EPRI Comments on Proposed Effluent Limitations Guidelines Rule

U.S. Environmental Protection Agency

Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category

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EXECUTIVE SUMMARY

The Electric Power Research Institute (EPRI) was established in 1973 as an independent, nonprofit center for public-interest energy and environmental research. EPRI brings together member organizations, the Institute's scientists and engineers, and other leading experts to work collaboratively on solutions to the challenges of electric power. These solutions span nearly every area of power generation, delivery, and use, including health, safety, and the environment.

EPRI is providing comments to the U.S Environmental Protection Agency (EPA) on the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, (referred to here as the "proposed revised Effluent Limitations Guidelines [ELG] rule") and on supporting information in docket EPA-HQ-OAR-2009-0819. The proposed revised ELG rule addresses three areas of the 2015 ELG rule—flue gas desulfurization (FGD) wastewater, combustion residual leachate (CRL), and bottom ash transport water (BATW). EPRI's comments focus on:

- Proposed best available technology (BAT) for FGD wastewater treatment (e.g., chemical precipitation, membranes, and brine management and encapsulation), including technical feasibility, capital cost, operating and maintenance costs, and pollutant reduction
- Proposed BAT for CRL wastewater treatment (chemical precipitation), including capital cost, operating and maintenance costs, and technical feasibility
- Potential stricter BAT for CRL wastewater treatment (membranes), including capital cost, operating and maintenance costs, and technical feasibility
- Proposed BAT for BATW that bans discharge from remote settling systems, focusing on technical feasibility

In 1996, EPRI initiated an effort to characterize plant wastewaters and to evaluate sampling and analytical techniques for low-level trace metals those wastewaters may contain. More recently, EPRI has conducted numerous studies to evaluate technologies for treatment of FGD wastewaters, including membrane treatment.

EPRI has evaluated CRL management through leachate characterization at dozens of combustion residual landfills across the country. EPRI has also researched treatment of CRL using chemical precipitation methods in bench-scale testing and in full-scale passive treatment systems.

EPRI has also assessed bottom ash handling options, working with more than 20 plants with high-recycle bottom ash systems to characterize water balance and management in near-closed loop systems. These results help EPRI and the industry better understand the needed operational flexibility of a purge option. As a result of these studies, EPRI has significant data and experience, which we are providing to EPA as technical input on the proposed ELG rule.

EPRI conducted as thorough a review of the proposed rule, the underlying data, and technical support documents as the 60-day comment period would allow. As there were more than 2,000 supporting documents, EPRI was unable to provide a truly comprehensive review; instead, it focused attention and technical input on the areas of expertise described above.

Key Comments on FGD BAT Wastewater Treatment Technical Feasibility

EPA rule making does not reflect an accurate calculational methodology for fly ash requirements and ash availability to estimate the cost to manage the resultant brine from membranes. EPRI's research shows EPA's current methodology significantly underestimates the industrywide feasibility and applicability of chemical precipitation (CP), membrane treatment, and encapsulation.

Key comments related to the technical feasibility of industry-wide application of membrane filtration followed by encapsulation for FGD wastewater include the following:

- EPA's approach of estimating fly ash required for brine encapsulation is not accurate. EPRI estimates more than 10x the amount of fly ash required as the EPA estimate. EPRI presents detailed comments on factors to consider in estimating fly ash requirements.
- EPRI research shows the EPA's estimate of the quantity of fly ash produced is overestimated by approximately 20 percent. Using the actual site-specific Energy Information Administration (EIA) reported data for all 22 plants is more accurate than using a "rule-of-thumb".
- The loss of fly ash beneficial reuse and impacts to the existing beneficial use markets is being underestimated and undervalued.
- EPRI observes that achievable membrane performance in FGD wastewater applications has not been accounted for leading to a 10x underestimation of brine management requirements.
- The available information provided in the Docket does not provide the basis that a higher level of membrane performance can and has been achieved by other industries and in international installations. Specifically, the EPA should demonstrate that high membrane recoveries (greater than 80 percent) are feasible in FGD wastewater applications.
- The number of plants that will require additional technologies to achieve zero liquid discharge (ZLD) will be higher than EPA estimates. In EPRI's analyses, membrane treatment alone is unlikely to be sufficient for FGD wastewater management at most sites, and many sites would likely consider thermal evaporation either standalone or in a combination with membranes and encapsulation.
- Achieving ZLD will be challenging for many sites. Due to issues related to water balance and pollutant cycling in the ZLD system, an option to discharge would provide operational flexibility.
- Achieving ZLD of FGD wastewater will require more than half of industry plants to install crystallizers leading to increased operational challenges.

Key Comments on FGD BAT Wastewater Treatment Cost

The EPA estimate for the total cost of implementing the BAT for proposed regulatory Option 3 based on chemical precipitation (CP), membrane filtration and brine encapsulation differs significantly from EPRI's estimates. EPRI's capital cost estimate is nine times higher than EPA's capital cost estimate for the same list of plants. EPRI's O&M cost estimate is more than 40 times higher than EPA's O&M cost estimate for the same list of plants. In evaluating the total annualized costs, EPRI's estimate of industry cost is more than 25 times higher than EPA's estimate. Cost estimating, flow rate, brine management and encapsulation estimates could be improved by considering the following:

- Use FGD peak flow to estimate capital costs.
- Use FGD purge flow to estimate O&M costs, instead of the optimized flow, for membrane filtration.
- Use membrane system recovery that can be consistently achieved. EPA has stated that 70 percent was "the average FGD wastewater recovery from the membrane treatment vendors." However, EPA appears to use a much higher recovery in its cost estimates.
- The cost and quantities of residual waste that would be generated for membrane filtration and encapsulation are significantly higher than the EPA estimates.
- Fly ash shortages will lead sites to experience challenges and significant costs to acquire or harvest additional fly ash, including excavation, transport and drying the harvested ash.

In addition, the following should be considered:

- EPA appears to have misreported the costs for six plants that plan to operate past 2032 and would be required to install membrane filtration and encapsulation systems.
- EPA has not adequately accounted for the higher costs for those plants that will retire or repower in less than 20 years.
- Many sites will incur costs that are inconsistent with EPA's estimated costs for chemical precipitation, membrane filtration and encapsulation. Fly ash availability and FGD purge flow and quality will ultimately drive plant decisions related to technologies required to achieve zero liquid discharge and associated costs. EPRI's estimate of the lowest cost option for ZLD is 6 times higher than EPA's cost estimate for the same list of plants.

Key Comments on FGD Wastewater Treatment Pollutant Reduction

EPA rule making fails to consider the following important factors to estimating the quantity of pollutant reduction achieved by implementing membranes as FGD BAT:

- Pollutant loading remaining in FGD water after treatment by the 2020 ELG BAT are mainly from pollutants with very low toxicity.
- Estimates of bromide in FGD water used are significantly above EPRI's experience, and thus significantly inflates total pollution reduction calculations.

Key Comments on CRL BAT Wastewater Treatment Cost

EPRI's annualized cost estimate of CRL BAT (CP) for the industry is approximately 170 percent higher than EPA's estimate. This appears to be due to failing to consider:

- Use leachate peak flow rate as the basis for engineering design of CRL CP in capital cost calculation. This will produce a more accurate estimate of the capital cost needed to build a reliable chemical precipitation treatment system.
- Base industry-level regulatory option cost for CRL BAT on all regulated CRL sites rather than a subset of the industry.
- Annual O&M labor requirements.
- Unit cost per flow at closed landfills are higher than active sites.

Key Comments on CRL Proposed BAT Limits

- EPA has not provided CRL data to show that the proposed BAT limits are technically feasible.
- Existing FGD wastewater data are not adequately representative of potential CRL CP effluent water quality. Therefore, it is not appropriate to use FGD wastewater data to set limits for CRL.
- Meeting BAT limit with CP treatment of FGD water has not been fully characterized.
- Given that dissolved arsenic concentration in CRL is higher than the BAT limit in many plants, the ability of CP to achieve dissolved arsenic removals to meet the 8 µg/L arsenic limit is uncertain.
- Flexibility for landfills nearing closure could avoid the construction of a larger and more expensive system that would only operate for a relatively short period of time.

Key Comment on Leachate Alternative Costs – Membrane

- EPA solicited comments on alternative Combustion Residual Leachate (CRL) BATs, to this end, EPRI has developed a cost estimate for leachate treatment consisting of advanced membrane filtration with brine solidification (AMF + BS). EPRI's estimated cost to the industry is $761 million more for AMF + BS than EPRI's estimate of CP.
- EPRI's cost estimate of CP + membrane is 3.5 more costly than EPRI's estimate of CP alone.

Key Comments on Bottom Ash Transport Water Proposed BAT Limits

The ability to purge water from high rate recycle remote bottom ash systems provides operational flexibility while allowing a very small incremental increase in pollutants.

- EPA fails to account for the plant's low capacity factor and uses non-representative water quality data in calculating Merrimack water quality so as to not overestimate pollution reduction.
- Blowdown purge is recommended to provide significant operational flexibility.

- EPA's cost estimate for the total cost to the industry to implement reverse osmosis to treat purge should be improved for accuracy as is, it underrepresents these costs significantly.
- Using reverse osmosis to manage purge from bottom ash systems will need brine encapsulation, requiring ash supply that is already challenged by FGD BAT.
- The blowdown purge banned in the 2023 proposed ELG BAT for BATW would provide operational flexibility while avoiding significant capital costs for water treatment/management.
- Allowing a purge still provides the majority of pollutant reduction that would be achieved by a complete ban.

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EPA's approach overestimates the quantity of fly ash produced by approximately 20 percent. We recommend use of actual site-specific EIA-reported data for all 22 plants versus using a "rule-of-thumb" estimate to improve accuracy. 13

The loss of fly ash beneficial reuse and impacts to the existing beneficial use markets is undervalued. 17

EPA's approach to estimating fly ash required for brine encapsulation is not accurate. We observe that the current methodology, if not improved, would lead to a 10x underestimation of brine management requirements. 20

The available information provided in the Docket does not provide basis that a higher level of membrane performance can and has been achieved by other industries and in international installations. Specifically, the EPA should demonstrate that high membrane recoveries (greater than 80 percent) are feasible in FGD wastewater applications. 21

The number of plants that will require additional technologies to achieve zero liquid discharge (ZLD) will be higher than EPA estimates. EPRI's research shows membrane treatment alone is unlikely to be sufficient for FGD wastewater management at most sites, and many sites would likely consider thermal evaporation either standalone or in a combination with membranes and encapsulation. 26

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BACKGROUND

On March 29, 2023, the U.S. Environmental Protection Agency (EPA) published a notice of proposed rulemaking (40 Code of Federal Regulations [CFR] Part 423: "Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category") to reduce the amount of pollutants discharged from power plants to surface waters. In this rulemaking, the EPA is proposing a regulation to revise the technology-based effluent limitations and standards (ELG) for the steam electric power generating point-source category for flue gas desulfurization (FGD) wastewater, bottom ash (BA) transport water, and combustion residual leachate (CRL) at existing sources.

In this set of comments, the Electric Power Research Institute (EPRI) addresses several fundamental scientific and technical questions raised by the proposed rulemaking and the various ancillary technical documents issued along with it. The key discussion is presented in seven sections. Section 1 and Section 2 offer EPRI's assessment for FGD best available technology (BAT) wastewater technical feasibility and costs to meet regulatory option 3: chemical precipitation (CP) + membrane filtration. Section 3 discusses FGD pollutant reduction. Section 4 and Section 5 present EPRI's evaluation of cost and technical feasibility to meet the limits for CP treatment of CRL. In response to EPA's solicitation of comments, Section 6 offers EPRI's alternative cost evaluation of CP + membrane filtration for treatment of CRL. Finally, Section 7 discusses proposed limits for BA transport water.

EPRI is also providing Appendix A through I, which provide further detail regarding the evaluations conducted by EPRI and related findings that support these comments.

1 FGD WASTEWATER TREATMENT TECHNICAL FEASIBILITY

COMMENT SUMMARY: The U.S. Environmental Protection Agency (EPA) selected membrane filtration as the BAT for FGD wastewater, which was considered to be achievable for all 22 coal-fired power plants expected to comply with regulatory Option 3 in the proposed rule. EPA rule making does not reflect an accurate calculational methodology for fly ash requirements and ash availability to estimate the cost to manage the resultant brine from membranes. The current methodology significantly underestimates the industrywide feasibility and applicability of chemical precipitation (CP), membrane treatment, and encapsulation.

EPA's approach of estimating fly ash required for brine encapsulation should be modified to increase accuracy. EPRI estimates more than 11x the amount of fly ash required compared to the EPA estimate.

EPA's approach to estimating fly ash required for brine encapsulation should be modified for several reasons. Most importantly, EPA's calculation should consider the mass of brine that would be generated and thus require encapsulation. EPA has stated that its estimate of fly ash required is based on a ratio of fly ash to flue gas desulfurization (FGD) purge flow as reported by EPRI in its 2020 comments. Using FGD purge flow to estimate fly ash required has significant problems. The amount of fly ash required will be directly proportional to the mass of brine produced, which is a direct result of the overall membrane recovery that can be achieved.

The role of the membrane is to serve as a selective barrier that will allow the passage of certain constituents and will retain other constituents found in the liquid. The liquid that has passed through the membrane is known as the *permeate*. Membrane permeate recovery, *r*, which is expressed as a percentage, represents the volume of water that is converted from feed water to permeate water, and is defined as [Metcalf & Eddy, 2014]:

$$r, \% = Q_p / Q_f \times 100$$

where Q_p is the permeate flowrate and Q_f is the feed water flowrate. Flows used to calculate permeate recovery (Q_p and Q_f) are in units of volumetric flowrate (e.g., gallons per minute, liters per hour, or cubic meters per second).

The remaining portion of the feed water and constituents that do not pass through the membrane are "rejected" by the membrane system. This flow is commonly referred to as the reject, concentrate, brine or waste stream. The flow quantity of the reject stream, Q_r, is defined as [Metcalf & Eddy, 2014]:

$$Q_r = Q_f - Q_p$$

EPA stated that it "estimated the amount of fly ash required for brine encapsulation. EPRI's comment letter presents costs for an example plant with a flow of 432,000 gallons per day (gpd) and reports the amount of fly ash required as 160,000 tons per year. ERG used this same ratio, 0.37 tons per year per gpd of FGD wastewater, to estimate the fly ash required for each plant in the final rule population." EPA further states that "EPRI's estimated fly ash tonnage requirement is two to three times greater than EPA's estimate. To protect information that EPA marked as confidential business information (CBI) for this analysis, EPA estimated its fly ash tonnage requirement for brine encapsulation as one half of EPRI's estimate." In taking this approach, EPA has used a ratio of 0.37 ÷ 2 = 0.185 tons per year per gpd of FGD wastewater feed flow to estimate the fly ash required for each plant.

EPRI would like to provide further guidance in how to correctly apply the information presented in EPRI's 2020 comments [EPRI, 2020]. In the 2020 comment letter, Appendix D, page D-3, EPRI states that "*EPRI estimated that roughly 160,000 tons per year of fly ash would be required for brine solidification for this CP + VCE/BS (chemical precipitation and vapor compression evaporator with brine solidification) case study*." As described, 160,000 tons per year of fly ash would be required for a chemical precipitation, vapor compression evaporator, and brine solidification system with 300-gallon-per-minute (gpm) peak FGD flow. Critically, this fly ash estimate was for brine generated by a thermal evaporator system. Thermal evaporators (i.e., brine concentrators) can typically achieve much higher recovery than membrane systems [EPRI, 2023] and therefore generate a much smaller volume of brine that requires fly ash for brine encapsulation. In the same Appendix D of EPRI's 2020 comments, page D-20, EPRI also states that "*EPRI estimated that roughly 454,000 tons per year of fly ash would be required for brine solidification*" for the chemical precipitation, membrane filtration, and brine solidification case study. Therefore, EPRI's 2020 comments showed that the fly ash required for membrane filtration is nearly three times the fly ash required for thermal evaporation.

Thus, EPRI recommends that, in order to utilize EPRI's calculations accurately, the approach would be to use the FGD purge flow for each plant and the overall recovery that can be consistently achieved based on the technology selected (i.e., membrane or evaporator) to then calculate the volume and mass of brine generated.

To properly calculate the mass flow of the brine, two items must be considered. First, there must be conservation of mass across the membrane system such that:

$$m_f = m_p + m_r$$

whereby m is the mass flow (e.g., pounds/minute or tons/day) for the feed water (m_f), permeate (m_p), and reject (m_r).

The stream density (defined as the stream mass per unit volume) and the specific gravity (unitless number defined as the ratio of the density of the stream to the density of water) needs to be considered. The specific gravity of a liquid increases based on the concentration of total dissolved solids (TDS) and therefore the mass of brine for a given volume will be greater than the mass of pure water occupying the same given volume. In its calculations, it appears

that EPA used the mass of brine and pure water interchangeably. Based on EPA's definition of industry average FGD wastewater [EPA, 2020], EPRI calculated and used a specific gravity of 1.018 for the FGD purge. The specific gravity of the permeate was assumed to be 1.0 for the membrane permeate. EPRI calculated a specific gravity of 1.06 for the brine generated by a 70 percent membrane recovery system. Therefore, the density of the membrane system brine would be:

8.34 pounds/gallon x 1.06 = 8.84 pounds/gallon

The density and specific gravity of the brine increases as the brine becomes more highly concentrated in higher recovery systems.

Next, EPRI recommends using the mass of brine to calculate the mass of fly ash and other additives required to encapsulate the brine.

In an actual application, plants would perform engineering studies that consider FGD purge flow and site-specific FGD purge quality with which to evaluate technology options based on the fly ash produced at each plant.

As described in detail in EPRI's Appendix D through E of these comments (and previously presented [EPRI,2020]), a relatively dry encapsulation mixture would be required to truck and dispose encapsulated brine in a landfill. EPRI recommends assuming a solid waste material composed of 18 weight percent of brine, 77 weight percent of fly ash, and 5 weight percent of quicklime as the basis for calculating fly ash requirements and assessing the feasibility and applicability of chemical precipitation, membrane filtration, and encapsulation.

The substantial differences in EPA's and EPRI's approaches are illustrated on Figure 1-1 and Figure 1-2, respectively. As shown in these figures and noted above, the quantity of fly ash that EPRI estimates to be required for a plant with 100 gpm of FGD purge and 70 percent overall membrane recovery is more than 11 times the quantity of fly ash estimated by EPA when assuming the same 100 gpm FGD flowrate.

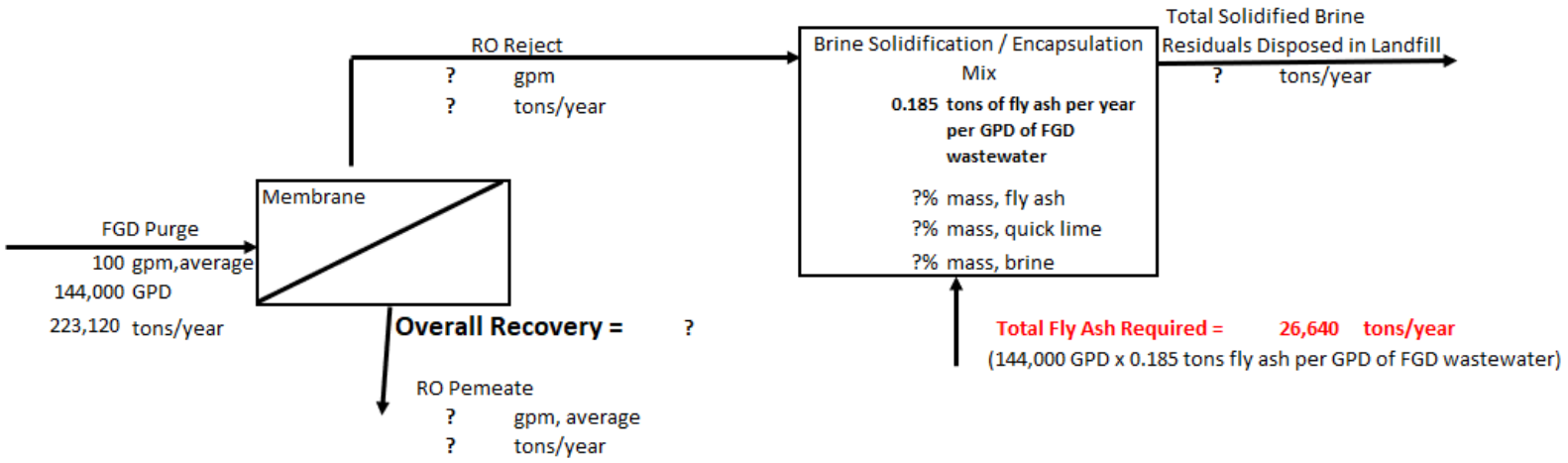


Figure 1-1. EPA calculation method for fly ash required

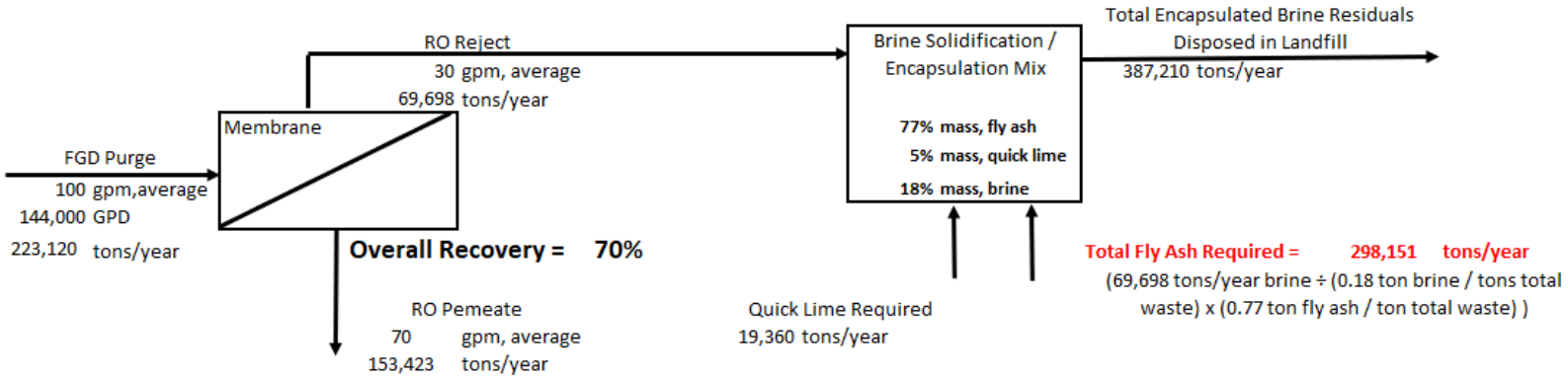


Figure 1-2. EPRI calculation method for fly ash required

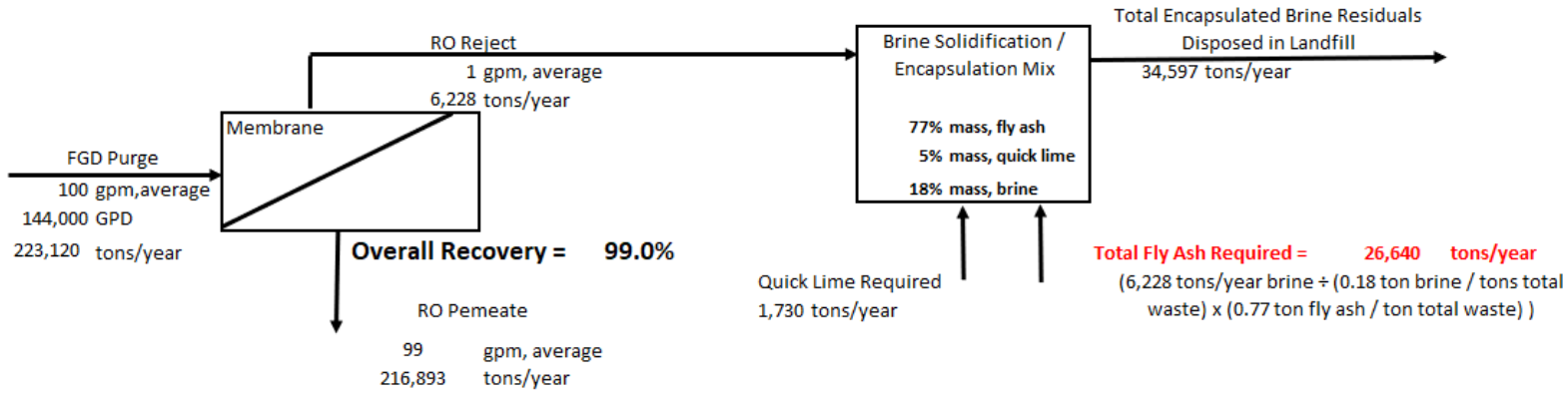


Figure 1-3. Membrane recovery required to match EPA estimate of fly ash required for truckable waste mixture

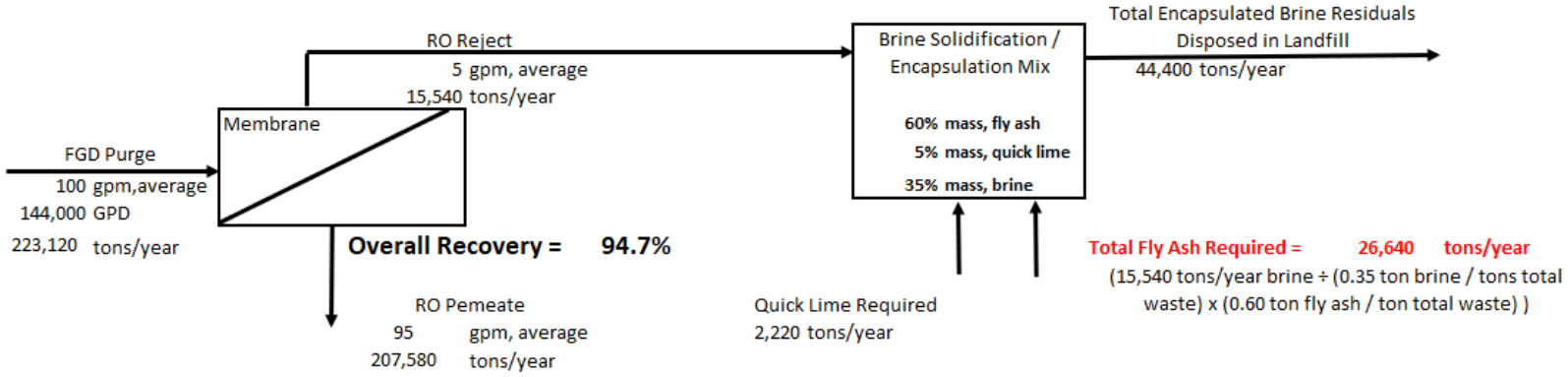


Figure 1-4. Membrane recovery required to match EPA estimate of fly ash required for paste waste mixture

Since EPA's fly ash estimates are confidential business information (CBI), the basis EPA is using to estimate fly ash required is unknown. EPRI has researched brine encapsulation mixture evaluations [EPRI, 2020 and EPRI, 2023] and has evaluated moisture conditioned (i.e., truckable) mixes and flowable paste mixes.

EPRI's basis for a moisture conditioned or a truckable waste mixture is that the solidification process would generate a non-pumpable solid waste stream which would be trucked and disposed of in a landfill. The solid waste material is assumed to be composed of 18 weight percent of brine, 77 weight percent of fly ash and 5 weight percent of quicklime. EPRI's research indicates that the suitable amount of brine in a non-pumpable mixture may be between 15 and 20 weight percent for plants burning eastern bituminous coal. [EPRI, 2020] "As more moisture is added, at some point a material will no longer be amenable to a given transportation mode (i.e., truck, conveyor) due to potential for liquefaction. This term is defined as the Transportable Moisture Limit (TML), which is the maximum moisture at which it is safe to transport a material by a given mode." [EPRI, 2023]

A "pumpable mixture or 'paste' contains a greater weight percentage of brine in the mixture (between 30 and 40 percent for plants burning eastern bituminous coal)." Based on EPRI's research, a paste mixture is composed of 35 weight percent of brine, 60 weight percent of fly ash, and 5 weight percent of quicklime. [EPRI, 2020] Many sites would not be able to use a paste encapsulation mixture due to limitations with proximity to an onsite landfill, structural/compaction requirements, regulatory/permitting authorization, and other limitations [EPRI, 2023].

The suitable amount of brine in the solid waste mixture would be significantly lower for plants burning powder river basin (PRB) coal. Sites that burn PRB coal can typically achieve higher cycles of concentration in scrubber and evaporative systems which may lead to smaller brine volumes. However, for a given flowrate, the FGD brine from a PRB site will be higher in TDS. The higher TDS leads to a lower range of brine mass suitable in the solidified mixture, leading to more fly ash and quicklime amendments being required and therefore higher costs.

To evaluate EPA's approach to calculating fly ash required as part of this rulemaking, EPRI considered EPA's assumed ratio of 0.185 tons of fly ash per year per gpd (fly ash/yr/gpd) of FGD wastewater and then back calculated the overall membrane recovery that would be required to meet EPA's estimate of fly ash required (26,640 tons/year). In this analysis, EPRI considered whether EPA may be using a truckable waste mixture (Figure 1-3) or a paste mixture (Figure 1-4), but EPA's actual approach is unknown.

As shown in Figure 1-3, EPRI estimates that 99.0 percent membrane recovery would be required on an annual average basis for a truckable waste mixture in order to match EPA's estimate of fly ash required. If instead EPA has assumed that all plants were able to use paste technology (Figure 1-4), EPRI estimates that approximately 94.7 percent membrane recovery would be required on an annual average basis to match EPA's estimate of fly ash required.

Table 1-1 provides a summary of the membrane recovery rate used by EPRI and the presumed EPA membrane recovery rates (back calculated by EPRI) based on EPRI's moisture conditioned and paste mix designs.

Table 1-1. Membrane Recovery Comparison EPRI vs EPA

EPRI's industry average consistently achievable membrane recovery	EPA calculated membrane recovery; based on EPRI's moisture conditioned mix design	EPA calculated membrane recovery; based on EPRI's paste mix design
70%	99.0%	94.7%

As is discussed further in these comments, it is not technically feasible that 94.7 to 99.0 percent overall membrane recovery can be consistently achieved in FGD wastewater applications. We recommend that the EPA update its approach in order to accurately estimate plants' abilities to implement membrane filtration and encapsulation in the industry.

EPRI has done extensive work on mix designs for wastewater encapsulation [EPRI, 2023] [EPRI, 1995]. Typically, fly ash is conditioned for disposal by adding 10 to 25 percent wastewater [EPRI, 1995]. As more moisture is added, at some point a material will no longer be amenable to a given transportation mode (i.e., truck, conveyor, barge, etc.) due to potential for liquefaction. Many landfills have local regulatory requirements related to compaction performance that aim to ensure long-term stability. For a material to compact well in a landfill, it is typically conditioned to near its optimum moisture content.

The optimum moisture content is the moisture content that resulted in the maximum dry density. For both fine-grained soils and fly ash, it is common to require compaction at geotechnical moisture contents within three percentage points of optimum moisture content. Beyond three percentage points above optimum moisture content, compaction behavior of fine-grained soils and fly ash begin to change, and pumping or weeping moisture under the compactor may result instead of densification. Compaction behavior is likely to limit the allowable moisture added to fly ash in landfills as optimum moisture content is most often lower than transportable moisture limit.

EPA may be considering paste-like methods that result in a truckable waste, such as putting waste material on a stack out pad, allowing the mixed material to dry or cure, and then excavating and trucking the dried or cured mixture to the landfill. Typical moisture conditioning systems are set up to deposit straight into a truck or conveyor belt, and would not accommodate these methods. Use of stack out pads would require more infrastructure, construction equipment and labor which should be considered.

In evaluating the 22 plants that must comply with chemical precipitation followed by membrane filtration for preferred regulatory Option 3 in the proposed rule (Table 1-1), EPA estimated that "*20 of the 22 plants produce enough fly ash for EPA's estimated brine encapsulation if none of that fly ash is sold*" and further that "*16 plants still have enough fly ash*

remaining to encapsulate brine generated from membrane filtration with no impact on the revenue generated from selling fly ash." [EPA, 2023a]

Conversely, EPRI's estimates indicate that only three of 22 plants produce sufficient fly ash to encapsulate brine with membrane filtration alone (assuming no fly ash is sold). Figure 1-5 shows EPA's estimate of fly ash required for each of the 22 plants compared to EPRI's estimate of fly ash required for the same plants assuming 70 percent overall membrane recovery and a truckable waste mixture. Figure 1-5 also shows that EPRI's estimates of fly ash required is 1 to 2 orders-of-magnitude higher than the fly ash estimates by EPA among industry plants.

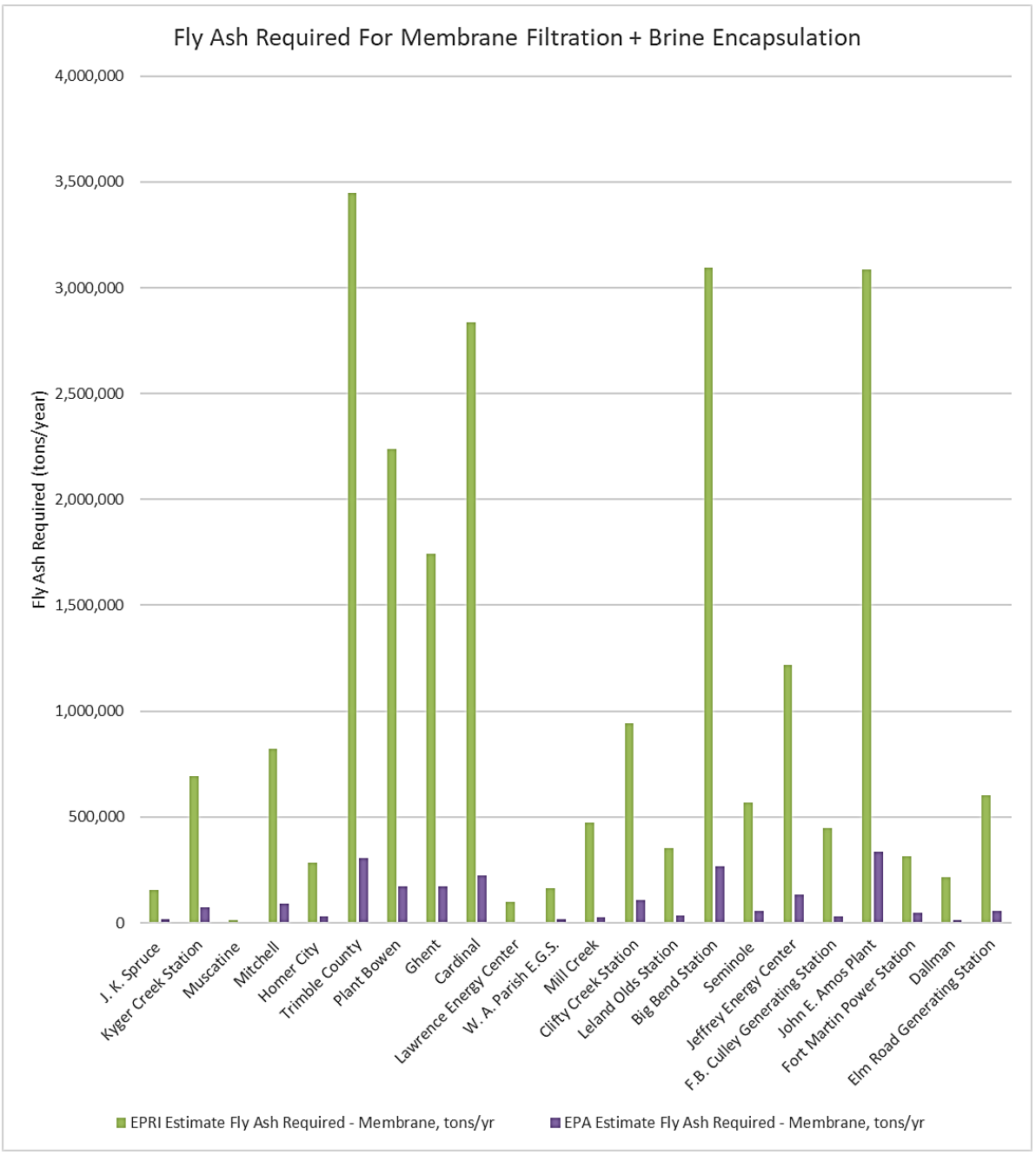


Figure 1-5. Comparison of EPRI and EPA estimates of fly ash required for membrane brine encapsulation [EPA, 2023b]

Table 1-2 shows each of the 22 plants that would be required to install membrane filtration and brine encapsulation as part of Regulatory Option 3 of the proposed rule, the flow basis used by EPA and EPRI to evaluate fly ash required, fly ash produced by each plant, and the fly ash quantity required for encapsulation using EPA's calculation method and EPRI's two calculation methods.

Based on Energy Information Administration (EIA) data, the average quantity of fly ash generated in years 2018 through 2020 for the 22 plants that would be required to comply with proposed regulatory option 3 was 4.6 million tons of fly ash per year [EPA, 2023a and EPA, 2023b]. EPA has estimated that the total quantity of fly ash required for the 22 industry plants is 2.2 million tons of fly ash per year. However, EPRI's estimate of fly ash required is much higher. EPRI's estimate of fly ash required for a truckable/conditioned ash mixture is more than 10 times higher than EPA's estimate, or 23.8 million tons of fly ash per year for the industry. EPRI's estimate of fly ash required, assuming all plants used a paste technology, is more than 4 times EPA's estimate, or 9.5 million tons of fly ash per year. Overall, using either the truckable or the paste encapsulation method, EPRI's analysis shows that there is insufficient fly ash for the 22 industry plants to implement membrane filtration with brine encapsulation.

Table 1-2. List of 22 coal-fired power plants required to implement membrane filtration followed by brine encapsulation for proposed rule, regulatory option 3

EPA ICR ID	Plant Name	EPA Assumed Plant Level FGD Purge (gpd)[1]	EPRI Assumed Annual Average FGD Purge (gpd)[2]	Total Fly Ash Production per Plant (Tons/Year)[3]	EPA Required Fly Ash (Tons/Year)[4]	EPRI Required Fly Ash – Truckable Mix (Tons/Year)[5]	EPRI Required Fly Ash – Paste Mix (Tons/Year)[6]
493	J. K. Spruce Power Plant	86,400	75,777	143,333	16,000	156,896	62,875
771	OVEC – Kyger Creek Station	385,920	335,583	186,300	71,467	694,822	278,445
904	Muscatine Power and Water Generating Station	7,500	7,200	18,333	1,389	14,908	5,974
1236	Mitchell Plant	486,000	397,894	214,033	90,000	823,837	330,146
1381	EME Homer City Generation L.P.	158,400	137,280	442,900	29,333	284,238	113,906
1674	Trimble County	1,644,985	1,664,480	228,833	304,627	3,446,299	1,381,077
2244	Georgia Power Company - Plant Bowen	937,201	1,080,000	310,500	173,556	2,236,135	896,113
2601	Ghent	928,800	842,851	431,833	172,000	1,745,120	699,343
3265	Cardinal	1,209,600	1,369,913	293,900	224,000	2,836,397	1,136,664
3309	Lawrence Energy Center	7,000	47,000	59,467	1,296	97,313	38,998
3464	W. A. Parish E.G.S.	95,040	78,585	300,933	17,600	162,711	65,205
3604	Mill Creek	149,254	229,231	286,067	27,640	474,621	190,201
5318	Clifty Creek Station	576,000	456,155	156,800	106,667	944,466	378,487
6334	Leland Olds Station	184,894	170,092	117,900	34,240	352,174	141,131
6377	Tampa Electric – Big Bend Station	1,435,680	1,495,043	52,367	265,867	3,095,479	1,240,489
7785	Seminole Generating Station	303,120	275,192	253,367	56,133	569,784	228,337
8353	Jeffrey Energy Center	720,000	587,520	201,767	133,333	1,216,457	487,486
8965	F.B. Culley Generating Station	157,622	216,000	60,667	29,189	447,227	179,223

EPA ICR ID	Plant Name	EPA Assumed Plant Level FGD Purge (gpd)[1]	EPRI Assumed Annual Average FGD Purge (gpd)[2]	Total Fly Ash Production per Plant (Tons/Year)[3]	EPA Required Fly Ash (Tons/Year)[4]	EPRI Required Fly Ash – Truckable Mix (Tons/Year)[5]	EPRI Required Fly Ash – Paste Mix (Tons/Year)[6]
9161	John E. Amos Plant	1,810,080	1,490,654	425,700	335,200	3,086,392	1,236,847
9225	Fort Martin Power Station	256,320	152,640	193,833	47,467	316,040	126,651
9971	Dallman	66,240	104,948	24,267	12,267	217,294	87,079
56068	Elm Road Generating Station	300,000	291,083	171,433	55,556	602,686	241,522
	TOTAL	11,906,056	11,505,120	4,574,533	2,204,825	23,821,297	9,546,197

1. EPA assumed purge flow as stated in 2023 Steam Electric Supplemental Proposed Rule: Fly Ash Availability [EPA, 2023a]
2. EPRI has estimated annual average FGD purge flows based on reported Energy Generating Unit capacity factors reported for years 2018 through 2020. For this reason, EPRI's assumed flows vary slightly from EPA's assumed flows and are typically slighter lower than those assumed by EPA in its analysis of fly ash required.
3. Average of total fly ash produced by plant over three years in 2018 – 2020 based on EIA Form 923 Schedule 8A [EPA, 2023a and EPA, 2023b].
4. EPA's reported estimate of fly ash required [EPA, 2023a and EPA, 2023b].
5. EPRI's estimate of fly ash required based on membrane filtration, 70 percent overall membrane recovery (i.e., 30 percent of all FGD purge flow ends up as brine), and truckable waste mixture consisting of 18 mass percent brine, 77 mass percent fly ash and 5 mass percent quicklime. In this calculation, EPRI uses an assumed specific gravity of 1.06 for the RO reject/brine.
6. EPRI's estimate of fly ash required based on membrane filtration, 70 percent overall membrane recovery (i.e., 30 percent of all FGD purge flow ends up as brine), and paste waste mixture consisting of 35 mass percent brine, 60 mass percent fly ash and 5 mass percent quicklime. In this calculation, EPRI uses an assumed specific gravity of 1.06 for the RO reject/brine.

gpd = gallons per day

EPA's approach overestimates the quantity of fly ash produced by approximately 20 percent. We recommend use of actual site-specific EIA-reported data for all 22 plants versus using a "rule-of-thumb" estimate to improve accuracy.

Through Form 923, the U.S. Energy Information Administration (EIA) collects data on ash production and disposition for plants greater than 100-megawatt (MW) steam turbine capacity. In its review of fly ash availability [EPA, 2023a] EPA stated, "*EPA estimated fly ash tonnage values instead of using the 2019 and 2020 Form EIA-923, Schedule 8A byproduct "Total" fly ash tonnage reported because reporting thresholds for respondents cause some plants to be excluded from the dataset*." EPA did not identify which plants were excluded from the EIA dataset; however, all 22 of the plants in EPA's review of fly ash availability have steam turbine capacities larger than 100 MW based on data in EIA Form 860. All 22 plants in the fly ash availability review reported total fly ash produced to EIA (Table 1-1), and the total fly ash from EIA reports for each of the 22 plants was included in the supporting EPA-developed worksheet [EPA, 2023b]. EPRI recommends that the EPA clarify why it used separate fly ash tonnage estimates when EIA reported values were available and used in other parts of the same analysis.

EPA estimated ash production using a rule-of-thumb calculation rather than using the EIA total ash production data for the 22 plants in the review. EPA's general rule-of-thumb calculation used an assumed fuel ash content of 10 percent, which appears to be inconsistent with the available data. EIA reports average annual electric power sector coal ash contents, which show that ash content in coal ranged from 8.48 percent to 8.67 percent from 2017 through 2020 [EIA, 2023]. Partly because of the assumed ash content, EPA's rule-of-thumb would thus considerably overestimate the fly ash produced from 2017 through 2020 in comparison to EIA-reported data. The overestimation for the 22 plants in the review ranged from 0.5 to 1.2 million tons per year (11 to 28 percent) as shown in Table 1-3. Over the 4-year period evaluated, the EPA rule-of-thumb calculation indicated that 20 percent more fly ash was produced than what plants actually reported to EIA.

Table 1-3. Comparison of EIA reported (actual) and EPA rule-of-thumb estimate (calculated) for total fly ash produced by 22 plants

Year	Total Fly Ash[1] EPA Rule-of-Thumb (Tons)	Total Fly ash[2] EIA 923 Report (Tons)	EPA Overestimation (Tons)	EPA Overestimation (Percent)
2017	6,273,186	5,063,900	1,209,286	24%
2018	6,141,725	5,136,400	1,005,325	20%
2019	5,473,549	4,939,300	534,249	11%
2020	4,662,522	3,647,900	1,014,622	28%
Total (All 4 years)	22,550,982	18,787,500	3,763,482	20%

1. Total quantity of fly ash produced by the 22 plants shown in [EPA, 2023a and EPA, 2023b] using EPA's rule-of-thumb method of 10 percent ash content in fuel.
2. Total quantity of fly ash produced for the same list of 22 plants shown in [EPA,2023a] based on EIA Form 923, Schedule 8A data reporting. [EIA, 2023 and EPA, 2023b]

EPA fails to use EIA-reported fly ash data, rather than fly ash calculated from fuel consumption and an arbitrary 10 percent ash content. For plants where EIA Form 923, Table 8A data is unavailable, EPA estimate would be improved through use of reported consumption-weighted fuel ash contents from EIA Form 923 Table 3 rather than an arbitrary 10 percent ash content. If estimates of fly ash are needed beyond those available from historical EIA production records, other EIA historical data can be used to develop representative fuel ash content scenarios rather than relying on an arbitrary assumption of 10 percent fuel ash content.

EPRI reviewed EPA's estimate of fly ash produced by each plant (using EPA's rule-of-thumb method) and compared it to the actual EIA Form 923, Schedule 8A reporting data for years 2018-2020. Figure 1-6 shows the average tonnage of fly ash produced over the 3-year period, based on EPA's estimate and actual EIA data reporting. As seen in Figure 1-5, EPA is significantly overestimating the fly ash produced for many of the 22 plants.

It should be further clarified that Figure 1-6 compares EPA's estimate to the total fly ash produced by each plant based on EIA data reporting. This includes all fly ash produced by the facility, regardless of whether the fly ash was disposed or sold. This comparison further emphasizes the need for EPA to use actual EIA data in its analysis.

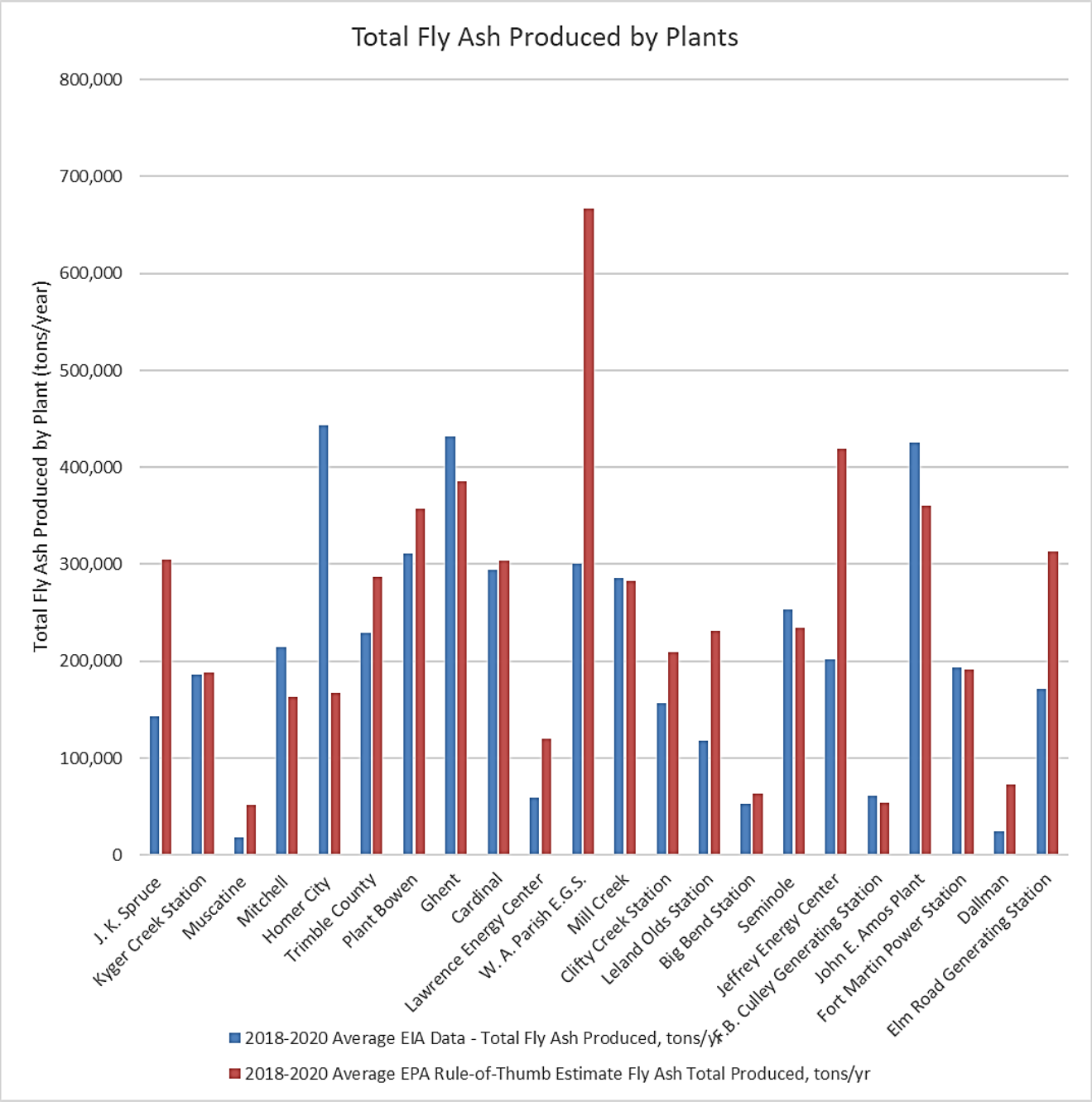


Figure 1-6. Comparison of EIA data and EPA's estimate for total fly ash produced by 22 plants (2018 through 2020)

The resulting underestimation of industrywide feasibility and applicability of membrane filtration and brine encapsulation can be seen on Figure 1-7. This figure compares EPA's estimate of fly ash required, EPRI's estimate of fly ash required, and the EIA reported total fly ash produced (average of years 2018-2020) for each of the 22 plants. As previously stated, EPRI's analysis shows that only three plants would have sufficient fly ash to adapt membrane filtration and brine encapsulation technology.

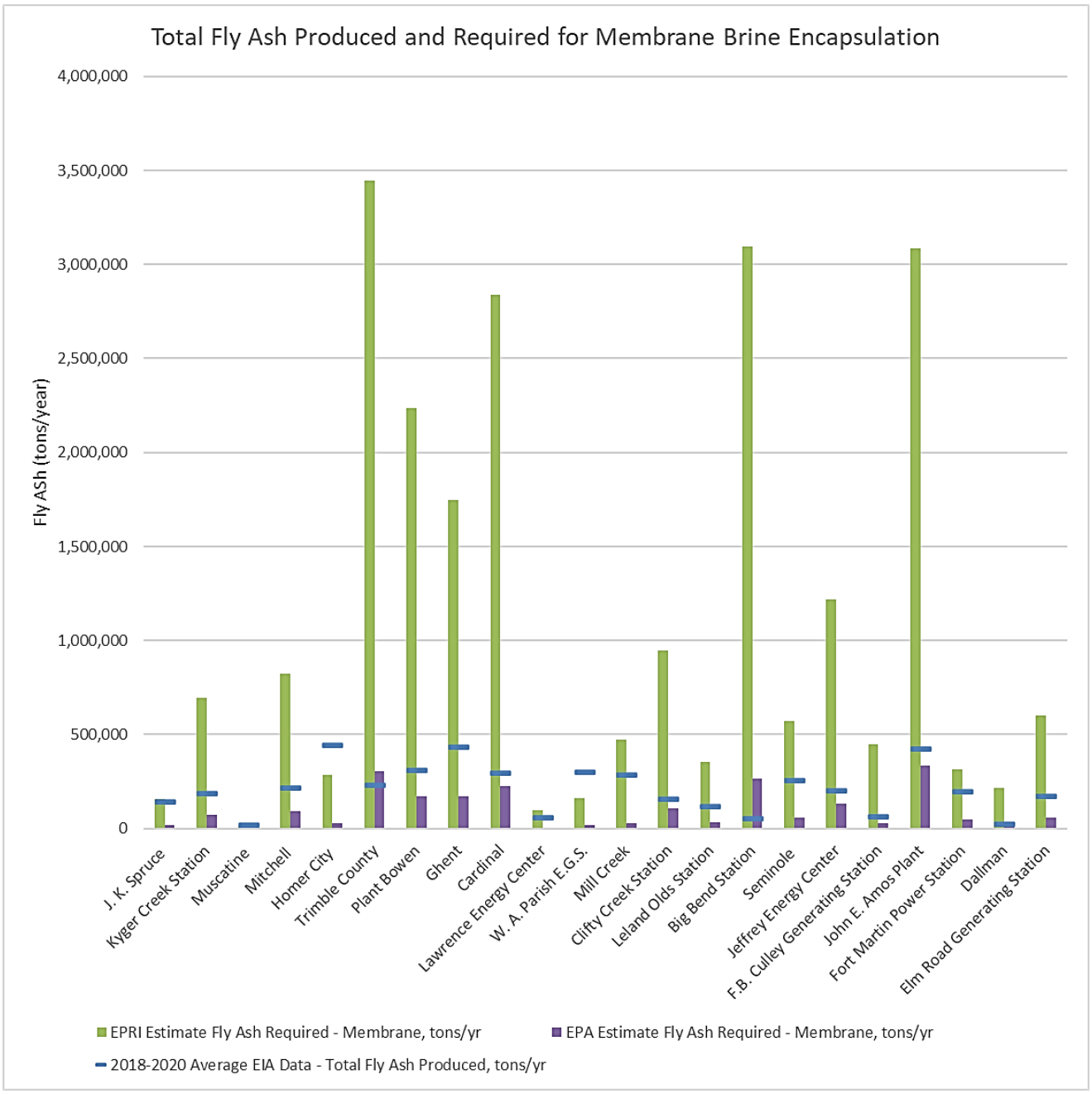


Figure 1-7. Comparison of EPA estimate of fly ash required, EPRI estimate of fly ash required, and EIA-reported fly ash produced for 22 plants

The loss of fly ash beneficial reuse and impacts to the existing beneficial use markets is undervalued.

Both EIA and American Coal Ash Association (ACAA) report coal combustion product production and beneficial use data. Each entity uses different survey methodology to collect data. EIA reports aggregate production and use on a plant-by-plant basis whereas ACAA reports industry-wide data for production and use broken down into applications, like cement replacement in concrete or waste stabilization. For assessing quantities produced and used at individual plants or small sets of plants, EPRI has found that EIA's plant-level data are likely more applicable than ACAA's industrywide data. EPRI recommends that EPA use EIA data, or similar plant-level data, where available. However, EPRI recommends using ACAA's industrywide data when considering impacts to specific beneficial use markets, like concrete or waste stabilization, in the absence of more detailed individual plant data.

Using EPA's rule-of-thumb calculation method to estimate fly ash, EPA concluded that "16 plants still have enough fly ash remaining to encapsulate brine generated from membrane filtration with no impact on the revenue generated from selling fly ash" [EPA,2023a]. On the other hand, EPRI's analysis considering EIA-reported fly ash data and EPRI's estimate of fly ash required for brine management using a "truckable" moisture conditioned waste mixture shows that:

- Only 5 of 22 plants did not sell ash between 2018 and 2020
- All of the remaining 17 plants would be required to divert beneficially used ash to encapsulate brine and would experience impacts on revenue generated and landfill utilization. In addition, current users of this fly ash would need to source replacement products.
- Further, EPRI's analysis shows that 15 of the 22 plants would be required to forfeit 100 percent of their fly ash sales in order to encapsulate brine. These plants would be required to use all of their total produced fly ash for brine encapsulation, including fly ash that is sold or disposed. Loss of 100 percent of sales at a power plant may have substantial local impact, especially to ready mix concrete producers who may be required to use fly ash for certain types of concrete.

EPA stated that it "*does not anticipate that the fly ash needed for brine encapsulation to significantly impact the fly ash market*" [Section 2, last paragraph, EPA,2023a]. Conversely, EPRI's review of EIA data suggests that 1.5 million tons of fly ash that is currently being beneficially used would be diverted to encapsulation. Further, if these shortages are filled with fly ash from the current beneficial use market, which would increase the total diverted fly ash from the beneficial use market to 19.9 million tons of fly ash/yr.

In 2018 through 2020, the ACAA reported that an average of approximately 18 million tons of fly ash was beneficially used in all applications, including 13 million tons in concrete and waste stabilization applications that are most analogous to brine encapsulation in terms of necessary fly ash properties [AACA, 2021]. Using EIA total fly ash data for the same 2018 through 2020

period and EPRI's estimate of fly ash required (based on 70% membrane recovery and truckable waste mix assumptions), approximately 8 percent of the fly ash currently sold by the 22 plants would be diverted from current beneficial use market to brine encapsulation (based on ACAA's total reported beneficial use quantities). If shortages of fly-ash-deficit plants are to be filled with fly ash from the current beneficial use market, EPRI's analysis shows that 109 percent of all fly ash currently being beneficially used would be diverted from market. If the fly ash used for encapsulation is exclusively drawn from fly ash used in applications with the most similar fly ash performance requirements (i.e., concrete and waste stabilization applications), then EPRI's analysis indicates that 154 percent of fly ash would be diverted from the current market for concrete and waste stabilization.

In addition, the total fly ash production is declining year-after-year. The increase in beneficial use of fly ash as a percentage of fly ash production, reflecting previously disposed ash entering the market, has partially offset the decline in total fly ash production. Figure 1-8 demonstrates that there has been a consistent decline in the total fly ash production over the past decade, and a fairly steady increase in percent utilization. At the same time, the production of Portland cement has been consistently rising, as shown in Figure 1-9. This overall decline in fly ash production means that fly ash use in concrete has not kept pace with growth in Portland cement use, despite the increase in percentage utilization of fly ash and the introduction of fly ash from landfill and impoundment harvesting projects beginning around 2018.

The decline in apparent cement replacement rate suggests there may already be unfulfilled demand for fly ash, although factors besides fly ash availability, like shifting uses of concrete in construction, may also contribute to changes in apparent cement replacement rate. Since current ash harvesting projects, and new marketing of previously disposed fresh production fly ash, have at best, only partially filled the gap resulting from the overall decline in fly ash production, EPRI suggests that EPA re-consider its assumption that the occurrence of fly ash disposal at some plants means this fly ash would be available for use in encapsulation or beneficial use at other plants. It's possible that deficits in fly ash for use in encapsulation could be filled by to-be-developed on-site landfill harvesting projects or the transfer of currently disposed ash from another power plant. However, plant-by-plant analyses of materials availability and costs, including processing and transportation requirements, is needed to demonstrate availability of fly ash for use in encapsulation and local impacts to existing fly ash markets of fly ash use in encapsulation.

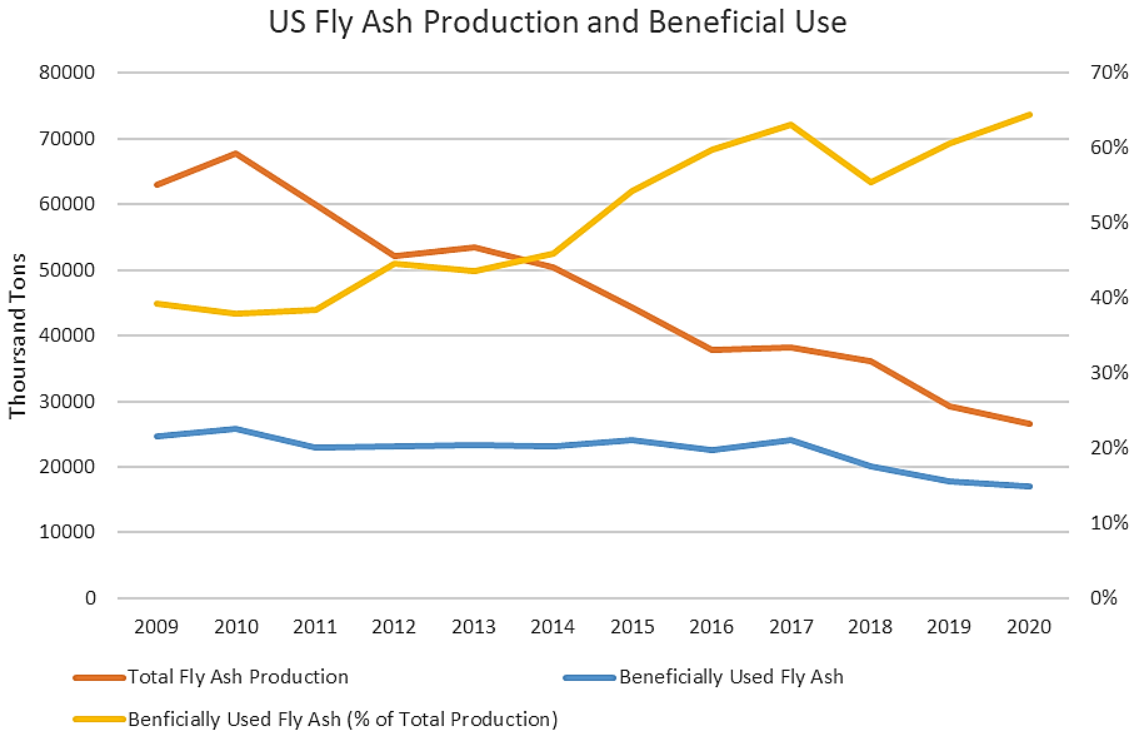


Figure 1-8. U.S. fly ash production and beneficial use trends, thousand tons of fly ash per year [EPRI, 2022, Figure 1]

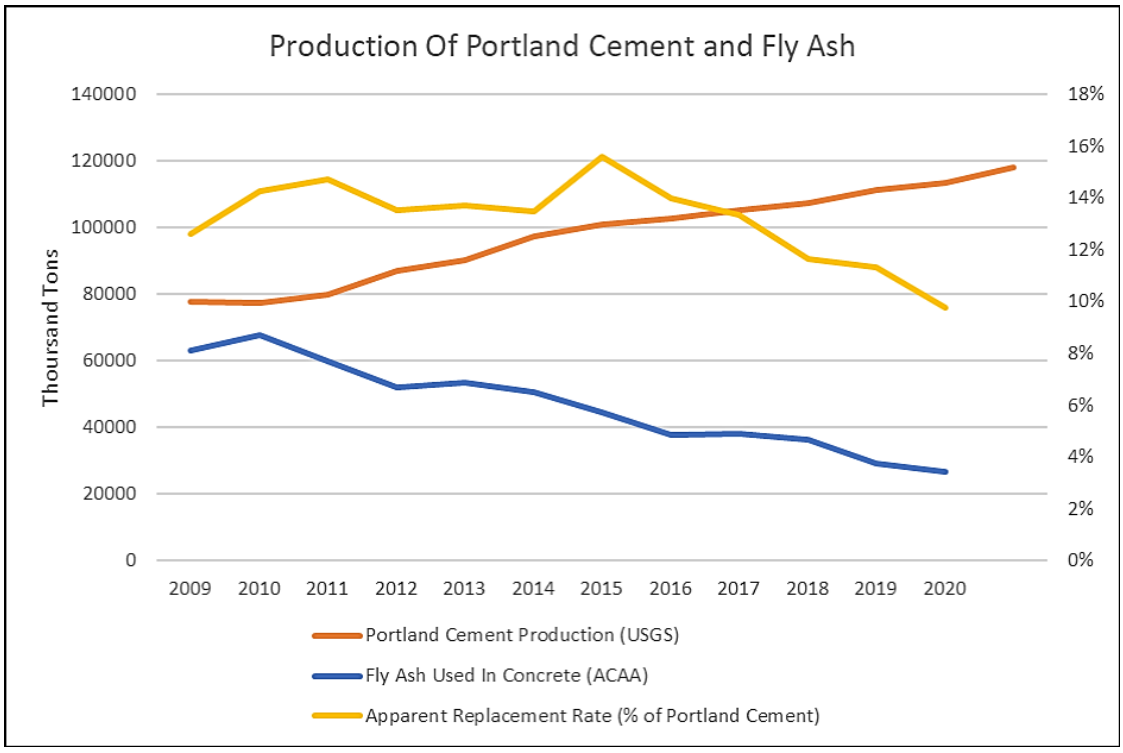


Figure 1-9. U.S. production of Portland cement and fly ash thousand tons of fly ash per year [EPRI, 2022, Figure 3]

EPA's approach to estimating fly ash required for brine encapsulation is not accurate. We observe that the current methodology, if not improved, would lead to a 10x underestimation of brine management requirements.

