

Carbon Capture Water Requirements and Wastewater Treatment

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ABSTRACT

Carbon capture systems tend to be water intensive due to the need for cooling water, demineralized water, and steam along with the generation of a flue gas condensate wastewater stream. These systems are frequently retrofitted into existing facilities where the utilization of existing water sources, treatment systems, and wastewater recycle/disposal can be unique and must be carefully considered. This paper provides guidance on water and wastewater issues associated with amine absorbent-based carbon capture systems.

INTRODUCTION

There is growing political and regulatory momentum towards reducing carbon dioxide emissions resulting in many power generation and industrial facilities considering the installation of carbon capture systems on their flue gas prior to being emitted out of the stack (Proctor 2023). Much of the early focus has been on the carbon capture removal technologies themselves since they can be quite complicated and expensive. However, these systems have significant cooling demands, demineralized water requirements, and generate a sizeable flue gas condensate stream along with smaller miscellaneous wastewater streams. The purpose of this paper is to provide an overview of the water and wastewater issues associated with an amine absorption-based carbon capture system.

CARBON CAPTURE PROCESS

There are many carbon capture technologies including solvent-based, sorbent-based, and membrane-based technologies each with their own water supply, wastewater generation, and cooling requirements (Department of Energy/National Energy Technology Laboratory, 2015). This paper focuses on an amine absorption-based system as shown in Figure 1. Other carbon capture technologies will differ from an amine absorption-based systems and therefore the commentary in this report may or may not apply to those technologies. Refer to other papers or publications for information on water and wastewater implications for other types of carbon capture systems (Erickson, 2022).

AMINE ABSORPTION-BASED CARBON CAPTURE DESCRIPTION

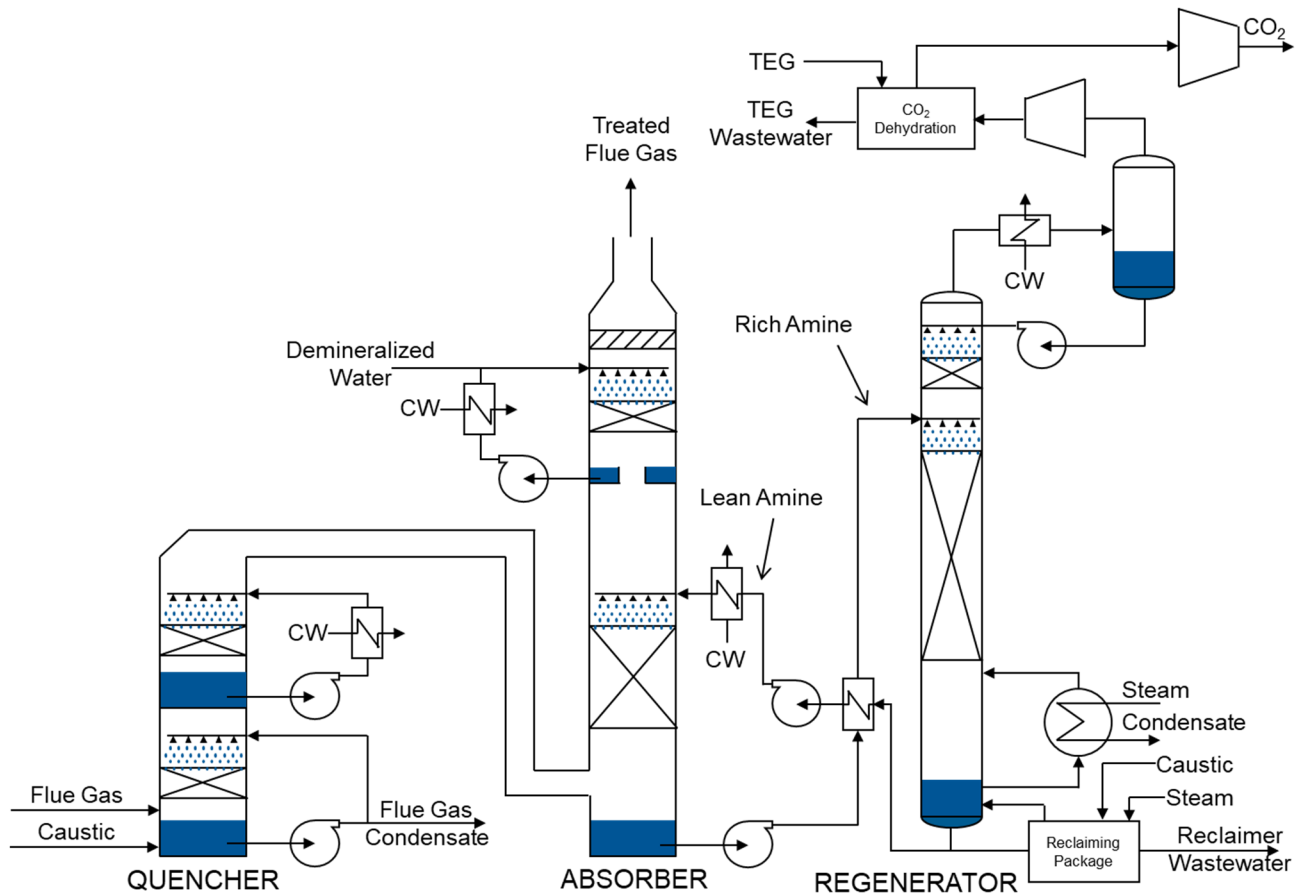
Cooling and pretreatment of the flue gas is required prior to the removal of carbon dioxide from the flue gas. This is accomplished by contacting the flue gas with recirculated water through a packed quenching tower. The water condensed out of the flue gas acts as the recirculated water and is cooled by another cooling source in a heat exchanger. The flue gas condensate must be purged out of the system to maintain the liquid level in the quencher. Caustic is often added into the quencher to remove sulfur dioxide from the flue gas to prevent heat stable salt formation in the downstream absorber. Other impurities, most notably flue gas particulates, are removed in the quencher as well.

