October 10, 2016

*Via electronic filing and electronic mail*

Chairman Brown, Comm'rs. Brisé, Edgar, Graham, Patronis
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, Florida 32399-0850

**Re: Planning for least-cost electric service in Florida**

Dear Commissioners:

Rapid changes in the electric sector make integrated resource planning more important than ever. Yet Florida electric utilities, especially the investor-owned utilities (IOUs), barely have any plans at all—besides adding natural gas-burning generation, which dwarfs everything else in their plans.[1] Sierra Club respectfully urges the Commission to reject them and require revised plans for four main reasons:

1. Florida law requires utilities to provide least-cost service, but the utilities are unprepared to do so because they fail to perform options analyses; the utilities thus never try to (nor could they) square their gas-laden plans with the alternatives available to them in the market.[2]

2. The proposed gas generation violates the least-cost standard because this generation is inherently high cost and high risk.

3. The proposed gas generation also violates the least-cost standard because it reduces fuel diversity and foregoes cost-effective renewables and energy efficiency, thereby pushing Florida's all-time high gas reliance, 71% of the state generation total, even higher, to 74%.

4. With no shortage of cost-effective alternatives in the market, especially renewables and energy efficiency, the only way to explain the utilities' gas generation proposals is that they aim to benefit entities other than customers.

[1] Unless stated otherwise, "plans" refers to ten-year site plans, and "utilities" refers to those that file them.

[2] To their credit, Staff issued extensive data requests. The responses, however, cannot cure the unlawful plans.

By now, it is unmistakable; the IOUs/their affiliates are investing heavily in every aspect of gas generation and infrastructure with a perverse incentive to continue to do so. They pass the resulting added cost of service onto their captive customers, and the resulting windfall profits to shareholders.

It is imperative that the Commission intervene and reject all of the unlawful plans. Revised plans should follow as soon as practicable. For the IOUs, this should be no later than April 1, 2017, the annual deadline for revised plans, to minimize the fallout from their conflict-ridden plans.

As we discuss below, at least one Florida utility, Lakeland Electric, recently undertook an assessments of its options under different scenarios, showing this is eminently doable. Moreover, practically all of the Florida utilities, with the glaring exception of the IOUs, have issued requests for proposals (RFPs) for renewables and found no shortage of cost-effective solar generation options in the Florida market. When done well, market assessments like these promote competition, stakeholder participation, and ultimately transparent, data-driven options analyses to guide utilities to least-cost investments.

The stakes are high. Every year that passes without plans for least-cost electric service further jeopardizes the competitiveness of Florida's economy and the wellbeing of its residents. This includes the millions of low-income/fixed-income Floridians who already face a disproportionate energy burden.

## DISCUSSION

**The Commission should reject the plans because they violate the least-cost standard under Florida law; the revised plans should include robust options analyses focusing on renewables and energy efficiency.**

We divided this discussion into three parts: First, we discuss the applicable least-cost standard under Florida law. Second, we show that the utility plans violate this standard, and the Commission should reject them. Finally, we conclude by urge the Commission to obtain revised plans, including the chronically missing options analyses, as soon as practicable, so that the Commission can meaningfully audit the utilities and ensure they are prepared to achieve least-cost service.

### I. Under Florida's least-cost standard, electric utilities must develop robust options analyses focusing on renewables and energy efficiency to guide the utilities to least-cost investments to serve their customers.

Florida law requires electric utility service to be least-cost. As the Florida Supreme Court affirmed, under this standard, the state's electric utilities must "t[ake] every reasonably

available prudent action to minimize [their cost of service]."[3] Planning is the critical first step. Per Commission rules, the utilities must develop and disclose "sufficient information to reassure the Commission that an adequate and reliable supply of electricity at the lowest cost possible is planned."[4]

### A. Utilities must develop robust options analyses to guide them to least-cost investments.

Options analyses are routine in the business world, and essential for the utilities to meet the least-cost standard under Florida law. This is a matter of Commission precedent and common sense.[5][6] Options typically available to utilities include but are not limited to:

- Alternatives to conventional generation, such as renewables[7] and energy efficiency;[8]
- Alternatives identified through market assessments such as the request for proposal process under Rule 25-22.082, F.A.C (i.e., the Commission's competitive "bid rule");[9]

[3] *Gulf Power Co. v. Florida pub. Service Com'n*, 453 So.2d 799, 802 (Fla. 1984).

[4] Rule 25-22.072(1), F.A.C., incorporating by reference Form PSC/RAD 43-E (11/97), at 4; *cf.* Section 366.82(5)(b)(requiring "analysis of various policy options … to achieve least-cost strategy").

[5] Order No. PSC-11-0547-FOF-EI, at 82, issued on November 23, 2011, in Docket No. 11 0009-EI, In re: Nuclear cost recovery clause; *See also* Order No. PSC-11-0547-FOF-EI (redacted Final Order) (noting approval of utility's rate increase request upon finding "no practical alternative") issued on November 23, 2011, in Docket No. 11 0009-EI, In re: Nuclear cost recovery clause; *cf.* Order No. PSC-11-0547-FOF-EI (redacted Final Order), at 6 (reviewing whether utilities properly considered "all available" demand-side and supply-side conservation and efficiency measures) issued on December 16, 2014, in Docket No. 130205-EI, In re: Commission review of numeric conservation goals (Florida Public Utilities Company).

[6] Order No. PSC-11-0547-FOF-EI, at 82 (noting the review of "all available options" is "routine procedure in the business world," including the electric utilty industry as it undertakes "long-term, complex project[s]") issued on November 23, 2011, in Docket No. 11 0009-EI, In re: Nuclear cost recovery clause.

[7] Unless otherwise noted, the terms "renewables" and "renewable energy" refer to the same energy resources. *See generally* Section 366.91(2)(d), F.S, (defining "renewable energy" in pertinent part as "electrical energy produced from a method that uses one or more of the following fuels or energy sources: hydrogen produced from sources other than fossil fuels, biomass, solar energy, geothermal energy, wind energy, ocean energy, and hydroelectric power").

[8] *See, e.g.,* Order No. PSC-14-0696-FOF-EU, at 39, issued on December 16, 2014, in Docket No. 130205-EI, In re: Commission review of numeric conservation goals (Florida Public Utilities Company) ("demand-side management is an alternative resource to generation plants and should be evaluated similarly for reliability and economic impacts."); *See also* Order No. PSC-16-0032-FOF-EI, at 13−15, issued on January 19, 2016, in Docket No. 150196-EI, In re: Petition for determination of need for Okeechobee Clean Energy Center Unit 1, by Florida Power & Light Company; *See also* Order No. PSC-11-0547-FOF-EI, issued on November 23, 2011, in Docket No. 11 0009-EI, In re: Nuclear cost recovery clause ("In 2006, we stated that utilities should not assume the automatic approval of natural gas-fired plants.").

- Incremental capacity increases;[10]
- Earlier or later extremes of commercial operations date;[11] and
- Retaining one vendor, retaining multiple vendors, or building the generation itself ("self-build").[12]

Robust options analyses are those that develop information on the economics of these wide ranging options under various scenarios.[13] A simple comparison of the status quo and one option is indefensible.[14]

### B. Utilities must focus on renewables and energy efficiency.

Florida Statutes brim with directives to diversify the fuels and the technologies the utilities use to serve customers.[15] More specifically, they emphasize and reiterate that Florida's reliance on inherently risky natural gas imports is a problem, and that cost-effective renewables and energy efficiency are solutions that are in the public interest. As the utilities perform options analysis, they must therefore focus on renewables and energy efficiency as part of their plan to serve customers at the least-cost.

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[9] *See*, *e.g.*, Order No. PSC-06-0779-PAA-EI, at 3, issued on September 19, 2006, in Docket No. 060426-E1, In re: Petition for exemption under Rule 25-22.082(18), F.A.C., from issuing request for proposals (RFPs), by Florida Power & Light Company ("the RFP process provides us with valuable information on the available capacity alternatives and is a valid tool for evaluating the cost-effectiveness of proposed generating units.").

[10] *See*, *e.g.*,Order No. PSC-13-0505-PAA-EI, at 13, issued on October 28, 2013, in Docket No. 130198-EI, In re: Petition for prudence determination regarding new pipeline system by Florida Power & Light Company; *See also* Florida Public Service Commission, *States' Electric Resurfacing Activities* (1997); *See also* F.L. House of Representatives, Committee on Utilities and Communications, *Overview of the Electric Industry*, 27 (2000), *available at* https://goo.gl/uKDBP6.