Membrane performance and recovery is of utmost importance and a critical assumption that if EPA uses will make calculations more accurate. The membrane recovery that can be consistently achieved (and not optimistically achieved in a short-term study with new membranes) will determine the volume of brine generated that each plant must manage. This directly results in the amount of fly ash that will be required.

As part of this rulemaking, EPA stated that "*the average FGD wastewater recovery from the membrane treatment vendors*" was 70 percent, and therefore EPA showed that 30 percent of the FGD wastewater volume would end up as brine to be managed [EPA, 2023c, page 47] as shown in Figure 1-10. EPRI agrees with the basis to use 70 percent membrane recovery in EPA's calculations.

EPA calculated brine flow rate based on the average recovery from the membrane treatment vendors used for FGD wastewater.

$$\text{brine flow} = 0.30 \times \text{purge flow}$$

Figure 1-10. Average FGD wastewater membrane recovery from membrane treatment vendors, according to EPA [EPA, 2023c, pg 47]

Based on quotation information provided directly by New Logic, a major membrane supplier (with several FGD wastewater pilot installations but no full-scale domestic installations) and based on EPA's definition of the average concentrations of pollutants present in FGD wastewater [Table 6-1 of EPA, 2020], such as an industry average of 24,100 milligrams per liter of total dissolved solids (TDS), EPRI has also concluded that 70 percent average membrane recovery would be consistently achievable. The basis for 70 percent overall membrane recovery is dependent on the assumption that the FGD purge is the industry-average of 24,100 mg/L TDS [EPA, 2020] and that 100 percent of the permeate is reused (i.e., the site operates a zero liquid discharge (ZLD) system). The overall membrane recovery would be lower, approximately 65 percent recovery as an industry average, if the permeate must achieve discharge limits consistent with the 2020 Voluntary Incentive Program (VIP) limits. If the permeate must achieve the 2020 VIP discharge limits, then plants would need to install additional reverse osmosis polishing stages to achieve limits, which lowers the overall recovery that can be achieved.

Table 1-4 illustrates the significant differences in brine volume generated based on overall membrane recovery. As shown, the difference between 70 percent recovery (the average stated by membrane vendors [EPA, 2023b]) and 97 percent recovery (average of what EPA has effectively assumed in its fly ash requirement calculations per Figures 1-3 and Figure 1-4.) is a 10-fold increase in brine volumes that must be managed and in fly ash quantity required.

Table 1-4. Brine flow produced for 100-gpm FGD purge flow

Overall Membrane Recovery (Percent)	Brine produced (gpm)
65	35
70	30
90	10
97	3

The available information provided in the Docket does not provide basis that a higher level of membrane performance can and has been achieved by other industries and in international installations. Specifically, the EPA should demonstrate that high membrane recoveries (greater than 80 percent) are feasible in FGD wastewater applications.

In this rulemaking, EPA discusses "how treatment systems using membranes have advanced since the 2020 rule's promulgation and continue to rapidly advance as an effective option for treating a wide variety of industrial pollution, including pollution from steam electric power plants." Further, EPA states that "In setting best available technologies [BAT], EPA uses not the average plant, but the optimally operating plant, the pilot plant that acts as a beacon to show what is possible." Finally, EPA states that "BAT is supposed to reflect the highest performance in the industry and may reflect a higher level of performance than is currently being achieved based on technology transferred from a different subcategory or category, bench-scale or pilot plant studies, or foreign plants." [EPA, 2023c].

In consideration of these statements, EPRI reviewed the documentation provided by EPA for records demonstrating high membrane performance and recoveries achieved.

One such record [EPA, 2023e] provides a technology summary for many FGD treatment technologies, not only limited to membrane or ZLD technologies. Review of this record found that one dataset contains information related to eight pilot tests on FGD wastewater using the New Logic Research's Vibratory Shear Enhanced Processing (VSEP) membrane filtration system. This record shows that the FGD wastewater pilot feed flow was typically 20 to 30 gpm, but the feed TDS concentration was highly variable, ranging from 4,000 milligrams per liter (mg/L) to 46,800 mg/L. Membrane recoveries were also provided for the dataset. EPRI's evaluation of this dataset showed a very clear downward trend in membrane recovery based on an increase in feed TDS concentration (Figure 1-11). This dataset also reinforces that for average FGD wastewater with a feed TDS of 24,100 mg/L [Table 6-1, EPA, 2020], a typical membrane recovery would be approximately 73 percent. This is generally consistent with EPRI's assumption of 70 percent recovery for all industry plants; however, it is notably different than EPA's calculation basis of 94.7 to 99.0 percent overall recovery. The average of this range, 97 percent overall recovery, is shown in Figure 1-11 for comparison purpose.

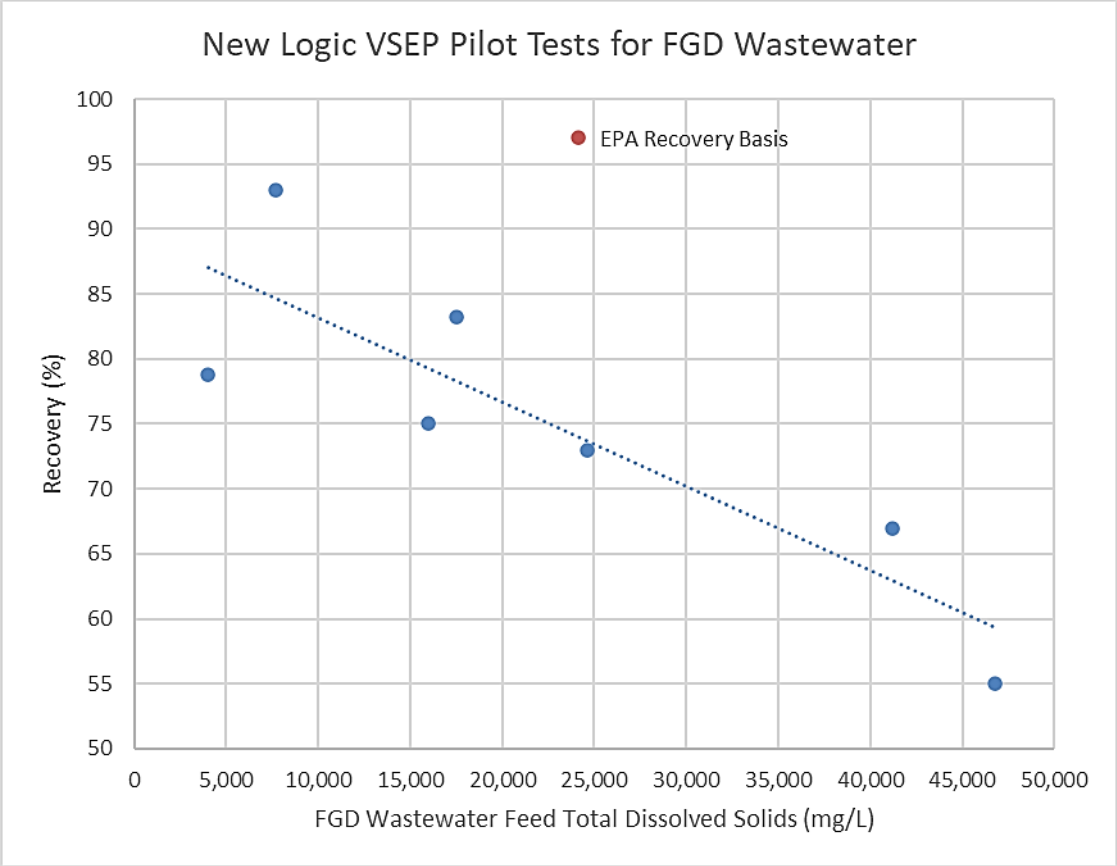


Figure 1-11. EPRI evaluation of New Logic VSEP pilot test summary data [EPA, 2023e]

In EPA's meeting with Dupont [ERG, 2020a], information was shared regarding the Changxing Power Plant, for which the FGD wastewater treatment system consists of lime soda softening, weak acid cation ion exchange system, two-pass reverse osmosis (RO), forward osmosis (FO), and a brine concentrator/crystallizer. This plant uses two seawater RO systems with a concentrate TDS of 60,000 mg/L. Even with the substantial pre-treatment and wastewater concentrating technologies used, this plant has achieved between 70 to 75 percent recovery since it began operating in 2015.

In the Dupont meeting notes, Attachment 3 [ERG, 2020a], EPA has also shared a copy of the International Water Conference (IWC) paper IWC 17-74 in which additional details are shared for full-scale FGD wastewater installations such as the Changxing Dupont system (previously described), the Oasys FO system, and Hanchuan membrane filtration pilots. The paper shared feed TDS and recovery information, which is shown on Figure 1-12. Similar to other EPA-provided documents, this data shows that membrane recovery for FGD wastewater systems may typically fall in the range of 65 to 80 percent recovery, which is considerably lower than EPA's basis for this rulemaking.

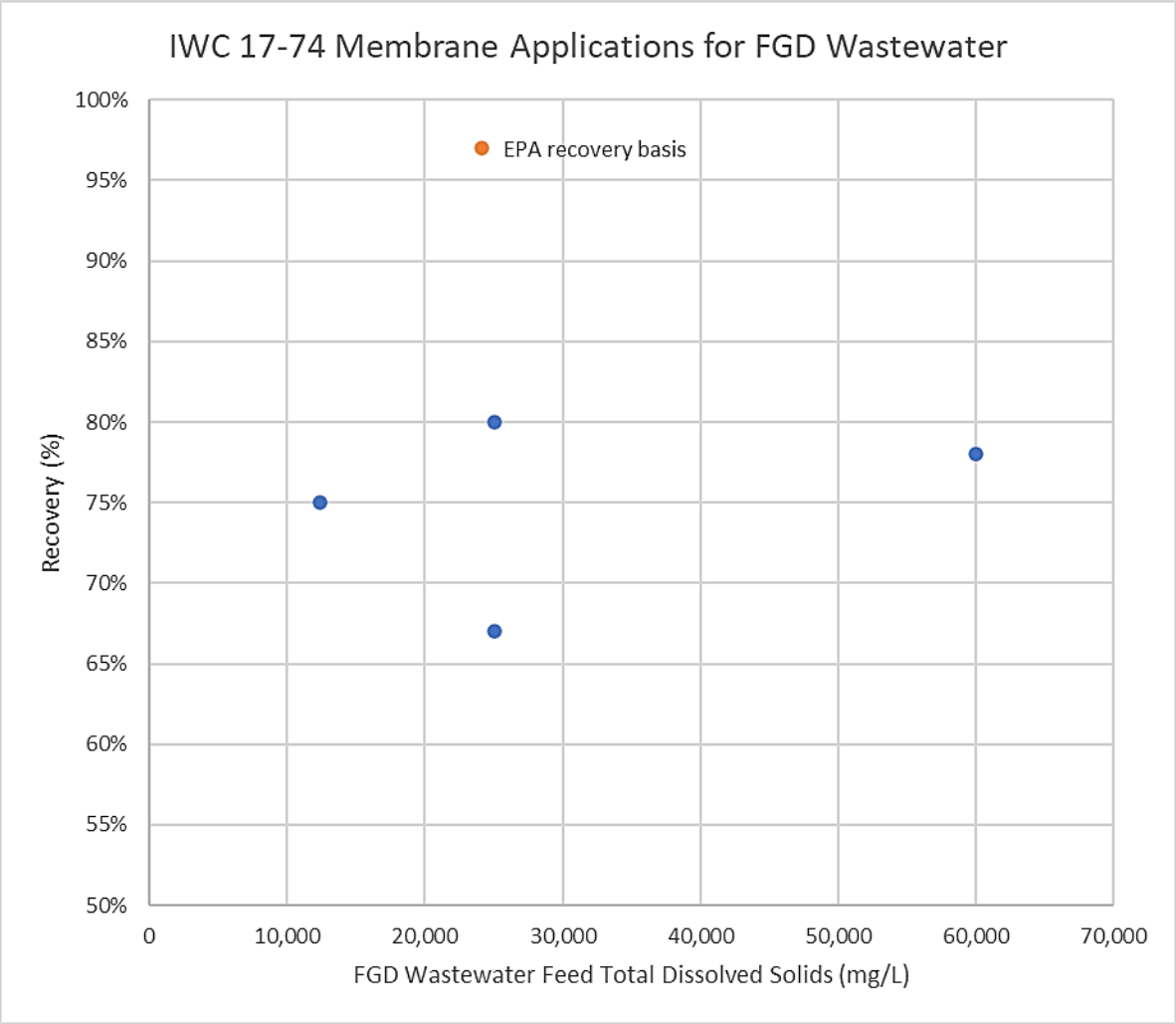


Figure 1-12. EPRI evaluation of Dupont/Dow membrane applications for FGD wastewater [ERG, 2020a]

In the same IWC 17-74 paper, Dow/Dupont, shared treatment limitations of RO, which considered a softened FGD wastewater feed and RO operating pressure limit of 1,200 pounds per square inch (psi). The paper provides information on the maximum, theoretical recovery that could be achieved using a four-stage RO system, whereas "*The softened effluent could hypothetically be concentrated up to 75% recovery (or 140,000 mg/L) before the osmotic pressure of the brine reaches the 1200 psi pressure limit and up to 82% recovery (~205,000 mg/L) before reaching 1740 psi.*" An excerpt of the plot is shown on Figure 1-13 to further illustrate these points related to maximum membrane recovery limitations for FGD wastewater applications [ERG, 2020a, Attachment 3]. This figure shows the absolute maximum recovery that could be achieved based on the membrane system's design rating, for which the maximum membrane recovery is shown to be 82 percent using an ultra-high pressure RO membrane.

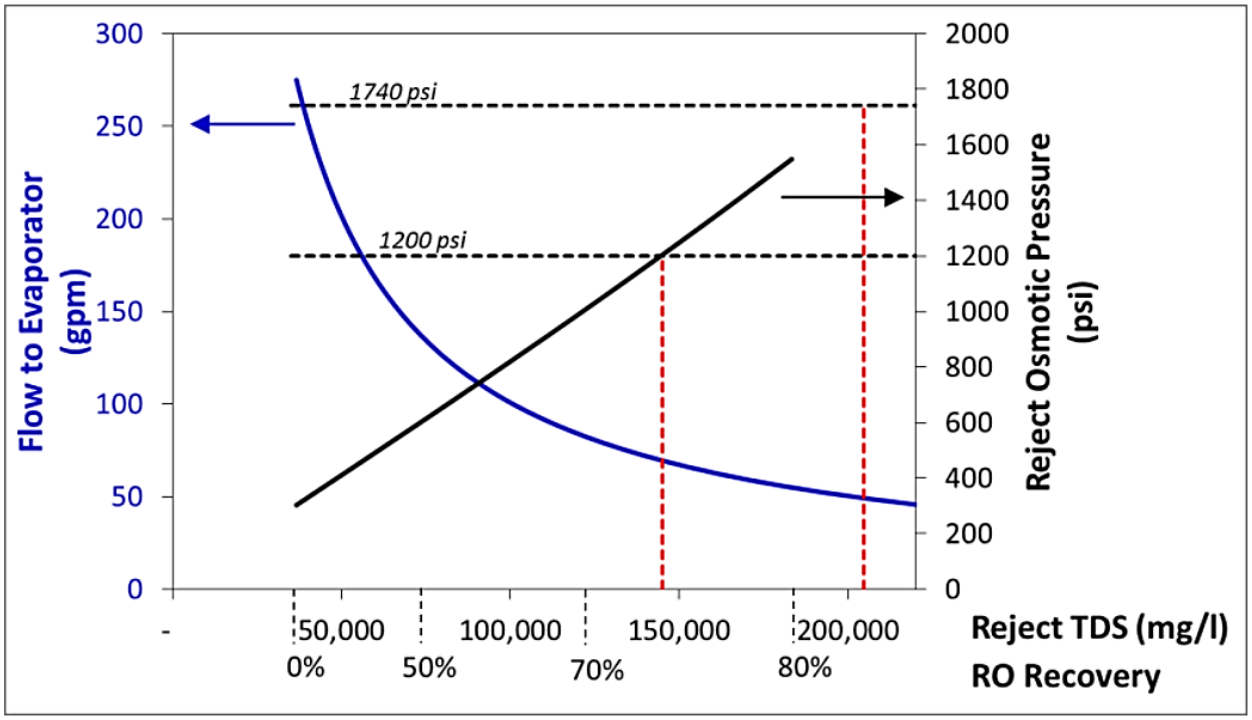


Figure 1-13. Dupont/Dow membrane treatment limitations of RO, assuming softened FGD wastewater feed and RO operating pressure limit of 1,200 psi [ERG, 2020a, Figure 3]

Additional membrane applications were provided in supporting documents of this rulemaking, but in EPRI's review no other examples of stand-alone, full-scale membrane filtration systems were provided. For example, Doosan's references for thermal ZLD for FGD wastewater [Doosan, undated] provides an example of several ZLD systems for FGD wastewater operations in Korea at the Young Dong Power Station and Young Heung Power Station. In these example international installations, membrane filtration is used only at the Young Heung Power Station and only for first stage volume reduction. Thermal technologies, such as brine concentrators and crystallizers, were essential for use in the ZLD installation. These examples do not support that membrane filtration alone can be used to achieve ZLD.

While the results presented in EPRI's 2014 VSEP study [EPRI, 2014] demonstrate that a high level of pollutants are rejected in the membrane process, interpretation of the results need to consider the conditions in which the system was operated. The VSEP study represents a theoretical maximum recovery and "best case" scenario for the treatment system configuration. The short time duration, low flow rate, controlled testing environment, and singular source water of the study are not indicative of how the system would operate at the full-scale over a period of months or years and located at sites with various water qualities. The total run time of the pilot was only 15.6 days, which included four different operational modes. The flow rate of the system was 0.5 gpm and the feed water TDS was 12,000 to 16,000 mg/L.

Another dataset referenced by EPA is EPRI's "Landfill Leachate Treatment Study: Evaluations of Membrane, Evaporation, and Encapsulation Technologies" [EPRI, 2020b]. The test included in this reference is more representative of long-term performance versus short-term testing done in the 2014 study. Overall recovery rate for the 2020 study was 76.6 percent, after treating 118,191 gallons of feed water with a TDS concentration of 3,500-4,300 mg/L. It should be noted that the feed TDS for this long-term test is considerably lower than industry average FGD wastewater of 24,100 mg/L [EPA, 2020, Table 6-1].

EPA also references EPRI's 2020 technical report on Saltworks EDR Selective Technology [EPRI, 2020c], however, additional context is required to properly interpret the results. The pilot tested FGD wastewater with a feed water TDS of 11,000 mg/L and VSEP/RO concentrated FGD wastewater with a feed water TDS of 33,000 mg/L. Some key items to note from the study include:

- Extreme complexity of Pretreatment for Flex EDR is not considered or mentioned by EPA:
  - A high-pH physical/chemical treatment step is required to remove low-solubility metals, fluoride, and silica by raising the pH to 11. Most, if not all, current Physical/Chemical treatment systems cannot achieve this extremely high pH setpoint, so equipment modifications and considerations for increased lime consumption and costs would need to be made. Equipment modifications could include the need for additional lime silos, lime slurry pumps, clarifier modifications, clarifier underflow slurry pump upgrades, and additional filter presses. Lime operating costs could increase by as much as 5-10 times compared to current operations.
  - After the high-pH step, the pH must be acidified to pH 3 with sulfuric acid to mitigate carbonate scaling. Most current Physical/Chemical treatment systems are not equipped to dose sulfuric acid. Equipment modifications including new sulfuric acid storage tanks and safety measures, sulfuric acid feed pumps, and reaction tanks would be required. Sulfuric acid operating costs would be significant, and the chemical presents additional safety hazards.
- Low flowrate, short duration pilot is not indicative of full-scale operations:
  - The system operated at 264 to 793 gpd (0.18 to 0.55 gpm). The small-scale pilot was not mean to represent operation of a full-scale system. The pilot operated for 1440 hours or 60 days and only 15 grab samples were collected.
  - The Flex EDR System has significant limitations in the quality of treated water and the extent of concentration, thus it likely requires additional treatment steps on both the treated water (e.g., RO) and concentrate (e.g., VCE and/or BC).
  - The Flex EDR Treated Water in the study had a chloride concentration ranging between 1,150 to 2,030 mg/L. This will require further downstream treatment (e.g., RO) prior to reuse. [EPRI, 2020c, Table 4-7]
  - The Flex EDR Concentrate is limited to a TDS concentration of 52,400 mg/L [EPRI, 2020c, Table 4-7, Section 3.2]. In comparison, the EDR concentrate is only roughly half the TDS

concentration of RO reject in membrane applications (Figure 1-13). Thus, salt rejection and concentration are severely limited. Most sites would need additional Flex EDR Concentrate treatment (e.g., thermal evaporator and/or crystallizer) to minimize the volume of the brine for encapsulation.

EPRI suggests that EPA consider these key factors when evaluating the EDR technology. It appears that EPA has assumed that the EDR technology can achieve high percent recoveries, high percentage uptime of continuous operations, selective removal of chloride, and the elimination of the need for a pre-treatment softening step without considering these limitations and factors from the study.

The number of plants that will require additional technologies to achieve zero liquid discharge (ZLD) will be higher than EPA estimates. EPRI's research shows membrane treatment alone is unlikely to be sufficient for FGD wastewater management at most sites, and many sites would likely consider thermal evaporation either standalone or in a combination with membranes and encapsulation.

EPRI estimates that only 3 of the 22 plants operating after 2032 would produce sufficient fly ash onsite to encapsulate membrane brine. The remaining 19 plants operating after 2032 would not have sufficient fly ash to encapsulate the high brine volume generated by membrane treatment alone and would need to consider thermal technologies to further concentrate the RO reject/brine.

Vapor compression evaporators (i.e., brine concentrators) can manage higher TDS wastewater and achieve higher recovery compared to membrane systems. EPRI's analysis for this rulemaking, similar to the analysis conducted in EPRI's 2020 comments, leads to an estimated 90 percent recovery for a vapor compressor evaporator system treating FGD wastewater. Therefore, installations using vapor compression evaporator systems will generate much less brine and will require less fly ash.

EPRI evaluated which plants likely produce sufficient fly ash for evaporator brine encapsulation. Of the 22 plants evaluated by EPA, EPRI's analysis shows that five additional plants would produce sufficient fly ash to encapsulate the evaporator brine (Figure 1-14). The remaining 14 of 22 plants would need to consider multi-staged membrane/thermal systems, install a crystallizer, purchase supplemental amendments for encapsulation, or consider other approaches. Refer to Appendix F for EPRI's estimates of fly ash required for each plant.

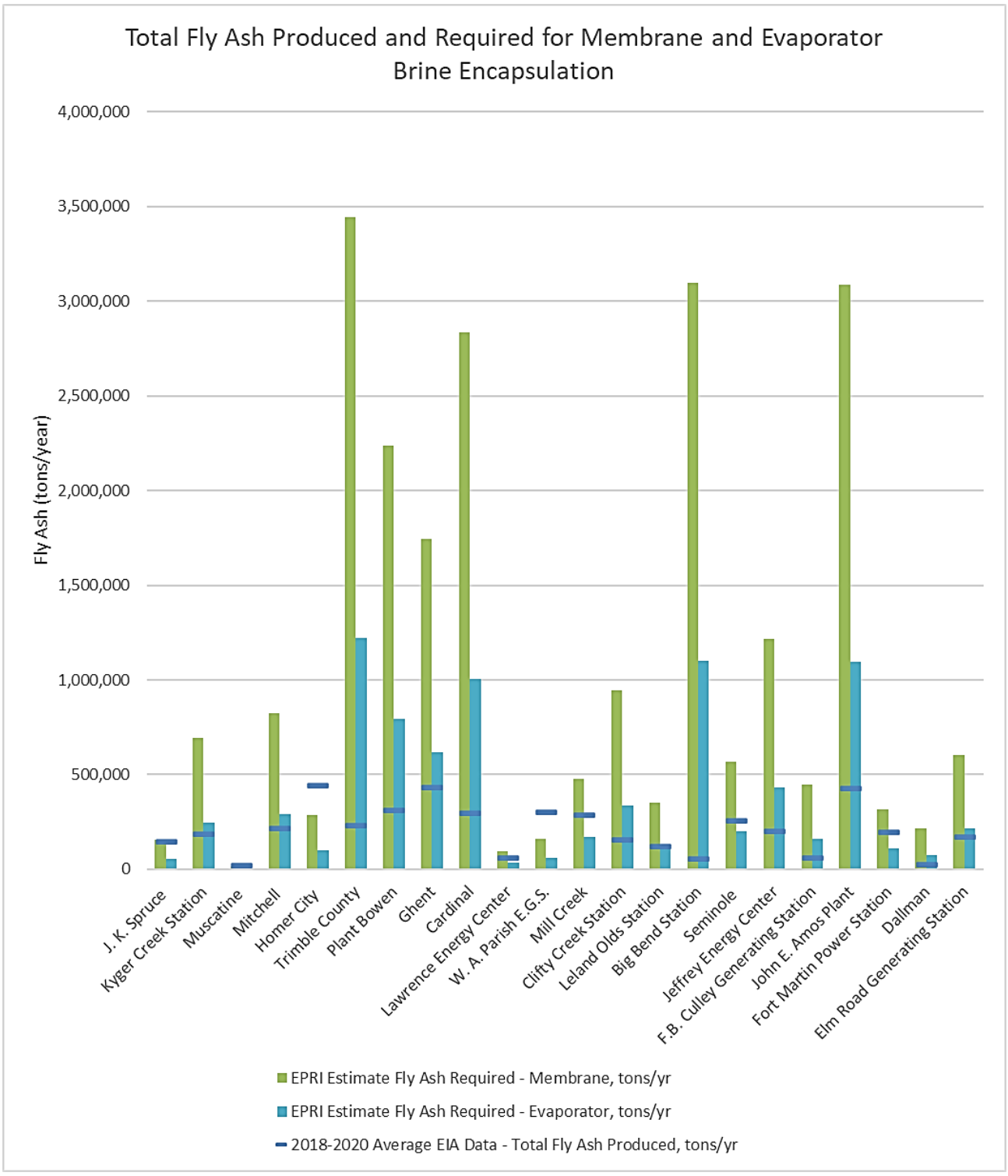


Figure 1-14. EPRI estimate of fly ash required for evaporator and membrane brine encapsulation compared to EIA-reported fly ash produced for 22 plants

Achieving ZLD will be challenging for many sites. Due to issues related to water balance and pollutant cycling in the ZLD system, an option to discharge would provide operational flexibility.

One challenge in managing ZLD systems is the cycling up of certain parameters, such as halogens, nitrate and boron. Constituents that are not highly rejected by membranes, such as boron, could cycle up in wastewater systems if not occasionally discharged. Similarly, halogens and nitrates can require occasional purging from ZLD systems. If not purged, the increase in these constituent concentrations can lead to lower recovery in membrane systems over time and challenges with boiling point rise in thermal systems.

EPRI's evaluation into brine chemistry of thermal systems (EPRI, 2020d) indicates that "bromide and nitrate salts and some chloride and sulfate salts are highly soluble relative to sodium chloride (NaCl) and occur in significant concentrations in FGD wastewater. If the system is not purged, the relative concentration of sodium nitrate will eventually dominate the salts in the crystallizer brine, and, because very soluble salts have higher boiling temperatures, the boiling point rise (BPR) of the brine rises beyond the crystallizer's capability. The energy input from the crystallizer would not be sufficient to generate vapor in the circulating brine. Under these circumstances, the vapor compressor would slowly start to lose suction flow and the system would have to be stopped to prevent damage to the compressor. The crystallizer would have to be completely drained and restarted with fresh feed – this is not an uncommon occurrence. For plants with relatively constant wastewater feed chemistry, this cycle repeats itself predictably, and, as such, many plants have determined how/when to intermittently purge the crystallizer to avoid major purges and operating interruptions."

Operating experience at Public Service Company of New Hampshire (now Granite Shore) Merrimack Power Station has shown that a small liquor purge is required to keep its crystallizer chemistry in balance, to manage the critical levels of the highly soluble salts and nitrates, and to keep within the process design envelope and avoid boiling point rise. "The crystallizer is purged at 2 - 3 gpm to control iodine, bromide, and nitrate levels." (EPRI, 2020d)

Further, plants may also be unable to use 100 percent of the permeate on a continuous basis. For example, the generating units may not be operating while the plant continues to treat FGD wastewater, and therefore the permeate/distillate cannot be used for boiler water or FGD makeup. If plants are unable to discharge the clean permeate, the alternative would be to install extra storage to accommodate long-term permeate storage.

Achieving ZLD of FGD wastewater will require more than half of industry plants to install crystallizers leading to increased operational challenges

EPA states that sites without sufficient fly ash for membrane filtration can utilize other brine management strategies, such as crystallizers or deep well injection. It is unlikely that plants will have access to dispose of brine into an offsite, existing Underground Injection Control (UIC) well

as EPA suggests. Further, EPRI's analysis shows that 14 of 22 plants would not have sufficient fly ash for membrane or vapor compression evaporator systems. Therefore, it is likely that many of these 14 plants would need to install a crystallizer to meet ZLD requirements of FGD wastewater.

EPRI evaluated five existing ZLD thermal wastewater treatment systems that have operated at power plants for several years: Redhawk Generating Station, Navajo Generating Station (NGS), Iatan Generating Station, Mayo Generating Station and Merrimack Generating Station. The findings from these case studies and site interviews demonstrate that crystallizer systems are complex and very challenging to operate. Common challenges for these operating crystallizer systems included (EPRI, 2020d):

- Specific ZLD operator training
- Increased sampling and analytical surveillance to maintain operability, ranging from two to 12 times per day (among the five plants)
- Scaling and line plugging
- System foaming
- Chemical and mechanical cleaning
- Salt dewatering
- Flow obstructions
- Energy transfer impedance
- Equipment performance not meeting design characteristics
- Instrumentation calibration or improper function

"Almost all of the plants that participated in the site visits stated that their evaporators do not meet original specification for maximum recovery (distillate production)." (EPRI, 2020)

Further, as described in Appendix C, full softening would be required for crystallizer pretreatment. Without softening, salts like calcium chloride ($CaCl_2$) and magnesium chloride ($MgCl_2$) and magnesium sulfate ($MgSO_4$) will form in the crystallizer, do not crystallize, and can inhibit crystal formation (EPRI, 2020). To prevent formation of hygroscopic salts, EPRI believes that EPA should consider the additional requirements and costs for chemical softening when evaluating crystallizers as brine management strategies.

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2 FGD WASTEWATER BAT TREATMENT COSTS

EPA's cost estimate methodology for the total cost to the industry to implement the BAT for proposed regulatory option 3 based on chemical precipitation (CP), membrane filtration and brine encapsulation should be improved for accuracy; as is, it underrepresents these costs significantly. EPRI's capital cost estimate is 9 times higher than EPA's capital cost estimate for the same list of plants. Notably, EPRI's operations and maintenance (O&M) cost estimate is 43 times higher than EPA's O&M cost estimate for the same list of plants. In evaluating the total annualized costs, EPRI's estimate of industry cost is 27 times higher than EPA's estimate. Further, EPRI's assessment indicates that membrane filtration is not economically achievable, as the O&M cost alone for a single plant was estimated to be 22 percent of the power plant's total revenue.

In this rulemaking, EPA presented its methodology and estimated costs for plants generating flue gas desulfurization (FGD) wastewater after 2032 that would be required to install a zero liquid discharge (ZLD) system based on CP followed by membrane filtration and brine encapsulation to comply with preferred regulatory option 3 of the proposed rule. In developing costs for the industry, EPA provides the following cost basis [EPA, 2023a; EPA, 2023b; EPA, 2023c]:

- 25 plants plan to generate FGD wastewater after 2032 that would, therefore, be required to install a ZLD FGD wastewater treatment system based on membrane filtration [Table 4, EPA, 2023a]
- Three plants (Cross, Monroe, and Scherer) are designated as having opted into the 2020 voluntary incentives program (VIP) [Table 3, EPA, 2023a]. For these plants, EPA estimated zero capital and zero O&M costs. [EPA, 2023c]
- For the remaining 22 plants, EPA estimated capital costs for membrane filtration only. EPA did not estimate additional costs for CP pretreatment for the membrane filtration technology option, as plants are assumed to have come into compliance with the 2020 rule and already have this treatment in place. [EPA, 2023c]
- To estimate O&M costs for the 22 plants, EPA estimated the difference in costs between biological low residence time reduction (LRTR) and membrane filtration.

EPRI has taken a similar approach to generally align with EPA's cost basis:

- EPRI has developed cost estimates for each of the 22 plants that would be required to comply with regulatory option 3. EPRI has not developed costs for the three plants that opted into the VIP.

- Further, regardless of each plant's FGD wastewater treatment equipment currently in place, EPRI has adapted EPA's basis assuming that all 22 plants have already installed CP and biological treatment as a baseline for estimating capital costs.
- Therefore, the costs developed by EPRI consider the capital costs to convert each plant from CP and biological treatment to CP, membrane filtration, and brine encapsulation.
- EPRI has evaluated the total O&M costs associated with operating a CP, membrane filtration, and brine encapsulation system. To better compare EPRI's and EPA's cost estimates for this treatment system, EPRI is comparing its O&M estimate to EPA's estimated O&M costs for membrane filtration as presented in its FGD Wastewater Cost Database [EPA, 2023b] and not EPA's O&M cost estimate as reported in EPA's Generating Unit-Level Costs and Loadings Estimates by Regulatory Option for the 2023 Proposed Rule [EPA, 2023a]. The latter appears to show only the O&M cost difference between LRTR and membrane filtration as discussed by EPA [EPA, 2023c] and contains several errors in reported costs, which will be addressed later in these comments.

Even when using a similar approach and baseline costs, EPRI arrives at a much higher industrywide cost for CP, membrane filtration, and brine encapsulation compared to those costs developed by EPA. Table 2-1 compares costs developed by EPRI and the costs presented by EPA for the same industry profile of 22 plants. As shown, EPRI's capital cost estimate is 9 times higher than EPA's capital cost estimate. Even more, EPRI's O&M cost estimate is 43 times higher than EPA's O&M cost estimate. In evaluating total annualized costs, EPRI's estimate of industry cost is 27 times higher than EPA's estimate.

Table 2-1. Comparison of EPRI and EPA industry-wide cost estimates to convert from CP and biological treatment to CP, membrane filtration, and brine encapsulation

Source of Industry Cost[1]	Capital Cost ($M)	Annual O&M Cost ($M/yr)	Total Annualized Cost ($M/yr)[2]	Ratio EPRI/EPA Capital Cost	Ratio EPRI/EPA O&M Cost	Ratio EPRI/EPA Total Annual Cost
EPRI	5,410	2,783	3,292	9	43	27
EPA	613	65	122			

$M/yr = million dollars per year (2021 dollars)

1. Includes 22 plants that are assumed to operate past 2032 and therefore required to comply with regulatory option 3 BAT: CP, membrane filtration, with brine encapsulation. EPA cost shown in the summation of costs for 22 plants as presented in FGD Wastewater Proposed Rule Cost Database [EPA, 2023b].
2. Total annualized cost which is a sum of the annualized cost of capital (assumes 7% interest rate and 20-year life) and the annual O&M cost

Table 2-2 provides a comparison of EPRI and EPA cost estimates for each of the 22 plants that would be required to install membrane filtration and brine encapsulation technology in compliance with proposed regulatory option 3.

Table 2-2. Comparison of EPRI and EPA cost estimates for each plant to convert from CP and biological treatment to CP, membrane filtration and brine encapsulation

EPA ICR ID	Plant Name	EPRI Cost Estimate[1]			EPA Cost Estimate[1]		
		Capital Cost ($M)	O&M Cost ($M/yr)	Total Annualized Cost ($M)[2]	Capital Cost ($M)	O&M Cost ($M/yr)	Total Annualized Cost ($M)[2]
493	J. K. Spruce Power Plant	51	16	21	6	0.6	1.1
771	Kyger Creek Station	159	70	85	18	2.0	3.8
904	Muscatine	24	3	5	2	0.5	0.7
1236	Mitchell Plant	223	86	107	21	4.4	6.4
1381	Homer City	67	23	29	9	1.1	1.9
1674	Trimble County	726	432	500	73	10.8	17.7
2244	Plant Bowen	522	275	324	90	5.3	13.8
2601	Ghent	376	186	221	42	4.1	8.0
3265	Cardinal	610	335	392	65	5.3	11.5
3309	Lawrence Energy Center	38	10	14	2	0.5	0.7
3464	W. A. Parish E.G.S.	49	15	20	6	0.9	1.4
3604	Mill Creek	112	44	55	13	1.5	2.7
5318	Clifty Creek Station	221	106	127	27	2.8	5.3
6334	Leland Olds Station	106	36	46	10	1.2	2.2
6377	Big Bend Station	641	396	456	64	6.5	12.5
7785	Seminole Generating Station	139	57	70	15	1.8	3.2
8353	Jeffrey Energy Center	268	142	167	33	2.7	5.8
8965	F.B. Culley Generating Station	117	55	66	8	0.8	1.5
9161	John E. Amos Plant	601	362	418	80	7.0	14.5
9225	Fort Martin Power Station	119	33	44	13	1.8	3.0

EPA ICR ID	Plant Name	EPRI Cost Estimate[1]			EPA Cost Estimate[1]		
		Capital Cost ($M)	O&M Cost ($M/yr)	Total Annualized Cost ($M)[2]	Capital Cost ($M)	O&M Cost ($M/yr)	Total Annualized Cost ($M)[2]
9971	Dallman	86	29	37	5	0.8	1.2
56068	Elm Road Generating Station	158	72	87	15	2.4	3.8
TOTAL		5,410	2,783	3,292	613	65	122

ICR = Information Collection Request

$M/yr = million dollars per year (2021 dollars)

1. Includes 22 plants that are assumed to operate past 2032 and therefore required to comply with regulatory option 3 BAT: CP, membrane filtration, with brine encapsulation. EPA cost shown in the summation of costs for 22 plants as presented in FGD Wastewater Proposed Rule Cost Database [EPA, 2023b].
2. Total annualized cost which is a sum of the annualized cost of capital (assumes 7% interest rate and 20-year life) and the annual O&M cost

Table 2-1 and Table 2-2 show that the largest disparity between EPRI's and EPA's costs exists in the O&M cost estimates. As discussed in Section 1, a significant reason for the O&M cost difference appears to be largely attributed to EPA's approach in underestimating brine management requirements and associated costs. Figure 2-1 shows EPRI's estimate of CP, membrane filtration, and brine encapsulation costs and the relative contribution of annualized capital cost versus annual O&M costs for each of the 22 plants that would be required to comply with regulatory option 3. As seen in this figure, the annual O&M cost estimate for each plant is approximately 3 to 6 times higher than the annualized capital cost estimate for each plant.

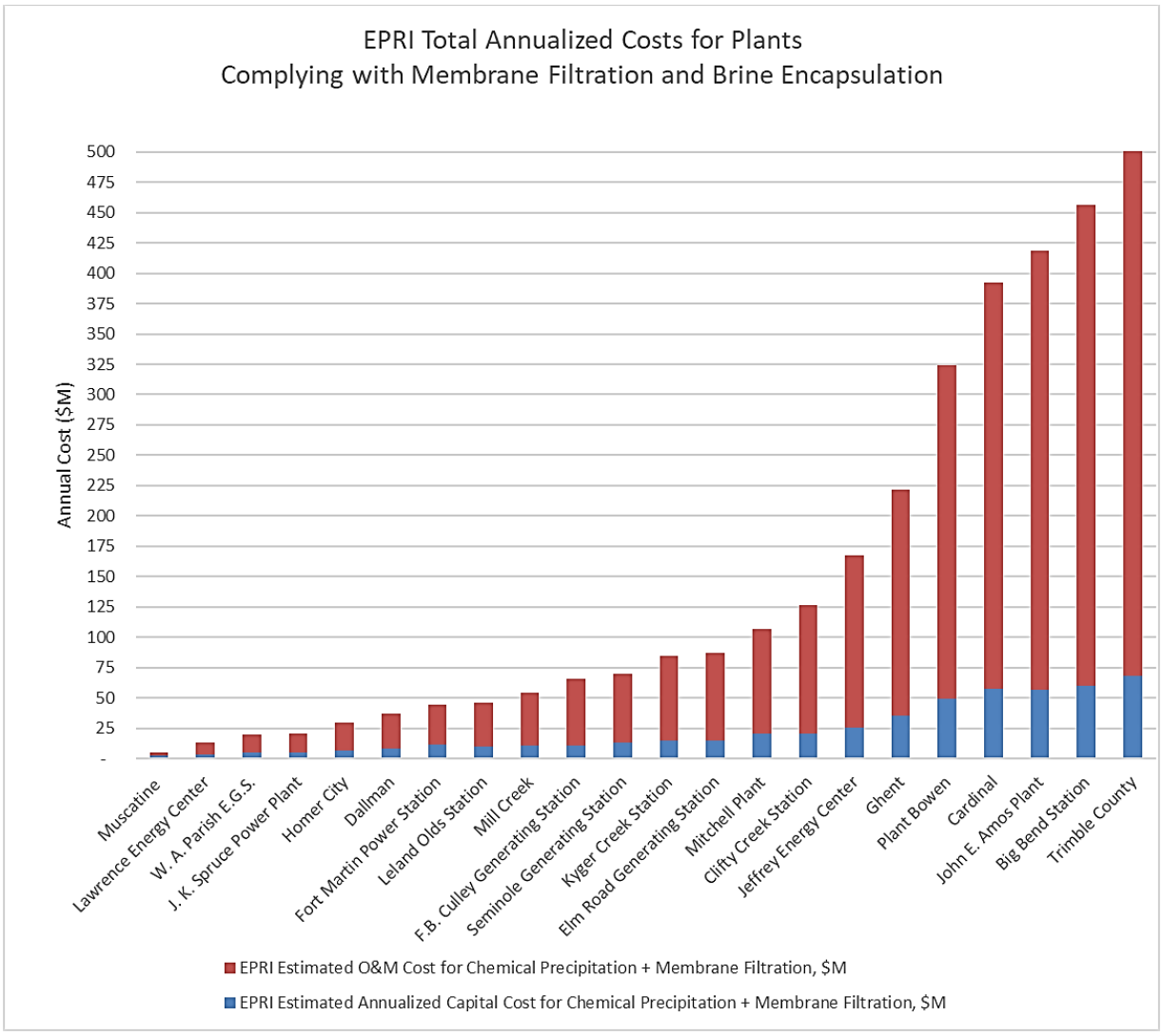


Figure 2-1. EPRI estimate of total annualized costs for 22 plants complying with BAT regulatory option 3: CP, membrane filtration, and brine encapsulation, 2021$

In comparison, EPA's estimate of CP, membrane filtration, and brine encapsulation costs and the relative contribution of capital cost versus annual O&M costs for each of the 22 plants (Figure 2-2) indicate that the annual O&M cost estimate for each plant is similar to the annualized capital cost estimate for each plant. Figure 2-2 shows the significant difference in EPA's costs in terms of the relative capital and O&M costs, and illustrates that EPA's costs are 1 to 2 orders of magnitude lower than EPRI's cost estimates.

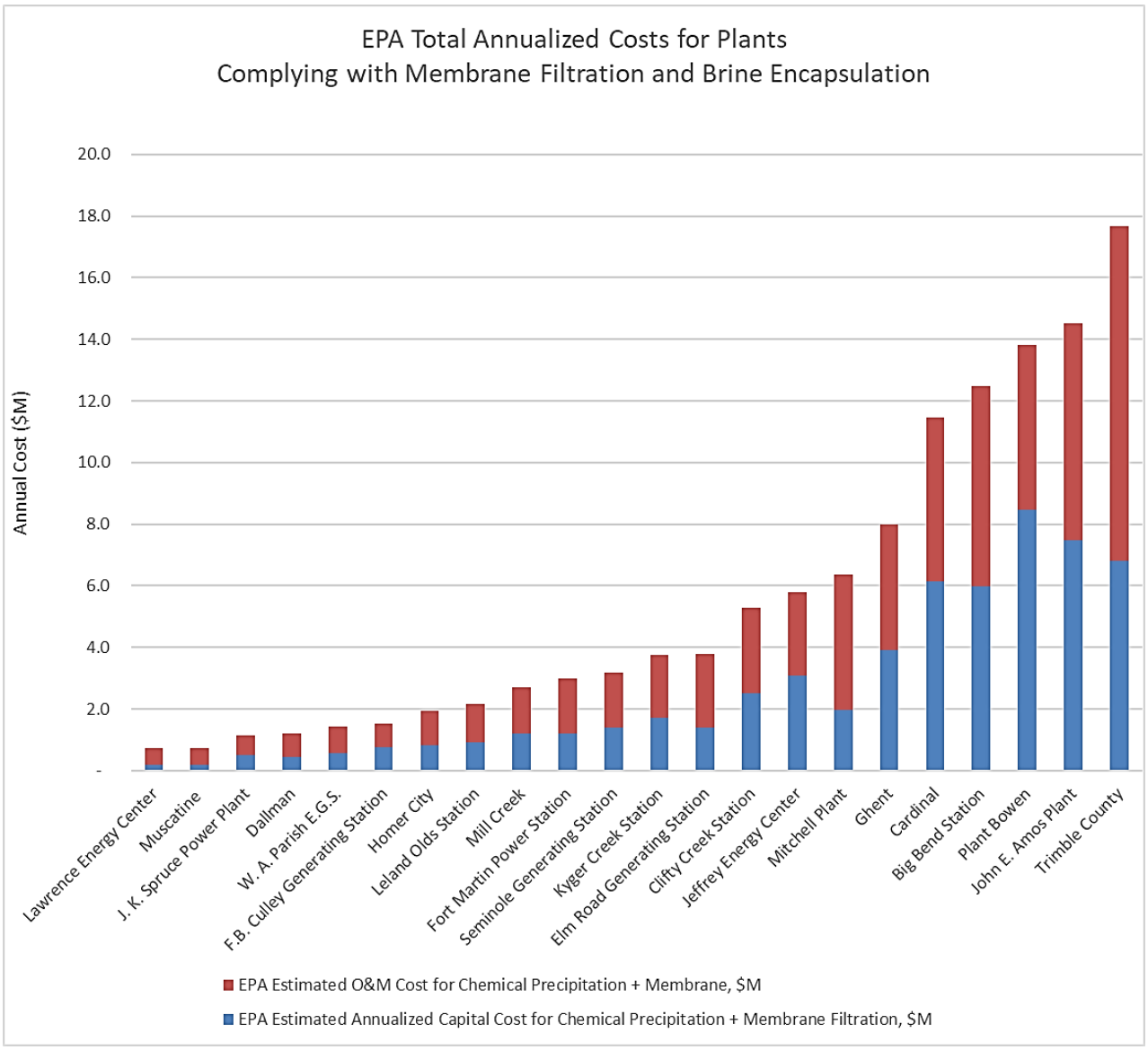


Figure 2-2. EPA estimate of total annualized costs for 22 plants complying with BAT regulatory option 3: CP, membrane filtration, and brine encapsulation, 2021$

Figure 2-3 shows a comparison of EPRI and EPA's estimate of total annualized cost for each plant treating FGD wastewater after 2023.

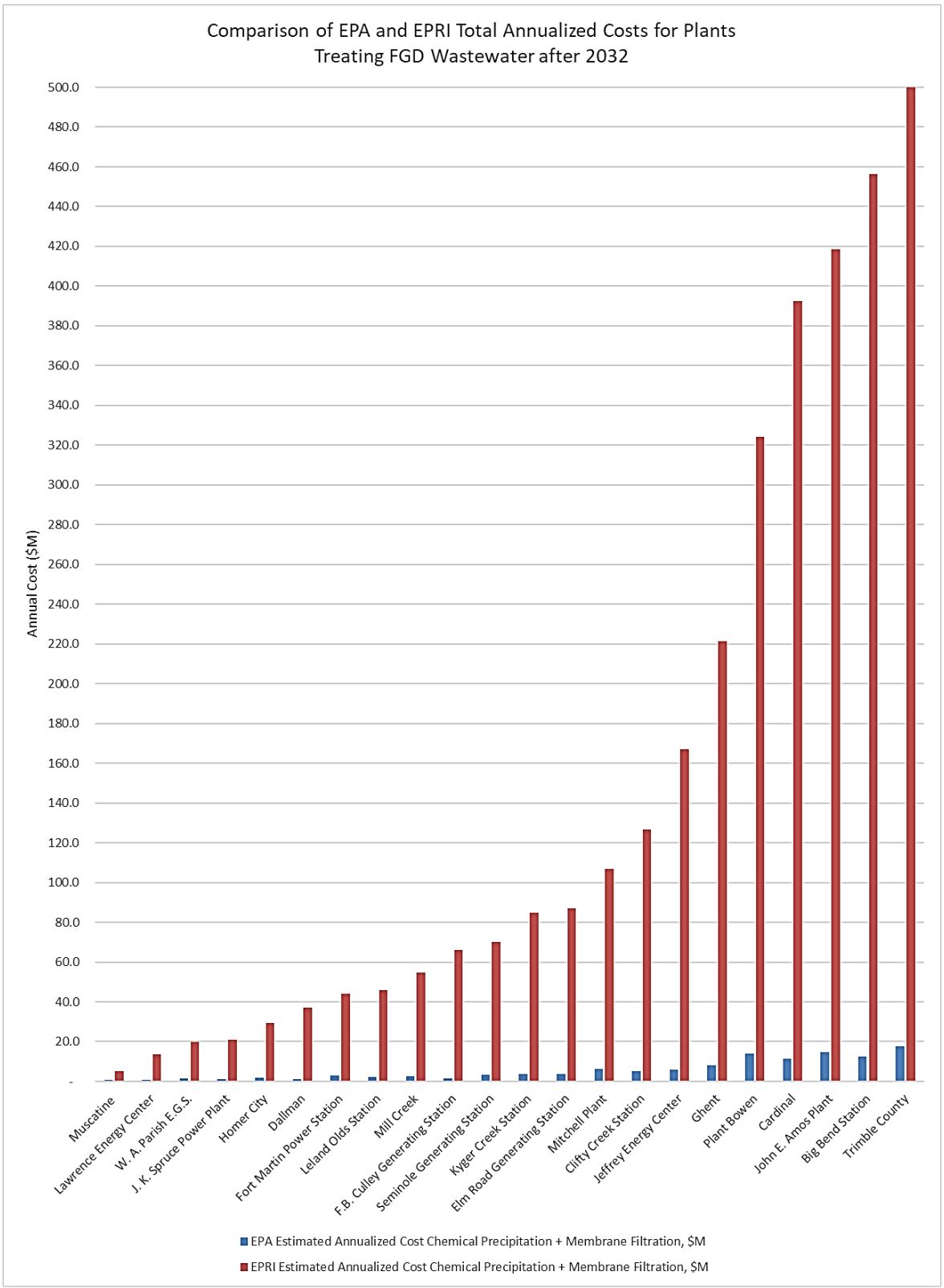


Figure 2-3. Comparison of EPA and EPRI estimate of total annualized costs for 22 plants complying with BAT regulatory option 3: CP, membrane filtration, and brine encapsulation, 2021$

EPA has significantly underestimated BAT costs for membrane filtration due to several key differences in flow rate, brine management, and encapsulation estimates.

As previously shown, EPRI's estimated costs for the industry to comply with membrane filtration is approximately 25 times higher than EPA's cost estimate for the same list of 22 plants. There are several key reasons for these differences, each of which is discussed below.

FGD peak flow with equipment redundancy should be used to estimate capital costs.

In the 2013 proposed ELG rule, EPA stated that the estimated flows for some FGD wastewater treatment systems were based on the typical or average flow reported by the power plant. That average flow rate was multiplied by a "mean capacity factor" of 1.99. EPRI agrees with the industry-standard approach of using a peaking factor as the basis for capital costs, as treatment systems must be able to treat to compliance levels at all operating flow conditions. However, in the 2019 cost estimate calculations, EPA did not multiply by a mean capacity factor, but instead asserted that plants can reduce to a lesser, optimized flow rate; therefore, designing for current average flow provides adequate conservatism [EPRI, 2020]. In this rulemaking, EPA has taken a similar approach as the 2019/2020 rulemaking, whereby treatment system equipment is sized based on FGD purge flow. In continuing to use average FGD purge flow to size and cost treatment equipment, EPA has not considered:

- The FGD peak flow that must be instantaneously processed by the membrane filtration system.
- The need to design the membrane filtration system for N+1 redundancy, which is typical in membrane applications. In this sizing approach, "N" is the peak design flow and the "+1" designates that a redundant equipment train is installed. Membrane systems are frequently taken offline for cleanings; therefore, it is critical to design membrane systems for a capacity greater than the peak design flow.
- In sizing the membrane filtration system, the capacity of existing CP pre-treatment systems installed must be considered. To maintain treatment system throughput, the membrane filtration system design flow should match the design capacity of the existing CP treatment system.

For the total industrywide flow of FGD wastewater needing treatment, EPRI estimates a peak/design flow of 17.3 million gallons per day (mgd) while EPA used 13.4 mgd (Table 2-3). This difference in flow rates contributes to the cost differences between EPA and EPRI.

Table 2-3. Comparison of EPA and EPRI flow basis used for capital and O&M cost basis

EPA ICR ID	Plant Name	Capital Cost Basis		O&M Cost Basis	
		EPA FGD Purge Flow (gpd)[1]	EPRI Peak FGD Flow (gpd)	EPA Optimized Flow (gpd)[1]	EPRI Annual Average FGD Purge Flow (gpd)
493	J. K. Spruce Power Plant	86,400	129,600	17,626	75,777
771	OVEC – Kyger Creek Station	385,920	385,920	241,200	335,583
904	Muscatine Power and Water Generating Station	7,500	28,800	4,688	7,200
1236	Mitchell Plant	486,000	796,320	308,813	397,894
1381	EME Homer City Generation L.P.	158,400	228,960	99,000	137,280
1674	Trimble County	1,644,985	2,468,160	1,644,985	1,664,480
2244	Georgia Power Company – Plant Bowen	2,052,000	2,160,000	769,500	1,080,000
2601	Ghent	928,800	1,393,920	565,020	842,851
3265	Cardinal	1,476,000	2,214,720	768,750	1,369,913
3309	Lawrence Energy Center	7,000	54,331	1,081	47,000
3464	W. A. Parish E.G.S.	95,040	142,560	59,400	78,585
3604	Mill Creek	252,972	380,160	158,108	229,231
5318	Clifty Creek Station	576,000	576,000	360,000	456,155
6334	Leland Olds Station	184,894	277,920	115,559	170,092
6377	Tampa Electric – Big Bend Station	1,435,680	1,684,272	957,125	1,495,043
7785	Seminole Generating Station	303,120	432,000	202,982	275,192
8353	Jeffrey Energy Center	720,000	720,000	348,300	587,520
8965	F.B. Culley Generating Station	157,622	236,160	19,703	216,000
9161	John E. Amos Plant	1,810,080	1,810,080	1,037,025	1,490,654
9225	Fort Martin Power Station	256,320	475,200	200,250	152,640
9971	Dallman	66,240	214,180	41,400	104,948
56068	Elm Road Generating Station	300,000	450,720	300,000	291,083
	Total	13,390,973	17,259,982	8,220,515	11,505,120

1. EPA reported flows used for compliance costs and pollutant loadings as shown in *Flue Gas Desulfurization Flow Methodology for Compliance Costs and Pollutant Loadings* [EPA, 2022a] and its reference *Flue Gas Desulfurization Flow Methodology and Compliance Costs and Pollutant Loadings* [EPA, 2020a]. Note: Some of the FGD purge plant flows reported in these references do not match the flows assumed by EPA in its fly ash availability review [EPA, 2023a], as shown in Table 1-2.

FGD purge flow should be used instead of optimized flow to estimate membrane filtration O&M costs.

In evaluating the quantity of fly ash required for brine encapsulation [EPA, 2023d], EPA used the FGD purge flow as the basis for analyzing FGD flows and O&M requirements. EPRI agrees that the annual average FGD purge flow should be used in estimating fly ash requirements and associated O&M quantities.

In estimating O&M costs, however, EPA states that the optimized flow was used as the basis for developing O&M costs such as brine management. Therefore, in switching to using optimized flow, EPA's approach leads to a much lower brine management cost estimate.

Further, EPA states that "For each plant, EPA estimated two FGD purge flow rates: the FGD purge flow rate (the typical amount of wastewater from the FGD scrubber that is sent to FGD wastewater treatment) and the FGD optimized flow rate (a reduced rate that considers a reduction in FGD wastewater purged from the system, where equipment metallurgy could accommodate increased chloride concentration in the FGD system)." [EPA, 2023c]

Use of optimized flow assumes there is a reduction in FGD wastewater purged from the system whereby equipment metallurgy could accommodate the increased chloride concentration in the FGD system. Using this approach for a membrane system is not appropriate for the following reasons:

- As discussed in Section 1 and shown in Figure 1-8, membrane system performance and permeate recovery will notably decline as FGD wastewater concentrations, such as chloride and overall total dissolved solids (TDS), increase.
- Therefore, an "optimized" FGD purge flow, as EPA has proposed, would likely lead to higher TDS in FGD wastewater feed to the membrane system.
- The higher TDS concentration in the FGD feed leads to a greater tendency for membrane scaling and lower membrane system percent recovery.
- This reduction in permeate recovery can consequently lead to an increase in brine flow and higher fly ash demands and operating costs.
- Further, an increase in chloride and TDS concentrations to the membrane system may also lead to higher-grade metallurgy selection in the membrane system, thereby increasing costs.

As shown in Table 2-3, EPA used 8.2 mgd total industrywide flow of FGD wastewater in developing O&M costs for membrane filtration. This is approximately 5 mgd less than the reported typical FGD purge flow to the industry.

Membrane system recovery that can be consistently achieved should be used; EPA has stated that 70% was "the average FGD wastewater recovery from the membrane treatment vendors." *However, it appears EPA uses a much higher recovery in its cost estimates.* recovery in its cost estimates.

As shown previously in Table 1-4, the membrane system recovery will significantly impact the volume of brine generated, the fly ash required, and the disposal costs to the landfill. In estimating potential costs to the industry, it is critically important to select an assumed membrane recovery that can be consistently achieved across the industry based on EPA's definition of typical CP treatment system effluent [Table 6-1, EPA, 2020b]. In considering this, EPRI employed 70 percent membrane recovery in its cost estimates. The selection of membrane recovery will have a significant impact on calculating all O&M quantities and costs.

To further illustrate the importance of selecting an appropriate recovery, EPRI has prepared several case studies and flow diagrams that compare a 70, 80, and 90 percent membrane recovery system. As shown in Figure 2-4 and Figure 2-6, the difference in brine management costs associated with 70 percent and 90 percent membrane recovery leads to a difference of $33 million in brine management costs, and difference in beneficial use of fly ash equal to $0.3 million, for the example case study of 153 gpm annual average FGD purge flow. A summary of the three case studies is shown in Table 2-4.

