Linear Models for Optimization of Infrastructure for CO_2 Capture and Storage

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***Abstract*—This paper presents linear models of the most common components in the value chain for CO_2 capture and storage. The optimal investment planning of new gas power plants traditionally includes the cost of fuel versus sales of electricity and heat from the plant. If a new power plant also causes additional investments in gas infrastructure, these should be included in the optimization. With the increasing focus on global CO_2 emissions, yet another aspect is introduced in the form of technology and infrastructure for capture, transport, and storage of CO_2. To be able to include all these aspects in the planning of new power plants, linear models for CO_2 capture and storage are formulated consistent with current models for gas, electricity, and heat infrastructures. This paper presents models for the following CO_2 infrastructure: source, combined cycle gas turbine producing electricity, heat and exhaust, capture plant, pipeline, liquefaction plant, storage, ship transport, injection pump, and demand/market.**

***Index Terms*—CO_2, carbon dioxide capture and storage (CCS), linear programming (LP), power system planning.**

I. Introduction

CO_2 emissions are the largest contribution to the greenhouse gasses released from human activities. The CO_2 level in the atmosphere has increased from 280 to 375 ppm since preindustrial times [1]. This is an increase of approximately 30% and there are currently few indications of a slow down. As the world is experiencing the consequences of global warming, there is a huge growth in the global energy demand. Especially, the Asian economies are growing rapidly leading to an almost exponential increase in energy consumption. For example, in 1973, China was responsible for only 5.7% of the world's total CO_2 emissions whereas they were responsible for 15% in 2003 [2].

Meeting the world's accelerating energy demand while stabilizing the CO_2 concentration in the atmosphere will be a great challenge. There are many ways to reduce the CO_2 emissions to the atmosphere, including switching to low-carbon and renewable fuels, using natural CO_2 sinks (forests, agriculture, etc.), reducing energy demand, etc. However, almost 50% of the future increase in CO_2 emissions is expected to come from large-scale power generation, implying that considerable amounts of CO_2 are produced in large stationary locations. This paper focuses on the capture and storage of CO_2 [*Carbon dioxide Capture and Storage* (CCS)] as an alternative that may be implemented in large scale in the near future.

The concept of CCS involves CO_2 capture from stationary emitters like power plants and industries along with transportation to long-term storage where the CO_2 is isolated from the atmosphere for a sufficiently long time. Possible long-term storage alternatives include depleted oil and gas reservoirs, enhanced oil recovery (EOR) in live reservoirs, unmineable coal seams, deep saline formations, and ocean storage.

A number of surveys show that there are enormous capacities for CO_2 storage in geological formations around the world. A study done by British Geological Survey in 1996 predicts about 800 billion tonne capacity for deposition of CO_2 in Northern Europe alone [3]. This is sufficient to store more than 30 years of today's global emission level [1]. The CO_2 injection into geological formations for EOR has been done for more than 30 years and can be characterized as a mature technology. It is perhaps the most likely method to be used in the introduction phase of a large-scale CCS program because the increased production of oil makes it economically interesting. Once the infrastructure and technology is in place, it might be utilized for storage long after the oil production is closed down.

Even though technologies for CO_2 capture, transport, and storage exist, there are no large-scale CCS chains in operation today. Several research projects and small-scale demonstration plants are being developed and there are a number of possible large-scale CCS projects being planned in Australia, Germany, United Kingdom, Norway, and the United States among others. Previous publications on CCS, however, mostly deal with specific technologies for capture, transport, or storage of CO_2, and very few consider development paths for several alternative transport scenarios [4].

The purpose of this paper is to develop a methodology to analyze how location, size, and/or timing of investments in fossil fueled power plants might be influenced by alternative technologies and infrastructures for CCS. To be able to include all these aspects in the same investment optimization, the paper formulates linear models for CCS infrastructure that are consistent with models for gas, electricity, and heat infrastructures. The purpose of the modeling is not to provide a detailed design tool for CCS solutions but to establish a mathematical framework that will enable decision makers to compare different design options in a systematic way.

The paper is organized as follows. Section II gives a brief overview of the eTransport optimization model and the network structure of multicommodity flows, Section III presents the linear programming (LP) formulations of CCS technologies, Section IV presents main results from a case study used

Manuscript received October 16, 2007; revised October 23, 2007. This work was supported in part by the Research Council of Norway. Paper no. TEC-00398-2007.

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Digital Object Identifier 10.1109/TEC.2008.921474

to test the models, while Section V contains summary and conclusions.

II. eTRANSPORT MODEL

The optimization model "eTransport" is developed for expansion planning in energy systems where several alternative energy carriers and technologies are considered simultaneously [5]–[7]. The model uses a detailed network representation of technologies and infrastructure to enable identification of single components, cables, and pipelines. The current version optimizes investments in infrastructure over a planning horizon of 10–30 years for most relevant energy carriers and conversion between these. It is not limited to continuous transport like lines, cables, and pipelines, but can also include discrete transport by ship, road, or rail.

The model is separated into an *operational model* (energy system model) and an *investment model* [7]. In the operational model, there are submodels for each energy carrier and for conversion components. The operational planning horizon is relatively short (1–3 days) with a typical time step of 1 h. The operational model finds the cost-minimizing diurnal operation for a given infrastructure and for given energy loads. Annual operating costs for different energy system designs are calculated by solving the operational model repeatedly for different seasons (e.g., peak load, low load, intermediate, etc.), investment periods (e.g., five-year intervals), and relevant system designs. Annual operating and environmental costs for all different periods and energy system designs are then used by the *investment model* to find the investment plan that minimizes the present value of all costs over the planning horizon.

Mathematically, the model uses a combination of LP and mixed integer programming (MIP) for the operational model, and dynamic programming (DP) for the investment model. The operational model is implemented in the AMPL programming language with CPLEX as solver [8], while the investment model is implemented in C++. A modular design ensures that new technology modules developed in AMPL for the operational model are automatically embedded in the investment model. A full-graphical windows interface is developed for the model in MS Visio. All data for a given case are stored in a database.