[11] *See*, *e.g.*, Order No. PSC-11-0547-FOF-EI, at 82.

[12] *See*, *e.g.*, Order No. PSC-08-0749-FOF-E, issued on Nov. 12, 2008, in Docket No. 080009-EI, In re: Nuclear cost recovery clause; *See also* Order No. PSC-09-0783-FOF-EI, issued on Nov. 19, 2009, in Docket No. 090009-EI, In re: Nuclear cost recovery clause; *See also* Order No. PSC-11-0547-FOF-EI.

[13] *See* Sierra Club Comments (Oct. 16, 2013) (hereinafter "Sierra Club 2013 Comments") (discussing best practices in integrated resource planning including options analysis), *available at* http://goo.gl/h9RHeT.

[14] *Gulf Power Co. v. Florida pub. Service Com'n*, 453 So.2d 799 (Fla. 1984) (affirming Commission disallowance of costs incurred pursuant to utility's failure to review other other options beyond its preferred proposal for years).

[15] For a recap of the relevant provisions in Florida Statutes, see Sierra Club Post-Hearing Brief in Docket No. 160021 (Sept. 19, 2016), *available at* https://goo.gl/X6QJ91.

## II. The Commission should reject the plans because they are in no way least-cost.

The plans fail to meet the least-cost standard under Florida law for many reasons. The most glaring one is that the utilities failed to present any options analyses. The utilities thus failed to reconcile their inherently high-cost, high-risk gas generation with the abundant, competitive renewables and energy efficiency in the market available to them, and in the case of the IOUs, plainly have a conflict of interest behind the omission.

### A. The utilities failed to present any options analyses in their plans.

This year, the utilities continued their practice[16] of presenting the Commission just their preferred generation proposals and asserting they considered/will continue to consider their options.[17] This violates the unambiguous requirement in Florida Statutes that the Commission "shall review"—"possible alternatives to the proposed plan[s]" of the utilities.[18] If the utilities present no data or analyses on the options/alternatives available to them in the market, they preclude the Commission from performing its plain duty under Florida Statutes.

To be sure, the utility responses to Staff data requests do not cure the unlawful plans. For all of the planned generating units, Staff asked the utilities to "identify the next best alternative that was rejected for each unit."[19] The fact that Staff had to ask for this information underscores how devoid the plans are of options analyses. The utility responses do, too. They are high-level comparisons between each planned ***gas*** generating unit and another ***gas*** generating unit. That is all. That is the sum total of the options analyses before the Commission.

No one can square the dearth of information presented by the utilities with the least-cost standard under Florida law. As discussed in Section I (above), the standard requires the utilities to conduct robust options analyses, focusing on renewables and energy efficiency, so that they are prepared to take every reasonably available prudent action to minimize cost of

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[16] *See* Sierra Club 2013 Comments (noting the unlawful practice), *available at* http://goo.gl/h9RHeT; Sierra Club Comments (Dec. 15, 2015) (hereinafter "Sierra Club 2015 Comments") (noting the same), *available at* https://goo.gl/IWbsDH.

[17] *See e.g.*, Florida Power & Light Company's 2016 Ten-Year Power Plant Site Plan (hereinafter "FPL 2016 TYSP"), Chapter III.C (noting "significant factors that either influenced the current resource plan presented in this document or which may result in changes in this resource plan in the future" but omitting data on or comparative analysis of those factors/ changes; i.e., options analysis); *available at* https://goo.gl/wgWn9Y; *see generally* 2016 Ten-Year Site Plans (similar omissions) *available at* https://goo.gl/1y17w9.

[18] Section 186.801(2), F.S.

[19] Staff data request no. 42.

service, and Florida's reliance on inherently risky natural gas imports. Working up the details of just one gas generation plan and then, at Staff's prodding, working up another is nowhere near the robust options analysis that is routine and essential to prepare electric utilities to provide least-cost service. The Commission therefore should reject the plans.

### B. The utilities failed to reconcile their inherently high-cost, high-risk gas generation proposals with the abundant, cost-effective renewables and energy efficiency in the market available to them.

The plans are indefensible and the Commission should reject them for the additional reason that they would increase gas generation, which is inherently high cost and high risk, especially as demand is down. The utilities never tried to (nor could they) reconcile their plans with the abundant, cost-effective renewables and energy efficiency in the market available to them.

#### 1. Demand is down and the growth projected by utilities has not materialized for eight straight years, a trend no one can square with adding gas generation in large, inflexible increments.

Since it peaked in 2005, demand for electricity across Florida is down. This is not due to the Recession alone, as the Commission itself noted.[20] Previous utility load forecasts required downward revisions due to slower-than-projected growth for eight straight years, including the last three.[21] The utilities themselves acknowledge that usage per customer is down.[22]

Yet the utilities project peak demand will somehow grow faster than one percent annually between 2016 and 2025 (net firm peak demand)—more than half again the rate experienced between 2004 and 2015 (0.76 percent CAAGR). This is inconsistent with, for example, the U.S. Energy Information Administration's lower projection of a 0.7 percent annual growth rate through 2025.[23]

More importantly and obviously, demand projections are never as good as verified actual data, and the actuals have shown a consistent downward trend. The best options for

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[20] FPSC, Review of the 2015 TYSPs, at 22, *available at* https://goo.gl/DTGoX1.

[21] *Compare* FRCC 2014 Presentation, at 7 ("Forecasted energy sales and winter firm peak demands are lower in 2014 TYSP compared to 2013 TYSP and forecasted summer firm peak demands are higher from 2017 forward."), *available at* https://goo.gl/ACqiVT; FRCC 2015 Presentation, at 7, ("forecasted energy sales and firm peak demands are lower in 2015 TYSP compared to 2014 TYSP"), *available at* https://goo.gl/mn4gUf; and FRCC 2016 Presentation, at 8 "forecasted energy sales and firm peak demands are lower in 2016 TYSPs compared to 2015 TYSPs"), *available at* https://goo.gl/UScXlk.

[22] Utility responses to Staff data request no. 10.

[23] This is EIA's projection for Florida as well as other South Atlantic states.

Florida therefore are those that (1) keep demand down to reduce cost (i.e., demand-side management), and (2) meet any growth in demand with incremental supply that closely matches the growth (i.e., flexible supply). The utilities failed to present any such options. The only option the utilities did present—large, inflexible gas generation additions—flies in the face of the market reality just described. It is indefensible also because the additional capacity maintained by the IOUs consistently exceeds the levels needed for an adequate and reliable supply of electricity.[24]

**2. Gas generation is inherently high cost and high risk.**

The Commission should not accept the utilities' complacency about the costs and risks of gas generation, especially as the state's reliance on natural gas is already at an all-time high—71% of the total generation.[25] The utilities propose to add another five gigawatts—pushing that up to 74% by 2025.[26] Even the smallest proposed increment exceeds 180 MW,[27] with projected capital costs measured in millions of dollars, and book lives in decades. Moreover, with the exception of Orlando Utilities Commission (OUC) and Florida Power & Light Company (FPL), the utilities propose inherently less efficient peaking generation—gas combustion turbines (CTs).[28]

All of the proposed gas generation raises stranded asset risk, but the utilities fail to mention that fact. This is a glaring omission as it is the judgment of Florida's largest utility FPL that in four years, 2020, gas peakers will be obsolete compared to energy storage and renewables.[29] It is even more troubling then that the utilities never present any options analyses for the proposed gas peakers. Nor even the basic data to allow for such a

[24] *See* the detailed briefing by Public Counsel, filed July 15, 2015, in Docket No. 160096-EI, Joint petition for approval of modifications to risk management plans by DEF, FPL, Gulf and TECO; *See also* joint petition filed by Public Council, filed Dec 9., 2015, in Docket No. 150196-EI, In re: Petition for determination of need for Okeechobee Clean Energy Center Unit 1, by Florida Power & Light Company, *available at* https://goo.gl/wBgl2S.

[25] FRCC, 2016 Presentation, at 22.

[26] *Id.*

[27] Tampa Electric Company's 2016 Ten-Year Site Plan (hereinafter "TECO 2016 TYSP") (planning to add 180 MW CT in 2019), *available at* https://goo.gl/zGh1Id.

