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ScienceDirect

Energy Procedia 86 (2016) 22 – 31

Energy Procedia

The 8th Trondheim Conference on CO_2 Capture, Transport and Storage

Identifying operational requirements for flexible CCS power plant in future energy systems

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Abstract

This paper aims at a discussion of operational requirements for thermal power plants with carbon capture and storage in terms of their interaction with the power system, in regions with high penetration of variable renewable energy sources. Market opportunities for flexible power plants equipped with carbon capture processes have been discussed. These opportunities comprise day-ahead markets, intraday markets, balancing markets and providing ancillary services for stable operation of the power grid. In addition, technical requirements for power units to provide ancillary services and bidding in different balancing markets in four different power areas in EU have been identified. The identified technical requirements can be used to define scenarios for operational flexibility studies based on dynamic process simulation of thermal power plants with CO_2 capture.

Peer-review under responsibility of the Programme Chair of the 8th Trondheim Conference on CO_2 Capture, Transport and Storage

Keywords: Operational flexibility, ancillary services, balancing, power system, operating reserves, power markets, CO_2 capture;

1. Introduction and scope

The European Union is committed towards a future energy system with reduced greenhouse gas emissions to 80-95% below 1990 levels by 2050. According to the European Commission, a secure, competitive and decarbonized energy system in 2050 is possible [1]. In decarbonized scenarios, electricity will play an increased role, together with renewable energy sources. Nevertheless, the mentioned target will exert intensive pressure on energy systems.

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Peer-review under responsibility of the Programme Chair of the 8th Trondheim Conference on CO_2 Capture, Transport and Storage
doi:10.1016/j.egypro.2016.01.003

Investment models to identify the most cost-effective route towards a decarbonized European power system have been developed by the Zero Emissions Platform. Their results show the requirement of an energy mix combining hydro, wind and solar power, together with a progressive introduction, between 2030 and 2050, of lignite, coal, gas, and biomass power plants with CO_2 Capture and Storage (CCS) [2]. Thermal power plants with CCS at commercial scale will require high capital investments and therefore will need to have high capacity factors along their lifetime in order to be profitable, or receive capacity payments, in addition to other support measures for early deployment [3].

Within a power system with high penetration of variable renewable energies (VRE), thermal power plants tend to operate in cycling mode to follow demand and generation variability. Besides selling energy in day-ahead markets, flexible fossil-fueled power plants acting as mid-merit plants might increase their profit margins by participating in other markets. These markets include intraday power markets, bidding in balancing markets, and providing ancillary services for grid stability. Another interesting option is capacity markets [4], which are out of the scope of this paper.

In recent years, there has been an increased concern of the role that CCS might have in future power systems with high penetration of VRE. Increasing interest has grown in the field of operational flexibility of thermal power plants with carbon sequestration technologies. A report from IEA summarizes several aspects of operational flexibility of different power plant technologies with and without CCS [5].

The scope of this paper is to identify market opportunities for flexible thermal power plants with CCS in different areas of the pan-European power system beyond selling energy in day-ahead markets. In addition, technical requirements for power units to bid in different balancing markets and provide ancillary services have been identified.

Nomenclature

VRE	Variable renewable energy sources
CCS	CO_2 capture and storage
TSO	Transmission system operator
ENTSO-E	European Network of Transmission System Operators
CHP	Combined heat and power
GB	Great Britain
GT	Gas Turbine
ASU	Air Separation Unit

2. Methodology

Results from a day-ahead multi-area power market simulator (EMPS) used for the TWENTIES EU project has been utilized in this paper [6]. The models were previously developed by SINTEF Energy Research. These results are used to plot wind power production and the market-based electric generation dispatch of three different thermal power plants in the Nordic and Continental Europe region. The objective is to illustrate some correlations between wind power production and cycling operation requirements of dispatchable power plants by 2030.

The European Commission has stated the goal of integrating European power markets for making efficient use of energy across national borders. The Network Codes, developed by the European Network of Transmission System Operators for Electricity (ENTSO-E) [7], are meant to overcome the challenge of integrating VRE into the future pan-European power system by 2030. These network codes are currently under development, and after becoming law, power system participants will have to adhere to these codes. These include power system operation, market related codes, and grid connection codes. The technical requirements that can be found in these codes are described as general guidelines. Since each power system has its own flexibility requirements [8], there is room for decision to be made at national level and local TSOs can define specific requirements within the frameworks defined by ENTSO-E.