The submodels for different components are connected by general energy flow variables that identify the flow between energy sources (*Supply_points*), network components for transport, conversion and storage (*Network_nodes*), and energy sinks like loads and markets (*Load_points*). The connections between supply points, network nodes, and load points are case specific, and they are identified by sets of pairs where each pair shows a possible path for the energy flow between component types:

Supply2net : Set of pairs (i, j) where $i \in$ *Supply_points* and $j \in$ *Network_nodes*
Supply2load : Set of pairs (i, j) where $i \in$ *Supply_points* and $j \in$ *Load_points*
Net2net : Set of pairs (i, j) where $(i, j) \in$ *Network_nodes*
Net2load : Set of pairs (i, j) where $i \in$ *Network_nodes* and $j \in$ *Load_points.*

General energy flow variables are defined over the energy system structure to account for the actual energy flow between different components (except for internal flow within each model). These general variables are included in and restricted by the various models and they are the link between the different models:

$Supply\_flow_{ijt}$: Energy flow from i to j at t where $(i, j) \in$ *Supply2net* and $t \in$ *Time_steps*
$Local\_flow_{ijt}$: Energy flow from i to j at t where $(i, j) \in$ *Supply2load* and $t \in$ *Time_steps*
$Net2net\_flow_{ijt}$: Energy flow from i to j at t where $(i, j) \in$ *Net2net* and $t \in$ *Time_steps*
$Load\_flow_{ijt}$: Energy flow from i to j at t where $(i, j) \in$ *Net2load* and $t \in$ *Time_steps.*

In the following mathematical formulation, these flow variables are identified by the superscripts "Sup", "Loc", "*N2N*" and "*Ld*", respectively.

In the *operational model*, the different technology models are added together to form a single linear optimization problem where the object function is the sum of the contributions from the different models, and the restrictions of the problem include all the restrictions defined in the models. Emissions are caused by a subset of components (power plants/combined heat and power plants (CHP), boilers, road/ship transport, etc.) that are defined as emitting CO_2, NOx, CO, and SOx. Further environmental consequences can be defined. Emissions are calculated for each module and accounted for as separate results. When emission penalties Pen^{Em} are introduced by the user (e.g., a CO_2 tax), the resulting costs are included in the objective function and thus added to operating costs.

The task for the *investment model* is to find the optimal set of investments during the period of analysis, based on investment costs for different projects and the precalculated annual operating costs for different periods and states. The optimal investment plan is defined as the plan that minimizes the discounted present value of all costs in the planning period, i.e., operating costs plus investment costs minus the rest value of investments. The optimal plan will, therefore, identify the optimal design of the energy system (i.e., the optimal state) in different periods. More details of the investment algorithm in eTransport can be found in [7].

III. CCS TECHNOLOGIES IN eTRANSPORT

The only flow variable in the original version of eTransport was *energy* (in megawatthours per hour) flowing from one node to another. When components for CCS are included this introduces the transportation of *mass* (in tonnes per hour). One of the main challenges of this paper has been to include such mass flow in the network structure, transforming eTransport into a multicommodity optimization model.

Furthermore, most of the components require energy to be able to operate. The current (energy) components may consume a given fraction of the energy that flows through them but the same method cannot be used for CCS components; e.g., it is not possible to use CO_2 boiloff to run a CO_2 ship. Hence, the new

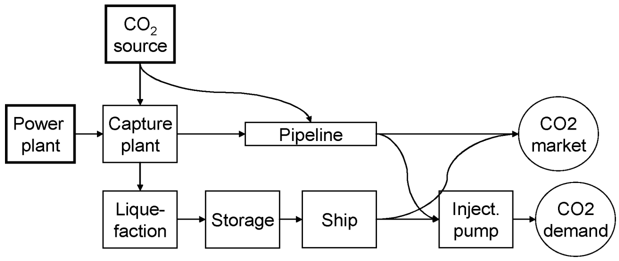

Fig. 1. Simplified CO_2 value chain implemented in eTransport [9].

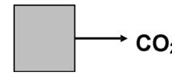

Fig. 2. Symbolic picture of CO_2 or exhaust source.

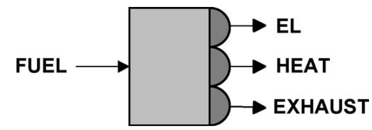

Fig. 3. Symbolic picture of power plant.

components need an energy supply in addition to the input and output flows of CO_2.

Fig. 1 shows the CO_2 technologies currently implemented in eTransport [9]. Note that each technology is displayed only once in this simplified graph, while in a real value chain, e.g., intermediate storage components may be used in several locations. The ten new models are listed next.

1) *Source*: CO_2 or exhaust gas that is bought at the system boundary (from power plants or industry) at a price defined by the user.
2) *Power plant*: Gas fired power plant producing electricity, heat, and exhaust with a certain CO_2 concentration.
3) *Capture plant*: Industrial plant where an exhaust gas goes in with a user-defined CO_2 concentration. The CO_2 is separated from the exhaust and a pure CO_2 flow continues along the value chain.
4) *Pipeline transport*: Transportation in large pipelines including compressors to reach required pressure level for dense phase CO_2 transport through the pipes.
5) *Liquefaction plant*: Before storage or transfer by the ship, the CO_2 is liquefied to increase its density.
6) *Storage*: Intermediate storage capacity is necessary, e.g., between each ship load. Storage facilities can also be used while waiting for better market prices for CO_2.
7) *Ship transport*: Transportation of CO_2 by the ship is actually a discrete process, but is currently represented as an average flow to simplify the model.
8) *Injection pumps*: Pumps and equipment needed offshore in order to inject the CO_2.
9) *Demand*: A need for CO_2, for instance, a demand for a certain amount CO_2 used for EOR.
10) *Market*: A market where CO_2 can be sold at a price defined by the user. The price can also be given as a negative number, implying a cost to dispose CO_2.

The following sections present the LP formulations for each of these components consistent with the network structure of the eTransport model. Due to space limitations, only the main LP equations are shown while standard formulations like non-negativity of variables, etc., are omitted.

A. CO_2 Source

The CO_2 source can represent pure CO_2 captured outside the boundary of the system, or it can be exhaust gas with a given CO_2 fraction from power generation or industry that must be connected to a capture plant and separated before being transported to some load or market. The symbolic source model in eTransport is illustrated in Fig. 2.

There is only one node attached to the source and one possible flow of CO_2 out of the source. Hence, the supply has only one decision variable representing the usage of CO_2, $U_{st}^{\mathrm{CO_2}}$. Equation (1) shows how the cost of the CO_2 supply is calculated. A positive cost parameter implies that the CO_2 is bought from the source at a given price while a negative cost means that the supplier is willing to (or obliged to) pay for the CO_2 disposal:

$$C^{\mathrm{CO_2\_sup}} = \sum_{t\in\mathrm{Time\_steps}} \left(\sum_{s\in\mathrm{Supply\_points(CO2)}} c_{st}^{\mathrm{CO_2}} U_{st}^{\mathrm{CO_2}} \right) \quad (1)$$

where

$c_{st}^{\mathrm{CO_2}}$ specific cost of CO_2 from source *s* at time t (in US dollar per tonne per hour);

$U_{st}^{\mathrm{CO_2}}$ use of CO_2 from source *s* at time t (in tonnes per hour).