[28] OUC and FPL propose gas combined cycle generation (CCs) with 2021 and 2024 in-service dates respectively. Like CTs, the CCs involve massive costs and risks, and the utilities can only add them in large, inflexible increments. Thus, beyond the marginal efficiency improvement of CCs over CTs, our discussion of the CTs applies equally to the CCs.

[29] NextEra on Storage: 'Post 2020, There May Never Be Another Peaker Built in the US,' Sept. 30, 2015, GreenTech Media [hereainafter "NextEra on Storage"], https://goo.gl/rQDK0H (referring to judgment of team including FPL executives).

comparison. In response to Staff data requests, for instance, the utilities omitted the inputs and workbooks that would allow independent verification of their summary comparisons between two gas generation options, discussed in Section II.B.1 above, and provided virtually no data on other, non-gas options, as discussed further below in Section II.B.3.

As the Commission maintains separate dockets on the operation and maintenance costs and risks of gas generation, it knows how astronomically high those costs and risks have proven to be. With gas prices at all-time lows—levels so low they are widely expected to only go up from here—Floridians have already lost billions of dollars on risk hedging programs.[30] Still, the hedging programs themselves are mere half-measures against the price and supply risks of Florida's reliance on natural gas imports—and useless against stranded asset risk. The FPL rate case underscores this.[31] FPL supported its request for a $1.3 billion annual rate increase and a 100 basis point return on equity increase with sworn testimony on all the costs and risks associated with managing its out-sized gas generation fleet.

Adding more gas generation is thus indefensible because it would exacerbate the burden on customers who essentially bear all the costs and risks. This includes the tremendous capital outlays required at the outset to add gas generation (recovered through base rates), and the tremendous operations and maintenance, including hedging expenses, over the 30 or more years these plants are supposed to be in service (recovered through separate clauses).

### 3. Renewables and energy efficiency are abundantly available to meet peak demand, and they can achieve deep cost-savings—unlike gas generation—through their flexible and diverse applications across the electric grid's generation, transmission, and distribution functions.

For alternatives to meet peak demand, such as renewables and energy efficiency, the market is better than ever. Yet the utilities only propose relatively modest amounts of solar, and even less amounts of other alternatives, despite these technologies' maturity, competitiveness, and widespread adoption in neighboring states. Moreover, these technologies can achieve deep cost-savings—unlike gas generation—through their flexible and diverse applications to the grid's electric generation, transmission, and distribution functions. As we discuss below, this is borne out by RFPs and integrated resource plans (IRPs) across our region and the country. We also discuss how the IOUs' refusal to conduct RFPs for renewables makes them particularly unprepared to deliver least-cost service.

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[30] *See* the detailed briefing by Public Counsel, filed July 15, 2015, in Docket No. 160096-EI, Joint petition for approval of modifications to risk management plans by DEF, FPL, Gulf and Tampa Electric Company.

[31] FPSC Docket No. 160021.

### a. Solar

Solar generation technologies, especially solar photovoltaics (PV) can meet peak demand[32] and achieve deep cost savings as a hedge against natural gas price volatility.[33] Solar PV is also a flexible resource, precisely what Florida needs as discussed in Section II.B.1 above. With an abundant solar resource—consistently ranked third best in the country for solar generation potential[34]—and ample support for developing it in Florida Statutes, discussed above in Section I.B, the utilities should be planning to "make Florida a leader in [this] new and innovative technolog[y]."[35]

Florida's tremendous solar potential, however, remains largely untapped because, in essence, the IOUs—with their overwhelming control of the state's energy market—sit on the tap. FPL is the sitter in chief. Florida's largest utility has not issued an RFP for renewable energy since 2007 and 2008, and never explains this omission, even though FPL acknowledges the cost of solar PV has since "plunged."[36] Likewise, DEF, the second largest utility, admits that it received "436 inquiries" from third parties interested in developing in-state renewables.[37] As Sierra Club has consistently highlighted, and as the Southern Alliance for Clean Energy (SACE) comments discuss in more detail, a disturbing lack of transparency shrouds such inquiries. This includes the modest solar power purchase agreements (PPAs) that DEF has negotiated to date. DEF refuses to disclose details, even such basic ones as the in-service, start, and end dates of the PPAs.[38] Gulf Power Company (Gulf) and Tampa Electric Company (TECO) are no better.[39]

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[32] *See, e.g.,* FPL 2016 TYSP, at 49-50 (crediting solar PV with 52% nameplate capacity at summer peak).

[33] Lawrence Berkeley National Laboratory, *Utility-Scale Solar 2014: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States* (Sept. 2015) at ii ("At these low levels – which appear to be robust, given the strong response to recent utility solicitations – PV compares favorably to just the fuel costs (i.e., ignoring fixed capital costs) of natural gas-fired generation, and can therefore potentially serve as a ['fuel saver'] alongside existing gas-fired generation (and can also provide a hedge against possible future increases in fuel prices).") (hereinafter "Utility-Scale Solar 2014"), *available at* https://goo.gl/0L2dDOU.

[34] *See, e.g.*, AEE, *Advanced Energy in Florida* (Jun. 11, 2015), *available at* https://goo.gl/BBL5M4.

[35] Section 366.91(1), F.S.

[36] NextEra on Storage, https://goo.gl/eIVoSL.

[37] DEF response to Staff data request no. 35.

[38] DEF response to Staff data request no. 28 (stating "n/a" or "TBD" for in-service, start, and end dates).

[39] *See generally* Gulf Power Company's 2016 Ten-Year Site Plan (hereinafter "Gulf 2016 TYSP"), *available at* https://goo.gl/PE1qbW; Gulf 2016 TYSP Workshop Presentation, *available at* https://goo.gl/GH9rME; TECO 2016 TYSP; TECO 2016 TYSP Workshop Presentation, *available at ht*tps://goo.gl/rQNeYF.

Collectively, the IOUs plan to add in ten years as much solar generation as Gulf's sister subsidiary, Georgia Power, will add by next year—more than a gigawatt.[40] Moreover, through additional RFPs, Georgia Power plans to double its installed capacity again in five years with more solar PV, battery storage, and other renewables.[41] Georgia Power is hardly alone. In 2015, 100% of Alabama Power's new generation came from solar, and that utility just gained approval to issue RFPs for 500 MW more.[42] In fact, RFPs in every single state in the Southeast have returned abundant, cost-effective solar PV bids.[43] These are widely reported precedents, which reputable entities such as the U.S. Department of Energy also verify and publish in market reports.[44] Yet the IOUs never mention them; much less reconcile their refusal to issue RFPs with the relatively modest amounts of solar they propose to build themselves.

Indeed, the utilities present no data or analyses whatsoever to justify the relatively modest amount of solar generation they propose. The RFPs of other Florida utilities, however, confirm there is no shortage of cost-effective solar PV in Florida.[45] As we highlighted last year, on a per customer basis these utilities have already installed far more solar capacity than the IOUs.[46]

The IOUs' proposals to add solar are also mere placeholders. Unlike the solar PV contracts that other utilities are negotiating with third parties, the IOUs have identified no particular process to set the terms of the solar they would build, such as the timing, sizing, siting, sourcing of inputs, and the costs. This gives the Commission—and the public—no reassurance whatsoever that the IOU investments in solar generation will in fact be optimally timed, sized, sited, etc. to achieve least-cost service. [47]

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[40] Georgia Power, Utility-Scale RFP Program, *available at* https://goo.gl/yEKHAu.

[41] Georgia Power 2016 Integrated Resource Plan, at 10-101, *available at* https://goo.gl/CdMFiZ.

[42] *See* Top 10 Solar States (2015), https://goo.gl/F3jIVu; *See also* Alabama Power's plan for 500 MW of renewables approved by regulators, Utility Dive, Sept. 3, 2015, https://goo.gl/uf5Ffm.

[43] *See* Exhibit A: Southeast RFPs for renewables.

[44] *See, e.g.,* Utility-Scale Solar 2014, at 37; *See also* Tracking the Sun IX: The Installed Price of Residential and Non-Residential Photovoltaic Systems in the United States (2016), *available at* https://goo.gl/SpUJY2.

[45] *See* Exhibit B: Florida RFPs for solar.

[46] *See* Sierra Club 2015 Comments, at 12.