The quenched flue gas is then sent to the absorber tower where it is contacted with an amine to chemically absorb the carbon dioxide out of the flue gas. The treated flue gas is then rinsed with demineralized water and/or an acid before being exhausted to the atmosphere. The rich amine (loaded with carbon dioxide) is sent to the regenerator where the carbon dioxide is removed in a steam driven reboiler type tower. The carbon dioxide exits the top of the regenerator and is compressed and dehydrated to remove trace amounts of water as needed based on the carbon dioxide purity requirements. The lean amine (low carbon dioxide content) is sent back to the absorber to absorb carbon dioxide. A solvent reclaiming package treats a slip stream of lean amine to remove amine degradation products, heat stable salts, soluble impurities, and suspended solids. The solvent reclaiming package generates a waste stream which is hauled offsite for

processing. Triethylene Glycol (TEG) is often utilized to dehydrate the carbon dioxide stream which generates a wastewater stream that is often referred to as the TEG wastewater stream.

Figure 1:

Simplified Amine Absorption-Based Carbon Capture System Flow Diagram



FLUE GAS CONDENSATE QUANTITY AND QUALITY

The flue gas condensate stream is the most critical carbon capture system wastewater stream of concern. The hot flue gas will contain an appreciable amount of water vapor in it depending on the combustion process. For example, different fuel types will have varying levels of inherent moisture and will also generate different amounts of water upon combustion. A portion of the moisture in the flue gas is condensed in the quencher as the flue gas is cooled. The amount of flue gas condensate is not only a function of the amount of water in the hot flue gas but is also a function of the quencher operating temperature and the total flue gas flow. The flue gas exiting the quencher will be fully saturated with moisture, and any excess water will condense and be purged out of the quencher to maintain the quencher liquid level. The design flue gas condensate

flowrate should be obtained by considering all potential operating fuels, combustion/boiler operating scenarios, as well as the operating conditions of the quencher.

The quality of the flue gas condensate stream will be impacted by the impurities in the flue gas, upstream air quality control equipment, and any chemicals that might be added into the quencher for neutralization. Most of the impurities in the flue gas are traced back to the fuel source and will be highly variable for each application. Ash removal and/or air quality control equipment may either reduce or contribute to the impurities in the flue gas condensate. For example, ammonia is used to remove NO_x from flue gas in a Selective Catalytic Reduction (SCR) process, which will reduce the NO and NO₂ in the flue gas but results in some ammonia slip causing ammonia to be present in the flue gas condensate. Caustic is often added to the quencher for pH control resulting in the removal of SO₂ from the flue gas, which will cause a subsequent increase in sodium sulfate in the flue gas condensate.

The quality of the flue gas condensate should be obtained based on the specific flue gas composition. Caution should be used if typical flue gas condensate quality data is used in lieu of projected quality data based on the actual fuel source, air quality controls, and quencher chemicals that will be used. Furthermore, technology suppliers may provide conservative not to exceed values (e.g., ammonia ≤10 ppm) which may be based on an overly conservative assumption that certain species will fully absorb in the quencher, but in reality, a portion may exit out in the quenched flue gas. Furthermore, technology suppliers estimates on SCR ammonia slip may be based on end of life catalyst conditions where ammonia slip would be greater than normal operation. This could result in overly conservative water treatment designs when compared to having more precise values. Table 1 provides high level guidance on the contaminants that are often found in flue gas condensate.

