ability of a power plant". As a matter of fact, the uncertainty of the future and the associated errors between forecasts and realizations depend on several external dynamics like the overall profile of generation portfolio in the country, condition and actions of other market players (i.e. GENCO's) and demand profile of the consumers. These two different environments would require different types of control. While under a deterministic environment, the goal would be having an operating schedule, which would maximize the profit, under a stochastic environment the aim would be having an operating schedule, which would not only maximize the profit but also minimize the risk based on a set of different future scenarios. Therefore in a deterministic environment, where the market conditions are not known perfectly, the power plant schedules might need to be "managed" rather than trying to be "optimized". For the sake of simplicity, in our analysis a deterministic modelling approach is adopted. Therefore, in this analysis ""perfect knowledge of the operating environment within the planning period" is assumed for all the cases investigated. Interviews with two power plant managers (The Netherlands, and Spain) show that in reality short-term load forecasting accuracy is rather high thanks to the state-of-art decision supports involved in the process. This implies that indeed the difference between deterministic and stochastic environments is rather small. However, still the reflection of this into the "type of control" and the resulting differences in optimization outcomes remains to be discovered. By intuition one could expect higher profit values for a deterministic case compared to a stochastic case due to less uncertainty. However, since in our analysis we don't use absolute measures but rather performance of different scenarios relative to each other, this discrepancy could be expected to be relatively low.

Although the schedule optimization model is deterministic, still a rolling horizon approach was needed. This is required to avoid shutdown decisions at the cool-down periods of each planning horizon. 96 hours rolling horizon and solution fixing of the first 24 hours makes sure that the warm up and cool down periods are managed properly. These assumptions are also aligned with those, which came out from the above-mentioned interviews.

4.1.3. Value chain scope

In terms of scope, the study investigates an IGCC with CCS that operates in day-ahead power and hydrogen markets in the EU. The investigated schedule restriction scenarios also partially accounts for the effects of bilateral contracts. In these scenarios the power plant runs continuously with minimum shutdowns, which is a typical behavior of power plants working with long-term power contracts. On the other hand, ancillary operations and derivative market operations are completely left out of scope of this study. Because demand for ancillary services is highly dependent on variables like the capacity and portfolio of the overall supply industry, demand profile, transmission constraints, and so on. Similarly, derivative markets (i.e. future and forward power markets) are not included in the analysis since they are driven by future price curves and hedging dynamics, which are very challenging to forecast accurately for the simulated year (i.e. 2015). Estimated impact of exclusion of ancillary and derivative market operations in the analysis is expected as lower profits, and a stricter operating schedule. To illustrate, normally, a power plant may use its derivative contracts to fulfill supply commitments instead of generating it, whenever it is more profitable. [Shadiahpour et al, 2002] Similarly, a power plant may intentionally under-utilize its capacity in order to keep slack capacity, for which it can charge ancillary services. However, in reality, power plants are designed to "run" rather than to "keep slack capacities" or to "purchase and sell derivatives" as their primary objective. Therefore operations in generation market (e.g. day-ahead market) still constitute the dominant part of the portfolio of a power utility.

From a value chain point of view, feedstock markets, power plant operations and power and hydrogen market sales are included in the analysis. Operations and economics of CO_2 sequestration are left out of scope, although the transportation cost of CO_2 to end user is taken into account. No storage of syngas or hydrogen is assumed in the value chain due to their high capital investment costs. Other assumptions related to market are that power or hydrogen can be sold whenever it is produced, therefore their production is only driven by the internal profit optimization goal of the plant. This is followed by a hydrogen price discount assumption in order to account for the customer-independent supply of hydrogen. Similarly, the IGCC is only price-taker in all product markets meaning that market prices are unaffected from the output level of the IGCC. This is expected to be aligned with the reality, since a single power generator constitutes only a small piece of the overall power supply portfolio.

Regional focus is in the Europe, due to availability of data and existence of the necessary infrastructure for different dual fuel and dual product business models. We believe that the results could also be applicable to other markets, which operate in decentralized, and CO2 restricted power markets and have the necessary infrastructure for the investigated business models.

In the dual fuel scenario, fuels are chosen as bituminous coal and natural gas due to technical reasons, ease of access, and high heating value. In the dual product scenario, hydrogen is chosen as secondary product due to existence of a hydrogen infrastructure in the EU. It is assumed that neither syngas nor hydrogen could be stored in the power plant, due to the high capital expenditure requirement for such an investment.

The key variables that are considered within the scope of this analysis are power and feedstock prices, CO2 emission and transportation costs, condition of the units (i.e. outages), start-up times, start-up costs, ramping rates, non-fuel operating costs, minimum load constraints.

One of the major variables not included into the analysis is the capital expenditure (i.e. CAPEX). There are two motivations for not involving CAPEX into the analysis. First, CAPEX values for future have a high uncertainty, since they are exposed to various other financial and material industries (e.g. steel industry). Therefore, predicting a CAPEX value for 2015 is a highly challenging task and inaccuracy of predictions would affect the analysis dramatically. Secondly, the aim of this study is to focus on the identification of the full potential lying within different flexibility options. In other words, the focus is on identification of benefits, which can be followed by a cost analysis in later stages. A decision maker should decide whether this potential is worthwhile to be exploited by integrating other capital expenditure and technical restrictions. As CAPEX is left out considering other financial measures like inflation and tax rates also become irrelevant. Furthermore, since the value of different options are calculated based on a base case which operates in a similar economic and tax environment the impact of these financial variables on the analysis, if there exists any, is expected to be negligibly small.

From climate change point of view, CO_2 framework is included from a cost perspective. CO_2 market price is paid for each ton of CO_2 that is emitted to the atmosphere, and transportation (to sequestration site) cost is paid for each ton of CO_2 captured. Additional revenues from CO_2 credit sales are treated similar to CAPEX or tax variables and therefore not included in the analysis. The motivation behind this is the difficulty of modeling the value of the exact amount of revenue from CO_2 allowance sales in 2015, since it highly depends on the developments in the EU Emissions Trading Scheme of scheme (e.g. cap & trade or auctioning methods, allocation of free emissions ...etc) and volatility of the CO_2 market.

4.1.4. Performance measures

Finally in comparing different cases to evaluate the value of options, two different measures have been used. Both of them are based on the daily profit distribution curves that are produced by the simulation. First one is the average daily operational profit. A second measure, namely risk of having loss at the end of any day is used as a complementary measure. This is calculated as the cumulative probability lying on the left hand side of zero profit. They are going to be discussed in more detail in the following section.

The length of each simulation run is 87,600 hours. This relatively long simulation length makes sure that the sample size is large enough to attain a significant confidence interval, and maintains the solution times in reasonable intervals. This value also corresponds to approximately the half of the lifetime of a typical power plant, which is 20-25 years.

4.2 Model Description

After introducing an overview of design choices in the previous section, here the detailed description of the model is given. Figure 7 depicts a black-box representation of the overall model.

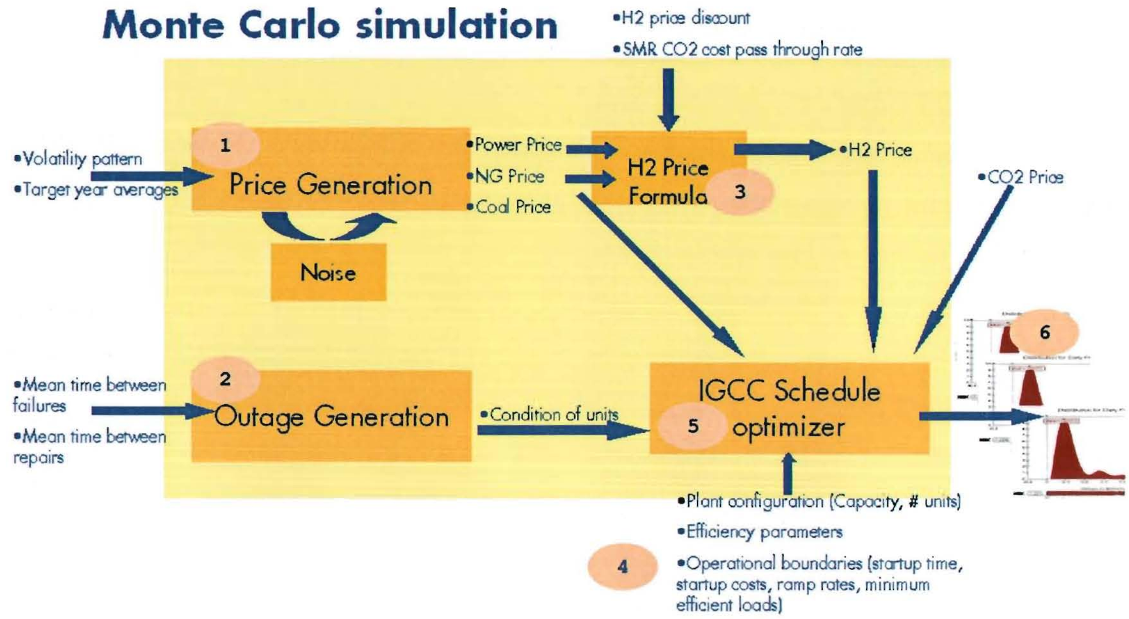

Figure 7 Black box representation of the overall simulation model

These steps can be explained by following the enumeration in the black-box figure:

<u>Step 1: Power and feedstock price simulation</u>

Price generation module generates power (hourly), coal (daily) and natural gas (daily) prices based on three elements: volatility and seasonality pattern, price averages for the target year, stochastic noise process. The formulization of this approach is as following: First, a base year is chosen to derive volatility and seasonality patterns from. As discussed, in our analysis 2007 EU day-ahead prices are used for this purpose. Then the price averages for the simulation target year are decided. In this study the target year is 2015, and the forecasted average prices are taken from a third-party consultancy report. Then, the base year seasonality is applied to target year prices by using the following multiplier:

M= (Target year average) / (Base year average)

This approach ensures that the % volatility is kept same, consistency between fuel-power correlations and seasonality patterns is preserved, and the forecasted yearly average values are applied properly. Finally, a stochastic noise is applied either intentionally to distort the seasonality pattern (to account for the risk of having a significantly different seasonality pattern in the future year), or to add additional volatility to analyze different scenarios.