With the purpose of identifying the technical requirements for grid connection of thermal power plants in current and future power systems, the grid codes of four selected European countries are studied. In addition, requirements for power plants to be able to bid in balancing markets are exposed in Table 1. The selected countries are Spain, Germany, Great Britain (GB), and Denmark.

3. Power system related requirements

Flexibility of a power system is the extent to which the system can modify electricity production or consumption in response to variability. In order to have a stable working system, the balance between supply and demand of electricity must be ensured at different time scales, comprising from milliseconds to seasons [9]. Expected and promoted higher penetration of VRE such as wind and solar will accentuate the challenge of power system balancing.

When considering power system balancing in regions with high penetration of VRE, it is the net load what matters, i.e., the demand curve after subtracting the power generation by VRE. Fluctuations in net load are more frequent and have stronger uncertainty impacts. The main needs for flexibility in the power system are net load fluctuation and uncertainty in contingencies. Main sources that can provide flexibility to ensure balancing at different time scales are dispatchable power plants, demand side management and response techniques, energy storage facilities and interconnection with adjacent markets [8].

Operational flexibility is one of the main challenges for modern thermal power plants. The main technical aspects of operational flexibility of mid-merit thermal power plants are the following:

- Start-up and shutdown sequence (hot, warm and cold).
- Part-load efficiency.
- Minimum stable load turndown with acceptable emission levels.
- Load ramps and reserve capacity for providing grid services.

Adding carbon capture equipment adds complexity to the power plant, with increased process integration and increased number of processes. This requires additional construction material, auxiliary equipment, and more fluid masses providing thermal and pressure inertia. As a result, the performance of the power plant is changed compared to similar plants without CCS. Slower changes in load, transient temperatures and pressure evolutions in the system are expected [10], in addition to a reduction in net plant efficiency. The main impacts of adding the carbon capture system regarding flexible performance of the power plant depend on the technology used [5].

3.1. Day-ahead market

In day-ahead power markets, buyers and sellers bid the volume they are willing to buy or sell for each hour (or possibly other time steps) of the next day (MWh/h) with their respective bidding price (EUR/MWh). The clearing price is stipulated in a so-called marginal price setting, where generation and supply curves intersect. The displacement in the merit order can be explained by the fact that thermal power plants have higher marginal costs of production than wind and solar, which have virtual null marginal costs. Thermal power marginal costs of generation mainly consist of fuel costs and CO_2 emission costs.

Whenever the wind or solar radiation conditions are adequate for power generation, VREs will bid with reduced marginal costs and therefore displace other generation units that otherwise would have been part of the generation schedule for the given hour of the day. Studies using coupled investment and dispatch models of Europe from McCoy et al. [11] show that increased penetration of VRE tend to increase the slope of the net load curve. Consequently, base load and mid-merit capacity power plants reduce their capacity factors in future scenarios with high penetration of VRE. Studies from high wind penetration scenarios in Netherlands by Brouwer et al. [12] explain that extensive integration of VRE may have several impacts in daily operation of power systems: increased demand for reserves, efficiency reduction of thermal power generation, wind curtailment and displacement of thermal power generation in the merit order. In addition, reduced load factors of thermal power plants are expected.

Day-ahead market results of thermal power dispatch from a day-ahead multi-area power market simulator (EMPS) have been utilized in this paper. The main purpose is to illustrate effects of wind power generation in thermal power plants dispatch in future day-ahead markets.

The model includes a detailed system description for Norway, Sweden, Finland, Denmark, Belgium, the Netherlands, Germany and Great Britain, including main transmission bottlenecks in the power system. Some of the model data were developed in TWENTIES EU by SINTEF Energy Research, and a detailed explanation of the

modeling assumptions and purpose of the project can be found in Twenties report task 16.3 [6]. Scenarios are considered for Northern Europe by 2030 with detailed assumptions for generation, transmission and consumption, and their respective development. Thermal power production is modeled by 350 thermal power plants being divided into base load (mainly nuclear and CHP), mid-merit, peaking, and non-dispatchable power plants.