Table 1:

Summary of Flue Gas Condensate Quality

<u>Condensate Quality</u>	<u>Source</u>	<u>Notes</u>
Hardness (Ca, Mg)	Fuel, Quencher Additives	Presence in the fuel. May be added into the quencher by way of lime feed for neutralization.
Sodium	Fuel, Quencher Additives	Presence in the fuel. Elevated levels may be present due to caustic addition into the quencher for neutralization.

<u>Condensate Quality</u>	<u>Source</u>	<u>Notes</u>
Alkalinity (HCO ₃ , CO ₃ , OH) and CO ₂	Flue Gas CO ₂ , Quencher Additives	CO ₂ in the flue gas will absorb into the flue gas condensate as HCO ₃ , CO ₃ , and/or CO ₂ depending on the CO ₂ concentration in the flue gas and the quencher pH. Quencher additives such as lime or caustic will control the pH to a near-neutral pH with the alkalinity primarily being in the form of HCO ₃ along with some dissolved CO ₂ .
Total Organic Carbon (TOC)	Fuel, Flue Gas	Incomplete combustion could result in organic carbon being present in the flue gas which could absorb into the flue gas condensate.
Chlorides (Cl)	Fuel, Quencher Additives	Presence in the fuel. Chlorides are present in caustic that is typically added into the quencher.
Sulfites (SO ₃) and Sulfates (SO ₄)	Fuel, Flue Gas SO _x	Presence of sulfur in the fuel results in flue gas SO _x which is absorbed in the quencher as SO ₃ and SO ₄ . May be high due to high sulfur fuels. Quencher additives (e.g., caustic) are often used to control the pH and obtain optimal SO _x absorption.
Nitrites (NO ₂) and Nitrates (NO ₃)	Fuel, Flue Gas NO _x	Presence of nitrogen in the fuel along with nitrogen in the combustion air results in flue gas NO _x where a portion is absorbed in the quencher.
Chemical Oxygen Demand (COD)	Fuel, Flue Gas SO _x and NO _x	Due to SO ₃ and NO ₂ in the flue gas condensate.
Silica	Fuel	Presence in the fuel.
Ammonia (NH ₃)	Ammonia Added to Flue Gas	Ammonia is added as part of an SCR or SNCR process to remove NO _x . Ammonia slip (excess ammonia) is partially absorbed in the quencher. Due to the near-neutral pH of the quencher, ammonia will primarily be in the form of ammonium (NH ₄ ⁺) instead of as a dissolved gas (NH ₃).
pH	Flue Gas, Quencher Additives	The flue gas condensate itself will tend to be acidic due to the absorption of CO ₂ , SO _x , and NO _x but is typically brought to near-neutral conditions with the addition of caustic or another alkaline chemical.
Total Suspended Solids (TSS)	Flue Gas, Quencher Additives	Particulates, also referred to as dust, in the flue gas will be removed in the flue gas condensate. Quencher additives might also add TSS (e.g., inert solids in the lime that is added for neutralization).

<u>Condensate Quality</u>	<u>Source</u>	<u>Notes</u>
Heavy Metals (e.g., As, Cd, Hg, Pb, Se)	Fuel	Heavy metals from the fuel source that are not removed in the upstream air quality control equipment may be present in the flue gas condensate. May be present as a dissolved ion and/or as part of the TSS.

FLUE GAS CONDENSATE TREATMENT, REUSE, AND/OR DISCHARGE

Each project must carefully develop a plan to treat, reuse, and/or discharge the flue gas condensate. The treatment configuration and capacity should be carefully selected to ensure that all the treatment objectives are met, while optimizing the capital and operating costs. Due to the wide variety of flue gas qualities and site-specific restrictions on water and wastewater, many different options are available for treatment, reuse, and recycle of flue gas condensate, as shown in Table 2. Although the potential treatment objectives are too numerous to expand upon in this paper, consideration should also be given to the capacity of the flue gas condensate treatment system. For example, a disposable cartridge filter system may be appropriate for a smaller flue gas condensate treatment system, while a backwashable multimedia filter with solids thickening and dewatering may be more appropriate for a larger system.