Table 2-4. Brine flow produced for 300 gpm peak / 153 gpm annual average FGD purge flow

Overall Membrane Recovery (%)	FGD Purge Flow (gpm)	Brine produced (gpm)	Fly ash required (tons/yr)	Total Fly Ash Produced – Disposed and Sold (tons/yr)	Supplemental Fly Ash Required (tons/yr)	Quicklime Required (tons/yr)	Net Increase in Residuals Disposed (dry tons/yr)
70	153	46	456,172	198,000	258,172	29,622	406,593
80	153	31	312,721	198,000	114,721	20,307	253,828
90	153	15	169,271	198,000	0	10,992	101,063

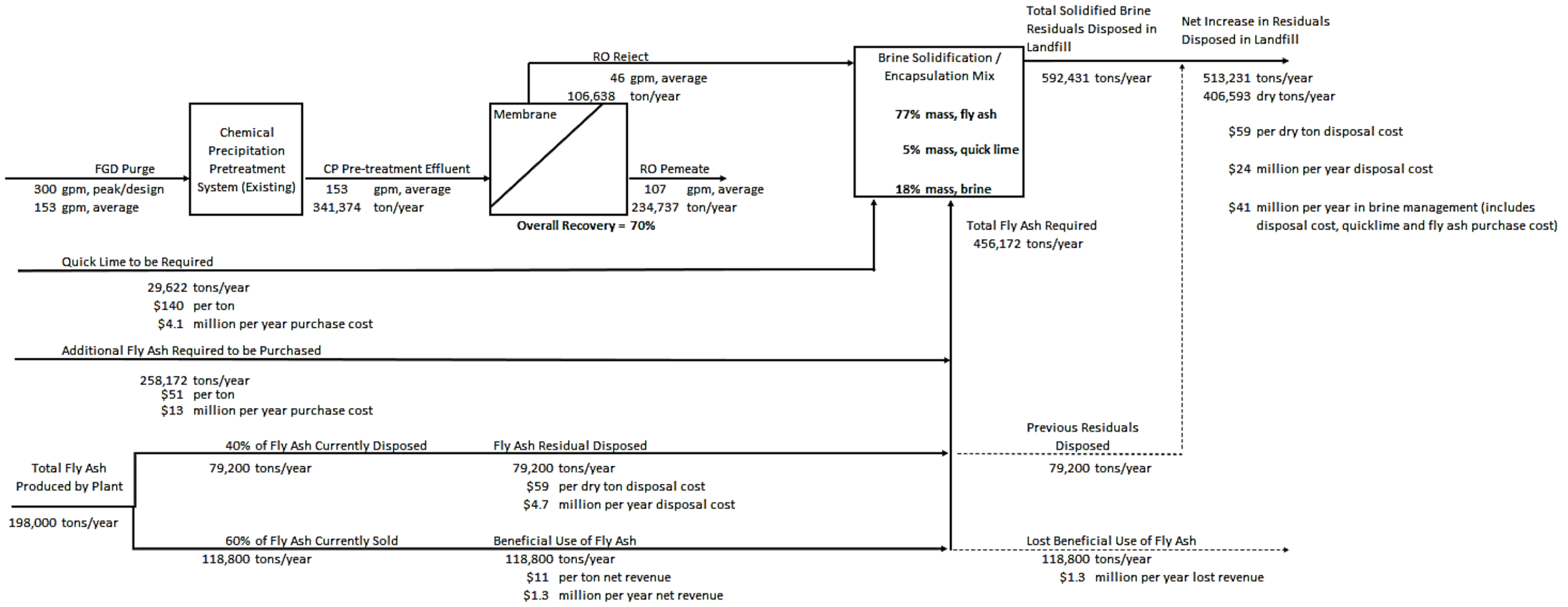


Figure 2-4. 70% recovery case study, 300 gpm peak / 153 gpm annual average FGD purge flow

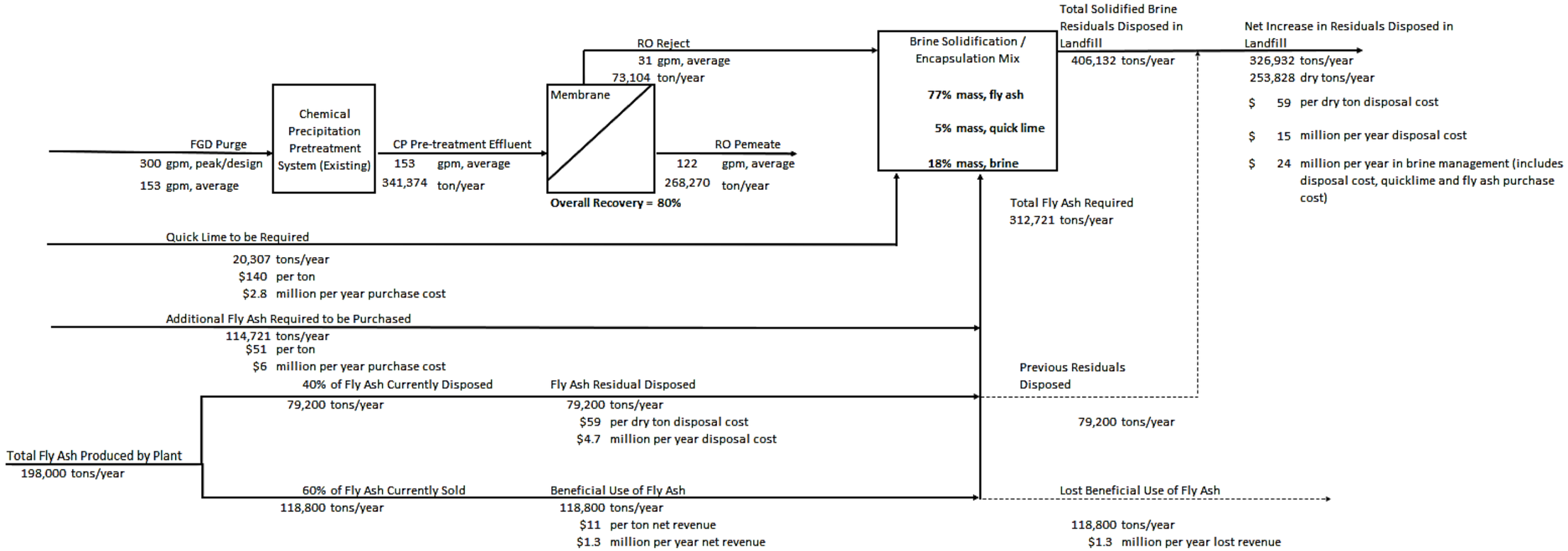


Figure 2-5. 80% recovery case study, 300 gpm peak / 153 gpm annual average FGD purge flow

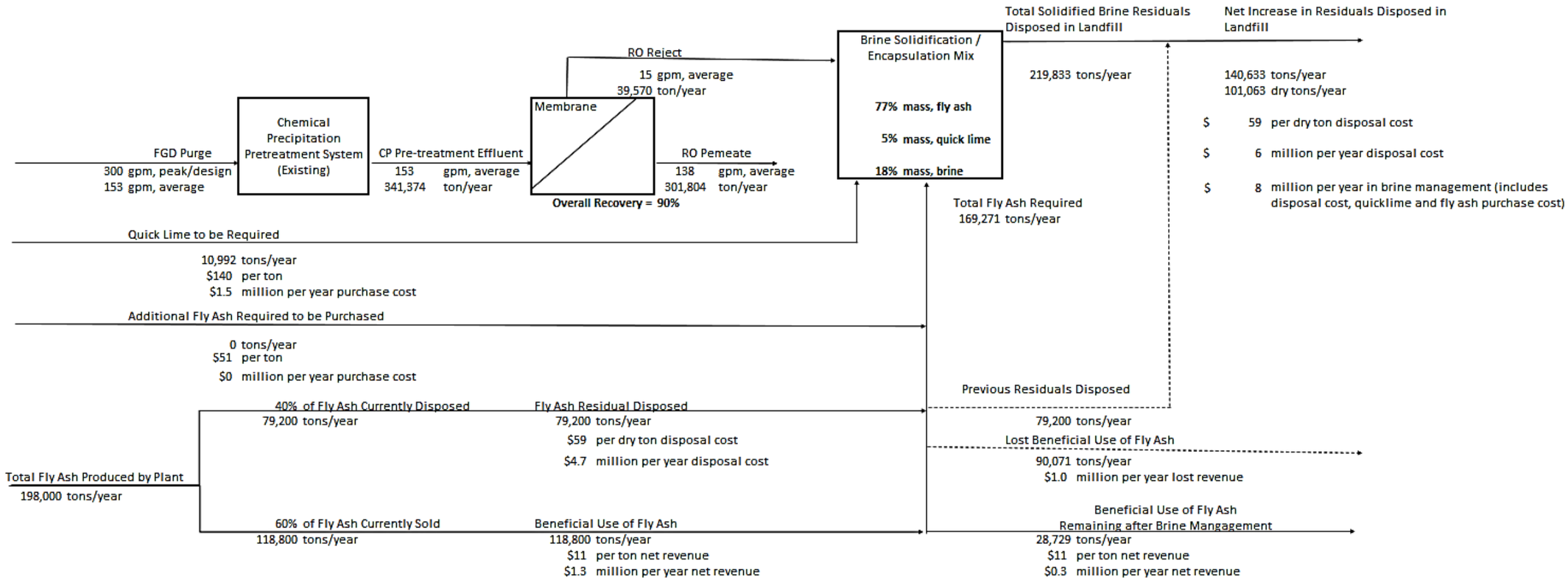


Figure 2-6. 90% recovery case study, 300 gpm peak / 153 gpm annual average FGD purge flow

EPA has significantly underestimated the O&M costs associated with brine management and encapsulation using its current calculation methods. EPRI's site-specific O&M cost estimate for a single plant is 35 times higher than EPA's cost estimate.

EPRI is presenting estimated costs through a site-specific case study to further illustrate a comparison of EPRI and EPA's costs differences. EPRI is committed to advancing safe, reliable, affordable, and environmentally responsible electricity generation. EPRI's analysis indicates that the proposed regulatory option for FGD wastewater is not affordable for power generating utilities with potential impacts to the public.

To illustrate this specific case study cost comparison, EPRI has selected Kyger Creek Power Plant (EPA ICR Plant ID 771). The rationale for selecting this plant over other plants in the industry profile includes, and is summarized in Table 2-5:

- Kyger Creek has an FGD purge flow that is near the industry average
- Kyger Creek produces a total fly ash quantity that is near the industry average
- EPA-estimated fly ash produced is similar to the U.S. Energy Information Administration (EIA) estimate of fly ash produced

Table 2-5 presents FGD wastewater flowrates and fly ash production rates used by EPRI and EPA.

Table 2-5. Kyger Creek Comparison to Industry Averages

Plant Statistics	EPRI Value	EPA Value	Industry Average (Based on EIA Data)[1]
Capital Cost Flow Basis (gpm)	268	268	--
O&M Cost Flow Basis (gpm)	233	168	--
Fly ash produced (tons/year)	186,300	187,716	208,000

1. Average of total fly ash produced by plant over 3 years (2018 – 2020) based on EIA Form 923 Schedule 8A

EPRI reviewed EPA's cost estimate for this plant and the flow and fly ash data available on the docket [EPA, 2023a; EPA, 2023b; EPA, 2023d]. The information suggests that EPA's method of estimating site-specific O&M cost is significantly low.

EPRI used the flows and fly ash quantities shown in Table 2-5 to estimate brine management costs for comparison to EPA's O&M cost estimate.

As the basis for evaluating EPA's costs, EPRI used EPA's estimate of total fly ash produced for Kyger Creek in 2018, 2019, and 2020 of 203,354, 195,763, and 164,031 tons/year, respectively. EPRI calculated the average of these 3 years and used this as the basis for developing estimated costs, which was 187,716 tons per year. For Kyger Creek, EPA's assumed flow basis for

estimating capital costs is 268 gallons per minute (gpm), and the optimized flow basis used to calculate O&M costs is 168 gpm.

In EPRI's cost estimates, the average of 2018, 2019, and 2020 fly ash production data for Kyger Creek, as reported by EIA Form 923 Schedule 8A, was used and calculated to be 186,300 tons per year. EPRI assumed the same flow basis for estimating capital costs for Kyger Creek (268 gpm), but used a higher flow basis to calculate O&M costs (233 gpm) compared to that assumed by EPA.

First, EPRI developed a case study and flow diagram based on EPA's flows, fly ash quantities and brine encapsulation ratio used as part of this rulemaking (Figure 2-7). Next, EPRI evaluated both EPA and EPRI's flows and fly ash quantities and costs based on a membrane system recovery of 70 percent. The block flow diagrams depicting the brine management scenarios using EPA and EPRI assumed quantities are shown in Figure 2-8 and Figure 2-9, respectively.

As shown in Figure 2-8, EPRI used EPA's flow basis and an assumed 70 percent membrane recovery to estimate the annual average reject flow as 50 gpm and the permeate flow as 118 gpm. Based on the mass flow rate of the RO reject, 117,092 tons per year, and the assumed encapsulation mixture of 77 mass percent fly ash/18 mass percent brine/5 mass percent quick lime, the total mass of quick lime required is 32,526 tons per year. This equates to a $4.6 million per year purchase cost based on the $140 per ton unit cost of quick lime.

Kyger Creek is estimated to produce 187,716 tons per year of fly ash based on EPA's rule-of-thumb estimate, all of which currently is being disposed. Kyger Creek does not sell any fly ash. Therefore, it is estimated that Kyger Creek would have 187,716 tons per year available for brine encapsulation; however, the mass balance shows that Kyger Creek would require a total of 500,894 tons per year of fly ash, meaning Kyger Creek would need to acquire (purchase) an additional 313,178 tons per year of fly ash. The total solidified brine residual to be hauled and disposed in landfill is 650,512 tons per year. Subtracting out the fly ash already being disposed (187,716 tons per year), a net total of 462,796 tons per year or 345,704 dry tons per year (deducting the mass of the brine) would be deposited in the landfill.

EPRI is assuming a unit disposal cost of $59 per dry ton, which is escalated to 2021 dollars based on EPA's unit disposal costs presented in the 2013 rulemaking. This increase in residual waste disposal quantity equates to an additional $20 million per year in disposal costs. The total brine management costs, including purchased quick lime, purchased additional fly ash, and net increase in residual waste disposed in the landfill, equals approximately $41 million per year.

The same methods were used in developing Figure 2-9, except that EPRI assumed flows and fly ash quantities were used. Since the EPRI and EPA's basis for design flow and fly ash production for Kyger Creek are nearly the same (Table 2-5), the only notable difference in Figure 2-7 is the annual average FGD flow assumed, i.e., EPA assumed 168 gpm optimized FGD flow and EPRI assumed 233 gpm annual average FGD purge flow. Therefore, the difference in EPA and EPRI assumed membrane feed flow is 65 gpm. As seen in Figure 2-7, this difference in feed flow leads to a 20-gpm increase in assumed brine flow and a significant difference in brine

management cost calculations. The estimated brine management costs using EPRI's assumed average FGD flow rate leads to a nearly 60 percent increase in brine management costs.

EPA's assumptions and methods for calculating brine management costs are unknown by EPRI; however, EPA has stated that the total O&M cost for membrane filtration at Kyger Creek is estimated to be $2 million per year. Given these calculation results and assumptions previously provided, EPA's costs appear to be 20 times too low (Table 2-6).

Further, EPRI's analysis of EIA revenue data shows that the average revenue for Kyger Creek in years 2018 through 2020 was approximately $314,500,000. EPRI's estimated O&M cost for Kyger Creek is $70,000,000 per year. This analysis indicates that the annual O&M cost for Kyger Creek alone, before accounting for capital costs, would be approximately 22 percent of Kyger Creek's total annual revenue.

Table 2-6. Kyger Creek Cost Comparison, Costs 2021$

Cost Item	Units	EPA Reported O&M Methods and Cost	EPRI Costing Method EPA Flow Basis	EPRI Costing Method EPRI Flow Basis
Quick Lime Purchase	Tons/year	?	32,526	45,110
	$M/year	?	$ 4.6	$ 6.3
Additional Fly Ash Purchase	Tons/year	?	313,178	508,393
	$M/year	0	$ 16	$ 26
Net Increase in Residuals to Landfill	Dry Tons/year	?	345,704	553,503
	$M/year	0	$ 20	$ 33
Subtotal Brine Management	$M/year	**?**	**$41**	**$ 65**
Total Annual O&M Cost	$M/year	**$ 2.0**	**--**	**$ 70**

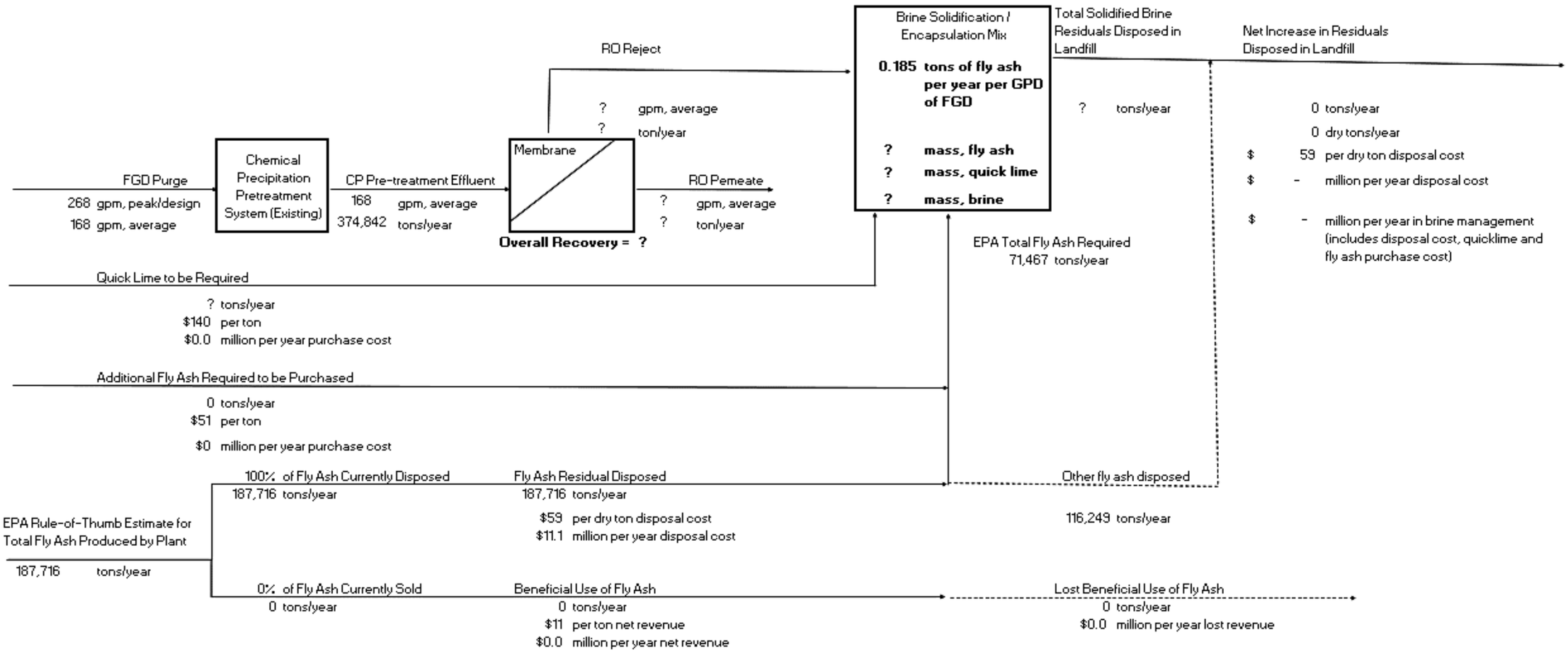


Figure 2-7. EPA brine management approach and costs – Kyger Creek

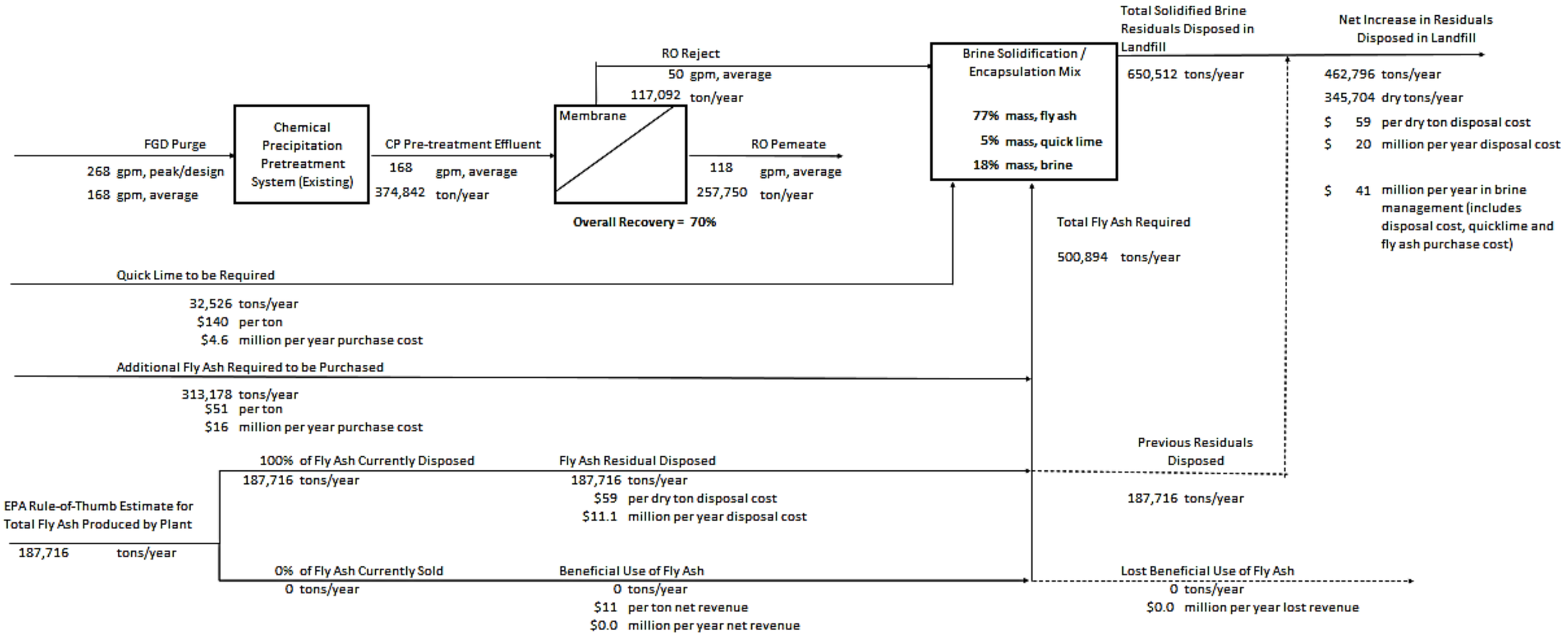


Figure 2-8. EPRI brine management approach using EPA flow and fly ash quantities – Kyger Creek

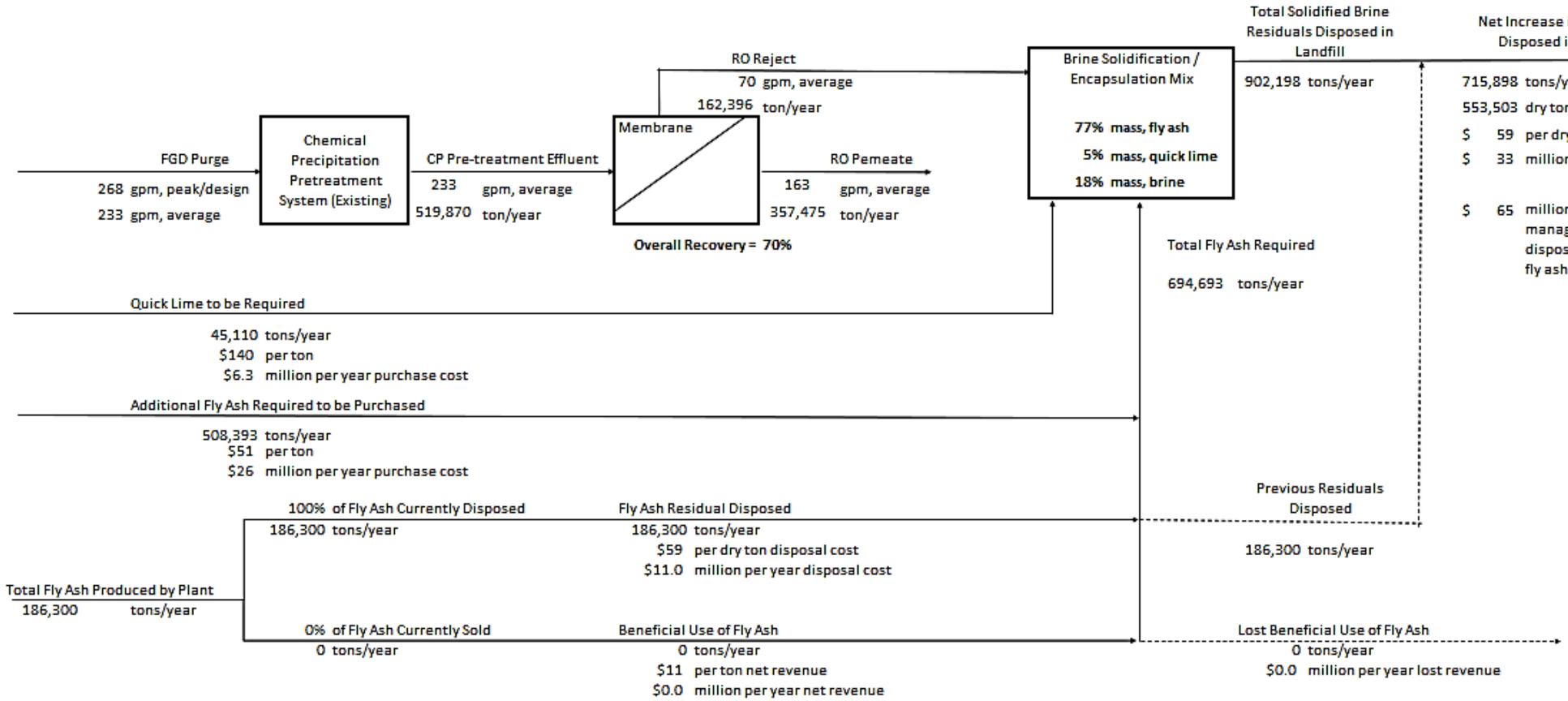


Figure 2-9. EPRI brine management approach, flow and fly ash quantities, and costs – Kyger Creek

Fly ash shortages will lead sites to experience challenges and significant costs to acquire or harvest additional fly ash, including excavation, transport, and drying the harvested ash.

Fly ash shortages would require deficit plants to consider alternative brine management strategies. This could lead plants to develop alternative material sources such as landfilled fly ash, offsite produced fly ash, or offsite produced lime. Alternative material sources are likely to have higher associated costs than onsite production fly ash.

EPA states that "If a deficit of fly ash remains at any plants, EPA expects that it will be minimal, and may be addressed by using fly ash generated in previous years for encapsulation by accessing fly ash from storage areas or landfills..." [EPA, 2023d]. There are important technological considerations and significant cost implications associated with using ash from landfills.

First, landfills do not allow for fly ash storage in dry, as-produced conditions. Instead, landfill placement requires the addition of moisture to allow compaction and to control fugitive emissions. Therefore, ash placed in a landfill will be wet and not suitable for use in encapsulation.

Industry specifications for beneficial use in concrete, like ASTM C 618, require fly ash moisture contents of less than 3 percent. Commercial waste stabilization operations use dry, as-produced fly ash. EPRI's research on brine encapsulation used dry, as-produced fly ash. Therefore, landfilled fly ash is unlikely to be directly useful in brine management.

It is unclear from EPA's assessment of fly ash availability [EPA, 2023d] if EPA envisions landfilled fly ash being used directly for encapsulation or it being processed prior to use in encapsulation. If EPA envisions that shortages in onsite-produced fly ash will be mitigated with ash removed directly from landfills, then the encapsulation approach needs to account for the water already contained in the landfilled fly ash. For the majority of sites, there will be an additional cost to excavate, process, and dry the fly ash before it can be used as an encapsulation additive and mixed with brine.

EPRI has estimated that the cost to harvest fly ash from storage areas or landfills is approximately $63 to $128 per ton of fly ash harvested. This estimate is comprised of $40 to $105 per ton for civil components to harvest the fly ash and $23 per ton for drying the harvested fly ash to less than 3 percent moisture prior to encapsulation with the membrane brine. The civil cost was estimated from the average contractor's civil cost for harvesting fly ash as presented in the Coal Combustion Residuals Recycling/Beneficial Use Assessment Business Plan prepared for Dominion Energy Virginia [AECOM, 2019]. The civil components include dewatering with water treatment, excavation, air drying to between 25 and 35 percent moisture content, screening, transportation, loading, and/or any other handling requirements to get the ash to the recycling/beneficiation process. The cost per ton for drying the harvested fly ash was based on information provided by two fly ash drying system equipment

manufacturers. The fly ash drying system manufacturers proposed scope of supply included a complete plant with feed bins, collector conveyor, weigh conveyor, parallel flow rotary dryer, combustion chamber, cyclone, baghouse, and control system. The dryer systems were assumed to be installed in a 3x50% configuration to provide n+1 redundancy.

EPA appears to have misreported the costs for six plants that plan to operate past 2032 and would be required to install membrane filtration and encapsulation systems.

EPA appears to have misreported the membrane filtration and encapsulation (ZLD) system costs stated in *Generating Unit-Level Costs and Loadings Estimates by Regulatory Option for the 2023 Proposed Rule* [EPA, 2023a] for six plants that plan to operate past 2023:

- Georgia Power Company's Plant Bowen
- PPL Corporation's Ghent plant
- Buckeye Power, Inc.'s Cardinal plant
- Westar Energy's Lawrence Energy Center
- NRG Electric's W.A. Parish Electricity Generating Station
- PPL Corporation's Mill Creek plant

EPA's cost basis for proposed regulatory option 3 assumes that all plants have already installed CP+LRTR equipment required to comply with the 2020 BAT determination for FGD wastewater, and that any plants that opted into VIP would have already installed evaporation technology and there would be zero costs to install the ZLD system. In *Table 4. Unit-Level costs for FGD Wastewater Treatment under Regulatory Option 3* [EPA, 2023a], the capital, O&M, and one-time annual costs for the previously mentioned six plants are presented as zero dollars. This suggests these facilities either opted into VIP or are subcategorized as CP+LRTR based on *Table 8. Technology Rule Basis* [EPA, 2023a]. EPRI believes this is incorrect. Based on EPRI's review of the database [EPA, 2023b], these six plants do not plan to retire or change combustion fuel by 2023, nor did they opt into VIP and install evaporative technology. As such, these plants would incur capital costs for procuring and installing a ZLD system and associated O&M costs. A presentation of these ZLD system capital cost discrepancies are shown in Table 2-7. EPRI believes that costs should be applied for these six plants for a ZLD system and requests EPA to review and correct its documentation to include these costs.

Table 2-7. EPA-reported Capital Cost Discrepancy for Several Plants

Plant Name	SE Unit	EPA ICR ID	Capital Cost Presented in EPA Database SE10416	Capital Cost Presented in Table 4 [EPA, 2023a]
Georgia Power Company – Plant Bowen	3	2244	$20,932,888	$0
Georgia Power Company – Plant Bowen	4	2244	$20,181,932	$0
Ghent	1	2601	$10,996,814	$0
Ghent	2	2601	$12,290,557	$0
Ghent	3	2601	$7,115,585	$0
Ghent	4	2601	$11,320,249	$0
Cardinal	2	3265	$13,368,867	$0
Cardinal	3	3265	$40,106,602	$0
Lawrence Energy Center	3	3309	$2,085,805	$0
W. A. Parish E.G.S	8	3464	$5,871,525	$0
Mill Creek	3	3604	$3,342,946	$0
Mill Creek	4	3604	$4,128,014	$0

EPA has not accounted for the higher costs for plants that will retire or repower in less than 20 years.

EPRI analyzed data for the anticipated year that plants will permanently cease coal combustion either due to plant retirement or due to the plant repowering to a non-coal fuel source, such as natural gas or green hydrogen. EPRI evaluated the cost for the 22 plants that would be required to install a membrane filtration system based on proposed regulatory option 3. Table 2-8 presents total annualized costs using two approaches: (1) capital cost annualized over 20-year design life and (2) capital cost annualized based on how long each plant is anticipated to generate FGD wastewater past the “no later than” compliance deadline of December 31, 2029 as stated in the proposed rulemaking [US, 2023].

Table 2-8. EPRI cost estimates for plants to comply with CP, membrane filtration, and brine encapsulation considering number of years operating before retirement, 2021$

EPA ICR ID	Plant Name	Estimated Year of Plant Retirement or Repowering[2]	Years Operating After 2029	EPRI Cost Estimate[1]			
				Capital Cost ($M)	O&M Cost ($M/yr)	Total Annualized Cost – 20 Years ($M)[3]	Total Annualized Cost – Years Operating ($M)[4]
493	J. K. Spruce Power Plant	2052	20	51	16	21	21
771	OVEC – Kyger Creek Station	2040	11	159	70	85	91
904	Muscatine Power and Water Generating Station	2052	20	24	3	5	5
1236	Mitchell Plant	2040	11	223	86	107	116
1381	EME Homer City Generation L.P.	2052	20	67	23	29	29
1674	Trimble County	2066	20	726	432	500	500
2244	Georgia Power Company – Plant Bowen	2035	6	522	275	324	385
2601	Ghent	2037	8	376	186	221	249
3265	Cardinal	2052	20	610	335	392	393
3309	Lawrence Energy Center	2052	20	38	10	14	14
3464	W. A. Parish E.G.S.	2045	16	49	15	20	20
3604	Mill Creek	2052	20	112	44	55	55
5318	Clifty Creek Station	2040	11	221	106	127	135
6334	Leland Olds Station	2052	20	106	36	46	46
6377	Tampa Electric – Big Bend Station	2052	20	641	396	456	456
7785	Seminole Generating Station	2052	20	139	57	70	70
8353	Jeffrey Energy Center	2039	10	268	142	167	180
8965	F.B. Culley Generating Station	2052	20	117	55	66	66

EPA ICR ID	Plant Name	Estimated Year of Plant Retirement or Repowering[2]	Years Operating After 2029	EPRI Cost Estimate[1]			
				Capital Cost ($M)	O&M Cost ($M/yr)	Total Annualized Cost – 20 Years ($M)[3]	Total Annualized Cost – Years Operating ($M)[4]
9161	John E. Amos Plant	2040	11	601	362	418	442
9225	Fort Martin Power Station	2052	20	119	33	44	44
9971	Dallman	2045	16	86	29	37	38
56068	Elm Road Generating Station	2035	6	158	72	87	105
Total Annualized Cost to Industry						3,292	3,461

ICR = Information Collection Request

$M/yr = million dollars per year (2021 dollars)

1. Includes 22 plants that are assumed to operate past 2032 and therefore required to comply with regulatory option 3 BAT: CP, membrane filtration, with brine encapsulation
2. Current "announced" year when facility will permanently cease coal combustion, either due to plant retirement or due to repowering to a non-coal fuel source, such as natural gas or green hydrogen
3. Total annualized cost which is a sum of the annualized cost of capital (assumes 7% interest rate and 20-year life) and the annual O&M cost
4. Total annualized cost which is a sum of the annualized cost of capital and the annual O&M cost. Annualized cost of capital is calculated based on a 7% interest rate and the number of operating years. The number of operating years are calculated from an assumed in-service date corresponding to the "no later than" proposed regulatory compliance date of December 31, 2029 to the plant's estimated retirement or repowering date.
5. EPRI's analyses was solely focused on the proposed ELG Rule and did not consider the impact of other proposed and future environmental regulations, including the proposed Greenhouse Gas 111(d) Rule. These various environmental regulations may impact the currently announced retirement dates.

Many sites will incur costs that are inconsistent with EPA's estimated costs for CP, membrane filtration, and encapsulation. Fly ash availability and FGD purge flow and quality will ultimately drive plant decisions related to technologies required to achieve ZLD and associated costs. EPRI's estimate of the lowest cost option for ZLD is 6 times higher than EPA's cost estimate for the same list of plants.

EPRI estimated the cost for the 22 industry plants that would be required to comply with regulatory option 3 to convert to a ZLD thermal and/or membrane-based treatment system. EPRI considered potential technology choices and estimated cost to the industry to convert to one of three potential thermal and/or membrane treatment systems:

1. Chemical softening, vapor-compression evaporation, and crystallization (CS + VCE/CRX), as presented in Appendix C.
2. Chemical precipitation, vapor-compression evaporation, and brine solidification (CP+VCE/BS), as presented in Appendix D
3. Chemical precipitation, advanced membrane filtration and brine solidification (CP+AMF/BS), as presented in Appendix E.

This analysis considered the FGD wastewater flows and fly ash quantities produced by each plant to arrive at one of the three technology options that appeared most suitable for each site and yielded the lowest total estimated annualized cost over a 20-year period. Table 2-8 provides a summary of the results, and Appendix F provides further analysis details.

EPRI's analysis indicated:

- Only three plants produced sufficient fly ash for membrane filtration.
- Membrane filtration was not the lowest cost technology alternative for any of the 22 plants.
- For 10 plants, thermal evaporation with brine solidification (CP + VCE/BS) was the lowest cost technology alternative.
- For the remaining 12 plants, installing a thermal evaporator and crystallizer (CS + VCE/CRX) was estimated to be the lowest cost technology alternative.

In actual applications, plants would need to conduct a detailed analysis of their site-specific flows and FGD wastewater quality to arrive at a technology selection; however, this analysis shows that membrane filtration alone is unlikely to be widely applicable across the industry.

As shown in Table 2-9, EPRI's estimate of lowest cost alternatives for ZLD are still 6 times higher than EPA's estimate for membrane filtration.

Table 2-9. Lowest Cost ZLD Analysis for 22 Plants under Regulatory Option 3

EPA ICR ID	Plant Name	EPRI Cost Estimate[1]				EPA Cost Estimate[2]			
		Technology Basis	Capital Cost ($M)	O&M Cost ($M/yr)	Total Annualized Cost ($M)[3]	Technology Basis	Capital Cost ($M)	O&M Cost ($M/yr)	Total Annualized Cost ($M)[3]
493	J. K. Spruce Power Plant	CP+VCE/BS	35	7	10	Membrane Filtration	6	0.6	1.1
771	Kyger Creek Station	CP+VCE/BS	66	14	20	Membrane Filtration	18	2.0	3.8
904	Muscatine	CP+VCE/BS	16	2	3	Membrane Filtration	2	0.5	0.7
1236	Mitchell Plant	CP+VCE/BS	104	20	30	Membrane Filtration	21	4.4	6.4
1381	Homer City	CS+VCE/CRX	97	5	14	Membrane Filtration	9	1.1	1.9
1674	Trimble County	CS+VCE/CRX	438	39	80	Membrane Filtration	73	10.8	17.7
2244	Plant Bowen	CS+VCE/CRX	402	27	65	Membrane Filtration	90	5.3	13.8
2601	Ghent	CS+VCE/CRX	298	21	49	Membrane Filtration	42	4.1	8.0
3265	Cardinal	CS+VCE/CRX	408	33	71	Membrane Filtration	65	5.3	11.5
3309	Lawrence Energy Center	CP+VCE/BS	22	4	6	Membrane Filtration	2	0.5	0.7
3464	W. A. Parish E.G.S.	CP+VCE/BS	37	6	9	Membrane Filtration	6	0.9	1.4
3604	Mill Creek	CP+VCE/BS	65	11	17	Membrane Filtration	13	1.5	2.7
5318	Clifty Creek Station	CS+VCE/CRX	171	12	28	Membrane Filtration	27	2.8	5.3
6334	Leland Olds Station	CP+VCE/BS	54	8	13	Membrane Filtration	10	1.2	2.2
6377	Big Bend Station	CS+VCE/CRX	343	33	65	Membrane Filtration	64	6.5	12.5
7785	Seminole Generating Station	CP+VCE/BS	71	14	21	Membrane Filtration	15	1.8	3.2
8353	Jeffrey Energy Center	CS+VCE/CRX	195	14	32	Membrane Filtration	33	2.7	5.8
8965	F.B. Culley Generating Station	CS+VCE/CRX	99	7	16	Membrane Filtration	8	0.8	1.5

EPA ICR ID	Plant Name	EPRI Cost Estimate[1]				EPA Cost Estimate[2]			
		Technology Basis	Capital Cost ($M)	O&M Cost ($M/yr)	Total Annualized Cost ($M)[3]	Technology Basis	Capital Cost ($M)	O&M Cost ($M/yr)	Total Annualized Cost ($M)[3]
9161	John E. Amos Plant	CS+VCE/CRX	359	37	71	Membrane Filtration	80	7.0	14.5
9225	Fort Martin Power Station	CP+VCE/BS	76	12	19	Membrane Filtration	13	1.8	3.0
9971	Dallman	CS+VCE/CRX	93	4	13	Membrane Filtration	5	0.8	1.2
56068	Elm Road Generating Station	CS+VCE/CRX	148	9	23	Membrane Filtration	15	2.4	3.8
TOTAL		--	3,596	339	677	--	613	65	122

$M/yr = million dollars per year (2021 dollars)

1. Includes 22 plants that are assumed to operate past 2032 and therefore required to comply with regulatory option 3 BAT: CP, membrane filtration, with brine encapsulation. EPRI estimated the lowest cost technology alternative for sites to achieve ZLD
2. EPA's cost estimate for 22 plants that would be required to comply with regulatory option 3 [EPA, 2023a and EPA, 2023b]
3. Total annualized cost which is a sum of the annualized cost of capital (assumes 7% interest rate and 20-year life) and the annual O&M cost

Leasing treatment equipment does not provide significant costs savings if needed for multiple years

The EPA's ELG documents include mention of leasing of treatment equipment. EPRI agrees that this may be more economical for short-term applications, such as emptying water from an impoundment or infrequent maintenance events. However, after a time, the cost of leasing becomes comparable to, or exceeds, purchasing the same equipment. The duration at which leasing exceeds cost of purchase varies by equipment and is typically two to five years. Many of power plants in the industry will need FGD treatment for longer. It should also be considered that equipment is typically 20 to 25 percent of total installed project cost. The balance of plant costs required when leasing treatment equipment include foundations, piping to and from treatment, bringing power and other utilities to treatment, a structure to protect equipment from weather, integration with plant control systems, and the engineering of the treatment system.

Technical challenges with leasing treatment equipment include:

- FGD water's corrosivity is likely not compatible with metallurgy of most equipment available for lease
- Most plants have FGD flow greater than leasable equipment's capacity

- Not all needed equipment can be leased, so some would need to be purchased
- Equipment available for lease may not be sufficient for the number of plants that need treatment

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3 FGD WASTEWATER TREATMENT POLLUTANT REDUCTION

Pollutant loading remaining in FGD water after treatment by the 2020 ELG FGD BAT are mainly from pollutants with very low toxicity.

The U.S. Environmental Protection Agency (EPA) estimated the industry-level wastewater pollutant reduction for each waste stream. Most of the pollutant reduction associated with the 2023 Effluent Limitations Guidelines (ELG) are from flue gas desulfurization (FGD).

Because the 2023 ELG best available technology (BAT) would result in no discharge of FGD water, the pollutant loading reduction associated with FGD water is equal to the pollutant loading remaining in FGD water after chemical precipitation plus low residence time reduction biological treatment (CP+LRTR).

EPA calculates the pollutant removal figure used in the ELG Fact Sheet (584 million pounds per year) using only the total suspended solids (TSS) and total dissolved solids (TDS). Documents in the docket provide water quality characterization for TSS and TDS, as well as a list of individual pollutants. It is noted that the sum of individual pollutants in the docket documents is less than TDS plus TSS.

Figure 3-1 shows the main contributors to FGD pollutant loading from individual pollutants. The industry-level loading for each pollutant can be estimated using the average CP+LRTR effluent concentrations from Table 15 of EPA's *Technical Development Document for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (EPA, 2023b) and the average optimized flow obtained using the site-specific optimized FGD daily flow data from *Flue Gas Desulfurization Flow Methodology for Compliance Costs and Pollutant Loadings* (EPA, 2023c). Bromide loading was added to the pollutant list using the maximum bromide baseline loading specified in EPA memorandum (EPA, 2022).

Figure 3-1 illustrates that approximately 94 percent of FGD's pollutant reduction would come from pollutants with very low toxicity, such as chloride, magnesium, and calcium. More than 97 percent of reduction comes from those three non-toxic ions, plus bromide, sodium, and boron. The non-toxic nature of the major pollutants that dominate the FGD pollutant reduction calculations can be understood using EPA's toxicity weighting factor (TWF), as shown in Table 3-1. The TWF values, listed in *Flue Gas Desulfurization Wastewater Proposed Rule Loadings Database* (EPA, 2023d), were developed by the EPA to gauge relative toxicity. Pollutants typically considered of concern have TWF values well above 1.0. For example, arsenic's TWF is 3.47, in contrast to the TWF's for the major pollutant loading contributors listed below, all of which are orders of magnitude lower than arsenic.

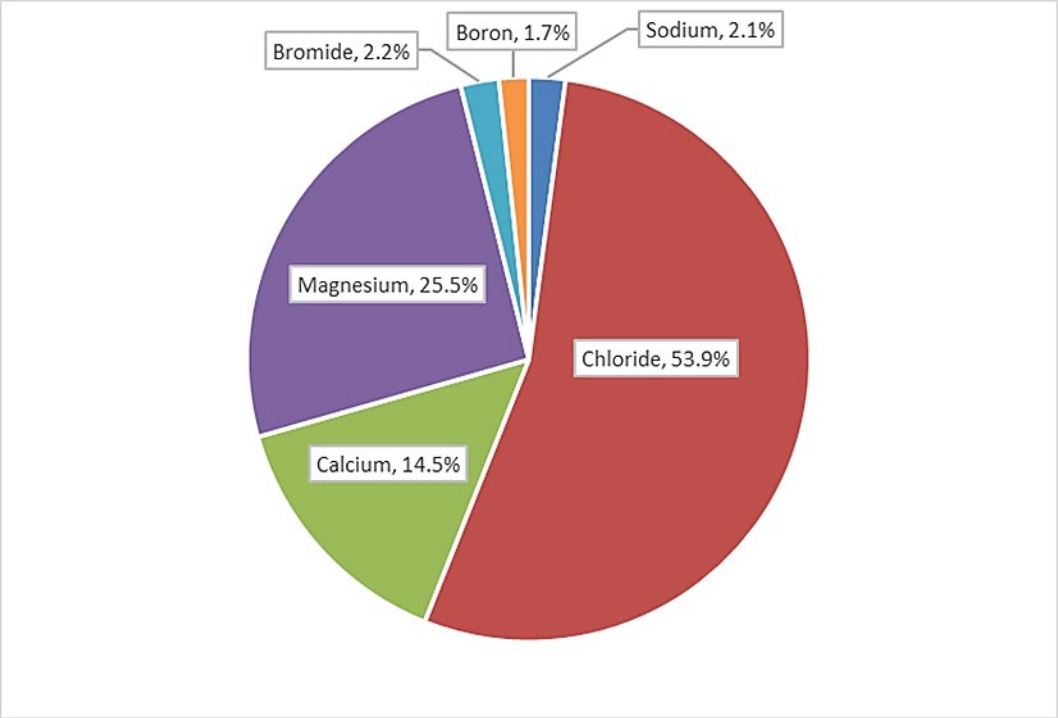


Figure 3-1. Main contributors to FGD pollutant loading based on CP+LRTR effluent quality and EPA-estimated bromide loading

Table 3-1. Toxicity weighting factors of the pollutants that dominate FGD pollutant loadings after CP+LRTR treatment.

Pollutant	Estimated Contribution to Total Pollutant Loading	TWF
Chloride	54%	0.00003
Magnesium	25%	0.00087
Calcium	14%	0.00003
Bromide	2%	None reported for bromide ion (0.01 for elemental bromine. Bromine may form brominated trihalomethanes, such as bromodichloromethane and dibromochloromethane, have TWFs that range up to 0.045)
Sodium	2%	0.00001
Boron	2%	0.00834

Estimates of bromide in FGD water used are significantly above EPRI's experience, and thus significantly inflate the total pollution reduction calculations dependent upon this estimate.

EPA's Benefit and Cost Analysis for Proposed Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (EPA, 2023a) document supports that nearly all of FGD pollutant load is not of significant concern to environment or human health. This is reflected in what EPA chooses to include in Table 3-1 of that document where reductions from the "…total loads for selected pollutants that inform EPA's analysis of the benefits" were presented. The average total annual reduction for FGD BAT for the selected pollutants used for benefits evaluation when all steam electric plants have implemented the treatment technology is 13.4 million pounds per year (lb/yr). Of this total reduction, 7.5 million lb/yr or 56 percent, was attributed to bromide (Figure 3-2).

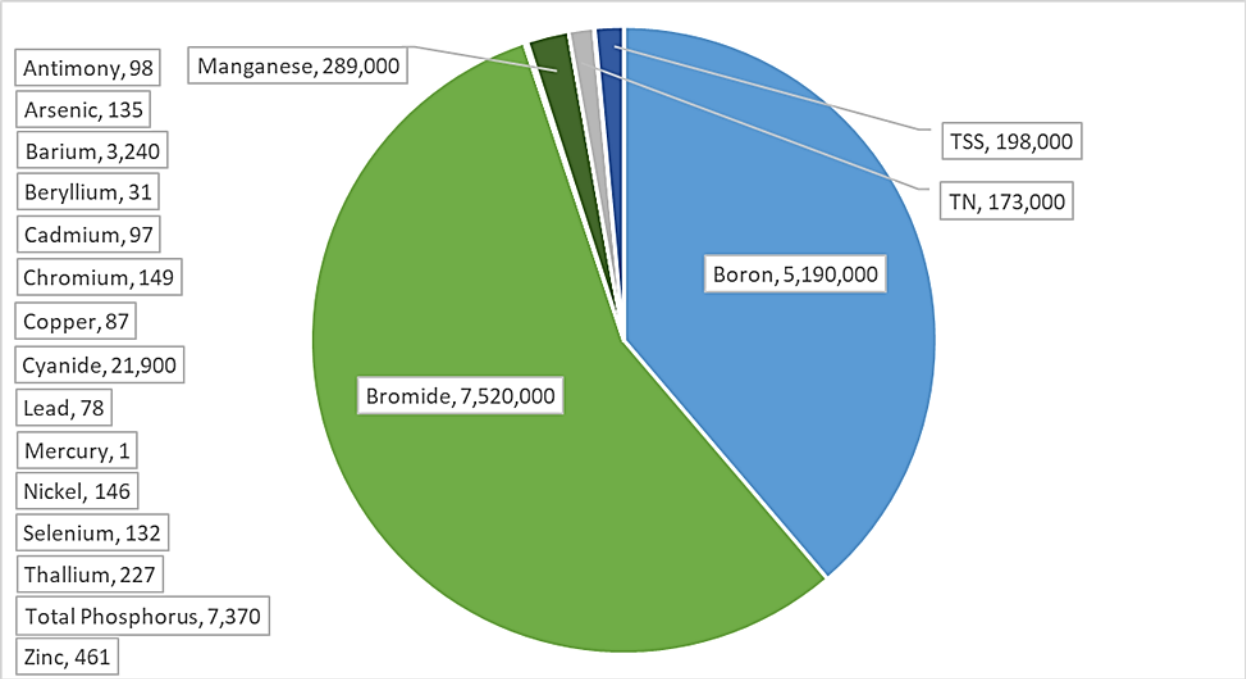


Figure 3-2. Average annual pollutant reduction for FGD using BAT after full implementation.

EPA based its bromide loading and reduction estimates on its 2020 halogen loading analysis, as discussed in *FGD Halogen Loadings from Steam Electric Power Plants* (EPA, 2022). In that document, a baseline maximum bromide loading was calculated using a mass-balance approach where bromine in FGD wastewater from three sources were combined. The total calculated maximum value was of 8,810,000 lb/yr. The three sources are described as either "Bromide (min)" and "Bromide (max)":

- Bromide (min), 1,070,000 lb/yr, included:
  - Bromine content in coal
  - Addition of bromine in flue gas for mercury emission control (use of brominated activated carbon [Br-AC] as part of an air emission control system)
- Bromide (max), 8,810,000 lb/yr, included:
  - Bromide (min)
  - Bromine loadings attributable to refined coal use or adding halogen compounds at the boiler for mercury emission control), 7,740,000 lb/yr

In EPRI's recent review of industry compliance with the Mercury and Air Toxics Standards (MATS) controls at the listed FGD sites, using EIA data for calendar year 2022, it was determined that refined coal use has dropped significantly in all sites, if not completely discontinued. Of the 22 wet FGD plants expected to be operating past 2028, only 2 burned refined coal prior to 2021. These two power plants—Elm Road Generating Station and Muscatine Plant #1—have ceased burning refined coal but now add bromide compounds prior to combustion. The other 20 power plants do not employ any bromide additive for MATS flue gas control. As such, EPA is overestimating the bromide (max) loading used as baseline for bromide removal, BAT pollutant reduction, and benefits analysis. The baseline loading should be adjusted such that the bromide (max) values are equal to bromide (min) (i.e., loadings from native coal content and Br-AC) for all sites except for the two mentioned sites.

In addition, the bromide pollutant reductions lead to estimated health benefits from the downstream formation of TTHM in municipal drinking water facilities. Accordingly, TTHM health benefit estimates are overestimated.

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4 LEACHATE BAT WASTEWATER TREATMENT COST

EPRI's annualized cost estimate of CRL BAT (chemical precipitation) for the industry is approximately 170 percent higher than EPA's estimate. EPRI recommends that the EPA revise its estimate.

EPRI compared EPA's cost estimates for chemical precipitation (CP) treatment published in Technical Development Document for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category [EPA, 2023a] with EPRI's estimate of the cost to comply with the ELG rule. It appears EPRI estimating differed from EPA's for following key reasons, which are further detailed in sections below:

- Number of plants that will have costs to comply with the BAT
- Use of a peak daily flow rather than long-term average to size treatment plant
- Operations and maintenance (O&M) cost factors

Table 4-1 compares EPA (EPA, 2023a; EPA, 2023b; EPA, 2023c; ERG, 2023) and EPRI chemical precipitation costs. EPRI CP costs are further discussed in Appendix H.

Table 4-1. CRL chemical precipitation cost comparison for the industry

	# of Plants Requiring BAT	Peak Flow (gpm)	Capital Cost ($M)	Average Flow (gpm)	Annual O&M Cost ($M/yr)	6-Year Recurring Cost ($M/yr)	Total Annualized Cost ($M/yr) @7%
EPA	69	63	747	63	43.5	7.37	115
EPRI	134	202	1,822	63	136	14.7	310

Use leachate peak flow rate as the basis for engineering design of CRL CP in its capital cost calculation. This will produce a more accurate EPA estimate of the capital cost needed to build a reliable chemical precipitation treatment system.

EPA used capital cost curves and O&M cost curves to estimate CP costs for combustion residual leachate (CRL). The cost curves were based on the daily leachate flow rate obtained either from:

1. Site-provided daily flow data
2. Estimated flow rate based on landfill acreage (active and inactive)
3. Median leachate flow rate for all sites included in the cost evaluation (46,160 gallons per day [gpd]).

EPA used the same flow rate (i.e., the plant's average daily leachate flow rate) for the capital cost curve and O&M cost curve to calculate the capital and O&M costs. Best engineering practice applies peak flow rate as the basis of design for wastewater treatment systems to provide sufficient capacity and ensure consistent treatment during peak flow events. By using average flow in its capital cost curve, EPA is underestimating the capital cost needed to build CRL CP and, consequently, is miscalculating the total annualized cost to the industry needed to reliably treat CRL and meet effluent limits.

EPRI's experience, based on EPRI research and the experience of EPRI members, is that peak flow of leachate is typically 2 to 4 times the average leachate flow. This is shown in Table 4-2, which summarizes Table 4-1 of EPRI's *Quantifying Leachate Volumes at Four Coal Combustion Product Landfills in the Southeastern United States* [EPRI, 2021], and in Figure 4-1 which illustrates variability in measured leachate flow in an active site.

Table 4-2. Maximum to average leachate generation rates ratio from four coal combustion product landfills.

Site	Generation or Closure Landfill	Study Period (months) 1 sample/month	Average Generation Rate (gpd per acre)	Maximum Generation Rate (gpd per acre)	Maximum to Average Generation Rate Ratio
33105	Closure	39	1,760	4,192	2.4
33449	Closure	33	2,477	4,895	2.0
33107	Active	113	888	3,250	3.7
33451	Active	15	1,174	3,118	2.7

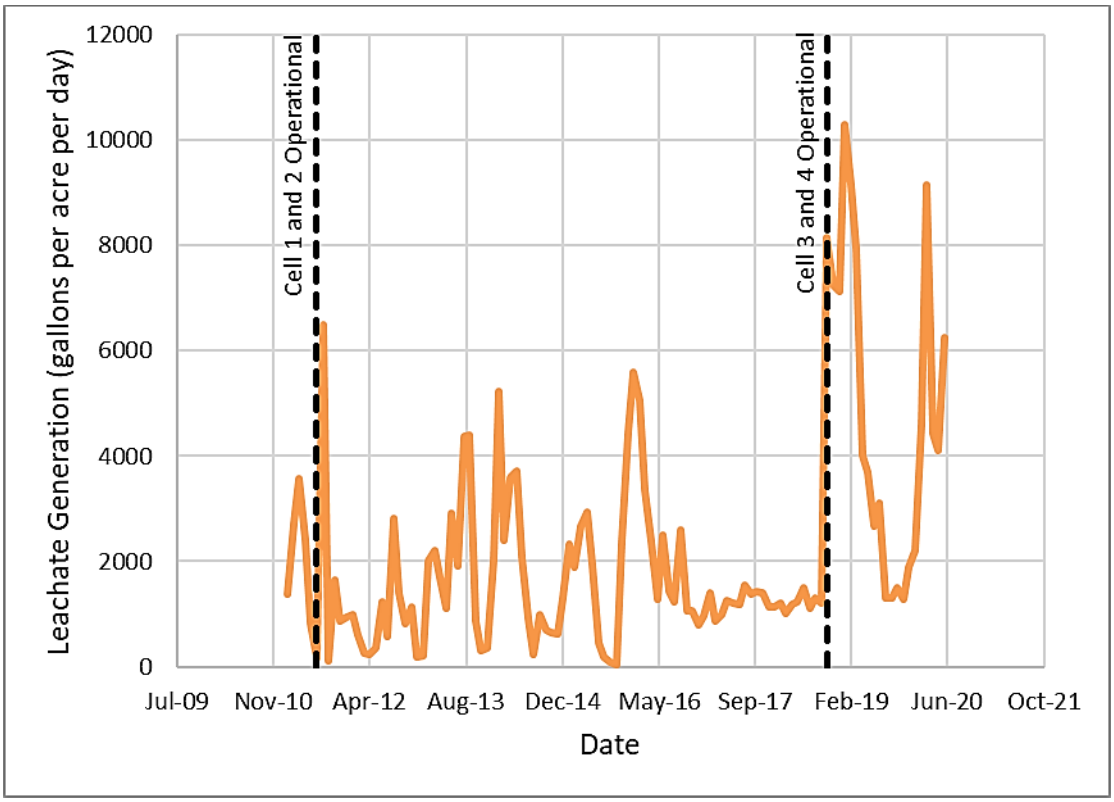


Figure 4-1. Variability in leachate generation at Coal Combustion Product Landfill Site 33107

The industry-level regulatory option cost for CRL BAT provided by EPA appears to be based on just a subset of the industry and excluded retired facilities, which results in a lower cost than the projected total industry cost for all regulated CRL landfills.

EPA estimated the industry cost of implementation for CRL BAT by adding electric generating unit (EGU)-level cost for 69 plants [Table 12 of EPA, 2023b]. EPA used data from 2009 Steam Electric Survey, removing plants that intend to retire all coal-fired EGUs by December 31, 2023, and adding landfills constructed since 2015 to obtain the 69 sites. These plants, listed in Table 10 of *Generating Unit-Level Costs and Loadings Estimates by Regulatory Option* [EPA, 2023c], are CRLs that collect and discharge leachate to either surface water or publicly owned treatment works (POTW). In practice, any landfill that continues to collect and discharge to surface water or POTW, regardless of whether the landfill is active, inactive or retired, may be subjected to the proposed regulation. EPA should clarify if the regulation applies to closed power plants and/or closed or retired landfills that continue to collect and discharge leachate. If regulated, those sites should be included in the industrywide cost calculation.

As part of the proposed 2023 Steam Electric Rulemaking, EPA conducted a sensitivity analysis to evaluate potential costs and loads associated with treating CRL discharged to groundwater. EPA's cost methodology is discussed in *Evaluation of Potential CRL in Groundwater* [EPA, 2023d]. From that memo, "*EPA used the criteria outlined in Section 2 to characterize whether*

each landfill does or does not have a composite liner. Landfills with composite liners were excluded from the groundwater pumping estimate analysis. Of the 243 total landfills that were evaluated:

- *69 landfills were categorized as composite-lined because they were already identified as lined in the CRL cost and loadings analyses associated with the proposed rule (see Section 5 of the TDD [U.S. EPA, 2023]).*
- *65 landfills were categorized as composite-lined because documents made available online by the power company identified that the landfill has a composite liner*."

EPRI has been unable to find in the ELG docket information on the location of these 65 plants, which rendered it unable to directly comment; however, since leachate produced from the other 65 composite-lined landfills will need to be collected and discharged, and subjected to CRL BAT, the cost of treatment at those 65 sites should be included in the industry-level costs.

EPA acknowledged in its sensitivity analysis that they identified additional lined landfills after the CRL-proposed rule population had been finalized. EPA indicated that they could update the CRL population for the final rulemaking.

The CRL BAT (chemical precipitation) annual O&M cost should reflect accurate labor requirements.

To separate out the effects of the two key variables discussed above, i.e., number of plants and peak flow rate, EPRI compared EPA's cost estimates for CRL CP at a given flow rate with EPRI's own estimate of the cost. EPA costs are as described in *Technical Development Document for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* [EPA, 2023a] and in *Regulatory Impact Analysis for Proposed Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* [EPA, 2023b]. EPRI used the EPA-provided average untreated leachate flow rate and the average leachate water quality data to develop a cost model for a CRL CP facility.

Table 4-3 compares EPA's and EPRI's CRL CP costs. EPA's total annualized cost, calculated by EPRI using EPA's CP capital cost and O&M cost curves, including EPA's six-year recurring cost for mercury analyzer (EPA, 2023a), is 20 percent lower than EPRI's calculated cost. Although the capital cost is relatively similar, EPA's O&M cost is 54 percent lower than EPRI's. EPRI's CP O&M cost is primarily driven by cost associated with labor required to operate different CP process units. EPA should verify that adequate labor cost for CP plant operators was included in its estimate. Additional information on EPRI's methods for calculating CRL CP cost is presented in Appendix H.

Table 4-3. Comparing EPA and EPRI cost estimates for a plant's CRL BAT, if same flow is used.

	Peak Flow	Average Flow	Capital Cost	O&M Cost	6-Year Recurring Cost	Total Annualized CP Cost[1]
EPA	63 gpm	63 gpm	$11.2M	$0.65M	$0.1M	$1.7M
EPRI	63 gpm	63 gpm	$11.3 M	$1.01M	$0.1M	$2.1M

$ = U.S. dollars, pre-tax in 2021 dollars

1. Total annualized cost is sum of annualized capital cost (assuming 7% interest rate and 20-year life), annual O&M cost, and one-sixth of 6-year recurring cost.

Unit cost per flow at closed landfills are higher than active sites.

The flow-based cost curves developed for active sites should be modified for closed landfills to account for challenges related to operating a CP system on closed or retired sites. These challenges could make cost per flow higher for cost elements such as:

- **Power** – the cost of power is expected to be higher in a closed site due to the additional cost needed to bring power to the facility where no power is being generated onsite.
- **Labor** – unlike in active sites where a CP operator could also assume other roles not related to CP system operation to offset labor cost, a CP operator for a closed or retired site will work exclusively on the wastewater treatment system.
- **Residuals management and disposal** – residuals from CP for closed or retired sites will need to be hauled and disposed in a different location, which results in higher hauling and disposal costs.

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5 LEACHATE PROPOSED BAT LIMITS

EPA has not provided combustion residual leachate (CRL) data to show that the proposed BAT limits are technically feasible.

