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IEAGHG Technical Report
2020-09
September 2020

Understanding the Cost of Reducing Water Usage in Coal and Gas Fired Power Plants with CCS

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The report should be cited in literature as follows:

'IEAGHG, Understanding the cost of reducing water usage in coal and gas fired power plants with CCS, 2020-09, September 2020.'

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UNDERSTANDING THE COST OF REDUCING WATER USAGE IN COAL AND GAS FIRED POWER PLANTS WITH CCS

Previous IEAGHG studies (IEAGHG 2010/05, IEAGHG 2012/12, and IEAGHG 2018/04) have identified key factors that affect the Energy-Water-CCS Nexus: location; the dependency of the costs and water consumption on the cooling system; and the post-combustion CO_2 capture (PCC) system. Additionally, extracting water from a CO_2 storage site can significantly increase the available volumetric space for CO_2 storage which could benefit PCC in the power sector.

The conclusions drawn from these studies identified the need to assess the technical and economic impact of water consumption in power plants with and without CO_2 capture systems in different locations. Further investigation also needs to encompass the impact of local regulations, ambient conditions, specific region-based power plants configurations, and water availability.

This current study was conducted in two phases. Phase 1 developed a hypothetical base case scenario of power plants with and without a PCC system in The Netherlands, assuming both on and offshore storage, and with and without treatment of the water extracted from the storage site for its reuse in the power plant. Phase 2 was based on four hypothetical PCC systems in South Africa, Australia, China and India.

Key Messages

- If more restrictive regulations are imposed on power plants that currently use evaporative freshwater cooling, the use of extracted and treated formation water in an integrated CCS-water loop could be a cost competitive alternative to retrofitting a power plant with an air cooling system.
- The results from this study confirm that adding a CO_2 capture system to the power plant may increase the water consumption of the whole facility. However, this increase can be mitigated through the implementation of different fitted strategies, such as using alternative water supply, recycling of water, or using alternative cooling techniques
- The outcomes from this study confirm that the selection of the cooling system has a strong impact on the water consumption. For example, evaporative natural draught cooling has a noticeably higher percentage increase in water withdrawal and consumption compared with the once-through seawater cooling systems.
- 16 Water-Energy-CCS nexus cases were modelled for a hypothetical location in the Netherlands. LCOE increases by 2-3 €/MWh and 3-6 €/MWh for onshore and offshore storage scenarios respectively. That includes CO_2 storage, water extraction, treatment, transport and disposal.

- Results show that, if water extraction is necessary for storage purposes, its treatment and beneficial reuse may present the most economic option, compared to the direct disposal in the onshore storage scenario
- In the second phase of this study, power plants in South Africa, Australia, China, and India were modelled. The results of this work show that the location of the power plant (with and without CO_2 capture system) influences the water availability, consumption and costs, due to the regulations, feedstock, ambient conditions, and cooling system.
- The lowest water withdrawal and consumption rates are evident from the case in China due to the ambient conditions, such as a lower temperature. In this scenario, building an air-cooled USCPC (Ultra Super-Critical Power Coal plant) is 30% cheaper, while this option is 20% more expensive in Australia and South Africa, compared to the USCPC base case in The Netherlands.
- Adding a CO_2 capture system at the power station, as well as ZLD (Zero Liquid Discharge) at the power stations in China, India and South Africa, increases the specific capital requirement by 52% - 60%. The LCOE increases by 44% - 55%, which equates to a LCOE of 62-91 €/MWh, depending on the location.
- CO_2 avoidance cost for the USCPC with capture is 36 – 51 €/t CO_2 in the CCS Base Case Scenario and increases to 41 – 58 €/t CO_2 in the Energy-Water-CCS nexus Scenario, with the Chinese power station having the lowest avoidance cost and the South African power station having the highest.
- Water extraction and treatment add a comparatively small capital cost to the examined CCS cases (5% increase), but the LCOE can increase by 11 – 12%.
- The treatment of extracted water may provide a value in water-stressed regions, especially when considering the associated cost of water shortages. In this study, the cost of product water, accounting for brine treatment and disposal costs, was found to be comparable to local water tariffs in the four countries, ranging from 1.12 €/m^3 to 2.43 €/m^3. When water extraction and transport costs are also included, product water cost exceed local water supply charges.

Scope of Work

CSIRO was commissioned by IEAGHG to provide a comprehensive techno-economic assessment of the water usage and consumption in power plants, with and without CO_2 capture systems, based on different geographical regions with differences on power plants configurations, CO_2 storage sites, and water quality and availability.

This study was divided in two phases, in order to provide a complete techno-economic evaluation of the entire energy-water-CCS nexus in different regions.

The first phase aimed to provide:

- a literature review of regulations;
- assessments on water consumption in power plants with CO_2 capture systems;
- techniques to reduce the water requirements in power plants with and without CO_2 capture systems;

- and current practice on water extraction in the storage sites to increase the CO_2 injection capacity.

This first phase focused on an assessment in a hypothetical location in the Netherlands, to develop a base case for IEAGHG techno-economic studies. In this phase, a methodology was developed to set the key techno-economic parameters and metrics for the second phase.

The second phase, based on the outputs from the first phase, assessed the entire CCS chain in four countries: South Africa; Australia; China; and India. The objectives were to explore the impact of the location on the power station configuration and performance, including options to reduce the water withdrawal in power plants with CCS. The second phase also evaluated the economic impact of water treatment on electricity cost; and identified cases where the re-use of water extracted from a storage site could be used as a water supply for power plants.

Findings of the Study

Phase 1

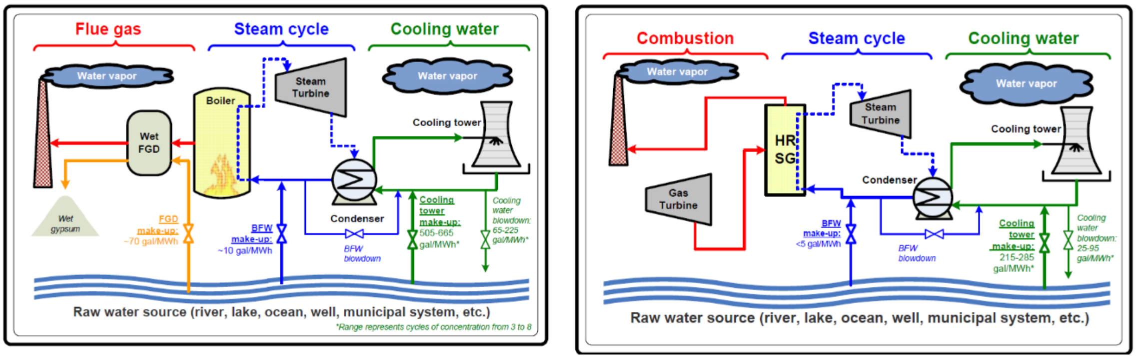

Figure 1 Water schematic at coal fired (left) and NGCC (right) plants (DOE-NETL, 2009)

Based on the results from IEAGHG (2018), the cooling system has a significant impact on the water consumption. The choice of the cooling system to use in a power plant is influenced by its location, local environmental regulations, and economics. Moreover, in the case of coal power plants, the desulphurization unit (FGD), will increase the water consumption.

Cooling systems for power plants can be divided into: once-through (single throughput and return to an external source such as the sea or a river); and re-circulating. Recirculating cooling systems can be classified into wet-cooling systems, dry (or air) cooling systems, and hybrid systems.

To reduce water consumption, several techniques can be considered. The main options include:

- alternative water supply;
- recycling/recovery/or reuse of water;
- using alternative cooling techniques.

Moreover, most countries have placed mandatory policies and legislation to regulate the amount of wastewater in power plants, while other plants in water stressed areas also operate under ZLD (Zero Liquid Discharge) arrangements.

In addition to water consumption regulations, governments have addressed CO_2 emissions from the power sector through different mechanisms, such as the EPS (emission performance standards) or ETS (emission trading schemes).

In the first phase of this study, a techno-economic analysis was carried out on one hypothetical case in The Netherlands based on financial and economic parameters used by IEAGHG in recent studies. The addition of a CO_2 capture system to the power plant modifies the water consumption of the whole facility. Specifically, using a chemical absorption system (post-combustion configuration), may increase the water consumption, which is mainly invested in the cooling system for the CO_2 capture, stripping process, and CO_2 compression. From an economic perspective, this study showed that the LCOE increases by 80% on average due to the addition of a PCC system.

For the storage site in The Netherlands the regulations limit the estimated CO_2 storage capacity to ~3,200 Mt. The water extraction from the storage site was modelled under three scenarios with different parameters: an extraction of between 0.2 and 1.1 Mt brine/year; an injection rate of between 0.05 and 0.66 Mt CO_2/year; and estimated annual costs from 0.81 to 3.54 MEUR/year. Re-using water extracted from the storage site for the power plant adds a water treatment cost to reach the quality requirements needed in the plant. In this case, mechanical vapour compression recovery was assumed.

In this study, 16 cases of USCPC and NGCC (Natural Gas Combined Cycle) power plants were modelled, as described in Table 1 and Table 3. The power plants were modelled with EBSILON, while the CO_2 capture system (piperazine (PZ) + 2-amino-2-methyl-1-propanol (AMP)) based chemical absorption) was designed in Protreat®. Results are included in Table 2 and Table 4.

Table 1 Description of the USCPC power plant cases modelled in this study

Case	Technical description	Case Name
Case 1.1A	USCPC boiler reference case based on standard supercritical steam conditions for a nominal 900 MW_e gross output power plant **without CCS**. Evaporative (EV) natural draught cooling tower (recirculating system) is used for the power plant.	**USCPC-EV**:
Case 1.1B	USCPC boiler for a nominal 900 MW_e gross output power plant with CCS. Evaporative (EV) natural draught cooling is used for both the power plant and capture plant.	**USCPC-EV-PCC**:
Case 1.1C	USCPC boiler for a nominal 900 MW_e gross output power plant with CCS. Evaporative (EV) natural draught cooling tower for the power plant, air cooling (AC) for the capture plant.	**USCPC-EV-PCC-AC**
Case 1.2A	USCPC boiler for a nominal 900 MW_e gross output power plant with CCS. Once-through (OT) seawater cooling is used for the power plant **without CCS**.	**USCPC-OT**
Case 1.2B	USCPC boiler for a nominal 900 MW_e gross output power plant with CCS. Once-through (OT) seawater cooling is used for both the power plant and the capture plant.	**USCPC-OT-PCC**
Case 1.2C	USCPC boiler for a nominal 900 MW_e gross output power plant with CCS. Once-through (OT) seawater cooling tower for the power plant, air cooling (AC) for the capture plant.	**USCPC-OT-PCC-AC**
Case 1.3A	USCPC boiler for a nominal 900 MW_e gross output power plant with CCS. Air cooling (AC) utilised for the power plant **without CCS.**	**USCPC-AC**
Case 1.3B	USCPC boiler for a nominal 900 MW_e gross output power plant with CCS. Air cooling (AC) is utilised for both the power plant and capture plant.	**USCPC-AC-PCC**

Table 2 Technical performance summary for USPC power plants with and without capture, extracted from the results in this study

Cases	1.1 A	1.1B	1.1C	1.2A	1.2B	1.2C	1.3A	1.3B
	USCPC-EV	**USCPC-EV-PCC**	**USCPC-EV-PCC-AC**	**USCPC-OT**	**USCPC-OT-PCC**	**USCPC-OT-PCC-AC**	**USCPC-AC**	**USCPC-AC-PCC**
Cooling technology	**Recirculating (EV)**		**EV + AC**	**Once-through (OT)**		**OT + AC**	**Air cooling (AC)**	
Gross power output (MW)	900	900	900	900	900	900	879	879
Auxiliary power (MW)	83	215.6	221.6	84	217.4	222.6	94.6	224.2
Net power output (MW)	817	684	678	816	683	677	785	655
CO_2 emission (t/MWh)	0.739	0.087	0.087	0.740	0.087	0.088	0.770	0.091
Water balance								
Water withdrawal (m^3/h)	1090.8	1368.9	857.0	54.0	54.2	54.2	54.0	54.2
Process water discharge (m^3/h)	259.2	328.7	201.6	0.0	0.0	0.0	0.0	0.0
Water consumption (m^3/h)	831.6	1040.2	655.4	54.0	54.2	54.2	54.0	54.2
Water withdrawal (m^3/MWh)	1.34	2.00	1.26	0.07	0.08	0.08	0.07	0.08
Water consumption (m^3/MWh)	1.02	1.52	0.97	0.07	0.08	0.08	0.07	0.08
Increase / decrease in relative water withdrawal due to CO_2 capture		50%	-5%		20%	20%		20%
Increase / decrease in relative water consumption due to CO_2 capture		49%	-5%		20%	20%		20%

Table 3 Description of the NGCC power plant cases modelled in this study

Case	**Technical description**	**Case name**
Case 2.1A	NGCC reference case for a nominal 890 MW_e gross output power plant without capture. Evaporative (EV) mechanical draught cooling tower (recirculating system) is used for the power plant.	**NGCC-EV**
Case 2.1B	Nominal 890 MW_e gross output NGCC power plant with CCS. Evaporative (EV) mechanical draught cooling is used for both the power plant and capture plant	**NGCC-EV-PCC**
Case 2.1C	Nominal 890 MW_e gross output NGCC power plant with CCS. Evaporative (EV) mechanical draught cooling tower for the power plant, air cooling (AC) for the capture plant	**NGCC-EV-PCC-AC**
Case 2.2A	Nominal 890 MW_e gross output NGCC power plant with CCS. Once-through (OT) seawater cooling is used for the power plant without capture	**NGCC-OT**
Case 2.2B	Nominal 890 MW_e gross output NGCC power plant with CCS. Once-through (OT) seawater cooling is used for both the power plant and the capture plant.	**NGCC-OT-PCC**
Case 2.2C	Nominal 890 MW_e gross output NGCC power plant with CCS. Once-through (OT) seawater cooling tower for the power plant, air cooling (AC) for the capture plant	**NGCC-OT-PCC-AC**
Case 2.3A	Nominal 890 MW_e gross output NGCC power plant with CCS. Air cooling (AC) utilised for the power plant without capture	**NGCC-AC**
Case 2.3B	Nominal 890 MW_e gross output NGCC power plant with CCS. Air cooling (AC) is utilised for both the power plant and capture plant	**NGCC-AC-PCC**

Table 4 Technical performance for NGCC cases with and without capture, extracted from the results in this study

Cases	**2.1A**	**2.1B**	**2.1C**	**2.2A**	**2.2B**	**2.2C**	**2.3A**	**2.3B**
	NGCC-EV	**NGCC-EV-PCC**	**NGCC-EV-PCC-AC**	**NGCC-OT**	**NGCC-OT-PCC**	**NGCC-OT-PCC-AC**	**NGCC-AC**	**NGCC-AC-PCC**
Cooling technology	Recirculating (EV)		EV + ACC	Once-through (OT)		OT + AC	Air cooling (AC)	
Gross power output (MW)	890	890	890	890	890	890	879	879
Auxiliary power (MW)	7.6	128.7	131.8	6.6	127.2	131.2	11.9	116
Net power output (MW)	882.2	761.3	758.2	883.3	762.8	758.8	866.9	762.8
CO_2 emission (t/MWh)	0.352	0.041	0.041	0.352	0.041	0.039	0.359	0.041
Energy consumption for PCC								
Total electrical energy consumption in PCC (MW)	0	44.3	47.4	0	43.5	47.4	0	47.4
Water balance								
Water withdrawal (m^3/h)	572.4	756.3	320.5	0	0.1	0.1	0	0.1
Process water discharge (m^3/h)	144	186.9	79.2	0	0	0	0	0
Water consumption (m^3/h)	428.4	569.4	241.3	0	0.1	0.1	0	0.1
Water withdrawal (m^3/MWh)	0.65	0.99	0.42	0	0	0	0	0
Water consumption (m^3/MWh)	0.49	0.75	0.32	0	0	0	0	0
Increase / decrease in relative water withdrawal due to CO_2 capture		53%	-35%					
Increase / decrease in relative water consumption due to CO_2 capture		54%	-34%					

The comparison of the different cases investigated in this study shows that the relative water withdrawal or consumption depends on the cooling system. Evaporative natural draught cooling used for both the power plant and capture plant (USCPC-EV-PCC, Table 2) has a noticeably higher percentage increase in water withdrawal and consumption compared with the once-through seawater cooling systems (USCPC-OT-PCC & USCPC-OT-PCC-AC, Table 2). The evaporative natural draught cooling tower for the power plant and air cooling for the capture plant (USCPC-EV-PCC-AC, Table 2) could even lead to a slight decrease in the demand for water. Evaporative mechanical draught cooling used for both the power plant and capture plant (NGCC-EV-PCC, Table 4) would increase water withdrawal and water consumption by over 50%, whereas the same system for the power plant linked to an air cooled system for the capture plant (NGCC-EV-PCC-AC, Table 4) could provide a notable decrease in water demand. This analysis gives an indication of potential mitigation pathways leading to water use reduction.

In Phase 1 the capture system was integrated with the offshore and onshore storage site cases (Figure 2), building up the Energy-Water-CCS nexus scenarios. A TOUGH2 code was used to model reservoir responses assuming a constant rate of injection for both open and closed reservoir boundary cases. The water recovery was between 25 and 50% of the extracted brine. These percentage rates equate to between 0.9 and 4.2 Mt/year for NGCC plans and between 1.7 and 7.8 Mt/year for USCPC cases.

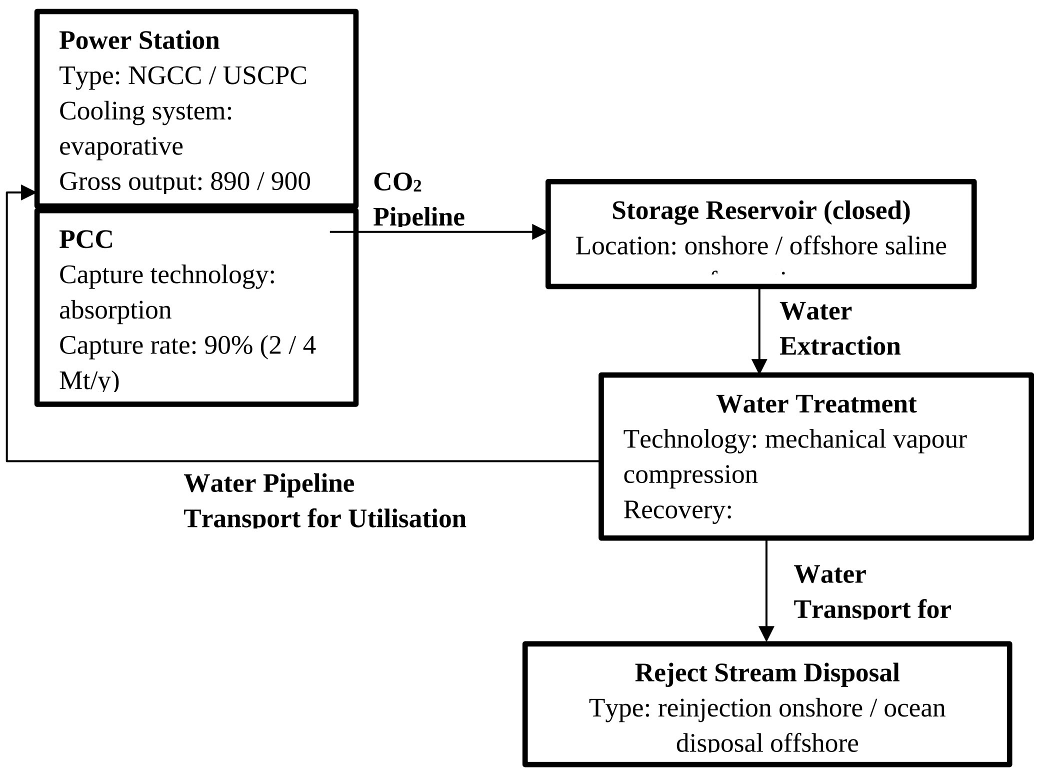

Figure 2 Energy-Water-CCS nexus scenarios with water extraction, treatment, and utilisation in the power plant with capture

Two extraction scenarios were considered for the Energy-Water-CCS nexus:

- A) extraction of the volumetrically equivalent brine amount required for safe CO_2 storage
- B) extraction of the volume of brine necessary to meet the freshwater demand of the power plant using evaporative cooling with capture using either evaporative or air cooling

The results of the water balance in the different scenarios are included in Table 5 and Table 6.

Table 5 Water balance of the Energy-Water-CCS nexus Scenario for the NGCC power plant using evaporative cooling and the capture plant using either evaporative cooling or air cooling. CO_2 storage with brine extraction occurs either onshore or offshore. The extracted brine is treated by the application of mechanical vapour compression (MVC).

		NGCC using evaporative cooling with state of the art absorption							
Cooling technology		**Capture using evaporative cooling**				**Capture using air cooling**			
Water consumption (total)	Mt/y	4.24				1.8			
Water consumption (capture only)	Mt/y	1.05				0.00			
Storage location		offshore saline		onshore saline		offshore saline		onshore saline	
Formation water salinity	mg/L	100,000		150,000		100,000		150,000	
Product water recovery rate MVC	%	50		25		50		25	
Energy-Water-CCS nexus		A	B	A	B	A	B	A	B
Water extraction rate	Mt/y	3.3	8.5	3.5	17.0	3.3	3.6	3.5	7.2
Product water	Mt/y	1.7	4.2	0.9	4.2	1.7	1.8	0.9	1.8
Reject brine	Mt/y	1.7	4.2	2.6	12.7	1.7	1.8	2.6	5.4

Table 6 Water balance of the Energy-Water-CCS nexus Scenario for the USCPC power plant using evaporative cooling and the capture plant using either evaporative cooling or air cooling. CO_2 storage with brine extraction occurs either onshore or offshore. The extracted brine is treated by the application of mechanical vapour compression (MVC).

		USCPC using evaporative cooling with state of the art absorption							
Cooling technology		**Capture using evaporative cooling**				**Capture using air cooling**			
Water consumption (total)	Mt/y	7.75				4.88			
Water consumption (capture only)	Mt/y	1.56				0.00			
Storage location		offshore saline		onshore saline		offshore saline		onshore saline	
Formation water salinity	mg/L	100,000		150,000		100,000		150,000	
Product water recovery rate MVC	%	50		25		50		25	
Energy-Water-CCS nexus scenario		A	B	A	B	A	B	A	B
Water extraction rate	Mt/y	6.7	15.5	6.9	31	6.7	9.8	6.9	19.5
Product water	Mt/y	3.4	7.8	1.7	7.8	3.4	4.9	1.7	4.9
Reject brine	Mt/y	3.4	7.8	5.2	23.3	3.4	4.9	5.2	14.6

An economic evaluation of the Phase 1 (NGCC and USCPC scenarios), was carried out (Table 5 and 6). The economic evaluation was based on a series of parameters applied to other recent IEAGHG studies.

In the case of USCPC power plant cases the biggest differences are predictably between scenarios with and without CO_2 capture (Table 7). The LCOE for the offshore base case scenarios with CCS show a limited range of LCOE values of between 86 and 95 €/MWh. The Energy-Water-CCS Nexus scenario has a more limited, but comparable range of between 90 and 96 €/MWh. The onshore open base case exhibits the lowest LCOE value of 81 €/MWh where evaporative and once through cooling is applied and lower values for all cooling technologies compared with closed base case scenarios. Onshore Energy-Water-CCS Nexus using evaporative or air cooling systems for the capture plant have the highest LCOE values (87-102 €/MWh). These onshore values are indicative of higher CAPEX and OPEX related to onshore operations in The Netherlands.

The CO_2 avoidance costs (Table 7) are broadly similar for the USCPC power plant base cases (46 – 54 €/t offshore open and closed cases) but higher for the Energy-Water- CCS cases (53 – 60 €/t). The onshore base cases range from 38 – 55 €/t, the lowest value is representative of an open reservoir system where the water extracted is volumetrically equivalent to CO_2

injected. The Energy-Water-CCS Nexus cases are notably higher 47 – 71 €/t. The CO_2 avoidance costs at the higher end of this range reflect the additional investment required for capture systems with water retention technologies.

Table 7 LCOE and CO_2 avoidance cost of the USCPC power plant cases, with and without CCS

LCOE											
Cooling technology		**Evaporative cooling**					**Once through cooling**			**Air cooling**	
Case name		**1.1A**	**1.1B**		**1.1C**		**1.2A**	**1.2B**	**1.2C**	**1.3A**	**1.3B**
LCOE USCPC		**w/o CCS**	**USCPC-EV-PCC**		**USCPC-EV-PCC-AC**		**w/o CCS**	**USCPC-OT-PCC**	**USCPC-OT-PCC-AC**	**w/o CCS**	**USCPC-AC-PCC**
Offshore											
Base case (open)	€/MWh	56	86		90		56	86	90	59	94
Base case (closed)	€/MWh	56	87		92		56	87	91	59	95
Energy-Water-CCS nexus	€/MWh	56	A90	B93	A95	B96					
Onshore											
Base case (open)	€/MWh	56	81		85		56	81	85	59	89
Base case (closed)	€/MWh	56	87		92		56	87	92	59	95
Energy-Water-CCS nexus	€/MWh	56	A87	B102	A91	B99					

CO_2 avoidance								
Cooling technology		**Evaporative**				**Once-through**		**Air**
Case name		**1.1B**		**1.1C**		**1.2B**	**1.2C**	**1.3B**
Avoidance cost USCPC		**USCPC-EV-PCC**		**USCPC-EV-PCC-AC**		**USCPC-OT-PCC**	**USCPC-OT-PCC-AC**	**USCPC-AC-PCC**
Offshore								
Base case (open)	€/t	46		52		46	52	52
Base case (closed)	€/t	48		54		48	54	54
Energy-Water-CCS nexus	€/t	A53	B56	A59	B60			
Onshore								
Base case (open)	€/t	38		45		38	45	44
Base case (closed)	€/t	47		54		48	55	54
Energy-Water-CCS nexus	€/t	A47	B71	A53	B66			

A = water extracted volumetrically equivalent to CO_2 injected; B = water extracted to meet freshwater demand of power plant with capture

The NGCC power plant cases (Table 8) are broadly similar to the USCPC case in terms of LCOE values and the CO_2 avoidance costs. Base case conditions for on and offshore have LCOE ranges from 75 – 86 €/MWh. Energy-Water-CCS Nexus cases range from 79 – 86 €/MWh with little difference between on and offshore.

CO_2 avoidance costs for the base cases span from 64 – 93 €/t. The higher values are related to offshore closed reservoir conditions where higher operational conditions prevail to provide freshwater demand for the power and capture plant. The CO_2 avoidance costs for the Energy-Water-CCS-Nexus scenarios reveal higher values for offshore (88 -101 €/t) compared to onshore (79 – 86 €/t).

Table 8 LCOE and CO_2 avoidance cost of the NGCC power plant cases, with and without CCS

LCOE											
Cooling technology		**Evaporative cooling**					**Once through cooling**			**Air cooling**	
Case name		**2.1A**	**2.1B**		**2.1C**		**2.2A**	**2.2B**	**2.2C**	**2.3 A**	**2.3B**
LCOE NGCC		**w/o CCS**	**NGCC-EV-PCC**		**NGCC-EV-PCC-AC**		**w/o CCS**	**NGCC -OT-PCC**	**NGCC -OT-PCC-AC**	**w/o CC S**	**NGCC -AC-PCC**
Offshore											
Base case (open)	€/MWh	56	80		84		55	80	84	58	86
Base case (closed)	€/MWh	56	80		84		55	80	84	58	86
Energy-Water-CCS nexus	€/MWh	56	A83	B84	A87	B87					
Onshore											
Base case (open)	€/MWh	56	75		80		55	75	79	58	81
Base case (closed)	€/MWh	56	79		83		55	79	83	58	85
Energy-Water-CCS nexus	€/MWh	56	A79	B86	A83	B85					

CO_2 avoidance								
Cooling technology		**Evaporative**				**Once-through**		**Air**
Case name		**2.1B**		**2.1C**		**2.2B**	**2.2C**	**2.3B**
Avoidance cost NGCC		**NGCC-EV-PCC**		**NGCC-EV-PCC-AC**		**NGCC-OT-PCC**	**NGCC-OT-PCC-AC**	**NGCC-AC-PCC**
Case nane		**2.1B**		**2.1C**		**2.2B**	**2.2C**	**2.3B**
Offshore								
Base case (open)	€/t	78		91		79	92	87
Base case (closed)	€/t	80		93		80	93	89
Energy-Water-CCS nexus	€/t	A88	B92	A 101	B 101			
Onshore								
Base case (open)	€/t	64		77		65	78	73
Base case (closed)	€/t	75		88		75	88	84
Energy-Water-CCS nexus	€/t	A79	B86	A83	B85			

Phase 2

Four locations were considered in the second phase of this study, South Africa, Australia, China, and India. The integration of the entire CCS chain was assessed. The cases included ultra-supercritical power plants (USCPC) with an output of approximately 900MW. The cases with a carbon capture plant are based on the recent IEAGHG benchmark system (advanced configuration of a chemical absorption system using an aqueous blend of 40wt.% PZ+AMP (IEAGHG, 2019) at full capture rate (90% capture of power plant emissions).

The power plants were defined under the local conditions outlined in Table 9. The storage sites used in this study are described in Table 10. Results of the water and energy balances are included in Table 11.

Table 9 Overview of coal type, ambient conditions, and cooling systems modelled in this study

Location	Feedstock	Ambient conditions	Regulations/ Water treatment	Cooling system	Case names
South Africa (inland)	Coal - South African bituminous	T: 15°C, H: 60% P: 86.2 kPa	ZLD/ RO+ MVC +FCC	Air cooling, capture plant using EV	USPC-AC USPC-AC-PCC-EV
Australia (inland)	Coal - Eastern Australia bituminous	T: 20°C, H: 65% P: 101 kPa	NA/FO+RO	Air cooling, capture plant using EV	USPC-AC USPC-AC-PCC-EV
China (inland)	Coal - Chinese bituminous	T: 0°C, H: 60% P: 98 kPa	ZLD/ RO+ MVC +FCC	Air cooling, capture plant using EV	USPC-AC USPC-AC-PCC-EV
India (inland)	Coal - F-Grade Indian Coal	T: 25°C, H: 80% P: 101 kPa	ZLD/ RO+ MVC +FCC	Natural draft cooling tower, raw water make-up	USPC-EV USPC-EV-PCC

ZLD: Zero liquid Discharge; FO: Forward Osmosis; RO: Reverse Osmosis; MVC: Mechanical vapour compression; FCC: Forced Circulation Crystalliser; NA: No regulation applied

Table 10 Key details of the CO_2 storage basins identified for this study, the required annual CO_2 injection and water extraction rates, extracted brine quantities and TDS

Country		**South Africa**	**Australia**	**China**	**India**
Storage basin		Zululand Basin	Surat Basin	Songliao Basin	Cambay Basin
Location		Onshore	Onshore	Onshore	Onshore
Reservoir permeability	mD	<1 – 229	Med 13, max 1,500	150 - 285	0.3 - 163
Reservoir porosity	%	4 – 41	17	18 – 20	2 - 14
Formation water salinity	mg/l	14,000 – 38,000	5,000 – 15,000	3,500 – 9,000	7,000 – 10,000
Reservoir boundaries		Open	open	open	open
CO_2 injection rate	Mt/y	4.18	3.98	4.16	4.27
Water extraction		No	No	No	No
Reservoir boundaries		Closed	Closed	Closed	closed
CO_2 injection rate	Mt/y	4.18	3.98	4.16	4.27
Water extraction		Yes	Yes	Yes	Yes
Water extraction rate	Mt/y	7.11	6.77	7.07	7.26
TDS range	mg/l				
Estimated average TDS		26,000	5,000	5,000	9,000
Product recovery	%	92.75	85	98.53	97.33
Recovered product	Mt/y	6.60	5.75	6.96	7.07
Disposal of reject stream		n/a	Evaporation ponds	n/a	n/a

The schematic integration of the Energy-Water-CCS nexus is included in Figure 3.

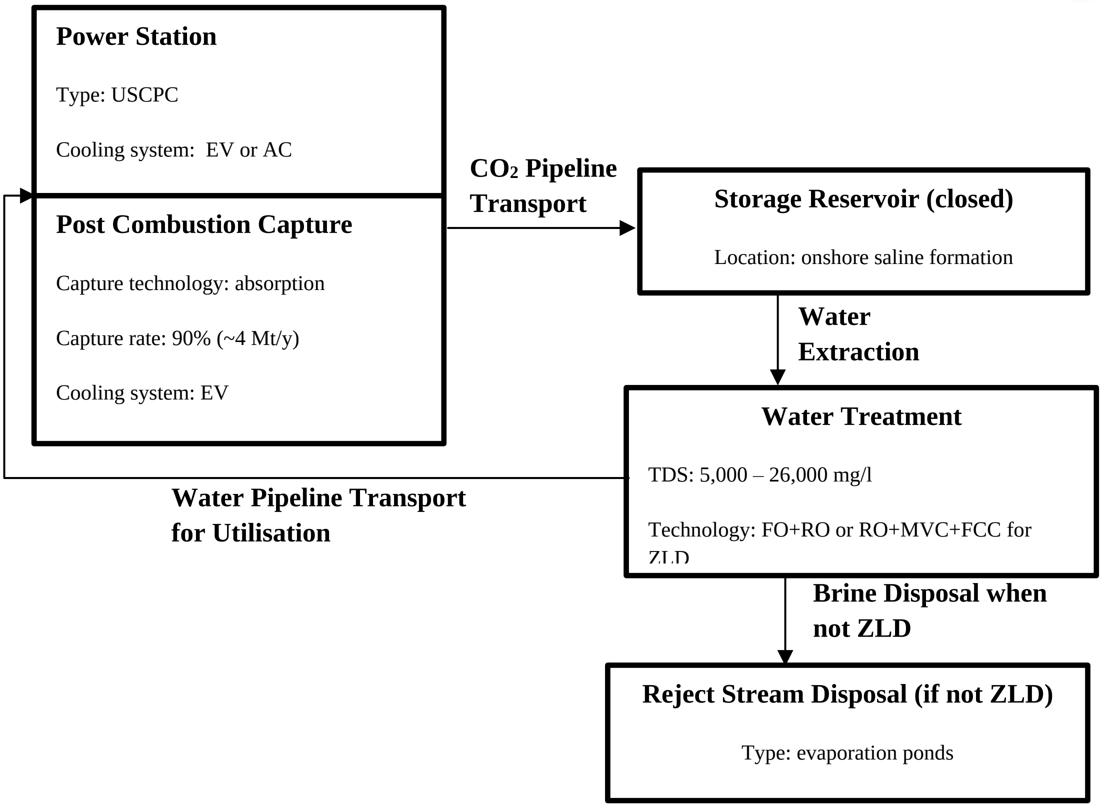

Figure 3 Flow diagram of the Energy-Water-CCS nexus Scenario with water treatment and utilisation in the power station with capture and other beneficial use (FO = forward osmosis, RO = reverse osmosis, MVC = mechanical vapour compression, FCC = forced circulation crystallizer, ZLD = zero liquid discharge)

Water withdrawal and consumption is similar in three cases (Australia, China and South Africa), approximately 0.07 m^3/MWh. The water withdrawal rate is higher in the Indian case, 0.83 m^3/MWh, although with a lower water consumption, 0.64 m^3/MWh. In all these cases the water requirement is mainly due to the need for make-up water in the fluegas desulfurization plant (FGD). If the CO_2 capture plant is added, the water requirement may increase significantly, for example in the case of South Africa from 55.4 to 839.87 m^3/h (Table 11).

Table 11 Water and energy balances of the cases with and without CO_2 capture considered in this study

Case	South Africa USCPC-AC	South Africa USCPC-AC-PCC-EV	Australia USCPC-AC	Australia USCPC-AC-PCC-EV	China USCPC-AC	China USCPC-AC-PCC-EV	India USCPC-EV	India USCPC-EV-PCC
Gross power output (MW)	879.3	879.3	879.7	879.7	879.5	879.5	899.7	899.7
Auxiliary power (MW)	110.6	251	157.6	286.7	92.2	240.7	106.9	259.8
Net power output (MW)	768.7	628.3	722.2	593.1	787.4	638.8	792.8	639.9
Net plant HHV efficiency (%)	39.94	32.64	37.51	28.99	40.90	33.17	41.17	33.23
Net plant LHV efficiency (%)	41.82	34.18	39.27	30.35	42.82	34.73	43.11	34.79
LHV efficiency loss due to PCC (%)		7.64		8.92		8.09		8.32
CO_2 generation (t/h)	624.1	624.1	593.8	593.8	620.1	620.1	637.5	637.5
CO_2 emission (t/h)	624.1	62.4	593.8	59.4	620.1	62	637.5	63.8
CO_2 emission (t/MWh)	0.812	0.099	0.822	0.1	0.788	0.097	0.804	0.1
CO_2 capture (t/h)	0	561.7	0	534.4	0	558.1	0	573.8
Energy consumption [MWh/t CO_2]		0.250		0.242		0.266		0.266
Energy consumption for absorbent pumps and blowers in PCC (MW)		8.98		8.55		8.93		9.11
Compressor energy (MW)		59.07		56.2		58.7		60.34
Pumps for cooling in PCC (MW)		7.46		7.09		7.41		7.62
Total electrical energy consumption in PCC (MW)		75.51		71.84		75.04		77.07
Water balance								
Water withdrawal (m^3/h)	55.40	839.87	50.72	774.90	53.41	589.30	657.85	1338.12
Process water discharge (m^3/h)	0	195.74	0	180.48	0	133.72	149.86	318.74
Water consumption (m^3/h)	55.40	644.13	50.72	594.42	53.41	455.58	507.99	1019.39
Water withdrawal (m^3/MWh)	0.07	1.34	0.07	1.31	0.068	0.92	0.83	2.09
Water consumption (m^3/MWh)	0.07	1.03	0.07	1.00	0.068	0.71	0.64	1.59
Increase in relative water withdrawal ([m^3/MWh]/[m^3/MWh])		1755%		1760%		1261%		152%
Increase in relative water consumption ([m^3/MWh]/[m^3/MWh])		1323%		1326%		952%		149%

For the economic analysis, the location factors from IEAGHG (2018) were used to translate the capital costs for different locations, together with some modifications based on the contractor experience.

As seen in IEAGHG (2018), the cost of CCS is dependent on the location. Based on the results from this study (Figure 4), the construction of a power plant with CCS in China is 30% cheaper than that in the Netherlands, while in South Africa and Australia it is 18 and 12% more expensive, respectively. Figure 4 also clearly shows that there is a significant addition cost for a power plant with a capture facility (PCC). This can be 52 - 60% of the power plant cost depending on location.

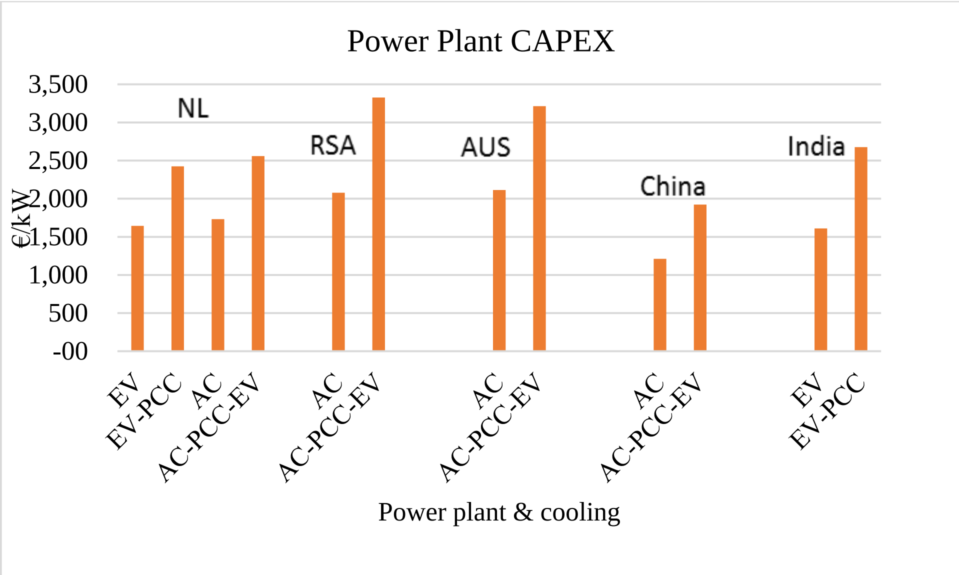

Figure 4 Capital cost of the base case reference power plant (NL) and the four selected countries, with and without CO_2 capture plant. (NL = The Netherlands, RSA = Republic of South Africa, AUS = Australia).

The operational costs for the reference base case (NL) and the four selected countries are depicted in Figure 5. In the case of each of the four countries investigated in Phase 2 there is a consistent trend which highlights the additional costs associated not only with capture but also water treatment, although there is some regional variation. Water treatment increases operational costs by 23 – 31%.

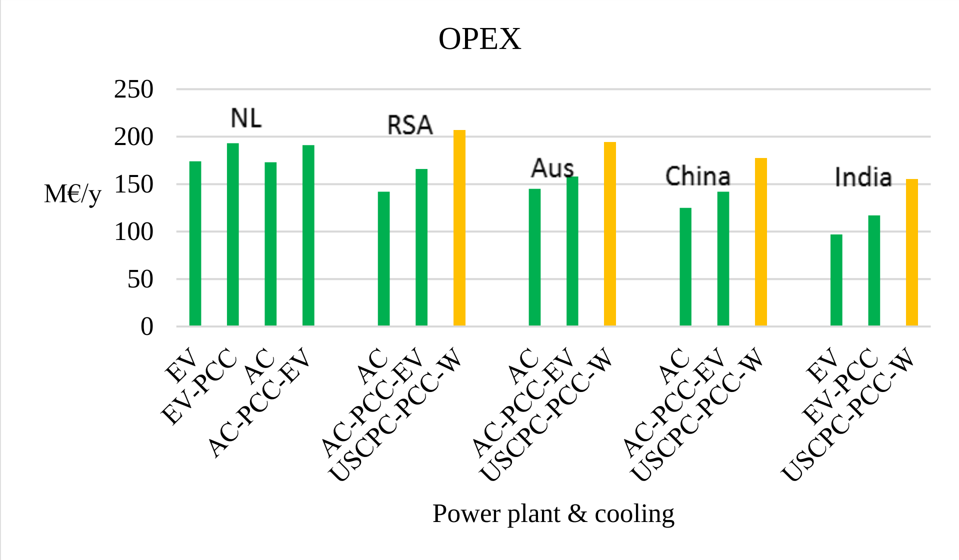

Figure 5 Operational costs of the base case reference power plant (NL) and the four selected countries, with and without CO_2 capture plant and with incorporated water treatment (-W). (NL = The Netherlands, RSA = Republic of South Africa, AUS = Australia).

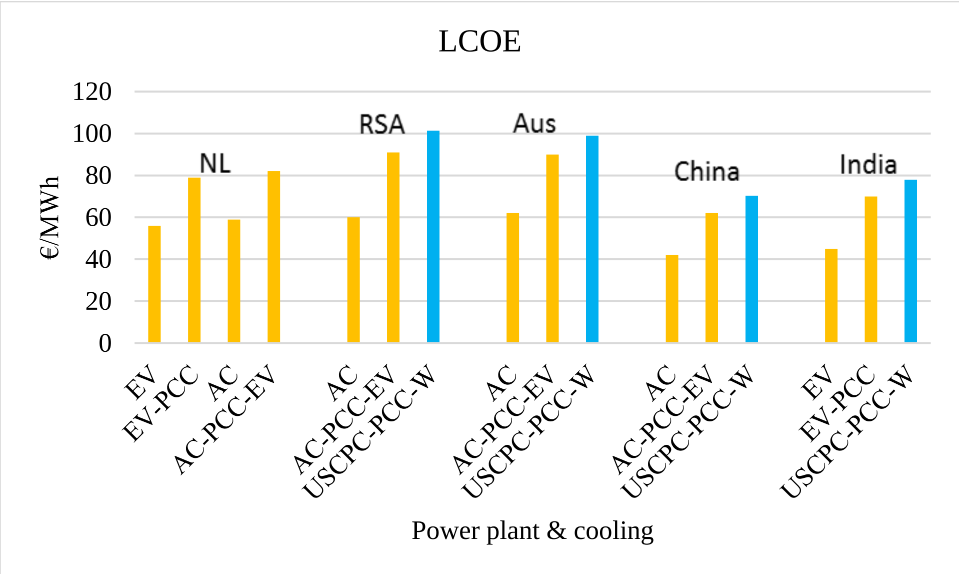

Figure 6 LCOE for the base case reference power plants (NL) and the power plants from the four selected countries with and without capture systems and incorporated water treatment systems (-W). (NL = The Netherlands, RSA = Republic of South Africa, AUS = Australia).

The LCOE for power plants using evaporative cooling systems without capture plant varied from 45 to 56 €/MWh, for India and the Netherlands respectively (Figure 6). If a CO_2 capture system is added, the cost rises to 62-83 €/MWh if evaporative cooling is also used in the CO_2 capture plant. Integrating this cooling technology into an Energy-Water-CCS nexus, increases the LCOE to 78-90 €/MWh. However, if the power plant uses air cooling, the LCOE is 42-62 €/MWh, and between 67 to 96 €/MWh with a CO_2 capture plant with evaporative cooling.

Integrating this system into an Energy-Water-CCS nexus, increases the LCOE to 70-101€/MWh (Figure 6). The impact of water treatment on the LCOE, and the range in values produced from this study, reflect the different labour, construction and material costs between the different countries. The variation in salinity in the extracted brines also partly explains the range in LCOE values. The underlying data is based on an example of the conditions in each location. Consequently, these results must be treated with discretion. For a comparison of the costs of each configuration it is convenient to review the results in Phase 1 and/or results from IEAGHG (2018). However, direct comparison needs to be qualified by checking detailed site-specific variations.

A breakdown of the capital and operational cost components that contribute to the LCOE (Figure 7) shows that the integration of the Energy-Water-CCS nexus has a relatively small impact on the LCOE. This means that the use of the water from the storage site could be used to cover some of the water requirements of the power plant with the CO_2 capture system. In water-stressed countries like South Africa this dimension could be an appealing option. Characterisation of the water extraction and water treatment systems were tailored to specific locations, although no reservoir storage modelling was carried out in this study.

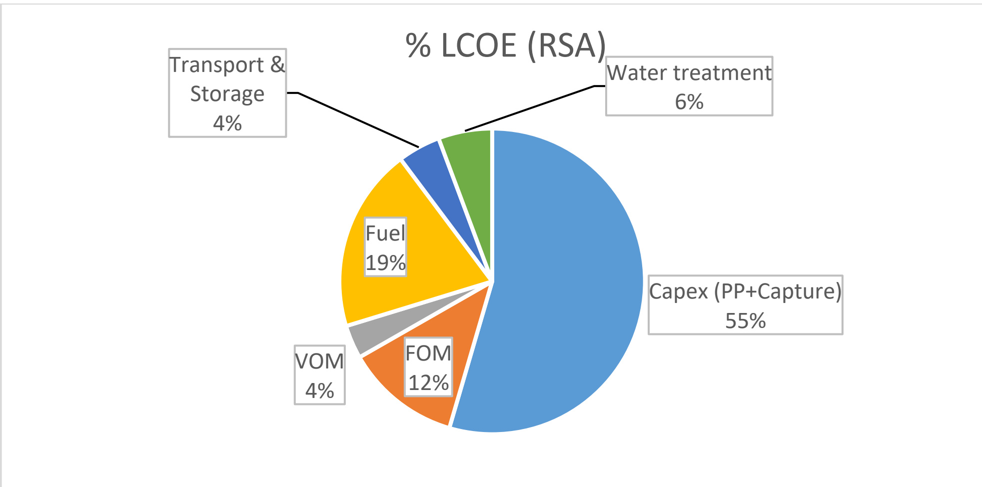

Figure 7 Percentage breakdown of capital and operational costs for a USCPC power plant in the Republic of South Africa (RSA) with capture plant and incorporated water treatment facility. (PP= Power Plant, VOM = variable operational and maintenance, FOM = fixed operational and maintenance cost)

Expert Review Comments

A review was undertaken by three international experts from the industrial sector and academia. The draft was generally well received.

The main comments and suggestions made by the reviewers were related to the techno-economic assumptions. Specifically, the contractor added more information to explain further assumptions and calculations related to the power and efficiency values, water-power-CCS scenarios, and definitions of water withdrawal, consumption, and discharge. It must be noted that the economic parameters are those in line with IEAGHG reports, and the solvent considered for the post-combustion capture system was the one described in IEAGHG (2019). That might result on differences with previous reports published by other organisations.

Conclusions

- If more restrictive regulations are imposed on power plants that currently use evaporative freshwater cooling, the use of extracted and treated formation water in an integrated CCS-water loop could be a cost competitive alternative to retrofitting a power plant with an air cooling system.
- Although adding a CO_2 capture system (amine-based chemical absorption) may increase the water consumption of the whole energy production system, there are available strategies to mitigate or even fully address this increase. Tailored early design of the Energy-Water-CCS nexus, that incorporates the cooling system and the potential reuse of water extracted from the storage site, is key.
- Based on the results from this study (Figure 4), the construction of a power plant with CCS in China is 30% cheaper than that in the Netherlands, while in South Africa and Australia it is 18 and 12% more expensive.
- There is a significant additional cost for a power plant with a capture facility which can be 52 - 60% of the power plant cost depending on location.
- There is a consistent trend in the additional costs associated not only with capture but also water treatment, although there is some regional variation. Water treatment increases operational costs by 23 – 31%.
- The LCOE for power plants using evaporative cooling systems without capture plant varied from 45 to 56 €/MWh, for India and the Netherlands respectively. If a CO_2 capture system is added, the cost rises to 62-83 €/MWh if evaporative cooling is also used in the CO_2 capture plant.
- Power plants modelled in this study that use air cooling have LCOE values of 42-62 €/MWh, and between 67 to 96 €/MWh with a CO_2 capture plant with evaporative cooling. Integrating this system into an Energy-Water-CCS nexus, increases the LCOE to 70-101€/MWh.
- The impact of water treatment on the LCOE, and the range in values produced from this study, reflect the different labour, construction and material costs between the different countries. The variation in salinity in the extracted brines also partly explains the range in LCOE values.

- Water extraction and treatment add a comparatively small capital cost to the examined CCS cases (5% increase), but the LCOE can increase by 11 – 12%.
- The normalised water withdrawal and consumption for air cooling power plants without capture is 0.07 m^3/MWh for the three countries (Australia, China, South Africa). With PCC using evaporative cooling, water withdrawal and consumption increases to 0.92 - 1.34 m^3/MWh and 0.71 - 1.03 m^3/MWh, respectively. The lowest withdrawal and consumption rates were achieved for the Chinese case, where the average air temperatures were extremely low.

Recommendations

This technical study covers one gap identified in previous reports: the integration of the Energy-Water-CCS nexus in different regions. It is recommended that IEAGHG should continue to maintain a watching brief of the Energy-Water-CCS nexus and advocate on transferring a transparent message for specialised audiences and the general public. Based on the results, the following areas are identified for further analysis:

- The assessment carried out in this technical study has limitations due to the techno-economic assumptions made. Specifically, the water extraction and CO_2 injection have a strong dependency on the characterization of specific storage sites. Further work should use the results from this study as a basis for further investigation centred on site-specific storage sites and brine characterisations.
- This study includes PZ+AMP-based chemical absorption as CO_2 capture system in the power plants. Recently, Rosa et al. (2020) explored chemical absorption, membrane separation, and adsorption into solid sorbents (temperature and pressure swing adsorption processes). Their objective was to link the modelled water consumption on the Energy-Water-CO_2 capture configurations with the water scarcity in different regions to promote their consideration on the evaluation of future CCS scenarios. A follow up on the increase on water consumption on Energy-Water-CCS nexus with different CO_2 capture systems would add value to the IEAGHG perspective.

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Understanding the Cost of Reducing Water Usage in Coal and Gas Fired Power Plants with CCS

Phase 1 Report

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IEAGHG
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Acknowledgments

Funding for this study was provided by the IEA Greenhouse Gas (IEAGHG) R&D Programme. The authors would like to thank Monica Garcia and James Craig from IEAGHG for providing valuable feedback on the report.

The authors would also like to acknowledge the support provided by CSIRO Energy, Australia.

Overview

Background

As demand for both water and energy increases, the interplay between power generation and water usage is growing in importance. Globally, thermal power generation from coal and natural gas is expected to increase from about 14 trillion kWh in 2015 to 18 trillion kWh in 2050 (EIA, 2017). Thermal plants require large quantities of water, primarily for cooling, and account for 40% of the total freshwater withdrawals every year (Feeley et al., 2008). Recent data from the US Energy Information Administration (EIA) shows that in the United States in 2010 alone almost 490 million cubic meters per day (Mm^3/d) of freshwater was withdrawn, and 13 Mm^3/d of water was consumed for power production (Diehl and Harris, 2014). In China, 84% of the freshwater intake in 2010 (70,000 GL) was for thermal power generation; with coal fired power accounting for 99% of the withdrawal (Pan et al., 2018; Qin et al., 2015). It is likely that as more power plants are built worldwide, and coupled with changing climates such as periods of drought and heatwaves becoming more common, this inter-dependency between energy and water means that thermal power production will become much more vulnerable to water demand and/or water supply concerns (Guerra and Reklaitis, 2018).

The presence of water in a potential storage formation reduces the available space for CO_2. Its extraction not only increases the storage capacity, but can also be beneficial in managing reservoir pressure and the plume. In previous work, the IEAGHG evaluated the benefits of extracting, processing and reusing the formation water from geological storage (IEAGHG, 2012b). The nature of the reservoir rock, reservoir boundary conditions and operational factors such as management of injection and extraction and placement of wells all influence the amount of water that may be extracted and, consequently, the amount of CO_2 that may be injected. Outputs indicated that the storage capacity of a reservoir can be increased, in exceptional circumstances, by between 100% and 1,300%, based on the pressure reduction within the geological storage formation. The report also considered water treatment methods to obtain an additional benefit through water reuse. Finally, although the treatment of extracted water is technically feasible, the economic challenges are potentially significant due to the typically high salinity of formation waters and the strict quality requirements for its reuse.

The present study builds on the previous work by incorporating reuse of extracted water as part of the whole CCS chain in a Dutch context. It explores the increase in water consumption resulting from CO_2 capture applying different cooling technologies, the potential of storing the captured CO_2 in saline formations onshore and offshore Netherlands and options for management of extracted water. An in-depth evaluation of the costs and benefits of integrating water usage with CCS and the factors influencing potential reuse of extracted water from the storage site is provided.

Scope of work

The objective of this study is to undertake a techno-economic evaluation of water usage along the whole CCS chain. This includes the development of the methodology which will be applied to assess the interrelation between water and CCS for a range of scenarios set in the Netherlands. More specifically, the study will explore the increase in water consumption associated with CO_2 capture and the potential for using extracted water from storage sites in power plant operations. The aim is to improve the integration of these processes, highlight existing challenges, and identify means to overcome them.

Specifically, this assessment aims to:

- Establish the state of the art in water reduction technology for power plants with and without capture, provide an overview of regulations relating to water usage and CO_2 emissions in power plants globally, identify storage capabilities in the Netherlands and establish state of the art technology for water extraction, management and treatment of geological water.
- Assess the water usage, waste water output and overall performance of coal fired and natural gas fired combined cycle power plants with and without capture using different cooling technologies.
- Assess the injection of CO_2 captured in the Netherlands in onshore and offshore saline formations, with and without brine extraction, and assess suitable strategies for managing the extracted brine based on Dutch regulations and water quality requirements.
- Assess the integrated CCS-water chain (CO_2 capture, compression, transport, and injection, and water extraction and its potential reuse), in which water management is considered in detail with extracted formation water being reused in the power plant, thus closing the CCS chain.
- Provide an economic assessment for the integrated CCS chain.
- Identify key factors influencing the potential reuse of extracted water, taking into account water quality requirements and non-technical matters.

Description of case studies

The following alternatives were assessed:

i. Base Case CCS Scenario, which considers the capture from an ultra-supercritical coal fired (USCPC) and a natural gas fired combined cycle (NGCC) power plant using different cooling technologies, transport and storage of CO_2 in onshore and offshore saline formations a) without water extraction; and b) with water extraction and disposal of the produced brine.

ii. CCS-Water-Nexus Scenario, which builds on the base case scenario and includes treatment of the extracted water for reuse in the power station and the capture plant. As only the power plants with evaporative cooling systems use significant volumes of freshwater, the other power plants are not considered in the integration of CCS and water extraction with reuse.

Figure 1 and Figure 2 illustrate the different cases of the two scenarios in a flow diagram.

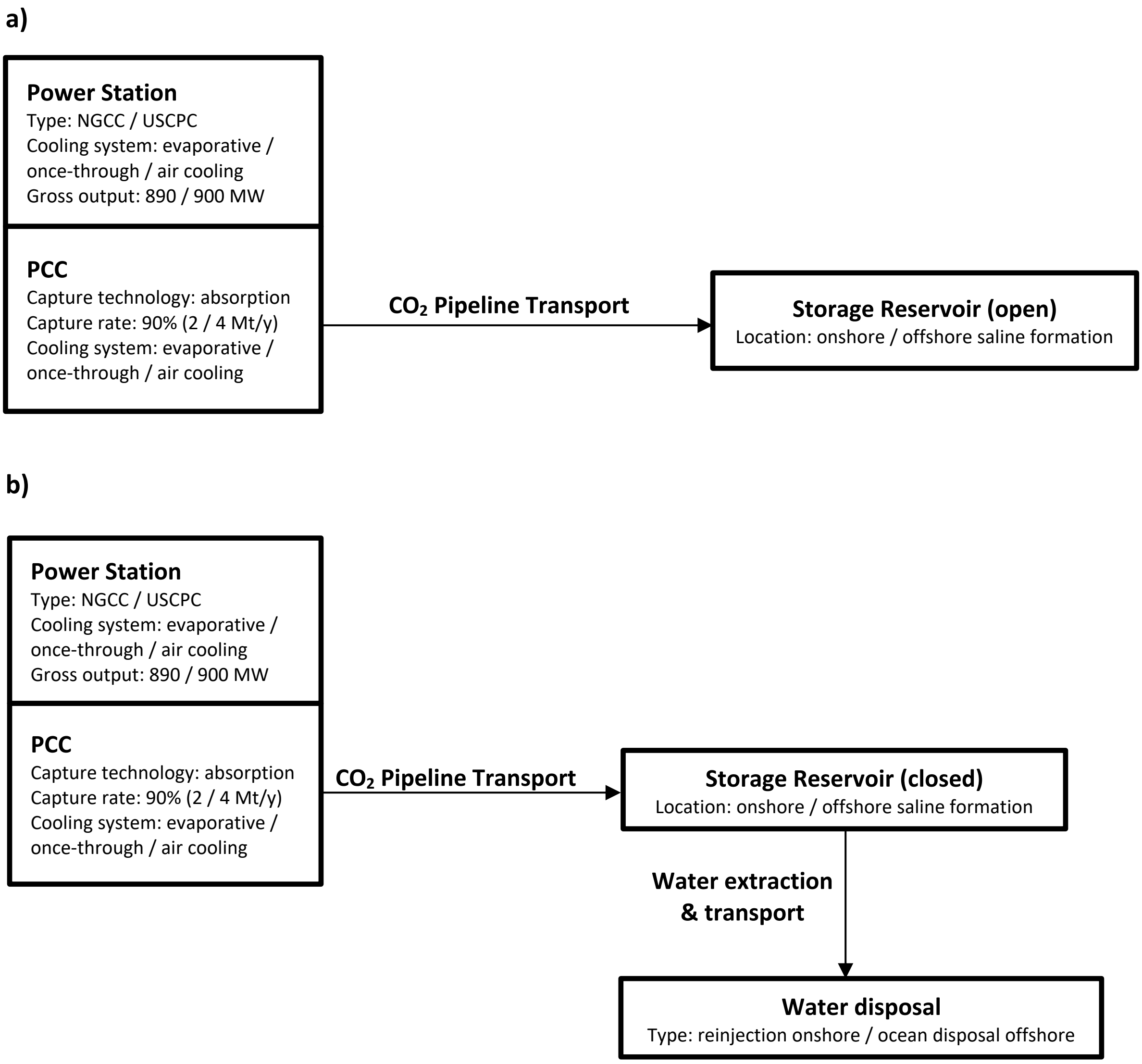

Figure 1 Flow diagram of the two cases of the Base Case CCS Scenario: a) CCS in an open formation without water extraction; b) CCS in a closed formation with water extraction and disposal

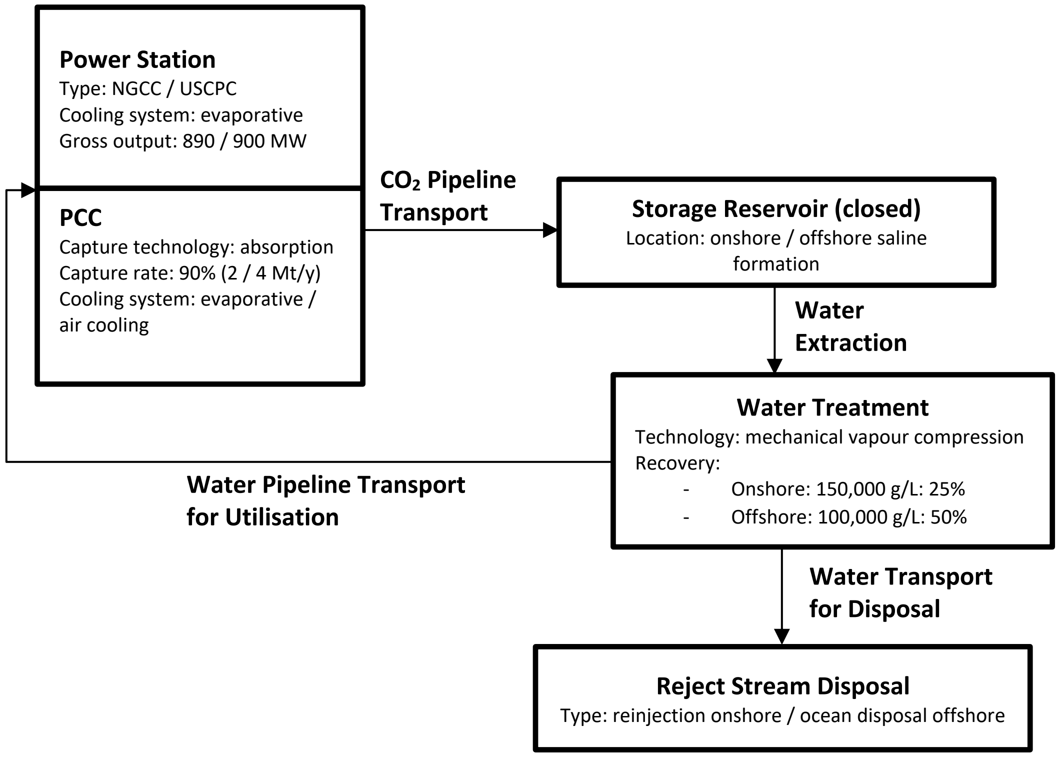

Figure 2 Flow diagram of the CCS-Water-Nexus Scenario with water treatment (CCS-water-nexus scenario) and utilisation in the power station with capture

Technical and economic basis

The detailed technical and economic assumptions of the study are outlined in the main report. The main baseline assumptions are as per below.

Economics

• Coal, €/GJ	2.5
• Natural Gas, €/GJ	5.0
• Maintenance costs indicative costs, % of TPC/y,	PC: 1.5; NGCC: 2.2
• Operating labour cost, €k/person-year	60
• Number of operators	18 for PC + PCC; 7 for NGCC+PCC
• Insurance cost, % of TPC	0.5
• Local taxes and fees, % of TPC	0.5
• Raw process water, €/m^3	0.2
• Limestone, €/t	20
• Discount rate:	8% in constant money values
• Discount rate sensitivity:	5%, 10%
• Cost year	2018
• Foreign exchange: 1 US$	0.85 €
• Currency	Euro

- Standard plant operating life, years 25
- Standard plant operating life sensitivity, years 40
- Capacity factor for power plants w/ and w/o CCS 85%
- Capacity factor in the first year of service 60%

Power plant and capture plant performance

- Nominal gross output of the power plants with and without capture:
    - USCPC: 900MWe
    - NGCC: 890MWe
- The post-combustion capture (PCC) technology is representative of a "Best Available Technology" absorption process utilising an aqueous solution of 40wt% piperazine/AMP in a 1:2 molar ratio
- The CO_2 capture rate is approximately 2 Mt/y for the NGCC and 4 Mt/y for the USCPC at a recovery rate of 90%
- Three cooling technologies are evaluated for each power plant with and without capture including evaporative, once-through seawater, and air cooling

Storage

- Homogeneous reservoir properties are used with representative values of permeability and porosity
    - Offshore: k = 100 md, ϕ = 0.15
    - Onshore: k = 200 md, ϕ = 0.2
- Formation water salinities are
    - Offshore: 100,000 mg/L
    - Onshore: 150,000 mg/L
- Reservoir boundaries are modelled as
    - Open
    - Closed
- The storage reservoirs are perfectly sealed by an overlying formation providing long-term containment
- Injection occurs over a period of 25 years at a rate of 2 Mt/y (for the NGCC) and 4 Mt/y (for the USCPC), corresponding to total injection amounts of 50 Mt and 100 Mt, respectively
- A single injection well is used for the 2 Mt/y scenario and two injection wells for the 4 Mt/y scenario
- Offshore, an existing platform can be modified for CO_2 storage operations
- New CO_2 and water extraction wells are drilled and completed onshore and offshore
- New pipelines for CO_2 and water transport are built and installed
- Extracted formation water disposal options are ocean discharge offshore and reinjection onshore (requiring newly drilled water disposal wells and pipelines)

Water treatment (CCS-Water-Nexus Scenario only)

- The extracted brines are treated using mechanical vapour compression (MVC)
- Recovery rates for water treatment applying MVC:
  - 50% recovery for a salinity of 100,000 mg/L (representative of the offshore brine)
  - 25% recovery for a salinity of 150,000 mg/L (representative of the onshore brine)
- The obtained water quality is that of freshwater
- The treated water is supplied to the power station with capture

Levelised cost of electricity

To determine the economic feasibility of each scenario, the economic assessment uses a net present value (NPV) discounted cash flow (NPV-DCF) model to estimate the lifetime cost, represented as the levelised cost of electricity (LCOE). The levelized cost of electricity is calculated assuming constant (real) prices for fuel and other costs, and a constant operating capacity throughout the plant lifetime apart from the lower capacity in the first year.

CO_2 avoidance cost

The cost of avoiding CO_2 emissions (as €/t CO_2 avoided) is calculated by comparing the costs and emissions of a plant with CCS and the costs and emissions of a reference case. The reference plant is the same type of generation technology and cooling technology as the plant with CCS. Sensitivity analysis evaluating the cost of avoidance where the reference plant for all scenarios is the power plant using evaporative cooling is also undertaken.

Notes

It should be noted that financing of the CCS project is not optimised and that the costs will be affected by the business model under which transport and storage is operated. For example, CO_2 may be captured from different sources and transported offshore for injection via the same pipeline thus incurring a CO_2 transport tariff. The presence of such a distribution network may decrease transport and injection unit costs as infrastructure costs are split over a larger quantity of CO_2 and the injected amount at a site may be optimised.

Costs presented in this report may only be treated as a preliminary guide. Cost sensitivities for transport and storage are not investigated within this study.

Results and discussion

Plant performance and water balance

Ultra-supercritical coal fired power plant

For both the USCPC and the NGCC power plant with and without capture different cooling systems are modelled, including evaporative cooling (EV), seawater once-through cooling (OT), and air cooling (ACC). The cooling system of the power plant may differ from the cooling system of the capture plant (PCC). The different cooling systems modelled for the USCPC power plant (Case 1) with and without capture are described in Table 1. The plant performance and water balances of the USCPC power plant with and without capture are summarised in Table 2.

Table 1 Cooling systems modelled for the USCPC power plant with and without capture

Case#	Case Name	Description
1.1A	USCPC-EV	USCPC boiler reference case based on standard supercritical steam conditions for a nominal 900 MWe gross output power plant without CCS. Evaporative (EV) mechanical draft cooling tower (recirculating system) is used for the power plant
1.1B	USCPC-EV-PCC	USCPC boiler for a nominal 900 MWe gross output power plant with CCS. Evaporative (EV) mechanical draft cooling is used for both the power plant and post-combustion capture (PCC) plant
1.1C	USCPC-EV-PCC-AC	Evaporative mechanical draft cooling tower is used for the power plant, air cooling is used for the PCC plant
1.2A	USCPC-OT	Once-through seawater cooling is used for the power plant without CCS
1.2B	USCPC-OT-PCC	Once-through seawater cooling is used for both the power plant and the PCC plant
1.2C	USCPC-OT-PCC-AC	Once-through seawater cooling tower for the power plant, air cooling for the PCC plant
1.3A	USCPC- AC	Air cooling is utilised for the power plant without CCS
1.3B	USCPC-AC-PCC	Air cooling is utilised for both the power plant and the PCC plant

Table 2 Technical performance for USCPC power plants (with and without capture)

Case name	1.1A	1.1B	1.1C	1.2A	1.2B	1.2C	1.3A	1.3B
	USCPC-EV	USCPC-EV-PCC	USCPC-EV-PCC-AC	USCPC-OT	USCPC-OT-PCC	USCPC-OT-PCC-ACC	USCPC-ACC	USCPC-ACC-PCC
Cooling technology	**Recirculating (EV)**		**EV + ACC**	**Once-through**		**OT + ACC**	**Air cooling (ACC)**	
Fuel input [t/h]	255.6	255.6	255.6	255.6	255.6	255.6	255.6	255.6
Gross power output (MW)	900	833.3	833.3	900	833.3	833.3	879.3	819.0
Auxiliary power (MW)	83	148.9	154.9	84	150.7	155.9	94.6	163.9
Net power output (MW)	817	684	678	816	683	677	785	655
Net plant HHV efficiency (%)	42.41	35.56	35.25	42.4	35.47	35.19	40.8	34.04
Net plant LHV efficiency (%)	44.40	37.23	36.90	44.4	37.13	36.85	42.7	35.64
CO_2 generation (t/h)	604	603.3	603.3	604	603.3	603.3	604	603.3
CO_2 emission (t/h)	604	59.3	59.3	604	59.3	59.3	604	59.3
CO_2 emission (t/MWh)	0.739	0.087	0.087	0.740	0.087	0.088	0.770	0.091
CO_2 capture (t/h)	0.0	544	544	0.0	544	544	0.0	544
Energy consumption								
Energy consumption for absorbent pumps and blowers in PCC (MW)	0.0	8.6	8.6	0.0	8.6	8.6	0.0	8.6
Compressor energy (MW)	0.0	57.2	57.2	0.0	57.2	57.2	0.0	57.2
Pumps/fans for cooling water in PCC (MW)	0.0	1.3	7.2	0.0	2.0	7.2	0.0	7.2
Total electrical energy consumption in PCC (MW)	0.0	67.1	73.1	0.0	67.9	73.1	0.0	73.1
Water balance								
Water withdrawal (m^3/h)	1090.8	1368.9	857.0	54.0	54.2	54.2	54.0	54.2
Process water discharge (m^3/h)	259.2	328.7	201.6	0.0	0.0	0.0	0.0	0.0
Water consumption (m3/h)	831.6	1040.2	655.4	54.0	54.2	54.2	54.0	54.2
Water withdrawal (m^3/MWh)	1.34	2.00	1.26	0.07	0.08	0.08	0.07	0.08
Water consumption (m^3/MWh)	1.02	1.52	0.97	0.07	0.08	0.08	0.07	0.08
Increase in relative water withdrawal		50%	-5%		20%	20%		20%
Increase in relative water consumption		49%	-5%		20%	20%		20%

Figure 3 shows the water balance around key process units within the USCPC power plants with and without capture using evaporative cooling systems. For the power plant without capture, the cooling tower accounts for the majority of the water withdrawal/consumption with 95% of the total usage. This is followed by the FGD make-up, accounting for the remaining 5%. Once CO_2 capture is implemented, the withdrawal rates in the power plant cooling towers increase by about 25%. Additional water withdrawal rates are required for the condenser cooling tower, CO_2 compression and PC cooling tower (for the process heat exchangers). When air cooling is utilised for the capture plant in a power plant with evaporative cooling, water use increases by 3%.

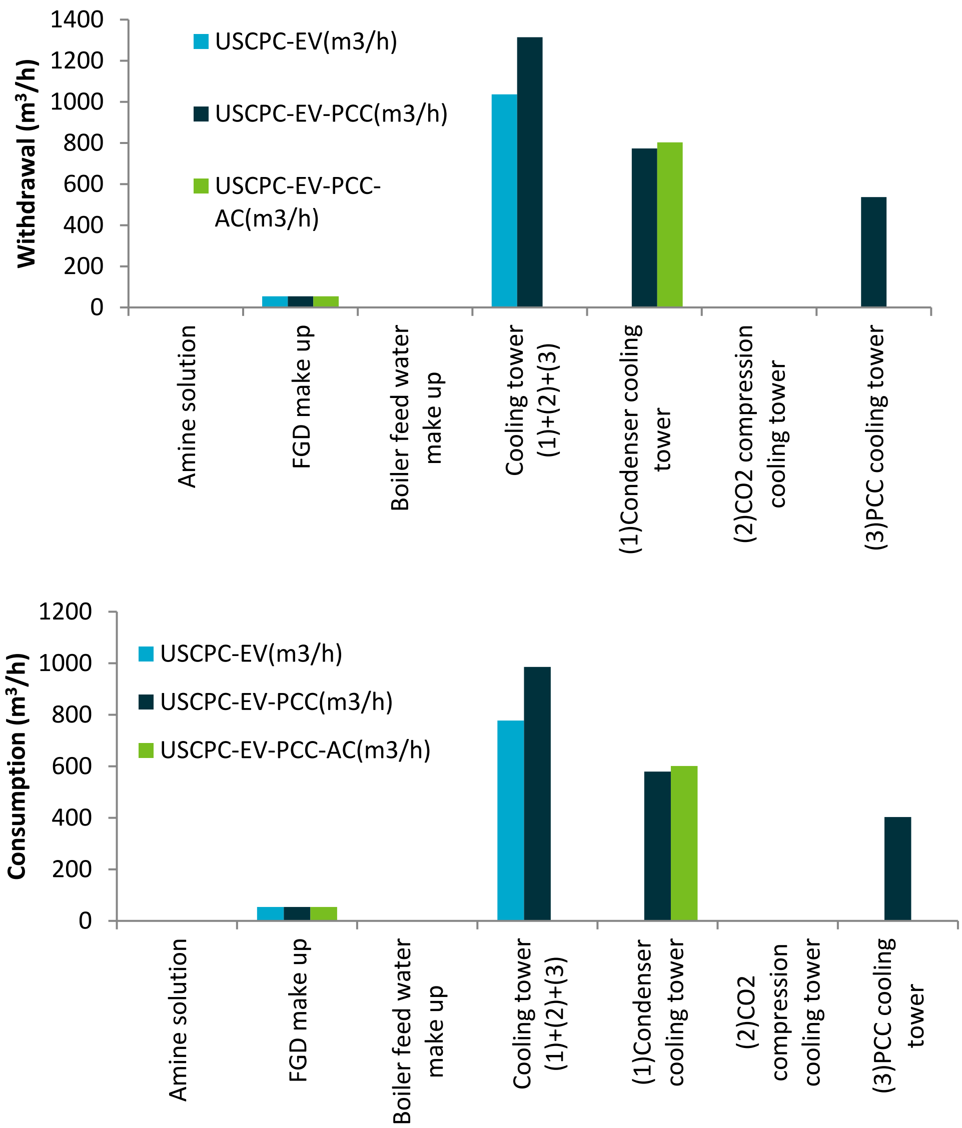

Figure 3 Absolute water withdrawal and consumption rates for the USCPC using evaporative cooling systems (Cases 1.1A/B/C)

Figure 4 shows the water balance for the USCPC power plants (with and without capture) using air cooling systems. The section requiring the majority of the freshwater is the FGD make-up, accounting for over 99% of the total water withdrawal/consumption. In absolute terms, this value is the same for both the power plants with and without capture - adding capture increases the water requirements by less than 1 m^3/h for the amine solution make-up.

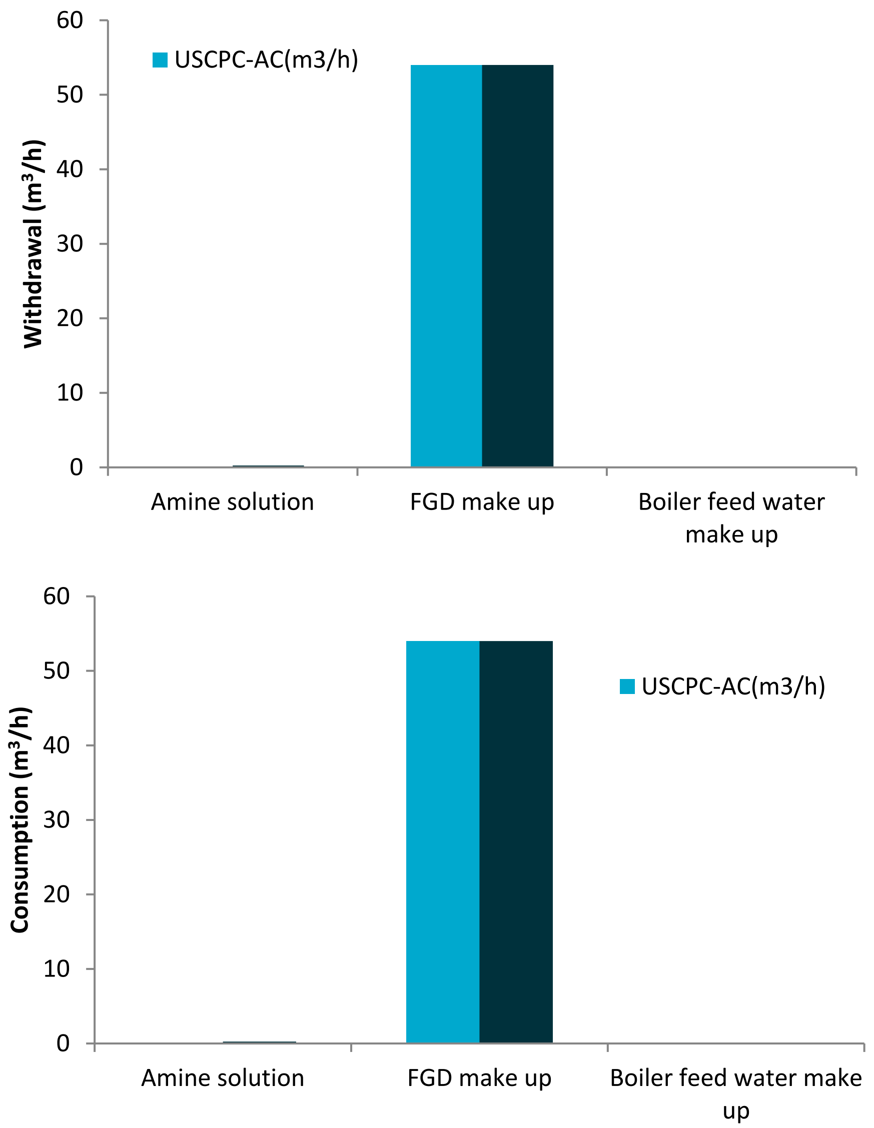

Figure 4 Absolute water withdrawal and consumption rates for the USCPC using air cooling systems (Cases 1.3A/B)

Using seawater once-through cooling systems (Figure 5), the primary process requiring freshwater is the FGD (accounting for all the water for the power plant without capture, and over 99% for the power plants with capture).

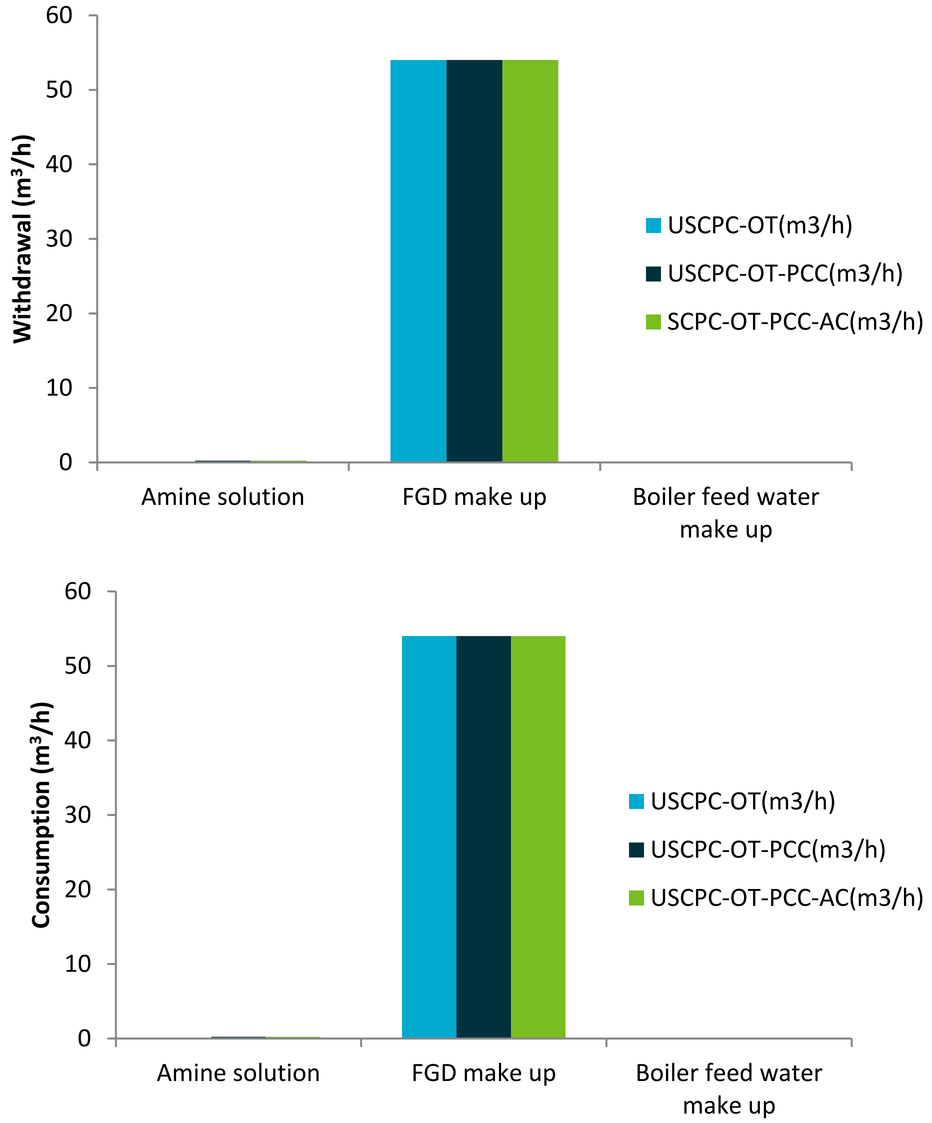

Figure 5 Absolute water withdrawal and consumption rates for the USCPC using once-through seawater cooling systems (Cases 1.2A/B/C)

Natural gas fired combined cycle power plant

Analogous to the USCPC, the different cooling systems modelled for the NGCC power plant (Case 2) with and without capture are described in Table 3. The technical performance and water balances of the NGCC power plant with and without capture are summarised in Table 4.

Table 3 Cooling systems modelled for the NGCC power plant with and without capture

Case#	Case Name	Description
2.1A	NGCC-EV	NGCC reference case for a nominal 890 MWe gross output power plant without CCS. Evaporative (EV) mechanical draft cooling tower (recirculating system) is used for the power plant
2.1B	NGCC-EV-PCC	Evaporative (EV) mechanical draft cooling is used for both the power plant and PCC plant
2.1C	NGCC-EV-PCC-AC	Evaporative mechanical draft cooling tower is used for the power plant, air cooling for the PCC plant
2.2A	NGCC-OT	Once-through seawater cooling is used for the power plant without CCS
2.2B	NGCC-OT-PCC	Once-through seawater cooling is used for both the power plant and the PCC plant
2.2C	NGCC-OT-PCC-AC	Once-through seawater cooling tower is used for the power plant, air cooling for the PCC plant
2.3A	NGCC-AC	Air cooling is utilised for the power plant without CCS
2.3B	NGCC-AC-PCC	Air cooling is utilised for both the power plant and PCC plant

Table 4 Technical performance for NGCC power plants (with and without capture)

Case name	2.1A	2.1B	2.1C	2.2A	2.2B	2.2C	2.3A	2.3B
	NGCC-EV	NGCC-EV-PCC	NGCC-EV-PCC-AC	NGCC-OT	NGCC-OT-PCC	NGCC-OT-PCC-AC	NGCC-AC	NGCC-AC-PCC
Cooling technology	Recirculating (EV)		EV + ACC	Once-through (OT)		OT + ACC	Air cooling (ACC)	
Fuel input [t/hr]	116.5	116.5	116.5	116.5	116.5	116.5	116.5	116.5
Gross power output (MW)	890.0	811.9	811.9	890	811.9	811.9	878.8	805.6
Auxiliary power (MW)	12.0	50.6	53.7	10.9	49.1	53.1	16.1	55.7
Net power output (MW)	878.0	761.3	758.2	883.3	762.8	758.8	862.7	749.9
Net plant HHV efficiency (%)	52.71	45.70	45.52	52.98	45.79	45.56	51.79	45.02
Net plant LHV efficiency (%)	58.34	50.59	50.39	58.65	50.69	50.42	57.33	49.83
CO_2 generation (t/h)	310	310	310	310	310	310	310	310
CO_2 emission (t/h)	310	30.9	30.9	310	30.9	30.9	310	30.9
CO_2 emission (t/MWh)	0.349	0.0375	0.0376	0.348	0.0374	0.0376	0.354	0.0380
CO_2 capture (t/h)	0	279.0	279.0	0	279.0	279.0	0	279.0
Energy consumption for PCC								
Energy consumption for absorbent pumps and blowers in PCC (MW)	0	13.1	13.1	0	13.1	13.1	0	13.1
Compressor energy (MW)	0	28.8	28.8	0	28.8	28.8	0	28.8
Pumps/fans for cooling water in PCC (MW)	0	2.3	5.4	0	1.5	5.4	0	5.4
Total electrical energy consumption in PCC (MW)	0	44.3	47.4	0	43.5	47.4	0	47.4
Water balance								
Water withdrawal (m^3/h)	572.4	756.3	320.5	0	0.1	0.1	0	0.1
Process water discharge (m^3/h)	144	186.9	79.2	0	0	0	0	0
Water consumption (m^3/h)	428.4	569.4	241.3	0	0.1	0.1	0	0.1
Water withdrawal (m^3/MWh)	0.65	0.99	0.42	0	0	0	0	0
Water consumption (m^3/MWh)	0.49	0.75	0.32	0	0	0	0	0
Increase in relative water withdrawal		53%	-35%					
Increase in relative water consumption		54%	-34%					

Figure 6, 7, and 8 show the water balance around key process units for the NGCC power plants with and without capture using evaporative, air and once-through cooling systems. Similar to the USCPC, water is required in the cooling towers. However, as there is no FGD, no make-up water is required. The absolute water withdrawal and consumption rates for the NGCC power plants are approximately half of that for the USCPC using evaporative cooling systems, and almost zero when air cooling or once-through seawater cooling is used. For NGCC power plants without capture, using air cooling or once-through seawater cooling, no water is required. Once capture is implemented, the absolute freshwater withdrawal and consumption rates increase by 0.13m^3/h.

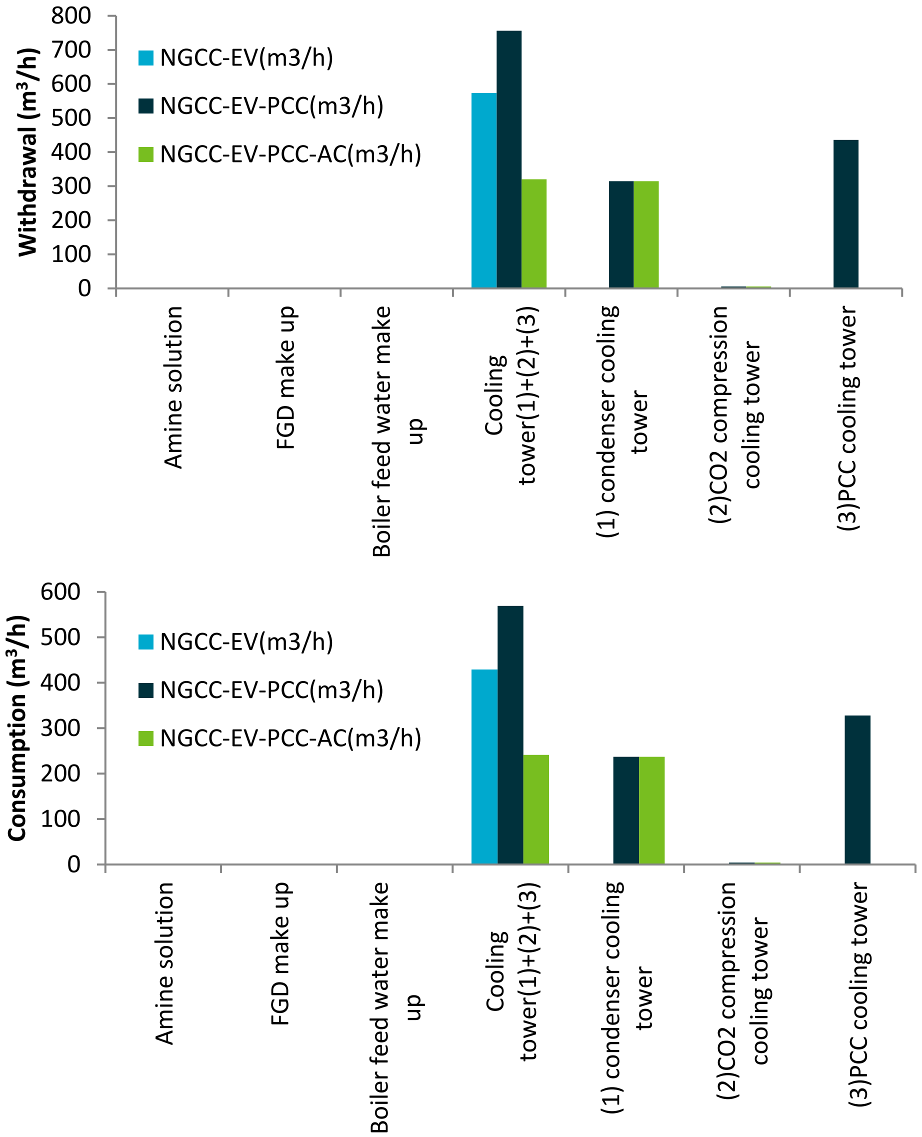

Figure 6 Absolute water withdrawal and consumption rates for the NGCC using evaporative cooling systems (Cases 2.1A/B/C)

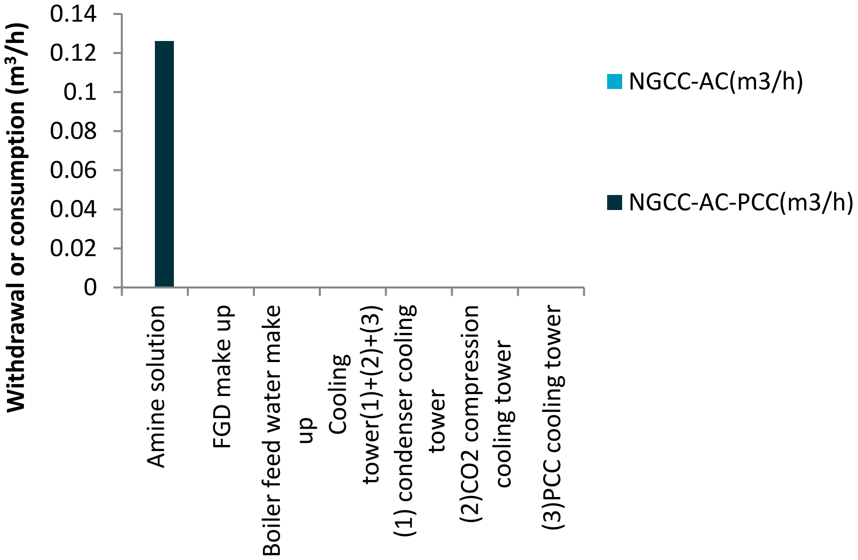

Figure 7 Absolute water withdrawal and consumption rates for the NGCC using air cooling systems (Cases 2.2A/B)

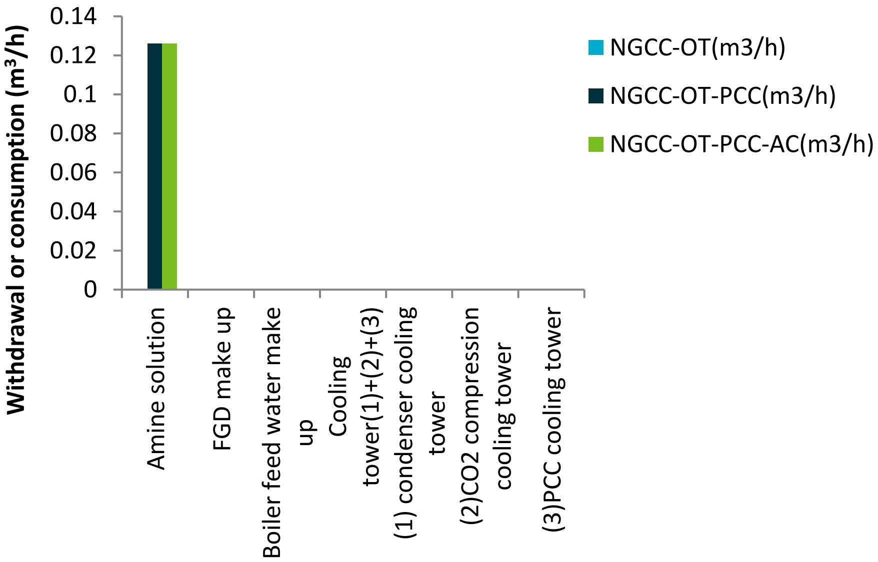

Figure 8 Absolute water withdrawal and consumption rates for the NGCC using once-through seawater cooling systems (Cases 2.3A/B/C)

CO_2 storage in the Netherlands

Two sites were selected for the modelling of CO_2 storage in the Netherlands, one onshore and one offshore formation. The formations were chosen based on the storage capacity they provide, which is matched with the CO_2 captured from the NGCC and the USCPC power plants over a period of 25 years. The reservoir units are assumed as homogenous, while in reality they are heterogeneous at multiple length scales. To improve the robustness of numerical predictions, it would be necessary to undertake a full reservoir modelling study once target storage formations have been chosen, but this is beyond the scope of this study.

The offshore formation is a saline aquifer in the Q1 block, which is part of the upper Rotliegend Group. Due to its size, this aquifer has been highlighted as a potential storage location for CO_2 captured in the Amsterdam and Rotterdam regions (Neele et al., 2011b). In this part of the offshore, the depth ranges from 2,200 m at the crest of the structure, down to 4,000 m at the base of the structural closure. The reservoir unit is quite thick in this region, ranging from 270 m to 360 m. Above this sandstone aquifer, a series of thick shale groups are present, acting as sealing units. As this reservoir is not well characterised, representative values for porosity (ϕ = 0.15) and permeability (k = 100 md) of similar magnitude to measurements in nearby wells are used. The salinity of the aquifer is modelled as 100,000 mg/L based on resistivity log data.

Onshore Netherlands, a large structural enclosure in the Rotliegend Group was identified as suitable for CO_2 storage. The reservoir varies in depth from 1,200 to 1,600 m and reaches thicknesses of over 400 m in parts. Representative values for porosity (ϕ = 0.2) and permeability (k = 200 md) are used as initial conditions and aquifer salinity is 150,000 mg/L.

Reservoir simulations are carried out using the TOUGH2 code (Pruess, Oldenburg and Moridis 1999). Several injection scenarios are considered for each of the onshore and the offshore sites, varying injection rate, injector number, boundary conditions as well as considering brine extraction. CO_2 injection rates investigated are 2 Mt/y and 4 Mt/y for a period of 25 years, representative of the amount of CO_2 captured from the NGCC and USCPC power plants, respectively. This corresponds to total injection amounts of 50 Mt (NGCC) and 100 Mt (USCPC). Constant injection rates are used, with either one or two injection wells, depending on the scenario. In practice, injectivity may be lower due to reservoir heterogeneity, in which case additional injection wells may be required. Furthermore, the injection rate will change over time depending on many factors, but for the purposes of an initial screening study for estimating storage capacity, the use of a constant injection rate is not expected to significantly alter the predictions.

The boundary conditions investigated for the onshore and the offshore scenario are closed and open boundary. In case of open boundaries, the storage simulations indicate that CO_2 can be stored at the desired rates without exceeding fracture threshold pressure. Pressure also remains below the fracture threshold in case of closed reservoir boundaries for the lower injection rate of 2 Mt/y over the injection time frame of 25 years. However, for the higher CO_2 injection rate of 4 Mt/y using two injection wells, the storage capacity of both the onshore and the offshore reservoir is pressure limited if boundary conditions are modelled as closed (Figure 9 and Figure 10). Fracture pressure is exceeded after approximately 10 years, limiting the storage capacity to 40 Mt, rather than the required 100 Mt. In this case, brine extraction volumetrically equivalent to the CO_2 injection rate is demonstrated to be an effective means to maintain pressure below the fracture threshold and enabling CO_2 injection at 4 Mt/y for a total capacity of 100 Mt over 25 years (compare Figure 9 and

Figure 10). This corresponds to a $H_2O:CO_2$ ratio of 1.68 and 1.73 in the offshore and onshore, respectively.

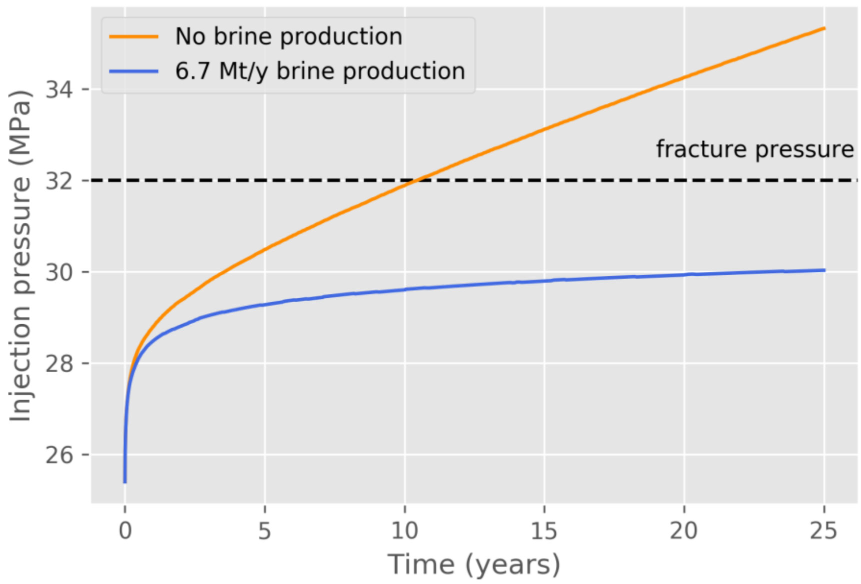

Figure 9 Bottomhole pressure for the offshore model with closed boundary conditions comparing injection with brine production (injection case Off-4c-2-2, blue curve) and without brine production (injection case Off-4c-2, orange curve) for a CO_2 injection rate of 4 Mt/y

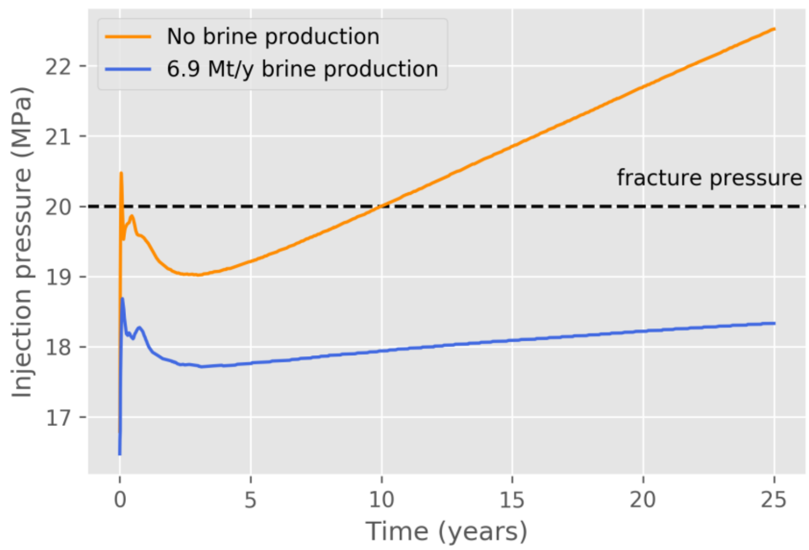

Figure 10 Bottomhole pressure for the onshore model with closed boundary conditions comparing injection with brine production (injection case On-4c-2-2, blue curve) and without brine production (injection case On-4c-2, orange curve) for a CO_2 injection rate of 2 Mt/year

The simulations further show the presence of a large region of mobile supercritical CO_2 at the top of the reservoir in both the onshore and the offshore model during and after production (compare Figure 11, which shows the extent of the plume at t = 100 years after 25 years of CO_2 injection in the offshore formation). This means that containment in this reservoir unit is contingent on the presence of a suitable sealing caprock.

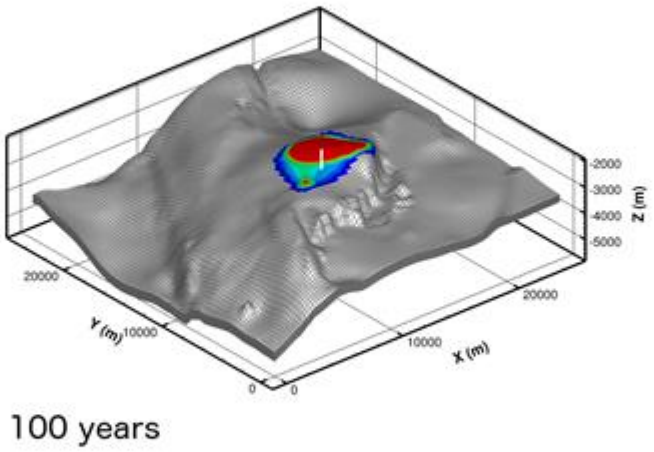

Figure 11 Offshore injection of 4 Mt/y CO_2 for 25 years (injection case Off-4o-1). Plume extent shown for 100 years

Due to the limited migration of the plume, only a small amount of CO_2 is immobilised in the pore space at residual saturation. In the offshore scenario at the end of the injection period, approximately 10% of the total CO_2 injected (corresponding to 10 Mt) is trapped by dissolution in the 4 Mt/y case, compared to approximately 12% (corresponding to 6 Mt dissolved) in the 2 Mt/y case. In the onshore scenario, 7% (7 Mt) is dissolved in the 4 Mt/y case after 25 years of injection, while for the 2 Mt/y case it is 9% (4.5 Mt).

The maximum storage capacity in the offshore aquifer model with open boundary conditions is estimated to be approximately 200 Mt, while in the onshore aquifer model it is 160 Mt. This is based on the size of the structures, their porosity and assuming a storage efficiency of 3%. If the aquifers are not assumed to be hydraulically connected to the surrounding reservoir, the injection rate of 4 Mt/y becomes pressure limited: for the 4 Mt/y injection scenario capacity was reached after 10 years at 40 Mt. However, this can be mitigated through brine production at a volumetrically equivalent rate.

The estimates are based on a simple model of the aquifers using representative properties and should therefore be considered preliminary estimates only.

Brine management in the Netherlands

Several options are available to manage the brine produced during CO_2 storage operations. For the offshore Q1 storage operation, disposal of produced brine in the order of ~7 Mt/y appears to be technically feasible, both in the form of discharge into the sea as well as reinjection into subsurface formations. From a regulatory point of view, it appears that countries are moving towards zero-impact emissions into the North Sea. While salinity has so far not been identified as a constraint for ocean disposal and produced brine for CO_2 storage would most likely contain significantly less contaminants related to petroleum processing and production, the Dutch regulator in the future may still require limited discharge to the North Sea and consider water reinjection as the preferred option.

In the onshore area, water disposal options are most likely limited to water reinjection. Water reinjection from oil and gas operations is currently common practice. However, existing onshore operations do not inject in excess of 1 Mt/y. Also, induced seismicity in response to water injection has been identified as an issue. Adequate storage capacity and injectivity for the reinjection of up to ~7 Mt/y would require additional geological and geomechanical assessments. Alternatively, produced water at the onshore CO_2 storage operation could be pipelined offshore for reinjection into offshore reservoirs or ocean disposal.

Water treatment may present a viable alternative where disposal of large volumes is either not feasible or not practical due to high costs. However, for the highly saline formation waters from the offshore and onshore storage sites, energy intensive thermal processes have to be applied for desalination. Applying mechanical vapour compression (MVC), a product water recovery of 50% can be expected for the brine concentration of 100,000 mg/L and 25% for the brine concentration of 150,000 mg/L. While other technologies can achieve considerably higher recovery rates, MVC is selected due to its cost competitiveness over other processes and its high product water quality. As a result of its high quality, the product water may be used as process feedwater, for agricultural uses, or to directly combat increasing salinisation in the Netherlands.

In this study, in the Base Case CCS Scenario the produced brine is disposed either via ocean disposal (offshore scenario) or reinjection (onshore scenario). In the CCS-Water-Nexus Scenario extracted brine is treated and used in the power plant where it can either substitute or complement the consumption of other freshwater sources. Two extraction scenarios are considered for the CCS-Water Nexus Scenario: A) extraction of the volumetrically equivalent brine amount required for safe CO_2 storage; B) extraction of the volume of brine necessary to meet the freshwater demand of the power plant using evaporative cooling with capture using either evaporative or air cooling. The water balances of the CCS-Water-Nexus scenarios are summarised in Table 5 and 6. Due to the significant water demand of the power plant with evaporative cooling and the comparatively low product water recovery of 25% and 50% using MVC to treat onshore and offshore extracted brine, respectively, the water extraction rates in Scenario B are typically considerably higher than in Scenario A.

Table 5 Water balance of the CCS-Water-Nexus Scenario for the NGCC power plant using evaporative cooling and the capture plant using either evaporative cooling or air cooling. CO_2 storage with brine extraction occurs either onshore or offshore with the extracted brine being treated applying mechanical vapour compression (MVC)

		NGCC using evaporative cooling with state of the art absorption							
Cooling technology		**Capture using evaporative cooling**				**Capture using air cooling**			
Water consumption (total)	Mt/y	4.24				1.8			
Water consumption (capture only)	Mt/y	1.05				0.00			
Storage location		offshore saline		onshore saline		offshore saline		onshore saline	
Formation water salinity	mg/L	100,000		150,000		100,000		150,000	
Product water recovery rate MVC	%	50		25		50		25	
CCS-Water-Nexus scenario		A	B	A	B	A	B	A	B
Water extraction rate	Mt/y	3.3	8.5	3.5	17.0	3.3	3.6	3.5	7.2

Product water	Mt/y	1.7	4.2	0.9	4.2	1.7	1.8	0.9	1.8
Reject brine	Mt/y	1.7	4.2	2.6	12.7	1.7	1.8	2.6	5.4

Table 6 Water balance of the CCS-Water-Nexus Scenario for the USCPC power plant using evaporative cooling and the capture plant using either evaporative cooling or air cooling. CO_2 storage with brine extraction occurs either onshore or offshore with the extracted brine being treated applying mechanical vapour compression (MVC)

		USCPC using evaporative cooling with state of the art absorption							
Cooling technology		**Capture using evaporative cooling**				**Capture using air cooling**			
Water consumption (total)	Mt/y	7.75				4.88			
Water consumption (capture only)	Mt/y	1.56				0.00			
Storage location		offshore saline		onshore saline		offshore saline		onshore saline	
Formation water salinity	mg/L	100,000		150,000		100,000		150,000	
Product water recovery rate MVC	%	50		25		50		25	
CCS-Water-Nexus scenario		A	B	A	B	A	B	A	B
Water extraction rate	Mt/y	6.7	15.5	6.9	31	6.7	9.8	6.9	19.5
Product water	Mt/y	3.4	7.8	1.7	7.8	3.4	4.9	1.7	4.9
Reject brine	Mt/y	3.4	7.8	5.2	23.3	3.4	4.9	5.2	14.6

Economic results

Table 7 and Table 8 summarise the LCOE, which include costs of CO_2 capture, transport, injection and storage as well as costs of water extraction, treatment and disposal where applicable, for all the cases examined for the USCPC and the NGCC power plants, respectively. These are the cases of the Base Case CCS Scenario, with storage in an open (no water extraction) and a closed (with water extraction) saline formation (Figure 1), and the cases of the CCS-Water-Nexus Scenario, with CO_2 storage in a closed formation investigating two different water extraction scenarios (extraction scenario A and B, described above) and treatment of the extracted water for reuse in the power plant with capture (Figure 2).

LCOE of the Base Case CCS Scenario without water extraction (open reservoir) range from 81 – 94 €/MWh for the USCPC and from 75 – 86 €/MWh for the NGCC (see Table 7 and Table 8). The LCOE vary as a function of cooling technology employed and storage location (i.e., onshore or offshore). For the Base Case CCS Scenario with water extraction (closed reservoir) there are modest increases in LCOE, with the LCOE ranging from 87 – 95 €/MWh for the USCPC and 79 – 86 €/MWh for the NGCC. The disposal options for the extracted water in the closed reservoir scenario have an effect on the LCOE. Offshore, water extraction and management only add up to 2 €/MWh to the LCOE due to the assumed no-cost disposal option of ocean discharge. However, onshore water extraction is associated with disposal costs which can increase the LCOE by up to 7 €/MWh. In spite of this, the analysis highlights that the LCOE for onshore storage are lower than for offshore storage (or maximum the same), even when water extraction and management is required onshore. This is due to the lower cost of transport and storage onshore, which offset the higher water management costs.

The analysis of the CCS-Water-Nexus Scenario highlights that if instead of water disposal, water treatment and reuse in the power station with capture is introduced, the LCOE increase by a relatively modest additional 3 €/MWh (less than 4%) for the offshore storage scenario, but remain the same for the onshore storage scenario or even decrease slightly if the water extracted is equivalent to the volume of CO_2 injected (extraction scenario A). This is because in the onshore scenario treatment of the produced water and its subsequent reuse in the power plant is more cost-effective than the direct disposal of produced water. Water disposal onshore is expensive due to a significant number of disposal wells being required. Reducing the brine volume for disposal by 25% is sufficient to justify the cost associated with brine treatment and reuse.

If the formation water extracted corresponds to the freshwater demand of the power plants with capture after treatment (extraction scenario B), the LCOE only increase by up to 3 €/MWh (maximum 3%) compared to extraction scenario A for offshore storage. Onshore, the increase in LCOE can be significantly greater at up to 15 €/MWh (17%) for the USCPC, though it can be as small as 2 €/MWh (2%) for the NGCC (compare Table 7 and Table 8). This is due to the very high additional costs of extraction and treatment arising from the low water recovery rates of the water treatment technology (25% for the 150,000 mg/L onshore brine and 50% for the 100,000 mg/L offshore brine) and the associated large water volumes that are therefore extracted. It should be noted that the USCPC consumes significantly larger volumes of water than the NGCC (compare Table 2 and Table 4) and thus requires higher water extraction rates to meet its demand.

The LCOE of the integrated CCS-Water-Nexus Scenario are comparable to those of power plants with CCS where air cooling is used (compare Table 7 and Table 8). This suggests that if stringent water regulations become imposed on power plants that currently use evaporative freshwater cooling, applying water utilisation from produced reservoir water as part of an integrated CCS chain becomes an opportunity.

Table 9 and Table 10 summarise the CO_2 avoidance cost for the USCPC and the NGCC scenarios, respectively. Avoidance costs are higher for capture from the NGCC than for the USCPC, while onshore storage results in lower avoidance costs than offshore storage.

For the CCS-Water-Nexus Scenario (power plant using evaporative cooling, capture plant using evaporative or air cooling), avoidance costs increase compared to the lowest cost scenario (the open reservoir base case) by up to 10 €/t CO_2 for offshore storage facilities, and by up to 15 €/t CO_2 avoided for onshore storage facilities. This is for the NGCC when water extraction is volumetrically equivalent to the CO_2 injected.

When water is extracted to meet the freshwater demand of the power plant with capture using evaporative cooling, avoidance cost can increase by up to 24 €/t (51%) in comparison to the scenario in which the volume of water extracted is volumetrically equivalent to the CO_2 injected. This is for the onshore extraction scenario as a result of the lower product recovery (25%) from the onshore brine.

Table 7 LCOE summaries for coal-fired USCPC power plants, with and without CCS

Cooling technology		Evaporative cooling					Once through cooling			Air cooling	
Case name		**1.1A**	**1.1B**		**1.1C**		**1.2A**	**1.2B**	**1.2C**	**1.3A**	**1.3B**
LCOE USCPC		**w/o CCS**	**USCPC-EV-PCC**		**USCPC-EV-PCC-AC**		**w/o CCS**	**USCPC-OT-PCC**	**USCPC-OT-PCC-AC**	**w/o CCS**	**USCPC-AC-PCC**
Offshore											
Base case (open)	€/MWh	56	86		90		56	86	90	59	94
Base case (closed)	€/MWh	56	87		92		56	87	91	59	95
CCS-Water-Nexus	€/MWh	56	A90	B93	A95	B96					
Onshore											
Base case (open)	€/MWh	56	81		85		56	81	85	59	89
Base case (closed)	€/MWh	56	87		92		56	87	92	59	95
CCS-Water-Nexus	€/MWh	56	A87	B102	A91	B99					

A = water extracted volumetrically equivalent to CO_2 injected; B = water extracted to meet freshwater demand of power plant with capture

Table 8 LCOE summaries for NGCC power plants, with and without CCS

Cooling technology		Evaporative cooling					Once through cooling			Air cooling	
Case name		**2.1A**	**2.1B**		**2.1C**		**2.2 A**	**2.2B**	**2.2C**	**2.3A**	**2.3B**
LCOE NGCC		**w/o CCS**	**NGCC-EV-PCC**		**NGCC-EV-PCC-AC**		**w/o CCS**	**NGCC -OT-PCC**	**NGCC-OT-PCC-AC**	**w/o CCS**	**NGCC-AC-PCC**
Offshore											
Base case (open)	€/MWh	56	80		84		55	80	84	58	86
Base case (closed)	€/MWh	56	80		84		55	80	84	58	86
CCS-Water-Nexus	€/MWh	56	A83	B84	A87	B87					
Onshore											
Base case (open)	€/MWh	56	75		80		55	75	79	58	81
Base case (closed)	€/MWh	56	79		83		55	79	83	58	85
CCS-Water-Nexus	€/MWh	56	A79	B86	A83	B85					

A = water extracted volumetrically equivalent to CO_2 injected; B = water extracted to meet freshwater demand of power plant with capture

Table 9 Cost of CO_2 avoidance summaries for coal-fired USCPC power plants, with and without CCS

Cooling technology		Evaporative				Once-through		Air
Case name		**1.1B**		**1.1C**		**1.2B**	**1.2C**	**1.3B**
Avoidance cost USCPC		**USCPC-EV-PCC**		**USCPC-EV-PCC-AC**		**USCPC-OT-PCC**	**USCPC-OT-PCC-AC**	**USCPC-AC-PCC**
Offshore								
Base case (open)	€/t	46		52		46	52	52
Base case (closed)	€/t	48		54		48	54	54
CCS-Water-Nexus	€/t	A53	B56	A59	B60			
Onshore								
Base case (open)	€/t	38		45		38	45	44
Base case (closed)	€/t	47		54		48	55	54
CCS-Water-Nexus	€/t	A47	B71	A53	B66			

A = water extracted volumetrically equivalent to CO_2 injected; B = water extracted to meet freshwater demand of power plant with capture

Table 10 Cost of CO_2 avoidance summaries for coal-fired NGCC power plants, with and without CCS

Cooling technology		Evaporative				Once-through		Air
Case name		**2.1B**		**2.1C**		**2.2B**	**2.2C**	**2.3B**
Avoidance cost NGCC		**NGCC-EV-PCC**		**NGCC-EV-PCC-AC**		**NGCC-OT-PCC**	**NGCC-OT-PCC-AC**	**NGCC-AC-PCC**
Offshore								
Base case (open)	€/t	78		91		79	92	87
Base case (closed)	€/t	80		93		80	93	89
CCS-Water-Nexus	€/t	A88	B92	A101	B101			
Onshore								
Base case (open)	€/t	64		77		65	78	73
Base case (closed)	€/t	75		88		75	88	84
CCS-Water-Nexus	€/t	A79	B86	A83	B85			

A = water extracted volumetrically equivalent to CO_2 injected; B = water extracted to meet freshwater demand of power plant with capture

Major conclusions

Power plant performance and water balance

- Power plants using evaporative cooling nominally require a substantial amount of freshwater. Adding CO_2 capture increases the consumption by approximately 50% for both USCPC and NGCC power plants.
- Power plants (NGCC and USCPC) using air cooling in both the power and capture plants have lower thermal plant efficiencies than evaporative cooling by 2%. The normalised water withdrawal and consumption for air cooling plants is almost negligible.
- Seawater once-through cooling in power plants with and without capture has thermal efficiencies similar to plants using evaporative cooling. The consumption of freshwater is almost negligible at 0.1 m^3/h.

Storage and brine management in the Netherlands

- In case of open reservoir boundaries, the storage simulations indicate that CO_2 can be injected at a rate of 2 Mt/y and 4 Mt/y over a period of 25 years without exceeding fracture threshold pressure while CO_2 plume migration is limited.
- In case of closed reservoir boundaries, for the CO_2 injection rate of 4 Mt/y using two injection wells, the storage capacity of both the onshore and the offshore reservoir is pressure limited. In this case, the capacity is 40 Mt which is reached after 10 years of injection, rather than the required 100 Mt.
- Brine extraction from two wells at a volumetrically equivalent rate (H_2O:CO_2 ratio of 1.73 and 1.68 onshore and offshore respectively) is found to be an effective mitigation option for maintaining pressure below the fracture threshold in the closed reservoir to enable CO_2 injection at 4 Mt/y for a total capacity of 100 Mt over 25 years.
- For the offshore Q1 storage operation, disposal of produced brine in the order of ~7 Mt/y through ocean discharge appears to be feasible from a technical and regulatory point of view.
- Onshore water disposal is limited to water reinjection. However, induced seismicity in response to water injection has been identified as an issue. Adequate storage capacity and injectivity for the reinjection of up to ~7 Mt/y would require additional geological and geomechanical assessments.
- Water treatment of produced brine and reuse presents an alternative to direct disposal. For the highly saline formation waters from the offshore and onshore storage sites mechanical vapour compression is identified as the most appropriate treatment technology due to its cost competitiveness and its high product water quality. Applying this technology, a product water recovery of 50% can be expected for the offshore brine concentration of 100,000 mg/L and 25% for the onshore brine concentration of 150,000 mg/L. The water is of suitable

quality to be used in the power plants to substitute or supplement the consumption of other freshwater sources.

Economics

- USCPC and NGCC power plants without CCS using evaporative and seawater once-through cooling systems have similar estimates for LCOE – approximately 56 €/MWh. If air cooling is used, the LCOE increases by approximately 5% (to 58 €/MWh for the NGCC and to 59 €/MWh for the USCPC).
- Adding capture increases the LCOE by around 20 €/MWh for the power plants using evaporative and once-through cooling systems. When the power plants with capture are air-cooled, the LCOE increase by around 20 €/MWh for the NGCC and more than 25 €/MWh for the USCPC.
- CO_2 storage onshore without water extraction is the cheapest storage option for both the USCPC (4 Mt/y) and the NGCC (2 Mt/y) at 3.31 €/t and 4.50 €/t of CO_2 stored, respectively.
- Integrating capture and storage in an open reservoir (i.e., no water extraction) with the NGCC power plant increases the LCOE by a minimum of approximately 20 €/MWh for onshore storage and a minimum of about 25 €/MWh for offshore storage. For CCS from the USCPC a minimum increase in LCOE of 25 €/MWh is expected for CCS onshore, while for CCS offshore the LCOE are estimated to increase by a minimum of 30 €/MWh. This is for power plants using evaporative and once-through cooling, while the increase in LCOE is higher when CCS is added to air-cooled power plants.
- The extraction of water and its disposal, i.e. no integration and reuse, only contributes a minor cost to the CCS project: offshore, water extraction and management may add up to 2 €/MWh (~2%) to the LCOE, though onshore the disposal costs can increase the LCOE by up to 7 €/MWh (~8%). This demonstrates that the economics of water extraction and management are affected by the water management strategies available offshore and onshore.
- By integrating storage-extracted water reuse with the CCS chain, water extraction, treatment, transport and disposal add between ~2-3 €/MWh to the LCOE in the offshore storage scenario and between ~3 - 6 €/MWh in the onshore scenario. If more brine than needed for safe CO_2 storage is extracted to meet the freshwater demand of the power station with capture, this can add up to 7 €/MWh (~8%) to the LCOE for the offshore storage scenario, and 15 €/MWh (~17%) to the onshore scenario.
- In the onshore storage scenario, treatment of the extracted formation water and its subsequent reuse in the NGCC or USCPC power plants is more cost-effective than the direct disposal of produced water due to long pipeline transport and a significant number of disposal wells being required. Reducing the brine volume for disposal by 25% is sufficient to justify the cost associated with brine treatment and reuse. For less saline brines (onshore brine: 150,000 mg/L) the economic benefits would improve further as product recovery would increase and/or cheaper treatment technologies may be applied. Therefore, where

water extraction is necessary for storage purposes, its treatment and beneficial reuse may present the most economic option.

- The LCOE of the USCPC and NGCC power plants with CCS and integrated formation water reuse are found to be comparable to the LCOE of USCPC and NGCC power plants with CCS where air cooling is used. If stringent water regulations become imposed on power plants that currently use evaporative freshwater cooling, using extracted and treated formation water in an integrated CCS-water loop may be cost competitive compared to retrofitting the power plant to use air cooling.

Introduction

As demand for both water and energy increases, the interplay between power generation and water usage is growing in importance. Globally, thermal power generation from coal and natural gas is expected to increase from about 14 trillion kWh in 2015 to 18 trillion kWh in 2050 (EIA, 2017). Thermal plants require large quantities of water, primarily for cooling, and account for 40% of the total freshwater withdrawals every year (Feeley et al., 2008). Recent data from the US Energy Information Administration (EIA) shows that in the United States in 2010 alone almost 490 million cubic meters per day (Mm^3/d) of freshwater was withdrawn, and 13 Mm^3/d of water was consumed for power production (Diehl and Harris, 2014). In China, 84% of the freshwater intake in 2010 (70,000 GL) was for thermal power generation with coal fired power accounting for 99% of the withdrawal (Pan et al., 2018; Qin et al., 2015). It is likely that as more power plants are built worldwide, particularly in Asia, and coupled with changing climates such as periods of drought and heatwaves becoming more common, this inter-dependency between energy and water means that thermal power production will become much more vulnerable to water demand and/or water supply concerns (Guerra and Reklaitis, 2018).

The presence of water in a potential storage formation reduces the available space for CO_2. Its extraction cannot only increase the storage capacity, but also be beneficial in managing reservoir pressure and the plume. In previous work, IEAGHG evaluated the benefits of extracting, processing, and reusing the formation water from geological storage (IEAGHG, 2012b). The nature of the reservoir rock, reservoir boundary conditions and operational factors such as management of injection and extraction and placement of wells all influence the amount of water that may be extracted and, consequently, the amount of CO_2 that may be injected. Outputs indicated that the storage capacity of a reservoir can be increased, in exceptional circumstances by between 100% and 1,300%, based on the pressure reduction within the geological storage formation. The report also considered water treatment methods to obtain an additional benefit through water reuse. Finally, although the treatment of extracted water is technically feasible, the economic challenges are potentially significant due to the typically high salinity of formation waters and the strict quality requirements for its reuse.

The present study builds on the previous work by incorporating reuse of extracted water as part of the whole CCS chain in a Dutch context. It explores the increase in water consumption resulting from CO_2 capture applying different cooling technologies, the potential of storing the captured CO_2 in saline formations onshore and offshore Netherlands and options for management of extracted water.

The objective of this study is to undertake a techno-economic evaluation of water usage along the whole CCS chain, including the different storage-extracted water management options available. This includes the development of the methodology which is applied to assess the interrelation between water and CCS for a range of scenarios set in the Netherlands. More specifically, the study explores the increase in water consumption associated with CO_2 capture and the potential for using extracted water from storage sites in power plant operations. The aim is to improve the integration of these processes, highlight existing challenges, and identify means to overcome them.

Chapter 1 presents a review of literature to establish the state of the art in water reduction technology for power plants with and without capture, provide an overview of regulations relating to water usage and CO_2 emissions in power plants globally, identify storage capabilities in the Netherlands, and establish state of the art technology for water extraction, management and treatment of geological water.

Chapter 2 presents the performance and water usage of ultra-supercritical coal fired (USCPC) and natural gas fired combined cycle (NGCC) power plants with and without capture for conditions representative of a hypothetical site in the Netherlands. The power stations have a gross output of 900 MWe and 890 MWe for the USCPC and the NGCC, respectively. The performance of the power stations is established with respect to different cooling technologies, including evaporative natural draught cooling (recirculating system), once-through cooling using seawater, and air cooling. The post-combustion capture (PCC) plant may utilise the same cooling technology as the corresponding power station or alternatively it may use air cooling.

Chapter 3 investigates the storage of CO_2 captured at the power plants described in Chapter 2 at two sites in the Netherlands. CO_2 injection is modelled for one offshore and one onshore location, assuming open as well as closed reservoir boundary conditions. The storage capacity as well as CO_2 containment and plume migration are assessed. Water extraction as a means to enhance storage capacity is simulated and options for extracted water management based on Dutch regulations are proposed.

In Chapter 4 the power plants described in Chapter 2, and CO_2 storage and brine management, as described in Chapter 3, are integrated to present the complete CCS chain, including CO_2 capture, compression, transport, and injection, and water extraction and its potential reuse. Two CCS scenarios with several sub-cases are considered: Base Case CCS Scenario and CCS-Water-Nexus Scenario.

The Base Case CCS Scenario represents the standard CCS chain of capture, transport and storage, but also considers the extraction of formation water and its disposal to increase the CO_2 storage capacity of a closed formation.

In the CCS-Water-Nexus Scenario the Base Case CCS Scenario is expanded upon to include treatment of the extracted water as a brine management strategy and its reuse in the power plant with capture to form a CCS loop. Two water extraction scenarios are investigated:

A. water extraction rate volumetrically equivalent to the amount of CO_2 injected.
B. water extraction rate after water treatment matched to the freshwater demand of the power plant with capture.

In the second water extraction scenario (scenario b) water beyond what is needed for safe CO_2 storage is extracted to meet the freshwater demand of the power station with capture. This is a hypothetical scenario that is economically assessed without reservoir simulation studies.

Chapter 5 presents the economic assessment of the Base Case CCS Scenario and the integrated CCS-Water-Nexus Scenario from Chapter 4. The assessment compares costs for power plants with and without capture, the costs for different cooling technologies deployed at the power plant and/or capture plant, the different storage options (onshore and offshore, open and closed reservoir boundaries), as well as the different brine management options available. The cost of CO_2 avoidance and the levelized cost of electricity are estimated for each scenario.

Sensitivities to the economic parameters discount rate and project life are also undertaken, as well as a sensitivity to the reference plant for the Base Case CCS Scenario. The sensitivity analysis is only presented for the Base Case CCS Scenarios with no brine extraction in an open reservoir (no water extraction and no utilisation) as the trends observed due to the sensitivities are also applicable in the cases with water extraction (closed reservoir), and water extraction and utilisation (CCS-Water-Nexus Scenario).

Chapter 6 identifies key factors influencing the potential reuse of extracted water, taking into account water quality requirements and the potential for using existing oil and gas infrastructure, while Chapter 7 presents the major findings of this study as well as recommendations to improve the technical and economic viability of water recovery for integrated power plants with water reuse.

1 Literature Review

1.1 Water usage in power plants

1.1.1 Cooling systems in thermal power plants

Thermal power plants, including coal, gas and biomass, require both cooling and process water. Typically, the amount of process water is minor, whilst the bulk of the water usage is for cooling requirements and is dependent on the cooling system used. The type and design of power plants affects the volume of water used (Feeley et al., 2008, IEAGHG, 2018a).

Cooling systems for power plants can be classified as once-through and re-circulating (Figure 1-1). Recirculating cooling systems can be sub-classified into wet-cooling systems, such as cooling ponds and cooling towers, dry (or air) cooling systems, or a hybrid of both. Each cooling system involves trade-offs associated with water usage, effects on the quality of water sources, and impacts on the efficiency and cost of the power plants. The choice of which cooling system to use is influenced by the location of the power plant, local environmental regulations and economics. For example, of the existing thermal power plants in the US about 43% use a once-through cooling water system with most of these plants built before 1970. After 1970, the majority of cooling systems installed use recirculating cooling. Also, wet-recirculating cooling systems are approximately 40% more expensive than once-through cooling systems, while dry-cooling systems are 3-4 times more expensive than wet-recirculating systems (DOE-NETL, 2009).

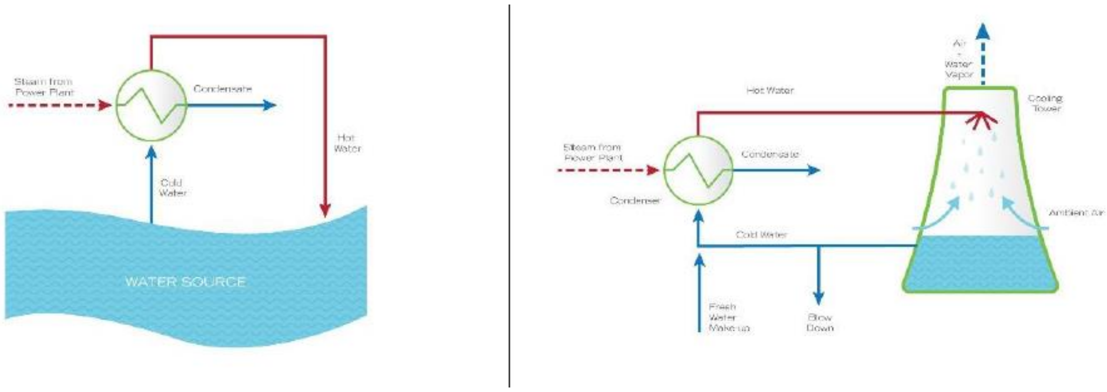

Figure 1-1 Once-through (left) and recirculating cooling systems (right) (Global CCS Institute, 2016)

Typically, once-through (OT) cooling systems withdraw large quantities of water, but return most of it to the source. Once-through cooling systems are normally used in areas where water is abundant. Once-through cooling takes water directly from a source such as a river, lake, or ocean and uses it to condense the steam in the boiler before returning it to the original source, though at a few degrees warmer. Apart from the simplicity of the design, once-through cooling systems have the advantage that if the water source is available at low temperatures and is plentiful, it is the most efficient and cost effective method of cooling. However, the primary concern with this design is the potential harm to aquatic life near the power plant, which can be caused by the mechanisms used to withdraw the water, and the higher temperature of the returning water.

Closed-loop or recirculating systems recirculate cooling water throughout the power plant and release the heat through a cooling tower or pond. The most common of the closed-loop systems is wet-cooling via cooling towers. The principal components of a conventional wet cooling system comprise the surface condenser, the wet tower, and the circulating water system that moves water from the condenser to the wet tower. In this system, the water goes through the steam condenser removing waste heat. Leaving the condenser, warm water is then pumped to the top of the cooling tower where it flows counter-current to a flow of extracted air. The circulating water is cooled by a combination of evaporation and convective heat exchange with the air. The warm moist plume rises from the tower, and the cooled water is collected at the bottom of the tower and pumped back to the condenser in a continuous cycle. Any water lost through evaporation in the cooling tower is replaced with new water taken from an external source. These evaporative losses can lead to the build-up of minerals and sediment in the water that could adversely affect performance of the process. To prevent this build-up, a portion of the cooling water, known as "blowdown", is periodically discharged from the system. This discharge to the water source is regulated and the cooling water is often treated before being returned to the source or evaporated in holding ponds.

Dry cooling systems (air cooling) uses air instead of water as the heat transfer medium; the turbine exhaust steam flows through air condenser tubes that are cooled directly by conductive heat transfer using a high flow rate of ambient air. In this type of cooling system, the power plant does not withdraw or consume any water for cooling purposes. However, as air is a less efficient cooling medium, it requires very large surface areas for effective heat exchange. As a consequence, dry cooling systems are used less prevalently than wet systems and are 3-4 times more expensive than the equivalent wet system. Dry cooling systems are usually used in dry and arid areas where water is scarce. Apart from the high capital costs associated with dry cooling systems, given that they are generally located in hot dry areas, during periods of extreme heat, the effectiveness of the cooling system decreases, severely affecting the performance of the power plant.

In addition to cooling and process water within thermal power plants, other processes including environmental controls can also increase water consumption. Flue gas desulphurisation (FGD) scrubbers used to reduce air emissions such as SOx consume water through losses from the formation of products such as gypsum, as well as processes such as ash management using traditional wet sluicing. The addition of carbon capture and storage technology will also increase water usage at power plants.

1.1.2 Water schematic at thermal power plants

A schematic of the water flows from a typical closed-loop conventional cooling system at a coal fired power plant, including process water, cooling water and environmental controls is shown in Figure 1-2. Water is used within a coal fired power plant as part of the steam cycle in the form of boiler feedwater, cooling cycle and flue gas treatment. The water balance comprises of input streams including the inherent water (from air, coal, etc.), cooling water make-up, FGD make up, limestone slurry, and boiler make-up. Outgoing water streams comprise of water losses from cooling water evaporation, flue gas vapours, water trapped in wet FGD gypsum, and blowdown discharges.

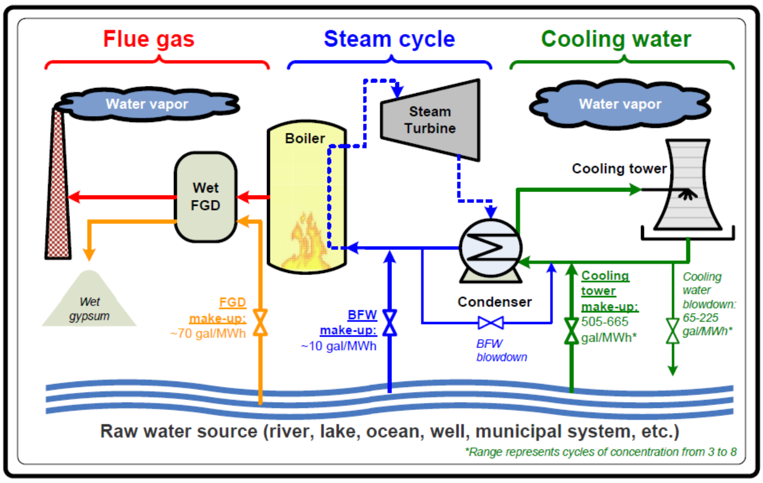

Figure 1-2 Water schematic at a coal fired plant (with wet-cooling tower) (DOE-NETL, 2009)

In a natural gas combined cycle (NGCC) power plant, the water schematic is similar to that of a coal fired power plant, except that there is no desulfurization stage. As a result, combined with the fact that most of the electrical output is generated in the gas turbine, the water profile, as shown in Figure 1-3, is lower than for an equivalent coal fired plant (DOE-NETL, 2009). Input water streams at a NGCC power plant comprise of the inherent sources, boiler feedwater and cooling tower make-up water, while output streams are water vapour losses from the cooling tower and stack flue gas, and cooling water blowdown.

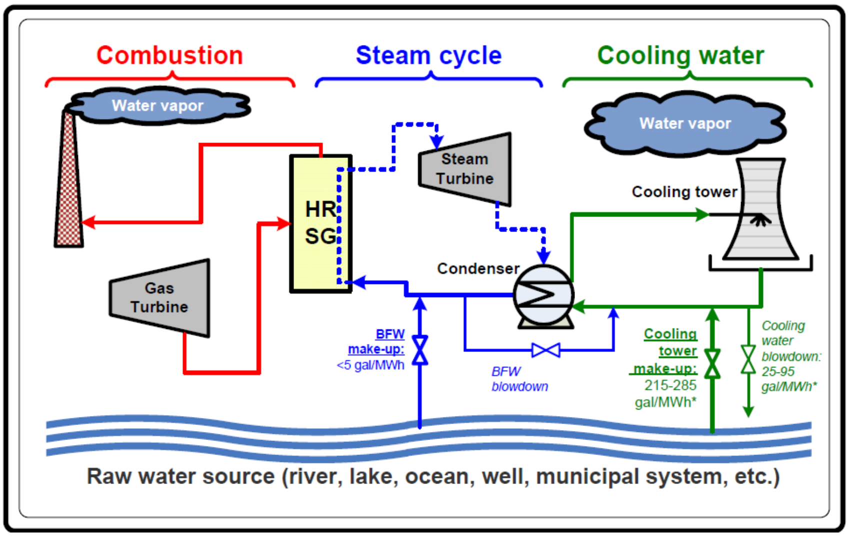

Figure 1-3 Water schematic at a NGCC plant (with wet cooling tower) (DOE-NETL, 2009)

In an integrated gasification combined cycle (IGCC) power plant (Figure 1-4), water usage is significantly lower than in coal fired power plants (super-and sub-critical plants). This is mainly due to the fact that, coupled with the high efficiency of the gas turbine and heat recovery steam generator (HRSG), 60% of the plant's electrical output is produced in the gas turbine which requires minimal water. As a result, the overall amount of water used per kWh is low. The inlet water streams at an IGCC plant include the gasification make-up water, boiler feed water make-up, cooling tower water, as well as inherent water in the coal. Outlet streams include water vapours in the stack, cooling towers and the blowdown. The water streams within an IGCC plant include the water for the gasification (steam condenser), for the acid gas removal (AGR) system, and for the compressor intercoolers in the tail gas treating unit (TGTU), as well as cooling water for the air separation unit (ASU). The amount of make-up water required in the gasification process is dependent on the type of gasifier used. Gasifiers developed by Shell and ConocoPhillips (E-GAS) require a large fraction of water for humidification of the syngas stream. In gasifiers by E-GAS and General Electric Energy (GEE), water is added to the coal to produce a slurry feed prior to gasification. In each of the designs, water is used for scrubbing of the syngas (DOE-NETL, 2009).

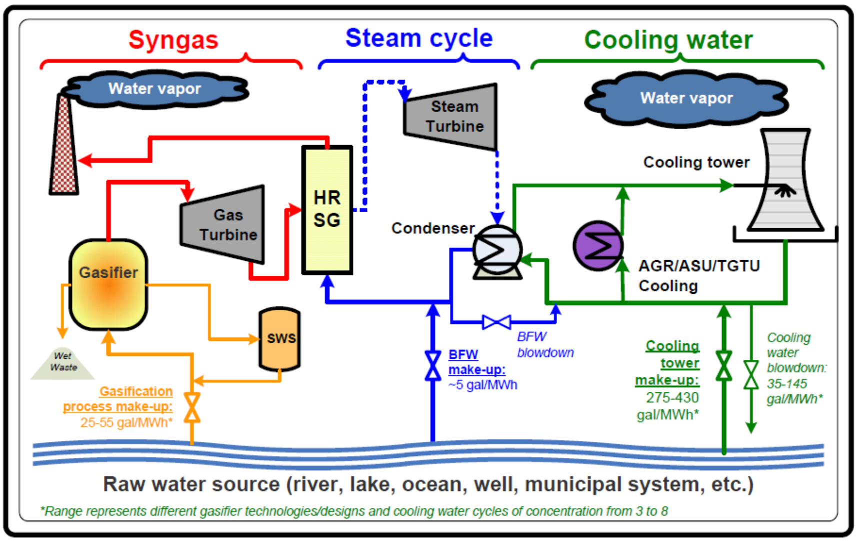

Figure 1-4 Water schematic at an IGCC plant (with wet cooling tower) (DOE-NETL, 2009)

1.1.3 Water withdrawal and consumption at thermal power plants

Common metrics used to describe the usage of water at power plants include withdrawal and consumption.

- Withdrawal is the total amount of water that is removed from a water source such as a lake or river. Often, a portion of this water is returned to the source and is available to be used again.
- Consumption describes the amount of water withdrawn and not returned to source, such as when it has evaporated, or is bounded in by-products, for example gypsum or sludge.
- Discharge is the return of water to its original source or a new source. Water discharge represents the difference between withdrawals and consumption.

Table 1-1 provides an overview of water consumption and withdrawal rates for once-through and recirculating cooling systems for three different types of thermal power plants, demonstrating that withdrawal from once-through cooling technologies can be up to 100 times more than recirculating cooling technologies. However, recirculating systems consume about 3-5 times as much water as once-through cooling. The amount of consumption as percentage of the withdrawn water for a once-through cooling system is about 2-5%, while for recirculating systems consumption can account for up to 90% of the withdrawal rates.

NGCC and IGCC power plants have lower water consumption compared to coal fired power plants due to the fact that almost 2/3 of a combined cycle power plant's output comes from the combustion turbines which require less water than the steam cycle (DOE-NETL, 2009). Table 1-2 summarises water consumption rates for different thermal power generators using various cooling technologies (recirculating towers, pond, once-through and dry-cooling).

Table 1-1 Typical water withdrawal and consumption for thermal power generation (adapted from Macknick et al., 2011)

Cooling system		**Rate (tonnes/MWh)**					
		PC (sub/super critical)		IGCC		NGCC	
		Min	Max	Min	Max	Min	Max
Once-through	Withdrawal	85.7	103	NA	NA	28.5	76
	Consumption	0.2	0.5	NA	NA	0.1	0.4
Recirculating	Withdrawal	1.8	2.7	1.4	2.3	0.6	1.1
	Consumption	1.5	2.5	1.2	1.7	0.5	1.1

Table 1-2 Water consumption breakdown (tonnes/MWh) of different cooling technologies for thermal power generation (adapted from Macknick et al., 2011)

			(tonnes/MWh)		
Fuel Type	**Cooling technology**	**Technology**	**Median**	**Min**	**Max**
Natural gas	Tower	Combined Cycle	0.7	0.5	1.1
		Steam	3.1	2.5	4.4
		Combined Cycle with CCS	1.4	1.4	1.4
	Once-through	Combined Cycle	0.4	0.1	0.4
		Steam	0.9	0.4	1.1
	Pond	Combined Cycle	0.9	0.9	0.9
	Dry	Combined Cycle	0.0	0.0	0.0
Coal	Tower	Generic	2.6	1.8	4.2
		Subcritical	1.8	1.5	2.5
		Supercritical	1.9	1.7	2.2
		IGCC	1.4	1.2	1.7
		Subcritical with CCS	3.6	3.6	3.6
		Supercritical with CCS	3.2	3.2	3.2
		IGCC with CCS	2.0	2.0	2.1
	Once-through	Generic	0.9	0.4	1.2
		Subcritical	0.4	0.3	0.5
		Supercritical	0.4	0.2	0.5
	Pond	Generic	2.1	1.1	2.6
		Subcritical	2.9	2.8	3.0
		Supercritical	0.2	0.0	0.2

1.1.4 Techniques to reduce water consumption and their associated costs

The motivation to conserve water in power plants has led to the development of a variety of processes to recover, recycle, and reuse water. The goal is to reduce the amount of fresh water required for make-up at the front end, and to reach a point of minimized water use or even zero discharge at the back end. Options to achieve this include using (EPRI, 2008; ICCC, 2016):

- alternate supplies of freshwater;
- recycling, recovery, and reuse of water from within the power plant to minimize water intake and discharge;
- utilising various dry technologies for cooling, scrubbing, and ash handling, as well as wet/dry hybrid technologies.

Alternate water sources

Alternative supplies of potable water offer power plants the opportunities to limit their use of freshwater from natural sources such as lakes and rivers. Potential sources include seawater and brackish groundwater, treated municipal wastewater and produced water (ICCC, 2016). This section summarises some of the alternate water sources for thermal power plants. More details about the methodologies and technologies discussed below can be found in the IEA Clean Coal Centre report by Carpenter (ICCC, 2016) and a report by the US Department of Energy (DOE-NETL, 2011).

Treated municipal wastewater (MWW) from domestic use, surface runoffs and industrial facilities may be utilised as alternate to or in conjunction with freshwater for cooling and process water in thermal power plants. One of the benefits of using MMW is that wastewater treatment facilities are often situated close to thermal power plants (ICCC, 2016).

Saline or brackish groundwater may also be used in thermal power plants, though withdrawal from this source can come with challenges. If the withdrawal rates are higher than natural rates of replenishment, the groundwater resource may become depleted, creating subsidence, increasing the salinity of the groundwater source, or affecting the quality and quantity of adjacent water bodies or aquifers (EPRI, 2008). In addition, high salinity levels cause equipment scaling (Massourdi and Cerha, 2013). This is also the case for seawater, which has been used in thermal power plants for cooling. Here, challenges include the ecological impacts to the surrounding environment, such as entrainment and impingement of organisms during water intake, and the effect of warm water on the surrounding waterways (Barnthouse, 2013).

Treated produced water from oil and gas and mining operations may provide a significant opportunity for power plants. However, salinity levels can range from 500 mg/l to over 400,000 mg/l, while contaminants can include organics and soluble hydrocarbons. In mining operations, the produced water may also contain heavy metals and naturally occurring radioactive materials (EPRI, 2008). Thus, not all produced water is treatable from a commercial perspective. Currently, the majority of produced water is re-injected underground for disposal or to enhance hydrocarbon recovery.

Saline water sources, such as those described above, can be treated by desalination. However, highly saline brines become increasingly expensive to treat as conventional seawater desalination methods are not designed for feed water streams higher than 50,000 mg/l (Kaplan et al., 2017). Further, desalination facilities can have an adverse impact on aquatic life in the area around the intake pipes. There is also the problem of disposal of the concentrated brine solution generated through the treatment process.

Water recovery

In addition to using alternate sources for freshwater, water usage within thermal power plants can also be reduced through conservation: recycling, recovery and reuse. This section summarises technology developments for water recovery, recycling and reuse in different streams. More details about the technologies discussed can be found in the IEA Clean Coal Centre reports by Carpenter (ICCC, 2017) and the Asia-Pacific Economic Cooperation (APEC) report on the water-energy nexus challenges and developments in APEC countries (APEC, 2016).

Water recovery from low rank coal

Low rank coals such as lignite have high inherent moisture (up to 70%) which can be recovered and utilised within coal power plants. New technologies for removing or extracting water from low rank coals that have been developed or are under development include (Karthikeyan et al., 2009; Jangam et al., 2011; Rao et al., 2015):

1. Evaporative processes, including rotary driers, fluidized bed driers, hot oil immersion drying and microwave drying.
2. Non-evaporative dewatering processes, including thermal dewatering, mechanical thermal expression (MTE), and solvent extraction processes. Due to the contamination of the extracted water with heavy metals present in the coals, this method requires significant post-treatment and is therefore costly.

Karakas et al. (2002) reported that evaporative technologies such as fluidised bed drying and MTE have lower energy consumption than rotary drying and that efficiency improvements in power plants applying these drying technologies can be up to 7%.

Water recovery from ash management

Water is used in the management of fly ash when converting it to slurry for transport to an ash pond and within wet ash handling systems for the management of bottom ash. Measures to reduce water consumption from wet ash handling include:

- Using recycled water in wet systems such as utilising waste water from another process in the power plant, for example blowdown from the cooling water system;
- Recovering water from the saturated ash using post-treatment, such as in semi-dry systems;
- Replacing wet systems with dry systems, which use air to cool and convey the ash away from the boiler bottom.

Literature studies comparing wet and dry ash handling systems found that significant water and energy savings can be achieved with the dry system (258,000 m^3/year for a 4 x 314 MW coal-fired power plant) (Cianci, 2007), while at the same time CO_2 emissions are reduced (Bassetti et al., 2015). Higher investment costs for the dry system (about 30% for a 800 MW PC power plant) are offset by much lower operating costs, a reduction of the ash handling energy consumption, and savings in water consumption (Bullock and Bergemann, 2010).

Water recovery from flue gas

Flue gas discharged from the boiler contains a large amount of water vapour, the main sources of which are the fuel moisture, oxidation of fuel hydrogen, and moisture carried into the boiler with the combustion air. The three main conventional separation technologies to recover water vapour from flue gas are condensation, membrane filtration, and desiccant absorption. Their advantages and disadvantages as well as costs and efficiencies are summarised in Table 1-3. The costs reported are as from the original studies, with no amortisation or harmonisation of the data. One of the major benefits of water recovery from flue gas is that it helps mitigate corrosion in the flue gas stack or if further pollution control is required, reduces the processes for dewatering.

Table 1-3 Technologies for water recovery from power plant flue gases

Technology	Condensation	Membrane filtration	Desiccant absorption
References	(Xiong et al., 2014, Wei et al., 2017)	(Zhao et al., 2017, Wang, 2012, Macedonio et al., 2013, Sijbesma et al., 2008)	(Copen et al., 2005, DOE-NETL, 2006)
Description	Cooling the flue gas to below 50°C (the water dew point) condenses the water vapour which can be extracted. Generally direct contact coolers are used with water as the cooling fluid. Indirect cooling can also be used. Recovery rates of 20-80% possible.	Water vapour permeates through the membranes and is transported to a condenser by applying a pressure differential using vacuum conditions. Membranes can be microporous polymeric or ceramic; water-selective. Recovery rates of up to 40% possible.	Cooled flue gas is sent to an absorption tower where desiccant absorbs water vapours from the flue gas. The desiccant is heated to release the water vapours water vapour which is then condensed, with the desiccant recycled. Recovery rates of 50-70% possible.
Advantages	Enables the recovery of latent and sensible heat. Reduces Mercury concentration in flue gas.	Produces high quality water (potable conditions). Integrated condenser systems also recover heat (possible heat recoveries of up to 55%).	Technically matured (air conditioning and natural gas dehydration) May act as polishing step to remove SO_2.
Disadvantages	Increase in flue gas pressure drop. Requires large equipment.	Increases flue gas pressure drop.	Contamination of desiccants will affect the performance. High costs.
Costs	Not reported	1.24–1.38 €/m^3 water produced	5.3-10.6 US$/m^3 water produced Capital costs ~20,500-30,800 US$/l/min Annual operating cost ~64-79 US$/h for 285 l/min system
Energy consumption		7 kWh/m^3 (water cooled); 35-40 kWh/m^3 (air cooled)	61-110 kWh/m^3 (water cooled)
Power Efficiency	1.2% increase in power plant efficiency if heat is recovered	0.1–1.1% reduction in power plant efficiency (without heat recovery)	0.8-1% reduction in power plant efficiency
Pilot/ Demonstration plants	Pilot testing suing flue gas slip stream at a lignite-fired power plant units in an Inner Mongolian (Xiong et al., 2014)	DOE project – pilot testing at Baltimore power plant, using flue gas slip stream (Wang, 2012). CapWa EU project – pilot testing at Rutenberg Power Station (Macedonio et al., 2013, Daal, 2013).	DOE project – tested using pilot scale combustor (Copen et al., 2005, DOE-NETL, 2006)

Water recovery from pollution control technologies

Desulphurisation systems

Traditionally, SO_2 is removed from the flue gas in a FGD scrubber using a spray tower which sprays limestone slurry into the gas stream. The main options to reduce water usage and/or loss during desulphurisation include:

- Cooling the flue gas before scrubbing to reduce evaporative losses in the FGD;
- Use of semi-dry or dry scrubbing in place of wet scrubbing systems.