Thermal power plants are modelled by their available generation capacity per week (corrected by an availability factor) and their marginal costs of operation. Main marginal costs of operation are fuel costs and CO_2 emission costs, according to Eq. (1). In the model, fuel costs are considered constant from 2020 to 2030 while CO_2 emission costs were considered to increase from 13 EUR/t by 2010 up to 44 EUR/t by 2030 [6], according to the assumptions made in the IEE-EU Offshore Grid project [13].

$$\text{marginal cost} = \frac{\text{fuel cost}}{\text{fuel efficiency}} + CO_2\,\text{cost} \tag{1}$$

Figure 1 shows wind production and day-ahead market dispatch of three thermal power plants for three consecutive weeks during January 2030; a 308 MW_{el} lignite fired power plant, a 127 MW_{el} coal fired thermal power plant and a 170 MW_{el} gas fueled thermal power plant. It can be observed that there is certain correlation between hours with high wind power production and part load operation or shut down of the thermal power generation plant. The zero marginal costs of VRE places thermal power generation out of production with several hours when the thermal power plants are not producing electricity. These thermal power plants operate in cycling mode i.e., under part load operation and even shutting down and starting-up several times during the time span of three weeks. The results show similar trends to those illustrated by Bruce et al. [14]. The illustrated results depend on the above stated assumptions for fuel and CO_2 emission costs.

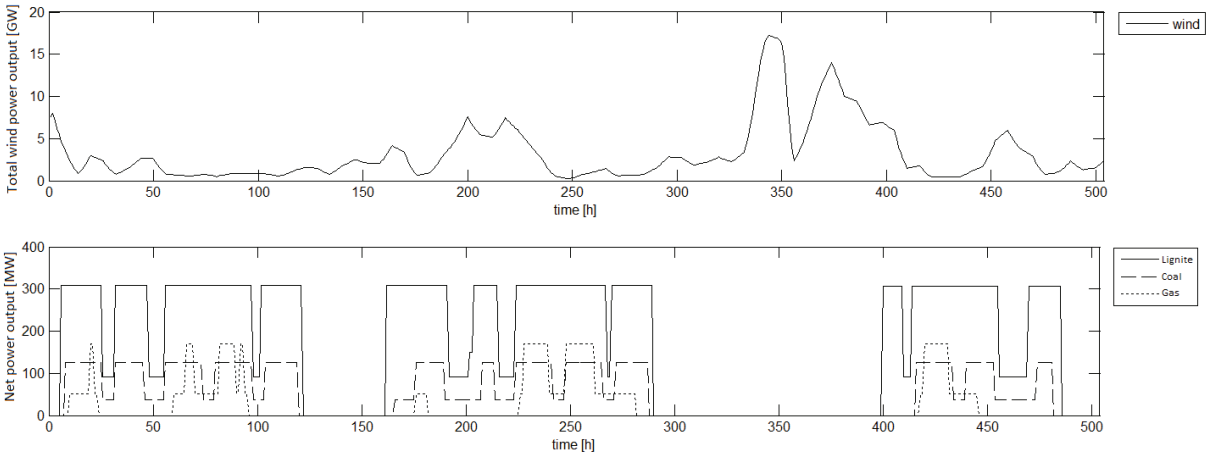

Figure 1. Total wind power production (top) and day-ahead market-based hourly dispatch of three dispatchable thermal power plants (bottom) in Northern and Continental Europe by 2030. The time span is three weeks during winter. Results from EMPS market simulation.

Changing in generation schedule of thermal power plants influences their profit margins. The profit margin is defined as the income due to electricity sold minus the production costs. To make a thermal power plant profitable, the margins should be higher than fixed maintenance and investment costs [6]. This might be a critical aspect for power plants with CCS, since such plants require additional process equipment resulting in increased fixed maintenance and investment costs [15]. Therefore, plant owners should look at other market opportunities beyond selling energy in day-ahead markets to increase their incomes.