As discussed in previous section, a Mean Reverting Geometric Brownian Motion (MRGBM), which is used extensively in finance and power sector to simulate commodity prices, is chosen as the stochastic process. The formula for a MRGBM series is [Blanco and Soronow, 2001]:

$$\underbrace{S_{t+1} - S_t}_{\text{Expected change in price at } t+1 \text{ and } t} = \underbrace{\alpha\left(S^* - S_t\right)}_{\text{Mean Reversion Component}} + \underbrace{\sigma\,\varepsilon_t}_{\text{Random Component}}$$

where:

S^* is the mean reversion level or long run equilibrium price

S_t is the spot price

α is the mean reversion rate

σ is the volatility

ε is the random shock to price from t to $t+1$

As can be seen in the formula, it has three key parameters: volatility, long-term mean and mean reverting speed. The parameters of the MRGBM process can be derived for power, natural gas and coal separately with a regression analysis [Blanco and Soronow, 2001]. Using prices of the previous time period as x values and corresponding price change as y values of the analysis, parameters of MRGBM could be calculated with the following formulas:

Mean reversion speed	=	-Slope
Long run mean	=	Intercept / Mean Reversion Speed
Volatility	=	(Standard error[3] y on x) / long term mean

Table 5 Derivations of MRGBM Parameters [Blanco and Soronow, 2001]

Since the aim of using MRGBM series is to add additional volatility or intentionally distort the seasonality of an already existing price series, a long-term mean of 1 is used. After generating the stochastic noise, it can be injected with a controlled ratio in order to manage the overall power price volatility. The overall price generation formula can be summarized as following:

Let;	
Baseyear_price(t) :	Price of commodity at time t in base year series (i.e. 2007)
Simulated_price(t):	Final simulated price
i:	Stochastic noise injection ratio
MRGBM(t):	Value of stochastic process at time t
M:	(M= (Target year average) / (Base year average))
Then;	
Simulated_price(t)= M Baseyear_price(t) + [i* (1-MRGBM) * M* Baseyear_price(t)]*	

Table 6 Power price (hourly), coal and natural gas (daily) generation formula

[3] Calculated using STEYX function in MS Excel

Following figure depicts an example of the base year prices (grey), adjusted prices (yellow) and the simulated prices (blue). The final price series (blue) follows the base year seasonality (grey) with additional volatility and also fits into the target year 2015 forecasted averages (yellow).

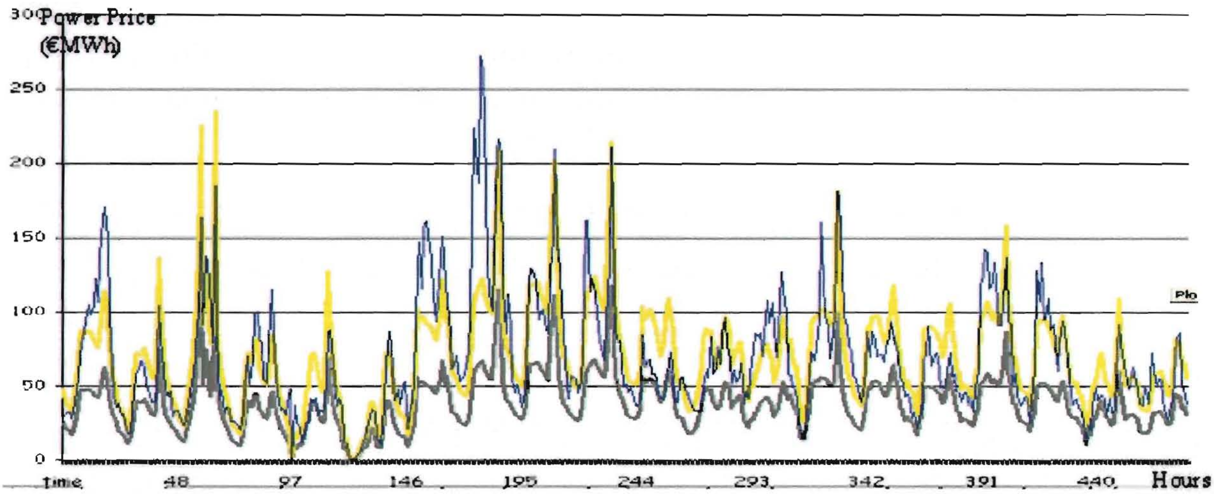

Figure 8 Illustration of generated prices

Step 2: Hydrogen price calculation

Hydrogen price is calculated dynamically with a formula based on natural gas and power price. This formula is provided by Shell's Contracting and Procurement Industrial Gas Department, and further modified in order to be able to investigate different hydrogen price scenarios. Using such a dynamic approach, rather than using static yearly constant hydrogen price the trade-off between hydrogen and power is better analyzed. Following formula produces the calculated hydrogen prices:

Let;	
H2Price (t):	Hydrogen price at time t (€/ton)
NG (t):	Natural gas price at time t (€/MWh gas)
E (t):	Electricity price at time t (€/KW)
CO2Price:	Average CO2 price throughout the year (€/ton)
h:	H2 price discount rate
%p:	Percentage of CO2 cost that is passed through to customers if SMR's become a part of CO2 frame
r:	CO2 emission rate of SMR's (ton CO2 per ton natural gas used)
Then;	
	Formula is masked

Table 7 Hydrogen price calculation formula

[4] IGCC's are already part of CO2 framework. Therefore in the analysis a CO2 penalty is paid for producing hydrogen as well as generating power. Currently Steam Methane Reformation (SMR) plants are the dominant hydrogen producers, but not part of the emission framework. This parameter is used for a what if analysis.

Step 3: Outage simulation

Outage simulation generates random failure and repair events for the gasifier, and CCGT units, assuming that time between failures and time between repairs are "exponentially" distributed.

Step 4: Other input parameters

In this step other parameters are provided to the model, including the following data:

Plant configuration
Number and capacities of units (i.e. gasifier, CCGT and PSA)
Efficiency parameters
Power generation efficiency
Hydrogen production efficiency
Coal to syngas efficiency
CO2 capture efficiency for coal
CO2 emission rate for coal
CO2 emission rate for natural gas
Operational boundaries of the units
Startup times
Startup costs
Ramping rates
Minimum efficient load
Non-fuel operating costs
Control variables
Max. Allowed natural gas access per hour (if 0, Mono fuel case)
Allow natural gas access only during gasifier outages (if 0, overall arbitrage)
Force gasifier to run (If 1, does not allow gasifier to shutdown)
Rolling horizon length
Planning revision length

Table 8 User-defined inputs

First three sets of parameters are discussed in more detail in the "Data Collection" Section. The control variables allow investigating the different scenarios. For instance by allowing no natural gas access, and using 1 for "force gasifier to run" variable, the case A2 (IGCC without shutdown) could be investigated.

Step 5: IGCC schedule optimization

All economical, technical and operational data is then sent to the power plant schedule optimization module to simulate the hourly behavior of the power plant. As explained in the previous section the optimization module is a mixed integer linear program with around 7.000 variables, and 30.000

constraints, solved by the commercial solver AIMMS. A graphical representation of the schedule looks like the below figure. The detailed description of the model is provided in Appendix 1.

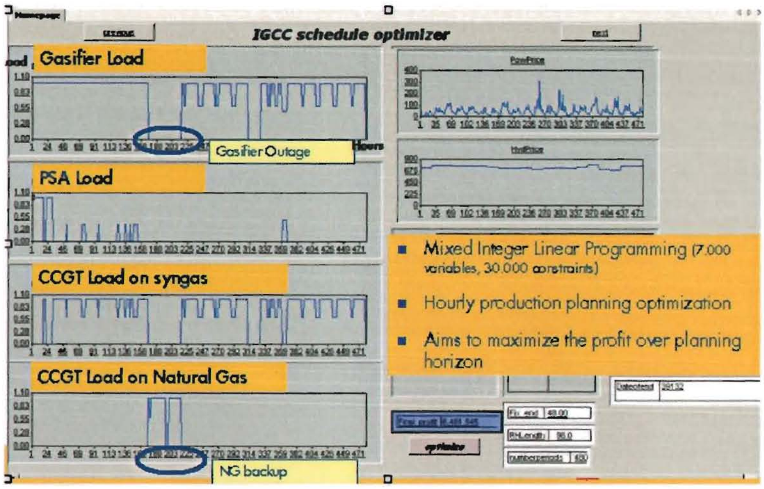

Figure 9 Illustration of MILP scheduling module using commercial AIMMS solver.

The key decision variables are load of gasifier, power unit (CCGT), and hydrogen purification unit (PSA). Power unit has two different load variables one for natural gas and one for syngas as feedstock. In this example a steady load on gasifier is maintained by diverting syngas between power and hydrogen until a gasifier outage occurs. During the outage natural gas backup is used to maintain power generation.

Step 6: Profit distribution charts

At the end of the simulation run, the following daily profit probability distribution chart is created.