Cooling the stack flue gas temperature by 15°C, 15-20% of evaporative losses can be avoided. This also decreases the volumetric flowrate, having the benefit of reducing the size of the absorbers. Often, flue gas cooling before the FGD is undertaken as part of broader water recovery such as recovery from flue gas (Xiong et al., 2014).

Semi-dry scrubbing systems use about 20% less water than wet scrubbing. The SO_2 removal efficiencies for semi-dry systems are about 80-90% of wet systems due to its lower reactivity and liquid to gas ratios. Dry scrubbing can achieve SO_2 removal efficiencies of up to 98%, coupled with a less complex disposal system than wet systems.

Table 1-4 summarises the costs for wet and semi-dry (spray dry) FGD systems from a 2001 US EPA study (US EPA, 2003) (with values escalated to 2017 values using the Chemical Engineering Plant Cost Index). The estimates show that the capital costs for both systems are comparable, while operating costs for the semi-dry process is higher. Overall, the cost as US$ per ton of pollutant removed is similar for both. The costs for dry scrubbing systems have been reported to be about 25-50% more expensive than wet systems, while operating costs are 30-60% higher (Kozlak et al., 2011).

Table 1-4 Reported cost comparison for wet and semi-dry FGD (2001 values, escalated to 2017 values) (US EPA, 2003)

Scrubber type	Unit size MW	Capital cost $/kW	O&M cost $/kW	Cost/pollutant removed $/ton
Wet	>400	100-250	2-8	200-500
	<400	250-1,500	8-20	500-5,000
Semi-dry	>400	40-150	4-10	150-300
	<400	150-1,500	10-300	500-4,000

Plume control

In recirculating or closed-loop cooling systems, a number of new technologies are available for reducing the total make-up water needed for cooling water. Water can be recovered from the evaporative plumes at the cooling towers through the use of heat exchangers or condensers. Technologies such as membrane condensers (Kim et al., 2018) can be used to recover these evaporative losses. Alternatively, water vapours can be recovered using an internal refrigeration system or mesh (ICCC, 2017). Other systems, such as the air-to-air systems, can also be utilised as part of hybrid-cooling technologies (EPRI, 2008; Mortensen, 2011).

Alternate cooling technologies: dry and hybrid systems

In addition to the three main technologies for cooling systems at thermal power plants (once-through, recirculating wet, and dry cooling systems), alternate cooling technologies are available that may require further consideration as the issue of water availability grows.

Dry cooling

Open and closed-loop recirculating wet based cooling systems can be retrofitted with dry air-based cooling systems, either using direct or indirect cooling systems. This technology has been used for nearly 70 years (EPRI, 2012). The direct cooling system utilises a large standalone air-cooled condenser (ACC) to cool the stream exiting the steam turbine. In an indirect cooling system, the closed-loop system means that there is no evaporative loss of water. Indirect cooling could also be classified as a hybrid system since it includes both wet and dry cooling components.

Hybrid cooling systems

Hybrid cooling systems combine both wet and dry cooling systems to make use of the advantages of both and to offset the disadvantages of each. Hybrid systems designed for water conservation have received increasing interest in recent years, although to date only a few are installed on US power plants (EPRI, 2008). They are intended to reduce the amount of water required for power plant cooling by using dry cooling during the cooler periods of the year and supplementing the dry capability with wet cooling during hotter periods.

Comparison of wet, dry and hybrid cooling technologies

As air is a less efficient heating/cooling medium compared to water, dry and hybrid cooling systems have much higher energy penalties on the power plant than the wet systems. Table 1-5 summarises the annual water consumption, annual cooling cost, capital cost requirements and thermal efficiency differences for wet (recirculating), dry and hybrid cooling systems.

Depending on the location and local climate of the power plant, dry cooling has efficiencies penalties of about 5% higher compared to wet systems for coal fired power plants (Table 1-5). Typical plant efficiency decreases are about 1% for every 0.55°C increase in the condenser temperature (Sanders, 2015).

One of the main disadvantages of dry cooling systems are their costs: average annualised cooling costs for dry systems in coal fired power stations are about 4-5 times higher for comparative cooling using wet systems. In terms of the change in levelised cost of electricity (LCOE), direct dry systems cost about 3-6 US$/MWh more than comparable wet systems. This is driven primarily by the high capital costs. The lower efficiencies of dry systems also mean that on per unit of electricity produced, the CO_2 emissions are also higher. In the study by Zhai and Rubin (2010), the CO_2

emissions from the wet-based system for a supercritical coal fired power plant are approximately 0.81 kg/MWh. When a dry system is utilised, the energy efficiency is 1.4% lower, thus the CO_2 emissions increase to about 0.85 kg/MWh.

For NGCC power plants, the annualised cooling costs (US$/MWh) for dry systems are about 4 times higher than for wet systems. Using a dry system the LCOE increases by 1.2 US$/MWh (Table 1-5). The capital costs are also higher at NGCC power plants, with wet systems costing about 29 US$/kW, while dry systems costs range from 45-82 US$/kW - dependign on the power plant location and local climate. The difference in thermal efficiencies between wet and dry cooling systems results in dry systems having penalties of approximately 0.22% higher (EPRI, 2012).

Table 1-5 Summary of reported cooling system performance and costs (with no escalation or harmonisation of the reported values)

		Annual water consumption t/MWh			Annualised LCOE cooling cost (US$/MWh)	Cooling system capital cost (US$/kW)	Penalty increase compared to wet	Reference
		Min	Max	Ave.	Average		Average	
Coal	Wet	1.44	1.88	1.60	0.8	43-51	-	EPRI (2012)
		1.5	2.5		3-4	90		Zhai and Rubin (2010)
						89-266 (€/MW)		APEC, 2016
	Dry direct	-	-	-	3.4	125-213	5.0%	EPRI (2012)
					4-7	224	1% - 3.8%	Zhai and Rubin(2010)
					5	100		Kablouti, (2015)
						112-331 (€/MW)		APEC (2016)
	Dry indirect	-	-	-	5.4	123-543	4.7%	EPRI (2012)
						105-288 (€/MW)		APEC, 2016
	Hybrid	0.41	1.16	0.68	2.7		2.3%	EPRI (2012)
NGCC	Wet	0.68	0.97	0.78	0.4	29	-	EPRI (2012)
	Dry direct			0	1.6	44-82	0.22%	EPRI (2012)
	Hybrid	0.18	0.70	0.36	1.3		-0.35%	EPRI (2012)

Technology developments for dry cooling

A number of technology developments have been underway to address some of the disadvantages of dry and hybrid cooling systems. They include options to enhance the heat transfer in the ACC by methods such as pre-cooling the ambient air, using spray cooling and deluge, or introducing flow disturbances to promote mixing. Using thermal energy or cool storage systems can also be utilised to improve the efficiency of dry cooling systems. A number of alternative technologies to ACC are also under development, including thermosyphons, heat pipes, desiccants, sorption/desorption, magnetic refrigeration, thermoelectric cooling, electrocaloric cooling, and thermoacoustic cooling.

Reductions in costs for dry systems are also critical to make them more competitive with wet systems, thus a number of studies have examined new designs to reduce capital cost. Studies have examined using alternate materials of construction such as polymers. The study of the IEA Clean Coal Centre by Carpenter (ICCC, 2017), provides a detailed summary of key developments in this area.

1.1.5 Global regulations: power plants

Water usage regulations worldwide

Most countries have legislation and regulation in place to manage their wastewater. A comprehensive summary of global wastewater regulations as they apply to coal fired power stations has been presented by Carpenter (ICCC, 2018).

Australia

In Australia the Department of Agriculture and Water Resources is responsible for water resources and the relating policies on a national level. The *National Water Quality Management Strategy* (NWQMS) provides a national framework "to protect the nation's water resources by maintaining and improving water quality" (Commonwealth of Australia, 2017a) and includes so-called trigger values for a ranges of substances. The NWQMS is delivered through policies, processes and guidelines, which inform policy and regulation on State and Territory level. Australian State and Territories have their own water quality information and guidance. These may include guideline values for physical and chemical stressors, which some jurisdiction have included in their legislation (Commonwealth of Australia, 2017b), e.g. regulations in Queensland define fees to be paid for discharge at temperatures of more than 2°C. States issue their own licences for power plant operations, which typically specify discharge limits for water pollutants and their monitoring frequency. A range of examples from different states is presented by Carpenter (ICCC, 2018).

Under the *National Environment Protection (National Pollutant Inventory) Measure* 1998 the release of 93 different substances (DoEE, 2019) to water, as well as air and land, must be reported by the operator to be added to the *National Pollutant Inventory* (NPI), if a specified threshold is exceeded. With respect to power stations, substances that are typically produced during combustion or other thermal processes are Category 2a and 2b and need to be accounted for when the below thresholds are exceeded (DoEE, 2015).

- Category 2a:
    - Burning either > 400 tonnes of fuel and/or waste in a reporting year or > 1 tonne of fuel and/or waste in one hour during the reporting year
- Category 2b:
    - Burning > 2,000 tonnes of fuel and/or waste in a reporting year
    - Consuming > 60,000 MWh of electrical energy in a reporting year or > 20 MW maximum power consumption for other than lighting or motive purposes

China

Due to significant problems with water pollution and availability in parts of the country, wastewater is managed through various policies and regulations in China. Relevant water pollutant discharge standards include the *Integrated Wastewater Discharge Standard (*Jinlong, 2012), which give maximum allowable discharge limits for pollutants with the limits varying depending on the place of discharge (e.g. a marine area or municipal wastewater sewage system). Specific to power stations is the *Discharge Standard for Wastewater from Limestone-Gypsum Flue Gas desulphurisation system in fossil fuel power plants*, which sets a limit of 2000 mg/L sulphates in all waste streams from the power station, amongst other pollutants such as mercury, cadmium, and TSS (ICCC, 2018). Wastewater discharge must not exceed the water quality standards defined for surface water, groundwater, seawater, and irrigation water by the Ministry of Environmental Protection (WEPA, 2017).

In addition, the *III. Law on Prevention and Control of Water Pollution* (PRC, 2008) dictates, amongst others, that (ICCC, 2018)

- all industrial wastewater must be categorised and treated before being discharged;
- thermal power stations have to pay for the volumes discharged;
- local governments have the authority to introduce stricter water standards which power station operators need to adhere to.

The Environmental Protection Tax Law (PRC, 2016) sets the limits on concentration and quantity of taxable pollutants emitted and charges the emitters for their discharge with the local governments deciding over the tax rate of the levied items (SAT PRC, 2018). The Catalogues of Classified Management of Pollutants Discharge Permit for Stationary Pollution Sources specifies the sectors regulated.

It is to further consider that in China national caps on water usage are in place (ICCC, 2015) and that the reuse of recycled water has to meet the relevant standard depending on its use, e.g. irrigation, groundwater recharge, industrial use (IWA, 2014).

For new coal-fired power plants Zero Liquid Discharge (ZLD) systems (see below) are mandatory with some existing power stations requiring retrofitting.

European Union

The *EU Directive 2000/60/EC*, known as the *EU Water Framework Directive* (WFD), establishes a framework for water policy. The amended WFD, *EU Directive 2013/39/EU*, contains aims and targets that needs to be legislated by the member states. It further contains a list of priority hazardous substances, such as mercury and cadmium, though no threshold values. Threshold values are defined in a number of directives, depending on the type of water (e.g., groundwater, surface water) and emitter.

The *Groundwater EU Directive 2006/118/EC* works under the assumption that groundwater should not be polluted at all. It thus prohibits the discharge of hazardous substances into groundwater and sets quality standards with respect to nitrates, pesticides and biocides. EU member states shall set their own pollutant thresholds for substances such as cadmium, mercury, chloride and sulphates.

Surface water bodies are covered in the *Environmental Quality Standards EU Directive 2008/105/EC,* which attempts to achieve a general minimum standard for surface water through pollutant limits – either average annual concentration or maximum allowable concentration. Inland surface waters and other surface waters have separate limits.

Discharge from point pollution sources to surface water must be controlled through i) emission controls based on best available techniques (BAT) or ii) the specific limits of the pollutants. The pollutant limits are defined in a number of Directives, for example the *Industrial Emissions Directive (IED) - EU Directive 2010/75/EU*. The IED also requires power stations to obtain a permit to operate, which typically limits pollutants to the level that can be achieved with BAT (ICCC, 2018). Permits also specify the maximum allowable temperature for cooling water discharged from once-through (open-loop) cooling towers with maximum temperatures given in the in the BAT reference document (BREF) (ICCC, 2018). A specific directive regulating the discharges from flue gas treatment into water bodies is *Commission Implementing Directive 2017/1442*, which stipulates limits for fluoride, sulphate, sulphite, sulphide, TSS and TOC and metals.

India

In India water policy is under the remit of the state governments, and therefore the central government can only provide guidance, funding and broad policy frameworks (Carpenter, 2018).

The Central Ground Water Authority has been constituted under Section 3 (3) of the Environment (Protection) Act, 1986 to regulate and control development and management of ground water resources in the country. To enable the states to enact ground water legislation, a "Model Bill to Regulate and Control Development of Ground Water" has been circulated by the Ministry of Water Resources to all the states. As a result, several states have enacted and implemented ground water legislation (CGWB, 2015).

Surface water is owned, and its allocation controlled, by the individual states (ICCC, 2018).

Standards for emission or discharge of environmental pollution from industry, operations or process are laid out in the Environment (Protection) Rules, 1986, Schedule I to IV. This includes wastewater discharge standards. The Central Pollution Control Board or a State Pollution Control Board may specify more stringent standards from those provided in Schedule I to IV.

The carrying on of processes and operations in different areas and the prohibition or restriction on the location of industries by the Central government is affected by several factors, including the maximum allowable limits of concentrations of various pollutants, the topographic and climatic features of an area, the biological diversity, net adverse environmental impacts, and so on.

Power plants operators require a consent order for the discharge of wastewater (ICCC, 2018), which may underlie stricter limits than those set out for the discharge of liquid effluents in Schedule I to IV and must be renewed periodically. Wastewater standards relating specifically to thermal power plants are defined in Environment (Protection) Rules, 1986, Schedule I, Item 5 (*http://www.lawsindia.com/Industrial%20Law/k57.htm#sSCHEDULE_I*).

Regarding water consumption, a specific limit, set by the Ministry of Environment, Forests and Climate Change in the Standards for Water Consumption vide Notification No S.O. 3305(E), applies to all new coal-fired power plants installed after 1 January 2017, with water consumption not allowed to exceed 2.5 m^3/MWh. Furthermore, treatment to ZLD is mandatory. Older power plants using once-through cooling were required to install cooling towers and achieve a maximum water consumption of 3.5 m^3/MWh by the end of 2017 (Srinivasan et al., 2018).

South Africa

In South Africa water resources are dealt with under various policies, water acts, regulations, and legislations, such as the *National Water Act, 1998* (NWA) (RSA, 1998) Water Resource Management is the responsibility of the Department of Water Affairs and Forestry.

Under the Receiving Water Quality Objectives (RWQO) approach, the South African quality guidelines were produced, covering water quality for domestic, recreational, industrial, and agricultural use, as well as aquatic ecosystems (Waternet, 2019; DWEA, 2019).

Based on the NWA, water allocation, use, and flow is regulated. As water must be used efficiently, wastewater should be treated, with the Department of Water and Sanitation setting effluent discharge limits (Carpenter, 2018). Water use, including discharge and disposal, must be licenced when exceeding the thresholds specified in Government Gazette No. 36820 (2013). After the polluter pays principle, emitters pay a waste discharge tariff. Limits also apply to the reuse of wastewater for irrigation.

With respect to power stations this means a water use licence needs to be obtained for operation. Such licences cover use of ground and surface water and other specified water uses as detailed in the NWA and will outline discharge limits for relevant pollutants. In addition, coal-fired power stations are typically required to have ZLD systems in place as part of their water use licence conditions.

USA

The *Federal Water Pollution Control Act*, also known as the *Clean Water Act* (CWA) establishes the basic structure for regulating discharges of pollutants into US water and regulating quality standards for surface waters (CWA, 2002). Under the CWA the US Environmental Protection Agency (EPA) has implemented pollution control programs, including setting wastewater standards for industry. To discharge any pollutant from a point source into navigable waters, point sources require a permit issued through the National Pollutant Discharge Elimination System (NPDES) (US EPA, 2018a). The permit needs to be renewed if a new pollutant discharge point is planned or every 5 years (US EPA, 2018b). Effluent limits can be set by the states and limits are also specified with respect to surface water temperature; states typically require surface water to remain below 32°C when heated cooling water is discharged (ICCC, 2018).

The *Steam Electric Power Generating Effluent Guidelines and Standards* (40 CFR Part 423) (US GPO, 2019) are incorporated in the NPDES and specifically cover wastewater discharges from power stations (US EPA, 2018c). The rule was finalised in 2015, for the first time setting federal limits on the level of toxic metals in wastewater that can be discharged from power stations. The limits are based on BTA and pre-treatment standards for existing sources (PSES). Furthermore, the rule also set new requirements for wastewater streams from FGD, bottom ash transport water, fly ash transport, flue gas mercury control, gasification of coal and petroleum coke, and combustion residual leachate. However, under a new government, the rule is being reconsidered to make it less stringent. A finale rule is intended December 2019.

Water regulations in the Netherlands

While the Netherlands are covered by the EU Water Framework Directive (WFD), specific regulations concerning power generation apply to the discharge of cooling water. While cooling water typically has temperatures of 8-12°C above intake temperatures for once-through cooling (Langford, 2001, Madden et al., 2013), (i) the maximum discharge temperature must be below 30°C; and (ii) the temperature difference between intake and discharge may not be more than 7°C in the summer and 15°C in the winter. Consequently, a water temperature of 23°C applies as the critical limit for the use of cooling water and the criteria for the mixing zone that determines the maximum allowable cooling water discharge temperature into a given water system has been introduced (Rajagopal et al., 2012).

Sources of effluent streams from power plants and indicative parameters and substances requiring monitoring for regulatory discharge compliance are given in Table 1-6.

Table 1-6 Effluent discharges from fossil fuel power plants and water quality requirements (APEC, 2016; ICCC, 2018)

Process/location	Indicative possible parameter/substances for monitoring
Cooling water	Heat/temperature, ammonia, total dissolved solids (TDS), suspended solids, chloride, phosphates and nitrates and microorganisms, iron manganese and other trace metals, and low concentrations of organic compounds
Flue gas desulphurisation (FGD)	Chloride, metals, suspended solids, pH, sulphate, chemical oxygen demand
Selective catalytic reduction (SCR) or other deNO$_X$ processes	Ammonia from reagent
Ash lagoons	Suspended solids, pH, trace metals, boron, sulphate
Coal stock run-offs	Suspended solids, pH, trace metals, polycyclic aromatic hydrocarbons (PAHs)
Boiler water make-up water and blow down	Suspended solids, dissolved salts and minerals in source water, dissolved oxygen, silica, chemical cleaning residues
Storage run-off	Chemicals (depending on storage), oil and grease
Water treatment/desalination	Concentrated brine with high dissolved solids and possibly metals, nutrients, organics, antifouling, biocide agents etc.

Zero Liquids Discharge in the power sector

Zero liquid discharge (ZLD) is a wastewater management strategy that aims to recycle and reuse all internal industrial wastewater streams to minimise any liquid waste. Interest in ZLD has become more widespread in recent years as one of the ways to meet the challenge of water scarcity and as a mitigation option to address more stringent regulations governing waterways and aquatic environments.

Applying ZLD at an industrial process or facility may lead to benefits such as lower waste volumes thus reducing the cost and energy consumption associated with waste management and discharge, as well as associated costs of monitoring and measurement. Further, recycling and reusing water onsite may lead to lower water acquisition costs and risk (as it reduces the need for freshwater consumption), with the benefit of improving the regulatory risk profile of a company for future permitting.

To date, ZLD has been applied in various industrial applications in a range of countries and regions including the European Union, Africa, North America (Canada, the US and Mexico), Australia, the Middle East, China and India. ZLD systems generally comprise of a series of processes including pre-treatment with clarification, softening, filtration, concentrators, reverse osmosis (RO), and associated thickening and dewatering processes. Figure 1-5 shows a simple schematic of a ZLD process. Conventional ZLD schemes utilise pre-treatment followed by thermal processes such as a brine concentrator or a brine crystallizer (or an evaporation pond). The condensed distillate water is collected for reuse, while the produced solids are either sent to a landfill or recovered as valuable salt by-products. These systems, while being mature technologies, are highly energy intensive and have high associated capital and operating costs.

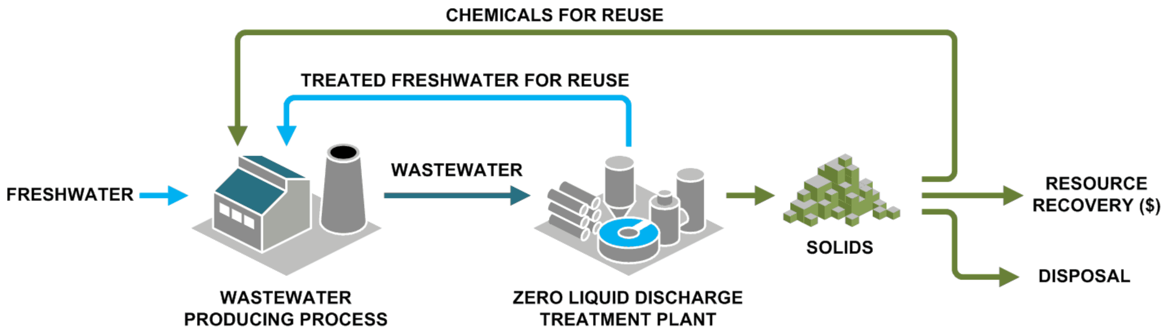

Figure 1-5 Schematic of zero liquids discharge at an industrial facility (Saltworks, 2019)

Alternate processes such as membrane-based systems are also being utilised within ZLD schemes to reduce the amount of wastewater treated in brine concentrators and other thermal processes, and thus lower overall energy consumption. Membrane processes such as reverse osmosis (RO) have proven particularly beneficial. There has also been development of new membranes to address some of the inherent disadvantages of scaling and fouling in existing commercial RO, including improvement of RO membranes with better resistance to organic and biological fouling. Alternative membranes such as electrodialysis (ED), forward osmosis (FO) and membrane distillation have also been developed for ZLD applications (Tong and Elimelech, 2016).

ZLD applications

With the water policies of some countries becoming more stringent, in addition to the options outlined above to recover and reduce water usage at thermal power plants, ZLD systems can also be employed to meet these regulations and reduce the dependency on freshwater intake.

Applications for ZLD at power plants include treating water from the cooling tower blowdown, produced water, FGD purge wastewater, IGCC wastewater, reverse osmosis reject, demineralisation regeneration wastewater. However, the reuse of recycled water at a power plant is limited by the water of the recipient stream and the water balance of the power plant. For example, the water required for the boiler make-up will be different than for the limestone slurry or for the cooling tower. Table 1-7 shows the rule of thumb of possible water uses in terms of descending water quality requirements as presented by EPRI (2008). Thus, in ZLD applications, if water is to be treated for reuse, ideally the water will be treated for the highest possible level use, and then cascaded down to lower uses.

Table 1-7 Water quality by use (EPRI, 2008)

Water use	Water quality requirements
Boiler/reactor feedwater	Highest quality
Gas turbine inlet cooling	High quality
Housekeeping and potable water	Medium quality
Cooling tower	Medium quality
Ash sluicing	Low quality
Limestone slurry for FGD	Low quality

The technologies required for the ZLD scheme at each power plant will be site specific and depend on a number of factors, including the level and type of impurities in the waste stream, limits set by local regulations for the discharge and/or solid by-product, flow volumes and type (intermittency or continuous), and variability in the flow and impurity levels. A number of examples of power plants operating with ZLD are presented below.

The Redhawk Power Station (Arizona Public Service) in the USA uses reclaimed effluent for power plant cooling, recycling more than 95% of the plant's wastewater. It employs a 1050 gpm RO system, and a 700 gpm demineralizer. The ZLD facility treats 102 m^3/h of high salinity blowdown from the cooling towers. It disposes of 60 tons/day of solid by-product cake offsite (EPRI, 2008). A schematic of the water balance of the Redhawk Power Station is presented in Figure 1-6.

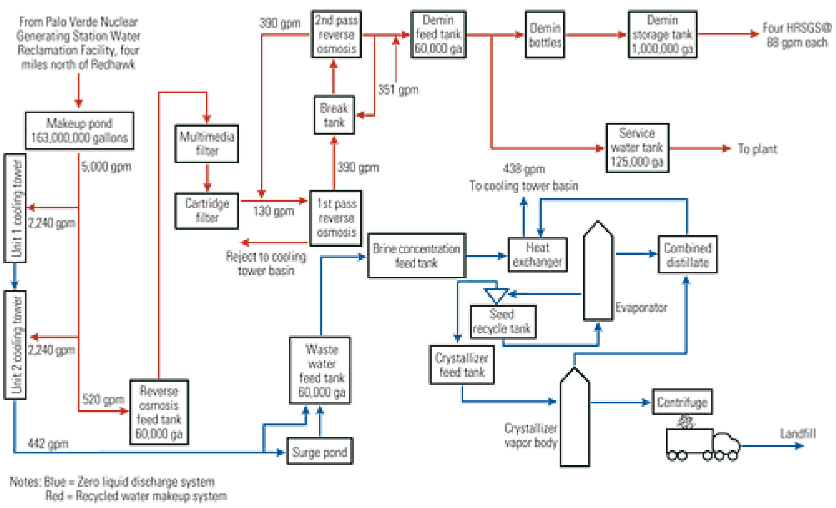

Figure 1-6 Water balance at Redhawk Power Station (from Yarbrough, 2006)

The Changxing Power Station (Huaneng Power International) in the Zhejiang Province in China treats the wastewater from FGD, blowdown wastewater stream and cooling tower blowdown using a membrane brine concentration (MBC) system, consisting of FO and RO, and a crystalliser (see Figure 1-7). The wastewater undergoes initial pre-treatment in a clarifier (Patel, 2016). The MBC processes about 30 m^3/h of wastewater with an average TDS of 9,000 mg/l at a recovery rate of more than 90% (Patel, 2016). The concentrated reject stream of about 2.5 m^3/h goes to the crystalliser, where the remaining water is removed to less than 0.5%. Salt crystals of more than 95% (NaCl + Na2SO4), produced as a by-product of the process, are sold to chemical manufacturers (Patel, 2016).

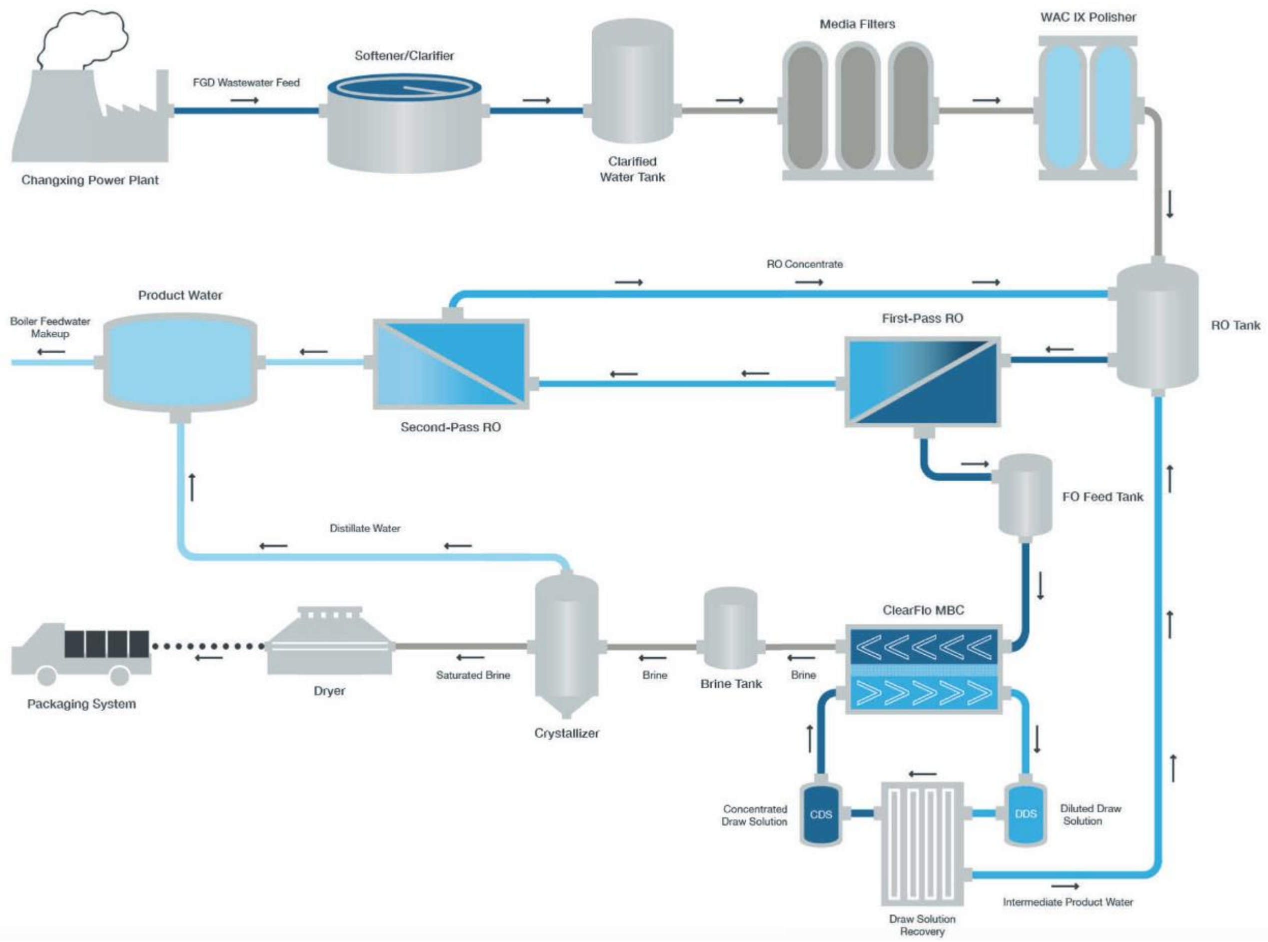

Figure 1-7 Changxing's ZLD process flow (from Oasys Water, 2016)

The Shand Power Station (SaskPower) in Canada operates with ZLD since 1992, with no liquid discharge into the environment and water leaving the site as evaporation from the ponds. The facility uses a combination of settling ponds, vapour compressor evaporator, activated carbon filter and RO (see Figure 1-8) to supply makeup water for the boiler, stator cooling, cooling tower, other internal cooling systems and demineralized water for the ion exchange process (Quagraine et al., 2010).

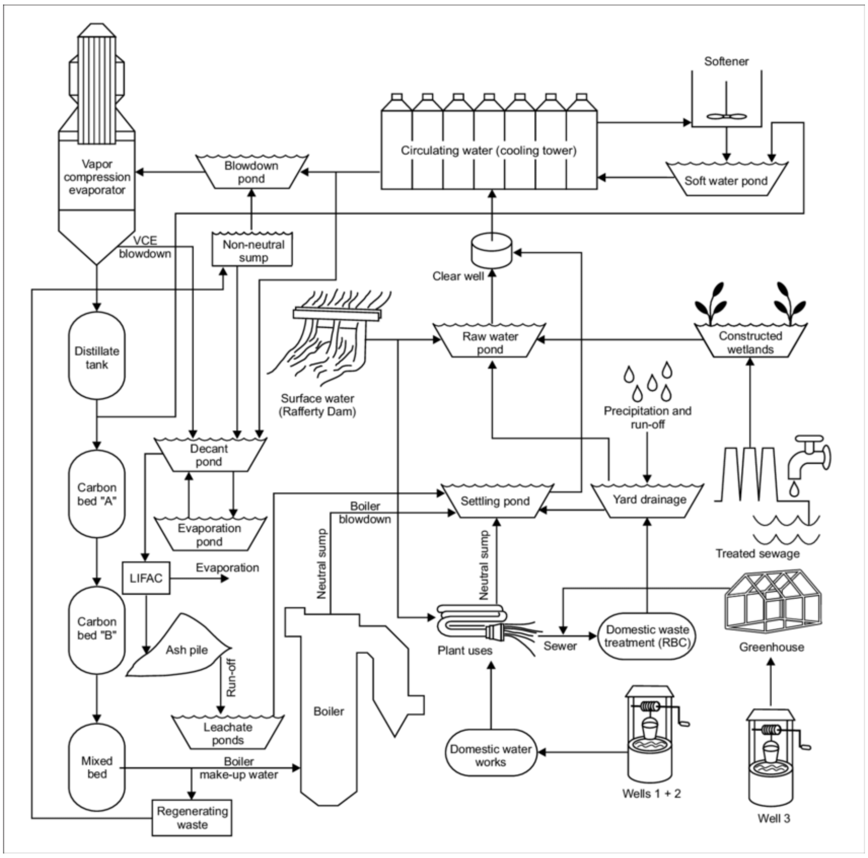

Figure 1-8 A schematic of the water balance at the Shand Power Station (from Quagraine, 2018)

At the Brindisi Power Plant (ENEL) in ItalyFGD wastewater (140 m^3/h) is treated to ZLD using a softening, evaporation and crystallisation process comprised of brine concentrators, vapor compressors and crystalliser (see Figure 1-9). The same ZLD approach has also been applied at ENEL's other power plants La Spezi, Sulcis, Fusina and Torrendord (Mosti and Cenci, 2012).

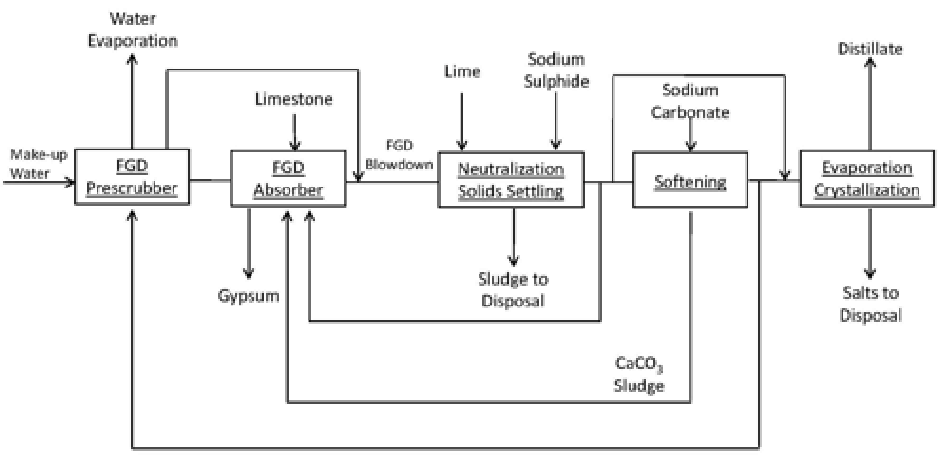

Figure 1-9 Schematic of the ZLD approach at Brindisi, Italy (from Aquatech, 2018a)

ZLD regulations worldwide

ZLD policies for a select number of countries are presented in Table 1-8. In China, all new coal-fired power plants built will have a mandatory ZLD policy. This is also true in India and South Africa. In Japan, there is no federal law mandating ZLD, but several power plant operators have internal ZLD policies. Similarly, in Australia, there is no federal mandate but plants operating in water stressed areas have ZLD policies such as the Bayswater Power Plant in New South Wales (Veolia, 2018b). In Canada, there is also no federal policy mandating ZLD (Environment Canada, 2014), however, individual plants such as the Shand Power Plant has implemented a ZLD policy since 1992, with no liquid discharge into the environment and water leaving the site as evaporation from the ponds (Quagraine et al., 2010). There is also no federal regulation mandating ZLD in North African countries such as Egypt, however stringent wastewater regulations relating to discharge into the Nile and canals has encouraged companies to implement ZLD (Abdel-Dayem, 2011; Rathi, 2017).

In the US, due to the restriction of applying for permits every five years as part of the National Pollution Discharge Elimination System (NPDES), some power plant operators have applied ZLD to overcome the uncertainty of the permit system. The US EPA has also noted a preference for ZLD as the preferred option for pollutants in fly ash transport water, bottom ash transport water, and wastewater from flue gas mercury control systems. The EU does not have mandatory ZLD requirements for power plants, but several operators, such as ENEL in Italy, have implemented ZLD facilities to overcome strict discharge regulations relating to FGD wastewater (Aquatech, 2018b; Mosti and Cenci, 2012). The report by the ICCC (ICCC, 2018) provides an extensive summary of wastewater regulations for these countries.

Table 1-8 ZLD policies for different countries

Country/region	ZLD policy
Australia	No federal policy. Several plants in water stressed area operate with ZLD policies.
Canada	No federal policy. Plants in water stressed area may operate with ZLD policies.
China	Mandatory for all new coal-fired power plants.
European Union	No EU wide law mandating ZLD. Some plants operate on ZLD policy.
India	Mandatory for new coal-fired power plants built after 1 January 2017.
Japan	Some plants operate on voluntary ZLD policy.
Egypt	No federal policy. Plants may operate with ZLD policies.
South Africa	Mandatory for new coal-fired plants, with many existing plants already operating with ZLD policies.
USA	Several plants operate on ZLD policy, EPA setting ZLD as the preferred option for pollutants in fly ash transport water, bottom ash transport water, and wastewater from flue gas mercury control systems.

CO_2 emissions regulations for power plants

Around the world, governments have tried to address CO_2 emissions from the power sector through different mechanisms. These include market forces such as establishing emission trading schemes (ETS) or enforcing emission performance standards (EPS) through legislation and regulation. The approaches to CO_2 emissions reduction policy of some key countries are described below, while Table 1-9 summarises the status of countries that have or are planning to implement an EPS or ETS, and where the power sector is a participant. Detailed summaries of international ETS schemes can be found in the reports by the International Carbon Action Partners (https://icapcarbonaction.com/).

Netherlands

In addition to being a participant of the EU ETS, in the Netherlands, according to the Large Combustion Plant Directive 2010/75/EU, holders of permits for installations with a capacity of 300 MW or more must assess (i) the availability of suitable CO_2 storage sites; (ii) the economic and technical feasibility of transport facilities; and (iii) the economic and technical feasibility to retrofit the installations for CO_2 capture (EU Environment 2016, CCUS LRN 2014). Further, emissions levels from large combustion plants are regulated through the Best Available Techniques reference document (LCP BREF 2017).

Australia

In July 2012, Australia implemented an ETS known as the Carbon Pricing Mechanism (CPM). However, this was repealed in July 2014. Currently there is no federal mandate on CO_2 emissions, though the National Energy Guarantee (NEG) is under development. The NEG proposes a reliability obligation and an emissions reduction target on energy retailers and a small number of large electricity users(Commonwealth of Australia, 2014; Department of the Environment and Energy, 2018).

Canada

In 2015 the Canadian Environmental Protection Act (CEPA), 1999, was updated to apply a performance standard to all new coal-fired electricity generation units, and units that have reached the end of their useful life (a unit that is 50 years of age) (Government of Canada, 2015). The performance standard is fixed at the emissions intensity level of a NGCC power plant at 0.420 t/MWh. Units that have incorporated CCS are able to receive a temporary exemption from the performance standard until December 31, 2024 through meeting a number of milestones.

Updated regulations for natural gas fired power generation have also been mandated as part of Canadian Environmental Protection Act, 1999, enacted in 2018 (Government of Canada, 2018). The legislation mandates that CO_2 emissions for new natural gas fired power generation (greater than 25 MW) are limited to 0.420 t/MWh (Government of Canada, 2018).

In the states of Quebec and Ontario, Canada, a Cap-and-Trade system has been implemented (ICAP, 2018a). In Quebec, the first compliance period of 2013-2014 imposed the cap-and-trade on the local electricity and industry sectors (> 25,000 t CO_{2e}/y), followed by the second and third compliance periods (2015-2017, 2018-2020) which will see distribution and import of fuels for transport and building included. In 2016, Ontario passed legislation and introduced regulations establishing a cap-and-trade program with a first compliance period of 2017–2020. The program covers facilities generating more than 25,000 tons of GHG, natural gas distributors, fuel suppliers and electricity importers. Nova Scotia has also scheduled a cap-and-trade program for commencement in 2018.

In Alberta, under the Climate Leadership Plan, coal-fired electricity will be phased out and replaced by renewable energy and natural gas-fired electricity, or by using technology to produce zero pollution, by 2030 (Osler, 2018). On January 1, 2017, a $20/tonne carbon price was implemented across all sectors, which increased to $30/tonne on January 1, 2018 (Osler, 2018).

China

At the end of 2017, China launched its national ETS, which is currently the largest carbon market in the world (ICAP, 2018a, Harvey, 2017, Zeng et al., 2018). The ETS regulates around 1,700 companies from the power sector,(Article 7, Work Plan) (Grantham Research Institute on Climate Change and the Environment, 2015), covering approximately 30% of overall emissions or 3,300 $MtCO_{2e}$, with the energy sector accounting for 72.4%. The development of the federal Chinese ETS comes off the learning of pilot ETS programs enacted in the following provinces: Beijing, Guangdong, Hubei, Shanghai, Shenzhen and Tianjin (ICAP, 2018a).

In 2015, as part of the 13th Five-Year-Plan, China's Action Plan for Upgrading of Coal Power Energy Conservation and Emission Reduction was implemented (Patel, 2017, NDRC, 2014, Yuan et al., 2016). As part of the Plan, specific technical standards for new and existing coal-fired power plants need to be met by 2020 (or by 2017 for plants in eastern China and 2018 in central China): 0.300 t/MWh for all new plants and 0.310 t/MWh for all existing plants. The Plan also mandates that new pulverized coal-fired units of more than 600 MW are to utilise ultra-supercritical technology, and that pulverized heating units and circulating fluidized bed (CFB) units of more than 300 MW employ supercritical technology.

The European Union (including Iceland, Liechtenstein and Norway)

The EU ETS was the world's first emissions trading scheme beginning in 2005 (ICAP, 2018a). Phases One and Two of the program (2005-2012) established a decentralised cap-setting. The current Phase Three (2013-2020) has set an EU-wide cap for stationary sources (including the power sector) set at 2,084 Mt CO_2e in 2013. This cap is annually reduced by 1.74%. Currently the ETS covers 45% of all emissions, with the energy sector accounting for 77.5% of those covered.

India

In India's National Electricity Plan (NEP) in 2016 (Central Electricity Authority, 2012), no specific government directives were issued with regards to CO_2 emissions standards for existing or newly built coal-fired power plants. However, the plan did mandate that 39% of new coal-fired power plants are to be supercritical. Currently almost all of India's coal power plants are subcritical, operating at an average efficiency of HHV 28% (Pandey, 2017). It is expected that implementation of the higher efficiency technology will reduce national annual emissions by 6.07 million tonnes from the power sector (as outline in Table 12.5 of the NEP).

Japan

At a federal level, Japan is evaluating the possibility of a national ETS (ICAP, 2018a, Environment, 2012, EDF, 2015b). In 2017, an expert committee was established to investigate how carbon pricing could help the country achieve long-term, substantial emissions reductions, while addressing economic and social issues. At present, a voluntary cap-and-trade system, the Advanced Technologies Promotion Subsidy Scheme with Emission Reduction Targets, has been established to allow companies to familiarise themselves with the proposed ETS (ICAP, 2018a). In parallel, a Joint Crediting Mechanism (JCM) is also being implemented. At regional levels, there is the existing Tokyo Cap-and Trade program and the Target Setting Emissions Trading System in Saitama. However, neither of these schemes includes the power sector.

Kazakhstan

The Kazakhstan Emissions Trading Scheme was established in January 2013 (NDRC, 2014). Currently in its third phase, (2018–2020) CO_2 emissions are capped at 161.9 Mt CO_2 per year. Its objective is to achieve a 5% reduction compared to 1990 levels by 2020. The energy sector in Kazakhstan contributes 74% of the country's overall emissions and was participant in the scheme since its inception.

New Zealand

The New Zealand (NZ) ETS was launched in 2008, incorporating all sectors (Ministry for the Environment, 2017, ICAP, 2018b, EDF, 2015a, Bullock, 2012). The NZ ETS requires all sectors of New Zealand's economy to report on their emissions and, with the exception of biological emissions from agriculture, to purchase and surrender emissions units to the Government for those emissions. Just over half of New Zealand's greenhouse gas emissions are covered by NZ ETS surrender obligations.

Republic of (South) Korea

In 1 January 2015, the Republic of (South) Korea launched its national ETS (Talberg and Swoboda, 2013, ICAP, 2018a). It was the first nationwide cap-and-trade program in East Asia. The ETS covers approximately 599 of the country's largest emitters and accounts for around 68% of national overall emissions.

UK

The UK is a participant in the EU ETS, and has introduced its own federal legislation for an EPS (Department of Energy and Climate Change, 2014, Department of Energy and Climate Change, 2015). The EPS is anticipated to work in conjunction with CCS-ready requirements and to form part of an overall decarbonisation strategy. The Emissions Performance Standard Regulations 2015 as part of The Energy Act 2013 was passed in 2014. It mandates that all new fossil fuel power generation above 50 MW is limited to 0.450 t CO2/MWh. The EPS is applicable to plants operating at 'baseload', which assumes that it is operating continuously over the course of a year at between 80-90% of its rated electrical output.

US

In 2015, under the Obama Administration, the Clean Air Act was legislated (US EPA, 2015, C2ES, 2017), which laid out different approaches to set two types of standards for power generation:

- Section 111(b) creates a federal program to establish standards for new, modified and reconstructed stationary sources.
- Section 111(d) is a state-based program for existing stationary sources where the EPA establishes guidelines and the states then design programs to fit in those reductions to get the required reductions.

For existing generation, the US EPA was to regulate carbon emissions from existing fossil fuel power plants known as the Clean Power Plan. Under the Plan, the US EPA typically sets the standards with the states to then implement them, for example through market-based mechanisms, such as averaging or trading. However, the Clean Power Plan is yet to be implemented (US EPA, 2017;Trump, 2017).

For new build fossil fuel power plants, as part of the Clean Air Act, the US EPA released the "Carbon Pollution Standard for New Power Plants", which establishes New Source Performance Standards (NSPS) to limit emissions of CO_2 from fossil fuel-fired power plants (US EPA, 2015). The NSPS limit emissions from new natural gas and coal power plants to 1,000 lbs/MWh (0.454 t/MWh) and 1,400 lbs CO_2/MWh (0.635 t/MWh), respectively. The NSPS are in effect, though they are currently under review by the EPA.

In addition to the Clean Air Act 2015, individual states have implemented ETS schemes. For example, the California Cap-and-Trade Program (since 2013) and the Regional Greenhouse Gas Initiative (RGGI) incorporating the states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont (since 2012) (ICAP, 2018a). Massachusetts also established the Massachusetts Limits on Emissions from Electricity Generators (MLEEG) (Richmond and Detterman, 2016), The MLEEG is a cap-and-trade program between electricity generators, which also sets annual individual emissions limits for existing and new facilities.

Summary

Table 1-9 summarises the status of countries that have or are planning to implement an EPS or ETS, and where the power sector is a participant. Although Switzerland and the regions of Tokyo and Saitama have ETS schemes, they have not been included in this table as the power sector is not covered in those programs.

Table 1-9 Status of countries and regions with EPS or ETS, incorporating the power sector

Region/Country	EPS status	ETS status
Asia- Pacific		
Australia		Repealed Carbon Pricing Mechanism
New Zealand		Active
China	Action Plan of Transformation and Upgrading of Coal Power for Energy Conservation and Emissions Reduction 2014–2020	Active
Japan		Under consideration
Republic of (South) Korea		Active
Taiwan, China		Under consideration
Thailand		Under consideration
Vietnam		Under consideration
North and South America		
Canada	Canadian Environmental Protection Act, 1999, updated 2015	None
Alberta		Active
Ontario		Active
Québec		Active
Nova Scotia		Scheduled
US	Clean Air Act 2015 - under repeal	
California		Active
Massachusetts		Active
RGGI		Active
Virginia		Scheduled
Oregon		Under consideration
Washington state		Under consideration
Brazil		Under consideration
Mexico		Scheduled - The first phase (pilot phase) will last for three years from August 2018 until August 2021
Chile		Under consideration
Colombia		Under consideration
Europe and Central Asia		
EU, Iceland, Liechtenstein and Norway		Active
UK	Emissions Performance Standard Regulations 2015	
Turkey		Under consideration
Ukraine		Scheduled

1.2 Water usage of power plants with CO_2 capture

1.2.1 CO_2 capture technologies

The three most common CO_2 capture systems applied to power plants include post-combustion capture, pre-combustion capture and oxy-combustion capture. For each capture system, various separation technologies such as solvent absorption, adsorption, membrane and cryogenic/hydrate can be utilised. Figure 1-10 shows the general schematic for post-combustion, pre-combustion, and oxy-combustion capture. The specific water requirements and usage for each capture system is dependent on the specific process equipment and configuration of the capture process.

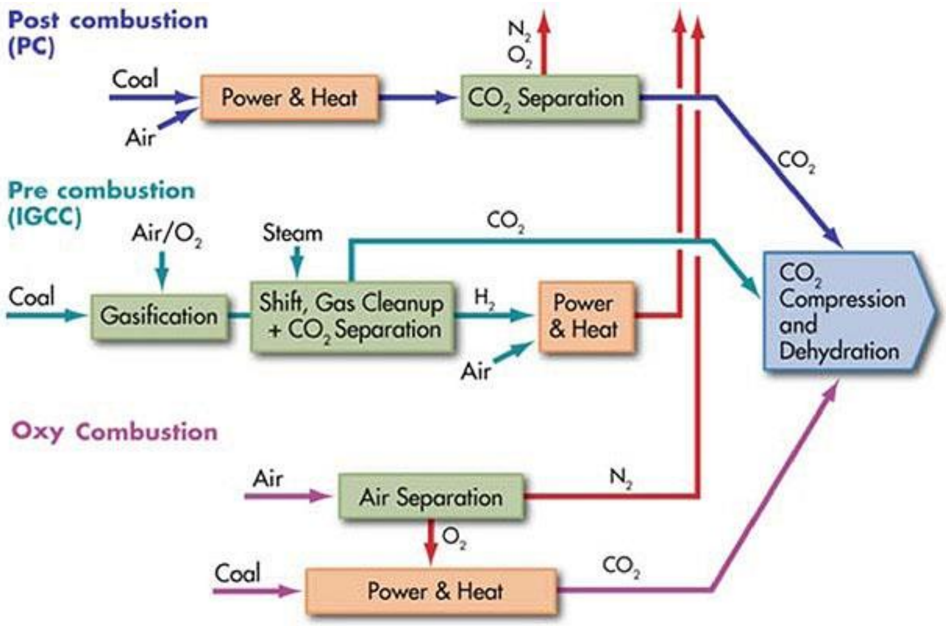

Figure 1-10 CO_2 capture systems: post-combustion, pre-combustion and oxy-combustion capture (Global CCS Institute, 2012)

Post-combustion capture

Post-combustion capture (PCC) of CO_2 captures the emission from the product gas stream of fuel combustion and has been implemented at commercial scale at various industrial sites. The technology has the advantage of being able to be retrofitted to an existing process without major modifications to the original industrial process. The use of chemical absorption solvents is the most common technique used in post-combustion capture of CO_2 as it is considered the most economically viable option at the present time.

Figure 1-11 shows the process diagram of a standard PCC chemical absorption process. Cooled flue gas enters the bottom of the absorber column and subsequently a counter-current flowing solvent in the column will absorb CO_2 with CO_2-free gas being vented into the atmosphere. The CO_2-rich solvent is pumped through a heat exchanger to be preheated before entering into the regenerator. In a final step CO_2 is removed from the top of the regenerator before undergoing compression for transport. Commonly used liquid solvents include amines, aqueous ammonia, and akali carbonates.

Figure 1-11 shows the key incoming and outgoing streams containing water. These include process cooling water for the coolers and compressors, power plant condensate (at 19 bar), steam for the stripper reboiler, condensate from the stripper reboiler, water in the flue gas, and demineralisation water for the water wash section at the top of the absorber where fresh water is used to recover the solvent present in droplets or as vapour in the outgoing flue gas. Outgoing streams containing water include the exiting process cooling water, power plant condensates, steam condensate from the reboiler, water in the outgoing flue gas, excess water from the direct contact coolers (DCC), reclaimer wastes and water in the CO_2 product (Hylkema and Read, 2014).

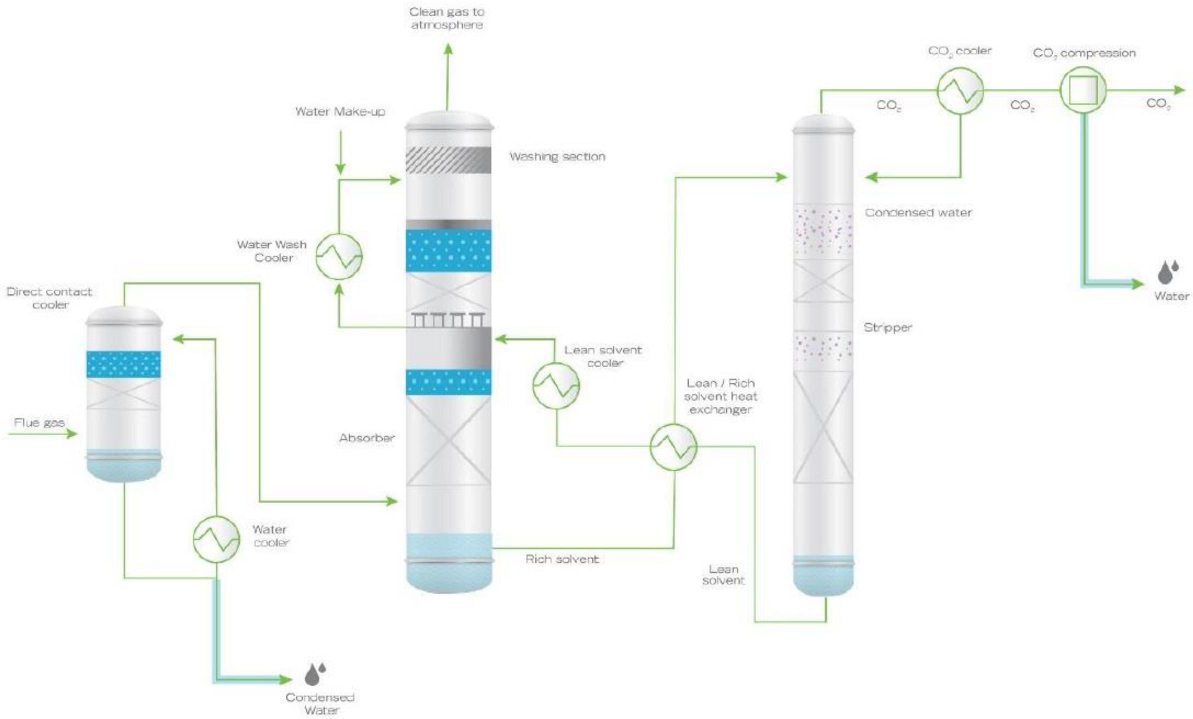

Figure 1-11 Process flow diagram of a post-combustion capture system using chemical absorption indicating the main process coolers and water inflow/outflow streams (Global CCS Institute, 2016)

Pre-combustion capture

Unlike post-combustion, pre-combustion involves a gasification step to produce a synthesis gas consisting of CO, CO_2, and H_2. The syngas is further processed in the water-shift reactor to convert residual CO to CO_2 and H2. The CO_2 is then separated from the hydrogen gas, which is directed to a turbine to produce power. Common CO_2 separation technologies include physical and chemical solvents, and hybrid membrane processes. A simplified block diagram illustrating pre-combustion CO_2 capture is in Figure 1-12.

According to the DOE (DOE-NETL, 2009), an increase in water usage compared to the reference power plant without capture is caused by increased process cooling requirements and increased make-up water needs. Make-up may play a more significant role for pre-combustion systems compared to post-combustion systems due to the addition of the water gas shift reaction (WGS). In fact, the WGS consumes a significant quantity of water, as steam is required to sustain the shift reaction.

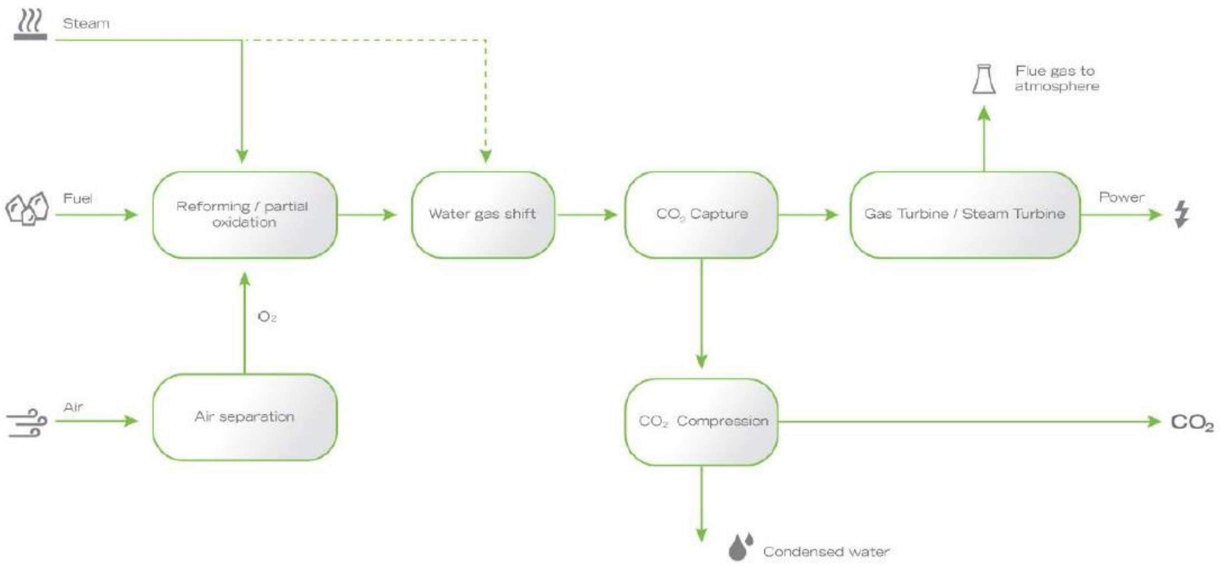

Figure 1-12 Simplified process flow diagram of a pre-combustion capture system using absorption indicating the main process coolers and water inflow/outflow streams (Global CCS Institute, 2016)

Oxy-combustion capture

Oxy-combustion capture is the combustion of fuel with oxygen, not air. This oxygen-rich, nitrogen-free atmosphere produces a gas steam consisting of mainly water and CO_2 (up to 80% by volume). Separation of the CO_2 from the water comprises of knock-out drums to remove the water and compressing the CO_2 for transport. Unlike post and pre-combustion capture, the majority of the energy and costs for oxy-combustion capture is for the separation of the oxygen from air rather than for separating the CO_2 from water. Figure 1-13 shows a simplified process diagram of oxy-fuel capture system. According to the DOE (DOE-NETL, 2009), the increase in water usage for an oxy-combustion system compared to a reference coal fired power plant without capture arises from the need to employ cooling water in the air separation unit (ASU) and the flue gas recycling (FGR) system of the oxy-combustion power plant.

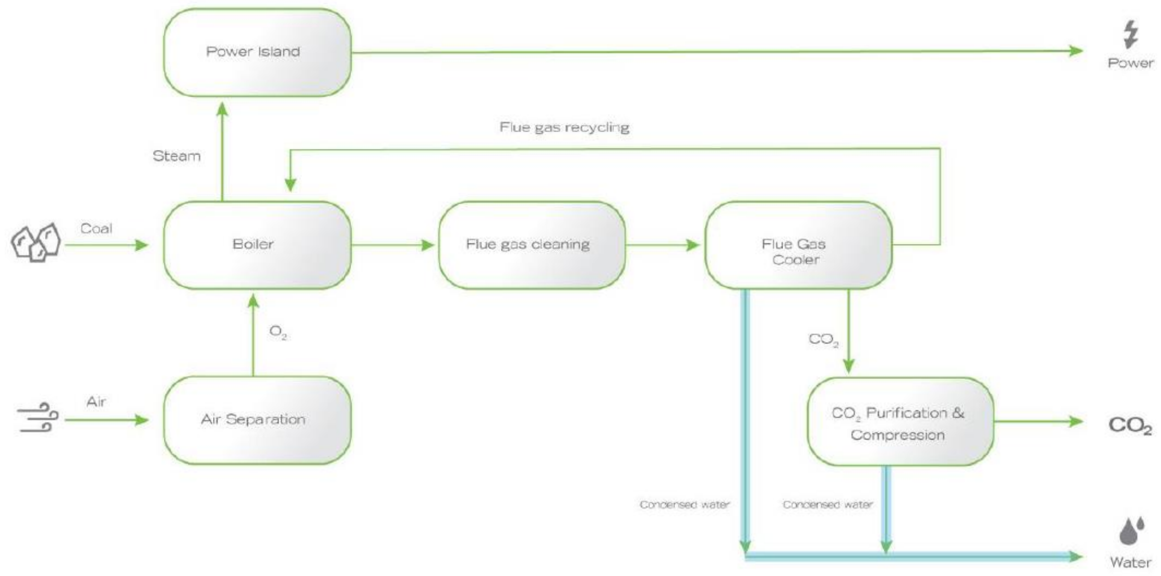

Figure 1-13 Simplified process flow diagram of an oxy-combustion system indicating main water inflow/outflow streams (Global CCS Institute, 2016)

1.2.2 Water use in CO_2 capture systems

The water usage in power plants will change with the introduction of a CO_2 capture system. Figure 1-14 shows the distribution points of water usage in a typical coal fired power plant with and without capture. The figure shows that the largest component (almost 80%) of the water use is the cooling system. It should be noted that the steam cycle cooling in the power plant with capture uses less water than without capture on a normalised basis (litres or m^3 of water used per MWh net power output). As the capture system in most analyses assumes a chemical solvent absorption system, low pressure steam is extracted from the power plant to regenerate the CO_2-rich solvent with the steam condensing in the reboiler of the capture plant, thus reducing the cooling requirement in the steam cycle of the power plant. However, the overall cooling requirement and water usage for power plants with capture is higher than plants without capture as additional cooling water is needed for the capture process' direct contact cooler, the CO_2 absorption and stripping processes, and compression (Figure 1-11).

The amount of cooling required for the capture process is also dependent on the energy efficiency of this process. Solvents requiring less heat for CO_2 regeneration will require a lower amount of steam to be extracted.

Furthermore, the specific cooling duty for power plants with capture will vary depending on the boiler technology (Zhai and Rubin, 2010; IEA/CIAB, 2010; Feron et al., 2017). Figure 1-15 shows that the water usage (as make-up water required for a wet once-through cooling system) reduces as the boiler technology improves from a subcritical to supercritical and ultra-supercritical, reducing by about 10% and 26%, respectively.

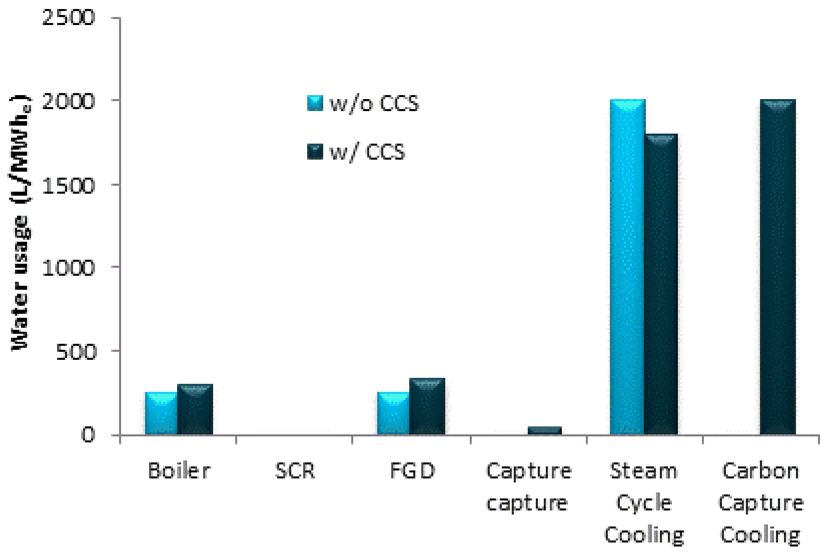

Figure 1-14 Water use distribution points for power plants with and without carbon capture (adapted from Zhai and Rubin, 2016). SCR and FGD denote selective catalytic reduction and flue gas desulphurisation respectively

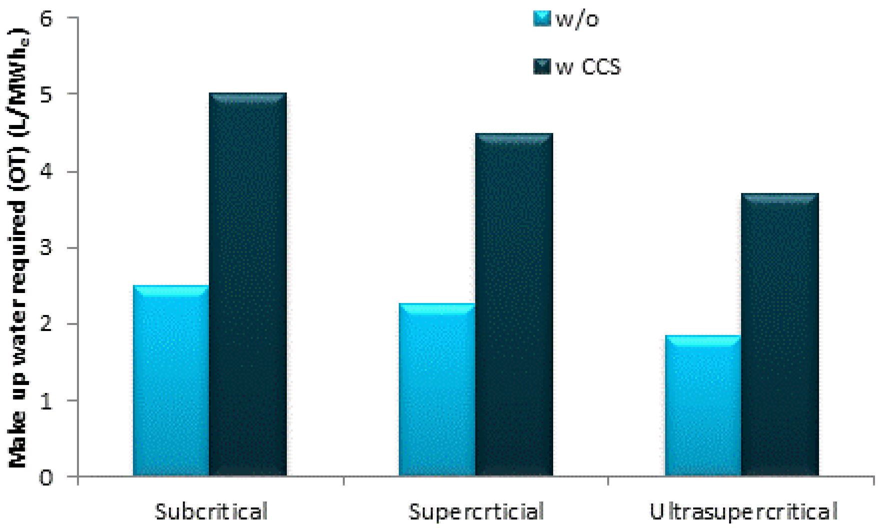

Figure 1-15 Water usage for different coal-fired power plant types with and without capture (adapted from Zhai and Rubin, 2016)

1.2.3 Water use in power stations with capture

In 2016, the Global CCS Institute released a report summarising the main studies in the literature available outlining the water usage of different types of power plants and capture systems (Global CCS Institute, 2016). The subsequent section will build on that summary by incorporating recent and other literature studies.

Post-combustion capture

Pulverised Coal

Table 1-10 provides an overview of the key metrics of water consumption and withdrawal (normalised and absolute) for post-combustion capture from coal-fired power plants. The normalised values represent the absolute consumption/withdrawal divided by the net power output. Note that, where necessary, the numbers have been adapted to represent a retrofitted case where the gross output is the same as the reference plant without capture. This approach follows that of the Global CCS Institute in their 2016 report whereby in order to simulate the effect of a retrofit, the reduced output is used and is calculated from the thermal input and the efficiency in CO_2 capture mode. The approach is to enable comparison between different studies.

For recirculating cooling systems, the increase in normalised water consumption due to carbon capture ranges from 49%-83% (Table 1-10), and for normalised water withdrawal from 53%-90% (DOE-NETL, 2015a, DOE-NETL, 2013). The significant difference in the normalised water consumption is a result of different solvents being used in the post-combustion carbon capture system: Shell Cansolv compared to Fluor Econoamine FG Plus. The use of the more advanced solvent has significantly reduced the energy penalty of the system (and increased the thermal efficiency of the power plant with capture), with the flow on benefit of reducing the absolute total water usage of the power plant with capture (by about 14%). The increase in absolute consumption and withdrawal for this technology is 20%-32% and 23%-36% respectively. The differences in the percentage increases between the normalised and absolute values show that reporting the water requirements only as normalised values can skew the analysis to make the water usage appear significantly larger than they actually are.

For once-through cooling systems using Econamine Plus in an ultrasuper-critical power plant, the increase in water withdrawal rates for plants with capture are about 63%-72% normalised and 25%-51% absolute (Table 1-10). If the plant type is supercritical, such as in the study by Zhai and Rubin (2010), the increase in water withdrawal due to capture is 87% (normalised). This is expected as the thermal efficiency differences between the studies is almost 10%. In a recent study by Stępczyńska et al. (2018) the increase in water usage for the power plant when using MEA is 46% normalised and 22% absolute. Although it is expected that using a MEA solvent system would have higher water usage than the more advanced Flour Econoamine Plus solvents, due to heat integration in the carbon capture system and the use of cold cooling water (9^oC) the capture systems requires less water (Stępczyńska et al., 2018).

Work undertaken by Zhai and Rubin (2016) suggests that using a hybrid wet-dry cooling system at a supercritical power plant can significantly change the amount of water consumed (Table 1-10). For the power plant without capture, normalised water consumption is about 0.2 t/MWh, which is almost one tenth of that required at an equivalent plant using only wet cooling (DOE, 2012). Once CO_2 capture is retrofitted to the power plant, this consumption increases to about 1.73 t/MWh. All of the water increases are related to the water usage within the capture process, and is a significant increase by a factor of 8 times or over 800%.

An IEAGHG (2011) study and the review of the ROAD project (Hylkema and Read, 2014) examined power plants with and without capture under a scenario where water discharge is highly regulated. The assessments include scenarios where process water is reused and recycled at an onsite wastewater treatment facility (with make-up using freshwater water) and seawater is utilised for cooling of the steam turbine. As a consequence, the water consumption rate for the reference power plant without capture is low at 0.09 t/MWh for the IEAGHG study and 0.15 t/MWh for the ROAD project (Table 1-10). When capture is implemented, the normalised consumption of water becomes negative, as water from the capture process is recycled within the wastewater treatment facility and is utilised in other parts of the power plant such as the FGD. However, the increase in actual raw water usage is almost four times, increasing from an intake of 0.1 to 0.4 t/MWh (IEAGHG, 2011). The absorber raw water usage accounts for almost half of this raw freshwater make-up. The increase in water withdrawal due to capture, which primarily reflects the increases in seawater used for the additional cooling needed in the absorption and compressor processes, is 72% normalised and 51% absolute for the IEAGHG study and 63% normalised and 25% absolute for the ROAD project.

Figure 1-16 presents the range in increases in normalised consumption and withdrawal for both recirculating and once-through cooling systems at pulverised coal power plants with capture.

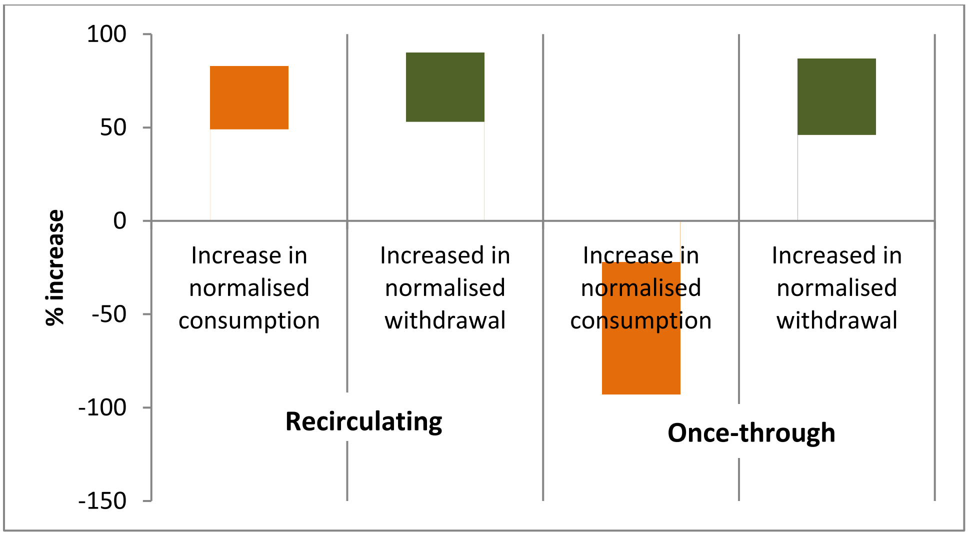

Figure 1-16 Range in increases in normalised consumption and withdrawal for recirculating and once-through cooling: coal fired power plant with post-combustion capture

Table 1-10 Water usage for post-combustion capture at coal fired power plants

Cooling technology		**Recirculating**		**Once-through**				**Hybrid (circulating wet-dry)**
Reference		DOE-NETL (2013)	DOE-NETL (2015a)	IEAGHG (2011)	Hylkema and Read (2014) ROAD Project	Zhai and Rubin (2010)	Stępczyńska et al. (2018)	Zhai and Rubin (2016)
Plant type Coal type		PC SC	PC SC	PC USC	PC USC	PC SC llinois #6	PC USC	PC SC Illinois#6
Capture technology		Fluor Econa-mine FG+	Cansolv	Fluor Econamine FG+	Fluor Econamine FG+	EconamineFG+	MEA 30%wt	Econamine FG+/Advanced amine
Heat integration		No	No	No	No	No	Yes	No
Normalised								
Without capture								
Gross power plant output	MWe	580	580	831		590		595
Power plant output (net)	Mwe	550	550	758	1070	550	778	550
Thermal efficiency	%	39.3 HHV	40 HHV	44 LHV	46 LHV	38.4 HHV	44 HHV	36.9 HHV
Total water in	t/MWh	2.3	2.2	140.0	86.7	99.7	94.8	
Total water out	t/MWh	0.5	0.5	139.9	86.6			
Consumed water	t/MWh	1.8	1.7	0.09	0.15	2.1		0.19
With 90% capture								
Gross power plant output	MWe	580	580	827		685		686
Net Power plant output	Mwe	395	440	666	822	550	650	550
Total water in	t/MWh	4.4	3.4	240.8	141.0	186.6	138.3	
Total water out	t/MWh	1.0	0.8	240.7	141.0			
Consumed water	t/MWh	3.4	2.6	0.07	0.01			1.7
Increase in normalised consumption		**83%**	**49%**	**-22%**	**-93%**	**Not given**	**Not given**	**811%**
Increase in absolute consumption		**32%**	**20%**	**-32%**	**-95%**	**Not given**	**Not given**	
Increased in normalised withdrawal		**90%**	**53%**	**72%**	**63%**	**87%**	**46%**	
Increased in absolute withdrawal		**36%**	**23%**	**51%**	**25%**		**22%**	**87%**

NGCC

For NGCC power plants, the cooling technology is primarily recirculating wet cooling towers (Table 1-11). The normalised consumption of water ranges from 0.66-0.76 t/MWh for NGCC power plants without capture, which is about 40% of that for using the same cooling technology at a coal fired power plant. Once capture is implemented, the water consumption increases by 66%-88% normalised or 47%-61% absolute. Withdrawal rates also increase by up to 100% normalised and 72% absolute. This is equivalent to consumption rates of 1.15-1.43 t/MWh (Table 1-11).

Using more advanced solvent systems reduces the water consumption: when MEA solvent is replaced with a propriety amine solvent (such as MHI's KS solvents or Cansolv) the reduction in consumed water is 2% (IEAGHG, 2012a). Similarly, where Cansolv replaces Fluor Econamine Plus water consumption decreases by about 14% (DOE-NETL, 2013, DOE-NETL, 2015a).

Figure 1-17 presents the range in increases in normalised consumption and withdrawal for recirculating cooling systems is presented for NGCC, IGCC power plants, and oxy-combustion power plants with capture.

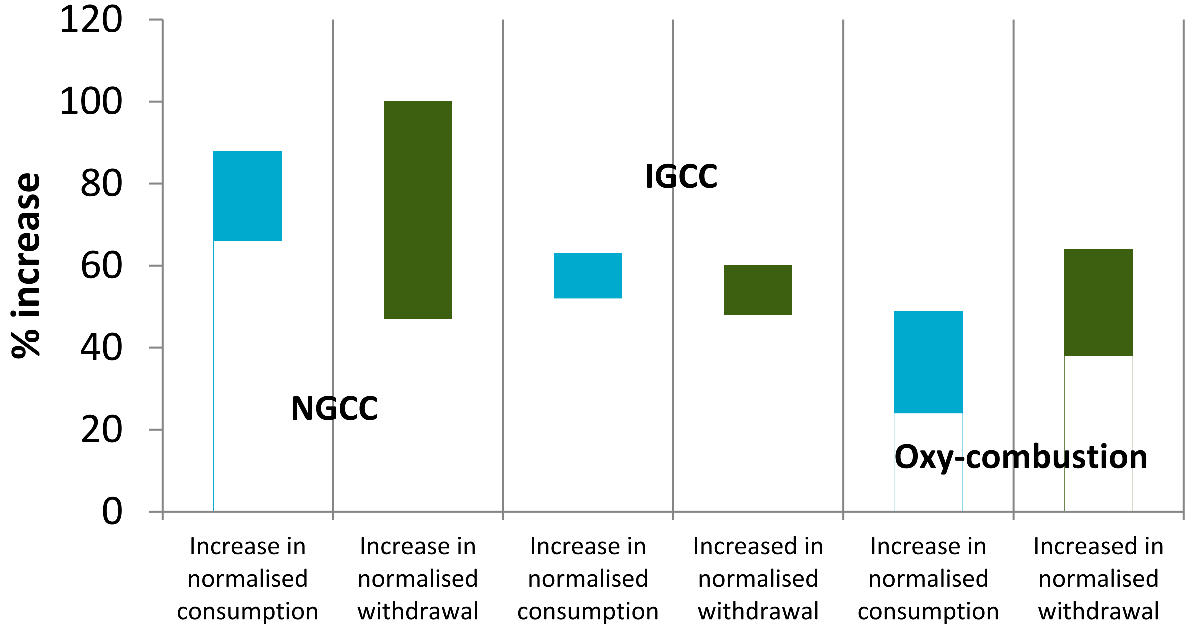

Figure 1-17 Range in increases in normalised consumption and withdrawal for recirculating cooling; NGCC, IGCC, oxy-combustion power plants with capture

Table 1-11 Water usage for post-combustion capture at NGCC power plants

Cooling technology		**Recirculating**				**Hybrid (circulating wet-dry)**
Reference		IEAGHG (2012a)	IEAGHG (2012a)	DOE (2013)	DOE (2015)	Zhai and Rubin (2016)
		NGCC	NGCC	NGCC	NGCC	NGCC
Capture technology		MEA 35%	Propriety solvent	Fluor E FG+	Cansolv	Fluor EFG+
Heat integration		No	No	No	No	No
Normalised						
Without capture						
Gross power plant output	MWe	934	934	564.7	641	600
Power plant output (net)	Mwe	910	910	555	630	581
Thermal efficiency	%	58.9 LHV	58.9 LHV	50.2 HHV	51.5 HHV	49.3 HHV
Total water in	t/MWh	0.79	0.79	0.97	0.95	
Total water out	t/MWh	0.13	0.13	0.22	0.21	
Consumed water	t/MWh	0.66	0.66	0.76	0.74	0.09
With 90% capture						
Gross power plant output	MWe	960	874	511	641	544
Net Power plant output	Mwe	789	804	473.57	559	502
Total water in	t/MWh	1.57	1.16	1.92	1.63	
Total water out	t/MWh	0.42	0.04	0.48	0.41	
Consumed water	t/MWh	1.15	1.12	1.43	1.23	0.86
Increase in normalised consumption		**75%**	**71%**	**88%**	**66%**	**856%**
Increase in absolute consumption		**52%**	**51%**	**61%**	**47%**	**726%**
Increased in normalised withdrawal		**100%**	**47%**	**98%**	**72%**	
Increased in absolute withdrawal		**73%**	**30%**	**69%**	**52%**	

Pre-combustion capture

In IGCC power plants, using recirculating closed-loop cooling systems, adding a physical solvent capture process such as the Selexol™ CO_2 removal process will increases the normalised water consumption by 63% for an E-Gas FGQ gasifier, and 52% for a GEE slurry feed quench gasifier. Increases in normalised water withdrawal are also 60% and 48%, respectively as shown in Table 1-12 Water usage for Pre-combustion IGCC power plants. The difference in water consumption and withdrawal between the two gasifiers arises because of the different gasifier configuration. Both the absolute increase in consumption and withdrawal are about 30%.

In comparison, Table 1-12 Water usage for Pre-combustion IGCC power plants shows that using a once-through open-loop cooling system at IGCC power plants, the increase in water consumption due to capture is significant with an increase of over 200% in normalised values. While the once-through system already has high withdrawal rates, implementing capture increases the withdrawal term by 26%.

Table 1-12 Water usage for Pre-combustion IGCC power plants

Cooling technology		**Recirculating**		**Once-through**
Reference		DOE-NETL (2015b) E-Gas	DOE-NETL (2015b) GEE quench	IEAGHG (2011) GEE quench
Capture technology		Selexol	Selexol	Selexol
Heat integration		No	No	No
Normalised				
Without capture				
Gross power plant output	MWe	738	748	988.7
Power plant output (net)	Mwe	625	622	826
Thermal efficiency	%	39.7 HHV	39 HHV	38 LHV
Total water in	t/MWh	1.59	1.733	147.06
Total water out	t/MWh	0.33	0.359	146.94
Consumed water	t/MWh	1.26	1.374	0.12
With 90% capture				
Gross power plant output	MWe	704	734	972.8
Power plant output (net)	Mwe	513	543	730
Total water in	t/MWh	2.55	2.567	185.67
Total water out	t/MWh	0.49	0.472	185.28
Consumed water	t/MWh	2.06	2.095	0.39
Increase in normalised consumption		**63%**	**52%**	**225%**
Increase in absolute consumption		**34%**	**33%**	**187%**
Increased in normalised withdrawal		**60%**	**48%**	**26%**
Increased in absolute withdrawal		**32%**	**29%**	**12%**

Oxy-combustion capture

The changes in water usage through implementing capture at an oxy-combustion power plant are highly dependent on the type of air separation unit (ASU) technology utilised. In the studies by the DOE-NETL (2012), the water withdrawal rates are compared for two ASU processes; traditional cryogenic distillation and a membrane ASU. The reference power plant for both cases is a supercritical coal-fired power plant. Using recirculating closed-loop cooling, the increase in normalised water consumption for the cryogenic ASU is 49%, and for the membrane ASU 24%; with absolute increases at 11% and 2% respectively (Table 1-13). The much lower increase for the membrane ASU system is due to less water being required for the membrane process.

For once-through open cooling systems, implementing oxy-combustion capture with the reference plant being a supercritical coal-fired power plant could result in less water being consumed compared to the reference case. In an IEAGHG (2011) study, for the highly regulated situation with on-site waste-water treatment, it was found that the normalised and absolute water consumption for an oxy-combustion power plant is less by 340% and 270% respectively compared to the reference supercritical plant. In this oxy-combustion process, the water produced as part of the boiler flue gas is recovered in the wastewater treatment facility, thus reducing the need for external water. For this process, external raw freshwater is only consumed as part of the demineralisation water unit and for compressor cooling water.

Table 1-13 Water usage for oxy-combustion power plants

Cooling technology		**Recirculating**		**Once-Through**
Reference		(DOE-NETL, 2012)	(DOE-NETL, 2012)	(IEAGHG, 2011)
ASU technology		Cryogenic ASU	Membrane ASU	
Heat integration		No	No	No
Normalised				
Without capture				
Gross power plant output	MWe			831
Power plant output (net)	Mwe	550	550	758
Thermal efficiency	%			
Total water in	t/MWh	2.193	2.193	139.976
Total water out	t/MWh	0.447	1.447	139.891
Consumed water	t/MWh	1.746	0.746	0.085
With 90% capture				
Gross power plant output	MWe			737
Power plant output (net)	Mwe	410	451	531
Total water in	t/MWh	3.607	3.016	226.182
Total water out	t/MWh	1.001	0.843	226.385
Consumed water	t/MWh	2.606	2.173	-0.203
Increase in normalised consumption		**49%**	**191%**	**-339%**
Increase in absolute consumption		**11%**	**139%**	**-267%**
Increased in normalised withdrawal		**64%**	**38%**	**62%**
Increased in absolute withdrawal		**23%**	**13%**	**13%**

1.2.4 Economic assessments of CO_2 capture at power plants

Table 1-14, Table 1-15, and Table 1-16 summarise the reported LCOE, electricity production efficiency and capital and operating costs of thermal power plants with capture compared to the reference power plants without. The reported values have not been amortised, escalated or harmonised with each other.

Using post-combustion capture (either Fluor Econamine FG+ or Cansolv), the cost of electricity for coal fired power plants with capture typically ranges from about 107 US$/MWh to over 145 US$/MWh (Table 1-14), increasing from baseline values of about 60-80 US$/MWh for the reference power plants. This corresponds to an average increase of 80% due to capture. The approximate capture cost expressed as CO_2 avoided are 70-100 US$/t. The power plant's thermal efficiency drops by about 8% when using an energy efficient solvent such as Shell Cansolv or about 10% if using Fluor Econamine FG+. The results from the studies by Zhai and Rubin (2010, 2013, 2016) also show that the cooling technology is affected by capture. At a power plant with wet cooling, the thermal efficiency reduction due to capture is 12%. However, at a power plant with dry cooling capture imposes a penalty of 12.6%. The assessment from the IEAGHG (2011) is an anomaly in terms of cost for post-combustion capture, with estimates almost half those of the DOE-NETL (2013, 2015) and Zhai and Rubin (2010, 2013, 2016). The much lower costs for the IEAGHG reference power plant and plant with capture arise due to the cost estimates being assessed for South African conditions with low fuel cost. In comparison, the other studies are based on conditions for the U.S. (Texas), where higher equipment, labour and material costs are assumed.

For the NGCC power plants with capture (Table 1-15), the cost of electricity is 83-94 US$/MWh and 70-77 €/MWh, which is lower than for coal fired power plants with capture. Although in the DOE-NETL (2013) study the cost of electricity at the reference NGCC power plant is similar in value to the coal fired power plant without capture (~60 US$/MWh), the increase in capital cost is lower when capture is applied: an increase of 840 US$/kW compared to 1770 US$/kW. Overall, the capture cost for NGCC power plants is 82-84 US$/t CO_2 avoided, with the lower cost arising when an efficient solvent such as Cansolv is utilised.

Implementing capture using pre-combustion and oxy-combustion technologies typically has lower capture costs than comparative estimates for post-combustion capture at coal fired power plants - by about 40%-80% (Table 1-16). This is based on the capture costs being calculated assuming the reference plant is the same plant without capture. Estimates for the LCOE for the IGCC power plants with capture are about 150 US$/MWh based on 2011 values (which has increased from an estimate of 105 US$/MWh in 2007). This is comparable to LCOE for post-combustion capture coal fired power plants. However, for IGCC power plants without capture, the LCOE is quite high at approximately 100 US$/MWh, and thus the increase in LCOE due to capture is less significant. The thermal efficiency penalty due to capture is about 7% at IGCC plants and is the same for both once-through open-cycle cooling (DOE-NETL, 2015) and recirculating closed-loop cooling (IEAGHG, 2011). For oxy-combustion power plants, the LCOE ranges from approximately 77-92 US$/MWh, with an average percentage increase in LCOE due to capture of 50%-60%. The lower increase in LCOE compared to post-combustion capture at coal fired power plants results in lower comparative capture costs, with values of 32-44 US$/t CO_2 avoided. The efficiency penalty for capture for oxy-combustion is 10%.

Table 1-14 Economic summaries of post-combustion capture for coal fired power plants

Power plant type Cooling technology	Unit	PC Recirculating		PC Once-through		PC Dry	PC Wet-dry
Reference		DOE 2013	DOE 2015	IEAGHG 2011	Zhai and Rubin 2013	Zhai and Rubin 2010	Zhai and Rubin 2016
Capture technology		Fluor EFG+	Cansolv	Fluor EFG+	Fluor EFG+	Fluor EFG+	Fluor EFG+
Cost year		2007	2011	2009	2009	2007	2012
Currency		US	US	Euro	US	US	US
Without capture							
Gross power plant output	MWe	580	580	831	590	601	595
Net power plant output	MWe	550	550	758	550	550	550
Plant efficiency	%	39.3 HHV	40.7 HHV	44 LHV	38.4 HHV	34.6 HHV	36.9 HHV
CO_2 net emissions	t/MWh	0.80	0.77	0.74	0.81	0.85	0.85
CAPEX	$/kW	2296	2026	1161	Not given	1940	
CAPEX	$/MWh	31.7	39	17.3			
OPEX	$/MWh	27.2	43.3	22.7			
FOPEX	$/MWh	8	9.6				
VOPEX	$/MWh	5	9.1				
FUEL	$/MWh	14.2	24.6				
LCOE without capture	$/MWh	58.9	82.3	€40 (~USD48)	69.3	73.1	65.3
With capture							
Gross power plant output	MWe	663	642	827	685	600.7	686
Net power plant output	MWe	550	550	665.6	550	550	550
Plant efficiency	%	28.4 HHV	32.5 HHV	34.8 LHV	26.4 HHV	22 HHV	26.4 HHV
CO_2 net emissions	t/MWh	0.11	0.10	0.12	0.09	0.12	0.12
CAPEX	$/kW	4070	3524	1655	Not given	Not given	Not given
CAPEX	$/MWh	59.6	72.2	26.3			
OPEX	$/MWh	46.9	61	31.7			
TRANSPORT & STORAGE (T&S)	$/MWh	5.6	9.6				
FOPEX	$/MWh	13	15.4				
VOPEX	$/MWh	8.7	14.7				
FUEL	$/MWh	19.6	30.9				
LCOE with capture only	$/MWh	106.5	133.2	€58 (~USD70)	121.2	145	110
LCOE with capture + Transport & Storage (T&S)	$/MWh	112.1	142.8				
CO_2 avoided to SC w/o capture reference plant	**$/t**	69					
CO_2 avoided to reference plant w/o T&S	**$/t**	**69**	**75**	**€29**	**72**	**98**	**61**
CO_2 avoided to reference plant w/ T&S	**$/t**	**77**	**89**				

Table 1-15 Economic summaries of post-combustion capture for NGCC power plants

Power plant **Cooling technology**	**Unit**	**NGCC** **Recirculating**				**NGCC** **Wet-Dry**
Reference		IEAGHG 2012a	IEAGHG 2012a	DOE 2013	DOE 2015	Zhai and Rubin 2016
Capture technology		MEA 35%	Propriety solvent	Fluor Econamine FG+	Cansolv	Fluor Econamine FG+
Cost year		2009	2009	2007	2011	2012
Currency		Euro	Euro	US	US	US
Without capture						
Gross power plant output	MWe	934	934	565	641	600
Net power plant output	MWe	910	910	555	630	581
Plant effiency	%	58.9 LHV	58.9 LHV	50.2 HHV	51.5 HHV	49.3 HHV
CO_2 net emissions	t/MWh	0.348	0.348	0.36	0.36	0.37
CAPEX	$/kW	637	637	771	685	
CAPEX	$/MWh	10	10	10.1	11.8	
OPEX	$/MWh	43.9	43.9	48.8	45.8	
FOPEX	$/MWh			3	3.4	
VOPEX	$/MWh			1.3	1.7	
FUEL	$/MWh			44.5	40.7	
LCOE without capture	$/MWh	€53.9 ~USD65)	€53.9 (~USD65)	58.9	57.6	67.8
With capture						
Gross power plant output	MWe	960	874	511	601	544
Net power plant output	MWe	789	804	474	559	502
Plant efficiency	%	51 LHV (46.1 HHV)	52 LHV (47 HHV)	42.8 HHV	45.7 HHV	42.5 HHV
CO_2 net emissions	t/MWh	0.041	0.04	0.04	0.04	0.04
CAPEX	$/kW	1401	1165	1614	1481	
CAPEX	$/MWh	23	19.5	22.3	26.9	9.8
OPEX	$/MWh	51.6	49.2	63.7	56.5	
TRANSPORT & STORAGE (T&S)	$/MWh	2	2	3.2	4	
FOPEX	$/MWh			5.7	6.6	2.4
VOPEX	$/MWh			2.6	4	2.8
FUEL	$/MWh			52.2	45.9	
LCOE with capture only	$/MWh	€76.6 (~USD92)	€70.7 (~USD85)	86	83.4	93.7
LCOE with capture + Transport & Storage (T&S)	$/MWh			89.2	87.4	
CO_2 avoided to SC w/o capture reference plant	$/t			36		
CO_2 avoided to reference plant w/o T&S	$/t	**€74**	**€55**	**84**	**82**	**78**
CO_2 avoided to reference plant w/ T&S		**84**	**65**	**94**	**94**	

Table 1-16 Economic summaries of pre-combustion and oxy-combustion power plants with capture

Power plant type Cooling technology	Unit	IGCC Recirculating			IGCC OT	Oxy Recirculating		Oxy OT
Reference		DOE 2013	DOE 2015	DOE 2015	IEAGHG 2011	DOE 2012	DOE 2012	IEAGHG 2011
Capture technology		Selexol	Selexol	Selexol	Selexol	Cryogenic ASU	Membrane ASU	Cryogenic ASU
Cost year		2007	2011	2011	2009	2007	2007	2009
Currency		US	US	US	Euro	US	US	Euro
Without capture						SC plant no capture		
Gross power plant output	MWe	747.8	738	748	989	580	580	831
Net power plant output	MWe	622.05	625	622	826	550	550	758
Plant efficiency	%	39 HHV	39.7 HHV	39 HHV	38 LHV	39.3 HHV	39.3 HHV	44 LHV
CO_2 net emissions	t/MWh	0.78	0.78	0.78	0.82	0.80	0.80	0.74
CAPEX	$/kW	2447	2372	2449	1483	2296	2296	1161
CAPEX	$/MWh	43.4	51.8	53.7	24.5	31.68	32.68	17.3
OPEX	$/MWh	32.9	47.9	48.8	25.5	27.2	27.2	22.7
FOPEX	$/MWh	11.3	13.5	13.7		7.97	7.97	
VOPEX	$/MWh	7.3	9.2	9.4		5.03	5.03	
FUEL	$/MWh	14.3	25.2	25.7		14.2	14.2	
LCOE without capture	$/MWh	76.3	99.7	102.5	€50	58.9	58.9	€40 (~USD48)
With capture								
Gross power plant output	MWe	734	704	734	937	791	965.7	737
Net power plant output	MWe	543.25	513	543	671	550.02	550.06	531.4
Plant efficiency	%	32.6 HHV	31 HHV	32.6 HHV	31.5 LHV	29.3 HHV	32.2 HHV	35.4 LHV
CO_2 net emissions	t/MWh	0.09	0.10	0.09	0.15	0	0.06	0.09
CAPEX	$/kW	3334	3540	3387	1779	$3,219	$3,137	1983
CAPEX	$/MWh	59.1	77.6	74.2	32	53.72	52.35	34
OPEX	$/MWh	41.2	64.2	61.1	31	37.36	34.84	30
TRANSPORT & STORAGE (T&S)	$/MWh	5.2	9.9	9.2		5.83	5.6	
FOPEX	$/MWh	14.8	19.1	18.2		11.81	11.53	
VOPEX	$/MWh	9.3	12.8	12.2		6.47	5.99	
FUEL	$/MWh	17.1	32.3	30.7		19.08	17.32	
LCOE with capture only	$/MWh	100.3	141.8	135.3	€63	91.08	87.19	€64 (~USD77)
LCOE with capture + Transport & Storage (T&S)	$/MWh	105.5	151.7	144.5				
CO_2 avoided to SC w/o capture reference plant	**$/t**	**66 (T&S)**	**102.9 (T&S)**	**91.7 (T&S)**				
CO_2 avoided to reference plant w/o T&S	**$/t**	**35**	**62**	**48**	**€21**	**36**	**32**	**€36 (~USD43)**
CO_2 avoided to reference plant w/ T&S	**$/t**	**42**	**77**	**61**				

1.3 CO_2 Storage and water management

1.3.1 CO_2 storage in the Netherlands

Underground storage of CO_2 in the Netherlands has typically been proposed and investigated for two different types of reservoirs: deep saline aquifers, and depleted hydrocarbon fields (both gas and oil). Ramirez et al. (2010) identified over five hundred potential sites for CO_2 storage in the Netherlands, the majority of which are hydrocarbon reservoirs that may be used for CO_2 storage once they have been depleted. Applying additional capacity constraints of a minimum storage capacity of 2 Mt for saline aquifers and 4 Mt for hydrocarbon fields, they reduced this number to 176 potential onshore and offshore storage sites, comprising 138 gas fields, 4 oil fields, and 34 deep saline aquifers. The spatial distribution of these sites, as well as their estimated capacity is presented in Figure 1-18. Most of the identified storage capacity is in gas fields, followed by saline aquifers, with oil fields making only a small contribution to the total estimated storage capacity.

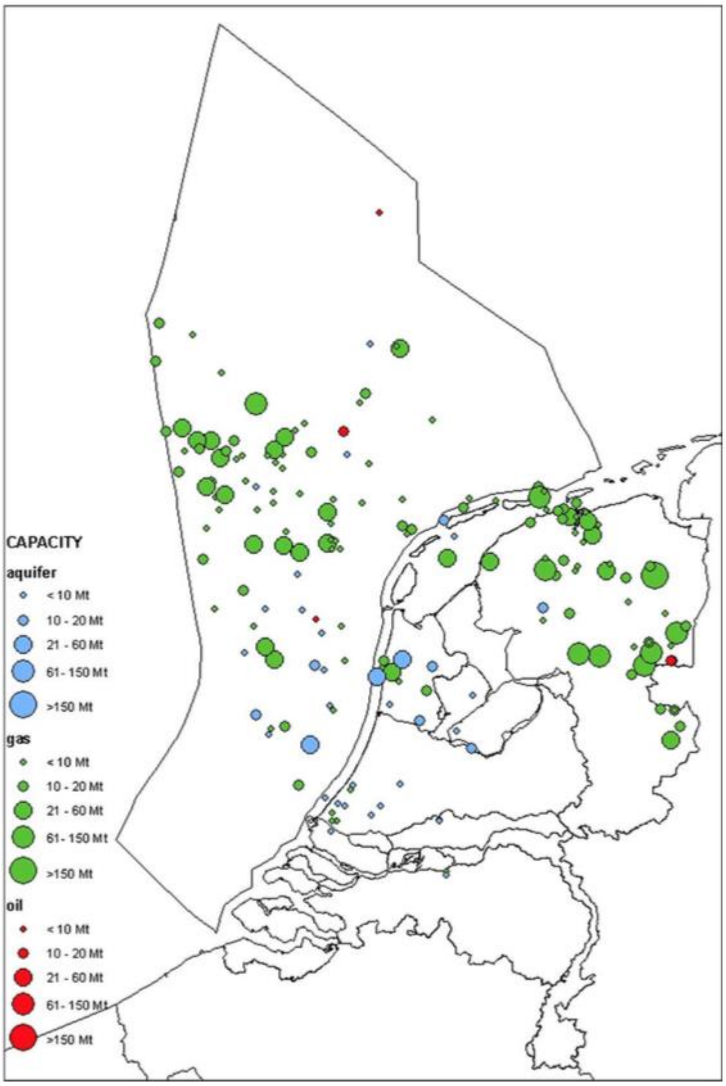

Figure 1-18: Map of possible geological storage locations in the Netherlands (Ramírez et al., 2010)

Total storage capacity of these fields is estimated as 3,200 Mt, with half of the identified storage sites having capacity estimates of less than 10 Mt (corresponding to approximately 20% of total storage capacity) (Ramirez et al., 2010). A summary of CO_2 storage capacity estimates and how they evolved over time is presented in Table 1-17, which indicates that initial estimates by Huurdeman (1992) were overly optimistic and reduced as knowledge improved. Volumetric efficiencies used to estimate the storage capacity in the Netherlands typically range between 2% for open aquifers, to 4% for closed aquifers (see for example, Huurdeman, 1992; van der Meer and Yavuz, 2009; Ramírez et al., 2010; Neele et al. 2012; Neele et al., 2013).

Table 1-17 Estimated total CO_2 storage capacities in the Netherlands published in the scientific literature

Estimated total CO_2 storage capacity (Mt)	Reference
50,000	Huurdeman (1992)
1,200	van der Meer (1992)
1,566[1]	van der Velde et al. (2008)
104	van der Meer and Yavuz (2009)
3,700	Damen, Faaij, and Turkenburg (2009)
3,630	Vangkilde-Pedersen et al. (2009)
3,200	Ramírez et al. (2010)
1,026[1]	Neele et al. (2011a)
1,850[2]	Neele et al. (2012), Neele et al. (2013)

Uncertainty in storage capacity estimates

The use of a single storage efficiency value in estimates of storage capacity introduces errors that may either underestimate or even overestimate the total storage capacity. Values published in the scientific literature vary from less than 1% to up to 10%, depending on the assumptions made in calculating these estimates (Bachu, 2015).

Storage efficiency can also be influenced by fluid properties and their dependence on pressure and temperature. Increasing the pressure in the reservoir can reduce the mobility ratio, resulting in an increase in storage efficiency (Bachu, 2015). Salinity can also affect the storage capacity, with brine density and viscosity increasing with increasing salinity, corresponding to a larger mobility ratio and hence lower storage efficiency (Brennan, 2014).

Simple volume-based estimates of storage efficiency also do not take into account potential storage due to dissolution of supercritical or gaseous CO_2 into the resident formation water in a saline aquifer, which can be a significant proportion of the total injected CO_2, (Bachu et al., 1994; Bachu and Adams, 2003; Ennis-King and Paterson, 2005).

Storage capacity can be limited by the maximum allowable pressure rise in the aquifer (van der Meer and Yavuz, 2009), which may be manageable via brine production to reduce the pressure build-up during injection, potentially increasing the storage efficiency. This option may be particularly useful for closed reservoirs, where it has been observed to make the largest difference in storage efficiency, with increases of over 100% observed in some site-specific simulations (Gorecki et al., 2015).

Adding to that, it has to be considered that not all of the storage capacity estimated is available at this stage, but capacity increases as hydrocarbon fields become depleted and

[1] Offshore (Dutch Continental Shelf) only.

[2] Offshore storage only.

production comes to an end. For example, Ramirez et al. (2010) suggested that half of their storage capacity estimate was available at the time of their study, while this number was to increase to approximately 75% by 2020. In a study confined to the offshore Dutch Continental Shelf, van der Velde et al. (2008) calculated that in 2010 the total storage capacity of this region was approximately 218 Mt, increasing to 1,566 Mt by the year 2030 when all gas production was expected to end.

Probable storage capacity in the Netherlands

It is likely that there is a large amount of effective storage capacity in the Netherlands, particularly in depleted gas fields, where the capacity estimates are subject to less uncertainty as they are based on previous production levels. The total storage capacity in depleted gas fields is likely to range between 1,500 Mt and 2,500 Mt, depending on the degree of optimism used in the level of total capacity that can be utilised. Depleted hydrocarbon fields present as an attractive option due to proven storage capability and the presence of existing surface and subsurface infrastructure, although the suitability of this infrastructure for CO_2 storage projects in depleted fields must be considered in detailed costing models, especially to ascertain whether new or upgraded facilities would be required.

It is more difficult to determine a robust prediction of the total storage capacity in saline aquifers, particularly when little characterisation has previously been undertaken. Detailed site characterisation and numerical simulations will be required to minimise the uncertainty in capacity predictions in saline aquifers, particularly if active reservoir management is proposed. Based on the available scientific literature, it is possible that there is between 300-500 Mt effective storage capacity in saline aquifers available in the Netherlands. One important observation of saline aquifer capacity made in several of the studies cited in this review is that it is extremely unlikely that there exists a single saline aquifer in either the onshore or offshore Netherlands with a storage capacity greater than 50 Mt (Vangkilde-Pedersen et al., 2008).

In the onshore region, eight suitable saline aquifers with a storage capacity of greater than 15 Mt have been identified, for a total capacity of 160 Mt (Vangkilde-Pedersen et al., 2008).

1.3.2 Storage regulations in the Netherlands

Onshore and offshore subsurface storage of CO_2 in the Netherlands, including the Dutch Continental Shelf, is covered under the Mining Act (2003, amended 2012), the Mining Decree (2003, updated 2011), and the Mining Regulations (2003, updated 2014), which explicitly make provisions for geological storage of CO_2 in the Netherlands.[3] These regulations substantially implement the requirements of the European Union CCS Directive[4].

The Mining Act provides information about the permits to store CO_2, for the exploration for suitable storage locations, and the criteria that must be met for such applications. The Act also regulates safety and the environmental impact of CO_2 capture and storage and its infrastructure (including transport networks), as well as liability during and after cessation of the project. According to the Act, existing oil and gas pipelines can only be used after the relevant fields are fully depleted. Offshore pipelines and pipes laid through dykes will require a separate permit under the Water Act.

Extra powers are available under the Spatial Planning Act (2008) which enable the national government to overrule local government regulations for projects of national importance (of which geological storage of CO_2 falls under).

An Environmental Impact Assessment has to be provided for the whole project, as well as any transport activities, under the Environmental Protection Act (Read et al., 2014). The relevant authorities in the Netherlands are the Ministry of Economic Affairs, Agriculture and Innovation and the Ministry of Infrastructure and Environment. Furthermore, an emissions permit for capture, transport and storage from the Dutch Emissions Authority is also required under the Environmental Protection Act. Depending on the activity and where it takes place, the authority may be delegated to the relevant Dutch province (Read et al., 2014).

OSPAR Decision 2007/01 prohibits the storage of CO_2 streams in the water column or on sea-bed, but amends Annexes II and III to the OSPAR Convention for the protection of the marine and environment of the North-East Atlantic to facilitate the long-term safe storage of CO_2 streams in geological formations (OSPAR Decision 2007/01).

1.3.3 Water extraction

Advantages and disadvantages of water extraction

When injectivity is limited by the boundaries of the structure and permeability distribution, water production has been proposed as early as 2008 as a method to reduce pressure and hence increase injectivity for CO_2 storage sites (Flett et al., 2008; Yang, 2008). This assists in overcoming pressure build-up concerns, provided that water disposal can be accommodated. More recently, Buscheck et al. (2016a, 2016b) discussed the option of pre-injection brine production from CO_2 storage intervals. In addition to increased storage capacity and efficiency, brine production prior to CO_2 storage would proactively manage initial injection pressures and would provide a better understanding of reservoir properties.

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[3] https://www.government.nl

[4] https://ec.europa.eu/clima/policies/lowcarbon/ccs/directive_en

The advantages of brine production in conjunction with CO_2 injection can be summarised as follows:

- Decreased bottomhole injection pressures.
- Decreased area of impact (pressure and CO_2 plume) in conjunction with a reduction in monitoring requirements.
- Increased storage capacity. For example, dynamic simulations of storage scenarios for the Minnelusa Formation (US) and the Bunter Sandstone (North Sea) predict a storage efficiency increase from 4.7% to 5.9% and 4.7% to 7.4% when using water extraction wells (IEAGHG, 2018b).
- Water production wells provide capability for adoptive plume and pressure management.
- Use of produced water for other industrial or agricultural purposes.

However, there are potential disadvantages associated with the extraction of water for CO_2 storage. These include:

- Increased costs due to additional wells and need for water management, either treatment or disposal.
- Increased environmental risks associated with produced water disposal.
- Breakthrough of CO_2 at water production wells needs to be avoided and managed.

As a result, the benefits of increased storage capacity versus increased CO_2 storage costs can vary significantly depending on the reservoir properties, water quality, water demand, and regulatory requirements for a specific CCS project.

Potential for cost reduction for water extraction

The main costs associated with water extraction are the costs of extraction wells. Like injection wells, the well type can be vertical or horizontal depending on the permeability of the reservoir, the water volumes to be extracted, and the cost of the specific well type. The aspects of drilling and completing water extraction wells are similar to other production wells, however, if the water extraction well may at some stage be converted to a CO_2 injection well, more stringent specifications with respect to pressure and corrosion apply. This may be the case where geological formations considered for storage are highly compartmentalised and laterally heterogeneous, as seen for the Tubaen Formation at Snohvit (Hansen et al., 2013; Shi et al., 2013).

Well drilling and completion make up 40%-50% of total capital expenses for wells offshore, while onshore this fraction can be as high as 65% (Brun et al., 2015). On average, 50% of this are costs for leasing rigs while the other 50% are for equipment, engineering services, consumables and project management (Brun et al., 2015). Between 2007 and 2014, average offshore well costs rose by 200%-250% due to higher rig rates caused by increased demand from high oil prices, higher well and completion costs as a result of more complex well designs and more expensive technologies, and process inefficiencies (Brun et al., 2015). However, daily rig rates have been decreasing since 2014 (see IHS Markit, 2018) due to the significant drop in oil price and the subsequent decrease in drilling activity. As a consequence, the costs of drilling have decreased from their peak levels.

As the main scope for cost reductions is to reduce time, technologies that make drilling more efficient and decrease down-time are beneficial (OG21, 2014). These include, but are not limited to:

- Managed pressure drilling
- Expandable tubular technology
- High speed well communication
- Automation and autonomous systems

Non-technology related measures to reduce offshore well costs suggested by Brun et al. (2015) include:

- cluster similar jobs to create repetitive jobs for drilling crews as through the standardisation of well types the amount of learning is reduced
- standardise and simplify wells to reduce unit costs
- improve or optimise procurement and supply chain management (practise "best practice")

Water extraction rates

Formation specific extraction to injection ratios will depend on a number of factors, such as subsurface heterogeneity (Buscheck et al., 2012), caprock integrity, value of pore space, and availability of freshwater (Klise et al., 2013). For having significant benefits to storage capacity and pressure management, brine production volumes need to be between equal to and up to 4 times higher than the volume of injected CO_2 (IEAGHG, 2012b).

As part of the EU FP7-funded Mitigation and Remediation of CO_2 Leakage project (MiReCOL), Govindan et al. (2017) investigated the feasibility of brine production for pressure and CO_2 plume management in depleted gas fields in the P18-A block located in the southern offshore region in the Netherlands (Table 1-18). While their numerical modelling generally shows that there is a significant benefit of using brine production for pressure management, the amount of plume steering is limited for the brine production layouts that were considered in the study. A summary of the simulation results is shown in Table 1-18 where the volume of brine extraction varied between 0.2 Mt and 1.1 Mt.

Table 1-18 Modelling results for three scenarios of CO_2 injection and brine production in three different compartments of the P18-2 reservoir (modified from Govindan et al., 2017)

	Scenario 1	Scenario 2	Scenario 3
CO_2 injection rate	0.66 Mt/year	0.17 Mt/year	0.05 Mt
CO_2 volume	8.58 Mt	1.36 Mt	0.85 Mt
Production layout	1 vertical well	4 vertical wells	1 horizontal well
Volume of brine extraction	0.9 Mt	1.1	0.2
Operating time of water production	17 years	22 years	12 years
Response time	5 years	3 years	0 years
Spatial extension	9.5	11.8	2.7
Impact	33% reduction in plume migration beyond reservoir per unit Mt of CO_2	46% reduction in plume migration beyond reservoir per unit Mt of CO_2	84 % pressure reduction
Est. annual costs (MEUR)	0.82	0.81	3.54

Chemical composition of produced brine

The chemistry of produced formation water may vary widely globally depending on the location of the CO_2 storage project. The salinity can range between potable water (< 500 mg/l) and saline brine of up to 400,000 mg/l and brines with salinity above that of seawater being dominantly of Na-Cl- or Na-Ca-Cl type (Klapperich et al., 2014a). Although there often is a general trend of increasing salinity with depth, there are sedimentary basins in which this is not the case and the overall salinity range can vary substantially (Figure 1-19). Also, the depth to the interface between fresh and brackish water can vary significantly between less than a 10 m in coastal areas to several kilometres in continental basins.

In the Netherlands, freshwater can be found to depths up to 500 m in the southeasternmost corner in the onshore area. Maximum salinities up to 330,000 mg/l are found in offshore petroleum fields targeting the Triassic Detfurth Formation (P06) and the Permian Zechstein Group (P02).

Klapperich et al. (2014a) suggest that in order to be economically treatable for further use, formation water salinity should be below 50,000 mg/l. According to Verweij (2003) more than 90% of available resistivity values for the Netherlands indicated water salinities above 55,000 mg/l. Salinity values reported for the reservoirs in the P18-A block are on the order of 100,000 mg/L (Tambach et al., 2012) to 150,000 mg/l (Creusen, 2018).

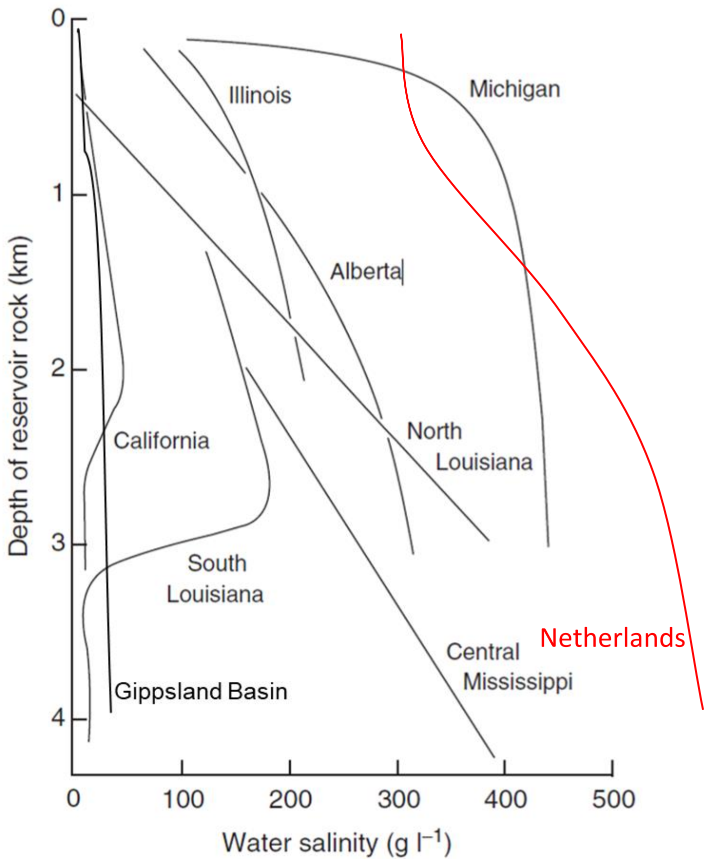


Figure 1-19 Salinity profiles in various sedimentary basins (modified from Kharaka and Thordsen, 1992). Approximate salinity profile for the Netherlands is shown in red

1.3.4 Water management

Water extracted for the purpose of CO_2 storage can either be treated for further use, for example in industrial processes or irrigation, or disposed, for example in an overlying saline aquifer. Possible solutions include (e.g., Arthur et al., 2011; Harto and Veil, 2011; Court et al., 2012a, 2012b; Hosseini and Nicot, 2012; Breunig et al., 2013):

- Re-injection for enhanced recovery processes
- Re-injection into the same formation it was produced from but at a different location. This could be combined with surface dissolution of CO_2 in brine
- Re-injection into a different formation, if water chemistries are compatible and allowable under existing regulations, possibly in conjunction with geothermal use
- Disposal into the ocean, if salinity is below seawater and allowable under existing regulations. This may require treatment of the produced brine
- Discharge at the surface, if allowable under existing regulations. This will require brine treatment
- Evaporation of the produced water, which is only practical in arid climates and may have large land requirements
- Treatment for re-use in the following applications:

    - Aquifer storage, if the water meets drinking water standards
    - Injection for hydrological purposes
        - Subsidence control, if water chemistries are compatible with the receiving formation
        - Saltwater intrusion control in which the treated water acts as a barrier to hold back saltwater intrusion from coastal aquifers
        - Stream level controls in which the water treated to discharge standards can help in augmenting declining water levels in streams
    - Agricultural use, such as irrigation
    - Domestic use
        - Drinking water and other domestic uses, which is beneficial in arid areas, but treatment costs may be high and treatment of alternative sources (such as moderately saline groundwater) may be the more economic option
    - Industrial purposes
        - Hydraulic fracturing fluid
        - Power plants, for which the water requires treatment and may be associated with great transport costs, depending on distance
        - Other, such as dust compression, car wash, firefighting, for which the water requires treatment and storage facilities
- Harvesting of minerals such as Li, Zn, Mn, KCl, $CaCl_2$, silica, borax, NaCl, Mg, B (for boric acid, B_2CO_3), K (for potash, K_2O), and Ca (for gypsum $Ca(SO_4)2(H_2O)$) through evaporation ponds and salt electrolysis treatment. The potential for mineral extraction will be highly site specific

Water treatment

Brines in storage aquifers have been regarded to be of low utility and are difficult to dispose at the surface (Aines et al., 2011). Treatment of such brines can produce a fresh water stream and reduce the volume that requires disposal. The water quality required will depend on the specific use and the appropriate treatment technology will depend on the original composition of the brine. The total dissolved solids (TDS) is a key parameter in determining which technology can be applied. An overview of different treatment technologies and their applicability was presented by Harto and Veil (2011) and is summarised in Table 1-19.

Table 1-19 Overview of water technologies for the removal of salt content, modified from Harto and Veil (2011)

Technology	Subcategory	Advantages	Disadvantages
Membrane processes	Micro-, ultra-, nano-filtration	Good pre-treatment for more advanced processes such as RO; lower pressure and lower cost than RO	Cannot remove most salinity
	Reverse osmosis	Effective up to ~50,000 mg/L	Requires pre-treatment and regular cleaning; not suitable for highly saline brines; potential for membrane fouling
Thermal processes	Distillation	Can process highly saline brines and generate very clean product water	High energy usage and cost; generates concentrated brine stream that requires disposal; potential for scaling
	Evaporation/ crystallisation	Can treat to ZLD standard	High energy usage and cost; requires disposal of salt residue; potential for scaling

To treat seawater, which has a typical concentration of ~35,000 mg/L, reverse osmosis (RO) is commonly applied (Aines et al., 2011). Reverse osmosis is considered most economical at concentrations below 30,000 mg/L with low recovery rates at concentrations above 50,000 - 60,000 mg/L (Harto and Veil, 2011). Aines et al. (2011) estimate that for brines with salinities of 10,000 – 40,000 mg/L TDS product recovery through standard RO processes exceeds 50%, while for brines of 40,000 – 85,0000 mg/L TDS recovery decreases to 10% and above.

Currently, thermal technologies are more suitable for industrial-scale desalination of hypersaline brine compared to membrane-based technologies (Morillo et al., 2014; Ghalavand et al., 2015; Burn et al., 2015). Though recovery rates are lower and concentrate disposal costs are higher for these systems, significant increases in energy requirements to treat the highly saline water are not expected (Harto and Veil, 2011).

Technologies that may be considered for treatment of highly saline brines are thermal technologies such as multistage flash distillation (MSF), multi-effect distillation (MED), single- or multi-effect evaporators (MEE) coupled with mechanical or thermal vapour compression (MVC/TVC), mechanical or thermal evaporative crystallisers, and cooling crystallisers. MED, MSF and MVC have become the preferred method in handling hypersaline formation waters due to their high level of reliability and resistance against scale formation (Thiel et al, 2015; Tong and Elimelech, 2016, Onishi et al. 2017, Vane 2017, Onishi et al. 2018).

Brine concentrators and crystallizers are typically applied for management of the concentrated brine in a ZLD system. Such processes can achieve water recovery rates of 90-98%. Evaporation ponds may present the final step in a ZLD process, but they have large land requirements and work better in hot and dry areas (Kaplan et al., 2017).

Kaplan et al. (2017) provide an overview of a range of emerging technologies that may be suitable to treat hypersaline feed streams, including forward osmosis (FO), membrane distillation (MD), humidification compression, fractional freeze crystallisation of ice, supercritical desalination processes, and anti-solvent addition. Other emerging technologies for desalinating highly saline brines include electro-dialysis (ED) and electro-dialysis reversal (EDR) (Kaplan et al., 2017). However, the energy requirements of ED have not been found to be less than those for evaporative processes (Kaplan et al., 2017), while for EDR the inlet stream concentration is limited to 80,000 mg/L of TDS - eliminating it as an option for treating hyper-saline brines (Kaplan et al., 2017).

Kaplan et al. (2017) identified multi-effect evaporation (MEE) as the most suitable existing technology for treating highly saline brine from the Mt Simon Sandstone (~200,000 mg/L TDS), a potential CO_2 storage site in Illinois, USA. Process simulations for near-zero liquid discharge treatment indicated that 88% of water may be recovered by MEE. Brines with concentrations above 300,000 mg/L are not likely to be treatable (Aines et al., 2011).

Pre-treatment of brine may be performed depending on the composition of the extracted water to reduce the impacts of fouling on the performance of the desalination process. Pre-treatments includes disinfection, removal of suspended solids and oils, and scale mitigation which can be carried out applying a range of process described in more detail in Arena et al. (2017).

Water treatment and disposal costs

An overview of the costs of different water management options has been provided by Harto and Veil (2011), though cost estimates for extracted water treatment and disposal are rare in public literature as detailed information is typically not shared by providers (Harto and Veil, 2011).

Harto and Veil (2011) reported that in the US discharge to a water body is typically the least expensive disposal option ranging from 0.01 – 2.9 US$/bbl (0.06 – 18.24 US$/m^3). However, due to the typically high concentrations of dissolved solids in produced water from oil and gas operations or those from desalination plants, deep well injection is the most common disposal option to comply with regulations and permitting requirements (Harto and Veil, 2011). To manage high TDS brines this is often the most cost effective option (Skehan et al., 2000), typically ranging from 0.3 - 2 US$/bbl (1.89 – 12.58 US$/m^3) though costs as high as US$10/bbl (US$62.90/m^3) have also been reported (Harto and Veil, 2011). Variations are caused by differences in the geological properties of the formation.

Evaporation as a means to dispose of produced water is common in arid regions. Costs include land, pond construction and transportation and can range from 0.05-4 US$/bbl (0.31 – 25.16 US$/m^3; Harto and Veil, 2011).

Where treatment is required or considered practical, treatment costs vary with salinity of the produced water, as well as with the presence of other components, and the treatment technology that may be applied.

Treatment costs of produced water (<10,000 mg/L) for cooling purposes and boiler usage at the GreenGen IGCC facility in China were estimated to be on the order of 3 US$/m^3 (Ziemkiewicz et al., 2016).

Treatment costs for brines with salinities of 35,000 mg/L or less using reverse osmosis have been quoted to range from 1.04 - 3.5 US$/bbl (6.54 – 22.02 US$/m^3; Harto and Veil, 2011), while Aines et al. (2011) estimates conventional seawater desalination costs as 0.81 - 1.14 US$/m^3 (Aines et al., 2011).

For higher concentrated brines thermal distillation can be applied with Harto and Veil (2011) quoting costs from 6.7 - 8.45 US$/bbl (42.14 – 53.15 US$/m^3). Others have reported indicative costs of thermal processes to treat hypersaline brines to range from 2.65 - 6.07 US$/m^3 (Al-Karaghouli and Kazmerski, 2013; Onishi et al., 2018; Bagheri et al., 2018). For thermal processes, the cost of energy is reported to be responsible for about 50% of the produced water cost (Al-Karaghouli and Kazmerski, 2013). The energy consumption for multi-effect distillation (MED) and single- and multi-effect evaporators (MEE) coupled with mechanical vapour compression (MVC) are given in Table 1-20. The energy consumption of brine crystallizer is nearly three times that of MVC (Tong and Elimelech, 2016). Out of the thermal processes, MVC has been reported to be competitive over MED and MSF with respect to energy requirements and costs (Alasfour and Abdulrahim, 2011; Shaffer et al., 2013; Chen et al., 2016; Jimenez et al., 2018), which is demonstrated in Table 1-20 and Table 1-21. Table 1-21 provides an overview of the costs of different thermal treatment processes for hypersaline brines.

Table 1-20 Energy consumption for multi-effect distillation (MED) and single-effect evaporators coupled with mechanical vapour compression (MVC)

Process	Feed and output brine salt concentrations	Energy requirement	Source
Five stage MED	Feed: 100 g/L Concentrate: 160 g/L	~156.78 kWh/m^3 thermal 0.6 kWh/m^3 electrical	Bagheri et al. (2018)
Three stage MED	Feed: 150 g/L Concentrate: 260 g/L	~250 kWh/m^3 thermal ~2 kWh/m^3 electrical	Thiel et al. (2015)
Six stage MEE	Feed: 200 g/L Concentrate: 400 g/L	~246 kWh/m^3 thermal (with salt drying) ~2 kWh/m^3 electrical ~212 kWh/m^3 thermal (without salt drying)	Kaplan et al. (2017)
Single stage MVC	Feed: 100 g/L Concentrate: 200 g/L	~37.9 kWh/m^3 electrical	Bagheri et al. (2018)
Single stage MVC	Feed: 150 g/L Concentrate: 260 g/L	~27 kWh/m^3 electrical	Thiel et al. (2015)

Table 1-21 Cost analysis for treatment of hypersaline formation water applying thermal process technologies

Process	Feed conc, g/L	Water recovery, %	Total water cost, \$/m^3	Source
MVC	100	50	1.244	Bhageri et al. (2018)
MVC	150	25	1.43	Bhageri et al. (2018)
MED	100	37.87	2.657	Bhageri et al. (2018)
MEE-SVC (with thermal integration)	70	77	6.70	Onishi et al. (2018)
MEE-SVC (with thermal integration)	220	26	7.298	Onishi et al. (2018)
FO-MVC	100	50	2.094	Cost for MVC adapted from Bhageri et al. (2018)

Transportation costs can significantly add to the overall costs of water management. Transport options include trucks and pipelines. Pipelines are preferable for shorter distances and continuous and constant supply of water. Trucking may be preferable if water supply is variable over time and distances between extraction and disposal site are longer. Pipeline transport cost have been estimated as 0.006-0.01 US\$/bbl-mile (0.04 – 0.06 US\$/m3-mile), while truck transport can range from 0.4-3.2 US$/bbl (2.52 – 20.13 US$/m3; Harto and Veil, 2011).

Based on the likely treatment and disposal costs of water extracted during CO_2 injection, Harto and Veil (2011) only consider water extraction a viable option where

I. injection can be performed inexpensively in a nearby formation to keep transportation costs low; or
II. where TDS are low, thus not requiring further treatment; or
III. where the extracted water may be treated effectively applying RO while utilising the elevated pressure at which the extracted water is produced to lower RO treatment cost.

Klise et al. (2013) quote the cost of water extraction, treatment and disposal for 172 US saline formations (with salinities between 10,000 – 35,000 mg/L) as less than US$4/$m^3$.

Water regulations in the Netherlands

Water management in the Netherlands is governed by legislations and regulations of the European Union as well as the International River Basin Commissions (Rhine, Scheldt, Meuse, Ems) (OECD, 2014). With regards to water, the EU Water Framework Directive (WFD, 2000) encompasses several directives with the combined objective to improve and protect the quality of groundwater and surface waters as well as groundwater quantity, and provide specific protection and improvement of nature reserves. It sets the standard for different substances for different water bodies, such as lakes, rivers, and coastal and ground water through a range of Directives under the WFD, such as the Marine Strategy Framework Directive (for saltwater) (MSFD, 2008), Priority Substances Directive (policy on potentially significant pollutants), and the Ground Water Directive (GWD, 2006), which requires EU member states to guarantee the chemical quality of the groundwater. The EU Surface Water Directive (75/440/EEC) sets standards for the quality of surface water intended for the consumption of drinking water. It should be noted, that the Water Framework Directive lists desalination as one of many supplementary measures to attain the goals of water quality protection and efficient management.

EU countries set restrictions on aquatic pollutants levels at the discharge point (effluent standards [ES]) and within the receiving environment (ambient standards [AS]). Concentration or load limits for ES and AS can be found in state, national and international legislations for different chemical substances, effluents and receiving water characteristics.

In the Netherlands deep underground water resources (> 500 m) as well as national water bodies are managed on a national level by the Ministry of Infrastructure and the Environment as well as the National Water Authority (OECD, 2014), while groundwater is managed by the 12 provinces. 24 water authorities exist that are responsible for water quantity, particular with respect to agriculture, flood protection, sewage water treatment and surface water quality (Ruijter, 2018; OECD, 2014). Surface water is assessed for its chemical quality (i.e., the presence and concentration of hazardous substances in the water) and its ecological quality (i.e., the extent of the presence of flora and fauna present) (NL Gov, 2018). Surface water and groundwater standards are recorded in the Decree on Quality Standards and Monitoring for Water (Overheid, 2017).

The National Water Act (Water Act, 2009) highlights an integrated water management approach linking water, water users, land use, environment and special planning. It addresses the relationship between quantity and quality of water and between surface and groundwater. The Water Act also introduced a water permit system (generally used along with environmental permits) and contains provision for levies for activities in water systems, such as discharge of polluting substances into surface water, extraction of groundwater, etc.

The National Water Plan (NWP, 2016) lays down the criteria of "polluter pays" in which the initiators of measures that lead to contamination or salinisation are responsible for mitigating or making up for adverse effects.

The National Waste Management Plan stipulates that liquid waste that is released in the production and treatment of, for example, oil and gas and salt, and that is not contaminated with components that are not in-situ can be returned to its place of origin, i.e. the same geological formation at the same depth or potentially a similar geological formation. The reinjection shall not result in a deterioration of the quality of the formation. However, exceptions may be granted by the competent authority when the reinjection is preferable from an environmental perspective or when the costs of alternatives are disproportionate to the environmental benefits of those alternatives (LAP, 2004).

As the Netherlands experience freshwater shortages once in a while, in a response to past droughts a 'sequence of priorities' has been drawn up which determines the order in which the scarce supply of water is allocated to users (Rijkswaterstaat, 2011). Four categories are differentiated with Category 1 getting the highest priority while Category 4 gets lowest priority. Category 1 is concerned with the safety and prevention of irreversible damage (such as stability of flood defence structures and nature dependent on soil conditions), Category 2 priorities are utilities: drinking water and power supply, Category 3 priorities are small-scale high-quality use, such as process water, and Category 4 contains economic considerations (including nature), such as shipping, agriculture, nature, and industry (Rijkswaterstaat, 2011).

In the offshore, the disposal of water is regulated via the OSPAR Convention, with the intention to protect the marine environment of the North-East Atlantic. Under the Best Available Technology (BAT) Principle, the re-injection of drill cuttings (as ground up material) and produced water into a subsurface reservoir is allowed for oil and gas operations. Disposal of produced water generally occurs into the producing reservoir and may be used to stimulate production through pressure maintenance. However, while the potential for contamination is considered unlikely in much of the OSPAR area, specific situations should always be investigated before disposal operations commence (OSPAR Commission, 2001).

1.3.5 Competition between CCS and other users on the surface and in the subsurface (including groundwater)

The potential interaction of other basin resource developments with CO_2 geological storage was discussed in detail by Field et al. (2013) and Michael et al. (2016). Sedimentary basins commonly host various natural resources, with primary basin resources being groundwater, hydrocarbons, coal and geothermal energy. Other resources include gas hydrates, mineral and oil sands, salt, potash, uranium, diamonds and other sediment hosted mineral deposits. Surface infrastructure and land use also impact subsurface resource development and must be considered in any basin resource management strategy. Geological storage of carbon dioxide is another basin activity that must be considered to ensure that multiple uses of the subsurface can sustainably and pragmatically co-exist.

Two general processes need to be considered when assessing the impact of CO_2 injection on other resources: a) migration of carbon dioxide and b) increase of pressure (Figure 1-20). Carbon dioxide may migrate laterally or vertically outside the planned storage complex. If migration did occur, it is possible that some carbon dioxide may comingle with natural gas or enter a coal seam. Another potential impact is that once a reservoir is used for geologic storage it may limit the use of that formation for future resource development such as for geothermal energy potential or undiscovered resources.

Injecting carbon dioxide into the subsurface increases pressure in the reservoir that, although very unlikely, could push saline formation water vertically along a wellbore or through existing fractures into groundwater sources (Birkholzer et al., 2011) or, if uncontrolled, cause fractures in top seals preventing further use of storage. Alternatively, increased pressure may provide support for oil or gas fields that have had their pressure reduced by production, and may even limit the decline of groundwater levels in stressed aquifer systems (Michael et al., 2016).

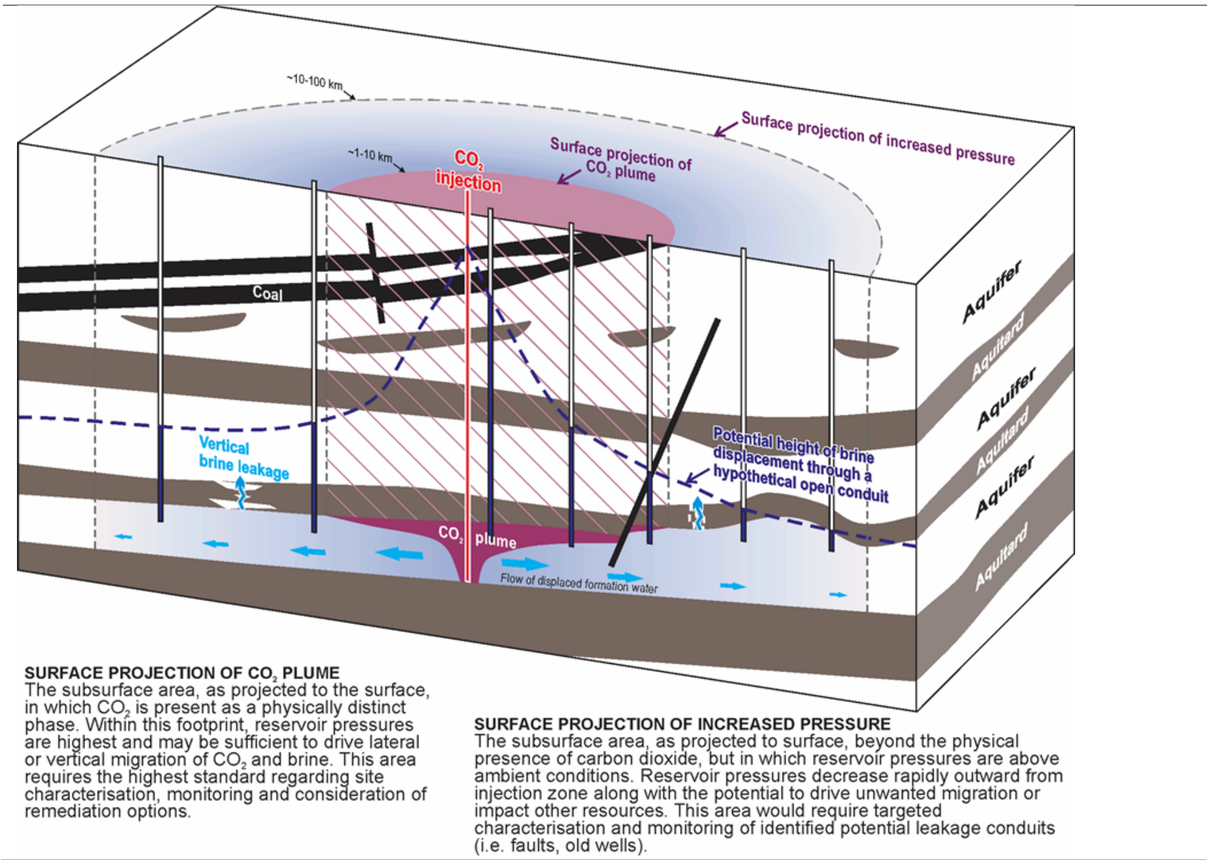


Figure 1-20 Schematic representation of the potential extent of impacts related to CO_2 injection (Michael et al., 2016)

Competition in the Netherlands

In the Netherlands, the main issue with onshore CCS activities is the public concern regarding the safety of storage projects. Currently, CCS projects only target offshore storage opportunities. Competition between CCS and other users were identified in a report by the IEAGHG (2014):

- Onshore, there is potential for competition at the surface with respect to land use and repurposing of pipelines with the underground gas storage (UGS) industry, gas processing facilities and other land development activities. However, increase of subsurface pressures due to CO_2 injection may counteract subsidence issues related to historic onshore gas field production.
- The main competitor for CCS for subsurface pore space in the onshore are UGS and water disposal operations and, to a lesser extent, the geothermal industry.
- Offshore, pressure interference of CO_2 injection projects with producing petroleum fields are of major concern and CCS infrastructure at the seafloor or ocean surface may interfere with the placement of offshore windfarms.

The potential for brine displacement and leakage in the North Sea has been primarily investigated in conjunction with faults assumed to act as migration pathways. For example, numerical simulation by Hannis et al. (2013) predict that brine migration along faults from the Bunter Sandstone Formation to the seafloor in the Southern North Sea on the order of 50 m^3/day/km^2 may be expected in response to large-scale CO_2 injection (75 Mt over 50 years). This amounts to a total of approximately 100 Mm^3 brine after 50 years or 2 Mm^3/year. In comparison, 175 Mm^3 of produced brine from petroleum fields were released into the sea in the UK sector in 2011. When simulating larger injection rates of up to 22 Mt CO_2 per year in the same formation, Noy et al. (2012) predicted brine expulsion of approximately 1,500 Mm^3 (30 Mm^3/year) to the seafloor.

Area of Review

The Area of Review (AOR), also known as Spatial Area of Evaluation (US EPA, 2008) or Area of Potential Impact (Bandilla et al., 2012), is a regulatory concept that defines the monitored area for CO_2 storage. The AOR includes the surface projections of the carbon dioxide plume in the subsurface, and the volume in the reservoir subjected to pressure increase beyond the plume itself (Figure 1-20). The focus of a resource management strategy should be within the defined AOR.

Pressure changes within the storage reservoir that result from injection of carbon dioxide (or any fluid) may be distributed across an area several orders of magnitude larger than that of the actual plume. The geology of the reservoir, its thickness, hydraulic properties and the presence of any restrictions are determining factors in the distribution of pressure. The extent of the AOR for basin resource management purposes should not be defined by the absolute increase in pressure, but should be constrained by the degree of pressure increase that potentially results in measurable geomechanical impacts or changes to water quality. For example, the United States Environmental Protection Agency (2008) has proposed to limit the extent of the AOR by the minimum pressure increase at which a sustained flow of brine upward through a hypothetical conduit into an overlying drinking water aquifer occurs. Other considerations are the pressure required to re-activate faults, to induce fractures in the seal, or to drive fluids from the injection reservoir into other natural resources.

2 Water consumption in power plants with and without CO_2 capture

This chapter presents the performance and water usage of ultra-supercritical coal fired (USCPC) and natural gas fired combined cycle (NGCC) power plants with and without capture for conditions representative of a hypothetical site in the Netherlands. The power stations have a gross output of 900 MW_e and 890 MW_e for the USCPC and the NGCC, respectively. The performance of the power stations is established with respect to different cooling technologies, including evaporative natural draught cooling (recirculating system), once-through cooling using seawater, and air cooling. The post-combustion capture (PCC) plant may utilise the same cooling technology as the corresponding power station or alternatively it may use air cooling.

Once-through river or pond cooling are not evaluated in this study as these conditions are not considered realistic for the hypothetical site location in the Netherlands.

The performance of the power plants is determined using EBSILON® based on technical specifications common to IEAGHG studies. The flue gas generated by EBSILON® is used as input to model the post-combustion capture process using Protreat®, where one PCC train is simulated. The results presented here form the basis of the techno-economic modelling presented in Chapter 5.

2.1 Ambient conditions

The analysis is determined for the hypothetical location in the Netherlands with ambient conditions as outlined in Table 2-1. The power plants are designed to generate 900 MW_e gross output. The plants are assumed to operate at 85% capacity under baseload conditions.

Table 2-1 Estimated ambient conditions in the Netherlands

Ambient conditions	Value
Temperature (dry bulb average)	9°C
Maximum temperature	30°C
Minimum temperature	-10°C
Humidity (average)	80%
Pressure (average)	101.3 kPa
Seawater temperature	12°C

2.2 Capture plant specification

The post-combustion capture technology modelled in this study is representative of a "Best Available Technology" chemical absorption process. It utilises a 40wt% aqueous solution of piperazine/AMP (Amino-Methyl-Propanol) in a 1:2 molar ratio (Cousins et al., 2019). 90% of the generated CO_2 is captured and compressed to 110 bar and cooled to 30°C. Table 2-2 outlines the specifications of the product CO_2 for pipeline transport.

Table 2-2 Specifications for CO_2 product

Parameter	Value
CO_2 capture rate	≥ 90%
CO_2 maximum impurities for pipelines (vol. basis)	
H_2O	50 ppm
N_2/Ar	4%
O_2	100 ppm
CO	0.2%
CH_4 and other hydrocarbons	4%
H_2S	20 ppm
SO_2	100 ppm
NO_x	100 ppm
Total non-condensables	4%
CO_2 conditions – pipeline transport	
Pressure	11 MPa
Maximum temperature	30°C

2.3 Coal fired power plants

For coal fired power plants, eight cases of water consumption are modelled. A common reference ultra-supercritical pulverised coal fired power plant (USCPC) is used for all cases. All scenarios are based on a gross output of 900 MW_e with differing net outputs.

The case studies include supercritical coal fired power plants (USCPC) with and without capture using the following cooling technologies:

- **Case 1.1A – USCPC-EV**: USCPC boiler reference case based on standard supercritical steam conditions for a nominal 900 MW_e gross output power plant without CCS. Evaporative (EV) natural draught cooling tower (recirculating system) is used for the power plant.
- **Case 1.1B – USCPC-EV-PCC**: USCPC boiler for a nominal 900 MW_e gross output power plant with CCS. Evaporative (EV) natural draught cooling is used for both the power plant and capture plant.
- **Case 1.1C – USCPC-EV-PCC-AC**: USCPC boiler for a nominal 900 MW_e gross output power plant with CCS. Evaporative (EV) natural draught cooling tower for the power plant, air cooling (AC) for the capture plant.
- **Case 1.2A – USCPC-OT**: USCPC boiler for a nominal 900 MW_e gross output power plant with CCS. Once-through (OT) seawater cooling is used for the power plant without capture.
- **Case 1.2B – USCPC-OT-PCC**: USCPC boiler for a nominal 900 MW_e gross output power plant with CCS. Once-through (OT) seawater cooling is used for both the power plant and the capture plant.
- **Case 1.2C - USCPC-OT-PCC-AC**: USCPC boiler for a nominal 900 MW_e gross output power plant with CCS. Once-through (OT) seawater cooling tower for the power plant, air cooling (AC) for the capture plant.
- **Case 1.3A – USCPC-AC**: USCPC boiler for a nominal 900 MW_e gross output power plant with CCS. Air cooling (AC) utilised for the power plant without CCS.
- **Case 1.3B – USCPC-AC-PCC**: USCPC boiler for a nominal 900 MW_e gross output power plant with CCS. Air cooling (AC) is utilised for both the power plant and capture plant.

Once-through river/pond cooling were not evaluated in this report as these conditions are considered not realistic for the hypothetical site location in the Netherlands.

The fuel is assumed to be Eastern Australian internationally traded open-cast coal. Table 2-3 outlines the specification of the coal.

Table 2-3 Coal specification: Eastern Australian coal

Proximate analysis	Value
Inherent moisture	9.50 wt%
Ash	12.20 wt%
Coal (dry, ash free)	78.30 wt%
Ultimate analysis (dry, ash free)	
Carbon	82.50 wt%
Hydrogen	5.60 wt%
Nitrogen	1.77 wt%
Oxygen	9.00 wt%
Sulphur	1.10 wt%
Chlorine	0.03 wt%
Ash fluid temperature at reduced atm	1350°C
HHV (Air Dried Basis)	27.06 MJ/kg
LHV (Air Dried Basis)	25.87 MJ/kg

2.3.1 Process description

USCPC power plant

The performance of an ultra-supercritical coal fired power plant (900 MWe gross output) is determined using EBSILON® using the coal specification given in Table 2-3 and other technical data common to IEAGHG studies. The boiler is operated with an air excess of 20% and generates supercritical steam at 600°C and 29.5 MPa with a single reheat (620°C, 5.5 MPa) of the returned steam after expansion in the high pressure steam turbine. After expansion through the medium pressure turbine and low pressure turbine, the steam is condensed. The condenser temperature is dependent on the average ambient conditions and dependent on the cooling system as shown in Table 2-4.

A general process flow diagram for the coal fired power plant without CO_2 capture is shown in Figure 2-1.

Table 2-4 Condenser temperatures for the chosen cooling systems

Cooling system	Condenser temperature, °C
Mechanical or mechanical draught evaporative cooling	28.3
Once-through seawater cooling	28.0
Air cooling	34.0

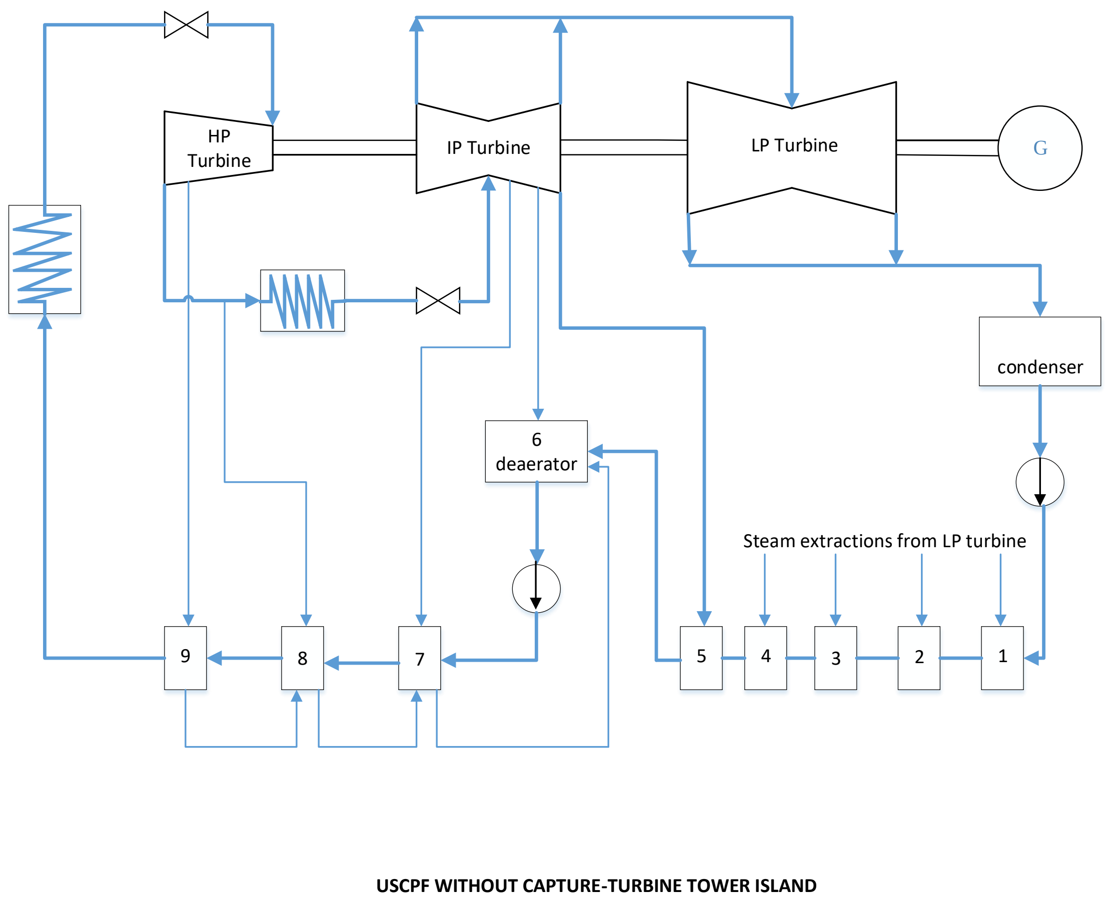


Figure 2-1 General steam flow diagram for steam cycle ultra-supercritical pulverised coal fired power station

The flue gas generated by EBSILON® is used as the input to the Protreat® PCC process simulations as per Table 2-5. One PCC process train was simulated in Protreat®. The results form the basis for the techno-economic modelling presented in Chapter 5.

Table 2-5 Flue gas details ultra-supercritical coal-fired power plant for one train

Property	Value
Flue gas flow rate	826.8 kg/s
No. trains	3
Flue gas flow per train	275.6 kg/s
Flue gas flow per train	9.47 kmol/s
Temperature	50°C
Pressure	101.8 kPa-a
H_2O	12.1 mol%
CO_2	13.4 mol%
N_2	70.4 mol%
Ar	0.8 mol%
O_2	3.3 mol%

In case of the integrated PCC process, the steam required for the regeneration of the amine solution is extracted from the cross-over point between the intermediate and low pressure turbines, as indicated in Figure 2-2. The extracted steam is condensed in the reboiler at a temperature of 133°C. The condensate is used to de-superheat the steam extracted from the steam cycle.

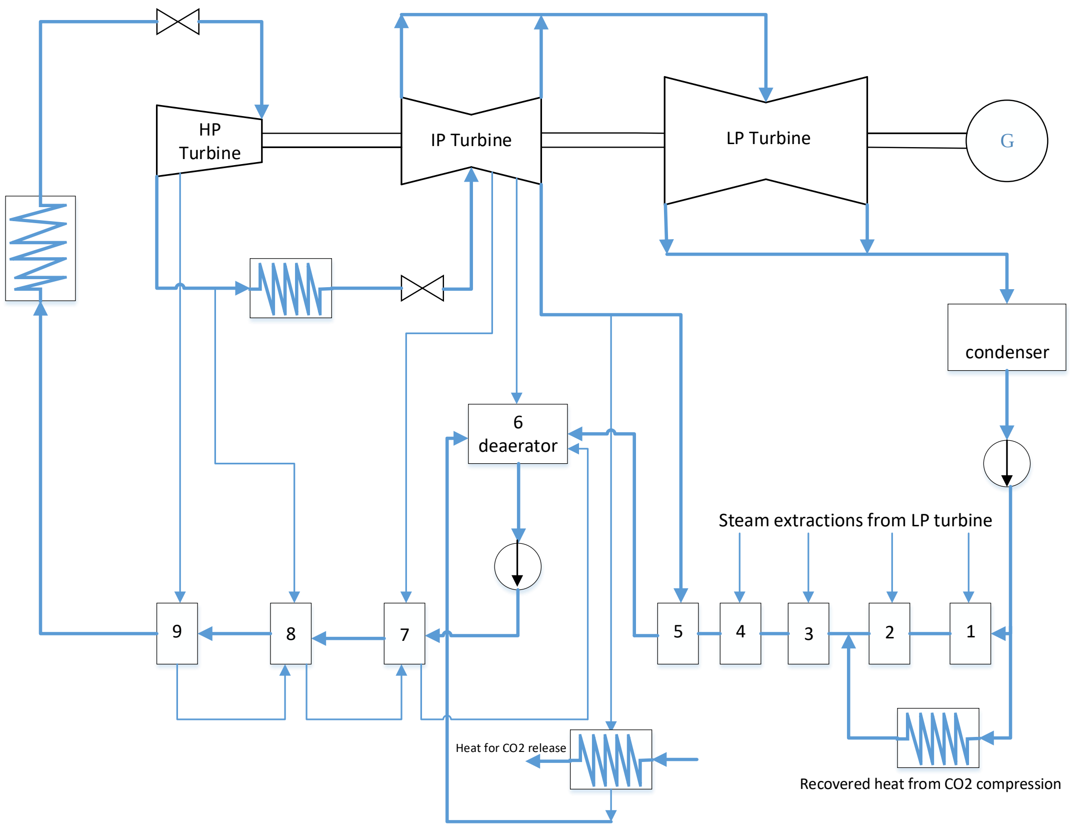


Figure 2-2 Steam flow diagram for an ultra-supercritical pulverised coal fired power plant with integrated post-combustion capture process

Post-combustion CO_2 capture plant and CO_2 compression plant

In the post-combustion CO_2 capture plant shown in Figure 2-3 the flue gas is cooled in the pre-treatment column in which the remaining SO_2 is mostly removed. In the CO_2 absorber the flue gas is brought into contact with the amine solution resulting in the transfer of CO_2 into the amine solution. To limit the temperature increase as a result of the reaction of CO_2 with the amines, absorber intercooling is applied. This will ensure that a high CO_2 loading of the solution is achieved. The resulting rich solution is split: the first fraction is pumped to the desorber via the lean-rich heat exchanger and the second fraction is pumped to the desorber top. This second fraction will cool down the wet CO_2 product from the desorber and recover part of the latent heat. The regenerated solution is then pumped back to the absorber via the lean-rich heat exchanger and the cooler.