The U.S. Environmental Protection Agency (EPA) stated that there is currently no available effluent data for landfill sites using chemical precipitation (CP) for leachate treatment. As such, EPA used FGD wastewater data based on the assertion that the metals removal observed for flue gas desulfurization (FGD) CP can be similarly achieved for combustion residual leachate (CRL) CP. Leachate data review and verification (and possibly further testing) would greatly improve the uncertainty in developing CRL best available technologies (BAT) limits that can be achieved.

Table 5-1. Proposed arsenic and mercury BAT Limits for CRL

Parameter		Concentration
Arsenic, µg/L	Max 1-day	11
	Average 30-day	8
Mercury, ng/L	Max 1-day	788
	Average 30-day	356

µg/L = micrograms per liter

ng/L = nanogram per liter

Existing FGD wastewater data are not adequately representative of potential CRL CP effluent water quality. Therefore, it is not appropriate to use FGD wastewater data to set limits for CRL.

EPA based the numeric standard for mercury and arsenic for CRL BAT (CP) on FGD CP effluent because the agency indicated that "CRL has similar wastewater characterization to FGD wastewater." EPRI agrees with EPA that FGD and CRL contain similar pollutants of concern; however, the amount and form of each pollutant present in each wastewater varies. The assumption that CP treatment of the two wastewaters can achieve similar effluent characteristics oversimplifies the underlying factors that dictate effective removal of specific pollutants.

EPA collected new data on CRL in 2020 via a voluntary request (ERG, 2022; EPA, 2022). This data set has lower arsenic concentrations than the data that EPA received via the Information Collection Request (ICR) presented in EPA's *Technical Development Document for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (EPA, 2015). Table 5-2 shows the water quality presented by EPA for untreated FGD and CRL for some of the pollutants.

Table 5-2. Comparison between untreated FGD and CRL water quality.

Pollutant	Average total concentration (particulate + dissolved) (µg/L)		
	FGD (EPA, 2015)[1]	CRL via 2009 ICR (EPA, 2015)[1]	CRL via 2022 voluntary data request (ERG, 2022; EPA, 2022)[2]
Arsenic	507	38	7.6
Mercury	289	1.1	0.04
Cadmium	127	10.1	4.5
Copper	673	7.6	13
Nickel	1,490	46	27
Selenium	3,130	111	86
Thallium	22.1	1.2	3.5
Zinc	4,110	211	40
Boron	242,000	22,400	23,000
Chloride	7,180,000	413,000	707,000
Iron	566,000	37,100	3,220
Molybdenum	273	1,380	12,000
Sodium	2,520,000	308,000	1,170,000
Sulfate		1,790,000	2,870,000
Total Suspended Solids	14,500,000	35,800	16,100
Total Dissolved Solids	33,300,000	3,500,000	5,570,000

1. Untreated FGD and untreated CRL water quality data presented in Table 6-3 and Table 6-9, respectively, of the Technical Development Document for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (EPA, 2015).
2. Recent untreated CRL data obtained from voluntary data request (ERG, 2022) presented in EPA's Combustion Residual Leachate Analytical Data Evaluation (EPA, 2022).

In general, metal concentrations are higher for FGD wastewater than CRL. The different metal forms (e.g., particulate versus dissolved), however, are different. Although total arsenic is higher for FGD, the dissolved arsenic concentration for CRL is higher than for FGD, as is shown in later portions of this section, thereby making arsenic more challenging to treat in CRL.

EPA acknowledged that particulate arsenic is more easily removed than dissolved arsenic. As noted in testing done for FGD wastewater in *Factors Affecting Arsenic Removal in FGD Wastewater Physical/Chemical Treatment* (Schubert, 2017), arsenic removals can vary depending on forms, environmental conditions (e.g., pH, oxidation-reduction potential (ORP)), and the presence of other ions in solution. Given the differences in FGD and CRL arsenic water quality as well as the limited dissolved arsenic removals for FGD using CP, the available data do

not adequately demonstrate that CP will be effective for arsenic removal from CRL. Additional data are needed to properly demonstrate technical feasibility and to determine numeric limits.

Meeting BAT limit with CP treatment of FGD water has not been fully characterized.

Removing dissolved arsenic using CP has not been fully characterized and is yet to be verified. In 2013, EPA presented an FGD wastewater data set for 3 plants (Keystone, Hatfield's Ferry, and Miami Fort) to show the technical feasibility in achieving FGD limits for arsenic through CP and low residence time reduction biological treatment (CP+LRTR) (ERG, 2012a; ERG, 2012b; ERG, 2012c). EPRI summarized the dissolved arsenic concentrations reported for those sites in Figure 5-1. EPRI commented that the data showed little or no dissolved arsenic removal due to minimal differences between the dissolved arsenic concentrations in the untreated and treated samples. EPA disagreed with that assertion, indicating that the lack of perceived removal was because "FGD wastewater samples were at or near the quantitation limit and, therefore, it is difficult to quantify further removals." However, the quantitation limit for Keystone and Hatfield's Ferry dissolved arsenic analyses was 4 µg/L (micrograms per liter) while for Miami Fort it was 3 µg/L, which indicates that several data points were reportedly above the quantification limit and further supports EPRI's comments that little or no dissolved arsenic removal has been observed in CP treatment.

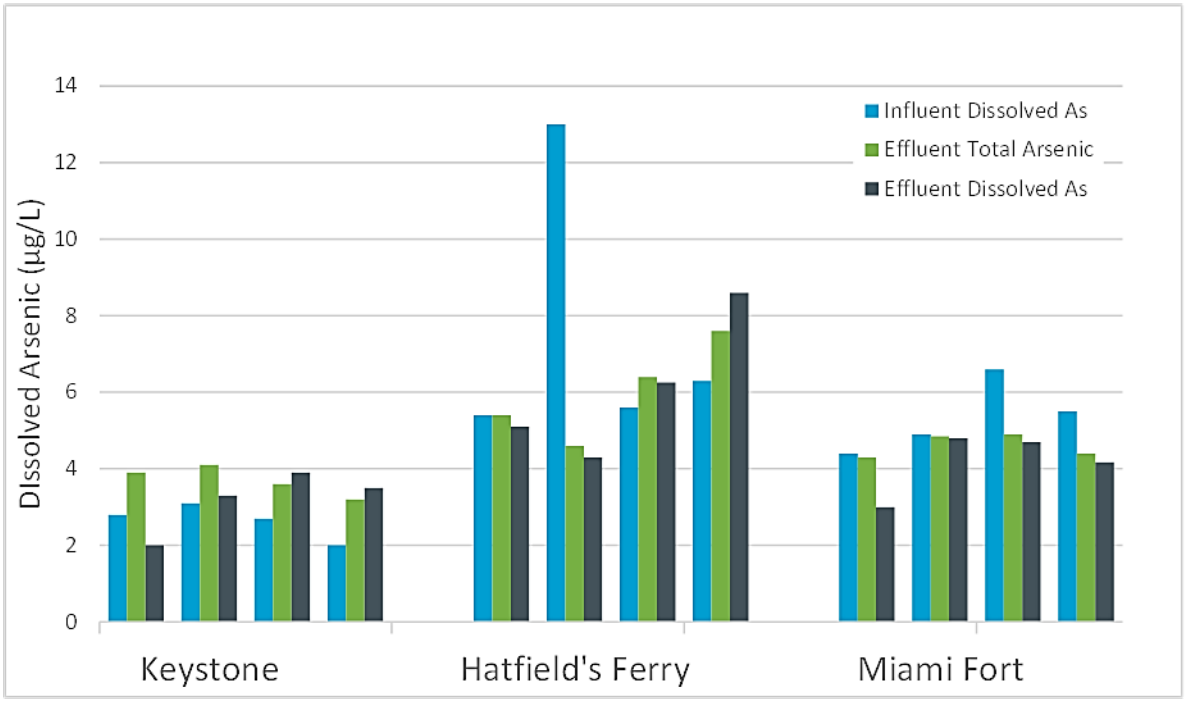


Figure 5-1. Dissolved arsenic concentration in FGD samples used in 2015 FGD BAT limits.

Given that dissolved arsenic concentration in CRL is higher than the BAT limit in many plants, the ability of CP to achieve dissolved arsenic removals to meet the 8 µg/L arsenic limit is uncertain.

In data provided by EPRI and EPA, untreated samples of CRL had higher dissolved arsenic concentrations than FGD wastewater samples used by EPA to set FGD limits (EPRI, 2006; EPA, 2022; ERG, 2022). In contrast to EPA's FGD water (Figure 5-1) where only one untreated FGD wastewater sample exceeded the proposed BAT limit of 8 µg/L arsenic, Figure 5-2 shows that in 6 out of the 10 coal ash landfill sites surveyed by EPRI (EPRI, 2006), the average dissolved arsenic concentration for that plant was greater than 8 µg/L. Also shown in Figure 5-2 are the only three sites that reported dissolved arsenic in EPA's recent voluntary CRL data request (EPA, 2022). One out of the three sites had higher than 8 µg/L average dissolved arsenic. Overall, the average dissolved arsenic concentration for FGD samples included in Figure 5-1 is 5 µg/L compared to 13 µg/L for CRL samples included in Figure 5-2.

This higher dissolved arsenic in CRL demonstrates the need for further testing to characterize the effectiveness of CP for removing dissolved arsenic from CRL samples. EPRI recommends obtaining untreated CRL samples in sufficient quantity to represent the broad range of dissolved arsenic concentrations observed in CRL, and testing with CP treatment, in order to characterize the industry-wide effectiveness of CP.

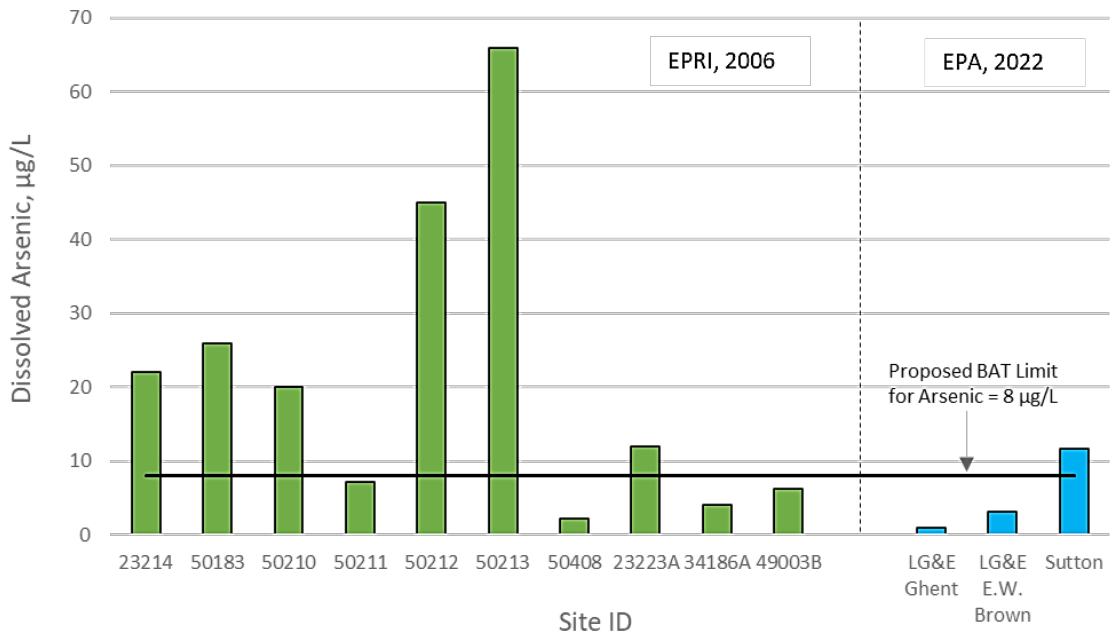


Figure 5-2. Average dissolved arsenic concentrations in leachate collected from coal ash landfills often higher than 8 µg/L BAT limit.

Much of the CRL arsenic data available is for total arsenic. Table 5-3 shows a summary of total arsenic data for landfill leachate obtained from EPA's ICR and voluntary data request (EPA, 2010; EPA, 2022; ERG, 2022). The summary indicates that between 32 percent (44 out of 136 samples) to 60 percent (119 out of 197 samples) of the arsenic analysis for landfill leachate had concentrations higher than the 8 µg/L. Although the data shown in Table 5-3 were reported as total arsenic, EPRI research indicates that unfiltered arsenic samples from CRL samples typically have similar concentrations as unfiltered samples. Specifically, in EPRI's report *Evaluation and Comparison of Leach Test and Porewater Variability for Multiple Coal Combustion Product Management Units* (EPRI, 2022), direct comparison between paired (i.e., collected at the same time) unfiltered (total) and filtered (dissolved) arsenic concentrations for leachate indicated 80 percent of the results were similar (Figure 5-3). As such, based on the average concentrations in Table 5-3 and the EPRI observation of similarity between total and dissolved arsenic in most landfill leachate samples, it can be concluded that many of the samples in EPA's total arsenic sample sets could have dissolved arsenic concentration greater than 8 µg/L.

Table 5-3. Summary of total arsenic concentration in leachate reported in EPA arsenic data evaluations.

Source	Average Arsenic (µg/L)	Median Arsenic (µg/L)	Number of samples with arsenic data	Number of samples with arsenic greater than 8 µg/L	Notes and qualifiers	Reference
EPA (DCN SE10249)	12	3	136	44	Average and median total arsenic shown for all samples analyzed	ERG, 2022; EPA, 2022
EPA (ICR Part G)	41	20	197	119	Data for untreated landfill leachate samples only; excluding impoundments, fully retired sites, and CBI data	EPA, 2010

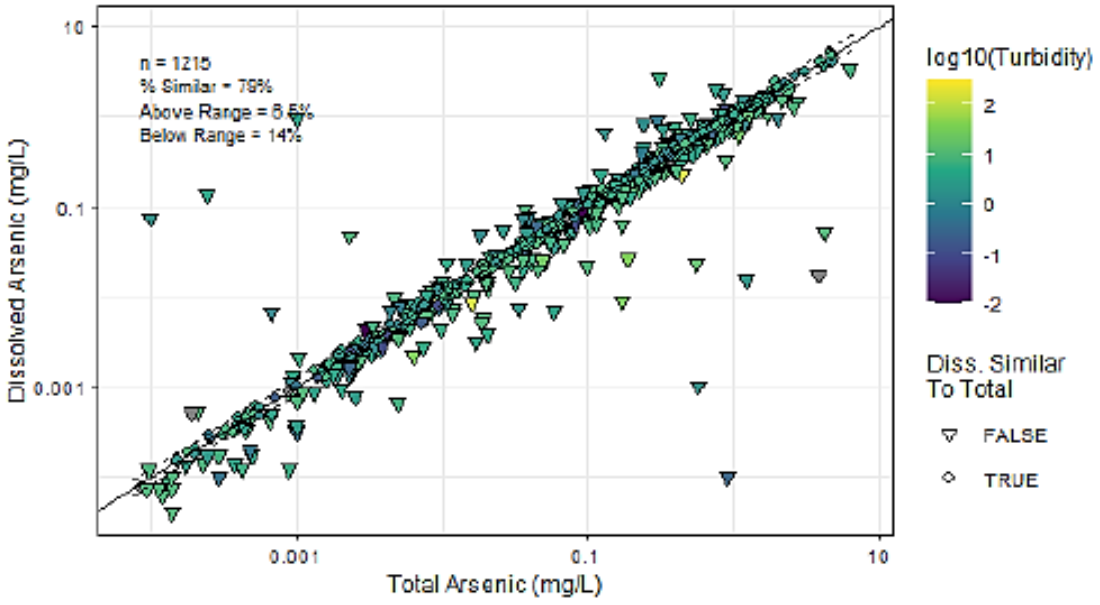


Figure 5-3. Relationship of dissolved to total arsenic concentrations in landfill leachate.

Flexibility for landfills nearing closure could avoid the construction of a larger and more expensive system that would only operate for a relatively short period of time.

EPA is soliciting comments if landfills and surface impoundments nearing closure should be given flexibility so that limitations could be postponed until after closure. This comment addresses how flexibility for near-closure landfills could consider differences in the pre- and post-closure peak leachate flow rate rates. In addition, flexibility could also consider the sharply declining initial depletion phase experienced by some coal combustion product (CCP) landfills, such as those consisting of moist CCPs, thin CCPs, and rapidly draining CCPs. Consideration of these physical aspects of post-closure landfills could limit the construction of larger, more expensive leachate treatment systems and better align treatment system construction with capacity needed to manage long-term post-closure flows. The paragraphs that follow detail results from EPRI research, including an ongoing EPRI modeling study, that quantifies the effects of closure and capping on leachate flows from a landfill under a variety of conditions.

Leachate flows in operating CCP landfills originate mainly from moisture conditioning water added to CCPs and from precipitation (EPRI, 2021a). Landfill closure terminates the addition of CCP and moisture conditioning water, and the landfill final cover significantly diminishes the contribution of precipitation to leachate (EPRI, 2015). As a result, landfill closure alters CCP leachate flows in at least two ways.

First, the variability of operating leachate flows, which result primarily from precipitation, is nearly immediately reduced after the final cover is installed. The engineered barrier in a landfill final cover system blocks nearly all precipitation from entering a landfill, and instead diverts

precipitation to runoff or evaporation. Therefore, the precipitation-related peak flows, on the order of 2 to 4 times greater the average flows for observed landfills (EPRI, 2021b), are nearly eliminated upon completion of closure and the final cover system.

Second, the average leachate flow rate declines as water contained between the CCP particles (CCP porewater) is depleted. This decline can be characterized by two phases: a rapid initial depletion phase and a slow secondary phase. The rapid initial decline is most strongly influenced by the CCP characteristics: CCP thickness, water content at closure, and hydraulic properties. The slow secondary phase is most strongly influenced by final cover system and weather, as infiltration through the cover balances with leachate flow. Ultimately, the long-term equilibrium flow rate can be several orders of magnitude smaller than the flow rate immediately before installation of the final cover (EPRI, 2015).

To better understand CCP porewater management in a landfill, EPRI has an ongoing study involving mechanistic modeling of landfill leachate flows. EPRI's study applies principles of soil physics to the unsaturated flow processes in CCP landfills. EPRI's study uses CCP properties developed by EPRI from standard benchtop experiments, as well as published properties developed by other researchers, to model flows in a range of CCP landfill scenarios using the widely accepted Seep/W modeling software. EPRI developed the landfill scenarios based on results of 2021 EPRI survey of CCP landfills (EPRI, 2021a). EPRI aims to publish this modeling study later in 2023.

The nature of the initial decline in leachate flow is strongly influenced by CCP thickness. Results of the EPRI's modeling to-date indicates that thinner landfills generally decline in flow rate faster than thicker landfills of the same CCP properties (EPRI, 2023). Figure 5-4, from the in-progress EPRI research, contrasts the decline in discharge rates from 75-feet- and 25-feet-thick landfills. Figure 5-4 considers this decline in the context of CCP with typical fly ash properties placed at five water contents spanning the range from relatively dry CCP from the power plant after moisture conditioning (lower) to relatively wet CCP placed in a landfill after closure of a surface impoundment by removal. The 75-foot thick landfill model exhibited a rapid decline in leachate discharge for CCP with higher water content at closure, but exhibited a slower initial decline in discharge rate for CCP with lower water contents. In contrast, the 25-foot thick landfill model exhibited substantial decline in initial discharge rate regardless of the CCP water content at closure. Over the two years following closure, model discharge from the thinner landfill declined by about 63% to 67%, and model discharge from the thicker landfill declined by 25% to 55%, depending on the water content of the CCP at closure.

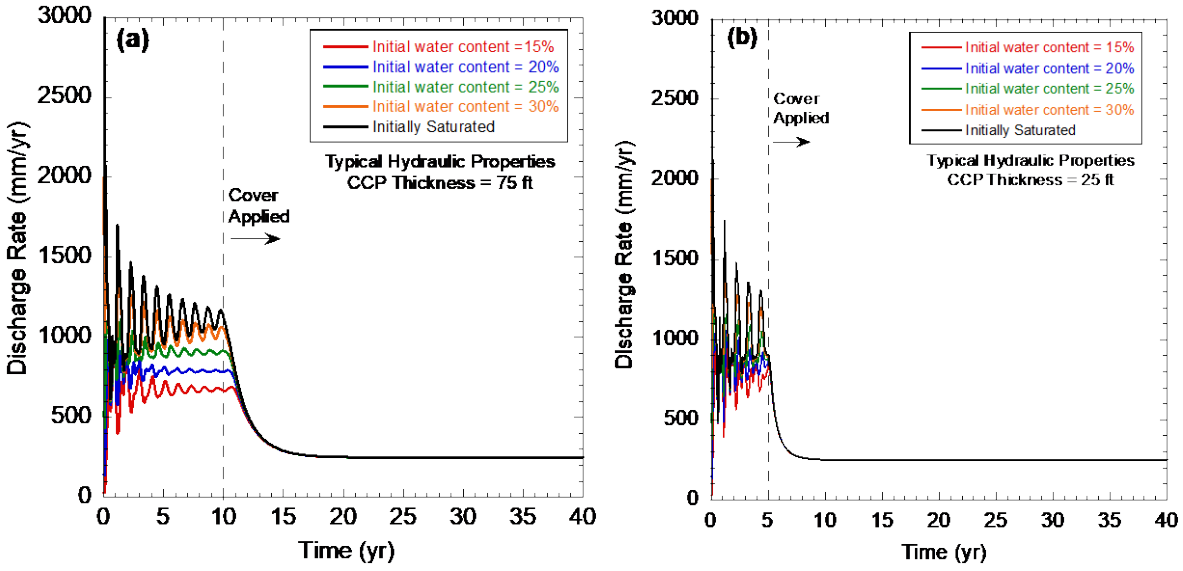


Figure 5-4. Model leachate discharge rates in humid climate. Landfill closed with compacted earthen cover. CCPs consist of fly ash with typical hydraulic properties having an initial water content ranging from 15% to saturated. (a) CCP thickness = 75 ft, (b) CCP thickness = 25 ft. The pre-closure conditions model weather and CCP addition on a yearly basis and do not model the influence of individual weather events on leachate discharge.

EPRI modeling also indicates CCP deposits with faster hydraulic properties, i.e., higher hydraulic conductivities, decline in flow rate faster than similar CCPs deposits with slower hydraulic properties or lower hydraulic conductivities (EPRI, 2023). Figure 5-5, from in-progress EPRI research, contrasts discharge rates from CCPs with properties of more permeable, typical, and less permeable fly ash placed in 75-feet- and 25-feet-thick landfills at typical water contents. In the thicker landfill model, the more permeable CCPs exhibited a faster decline in initial discharge rate than the less permeable CCPs. In the thinner landfill model, the more permeable and less permeable CCPs exhibited similar declines in initial discharge rate. Over the two years following closure, model discharge from the thinner landfill declined by about 65% and model discharge from the thicker landfill declined by 45% to 55%, depending on the CCP hydraulic properties.

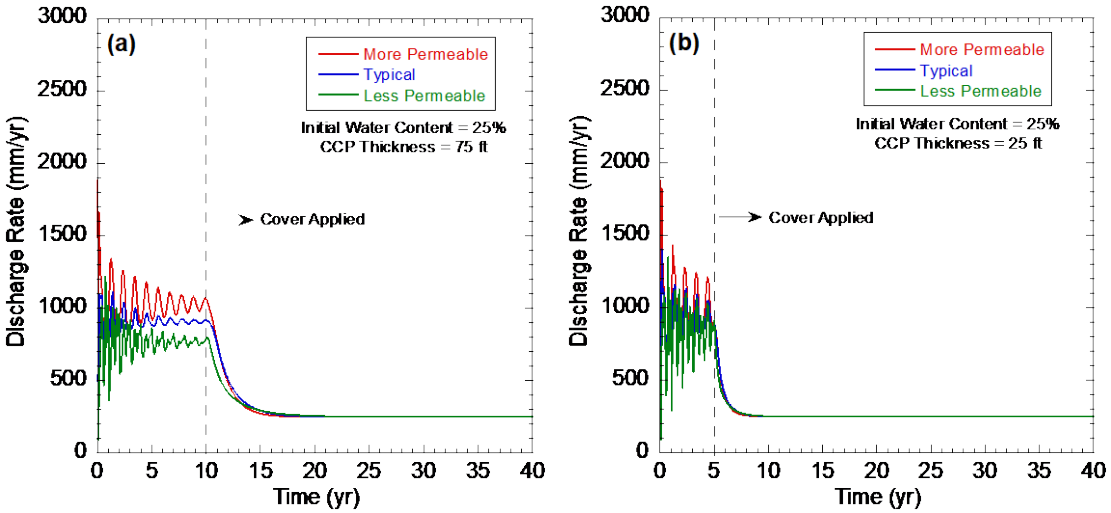


Figure 5-5. Model leachate discharge rates in humid climate. Landfill closed with compacted earthen cover. CCPs consist of more permeable, typical, or less permeable fly ash with an initial water content of 25%. (a) CCP thickness = 75 ft, (b) CCP thickness = 25 ft. The pre-closure conditions model weather and CCP addition on a yearly basis and do not model the influence of individual weather events on leachate discharge.

EPRI modeling shows the cover system type and external ambient climate conditions have a small influence on the post-closure decline in leachate flow rate but control the long-term equilibrium flow rate. Figure 5-6, from in-progress research, shows landfills with earthen and geosynthetic cover systems experience similar initial declines in discharge rate but differ in long-term equilibrium discharge rate (EPRI, 2023).

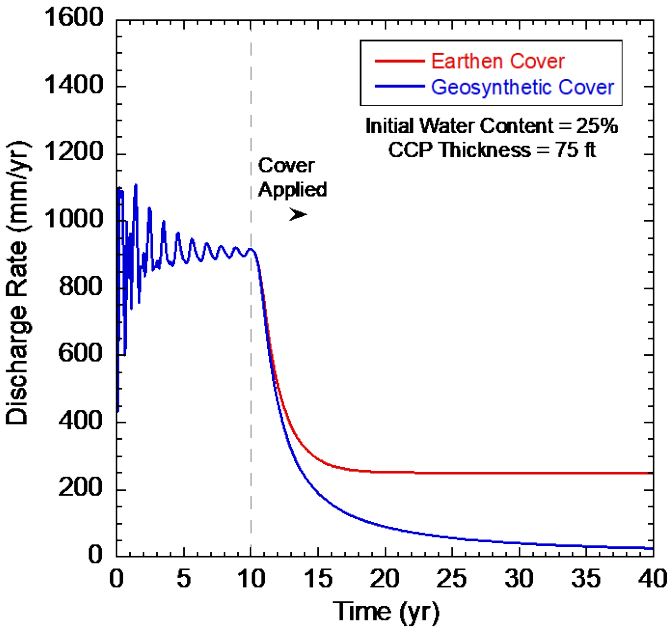


Figure 5-6. Model leachate discharge rates in humid climate for landfills closed with compacted earthen or geosynthetic covers. CCPs with typical fly ash hydraulic properties, initial water content of 25%, and thickness of 250 ft.

In summary, the EPRI modeling presented here, which will be publicly available later in 2023, is directly applicable to EPA's request for information on flexibility for landfills nearing closure because the modeling illustrates that leachate flows can be expected to change, and those changes can be substantial, following closure and capping. Closure and capping will have two effects: 1) peak flows caused by large precipitation events will be eliminated, and 2) average flows will decrease, and those decreases may be both rapid and substantial depending on CCP thickness, initial moisture content, and hydraulic properties.

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6 LEACHATE ALTERNATIVE COSTS – MEMBRANE

EPA solicited comments on alternative Combustion Residual Leachate (CRL) BATs, to this end, EPRI has developed a cost estimate for leachate treatment consisting of advanced membrane filtration with brine solidification (AMF + BS). EPRI's estimated cost to the industry is $761 million more for AMF + BS than EPRI's estimate of CP, assuming 134 plants require BAT.

EPRI developed a cost estimate for the leachate treatment alternative of CP, advanced membrane filtration and brine encapsulation (AMF+BS) based on a case study for a single plant. The following key assumptions were made for this analysis. Refer to Appendix G for additional details on the general design basis for leachate treatment.

- Flow – 63 gpm average, 202 gpm peak
- Water quality – total dissolved solids (TDS) concentration of 3,500 mg/L; refer to Appendix G for other assumed influent leachate water quality parameters.
- The CRL has a TDS concentration of 3,500 mg/L whereas FGD wastewater has an industry average TDS concentration of 24,100 mg/L. Therefore, the TDS concentration of CRL is approximately 7 times lower than FGD wastewater.
- As previously described (Figure 1-10), wastewaters with lower TDS should typically achieve higher permeate recovery. Based on vendor input, EPRI assumed that the CRL membrane system achieves an overall recovery of 94 percent.
- The treated leachate from the AMF+BS will be discharged to surface water. A ZLD option is not applicable and was not considered due to limited water reuse opportunities near the landfill and leachate treatment facility. Further, retired plants would not have the need to reuse leachate permeate.
- This case study assumes that the power plant is operating and producing fly ash, and therefore has fly ash available onsite for use in brine encapsulation. Retired plants would not produce fly ash and would need to purchase amendments with which to encapsulate the brine from CRL membrane treatment.
- None of the fly ash currently being sold would need to be diverted for use as brine solidification material. Further, no supplemental fly ash would need to be imported for brine solidification (assuming power plant is not retired).

Table 6-1 presents EPRI's CRL AMF+BS costs. Additional information on EPRI's methods for calculating CRL AMF+BS cost is presented in Appendix I.

Table 6-1. EPRI cost estimates for a plant's CRL AMF+BS treatment, if same flow is used.

	Peak Flow	Average Flow	Capital Cost	O&M Cost[1]	Annualized AMF+BS Cost[2]
EPRI	202 gpm	63 gpm	$58.6M	$2.5M	$8.0M

$ = U.S. dollars, pre-tax in 2021 dollars

1. Includes 6-year recurring cost assumed by EPA for in-line mercury analyzer replacement.
2. Total annualized cost is sum of annualized capital cost (i.e., industry capital cost annualized over 20 years with a 7% rate of return), annual operations and maintenance cost and one-sixth of 6-year recurring cost.

EPRI compared EPA's cost estimates for chemical precipitation (CP) treatment published in Technical Development Document for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category [EPA, 2023a] with EPRI's estimate of the cost to comply with the ELG rule utilizing AMF+BS treatment. Table 6-2 compares EPA's cost estimate for CP treatment, EPA's cost estimate for CP + membrane treatment, EPRI's cost estimate for CP treatment, and EPRI's AMF+BS treatment.

Table 6-2. CRL cost comparison for the industry for the proposed BAT (CP) and alternative BATs (CP + Membrane, AMF+BS).

	# of Plants Requiring BAT	Peak Flow (gpm)	Capital Cost ($M)	Average Flow (gpm)	Annual O&M Cost ($M/yr)	6-Year Recurring Cost ($M/yr)[1]	Total Annualized Cost ($M/yr)[2]	Annualized cost per plant ($M/yr)[2]
EPA (CP)[3]	69	63	747	63	43.5	7.37	115	1.7
EPA (CP + Membrane Filtration)[4]	69	63	1,138	63	113	7.37	221	3.2
EPRI (CP, see Section 4)	134	202	1,822	63	136	14.7	310	2.3
EPRI (AMF + BS)	134	202	7,852	63	330	14.7	1,071	8.0

$ = U.S. dollars, pre-tax in 2021 dollars

1. EPA assumed a six-year recurring cost of $110,039 per plant for in-line mercury analyzer replacement. EPRI used the same approach and applied this same cost to the 134 plants.
2. Total annualized cost is sum of annualized capital cost (i.e., industry capital cost annualized over 20 years with a 7% rate of return), annual operations and maintenance cost and one-sixth of 6-year recurring cost.
3. [EPA, 2023a; EPA, 2023b; EPA, 2023c; ERG, 2023]
4. [ERG, 2023]. Information provided from the CRL Proposed Rule Cost Database under query "4_CP+Memb Total Plant Level Costs (2021$)" as shown in the "SumOfUnit Memb" columns. EPRI's analysis of the database and membrane cost curves provided by EPA suggest that the costs shown in the "SumOfUnit Memb" columns are EPA's estimated costs for CP+Membrane. EPRI could not find information explaining EPA's basis and methodology for these costs in the docket. Basis for these costs were not included in the database file or the docket documentation.

EPRI's estimated annualized cost per plant for AMF+BS is approximately 2.5 times higher than EPA's estimated cost for CP + Membrane. EPRI's cost estimate of AMF + BS is 3.5 times more costly, or $761 million more for the industry, than EPRI's estimate of CP alone (see Section 4). When considering the cost to the industry, EPRI's estimated cost for AMF+BS for the industry is approximately 4.8 times higher than EPA's industry cost estimate of CP + Membrane and approximately 9 times higher than EPA's industry cost estimate of the proposed CRL BAT (i.e., CP) for the industry.

Refer to Appendix I for further information and additional assumptions on the AMF + BS cost estimate.

As described in Section 3, there would only be a minor increase in the pollutant reduction of highly toxic pollutants achieved from implementing the proposed 2023 ELG FGD BAT (CP + membrane filtration) over the 2020 ELG FGD BAT (CP + biological). Similarly, EPRI believes there would only be a minor increase in pollutant reduction if membrane treatment was the BAT for CRL instead of CP alone. Per EPRI'S estimates, this minor incremental increase in pollutant reduction achieved from installing AMF + BS over CP alone would cost approximately $761 million more for the industry.

References

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7 BOTTOM ASH TRANSPORT WATER PROPOSED BAT ZERO DISCHARGE LIMIT

EPA fails to account for the plant's low capacity factor and uses non-representative water quality data in in calculating Merrimack water quality so as to not overestimate pollution reduction.

The EPA's estimate of pollutant reduction due to the best available technology (BAT) for bottom ash transport water (BATW) is 25,900,000 pounds per year (lb/yr), as shown in the U.S. Environmental Protection Agency's (EPA) *Technical Development Document for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (TDD) Table 19 [EPA, 2023a]. EPRI reviewed EPA's supporting calculations in the memo Generating Unit-level Costs and Loadings Estimates by Regulatory Option for the 2023 Proposed Rule – DCN SE10381 [EPA, 2023b]. Table 12 of this memo shows that one plant, PSNH Merrimack, accounts for 17,730,000 lb/yr of this total, or approximately 70 percent of the calculated industry total.

EPA's estimate of the BATW and Merrimack should be reviewed for the following two assumptions: assuming 365 day/yr flow, and using a total dissolved solids (TDS) value that is not representative. Both are explained in this comment.

EPA assumes the daily flow (4.5 million gallons per day [mgd]) of bottom ash water is discharged daily. This is an overestimate. The Merrimack plant capacity factor is low – averaging at 0.09 from 2018 to 2022.

EPA calculates pollutant load as the product of BATW flow discharged times water quality expressed as total suspended solids (TSS) plus TDS. At Merrimack, EPA uses the plant's BATW flow without recycling, which is 4.5 mgd; however, EPA uses the same water chemistry as in high-rate recycle systems, i.e., TDS of 1,290 milligrams per liter (mg/L) and TSS of 13 mg/L.

A TDS of 1,290 mg/L may be representative for a BATW recirculating system, but it is significantly higher than, and not representative of, sites that do not recycle their BATW. EPRI contacted Merrimack staff, who had one sample result of BATW from 2017, which was 520 mg/L TDS.

EPRI notes that in its PISCES program characterizing water at five sites [EPRI 1997a, EPRI 1997b, EPRI 1998, EPRI 2000], including dozens of samples of BATW TDS, was very similar to the Plant Intake Water TDS, adding only 10 to 30 mg/L of TDS. EPRI results were lower than the one data point at Merrimack, ranging from 30 to 150 mg/L TDS.

If a TDS concentration of 520 mg/L is used in the calculation with Merrimack's BATW flow of 4.5 mgd flow, and a CF of 0.09, the pollutant load would be 0.7 million lb/yr, as opposed to EPA's calculated 18 million lb/yr.

Using this value in the industrywide calculation would change the industrywide pollutant reduction from 26 million lb/yr to 9 million lb/yr. This reduces the industrywide pollutant reduction by approximately 65 percent.

Further review of EPA's calculated BATW pollutant loading for all other plants showed that, like Merrimack, EPA did not apply real CF to adjust BATW flow (e.g., EPA used 365 days to obtain the annual value instead of a plant-specific operation period). This resulted in EPA overestimating the industrywide pollutant reduction. As most plants, if not all, would operate at CF less than 0.5, the expected pollutant reduction would be less than 5 million lb/yr or about 80 percent lower than the BATW BAT pollutant reduction stated by EPA.

Blowdown purge is recommended to provide significant operational flexibility. Water chemistry issues have caused plants to purge water from BATW systems.

The EPA describes several potential reasons why a purge from remote recycle system is currently required, and then explains why each does not warrant a purge. In the Proposed Rule, EPA then solicits comment, *"… on the extent to which any plant using an RMDS has tried all the processes* (chemical addition and RO [reverse osmosis] treatment and reuse) *described above and still failed to adequately control system chemistry."* Those processes include chemistry addition and treating water with reverse osmosis.

In recent EPRI research on bottom ash transport water, the results of staff interviews at 21 plants that installed high recycle rate bottom ash systems were provided; 16 out of the 21 plants included a remote mechanical drag system (RMDS) [EPRI, 2018; EPRI, 2019]. The others use tanks and bins to settle out ash. Forty four percent of the plants with RMDSs had a blowdown purge due to water chemistry issues. In these reports, provided to EPA during the 2020 rulemaking, EPRI provides examples of power plants that used a purge from their bottom ash remote systems.

Approximately half the plants surveyed [EPRI, 2019] observed acidity in the recirculated system originating from the seal water or cooling water in the hopper overflow that commingles with transport water. This water is difficult to segregate from recirculation systems because of its water contributions during sluicing and maintenance or from leaks that generally end up in the same area sumps as transport water. Levels of acidity coincide with increases in sulfates; this increase has resulted in calcium sulfate scaling in at least one system. A combination of chemical treatment and purging is often required to avoid corrosive or scaling conditions.

EPRI notes that identifying plants that have exhausted options to address purge due to chemistry is problematic, as currently a purge is allowed.

EPA's cost estimate for the total cost to the industry to implement reverse osmosis to treat purge should be improved for accuracy as is, it underrepresents these costs significantly.

In preamble, EPA presents cost to industry as $45 million per year, "based on all facilities using a remote MDS needing a 10 percent purge to be treated with RO in order to achieve complete recycle." EPA reduced estimate from $60 million per year in 2020, based on EPA's update of industry model.

EPRI estimates the size and cost of an RO system for bottom ash purge to be comparable to that of membrane system described for leachate as in Appendix I. This cost was $8 million per year per plant. Per the EPA's 2023 Technology Development Document, there are 35 to 42 plants that would be impacted by this regulation of bottom ash.

Using reverse osmosis to manage purge from bottom ash systems will need brine encapsulation, requiring ash supply that is already challenged by FGD BAT.

Using reverse osmosis (RO) treatment to concentrate contaminants in purge water to a brine would require brine encapsulation and disposal. As discussed in the section above on FGD water, the availability of fly ash generated at sites is limited. If a site has to use fly ash to encapsulate brine from FGD membrane treatment and brine from bottom ash purge treatment, the challenges and costs discussed in the FGD section above will be increased.

The blowdown purge, which is banned in the 2023 proposed ELG BAT for BATW, would provide significant operational flexibility. Water balance issues have caused plants to purge water from BATW systems.

In EPRI studies on bottom ash transport water [EPRI, 2018; EPRI, 2019], the results of staff interviews at 21 plants that installed high recycle rate bottom ash systems, all 21 plants with RMDSs had a blowdown purge due to maintenance and water imbalance issues. The reasons for the necessary purge from the RMDSs are provided below.

Reason #1. The following are examples of plants to directly respond to EPA soliciting comment "…on whether the best performing RMDSs have documented non-BA [bottom ash] transport water inflows regularly exceeding the ability of the systems to reuse their wastewater."

- Plant O uses an RMDS with high-rate water recirculation. The system has inflows that exceed the ability of its bottom ash system to reuse the plant's wastewater. These inflows include cooling water and seal trough water [EPRI, 2019]. This plant purges approximately 32,500 gallons per day (gpd) from the bottom ash system.

- Plant W uses an RMDS with high-rate water recirculation. The system has inflows that exceed the ability of its bottom ash system to reuse the plant's wastewater. These inflows include boiler tube leaks [EPRI, 2019]. This plant purges approximately 144,000 gallons per leak event from the bottom ash system.

Types of inflows experienced by plants operating RMDS systems [EPRI, 2019] included:

- Utilizing bottom ash dewatering equipment to treat other waste streams (e.g., wastewater from equipment cleaning)
- Boiler tube leaks adding water to bottom ash hoppers
- Use of service water (rather than bottom ash recirculated water) as cooling water for ash hopper(s) due to recirculated water supply being too hot
- Water introduction to bottom ash hopper area sump(s), such as area washdowns

Reason #2. Maintenance and inspections are required on RMDS. EPA, in the ELG preamble, refers to the EPRI 2018 bottom ash report and states that, "EPRI did not provide information about a specific RMDS unable to manage these maintenance events with existing maintenance tanks." The EPRI report states that tanks can be rented when maintenance is required.

Temporary storage is an option, although it limits operational flexibility (due to lead time of renting tanks) and adds cost that prevent discharge of only an extremely small amount of bottom ash purge. EPRI's 2019 study identified that some plants observed solids buildup in storage tanks due to closed-loop operations' solids carry-over, which reduces the residence time of the storage tanks. The following are examples of plants directly responding to EPA soliciting comment "*… on whether data from such systems* [those needing infrequent maintenance events] *would suggest a purge allowance is or is not warranted, as well as on the underlying data"* - EPRI's 2019 study interviewed staff from all 21 plants that built RMDSs reported a need to purge due to minor or scheduled maintenance. The purge volumes reported ranged from 500,000 to 1.5 million gallons.

The EPA docket materials (database SE10423), the data shows that for the 82 plants, RMDS volumes range from 175,000 gallons to 1.36 million gallons, with a median volume of approximately 630,000 gallons. Draining these RMDSs produce a purge volume that could not easily be managed in temporary storage tanks. The typical rented "frac tank" is 20,000 gallons. Renting dozens of these tanks to manage water produced from draining an RMDS would require large flat areas, which may not be available.

Examples of plants that had full RMDS purges due to maintenance or inspection included:

- Plant A reported purges due to maintenance events of 560,000 gallons
- Plant C reported purges due to maintenance events of 500,000 gallons

Types of maintenance that resulted in purging water experienced by plants operating RMDS systems [EPRI, 2019] included:

- Drain dewatering system component(s) to inspect interior
- Drain RMDS to replace/repair components (such as the chain)
- Drain hopper contents during scheduled maintenance, including refractory or steel hopper replacement

Reason #3. EPA solicits comment *"… on whether the best performing RMDSs have documented precipitation inflows that have exceeded the ability of the systems to reuse or store its wastewater, or whether the technology issue can be addressed by undertaking measures at a reasonable additional cost. EPA solicits comment providing data from such systems that would suggest whether a purge allowance is or is not warranted."*

EPRI identified [EPRI, 2019] that stormwater can flow into the closed-loop RMDS by falling directly into the dewatering equipment or flowing into area sumps, and that measures should be taken to minimize these stormwater inputs. This was reported at several of the plants interviewed.

Facilities with low capacity factors may be impacted by multiple storm events during down periods that may exceed the design storm for an outdoors RMDS systems (resulting in an imbalance of more water into bottom ash system than capacity of the system). A purge stream would help alleviate this concern.

Allowing a purge still provides the majority of pollutant reduction that would be achieved by a complete ban

The requirement of the 2020 ELG to recirculate water used to transport bottom ash eliminates the significant majority of pollutants discharged. A purge carries a fraction of the pollutant load of bottom ash water. The EPA's flow estimates in the BATW database (EPA, 2023b), when normalized by size (MW), are less than 1 percent of once-through bottom ash flows.

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A COST AND POLLUTANT REMOVAL ESTIMATING METHODOLOGY SUMMARY FOR TREATMENT OF COMBUSTION RESIDUAL LANDFILL LEACHATE AND FLUE GAS DESULFURIZATION WASTEWATER

A.1 Introduction

The revision to Title 40 Code of Federal Regulations Part 423, commonly known as the Steam Electric Effluent Limitation Guidelines (ELG), has been through various stages of rulemaking since 2013; effluent limits and best available treatment technologies (BAT) economically achievable set by the U.S. Environmental Protection Agency have been changed iteratively. Through the years, the Electric Power Research Institute (EPRI) evaluated and prepared cost estimates for several technologies considered as a potential ELG BAT for treatment of flue gas desulfurization (FGD) and combustion residual landfill leachate wastewater to the steam electric industry. These technologies are:

FGD Treatment

- Chemical precipitation
- Biological
- Thermal
  - Chemical softening, vapor-compression evaporation, and crystallization
  - Chemical precipitation, vapor-compression evaporation, and brine solidification
- Membrane
  - Chemical softening, seawater reverse osmosis and brine solidification
  - Chemical precipitation, advanced membrane filtration and brine solidification

Leachate Treatment

- Chemical precipitation
- Advanced membrane filtration and brine solidification

The cost estimating approach used by EPRI follows a common cost methodology. This appendix summarizes the cost estimating methodology used for the treatment technologies listed above. Specific case studies are developed based on a selected wastewater flow and quality. Case study cost estimates are determined using the conceptual design of each treatment system and specific design parameters. Costs for the industry to employ a technology are then evaluated.

A.2 Conceptual Design Basis

Cost estimates for each treatment technology were developed using specific design parameters as the bases for the cost estimate. Important design parameters include a) flow rate of waste stream that needs to be treated, b) water quality of the untreated waste stream, and c) desired effluent quality.

A.2.1 Flow Rate Basis

Flow capacity is a key factor in the cost of many treatment components. EPRI uses peak flow to size equipment to determine the capital cost of a treatment system. Average flow is used to determine operating cost elements, such as chemical feed, waste disposal, and utilities.

A.2.2 Feed Water Quality Characteristics

Wastewater treatment equipment is primarily sized based on flow; however, feed water quality characteristics have important implications on the design of specific process units. For instance, the materials of construction need to be compatible with the waste stream for the treatment system to be operational. Important parameters, such as suspended solids loading, impacts the size and cost of dewatering equipment. Pertinent water quality criteria that dictate required process units for each treatment technology evaluated are listed in each corresponding appendix.

A.2.3 Treatment Goals

Effluent water quality goals will impact treatment system requirements. For instance, the need to include filtration polishing to remove small particulates not removed in upstream treatment is determined based on effluent limits. EPRI used the BAT limits in the 2023-proposed ELG as the target effluent in determining treatment system design, sizing, and cost estimating.

A.3 Capital Cost Assumptions

A.3.1 Classification of Estimate

The Association for the Advancement of Cost Engineering (AACE) International Recommended Practice 18R-97 [AACE International, 2011] provides guidelines that classify cost estimates and their relative accuracy. A cost estimate's accuracy is generally a function of the amount of engineering completed at the time of the estimate. Table A-1 shows the class of total installed cost estimates, the relative accuracy, and the project definition percent complete for each estimate.

Table A-1. AACE cost estimating guideline.

Estimate Class	Level of Accuracy (% of estimated cost)	Project Definition (%)
5	–50 to +100	0 to 2
4	**–30 to +50**	**1 to 15**
3	–20 to +30	10 to 40
2	–15 to +20	30 to 70
1	–10 to +20	50 to 100

Source: AACE, 2011

EPRI's cost estimates for the treatment systems considered are Class 4 estimates, generally defined as study- or feasibility-level estimates and are presented as total installed costs. To prepare a Class 4 estimate, quotes should be obtained for major equipment items; however, according to AACE 18R-97, these estimates can be produced with parametric models and even cost factoring (CH2M HILL, 2009). Class 4 cost estimates are not for any specific plant, but for a hypothetical set of conditions.

These estimates were prepared to guide the technology evaluation and are based solely on the information available at the time. Actual final costs will depend on the actual labor and material costs, competitive market conditions, site conditions, final project scope, implementation schedule, and other variable factors.

A.3.2 Cost Model Factors

Systemwide cost factors are typically applied to develop a cost estimate. Table A-2 provides a definition of these cost factors and the typical values used for the estimates.

Table A-2. Model cost factors applied to treatment system cost.

Cost Items	Definition	Suggested Range (%)		Value Used (%)	Rationale for Selected Value
Direct Cost					
Site work	Costs associated with common site work such as fencing, grading, roads, sidewalks, and similar items	3	5	4	Range mid-point
Concrete	Costs related to concrete such as foundations	15	20	17.5	Range mid-point
Piping	Costs for process piping; may include costs for pipe hangers, fittings, valves, insulation, etc.	6	8	7 or 25	Variable to reflect system requirements[1]
Miscellaneous metals, finishes	Accounts for miscellaneous metals, finishes included in the treatment system	5	15	10 or 15	Variable to reflect system requirements[2]
Mechanical, heating/ventilation/air conditioning (HVAC)	Cost associated with HVAC such as heating for buildings	5	10	7.5	Range mid-point
Electrical	Costs for common electrical equipment and components such as, switches, conduit, wire, fittings, feeders, grounding, lighting, panels, etc.	14	30	22	Range mid-point
Instrumentation and control	Costs associated with field instrumentation and control logic programming	10	20	15	Range mid-point
Tie-in/Integration	Costs associated with tie-in requirements to existing system and effluent discharge	NA	NA	Variable	Variable to reflect system requirement[3]

Cost Items	Definition	Suggested Range (%)		Value Used (%)	Rationale for Selected Value
Indirect Cost					
Subcontractor overhead	General Contractor's (GC) costs for subcontractors who perform work on the site	5	15	0 or 10	Variable (could be vendor specific)[4]
GC's general conditions	Items and resources needed for project completion that will not be part of the finished product that is turned over to the owner	11	14	12.5	Range mid-point
Bonding and insurance	These costs are affected by project size, regional costs, contractor's historical record on similar projects, project complexity, and current bonding limits	2.7	3	2.85	Range mid-point
GC profit	Profit	14.1	14.4	14.25	Range mid-point
Miscellaneous unidentified cost (Contingency)	Covers unforeseen conditions, area economic factors, and general project complexity	10	30	20	Range mid-point
Engineering (design, services during construction, startup, and operator training)	Accounts for design, services during construction, and start-up	15	25	20	Range mid-point
Owner Administrative and Overhead	Costs incurred by owner	5	9	7	Range mid-point

1. Piping cost factor for FGD wastewater (25%) is higher than leachate (7%) to account for corrosion-resistant piping material needed for FGD.
2. Cost factor for miscellaneous metals and finishes are higher for membrane treatment (15%) compared to others (10%), assuming higher-grade alloys needed for brine management.
3. Tie-in integration cost factor varies depending on specific system requirements.
4. For chemical precipitation, subcontractor overhead (10%) was added for systems installed primarily as a vendor package.

Except in a few cases, the same cost factor values were used to develop cost estimates for each treatment system evaluated by EPRI. The factors used are based on common industry standards or a suggested range developed through knowledge accumulated by the engineering industry and refined by professional cost estimators to apply specifically to water treatment. In most cases, the mid-point value for each cost factor's suggested range was used. When necessary, adjustments to some cost factors were made to account for system complexity and specific system requirements. For example, FGD treatment systems will require a higher cost factor for piping since corrosion-resistant materials are needed for such systems as opposed to landfill leachate. In addition, membrane treatment systems will require higher-grade-alloy materials for brine management, and therefore will need a higher miscellaneous metals/finishes cost factor. As some vendor-supplied packages will have cost adders already included in the system price, these cost factors were not added by EPRI.

A.3.3 Capital Cost Estimate

The capital costs presented in EPRI estimates are based on total installed costs, which include both direct and indirect costs as defined below:

- **Direct costs** – equipment costs plus cost associated with freight, and field construction (buildings, site work, concrete foundation, piping, mechanical, electrical, and field instrumentation and controls)
- **Indirect costs** – percentages of total direct costs related to GC general conditions, bonding and insurance, and other costs related to engineering, commissioning and start-up, contractor profit, client administrative, and contingency for miscellaneous unidentified costs, etc.

An example worksheet (Table A-3) shows how the direct cost is calculated based on the initial purchased equipment cost to the delivered cost followed by the addition of each cost markup associated with the cost factors listed in each row. The direct cost subtotal is then multiplied with corresponding indirect cost markups to obtain the indirect cost subtotal. The capital cost is obtained by adding the direct cost and indirect cost items.

Table A-3. Capital cost estimating approach.

Item	Cost Element	Cost
A	Purchased Cost and Installation Item	**A**
B	*Freight*	% of A
C	Purchased and Installed Equipment	**A + B**
-	Additional Direct Costs:	
D	*Site work*	% of C
E	*Concrete*	% of C
F	*Piping*	% of C
G	*Miscellaneous metals, finishes*	% of C
H	*Mechanical, heating/ventilation/air conditioning (HVAC)*	% of C
I	*Electrical*	% of C
J	*Instrumentation and controls*	% of C
K	*Tie-in/Integration*	% of C
L	Additional Direct Costs	**Sum of D through K**
M	*Subcontractor Overhead*	**% of (C + L)**
N	Subtotal Direct Cost	**C + L + M**
O	*General Contractor General Conditions*	% of N
P	*Bonding and Insurance*	% of N
Q	*General Contractor Profit*	% of N
R	Subtotal Direct and Indirect Cost	**Sum of N through Q**
S	*Miscellaneous Unidentified Cost (Contingency)*	% R
T	Subtotal Estimated Construction Cost	**R + S**
U	*Engineering* *(Design, Services During Construction,* Startup, and Operator *Training)*	% of T
V	*Owner Administrative and Overhead*	% of T
W	*Permitting*	W
X	Total Estimated Capital Cost (+50%/-30%)	**Sum of T through W**

1. Installation for chemical precipitation treatment systems is separate cost item.
2. Permitting cost assumed to be $62,000.

A.4 Operations and Maintenance Cost Assumptions

A key component of a total cost estimate is the annual operation and maintenance (O&M) cost, which is the annual expenditure to operate and maintain the treatment system and is based on the average flow rate and loading.

A.4.1 Cost Elements

Although each treatment technology will have specific O&M requirements, common cost elements used in the estimate are:

- Chemicals
- Electricity
- Residuals disposal
- Equipment maintenance
- Labor
- Compliance monitoring

The O&M cost factors and specific cost items used (when applicable) across EPRI's costs estimates are summarized in Table A-4.

Table A-4. Model unit costs and cost factors applied to O&M cost.

Cost Item	Units	Unit Cost Used (in 2021$)
Chemicals		
Hydrochloric acid (30% w/w)	$/gal	$0.74
Sulfuric acid	$/gal	$1.64
Sodium bisulfite	$/gal	$3.17
Organosulfide	$/gal	$12.85
Ferric chloride (35% w/w)	$/gal	$2.13
Antiscalant	$/gal	$18.78
Antifoam	$/gal	$18.78
Sodium hydroxide (50% w/w)	$/gal	$3.75
Sodium hydroxide (25% w/w)	$/gal	$1.41
Polymer	$/gal	$39.67
Polymer	$/lb	$2.04
Quick lime	$/lb	$0.07
Portland Cement	$/lb	$0.06
Hydrated lime	$/lb	$0.10
Sodium carbonate	$/lb	$0.18
Fly ash (purchased)	$/ton	$51.05
Membrane maintenance chemicals	$/gal	$14.95
Electricity	$/kWhr	$0.0559
Cooling water	$/ gal	$0.002

Cost Item	Units	Unit Cost Used (in 2021$)
Steam	$/lb	$0.0011
Residual disposal	$/ton	$59
Lost fly ash sales	$/ton	$11
Building		
Single-story	$/sq ft	$231
Two-story	$/sq ft	$345
Labor		
Operator Labor Cost	$/hr	$54
Supervisor Labor Cost	$/hr	$84
Chemical Engineer Labor Cost	$/hr	$100
Maintenance of Total Eqpt Cost (TEC)	**%**	**3%**
Operation time in %	%	51%-100%

gal = gallons
hr = hour
kWhr = kilowatt hour
sq ft = square foot
w/w = weight per weight (weight concentration)

The disposal cost shown in Table A-4 was developed as a weighted average using the on-site and off-site disposal costs previously provided in EPA's Incremental Costs and Pollutant Removals for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Generating Point Source Category [EPA, 2013]. EPRI assumed 75 percent of plants would use on-site disposal facilities at $40.41 per dry ton (June 2010$), and 25 percent of plants would use off-site disposal facilities at $49.82 per dry ton (June 2010$), to arrive at a weighted average of $42.76 per dry ton (June 2010$). This weighted unit cost was then escalated to a 2021 cost basis of approximately $59 per dry ton.

A.5 Other Cost Assumptions

A.5.1 Annualized Cost

EPRI assumed a 20-year life and 7 percent interest rate to calculate an annualized capital cost payment for each facility's system. Total annualized costs for each facility were estimated by adding the annualized capital cost and annual operating cost to calculate a total annualized cost.

A.5.2 Escalation

To account for changes in the cost of specific cost elements, EPRI used the Construction Cost Index (CCI) published by Engineering News-Record (ENR) to adjust previously obtained equipment, materials, and labor costs to present-day cost values. That previously obtained cost becomes the reference cost. The CCI is a 20-city national average index that ENR tracks monthly and is widely used in the construction industry. The escalated cost is calculated by multiplying the reference cost by the ratio of the escalated day CCI to the reference cost CCI.

References

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B FLUE GAS DESULFURIZATION (FGD) WASTEWATER: BACKGROUND

The revision to Title 40 Code of Federal Regulations (CFR) Part 423, commonly known as the Steam Electric Effluent Limitation Guidelines (ELGs), has been through various stages of rulemaking since 2013 where the limits and best available treatment technologies economically achievable (BAT) set by the U.S. Environmental Protection Agency (EPA) have been changed iteratively. In 2020, the EPA selected chemical precipitation + low hydraulic residence time reactor (LRTR) biological treatment (i.e., CP + Bio) as a model BAT technology for FGD wastewater [US, 2020]. In August 2021, EPA specifically stated that it would continue to evaluate membrane treatment and "evaluate whether this technology should serve as the basis for the "best available technology economically achievable" under the Clean Water Act to control discharges of pollutants found in flue gas desulfurization (FGD) wastewater discharges as part of the new rulemaking" [US, 2021]. In EPA's 2023 proposed revised ELG, the EPA selected chemical precipitation and membrane filtration as the proposed BAT for FGD wastewater treatment.

The Electric Power Research Institute (EPRI) previously evaluated and prepared cost estimates for several technologies considered as potential model BAT technologies for treatment of FGD wastewater. EPRI also evaluated technologies previously considered under the FGD wastewater voluntary incentives program (VIP). The treatment technologies evaluated by EPRI include:

- Chemical precipitation (CP)
- Biological (Bio), including the ABMet® and the SeHAWK® systems
- Chemical softening, vapor-compression evaporation, and crystallization (CS + VCE/CRX)
- Chemical precipitation, vapor-compression evaporation, and brine solidification (CP+VCE/BS)
- Chemical softening, seawater reverse osmosis (SWRO) and brine solidification (CS + SWRO/BS)
- Chemical precipitation, advanced membrane filtration (AMF) and brine solidification (CP+AMF/BS)

EPRI has evaluated and prepared cost estimates for several thermal and/or membrane technologies, as are described in Appendices C through F.

This appendix describes the basis of design used to determine the capital and operations and maintenance (O&M) cost for the FGD wastewater treatment technologies. It identifies important parameters and specific values applied in EPRI's engineering costs.

B.1 Conceptual Design Basis

Cost estimates for each treatment technology were developed using a specific engineering design basis. Important design parameters include flow rate of the wastestream that needs to be treated, water quality of the untreated wastestream, and desired effluent quality and pollutant removal.

B.1.1 FGD Wastewater Flowrate

Flow capacity is a key factor in the cost of many treatment components. In most cases, EPRI has used the same FGD wastewater flow basis in all its case studies to allow for consistent evaluation and comparison of FGD treatment costs. The flow basis typically assumed for FGD wastewater case studies is shown in Table B-1.

The peak FGD wastewater flow rate is used to size all equipment and determine the capital cost of the system. In other words, the wastewater treatment plant would be designed to treat 300 gpm of FGD wastewater on a consistent basis.

The annual average FGD wastewater flow rate is used to calculate the operations and maintenance (O&M) quantities and costs for the treatment system such as chemical usage, waste disposal, and electricity. The annual average flow rate is determined based on the assumed plant capacity factor and represents the typical flows treated by the case study plant.

In all of the FGD wastewater case studies presented in these comments, EPRI has assumed a plant capacity factor of 0.51, which is the industry median based on EIA data from 2015 through 2017.

Table B-1. FGD Wastewater Case Study Flow Basis

	Peak	Annual Average
Flowrate (gpm)	300	153

B.1.2 FGD Wastewater Quality

EPRI is using EPA's definition of untreated and treated FGD wastewater quality. EPA reported the industry average concentration of pollutants present in untreated FGD wastewater in Table 6-3 of EPA's 2015 Technical Development Document [EPA, 2015]. Later, in 2020, EPA provided characterization for FGD wastewater treatment effluent for various technology options. The assumed water quality of pre-treated FGD wastewater for membrane feed water was developed based on EPA's reported average concentration of pollutants present in treated FGD wastewater effluent as reported in Table 6-1 of EPA's 2020 Technical Development Document [EPA, 2020].

EPRI has assumed the following for membrane system feed:

- The concentration of total suspended solids (TSS), total dissolved solids (TDS), and calcium are assumed to be those reported for chemical precipitation treated effluent
- The concentration of most other parameters were assumed to be those reported for FGD surface impoundment effluent, based on the assumption that sites may be required to limit or forego use of chemicals to pre-treat for metals upstream of membrane filtration due to potential concerns of membrane surface fouling
- An average sulfate concentration was not provided by EPA, therefore an estimated sulfate concentration was used to complete the ion balance for the assumed water quality

The assumed water quality for untreated FGD wastewater and FGD membrane feed water is shown in Table B-2.