3.2. Intraday market

Nowadays, the majority of the volume traded in liberalized wholesale power markets is through the day-ahead market, and balance between demand and supply can be mainly stablished there. However, incidents may occur between the closing of the day-ahead market and real-time, which comprise between 12 and 36 hours. For example, updated wind forecasts can show higher production than expected, while a nuclear or another thermal power plant may stop generating due to a contingency. In intraday markets, buyers and sellers can update their traded volumes closer to real-time. In Nordel, an intraday market known as Elbas is operated by Nord Pool Spot AB. Elbas is a continuous market, where trading takes place anytime around the clock until one hour before real-time. The price is set by matching the highest buying price with the lowest selling price.

As higher penetration of VRE enters into the grid, intraday balancing markets are expected to become more and more important. Trading in intraday markets could be an opportunity for slower flexible resources to improve their profits. It makes sense that thermal power plants with flexible carbon capture technologies operated as dispatchable thermal power plants could bid in these markets. Nevertheless, no specific operating requirements from the power grid are required to bid in such markets.

3.3. Balancing markets

In liberalized power markets, the day-ahead clearing market results in a balance between the expected consumption and the expected power generation. In intraday markets buyers and sellers can update their traded volumes closer to real-time, until around one hour before actual production and consumption. Even closer to real-time, system imbalance between the actual power generation and actual consumption occurs. System balancing is one of the main responsibilities of a transmission system operator (TSO). Power consumers or producers can provide these services. In order to guarantee system stability and security, TSOs must procure and operate the so-called ancillary services. These include frequency response, fast reserve (to provide fast energy to counteract sudden and sometimes unpredictable unbalance between generation and load), black start capability and the provision of reactive power, among others.

Power plants with CCS at commercial scale will likely be designed for capacities above 200 MW_{el}. This means that power plants with CCS would be classified as large generators in most grid connection codes, as it is the case with ENTSO-E codes [7]. Therefore, CCS power plants are likely to participate in providing services for power grid stability.

Power system frequency is a continuously changing variable that is controlled by the second-to-second balance between demand and generation. If generation is greater than demand, the frequency of the system raises, if demand is greater than generation, the system frequency drops. The TSO is in charge of keeping the frequency close to the nominal value within a narrow band. To achieve that, the responsible TSO must ensure that sufficient flexible reserves are available to provide balance between demand and supply close to real-time [16].

Primary reserve or primary frequency response is an automatic change in active power output in response to a frequency change (increase when dropping system frequency or decrease when increasing system frequency) [17]. Synchronized generators make use of automatic speed governors defined by a characteristic droop, as expressed in Eq. 2.

The droop is defined as the “ratio of the steady-state change of frequency (referred to nominal frequency) to the steady-state change in power output (referred to maximum capacity)” [7]. Note that from a control theory point of view the primary frequency control is a proportional regulator. This is meant to limit and stop main system frequency excursions from its set value, however a new steady-state point will be reached [18].

$$s = -\frac{\Delta f / f_{nom}}{\Delta P / P_{nom}} \tag{2}$$

Secondary frequency control is a centralized automatic control that has the function of restoring the system frequency. While primary frequency control limits and stops frequency excursions, secondary control restores the frequency to its set value. The units in the area where the imbalance occurs will participate. Secondary frequency control is not indispensable and thus not all power systems implement it, as it is the case of Great Britain [19].

Tertiary frequency control is utilized for restoring primary and secondary reserves, and to balance large and remaining system imbalance due to forecast errors, failures or other contingencies. It refers to manual changes in the dispatching and commitment of generating units, and it can be used as a mechanism for market participants to balance their financial positions [19]. It means that slower flexible resources than those providing primary and secondary response can also participate in tertiary frequency response [18].

This opens up an opportunity for flexible CCS units to bid in these markets. Main technical requirements for frequency related ancillary services are specified by deployment times [19]:

- Deployment start: maximum amount of time between requests from TSO to start of the response.
- Full availability: maximum time that can elapse between start of the response until the full response is stablished.
- Deployment end: maximum amount of time during which the service must be provided.

Table 1 contains main technical requirements for participating in balancing markets and provide ancillary services by power generation units according to regulations in Spain, Germany, Great Britain and Denmark. Primary frequency response is a mandatory and non-paid service in Spain [20], while being mandatory and paid via a holding payment and an energy payment in GB [17]. In Germany, providers of primary frequency must bid in weekly tenders to provide primary frequency response, and providers of this service will receive a capacity payment [18].