The stream data for the indicated streams in the post-combustion capture plant in Figure 2-3 are given in Table 2-6.

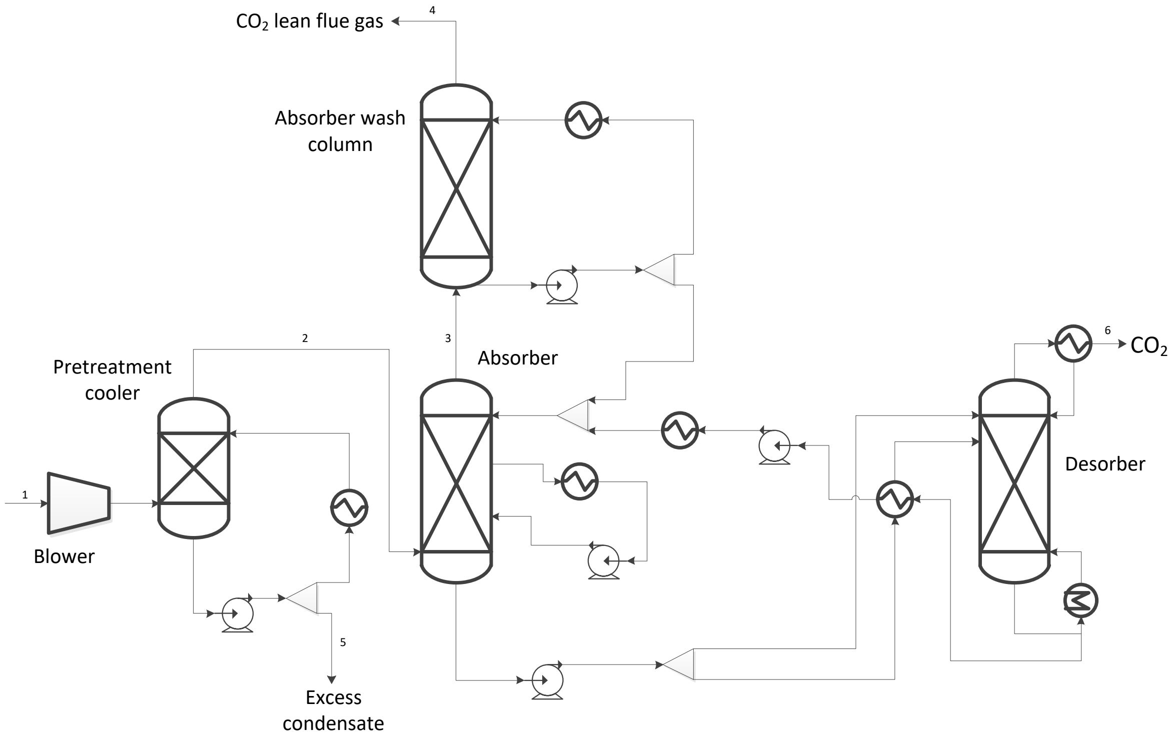


Figure 2-3 Line diagram of CO_2 capture plant used in amine-based post-combustion capture simulations. The layout includes absorber intercooling and rich-split process modifications

Table 2-6 Stream data for 90% capture from an ultra -supercritical pulverised coal fired power station flue gas (one train)

Stream		**1**	**2**	**3**	**4**	**5**	**6**
Water	mol%	12.10	7.11	22.64	7.60	99.99	4.04
Carbon dioxide	mol%	13.40	14.16	1.39	1.60	0.01	95.95
Piperazine	mol%	0.00	0.00	0.04	0.00	0.00	0.00
AMP	mol%	0.00	0.00	0.09	0.00	0.00	0.00
Nitrogen	mol%	70.40	74.40	71.67	85.81	0.00	0.01
Argon	mol%	0.80	0.85	0.81	0.98	0.00	0.00
Oxygen	mol%	3.30	3.49	3.36	4.02	0.00	0.00
Total flow	kmol/s	9.47	8.96	9.31	7.77	0.51	1.19
Total flow	kg/s	275.60	266.43	243.78	215.20	9.17	51.26
Temperature	°C	50.00	40.00	57.47	35.56	47.49	40.00
Pressure	kPa	101.80	106.19	101.90	99.10	110.00	184.18

The CO_2 product is subsequently compressed to 110 bar in a four-stage process depicted in the flow diagram in Figure 2-4. Intercooling is performed with the condensate from the steam turbine, where the temperature levels enable this. After the first and second stage, additional cooling is used.

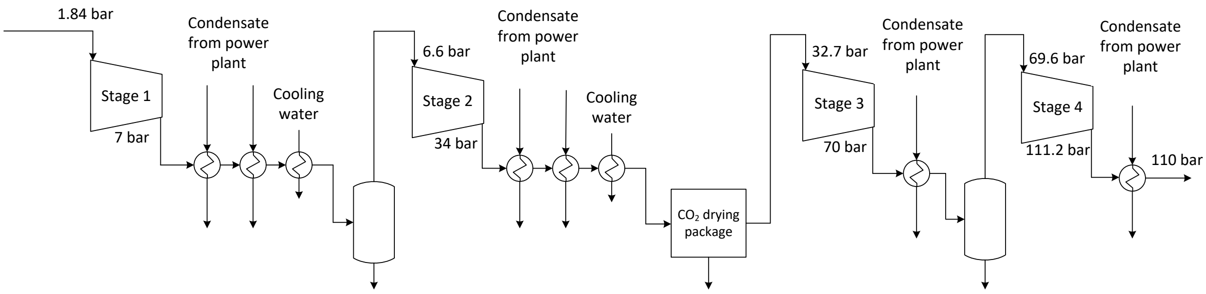


Figure 2-4 Four-stage CO_2 compression flow diagram

Evaporative cooling

A schematic of the reference USCPC power plant using evaporative (EV) cooling is presented in Appendix A.1, while a schematic of the USCPC power plant with CO_2 capture using evaporative cooling (EV), which is identical to the air-cooled (AC) capture plant, is in Appendix A.3. The process comprises of:

- Coal and ash handling (Unit 100)
- Boiler island (Unit 200)
- FGD and handling plant (Unit 300)
- DeNOx plant (Unit 400)
- Steam turbine island (Unit 500)

While the power plant with capture comprises the additional blocks:

- CO_2 recovery (Unit 600)
- CO_2 compression (Unit 700)

The complete USCPC power plant process flow diagram with and without CO_2 capture is shown in Appendix A.2 and A.4, respectively.

Once-through cooling

A schematic of the reference USCPC power plant using once-through (OT) seawater cooling is presented in Appendix A.5, while a schematic of the USCPC power plant with CO_2 capture using once-through (OT) seawater cooling, which is identical to the air-cooled (AC) capture plant, is in Appendix A.7. The process comprises of:

- Coal and ash handling (Unit 100)
- Boiler island (Unit 200)
- FGD and handling plant (Unit 300)
- DeNOx plant (Unit 400)
- Steam turbine island (Unit 500)

While the power plant with capture comprises the additional blocks:

- CO_2 recovery (Unit 600)
- CO_2 compression (Unit 700)

The complete USCPC power plant process flow diagram with and without CO_2 capture is shown in Appendix A.6 and A.8, respectively.

Air cooling

A schematic of the reference USCPC power plant using air cooling (AC) is presented in Appendix A.9, while a schematic of the USCPC power plant with CO_2 capture using air cooling (AC) for power plant and capture plant is in Appendix A.11. The process comprises of:

- Coal and ash handling (Unit 100)
- Boiler island (Unit 200)
- FGD and handling plant (Unit 300)
- DeNOx plant (Unit 400)
- Steam turbine island (Unit 500)

While the power plant with capture comprises the additional blocks:

- CO_2 recovery (Unit 600)
- CO_2 compression (Unit 700)

The complete USCPC power plant process flow diagram with and without CO_2 capture is shown in Appendix A.10 and A.12, respectively.

2.3.2 Technical performance: USCPC

The technical performance for the eight coal fired power plant cases are summarised in Table 2-7.

For power plants without capture, utilising air cooling reduces the net plant efficiency by almost 2% - reducing from 44.4% using evaporative cooling to 42.7% using air cooling. The reason for the reduction in power output is the higher condenser temperature and the higher power consumption of the air cooling fans.

As the coal input into all cases is assumed to be constant, the CO_2 emissions for the power plant utilising air cooling are higher than the plant using recirculating evaporative cooling, with the emissions on t/MWh basis approximately 4% higher. The normalised water withdrawal and consumption for air cooling plants is almost negligible but not zero at 0.07 m^3/MWh. This consumption is for the make-up water required at the FGD plant.

For power plants utilising once-through seawater cooling, the normalised withdrawal and consumption of freshwater is also very low at 0.07 m^3/MWh. As for the air-cooled plants, this withdrawal and consumption of freshwater is mostly for the make-up required at the FGD plant. The total cooling duty of the power plant however is approximately 108,000 m^3/h.

Implementing capture, the increase in relative water withdrawal and consumption for the evaporative cooling technology is about 50%. In the air-cooled power plants, the capture plant increases the water withdrawal/consumption by 0.01 m^3/MWh or 20%, which is due to the need for freshwater make-up for the solvent. Similarly, for the once-through seawater power plant, the increase in freshwater withdrawal and consumption due to the capture plant is small at 0.01 m^3/MWh or 20%. This is because the seawater is utilised for the process cooling required, such as for the heat exchangers, condenser and CO_2 compressor.

If air cooling is utilised for the capture plant rather than evaporative cooling (Case 1.1C), the relative change in the freshwater usage compared to the power plant without capture (Case 1.1A) is -5%. For once-through cooling, replacing seawater cooling in the capture plant (Case 1.2B) with air cooling (Case 1.2C) does not change the relative increases in freshwater usage compared to the power plant without capture. This is because the required freshwater is for the make-up solvent. In both Cases of 1.1C and 1.2C, using air cooling for the capture plant reduces the efficiency of the power plant with capture by a further 2% compared to using only evaporative or seawater cooling technologies.

Table 2-7 Technical performance for USCPC power plants (with and without capture)

Cases	1.1A USCPC-EV	1.1B USCPC-EV-PCC	1.1C USCPC-EV-PCC-AC	1.2A USCPC-OT	1.2B USCPC-OT-PCC	1.2C USCPC-OT-PCC-AC	1.3A USCPC-AC	1.3B USCPC-AC-PCC
Cooling technology	Recirculating (EV)		EV + AC	Once-through (OT)		OT + AC	Air cooling (AC)	
Fuel input (t/h)	255.6	255.6	255.6	255.6	255.6	255.6	255.6	255.6
Gross power output (MW)	900	833.3	833.3	900	833.3	833.3	879.3	819.0
Auxiliary power (MW)	83	148.9	154.9	84	150.7	155.9	94.6	163.9
Net power output (MW)	817	684	678	816	683	677	785	655
Net plant HHV efficiency (%)	42.41	35.56	35.25	42.40	35.47	35.19	40.80	34.04
Net plant LHV efficiency (%)	44.40	37.23	36.90	44.40	37.13	36.85	42.70	35.64
LHV efficiency loss due to PCC (%)		7.17	7.50		7.27	7.55		7.06
CO_2 generation (t/h)	604	603.3	603.3	604	603.3	603.3	604	603.3
CO_2 emission (t/h)	604	59.3	59.3	604	59.3	59.3	604	59.3
CO_2 emission (t/MWh)	0.739	0.087	0.087	0.740	0.087	0.088	0.770	0.091
CO_2 capture (t/h)	0.0	544	544	0.0	544	544	0.0	544
Energy consumption								
Energy consumption for absorbent pumps and blowers in PCC (MW)	0.0	8.6	8.6	0.0	8.6	8.6	0.0	8.6
Compressor energy (MW)	0.0	57.2	57.2	0.0	57.2	57.2	0.0	57.2
Pumps/fans for cooling in PCC (MW)	0.0	1.3	7.2	0.0	2.0	7.2	0.0	7.2
Total electrical energy consumption in PCC (MW)	0.0	67.1	73.1	0.0	67.9	73.1	0.0	73.1
Water balance								
Water withdrawal (m^3/h)	1090.8	1368.9	857.0	54.0	54.2	54.2	54.0	54.2
Process water discharge (m^3/h)	259.2	328.7	201.6	0.0	0.0	0.0	0.0	0.0
Water consumption (m^3/h)	831.6	1040.2	655.4	54.0	54.2	54.2	54.0	54.2
Water withdrawal (m^3/MWh)	1.34	2.00	1.26	0.07	0.08	0.08	0.07	0.08
Water consumption (m^3/MWh)	1.02	1.52	0.97	0.07	0.08	0.08	0.07	0.08

Increase in relative water withdrawal due to CO_2 capture	50%	-5%	20%	20%	20%
Increase in relative water consumption due to CO_2 capture	49%	-5%	20%	20%	20%

2.3.3 Water balance breakdown: USCPC

Figure 2-5 shows the water balance around key process units within the USCPC power plants with and without capture. The figure highlights that for the power plant without capture, the cooling tower accounts for the majority of the water withdrawal/consumption with 95% of the total usage. This is followed by the FGD make-up, accounting for the remaining 5%. Once CO_2 capture is implemented, the withdrawal rates in the power plant cooling towers increase by about 25%. Additional water withdrawal rates of almost 280m^3/h are also required for the condenser cooling tower, CO_2 compression, and PCC cooling tower (for the process heat exchangers). When the air-cooling is utilised for the capture plant in a power plant with evaporative cooling (Case 1.1C), an increase of water use of 3% is observed in the condenser cooling tower compared to the case where the capture plant utilises evaporative cooling (Case 1.1B). However, there is no water required for the power plant cooling towers, or the CO_2 compression and PCC cooling towers as this cooling is achieved using the air cooling system.

Figure 2-6 shows the water balance for the USCPC power plants (with and without capture) using air cooling systems. The section requiring the majority of the freshwater is the FGD make-up, accounting for over 99% of the total water withdrawn/consumption. In absolute terms, this value is the same for both the power plant without capture (Case 1.2A) and the power plant with capture (Case 1.2B). For the power plant, adding capture increases the water requirements by less than 1 m^3/h for the amine solution make-up.

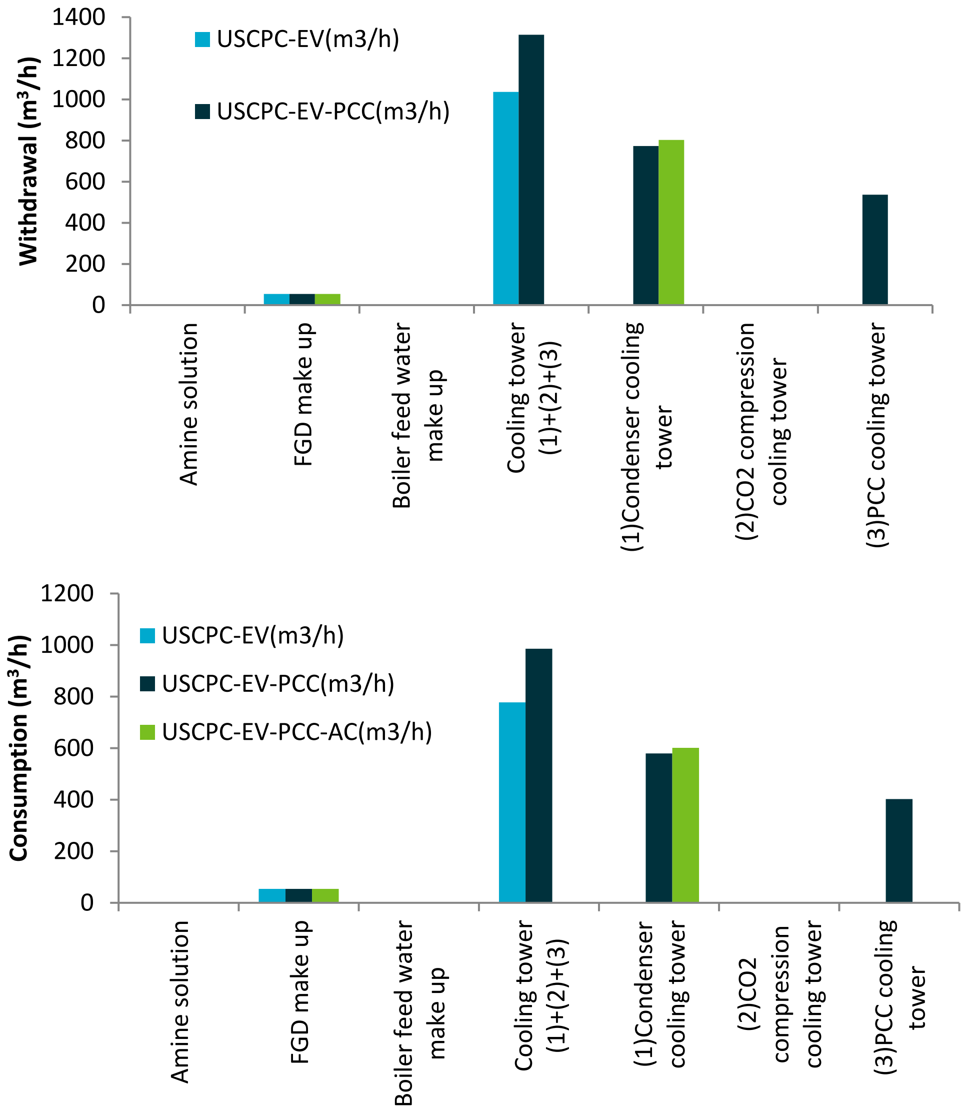


Figure 2-5 Absolute water withdrawal and consumption rates for the USCPC using evaporative cooling systems comparing Case 1.1A (USCPC-EV), Case 1.1B (USCPC-EV-PCC), and Case 1.1C (USCPC-EV-PCC-AV)

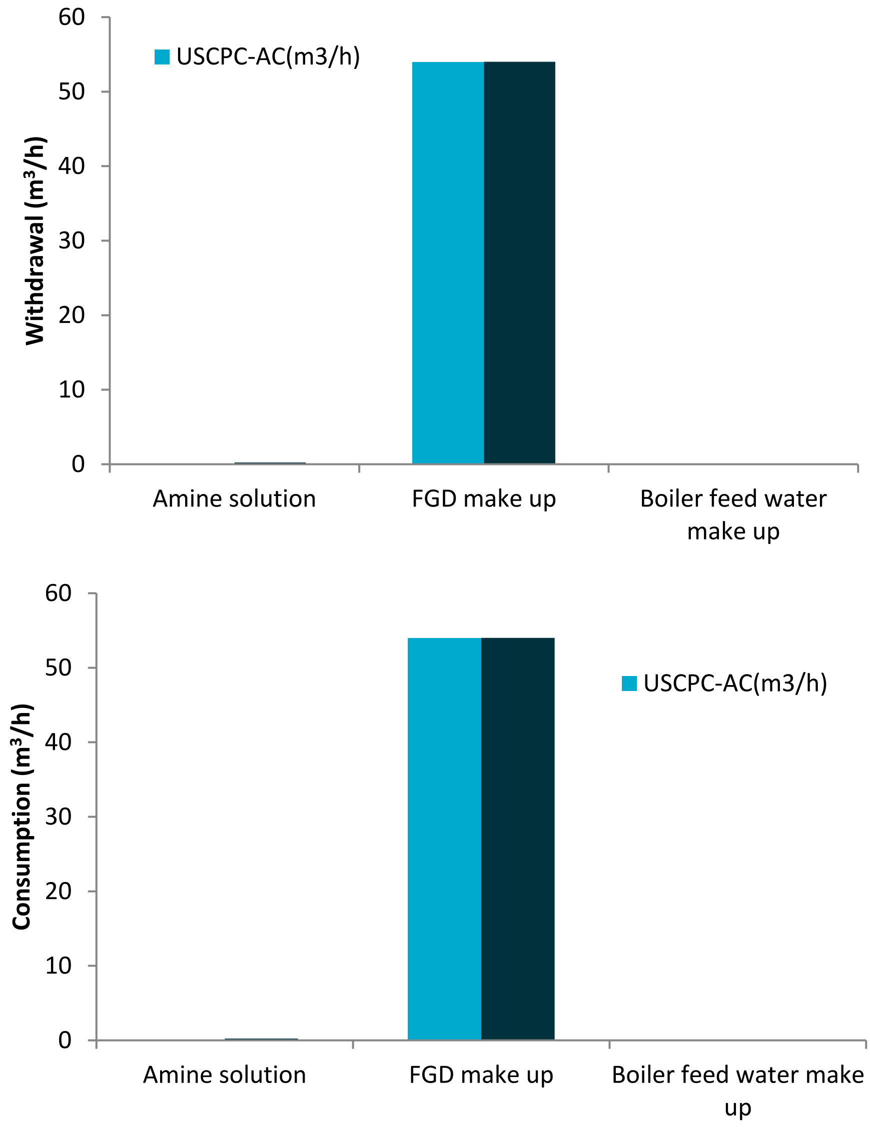


Figure 2-6 Absolute water withdrawal and consumption rates for the USCPC using air cooling systems comparing Case 1.3A (USCPC-AC) and Case 1.3B (USCPC-AC-PCC)

Similar to the air cooling systems, using seawater once-through cooling systems (Figure 2-7), the primary process requiring freshwater is the FGD, which accounts for all the water for the power plant without capture, and over 99% for the power plants with capture.

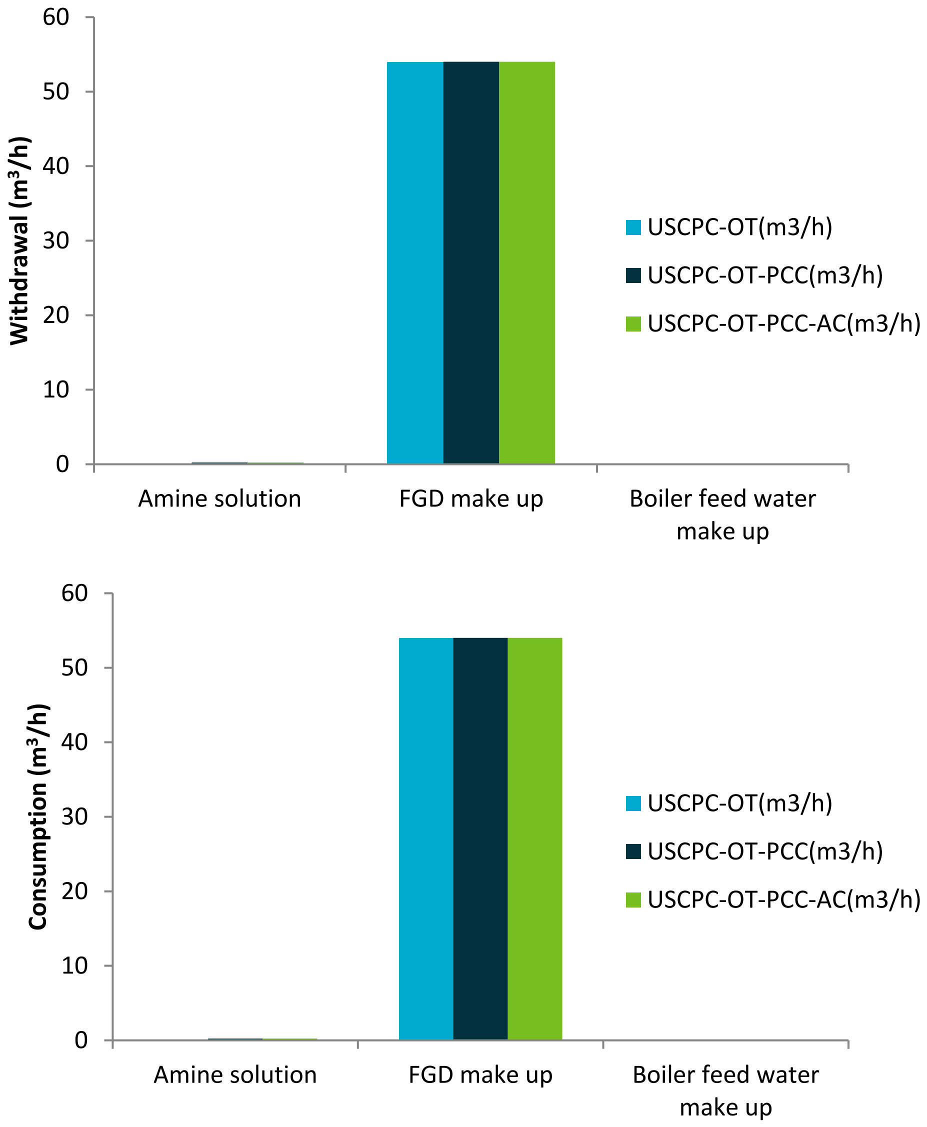


Figure 2-7 Absolute water withdrawal and consumption rates for the USCPC using once-through seawater cooling systems comparing Case 1.2A (USCPC-OT), Case 1.2B (USCPC-OT-PCC), and Case 1.2C (USCPC-OT-PCC-AV)

2.3.4 Detailed water flow diagram: USCPC

Detailed water flow diagrams for the USCPC power plants with and without capture using evaporative cooling (Cases 1.1A, 1.1B, and 1.1C), once-through cooling (Cases 1.2A, 1.2B, and 1.2C), and air cooling (Cases 1.3A and 1.3B) are presented in Appendix A.13.

2.4 Natural gas fired combined cycle power plants

For natural gas fired combined cycle (NGCC) power plants, eight cases of water consumption are modelled. These include power plants with and without capture using the following cooling technologies:

- **Case 2.1A – NGCC-EV**: NGCC reference case for a nominal 890 MW_e gross output power plant without capture. Evaporative (EV) mechanical draught cooling tower (recirculating system) is used for the power plant.
- **Case 2.1B – NGCC-EV-PCC**: Nominal 890 MW_e gross output NGCC power plant with CCS. Evaporative (EV) mechanical draught cooling is used for both the power plant and capture plant.
- **Case 2.1C – NGCC-EV-PCC-AC**: Nominal 890 MW_e gross output NGCC power plant with CCS. Evaporative (EV) mechanical draught cooling tower for the power plant, air cooling (AC) for the capture plant
- **Case 2.2A – NGCC-OT**: Nominal 890 MW_e gross output NGCC power plant with CCS. Once-through (OT) seawater cooling is used for the power plant without capture
- **Case 2.B – NGCC-OT-PCC**: Nominal 890 MW_e gross output NGCC power plant with CCS. Once-through (OT) seawater cooling is used for both the power plant and the capture plant.
- **Case 2.2C - NGCC-OT-PCC-AC**: Nominal 890 MW_e gross output NGCC power plant with CCS. Once-through (OT) seawater cooling tower for the power plant, air cooling (AC) for the capture plant
- **Case 2.3A – NGCC-AC**: Nominal 890 MW_e gross output NGCC power plant with CCS. Air cooling (AC) utilised for the power plant without capture
- **Case 2.3B – NGCC-AC-PCC**: Nominal 890 MW_e gross output NGCC power plant with CCS. Air cooling (AC) is utilised for both the power plant and capture plant

Natural draught cooling tower and once-through river/pond cooling were not evaluated as these conditions were considered not realistic for the hypothetical site location.

The natural gas is assumed to be supplied as per Table 2-8.

Table 2-8 Natural gas supply specification

Natural gas	Value
Supply temperature	9°C
Supply pressure	7 MPa
Molecular weight	18.02 g/mol
Total LHV and sensible heat at 9°C	46,474 kJ/kg
Total fuel enthalpy reference to 0°C	51,631 kJ/kg
Heat values at 25°C: LHV/HHV	46,506 / 51,477 kJ/kg
Natural gas analysis	Vol%
Methane	89.0
Ethane	7.0
Propane	1.0
Butane	0.1
Pentane	0.01
Carbon dioxide	2.0
Nitrogen	0.89

2.4.1 Process description

NGCC Power plant

The performance of a natural gas fired combined cycle power plant with 890 MW_e gross output consisting of two F-class, 278 MW_e gas turbines and a 327 MW_e steam cycle is determined using EBSILON® with the natural gas specification given in Table 2-8 and other technical data common to IEAGHG studies. The incoming combustion air is compressed to 34 bar, mixed with the natural gas, ignited and expanded through the turbine, generating electricity (Figure 2-8). After expansion, the combustion gas enters the heat recovery steam generator at 620°C, where steam is produced at 585°C and 15.9 MPa. Steam is expanded through the high pressure, intermediate pressure and low pressure turbines, after which it is condensed. The condenser temperature is dependent on the average ambient conditions and dependent on the cooling system as shown in Table 2-9.

Table 2-9 Condenser temperatures for the different cooling systems

Cooling system	Condenser temperature, °C
Mechanical draught evaporative cooling	28.3
Once-through seawater cooling	28.0
Air cooling	34.0

The flue gas generated by EBSILON® is used as the input to the Protreat® PCC process simulations (Table 2-10). One post-combustion capture process train is simulated in Protreat®. The results form the basis for the techno-economic modelling in Chapter 5.

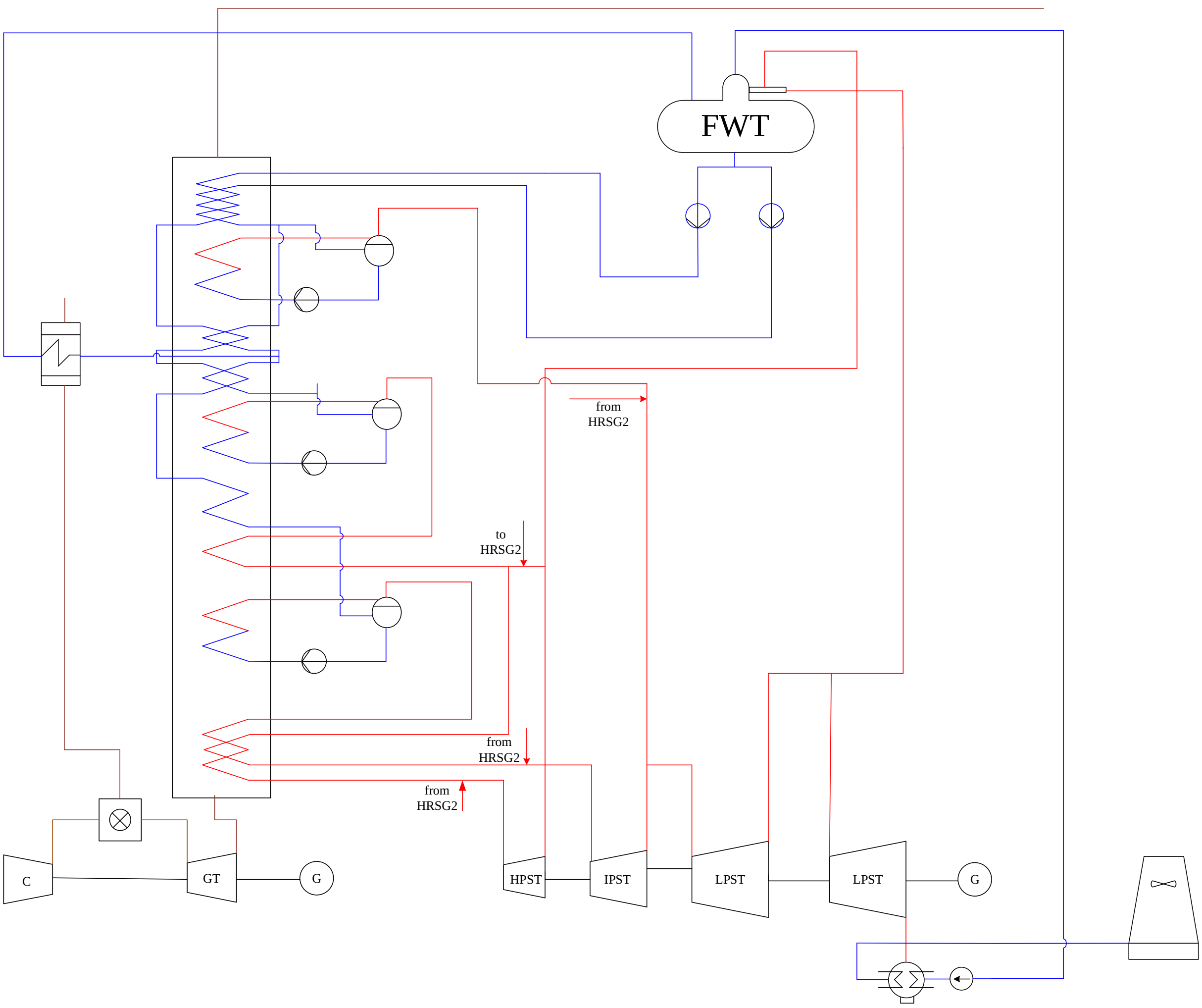


Figure 2-8 Process diagram for natural gas fired combined cycle power plant

Table 2-10 Flue gas properties used in post-combustion capture process simulations for a natural gas fired combined cycle power plant

Property	Value
Flue gas flow rate	1319.8 kg/s
No. trains	4
Flue gas flow per train	329.9 kg/s
Flue gas flow per train	11.65 kmol/s
Temperature	85.2°C
Pressure	101.8 kPa-a
H_2O	8.5 mol%
CO_2	4.2 mol%
N_2	74.4 mol%
Ar	0.9 mol%
O_2	12 mol%

In the NGCC with CO_2 capture (Figure 2-9) the steam required for the regeneration of the amine solution is extracted from the steam cycle and expanded in an additional turbine, as indicated in Figure 2-9. The extracted steam is condensed in the reboiler at a temperature of 133°C. The condensate is used to de-superheat the steam extracted from the steam cycle.

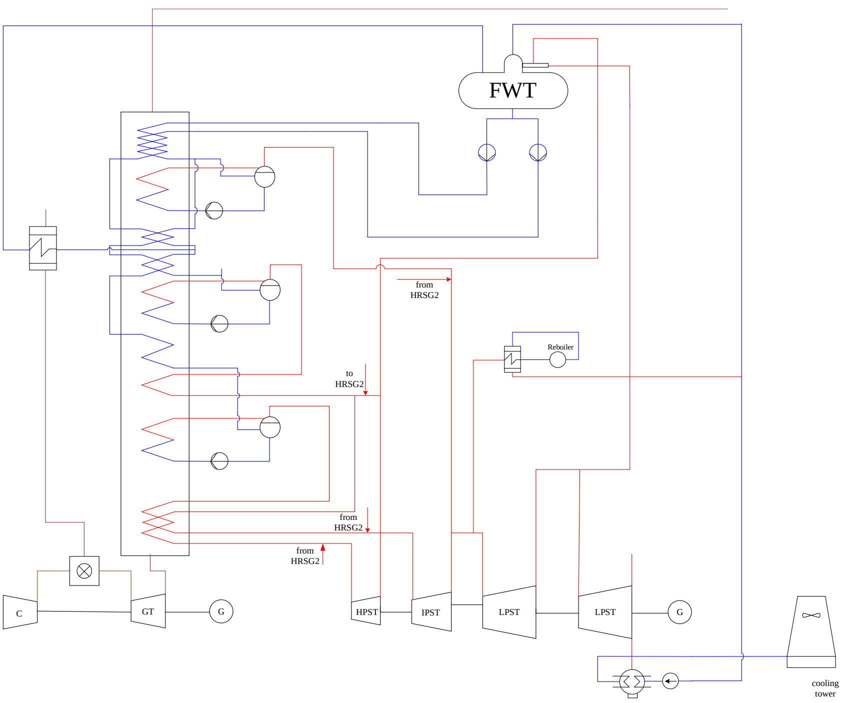


Figure 2-9 Process flow diagram for a natural gas fired combined cycle power plant with integrated post-combustion capture

Post-combustion CO_2 capture plant and CO_2 compression plant

In the post-combustion CO_2 capture plant shown in Figure 2-10, the flue gas is cooled in the pre-treatment column. In the CO_2 absorber the flue gas is brought into contact with the amine solution, resulting in the transfer of CO_2 into the amine solution. To limit the temperature increase as a result of the reaction of CO_2 with the amines, absorber intercooling is applied. This will ensure that a high CO_2-loading of the solution is achieved. The resulting rich solution is split: the first fraction is pumped to the desorber via the lean-rich heat exchanger and the second fraction is pumped to the desorber top. This second fraction will cool down the wet CO_2 product from the desorber and recover part of the latent heat. The regenerated solution is then pumped back to the absorber via the lean-rich heat exchanger and the cooler.

The stream data for the indicated streams in Figure 2-10 are given in Table 2-11.

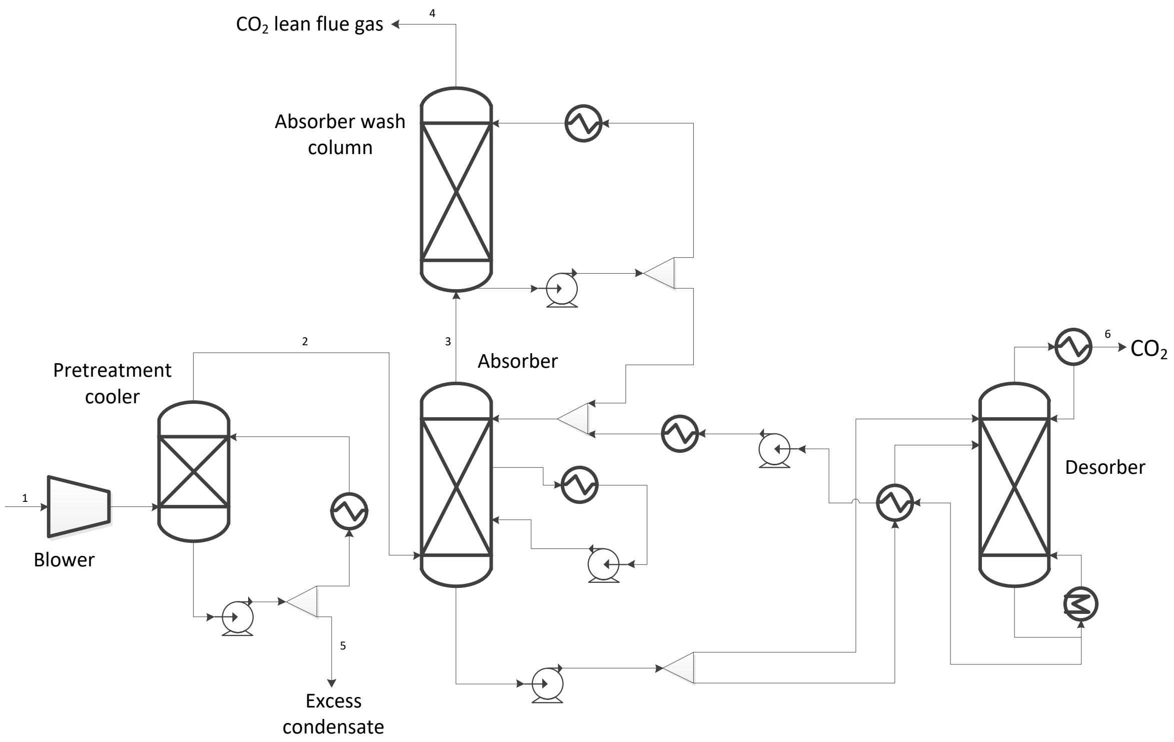


Figure 2-10 Line diagram of CO_2 capture plant used in amine-based post-combustion capture simulations. The layout includes absorber intercooling and rich-split process modifications

Table 2-11 Stream data for 90% CO_2 capture from natural gas combined cycle power station flue gas (one train)

Stream		1	2	3	4	5	6
Water	mol%	8.50	7.15	12.04	7.27	100.00	4.05
Carbon dioxide	mol%	4.20	4.26	0.45	0.44	0.00	95.93
Piperazine	mol%	0.00	0.00	0.02	0.00	0.00	0.00
AMP	mol%	0.00	0.00	0.05	0.00	0.00	0.00
Nitrogen	mol%	74.40	75.50	74.52	78.65	0.00	0.01
Argon	mol%	0.90	0.91	0.90	0.95	0.00	0.00
Oxygen	mol%	12.00	12.18	12.02	12.68	0.00	0.00
Total flow	kmol/s	11.65	11.48	11.63	11.02	0.17	0.46
Total flow	kg/s	329.94	326.89	318.85	307.18	3.05	19.71
Temperature	°C	85.20	39.94	48.92	35.87	46.74	40.00
Pressure	kPa	101.80	106.09	100.74	98.89	110.00	184.38

The CO_2 product is subsequently compressed to 110 bar in a four-stage process as shown in the flow diagram in Figure 2-11. Intercooling is performed with the condensate from the steam turbine where the temperature levels enable this. After the first and second stage, additional cooling is used.

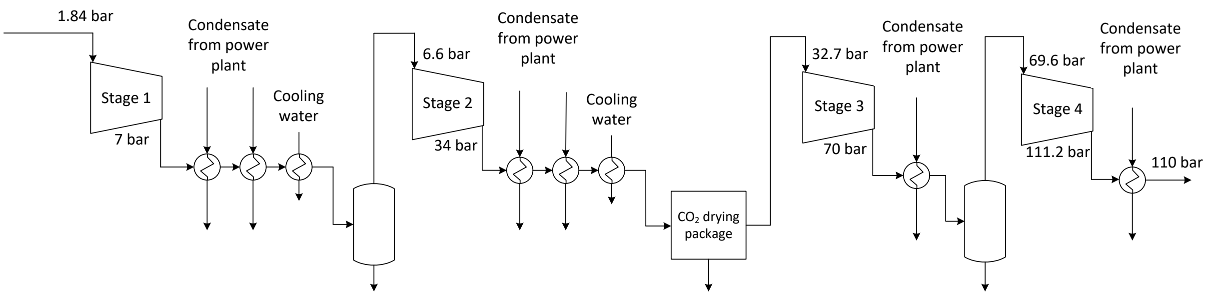


Figure 2-11 Four-stage CO_2 compression flow diagram for natural gas fired combined cycle power plant

Evaporative cooling

A schematic of the reference NGCC power plant using evaporative (EV) cooling is presented in Appendix A.14, while a schematic of the NGCC power plant with CO_2 capture using evaporative cooling, which is identical to the air-cooled (AC) capture plant, is in Appendix A.16. The process comprises of:

- Combustor (Unit 100)
- Gas turbine island (Unit 200)
- Heat recovery steam generator (Unit 300)
- Steam turbine island (Unit 400)

While the power plant with capture comprises the additional blocks:

- CO_2 recovery (Unit 600)
- CO_2 compression (Unit 700)

The complete NGCC power plant process flow diagram with and without CO_2 capture is shown in Appendix A.15 and A.17, respectively.

Once-through seawater cooling

A schematic of the reference NGCC power plant using once-through (OT) seawater cooling is presented in Appendix A.18, while a schematic of the NGCC power plant with CO_2 capture using once-through seawater cooling (OT), which is identical to the air-cooled (AC) capture plant, is in Appendix A.20. The process comprises of:

- Combustor (Unit 100)
- Gas turbine island (Unit 200)
- Heat recovery steam generator (Unit 300)
- Steam turbine island (Unit 400)

While the power plant with capture comprises the additional blocks:

- CO_2 recovery (Unit 600)
- CO_2 compression (Unit 700)

The complete NGCC power plant process flow diagram with and without CO_2 capture is shown in Appendix A.19 and A.21, respectively.

Air cooling

A schematic of the reference NGCC power plant using air cooling (AC) is presented in Appendix A.22A.18, while a schematic of the NGCC power plant with CO_2 capture using air cooling (AC) for power plant and capture plant is in Appendix A.24. The process comprises of:

- Combustor (Unit 100)

- Gas turbine island (Unit 200)
- Heat recovery steam generator (Unit 300)
- Steam turbine island (Unit 400)

While the power plant with capture comprises the additional blocks:

- CO_2 recovery (Unit 600)
- CO_2 compression (Unit 700)

The complete NGCC power plant process flow diagram with and without CO_2 capture is shown in Appendix A.23 and A.25, respectively.

2.4.2 Technical performance: NGCC

The technical performances for the eight NGCC cases are summarised in Table 2-12. Similar to the results for the USC coal fired power plants, air cooling reduces the efficiency of the NGCC power plant compared to using evaporative cooling, with a reduction of 1% in LHV. This results from the higher condenser temperature and higher electricity consumption for air cooling. Using once-through seawater compared to evaporative cooling, the LHV efficiency of the power plant without capture is 0.2% higher. The normalised withdrawal and consumption for the NGCC power plant using evaporative cooling is 0.65 and 0.49 m^3/MWh respectively. For power plants without capture, using air cooling or once-through cooling, the withdrawal and consumption rates are zero for both.

Adding capture, the freshwater usage increases by approximately 50% or 0.3 m^3/MWh for evaporative cooling systems, and by approximately 1.7E-4 m^3/MWh for air-cooling and once-through cooling systems.

Using the option of air-cooling for the capture plant at NGCC power plants with evaporative cooling (case 2.1C), the absolute withdrawal and consumption rates of freshwater are significantly reduced to almost half of that of the plant without capture. In normalised terms, the withdrawal and consumption rates are about -35%.

Table 2-12 Technical performance for NGCC power plants (with and without capture)

Cases	2.1A NGCC-EV	2.1B NGCC-EV-PCC	2.1C NGCC-EV-PCC-AC	2.2A NGCC-OT	2.2B NGCC-OT-PCC	2.2C NGCC-OT-PCC-AC	2.3A NGCC-AC	2.3B NGCC-AC-PCC
Cooling technology	**Recirculating (EV)**		**EV + ACC**	**Once-through (OT)**		**OT + AC**	**Air cooling (AC)**	
Fuel input [t/h]	116.5	116.5	116.5	116.5	116.5	116.5	116.5	116.5
Gross power output (MW)	890	811.9	811.9	890	811.9	811.9	878.8	805.6
Auxiliary power (MW)	12	50.6	53.7	10.9	49.1	53.1	16.1	55.7
Net power output (MW)	878	761.3	758.2	883.3	762.8	758.8	862.7	749.9
Net plant HHV efficiency (%)	52.71	45.70	45.52	52.98	45.79	45.56	51.79	45.02
Net plant LHV efficiency (%)	58.34	50.59	50.39	58.65	50.69	50.42	57.33	49.83
LHV efficiency loss due to PCC (%)		7.75	7.95		7.96	8.23		7.5
CO_2 generation (t/h)	310.9	310.9	310.9	310.9	310.9	310.9	310.9	310.9
CO_2 emission (t/h)	310.9	31.09	31.09	310.9	31.09	31.09	310.9	31.09
CO_2 emission (t/MWh)	0.352	0.041	0.041	0.352	0.041	0.039	0.359	0.041
CO_2 capture (t/h)	0	279.8	279.8	0	279.8	279.8	0	279.8
Energy consumption for PCC								
Energy consumption for absorbent pumps and blowers in PCC (MW)	0	13.1	13.1	0	13.1	13.1	0	13.1
Compressor energy(MW)	0	28.8	28.8	0	28.8	28.8	0	28.8
Pumps for cooling (MW)	0	2.3	5.4	0	1.5	5.4	0	5.4
Total electrical energy consumption in PCC (MW)	0	44.3	47.4	0	43.5	47.4	0	47.4
Water balance								
Water withdrawal (m^3/h)	572.4	756.3	320.5	0	0.1	0.1	0	0.1
Process water discharge (m^3/h)	144	186.9	79.2	0	0	0	0	0
Water consumption (m^3/h)	428.4	569.4	241.3	0	0.1	0.1	0	0.1
Water withdrawal (m^3/MWh)	0.65	0.99	0.42	0	0	0	0	0
Water consumption (m^3/MWh)	0.49	0.75	0.32	0	0	0	0	0
Increase in relative water withdrawal due to CO_2 capture	53%	-35%						
Increase in relative water consumption due to CO_2 capture	54%	-34%						

2.4.3 Water balance breakdown: NGCC

Figure 2-12 - Figure 2-14 show the water balance around key process units for the NGCC power plant without capture. Similar to the USCPC, water is required in the cooling towers. However, as there is no FGD, no make-up water is required. The absolute water withdrawal and consumption rates for the NGCC power plants are approximately half of that for the USCPC using evaporative cooling systems, and almost zero when air cooling or once-through seawater cooling is used.

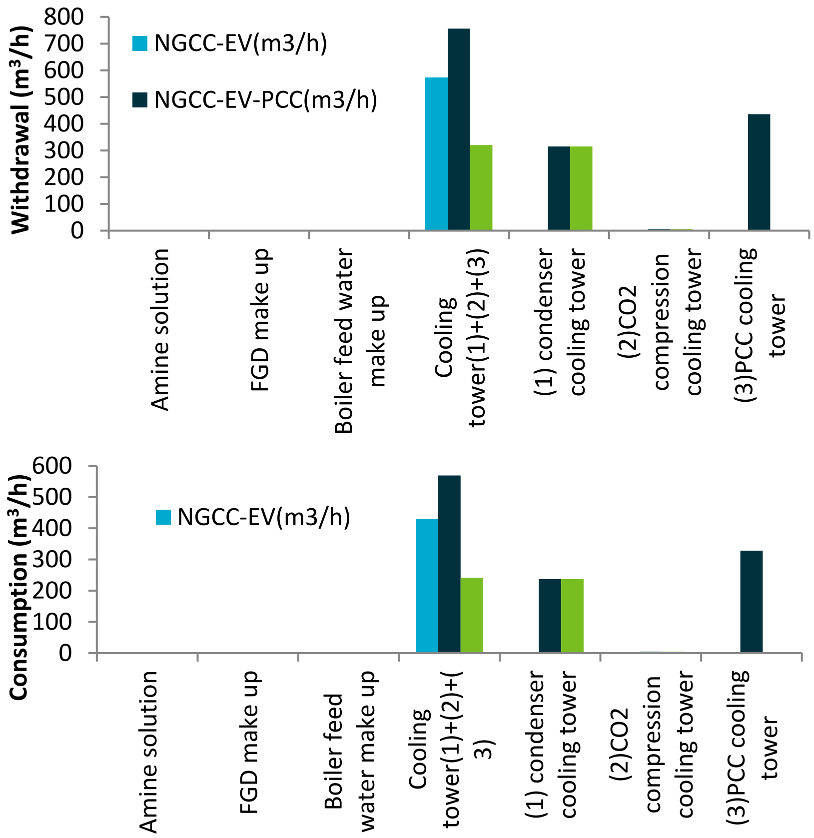


Figure 2-12 Absolute water withdrawal and consumption rates for the NGCC using evaporative cooling systems comparing Case 2.1A (NGCC-EV), Case 2.1B (NGCC-EV-PCC), and Case 2.1C (NGCC-EV-PCC-AC)

Figure 2-12 summaries the absolute water withdrawal and consumption rates for the NGCC power plant, without (Case 2.1A) and with capture (Cases 2.1B and 2.1C). The process unit requiring the majority of water for all three cases is the power plant cooling tower(s). Implementing capture introduces additional water requirements in the condenser cooling tower (for both Cases 2.1B and 2.1C), the compression cooling towers (for Cases 2.1B and 2.1C), and for the PCC cooling tower (for Case 2.1B only).

Figure 2-13 and Figure 2-14 show that for the NGCC power plants without capture, using air cooling or once-through seawater cooling, no water is required. Once capture is implemented, the absolute freshwater withdrawal and consumption rates increase by 0.13m^3/h.

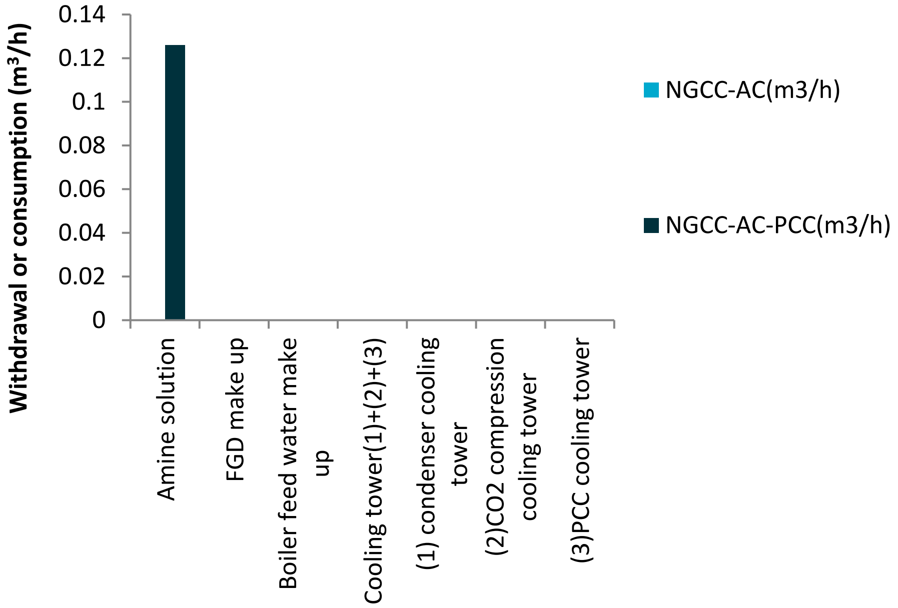


Figure 2-13 Absolute water withdrawal and consumption rates for the NGCC using air cooling systems comparing Case 2.3A (NGCC-AC) and Case 2.3B (NGCC-AC-PCC)

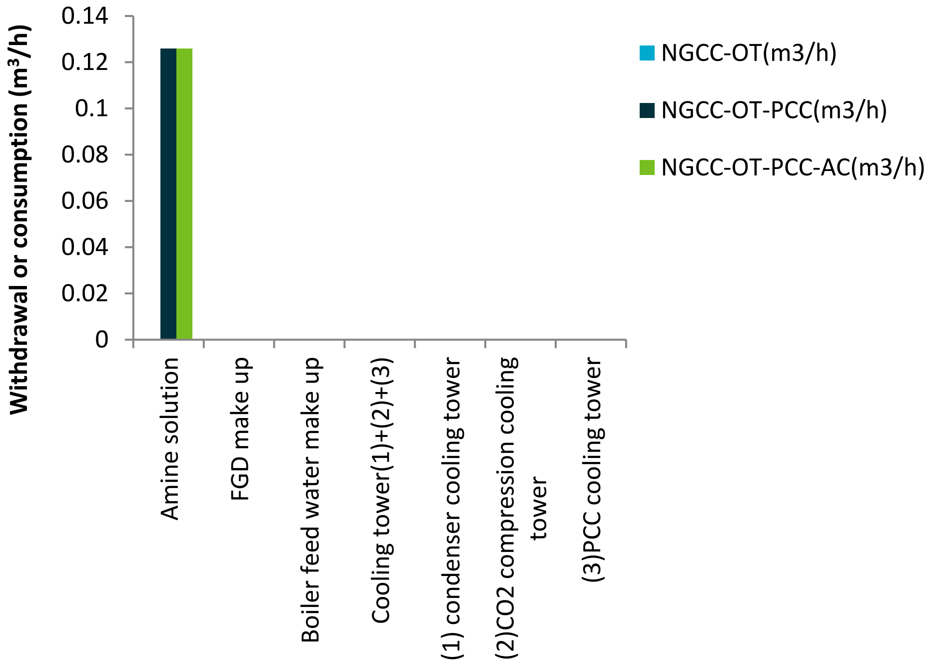


Figure 2-14 Absolute water withdrawal and consumption rates for the NGCC using once-through seawater cooling systems comparing Case 2.2A (NGCC-OT), Case 2.2B (NGCC-OT-PCC), and Case 2.2C (NGCC-OT-PCC-AC)

2.4.4 Detailed water flow diagram: NGCC

Detailed water flow diagrams for the NGCC power plants with and without capture using evaporative cooling (Cases 2.1A, 2.1B, and 2.1C), once-through seawater cooling (Cases 2.2A, 2.2B, and 2.2C), and air cooling (Cases 2.3A and 2.3B) are presented in Appendix A.13.

3 CO_2 storage and brine management in the Netherlands

This chapter investigates the storage of CO_2 captured at the power plants described in Chapter 2 at two sites in the Netherlands. CO_2 injection is modelled for one offshore and one onshore location, assuming open as well as closed reservoir boundary conditions. The storage capacity as well as CO_2 containment and plume migration are assessed. Water extraction as a means to enhance storage capacity is simulated and options for extracted water management are proposed.

3.1 CO_2 storage onshore and offshore Netherlands

Underground storage of CO_2 in the Netherlands has previously been proposed and investigated for deep saline aquifers and depleted hydrocarbon fields (both gas and oil). In both cases, it is commonly assumed that structural or stratigraphic trapping is the primary mechanism to secure any injected CO_2 in the Netherlands context. This has an implication on the selection of possible storage sites, as they must feature a regional seal of sufficient thickness to effectively impede buoyant vertical migration of CO_2 to the shallower subsurface.

Several studies attempting to identify suitable reservoirs in the Netherlands have appeared in the published literature (for example Huurdeman, 1992; van der Velde et al., 2008; Damen et al., 2009; Vangkilde-Pedersen et al., 2009; van der Meer and Yavuz, 2009; Ramírez et al., 2010; Neele et al., 2012, 2013). These have typically used a set of criteria to screen the suitability of reservoirs for geological storage, which may be summarised as:

- Structural closure - reservoirs must have a structural trap that can contain injected CO_2;
- Presence of seal - reservoirs must have a laterally extensive regional sealing unit capable of preventing vertical migration;
- Reservoir properties - reservoirs should have sufficient porosity and permeability;
- Reservoir thickness - reservoirs should be sufficiently thick (greater than 10 m);
- Reservoir depth - reservoirs should be at least 800 m below the surface, where injected CO_2 remains in a supercritical state.

Over five hundred potential sites for CO_2 storage have been identified in the Netherlands (Ramírez et al., 2010), the majority of which are hydrocarbon reservoirs that may be used for CO_2 storage once they have been depleted. Ramírez et al. (2010) applied an additional capacity constraint to these potential sites to exclude sites that did not provide sufficient capacity for large-scale CO_2 storage (a minimum capacity of 2 Mt for saline aquifers and 4 Mt for hydrocarbon fields was used). They identified 176 potential storage sites in the

Netherlands (both onshore and offshore), comprising 138 gas fields, 4 oil fields, and 34 deep saline aquifers.

3.1.1 Storage sites

In this study, storage of CO_2 in saline aquifers in both the onshore and offshore region is considered, rather than storage in depleted hydrocarbon fields. The two sites were selected based on the storage capacity they provide, which is matched with the CO_2 captured from the NGCC and the USCPC power stations described in Chapter 2 over a period of 25 years.

A saline aquifer in the Q1 block was chosen for the offshore storage scenario. Due to its size, this aquifer has been highlighted as a potential storage location for CO_2 captured in the Amsterdam and Rotterdam regions (Neele et al., 2011b). It is located approximately 110 km offshore from Rotterdam. The location and depths of the top surface are shown in Figure 3-1. The reservoir is part of the upper Rotliegend Group with thicknesses ranging from 270 – 360 m in this region at depths of more than 2,200 m. This sandstone aquifer is sealed by a series of thick shale groups.

A large structural enclosure in the onshore Rotliegend Group, approximately 45 km from Rotterdam, was identified as suitable for initial modelling of onshore CO_2 storage in the Netherlands (see Figure 3-1). In contrast to the offshore model, this reservoir is much shallower, but the reservoir unit in this region is also quite thick, with thicknesses of over 400 m in parts.

Due to the absence of detailed reservoir models for the selected storage sites, the computational models were constructed using publicly available datasets from NLOG (www.nlog.nl) (see Figure 3-1).

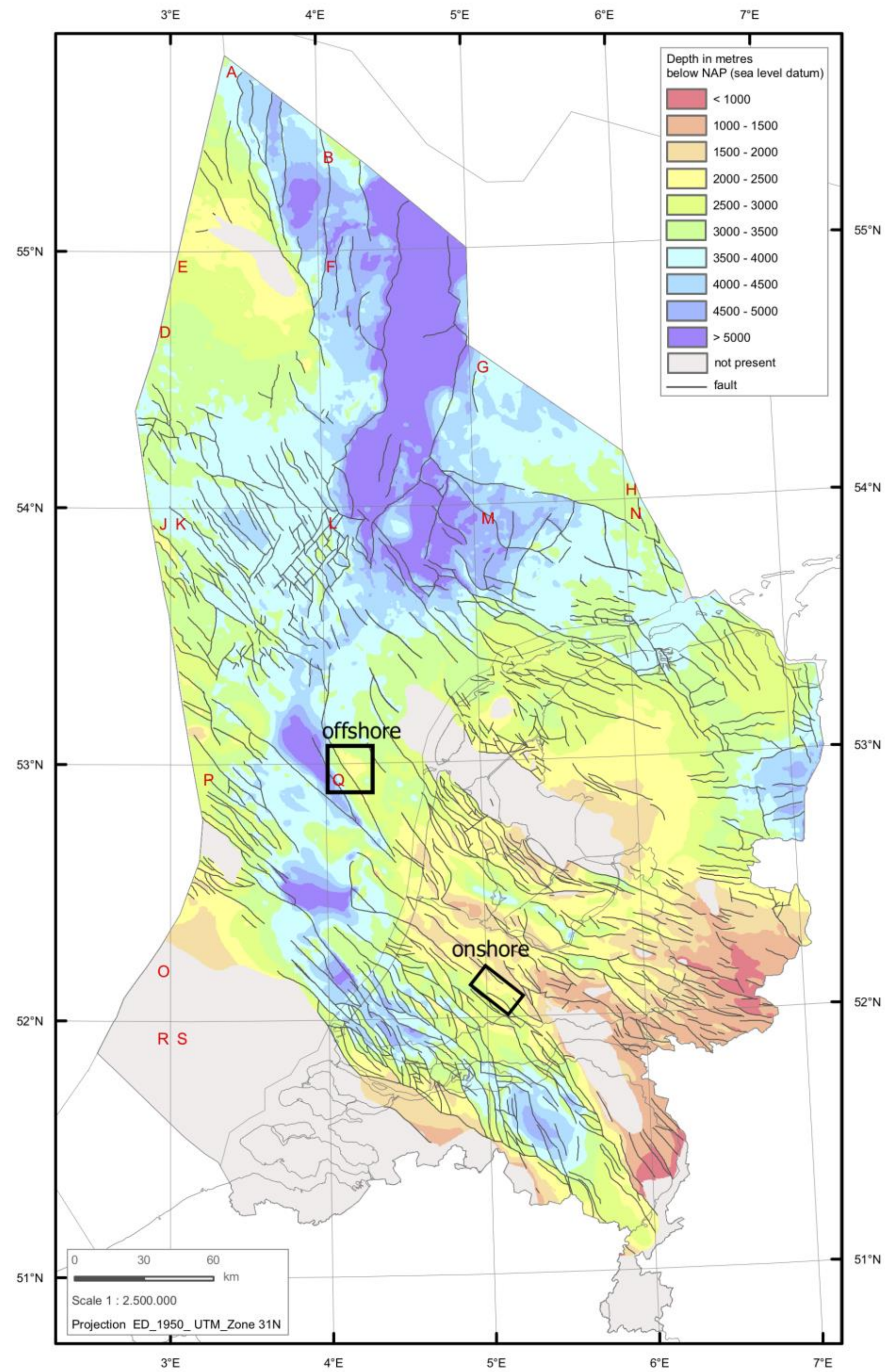


Figure 3-1 Location of offshore and onshore models (location indicated by the black rectangles). Depths are the base of the Zechstein group, which corresponds to the top surface of the reservoir models (www.nlog.nl)

3.1.2 Reservoir model

Several simplifying assumptions have been used to make the modelling study tractable:

- Homogeneous reservoir properties are used with representative values of permeability and porosity (taken from nearby well logs provided by NLOG);

- It is assumed that the overlying formation provides a perfect seal (as such, this sealing unit is not included in the model, with the upper boundary considered impermeable).

Each of these assumptions can affect the robustness of conclusions drawn from numerical results. However, for the purposes of this study, any uncertainty due to such assumptions are not expected to significantly affect the storage estimates nor the final economic estimates. As injection takes place in a structural enclosure in each case, the effect of reservoir properties on the subsequent migration of the plume of CO_2 can be expected to be small in comparison to the topography of the reservoir units.

In reality, the reservoir units are not homogeneous, and are instead heterogeneous at multiple length scales. To improve the robustness of numerical predictions and hence reduce the uncertainties in storage cost estimates, it would be necessary to undertake a full reservoir modelling study once target storage formations have been chosen, but this is beyond the scope of this study.

Offshore reservoir model

A saline aquifer in the Q1 field was chosen for the offshore storage scenarios (Figure 3-1). A large structural enclosure was identified in this reservoir, which forms the basis of the offshore model. The reservoir is part of the upper Rotliegend Group. Above this sandstone aquifer, a series of thick shale groups are present, which are assumed to act as perfect sealing units for the purpose of modelling.

As little publicly-available data characterising this reservoir unit is available, representative values for porosity and permeability of similar magnitude to measurements in nearby wells are used. Temperature is taken from nearby well log data and hydrostatic pressure gradients are used as an initial condition. Lateral boundary conditions of the storage reservoir are modelled as either open, representative of a hydraulically connected aquifer, or closed, representing a compartmentalised aquifer. The reservoir properties are summarised in Table 3-1.

Table 3-1 Reservoir properties of the offshore and onshore models

Property	Offshore model	Onshore model
Porosity	0.15	0.20
Permeability	100 md	200 md
Pressure (hydrostatic)	20 MPa – 50 MPa	12 MPa – 26 MPa
Temperature	90°C	70°C
Salinity	100,000 ppm	150,000 ppm
Fracture gradient	16 MPa/km	16 MPa/km
Lateral boundary condition	open/closed	open/closed

The computational model used for the offshore storage modelling is presented in Figure 3-2. In this part of the offshore, the depths of the model range from 2,200 m at the crest of the structure, down to 4,000 m at the base of the structural closure. The reservoir unit is quite thick, with thicknesses ranging from 270 m to 360 m in this region. A significant offset fault is present along one side of the structural closure. The fault is assumed to act as a flow barrier in the absence of greater understanding of the role of this faulting.

The computational mesh used in this study is quite coarse, in part due to the resolution of the surface data, and also to enable a suite of reservoir simulations to be undertaken in the time available for the study. Lateral grid resolution is 250 m, while vertical resolution varies from 20 m near the base of the model to 5 m near the top surface to provide increased resolution at the top of the model where the injected CO_2 is expected to migrate due to buoyancy. Approximately 100,000 elements are used in each of the models, allowing each simulation to be run in less than 12 hours.

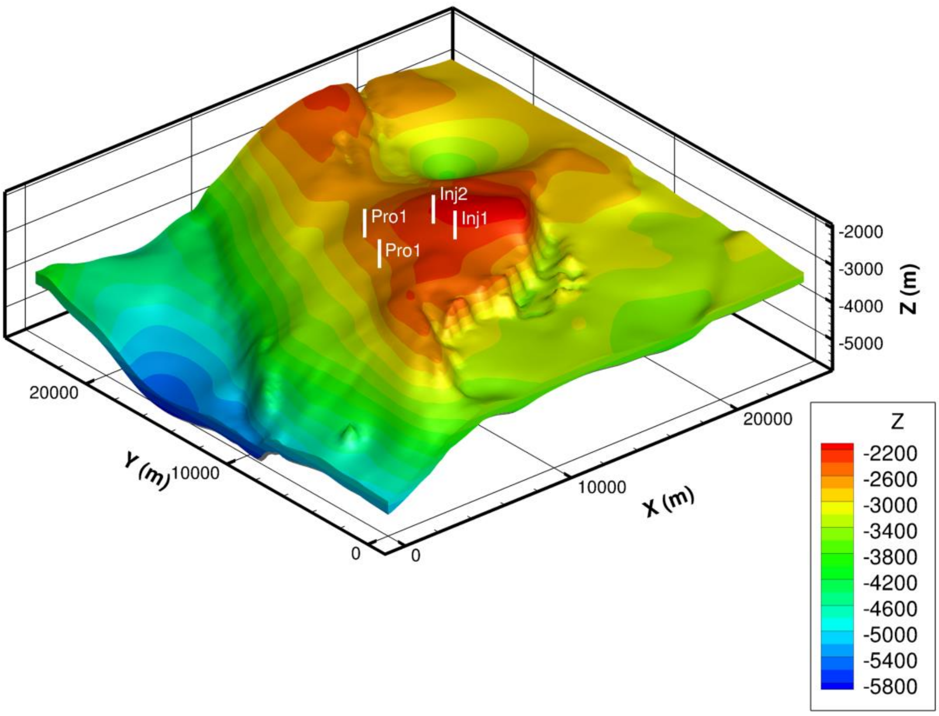


Figure 3-2 Computational reservoir model of the offshore aquifer in the Q1 block. Contours indicate depth in metres. Injection and production well locations shown

Onshore reservoir model

A large structural enclosure in the onshore Rotliegend Group was identified as suitable for initial modelling of onshore CO_2 storage (see Figure 3-3). The reservoir varies in depth from 1,200 m to 1,600 m near the crest of the structural enclosure, reaching thicknesses of over 400 m in parts. Representative values for porosity, permeability, and temperature from nearby wells are used, and hydrostatic pressure gradients are used as an initial condition. The reservoir properties for the onshore reservoir model are summarised in Table 3-1. As the onshore model is shallower than the offshore model, the temperature and pressure ranges are lower in the onshore model than for the offshore model (compare Table 3-1). Analogous to the offshore scenario, reservoir boundaries are modelled as either open or closed.

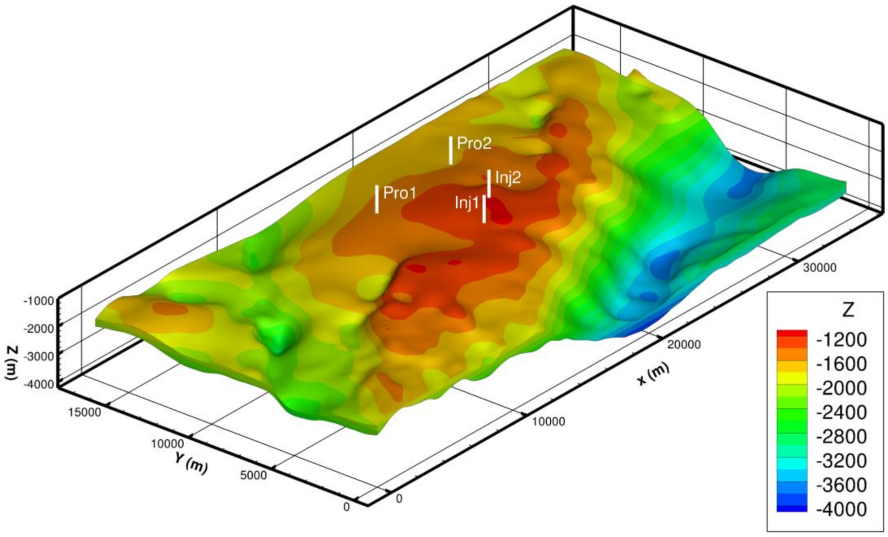


Figure 3-3 Computational reservoir model of the onshore aquifer. Contours indicate depth in metres

3.1.3 Brine composition

Salinity is an important consideration for water treatment options, but is typically subject to significant variation even within the same reservoir unit. No groundwater data exists for the chosen storage locations, instead resistivity well log data from the reservoir unit was used to estimate salinity. Figure 3-4 presents resistivity log data from a number of onshore and offshore wells in the Netherlands, where it is observed that resistivity in the Rotliegend Group varies significantly from approximately 0.04 Ohm to 0.15 Ohm, which correspond to salinities of approximately 200,000 mg/L to 50,000 mg/L, respectively. A general trend of increasing resistivity (and hence decreasing salinity) with depth is observed, suggesting that the groundwater is less saline in the deep offshore regions in comparison to the shallower onshore regions.

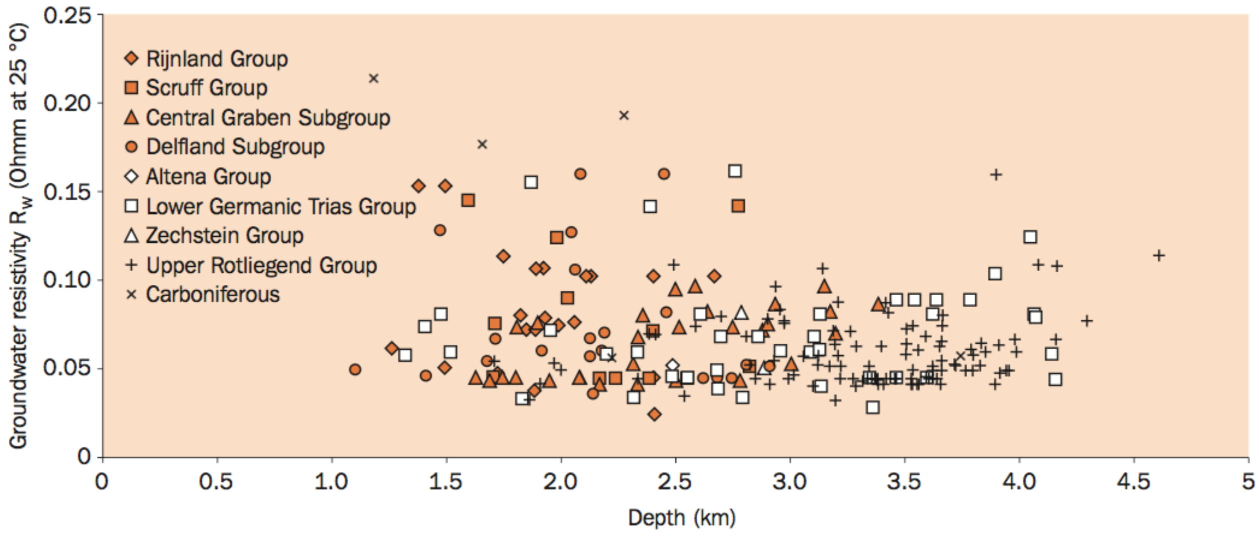


Figure 3-4 Resistivity log data from onshore and offshore wells in the Netherlands for various stratigraphic groups. Source: Verweij (2003)

Based on analysis of formation water from the Rotliegend Formation, salinities range from 50,000 mg/L in the onshore to up to 300,000 mg/L in the offshore areas. The distribution of salinity across the Rotliegend reservoirs offshore Netherlands is in Figure 3-5, water analysis from selected well is in Table 3-2. However, it should be noted that the analysis includes neither samples from the Q1 block, nor from the onshore Rotliegend Formation.

Table 3-2 Rotliegend Formation water analyses from selected wells in the Netherlands (from Verweij et al., 2003)

Well	Depth, m	Salinity, g/L	Na, g/L	K, g/L	Mg, g/L	Ca, g/L	Cl, g/L	HCO_3, g/L	SO_4, g/L
Q07-01	2375-2408	256	84		1.3	13.5	157	0.2	0.4
L07-06	3929-3952	228	63	2.1	3.4	17.3	141	0.6	0.4
L10-19ST	3988-4019	78	18	3.7	2.0	4.4	47	0.8	0.9
K12-03	3600	257	77		3.2	17.5	162	0.4	0.4
L07-07	3655-3677	261	76	2.1	4.5	14.8	134	0.2	0.4
L11-01	3620	217	63		2.2	16.9	134	0.5	0.9
P05-01	3053-3088	150	49	1.6	0.4	7.0	88	0.1	0.3
M07-01x	3245-3460	265	27	1.7	6.8	60.0	169	0.25	0.3
P12-04x	~3000	143	50	1.1	1.5	2.2	85	0.6	1.8

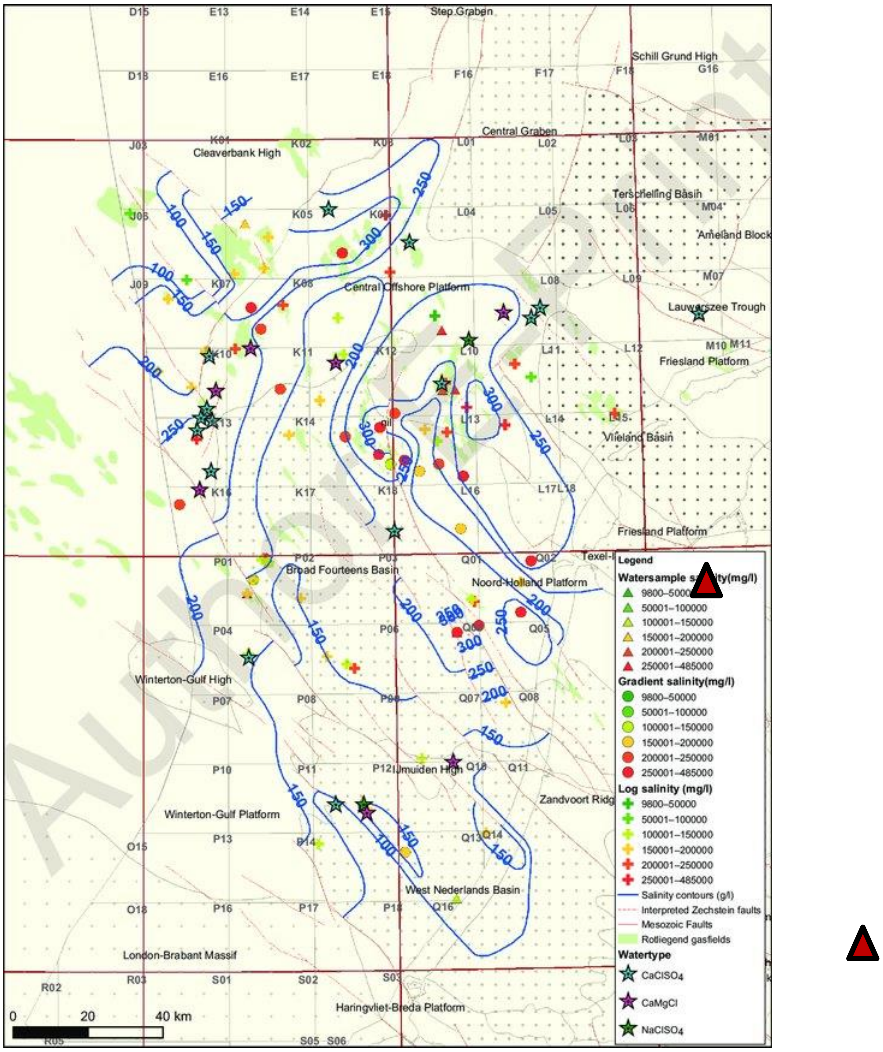


Figure 3-5 Distribution of salinity (contour lines in g/l) and hydrochemical types of formation water in the Permian Rotliegend reservoirs in the Netherlands offshore (Verweij et al., 2011). The triangles show the approximate location of the two modelled storage reservoirs

The majority of the Rotliegend Formation water are of a Na-Cl or Na-Ca-Cl type (Table 3-2). Other components found in the formation water such as magnesium (Mg) and potassium (K) are listed in Table 3-2 with their respective concentrations at the sample wells.

The resistivity data presented in Figure 3-4 is used to estimate the salinity for the onshore and offshore reservoir models. In the onshore model the depth varies from 1,200 m to 1,600 m, suggesting that the salinity in the onshore region is approximately 150,000 ppm (corresponding to a resistivity of approximately 0.05 Ohm). This is also in agreement with the salinity distribution presented in Figure 3-5.

In the deeper offshore model, where the depths are between 2,000 m to 3,000 m near the structural enclosure, Figure 3-4 suggests that salinities range from 75,000 mg/L to 200,000 mg/L at these depths, with an average of approximately 100,000 mg/L (corresponding to resistivities between 0.04 Ohm and 0.1 Ohm, with an average of 0.07 Ohm). This is higher than the salinity indicated for the Rotliegend Group in Figure 3-5, but is justified through the variability encountered. The uncertainty in salinity will have only a small effect on the storage modelling, primarily through the solubility of CO_2 in the brine. The values used in this study, while approximate, do capture the important feature in that the groundwater is more saline than seawater. However, the salinity will have a significant effect on the potential for water treatment. This is discussed in Chapter 3.2.3.

3.1.4 Numerical modelling

Reservoir simulations were undertaken using the TOUGH2 code (Pruess, Oldenburg and Moridis 1999). TOUGH2 is a multiphase, multicomponent code for non-isothermal flow in porous and fractured media. It has a modular design, with several equation of state modules available. TOUGH2 has been used extensively in numerical modelling of geological storage of CO_2, with a large body of published studies present in the literature.

Of particular utility in geological storage of CO_2 is the ECO2N equation of state (Pruess 2005), a highly sophisticated fluid property module which incorporates a comprehensive representation of the physical and thermodynamical properties of brine and CO_2 mixtures. It allows for mutual solubility of brine and CO_2, as well as precipitation or dissolution of salt. The ECO2N equation of state module has been rigorously benchmarked against available experimental results (Pruess 2005).

TOUGH2 has been demonstrated to provide comparable results with several other numerical codes commonly used in computational studies of geological storage of CO_2 in international code comparison studies (Pruess et al. 2001; Pruess et al. 2004; Class et al. 2009).

TOUGH2 allows for several functional forms of the relative permeability and capillary pressure curves to be implemented. In this study, non-hysteretic relative permeability and capillary pressure curves of the van Genuchten form were used (van Genuchten 1980).

3.1.5 Injection scenarios

Several injection scenarios were considered for each the onshore and the offshore site. Annual injection rates of 2 Mt/y and 4 Mt/y were used for a period of 25 years, corresponding to total injection amounts of 50 Mt and 100 Mt, respectively. These injection rates are representative of the amount of CO_2 captured from the 890 MW_e NGCC power station (2 Mt/y) and the 900 MW_e USCPC power station (4 Mt/y).

For simplicity, a constant rate of injection is used for all cases, with the injection interval of 20 m located at the base of the aquifer unit. It should be noted that in a practical injection scenario, injection rate would not be constant due to heterogeneity in the reservoir, and would instead drop off as pressure in the reservoir builds. The full injection rate is assumed to be possible using either one or two injection wells. Again, in practice, injectivity may be lower due to reservoir heterogeneity, in which case additional injection wells may be required. These considerations are site specific, so would need further reservoir characterisation which is beyond the scope of the current project.

Two scenarios are investigated for the two storage sites: open and closed reservoir boundaries. For the closed boundary scenario, brine extraction is considered to accommodate the total volume of CO_2 stored while still maintaining pressure below the fracture threshold. Different extraction rates were modelled to match the volumetric CO_2 injection rate so that the pore volume of fluid in the aquifer is constant. For the offshore aquifer, this corresponds to brine production of 3.3 Mt/y for a CO_2 injection rate of 2 Mt/y (H_2O/CO_2 injection ratio of 1.65), and 6.7 Mt/y for 4 Mt/y (H_2O/CO_2 injection ratio of 1.68). Similarly, brine production rates in the onshore aquifer are 3.5 Mt/y and 6.9 Mt/y for CO_2 injection rates of 2 Mt/y and 4 Mt/y, respectively (H_2O/CO_2 injection ratio of 1.75 and 1.73, respectively). The water extraction to CO_2 injection ratio is less offshore due to the greater depth. For having significant benefits to storage capacity and pressure management, brine production volumes need to be between equal to and up to 4 times higher than the volume of injected CO_2 (IEAGHG, 2012b). The offshore storage cases are summarised in Table 3-3, while the onshore storage cases are summarised in Table 3-4.

Table 3-3 Offshore injection cases for storage modelling

Case	CO_2 injection, Mt/yr	Injector number	Injector depth, m	Water extraction, Mt/yr	Extractor number	Extractor depth, m	Boundary condition
Off-2o-1	2	1	2600	-	-	-	open
Off-2c-1	2	1	2600	-	-	-	closed
Off-2c-1-1-A	2	1	2600	3.3	1	2800	closed
Off-4o-1	4	1	2600	-	-	-	open
Off-4o-2	4	2	2600/2570	-	-	-	open
Off-4c-1	4	1	2600	-	-	-	closed
Off-4c-2	4	2	2600/2570	-	-	-	closed
Off-4c-2-2-A	4	2	2600/2570	6.7	2	2800/2840	closed

Off = offshore; o = open boundary, c = closed boundary; PP = water extracted to meet max power plant demand; * = denotes the cases for which storage modelling was not carried out, but which are assessed as part of the integration of the CCS chain with extracted water utilisation and its economic evaluation

Table 3-4 Onshore injection cases for storage modelling

Case	CO_2 injection, Mt/yr	Injector number	Injector depth, m	Water extraction, Mt/yr	Extractor number	Extractor depth, m	Boundary condition
On-2o-1	2	1	1450	-	-	-	open
On-2c-1	2	1	1450	-	-	-	closed
On-2c-1-A	2	1	1450	3.5	1	1550	closed
On-4o-1	4	1	1450	-	-	-	open
On-4o-2	4	2	1450/1480	-	-	-	open
On-4c-1	4	1	1450	-	-	-	closed
On-4c-2	4	1	1450	-	-	-	closed
On-4c-2-2-A	4	2	1450/1480	6.9	2	1550/1510	closed

On = onshore; o = open boundary, c = closed boundary; PP = water extracted to meet max power plant demand; * = denotes the cases for which storage modelling was not carried out, but which are assessed as part of the integration of the CCS chain with extracted water utilisation and its economic evaluation

3.1.6 Offshore storage Netherlands

This section describes the containment of the injected CO_2 in the offshore saline aquifer as well as its storage capacity.

Plume migration and containment - offshore storage

4 Mt/y injection rate - offshore storage

The geometry of the plume of supercritical phase CO_2 at various times for the offshore injection scenario of 4 Mt/y is presented in Figure 3-6. After 10 years of injection, the plume has migrated vertically as a result of buoyancy and has begun to spread beneath the sealing unit. At this time, the plume is approximately 4,000 m in diameter at the top of the reservoir. After 25 years, 100 Mt of CO_2 has been injected. The saturation at the top of the reservoir has increased as CO_2 accumulates beneath the seal at the top of the structural enclosure. At this stage, the plume fills a large area of the structural closure.

After injection ceases, the mobile supercritical CO_2 continues to migrate towards the top of the structural closure due to the density contrast. The CO_2 follows the geometry of the top of the reservoir unit, moving slightly away from the injection well towards the peak of the structural closure. In this case, all of the injected CO_2 is contained within the main structural enclosure and no spilling has occurred.

The presence of a large region of mobile supercritical CO_2 in the structural closure means that containment in this reservoir unit is contingent on the presence of a suitable sealing caprock. Due to the limited migration of the plume, only a small amount of CO_2 is immobilised in the pore space at residual saturation. For example, after 100 years the CO_2 at 5% saturation is immobilised in the vertical section due to residual trapping.

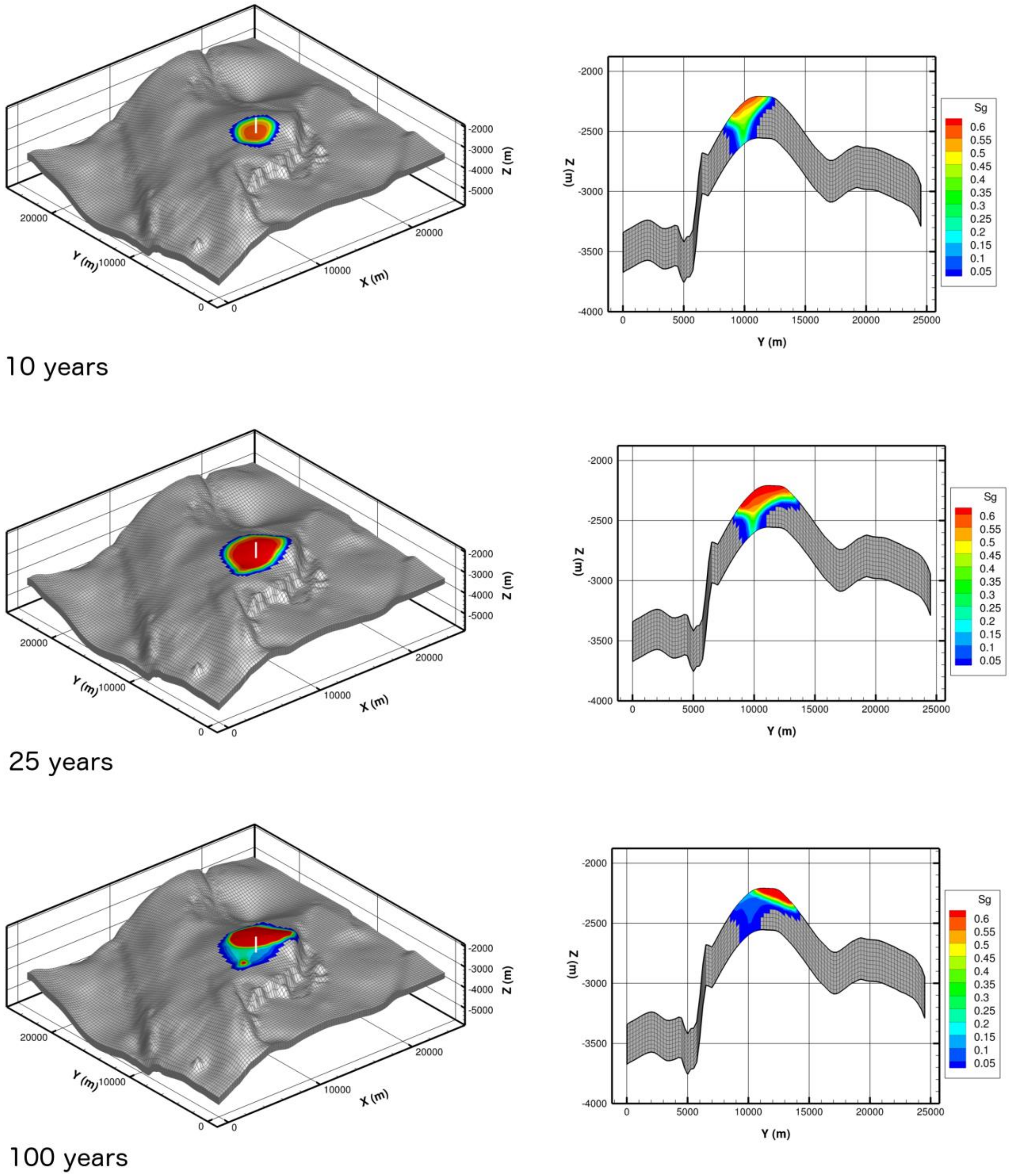


Figure 3-6 Offshore injection of 4 Mt/y CO_2 for 25 years (injection case Off-4o-1). Plume extent and vertical section through injection well shown for 10 years (top), 25 years (middle), and 100 years (bottom). Note that the vertical scale is exaggerated in the vertical sections

Adding brine production or using multiple injection wells has a barely discernible effect on the plume geometry (see Figure 3-7). In this comparison, the plume extent and location is nearly identical at the end of the injection period. This is expected, as the topology of the structural enclosure is the most important aspect when relying on this form of trapping (provided that pressure increases do not exceed the fracture gradient in the reservoir).

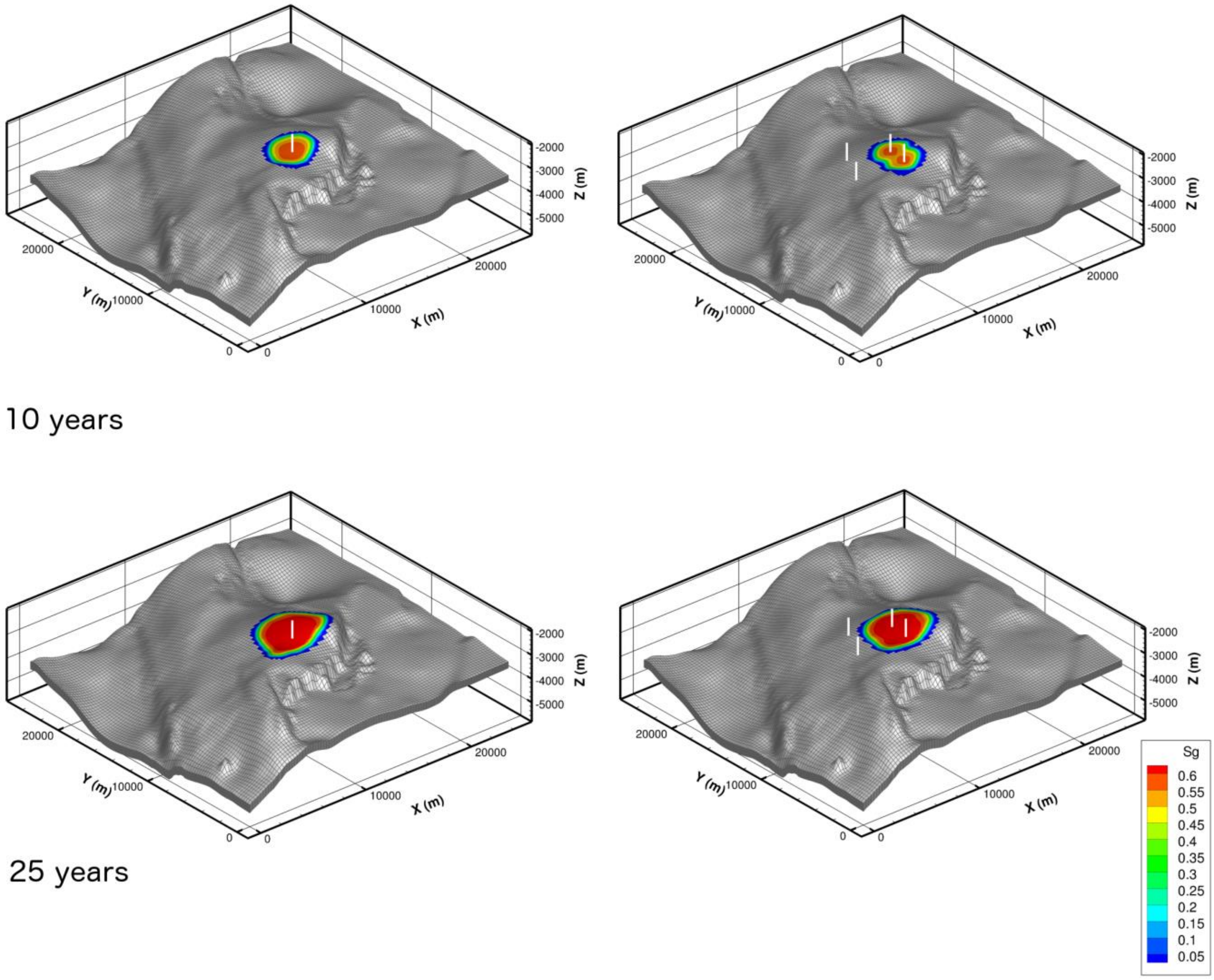


Figure 3-7 Comparison of a single injection well and no production well (injection case Off-4c-1, left), and two injection wells and two production wells (injection case Off-4c-2-2-A, right) after 10 years (top) and 25 years (bottom)

2 Mt/y injection rate - offshore storage

The CO_2 injected during the smaller injection scenario of 2 Mt/y is also effectively contained by the structural enclosure (Figure 3-8). As the amount of CO_2 injected is less in this case, it follows that the lateral extent of the plume is also smaller. All of the observations about plume migration towards the top of the structural enclosure for the higher injection rate of 4 Mt/y are also applicable to this case. In particular, there is still a significant amount of CO_2 in the mobile supercritical phase for this case as well. This demonstrates the importance of an effective sealing unit to safely contain any CO_2 injected into this reservoir unit.

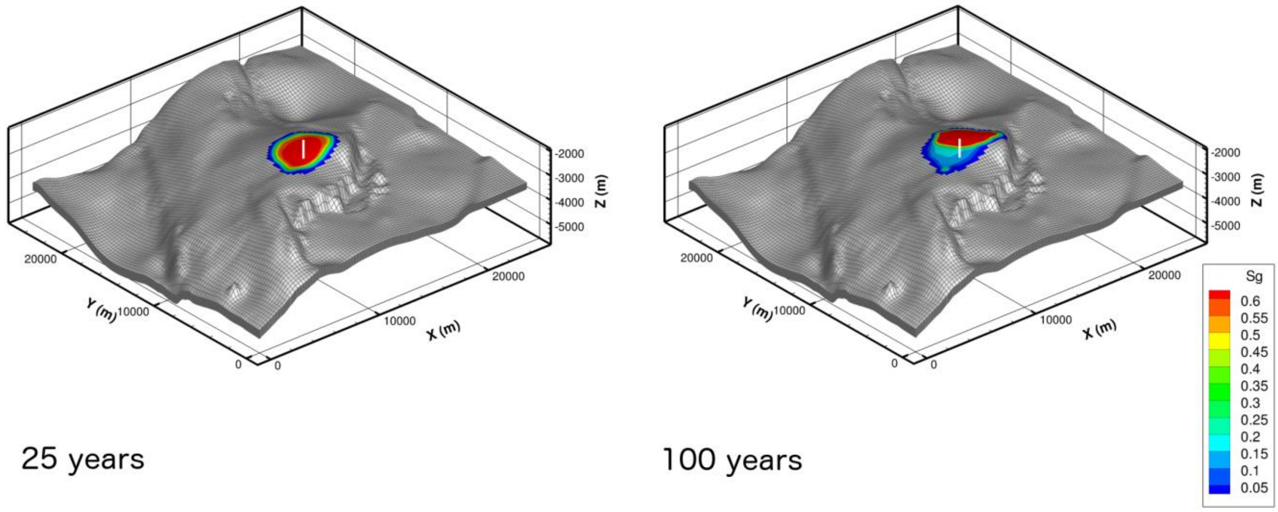


Figure 3-8 Offshore injection of 2 Mt/y for 25 years (injection case Off-2o-1). Plume extent at 25 years (left) and 100 years (right)

Dissolution trapping offshore storage

Dissolution of CO_2 into the resident brine is one of the important trapping mechanisms of geological storage of CO_2 in saline aquifers. As CO_2-saturated brine is denser than unsaturated brine, it descends into the reservoir due to gravity. As a result, all CO_2 that is dissolved in the brine is no longer in the buoyant supercritical phase, and therefore is no longer reliant on an overlying caprock for containment, reducing the possibility of the leakage into shallower formations.

The proportion of total CO_2 dissolved in the brine for the offshore model is presented in Figure 3-9 for injection rates of 4 Mt/y and 2 Mt/y for a period of 25 years. During the injection period, the proportion of CO_2 dissolved in the brine decreases with time. This can be attributed to an overestimate in the amount of dissolved CO_2 in the short term due to finite grid block size (Green and Ennis-King, 2012).

At the end of the injection period, approximately 10% of the total CO_2 injected in the 4 Mt/y case is dissolved (corresponding to 10 Mt). A slightly larger fraction of CO_2 has been dissolved in the 2 Mt/year scenario, where approximately 12% of the total amount is trapped by dissolution (which corresponds to 6 Mt dissolved).

After injection ceases, migration of the plume under buoyancy results in a larger interface between the mobile supercritical CO_2 and the unsaturated brine in the reservoir. This in turn results in increasing dissolution with time. After 100 years, nearly 16% of the total amount of CO_2 is dissolved in the 4 Mt/y injection scenario, while nearly 19% is dissolved in the 2 Mt/y scenario. These proportions correspond to approximately 16 Mt and 9.5 Mt of CO_2 dissolved in the brine, respectively.

These results indicate that there is still a substantial amount of CO_2 in the mobile supercritical phase for each injection scenario. Therefore, the presence of a suitable seal is essential for secure long-term geological storage in the offshore Q1 reservoir.

Figure 3-9 Dissolved CO_2 fraction in the offshore model with open boundary conditions over time for the 2 Mt/y injection case Off-2o-1 (orange curve) and the 4 Mt/y injection case Off-4o-1 (blue curve)

CO_2 storage capacity offshore

Injection pressure behaviour during injection offshore

It is important to maintain a pressure increase in the reservoir below some fraction of the fracture pressure gradient of the reservoir. Assuming a fracture gradient of 16 MPa/km, and maintaining a maximum pressure increase of less than 90% of the fracture pressure, the total pressure in the offshore model should be limited to 32 MPa, or an increase above hydrostatic pressure of 12 MPa.

Open boundary conditions – offshore storage

As CO_2 is injected into the offshore model, the pressure is observed to increase throughout the injection period (Figure 3-10). In this case, where the aquifer is modelled as an infinite aquifer, the pressure has increased by approximately 5 MPa for the high injection case Off-4o-1 (from 21.5 MPa to 26.5 MPa), and by 3 MPa for the low injection case Off-2o-1 (from 21.5 MPa to 24.5 MPa). These pressure rises are modest and do not pose a risk of exceeding the hydraulic fracture gradient.

The pressures presented in Figure 3-10 are calculated using finite sized grid blocks where injection is approximated by a point source in each computational cell. Using a correction to relate the reported grid block pressure to the well pressure (Peaceman, 1978), the pressure at the well can be estimated. Due to simplifications in the reservoir properties and the underlying assumptions in the scaling, the pressure at an actual well may be higher than this due to heterogeneity near the wellbore. A more accurate prediction of wellbore pressure would require a significant effort in characterising the reservoir properties near the well, as well as a highly refined computational model, both of which are beyond the scope of this study.

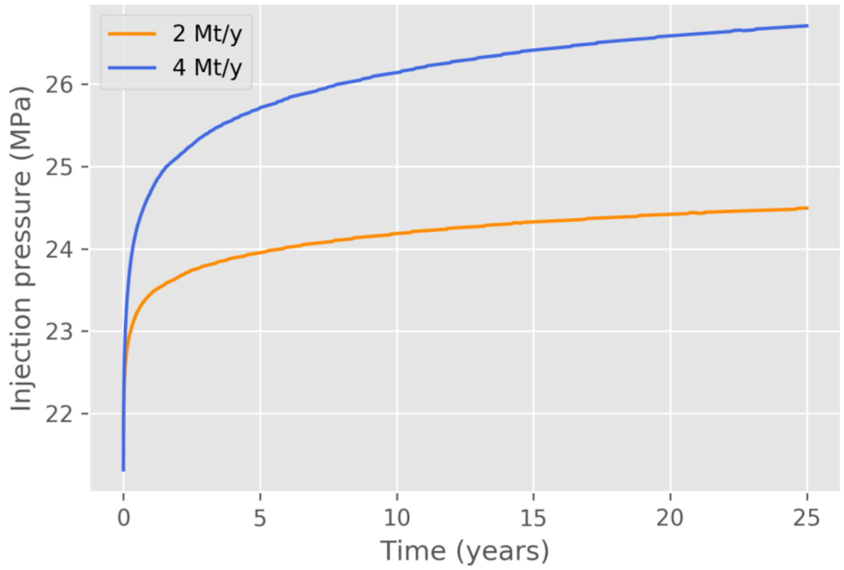


Figure 3-10 Bottomhole pressure for the offshore model with open aquifer boundary conditions for the 2 Mt/y injection case Off-2o-1 (orange curve) and the 4 Mt/y injection case Off-4o-1 (blue curve)

Closed boundary conditions with and without brine production – offshore storage

If the offshore storage site is modelled as a closed system, where the target aquifer is assumed to be hydraulically isolated from surrounding aquifers, then the pressure increases due to injection are larger than observed for the open boundary conditions presented in Figure 3-10. For an injection rate of 2 Mt/y, the pressure increases to over 28 MPa in the closed model (see Figure 3-11), compared to 24.5 MPa for the open system (Figure 3-10). This increased pressure is still less than the threshold fracture pressure, so injecting 2 Mt/y is feasible even assuming a closed aquifer. Nevertheless, the pressure increase in the closed model can be mitigated using brine production (Figure 3-11). In this case, brine production can reduce the pressure build up by at least 1 MPa for the water extraction rate of 3.3 Mt/y.

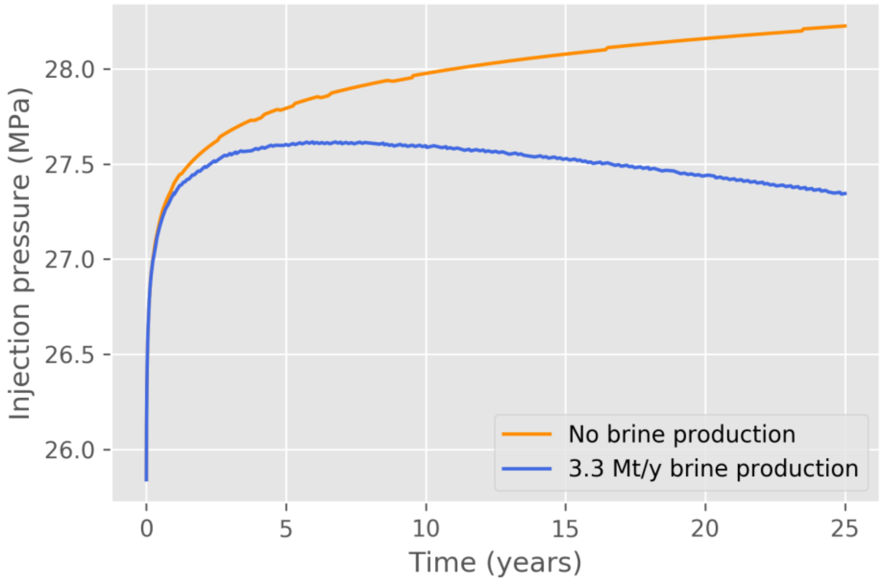


Figure 3-11 Bottomhole pressure for the offshore model with closed boundary conditions comparing injection with brine production (injection case Off-2c-1-1, blue curve) and without brine production (injection case Off-2c-1, orange curve) for an injection rate of 2 Mt/y.

If CO_2 is injected in the closed model at a rate of 4 Mt/y, the pressure rises steadily to nearly 35 MPa at the end of the injection period, exceeding the fracture gradient and therefore admitting the possibility of fault reactivation or other geomechanical damage. To limit the maximum pressure to less than 32 MPa, injection at this rate could only continue for ten years, reducing the total storage potential. Alternatively, the pressure increase could be mitigated by increasing the number of injection wells and reducing the injection rate through each well, or by producing brine from the model to reduce the pressure.

Brine production is modelled using an extraction rate of 6.7 Mt/y, corresponding to an equivalent volumetric rate. In this case, the maximum pressure in the model is reduced to 30 MPa (Figure 3-12), which is below the specified fracture threshold. This suggests that brine production could be used to enable underground storage of CO_2 in a closed aquifer at the scale required for the USCPC power plant considered in Chapter 2.

The behaviour of bottomhole pressure over time for all offshore cases modelled is presented in Appendix B.1.

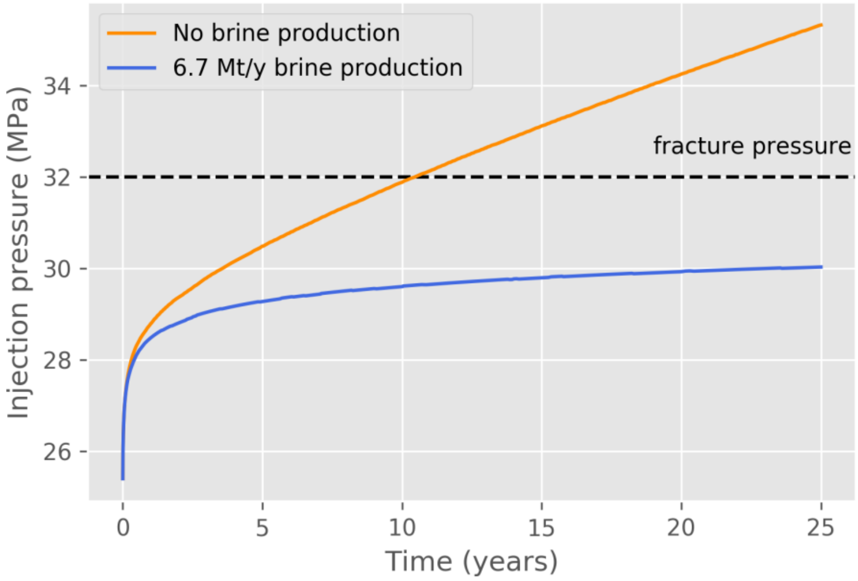


Figure 3-12 Bottomhole pressure for the offshore model with closed boundary conditions comparing injection with brine production (injection case Off-4c-2-2, blue curve) and without brine production (injection case Off-4c-2, orange curve) for a CO_2 injection rate of 4 Mt/y

Maximum storage capacity offshore

The maximum storage capacity in the offshore aquifer model with open boundary conditions is estimated to be approximately 200 Mt based on the size of the structure, its porosity and assuming a storage efficiency of 3%. Numerical simulations of continued injection out to 50 years at an injection rate of 4 Mt/y indicate that this amount of CO_2 is still contained within the structural enclosure, with little migration beyond the main structure (see Figure 3-13).

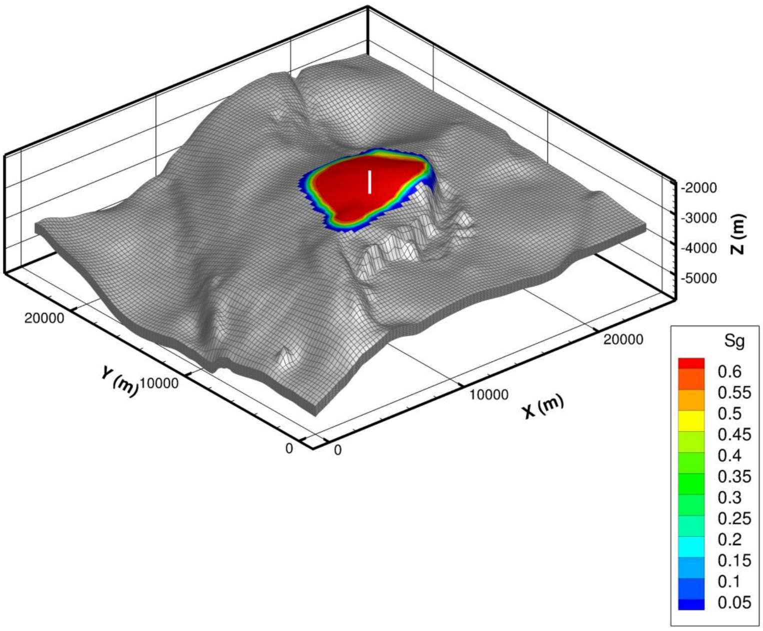


Figure 3-13 4 Mt/y injection for 50 years in the offshore model with open boundary conditions. The plume is just about to migrate away from the main structure

If the aquifer is not assumed to be hydraulically connected to the surrounding reservoir, then the injection rate becomes pressure limited, although this can be mitigated using brine production as discussed in the previous section.

The estimated maximum storage capacity for the offshore model is summarised in Table 3-5. It is important to note that these estimates are based on a simple homogeneous model of the aquifer using representative properties and should therefore be considered preliminary estimates only.

Table 3-5 Storage capacity estimates for the offshore model

Boundary conditions	Estimated capacity offshore
Open aquifer (hydraulically connected)	~200 Mt
Closed aquifer (hydraulically disconnected)	~40 Mt (at 4Mt/y)
	50+ Mt/y (at 2 Mt/y)
Closed aquifer with brine production	~200 Mt

3.1.7 Onshore storage Netherlands

This section described the containment of the injected CO_2 in the onshore saline aquifer as well as its storage capacity.

Plume migration and containment – onshore storage

4 Mt/y injection rate – onshore storage

The extent of the plume of CO_2 in the supercritical phase for the onshore injection scenario of 4 Mt/y is presented in Figure 3-14. The mobile CO_2 migrates to the top of the reservoir, where it spreads laterally to form a region of high saturation. After the injection period, a small part of the plume has migrated to fill a small structure at a shallower depth (Figure 3-14). This results in the small region of high saturation away from the main plume.

Despite this observation, overall lateral migration after the injection period is relatively small, which suggests that the bulk of the CO_2 in the supercritical phase is contained within the main structural enclosure in the vicinity of the injection well.

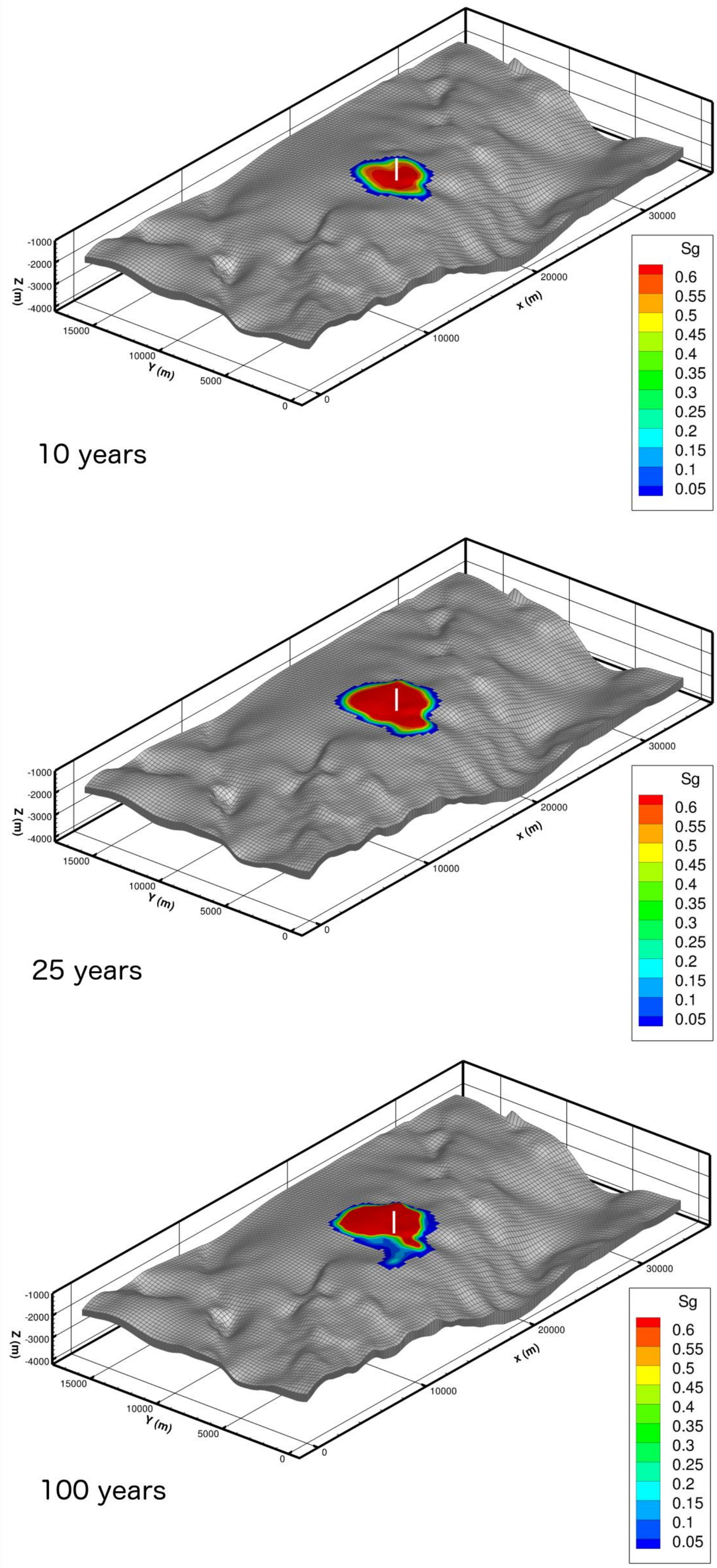


Figure 3-14 Onshore CO_2 injection of 4 Mt/y for 25 years (injection case On-4o-1). The plume extent at 10 years (top), 25 years (middle), and 100 years (bottom)

Like the offshore case, including brine production and injection of CO_2 using multiple wells has only a small effect on the plume geometry and extent, with the topology of the structural enclosure the largest influence on the plume. This can be seen in Figure 3-15, where the plume at the end of the injection period is of comparable size, location and shape for both injection scenarios depicted.

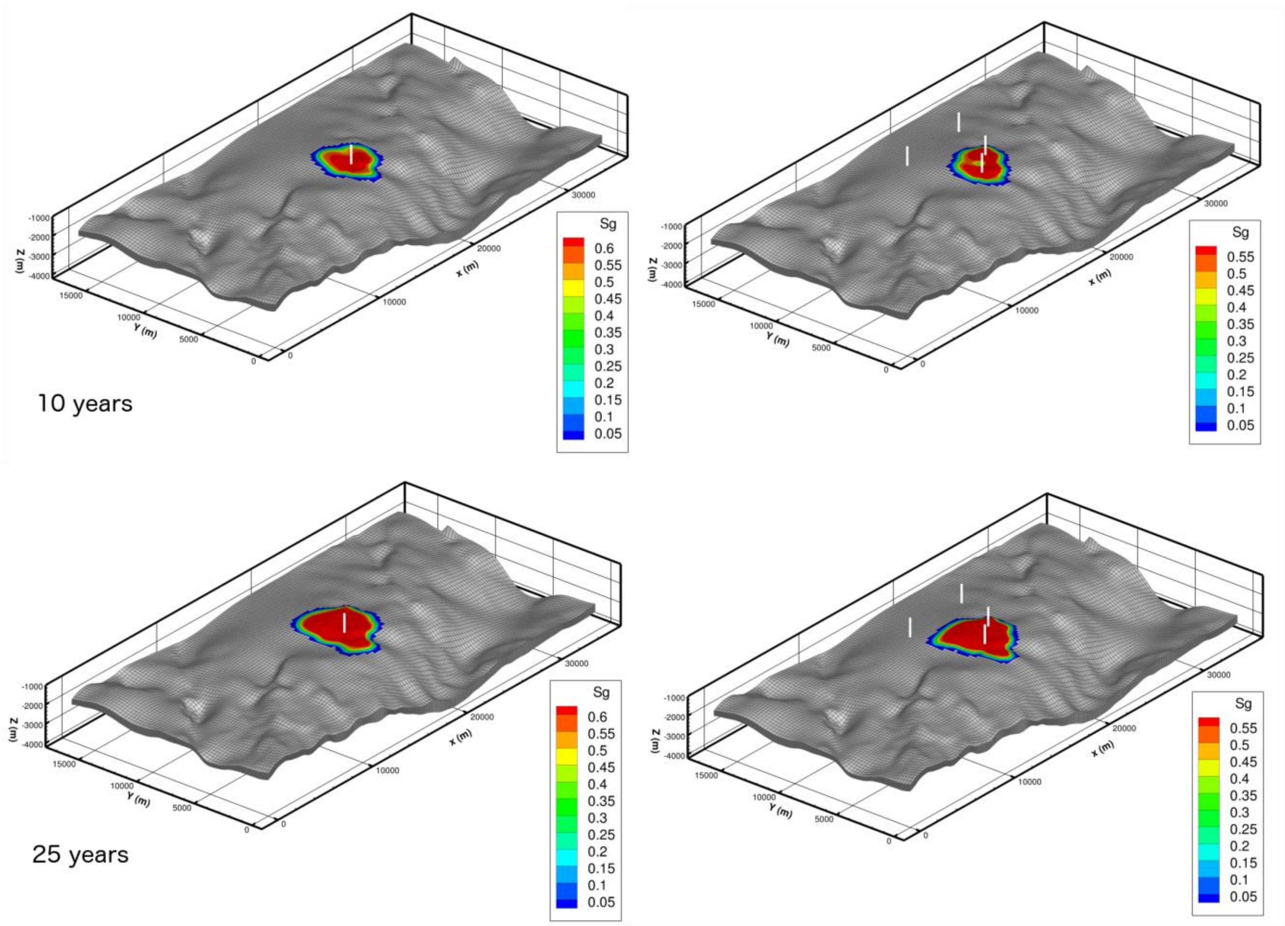


Figure 3-15 Comparison of a single injection well and no production well (injection case On-4c-1, left), and two injection wells and two production wells (injection case On-4c-2-2-A, right) onshore after 10 years (top) and 25 years (bottom)

2 Mt/y injection rate – onshore storage

A smaller plume is observed for the lower injection rate with less lateral spreading (see Figure 3-16). No significant lateral migration is observed after injection. As with the large injection scenario, a region of high saturation has formed at the top of the reservoir. As with the offshore model and the large onshore model results, this region of large supercritical phase saturation highlights the importance of an effective seal to securely contain any injected CO_2.

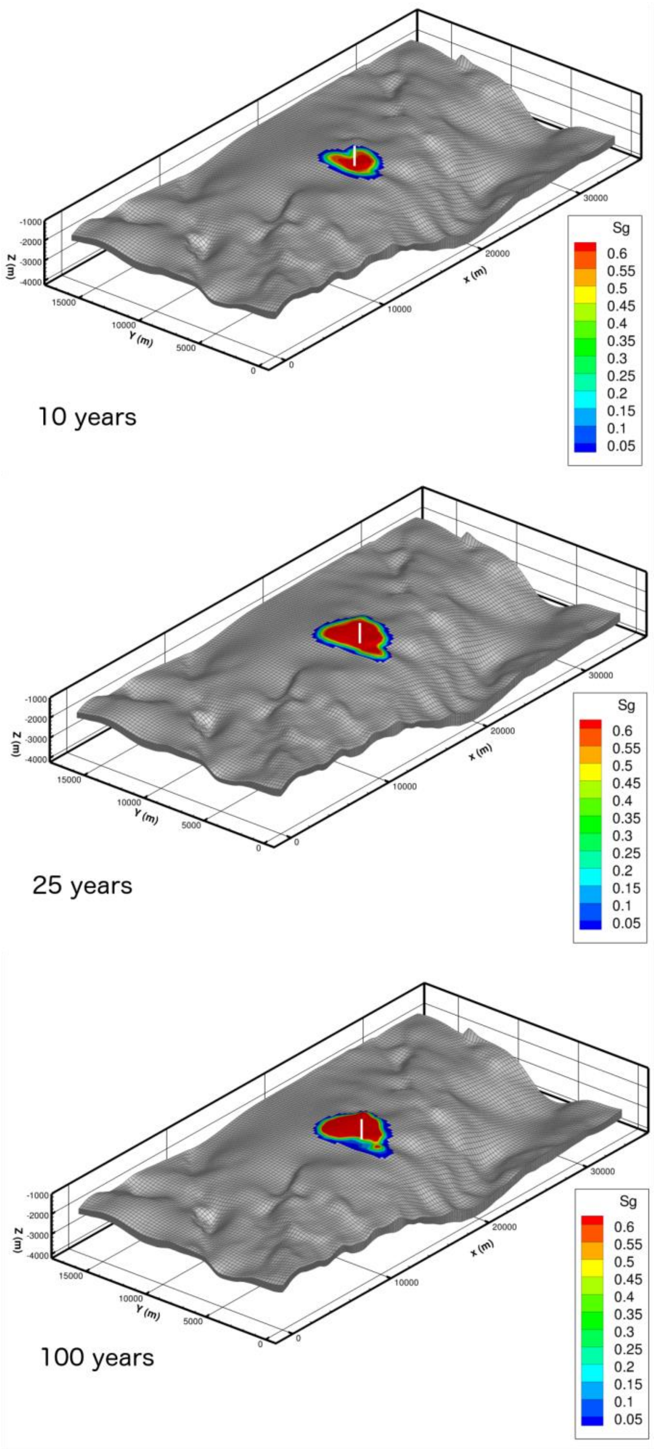


Figure 3-16 Onshore CO_2 injection of 2 Mt/y for 25 years (injection case On-2o-1). The plume extent at 10 years (top), 25 years (middle), and 100 years (bottom)

Dissolution trapping – onshore storage

Like the offshore model, the amount of CO_2 dissolved in the resident brine for the onshore injection scenarios can be quantified (Figure 3-17). Similar behaviour is observed in this model, except the total proportion of CO_2 dissolved in the onshore case is smaller than for the corresponding injection scenario in the offshore model. Several factors contribute to this, particularly the increased salinity and reduced pressure, both of which correspond to lower solubility of CO_2 in brine.

After the injection period ceases, approximately 7% of the total CO_2 is dissolved for the 4 Mt/y scenario, and approximately 9% is dissolved in the 2 Mt/y scenario. This increases post-injection due to plume migration and the larger interface between the plume of supercritical CO_2 and unsaturated brine in the reservoir. After 100 years, just over 10% of the CO_2 is dissolved for the 4 Mt/y scenario, while approximately 12% is dissolved in the 2 Mt/y scenario. These fractions correspond to 10 Mt and 6 Mt, respectively.

As for the offshore model, these results suggest that the presence of a suitable sealing unit is essential for geological storage in the onshore Rotliegend Group.

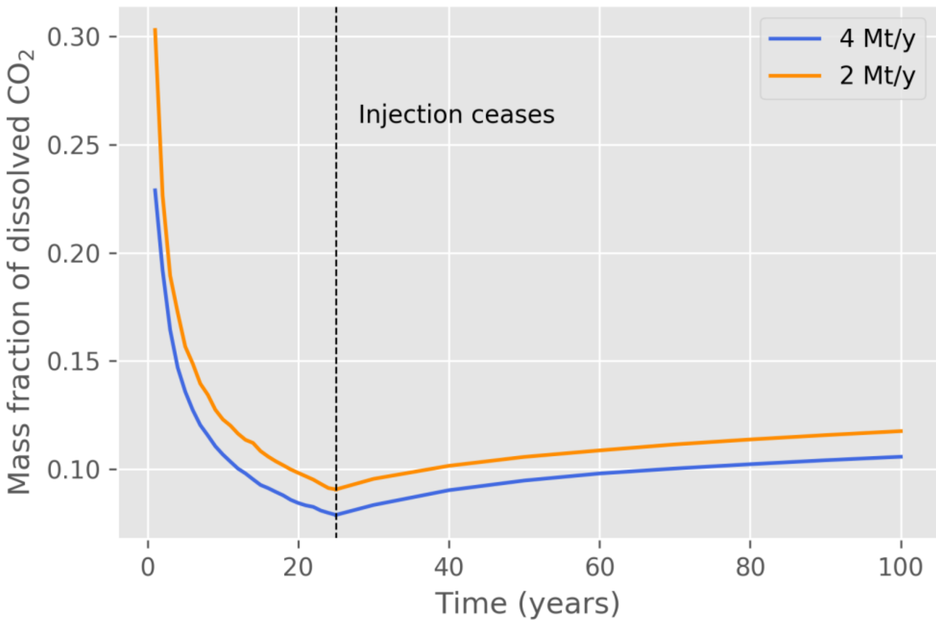


Figure 3-17: Dissolved CO_2 fraction in the onshore model over time for the 2 Mt/y injection case (On-2o-1, orange curve) and the 4 Mt/y injection case (On-4o-1, blue curve)

CO_2 storage capacity onshore

Injection pressure behaviour during onshore storage

With a fracture gradient of 16 MPa/km, and maintaining a maximum pressure increase of less than 90% of the fracture pressure, the total pressure in the onshore model should be limited to 20 MPa, or an increase above hydrostatic pressure of 5 MPa.

Open boundary conditions – onshore storage

For the onshore model with aquifer boundary conditions (assuming that the model is hydraulically connected to a larger aquifer), pressure rises are modest (see Figure 3-18). The pressure increases rapidly from the hydrostatic pressure of 15 MPa to 19.2 MPa for the high injection rate of 4 Mt/y, and to 17.6 MPa for the lower injection scenario of 2 Mt/y. However, unlike the offshore model, the pressure drops off slowly after this initial peak, and reaches a steady value after approximately 10 years. For the 4 Mt/y injection scenario, the pressure increase due to injection of CO_2 is approximately 2.25 MPa, while for the 2 Mt/y injection scenario, this pressure increase is only 1.5 MPa.

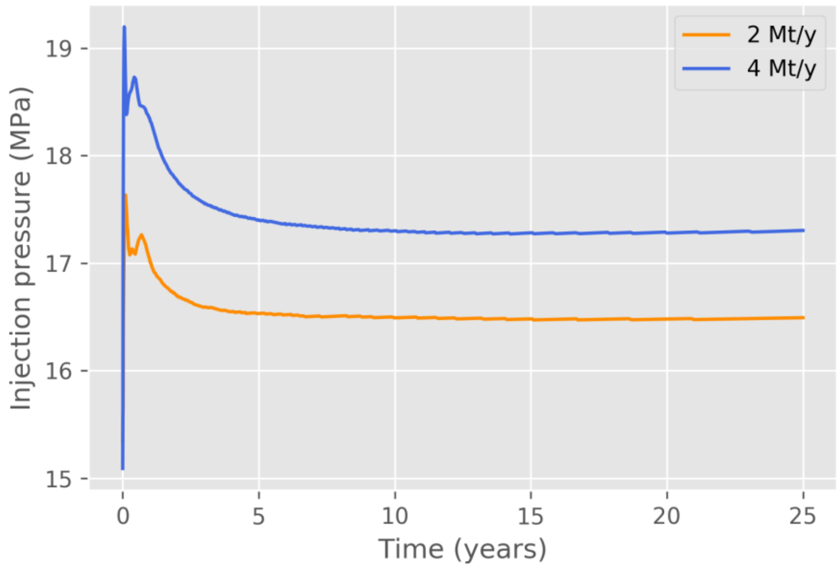


Figure 3-18 Bottomhole pressure for the onshore model with open aquifer boundary conditions for the 2 Mt/y injection case On-2o-1 (orange curve) and the 4 Mt/y injection case On-4o-1 (blue curve)

Closed boundary conditions with and without brine production – onshore storage

Modelling the onshore reservoir with closed boundary conditions, so that it is no longer connected to the surrounding aquifer, larger pressure increases at the wellbore are predicted (see Figure 3-19) for the 2 Mt/y injection scenario. In this case, the pressure increases to 17.8 MPa at the end of the injection period, in comparison to 16.5 MPa for the open aquifer (compare Figure 3-18). However, the predicted pressure increase for this injection rate is still below the maximum fracture pressure, so storage is still volume limited in this case. The pressure increase can be reduced using pressure management via brine production as shown in Figure 3-19. Brine is extracted at a rate of 3.5 Mt/y, which corresponds to a produced brine volume equivalent to the injected CO_2 volume. As a consequence, the pressure increase is reduced with the pressure at the end of the injection period being approximately 17.3 MPa.

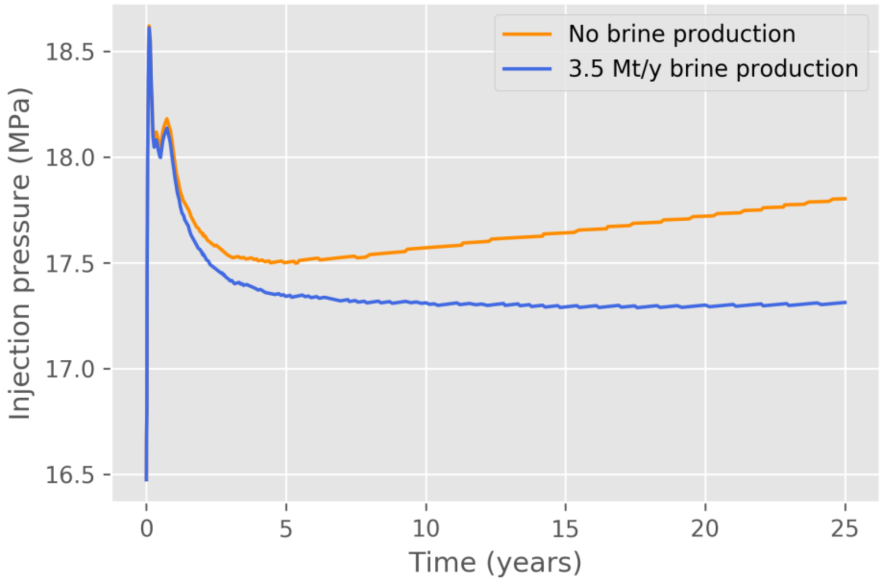


Figure 3-19 Bottomhole pressure for the onshore model with closed boundary conditions comparing injection with brine production (injection case On-2c-1-1, blue curve) and without brine production (injection case On-2c-1, orange curve) for a CO_2 injection rate of 2 Mt/y

For the larger CO_2 injection rate of 4 Mt/y, the injection pressure exceeds the imposed fracture threshold pressure after approximately 10 years (Figure 3-20), limiting the amount of storage possible in a closed aquifer with no additional pressure management. In this case, the maximum possible storage is pressure limited, and not limited by the available pore volume in the structural enclosure.

To limit the pressure increase due to CO_2 injection, brine production at a rate that is volumetrically equivalent to the injection rate at the reservoir conditions, which equates to a brine production rate of 6.9 Mt/y, limits the pressure increase in the closed onshore model. The observed pressure at the injection well is reduced to approximately 18.3 MPa, which is below the imposed fracture threshold (Figure 3-20). This demonstrates that brine production can effectively mitigate the pressure increase due to large-scale injection of CO_2 in this case, which may enable a much larger volume of CO_2 to be stored in a closed aquifer system than would otherwise be possible with no brine production. In this case, storage capacity again becomes volume-constrained rather than pressure-constrained.

The behaviour of bottomhole pressure over time for all offshore cases modelled is presented in Appendix B.2.

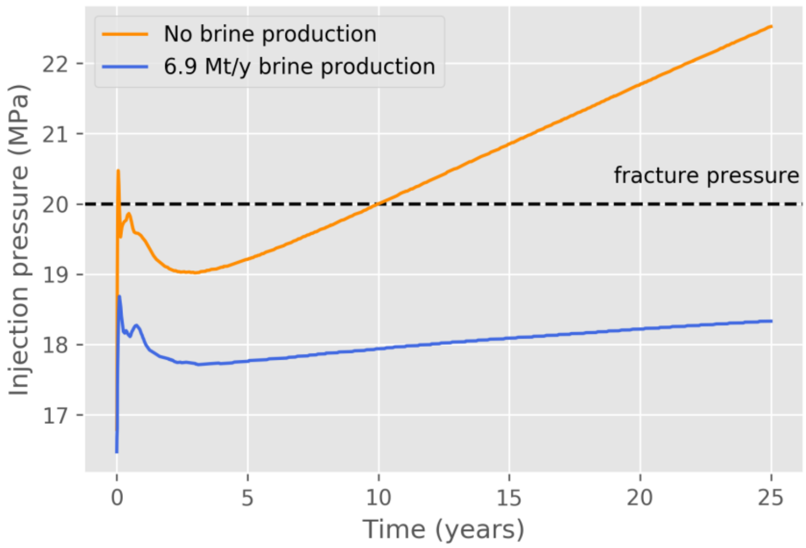


Figure 3-20 Bottomhole pressure for the onshore model with closed boundary conditions comparing injection with brine production (injection case On-4c-2, orange curve) and without brine production (injection case On-4c-2-2, blue curve) for an injection rate of 4 Mt/y

Maximum storage capacity onshore

The maximum storage capacity in the onshore aquifer model with open boundary conditions is estimated to be approximately 160 Mt based on the size of the structure, its porosity and assuming a storage efficiency of 3% (as for the offshore model). Numerical simulations of continued injection out to 50 years at an injection rate of 4 Mt/y indicate that CO_2 migrates updip and away from the main structure after approximately 45 years, when 180 Mt has been injected (Figure 3-21).

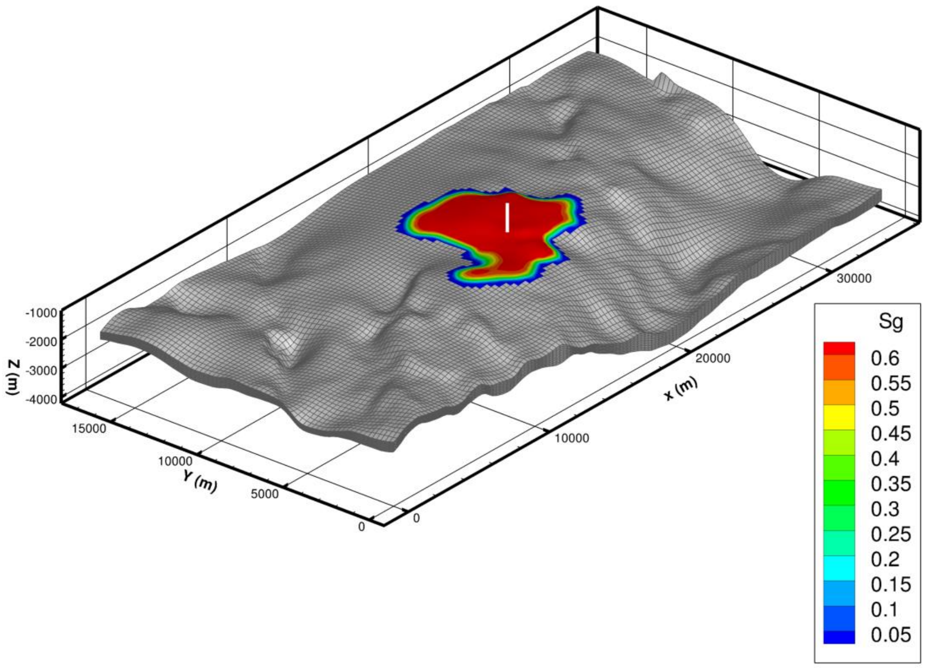


Figure 3-21 Injection of 4 Mt/y CO_2 for 40 years in the onshore model with open boundary conditions. The plume has begun to migrate away from the main structure

If the aquifer is not assumed to be hydraulically connected to the surrounding reservoir, then the injection rate becomes pressure limited, although this can be mitigated through the extraction of brine (see Figure 3-20). In this case, the maximum storage capacity becomes volume limited.

Like the offshore model, these estimates are based on a simple model of the aquifer using representative properties, and should therefore be considered preliminary estimates only.

Table 3-6: Storage capacity estimates for onshore model

Boundary conditions	Estimated capacity onshore
Open aquifer (hydraulically connected)	~160 Mt
Closed aquifer (hydraulically disconnected)	~40 Mt (at 4 Mt/y)
	50+ Mt (at 2 Mt/y)
Closed aquifer with brine production	~160 Mt

3.2 Management of extracted brine

The storage simulations highlight that for the higher CO_2 injection rate of 4 Mt/y the storage capacity of both the onshore and the offshore reservoir is pressure limited, if boundary conditions are modelled as closed. For these cases, brine extraction at the equivalent volumetric rate of 6.7 Mt/y offshore and 6.9 Mt/y onshore was demonstrated to be an effective means to maintain pressure below the fracture threshold. Several options are available to manage the produced brine, depending on its composition and the regulations in place.

Possible solutions to manage the produced brine include (e.g., Court et al., 2012b; Hosseini and Nicot, 2012):

- Reinjection of the brine into the same formation it was produced from, but at a different location. This could be combined with surface dissolution of CO_2 in brine.
- Reinjection of the brine into a different formation, if water chemistries are compatible and it is allowed under existing regulations. Possibly in conjunction with geothermal use.
- Disposal of the brine into the ocean if the salinity is below seawater and it is allowed under existing regulations. This may require treatment prior to disposal.
- Discharge at the surface, if allowed under existing regulations. This will require treatment.
- Agricultural or industrial use after desalination, if economic.
- Mineral production from highly saline brine, which may partly offset treatment and disposal costs.

The different disposal options are discussed separately for the offshore and onshore storage scenarios in the subsequent sections.

3.2.1 Disposal options for brine produced from the offshore Q1 storage reservoir

The two main disposal options in an offshore environment are ocean disposal and reinjection into subsurface formations. The Netherlands have been developing a new National Water Plan 2016-2021 with the Maritime Spatial Plan (included in the Policy Document on the North Sea 2016-2021) as an appendix. Current space utilisation in the Dutch sector of the North Sea is presented in Figure 3-22.

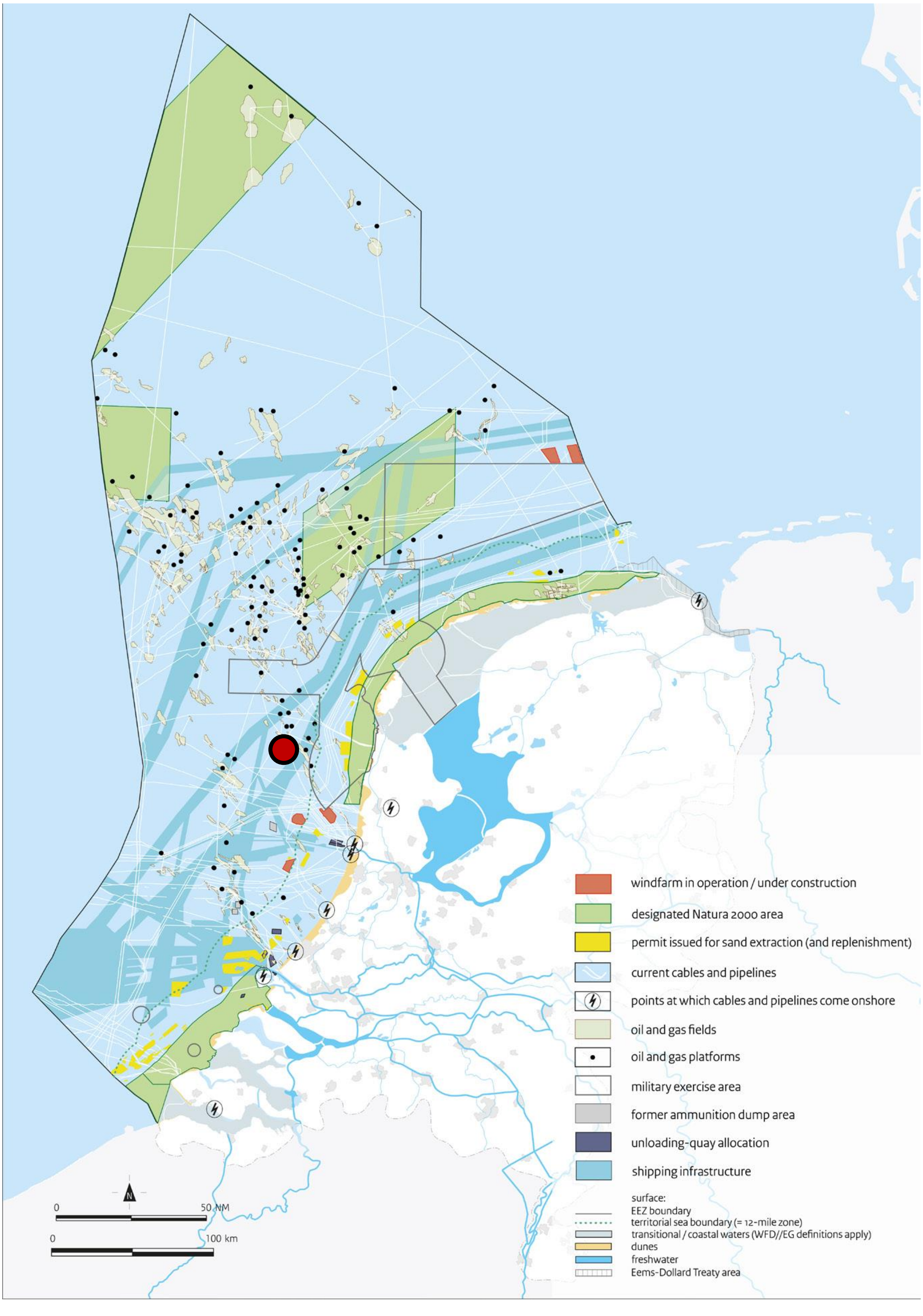


Figure 3-22 Current space utilisation in the Dutch sector of the North Sea (from the Policy Document on the North Sea 2016-2021). The location of the Q1 field is depicted by the red circle

Ocean Disposal

Historically, a large percentage of produced formation water from petroleum production in the entire North Sea has been treated and discharged into the sea. For example, in 2003, 419 Mm^3 from a total of 478 Mm^3 of produced water were discharged, with the remainder reinjected into saline formations (Garland, 2005). From a regulatory perspective, the main constraints for ocean disposal are based on the 'Convention for the protection of the marine environment of the North-East Atlantic' (OSPAR), which came into force in 1998 and has since been added to. Further restrictions may have been implemented by individual countries.

The Netherland's Policy Document on the North Sea 2016-2021 notes that measures implemented by the gas and oilfield operators in the last decades to reduce adverse effects on the environment have ensured that "at present, discharges that are the product of oil and gas projects have minimal adverse effects on the natural values of the North Sea". Hence, ocean disposal may present a viable option for brine disposal from CO_2 storage projects. However, any such project would be regulated primarily by means of permit issuance within the framework of the Mining Act and each permit may include specific operational limitations referring to water disposal.

Following the OSPAR Convention, restrictions with respect to the quality of discharged water are generally limited to:

- Hydrocarbons: generally < 30 mg/L (OSPAR Commission, 2010). Some countries, such as the UK, require a specific permit to discharge water containing oil
- Trace metals: based on the ratio of modelled predicted concentration in the environment to the predicted no-effect concentrations of those substances (PEC:PNEC). If PEC:PNEC ≤ 1 then the risk is controlled. If PEC:PNEC > 1 then this may present an unacceptable or uncontrolled risk and operators should revise their management and handling of produced waters. Examples for PNEC concentrations are shown in Table 3-7.
- Naturally occurring radioactive materials (NORM)
- Other substance emissions: associated with brine disposal from CO_2 storage projects, such as sewage, general waste and any other substance not already mentioned above associated with shipping, pipelines or CO_2 processing. These emissions should be regulated through the permitting under the Mining Act or CO_2 storage amendments

It should be noted that formation water salinity has not been identified as limiting parameter in any national regulation or international convention.

Table 3-7 Predicted no effect concentrations (μg/L) from OSPAR Guidelines in support of Recommendation 2012/5

Metal	PNEC Concentration (μg/L)
Arsenic	TBD
Nickel	8.60
Cadmium	0.21 + background concentration (Cb)
Chromium	0.60 + Cb
Copper	2.60
Mercury	0.047 + Cb
Lead	1.30
Zinc	3.00 + Cb

Reinjection of brine

A viable option to dispose of the extracted water from the offshore storage formation would be reinjection of the extracted brine into depleting oil and gas fields. At the Q1 block, water has been extracted from the saline formation particularly for this purpose as the oil fields in the Q1 block are close to the end of their life and require pressure maintenance (Neele et al., 2011b). This activity has a number of benefits: i.) the pressure in the saline formation is now well below the initial hydrostatic pressure, providing increased storage capacity for the CO_2 in the reservoir (Neele et al., 2011b); ii.) the beneficial reuse of the extracted formation water; and iii.) (some of) the required infrastructure is already in place.

According to the NLOG database, 8.36 Mt of water were injected into offshore fields in 2017 (Table 3-8). The 5.5 Mt injected annually in the Q1 Helder field is of a similar order of magnitude as required for the brine disposal at the Q1 CO_2 storage site (6.7 Mt/y brine).

Table 3-8 Water injection into oil and gas fields in the offshore area of the Netherlands in 2017. Data summarised from www.nlog.nl/

Field	# of injection wells	Annual water injection (m^3)
F02a-Hanze	1	1,886,307
Q1 Helder	1	5,544,378
K08-FA	1	27,014
K09c-A	1	829
K14-FA	1	18,766
K15-FA	1	7,956
K15-FB	1	5,102
P15 Rijn	5	224,761
Q13a-Amstel	1	645,762
Total		**8,360,875**

Due to the hydrogeological conditions in the North Sea, it is deemed unlikely by OSPAR that the leakage of offshore injected drill or production waters would impact on potable aquifers onshore. However, OSPAR recommendations (OSPAR Commission 2001: The environmental aspect of on and off-site injection of drill cuttings and produced water) for the assessment of a specific injection project include:

- Modelling of the situation to obtain an understanding of the main features which will affect the fracture growth and the associated characteristics, and making predictions of injection characteristics for subsequent monitoring and comparison.
- Monitoring the injection parameters (rates and pressures) and comparing with predictions. When deviations are observed operations would need to cease, at least until it was firmly established that the deviation did not indicate undue vertical propagation of the fracture.
- During disposal operations the annulus pressures of nearby wells should be monitored to check for possible fracture intersection with the well. Pressure increase from swelling of reactive clays should also be modelled and monitored.
- A review of the long term considerations should be made so that the risk to potential potable water sources would be established prior to any initiation of the disposal fracturing operations.
- Alternative disposal options for use on a contingency basis should be prepared.

3.2.2 Disposal options for brine produced from the onshore storage reservoir

For the onshore storage scenario, the most suitable option for onshore brine disposal appears to be underground storage. Due to the large volumes and the high salinity (150,000 mg/L) costs for desalination of the water for either discharge into surface water bodies or reuse elsewhere are expected to be very high. The reinjection of water as a by-product from oil or gas production has been implemented at various locations in the Netherlands (see Table 3-9 and Figure 3-23). The maximum annual injection volume in 2017 was approximately 1 Mt/y at Rossum-Weerselo using four injectors. This is considerably less than the required disposal of 6.9 Mt/y brine produced during the 4 Mt/y onshore CO_2 storage project. Taking the water disposal at Rossum-Weerselo as an analogue for brine disposal at the onshore CO_2 project, up to 28 injection wells would be required. This number is just an estimate and more geological assessment is needed to confirm sufficient storage capacity and injectivity at the site.

Induced seismicity as a result of water injection has been identified as a possible risk at the Schoonebeek and Twente fields (NAM, 2015a, 2015b, 2016). However, these sites conduct water flooding for enhanced oil recovery and the majority of the injected water is produced back with the oil.

A permit needs to be obtained to undertake water reinjection, which also requires the operator to report injection volumes and water quality on a monthly basis. Most of the existing operations also inject various proportions of hydrocarbons and other components from petroleum processing that need to be reported.

Alternatively, produced water at the onshore CO_2 storage operation could be pipelined offshore for reinjection into offshore reservoirs or ocean disposal.