Table B-2. Assumed FGD Wastewater Quality, Untreated and Membrane Feed

Parameter	Unit	Untreated		Membrane Feed	
		Value	Basis	Value	Basis
Total suspended solids	mg/L	14,500	1	10	3
Total dissolved solids	mg/L	33,300	1	24,100	3
Calcium	mg/L	3,290	1	1,920	3
Magnesium	mg/L	3,250	1	3,370	2
Sodium	mg/L	2,520	1	276	2
Mercury	mg/L	0.289	1	0.00778	2
Barium	mg/L	2.75	1	0.030	2
Antimony	mg/L	--		0.0129	2
Beryllium	mg/L	--		0.00192	2
Iron	mg/L	566	1	1.51	2
Manganese	mg/L	--		93.4	2
Aluminum	mg/L	331	1	2.08	2
Cadmium	mg/L	0.127	1	0.113	2
Chromium	mg/L	1.27	1	0.0178	2
Cobalt	mg/L	0.245	1	0.183	2
Copper	mg/L	0.673	1	0.0218	2
Lead	mg/L	0.315	1	0.00466	2
Nickel	mg/L	1.49	1	0.878	2

Parameter	Unit	Untreated		Membrane Feed	
		Value	Basis	Value	Basis
Molybdenum	mg/L	--		0.125	2
Thallium	mg/L	--		0.0137	2
Titanium	mg/L	--		0.0271	2
Vanadium	mg/L	--		0.0164	2
Zinc	mg/L	4.11	1	1.39	2
Sulfate	mg/L	13,300	1	8,541	3
Chloride	mg/L	7,180	1	7,120	2
Arsenic	mg/L	0.507	1	0.00759	2
Selenium	mg/L	3.13	1	1.17	2
Nitrate as N	mg/L	91.4	1	96	2
Phosphorus	mg/L	4.02	1	0.319	2
Cyanide	mg/L	0.733	1	0.949	2
Boron	mg/L	242	1	243	2
Ammonia as N	mg/L	--		6.85	2

1. Total concentrations of analytes in untreated FGD wastewater as reported in Table 6-3 of EPA 2015 Technical Development Document [EPA, 2015]
2. Reported average concentration in treated effluent from FGD surface impoundments, Table 6-1, of EPA 2020 Technical Development Document [EPA, 2020]
3. Reported average concentration in treated effluent from chemical precipitation treatment system, Table 6-1, of EPA 2020 Technical Development Document [EPA, 2020]

B.3 Industry Profile

In developing industry cost estimates for the FGD treatment technology options, EPRI has assumed the following:

- EPRI has developed cost estimates for each of the 22 plants that would be required to comply with regulatory option 3, consistent with EPA's assumed list of plants [EPA, 2023]. EPRI has not developed costs for the three plants that opted into the VIP.
- The industry average FGD wastewater quality (Table B-2) was assumed for all plants. This approach was used because site-specific FGD wastewater quality was not available for all plants. In actual application, FGD wastewater quality will vary.
- The average plant capacity factor reported by EIA for years 2019 through 2021 was used for each individual plant. [EIA, 2019-2021]
- Peak and average FGD wastewater flows were estimated for each plant (Table B-3).

- The peak FGD wastewater flow methodology was as follows:
  - For 2 plants, EPRI received the reported peak flow of the existing FGD treatment system directly from plant personnel and used this flow in place of the ICR response.
  - For 9 plants, EPRI used the plant's reported peak wastewater treatment system (WWTS) design flow (2009 ICR response D5-3). No peaking factor was applied where EPRI used the plant's reported peak WWTS design flow.
  - For the remaining plants, EPRI used the rationale as described in EPRI's 2020 ELG comments. If it appeared that EPA made reasonable adjustments to plant's reported typical purge flow based on units retired since the ICR response, then to determine peak flow, EPRI multiplied EPA's purge flow by a peaking factor of 1.5.
- The annual average FGD wastewater flow methodology was as follows:
  - For 2 plants, EPRI received annual average FGD wastewater flows directly from plant personnel and used this flow.
  - EPRI evaluated power plant capacity factors for recent years 2019 through 2021 and calculated the average capacity factor for these three years.
    - For 16 plants, EPRI determined that the average capacity factor for recent years 2019 – 2021 was lower than previously evaluated in 2020 ELG rulemaking. EPRI used this recent average capacity factor to scale each individual plant's 2009 ICR average flow in order to estimate the annual average FGD wastewater flow generated.
    - For 2 plants, EPRI determined that the average capacity factor for years 2019 – 2021 was equal to the capacity factor previously evaluated in 2020 ELG rulemaking. EPRI used this recent average capacity factor to scale each individual plant's 2009 ICR average flow in order to estimate the annual average FGD wastewater flow generated
    - For the 2 remaining plants, EPRI did not have recent power plant capacity factors for years 2019 – 2022. EPRI used the original ICR response for FGD purge flow (ICR response B5-2) for the remaining 2 plants.
  - The TSS assumptions for each power plant used to develop the industry cost extrapolation are based on ICR data and are the same as assumed in previous EPRI cost estimates [EPRI 2020]. The TSS concentration was adjusted for each plant's estimated solids loading to size solids dewatering equipment and estimate solids disposal costs.
  - The average fly ash data reported by EIA for years 2018 through 2020 was used for each individual plant. This includes the total production of fly ash by the plant, the quantity of fly ash disposed, and the quantity of fly ash sold. [EIA 2018 – 2020].

Table B-3 provides the assumed industry profile used in developing FGD wastewater capital and O&M costs to the industry as part of EPRI's comments.

Table B-3. Assumed FGD Wastewater Quality, Untreated and CP treated effluent

EPA ICR ID	Plant Name	EPRI Peak FGD Flow (GPM)	EPRI Annual Average FGD Purge Flow (GPM)	Capacity Factor[1]	Typical Fly Ash Produced (tons/year)[2]	Fly Ash Disposed (tons/year)[2]	Fly Ash Sold (tons/year)[2]
493	J. K. Spruce Power Plant	90	53	0.54	143,333	0	129,067
771	OVEC – Kyger Creek Station	268	233	0.60	186,300	186,300	0
904	Muscatine Power and Water Generating Station	20	5	0.41	18,333	3,333	14,967
1236	Mitchell Plant	553	276	0.33	214,033	183,500	30,533
1381	EME Homer City Generation L.P.	159	95	0.29	442,900	4,567	0
1674	Trimble County	1,714	1,156	0.75	228,833	50,700	178,133
2244	Georgia Power Company – Plant Bowen	750	360	0.48	310,500	42,000	263,333
2601	Ghent	968	585	0.61	431,833	311,867	25,167
3265	Cardinal	1,538	951	0.59	293,900	293,900	0
3309	Lawrence Energy Center	38	33	0.67	59,467	20,100	27,733
3464	W. A. Parish E.G.S.	99	55	0.55	300,933	17,833	283,100
3604	Mill Creek	264	159	0.61	286,067	91,033	93,967
5318	Clifty Creek Station	400	317	0.49	156,800	156,800	0
6334	Leland Olds Station	193	118	0.53	117,900	90,533	27,367
6377	Tampa Electric – Big Bend Station	1,170	1038	0.35	52,367	3,233	49,133
7785	Seminole Generating Station	300	191	0.63	253,367	130,900	122,467
8353	Jeffrey Energy Center	500	408	0.41	201,767	105,333	96,433

EPA ICR ID	Plant Name	EPRI Peak FGD Flow (GPM)	EPRI Annual Average FGD Purge Flow (GPM)	Capacity Factor[1]	Typical Fly Ash Produced (tons/year)[2]	Fly Ash Disposed (tons/year)[2]	Fly Ash Sold (tons/year)[2]
8965	F.B. Culley Generating Station	164	150	0.70	60,667	8,000	0
9161	John E. Amos Plant	1,257	1,035	0.42	425,700	311,800	113,900
9225	Fort Martin Power Station	330	106	0.59	193,833	11,067	12,933
9971	Dallman	149	73	0.49	24,267	0	23,867
56068	Elm Road Generating Station	313	202	0.69	171,433	133	171,300

1. Form EIA-923, Power Plant Operations Report – Schedules 1-3-4-5-M-12, Net Generation. 2019, 2020, 2021.
2. Form EIA-923, Schedule 8, Power Plant Operations Report. 2018, 2019, 2020.

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C FGD WASTEWATER TREATMENT COST METHODOLOGY—VAPOR-COMPRESSION EVAPORATION/CRYSTALLIZATION

C.1 Cost estimating summary for chemical softening with vapor compression evaporation/crystallization treatment of flue gas desulfurization wastewater

C.1.1 Summary

The Electric Power Research Institute (EPRI) estimated the cost of chemical softening with vapor-compression evaporation/crystallization (CS + VCE/CRX) treatment of flue gas desulfurization (FGD) wastewater to the steam electric industry based on EPA's industry profile [EPA, 2023]. This technical memorandum describes the method for calculation of cost of treatment for an individual plant, the assumptions associated with the cost calculations, and the estimated costs for treatment to the steam electric industry. Table C-1 outlines the cost to the current industry to install CS + VCE/CRX treatment of FGD wastewater.

Table C-1. Treatment costs to current industry for FGD wastewater, in 2021 dollars [1]

Treatment Option	Capital Cost ($M)	Operations and Maintenance Cost ($M per year)	Total Annualized Cost [2] ($M per year)
CS + VCE/CRX	$3,998	$290	$666

$ = U.S. dollars
M = million

1. The cost for the industry was estimated assuming that industry plants would install a 2 x 60% redundancy CS+VCE/CRX system, as described in this appendix.
2. Total annualized cost is annualized capital cost (based on a 20-year equipment life and 7% interest rate) plus annual operations and maintenance cost.

C.1.2 Introduction

EPRI has prepared updated cost estimates of FGD wastewater treatment technologies for commenting on the revised draft ELG rule as discussed in Appendix A and B. This appendix evaluates costs for chemical softening followed by vapor-compression evaporation/ crystallization (CS + VCE/CRX). An overview of the treatment technology is included below including specific cost methodology and basis of costs unique for this cost evaluation.

C.1.3 CS + VCE/CRX treatment overview

This evaluation focuses on a system that uses chemical softening, evaporation, and crystallization.

The softening pretreatment needed for crystallization requires large quantities of chemicals and produces a large amount of residual solids. It consists of cold lime (or caustic) and soda ash softening to remove calcium, magnesium, and silica from the FGD wastewater, followed by pH neutralization using sulfuric acid. Neutralization is required to degas the wastewater in a deaerator before reaching the VCE processes. For the EPRI evaluation, the pretreatment equipment selected included mix tanks, clarifiers, neutralization tanks, process pumps, and filter presses to remove the solids. Some recirculation of the softened water was used as make-up water for the lime and soda ash feed slurries.

For EPRI's design, the primary evaporative stage includes a vapor-compression, falling film evaporator (brine concentrator) to compress the vapor (distillate) mechanically and heat the brine. This type of evaporator is more energy efficient because the latent heat of evaporation energy is reused, thereby reducing energy requirements as compared to a steam-driven brine concentrator, which was not considered. The vapor-compression evaporator, however, cannot alone reach the crystallization temperature required. A vapor-compression crystallizer was assumed to be used downstream of the evaporator to further concentrate the evaporator brine and to meet the higher boiling requirements required as salinity increases. This combination of vapor-compression evaporator followed by crystallizer provides a favorable cost and energy-efficient design solution.

This CS + VCE/CRX alternative does not produce liquid waste streams requiring discharge or landfilling, and results in a crystallizer salt cake. Since calcium chloride and magnesium chloride salts cannot crystallize at a temperature that is readily achieved, crystallization requires softening pretreatment to remove calcium and magnesium. This crystallization process produces a sodium chloride and sodium sulfate salt cake. Final residuals of the CS + VCE/CRX process consist of dewatered softener sludge and salt cake solids requiring disposal in a lined landfill.

A block flow diagram representing the configuration of the CS + VCE/CRX system assumed for cost estimating is shown in Figure C-1. The key aspects of this system are:

- **Treatment objective** – Elimination of wastewater discharge by means of thermal treatment and evaporation of water. Resulting solids from softening sludge and salt cake are disposed to a landfill. Softening pretreatment is required to reduce crystallizer operating temperature and corrosivity.
- **Key equipment** – Equalization tank, softening reaction tanks, softening clarifiers, neutralization tank, evaporator feed tank, chemical feed systems, vapor-compression evaporator system, vapor-compression crystallizer, temporary brine storage tank, distillate/reuse tank, and filter presses.
- **Wastes** – The final residuals are softener solids and salt cake solids, both requiring disposal in a lined landfill.

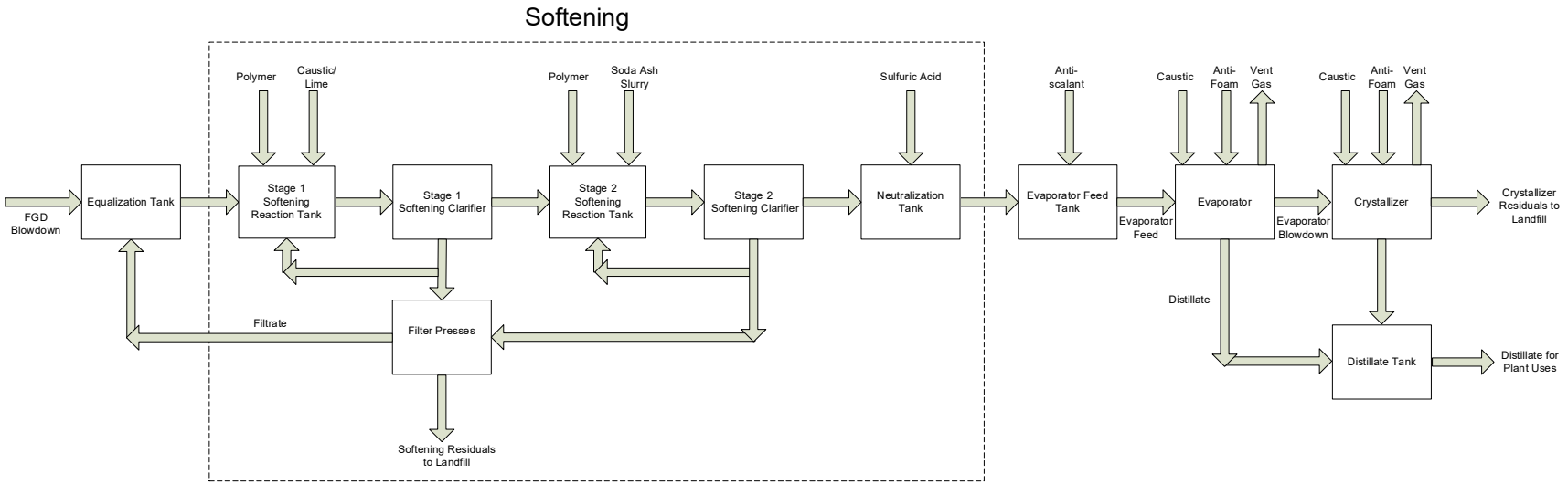


Figure C-1. Chemical softening with evaporation/crystallization system

C.1.4 Conceptual design basis

EPRI's general cost methodology is discussed in Appendix A and the assumed FGD wastewater basis of design is discussed in Appendix B. The design basis specifically applied for CS + VCE/CRX cost estimate is detailed in this section.

C.1.4.1 Flow rate basis

As described in Appendices A and B, flow capacity is a key factor in the cost of many treatment components. Peak flow rate is the main consideration in sizing equipment. Average flow rate has a large impact on operating cost elements such as chemical feed, waste disposal, and electricity.

Conceptual costs were estimated for two system sizes, a small model plant flow rate and a large model plant flow rate. These two sizes are:

- "Small flow rate" system = FGD blowdown flow rate of 300 gallons per minute (gpm)
- "Large flow rate" system = FGD blowdown flow rate of 600 gpm

Conceptual design cost estimates were prepared for these two flow capacities and for two different levels of equipment redundancy:

- "2 x 100%" = two identical trains at 100 percent capacity for all equipment, including the evaporator and crystallizer systems
- "2 x 60%" = two identical trains at 60 percent capacity for all equipment, except for the crystallizer which is sized for 100 percent capacity to service both trains.

Capital costs for the CS + VCE/CRX technology option were calculated for four theoretical case study plants based on FGD blowdown rate and assumed redundancy. A flow rate basis was chosen because the size of the power plant (in megawatts [MW]) does not capture cost of treatment. Factors such as coal chloride concentration and water recycling play a large role in determining FGD water flow rate.

Table C-2. Flow rate and redundancy options considered

Parameter	Small System		Large System	
Flow rate (gpm)	300	300	600	600
Flow rate (MGD)	0.43	0.43	0.86	0.86
Equipment Redundancy:				
CS System	2 x 100%	2 x 60%	2 x 100%	2 x 60%
VCE System	2 x 100%	2 x 60%	2 x 100%	2 x 60%
CRX System	2 x 100%	1 x 100%	2 x 100%	1 x 100%

The estimated capital and O&M costs for these case studies were used to develop industry-wide cost estimates as described in Section C.1.9.

C.1.4.2 Feed water quality characteristics

Feed water chemistry used for this evaluation is summarized in Table C-3. As described in Appendix B, EPA's definition of untreated FGD wastewater appears to most closely align with FGD blowdown from a plant that burns eastern bituminous coal. The FGD water quality used in this evaluation is referred to as the original feed water chemistry in Table C-3.

EPRI used OLI Studio: Stream Analyzer (a commercially available computer software program used to model aqueous systems) to evaluate the original water chemistry assumed by EPA. The total parameter concentrations for this water were input to the model. The reconciled feed water chemistry detailed below reflects the OLI Studio: Stream Analyzer adjusted water quality, which varies from the original feed water quality primarily in dissolved calcium and sulfate concentrations. Adjustment to the assumed water quality was necessary to reconcile the stream for electroneutrality (i.e., charge balance). The model makes minor adjustments to other ion concentrations if needed. EPRI assumed a default temperature value of 95 degrees Fahrenheit (°F) for the feed water. Based on the water chemistry input, the model calculated the pH of the feed water to be 6.4.

This evaluation assumes no pretreatment of FGD blowdown upstream of the CS + VCE/CRX system. A total suspended solids (TSS) loading value of 13,315 milligrams per liter (mg/L) was determined by the model for the reconciled feed water under equilibrium conditions. The assumed concentration of 13,315 mg/L TSS in this evaluation is slightly less than EPA's reported typical TSS concentration of 14,500 mg/L in FGD scrubber purge [EPA, 2015].

EPRI also used OLI Studio: Stream Analyzer to model complete lime and soda ash softening of the FGD feed water. The results of the simulated softening assumed a clarifier effluent of 30 mg/L TSS and neutralization to pH 5.5 suitable for deaerator feed.

Table C-3. Water chemistry

Parameter	Original Feed Water Chemistry [1]		Reconciled Feed Water Chemistry [2]	
Temperature (°F)	NR		95	
pH	NR		6.4	
Density (g/mL)	NR		1.02	
Total suspended solids	14,500		13,315	
Total dissolved solids	33,300		25,310	
Parameter Concentrations	**Total (mg/L)**	**Dissolved (mg/L)**	**Total (mg/L) [3]**	**Dissolved (mg/L)**
Calcium	3,290	2,050	3,290	667
Magnesium	3,250	3,370	3,250	3,250
Sodium	2,520	276	2,520	2,520
Barium	2.75	0.284	2.75	0.009
Iron	566	0.100	566	0.00005
Manganese	85.7	106	85.7	85.7
Aluminum	331	1.47	331	0.0003
Sulfate	13,300	NA	16,116	9,818
Chloride	7,180	NA	7,180	7,180
Nitrate as N	91.4	NA	91.4	94.1
Boron	242	266	242	242
Phosphorus	4.02	NA	4.02	4.02
Arsenic	0.507	0.0071	0.507	0.507
Cadmium	0.127	0.128	0.127	0.127
Chromium	1.27	0.00417	1.27	0.0041
Cobalt	0.245	0.206	0.250	0.250
Copper	0.673	0.0201	0.673	0.673
Cyanide	0.733	NA	0.733	0.733
Lead	0.315	0.001	0.315	0.315
Nickel	1.49	0.973	1.49	0.000015
Mercury	0.289	0.0072	0.289	0.289
Selenium	3.13	1.13	3.13	3.13
Silver	0.0082	0.001	0.0082	0.0082
Zinc	4.11	1.58	4.11	0.06
Bicarbonate	NR	NR	0	0

Parameter	Original Feed Water Chemistry [1]		Reconciled Feed Water Chemistry [2]	
Fluoride	NR	NR	0	0
Silica	NR	NR	0	0

°F = degrees Fahrenheit, g/mL = grams per milliliter, gpm = gallons per minute, mg/L = milligrams per liter, MGD = million gallons per day

1. Original feed chemistry for total and dissolved concentrations of analytes in untreated FGD wastewater as reported in EPA, 2015, Table 6-3.
   NR = Not reported.
   NA = EPA reported as "Not Applicable. Samples were not analyzed for this particular analyte." Antimony, beryllium, molybdenum and thallium were reported at low concentrations and were not included in the model input.
2. When reconciling the water chemistry data using OLI Stream Analyzer, small adjustments to the concentrations might occur for things such as ion balancing and speciation of certain components. The software model also predicts the partitioning of ions in the dissolved and solid phases under equilibrium conditions.
3. Total concentration is shown as the sum of aqueous and solid phase concentration values reported by the model.

C.1.5 Cost development methods

C.1.5.1 Equipment cost assumptions

Equipment costs were provided by two equipment vendors with experience providing systems for similar applications, Vendor A and Vendor B.

C.1.5.1.1 Vendor A

Using the feed chemistry provided in Table C-3, Vendor A provided quotations for the total installed capital cost for a system consisting of partial softening, seeded slurry brine concentration, and mixed salt crystallization for the flow options considered.

Upstream and downstream equipment from the evaporator and crystallizer system, including evaporator feed handling equipment, chemical feed equipment, softening process equipment, and solids dewatering equipment were part of the quotation. Vendor A estimated a packaged system cost that included all process and mechanical equipment, site work (with allowance for brownfield construction), concrete foundations, interconnect piping, electrical wiring to and including the motor control center (MCC), new electrical feeder to the MCC, instrumentation, controls, metals, finishes, and a process building to support all equipment. The total installed cost estimate also included equipment freight, general contractor general and administrative costs and profit, onsite consumables, construction equipment, engineering, services during construction, startup, commissioning and start-up spare parts, and a 10 percent contingency for all cost categories [2018/2019, personal communications].

EPRI separately estimated the costs for additional equipment outside the vendor's package which consisted of equalization tank storage upstream of the vendor system and distillate storage/reuse tank downstream of the vendor system. EPRI has also assumed that the mixed

salt cake generated from the partial softening process will contain hygroscopic $CaCl_2$ and $MgCl_2$ salts, which would need to be stabilized. Correspondence with the vendor indicated that the mixed salt cake, which would be placed in supersacks, would leach. Therefore, when developing total costs for this vendor, EPRI has included the equipment costs to amend the crystallizer salt with stabilization material (fly ash and quicklime) prior to deposition in the landfill.

Because the quoted evaporator/crystallizer system was provided as a total installed cost, EPRI considered the known cost factors assumed by the vendor in quoting the total installed cost and professional best judgment in order to estimate the total equipment cost of the vendor's quoted system. Most system-wide cost factors used in the EPRI estimates (see Appendix A) were not applied to Vendor A's costs; however, the estimated total equipment cost was used to develop these additional cost factors if required. For example, general contractor bonding and insurance, permitting and owner's administrative costs were not included in the quotation, so these cost factors were applied. A cost factor of 20 percent was applied for engineering the entire treatment system to account for the higher costs of engineering for electrical infrastructure and coordination with the vendor's design package.

Further, the cost factor for miscellaneous unidentified costs (i.e., contingency) was increased from the vendor's assumption of 10 percent to 20 percent to remain consistent with other treatment technologies evaluated (chemical precipitation and biological). A detailed explanation of the cost factors used for developing capital cost estimates is provided in subsection C.1.6.2 below.

C.1.5.1.2 Vendor B

Using the softened water chemistry for the reconciled FGD water, Vendor B provided package costs for a system consisting of seeded slurry brine concentration and crystallization for the flow options considered.

Vendor B estimated costs for a "turnkey" system that included all costs within battery limits of the vendor's equipment package. This included all process and mechanical equipment, concrete foundations, interconnect piping, instrumentation, controls, and electrical wiring to and including the motor control center (MCC). The turnkey estimate also included all labor required to install, test, and commission the evaporator/crystallizer system [2019, personal communication].

Upstream and downstream equipment from the evaporator and crystallizer system, including equalization equipment, chemical feed equipment, softening process equipment, solids dewatering equipment, and distillate storage system were not part of the turnkey design. Therefore, EPRI estimated the costs for this additional equipment. EPRI has not included equipment costs for amending the crystallizer salt with stabilization material (fly ash and quicklime) in development of Vendor B costs, since the basis for this vendor's costs assumed complete softening (i.e., removal of calcium and magnesium) upstream of the evaporator/crystallizer system.

Because the quoted evaporator/crystallizer system is turnkey, most system-wide cost factors used in the EPRI estimates (see Appendix A) were not applied to the evaporator/crystallizer package installed equipment costs, with a few exceptions. Site work was not included in the turnkey quotation, so a cost factor was applied to the vendor package. Since only electrical wiring within the battery limits and to the MCC was provided with the vendor quotation, an industry average electrical cost factor of 22 percent was applied for the entire wastewater treatment system to account for new electrical supply infrastructure costs upstream of the MCC. Similarly, a cost factor of 20 percent was applied for engineering the entire treatment system to account for the higher costs of engineering for electrical infrastructure and coordination with the vendor's design package.

System-wide cost factors (Appendix A) were applied to all equipment outside of the battery limits of the vendor's provided evaporator/crystallizer system.

General contractor bonding and insurance, permitting and owner's administrative costs were not included in the vendor's quotation, so these cost factors were also applied to the vendor package.

A cost factor of 20 percent was applied for miscellaneous unidentified costs consistent with other treatment technologies evaluated (chemical precipitation and biological). A detailed explanation of the cost factors used for developing capital cost estimates is provided in Appendix A.

C.1.6 Capital cost assumptions

C.1.6.1 Classification of estimate

This memorandum presents Class 4 cost estimates, generally defined as study- or feasibility-level estimates, for total installed costs (+50 percent to -30 percent accuracy). A definition of cost estimate classifications is presented in Appendix A.

Vendor-developed costs were used for the major unit process systems (for example, evaporator and crystallizer systems), considering the assumptions indicated by the vendor quote. Support equipment items (not included with major systems) were estimated based on costs supplied from other equipment vendors, internal databases, and chemical suppliers. Vendor-developed costs and support equipment costs were summed to calculate a purchased equipment cost (PEC).

C.1.6.2 Cost model factors

System-wide cost factors were applied to develop the cost estimate as described in Appendix A. The mid-point of the suggested range for each cost factor was used to estimate costs for this evaluation; however, a 25 percent factor was applied for piping assuming high-grade alloy would be installed (typical range of 6 to 8 percent is for conveyance piping), and a 15 percent factor was applied for miscellaneous metals and finishes assuming fiberglass materials would

be installed due to the corrosive environment. No subcontractor overhead was applied in this estimate.

C.1.6.3 Major assumptions

Major cost assumptions used to develop estimates are presented in Appendix A.

In addition, the following major assumptions for this capital cost evaluation include:

- Costs are presented in 2021 dollars. The average of the 2021 Construction Cost Index values published by Engineering News Record (ENR) , were used to escalate costs to 2021 pricing.
- Wastewater tie-in piping of 1,000 linear feet will be installed above grade.
- The power plant has no existing pretreatment system for the FGD wastewater.
- The basis for Vendor A's costs are partial caustic and soda ash softening, whereas the basis for Vendor B's cost are full lime and soda ash softening.
- The conceptual design includes evaporator brine storage tanks and mixers, which would be used to provide intermittent brine storage ahead of the crystallizer system.
  - Equipment for the 2 x 100 percent redundancy conceptual designs includes two 24-hour evaporator brine storage tanks and mixers.
  - The 2 x 60 percent redundancy conceptual designs, which include only a single 100 percent capacity crystallizer, include equipment sized for two weeks of storage capacity. This allows for intermittent evaporator brine storage when the crystallizer is not operating. This conceptual design also includes an allowance for crystallizer critical spare parts.

C.1.7 Operations and maintenance costs assumptions

C.1.7.1 Cost elements

Operations and maintenance (O&M) requirements for this estimate include the following cost elements:

- Chemicals
- Utilities (electricity, steam, cooling water)
- Residuals disposal (softening solids, crystallizer solids)
- Evaporator and crystallizer cleaning
- Labor
- Equipment maintenance
- Compliance monitoring and mercury analyzer

- Miscellaneous unidentified costs (i.e., contingency)

C.1.7.2 Major assumptions

Major cost assumptions used to develop estimates are presented in Appendix A.

In addition, the following major assumptions for this O&M cost evaluation include:

- O&M costs are based on the Vendor B conceptual design approach, which assumed full chemical softening using lime and soda ash, followed by sodium chloride salt crystallization. Chemical costs are not included for fly ash, quicklime or Portland cement to amend the crystallizer salt slurry.
- EPRI assumed that the FGD system will operate and generate wastewater 51 percent of the time. The assumed 51 percent is based on the median gross capacity factor reported for 2015, 2016 and 2017 at the plants listed in EPA's 2013 cost estimates. Therefore, EPRI used a plant capacity factor equal to 0.51 which was applied to the O&M quantities.
- Labor: a total of 10 full-time equivalent (FTE) operators at $54/hour, one supervisor at $84/hour, and one chemical engineer at $100/hour were assumed to staff the facility. It is assumed that the facility will be staffed five days per week.
- Chemical dosage rates based on modeling results or typical values. (Actual dosage rates could vary depending on FGD wastewater chemistry.) Chemical supply costs presented in Appendix A were used. Actual costs will vary by geography, delivery method, and chemical supplier.
- Chemical dosages were based on full softening pre-treatment using hydrated lime and soda ash. Either caustic or lime could be used along with soda ash for softening. The advantage of using caustic softening is the generation of less softening solids, however the unit cost of caustic is considerably higher than that of lime. Therefore, the chemical costs associated with caustic-soda ash softening are estimated to be higher than lime-soda ash softening. EPRI considered both options for chemical softening and the analysis showed that lime-soda ash softening would be the more cost-effective softening method for this assumed FGD water quality considering both chemical supply and disposal costs.
- Electricity cost of $0.0559 per kilowatt hour
- Cooling water demand was calculated assuming the water vapor mass flow rate from the evaporator deaerator is 1.5 percent of evaporator feed flow rate. Cooling water demand for the crystallizer was calculated assuming a cooling water temperature rise of 40 °F. The assumed cost for cooling water is $2 per 1,000 gallons.
- The mechanical vapor compression crystallizer would only require steam during startup. Steam demand was provided by one of the vendors assuming an estimated cold startup of one day per month. The cost of steam is assumed to be $10.50 per 1,000 pounds. One pound of steam was assumed to be equal to 970 British thermal units.

- EPRI has assumed that the evaporator/crystallizer system would only typically be run when the power units are operating and generating steam and FGD wastewater. Therefore, steam for startup should be available at the plant. EPRI has not included a cost for a backup secondary steam supply.
- Residuals disposal unit cost of $59/ton on a dry-weight basis, which is based on EPA's disposal costs [EPA, 2013]and escalated to 2021 dollars. EPRI developed the unit cost assuming that 25 percent of plants would use offsite landfills and 75 percent use onsite landfills.
- All wastes were assumed to be RCRA nonhazardous solids. All landfills assumed to be lined and monitored.
- Falling-film evaporator tube cleanings and crystallizer cleanings will occur twice per year per equipment system.
- Annual equipment maintenance cost equal to 3 percent of total equipment cost.
- Compliance monitoring costs equal to the sum of chemical precipitation monitoring ($81,000) plus evaporation monitoring ($82,000).

C.1.8 Cost estimates summary

Example cost estimates for the CS + VCE/CRX case studies are provided in the following subsections

C.1.8.1 Capital costs

Total estimated capital costs were developed for the four case study plants, based on the two design flowrates and the two equipment redundancy cases, and are provided in Table C-4. The total estimated capital cost for were developed by using Vendor B costs since these costs were consistent with the fully softened pre-treatment design basis. The equipment costs are based on cost quotes provided by the equipment vendors. The cost model factors shown in Table C-4 were added to the installed equipment costs to obtain the total estimated capital costs for the system.

Table C-4. Summary of estimated treatment capital costs, in 2021 dollars

Cost Element ($ thousand)	300 gpm Flow		600 gpm Flow	
	2 x 60%	2 x 100%	2 x 60%	2 x 100%
Evaporator/Crystallizer vendor package [1]	$30,700	$47,700	$42,800	$62,800
Support equipment				
Equalization system	$1,591	$2,582	$3,033	$5,016
Evaporator feed handling equipment	$168	$192	$201	$257
Chemical feed equipment (other than softening)	$277	$309	$304	$336
Softening equipment	$3,901	$4,451	$5,529	$7,815
Softening solids dewatering	$6,556	$7,073	$11,024	$12,004
Brine handling and storage equipment	$3,555	$0	$6,812	$0
Fly ash/lime/cement handling and mixing equipment for stabilization	$0	$0	$0	$0
Cold distillate handling and storage equipment	$397	$541	$614	$905
Freight (4%) and taxes (0%)	$1,886	$2,513	$2,813	$3,565
Subtotal – Purchased Support Equipment Cost as Delivered	**$17,103**	**$15,148**	**$28,618**	**$27,386**
Subtotal – Purchased Equipment Cost as Delivered	**$49,031**	**$62,362**	**$73,130**	**$92,698**
Additional cost items [3]				
Pre-engineered building [4]	$10,348	$10,348	$13,798	$13,798
Critical Spare Parts	$0	$0	$0	$0
Tie-in allowance [5]	$217	$97	$217	$97
Site work [6]	$97	$2,614	$97	$3,708
Piping [2]	$1,961	$3,939	$2,925	$6,847
Mechanical/HVAC [2]	$4,276	$1,182	$7,155	$2,054
I&C [2]	$1,283	$2,363	$2,146	$4,108
Electrical	$2,565	$14,380	$16,089	$20,403
Concrete [2]	$2,993	$2,757	$5,008	$4,792
Miscellaneous metals, finishes [2]	$2,565	$2,363	$4,293	$4,108
Subtotal – Direct Costs	**$86,123**	**$105,405**	**$129,151**	**$152,605**
General contractor general conditions [2,3]	$6,774	$6,975	$10,580	$10,912
Bonding and insurance [3]	$2,455	$3,004	$3,681	$4,349
General contractor profit [2,3]	$7,723	$7,951	$12,061	$12,439

Cost Element ($ thousand)	300 gpm Flow		600 gpm Flow	
	2 x 60%	2 x 100%	2 x 60%	2 x 100%
Subtotal – Direct and Indirect Costs	**$103,075**	**$123,355**	**$155,473**	**$180,305**
Miscellaneous unidentified cost [3]	$20,615	$24,667	$31,095	$36,061
Subtotal – Estimated Construction Cost	**$123,690**	**$148,002**	**$186,568**	**$216,366**
Engineering (design, SDC, startup, and operator training) [3]	$24,738	$29,600	$37,314	$43,273
Client administrative and overhead [3]	$8,658	$10,360	$13,060	$15,146
Permitting	$62	$62	$62	$62
Total Estimated Capital Cost ($M)	**$157**	**$188**	**$237**	**$275**
Total Estimated Capital Cost ($M) +50%	**$236**	**$282**	**$356**	**$412**
Total Estimated Capital Cost ($M) –30%	**$110**	**$132**	**$166**	**$192**

$ = U.S. dollars, M = million, HVAC = heating, ventilation, and air conditioning, I&C = instrumentation and controls, SDC = services during construction

1. Vendor B provided a cost quotation for a turnkey process island (total installed cost) in June 2018, consisting of the evaporator and crystallizer systems only. Cost escalated to 2021.
2. Included in vendor package, therefore was applied to support equipment only
3. See Appendix A for factors used to estimate these additional cost items.
4. Pre-engineered building was estimated at 30,000 square feet and 40,000 square feet for the 300 gpm and 600 gpm case studies, respectively. Building was assumed to include two floors and accommodate an office, motor control center (MCC), chemicals storage, dewatering equipment and evaporator/crystallizer system.
5. Assumes wastewater tie-in piping of 1,000 linear feet installed above grade.
6. Includes fencing, grading, roads, sidewalks, and similar items.

C.1.8.2 Operations and maintenance costs and quantities

The total estimated O&M costs for the system are provided in Table C-5. O&M unit quantities, and therefore costs, are based on average feed flow, water chemistry and solids loading. Therefore, the O&M costs estimated by EPRI are similar for the 2 x 60% and 2 x 100% design options. O&M costs are based on the conceptual design approach using full chemical softening with hydrated lime and soda ash. Since this concept would lead to formation of a sodium-based salt, EPRI has not included the costs for amendments (e.g., quicklime) to be mixed with the crystallizer salt. Unit costs used to develop the annual O&M cost estimates were previously presented in Appendix A.

Table C-5. Summary of treatment annual O&M costs, in 2021 dollars

Cost Element ($ thousand per year)	300 gpm		600 gpm	
	2 x 60%	2 x 100%	2 x 60%	2 x 100%
Chemicals [1]				
Antiscalant	$12	$12	$23	$46
Antifoam	$12	$12	$25	$49
Sulfuric acid (93%)	$77	$77	$154	$302
Caustic (50%)	$26	$26	$52	$102
Polymer	$256	$256	$512	$1,003
Hydrated lime	$702	$702	$1,403	$2,751
Soda ash	$923	$923	$1,847	$3,621
Subtotal – Chemicals	**$2,008**	**$2,008**	**$4,016**	**$7,874**
Electricity	$540	$565	$2,066	$2,189
Steam	$1	$1	$1	$1
Cooling water	$367	$367	$1,441	$1,441
Residuals disposal, non-hazardous onsite landfill	$1,068	$1,068	$4,188	$4,188
Maintenance	$864	$864	$1,303	$1,511
Labor	$1,501	$1,501	$1,502	$1,502
Evaporator/Crystallizer Cleanings	$631	$631	$1,262	$2,131
Compliance Monitoring	$166	$166	$166	$166
Total Estimated O&M Cost ($M per year)	**$7.1**	**$7.8**	**$12.2**	**$13.3**

$ = U.S. dollars, M = million, O&M = operations and maintenance, RCRA = Resource Conservation and Recovery Act

1. Chemical costs are industry average and include an assumed national average freight. Chemicals costs will vary depending on plant location and local chemical distributors.

Annual estimates for O&M quantities are presented in Table C-7. Annual estimates for O&M quantities assumed a 51 percent online factor.

Table C-6. Summary of estimated annual O&M quantities

	300 gpm		600 gpm	
Cost Element	**2 x 60%**	**2 x 100%**	**2 x 60%**	**2 x 100%**
Major Chemicals				
Sulfuric acid (93%) (gallons)	47,000	47,000	94,000	94,000
Caustic (50%) (gallons)	6,900	6,900	14,000	14,000
Hydrated lime (tons)	3,600	3,600	7,200	7,200
Soda ash (tons)	2,600	2,600	5,300	5,300
Electricity (megawatt hours)	9,700	10,103	19,000	20,000
Steam (million British thermal units)	14	14	14	14
Cooling water (million gallons)	200	200	400	400
Residual – softening and blowdown solids (dry tons solids)	15,000	15,000	30,000	30,000
Residual – crystallizer solids (dry tons solids)	3,300	3,300	6,700	6,700
Full time employee – operator	10	10	10	10
Full time employee – supervisor	1	1	1	1
Full time employee – chemical engineer	1	1	1	1
Full time employee – total	12	12	12	12

C.1.8.3 Annualized costs

Capital cost estimates (Table C-5) and O&M cost estimates (Table C-6) were used to calculate total annualized costs for the system. Capital costs were annualized assuming an equipment lifetime of 20 years and 7 percent interest rate. Annualized costs are presented in Table C-7.

Table C-7. Treatment annualized costs, in 2021 dollars

Cost Element	300 gpm	300 gpm	600 gpm	600 gpm
	2 x 60%	**2 x 100%**	**2 x 60%**	**2 x 100%**
Capital costs ($M)	157	188	237	275
Annualized Capital costs ($M per year) [1]	15	18	22	26
Annual O&M costs ($M per year)	7	8	12	13
Total annualized costs ($M per year) [2]	22	26	34	39

$ = U.S. dollars, M = million, O&M = operations and maintenance

1. Capital costs are annualized by assuming a lifetime of 20 years and 7 percent interest rate. Annualized costs shown are for Year 1.
2. Total annualized cost is sum of annualized capital cost and annual O&M cost.

C.1.9 Industry cost extrapolation

Industry costs were estimated for the list of 22 plants that EPA estimates will discharge FGD wastewater after 2028 and therefore would be required to comply with regulatory option 3, which requires zero liquid discharge (ZLD) of FGD wastewater. Assumptions used to develop the list of plants and flow rate basis for industry extrapolation are presented in Appendix B.

Table C-8. Treatment costs to 22 industry plants for FGD wastewater, in 2021 dollars [1]

Treatment Option	Capital Cost ($M)	Operations and Maintenance Cost ($M per year)	Total Annualized Cost [2] ($M per year)
CS + VCE/CRX	$3,998	$290	$666

$ = U.S. dollars
M = million

1. The cost for the industry was estimated assuming that industry plants would install a 2 x 60% redundancy CS+VCE/CRX system, as described in this appendix.
2. Total annualized cost is annualized capital cost (based on a 20-year equipment life and 7% interest rate) plus annual operations and maintenance cost.

References

EPA, 2013. U.S. Environmental Protection Agency. *Incremental Costs and Pollutant Removals for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Generating Point Source Category*. EPA-HQ-OW-2009-0819-2256, DCN SE01825.

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D FGD WASTEWATER TREATMENT COST METHODOLOGY—BRINE SOLIDIFICATION

D.1 Cost estimating summary for brine solidification options for flue gas desulfurization wastewater

D.1.1 Summary

The Electric Power Research Institute (EPRI) estimated the cost of chemical softening with vapor-compression evaporation and crystallization (CS + VCE/CRX) treatment of flue gas desulfurization (FGD) wastewater to the steam electric industry, as previously presented in Appendix C.

EPRI has also developed case study cost estimates for other thermal and membrane technology options that, similar to CS + VCE/CRX, have the ability to eliminate direct discharge of FGD wastewater. Given that EPA assumes that most FGD sites will already have CP, three options that employ FGD wastewater concentration and solidification (i.e., brine encapsulation) were incorporated to CP. These technologies were:

- Chemical precipitation (CP) followed by vapor-compression evaporation and brine solidification (CP + VCE/BS) (Section D.1.2)
- Chemical softening (CS) followed by seawater reverse osmosis and brine solidification (CS + SWRO/BS) (Section D.1.3)
- Chemical precipitation (CP) followed by advanced membrane filtration and brine solidification (CP + AMF/BS) (Appendix E)

This technical memorandum describes the method for calculating the cost of treatment for an individual case study plant for CP + VCE/BS and CS + SWRO/BS. Cost estimate development for CP + AMF/BS is discussed in Appendix E. Table D-1 outlines the cost of treatment for a conceptual treatment system for an FGD wastewater flow rate of 300 gallons per minute (gpm) for these options.

Table D-1. Brine solidification technology options, case study treatment costs for a 300 gpm system for one power plant, in 2021 dollars

Treatment Option	Capital Cost ($M)	Operations and Maintenance Cost [1] ($M per year)	Total Annualized Cost [2] ($M per year)
CP + VCE/BS [3]	109	10	22
CS + RO/BS [4]	115	31	42
CP + AMF/BS [5]	170	47	63

M = million
$ = U.S. dollars

1. Plant assumed to have a capacity factor of 0.51.
2. Total annualized cost is annualized capital cost (based on a 20-year equipment life and 7% interest rate) plus annual operations and maintenance cost.
3. System designed with 2x60% redundancy CP system, 2x60% redundancy VCE system and N+1 redundancy pugmills.
4. System designed with 2x60% redundancy CS system, N+1 redundancy membrane system and N+1 redundancy pugmills.
5. System designed with 2x60% redundancy CP system, 120% redundancy VSEP + spiral wound RO polishing system and N+1 redundancy pugmills, higher fly ash cost case. See Appendix E.

D.1.2 Treatment overview of chemical precipitation with vapor-compression evaporation and brine solidification (CP + VCE/BS)

This evaluation considers a treatment option that includes FGD wastewater chemical precipitation followed by thermal evaporation and brine solidification.

There are two key differences for this case study, compared to the conceptual design assumed in Appendix C, which include:

- The pre-treatment for this case study assumes chemical precipitation (CP) for solids removal. Full chemical softening (CS), using hydrated lime and soda ash, are not assumed for this case study.
- This case study assumes solidification (i.e., encapsulation) of the evaporator brine as opposed to further concentrating the evaporator brine by using a crystallizer (the latter was assumed in Appendix C for CS + VCE/CRX).

As noted in Appendix C, EPRI has used EPA's definition of untreated FGD wastewater, which most closely aligns with FGD blowdown from a plant that burns eastern bituminous coal. The pretreatment for the assumed FGD wastewater in this case study consists of hydrated lime addition to pH 9 to encourage calcium sulfate precipitation and to reduce the solids concentration fed to the evaporator. The objective of this pre-treatment is solids precipitation only. Pretreatment for this option does not require targeted removal of dissolved hardness parameters (i.e., calcium and magnesium). Therefore, the chemical precipitation (CP)

pretreatment needed for this option requires fewer chemicals (e.g., soda ash is not required for calcium removal), a lesser quantity of chemicals (e.g., less hydrated lime is added since magnesium removal is not targeted) and generates fewer solid residuals compared to full softening pretreatment (CS) required for crystallization (Appendix C) or reverse osmosis (Section D.1.3). Precipitation of calcium sulfate is followed by pH neutralization using sulfuric acid and degasification of the wastewater in a deaerator before reaching the VCE process.

The VCE evaporator system assumed for this option was previously described in Section C.1.3. The evaporator was estimated to achieve 90 percent overall recovery. At the design flow rate of 300 gpm, the case study system would generate 270 gpm of evaporator distillate and 29 gpm of brine. For this option, the evaporator brine would be mixed with amendments to form a solid, and then the solidified brine/ash material would be disposed of in a lined landfill.

Brine solidification is a highly site-specific process whereby the composition of the FGD wastewater brine and water treatment chemicals (antiscalants, defoamers, acid/bases) will impact the solidification amendments required to properly dispose of the final composite waste. Bench- and pilot-scale testing would be required for any plant to determine the preferred mixture of amendment materials and to confirm whether the waste material can meet all the requirements for landfill disposal. These requirements may include passing the toxicity characteristic leaching procedure or “paint filter” test as well as meeting other property requirements necessary for long-term deposition in a landfill, such as hydraulic conductivity, compressive strength and other requirements.

EPRI has been evaluating processes for brine solidification for several years [EPRI, 2017; EPRI, 2018; EPRI 2019] and considered potential options for brine disposal. Two options have been considered by EPRI in past work [EPRI, 2020]:

- **Truckable Mixture:** Producing a non-pumpable solid waste stream which could be handled relatively dry, placed in a dump truck, and trucked and disposed of in a landfill. The solid waste material is assumed to be composed of 18 weight percent of brine, 77 weight percent of fly ash and 5 weight percent of quicklime. EPRI’s research indicates that the suitable amount of brine in a non-pumpable mixture may be between 15 and 20 weight percent for plants burning eastern bituminous coal. To prepare this mixture, a significant quantity of fly ash is required. For every gallon of FGD brine (i.e., approximately 8.8 lb), approximately 37.5 pounds of fly ash is required to encapsulate the brine.
- **Pumpable Mixture:** Producing a pumpable mixture or “paste” that contains a greater weight percentage of brine in the mixture (between 30 and 40 percent for plants burning eastern bituminous coal). The pumpable brine/ash slurry material is assumed to be composed of 35 weight percent of brine, 60 weight percent of fly ash and 5 weight percent of quicklime. For every gallon of FGD brine (i.e., approximately 8.8 lb), approximately 15.0 pounds of fly ash is required to encapsulate the brine. Therefore, the paste disposal option would require significantly less fly ash (less than half of the fly ash required for the truckable mixture). The pumpable mixture reduces the amount of fly ash required for brine

disposal and would also lead to less residual waste. However, its applications are more limited, as described below.

For this case study, EPRI has assumed that the solidification process would generate a truckable (non-pumpable) solid waste stream which would be trucked and disposed of in a landfill. The solid waste material is assumed to be composed of 18 weight percent of the evaporator brine, 77 weight percent of fly ash and 5 weight percent of quicklime. Table D-4 shows that the costs for residuals disposal are the highest O&M cost element for this option.

The suitable amount of brine in the solid waste mixture would be significantly lower for plants burning powder river basin (PRB) coal. Sites that burn PRB coal can typically achieve higher cycles of concentration in scrubber and evaporative systems which may lead to smaller brine volumes. However, for a given flowrate, the FGD brine from a PRB site will be higher in TDS. The higher TDS leads to a lower range of brine mass suitable in the solidified mixture, leading to more fly ash and quicklime amendments being required and therefore higher costs.

Both the truckable (non-pumpable) and paste (pumpable) options may be considered in an actual installation. However, EPRI has selected the truckable (non-pumpable) basis for this costing since it is more commonplace in the United States and allows greater flexibility for waste placement in either an onsite or offsite landfill. The truckable approach is estimated to be $7M/year higher annualized cost compared to the pumpable option, assuming the pumpable brine/ash material is composed of 35 weight percent of the evaporator brine, 60 weight percent of fly ash and 5 weight percent of quicklime. Cost variances for capital and O&M costs for a pumpable approach are provided in Section D.1.2.2 and Section D.1.2.3.

EPRI used responses to EPA's ELG Information Collection Request (ICR) for megawatts scrubbed and FGD wastewater design flow to estimate typical fly ash availability at a plant that generates 300 gpm of FGD wastewater. The estimated fly ash generation range was estimated to be between 119,000 to 336,000 tons per year, with an average of 198,000 tons per year per plant.

Further, EPRI evaluated data from Form EIA-923 "Power Plant Operations Report", Schedule 8, Part A "Annual Byproduct Disposition" for recent reporting years 2018, 2019 and 2020. These reports indicate that the median quantity of fly ash byproducts produced from "standard boiler/PCD units" for the 22 plants planning to generate FGD wastewater past 2032 was 197,800 tons per year, which nearly matches EPRI's fly ash production assumption.

The required quantities of fly ash and amendments required for brine solidification will be explained in further detail in Appendix E. For this case study for a 90 percent recovery VCE evaporator, EPRI estimated that roughly 160,000 tons per year of fly ash would be required for brine solidification for this CP + VCE/BS case study. Therefore, EPRI has assumed there is sufficient fly ash available for this hypothetical case study plant.

Many sites currently sell their fly ash for profit. Therefore, sites using brine solidification may need to forfeit sale of some or all of their fly ash for use in the solidification process. EPRI assumed an average plant across the industry:

- Currently produces 198,000 tons per year of fly ash
- Sells 60 percent of their fly ash, or 119,000 tons per year
- Disposes of the remaining 40 percent of their fly ash, or 79,000 tons per year
- The case study plant would require 160,000 tons fly ash per year for evaporator brine solidification. All of the fly ash currently being disposed (79,000 tons per year) would be used for brine solidification. An additional 81,000 tons of fly ash per year would be diverted from current beneficial reuse sales for brine solidification. This results in a profit loss incurred as an additional annual cost.
- The remaining 38,000 tons per year of available fly ash would continue to be sold by the plant.
- Sites may need to make improvements to landfill operations (i.e., permit modifications, updated fill plan) and/or landfill leachate collection, management and treatment systems in order to dispose of the solidified brine/ash material. These are potential additional site-specific costs that are not included in this case study.

The key aspects of a CP + VCE/BS treatment system are:

- **Treatment objective** – Elimination of wastewater direct discharge by means of thermal treatment and evaporation of water. This results in a distillate stream and a concentrated wastewater (brine) with a reduced flow. Amendments are mixed with the concentrated wastewater stream resulting in a non-pumpable (truckable) material. This material, along with solids removed in the pretreatment (chemical precipitation) process, are disposed in a landfill. This case study assumes that the distillate stream will be recycled back into the plant for reuse. Certain plants may be permitted and choose to discharge their distillate. Site-specific analysis of the challenges related to reuse and direct discharge of distillate would be required for all sites.
- **Key equipment** – Equalization tank, chemical reaction tanks, clarifiers, neutralization tank, evaporator feed tank, chemical feed systems, vapor-compression evaporator system, brine storage tank, distillate/reuse tank, pug mill, and filter presses.
- **Wastes** – The final residuals are calcium sulfate pretreatment solids and solidified brine/ash material, both requiring disposal in a lined landfill.

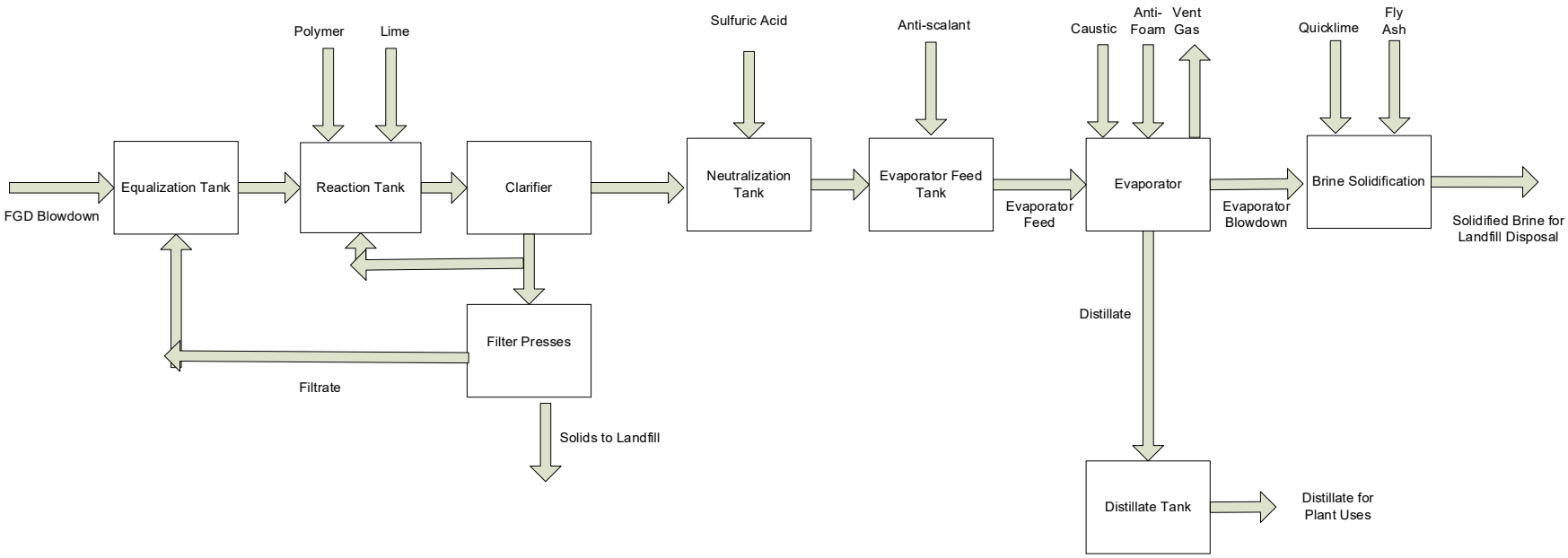


Figure D-1. Chemical precipitation with vapor compression evaporation and brine solidification system

D.1.2.1 Cost development methods

In this case study, EPRI has assumed a single plant's FGD wastewater design flow rate of 300 gpm.

FGD wastewater is pretreated through two identical trains at 60 percent capacity for all pretreatment equipment. The actual degree of redundancy that plants will choose will be based on site-specific considerations.

Using the reconciled FGD water quality (Table C-3), a major equipment vendor provided an installed cost quotation for a system consisting of two identical trains of seeded slurry brine concentrators each sized for 60 percent of the design flow rate and a single pug mill system for brine solidification. EPRI added the cost of a second pug mill, to provide redundancy.

The vendor estimated the cost for a "turnkey" system that included total installed costs within battery limits of the equipment package. Assumptions related to the scope of the turnkey system are the same as shown for Vendor B in Appendix C.

Upstream and downstream equipment from the evaporator system, including equalization equipment, chemical feed equipment, solids dewatering equipment, intermittent brine storage system, and distillate storage system were not part of the turnkey design. Therefore, EPRI costed these systems separately. In addition, this conceptual design assumes the need for a redundant pug mill system. EPRI estimated the cost for an additional pug mill system since only one pug mill system was quoted by the vendor.

D.1.2.2 Capital cost assumptions and estimate

The costs presented represent Class 4 estimates, generally defined as study- or feasibility-level estimates, for total installed costs (+50% to -30% accuracy). A definition of cost estimate classifications is presented in Appendix A.

Cost model factors and other major assumptions align with CS + VCE/CRX assumptions outlined in Section C.1.6. Specific assumptions for this option include:

- The power plant already has fly ash silos installed for its existing fly ash; therefore, no costs were added for fly ash silos.
- EPRI has included the cost of new quicklime silos that would be required for chemical supply as part of the brine solidification process.
- Engineering costs include an additional 1 percent of the total construction costs to account for the costs for bench- and pilot-scale brine solidification testing, which would be required for this option.
- Two 24-hour intermittent evaporator brine storage tanks and mixers were included, which would allow for intermittent brine storage when the pug mills are not operating.

- Costs for landfill operation improvements (i.e., permit modifications, updated fill plan) are potential plant costs that are not included in this case study.
- Cost for improvements to landfill leachate collection, management and treatment systems are potential additional costs that are not included in this case study cost estimate.

Table D-2. Summary of estimated CP + VCE/BS treatment capital costs, non-pumpable solid waste, in 2021$ dollars

Cost Element ($ thousand)	
Evaporator Vendor System Installation [1]	$25,000
Support equipment	
Equalization system	$1,456
Evaporator feed handling and storage equipment	$168
Chemical feed equipment	$219
Chemical precipitation equipment	$1,597
Chemical precipitation solids dewatering	$2,807
Brine handling and storage equipment, Spare pugmill	$1,233
Quicklime feed and quicklime silo	$1,206
Cold distillate handling and storage equipment	$380
Freight (4%) and taxes (0%)	$1,363
Subtotal – Purchased Support Equipment Cost as Delivered	**$9,429**
Subtotal – Vendor System Installation and Purchased Support Equipment Cost as Delivered	**$35,429**
Additional cost items [2]	
Pre-engineered building [4]	$7,761
Tie-in allowance [5]	$97
Site work [6]	$1,417
Piping [3]	$2,357
Mechanical / Heating, Ventilation, and Cooling [3]	$707
Instruments and Controls [3]	$1,414
Electrical	$7,794
Concrete [3]	$1,650
Miscellaneous metals, finishes [3]	$1,414
Subtotal – Direct Costs	**$60,040**
General contractor general conditions [2, 3]	$4,255
Bonding and insurance [2]	$1,711

Cost Element ($ thousand)	
General contractor profit [2, 3]	$4,851
Subtotal – Direct and Indirect Costs	**$70,857**
Miscellaneous unidentified cost [2]	$14,171
Subtotal – Estimated Construction Cost	**$85,028**
Engineering (design, testing, startup during construction, startup, and operator training) [2, 7]	$17,856
Client administrative and overhead [2]	$5,952
Permitting	$62
Total Estimated Capital Cost ($M)	**$109**
Total Estimated Capital Cost ($M) +50%	**$163**
Total Estimated Capital Cost ($M) –30%	**$76**

M = million
$ = U.S. dollars

1. Vendor provided quotation for a turnkey process island (total installed cost) in December 2018. System consists of 2 x 60% evaporator system and single pug mill system.
2. See Appendix A for factors used to estimate these additional cost items.
3. Included in vendor system installed cost, therefore this cost factor was applied to support equipment costs only
4. Pre-engineered building was estimated at 22,500 square feet which includes two floors. Building was assumed to accommodate an office, motor control center (MCC), chemicals storage, dewatering equipment and evaporator system.
5. Assumes wastewater tie-in piping of 1,000 linear feet installed above grade.
6. Includes fencing, grading, roads, sidewalks, and similar items.
7. Assumes 21 percent for engineering. An additional 1 percent of the total construction cost is added in this cost estimate to account for the costs of bench- and pilot- scale brine solidification testing.

Using a similar approach, EPRI estimated the capital costs for the case study site assuming a pumpable solid waste mixture (35 weight percent brine) would be generated. Using this basis, the capital costs for the system were estimated to be $107 million, roughly the same capital costs for a system generating a non-pumpable solid waste. Key differences for the pumpable case study costs were assumed to be: (1) additional pumps and one-mile pipeline to convey the waste to the landfill and (2) reduced size of the brine solidification equipment including fly ash pug mills and quicklime storage silo. Table D-3 provides an abbreviated table showing equipment costs that differ for this case study compared to the non-pumpable case study costs shown in Table D-2.

Table D-3. Estimated capital cost variances for CP + VCE/BS treatment, pumpable solid waste, in 2021 dollars

Cost Element ($ thousand)	
Support equipment with cost that differ from Non-Pumpable option (see prior table)	
Brine handling and storage equipment, Spare pugmill	$1,201
Quicklime feed and quicklime silo	$611
Additional cost items not in the Non-Pumpable option (see prior table)	
Solid waste piping to landfill [1]	$414

M = million
$ = U.S. dollars

1. Assumes one-mile buried pipeline to convey pumpable solid waste to landfill.

D.1.2.3 Operations and maintenance cost assumptions and estimate

Major assumptions align with CS + VCE/CRX assumptions outlined in Section C.1.7, with additional or different assumptions as follows:

- Pretreatment chemical dosages for this option were based on calcium sulfate precipitation pre-treatment using hydrated lime at pH 9.
- Labor is assumed to be the same as the CS + VCE/CRX option: a total of 10 full-time equivalent (FTE) operators at $54/hour, one supervisor at $84/hour, and one chemical engineer at $100/hour were assumed to staff the facility.
- As noted in Section D.1.2, EPRI is assuming that the case study plant currently disposes of 40 percent of their fly ash. EPRI estimated the disposal cost for the entire solidified brine waste (including fly ash) and then applied a cost deduction for the 40 percent of the fly ash that is already being disposed (baseline assumption) as to only include the incremental cost increase due to new wastewater treatment.
- EPRI has assumed that the average plant in the industry sells 60 percent of their fly ash (119,000 tons per year) and must forfeit selling 81,000 tons of fly ash per year for beneficial reuse as a result of implementing this technology option. The net revenue loss as a result of forfeited fly ash sales was assumed to be $11 per ton. Not all plants sell their fly ash and those that do may sell more or less than the tons assumed in this case study. Therefore, lost fly ash sales and the existing cost for fly ash onsite disposal are shown separately at the bottom of Table D-4 so that O&M costs may be estimated with and without these site-specific costs.
- Residuals disposal is the highest O&M cost element and will vary greatly based on the plant's landfill location, transportation methods, current landfill capacity and other factors. EPRI has assumed $59/ton on a dry-weight basis (Appendix C). EPRI is showing these costs separately in Table D-4 due to the significance and variability of this site-specific cost element.
- EPRI has assumed that falling-film evaporator tube cleanings will occur twice per year.

- EPRI has assumed a plant capacity factor of 0.51, which is the industry average based on data from 2015 through 2017.