[47] Sierra Club supports SACE's comments and shares SACE's concern that, beyond ten-year site plan reviews, the Commission may not get another opportunity to conduct fact-finding until after the utilities have already built whatever solar generation they unilaterally selected.

### b. Energy storage

Energy storage is another competitive alternative to gas generation. Tellingly, the states that already use energy storage want to add more of it. This includes Alabama,[48] Georgia,[49] West Virginia,[50] Tennessee,[51] and California.[52] Other states with energy storage market studies, such as Texas and Massachusetts, also report that this technology can provide immense improvements to the electric grid—and deep cost-savings relative to the status quo.

In contrast, there is a glaring omission of energy storage from the Florida utility plans. At the planning workshop, DEF explained that it lumps energy storage with offshore wind,[53] but that technology came online for the first time this summer.[54] Energy storage projects in contrast have been operational for decades. The first advanced compressed air energy storage (CAES) plant came online in 1978, and the first one in the US, in 1991, in

[48] As noted above, Alabama Power recently gained approval to issue additional RFPs for renewables. The company built the country's first compressed air energy storage CAES plant, 110-MW McIntosh plant, in 1991. PowerSouth Energy Cooperative, https://goo.gl/idGTAz. ("The unit captures off-peak energy at night, when utility system demand and costs are lowest. […] PowerSouth uses the stored energy during intermediate and peak energy demand periods to generate electricity.").

[49] As of September of 2015, Georgia has the largest Southern Company battery storage research project, which is testing a 1 MW/2 MWh lithium-ion battery storage system at a solar facility. Southern Company: Cedartown Battery Energy Storage Project, Sept. 17, 2015, https://goo.gl/MvLO7a; Southern Company also has a partnership with Tesla to test energy-storage products for commercial customers. Southern Co. goes all in on solar, storage, smart homes, EnergyWire, May 28, 2015, https://goo.gl/LjxEwD.

[50] In West Virginia, AES Energy Storage installed the Laurel Mountain Energy Storage Project at the Laurel Mountain wind plant, which delivers 32 MW of regulation and wind smoothing. The World's Largest Lithium-Ion Battery Farm Comes Online, Forbes, Oct. 27, 2011, https://goo.gl/L5g8K9.

[51] The Tennessee Valley Authority (TVA) operates the Raccoon Mountain Pumped-Storage Plant in Marion County, Tennessee. With capacity of 1,616 MW, it is TVA's largest hydroelectric facility and "provides critical flexibility." 2015 Tennessee Valley Authority Integrated Resource Plan (hereinafter "2015 TVA IRP"), at 40, *available at* https://goo.gl/GiURX3.

[52] World's Largest Storage Battery Will Power Los Angeles, Scientific American, July 7. 2016, https://goo.gl/cvGXzD; CNBC, Tesla tackles California energy woes with massive energy-storage deal, Sept. 16, 2016, https://goo.gl/z1YELb; California Dreaming: 5,000MW of Applications for 74MW of Energy Storage at PG&E, GreenTech Media, May 28, 2015, https://goo.gl/nuZRT4.

[53] Duke Energy has relegated energy storage has into a third category of "Emerging Technologies," along with offshore wind technologies. Duke Energy, A Brief Overview of DEF Planning. Duke Presentation, given at the Sept. 14, 2016 Ten-Year Site Plan Workshop, *available at* https://goo.gl/STKM0q.

[54] Offshore Wind Arrives in America, Energy.gov, Sept. 9, 2016, https://goo.gl/sqjxpr.

Alabama.[55] Now, as utilities across the country are rapidly procuring storage, Florida utilities are behind, without even a plan to explore procurements of their own.

As noted above, FPL itself acknowledges that energy storage is a competitive alternative to peakers. Market studies commissioned by state energy regulators and by other utilities agree: energy storage investments can save hundreds of millions, if not billions of dollars.[56] These projected savings stem from the wide-ranging applications of this technology, spanning electric generation (on and off peak), transmission, and distribution.

Peak generation is of course the most expensive generation, and storage allows utilities to reduce or avoid that generation altogether by redeploying surplus energy from lower cost, off-peak hours. A 2016 report by the state of Massachusetts concluded that this application alone could save customers in that state more than a billion dollars. Other studies document the cost savings from energy storage's ability to reduce transmission and distribution-related maintenance, as well as defer and even avoid huge capital expenditures.[57] In 2014, Texas utility, Oncor, announced it would seek approval to build 5,000 MW of energy storage citing over $625 million of projected customer savings.[58]

Storage can also reduce risk by providing both flexibility and reliability. Energy storage is in fact highly accommodating with sizing, siting, permitting, and construction time. Because this technology does not produce direct air emissions, or have large land requirements, the permitting and siting processes are far easier.[59] Because individual storage systems are modular, one system can consist of many modules operating simultaneously, and can take on additional modules incrementally, so the system will not fail from the breakdown of one module.[60] Additionally, several types of advanced storage technologies are commercially viable,[61] including batteries, compressed air energy storage, liquid air energy storage, pumped hydroelectric storage, and flywheels.[62] They are also readily available. A

[55] PowerSouth Energy Cooperative, https://goo.gl/idGTAz.

[56] A 2016 report by the state of Massachusetts concludes that 600 megawatts of storage capacity installed by 2025 would save ratepayers $800 million in system costs. Massachusetts Energy Storage Initiative Study (2016), at xvi-xvii, *available at* https://goo.gl/D3zviD.

[57] *Id.* at 86-89.

[58] The Value of Distributed Electricity Storage in Texas Proposed Policy for Enabling Grid-Integrated Storage Investments (2014), at 14, *available at* https://goo.gl/fv2mYF.

[59] Massachusetts Energy Storage Initiative Study, at 9.

[60] Massachusetts Energy Storage Initiative Study, at 10.

[61] This is evidenced by their widespread use in competitive markets without subsidies. *Id.* at 2.

[62] Energy Storage Technologies, https://goo.gl/5vcJTb.

2016 study found utilities could procure these advanced technologies within months—four to six times faster than conventional technologies.[63]

The value of energy storage is also apparent in California's use of it to solve the emergency that resulted from the massive gas facility failure at Aliso Canyon. That failure put the entire region at high risk of far-reaching power outages. State regulators directed utilities to speed up the deployment of large-scale, grid-connected storage. As of August, California utilities have proposed three large-scale battery installations[64]—one with an in-service date just five months after it was proposed.[65]

### c. Energy efficiency

Energy efficiency is the lowest-cost energy resource available,[66] and is essential to deliver least-cost electric service. More specifically, the wide-ranging technologies labeled as energy efficiency are part of the demand-side management that Florida needs to keep demand down and electric bills low, as noted in Section II.B.1 above. Yet the utilities continue their practice of ignoring any incremental energy efficiency additions beyond the levels set by the Commission based on information three or more years old.[67] This cannot be squared with the more recent market assessments, including those in other Southeast states, consistently showing that energy efficiency is not only cost-effective, but a critical resource to meet peak demand,[68] reduce risk, and save customers money.[69]

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[63] *Id.* at 10.

[64] They proposed two 20 MW (80 MWh) facilities from SCE and a 37.5 MW (150 MWh) project from SDG&E. 'Eyes wide open': Despite climate risks, utilities bet big on natural gas, Utility Dive, Sept. 27, 2016, https://goo.gl/697hYh.

[65] As Aliso Canyon Gas Shortage Looms, Southern California Looks to Energy Storage, Greentech Media, Jun. 02, 2016, https://goo.gl/JrI0O4; *See also* California Utilities Are Fast-Tracking Battery Projects to Manage Aliso Canyon Shortfall, GreenTech Media, Aug. 18, 2016, https://goo.gl/9XyYx1. (stating that the projects must be grid-ready by year's end, in SCE's case, or by Jan. 31, 2017, in SDG&E's case.).

[66] SEE, Guide For States: Energy Efficiency As A Least-Cost Strategy To Reduce Greenhouse Gases And Air Pollution, And Meet Energy Needs In The Power Sector (2016), *available at* https://goo.gl/ZtQ7pc; *See also* ClimateWorks & Fraunhofer ISI, How Energy Efficiency Cuts Costs for a 2°C Future (2015), *available at* https://goo.gl/fjf0xR; *See also* The Best Value for America's Energy Dollar: A National Review of the Cost of Utility Energy Efficiency Programs (2014), *available at* https://goo.gl/GPYhzU.