Table 3-9 Water injection in oil and gas fields in the onshore area of the Netherlands in 2017. Asterix denote fields that are not currently under production. Data summarised from www.nlog.nl/

Field	# of injection wells	Annual water injection (m^3)
Ameland-Oost*	1	11,765
Bergermeer*	1	4,698
Groningen	1	504,834
Nijensleek*	1	1,398
Pernis-West	1	68,182
Rossum-Weerselo*	4	976,711
Rotterdam	4	437,622
Schoonebeek Gas	2	79,619
Schoonebeek Olie	25	906,603
Slootdorp	1	3,119
Starnmeer*	1	19,030
Total		**3,013,581**

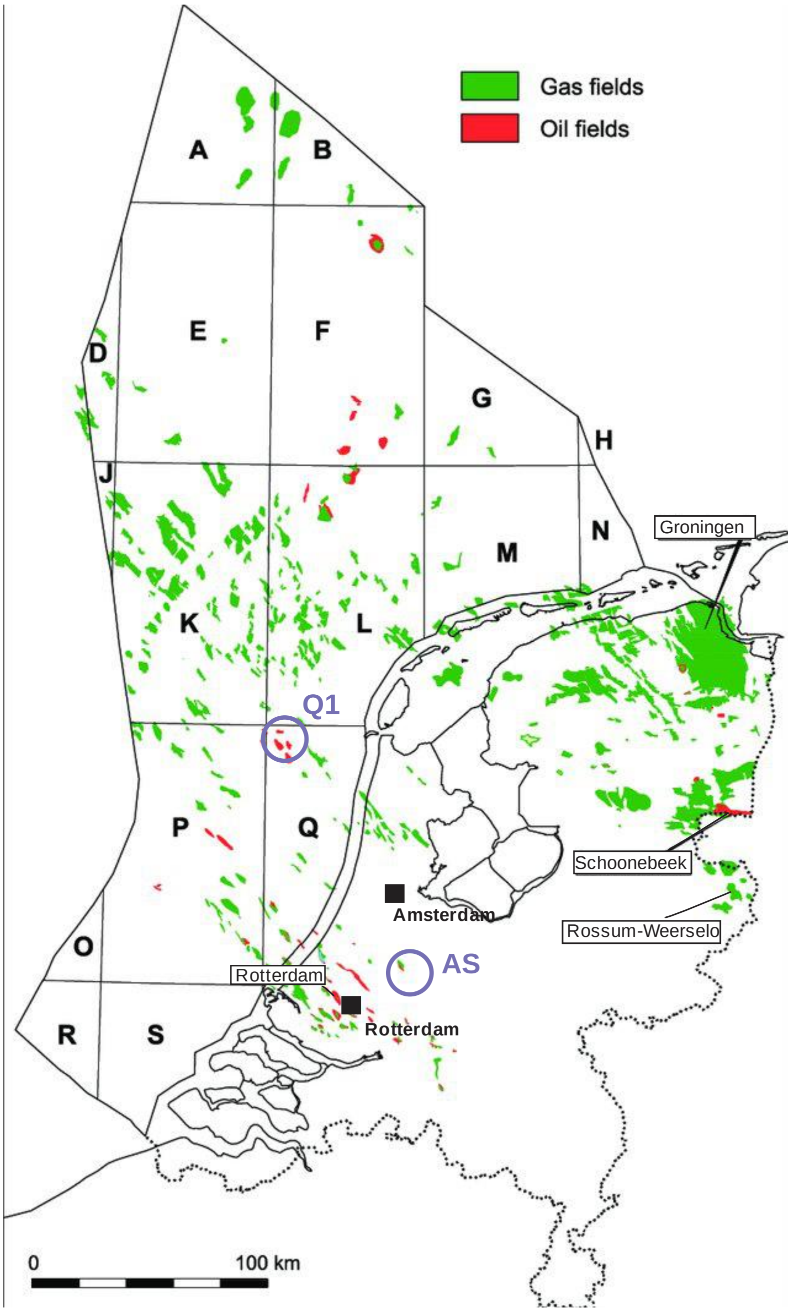


Figure 3-23 Location of oil and gas fields in the Netherlands. The four fields with the largest water injection onshore are labelled (see Table 3-9). The two potential CO_2 storage sites are identified by purple circles

3.2.3 Treatment and reuse of extracted brine

Where water disposal through reinjection is not possible, for example due to a lack of suitable formations for disposal or considerable transport distances or regulations, water treatment for reuse may present a viable alternative (Kaplan et al., 2017). As indicated above, this may be the case in the onshore scenario where the storage capacity for water is limited in comparison to offshore. Furthermore, in regions where water is scarce, water produced for the purpose of CO_2 storage may present an additional source of useable water after potential treatment.

Water reuse

Many reuse and recycling options for extracted and treated water may be considered. Potential beneficial uses include industrial cooling water or process feedwater, a variety of agricultural uses, and a source of potable water. The water quality required for each beneficial use and the associated permitting requirements vary greatly (Klapperich et al., 2014a). For example, for agricultural purposes, drinking water, and industrial processes the water cannot be too saline. To be used as cooling water, it cannot be too warm. Furthermore, water pollution is inacceptable (Rijkswaterstaat, 2011).

In the Netherlands a significant amount of water is stored in Lake Ijsselmeer to be used for production of drinking water, irrigation and others. Water can also be supplied to canals to ensure that sufficient water is available for shipping, to fight saline intrusion of groundwater and keep seawater at bay (Rijkswaterstaat, 2011), and to ensure the stability of dikes, engineering structures and foundations which can be affected by lowering water levels (Rijkswaterstaat, 2011).

Salinisation is a problem in the Netherlands, where deep groundwater is brackish to salty in most parts. Particularly in the northern and western parts of the Netherlands salinisation is occurring. Salt can move inland via surface water (external salisination) or work its way up through soil in groundwater (internal salisination) (Rijkswaterstaat, 2011). As a consequence of increased freshwater demand and climate change, salinisation is expected to become worse: seepage water pressure is forecasted to increase and seepage water rising from the ground will become more saline. The combination of sea level rise and lower river discharges in summer will lead to increased salinisation. Only few locations are predicted to experience a decline in salt concentration (Rijkswaterstaat, 2011).

To combat internal salinisation freshwater is pumped into polders to provide counter pressure to saline seepage water and to flush the watercourse so that water in regional systems is maintained at a certain chloride concentration (Rijkswaterstaat, 2011). However, this requires sufficient levels of good quality water in the main water system to supply to the regional systems, which is forecast to decrease as the need increases. Water demands on a whole are also expected to increase as a result of more shipping activity, water recreation, and use of electricity (Rijkswaterstaat, 2011).

Salisination affects the agricultural industry due to reduced availability of freshwater, the drinking water industry which may require desalination of high chloride content water, and energy companies and other industries who used construction materials selected for freshwater intake (Rijkswaterstaat, 2011).

The Dutch standard for chloride content in drinking water is 150 mg/l, while the European standard is 250 mg/l, and the standard of the World Health Organisation is 300 mg/l. The standard applied by industry for process water is also 150 mg/l, while the cooling water standard depends on the materials used in the construction of the cooling installations. This means seawater can be used for cooling if installations are purpose built (Rijkswaterstaat, 2011).

There are no clear standards for irrigation water in the Netherlands. The chloride standard depends on the crops being grown with different standards being applied for growing fruit and potatoes. The Cultural Technical Handbook from 1988 defines a standard of 300 mg/l for fruit cultivation and 600 mg/l for potatoes. Regional differences in perception also play a role in what constitutes an acceptable level of chlorine: for example, farmers in the western part of the country apply a stricter standard on what constitutes acceptable chloride levels for irrigation (Rijkswaterstaat, 2011).

The appropriate water treatment to achieve the desired water quality depends on the original composition of the water and its intended purpose.

Water treatment

The high salinity of the extracted formation water onshore (150,000 mg/L) and offshore (100,000 mg/L) presents a challenge for current treatment technologies, which are mainly designed to treat seawater (~35,000 mg/L) and brackish water (TDS < 10,000 mg/L). As the composition of the onshore and offshore formation waters is predominantly sodium and chloride by mass, its saturation would be the upper limit on the water recovery. The high TDS content in the formation waters poses specific desalination challenges, mostly related to high energy consumption and operational problems produced by scaling, fouling, and corrosion (Kaplan et al. 2017). Other parameters such as dissolved silica, organic compounds, dissolved gases, pH and temperature would also have an effect on the degree of supersaturation that may be achieved and the amount of water recovered (Thiel and Lienhard, 2014).

Technologies that may be considered for treatment of the onshore and the offshore brines are thermal technologies such as multistage flash distillation (MSF), multi-effect distillation (MED), single- or multi-effect evaporators (MEE) coupled with mechanical or thermal vapour compression (MVC/TVC), mechanical or thermal evaporative crystallisers, and cooling crystallisers. MED, MSF and MVC have become the preferred method in handling hypersaline formation waters due to their high level of reliability and resistance against scale formation (Thiel et al., 2015; Tong and Elimelech, 2016; Onishi et al., 2017; Vane, 2017; Onishi et al. 2018).

Emerging membrane technologies such as membrane distillation (MD) and forward osmosis (FO) are also being studied for handling hypersaline brines (Mickley, 2008; McGinnis et al., 2012; Miner-Matar et al., 2016; Tong and Elimelech, 2016, Salcedo-Diaz et al., 2017; Silva et al., 2017), though these technologies are still in the developmental pilot scale.

It should be noted that, in general, the higher the feedwater salt concentration, the smaller the fraction of product water that can be recovered. Depending on the feedwater concentration, product water recovery from hypersaline solution through thermal treatment can range between 10 - 50%. Feed waters with salt concentrations of 250,000 - 300,000 mg/L are not likely to be treatable to recover substantial volumes of product water (the upper limit of NaCl solubility is approximately 370,000 mg/L at 60°C) with the technologies currently available (Aines et al., 2011, Shaffer et al., 2013).

The technology identified to treat the highly saline brines of 150,000 and 100,000 mg/L from the onshore and the offshore storage reservoirs, respectively is MVC. MVC has been selected out of the thermal processes as it has been reported to be more competitive compared to MED and MSF with respect to energy requirements and costs and less prone to scale formation as it can be operated at lower temperatures (Khawaji et al., 2008; Alasfour and Abdulrahim, 2011; Shaffer et al., 2013; Chen et al., 2016; Jimenez et al., 2018). Indicative costs for these technologies were presented in Table 1-11 (Chapter 1.3.4). The MVC system comprises of major equipment such as preheater (plate type heat exchanger), evaporator/condenser, vapour compressor, water circulation pumps and venting units. The evaporator/condenser generally contains horizontal heat exchanger tubes, spray nozzles, vapour suction tubes, and a mesh type mist eliminator. The saline formation water is preheated in the heat exchanger. The feed from the preheater is then sprayed over horizontal evaporator tube bundles in the evaporator/condenser unit, forming a falling film over the tube rows, where it evaporates partially to produce vapour. The remaining unevaporated feed containing the salts and other minerals leaves as brine and preheats the saline feed water in the preheater. The vapour formed in the evaporator/condenser unit is transferred to the compressor (mechanical/electrical energy for MVC, steam to drive compressor for thermal vapour compression [TVC]) after passing through the wire-mesh mist eliminator. This is to avoid entrainment of the brine droplets in the vapour stream which would result in damage to the compressor blades. The vapour is compressed to a higher pressure and temperature and fed back into the evaporator/condenser where it condenses inside the tubes. The heat required to evaporate the feed solution which flows on the evaporator tubes is supplied through simultaneous condensation of the vapour distillate inside the tubes (thereby supplying the latent heat required for the evaporation process). That is, the latent heat is exchanged in the evaporation-condensation process within the system. The condensed distillate is recovered as product water with low TDS. Most of the energy consumption in the MVC is in the electrical work required to drive the compressor and with a small portion required for the circulation pumps. A schematic diagram of a typical MVC unit is shown in Figure 3-24.

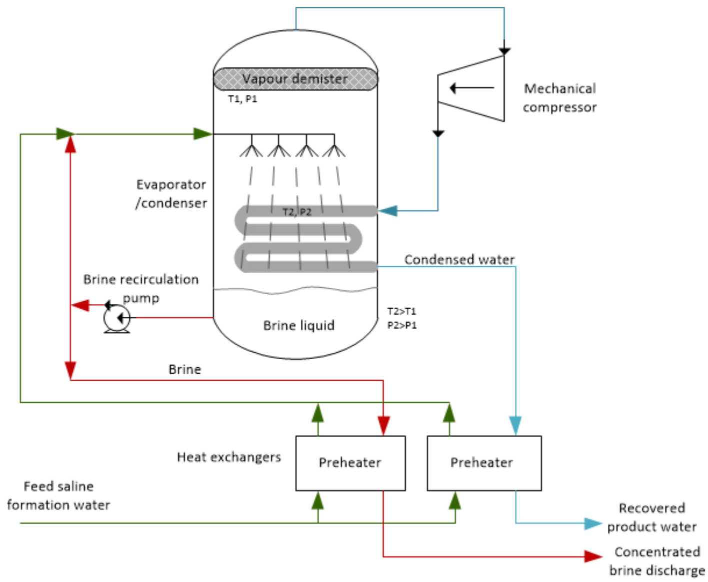


Figure 3-24 Schematic of mechanical vapour compression process for desalination of saline formation water

Applying this technology, a product water recovery of 50% can be expected for the lower brine concentration of 100,000 mg/L offshore and 25% for the higher brine concentration of 150,000 mg/L onshore. The quantities of water recovered from the storage operations with water extraction are summarised in Table 3-10. The product water is of sufficient quality to be used in industrial processes, such as in the NGCC or the USCPC where it can substitute the consumption of fresh water.

Table 3-10 Product water recovered from storage-extracted brine for the offshore and onshore storage scenario

Location	Salinity, mg/l	CO_2 injection rate, Mt/y	Brine extraction rate, Mt/y	Product recovery rate, %	Product water, Mt/y
Offshore	100,000	2	3.3	50	1.65
		4	6.7	50	3.35
Onshore	150,000	2	3.5	25	0.88
		4	6.9	25	1.73

3.2.4 Recommendations for extracted brine management

For the offshore Q1 storage operation, disposal of produced brine in the order of ~7 Mt/y appears to be technically feasible, both in the form of discharge into the sea as well as reinjection into subsurface formations. From a regulatory point of view, it appears that countries are moving towards zero-impact emissions into the North Sea. While salinity has so far not been identified as a constraint for ocean disposal and produced brine for CO_2 storage would most likely contain significantly less contaminants related to petroleum processing and production, the Dutch regulator in the future may still require limited discharge to the North Sea and consider water reinjection as the preferred option.

In the onshore area, water disposal options are most likely limited to water reinjection. Water re-injection from oil and gas operations is currently common practice, however, existing onshore operations do not inject in excess of 1 Mt/y. Also, induced seismicity in response to water injection has been identified as an issue. Adequate storage capacity and injectivity for the reinjection of up to ~7 Mt/y would require additional geological and geomechanical assessments. Alternatively, produced water at the onshore CO_2 storage operation could be pipelined offshore for reinjection into offshore reservoirs or ocean disposal.

Water treatment may present a viable alternative where disposal of large volumes is either not feasible or not practical due to high costs. However, for the highly saline formation waters of the offshore and onshore storage sites, energy intensive thermal processes have to be applied for desalination and product recovery is limited: 25% for the 150,000 mg/L brine and 50% for the 100,000 mg/L brine. The recovered water may be used as process feedwater, for agricultural uses, or as a source of potable water. It can thus provide some relief from the expected increasing pressures from salinisation in the Netherlands which is affecting freshwater availability.

In the subsequent section, both disposal of the extracted water and the reuse of the extracted water in the power plants described in Chapter 2 will be considered.

4 Integration of CO_2 capture, storage and brine management

In this chapter the power plants described in Chapter 2, and CO_2 storage and brine management, as described in Chapter 3, are integrated to present the complete CCS chain. Two CCS scenarios with several sub-cases are considered: Base Case CCS Scenario and CCS-Water-Nexus Scenario.

The Base Case CCS Scenario represents the standard CCS chain of capture, transport and storage, but also considers the extraction of formation water and its disposal to increase the CO_2 storage capacity of a closed formation.

In the CCS-Water-Nexus Scenario the Base Case CCS Scenario is expanded upon to include treatment of the extracted water as a brine management strategy and its reuse in the power plant to form a CCS loop. Two water extraction scenarios are investigated:

A. water extraction rate volumetrically equivalent to the amount of CO_2 injected.
B. water extraction rate after water treatment matched to the freshwater demand of the power plant with capture.

In the second scenario (scenario b) water beyond what is needed for safe CO_2 storage is extracted to meet the freshwater demand of the power station with capture. This is a hypothetical scenario that will be assessed without reservoir simulation studies.

The subsequent sections state the assumptions about the two scenarios.

4.1 Scenario assumptions

4.1.1 Power plants

The power plants and capture systems considered in this assessment are those described in Chapter 2: the ultra-supercritical coal fired power plant and the natural gas fired combined cycle power plant power plant with evaporative cooling, once-through cooling, and air cooling. An overview of each power plant (with and without capture) investigated and the cooling system it utilises is presented in Table 4-1 for the USCPC (Case 1) and Table 4-2 for the NGCC (Case 2). The USCPC has a gross output of 900 MW_e, while the NGCC has a gross output of 890 MW_e. CO_2 is captured at a rate of 90%, corresponding to ~4 Mt/y from the USCPC and ~2 Mt/y from the NGCC. The power plants and the capture plants are assumed to be newly built.

With respect to water consumption, the power plants using evaporative cooling technologies are the only ones using considerable quantities of freshwater (compare Table 4-1 and Table

4-2). The freshwater consumption of the NGCC with capture using evaporative cooling systems (NGCC-EV-PCC) is 4.24 Mt/y, while the equivalent USCPC with capture (USCPC-EV-PCC) has a consumption of 7.75 Mt/y. Freshwater consumption in the USCPC using air cooling and seawater once-through cooling technologies is comparatively low at 0.4 Mt/y, while in the NGCC using once-through cooling and air cooling it is even lower at 0.00094 Mt/y. Though the power plants using once-through cooling use considerable water volumes, the water used is seawater rather than freshwater. The consumed seawater volumes are too large to consider replacing the seawater with extracted treated water a feasible option. It may be argued that if seawater was not readily available a different cooling technology would be applied, such as evaporative cooling or air cooling.-Due to the above, power plants using evaporative cooling systems present the main focus of this integration work.

Table 4-1 Ultra-supercritical coal fired (USCPC) power plant with and without capture using different cooling systems: evaporative cooling (recirculating system), seawater once-through cooling, and air cooling

Case#	Case Name	Description	Freshwater consumption
1.1A	USCPC-EV	USCPC boiler reference case based on standard supercritical steam conditions for a nominal 900MWe gross output power plant without CCS. Evaporative (EV) mechanical draft cooling tower (recirculating system) is used for the power plant	6.19 Mt/y
1.1B	USCPC-EV-PCC	USCPC boiler for a nominal 900MWe gross output power plant with CCS. Evaporative (EV) mechanical draft cooling is used for both the power plant and post-combustion capture (PCC) plant	7.75 Mt/y
1.1C	USCPC-EV-PCC-AC	Evaporative mechanical draft cooling tower for the power plant, air cooling for the PCC plant	4.88 Mt/y
1.2A	USCPC-OT	Once-through seawater cooling is used for the power plant without CCS	0.4 Mt/y
1.2B	USCPC-OT-PCC	Once-through seawater cooling is used for both the power plant and the PCC plant	0.4 Mt/y
1.2C	USCPC-OT-PCC-AC	Once-through seawater cooling tower for the power plant, air cooling for the PCC plant	0.4 Mt/y
1.3A	USCPC- AC	Air cooling utilised for the power plant without CCS	0.4 Mt/y
1.3B	USCPC-AC-PCC	Air cooling is utilised for both the power plant and PCC plant	0.4 Mt/y

Table 4-2 Natural gas fired combined cycle (NGCC) power plant with and without capture using different cooling systems: evaporative cooling (recirculating system), seawater once-through cooling, and air cooling

Case#	Case Name	Description	Freshwater consumption
2.1A	NGCC-EV	NGCC reference case for a nominal 900MWe gross output power plant without CCS. Evaporative (EV) mechanical draft cooling tower (recirculating system) is used for the power plant	2.76 Mt/y
2.1B	NGCC-EV-PCC	Evaporative (EV) mechanical draft cooling is used for both the power plant and PCC plant	4.24 Mt/y
2.1C	NGCC-EV-PCC-AC	Evaporative mechanical draft cooling tower for the power plant, air cooling for the PCC plant	1.8 Mt/y
2.2A	NGCC-OT	Once-through seawater cooling is used for the power plant without CCS	0.001 Mt/y
2.2B	NGCC-OT-PCC	Once-through seawater cooling is used for both the power plant and the PCC plant	0.001 Mt/y
2.2C	NGCC-OT-PCC-AC	Once-through seawater cooling tower for the power plant, air cooling for the PCC plant	0.001 Mt/y
2.3A	NGCC-AC	Air cooling utilised for the power plant without CCS	0.001 Mt/y
2.3B	NGCC-AC-PCC	Air cooling is utilised for both the power plant and PCC plant	0.001 Mt/y

4.1.2 CO_2 storage and water extraction

CO_2 captured from the NGCC or USCPC power plant may be stored onshore or offshore Netherlands. For the onshore storage scenario, CO_2 injection into a saline formation of the onshore Rotliegend Group approximately 45 km from Rotterdam is modelled. Offshore, storage occurs in the saline formation of the upper Rotliegend Group in the Q1 block, located approximately 110 km from Rotterdam

For the offshore scenario, it is assumed that an existing platform in the Q1 oil field can be converted for CO_2 storage (IEAGHG, 2018c). However, all CO_2 injection and water extraction wells are newly drilled and completed.

CCS Base Case Scenario

The storage cases considered as part of the CCS Base Case Scenario are summarised in Table 4-3 for the offshore and onshore storage scenarios. For the cases for which the reservoir is modelled with open boundary conditions, no water extraction is carried out, while for all closed reservoir cases water is extracted from the reservoir at a volumetrically equivalent rate (as per Table 4-3). The cases are chosen based on the results presented in Chapter 3, limiting the selection to those cases that will add the most value to the assessment. For example, CO_2 storage in a closed reservoir without water extraction is not further evaluated as for the 2 Mt/y case the results would be the same as for the open reservoir, while in the 4 Mt/y case it was shown the CO_2 storage capacity was pressure limited to approximately 40 Mt/y. For the high injection rate of 4 Mt/y only cases using two injection wells are included as they are deemed more realistic.

Table 4-3 CO_2 storage cases in the CCS Base Case Scenario

Case	CO_2 injection, Mt/yr	Injector number	Injector depth, m	Water extraction, Mt/yr	Extractor number	Extractor depth, m	Boundary condition
Offshore storage cases in the CCS Base Case Scenario							
Off-2o-1	2	1	2600	-	-	-	open
Off-2c-1-1-A	2	1	2600	3.3	1	2800	closed
Off-4o-2	4	2	2600/2570	-	-	-	open
Off-4c-2-2-A	4	2	2600/2570	6.7	2	2800/2840	closed
Onshore storage cases in the CCS Base Case Scenario							
On-2o-1	2	1	1450	-	-	-	open
On-2c-1-1-A	2	1	1450	3.5	1	1550	closed
On-4o-2	4	2	1450/1480	-	-	-	open
On-4c-2-2-A	4	2	1450/1480	6.9	2	1550/1510	closed

Off = offshore; On = onshore; o = open boundary, c = closed boundary; A = water extracted volumetrically equivalent to CO_2 injected

CCS-Water-Nexus Scenario

The storage cases considered as part of the CCS-Water-Nexus Scenario are summarised in Table 4-4 for both storage scenarios (onshore and offshore). In the CCS-Water-Nexus Scenario only cases with water extraction are included.

In addition to the cases modelled in Chapter 3 (which are marked "-A" in Table 4-4), four new cases are evaluated for the CCS-Water-Nexus Scenario (which are marked "-B" in Table 4-4). These cases consider the extraction of water beyond that needed for safe CO_2 storage to meet the freshwater demand of the power plant the CO_2 was captured from. The water may be extracted from alternative storage formations when the available formation water volume is exhausted.

As demonstrated in Table 4-1 and Table 4-2, the power plants with capture using evaporative cooling systems have the highest freshwater demand out of those investigated. Based on the product recovery that may be achieved with the water treatment technology defined in Chapter Y, mechanical vapour compression (MVC), the freshwater consumption of 4.24 Mt/y for the NGCC with capture using evaporative cooling systems (NGCC-EV-PCC) corresponds to an extraction rate of 8.5 Mt/y offshore (Case Off-2c-1-3-B; based on 50% product recovery for 100,000 mg/L TDS brine) and 17 Mt/y onshore (Case On-2c-1-5-B; based on 25% product recovery for 150,000 mg/L TDS brine). The freshwater consumption of 7.75 Mt/y for the USCPC (USCPC-EV-PCC) with capture using evaporative cooling systems corresponds to an extraction rate of 15.5 Mt/y offshore (Case Off-4c-2-5-B; based on 50% product recovery for 100,000 mg/L TDS brine) and 31 Mt/y onshore (Case On-4c-2-10-B; based on 25% product recovery for 150,000 mg/L TDS brine). The varying water extraction volumes do not affect the volumes of CO_2 stored in this assessment, which only change as a function of the power plant type: 2 Mt/y for the NGCC and 4 Mt/y for the USCPC.

Because of the high additional costs incurred through the production and treatment of excess brine, these cases are only of interest if the increased storage volume is used to store CO_2 from additional sources. Therefore, CO_2 storage and water extraction is not simulated for these cases, but is only assessed as part of the integration of water extraction with the CCS chain and its economic evaluation.

Table 4-4 CO_2 storage cases in the CCS-Water-Nexus Scenario

Case	CO_2 injection, Mt/yr	Injector number	Injector depth, m	Water extraction, Mt/yr	Extractor number	Extractor depth, m	Boundary condition
Offshore storage cases in the CCS-Water-Nexus Scenario							
Off-2c-1-1-A	2	1	2600	3.3	1	2800	closed
Off-2c-1-3-B	2	1	2600	8.5	3	~2800	closed
Off-4c-2-2-A	4	2	2600/2570	6.7	2	2800/2840	closed
Off-4c-2-5-B	4	2	2600/2570	15.5	5	~2800	closed
Onshore storage cases in the CCS-Water-Nexus Scenario							
On-2c-1-1-A	2	1	1450	3.5	1	1550	closed
On-2c-1-5-B	2	1	1450	17	5	~1550	closed
On-4c-2-2-A	4	2	1450/1480	6.9	2	1550/1510	closed
On-4c-2-10-B	4	2	1450/1480	31	10	~1550	closed

Off = offshore; On = onshore; o = open boundary, c = closed boundary; A = water extracted volumetrically equivalent to CO_2 injected; B = water extracted to meet max power plant demand: storage modelling was not carried out for these cases, but they are assessed as part of the integration of the CCS chain with extracted water utilisation and its economic evaluation

4.1.3 CO_2 transport

Details of the location of the hypothetical power plant in relation to the storage sites onshore and offshore Netherlands are given in Table 4-5. The power plant is located in or near Rotterdam, with the onshore storage site located approximately 45 km from the power plant, while the Q1 aquifer is 110 km offshore from the power plant.

Transport of CO_2 and brine is via pipeline, which are assumed to be newly built and installed for CCS.

Table 4-5 Location of the CO_2 storage sites relative to the hypothetical power station near Rotterdam

Item	Location	Transport
Power station (NGCC / USCPC) location	Rotterdam	Pipeline
Offshore storage site	110 km offshore from power plant	Pipeline
Onshore storage site	45 km onshore from power plant	pipeline

4.1.4 Brine management

Base Case CCS Scenario

In the Base Case CCS Scenario there is no brine extraction for the cases for which the reservoir is modelled as open, while for the storage reservoirs with closed boundaries brine extraction is carried out. However, the extracted water is not integrated with the CCS chain but is disposed in a suitable manner, depending on the location of the storage site and the governing regulations as per Table 4-6. In the offshore scenario, the extracted brine is discharged to the ocean in the proximity to where it is produced. To cool the hot water prior to discharge, geothermal energy may be derived from the extracted brine, however this option is not explicitly considered in this study. It is also to consider that currently water is being extracted at the Q1 aquifer for the purpose of injecting it into the nearby Q1 oil field. If CO_2 storage in the saline formation and oil production at the Q1 block occur at the same time, water extracted for CO_2 storage could be used to replace this water (RCI, 2013).

In the onshore scenario reinjection into an alternative formation is proposed. The brine is reinjected at Rossum-Weerselo, 170 km from the onshore storage site. The number of brine injection wells required at Rossum-Weerlselo depends on the volume of brine that is to be disposed: a viable water injection rate of 0.25 Mt/y/well is assumed.

The brine injection wells will be newly drilled and completed. Transport of brine is via newly built and installed pipelines.

Table 4-6 Brine disposal options for the offshore and onshore storage sites with closed reservoir boundary conditions using water extraction for the Base Case CCS Scenario

Storage site	Brine salinity	Brine disposal type	Disposal location and transport
Offshore	100,000 mg/L	Ocean discharge	Q1 block
Onshore	150,000 mg/L	Reinjection at Rossum-Weerselo at 0.25 Mt/y/well	170 km from onshore storage site via pipeline

CCS-Water-Nexus Scenario

In the CCS-Water-Nexus Scenario brine is extracted from the closed storage formations, treated on-site, and the product water is supplied to the power plant with capture to supplement or substitute the freshwater consumed. The water treatment technology applied is mechanical vapour compression (MVC) as described in Chapter 3.2.3. MVC has an estimated product recovery of 50% for the offshore brine of 100,000 mg/L TDS, and a recovery of 25% for the onshore brine of 150,000 mg/L TDS. The highly saline reject from the treatment process is disposed as per Table 4-7, analogous to the Base Case Scenario: offshore it is discharged to the ocean after cooling, onshore disposal is via reinjection at Rossum-Weerselo. The disposal of the highly saline reject stream onshore and offshore would be primarily regulated through the issuance of permits within the framework of the Mining Act, which may include specific operational limits referring to water disposal. Potential issues relating to scaling due to injection of the highly saline reject stream are not considered as part of this study.

Transport of brine and product water is via newly built and installed pipelines. Transport distances for the different streams are in Table 4-8.

Table 4-7 Brine management for the offshore and onshore storage sites in the CCS-Water-Nexus Scenario

Storage site	Treatment	Product recovery	Reuse location	Reject disposal	Disposal location
Offshore	MVC	50%	Power plant: 110 km onshore	Ocean discharge	Q1 block
Onshore	MVC	25%	Power plant: 45 km onshore	Reinjection at Rossum-Weerselo at 0.25 Mt/y/well	170 km from onshore storage site

Table 4-8 Transport of concentrated brine and product water for the offshore and onshore storage sites in the CCS-Water-Nexus Scenario

Item	Destination	Transport
Offshore product water transport	110 km to onshore power plant	Pipeline
Offshore concentrated brine transport	On site (0 km)	-
Onshore product water transport	45 km to power plant	Pipeline
Onshore concentrated brine transport	170 km to reinjection site	Pipeline

4.2 Integrated cases

4.2.1 Base Case CCS Scenario

CO_2 capture, transport, storage and brine management described above are integrated to form the Base Case CCS Scenario. A schematic of the Base Case CCS Scenario is presented in Figure 4-1. The Base Case CCS Scenario considers CO_2 capture from the hypothetical NGCC and the USCPC (using evaporative, seawater once-through, and air cooling systems), CO_2 transport and injection without brine extraction in an open reservoir and with brine extraction and brine disposal in a closed reservoir. The specific combinations of power plant type, storage case, and water management are given in Table 4-9 for the NGCC and Table 4-10 for the USCPC. Matrices presenting the details of the integrated cases outlined in Table 4-9 and Table 4-10 are in Table 4-11 - Table 4-16.

Table 4-9 Cases of the Base Case CCS Scenario with capture from the NGCC with different cooling systems

Power plant	Storage case	Reservoir boundaries	Water extraction	Water disposal	Matrix
NGCC-EV-PCC	Off-2o-1	Open	-	-	Table 4-11
Case 2.1B	Off-2c-1-1-A	Closed	3.3 Mt/y	Ocean discharge	
	On-2o-1	Open	-	-	
	On-2c-1-1-A	Closed	3.5 Mt/y	Reinjection onshore	
-NGCC-EV-PCC-AC	Off-2o-1	Open	-	-	Table 4-11
Case 2.1C	Off-2c-1-1-A	Closed	3.3 Mt/y	Ocean discharge	
	On-2o-1	Open	-	-	
	On-2c-1-1-A	Closed	3.5 Mt/y	Reinjection onshore	
NGCC-OT-PCC	Off-2o-1	Open	-	-	Table 4-12
Case 2.2B	Off-2c-1-1-A	Closed	3.3 Mt/y	Ocean discharge	
	On-2o-1	Open	-	-	
	On-2c-1-1-A	Closed	3.5 Mt/y	Reinjection onshore	
NGCC-OT-PCC-AC	Off-2o-1	Open	-	-	Table 4-12
Case 2.2C	Off-2c-1-1-A	Closed	3.3 Mt/y	Ocean discharge	
	On-2o-1	Open	-	-	
	On-2c-1-1-A	Closed	3.5 Mt/y	Reinjection onshore	
NGCC-AC-PCC	Off-2o-1	Open	-	-	Table 4-13
Case 2.3B	Off-2c-1-1-A	Closed	3.3 Mt/y	Ocean discharge	
	On-2o-1	Open	-	-	
	On-2c-1-1-A	Closed	3.5 Mt/y	Reinjection onshore	

Off = offshore; On = onshore; o = open boundary, c = closed boundary; A = water extracted volumetrically equivalent to CO_2 injected

Table 4-10 Cases of the Base Case CCS Scenario with capture from the USCPC with different cooling systems

Power plant	Storage case	Reservoir boundaries	Water extraction	Water disposal	
USCPC-EV-PCC	Off-2o-1	Open	-	-	Table 4-14
Case 1.1B	Off-2c-1-1-A	Closed	6.7 Mt/y	Ocean discharge	
	On-2o-1	Open	-	-	
	On-2c-1-1-A	Closed	6.9 Mt/y	Reinjection onshore	
USCPC -EV-PCC-AC	Off-2o-1	Open	-	-	Table 4-14
Case 1.1C	Off-2c-1-1-A	Closed	6.7 Mt/y	Ocean discharge	
	On-2o-1	Open	-	-	
	On-2c-1-1-A	Closed	6.9 Mt/y	Reinjection onshore	
USCPC -OT-PCC	Off-2o-1	Open	-	-	Table 4-15
Case 1.2B	Off-2c-1-1-A	Closed	6.7 Mt/y	Ocean discharge	
	On-2o-1	Open	-	-	
	On-2c-1-1-A	Closed	6.9 Mt/y	Reinjection onshore	
USCPC -OT-PCC-AC	Off-2o-1	Open	-	-	Table 4-15
Case 1.2C	Off-2c-1-1-A	Closed	6.7 Mt/y	Ocean discharge	
	On-2o-1	Open	-	-	
	On-2c-1-1-A	Closed	6.9 Mt/y	Reinjection onshore	
USCPC -AC-PCC	Off-2o-1	Open	-	-	Table 4-16
Case 1.3B	Off-2c-1-1-A	Closed	6.7 Mt/y	Ocean discharge	
	On-2o-1	Open	-	-	
	On-2c-1-1-A	Closed	6.9 Mt/y	Reinjection onshore	

Off = offshore; On = onshore; o = open boundary, c = closed boundary; A = water extracted volumetrically equivalent to CO_2 injected

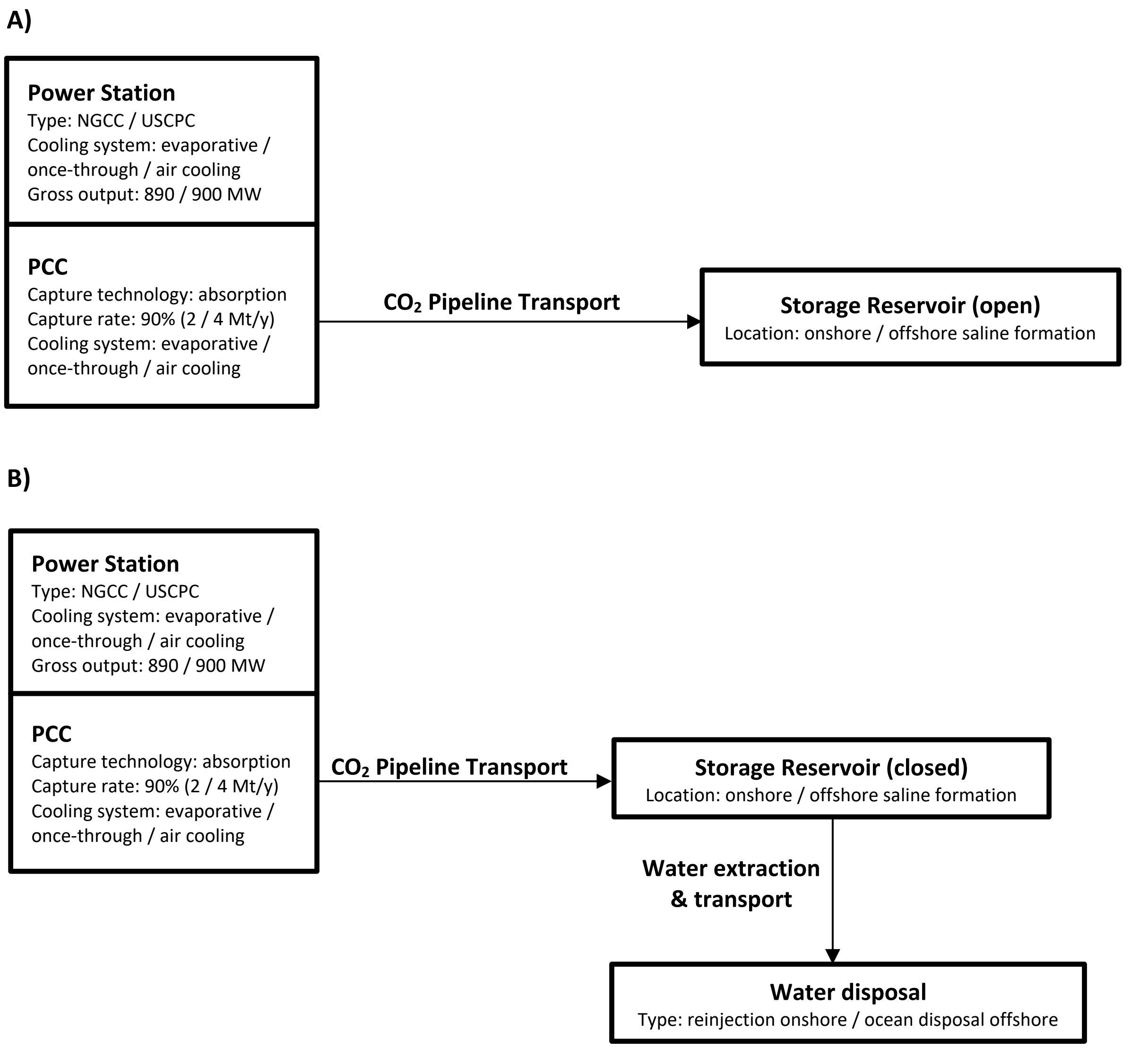


Figure 4-1 Flow diagram of the two cases of the base case scenario: a) CCS in an open formation without water extraction; b) CCS in a closed formation with water extraction and disposal

Table 4-11 Details of the Base Case CCS Scenario for the NGCC using evaporative cooling and the capture plant using either evaporative cooling or air cooling. CO_2 storage cases are onshore and offshore in a closed and open saline formation

		NGCC using evaporative cooling with state of the art absorption							
Cooling technology		**Capture using evaporative cooling**				**Capture using air cooling**			
Efficiency	%HHV	45.56				45.38			
Gross power	MW	890				890			
Net power	MW	761.3				758.2			
Water consumption (total)	Mt/y	4.24				1.8			
Water consumption (capture only)	Mt/y	1.05				0.00			
Storage									
Storage location		offshore saline		onshore saline		offshore saline		onshore saline	
Distance to power station	km	110		45		110		45	
Reservoir permeability	md	100		200		100		200	
Reservoir porosity		0.15		0.2		0.15		0.2	
Formation water salinity	mg/l	100,000		150,000		100,000		150,000	
Reservoir boundaries		open	closed	open	closed	open	closed	open	closed
Water extraction rate	Mt/y	-	3.3	-	3.5	-	3.3	-	3.5
Water Management									
Disposal type		-	ocean	-	reinjection	-	ocean	-	reinjection
Distance to storage site	km	-	0	-	170	-	0	-	170
Number of water reinjectors		-	-	-	14	-	-	-	14
Emissions data									
CO_2 emitted	t/h	30.90				30.90			
CO_2 emitted	Mt/y	0.23				0.23			
CO_2 emitted	t/MWh	0.041				0.041			
Total CO_2 captured = CO_2 stored	t/h	279				279			
Total CO_2 captured = CO_2 stored	Mt/y	2.08				2.08			
Total CO_2 avoided	t/MWh	0.311				0.311			
Total CO_2 avoided	Mt/y	1.76				1.75			

Table 4-12 Details of the Base Case CCS Scenario for the NGCC using once-through seawater cooling and the capture plant using either once-through cooling or air cooling. CO_2 storage cases are onshore and offshore in a closed and open saline formation

		NGCC using once-through cooling with state of the art absorption							
Cooling technology		**Capture using once-through cooling**				**Capture using air cooling**			
Efficiency	%HHV	45.56				48.25			
Gross power	MW	890				890			
Net power	MW	762.8				758.8			
Water consumption (total)	Mt/y	0.00094				0.00094			
Water consumption (capture only)	Mt/y	-				-			
Storage									
Storage location		offshore saline		onshore saline		offshore saline		onshore saline	
Distance to power station	km	110		45		110		45	
Reservoir permeability	md	100		200		100		200	
Reservoir porosity		0.15		0.2		0.15		0.2	
Formation water salinity	mg/l	100,000		150,000		100,000		150,000	
Reservoir boundaries		open	closed	open	closed	open	closed	open	closed
Water extraction rate	Mt/y	-	3.3	-	3.5	-	3.3	-	3.5
Water Management									
Disposal type		-	ocean	-	reinjection	-	ocean	-	reinjection
Distance to storage site	km	-	0	-	170	-	0	-	170
Number of water reinjectors		-	-	-	14	-	-	-	14
Emissions data									
CO_2 emitted	t/h	30.90				30.90			
CO_2 emitted	Mt/y	0.23				0.23			
CO_2 emitted	t/MWh	0.041				0.041			
Total CO_2 captured = CO_2 stored	t/h	279				279			
Total CO_2 captured = CO_2 stored	Mt/y	2.08				2.08			
Total CO_2 avoided	t/MWh	0.310				0.311			
Total CO_2 avoided	Mt/y	1.76				1.75			

Table 4-13 Details of the Base Case CCS Scenario for the NGCC using air cooling and the capture plant also using air cooling. CO_2 storage cases are onshore and offshore in a closed and open saline formation

NGCC using air cooling with state of the art absorption

Cooling technology		**Capture using air cooling**			
Efficiency	%HHV	44.9			
Gross power	MW	878.8			
Net power	MW	749.9			
Water consumption (total)	Mt/y	0.00094			
Water consumption (capture only)	Mt/y	-			
Storage					
Storage location		offshore saline		onshore saline	
Distance to power station	km	110		45	
Reservoir permeability	md	100		200	
Reservoir porosity		0.15		0.2	
Formation water salinity	mg/l	100,000		150,000	
Reservoir boundaries		open	closed	open	closed
Water extraction rate	Mt/y	-	3.3	-	3.5
Water Management					
Disposal type		-	ocean	-	reinjection
Distance to storage site	Km	-	0	-	170
Number of water reinjectors		-	-	-	14
Emissions data					
CO_2 emitted	t/h	30.90			
CO_2 emitted	Mt/y	0.23			
CO_2 emitted	t/MWh	0.041			
Total CO_2 captured = CO_2 stored	t/h	279			
Total CO_2 captured = CO_2 stored	Mt/y	2.08			
Total CO_2 avoided	t/MWh	0.316			
Total CO_2 avoided	Mt/y	1.77			

Table 4-14 Details of the Base Case CCS Scenario for the USCPC using evaporative cooling and the capture plant using either evaporative cooling or air cooling. CO_2 storage cases are onshore and offshore in a closed and open saline formation

		USCPC using evaporative cooling with state of the art absorption							
Cooling technology		**Capture using evaporative cooling**				**Capture using air cooling**			
Efficiency	%HHV	35.56				35.25			
Gross power	MW	900				900			
Net power	MW	684.4				678.4			
Water consumption (total)	Mt/y	7.75				4.88			
Water consumption (capture only)	Mt/y	1.56				0.002			
Storage									
Storage location		offshore saline		onshore saline		offshore saline		onshore saline	
Distance to power station	km	110		45		110		45	
Reservoir permeability	md	100		200		100		200	
Reservoir porosity		0.15		0.2		0.15		0.2	
Formation water salinity	mg/l	100,000		150,000		100,000		150,000	
Reservoir boundaries		open	closed	open	closed	open	closed	open	closed
Water extraction rate	Mt/y	-	6.7	-	6.9	-	6.7	-	6.9
Water Management									
Disposal type		-	ocean	-	reinjection	-	ocean	-	reinjection
Distance to storage site	km	-	0	-	170	-	0	-	170
Number of water reinjectors		-	-	-	28	-	-	-	28
Emissions data									
CO_2 emitted	t/h	59.10				59.10			
CO_2 emitted	Mt/y	0.44				0.44			
CO_2 emitted	t/MWh	0.086				0.087			
Total CO_2 captured = CO_2 stored	t/h	544				544			
Total CO_2 captured = CO_2 stored	Mt/y	4.05				4.05			
Total CO_2 avoided	t/MWh	0.652				0.651			
Total CO_2 avoided	Mt/y	3.32				3.29			

Table 4-15 Details of the Base Case CCS Scenario for the USCPC using once-through seawater cooling and the capture plant using either once-through cooling or air cooling. CO_2 storage cases are onshore and offshore in a closed and open saline formation

		USCPC using once-through cooling with state of the art absorption							
Cooling technology		**Capture using once-through cooling**				**Capture using air cooling**			
Efficiency	%HHV	35.47				35.19			
Gross power	MW	900				900			
Net power	MW	682.6				677.4			
Water consumption (total)	Mt/y	0.4				0.4			
Water consumption (capture only)	Mt/y	0.0018				0.0018			
Storage									
Storage location		offshore saline		onshore saline		offshore saline		onshore saline	
Distance to power station	km	110		45		110		45	
Reservoir permeability	md	100		200		100		200	
Reservoir porosity		0.15		0.2		0.15		0.2	
Formation water salinity	mg/l	100,000		150,000		100,000		150,000	
Reservoir boundaries		open	closed	open	closed	open	closed	open	closed
Water extraction rate	Mt/y	-	6.7	-	6.9	-	6.7	-	6.9
Water Management									
Disposal type		-	ocean	-	reinjection	-	ocean	-	reinjection
Distance to storage site	km	-	0	-	170	-	0	-	170
Number of water reinjectors		-	-	-	28	-	-	-	28
Emissions data									
CO_2 emitted	t/h	59.10				59.10			
CO_2 emitted	Mt/y	0.44				0.44			
CO_2 emitted	t/MWh	0.086				0.087			
Total CO_2 captured = CO_2 stored	t/h	544				544			
Total CO_2 captured = CO_2 stored	Mt/y	4.05				4.05			
Total CO_2 avoided	t/MWh	0.652				0.651			
Total CO_2 avoided	Mt/y	3.32				3.29			

Table 4-16 Details of the Base Case CCS Scenario for the USCPC using air cooling and the capture plant also using air cooling. CO_2 storage cases are onshore and offshore in a closed and open saline formation

USCPC using air cooling with state of the art absorption

Cooling technology		**Capture using air cooling**			
Efficiency	%HHV	34.04			
Gross power	MW	879.4			
Net power	MW	655.18			
Water consumption (total)	Mt/y	0.4			
Water consumption (capture only)	Mt/y	0.0018			
Storage					
Storage location		offshore saline		onshore saline	
Distance to power station	km	110		45	
Reservoir permeability	md	100		200	
Reservoir porosity		0.15		0.2	
Formation water salinity	mg/l	100,000		150,000	
Reservoir boundaries		open	closed	open	closed
Water extraction rate	Mt/y	-	6.7	-	6.9
Water Management					
Disposal type		-	ocean	-	reinjection
Distance to storage site	km	-	0	-	170
Number of water reinjectors		-	-	-	28
Emissions data					
CO_2 emitted	t/h	59.10			
CO_2 emitted	Mt/y	0.44			
CO_2 emitted	t/MWh	0.090			
Total CO_2 captured = CO_2 stored	t/h	544			
Total CO_2 captured = CO_2 stored	Mt/y	4.05			
Total CO_2 avoided	t/MWh	0.679			
Total CO_2 avoided	Mt/y	3.31			

4.2.2 CCS-Water-Nexus Scenario

For the CCS-Water-Nexus Scenario the CCS Base Case Scenario is expanded to include treatment of the produced water for reuse in the power station and the capture plant. A schematic of the CCS-Water-Nexus Scenario is presented in Figure 4-2.The CCS-Water-Nexus Scenario integrates CO_2 capture from the hypothetical NGCC or USCPC power plant, CO_2 transport and injection, brine extraction with subsequent treatment, supply of product water to the power plant and disposal of the concentrated reject brine. As only the power plants with evaporative cooling systems use significant volumes of freshwater (see Table 4-1 and Table 4-2) they present the focus of the analysis. Due to the lack of freshwater consumption, the other power plants are not considered in the integration of CCS and water extraction with reuse.

The specific combinations of power plant, storage case, and water management are given in Table 4-17 for the NGCC and Table 4-18 for the USCPC. The storage cases marked with an A present those where the water extracted is volumetrically equivalent to the CO_2 injected. The storage cases marked with a B indicate those in which water is extracted beyond what is required for safe CO_2 storage to meet the freshwater demand of the power plant with evaporative (EV) cooling, using either evaporative (EV) or air cooling (AC) for the capture plant. Matrices presenting the details of the integrated cases outlined in Table 4-17 and Table 4-18 are in Table 4-19 and Table 4-20.

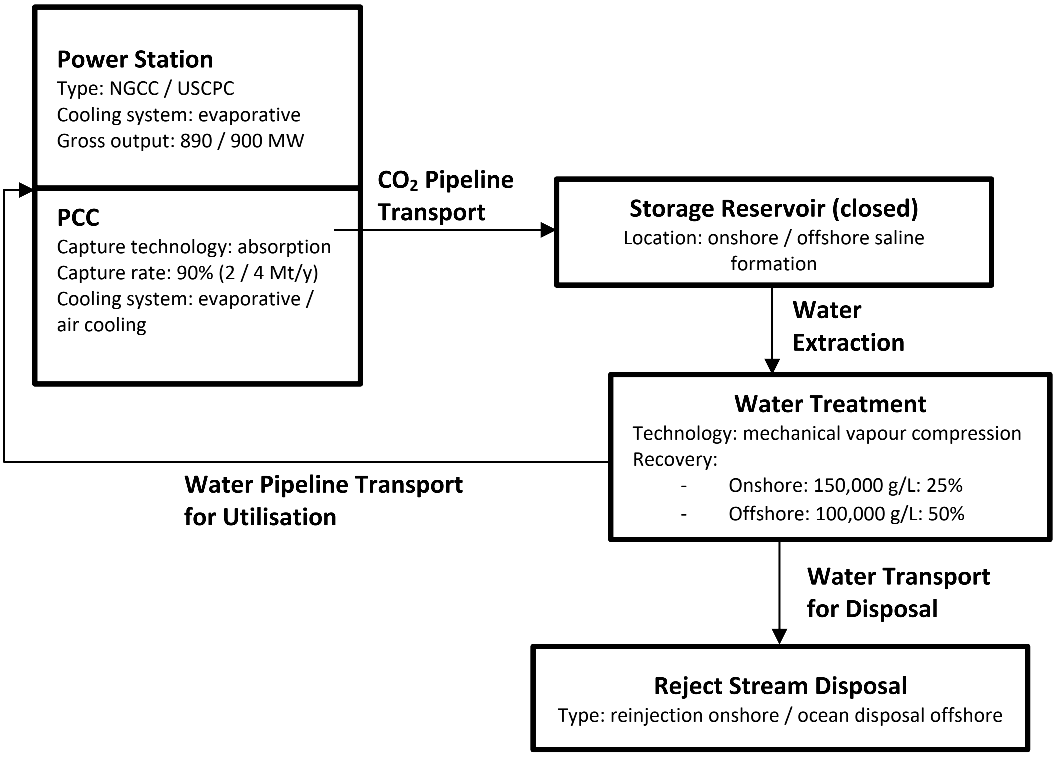


Figure 4-2 Flow diagram of the CCS-Water-Nexus Scenario with water extraction, treatment, and utilisation in the power station with capture

Table 4-17 Cases of the CCS-Water-Nexus Scenario with capture from the NGCC with evaporative cooling technology for the power plant and evaporative or air cooling for the capture plant

Power plant	Storage case	Reservoir boundaries	Water extraction	Water treatment	Water recovery	Water to power plant
NGCC-EV-PCC	On-2c-1-1-A	Closed	3.5 Mt/y	MVC	25%	0.9 Mt/y
Case 2.1B	On-2c-1-5-B	Closed	17 Mt/y	MVC	25%	4.2 Mt/y
	Off-2c-1-1-A	Closed	3.3 Mt/y	MVC	50%	1.7 Mt/y
	Off-2c-1-3-B	Closed	8.5 Mt/y	MVC	50%	4.2 Mt/y
NGCC-EV-PCC-AC	On-2c-1-1-A	Closed	3.5 Mt/y	MVC	25%	0.9 Mt/y
Case 2.1A	On-2c-1-3-B	Closed	7.2 Mt/y	MVC	25%	1.8 Mt/y
	Off-2c-1-1-A	Closed	3.3 Mt/y	MVC	50%	1.7 Mt/y
	Off-2c-1-1-B	Closed	3.6 Mt/y	MVC	50%	1.8 Mt/y

Off = offshore; On = onshore; c = closed boundary; A = water extracted volumetrically equivalent to CO_2 injected; B = water extracted to meet max power plant demand: storage modelling was not carried out for these cases, but they are assessed as part of the integration of the CCS chain with extracted water utilisation and its economic evaluation

Table 4-18 Cases of the CCS-Water-Nexus Scenario with capture from the USCPC with evaporative cooling technology for the power plant and evaporative or air cooling for the capture plant

Power plant	Storage case	Reservoir boundaries	Water extraction	Water treatment	Water recovery	Water to power plant
USCPC-EV-PCC	On-4c-2-2-A	Closed	6.9 Mt/y	MVC	25%	1.7 Mt/y
Case 1.1B	On-4c-2-10-B	Closed	31 Mt/y	MVC	25%	7.8 Mt/y
	Off-4c-2-2-A	Closed	6.7 Mt/y	MVC	50%	3.4 Mt/y
	Off-4c-2-5-B	Closed	15.5 Mt/y	MVC	50%	7.8 Mt/y
USCPC-EV-PCC-AC	On-4c-2-2-A	Closed	6.9 Mt/y	MVC	25%	1.7 Mt/y
Case 1.1C	On-4c-2-6-B	Closed	19.5 Mt/y	MVC	25%	4.9 Mt/y
	Off-4c-2-2-A	Closed	6.7 Mt/y	MVC	50%	3.4 Mt/y
	Off-4c-2-3-B	Closed	9.8 Mt/y	MVC	50%	4.9 Mt/y

Off = offshore; On = onshore; c = closed boundary; A = water extracted volumetrically equivalent to CO_2 injected; B = water extracted to meet max power plant demand: storage modelling was not carried out for these cases, but they are assessed as part of the integration of the CCS chain with extracted water utilisation and its economic evaluation

Table 4-19 Details of the CCS-Water-Nexus Scenario for the NGCC using evaporative cooling and the capture plant using either evaporative cooling or air cooling. CO_2 storage cases are onshore and offshore in a closed saline formation with extracted water being treated applying multi-effect evaporation with mechanical vapour compression (MVC)

		NGCC using evaporative cooling with state of the art absorption							
Cooling technology		**Capture using evaporative cooling**				**Capture using air cooling**			
Efficiency	%HHV	45.56				45.38			
Gross power	MW	890				890			
Net power	MW	761.3				758.2			
Water consumption (total)	Mt/y	4.24				1.8			
Water consumption (capture only)	Mt/y	1.05				0.00			
Storage									
Storage location		offshore saline		onshore saline		offshore saline		onshore saline	
Distance to power station	km	110		45		110		45	
Reservoir permeability	md	100		200		100		200	
Reservoir porosity		0.15		0.2		0.15		0.2	
Formation water salinity	mg/L	100,000		150,000		100,000		150,000	
Purpose of water extraction		storage	reuse	storage	reuse	storage	reuse	storage	reuse
Water extraction rate	Mt/y	3.3	8.5	3.5	17.0	3.3	3.6	3.5	7.2
Water extraction wells		1	3	1	5	1	1	1	3
Water Management									
Water treatment technology		MVC				MVC			
Product water recovery rate	%	50		25		50		25	
Product water	Mt/y	1.7	4.2	0.9	4.2	1.7	1.8	0.9	1.8
Reject brine	Mt/y	1.7	4.2	2.6	12.7	1.7	1.8	2.6	5.4
Disposal type		ocean		reinjection		ocean		reinjection	
Distance to storage site	km	0		170		0		170	
Number of water reinjectors		-	-	10	51	-	-	10	22
Emissions data									
CO_2 emitted	t/h	30.90				30.90			
CO_2 emitted	Mt/y	0.23				0.23			
CO_2 emitted	t/MWh	0.041				0.041			
Total CO_2 captured = CO_2 stored	t/h	279				279			
Total CO_2 captured = CO_2 stored	Mt/y	2.08				2.08			
Total CO_2 avoided	t/MWh	0.311				0.311			
Total CO_2 avoided	Mt/y	1.76				1.75			

Table 4-20 Details of the CCS-Water-Nexus Scenario for the USCPC using evaporative cooling and the capture plant using either evaporative cooling or air cooling. CO_2 storage cases are onshore and offshore in a closed saline formation with extracted water being treated applying multi-effect evaporation with mechanical vapour compression

		USCPC using evaporative cooling with state of the art absorption							
Cooling technology		**Capture using evaporative cooling**				**Capture using air cooling**			
Efficiency	%HHV	35.56				35.25			
Gross power	MW	900				900			
Net power	MW	684.4				678.4			
Water consumption (total)	Mt/y	7.75				4.88			
Water consumption (capture only)	Mt/y	1.56				0.00			
Storage									
Storage location		offshore saline		onshore saline		offshore saline		onshore saline	
Distance to power station	km	110		45		110		45	
Reservoir permeability	md	100		200		100		200	
Reservoir porosity		0.15		0.2		0.15		0.2	
Formation water salinity	mg/L	100,000		150,000		100,000		150,000	
Purpose of water extraction		storage	reuse	storage	reuse	storage	reuse	storage	reuse
Water extraction rate	Mt/y	6.7	15.5	6.9	31	6.7	9.8	6.9	19.5
Water extraction wells		2	5	2	10	2	3	2	6
Water Management									
Water treatment technology		MVC				MVC			
Product water recovery rate	%	50		25		50		25	
Product water	Mt/y	3.4	7.8	1.7	7.8	3.4	4.9	1.7	4.9
Reject brine	Mt/y	3.4	7.8	5.2	23.3	3.4	4.9	5.2	14.6
Distance to reuse site	km	110		45		110		45	
Disposal type for reject brine		ocean		reinjection		ocean		reinjection	
Distance to treatment site	km	0		170		0		170	
Number of water reinjectors		-		21	93	-		21	58
Emissions data									
CO_2 emitted	t/h	59.10				59.10			
CO_2 emitted	Mt/y	0.44				0.44			
CO_2 emitted	t/MWh	0.086				0.087			
Total CO_2 captured = CO_2 stored	t/h	544				544			
Total CO_2 captured = CO_2 stored	Mt/y	4.05				4.05			
Total CO_2 avoided	t/MWh	0.652				0.651			
Total CO_2 avoided	Mt/y	3.32				3.29			

5 Economic evaluation of the CCS-Water Nexus

5.1 Scope

This chapter presents the economic assessment of the Base Case CCS Scenario and the integrated CCS-Water-Nexus Scenario described in detail in Chapter 4. The assessment compares costs for power plants with and without capture, the costs for different cooling technologies deployed at the power plant and/or capture plant, the different storage options (onshore and offshore, open and closed reservoir boundaries) as well as the different brine management options available.

A brief overview of the cases evaluated was presented in Table 4-9 and Table 4-10 for the Base Case CCS Scenario and Table 4-17 and Table 4-18 for the CCS-Water-Nexus Scenario with more detail of each integrated case in Table 4-11 - Table 4-16 for the Base Case CCS Scenario and Table 4-19 - Table 4-20 for the CCS-Water-Nexus Scenario.

The analysis presented in this chapter evaluates the capital and operating costs for the:

- Power plant (USCPC or NGCC)
- Post combustion capture (PCC) plant
- Transport pipelines
- Storage facilities: onshore and offshore
- Water extraction
- Water management
    - Water disposal
    - Water treatment and reuse at the power plant

The cost of CO_2 avoidance and the levelized cost of electricity are also estimated for each scenario. No carbon tax or revenues from other emissions trading is included.

Sensitivities to the economic parameters discount rate and project life are undertaken, as well as a sensitivity to the reference plant for the Base Case CCS Scenario. The sensitivity analysis will only be presented for the Base Case CCS Scenarios with no brine extraction in an open reservoir (no water extraction and no utilisation) as the trends observed due to the sensitivities are also applicable in the cases with water extraction (closed reservoir), and water extraction and utilisation (CCS-Water-Nexus Scenario).

The costs presented in the subsequent sections may only be treated as a preliminary guide. Cost sensitivities for transport and storage are not further investigated within this study.

5.2 Economic methodology

This section presents the assumptions and methodology applied for the economic assessment of the Base Case CCS Scenario and the CCS-Water-Nexus Scenario described in Chapter 4 and are limited to those scenarios under the described assumptions.

5.2.1 General economic assumptions

General economic assumptions used in this study applicable to the power plant, capture, transport, storage and water extraction, disposal and treatment include:

- Discount rate:
    - Based on the IEA GHG's standard a discount rate of 8% in constant money values
    - Sensitivities to discount rates of 10% and 5% are also assessed
- Plant life:
    - A standard plant operating life of 25 years is used for the economic assessments.
    - The sensitivity to a 40 year life is also assessed
- Operating capacity factor:
    - The annual average operating capacity factor is the annual output of the plant divided by the rated output at the average ambient conditions. The capacity factor is based on the IEA GHG's default assumption for fossil fuel power plants with and without CCS plants of 85%
    - The capacity factor in the first year of service is assumed to be 60%, ramping to 85% from the second year onwards
- The total annual cost of insurance, local property taxes and miscellaneous regulatory and overhead fees is assumed to be a total of 1% of total plant cost (TPC)
- Cost year
    - All estimates are presented on current money values (2018 costs)
    - All costs are escalated to Q2 2018 using the Upstream Capital Cost Index (UCCI), the Upstream Operating Cost Index (UOCI), or Chemical Engineering Plant Cost Index (CEPCI) as appropriate
- Currency:
    - All costs are presented in Euros
    - Foreign exchange has been assumed as 0.85 Euro = 1USD

With regards to the cost year, it should be noted that as capital costs may have decreased in comparison to 5 and 10 years ago, the cost estimates may be lower than in the original references. For example in the oil and gas industry, 2018 upstream operating expenditure increased in comparison to 10 years ago, but decreased compared to 5 years ago.

It should further be considered that financing of the CCS project is not optimised and that the costs will be affected by the business model under which transport and storage in the Netherlands or in Europe may operate. Researchers have investigated different scenarios to show how variations will affect the costs, i.e. CO_2 may be captured from different sources and transported offshore for injection via the same pipeline thus incurring a CO_2 transport tariff (Loeve et al., 2013; RCI, 2013). The presence of such a distribution network may decrease transport and injection unit costs as infrastructure costs are split over a larger quantity of CO_2 and the injected amount at a site may be optimised.

5.2.2 Net present value and levelised cost of electricity

To determine the economic feasibility of each scenario, the economic assessment uses a net present value (NPV) discounted cash flow (NPV-DCF) model to estimate the lifetime cost, which are represented as the levelised cost of electricity (LCOE).

The NPV of an item, for example costs, may be determined as

$$NPV = \sum_{t=0}^{n} \frac{C_t}{(1+i)^t} \quad , \tag{5-1}$$

in which C_t is the cost at time t in €, and i is the discount rate.

The LCOE in €/MWh can be calculated as:

$$LCOE = \frac{NPV\ Capex_{Power\ Plant} + NPV\ Opex_{Power\ Plant} + NPV\ Capex_{CCS} + NPV\ Opex_{CCS}}{NPV\ Net\ Generation} \tag{5-2}$$

5.2.3 Cost of CO_2 avoided

The cost of avoiding CO2 emissions (as €/t CO2 avoided) is calculated by comparing the costs and emissions of a plant with CCS and the costs and emissions of a reference case, using the following equation:

$$C_{CO2avoided} = \frac{LCOE_{CCS} - LCOE_{REF}}{CO_{2,REF} - CO_{2,CCS}} \tag{5-3}$$

With $C_{CO2avoided}$ being the cost of emissions avoidance in €/t CO_2 avoided, $LCOE_{CCS}$ being the levelised electricity cost for the CCS project in €/MWh, $LCOE_{REF}$ being the levelised electricity cost for the reference power plant without CCS in €/MWh, CO_{2REF} being the emissions from the reference power plant in t/MWh, and CO_{2CCS} being the emissions from the power station with CCS in t/MWh.

The reference plant is the same type of generation technology and cooling technology as the plant with CCS. In the case of the USCPC, the reference plant for the evaporative cooling scenario is Case 1.1A, for once-through seawater cooling the reference is Case 1.2A, and for air cooling it is Case 1.3A (see Table 4-1). For the NGCC the reference plant for the evaporative cooling scenario is Case 2.1A, for once-through seawater cooling the reference is Case 2.2A and for air cooling it is Case 2.3A as per Table 4-2.

Sensitivity analysis evaluating the cost of avoidance where the reference plant for all scenarios is the power plant using evaporative cooling is also undertaken. That is, for the USCPC scenario for Cases 1.2 (once-through seawater cooling) and Cases 1.3 (air cooling) (see Table 4-1), the reference plant is the power plant without capture using evaporative cooling (Case 1.1A). Similarly, for the NGCC scenario, Case 2.1A (the power plant without capture using evaporative cooling) is taken as the reference plant for Cases 2.2 (once-through seawater cooling) and Cases 2.3 (air cooling).

5.3 Costs of CO_2 capture

5.3.1 Capital costing

The costs of power plants with and without capture in this study have been estimated based on values quoted by vendors. The cost estimating accuracy is within ±35%. The capital costs include all components of the power plant, post-combustion capture plant and compression to 110 bar for transport.

The cost estimates are taken for 'nth plants' based on current knowledge of the technology. Costs normally associated with 1st-of-a-kind commercial have been excluded in this analysis.

The total plant cost (TPC) and total capital requirement (TCR) are estimated. TPC is the installed cost of the plant including contingencies. TCR includes TPC, interest during construction, owner's costs, spare parts, working capital and start-up costs.

Contingency costs, as per the IEAGHG methodology are assumed to be 10% of the total plant costs to cover for estimating errors and estimating omissions.

Owners' costs include owner company overheads, project financing, insurances, in-house engineering costs, and fees for development, legal, connection, permitting and consenting.

Start-up costs include costs for the commissioning period which includes labour and management.

The breakdown in capital costing methodology is shown in Table 5-1.

Table 5-1 Economic criteria for capital cost estimation of the power plants and pos-combustion capture plants

Plant Cost (TPC)	Value
Project contingency, % plant cost	10%
Total Capital Requirement (TCR)	
Owners costs and fees, % of TPC	7
Interest during construction	From expenditure schedule and discount rate
Spare parts	0.5% of TPC
Construction time	
Gas plants, years	3
Coal plants, years	4
Capital expenditure schedule	
Gas and pulverised coal plants, % of TPC, years 1-3	20/45/35
Start-up costs	
Maintenance and operating and support labour costs	3 months
Maintenance materials	1 month
Chemicals, consumables and waste disposal costs	1 month
Fuel cost, % of full load	25% of 1 month
Modifications	2% of TPC
Working capital	
Coal and other solid fuel stocks, days at full load	30
Chemicals and consumables, days at full load	30
Decommissioning cost	0

5.3.2 Operating costs

The operating costs assumptions for the power plant and the post-combustion capture plant are listed in Table 5-2.

Table 5-2 Operating costs assumptions for the power plants and post combustion capture plants

Operating Costs	Value
Fuel prices	
Coal €/GJ	2.5
Natural Gas €/GJ	5.0
Fixed operating costs	
Maintenance costs indicative costs, % of TPC/y	
PC plants	1.5
NGCCs	2.2
Operating labour cost, €k/person-year	60
Number of operators	18 for Coal+PCC; 7 for NGCC+PCC
Number of operating shifts	5
Administrative/support labour, % of operating labour	30
Administrative/support labour, % of maintenance cost	12
Insurance cost, % of TPC	0.5
Local taxes and fees, % of TPC	0.5
Variable operating costs	
Raw process water, €/m3	0.2
Limestone, €/t	20

5.4 Cost of CO_2 transport and storage, and water extraction, disposal and treatment

CO_2 storage can be sub-divided into different stages: construction of new wells and pipelines or modification of existing ones prior to CO_2 injection, maintenance and monitoring activities during CO_2 injection, well close in and monitoring post-injection, and finally well abandonment (Neele et al., 2011c).

Operating costs incurred by the injection of CO_2 include, amongst others, costs for operation and inspection, maintenance, logistics and CO_2 monitoring (van de Velde et al., 2008). Costs of CO_2 injection operations may be comparable to those of gas production (van de Velde et al., 2008).

Costs for Measurement, Monitoring and Verification (MMV) are affected by the length of the MMV period. Loeve et al. (2013) assume a MMV period of 2 years, though the authors point out that the EU Directive prescribes a period of 20 years of MMV after well shut-in. This would delay final abandonment by the same time frame.

A significant amount of work has been carried out to provide cost estimates for offshore CO_2 transport and storage in the Netherlands (e.g., van de Velde et al., 2008; Neele et al., 2011c; RCI, 2013). As these studies present the individual cost items in great detail, estimates from these studies are used to assess the costs of transport and storage in the onshore and offshore saline formations in the Netherlands for the 2018 cost year.

5.4.1 Transport costs

Transport costs are a function of distance, CO_2 flow rate and the conditions at which the CO_2 is transported. Pipelines are more suitable when distances are shorter and the supply of CO_2 is continuous for a long term. Ship transport allows for more flexibility, being preferable for shorter operational time frames, e.g., when injecting into reservoirs with limited storage capacity (RCI, 2013).

Due to the continuous supply of CO_2 over 25 years, pipeline transport to the injection site is modelled. Properties of the onshore and offshore pipelines are in Table 5-3. Capital and operating expenditure for CO_2 pipelines are summarised in Table 5-4 and Table 5-5. A detailed description of the components affecting the costs of offshore pipelines can be found elsewhere (van de Velde et al., 2008).

The material cost of a pipeline is determined as:

$$C_M = \pi \cdot L \cdot t \cdot (D - t) \cdot \rho_M \cdot P_M \qquad (5\text{-}4)$$

With C_M being the total cost of the pipeline material, L being the length of the pipeline, t being the wall thickness, D being the outer diameter, ρ_M being the density of the material and P_M being the material price.

Compression to 110 bar for transport and injection occurs at the capture site and is included in the CO_2 capture costs and thus not further considered here, though booster stations along the pipeline may be necessary to ensure the CO_2 remains in the liquid phase, depending on the transport distance.

Table 5-3 Pipeline properties for CO_2 transport onshore and offshore Netherlands

Property	Value	Reference
Total length offshore/onshore	110/45 km	
CO_2 flow rate	2/4 Mt/y	
Diameter	0.3/0.4 m	
Wall thickness	0.032 m	Atlas Steels (2011)

Table 5-4 Capital investment for pipeline in 2018 costs

Cost item	Value	Reference
Price of material - steel	570 €/t	MEPS (2018)
Labour	0.12 M€/km	Loeve et al. (2013)
Overheads	0.10 M€/km	Loeve et al. (2013)
Offshore capital	0.75 M€/km	van de Velde et al. (2008), Vermeulen (2009)
Offshore infrastructure crossing (36” x 8”)	3.31 M€/crossing	van de Velde et al. (2008), Vermeulen (2009)
Offshore infrastructure crossing (36” x 36”)	6.62 M€/crossing	van de Velde et al. (2008), Vermeulen (2009)
Offshore waterway crossing	9.1-13.2 M€/crossing	van de Velde et al. (2008), Vermeulen (2009)
Land fall	5.79 M€/land fall	van de Velde et al. (2008), Vermeulen (2009)

Table 5-5 Operational expenditure for pipeline in 2018 costs

Cost item	Value	Reference
Fixed operating costs	0.25% of capital investment	ZEP (2011), Loeve et al. (2013)
Variable operating costs	0.29 €/t CO_2	ZEP (2011), Loeve et al. (2013)

5.4.2 Storage costs

Capital investment for CO_2 storage onshore and offshore Netherlands is summarised in Table 5-6. Cost items include offshore platforms, injection wells, and monitoring. The costs are indexed to the 2018 cost year.

Construction of new or modification of existing platforms is necessary for offshore CO_2 storage operations. For a new platform, costs have been quoted as 39.5 M€ (Vermeulen, 2009) and 61 M€ (van den Broek et al., 2010). Modifications to convert existing oil and gas platforms for CO_2 injection are estimated to cost 12 M€ (Vermeulen, 2009; RCI, 2013). Modification of oil and gas platforms includes installation of additional equipment such as pumps and heaters, and control and monitoring devices as well as modification of the existing piping (van de Velde et al., 2008). It is assumed that production platforms of the Q1 oil field may be converted for CO_2 injection (RCI, 2013). As the oil field is currently still in production and may still be when CO_2 injection into the Q1 saline formation commences, costs associated with mothballing are not included in the analysis. Modifications to the platform are estimated as 9.46 M€ (see Table 5-6).

Facilities for onshore injection are only a fraction of the costs and have been estimated as 1.5 Mt (van den Broek et al., 2010).

Costs of wells are largely affected by location, i.e. onshore or offshore, and by the depth of the well. Wells drilled onshore are considerable less expensive than offshore wells. EBN (2011) stated that all their onshore wells cost below 10 M€, including wells with horizontal offsets of more than 2000 m at 3000 m vertical depth. Offshore wells can vary significantly in their cost (by tens of millions of euros), even at comparable depth and outsteps (EBN, 2011). However, vertical wells with no horizontal outstep are less, ranging between 10-20 M€/well, while wells between 3000 and 4000 m typically range from 10-30 M€/well (including those with outsteps of up to 4000 m) with some wells costing as much as 30-40 M€/well at this depth (EBN, 2011). In OGA (2017) the cost of a vertical well in the Southern North Sea is estimated as 13 MGBP (~15 M€ at an exchange rate of 1 Euro = 0.87 GBP). Costs may be reduced if existing wells, such as those in depleted oil and gas fields, can be converted to injection wells. In EBN/GASUNIE (2010) the cost of converting an onshore well in a depleted oil and gas field to a CO_2 injection well are estimated as 3.7 M€/well, which decreases to 2.75 M€/well and 2.18 M€/well for 2 and 5 wells respectively.

Van den Broek et al. (2010) estimated onshore drilling unit costs as 3000 €/m, while offshore drilling costs are 5314 €/m, equating to 9 M€ and 15.94 M€ for a 3000 m deep onshore and offshore well respectively. The unit cost presented by van den Broeck et al. (201) is used to determine the economics of CO_2 storage in the Dutch reservoirs investigated.

For monitoring of CO_2 storage in aquifers, costs have been quoted as 2.8 M€ (Vermeulen, 2009) and 1.5 M€ (Ramirez et al., 2010). Costs for monitoring onshore and offshore are the same. In this study, monitoring expenditure of 2.8 M€ is assumed, indexed to 2018.

Construction occurs over 2 years, with 40% of budget spent in the first and 60% in the second year.

Cost of decommission or abandonment are estimated as 25% of capital investment.

Table 5-6 Capital investment for CO_2 injection in 2018 costs

Property	Value	Reference
Platform modifications offshore	9.46 M€	Vermeulen (2009)
New platform offshore	35.22 M€	Vermeulen (2009)
Surface facilities onshore	1.32 M€	Van den Broek (2010)
New well onshore	2650 €/m	Van den Broek (2010)
New well offshore	4693 €/m	Van den Broek (2010)
Monitoring	2.50 M€	Vermeulen (2009)

Operational expenses for the Dutch onshore and offshore storage sites are presented in Table 5-7.

Van de Velde et al. (2008) expect the expenses for operating offshore CO_2 injection facilities to be comparable to those of gas production operations, estimating the average annual operating costs for a main landing platform to be 10 M€/year. This is half the average operating cost for gas treatment platforms as most facilities would be obsolete (van de Velde et al., 2008).

In addition to the fixed operational costs for platform operations, RCI (2013) account for the cost of CO_2 injection and well operation. Van den Broek et al. (2010) estimate annual expenditure for operation, maintenance and monitoring as 5% of initial development costs.

During injection, cost of measuring, monitoring and verification are estimated as 2.83 M€/y (Vermeulen, 2009). This cost may reduce to 10% of that after well close-in (Loeve et al., 2013). However, monitoring after well close-in is not included in this analysis. Due to the comparatively small cost and the time value of money it will not have a significant effect on CO_2 storage costs, in particular as it delays the final cost of abandonment into the future.

Table 5-7 Operational expenses for CO_2 injection in 2018 costs

Property	Value	Reference
Platform operations	10.40 M€/y	van de Velde et al. (2008)
Surface facilities onshore	5%	Van den Broek (2010)
CO_2 injection	1.40 €/t CO2	Neele et al. (2012)
Well Opex	0.28 M€/well/y	Neele et al. (2012)
Monitoring	2.91 M€/y	Vermeulen (2009)

5.4.3 Cost of formation water extraction and disposal

Capital and operating costs for water extraction, transport, and disposal are summarised in Table 5-8. In this study, the same unit costs are applied for CO_2 injection and water extraction wells (see Table 5-6).

Pumps are required for water lift as well as for potential transport of the injected water. Pump requirements may be estimated as:

$$P = \frac{Q \cdot H \cdot g \cdot \rho_F}{\eta_P} \qquad (5\text{-}5)$$

With P being the energy required, Q being flow rate, H being head, g being gravity, ρ_F being density of the fluid, and η_P being the efficiency of the pump.

Pipelines for water transport are calculated in the same manner as CO_2 pipelines (Table 5-4), with the exception that the pipeline material is HDPE rather than steel.

With regards to disposal, the reinjection of saline water via designated disposal wells incurs a cost, while the cost of ocean discharge is estimated as zero (Table 5-8). This is based on the assumption that geothermal energy may be harvested from the extracted brine, which is sufficient to offset the cost of ocean disposal, such as the associated infrastructure and cooling of the hot brine. Likewise, if, alternatively, disposal through reinjection into depleting oil and gas fields, such as the Q1 oil field, for pressure maintenance is considered, this would also not incur any additional disposal costs.

Table 5-8 Water extraction, transport, and disposal costs

Property	Value	Reference
Extraction/disposal well onshore	2650 €/m	Van den Broek (2010)
Extraction/disposal well offshore	4693 €/m	Van den Broek (2010)
Pipeline material cost – HDPE	1400 €/t	Plasticker (2018)
Capex water pump	0.6375 M€/MW	Almasi (2014)
Fixed Opex water pump	1.5%	Roach et al. (2014)
Variable Opex	45 €/MWh	ECN (2016)
Ocean disposal	0 €/t	
Injection into depleting O&G fields	0 €/t	

5.4.4 Water treatment

Specifically for the cases investigated in the CCS-Water-Nexus Scenario (Table 4-17 and Table 4-18), water treatment of the extracted brine is required before reuse in the power and capture plants. The technology identified to treat the highly saline onshore and offshore formation waters with TDS concentrations of 150,000 and 100,000mg/L, respectively, is mechanical vapour compression (MVC). MVC has been selected out of the thermal processes as it has been reported to be more competitive compared to MED and MSF with respect to energy requirements and costs (Alasfour and Abdulrahim, 2011; Shaffer et al., 2013; Chen et al., 2016; Jimenez et al., 2018). Product water recovery of 50% can be expected applying MVC to treat the offshore extracted brine, while for the higher concentrated brine extracted onshore product recovery reduces to 25%.

Relevant details of the water treatment technology and its costs are summarised in Table 5-9. Costs scale with the size of the operation applying a factor of 0.6. Indicative water production costs applying a thermal process to the treatment of hypersaline brines have been quoted to range from \$2.65/m^3 to \$6.07/m^3 (Al-karaghouli et al., 2013; Bagheri et al. 2018; Onishi et al., 2018).

Table 5-9 Water treatment costs for the highly saline formation waters

Item	Value
Offshore formation water	100,000 mg/L
Treatment technology	MVC
Estimated product recovery MVC	50%
Capital cost for product stream of 0.36 Mt/y	3.00 M€
Operating cost	0.64 €/m^3
Estimated treatment cost MVC	1.057 €/m^3
Onshore formation water	150,000 mg/L
Treatment technology	MVC
Estimated product recovery MVC	25%
Capital cost for product stream of 0.36 Mt/y	3.00 M€
Operating cost	0.74 €/m^3
Estimated treatment cost MVC	1.22 €/m^3

5.5 Economic results

This section summarises the capital and operating costs, as well as levelised cost of electricity and avoidance cost for the power plant (USCPC or NGCC) with and without post-combustion capture (PCC) plant.

It also presents the capital and operating costs, and cost per tonne of CO_2 stored for transport and storage onshore and offshore for the CO_2 captured from the USCPC and NGCC power plants with capture.

Capture costs and storage are then integrated to present the costs for the Base Case CCS Scenario, which includes costs to extract water from the storage site as well as its subsequent disposal, and for the CCS-Water-Nexus Scenario, which includes costs of water extraction, treatment, and reuse in the power plant with capture.

5.5.1 CO_2 capture

This section presents the economic summary for the power plants with and without capture as modelled in Chapter 2.

USCPC

The capital costs for the USCPC power plant without capture using evaporative cooling is estimated to be about 1650 €/kW (Case 1.1A, Table 5-10). This increases by 800 €/kW to install state-of-the-art post-combustion capture using solvent absorption (Case 1.1B). By utilising air cooling for the capture plant in place of evaporative cooling, this cost increases by a further 200 €/kW (Case 1.1C). The higher costs result from the more expensive cooling technology.

For once-through seawater cooling, the power plant without capture is similar in capital cost to the plant using evaporative cooling with an estimate of 1645 €/kW (Case 1.2A, Table 5-10). Implementation of capture also follows similar trends in cost increases.

In contrast, the power plant using air cooling without capture is estimated to be 1730 €/kW (Case 1.3A), which is about 100 €/kW higher than using evaporative cooling. This is consistent with estimates presented in the literature review as described in Chapter 1. Adding capture to this plant utilising air cooling increases the capital costs by 1000 €/kW (Case 1.3B, Table 5-10).

The changes in LCOE for these cases are discussed in Section 5.6.1.

Table 5-10 Techno-economic summary for state-of-the-art absorption post-combustion capture: USCPC

Case name	1.1A	1.1B	1.1C	1.2A	1.2B	1.2C	1.3A	1.3B
	USCPC-EV	USCPC-EV-PCC	USCPC-EV-PCC-AC	USCPC-OT	USCPC-OT-PCC	USCPC-OT-PCC-AC	USCPC-AC	USCPC-AC-PCC
	Evaporative cooling			Once through cooling			Air cooling	
USCPC	w/o CCS	w/ CCS-EV	w/ CCS-AC	w/o CCS	w/ CCS-OT	w/ CCS-AC	w/o CCS	w/ CCS
Total capital requirement (million €)	1342.8	1659.3	1785.1	1341.8	1655.3	1781.3	1359.2	1803.5
Specific capital requirement (€/kW)	1647	2424	2631	1644	2424	2630	1732	2753
Fixed O&M (million €)	37.7	45.9	48.7	37.6	45.7	48.6	38.0	49.2
Variable O&M (million €)	7.54	17.8	17.0	6.0	15.8	15.8	6.0	15.8
Capital (€/MWh)	27.39	40.38	43.82	27.40	40.39	43.80	28.86	45.84
Fixed O&M (€/MWh)	6.36	9.24	9.89	6.35	9.23	9.89	6.67	10.35
Variable O&M (€/MWh)	1.27	3.58	3.45	1.01	3.19	3.21	1.05	3.32
Fuel (€/MWh)	21.20	24.80	25.50	21.20	25.40	25.60	22.10	26.40
LCOE (€/MWh)	56.22	78.01	82.67	55.97	78.21	82.50	58.69	85.92

NGCC

The NGCC power plants without capture have specific capital cost estimates of about 940 €/kW for evaporative cooling (Case 2.1A), 960 €/kW for once-through seawater cooling (Case 2.2A), and 1015 €/kW for air cooling systems (Case 2.3A) (Table 5-11). Adding capture to these facilities using the same cooling technology increases the specific capital costs to 1530 €/kW using evaporative cooling (Case 2.1B), 1535 €/kW using once-through cooling (Case 2.2B) and 1800 €/kW for air cooling (Case 2.3B). For the scenarios where the NGCC using evaporative or once-through cooling uses air cooling for PCC, the specific capital cost becomes about 1720 €/kW (Case 2.1C and Case 2.2C) (Table 5-11). Discussion of the LCOE for these cases are summarised in Section 5.6.1

Table 5-11 Techno-economic summary for state-of-the-art absorption post-combustion capture: NGCC

Case name	2.1A	2.1B	2.1C	2.2A	2.2B	2.2C	2.3A	2.3B
	NGCC-EV	NGCC-EV-PCC	NGCC-EV-PCC-AC	NGCC-OT	NGCC-OT-PCC	NGCC-OT-PCC-AC	NGCC-AC	NGCC-AC-PCC
	Evaporative cooling			Once through cooling			Air cooling	
NGCC	w/o CCS	w/ CCS-EV	w/ CCS-AC	w/o CCS	w/ CCS-OT	w/ CCS-AC	w/o CCS	w/ CCS
Total capital requirement (million €)	835.7	1166.3	1302.1	850.2	1169.8	1304.9	890.3	1349.6
Specific capital requirement (€/kW)	939	1531	1717	962	1534	1720	1013	1800
Fixed O&M (million €)	29.2	39.5	41.7	27.8	38.2	41.8	29.0	43.2
Variable O&M (million €)	3.4	8.4	8.4	2.6	8.0	8.0	2.6	8.0
Capital (€/MWh)	15.86	25.60	28.68	16.10	25.62	28.72	17.18	30.05
Fixed O&M (€/MWh)	4.56	7.15	7.58	4.34	6.90	7.59	4.61	7.94
Variable O&M (€/MWh)	0.53	1.52	1.53	0.41	1.45	1.45	0.41	1.47
Fuel (€/MWh)	34.60	39.60	40.10	34.30	39.70	39.90	35.80	40.10
LCOE (€/MWh)	55.55	73.87	77.89	55.14	73.67	77.66	58.00	79.56

5.5.2 CO_2 transport and storage (incl. water extraction and disposal)

The economics for the storage cases of the Base Case CCS Scenario and the CCS-Water-Nexus-Scenario described in Chapter 4 are presented below.

Storage economics of the Base Case CCS Scenario

In the CCS Base Case Scenario water extraction only occurs for the purpose of storing the captured CO_2 in the closed saline formation. In case of an open formation, no water extraction is necessary. The results with respect to CO_2 transport, storage, and water extraction are presented below.

Storage from the USCPC (4 Mt/y)

This section presents the costs for storage of the CO_2 captured from the coal fired power plant (~4 Mt/y) in the Base Case CCS Scenario, in which no utilisation of water is considered. Four cases are distinguished:

- Storage in the Q1 saline formation with open reservoir boundaries offshore Netherlands
- Storage in the Q1 saline formation with closed reservoir boundaries and water extraction offshore Netherlands
- Storage in a saline formation with open reservoir boundaries onshore Netherlands
- Storage in a saline formation with closed reservoir boundaries and water extraction onshore Netherlands

The costs for the different cases are summarised in Table 5-12 and described below. Storage and CO_2 transport costs remain the same for the closed and the open reservoir and only vary for onshore and offshore storage. However, the closed reservoir has additional brine extraction and disposal costs.

Table 5-12 2018 costs (undiscounted) for CO_2 transport and storage in the offshore Q1 saline formation 110 km from Rotterdam and the onshore saline formation 45 km from Rotterdam for the USCPC scenario (4 Mt/y of CO_2 injected over 25 years). The unit costs are discounted costs

Scenario	**USCPC onshore storage**		**USCPC offshore storage**	
Case	**On-4o-2**	**On-4c-2-2-A**	**Off-4o-2**	**Off-4c-2-A**
Location	Onshore	Onshore	Offshore	Offshore
Reservoir boundary	Open	Closed	Open	Closed
Water extraction	No	Yes	No	Yes
Injection wells	2	2	2	2
Extraction wells	-	2	-	2
Extraction rate, Mt/y	-	6.9	-	6.7
Transport costs				
Capex, M€	17.77	17.77	138.30	138.30
Opex, M€	30.11	30.11	37.64	37.64
Unit Cost, €/t	0.74	0.74	3.83	3.83
Storage costs				
Capex, M€	11.50	11.50	36.36	36.36
Opex, M€	228.10	228.10	486.54	486.54
Unit Cost, €/t	2.57	2.57	5.77	5.77
Water extraction & disposal costs				
Capex, M€	-	175.24	-	30.80
Opex, M€	-	361.54	-	76.59
Unit Cost, €/t	-	7.98	-	1.53
Total unit cost, €/t	3.31	11.29	9.60	11.13

Open reservoir offshore – no water extraction (Off-4o-2)

In the offshore storage scenario, CO_2 transport costs include costs for a 110 km offshore pipeline connecting Rotterdam and the storage site. Capital costs for a pipeline with a capacity of 4 Mt/y of CO_2 are estimated as 138.30 M€ respectively. The corresponding annual operating costs are 1.51 M€/y. The discounted unit cost of CO_2 transport is estimated as to 3.83 €/t (Table 5-12).

Existing production platforms of the Q1 oil field are assumed to be converted for CO_2 injection (RCI, 2013) at a cost of 9.46 M€ (see Table 5-6). However, new injection wells are required to be drilled. Based on the unit cost estimate provided by van den Broek et al. (2010) and an injection well depth of 2,600 m, the cost of an injection well is 12.2 M€. In comparison, typical costs for new offshore wells have been quoted to range between 10 and 30 M€/well (Ramirez et al., 2009; EBN, 2011, RCI, 2013, Neele et al., 2011c; OGA, 2017).

Capital costs for this case are 36.36 M€, while operating expenses are 19.46 M€/y. The discounted unit cost for CO_2 storage is 5.77 €/t (Table 5-12).

Total cost of CO_2 transport and storage is 9.60 €/t (Table 5-12).

Closed offshore reservoir with water extraction (Off-4o-2-2-A)

For the cases for which water extraction is modelled (closed reservoir), extraction costs are 30.80 M€ (Capex) and 3.06 M€/year (Opex). This equates to water extraction costs of 1.53 €/t (discounted, Table 5-12).

The cost of disposing the water extracted from the Q1 saline formation is assumed as zero (see Table 5-8). This is based on the disposal options ocean discharge and/or reinjection into depleting petroleum reservoirs.

Total cost of CO_2 transport and storage with water extraction and disposal is 11.13 €/t (Table 5-12).

Open reservoir onshore – no water extraction (On-4o-2)

In the onshore storage scenario, CO_2 transport costs include costs for a 45 km onshore pipeline connecting Rotterdam and the storage site. The capital investment for a pipeline with a capacity of 4 Mt/y of CO_2 is estimated as 17.77 M€. The corresponding annual operating costs are 1.2 M€/y. The discounted unit cost of CO_2 transport is estimated as 0.74 €/t (Table 5-12).

Injection wells for storage in the saline formation onshore are estimated to cost 3.84 M€/well based on the unit cost given in Table 5-6 and a well depth of 1450 m. Capital costs are 11.50 M€, operating expenses are 9.12 M€/y. The discounted unit cost for CO_2 storage is 2.57 €/t (Table 5-12).

Total cost of CO_2 transport and storage is 3.31 €/t.

Closed onshore reservoir with water extraction (On-4o-2-2-A)

For the cases for which water extraction is required to accommodate CO_2 storage, extraction costs are 10.18 M€ (Capex) and 1.65 M€/y (Opex).

In contrast to the offshore scenario, water disposal in the onshore scenario is associated with substantial costs. The water is assumed to be reinjected at Rossum-Weerselo, about 170 km from the storage site, requiring pipeline transport. At the disposal site, additional disposal wells are necessary to accommodate the considerable volumes of water produced in the USCPC scenario. Assuming a water injection rate of 0.25 Mt/year at Rossum-Weerselo, 28 water disposal wells are estimated to be drilled.

The pipeline is estimated to cost 47.77 M€ with operating costs of 1.79 M€/y.

Capital investment for water disposal at Rossum-Weerselo is 117.29 M€, which are predominantly the cost of water disposal wells. The corresponding operating costs are 11.02 M€/year.

The unit cost for water extraction, transport and disposal for the onshore storage scenario is estimated as 7.98 €/t (Table 5-12).

Total cost of CO_2 transport and storage with water extraction and disposal is 11.29 €/t (Table 5-12).

Storage from the NGCC (2 Mt/y)

This section presents the costs for storage of the CO_2 captured from the natural gas combined cycle power plant (~2 Mt/y) in the Base Case CCS Scenario in which no utilisation of water is considered. Four cases are distinguished:

- Storage in the Q1 saline formation with open reservoir boundaries offshore Netherlands
- Storage in the Q1 saline formation with closed reservoir boundaries and water extraction offshore Netherlands
- Storage in a saline formation with open reservoir boundaries onshore Netherlands
- Storage in a saline formation with closed reservoir boundaries and water extraction onshore Netherlands

The costs for the different cases are summarised in Table 5-13 and described below.

Table 5-13 2018 costs (undiscounted) for CO_2 transport and storage in the offshore Q1 saline formation 110 km from Rotterdam and the onshore saline formation 45 km from Rotterdam for the NGCC scenario (2 Mt/y of CO_2 injected over 25 years). The unit costs are discounted costs

Scenario	**NGCC onshore storage**		**NGCC offshore storage**	
Case	**On-2o-1**	**On-2c-1-1-A**	**Off-2o-1**	**Off-2c-1-A**
Location	Onshore	Onshore	Offshore	Offshore
Reservoir boundary	Open	Closed	Open	Closed
Water extraction	No	Yes	No	Yes
Injection wells	1	1	1	1
Extraction wells	-	1	-	1
Extraction rate, Mt/y	-	3.5	-	3.3
Transport costs				
Capex, M€	15.75	15.75	133.35	133.35
Opex, M€	15.48	15.48	22.83	22.83
Unit Cost, €/t	1.10	1.10	7.11	7.11
Storage costs				
Capex, M€	7.66	7.66	24.15	24.15
Opex, M€	151.29	151.29	409.74	409.74
Unit Cost, €/t	3.41	3.41	9.40	9.40
Water extraction & disposal costs				
Capex, M€	-	108.33	-	15.36
Opex, M€	-	191.35	-	36.97
Unit Cost, €/t	-	9.23	-	1.50
Total unit cost, €/t	4.50	13.73	16.51	18.02

Open reservoir offshore – no water extraction (Off-2o-2)

In the offshore storage scenario, CO_2 transport costs include costs for a 110 km offshore pipeline connecting Rotterdam and the storage site. The capital cost for a pipeline with a capacity of 2 Mt/y is estimated as 133.35 M€ with the corresponding annual operating costs being 0.91 M€/y. The discounted unit cost of CO_2 transport is estimated as 7.11 €/t (Table 5-13).

Capital investment for CO_2 injection operations offshore is 24.15 M€, while operating expenses are 16.39 M€/y. The discounted unit cost for CO_2 storage is 9.40 €/t (Table 5-13).

Total cost of CO_2 transport and storage in the open reservoir offshore is 16.51 €/t (Table 5-13).

Closed reservoir offshore with water extraction (Off-2c-1-1-A)

For the cases for which water extraction from the offshore formation is modelled, extraction costs are 15.36 M€ with operating expenses of 1.48 M€/y. This equates to water extraction costs of 1.5 €/t (Table 5-13).

As above for the USCPC scenario, based on the offshore disposal options ocean discharge and reinjection for pressure maintenance, the cost of disposing the water extracted from the Q1 saline formation is assumed as zero (see Table 5-8).

Total cost of CO_2 transport and storage offshore with water extraction and disposal is 18.02 €/t (Table 5-13).

Open reservoir onshore – no water extraction (On-4o-2)

In the onshore storage scenario, CO_2 transport costs include costs for a 45 km onshore pipeline connecting Rotterdam and the storage site. Capital costs for a pipeline with a capacity of 2 Mt/y of CO_2 are estimated as 15.75 M€. The corresponding annual operating costs are 0.62 M€/y. The discounted unit cost of CO_2 transport is estimated as 1.10 €/t (Table 5-13).

Injection wells for storage in the saline formation onshore are estimated to cost 3.84 M€/well based for a well depth of 1450 m. Capital investment is 7.66 M€, while operating expenses are 6.05 M€/year. The discounted unit cost for CO_2 storage is 3.41 €/t (Table 5-13).

Total cost of CO_2 transport and storage in the open reservoir onshore is 4.5 €/t (Table 5-13).

Closed reservoir onshore with water extraction (On-2c-1-1-A)

For the onshore storage case in a closed reservoir with water extraction, extraction costs are 5.11 M€ with operating expenses of 0.82 M€/y.

Analogous to the USCPC scenario, brine extracted onshore is assumed to be disposed in Rossum-Weerselo, about 170 km from the storage site requiring new disposal wells. Assuming a water injection rate of 0.25 Mt/year at Rossum-Weerselo, 14 water disposal wells are estimated. Capital investment for water disposal is 58.69 M€ with the corresponding operating costs being 5.54 M€/year. The pipeline from the extraction site to the disposal site is estimated to cost 44.54 M€ with annual operating costs of 1.30 M€/y.

The resulting unit cost for water extraction, transport and disposal for the onshore storage case is 9.23 €/t.

Total cost of CO_2 transport and storage in the onshore formation with water extraction and disposal are 13.73 €/t (Table 5-13).

Comparison of Base Case CCS Scenario storage costs

A comparison of the total storage costs of the different cases described above is presented in Table 5-14. Total storage costs include all activities associated with storage, including CO_2 transport and brine extraction and management.

The comparison highlights that CO_2 storage onshore without water extraction is the cheapest storage option for both the USCPC (4 Mt/y) and the NGCC (2 Mt/y) at 3.31 €/t and 4.50 €/t of CO_2 stored, respectively (Table 5-14). If water extraction is required to safely store the CO_2 in a closed reservoir, this adds a considerable cost to the onshore cases; increasing onshore storage costs to 11.29 €/t for the USCPC and 13.73 €/t for the NGCC. Storage for the NGCC is more expensive due to the smaller volume of CO_2 stored in this case, negatively affecting the economies of scale.

The onshore storage costs without water extraction and management are in good agreement with literature costs for CO_2 storage in the Netherlands. ZEP (2011) estimated the cost of CO_2 storage onshore in Europe to range from 1-10 €/t for depleted oil and gas fields and 2-12 €/t for saline aquifers.

Offshore storage is significantly more expensive than storage onshore at 9.60 €/t for the USCPC and 16.51 €/t for the NGCC (Table 5-14). However, due to the cost-effective disposal option selected offshore (disposal costs = 0), water extraction and management only adds a comparatively small penalty in this scenario: for the USCPC the storage cost increases to 11.13 €/t, while for the NGCC it increases to 18.02 €/t. This demonstrates that the economics of water extraction and management are strongly affected by the available water management strategy options.

It should be noted that in the USCPC scenario storage offshore becomes more cost-effective than storage onshore when water extraction is required to safely store CO_2 in a closed formation, as was demonstrated in Table 5-12: 11.13 €/t offshore compared to 11.29 €/t onshore (Table 5-14).

The offshore storage costs without water extraction and management presented here are in good agreement with literature costs for CO_2 storage in the Netherlands. ZEP (2011) estimated the cost of CO_2 storage offshore in Europe to range from 2-14 €/t for depleted oil and gas fields and 6-20 €/t for saline aquifers. Van de Velde et al. (2008) estimate the cost of CO_2 transport and storage in depleted gas fields offshore Netherlands as 8 €/t CO_2. In a report by RCI (2009), costs per unit of CO_2 transported and stored were estimated to range from 20-29 €/t for a volume of up to 6 Mt/y, 13-21 €/t for a volume of 6-10 Mt/y and 13-38 €/t for a volume of more than 17 Mt/y.

Table 5-14 Comparison of the total cost of storage onshore and offshore for an open formation (no water extraction required) and a closed formation (water extraction required) for the USCPC (4 Mt/y CO_2) and the NGCC (2 Mt/y CO_2)

	Total cost of storage	
Scenario	**Open reservoir (no water extraction)**	**Closed reservoir (with water extraction)**
USCPC onshore	3.31 €/t	11.29 €/t
USCPC offshore	9.60 €/t	11.13 €/t
NGCC onshore	4.50 €/t	13.73 €/t
NGCC offshore	16.51 €/t	18.02 €/t

Storage economics of the CCS-Water-Nexus Scenario

In the CCS-Water-Nexus Scenario the integration of CCS with formation water extraction and utilisation in the power plant is assessed. The results with respect to CO_2 transport, storage, water extraction and utilisation are presented below.

Storage from the USCPC (4 Mt/y)

This section presents the costs for storage of the CO_2 captured from the coal fired power plant (~4 Mt/y) in the CCS-Water-Nexus Scenario in which formation water extraction, treatment and utilisation is considered. Six cases are distinguished:

- Storage in the Q1 saline formation with closed reservoir boundaries offshore Netherlands with brine extraction volumetrically equivalent to CO_2 injection
- Storage in the Q1 saline formation with closed reservoir boundaries offshore Netherlands with brine extraction as to meet freshwater demand of the USCPC using evaporative cooling and the capture plant using air cooling
- Storage in the Q1 saline formation with closed reservoir boundaries offshore Netherlands with brine extraction as to meet freshwater demand of the USCPC with capture using evaporative cooling
- Storage in a saline formation with closed reservoir boundaries onshore Netherlands with brine extraction volumetrically equivalent to CO_2 injection
- Storage in a saline formation with closed reservoir boundaries onshore Netherlands with brine extraction as to meet freshwater demand of the USCPC using evaporative cooling and the capture plant using air cooling
- Storage in a saline formation with closed reservoir boundaries onshore Netherlands with brine extraction as to meet freshwater demand of the USCPC with capture using evaporative cooling

The costs for the different cases are summarised in Table 5-15. Storage and transport costs remain the same throughout and only vary for onshore and offshore storage. Water extraction, treatment and disposal costs vary based on the two different storage sites (i.e. onshore and offshore) and the different extraction rates as to accommodate power station freshwater needs.

In the CCS-Water-Nexus Scenario CO_2 storage and transport costs are the same as for the equivalent Base Case CCS Scenario case. The difference is the addition of water treatment and utilisation. For the case in which the extracted brine is volumetrically equivalent to the CO_2 injected (6.9 and 6.7 Mt/y in the onshore and offshore case, respectively), the discounted cost of water extraction, treatment and disposal is 7.29 €/t, bringing the total costs of CO_2 storage to 10.61 €/t for the onshore case (Table 5-15). Offshore, the unit costs from water extraction and reuse are lower at 5.72 €/t due to the lower salinity of the extracted brine and the inexpensive disposal of the concentrated reject stream from the treatment. The total costs of storage offshore become 15.32 €/t (Table 5-15).

As more water is extracted to meet the freshwater consumption of the respective power plant, unit costs per tonne of CO_2 stored increase though the CO_2 injection rate does not change. As a result, for the USCPC using evaporative cooling with capture using air cooling having a freshwater demand of 4.9 Mt/y, total storage costs increase to 20.78 €/t onshore and 16.45 €/t offshore. For the USCPC with capture using evaporative cooling, which has a freshwater requirement of 7.8 Mt/y, total storage costs increase further to 30.21 €/t onshore and 18.65 €/t offshore (Table 5-15).

Table 5-15 2018 costs (undiscounted) for CO_2 transport and storage in the offshore Q1 saline formation 110 km from Rotterdam and the onshore saline formation 45 km from Rotterdam for the USCPC scenario (4 Mt/y of CO_2 injected over 25 years). The unit costs are discounted costs

Scenario	USCPC onshore storage			USCPC offshore storage		
Storage case	**On-4c-2-2-A**	**On-4c-2-6-B**	**On-4c-2-10-B**	**Off-4c-2-2-A**	**Off-4c-2-3-B**	**Off-4c-2-5-B**
Location	Onshore	Onshore	Onshore	Offshore	Offshore	Offshore
Reservoir boundary	Closed	Closed	Closed	Closed	Closed	Closed
Water extraction	Yes	Yes	Yes	Yes	Yes	Yes
Injection wells	2	2	2	2	2	2
Extraction wells	2	6	10	2	3	5
Extraction rate, Mt/y	6.9	19.5	31	6.7	9.8	15.5
Product volume, Mt/y	1.7	4.9	7.8	3.4	4.9	7.8
Disposal volume, Mt/y	5.2	14.6	23.3	3.4	4.9	7.8
Transport costs						
Capex, M€	17.77	17.77	17.77	138.30	138.30	138.30
Opex, M€	30.11	30.11	30.11	37.64	37.64	37.64
Unit Cost, €/t	0.74	0.74	0.74	3.83	3.83	3.83
Storage costs						
Capex, M€	11.50	11.50	11.50	36.36	36.36	36.36
Opex, M€	228.10	228.10	228.10	486.54	486.54	486.54
Unit Cost, €/t	2.57	2.57	2.57	5.77	5.77	5.77
Water extraction, treatment & disposal costs						
Capex, M€	162.80	354.28	529.38	165.89	184.92	221.26
Opex, M€	323.86	864.56	1370.92	158.19	224.22	353.66
Unit Cost, €/t	7.29	17.47	26.90	5.72	6.85	9.05
Total unit cost, €/t	10.61	20.78	30.21	15.32	16.45	18.65

Water treatment costs for the six cases are presented in Table 5-16. While the operating unit costs are estimated to remain constant for the same feed concentration even as the feed volume changes, the required increase in capacity drives up capital investment. For the onshore brine with a salinity of 150,000 mg/L undiscounted unit costs for water treatment applying mechanical vapour compression range from 0.84 – 0.92 €/m^3 product. For the less saline offshore brine (TDS 100,000 mg/L) treatment costs range from 0.74 – 0.78 €/m^3 product. The unit costs decrease with higher feed volumes due to economies of scale.

Table 5-16 Water treatment costs using mechanical vapour compression for the onshore and offshore brines for various water extraction rates for the USCPC scenario. The unit cost is not discounted

Scenario	**USCPC onshore storage**			**USCPC offshore storage**		
Storage case	**On-4c-2-2-A**	**On-4c-2-6-B**	**On-4c-2-10-B**	**Off-4c-2-2-A**	**Off-4c-2-3-B**	**Off-4c-2-5-B**
Treated volume, Mt/y	6.9	19.5	31	6.7	9.76	15.5
Salinity, mg/L	150,000	150,000	150,000	100,000	100,000	100,000
Product recovery, %	25	25	25	50	50	50
Product volume, Mt/y	1.7	4.9	7.8	3.4	4.9	7.8
Capex, M€	7.57	14.29	18.88	11.47	14.29	18.88
Opex, €/m^3 product	0.74	0.74	0.74	0.64	0.64	0.64
Total Opex, M€	31.50	90.80	144.53	54.77	78.93	125.64
Unit cost, €/m^3 product	0.92	0.86	0.84	0.78	0.76	0.74

Storage from the NGCC (2 Mt/y)

This section presents the costs for storage of the CO_2 captured from the natural gas fired combined cycle power plant (~2 Mt/y) in the CCS-Water-Nexus Scenario in which formation water extraction, treatment and utilisation is considered. Six cases are distinguished:

- Storage in the Q1 saline formation with closed reservoir boundaries offshore Netherlands with brine extraction volumetrically equivalent to CO_2 injection
- Storage in the Q1 saline formation with closed reservoir boundaries offshore Netherlands with brine extraction as to meet freshwater demand of the NGCC with evaporative cooling using air cooling for the capture plant
- Storage in the Q1 saline formation with closed reservoir boundaries offshore Netherlands with brine extraction as to meet freshwater demand of the NGCC and the capture plant both using evaporative cooling
- Storage in a saline formation with closed reservoir boundaries onshore Netherlands with brine extraction volumetrically equivalent to CO_2 injection
- Storage in a saline formation with closed reservoir boundaries onshore Netherlands with brine extraction as to meet freshwater demand of the NGCC with evaporative cooling and air cooling for the capture plant
- Storage in a saline formation with closed reservoir boundaries onshore Netherlands with brine extraction as to meet freshwater demand of the NGCC and the capture plant both using evaporative cooling

The costs for the different cases are summarised in Table 5-17 and described below. Storage and transport costs remain the same throughout and only vary for onshore and offshore storage. Water extraction, treatment and disposal costs vary based on the two different storage sites (i.e. onshore and offshore) and the different extraction rates as to accommodate power station freshwater needs.

Analogous to the USCPC scenario, the difference between the CCS-Water-Nexus Scenario and the equivalent Base Case CCS Scenario are the costs of water treatment and utilisation. For the case in which the extracted brine is volumetrically equivalent to the CO_2 injected (3.5 and 3.3 Mt/y in the onshore and offshore case, respectively), the discounted cost of water extraction, treatment and disposal is 8.71 €/t, bringing the total costs of CO_2 storage to 13.21 €/t for the onshore case (Table 5-17). Offshore, the unit costs from water extraction and reuse are comparable at 8.95 €/t. The total costs of storage offshore become 25.46 €/t (Table 5-17).

As more water is extracted to meet the freshwater consumption of the power plants, unit costs per tonne of CO_2 stored increase though the CO_2 injection rate remains constant. As a result, for the NGCC using evaporative cooling with capture using air cooling with a freshwater demand of 1.8 Mt/y, total storage costs increase to 19.99 €/t onshore and 25.59 €/t offshore. For the NGCC with capture using evaporative cooling, which has a freshwater requirement of 4.2 Mt/y, total storage costs increase further to 35.41 €/t onshore and 29.58 €/t offshore.

Table 5-17 2018 costs (undiscounted) for CO_2 transport and storage in the offshore Q1 saline formation 110 km from Rotterdam and the onshore saline formation 45 km from Rotterdam for the NGCC scenario (4 Mt/y of CO2 injected over 25 years). The unit costs are discounted costs

Scenario	**NGCC onshore storage**			**NGCC offshore storage**		
Storage case	**On-2c-1-1-A**	**On-2c-1-3-B**	**On-2c-1-5-B**	**Off-2c-1-1-A**	**Off-2c-1-1-B**	**Off-2c-1-3-B**
Location	Onshore	Onshore	Onshore	Offshore	Offshore	Offshore
Reservoir boundary	Closed	Closed	Closed	Closed	Closed	Closed
Water extraction	Yes	Yes	Yes	Yes	Yes	Yes
Injection wells	1	1	1	1	1	1
Extraction wells	1	3	5	1	1	3
Extraction rate, Mt/y	3.5	7.2	17	3.3	3.6	8.48
Product volume, Mt/y	0.9	1.8	4.2	1.7	1.8	4.2
Disposal volume, Mt/y	2.6	5.4	12.7	1.7	1.8	4.2
Transport costs						
Capex, M€	15.75	15.75	15.75	133.35	133.35	133.35
Opex, M€	15.48	15.48	15.48	22.83	22.83	22.83
Unit Cost, €/t	1.10	1.10	1.10	7.11	7.11	7.11
Storage costs						
Capex, M€	7.66	7.66	7.66	24.15	24.15	24.15
Opex, M€	151.29	151.29	151.29	409.74	409.74	409.74
Unit Cost, €/t	3.41	3.41	3.41	9.40	9.40	9.40
Water extraction, treatment & disposal costs						
Capex, M€	106.46	171.99	315.93	145.05	145.63	182.32
Opex, M€	170.17	345.67	758.20	85.48	90.33	198.55
Unit Cost, €/t	8.71	15.48	30.90	8.95	9.07	13.06
Total unit cost, €/t	13.21	19.99	35.41	25.46	25.59	29.58

Water treatment costs

Water treatment costs for the six cases are presented in Table 5-18. While the operating unit costs are estimated to remain constant for the same feed concentration even as the feed volume changes, the required increase in capacity drives up capital investment. For the onshore brine with a salinity of 150,000 mg/L treatment undiscounted unit costs for water treatment with mechanical vapour compression range from 0.87 – 0.97 €/m^3 product. For the less saline offshore brine (TDS 100,000 mg/L) treatment costs range from 0.77 – 0.82 €/m^3 product. As above for the USCPC scenario, the unit costs decrease with higher feed volumes due to economies of scale.

Table 5-18 Water treatment costs using MVC for the onshore and offshore brines for various water extraction rates for the NGCC scenario. The water treatment unit cost is not discounted

Scenario	NGCC onshore storage			NGCC offshore storage		
Storage case	**On-2c-1-1-A**	**On-2c-1-3-B**	**On-2c-1-5-B**	**Off-2c-1-1-A**	**Off-2c-1-1-B**	**Off-2c-1-3-B**
Treated volume, Mt/y	3.5	7.2	17	3.3	3.6	8.48
Salinity, mg/L	150,000	150,000	150,000	100,000	100U,000	100,000
Product recovery, %	25	25	25	50	50	50
Product volume, Mt/y	0.9	1.8	4.2	1.7	1.8	4.2
Capex, M€	5.17	7.83	13.02	7.57	7.83	13.02
Opex, €/m^3 product	0.74	0.74	0.74	0.64	0.64	0.64
Total Opex, M€	16.68	33.35	77.83	27.38	28.99	67.65
Unit cost, €/m^3 product	0.97	0.92	0.87	0.82	0.82	0.77

Comparison of storage costs in the Base Case CCS and the CCS-Water-Nexus Scenario

USCPC

The costs of CO_2 transport and storage, and brine extraction and management are compared in Table 5-19 for storage onshore and Table 5-20 for storage offshore in the USCPC scenario. The results highlight that transport and storage costs remain constant as long as the storage site is the same, because the CO_2 injected and stored is not affected by the water management strategy.

The results further highlight that the extraction of water can add a substantial cost to a storage project: onshore, the minimum cost for water extraction and management is 7.29 €/t of CO_2 stored (Table 5-19). Offshore, where disposal was assumed to be free of charge, it is much lower at 1.53 €/t (Table 5-20). This indicates the range of water extraction and management costs.

Onshore, the extraction of water increases the total cost of CO_2 storage significantly from 3.31 €/t to a minimum of 10.61 €/t using the cheapest water management option (Table 5-19). Offshore, where storage costs are higher to start with, water extraction and management increase the cost of CO_2 storage from 9.60 €/t to 11.13 €/t (Table 5-20).

It is worth pointing out that in the onshore scenario treatment of the produced water and its subsequent reuse in the power station is more cost effective than the direct disposal of produced water: 7.29 €/t compared to 7.98 €/t (Table 5-19). Water disposal onshore at Rossum-Weerselo is expensive due to long pipeline transport and a significant number of disposal wells being required. Reducing the brine volume for disposal by 25% is sufficient to justify the cost associated with brine treatment and reuse. For less saline brines (onshore brine: 150,000 mg/L) the economic benefits would improve further as product recovery would increase and/or cheaper treatment technologies may be applied, such as reverse osmosis. Therefore, where water extraction is necessary for storage purposes, its treatment and beneficial reuse may be the most economic option.

Table 5-19 2018 costs for CO_2 transport, storage, and brine management in the onshore saline formation 45 km from Rotterdam for the USCPC scenario (4 Mt/y of CO_2 injected over 25 years)

Scenario	**Base Case CCS: USCPC**		**CCS-Water-Nexus: USCPC**		
Storage case	**On-4o-2**	**On-4c-2-2-A**	**On-4c-2-2-A**	**On-4c-2-6-B**	**On-4c-2-10-B**
Location	Onshore	Onshore	Onshore	Onshore	Onshore
Reservoir boundary	Open	Closed	Closed	Closed	Closed
Water extraction	No	Yes	Yes	Yes	Yes
Injection wells	2	2	2	2	2
Extraction wells	-	2	2	6	10
Extraction rate, Mt/y	-	6.9	6.9	19.5	31
Product volume, Mt/y	-	-	1.7	4.9	7.8
Disposal volume, Mt/y	-	-	5.2	14.6	23.3
Transport cost, €/t	0.74	0.74	0.74	0.74	0.74
Storage cost, €/t	2.57	2.57	2.57	2.57	2.57
Water extraction & management cost, €/t	-	7.98	7.29	17.47	26.90
Total cost, €/t	3.31	11.29	10.61	20.78	30.21

Table 5-20 2018 costs for CO_2 transport, storage, and brine management in the offshore Q1 saline formation 110 km from Rotterdam for the USCPC scenario (4 Mt/y of CO_2 injected over 25 years)

Scenario	Base Case CCS: USCPC		CCS-Water-Nexus: USCPC		
Storage case	**Off-4o-2**	**Off-4c-2-2-A**	**Off-4c-2-2-A**	**Off-4c-2-3-B**	**Off-4c-2-5-B**
Location	Offshore	Offshore	Offshore	Offshore	Offshore
Reservoir boundary	Open	Closed	Closed	Closed	Closed
Water extraction	No	Yes	Yes	Yes	Yes
Injection wells	2	2	2	2	2
Extraction wells	-	2	2	3	5
Extraction rate, Mt/y	-	6.7	6.7	9.8	15.5
Product volume, Mt/y	-	-	3.4	4.9	7.8
Disposal volume, Mt/y	-	-	3.4	4.9	7.8
Transport cost, €/t	3.83	3.83	3.83	3.83	3.83
Storage cost, €/t	5.77	5.77	5.77	5.77	5.77
Water extraction & management cost, €/t	-	1.53	5.35	6.30	8.14
Total cost, €/t	9.60	11.13	14.95	15.90	17.74

NGCC

The costs of CO_2 transport and storage, and brine extraction and management in the NGCC scenario are compared in Table 5-21 for onshore storage and Table 5-22 for offshore storage.

As for the USCPC scenario, the results show that water extraction and management can add a substantial cost to a storage project: onshore, the minimum cost for water extraction and management is 8.71 €/t of CO_2 injected (Table 5-21). In the offshore case, where the cost of brine disposal is estimated as zero, it is only 1.50 €/t (Table 5-22).

Onshore, the extraction of water increases the total cost of CO_2 storage from 4.50 €/t to a minimum of 13.21 €/t when the cheapest water management option is selected (Table 5-21). Offshore, minimum storage costs are already high at 16.51 €/t, with water extraction increasing these to 18.02 €/t (Table 5-22).

Analogous to the USCPC scenario, treatment of the produced water and its subsequent reuse in the power station is more cost effective than the direct disposal of produced water in the onshore case: 8.71 €/t compared to 9.23 €/t (Table 5-21) as a result of the reduced disposal volume.

Table 5-21 2018 costs for CO_2 transport, storage, and brine management in the onshore saline formation 45 km from Rotterdam for the NGCC scenario (4 Mt/y of CO_2 injected over 25 years)

Scenario	**Base Case CCS: NGCC**		**CCS-Water-Nexus: NGCC**		
Storage case	**On-2o-1**	**On-2c-1-1-A**	**On-2c-1-1-A**	**On-2c-1-3-B**	**On-2c-1-5-B**
Location	Onshore	Onshore	Onshore	Onshore	Onshore
Reservoir boundary	Open	Closed	Closed	Closed	Closed
Water extraction	No	Yes	Yes	Yes	Yes
Injection wells	1	1	1	1	1
Extraction wells	-	1	1	3	5
Extraction rate, Mt/y	-	3.5	3.5	7.2	17
Product volume, Mt/y	-	-	0.9	1.8	4.2
Disposal volume, Mt/y	-	-	2.6	5.4	12.7
Transport cost, €/t	1.10	1.10	1.10	1.10	1.10
Storage cost, €/t	3.41	3.41	3.41	3.41	3.41
Water extraction & management cost, €/t	-	9.23	8.71	15.48	30.90
Total cost, €/t	4.50	13.73	13.21	19.99	35.41

Table 5-22 2018 costs for CO_2 transport, storage, and brine management in the offshore Q1 saline formation 110 km from Rotterdam for the NGCC scenario (2 Mt/y of CO_2 injected over 25 years)

Scenario	**Base Case CCS: NGCC**		**CCS-Water-Nexus: NGCC**		
Storage case	**Off-2o-1**	**Off-2c-1-1A**	**Off-2c-1-1-A**	**Off-2c-1-1-B**	**Off-2c-1-3-B**
Location	Offshore	Offshore	Offshore	Offshore	Offshore
Reservoir boundary	Open	Closed	Closed	Closed	Closed
Water extraction	No	Yes	Yes	Yes	Yes
Injection wells	1	1	1	1	1
Extraction wells	-	1	1	1	3
Extraction rate, Mt/y	-	3.3	3.3	3.6	8.48
Product volume, Mt/y	-	-	1.7	1.8	4.2
Disposal volume, Mt/y	-	-	1.7	1.8	4.2
Transport cost, €/t	7.11	7.11	7.11	7.11	7.11
Storage cost, €/t	9.40	9.40	9.40	9.40	9.40
Water extraction & management cost, €/t	-	1.50	8.95	9.07	13.06
Total cost, €/t	16.51	18.02	25.46	25.59	29.58

5.6 Integration of CCS economics

This section presents the economics of the integrated cases outlined in Chapter 4 using the economic results presented above: CO_2 capture from a coal fired or natural gas combined cycle power plant located in or near Rotterdam using either evaporative cooling, once-through seawater cooling, or air cooling with CO_2 storage in either onshore or offshore Netherlands in a closed or open saline formation. For the purpose of this study, CO_2 storage in a closed formation is assumed to require water extraction for safe long term storage of CO_2. In the Base Case CCS Scenario the extracted water is disposed in the manner considered most appropriate, while in the CCS-Water-Nexus Scenario the extracted brine is treated for utilisation in the power station with capture.

5.6.1 Base Case CCS Scenario

The integrated economics of the Base Case CCS Scenario are presented below for the USCPC and the NGCC. First, the economics of CCS in an open saline formation onshore and offshore are assessed. This means no brine extraction and no subsequent brine management is required. The subsequent section will present the integrated economics of CCS in a closed saline formation onshore and offshore, for which brine extraction and disposal is included in the analysis.

CCS from USCPC power plants with storage in open saline formations (no water extraction)

Table 5-23 and Table 5-24 summarise in detail the cost breakdown of USCPC power plants (Case 1, see Table 4-1) with different cooling technologies, post-combustion capture, as well as transport and storage in saline formations with open reservoir boundaries onshore and offshore Netherlands, including capital investment, operating expenses, LCOE, and CO_2 avoidance cost.

The LCOE for CCS from USCPC power plants is presented Figure 5-1. The LCOE varies from 56 to 59 €/MWh for power plants without CCS, increasing by approximately 25 €/MWh for CCS based on onshore storage, and 29 €/MWh for CCS based on offshore storage (Figure 5-1). This is for the cases where the PCC plant uses the same cooling technology as in the reference power plant.

If air cooling is used for the PCC rather than evaporative or once-through cooling, the increase in LCOE for USCPC power plants is 29 €/MWh for onshore storage and 34 €/MWh for offshore storage. The increase in 5€/MWh arises due to the change in capital and operating costs for the PCC plant because of the large air-coolers.

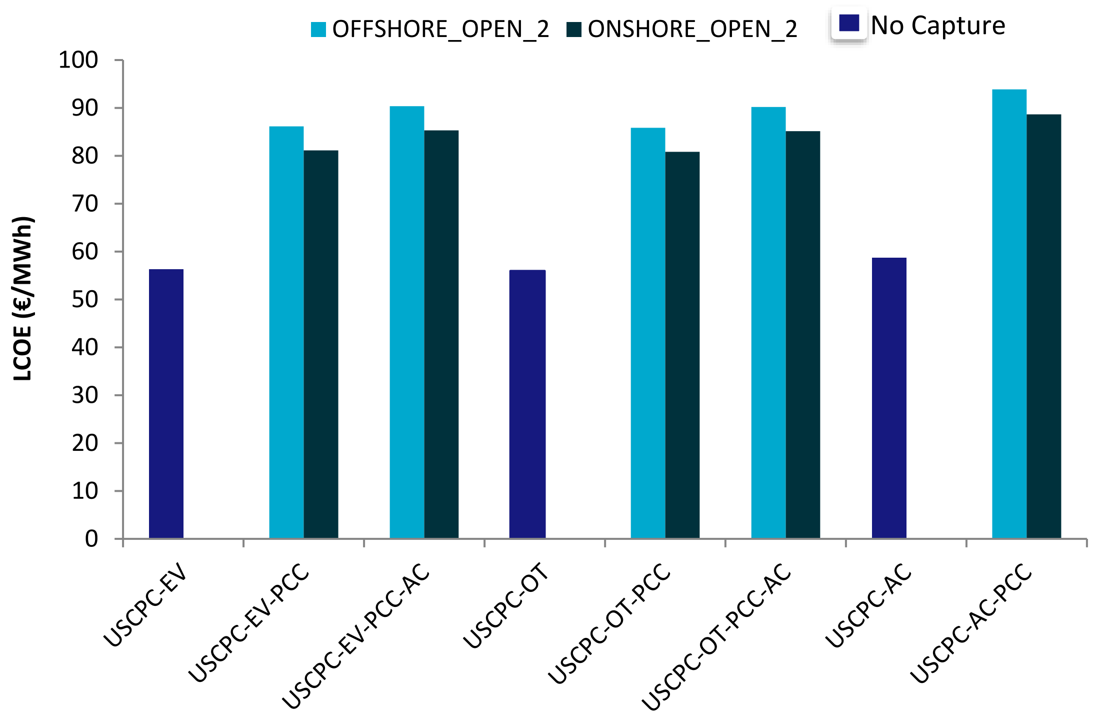


Figure 5-1 LCOE of USCPC power plants without (USCPC-EV, USCPC-OT, USCPC-AC) and with CCS in saline formations with open reservoir boundaries onshore and offshore Netherlands

The CO_2 avoidance costs for the integrated USCPC cases are presented in Figure 5-2 and Figure 5-3, and range from 38 €/t CO_2 avoided for the USCPC power plant using evaporative cooling with onshore storage to 46 €/t CO_2 avoided for the power plant using evaporative cooling with offshore storage (Figure 5-2). Similar avoidance costs are also estimated for the power plants using once-through cooling.

For the power plants for which the capture plants use air cooling (Cases 1.1C, 1.2C, 1.3B, see Table 4-1), the avoidance costs are about 45€/t CO_2 avoided for onshore storage and 52 €/t CO_2 avoided for offshore storage. There is not much variation in the avoidance cost between the different power stations as the reference plant is taken to be the same plant without capture: that is Cases 1.1A, 1.2A, and 1.3A respectively.

If the reference plant is changed to the USCPC power plant using evaporative cooling (Case 1.1A) for all cases, then the avoidance cost for Cases 1.2C and 1.3B change due to the differences in LCOE and CO_2 emissions for the reference plant. Figure 5-3 outlines this situation. For the power plant with capture using once-through cooling (Cases 1.2B and 1.2C), the avoidance costs do not change significantly with the change in reference plant because Case 1.1A and Case 1.2A have very similar costs and emissions. However, for Case 1.3B, where the USCPC power plant with capture uses air cooling, because the reference plant is now a cheaper plant (compare power plant with evaporative cooling and air cooling in Table 5-10), the increase due to CCS is larger: the avoidance cost is about 50 €/t CO_2 avoided with onshore storage and 58€/t CO_2 avoided with offshore storage.

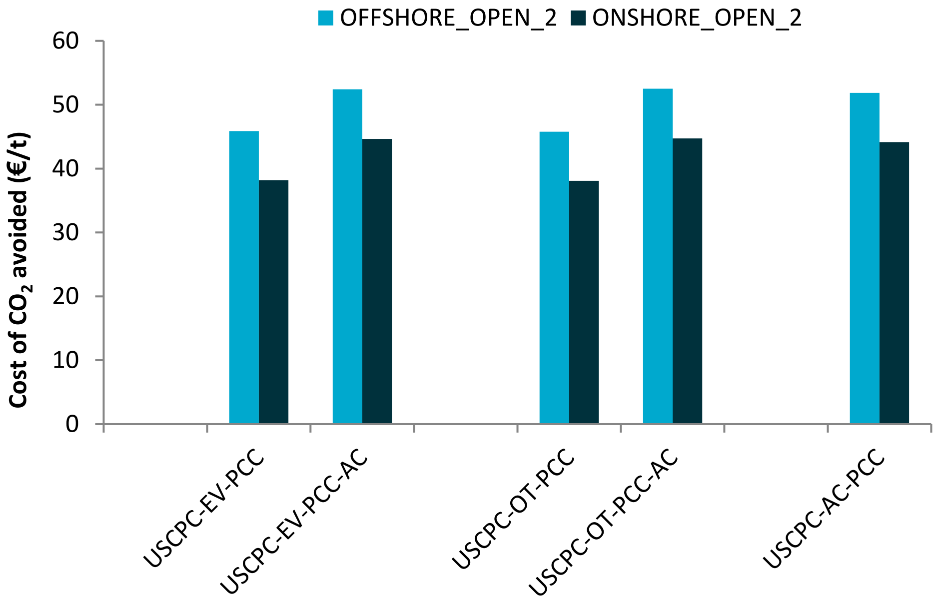


Figure 5-2 Cost of CO_2 avoided for USCPC power plants with CCS in saline formations with open reservoir boundaries onshore and offshore Netherlands

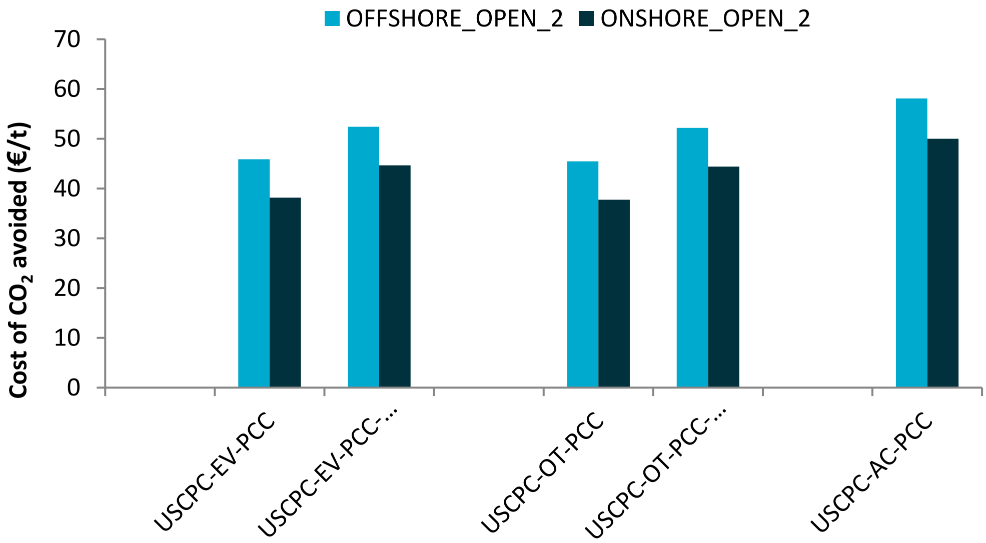


Figure 5-3 Cost of CO_2 avoided for USCPC power plants with CCS in saline formations with open reservoir boundaries onshore and offshore Netherlands, where the reference plant is the USCPC-EV (Case 1.1A)

Table 5-23 USCPC with and without CCS: offshore storage in the Q1 saline aquifer with open reservoir boundaries

		Evaporative cooling			Once through (OT) cooling			Air cooling	
Case name		**USCPC-EV**	**USCPC-EV-PCC**	**USCPC-EV-PCC-AC**	**w/o CCS**	**USCPC-OT-PCC**	**USCPC-OT-PCC-AC**	**USCPC-AC**	**USCPC-AC-PCC**
Cooling technology		**w/o CCS**	**Capture using evaporative cooling**	**Capture using air cooling**	**w/o CCS**	**Capture using OT cooling**	**Capture using air cooling**	**w/o CCS**	**Capture using air cooling**
Efficiency	%LHV	44.40	37.23	36.90	44.40	37.13	36.85	42.70	35.64
Net power	MW	817	684.4	678.4	816	682.6	677.4	784.8	655.2
Water consumption (Total)	Mt/y		7.75	4.88		0.4	0.4		0.4
Water consumption (Capture only)	Mt/y		1.56			0.0018	0.0018		0.0018
Transport and Storage									
Storage location			offshore	offshore		offshore	offshore		offshore
Distance to power station	km		110	110		110	110		110
Reservoir permeability	mD		100	100		100	100		100
Reservoir porosity			0.15	0.15		0.15	0.15		0.15
Reservoir boundaries			open	open		open	open		open
Formation water salinity	ppm		100,000	100,000		100,000	100,000		100,000
Water Management		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Emissions data									
CO_2 emitted	t/MWh	0.738	0.086	0.08712	0.739	0.087	0.087	0.769	0.09020
Capital Costs									
Power Plant with capture	million €	1342.8	1659.3	1785.1	1341.8	1655.3	1781.3	1359.2	1803.5
Start-up costs	million €	39.0	47.3	50.6	38.9	47.2	50.5	39.4	51.1
CO2 Transport	million €		138.30	138.30		138.30	138.30		138.30
CO2 Storage	million €		36.36	36.36		36.36	36.36		36.36
Water extraction	million €	0	0	0	0	0	0	0	0
Total Capex, incl. decommissioning and monitoring	million €	***1382***	***2198***	***2453***	***1381***	***2191***	***2132***	***1399***	***2474***
Operating Costs									
Power Plant and Capture									
Fixed	million €/y	37.7	45.9	48.7	37.6	45.7	48.6	38	49.2
Variable	million €/y	7.54	17.8	17	6	15.8	15.8	6	15.8
Fuel	million €/y	129	129	129	129	129	129	129	129
Transport									
Fixed	million €/y		0.35	0.35		0.35	0.35		0.35

		Evaporative cooling			Once through (OT) cooling			Air cooling	
Case name		**USCPC-EV**	**USCPC-EV-PCC**	**USCPC-EV-PCC-AC**	**w/o CCS**	**USCPC-OT-PCC**	**USCPC-OT-PCC-AC**	**USCPC-AC**	**USCPC-AC-PCC**
Variable	million €/y		1.16	1.16		1.16	1.16		1.16
Storage									
Fixed	million €/y		13.87	13.87		13.87	13.87		13.87
Variable	million €/y		5.59	5.59		5.59	5.59		5.59
Water extraction				0	0	0	0	0	0
Fixed	million €/y	0	0	0	0	0	0	0	0
Variable	million €/y	0	0	0	0	0	0	0	0
Total Opex	**million €/y**	***174***	***214***	***215***	***172***	***212***	***214***	***173***	***215***
LCOE									
Capex (PP+Capture)	€/MWh	27.39	40.39	43.82	27.40	40.39	43.80	28.86	45.84
FOM	€/MWh	6.36	9.24	9.89	6.35	9.23	9.89	6.67	10.35
VOM	€/MWh	1.27	3.58	3.45	1.01	3.19	3.21	1.05	3.32
Fuel	€/MWh	21.20	25.30	25.50	21.20	25.40	25.60	22.10	26.40
Transport & Storage	€/MWh	0.00	7.62	7.69	0.00	7.64	7.70	0.00	7.96
Water treatment	€/MWh	0	0	0	0	0	0	0	0
Total LCOE	**€/MWh**	**56.22**	**86.13**	**90.36**	**55.97**	**85.85**	**90.20**	**58.69**	**93.88**
CO_2 avoided cost (€/t CO_2)			**46**	**52**		**46**	**52**		**52**

Table 5-24 USCPC with and without CCS: onshore storage in a saline aquifer with open reservoir boundaries

		Evaporative cooling			Once through cooling			Air cooling	
Power station type		**USCPC-EV**	**USCPC-EV-PCC**	**USCPC-EV-PCC-AC**	**w/o CCS**	**USCPC-OT-PCC**	**USCPC-OT-PCC-AC**	**USCPC-AC**	**USCPC-AC-PCC**
Cooling technology		**w/o CCS**	**Capture using evaporative cooling**	**Capture using air cooling**	**w/o CCS**	**Capture using OT cooling**	**Capture using air cooling**	**w/o CCS**	**Capture using air cooling**
Efficiency	%LHV	44.40	37.23	36.90	44.40	37.13	36.85	42.70	35.64
Net power	MW	817	684.4	678.4	816	682.6	677.4	784.8	655.2
Water consumption (Total)	Mt/y		7.75	4.88		0.4	0.4		0.4
Water consumption (Capture only)	Mt/y		1.56			0.0018	0.0018		0.0018
Transport and Storage									
Storage location			onshore	onshore		onshore	onshore		onshore
Distance to power station	km		45	45		45	45		45
Reservoir permeability	mD		200	200		200	200		200
Reservoir porosity			0.2	0.2		0.2	0.2		0.2
Reservoir boundaries			open	open		open	open		open
Formation water salinity	ppm		150,000	150,000		150,000	150,000		150,000
Water Management		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Emissions data									
CO_2 emitted	t/MWh	0.738	0.086	0.08712	0.739	0.087	0.087	0.769	0.09020
Capital Costs	Unit								
Power Plant with capture	million €	1342.8	1659.3	1785.1	1341.8	1655.3	1781.3	1359.2	1803.5
Start-up costs	million €	39.0	47.3	50.6	38.9	47.2	50.5	39.4	51.1
CO2 Transport	million €		15.75	15.75		15.75	15.75		15.75
CO2 Storage	million €		11.50	11.50		11.50	11.50		11.50
Water extraction	million €	0	0	0	0	0	0	0	0
Total Capex, incl. decommissioning and monitoring	million €	***1382***	***2050***	***2305***	***1381***	***2043***	***1985***	***1399***	***2326***
Operating Costs									
Power Plant and Capture									
Fixed	million €/y	37.7	45.9	48.7	37.6	45.7	48.6	38	49.2
Variable	million €/y	7.54	17.8	17	6	15.8	15.8	6	15.8
Fuel	million €/y	129	129	129	129	129	129	129	129
Transport									
Fixed	million €/y		0.04	0.04		0.04	0.04		0.04

		Evaporative cooling		Once through cooling				Air cooling	
Power station type		USCPC-EV	USCPC-EV-PCC	USCPC-EV-PCC-AC	w/o CCS	USCPC-OT-PCC	USCPC-OT-PCC-AC	USCPC-AC	USCPC-AC-PCC
Variable	million €/y		1.16	1.16		1.16	1.16		1.16
Storage									
Fixed	million €/y		3.53	3.53		3.53	3.53		3.53
Variable	million €/y		5.59	5.59		5.59	5.59		5.59
Water extraction				0	0	0	0	0	0
Fixed	million €/y	0	0	0	0	0	0	0	0
Variable	million €/y	0	0	0	0	0	0	0	0
Total Opex	**million €/y**	***174***	***203***	***205***	***172***	***201***	***204***	***173***	***204***
LCOE									
Capex (PP+Capture)	€/MWh	27.39	40.39	43.82	27.40	40.39	43.80	28.86	45.84
FOM	€/MWh	6.36	9.24	9.89	6.35	9.23	9.89	6.67	10.35
VOM	€/MWh	1.27	3.58	3.45	1.01	3.19	3.21	1.05	3.32
Fuel	€/MWh	21.20	25.30	25.50	21.20	25.40	25.60	22.10	26.40
Transport & Storage	€/MWh	$0.00	$2.61	$2.63	$0.00	$2.62	$2.64	$0.00	$2.73
Water treatment	€/MWh	$0	$0	$0	$0	$0	$0	$0	$0
Total LCOE	**€/MWh**	**56.22**	**81.12**	**85.30**	**55.97**	**80.83**	**85.13**	**58.69**	**88.64**
CO_2 avoided cost (€/t CO_2)			**38**	**45**		**38**	**45**		**44**

CCS from NGCC power plants with storage in open saline formations (no water extraction)

The LCOE for CCS from NGCC power plants (Case 2, see Table 4-2) with CO_2 storage in saline formations with open reservoir boundaries onshore and offshore Netherlands is presented in Figure 5-4. The LCOE for plants without CCS ranges from 56 €/MWh for evaporative and once-through cooling to 58 €/MWh for power plants using air cooling (Figure 5-4). Implementing CCS using onshore storage increases the LCOE to 77 and 83 €/MWh (Figure 5-4). Utilising offshore storage, the LCOE increases to about 80 and 86 €/MWh.

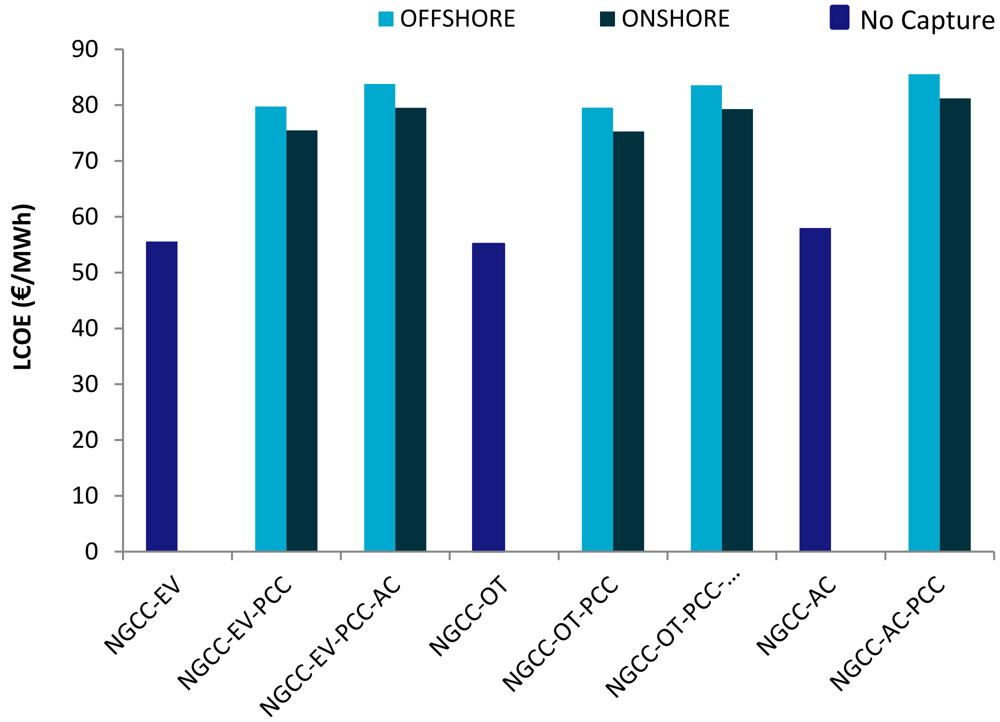


Figure 5-4 LCOE of NGCC power plants without (NGCC-EV, NGCC-OT, NGCC-AC) and with CCS in saline formations with open reservoir boundaries onshore and offshore Netherlands

The avoidance costs for NGCC power plants are presented in Figure 5-5 and Figure 5-6 and range from 64 €/t CO_2 avoided for onshore storage and 78 €/t CO_2 avoided for offshore storage (Figure 5-5). If the PCC uses air cooling rather than evaporative or once-through cooling (Cases 2.1C and 2.2C, see Table 4-2), the large air-coolers needed increase the avoidance costs for these cases by about 13 €/t CO_2 avoided.

Figure 5-6 shows the avoidance costs when the reference plant is taken to be the power plant without capture using evaporative cooling for all cases. The avoidance cost for the power plant with CCS using once-through cooling is about 63.5 €/t CO_2 avoided for onshore storage and 77 €/t CO_2 avoided for offshore storage. This increases to 76 €/t CO_2 avoided for onshore storage and 90 €/t CO_2 avoided for offshore storage if the PCC plant uses air cooling. For the power plant with CCS using air cooling, the change in reference plant increases the avoidance cost to 83 €/t CO_2 avoided for onshore storage and 97 €/t CO_2 avoided for offshore storage.

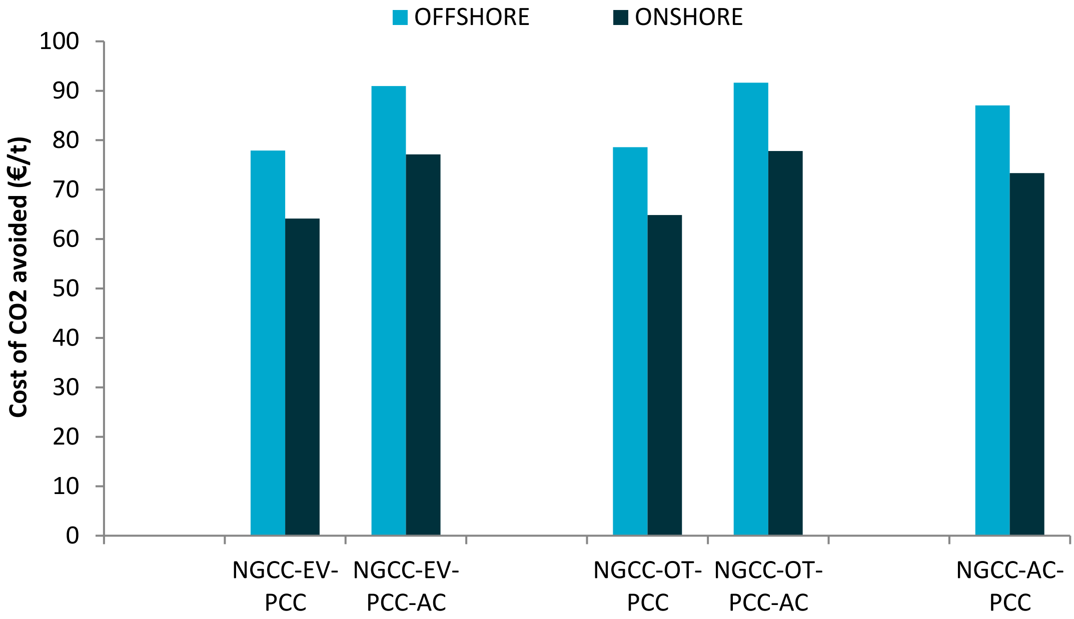


Figure 5-5 Cost of CO_2 avoided for NGCC power plants without and with CCS in saline formations with open reservoir boundaries onshore and offshore Netherlands

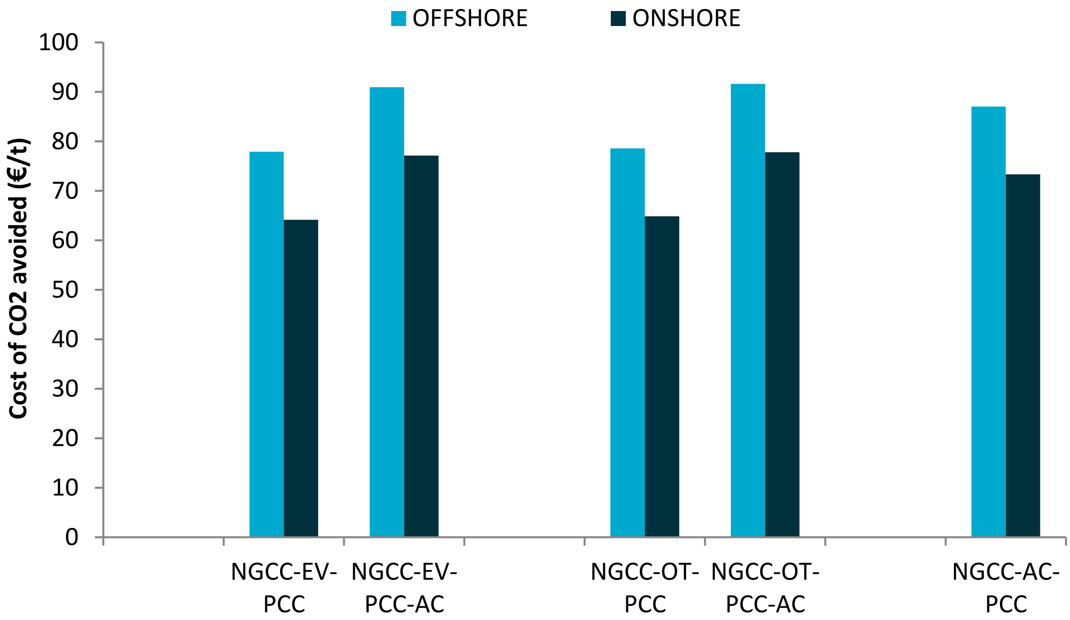


Figure 5-6 Cost of CO_2 avoided for NGCC power plants with CCS in saline formations with open reservoir boundaries onshore and offshore Netherlands where reference plant is the NGCC-EV (Case 2.1A)

Table 5-25 NGCC with and without CCS: offshore storage in the Q1 saline aquifer with open reservoir boundaries

NGCC		Evaporative cooling			Once through cooling			Air cooling	
Power station type		**NGCC-EV**	**NGCC-EV-PCC**	**NGCC-EV-PCC-AC**	**NGCC-OT**	**NGCC-OT-PCC**	**NGCC-OT-PCC-AC**	**NGCC-AC**	**NGCC-AC-PCC**
Cooling technology		**w/o CCS**	**Capture using evaporative cooling**	**Capture using air cooling**	**w/o CCS**	**Capture using OT cooling**	**Capture using air cooling**	**w/o CCS**	**Capture using air cooling**
Efficiency	%LHV	58.34	50.59	50.39	58.65	50.69	50.42	57.33	49.83
Net power	MW	878	761.3	758.2	883.3	762.8	758.8	862.7	749.9
Water consumption (Total)	Mt/y		4.24	1.8		0.000938	0.000938		0.000938
Water consumption (Capture only)	Mt/y		1.05						
Transport and Storage									
Storage location			offshore	offshore		offshore	offshore		offshore
Distance to power station	km		110	110		110	110		110
Reservoir permeability	mD		100	100		100	100		100
Reservoir porosity			0.15	0.15		0.15	0.15		0.15
Reservoir boundaries			open	open		open	open		open
Formation water salinity	ppm		100,000	100,000		100,000	100,000		100,000
Water Management									
Emissions data									
CO2 emitted	t/MWh	0.351	0.041	0.04075	0.351	0.041	0.041	0.358	0.04121
Capital costs									
Power Plant with capture	million €	835.7	1166.3	1302.1	850.2	1169.8	1304.9	890.3	1349.6
Start-up costs	million €	28.7	37.9	41.2	28.7	37.6	41.2	29.9	42.5
CO2 Transport	million €		133.35	133.35	0.00	133.35	133.35	0.00	133.35
CO2 Storage	million €		24.15	24.15	0.00	24.15	24.15	0.00	24.15
Water extraction	million €	0	0	0	0	0	0	0	0
Total Capex, incl. decommissioning and monitoring	million €	***864***	***1692***	***1967***	***879***	***1685***	***1639***	***920***	***2009***
Operating costs									
Power Plant and Capture									
Fixed	million €/y	29.2	39.5	41.7	27.8	38.2	41.8	29	43.2
Variable	million €/y	3.4	8.4	8.4	2.6	8	8	2.6	8
Fuel	million €/y	227	224	226	226	225	225	231	224
Transport									
Fixed	million €/y		0.33	0.33		0.33	0.33		0.33

NGCC		Evaporative cooling			Once through cooling			Air cooling	
Power station type		NGCC-EV	NGCC-EV-PCC	NGCC-EV-PCC-AC	NGCC-OT	NGCC-OT-PCC	NGCC-OT-PCC-AC	NGCC-AC	NGCC-AC-PCC
Variable	million €/y		0.58	0.58		0.58	0.58		0.58
Storage									
Fixed	million €/y		13.59	13.59		13.59	13.59		13.59
Variable	million €/y		2.79	2.79		2.79	2.79		2.79
Water extraction			0	0	0	0	0	0	0
Fixed	million €/y	0	0	0	0	0	0	0	0
Variable	million €/y	0	0	0	0	0	0	0	0
Total Opex	**million €/y**	***260***	***289***	***293***	***256***	***289***	***292***	***263***	***293***
LCOE									
Capex (PP+Capture)	€/MWh	15.86	25.60	28.68	16.10	25.62	28.72	17.18	30.05
FOM	€/MWh	4.56	7.15	7.58	4.34	6.90	7.59	4.61	7.94
VOM	€/MWh	0.53	1.52	1.53	0.41	1.45	1.45	0.41	1.47
Fuel	€/MWh	34.60	39.60	40.10	34.30	39.70	39.90	35.80	40.10
Transport & Storage)	€/MWh	$0.00	5.89	5.91	0.00	5.88	5.91	0.00	5.98
Water treatment	€/MWh	$0	0	0	0	0	0	0	0
Total LCOE	**€/MWh**	**55.55**	**79.76**	**83.80**	**55.14**	**79.55**	**83.57**	**58.00**	**85.54**
CO_2 avoided cost (€/t CO_2)			**78**	**91**		**79**	**92**		**87**

Table 5-26 NGCC with and without CCS: onshore storage in a saline formation with open reservoir boundaries

NGCC		Evaporative cooling			Once through cooling			Air cooling	
Power station type		**w/o CCS**	**w/ CCS-EV**	**w/ CCS-AC**	**w/o CCS**	**w/ CCS-OT**	**w/ CCS-AC**	**w/o CCS**	**w/ CCS**
Cooling technology		EV w/o CCS	EV w/ CCS-EV	EV w/ CCS-AC	OT w/o CCS	OT w/ CCS-OT	OT w/ CCS-AC		
Efficiency	%LHV	58.34	50.59	50.39	58.65	50.69	50.42	57.33	49.83
Net power	MW	878	761.3	758.2	883.3	762.8	758.8	862.7	749.9
Water consumption (Total)	Mt/y		4.24	1.8		0.0009	0.0009		0.0009
Water consumption (Capture only)	Mt/y		1.05						
Transport and Storage									
Storage location			onshore	onshore		onshore	onshore		onshore
Distance to power station	km		45	45		45	45		45
Reservoir permeability	mD		200	200		200	200		200
Reservoir porosity			0.2	0.2		0.2	0.2		0.2
Reservoir boundaries			open	open		open	open		open
Formation water salinity	ppm		150,000	150,000		150,000	150,000		150,000
Water Management			N/A	N/A	N/A	N/A	N/A	N/A	N/A
Emissions data									
CO_2 emitted	t/MWh	0.351	0.041	0.041	0.351	0.041	0.041	0.358	0.041
Capital costs									
Power Plant with capture	million €	835.7	1166.3	1302.1	850.2	1169.8	1304.9	890.3	1349.6
Start-up costs	million €	28.7	37.9	41.2	28.7	37.6	41.2	29.9	42.5
CO2 Transport	million €		15.75	15.75		15.75	15.75		15.75
CO2 Storage	million €		7.66	7.66		7.66	7.66		7.66
Water extraction	million €		0	0	0	0	0	0	0
Total Capex, incl. decommissioning and monitoring	million €	***864***	***1558***	***1833***	***879***	***1550***	***1505***	***920***	***1875***
Operating costs									
Power Plant and Capture									
Fixed	million €/y	29.2	39.5	41.7	27.8	38.2	41.8	29	43.2
Variable	million €/y	3.4	8.4	8.4	2.6	8	8	2.6	8
Fuel	million €/y	227	224	226	226	225	225	231	224
Transport									
Fixed	million €/y		0.04	0.04		0.04	0.04		0.04
Variable	million €/y		0.58	0.58		0.58	0.58		0.58
Storage									

NGCC		**Evaporative cooling**			**Once through cooling**			**Air cooling**	
Power station type		**w/o CCS**	**w/ CCS-EV**	**w/ CCS-AC**	**w/o CCS**	**w/ CCS-OT**	**w/ CCS-AC**	**w/o CCS**	**w/ CCS**
Fixed	million €/y		3.26	3.26		3.26	3.26		3.26
Variable	million €/y		2.79	2.79		2.79	2.79		2.79
Water extraction			0	0	0	0	0	0	0
Fixed	million €/y	0	0	0	0	0	0	0	0
Variable	million €/y	0	0	0	0	0	0	0	0
Total Opex	**million €/y**	***260***	***279***	***283***	***256***	***278***	***281***	***263***	***282***
LCOE									
Capex (PP+Capture)	€/MWh	15.86	25.60	28.68	16.10	25.62	28.72	17.18	30.05
FOM	€/MWh	4.56	7.15	7.58	4.34	6.90	7.59	4.61	7.94
VOM	€/MWh	0.53	1.52	1.53	0.41	1.45	1.45	0.41	1.47
Fuel	€/MWh	34.60	39.60	40.10	34.30	39.70	39.90	35.80	40.10
Transport & Storage	€/MWh	0.00	1.62	1.62	0.00	1.61	1.62	0.00	1.64
Water treatment	€/MWh	0	0	0	0	0	0	0	0
Total LCOE	**€/MWh**	**55.55**	**75.49**	**79.51**	**55.14**	**75.28**	**79.29**	**58.00**	**81.20**
CO_2 avoided cost (€/t CO_2)			**64**	**77**		**65**	**78**		**73**

Economic sensitivities

The following section presents the LCOE and cost of CO_2 avoidance for the Base Case CCS Scenario with storage in open saline formations (i.e. no water extraction) onshore and offshore as a function of discount rate and project life. In addition, the sensitivity of the cost of avoidance to discount rate and project life for the USCPC and NGCC scenarios is also presented for the case in which the reference plant is assumed to be the power plant without capture using evaporative cooling.