Table D-4. Summary of CP + VCE/BS treatment annual O&M costs, in 2021 dollars

Cost Element ($ thousand per year)	
Chemicals [1]	
Antiscalant	$12
Antifoam	$13
Sulfuric acid (93%)	$39
Caustic (50%)	$1
Polymer	$37
Quicklime for solidification	$1,553
Hydrated lime for chemical precipitation	$66
Supplemental fly ash for solidification	$0
Subtotal – Chemicals	$1,720
Electricity	$462
Steam	$0
Cooling water	$61
Evaporator tube cleanings	$588
Maintenance	$599
Labor	$1,506
Compliance monitoring	$166
Total Estimated O&M Cost for Wastewater Treatment	$5,102
Lost fly ash sales	$885
Residuals, incremental cost, non-RCRA hazardous landfill disposal [2]	$5,701
Total Estimated O&M Cost with Fly Ash Sales and Disposal Costs ($ million/yr)	**$11.7**

M = million
O&M = operations and maintenance
RCRA = Resource Conservation and Recovery Act
$ = U.S. dollars

1. Chemical costs are industry average and include an assumed national average freight. Chemical costs will vary depending on plant location and local chemical distributors.
2. Incremental cost of dry residuals disposal, after deducting the mass of existing fly ash being disposed and the mass of brine.

Using a similar approach, EPRI estimated the O&M costs for the pumpable solid waste mixture to be $5M per year, more than half of the O&M cost estimated for a system generating a non-pumpable solid waste. Key differences for the pumpable case study costs were assumed to be: (1) reduced quicklime quantity needed for brine solidification, (2) no loss of fly ash sales (fly ash tons currently disposed is greater than fly ash tons required for solidification), and (3) reduced residuals quantities for disposal.

The same residuals disposal cost, $59/ton on a dry-weight basis, was assumed in developing the pumpable solid waste cost estimate. There is likely to be a different $/ton disposal cost for a paste system given that the transportation system is capitalized (i.e., piping and pumps) instead of hauled by trucking and the deposition in the landfill is passive and less labor/equipment intensive.

Table D-5 provides an abbreviated table showing costs that differ for this case study from the non-pumpable case study costs shown in Table D-4.

Table D-5. Estimated O&M cost variances for CP + VCE/BS treatment, pumpable solid waste, in 2021 dollars

Cost Element ($ thousand per year) that differ from non-pumpable option in prior table	
Chemicals [1]	
Quicklime for solidification	$799
Lost fly ash sales	$0
Residuals, incremental cost, non-RCRA hazardous landfill disposal [2]	$409

O&M = operations and maintenance
RCRA = Resource Conservation and Recovery Act
$ = U.S. dollars

1. Chemical costs are industry average and include an assumed national average freight. Chemical costs will vary depending on plant location and local chemical distributors.
2. Incremental cost of dry residuals disposal, after deducting the mass of existing fly ash being disposed and the mass of brine.

D.1.3 Treatment overview of chemical softening followed by seawater reverse osmosis and brine solidification (CS + SWRO/BS)

This evaluation considers a treatment option that includes full chemical softening (CS) followed by membrane separation and brine solidification (Figure D-2). Like the CP + VCE/BS option (Section D.1.2), this option assumes solidification (i.e., encapsulation) and landfill disposal of concentrated FGD wastewater. For this reason, this conceptual design will refer to the final treatment process as “brine solidification” as a means of clarifying that the process and underlying assumptions are generally the same as the “brine solidification” process previously described in Section D.1.2

- Key design requirements for this membrane case study, compared to the conceptual designs assumed in Appendix C and Section D.1.2, include:
- This option requires chemical softening (CS) pretreatment upstream of the membrane system to remove calcium, magnesium, and silica that would otherwise cause significant scaling issues on the surface of the membranes. The softening approach is the same lime and soda ash softening system as previously described for CS + VCE/CRX treatment in Appendix C.
- The brine solidification process and approach are assumed to generally be the same as the CP + VCE/BS solidification system (Section D.1.2), however the membrane process would produce a much greater volume of concentrated wastewater that must be solidified and then disposed.

This treatment option includes full chemical softening pre-treatment followed by neutralization to pH 7 using sulfuric acid. The neutralized, softened, settled stream would be treated through either a microfiltration (MF) or ultrafiltration (UF) system for removal of total suspended solids (TSS). The objective of the MF (or UF) system is to remove suspended solids in the softening clarifier overflow (typically around 30 mg/L TSS) and thereby protect the reverse osmosis membranes downstream. The MF system was assumed to achieve 95 percent recovery and the remaining 5 percent of filtrate would be used for MF backwashing. The MF backwash system would include a backwash collection tank followed by a backwash settling tank for settling of the backwashed solids. The supernatant from the settling tank would be returned to the equalization tank. Settled backwash solids could be pumped to the final waste tank for solidification and disposal, if necessary.

The MF filtrate would be treated with an antiscalant and then fed to the RO system. For this conceptual design, EPRI selected a three-stage seawater reverse osmosis (SWRO) system to maximize the permeate recovery and reduce concentrate flow. Interstage booster pumps would be used between the first and second stages to promote a flux balance. EPRI performed membrane projection and antiscalant modeling for this system which indicated that the maximum achievable permeate recovery would be 81 percent, which is limited by the recovery achievable based on the FGD wastewater's salinity and the allowable SWRO membrane design pressure. If the permeate recovery was limited by the membrane scaling tendency (for example, if the softening system was less effective or the feed water quality was more challenging) then the maximum achievable recovery would likely be less. At the design flow rate of 300 gpm and the design recovery of 81 percent, the system would generate 243 gpm of permeate and 57 gpm of RO concentrate.

This case study was developed to maximize RO recovery assuming that the RO permeate would be used for onsite reuse. If reused, it would need to be used in a process that does not discharge to a permitted outfall. Designing a membrane system for discharging permeate to a permitted outfall, which must therefore meet the ELG limits for this option, would likely require designing for a reduced RO recovery leading to higher RO concentrate flows, increased solid waste generation, and therefore higher costs. The RO concentrate would be pumped to the final waste tank and then solidified for landfill disposal using a pug mill system.

The brine solidification process and approach are assumed to generally be the same as the CP+ VCE/BS solidification system (Section D.1.2). For example, the process would generate a non-pumpable solid waste stream which would be trucked and disposed of in a landfill. The solid waste material is assumed to be composed of 18 weight percent of the evaporator brine, 77 weight percent of fly ash and 5 weight percent of quicklime.

EPRI estimated that roughly 309,000 tons per year of fly ash would be required for brine solidification for this case study. This exceeds the estimated 198,000 tons of fly ash generation per year for an average plant that generates 300 gpm of FGD wastewater (Section D.1.2). Therefore, EPRI has assumed there would not be sufficient fly ash available at this case study plant and supplemental fly ash would need to be purchased from another site. This conceptual design includes 111,000 tons per year of additional purchased fly ash, transportation, and new fly ash silos to store the additional fly ash required.

As with CP + VCE/BS, some sites may need to make improvements to landfill operation (i.e., permit modifications, updated fill plan) and/or landfill leachate collection, management and treatment systems in order to dispose of the solidified brine/ash material. These are potential costs that are not included in this case study.

The RO and MF membrane systems would require a clean-in-place (CIP) chemical cleaning system. The CIP system would be used for periodic maintenance and recovery cleanings of the membranes to keep the surfaces of the membrane clean and to prolong the life of the membranes. The RO system would also require a flush system. The flush system would be used to flush a RO skid immediately after it is taken offline.

The key aspects of this CS + SWRO/BS treatment system are:

- **Treatment objective** – Elimination of wastewater direct discharge by means of membrane separation of water and solids. This results in a permeate stream and a concentrated wastewater (concentrate) with a reduced flow. Amendments are mixed with the concentrated wastewater stream resulting in a non-pumpable (truckable) material. Softening pretreatment and antiscalants are required to prevent membrane scaling. The solids from the solidified brine and softening solids are disposed in a landfill. EPRI assumed that the permeate will need to be recycled back into the plant. Reuse options will be challenging for some plants.
- **Key equipment** – Equalization tank, softening reaction tanks, softening clarifiers, membrane feed tanks, chemical feed systems, microfiltration system, reverse osmosis filtration system, RO concentrate storage tank, pug mill, clean-in-place system, backwash tanks and pumps, flush tank, permeate storage tank and filter presses.
- **Wastes** – The final residuals are softener solids and solidified concentrate solids, both requiring disposal in a lined landfill.

D.1.3.1 Cost development methods

In this case study, EPRI has assumed a single plant's FGD wastewater flow rate of 300 gpm. FGD wastewater is pretreated through two identical trains at 60 percent capacity for all equipment. The actual degree of redundancy that plants will choose will be based on site-specific considerations.

The membrane systems (MF/UF and RO) were designed for N+1 treatment train redundancy, meaning that the design system flow capacity is satisfied by "N" trains plus one redundant (standby) train. Therefore, in this 300 gpm design case study, EPRI has assumed a membrane system design consisting of four trains each sized for 100 gpm (400 gpm total feed capacity).

The equipment costs for the membrane system were provided by a major equipment vendor (Vendor C). Using the softened water chemistry for the reconciled FGD water, the vendor provided equipment costs for four ultrafiltration system skids, the backwash pump skid, four 3-stage seawater reverse osmosis system skids, the CIP system, the CIP chemical dosing system, an air supply system (for instrument air and air scour operations), master control panels, and startup services.

The vendor quote for this case study included only the equipment skid packages and excluded all other direct cost items, including interconnect piping between skids and tanks. For this reason, the membrane vendor costs were not "turnkey," which is unlike the quotations provided by the thermal equipment vendors (Appendix C and Section D.1.2). Therefore, for this case study, all the system-wide cost factors used in the EPRI estimates (see Appendix A) were applied to the membrane vendor's quoted equipment costs.

Upstream and downstream equipment from the membrane system, including equalization equipment, chemical feed equipment, softening process equipment, solids dewatering equipment, MF feed tank, MF filtrate tank, backwash system, flush tank system, temporary RO concentrate storage system, the permeate storage system, and the dual pug mill system were not part of the vendor's costs. Therefore, EPRI estimated the costs for this additional equipment.

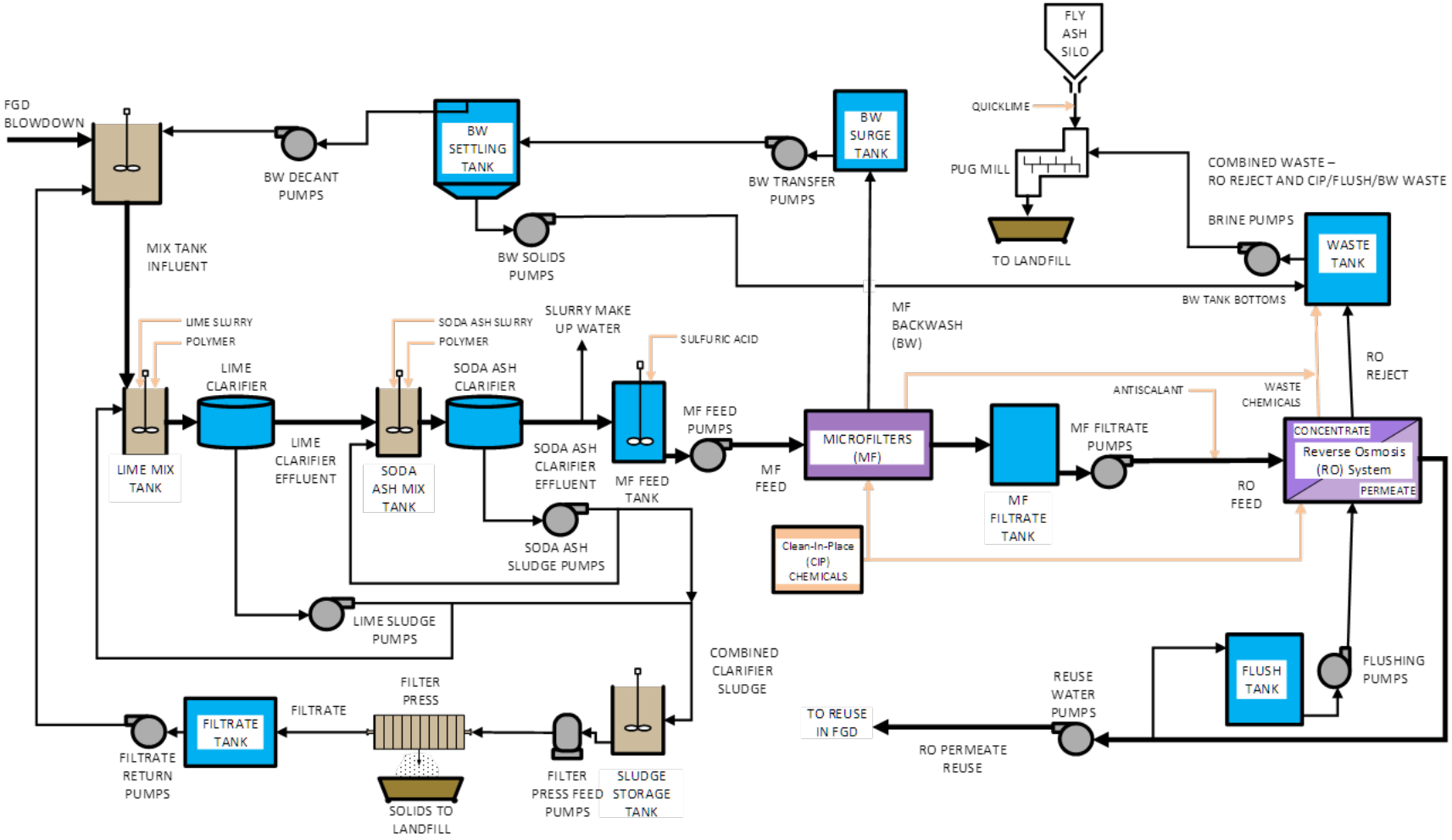


Figure D-2. Chemical softening with reverse osmosis and brine solidification system

D.1.3.2 Capital cost assumptions and estimate

The costs presented represents Class 4 estimates, generally defined as study- or feasibility-level estimates, for total installed costs (+50% to -30% accuracy). A definition of cost estimate classifications is presented in Appendix A.

Cost model factors and other major assumptions align with assumptions outlined in Section C.1.6 and Section D.1.2.2. Specific assumptions for this option include:

- Cost estimate includes the cost of two pug mill systems.
- Two 24-hour intermittent RO concentrate storage tanks and mixers which would allow for intermittent concentrate storage when the pug mills are not operating.

The capital cost estimate for the CS+ SWRO/BS case study is shown in Table D-6.

Table D-6. Summary of estimated CS + SWRO/BS treatment capital costs, in 2021 dollars

Cost Element ($ thousand)	
Equipment	
Equalization system	$1,480
Lime Softening	$1,940
Soda Ash Softening	$1,740
Membrane Filtration [1]	$1,330
Reverse Osmosis [1]	$2,050
Brine handling and storage, Pug mills	$3,111c
Solids Dewatering	$6,480
Backwash Pumping and Storage	$260
Permeate Reuse Pumping and Storage	$1,800
Quicklime feed and silo storage, Fly ash silo storage	$4,561
Mercury Analyzer and Recycle Pumps	$105
Freight (4%) and taxes (0%)	$884
Subtotal – Purchased Equipment Cost as Delivered	**$25,741**
Additional cost items [2]	
Pre-engineered building [3]	$8,375
Tie-in allowance [4]	$97
Site work [5]	$884
Piping	$5,526
Mechanical / Heating, Ventilation, and Cooling	$1,658

Cost Element ($ thousand)	
Instruments and Controls	$3,3315
Electrical	$4,863
Concrete	$3,868
Miscellaneous metals, finishes	$3,315
Subtotal – Direct Costs	**$57,642**
General contractor general conditions [2]	$7,205
Bonding and insurance [2]	$1,643
General contractor profit [2]	$8,214
Subtotal – Direct and Indirect Costs	$74,704
Miscellaneous unidentified cost [2]	$14,941
Subtotal – Estimated Construction Cost	**$89,645**
Engineering (design, testing, startup during construction, startup, and operator training) [2, 6]	$18,825
Client administrative and overhead [2]	$6,275
Permitting	$62
Total Estimated Capital Cost ($M)	**$115**
Total Estimated Capital Cost ($M) +50%	**$173**
Total Estimated Capital Cost ($M) –30%	**$81**

M = million
$ = U.S. dollars

1. Vendor provided costs for a UF/RO/CIP equipment package in March 2019.
2. See Table C-4 for factors used to estimate these additional cost items.
3. Pre-engineered building was estimated at 33,500 square feet which includes two floors. Building was assumed to accommodate an office, motor control center (MCC), chemicals storage, dewatering equipment and membrane equipment. The building area required for the UF/RO equipment skids was developed based on vendor input.
4. Assumes wastewater tie-in piping of 1,000 linear feet installed above grade.
5. Includes fencing, grading, roads, sidewalks, and similar items.
6. Assumes 21 percent for engineering. The additional 1 percent of total construction cost is to account for the costs of bench- and pilot- scale brine solidification testing.

D.1.3.3 Operations and maintenance cost assumptions and estimate

RO treatment will result in approximately twice as much concentrated wastewater for disposal compared to VCE in comparably sized systems. Thus, the greater volume of liquid for disposal requires proportionately more quicklime and fly ash, and the disposal costs for this RO option are greater than those shown for CP + VCE/BS in Section D.1.2.3.

Major assumptions for chemical softening align with CS + VCE/CRX assumptions outlined in Appendix C. This case study includes additional O&M assumptions as follows:

- Labor: a total of 14 full-time equivalent (FTE) operators at $54/hour, one supervisor at $846/hour, and one chemical engineer at $100/hour were assumed to staff the facility. Additional operators were included in this case study due to the greater amount of encapsulated waste generated and the assumed need to operate the treatment system 7 days per week.
- The CIP system would use the following chemicals:
  - Sodium Hypochlorite ($1.19/lb.)
  - Citric Acid ($1.74/lb.)
  - Sodium hydroxide ($0.67/lb.)
  - Sodium tripolyphosphate (STPP) ($2.15/lb.)
  - Sodium ethylenediaminetetraacetic acid (Na-EDTA) (0.96/lb.)
- Membrane cleaning frequency has not been clearly demonstrated and is unknown. This case study assumed membrane cleaning would be required weekly for UF maintenance cleans, monthly for UF recovery cleans and quarterly for RO recovery cleans. More frequent cleaning may be needed at some plants thereby increasing operating costs and causing more of an operability challenge.
- Element replacement frequency has also not been clearly demonstrated and is unknown. This case study assumed that element replacements would occur every three months for cartridge filters (roughing filters to UF system), every five years for UF membranes and every three years for reverse osmosis membranes. The costs of these element replacements were averaged over the replacement period to calculate an annual replacement cost.
- EPRI has assumed a plant capacity factor of 0.51, which is the industry average based on data from 2015 through 2017.
- EPRI has assumed that the average site across the industry (198,000 tons of fly ash per year) would not generate sufficient fly ash to solidify the RO reject wastewater on an annual basis. EPRI estimates that approximately 111,000 tons per year of additional fly ash would need to be purchased. The total purchased fly ash cost of $51.05 was used similar to Appendix C and Section D.1.2 for total purchased fly ash cost of $46.51 per ton.

The O&M cost estimate for the CS+ SWRO/BS case study is shown in Table D-7.

Table D-7. Summary of CS + SWRO/BS treatment annual O&M costs, in 2021 dollars

Cost Element ($ thousand per year)	
Chemicals [1]	
Hydrated lime for softening	$702
Soda Ash for softening	$923
Polymer	$243
Sulfuric acid (93%)	$74
Antiscalant	$4
Sodium Hypochlorite	<$1
Caustic	<$1
Citric acid	$1
STPP	$1
Na-EDTA	$1
CIP Neutralization chemicals	$2
Quicklime for solidification	$3,006
Supplemental fly ash for solidification	$5,659
Subtotal – Chemicals	**$10,616**
Electricity	$157
Filtration element replacement	$37
Maintenance	$663
Labor	$1,954
Compliance monitoring	$163
Total Estimated O&M Cost for Wastewater Treatment	**$13,590**
Lost fly ash sales	$1,307
Residuals, incremental cost, non-hazardous landfill disposal [2]	$15,886
Total Estimated O&M Cost with Fly Ash Sales and Residuals ($M per year)	**$30.8**

M = million
O&M = operations and maintenance
$ = U.S. dollars

1. Chemical costs are industry average and include an assumed national average freight. Chemical costs will vary depending on plant location and local chemical distributors.
2. Incremental cost of dry residuals disposal, after deducting the mass of existing fly ash being disposed and the mass of brine.

References

EPRI, 2019. Electric Power Research Institute. *Program on Technology Innovation: State of Knowledge Report on Wastewater Encapsulation.* Palo Alto, CA: 3002010778.

Ellison, K., 2018. Wastewater and Brine Management using Encapsulation: Laboratory and Pilot Testing, New Findings, and Testing Recommendations. IWC 18–44. Paper presented at the 2018 International Water Conference, Scottsdale AZ, November 4–8.

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E FGD WASTEWATER TREATMENT COST METHODOLOGY— CONVERSION TO MEMBRANE TREATMENT SYSTEM

E.1.1 Introduction

The revision to Title 40 Code of Federal Regulations (CFR) Part 423, commonly known as the Steam Electric Effluent Limitation Guidelines (ELGs), has been through various stages of rulemaking since 2013 where the limits and best available treatment technologies economically achievable (BAT) set by the U.S. Environmental Protection Agency (EPA) have been changed iteratively. The Electric Power Research Institute (EPRI) previously evaluated and prepared cost estimates for several technologies considered as potential model BAT technologies for treatment of flue gas desulfurization (FGD) wastewater. EPRI also evaluated technologies considered under the FGD wastewater voluntary incentives program (VIP). The treatment technologies evaluated by EPRI include:

- Chemical precipitation (CP)
- Biological (Bio), including the ABMet® and the SeHAWK® systems
- Chemical softening, vapor-compression evaporation, and crystallization (CS + VCE/CRX)
- Chemical precipitation, vapor-compression evaporation, and brine solidification (CP+VCE/BS)
- Chemical softening, seawater reverse osmosis (SWRO) and brine solidification (CS + SWRO/BS)
- Chemical precipitation, advanced membrane filtration (AMF) and brine solidification (CP+AMF/BS)

In 2020, the EPA selected chemical precipitation + low hydraulic residence time biological treatment (CP + Bio) as a model BAT technology for FGD wastewater [US, 2020]. In August 2021, EPA specifically stated that it would continue to evaluate membrane treatment and "evaluate whether this technology should serve as the basis for the "best available technology economically achievable" under the Clean Water Act to control discharges of pollutants found in flue gas desulfurization wastewater discharges as part of the new rulemaking" [US, 2021]. In EPA's 2023 proposed revised ELG, the EPA selected chemical precipitation, membrane filtration, and brine encapsulation as the proposed BAT for FGD wastewater treatment.

This appendix takes a case study approach to evaluate the technical considerations and costs for a facility that had previously installed a CP + Bio treatment system for FGD wastewater (to comply with EPA's determination of BAT in the 2015 and 2020 ELG rules) followed by the facility modifying its treatment system to membrane treatment and brine solidification (to comply with a proposed 2023 ELG rule).

Membrane treatment, including its necessary pretreatment (to minimize membrane fouling and scaling), its fundamental treatment (to separate contaminants and meet applicable discharge limits) and its necessary post-treatment (to meet the objectives of RO brine solidification for waste disposal), is a site-specific process dependent on FGD wastewater characteristics and site conditions. The case study described in this appendix makes some general assumptions on what treatment systems would be required to operate a membrane filtration treatment system; however, this will vary considerably from site to site.

Also, since there are no, full-scale, permanent installations in the United States of membrane treatment systems for FGD wastewater, there are many unknowns for the application of membranes to treat FGD wastewater.

E.2.1 Case Study Conceptual Design Basis

The design basis for the membrane conversion case study is described in this section.

E.2.1 FGD Wastewater Quantity

Flow capacity is a key factor in the cost of many treatment components. The flow basis assumed for this case study is shown in Table E-1. The peak flow rate was used to size all equipment and determine the capital cost of the system. In other words, the wastewater treatment plant would be designed to treat 300 gpm of FGD wastewater on a consistent basis.

EPRI has assumed a plant capacity factor of 0.51 for this case study, which is the industry median based on EIA data from 2015 through 2017.

The annual average flow rate was determined based on the assumed plant capacity factor of 51 percent and represents the typical flows treated by the case study plant. The annual average flow rate was used to calculate the operations and maintenance (O&M) costs for the treatment system such as chemical feed, waste disposal, and electricity.

Table E-1. Case Study Flow Basis

	Peak	Annual Average
Flowrate (gpm)	300	153

E.2.2 FGD Wastewater Quality

The assumed water quality of pre-treated FGD wastewater for this case study was developed based on EPA's reported average concentration of pollutants present in treated FGD wastewater effluent as reported in Table 6-1 of EPA's 2020 Technical Development Document [EPA, 2020]. Given that the chemical precipitation treatment system for this case study is assumed to be operated only with lime desaturation and solids settling (without the use of

targeted metals removal, ferric chloride, organosulfide and polymer addition), EPRI has assumed the following:

- The concentration of most parameters were assumed to be those reported for FGD surface impoundment effluent
- The concentration of total suspended solids (TSS), total dissolved solids (TDS), and calcium were assumed to be those reported for chemical precipitation treated effluent
- An average sulfate concentration was not provided by EPA, therefore an estimated sulfate concentration was used to complete the ion balance for the assumed water quality

The assumed water quality for chemical pre-treatment effluent and the feed water to the membrane system for this case study is shown in Table E-2. Some parameter values that were not provided by EPA, such as pH and temperature, were assumed for this case study.

Table E-2. Assumed Membrane Feed Water Quality

Parameter	Unit	Value	Basis
Temperature	°F	95	1
pH	s.u.	7	1
Density	g/mL	1.02	1
Total suspended solids	mg/L	10	3
Total dissolved solids	mg/L	24,100	3
Calcium	mg/L	1,920	3
Magnesium	mg/L	3,370	2
Sodium	mg/L	276	2
Mercury	mg/L	0.00778	2
Barium	mg/L	0.030	2
Antimony	mg/L	0.0129	2
Beryllium	mg/L	0.00192	2
Iron	mg/L	1.51	2
Manganese	mg/L	93.4	2
Aluminum	mg/L	2.08	2
Cadmium	mg/L	0.113	2
Chromium	mg/L	0.0178	2
Cobalt	mg/L	0.183	2
Copper	mg/L	0.0218	2
Lead	mg/L	0.00466	2
Nickel	mg/L	0.878	2

Parameter	Unit	Value	Basis
Molybdenum	mg/L	0.125	2
Thallium	mg/L	0.0137	2
Titanium	mg/L	0.0271	2
Vanadium	mg/L	0.0164	2
Zinc	mg/L	1.39	2
Sulfate	mg/L	8,541	4
Chloride	mg/L	7,120	2
Arsenic	mg/L	0.00759	2
Selenium	mg/L	1.17	2
Nitrate as N	mg/L	96	2
Phosphorus	mg/L	0.319	2
Cyanide	mg/L	0.949	2
Boron	mg/L	243	2
Ammonia as N	mg/L	6.85	2

1. Case study assumption
2. Reported average concentration in treated effluent from FGD surface impoundments, Table 6-1, of EPA 2020 Technical Development Document [EPA, 2020]
3. Reported average concentration in treated effluent from chemical precipitation treatment system, Table 6-1, of EPA 2020 Technical Development Document [EPA, 2020]
4. Calculated

E.2.3 Fly Ash Generated by Facility

EPRI used responses to EPA's ELG Information Collection Request (ICR) for megawatts scrubbed and FGD wastewater design flow to estimate typical fly ash availability at a plant that generates 300 gpm of FGD wastewater. EPRI's analysis of the ICR data indicates that that size of a plant that generates 300 gpm of FGD wastewater may be between 600 and 1700 MW. The fly ash generation for plants of this size was estimated to be between 119,000 to 336,000 tons per year, with an average of 198,000 tons per year per plant. Therefore, it was assumed that this case study plant produces 198,000 tons of fly ash per year.

Further, EPRI evaluated data from Form EIA-923 "Power Plant Operations Report", Schedule 8, Part A "Annual Byproduct Disposition" for recent reporting years 2018, 2019 and 2020. These reports indicate that the median quantity of fly ash byproducts produced from "standard boiler/PCD units", "fly ash from FBC units" and "fly ash from units with dry FGD" for the 22 plants planning to generate FGD wastewater past 2032 was 197,800 tons per year, which nearly matches EPRI's fly ash production assumption.

E.2.4 Fly Ash Sales

EPRI's assumption for this evaluation is that the case study plant sells 60 percent of its fly ash for beneficial reuse. Plants that currently sell fly ash may need to forfeit selling some or all their fly ash to instead use the fly ash for brine solidification. Therefore, it was assumed that this case study plant sells 60 percent of the 198,000 tons of fly ash produced each year, and that the plant beneficial reuses 118,800 tons of fly ash per year.

In addition, for the 22 facilities with wet FGD discharges that are expected to be operating beyond 2032, EPRI evaluated data reported in Form EIA-923 for recent reporting years 2018, 2019 and 2020 related to beneficial fly ash use and sales. The EIA dataset indicates that the median quantity of fly ash beneficially used or sold was 29,100 tons of fly ash per year. However, the average fraction of fly ash sold amongst the 22 plants was 44 percent of the total fly ash produced. This is slightly lower than EPRI's assumption of 60 percent fly ash sales for this example case study.

E.3 Overview of Assumed Treatment Systems for Case Study

This section provides a description of the existing chemical precipitation and biological treatment system assumedly installed to comply with the 2015 and 2020 ELG rules and the chemical precipitation, advanced membrane filtration and brine solidification system that would replace the previously installed system.

E.3.1 Existing Facility

The existing facility is assumed to currently operate a chemical precipitation and biological system for treatment of FGD wastewater. The design basis for FGD wastewater flows, fly ash generation, and fly ash sales were presented in the previous section. A block flow diagram depicting the assumptions for the existing facility are shown in Figure E-1.

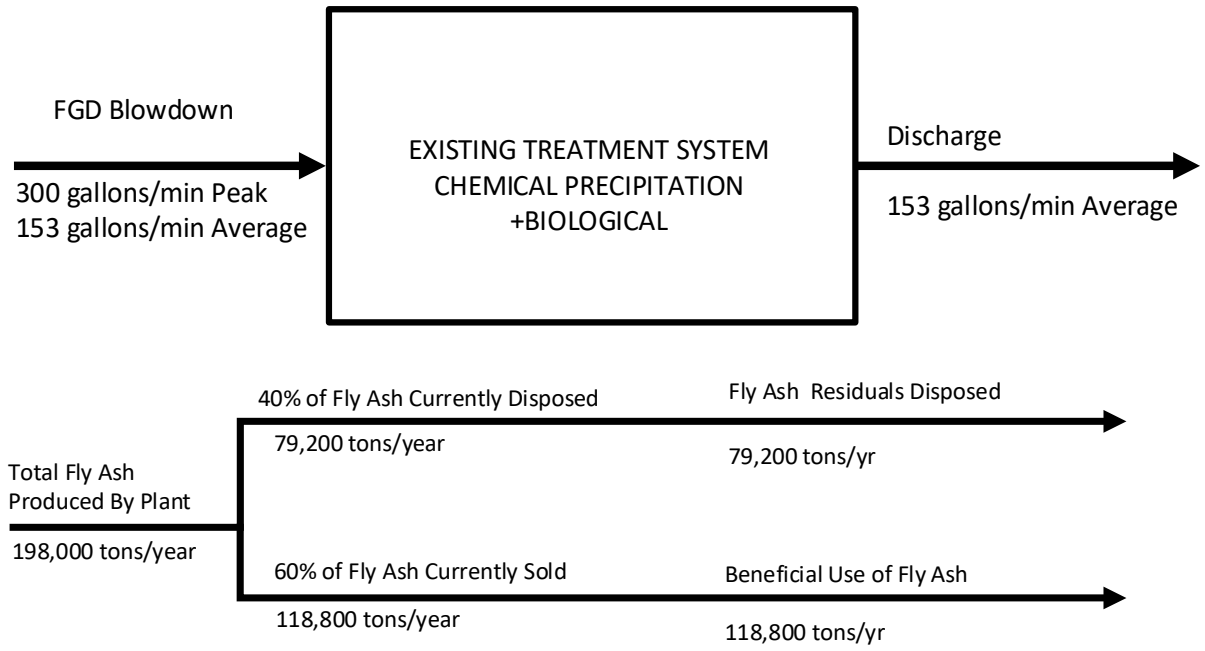


Figure E-1. Flow Diagram of Existing Facility

E.3.2 Existing Chemical Precipitation + Biological Treatment System

The chemical precipitation treatment system assumed for this case study consists of equalization storage, gypsum desaturation using caustic/lime, chemical addition (ferric chloride, organosulfide, and polymer) to enhance metals removal, clarification, pH neutralization, effluent media filtration, and solids dewatering. This is a fully optimized chemical precipitation system as defined by the EPA [Section 5.2.2, EPA, 2020]. Figure E-2 shows an example process flow diagram of this chemical precipitation treatment system. Individual site configurations may vary from what is shown in Figure E-2, such as chemical feed locations, use of mixers, and other design details.

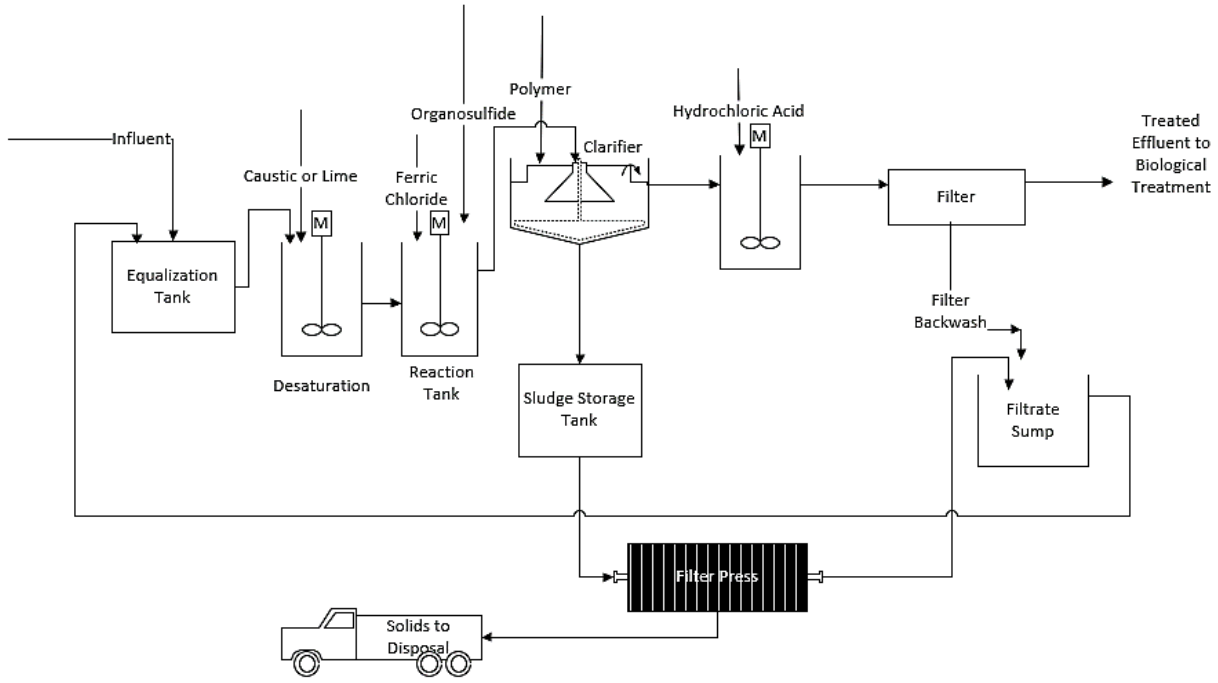


Figure E-2. Chemical precipitation treatment system

The biological treatment system in this case study (Figure E-3) consists of a Biological Metals Removal SeHAWK® system. The treatment equipment for the SeHAWK® system consists of two-stage treatment using an upflow, fluidized bed reactor followed by a downflow media bed. A backwash water supply tank is also provided. It is assumed that backwashed solids are handled and dewatered as part of the up-stream physical/chemical treatment process (Figure E-2).

A heat exchanger is included to cool (or heat) the FGD wastewater prior to entry into the SeHAWK® system. Denitrification would be needed for pre-treatment of high-nitrate (greater than 50 milligrams per liter as N [mg/L-N]) FGD wastewater prior to the SeHAWK® system [ERG, 2019]. Based on the water quality assumptions for this case study (Table E-2), a denitrification system is also included in this case study.

Microbial growth in the SeHAWK® system is supported by nutrients in the system's influent wastewater, and by supplemental nutrient addition in case the feed water does not have sufficient amounts or kinds of nutrients. Ultrafiltration membrane post-treatment was assumed after the SeHAWK® system to meet ELG limits for selenium and mercury. Some sites may also choose to use a reducing agent for ORP and sulfide control in the bioreactor system effluent, which is not assumed for this case study.

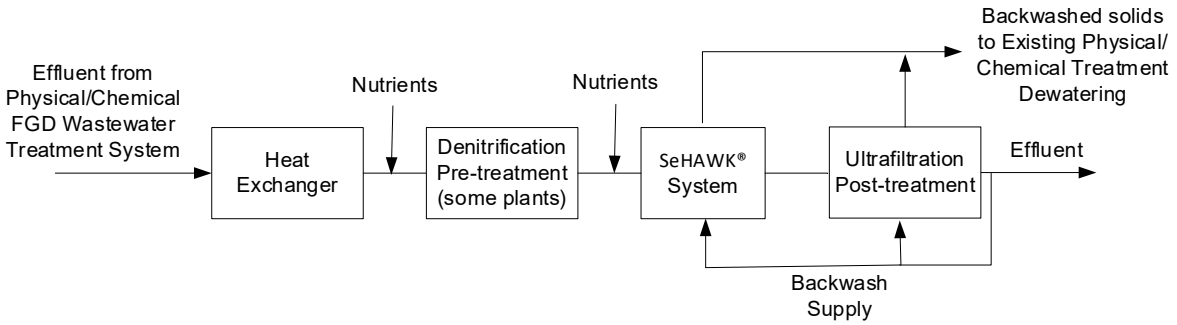


Figure E-3. SeHAWK® biological wastewater treatment system

E.3.3 New Chemical Precipitation + Membrane Treatment System

This section provides a description of the treatment system that would replace the existing chemical precipitation and biological treatment system. The complete membrane treatment system for this case study includes chemical precipitation (CP) pre-treatment followed by an advanced membrane filtration (AMF) system, further followed by membrane brine solidification (BS) (Figure E-4). EPA has used the terminology of brine encapsulation, while EPRI uses the term brine solidification. For the purposes of this case study, brine encapsulation and brine solidification should be considered synonymous.

E.3.3.1 Chemical Precipitation Pretreatment

The pretreatment for the assumed FGD wastewater in this case study consists of hydrated lime addition to precipitate calcium sulfate and to reduce the dissolved solids concentration fed to the AMF process (some sites may also use caustic in place of hydrated lime). The objective of this pre-treatment is to precipitate and remove solids primarily in the form of gypsum ($CaSO_4 \cdot 2H_2O$) although some metals may also be removed as metal hydroxide solids. Pretreatment for this option does not include targeted removal of dissolved hardness parameters (i.e., calcium and magnesium) nor parameters with 2020 ELG FGD discharge limitations (i.e., arsenic, mercury, selenium and nitrate/nitrite). Depending on the site-specific water chemistry, some sites may also be required to add iron salt and organosulfide to the chemical pre-treatment system. This is discussed later in this appendix. The chemically pre-treated, but unsoftened, FGD wastewater basis was selected in order to match EPA's 2020 design basis for the membrane technology option which includes "pretreatment with chemical precipitation, membrane filtration, and concentrate management" [EPA, 2020]. As seen in Figure E-4, chemical pretreatment and clarification is followed by pH neutralization using hydrochloric acid ahead of the membrane process.

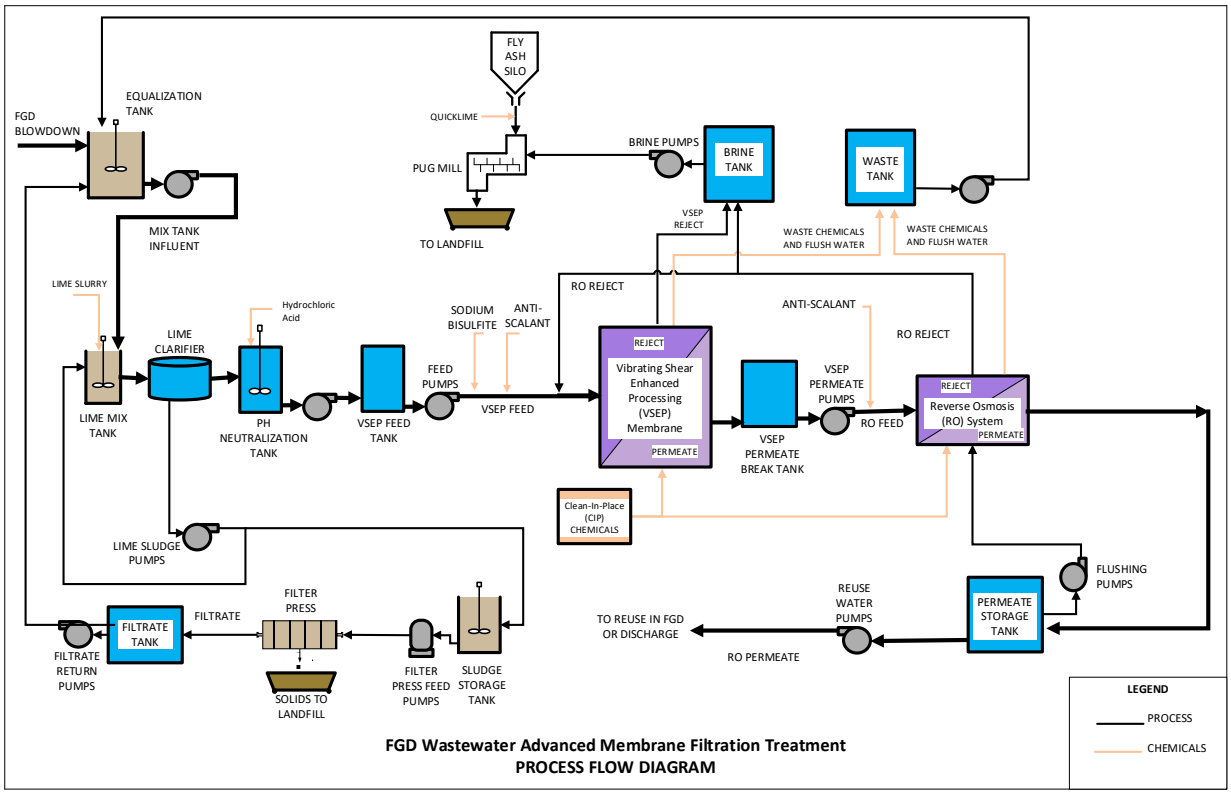


Figure E-4. Chemical precipitation with advanced membrane filtration and brine solidification system

E.3.3.2 Membrane Treatment

Many membrane treatment systems and configurations exist, only some of which could potentially be considered for treatment of FGD wastewater. The type and degree of pretreatment required upstream of the membrane system will depend on the membrane technology implemented. This case study assumes use of an "advanced membrane filtration treatment" system. The term AMF was used to define the membrane systems considered by EPA in the 2020 ELG reconsideration rulemaking as being, "designed specifically for high TDS and TSS waste streams," and, "designed to eliminate fouling and scaling associated with industrial wastewater" [EPA, 2019]. Example AMF technologies identified by EPA in the 2019 draft ELG reconsideration rule include the BKT FMX membrane technology, KLeenWater technology, New Logic Vibratory Shear Enhanced Process (VSEP) membrane technology, Oasys forward osmosis technology, Purestream membrane technology and Saltworks technology.

The membrane equipment configuration assumed in this case study is the New Logic VSEP filtration system followed by a single pass reverse osmosis (RO) membrane system to further treat (i.e., polish) the permeate from the VSEP system. Pumps and a break tank are included between the VSEP and RO systems. The RO reject is recycled to the influent of the previous RO stage rather than being directly discharged. The reject stream from the first stage VSEP system is discharged as a waste stream.

Chemical addition was assumed to consist of antiscalant and sodium bisulfite. Antiscalant would be added upstream of the VSEP filtration system and upstream of the RO polishing system. Sodium bisulfite would be added upstream of the VSEP filtration system to protect and prevent oxidant attack of the membranes.

The VSEP and RO filtration systems would require a clean-in-place (CIP) chemical cleaning system. The CIP system would be used for periodic maintenance and recovery cleanings of the membranes to keep the surfaces of the membrane clean and to prolong the life of the membranes. The RO system would also require a flush system. The flush system would be used to flush a RO skid immediately after it is taken offline. The CIP waste and the flush waste would be directed to a combined waste tank where the waste would be neutralized and then recycled to the equalization tank.

E.3.3.3 Permeate Discharge vs. Reuse

The combined membrane system in this case study is designed for an overall recovery of 70% based on the case study feed water quality (Table E-2) and quotation from New Logic. A 70 percent permeate recovery means that 70 percent of the FGD wastewater volume fed to the AMF system could be recovered as clean permeate and the remaining 30 percent of the FGD wastewater volume would become a waste brine requiring disposal. The assumed 70% recovery is consistent with the pilot dataset provided by New Logic VSEP [ERG, 2019a] showing a range of 55 to 83.2 percent achieved in six different FGD wastewater pilots. As part of the 2023 rulemaking, EPA provided additional pilot study data for VSEP system applications of FGD wastewater [EPA, 2023b]. As shown in Figure E-5 below, this dataset contains information related to eight pilot tests on FGD wastewater using the New Logic Research's Vibratory Shear

Enhanced Processing (VSEP) membrane filtration system. This record shows that the FGD wastewater pilot feed flow was typically 20 to 30 gpm, but the feed TDS concentration was highly variable, ranging from 4,000 milligrams per liter (mg/L) to 46,8000 mg/L. Membrane recoveries were also provided for the dataset. EPRI's evaluation of this dataset showed a similar reported range of VSEP membrane system recovery with a very clear downward trend in membrane recovery based on an increase in feed TDS concentration (Figure E-5).

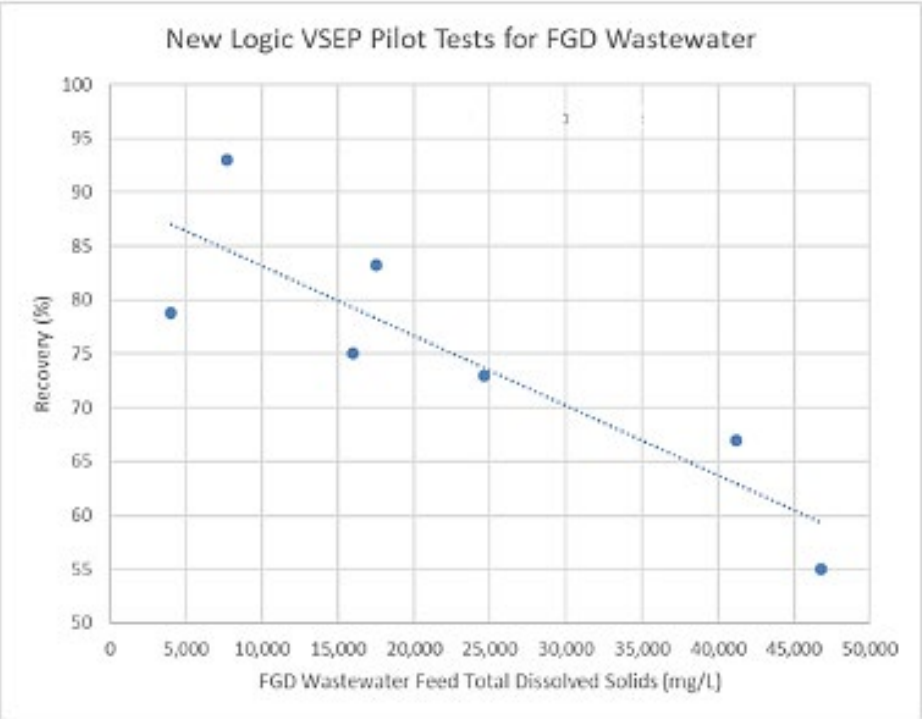


Figure E-5. EPRI's analysis of New Logic VSEP pilot test summary [EPA, 2023b]

This overall recovery is based on two stages of treatment, which includes stage 1 VSEP filtration and stage 2 RO polishing (single pass RO).

This case study assumes the membrane system would be designed for zero liquid discharge (ZLD). The membrane system would need to be designed to consistently comply with the water quality requirements of the end use system.

Preliminary evaluation and consultation with New Logic suggests that the assumed system for this case study (VSEP + single stage RO polishing) would not be capable of meeting the 2020 ELG VIP limits and would only apply in scenarios where sites could consistently achieve 100% reuse. To achieve the 2020 ELG VIP limits, a second stage of RO polishing would be required.

This case study assumes that the membrane system would be a zero-liquid discharge (ZLD) and the permeate would be reused onsite for FGD scrubber makeup and cannot be discharged. Tanks and piping would be required to convey permeate back to the FGD scrubber for makeup. To account for potential low water demand periods, four days of RO permeate storage was

assumed for the permeate tank design. It should be noted that some power plants would have challenges in being able to reuse 100 percent of the permeate for makeup water.

E.3.3.4 Brine Solidification

E.3.3.4.1 Brine mass calculation methods

The role of the membrane is to serve as a selective barrier that will allow the passage of certain constituents and will retain other constituents found in the liquid. The liquid that has passed through the membrane is known as the *permeate*. Membrane permeate recovery, *r*, which is expressed as a percentage, represents the volume of water that is converted from feed water to permeate water, and is defined as [Metcalf & Eddy, 2014]:

$$r, \% = Q_p / Q_f \times 100$$

where Q_p is the permeate flowrate and Q_f is the feed water flowrate. Flows used to calculate permeate recovery (Q_p and Q_f) are in units of volumetric flowrate (e.g., gallons per minute, liters per hour, or cubic meters per second).

The remaining portion of the feed water and constituents that do not pass through the membrane are "rejected" by the membrane system. This flow is commonly referred to as the reject, concentrate, brine or waste stream. The flow quantity of the reject stream, Q_r, is defined as [Metcalf & Eddy, 2014]:

$$Q_r = Q_f - Q_p$$

To properly calculate the mass flow of the brine, two items must be considered. First, there must be conservation of mass across the membrane system such that:

$$m_f = m_p + m_r$$

whereby m is the mass flow (e.g., pounds/minute or tons/day) for the feed water (m_f), permeate (m_p), and reject (m_r).

The stream density (defined as the stream mass per unit volume) and the specific gravity (unitless number defined as the ratio of the density of the stream to the density of water) needs to be considered. The specific gravity of a liquid increases based on the concentration of total dissolved solids (TDS) and therefore the mass of brine for a given volume will be greater than the mass of pure water occupying the same given volume. Based on EPA's definition of industry average FGD wastewater [EPA, 2020], EPRI calculated and used a specific gravity of 1.018 for the FGD purge. The specific gravity of the permeate was assumed to be 1.0 for the membrane permeate. EPRI calculated a specific gravity of 1.06 for the brine generated by a 70 percent membrane recovery system. Therefore, the density of the membrane system brine would be:

8.34 pounds/gallon x 1.06 = 8.84 pounds/gallon

An example calculation of mass balance around membrane feed, permeate and reject is presented below, in reference to Figure 1-2 in Section 1.

Inputs

$Qpurge := 100\,gpm$ *average flowrate from FGD purge/blowdown*

$Density_Water := 8.34\,\frac{lb}{gal}$

$Recovery := 0.7$

$MassPercentFlyAsh := 0.77$

Truckable mix recipe

$MassPercentQuickLime := 0.05$

$MassPercentBrine := 0.18$

$PurgeDensity := Density_Water \cdot 1.018 = 8.49 \cdot \frac{lb}{gal}$ Industry *average purge water density with specific gravity of 1.018.*

$RejectDensity := Density_Water \cdot 1.06 = 8.84 \cdot \frac{lb}{gal}$ *Industry average reject brine density with specific gravity of 1.06.*

$PermeateDensity := Density_Water \cdot 1 = 8.34 \cdot \frac{lb}{gal}$

Calculations and Results

Using Industry Average Specific Gravities

$Qreject := (1 - Recovery) \cdot Qpurge = 30 \cdot gpm$

$Qpermeate := Qpurge \cdot Recovery = 70 \cdot \frac{gal}{min}$

$$Mpurge := Qpurge \cdot 60\,\frac{min}{hr} \cdot 24\,\frac{hr}{day} \cdot PurgeDensity \cdot 365\,\frac{day}{yr} \cdot \frac{1}{2000}\,\frac{ton}{lb} = 223120 \cdot \frac{ton}{yr}$$

$$Mreject := Qreject \cdot 60\,\frac{min}{hr} \cdot 24\,\frac{hr}{day} \cdot RejectDensity \cdot 365\,\frac{day}{yr} \cdot \frac{1}{2000}\,\frac{ton}{lb} = 69698 \cdot \frac{ton}{yr}$$

$$Mpermeate := Qpermeate \cdot 60\,\frac{min}{hr} \cdot 24\,\frac{hr}{day} \cdot PermeateDensity \cdot 365\,\frac{day}{yr} \cdot \frac{1}{2000}\,\frac{ton}{lb} = 153423 \cdot \frac{ton}{yr}$$

We can also solve for Mreject by

$$Mrejectalt := Mpurge - Mpermeate = 69698 \cdot \frac{ton}{yr}$$

$$QuickLimeRequired := \frac{Mreject}{MassPercentBrine} \cdot MassPercentQuickLime = 19360 \cdot \frac{ton}{yr}$$

$$TotalEncapsulatedBrine := \frac{Mreject}{MassPercentBrine} = 387210 \cdot \frac{ton}{yr}$$

$$TotalRequiredFlyAsh := \frac{Mreject}{MassPercentBrine} \cdot MassPercentFlyAsh = 298151 \cdot \frac{ton}{yr}$$

A description of variables follows.

- Qpurge is volumetric flow of FGD purge in gpm
- Qreject is volumetric flow of membrane reject (brine) in gpm
- Qpermeate is volumetric flow of membrane permeate in gpm
- Mpurge is mass flow of FGD purge in lb/d using industry average specific gravity of 1.018
- Mreject is mass flow of membrane reject (brine) in lb/d using industry average specific gravity of 1.06
- Mpermeate is mass flow of membrane permeate in lb/d using industry average specific gravity of 1.0
- Mrejectalt is an alternative calculate method of membrane reject mass flow
- QuickLimeRequired is the required mass of quick lime based on the truckable mix recipe.
- TotalEncapsulatedBrine is the mass of brine encapsulated based on the truckable mix recipe.
- TotalRequiredFlyAsh is the mass of fly ash required to encapsulate brine based on the truckable mix recipe.

E.3.3.4.2 Waste Mixture

Brine solidification is a highly site-specific process whereby the composition of the FGD wastewater brine and water treatment chemicals (antiscalants, defoamers, acid/bases) will impact the solidification amendments required to properly dispose of the final composite waste. Bench- and pilot-scale testing would be required for any plant to determine the preferred mixture of amendment materials and to confirm whether the waste material can meet all the requirements for landfill disposal. These requirements may include passing the toxicity characteristic leaching procedure (TCLP) and/or "paint filter" test as well as meeting other property requirements necessary for long-term deposition in a landfill, such as hydraulic conductivity, compressive strength, and other requirements.

EPRI has been evaluating processes for brine solidification for several years [EPRI, 2017; EPRI, 2018; EPRI 2019] and considered potential options for brine disposal. Two options have been considered by EPRI in past work [EPRI, 2020]:

- **Truckable Mixture:** Producing a non-pumpable solid waste stream which could be handled relatively dry, placed in a dump truck, and trucked and disposed of in a landfill. The solid waste material is assumed to be composed of 18 weight percent of brine, 77 weight percent of fly ash and 5 weight percent of quicklime. EPRI's research indicates that the suitable amount of brine in a non-pumpable mixture may be between 15 and 20 weight percent for plants burning eastern bituminous coal. To prepare this mixture, a significant quantity of fly ash is required. For every gallon of FGD brine (i.e., approximately 8.8 lb), approximately 37.5 pounds of fly ash is required to encapsulate the brine.
- **Pumpable Mixture:** Producing a pumpable mixture or "paste" that contains a greater weight percentage of brine in the mixture (between 30 and 40 percent for plants burning eastern bituminous coal). The pumpable brine/ash slurry material is assumed to be composed of 35 weight percent of brine, 60 weight percent of fly ash and 5 weight percent of quicklime. For every gallon of FGD brine (i.e., approximately 8.8 lb), approximately 15.0 pounds of fly ash is required to encapsulate the brine. Therefore, the paste disposal option would require significantly less fly ash (less than half of the fly ash required for the truckable mixture). The pumpable mixture reduces the amount of fly ash required for brine disposal and would also lead to less residual waste. However, its applications are more limited, as described below.

For this case study, EPRI has assumed that the solidification process would be designed based on the truckable mixture to produce a drier non-pumpable solid waste stream that would be trucked and disposed of in a landfill. The truckable (i.e., non-pumpable) basis allows greater flexibility for waste placement given the uncertain proximity to either an onsite or offsite landfill and is likely to be the most adaptable option by the industry. Both the truckable and pumpable options may be considered for brine disposal in an actual installation. Power facilities would need to evaluate permitting and landfill management impacts and seek the necessary approvals to allow for disposal of the residuals.

Power plants may face significant challenges in permitting a pumpable paste waste to a landfill and may ultimately be required to dispose of materials by truck. Therefore, the pumpable option is likely to have more limited applicability and a greater number of challenges. For these reasons, the cost estimates developed by EPRI assume the truckable mixture ratios and associated material and disposal costs.

The suitable amount of brine in the solid waste mixture for plants burning Powder River Basin (PRB) coal would require other considerations. Sites that burn PRB coal can typically achieve higher cycles of concentration in scrubber and evaporative systems which may lead to smaller brine volumes. However, for a given flowrate, the FGD brine from a PRB site will be higher in TDS. The higher TDS leads to reduced membrane recovery (higher brine flows) and/or a lower range of brine mass suitable in the solidified mixture, leading to more fly ash and quicklime amendments being required and therefore higher costs.

The use of quicklime in the solidified brine mixture will be dependent on the type of fly ash produced by the site. This case study assumed that the site produced Class F fly ash and therefore 5 percent quicklime would be required. Sites with Class C fly ash would be required to add less quicklime (or possibly no quicklime) to the solidified brine mixture. The waste would be mixed with fly ash and quicklime in a pug mill system.

E.3.3.4.3 Brine Management and Fly Ash Quantities Required

The quantity of fly ash required will be significantly impacted by the overall membrane recovery that can be reliably and consistently achieved. This case study assumed that the membrane system would achieve an average of 70 percent permeate recovery, meaning that 70 percent of the FGD wastewater volume that is fed to the AMF system could be recovered as clean permeate and the remaining 30 percent of the FGD wastewater volume would become a waste brine requiring disposal.

As previously described, EPRI estimated the typical quantity of fly ash generated by a plant that generates 300 gpm of FGD wastewater. EPRI's analysis indicates that the fly ash generation for plants of this size would be an average of 198,000 tons per year per plant. Further, EPRI has assumed that the average plant in the industry sells 60 percent of their fly ash for beneficial reuse. This case study assumes that the site would divert all the fly ash that is currently disposed and use that fly ash for brine solidification prior to diverting any fly ash that is currently sold.

Figure E-5 provides a simplified block flow diagram of the brine flow and fly ash requirements for this case study.

As illustrated in Figure E-5, the average RO reject (or brine) generated by the 70 percent recovery membrane system would be approximately 46 gallons per minute or 106,638 tons per year. The brine mass would make up 18 mass percent of the total brine solidification waste. Fly ash would make up 77 mass percent of the waste. Therefore, the fly ash demand would be

456,172 tons of fly ash per year (at average conditions). This requirement of 456,172 tons of fly ash per year exceeds the estimated fly ash available by 258,172 tons per year.

Further, as previously noted, the range of fly ash generated by a site that generates 300 gpm of FGD wastewater is 119,000 to 336,000 tons per year. This indicates a significant fly ash deficit; indicating that most facilities would require an additional 34 to 280 percent of imported fly ash for solidification compared to the site's estimated fly ash produced onsite.

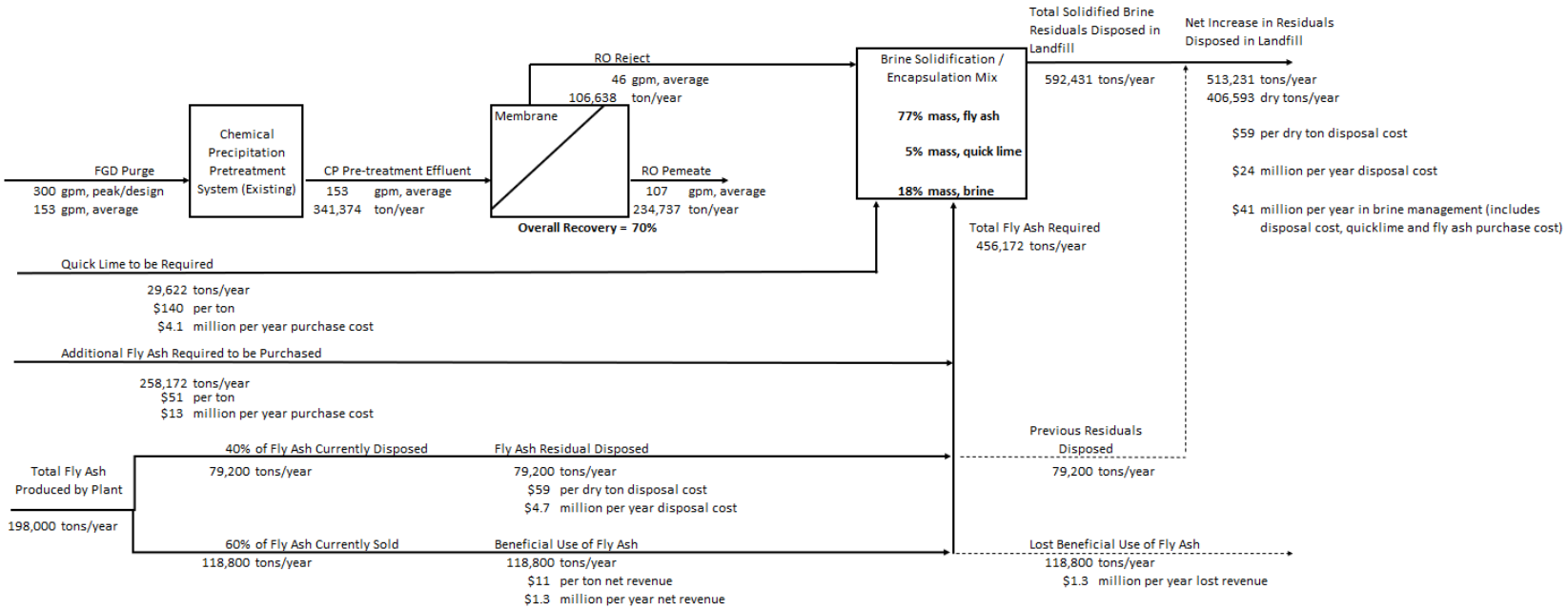


Figure E-5. Case Study Fly Ash Demand

Table E-3 provides various scenarios for membrane system overall recoveries (50%, 70%, and 81%) and EPRI's estimated range of fly ash generation for a plant that generates 300 gpm FGD wastewater (119,000 to 336,000 tons of fly ash per year). In previous evaluations by EPRI [EPRI, 2020], a recovery of 81% was the maximum recovery that could be achieved using a conventional membrane approach, namely full softening pre-treatment followed by a 3-stage seawater reverse osmosis (SWRO) system with an interstage booster pump system. Therefore, this is the maximum recovery assumed in Table E-3.