[67] Here, "utilities" refers to the utilities subject to the Florida Energy Efficiency and Conservation Act (FEECA). The other Florida utilities also have an obligation to provide least-cost service and to that end should develop and disclose robust options analyses focusing on energy efficiency.

[68] At very low cost and risk, efficiency offers flexibility in meeting peak demand. Florida utilities can quickly ramp up efficiency to meet demand growth and thereby reduce or entirely avoid costly infrastructure improvements and expansion. RAP, Recognizing the Full Value of Energy Efficiency (What's Under the Feel-

Energy efficiency programs are inherently less risky since they consist of many discrete resources that will not fail all at once.[70] Additionally, efficiency increases system reliability by reducing the stress on it. Many utilities give energy efficiency resources a risk credit, meaning the risk reduction effects of implementing efficiency reduced the cost of energy efficiency.[71] Thus, efficiency is a highly predictable and reliable cost-effective resource that enables the utility system to avoid the risk of surpluses, shortages, and periodic outages.

The utilities' refusal to consider incremental energy efficiency additions is even more alarming given the highly publicized, rapid changes in the market, and the billions of dollars that other utilities reported saving in recent years from geographically targeted energy efficiency programs, especially those that defer or avoid large transmission and distribution expenditures.[72] This Commission itself stated that, "at any time," it is ready to "reexamine and then adopt new [energy efficiency/demand-side management] goals or changes to those goals." [73] It is the responsibility of the utilities to develop data and analysis to allow the Commission to do so.

Indeed, if the utilities and the Commission are serious about closing the gap that minority and low-income households spend on energy, then they will rapidly develop plans to increase investment in energy efficiency, as leading energy efficiency experts have recommended.[74]

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Good Frosting of the World's Most Valuable Layer Cake of Benefits) (2013) (hereinafter "2013 RAP Energy Efficiency Report"), at 41, *available at* https://goo.gl/APjr2s.

[69] Because efficiency reduces all pollutants, it can also save ratepayers money by satisfying environmental regulations without building new power plants, which require huge, inflexible capital outlays.

[70] 2013 RAP Energy Efficiency Report, at 41.

[71] The 2013 PacifiCorp IRP and the Northwest Power Council both give energy efficiency resources risk credit. ACEEE Comments on 2015 Tennessee Valley Authority Draft Integrated Resource Plan, at 3.

[72] For instance, in 2011, Consolidated Edison estimated that including the effects of geographically-targeted efficiency programs in its 10-year forecast reduced costs by over $1 billion. Additionally, since 2012, ISO New England identified over $400 million in deferred transmission investments due to efficiency. NEEP Northeast Energy Efficiency Partnerships: Energy Efficiency as a T&D Resource: Lessons from Recent U.S. Efforts to Use Geographically (2015), at 12 available at https://goo.gl/AXRf3m.

[73] FPSC Transcript Document No. 06614-14, at 21, Order No. PSC-14-0696-FOF-EU, filed Dec. 5, 2014, in Docket No. 130205-EI.

[74] ACEE, Lifting the High Energy Burden in America's Largest Cities: How Energy Efficiency Can Improve Low-Income and Underserved Communities, Apr. 20, 2016, at 3-4. (For African-American, Latino, and renting households, 42%, 68%, and 97% of their excess energy burdens, respectively, could be eliminated by raising household efficiency to the median.).

**C. Rather than minimize cost of service to customers, the plans pave the way for windfalls for the IOUs/their affiliates at the expense of the captive customer base; it is imperative for the Commission to intervene and reject the plans.**

As discussed above, the plans are in no way least-cost from an electric utility customer perspective. Others, however, certainly profit from these gas-laden proposals. The most obvious profiteers are the shareholders of the IOUs/their affiliates—together they are heavily investing in gas generation and infrastructure, such as inter-state pipelines. This gives the IOUs a perverse incentive to increase their reliance on and subsidize the inefficient production and distribution of natural gas as they pass increases in fuel costs directly to customers.

In his testimony before the Senate Energy and Natural Resources Committee, Jonathan Peress highlights "a disturbing trend of utilities pursuing a capacity expansion strategy by imposing transportation contract costs on state-regulated retail utility ratepayers so that affiliates of those same utilities can earn shareholder returns as pipeline developers. . . . Thus ratepayer costs which may not be justified by ratepayer demand are being converted into shareholder return."[75] Mr. Peress further explains, "the effect of these affiliate transactions, whereby utilities commit their captive customers to pay for pipelines being developed by the same corporate group, is that customers are saddled with risky 20 year financial obligations to provide nearly risk free shareholder returns of 14% per year or more."[76]

Ultimately, Mr. Peress warns, affiliate transactions can hurt not only customers but also market participants. In Florida, this includes business, large or small, that lose opportunities to provide efficient solutions for electric service due to the control that the IOUs/their affiliates exert over the state's energy market. This is the rub, for instance, in FPL and DEF's decision to import more gas through the Southeast Market Pipeline Project instead of less costly, Florida-made solutions for them to provide an adequate and reliable supply of electricity.

In recent years, mergers between the IOUs and pipeline companies have proliferated[77]—growing the potential for the fallout described by Mr. Peress. Again, the Southeast Market Pipeline Project [78] is case in point: FPL and DEF back this pipeline even

[75] Jonathan Peress, Testimony Before the Senate Energy and Natural Resources Committee (June 14, 2016), at 5, https://goo.gl/rPoudE.

[76] *Id.*

[77] *See* Exhibit C: Mergers between pipeline companies and IOUs/their affiliates.

[78] Sabal Trail is part of multiple pipeline expansions and a joint venture of DEF's parent, Duke Energy Corporation, and FPL's parent, NextEra.

though it would more than double the amount of natural gas that FPL and Duke themselves project needing.[79]

Coupled with the utilities' hedging programs, the recent mergers and affiliate transactions raise an acute threat of improper subsidization of pipeline companies by Florida electric utility customers.[80] Between 2002 and 2015, the four IOUs saddled their customers with more than a $6 billion bill for fuel costs higher than market price.[81] Public Counsel has protested this, citing the IOUs' own estimates of another $559 million in losses-borne again by customers.[82] If the Commission were to allow the utilities, now merged with pipeline companies, to increase their gas generation, customer bill could soar even higher.

As the Antitrust Division of the United States Department of Justice recognizes, this type of vertical integration "may be used by monopoly public utilities subject to rate regulation as a tool for circumventing that regulation. The clearest example is the acquisition by a regulated utility of a supplier of its fixed or variable inputs. After the merger, the utility would be selling to itself and might be able arbitrarily to inflate the prices of internal transactions. Regulators may have great difficulty in policing these practices, particularly if there is no independent market for the product (or service) purchased from the affiliate."[83] Vertical integration of the retail distribution and generation markets plus financial hedging of natural gas thus presents a clear conflict of interest whereby self-dealing practices can rampantly exploit the captive customer base.

To protect customers and diverse businesses in Florida, it is imperative for the Commission to reject the plans, and put all the utilities on a path to reduce, not increase, Florida's generation.

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[79] FPL admitted that it would only require 400,000 Dth/day by 2017 and 600,000 Dth/day by 2020, yet it moved forward with the construction of Sabal Trail, which will ship double that amount—800,000 Dth/day by 2017 and 1.1 billion Dth/day by 2020. *Compare* Testimony of Heather C. Stubblefield on behalf of the Florida Power & Light Co., FPSC Docket No. 130198, July 26, 2013 at 9:10-13, (testifying that FPL requested these amounts "based on FPL's analyses of its future gas transportation requirements"); Application by Florida Southeast Connection, LLC ("FSC") to FERC for a Certificate of Public Convenience and Necessity and for Related Authorizations, Sept, 26, 2014 at 2, (stating amount that Sabal Trail will ship).

[80] For example, the $3 billion Atlantic Sunrise gas pipeline expansion proposal pending before the Federal Energy Regulatory Commission (Docket No. CP15-138) would connect to delivery points in Florida, and FPL and DEF have intervened in the FERC proceeding, indicating they have a material interest in this pipeline.

[81] Office of Public Counsel Protest, Document No. 05102-16, at 2, filed July 15, 2016, in Docket No. 160096-EI (hereinafter "Public Counsel Protest of Hedging Losses").

[82] Public Counsel Protest of Hedging Losses, at 2.

[83] United States Department of Justice, Antitrust Division, Non-Horizontal Merger Guidelines § 4.3 Evasion of Rate Regulation, *available at* https://goo.gl/9xw0QB.