Providing secondary frequency control in Spain requires a deployment start of 30 seconds and full action should be provided within 15 minutes. Providers of this service bid the power band to be increased or decreased together with the energy price when providing that service. The allocation is based on merit order clearing [20]. In Germany, this service is procured with weekly tenders with a minimum bid amount of 5 MW and 1 MW increments, stablished with a pay-as-bid mechanism, being paid capacity and energy produced while providing this service [18]. In GB secondary control as defined above is not implemented [19]. In Denmark, providing secondary frequency control requires an activation time of 30 seconds followed by a full activation within 15 minutes. A capacity payment is stablished via a pay-as-bid method in a monthly basis and energy produced while providing the service is remunerated [21].

Tertiary frequency response in Spain consists of the maximum variation of power that can be sustained for at least 2 hours. The service remuneration price is the marginal price of the allocated bids each hour. Bids are sent the day before and can be updated until 25 minutes of the beginning of the hour [20]. In Germany, the tertiary control reserve is known as minute's reserve, and the provider has to provide the bid MW within 15 minutes [18]. In Great Britain, there are various reserve services differentiated as fast reserve and short term operating reserve [17].

Challenges for providing primary frequency control on CCS power plant should not be more demanding than for conventional thermal power plants. An important question is whether the capture processes can influence the capability of the plant to provide fast enough ramping response to bid a substantial amount of power and provide secondary and tertiary control, and how providing such fast requirements is going to affect operability and controllability of the plant. In addition, parameters such as CO_2 capture ratio can be affected during the transient performance.

Note that primary, secondary and tertiary procured reserves are limited within a given power area. Hence, the CCS flexibility resource must be able to compete with other flexible resources in order to provide ancillary services and bidding in balancing markets.

Operation of a power plant with CCS under different market conditions is of importance. These market conditions comprise fuel prices, CO_2 emission costs, possible CO_2 capture premium payments and electricity prices. Different studies are found in literature, most of them focusing in post-combustion technology [10,14,22,23,24]. These studies can give insight on which market conditions would provide value to plant owners to operate the plant in flexible mode, with different plant operation strategies.

Table 1. Technical requirements framework for generating units to provide ancillary services and bid in balancing markets in Spain, Germany, GB, and Denmark.

Area	TSO	Primary reserve	Secondary reserve	Tertiary reserve
Spain [20]	Red Eléctrica de España (50 Hz)	*Primary regulation* Mandatory for all generation units. Load change of 1.5% of nominal (0<t<15 sec) for frequency changes ≤100 mHz. Lineal from 15<t<30 sec. Non-paid service.	*Secondary regulation* Automatic and hierarchical control. Start ≤ 30 sec from notice and full action in 15 min. Licensed generation units bid power band to be increased and reduced (MW) and power band price (€/MWh). Reserve allocation based on economic merit order. Uniform price.	*Tertiary regulation* Maximum variation of power within 15 min. that deployment end of at least 2 h. Bids sent the day before and updated until 25 min. before the beginning of the hour. *Slow reserve* Running reserves of connected thermal units providing power output in 30 min. and can be sustained up to 4-5 hours.
Germany [18]	Amprion 50 Hertz TenneT TSO EnBW Transportnetze (50 Hz)	Primary reserve TSO responsible for provision of primary regulation required for its area. 30 sec to be activated. Weekly tender period (competitive bidding). Minimum bid amount 1 MW (1 MW increment). Call for tender as capacity price merit-order. Remunerated as pay-as-bid.	Secondary reserve Should be activated after 30 sec. from call and achieve full response within 5 minutes. Sustained 15 min. Weekly tender period. Minimum bid amount 5 MW (1 MW increment). Positive and negative differentiation. Energy price merit-order. Pay-as-bid (Capacity price and energy price).	*Minutes reserve* Activated in quarterly hour intervals if needed. Complete activation within 15 min. Sustained for t>15 min up to several hours. Daily tender period. Minimum bid amount (blocks of maximum 25 MW with 1 MW increment). Energy price merit-order. Pay-as-bid (Capacity price and energy price).
GB [17]	National Grid (50 Hz)	*Primary* Mandatory for large units ≥ 100MW. Droop 3-5%. Active power provided within 10 sec. and sustained for further 20 sec. Holding Payment (£/h). Monthly basis price. Response energy payment (£/MWh). *Secondary* Mandatory for large units ≥ 100 MW. Droop 3-5%. Active power provided within 30 sec. and sustained for further 30 min. Capacity Payment (£/h). Response energy payment (£/MWh).		*Fast reserve* Dispatch instruction from TSO. Must start after 2 min. of dispatch instruction. Delivery rate in excess of 25 MW/min. Full response sustained for a minimum of 15 min (min. 50 MW). Monthly procurement. Availability fee (£/h) and utilization fee for energy delivered ((£/MWh).
Denmark **(Western)** [21]	Energinet.dk (50 Hz)	*Primary reserve* Droop normal operation 4-6% at 50±0.1 Hz. Daily auction in six equally divided blocks. Marginal price principle for capacity payments.	*Secondary reserve* Activation time of 30 sec. Full activation 15 min. Monthly pay-as-bid method for capacity payment. Energy payment.	*Manual reserve* Daily auctions The reserve must be able to be provided within 15 minutes.