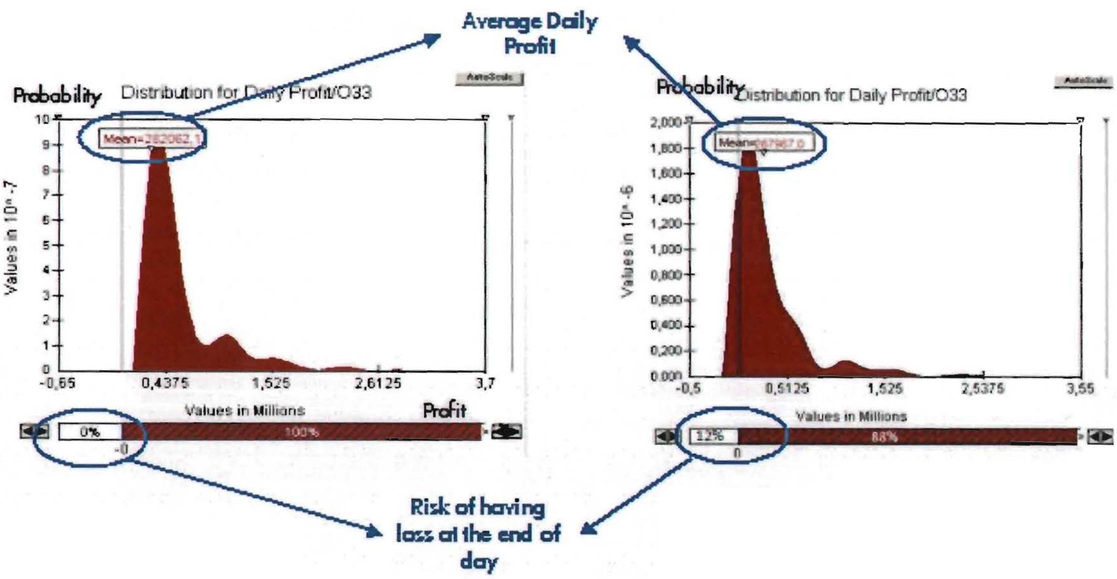

Figure 10 Profit distribution

It could be easily noticed that these distribution charts do not represent a perfect bell-shaped curve; instead there are several peaks with different magnitudes. The reason is that the feedstock and fuel prices do not follow a single distribution, but rather a distribution "shifting" throughout the year due to high seasonality of those price series. This results in several linked small bell-curves with different profits depending on the time of season. Two characteristics of this distribution curve are especially appealing in terms of our analysis. First one is the mean value of the curve, which could be interpreted as "average daily profit". This measure is used to compare profitability of different IGCC scenarios with the base case scenario in order to identify the associated value added. Furthermore, as explained earlier, one of the motivations to adopt a Monte Carlo simulation approach was to study the related risks as well as the profitability changes. Therefore, second measure that is important to consider is the cumulative distribution lying on the left-hand side of a threshold profit. This threshold profit is chosen as zero in order to distinguish profits from losses. This measure can be interpreted as "Probability of having loss at the end of any day". This risk measure provides additional information regarding the value of different IGCC options compared to simple profit values that could be obtained by a discounted cash flow analysis.

4.3. Model implementation

The model is implemented into two platforms linked to each other: MS Excel, and AIMMS commercial optimization solver. The price simulation, outage simulation, and user-inputs are controlled by a MS Excel workbook, which is powered by a commercial simulation add-on called "@risk". The schedule optimization model is implemented to AIMMS. The worksheet and the optimization model is linked with each other via AIMMS Excel Bridge add-on. The control of simulation and the reporting of the results are managed by the @risk add-on. The illustration of the implementation is provided in Appendix 2.

4.4. Model Validation

Due to large size of the model, complex interactions between variables and the high human interaction involved the validation was crucial before producing the final results. A special attention has been paid into the "internal validation" of the model. The model is checked with Shell's optimization team's insights both during development and after implementation. Furthermore, several pilot cases are investigated to detect the possible unusual behaviors of the model. Typical examples of this cases are; no operational boundaries and prices are the yearly averages, gasifier, CCGT, PSA outages, natural gas is very cheap compared to coal, hydrogen is very cheap compared to coal and so on. No unusual behaviors were detected. Finally, as will be discussed in the discussion section of this report, the results are tried to be explained by intuition whenever possible. Due to non-availability of a similar benchmark model, "external validity" could not be investigated in the model level. However, some of the results could be crosschecked with some recent internal reports, which showed aligned figures.

SECTION 5: DATA COLLECTION & PLANT CONFIGURATION

5.1. Data collection

The study required the collection of numerous technical, economical and operational data. Following data sources are used for this purpose:

- Technical documents from Shell coal gasification, hydrogen, and power teams.
- Interviews with Shell experts and managers.
- Interviews with two power plant managers
- A plant visit to Bugganum IGCC in NL
- External reports: Academic articles, Third-party organization reports (CERA, Foster Wheeler, IEA)

The overview of input data used in the analysis is presented in Table 9.

ECONOMICAL PARAMETERS	VALUE	UNIT	Type	Source
2015 average yearly power price	masked	€ per Mwh	confidential	third-party
2015 average yearly coal price	masked	€ per ton	confidential	third-party
2015 average yearly natural gas price	masked	€ per Mwh gas	confidential	third-party
2015 average cost of emitting CO2	masked	€ per ton CO2	confidential	third-party
2015 average cost of transporting CO2	masked	€ per ton CO2	confidential	Shell coal gasification team
Power price volatility and seasonality pattern	price series	€ per Mwh	public	2007 NL spot market prices
Coal price volatility and seasonality pattern	price series	€ per ton	public	2007 NL spot market prices
Natural gas price volatility and seasonality pattern	price series	€ per Mwh gas	public	2007 NL spot market prices
OPERATIONAL PARAMETERS	**VALUE**	**UNIT**	**Type**	**Source**
Gasifier startup times	masked	hours	confidential	Shell coal gasification team
Gasifier startup costs	masked	€ per startup	confidential	Shell coal gasification team
Gasifier ramping rate	masked	% capacity per min	confidential	Shell coal gasification team
Gasifier minimum efficient load	masked	% of full capacity	confidential	Shell coal gasification team
Gasifier mean time to failure	masked	days	confidential	Shell coal gasification team

Gasifier mean time to repair	masked	days	confidential	Shell coal gasification team
Gasifier non-fuel OPEX	masked	€ per ton syngas	confidential	Shell coal gasification team
CCGT startup times	masked	hours	confidential	Shell ESPANA CCGT
CCGT startup costs	masked	€ per startup	confidential	Shell ESPANA CCGT
CCGT ramping rate	masked	Mwh per min	confidential	Shell ESPANA CCGT
CCGT minimum efficient load	masked	% of full capacity	confidential	Shell ESPANA CCGT
CCGT mean time to failure	masked	days	confidential	Shell ESPANA CCGT
CCGT mean time to repair	masked	days	confidential	Shell ESPANA CCGT
CCGT non-fuel OPEX	masked	€ per Mwh power	confidential	Shell coal gasification team
TECHNICAL PARAMETERS	**VALUE**	**UNIT**	**Type**	**Source**
Coal to syngas efficiency	masked	ton syngas per ton coal	confidential	Shell coal gasification team
Syngas to power efficiency	masked	ton syngas per MWh power	confidential	Shell coal gasification team
Syngas to hydrogen efficiency	masked	ton syngas per ton H2	confidential	Shell coal gasification team
Natural gas to power efficiency	masked	ton natural gas per MWh power	confidential	Shell ESPANA CCGT
Rate of CO2 emission per syngas consumption	masked	ton CO2 per ton syngas	confidential	Shell coal gasification team
Rate of CO2 capture per syngas consumption	masked	ton CO2 per ton syngas	confidential	Shell coal gasification team
Rate of CO2 emission per natural gas consumption	masked	ton CO2 per ton natural gas	confidential	Shell ESPANA CCGT

Table 9 Overview of input data used in the analysis.

It could be observed that three types of input data are collected. Economical data includes a base year for identifying volatility and seasonality, target year price forecasts, and CO2 penalties. Operational parameters cover startup times, startup costs, ramping rates, non-fuel OPEX costs and minimum efficient load restrictions. As could be seen, ramping rates are relatively fast within an hour; therefore they don't constitute a significant restriction on the schedule. Furthermore, the operational boundaries for PSA (i.e. hydrogen purification unit) are found to be insignificant and therefore they are not included into the analysis. However PSA unit is still a part of the process flow and plays an important role in the syngas balance constraints. Finally the main technical parameters are the efficiency factors related to feedstock to product and product to CO2 conversions. It could be easily noticed that in this study three different output efficiency figures are used instead of a single figure; coal to syngas efficiency, syngas to power efficiency and syngas to hydrogen efficiency. This is again related to the "decoupling" optimization approach adopted in this study. CO2 efficiency figures are also investigated in three steps; CO2 emissions per syngas consumption, CO2 emissions per natural gas consumption and CO2 capture per syngas consumption.

5.2. Base case description

In addition to this input parameters, a base case around the configuration of the plant was also required. Following approach is used to define the base case; first the power generation capacity is considered to be equal to *masked* MWh, which corresponds to capacity of the most recent IGCC projects. Then, the equivalent gasifier capacity, which could run the CCGT full capacity, is calculated using the efficiency formulas. Finally, this is translated into the capacity of hydrogen production unit by using syngas to hydrogen efficiency ratios. Therefore with these capacity figures, IGCC is capable of switching between 100% hydrogen production and power generation. Here it was also important to check whether the hydrogen market could absorb this amount. This implies the alignment of the base case with capacities of the SMR's and power plants in the existing network. Ultimately following base configuration is attained for the IGCC: 1 Gasifier (*masked* ton coal input per hour), 1 CCGT (*masked* MW), 1 PSA (*masked* ton hydrogen per hour).

SECTION 6: RESULTS

Case	Relevance	Description	Avg. daily profit	Value added	Loss risk
A1	Schedule restriction	Standard IGCC – Always run at full capacity	€ 230,102	-14%	23%
A2	Schedule restriction	Standard IGCC – No shutdown allowed (except outages)	€ 245,321	-8%	18%
B	**BASE CASE**	Standard IGCC – No operating schedule restrictions	€ 267,967	n/a	12%
C1	Business model	Dual fuel IGCC – Natural gas backup during gasifier outages	*masked*	*masked*	*masked*
C2	Business model	Dual fuel IGCC – Natural gas and coal fuel arbitrage	*masked*	*masked*	*masked*
D	Business model	Dual product IGCC- Hydrogen co-production	*masked*	*masked*	*masked*
E	R&D	More efficient IGCC	€ 279,275	4%	5%
F	R&D	Fully flexible IGCC	€ 282,062	5%	0%

Table 10 Summary of simulation results

Avg. daily profit is the mean value of the profit distribution. Loss risk is the probability of having a negative profit at the end of any day. Value added is the relative profit increase compared to the base case, which is case B. Detailed probability distribution curves are provided in the Appendix 1.