**D. The utilities acknowledge they can wait many months, even years before committing resources to add any gas generation, so they have time to pursue alternatives instead.**

The utilities cite no reason to move forward now with their proposals to add gas generation.[84] Indeed, the purpose of this generation is mainly to meet projected growth in peak demand.[85] We reiterate that this growth may never materialize. Even if it did, the utilities acknowledge they can wait many months, even years, before committing any resources to adding gas generation.[86] More specifically, November 2017 is the earliest "drop dead" date (for a 200 MW CT with a May 2020 in-service date), and that could be pushed back by six months.[87] The utilities thus have ample time to complete the missing RFPs and options analyses and revise their plans to pursue cost-effective alternatives instead.

**E. Florida's high-cost, high-risk coal generation reinforces the need for revised plans including the chronically missing options analyses.**

While the utilities are not proposing any new coal generation, their existing coal burning generation undermines their ability to provide least-cost service. Burning coal to generate electricity lost whatever economic edge it once had, as evidenced by the overwhelming national coal divestment trend.[88] To be sure, coal is a terrible deal: Not only is burning coal one of the priciest[89] and most polluting[90] ways to generate electricity, importing coal from out of state also stunts local economic growth.[91]

With no shortage of low-cost, low-risk alternatives in the market, all remaining coal owners and operators owe their regulators robust options analyses focusing on options for transitioning to the alternatives as soon as practicable. The regulators, in turn, are wise to

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[84] Staff data request no. 42.

[85] As noted above, OUC and FPL propose adding CCs as well.

[86] *See* response to Staff data request no. 40; *See also* 2016 TYSP Schedule 9s.

[87] TECO 2016 TYSP; *See also* TECO response to Staff data request no. 40.

[88] *See*, *e.g.*, EIA, 'Coal made up more than 80% of retired electricity generating capacity in 2015' (Mar. 8, 2016) available at https://goo.gl/b0xcAq; *See also* Sierra Club, Open letter to coal industry: United States and the world are moving away from coal, toward clean energy (Apr. 21. 2016) *available at* http://goo.gl/kE94J6.

[89] *See* 2016 TYSP Comments, *supra* n. 3 (citing sources on how coal generation costs compare to alternatives).

[90] *See* Mother Jones, 'Environmentalists Hate Fracking. Are They Right?' (May 11, 2016) *available at* http://goo.gl/dGtFju.

[91] *See* Union of Concerned Scientists, Burning Coal, Burning Cash: 2014 Update; Fact Sheet: Florida's Dependence on Imported Coal (Jan. 2014) *available at* http://goo.gl/Y3Yw21.

disallow further expenditures on uncompetitive coal generation, as the Georgia Public Service Commission just did in the integrated resource planning proceeding it recently concluded for that state's largest electric utility Georgia Power.[92]

Yet in Florida, the utilities have continued their practice of presenting no options analyses regarding their existing coal generation. This is a grave omission, as we have consistently warned, because the utilities' own, incomplete regulatory compliance cost estimates for this generation range in the hundreds of millions to billions of dollars.[93] Moreover, when Staff asked for up-to-date information—underscoring the dearth of information in the plans—the utilities indicated that their analyses are still incomplete, and they failed to provide any estimate whatsoever for several existing regulations.[94]

One glaring omission concerns the Effluent Limitations Guidelines (ELGs), the new U.S. Environmental Protection Agency rule to protect our waters from the toxic pollutants in the discharge of coal generators. The ELGs became effective on January 4, 2016, and the default deadline is November 2018. As it took EPA decades to issue this rule, utilities have long anticipated and planned for it.[95] Indeed, the IOUs must report their compliance estimates under federal financial disclosure rules, and have in fact reported such estimates for ELGs, which are as high as $50 million for just one of a dozen Florida coal plants.[96]

With such massive costs looming over them, it is unacceptable for the utilities to continue to delay studying their options to transition to non-fossil generation.[97] Indeed, as we highlighted last year, Lakeland Electric stands out as the one Florida utility that already commissioned such a study. Lakeland compared several retrofit and retirement scenarios for its aging coal plant, showing that the analysis itself is eminently doable.[98] Predictably, Lakeland's conclusion, which the utility is now refining with further studies, is that

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[92] *See* Exhibit D – Georgia Power IRP Stipulation, at 3 ("minimiz[ing] all capital expenditures" on two large coal generation facilities); *See also* GPSC Docket No. 40161, Direct Testimony of T. Newsome and P. Hayet, at 7 and 51 (Commission staff expert recommending "all capital investment" on costly coal plants be "minimize[d]") (May 6, 2016) *available at* http://goo.gl/SF9rba.

[93] *See* Sierra Club 2015 Comments, at 7.

[94] *See generally* Utility responses to Staff data requests nos. 50-62.

[95] *See* Exhibit E – Sierra Club Comments to Florida Dep't of Environmental Protection (FDEP) re: ELGs.

[96] *See* Exhibit F – Sierra Club Comments to FDEP re: Crystal River Energy Center.

[97] To be clear, Sierra Club does not support new nuclear generation as it extremely high cost and high risk and thus a nonsensical choice given all of the better alternatives available in the market.

[98] nFront Consulting LLC, "Strategic Resource Plan, Lakeland Electric,"(Mar. 2015), *available at* http://goo.gl/B2BmRK.

renewables and energy efficiency will meet its load growth over the next 20 years more cost-effectively than all three fossil fuel expansion scenarios studied.[99]

## III. The Commission should require the utilities to file revised plans as soon as practicable.

For all the foregoing reasons, the Commission should reject the plans and require all the utilities to file revised plans as soon as practicable, including the chronically missing options analyses. The IOUs should file revised plans no later April 1, 2017, the annual deadline for plan revisions, to minimize the fallout from their conflict-ridden plans.

Thank you for your consideration.

Respectfully submitted,

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[99] *Id.* at 3-13, 3-24.

# EXHIBIT A

**Exhibit A: RFPs for Renewables in the Southeast**

The following is an illustrative list of RFPs for renewables in the Southeast.

**Alabama**

- The Alabama Public Service Commission (PSC) approved a proposal from Southern Company subsidiary Alabama Power, the state's dominant electricity provider, to procure up to 500 MW of renewable energy from 80 MW or smaller facilities. The utility's proposal cited both a need for renewables to meet Clean Power Plan emissions reductions requirements and customer demand. The utility's request for proposals (RFP) requires renewables projects to be priced below what it would expect to pay for other generation sources, unless the off-taker agrees to pay the difference.[1]
- On September 27, 2016, Alabama Power issued a request for proposals (RFP) for renewable energy resources. For a proposed project to be considered under this RFP, the generation resource must be either a renewable resource, as identified in Section 40-18-1(30), Code of Alabama (1975), or an environmentally specialized generating resource. Eligible projects include solar, wind, geothermal, tidal or ocean current, low-impact hydro and biomass.[2]

**Georgia**

- Georgia Power Company's 2015/2016 Advanced Solar Initiative Distributive Generation Program sought proposals and applications for solar photovoltaic generation. The Georgia public Service Commission has given approval to Georgia Power Co., a unit of Southern Co., to release a request for proposal for 495 MW of new solar power generation. The commission approved 425 MW of the requested amount on July 12, 2013 as part of the 2013 Georgia Power Co. Integrated Resource Plan and 70 MW as part of the utility's Advanced Solar Initiative November 20, 2012.[3]

**Kentucky**

- East Kentucky Power Cooperative RFP sought to obtain up to 300 MW of generation, including renewable resources with a capacity of 5 MW or larger. EKPC will retain all environmental attributes associated with the renewable resources.[4] (Closed August 30, 2012)

**Mississippi**

- The South Mississippi Electric Power Association RFP sought capacity and/or related energy from wind resources with up to 250 MW of nameplate capacity.[5] (Closed August 31, 2015)

**Tennessee**

- State of Tennessee RFP sought proposals for design, delivery, installation, operation and maintenance of renewable energy systems using solar photovoltaic electric generating technologies to supply energy to the State at multiple sites.[6] (Closed August 9, 2016).

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[1] https://goo.gl/dnY5Ea.
[2] https://goo.gl/XXCQAh.
[3] https://goo.gl/FkAz21.
[4] https://goo.gl/7GhgcP.
[5] https://goo.gl/OS1kKz.
[6] https://goo.gl/CsM2QY.