4. Discussion

An assessment of potential flexibility of power plants with CCS by IEA Greenhouse Gas R&D Program summarizes main flexibility issues and reviews suggested strategies to provide flexibility [5]. The main impacts of adding the carbon capture system regarding flexible performance of the power plant depend on the technology used.

Conventional NGCC and ultra-super critical pulverized coal power plant (USC PC) have good cycling properties, with relatively short hot start-up and fast load changes together with good part-load efficiency and low minimum turndown. However, adding a post-combustion capture unit to these power plants can impose bottlenecks for turndown (due to the minimum CO_2 compressor load of 70%, and the capture unit minimum load [5]). In addition, longer start-up time due to the need for regenerator preheating can extend the start-up process. To the extent of the authors' knowledge, effects on transient performance during load changes are still unclear, due to the lack of transient data from actual large-scale plants.

Several options have been proposed to operate flexible thermal power plants equipped with post-combustion capture in order to provide peak electricity when electricity prices are high, and to participate in providing ancillary services. Three main options are [5]:

- Varying the CO_2 capture rate, depending on electricity prices and CO_2 costs.
- Turning on and off the CO_2 capture unit and providing solvent storage to decouple plant operation (boiler or GT) from the CO_2 capture.
- Allowing the power plant to increase or decrease load, following its own ramp up or down rates.

The first option is also known as flue gas bypass, which consists of stopping the CO_2 capture plant and venting the CO_2, therefore increasing plant net power output by reducing the energy penalty. E. Delarue et al. [15] discusses that profit maximization by using this option depends on the ratio of electricity selling price and CO_2 emission allowances price. At relatively high CO_2 emission prices, the cost of emitting CO_2 can offset the benefit from flexible operation, and therefore capturing CO_2 becomes more interesting. It also discusses the option for providing ancillary services, assuming that the plant is fast enough to provide substantial amount of power within the typical 15 minutes framework for full activation. Their sensitivity studies conclude that only at relatively low CO_2 emission prices this operation mode could be profitable and competitive against open cycle gas turbines to provide ramp-up reserve, in the case of power shortage. Therefore, this option might be interesting for implementation under policies that support CO_2 carbon capture implementation without extensive CO_2 emission price increase [22].

Another suggested option to provide net power flexibility in post-combustion capture power plants is the use of solvent storage to decouple the absorption and desorption processes storing rich solvent during peak electricity demand to delay the energy penalty to times with low electricity price. This option would be profitable if relatively high profits are obtained, since further capital investment is to be expected due to the need for storage vessels, more solvent inventory and larger compression and stripper equipment [10] [23].

Several technical challenges remain in order to make this technology attractive. Among them, and as stated by K. Jordal et al. [24], there is need for research for understanding part load operation and behavior of a power plant with integrated post-combustion capture of CO_2, as well as understanding the dynamic interaction between the capture process unit and the power plant during start-up, load change and shut-down.

Regarding oxy-combustion power plants there are different options due to different process schemes proposed in literature, but most flexibility studies discuss the possibility of bypassing flue gas before the purification and compression processes, or making use of intermediate storage of liquid O_2 between the cryogenic air separation unit (ASU) and the combustion process.