The analysis in Table E-3 shows that there is a predicted fly ash deficit in all but one membrane treatment scenario (maximum membrane recovery, largest MW plant). This would indicate that most sites would be required to evaluate additional options to arrive at a viable membrane treatment solution and a suitable brine and fly ash mass balance. Options could include purchasing significant quantities of supplemental amendments or evaluating technologies that would be capable of further concentrating brine volumes (e.g., concentrating RO reject with a thermal system or replacing membrane with a thermal evaporative systems).

Table E-3. Fly Ash Quantities for Variable Membrane Scenarios

Assumed Membrane Recovery (%)	Fly ash Required (tons/year)	Assumed Fly Ash Available (tons/year)	Fly Ash Deficit (tons/year)
50	732,000	119,000	613,000
50	732,000	198,000	534,000
50	732,000	336,000	396,000
70	456,000	119,000	337,000
70	456,000	198,000	258,000
70	456,000	336,000	120,000
81	309,000	119,000	190,000
81	309,000	198,000	111,000
81	309,000	336,000	0

Previous analysis by EPRI, as presented in Table 4-2 of the 2020 ELG comments [EPRI, 2020], showed that the total annualized costs for a plant could vary by $60 million dollars annually based only on the ability of the membrane system to achieve 50 percent versus 81 percent overall recovery.

E.3.4 Treatment System Capacity and Equipment Redundancy

In this case study, EPRI has assumed that the existing chemical precipitation system was designed for 120 percent of the 300 gpm peak flow, meaning that the system would be capable of treating a maximum flowrate of 360 gpm. Further, it was assumed that the FGD wastewater was pretreated through two identical chemical precipitation treatment trains, each train sized at 60 percent of peak capacity for all equipment.

The existing biological system capacity was assumed to be sized for the peak flow of 300 gpm with equipment sizing based on N+1 redundancy. The dewatering equipment was also sized for N+1 redundancy.

This case study assumed that the facility would continue to operate the existing chemical precipitation pretreatment system. Therefore, it was assumed that the membrane system would be designed to accommodate the maximum chemical precipitation effluent flowrate of 360 gpm. The membrane system would be designed for a total capacity of 360 gpm and would be configured with multiple trains to provide for N+1 redundancy should one train need to be taken out of service for maintenance.

A dual pug mill system (N+1 design redundancy) was assumed for the brine solidification subsystem. The actual degree of redundancy that plants will choose will be based on site-specific considerations, including equipment already in place at the time of membrane treatment conversion.

E.4 Case Study Evaluation of Conversion to Membrane Treatment

This section evaluates the requirements for a site to convert from a chemical precipitation followed by biological treatment system (Figures E-2 and E-3) to a chemical precipitation followed by membrane treatment and brine solidification system (Figure E-4), as described in the previous sections.

The basis for this conversion is shown in Figure E-6.

Membrane treatment, including its necessary pretreatment (to minimize membrane fouling and scaling), and its necessary post-treatment (to meet the objectives of RO brine solidification for waste disposal), is a site-specific process dependent on FGD wastewater characteristics and site conditions. This case study makes some general assumptions on what treatment systems would be required to operate a membrane filtration treatment system; however, this will vary considerably from site to site. Also, since there are no, full-scale, permanent installations of membrane treatment systems for FGD wastewater in the United States, there are many unknowns for the application of membranes to treat FGD wastewater.

This case study assumes that most of the chemical precipitation system would continue to operate for membrane pretreatment. This is illustrated in Figure E-6. Many sites will not have a fully optimized chemical precipitation system (Figure E-2) and may also need to upgrade their existing chemical precipitation systems in order meet the feed requirements for membrane systems.

Chemical use in the chemical precipitation pre-treatment system would require site-specific evaluation. For this case study, it is assumed that lime would continue to be added to the FGD wastewater to desaturate and precipitate calcium sulfate upstream of the membrane system. The clarifier sludge would be managed using the existing sludge storage and dewatering equipment.

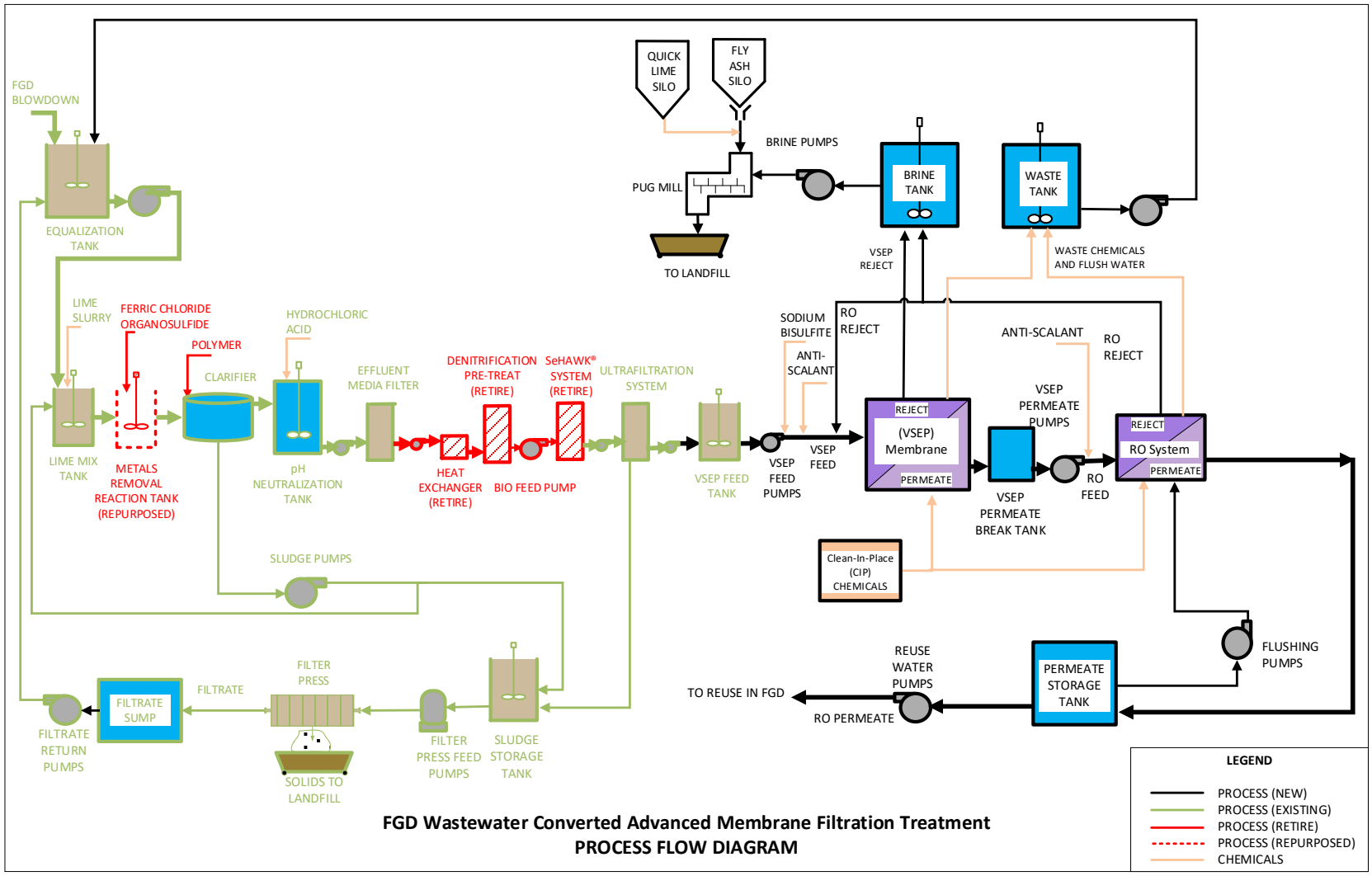


Figure E-6. Chemical precipitation + biological conversion to chemical precipitation + advanced membrane filtration and brine solidification

The remaining chemicals (ferric chloride, organosulfide polymer, and cationic polymer) were assumed to be decommissioned as the membrane system is brought online, based on the following rationale and consultation with AMF equipment suppliers:

- Use of cationic polymers can irreversibly foul membranes. Therefore, it was assumed that the use of polymer would need to be discontinued.
- Use of organosulfide polymer can lead to membrane operating challenges and has been shown to negatively affect VSEP recovery rates, leading to an increase in the brine volume generated. Therefore, this case study assumed that organosulfide use would be discontinued. However, in actual application, plants will need to weigh whether to use organosulfide pre-treatment upstream of membrane systems based on site-specific FGD wastewater quality and system design.
- Naturally occurring mineral salts, like ferric chloride, are typically used for arsenic and mercury removal and may continue to be used for membrane pre-treatment. However, ferric chloride coagulation can have reduced performance without the use of the beforementioned polymer for flocculation and settling. For this reason, this case study assumed that ferric chloride addition would be discontinued. Actual sites will need to determine whether there are advantages to using mineral salt additives based on the site-specific FGD wastewater quality and system design.

Ferric chloride, organosulfide and polymers are typically added to provide targeted metals removal and solids pre-treatment in existing chemical precipitation treatment systems to achieve discharge limits but would be retired based on the rationale stated above. However, some sites may need to leave the metals removal system in place, particularly where the membrane system is unable to consistently produce permeate quality objectives.

For this case study, the only chemical precipitation equipment that was assumed to be removed from service was the metals removal reaction tank, mixer, and chemical feed systems (except for lime, which would continue to be used for desaturation). The metals removal reaction tank and mixer were assumed to be repurposed for use as the VSEP feed tank.

This case study assumed that most sites would continue to operate the chemical precipitation effluent media filter and filter backwash system. Previous VSEP pilot test results indicate that operating a VSEP system with FGD feed wastewater of 30 to 40 mg/L TSS was acceptable [New Logic, 2015]. Some facilities may not be able to consistently achieve a low TSS carryover in the clarifier and may be required to continue to operate (or install) a chemical precipitation system effluent filter. Solids removal pre-treatment requirements will vary based on the type of membrane system installed.

Most of the biological treatment system components would be retired in this case study, including the heat exchanger, the denitrification system, and the SeHAWK® biological system (for selenium and nitrate reduction).

The heat exchanger, which was previously included for cooling (or heating) the FGD wastewater prior to the SeHAWK® system, is assumed to be retired. Membrane elements have a maximum allowable operating temperature limitation. The industry standard for reverse osmosis and nanofiltration membrane elements is typically a maximum operating temperature of 45 deg C (113 deg F) [IWC,2019]. This case study assumes that the FGD feed water would be lower at 95 deg F (Table E-2). Therefore, this case study assumes that cooling the FGD wastewater upstream of the membrane system would not be required. However, some facilities may be required to continue operating the heat exchanger, depending on the influent FGD feed water temperature and the preferred membrane operating temperature.

This case study assumes that an ultrafiltration membrane post-treatment system would have been installed downstream of the SeHAWK® bioreactor for removal of particulate or colloidal metals. Some facilities may choose to continue to operate their ultrafiltration system to safeguard against membrane scaling/fouling or to achieve greater overall recovery in the VSEP/RO system. Therefore, this case study assumes that the ultrafiltration system would continue to operate and provide additional pretreatment ahead of the VSEP/RO system.

This case study assumes that a sodium bisulfite (SBS) feed system would be added ahead of the VSEP/RO. Previous EPRI research has indicated there is a concern that the highly oxidized nature of FGD wastewater could significantly reduce membrane life; however, there is limited information available on the forms/types of oxidants. Sodium bisulfite is a reducing agent that could be used for free chlorine and oxidant removal to guard against membrane attack [EPRI, 2019b].

The remainder of the equipment necessary to operate the membrane treatment system would be newly installed. A set of new high pressure VSEP feed pumps would transfer wastewater from the pre-treatment system to the membrane system. The membrane treatment system components were previously described in Section E.3.3.2. It is assumed that a new dedicated building would be required to house the membrane treatment system, chemicals and the pug mill system. The waste tanks would be installed outdoors.

E.5 Case Study Cost Estimates

EPRI has previously developed cost estimates for chemical precipitation and biological treatment systems for FGD wastewater. The cost estimates developed for this case study analysis follow the same cost methodology and basis as previously costed for ELG rule commenting in 2020 [EPRI, 2020]. The estimates in this memo differ from EPRI cost estimates previously presented in 2020 as follows:

- **Chemical precipitation** – the previous conceptual design was a 2x100% configuration [Table A-5, EPRI, 2020], whereas the basis for this estimate assumes that a 2x60% configuration was originally installed.
- **Biological** – the previous conceptual design included the costs for pile foundations [Table B-5, EPRI, 2020], whereas these costs have been removed in this case study to

simplify and focus the approach in evaluating potential membrane conversion costs. The previous cost estimate [Table B-6, EPRI, 2020] included 50 percent of the total estimated cost of a sodium bisulfite system, whereas this case study assumes this system was not originally installed and must be installed new as part of the membrane conversion.

E.5.1 Brine Solidification Cost Estimating Basis

This case study considered two potential costing scenarios in development of the brine solidification costs, based on two key variables introduced previously (fly ash available and fly ash sold). The assumed membrane recovery is the same for both costing scenarios, and equal to 70 percent. The two cost scenarios are described below and further illustrated in Figures E-7 and E-8 at the end of Section E.5:

- Higher fly ash cost (Figure E-7):
  - Case study site produces the average of the EPRI estimated fly ash range equal to 198,000 tons of fly ash per year, which is an insufficient quantity for brine solidification.
  - The site would be required to (and is able to) purchase and import approximately 258,172 tons of supplemental fly ash per year.
  - Case study site currently sells 60 percent of its fly ash (118,800 tons per year) and disposes of the other 40 percent of fly ash (79,200 tons per year). All the fly ash that is currently produced (all ash disposed and sold) is diverted for use in brine solidification. This results in 118,800 tons per year of lost fly ash sales.
  - Case study site currently disposes of 79,200 tons of fly ash per year. The new brine solidification waste generated would be 592,431 tons per year on average. This results in a net increase of 513,231 tons per year of residual waste that requires landfill disposal.
  - The residuals disposal costs are estimated on a dry weight basis. For this reason, the mass of brine (106,638 tons per year) was further deducted from the net increase in residual waste (513,231 tons per year). Therefore, the residual quantity used for costing purposes was 406,593 dry tons per year.
- Lower fly ash cost (Figure E-8):
  - Case study site produces enough fly ash onsite for brine solidification (equal to or greater than 456,172 tons per year). As noted, this quantity is higher than the predicted range of fly ash available for a 300 gpm FGD wastewater plant and represents a low-cost scenario.
  - The site is not required to import any fly ash. As previously noted in Section E.2.3, EPRI found that for sites with 300 gpm of FGD wastewater, the fly ash generation was estimated to be between 119,000 to 336,000 tons per year, with an average of 198,000 tons per year per plant, meaning most sites would not generate the 456,172 tons per year of fly ash that this scenario assumes.

- Case study site currently sells no fly ash and disposes of 100 percent of its fly ash. Therefore, the site is not required to forego any fly ash sales.
- Case study site currently disposes of 456,172 tons of fly ash per year. The new brine solidification waste generated would be 592,431 tons per year on average. This results in a net increase of 136,259 tons per year of residual waste requiring landfill disposal.
- The residuals disposal costs are estimated on a dry weight basis. For this reason, the mass of brine (106,638 tons per year) was further deducted from the net increase in residual waste (136,259 tons per year). Therefore, the residual quantity used for costing purposes was 29,622 dry tons per year.

E.5.2 Capital Cost Estimate

The capital costs presented in this estimate are based on total installed costs, which include:

- **Direct costs** – equipment, freight, taxes, field construction (buildings, site work, concrete foundation, piping, mechanical, electrical, and field instrumentation, and controls), general conditions, and bonding.
- **Indirect costs** – engineering, commissioning and start-up, contractor profit, and contingency for miscellaneous unidentified costs.
- **Owner's costs** – costs incurred by owners to manage and implement the project from start to acceptance.

This memorandum presents cost estimates in 2021 dollars. The cost estimates prepared are AACE Class 4 estimates (+50%/-30% accuracy), generally defined as study- or feasibility-level estimates, for total installed costs. System-wide cost factors were also applied to develop the cost estimate. Table E-5 shows a comparison of the cost factors that were previously assumed for the chemical precipitation system [EPRI, 2020] and the factors assumed for costing the converted chemical precipitation, advanced membrane filtration and brine solidification system.

Table E-4. Capital Cost Factors

Additional Cost Items	CP (%)	Converted CP + AMF/BS [1] (%)	Rationale for membrane system costs
Site work	4.0	4.0	Same as CP
Concrete	17.5	17.5	Same as CP
Piping	25.0	25.0	Same as CP
Miscellaneous metals, finishes	10.0	15.0	Higher than CP, assumes higher-grade alloys for brine management
Mechanical, heating/ventilation/air conditioning	7.5	7.5	Same as CP
Electrical (process electrical and site electrical)	22.0	22.0	Same as CP
Instrumentation and control	15.0	15.0	Same as CP
Subcontractor overhead	10.0	--	None, assumes membrane system would be installed primarily as vendor package with general contractor
General contractor general conditions	12.5	12.5	Same as CP
Bonding and insurance	2.85	2.85	Same as CP
General contractor profit	14.25	14.25	Same as CP
Miscellaneous unidentified cost (contingency)	20.0	20.0	Same as CP
Engineering (design, services during construction, start-up, operator training and pilot testing)	20.0	21.0	Same as CP, plus an additional 1% for pilot testing
Client Administrative and Overhead	--	7.0	Same as Bio

1. Cost factors applied to the newly installed equipment.

The costs associated with tie-ins and retrofitting will be highly site specific. For this cost estimate, EPRI estimated the same tie-in cost as for thermal evaporation case studies.

Facilities may have the opportunity to repurpose some of their existing equipment that would be otherwise retired. The costs developed for this case study sought to maximize equipment repurposing to minimize the cost of new equipment expenditures. Given the site-specific considerations for equipment repurposing, including appropriate sizing and physical location, opportunities for equipment repurposing will vary. This case study found limited opportunities to reuse existing equipment for other purposes. Only the metals mix tank and mixer were assumed to be repurposed as the VSEP permeate break tank. However, as previously stated,

some sites may have a strong preference to keep the equipment designated for targeted metals removal in service. If so, those sites may choose not to repurpose this tank.

Further, how retired equipment is managed will also be highly site-specific. Some facilities may choose to leave retired equipment in place, mothball or may perform deconstruction/demolition activities to remove equipment. For this case study, EPRI has assumed that retired equipment would remain in place. No costs have been added to account for equipment mothballing or demolition.

The VSEP and RO system equipment costs were estimated based on two equipment quotations provided to EPA by New Logic [ERG, 2019a] and other, recent cost estimates available to EPRI.

Table E-6 provides the capital cost estimate for a site to add an advanced membrane filtration and brine solidification system (AMF + BS) to the existing chemical precipitation and biological treatment system (CP + bio). Equipment components that would be reused but were already purchased during the original installation of the CP+ bio system, are shown as zero cost. Equipment components that assumedly would be retired (as shown in Figure E-6) are excluded from Table E-5.

Table E-5. Capital Cost Estimates (2021$)

Cost Element	Cost of Converted CP + AMF/BS	
	Lower Fly Ash Cost Scenario [1]	Higher Fly Ash Cost Scenario [2]
Equipment (Installed Cost)		
Equalization	--	--
Desaturation	--	--
Clarification	--	--
Neutralization	--	--
Solids Dewatering	--	--
Support Equipment (pumps, waste sump)	--	--
Effluent Filtration	--	--
Ultrafiltration	--	--
Membrane Feed System	148,000	148,000
VSEP / RO System	13,000,000	13,000,000
Chemical Feed Systems (Antiscalant, SBS)	193,000	193,000
Permeate Handling & Storage	1,999,000	1,999,000
Membrane Waste Neutralization & Handling	205,000	205,000
Brine Handling & Storage	1,784,000	1,784,000
Pugmill	2,073,000	2,073,000

Cost Element	Cost of Converted CP + AMF/BS	
	Lower Fly Ash Cost Scenario [1]	Higher Fly Ash Cost Scenario [2]
Quicklime Feed and Quicklime Silo	1,389,000	1,389,000
Fly Ash Silo	--	8,306,000
Freight (4%) and Taxes (0%)	832,000	1,164,000
Subtotal – Purchased Equipment Cost as Delivered	**21,623,000**	**30,261,000**
Additional Direct Costs		
Pre-engineered building	2,587,000	2,587,000
Tie-in allowance	97,000	97,000
Site work	865,000	1,210,000
Piping	5,406,000	7,565,000
Mechanical/ HVAC	1,622,000	2,270,000
Instrumentation and Controls	3,243,000	4,539,000
Electrical	4,757,000	6,657,000
Concrete	3,784,000	5,296,000
Miscellaneous metals, finishes	3,243,000	4,539,000
Subtotal Direct Cost	**47,227,000**	**65,021,000**
General Contractor General Conditions	5,903,000	8,128,000
Bonding and insurance	1,346,000	1,853,000
General Contractor Profit	6,730,000	9,265,000
Subtotal	**61,206,000**	**84,267,000**
Miscellaneous Unidentified Cost (Contingency)	12,241,000	16,853,000
Subtotal – Estimated Construction Cost	**73,447,000**	**101,120,000**
Engineering (Design, Services During Construction, Startup, Operator Training and Pilot Testing)	15,424,000	21,235,000
Permitting	62,000	62,000
Client Administrative and overhead	5,141,000	7,078,000
Total Estimated Capital Cost (+50%/-30%)	**94,000,000**	**130,000,000**

1. Lower fly ash cost scenario which assumes no cost for offsite purchase and import of fly ash (i.e., site has sufficient fly ash available). This scenario also assumes that fly ash is not sold by the utility. See Section E.5.1 for description.
2. Higher fly ash cost scenario which assumes site must purchase, import, and store additional fly ash equal to 258,000 tons of fly ash per year. This scenario also assumes that 60 percent of fly ash is currently sold by the utility. See Section E.5.1 for description.

E.5.3 Operations and Maintenance Cost Estimate

The operations and maintenance (O&M) requirements and cost estimate for this case study are provided in this section.

Major assumptions for the case study O&M cost estimate include:

- The annual average FGD wastewater flow is 153 gpm (Table E-1). The VSEP/RO system is assumed to recover 70% of water overall. Thus, 30% of the FGD wastewater would be rejected as RO waste brine, equal to 46 gpm on an annualized average basis.
- The total quantity of RO waste brine generated would be 106,638 tons per year. This brine would be mixed with quicklime (5 mass percent of total waste) and fly ash (77 mass percent of total waste) and disposed of as a solid waste residual.
- The VSEP filtration system and RO membranes elements are assumed to be replaced out once every three years.
- Membrane cleaning frequency has not been clearly demonstrated and is unknown. Several types of membrane cleaning chemicals may be used depending on the membrane system installed and characteristics of the FGD wastewater. Past pilot reports by VSEP [New Logic Research, 2015], described use of “NLR 404” an acidic cleaning solution and “NLR 505” a caustic cleaning solution. This case study assumed an average use of 40 gallons per day for a membrane cleaning chemical.
- As noted, EPRI has assumed a plant capacity factor of 0.51, which is the industry average based on data from 2015 through 2017. (The assumed online factor for the biological system was higher at 0.75 to account for wastewater recirculation and nutrient feed demands that would be required to sustain the microbe community even when the power plant is not operating.)
- Labor requirements for the converted CP + AMF/BS system would be similar to existing operations, whereas:
  - EPRI had previously estimated that four full-time equivalent (FTE) operators, one FTE dedicated to dewatering operations and one supervisor would be required for the CP system [EPRI, 2020]. It is assumed that these staff would continue to oversee operations of the chemical precipitation pre-treatment system.
  - EPRI had assumed that two FTE operators would be required to operate a biological treatment system that included denitrification pretreatment [EPRI, 2020].
  - This case study assumes that no additional FTE operators would be required to operate the membrane and brine solidification system. It is assumed that the two biological treatment system operators would be re-trained to operate the new VSEP/RO system and continue to operate the ultrafiltration system.
  - It is also assumed that the operators running the existing ash conditioning system would be re-trained to operate the new pug mill system. Additional operators may be required

to support brine solidification activities based on the quantity of solidified brine waste generated.

  - One new chemical engineer would be hired to support membrane chemistry and solidification waste chemistry analysis.
  - Therefore, this case study assumes a total of seven FTE operators, one FTE supervisor and one FTE chemical engineer would be required to operate the treatment system.

- Residuals were assumed to be disposed as non-hazardous waste at $59 per dry ton. All solids were assumed to be Resource Conservation and Recovery Act (RCRA) nonhazardous solids. The disposal cost was developed as a weighted average using the on-site and off-site disposal costs previously provided in EPA's Incremental Costs and Pollutant Removals for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Generating Point Source Category [EPA, 2013]. EPRI assumed 75 percent of plants would use on-site disposal facilities at $40.41 per dry ton (June 2010$), and 25 percent of plants would use off-site disposal facilities at $49.82 per dry ton (June 2010$), to arrive at a weighted average of $42.76 per dry ton (June 2010$). This weighted unit cost was then escalated to a 2021 cost basis of approximately $59 per dry ton.
- EPRI is making the assumption that there is sufficient fly ash available in the industry that would allow sites to consider purchasing additional fly ash as needed. Given recent coal plant retirements, this may not be possible.
- The market price for imported fly ash (i.e., the additional fly ash required for brine solidification beyond what the site generates), was assumed to be $51 per ton in 2021$ (including transportation). EPRI believes this to be a reasonable, relatively low market price for fly ash based on recent publications by Boral that indicate fly ash pricing is growing [Boral, 2018]:
  - In 2018, Boral presented a fly ash market price range of $25 to $75 per ton. The average market price escalated to June 2022$ would be $59 per ton. [Boral, 2018]
  - In 2019, Boral presented a fly ash market price range of $40 to $100 per ton. The average market price escalated to June 2022$ would be $82 per ton. [Boral, 2019]
- The net revenue loss for fly ash sales was assumed to be $11 per ton in 2021$.

The O&M cost estimate for this case study includes the following cost elements:

- Chemicals (see Table E-7)
- Brine solidification supplements (quicklime, imported fly ash)
- Electricity
- Residuals disposal (pre-treatment sludge waste, solidified brine waste)
- Equipment maintenance
- Membrane replacement

- Labor
- Compliance monitoring
- Lost fly ash sales revenue

Table E-6. Wastewater Treatment Chemical Use

Chemical	Dosages (mg/L)	
	CP + Bio	CP + AMF/ BS
Hydrated Lime	3,000	3,000
Organosulfide	30	--
Ferric chloride	100	--
Premixed polymer	10	--
Hydrochloric acid	300	300
Sodium Bisulfite	--	20
Antiscalant	--	20

Table E-8 provides the O&M cost estimates for the new annual O&M costs to operate a treatment system consisting of chemical precipitation pre-treatment, advanced membrane filtration and brine solidification system (CP + AMF/BS). The O&M costs presented provide a total cost estimate for the case study site to continue operating the chemical precipitation treatment subsystems (those CP subsystems that would remain in service) and also the cost to operate the new membrane and brine solidification systems. These estimates do not include the cost to operate the biological treatment system (except for the ultrafiltration system). O&M cost estimates are presented for the lower and higher fly ash cost scenarios in Table E-8.

The total O&M cost estimate for the converted CP + AMF/BS system is shown compared to a chemical precipitation followed by biological treatment system (CP + bio system) in Table E-8. As shown, the additional annual cost to operate a converted CP + AMF/BS system is estimated to be approximately $10 to $47 million per year.

Table E-7. Annual O&M Costs (2021$)

Cost Element	CP + Bio [1]		Converted CP + AMF/BS		Cost Basis
	CP	Bio	Lower Fly Ash Cost Scenario [2]	Higher Fly Ash Cost Scenario [3]	
Chemicals / Amendments					
Hydrated lime	234,000	--	235,000	235,000	$0.10 per pound
Ferric chloride (35%)	25,000	--	--	--	$2.13 per gallon
Organosulfide	10,000	--	--	--	$12.85 per gallon
Hydrochloric acid (30%)	18,000	--	17,000	17,000	$0.74 per gallon
Polymer	6,000	--			$39.67 per gallon
Reagents	--	4,000	--	--	Placeholder
Antiscalant	--	--	33,000	33,000	$18.78 per gallon
Sodium Bisulfite	--	--	5,000	5,000	$3.17 per gallon
Membrane Cleaning	--	--	213,000	213,000	$14.95 per gallon
Quicklime	--	--	4,435,000	4,435,000	$0.075 per pound
Fly Ash (Imported)	--	--	--	13,181,000	$51.05 per ton
Electricity [4]	31,000	400,000	240,000	240,000	$0.0559 per kW-hr
Residuals					
Chemical Precipitation	320,000	--	321,000	321,000	$59 per dry ton (RCRA nonhazardous)
Biological	--	2,000			$59 per dry ton (RCRA nonhazardous)
Solidified Brine [5]	--	--	1,749,000	23,989,000	$59 per dry ton (RCRA nonhazardous)
Maintenance	212,000	86,000	682,000	927,000	3%/yr of installed equipment cost
Membrane Element Replacement	--	--	889,000	889,000	Replace every 3 years

Cost Element	CP + Bio [1]		Converted CP + AMF/BS		Cost Basis
	CP	Bio	Lower Fly Ash Cost Scenario [2]	Higher Fly Ash Cost Scenario [3]	
Labor					
CP Operators	449,000		449,000	449,000	4 FTEs, $54 per hour
CP Dewatering Operators	113,000	--	112,000	112,000	1 FTE, $54 per hour
Bio Operators		224,000	--	--	2 FTEs, $54 per hour
Membrane Operators	--	--	174,000	225,000	2 FTEs, $54 per hour
Pugmill Operators	--	--	--	--	0 FTEs, $54 per hour
Supervisor	173,000	--	174,000	174,000	$84 per hour
Chemical Engineer	--	--	209,000	209,000	$100 per hour
Compliance	165,000		166,000	166,000	Placeholder
Lost Fly Ash Sales	--	--	--	1,305,000	$11 per ton
Total Estimated O&M Cost per Year ($M)	1.7	0.8	10.1	47.1	
Total Estimated O&M Cost per Year ($M)	2.5		10.1	47.1	

1. Costs presented in EPRI 2020 comments [EPRI, 2020] Appendix A and B, escalated to 2021 dollars.
2. Lower fly ash cost scenario which assumes no cost for offsite purchase and import of fly ash (i.e., site has sufficient fly ash available). This scenario also assumes that fly ash is not sold by the utility. See Section E.5.1 for description.
3. Higher fly ash cost scenario which assumes site must purchase, import, and store additional fly ash equal to 258,000 tons of fly ash per year. This scenario also assumes that 60 percent of fly ash is currently sold by the utility. See Section E.5.1 for description.
4. Combined SeHAWK® cost estimate for energy and chemicals
5. Incremental cost of dry residuals disposal, after deducting the mass of existing fly ash being disposed and the mass of brine.

Figures E-7 and E-8 provide block flow diagrams, mass balances and O&M costs to further explain the brine solidification aspects of this case study for the high and low fly ash cost options, respectively.

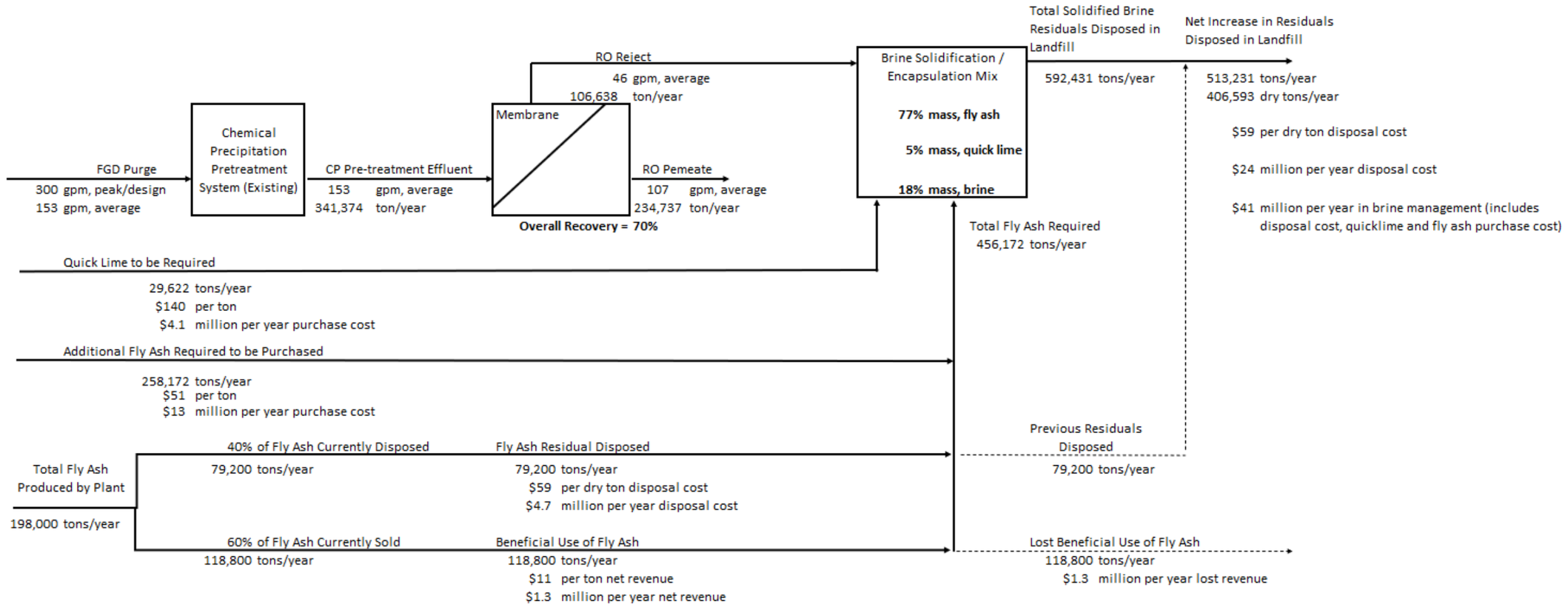


Figure E-7. Case Study Block Flow Diagram, Higher Fly Ash Cost Scenario

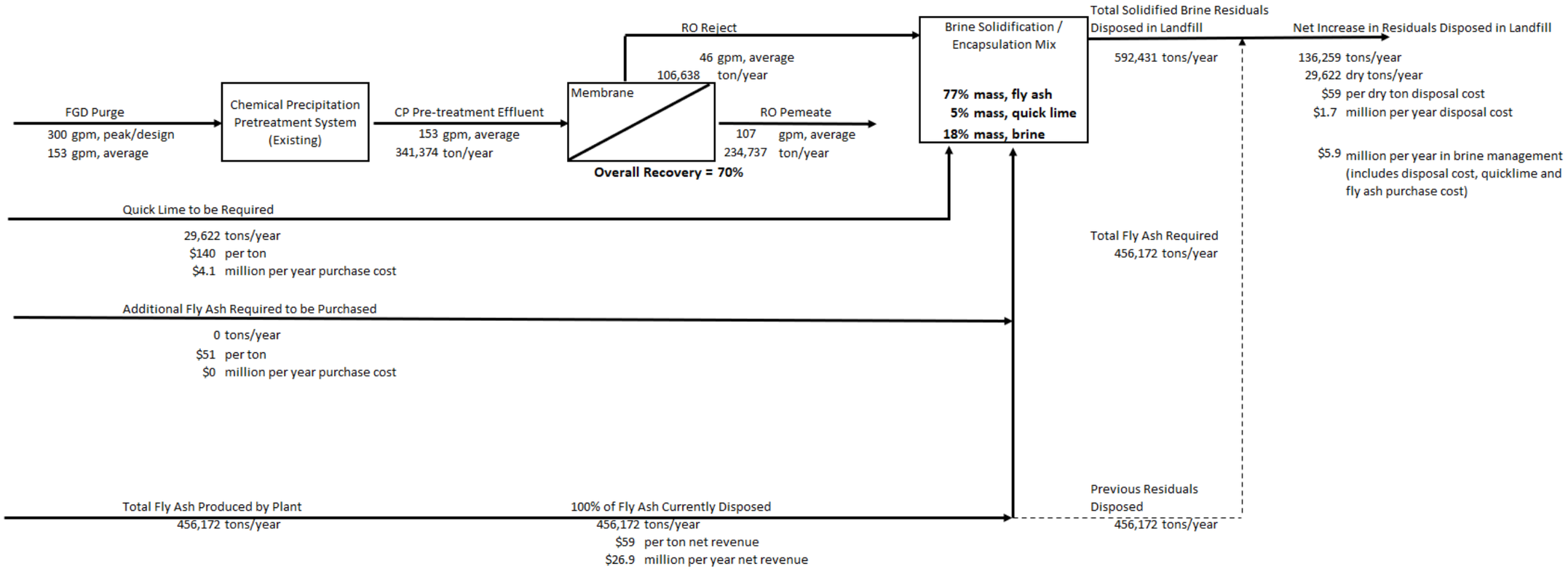


Figure E-8. Case Study Block Flow Diagram, Lower Fly Ash Cost Scenario

E.6 BAT Comparative Cost Summary

As noted, EPRI has previously developed cost estimates for chemical precipitation and biological treatment systems when these technologies were proposed as BAT in 2013 and 2019. Using these past cost estimate methodologies, the estimated capital cost for a 300 gpm FGD wastewater treatment system, with two trains at 60 percent peak flow capacity per CP train and N+1 redundancy for the biological system, would be approximately $57 million.

Table E-9 provides a comparative cost summary of FGD wastewater BAT options. The first column provides the cost estimate for a plant to implement a 300 gpm CP + Bio treatment system. The next two columns show the cost estimates for a site to convert from a CP + Bio system to a 300 gpm CP + AMF/BS system based on the lower fly ash and higher fly ash cost scenarios, respectively. It is important to point out that the capital cost for the converted option represents only the expenditure to convert the existing CP + bio treatment system to include advanced membrane filtration and brine solidification. As such, these columns show only the capital costs for the new equipment systems added (AMF and BS) and do not represent the total power plant capital expenditure for previously installed (and reused) chemical precipitation and biological systems. The total estimated capital expenditure (CP + Bio + AMF + BS) is presented in the fourth column as “CP + AMF/BS Total Converted” and is based on the higher fly ash cost scenario. Finally, the last column in Table E-9 shows the cost for a site to install a CP + AMF/BS as a new system assuming a CP + Bio system was never installed, which is labeled as “CP + AMF/BS New,” and is also based on the higher fly ash cost scenario. This final cost estimate for a new CP + AMF/BS has been developed to compare the cost expenditure for a new system and a converted system. As shown in Table E-3, it is anticipated that most sites will not have sufficient fly ash available. Therefore, the higher fly ash cost scenario is most appropriate for a BAT option cost comparison.

The O&M costs for operating each of the BAT options are also shown in Table E-8. The annualized cost for a converted FGD wastewater treatment system was estimated to be approximately $19 million to $59 million per year, which is significantly more costly than the $7.7 million estimated annualized cost for an existing CP + Bio treatment system.

Table E-8. BAT Cost Summary (2021$)

Cost Element	CP + Bio	Converted CP + AMF/BS (Low Fly Ash Cost) [4]	Converted CP + AMF/BS (High Fly Ash Cost) [4]	CP + AMF/BS Total Converted [5] (High Fly Ash Cost)	CP+AMF/BS New [6] (High Fly Ash Cost)
Capital Costs ($M)	57	94	130	187	170
Annualized Capital Costs ($M per year) [1]	5.4	8.8	12.2	17.6	16.0
O&M Costs ($M per year) [2]	2.4	10.2	47.1	47.1	47.1
Total Annualized Costs ($M per year) [3]	7.8	19	59	65	63

1. Annualized cost based on a 20-year equipment life and 7% interest rate.
2. Total O&M cost including wastewater treatment costs and disposal costs. O&M costs to operate a CP + bio system are compared to the O&M costs to operate a CP + AMF/BS system. These costs include imported fly ash and lost fly ash sales for the high fly ash option.
3. Total annualized cost is sum of annualized capital cost and annual O&M cost.
4. Capital cost represents the expenditure to convert the treatment system to advanced membrane filtration and brine solidification. Costs include only the new equipment systems added and do not represent the total power plant expenditure for previously installed chemical precipitation and biological systems.
5. Capital cost represents the total capital expenditure for a converted CP+AMF/BS system, including retired-in-place biological equipment and the costs to retrofit the CP + bio system.
6. Capital cost represents the cost to newly install a CP + AMF/BS system, assuming a CP + bio system was never installed.

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F SUMMARY OF FGD WASTEWATER INDUSTRY COST METHODOLOGY — THERMAL AND/OR MEMBRANE ZERO LIQUID DISCHARGE TREATMENT

F.1 Cost Estimate Summary

The Electric Power Research Institute (EPRI) estimated the cost for the steam electric power industry to convert to a thermal and/or membrane-based zero liquid discharge (ZLD) treatment system for flue gas desulfurization (FGD) wastewater. The industry profile is based on the list of 22 plants that are anticipated to discharge FGD wastewater after 2032 and therefore would need to comply with proposed regulatory option 3: chemical precipitation (CP) followed by membrane filtration. This list of industry plants is provided in Table F-9.

This technical memorandum provides the technical considerations and methodology for estimating the cost of thermal and/or membrane treatment to the steam electric power industry. EPRI's method considers the cost for each facility to modify its existing treatment system, which is assumed to be CP + biological treatment for all plants, and convert to a thermal and/or membrane-based treatment system to comply with the proposed supplemental 2023 ELG rule. Table F-1 summarizes the projected technology choices and estimated cost to the industry to convert from the power plant's existing CP + biological FGD wastewater treatment system to one of three potential thermal and/or membrane ZLD treatment systems:

1. Chemical softening, vapor-compression evaporation, and crystallization (CS + VCE/CRX), as presented in Appendix C.
2. Chemical precipitation, vapor-compression evaporation, and brine solidification (CP+VCE/BS), as presented in Appendix D.
3. Chemical precipitation, advanced membrane filtration (AMF) and brine solidification (CP+AMF/BS), as presented in Appendix E.

EPRI selected one of the above technology options for each of the 22 industry plants based on the annual average FGD wastewater flows and the total quantity of fly ash produced by each individual facility. The following methodology was used:

- If the facility produced sufficient fly ash to solidify the brine generated from a 70 percent recovery membrane system, assuming a truckable waste mixture (18 weight percent brine, 77 weight percent fly ash, and 5 weight percent quicklime), then EPRI selected CP+AMF/BS technology.
- If the facility produced sufficient fly ash to solidify the brine generated from a 90 percent recovery vapor compression evaporation system, also assuming a truckable waste mixture, then EPRI selected CP+VCE/BS.

- If the facility did not produce sufficient fly ash to solidify the volume of brine generated from a membrane or a vapor compression evaporator system, then EPRI selected CS+VCE/CRX.

The results of this analysis indicate that only three of 22 plants produce sufficient fly ash to consider CP + AMF/BS and only 5 plants produce sufficient fly ash to consider CP + VCE/BS, as shown in Table F-1. The remaining 14 plants would need to install CS+VCE/CRX or consider other options.

Table F-1. Thermal and/or Membrane Treatment Cost to Industry for FGD wastewater, in 2021 dollars [1]

Treatment Option	Number of Plants	Capital Cost ($M)	Operations and Maintenance Cost ($M per year)	Annualized Cost [1] ($M per year)
CP + AMF/BS	3	**139**	**41**	**54**
CP + VCE/BS	5	**268**	**48**	**73**
CS + VCE/CRX	14	**3,401**	**262**	**582**
Total Industry	22	**3,808**	**351**	**709**

1. Annualized cost based on a 20-year equipment life and 7% interest rate.

$ = U.S. dollars

M = million

Next, EPRI evaluated the total cost to the industry if all 22 plants installed one of the three technology options considered. A summary of the estimated industrywide costs is shown in Table F-2.

Table F-2. Thermal and/or Membrane Treatment Cost to Industry for FGD wastewater, in 2021 dollars [1]

Treatment Option	Total Plants in Industry	Capital Cost ($M)	Operations and Maintenance Cost ($M per year)	Total Annualized Cost [a] ($M per year)
CP + AMF/BS	22	5,410	2,783	3,292
CP + VCE/BS	22	2,050	893	1,086
CS + VCE/CRX	22	4,145	303	693

1. Total annualized cost is annualized capital cost (based on a 20-year equipment life and 7% interest rate) plus annual operations and maintenance cost.

$ = U.S. dollars

M = million

Finally, EPRI evaluated the cost estimates for the three technology options for each plant and identified the lowest cost ZLD option for each of the 22 plants. The total lowest cost to the industry is shown in Table F-3.

Table F-3. Thermal and/or Membrane Treatment Cost to Industry for FGD wastewater, in 2021 dollars [1]

Treatment Option	Number of Plants	Capital Cost ($M)	Operations and Maintenance Cost ($M per year)	Total Annualized Cost [a] ($M per year)
CP + AMF/BS	0	0	0	0
CP + VCE/BS	10	546	98	149
CS + VCE/CRX	12	3,050	241	528
Total Industry	**22**	**3,596**	**339**	**677**

1. Total annualized cost is annualized capital cost (based on a 20-year equipment life and 7% interest rate) plus annual operations and maintenance cost.

F.2 Introduction

The revision to Title 40 Code of Federal Regulations (CFR) Part 423, commonly known as the Steam Electric Effluent Limitation Guidelines (ELGs), has been through various stages of rulemaking since 2013 where the limits and best available treatment technologies economically achievable (BAT) set by the EPA have been changed iteratively. EPRI has evaluated and prepared cost estimates for several thermal and/or membrane technologies, as described in preceding appendices.

This appendix evaluates the technical considerations and costs for the 22 plants that are anticipated to generate FGD wastewater after 2032. These plants would be required to convert their existing FGD wastewater CP + biological treatment system to a thermal and/or membrane-based ZLD treatment system.

F.3 Case Study Basis

As previously described in Appendices C through E, EPRI has evaluated several technologies that could be used to implement zero liquid discharge (ZLD) treatment for FGD wastewater. A comparative summary of the capital, O&M and total annualized cost estimates for the different ZLD design technology options is presented in Table F-4. Each case study cost estimate presented in Table F-4 assumes a 300 gpm FGD wastewater design flow basis but varies based on the assumed equipment redundancy and technology option selected.

Table F-4. FGD wastewater BAT Cost Summary for 300 gpm case study (2021$)

Cost Element	CP + Bio	CS + VCE/CRX [5]	CP + VCE/BS [6]	CS + SWRO/BS [7]	CP+AMF/BS [8]
Capital Costs ($M) [1]	57	157	109	115	170
Annualized Capital Costs ($M per year) [2]	5.4	14.8	10.2	10.8	16.0
O&M Costs ($M per year) [3]	2.4	7.1	11.7	30.8	47.1
Total Annualized Costs ($M per year) [4]	7.8	22	22	42	63

1. Capital cost to newly install the FGD wastewater treatment system.
2. Annualized cost based on a 20-year equipment life and 7% interest rate.
3. Total O&M cost including wastewater treatment costs and disposal costs. O&M costs to operate a CP + bio system is compared to the O&M costs to operate other systems. These costs include imported fly ash and lost fly ash sales, when applicable.
4. Total annualized cost is sum of annualized capital cost and annual O&M cost.
5. Cost of chemical softening (CS) with vapor-compression evaporation/crystallization (CS + VCE/CRX) assuming 2 × 60% redundancy system (Appendix C)
6. Cost of chemical precipitation (CP) followed by vapor-compression evaporation and brine solidification (CP + VCE/BS) (Section D.1.2)
7. Cost of chemical softening (CS) followed by seawater reverse osmosis and brine solidification (CS + SWRO/BS) (Section D.1.3)
8. Cost of chemical precipitation (CP) followed by advanced membrane filtration and brine solidification (Appendix E). Capital cost represents the cost to newly install a CP + AMF/BS system, assuming a CP + bio system was never installed. Costs shown are for the higher cost fly ash option.

F.4 Industry Profile

EPRI's estimate of industry cost was prepared for 22 plants that EPA reported will be generating FGD wastewater after 2032 [EPA, 2023a]. Three plants (Cross, Monroe, and Scherer) are designated as having opted into the 2020 voluntary incentives program (VIP) [Table 3, EPA, 2023b]. For these plants, EPA estimated zero capital and zero O&M costs [EPA, 2023c]. Similar to EPA, EPRI is not estimating costs for these three plants that elected to opt into the VIP.

For the 22 plants, EPA estimated capital costs for membrane filtration only. EPA did not estimate additional costs for CP pretreatment for the membrane filtration technology option, as plants are assumed to have come into compliance with the 2020 rule and already have this treatment in place. [EPA, 2023c] In order to match EPA's industry profile and cost basis, regardless of each plant's FGD wastewater treatment equipment currently in place, EPRI has assumed that all 22 plants have already installed CP and biological treatment as a baseline for costs.

F.4.1 Power Plant Capacity Factor

EPRI used the net generation rates from 2019 to 2021 to estimate an average capacity factor for each power plant. [EIA, 2019-2021]. The average capacity factor for each individual plant was used in place of the 0.51 capacity factor previously assumed in EPRI's FGD wastewater case study cost estimates.

F.4.2 Flow Basis

F.4.2.1 Peak Flow

The peak FGD wastewater flowrate reported for each plant was used to size all equipment and thereby determine the capital cost of the thermal and/or membrane system.

- For 2 plants, EPRI received the reported peak flow of the existing FGD treatment system directly from plant personnel and used this flow in place of the ICR response.
- For 9 plants, EPRI used the plant's reported peak wastewater treatment system (WWTS) design flow (2009 ICR response D5-3). No peaking factor was applied where EPRI used the plant's reported peak WWTS design flow.
- For the remaining plants, EPRI used the rationale as described in EPRI's 2020 ELG comments. If it appeared that EPA made reasonable adjustments to plant's reported typical purge flow based on units retired since the ICR response, then to determine peak flow, EPRI multiplied EPA's purge flow by a peaking factor of 1.5.

F.4.2.2 Annual Average Flow

The annual average FGD wastewater flowrate was used to calculate the operations and maintenance (O&M) quantities and the corresponding costs of operating the thermal and/or membrane system. EPRI estimated the annual average FGD wastewater flow for each plant in the following ways:

- For 2 plants, EPRI received annual average FGD wastewater flows directly from plant personnel and used this flow.
- EPRI evaluated power plant capacity factors for recent years 2019 through 2021 and calculated the average capacity factor for these three years.
- For 16 plants, EPRI determined that the average capacity factor for recent years 2019 - 2021 was lower than previously evaluated in 2020 ELG rulemaking. EPRI used this recent average capacity factor to scale each individual plant's 2009 ICR average flow in order to estimate the annual average FGD wastewater flow generated.
- For 2 plants, EPRI determined that the average capacity factor for years 2019 – 2021 was equal to the capacity factor previously evaluated in 2020 ELG rulemaking. EPRI used this recent average capacity factor to scale each individual plant's 2009 ICR average flow in order to estimate the annual average FGD wastewater flow generated.
- For the 2 remaining plants, EPRI did not have recent power plant capacity factors for years 2019 – 2022. EPRI used the original ICR response for FGD purge flow (ICR response B5-2) for the remaining 2 plants.

Table F-5 provides a summary of the peak and annual average flows assumed by EPRI for each of the 22 plants.

Table F-5. EPRI Peak and Annual Average FGD wastewater Flows Used for Cost Estimations

EPA ICR ID	Plant Name	Capital Cost Basis		O&M Cost Basis	
		EPRI Peak FGD Flow (GPM)	EPRI Peak FGD Flow (GPD)	EPRI Annual Average FGD Purge Flow (GPM)	EPRI Annual Average FGD Purge Flow (GPD)
493	J. K. Spruce Power Plant	90	129,600	53	75,777
771	OVEC – Kyger Creek Station	268	385,920	233	335,583
904	Muscatine Power and Water Generating Station	20	28,800	5	7,200
1236	Mitchell Plant	553	796,320	276	397,894
1381	EME Homer City Generation L.P.	159	228,960	95	137,280
1674	Trimble County	1,714	2,468,160	1,156	1,664,480

EPA ICR ID	Plant Name	Capital Cost Basis		O&M Cost Basis	
		EPRI Peak FGD Flow (GPM)	EPRI Peak FGD Flow (GPD)	EPRI Annual Average FGD Purge Flow (GPM)	EPRI Annual Average FGD Purge Flow (GPD)
2244	Georgia Power Company – Plant Bowen	1,500	2,160,000	750	1,080,000
2601	Ghent	968	1,393,920	585	842,851
3265	Cardinal	1,538	2,214,720	951	1,369,913
3309	Lawrence Energy Center	38	54,331	33	47,000
3464	W. A. Parish E.G.S.	99	142,560	55	78,585
3604	Mill Creek	264	380,160	159	229,231
5318	Clifty Creek Station	400	576,000	317	456,155
6334	Leland Olds Station	193	277,920	118	170,092
6377	Tampa Electric – Big Bend Station	1,170	1,684,272	1038	1,495,043
7785	Seminole Generating Station	300	432,000	191	275,192
8353	Jeffrey Energy Center	500	720,000	408	587,520
8965	F.B. Culley Generating Station	164	236,160	150	216,000
9161	John E. Amos Plant	1,257	1,810,080	1,035	1,490,654
9225	Fort Martin Power Station	330	475,200	106	152,640
9971	Dallman	149	214,180	73	104,948
56068	Elm Road Generating Station	313	450,720	202	291,083

F.4.3 Solids Loading Basis

The TSS assumptions for each power plant used to develop the industry cost extrapolation are based on ICR data and are the same as assumed in previous EPRI cost estimates [EPRI 2020]. The TSS concentration was adjusted for each plant's estimated solids loading to size solids dewatering equipment and estimate solids disposal costs.

F.4.4 Fly Ash Production

EPRI evaluated data from the U.S. Energy Information Administration (EIA) Form EIA-923 "Power Plant Operations Report", Schedule 8, Part A "Annual Byproduct Disposition" [EIA 2023]. These reports provide the total quantity of fly ash byproducts produced from "standard boiler/PCD units", "fly ash from FBC units" and "fly ash from units with dry FGD", including the specific quantities of fly ash that were reported as disposed, sold, beneficially

used, or stored for each power plant for each reporting year. EPRI used the *total* reported fly ash quantities in the EIA report to calculate the average fly ash produced for each of the 22 facilities. EPRI used EIA data for recent reporting years 2018, 2019 and 2020, and the reported quantities for these three years were used to calculate an average fly ash quantity per year.

The 2018 – 2020 average fly ash quantity for each facility was assumed to be the typical *total* fly ash quantity that is produced by each plant. EPRI used this typical fly ash quantity as the basis for the annual quantity of fly ash that would be available to each site for brine solidification.

It is important to highlight that EPRI used the *total* fly ash reportedly generated by each plant as the criteria with which to evaluate fly ash available for brine solidification, which includes all fly ash generated by the facility including fly ash that is disposed or beneficially used/sold. The average 2018 – 2020 EIA data for total quantity of fly ash produced, the quantity disposed, and the quantity sold by each of the 22 plants and used as the basis for EPRI's cost estimates is shown in Table F-6.

Table F-6. EIA Fly Ash Data Used for EPRI Cost Estimations

EPA ICR ID	Plant Name	Fly Ash Reported 2018 – 2020 Average EIA Data (tons/year)		
		Total Fly Ash Produced	Fly Ash Disposed	Fly Ash Sold
493	J. K. Spruce Power Plant	143,333	0	129,067
771	OVEC – Kyger Creek Station	186,300	186,300	0
904	Muscatine Power and Water Generating Station	18,333	3,333	14,967
1236	Mitchell Plant	214,033	183,500	30,533
1381	EME Homer City Generation L.P.	442,900	4,567	0
1674	Trimble County	228,833	50,700	178,133
2244	Georgia Power Company – Plant Bowen	310,500	42,000	263,333
2601	Ghent	431,833	311,867	25,167
3265	Cardinal	293,900	293,900	0
3309	Lawrence Energy Center	59,467	20,100	27,733
3464	W. A. Parish E.G.S.	300,933	17,833	283,100
3604	Mill Creek	286,067	91,033	93,967
5318	Clifty Creek Station	156,800	156,800	0
6334	Leland Olds Station	117,900	90,533	27,367
6377	Tampa Electric – Big Bend Station	52,367	3,233	49,133
7785	Seminole Generating Station	253,367	130,900	122,467

EPA ICR ID	Plant Name	Fly Ash Reported 2018 – 2020 Average EIA Data (tons/year)		
		Total Fly Ash Produced	Fly Ash Disposed	Fly Ash Sold
8353	Jeffrey Energy Center	201,767	105,333	96,433
8965	F.B. Culley Generating Station	60,667	8,000	0
9161	John E. Amos Plant	425,700	311,800	113,900
9225	Fort Martin Power Station	193,833	11,067	12,933
9971	Dallman	24,267	0	23,867
56068	Elm Road Generating Station	171,433	133	171,300

F.4.5 Fly Ash Beneficial Reuse and Sales

EPRI reviewed the same EIA data set (Form EIA-923, Schedule 8) for years 2018 - 2020 related to reported beneficial fly ash sales. The EIA dataset for the 22 facilities indicates that the median quantity of fly ash beneficially used/sold was 29,100 tons of fly ash per year including sites that sell 0 tons of fly ash per year. The average quantity of fly ash beneficial used/sold was 75,600 tons of fly ash per year. For each plant, EPRI calculated the average fly ash sold over the three years. This average quantity of fly ash sold was used to estimate the lost fly ash revenue to each site for brine solidification.

Table F-7 provides a summary of the EIA data reviewed and summarized by EPRI for the industry fly ash analysis.

Table F-7. 2018 – 2020 Fly Ash Data Statistical Summary for 22 Facilities Generating FGD WW After 2028 (EIA-923, Schedule 8) [1]

	Minimum	Median	Average	Maximum
Fly Ash Produced, Total (tons/year)	18,300	197,800	207,900	442,900
Fly Ash Disposed (tons/year)	0	46,400	92,000	311,900
Fly Ash Sold (tons/year)	0	29,100	75,600	283,100

1. For only one facility, fly ash quantities were not reported by EIA for years 2018 – 2020. EPRI calculated the average fly ash quantity based on the EIA data set from earlier years 2009 – 2011.

F.5 Thermal and/or Membrane Treatment Technology Selection

EPRI considered three potential thermal and/or membrane-based treatment systems for each power plant, which included:

- Chemical softening, vapor-compression evaporation, and crystallization (CS + VCE/CRX), based on the case study presented in Appendix C
- Chemical precipitation, vapor-compression evaporation, and brine solidification (CP+VCE/BS), based on the case study presented in Appendix D
- Chemical precipitation, advanced membrane filtration (AMF) and brine solidification (CP+AMF/BS), based on the case study presented in Appendix E

The two brine solidification technology options (CP + AMF/BS and CP+VCE/BS) assume that the treatment system would be designed to produce a truckable waste mixture composed of 18 weight percent of brine, 77 weight percent of fly ash and 5 weight percent of quicklime.

The membrane brine solidification technology option, CP + AMF/BS, would generate the greatest volume of brine amongst the three technology options. Membrane technologies usually cannot achieve the same concentration factor as thermal technologies, particularly for high-TDS wastewater. Therefore, the CP + AMF/BS technology option would produce the greatest brine volume and would require the most fly ash to solidify the brine amongst the three technology options considered. EPRI used the average FGD wastewater flow for each plant and an assumed 70 percent membrane recovery (as assumed in the Appendix E case study) to calculate the waste brine volume that would be generated for each facility. The annual average waste brine was used to calculate the annual average fly ash and quicklime required for each facility and the total waste quantity generated.

The thermal brine solidification technology option, CP +VCE/BS, would generate less brine since thermal evaporators can produce a more highly concentrated brine and achieve a higher overall recovery. EPRI used the average FGD wastewater flow for each plant and 90 percent thermal evaporator recovery (as assumed in the Appendix D case study) to calculate the waste brine volume that would be generated for each facility for the evaporator technology option. The annual average waste brine was used to calculate the annual average fly ash and quicklime required for each facility and the total waste quantity generated.

The last technology option considered, CS + VCE/CRX, does not solidify the waste brine but instead produces a salt cake residual waste. The annual average FGD wastewater flow for each plant was used to calculate the total waste quantity generated.

Next, EPRI calculated the site-specific quantity of fly ash required for each plant based on the two brine solidification technology options and compared these quantities to the total fly ash produced according to EIA data (Table F-5). Given the logistical challenges and high costs associated with purchasing and importing supplemental fly ash (see Appendix E for related discussion and costs), EPRI assumed that sites could not consider a technology unless the site produced enough fly ash onsite as required by the technology option.

From this analysis and on that basis, EPRI concluded the following:

- Three of the 22 plants produce sufficient fly ash onsite to solidify the brine volume produced by the membrane technology option (CP + AMF/BS). These facilities were costed based on the CP + AMF/BS case study presented in Appendix E.
- Five of the 22 plants produce sufficient fly ash onsite to solidify the brine volume produced by the thermal technology option (CP + VCE/BS). These facilities were costed based on the CP + VCE/BS case study presented in Appendix D.
- The remaining 14 plants in the industry profile did not produce sufficient fly ash onsite for brine solidification by either technology option. Therefore, a total of 14 plants in the industry were assumed to install a chemical softening, thermal evaporation, and crystallization treatment system (CS + VCE/CRX). These case studies were costed based on the case study presented in Appendix C.

A summary of the technology options, the number of plants in the industry selected for each technology option, and the corresponding percentage of plants in the industry are shown in Table F-8.