**Virginia**

- EPB RFP sought proposals from qualified contractors for the labor and materials needed to build the first of two community solar power generation facilities under its Solar Share pilot project. The first project will be built in the Bakewell community of northern Hamilton County and the second one is planned near existing EPB facilities in Chattanooga. The two projects will provide a combined 1.35 megawatt generation capacity.[7] (Closed May 15, 2016)
- The Council of Independent Colleges in Virginia (CICV) RFP sought proposals to construct and finance up to 37.8 MW solar photovoltaics (PV) systems at the campuses of some of its member colleges. The project is supported by the U.S. Department of Energy's SunShot Initiative. Bidders shall propose the construction of different types of PV systems under various financing mechanisms that creates net cost savings to participating colleges.[8] (Closed January 22, 2016)
- Solarize Harrisonburg RFP sought a single price/kW installed for a group of residential homeowners in Harrisonburg, Virginia. This price will be offered to all homeowners participating in the group. The PV projects are to be installed on the roofs of each of the properties and will be owned by the individual property owners.[9] (Closed September 11, 2014)
- Appalachian Power Company RFP sought proposals to solicit and subsequently pre-qualify companies who have an interest in participating in the company's RFP for obtaining up to 10 MW (AC) of ground-mounted solar energy resources via either an asset purchase with 100% ownership or 20-year PPA. Proposed projects must be located within Virginia, be interconnected to the PJM Regional Transmission Operator or Appalachian Power's distribution system, and have a minimum nameplate rating of 5 MW (AC).[10] (Closed February 5, 2016)

**North Carolina**

- The City of Raleigh RFP sought proposals from qualified solar energy developers to own, install, operate, and maintain solar systems on approximately 53 acres of city-owned land near the Neuse River Resource Recovery Facility.[11] (Closed January 8, 2016)
- NC GreenPower RFP sought proposals for up to 60,000 MWh of renewable energy through a purchase with either a one- or two-year term. The potential generator of renewable energy will be required to enter into a Power Purchase Agreement with a North Carolina electric utility and the generated power will be delivered to North Carolina's electrical supply.[12] (Closed January 6, 2016)
- NC GreenPower RFP sought proposals for up to 40,000,000 kWh of Renewable Energy Certificates (RECs) generated in North Carolina through one- or two-year terms from qualifying renewable energy projects.[13] (Closed November 25, 2014)

**South Carolina**

- Duke Energy Carolinas and Duke Energy Progress RFP sought approximately 40 MW and 13 MW of eligible photovoltaic generation capacity and all associated renewable attributes located in and

[7] https://goo.gl/y0a1sk.
[8] https://goo.gl/Ay3DUh.
[9] https://goo.gl/mWiAcl.
[10] https://goo.gl/vNNFbr.
[11] https://goo.gl/1fZ1sQ.
[12] https://goo.gl/Yrjj3M.
[13] https://goo.gl/2iZOSd.

directly interconnected to its retail service areas in South Carolina via a combination of Power Purchase Agreements and turnkey proposals with engineering, procurement and construction agreements in the form of Design-Build-Transfer Asset Purchase proposals.[14] (Closed October 27, 2015)

- Duke Energy Carolinas and Duke Energy Progress RFP sought approximately 4 MW and 1 MW of eligible photovoltaic generation capacity and all associated renewable attributes located in and directly interconnected to its retail service areas in South Carolina via a combination of Power Purchase Agreements and turnkey proposals with engineering, procurement and construction agreements in the form of Design-Build-Transfer Asset Purchase proposals. Proposals must comply with Duke Energy's "Shared Solar Program" requirements under the South Carolina Distributed Energy Resource Program Act and be in service by December 31, 2016.[15] (Closed October 27, 2015)
- South Carolina Electric & Gas Company RFP seeking bidders to provide solar power to the utility through purchased power agreements. SCE&G intends to work with solar developers to locate the solar farms on company-owned property in North Charleston (up to 500 kW) and Cayce (up to 4 MW).[16] (Closed October 3, 2014)

**Louisiana**

- State of Louisiana Department of Education RFP seeking bids for the installation of solar panels at Andrew Jackson Elementary School located in New Orleans, LA.[17] (Closed June 26, 2012)
- AEP Southwestern Electric Power Company (SWEPCO) RFP seeking long-term renewable energy to help fulfill energy-supply requirements for its customers. The request was issued as part of the Louisiana Public Service Commission's Renewable Energy Pilot Program. Proposals for approximately 31 megawatts of new renewable-energy resources deliverable to the Southwest Power Pool (SPP). Resources must be able to begin operating by Dec. 31, 2014, and have a minimum 10-year PPA.[18] (Closed June 15, 2011)

**Multiple States in the Southeast Involved**

- Southern Alliance for Clean Energy RFP sought a contractor to perform a transmission analysis for gigawatt-scale offshore wind energy off North Carolina, South Carolina and Georgia. (Phase 2C - Offshore Wind Energy Transmission Study).[19] (Closed February 16, 2011)
- Appalachian Power RFP sought up to 150 megawatts of wind power. Proposals should allow Appalachian Power to own one or more wind projects or purchase the output from wind projects under one or more 20-year renewable energy power purchase agreements. Qualified projects must be located within Virginia, West Virginia, eastern Indiana, Kentucky, Maryland, North Carolina, Ohio or Pennsylvania, be interconnected to the PJM Regional Transmission Operator, and have a minimum nameplate rating of 40 MW.[20] (Closed April 1, 2016)

[14] https://goo.gl/uv2Mj8; https://goo.gl/K5U7TY.
[15] https://goo.gl/b4dpPR.
[16] https://goo.gl/toZd3Q.
[17] https://goo.gl/l2hDuK.
[18] https://goo.gl/iu1fM6.
[19] https://goo.gl/fLSBAe.
[20] https://goo.gl/8S6l5C.

# EXHIBIT B

**Exhibit B: Florida RFPs for solar**

The following is an illustrative list of recent RFPs in Florida.

1. JEA issued an RFP for solar PV Power Purchase Agreements (PPA) in April of 2015, and entered into seven PPAs.[1] In 2015, JEA awarded a total of 31.5 MW of solar PPAs. Agreements have been finalized for five projects for a total of 25.5 MW.[2] Additionally, in December of 2014, JEA issued a solar photovoltaic RFP. Earlier, in May of 2009, JEA entered into a PPA with Jacksonville Solar, LLC to receive up to 15 MW from the solar plant located in western Duval County. The facility consists of approximately 200,000 photovoltaic panels, and generated 20,132 MWh in 2015.[3]

2. Seminole issued a solar RFP in March 2015 for a minimum of 2 MW and maximum of 20 MW to be in operation before November 2, 2016. Seminole received seventeen different offers with photovoltaic technology to be in service by the end of 2016. Seminole also incorporated a 2 MW solar photovoltaic facility into Seminole's ten-year plan. Finally, on March 21, 2016, Seminole finalized agreements for a 2.2 MW solar facility to be constructed in Hardee County.[4]

3. The City of Tallahassee issued a RFP for a PPA for a 10 MW utility scale solar photovoltaic project.[5] During negotiations, the project developer offered double the capacity of the project, and the City Commission voted to authorize the PPA for 20 MW.[6]

4. Lakeland Electric issued an RFP in November of 2007, seeking an investor to purchase and install investor-owned photovoltaic systems totaling 24 megawatts. In October of 2008, the project was approved, and installed two years later. The projected reduction in annual fossil-fuel generation is expected to be 31,800 megawatt-hours. In addition, Lakeland Electric issued another RFP in November 2007 for the expansion of its Residential Solar Water Heating Program. Lakeland's proposal was for the installation and operation of 3,000 – 10,000 solar residential water heaters, and annual projected energy savings ranged between 7,500 and 25,000 megawatt-hours.[7]

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[1] Solar Photovoltaic Power Purchase Agreements, Dec. 22, 2014, *available at* https://goo.gl/X4C2hu.
[2] *See* JEA 2016 Ten-Year Site Plan, at 12.
[3] *See id.* at 3.
[4] Seminole response to Staff data request no. 36; *See also* Seminole 2016 Ten-year site plan, at 25; *See also* Seminole Electric Cooperative Issues Request for Proposals for Solar Energy, Mar. 31, 2015, https://goo.gl/fkRXXg.
[5] 2015 Solar Procurement in the South, Oct. 6, 2015, https://goo.gl/jFaYnj.
[6] *See* City of Tallahassee 2016 Ten-year site plan, at 41-42; *see also* Tallahassee prepares to add solar power to portfolio, Mar. 24, 2015, https://goo.gl/47IWrv.
[7] *See also* Lakeland Electric's 2016 Ten-Year Site Plan.