Note that the use of CO_2 in (1) is measured in (in tonnes per hour), and enters the system as a *mass flow M* (in tonnes per hour). This mass is either flowing further into the network, (*s, i*) ∈ *Supply2net,* or to a local CO_2 load connected directly at the source (*s, l*) ∈ *Supply2load*:

$$U_{st}^{\mathrm{CO_2}} = \sum_{i:(s,i)\in\mathrm{Supply2net}} M_{\mathrm{sit}}^{\mathrm{Sup}} + \sum_{l:(s,l)\in\mathrm{Supply2load}} M_{\mathrm{slt}}^{\mathrm{Loc}} \quad (2)$$

where

$M_{\mathrm{sit}}^{\mathrm{Sup}}$ mass flowing from supply node *s* to network node(s) i (in tonnes per hour);

$M_{\mathrm{slt}}^{\mathrm{Loc}}$ mass flowing from supply node *s* to local load(s) *l* (in tonnes per hour).

B. Power Plant

In order to use CO_2 capture as a separate (postcombustion) technology in eTransport, a CHP plant model is modified to yield exhaust gas as a separate output, see Fig. 3. Alternative solutions for CO_2 capture like precombustion or oxyfuel are currently not implemented.

The cost of fuel used by power plants and other technologies in eTransport is normally allocated to the source(s) at the system border as seen in (1). The cost function for combined cycle gas turbine (CCGT) power plants without CO_2 capture (CC_*nocap*) thus consists only of a start-up cost and penalties for emissions:

$$C^{\mathrm{CC\_nocap}} = \sum_{t \in \mathrm{Time\_steps}} \sum_{p \in \mathrm{Nocaps}} \left[c_p^{\mathrm{Start}} \mathrm{Start}_{pt} + \sum_{e \in \mathrm{Emissions}} \mathrm{Pen}_{pe}^{\mathrm{Em}} \mathrm{Emit}_{ept} \right] \quad (3)$$

where

$$\mathrm{Start}_{pt} \geq \mathrm{Run}_{pt} - \mathrm{Run}_{p,t-1} \quad (4)$$

$$\mathrm{Emit}_{ept} = \varepsilon_{pe} F_{pt}^{\mathrm{CC\_nocap}} \qquad \forall e \in \mathrm{Emissions} \quad (5)$$

ε_{ep} coefficient for emission type *e* (in tonnes per megawatthour);
c_p^{Start} start-up cost for the plant (in US dollar per start);
Run_{pt} binary variable (1 when running, 0 when not);
$\mathrm{Pen}_{pe}^{\mathrm{Em}}$ penalty for emission *e* from plant *p* (in US dollar per tonne).

The fuel consumed by the power plant *p*, $F_{pt}^{\mathrm{CC\_nocap}}$, is delivered either directly from a source *(s,p)*∈*Supply2net*, or from energy infrastructure (e.g., gas pipeline) included in the model *(n,p)*∈*Net2net*. The fuel balance for the plant is thus expressed in a similar way as the mass flow in (2):

$$F_{pt}^{\mathrm{CC\_nocap}} = \sum_{s:(s,p) \in \mathrm{Supply2net}} F_{spt}^{\mathrm{Sup}} + \sum_{n:(n,p) \in \mathrm{Net2net}} F_{npt}^{N2N}. \quad (6)$$

The heat to power ratio α_p^{Heat} is a function of the heat temperature t as shown in (7). The expression is derived from simulations of incremental power reduction with variation in steam temperature and pressure [11]. The value is applied in (8) where the relation between electricity and heat production from fuel input is decided:

$$\alpha_p^{\mathrm{Heat}} = -5 \times 10^{-6} T^2 + 3 \times 10^{-3} T - 0.1023 \quad (7)$$

$$\eta_p F_{pt}^{\mathrm{CC\_nocap}} = P_{pt}^{\mathrm{CC\_nocap}} + \alpha_p^{\mathrm{Heat}} Q_{pt}^{\mathrm{CC\_nocap}} \quad (8)$$

where

η_p maximum efficiency for electricity production;
$P_{pt}^{\mathrm{CC\_nocap}}$ produced electricity (in megawatts);
$Q_{pt}^{\mathrm{CC\_nocap}}$ produced heat (in megawatts).

The emission of exhaust from the power plant (in tonnes per hour) is proportional to the fuel consumption. Equivalent to (2), this mass is either distributed further into the network, *(p,n)*∈*Net2net,* or to an exhaust/CO_2 load directly connected to the plant *(p,l)*∈*Net2load*)

$$M_{pt}^{\mathrm{Exh}} = \mu_p^{\mathrm{Gas}} F_{pt}^{\mathrm{CC\_nocap}} = \sum_{n:(p,n) \in \mathrm{Net2net}} M_{pnt}^{N2N} + \sum_{l:(p,l) \in \mathrm{Net2load}} M_{plt}^{Ld} \quad (9)$$

where μ_p^{Gas} is the CO_2 emissions from fuel (in kilograms per megawatthour); default value 194 [1].

C. CO_2 Capture Plant

Postcombustion CO_2 capture is a technology to separate CO_2 from exhaust gas, usually with chemical absorption. The exhaust

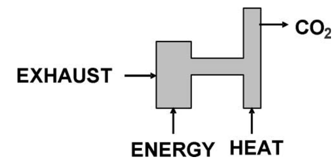

Fig. 4. Symbolic picture of CO_2 capture plant.

gas is brought in contact with an amine absorbent that ties up CO_2 and allows CO_2 free exhaust to be vented to air. The CO_2 rich amine then has to be heated to reduce the ability to tie up CO_2 and the pure CO_2 is released ("stripped"). As Fig. 4 shows, the capture plant needs mechanical energy in the absorber and heat in the stripper to separate CO_2 from the exhaust. The capture plant model is designed to enable CO_2 separation from various CO_2 emitters, including industrial emission sources, as long as the CO_2 concentration of the exhaust is known.