Discount rate

USCPC

The baseline value for the discount rate is 8% in this study. The effect of discount rates of 5% and 10% on the LCOE of the USCPS is summarised in Table 5-27.

A decrease in discount rate from 8% to 5% results in reductions in the LCOE of 14.3% for the USCPC power plants without CCS using evaporative cooling or once-through cooling, up to 16.9% for the USCPC with PCC using air cooling with onshore CO_2 storage (Table 5-27).

Similarly, an increase in discount rate from 8% to 10% results in an increase of the LCOE, ranging from 11.9% for the USCPC power plant without CCS using air cooling, up to 13.3% for the USCPC using evaporative cooling or once-through cooling with the PCC using air cooling with offshore CO_2 storage (Table 5-27). This demonstrates that a comparatively small change in discount rate will have a considerable effect on the LCOE.

Table 5-27 Variation in LCOE with discount rate: USCPC with CCS in saline formations with open reservoir boundaries

		LCOE (€/MWh)							
		Case 1.1A	**Case 1.1B**	**Case 1.1B**	**Case 1.2A**	**Case 1.2B**	**Case 1.2C**	**Case 1.3A**	**Case 1.3A**
Discount rate	**Storage**	**USCPC-EV**	**USCPC-EV-PCC**	**USCPC-EV-PCC-AC**	**USCPC-OT**	**USCPC-OT-PCC**	**USCPC-OT-PCC-AC**	**USCPC-AC**	**USCPC-AC-PCC**
5%	Onshore	48	69	72	48	68	71	50	74
	Offshore	48	73	76	48	72	76	50	79
8%	Onshore	56	81	85	56	81	85	59	89
	Offshore	56	86	90	56	86	90	59	94
10%	Onshore	63	91	96	63	91	96	66	100
	Offshore	63	97	102	63	97	102	66	106

CO_2 avoidance costs are similarly affected by variations in the discount rate as shown in Table 5-28. A decrease in discount rate from 8% to 5% lowers CO_2 avoidance costs by as much as 15.8% for the USCPC with PCC using evaporative or once-through cooling and onshore storage (Table 5-28), and by as much as 18.2% for the USCPC with PCC using air cooling and onshore CO_2 storage.

An increase in discount rate by 2 percentage points from 8% to 10% results in an increase of 13.0% for the USCPC with PCC using evaporative or once-through cooling and offshore storage, and an increase of 15.9% for the USCPC with PCC using air cooling and onshore CO_2 storage (Table 5-28).

As for the LCOE, the analysis shows that a comparatively small change in discount rate will have a considerable higher effect on the CO_2 avoidance costs.

Table 5-28 Variation in CO_2 avoided costs with discount rate: USCPC with CCS in saline formations with open reservoir boundaries

		CO_2 avoidance cost (€/t CO_2 avoided)				
		Case 1.1B	Case 1.1C	Case 1.2B	Case 1.2C	Case 1.3B
Discount rate	Storage	USCPC-EV-PCC	USCPC-EV-PCC-AC	USCPC-OT-PCC	USCPC-OT-PCC-AC	USCPC-AC-PCC
5%	Onshore	32	37	32	37	36
	Offshore	38	43	38	43	43
8%	Onshore	38	45	38	45	44
	Offshore	46	52	46	52	52
10%	Onshore	43	51	43	51	51
	Offshore	52	60	52	60	59

NGCC

The baseline value for the discount rate is 8% in this study. The effect of discount rates of 5% and 10% on the LCOE of the NGCC is summarised in Table 5-29.

In comparison to the USCPC, a change in discount rate has a smaller effect on the LCOE and the CO_2 avoidance cost of the NGCC: a decrease in discount rate from 8% to 5% results in a decrease in the LCOE of 8.6% for the NGCC power plant without CCS using air cooling, and a decrease of 11.9% for the NGCC power plants using evaporative cooling or once-through cooling with PCC using air cooling and offshore storage (Table 5-29).

Similarly, an increase in discount rate from 8% to 10% results in an increase of the LCOE, ranging from 5.4% for the NGCC power plant without CCS using evaporative cooling, up to 9.8 % for the NGCC power plant with PCC using air cooling and onshore storage (Table 5-29). While the effect of the discount rate on the LCOE of the NGCC is lower than for the USCPC, it nevertheless shows sensitivity to the discount rate.

CO_2 avoidance costs are more affected by variations in the discount rate as shown in Table 5-30. A decrease in discount rate from 8% to 5% lowers CO_2 avoidance costs by 15.2% for the NGCC with PCC using once-through cooling and offshore storage (Table 5-30), and by as much as 17.8% for the NGCC with PCC using air cooling and onshore CO_2 storage.

An increase in discount rate by 2 percentage points from 8% to 10% results in an increase of 12% to 15% for onshore storage, and from 11% to 14% for offshore storage.

Table 5-29 Variation in LCOE with discount rate: NGCC with CCS in saline formations with open reservoir boundaries

LCOE (€/MWh)

		Case 2.1A	Case 2.1B	Case 2.1B	Case 2.2A	Case 2.2B	Case 2.2C	Case 2.3A	Case 2.3A
Discount rate	**Storage**	**NGCC -EV**	**NGCC -EV-PCC**	**NGCC-EV-PCC-AC**	**NGCC -OT**	**NGCC-OT-PCC**	**NGCC-OT-PCC-AC**	**NGCC-AC**	**NGCC-AC-PCC**
5%	Onshore	51	67	71	50	67	70	53	72
	Offshore	51	71	74	50	71	74	53	76
8%	Onshore	56	75	80	55	75	79	58	81
	Offshore	56	80	84	55	80	84	58	86
10%	Onshore	59	82	87	59	82	86	62	89
	Offshore	59	87	91	59	86	91	62	94

Table 5-30 Variation in CO_2 avoided costs with discount rate: NGCC with CCS in saline formations with open reservoir boundaries

CO_2 avoidance cost (€/t CO_2 avoided)

		Case 2.1B	Case 2.1C	Case 2.2B	Case 2.2C	Case 2.3B
Discount rate	**Storage**	**NGCC-EV-PCC**	**NGCC-EV-PCC-AC**	**NGCC-OT-PCC**	**NGCC-OT-PCC-AC**	**NGCC-AC-PCC**
5%	Onshore	54	64	55	65	60
	Offshore	66	76	67	77	72
8%	Onshore	64	77	65	78	73
	Offshore	78	91	79	92	87
10%	Onshore	72	88	73	88	84
	Offshore	87	103	88	103	99

Project life

The variation in project life from 25 years to 40 years and its effect on the LCOE is shown in Table 5-31 for the USCPC and in Table 5-32 for the NGCC for the Base Case CCS Scenario with storage in open saline formations onshore and offshore Netherlands. For the discount rate of 8%, a 15 year increase in project life decreases the LCOE between 5 – 6% for the USCPC and 3 – 5% for the NGCC. This is due to the project being discounted over a longer period.

Table 5-31 Variation in LCOE with project life for the USCPC power plants with storage onshore and offshore Netherlands in open saline formations: 25 and 40 years

		LCOE (€/MWh)							
		Case 1.1A	Case 1.1B	Case 1.1B	Case 1.2A	Case 1.2B	Case 1.2C	Case 1.3A	Case 1.3A
Project life, y	**Storage**	**USCPC -EV**	**USCPC -EV-PCC**	**USCPC -EV-PCC-AC**	**USCPC -OT**	**USCPC -OT-PCC**	**USCPC-OT-PCC-AC**	**USCPC -AC**	**USCPC -AC-PCC**
25	Onshore	56	81	85	56	81	85	59	89
	Offshore	56	86	90	56	86	90	59	94
40	Onshore	53	77	81	53	76	80	56	84
	Offshore	53	81	85	53	81	85	56	89

Table 5-32 Variation in LCOE with project life for the NGCC power plants with storage onshore and offshore Netherlands in open saline formations: 25 and 40 years

		LCOE (€/MWh)							
		Case 2.1A	Case 2.1B	Case 2.1B	Case 2.2A	Case 2.2B	Case 2.2C	Case 2.3A	Case 2.3A
Project life, y	**Storage**	**NGCC-EV**	**NGCC-EV-PCC**	**NGCC-EV-PCC-AC**	**NGC C-OT**	**NGCC-OT-PCC**	**NGCC-OT-PCC-AC**	**NGCC-AC**	**NGCC-AC-PCC**
25	Onshore	56	75	80	55	75	79	58	81
	Offshore	56	80	84	55	80	84	58	86
40	Onshore	54	73	76	53	72	76	56	78
	Offshore	54	77	80	53	76	80	56	82

The effect of a longer project life of 15 years on the CO_2 avoidance costs is indicated in Table 5-33 for the USCPC and in Table 5-34 for the NGCC for the Base Case CCS Scenario with storage in open saline formations onshore and offshore Netherlands. For the discount rate of 8%, a 15 year increase in project life decreases the CO_2 avoidance cost by about 5 – 7% for both the USCPC and the NGCC due to the extended discounting period.

Table 5-33 Variation in avoidance cost with project life for the USCPC power plants with storage onshore and offshore Netherlands in open saline formations: 25 and 40 years

		CO₂ avoidance cost (€/t CO₂ avoided)				
		Case 1.1B	**Case 1.1C**	**Case 1.2B**	**Case 1.2C**	**Case 1.3B**
Project life, y	**Storage**	**USCPC-EV-PCC**	**USCPC-EV-PCC-AC**	**USCPC-OT-PCC**	**USCPC-OT-PCC-AC**	**USCPC-AC-PCC**
25	Onshore	38	45	38	45	44
	Offshore	46	52	46	52	52
40	Onshore	36	42	36	42	41
	Offshore	43	49	43	49	49

Table 5-34 Variation in avoidance cost with project life for the NGCC power plants with storage onshore and offshore Netherlands in open saline formations: 25 and 40 years

		CO_2 avoidance cost (€/t CO_2 avoided)				
		Case 2.1B	**Case 2.1C**	**Case 2.2B**	**Case 2.2C**	**Case 2.3B**
Project life, y	**Storage**	**NGCC-EV-PCC**	**NGCC-EV-PCC-AC**	**NGCC-OT-PCC**	**NGCC-OT-PCC-AC**	**NGCC-AC-PCC**
25	Onshore	64	77	65	78	73
	Offshore	78	91	79	92	87
40	Onshore	61	73	61	73	69
	Offshore	74	85	74	86	82

Reference plant

This section evaluates the effect of the reference plant on CO_2 avoidance cost. The baseline values presented in Table 5-35 and Table 5-36 for the USCPC and the NGCC respectively are those presented in the sections above and are representative of the cases for which the reference plant is the same power plant (utilising the same cooling technology) as the power plant with CCS.

Changing the reference plant to i.) Case 1.1A - USCPC without capture using evaporative cooling for all the USCPC cases (Table 5-35); and ii.) Case 2.1A - NGCC without capture using evaporative cooling for all the NGCC cases (Table 5-36) shows that only for the power plants with capture using air cooling there are noticeable changes in the CO_2 avoidance cost. This is due to the new reference plant being comparatively cheaper than the USCPC or NGCC power plants without CCS using air cooling. For the USCPC avoidance cost increase by 6 €/t, from 44 €/t and 52 €/t to 50 €/t and 58 €/t for the onshore and offshore storage case, respectively

(Table 5-35). Similarly, for the NGCC the cost increase by 10 €/t, from 73 €/t and 87 €/t to 83 €/t and 97 €/t for the onshore and offshore storage case, respectively.

For the USCPC with CCS using once-through cooling, there is no change in cost as the USCPC power plants without CCS using evaporative cooling and once-through cooling have very similar costs and emissions (Table 5-35). For the NGCC the change in reference plant decreases avoidance cost for the NGCC with CCS using once-through cooling by 2 €/t (Table 5-36).

For the power plants with CCS using evaporative cooling there is no change in avoidance cost as the reference plant remains the same (Table 5-35 and Table 5-36).

Table 5-35 Cost of CO_2 avoided for USCPC power plants with CCS in open reservoir where the reference plant is the USCPC-EV (Case 1.1A) for all scenarios

		CO_2 avoidance cost (€/t CO_2 avoided)				
		Case 1.1B	**Case 1.1C**	**Case 1.2B**	**Case 1.2C**	**Case 1.3B**
Reference plant	**Storage**	**USCPC-EV-PCC**	**USCPC-EV-PCC-AC**	**USCPC-OT-PCC**	**USCPC-OT-PCC-AC**	**USCPC-AC-PCC**
Baseline	Onshore	38	45	38	45	44
	Offshore	46	52	46	52	52
Case 1.1A:	Onshore	38	45	38	44	50
USCPC-EV	Offshore	46	52	45	52	58

Table 5-36 Cost of CO_2 avoided for NGCC power plants with CCS in open reservoir where the reference plant is the NGCC-EV (Case 2.1A) for all scenarios

		CO_2 avoidance cost (€/t CO_2 avoided)				
		Case 2.1B	**Case 2.1C**	**Case 2.2B**	**Case 2.2C**	**Case 2.3B**
Reference plant	**Storage**	**NGCC-EV-PCC**	**NGCC-EV-PCC-AC**	**NGCC-OT-PCC**	**NGCC-OT-PCC-AC**	**NGCC-AC-PCC**
Baseline	Onshore	64	77	65	78	73
	Offshore	78	91	79	92	87
Case 2.1A:	Onshore	64	77	63	76	83
NGCC-EV	Offshore	78	91	77	90	97

CCS from USCPC power plants with storage in closed saline formations (with water extraction)

In this section the integrated economics of CCS in closed saline formations onshore and offshore Netherlands are presented. In the closed reservoir scenario, brine extraction from the reservoir for the purpose of long term safe CO_2 storage and its subsequent disposal are included in the analysis. First, the economics of the coal fired power plants with CCS are evaluated.

The LCOE for CCS from USCPC power plants (Case 1, see Table 4-1) with CO_2 storage in saline formations with closed reservoir boundaries onshore and offshore Netherlands is presented in Figure 5-7. The LCOE for the power plants without CCS are those presented earlier in Section 5.6.1. The LCOE is lowest for the USCPC power plant with post-combustion capture using either evaporative or once-through cooling (Figure 5-7). It varies from 87 to 95 €/MWh for power plants with CCS in both the onshore and offshore storage scenario. (Figure 5-7). This is for the cases where the power plant with capture uses the same cooling technology as the reference power plant. The LCOE onshore and offshore are comparable as the higher CO_2 storage and transport costs associated with the offshore location are offset by the inexpensive brine disposal option offshore (ocean disposal), while onshore expensive brine reinjection is required.

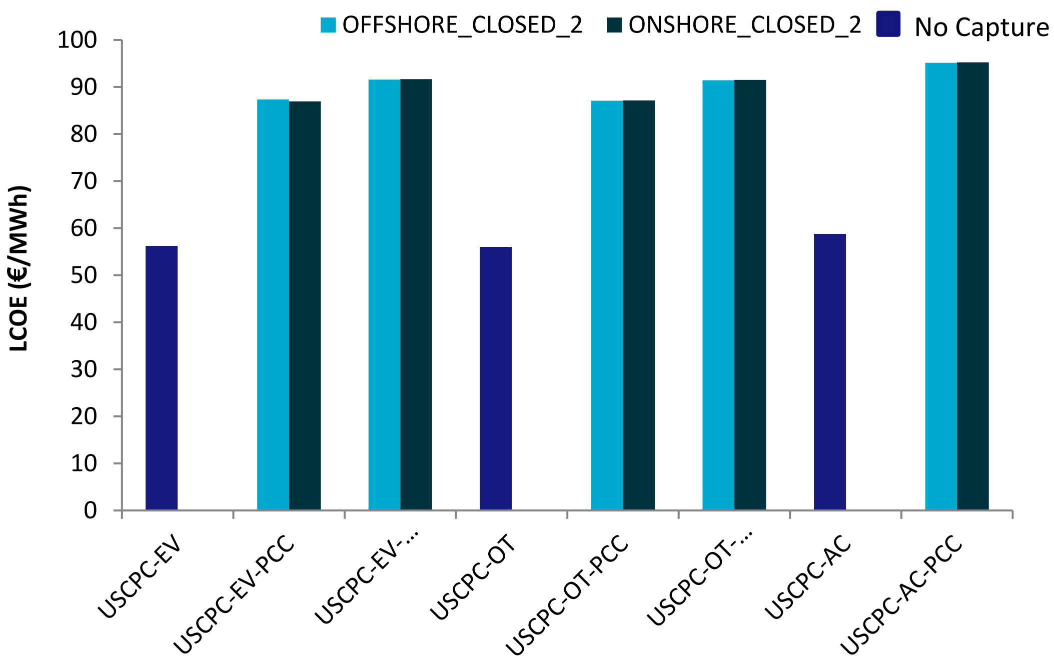


Figure 5-7 LCOE of USCPC power plants without and with CCS in closed saline formations offshore and onshore Netherlands

CO_2 avoidance cost for the USCPC power plants are presented in Figure 5-8. CO_2 avoidance cost are lowest for the USCPC power plant with post-combustion capture using either evaporative or once-through cooling. The costs for the power plants with CCS and offshore storage range from 48 - 54 €/t CO_2 avoided. For onshore storage, the avoidance costs range from 47 - 55 €/t CO_2 avoided, indicating again that neither storage location is favourable over the other when water extraction is included.

A detailed summary of the components of the integrated USCPC-CCS scenario with CO_2 storage in closed saline formations and their economics is presented in Table 5-37 for the offshore storage case and Table 5-38 for the onshore storage case.

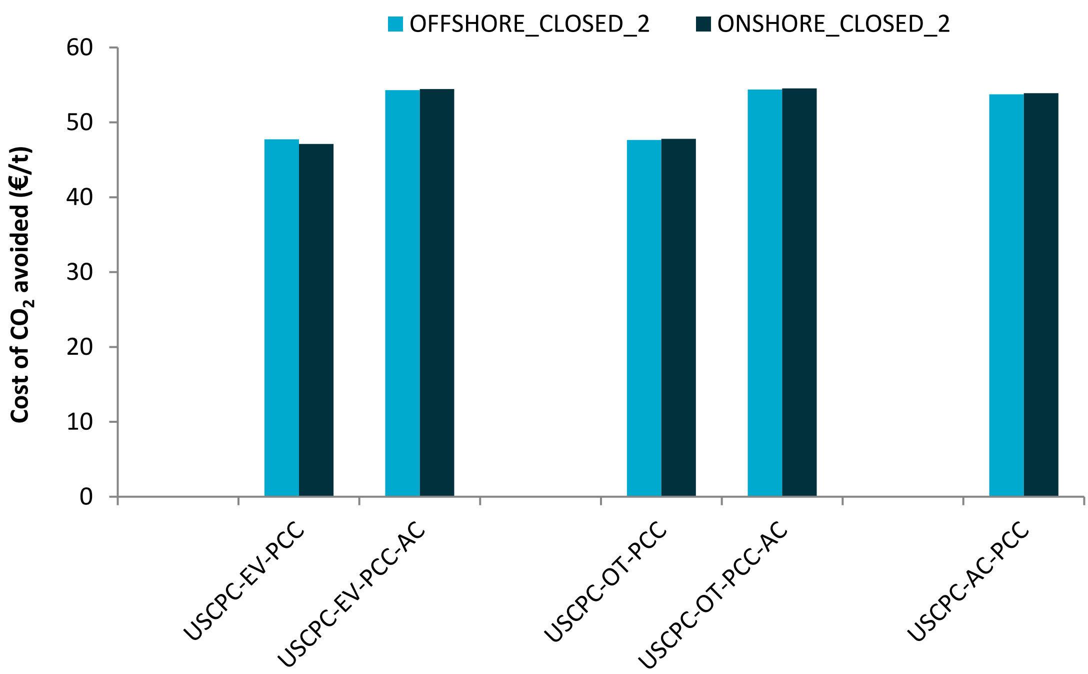


Figure 5-8 Cost of CO_2 avoided for USCPC power plants with CCS in closed saline formations offshore and onshore Netherlands

Table 5-37 USCPC with and without CCS: offshore storage in the Q1 saline formation with closed reservoir boundaries

USCPC		Evaporative cooling			Once through cooling			Air cooling	
Power station type		**USCPC -EV**	**USCPC-EV-PCC**	**USCPC-EV-PCC-AC**	**w/o CCS**	**USCPC-OT-PCC**	**USCPC-OT-PCC-AC**	**USCPC-AC**	**USCPC-AC-PCC**
Cooling technology		EV w/o CCS	EV w/ CCS-EV	EV w/ CCS-AC	OT w/o CCS	OT w/ CCS-OT	OT w/ CCS-AC		
Efficiency	%HHV	42.41	35.56	35.25	42.4	35.47	35.19	40.8	34.04
Gross power	MW	900	900	900	900	900	900	879.4	879.4
Net power	MW	817	684.4	678.4	816	682.6	677.4	784.8	655.18
Water consumption (Total)	Mt/y		7.75	4.88		0.4	0.4		0.4
Transport and Storage									
Storage location			offshore	offshore		offshore	offshore		offshore
Reservoir boundaries			closed	closed		closed	closed		closed
Formation water salinity	ppm		100,000	100,000		100,000	100,000		100,000
CO2 injection rate	Mt/y		4.05	4.05		4.05	4.05		4.05
Injection well number			2.0	2		2	2		2
Water extraction rate	Mt/y		6.7	6.7		6.7	6.7		6.7
Extraction well number			2	2		2	2		2
Water Management									
Treatment or direct disposal			direct disposal	direct disposal		direct disposal	direct disposal		direct disposal
Disposal of extracted brine or reject stream (reinjection or ocean)			ocean	ocean		ocean	ocean		ocean
Number of water injectors			-	-		-	-		-
Emissions data									
CO2 emitted	t/MWh	0.738	0.086	0.08712	0.739	0.087	0.087	0.769	0.09020
Capex									
Power Plant with capture	million €	1342.8	1659.3	1785.1	1341.8	1655.3	1781.3	1359.2	1803.5
Start-up costs	million €	39.0	47.3	50.6	38.9	47.2	50.5	39.4	51.1
CO2 Transport	million €		138.30	138.30		138.30	138.30		138.30
CO2 Storage	million €		36.36	36.36		36.36	36.36		36.36
Water extraction	million €	0	30.8	30.8	30.8	30.8	30.8	30.8	30.8
Water treatment	million €	0	0	0	0	0	0	0	0
Total Capex	million €	***1382***	***2198***	***2453***	***1381***	***2191***	***2132***	***1399***	***2474***
Opex									
Power Plant and Capture									

USCPC		Evaporative cooling			Once through cooling			Air cooling	
Power station type		USCPC -EV	USCPC-EV-PCC	USCPC-EV-PCC-AC	w/o CCS	USCPC-OT-PCC	USCPC-OT-PCC-AC	USCPC-AC	USCPC-AC-PCC
fixed	million €/y	37.7	45.9	48.7	37.6	45.7	48.6	38	49.2
variable	million €/y	7.54	17.8	17	6	15.8	15.8	6	15.8
fuel	million €/y	129	129	129	129	129	129	129	129
Transport									
fixed	million €/y		0.35	0.35		0.35	0.35		0.35
variable	million €/y		1.16	1.16		1.16	1.16		1.16
Storage									
fixed	million €/y		13.87	13.87		13.87	13.87		13.87
variable	million €/y		5.59	5.59		5.59	5.59		5.59
Water extraction, transport and disposal									
fixed	million €/y	0	0.69	0.69	0.69	0.69	0.69	0.69	0.69
variable	million €/y	0	2.37	2.37	2.37	2.37	2.37	2.37	2.37
Water treatment				0	0	0	0	0	0
fixed	million €/y			0	0	0	0	0	0
variable	million €/y			0	0	0	0	0	0
Total Opex	**million €/y**	***174***	***217***	***219***	***175***	***215***	***218***	***176***	***218***
LCOE calculations									
Capex (PP+Capture)	€/MWh	27.39	40.39	43.82	27.40	40.39	43.80	28.86	45.84
FOM	€/MWh	6.36	9.24	9.89	6.35	9.23	9.89	6.67	10.35
VOM	€/MWh	1.27	3.58	3.45	1.01	3.19	3.21	1.05	3.32
Fuel	€/MWh	21.20	25.30	25.50	21.20	25.40	25.60	22.10	26.40
Transport & Storage	€/MWh	0.00	7.62	7.69	0.00	7.64	7.70	0.00	7.96
Water extraction & management	*€/MWh*	*0*	*1*	*1*	*0*	*1*	*1*	*0*	*1*
Total LCOE	**€/MWh**	**56.22**	**87.35**	**91.59**	**55.97**	**87.07**	**91.43**	**58.96**	**95.15**
CO_2 avoided cost (€/t CO_2)			**48**	**54**		**48**	**54**		**54**

Table 5-38 USCPC with and without CCS: onshore storage in the saline formation with closed reservoir boundaries

USCPC		Evaporative cooling			Once through cooling			Air cooling	
Power station type		**USCPC -EV**	**USCPC-EV-PCC**	**USCPC-EV-PCC-AC**	**w/o CCS**	**USCPC-OT-PCC**	**USCPC-OT-PCC-AC**	**USCPC-AC**	**USCPC-AC-PCC**
Cooling technology		EV w/o CCS	EV w/ CCS-EV	EV w/ CCS-AC	OT w/o CCS	OT w/ CCS-OT	OT w/ CCS-AC		
Efficiency	%HHV	42.41	35.56	35.25	42.4	35.47	35.19	40.8	34.04
Gross power	MW	900	900	900	900	900	900	879.4	879.4
Net power	MW	817	684.4	678.4	816	682.6	677.4	784.8	655.18
Water consumption (total)	**Mt/y**		7.75	4.88		0.4	0.4		0.4
Transport and Storage									
Storage location			onshore	onshore		onshore	onshore		onshore
Formation water salinity	ppm		150,000	150,000		150,000	150,000		150,000
CO2 injection rate	Mt/y		4.05	4.05		4.05	4.05		4.05
Injection well number			2.0	2		2	2		2
Water extraction rate	Mt/y		6.9	6.9		6.9	6.9		6.9
Extraction well number			2	2		2	2		2
Water Management									
Treatment or direct disposal			direct disposal	direct disposal		direct disposal	direct disposal		direct disposal
Transport of reject stream			170	170		170	170		170
Disposal of extracted brine or reject stream (reinjection or ocean)			reinjection	reinjection		reinjection	reinjection		reinjection
Number of water injectors			28	28		28	28		28
Emissions data									
CO2 emitted	t/MWh	0.738	0.086	0.08712	0.739	0.087	0.087	0.769	0.09020
Capex									
Power Plant with capture	million €	1342.8	1659.3	1785.1	1341.8	1655.3	1781.3	1359.2	1803.5
Start-up costs	million €	39.0	47.3	50.6	38.9	47.2	50.5	39.4	51.1
CO2 Transport	million €		15.75	15.75		15.75	15.75		15.75
CO2 Storage	million €		11.50	11.50		11.50	11.50		11.50
Water extraction	million €	0	10.18	10.18		10.18	10.18		10.18
Water treatment	million €	0	0.00	0.00		0.00	0.00		0.00
Water transport of treated water	million €	0	0.00	0.00		0.00	0.00		0.00
Water transport (untreated/reject produced water)	million €	0	47.77	47.77		47.77	47.77		47.77

USCPC		Evaporative cooling			Once through cooling			Air cooling	
Power station type		**USCPC -EV**	**USCPC-EV-PCC**	**USCPC-EV-PCC-AC**	**w/o CCS**	**USCPC-OT-PCC**	**USCPC-OT-PCC-AC**	**USCPC-AC**	**USCPC-AC-PCC**
Water disposal (untreated/reject produced water)	million €	0	117.29	117.29		117.29	117.29		117.29
Total Capex	million €	***1382***	***2050***	***2305***	***1381***	***2043***	***1985***	***1399***	***2326***
Opex									
Power Plant and Capture									
fixed	million €/y	37.7	45.9	48.7	37.6	45.7	48.6	38	49.2
variable	million €/y	7.54	17.8	17	6	15.8	15.8	6	15.8
fuel	million €/y	129	126	129	129	129	129	129	129
Transport									
fixed	million €/y		0.04	0.04		0.04	0.04		0.04
variable	million €/y		1.16	1.16		1.16	1.16		1.16
Storage									
fixed	million €/y		3.53	3.53		3.53	3.53		3.53
variable	million €/y		5.59	5.59		5.59	5.59		5.59
Water extraction									
fixed	million €/y	0	0.61	0.61		0.61	0.61		0.61
variable	million €/y	0	1.03	1.03		1.03	1.03		1.03
Water treatment									
fixed	million €/y	0	0.00	0.00		0.00	0.00		0.00
variable	million €/y	0	0.00	0.00		0.00	0.00		0.00
Water transport of treated water									
fixed	million €/y	0	0.00	0.00		0.00	0.00		0.00
variable	million €/y	0	0.00	0.00		0.00	0.00		0.00
Water transport (untreated/reject produced water)									
fixed	million €/y	0	0.16	0.16		0.16	0.16		0.16
variable	million €/y	0	1.63	1.63		1.63	1.63		1.63
Water disposal (untreated/reject produced water)									

USCPC		Evaporative cooling			Once through cooling			Air cooling	
Power station type		**USCPC -EV**	**USCPC-EV-PCC**	**USCPC-EV-PCC-AC**	**w/o CCS**	**USCPC-OT-PCC**	**USCPC-OT-PCC-AC**	**USCPC-AC**	**USCPC-AC-PCC**
fixed	million €/y	0	7.86	7.86		7.86	7.86		7.86
variable	million €/y	0	3.16	3.16		3.16	3.16		3.16
Total Opex	**million €/y**	***174***	***215***	***219***	***172***	***215***	***218***	***173***	***219***
LCOE calculations									
Capex (PP+Capture)	€/MWh	27.39	40.38	43.82	27.40	40.39	43.80	28.86	45.84
FOM	€/MWh	6.36	9.24	9.89	6.35	9.23	9.89	6.67	10.35
VOM	€/MWh	1.27	3.58	3.45	1.01	3.19	3.21	1.05	3.32
Fuel	€/MWh	21.20	24.80	25.50	21.20	25.40	25.60	22.10	26.40
Transport & Storage	€/MWh	0.00	2.61	2.63	0.00	2.62	2.64	0.00	2.73
Water extraction & management	*€/MWh*	*0*	*6*	*6*	*0*	*6*	*6*	*0*	*6*
Total LCOE	**€/MWh**	**56.22**	**86.97**	**91.68**	**55.97**	**87.17**	**91.52**	**58.69**	**92.25**
CO_2 avoided cost (€/t CO_2)			**47**	**54**		**48**	**55**		**54**

CCS from NGCC power plants with storage in closed saline formations (with water extraction)

This section presents the LCOE for CCS from NGCC power plants (Case 2, see Table 4-2) with CO_2 storage in saline formations with closed reservoir boundaries onshore and offshore Netherlands, as shown in Figure 5-9. The LCOE for the NGCC power plants without CCS are those presented earlier in Section 5.6.1. The LCOE is lowest for the NGCC power plant with post-combustion capture using either evaporative or once-through cooling (Figure 5-9). It varies from 80 to 86 €/MWh for power plants with CCS for offshore storage and from 79 to 85 €/MWh for onshore storage (Figure 5-9). This is for the cases where the power plant with capture uses the same cooling technology as the reference power plant. Analogous to CCS from the USCPC power plant in the closed formation, the higher offshore storage costs are offset by the less expensive water management strategy available. This results in similar LCOE for onshore and offshore storage.

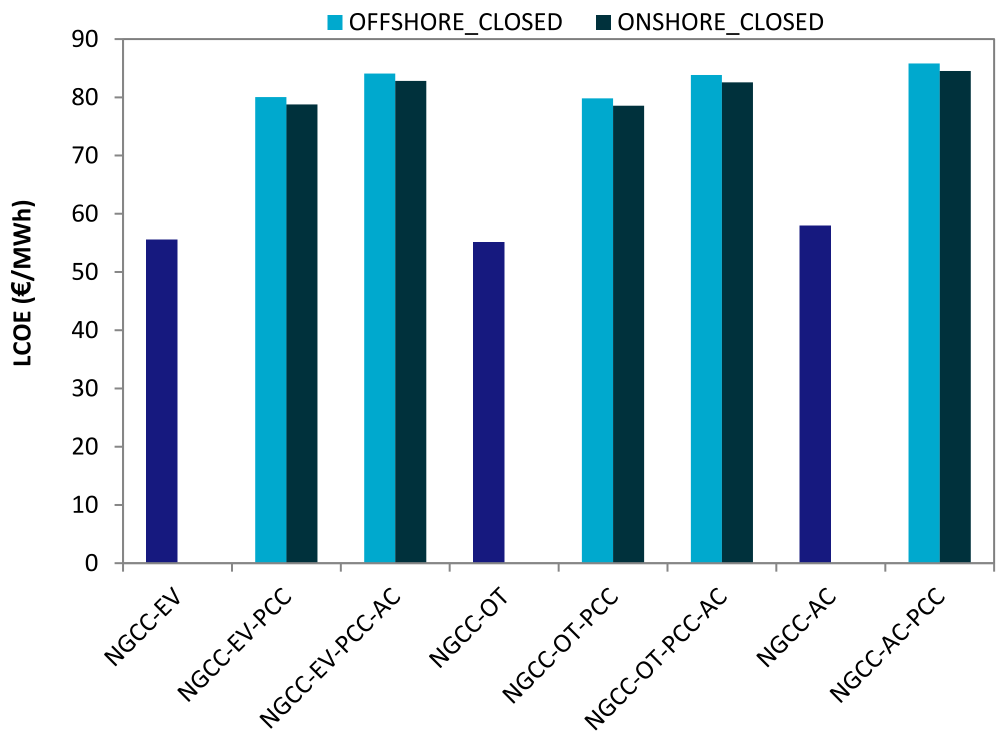


Figure 5-9 LCOE of NGCC power plants without and with CCS in closed saline formations offshore and onshore Netherlands

CO_2 avoidance cost for the NGCC power plants are presented in Figure 5-10. CO_2 avoidance cost are lowest for the NGCC power plant with PCC using either evaporative or once-through cooling. The costs for the power plants with CCS and offshore storage range from 80 to 93 €/t

CO_2 avoided. For onshore storage, the avoidance costs are less and range from 75 to 88 €/t CO_2 avoided.

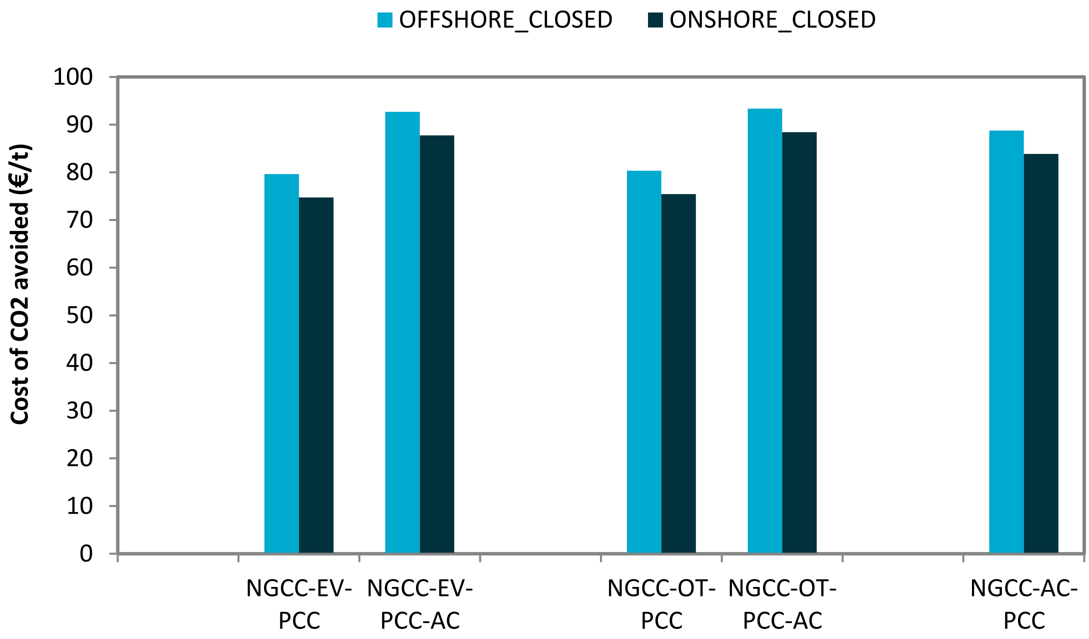


Figure 5-10 Cost of CO_2 avoided for NGCC power plants without and with CCS in closed saline formations offshore and onshore Netherlands

A detailed summary of the components of the integrated NGCC-CCS scenario with CO_2 storage in closed saline formations and their economics is presented in Table 5-39 for the offshore storage case and Table 5-40 for the onshore storage case.

Table 5-39 NGCC with and without CCS: offshore storage in the Q1 saline formation with closed reservoir boundaries

NGCC		Evaporative cooling				Once through cooling		Air cooling	
Power station type		**NGCC-EV**	**NGCC-EV-PCC**	**NGCC-EV-PCC-AC**	**w/o CCS**	**NGCC-OT-PCC**	**NGCC-OT-PCC-AC**	**NGCC-AC**	**NGCC-AC-PCC**
Cooling technology		EV w/o CCS	EV w/ CCS-EV	EV w/ CCS-AC	OT w/o CCS	OT w/ CCS-OT	OT w/ CCS-AC		
Efficiency	%LHV	58.34	50.59	50.39	58.65	50.69	50.42	57.33	49.83
Gross power	MW	878	761.3	758.2	883.3	762.8	758.8	862.7	749.9
Net power	MW	882.2	761.3	758.2	883.3	762.8	758.8	866.9	749.9
Water consumption (Total)	Mt/y		4.24	1.8		0.000938	0.000938		0.000938
Transport and Storage									
Storage location			offshore	offshore		offshore	offshore		offshore
Distance to power station	km		110	110		110	110		110
Reservoir permeability	mD		100	100		100	100		100
Reservoir porosity			0.15	0.15		0.15	0.15		0.15
Reservoir boundaries			closed	closed		closed	closed		closed
Formation water salinity	ppm		100,000	100,000		100,000	100,000		100,000
CO2 injection rate	Mt/y		2.08	2.08		2.08	2.08		2.08
Injection well number			1	1		1	1		1
Water extraction rate	Mt/y		3.3	3.3		3.3	3.3		3.3
Extraction well number			1	1		1	1		1
Water Management									
Treatment or direct disposal			direct disposal	direct disposal		direct disposal	direct disposal		direct disposal
Disposal of extracted brine or reject stream (reinjection or ocean)			ocean	ocean		ocean	ocean		ocean
Number of water injectors			-	-		-	-		-
Emissions data									
CO_2 emitted	t/MWh	0.351	0.041	0.041	0.351	0.041	0.041	0.358	0.041
Capex	Unit								
Power Plant with capture	million €	835.7	1166.3	1302.1	850.2	1169.8	1304.9	890.3	1349.6
Start up costs	million €	28.7	37.9	41.2	28.7	37.6	41.2	29.9	42.5
CO_2 Transport	million €		133.35	133.35		133.35	133.35		133.35
CO_2 Storage	million €		24.15	24.15		24.15	24.15		24.15
Water extraction	million €		15.36	15.36		15.36	15.36		15.36
Water treatment	million €	0	0	0	0	0	0	0	0

NGCC		**Evaporative cooling**				**Once through cooling**		**Air cooling**	
Power station type		**NGCC-EV**	**NGCC-EV-PCC**	**NGCC-EV-PCC-AC**	**w/o CCS**	**NGCC-OT-PCC**	**NGCC-OT-PCC-AC**	**NGCC-AC**	**NGCC-AC-PCC**
Total Capex, incl. decommissioning and monitoring	million €	***860***	***1362***	***1501***	***875***	***1365***	***1504***	***916***	***1550***
Opex									
Power Plant and Capture									
fixed	million €/y	29.2	39.5	41.7	27.8	38.2	41.8	29	43.2
variable	million €/y	3.4	8.4	8.4	2.6	8	8	2.6	8
fuel	million €/y	227	224	226	226	225	225	231	224
Transport									
fixed	million €/y		0.33	0.33		0.33	0.33		0.33
variable	million €/y		0.58	0.58		0.58	0.58		0.58
Storage									
fixed	million €/y		13.59	13.59		13.59	13.59		13.59
variable	million €/y		2.79	2.79		2.79	2.79		2.79
Water extraction									
fixed	million €/y		0.31	0.31		0.31	0.31		0.31
variable	million €/y		1.17	1.17		1.17	1.17		1.17
Water treatment			0	0	0	0	0	0	0
fixed	million €/y		0	0	0	0	0	0	0
variable	million €/y		0	0	0	0	0	0	0
Total Opex	**million €/y**	***260***	***291***	***295***	***256***	***290***	***294***	***263***	***294***
LCOE calculations									
Capex (PP+Capture)	€/MWh	15.86	25.60	28.68	16.10	25.62	28.72	17.18	30.05
FOM	€/MWh	4.56	7.15	7.58	4.34	6.90	7.59	4.61	7.94
VOM	€/MWh	0.53	1.52	1.53	0.41	1.45	1.45	0.41	1.47
Fuel	€/MWh	34.60	39.60	40.10	34.30	39.70	39.90	35.80	40.10
Transport & Storage	€/MWh	0.00	5.89	5.91	0.00	5.88	5.91	0.00	5.98
Water extraction & management	*€/MWh*	*0.00*	*0.54*	*0.54*	*0.00*	*0.54*	*0.54*	*0.00*	*0.54*
Total LCOE	**€/MWh**	**55.55**	**80.03**	**84.34**	**55.14**	**80.08**	**84.11**	**58.00**	**86.08**

NGCC		**Evaporative cooling**				**Once through cooling**		**Air cooling**	
Power station type		**NGCC-EV**	**NGCC-EV-PCC**	**NGCC-EV-PCC-AC**	**w/o CCS**	**NGCC-OT-PCC**	**NGCC-OT-PCC-AC**	**NGCC-AC**	**NGCC-AC-PCC**
CO_2 avoided cost (€/t CO_2)			**80**	**93**		**80**	**93**		**89**

Table 5-40 NGCC with and without CCS: onshore storage in the saline formation with closed reservoir boundaries

NGCC		Evaporative cooling			Once through cooling			Air cooling	
Power station type		**NGCC-EV**	**NGCC-EV-PCC**	**NGCC-EV-PCC-AC**	**w/o CCS**	**NGCC-OT-PCC**	**NGCC-OT-PCC-AC**	**NGCC-AC**	**NGCC-AC-PCC**
Cooling technology		EV w/o CCS	EV w/ CCS-EV	EV w/ CCS-AC	OT w/o CCS	OT w/ CCS-OT	OT w/ CCS-AC		
Efficiency	%LHV	58.34	50.59	50.39	58.65	50.69	50.42	57.33	49.83
Gross power	MW	878	761.3	758.2	883.3	762.8	758.8	862.7	749.9
Net power	MW	882.2	761.3	758.2	883.3	762.8	758.8	866.9	749.9
Water consumption (Total)	Mt/yr		4.24	1.8		0.000938	0.000938		0.000938
Transport and Storage									
Storage location			onshore	onshore		onshore	onshore		onshore
Distance to power station	km		45	45		45	45		45
Reservoir boundaries			closed	closed		closed	closed		closed
Formation water salinity	ppm		150,000	150,000		150,000	150,000		150,000
CO2 injection rate	Mt/y		2.08	2.08		2.08	2.08		2.08
Injection well number			1	1		1	1		1
Water extraction rate	Mt/y		3.5	3.5		3.5	3.5		3.5
Extraction well number			1	1		1	1		1
Water Management									
Treatment or direct disposal			direct disposal	direct disposal		direct disposal	direct disposal		direct disposal
Emissions data									
CO2 emitted	t/MWh	0.351	0.041	0.041	0.351	0.041	0.041	0.358	0.041
Capex	Unit								
Power Plant with capture	million €	835.7	1166.3	1302.1	850.2	1169.8	1304.9	890.3	1349.6
Start up costs	million €	28.7	37.9	41.2	28.7	37.6	41.2	29.9	42.5
CO_2 Transport	million €		15.75	15.75		15.75	15.75		15.75
CO2 Storage	million €		7.66	7.66		7.66	7.66		7.66
Water extraction	million €		5.11	5.11		5.11	5.11		5.11
Water treatment	million €		0	0		0	0		0
Water transport of treated water	million €		0	0		0	0		0
Water transport (untreated/reject produced water)	million €		44.54	44.54		44.54	44.54		44.54
Water disposal (untreated/reject produced water)	million €		58.69	58.69		58.69	58.69		58.69
Total Capex, incl. decommissioning and monitoring	million €	***860***	***1306***	***1445***	***875***	***1310***	***1448***	***916***	***1494***

NGCC		Evaporative cooling			Once through cooling			Air cooling	
Power station type		**NGCC-EV**	**NGCC-EV-PCC**	**NGCC-EV-PCC-AC**	**w/o CCS**	**NGCC-OT-PCC**	**NGCC-OT-PCC-AC**	**NGCC-AC**	**NGCC-AC-PCC**
Opex									
Power Plant and Capture									
fixed	million €/y	29.2	39.5	41.7	27.8	38.2	41.8	29	43.2
variable	million €/y	3.4	8.4	8.4	2.6	8	8	2.6	8
fuel	million €/y	227	224	226	226	225	225	231	224
Total PP+Capture Opex	million €/y	260	272	276	256	272	275	263	275
fixed	€/MWh	4.4	7.0	7.4	4.2	6.7	7.4	4.5	7.7
variable	€/MWh	0.52	1.48	1.49	0.40	1.41	1.42	0.40	1.43
fuel	€/MWh	34.6	39.6	40.1	34.3	39.7	39.9	35.8	40.1
Total PP+Capture Opex	€/MWh	40	48	49	39	48	49	41	49
Transport									
fixed	million €/y		0.04	0.04		0.04	0.04		0.04
variable	million €/y		0.58	0.58		0.58	0.58		0.58
Storage									
fixed	million €/y		3.26	3.26		3.26	3.26		3.26
variable	million €/y		2.79	2.79		2.79	2.79		2.79
Water extraction									
fixed	million €/y		0.29	0.29		0.29	0.29		0.29
variable	million €/y		0.52	0.52		0.52	0.52		0.52
Water treatment									
fixed	million €/y		0.00	0.00		0.00	0.00		0.00
variable	million €/y		0.00	0.00		0.00	0.00		0.00
Water transport of treated water									
fixed	million €/y		0.00	0.00		0.00	0.00		0.00
variable	million €/y		0.00	0.00		0.00	0.00		0.00
Water transport (untreated/reject produced water)									
fixed	million €/y		0.14	0.14		0.14	0.14		0.14

NGCC		Evaporative cooling			Once through cooling			Air cooling	
Power station type		**NGCC-EV**	**NGCC-EV-PCC**	**NGCC-EV-PCC-AC**	**w/o CCS**	**NGCC-OT-PCC**	**NGCC-OT-PCC-AC**	**NGCC-AC**	**NGCC-AC-PCC**
variable	million €/y		1.16	1.16		1.16	1.16		1.16
Water disposal (untreated/reject produced water)									
fixed	million €/y		3.93	3.93		3.93	3.93		3.93
variable	million €/y		1.60	1.60		1.60	1.60		1.60
Total Opex	**million €/y**	***339***	***369***	***375***	***334***	***368***	***373***	***344***	***374***
LCOE calculations									
Capex (PP+Capture)	€/MWh	15.86	25.60	28.68	16.10	25.62	28.72	17.18	30.05
FOM	€/MWh	4.56	7.15	7.58	4.34	6.90	7.59	4.61	7.94
VOM	€/MWh	0.53	1.52	1.53	0.41	1.45	1.45	0.41	1.47
Fuel	€/MWh	34.60	39.60	40.10	34.30	39.70	39.90	35.80	40.10
Transport & Storage	€/MWh	0.00	1.62	1.62	0.00	1.61	1.62	0.00	1.64
Water extraction & management	*€/MWh*	*$0.00*	*3.28*	*3.29*	*0*	*3.27*	*3.29*	*$0.00*	*3.33*
Total LCOE	**€/MWh**	**55.55**	**78.77**	**82.81**	**55.14**	**78.56**	**82.58**	**58.00**	**84.53**
CO_2 avoided cost (€/t CO_2)			**75**	**88**		**75**	**88**		**84**

5.6.2 CCS-Water-Nexus Scenario

The following results present the economic assessment of the CCS-Water-Nexus Scenario for which the Base Case CCS Scenario is expanded to include treatment of the produced water for reuse in the power station and the capture plant. The CCS-Water-Nexus Scenario integrates CO_2 capture from the hypothetical NGCC or USCPC power plant, CO_2 transport and injection, brine extraction with subsequent treatment, supply of product water to the power plant and disposal of the concentrated reject brine.

As only the power plants with evaporative cooling systems use significant volumes of freshwater (see Table 4-1 and Table 4-2) they present the focus of the analysis. Due to the lack of freshwater consumption, the other power plants are not considered in the integration of CCS and water extraction and reuse.

The specific combinations of power plant, storage case, and water management were given in Table 4-17 for the NGCC and Table 4-18 for the USCPC. Matrices presenting further details of the integrated cases were in Table 4-19 and Table 4-20. It should be reiterated that in the CCS-Water-Nexus Scenario two water extraction cases are considered for each power plant type (USCPC and NGCC using evaporative cooling) for each storage scenario, i.e. onshore and offshore. These are defined in Table 5-41.

Table 5-41 Water extraction scenarios in the CCS-Water-Nexus Scenario

Water extraction scenario	Description
Extraction scenario A	Extraction of the volumetrically equivalent water amount required for safe CO_2 storage
Extraction scenario B	Extraction of the volume of brine necessary to meet the freshwater demand of the power plant using evaporative cooling with capture using either evaporative or air cooling

Scenario A extracts the volumes of water necessary for safe CO_2 storage, which, as indicated in 4.2.2, is not sufficient to meet the water demands of the power station with capture after water treatment. In scenario A, all treated water is utilised within the power and/or capture plants. The additional freshwater needed by the power and capture plants is assumed to be provided by raw water make-up.

In scenario B, the extracted water volume matches the freshwater consumption of the power plant with capture. The extraction rate varies depending on the exact water requirements of the power plant with capture, as well as the salinity of the formation water, which determines product recovery.

The cases analysed in the CCS-Water-Nexus Scenario are compared to those from the Base Case CCS Scenario with storage in an open saline formation, i.e. without water extraction.

CCS from USCPC power plants with storage in closed saline formations, water extraction, and utilisation

This section presents the cost of CCS from the USCPC power plant with onshore and offshore storage in the CCS-Water-Nexus Scenario. The specific combinations of power plant, storage location, and water extraction and treatment considered for the USCPC with capture in the CCS-Water-Nexus Scenario are presented in Table 5-42.

The details of each CCS-Water-Nexus Scenario modelled for the USCPC, including detailed results for costing, LCOE and avoidance cost are presented in Table 5-45 for the offshore storage scenario and Table 5-46 for the onshore storage scenario.

Table 5-42 USCPC cases modelled as part of the CCS-Water-Nexus Scenario injecting 4 Mt/y of CO_2

Case	Power Plant	Storage case	Location	Water extraction	Water recovery	Water to PP and/or PCC
1.1B	USCPC-EV-PCC-A	On-4c-2-2-A	Onshore	6.9 Mt/y	25%	1.7 Mt/y
	USCPC-EV-PCC-B	On-4c-2-10-B	Onshore	31 Mt/y	25%	7.8 Mt/y
	USCPC-EV-PCC-A	Off-4c-2-2-A	Offshore	6.7 Mt/y	50%	3.4 Mt/y
	USCPC-EV-PCC-B	Off-4c-2-5-B	Offshore	15.5 Mt/y	50%	7.8 Mt/y
1.1C	USCPC-EV-PCC-AC-A	On-4c-2-2-A	Onshore	6.9 Mt/y	25%	1.7 Mt/y
	USCPC-EV-PCC-AC-B	On-4c-2-6-B	Onshore	19.5 Mt/y	25%	4.9 Mt/y
	USCPC-EV-PCC-AC-A	Off-4c-2-2-A	Offshore	6.7 Mt/y	50%	3.4 Mt/y
	USCPC-EV-PCC-AC-B	Off-4c-2-3-B	Offshore	9.8 Mt/y	50%	4.9 Mt/y

Off = offshore; On = onshore; c = closed boundary; A = water extracted volumetrically equivalent to CO_2 injected; B = water extracted to meet max power plant demand: storage modelling was not carried out for these cases, but they are assessed as part of the integration of the CCS chain with extracted water utilisation and its economic evaluation; PP = power plant; PCC = post-combustion capture plant

The LCOE for CCS from USCPC power plants using evaporative cooling, integrated with formation water extraction, treatment and utilisation in the USCPC is presented in Figure 13 and Table 5-43 in comparison to the equivalent Base Case CCS Scenario with storage in an open saline formation (no water extraction).

For extraction case A (extracted water volumetrically equivalent to CO_2 injected), compared to the power plant without CCS, the LCOE increases by about 61% in the CCS-Water-Nexus Scenario offshore and by 55% onshore for the USCPC with PCC using evaporative cooling (USCPC-EV-PCC-A): from 56 to 90 €/MWh offshore and to 87 €/MWh onshore (see Table 5-43). When air cooling is used for the capture plant (USCPC-EV-PCC-AC-A), LCOE rise to 95 €/MWh offshore and 91 €/MWh onshore (Table 5-43).

In comparison to the equivalent Base Case CCS Scenario with CO_2 storage in an open saline formation (no water extraction), the extraction and reuse of water increase the LCOE by almost 5% (4 €/MWh) offshore and by more than 7% (6 €/MWh) onshore for the USCPC with capture using evaporative cooling (case USCPC-EV-PCC-A) (Table 5-43). When air cooling is used for the capture plant (case USCPC-EV-PCC-AC-A) the LCOE increase by about 6% (5 €/MWh) offshore and 7% (6 €/MWh) onshore (to 95 €/MWh and 91 €/MWh offshore and onshore, respectively). This is shown in Table 5-43.

The analysis shows that by integrating the water-nexus through utilising reservoir water extraction, water treatment, disposal, and transport of the treated water to the USCPC, 4 to 5 €/MWh is added to the LCOE for offshore storage and 6 €/MWh for onshore storage (compare Table 5-43 for USCPC-EV-PCC-A and USCPC-EV-PCC-AC-A).

For extraction scenario B, in which water beyond what is needed is extracted to meet the freshwater demand of the power plant with capture, the LCOE increases by 8% offshore (to 93 €/MWh) and by as much as 26% onshore (to 9102 €/MWh) for the USCPC with PCC using evaporative cooling (case USCPC-EV-PCC-B). For the air-cooled capture plant (USCPC-EV-PCC-AC-B), the LCOE increases by almost 7% (to 96€/MWh) in the offshore storage scenario and more than 16% (to 99 €/MWh) in the onshore storage scenario (Table 5-43). This is in comparison the Base Case CCS Scenario without water extraction.

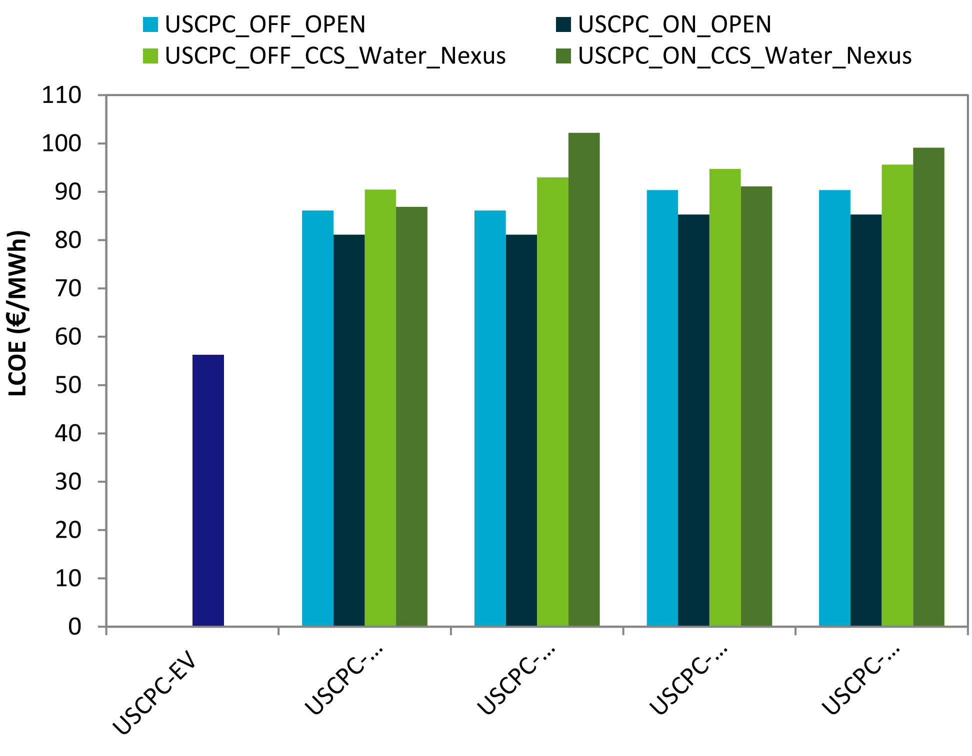


Figure 5-11 Comparison of LCOE of USCPC power plants in the CCS-Water-Nexus Scenario (onshore [ON] and offshore [OFF] with water extraction and utilisation: USCPC_CCS_Water_Nexus) with i.) a power plant without capture (USCPC-EV); and ii.) USCPC with CCS in open saline formations (no water extraction and management: USCPC_OPEN)

Table 5-43 Summary of LCOE for the USCPC in the CCS-Water-Nexus Scenario

LCOE (€/MWh)					
Case name	**1.1A**	**1.1B-A**	**1.1B-B**	**1.1C-A**	**1.1C-B**
	USCPC -EV	**USCPC-EV-PCC-A**	**USCPC-EV-PCC-B**	**USCPC-EV-PCC-AC-A**	**USCPC-EV-PCC-AC-B**
Description	No CCS	Water utilisation matches storage need	Water utilisation in both PP and PCC	Water utilisation matches storage need	Water utilisation in PP only (PCC air cooled)
Base Case (open) offshore	56	86	86	90	90
Base Case (open) onshore	56	81	81	85	85
CCS-Water-Nexus offshore	56	90	93	95	96
CCS-Water-Nexus onshore	56	87	102	91	99

PP = power plant; PCC = post-combustion capture

The cost of CO_2 avoidance behave in a similar manner to the LCOE and are presented in Figure 5-12 and Table 5-44. The cost of avoidance for water extraction scenario A, in which the water extracted is volumetrically equivalent to the CO_2 stored, range from 47 €/t to 59 €/t (Table 5-44). In comparison to the Base Case CCS Scenario with no water extraction the relative increase ranges from 14 to up to 24%.

For water extraction scenario B, in which water is extracted to meet the freshwater demand of the power plant with capture, avoidance cost range from 56 €/t to 71 €/t (Table 5-44). Here, an increase in avoidance cost of up to 87% (corresponding to an increase from 38 €/t to 71 €/t) are observed. This is for the USCPC with capture using evaporative cooling (onshore storage scenario). This combination has the highest freshwater water consumption (7.75 Mt/y - Table 5-46), combined with a lower product recovery of 25% (due to a salinity of 150,000 mg/L, see Table 5-42), and therefore has the highest water extraction, treatment, transport and disposal costs.

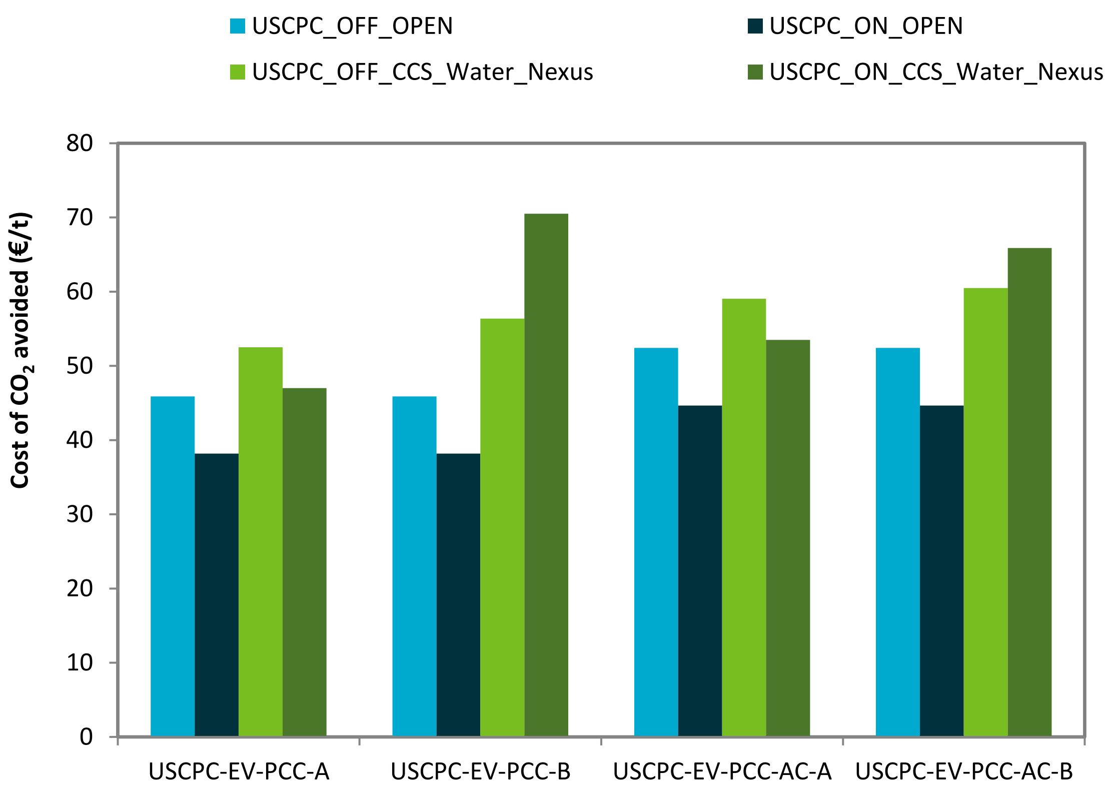


Figure 5-12 Comparison of CO_2 avoidance cost of USCPC power plants in the CCS-Water-Nexus Scenario (onshore [ON] and offshore [OFF] storage with water extraction and utilisation: USCPC_CCS_Water_Nexus) with USCPC with CCS in open saline formations (no water extraction and management: USCPC_OPEN)

Table 5-44 Summary of CO_2 avoidance cost for the USCPC in the CCS-Water-Nexus Scenario

Case name	**1.1B USCPC-EV-PCC-A**	**1.1B USCPC-EV-PCC-B**	**1.1C USCPC-EV-PCC-AC-A**	**1.1C USCPC-EV-PCC-AC-B**
Description	Water utilisation matches storage need	Water utilisation in both PP and PCC	Water utilisation matches storage need	Water utilisation in PP only (PCC air cooled)
Base Case (open) offshore	46	46	52	52
Base Case (open) onshore	38	38	45	45
CCS-Water-Nexus offshore	53	56	59	60
CCS-Water-Nexus onshore	47	71	53	66

PP = power plant; PCC = post-combustion capture

The analysis shows that the extraction and treatment of water for utilisation in the power plant beyond what is required for safe CO_2 storage can significantly increase both LCOE and CO_2 avoidance cost. This is a result of the higher water extraction, treatment, disposal, and transport costs caused by the higher water extraction rates. The LCOE increase by up to 17% from water extraction case A to water extraction case B in the onshore storage scenario. This corresponds to an increase in LCOE of 15 €/MWh (Table 5-43). Avoidance cost increase by up to 51% onshore, an increase of as much as 24 €/t (Table 5-44). In comparison, in the offshore scenario the increase in LCOE and avoidance cost is much less: LCOE increase by up to 3% or 3 €/MWh, while avoidance cost increase by up to 6% (3 €/t).

Table 5-45 Detailed results of the CCS-Water-Nexus Scenario for the USCPC using evaporative cooling and the capture plant using either evaporative cooling or air cooling – offshore storage

			Water utilisation matches storage	Water utilisation in both PP and PCC	Water utilisation matches storage	Water utilisation in PP only
Power station type		**USCPC-EV**	**USCPC-EV-PCC-A**	**USCPC-EV-PCC-B**	**USCPC-EV-PCC-AC-A**	**USCPC-EV-PCC-AC-B**
Cooling technology		EV w/o CCS	EV w/ CCS-EV	EV w/ CCS-EV	EV w/ CCS-AC	EV w/ CCS-AC
Capture technology		No Capture	SoA solvent absorption	SoA solvent absorption	SoA solvent absorption	SoA solvent absorption
Efficiency	%LHV	44.40	37.23	37.23	36.90	36.90
Gross power	MW	900	900	900	900	900
Net power	MW	817	684.4	684.4	678.4	678.4
Water consumption (Total)	Mt/y		7.75	7.75	4.88	4.88
Water consumption (Capture only)	Mt/y		1.56	1.56		0
Transport and Storage						
Storage location			offshore	offshore	offshore	offshore
Distance to power station	km		110	110	110	110
Reservoir permeability	mD		100	100	100	100
Reservoir porosity			0.15	0.15	0.15	0.15
Reservoir boundaries			closed	closed	closed	closed
Formation water salinity	ppm		100,000	100,000	100,000	100,000
CO2 injection rate	Mt/y		4.05	4.05	4.05	4.05
Injection well number			2	2	2	2
Water extraction rate	Mt/y		6.7	15.5	6.7	9.8
Extraction well number			2	5	2	3
Water Management						
Treatment or direct disposal			Treatment	Treatment	Treatment	Treatment
Treatment technology			MVC	MVC	MVC	MVC
Feed stream (for water treatment, in case not all produced water treated)	Mt/y		6.7	15.5	6.7	9.8
Freshwater/Product stream (after treatment)	Mt/y		3.4	7.8	3.4	4.9
Reject stream	Mt/y		3.4	7.8	3.4	4.9
Transport of freshwater (to site of use)	km		110	110	110	110
Transport of reject stream	km		0	0	0	0
Disposal of extracted brine or reject stream (reinjection or ocean)			ocean	ocean	ocean	ocean
Number of water injectors			0	0	0	0
Emissions data						
CO_2 emitted	t/MWh	0.738	0.09	0.086	0.08712	0.08712
Capex						
Power Plant with capture	million €	1342.8	1659.3	1659.3	1785.1	1785.1
Start-up costs	million €	39.0	47.3	47.3	48.0	50.6
CO2 Transport	million €		138.30	138.30	138.30	138.30
CO2 Storage	million €		36.36	36.36	36.36	36.36
Water extraction	million €	0	28.54	76.12	28.54	45.99

			Water utilisation matches storage	Water utilisation in both PP and PCC	Water utilisation matches storage	Water utilisation in PP only
Power station type		**USCPC-EV**	**USCPC-EV-PCC-A**	**USCPC-EV-PCC-B**	**USCPC-EV-PCC-AC-A**	**USCPC-EV-PCC-AC-B**
Water treatment	million €	0	11.47	18.88	11.47	14.29
Water transport of treated water	million €	0	123.62	126.25	123.62	124.64
Water transport (untreated/reject produced water)	million €	0	0	0		0
Water disposal (untreated/reject produced water)	million €	0	0	0	0	0
Total Capex, incl. decommissioning and monitoring	**million €**	**1382**	**2361**	**2414**	**2362**	**2634**
Opex						
Power Plant and Capture						
fixed	million €/y	37.70	45.90	45.90	48.70	48.70
variable	million €/y	7.54	17.12	16.24	16.32	16.02
fuel	million €/y	128.97	128.93	128.93	128.81	128.81
Total PP+Capture Opex	million €/y	174.21	191.07	191.07	193.83	193.53
Transport						
fixed	million €/y		0.35	0.35	0.35	0.35
variable	million €/y		1.16	1.16	1.16	1.16
Storage						
fixed	million €/y		13.87	13.87	13.87	13.87
variable	million €/y		5.59	5.59	5.59	5.59
Water extraction						
fixed	million €/y	0	0.69	2.17	0.69	1.13
variable	million €/y	0	2.37	5.47	2.37	3.45
Water treatment						
fixed	million €/y	0	0	0	0	0
variable	million €/y	0	2.19	5.03	2.19	3.16
Water transport of treated water						
fixed	million €/y	0	0.33	0.34	0.33	0.33
variable	million €/y	0	0.75	1.14	0.75	0.90
Water transport (untreated/reject produced water)						
fixed	million €/y	0	0	0	0	0
variable	million €/y	0	0	0	0	0
Water disposal (untreated/reject produced water)						
fixed	million €/y	0	0	0	0	0
variable	million €/y	0	0	0	0	0
Total Opex	**million €/y**	***174***	***218***	***226***	**221**	***223***
LCOE calculations						
Capex (PP+Capture)	€/MWh	27.39	40.39	40.39	43.82	43.82
FOM	€/MWh	6.36	9.24	9.24	9.89	9.89

			Water utilisation matches storage	Water utilisation in both PP and PCC	Water utilisation matches storage	Water utilisation in PP only
Power station type		**USCPC-EV**	**USCPC-EV-PCC-A**	**USCPC-EV-PCC-B**	**USCPC-EV-PCC-AC-A**	**USCPC-EV-PCC-AC-B**
VOM	€/MWh	1.27	**3.45**	**3.27**	**3.32**	**3.25**
Fuel	€/MWh	21.20	25.30	25.30	25.50	25.30
Transport & Storage	€/MWh	0.00	7.62	7.62	7.69	7.69
Water extraction & management	*€/MWh*	0	**4.46**	**7.16**	**4.5**	**5.45**
Total LCOE	***€/MWh***	**56.22**	**90.46**	**92.98**	**94.72**	**95.61**
CO_2 avoided cost (€/t CO_2)	**where ref is same plant**		**53**	**56**	**59**	**60**

Table 5-46 Detailed results of the CCS-Water-Nexus Scenario for the USCPC using evaporative cooling and the capture plant using either evaporative cooling or air cooling – onshore storage

			Water utilisation matches storage	**Water utilisation in both PP and PCC**	**Water utilisation matches storage**	**Water utilisation in PP only**
Power station type		**USCPC-EV**	**USCPC-EV-PCC-A**	**USCPC-EV-PCC-B**	**USCPC-EV-PCC-AC-A**	**USCPC-EV-PCC-AC-B**
Cooling technology		EV w/o CCS	EV w/ CCS-EV	EV w/ CCS-EV	EV w/ CCS-AC	EV w/ CCS-AC
Capture technology		No capture	SoA solvent absorption	SoA solvent absorption	SoA solvent absorption	SoA solvent absorption
Efficiency	%LHV	44.40	37.23	37.23	36.90	36.90
Gross power	MW	900	900	900	900	900
Net power	MW	817	684.4	684.4	678.4	678.4
Water consumption (Total)	Mt/y		7.75	7.75	4.88	4.88
Water consumption (Capture only)	Mt/y		1.56	1.56		
Transport and Storage						
Storage location			onshore	onshore	onshore	onshore
Distance to power station	km		45	45	45	45
Reservoir permeability	mD		200	200	200	200
Reservoir porosity			0.2	0.2	0.2	0.2
Reservoir boundaries			closed	closed	closed	closed
Formation water salinity	ppm		150,000	150,000	150,000	150,000
CO2 injection rate	Mt/y		4.05	4.05	4.05	4.05
Injection well number			2	2.0	2	2
Water extraction rate	Mt/y		6.9	31	6.9	19.5
Extraction well number			2	10	2	6
Water Management						
Treatment or direct disposal			Treatment	Treatment	Treatment	Treatment
Treatment technology			MVC	MVC	MVC	MVC
Feed stream (for water treatment, in case not all produced water treated)	Mt/y		6.9	31.0	6.9	19.5
Freshwater/Product stream (after treatment)	Mt/y		1.7	7.8	1.7	4.9
Reject stream	Mt/y		5.2	23.3	5.2	14.6
Reuse of freshwater (in power station or capture plant - state either PS or PCC)			PS	PS	PS	PS
Transport of freshwater (to site of use)	km		45	45	45	45
Transport of reject stream	km		170	170	170	170

			Water utilisation matches storage	Water utilisation in both PP and PCC	Water utilisation matches storage	Water utilisation in PP only
Power station type		**USCPC-EV**	**USCPC-EV-PCC-A**	**USCPC-EV-PCC-B**	**USCPC-EV-PCC-AC-A**	**USCPC-EV-PCC-AC-B**
Disposal of extracted brine or reject stream (reinjection or ocean)			reinjection	reinjection	reinjection	reinjection
Number of water injectors			21	93	21	58
Emissions data						
CO_2 emitted	t/MWh	0.738	0.09	0.086	0.087	0.087
Capex						
Power Plant with capture	million €	1342.8	1659.3	1659.3	1785.1	1785.1
Start-up costs	million €	39.0	47.3	47.3	50.6	50.6
CO2 Transport	million €	0.00	17.77	17.77	17.77	17.77
CO2 Storage	million €	0.00	11.50	11.50	11.50	11.50
Water extraction	million €	0	10.18	49.87	10.18	30.19
Water treatment	million €	0	7.57	18.88	7.57	14.29
Water transport of treated water	million €	0	11.57	12.76	11.57	12.12
Water transport (untreated/reject produced water)	million €	0	46.29	57.16	46.29	52.87
Water disposal (untreated/reject produced water)	million €	0	87.20	390.71	87.20	244.82
Total Capex, incl. decommissioning and monitoring	**million €**	***1382***	***1899***	***2265***	***2028***	***2219***
Opex						
Power Plant and Capture						
fixed	million €/y	37.7	45.9	45.9	48.7	48.7
variable	million €/y	7.54	17.455	16.24	16.655	16.02
fuel	million €/y	129	128.93	129	129	129
Total PP+Capture Opex	million €/y	174	191.07	191	194	194
Transport						
fixed	million €/y		0.04	0.04	0.04	0.04
variable	million €/y		1.16	1.16	1.16	1.16
Storage						
fixed	million €/y		3.53	3.53	3.53	3.53
variable	million €/y		5.59	5.59	5.59	5.59
Water extraction						

			Water utilisation matches storage	Water utilisation in both PP and PCC	Water utilisation matches storage	Water utilisation in PP only
Power station type		**USCPC-EV**	**USCPC-EV-PCC-A**	**USCPC-EV-PCC-B**	**USCPC-EV-PCC-AC-A**	**USCPC-EV-PCC-AC-B**
fixed	million €/y	0	0.61	4.10	0.61	2.16
variable	million €/y	0	1.03	4.63	1.03	2.92
Water treatment						
fixed	million €/y					
variable	million €/y		1.26	5.78	1.26	3.63
Water transport of treated water						
fixed	million €/y	0	0.04	0.04	0.04	0.03
variable	million €/y	0	0.22	0.24	0.22	0.18
Water transport (untreated/reject produced water)						
fixed	million €/y	0	0.15	0.21	0.15	0.19
variable	million €/y	0	1.42	3.00	1.42	2.37
Water disposal (untreated/reject produced water)						
fixed	million €/y	0	5.84	26.18	5.84	16.40
variable	million €/y	0	2.38	10.67	2.38	6.69
Total Opex	**million €/y**	**174**	**214**	**256**	**217**	**239**
LCOE calculations						
Capex (PP+Capture)	€/MWh	27.39	40.39	40.39	43.82	43.82
FOM	€/MWh	6.36	9.24	9.24	9.89	9.89
VOM	€/MWh	1.27	3.51	3.27	3.38	3.25
Fuel	€/MWh	21.20	25.30	25.30	25.50	25.50
Transport & Storage	€/MWh	0.00	2.65	2.65	2.67	2.67
Water extraction & management	*€/MWh*	0	5.78	21.35	5.83	13.98
Total LCOE	***€/MWh***	**56.22**	**86.87**	**102.20**	**91.1**	**99.13**
CO_2 avoided cost (€/t CO_2)	**where ref is same plant**		**47**	**71**	**53**	**66**

CCS from NGCC power plants with storage in closed saline formations, water extraction, and utilisation

This section presents the cost of CCS from the NGCC power plant with onshore and offshore storage in the CCS-Water-Nexus Scenario. The specific combinations of power plant, storage location, and water extraction and treatment considered for the NGCC in the CCS-Water-Nexus Scenario are presented in Table 5-47.

The details of each CCS-Water-Nexus Scenario modelled for the NGCC, including detailed costing results, LCOE and avoidance cost are presented in Table 5-50 for the offshore storage scenario and Table 5-51 for the onshore storage scenario.

Table 5-47 NGCC cases modelled as part of the CCS-Water-Nexus Scenario injecting 2 Mt/y of CO_2

Case	Power Plant	Storage case	Location	Water extraction	Water recovery	Water to PP and/or PCC
2.1B	NGCC-EV-PCC-A	On-2c-1-1-A	Onshore	3.5 Mt/y	25%	0.9 Mt/y
	NGCC-EV-PCC-B	On-2c-1-5-B	Onshore	17 Mt/y	25%	4.2 Mt/y
	NGCC-EV-PCC-A	Off-2c-1-1-A	Offshore	3.3 Mt/y	50%	1.7 Mt/y
	NGCC-EV-PCC-B	Off-2c-1-3-B	Offshore	8.5 Mt/y	50%	4.2 Mt/y
2.1C	NGCC-EV-PCC-AC-A	On-2c-1-1-A	Onshore	3.5 Mt/y	25%	0.8 Mt/y
	NGCC-EV-PCC-AC-B	On-2c-1-3-B	Onshore	7.2 Mt/y	25%	1.8 Mt/y
	NGCC-EV-PCC-AC-A	Off-2c-1-1-A	Offshore	3.3 Mt/y	50%	1.7 Mt/y
	NGCC-EV-PCC-AC-B	Off-2c-1-1-B	Offshore	3.6 Mt/y	50%	1.8 Mt/y

Off = offshore; On = onshore; c = closed boundary; A = water extracted volumetrically equivalent to CO_2 injected; B = water extracted to meet max power plant demand: storage modelling was not carried out for these cases, but they are assessed as part of the integration of the CCS chain with extracted water utilisation and its economic evaluation; PP = power plant; PCC = post-combustion capture plant

The LCOE for CCS from NGCC power plants using evaporative cooling, integrated with formation water extraction, treatment and utilisation in the NGCC is presented in Figure 5-13 and Table 5-48 in comparison to the equivalent Base Case CCS Scenario with storage in an open saline formation (no water extraction and management). For NGCC power plants, utilising water treatment of reservoir water for reuse in the power plant increases the LCOE, both for onshore and offshore storage options. The LCOE for power plants with CCS-water-nexus ranges from 79 to 85 €/MWh for onshore storage and from 83 to 87 €/MWh for offshore storage.

For extraction case A (extracted water volumetrically equivalent to CO_2 injected), compared to the power plant without CCS, the LCOE increases by about 48% in the CCS-Water-Nexus Scenario offshore and by 41% onshore for the NGCC with post-combustion capture using evaporative cooling (NGCC-EV-PCC-A): from 56 to 83 €/MWh offshore and to 79 €/MWh onshore (see Table 5-48). When air cooling is used for the capture plant (NGCC-EV-PCC-AC-A), the LCOE rise to 87 €/MWh offshore and 83 €/MWh onshore (Table 5-48).

In comparison to the equivalent Base Case CCS Scenario with CO_2 storage in an open saline formation (no water extraction), the extraction and reuse of water increase the LCOE by 4-5% (3-4 €/MWh) offshore and onshore for the NGCC with capture using either evaporative cooling (case NGCC-EV-PCC-A) or air cooling for the capture plant (case NGCC-EV-PCC-AC-A) (Table 5-48).

The analysis shows that by integrating the water-nexus through utilising reservoir water extraction, water treatment, disposal and transport of the treated water to the NGCC, 3-4 €/MWh is added to the LCOE for offshore and onshore storage in comparison to the CCS Base Case Scenario with no water extraction (compare Table 5-48).

For extraction scenario B, in which water beyond what is needed for safe CO_2 storage is extracted to meet the freshwater demand of the power plant with capture, the LCOE increases by 5% offshore (to 84 €/MWh) and 15% onshore (to 86 €/MWh) for the NGCC with post-combustion capture using evaporative cooling (case NGCC-EV-PCC-B). For the air cooled capture plant (NGCC-EV-PCC-AC-B), the LCOE increases by 4% (to 87 €/MWh) in the offshore storage scenario and by 6% (to 85 €/MWh) in the onshore storage scenario (Table 5-48). This is in comparison the Base Case CCS Scenario without water extraction.

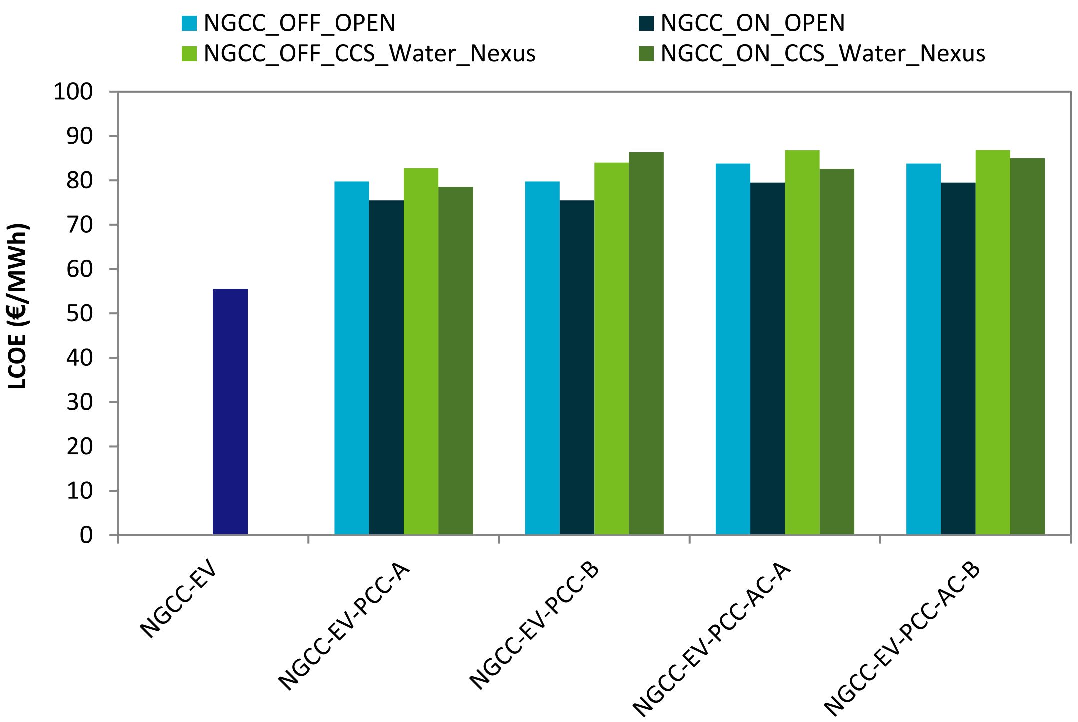


Figure 5-13 Comparison of LCOE of NGCC power plants in the CCS-Water-Nexus Scenario (onshore [ON] and offshore [OFF] with water extraction and utilisation: NGCC_CCS_Water_Nexus) with i.) a power plant without capture (NGCC-EV); and ii.) NGCC with CCS in open saline formations (no water extraction and management: NGCC_OPEN)

Table 5-48 Summary of LCOE for the NGCC in the CCS-Water-Nexus Scenario

LCOE (€/MWh)					
Case name	**2.1A**	**2.1B-A**	**2.1B-B**	**2.1C-A**	**2.1C-B**
	NGCC-EV	**NGCC-EV-PCC-A**	**NGCC-EV-PCC-B**	**NGCC-EV-PCC-AC-A**	**NGCC-EV-PCC-AC-B**
Description	No CCS	Water utilisation matches storage need	Water utilisation in both PP and PCC	Water utilisation matches storage need	Water utilisation in PP only (PCC air cooled)
Base Case (open) offshore	56	80	80	84	84
Base Case (open) onshore	56	75	75	80	80
CCS-Water-Nexus offshore	56	83	84	87	87
CCS-Water-Nexus onshore	56	79	86	83	85

PP = power plant; PCC = post-combustion capture

The cost of CO_2 avoidance behave in a similar manner to the LCOE and are presented in Figure 5-14 and Table 5-49. The cost of avoidance for the power plants with water utilisation from the reservoirs ranges from 74 to 99 €/t CO_2 avoided for onshore storage and 87 to 101 €/t CO_2 avoided for offshore storage.

The cost of avoidance for water extraction scenario A, in which the water extracted is volumetrically equivalent to the CO_2 stored, range from 74 €/t to 100 €/t (Table 5-49). In comparison to the Base Case CCS Scenario with no water extraction the relative increase ranges from 10% to 16%.

For water extraction scenario B, in which water is extracted to meet the freshwater demand of the power plant with capture, the range of avoidance cost is narrower, ranging from 92 €/t to 101 €/t (Table 5-49). Here, an increase in avoidance cost of up to 55% (corresponding to an increase from 64 €/t to 99 €/t) are observed. This is for the NGCC with post-combustion capture using evaporative cooling in the onshore storage scenario. This case has the highest freshwater water consumption (4.24 Mt/y - Table 5-51), combined with a lower product recovery of 25% (due to a salinity of 150,000 mg/L, see Table 5-47), and therefore has the highest water extraction, treatment, transport, and disposal costs.

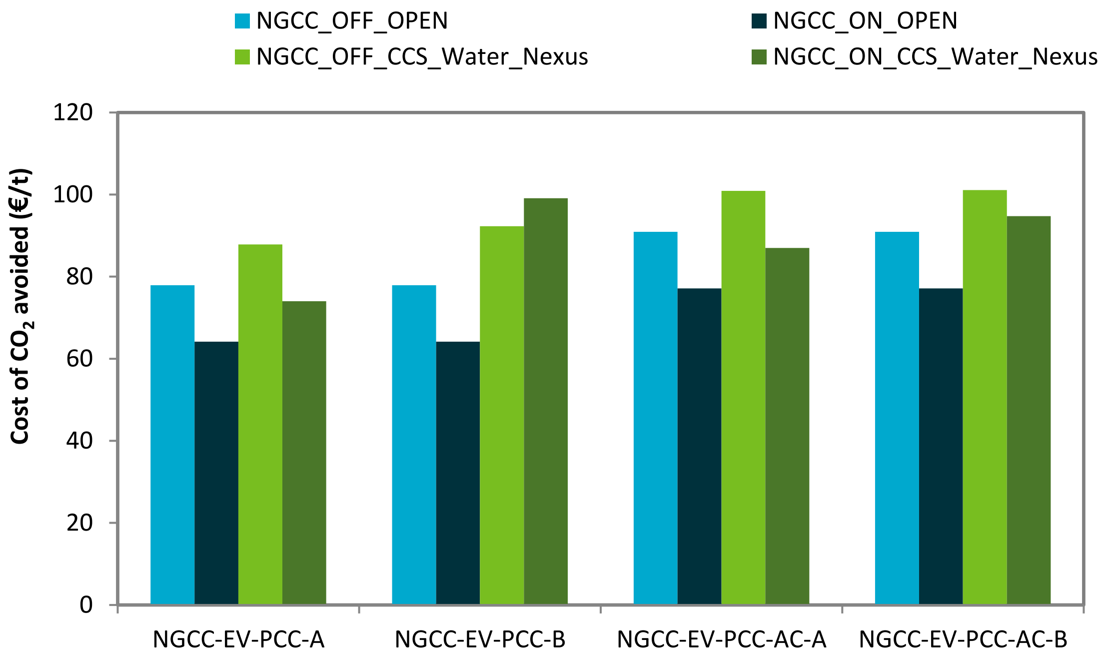


Figure 5-14 Comparison of cost of avoidance of NGCC power plants in the CCS-Water-Nexus Scenario (onshore [ON] and offshore [OFF] with water extraction and utilisation: NGCC_CCS_Water_Nexus) with NGCC with CCS in open saline formations (no water extraction and management: NGCC_OPEN)

Table 5-49 Summary of CO_2 avoidance cost for the NGCC in the CCS-Water-Nexus Scenario

Case name	**2.1B-A**	**2.1B-B**	**2.1C-A**	**2.1C-B**
	NGCC-EV-PCC-A	**NGCC-EV-PCC-B**	**NGCC-EV-PCC-AC-A**	**NGCC-EV-PCC-AC-B**
Description	Water utilisation matches storage need	Water utilisation in both PP and PCC	Water utilisation matches storage need	Water utilisation in PP only (PCC air cooled)
Base Case (open) offshore	78	78	91	91
Base Case (open) onshore	64	64	77	77
CCS-Water-Nexus offshore	87	92	100	101
CCS-Water-Nexus onshore	74	99	87	95

PP = power plant; PCC = post-combustion capture

The analysis shows that the extraction and treatment of water for utilisation in the power plant beyond what is required for safe CO_2 storage can have a noticeable impact on both LCOE and CO_2 avoidance cost, though in the offshore scenario the maximum increase is only about 1% in LCOE (from 83 €/MWh to 84 €/MWh, Table 5-48) and about 6% in avoidance cost (from 87 €/t to 92 €/t, Table 5-49). This is a result of the higher water extraction, treatment, disposal, and transport costs caused by the higher water extraction rates. In the onshore scenario, the LCOE increase by up to 9% from water extraction case A to water extraction case B, corresponding to an increase in LCOE of 7 €/MWh (from 79 €/MWh to 86 €/MWh, Table 5-48). Avoidance cost, however, increase by up to 34% onshore, an increase of 15 €/t (Table 5-49).

Table 5-50 Detailed results of the CCS-Water-Nexus Scenario for the NGCC using evaporative cooling and the capture plant using either evaporative cooling or air cooling - offshore storage

NGCC			**Water utilisation matches storage**	**Water utilisation in both PP and PCC**	**Water utilisation matches storage**	**Water utilisation in PP only**
Power station type		**NGCC-EV**	**NGCC-EV-PCC-A**	**NGCC-EV-PCC-B**	**NGCC-EV-PCC-AC-A**	**NGCC-EV-PCC-AC-B**
Cooling technology		EV w/o CCS	EV w/ CCS-EV	EV w/ CCS-EV	EV w/ CCS-AC	EV w/ CCS-AC
Capture technology		No Capture	SoA Solvent Absorption	SoA Solvent Absorption	SoA Solvent Absorption	SoA Solvent Absorption
Efficiency	%LHV	58.34	50.59	50.59	49.83	49.83
Gross power	MW	890	890	890	878.8	878.8
Net power	MW	878	761.3	761.3	749.9	749.9
Water consumption (Total)	Mt/y		4.24	4.24	1.8	1.8
Water consumption (Capture only)	Mt/y		1.05	1.05		
Transport and Storage						
Storage location			offshore	offshore	offshore	offshore
Distance to power station	km		110	110	110	110
Reservoir permeability	mD		100	100	100	100
Reservoir porosity			0.15	0.15	0.15	0.15
Reservoir boundaries			closed	closed	closed	closed
Formation water salinity	ppm		100,000	100,000	100,000	100,000
CO2 injection rate	Mt/y		2.08	2.08	2.08	2.08
Injection well number			1	1	1	1
Water extraction rate	Mt/y		3.3	8.5	3.3	3.6
Extraction well number			1	3	1	1
Water Management						
Treatment or direct disposal			Treatment	Treatment	Treatment	Treatment
Treatment technology			MVC	MVC	MVC	MVC
Feed stream (for water treatment, in case not all produced water treated)	Mt/y		3.3	8.5	3.3	3.6
Freshwater/Product stream (after treatment)	Mt/y		1.7	4.2	1.7	1.8
Reject stream	Mt/y		1.7	4.2	1.7	1.8
Reuse of freshwater (in power station or capture plant - state either PS or PCC)			PS	PS	PS	PS
Transport of freshwater (to site of use)	km		110	110	110	110
Transport of reject stream	km		0	0	0	0
Disposal of extracted brine or reject stream (reinjection or ocean)			ocean	ocean	ocean	ocean
Number of water injectors				-		
Emissions data						
CO_2 emitted	t/MWh	0.351	0.04	0.041	0.041	0.041
Capex						

NGCC			Water utilisation matches storage	Water utilisation in both PP and PCC	Water utilisation matches storage	Water utilisation in PP only
Power station type		**NGCC-EV**	**NGCC-EV-PCC-A**	**NGCC-EV-PCC-B**	**NGCC-EV-PCC-AC-A**	**NGCC-EV-PCC-AC-B**
Power Plant with capture	million €	835.7	1166.3	1166.3	1302.1	1302.1
Start-up costs	million €	28.7	37.88	37.88	41.18	41.18
CO2 Transport	million €		133.35	133.35	133.35	133.35
CO2 Storage	million €		24.15	24.15	24.15	24.15
Water extraction	million €		15.36	45.10	15.36	15.57
Water treatment	million €	0	7.57	13.02	7.57	7.83
Water transport of treated water	million €	0	122.12	124.19	122.12	122.22
Water transport (untreated/reject produced water)	million €	0	0	0	0	0
Water disposal (untreated/reject produced water)	million €	0	0	0	0	0
Total Capex	***million €***	***864***	***1507***	***1544***	***1646***	***1646***
Opex						
Power Plant and Capture						
fixed	million €/y	29.2	39.5	39.5	41.7	41.7
variable	million €/y	3.4	8.06	7.56	8.06	8.04
fuel	million €/y	227	224.48	224	226	226
Total PP + Capture	million €/y	260	272	272	276	276
Transport						
fixed	million €/y	0	0.33	0.33	0.33	0.33
variable	million €/y	0	0.58	0.58	0.58	0.58
Storage						
fixed	million €/y	0	13.59	13.59	13.59	13.59
variable	million €/y	0	2.79	2.79	2.79	2.79
Water extraction						
fixed	million €/y	0	0.31	1.09	0.31	0.31
variable	million €/y	0	1.17	2.99	1.17	1.28
Water treatment						
fixed	million €/y	0	0	0	0	
variable	million €/y	0	1.10	2.71	1.10	1.16
Water transport of treated water						
fixed	million €/y	0	0.32	0.33	0.32	0.32
variable	million €/y	0	0.53	0.83	0.53	0.54
Water transport (untreated/reject produced water)						
fixed	million €/y	0	0	0	0	0
variable	million €/y	0	0	0	0	0
Water disposal (untreated/reject produced water)						

NGCC			Water utilisation matches storage	Water utilisation in both PP and PCC	Water utilisation matches storage	Water utilisation in PP only
Power station type		**NGCC-EV**	**NGCC-EV-PCC-A**	**NGCC-EV-PCC-B**	**NGCC-EV-PCC-AC-A**	**NGCC-EV-PCC-AC-B**
fixed	million €/y	0	0	0	0	0
variable	million €/y	0	0	0	0	0
Total Opex	***million €/y***	***260***	***293***	***297***	***297***	***297***
LCOE calculations						
Capex (PP+Capture)	€/MWh	15.86	25.60	25.60	28.68	28.68
FOM	€/MWh	4.56	7.15	7.15	7.58	7.58
VOM	€/MWh	0.53	1.46	1.37	1.47	1.46
Fuel	€/MWh	34.60	39.60	39.60	40.10	40.10
Transport & Storage	€/MWh	0.00	5.89	5.89	5.91	5.91
Water extraction & management	*€/MWh*	*0.00*	3.03	4.40	3.04	3.08
Total LCOE	**€/MWh**	**55.55**	**82.73**	**84.01**	**86.78**	**86.81**
CO_2 avoided cost (€/t CO_2)			**87**	**92**	**100**	**101**

Table 5-51 Detailed results of the CCS-Water-Nexus Scenario for the NGCC using evaporative cooling and the capture plant using either evaporative cooling or air cooling – onshore storage

NGCC			**Water extraction matches storage**	**Water utilisation for both PP and PCC**	**Water extraction matches storage**	**Water utilisation for PP only**
Power station type		**NGCC-EV**	**NGCC-EV-PCC-A**	**NGCC-EV-PCC-B**	**NGCC-EV-PCC-AC-A**	**NGCC-EV-PCC-AC-B**
Cooling technology		EV w/o CCS	EV w/ CCS-EV	EV w/ CCS-EV	EV w/ CCS-AC	EV w/ CCS-AC
Capture technology						
Efficiency	%LHV	58.34	50.59	50.59	49.83	49.83
Gross power	MW	890	890	890	878.8	878.8
Net power	MW	878	761.3	761.3	749.9	749.9
Water consumption (Total)	Mt/y		4.24	4.24	1.8	1.8
Water consumption (Capture only)	Mt/y		1.05	1.05		
Transport and Storage						
Storage location			onshore	onshore	onshore	onshore
Distance to power station	km		45	45	45	45
Reservoir permeability	mD		200	200	200	200
Reservoir porosity			0.2	0.2	0.2	0.2
Reservoir boundaries			closed	closed	closed	closed
Formation water salinity	ppm		150,000	150,000	150,000	150,000
CO2 injection rate	Mt/y		2.08	2.08	2.08	2.08
Injection well number			1	1	1	1
Water extraction rate	Mt/y		3.5	17	3.5	7.2
Extraction well number			1	5	1	3
Water Management						
Treatment or direct disposal			Treatment	Treatment	Treatment	Treatment
Treatment technology			MVC	MVC	MVC	MVC
Feed stream (for water treatment, in case not all produced water treated)	Mt/y		3.5	17	3.5	7.2
Freshwater/Product stream (after treatment)	Mt/y		0.9	4.3	0.9	1.8
Reject stream	Mt/y		2.6	12.8	2.6	5.4
Reuse of freshwater (in power station or capture plant - state either PS or PCC)			PS	PS	PS	PS
Transport of freshwater (to site of use)	km		45	45	45	45
Transport of reject stream	km		170	170	170	170
Disposal of extracted brine or reject stream (reinjection or ocean)			reinjection	reinjection	reinjection	reinjection
Number of water injectors			10	51	10	22
Emissions data						
CO_2 emitted	t/MWh	0.351	0.04	0.041	0.041	0.041
Capex						

NGCC			Water extraction matches storage	Water utilisation for both PP and PCC	Water extraction matches storage	Water utilisation for PP only
Power station type		**NGCC-EV**	**NGCC-EV-PCC-A**	**NGCC-EV-PCC-B**	**NGCC-EV-PCC-AC-A**	**NGCC-EV-PCC-AC-B**
Power Plant with capture	million €	835.7	1166.3	1166.3	1302.1	1302.1
Start-up costs	million €	28.7	37.9	37.88	41.18	41.18
CO2 Transport	million €		15.75	15.75	15.75	15.75
CO2 Storage	million €		7.66	7.66	7.66	7.66
Water extraction	million €		5.11	25.38	5.11	14.35
Water treatment	million €	0	5.17	13.02	5.17	7.83
Water transport of treated water	million €	0	10.75	12.00	10.75	11.20
Water transport (untreated/reject produced water)	million €	0	43.43	51.77	43.43	46.47
Water disposal (untreated/reject produced water)	million €	0	42.01	213.76	42.01	92.14
Total Capex	***million €***	***864***	***1305***	***1476***	***1443***	***1497***
Opex						
Power Plant and Capture						
fixed	million €/y	29.2	39.5	39.5	41.7	41.7
variable	million €/y	3.4	8.22	7.54	8.22	8.04
fuel	million €/y	227	224.5	224.5	226.4	226.39
Total PP + Capture	million €/y		272	272	276	276
Transport						
fixed	million €/y		0.04	0.04	0.04	.04
variable	million €/y		0.58	0.58	0.58	0.58
Storage						
fixed	million €/y		3.26	3.26	3.26	3.26
variable	million €/y		2.79	2.79	2.79	2.79
Water extraction						
fixed	million €/y		0.29	1.75	0.29	0.92
variable	million €/y		0.52	2.55	0.52	1.07
Water treatment						
fixed	million €/y					
variable	million €/y		0.67	3.11	0.67	1.33
Water transport of treated water						
fixed	million €/y	0	0.03	0.04	0.03	0.03
variable	million €/y	0	0.16	0.34	0.16	0.22
Water transport (untreated/reject produced water)						
fixed	million €/y	0	0.13	0.18	0.13	0.15
variable	million €/y	0	1.00	2.21	1.00	1.44
Water disposal (untreated/reject produced water)						

NGCC			Water extraction matches storage	Water utilisation for both PP and PCC	Water extraction matches storage	Water utilisation for PP only
Power station type		**NGCC-EV**	**NGCC-EV-PCC-A**	**NGCC-EV-PCC-B**	**NGCC-EV-PCC-AC-A**	**NGCC-EV-PCC-AC-B**
fixed	million €/y	0	2.81	14.32	2.81	6.18
variable	million €/y	0	1.19	5.82	1.19	2.47
Total Opex	**million €/y**	***260***	**286**	**309**	**290**	**297**
LCOE calculations						
Capex (PP+Capture)	€/MWh	15.86	25.60	25.60	28.68	28.68
FOM	€/MWh	4.56	7.15	7.15	7.58	7.58
VOM	€/MWh	0.53	1.49	1.36	1.49	1.46
Fuel	€/MWh	34.60	39.60	39.60	40.10	40.10
Transport & Storage	€/MWh	0.00	1.62	1.62	1.62	1.62
Water extraction & management	€/MWh	0.00	3.10	11.02	3.11	5.54
Total LCOE	**€/MWh**	**55.55**	**78.55**	**86.35**	**82.59**	**84.98**
CO_2 avoided cost (€/t CO_2)			**74**	**99**	**87**	**95**

5.7 Summary of integrated results

The section provides a comparison of the LCOE and the avoidance cost of the CCS Base Case Scenarios with the CCS-Water-Nexus-Scenarios presented above. Table 5-52 and Table 5-53 summarise the LCOE for all the cases examined for the USCPC and NGCC power plants respectively, while Table 5-54 and Table 5-55 present the CO_2 avoidance cost.

Comparison of the LCOE for the USCPC and the NGCC (Table 5-52 and Table 5-53) demonstrates that the LCOE are lower for the NGCC with capture than for the USCPC with capture.

Comparing the LCOE of the Base Case CCS Scenarios (closed and open reservoir) in Table 5-52 and Table 5-53, the analysis shows that the disposal options only provide a comparatively minor contribution to the overall costs. Offshore, water extraction and management only add up to 2 €/MWh to the LCOE due to the assumed no-cost disposal option of ocean discharge. However, onshore water extraction is associated with disposal costs which can increase the LCOE by up to 7 €/MWh. In spite of this, the analysis highlights that the LCOE for onshore CO_2 storage are lower (or maximum the same) than for offshore storage, even when water extraction and management is required onshore (compare Table 5-52 and Table 5-53). This is due to the lower costs of CO_2 transport and storage onshore, which offset the higher onshore water management costs.

The analysis of the CCS-Water-Nexus Scenario highlights that if instead of water disposal, water treatment and reuse in the power station with capture is introduced, the LCOE increase by a further 3 €/MWh for the offshore storage scenario, but remain the same for the onshore storage scenario (or even decrease slightly). This is because in the onshore scenario treatment of the produced water and its subsequent reuse in the power plant is more cost effective than the direct disposal of produced water (compare Table 5-19). Water disposal onshore is expensive due to a significant number of disposal wells being required. Reducing the brine volume for disposal by 25% is sufficient to justify the cost associated with brine treatment and reuse. For less saline brines (onshore brine: 150,000 mg/L) the economic benefits would improve further as product recovery would increase and/or cheaper treatment technologies may be applied. This indicates that in cases for which water extraction is necessary to safely store the required volumes of CO_2, the reuse of water may not come at an additional expense as the cost of water treatment and disposal may be lower than the cost of direct disposal of the extracted brine without treatment.

The lower LCOE for the NGCC with capture over the USCPC with capture and the lower cost of onshore storage over offshore storage suggests that early implementation of the CCS-Water-Nexus would be most cost effective at NGCC power plants with CCS with onshore storage.

The analysis also shows that for CCS water treatment and utilisation applications, the volumes of water extracted and treated should be limited to those required for safe CO_2 storage rather than trying to provide all of the freshwater needs of the power and capture plants. Offshore, LCOE only increase by up to 3 €/MWh as a result of incremental water extraction with treatment and reuse. Onshore, the increase in LCOE can be as high as 15 €/MWh for the USCPC, but as low as 2 €/MWh for the NGCC. This is due to the very high additional costs of extraction and treatment arising from the low water recovery rates of the water treatment technology (25% for the 150,000 mg/L onshore brine and 50% for the 100,000 mg/L offshore brine) and the associated large water volumes that are therefore extracted. However, if through the incremental extraction of water additional storage capacity is generated at the same site that can be effectively utilised, this may present a cost-effective alternative to developing a new storage site. This would require investigation in a separate analysis.

Comparing the LCOE of the integrated CCS-Water-Nexus scenarios to the CCS scenario using air cooling(USCPC-AC-PCC and NGCC-AC-PCC), in the offshore CO_2 storage scenario the LCOE is less for the CCS-Water-Nexus-Scenario with water extraction to meet the demand of the power plant (compare USCPC-EV-PCC-B and NGCC-EV-PCC-B) (compare Table 5-52 and Table 5-53). This suggests that if stringent water regulations become imposed on power plants that currently use evaporative freshwater cooling, applying water utilisation from produced reservoir water as part of an integrated CCS chain can become an opportunity.

The LCOE of the power plants with and without post-combustion capture using evaporative cooling and once-through seawater cooling were found to be very similar (see Table 5-10 and Table 5-11), which is reflected in the LCOE when CO_2 storage is added (compare base case results presented in Table 5-52 and Table 5-53). It suggests that in scenarios where the use of seawater is not limited by either physical availability or regulations, once-through seawater cooling presents a low freshwater consuming alternative to evaporative cooling at a comparable cost. This is emphasized by the increase in LCOE when water reuse is applied in the power plant with capture using evaporative cooling to eliminate any additional freshwater demand (extraction scenario B, Table 5-52 and Table 5-53): in this case the LCOE are higher than for the power plants with capture using once-through cooling.

Table 5-52 LCOE summaries for coal fired USCPC power plants, with and without CCS

Cooling technology		**Evaporative cooling**					**Once through cooling**			**Air cooling**	
Case name		**1.1A**	**1.1B**		**1.1C**		**1.2A**	**1.2B**	**1.2C**	**1.3A**	**1.3B**
LCOE USCPC		**w/o CCS**	**USCPC-EV-PCC**		**USCPC-EV-PCC-AC**		**w/o CCS**	**USCPC-OT-PCC**	**USCPC-OT-PCC-AC**	**w/o CCS**	**USCPC-AC-PCC**
Offshore											
Base case (open)	€/MWh	56	86		90		56	86	90	59	94
Base case (closed)	€/MWh	56	87		92		56	87	91	59	95
CCS-Water-Nexus	€/MWh	56	A90	B93	A95	B96					
Onshore											
Base case (open)	€/MWh	56	81		85		56	81	85	59	89
Base case (closed)	€/MWh	56	87		92		56	87	92	59	95
CCS-Water-Nexus	€/MWh	56	A87	B102	A91	B99					

A = water extracted volumetrically equivalent to CO_2 injected; B = water extracted to meet freshwater demand of power plant with capture

Table 5-53 LCOE summaries for NGCC power plants, with and without CCS

Cooling technology		Evaporative cooling			Once through cooling			Air cooling	
Case name		**2.1A**	**2.1B**	**2.1C**	**2.2 A**	**2.2B**	**2.2C**	**2.3A**	**2.3B**
LCOE NGCC		**w/o CCS**	**NGCC-EV-PCC**	**NGCC-EV-PCC-AC**	**w/o CCS**	**NGCC -OT-PCC**	**NGCC-OT-PCC-AC**	**w/o CCS**	**NGCC-AC-PCC**
Offshore									
Base case (open)	€/MWh	56	80	84	55	80	84	58	86
Base case (closed)	€/MWh	56	80	84	55	80	84	58	86
CCS-Water-Nexus	€/MWh	56	A83 B84	A87 B87					
Onshore									
Base case (open)	€/MWh	56	75	80	55	75	79	58	81
Base case (closed)	€/MWh	56	79	83	55	79	83	58	85
CCS-Water-Nexus	€/MWh	56	A79 B86	A83 B85					

A = water extracted volumetrically equivalent to CO_2 injected; B = water extracted to meet freshwater demand of power plant with capture

Table 5-54 and Table 5-55 summarise the CO_2 avoidance cost for the USCPC and the NGCC scenarios, respectively. Avoidance cost are higher for capture from the NGCC than for the USCPC, while onshore storage results in lower avoidance cost than offshore storage.

For the CCS-Water-Nexus Scenario (power plant using evaporative cooling, capture plant using evaporative or air cooling), avoidance cost increase compared to the lowest cost scenario (the open reservoir base case) by up to 10 €/t CO_2 for offshore storage facilities, and by up to 24 €/t CO_2 avoided for onshore storage facilities. This is for the NGCC when water extraction is volumetrically equivalent to the CO_2 injected.

When water is extracted to meet the freshwater demand of the power plant with capture using evaporative cooling, avoidance cost can increase by as little as 0 €/MWh and by as much as 24 €/t in comparison to the scenario in which the volume of water extracted is volumetrically equivalent to the CO_2 injected. The highest increase is observed for the onshore storage scenario with capture from the USCPC as a result of the low product recovery (25%) from the onshore brine.

Table 5-54 Cost of CO_2 avoidance summaries for coal fired USCPC power plants, with and without CCS

Cooling technology		Evaporative				Once-through		Air
Case name		1.1B		1.1C		1.2B	1.2C	1.3B
Avoidance cost USCPC		USCPC-EV-PCC		USCPC-EV-PCC-AC		USCPC-OT-PCC	USCPC-OT-PCC-AC	USCPC-AC-PCC
Offshore								
Base case (open)	€/t	46		52		46	52	52
Base case (closed)	€/t	48		54		48	54	54
CCS-Water-Nexus	€/t	A53	B56	A59	B60			
Onshore								
Base case (open)	€/t	38		45		38	45	44
Base case (closed)	€/t	47		54		48	55	54
CCS-Water-Nexus	€/t	A47	B71	A53	B66			

A = water extracted volumetrically equivalent to CO_2 injected; B = water extracted to meet freshwater demand of power plant with capture

Table 5-55 Cost of CO_2 avoidance summaries for NGCC power plants, with and without CCS

Cooling technology		Evaporative				Once-through		Air
Case name		2.1B		2.1C		2.2B	2.2C	2.3B
Avoidance cost NGCC		NGCC-EV-PCC		NGCC-EV-PCC-AC		NGCC-OT-PCC	NGCC-OT-PCC-AC	NGCC-AC-PCC
Offshore								
Base case (open)	€/t	78		91		79	92	87
Base case (closed)	€/t	80		93		80	93	89
CCS-Water-Nexus	€/t	A88	B92	A101	B101			
Onshore								
Base case (open)	€/t	64		77		65	78	73
Base case (closed)	€/t	75		88		75	88	84
CCS-Water-Nexus	€/t	A79	B86	A83	B85			

A = water extracted volumetrically equivalent to CO_2 injected; B = water extracted to meet freshwater demand of power plant with capture

5.8 Comparison of economic evaluation with literature

5.8.1 Comparison of economic evaluation of power plants with CCS with the literature – no water integration

Few studies are available in the open literature that have reported the cost of CO_2 avoided for the full CCS chain; considering CO_2 capture, transport and storage, as costs particularly for transport and storage are highly site and location specific. To enable cost comparisons with those in the literature, the cost of transport and storage have been removed from the results of this study in the following discussion.

For USCPC power plants with capture using evaporative or once-through cooling, the reported cost of avoidance is about 40 €/t CO_2, and for air cooling it is 46 €/t CO_2. Estimates for capture costs of USCPC power plants from the literature are in the range of 70-100 US$/t CO_2 or approximately 60-85 €/t CO_2, which are higher than those from this study. The lower estimates in this study arise due to the different economic and processing assumptions.

For NGCC power plants with capture (and without transport and storage), the CO_2 avoidance costs are approximately 72 €/t CO_2 using evaporating or once-through cooling, and 80€/t CO_2 using air cooling. These costs for evaporative cooling are similar to those estimated in the literature (IEAGHG, 2012a; DOE-NETL, 2015) where the costs are in the range of 55-74 €/t CO_2.

No studies have reported capture cost for NGCC using once-through or air-cooling systems for comparison.

5.8.2 Comparison to power plants with capture under water-stressed conditions (including water reuse)

There have been some studies in the public domain which have examined and outlined the economics for power plants under water stressed conditions. These include the IEAGHG (2011) and Tenaska Trailblazer CCS project (2012).

The IEAGHG (2011) study evaluated USPC power plants with once-through seawater or air cooling where water discharge is highly regulated. The assessments included scenarios where process water is reused and recycled at an onsite wastewater treatment under ZLD regulations. When capture is implemented, water from the capture process is recycled within the wastewater treatment facility and is reused and utilised in other parts of the power plant such as the FGD. The reported cost of CO_2 avoided (without transport and storage) is 29 €/t CO_2 avoided if the power plant is located in a coastal region using once-through cooling, increasing to 34 €/t CO_2 avoided if the power plant is located inland in an arid region using air cooling (see Table 5-56).

In the Tenaska Trailblazer CCS project, located in arid Texas, a dry air cooling system was considered for both the power and capture plants due to the local environmental impacts (Tenaska Trailblazer Partners, 2012). ZLD regulations were also applicable, with wastewater treatment considered in the project plan. The cost estimate for this project is very high - in the order of 7,000 to 8,300 $/kW(net) for the power and capture plants. LCOE and avoidance costs were not reported (Table 5-56).

Both these studies examining power plants with CCS under stressed water conditions utilise wastewater treatment to fulfil their water requirements. In comparison, for this study, an alternative approach is considered where the freshwater requirements of the power plant with capture are provided by extracted and treated formation water. The costs reported in the three studies are compared in Table 5-56. The cost estimates in the present study are much higher than those reported by the IEAGHG (2011), with avoidance costs of 39-46 €/t CO_2 avoided (without transport and storage). The higher costs arise due to the higher fuel costs assumed in this study and the different location factors assumed. The cost differences could also be due to the different water management systems – wastewater treatment vs. reuse of extracted water. However, the different economic assumptions make direct comparison between the different water management systems difficult.

Similarly, the Tenaska Trailblazer CCS project has capital cost estimates of almost two to almost three times higher than this study. Unfortunately, there is limited cost data from the Trailblazer FEED study to enable further comparison.

There are no current publicly available studies that have outlined detailed integrated assessments of power plants with CCS using extracted and treated formation water for direct comparison with this study. In their study outlining the benefits of active reservoir management to provide additional water resources for power plants with CCS, Klapperich et al. (2014) have provided conceptual arguments for the case, however, no specific case studies were assessed.

Table 5-56 Comparison of economic outputs for studies examining power plants with CCS under water stressed regulations

Project		This study	This study	USCPC Wet	USCPC Dry	Tenaska Trailerblazer
Location	**Unit**	**Netherlands**	**Netherlands**	**South Africa**	**South Africa**	**USA**
Reference		SCPC-EV-PCC	SCPC-EV-PCC-AC	IEAGHG 2011	IEAGHG 2011	Tenaska 2012
Cooling technology		**Evaporative cooling**	**Evaporative cooling + ACC**	**OT**	**Air cooling**	**Air Cooling**
		Extracted formation water	Extracted formation water	ZLD	ZLD	ZLD
Capture technology		PZ/AMP	PZ/AMP	Fluor EFG+	Fluor EFG+	Fluor EFG+
Cost year		2018	2018	2009	2009	2011
Currency		Euro	Euro	Euro	Euro	US
Power plant with capture						
Gross power plant output	MWe	833.3	833.3	827		
Net power plant output	MWe	684	678	665.6		550
Net water balance	t/MWh	0	0	0.07	0	0
Capex	M€	1660	1785	1,101	1,187	3,800-4,550
	€/kW	2,650	3,410	1,655	1,905	6945 -8,315
LCOE without capture	€/MWh	56	56	40	43	
LCOE with capture only	€/MWh	82	86	58	65	
CO_2 avoided to reference plant w/o T&S	**€/t**	**39**	**46**	**29**	**34**	

6 Challenges in the extraction-reuse network

The economic analysis in Chapter 5 demonstrates that extraction of highly saline brines to improve storage capacity adds additional costs to the CCS project. While offshore disposal was assumed free of charge (assuming any costs may be offset by the benefits of geothermal energy generation or brine may be reinjected for pressure maintenance in nearby oil fields), brine disposal from the onshore site adds a substantial cost to the project due to transportation and injection costs. Breunig et al. (2013) state that finding cost-effective, large-scale disposal options will continue to remain a significant challenge of brine management. Furthermore, costs may change over time as brine storage options reach their capacities and more expensive options need to be considered (Breunig et al., 2013).

For the extracted brines in the present study, direct reuse is not a feasible option due to their very high salinity (100,000 mg/L and 150,000 mg/L for the offshore and onshore brine, respectively) which leads to scale formation, corrosion and fouling. Power station cooling water systems may be specifically designed to utilise highly impaired waters (TDS > 70,000 mg/L), though the majority of existing plants are much more restrictive and often limited to TDS concentrations of 500 mg/L or less (Klapperich et al., 2014b).

Another factor to consider are the transport costs for the extracted water. Even if the water quality is sufficient to be directly (or with minimal treatment) used as cooling water, if the water source is not near where it is needed, transport costs will considerably impact the feasibility of produced water reuse in the power station. In many cases it may be more practical to use seawater rather than extracted brine, depending on the accessibility of seawater vs the accessibility of the extracted brine. This will depend on the location of the power plant and the location of the storage site in relation to the power plant. Furthermore, water extracted from deep reservoirs is typically produced at very high temperatures, making it unsuitable for cooling.

Treatment can reduce the volumes of brine to be disposed and provide an additional freshwater source. However, this is at an additional cost. The advantage is that freshwater has a wider application than saline water and thus has a higher possibility to be used where it is produced. Still, the reject from the water treatment also requires disposal.

6.1 Efficient use of extracted water

To improve the efficiency and economics of water extraction relating to CO_2 storage operations, an integration of the different options available for brine management has been proposed by Breunig et al. (2013). They presented a generic brine use sequence (BUS) including resource harvesting (e.g., energy recovery), treatment and disposal stages. A brine use sequence specific to the Netherlands would be necessary to obtain a more accurate estimate of the costs and benefits of brine extraction in this location. Such a sequence does not only consider a range of options, such as use of geothermal energy, water treatment, reuse of the produced freshwater, mineral harvesting, and disposal of the wastewater stream, but also contemplates the integration of these options rather than considering them in isolation. Breunig et al. (2013) demonstrated that in that manner, depending on the options available and selected at each site, positive net present values could be obtained, but only under optimal conditions and assuming technological learning.

In the present study, due to the depth of the considered storage reservoirs, geothermal energy production is an option to offset (some of the) costs associated with brine extraction. The amount of energy will depend on the extracted water temperature, which was estimated as 70°C for the saline aquifer onshore and 90°C for the deeper aquifer offshore. Above 70°C geothermal energy is hot enough to be harnessed for the production of electricity (DJPR, 2019). Energy production would occur at the extraction site and may be used to support CO_2 storage and brine extraction operations.

After harvesting of geothermal energy the extracted water may be treated to freshwater quality standards as per Chapter 3.2.3 using mechanical vapour compression. Depending on the amount of energy generated from geothermal, it may be used to provide energy for the water treatment process, reducing product water costs. Alternatively, depending on the temperature the brine is produced at, it may be more beneficial to treat the water immediately after extraction to reduce energy requirements of thermal treatment processes and potentially increase product recovery. This will depend on the treatment technology considered, the composition of the brine and its temperature, amongst others. For lower salinity brines (10,000 - 85,000 mg/L – Aines et al., 2011) that may be treated applying reverse osmosis (RO), the high pressures at which the water may be produced due to the pressure maintenance from CO_2 injection will aid in lowering treatment costs, with Aines et al. (2011) expecting costs to reduce by as much as 50% when produced water pressure is above 8 MPa. The harvesting of geothermal energy prior to RO reduces the water temperature as to avoid causing harm to the membrane. A detailed site specific evaluation would need to be carried out to assess which options are feasible and provide the highest economic benefit. The produced reject after treatment may be harvested for mineral production, such as NaCl, Mg, B, K, Ca via evaporation ponds and salt electrolysis treatment (Breunig et al., 2013). However, in an offshore location this would be challenging.

Depending on the quality of the (treated or untreated) water its use will differ. The Dutch standard for chloride content in drinking water is 150 mg/l, while the European standard is 250 mg/l, and the standard of the World Health Organisation is 300 mg/l. The standard applied by industry for process water is also 150 mg/l, while the cooling water standard depends on the materials used in the construction of the cooling installations. This means seawater can be used for cooling if installations are purpose built (Rijkswaterstaat, 2011).

There are no clear standards for irrigation water in the Netherlands. The chloride standard depends on the crops being grown with different standards being applied for growing fruit and potatoes. The Cultural Technical Handbook from 1988 defines a standard of 300 mg/l for fruit cultivation and 600 mg/l for potatoes. Regional differences in perception also play a role in what constitutes an acceptable level of chlorine: for example, farmers in the western part of the country apply a stricter standard on what constitutes acceptable chloride levels for irrigation (Rijkswaterstaat, 2011).

Therefore, to improve the cost-effectiveness of the process, the primary utilisation of the produced water needs to be defined prior as to design the optimal brine use sequence. The appropriate water treatment as part of the BUS will depend on the original composition of the water and its intended purpose.

The highly saline brines from the Dutch storage sites investigated in this study are treated applying a thermal processes. As a consequence, the produced water quality will be that of freshwater, thus not providing a limit to its use. The use will most likely depend on where the water is being produced as to eliminate, or at least reduce, the cost of transport. The water may thus be used in industrial applications, such as the hypothetical power plants in this study, for agricultural purposes or to combat salinisation directly by providing counter pressure to saline seepage water through pumping freshwater into polders.

6.2 Reuse of existing infrastructure

In addition to optimising the brine use sequence, costs of integrating the reuse of extracted water may be lowered through the use of existing infrastructure from oil and gas production. The ability to convert and use an existing oil platform for CO_2 injection and water extraction operations was also assumed in this study. Reusing existing infrastructure is not only of interest from an economic point of view with respect to storage, but it also presents an opportunity to deliver additional value from assets that would otherwise be decommissioned (Acorn, 2018). In the Netherlands, a large portion of oil and gas infrastructure is expected to reach the end of its economic life over the next two decades, comprising 156 platforms, more than 3,000 km of pipeline and approximately 700 wells (Offshore Holland, 2017). Decommissioning of these assets is estimated to cost close to 7 billion Euro (EBN, 2016). However, adapting existing infrastructure for CO_2 transport and storage operations may bear technical, safety, as well as regulatory challenges.

With regards to the technical aspects, the platforms have a limited life expectancy and were designed for their initial purpose of petroleum extraction. For platforms nearing the end of their intended operating life, extending life beyond this may be possible if the integrity of the structure can be maintained. For example, load on the structure may be reduced by removing process equipment from the platform which will not be necessary for CO_2 storage (EIL, 2013).

Furthermore, it will have to be demonstrated that an existing platform is able to accommodate either newly drilled wells or provide existing petroleum wells that may be converted to CO_2 injectors or water extractors (BERR, 2007). To convert existing wells to CO_2 injection wells, the integrity of the well needs to be established first. It will be crucial to ascertain wells are not leaking and CO_2 can be injected and stored safely. This will require wellbore and completion integrity assessment and possible remedial work (BERR, 2007).

Alternatively, if these are not viable options, new wells can be drilled as subsea wells that may be connected by a short pipeline to the existing platform (BERR, 2007).

If CO_2 injection operations are added to a platform that is still operating, for example for the purpose of EOR, the platform will need to be able to accommodate the additional equipment with regards to weight and space (EIL, 2013).

An alternative to constructing completely new platforms may also be the option to reuse part of a decommissioned platform elsewhere. For example, in 2008 the top sides of the P14-A satellite platform were removed and cleaned to be reused on platform E18-A (Nextstep, 2018).

The Mining Act stipulates that where onshore and offshore oil and gas installations can no longer be used efficiently and there is no prospect of reuse, the infrastructure owner is responsible for decommissioning the installations (Offshore Holland, 2017). This highlights that timely planning of potential reuse options is of high importance.

As for all new and modified operations, a review of operational safety is required and necessary modifications identified should be implemented (EIL, 2013).

The suitability of a platform would have to be assessed on a case by case basis. Nextstep (2018) suggest that between 30 and 50 platforms are suitable for CO_2 storage.

The use of existing oil and gas pipelines is expected to considerably lower CO_2 transportation costs. The highest risk associated with repurposing hydrocarbon pipelines is overestimating pipeline integrity. Key factors affecting the suitability of a pipeline for CO_2 transport are its age, condition, and pressure rating (Acorn, 2018). Older and abandoned pipelines are more likely to exhibit corrosion or other integrity concerns. As the condition of redundant pipelines is often uncertain, they will require assessment and potentially remedial intervention. Still, such works are expected to cost only 1-10% of the cost of building and installing a new pipeline (Acorn, 2018). Alternatively, costs may be reduced by installing new pipelines along existing ones by reusing existing pipeline rights of way (Bellona, 2015). Another aspect that requires consideration is the purity of the CO_2 to be transported in the pipeline with regards to corrosion, in particular its water content. (Rabindran et al., 2011). However, this aspects also applies to purpose-built CO_2 pipelines.

Existing pipeline infrastructure may also be used for the transport of extracted water where appropriate. In this case, requirements on the pipeline are less stringent than for CO_2 transport.

Based on the Dutch Mining Act, existing oil and gas pipelines can only be used after the relevant fields are fully depleted. Currently, in contrast to platforms, they may be left in-situ, though the Dutch Minister of Economic Affairs may also order their removal (Offshore Holland, 2017). Under the latest North Sea Policy Document new offshore pipelines will require removal once no longer in use, unless a social-cost benefit analysis indicates in-situ decommissioning is preferable.

For the use of oil and gas pipelines it is typical to have access agreements with the pipeline operator (Oosterhuis and de Vlam, 2016), which may be expected to be the same if the pipelines carry CO_2.

Non-technical challenges may apply if the CO_2 storage operator is not the same as the oil and gas platform operator as responsibilities and liabilities have to be allocated and transferred with regards to past and future operations (EIL, 2013). As the Dutch government applies a "polluter pays" approach, it has to be determined prior which party will be responsible if a converted well leaks CO_2 and the party that has to carry out and pay for the decommissioning of the facilities. Long-term liability with respect to leakage and maintenance is an acknowledged issue (Mikunda and Haan-Kamminga, 2013). The Mining Act regulates safety and environmental impacts, as well as liability during and after cessation of a project for oil and gas operations and its infrastructure (including transport networks) as well as CO_2 transport and storage operations and its infrastructure.

It should be considered that the reuse of existing infrastructure is only of interest if it is in proximity to a potential storage site, either depleted hydrocarbon field or saline aquifer, which meets the geological requirements.

6.3 Key factors affecting efficient water reuse for CCS

Based on the above, the following factors will require consideration for the effective integration of the CCS chain with water extraction and reuse:

- Freshwater consumption of the power station: where freshwater consumption is low, such as for air cooling and seawater once-through cooling systems, integrating the reuse of extracted water may not be practical due to economies of scale.
- Local regulations:
  - Regulations may prescribe ZLD for power plants, making the recycling of wastewater necessary.
  - Regulations may limit or eliminate cost-effective disposal of extracted water, thus making treatment and subsequent reuse a viable option.
- Cost of incremental storage: the extraction and management of formation water to obtain additional storage capacity may be more cost-effective than developing a new storage site.
- Annual CO_2 injected and stored: the injection rate will affect how much water needs to be extracted and thus how much water needs to be managed.
- Location of the CO_2 storage site:
  - Offshore CO_2 storage: water extracted offshore is not expected to be reused due to cost-effective disposal options, such as ocean disposal or reinjection, as well as a lack of significant demand offshore, thus necessitating transport to potential users onshore. However, if existing offshore infrastructure is reused for water transport, the transport challenge may be eliminated.
  - Onshore CO_2 storage: disposal options for onshore extracted water are limited and thus significantly more expensive than offshore, potentially requiring transport. Water treatment may be a viable alternative to reduce disposal costs and derive a benefit from freshwater.
- The location of the power station with regards to the location of water extraction:
  - To reduce transport costs, the power station should be located in close proximity to the site of brine extraction. Alternatively, the reuse of existing oil and gas pipelines may be investigated.
  - If seawater is readily available, its use in the power station (potentially after treatment) is likely to be more economic than most extracted brines.
- Access to potential users: the reuse of water is only of value, if there is a demand for it and will be more beneficial if extraction and potential treatment occur in proximity to potential users.
- Use of existing oil and gas infrastructure: where possible, this could reduce the water transport challenge when integrating water reuse with CCS.
- The quality of the extracted water:

    - Brines with salinities up to 50,000 mg/L can be treated with conventional seawater desalination methods (Kaplan et al., 2017).
    - Brines with salinities exceeding 50,000 mg/L require increasingly more expensive treatment technologies.
- The intended purpose of the produced water:
    - Cooling water: seawater quality may be sufficient, if installations are purpose built. However, the extracted formation water is typically at elevated temperatures, not suitable for cooling.
    - Process water/freshwater: the extracted formation will require treatment
- Site specific additional benefits from the extraction of water: to lower the cost of water extraction the potential of harvesting geothermal energy, minerals, and other options requires investigation.

While there are numerous applications for extracted water, the opportunities for an economically viable integration of water reuse in the CCS chain are likely to be limited and will need to be assessed on a case by case basis (Klapperich et al., 2014a). Harto and Veil (2011) only consider the reuse of extracted water a viable option where i.) salinities are low, thus not requiring further treatment; or where ii.) reverse osmosis can be effectively applied to treat water and the high pressure of the produced water reduces processing costs.

However, an interesting consideration is accounting for the incremental storage capacity that can be obtained through the extraction of water. Depending on storage costs and water extraction and management costs, increasing the capacity of a storage formation through water extraction may be more economical than the development of a new storage site.

7 Conclusions and recommendations

7.1 Conclusions

This study has provided an in-depth evaluation of the costs and benefits of integrating water usage for both coal fired ultra-supercritical (USCPC) and natural gas fired combined cycle (NGCC) power plants with CCS. The report includes assessments of the increase in water consumption resulting from CO_2 capture, comparisons of power plant performance using different cooling technologies, the impact of water extraction on CO_2 storage capacity and containment, as well as an investigation into the potential reuse of extracted water from the storage site in the power plants, including the key factors affecting efficient reuse in CCS.

Key conclusions from the detailed technical and economic assessment are separated into those relating to power plant performance, storage operations, water management of produced brine, and economics.

7.1.1 Power plant performance and water balance

- Power plants (USCPC and NGCC) using evaporative cooling nominally require a substantial amount of freshwater, with normalised water consumption rates of over 1 m^3/MWh for USCPC power plants and 0.75 m^3/MWh for NGCC power plants driven primarily by the water needed in the cooling tower (95% of the total usage).
- Adding CO_2 capture was found to increase water consumption by approximately 50% for both USCPC and NGCC power plants using evaporative cooling. This arises due to increases in water usage in the power plant cooling towers, the condenser cooling tower, CO_2 compression and cooling towers for the capture process heat exchangers.
- When air cooling is utilised the power plants have lower thermal plant efficiencies than evaporative cooling (by 2%) due to the higher power consumption of the air cooling fans. The normalised water withdrawal and consumption for air cooling plants is zero for NGCC power plants and almost negligible at 0.07 m^3/MWh for USCPC power plants. This consumption is for the make-up water required at the FGD plant.
- Seawater once-through cooling in power plants with and without capture has thermal efficiencies similar to plants using evaporative cooling. As with air cooling, the consumption of freshwater is zero at NGCC power plants and almost negligible at 0.1 m^3/h for USCPC power plants.
- If air cooling is utilised for the capture plant while the power plant (NGCC or USCPC) uses evaporative cooling, the relative change in the freshwater usage compared to the power plant without capture is -5%. Similarly, for once-through cooling, replacing seawater cooling in the capture plant with air cooling does not change the relative increases in freshwater usage compared to the USCPC or NGCC power plants without capture as the required freshwater is very small (for the make-up solvent). In all cases, using air cooling for the

capture plant reduces the efficiency of the power plant with capture by a further 2% compared to using only evaporative or seawater cooling technologies.

7.1.2 Storage in the Netherlands

- The boundary conditions investigated for the saline storage formations onshore and offshore Netherlands are closed and open boundary. In case of open boundaries, the storage simulations indicate that CO_2 can be stored at a rate of 2 Mt/y and 4 Mt/y over a period of 25 years without exceeding fracture threshold pressure, while CO_2 plume migration is limited.
- In case of closed reservoir boundaries, pressure remains below the fracture threshold for the lower injection rate of 2 Mt/y using a single injection well over the injection time frame of 25 years, enabling storage of the full amount captured from the NGCC (50 Mt).
- For the CO_2 injection rate of 4 Mt/y using two injection wells, the storage capacity of both the closed onshore and the offshore reservoir is pressure limited. In this case, the capacity is 40 Mt which is reached after 10 years of injection, rather than the required 100 Mt.
- Brine extraction from two wells at a volumetrically equivalent rate (H_2O:CO_2 ratio of 1.73 and 1.68 onshore and offshore, respectively) is found to be an effective mitigation option for maintaining pressure below the fracture threshold in the closed reservoir to enable CO_2 injection at 4 Mt/y for a total capacity of 100 Mt over 25 years. Plume migration is not notably affected by the extraction of formation water.
- A large region of mobile supercritical CO_2 at the top of the reservoir in both the onshore and the offshore model during and after production means containment in these reservoir units is contingent on the presence of a suitable sealing caprock. Due to the limited migration of the plume, only a small amount of CO_2 is immobilised in the pore space at residual saturation.
    - In the offshore scenario at the end of the injection period, approximately 10% of the total CO_2 injected (corresponding to 10 Mt) is trapped by dissolution in the 4 Mt/y case, compared to approximately 12% (corresponding to 6 Mt dissolved) in the 2 Mt/y case.
    - In the onshore scenario, 7% (7 Mt) of CO_2 is dissolved in the 4 Mt/y case after 25 years of injection, while for the 2 Mt/y case it is 9% (4.5 Mt).
- The maximum storage capacity in the offshore aquifer model with open boundary conditions is estimated to be approximately 200 Mt, while in the onshore aquifer model it is 160 Mt. This is based on the size of the structures, their porosity and assuming a storage efficiency of 3%. With water extraction, the same storage capacity can be achieved in the closed formation.

7.1.3 Management of produced brine

- For the offshore storage operation in the Q1 saline aquifer, disposal of produced brine in the order of ~7 Mt/y through ocean discharge appears to be feasible from a technical and regulatory point of view. However, countries are moving towards zero-impact emissions into the North Sea and the Dutch regulator may require limited discharge to the North Sea in the future. In this case water reinjection into subsurface formations may be the preferred option.
- Onshore water disposal is limited to water reinjection. However, existing onshore operations in the Netherlands do not inject in excess of 1 Mt/y. Also, induced seismicity in response to water injection has been identified as an issue. Adequate storage capacity and injectivity for the reinjection of up to ~7 Mt/y would require additional geological and geomechanical assessments. Alternatively, produced water at the onshore CO_2 storage operation could be pipelined offshore for reinjection into offshore reservoirs or ocean disposal.
- Water treatment of produced brine and reuse presents an alternative to direct disposal. However, for the highly saline formation waters from the offshore and onshore storage sites, energy intensive thermal processes have to be applied for desalination. Mechanical vapour compression is selected due to its cost competitiveness and its high product water quality. Applying this technology, a product water recovery of 50% can be expected for the brine concentration of 100,000 mg/L (offshore saline formation) and 25% for the brine concentration of 150,000 mg/L (onshore saline formation). The water is of suitable quality to be used in the power plants to substitute or supplement the consumption of other freshwater sources. For the power plant with capture using evaporative cooling the recovered product water quantity is not sufficient. To meet the freshwater demand of the power station with capture, brine in excess to that required for storage needs to be extracted from the formation.

7.1.4 Economics

- USCPC and NGCC power plants without CCS using evaporative and seawater once-through cooling systems have similar estimates for LCOE – approximately 56 €/MWh. If air cooling is used, the LCOE increases by approximately 5% (to 58 €/MWh for the NGCC and to 59 €/MWh for the USCPC).
- Adding capture to the USCPC and the NGCC power plants using evaporative and once-through cooling systems increases the LCOE by around 20 €/MWh to 78 €/MWh for the USCPC and 74 €/MWh for the NGCC.
- When the power plants with capture are air-cooled, the LCOE increase to 86 €/MWh for the USCPC and 80 €/MWh for the NGCC.
- For power plants that use evaporative or seawater once-through cooling for the power plant but air cooling for the capture plant, LCOE are 83 €/MWh for the USCPC and 78 €/MWh for the NGCC.

- CO_2 storage onshore without water extraction is the cheapest storage option for both the USCPC (4 Mt/y) and the NGCC (2 Mt/y) at 3.31 €/t and 4.50 €/t of CO_2 stored, respectively.
- Offshore storage is significantly more expensive than storage onshore at 9.60 €/t for the USCPC (4 Mt/y) and 16.51 €/t for the NGCC (2 Mt/y).
- CCS from the NGCC power plant in an open reservoir (i.e. no water extraction) increases the LCOE of the NGCC by a minimum of approximately 20 €/MWh for onshore storage (to 75 €/MWh) and a minimum of about 25 €/MWh (to 80 €/MWh) for offshore storage. For CCS from the USCPC a minimum increase in LCOE of 25 €/MWh is expected for onshore storage, while for offshore storage the LCOE are estimated to increase by a minimum of 30 €/MWh. This is for power plants using evaporative and once-through cooling - the increase in LCOE is higher when CCS is added to air-cooled power plants.
- The minimum cost of water extraction and management onshore is 7.29 €/t of CO_2 stored. Offshore, where ocean disposal is assumed to not incur any costs due to offsets from harvesting geothermal energy, water extraction and management may only add a small penalty: 1.50 €/t. More generally, offshore, water extraction and management can add up to 2 €/MWh (~2%) to the LCOE of a CCS project, while onshore the LCOE increase by up to 7 €/MWh (~8%). This indicates that the economics of water extraction and management are affected by the water management strategies available onshore and offshore.
- The LCOE of CCS with offshore storage of CO_2 in the Netherlands is about 5 €/MWh higher than for onshore storage when no water extraction is carried out (open reservoirs). When water extraction with subsequent disposal is performed (closed reservoir), the difference between offshore and onshore storage decreases to 0 - 1 €/MWh due to low estimated brine disposal costs offshore. The lower cost of CO_2 transport and storage onshore offset the higher onshore water management costs.
- By integrating storage-extracted water reuse in the CCS chain, water extraction, treatment, transport and disposal add between 3 - 5 €/MWh to the LCOE in the offshore storage scenario and between 3 - 6 €/MWh in the onshore scenario. If more brine than needed for safe CO_2 storage is extracted to meet the freshwater demand of the power station with capture, this can add up to 7 €/MWh (~8%) to the LCOE for the offshore storage scenario, and 15 €/MWh (~17%) to the onshore scenario. This is in comparison to the no water extraction scenario (storage in an open reservoir).
- In the onshore storage scenario, treatment of the extracted formation water and its subsequent reuse in the NGCC or USCPC power plants is more cost-effective than the direct disposal of produced water due to long pipeline transport and a significant number of disposal wells being required. Reducing the brine volume for disposal by 25% is sufficient to justify the cost associated with brine treatment and reuse. For less saline brines (onshore brine: 150,000 mg/L) the economic benefits would improve further as product recovery would increase and/or cheaper treatment technologies may be applied. Therefore, where water extraction is necessary for storage purposes, its treatment and beneficial reuse may present the most economic option.

- The economic analysis suggests that if stringent water regulations become imposed on power plants that currently use evaporative freshwater cooling or plants operating in water-stressed regions, using extracted and treated formation water in an integrated CCS-water loop may be cost competitive compared to retrofitting the power plant to use air cooling.
- Where the use of seawater is not limited by either physical availability or regulations, once-through seawater cooling presents a low freshwater consuming alternative to evaporative cooling at a comparable cost.
- No carbon tax has been included in this analysis. The inclusion of a carbon tax may change the results and conclusion of this study. Furthermore, no potential revenue streams from CO_2 utilisation have been considered considered, which may affect the results of the analyses presented.

7.2 Recommendations for cost reductions of water recovery from the CCS chain

This study of the cost of the potential reuse of storage-extracted water in Dutch power stations found that, overall, the most cost-effective CCS scenario with water extraction is the NGCC that uses evaporative cooling with the CO_2 being stored onshore. This scenario has a LCOE of 79 €/MWh. In the onshore storage scenario, the costs for treating the storage-extracted highly saline brine (150,000 mg/l) via MVC at a recovery rate of 25% with subsequent disposal of the reject stream are comparable to the costs of disposing all the extracted brine onshore via reinjection (8.71 €/t vs 9.23 €/t of CO_2 stored). Thus, in terms of the LCOE, out of the scenarios investigated, this is the most favourable scenario overall to establish a CCS-Water-Nexus. This is especially noteworthy as current Dutch regulations do not explicitly require the treatment and recycling of highly saline brines. Thus, in spite of current regulations and the very high salinity, in the onshore scenario treatment of the extracted brine is beneficial over direct disposal.

With regards to the CO_2 avoided, the lowest avoidance cost in a water extraction scenario at 47 €/t are achieved by the USCPC with evaporative cooling and onshore CO_2 storage and brine extraction. As above, due to the costs for MVC water treatment with subsequent reject disposal and direct disposal of the extracted brine via reinjection being comparable, the avoidance costs are the same for both cases. The avoidance cost for the USCPC are lower than for the NGCC owing to its significantly higher initial CO_2 emissions (approximately twice those of the NGCC).

To improve the technical and economic viability of water recovery for integrated power plants with water reuse, the following recommendations apply.

With regards to the capture process, integrated and novel operation of capture processes may be used that reduces or even produces water for consumption. Feron et al. (2017) proposed a novel integrated liquid absorbent-based CO_2 capture and desalination process with 0.4–0.6 m^3/MWh_e of water being produced while having negligible additional energy use. The produced water can be used as make-up for flue gas desulphurization and/or cooling tower makeup. Another method of water recovery from the capture plant has been proposed by Tu et al. (2019). In this configuration, water recovery is improved using a N_2-cooling ceramic membrane which replaces a traditional condenser after desorption of CO_2 in an absorption process.

As a strategy to reduce the cost associated with water treatment, suitable geological formations with low salinity brines may be targeted first (Kaplan et al., 2017). Such brines may be treated cost-effectively using conventional methods, such as reverse osmosis (RO).

However, as extracted brines often exhibit high TDS, to treat these brines cost-effectively further technology development is required. Emerging technologies for treating highly saline brines that may prove viable in the future but require further research and development are forward osmosis (FO), membrane distillation (MD), electrodyalysis (ED) and electrodyalysis reversal (EDR), multi-effect distillation (MED) and multi-stage flash distillation (MSF), and humidifcation compression, as well as combinations of ED and RO (Kaplan et al., 2017). Other technologies include fractional freeze crystallisation of ice, supercritical desalination processes, and antisolvent addition (Kaplan et al., 2017). Researchers have also suggested that into the future RO of brine with salinities up to 90,000 mg/L will be feasible at low recovery rates (Aines et al., 2011; Breunig et al., 2013).

Cost reductions may also be obtained through improved integration of brine extraction and reuse. For example, the high pressures at which the extracted brines are produced lower treatment costs for reverse osmosis (Aines et al., 2011). Prior cooling of the brine necessary for this process can occur through harvesting of geothermal energy (Breunig et al., 2013).

Furthermore, the potential for reusing existing oil and gas infrastructure not only for CO_2 storage and transport (as per IEAGHG [2018c]), but also for water extraction and transport may apply in specific cases and could help lower costs of water reuse.