Running the analysis model for the each of the described scenarios provides profit distribution charts with associated mean values and loss risks of which are demonstrated in above table. (Detailed probability curves are provided in Appendix 3). Here, it is important to note once again that the profit values are indicative rather than descriptive since they don't include CAPEX and tax considerations. However, they facilitate a common basis to compare different scenarios with each other.

First, the impact of schedule restrictions can be assessed by comparing the first three scenarios; A1, A2 and B. As demonstrated in the above table, forcing the IGCC to run non-stop (except outages) at full capacity results in significantly low profits and high loss risk. This is due to the fact that in case A1, IGCC is completely exposed to the power price and feedstock fluctuations and cannot react to the price peaks and dips by changing its schedule accordingly. In the next scenario (A2) allowing the IGCC to lower load during times when power is unprofitable helps alleviate the effects of the previous case. The difference between cases A1 and A2 is aligned with simple intuition. The profit delta between A2 and B corresponds to 0.6 of the profit delta between A1 and B. This is due to the fact that in case A2 can the IGCC run on 60% load instead of 100% load in Case A1, and therefore can protect itself against 40% of the losses associated with this inflexibility. (Note that 60% is the minimum load constraint for power island). (Refer back to Figure 5 for the distinctions of cases A1, A2 and B)

Our analysis also provides some insights about different business models; namely dual fuel and dual product IGCC's (Cases C and D). First, a business model in which natural gas is used as well as coal results in a *masked* and *masked* increase in profits, respectively for a case in which natural gas is only used during gasifier outages, and a second case in which natural gas is used whenever it is more profitable than coal. The value of natural gas as a backup is again aligned with simple intuition in this case. In the first case natural gas can be accessed during gasifier outages, which occurs approximately *masked* of the time, and power generation on natural gas and coal is almost equally profitable according the input set used in this analysis. Apart from this value arising from maintaining power generation, a second benefit is also present. This second value arises from decoupling of power island and gasification island, and so that power island does not have to shut down during gasifier outages. However, due to relatively high availability assumption, and quick power island startup times (*masked*) impact of this effect was very subtle. Allowing access to natural gas not only during gasifier outages but whenever it is a more profitable power generation option enables an arbitrage opportunity. Thus this business model builds upon the first one, and further improves the plant profitability and reduces loss risk.

In the second business model investigated, the value of hydrogen co-production business model shows a range between *masked* to *masked* increase in profits. This range captures different combinations of three scenario variables: hydrogen price discount, positioning of SMR's in CO2 framework and finally power price volatility. As a starting point for analyzing this case a 25% H2 price discount is considered, since hydrogen production is not steady and fully determined by the IGCC's own operating schedule optimization rather than external customer demand. Positioning of SMR's in CO2 framework is also an important variable to analysis due to the fact that IGCC's are a part of CO2 framework in the EU, whereas SMR's are not. Furthermore, hydrogen price is chiefly determined by SMR's. Thus in this analysis cost of hydrogen based on coal includes CO2 penalties. As a scenario, inclusion of SMR's into the CO2 framework in which case a 50% of CO2 costs passes through to the customers is considered. This case results in significantly higher value for hydrogen production due to the rise in hydrogen prices. Finally, impact of 25% more power price volatility on profitability of dual product business model is investigated. In this case, profits of a traditional mono product IGCC shows a slight 2% decrease due to the increasing complexity of following the load with schedule changes. Value of hydrogen co-production on the other hand increases approximately in each case by *masked* since dual product IGCC can response better to power price fluctuations by diverting syngas to hydrogen production instead of generating power. As expected, all of the hydrogen co-production cases result in a lower probability of having loss.

Finally the values of two R&D improvement cases are identified: a more efficient and a more flexible IGCC. (Cases E and F). A 1% point increase in efficiency increases the profits by 4%, and decreases the loss risk, since the profit margins from power is now higher. These results are also aligned with simple intuition, and can be crosschecked with a simple calculation on yearly average figures given in the input data table. The reason for this alignment with daily and yearly analysis arises from the fact that 1% increase, although technically is not an effortless target to achieve, does not change the operating mode of the IGCC dramatically in this case. Thus, the optimized schedules do not differ significantly and the main difference arises directly from the profit margins. For more significant changes in the efficiency rate, the operating mode is also expected to change, and thus the value calculated based on yearly averages would be different from the value calculated by the model.

A perfectly responsive IGCC with no start-up times, no start-up costs and no minimum efficient load constraints generates 5% more profit and possesses zero loss of risk as expected. This is due to the fact that IGCC can instantly shutdown during times in which power generation is not profitable. This case can also be assessed together with the schedule restriction cases A1, A2 and B in order to identify step by step the value of relaxing boundaries in operations planning of the power plants. The value added by this case might seem to be relatively lower than the performance increase achieved by moving away from A1 and A2 cases to base case B. This can be explained by a couple of reasons. First, A1 and A2 cases are exposed to market risks higher than B and F cases since they are not allowed to shutdown during loss periods. B and F on the other hand can both shut down during loss periods but mainly differ in their reaction times and costs to reaction to those market fluctuations. Secondly, the value of perfect flexible IGCC can differ depending on three main inputs; start-up times and costs, availability and efficiency. In our analysis we used relatively high availability assumption (masked) and quick start-up times (masked hour for gasifier and masked hours for power island). Technical sources show that gasifier start-up time could be much higher depending on the cold and hot condition of the unit, and availability might be lower especially in the first years of the plant. Thus, one can easily expect that a lower availability and a longer start-up time assumption would inflate the value of flexible unit. Because the difference between a flexible and inflexible unit becomes especially apparent when plant is being restarted after a shutdown. The shutdown decision in this case can either be one that is given on purpose to optimize the operating schedule or one that has arisen from an unplanned outage. In our case the effect of the second type is relatively small due to high availability assumption. Finally, the study of German power utility E.ON reports that value of a flexible IGCC highly depends on whether it is running on base load or load following operating modes, therefore on market conditions and efficiency of the IGCC. [EON, 2001] This implies that when market conditions and efficiency of the IGCC favors a base load operating mode, then the need for flexibility would be lower, since it would be running on full load most of the time. Thus the value of case F might be expected to be higher under lower power price, higher feedstock price or lower efficiency scenarios.

SECTION 7: DISCUSSION & MANAGERIAL INSIGHTS

This study was aimed to develop a methodology to combine several economical, technical and operational aspects to analyze value of different IGCC scenarios. Results could be grouped under three main topics: impact of schedule restrictions, value added from dual fuel and dual product business models and value of R&D improvements in plant efficiency and operational flexibility. An overview of the findings is illustrated in below figure.

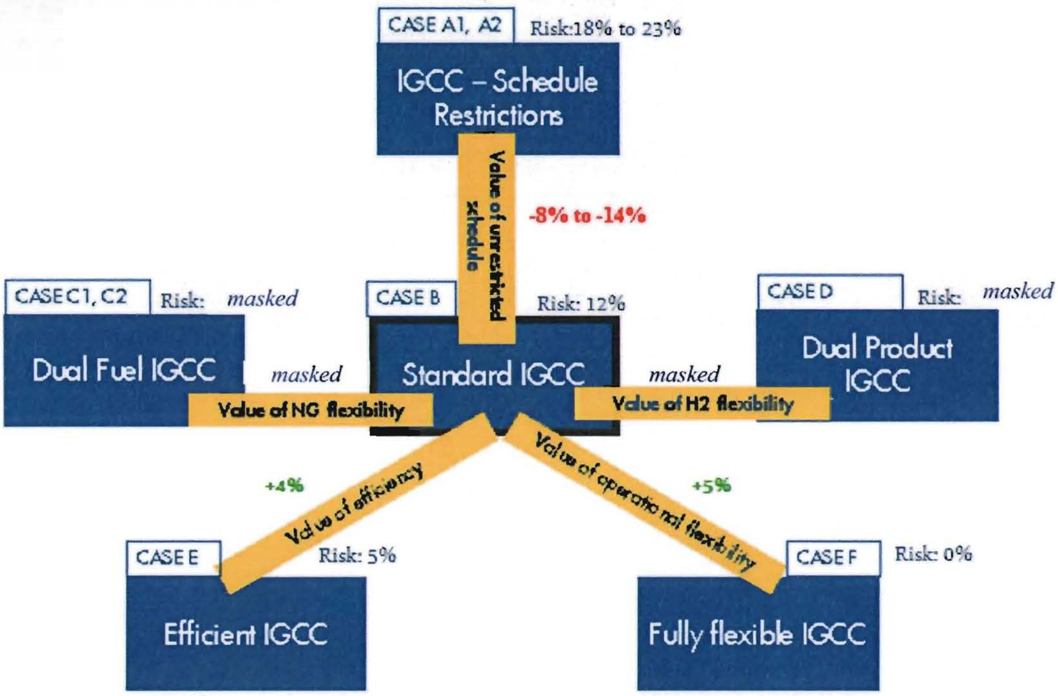

Figure 11 Summary of findings

Blue figures represent probability of having loss at the end of any day. Green and red figures are the percentage change in operational profits compared to the base case in the middle.

From managerial perspective there might be several interesting insights related to these results. First of all, analysis shows that there is a cost of forcing the power plant to run with minimum shutdowns. As discussed earlier, there might be various reasons for utilities to adopt such an operating model, especially related to long-term supply contracts and extending the lifetime of the equipment. Results show that this operating mode, if used in power day-ahead market operations could decrease the operational profits by 8%. Secondly, the study shows that apart from traditional mono-fuel mono-product IGCC business model, there might be significant value in other opportunities, which IGCC is technically capable to exploit. A dual fuel model in which natural gas used together with coal can increase operational profits by *masked* if used during gasifier outages, and by *masked* more profits if used whenever it is more profitable than coal. This value could be expected to rise with lower gasifier availability, although this case is not investigated here exclusively. IGCC's are capable of producing syngas out of coal, which can be used in many different applications apart from power. Our analysis with a hydrogen co-production case shows that there might be significant added value in this business model, depending on the negotiated hydrogen price, future of Steam Methane Reformation (SMR) utilities in CO2 framework and finally the power price volatility. A case in which power price volatility is 25% higher than that of 2007, SMR's are a part of CO2 framework and 50% of their cost passes through to the hydrogen price, and hydrogen could be sold at market price results in about *masked* increase in plant profitability.