The cost function for CO_2 capture plants (CO_2*_cap*) is formulated as a function of input mass flow $M_{pt}^{\mathrm{CO_2\_cap}}$ and emission penalties

$$C^{\mathrm{CO_2\_cap}} = \sum_{t \in \mathrm{Time\_steps}} \sum_{p \in \mathrm{Captures}} \left[c_p^{\mathrm{TOT}} M_{pt}^{\mathrm{CO_2\_cap}} + \sum_{e \in \mathrm{Emissions}} \mathrm{Pen}_{pe}^{\mathrm{Em}} \mathrm{Emit}_{ept} \right] \quad (10)$$

where the total operational cost c_p^{TOT} is calculated as the sum of a flow-dependent cost and a function of the use of chemicals in the process:

$$c_p^{\mathrm{TOT}} = c_p + \sum_{k \in \mathrm{Chemicals}} c_{kp} m_{kp}^{\mathrm{CO_2\_cap}} \quad (11)$$

where

c_p operating cost (in US dollar per tonne CO_2);
c_{kp} cost of chemical *k* (in US dollar per kilogram chemical);
$m_{kp}^{\mathrm{CO_2\_cap}}$ mass required of chemical *k* (in kilograms chemical per tonne CO_2).

There are minor emissions from the capture plant during operation, but these are overshadowed by the CO_2 emissions during periods when the plant is not in operation, when all the received CO_2 is emitted directly to the atmosphere (unless some kind of temporary storage is installed). Thus,

$$\mathrm{Emit}_{ept} \approx \mathrm{Emit}_{\text{'}\mathrm{CO_2}\text{',pt}} = (1 - \tau_p \varsigma_p) M_{pt}^{\mathrm{CO_2\_cap}} \quad (12)$$

where

τ_p utilization rate;
ς_p cleaning fraction.

The CO_2 (or exhaust) that flows into the capture plant may originate directly from one or more CO_2 sources or from one or more power plants included in the model, and is expressed similar to the fuel input in (6):

$$M_{pt}^{\mathrm{CO_2\_cap}} = \sum_{s:(s,p) \in \mathrm{Supply2net}} M_{spt}^{\mathrm{Sup}} + \sum_{n:(n,p) \in \mathrm{Net2net}} M_{npt}^{N2N}. \quad (13)$$

The CO_2 output from the capture plant is proportional to the utilization rate τ_p and the cleaning fraction ζ_p, and is either distributed further into the model network or delivered directly to a load at the capture plant as in (9):

$$\mathrm{M\_out}_{pt}^{\mathrm{CO_2\_cap}} = \tau_p \varsigma_p M_{pt}^{\mathrm{CO_2\_cap}} = \sum_{n:(p,n)\in \mathrm{Net2net}} M_{pnt}^{N2N} + \sum_{l:(p,l)\in \mathrm{Net2load}} M_{plt}^{Ld}. \tag{14}$$

The capture plant needs both mechanical energy (in absorber and pumps) and heat (in stripper) to operate. This energy is supplied either directly from sources or other network elements similar to (6):

$$W_{\mathrm{pt}}^{\mathrm{Mech\_Cap}} = \left[w_p^{\mathrm{Abs}} + w_p^{\mathrm{Pump}} \varsigma_p\right] \tau_p M_{pt}^{\mathrm{CO_2\_cap}} = \sum_{s:(s,p)\in \mathrm{Supply2net}} \eta_{sp} F_{spt}^{\mathrm{Sup}} + \sum_{n:(n,i)\in \mathrm{Net2net}} \eta_{np} F_{npt}^{N2N} \tag{15}$$

where
- w_p^{Abs} mechanical work in absorber (in megawatthours per tonne);
- w_p^{Pump} pump work between absorber and stripper (in megawatthours per tonne);

$$\eta_{sp}, \eta_{np} \in \left\{\eta^{'El'}, \eta^{'\mathrm{Gas}'}, \eta^{'\mathrm{Oil}'}\right\}$$

$$W_{\mathrm{pt}}^{\mathrm{Heat\_Cap}} = w_p^{\mathrm{Heat}} \tau_p M_{pt}^{\mathrm{CO_2\_cap}} = \sum_{s:(s,p)\in \mathrm{Supply2net}} W_{spt}^{\mathrm{Sup}} + \sum_{n:(n,p)\in \mathrm{Net2net}} W_{npt}^{N2N} \tag{16}$$

where w_p^{Heat} is the heat required in stripper (in megawatthours per tonne).

D. CO_2 Pipeline

In order to transport CO_2 by pipelines, the CO_2 is normally compressed to between 80–150 bar. At this pressure level, the CO_2 will be in supercritical phase where the volume is reduced to about 0.2% of the volume at standard temperature and pressure. All existing large-scale CO_2 pipelines are designed for supercritical conditions. The pressure into the pipe has to be high enough to overcome both frictional and static pressure drop during transport and deliver CO_2 at a pressure sufficient to avoid flashing of the gas at the outlet of the pipeline.

If seawater at low temperatures is available, a two-stage process of compression and pumping is preferred. First, the CO_2 is compressed to supercritical state, and then, further increase in pressure is done by pumping. This method reduces the operating cost since pumping is less energy consuming than compression. In addition, smaller compressors are needed and the investment costs decrease [10]. Thus, the model for pipeline transport includes compressors, pumps, and pipes. Additional energy is required by the pipeline model to run the compressors and the pumps, as illustrated in Fig. 5.

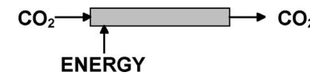

Fig. 5. Symbolic picture of CO_2 pipeline.

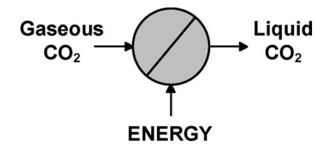

Fig. 6. Symbolic picture of CO_2 liquefaction plant.

The cost function for CO_2 pipelines is formulated as in (10) for the capture plant. In this case, however, the flow related cost c_p is normally set to zero, as the operating cost of the pipeline is reflected in the consumption of energy:

$$W_{\mathrm{pt}}^{\mathrm{Mech\_Pipe}} = \left[w_p^{\mathrm{Comp}}(\Delta P_1) + w_p{}^{\mathrm{Pump}}(\Delta P_2)\right] M_{pt}^{\mathrm{CO_2\_pipe}} \tag{17}$$

where
- $w_p^{\mathrm{Comp}}(\Delta P_1)$ work required to compress CO_2 from starting pressure P_0 to liquid state P_1 (in megawatthours per tonne); $\Delta P_1 = P_1 - P_0$;
- $w_p^{\mathrm{Pump}}(\Delta P_2)$ work required to pump the CO_2 from liquid state P_1 to required pressure in pipe P_2 (in megawatthours per tonne); $\Delta P_2 = P_2 - P_1$.

The fuel for this mechanical energy is supplied either directly from one or more sources or from other network elements in the system as formulated in (15).