Table 2:

Flue Gas Condensate Handling Philosophies

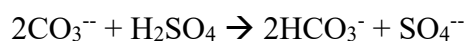
<u>Objective</u>	<u>Potential Treatment</u>	<u>Reasoning for the Treatment</u>
Flue Gas Condensate Storage Before Treatment	1. Disinfection	Flue gas condensate is typically warm and prone to biological growth. Maintaining a small chlorine residual may be warranted.
Recycle Flue Gas Condensate as Service Water	1. TSS removal 2. Ammonia removal 3. pH adjustment 4. Stabilization (hardness addition) and/or corrosion inhibitor	TSS may build up in the service water tank and piping system. Ammonia may act as a nutrient and may cause odor issues. pH adjustment, stabilization, and/or corrosion inhibitor addition may be needed to mitigate service water system corrosion.

Objective	Potential Treatment	Reasoning for the Treatment
Recycle Flue Gas Condensate as Cooling Tower Makeup	<ol style="list-style-type: none"> 1. TSS removal 2. Ammonia removal 3. Nitrate removal 4. pH adjustment 5. Sulfate resistant concrete 	TSS may build up on cooling tower fill and in the basin. Ammonia may act as a nutrient and/or combine with free chlorine to form less effective combined chlorine. High nitrates may act as a nutrient for biological growth. High pH could result in localized scaling at the cooling tower makeup point due to elevated levels of hardness in the cooling tower water. High sulfates will cycle up in the cooling tower and may require the use of sulfate resistant concrete for the cooling tower basin.
Recycle Flue Gas Condensate as Boiler Makeup	<ol style="list-style-type: none"> 1. TSS removal 2. Hardness or Total Dissolved Solids (TDS) Reduction 3. Ammonia removal 	TSS removal is likely required as pretreatment to hardness or TDS treatment. Hardness or TDS reduction (e.g. sodium zeolite softening, reverse osmosis, and/or ion exchange) will be needed depending on the boiler chemistry requirements. Although most boiler chemistry programs can tolerate ammonia in the boiler makeup, ammonia may interfere with hardness and TDS treatment.
Recycle Flue Gas Condensate as Potable Water	Likely not feasible	Potable water is typically made by treating a natural water source such as a surface or groundwater supply. Treating flue gas condensate for potable water use may be difficult or not permissible due to potable water regulations.
Discharge Flue Gas Condensate Offsite	<ol style="list-style-type: none"> 1. TSS removal 2. Ammonia removal 3. pH adjustment 4. Heavy metals removal 5. Nitrate/Nitrite removal 6. Cooling 	Treatment of some type is likely required before discharging flue gas condensate offsite into a receiving body. Treatment requirements will be a function of the condensate quality as well as the discharge permit limitations. The condensate is typically warm and may require cooling prior to discharge.

The International Association for the Properties of Water and Steam (IAPWS) is developing a technical guidance document on water treatment of flue gas condensate (Dooley, 2022), which has not been issued at the time of development for this paper. It is anticipated that this document will be a valuable resource, especially since papers on flue gas condensate treatment are limited.

CARBON DIOXIDE RELEASE – Some of the carbon dioxide from the flue gas condensate will be absorbed as carbon dioxide, bicarbonate, and/or carbonate depending on the flue gas condensate pH. At a lower pH carbon dioxide and bicarbonate will dominate but this will shift towards a combination of carbonate and bicarbonates at a pH around 8.5. This can result in the release of carbon dioxide into the atmosphere during the treatment and/or reuse of the flue gas condensate. This loss of carbon dioxide may need to be deducted from calculated carbon dioxide reduction in the carbon capture system to determine the net carbon dioxide removed. In some cases, it may be possible to include additional treatment to strip the carbon dioxide back out of the flue gas condensate to be recycled back to the carbon capture system. However, it is likely that the amount of carbon dioxide released during the treatment and/or reuse of flue gas condensate will be very small when compared to the amount of carbon dioxide removed in the carbon capture process.

The most notable instance of carbon dioxide release would occur when treated flue gas condensate is reused as cooling tower makeup. The pH in the cooling tower tends to become more basic as the bicarbonates and carbonates from the cooling tower makeup cycle up in the cooling tower circulating water. An acid is fed into the cooling tower to control the pH which will convert carbonates to bicarbonates and then convert a portion of the bicarbonates to carbon dioxide as shown in the equations below. The carbon dioxide will tend to off gas out of the cooling tower circulating water into the atmosphere (Sampson, 2010) as shown in the chemical reaction below.