From R&D perspective, our analysis also illustrates the value of two improvement options: efficiency and operational flexibility. Results show there could be important value in both options, in terms of risk elimination and profit maximization. According to results a 1% efficiency increase, although it is not a very easy target to achieve, adds value to profits almost equal to that of a perfectly flexible power plant (which is virtually impossible to achieve). However, a further research is necessary to explore the value of these options under more dramatic efficiency increase / decreases, and different availability and start-up times. Literature research shows that value of flexibility might increase, as the utilization of the plant gets lower. Furthermore, especially in the first years of investment availability figures are generally lower than the planned average figures, which would increase the comparative value of a flexible power plant, since the frequency of restarts would increase.

Apart from the findings related to different IGCC options that are presented here, we believe that the approach itself might also add value to assessment of different subjects in power generation industry. First of all, compared to solely economic (simple yearly average calculation, spark spread analysis, real option analysis ...etc) and solely operational (unit commitment, economic dispatch ...etc) techniques, the model represented here combines numerous economic, operational and technical variables in one simulation framework. With its embedded operational schedule optimization module, the model can simulate the real operation of a power plant in hourly basis by responding to changes in market dynamically. The Monte Carlo simulation technique on the other hand enables assessment of different types of risks. A rough benchmark with a simple decision support tool, which uses a single average value for power and feedstock prices over a year, shows that the simple method undershoots operational profits by 10%. The reason is that in reality, neither power price nor feedstock prices are constant throughout the year. Therefore plant needs to run on different loads in different hours of the day. This inaccuracy rate of simple yearly calculations might become higher and lower depending on the input data that has been used. For higher volatility markets using a simple yearly average calculation would result in lower accuracy in calculating operational profits. Apart from calculating a traditional IGCC's operational profit, the real strength of this model becomes evident during investigation of more exotic cases. Examples are evaluation of dual fuel and dual product business models, impact of different operating schedules, and operational flexibility, all of which are difficult to analyze in either solely economical or solely operational models.

From academic perspective this study contributes to the economical-operational hybrid power industry literature. Majority of the power literature does not include operational perspective when evaluating a power generation asset. Furthermore, the dual fuel (natural gas and coal), and dual product (power and hydrogen) business models have not been investigated sufficiently. This study presents several IGCC options with a common basis to compare. The foremost strength of the approach in this study especially lies within the hourly schedule optimization, which follows a "decoupled" approach. In other words separate decisions are given for gasification island, power island and hydrogen purification unit contrary to mainstream approach in the literature which considers the whole IGCC as a single production unit. With such structuring of the problem, different scenarios are easily investigated. Finally, we believe that this modeling approach might open window to exploring many other power industry questions. Some of them are discussed in the next section.

Ultimately, the study offers insights about the value of integrating operations management elements into strategic planning level decisions in power industry. So far, operations management discipline found itself a role in the operational level decisions of power plants. Strategic decisions on the other hand are mostly driven by economical and financial measures. However, due the unique characteristics of power markets (e.g. high volatility, non-storability), an investment or planning decision based on simple economics (e.g. spark spreads on yearly averages) without integrating operational elements may result in significant inaccuracy. The results of this study show that many of the operations management and operations research tools can add significant benefit to accurate valuation of generation assets and therefore to investment decisions.

SECTION 8: FURTHER RESEARCH

In this study several different IGCC options are analyzed with an economical-operational hybrid simulation model. However due to time restrictions and based on the business interests of the company, the analysis was carried around a base case plant and market configuration to give a big picture of value of different scenarios within a limited time. Hydrogen co-production case is given a higher priority and has been explored in more detail to account for different market scenarios. We believe that there is a significant amount of room and motivation to investigate each of the cases in further detail, by studying different plant configurations and market environments. Especially, the value of natural gas dual fuel, and operational flexibility might be expected to increase for low availability, longer start-up time cases. Furthermore impact of more dramatic changes on power and feedstock prices, volatilities and efficiency rates on these cases remains to be explored.

Apart from the research questions investigated here, many other topics can also be analyzed using the approach demonstrated in this study. Some interesting examples are determination of the bottleneck operational boundary among start-up times, ramping rates, minimum efficient loads and availability for different plant and market configurations. Another interesting question would be applying this methodology to optimize the best train configuration of a power plant. For instance, two small gasification units would add higher flexibility to the system and would lower the impact of outages, but they would require higher CAPEX investments. An analysis of both configurations under the same market conditions by using this model would reveal the more profitable configuration.

Finally, the analysis model itself is also open to further improvements and modifications. The exact impact of stochastic versus deterministic optimization still needs be studied although insights from practice show that short-term deterministic forecasts are relatively accurate. Secondly, other power markets, namely long term contracts, and ancillary services could also be integrated into the analysis to give a fuller picture of the plant operations. These would require however an optimization of overall power portfolio subjected not only to spot market prices but also to the future prices.

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APPENDIX 1

MILP SCHEDULE OPTIMIZATION MODEL FOR DUAL FUEL DUAL PRODUCT IGCC

The MILP model is described using AIMMS syntax, since it is an easy way to describe complex models and makes it easy to implement the model. The main building blocks are the mathematical model (e.g. the objective function), sets (i.e. sets of indices), parameters, variables and constraints.

MATHEMATICAL PROGRAM:

identifier : MaxHorizonProfit

description : the objective function that maximizes the operational profit over planning horizon

objective : HorProfit

direction : maximize

type : MIP ;

SET:

identifier : Gasifiers

description : index set for gasifier units

subset of : Allunits

index : gasifier ;

SET:

identifier : CCGTs

description : index set for CCGTs

subset of : Allunits

index : CCGT ;

SET:

identifier : PSAs

description : index set for hydrogen purification units (i.e. PSA:pressure swing adsorption)

subset of : Allunits

index : psa ;

SET:

identifier : timeperiod

index : t

description : index set for time periods

SET:

identifier : Allunits

description : index set for all units

index : u

definition : Gasifiers + PSAs + CCGTs ;

PARAMETER:

identifier : ForceGasifierRun ;

description : A binary variable which activates a dummy objective function to penalize not runningthe gasifier with a big M multilplier. Used for investigating cases A1 and A2

PARAMETER:

identifier : NGonlyifGasifierFails

description : A binary variable which restricts natural gas access only during gasifier outages. Used for investigating case C1

range : binary ;

PARAMETER:

identifier : BigM ;

description : an artificially big number to be used in the constraints

PARAMETER:

identifier : Ramping

description :hourly ramping restriction of the unit u (% load change per hour)

index domain : (u) ;

PARAMETER:

identifier : Setuptime

description : startup time of the unit u (hours per startup)

index domain : (u) ;

PARAMETER:

identifier : Setupcost

description : startup cost of the unit u (€ per startup)

index domain : (u) ;

PARAMETER:

identifier : OPEX

description : non-fuel operating cost for unit u ((€ per unit output. For gasifier: € per ton syngas, For CCGT: € per MWh power, For PSA: € per ton hydrogen)

index domain : (u) ;

PARAMETER:

identifier : Min_Eff_Load

description : minimum efficient load constraint for unit u (defined as % of the full capacity)

index domain : (u) ;

PARAMETER:

identifier : Inst_Cap

description : installed capacity of unit u (For gasifier: ton coal, For CCGT: MWh power, For PSA: ton Hydrogen)

index domain : (u) ;

PARAMETER:

identifier : UnitCondition

description : condition of unit at time t (1 if the unit can run, 0 if there is an outage)

index domain : (u,t) ;

PARAMETER:

identifier : LC

description : a derived parameter to be used in ramping constraints

index domain : (u)
definition : max[0, Min_Eff_Load(u) - Ramping(u)] ;

PARAMETER:
identifier : MaxNGAccess
description : maximum hourly natural gas access. If zero no natural gas can be used as fuel

PARAMETER:
identifier : PowPrice
description : price of power at time t (€ per MWh)
index domain : (t) ;

PARAMETER:
identifier : HydPrice
description : price of hydrogen at time t (€ per ton)
index domain : (t) ;

PARAMETER:
identifier : NGPrice
description : price of natural gas at time t (€ per MWh-gas)
index domain : (t) ;

PARAMETER:
identifier : CoalPrice
description : price of coal at time t (€ per ton)
index domain : (t) ;

PARAMETER:
identifier : CO2Price
description : CO2 emission penalty (€ per emitted ton of CO2) ;

PARAMETER:
identifier : CO2TransportCost

description : average price of transporting CO2 to sequestration site (€ per captured ton of CO2) ;

PARAMETER:

identifier : Coal2SG

description : ton of syngas produced out of one ton coal

PARAMETER:

identifier : Pow2SG ;

description : ton of syngas required for 1 MWh power

PARAMETER:

identifier : Pow2NG ;

description : ton of natural gas required for 1 MWh power

PARAMETER:

identifier : Hyd2SG ;

description : ton of syngas required for 1 ton hydrogen

PARAMETER:

identifier : SG2CO2_v ;

description : ton of CO2 emitted per ton syngas used

PARAMETER:

identifier : SG2CO2_c ;

description : ton of CO2 captured per ton syngas used

PARAMETER:

identifier : NG2CO2_v ;

description : ton of CO2 emitted per MWh-gas natural gas used

VARIABLE:

identifier : O

description: 1 if the unit is On, 0 if OFF *index domain : (u,t)*

range : binary ;

VARIABLE:

identifier : L

description: Load of the unit as a percentage of the overall capacity

index domain : (u,t) | u in (Gasifiers + PSAs)

range : [0, 1] ;

VARIABLE:

identifier : Up

description: 1 if the unit u is started at time t

index domain : (u,t)

range : binary ;

VARIABLE:

identifier : Down

description: 1 if the unit u is shut down at time t

index domain : (u,t)

range : binary ;

VARIABLE:

identifier : L_SG

description: Load of CCGT on syngas as a percentage of the overall capacity (Note that for CCGT we use two load variables, while for gasifiers and psa's it is a single variable.

index domain : (u,t) | u in CCGTs

range : [0, 1] ;