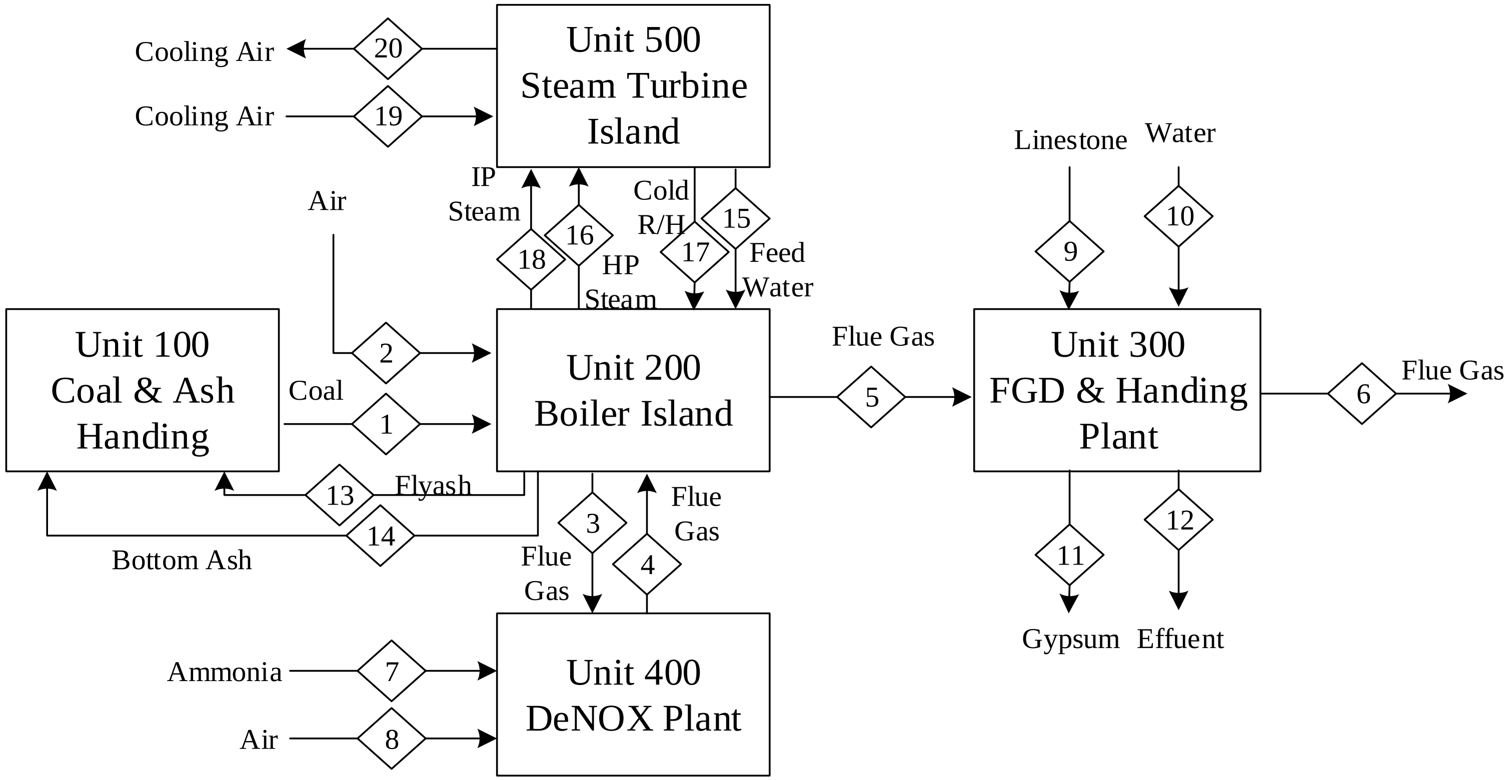
Alternatively, other water recovery strategies could be employed to lower the freshwater consumption of the power stations. These include the addition of ZLD technology to the power station to treat discharged process water and reuse it in the power station, or the reuse of other nearby sources of treated wastewater. For example, these sources could be water extracted as part of coal mining operations or sewage treatment plants. However, these strategies are typically only practiced where regulations require it, or incentives are in place to encourage their uptake.

Another consideration may be to reuse the storage-extracted and treated brine to enable the use of a more efficient cooling technology for the power station with capture, i.e. evaporative over air cooling. This would increase the efficiency of the power station and lower its LCOE. The benefits of this would have to be evaluated on a case by case basis, considering the extracted brine quality, transport distance to the power station, as well as other potential sources of “unconventional” water nearby. In this study, comparing the LCOE of the integrated CCS-Water-Nexus scenarios (using evaporative cooling) to power plants with CCS where air cooling is used, the LCOE is less for the corresponding CCS-Water-Nexus-Scenario in the offshore storage scenario. This suggests that if stringent water regulations become imposed on power plants that currently use evaporative freshwater cooling, applying water utilisation from produced reservoir water as part of an integrated CCS chain becomes an opportunity and is preferable from an economic point of view over retro-fitting the power station with air cooling.

While formation water extraction and its management constitute an additional cost to a CCS project, if the additional storage capacity generated through the extraction of brines can be effectively utilised, this may present a cost-effective alternative over the characterisation and development of a new storage site. This would require investigation in a separate analysis.

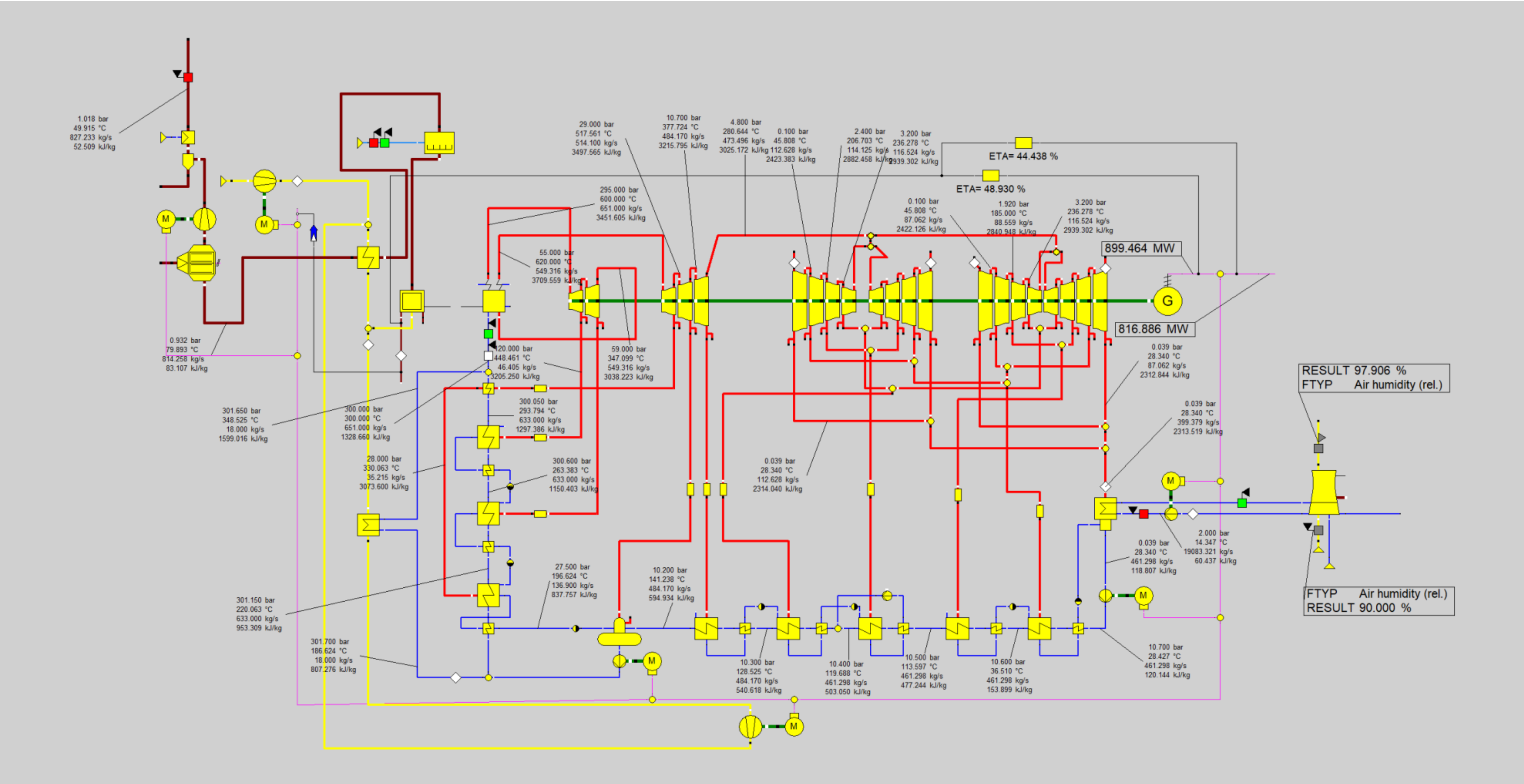
Appendix A - Flow diagrams of the power plants with and without capture using different cooling technologies

A.1 Schematic of the reference USCPC power plant using evaporative (EV) cooling



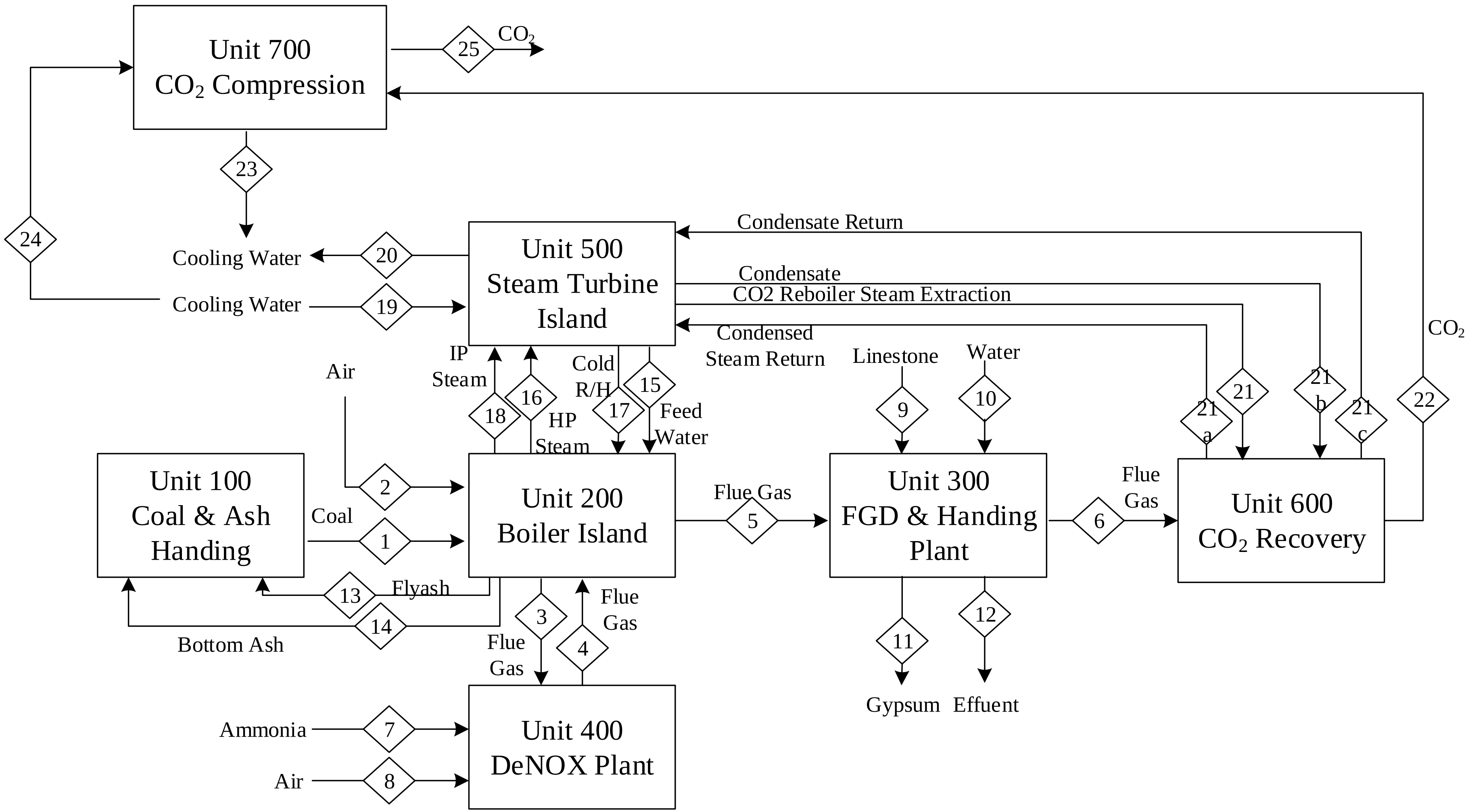
Apx Figure A.1 USCPC power plant with evaporative (EV) cooling (Case 1.1A: USCPC-EV)

A.2 Flow diagram of the USCPC power plant process using evaporative (EV) cooling



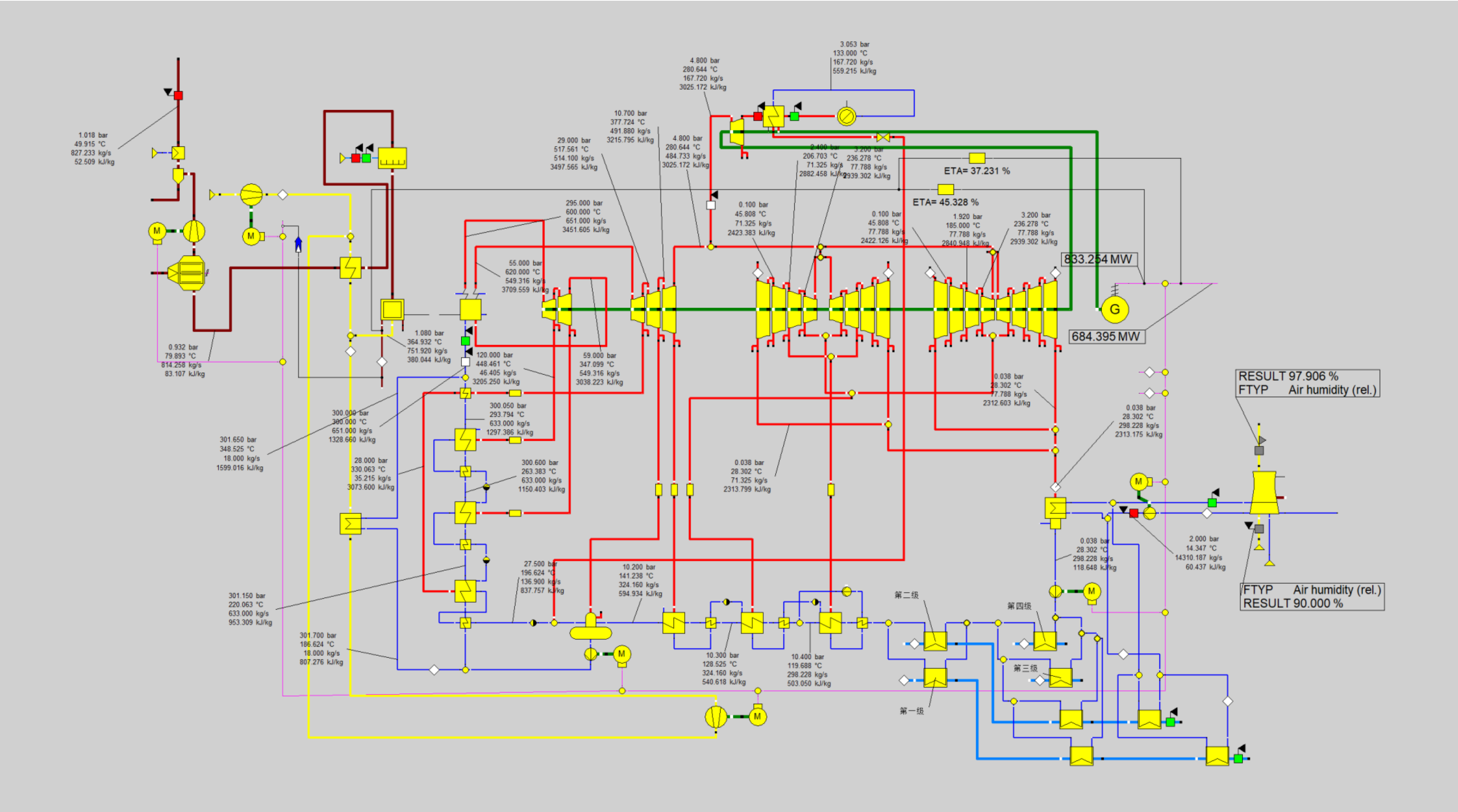
Apx Figure A.2 Flow diagram of the USCPC power plant process using evaporative (EV) cooling

A.3 Schematic of the USCPC power plant with capture using evaporative (EV) cooling



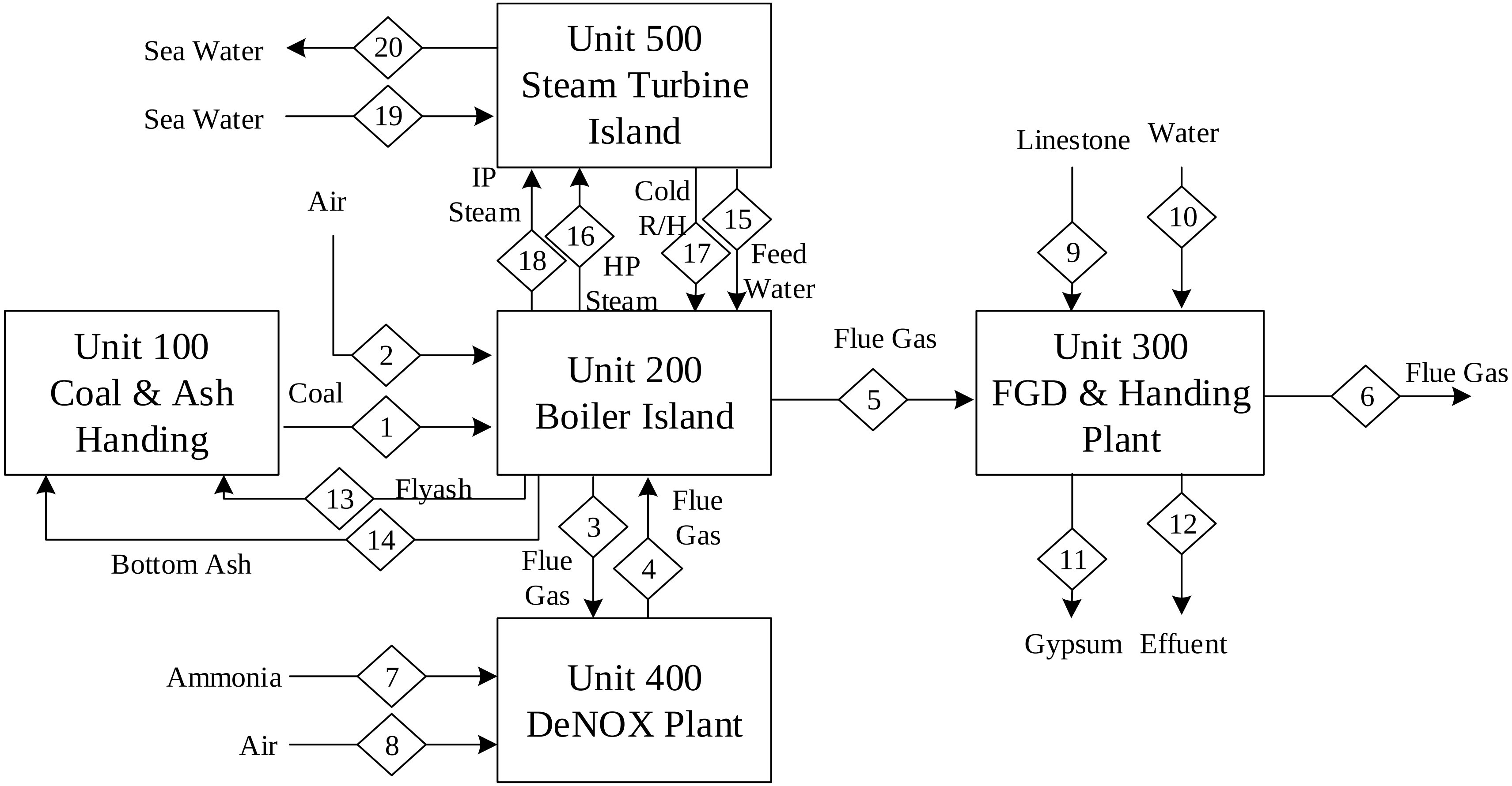
Apx Figure A.3 USCPC power plant with CO_2 capture with evaporative (EV) cooling and same or air-cooled (AC) capture plant (Case 1.1B: USCPC-EV-PCC or Case 1.1C: USCPC-EV-PCC-AC)

A.4 Flow diagram of the USCPC power plant process with capture using evaporative (EV) cooling



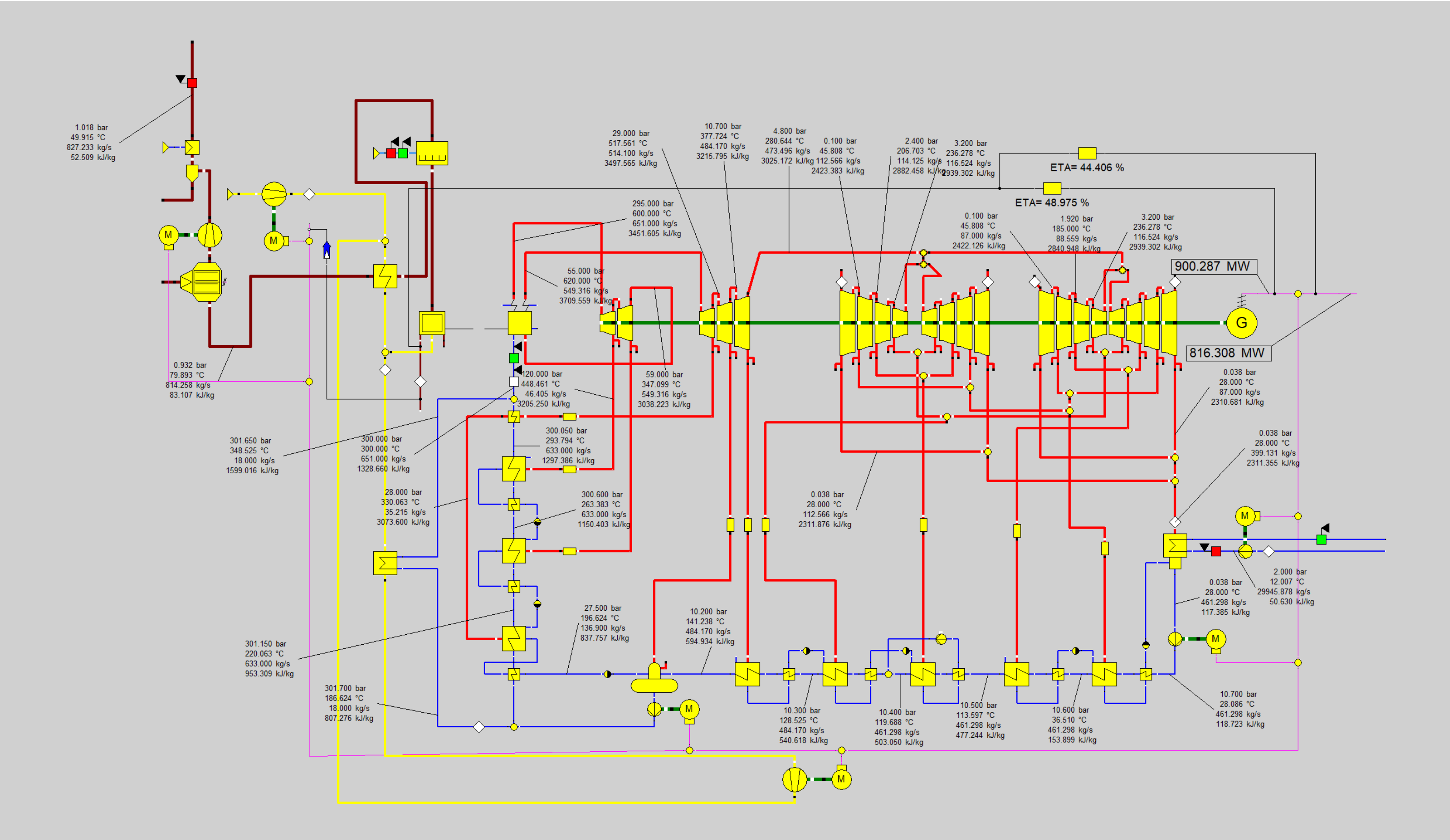
Apx Figure A.4 Flow diagram of the USCPC power plant process with capture using evaporative (EV) cooling

A.5 Schematic of the reference USCPC power plant using once-through (OT) seawater cooling



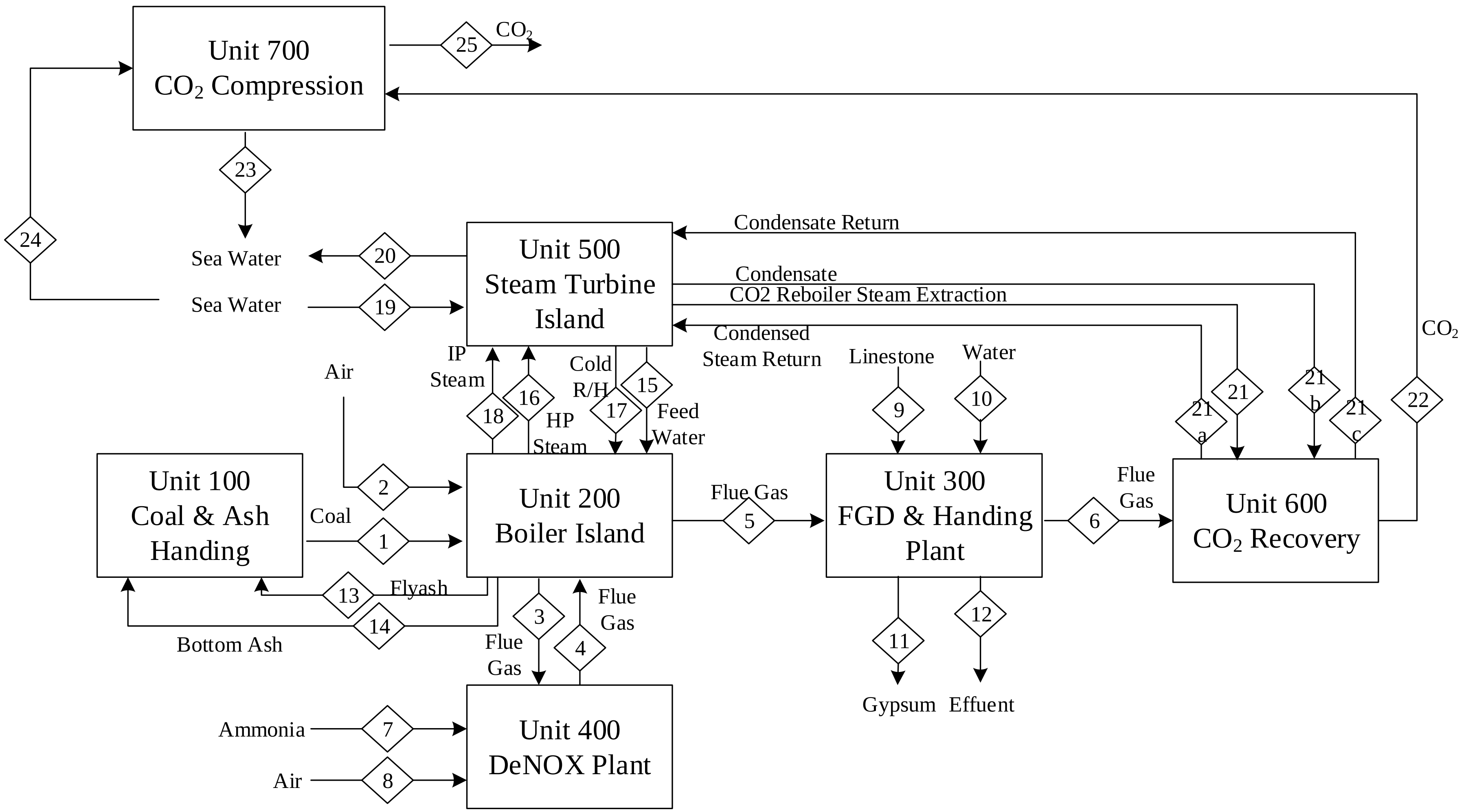
Apx Figure A.5 USCPC power plant with once-through (OT) seawater cooling (Case 1.2A: USCPC-OT)

A.6 Flow diagram of the USCPC power plant process using once-through (OT) cooling



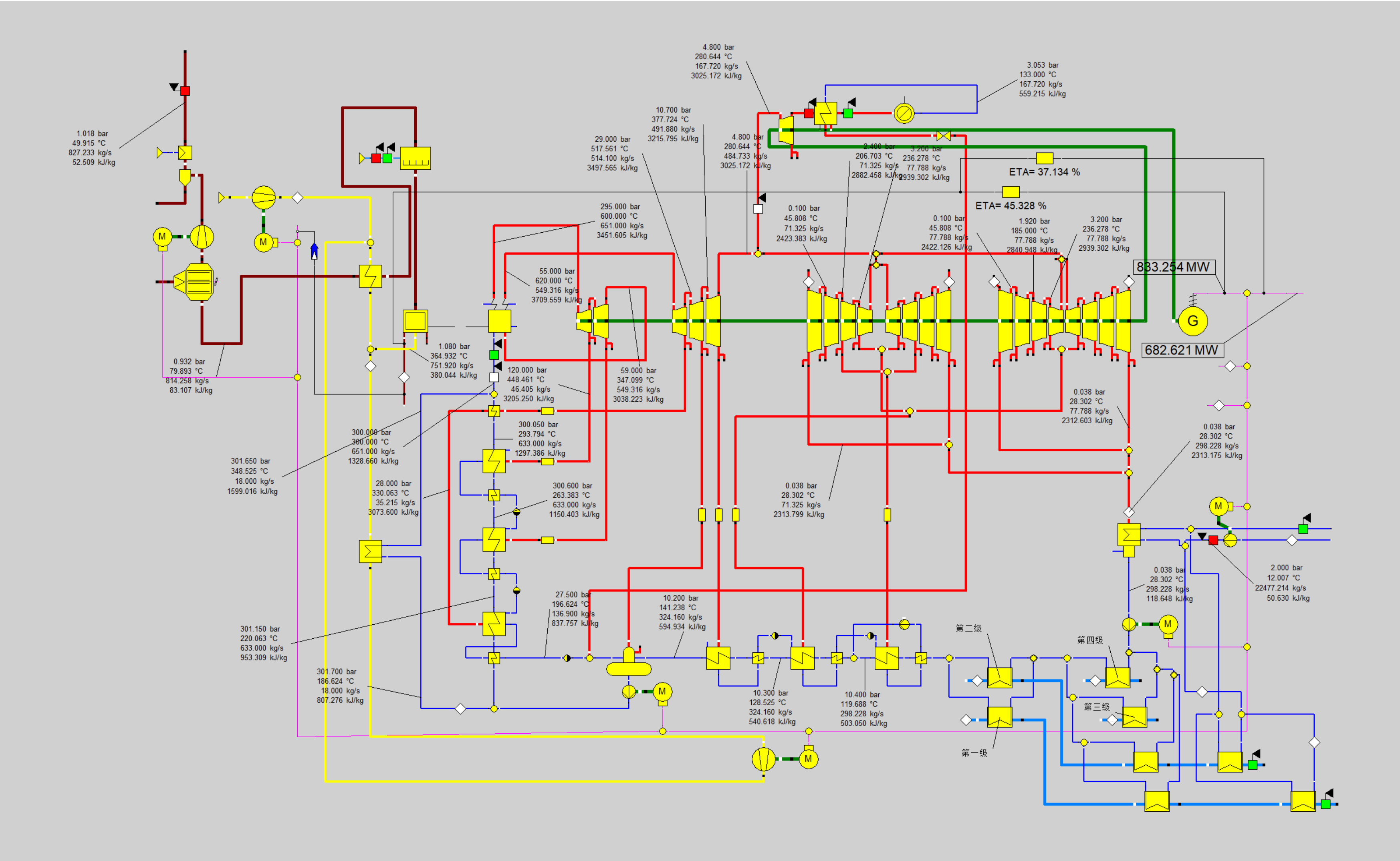
Apx Figure A.6 Flow diagram of the USCPC power plant process using once-through (OT) cooling

A.7 Schematic of the USCPC power plant with CO_2 capture using once-through (OT) seawater cooling



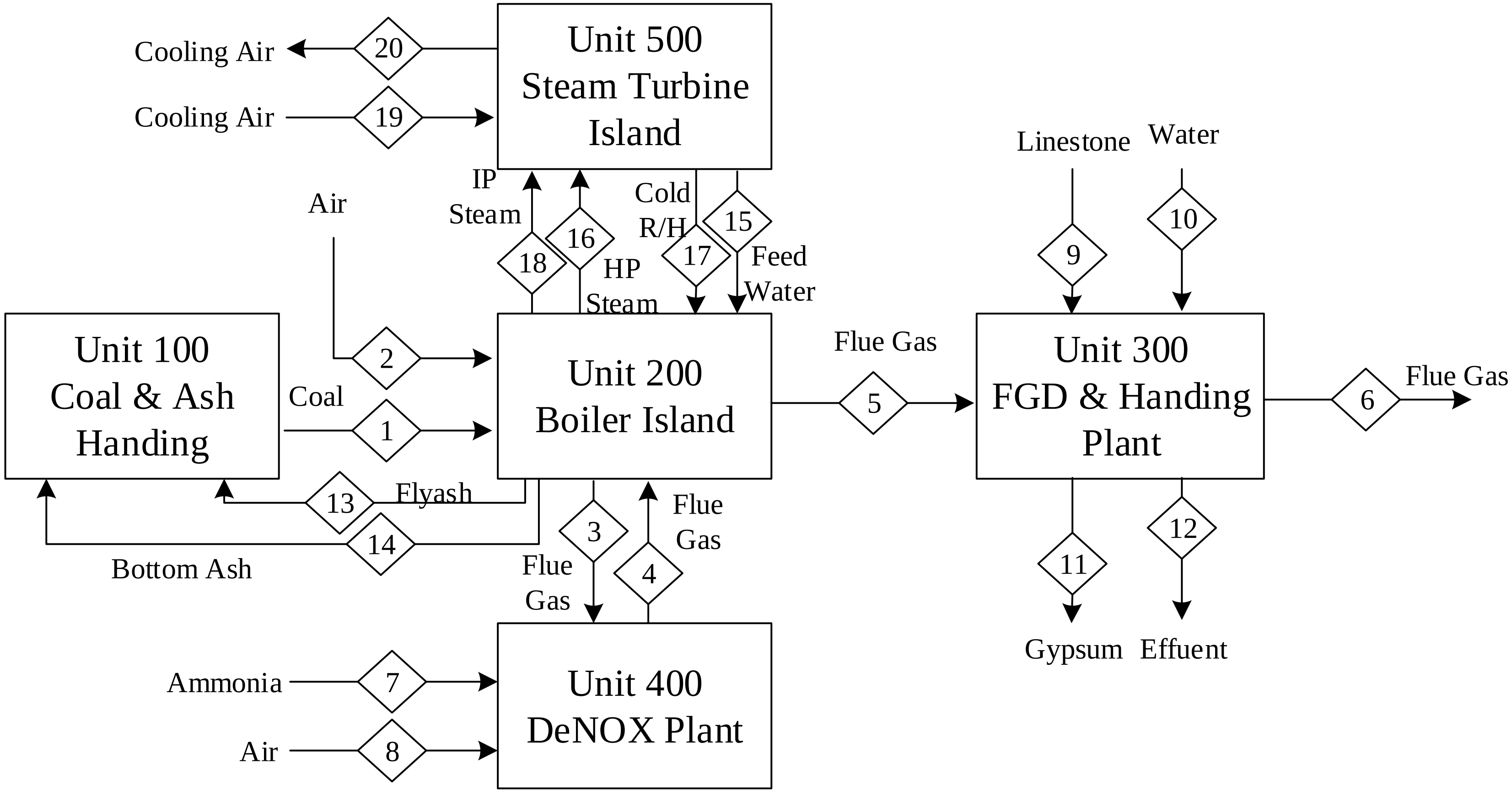
Apx Figure A.7 USCPC power plant with CO_2 capture with once-through (OT) seawater cooling and same or air-cooled (AC) capture plant (Case 1.2B: USCPC-OT-PCC or Case 1.2C: USCPC-OT-PCC-AC)

A.8 Flow diagram of the USCPC power plant process with capture using once-through (OT) cooling



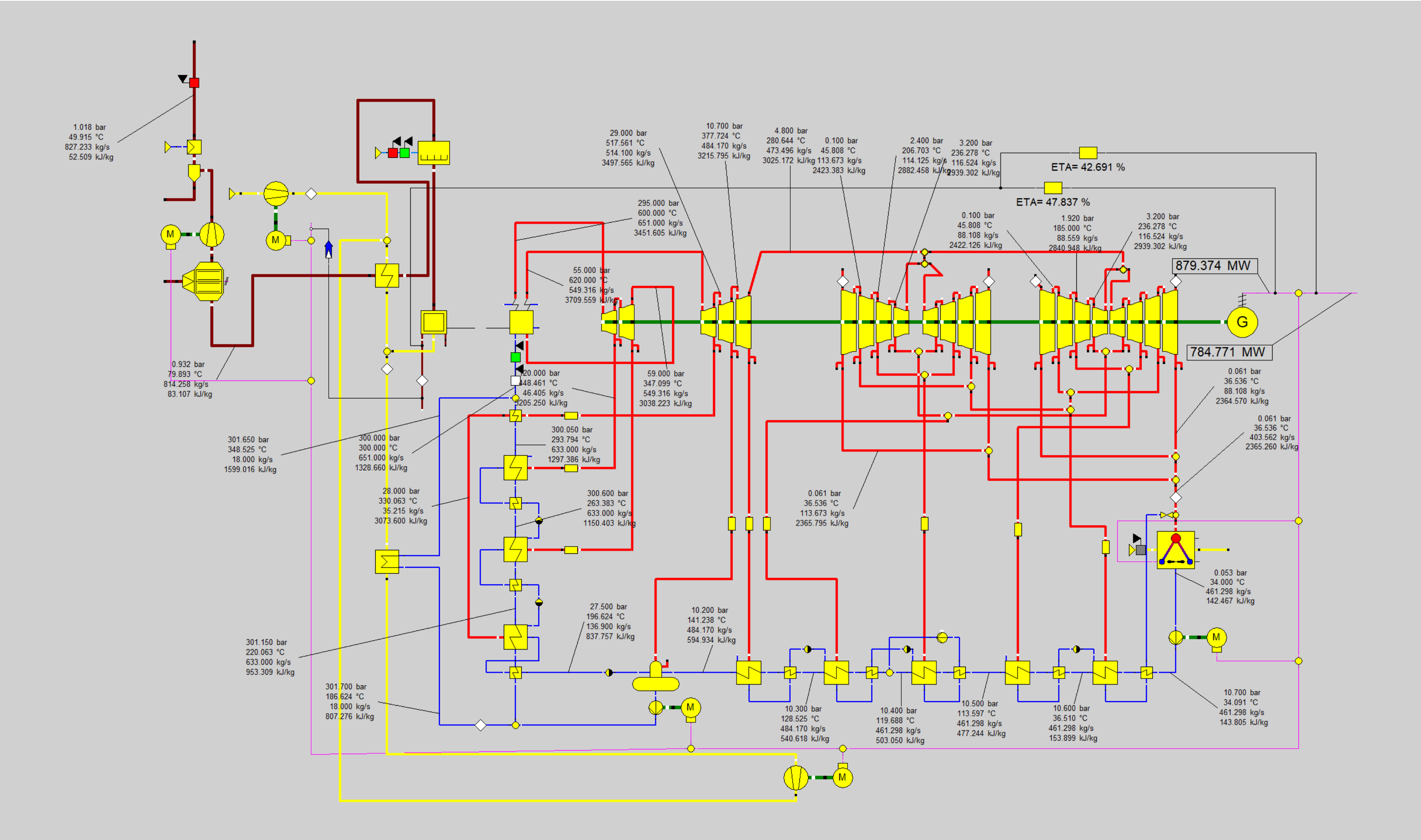
Apx Figure A.8 Flow diagram of the USCPC power plant with capture process using once-through (OT) cooling

A.9 Schematic of the reference USCPC power plant using air cooling (AC)



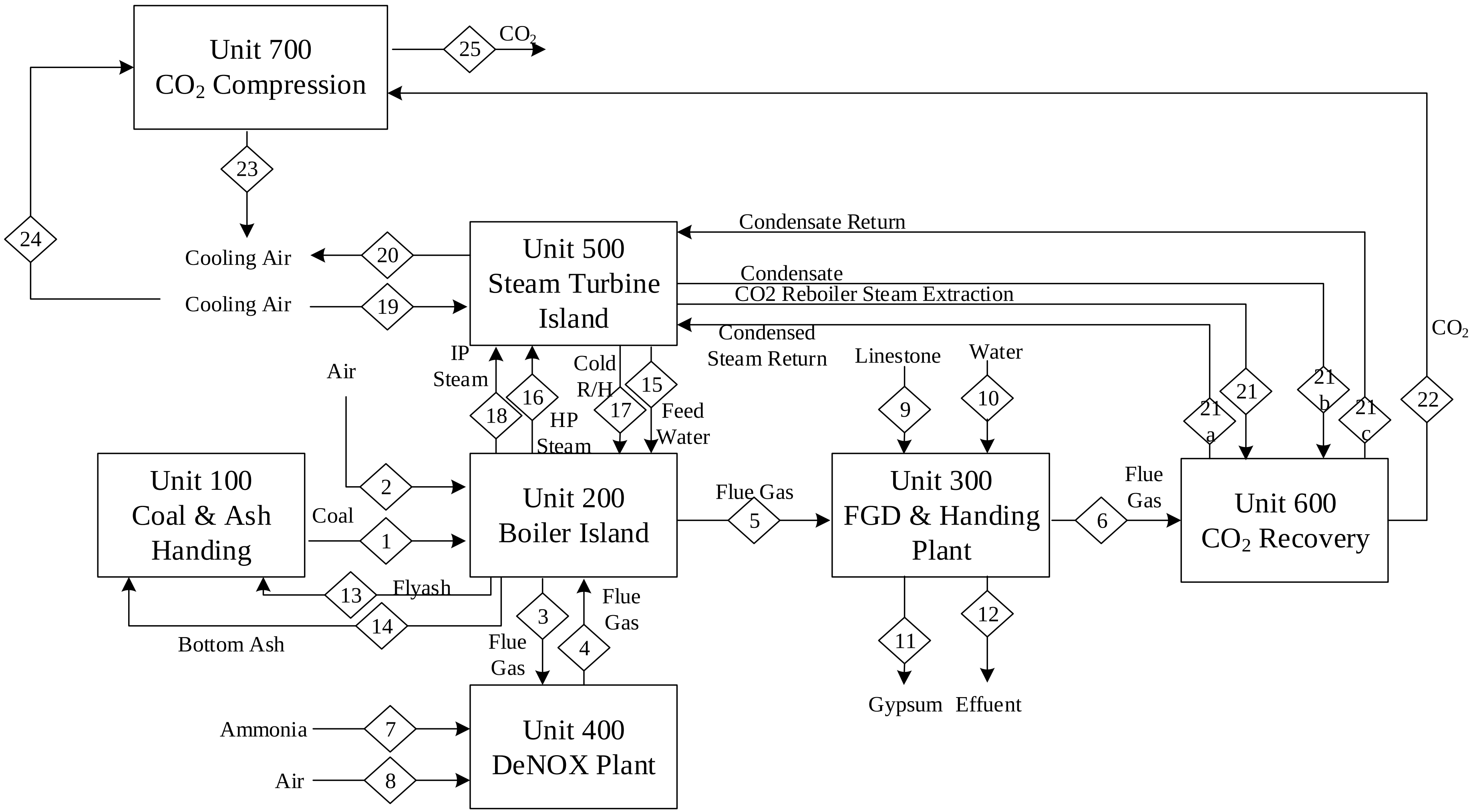
Apx Figure A.9 USCPC power plant with air cooling (AC) (Case 1.3A: USCPC-AC)

A.10 Flow diagram of the USCPC power plant process using air cooling (AC)



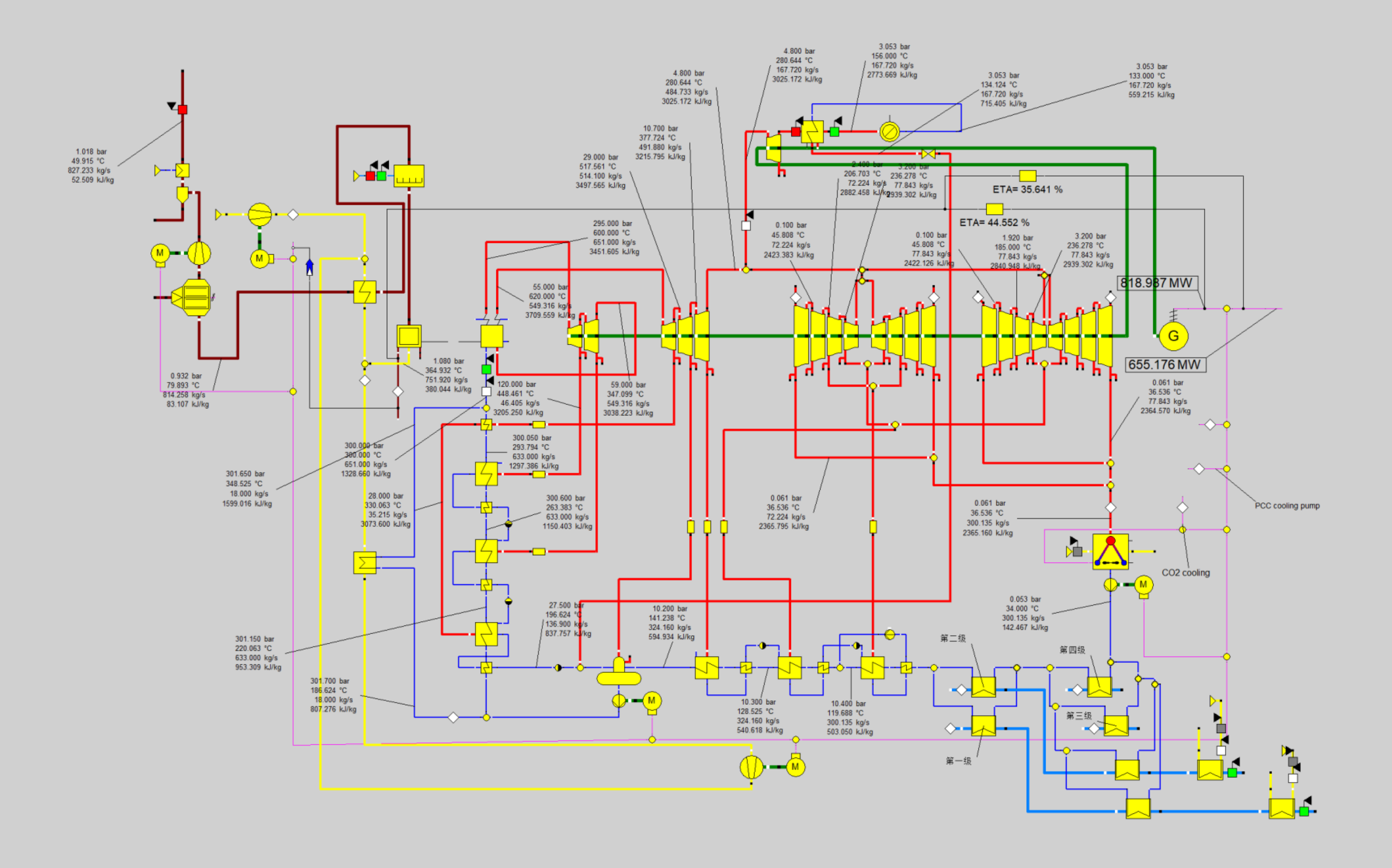
Apx Figure A.10 Flow diagram of the USCPC power plant process using air cooling (AC)

A.11 Schematic of the USCPC power plant with CO_2 capture using air cooling (AC)



Apx Figure A.11 USCPC power plant with CO_2 capture with air cooling (Case 1.3A: USCPC-AC-PCC)

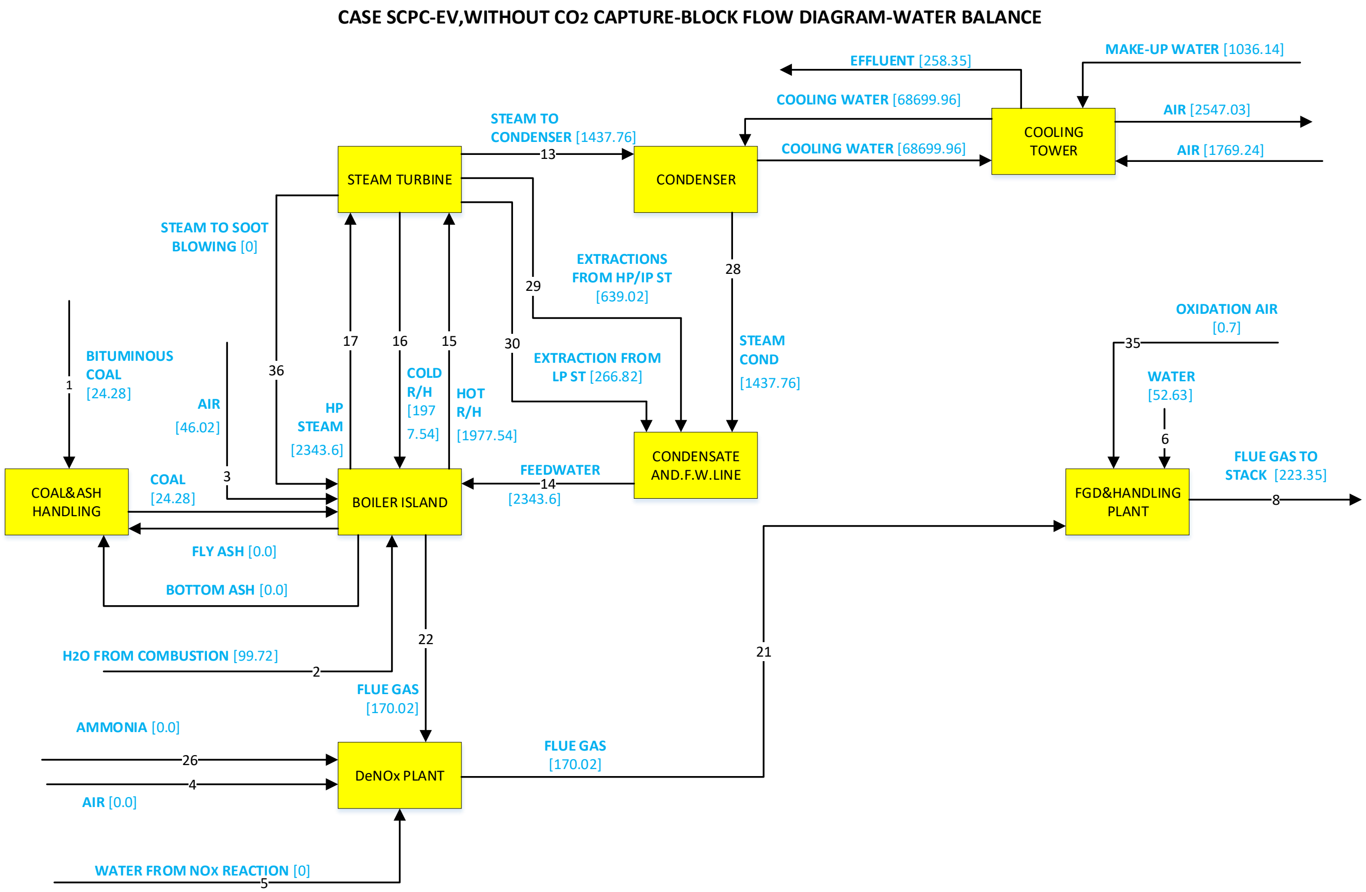
A.12 Flow diagram of the USCPC power plant process with capture using air cooling (AC)



Apx Figure A.12 Flow diagram of the USCPC power plant with capture process using air cooling (AC)

A.13 Detailed water flow diagrams: USCPC

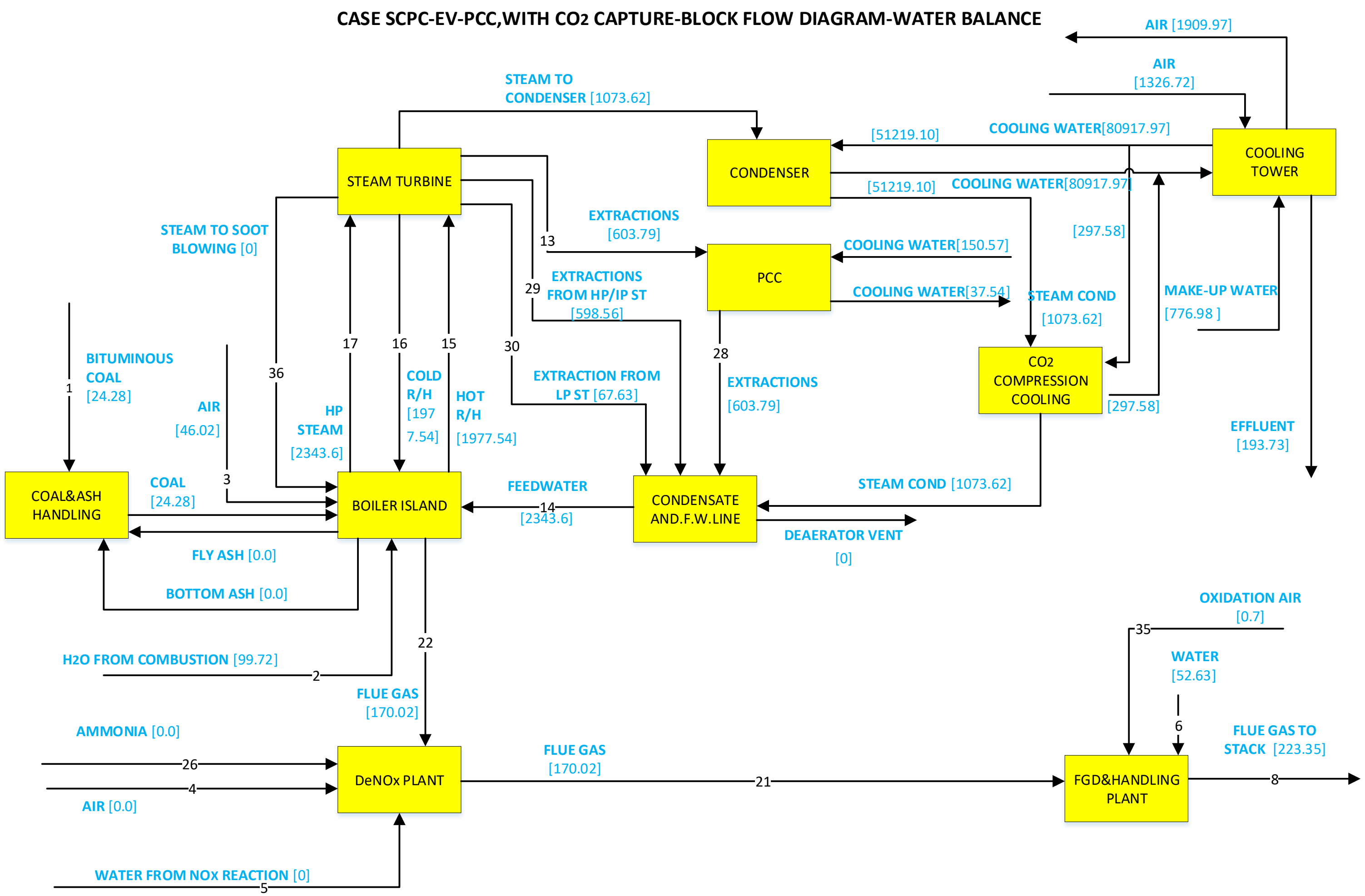
USCPC-EV



[xxx] water flowrates in ton/h

Apx Figure A.13 Water balance in tonnes/hour (t/h) for USCPC power plant without capture using evaporative (EV) cooling (Case 1.1A: USCPC-EV)

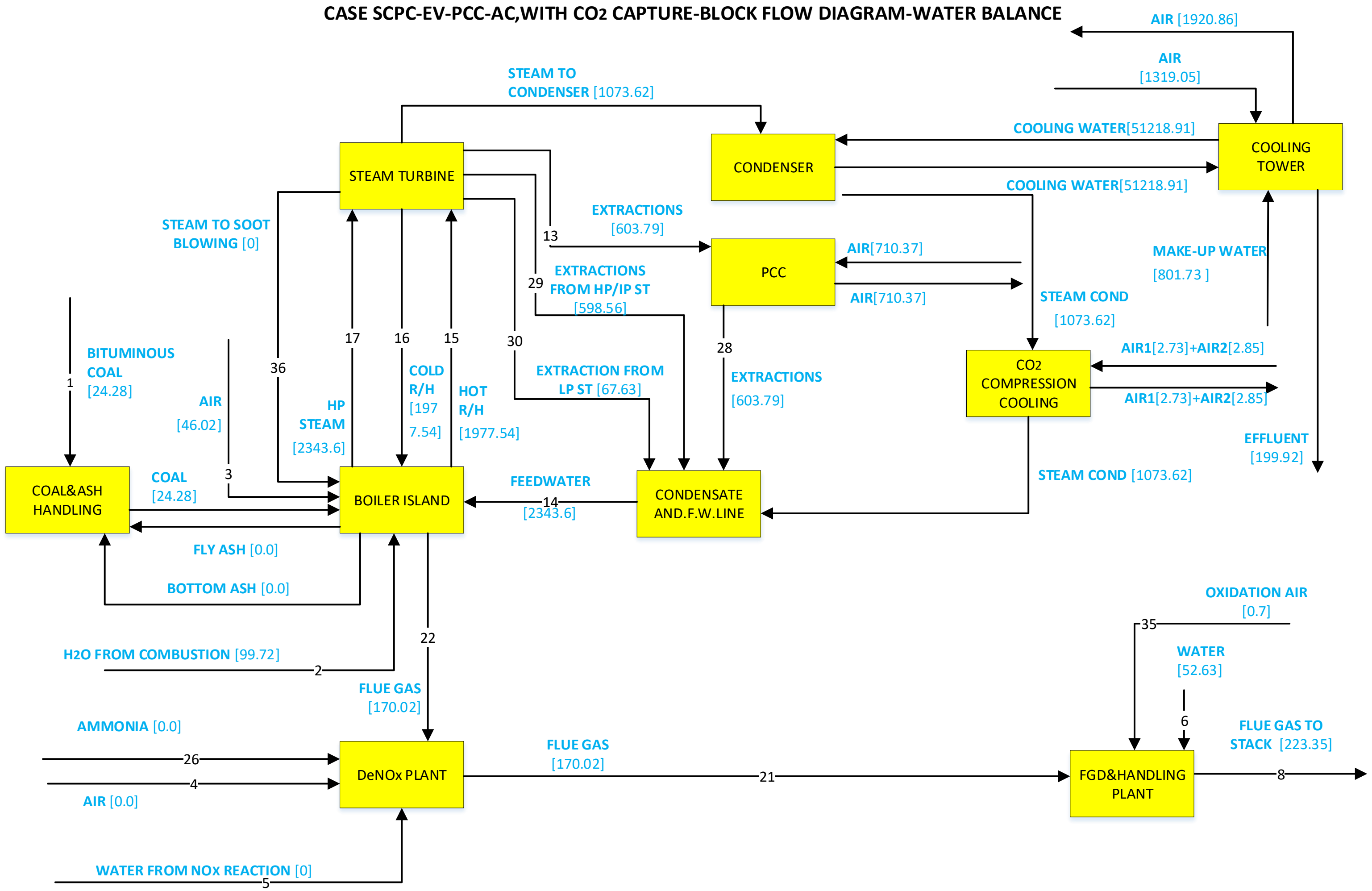
USCPC-EV-PCC



[xxx] water flowrates in ton/h

Apx Figure A.14 Water balance in tonnes/hour (t/h) for USCPC power plant with capture using evaporative (EV) cooling (Case 1.1B: USCPC-EV-PCC)

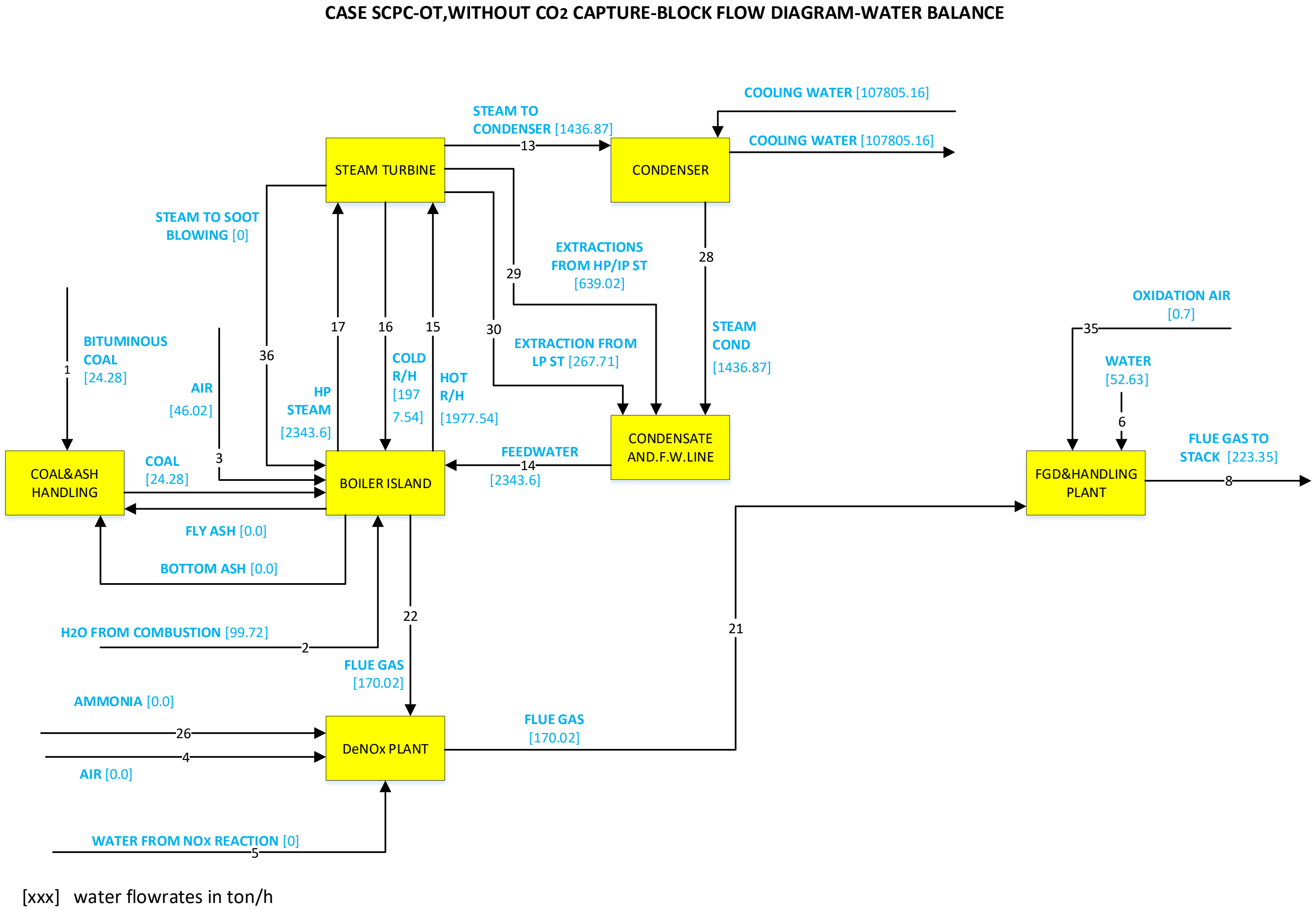
USCPC-EV-PCC-AC



[xxx] water flowrates in ton/h

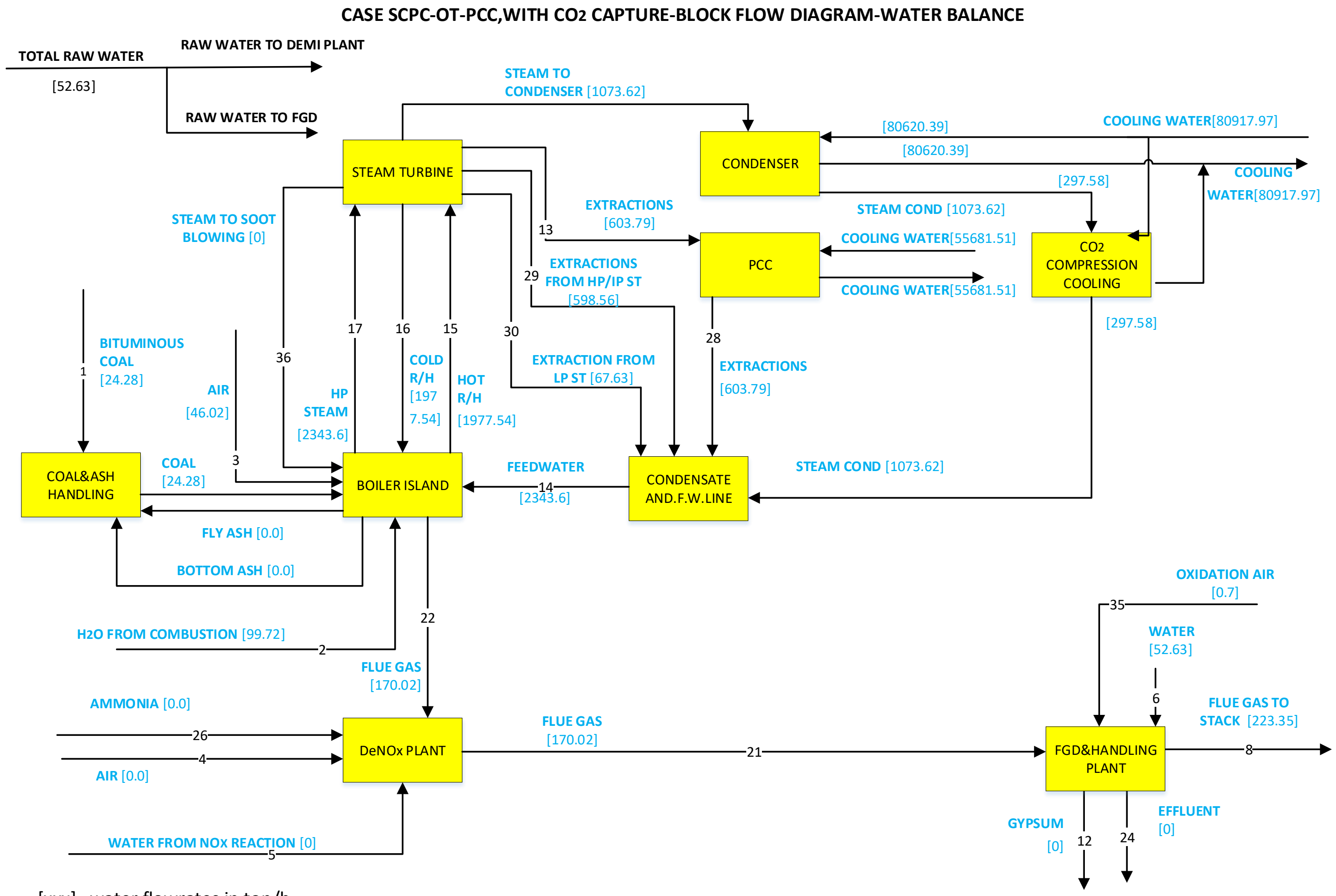
Apx Figure A.15Water balance in tonnes/hour (t/h) for USCPC power plant with capture using evaporative (EV) cooling for the power plant and air cooling (AC) for the capture plant (Case 1.1C: USCPC-EV-PCC-AC)

USCPC-OT



Apx Figure A.16Water balance in tonnes/hour (t/h) for USCPC power plant without capture using once-through (OT) seawater cooling (Case 1.2A: USCPC-OT)

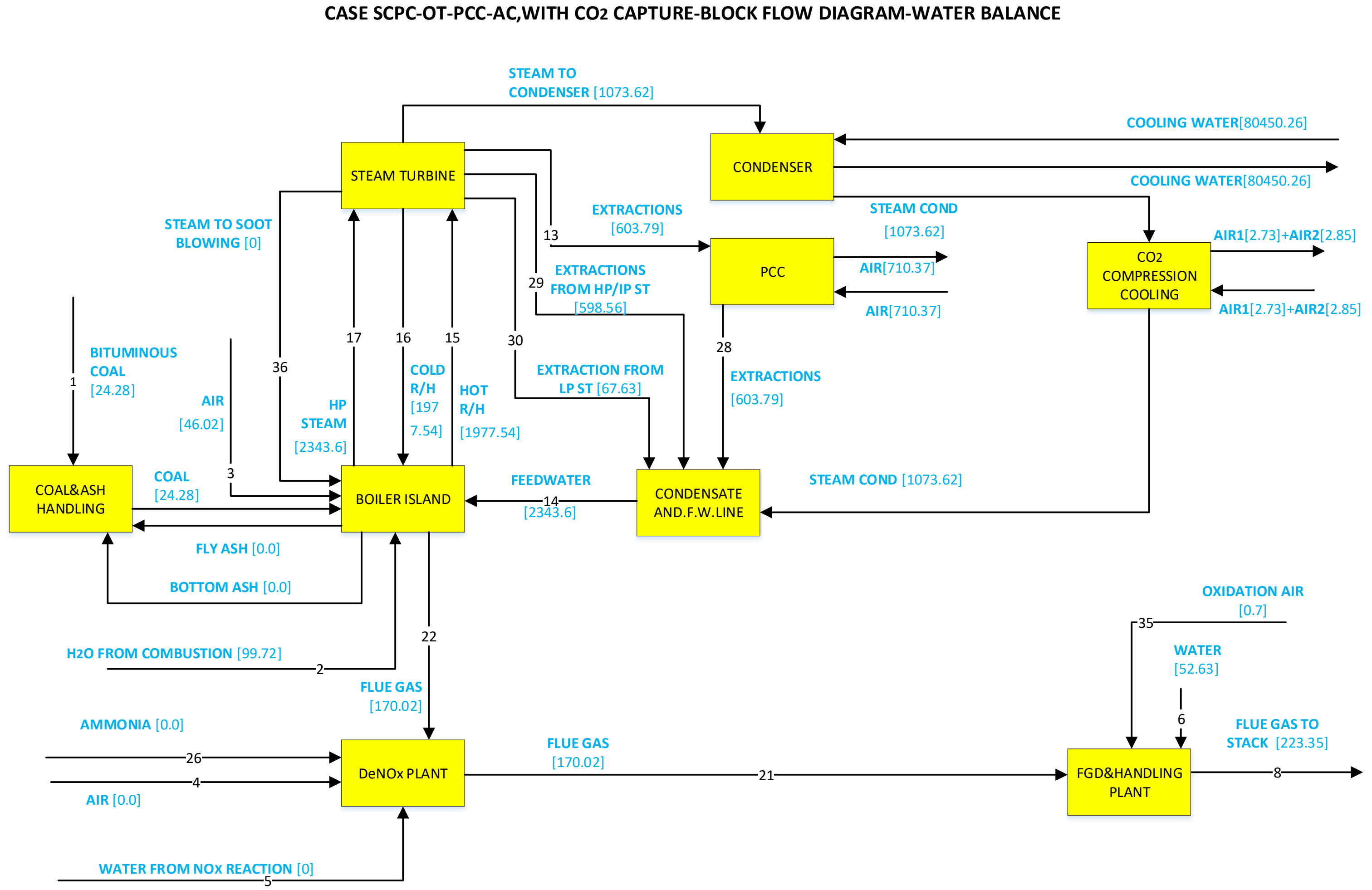
USCPC-OT-PCC



[xxx] water flowrates in ton/h

Apx Figure A.17Water balance in tonnes/hour (t/h) for USCPC power plant with capture using once-through (OT) seawater cooling (Case 1.2B: USCPC-OT-PCC)

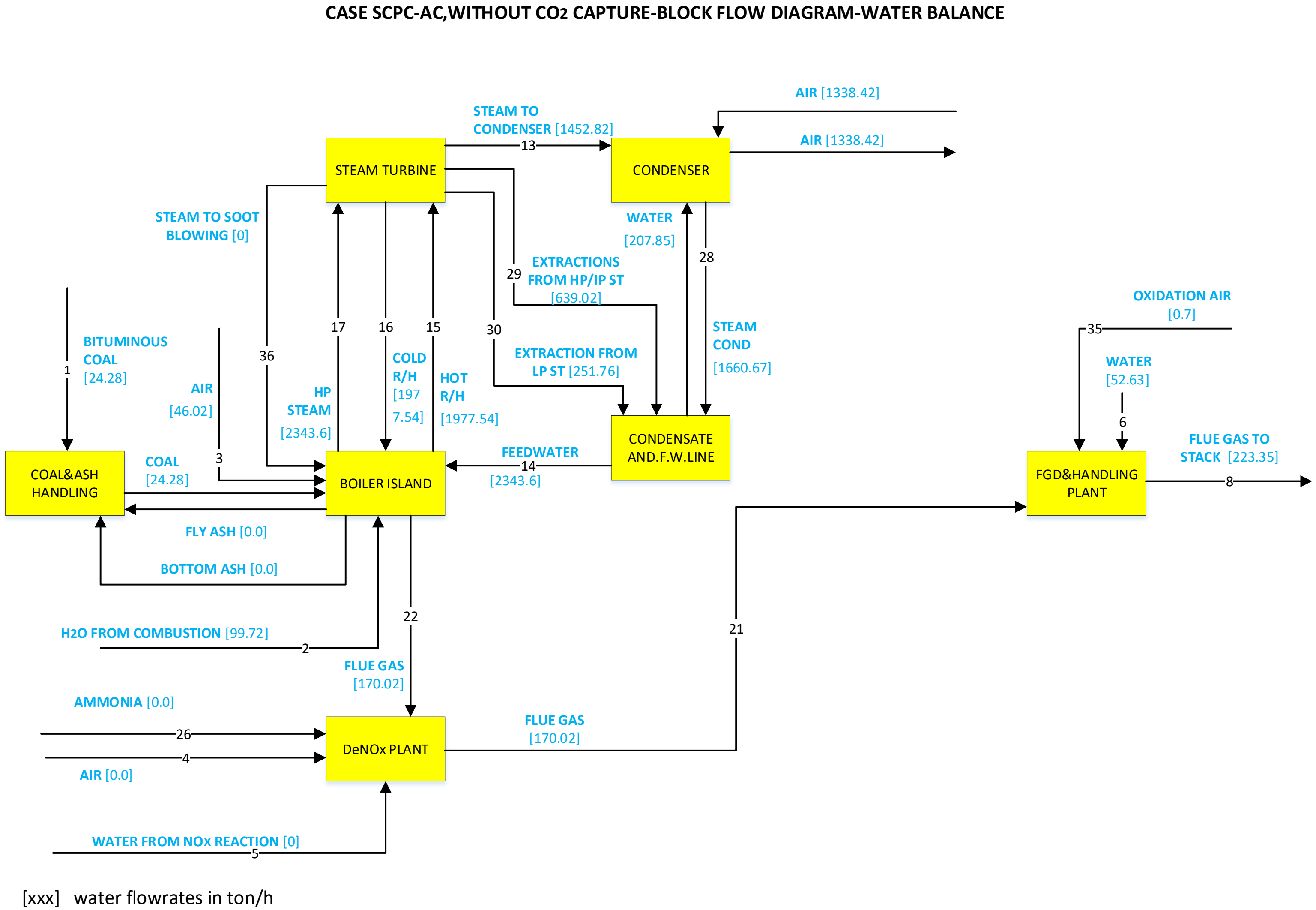
USCPC-OT-PCC-AC



[xxx] water flowrates in ton/h

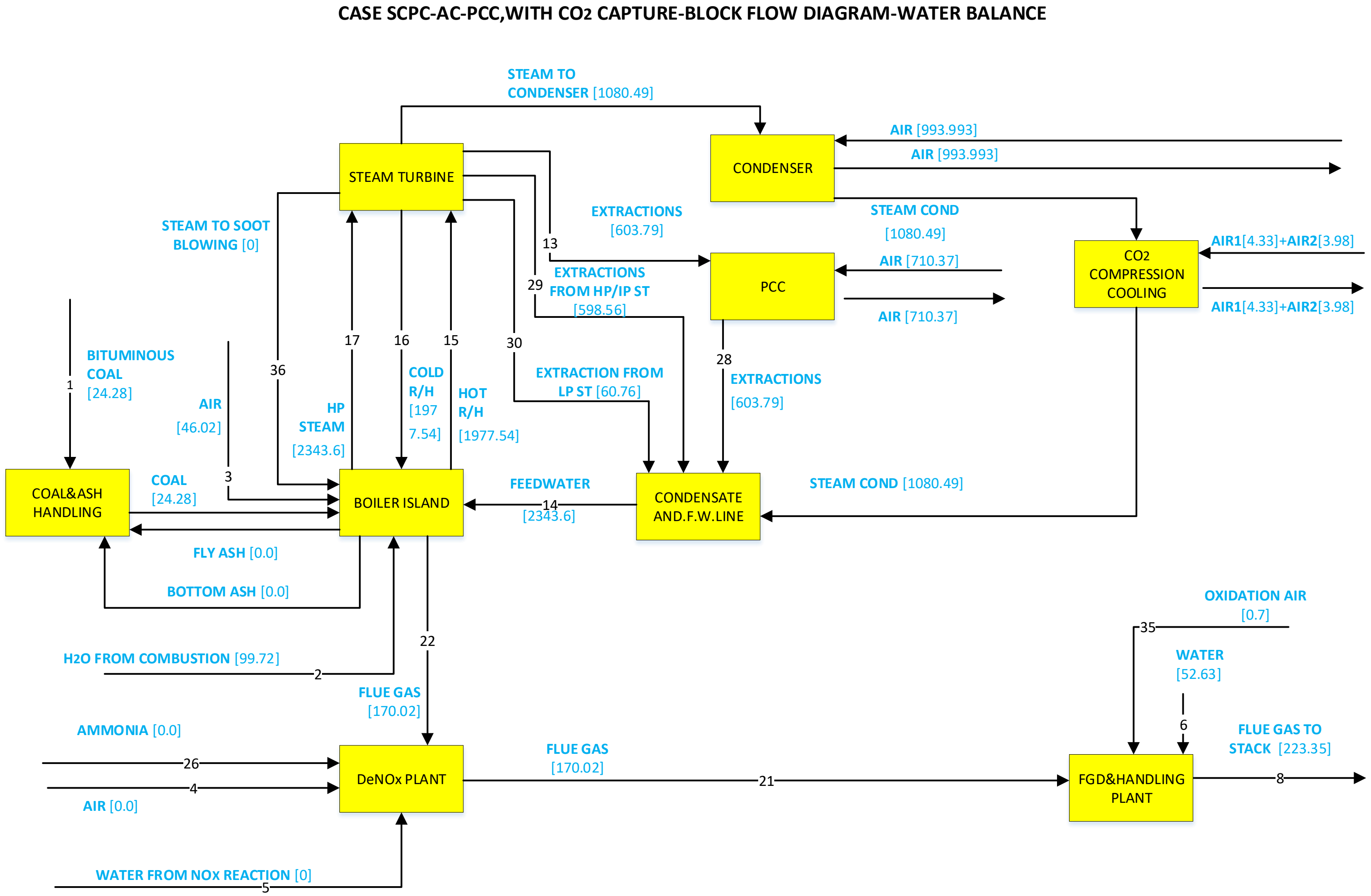
Apx Figure A.18Water balance in tonnes/hour (t/h) for USCPC power plant using once-through (OT) seawater cooling for the power plant and air cooling (AC) for the capture plant (Case 1.1C: USCPC-OT-PCC-AC)

USCPC-AC



Apx Figure A.19Water balance in tonnes/hour (t/h) for USCPC power plant without capture using air cooling (AC) (Case 1.3A: USCPC-AC)

USCPC-AC-PCC

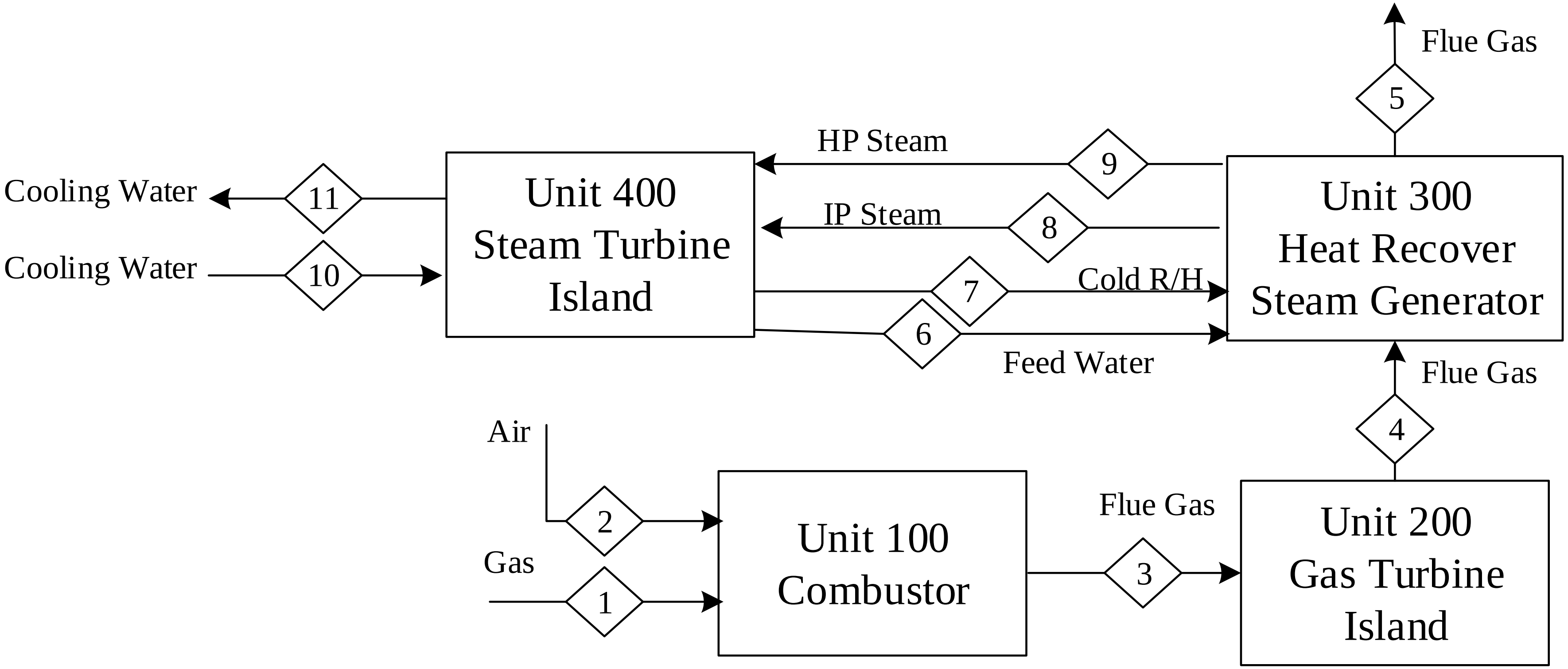


[xxx] water flowrates in ton/h

Apx Figure A.20 Water balance in tonnes/hour (t/h) for USCPC power plant with capture using air cooling (AC) (Case 1.3B: USCPC-AC-PCC)

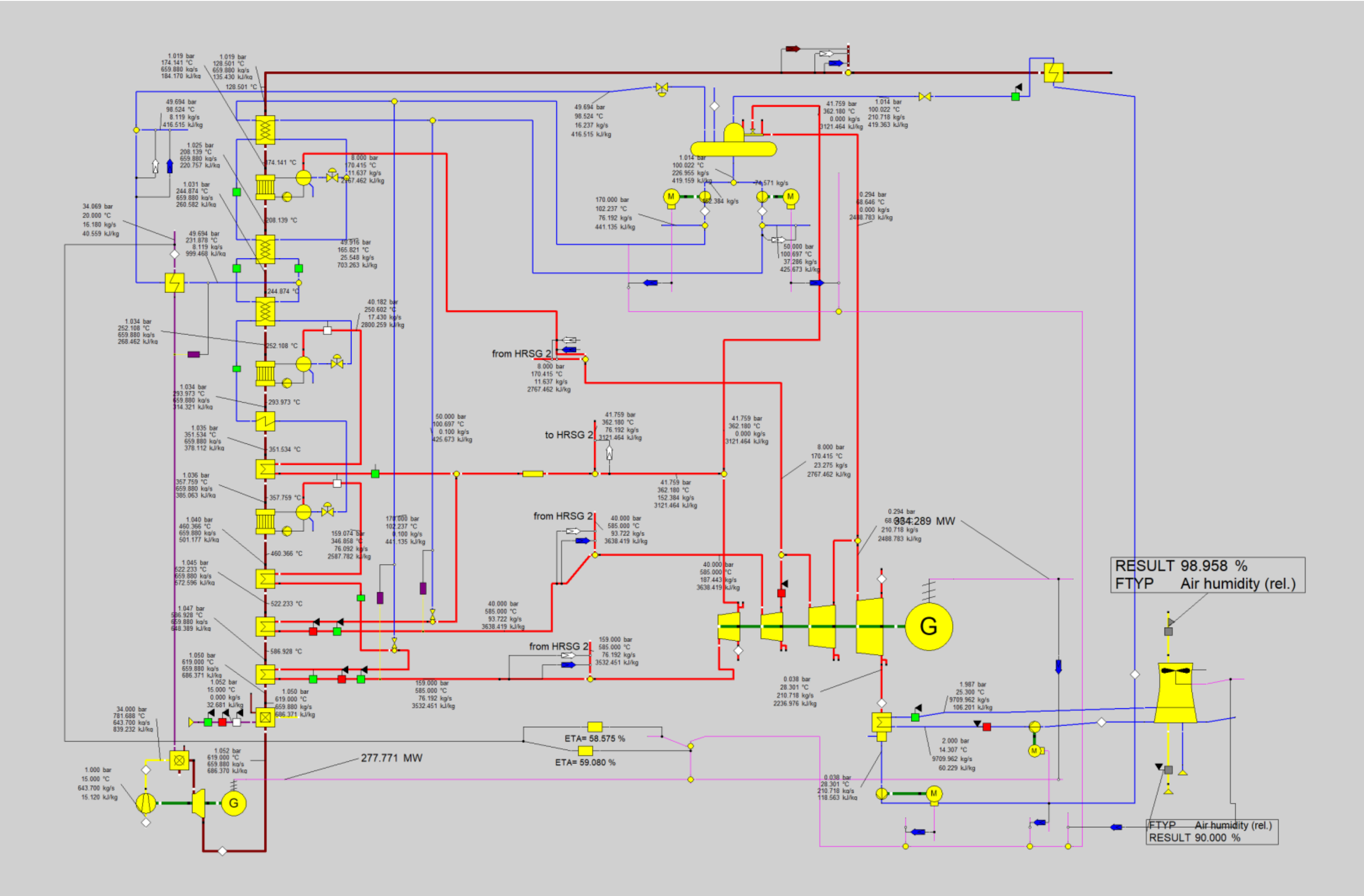
A.14 Schematic of the reference NGCC power plant using evaporative (EV) cooling

NGCC-EV



Apx Figure A.21 NGCC power plant using evaporative (EV) cooling (Case 2.1A: NGCC-EV)

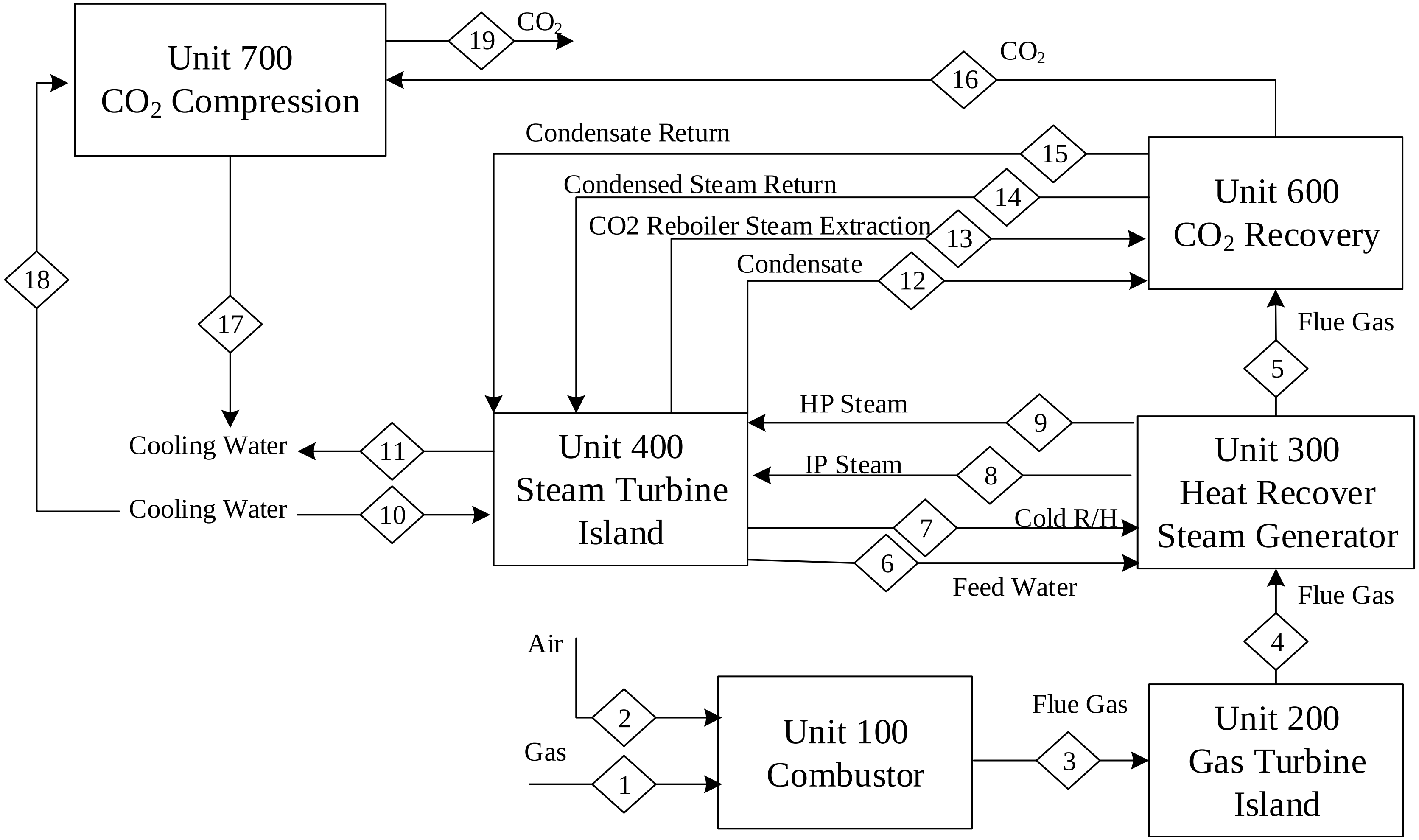
A.15 Flow diagram of the NGCC power plant process using evaporative (EV) cooling



Apx Figure A.22 Flow diagram of the NGCC power plant process using evaporative (EV) cooling

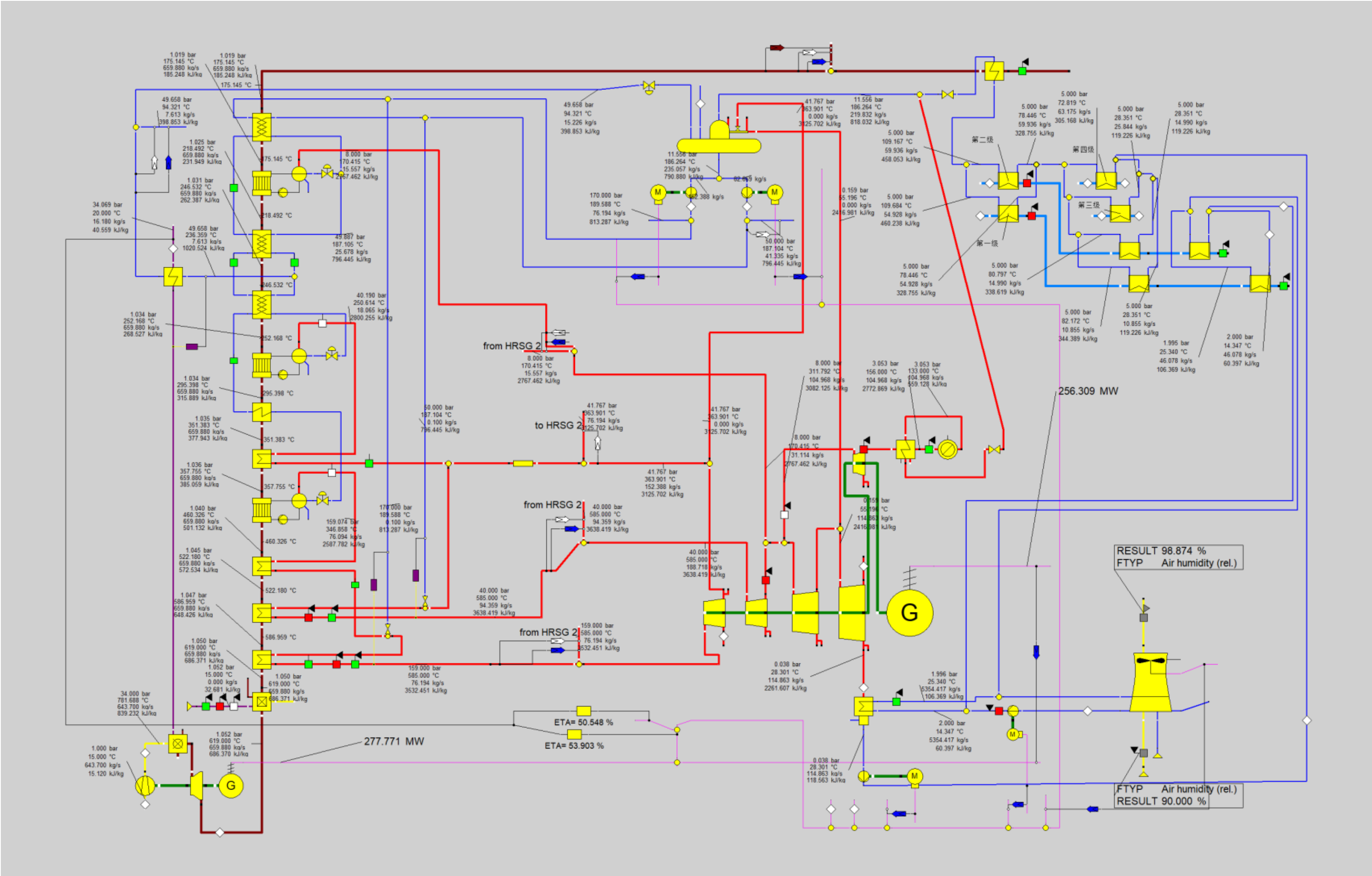
A.16 Schematic of the NGCC power plant with capture using evaporative (EV) cooling

NGCC-EV-PCC



Apx Figure A.23 NGCC power plant with capture using evaporative (EV) cooling and same or air-cooled (AC) capture plan (Case 2.1B: NGCC-EV-PCC or Case 2.1C: NGCC-EV-PCC-AC)

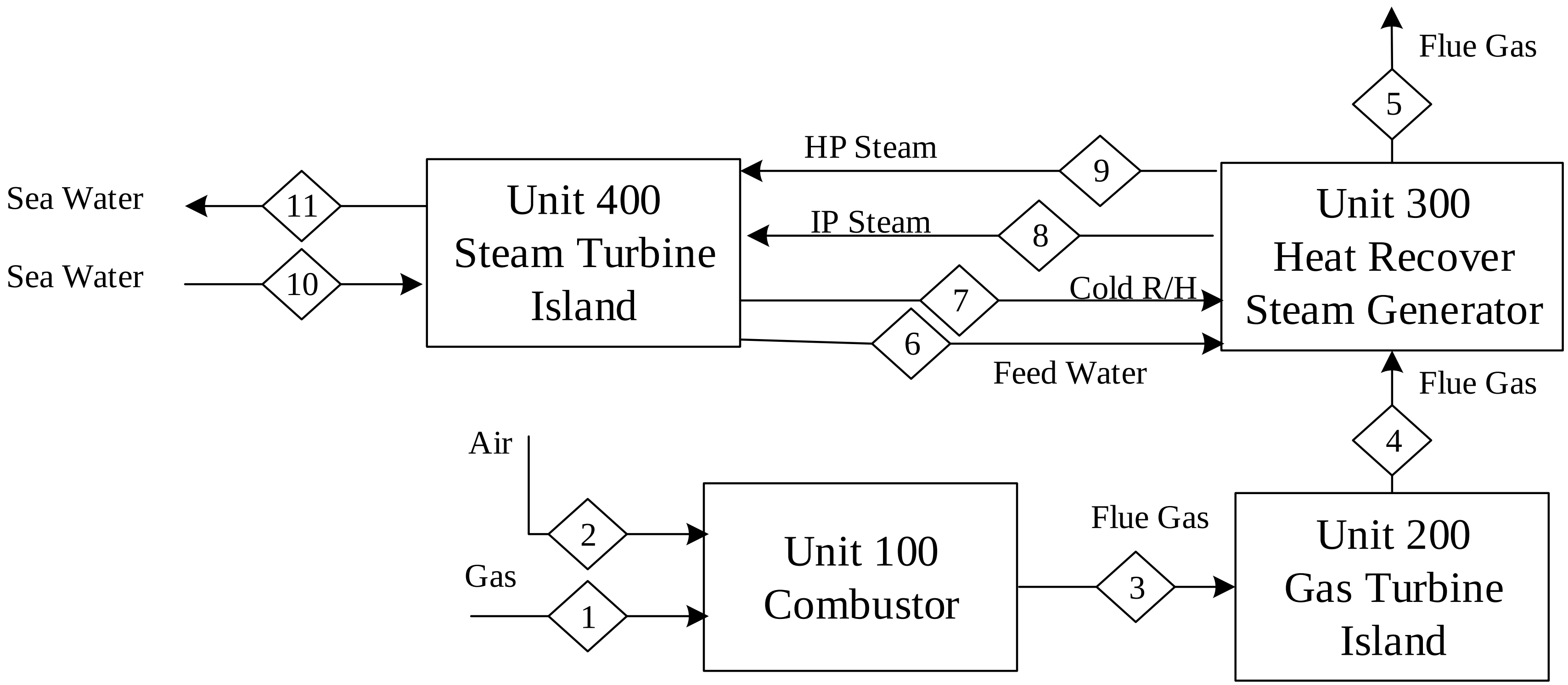
A.17 Flow diagram of the NGCC power plant process with capture using evaporative (EV) cooling



Apx Figure A.24 Flow diagram of the NGCC power plant process with capture using evaporative (EV) cooling

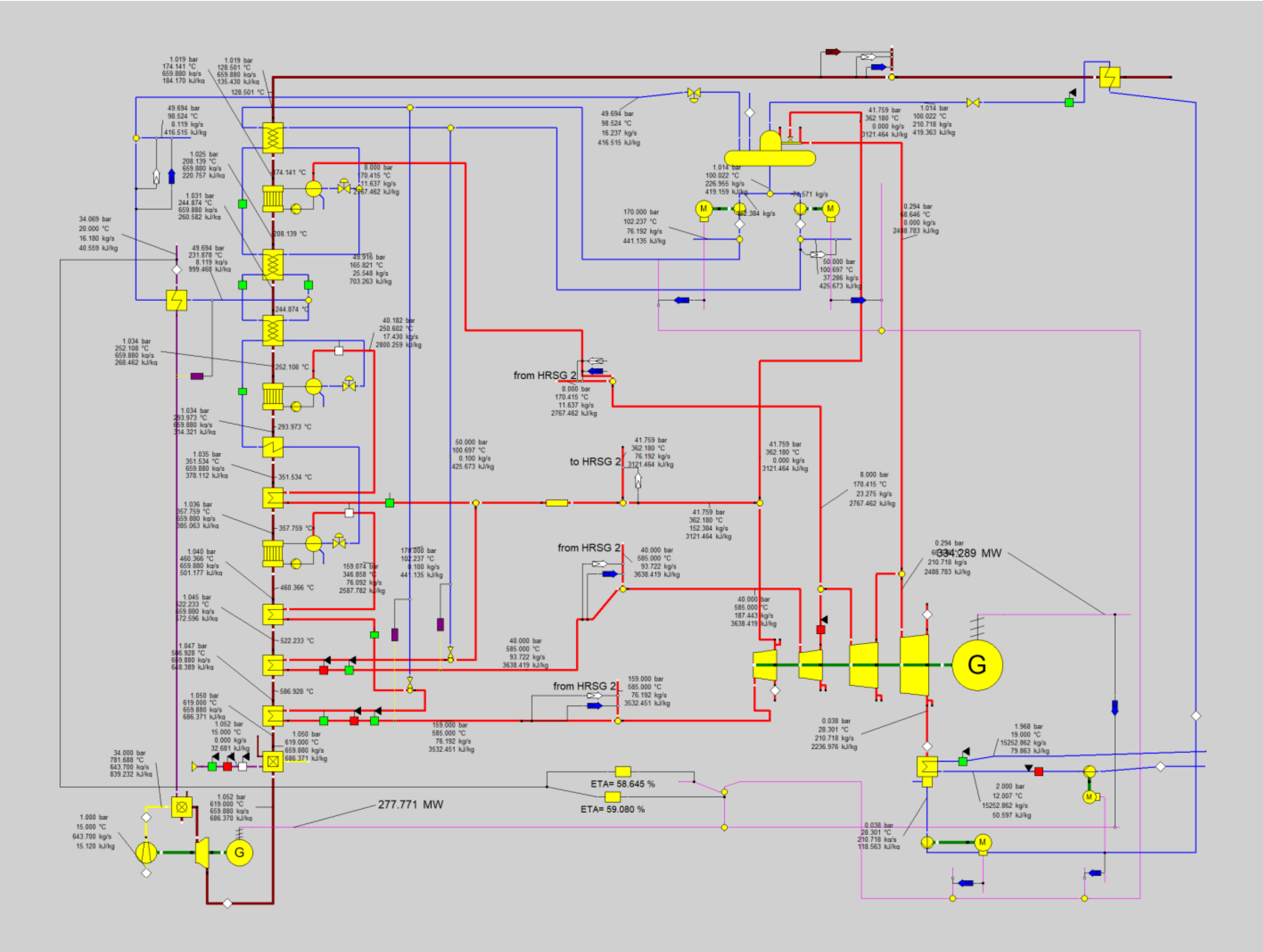
A.18 Schematic of the reference NGCC power plant using once-through (OT) seawater cooling

NGCC-OT



Apx Figure A.25 NGCC power plant without capture using once-through (OT) seawater cooling (Case 2.2A: NGCC-OT)

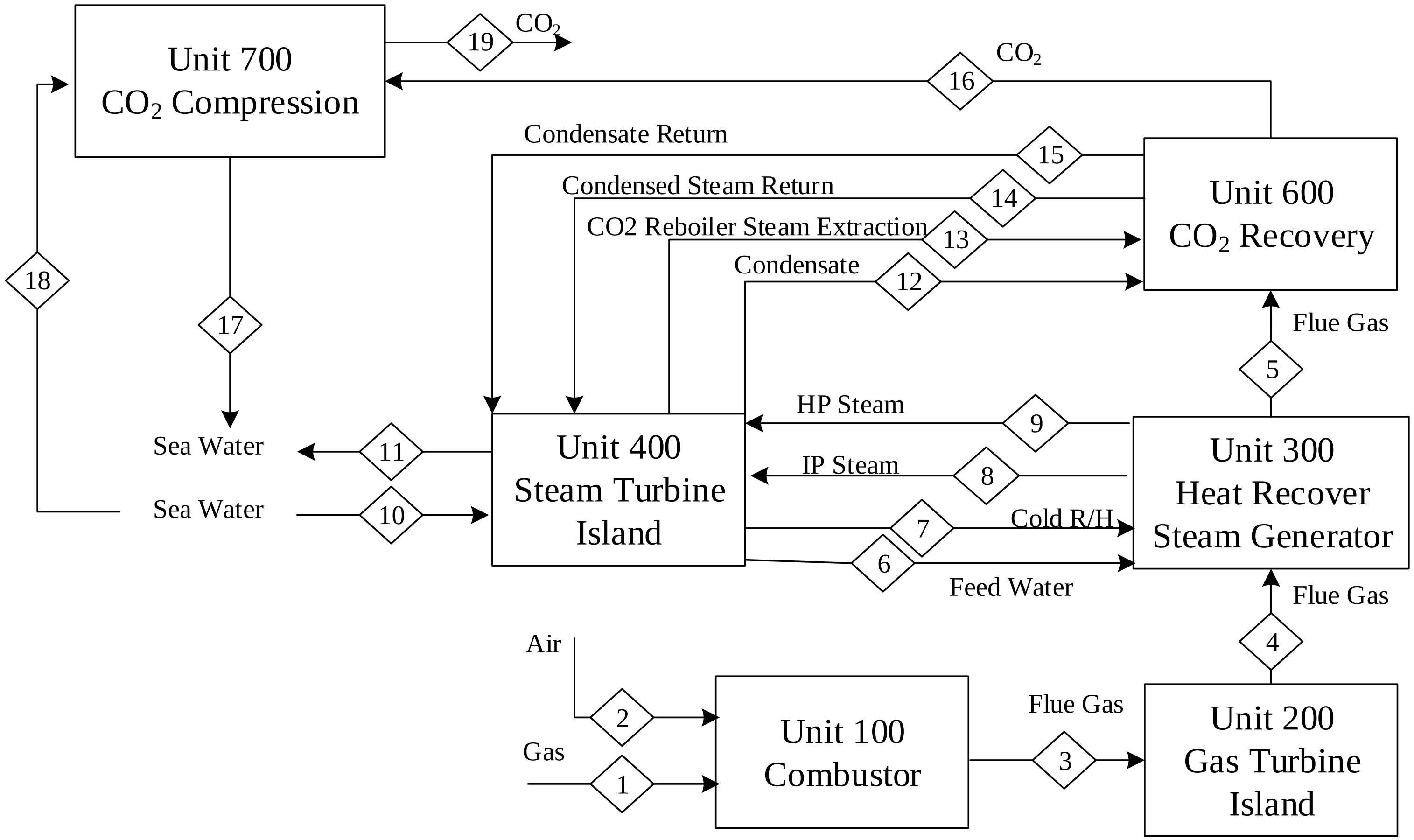
A.19 Flow diagram of the NGCC power plant process using once-through (OT) cooling



Apx Figure A.26 Flow diagram of the NGCC power plant process using once-through (OT) cooling

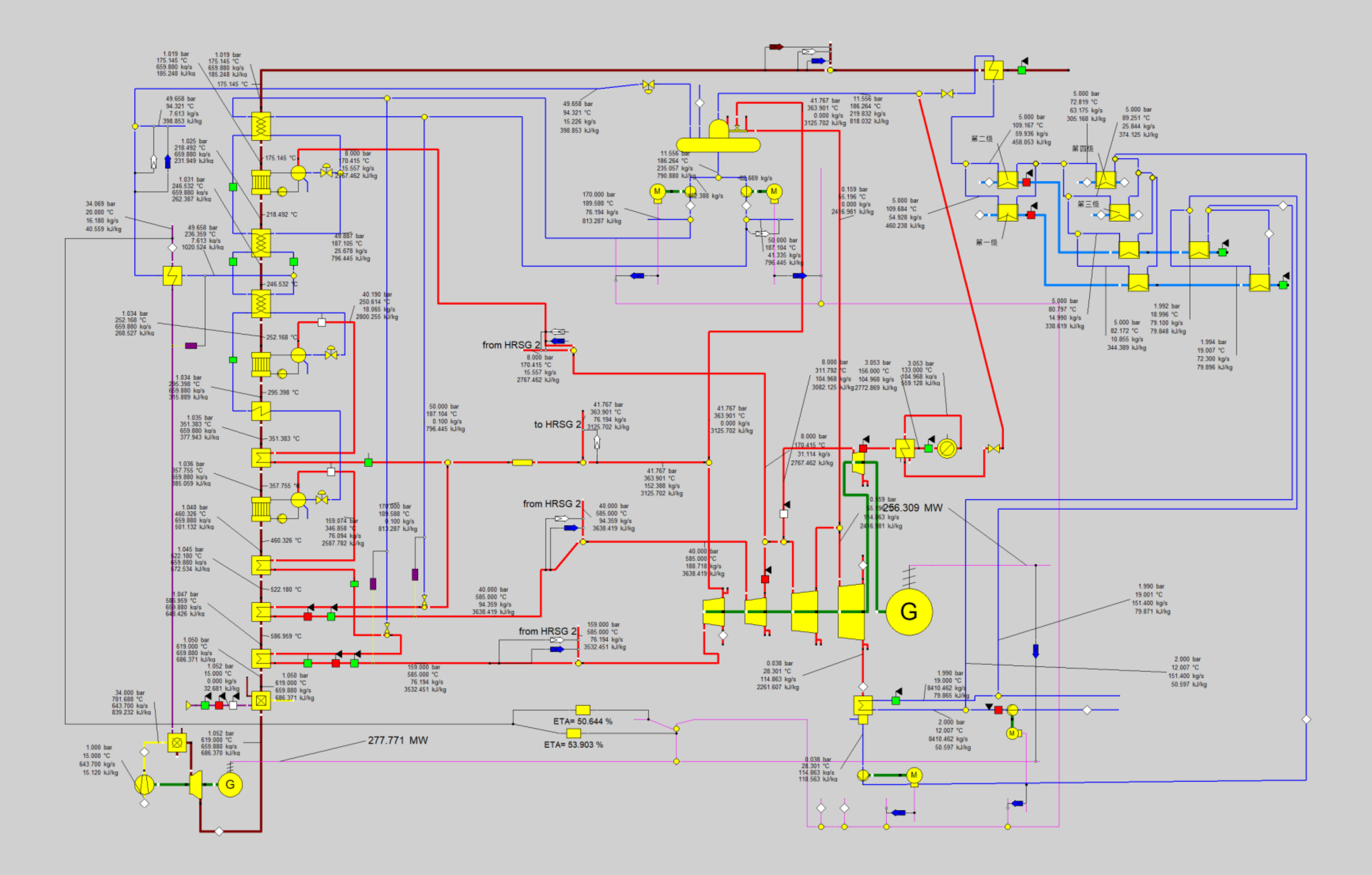
A.20 Schematic of the NGCC power plant with capture using once-through (OT) seawater cooling

NGCC-OT-PCC



Apx Figure A.27 NGCC power plant with capture using once-through (OT) seawater cooling using same or air cooling for capture plant (Case 2.2B: NGCC-OT-PCC or Case 2.2C: NGCC-OT-PCC-AC)

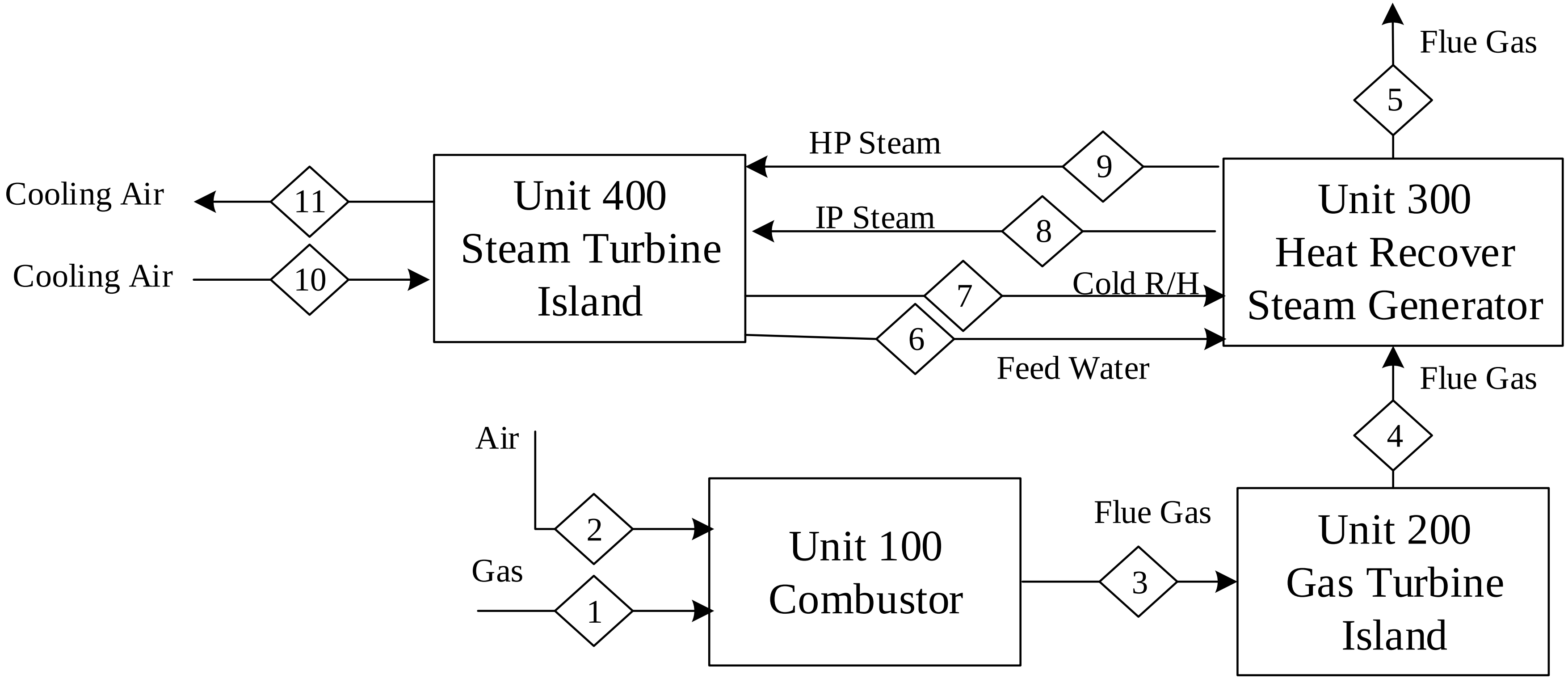
A.21 Flow diagram of the NGCC power plant process with capture using once-through (OT) cooling



Apx Figure A.28 Flow diagram of the NGCC power plant process with capture using once-through (OT) cooling

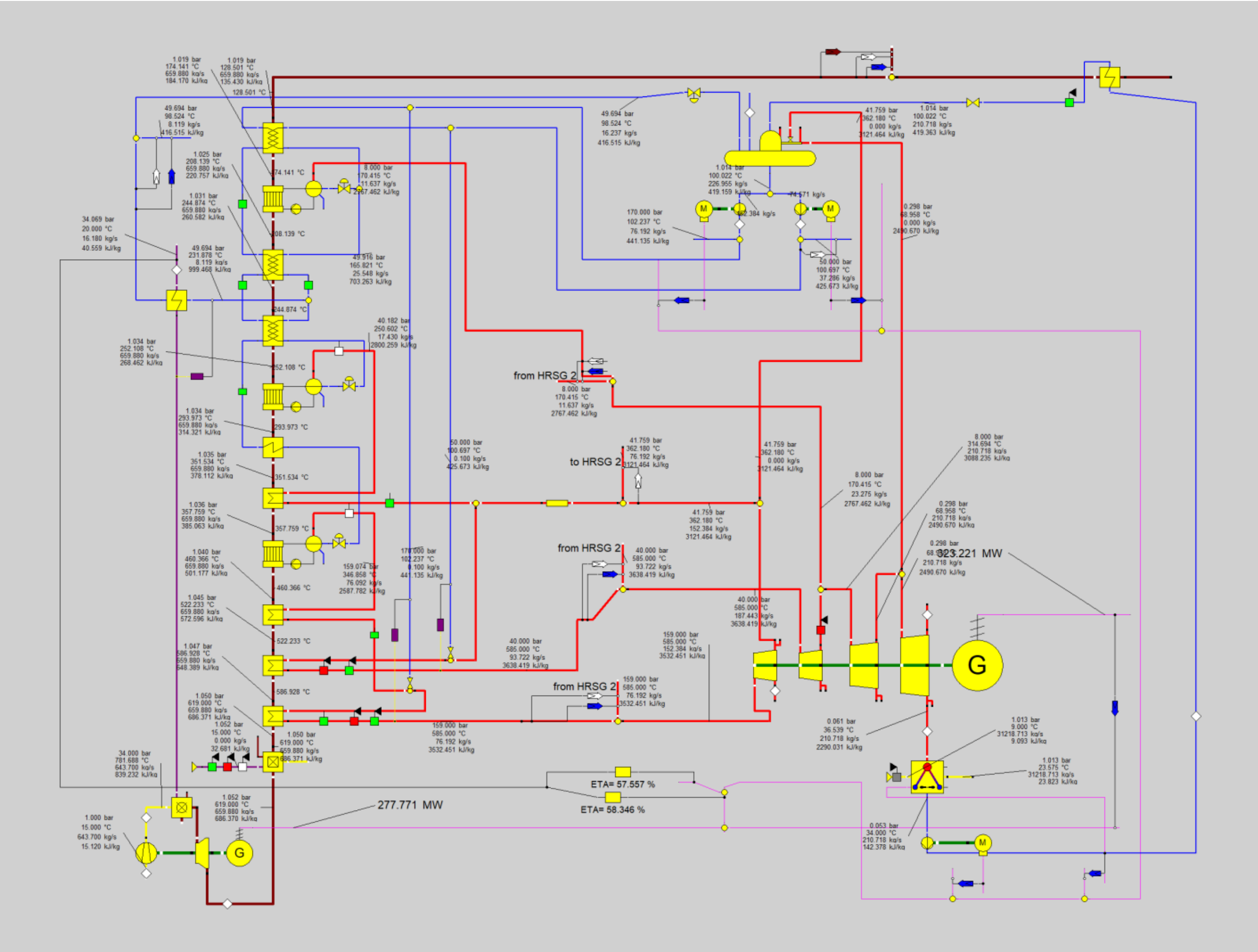
A.22 Schematic of the reference NGCC power plant using air cooling (AC)

NGCC-AC



Apx Figure A.29 NGCC power plant using air cooling (AC) (Case 2.3A: NGCC-AC)

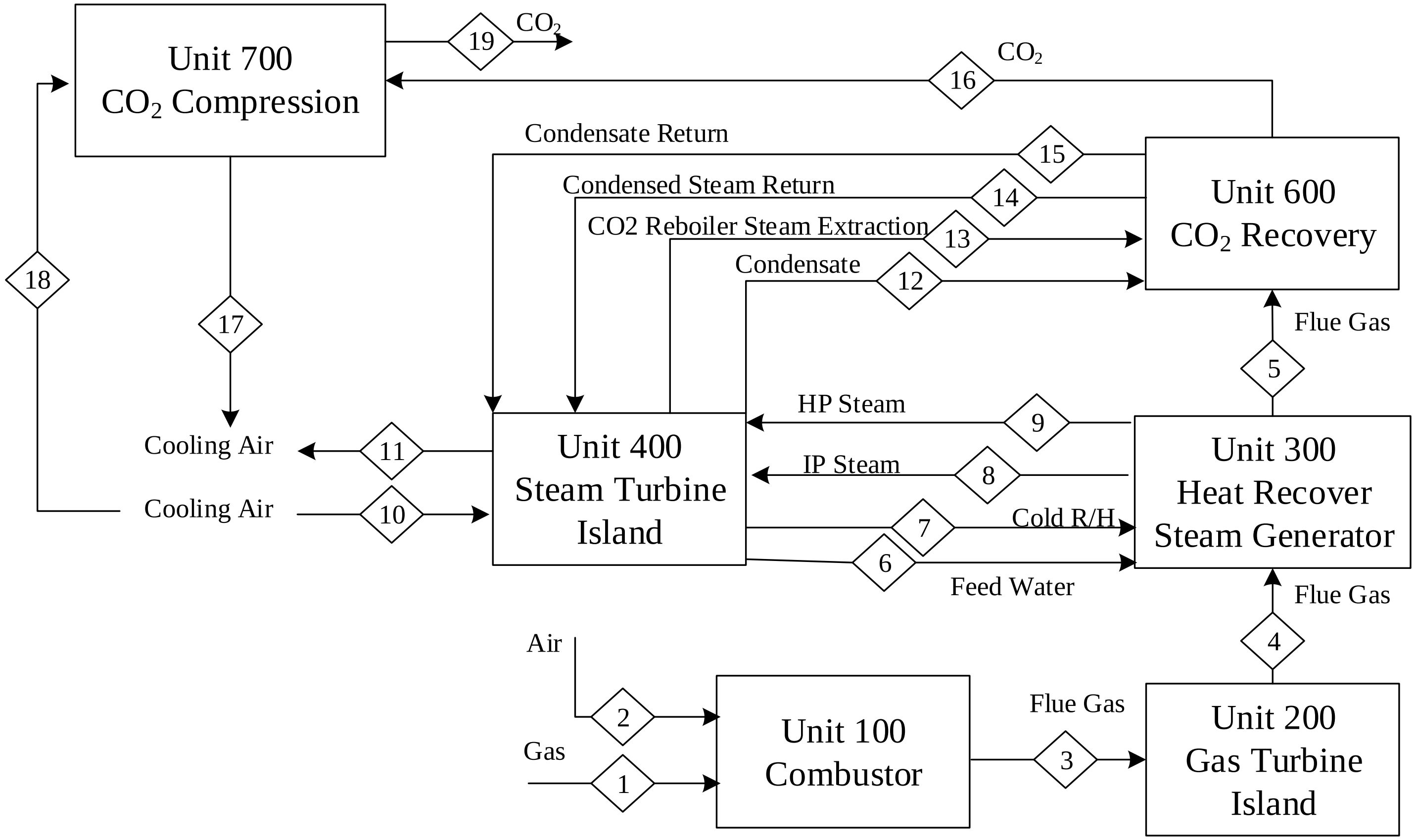
A.23 Flow diagram of the NGCC power plant process using air cooling (AC)



Apx Figure A.30 Flow diagram of the NGCC power plant process using air cooling (AC)

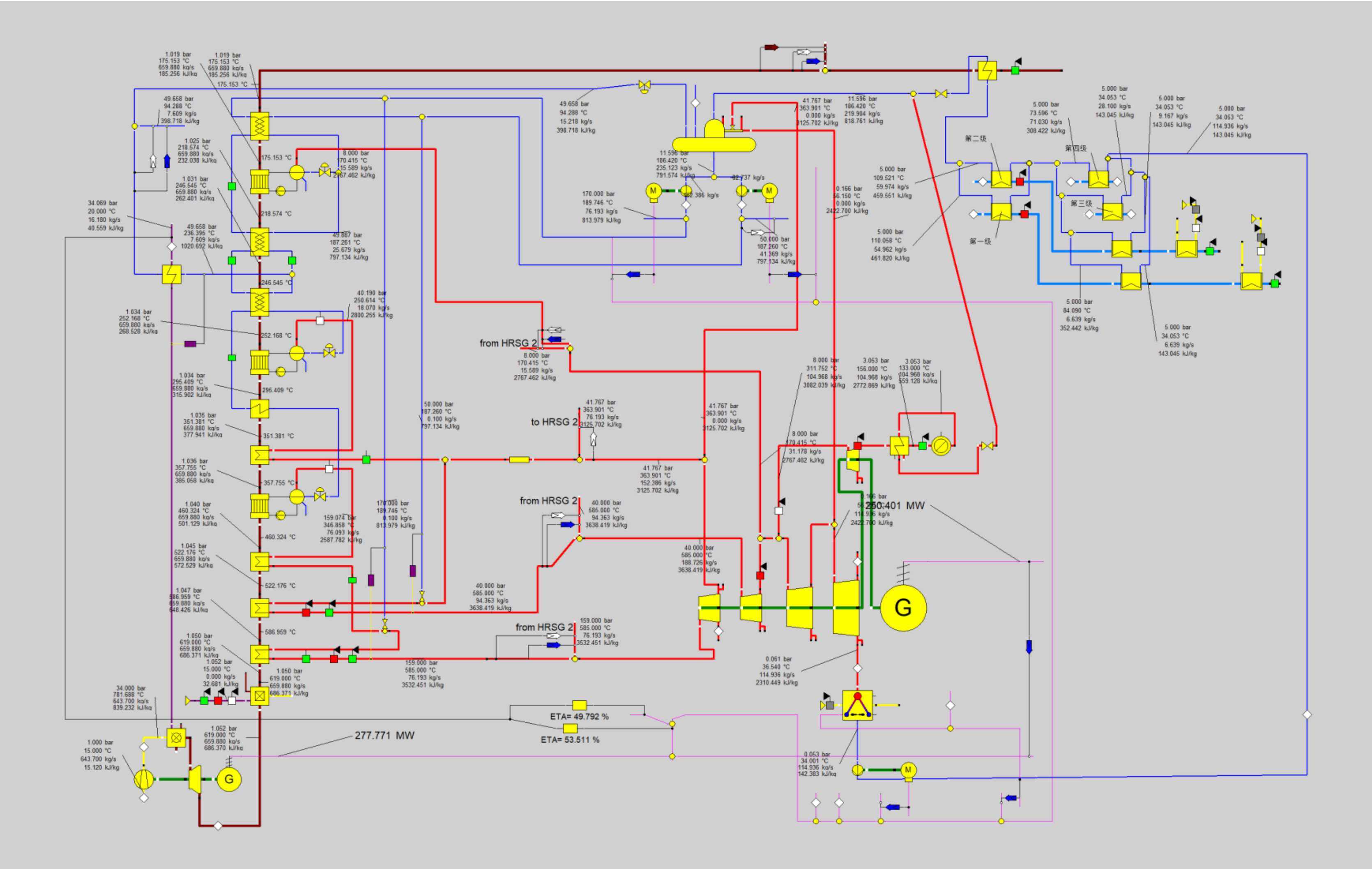
A.24 Schematic of the NGCC power plant with capture using air cooling (AC)

NGCC-AC-PCC



Apx Figure A.31 NGCC power plant with capture using air cooling (AC) (Case 2.3B: NGCC-AC-PCC)

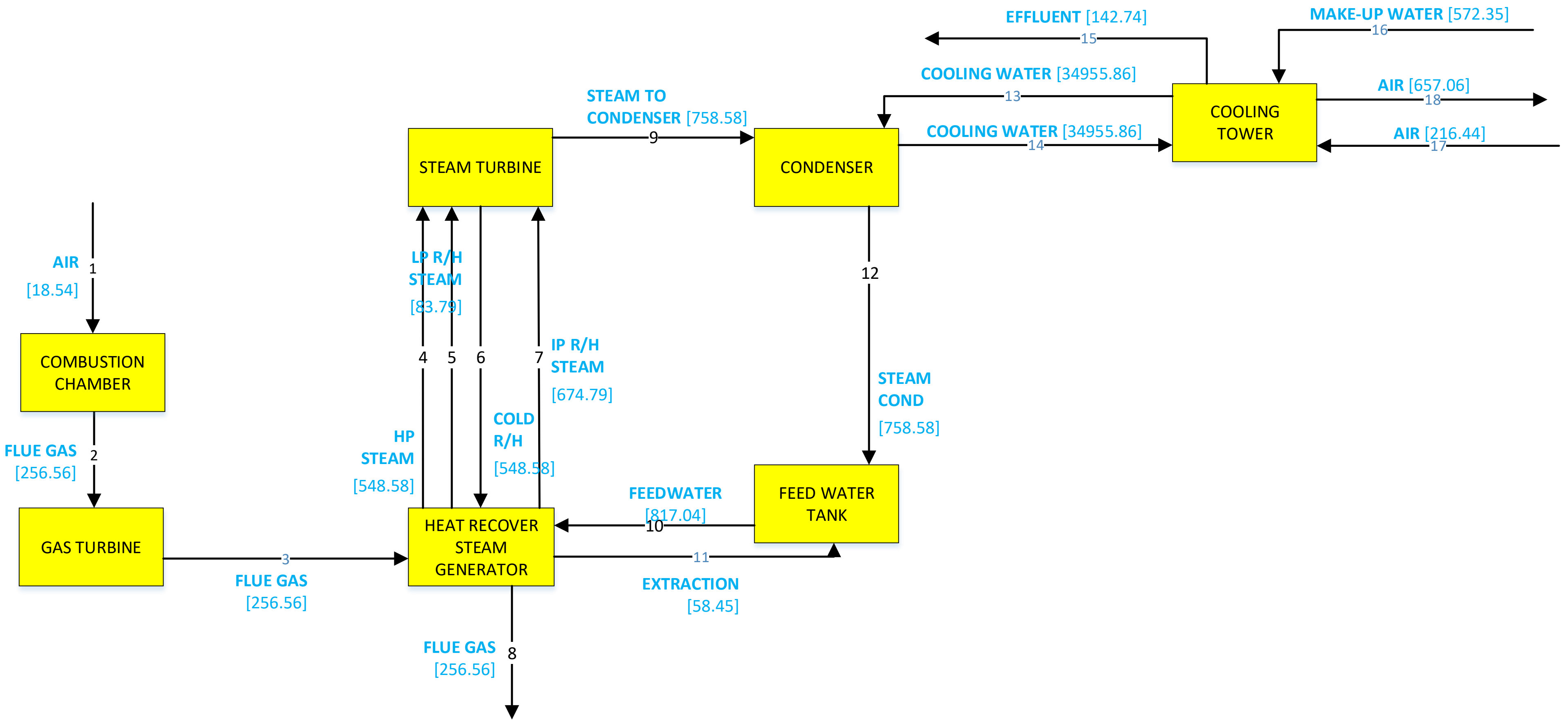
A.25 Flow diagram of the NGCC power plant process with capture using air cooling (AC)



Apx Figure A.32 Flow diagram of the NGCC power plant process with capture using air cooling (AC)

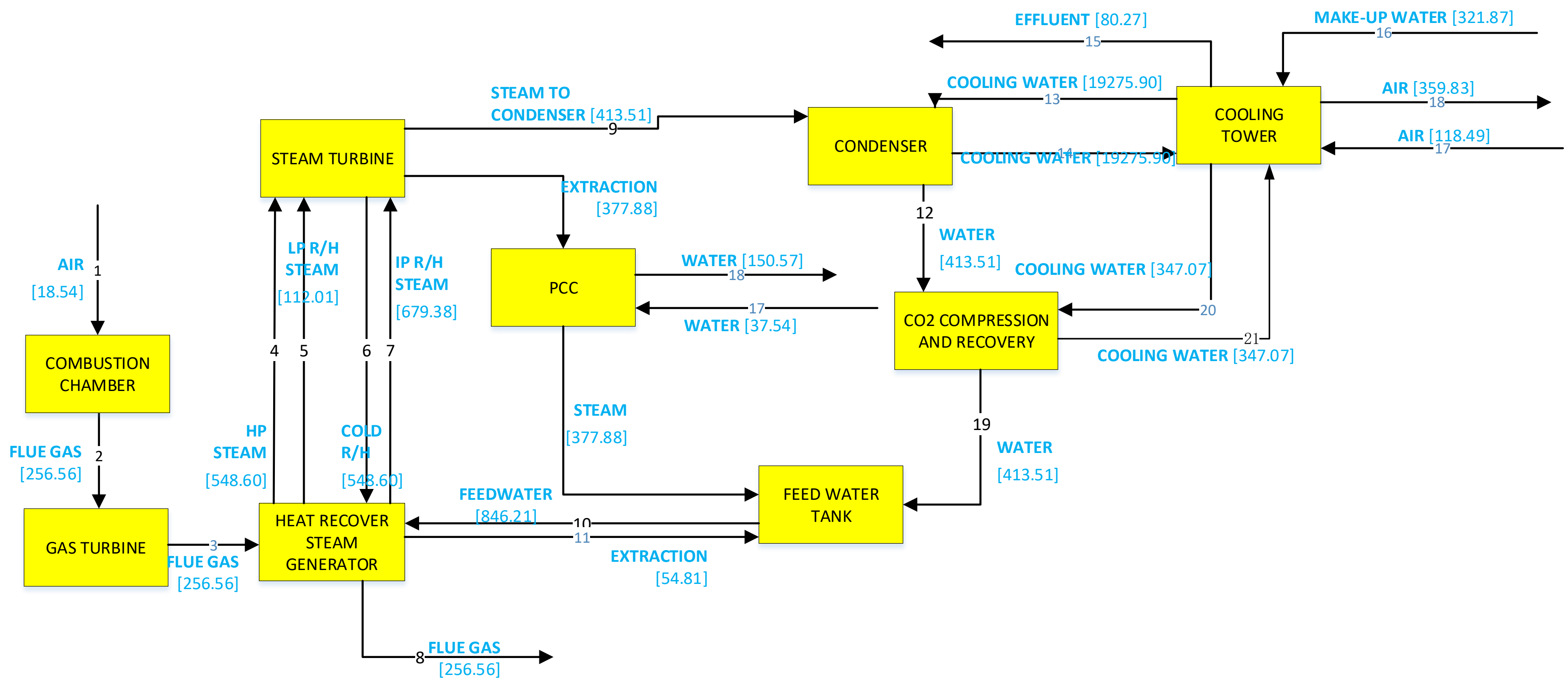
A.26 Detailed water flow diagrams: NGCC

NGCC-EV



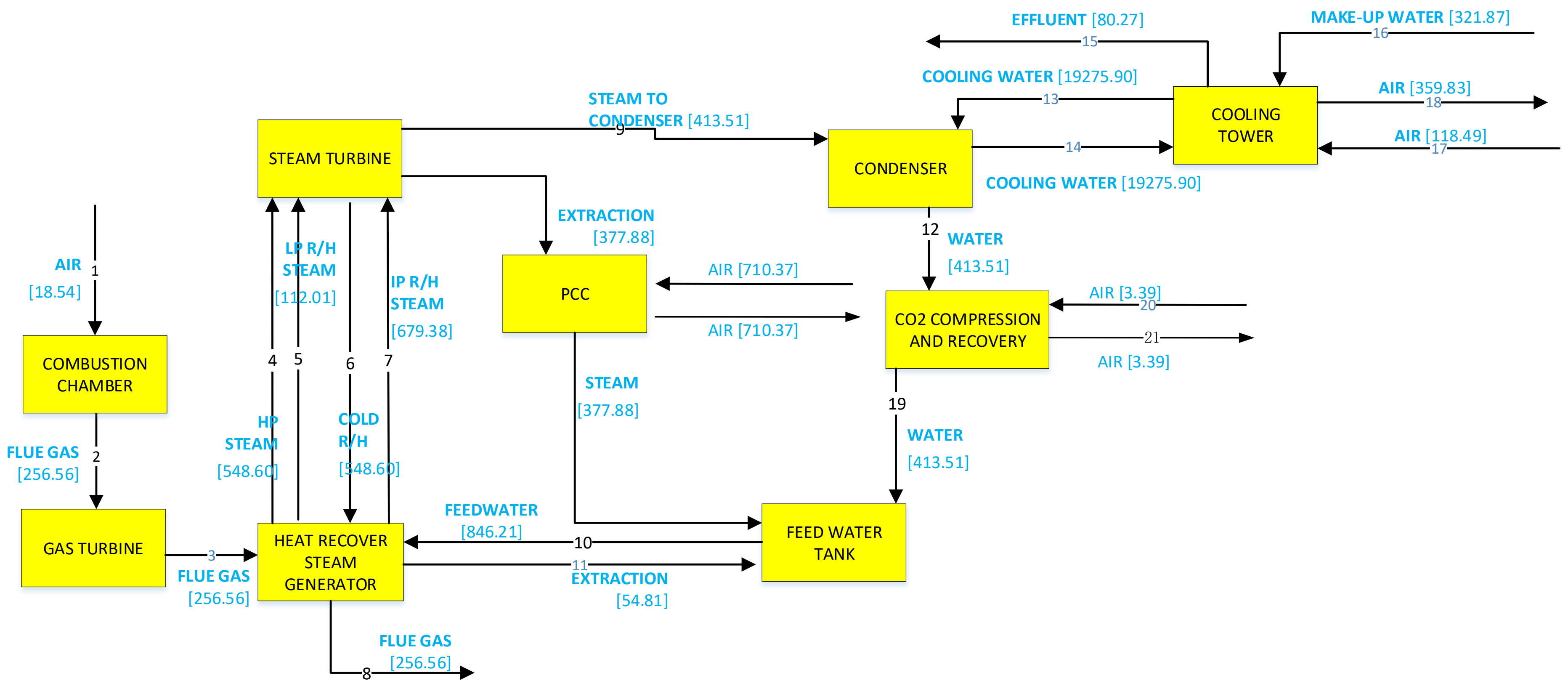
Apx Figure A.33 Water balance in tonnes/hour (t/h) for NGCC power plant without capture using evaporative (EV) cooling (Case 2.1A: NGCC-EV)

NGCC-EV-PCC



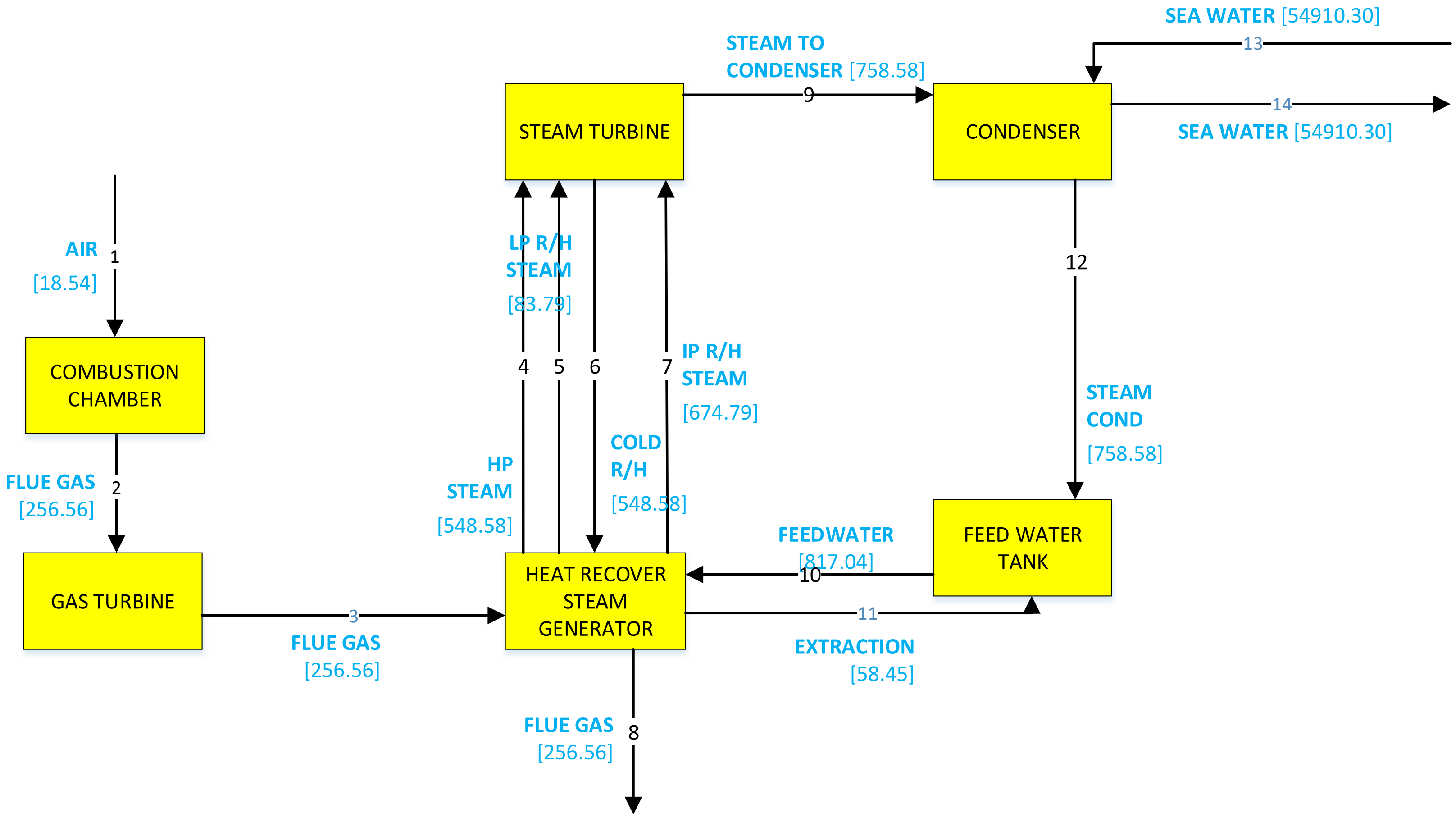
Apx Figure A.34 Water balance in tonnes/hour (t/h) for NGCC power plant with capture using evaporative (EV) cooling (Case 2.1B: NGCC-EV-PCC)

NGCC-EV-PCC-AC



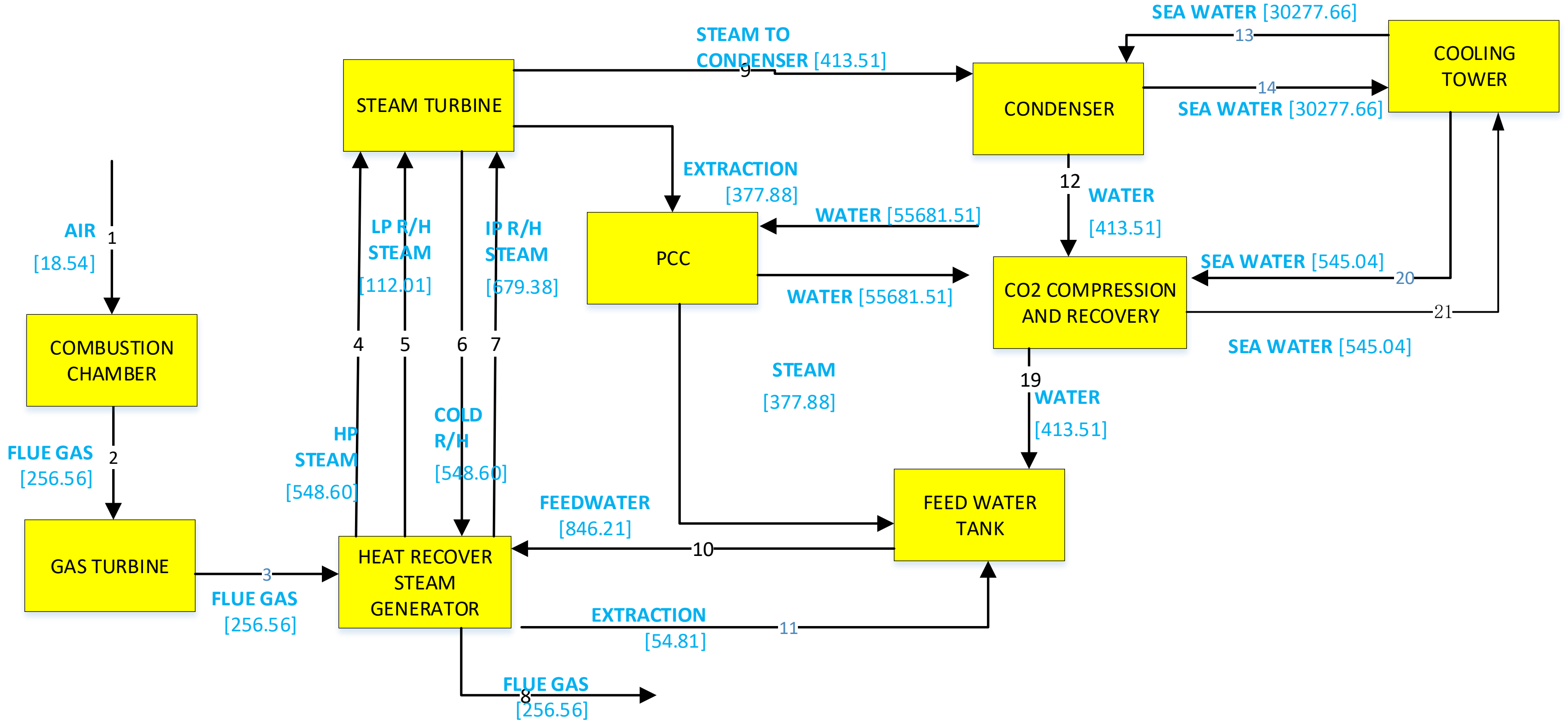
Apx Figure A.35 Water balance in tonnes/hour (t/h) for NGCC power plant with capture using evaporative (EV) cooling for the power plant and air cooling (AC) for the capture plant (Case 2.1C: NGCC-EV-PCC-AC)

NGCC-OT



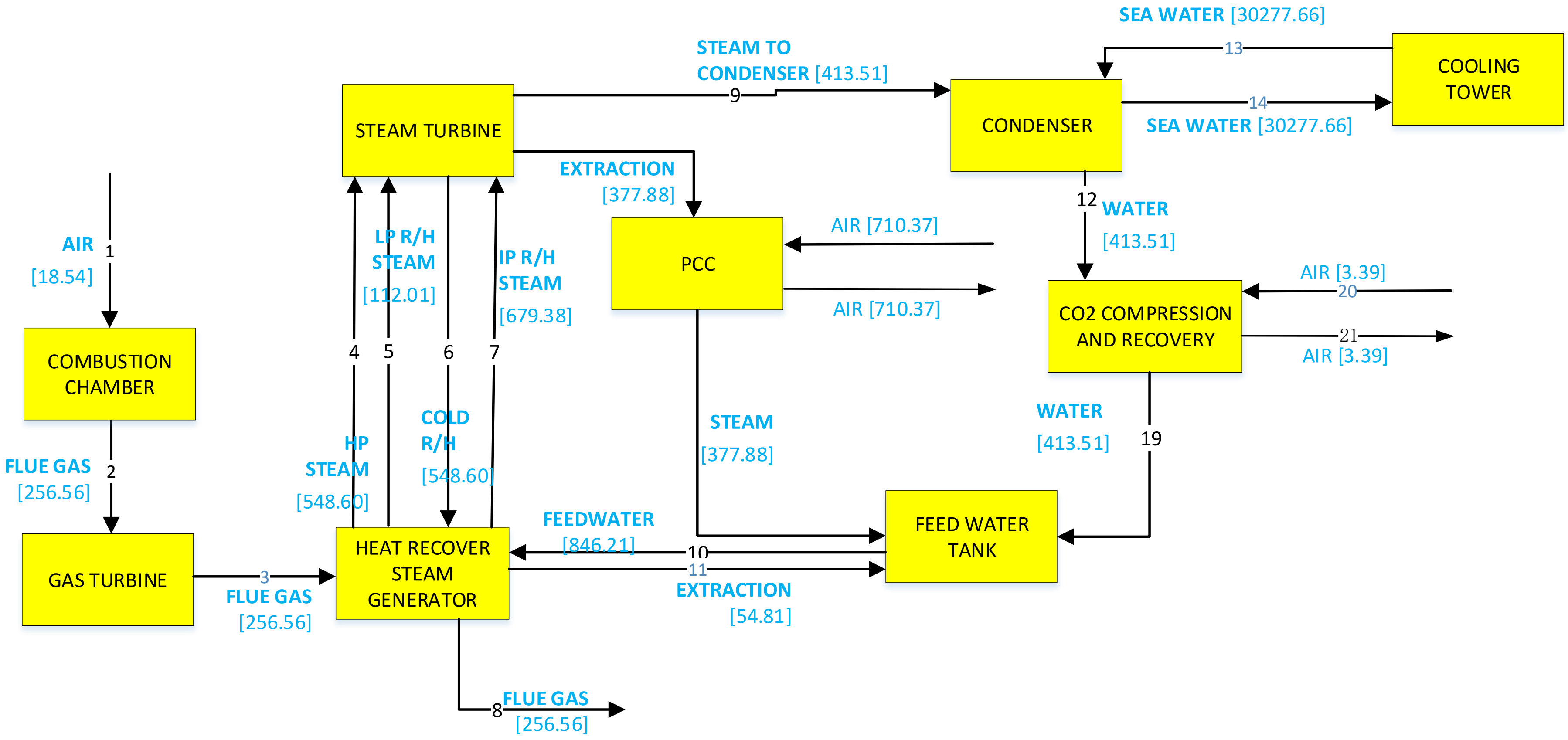
Apx Figure A.36 Water balance in tonnes/hour (t/h) for NGCC power plant without capture using once-through (OT) cooling (Case 2.2A: NGCC-OT)

NGCC-OT-PCC



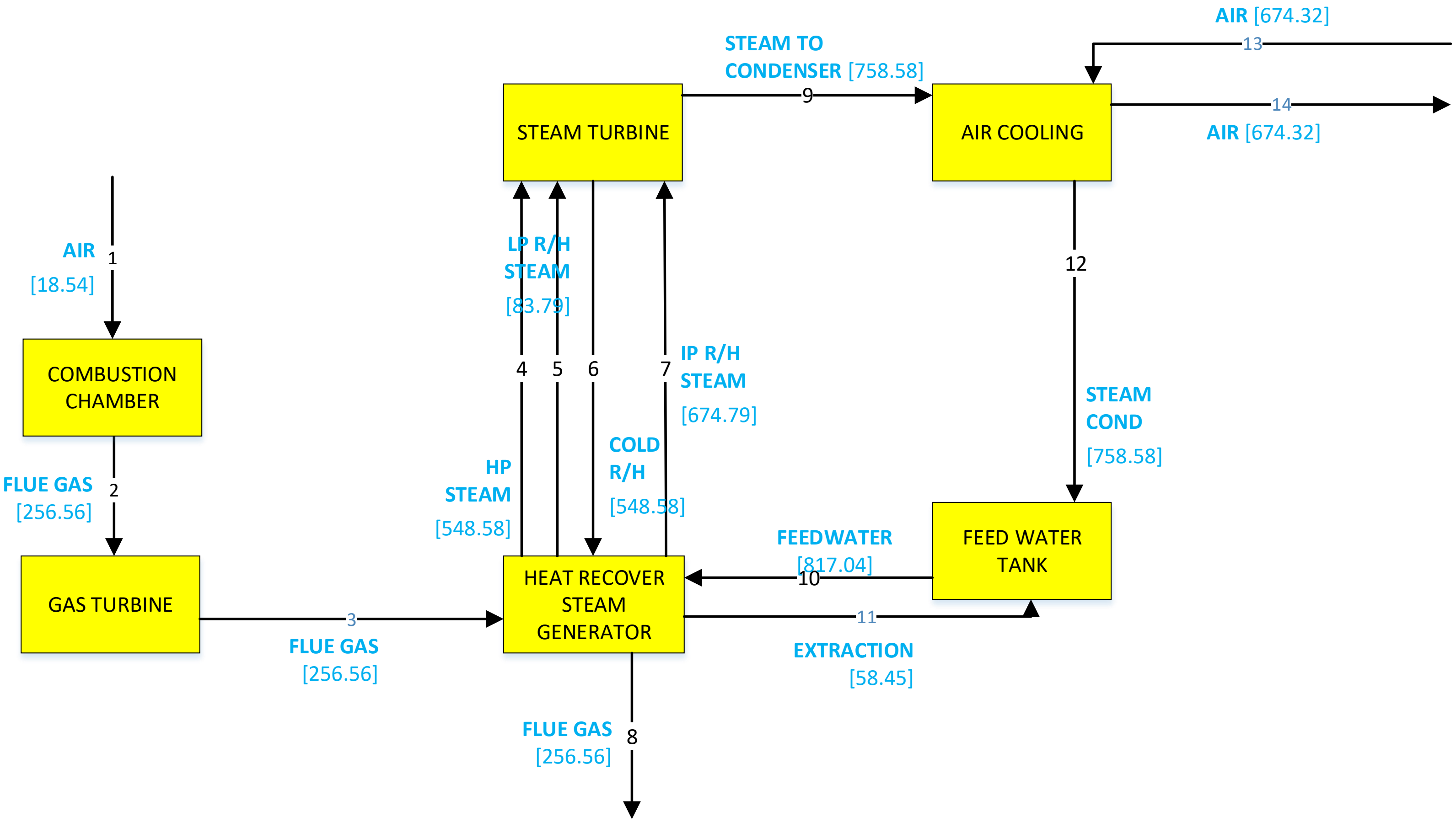
Apx Figure A.37 Water balance in tonnes/hour (t/h) for NGCC power plant with capture using once-through (OT) cooling (Case 2.2B: NGCC-OT-PCC)

NGCC-OT-PCC-AC



Apx Figure A.38 Water balance in tonnes/hour (t/h) for NGCC power plant using once-through (OT) cooling for the power plant and air cooling (AC) for the capture plant (Case 2.2C: NGCC-OT-PCC-AC)

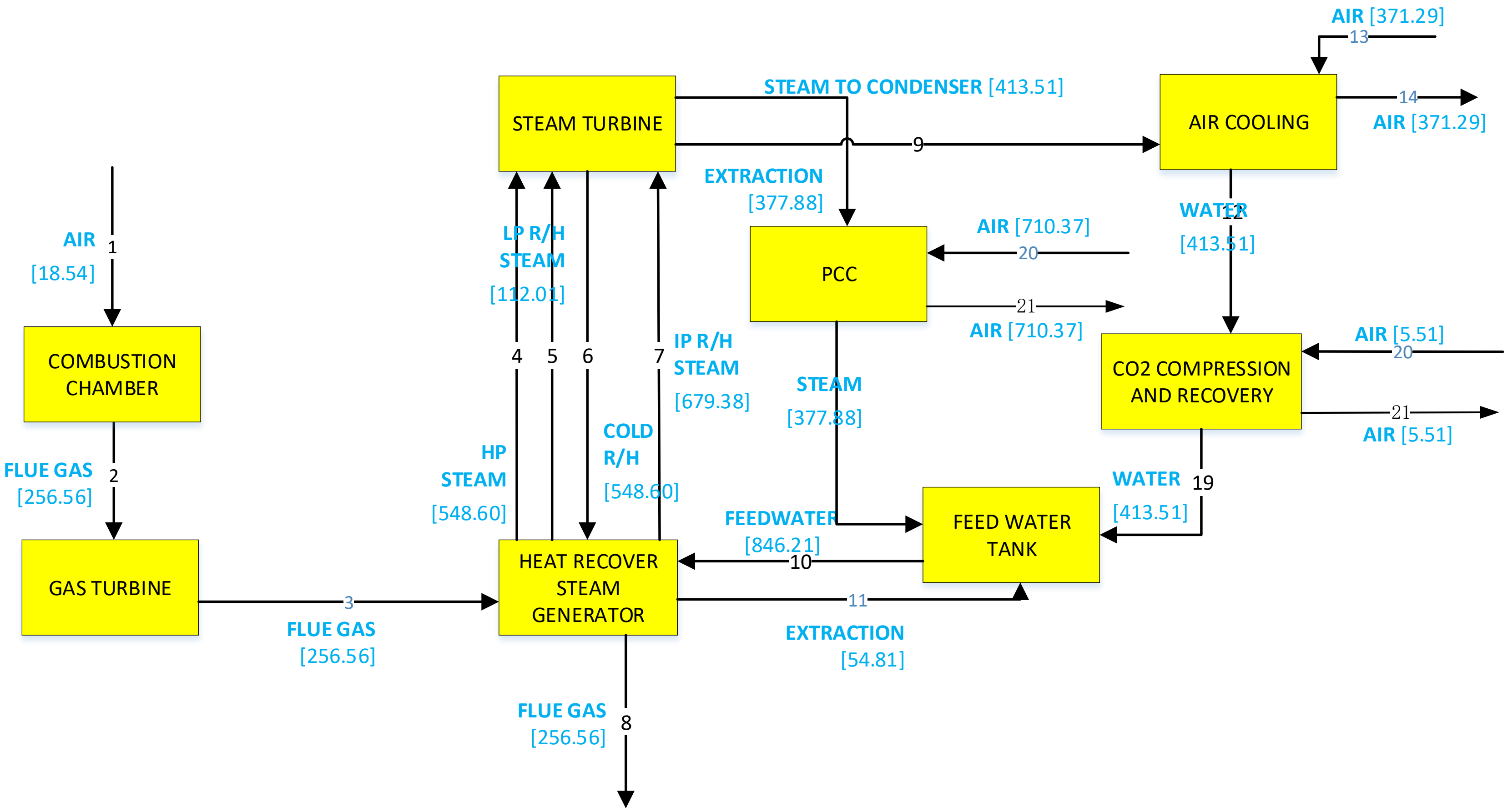
NGCC-AC



[xxx] water flowrates in ton/h

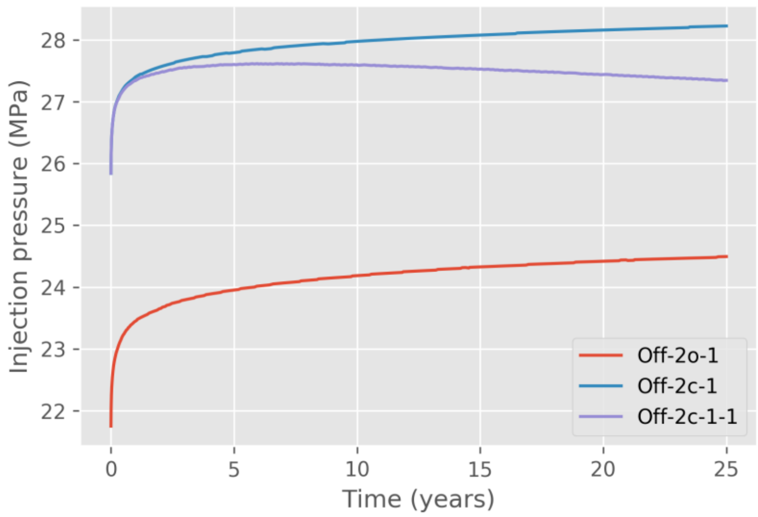
Apx Figure A.39 Water balance in tonnes/hour (t/h) for NGCC power plant without capture using air cooling (AC) (Case 2.3A: NGCC-AC)

NGCC-AC-PCC

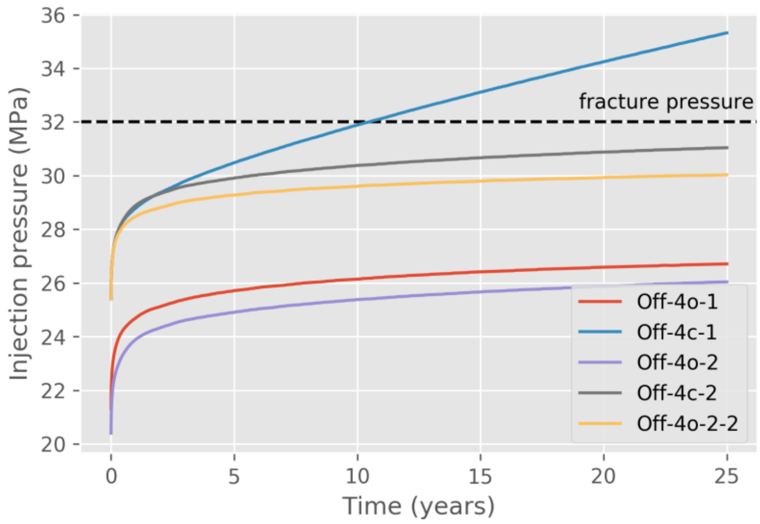


Apx Figure A.40 Water balance in tonnes/hour (t/h) for NGCC power plant with capture using air cooling (AC) (Case 2.3B: NGCC-AC-PCC)

B.1 Bottom-hole pressure behaviour: offshore Netherlands

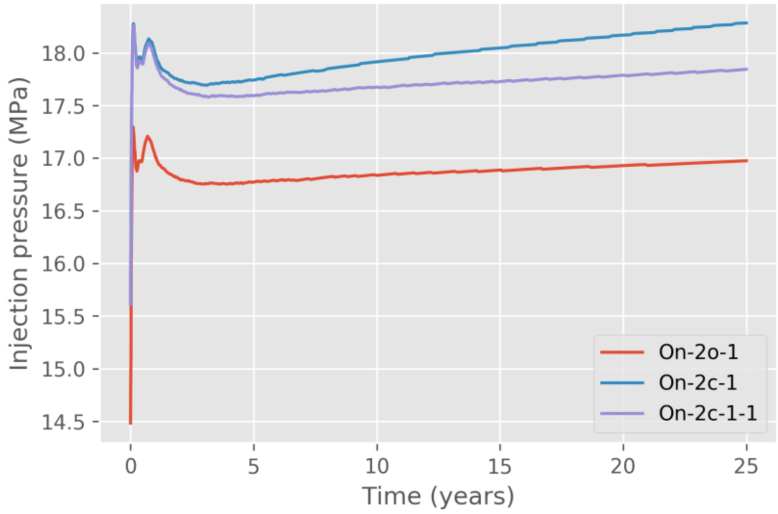


Apx Figure B.41 Bottomhole pressure for all 2 Mt/y injection scenarios for the offshore model

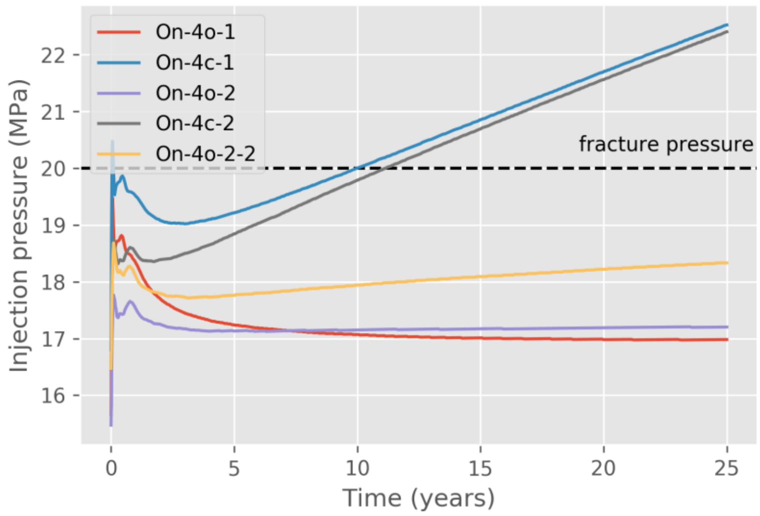


Apx Figure B.42 Bottomhole pressure for all 4 Mt/y injection scenarios for the offshore model

B.2 Bottomhole pressure behaviour onshore Netherlands



Apx Figure B.43 Bottomhole pressure for all 2 Mt/y injection scenarios for the onshore model



Apx Figure B.44 Bottomhole pressure for all 4 Mt/y injection scenarios for the onshore model

Shortened forms

AC	air cooling
AGR	acid gas removal
AMP	Amino-Methyl-Propanol
AOR	area of review
AS	ambient standards
ASU	air separation unit
BAT	best available technology
CAPEX	capital expenditure
CCS	carbon capture and storage
DCC	direct contact coolers
ED	electro-dialysis
EDR	electro-dialysis reversal
ES	effluent standards
ETS	emission trading scheme
EV	evaporative cooling
FGD	flue gas desulphurisation
FGR	flue gas recycling
FO	forward osmosis
FOPEX	fixed operating costs
GWD	Ground Water Directive
HHV	higher heating value
HRSG	heat recovery steam generator
IGCC	integrated gasification combined cycle
LCOE	levelised cost of electricity
LVH	lower heating value
M	million
MD	membrane distillation
MEA	monoethanolamine
MED	multi-effect distillation
MEE	multi-effect evaporation

MSF	multistage flash distillation
MSFD	Marine Strategy Framework Directive
Mt	million tonne
MTE	mechanical thermal expression
MVC	mechanical vapour compression
MW	megawatt
MWh	megawatt hour
NGCC	natural gas fired combined cycle power plant
NORM	Naturally occurring radioactive materials
NWP	National Water Plan
OPEX	operating expenditure
OT	once-through cooling
PCC	post-combustion capture
PEC	predicted effect concentration
PNEC	predicted non-effect concentration
PP	power plant
PSES	pre-treatment standards for existing sources
RO	reverse osmosis
t	tonne
T&S	transport and storage
TDS	total dissolved solids
TGTU	tail gas treating unit
TPC	total plant cost
TSS	total suspended solids
TVC	thermal vapour compression
UGS	underground gas storage
USCPC	ultra-supercritical coal fired power plant
VOPEX	variable operating cost
WFD	Water Framework Directive
WGS	water gas shift reaction
y	year
ZLD	zero liquid discharge

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Understanding the Cost of Reducing Water Usage in Coal and Gas Fired Power Plants with CCS

Phase 2 Report

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Acknowledgments

Funding for this study was provided by the IEA Greenhouse Gas (IEAGHG) R&D Programme.