Table F-8. Thermal and/or Membrane Technology Selection for the Industry

Treatment Option	Treatment Option Description	Number of Facilities	Percentage of Industry
CP + AMF/BS	Chemical Precipitation, Advanced Membrane Filtration, Brine Solidification	3	13
CP + VCE/BS	Chemical Precipitation, Thermal Evaporation, Brine Solidification	5	23
CS + VCE/CRX	Chemical Softening, Thermal Evaporation, Crystallization	14	64
	Total Industry	**22**	**100**

F.6 Thermal and/or Membrane Treatment Capital Cost Methodology

EPRI calculated estimated capital costs for each of the 22 plants based on the conceptual case studies developed in Appendices C, D and E. The following methodology was used to develop capital costs for each of the plants:

- EPRI used a site-specific capacity factor for each of the plants.
- EPRI used the 300 gpm case study for each technology option to scale the equipment sizes and costs based on each plant's reported peak flow.
- All plants were assumed to have an existing chemical precipitation equipment subsystems (consisting of equalization, desaturation, clarifiers, pH neutralization, filtration and dewatering processes), and low residence time reactor (LRTR) biological treatment system.

F.7 Thermal and/or Membrane Treatment O&M Cost Methodology

EPRI calculated O&M costs for each of the 22 plants based on the case studies presented in Appendix C, D and E and by the following approach:

- Labor costs were estimated to be the same as the case study for all industry plants (i.e., labor costs were scaled up or down based on the size of the treatment system).
- The O&M costs for electricity, steam, cooling water, and chemical use were scaled from the conceptual design cases based on each plant's annual average flow rate and average solids loading.
- Annual average brine solidification quantities were calculated for each plant and compared to EIA fly ash data to develop O&M costs for quicklime, fly ash required, disposal quantities and lost fly ash sales.
- No cost was applied for the annual average quantity of fly ash that is currently being disposed by each facility. Therefore, only the net increase in disposal quantity was applied as an O&M cost. Brine mass was also not included in the calculated disposal costs as the unit cost is on a dry weight basis.
- A 3 percent equipment maintenance cost was applied based the on the total equipment cost estimated for each individual plant.

F.8 Industry Profile and Cost Summary

The industry profile for the 22 plants that are anticipated to generate FGD wastewater after 2032 and thus would be required to convert to a thermal and/or membrane ZLD treatment system are shown in Table F-9. The selected treatment option for each plant shown in Table F-9 is based on methodology described in Section F.4.

Table F-9. Industry Profile Assumed for FGD Wastewater Costing

EPA ICR ID	Plant Name	EPRI Peak FGD Flow (GPM)	EPRI Annual Average FGD Purge Flow (GPM)	Capacity Factor	Typical Fly Ash Produced (tons/year)	Technology Option Selected
493	J. K. Spruce Power Plant	90	53	0.54	143,333	CP + VCE/BS
771	OVEC – Kyger Creek Station	268	233	0.60	186,300	CS + VCE/CRX
904	Muscatine Power and Water Generating Station	20	5	0.41	18,333	CP + AMF/BS
1236	Mitchell Plant	553	276	0.33	214,033	CS + VCE/CRX

EPA ICR ID	Plant Name	EPRI Peak FGD Flow (GPM)	EPRI Annual Average FGD Purge Flow (GPM)	Capacity Factor	Typical Fly Ash Produced (tons/year)	Technology Option Selected
1381	EME Homer City Generation L.P.	159	95	0.29	442,900	CP + AMF/BS
1674	Trimble County	1,714	1,156	0.75	228,833	CS + VCE/CRX
2244	Georgia Power Company – Plant Bowen	1500	750	0.48	310,500	CS + VCE/CRX
2601	Ghent	968	585	0.61	431,833	CS + VCE/CRX
3265	Cardinal	1,538	951	0.59	293,900	CS + VCE/CRX
3309	Lawrence Energy Center	38	33	0.67	59,467	CP + VCE/BS
3464	W. A. Parish E.G.S.	99	55	0.55	300,933	CP + AMF/BS
3604	Mill Creek	264	159	0.61	286,067	CP + VCE/BS
5318	Clifty Creek Station	400	317	0.49	156,800	CS + VCE/CRX
6334	Leland Olds Station	193	118	0.53	117,900	CS + VCE/CRX
6377	Tampa Electric – Big Bend Station	1,170	1038	0.35	52,367	CS + VCE/CRX
7785	Seminole Generating Station	300	191	0.63	253,367	CP + VCE/BS
8353	Jeffrey Energy Center	500	408	0.41	201,767	CS + VCE/CRX
8965	F.B. Culley Generating Station	164	150	0.70	60,667	CS + VCE/CRX
9161	John E. Amos Plant	1,257	1,035	0.42	425,700	CS + VCE/CRX
9225	Fort Martin Power Station	330	106	0.59	193,833	CP + VCE/BS
9971	Dallman	149	73	0.49	24,267	CS + VCE/CRX
56068	Elm Road Generating Station	313	202	0.69	171,433	CS + VCE/CRX

Based on the plant quantities and technology selections shown in Table F-9, the costs for the industry to convert to a thermal and/or membrane ZLD treatment system is summarized in Table F-10 below.

Table F-10. Thermal and/or Membrane Treatment Cost to Industry for FGD wastewater, in 2021 dollars [1]

Treatment Option	Number of Plants	Capital Cost ($M)	Operations and Maintenance Cost ($M per year)	Total Annualized Cost [1] ($M per year)
CP + AMF/BS	3	**139**	**41**	**54**
CP + VCE/BS	5	**268**	**48**	**73**
CS + VCE/CRX	14	**3,401**	**262**	**582**
Total Industry	22	**3,808**	**351**	**709**

1. Total annualized cost is annualized capital cost (based on a 20-year equipment life and 7% interest rate) plus annual operations and maintenance cost.

$ = U.S. dollars

M = million

Next, EPRI evaluated the total cost to the industry if all 22 plants installed one of the three technology options considered. A summary of the estimated industrywide costs are shown in Table F-11.

Table F-11. Thermal and/or Membrane Treatment Cost to Industry for FGD wastewater, in 2021 dollars [1]

Treatment Option	Total Plants in Industry	Capital Cost ($M)	Operations and Maintenance Cost ($M per year)	Annualized Cost [1] ($M per year)
CP + AMF/BS	22	5,410	2,783	3,292
CP + VCE/BS	22	2,050	893	1,086
CS + VCE/CRX	22	4,145	303	693

1. Total annualized cost is annualized capital cost (based on a 20-year equipment life and 7% interest rate) plus annual operations and maintenance cost.

$ = U.S. dollars

M = million

Finally, EPRI evaluated the cost estimates for the three technology options for each plant and identified the lowest cost ZLD option for each of the 22 plants. The total lowest cost to the industry is shown in Table F-12.

Table F-12. Thermal and/or Membrane Treatment Cost to Industry for FGD wastewater, in 2021 dollars [1]

Treatment Option	Number of Plants	Capital Cost ($M)	Operations and Maintenance Cost ($M per year)	Annualized Cost [1] ($M per year)
CP + AMF/BS	0	0	0	0
CP + VCE/BS	10	546	98	149
CS + VCE/CRX	12	3,050	241	528
Total Industry	**22**	**3,596**	**339**	**677**

1. Total annualized cost is annualized capital cost (based on a 20-year equipment life and 7% interest rate) plus annual operations and maintenance cost.

$ = U.S. dollars

M = million

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G COMBUSTION RESIDUAL LEACHATE COSTS: BACKGROUND

Combustion residual leachate (CRL), or "leachate" in this document, is proposed to be regulated by the Steam Electric Effluent Limitation Guidelines (ELG). The Electric Power Research Institute (EPRI) prepared a case study to estimate the compliance cost for chemical precipitation (CP) as the best available treatment (BAT) for treating CRL (Appendix H). EPRI developed a second case study to estimate cost for membrane treatment as an alternate treatment option (Appendix I). EPRI's general cost methodology is presented in Appendix A.

This appendix describes the general basis of design used to determine the capital cost and operation and maintenance (O&M) cost for CRL treatment. It identifies important parameters and specific values applied in EPRI's engineering costs. EPRI used U.S. Environmental Protection Agency (EPA)-provided data and data collected from the power industry to develop cost estimates.

G.1 CRL Definition and Regulatory History

In 2015, EPA's Technical Development Document for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (EPA, 2015) defined CRL as "leachate from landfills or surface impoundments containing combustion residual." In addition, EPA characterized leachate as liquid that has "percolated through or drained from waste or other material emplaced in a landfill." Liquid that passed through containment of surface impoundments, such as bottoms, dikes, and berms, are also considered leachate. EPA published a new version of the proposed ELG in March 2023, which included BAT limits for CRL for arsenic and mercury and CP as the preferred BAT option (Technical Development Document for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (EPA, 2023a)

In the 2013 Proposed Rule, EPA categorized wastewater generation rate and water quality to show contributions from landfill leachate and impoundment leachate *(Technical Development Document for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (EPA, 2013). The landfill leachate flow was further subdivided based on management unit status, i.e., active, inactive, planned, and retired. Specific leachate water quality was presented for each category. EPA also presented water quality of impoundment leachate. In the 2015 ELG update, EPA did not differentiate flow between active and inactive sites, nor include flows from retired units. The leachate water quality represented the average pollutant concentration for both landfills and impoundments.

In the 2023 proposed rulemaking, EPA updated the population of landfills containing combustion residuals starting with the 2009 Steam Electric Survey, and removing coal-fired units that are retiring by the end of 2023 and adding plants that have constructed new landfills since 2015. EPA listed 69 sites that were used to evaluate engineering cost and pollutant loading evaluation. In terms of CRL water quality, EPA used the data presented in 2015.

This recent approach by EPA, although not explicitly stated, indicates that the proposed BAT limits apply to active landfill sites. However, the proposed rule does not restrict the BAT to only active landfills, so any landfill that continues to collect and discharge to surface water or publicly owned treatment works (POTW), may be subjected to the proposed regulation. Pending further clarification from EPA or modification in the final ELG rulemaking, EPRI developed case studies that estimated treatment cost only for active sites. There are unique limitations and cost-related challenges associated with operating BAT in inactive and retired facilities. A separate evaluation and case study would be needed for those sites if included in the regulation.

G.2 Conceptual Design Basis

Cost estimates for each treatment technology were developed using a specific engineering design basis. Important design parameters include flow rate of waste stream that needs to be treated, water quality of the untreated waste stream, and desired effluent quality and pollutant removal.

G.2.1 Flow Rate Basis

Flow is a key factor in designing many treatment components. It is used to properly size equipment and is applied to estimate operating cost elements. In the 2023 ELG proposal, EPA provided plant-level flow data (*Combustion Residual Leachate (CRL) Proposed Rule Cost Database* [ERG, 2023a]; *Combustion Residual Leachate (CRL) Proposed Rule Loadings Database* [ERG, 2023b]) (Table G-1) for daily leachate flow. EPA indicated that these flows were obtained either from:

1. Site-provided daily flow data
2. Estimated flow rate based on landfill acreage (active and inactive)
3. Median leachate flow rate for all sites included in the cost evaluation (46,160 gallons per day [gpd]).

Table G-1. Plant-level combustion residual leachate flow

EPA ICR ID	Plant Name	Leachate Flow, gpd
103	W. H. Sammis Plant	16,055
217	Iatan Generating Station	17,296
265	Kingston	46,160
270	Tampa Electric - Polk Power Station	1,996
494	Twin Oaks Power	53,220
548	James River Power Station	15,079
654	Jack Watson	30,602
737	Limestone Electrical Generating Station	215,542
771	OVEC - Kyger Creek Station	79,830
864	Williams Station	100,520
1381	EME Homer City Generation L.P.	149,863
1476	Northside Generating Station	22,618
2268	Conemaugh	231,507
2550	Allen Steam Station	33,262
2623	Deerhaven Generating Station	16,631
2673	Entergy Gulf States, LLC - Roy S. Nelson Station	30,248
3087	Wateree Station	93,601
3095	PSNH - Merrimack Station	4,524
3097	Wisconsin Public Service - Weston Plant	1,441
3196	Cayuga	17,740
3265	Cardinal	84,487
3309	Lawrence Energy Center	60,538
3597	Marshall Steam Station	4,992
3604	Mill Creek	119,080
3709	Oak Creek Power Plant	34,852
3728	Wisconsin Power and Light - Columba Energy Center	41,578
3831	RRI Energy Keystone Generating Station	125,599
3887	Belle River Power Plant	332,625
3978	Flint Creek Power Plant	26,610
3989	Sherburne County Generating Plant	30,602
4011	Allen S King Generating Plant	29,936

EPA ICR ID	Plant Name	Leachate Flow, gpd
4122	PPL Brunner Island	12,640
4161	Lon D. Wright Power Plant	7,557
4543	Mountaineer Plant	288,275
4547	TransAlta Centralia Generation, LLC	37,919
4598	East Bend Station	106,440
4692	Clover Power Station	84,120
4702	Plant Crist	86,885
4706	General James M. Gavin	212,688
4781	Nebraska City Station	61,868
5265	Southwest Power Station	30,522
5318	Clifty Creek Station	133,050
5839	JH Campbell Power Plant	312,800
6279	Gallatin	46,160
6602	Shawnee	46,160
6606	New Madrid Power Plant	166,312
6616	Morgantown Generating Station (Mirant Mid-Atlantic, LLC)	60,316
6672	Choctaw Generation, LP	99,788
6848	George Neal North	14,769
7135	Harrison Power Station	39,168
7411	Winyah Generating Station	46,160
7434	Louisa Generating Station	46,160
7761	EKPC Spurlock Station	46,160
7785	Seminole Generating Station	67,856
7821	Dunkirk Generating Plant	41,212
8281	Pleasants Power Station	56,414
8308	Miami Fort Station	73,178
8353	Jeffrey Energy Center	164,317
8490	Newton	7,318
8661	Belews Creek Steam Station	79,608
9161	John E. Amos Plant	1,154,208
9225	Fort Martin Power Station	72,313
9289	Mount Storm Power Station	167,784

EPA ICR ID	Plant Name	Leachate Flow, gpd
9373	John P. Madgett	7,983
9391	Roxboro Steam Plant	227,981
9475	W H Zimmer Station	46,106
9671	AES Cayuga LLC	23,683
9805	PPL Montour	42,576
9971	Dallman	178
Number of Plants		69
Median Flow, gpd		46,160
Median Flow, gallons per minute (gpm)		32
Average Flow, gpd		**91,120**
Average Flow, gpm		**63**

EPRI used the average of the plant-level flows (Table G-1) to establish the average flow for use in determining operating cost elements, such as chemical feed, waste disposal, and utilities.

In sizing process equipment, best engineering practice applies peak flow rate as the basis of design for wastewater treatment systems to provide sufficient capacity and ensure consistent treatment during peak flow events. EPA did not provide peak flow data, but EPRI's experience, based on EPRI research and the experience of EPRI members, is that peak flow of leachate is typically 2 to 4 times the average leachate flow, as shown in Table G-2 and Figure G-1 (EPRI, 2021).

Table G-2. Maximum to average leachate generation rates ratio from four coal combustion product landfills.

Site	Generation or Closure Landfill	Study Period (months) 1 sample/month	Average Generation Rate (gpd per acre)	Maximum Generation Rate (gpd per acre)	Maximum to Average Generation Rate Ratio
33105	Closure	39	1,760	4,192	2.4
33449	Closure	33	2,477	4,895	2.0
33107	Active	113	888	3,250	3.7
33451	Active	15	1,174	3,118	2.7

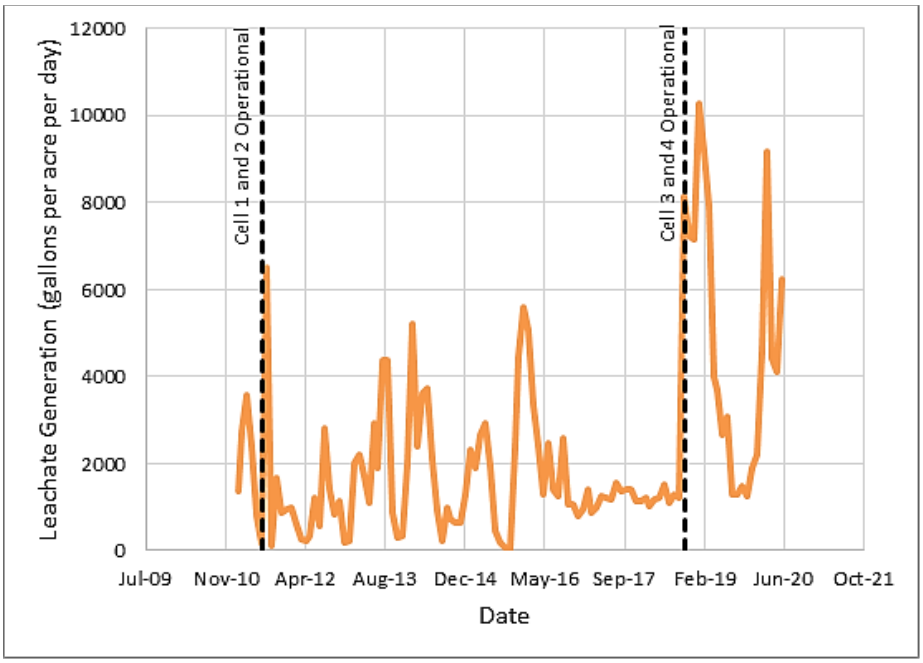


Figure G-1. Variability in leachate generation at Coal Combustion Product Landfill Site 33107

EPRI calculated the ratio of the maximum leachate generation rate and average generation rate for each of two active sites and determined the average of the two ratios to obtain the peaking factor of 3.2. This peaking factor was then multiplied to EPA's average leachate flow to estimate the peak flow (Table G-3).

Table G-3. CRL flow rates used in EPRI's treatment system cost estimates

CRL Flow	Value (gallons per minute)	Notes
Average	63	Based on the average of plant-level daily leachate provided by EPA for 69 sites
Peak	202	Average flow × 3.2 (EPRI's peaking factor estimate)

G.2.2 Leachate Water Quality

Wastewater treatment equipment is primarily sized based on flow; however, leachate water quality for both the untreated influent and desired effluent also impact the design of specific treatment process units. For instance, pollutant loading from the untreated influent and the target effluent quality will define the extent of treatment needed to meet set criteria. In addition, the materials of construction need to be compatible with the waste stream for the treatment system to be operational. Other water quality criteria that dictate process design for membrane treatment technology evaluated are listed in Appendix I.

As the basis for its engineering cost estimates, EPRI used the leachate characteristics presented by EPA (EPA, 2023a) and is presented in Table G-4.

Table G-4. CRL average pollutant concentration used in EPRI's cost estimates

Pollutant	Untreated Leachate (microgram/L)	Chemical Precipitation Effluent (microgram/L)
Total Suspended Solids	35,800	8,590
Priority Pollutants		
Antimony	3.75	3.75
Arsenic	38.4	5.83
Cadmium	10.1	4.21
Chromium	2,120	6.45
Copper	7.58	3.78
Mercury	1.06	0.139
Nickel	46.5	9.11
Selenium	111	111
Thallium	1.16	1.16
Zinc	211	20
Non-conventional Pollutants		
Aluminum	2,990	120
Barium	53.2	53.2
Boron	22,400	22,400
Calcium	408,000	408,000
Chloride	413,000	413,000
Cobalt	38.6	9.3
Iron	37,100	110
Magnesium	118,000	118,000
Manganese	2,720	2,720
Molybdenum	1,380	125
Sodium	308,000	276,000
Sulfate	1,790,000	1,240,000
Total Dissolved Solids	3,500,000	3,500,000
Vanadium	1,910	12.6

G.2.3 Industry Population

EPA estimated the industry cost of implementation for CRL BAT by adding electric generating unit-level cost for 69 plants (EPA, 2023a). These plants, listed previously in Table G-1, are CRLs that collect and discharge leachate to either surface water or POTWs.

EPA also conducted a sensitivity analysis to evaluate potential cost and loads associated with treating CRL discharged to groundwater. EPA's cost methodology is discussed in *Evaluation of Potential CRL in Groundwater* (EPA, 2023b). An excerpt of that memorandum reads:

"EPA used the criteria outlined in Section 2 to characterize whether each landfill does or does not have a composite liner. Landfills with composite liners were excluded from the groundwater pumping estimate analysis. Of the 243 total landfills that were evaluated:

- 69 landfills were categorized as composite-lined because they were already identified as lined in the CRL cost and loadings analyses associated with the proposed rule (see Section 5 of the TDD [EPA, 2023]).
- 65 landfills were categorized as composite-lined because documents made available online by the power company identified that the landfill has a composite liner."

Leachate produced from the 65 composite-lined landfills mentioned above will need to be collected and discharged, and subjected to CRL BAT. Therefore, EPRI included the cost of treatment at those 65 sites in the industry-level costs. The industry-level cost for CRL treatment is obtained by multiplying the case study cost by the total number of landfills categorized above, i.e., 134, assuming all these plants will need CP.

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H COST ESTIMATING SUMMARY FOR CHEMICAL PRECIPITATION OF COMBUSTION RESIDUAL LANDFILL LEACHATE

H.1 Summary

The Electric Power Research Institute (EPRI) estimated the costs of chemical precipitation treatment of combustion residual leachate (CRL) to the steam electric industry. The method for calculating chemical precipitation treatment costs for an individual plant, the assumptions associated with the cost calculations, and the estimated costs for chemical precipitation treatment to the steam electric industry are described below.

The chemical precipitation treatment system used to evaluate costs consists of equalization, chemical addition to enhance metals removal, clarification, and solids dewatering. Figure H-1 shows a simplified process flow diagram of the chemical precipitation treatment process using this system.

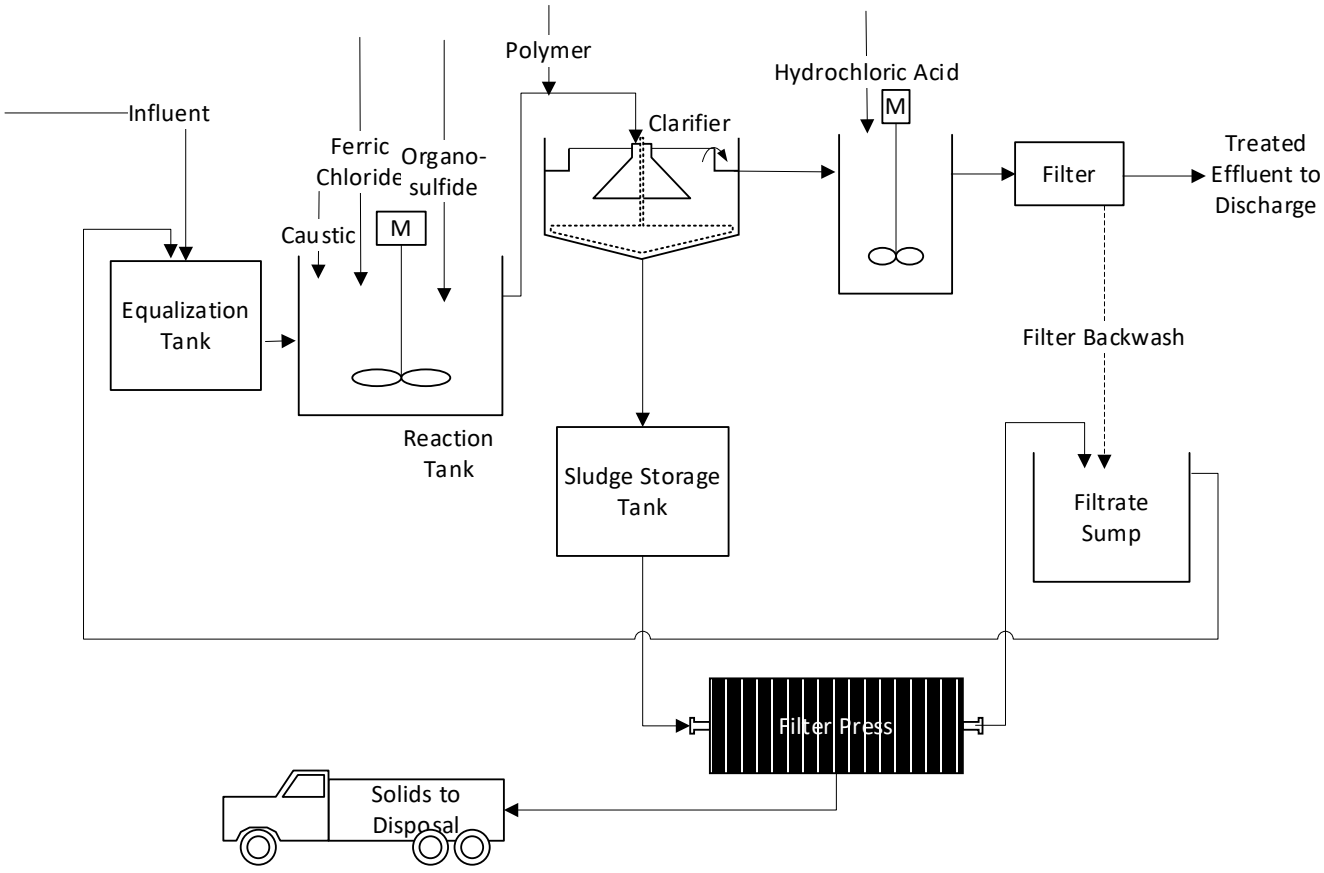


Figure H-1. Chemical precipitation treatment system

EPRI developed a cost model to estimate chemical precipitation treatment cost for CRL in an active site. The U.S. Environmental Protection Agency (EPA) uses 69 plants to define the industry in its *Technical Development Document for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (TDD) (EPA, 2023a). However, other EPA documents in the docket appear to show that there are 65 additional plants that require CRL treatment (*Evaluation of Potential CRL in Groundwater* (EPA, 2023b) , which would make the total count 134 plants.

Table H-1 presents industry costs for chemical precipitation treatment of landfill leachate for both industry profile scenarios.

Table H-1. Industry Cost for Chemical Precipitation Treatment of CRL

	Cost (2021 $M) if 69 Plants	Cost (2021 $M) if 134 Plants
Industry capital cost [1]	938	1,822
Industry annual operations and maintenance (O&M) cost [1]	70	136
Industry 6-year recurring cost (in-line mercury analyzer replacement) [1]	8	15
Total annualized industry cost [2]	160	310

1. Industry cost is cost per site multiplied by number of plants, assuming all plants will need CP.
2. Total annualized industry cost is annualized capital costs (annualized over 20 years using 7 percent interest rate) plus annual O&M cost and one-sixth of 6-year recurring cost.

$ = U.S. dollars

M = million

H.2 Cost Estimate for Chemical Precipitation Treatment of Active Landfills

The design basis for this cost estimate is described in this section.

H.2.1 Conceptual Design Basis

H.2.1.1 Flow Rate Basis

Flow capacity is a key factor in the cost of many treatment components. As described in Appendix G, EPRI used 202 gallons per minute (gpm) as peak flow for equipment sizing and the average flow of 63 gpm to determine operating and maintenance (O&M) cost elements.

Chemical precipitation treatment costs of CRL to the steam electric industry were estimated assuming all plants operate the treatment system 90 percent of the time in a given year.

H.2.1.2 Feed Water Quality Characteristics

Wastewater treatment equipment is generally sized based on flow; however, suspended solids loading is used to size solids dewatering equipment and estimate solids disposal costs. EPRI used the average total suspended solids (TSS) concentration of 36 milligrams per liter (mg/L) for CRL provided in Table 17 of EPA's TDD in estimating costs.

H.2.2 Cost Development Methods

H.2.2.1 Equipment Cost Assumptions

For each subsystem in the treatment train, a cost curve was developed as a function of a key variable affecting cost. The curves include the expected cost based on the cost of the elements that make up the subsystems (e.g., pumps, mixers, tanks). Cost curves assumed installation of two identical trains at 60 percent capacity for all equipment. The equipment in each subsystem and the design criteria used for equipment sizing follow those presented in Table H-2.

Table H-2. Equipment Cost Assumptions

Equipment	Design Criteria	Units	Criteria
Equalization			
Equalization tank	Hydraulic detention time at peak flow FRP tank with dip tube, baffles, and bridge for top-mounted mixer(s); top-entry mixer(s) of suitable material to resist chloride corrosion	hr	12
Equalization tank mixer(s)	Number and size of mixers based on professional judgment	hp/1,000 gal	0.1
Metals Removal			
Base feed system	Dose	mg/L (chemical/wastewater)	20
Organosulfide chemical feed system	Dosage based on industry experience	mg/L (chemical/wastewater)	30
Ferric chloride feed pump system	Dose	mg/L (chemical/wastewater)	100
Solids Removal/ Clarification			
Reactor tank	Hydraulic detention time at peak flow Includes FRP tank with dip tube, baffles, and bridge for top-mounted mixer	min	20
Reactor tank mixer	Number and size of mixers based on professional judgment	hp/1,000 gal	1
Polyblend system	Dose	mg/L (chemical/wastewater)	10

Equipment	Design Criteria	Units	Criteria
Clarifier	Surface overflow rate Includes circular, steep floor, coated-steel clarifier; high-torque clarifier-drive mechanism of stainless steel; picket fence floc mechanism	gpm/ft^2	0.33
Clarifier sludge pumps	Flow	gpm	50% of clarifier influent flow
Neutralization			
Acid feed system	Dose	mg/L (chemical/wastewater)	20
Reactor tank	Hydraulic detention time Includes FRP tank with dip tube and bridge for top-mounted mixer	min	20
Reactor tank mixer	Number and size of mixers based on professional judgment	hp/1,000 gal	1
Solids Dewatering			
Sludge holding tank	Hydraulic detention time Includes FRP tank with bridge for top-entry mixer	hr	24
Sludge holding tank mixer	Mixer motor horsepower sized depending on tank volume	hp/1,000 gal	0.5
Filter press feed pump	Pump flow capacity Includes centrifugal-type pump		Pump sized to fill press in 5 min
Filter press	Press size		Press solids capacity sufficient for up to 2 to 3 days of solids production
Support Equipment			
Waste sump	Based on best professional judgment	gal	6,000
Flushing pumps	Flow	gpm	Equal to wastewater flow
Seal water pumps	Flow	gpm	4% of wastewater flow

ft^2 = square feet
FRP = fiber-reinforced plastic
gal = gallons
hp = horsepower
hr = hours
min = minute(s)

H.2.3 Capital Cost Assumptions

H.2.3.1 Classification of Estimate

EPRI's estimated costs of chemical precipitation treatment of CRL to the steam electric industry represent Class 4 estimates, generally defined as study- or feasibility-level estimates (AACE, 2011). These estimates were prepared to support the evaluation of the technology and are based solely on the information available at the time of the estimate. Actual final costs will depend on the actual labor and material costs, competitive market conditions, site conditions, final project scope, implementation schedule, and other variable factors.

The capital costs presented in this estimate are based on total installed costs, which include:

- **Direct costs** – equipment, freight, taxes, field construction (buildings, site work, concrete foundation, piping, mechanical, electrical, and field instrumentation and controls), general conditions, and bonding
- **Indirect costs** – engineering, commissioning and start-up, contractor profit, and contingency for miscellaneous unidentified costs

H.2.3.2 Cost Model Factors

Systemwide cost model factors, described in Appendix A, were applied to develop the cost estimate.

H.2.3.3 Major Assumptions

The following major assumptions were made for this capital cost evaluation:

- Freight is assumed to be 4 percent of equipment cost.
- Costs are presented in 2021 dollars. Construction Cost Index values, as published by Engineering News Record, were used to escalate costs to 2021 pricing.
- Dewatering for construction is not required.
- The site is balanced cut/fill.
- 1.3 miles (6,864 feet) of influent line piping from the landfill to treatment will be installed above ground, priced at $83 per linear foot, to tie into the existing landfill leachate collection systems. Assumed 1.3 miles of pipe from landfill to treatment based on EPA's *Incremental Costs for Pollutant Removals for the Proposed Effluent Limitations Guidelines and Standards for the Stream Electric Power Generating Point Source Category* (EPA, 2013), Chapter 9.
- For all installation, the sizes and quantities of all equipment were selected based on the system design redundancy. For example, the cost estimate for two trains at 60 percent capacity per train assumes that two tanks will be installed in parallel, both designed for 60 percent capacity. The only exception is filter presses used for dewatering, where only one spare filter press was assumed.

- No chemical storage tanks were included in the cost; chemicals were assumed to be fed from totes.
- No costs were included for cold-weather protection for equipment installed outdoors (e.g., heat tracing, except freeze protection for piping, insulation), new site development (e.g., significant excavation), or installation in areas of limited footprint or remote locations involving delivery issues. These types of cost factors would increase cost estimates for the chemical precipitation treatment system.
- Project will be sales-tax exempt.

H.2.4 Operations and Maintenance Cost Assumptions

H.2.4.1 Cost Elements

O&M requirements for this estimate include the following cost elements:

- Chemicals
- Electricity
- Residuals disposal
- Equipment maintenance
- Labor
- Compliance monitoring

H.2.4.2 Major Assumptions

EPRI used general assumptions for O&M as described in Appendix A. Additional assumptions unique for this O&M cost evaluation are:

- Labor: a total of five full-time equivalent (FTE) operators at $54/hour (to provide one person at the treatment system 24/7) and one FTE supervisor operator (five days / 40 hours per week) at $84/hour were assumed to staff the treatment plant.
- Dosage rates will be typical values, but actual dosage rates could vary depending on leachate wastewater chemistry. Actual costs will also vary by geography, delivery method, and chemical supplier, but the chemical costs shown in Appendix A were used for ferric chloride, caustic, organosulfide, polymer and hydrochloric acid.
- All solids will be non-Resource Conservation and Recovery Act (RCRA) hazardous solids with a disposal unit cost of $59 per dry ton. The disposal cost was developed as a weighted average using EPA-provided onsite and offsite disposal costs (EPA, 2013) escalated to 2021 dollars.

- The physical /chemical treatment system will operate 90 percent year-round, with the remaining 10 percent accounting for offline time needed for scheduled outages and other plant-related events.
- Compliance monitoring cost ($80,739 per year) includes costs for sampling and analysis of leachate wastewater effluent discharge.
- Cost for in-line mercury analyzer and replacement every 6 years is included as a separate cost line item and is based on the EPA-provided cost ($110,039 in 2021 dollars).

H.2.5 Example Cost Estimate

The cost estimate for chemical precipitation treatment for an example system with design peak flow of 202 gpm and two x 60 percent redundancy is provided in the following subsections.

H.2.5.1 Capital Cost

An example worksheet that shows the total estimated capital costs for a 202-gpm peak flow chemical precipitation treatment system is provided in Table H-3. The estimate below assumes a TSS concentration of 36 mg/L in the treatment system influent. Equipment costs are based on vendor-provided cost quotes. The cost model factors shown in Table H-3 are added to the purchased equipment cost to obtain the system's total estimated capital cost.

Table H-3. Summary of Estimated Chemical Precipitation Treatment System Capital Costs for a 202-gpm System

Cost Element	Cost
Process Equipment by Subsystem	
Equalization	$460,000
Metals removal	$380,000
Clarification	$400,000
Filtration	$300,000
Solids dewatering	$90,000
Support equipment (pumps, waste sump)	$290,000
Freight (4%) and taxes (0%)	$77,000
Subtotal – Purchased Equipment Cost as Delivered	$1,997,000
Installation	$360,000
Additional cost items [1]	
Pre-engineered building [2]	$1,730,000
1.3 miles of influent pipe [3]	$570,000
Site work [4]	$77,000
Piping	$134,000

Cost Element	Cost
Mechanical/Heating, ventilation, and air conditioning	$144,000
Instrumentation and controls	$288,000
Electrical	$422,000
Concrete	$336,000
Miscellaneous metals, finishes	$192,000
Subtotal – Subcontractor Direct Cost	$6,250,000
Subcontractor overhead and profit	$625,000
Subtotal – Subcontractor Cost	$6,875,000
General contractor general conditions [1]	$859,000
Bonding and insurance [1]	$196,000
General contractor profit [1]	$980,000
Subtotal – Direct Costs	$8,910,000
Miscellaneous unidentified cost [1]	$1,782,000
Subtotal – Estimated Construction Cost	$10,692,000
Engineering (design, services during construction, startup, and operator training) [1]	$2,138,000
Owner's cost and use	$748,000
Permitting	$62,000
Total Estimated Capital Cost ($)	**$13,600,000**
Total Estimated Capital Cost ($) +50%	$20,400,000
Total Estimated Capital Cost ($) –30%	$9,500,000

1. See Table H-3 for factors used to estimate these additional cost items.
2. Pre-engineered building was estimated at 7,500 square feet. Building was assumed to accommodate an office, motor control center, chemicals storage, and dewatering equipment.
3. Assumes wastewater tie-in piping of 1.3 miles installed above ground
4. Includes fencing, grading, roads, sidewalks, and similar items

H.2.5.2 O&M Cost and Quantities

The total estimated O&M costs for chemical precipitation treatment for a 63-gpm average flow chemical precipitation treatment system with a 36-mg/L TSS-concentration-based design basis described in Section H.2.2.1 are provided in Table H-4.

Table H-4. Summary of Chemical Precipitation Treatment Annual O&M Costs for a 63-gpm Average Leachate Flow System

Cost Element	Cost (per year)	Assumptions
Electricity	$28,000	$0.056 per kilowatt-hour
Residuals	$300	14 lb/day dry weight. $59 per dry ton. All wastes are assumed to be RCRA non-hazardous solids.
Maintenance	$50,000	3.0% of total installed equipment cost
Major Chemicals	$17,000	Caustic, organosulfide, iron chloride, , polymer, hydrogen chloride
Labor	$838,000	5 FTE operators,1 FTE supervisor
Compliance	$81,000	Sampling labor, material cost, shipping cost, and lab analysis
Estimated O&M Cost	**$1,013,000**	
In-line mercury analyzer	$18,000	$110,039 cost to replace analyzer divided by 6 years
Total Estimated O&M Cost	**$1,031,000**	Including analyzer replacement cost

H.3. Annualized Costs

Capital cost estimate and O&M cost estimate for a plant with flows described in the sections above were used to calculate total annualized cost for chemical precipitation treatment and conveyance. Capital cost was annualized assuming an equipment lifetime of 20 years and 7 percent interest rate. The total annualized cost for chemical precipitation treatment was determined to be $2.3M, as shown in Table H-5.

Table H-5. Annualized Cost for Chemical Precipitation Treatment of CRL

	Cost (in 2021 dollars)
Capital cost	$14 million
Annual O&M cost	$1 million
6-Year recurring cost	$100,000
Total annualized cost [1]	$2.3 million

1. Total annualized cost is annualized capital costs (annualized over 20 years using 7 percent interest rate) plus annual O&M and one-sixth of 6-year recurring cost.

H.3.1 Industry Cost Extrapolation

Using the data shown in Table H-6, EPRI estimated the industry-level cost by applying the capital cost and O&M cost calculated from the cost model to 134 sites. The 134 sites were the sum of the 69 plants used by EPA to define the industry (EPA, 2023a) and the 65 additional landfills categorized by EPA as "composite-lined because documents made available online by the power company identified that the landfill has a composite liner" (EPA, 2023b). These additional plants will require CRL treatment and therefore were included in the industry cost extrapolation.

EPRI's industry capital cost estimate is shown in Table H-6.

Table H-6. Industry Cost for Chemical Precipitation Treatment of Leachate

	Cost for 134 Plants (in 2021 dollars) [1]
Industry capital cost	$1,822 million
Industry annual O&M cost	$136 million
Industry 6-year recurring cost (in-line mercury analyzer replacement)	$15 million
Total annualized industry cost [2]	$310 million

1. Industry cost is cost per site multiplied by 134 plants, assuming all plants will need CP.
2. Total annualized industry cost is annualized capital costs (annualized over 20 years using 7 percent interest rate) plus annual O&M cost and one-sixth of 6-year recurring cost.

References

AACE International. 2011. Cost Estimate Classification System—As Applied in Engineering, Procurement, and Construction for the Process Industries. International Recommended Practice 18R-97. November 29, 2011.

EPA, 2023a. Technical Development Document for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (EPA Document No. 821R23005).

EPA, 2023b. Evaluation of Potential CRL in Groundwater, DCN SE10250.

EPA, 2013. Incremental Costs and Pollutant Removals for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Generating Point Source Category. EPA-HQ-OW-2009-0819-2256, DCN SE01825.

I COST ESTIMATING SUMMARY FOR MEMBRANE TREATMENT OF COMBUSTION RESIDUAL LANDFILL LEACHATE

I.1 Industry Cost Estimating Summary for Membrane Treatment of Combustion Residual Landfill Leachate

The Electric Power Research Institute (EPRI) estimated the costs of membrane treatment of combustion residual landfill leachate to the steam electric industry. The method for calculating membrane treatment costs for an individual plant, the assumptions associated with the cost calculations, and the estimated costs for membrane treatment to the steam electric industry are described below.

The membrane treatment system used to evaluate costs for the industry consists of equalization, chemical addition for pH adjustment, an advanced membrane filtration (AMF) system followed by membrane brine solidification (BS). Figure I-1 shows a process flow diagram of the AMF + BS treatment process using this system.

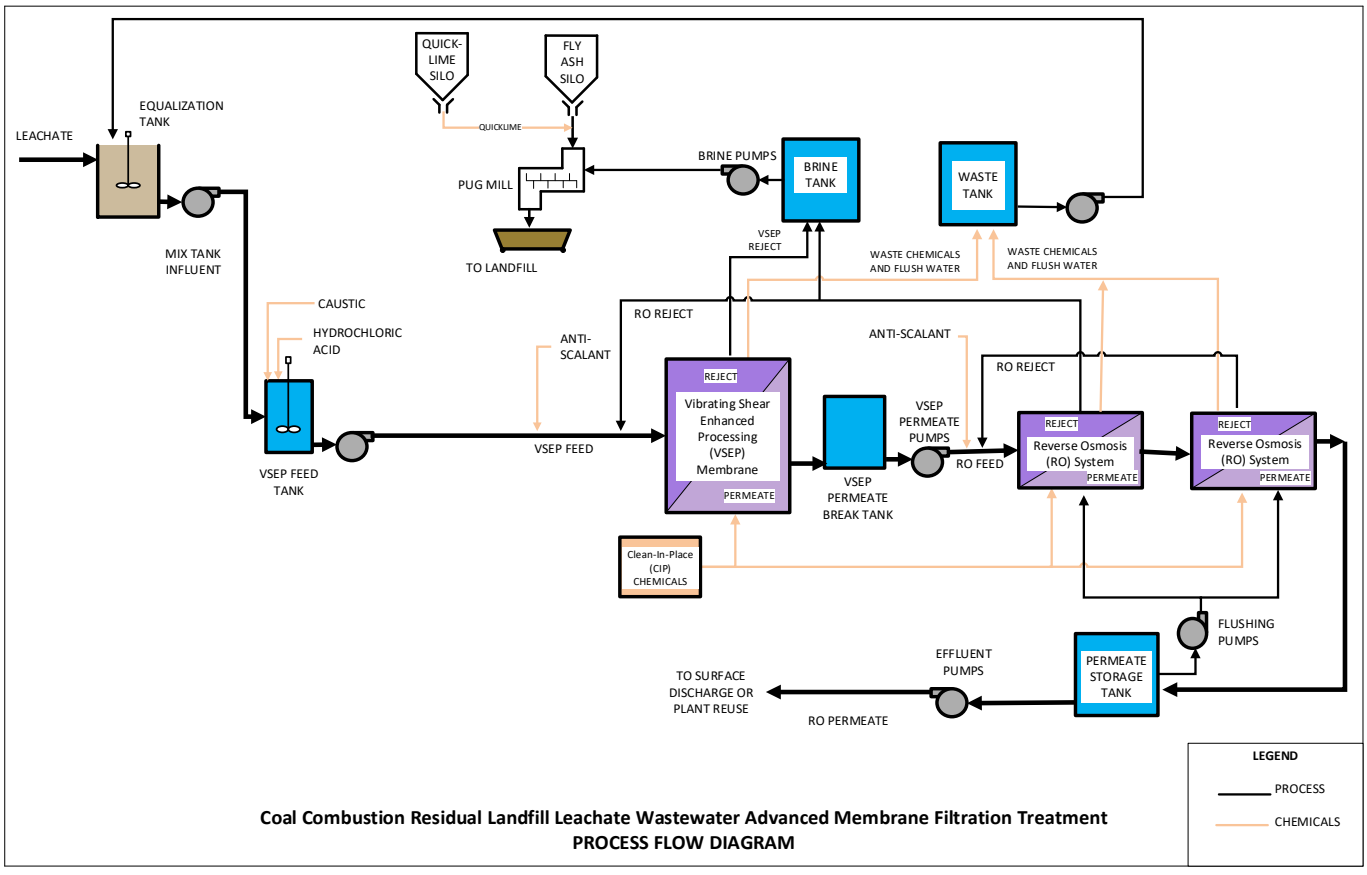


Figure I-1. AMF treatment and brine solidification system

Many membrane treatment systems and configurations exist, some of which could potentially be considered for treatment of combustion residual leachate (CRL) wastewater. The percent recovery and degree of pretreatment required upstream of the membrane system will depend on the membrane technology implemented. This case study assumes use of an "advanced membrane filtration treatment" system. The term AMF was used to define the membrane systems considered by EPA in the 2020 ELG reconsideration rulemaking as being, "designed specifically for high TDS and TSS waste streams," and, "designed to eliminate fouling and scaling associated with industrial wastewater" [EPA, 2019]. Example AMF technologies identified by EPA in the 2019 draft ELG reconsideration rule include the BKT FMX membrane technology, KLeenWater technology, New Logic Vibratory Shear Enhanced Process (VSEP) membrane technology, Oasys forward osmosis technology, Purestream membrane technology and Saltworks technology. Non-AMF technologies, such as a traditional, spiral wound seawater reverse osmosis (SWRO), could also be used to treat leachate; however, a traditional SWRO system by itself would require additional pretreatment and would not be capable of achieving as high of a recovery as the AMF system. This would lead to a higher volume of brine generated a more costly brine solidification system.

EPRI developed a cost model to estimate AMF+BS costs for CRL in an active site. Retired landfills were not included in the estimate. It is unlikely that a retired landfill would convert their existing treatment system to a membrane treatment system because of the smaller flows present at retired landfills. Further, membrane systems require continuous operational support and oversights, and it is unlikely that a retired landfill site would be regularly staffed.

I.2 Case Study Cost Estimate for AMF + BS of Active Landfill Leachate

The design basis for the conceptual case study and cost estimate is described in this section.

I.2.1 Conceptual Design Basis

I.2.1.1 Flow Rate Basis

Flow capacity is a key factor in the cost of many treatment components. As described in Appendix G, EPRI used 202 gallons per minute (gpm) as peak flow for equipment sizing and the average flow of 63 gpm to determine operating and maintenance (O&M) cost elements.

AMF + BS costs of CRL to the steam electric industry were estimated assuming all plants operate the leachate treatment system 90 percent of the time in a given year.

I.2.1.2 Leachate Quality Characteristics

The assumed water quality of CRL used for this case study is described in Appendix G.

I.2.2 Cost Development Methods

I.2.2.1 AMF + BS Cost Assumptions

This case study assumes use of an "advanced membrane filtration treatment" system. The term AMF was previously introduced in Appendix E for treatment of FGD wastewater.

The assumed major equipment for this case study is shown in Figure I-1. The membrane equipment configuration assumed in this case study is the New Logic VSEP filtration system followed by a two-pass reverse osmosis (RO) membrane system to further treat (i.e., polish) the permeate from the VSEP system. The treated leachate from the RO will be discharged to surface water. A ZLD option is not applicable and was not considered due to limited water reuse opportunities near the landfill and leachate treatment facility. Further, retired plants would not have the need to reuse leachate permeate. Pumps and a break tank are included between the VSEP and RO systems. The RO reject is recycled to the influent of previous stage rather than being directly wasted. The reject stream from the first stage VSEP system is discharged as a waste stream. This treatment configuration is designed to improve permeate recovery and minimize reject wastewater flow.

This case study assumed that the AMF + BS system would be designed to accommodate the peak leachate flowrate of 202 gpm. The AMF + BS system would be designed for a total capacity of 120 percent of the peak flow, or 242 gpm, and would be configured with multiple trains in order to provide for N+1 redundancy should one train need to be taken out of service for maintenance.

Antiscalant would be added upstream of the VSEP filtration system and upstream of the RO polishing system.

The VSEP and RO filtration systems would require a clean-in-place (CIP) chemical cleaning system. The CIP system would be used for periodic maintenance and recovery cleanings of the membranes to keep the surfaces of the membrane clean and to prolong the life of the membranes. The RO system would also require a flush system. The flush system would be used to flush a RO skid immediately after it is taken offline. The CIP waste and the flush waste would be directed to a combined waste tank where the waste would be neutralized and then recycled to the equalization tank.

I.2.2.2 Brine Solidification Cost Assumptions

The brine solidification mixture and process was assumed to be the same as assumed for FGD wastewater (see Appendices D and E). Namely, the following assumptions apply:

- The solidification process would be designed based on a truckable mixture producing a solid waste material composed of 18 weight percent of brine, 77 weight percent of fly ash and 5 weight percent of quicklime.
- The case study assumes that the plant produces 198,000 tons of fly ash per year.

- The case study plant sells 60 percent of the 198,000 tons of fly ash produced each year, meaning, the plant beneficial reuses 118,800 tons of fly ash per year and disposes of 79,200 tons of fly ash per year.
- The VSEP/RO system is assumed to achieve 94% overall recovery, as estimated from the vendor's application analysis which considered a high-pressure system and the landfill leachate quality listed in Appendix G. Given this, the annual quantity of fly ash required (33,000 tons/year) is less than the current quantity of fly ash disposed (79,200 tons/year). Therefore, this case study assumes that none of the fly ash that is currently being sold would need to be diverted for use as brine solidification material. Further, no supplemental fly ash would be required to be imported for brine solidification.

This case study looks independently at the fly ash required for leachate brine solidification and does not evaluate the fly ash that may be required to manage other brine streams. Therefore, it should be noted that this case study and associated cost estimates do not consider the combined need of fly ash required to solidify both FGD brine and leachate brine. As noted in Appendix E, most sites do not have sufficient fly ash available to manage FGD brine. Therefore, many sites considering co-treatment of FGD and leachate brine also would also not have sufficient fly ash available.

A dual pug mill system (N+1 design redundancy) was assumed for the brine solidification subsystem. New quicklime and fly ash silos are included. The actual degree of redundancy and silos that plants will choose will be based on site-specific considerations, including equipment already in place at the time of membrane treatment conversion.

I.2.2.3 Support Equipment Cost Assumptions

Pretreatment for the leachate membrane system was assumed to include equalization storage and pH neutralization using caustic or hydrochloric acid addition. In this case study, EPRI has assumed that the leachate would be pretreated through two identical pretreatment trains, each train sized at 60 percent of peak capacity for all equipment.

For each ancillary subsystem in the treatment train that was not included in the membrane system vendor quote, a cost curve was developed as a function of a key variable affecting cost. The curves include the expected cost based on the cost of the elements that make up the subsystems (e.g., pumps, mixers, tanks).

I.2.3 Capital Cost Assumptions

I.2.3.1 Classification of Estimate

EPRI's estimated costs of AMF + BS treatment of CRL to the steam electric industry represent Class 4 estimates, generally defined as study- or feasibility-level estimates (AACE, 2011). These estimates were prepared to guide evaluation of the technology and are based solely on the information available at the time of the estimate. Actual final costs will depend on the actual

labor and material costs, competitive market conditions, site conditions, final project scope, implementation schedule, and other variable factors.

The capital costs presented in this estimate are based on total installed costs, which include:

- **Direct costs** – equipment, freight, taxes, field construction (buildings, site work, concrete foundation, piping, mechanical, electrical, and field instrumentation and controls), general conditions, and bonding
- **Indirect costs** – engineering, commissioning and start-up, contractor profit, and contingency for miscellaneous unidentified costs

I.2.3.2 Cost Model Factors

Systemwide cost factors were applied to develop the cost estimate. These factors, shown in Appendix A, are generally the mid-point of common industry standards unless specified to account for treatment train requirements and to reflect market conditions during estimate development.

I.2.3.3 Major Assumptions

The following major assumptions were made for this capital cost evaluation:

- Freight is assumed to be 4 percent of equipment cost.
- Costs are presented in 2021 dollars. Construction Cost Index values, as published by Engineering News Record (ENR), were used to escalate costs to 2021 pricing.
- Dewatering for construction is not required.
- The site is balanced cut/fill.
- 1.3 miles (6,864 feet) of influent line piping from the landfill to treatment will be installed above ground, priced at $83 per linear foot, to tie into the existing landfill leachate collection systems. Assumed 1.3 miles pipe from landfill to treatment based on EPA's Incremental Costs for Pollutant Removals for the Proposed Effluent Limitations Guidelines and Standards for the Stream Electric Power Generating Point Source Category (EPA, 2013b), Chapter 9.
- For all installation, the sizes and quantities of all equipment were selected based on the system design redundancy. For example, the cost estimate for two trains at 60 percent capacity per train assumes that two tanks will be installed in parallel, both designed for 60 percent capacity.
- If greater than 500 gallons of chemical storage was required to provide 15 days of storage time, a chemical storage tank was assumed. If not, then it was assumed that the chemical would be stored in totes (not tanks).
- A 3,700 square foot (sf) pre-engineered, single-story building for housing of the membrane equipment, chemical storage, the neutralization reactor tank, an office, and motor control

center was included in the cost estimate. A 1,500-sf pre-engineered, two-story building was assumed for housing the pug mill to allow for dropping of the solids directly into trucks for transport. A pre-engineered, single-story building cost of $231 per sf and a two-story building cost of $345 per sf was assumed.

- No costs were included for cold weather protection for equipment installed outdoors (e.g., heat tracing, except freeze protection for piping, insulation), new site development (e.g., significant excavation), or installation in areas of limited footprint or remote locations involving delivery issues. These types of cost factors would increase cost estimates for the chemical precipitation treatment system.
- Project will be sales-tax exempt.

I.2.4 Operations and Maintenance Cost Assumptions

I.2.4.1 Cost Elements

O&M requirements for this estimate include the following cost elements:

- Electricity
- Chemicals
- Labor
- Compliance monitoring
- Equipment maintenance
- Membrane replacement
- Residuals disposal

I.2.4.1 Major Assumptions

The following major assumptions are unique for this O&M cost evaluation:

- This case study assumed an average leachate flow of 63 gallons per day, which was used to estimate chemical usage and electrical usage.
- Costs are presented in 2021 dollars. Construction Cost Index values, as published by ENR, were used to escalate costs to 2021 pricing.
- The VSEP/RO system is assumed to achieve 94% overall recovery. Thus, 6% of the leachate would be rejected as RO waste brine, equal to 3.8 gpm on an annualized average basis.
- The total quantity of RO waste brine generated would be 24 wet tons per year. This brine would make up 18 mass percent of the total waste and be mixed with quicklime (5 mass percent of total waste) and fly ash (77 mass percent of total waste) and disposed of as a solid waste residual. The weight of the encapsulated waste product would be 132 wet tons per year.

- The VSEP filtration system and RO membranes elements are assumed to be replaced once every three years.
- Several types of membrane cleaning chemicals may be used depending on the membrane system installed and characteristics of the FGD wastewater. Past pilot reports by VSEP [New Logic Research, 2015], described use of "NLR 404," an acidic cleaning solution, and "NLR 505," a caustic cleaning solution.
- Labor: a total of five full-time equivalent (FTE) operators at $54/hour (to provide one person at the system 24/7) and one FTE supervisor operator at $84/hour were assumed to staff the treatment plant.
- Dosage rates were assumed to be typical values, but actual dosage rates could vary depending on leachate wastewater chemistry. Actual costs will also vary by geography, delivery method, and chemical supplier, but the following chemical costs in 2021 dollars were used for the estimate:
  - Hydrochloric acid (30 percent) – $0.74/gallon
  - Antiscalant - $18.78/gallon
  - Sodium hydroxide (50 percent) – $3.75/gallon
  - Quick lime – $0.07/pound
  - All solids will be non-Resource Conservation and Recovery Act (RCRA) hazardous solids with a disposal unit cost of $59 per dry ton. The disposal cost was developed as a weighted average using EPA-provided onsite and offsite disposal costs (EPA, 2013) and escalated to 2021 dollars.
  - Electrical costs will be $0.0559/kilowatt-hour
  - Annual equipment maintenance costs will be 3 percent of the total equipment costs for the facility.
  - The treatment system will operate 90 percent year-round. It is estimated that the treatment system will be offline 10 percent of the time due to scheduled outages and other plant-related events.
  - Compliance monitoring costs include costs for sampling and analysis of leachate wastewater effluent discharge.

I.2.5 Case Study Cost Estimate

The cost estimate for this leachate AMF + BS treatment system case study with a peak design flow of 202 gpm is provided in the following subsections.

I.2.5.1 Capital Cost

An example worksheet that shows the total estimated capital costs for a 202-gpm peak flow AMF + BS treatment system is provided in Table I-2. The estimate below assumes the influent water quality described in Section I.2.1.2. The equipment costs are based on cost quotes provided by equipment vendors. The cost model factors shown in Table I-1 are added to the installed purchased equipment cost to obtain a total estimated capital cost for the system.

Table I-1. Summary of Estimated AMF Treatment System Capital Costs for a 202-gpm System

Cost Element	AMF Treatment
Process Equipment (Installed) by Subsystem	
AMF system	$8,600,000
Equalization	$915,000
Neutralization Equipment	$135,000
Membrane Feed System	$148,000
Chemical Feed Equipment	$299,000
Permeate Handling and Storage Equipment	$127,000
Membrane Waste Handling	$127,000
Brine Handling and Storage Equipment	$313,000
Pugmill System	$911,000
Lime/Cement Chemical Feed and Storage	$343,000
Fly Ash Storage	$2,377,000
Freight (4%) and taxes (0%)	$572,000
Subtotal – Purchased Installed Equipment Cost as Delivered	**$14,867,000**
Additional cost items [1]	
Pre-engineered building [2]	$1,371,000
1.3 miles of influent pipe [3]	$568,000
Site work [4]	$572,000
Piping	$1,001,000
Mechanical/Heating, Ventilation, and Air Conditioning VAC (HVAC)	$1,072,000
Instrumentation and controls (I&C)	$2,144,000
Electrical	$3,145,000
Concrete	$2,502,000
Miscellaneous metals, finishes	$2,144,000
Subtotal –Direct Costs	**$29,386,000**

Cost Element	AMF Treatment
General contractor general conditions [1]	$3,673,000
Bonding and insurance [1]	$838,000
General contractor overhead and profit [1]	$4,188,000
Subtotal – Direct and Indirect Costs	**$38,085,000**
Miscellaneous unidentified cost [1]	$7,617,000
Subtotal – Estimated Construction Cost	**$45,702,000**
Engineering (design, services during construction (SDC), startup, operator training, and testing) [1]	$9,597,000
Owner's cost and use [1]	$3,199,000
Permitting	$62,000
Total Estimated Capital Cost ($M)	**$59**
Total Estimated Capital Cost ($M) +50%	**$88**
Total Estimated Capital Cost ($M) –30%	**$41**

1. See Table 1-3 for factors used to estimate these additional cost items.
2. Pre-engineered building was estimated at 5,200 square feet (single story). Building was assumed to accommodate the AMF system, an office, motor control center, chemicals storage, and dewatering equipment.
3. Assumes wastewater tie-in piping of 1.3 miles installed above ground
4. Includes fencing, grading, roads, sidewalks, and similar items

I.2.5.2 O&M Cost and Quantities

The total estimated O&M costs for chemical precipitation treatment for an 202-gpm peak flow AMF + BS treatment system with water quality as described in Section I.2.1 are provided in Table I-2.

Table I-2. Summary of AMF Treatment Annual O&M Costs for an 202-gpm System

Cost Element	Quantity	Cost [1] ($/year)	Assumptions
Electricity	293 kW	130,000	$0.0559 per kW-hr
Chemicals			
Hydrochloric Acid (30%)	87 gallon/day	$21,000	$0.74 per gallon
Antiscalant	0.9 gallon/day	$5,000	$18.77 per gallon
Sodium Hydroxide (50% w/w)	2.4 gallon/day	$3,000	$3.75 per gallon
Quick Lime	13,188 lb/day	$324,000	$0.07 per pound
Membrane Maintenance Chemicals	13 gallon/day	$75,000	$16.00 per gallon
Labor			

Cost Element	Quantity	Cost [1] ($/year)	Assumptions
Operator	5 FTEs	$561,000	$54 per hour
Supervisor	1 FTE	$174,000	$84 per hour
Compliance Monitoring		$99,000	
Equipment Maintenance		$380,000	3%/year of installed equipment cost
Membrane Replacement		$581,000	Replace every 3 years
Residuals			
Solidified Brine Disposal [2]	6.6 dry tons per day	$129,000	$59 per dry ton (RCRA nonhazardous); quantity of solids accounts for fly ash not being disposal elsewhere onsite
Total Annual O&M Costs	63 gpm	$2,483,000	See Section I.2.4
Total Estimated O&M Cost ($million/year)		**$2.5**	

1. Costs presented in 2021 dollars
2. Incremental cost of dry residuals disposal, after deducting the mass of existing fly ash being disposed and the mass of brine.

I.3 Annualized Costs

Capital cost estimates and O&M cost estimates were used to calculate total annualized costs for AMF + BS leachate treatment and conveyance. Capital costs were annualized assuming an equipment lifetime of 20 years and 7 percent interest rate. This corresponds to an annualized cost of capital of $5.5M/year and a total annualized cost, including O&M, of $8.0M/year.

I.4 Industry Cost Extrapolation

As presented in Appendix H, the U.S. Environmental Protection Agency (EPA) uses 69 plants to define the industry in its Technical Development Document for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (TDD) (EPA, 2023a). However, other EPA documents in the docket appear to show that there are 65 additional plants that require CRL treatment (Evaluation of Potential CRL in Groundwater (EPA, 2023b), which would make the total count 134 plants. Table I-3 presents EPRI's estimate of the industry costs for AMF + BS treatment of CRL. For comparison, EPRI'S estimate of the industry cost for chemical precipitation (Appendix H) is also presented in Table I-3

Table I-3. Industry Cost (2021 $) for chemical precipitation and AMF + BS of CRL assuming 134 plants [1]

	CP Cost (See Appendix H)	AMF+BS Cost
Industry capital cost	$1,822 million	$7,852 million
Industry annual operations and maintenance cost	$136 million	$330 million
Industry 6-year recurring cost (in-line mercury analyzer replacement)	$15 million	$15 million
Total annualized industry cost [2]	$310 million	$1,071 million

1. Industry cost is cost per site multiplied by number of plants.
2. Total annualized cost is sum of annualized capital cost (i.e., industry capital cost annualized over 20 years with a 7% rate of return), annual operations and maintenance cost and one-sixth of 6-year recurring cost.

$ = U.S. dollars

M = million

References

AACE International. 2011. Cost Estimate Classification System—As Applied in Engineering, Procurement, and Construction for the Process Industries. International Recommended Practice 18R-97. November 29, 2011.

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EPA, 2023a. Technical Development Document for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (EPA Document No. 821R23005).

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