VARIABLE:

identifier : L_NG

description: Load of CCGT on natural gas as a percentage of the overall capacity(Note that for CCGT we use two load variables, while for gasifiers and psa's it is a single variable.

index domain : (u,t) | u in CCGTs

range : [0, 1] ;

VARIABLE:

identifier : SGYield

description: total syngas yield from gasifiers at time t

index domain : t

property : Inline

*definition : sum[(u) | u in Gasifiers, L(u,t) * Inst_Cap(u) * Coal2SG]*

VARIABLE:

identifier : SGDemand

description: total syngas demand from CCGTs and PSAs at time t

index domain : (t)

property : Inline

*definition : sum[(u)| u in CCGTs, L_SG(u,t) * Inst_Cap(u) * Pow2SG] + sum[(u)| u in PSAs, L(u,t) * Inst_Cap(u) * Hyd2SG]*

VARIABLE:

identifier : HydYield

description: total hydrogen yield from CCGTs at time t

index domain : (t)

property : Inline

*definition : sum[(u) | u in PSAs, L(u,t) * Inst_Cap(u)]*

VARIABLE:

identifier : PowYield

description: total power yield from CCGTs at time t

index domain : (t)

property : Inline

*definition : sum[(u), (L_SG(u,t) + L_NG(u,t)) * Inst_Cap(u)]*

VARIABLE:

identifier : NGDemand

description: total natural gas demand from PSAs at time t

index domain : (t)

```
property   : Inline
definition  : sum[(u), L_NG(u,t) * Inst_Cap(u) * Pow2NG] ;

VARIABLE:
 identifier  : VentedCO2
 description: total emitted CO2 at time t
 index domain : (t)
 property   : Inline
 definition  : SGYield(t) * SG2CO2_v + NGDemand(t) * NG2CO2_v ;

VARIABLE:
 identifier  : CapturedCO2
 description: total captured CO2 at time t
 index domain : (t)
 property   : Inline
 definition  : SGYield(t) * SG2CO2_c ;

VARIABLE:
 identifier  : FuelCost
 description: total fuel cost at time t
 index domain : (t)
 property   : Inline
 definition  : (SGYield(t) / Coal2SG) * CoalPrice(t) + NGDemand(t) * NGPrice(t) ;

VARIABLE:
 identifier  : CO2Cost
 description: total CO2 cost at time t
 index domain : (t)
 property   : Inline
 definition  : VentedCO2(t) * CO2Price + CapturedCO2(t) * CO2TransportCost ;

VARIABLE:
 identifier  : OPEXCost
```

description: total operating cost at time t (its unit is € per output. i.e. for gasifier it is € per ton syngas produced, for CCGT € per MWh power generated, for PSA € per ton hydrogen yield)

index domain : (t)

property : Inline

*definition : sum[(u) | u in CCGTs, (L_NG(u,t) + L_SG(u,t)) * Inst_Cap(u) * OPEX(u)] + sum[(u) | u in PSAs, L(u,t) * Inst_Cap(u) * OPEX(u)] + sum[(u) | u in Gasifiers, L(u,t) * Inst_Cap(u) * OPEX(u)*coal2sg] ;*

VARIABLE:

identifier : SUCost

description: total startup cost at time t, based on the startup decisions given

index domain : (t)

property : Inline

*definition : sum[(u), Up(u,t-startuptime(u)) * setupcost(u)] ;*

VARIABLE:

identifier : PowRev

description: total revenue from power sales at time t

index domain : (t)

property : Inline

*definition : PowYield(t) * PowPrice(t) ;*

VARIABLE:

identifier : HydRev

description: total revenue from hydrogen sales at time t

index domain : (t)

property : Inline

*definition : HydYield(t) * HydPrice(t) ;*

VARIABLE:

identifier : Profit

description: total profit at time t

index domain : (t)

definition : HydRev(t) + PowRev(t) - FuelCost(t) - CO2Cost(t) -OPEXCost(t) - SUCost(t)

VARIABLE:

identifier : HorProfit

description: total profit over planning horizon (OBJECTIVE FUNCTION TO MAXIMIZE)

*definition : (sum[t | ord(t)>=RH_start AND ord(t)<=RH_end, Profit(t)]) + (ForceGasifierRun * (sum[t | ord(t)>=RH_start AND ord(t)<=RH_end, BigM *O(Element(Gasifiers,1),t)]))*

comment : first term the usual horizon profit, second term puts an additional weight to running gasifier to study cases A1 and A2. RH_start and RH_end defines the planning horizon

VARIABLE:

identifier : Final_profit

definition : Sum(t, Profit(t)) ;

CONSTRAINT:

identifier : SG_Balance

description: syngas balance constraint at time t

index domain : t

definition : SGDemand(t) <= SGYield(t) ;

CONSTRAINT:

identifier : NG_Balance

description: natural gas balance constraint at time t

index domain : (t)

*definition : NGDemand(t) <= (1-NGonlyifGasifierFails) * (MaxNGAccess) + (NGonlyifGasifierFails * (MaxNGAccess*(1-UnitCondition(element(Gasifiers,1),t)))) ;*

comment : first part is active while studying case C1, other part is active for the rest of the cases. element(s, n) implies the nth unit in set 1. If there are more than 1 gasifier in the configuration additional terms can be added in the final part.

CONSTRAINT:

identifier : On_Outage

description: this constraint links variable On to parameter Condition

index domain : (u,t)

definition : O(u,t) <= UnitCondition(u,t) ;

CONSTRAINT:

identifier : Load_ON1

description: Load cannot be positive if the unit is off

index domain : (u,t) |u in (Gasifiers + PSAs)

definition : L(u,t) <= O(u,t) ;

CONSTRAINT:

identifier : Load_ON2

description: Load should be higher than minimum efficient load if the unit is On

index domain : (u,t) |u in (Gasifiers + PSAs)

*definition : L(u,t) >= O(u,t) * Min_Eff_Load(u) ;*

CONSTRAINT:

identifier : Load_ON3

description: similar load constraints for CCGT, since it has two separate load decisions

index domain : (u,t) | u in CCGTs

definition : L_NG(u,t) + L_SG(u,t) <= O(u,t) ;

CONSTRAINT:

identifier : Load_ON4

description: similar load constraints for CCGT, since it has two separate load decisions

index domain : (u,t) | u in CCGTs

*definition : L_NG(u,t) + L_SG(u,t) >= O(u,t) * Min_Eff_Load(u) ;*

CONSTRAINT:

identifier : StartUP1

description: links ON, OFF condition of the unit with startup decision

index domain : (u,t)

definition : Up(u,t) >= O(u,ord(t)+setuptime(u)) - O(u,t+setuptime(u)-1) ;

CONSTRAINT:

identifier : StartUP2

description: links ON, OFF condition of the unit with startup decision

index domain : (u,t)

definition : Up(u,t) <=O(u,ord(t)+setuptime(u)) ;

CONSTRAINT:

identifier : StartUP3

description: links ON, OFF condition of the unit with startup decision

index domain : (u,t)

definition : Up(u,t)<= 1 - O(u,t+setuptime(u)-1) ;

CONSTRAINT:

identifier : ShutDown1

description: shutdown constraints similar to startup constraints

index domain : (u,t)

definition : Down(u,t)>=O(u,t)-O(u,ord(t)+1) ;

CONSTRAINT:

identifier : ShutDown2

description: shutdown constraints similar to startup constraints

index domain : (u,t)

definition : Down(u,t)<= O(u,t) ;

CONSTRAINT:

identifier : ShutDown3

description: shutdown constraints similar to startup constraints

index domain : (u,t)

definition : Down(u,t)<=1-O(u,ord(t)+1) ;

CONSTRAINT:

identifier : Ramping1

description: if the unit is starting up it can climb from zero to minimum efficient load, otherwise it should follow ramping limits

index domain : (u,t) | u in (Gasifiers + PSAs)

*definition : L(u,t)-L(u,ord(t)-1)<=Ramping(u) + Up(u,ord(t)-Setuptime(u)) *LC(u) ;*

CONSTRAINT:

identifier : Ramping2

description: if the unit is starting up it can climb from zero to minimum efficient load, otherwise it should follow ramping limits

index domain : (u,t) | u in (Gasifiers + PSAs)

*definition : L(u,ord(t)-1) - L(u,t)<=Ramping(u) + Down(u,ord(t)-1) *LC(u) ;*

CONSTRAINT:

identifier : Ramping3

description: if the unit is starting up it can climb from zero to minimum efficient load, otherwise it should follow ramping limits

index domain : (u,t) | u in CCGTs

*definition : L_NG(u,t)+L_SG(u,t)-L_NG(u,ord(t)-1)-L_SG(u,ord(t)-1)<=Ramping(u) + Up(u,ord(t)-Setuptime(u)) *LC(u) ;*

CONSTRAINT:

identifier : Ramping4

description: if the unit is starting up it can climb from zero to minimum efficient load, otherwise it is restricted with the normal ramping limits.

index domain : (u,t)

*definition : L_NG(u,ord(t)-1) + L_SG(u,ord(t)-1)- L_NG(u,t) - L_SG(u,t)<=Ramping(u) + Down(u,ord(t)-1) *LC(u) ;*

CONSTRAINT:

identifier : DownTime

description: : unit should stay off for the startup time amount of periods after startup decision is given

index domain : (u,t)