The emissions from the pipeline consist of emissions from the operation of pumps and compressors (all types of emissions) and of leakages of the transported CO_2:

$$\mathrm{Emit}_{ept} = \varepsilon_{ep} W_{pt}^{\mathrm{Mech}}\Big|_{\forall e\in \mathrm{Emissions}} + \delta_p M_{pt}^{\mathrm{CO_2\_pipe}}\Big|_{e='\mathrm{CO_2}'} \tag{18}$$

where
- ε_{ep} coefficient for emission type e (in tonnes per megawatthour);
- δ_p leakage coefficient for CO_2.

The flow of CO_2 between the pipeline and the surrounding network is formulated as in (13)–(14). The flow out of the pipeline is proportional to the input minus leakage:

$$M\_\mathrm{out}_{pt}^{\mathrm{CO_2\_pipe}} = (1-\delta_p) M_{pt}^{\mathrm{CO_2\_pipe}}. \tag{19}$$

E. CO_2 Liquefaction Plant

The ship transport of CO_2 requires that the CO_2 is in liquid form, thus a liquefaction plant is needed. The liquefaction plant receives pure CO_2 and uses energy to liquefy the CO_2, normally through compression and condensation with cooling and throttling (or expansion). This requires energy, and the liquefaction plant is therefore modeled with an energy input, as shown in Fig. 6.

The cost function for CO_2 liquefaction plants is formulated as in (10) with c_p (in US dollar per tonne) as a parameter.

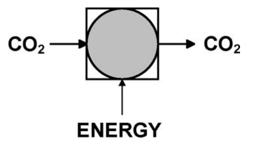

Fig. 7. Symbolic picture of CO_2 intermediate storage.

The mass flow into and out of the plant is formulated as in (13)–(14), and the emissions as a combination of emissions from the operation of pumps and compressors (all emissions) and of leakages of the liquefied CO_2 as in (18). The mechanical energy needed to operate the plant is

$$W_{\mathrm{pt}}^{\mathrm{Mech\_Liq}} = w_p^{\mathrm{Comp}} M_{pt}^{\mathrm{CO_2\_Liq}} \tag{20}$$

where $w_p^{\mathrm{Comp}} = 0.12$ MWh/tonne CO_2 for default compression from 1 to 70 bar to liquefy CO_2.

The output of (liquid) CO_2 from the liquefaction plant $M\_\mathrm{out}_{pt}^{\mathrm{CO_2\_Liq}}$ is formulated as in (19).

F. CO_2 Storage

Depending on the design of the CO_2 chain, intermediate storage may be needed (see Fig. 7). The storage unit is assumed to be steel tanks, with capacity typically 1.5 times the capacity of the ship. After liquefaction, the CO_2 is transferred to the tanks where energy is required to keep the CO_2 in liquid phase.

The cost function for intermediate CO_2 storage is expressed as a function of stored volume $V^{\mathrm{CO_2_Stor}}$rather than mass flow:

$$C^{\mathrm{CO_2\_Stor}} = \sum_{t\in\mathrm{Time\_steps}} \sum_{p\in\mathrm{Storages}} \left[c_p V_{pt}^{\mathrm{CO_2\_Stor}} + \sum_{e\in\mathrm{Emissions}} \mathrm{Pen}_{pe}^{\mathrm{Em}} \mathrm{Emit}_{ept} \right] \tag{21}$$

where

$$V_{pt}^{\mathrm{CO_2\_Stor}} = (1-\nu_p) V_{p,(t-1)}^{\mathrm{CO_2\_Stor}} + M_{pt}^{\mathrm{CO_2\_Stor}} - \sum_{n:(p,n)\in\mathrm{Net2net}} M_{pnt}^{N2N} - \sum_{l:(p,l)\in\mathrm{Net2load}} M_{plt}^{Ld} \tag{22}$$

where ν_p is the proportion of CO_2 leakage per hour; default value 0.01%/h [15].

As for the previous models, emissions from the storage are the sum of (all) emissions due to the operation of the storage plus leakage of CO_2. Consumption of energy due to the operation of the storage is proportional to the stored volume

$$\mathrm{Emit}_{ept} = \varepsilon_{ep} W_{pt}^{\mathrm{Mech}}\Big|_{\forall e\in\mathrm{Emissions}} + \nu_p V_{pt}^{\mathrm{CO_2\_Stor}}\Big|_{e='\mathrm{CO_2}'} \tag{23}$$

$$W_{\mathrm{pt}}^{\mathrm{Mech\_Stor}} = w_p^{\mathrm{Stor}} V_{pt}^{\mathrm{CO_2\_Stor}} \tag{24}$$

where w_p^{Stor} is the energy required to keep 1 tonne CO_2 stored in 1 h (in megawatthours per tonne).

The CO_2 output from the storage is distributed further into the model network or delivered to a load directly connected to the storage as expressed in (14). Furthermore, the storage has a maximum input and output capacity per time step Δt:

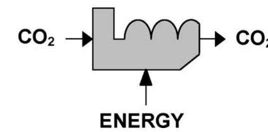

Fig. 8. Symbolic picture of CO_2 ship transport.

$$M_{pt}^{\mathrm{CO_2\_Stor}} \le \mathrm{Max\_input}_p \Delta T \tag{25}$$

$$\sum_{n:(p,n)\in\mathrm{Net2net}} M_{pnt}^{N2N} + \sum_{l:(p,l)\in\mathrm{Net2load}} M_{plt}^{Ld} \le \mathrm{Max\_output}_p \Delta T. \tag{26}$$

G. CO_2 Ship Transport

Small-scale ship transport of CO_2 exists today, but only for limited amounts of high-purity CO_2, (for beverages, etc.). The lack of operative technology for large-scale ship transport of CO_2 is not expected to be a bottleneck, however, as similar technology to existing LNG ships is likely to be used. Fig. 8 shows the symbolic picture of a CO_2 ship in the model. Mathematically, ship is a discrete transport solution but in the current model, a simplified linear approximation is used to reduce the number of integer variables. The linear approximation is considered to be acceptable given that the transportation itself does not bear the largest part of total cost for CCS. Since the investment cost of new ships is highly uncertain (and the same ship is likely to be used in more than one location), the ships are modeled so that the user can chose either to invest in a ship, or to lease a ship at an hourly cost. The energy requirement of the ship can be supplied by gas, oil, or electricity, and the emission level can be adjusted according to the fuel.