WASTEWATER DISCHARGE – Carbon capture systems generally will utilize water in such a way that there will be a wastewater stream that must be discharged. This could include wastewater from water treatment equipment, cooling tower blowdown, and even treated flue gas condensate. An offsite wastewater discharge will be needed, unless wastewater streams can be recycled to an existing facility water user, deep well injected, hauled offsite for disposal, or a zero-liquid discharge wastewater treatment system is utilized. These options will not be feasible or practical for most carbon capture systems. In most cases, all or a portion of the carbon capture system wastewater will need to be treated and discharged to an offsite receiving body through a National Pollution Discharge Elimination System (NPDES) permit.

Treatment may be required prior to recycling or discharging flue gas condensate or associated wastewater streams, as noted in Table 2. Beyond the typical NPDES limits on discharging wastewater (e.g., TSS, oil/grease, pH), the EPA utilizes industry specific Effluent Limitation Guidelines (ELG) (US EPA). Additional wastewater limits may be applicable based on the following:

- State, local, or receiving body limits set by the State permitting authority. These are difficult to predict and could be prohibitive for already impaired receiving bodies.
- If the carbon capture system is installed in an industry that has a defined ELG, there may be additional wastewater limitations or prescribed wastewater treatment techniques that must be employed.

One interesting ELG example is the Steam Electric Power ELG which provides limitations on discharges from low volume wastes, coal pile runoff, fly ash and bottom ash transport, metal cleaning wastes, cooling tower blowdown, and FGD wastewater. Of greatest interest is the definition of FGD wastewater found in 40 CFR 423.11.n:

The term flue gas desulfurization (FGD) wastewater means any wastewater generated specifically from the wet flue gas desulfurization scrubber system that comes into contact with the flue gas or the FGD solids, including but not limited to, the blowdown from the FGD scrubber system, overflow or underflow from the solids separation process, FGD solids wash water, and the filtrate from the solids dewatering process. Wastewater generated from cleaning the FGD scrubber, cleaning FGD solids separation equipment, cleaning FGD solids dewatering equipment, FGD paste equipment cleaning water, treated FGD wastewater permeate or distillate used as boiler makeup water, or water that is collected in floor drains in the FGD process area is not considered FGD wastewater. (Code of Federal Regulations)

This FGD definition could be applied to the carbon capture quencher installed on gas fired power plants since it is in contact with flue gas and will desulfurize it by removing SO₂. Although the Steam Electric Power ELG's focus on wastewater streams associated with coal power plants, 40 CFR 423 does specifically note that it applies to fossil fired plants which includes coal, oil, and gas (Code of Federal Regulations). However, the flue gas condensate from a gas fired power plant will generate a considerably cleaner wastewater than FGD wastewater from a coal fired power plant. Some examples are that the FGD wastewater typically has TSS in the percentage range, fully saturated with calcium sulfate, and can have elevated levels of mercury, selenium and arsenic, while these constituents are found in much lower concentrations for flue gas condensate wastewater from a gas fired power plant. The justifications set by the EPA to place limits on FGD wastewater would not seem to apply for gas fired power plant flue gas condensate. However, the main similarity between the two wastewater streams is nitrates/nitrates which may justify flue gas condensate treatment. But if the permitter applies FGD wastewater limits to gas fired power plant flue gas condensate, then this may push facilities to installing zero liquid discharge treatment system which will have dramatic impact to projects.

COOLING WATER REQUIREMENTS

Amine absorption-based carbon capture systems require cooling for the flue gas quencher, absorber, and regenerator. Refer to Figure 1 for a simplified diagram showing key points where cooling is needed. Additional cooling may be needed as part of a full carbon capture system including cooling for the carbon dioxide compressor. The cooling requirements can be quite substantial, even if you only consider the cooling needed during the quench step since a portion of the vaporous water in the flue gas has to be condensed into water.

Cooling can be accomplished by either wet cooling, dry cooling, or a combination of both. The choice of cooling methods will impact the achievable cooled process temperatures in the carbon capture system. Wet cooling methods are limited by an approach to the ambient wet bulb temperature, while dry cooling methods are limited by an approach to the ambient dry bulb temperature. Since the ambient wet bulb temperature is lower than the ambient dry bulb temperature, except when the humidity level is 100%, wet cooling can achieve lower cooled process temperatures. Utilizing a closed cycle cooling loop to absorb heat from the process and then rejecting the heat back into wet or dry cooling system is common and provides some design and operating benefits. However, this will introduce another layer of heat transfer that requires a temperature differential which in turn will result in high cooled process temperatures. The carbon capture process will have limitations on cooled process temperatures for the various heat exchangers. In some cases, these may be hard limits that must be met while in other cases lower cooled process temperatures may improve the operation and/or performance of the carbon capture system. Therefore, it is imperative to work closely with the carbon capture system supplier to design the cooling systems to meet the performance and economic objectives.