The authors would also like to acknowledge the support provided by CSIRO Energy, Australia.

The authors thank Monica Garcia and James Craig from IEAGHG, Gustavo Fimbres-Weihs from the University of Sydney, as well as two external reviewers for their review and the feedback provided.

Overview

Background

This study presents Phase 2 of the IEAGHG study "Understanding the Cost of Reducing Water Usage in Coal and Gas Fired Power Plants with CCS". Phase 1 evaluated the reuse of extracted water in the CCS chain in a Dutch context. It explored the increase in water consumption resulting from CO_2 capture applying different cooling technologies, the potential of storing the captured CO_2 in saline formations onshore and offshore Netherlands, and options for management of extracted water. An in-depth evaluation of the costs and benefits of integrating water usage with CCS and the factors influencing potential reuse of extracted water from the storage site was also provided.

Phase 2 focusses on water-stressed regions, namely South Africa, Australia, China and India. The effect of location on power station performance is evaluated, under the consideration of local conditions and regulations. Suitable onshore storage basins with the potential to provide adequate CO_2 storage capacity and long-term containment are identified for each country. However, in contrast to the Phase 1 study, no storage modelling is carried out due to the limited availability of data and lack of characterisation in some countries investigated. Consequently, storage estimates presented in this report are only approximate initial estimates. For the economic assessment an estimated flat rate for CO_2 storage and transport as well as for water extraction and transport is assumed. The reuse of treated extracted water in the power station with capture is evaluated and alternative beneficial use options and associated challenges are discussed.

Scope of work

The objective of this study is to undertake a techno-economic evaluation of water usage along the whole CCS chain in four water stressed regions, applying the methodology developed as part of Phase 1. The regions are: South Africa, Australia, China and India. In particular, the study will explore the effect of location on power station performance, including the increase in water consumption associated with CO_2 capture, and the potential and costs for reusing extracted water from storage sites in power plant operations, taking into account local regulations. The aim is to highlight the potential for reusing extracted water, as well as challenges affecting the reuse potential and means to overcome them.

Specifically, this assessment aims to:

- Assess the water usage, wastewater output and overall performance of coal fired power plants with and without capture using evaporative cooling for the capture plant and either air cooling or evaporative cooling for the power plant in South Africa, Australia, China and India.
- Identify suitable geological basins for CO_2 storage in the four regions with adequate storage capacity and provide information on expected water quality.

- Identify suitable water treatment technologies for storage-extracted brine in the four regions under the consideration of local regulations.
- Develop a methodology to adapt the costs generated for the Dutch power stations with and without capture in Phase 1 to be representative of the four regions of interest.
- Assess the integrated CCS-water chain, in which water management is considered in detail with extracted formation water being reused in the power plant with capture, thus closing the CCS chain.
- Provide an economic assessment for the integrated CCS chain.
- Identify key factors influencing the potential reuse of extracted water, taking into account water quality requirements and non-technical matters.

Description of case studies

Four locations are considered for this part of the study: South Africa, Australia, China and India. An overview of the key details of each location are presented in Table 1.

Table 1 Key details for evaluation of the CCS-Water-Nexus in the four locations of interest

Location	Power station type	Cooling system	Storage Basin	Formation water TDS[2]	Reference
South Africa (inland)	USCPC[1]	Air cooling, capture plant using EV	Zululand (onshore)	26,000 mg/l	Viljoen et al., 2010, Chabangu et al., 2014a
Australia (inland)	USCPC[1]	Air cooling, capture plant using EV	Surat (onshore)	5,000 mg/l	Hodgkinson et al., 2010
China (inland)	USCPC[1]	Air cooling, capture plant using EV	Songliao (onshore	5,000 mg/l	Su et al., 2013
India (inland)	USCPC[1]	Natural draft cooling tower, raw water make-up	Cambay (onshore)	9,000 mg/l	Rebary et al., 2014

[1]USCPC = ultra-supercritical coal fired power station; [2]TDS = total dissolved solids

The following cases are evaluated:

i. Base Case CCS Scenario, which considers CO_2 capture from an ultra-supercritical coal fired (USCPC) power plant using either air cooling (South Africa, Australia, China) or evaporative cooling (India) and evaporative cooling for the capture plant, and transport and storage of CO_2 in onshore saline formations without water extraction (open reservoir), assuming that open reservoir boundaries enable CO_2 injection at the required annual rates.

ii. CCS-Water-Nexus Scenario, which builds on the base case scenario and includes brine extraction to increase storage capacity, and treatment of the extracted water for reuse in the power station and the capture plant, where possible.

i.) Base Case CCS Scenario

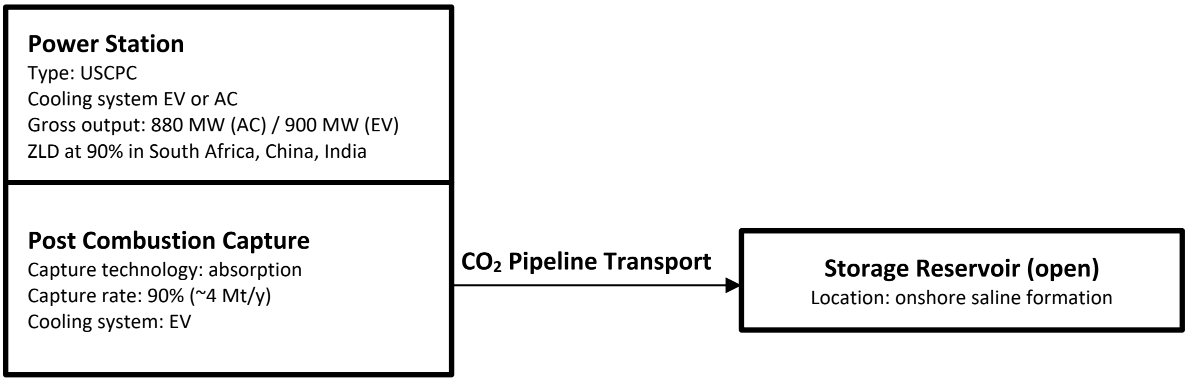

Figure 1 Flow diagram of the Base Case CCS Scenario: CCS in an open formation without water extraction (EV = evaporative cooling, AC = air cooling, ZLD = zero liquid discharge)

ii.) CCS-Water-Nexus Scenario

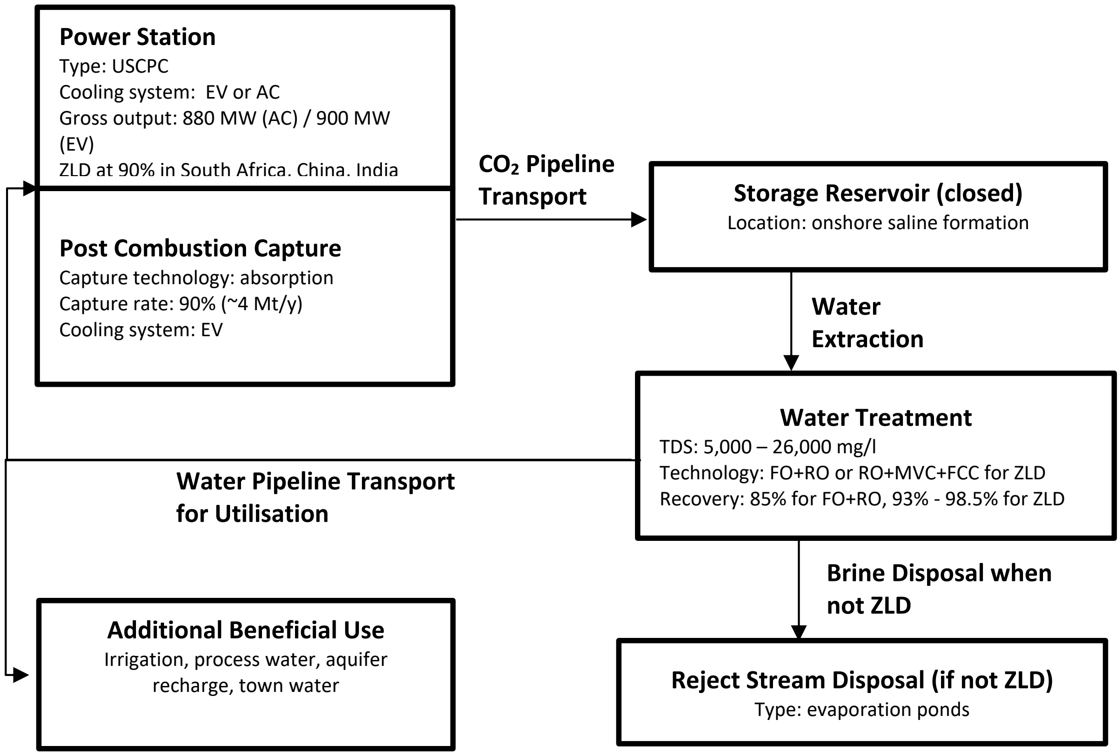

Figure 2 Flow diagram of the CCS-Water-Nexus Scenario with water treatment and utilisation in the power station with capture and other beneficial use (FO = forward osmosis, RO = reverse osmosis, MVC = mechanical vapour compression, FCC = forced circulation crystallizer, ZLD = zero liquid discharge)

Technical and economic basis

The detailed technical and economic assumptions of the study are outlined in the main report. The main baseline assumptions are as per below.

Economics

• Discount rate:	8% in constant money values
• Cost year	2018
• Foreign exchange: 1 US$	0.85 €
• Currency	Euro
• Standard plant operating life, years	25
• Capacity factor for power plants w/ and w/o CCS	85%
• Fuel price (coal)	
o South Africa	1.8 €/GJ LHV
o Australia	2.0 €/GJ LHV
o China	1.8 €/GJ LHV
o India (local coal)	1.0 €/GJ LHV
• Flat rate CO_2 transport and storage onshore	5 €/t CO_2 stored
• Flat rate water extraction and transport onshore	2.5 €/t CO_2 stored

Power plant and capture plant performance

- Nominal gross output of the USCPC power plants with and without capture:
  - 900 MWe with evaporative cooling
  - 880 MWe with air cooling
- The post-combustion capture (PCC) technology is representative of a "Best Available Technology" absorption process utilising an aqueous solution of 40wt% piperazine/AMP in a 1:2 molar ratio (Cousins et al., 2019)
- The CO_2 capture rate is approximately 4 Mt/y for the USCPC in each country, at a recovery rate of 90%
- All USCPC power plants use evaporative cooling for the capture plant
- Based on local regulations, treatment of the wastewater to zero liquid discharge (ZLD) is required at the power stations in South Africa, China, and India using a membrane brine concentration (MBC) system and a crystalliser as the final step. The recovered water is reused in the power station.

CO_2 Storage

- No reservoir modelling is carried out due to the lack of data in some of the regions of interest. Therefore, the storage estimates presented in this study are only approximate initial estimates
- All geological storage basins identified for this study are located onshore
- Average formation salinities vary by country/basin and range from 5,000 – 26,000 mg/l
- Reservoir boundaries are assumed as

    - Open (no water extraction necessary: Base Case CCS Scenario)
    - Closed (water extraction required: CCS-Water-Nexus Scenario)
- The storage reservoirs are perfectly sealed by an overlying formation providing long-term containment
- Injection occurs over a period of 25 years at a rate of ~4 Mt/y corresponding to total injection amounts of 100 Mt
- Water extraction occurs at a H_2O to CO_2 ratio of 1.7 to 1, based on Phase 1 findings. Thus, the water extraction rate is around 6.8 Mt/y
- Generic costs are estimated for CO_2 transport and storage, as well as for water extraction and storage
    - A flat rate for onshore CO_2 transport and storage of 5 €/t CO_2 stored is assumed as a conservative estimate based on IEAGHG (2014) and Phase 1 results
    - A flat rate for onshore water extraction and transport of 2.5 €/t CO_2 stored is assumed based on Phase 1 results

Management of storage-extracted water (CCS-Water-Nexus Scenario only)

- All of the storage-extracted brine is treated to freshwater quality of 100 mg/l TDS
- To align with local regulations for the coal-fired power stations, the storage-extracted brine is treated to ZLD in South Africa, China, and India.
- In Australia, treatment to ZLD is not necessary and thus not considered
- The product recovery rate varies with the salinity of the extracted formation water and the treatment process applied
- The treated water is supplied to the power station with capture and other beneficial uses where possible
- The reject stream is disposed via evaporations ponds with the remaining salt going to landfill or being supplied to chemical industries

Levelised cost of electricity

To determine the economic feasibility of each scenario, the economic assessment uses a net present value (NPV) discounted cash flow (NPV-DCF) model to estimate the lifetime cost, represented as the levelised cost of electricity (LCOE). The levelized cost of electricity is calculated assuming constant (real) prices for fuel and other costs, and a constant operating capacity throughout the plant lifetime apart from the lower capacity in the first year.

CO_2 avoidance cost

The cost of avoiding CO_2 emissions (as €/t CO_2 avoided) is calculated by comparing the costs and emissions of a plant with CCS and the costs and emissions of a reference case. The reference plant is the same type of generation technology and cooling technology as the plant with CCS.

Notes

Due to the range of limiting technical and economic assumptions, costs presented in this report may only be treated as a preliminary guide.

Results and discussion

Performance and water balance ultra-supercritical coal fired power plant

In South Africa, Australia, and China, the USCPC power plants are modelled as air cooled. In India, the power plant uses evaporative cooling. All capture plants use evaporative cooling. Feedstock and ambient conditions vary from country to country, affecting the performance of the power station. The cooling systems modelled for the USCPC power plants with and without capture in the four countries as well as the different ambient conditions and feedstock are summarised in Table 2. The plant performance and water balances of the USCPC power plants with and without capture are summarised in Table 3. The plants in South Africa, China, and India operate with ZLD with a wastewater recovery rate of 90%. Thus, 90% of the process water discharge in Table 3 is recycled and reused in the power station with capture.

Table 2 Overview of coal type, ambient conditions, and cooling systems modelled in this study

Case	Location	Feedstock	Ambient conditions	Cooling system	Case names
1	**South Africa (inland)**	Coal - South African bituminous	T: 15°C, H: 60% P: 86.2 kPa	Air cooling, capture plant using EV	USCPC-AC USCPC-AC-PCC-EV
2	**Australia (inland)**	Coal - Eastern Australia bituminous	T: 20°C, H: 65% P: 101 kPa	Air cooling, capture plant using EV	USCPC-AC USCPC-AC-PCC-EV
3	**China (inland)**	Coal - Chinese bituminous	T: 0°C, H: 60% P: 98 kPa	Air cooling, capture plant using EV	USCPC-AC USCPC-AC-PCC-EV
4	**India (inland)**	Coal - F-Grade Indian Coal	T: 25°C, H: 80% P: 101 kPa	Natural draft cooling tower, raw water make-up	USCPC-EV USCPC-EV-PCC

Table 3 Technical performance for USCPC power plants (with and without capture) for South Africa, Australia, China and India

Case	South Africa USCPC-AC	South Africa USCPC-AC-PCC-EV	Australia USCPC-AC	Australia USCPC-AC-PCC-EV	China USCPC-AC	China USCPC-AC-PCC-EV	India USCPC-EV	India USCPC-EV-PCC
Fuel input (t/h)	258.9	258.9	343.3	343.3	275.3	275.3	426.6	426.6
Gross power output (MW)	879.3	808.3	879.7	816.7	879.5	800.0	899.7	817.7
Auxiliary power (MW)	110.6	180.0	157.6	223.6	92.2	161.2	106.9	259.8
Net power output (MW)	768.7	628.3	722.2	593.1	787.4	638.8	792.8	639.9
Net plant HHV efficiency (%)	39.94	32.64	37.51	28.99	40.90	33.17	41.17	33.23
Net plant LHV efficiency (%)	41.82	34.18	39.27	30.35	42.82	34.73	43.11	34.79
LHV efficiency loss due to PCC (%-points)		7.64		8.92		8.09		8.32
CO_2 generation (t/h)	624.1	624.1	593.8	593.8	620.1	620.1	637.5	637.5
CO_2 emission (t/h)	624.1	62.4	593.8	59.4	620.1	62	637.5	63.8
CO_2 emission (t/MWh)	0.812	0.099	0.822	0.1	0.788	0.097	0.804	0.1
CO_2 capture (t/h)	0	561.7	0	534.4	0	558.1	0	573.8
Specific equivalent electricity consumption [MWh/t CO_2]		0.250		0.242		0.266		0.266
Energy consumption for absorbent pumps and blowers in PCC (MW)		8.98		8.55		8.93		9.11
Compressor energy (MW)		59.07		56.2		58.7		60.34
Pumps for cooling in PCC (MW)		7.46		7.09		7.41		7.62
Total electrical energy consumption in PCC (MW)		75.51		71.84		75.04		77.07
Water balance								
Water withdrawal (m^3/h)	55.40	839.87	50.72	774.90	53.41	589.30	657.85	1338.12
Process water discharge (m^3/h)	0	195.74	0	180.48	0	133.72	149.86	318.74
Water consumption (m^3/h)	55.40	644.13	50.72	594.42	53.41	455.58	507.99	1019.39
Water withdrawal (m^3/MWh)	0.07	1.34	0.07	1.31	0.068	0.92	0.83	2.09
Water consumption (m^3/MWh)	0.07	1.03	0.07	1.00	0.068	0.71	0.64	1.59
Increase in relative water withdrawal ([m^3/MWh]/[m^3/MWh])		1755%		1760%		1261%		152%
Increase in relative water consumption ([m^3/MWh]/[m^3/MWh])		1323%		1326%		952%		149%

CO_2 storage in South Africa, Australia, China and India

The considerable storage capacity required to accommodate the CO_2 captured from the USCPC over the plant life of 25 years (~100 Mt at a rate of ~4 Mt/y) makes saline formations the most attractive storage options for our study. In South Africa the Zululand Basin is identified as a high potential storage basin, in Australia the Surat Basin is chosen, for China CO_2 storage in the Songliao Basin is proposed, while in India the Cambay Basin is highlighted as a potential site. All four basins have in common that they are located onshore, thus making the extraction and beneficial reuse of storage-extracted water a more realistic option. Importantly, literature indicates that these basins can accommodate the quantities of CO_2 captured over the life of the respective coal-fired power station.

No storage modelling is carried out due the lack of storage characterisation work and data availability in some of these places. CO_2 injection volumes are determined by the CO_2 captured from the power stations, while water extraction volumes, in case of closed reservoir boundaries, are estimated based on those determined in Phase 1 for the Dutch storage scenarios. A water extraction rate of 1.7 parts of water per 1 part of CO_2 injected is assumed to provide brine extraction volumetrically equivalent to the CO_2 injection rate to enable safe CO_2 storage and not exceed fracture pressure. Details of the four storage basins, CO_2 injection rates, water extraction rates, and formation water salinity are presented in Table 4

Table 4 Key details of the CO_2 storage basins identified for this study and the required annual CO_2 injection and water extraction rates (data from Viljoen et al., 2010; Chabangu et al., 2014a; Hodgkinson et al., 2010; Bradshaw et al., 2011; CTSCo, 2018; Su et al., 2013; Hardas et al., 1989; Senapati et al., 1993; Mandal and Bhattacharya, 1997; Rebary et al., 2014)

Country		South Africa	Australia	China	India
Storage basin		Zululand Basin	Surat Basin	Songliao Basin	Cambay Basin
Location		Onshore	Onshore	Onshore	Onshore
Reservoir permeability	md	<1 – 229	Med 13, max 1,500	150 - 285	0.3 - 163
Reservoir porosity	%	4 - 41	17	18 – 20	2 - 14
Formation water salinity	mg/l	14,000 – 38,000	5,000 – 15,000	3,500 – 9,000	7,000 – 10,000
Reservoir boundaries		open	open	open	open
CO_2 injection rate	Mt/y	4.18	3.98	4.16	4.27
Water extraction		No	No	No	No
Reservoir boundaries		Closed	Closed	Closed	closed
CO_2 injection rate	Mt/y	4.18	3.98	4.16	4.27
Water extraction		Yes	Yes	Yes	Yes
Water extraction rate	Mt/y	7.11	6.77	7.07	7.26

Water management along the CCS chain

In contrast to the Dutch scenario in Phase 1 where the direct disposal of storage-extracted water was also considered as an option, in this Phase 2 of the study only the treatment and beneficial reuse of the extracted brine is considered. This is due to three reasons: i.) the regions are already water-stressed, having a demand for unconventional sources of water; ii.) the salinities of the extracted brines are significantly lower than in the Dutch scenario and lower than those of seawater (see Table 5), making treatment and reuse a much more attractive option; iii.) three of the four countries examined have ZLD regulations for power stations in place, making the requirement to treat storage-extracted brines to ZLD likely into the future.

The power plants in South Africa, China, and India operate with ZLD with a wastewater recovery rate of 90%. Thus, 90% of the process water discharge in Table 5 may be recovered applying a membrane brine concentration (MBC) system and a crystalliser as the final step in the chain.

With regards to the storage-extracted brine, treatment to ZLD is applied in South Africa, China and India, to be in line with the ZLD regulations for the power stations in these countries. The water treatment includes pre-treatment, reverse osmosis (RO), followed by mechanical vapour compression (MVC), and a forced circulation crystalliser (FCC). In this manner, depending on the initial salinity of the brine, product recoveries between 93% -98.5% may be achieved (see Table 5).

In the Australian case, where there is no ZLD requirement, the water treatment technology applied for the storage-extracted brine is a combination of forward osmosis and reverse osmosis (FO-RO) with an estimated product recovery of 85% (see Table 5).

The concentrated reject is disposed and concentrated further via evaporation ponds (see Table 5) with final disposal of the remaining salt in landfill or alternatively it may be supplied to chemical industries to derive additional value.

For all cases the product water is high quality ultrapure water with typically less than 100 mg/l TDS, which is suitable for various beneficial uses, including use in power stations and other industrial applications.

Due to the high recovery rates of the treatment processes, the total amount of water that may be recovered along the CCS chain, including ZLD at the power station and storage-extracted water treatment, exceeds the demand of the power stations with capture in all four locations. Thus, in addition to supplying the power station, product water is available for beneficial uses. The surplus water is 1.3 Mt/y in Australia, 1.6 Mt/y in India, 3.1 Mt/y in South Africa, up to almost 4.5 Mt/y in China. The water balance is presented in Table 5.

Table 5 Water balance of the CCS-Water-Nexus Scenario for the USCPC power plants in the four locations of interest

	USCPC with capture plant using state of the art absorption			
Country	**South Africa**	**Australia**	**China**	**India**
Power station with capture				
Power station	USCPC	USCPC	USCPC	USCPC
Cooling technology power station	Air	Air	Air	Evaporative
Cooling technology capture plant	Evaporative	Evaporative	Evaporative	Evaporative
Water consumption (total), Mt/y	4.77	4.43	3.39	7.59
Water consumption (capture only), Mt/y	4.38	4.03	3.00	3.81
Process water discharge, Mt/y	1.46	1.34	1.00	2.37
ZLD at power station	Yes	No	Yes	Yes
ZLD technology	MBC	-	MBC	MBC
Water recovery, %	90	-	90	90
Product water, Mt/y	1.31	-	0.9	2.14
Storage				
Storage basin	Zululand Basin	Surat Basin	Songliao Basin	Cambay Basin
Location	Onshore	Onshore	Onshore	Onshore
Estimated average TDS, mg/l	26,000	5,000	5,000	9,000
Water extraction rate, Mt/y	7.11	6.77	7.07	7.26
Treatment to ZLD	Yes	No	Yes	Yes
Technology	RO+MVC+FCC	FO-RO	RO+MVC+FCC	RO+MVC+FCC
Recovery rate, %	92.75	85	98.53	97.33
Product water, Mt/y	6.60	5.75	6.96	7.07
Concentrated brine disposal	Evaporation ponds	Evaporation ponds	Evaporation ponds	Evaporation ponds
Total recovered water CCS chain, Mt/y	7.91	5.75	7.86	9.21
Surplus product water (incl. ZLD from PP), Mt/y	3.14	1.32	4.46	1.61

A range of beneficial reuse options are available for the surplus water and practical examples in some countries have demonstrated their feasibility. For example, in Australia, water co-produced during coal seam gas operations is treated to a specified minimum standard and provided to users via major irrigation schemes. In South Africa, excess water produced at a coal mine is treated and supplied as town water. In India, power stations have to buy treated wastewater if the treatment plant is located within a 50 km radius of the power station. These existing examples reduce economic and regulatory uncertainty, making similar future projects much more likely.

Economic results

Capital cost factors relative to the Netherlands were derived based on IEAGHG (2018) to evaluate the cost for each of the four locations. They are presented in Table 6. The location cost factors are used to determine capital costs of the power plants with and without capture based on the Phase 1 Dutch power plants, and to adapt cost for water treatment in the respective countries.

Table 6 Location capital cost factors of the four countries of interest relative to the Netherlands. Capital cost factors are derived based on power plants without capture

Location	Capital cost factor
The Netherlands	1.00
South Africa (inland)	1.20
Australia	1.22
China (inland)	0.70
India	0.98

The specific capital requirement for the power plants range from 1248 €/kW installed in China and 1746 €/kW for India to 2136 – 2171 €/kW installed for the power plants in South Africa and Australia. In comparison to the cost of building the hypothetical Netherlands plant, building an air-cooled USCPC in China is about 30% cheaper, while building the same plant in Australia and South Africa is about 20% more expensive. The higher costs for the Australian and South African cases arise due to the high costs of building in these countries caused by high labour cost and a low productivity factor (IEAGHG, 2018). In comparison, the lower cost for China arises due to significant material and construction labour cost reductions. Building the USCPC with evaporative cooling in India, the costs are comparable to the reference plant in the Netherlands (~3% difference), though in contrast to the Indian plant, the Dutch plant does not utilise ZLD technology to treat the discharged process water.

The LCOE for the USPC power plants without capture range from 42 €/MWh and 45 €/MWh for China and India (ZLD adds less than 3 €/MWh in the India case), respectively, to about 60 €/MWh in Australia and South Africa (compare Table 7).

Adding CO_2 capture at the power stations, as well as ZLD at the power stations in China, India and South Africa with reuse of the ZLD-recovered product water, the increase in total capital requirement ranges from 25% - 31%, while specific capital requirements (in €/kW installed) increase by 52% - 60%. The LCOE increase by 44% - 55%, ranging from 62 €/MWh for the power plant with capture in China, 70 €/MWh in India, to 90 €/MWh and 91 €/MWh in Australia and South Africa, respectively.

In the CCS Base Case Scenario CO_2 transport and storage costs at an estimated flat rate of 5 €/t CO_2 stored for all locations add about 4.6 €/MWh to the LCOE in comparison to the power station with capture only, corresponding to an increase of 5% – 7%. Similarly, the costs of CO_2

avoided increase by 6 - 7 €/t, or 15% (for South Africa) up to 22% (for China). The LCOE and avoidance cost for the Base Case Scenario are presented in Table 7 and Table 8, respectively.

Table 7 LCOE for coal-fired USCPC power plants with and without CCS in five countries

Cooling technology power plant		Air cooling			Evaporative cooling		
Cooling technology capture plant		**Evaporative cooling**			**Evaporative cooling**		
LCOE		**USCPC-AC**	**USCPC-AC-PCC-EV**		**USCPC-EV**	**USCPC-EV-PCC**	
CCS Scenario		**No CCS**	**Base Case**	**Water-Nexus**	**No CCS**	**Base Case**	**Water-Nexus**
Netherlands*	€/MWh	59	86	94	56	83	90
South Africa	€/MWh	60	96	101	-	-	
Australia	€/MWh	62	94	99	-	-	
China	€/MWh	42	67	70	-	-	
India	€/MWh	-	-		45	74	78

* The LCOE for the Dutch power stations in the CCS Base Case and the CCS-Water-Nexus scenarios vary slightly from Phase 1 due to CO_2 storage and transport cost and water extraction and transport cost now being assumed as a 5 €/t and a 2.5 €/t flat rate, respectively to align with the four other cases

Table 8 Avoidance cost for coal-fired USCPC power plants with and without CCS in five countries

Cooling technology power plant		Air cooling		Evaporative cooling	
Cooling technology capture plant		**Evaporative cooling**		**Evaporative cooling**	
CO_2 avoidance cost		**USCPC-AC-PCC-EV**		**USCPC-EV-PCC**	
CCS Scenario		**Base Case**	**Water-Nexus**	**Base Case**	**Water-Nexus**
Netherlands*	€/t CO_2	41	52	40	51
South Africa	€/t CO_2	51	58		
Australia	€/t CO_2	44	50		
China	€/t CO_2	36	41		
India	€/t CO_2			41	47

* The CO_2 avoidance cost for the Dutch power stations in the CCS Base Case and the CCS-Water-Nexus scenarios vary slightly from Phase 1 due to CO_2 storage and transport cost and water extraction and transport cost now being assumed as a 5 €/t and a 2.5 €/t flat rate, respectively to align with the four other cases

In comparison to the CCS Base Case Scenario, the LCOE for the CCS-Water-Nexus Scenario increase only marginally: by 3 €/MWh in China, 4 €/MWh in India, 5 €/MWh in Australia and South Africa (which all correspond to an increase of about 5%), and 7 €/MWh in the Netherlands (8% increase), see Table 7. This is based on the estimated water extraction and transport flat rate of 2.5 €/t CO_2 stored for all locations in addition to water treatment costs. Due to the assumed flat rate, variations in costs are caused by differences in water treatment costs in the four locations; they vary as a result of different labour, construction and material costs between the countries, as well as the treatment technology applied to the brines of different salinities.

CO_2 avoidance cost for the USCPC power stations range from 36 – 51 €/t CO_2 in the CCS Base Case Scenario and increase to 41 – 58 €/t CO_2 in in the CCS-Water-Nexus Scenario (Table 8). In both scenarios the Chinese case has the lowest avoidance cost, while South Africa has the highest.

The analysis shows that local conditions, such as local labour, construction, material, and fuel cost, as well as environmental conditions, such as ambient temperature, can have a significant effect on the cost of CCS. This is best illustrated by comparing the China and the South Africa case, with the South African LCOE being about 30 €/MWh, or 44%, higher.

The analysis further demonstrates that water extraction and treatment add a comparatively small cost to a CCS project. Therefore, the extracted and treated water may provide a valuable unconventional water resource in regions that are suffering water stress, especially when considering the associated cost of water shortages. In this study, the cost of product water, accounting for brine treatment and disposal costs, were found to be comparable to local water tariffs in the four countries, ranging from 1.12 €/m^3 in China up to 2.43 €/m^3 in South Africa. When water extraction and transport costs are also included product water cost exceed local water supply charges, ranging from 2.61 €/m^3 in China up to 4.02 €/m^3 in South Africa

Major conclusions

Power plant performance and power plant water balance

- For power plants without capture utilising air cooling, the thermal efficiencies range from 39% LHV in Australia to 42% LHV in South Africa and 43% LHV in China. The addition of PCC using evaporative cooling reduces the thermal efficiencies for these air-cooled plants by 8.9% in Australia, 7.6% in South Africa, and 8.1% in China.
- For the power plant in India using evaporative cooling for both the power and the capture plant, the initial thermal efficiency of 43% LHV reduces to 34.8% with PCC.

- The energy consumption for the capture plants using evaporative cooling is relatively similar across all four power plants; with the lowest in Australia at 0.24 MWh/t CO_2 captured and the highest in China and India at 0.27 MWh/t CO_2 captured.
- The normalised water withdrawal and consumption for air-cooled power plants without capture is 0.07 m^3/MWh for the three countries (Australia, China, South Africa). With PCC using evaporative cooling, water withdrawal and consumption increases to 0.92 - 1.34 m^3/MWh and 0.71 - 1.03 m^3/MWh, respectively. The lowest withdrawal and consumption rates are achieved for the Chinese case, where the average air temperatures are extremely low (compare Table 2).
- For the Indian power plant using evaporative cooling water withdrawal and consumptions rates are 0.83 m^3/MWh and 0.64 m^3/MWh, respectively. Implementing capture (using evaporative cooling), this increases to 2.09 m^3/MWh and 1.59 m^3/MWh - well below the regulatory water consumption limit of 2.5 m^3/MWh for new coal-fired power plants in India.
- Treatment of the power plant's wastewater to ZLD is required in South Africa, China, and India. Product water recovery is 90%, applying a membrane brine concentration (MBC) system and a crystalliser. The product water is reused in the power plant to lower its freshwater demand. However, for the air-cooled power plants wastewater discharge is negligible, thus in this case only the wastewater from the capture plant requires treatment.

CO_2 storage and water extraction

- The geological basins identified as suitable for storage in South Africa, Australia, China and India are the Zululand Basin, the Surat Basin, the Songliao Basin, and the Cambay Basin, respectively. They are considered to have the potential to provide the necessary storage capacity (100 Mt over 25 years) as well as long-term containment. However, any storage estimates presented in this report are only approximate initial estimates.
- All identified basins, except the onshore Zululand Basin in South Africa, are hosts to oil and/or gas production. This implies infrastructure to support CO_2 storage development is already in place, likely lowering the barrier for CCS in this region.
- CO_2 injection at a rate of ~4 Mt/y is assumed to be possible in case of open reservoir boundaries, to enable storage of ~100 Mt over 25 years.
- In case of a reservoir with closed boundaries, water extraction at a ratio of H_2O : CO_2 of 1.7 : 1 is assumed to be necessary based on Phase 1 findings, resulting in an annual brine extraction rate of ~7 Mt.
- In Australia, the storage-extracted brine with an estimated TDS of 5,000 mg/l may be treated via a combined forward osmosis – reverse osmosis process at a recovery rate of 85%. Treatment to ZLD is not a requirement.

- To align with requirements at the coal fired power stations in South Africa, China, and India, treatment to ZLD is assumed for the storage-extracted brine in these locations. The process consists of pre-treatment, reverse osmosis, mechanical vapour compression, and a forced circulation crystalliser. Recoveries range from 92.75% (South Africa) up to 98.53% (China), depending on the initial concentration of the brine.
- The concentrated reject is disposed via evaporation ponds with final disposal of the remaining salt in landfill or alternatively it may be supplied to chemical industries to derive additional value.
- The treated water is high quality ultrapure water with typically less than 100 mg/l TDS and is suitable for various beneficial uses, may be used in the power stations and other industrial applications.
- The high recovery rates of the treatment processes for the extracted brines, in addition to the integration of ZLD at the power stations in South Africa, China, and India, result in water recoveries along the CCS chain that exceed the freshwater demands of the power stations with capture. This surplus product water, ranging from 1.3 Mt/y in Australia, 1.6 Mt/y in India, 3.1 Mt/y in South Africa, up to almost 4.5 Mt/y in China, may be provided for beneficial uses.
- A range of beneficial reuse options are available for the surplus water and practical examples in some countries have demonstrated their feasibility. For example, in Australia, water co-produced during coal seam gas operations is treated to a specified minimum standard and provided to users via major irrigation schemes. In South Africa, excess water produced at a coal mine is treated and supplied as town water. In India, power stations have to buy treated wastewater if the treatment plant is located within a 50 km radius of the power station. These existing examples reduce economic and regulatory uncertainty, making similar future projects much more likely.

Economics

- In comparison to the cost of building the hypothetical Netherlands plant, building an air-cooled USCPC in China is about 30% cheaper due to significant material and construction labour cost reductions, while building the same plant in Australia and South Africa is about 20% more expensive as a result of high labour cost and a low productivity factor (IEAGHG, 2018).
- Building the USCPC with evaporative cooling in India, the costs are comparable to the reference plant in the Netherlands (~3% difference), though in contrast to the Indian plant, the Dutch plant does not utilise ZLD technology to treat the discharged process water.
- The LCOE for the USCPC power plants without capture range from 42 €/MWh and 45 €/MWh for China and India (ZLD at the power station adds 2 €/MWh in the India case), respectively, to 60 €/MWh in South Africa and 62 €/MWh in Australia.

- Adding CO_2 capture at the power stations, as well as ZLD at the power stations with capture in China, India and South Africa, the LCOE increase by 44% - 55%. They range from 62 €/MWh in China, 70 €/MWh in India, with the highest cost in Australia and South Africa at 90 €/MWh and 91 €/MWh, respectively.
- ZLD at the power station contributes 5 €/MWh at the Indian and the South African power station with capture, and 3 €/MWh at the Chinese power station with capture.
- In the CCS Base Case Scenario, CO_2 transport and storage cost at an estimated flat rate of 5 €/t CO_2 stored adds about 4.6 €/MWh to the LCOE, bringing the LCOE to 67 €/MWh in China, 74 €/MWh in India, and 94 and 96 €/MWh in Australia and South Africa, respectively. The equivalent Dutch power station has a LCOE of 86 €/MWh.
- In the CCS-Water-Nexus Scenario, adding the flat rate for water extraction and transport of 2.5 €/t CO_2 stored as well as costs associated with water treatment, the LCOE increase only marginally compared to the CCS Base Case Scenario: by 3 €/MWh in China, 4 €/MWh in India, 5 €/MWh in Australia and South Africa (all corresponding to an increase of about 5%), and 7 €/MWh in the Netherlands (8% increase). Water management costs vary as a result of differences in extracted brine salinity, brine treatment technology applied, and labour, construction and material costs between the five countries.
- CO_2 avoidance cost for USCPC range from 36 – 51 €/t CO_2 in the CCS Base Case Scenario and increase to 41 – 58 €/t CO_2 in the CCS-Water-Nexus Scenario, with the Chinese power station having the lowest and the South African power station having the highest avoidance cost.
- Local conditions can have a significant effect on the costs of CCS. This is best illustrated by comparing the equivalent China and South Africa case, with the South African LCOE being about 30 €/MWh or 44% higher.
- Water extraction and treatment add a comparatively small cost to the examined CCS projects (5% increase in LCOE). Therefore, the extracted and treated water may provide a valuable unconventional water resource in regions that are suffering water stress, especially when considering the cost associated with water shortages. In this study, the cost of product water, accounting for brine treatment and disposal costs, were found to be comparable to local water tariffs in the four countries, ranging from 1.12 €/m^3 in China up to 2.43 €/m^3 in South Africa. When water extraction and transport costs are also included product water cost exceed local water supply charges.

Introduction

This study presents a continuation of the first Phase of IEA/CON/18/246 “Understanding the Cost of Reducing Water Usage in Coal and Gas Fired Power Plants with CCS”. Phase 1 evaluated the CCS-Water-Nexus chain for CO_2 storage onshore and offshore in the Netherlands. In this phase of the project, Phase 2, the economics of CCS with and without water extraction for CO_2 storage are investigated for four regions suffering water stress: South Africa (inland), Australia (inland), China (inland), and India (inland) under the consideration of local regulations.

First (Chapter 1), the effect of local conditions on the performance of the power stations with and without post combustion capture in the four regions is assessed. The power plants are coal fired using air cooling in South Africa, Australia, and China, while in India evaporative cooling is used. For all four countries, evaporative cooling is modelled for the capture plant. The cooling technologies deployed at the power plants and the capture plants are based on those presented in IEAGHG (2018). A brief summary of local water regulations affecting wastewater treatment at the power stations is provided.

Suitable CO_2 storage basins identified in the four countries of interest are presented in Chapter 2. The storage basins selected for this study are the Zululand Basin in South Africa, the Surat Basin in Australia, the Songliao Basin in China, and the Cambay Basin in India. All basins are located onshore. No storage modelling is carried out due the lack of storage characterisation work and data availability in some of these places. CO_2 injection volumes are determined by the CO_2 captured from the power stations, assuming all basins are able to accommodate the CO_2 captured over 25 years. Water extraction volumes are estimated based on those determined in Phase 1. The water quality of the potential storage sites is included, to inform selection of a suitable water treatment process for potential reuse.

Chapter 3 provides an overview of the technologies applied for the treatment of storage-extracted brine. Due to the extracted water from the four basins being significantly less saline than in the case of the Netherlands, different technologies may be applied and recovery rates increase notably.

In Chapter 4 the economic methodology and assumptions applied to carry out the economic assessment of the CCS Base Case Scenario without water extraction and the CCS-Water-Nexus Scenario including water extraction and reuse at the power station with capture for the four different locations in introduced. This follows the methodology laid out in Phase 1 and extends it to account for location-specific cost differences based on the data presented in IEAGHG (2018). Based on local regulations, the addition of zero liquid discharge technology at the power stations in South Africa, China, and India is included.

The results of the economic assessment are presented in Chapter 5, which highlights the cost of the power stations with and without capture in the different locations and compares the cost of the CCS Base Case Scenario and the CCS-Water-Nexus Scenario.

Chapter 6 presents the specific challenges faced by the four countries of interest in relation to water stress and suggests beneficial reuse options based on real-life examples. It also includes a comparison of the cost of treated water to local water tariffs.

Findings of this study are summarised in Chapter 7, which also presents recommendations for encouraging water recovery along the CCS chain, and for alternative uses of the storage-extracted water.

1 The effect of location on power station performance

This chapter presents results and assumptions of the power plant modelling for four different locations using different cooling technologies deployed at the power plant and/or capture plant. The four locations of interest are South Africa, Australia, China and India (Table 1-1).

The cooling systems for each of the location were chosen to reflect those selected in the IEAGHG (2018) study; that is air-cooling is used for the power plants in South Africa and China, while evaporative draft cooling is used in the Indian power plant. However, the cooling system chosen for the Australian power plant is air-cooling rather than once-through cooling to reflect local conditions.

Table 1-1 provides an overview of the chosen local cooling systems and the specific conditions assumed for these countries.

Table 1-1 Overview of cases, coal type, ambient conditions, and cooling systems modelled in this study

Case	Location	Feedstock	Ambient conditions	Cooling system	Case names
1	**South Africa (inland)**	Coal - South African bituminous	T: 15°C, H: 60% P: 86.2 kPa	Air cooling, capture plant using EV	USCPC-AC USCPC-AC-PCC-EV
2	**Australia (inland)**	Coal - Eastern Australia bituminous	T: 20°C, H: 65% P: 101 kPa	Air cooling, capture plant using EV	USCPC-AC USCPC-AC-PCC-EV
3	**China (inland)**	Coal - Chinese bituminous	T: 0°C, H: 60% P: 98 kPa	Air cooling, capture plant using EV	USCPC-AC USCPC-AC-PCC-EV
4	**India (inland)**	Coal - F-Grade Indian Coal	T: 25°C, H: 80% P: 101 kPa	Natural draft cooling tower, raw water make-up	USCPC-EV USCPC-EV-PCC

Table 1-2 provides further information on coal properties for the chosen locations. Information on coal properties were taken a previous study commissioned by IEAGHG (IEAGHG, 2018), except for the Australian inland location where a more representative Surat-basin type coal was utilised (AGO,2006).

Table 1-2 Coal properties for the chosen locations

Coal type	South Africa (inland)	Australia (inland)	China (inland)	India (inland)
Moisture (as-received), wt%	6.7	12.4	15.00	5.98
Ash (as-received), wt%	13.7	25.4	9.78	38.63
Carbon (dry ash free), wt%	83.30	76.5	82.38	74.22
Hydrogen (dry ash free), wt%	4.57	6.45	5.08	4.98
Oxygen (dry ash free), wt%	9.37	15.57	10.60	17.86
Nitrogen (dry ash free), wt%	1.99	0.95	1.05	2.20
Sulphur (dry ash free), wt%	0.76	0.53	0.85	0.74
Chlorine (dry ash free), wt%	0.00	0.00	0.00	0.00
HHV (as-received), MJ/kg	26.65	20.41	25.57	16.45
LHV (as-received), MJ/kg	25.67	19.24	24.14	15.68

1.1 Power plant performance assessment

1.1.1 Power plant modelling approach

The cases presented here relate to the ultra-supercritical coal fired (USCPC) power stations that have been modelled in Ebsilon® as outlined in Chapter 2 of Phase 1 of this report. For this study, the same steam cycle is used for the additional cases based in South Africa, Australia, China and India. However, the coal properties and cooling systems that have been considered are different from the initial Ebsilon modelling. In three cases (South Africa, Australia, China) the power station is air-cooled, but the capture plant uses an evaporative cooling system with the option of taking in water sourced from storage-extracted water. The fourth case is a power station in India that uses evaporative cooling for both power plant and capture plant with the option of taking in water sourced from storage-extracted water. The nominal gross output of the USCPC power plant is 900 MWe with evaporative cooling and 880 MWe with air cooling.

It is assumed that the power plant with post-combustion capture (PCC) is based on 90% CO_2 capture, resulting in a CO_2 capture rate of approximately 4 Mt/y. The power plants with capture were not modelled individually using the actual flue gas, but the energy and cooling requirement were scaled from the previous results determined with an aqueous solution of 40wt% piperazine/AMP in a 1:2 molar ratio (Cousins et al., 2019) and the process design that incorporated intercooling and cold rich split as per Chapter 2 of Phase 1.

1.1.2 Power plant performance results

Implementation of PCC at a power station results in additional cooling demands. In Phase 1, the impact of PCC was assessed for power plants with once-through cooling, evaporative cooling and air cooling for a plant located in the Netherlands. The availability of water extracted during CO_2 storage activities could impact beneficially on the cooling demands of the power station with PCC. In this report, the analysis examines the performance of a power plant using air cooling with evaporating water cooling for the capture plant in South Africa, Australia and China. Further, the performance of a power plant in India that uses evaporative cooling for both the power and the capture plant is investigated. The technical performance for the four locations is summarised in Table 1-3. The specific equivalent electricity consumption is obtained by the difference in net power plant output (in MW) for the plants with and with PCC divided by the amount of CO_2 captured (t/h).

For power plants without capture utilising air cooling, the thermal efficiencies range from 39% LHV in Australia to 42% LHV in South Africa and 43% LHV in China, somewhat reflecting the different air temperatures used for cooling in these countries as per Table 1-1 that will affect generation efficiency. The addition of PCC using evaporative cooling reduces the thermal efficiencies for these air-cooled plants by 7.6% for the plant in South Africa, 8.1% for the power plant in China, while the power plant in Australia has a thermal efficiency reduction of

8.9% LHV. The differences between the countries cover not only different atmospheric conditions, but also quite different coal compositions (Table 1-1) and heating values. This makes a comparison complex. The lowest efficiencies were found for the Australian case because of the combined effect of higher cooling temperature and high ash content and moisture in the coal. Although the Indian coal had a higher ash content, the cooling conditions were more favourable because of the evaporative cooling system used. In the case of the Indian power plant where evaporative cooling is used in both the power and capture plants, the initial thermal efficiency is 43% LHV, reducing to 34.8% with PCC.

The specific equivalent electricity consumption for the capture plant using evaporative cooling is relatively similar for all four power plants; with the lowest in Australia at 0.24 MWh/t CO_2 captured to 0.27 MWh/t CO_2 captured for the power plants in China and India.

The CO_2 emissions for the four countries range from 0.79 t/MWh in China to 0.82 t/MWh in Australia. Once capture is implemented, the CO_2 emissions reduce to about 0.1 t/MWh for all countries.

The normalised water withdrawal and consumption for air cooling power plants without capture is 0.07 m^3/MWh for the three countries (Australia, China, South Africa). This consumption is mostly for the make-up water required at the FGD plant. Once PCC is implemented, as the cooling system for the capture plant is based on evaporative cooling, the water withdrawal and consumption increases to 0.92 - 1.34 m^3/MWh and 0.71 - 1.03 m^3/MWh, respectively. The lowest withdrawal and consumption rates were achieved for the Chinese case where the average air temperatures were extremely low (compare Table 1-3). The relative increase for withdrawal and consumption are about 1200% - 1800% and 950% - 1300% respectively. This increase in water for PCC is due to the cooling requirements for the absorption liquid, flue gas, and product CO_2 (though this is limited as CO_2 compression is heat integrated with the power plant).

For the Indian power plant using evaporative cooling technology in both the power and capture plant, the increase in water withdrawal and consumption due to the PCC is about 110%. Without capture, the withdrawal and consumptions rates are 0.83 m^3/MWh and 0.64 m^3/MWh, respectively. Implementing capture, this increases to 2.09 m^3/MWh and 1.59 m^3/MWh (see Table 1-3). This is well below the water consumption limit of 2.5 m^3/MWh imposed by the Indian government for new coal-fired power plants (Srinivasan et al., 2018) and thus meets Indian regulations.

Table 1-3 Technical performance for USCPC power plants (with and without capture) for South Africa, Australia, China and India

Case	South Africa USCPC-AC	South Africa USCPC-AC-PCC-EV	Australia USCPC-AC	Australia USCPC-AC-PCC-EV	China USCPC-AC	China USCPC-AC-PCC-EV	India USCPC-EV	India USCPC-EV-PCC
Fuel input (t/h)	258.9	258.9	343.3	343.3	275.3	275.3	426.6	426.6
Gross power output (MW)	879.3	808.3	879.7	816.7	879.5	800.0	899.7	817.7
Auxiliary power (MW)	110.6	180.0	157.6	223.6	92.2	161.2	106.9	177.8
Net power output (MW)	768.7	628.3	722.2	593.1	787.4	638.8	792.8	639.9
Net plant HHV efficiency (%)	39.94	32.64	37.51	28.99	40.90	33.17	41.17	33.23
Net plant LHV efficiency (%)	41.82	34.18	39.27	30.35	42.82	34.73	43.11	34.79
LHV efficiency loss due to PCC (%-points)		7.64		8.92		8.09		8.32
CO_2 generation (t/h)	624.1	624.1	593.8	593.8	620.1	620.1	637.5	637.5
CO_2 emission (t/h)	624.1	62.4	593.8	59.4	620.1	62	637.5	63.8
CO_2 emission (t/MWh)	0.812	0.099	0.822	0.100	0.788	0.097	0.804	0.100
CO_2 capture (t/h)	0	561.7	0	534.4	0	558.1	0	573.8
Specific equivalent electricity consumption [MWh/t CO_2]		0.250		0.242		0.266		0.266
Energy consumption for absorbent pumps and blowers in PCC (MW)		8.98		8.55		8.93		9.11
Compressor energy (MW)		59.07		56.2		58.7		60.34
Pumps for cooling in PCC (MW)		7.46		7.09		7.41		7.62
Total electrical energy consumption in PCC (MW)		75.51		71.84		75.04		77.07
Water balance								
Water withdrawal (m^3/h)	55.40	839.87	50.72	774.90	53.41	589.30	657.85	1338.12
Process water discharge (m^3/h)	0	195.74	0	180.48	0	133.72	149.86	318.74
Water consumption (m^3/h)	55.40	644.13	50.72	594.42	53.41	455.58	507.99	1019.39
Water withdrawal (m^3/MWh)	0.07	1.34	0.07	1.31	0.068	0.92	0.83	2.09
Water consumption (m^3/MWh)	0.07	1.03	0.07	1.00	0.068	0.71	0.64	1.59
Increase in relative water withdrawal ([m^3/MWh]/[m^3/MWh])		1755%		1760%		1261%		152%
Increase in relative water consumption ([m^3/MWh]/[m^3/MWh])		1323%		1326%		952%		149%

1.2 Local water regulations affecting power stations

A summary of global wastewater regulations was provided in Chapter 1.1.6 in Phase 1 of this report. Below is a brief summary of the regulations as they specifically concern coal-fired power stations.

1.2.1 Water regulations in South Africa

In South Africa power stations require a water use licence for operation. Such licences cover use of ground and surface water and other specified water uses as detailed in the *National Water Act, 1998* (NWA) and will outline discharge limits for relevant pollutants. In addition, the Department of Water and Sanitation typically requires coal-fired power plants to be ZLD as part of their water use licence conditions (van den Berg et al., 2015). For example, the dry-cooled supercritical Medupi power plant in the northwest of the Karoo Basin is a ZLD plant, although its water use licence includes provision for the discharge of up to 62,000 m^3/month of domestic wastewater into the Mokolo River, and the use of up to 730,000 m^3/year of wastewater for irrigation (Eskom, 2009; Savannah Environmental (Pty) Ltd, 2014).

1.2.2 Water regulations in Queensland, Australia

In Queensland, Australia, licences or permits for power plants are issued by the Department of Environment and Heritage Protection, which is responsible for environmental protection in Queensland (*https://www.ehp.qld.gov.au/).* The licenses typically specify discharge limits for water pollutants and their monitoring frequency. For example, discharge limits from a cooling water dam to surface water, in this case for the Tarong North power plant in Queensland, are 17,000 m^3/day and only cooling water can be released (Carpenter, 2018). For the Swanbank B power plant, water released from an ash dam limits suspended solids to 80 mg/l and total dissolved solids to 2,500 mg/l (Carpenter et al., 2018).

The application of ZLD technology is not legislated on a federal level in Australia, though ZLD has been applied to power plants and other industrial processes. In Queensland, ZLD may be applied to treat water co-produced during coal seam gas production as a result of changes in state legislation, though it is not a regulatory requirement.

1.2.3 Water regulations in China

Discharge of wastewater in China is governed by the *Law on Prevention and Control of Water Pollution* (Carpenter, 2018), which defines allowable emissions and the degree of allowable pollution that power plants have to comply with. In addition, discharge from power plants must not cause water quality standards as defined for surface water (GB3808-2002), ground water (GB/T14848- 93), irrigation (GB5084-92) and seawater (GB3097-1997)[1] to be exceed.

Specific to power stations is the *Discharge Standard for Wastewater from Limestone-Gypsum Flue Gas desulphurisation system in fossil fuel power plants*, which sets a limit of 2000 mg/l sulphates in all waste streams from the power station, amongst other pollutants such as mercury, cadmium, and TSS (Carpenter, 2018). Based on the *III. Law on Prevention and Control of Water Pollution* (PRC, 2008) all industrial wastewater must be categorised and treated before being discharged and thermal power stations have to pay for the volumes discharged.

For new coal-fired power plants ZLD systems are mandatory with some existing power stations requiring retrofitting.

1.2.4 Water regulations in India

In India, power plant operators require a consent order for the discharge of wastewater (Carpenter, 2018) that must be renewed periodically. Wastewater standards relating specifically to thermal power plants are defined in Environment (Protection) Rules, 1986, Schedule I, Item 5 (*http://www.lawsindia.com/Industrial%20Law/k57.htm#sSCHEDULE_I*). In 2015 it was mandated for power plants to buy treated wastewater from sewage treatment plants, where the two plants are within a 50 km radius of each other (ERP, 2019).

Regarding water consumption, a specific limit, set by the Ministry of Environment, Forests and Climate Change in the Standards for Water Consumption vide Notification No S.O. 3305(E), applies to all new coal-fired power plants installed after 1 January 2017, with water consumption not allowed to exceed 2.5 m^3/MWh. Furthermore, treatment to ZLD is mandatory. Older power plants using once-through cooling were required to install cooling towers and achieve a maximum water consumption of 3.5 m^3/MWh by the end of 2017 (Srinivasan et al., 2018), with existing cooling tower-based plants having to reduce their consumption to the same target (ERP, 2019).

1.2.5 Zero liquid discharge at power stations

Treatment to zero liquid discharge (ZLD) is a regulatory requirement in South Africa, China, and India for newly installed coal-fired power stations. ZLD is not required for power stations in the Netherlands and is not legislated on a federal level in Australia, though it has been applied to power plants and other industrial processes. An overview in which country ZLD is a requirement to treat power plant wastewater is presented in Table 1-4.

[1] The water quality and discharge standards can be found on the Ministry of Environmental Protection http://english.sepa.gov.cn/Resources/standards/water_environment/

Table 1-4 Overview of ZLD regulations for power stations in the five locations of interest

Location	ZLD regulation for power station
The Netherlands	No
South Africa	Yes
Australia	No
China	Yes
India	Yes

To account for local conditions, in this study we include the cost of ZLD for the power stations with and without capture in South Africa, China, and India, but not in Australia and the Netherlands. However, as the power stations in South Africa and China are air-cooled and their wastewater discharge is negligible (compare Table 1-3), ZLD is only required to treat the discharged water from the power station with capture using evaporative cooling in these locations. The Indian power station is thus the only power station without capture that is equipped with a ZLD system in our study.

2 CO_2 storage in South Africa, Australia, China and India

This chapter outlines potential CO_2 storage basins identified for this study to store the CO_2 captured from the ~900 MW coal-fired power stations in South Africa, Australia, China and India. In South Africa, the Zululand Basin is identified as a high potential storage basin, in Australia the Surat Basin is chosen, for China CO_2 storage in the Songliao Basin is proposed, while in India the Cambay Basin is highlighted as a potential site. All four basins have in common that they are located onshore, thus making the extraction and beneficial reuse of storage-extracted water a more realistic option. Importantly, literature indicates that these basins may have the potential to accommodate the quantities of CO_2 captured over the life of the respective coal-fired power station.

No storage modelling is carried out due the lack of storage characterisation work and limited availability of data in some of these places, such as detailed knowledge of reservoir permeability and porosity and its distribution, or reservoir geometry. CO_2 injection volumes are determined by the CO_2 captured from the power stations, while water extraction volumes are estimated based on those determined in Phase 1 for the Dutch storage scenarios. A water extraction rate of 1.7 parts of water per 1 part of CO_2 injected is assumed to provide brine extraction volumetrically equivalent to the CO_2 injection rate to enable safe CO_2 storage and not exceed fracture pressure.

The water quality of the potential storage sites is included where possible, to inform selection of a suitable water treatment process for potential reuse.

2.1 South Africa

Approximately 90% of South Africa's primary energy is derived from fossil fuels, with most of its electricity being generated from coal (SA DEA, 2010). The attempt to address the associated emissions has prompted evaluations of potential CO_2 storage locations in South Africa. The South African Centre for Carbon Capture and Storage published an Atlas describing the potential for geologic storage of CO_2 in South Africa (Cloete, 2010), investigating saline formations, depleted oil and gas reservoirs, and unmineable coals seams. They concluded that the majority of South Africa's sedimentary basins are metamorphosed and structurally complex. In addition, they have very low primary porosity and only secondary porosity contained in faults and fractures. This leads to a lack of storage capacity and a high level of uncertainty associated with the permeability distribution. Only the Late Mesozoic basins (Orange, Outeniqua, and Durbun/Zululand basins) are considered to have notable potential for storage (Figure 2-1). These basins are relatively young, unmetamorphosed and geologically quite well understood. The Late Paleozoic Karoo Basin has also been considered for CO_2 storage, though the low permeability obtained from borehole data is expected to present a challenge for CO_2 injectivity (Cloete, 2010; Viljoen et al., 2010).

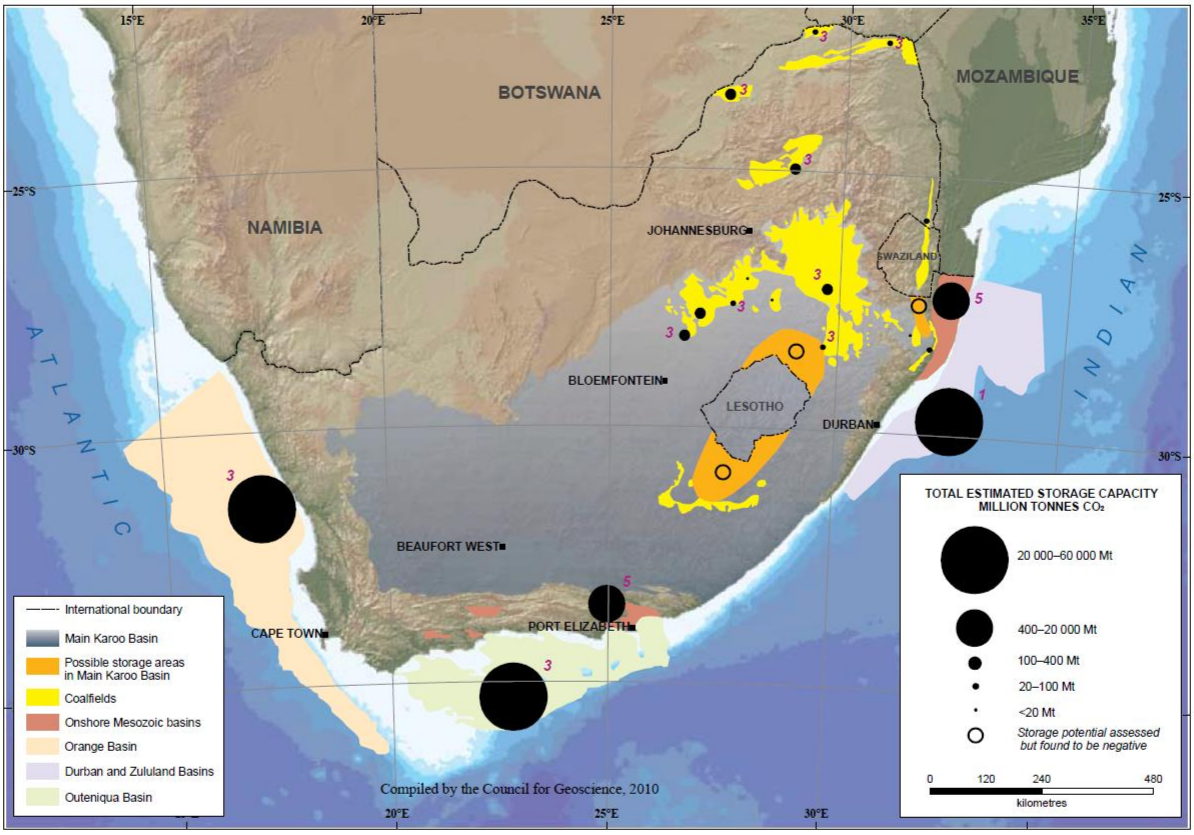

Figure 2-1 Possible deep saline formation storage opportunities onshore and offshore in Mesozoic basins along the coast of South Africa and for the deep coal fields of the Karoo Basin. Storage capacity of the basins and coal fields are indicated by round symbols (black) and data confidence by purple values ranging between 1 = lowest to 9 = highest confidence (from Viljoen et al., 2010)

Significant storage capacity of 148 Gt CO_2 is expected to be present in deep saline formations in the offshore Mesozoic Orange, Outeniqua, Durban and Zululand basins (Cloete, 2010) (Figure 2-1). While the Outeniqua Basin has been earmarked as the offshore basin with the highest potential, its location offshore and the distance to the main CO_2 point sources is considered a challenge in its development for CO_2 storage (Cloete, 2010). Onshore, 500 Mt of CO_2 could potentially be stored in each the Late Mesozoic onshore Zululand Basin and the Algoa Basin (Cloete, 2010) (Figure 2-1).

The storage capacity of deep unmineable coal seams is estimated as 277 – 1,386 Mt based on the methane volume stored. However, this comparatively small storage capacity is dispersed amongst smaller storage basins/areas in the Karoo Basin (Cloete, 2010). The storage potential estimated for depleted oil and gas fields is even smaller at 62 Mt with another 15 Mt available in the future after depletion. The fields are located offshore in the Outeniqua Basin (Cloete, 2010).

A summary of South Africa's CO_2 storage potential is presented in Table 2-1.

Table 2-1 CO_2 storage potential of South Africa's geological basins (Cloete, 2010; Viljoen et al., 2010)

Basin	Aquifer, Gt	Oil and gas fields, Gt	Coalfields, Gt
Offshore			
Outeniqua	48	0.077	
Orange	57		
Durban/Zululand	42		
Onshore			
Zululand	0.46		
Algoa	0.4		
Karoo			0.28 – 1.4

2.1.1 CO_2 storage potential of the Zululand Basin

The number of potential CO_2 onshore storage basins is limited with only three basins having been evaluated as potential candidates in the past: the Karoo Basin, the Zululand Basin, and the Algoa Basin (Cloete, 2010; Chabangu et al., 2014a, 2014b; SLR, 2016). The Karoo Basin is not considered despite its high theoretical storage capacity due to the aforementioned reasons of low permeability and injectivity. The Zululand Basin is selected for this study as it is currently considered for a Pilot CO_2 Storage Project (PCSP) (SLR, 2016). It has been identified as a candidate for CO_2 storage owing to its low seismicity, favourable depth, storage capacity (which is larger than the available CO_2 source), low impacts on other resources, legally accessible areas and no freshwater connectivity (SLR, 2016). The area available for storage is estimated as 200 km^2, though more potential storage areas may exist that have not been identified yet due to a lack of data (Viljoen et al., 2010). On the downside, community acceptance for storage in the Zululand Basin is considered to be low and storage activities may impact on the pristine areas and tribal land. The basin also has no existing infrastructure to support CO_2 storage development (SLR, 2016). The closest power station (Majuba) is located approximately 350 km west of potential storage options in the Zululand Basin.

The onshore Zululand Basin is located to the north of the KwaZulu-Natal Province on the east coast of South Africa near the Mozambique border (Figure 2-1). The basin forms the southern extension of the large oil- and gas-rich Mozambique Basin located to the north (Chabangu et al., 2014a) with sediment thicknesses of up to 2,000 m (Viljoen et al., 2010; SLR 2016). Its areal extent onshore is 7,500 km^2 (Singh and McLachlan, 2003).

The onshore Zululand Basin is structurally compartmentalized into two sub-basins, the northern Kosi Trough (Figure 2-2) and the southern St Lucia Trough, which are separated by the Bumbeni Ridge. Six sandstone packages with varying reservoir properties have been identified in the Zululand Basin, however only two of these are considered to be of interest for CO_2 storage due to depth restrictions (Chabangu et al., 2014a). These are the basal Aptian-aged sandstone identified in the Makatini Formation, and the Cenomanian sandstone, which occurs along the boundary of the Mzinene and St Lucia Formations (Figure 2-2). Both reservoir packages are well developed at the Kosi Trough (Chabangu et al., 2014a).

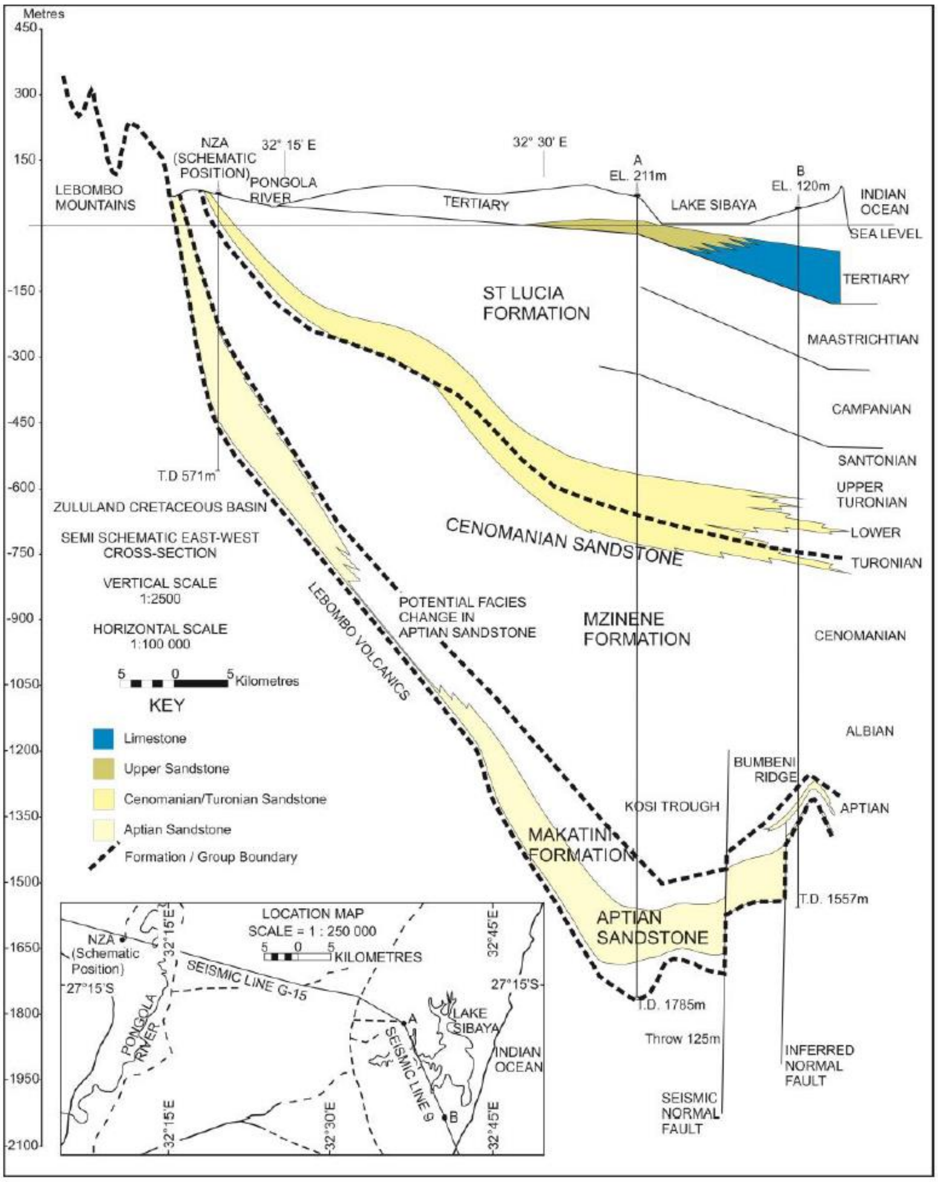

Figure 2-2 Schematic cross-section of the Zululand Basin from west to east (Chabangu et al., 2014a)

The Aptian sandstone occurs at depths of 1,200 – 1,800 m, with a thickness of 100 - 250 m over an areal extent of 1,680 km^2. The sandstone unit thins out across the Bumbeni Ridge to the south. Sandstone porosities range from 4 - 27% (Chabangu et al., 2014a). Permeabilities measured on core samples were found to be very low permeability (< 1 mD) (Viljoen et al., 2010; Chabangu et al., 2014a), though a drill-stem test indicated more permeable sandstone (Viljoen et al., 2010). Assuming a storage efficiency factor of 4%, the CO_2 storage capacity of the Aptian sandstone is estimated to range from 228 – 2,599 Mt (P90 and P10 values, respectively) (Chabangu et al., 2014a).

A caprock is present, but its ability to act as an effective seal has not yet been proven, mainly due to a lack of data (seismic, analysis of caprock and seal samples, pressure tests, etc.) (Viljoen et al., 2010). However, the substantial thickness of the caprock of more than 100 m is a positive factor.

The Cenomanian sandstone is made up of two potential sandstone areas, the Cenomanian sandstone North (CSN) in the Kosi Trough, and Cenomanian sandstone South (CSS) in the St Lucia Trough. The areal extent for the CSN and CSS is 222 km^2 and 130 km^2, respectively (Chabangu et al., 2014a). The Cenomanian sandstone succession comprises a 30 - 35 m thick sandstone unit (Viljoen et al., 2010; Chabangu et al., 2014a), which forms the largest and most continuous reservoir unit in the Zululand Basin. Porosity of the Cenomanian sandstone unit is estimated from cores and sidewall cuttings to be between 15 – 35% with a horizontal permeability of 20.2 - 229 mD and thickness variation of 10 – 150 m (Chabangu et al., 2014a). As this unit occurs between depths of 23 – 1,035 m, its depth was initially deemed to be too shallow for supercritical-state storage. However current analyses suggest that a site for possible continued study occurs in the Kosi Trough where the unit is present below 800 m depth (Chabangu et al., 2014a).

The target sandstone interval is located within a succession of interfingering sandstone and siltstone layers, where the latter are expected to have some sealing potential. However, the hydraulic properties and their distribution are not well constrained and the detailed sealing potential is unknown at this point. The existence of an effective cap rock above the Cenomanian sandstone has not been tested, and if identified would increase the prospectivity of the unit (Chabangu et al., 2014a).

The storage potential assessment of the onshore Zululand Basin undertaken by Viljoen et al. (2010) and Chabangu et al. (2014a) are reliant on very limited available data from oil and gas exploration in the 1960s with no new testing and analyses undertaken. As a result, the uncertainty associated with these estimates is considerable. A summary of key CO_2 storage properties for the Zululand Basin is presented in Table 2-2.

Table 2-2 Summary of data and estimated CO_2 storage capacities for the onshore Zululand Basin (Viljoen et al., 2010, Chabangu et al., 2014a)

Aquifer properties	Onshore Zululand Basin
Age	Mesozoic
Estimated available storage area, km^2	200
Net thickness, m	0 – 220
Estimated CO_2 storage capacity, Mt	466 (228 – 2,599)
Depth to target, m	800 – 1,700
Porosity, %	4 - 41
Permeability, mD	< 1 – 229
Salinity, mg/l	14,000 – 38,000
Geothermal gradient (°C/km)	16.6 – 44.6
Caprock/seal	Present, but effectiveness not yet proven

CO_2 injection and water production rates

In our study, a CO_2 quantity of 4.2 Mt/y is required to be stored in the deep saline formations of the Zululand Basin. In the absence of more specific site characterisation and simulation work pertaining to the Zululand Basin, the injectivity of the formation and the number of CO_2 injection wells required cannot be estimated. Assuming the same volumetric water extraction to CO_2 injection ratio of about 1.7 as in our Netherlands study in Phase 1 to reduce pressure build-up and enable long-term safe CO_2 injection at high rates, brine production is estimated at 7.1 Mt/y.

2.1.2 Water chemistry

Publicly accessible information relating to water chemistry and composition in the Zululand Basin is limited to its shallower formations, not suitable for CO_2 storage. However, it has been stated that the salinity of the groundwater generally increases with depth and varies from about 13,000 – 38,000 mg/l (Gerrard, 1972a; Stojcic, 1979 in Viljoen et al., 2010).

2.2 Australia

In Australia, a considerable amount of research has been carried out to characterise geological basins for their potential to store CO_2 captured from stationary sources. The Carbon Storage Taskforce (2009) has delivered an evaluation of Australia's storage potential, while Bradshaw et al. (2011) presented a CO_2 geological storage atlas for Queensland. Potential CO_2 storage reservoirs in Australia include depleted oil and gas fields as well as saline aquifers and deep, unmineable coal reservoirs.

A map highlighting the varying degrees of suitability of Australia's geological basins for CO_2 storage is presented in Figure 2-3. The majority of Australia's CO_2 storage potential is hosted in saline aquifers. The proven (90% confidence level) CO_2 storage capacity of saline aquifers ranges from 33 Gt to 226 Gt, depending on the storage efficiency factor applied (0.5% for the low range and 4% for the high range). At 50% confidence level, the storage capacity ranges from 50 Gt (at 0.5% storage efficiency) to more than 400 Gt (at 4% storage efficiency) (Carbon Storage Taskforce, 2009).

The CO_2 storage capacity of Australian oil and gas fields is also significant at 16.5 Gt, with most of this capacity being located offshore (~15.6 Gt). However, a large fraction of the capacity is in Australia's northwest (13.4 Gt), far from the major emission sources in southwest Western Australia and eastern Australia (Carbon Storage Taskforce, 2009). Fields in the onshore Bowen and Surat basins in Queensland are expected to be able to accommodate local small volume CO_2 sources, while the offshore Gippsland Basin in Victoria is perceived to have the potential to hold significant volumes of CO_2 (Carbon Storage Taskforce, 2009).

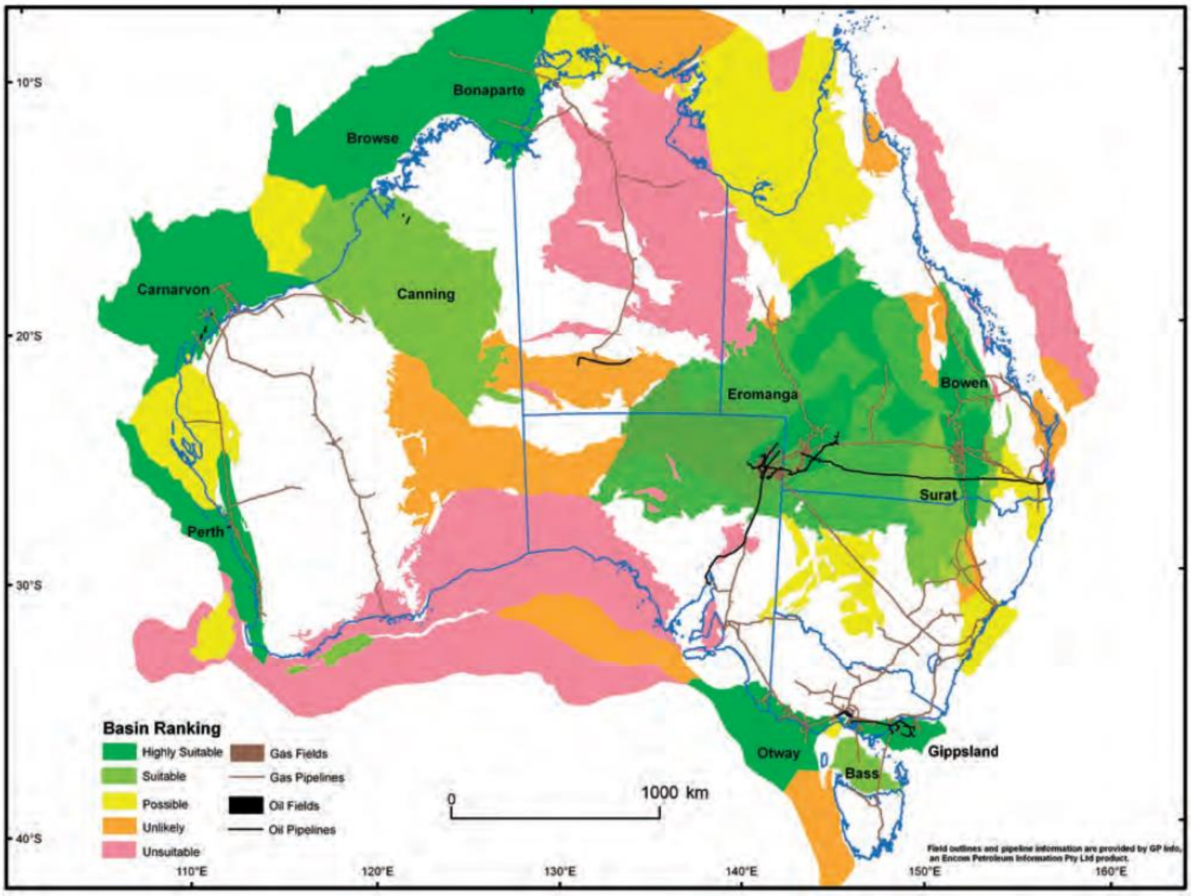

Figure 2-3 The suitability of Australia's geological basins for CO_2 storage (from Carbon Storage Taskforce, 2009)

The Queensland CO_2 geological storage atlas (Bradshaw et al., 2011) assessed 36 onshore Queensland basins for their prospectivity for geological storage of CO_2 with the results presented in Figure 2-4. The Bowen, Cooper, Eromanga, Galilee and Surat basins were classified as highly prospective, indicated in green in Figure 2-4, with a combined storage capacity of 53 Gt. The Surat and the Eromanga basin achieved the highest scores based on the methodology applied. The vast majority of onshore CO_2 storage potential in onshore Queensland is present in saline aquifers, with depleted oil and gas fields expected to provide only limited capacity (Bradshaw et al., 2011).

A summary of the storage estimates presented by the Carbon Storage Taskforce (2009) for Australia, and Bradshaw et al. (2011) for onshore Queensland is presented in Table 2-3.

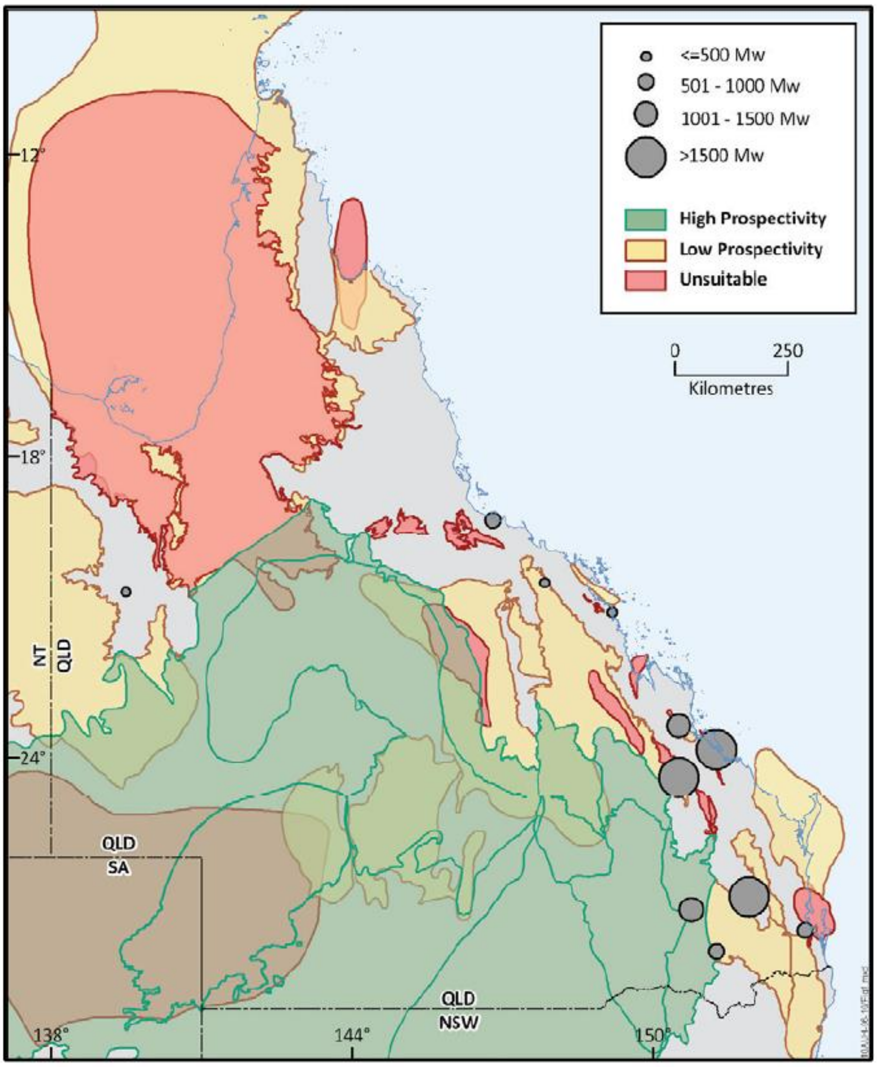

Figure 2-4 Geological storage prospectivity of onshore Queensland basins, including locations of major stationary emissions nodes (Bradshaw et al., 2011)

Table 2-3 CO_2 storage potential onshore and offshore Australia and in the state of Queensland (Carbon Storage Taskforce, 2009; Bradshaw et al., 2011)

Storage option	Australia	Onshore Queensland
Saline aquifer, Gt	33 – 226 (90 confidence level)	53
Depleted oil and gas fields, Gt	16.5	0.4

2.2.1 CO_2 storage potential of the Surat Basin

The Surat Basin has been identified by the Queensland Government as one of the most prospective locations for large, commercial-scale CO_2 storage (Bradhshaw et al., 2011; CTSCo, 2018) with several major stationary CO_2 emission nodes located within 0 – 300 km of potential storage areas (Bradshaw et al., 2011; compare Figure 2-4). Furthermore, existing infrastructure from coal seam gas developments in this basin could support the development of CO_2 storage operations and potentially reduce associated costs. Due to the location of the hypothetical coal-fired power station in inland Queensland, as well as its ranking as a high potential onshore CO_2 storage basin, the Surat Basin is selected as a suitable basin for the Australian case study.

The Surat Basin is a geological north–south trending, asymmetric, intra-cratonic basin that extends across south-east Queensland and into New South Wales. It unconformably overlies the Bowen and Gunnedah basins and covers an area of ~327,000 km^2 in central southern Queensland (Bradshaw et al., 2009). It contains a maximum thickness of approximately 2,500 m of relatively continuous and widespread Jurassic and Cretaceous continental and marine clastic sediments (Allen 1976; Thomas et al. 1982).

The Precipice Sandstone is considered to be the most feasible candidate for CO_2 injection in the Surat Basin and is currently subject of a site investigation for a potential future small-scale CO_2 injection trial of 60,000 t/y of CO_2 over three years (CTSCo, 2018). The stratigraphy of the Surat Basin is shown in Figure 2-5.

The predominantly coarse-grained Precipice Sandstone unconformably overlies an extensively eroded and peneplained surface of Permo-Triassic Bowen Basin sediment and older basement rocks (see Figure 2-5) (Exon, 1976; Martin, 1981). The Precipice Sandstone is a relatively thin unit with good porosity and permeability characteristics. The low fault displacement through the unit suggests horizontal hydraulic communication across the fault plane without compromising the effectiveness of the overlying Evergreen Formation regional seal (see Figure 2-5). Groundwater flow velocities are very low and regional structural dip in the basin is minimal, limiting the effects of buoyancy driven flow The Evergreen Formation seal consists of the Upper Evergreen, Boxvale and Basal members. The Upper Evergreen Formation is the conventional seal for the Precipice Sandstone, while Boxvale and Basal sandstones are of low permeability and will provide pressure dissipation during CO_2 injection.

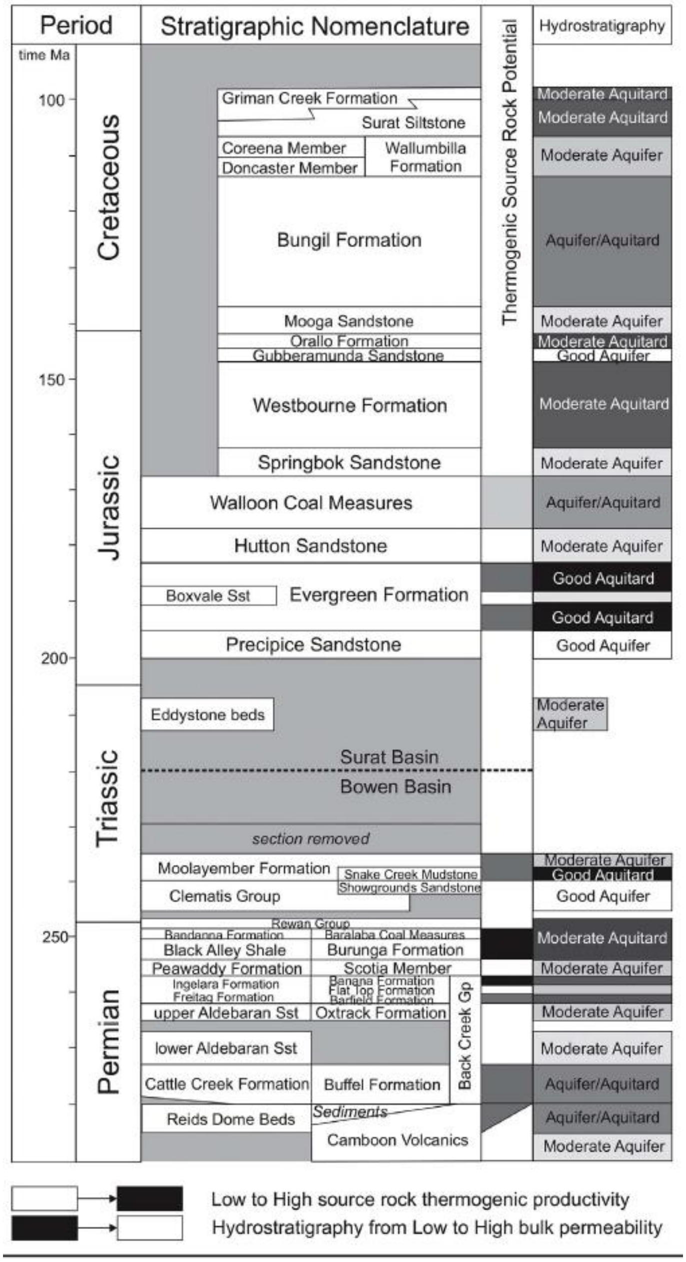

Figure 2-5 Stratigraphy of the Surat Basin and the underlying Bowen Basin with indications of source rock and hydro-stratigraphic significance of aquifers and aquitards (from Underschultz et al. [2018] with modifications from Shaw et al. [2000] and Korsch et al. [1998]).

The Precipice Sandstone shows the greatest potential as a CO_2 geostorage target in the southeast of the Surat Basin. Sealing characteristics of the upper Precipice Sandstone and the Evergreen Formation in this area of the basin are reasonably well constrained at the regional scale and oil accumulations in the Moonie structure support this interpretation.

The Hutton Sandstone is deposited over the Evergreen Formation and contains sandstone inter-bedded with fine grained deposits (Green et al., 1997). The Hutton Sandstone also has favourable reservoir/aquifer properties, but significant uncertainty remains with regards to an effective seal as well as possible negative impacts on shallower aquifers that are exploited for groundwater resources.

The maximum theoretical storage capacity of the Surat Basin is estimated as ~3 Gt (Bradshaw et al., 2011), with most of the capacity being in the Precipice and the Hutton sandstones (Table 2-4). Due to its storage capacity and the regional sealing characteristics of the Evergreen Formation, the Precipice sandstone is selected as the CO_2 storage reservoir for this study. A summary of key CO_2 storage properties for the Precipice sandstone is presented in Table 2-5.

Table 2-4 Parameters for the Precipice, Evergreen/Boxvale, and Hutton sandstones in the Surat Basin relevant for CO_2 storage (from Bradshaw et al., 2011)

Property	Precipice Sandstone	Evergreen/Boxvale sandstones	Hutton Sandstone
Average net thickness (m)	4	8.4	32.7
Average porosity (%)	16.8	15.7	17.6
Median horizontal permeability (mD)	13	7.1	98
Max horizontal permeability (mD)	1,519	7,380	13,600
Storage area (km^2)	39,491	7,300	12,748
CO_2 storage capacity (Mt)	1,298	454	1,198

Table 2-5 Key properties of the Precipice Sandstone of the Surat Basin for CO_2 storage (data from Hodgkinson et al., 2010; Bradshaw et al., 2011; CTSCo, 2018)

Aquifer property	Precipice Sandstone
Age	Jurassic
Surat Basin area, km^2	327,000
Storage area, km^2	39,491
Theoretical CO_2 storage capacity, Mt	2,950
Depth for storage, m	≥ 1200
Average porosity, %	17
Median permeability, mD	13
Maximum permeability, mD	1,500
Total dissolved solids, mg/l	500 – 15,000
Geothermal gradient, °C	28
Regional caprock/seal	Evergreen Formation

CO_2 injection and water production rates

In this study, a CO_2 quantity of 4.0 Mt/y is expected to be stored in the Precipice Sandstone of the Surat Basin. Assuming the same water extraction to CO_2 injection ratio of about 1.7 as in the Phase 1 Netherlands study, brine production is estimated at 6.8 Mt/y.

2.2.2 Water chemistry of the Precipice aquifer, Surat Basin

A notable characteristic of the Surat Basin groundwater is that the salinity is low, even in the deepest areas of the basin (Hodgkinson et al., 2010). There are small 'compartments' within the aquifers that show localised, high salinity groundwater spikes. Hydrochemical evolution is the reverse of that seen in many deep aquifers, which typically exhibit a shift from fresh Na-HCO_3 compositions to more saline Na-Cl character. The salinity in the Hutton and Precipice aquifers in the north-eastern corner of the Surat Basin varies from less than 500 mg/l to up to a maximum of 15,000 mg/l, though it is largely less than 5000 mg/l.

The chemical composition of the Precipice aquifer is summarised in Table 2-6, while the alkalinity as a function of aquifer depth is indicated in Figure 2-6.

Table 2-6 Chemical composition of the Precipice Sandstone based on 248 samples (Hodgkinson et al., 2010)

	Na	K	Ca	Mg	Fe	Mn	HCO_3	CO_3	Cl	SO_4
Mean	88.5	2.2	12.4	4.7	0.16	0.02	149.2	9.6	64.6	9.3
Median	44.3	1.9	2.5	0.6	0.00	0.00	106.8	0.1	14.0	0.0
Mode	31	0.0	2.0	0.3	0.00	0.00	105.0	0.0	012.0	0.0
St Dev	190.1	3.1	34.3	21.6	0.79	0.06	243.1	31.2	238.8	58.6
Min	2	0.0	0.0	0.0	0.00	0.00	0.0	0.0	5.0	0.0
Max	1590	30	290	275.5	8.7	0.47	3103.1	203.3	2189.7	753.9

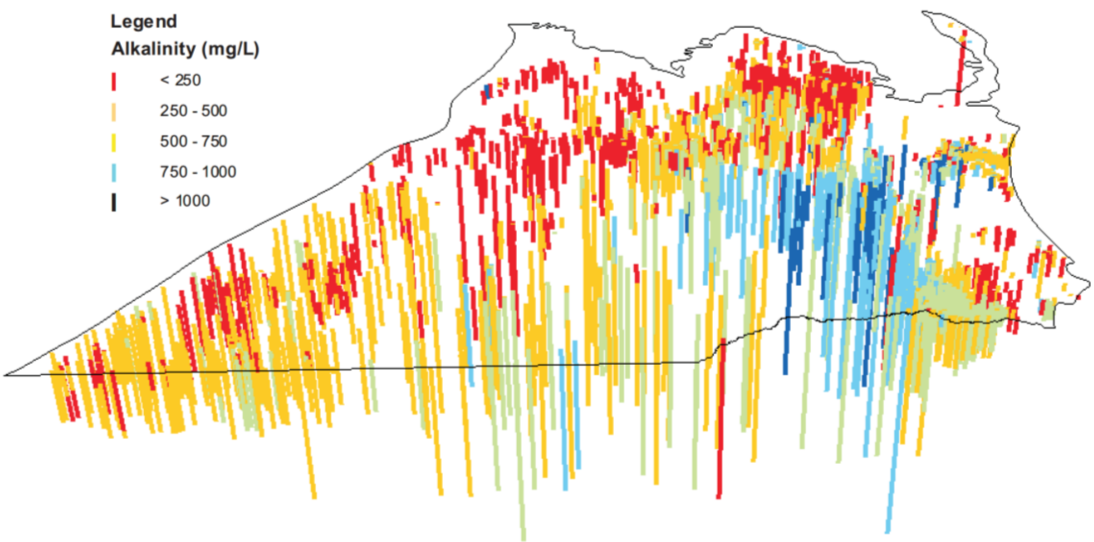

Figure 2-6 Groundwater alkalinity in relation to the depth of the aquifer in the Surat Basin (Hodgkinson et al., 2010)

2.3 China

Carbon capture and storage may be an important option for reducing greenhouse gas emissions in China, particularly due to the considerable and rapidly growing CO_2 emissions caused by the large population and dependence on fossil fuels. As shown in Figure 2-6, China has a significant number of large emission sources, particularly in the eastern part of the country where the main population centres are located. The vast majority of China's CO_2 emissions are due to power generation, predominantly from coal-fired power stations (Gallo and Lecomte, 2011).

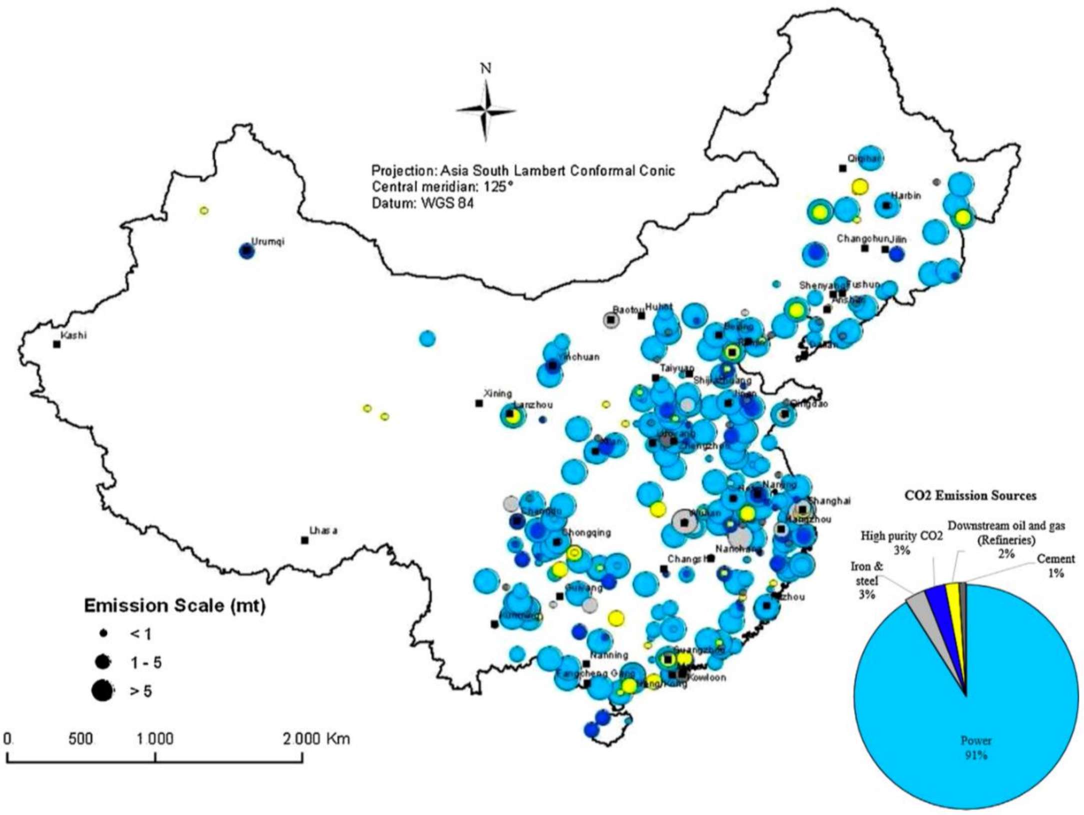

Table 2-7 Annual emissions sources in China (from Gallo and Lecomte, 2011)

Estimates of the potential underground CO_2 storage capacity in China can vary greatly depending on the assumptions used in the calculations and the methodology chosen. Several studies have attempted to characterise the underground storage capacity in China in existing gas and oil fields (once depleted), deep saline aquifers and unmineable coal seams (Dahowski et al., 2009; Li et al., 2009; Vincent et al., 2009; , Wu et al., 2009; Jiao et al., 2011; Poulsen et al., 2011; Vincent et al., 2011; Zhang et al., 2011; Zhou et al., 2011; Qiao et al., 2012; Tang et al., 2014; Jafari et al., 2017; Sun et al., 2018), see Table 2-8. The locations of these storage options are shown in Figure 2-7.

Despite the range of estimated storage capacity, it is clear that China has the underground resources to potentially store significant quantities of CO_2, with estimated storage capacity greater than 100 years of emissions at the current rate (Sun et al, 2018).

Table 2-8: Estimated underground CO_2 storage capacity in China (Dahowski et al., 2009; Tang et al., 2014; Jafari et al., 2017; Sun et al., 2018)

Storage option	Number of sites	Total storage potential (Gt)
Gas field	32	5.2 - 30.5
Oil field	46	4.6 – 4.8
Saline aquifer	24	143.5 – 3,100
Coal seam	68	11.9 - 142.7

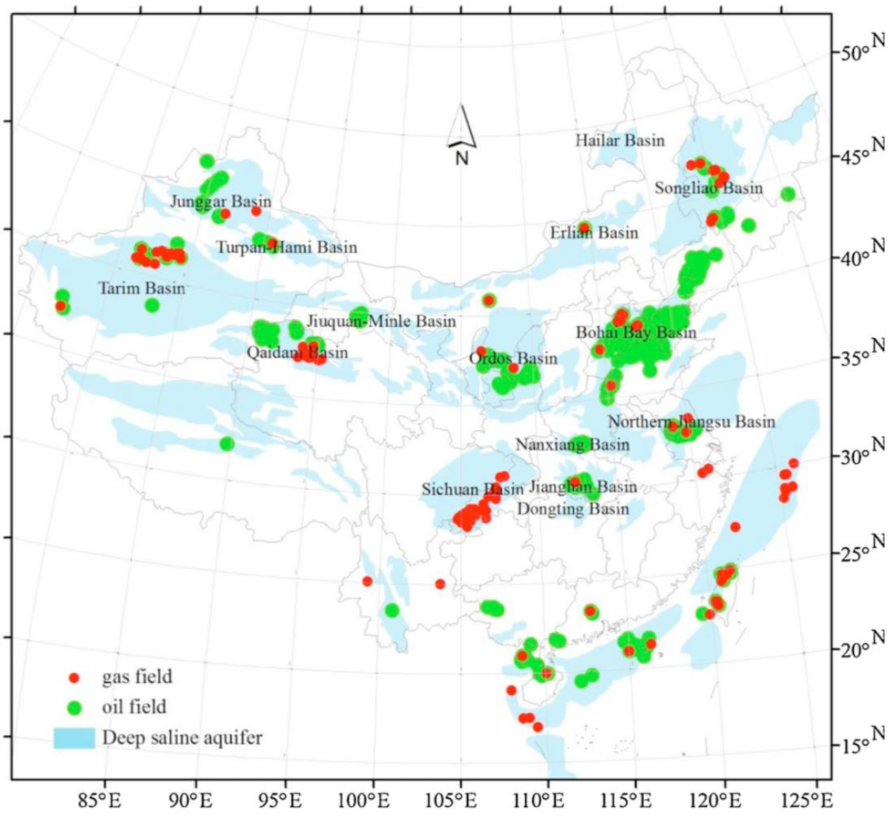

Figure 2-7 Oil, gas and deep saline aquifer locations in China (from Wei et al., 2013)

2.3.1 CO_2 storage potential of the Songliao Basin

The evaluation framework presented by Wei et al. (2013) is followed to select a suitable geological basin for storing CO_2 for this study. Wei et al. (2013) produced maps ranking deep saline aquifers in terms of suitability for large-scale CO_2 storage and assigned priority to each aquifer, see Figure 2-8 and Figure 2-9, respectively.

As most of the emission sources are clustered on the eastern side of China (see Figure 2-6), priority is typically aligned with proximity to emission sources, see Figure 2-9. Despite the large saline aquifers in the west of China (Tarim Basin, Zhunggar Basin and Qaidam Basin) having geological characteristics and capacities that make them amongst the most suitable potential storage sites in China (see Figure 2-8), their distance from the main emission sources lowers their development priority in comparison to some of the less suitable aquifers, see Figure 2-9.

Based on these considerations, the Songliao Basin in the north-east of China has been identified as a suitable aquifer for this study, with a high ranking in terms of potential storage capacity, proximity to large emission sources and prescribed development priority. Its theoretical storage capacity has been estimated as 120 Gt (Sun et al., 2018). In addition, the Songliao Basin is host to several producing oil and gas fields, amongst them the Daqing oil field. The Daqing oil field is one of China's oldest and most prolific fields, constituting 19% of China's overall crude oil production (EIA, 2016). This means infrastructure that can support CO_2 storage development is in place in this region, lowering the barrier for the implementation of CCS.

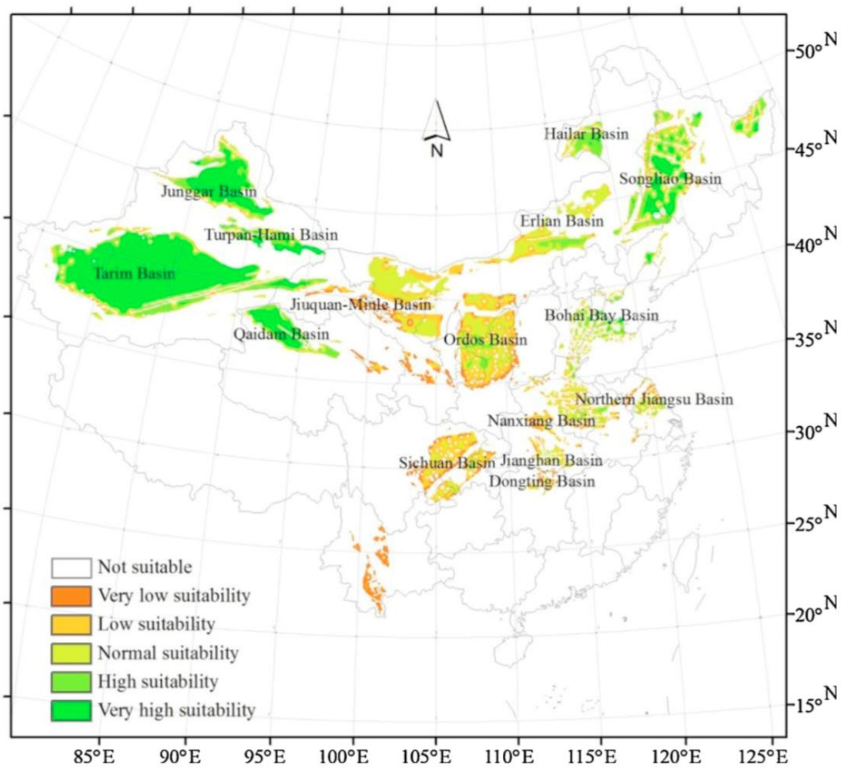

Figure 2-8 Suitability of saline aquifers for CO_2 storage in China (from Wei et al., 2013)

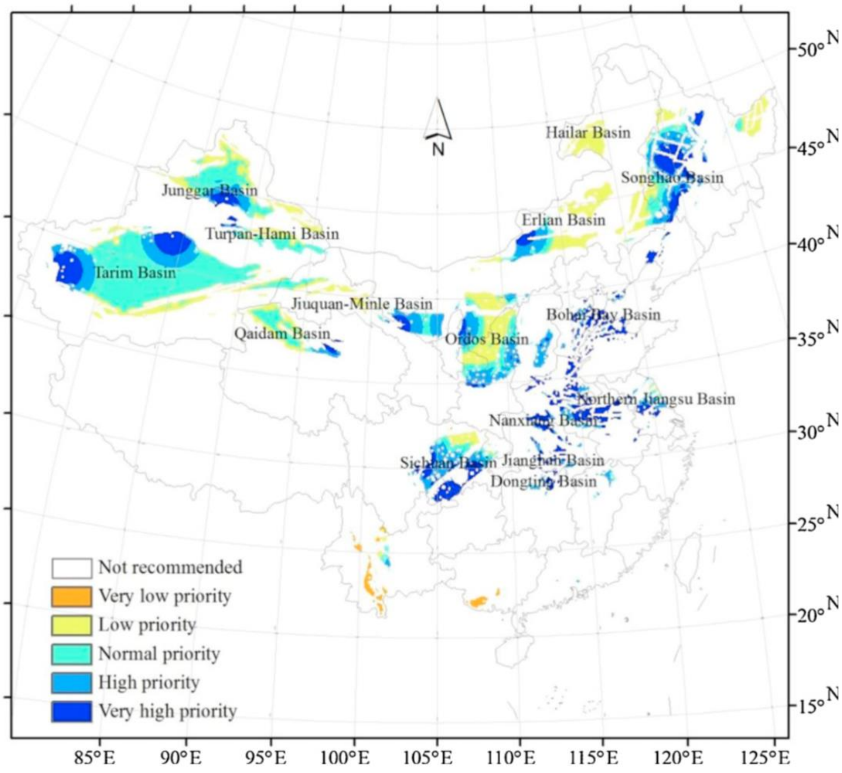

Figure 2-9 Priority assigned to saline aquifers for CO_2 storage in China (from Wei et al., 2013)

The Songliao Basin is a large (area of 260,000 km^2) Mesozoic-Cenozoic intracratonic sedimentary onshore basin developed as the result of continental rifting during the late Jurassic. A stratigraphy typical of the Songliao Basin is presented in Figure 2-10 (Su et al., 2013).

The saline aquifers in the Songliao Basin that are suitable for large-scale storage of CO_2 are located mainly in the Cretaceous formations of the Songliao Basin, see Figure 2-10. The six potential reservoirs are (Su et al, 2013):

1) The shallowest aquifer with CO_2 storage potential is the third and fourth members of the Nenjiang Formation (see Figure 2-10). This reservoir is typically at depths of 800 – 1,000 m, has average porosity of 20%, permeability of 200 mD, and formation water TDS of between 4,000 - 6,000 mg/l (Su et al., 2013).

2) The first member of the Nenjiang Formation and the second and third members of the Yaojia Formation. Average depths are 1,000 - 1,200 m, average porosity is 20%, average permeability 285 mD, and formation water TDS between 4,000 - 6,000 mg/l (Su et al., 2013).

3) The first member of the Yaojia Formation. Depth is approximately 1,200 - 1,500 m. Average porosity is 18%, average permeabilty is 150 mD, and formation water TDS ranges between 6,000 - 9,000 mg/l (Su et al., 2013).

4) The second and third members of the Qingshankou Formation. Depth ranges from 1,500 - 2,000 m. Average porosity in this reservoir is 19%, average permeability is 200 mD, and formation water TDS ranges from 3,500 - 7,300 mg/l (Su et al, 2013).

5) The fifth potential reservoir is the fourth member of the Quantou Formation, with depth ranging from 1,800 - 2,500 m. Average porosity is 14%, average permeability is 30 mD. Formation groundwater TDS ranges from 3,000 to 4,000 mg/l (Su et al., 2013).
6) The last potential reservoir is the third member of the Quantou Formation. The depth of this reservoir is between 2,000 - 2,500 m, with average porosity of 12% and average permeability of 10 mD. Formation water TDS ranges from 3,000 - 6,000 mg/l (Su et al., 2013).

Of these potential reservoirs, the first four appear suitable for large-scale injection of CO_2 as they have larger porosities and higher permeabilities. For the purpose of this study, we can assume representative reservoir properties summarized in Table 2-9.

Table 2-9 Representative reservoir and fluid properties in the Songliao Basin (data from Su et al., 2013)

Aquifer and fluid properties	**Songliao Basin**
Age	Lower Cretaceous
Area, km^2	260,000
Theoretical CO_2 storage capacity, Gt	120
Depth, m	1,000 – 2,000
Porosity, %	18 - 20
Permeability, mD	150 - 285
Pressure, MPa	15 MPa
Temperature, C	50
Total dissolved solids, mg/l	3,500 – 9,000
Geothermal gradient, °C/km	29 - 51
Regional caprock/seal	Sifangtai and Mingshui formations
CO_2 density, kg m^{-3}	700
Brine density, kg m^{-3}	997

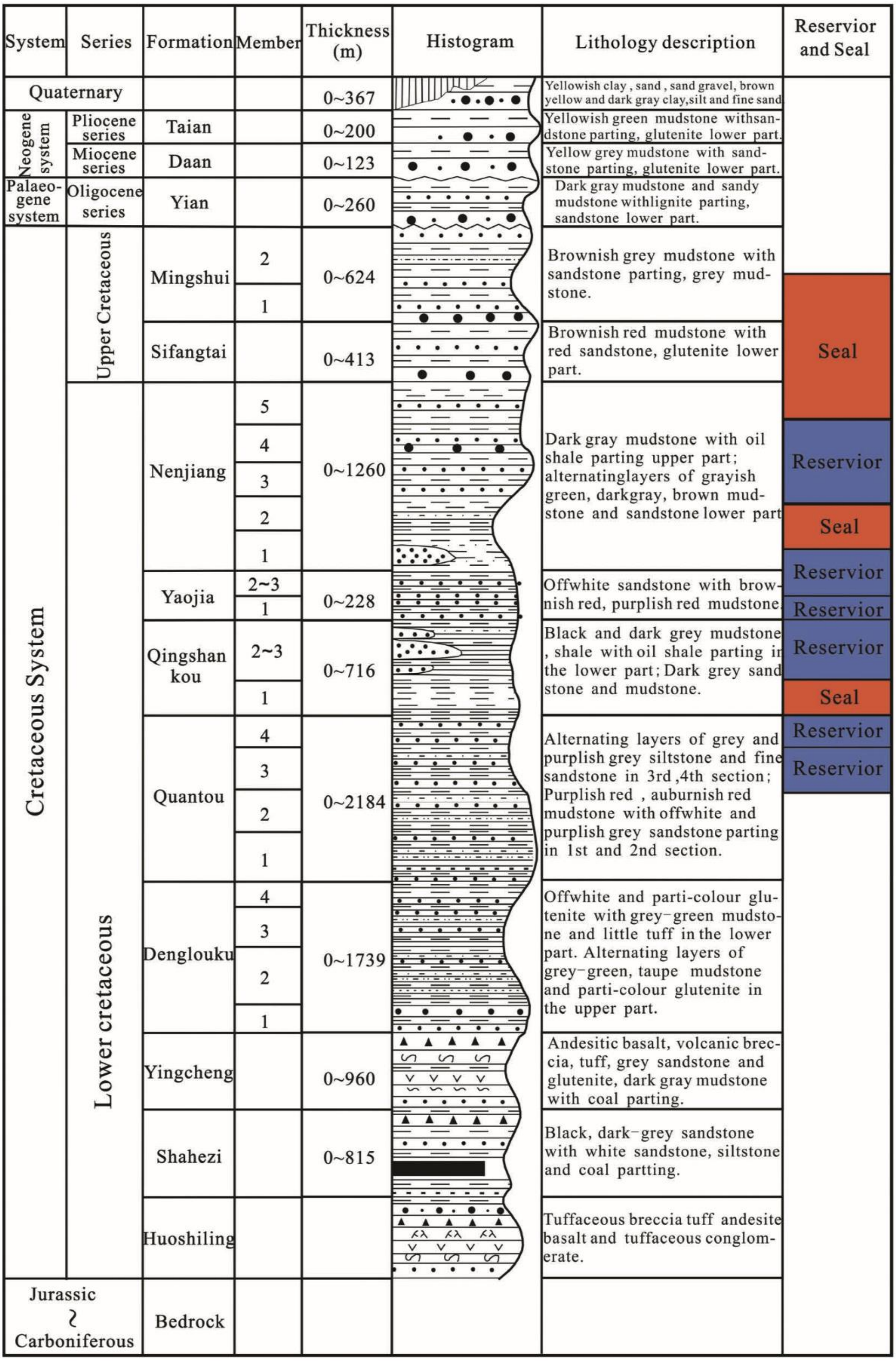

Figure 2-10 Lithological section of the Songliao Basin. Target reservoirs shown in blue; seals in red (from Su et al., 2013)

CO_2 injection and water production rates

Dahowski et al (2009) estimated injectivity of each saline aquifer using representative properties. Using an average permeability of 250 mD in the Songliao Basin (towards the higher end of the range shown in Table 2-9), they estimated that a single well could inject 0.4 Mt/year of CO_2. This estimate is based on benchmarking to the observed injectivity of the Sleipner project, and detailed site-specific calculations are recommended for more accurate injection rates per well. For example, Zhao et al. (2012) considered the pressure build-up in the Songliao Basin during injection of 3 Mt/y in five wells for a total of fifty years. The numerical simulations predict that the pressure build-up didn't exceed 11 MPa in all cases considered and was beneath the limiting fracture pressure gradient.

If we consider an annual injection rate of about 4.2 Mt/y, it is likely that between two and four wells would be sufficient based on the study of Zhao et al. (2012), with total injection rates of between 1 Mt/y and 2 Mt/y per well. Pressure build-up could be expected to be less than the fracture pressure gradient, particularly if brine is produced as part of the project.

Assuming the same water extraction to CO_2 injection ratio of about 1.7 as for the Netherlands study in Phase 1 to reduce pressure build-up and enable long-term safe CO_2 injection at high rates, brine production would need to be approximately 7.1 Mt/y. Assuming that the water production rate per well is similar to the CO_2 injection rate per well, this means that between four and seven water production wells may be required.

2.3.2 Water chemistry in saline aquifers of the Songliao Basin

Hydrogeochemistry of the saline aquifers is an important consideration in a large-scale CO_2 storage project, particularly when active pressure management of the reservoir through water extraction is a component of the project. The Songliao Basin is one of the fresh – microsaline (TDS < 10,000 mg/) lbasins identified in Li et al. (2017; Figure 2-11), with total salinity ranging from 1,000 mg/l TDS to 12,000 mg/l TDS (Zhang et al., 2009; Xie et al., 2013). A plot of TDS in the Songliao Basin aquifers as a function of depth is presented in Figure 2-12 (Xie et al., 2013). For the most part of the Songliao Basin, TDS ranges between 1,500 mg/l to 6,000 mg/l, with some higher values (up to 12,000 mg/l) observed at depths of approximately 2,500 m (see Figure 2-12).

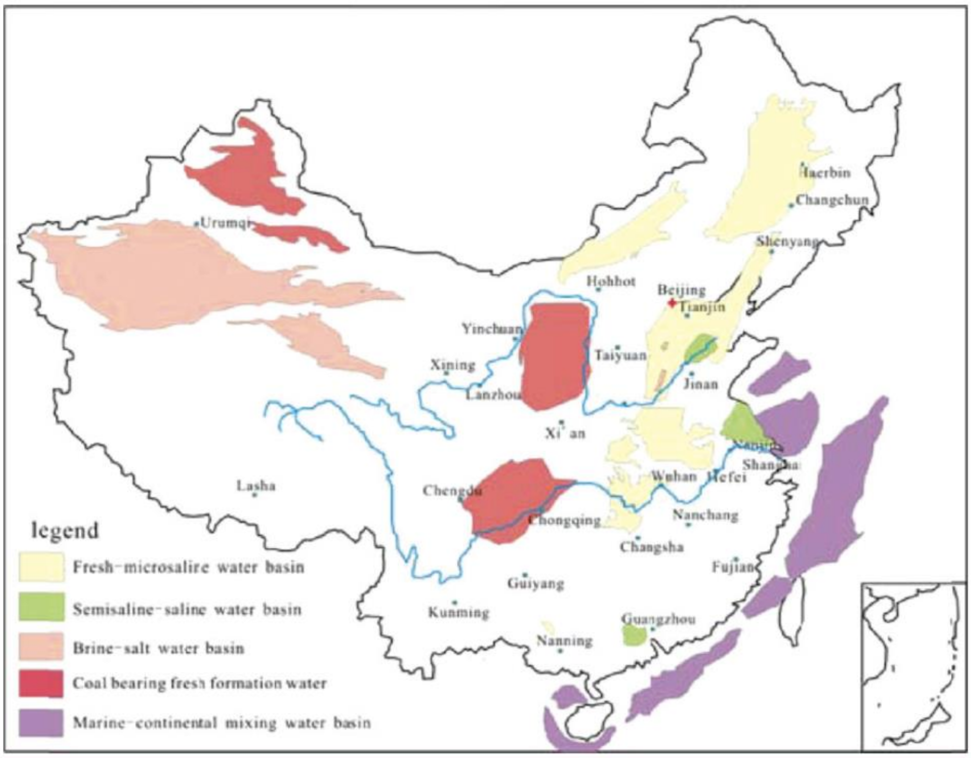

Figure 2-11 Saline aquifers in China coloured by water salinity (see Error! Reference source not found. **for descriptions; from Li et al., 2017)**

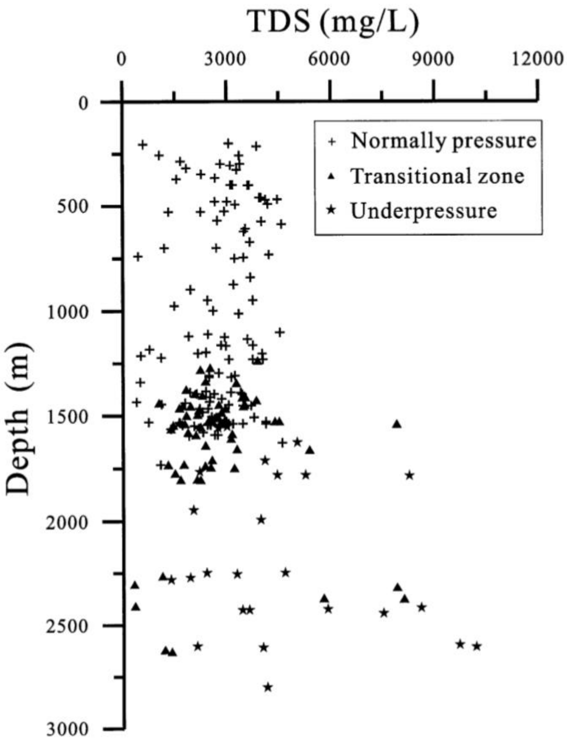

Figure 2-12 Total dissolved solids versus depth in the Songliao Basin. From Xie et al (2013).

Detailed water composition information is difficult to find in the literature; however, several studies have noted that the predominant water type in the Songliao Basin is $NaHCO_3$ water, in which Na, Cl and HCO_3 are the dominant ions in the composition of the formation water, with only trace amounts of Mg present (Cheng et al., 2006; Li and Pang, 2017).

Zhang et al. (2009) present results of a simulation study of the long-term role of geochemical reactions in large-scale CO_2 storage in the Songliao Basin. They use a representative water chemistry where NaCl makes up over 95.8% of the TDS, HCO_3 comprises 3.7%, and the remaining 0.5% is made up of Fe, K, Si, Mg and Ca, see Table 2-10.

Table 2-10 Water composition in the Songliao Basin study of Zhang et al. (2009)

Component	Proportion of water
Na	0.454
Cl	0.504
C (mainly HCO_3)	0.037
Fe	1.92e-6
K	3.07e-3
Si	1.45e-3
Mg	3.69e-4
Ca	1.09e-4

2.4 India

While having significant CO_2 emissions, the majority of which is produced by large point sources, there is only very limited information and data available regarding the CO_2 storage potential of India. The most detailed study evaluating India's storage potential, and still most relevant to date, is the assessment presented by Holloway et al. in 2008. However, the assessment is mostly qualitative, classifying geological basins as “good”, “fair”, and “limited” as per Figure 2-13.

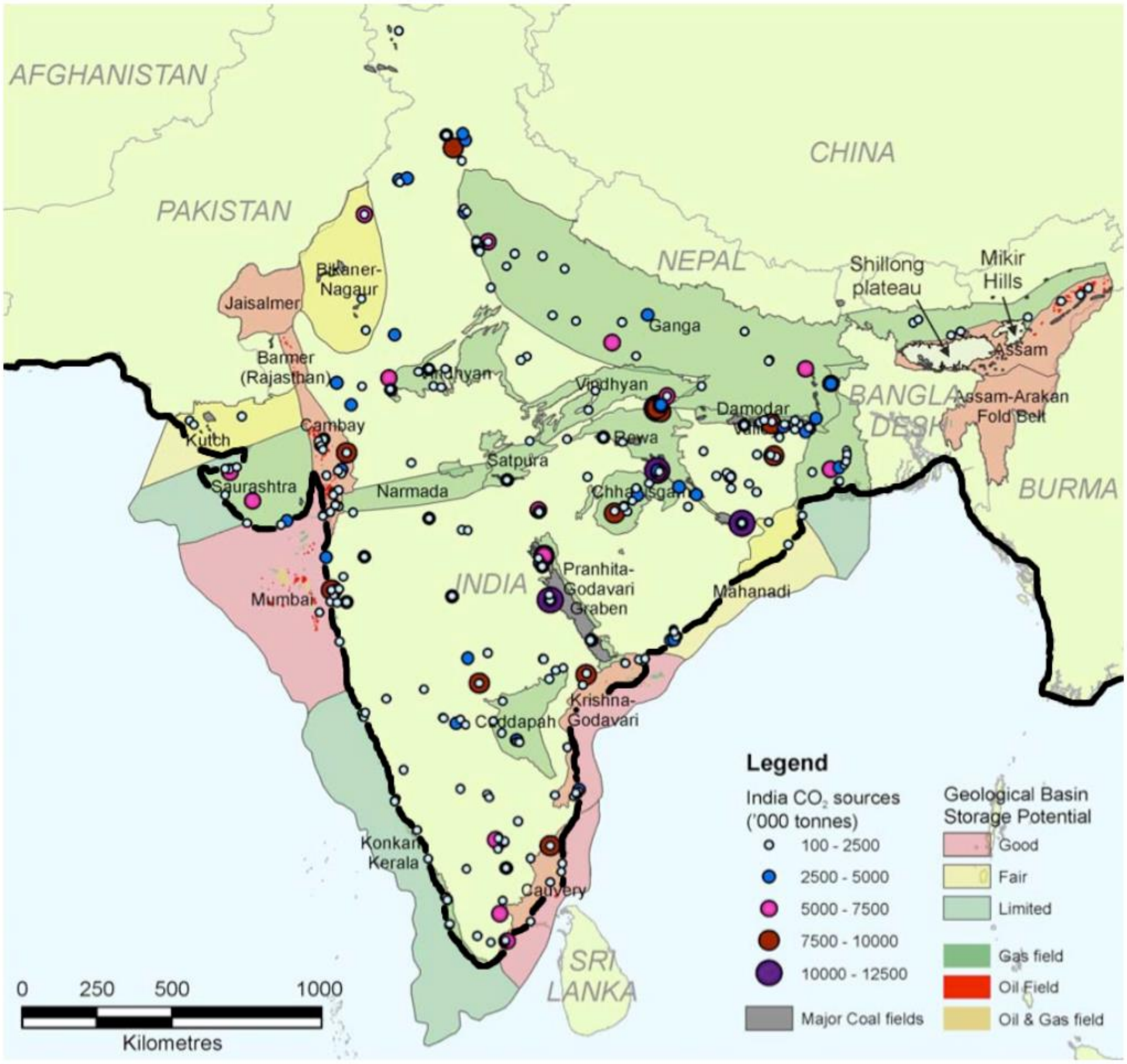

Figure 2-13 Map showing potential geological storage basins classified as good, fair, and limited, as well as the location of major coal fields, and oil and gas fields relative to stationary CO_2 sources (from Holloway et al., 2008 with modifications from Viebahn et al., 2012)

While general assessments of the Indian storage capacity for CO_2 have been presented in literature (Dooley et al., 2005; Singh et al., 2006; Holloway et al., 2008), except for an estimate of the theoretical storage capacity of the basins presented by Holloway et al. (2008), no precise basin scale assessment has been performed. The largest storage potential is expected to be present in deep saline aquifers, located onshore and offshore India. Saline aquifers are located around the margins of the peninsula, often in the offshore basins, but also onshore such as in the states of Gujarat and Rajasthan (Holloway et al., 2009).

Other potential storage reservoirs include oil and gas fields, as well as India's many coal seam gas reservoirs. However, while the Indian coal resources are considerable, a large fraction of it is readily minable and thus unsuitable for storage (Holloway et al., 2009).

India's oil and gas fields are predominantly located around the margins of the peninsula, often offshore, in the Krishna-Godavari Basin, the Cauvery Basin and the

Mumbay/Cambay/Barmer/Jaisalmer Basin area (compare Figure 2-13). While their total estimated storage capacity is large, 3.7 – 4.6 Gt of CO_2 (Holloway et al., 2009), individual fields are typically small and unlikely to hold the lifetime emissions of a medium sized coal-fired power plant (Holloway et al., 2009).

An overview of India's estimated CO_2 storage capacity is presented in Table 2-11, highlighting the significant storage potential of the saline aquifers in comparison to India's oil and gas fields and coal seams.

Table 2-11 CO_2 storage capacity estimates in Gigatonnes presented by different authors as modified and presented by Viebahn et al. (2012)

	Dooley et al., 2005	**Singh et al., 2006, 2008**	**Holloway et al., 2008 with modifications by Viebahn et al., 2012**		
			Good, fair, limited	Good, fair	Good
Oil fields		7		1.0 – 1.1	
Gas fields	2			2.7 – 3.5	
Aquifers	102	360	138	59	43
Coal seams	2	4.5		0.345	
Basalts		200		0 (too uncertain)	
Total	104	572	142	63	47

2.4.1 CO_2 storage potential of the Cambay Basin

Based on the review of potential storage CO_2 storage basins presented by Holloway et al. (2008) and their relative location to major emissions sources, there is potential for source sink matches in the north-west of the Indian peninsula in the Mumbay Basin and the Cambay Basin, as well as along its south-east coast in the Krishna-Godavari and Cauvery Basin (compare Figure 2-13). In this study preference is given to onshore storage basins due to the interest in matching water extracted during storage with potential users onshore. The Cambay Basin in the state of Gujarat in north-west India is identified as suitable for this study. The Cambay Basin has been rated as having "good" CO_2 storage potential in the qualitative assessment presented by Holloway et al. (2009) and is in proximity to major emissions sources. Furthermore, it has existing oil production, thus with the infrastructure already in place the barriers for CO_2 storage development in the Cambay Basin may be lowered.

The Cambay Basin (Figure 2-13) is an intracratonic fault-bounded NNW-SSE trending graben located near the western margin of the Indian craton (Biswas, 1987; Choudhary et al., 1997). It is bounded by the Saurashtra peninsula to the west, the Mumbai Basin to the southwest, the Precambrian Aravalli-Delhi fold belt to the northeast, the Deccan traps of Rajpipla-Navasari-Mumbai to the southeast, and by Deccan trap inliers and the Precambrian Champaner series to the east (Raju & Srinivasan, 1993). To the south the basin extends onto the continental shelf through the Gulf of

Cambay (Raju & Srinivasan, 1993), while the northern end of Cambay Graben extends north of Gujarat State into Rajasthan, where it is known as the Barmer Basin.

The Cambay Basin can be subdivided into five tectonic blocks, which are presented in Figure 2-14: Sanchor-Patan (Block 1), Mehsana-Ahmedabad (Block 2), Tarapur-Cambay (Block 3), Jambusar-Broach (Block 4), and Narmada-Tapti (Block 5).

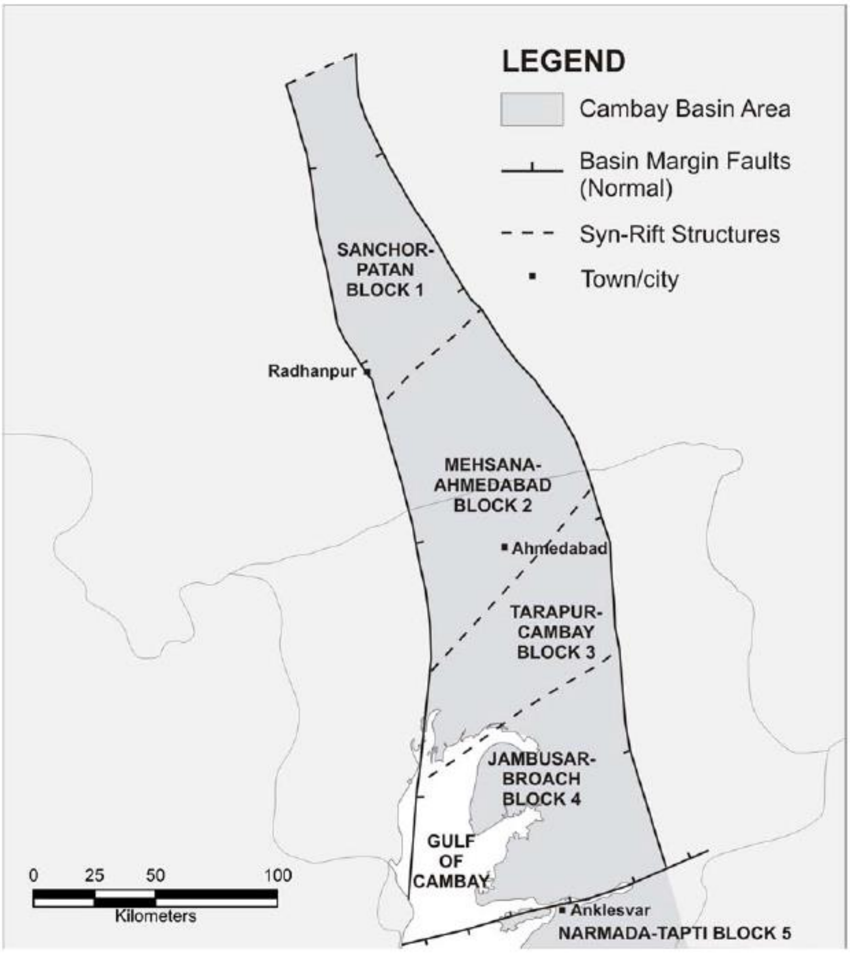

Figure 2-14 Division of the Cambay Basin into five tectonic blocks

The stratigraphy of the Cambay Basin is presented in Figure 2-15. With respect to storage potential the main reservoir rocks are of Middle-Upper Eocence age (Holloway et al., 2007). The Kalol Formation (potential reservoir rock) on the Ahmedabad-Mehsana block and the Anklesvar Formation on the Jambusar-Broach and Narmada-Tapti blocks were deposited during the Middle Eocene, while the Cambay-Tarapur block has only poor Middle Eocene reservoir potential (Raju and Srinivasan, 1993). The Kalol Formation, a potential reservoir rock, overlies the Cambay Shale and the Kadi Formation in the northern part of the Cambay Basin. In the southern part the Cambay Shale is overlain by the Anklesvar Formation. The Tarapur Shale Formation in the northern Cambay Basin and its equivalent in the southern Cambay Basin, the Dadhar Formation, were deposited in the Late Eocence to Oligocene across the whole Cambay Basin and represent a regional caprock (Raju and Srinivasan, 1993).

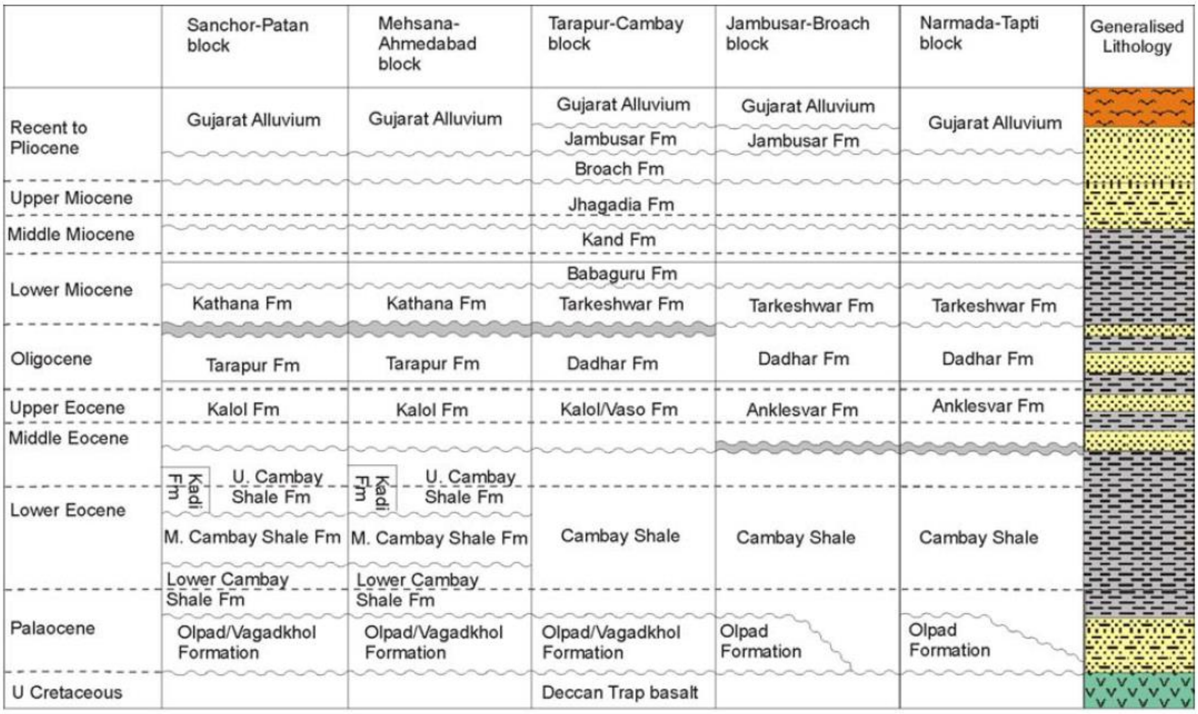

Figure 2-15 Stratigraphy of the Cambay Basin (presented in Holloway et al. [2007], adapted from Raju and Srinivasan [1993] and Wani et al. [1995])

The interest in the Cambay Basin as a potential storage reservoir for CO_2 stems from its history as an oil and gas producer. The basin has been explored since the 1950s, hosting more than 75 oil and gas fields (Das et al., 2006), with the Mehsana-Ahmedabad Block (see Figure 2-14) hosting the largest fraction of the fields. 90% of the confirmed oil and gas reserves are trapped in the Middle Eocene reservoir rocks (Holloway et al., 2007) with the Tarapur Shale Formation and the Dadhar Formation forming a regional seal (Raju & Srinivasan, 1993).

Porosity of the Middle-Upper Eocene reservoir rocks is typically in the range of 2 – 14% (Hardas et al., 1989; Senapati et al., 1993), while permeability ranges from 0.3 – 163 mD (Senapati et al., 1993; Mandal & Bhattacharya, 1997 in Holloway et al., 2007), though permeabilities of up to 3,000 mD have been reported for the oil producing Kalol Formation in the Mehsana-Ahmedabad Block (Das et al., 2006; Gosh et al., 2006). The geothermal gradient in the oil and gas fields of the Mehsana-Ahmedabad Block is 35 - 40°C/km with an average formation temperature of 90 - 100°C (Vajpayee et al., 2016), implying a reservoir depth of more than 2000 m.

An estimate of the theoretical CO_2 storage capacity of the Cambay Basin was presented in Viebahn et al. (2012) based on work by DGH (2006) and Holloway et al. (2008). Applying a specific storage density of 0.2 Mt of CO_2 per km^2 (Wildenborg et al., 2004) and the assumption that aquifers suitable for storage are present in 50% of the basin, the theoretical storage capacity for the 53,500 km^2 Cambay Basin is 5,350 Mt of CO_2.

A summary of key CO_2 storage properties for the Cambay Basin is presented in Table 2-12. For this study, CO_2 injection is assumed to occur in the Mehsana-Ahmedabad Block (see Figure 2-14) owing to it being the most explored area of the Cambay Basin.

Table 2-12 Key properties for CO_2 storage of the Cambay Basin (data from Hardas et al., 1989; Senapati et al., 1993; Mandal and Bhattacharya, 1997; Rebary et al., 2014)

Aquifer property	Cambay Basin
Age	Middle-Upper Eocene
Cambay Basin area, km^2	53,500
Estimated area suitable for storage, km^2	26,750
Theoretical CO_2 storage capacity, Mt	5,350
Depth, m	>2,000
Porosity, %	2 - 14
Permeability, mD	0.3 – 162.5
Total dissolved solids, mg/l	2,850 – 29,120
Geothermal gradient, °C/km	29.8 - 35
Regional caprock/seal	Tarapur and Dadhar formations

CO_2 injection and water production rates

The lack of CO_2 storage specific characterisation work and precise estimates for India in general and the Cambay Basin specifically, severely limits the ability to make assumptions about injectivity of the formation and the number of CO_2 injection wells required. In our study, a CO_2 quantity of 4.3 Mt/y is required to be stored in the deep saline formations of the Cambay Basin. Assuming the same water extraction to CO_2 injection ratio of about 1.7 as in the Netherlands study in Phase 1 to reduce pressure build-up and enable long-term safe CO_2 injection at high rates, brine production is estimated at 7.3 Mt/y.

2.4.2 Water chemistry of the deep saline aquifers of the Cambay Basin

Brackish to saline conditions are observed in deeper aquifers of the Cambay Basin at depth of 250 m or more, though occasionally they have been found at shallower depths (Gupta and Deshpande, 1999). In the absence of a detailed characterisation of the deep saline aquifers in the Cambay Basin for the purpose of CO_2 storage, water chemistry data from water samples extracted from the oilfields in the area of interest, the Ahmedabad/Mehsana Block, are used to provide an indication of expected salinities and other components present in the extracted brine.