The cost function for CO_2 ships is formulated as follows:

$$C^{\mathrm{CO_2\_Ship}} = \sum_{t\in\mathrm{Time\_steps}} \sum_{p\in\mathrm{CO_2\_Ships}} \left[c_p M_{pt}^{\mathrm{CO_2\_Ship}} + \sum_{e\in\mathrm{Emissions}} \mathrm{Pen}_{pe}^{\mathrm{Em}} \mathrm{Emit}_{ept} \right]. \tag{27}$$

Assuming that the CO_2 ship is hired and not owned by the transporting entity, the operating cost of the ship is a function of the travel time, fees, and taxes:

$$c_p = \frac{c_p^{\mathrm{Hire}} (T_p^{\mathrm{Load}} + T_p^{\mathrm{Sail}} + T_p^{\mathrm{Dock}})}{\mathrm{Capacity}_p} + c_p^{\mathrm{HarbourTax}} \tag{28}$$

where

c_p^{Hire}	hire fee (in US dollar per hour);
T_p^{Load}	time duration for loading and unloading of the ship (in hours);
T_p^{Sail}	round-trip sailing time (in hours);
T_p^{Dock}	time needed for docking and undocking the ship (in hours);
$c_p^{\mathrm{HarbourTax}}$	specific tax for docking the ship (in US dollar per tonne);
$\mathrm{Capacity}_p$	CO_2 loading capacity of ship (in tonnes).

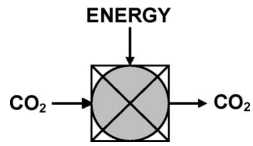

Fig. 9. Symbolic picture of CO_2 injection pump.

The flow of mass into and out of the ship during loading and unloading is expressed as in (13)–(14). Emissions from the ship are expressed as the sum of (all) emissions due to the operation of the ship plus boiloff β_p of CO_2:

$$\mathrm{Emit}_{ept} = \varepsilon_{ep} W_{pt}^{\mathrm{Ship}} \Big|_{\forall e \in \mathrm{Emissions}} + \beta_p M_{pt}^{\mathrm{CO_2\_Ship}} \Big|_{e='\mathrm{CO_2}'} \quad (29)$$

where

$$W_{\mathrm{pt}}^{\mathrm{Ship}} = w_p M_{pt}^{\mathrm{CO_2\_Ship}} \quad (30)$$

$$w_p = \frac{w_p^{\mathrm{Load}} T_p^{\mathrm{Load}} + w_p^{\mathrm{Sail}} (T_p^{\mathrm{Sail}} + T_p^{\mathrm{Dock}})}{\mathrm{Capacity}_p} \quad (31)$$

where

w_p^{Load} energy requirement when loading/unloading the ship (in megawatts per hour);

w_p^{Sail} energy requirement when sailing or arriving/departing from a harbor (in megawatts per hour).

The mass flow out of the ship is proportional to the input minus the boiloff β_p:

$$\mathrm{M\_out}_{pt}^{\mathrm{CO_2\_Ship}} = (1 - \beta_p) M_{pt}^{\mathrm{CO_2\_Ship}}. \quad (32)$$

H. CO_2 Injection Pump

Prior to final CO_2 storage in depleted oil and gas fields or in saline aquifers at more than 800 m depth, the pressure has to be increased in order to inject the CO_2 to such deep storage. The injection pump receives CO_2 at intermediate pressure and increases the pressure using energy as illustrated in Fig. 9.

The cost function for CO_2 injection pumps is formulated as in (10) with c_p (in US dollar per tonne) as parameter. The mass flow into the pump is formulated as (13), and emissions as (18). The mechanical energy needed to operate the pump is

$$\mathrm{W}_{\mathrm{pt}}^{\mathrm{Mech\_Pump}} = w_p^{\mathrm{Pump}} M_{pt}^{\mathrm{CO_2\_Pump}} \quad (33)$$

where w_p^{Pump}= 5.5 kWh/tonne when pumping CO_2 from pipeline, or 6.4 kWh/tonne when pumping CO_2 from ship.

I. CO_2 Demand and Market

A CO_2 demand is used in cases where there exists a given demand for CO_2 that has to be covered. For example, if an oil company has invested in technology for capture and transport of CO_2 planning to use it for EOR, it is likely that they will have a fixed demand for CO_2. This can be a constant requirement or a given diurnal and/or seasonal profile. On the other hand, industrial demand for CO_2 can also be modeled as a market with a price of CO_2 depending on the companies' willingness to pay.

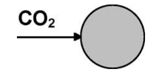

Fig. 10. Symbolic picture of CO_2 demand (exogenous quantity).

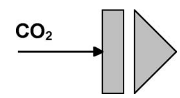

Fig. 11. Symbolic picture of CO_2 market (exogenous price).

Injecting CO_2 to increase the production of oil can generate extra revenues that offset all or parts of the cost for CO_2 transportation and capture [12].

Figs. 10 and 11 show how the CO_2 demand and market are represented in eTransport. The CO_2 load and the CO_2 market share the same model file separated by two sets of indices, one for loads (CO_2*_loads*) and one for markets (CO_2*_markets*). A main difference is that a penalty $\mathrm{Pen}_{pe}^{\mathrm{CO_2}}$ (in US dollar per tonne) for nondelivery is included in the demand model. This implies that a large cost appears if the demand is not covered. A CO_2 market, on the other hand, does not *require* any CO_2 delivery, but CO_2 is sold at a user-defined price $p_{lt}^{\mathrm{CO_2}}$ (in US dollar per tonne per hour) at node *l*. Income from this sale is subtracted from the total cost:

$$C^{\mathrm{CO_2\_load}} = \sum_{t \in \mathrm{Time\_steps}} \left[\sum_{l \in \mathrm{CO_2\_loads}} \mathrm{Pen}_l^{\mathrm{CO_2}} D_{lt}^{\mathrm{CO_2}} - \sum_{l \in \mathrm{CO_2\_markets}} p_{lt}^{\mathrm{CO_2}} S_{lt}^{\mathrm{CO_2}} \right]. \quad (34)$$

The mass balance of a CO_2 load is expressed in the same way as an energy balance; the mass flowing into the load node from the network M^{Ld} and/or directly from a supply node M^{Loc} is equal to the sum of mass delivered to load $L^{\mathrm{CO_2}}$ or sold $S^{\mathrm{CO_2}}$ minus delivery deficit $D^{\mathrm{CO_2}}$:

$$\sum_{i:(i,l) \in \mathrm{Net2load}} M_{ilt}^{Ld} + \sum_{i:(i,l) \in \mathrm{Supply2load}} M_{ilt}^{\mathrm{Loc}} = L_{lt}^{\mathrm{CO_2}} + S_{lt}^{\mathrm{CO_2}} - D_{lt}^{\mathrm{CO_2}}. \quad (35)$$

IV. CASE STUDY

Having implemented linear models for optimization of CO_2 capture and storage technologies in the framework of eTransport, the next step is to test the models. It is not a straightforward task to find accurate data describing technologies that are still in the research phase or where only a few full-scale versions are constructed, and the models are therefore tested in fictive cases with the best data available [1], [2], [10], [12]. Due to space limitations, only main elements of a regional scale case study are presented here: construction of a gas fired power plant with carbon capture and EOR options [9].