DRY COOLING - Dry cooling typically utilizes air-cooled heat exchangers to reject heat into the ambient air. This can be done directly by having the process stream that requires cooling to be sent to an air-cooled heat exchanger, or indirectly by having a closed loop cooling system where heat from the process is rejected to the water filled closed loop system which then rejects heat to an air-cooled heat exchanger. Utilizing a closed loop system provides practical benefits of being able to use plate and frame or shell and tube heat exchangers for the process cooling but then results in warmer process temperatures due to the need for temperature differentials across two sets of heat exchangers. If a closed loop cooling water system is used, then typical practice is to utilize demineralized water with corrosion inhibitors, and possibly a glycol solution if freeze protection is required. However, a continuous water makeup is not needed for either the direct dry cooling option or the closed loop dry cooling system option, which is advantageous to sites with limited water supplies. But the use of dry cooling does not allow for treated flue gas condensate to be recycled to a cooling tower which can result in an excess of wastewater that either will need to be recycled elsewhere or discharged.

WET COOLING - Wet cooling utilizes an open loop circulating water system with an evaporative cooling tower or wet surface air cooler (WSAC). Cooling is accomplished by evaporating water into air which in turn results in the concentration of dissolved solids in the circulating water. The cycles of concentration of the dissolved solids will have an economical, corrosion, and/or scaling limit resulting in the need to blowdown water out of the system. In some cases, the cycles of concentration will be limited by cooling tower blowdown quality

limitations in the NPDES permit or by drift TDS limits in the air permit. The total makeup water to the wet cooling system will be the sum of the evaporative losses, cooling tower drift, and blowdown.

Systems employing an evaporative cooling tower or WSAC will need a continuous makeup water source. A portion of this water could be from treated flue gas condensate. However, it is unlikely that there will be an adequate amount of flue gas condensate to supply the full makeup water supply which will necessitate an alternate makeup source. It has been the authors experience that 20-30% of the makeup water can be sourced from treated flue gas condensate while the remainder must come from another water source. However, this percentage may vary considerably for other applications based on different fuel types, cooling tower cycles of concentration, ambient temperatures, etc.

COMBINATION COOLING - A combination of wet and dry cooling can be utilized to reduce the cooling tower makeup water and blowdown while still achieving or approaching the lower cooled process temperatures that wet cooling can achieve. Combination cooling can be accomplished in many ways:

- Dry cooling is used first to provide the majority of the cooling. Then wet cooling is used as a polishing step.
- Dry cooling is utilized only for certain heat exchangers that can tolerate higher cooled process temperatures while wet cooling is used for the remainder of heat exchanger cooling.
- Dry cooling is utilized as much as practical based on the ambient temperatures. Then wet cooling is used during hotter ambient temperature months.

CLOSED LOOP COOLING - Closed cooling loops only require an initial fill of demineralized water with a corrosion inhibitor along with an occasional top off due to slow leaks and losses. Therefore, it is not advisable to plan for a continuous makeup stream to a closed cooling loop.

DEMINERALIZED WATER REQUIREMENTS

Demineralized water is often needed for boiler makeup, continuous carbon capture system makeup (e.g., pump seal water), and for initial carbon capture system makeup during startup. The demineralized water quality and quantity is dictated by the carbon capture system supplier and will vary for each project.

Steam is needed to drive the regenerator reboiler and is either provided from an existing site steam source or by an auxiliary boiler that is provided as part of the process. Although the vast majority of the steam is recovered as condensate, the system will have losses due to boiler blowdown, sampling losses, and miscellaneous losses. These losses must be made up by utilizing demineralized water. In cases where a high purity steam cycle is utilized, the makeup water will need to be high purity demineralized water. However, it may be possible to utilize a lower purity steam cycle which would require a lower purity softened water instead of demineralized water. The demineralized makeup rate for a high purity steam cycle is typically 1-2% of the steaming rate, while the softened water makeup rate for a lower purity cycle is typically in the 2-10% range depending on the quality of the softened water.

The quality and quantity of demineralized water needed for the carbon capture system will be specified by the carbon capture system supplier. Although two different grades of demineralized water may be specified, providing a single high quality demineralized water supply for all users tends to be the most optimal solution since providing an additional low quality demineralized storage and distribution system usually would not offset the savings associated with lower treatment costs for a portion of the demineralized water. The carbon capture system demineralized water quality requirement is typically lower than what is needed for a high purity auxiliary boiler and therefore should be carefully reviewed to determine the optimal level of treatment. Consideration should also be given to using demineralized water that may already be available at an existing site. For smaller carbon capture systems, it may be desirable to utilize rental reverse osmosis and/or ion exchange systems instead using a permanent system. It is important to note that rental ion exchange systems used for potable water applications can be more economically regenerated than those used for industrial water applications. This is because resins associated with industrial applications tend to be more difficult to regenerate and are not reused for potable water applications due to concerns about cross-contamination of potentially toxic residual contaminants. Therefore, it may be advisable to utilize a city water, surface water, or ground water makeup source instead of using flue gas condensate to significantly reduce the regeneration costs.