Rebary et al. (2014) investigated water samples from three oilfields in different fields in the Cambay Basin – Ahmedabad, Mehsana, and Ankleshwar to determine the potential for iodine, lithium, and strontium extraction. Thus, only cations in the water were analysed. 45 samples were collected: 17 from Ahmedabad, 12 from Mehsana, and 16 from Ankleshwar. The depth of the sampled wells ranged from 1000 – 5000 m.

For Ahmedabad and Mehsana the pH of the oilfield water was mildly alkaline (7.1 – 8.5), and mildly acidic for Ankleshwar (4.3 – 6.5). Total dissolved solids (TDS) in the different samples varied and ranged from 2,850 – 11,880 ppm in Ahmedabad, 6,140 – 21,300 ppm in Mehsana, to 2,920 – 29,120 ppm in Ankleshwar (Rebary et al., 2014). On average, Ahmedabad had 7,314 ppm of TDS, Mehsana 10,277 ppm, and Ankleshwar 15,433 ppm. The TDS and other components and their quantities found in the 45 water samples are summarised in Table 2-13.

Elements such as iodine, lithium, and strontium, which are of economic value, are present in the co-produced water, but not in concentrations typically considered to enable commercial extraction.

Table 2-13 Average water composition for three blocks in the Cambay Basin and the minimum and maximum values measured for each component in the respective block using data presented by Rebary et al. (2014). Due to the purpose of their study, the investigation of the presence of elements of economic value in the produced water, only cations were investigated

		Ahmedabad			Mehsana			Ankleswhar		
		Average	Min	Max	Average	Min	Max	Average	Min	Max
Total dissolved solids TDS	**ppm**	7,314	2,850	11,880	10,277	6,140	21,300	15,433	2,920	29,120
Sodium Na	**mg/l**	2,536	55	3,845	3,353	127	5,462	4,271	856	8,909
Potassium K	**mg/l**	81	22.33	134.4	177	52.16	370.8	100	12.6	259
Magnesium Mg	**mg/l**	28	5.56	77.52	488	2.06	1673	318	42.96	968.3
Calcium Ca	**mg/l**	61	15.97	227.9	272	110.9	1014	263	53.1	587.6
Barium Ba	**mg/l**	0.94	0.23	1.63	1.73	0.12	4.29	6.87	0.3	35
Boron B	**mg/l**	12.76	3.35	24.51	6.01	0.99	8.55	23.91	1.19	43.38
Aluminium Al	**mg/l**	0.22	0.01	1.7	0.27	0.09	0.87	0.90	0.05	7.55
Iron Fe	**mg/l**	0.40	0.01	3.58	0.77	0.03	5.22	0.71	0	5.76
Zinc Zn	**mg/l**	0.04	0.01	0.36	0.06	0.01	0.4	0.07	0	0.91
Selenium Se	**mg/l**	0.31	0.05	0.84	1.77	0	3.75	0.20	0	0.39
Iodine I	**mg/l**	1.06	0.25	1.89	0.96	0.19	1.79	0.48	0.08	1.1
Lithium Li	**mg/l**	0.20	0.06	0.87	0.63	0.08	1.97	0.63	0.23	2.9
Strontium Sr	**mg/l**	2.66	0.32	7.05	2.16	0.24	7.99	21.93	0.49	73.5

3 Management of CO_2 storage-extracted water

In contrast to the Dutch scenario in Phase 1, where the direct disposal of storage-extracted water was also considered as an option, in this Phase 2 of the study only the treatment and beneficial reuse of the extracted brine is considered. This is due to three reasons: i.) the regions are already water-stressed, having a demand for unconventional sources of water; ii.) the salinities of the extracted brines are significantly lower than in the Dutch scenario and lower than those of seawater (see Table 3-1), making treatment and reuse a much more attractive option; iii.) three of the four countries examined have ZLD regulations for power stations in place, making the requirement to treat storage-extracted brines to ZLD likely into the future. Consequently, all the storage-extracted water is assumed to be treated in this study, rather than just the portion equivalent to the freshwater demand of the power station with capture.

The lower salinities compared to the Dutch brines imply that a more economical treatment technology may be applied, while at the same time achieving higher recovery rates. In contrast to the Dutch scenario, treatment to ZLD is applied in South Africa, China and India to be in line with the ZLD regulations for the power stations in these countries. While at this stage there is no regulatory requirement to treat the storage-extracted brine to ZLD in these countries, this assumption is made for consistency to have the whole CCS chain ZLD. Only in Australia, where there is no requirement for ZLD at the power station, no further treatment of the reject stream is assumed after initial water treatment, and the reject is disposed and concentrated in evaporation ponds (see Figure 3-1).

In the Australian case, the water treatment technology applied is a combination of membrane-based processes: a combination of forward osmosis and reverse osmosis (FO-RO). The schematic of the treatment process adopted is given in Figure 3-1. The forward osmosis process utilises an osmotic pressure difference between the feed and the draw solution to drive the water permeation across the semipermeable membrane. Water flows from the feedwater to the draw solution with a higher osmotic pressure and the diluted draw solution is regenerated by the RO and recirculated back to FO (Figure 3-1). Water is recovered from RO as permeate and the concentrated brine waste from FO is sent to salt concentration evaporation pond for disposal. With the average feed water concentration of 5,000 mg/l, the product water recovery of about 85% is estimated using the combined FO-RO treatment (see Table 3-1). FO is not a hydraulic pressure driven process and generally has a less fouling propensity than RO (Shaffer D.L., 2015). The water recovered in this manner is high quality ultrapure water with typically less than 100 mg/l TDS, which is suitable for various beneficial uses, including use in power stations and other industrial applications.

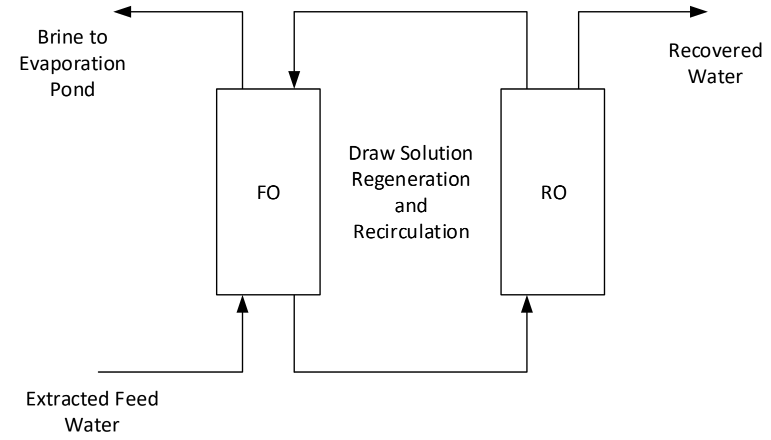

Figure 3-1 Schematic of combined FO-RO treatment for extracted water from Australia

For South Africa, China and India, where treatment to ZLD is assumed, a combination of a membrane process (conventional RO) followed by thermal-based brine concentration is applied to achieve water recovery and reduce brine waste. As the average feed water salt concentrations in the Indian case (9,000 mg/l) and especially in the South African case (26,000 mg/l) are higher than in the Australian case, more extensive pre-treatment prior to RO, such as suspended solids removal, chemical softening, pH adjustment, etc., is required. Conventional RO is the first brine concentration step, which is followed by mechanical vapour compression (MVC) for further brine concentration and water recovery. The brine from MVC is near saturation with significantly reduced brine volume and can be sent to an evaporation pond or to a forced circulation crystalliser (FCC), followed by a belt press or centrifuge to obtain dry salt (Figure 3-2). Product water recoveries of about 90% - 98% is expected with the RO-MVC-FCC brine concentration process, depending on initial feed water concentration. The product water recovered has a concentration of 100 mg/l TDS. Recoveries for each country are summarised in Table 3-1, alongside initial feed water concentrations in the four regions and treatment technologies applied.

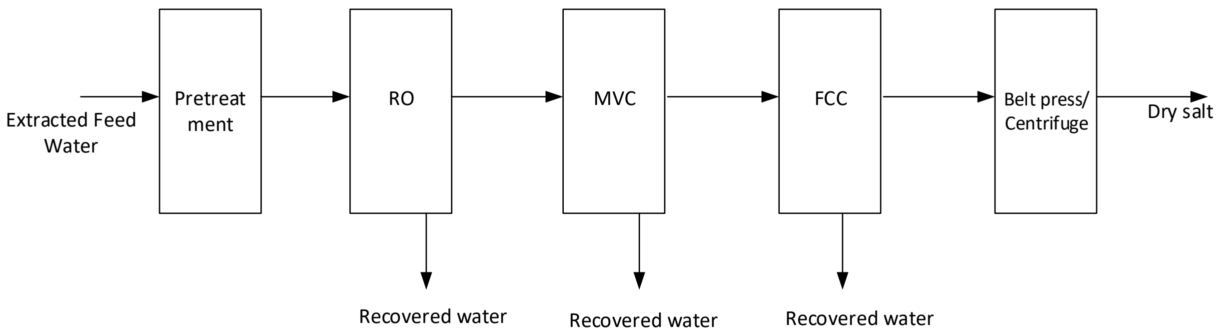

Figure 3-2 Process schematic for the ZLD treatment of extracted water from South Africa, China, and India

The highly concentrated brine (see Table 3-1 for reject quantities) is sent to evaporation ponds for further concentration and disposal with minimal environmental impacts. The disposal options depend on the treatment location, geological conditions and local environmental regulatory requirements (Panagopoulos et al. 2019, Khan et. al. 2009) and include disposal to landfill, as well as sale of the concentrated near-saturation sodium chloride brines to derive additional value. For example, the concentrated brines may be used as feedstock in various chemical industries including chlor-alkali plants to produce caustic soda and chlorine (Reig et al. 2014)

Table 3-1 Extracted brine quantities and TDS for the four storage basins of interest

Country	South Africa	Australia	China	India
Geological basin	Zululand	Surat	Songliao	Cambay
Extracted brine, Mt/y	7.11	6.77	7.07	7.26
TDS range, mg/l				
Estimated average TDS, mg/l	26,000	5,000	5,000	9,000
Treatment to ZLD	Yes	No	Yes	No
Treatment technology	RO-MVC-FCC	FO-RO	RO-MVC-FCC	RO-MVC-FCC
Product recovery, %	92.75	85	98.53	97.33
Product water, Mt/y	6.60	5.75	6.96	7.07
Reject stream, Mt/y	0.51	1.02	0.11	0.19
Disposal of reject stream	Evaporation ponds	Evaporation ponds	Evaporation ponds	Evaporation ponds

Rather than treating the extracted brine to freshwater quality, the saline water may be used directly in the cooling system of the power station. However, this requires specifically designed cooling systems, affecting power station costs.: in comparison to cooling systems designed to operate on freshwater, systems using saline water are more expensive. The reasons for this are outlined in Maulbetsch and DiFilippo (2010), who also state that the costs are highly variable, site-specific and thus difficult to generalise. The use of the storage-extracted water as cooling water in the power station with capture without desalination is not further investigated in this study and all storage-extracted water is assumed to be treated to freshwater quality of 100 mg/l or less.

4 Methodology for the location-specific assessment of CCS

4.1 Economic scenarios

Two scenarios are investigated for Phase 2 of this study: i.) the Base Case CCS Scenario without any water extraction (assuming open reservoir boundaries and that CO_2 injection at the required annual rates is possible); and ii.) the CCS-Water-Nexus Scenario in which water is extracted to enable CO_2 injection at the required annual rates and then reused at the power station after treatment. These scenarios were described in Chapter 4.2 of Phase 1 and schematics are presented in

Figure 4-1 and Figure 4-2 with the updated specifications pertaining to the cases investigated in Phase 2.

The number of cases investigated in Phase 2 of this study is less than in Phase 1 as only the USCPC with specified cooling technologies in each country is investigated rather than a selection of power stations with different cooling technologies. The storage options with and without water extraction are also reduced, considering only the case with no water extraction (CCS Base Case Scenario) and the case with water extraction and treatment of all water produced for reuse in the power station (CCS-Water-Nexus Scenario). In those cases where the extracted water is surplus to the needs of the power station with capture, additional beneficial use options for the water are assumed to be taken up. These are highlighted in Chapter 6 for the different locations.

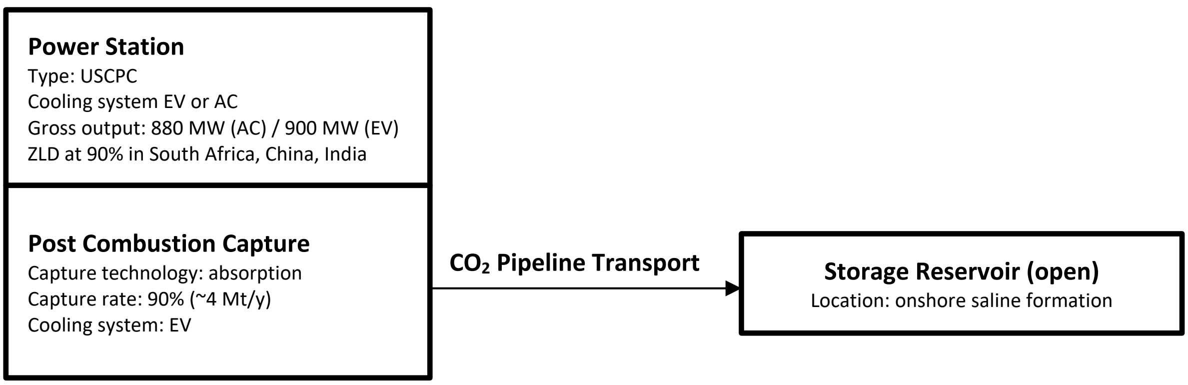

Figure 4-1 Flow diagram of the base case scenario: CCS in an open formation without water extraction. AC = air cooling, EV = evaporative cooling

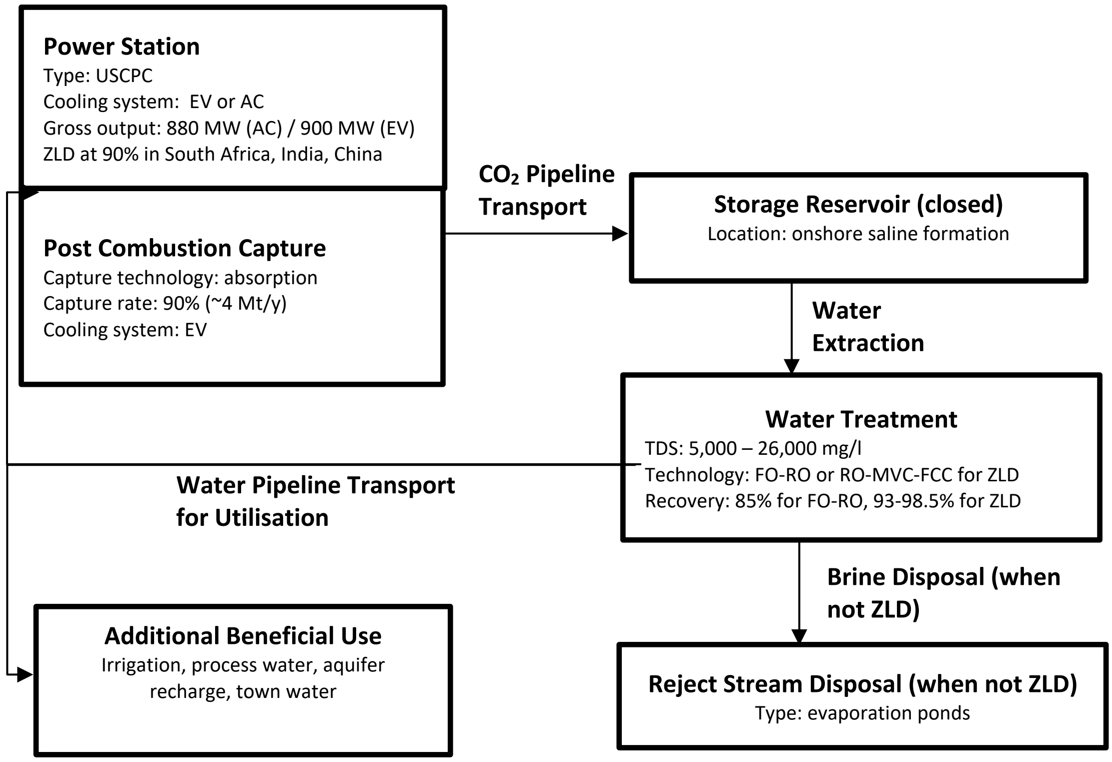

Figure 4-2 Flow diagram of the CCS-Water-Nexus Scenario with water extraction, treatment, and utilisation in the power station with capture and additional beneficial use options. AC = air cooling, EV = evaporative cooling, FCC = forced circulation crystalliser, FO-RO = forward osmosis – reverse osmosis, MVC = mechanical vapour compression, TDS = total dissolved solids, ZLD = zero liquid discharge

4.1.1 Base Case CCS Scenario

The Base Case CCS Scenario considers CO_2 capture from the hypothetical USCPC using air cooling for the power stations in South Africa, Australia and China, and evaporative cooling in India, while all capture plants use evaporative cooling (Table 4-1). ZLD to treat the power station's waste water is applied at those power stations where it constitutes a regulatory requirement (i.e., South Africa, China and India). The recovered product water is reused in the power station.

CO_2 is transported to a storage site in the identified geological basin and injected under the assumption that open reservoir boundaries enable CO_2 injection at the required annual rates. Thus, no water extraction as part of CO_2 storage operations is carried out.

The details of the CCS Base Case Scenarios in the four countries are summarised in Table 4-1.

Table 4-1 Details of the Base Case CCS Scenario (no water extraction) in South Africa, Australia, China and India

		USCPC with capture plant using state of the art absorption			
Country		**South Africa**	**Australia**	**China**	**India**
Power station with capture					
Power station		USCPC	USCPC	USCPC	USCPC
Cooling technology power station		Air	Air	Air	Evaporative
Cooling technology capture plant		Evaporative	Evaporative	Evaporative	Evaporative
Efficiency	%LHV	34.18	30.35	34.73	34.79
Gross power	MW	808.3	816.7	800.0	817.7
Net power	MW	628.3	593.1	638.8	639.9
Water consumption (total)	Mt/y	4.77	4.43	3.39	7.59
Water consumption (capture only)	Mt/y	4.38	4.03	3.00	3.81
Process water discharge	Mt/y	1.46	1.34	1.00	2.37
ZLD at power station		Yes	No	Yes	Yes
ZLD technology		MBC	-	MBC	MBC
Water recovery	%	90	-	90	90
Product water	Mt/y	1.31	-	0.9	2.14
Storage					
Storage basin		Zululand Basin	Surat Basin	Songliao Basin	Cambay Basin
Location		Onshore	Onshore	Onshore	Onshore
Reservoir permeability	md	<1 – 229	Med 13, max 1,500	150 - 285	0.3 - 163
Reservoir porosity	%	4 - 41	17	18 – 20	2 - 14
Formation water salinity	mg/l	14,000 – 38,000	5,000 – 15,000	3,500 – 9,000	7,000 – 10,000
Reservoir boundaries		open	open	open	open
CO_2 injection rate	Mt/y	4.18	3.98	4.16	4.27
Emissions data					
CO_2 emitted	t/h	62.4	59.4	62.0	63.8
CO_2 emitted	Mt/y	0.46	0.44	0.46	0.48
CO_2 emitted	t/MWh	0.099	0.100	0.097	0.100
Total CO_2 captured = CO_2 stored	t/h	561.7	534.4	558.1	573.8
Total CO_2 captured = CO_2 stored	Mt/y	4.18	3.98	4.16	4.27
Total CO_2 avoided	t/MWh	0.713	0.722	0.690	0.704
Total CO_2 avoided	Mt/y	3.33	3.19	3.28	3.36

4.1.2 CCS-Water-Nexus-Scenario

For the CCS-Water-Nexus Scenario the CCS Base Case Scenario is expanded to include treatment of the produced water for reuse in the power station and the capture plant. A schematic of the CCS-Water-Nexus Scenario is presented in Figure 4-2. The CCS-Water-Nexus Scenario integrates CO_2 capture from the hypothetical USCPC power plant in each of the four countries, CO_2 transport and injection, brine extraction with subsequent treatment, and supply of product water to the power plant. In line with ZLD requirements for the respective power stations, the storage-extracted water is also treated to ZLD where this constitutes a regulatory requirement for the power station. Disposal of the concentrated reject brine after treatment occurs via evaporation ponds and landfill or through reuse of the concentrated brines as feedstock for chemical industries. Where the extracted water is surplus to the needs of the power station with capture, additional beneficial use options for the water are assumed to be taken up. These are highlighted in Chapter 6 for the different locations.

Specific details of each Phase 2 CCS-Water-Nexus Scenario are presented in Table 4-2. The table shows that for all locations some of the storage-extracted and treated water is surplus to the demands of the power station, even in the case of the Indian power station using evaporative cooling. This is due to the high product recovery from the storage-extracted water, as well as the application of ZLD at the power station, which lowers the freshwater demand. This surplus water, ranging from 1.3 Mt/y in Australia, 1.6 Mt/y in India, 3.1 Mt/y in South Africa, up to almost 4.5 Mt/y in China, may be provided for other beneficial uses.

Table 4-2 Details of the CCS-Water-Nexus-Scenario in South Africa, Australia, China and India

		USCPC with capture plant using state of the art absorption			
Country		**South Africa**	**Australia**	**China**	**India**
Power station with capture					
Power station		USCPC	USCPC	USCPC	USCPC
Cooling technology power station		Air	Air	Air	Evaporative
Cooling technology capture plant		Evaporative	Evaporative	Evaporative	Evaporative
Efficiency	%LHV	34.18	30.35	34.73	34.79
Gross power	MW	808.3	816.7	800.0	817.7
Net power	MW	628.3	593.1	638.8	639.9
Water consumption (total)	Mt/y	4.77	4.43	3.39	7.59
Water consumption (capture only)	Mt/y	4.38	4.03	3.00	3.81
Process water discharge	Mt/y	1.46	1.34	1.00	2.37
ZLD at power station		Yes	No	Yes	Yes
ZLD technology		MBC	-	MBC	MBC
Water recovery	%	90	-	90	90
Product water	Mt/y	1.31	-	0.9	2.14
Storage					
Storage basin		Zululand Basin	Surat Basin	Songliao Basin	Cambay Basin
Location		Onshore	Onshore	Onshore	Onshore
Reservoir permeability	md	<1 – 229	Med 13, max 1,500	150 - 285	0.3 - 163
Reservoir porosity	%	4 - 41	17	18 – 20	2 - 14
Formation water salinity	mg/l	14,000 – 38,000	5,000 – 15,000	3,500 – 9,000	7,000 – 10,000
Reservoir boundaries		open	open	open	open
CO_2 injection rate	Mt/y	4.18	3.98	4.16	4.27
Water extraction		Yes	Yes	Yes	Yes
Water extraction rate	Mt/y	7.11	6.77	7.07	7.26
Water Management					
Treatment storage-extracted water		Yes	Yes	Yes	Yes
Treatment to ZLD		Yes	No	Yes	Yes
Technology		RO+MVC+FCC	FO-RO	RO+MVC+FCC	RO+MVC+FCC
Recovery rate	%	92.75	85	98.53	97.33
Product water storage	Mt/y	6.60	5.75	6.96	7.07
Total water recovery CCS chain	Mt/y	7.91	5.75	7.86	9.21
Surplus water (incl. ZLD from PP)	Mt/y	3.14	1.32	4.46	1.61
Additional beneficial use possible		Yes	Yes	Yes	Yes
Concentrated brine disposal		Evaporation ponds	Evaporation ponds	Evaporation ponds	Evaporation ponds
Emissions data					
CO_2 emitted	t/h	62.4	59.4	62.0	63.8
CO_2 emitted	Mt/y	0.46	0.44	0.46	0.48
CO_2 emitted	t/MWh	0.099	0.100	0.097	0.100
Total CO_2 captured = CO_2 stored	t/h	561.7	534.4	558.1	573.8
Total CO_2 captured = CO_2 stored	Mt/y	4.18	3.98	4.16	4.27
Total CO_2 avoided	t/MWh	0.713	0.722	0.690	0.704
Total CO_2 avoided	Mt/y	3.33	3.19	3.28	3.36

4.2 General economic assumptions

The general economic assumptions are the same as outlined in Chapter 5.2 in Phase 1. The key parameters included in this assessment are summarised below:

- Discount rate: 8% in constant money values
- Plant life: standard plant operating life of 25 years
- Operating capacity factor: power plants with and without CCS plants of 85%
- Cost year: 2018 values (€)

4.3 Location costing approach

The power plant capital and operating costs for each of the locations evaluated in this study (South Africa, Australia, China and India) are estimated using the IEAGHG (2018) study which reported on the effects of location on the cost of CO_2 capture. Using the methodology and results of the IEAGHG (2018) study, location factors for capital costs are derived for the different locations relative to the Netherlands, the standard location used in IEAGHG studies. The location cost factors (summarised in Table 4-3) are then used to determine capital cost of the power plants with and without capture in the four locations of interest. The methodology applied to derive the cost factors is detailed below.

4.3.1 Location capital cost factor derivation

IEAGHG (2018) presents capital and operating costs for power plants and power plants with capture for the countries of interest in this study: the Netherlands, South Africa, Australia, China and India. With respect to the Netherlands, different cases are distinguished:

- a "Reference" case, which is a power plant using evaporative cooling for both the power plant (Case 1A in Table A 1 in Appendix A.1) and the capture plant (Case 1B in Table A 1 in Appendix A.1), assuming ambient conditions and fuel quality representative of the Netherlands; and
- a "Hypothetical Netherlands" case, in which power plants are built in the Netherlands, thus assuming Dutch costs for labour and equipment, but use cooling water systems, ambient conditions and fuel grade representative of the country of interest.

Table A 1 in Appendix A.1 summarises the capital and operating costs of the power plants with and without capture in the selected locations, as well as the equivalent hypothetical plant in the Netherlands ("Hypothetical Netherlands") and the "Reference" power plant in the Netherlands (Case 1A/1B) presented in IEAGHG (2018).

As the power plants located in India and the Netherlands Reference case (Table A 1 in Appendix A.1) in the IEAGHG (2018) study use the same cooling technology (evaporative cooling) as the Indian and the Dutch power plants presented in this study (see Chapter 2, Phase 1 report), we use the ratio of the specific capital requirement (SCR) of the IEAGHG (2018) power plant in India (Case 7A in Table A 1 in Appendix A.1) to the IEAGHG (2018) power plant in the Netherlands Reference case (Case 1A) to estimate a location capital cost factor (LCCF) for India relative to the Netherlands. The LCCF for India is derived as per Eq. (4-1) and considers not only the differences in labour and equipment cost between the Netherlands and India, but in this case also includes the differences in cooling water systems, ambient conditions and fuel grade. The LCCF can then be applied to determine the specific capital requirement of the Indian power plant described in this study.

$$\left(\frac{SCR_{India}}{SCR_{RefNetherlands}}\right)_{IEAGHG(2018)} = LCCF_{India} \qquad (4\text{-}1)$$

SCR_i = specific capital requirement of the power plant in the location of interest (€/kW); *$LCCF_i$* = location capital cost factor for the location of interest relative to The Netherlands

The IEAGHG (2018) study did not evaluate a power plant with air-cooling in the Netherlands and thus a direct and simple cost translation analogous to the India case is not possible for this power plant. Therefore, for the air-cooled power plants in Australia (Case 6A in Table A 1 in Appendix A.1), China (Case 8A), and South Africa (Case 5A) the location capital cost factors are estimated as the ratio of the cost of building the power plants in those locations to the cost of building the equivalent "Hypothetical Netherlands" power plant (Case 6A*, 8A*, and 5A* in Table A 1 in Appendix A.1 for the power plants equivalent to Australian, Chinese, and South African conditions, respectively), as outlined in IEAGHG (2018). Therefore, the location capital cost factor for the power plants built in Australia, South Africa, or China reflects the differences in labour and equipment cost and does not consider cost differences due to differences in cooling water systems, ambient conditions and fuel grade.

$$\left(\frac{\boldsymbol{SCR_{Aus,China,SA}}}{\boldsymbol{SCR_{HypoNetherlands}}}\right)_{\boldsymbol{IEAGHG(2018)}} = \boldsymbol{LCCF_{Aus,China,SA}} \qquad (4\text{-}2)$$

The resulting location capital cost factors are presented in Table 4-3.

Table 4-3 Location capital cost factors of the four countries of interest relative to the Netherlands. Capital cost factors are derived based on power plants without capture

Location	Capital cost factor
The Netherlands	1.00
South Africa (inland)	1.20
Australia	1.22
China (inland)	0.70
India	0.98

4.3.2 Estimating power plant capital cost

To determine the capital costs for the USPC power plants located in South Africa, Australia, China and India the relevant location capital cost factor is applied to the capital cost of the USPC power plant with the same cooling technology located in the Netherlands. The capital costs of the relevant power stations were presented in Chapter 5 (Table 5-10) in the Phase 1 report of this study and are summarised in Table 4-4. In Table 4-4 total plant costs are the cost of the power plant with and without capture, while the total capital requirement also includes the start-up costs for the power plant with and without capture. The specific cost is the ratio of the capital cost to the net power output of the power station of interest as per Eq. (4-3).

$$SCR = \frac{TCR}{P_{net}} \quad (4\text{-}3)$$

TCR = total capital requirement (€); P_{net} = net power output from the power station (kW)

Table 4-4 Total capital requirement for USPC power plants, with and without capture in the Netherlands from Chapter 5 Phase 1 (Table 5-23)

Plant in The Netherlands	Total plant cost (M€)	Specific total plant cost (€/kW)	Total capital requirement (M€)	Specific capital requirement (€/kW)
PCC-EV	317	-		
USPC-EV	1343	1644	1382	1691
USPC-EV-PCC	1659	2424	1707	2494
USPC-AC	1359	1732	1400	1782
USPC-AC-PCC-EV	1676	2558	1723	2630

Based on the location capital cost factors in Table 4-3 and the capital cost of the power plants located in the Netherlands presented in Table 4-4, the capital costs for the USPC power plants with and without capture using the same cooling technology located in South Africa, Australia, China and India can be estimated as per Eq. (4-4) to (4-7) using a scaling factor of 0.6. This approach considers the change in net power output for each of the locations arising from the different ambient conditions and coal type. The methodology for calculating the total capital requirement for the capture plant is described in the next section.

Capital cost for power plant:

$$TCR_{PP,i} = LCCF_i \cdot TCR_{PP,Netherlands} \times \left(\frac{P_{gross,i}}{P_{gross,Netherlands}}\right)^{0.6} \quad (4\text{-}4)$$

$$SCR = \frac{TCR_{PP,i}}{P_{net,i}} \quad (4\text{-}5)$$

Capital costs for power plant with capture (estimation of the capture plant cost is described in the next section):

$$TCR_{PP-PCC,i} = TCR_{PP,i} + TCR_{PCC,i} \quad (4\text{-}6)$$

$$SCR = \frac{TCR_{PP-PCC,i}}{P_{net,PCC,i}} \quad (4\text{-}7)$$

Table 4-5 presents the estimated specific capital requirement for the five locations in comparison to the cost presented in IEAGHG (2018). ZLD costs are included as part of the total plant costs for the China, India, and South Africa cases. However, due to the power plants without capture in China and South Africa being air-cooled (which has negligible water discharge as shown in Table 1-3) treatment to ZLD is only included for the power stations with capture (which use evaporative cooling). As a result, in the scenario without capture, the Indian power plant is the only one fitted with a ZLD system. The derivation of ZLD costs is described later.

The analysis shows that the two estimates are in-line with each other, with estimates less than 10% different. As this study is a high-level scoping assessment, this falls within the +/- 30% error expected for preliminary estimates.

Table 4-5 Comparison of the specific capital requirement (SCR) for the five locations between the IEAGHG (2018) and this study, including ZLD costs for the Indian power station

Location	Cooling type for power plant	Specific capital requirement (€/kW)		Difference (%)
		IEAGHG (2018)	This study	
The Netherlands	Evaporative/draft	1840	1691	-8%
The Netherlands	Air	Not available	1782	--
South Africa (inland)	Air	2126	2136	0%
Australia#	Air	Not available	2171	--
China (inland)	Air	1173	1248	6%
India*	Evaporative/draft	1809	1737	-4%

#In the IEAGHG (2018) study, the Australian case 6A/6B is based on once-through cooling, while in this study, air-cooling was selected for the Australian cooling system.

*The Indian power station is the only one that uses ZLD technology in the no capture scenario due to air-cooling being used in China and South Africa.

4.3.3 Estimating capture plant capital cost

Analogous to the power plant capital cost, the capture plant capital costs for the different locations are derived using the location capital cost factors generated above. The location factors are applied to the capture plant unit capital cost representative of the Netherlands [Eq. (4-8)] to determine a country specific unit capital cost for the capture plant with evaporative cooling as per Eq. (4-9). Capture plant capital costs may be calculated as per Eq. (4-10).

$$UC_{PCC-EV_{Netherlands}} = \left(\frac{CPC_{PCC-EV}}{CO_{2,captured}}\right)_{Netherlands} \tag{4-8}$$

$$UC_{PCC-EV_i} = UC_{PCC-EV_{Netherlands}} \cdot LCCF_i \tag{4-9}$$

$$CPC_{PCC-EV_i} = \left(UC_{PCC-EV_i} \cdot CO_{2,captured}\right)_i \tag{4-10}$$

$UC_{PCC\text{-}EV,Netherlands}$ = unit capital cost of the capture plant using evaporative cooling in the Netherlands [M€/(t/h)] (with or without start-up cost); $CPC_{PCC\text{-}EV,\ Netherlands}$ = capital cost of the capture plant using evaporative cooling in the Netherlands [M€] (with or without start-up cost); $CO_{2,captured,Netherlands}$ = total amount of CO_2 captured from the power plant in the Netherlands [t/h]; $UC_{PCC\text{-}EV,i}$ = unit capital cost of the capture plant using evaporative cooling in the country of interest [M€/(t/h)] (with or without start-up cost); $CPC_{PCC\text{-}EV,\ i}$ = capital cost of the capture plant using evaporative cooling in the country of interest [M€] (with or without start-up cost); $CO_{2,captured,i}$ = total amount of CO_2 captured from the power in the country of interest [t/h]

As the amount of CO_2 captured varies between the locations due to differences in coal quality and changes in ambient conditions, the size of the capture plant will also be different. This is reflected in the capture plant capital cost estimates presented in Table 4-6 for the five locations of interest.

Table 4-6 Capture plant costs for the different locations

Capital cost capture plant	The Netherlands	South Africa	Australia	China	India
Total capital cost of capture plant using EV, M€	316.5	392	379	227	327
Total start up cost for the capture plant using EV, M€	8.3	12.5	9.8	7.3	9.4
Total capital cost for capture plant including start up cost, M€	324.8	404.6	389.2	234.6	336.5
Unit capital plant cost of capture plant using EV, M€/CO_2 captured t/h	0.58	0.70	0.71	0.41	0.57
Unit capital cost of capture plant including start up cost using EV, M€/CO_2 captured t/h	0.6	0.72	0.73	0.42	0.59

4.3.4 Estimating power and capture plant operating cost

The operating cost assumptions, including fuel prices and raw water make-up costs, are outlined in Table 4-7. The values for the coal prices and raw water make-up were taken to be the same as those from the IEAGHG (2018) study. The fixed operating and variable operating costs (excluding fuel) were calculated to be a percentage of the total plant capital costs as per Eq. (4-11) – (4-13) using the results presented in the IEAGHG (2018) study for the five locations.

$$\frac{1}{2}\cdot\left[\left(\frac{FOM_i}{TCR_i}\right)_{PP,IEAGHG(2018)}+\left(\frac{FOM_i}{TCR_i}\right)_{PP-PCC,IEAGHG(2018)}\right]=\%FOM_i \qquad (4\text{-}11)$$

$$\left(\frac{VOM_i}{TCR_i}\right)_{PP,IEAGHG(2018)}=\%VOM_{PP,i} \qquad (4\text{-}12)$$

$$\left(\frac{VOM_i}{TCR_i}\right)_{PP-PCC,IEAGHG(2018)}=\%VOM_{PP-PCC,i} \qquad (4\text{-}13)$$

FOM_i = fixed operating and maintenance cost for the location of interest; TCR_i = total capital requirement for the location of interest; *PP* = power plant; *PP-PCC* = power plant with capture

The resulting percentages for fixed and variable operating costs are summarised in Table 4-7. The percentage values for the variable operating costs of the plants with capture are higher than for the plants without to reflect the higher costs due to materials usage and the waste disposal required for the solvent absorption system.

Table 4-7 Operating costs assumptions for the different locations

Operating Costs	**The Netherlands**	**South Africa**	**Australia**	**China**	**India**
Fuel prices					
Coal, €/GJ LHV	2.5	1.8	2	1.8	1 (local coal)
Natural Gas, €/GJ	5.0	8.5	3.5	7.5	3.2
Fixed operating costs, % of TPC/y	2.4	2.7	2.40	2.84	2.90
Variable operating costs (excluding fuel) for **plant w/o capture**, % of TPC/y	0.43	0.40	0.35	0.53	0.25
Variable operating costs (excluding fuel) for **plant w/ capture**, % of TPC/y	0.66	0.60	0.50	0.93	0.55
Raw process water, €/m^3	0.2	0.2	0.2	0.2	0.2

4.3.5 Estimating cost for zero liquid discharge at the power station

As summarised in Table 1-4, ZLD is applicable only to power plants in South Africa, China and India, but not Australia and the Netherlands. In this study, costs for ZLD at the power stations in these three countries are derived based on the cost for the ZLD system built at the Huaneng Power International's Changxing power plant in China, which is a new 1.3 GW high efficiency ultra-supercritical coal-fired power plant. The ZLD system at Changxing consists of a membrane brine concentration (MBC) system and a crystalliser as the final step in the chain. The MBC processes about 30 m^3/h of wastewater with an average TDS of 9,000 mg/l at a recovery rate of more than 90% (Patel, 2016). The concentrated reject stream of about 2.5 m^3/h goes to the crystalliser, where the remaining water is removed to less than 0.5%. Salt crystals of more than 95% (NaCl + Na2SO4), produced as a by-product of the process, are sold to chemical manufacturers (Patel, 2016).

Capital costs for the ZLD system at Changxing power plant have been quoted as US$20M, while average operating cost for treating water to 95.5% of solids range between 3 – 3.5 US$/m^3 (World Bank, 2016). The estimated unit cost per m^3 of treated water is US$5/m^3. For our study, capital costs are adjusted based on the size of the process water discharge stream of each power station with and without capture using a scaling factor of 0.6 as per Eq. (4-14). Operating costs remain the same, using US$3.5/m^3 of wastewater to be treated as a conservative estimate. The cost assumptions for the ZLD system are summarised in Table 4-8.

$$ZLD_{China} = \left(\frac{PWD_{China}}{PWD_{Changxing}}\right)^{0.6} \cdot ZLD_{Changxing} \qquad (4\text{-}14)$$

ZLD$_i$ = capital cost for treatment to zero liquid discharge in the country of interest; PWD = process water discharge (= water to be treated to ZLD) for the specific power station/country of interest

Table 4-8 Parameters for estimating costs for a ZLD system based on the ZLD system consisting of membrane brine concentration system and crystalliser at the Changxing power plant in China

Changxing Power Plant, China	Value	Reference
Capital cost for treatment of 30 m^3/h wastewater, US$M	20	World Bank, 2016
Operating cost for treatment of 30 m^3/h wastewater, US$/m^3	3 – 3.5	World Bank, 2016
Estimated unit cost for product water, US$/m^3	5	World Bank, 2016
Capital cost scaling factor	0.6	
Recovery factor, %	90	Patel, 2016

ZLD cost derived through Eq. (4-14) are representative of Chinese power plants. To convert Chinese ZLD cost to Indian and South African cost, the ratio of the LCCF for India/South Africa and China is applied to determine the appropriate capital cost as per Eq. (4-15).

$$ZLD_{India/SA} = \left(\frac{PWD_{India/SA}}{PWD_{Changxing}}\right)^{0.6} \cdot ZLD_{Changxing} \cdot \frac{LCCF_{India/SA}}{LCCF_{China}} \qquad (4\text{-}15)$$

The operating cost of US$3.5/m^3 of process water discharge remain the same for each country (i.e. no location cost factor is applied) due to the high uncertainty associated with these costs.

It should be noted that in the China and the South Africa case the power plants without capture are air-cooled and thus the process water discharge is negligible (see Table 1-3) and treatment to ZLD is not needed. However, the introduction of CO_2 capture using evaporative cooling results in noticeable quantities of wastewater (Table 1-3) that require treatment to ZLD. The ZLD cost estimated for China, India and South Africa are presented in Table 4-9, with the corresponding unit cost for treating the discharged process water and the product water unit cost presented in Table 4-10. Cost of product water are lowest in India, estimated as €5.44/t of freshwater produced and most expensive in China at €6.55/t. The higher Chinese cost are caused by the lower economies of scale due to the lower volume of process water discharge requiring treatment.

Table 4-9 Capital cost and operating cost for zero liquid discharge treatment in China, India and South Africa as a function of wastewater volume to be treated in 2018€

Country	Discharge, m^3/h	Capex, M€	Opex, M€/y
South Africa – USCPC-AV-PCC-EV	196	99.98	4.32
China – USCPC-AV-PCC-EV	134	46.40	2.95
India – USCPC-EV	150	69.56	3.31
India – USCPC-EV-PCC	319	109.39	7.04

Table 4-10 Zero liquid discharge treatment unit cost (discounted and undiscounted) for China, India and South Africa as a function of i.) wastewater quantity to be treated; and ii.) product water quantity in 2018€

Country	Undiscounted Unit cost, €/t discharge	Unit cost, €/t product	Discounted Unit cost, €/t discharge	Unit cost, €/t product
South Africa – USCPC-AV-PCC-EV	4.23	4.70	5.75	6.38
China – USCPC-AV-PCC-EV	4.47	4.97	6.28	6.98
India – USCPC-EV	4.40	4.88	6.11	6.79
India – USCPC-EV-PCC	3.97	4.41	5.17	5.74

The water recovered from the ZLD process at a rate of 90% is used to supplement the water requirements of the power plant with capture (and in the Indian case also the power plant without capture), thus lowering the volume of freshwater purchased. A comparison of recovered product water and water consumption of the power station with capture is in Table 4-11. The ZLD recovered water can provide about 27% of the water consumption of the power plants with capture.

Table 4-11 Process discharge water quantity and ZLD recovered product water at 90% recovery at the power stations with capture in China, India and South Africa

Country	Discharge water, Mt/y	Product water, Mt/y	Water consumption PCC, Mt/y	Water consumption PP+PCC, Mt/y
South Africa – USCPC-AV-PCC-EV	1.46	1.31	4.38	4.80
China – USCPC-AV-PCC-EV	1.00	0.9	3.00	3.39
India – USCPC-EV	1.12	1.00	n/a	3.78
India – USCPC-EV-PCC	2.37	2.14	3.81	7.59

4.4 Storage costing

4.4.1 CO_2 transport and storage cost

Due to the hypothetical, non-specified location of the power plants with capture in the countries of interest and even more so the uncertainties associated with the storage sites in some of these countries, transport and storage costs are fixed at 5 €/t CO_2 stored for all cases. 5 €/t were selected over the typically applied estimate of 10 €/t due to all storage sites being onshore. This is a conservative estimate in comparison to the onshore storage cost estimates reported in IEAGHG (2014), as well as the costs for onshore storage estimated for CO_2 storage onshore Netherlands in Phase 1 of this study. It incorporates the significant degree of uncertainty associated with the selected storage sites and the unspecified locations of the power plants. Using a constant CO_2 transport and storage cost across all sites enables better comparison of the cost difference between power stations as a function of location as well of the cost of water treatment and reuse in the power station in the different locations.

4.4.2 Water extraction and transport cost

Water extraction and transport is estimated as half of CO_2 transport and storage cost at 2.5 €/t of CO_2 stored, as the Netherlands case study in Phase 1 indicated water extraction per unit of CO_2 stored to be significantly cheaper than CO_2 storage operations. Furthermore, it may be assumed that the produced water may only be transported to the power station if the power station is near the storage site. If this is not the case, the extracted and treated water may be used for alternative purposes located closer to the extraction site. This is a likely scenario in the highly water stressed regions investigated in this second phase of the study.

4.5 Storage-extracted water treatment cost

For the treatment of storage-extracted water in the Australia case, where there is no requirement for ZLD, a combined FO-RO process is adopted for cost estimation. With the introduction of a non-pressure (osmotic pressure instead of hydraulic pressure) driven FO prior to RO, the pre-treatment requirements for feed water are reduced compared to a conventional RO. This also reduces the operating cost as it lowers the requirement of chemical cleaning and RO membrane replacement. However, FO is still an emerging technology that is less mature than RO and the FO membrane cost is still high compared to RO membranes. For example, currently the cost of an FO membrane could be about 10 - 20 times higher than the cost of a RO membrane depending on various factors including the type of membrane used and the application scale. However, for certain treatment applications a cost saving of at least 10% - 15% is estimated to be achievable by using a combined FO-RO treatment method over conventional RO treatment methods (Thiruvenkatachari et al. 2016).

For South Africa, China and India, where ZLD requirements are incorporated, a combination of a membrane-based process (RO) with thermal based MVC-FCC processes are applied for brine volume reduction and concentration. Thermal brine concentrators generally have high capital and operating costs (compared to RO) due to their high energy requirements. However, currently, thermal based brine concentrators are indispensable where treatment to ZLD is required.

The preliminary cost estimates with the application of various treatment technologies for the storage-extracted brines from the four different countries are given in Table 4-12, including the initial brine concentration in each location and expected recovery rate. The unit water cost is the cost of product water, taking into account capital and operating expenses for treating the extracted water. Costs for the different countries were adapted applying IMF price level indices (Statista, 2019). The assumptions used for the cost estimation are given in Appendix A.2. Product water costs range from 1.09 €/m^3 in China up to 2.33 €/m^3 in South Africa. This is due to South Africa having higher costs than China, but even more so a result of the higher concentrated extracted brine in South Africa compared to China (see Table 4-12). The treatment of the higher concentrated brine requires more energy, amongst others.

The unit water cost does not include disposal costs, which typically only present a small fraction of the total costs for the ZLD scenarios due to the high product water recovery. Only for the Australian case do the disposal costs present a considerable fraction of the total water treatment operating costs. This is due to high disposal costs in Australia in addition to the higher reject stream from the FO-RO process (see Table 4-12). It should be highlighted that even where treatment to ZLD occurs, the final step of evaporating the remaining liquid left in the highly concentrated brine in a crystallisation or evaporation pond is referred to as “disposal” in this study though it is part of the treatment to ZLD. The disposal costs presented in Table 4-12 only include costs associated with disposal in evaporation ponds and not those of the final disposal of the remaining salt/brine solution. This can occur via landfill or alternatively the remaining salt crystals may be supplied to chemical industries to derive additional value such as in the case of the Huaneng Power International’s Changxing power plant in China (see Chapter 4.3.5). Due to the potential value-add, salt disposal costs are not accounted for here.

Table 4-12 Cost estimates for treatment and disposal of the extracted brines from South Africa (Zululand Basin), Australia (Surat Basin), China (Songliao Basin), and India (Cambay Basin) in 2018€. Treatment to ZLD is assumed for the brines in South Africa, China, and India

Treatment cost	South Africa	Australia	China	India
Salinity, mg/l	26,000	5,000	5,000	9,000
Feed stream, Mt/y	7.11	6.77	7.07	7.26
Recovery rate, %	92.75	85	98.53	97.33
Product water, Mt/y	6.60	5.75	6.96	7.07
Reject stream, Mt/y	0.51	1.02	0.11	0.19
Treatment technology	RO-MVC-FCC	FO-RO	RO-MVC-FCC	RO-MVC-FCC
Disposal of reject stream	Evaporation ponds	Evaporation ponds	Evaporation ponds	Evaporation ponds
Capital investment, M€	51.81	38.16	27.50	16.97
Operating cost, €/m^3	1.46	0.43	0.70	0.86
Unit water cost - undiscounted, €/m^3	1.88	0.77	0.86	0.98
Unit water cost - discounted, €/m^3	2.33	1.15	1.09	1.11
Disposal cost, €/ m^3	1.23	3.88	1.98	1.81

5 Economic evaluation of CCS in different locations

This section presents the results of the economic assessment of the power stations with capture, as well as the economics of the CCS Base Case Scenario and the CCS-Water-Nexus Scenario in the four countries.

5.1 Power station with capture

The capital, operating and LCOE costs for the power plants with and without CO_2 capture at the different locations are summarised in Table 5-1. The costs for the equivalent plants in the Netherlands are also presented for comparison.

The specific capital requirement for the power plants range from 1248 €/kW installed in China and 1746 €/kW for India to 2136 and 2171 €/kW installed for the power plants in South Africa and Australia, respectively. In comparison to the cost of building the hypothetical the Netherlands plant, building an air-cooled USCPC in China is about 30% cheaper, while building the same plant in Australia and South Africa is about 20% more expensive. The higher cost for the Australian and South African cases arises due to the high costs of building in these countries due to high labour cost and low productivity factor (IEAGHG, 2018). In comparison, the lower cost for China arise due to significant material and construction labour cost reductions.

Building the USCPC with evaporative cooling in India, the costs are comparable to the reference plant in the Netherlands (~3% difference), though in contrast to the Indian plant the Dutch plant does not utilise ZLD technology to treat the discharged process water. Without the addition of ZLD, the Indian plant would be 5% cheaper than the Dutch reference plant due to material and construction labour cost reductions.

Comparing the LCOE for the USCPC power plants without capture, accounting also for operating expenses and cost of fuel, the LCOE range from 42 €/MWh and 45 €/MWh for China and India (ZLD at the power station adds 2 €/MWh in the India case), respectively, to 60 €/MWh in South Africa and 62 €/MWh in Australia (Table 5-1). The power station in Australia has the highest LCOE due to having the highest specific capital requirement and the highest fuel price (2 €/GJ, compare Table 4-7), while both the specific capital requirement and the fuel price in South Africa is lower (1.8 €/GJ, Table 4-7), though operating expenses are slightly higher (compare Table 5-1). Conversely, for China and India, the LCOE for power plants without capture are significantly lower by almost one third. For the Chinese case, this is a result of the lower capital requirement and lower operating expenses (Table 5-1), with the cost of fuel being the same as for the South African power station (1.8 €/GJ). For the Indian power station the specific capital requirement and annual operating costs are higher than for the Chinese power station. However, using local coal at 1 €/GJ (compare Table 4-7), its fuel costs are significantly lower.

Table 5-1 Economic summaries for coal fired USCPC power plants in the Netherlands, South Africa, Australia, China and India. ZLD at the power station is included for the Indian USCPC with and without capture and for the capture plants in China and South Africa

	TCR		Specific capital requirement		FOM	VOM	Fuel	OPEX	LCOE	CO_2 avoided
	Power plant	Total (including start-up costs)	Power plant	Total	Power plant	Power Plant	Power plant	Total	Total	Total
	M€	M€	€/kW	€/kW	M€ /y	M€ /y	M€ /y	M€/y	€/MWh	€/t CO_2
Netherlands										
USPC-EV	1343	1382	1644	1691	38	8	129	174	56	-
USPC-EV-PCC	1659	1715	2424	2506	46	18	129	193	79	34
USPC-AC	1359	1399	1732	1782	38	6	129	173	59	-
USPC-AC-PCC-EV	1676	1723	2558	2630	46	16	129	191	82	35
South Africa										
USCPC-AC	1597	1642	2078	2136	43	6	93	142	60	-
USCPC-AC-PCC-EV	2090	2147	3326	3418	56	17	93	166	91	44
Australia										
USCPC-AC	1526	1568	2113	2171	37	5	103	145	62	-
USCPC-AC-PCC-EV	1906	1957	3213	3300	46	10	103	158	90	38
China										
USCPC-AC	955	982	1212	1248	27	5	93	125	42	-
USCPC-AC-PCC-EV	1228	1264	1923	1978	35	14	93	142	62	29
India										
USPC-EV	1346	1384	1611	1746	39	6	52	97	45	-
USPC-EV-PCC	1713	1761	2677	2752	50	16	52	117	70	35

Adding CO_2 capture at the power station, as well as ZLD at the power stations in China, India and South Africa and the reuse of the ZLD-recovered product water, the increase in total capital requirement does not vary considerably between the different locations, ranging from 25% - 31%, while specific capital requirements (in €/kW installed) increase by 52% - 60%. In South Africa, the specific capital cost increase due to capture is 60%, 58% in China and India, and 52% in Australia. The increase in LCOE due to capture is 44% in Australia, about 50% in South Africa and China, and 55% in India. In absolute values, the LCOE for the power plants with capture range from 62 €/MWh in China, 70 €/MWh in India, with the highest cost in Australia and South Africa at 90 €/MWh and 91 €/MWh, respectively. The South African power station with capture has a higher LCOE than the Australian power station due to the additional cost of ZLD, as well as higher operating expenses, which outweigh the higher Australian fuel costs (compare Table 5-1). ZLD contributes 5 €/MWh at the South African and the Indian power stations, and 3 €/MWh at the Chinese power station, while there is no ZLD practiced at the Australian power station.

5.2 CCS Base Case Scenario

The economics for the CCS Base Case Scenario, including CO_2 transport and storage cost at a flat rate of 5 €/t CO_2 stored for all four locations, are summarised in Table 5-2. Table 5-2 also includes the cost for the corresponding cases for the Netherlands from Phase 1: the USCPC power plant using the same cooling technology with CO_2 storage onshore. To align with the other cases examined, CO_2 transport and storage costs for the Dutch cases are now also assumed as a flat rate of 5 €/t.

Annual storage costs, as variable operating costs, range from 20 – 21 M€/y, depending on the quantity of CO_2 captured and stored, see Table 5-4. A detailed cost breakdown of the CCS Base Case Scenario with USCPC power plants in South Africa, Australia, China and India is presented in Table 5-4, including capital investment, operating expenses, LCOE, and CO_2 avoidance cost.

In comparison to the equivalent power station without capture, the LCOE for the CCS Base Case Scenario increase by 25 €/MWh (60%) in China, 29 €/MWh (65%) in India, 32 €/MWh (51%) in Australia, and by 36 €/MWh (60%) in South Africa. This is indicated in Figure 5-1, which shows the LCOE for the CCS Base Case Scenario (ranging from 67 €/MWh for China up to 96 €/MWh for South Africa), with the breakdown in LCOE summarised in Table 5-3. While the increase in LCOE in India is the second lowest, as a fraction it is the highest due to the LCOE of the Indian power station without capture being significantly lower than for the Australian and South African power stations.

CO_2 transport and storage constitutes a comparatively small fraction of the total LCOE at 4.6 €/MWh (see Table 5-3), corresponding to about 5 – 7%.

The LCOE for the Dutch CCS Base Case Scenario using the same power station and cooling technology are higher than for the equivalent Indian power station (using evaporative cooling): 83 €/MWh compared to 74 €/MWh. While the equivalent Indian power station has higher capital requirements, its fuel costs are less than half of the Dutch power station (compare Table 5-3) due to the lower price of the Indian coal (2.5 €/GJ vs 1 €/GJ - compare Table 4-7).

For the power station using air cooling and evaporative cooling for the capture plant, the power station in the Netherlands has higher LCOE than the equivalent power station in China (86 €/MWh compared to 67 €/MWh), but lower than those in South Africa (96 €/MWh) and Australia (94 €/MWh). This is in spite of the higher Dutch fuel costs compared to South Africa and Australia. The LCOE in South Africa and Australia are higher due to higher capital investment for the power plant with capture. In China, capital costs, operating costs as well as fuel costs are lower than in the Netherlands, as well as in South Africa and Australia. This is demonstrated in Table 5-3.

CO_2 avoidance cost are presented in Figure 5-2, ranging from 36 €/t in China up to 51 €/t in South Africa, with India and Australia in the middle at 41 and 44 €/t, respectively.

Table 5-2 Economic summaries for coal fired USCPC power plants, with and without CCS in the Base Case Scenario without water extraction for the Netherlands, South Africa, Australia, China and India. ZLD at the power station is included for the Indian USCPC with and without CCS and for the capture plants in China and South Africa

	TCR			Specific capital requirement		FOM		VOM		Fuel	OPEX	LCOE	CO_2 avoided (incl. T&S)
	Power plant	Storage	Total (including start-up costs)	Power plant	Total	Power plant	Storage	Power Plant	Storage	Power plant	Total	Total	Total
	M€	M€	M€	€/kW	€/kW	M€/y	M€/y	M€/y	M€/y	M€/y	M€/y	€/MWh	€/t CO_2
The Netherlands													
USPC-EV	1343	0	1382	1644	1691	38	0	8	0	129	174	56	-
USPC-EV-PCC	1659	0	1715	2424	2506	46	0	18	20	129	213	83	40
USPC-AC	1359	0	1399	1732	1782	38	0	6	0	129	173	59	-
USPC-AC-PCC-EV	1676	0	1723	2558	2630	46	0	16	20	129	212	86	41
South Africa													
USCPC-AC	1597	0	1642	2078	2136	43	0	6	0	93	142	60	-
USCPC-AC-PCC-EV	2090	0	2147	3326	3418	56	0	17	21	93	187	96	51
Australia													
USCPC-AC	1526	0	1568	2113	2171	37	0	5	0	103	145	62	-
USCPC-AC-PCC-EV	1906	0	1957	3213	3300	46	0	10	20	103	178	94	44
China													
USCPC-AC	955	0	982	1212	1248	27	0	5	0	93	125	42	-
USCPC-AC-PCC-EV	1228	0	1264	1923	1978	35	0	14	21	93	163	67	36
India													
USPC-EV	1346	0	1384	1611	1746	39	0	6	0	52	97	45	-
USPC-EV-PCC	1713	0	1761	2677	2752	50	0	16	21	52	139	74	41

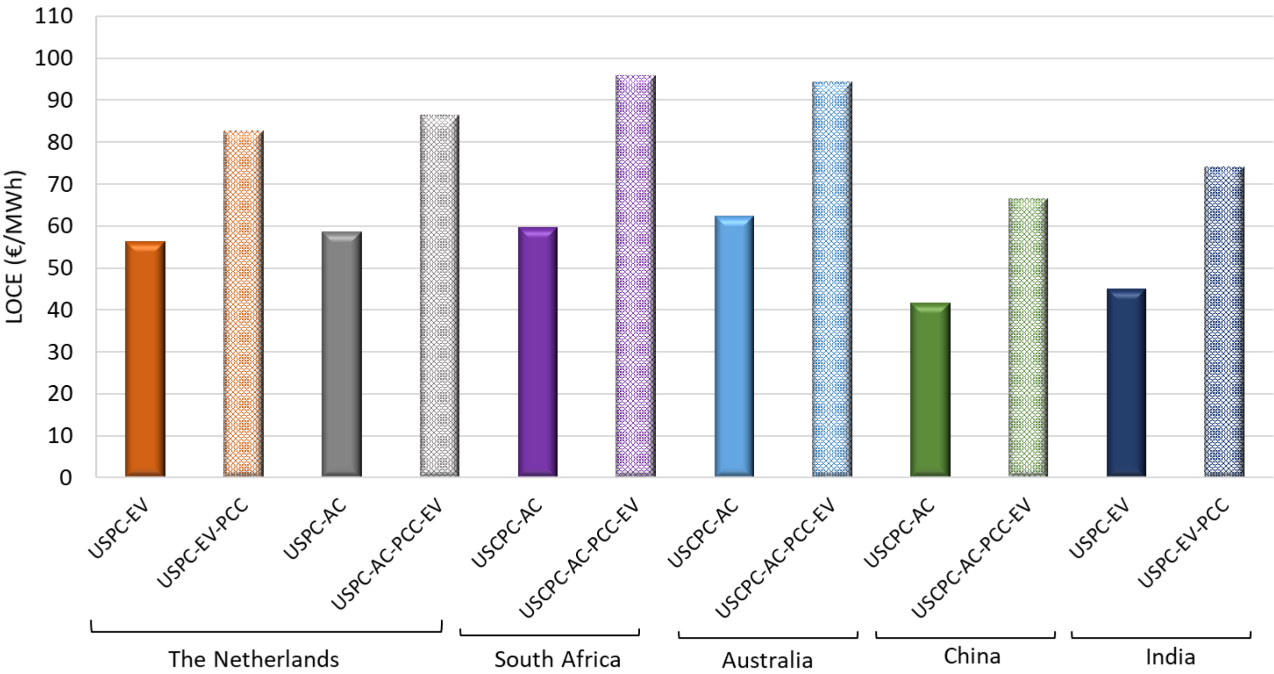

Figure 5-1 Comparison of LCOE of USCPC power plants in the CCS Base Case Scenario without water extraction located in the Netherlands, South Africa, Australia, China and India

Table 5-3 Breakdown of LCOE of USCPC power plants in the CCS Base Case Scenario without water extraction located in the Netherlands, South Africa, Australia, China and India (T&S = CO_2 transport and storage)

		The Netherlands				South Africa		Australia		China		India	
LCOE breakdown		USPC-EV	USPC-EV-PCC	USPC-AC	USCPC-AC-PCC-EV	USCPC-AC	USCPC-AC-PCC-EV	USCPC-AC	USCPC-AC-PCC-EV	USCPC-AC	USCPC-AC-PCC-EV	USPC-EV	USPC-EV-PCC
Capex (PP+PCC)	€/MWh	27.4	40.4	28.9	42.6	34.6	55.4	35.2	53.5	20.2	32.0	28.3	44.6
FOM	€/MWh	6.4	9.2	6.7	9.7	7.7	12.4	7.0	10.6	4.7	7.5	6.8	10.7
VOM	€/MWh	1.3	3.6	1.1	3.4	1.1	3.6	1.0	2.2	0.9	3.1	1.1	3.5
Fuel	€/MWh	21.2	25.3	22.1	26.4	16.2	19.8	19.2	23.4	15.8	19.5	8.7	10.8
T&S	€/MWh	0.0	4.1	0.0	4.3	0.0	4.6	0.0	4.6	0.0	4.5	0.0	4.6
Total LCOE	**€/MWh**	**56.2**	**82.6**	**58.7**	**86.4**	**59.7**	**95.8**	**62.4**	**94.3**	**41.7**	**66.6**	**44.9**	**74.2**

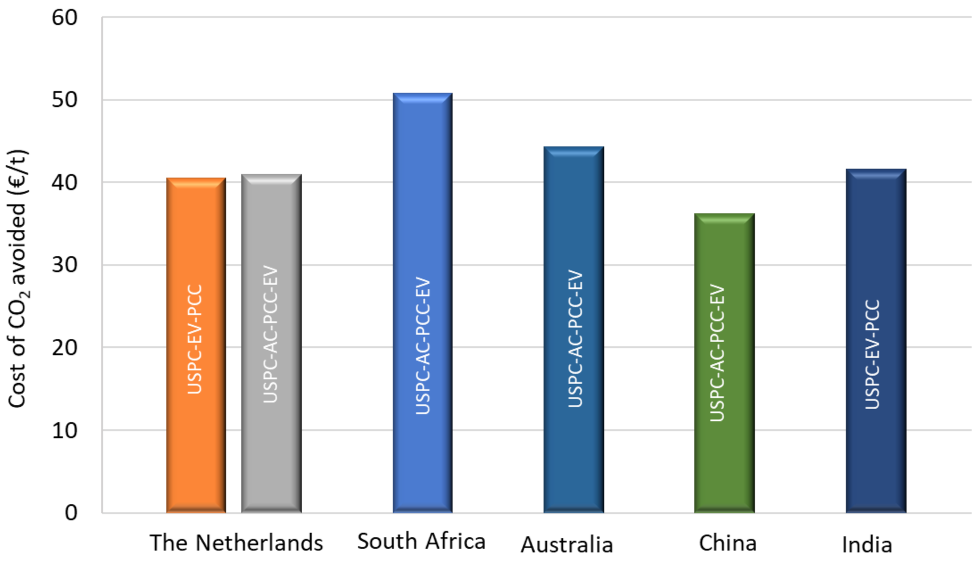

Figure 5-2 Cost of CO_2 avoided of USCPC power plants in the CCS Base Case Scenario without water extraction located in the Netherlands, South Africa, Australia, China and India

Table 5-4 Cost breakdown of the power station without capture and the CCS Base Case Scenario (no water extraction) with the USCPC using different cooling technologies for the power station and the capture plant in South Africa, Australia, China and India

		South Africa		**Australia**		**China**		**India**	
Power station type		**USCPC**	**USCPC-PCC**	**USCPC**	**USCPC-PCC**	**USCPC**	**USCPC-PCC**	**USCPC**	**USCPC-PCC**
Cooling technology power station		**Air**	**Air**	**Air**	**Air**	**Air**	**Air**	**Evap.**	**Evap.**
Cooling capture plant		**-**	**Evap.**	**-**	**Evap.**	**-**	**Evap.**	**-**	**Evap.**
Power station and capture									
Efficiency	%LHV	41.82	34.18	39.27	30.35	42.82	34.73	43.11	34.79
Net power	MW	769	628	722	593	787	639	793	640
Water consumption (total)	Mt/y	0.41	4.80	0.40	4.43	0.40	3.39	3.78	7.59
Water consumption (capture only)	Mt/y		4.38		4.03		3.00		3.81
Process water discharge	Mt/y	0	1.46	0	1.34	0	1.00	1.12	2.37
ZLD at power station		n/a	yes	n/a	no	n/a	yes	yes	yes
ZLD technology			MBC		-		MBC	MBC	MBC
Water recovery	%		90		-		90	90	90
Product water	Mt/y		1.31		-		0.9	1.00	2.14
CO_2 transport and storage									
Storage location			onshore		onshore		onshore		onshore
Geological storage basin			Zululand		Surat		Songliao		Cambay
Reservoir permeability	mD		<1 – 229		med 13, max 1,500		150-285		0.3-163

		South Africa		Australia		China		India	
Power station type		**USCPC**	**USCPC-PCC**	**USCPC**	**USCPC-PCC**	**USCPC**	**USCPC-PCC**	**USCPC**	**USCPC-PCC**
Reservoir porosity	%		4-41		17		18–20		2-14
CO_2 injection rate	Mt/y		4.18		3.98		4.16		4.27
Reservoir boundaries			open		open		open		open
Formation water salinity	ppm		14,000 – 38,000		5,000 – 15,000		3,500 – 9,000		7,000 – 10,000
Water extraction for storage		n/a	no	n/a	no	n/a	no	n/a	no
Emissions data									
CO_2 emitted	t/MWh	0.812	0.099	0.822	0.100	0.788	0.097	0.804	0.098
Capital costs									
ZLD at power station	M€	n/a	89.8	-	-	n/a	41.68	62.48	98.26
Power plant with capture (incl. ZLD)	M€	1597	2090	1526	1906	955	1228	1346	1713
Start-up costs	M€	44.7	57.8	41.8	51.7	27.8	35.2	37.8	47.8
CO_2 transport & storage	M€	n/a	0	n/a	0	n/a	0	n/a	0
Water extraction & treatment	M€	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Total Capex	M€	**1642**	**2147**	**1568**	**1957**	**982**	**1264**	**1384**	**1761**
Operating costs									
Power Plant and Capture									
Fixed	M€/y	43.13	56.14	36.63	45.73	27.11	34.75	38.84	49.36
Variable	M€/y	6.39	16.60	5.34	9.53	5.06	14.20	6.48	16.04
Fuel	M€/y	92.9	92.9	103.2	103.2	92.9	92.9	51.6	51.6
CO_2 transport & storage									
Fixed	M€/y								
Variable	M€/y		20.91		19.90		20.78		21.36
Water extraction & treatment									
Fixed	M€/y	0	0	0	0	0	0	0	0
Variable	M€/y	0	0	0	0	0	0	0	0
Total Opex	M€/y	**142**	**187**	**145**	**178**	**125**	**163**	**97**	**139**
LCOE									
Capex (PP+Capture)	€/MWh	34.6	55.4	35.2	53.5	20.2	32.0	28.1	44.6
FOM	€/MWh	7.7	12.4	7.0	10.6	4.7	7.5	6.8	10.7
VOM	€/MWh	1.1	3.6	1.0	2.2	0.9	3.1	1.1	3.5
Fuel	€/MWh	16.2	19.8	19.2	23.4	15.8	19.5	8.7	10.8
Transport & Storage	€/MWh	0.0	4.6	0.0	4.6	0.0	4.5	0.0	4.6
Water treatment	€/MWh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total LCOE	**€/MWh**	**59.7**	**95.5**	**62.4**	**94.3**	**41.7**	**66.6**	**44.7**	**74.2**
CO_2 avoided cost (€/t CO_2)			**50.68**		**44.21**		**36.14**		**41.50**

5.3 CCS-Water-Nexus Scenario

The economics for the CCS-Water-Nexus Scenario, including CO_2 transport and storage cost at a flat rate of 5 €/t CO_2 stored and water extraction and transport cost at a rate of 2.5 €/t of CO_2 stored for all four locations, are summarised in Table 5-5. Table 5-5 also includes the cost for the corresponding cases for the Netherlands from Phase 1: the USCPC power plant using the same cooling technology with CO_2 storage onshore. To align with the other cases examined, CO_2 transport and storage costs for the Dutch cases are now also assumed as a flat rate of 5 €/t, while water extraction and transport is estimated at 2.5 €/t.

CO_2 transport and storage costs remain unchanged to the CCS Base Case Scenario, but costs for water extraction, transport, and management are added. Water management costs are those of water treatment and reject management in evaporation ponds. It should be highlighted that even where treatment to ZLD occurs, the final step of evaporating the remaining water left in the highly concentrated brine in a crystallisation or evaporation pond is referred to as “disposal” in this study though it is part of the ZLD treatment. Water extraction and transport costs (as variable operating costs) range from around 10 – 11 M€/y, depending on the quantity of CO_2 captured and stored (see Table 5-7).

The capital and operating costs of water treatment for the four different countries are in Table 5-7, which presents a detailed cost breakdown of the CCS-Water-Nexus Scenario from USCPC power plants in South Africa, Australia, China and India, including capital investment, operating expenses, LCOE, and CO_2 avoidance cost. Water treatment adds between 17 – 52 M€ in capital costs. Variations occur due to differences in brine salinity and subsequently the treatment technology applied, as well as labour, material and construction costs. Thus, in spite of having the lowest estimated concentration of TDS (5,000 mg/l – the same as the Chinese brine) Australia exhibits the highest capital costs due to a more advanced treatment technology being used and Australia having the highest material and construction costs out of the four countries.

Treatment and brine disposal operating costs range from 5 – 11 M€/y, with South Africa having the highest operating costs due to having the highest initial TDS concentration in the feed stream (estimated as 26,000 mg/l) as well as high labour and material costs and China exhibiting the lowest operating costs due to a low initial TDS concentration (5,000 mg/l) and comparatively low labour, material and construction costs.

Water extraction, transport and its management adds between 4 – 6 €/MWh to the LCOE of the CCS-Water-Nexus Scenario; in China and India it adds 4 €/MWh, in Australia 5 €/MWh and in South Africa 6 €/MWh (compare Table 5-6). While the Australian and Chinese brines have the same estimated salinity, high labour, construction and material costs combined with the use of a more advanced treatment technology and higher disposal costs in Australia result in a higher LCOE.

For the Dutch cases from Phase 1, water management adds approximately 7 €/MWh. The LCOE of water management are higher than for all other examined countries due to the very high salinity of the Dutch onshore brines (150,000 mg/l) and low associated recoveries, resulting in disposal of a large reject stream after treatment via reinjection.

The overall increase in the LCOE for the CCS-Water-Nexus scenarios in comparison to the same power station without CCS is presented in Figure 5-3 for each country. In comparison to the power station without capture, adding CCS with water extraction and recovery increases the LCOE by 28 €/MWh (69%) to 70 €/MWh in China, by 33 €/MWh (73%) to 78 €/MWh in India, by 36 €/MWh (58%) to 99 €/MWh in Australia, and by 42 €/MWh (70%) to 101 €/MWh in South Africa (compare Table 5-6). The highest LCOE in South Africa are a result of the highest operating expenses of the four locations, higher labour, material and construction costs in comparison to China and India, as well as the additional cost of ZLD for the power station with capture in comparison to the Australian case.

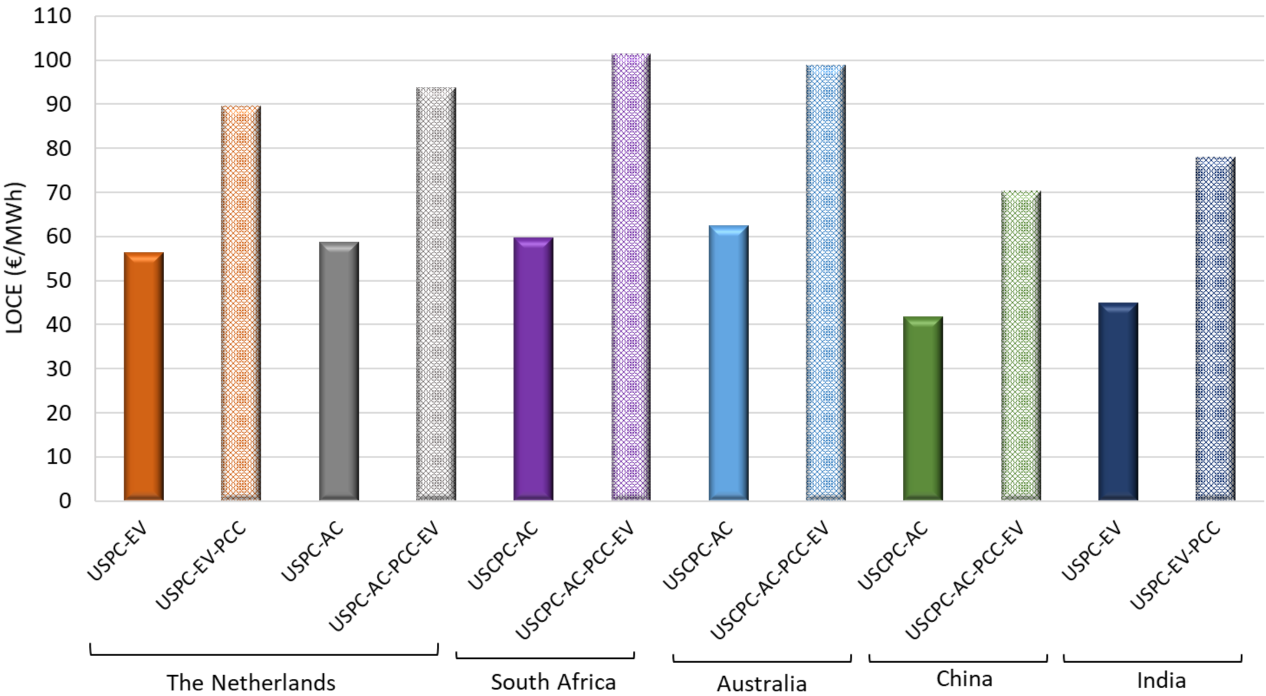

Figure 5-3 Comparison of LCOE of USCPC power plants in the CCS-Water-Nexus Scenario with water extraction and treatment located in the Netherlands, South Africa, Australia, China and India

Table 5-5 Economic summaries for coal fired USCPC power plants, with and without CCS in the Base Case Scenario without water extraction for The Netherlands, South Africa, Australia, China and India. ZLD at the power station is included for the Indian USCPC with and without CCS and for the capture plants in China and South Africa

	TPC		TRC	SCR	SCR	FOM		VOM		Fuel			
	Power plant	Storage & water management	Total (incl. start up costs)	Power plant	Total (incl. start up costs)	Power plant	Storage & water management	Power Plant	Storage & water management	Power plant	Total	LCOE	CO_2 avoided (incl. T&S)
	M€	M€	M€	€/kW	€/kW	M€ /yr	M€ /yr	M€ /yr	M€ /yr	M€ /yr	M€ /yr	€/MWh	€/t CO2
The Netherlands													
USPC-EV	1343	0	1382	1644	1691	38	0	8	0	129	174	56	-
USPC-EV-PCC	1659	141	1848	2424	2700	46	6	17	34	129	232	90	51
USPC-AC	1359	0	1399	1732	1782	38	0	6	0	129	173	59	-
USPC-AC-PCC-EV	1676	141	1865	2558	2846	46	6	16	34	129	231	94	52
South Africa													
USCPC-AC	1597	0	1642	2078	2136	43	0	6	0	93	142	60	-
USCPC-AC-PCC-EV	2090	52	2199	3326	3500	56	0	15	42	93	207	101	58
Australia													
USCPC-AC	1526	0	1568	2113	2171	37	0	5	0	103	145	62	-
USCPC-AC-PCC-EV	1906	38	1995	3213	3364	46	0	8	37	103	194	99	50
China													
USCPC-AC	955	0	982	1212	1248	27	0	5	0	93	125	42	-
USCPC-AC-PCC-EV	1228	28	1291	1923	2021	35	0	13	0	93	141	70	41
India													
USPC-EV	1346	0	1384	1611	1746	39	0	6	0	52	97	45	-
USPC-EV-PCC	1713	17	1778	2677	2778	50	0	15	39	52	155	78	47

Table 5-6 Breakdown of LCOE of USCPC power plants in the CCS-Water-Nexus Scenario with water extraction and treatment located in the Netherlands, South Africa, Australia, China and India (T&S = CO_2 transport and storage)

LCOE breakdown		The Netherlands				South Africa		Australia		China		India	
Power station		USPC-EV	USPC-EV-PCC	USPC-AC	USCPC-AC-PCC-EV	USCPC-AC	USCPC-AC-PCC-EV	USCPC-AC	USCPC-AC-PCC-EV	USCPC-AC	USCPC-AC-PCC-EV	USPC-EV	USPC-EV-PCC
Capex (PP+Capture)	€/MWh	27.4	40.4	28.9	42.6	34.6	55.4	35.2	53.5	20.2	32.0	28.3	44.6
FOM	€/MWh	6.4	9.2	6.7	9.7	7.7	12.4	7.0	10.6	4.7	7.5	6.8	10.7
VOM	€/MWh	1.3	3.5	1.1	3.3	1.1	3.4	1.0	1.9	0.9	2.8	1.1	3.1
Fuel	€/MWh	21.2	25.3	22.1	26.4	16.2	19.8	19.2	23.4	15.8	19.5	8.7	10.8
T&S	€/MWh	0.0	4.1	0.0	4.3	0.0	4.6	0.0	4.6	0.0	4.5	0.0	4.6
Water treatment	€/MWh	0.0	7.0	0.0	7.3	0.0	5.8	0.0	4.8	0.0	3.9	0.0	4.1
Total LCOE	**€/MWh**	**56.2**	**89.5**	**58.7**	**93.7**	**59.7**	**101.3**	**62.4**	**98.8**	**41.7**	**70.3**	**44.9**	**77.9**

CO_2 avoidance cost for the CCS-Water-Nexus Scenario range from 41 €/t of CO_2 for China up to 58 €/t for South Africa (see Figure 5-4 and Table 5-5). Avoidance cost in India and Australia are in the middle at 47 €/t and 50 €/t, respectively.

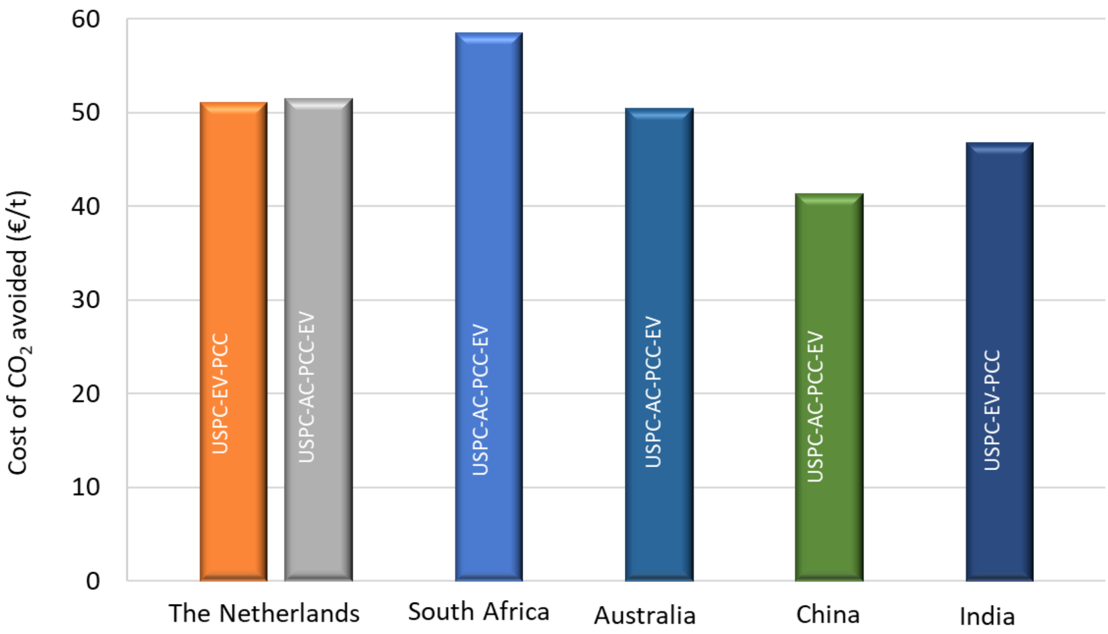

Figure 5-4 CO_2 avoidance costs of USCPC power plants in the CCS-Water-Nexus Scenario with water extraction and treatment located in the Netherlands, South Africa, Australia, China and India

Table 5-7 Cost breakdown of the USCPC without capture and the CCS-Water-Nexus Scenario with the USCPC using different cooling technologies for the power station and the capture plant in South Africa, Australia, China and India

		South Africa		Australia		China		India	
Power station type		**USCPC**	**USCPC-PCC**	**USCPC**	**USCPC-PCC**	**USCPC**	**USCPC-PCC**	**USCPC**	**USCPC-PCC**
Cooling technology power station		**Air**	**Air**	**Air**	**Air**	**Air**	**Air**	**Evap.**	**Evap.**
Cooling capture plant		**-**	**Evap.**	**-**	**Evap.**	**-**	**Evap.**	**-**	**Evap.**
Power station and capture									
Efficiency	%LHV	41.82	34.18	39.27	30.35	42.82	34.73	43.11	34.79
Net power	MW	769	628	722	593	787	639	793	640
Water consumption (total)	Mt/y	0.41	4.80	0.40	4.43	0.40	3.39	3.78	7.59
Water consumption (capture only)	Mt/y		4.38		4.03		3.00		3.81
Process water discharge	Mt/y	0	1.46	0	1.34	0	1.00	1.12	2.37
ZLD at power station		n/a	yes	n/a	no	n/a	yes	yes	yes
ZLD technology			MBC		-		MBC	MBC	MBC
Water recovery	%		90		-		90	90	90
Product water	Mt/y		1.31		-		0.9	1.00	2.14
CO_2 transport and storage with water treatment									
Storage location			onshore		onshore		onshore		onshore
Geological storage basin			Zululand		Surat		Songliao		Cambay
Reservoir permeability	mD		<1 – 229		med 13, max 1,500		150-285		0.3-163
Reservoir porosity	%		4-41		17		18–20		2-14
CO_2 injection rate	Mt/y		4.18		3.98		4.16		4.27
Reservoir boundaries			Closed		Closed		Closed		Closed
Formation water salinity	ppm		14,000 – 38,000		5,000 – 15,000		3,500 – 9,000		7,000 – 10,000
Water extraction for storage		n/a	Yes	n/a	Yes	n/a	Yes	n/a	yes
Water extraction rate			7.11		6.76		7.06		7.26
Water recovery	%		92.75		85		98.525		97.325
Product water	Mt/y		6.60		5.75		6.96		7.07
Emissions data									
CO_2 emitted	t/MWh	0.812	0.099	0.822	0.100	0.788	0.097	0.804	0.098
Capital costs									
ZLD at power station	M€	n/a	89.8	-	-	n/a	41.68	62.48	98.26
Power plant with capture (incl. ZLD)	M€	1597	2090	1526	1906	955	1228	1346	1713
Start-up costs	M€	44.7	57.8	41.8	51.7	27.8	35.2	37.8	47.8
CO_2 transport & storage	M€	n/a	0	n/a	0	n/a	0	n/a	0
Water extraction & treatment	M€	n/a	51.8	n/a	38.2	n/a	27.5	n/a	16.9
Total Capex	M€	**1642**	**2199**	**1568**	**1995**	**982**	**1291**	**1384**	**1778**
Operating costs									
Power Plant and Capture									
Fixed	M€/y	43.13	56.14	36.63	45.73	27.11	34.75	38.84	49.36
Variable	M€/y	6.39	16.60	5.34	9.53	5.06	14.20	6.48	16.04

		South Africa		Australia		China		India	
Power station type		**USCPC**	**USCPC-PCC**	**USCPC**	**USCPC-PCC**	**USCPC**	**USCPC-PCC**	**USCPC**	**USCPC-PCC**
Fuel	M€/y	92.9	92.9	103.2	103.2	92.9	92.9	51.6	51.6
CO_2 transport & storage									
Fixed	M€/y								
Variable	M€/y		20.91		19.90		20.78		21.36
Water extraction									
Fixed	M€/y	0	0	0	0	0	0	0	0
Variable	M€/y	0	10.46	0	9.95	0	10.39	0	10.68
Water treatment									
Fixed	M€/y	0	0	0	0	0	0	0	0
Variable	M€/y	0	10.35	0	2.90	0	4.91	0	6.23
Concentrated brine disposal									
Fixed	M€/y	0	0	0	0	0	0	0	0
Variable	M€/y	0	0.63	0	3.94	0	0.21	0	0.35
Total Opex	M€/y	**142**	**207**	**145**	**194**	**125**	**177**	**97**	**155**
LCOE									
Capex (PP+Capture)	€/MWh	34.6	55.4	35.2	53.5	20.2	32.0	28.1	44.6
FOM	€/MWh	7.7	12.4	7.0	10.6	4.7	7.5	6.8	10.7
VOM	€/MWh	1.1	3.6	1.0	2.2	0.9	3.1	1.1	3.5
Fuel	€/MWh	16.2	19.8	19.2	23.4	15.8	19.5	8.7	10.8
Transport & Storage	€/MWh	0.0	4.6	0.0	4.6	0.0	4.5	0.0	4.6
Water treatment	€/MWh	0.0	5.8	0.0	4.8	0.0	3.9	0.0	4.1
Total LCOE	**€/MWh**	**59.7**	**101.3**	**62.4**	**98.8**	**41.7**	**70.3**	**44.7**	**77.9**
CO_2 avoided cost (€/t CO_2)			**58.41**		**50.43**		**41.38**		**46.85**

5.4 Summary of results

The section provides a comparison of the LCOE and the avoidance costs of the CCS Base Case scenarios with the CCS-Water-Nexus scenarios presented above for the four countries examined in this study, as well as the relevant Dutch cases from Phase 1.

Table 5-8 summarises the LCOE for the USCPC power plants with and without capture using different cooling technologies in the different countries, while Table 5-9 present the CO_2 avoidance cost.

Without capture, the air-cooled power station is the least expensive in China (at 42 €/MWh), while in the Netherlands, South Africa, and Australia the LCOE are higher and compare to one another (59 – 62 €/MWh). Adding CCS with the capture plant using evaporative cooling and no water extraction and management (CCS Base Case Scenario), the Base Case Scenario is cheapest in China (67 €/MWh), while in comparison to the scenario without CCS, the costs in South Africa and Australia increase more than in the Netherlands (96 and 94 €/MWh, respectively compared to 86 €/MWh). Due to the assumed flat rate, CO_2 transport and storage costs are comparable for all cases, thus the difference is caused by the higher capital and fixed operating costs for the power plant with capture. This is despite the fuel cost being cheaper in South Africa and Australia in comparison to the Netherlands.

The trend continues for the CCS-Water-Nexus Scenario, where water extraction and treatment for reuse in the power station and other beneficial uses is assumed. In comparison to the CCS Base Case Scenario, the LCOE for the CCS-Water-Nexus scenarios increase only marginally: by 3 €/MWh in China, 5 €/MWh in Australia and South Africa (which all correspond to an increase of about 5%), and 7 €/MWh in the Netherlands (8% increase). The different treatment costs are not only a result of different labour, construction and material costs between the different countries, but also affected by the treatment options applied to the brines of different TDS concentrations. For example, the Dutch brine has a significantly higher salinity than all the other brines considered in this study (150,000 mg/l compared to 26,000 mg/l or less)

In the India case, where evaporative cooling is used in both the power and the capture plant, the LCOE are less for the Indian power station (45 €/MWh) than for the equivalent Dutch power station (56 €/MWh). The absolute difference decreases slightly when CCS without water extraction is added (74 and 83 €/MWh for India and the Netherlands, respectively), indicating that building and operating the capture plant in India is more expensive than in the Netherlands in terms of LCOE. This is also a result of the requirement of ZLD at the Indian power station, which is not part of the Dutch power station. Analogous to the other countries, the Indian CCS-Water-Nexus Scenario only adds a comparatively small cost on top of the CCS Base Case Scenario: 4 €/MWh (5%) for the Indian case and 7 €/MWh (8%) for the Dutch case.

Table 5-8 LCOE for coal-fired USCPC power plants with and without CCS in five countries

Cooling technology power plant		Air cooling			Evaporative cooling		
Cooling technology capture plant		**Evaporative cooling**			**Evaporative cooling**		
LCOE		**USCPC-AC**	**USCPC-AC-PCC-EV**		**USCPC-EV**	**USCPC-EV-PCC**	
CCS Scenario		**No CCS**	**Base Case**	**Water-Nexus**	**No CCS**	**Base Case**	**Water-Nexus**
Netherlands*	€/MWh	59	86	94	56	83	90
South Africa	€/MWh	60	96	101	-	-	
Australia	€/MWh	62	94	99	-	-	
China	€/MWh	42	67	70	-	-	
India	€/MWh	-	-		45	74	78

*The LCOE for the Dutch power stations in the CCS Base Case and the CCS-Water-Nexus scenarios vary slightly from Phase 1 due to CO_2 storage and transport cost and water extraction and transport cost now being assumed as a 5 €/t and a 2.5 €/t flat rate, respectively to align with the four other cases

CO_2 avoidance cost for the air-cooled power station with the capture plant using evaporative cooling range from 36 – 51 €/t CO_2 in the CCS Base Case Scenario and increase to 41 – 58 €/t CO_2 in the CCS-Water-Nexus Scenario (Table 5-9). In both scenarios, the Chinese case has the lowest avoidance cost, while South Africa has the highest. The highest increase in avoidance cost is recorded for the Netherlands from 41 to 52 €/t CO_2 (compare Table 5-9).

For the power plant with capture using evaporative cooling avoidance cost are comparable for India (40 €/t CO_2) and the Netherlands (41 €/t CO_2), but the increase from the CCS Base Case to the CCS-Water-Nexus Scenario is higher for the Netherlands case than for the India case (compare Table 5-9) due to higher water management costs.

Table 5-9 Avoidance cost for coal-fired USCPC power plants with and without CCS in five countries

Cooling technology power plant		Air cooling		Evaporative cooling	
Cooling technology capture plant		**Evaporative cooling**		**Evaporative cooling**	
CO_2 avoidance cost		**USCPC-AC-PCC-EV**		**USCPC-EV-PCC**	
CCS Scenario		**Base Case**	**Water-Nexus**	**Base Case**	**Water-Nexus**
Netherlands*	€/t CO_2	41	52	40	51
South Africa	€/t CO_2	51	58		
Australia	€/t CO_2	44	50		
China	€/t CO_2	36	41		
India	€/t CO_2			41	47

*The CO_2 avoidance cost for the Dutch power stations in the CCS Base Case and the CCS-Water-Nexus scenarios vary slightly from Phase 1 due to CO_2 storage and transport cost and water extraction and transport cost now being assumed as a 5 €/t and a 2.5 €/t flat rate, respectively to align with the four other cases

The analysis shows that local conditions, such as local labour, construction, material, and fuel cost, as well as environmental conditions, such as ambient temperature, can have a significant effect on the cost of CCS. This is best illustrated comparing the China and the South Africa case, with the South African LCOE being about 30 €/MWh or 44% higher.

The analysis also shows that water extraction and treatment add a comparatively small cost to a CCS project. Therefore, the extracted and treated water may provide a valuable unconventional water resource in regions that are suffering water stress, especially when considering the associated cost of water shortages. For example, in South Africa in 2015/2016 drought and related water stress resulted in a financial impact of 39 M€ for just 10 companies (CDP, 2010), while in China between 2001 and 2005, water shortages caused industrial losses of 1.62% of China's annual GDP (MWR, 2007). The economic viability of reusing the treated storage-extracted water is discussed in Chapter 6, which presents a comparison of water treatment costs and local water charges (Chapter 6.5). In addition, water stress in South Africa, Australia, China and India and options for beneficial use of storage-extracted and recycled water are discussed in more detail.

6 The extraction-reuse network: beneficial use and challenges

This section presents the particular water-related challenges faced by the four countries of interest in this study; South Africa, Australia, China and India. Alternative or additional uses of the storage-extracted water to its reuse in the power station with capture are suggested and the costs of treated storage-extracted water are compared to local water tariffs.

All four countries have in common that they are already facing water stress[2], which is expected to worsen over the next decades, with high water stress expected in all four countries by 2040 as per Figure 6-1. This suggests that storage-extracted water may present a valuable unconventional resource.

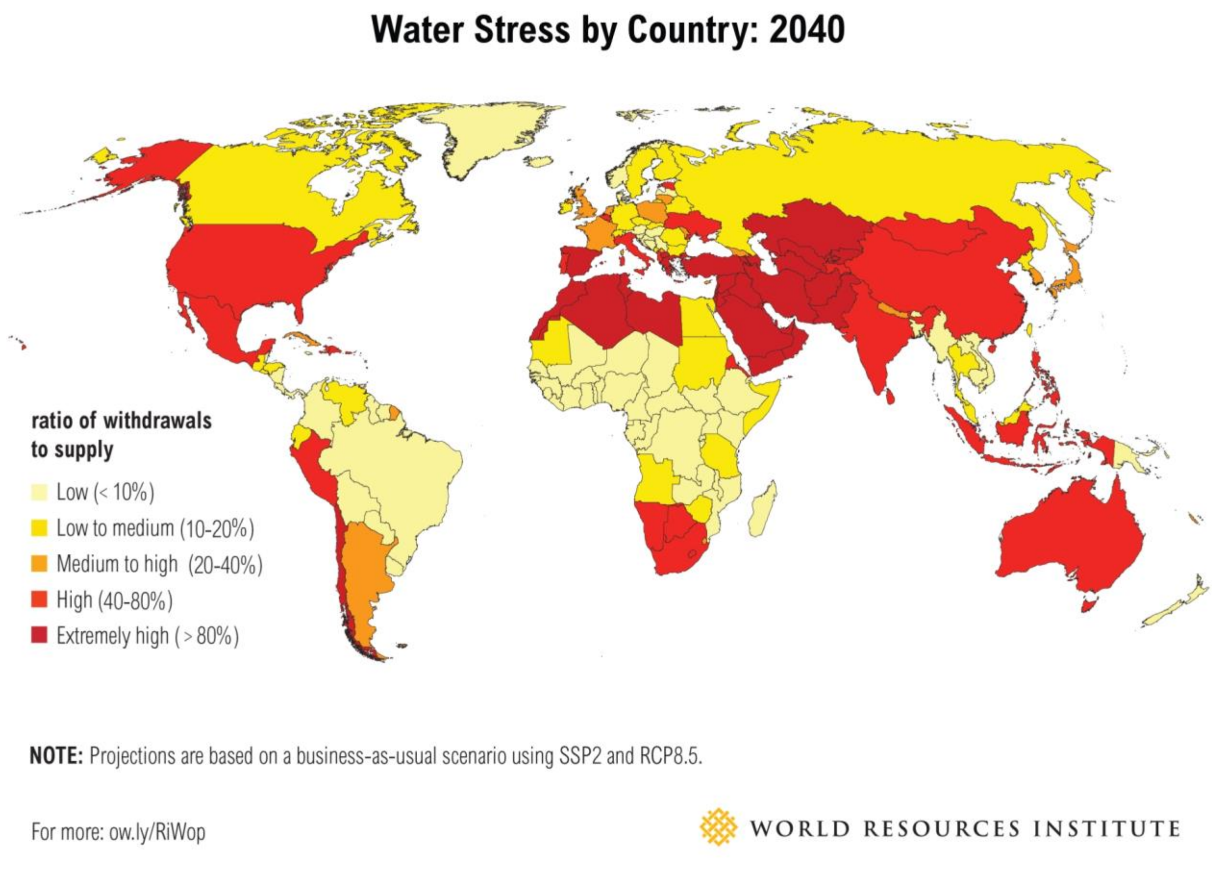

Figure 6-1 Estimated water stress by country by 2040 (WRI, 2015)

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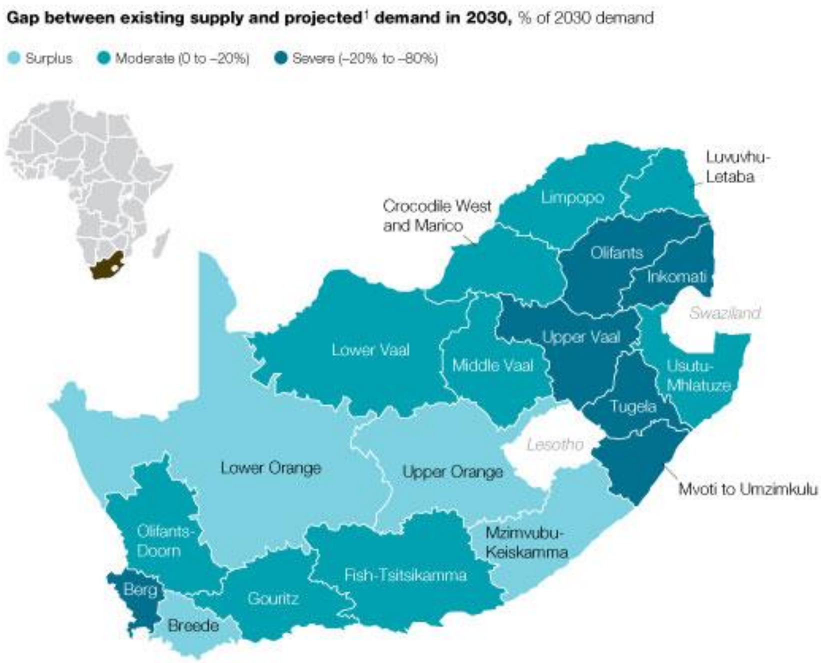
[2] Water stress is the ratio of total water withdrawal over available supply (Gassert et al. 2014).

6.1 South Africa

6.1.1 Water stress in South Africa

South Africa is a semiarid country characterized by low rainfall, limited underground aquifers, and a reliance on significant water transfers from neighbouring nations. Into the future, the country is expected to face difficult economic and social choices between the demands of agriculture, key industrial activities such as mining and power generation, and large and growing urban centres (McKinsey, 2010).

Cities in South Africa are typically located around mineral deposits rather than near water resources. This requires the transfer of water from an area of water surplus to an area of water deficit (Hallowes, 2019). For example, South Africa is importing water from other countries in the Southern Africa Development Community (SADC) region, such as the inter-basin transfer of water for domestic and industrial use from Lesotho to the Gauteng Province, an economic hub in South Africa with the major cities of Johannesburg and Pretoria, as part of the Lesotho Highlands Water Project (Matchaya et al., 2019). The water purchased from Lesotho constitutes almost 25% of South Africa's total water supply (McKinsey, 2010). A map highlighting the predicted gaps in water supply in 2030 by region is presented in Figure 6-2.



[1]Frozen irrigation levels and limited ability to increase rainfed land will drive an increase in virtual water trade between water-management areas and internationally with trading partners.

Source: Water Research Commission; South African Department of Water Affairs and Forestry (DWAF); Statistics South Africa; 2030 Water Resources Group

Figure 6-2 South Africa's water demand gap between existing supply and projected demand in 2030 by region (from McKinsey, 2010)

A country-wide water shortage is predicted to be just a decade away unless urgent action is taken. The Department of Water and Sanitation (DWS) expects a water deficit of about 3 billion m^3 of water per year by 2030 (Kretzmann, 2019; McKinsey, 2010), with an estimated overall demand of ~18 billion m^3 (McKinsey, 2010). Irrigation for agriculture is estimated to consume 45% of this, followed by 20% for households and 19% for industrial purposes (McKinsey, 2010). However, water scarcity has already been found to have had severe impacts on the economy in the past: in 2015/2016 drought and related water stress resulted in a financial impact of 610 MZAR (~39 M€) for just 10 companies (CDP, 2016).

The growing water crisis is a result of a range of factors, amongst them climate change, infrequent rainfall, migration from rural villages to the cities (McKinsey, 2010), as well as deteriorating infrastructure (Kretzmann, 2019), population growth and economic growth (McKinsey, 2010). Economic growth is associated with an increase in power consumption, with much of the additional power generation capacity planned for 2025 to come from coal-fired power plants located near coal mines. An increased reliance on water transfers in these areas is expected (McKinsey, 2010).

The increasing water scarcity is reflected in the rise in water tariffs proposed by the DWS by at least 16.5% (Head, 2019). In Johannesburg water tariffs for both domestic and industrial users have already been increased by 10% from 2019 to 2020, now reaching 42.2 ZAR/m^3 (~2.70 €/m^3), while domestic users pay up to ~50 ZAR/m^3 (3.20 €/m^3) (City of Johannesburg, 2019). In Durban, over the same time frame, domestic and industrial rates have risen by close to 15% with domestic tariffs now as high as 57 ZAR/m^3 (~3.70 €/m^3), though tariffs for industrial users are significantly lower at 33 ZAR/m^3 (~2.10 €/m^3) (eThekwini Municipality, 2019).

6.1.2 Beneficial reuse of water in South Africa and associated challenges

Due to the scarcity of water and the increasing cost to users, recycling of storage-extracted water may present an attractive option in South Africa. However, due to the high salinity of the storage-extracted water from the Zululand Basin with an average estimated TDS of 26,000 mg/l, the water does require treatment before it may be reused. Recommended maximum TDS for treated waste water for irrigation purposes is 1,000 mg/l (DWA, 1996a), while the target range for drinking water is 0 – 450 mg/l (DWAF, 1996b). Still, due to its salinity being less than that of seawater and the location of the storage site being onshore, it likely presents a more attractive option than the treatment and reuse of seawater. The estimated cost of 2.33 €/m^3 (compare Table 4-12), or 2.43 €/m^3 including disposal cost of the reject stream, for treated storage-extracted water from the Zululand Basin in this study compares well to the tariffs charged to industrial users in South African cities (e.g., 2.10 – 3.70 €/m^3 in Johannesburg and Durban), making it a feasible substitute over the purchase of freshwater. However, at this price the treated water cannot compete with abstracted water, which is typically supplied at a fraction of the cost (OECD, 1999).

An example of a beneficial reuse scheme is the treatment of the excess water (123,250 ML/d) produced from the Emalahleni Coalfields. The mine water is treated to potable standard at a recovery rate of 97% and supplied to the Emalahleni Municipality (DWA, 2011).

Another option includes the artificial recharge of aquifers to increase the yield of the groundwater system through limiting groundwater evapo-transpiration losses. Aquifers with a yield ≥ 5 l/s are considered suitable for artificial recharge applications (DWA, 2011).

To enable large-scale beneficial reuse of water in South Africa, the use of non-conventional water needs to be properly managed and controlled. Appropriate guidelines for water recycling, reuse and reclamation should be developed in combination with a clear policy and strategy to encourage the introduction of beneficial reuse schemes. The new National Water and Sanitation Master Plan has been announced by the DWS, which also includes the initiation of a programme to use alternative water sources such as desalination and recycling (Kretzmann, 2019). Monitoring and regulation of non-conventional water resources is also necessary (DWA, 2011). Currently, the reuse of effluent streams requires environmental authorisation in terms of the National Environmental Management Act, Act 107 of 1998 (And its amendments and SEMAs), and in some cases, depending on the intended use, requires water use licences in terms of the National Water Act, Act 36 of 1998 (DWA, 2011).

6.2 Australia

6.2.1 Water stress in Australia

Data from the Australian Bureau of Statistics shows that between 2009 and 2017 the amount of water extracted from the environment and used within the Australian economy increased 19% from 64,076 to 76,159 gigalitres (GL) (Colombo, 2019). Water consumption (i.e., water not returned to the environment) increased by 23% from 13,476 GL to 16,558 GL, linked to a growth in GDP and population. Australia's primary water user is the agricultural sector, accounting for three quarters of total water use, followed by industry and households (ABARES, 2019a).

Urban water supply is mostly sourced from surface water, though in Perth in Western Australia, the majority is supplied from groundwater as well as desalinated water. Threat to household water supplies triggered by the "Millennium Drought" has prompted the construction of desalination plants in Australia's main cities. These plants have greatly improved water security of major urban areas (Climate Council, 2018).

However, water scarcity is an ongoing issue in Australia due to its relatively dry and variable climate. Climate change has further impacted this situation with shifting rainfall patterns and the severity of floods and droughts increasing (ABARES, 2019a). While several areas across Australia are already severely water stressed as per Figure 6-3, demand for freshwater is expected to increase further over the next decades. Increasing competition for water has also been reflected in the increase in water allocation prices. Water rights are traded on water markets to enable efficient allocation between competing uses in response to fluctuations in supply and demand (ABARES, 2019a). In July 2018 water allocation prices were 250 AU$/ML, but exceeded 500 AU$/ML in June 2019 with an annual average price of 450 AU$/ML (ABARES, 2019b). For 2019-2020 an annual average water allocation price of 526 AU$/ML is estimated for the dry scenario, 651 AU$/ML for the extremely dry scenario and much lower prices of 332 AU$/ML and 258 AU$/ML for the average and wet scenarios, respectively.

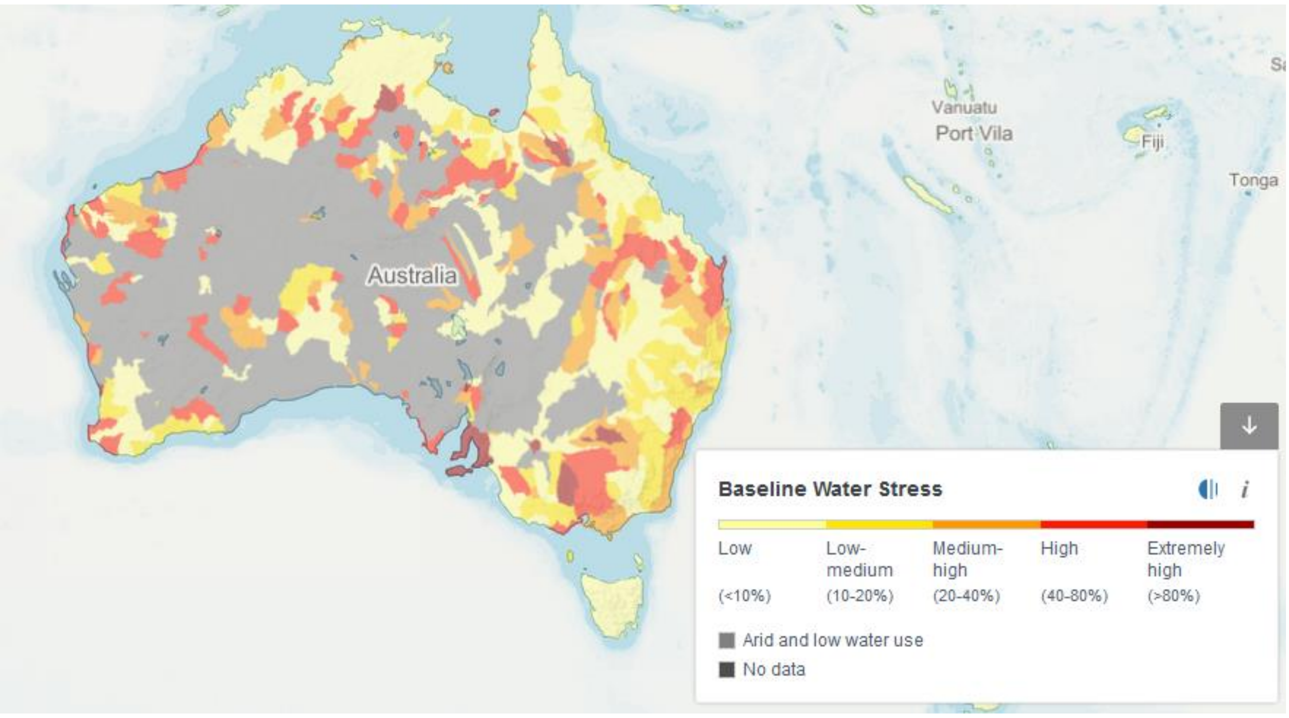


Figure 6-3 Water risk in Australia as per WRI's Aqueduct Water Risk Atlas (WRI, 2019)

In Queensland, the pressure on water resources from large-scale coal seam gas (CSG) operations due to the co-production of water has been addressed through the setting up of cumulative management areas (CMA). A CMA is an area of concentrated development, where impacts on water pressure in aquifers are likely to be overlapping from multiple petroleum operations. In these areas, the Office of Groundwater Impact Assessment (OGIA) is responsible for (Department of Natural Resources and Mines, 2016):

- predicting the regional impacts on water pressures in aquifers;
- developing water monitoring and spring management strategies;
- assigning responsibility to individual petroleum tenure holders for implementing specific parts of these strategies.

The regulatory framework provides that OGIA set out these predictions, strategies and responsibilities in an underground water impact report (UWIR). The Surat CMA, established in 2011, covers the area of current and planned CSG developments in the Surat Basin and the southern

Bowen Basin as per Figure 6-4. A CCS project located in the Surat Basin that includes extraction of large volumes of saline formation water would most likely require consideration within the relevant UWIR. The first Surat UWIR was prepared in 2012 and updated in 2016 (Queensland Government, 2019a).

Figure 6-4 Surat Cumulative Management Area (Queensland Government, 2019b)

6.2.2 Beneficial use of extracted water in Australia and its challenges

In Queensland, water is regulated by the *Environment Protection Act 1994* for physical and chemical parameters. The allowable concentrations are dependent on the application in which the water is to be used. Currently, co-produced water from the Surat Basin is legislated to be used for livestock watering, irrigation, coal washing, aquaculture, industrial and manufacturing operations, drinking water, and domestic purposes for landowners within petroleum tenure (Rebello et al., 2016). The beneficial use of such co-produced water is regulated through a permit granting the approval of a specific beneficial use, which also stipulates the conditions that are required to be met prior to the water being used (Rebello et al., 2016). For each beneficial use the approval contains specific physical and chemical water quality parameters that need to be met. For the same application, water quality specifications such as pH, TDS, EC, TPH, SAR and bicarbonate ion content typically vary between the environmental authorities granted (Rebello et al., 2016). Other factors that need to be considered regarding the beneficial use of extracted and treated water include (Fergus and Page, 2014):

- Transport costs: where is the water extracted, where is it treated, where is it supplied?
- Land access to transport the brine via pipelines
- Energy source: what energy source is available at the site of water treatment?
- Equipment capacity: water extraction rates may vary over time
- Reinjection of concentrated brine for disposal (if not ZLD): Investigations to determine feasibility of brine injection are necessary, which require a long lead time
- Salt disposal cost: In Queensland disposal directly to landfill is not a regulator preferred option and is subject to availability of 3rd party landfill operators and licensing of the salt disposal. In some areas a landfill levy, potentially as high as 150 AUS$/t, applies.

For this study, the cost of treated storage-extracted water in Queensland is estimated to be 1.15 €/m^3 (see Table 4-12), though this does not include disposal of the reject brine (3.88 €/m^3 of reject brine disposed). Including disposal costs the cost of product water increase to 1.84 €/m^3. This is still well within the lower end of the range of water prices charged in Australian capital cities, which for the financial year 2019/2020 are set as low as 1.06 A$/m^3 (~0.70 €/m^3) in Hobart (Tasmania), 3.12 A$/m^3 (2.00 €/m^3) in Brisbane (Queensland), and as high as 4.94 A$/m^3 (~3.20 €/m^3) in Canberra (Australian Capital Territory) (Team Poly, 2019).

Water allocation prices, however, are much lower. They are expected to range from approximately 260 A$/ML (~0.17 €/m^3) up to 650 A$/ML (0.42 €/m^3) for 2019/2020 (ABARES, 2019b). This makes the use of treated storage-extracted water for purposes such as irrigation unattractive from an economic perspective. Still, this is one of the reuse options currently being practiced in the Surat Basin and is described below.

Co-produced water from coal seam gas fields in the Surat CMA is collected and treated in dedicated water treatment plants. A volume of 200,000 m^3/d of co-produced water can be treated with a recovery of 97% using reverse osmosis as the primary treatment technology (Pump Industry, 2013; QGC, 2013; Water Technology, 2014; Shell, 2019). The product water is of good quality, suitable for beneficial use with a maximum allowable TDS of 320 mg/l and maximum allowable TSS of 175 mg/l (QGC, 2013). The reject stream is further concentrated in brine concentrators, producing purified water and salt as the end product for disposal (Water Technology, 2014). The treated water is delivered into two major irrigation schemes on the Condamine and Dawson Rivers (Shell, 2019), which is facilitated through a long-term arrangement with a distributor to ensure continuous water uptake. The treated water provides access for farmers and irrigators to a secure supply of clean water in an area naturally prone to drought. In addition, it reduces pressure on the river system for irrigation, protecting local ecosystems (Mianzan, 2017). The infrastructure required for water gathering and treatment is paid for by the CSG company (Mianzan, 2017).

Additional examples of beneficial use of co-produced water in the Surat Basin include the use of recycled water in a power station and its injection into aquifers. Recycled co-produced CSG water is used at the Condamine power station in an evaporative-cooling tower. Enabling this technology to be used over an alternative dry-cooling system through the availability of the recycled water improved the output, efficiency and greenhouse impact of the steam turbine (WSP, 2019).

The reinjection of treated water into aquifers is another option that has been practiced to improve the overall condition of the groundwater resource that supports water supply bores in the Surat CMA. This activity complies with Australian Government Federal legislation for the protection of depleting aquifers (Rebello et al., 2016). While there are technical difficulties to overcome in order to safely inject the water, Origin Energy has recently established injection facilities at the Spring Gully and Reedy Creek gas fields, where it is injecting 27 ML/day (equivalent to about 9,900 ML/year) into the Precipice Sandstone. It is essential that the water reinjected protects the ecology of the aquifer. Key points to consider include pH adjustment, deoxygenating, and sterilisation (removal of solids and bacteria) of the associated water prior to reinjection (APLNG, 2012).

The above presented examples highlight not only the potential for the various beneficial reuse opportunities of storage-extracted and treated water, but also demonstrate that these are practically feasible. The success of these projects reduces economic and regulatory uncertainty, making similar future projects much more likely.

6.3 China

6.3.1 Water stress in China

China has been experiencing water shortages of increasing magnitude and frequency since the 1980s (World Bank, 2002). The majority of water (85%) is consumed by agriculture and industry (GRI, 2017). In normal water years, out of 662 cities 300 will have insufficient water supplies and 110 will experience severe water shortages (Li, 2006). In 2014, 11 out of 31 Chinese provinces did not meet the World Bank's water needs criteria of 1500 m^3 per person (GRI, 2017). Water shortages also have had significant effects on the economy: during 2001–2005, water shortages caused industrial losses of 1.62% of China's annual GDP (MWR, 2007). Experts predict that, if China carries on with business as usual, water supply will outstrip demand by 2030 (GRI, 2017).

The causes for the water shortages are multi-fold. China has 20% of the world's population but only 7% of its freshwater (GRI, 2017). Furthermore, the water resources are not evenly distributed; water resources are mainly in southern China (~80%), but the majority of water is consumed in the highly populated north, which holds ~2/3 of China's agricultural (GRI, 2017). Contributing to that, climate change has decreased the available water resources in the north over the past 20 years by reducing annual flow of rivers and through the loss of glaciers (Wang et al., 2006; MWR, 2007; GRI, 2017). The uneven distribution of water availability and consumption between China's north and south is highlighted in Figure 6-5.

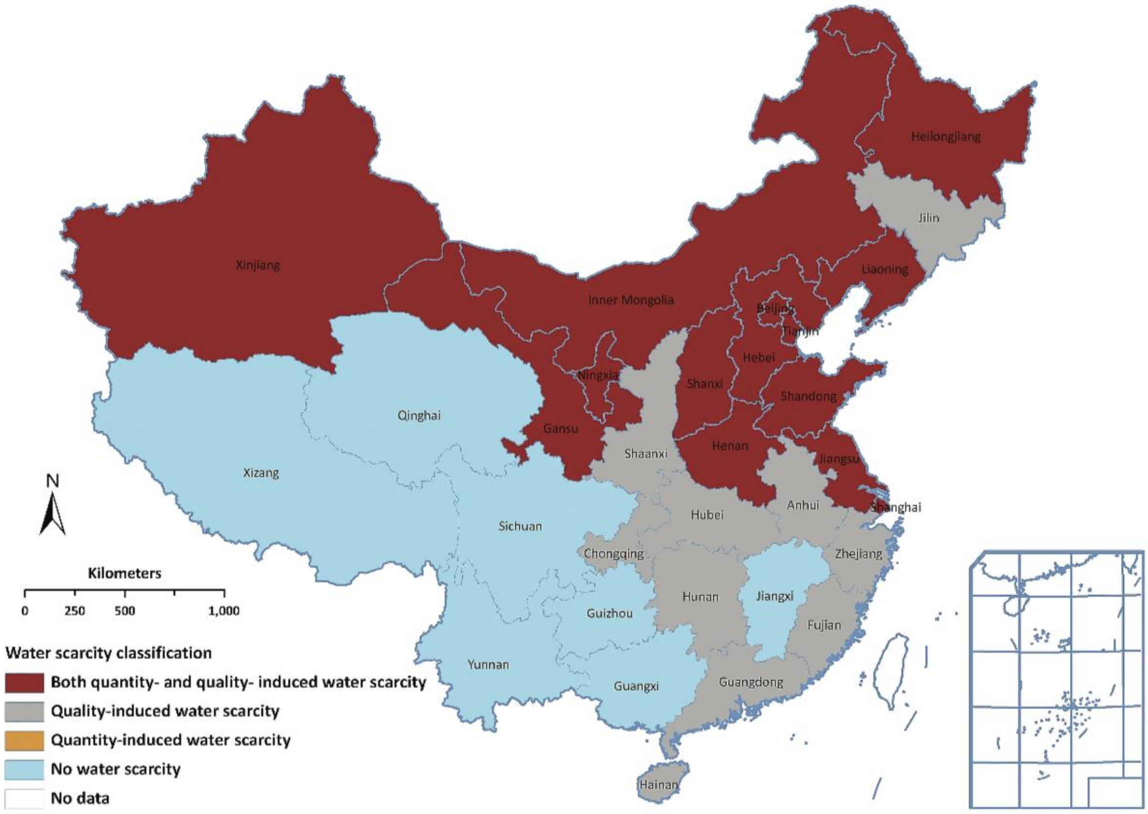


Figure 6-5 Water scarcity assessment of China (from Liu et al., 2017)

Other contributing factors to China's water scarcity are its rapid industrialisation and urbanisation, coupled with a growing, large population, creating an ever-increasing demand for water (Jiang, 2009). In addition, artificially low pricing of water has encouraged poor water management and inefficient use. A 2009 World Bank report stated that China was using ten times more water per unit of production than the average industrialised country (GRI, 2017). Prices can vary considerably between regions with industrial use prices as low as 2.2 RMB/ton (~0.3 €/m^3) in Haikou, 5.5 RMB/ton (~0.7 €/m^3) in Hohhot, and as high as 9.5 RMB/ton (1.25 €/m^3) in Beijing (CEIC, 2010)

Aside from water scarcity caused by lack of resources it may also be caused by pollution: water scarcity due to poor water quality has occurred in northern and eastern China (see Figure 6-5) and can threaten water supply even in water abundant regions (Jiang, 2009; Liu et al., 2017). This is also reflected in China's average recycling rate of industrial water, which at an estimated 40–50% is significantly lower than in developed countries at around 80% (CAS, 2007).

As a consequence, severe impacts on China's domestic economic stability may be expected in the long term, as its electricity generation is reliant on water and 45% of freshwater reliant power generation facilities are in water-stressed provinces (GRI, 2017). World markets may also be affected as seen in 2011, when the winter drought in China's eastern wheat-growing province forced China to purchase vast volumes of wheat on international markets. This caused a doubling of global wheat prices (GRI, 2017).

Over-exploitation of water resources (in 164 regions by the early 2000s [MWR, 2007]) has caused ground subsidence in northern and eastern China (Li et al., 2015). Even Beijing and Shanghai have been subject to ground subsidence of up to several metres (Shalizi, 2006). Seawater intrusion has occurred in 72 locations in coastal regions due to falling groundwater tables (World Bank, 2001). In addition, groundwater overexploitation has led to aquifer salinisation (Foster et al., 2004).

6.3.2 Beneficial use of water in norther China and its challenges

The interest in unconventional water resources in China is indicated by the appearance of proposals for CO_2 enhanced water recovery (CO_2-EWR) in the literature as one means to address China's water shortage (e.g., Li et al, 2015, Yang et al., 2019). As water is scarce in the north, the storage-extracted water from the Songliao Basin may present a much-needed additional resource that could be supplied to various applications. For example, depending on its actual quality, it may be directly used for irrigation purposes. The permissible limit of TDS for irrigation is 3,000 mg/l, above which salinisation and other soil problems are likely to be caused (Li et al., 2013). However, for the storage-extracted brine a salinity range of 3,500 – 9,000 mg/l has been indicated, thus likely requiring additional treatment (Table 2-9). The reuse of the storage-extracted brine would not only aid in alleviating water demands in a water scarce region but may also reduce associated CO_2 emissions. Irrigation in China has been found to contribute 33 Mt of CO_2 per year (close to 0.5% of China's overall CO_2 emissions) due to the pumping from increasingly deeper underground sources (Wang et al., 2012).

The reuse of the treated storage-extracted water from the Songliao Basin may present a viable option in this study based on the estimated product water cost of 1.09 €/m^3 (see Table 4-12; 1.12 €/m^3 including disposal of the reject brine). In comparison, Chinese water rates range from ~0.3 – 1.25 €/m^3, as described above. However, the cost of irrigation water is typically only a fraction of residential or industrial water supply charges (Webber et al., 2008; Wang, 2010), making the use of treated storage-extracted water for such purposes economically unattractive.

To satisfy existing and increasing water demand in China, engineering projects are installed, such as the large-scale South-North Water Diversion Project with a 1,200 km canal stretching from the Yangtze to Beijing (GRI, 2017) and potential CO-EWR projects. In addition to such efforts the efficiency of water use in China also requires improvement. Jiang (2009) suggests registration and regulation of water withdrawal, clearly defined legally enforceable water rights, as well as a more market-based approach. The introduction of the ZLD requirement at power stations indicates steps towards more efficient water use have been taken.

6.4 India

6.4.1 Water stress in India and Gujarat

Freshwater resources are scarce in most parts of India. 75.8 million people in India have no access to safe potable water sources (WHO/UNICEF, 2015). The country is poised to face acute water scarcity by 2025 as all known sources of water including aquifers may be harnessed or exhausted by then (Das, 2019).

Gujarat, which hosts the Cambay Basin, is one of the most water scarce regions in India with nearly 80% of its geographical area having a renewable water resource endowment of less than 1,000 m^3 per capita per annum, with north Gujarat being absolutely water-scarce (less than 500 m^3 per capita per annum) (Brewster et al., 2014). More importantly, the regions with a poor water endowment have excessively high water demands with most of it coming from agriculture (Brewster et al., 2014). Water use in three out of the four regions, namely north Gujarat, Saurashtra, and Kachchh, is currently unsustainable. In response to the increasing water scarcity, in 2018 the state of Gujarat reduced its water supply to industry and for irrigation purposes to prioritise drinking water supply (India Briefing, 2018).

One or more of the following problems are seen in most parts of Gujarat (Gupta and Deshpande, 1999):

- Steady decline of the water table between 3 – 50 m over the last few decades
- Progressively increasing fluoride in groundwater in large parts
- Sea water intrusion in the coastal aquifers
- Water logging, salinisation of soils and pollution of groundwater
- Pollution of surface and groundwater around large towns and cities
- Increased incidence of water borne diseases like malaria, filaria, falciparum, cholera and others

6.4.2 Water stress in the Indian power sector

With the Indian economy projected to double by 2030 (PWC, 2017), its demand for water is also expected to grow significantly (CWC, 2015). The Indian power sector is greatly affected by water stress, while in turn adding to the existing stress encountered. More than 80% of India's electricity is generated from thermal power plants, relying heavily on water for cooling (WRI, 2018). India's thermal power industry's annual water requirement, estimated at 22 billion m^3, is equal to over half of India's total domestic water needs (EPR, 2019). More than 80% of total thermal generation is cooled by freshwater recirculating systems (WRI, 2018).

While water withdrawals between 2011 and 2016 have remained constant due to no new freshwater once-through cooled plants having been built since 2011, freshwater consumption has increased substantially as a result of a steady growth in electricity generation. Contributing to that is that India's coal fired power stations with cooling towers consume twice as much water as their global counterparts at around 4 m^3/MWh (EPR, 2019).

Cooling water shortages have resulted in power station shut-downs in the past (Luo, 2017). For example, in 2016 water-related shut-downs were recorded for 12 plants, combined losing more than 614 MUS$ in potential revenue (WRI, 2018). The situation is aggravated by 39% of the capacity of India's freshwater-cooled thermal utilities being installed in high water-stress regions, indicating a high level of competition in water use. WRI (2018) found that plants in high-stress areas have a lower average capacity factor than those in low and medium water-stress areas.

Gujarat has the third highest installed capacity in the country (~17 GW), but is also one of the regions experiencing the highest water-stress (WRI, 2018). This is illustrated in Figure 6-6.

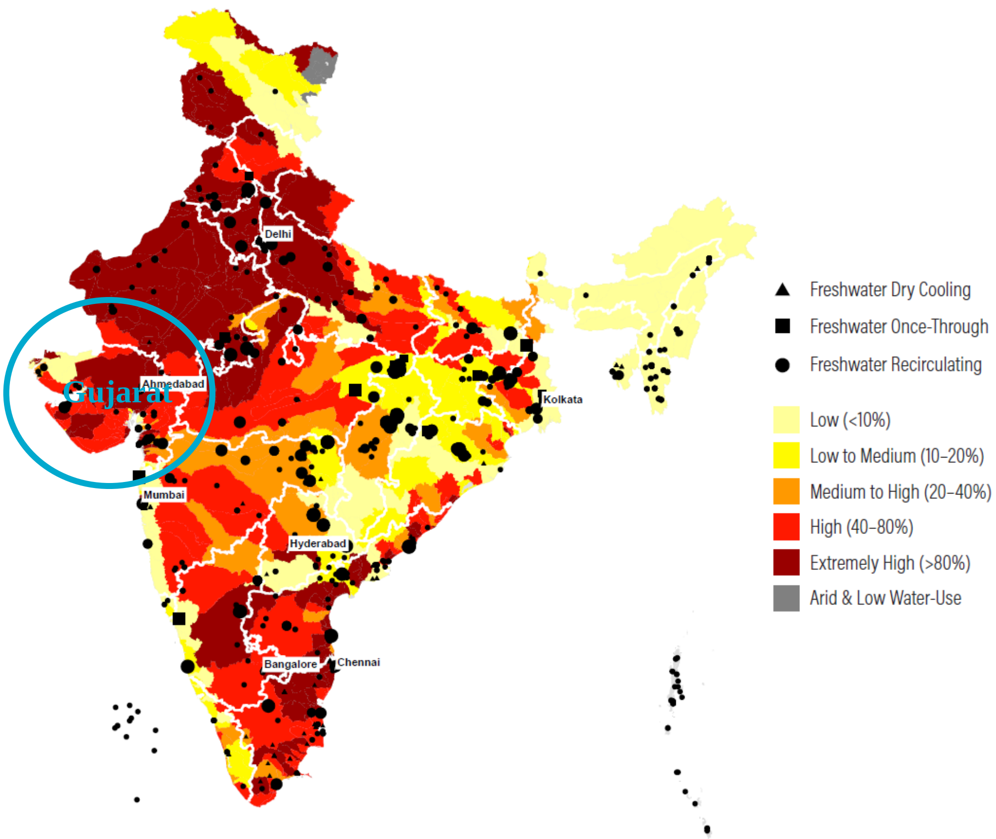


Figure 6-6 Map of water stress levels in India and location of freshwater-cooled thermal utilities (from WRI, 2018)

6.4.3 Beneficial use of extracted water in Gujarat and its challenges

The combination of water scarcity and deteriorating water quality indicates a significant opportunity for the beneficial reuse of storage-extracted water. The level of treatment of the produced water depends on the original composition of the extracted water and its purpose for use. For example, for irrigation, salinities of up to 2,100 mg/l are acceptable, while drinking water should have salinities of 500 mg/l or less, though up to 2,000 mg/l of dissolved solids are permitted. Based on the expected salinities of the extracted water from the Cambay Basin (9,000 mg/l estimated in this study), treatment prior to beneficial reuse is required.

Reuse of storage-extracted water (after treatment) in a nearby power station or another water demanding industry is an option. For example, in 2015 the Indian government mandated for power plants to buy treated wastewater from sewage treatment plants, where the two plants are within a 50 km radius of each other. The estimated cost of treated storage-extracted water in this study is 1.11 €/m^3 (Table 4-12; 1.16 €/m^3 including brine disposal), which compares well to water rates in Delhi (1.18 €/m^3), but is significantly higher than water rates in Gujarat (0.30 €/m^3), with Tamil Nadu having the lowest water rates (0.20 €/ m^3) (India Briefing, 2010). This indicates that depending on local water prices the reuse of storage-extracted water may present a viable alternative to the purchase of freshwater, though at current prices in Gujarat treatment of water extracted from the Cambay Basin is not cost competitive.

Alternatively, treated extracted water may be used for irrigation, though this option appears economically unattractive. While a levy for groundwater for consumption beyond a certain limit was introduced from June 2019 to discourage further large scale groundwater extraction, the irrigation sector has been exempted from this levy (Sarkar, 2019).

In Gujarat, considerable investments have been made in water infrastructure, including large-scale infrastructure for transfer of water from relatively water rich regions to water-scarce regions such as the Sardar Sarovar Project (Brewster et al., 2014). Some of the large industrial groups, such as Tata Chemicals and Reliance Petroleum, have set up their own desalination systems in the coastal areas of Saurashtra (Brewster et al., 2014). There is significant pressure on the government from industrial groups to invest in infrastructure that would help them secure freshwater supplies on a long-term basis (Brewster et al., 2014).

In addition to the economic viability, another challenge to reusing the extracted water lies in managing and distributing the available water resource. Water allocations need to be defined to avoid inefficient use of water (Brewster et al., 2014).

Prior to treatment and further use, the storage-extracted water may be used to generate electricity. Factors affecting the amount of energy that may be extracted from geothermal resources are the chemical composition of the brine, its temperature, pressure, and flow rate (Vajpayee et al., 2017). In the Cambay Basin, Vajpayee et al. (2017) identified the Mehsana Asset, an oil field with co-produced water, as a promising area for the development of co-produced power, due the favourable heat flows in this area, as well as the high water cut (~70%) and a promising geothermal gradient of 35 - 40°C/km. This is in spite of the co-produced water only being available at a comparatively low temperature of 45°C (after exiting the knock out drum where it is separated from the produced oil). Bennett et al. (2012) found that flow rate is equally important as temperature of the extracted fluid in the generation of energy from geothermal resources, indicating that the very high water extraction rates associated with CO_2 storage activities would be highly beneficial for the generation of geothermal energy.

6.5 Comparison of water cost

A comparison of the cost of product water derived from the storage-extracted brines and local water tariffs is presented in Table 6-1 for South Africa, Australia, China and India. Water treatment costs range from 1.09 €/m^3 in China up to 2.33 €/m^3 in South Africa, which was described in Chapter 4.5. Treatment costs compare well to local water charges in South Africa and Australia and are on the upper end of water rates in China and India as indicated in Table 6-1. Disposal costs for the highly concentrated reject brines are typically very small due to the treatment to ZLD in South Africa, China and India and the associated small disposal volumes (Table 6-1). Only in Australia does reject brine disposal present a significant fraction of the cost of product water at 0.69 €/m^3, taking the cost of product water to 1.83 €/m^3. This is still well within the range of Australian water tariffs and below those in Brisbane, Queensland (2.00 €/m^3) (Team Poly, 20190.

Including the costs of water extraction and transport, which are estimated to be a flat rate of 2.5 €/t of CO_2 stored in this study, total product water costs increase above current water tariffs in the four countries as per Table 6-1. The difference between product water costs and local water tariffs is much less in South Africa and Australia than in China and India where the cost of product water is more than twice the upper end of the country's water tariffs.

Table 6-1 Comparison of product water cost estimates for storage-extracted water in South Africa, Australia, China and India in €/m^3 of product water obtained

Country	Water extraction & transport, €/m^3	Water treatment, €/m^3	Brine disposal, €/m^3	Total product water cost, €/m^3	Local water tariffs, €/m^3	Reference
South Africa	1.59	2.33	0.096	4.02	2.10 – 3.70	City of Johannesburg, 2019; eThekwini Municipality, 2019
Australia	1.73	1.15	0.685	3.57	0.7 – 3.2	Team Poly, 2019
China	1.49	1.09	0.030	2.61	0.30 – 1.25	CEIC, 2019
India	1.51	1.11	0.050	2.67	0.20 – 1.18	Indian Briefing, 2018

The cost comparison indicates that if water was available from CO_2 storage activities, treatment of the storage-extracted water and its beneficial reuse may present a viable option and can substitute other freshwater sources. The competitiveness strongly depends on the local water tariffs charged which can vary considerably across a country as highlighted in Table 6-1. If water extraction and transport costs are also accounted for in the total product water cost, water extraction and its reuse becomes unattractive in comparison to local water supply charges.

It should be noted that for purposes such as irrigation or large-scale industrial process abstracted water is typically used which is supplied at a fraction of local water tariffs (OECD, 1999). Therefore, using treated storage-extracted water where abstracted water is typically used does not appear attractive from an economic perspective, but may still be practiced under the consideration of other factors or where regulations encourage or stipulate it.

7 Conclusions and recommendations

7.1 Conclusions

Power plant performance and power plant water balance

- For power plants without capture utilising air cooling, the thermal efficiencies range from 39% LHV in Australia to 42% LHV in South Africa and 43% LHV in China. The addition of PCC using evaporative cooling reduces the thermal efficiencies for these air-cooled plants by 8.9% in Australia, 7.6% in South Africa, and 8.1% in China.
- For the power plant in India using evaporative cooling for both the power and the capture plant, the initial thermal efficiency of 43% LHV reduces to 34.8% with PCC.
- The energy consumption for the capture plants using evaporative cooling is relatively similar across all four power plants; with the lowest in Australia at 0.24 MWh/t CO_2 captured and the highest in China and India at 0.27 MWh/t CO_2 captured.
- The normalised water withdrawal and consumption for air-cooled power plants without capture is 0.07 m^3/MWh for the three countries (Australia, China, South Africa). With PCC using evaporative cooling, water withdrawal and consumption increases to 0.92 - 1.34 m^3/MWh and 0.71 - 1.03 m^3/MWh, respectively. The lowest withdrawal and consumption rates are achieved for the Chinese case, where the average air temperatures are extremely low.
- For the Indian power plant using evaporative cooling water withdrawal and consumptions rates are 0.83 m^3/MWh and 0.64 m^3/MWh, respectively. Implementing capture (using evaporative cooling), this increases to 2.09 m^3/MWh and 1.59 m^3/MWh - well below the regulatory water consumption limit of 2.5 m^3/MWh for new coal-fired power plants in India.
- Treatment of the power plant's wastewater to ZLD is required in South Africa, China, and India. Product water recovery is 90%, applying a membrane brine concentration system and a crystalliser. The product water is reused in the power plant to lower its freshwater demand. However, for the air-cooled power plants wastewater discharge is negligible, thus in this case only the wastewater from the capture plant requires treatment.

CO_2 storage and water extraction

- The geological basins identified as suitable for storage in South Africa, Australia, China and India are the Zululand Basin, the Surat Basin, the Songliao Basin, and the Cambay Basin, respectively. They are considered to have the potential to provide the necessary storage capacity (100 Mt over 25 years) as well as long-term containment. However, any storage estimates presented in this report are only approximate initial estimates.

- All identified basins, except the Zululand Basin in South Africa, are hosts to oil and/or gas production. This implies infrastructure to support CO_2 storage development is already in place, likely lowering the barrier for CCS in this region.
- CO_2 injection at a rate of ~4 Mt/y is assumed to be possible in case of open reservoir boundaries, enabling storage of ~100 Mt CO_2 over 25 years without water extraction.
- In case of a reservoir with closed boundaries, water extraction at a ratio of H_2O : CO_2 of 1.7 : 1 is assumed to be necessary to store ~4 Mt/y of CO_2 based on Phase 1 findings, resulting in an annual brine extraction rate of ~7 Mt.

Water management along the CCS chain

- In Australia the storage-extracted brine with an estimated TDS of 5,000 mg/l may be treated via a combined forward osmosis – reverse osmosis process at a recovery rate of 85%. Treatment to ZLD is not a requirement.
- To align with requirements at the coal fired power stations in South Africa, China, and India, treatment to ZLD is assumed for the storage-extracted brine in these locations. The process consists of pre-treatment, reverse osmosis, mechanical vapour compression, and a forced circulation crystalliser. Recoveries range from 92.75% (South Africa) up to 98.53% (China), depending on the initial concentration of the brine.
- The concentrated reject is disposed via evaporation ponds with final disposal of the remaining salt in landfill or alternatively it may be supplied to chemical industries to derive additional value.
- The treated water is high quality ultrapure water with typically less than 100 mg/l TDS and is suitable for various beneficial uses, including use in power stations and other industrial applications.The high recovery rates of the treatment processes for the extracted brines, in addition to the integration of ZLD at the power stations in South Africa, China, and India, result in water recoveries along the CCS chain that exceed the freshwater demands of the power stations. This surplus water, ranging from 1.3 Mt/y in Australia, 1.6 Mt/y in India, 3.1 Mt/y in South Africa, up to almost 4.5 Mt/y in China, may be provided for beneficial uses.
- A range of beneficial reuse options are available for the surplus water and practical examples in some countries have demonstrated their feasibility. For example, in Australia, water co-produced during coal seam gas operations is treated to a specified minimum standard and provided to users via major irrigation schemes. In South Africa, excess water produced at a coal mine is treated and supplied as town water. In India, power stations have to buy treated wastewater if the treatment plant is located within a 50 km radius of the power station. These existing examples reduce economic and regulatory uncertainty, making similar future projects much more likely.

Economics

- In comparison to the equivalent power station in the Netherlands, building an air-cooled USCPC in China is about 30% cheaper due to significant material and construction labour cost reductions, while building the same plant in Australia and South Africa is about 20% more expensive as a result of high labour cost and a low productivity factor (IEAGHG, 2018).
- Building the USCPC with evaporative cooling in India, the costs are comparable to the reference plant in the Netherlands (~3% difference), though in contrast to the Indian plant the Dutch plant does not utilise ZLD technology. Without ZLD, the Indian plant would be 5% cheaper than the Dutch reference plant due to material and construction labour cost reductions.
- The LCOE for the USCPC power plants without capture range from 42 €/MWh and 45 €/MWh for China and India (ZLD at the power station adds 2 €/MWh in the India case), respectively, to 60 €/MWh in South Africa and 62 €/MWh in Australia.
- Adding CO_2 capture at the power station, as well as ZLD at the power stations in China, India and South Africa, the increase in specific capital requirement ranges from 52% - 60%. The LCOE increase by 44% - 55%, ranging from 62 €/MWh for the power plants with capture in China, 70 €/MWh in India, with the highest cost in Australia and South Africa at 90 €/MWh and 91 €/MWh, respectively. In comparison, the LCOE of the equivalent Dutch power station is 82 €/MWh.
- ZLD contributes 5 €/MWh at the Indian and the South African power station with capture, and 3 €/MWh at the Chinese power station with capture.
- In the CCS Base Case Scenario, the assumed CO_2 transport and storage cost at a flat rate of 5 €/t CO_2 stored adds about 4.6 €/MWh to the LCOE, bringing the LCOE to 67 €/MWh in China, 74 €/MWh in India, and 94 and 96 €/MWh in Australia and South Africa, respectively. The equivalent Dutch power station has a LCOE of 86 €/MWh.
- In the CCS-Water-Nexus Scenario, adding the flat rate for water extraction and transport of 2.5 €/t CO_2 stored as well as costs associated with water treatment, the LCOE increase only marginally: by 3 €/MWh in China, 4 €/MWh in India, 5 €/MWh in Australia and South Africa (all corresponding to an increase of about 5%), and 7 €/MWh in the Netherlands (8% increase). Differences in water management costs are not only a result of different labour, construction and material costs between the five countries, but also affected by the initial salinity of the brines and the applied treatment technologies.
- CO_2 avoidance cost for the USCPC with capture range from 36 – 51 €/t CO_2 in the CCS Base Case Scenario and increase to 41 – 58 €/t CO_2 in the CCS-Water-Nexus Scenario, with the Chinese power station having the lowest and the South African power station having the highest avoidance cost.
- The analysis shows that local conditions, such as local labour, construction, material, and fuel cost, as well as environmental conditions, such as ambient temperature, can have a significant effect on the costs of CCS. This is best illustrated by comparing the equivalent

China and South Africa case, with the South African LCOE being about 30 €/MWh or 44% higher.

- Water extraction and treatment add a comparatively small cost to the examined CCS projects (5% increase). Therefore, the extracted and treated water may provide a valuable unconventional water resource in regions that are suffering water stress, especially when considering the associated cost of water shortages. In this study, the cost of product water, accounting for brine treatment and disposal costs, were found to be comparable to local water tariffs in the four countries, ranging from 1.12 €/m^3 in China up to 2.43 €/m^3 in South Africa. When water extraction and transport costs are also included product water cost exceed local water supply charges.

7.2 Recommendations

The analysis presented in this study demonstrates that CO_2 capture and storage can be considerably affected by location, including the prevailing economic and environmental conditions. Out of the five countries examined (including the Netherlands case presented in Phase 1), the air-cooled power station in China, using evaporative cooling for capture, has the lowest cost, as reflected in the LCOE. This indicates that in countries where the conditions are conducive (e.g., low ambient temperature), low water consuming technologies can present an effective means of preserving valuable water resources.

Alternatively, in countries where conditions are less conducive for air-cooled power stations, such as in warm climates, the extraction of brine for CO_2 storage operations may present an opportunity to improve efficiencies of the power station by employing a more water intensive cooling technology, such as evaporative cooling. This could also decrease greenhouse emissions. An example for this is the Condamine power station in the Surat Basin in Australia, for which the availability of recycled co-produced water from coal seam gas operations enabled the application of an evaporative cooling tower over a less efficient dry-cooling system (WSP, 2019). The trade-offs of reusing the extracted water in the power station over other beneficial use options would have to be assessed on a case by case basis. Whether it presents a suitable use of storage-extracted water is likely affected by the demand for freshwater vs the availability of freshwater in a particular region, as well as other factors, such as the efficiency improvements achieved by evaporative cooling over air cooling, and the cost of using treated water for cooling over the cost of air cooling.

The latter is largely affected by the quality of the storage-extracted brines. The lower the salinity of the brine, the lower will be treatment costs, assuming all other factors being equal. The storage location relative to the location of the power station is another critical factor. Typically, onshore locations would offer better economics as they are more likely to be located close to users of the extracted water. In addition, building new or updating existing infrastructure onshore is less expensive than offshore. The economics will improve with decreasing distance between water extraction site and the site of reuse.

This study demonstrates that by integrating water recovery along the CCS chain through wastewater recovery at the power station and treatment of storage-extracted brine, the volume of recycled water can exceed the freshwater demand of the power station with capture, even for water intensive cooling technologies like evaporative cooling. To encourage such integration with the CCS project becoming a net water producer rather than consumer, the following conditions should be in place:

- The storage-extracted brine has comparatively low salinity.
- A regulatory requirement to treat the extracted brine for beneficial reuse is in place. Or, alternatively, disposal of extracted brine becomes illegal.
- A regulatory requirement for ZLD at the power station is in place.

Appendix A

A.1 Capital and operating costs data from IEAGHG (2018) report

Table A 1 Capital and operating costs data from Table 1 of the IEAGHG (2018) report for the selected locations. Cases marked with a (*) represent plants located in the "Hypothetical The Netherlands" location (differing from the reference case 1A/1B for cooling water system, coal type and ambient conditions)

IEAGHG 2018 Case name	IEAGHG 2018 case number		Total Plant Cost (M €)	Specific capital requirement (€/kW)	Total capital requirement (M€)	Specific capital requirement (€/kW)	Fuel price (€/GJ)	Fixed O&M (M€/yr)	Variable O&M (M€/yr)	Fuel (million €/yr)	Total VOM(including fuel) (M€/yr)	Ratio capital cost increase compared to Hypothetical The Netherlands	LCOE (€/MWh)
The Netherlands (Reference case)	1A	SCPC w/o CCS	1451	1410	1895	1840		2.7	46.3	8.105	181.8		53
The Netherlands	1B	SCPC-EV-PCC	2216	2695	2882	3504		2.7	67.581	19.125	181.9		65
South Africa	5A - Inland	SCPC-AC	1624	1636	2110	2126	1.8	57.7	8.3	119.3	127.6	~1.20	51.4
Hypothetical Netherlands	5A*	SCPC-AC	1337	1347	1710	1753	2.7						
South Africa	5B - Inland	SCPC-AC-PCC	2409	3095	3124	4014	1.8	83.2	19.0	119.3	138.3	~1.20	97.8
Hypothetical Netherlands	5B*	SCPC-AC-PCC	2006	2577	2603.2	3344	2.7						
Australia	6A	SCPC-OT	1837	1840	2387	2390	2	59.1	8.1	132.6	140.6	~1.22	56.5
Hypothetical Netherlands	6A*	SCPC-OT	1481	1483	1927.4	1930							
Australia	6B	SCPC-OT-PCC	2761	3506	3578.1	4544	2	84.9	18.3	132.6	150.9	~1.22	106.1
Hypothetical Netherlands	6B*	SCPC-OT-PCC	2256	2865	2926.8	3717							
China	8.1A -Inland	SCPC-AC	923	898	1206.9	1173	1.8	34.5	6.5	119.3	125.7	~0.70	35
Hypothetical Netherlands	8.1A*	SCPC-AC	1337	1284	1739.5	1671							

IEAGHG 2018 Case name	IEAGHG 2018 case number		Total Plant Cost (M €)	Specific capital requirement (€/kW)	Total capital requirement (M€)	Specific capital requirement (€/kW)	Fuel price (€/GJ)	Fixed O&M (M€/yr)	Variable O&M (M€/yr)	Fuel (million €/yr)	Total VOM(including fuel) (M€/yr)	Ratio capital cost increase compared to Hypothetical The Netherlands	LCOE (€/MWh)
China	8.1B -Inland	SCPC-AC-PCC-EV	1400	1724	1824.1	2246	1.8	51.6	17.0	119.3	136.3	~0.71	67.5
Hypothetical Netherlands	8.1B*	SCPC-AC-PCC-EV	2007	2436	2605.6	3161							
India	7A - F grade local coal	SCPC-EV	1340	1396	1736.7	1809	1	50.5	4.3	66.3	70.6		40
Hypothetical Netherlands	7A*	SCPC-EV	1561	1592	2021.8	2062							
India	7B	SCPC-EV-PCC	2036	2738	2637.1	3546	1	75.5	14.6	66.3	80.9		83.5
Hypothetical Netherlands	7B*	SCPC-EV-PCC	2351	3118	3040.8	4034		1					51.4

A.2 Assumptions for the derivation of storage-extracted water treatment cost

Table A 2 Assumption used for the water treatment cost of storage-extracted water from South Africa, Australia, China and India

Parameters/Plant and process details	South Africa	Australia	China	India	Notes
Treatment process adopted	RO-MVC-FCC	FO-RO	RO-MVC-FCC	RO-MVC-FCC	
Feed water concentration, g/L	26	5	5	9	
Feed water treatment capacity, m^3/d	20,000	20,000	20,000	20,000	
Plant operation, h/days	24/365				
Plant processing capacity, %	100				
Plant life, y	25				
Discount rate, %	8				
Conversion rate €/AU$	0.65				
Power consumption, kWh/m^3	RO: 3.25 MVC: 32 FCC: 68.5	(FO+RO): 3.17	RO: 2.92 MVC: 24 FCC: 52	RO: 3.07 MVC: 28 FCC: 61	(Thiel et al, 2015, Tong and Elimaleigh 2016, Lanntech 2018, Mickley 2008)
Electricity price, AU$ /kWh	0.07	0.14	0.11	0.1	
RO/FO membrane cost, AU$/$m^2$	RO: 22	FO: 438 RO: 22	RO: 22	RO: 22	From supplier 2018/2019
Clean water price, AU$/$m^3$	0.05	0.1	0.05	0.03	Based on Australia cost
Number of plant personnel	23	9	17	20	Assumption
Labour cost, AU$/y/ person	7,795	77,948	8,574	1,559	Based on average weekly earnings in Australia

Shortened forms

€	Euro
AC	air cooling
AGR	acid gas removal
AMP	Amino-Methyl-Propanol
AOR	area of review
AS	ambient standards
ASU	air separation unit
BAT	best available technology
CAPEX	capital expenditure
CCS	carbon capture and storage
DCC	direct contact coolers
ED	electro-dialysis
EDR	electro-dialysis reversal
ES	effluent standards
ETS	emission trading scheme
EV	evaporative cooling
FCC	forced circulation crystalliser
FGD	flue gas desulphurisation
FGR	flue gas recycling
FO	forward osmosis
FOPEX	fixed operating costs
GWD	Ground Water Directive
HHV	higher heating value
HRSG	heat recovery steam generator
IGCC	integrated gasification combined cycle
LCOE	levelised cost of electricity
LVH	lower heating value
M	million
MD	membrane distillation

MEA	monoethanolamine
MED	multi-effect distillation
MEE	multi-effect evaporation
MSF	multistage flash distillation
MSFD	Marine Strategy Framework Directive
Mt	million tonne
MTE	mechanical thermal expression
MVC	mechanical vapour compression
MW	megawatt
MWh	megawatt hour
NGCC	natural gas fired combined cycle power plant
NORM	Naturally occurring radioactive materials
NWP	National Water Plan
OPEX	operating expenditure
OT	once-through cooling
PCC	post-combustion capture
PEC	predicted effect concentration
PNEC	predicted non-effect concentration
PP	power plant
PSES	pre-treatment standards for existing sources
RO	reverse osmosis
t	tonne
T&S	transport and storage
TDS	total dissolved solids
TGTU	tail gas treating unit
TPC	total plant cost
TSS	total suspended solids
TVC	thermal vapour compression
UGS	underground gas storage
USCPC	ultra-supercritical coal fired power plant
VOPEX	variable operating cost
WFD	Water Framework Directive

WGS	water gas shift reaction
y	year
ZLD	zero liquid discharge

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