Outside the region of mid-Norway, there are large oil and gas fields on the continental shelf. One of the projects discussed in

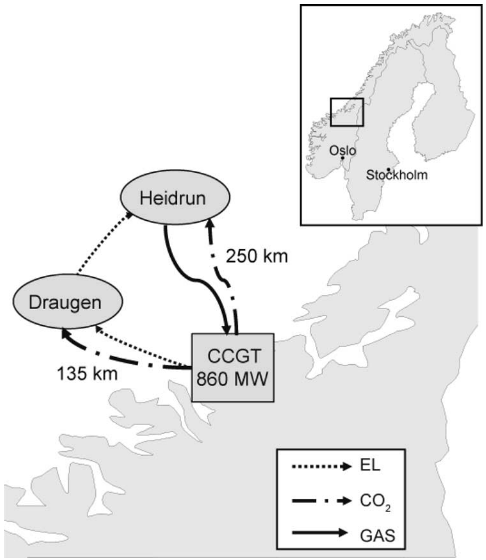

Fig. 12. Regional case with CO_2 capture and EOR.

the region is illustrated in Fig. 12: construction of an 860 MW gas fired power plant with CO_2 capture using postcombustion and amine for gas separation. A 250 km gas pipe from the "Heidrun" field to the shore is already in operation, and the power plant is planned at the site of the pipeline terminal. Options for the project include using CO_2 for EOR initially at the oil field "Draugen" 135 km offshore, later possibly also at "Heidrun" and other neighboring fields. The electricity from the plant can be sold at the Nordic Elspot market, but may also be used for *offshore electrification*, replacing the existing gas turbines offshore (110 MW_e at Heidrun, 100 MW_e at Draugen), and/or to run the CO_2 capture plant onshore.

Table I shows the main economic data for the case. Gas produced at the Heidrun field is assumed to have a cost of US$ $0.11/\mathrm{S} \cdot \mathrm{m}^3$. Production from both fields will be closed down in 2025. The period of analysis is set to 20 years (2010–2030) split in four investment periods of five years. The onshore emissions taxes are US$ 15.4/tonne CO_2 and US$ 0.15/kg NOx, while *offshore* emission taxes are US$ 5.38/kg NOx and US$ 49.2/ton CO_2. Spot market electricity price has a diurnal variation between US$ 30.8/MWh and US$ 64.6/MWh.

A. Comparison of Electrification and CCS Solutions Versus Conventional Power Plant

Table II shows the initial ranking of investment alternatives. The annual emissions given in the table are valid for the first investment period. The CCS alternatives are clearly not competitive with a conventional power plant with the current assumptions, but electrification is profitable due to the high offshore emission taxes.

Sensitivity analyses show that onshore emission taxes have to rise above US$ 3.1/kg NOx and US$ 42.3/tonne CO_2, respectively, to make alternatives with CCS competitive. Below those levels, it is more profitable to sell all electricity to the Nordic Elspot market. Note that postcombustion capture requires low NOx concentration in the exhaust, meaning that NOx have to be removed prior to CO_2 capture. NOx emissions are thus negligible from the power plant when CCS included.

Another sensitivity analysis is made to examine how the willingness to pay for the CO_2 delivered to the platform will influence the CCS profitability. The results show that a power plant with CCS will not be competitive unless the price of pressurized CO_2 delivered to Draugen is over US$ 90/tonne. This might seem very high, but 1 tonne CO_2 can provide approximately 0.5 tonne or roughly 3.5 bbl additional oils. Using an oil price of

TABLE I
INVESTMENT PARAMETERS FOR CASE STUDY

	Investment [mUSD]	**Operation [mUSD/year]**	**Lifetime [years]**
Power plant 860 MW	409	62	25
Capture plant	240	37	25
CO2 pipeline			
to Draugen (135 km)			
- Low pressure	162	3.2	30
- High pressure	180	3.6	30
to Heidrun (250 km)			
- Low pressure	233	4.6	30
- High pressure	261	5.2	30
Ship (15 000m^3)	46	2.3	30
Liquefaction	76	3.8	30
Storage (24 000 m^3)	60	1.2	30
Injection-pumps +equipment offshore			
- gas turbines	-	20	-
- after pipelines	8	0.2	30
- after ship transport	33	0.6	30
Electricity cable			
- to Draugen	46	0.7	30
- Draugen-Heidrun	34	0.5	30

TABLE II
GAS FIRED POWER PLANT WITH OR WITHOUT CCS

	Annual cost (mill USD/year)	**Investments & Emissions**
1	23.538	Conv. power plant without CCS Electrification of Draugen and Heidrun - CO_2 = 2 Mtonne/year - NOx = 7 000 tonne/year
2	26.769	Conv. power plant without CCS EL to Draugen; Gas turbines on Heidrun - CO_2 = 2.5 Mtonne/year - NOx = 9 000 tonne/year
3	27.692	Conv. power plant without CCS No electrification - CO_2 = 3 Mtonne/year - NOx = 11 000 tonne/year
4	111.846	Power plant w/CCS, CO_2 pipe to Draugen Electrification of Draugen and Heidrun - CO_2 = 0.4 Mtonne/year - NOx = 0 tonne/year
5	115.077	Power plant w/CCS, CO_2 to Draugen EL to Draugen; Gas turbines on Heidrun - CO_2 = 0.9 Mtonne/year - NOx = 2 000 tonne/year
6	118.000	Power plant w/CCS, CO_2 to Draugen No electrification - CO_2 = 1.3 Mtonne/year - NOx = 3 000 tonne/year

TABLE III
RANKING OF DIFFERENT CO_2 TRANSPORT ALTERNATIVES

	Annual cost (mill USD/year)	Investments & Emissions
1	46.462	High pressure pipeline CO_2 = 1.32 Mtonne/year
2	47.231	Low pressure pipelines with injection pump CO_2 = 1,33 Mtonne
3	57.077	Ship transport (when ship is purchased) CO_2 = 1,57 Mtonne

US$ 40/bbl, this will yield an income of US$ 140/tonne CO_2 from increased oil production.