MISCELLANEOUS WASTE STREAMS

Amine absorption-based carbon capture systems can generate miscellaneous waste streams including TEG wastewater, reclaimers wastes, and acid wash wastewater. These waste streams are typically not combined with other wastewater streams.

TEG WASTEWATER – The carbon dioxide recovered from the regenerator has moisture that is removed by a glycol absorbent system. Triethylene glycol (TEG) is one of the more common glycols used. The water is purged from the glycol absorbent system in the form of a dilute (~5% or less) TEG water solution which is typically hauled offsite for disposal. The annual disposal costs can be high due to the cost of transportation and disposal, even though the generation of TEG wastewater is relatively low. Although it may be possible to treat the TEG wastewater stream for volume reduction, industrial experience is limited and obtaining wastewater treatment performance guarantees may be challenging. However, due to the low wastewater flowrates it may be worthwhile to purchase a relatively cheap system without performance guarantees with the possibility of a significant reduction in wastewater disposal costs while the costs associated with a failed system would be tolerable. Potential treatment technologies include reverse osmosis, vibrating shear enhanced processing membranes, disc tube reverse osmosis, pervaporation, membrane distillation, reverse osmosis with brine concentration using membrane distillation, and packaged evaporators. A full analysis including all of the impurities that may be in the TEG wastewater stream is often not provided by the carbon capture system supplier making it difficult to determine the ability of the various technologies to handle all potential impurities with an acceptable level of fouling.

RECLAIMER WASTES – Impurities in the flue gas stream can degrade the performance of the carbon capture system. An amine reclaiming system is used to prevent impurities from building up in the system. The reclaimer produces a waste stream which is hauled offsite for processing.

ACID WASH WASTEWATER - The flue gas is rinsed in the absorber with demineralized water to reduce the VOC's, aldehydes, amines, and ammonia in the flue gas prior to being emitted into the atmosphere. The removal of these constituents can be enhanced by adding a final sulfuric acid rinse step in the absorber tower. However, this produces an acid wash wastewater that must be hauled offsite for disposal.

CONCLUSION

Amine absorption-based carbon capture systems have significant cooling demands, demineralized water requirements, and generate a sizeable flue gas condensate stream along with smaller miscellaneous waste streams. The carbon capture system designs will vary due to the types of fuel that are combusted at different facilities, resulting in differences in the cooling requirements, demineralized water requirements, and wastewater generation. The flue gas condensate stream is the largest wastewater stream generated by the carbon capture system with the quality being linked to the flue gas quality, which in turn is linked to the fuel quality. In some cases, it may be possible to recycle a portion or all of the treated flue gas condensate as cooling tower makeup or to another existing water user at the site. Discharge limitations will vary from site to site and can have a significant impact on the water/wastewater treatment and water recycling philosophy. Several small wastewater streams such as TEG wastewater, reclaimer waste, and acid wash water may be generated requiring the need for offsite handling and/or disposal. Each carbon capture system design must incorporate a practical plan to handle the various water demands and wastewater recycle/discharge within the site limitations. This paper has highlighted many important considerations which should be helpful during the planning and detailed design stages of a carbon capture system project.

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**Prepared Discussion of:
Carbon Capture Water Requirements and
Wastewater Treatment**

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INTRODUCTORY COMMENTS

I very much wish to thank the authors for providing a paper with excellent information. They correctly emphasize the momentum that is growing to reduce carbon dioxide emissions from numerous sources, with the power industry being a primary target. Many people are pushing for strong actions now in fear that we may soon reach the “tipping point” in climate change. To what extent flue gas carbon capture becomes a part of an overall carbon reduction strategy remains to be seen, but if saving some of our coal-fired units to help maintain grid stability is an option, then carbon capture will be necessary.

The authors focus on probably the most well-known technology at present, amine-absorption carbon capture, which is quite enough for a full paper. But researchers are working on many other potential carbon capture technologies, and it will be interesting to see which of these move from the laboratory to pilot testing and full-scale application.