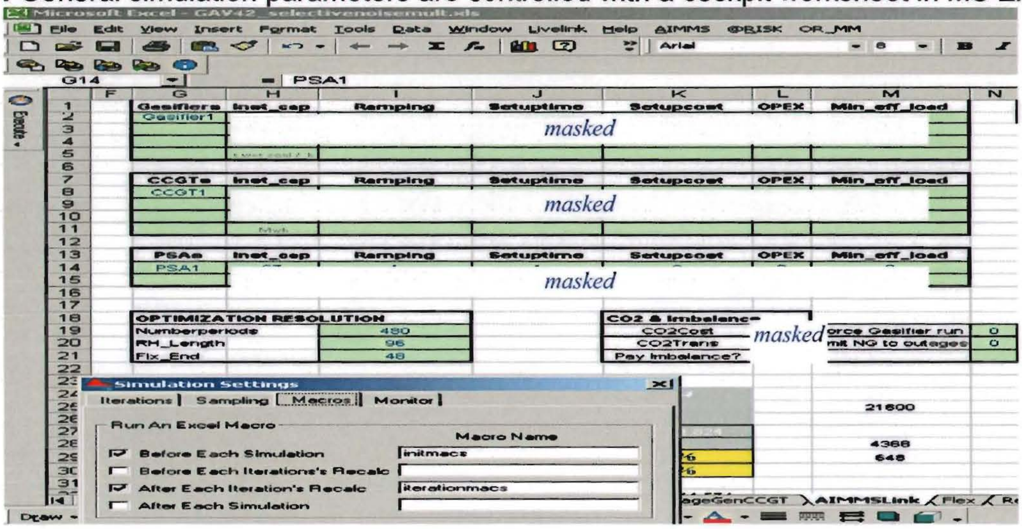
*definition : Up(u,t) * Setuptime(u) <= Sum(k | (ord(k) <= Setuptime(u)) , (1 - O(u , element(timeperiod, ord(t) + ord(k)-1)))) ;*

comment : right hand side of the inequality indeed simply counts the number of periods between startup decision and the actual startup

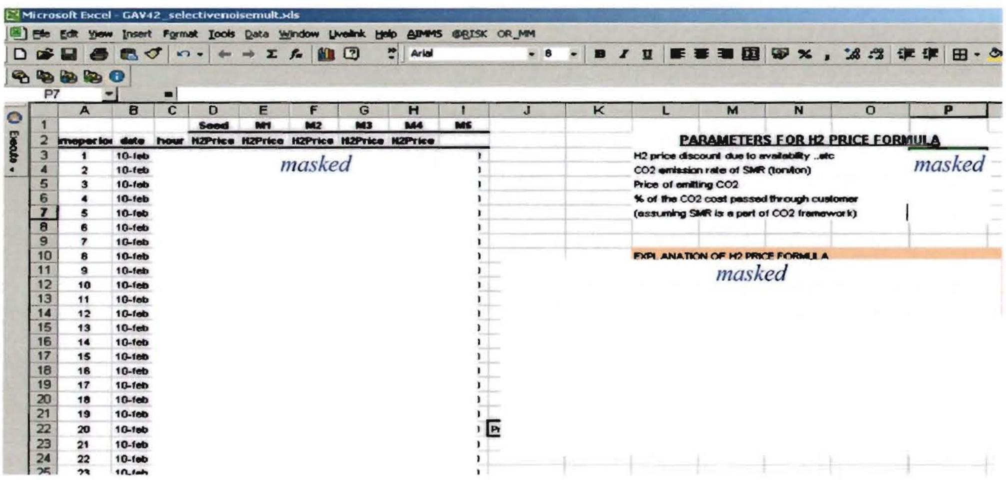
APPENDIX 2

ILLUSTRATION OF THE IMPLEMENTATION OF THE MODEL

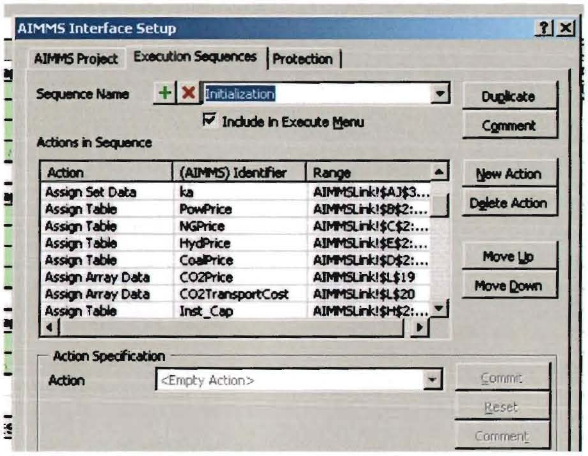
STEP 1: General simulation parameters are controlled with a cockpit worksheet in MS Excel



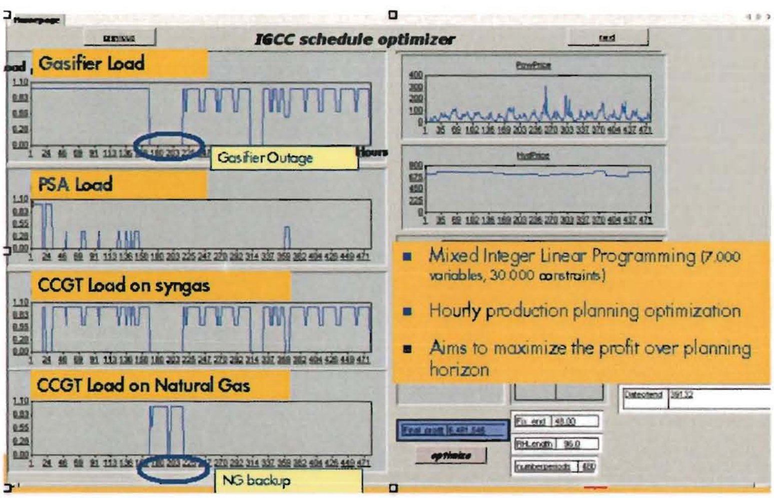
STEP 2: The primary calculations are made by Excel model. These involve price generation, outage generation, and hydrogen price calculation.



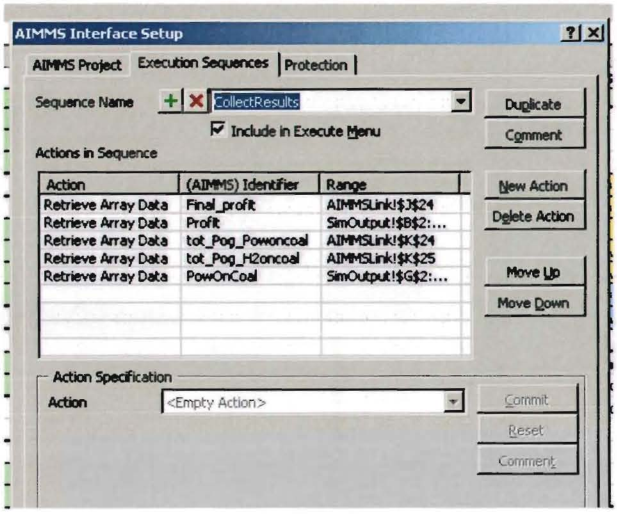
STEP 3: AIMMS Excel Bridge add-on is used to communicate the input parameters to the AIMMS to solve the schedule optimization.



STEP 4: AIMMS solves the schedule optimization problem for the provided data set by maximizing the operational profit.

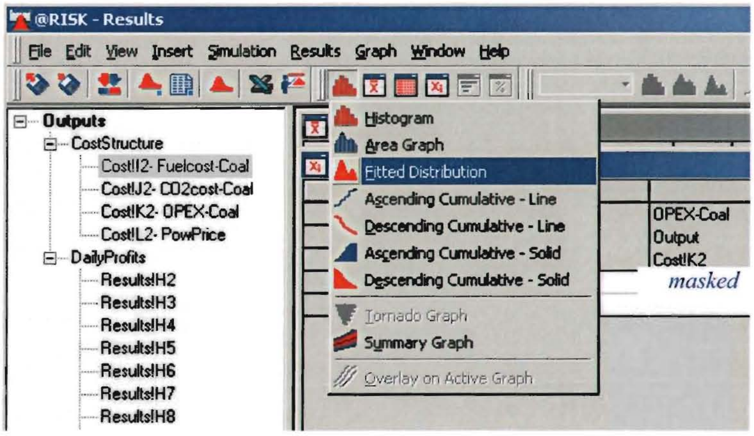


STEP 5: Results are communicated back to Excel model again using AIMMS bridge add-on.



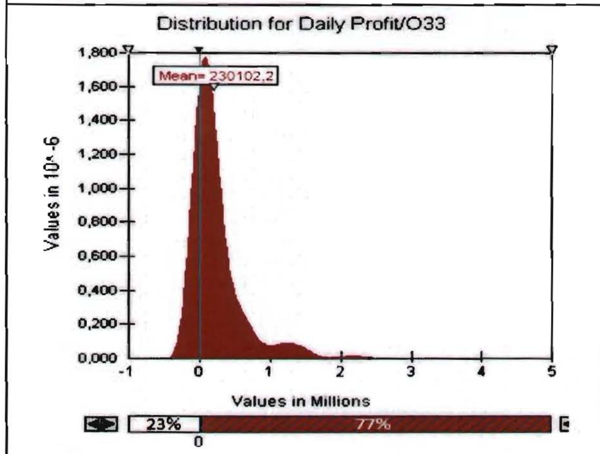
STEP 6: Iterate steps 2 to 5 until the desired simulation length is achieved.

STEP 7: When the simulation finishes, @ risk add-on prepares a simulation report. Built-in tools can be used to develop a distribution function, with average profit and risk values.