B. Alternative CO_2 Transport Solutions

To evaluate the possible transportation alternatives, the case is now extended, introducing two sets of CO_2 pipelines, one with high pressure (350–300 bar), and one with lower pressure (150–100 bar) plus offshore injection pump (the high pressure pipelines do not need any injection pump at the platform). Investment in ship transport including liquefaction plant and intermediate storage is added as a third option. The option to construct a conventional power plant without CCS is removed from the case. In this case, the electricity price is assumed to be stable at US$ 61.5/MWh.

The results in Table III show that the differences are rather small compared to the total cost. The high-pressure pipeline is best, closely followed by the low-pressure pipe, and finally, the ship transport. The high, stable electricity price makes it profitable to sell as much electricity as possible to the market, thus the offshore fields are not electrified in this case. The injection pump needed after the low-pressure pipe takes its energy from the offshore turbine. Offshore turbines are more costly and releases more emissions than onshore electricity. As a result it is advantageous to keep the energy demand onshore, favoring high-pressurized pipelines. The average electricity price has to sink below US$ 52/MWh to make offshore electrification profitable.

The high electricity price also makes ship transportation less profitable. The liquefaction plant and the intermediate storage have a significant energy demand, resulting in less electricity available for sale to the market. In addition, a considerable amount of CO_2 is lost during the liquefaction, reducing the amount delivered to Draugen for EOR by 250 000 tonne/year. Thus, pipeline transport is preferable to a ship also from an environmental point of view.

A second optimization where the CO_2 ship is hired instead of purchased shows that a hire rate of US$ 920/h is equivalent to the investment of US$ 46 million. However, even if the ship itself was available without cost, the costs of the liquefaction plant and storage make the ship alternative less profitable than the pipeline alternatives. Generally, the ship transport is not recommended below distances of 500 km unless special distributed solutions should make pipelines unfeasible.

TABLE IV
CCS AND EOR IN DIFFERENT TIME WINDOWS

	Annual cost (mill USD/year)	Investments
1	58.462	2010: Low press. CO_2 pipe to Draugen 2020: Low press. CO_2 pipe to Heidrun No electrification
2	59.231	2010: Low press. CO_2 pipe to Draugen 2020: High press. CO_2 pipe to Heidrun No electrification
3	59.385	2010: High press. CO_2 pipe to Draugen 2020: Low press. CO_2 pipe to Heidrun No electrification
4	61.385	2010: Low press. CO_2 pipe to Draugen No electrification
5	62.769	2010: High press. CO_2 pipe to Draugen No electrification
6	66.308	2010: Ship transport to Draugen to 2020, using the same ship to Heidrun from 2020 No electrification
7	67.385	2010: Ship transport to Draugen to 2020, using the same ship to Heidrun from 2020-2025 2025: High pressure pipe to Heidrun No electrification
8	78.923	2010: Low press. CO_2 pipe to Draugen 2020: Low press. CO_2 pipe to Heidrun Electrification

C. Different Time Windows for Electrification and EOR

Finally, a more complicated case is constructed, including the possibility of EOR at both Draugen and Heidrun. It is now assumed that the demand for CO_2 for EOR at Draugen only lasts until 2020, replaced by a demand at Heidrun. Furthermore, the oil production at Draugen is expected to end in 2025, leading to zero electricity demand at Draugen after 2025. The EOR is expected to prolong the production at Heidrun to 2030.

The main results are shown in Table IV. Due to the reduced lifetime of Draugen, investments in electrification are not competitive, even though low-pressure pipelines are chosen before high-pressure pipelines. The injection pumps thus take their energy from offshore turbines, and the electricity can be sold to the market instead. The first three alternatives are variations of the same basic solution, while nos. 4 and 5 are solutions where EOR is not implemented at Heidrun at all. Also note that the same ship is used for different routes as the CO_2 demand is changing from one field to another.

V. SUMMARY AND CONCLUSION

This paper has presented linear models for CCS infrastructure that are consistent with models for gas, electricity, and heat infrastructures in an optimization model for expansion planning in multicommodity energy systems. The purpose of the modeling has not been to provide a detailed design tool for CCS solutions but to establish a mathematical framework that will enable decision makers to compare different design options in a systematic way. Using the results from the case study, it is possible to draw the following conclusions.

1) CCS increases the production cost of power generation from gas fired power plants by approximately US$ 18.5/MWh using pipelines to transport the CO_2 to offshore

fields for EOR. If ship transport is used, the production cost increase with additionally US$ 2.5/MWh. Other studies suggest that CCS will increase the cost of electricity production by US$ 25/MWh [10], or typically, a 60% increase in production cost using postcombustion for capturing the CO_2 [14]. Considering the major uncertainties involved, there is an acceptable agreement between former estimations and the results from eTransport.

2) It is possible to reduce annual CO_2 emissions by approximately 2.5 Mtonne if the power generation with CCS is combined with offshore electrification. The result suggests that the offshore NOx penalty has to be higher than US$ 3/kg to make electrification beneficial. Similarly, the CO_2 tax offshore has to stay above US$ 42/tonne.
3) Increasing the onshore tax on CO_2 emissions will reduce the cost difference between conventional power generation and power generation with CCS. However, even with a CO_2 penalty of US$ 69/tonne the conventional power plant is still more profitable.
4) It is necessary to have a market price of CO_2 in the range of US$ 61/tonne to make power generation with CCS profitable. This largely agrees with other studies suggesting a price of US$ 68/tonne CO_2 [10]. However, these prices imply that the demand for CO_2 stays stable during the entire planning period. If CO_2 is delivered to only one field for a limited period of time, the price for CO_2 has to be significantly higher to break even.
5) The design pressure of the pipelines only causes minor differences in the total cost. High-pressure pipelines are more advantageous when the offshore installations use gas turbines for energy supply. If offshore electrification is implemented, low-pressure pipelines with offshore injection pumps are better.
6) Ship transport is not competitive for short distances and limited amounts of CO_2. The investment costs of the required liquefaction and storage units are large, making ship transport less profitable even if the ships can be hired at a low cost. Sensitivity analyses also show that the ship transport is less profitable if the price of CO_2 increases. The liquefaction plant suffers from a great loss of CO_2, reducing the amount for sale. Even though the ship transport is more flexible if the demand for CO_2 changes from one field to another, this does not have enough impact to change the conclusion. However, the flexibility of using ship transport if the CO_2 is to be collected from scattered sources might change the conclusion.

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