SPECIFIC COMMENTS

I have a few thoughts regarding the discussion and have arranged them per some sections of the paper. My comments in large part are based on my nearly 20 years at two coal-fired power plants, but I know that carbon capture is being considered for other applications, including combined cycle power generation.

Amine Absorption-Based Carbon Capture Description

Figure 1 in the second section of the paper offers a straightforward process flow diagram (PFD) of the amine-based system, and is easy to understand. However, two sentences in this first section need more discussion. The direct quote is, “Caustic is often added into the quencher to remove sulfur dioxide from the flue gas to prevent heat stable salt formation in the downstream absorber. Other impurities, most notably flue gas particulates, are removed in the quencher as well.” The comment about caustic (and the reference in Table 1 in the next section to caustic being the common source of chlorides) makes me think of industrial boilers such as incinerators, where caustic is a common acid-neutralizer. But for carbon capture retrofitted on existing coal plants, some facilities already have wet-limestone or perhaps wet-lime scrubbers. These produce a solid precipitate (usually gypsum), which is extracted as a slurry from the quencher and dewatered for disposal. The scrubbing agent is not caustic. Other coal plants may use Powder River Basin (PRB) coal as the fuel, which often doesn’t require a scrubber.

Secondly, almost all coal-fired units have an upstream electrostatic precipitator (ESP) or fabric filter device, aka baghouse, for particulate removal. So, particulate loading in the quencher should be minimal for these units. And, of course, combined cycle units are typically fired with natural gas, which doesn’t produce particulates and very little SO₂.

Flue Gas Condensate Quantity and Quality

Perhaps anticipating my comments above, the authors do state correctly that, “Most of the impurities in the flue gas are traced back to the fuel source and will be highly variable for each application. Ash removal and/or air quality control equipment may either reduce or contribute to the impurities in flue gas condensate.” However, they then re-emphasize the use of caustic for pH control in the quencher, which in many cases may not be the scrubbing reagent.

I have several comments regarding items from Table 1.

- **Hardness:** The authors correctly point out that hardness, “May be added into the quencher by way of lime [or limestone] feed for neutralization.” Even though limestone and lime generate a sulfite/sulfate precipitate, a significant concentration of dissolved hardness will remain in the liquid stream. Some additional discussion in the section with Table 2 is warranted.
- **Alkalinity:** The typical operating pH in a wet-limestone scrubber is 5.6-5.8 or thereabouts because the mild acidity is necessary to ensure proper limestone dissolution.
- **TOC:** This is an issue with coal combustion. An ESP or baghouse should remove the material. I worked with one of the rare power boilers that removed fly ash in the scrubber rather than in an ESP. Even though the boiler was a cyclone unit, the fly ash loading in the scrubber was still substantial. Most of the ash came out with the scrubber waste solids, but both the solids and quench/slurry water went to the same permanent storage pond, so discharge issues were not of concern.
- **Chlorides:** For coal-fired boilers, chlorides from the fuel will dwarf anything that might be introduced by the scrubbing reagent. Concentrations (mg/L) in the five figures are not uncommon in wet-scrubber solutions.
- **Sulfites and Sulfates:** The notes again emphasize caustic as the neutralizing reagent, which may not be the case. **However, I will ask one question. For systems that use caustic as the reactant, has there been any investigation into sodium sulfate recovery for sale as a commodity chemical?**
- **pH:** Again, for wet-limestone scrubbers a mildly acidic pH is typical.
- **TSS:** Refer to the notes above about ESPs or baghouses for flue gas particulate removal.

Flue Gas Condensate Treatment, Reuse, and/or Discharge

Table 2 provides a good overview of potential treatment methods for a variety of applications. However, for coal units, hardness and chlorides present major issues. Lime-softening clarification may be needed for hardness removal. Chlorides represent the “800-pound gorilla in the room,” as there is no easy or economical method to remove these very soluble anions, and in the *Wastewater Discharge* sub-section, the authors correctly conclude that some form of wastewater treatment will be needed but that “[many] options will not be feasible or practical for most carbon capture systems. In most cases, all or a portion of the carbon capture system wastewater will need to be treated and discharged to an offsite receiving body through a National Pollution Discharge Elimination System (NPDES) permit.” Later in this sub-section, they

acknowledge that “the flue gas condensate from a gas fired power plant will generate a considerably cleaner wastewater than FGD wastewater from a coal fired power plant.”

CONCLUSION

I thought the authors did an excellent job of outlining issues related to makeup water and wastewater treatment of amine-based carbon capture technology. The information makes it clear that much planning and careful consideration are necessary when designing, installing, and operating water treatment systems for these projects. Environmental concerns are critically important. My comments in large measure address additional issues for coal-fired power plants.