Bypassing the flue gas just before the CO_2 compression process, therefore the energy for compression can be used to provide electricity, with the penalty of higher CO_2 emissions. With liquid oxygen storage, the oxygen production is switched towards hours with low electricity prices, to switch off the ASU during peak electricity prices and gain the extra power for running the ASU (mainly the air compression process). Similar to post-combustion, bypassing is only profitable if the relationship between electricity selling price and CO_2 emission certificates is high. Oxygen storage can be an interesting option if sufficient profits are obtained during peak hours to pay-off the increased capital investment [10]. The air separation unit is the main component affecting the cyclic performance of oxy-combustion

power plants using ASU due to its minimum turndown of around 50% and its slow start-up and relatively slow ramp rate 3%/min [5].

Despite of the potential greater income obtained by plant owners in the short term due to a cyclic operating mode, a reduction of lifetime of the most critical components is likely to occur, due to thermo-mechanic fatigue loadings together with creep loads, corrosion and erosion mechanisms [25]. This causes accelerated ageing, and therefore additional costs related to unplanned maintenance and unavailability of the plant due to outages [26].

Due to the necessity to evaluate the plant performance under transient operation and the scarce availability of transient performance data from commercial scale plants with CCS, an increasing interest has grown during recent years in the field of dynamic modeling, simulation and optimization of thermal power plants with CCS [27].

Simulations from properly validated models can give insight on which are the bottlenecks for different transient operations of power plants, developing proper plant control strategies and assesses the feasibility of different strategies for flexible operation of the power plant, during the design phase. The requirements collated in Table 1 can be utilized to define market-based scenarios for dynamic process simulation studies, regarding ancillary services provision.

It might be done by considering activation start, full availability and deployment end times. Valuing the flexible operation of a power plant with CCS under different market conditions is of importance. These market conditions comprise fuel prices, CO_2 emission costs, possible CO_2 capture premium payments and electricity prices. Different studies are found in literature, most of them focusing in post-combustion technology [10,14,22,23,24]. These studies can give insight on which market conditions would provide value to plant owners to operate the plant in flexible mode, with different plant operation strategies.

5. Conclusions

An increased interest has arisen within the last years concerning the role that CCS power plants might have in future energy systems with high penetration of variable renewable energies. Such power plants might be operated as load following plants forced by market conditions and power system operation requirements. According to the results from an EMRS day-ahead market simulation in Northern and Continental Europe by 2030, thermal power plants tend to operate in cycling mode i.e., under part load operation and even shutting down and starting-up several times along three winter weeks. It means that thermal power plants are being displaced in the merit order in scenarios with high penetration of variable renewable energies. Hence, plant operators should look at further opportunities beyond selling energy in day-ahead markets in order to increase their profits. Intraday markets have been identified as especially interesting markets for power plants with CCS since slower flexible resources can have a chance in these growing markets. Nonetheless, no specific operating requirements from the power grid are required to bid in intraday markets.

Technical grid requirements and frameworks for power units to provide ancillary services and bidding in balancing markets in four different power areas in EU have been identified. The areas comprise Spain, Germany, GB, and Western Denmark. These requirements can be utilized to define market-based scenarios for dynamic process simulation studies, considering activation start, full availability and deployment end times. These scenarios will reflect today's requirements for providing the mentioned flexibility services.

Future work should consist of the development of dynamic process simulation models of power plants with carbon capture technologies. These models must be validated against plant data to the greatest extent possible. Simulation from plant models will be utilized to study the flexible operation of the plant and implications of adding capture technology on the plant controllability and capture plant transient performance. In addition, the models might help to identify possible bottlenecks for transient performance under different transient scenarios, and the possible implications on the power plant design. The transient scenarios should include transient performance on load changes and strategies for providing ancillary services, defining the scenarios by using the requirements identified in this paper. Current work comprises the ongoing development of dynamic process models for a Natural Gas Combined Cycle power plant with post-combustion CO_2 capture.

Acknowledgements

The authors would like to acknowledge the Department of Energy and Process Engineering at the Norwegian University of Science and Technology for funding this project.

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