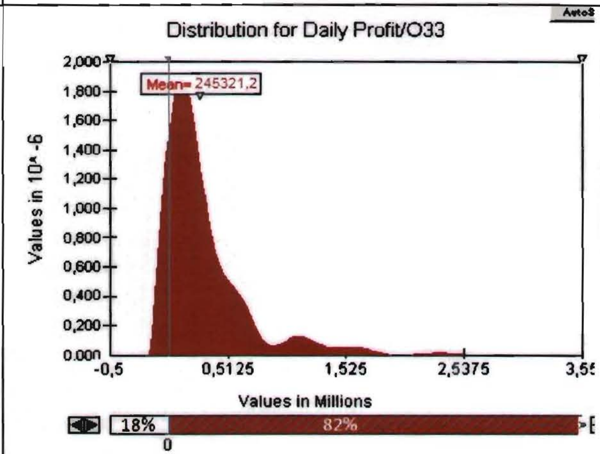


APPENDIX 3: Profit distribution charts

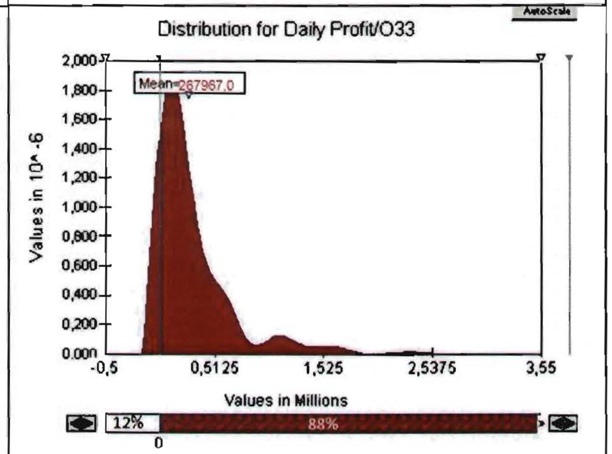
CASE A1: Standard IGCC: Forced to run on full load



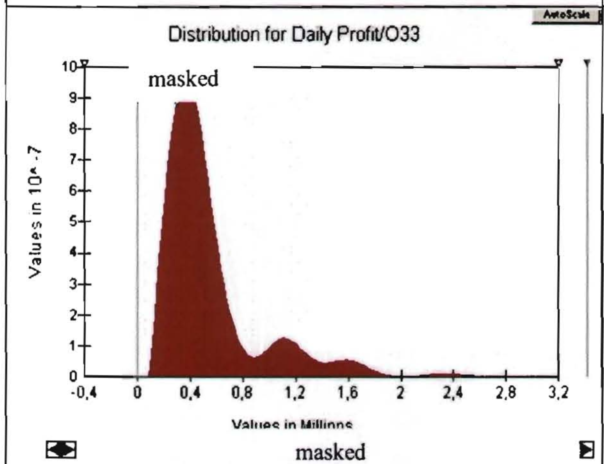
CASE A2: Standard IGCC: No shutdown allowed (except outages)



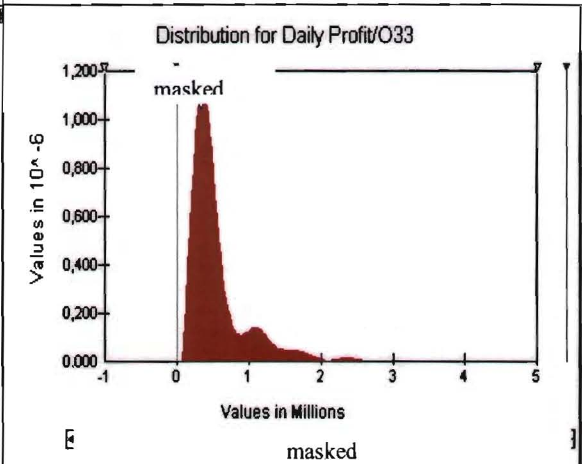
CASE B: Standard IGCC without any schedule restrictions **(BASE CASE)**



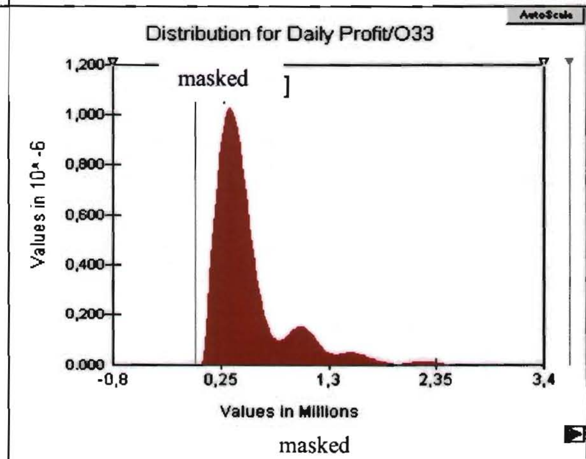
CASE C1: Dual Fuel IGCC: Natural gas backup during gasifier outages

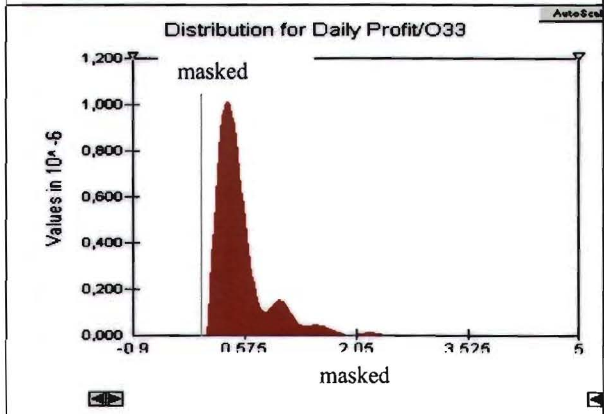
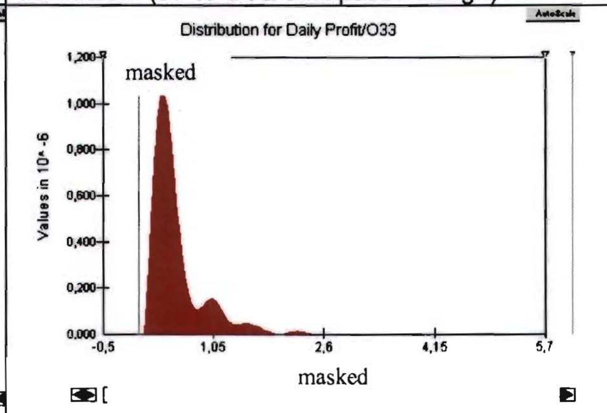
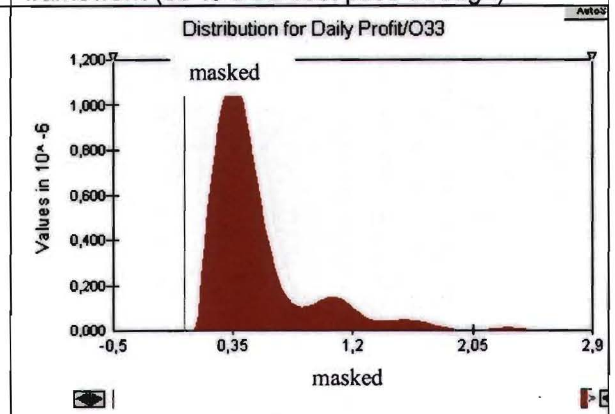
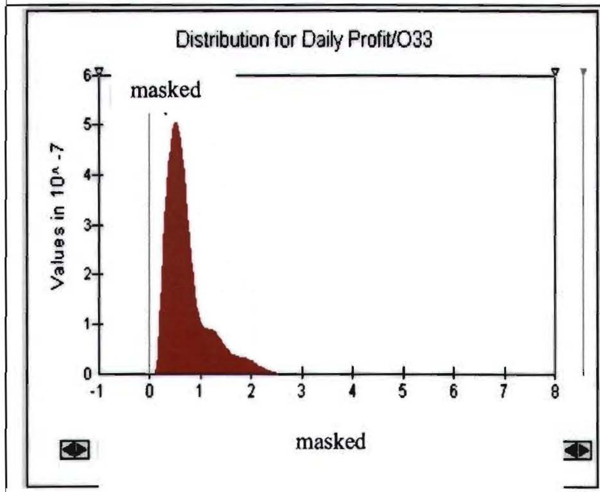
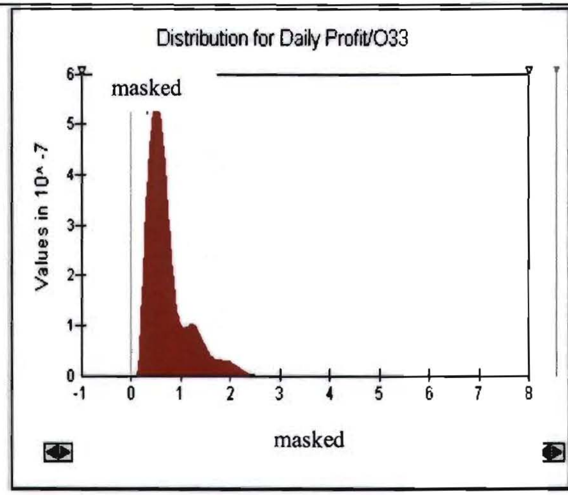
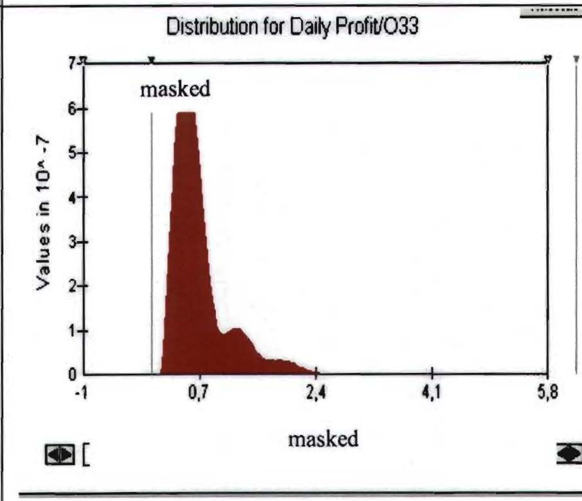


CASE C2: Dual Fuel IGCC: Coal vs. Natural gas arbitrage any time



CASE D: Dual Fuel IGCC: Hydrogen coproduction
25% price discount



CASE D: Dual Fuel IGCC: Hydrogen coproduction No price discount	**CASE D:** Dual Fuel IGCC: Hydrogen coproduction 25% price discount + SMR's part of CO2 framework (50 % CO2 cost pass-through)	**CASE D:** Dual Fuel IGCC: Hydrogen coproduction No price discount + SMR's part of CO2 framework (50 % CO2 cost pass-through)
		
CASE D: Standard IGCC: Hydrogen coproduction 25% more power price volatility	**CASE D:** Dual Fuel IGCC: Hydrogen coproduction 25% more power price volatility + 25% price discount + SMR's part of CO2 framework (50 % CO2 cost pass-through)	**CASE D:** Dual Fuel IGCC: Hydrogen coproduction 25% more power price volatility + No price discount + SMR's part of CO2 framework (50 % CO2 cost pass-through)
		

CASE E: More efficient IGCC (1% point)	CASE F: Fully flexible IGCC: Instant startup times, no startup cost, no minimum efficient load constraints