# EXHIBIT C

**Exhibit C: Mergers between pipeline companies and IOUs/their affiliates.**

The following is an illustrative list of mergers between pipeline companies and the IOUs/their affiliates.

1. AGL the largest natural gas distributor in the Southeast merged with Southern Company, which is the parent company of Gulf Power. The merger creates operations of more than 80,000 miles of pipelines.[1]

2. There is a pending merger between Duke Energy and Piedmont. Both are partners on a $5 billion Atlantic Coast Pipeline.[2]

3. NextEra Energy Partners, LP, parent company of Florida Power & Light, acquired NET Midstream, owner of seven long-term contracted natural gas pipeline assets.[3]

Mergers aside, Tampa Electric Company also has substantial stakes in gas infrastructure. TECO's subsidiary, SeaCoast Gas Transmission, L.L.C, operates a 25-mile pipeline system, which can deliver 100,000 MMBtus per day of natural gas to northeast Florida.[4] Another affiliate, New Mexico Gas Company, also owns and operates pipelines.[5]

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[1] Southern Company and AGL Resources complete merger, create a leading U.S. energy company, Southern Company, July 1, 2016, https://goo.gl/lHeHHU.
[2] North Carolina environmental groups oppose Duke-Piedmont merger, Crain's Raleigh-Durham, July 22, 2016, goo.gl/GSoCQ0
[3] NextEra Energy Partners, LP completes the acquisition of natural gas pipelines in Texas, PR Newswire, Oct. 5, 2015, goo.gl/WlaS4X.
[4] TECO Energy announces the formation of a new subsidiary, SeaCoast Gas Transmission, LLC, TECO Energy, Aug. 4, 2008, https://goo.gl/0ebj7J.
[5] Overview — New Mexico Gas Company, https://goo.gl/jQtnwL.

# EXHIBIT D

STATE OF GEORGIA

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

| | | |
|---|---|---|
| IN RE: | ) | |
| | ) | |
| Georgia Power Company's | ) | Docket No. 40161 |
| 2016 Integrated Resource Plan and | ) | |
| Application for Decertification of Plant | ) | |
| Mitchell Units 3, 4A and 4B, Plant Kraft | ) | |
| Unit 1 CT, and Intercession City CT | ) | |
| | ) | |
| Georgia Power Company's Application for | ) | Docket No. 40162 |
| the Certification, Decertification, and | ) | |
| Amended Demand Side Management Plan | ) | |
| | ) | |

**Stipulation**

The Georgia Public Service Commission (the "Commission") Public Interest Advocacy Staff ("PIA Staff"), Georgia Power Company ("Georgia Power" or the "Company") and the undersigned intervenors (collectively the "Stipulating Parties") agree to the following stipulation as a resolution of the above-styled proceedings to consider the Company's 2016 Integrated Resource Plan (the "2016 IRP") and the Application for the Certification, Decertification, and Amended Demand Side Management Plan (the "2016 DSM Plan"). The Stipulation is intended to resolve all of the issues in these Dockets. The Stipulating Parties agree as follows:

**Supply Side Plan**

1. The 2016 IRP is approved as amended by this Stipulation.

2. Plant Mitchell Units 3, 4A and 4B, Plant Kraft Unit 1CT and Intercession City CT shall be decertified and retired as provided for in the 2016 IRP.

3. The Renewable Energy Development Initiative ("REDI") is approved and shall be increased such that it will procure 1,200 MW (150 MW of Distributed Generation ("DG") and 1,050 MW of utility scale resources). Utility scale procurement shall take place through two separate Requests For Proposals ("RFP"). The first RFP will be issued to the marketplace in 2017 and will seek 525 MW of renewables with in service dates of 2018 and 2019. The second RFP will be issued to the marketplace in 2019 and will seek 525 MW of renewables with in service dates of 2020 and 2021. No more than a total of 300 MW of wind resources shall be procured through REDI. Bid fees for the utility scale solicitation shall be set at five thousand dollars ($5,000) or three hundred dollars per MW

($300/MW), whichever is greater. The cost to implement and administer the REDI program shall be recovered through the fuel clause. Provided, however, that any costs recovery related to the ASI Prime Program in excess of ongoing ASI Prime costs shall be allocated to REDI and shall not be recovered through the fuel clause. All bid fees collected will be credited to the fuel clause.

4. In 2017, the Company shall issue an RFP for 100 MW of DG greater than 1kW but not more than 3 MW with a commercial operation date of 2018 or 2019. Contract terms will be up to 35 years and solar DG projects must interconnect at Georgia Power's owned distribution system. Bid fees for the DG solicitations shall be set at $4/kW.

5. By the end of 2018, the Company shall procure an additional 50 MWs of customer sited DG projects. Such projects shall be greater than 1kW but not more than 3 MW and must have an installed DC capacity that is less than or equal to 125% of the actual annual peak demand of the customer's Premises in 2015 and be a current GPC customer at the time of award. Procurement shall be done through an application process and if oversubscribed, a lottery will be conducted. Participant fees for the DG solicitations shall be set at $3/kW. Any MWs that are unsubscribed from the customer sited program shall be allocated to the DG RFP reserve list. Customer sited projects will be paid avoided costs using the process as described below in item 8(a).

6. The specific process that will be utilized for the evaluation (such as whether to use a project and/or portfolio analysis) for projects submitted into REDI will be finalized during the review and approval of the REDI RFP documents.

7. The Renewable Cost Benefit framework ("RCB") as provided in paragraph 8(a) shall be utilized in the evaluation of bids received through the REDI RFPs for utility scale and DG projects. The Company and Staff will work collaboratively to develop a process and recommendations for the continued implementation of RCB. Within (4) months from the issuance of the Final Order in this case, the Company and Staff will file their proposal with the Commission for implementation of RCB. If an agreement is reached between the Company and Staff on implementation of RCB, the Company and Staff can recommend to the Commission utilization of the full RCB in REDI.

8. The RCB shall be modified for use in the REDI program as follows:

(a) The Company shall evaluate the bids received in response to REDI RFPs using the RCB. The evaluation of REDI proposals will be limited to the consideration of Avoided Energy and Deferred Generation Capacity cost components consistent with the Framework methodology. Further, the Company will evaluate the appropriate transmission and distribution costs and benefits on a case by case basis as proposed in the Framework document.

(b) Once the evaluation in 8(a) is concluded the Company will conduct, for information purposes only, an evaluation using the entire RCB as filed by the Company to allow Staff

and the Independent Evaluator ("IE") to gain familiarity with the RCB. The evaluation will include all aspects of the Framework including specifically, Generation Remix, Support Capacity, and Bottom Out Adjustments. The Company will file its results with the Commission.

9. The Additional Sum for utility scale resources procured through REDI shall be set at 8.5% of shared savings. This amount shall be levelized and recovered annually for the term of the PPA.

10. The Company's closed ash pond solar demonstration project is approved as filed by the Company. The Company will be required to file quarterly construction monitoring reports and will be required to demonstrate the reasonableness and prudency of any recovery in excess of the budget for this project filed in the 2016 IRP. The Simple Solar program is approved with the modifications to the sourcing of the program as recommended by Staff.

    In addition, the Company's High Wind Study is approved as filed. The Company agrees to file quarterly reports providing the status of the High Wind Study. The Staff and Company will collaborate on what, if any, information from the wind study will be made available to interested parties.

11. The Commission approves an additional 200 MW of self-build capacity for use by the Company to develop additional renewable projects in collaboration with customers, including potential projects at Robins Air Force Base and Fort Benning. The projects must be at or below the Company's avoided costs. No more than 75 MW of the 200 MWs provided for in this provision may be used for non-military customer projects. For the non-military customer projects, the Company must demonstrate that the project meets a special public interest need and could not reasonably be achieved using the competitive bid process. The RECs for the non-military customer projects shall accrue to the benefit of all customers.

12. The Company shall consider the development of a renewable Commercial and Industrial Program. No more than 200 MW shall be allocated for such a program and such program must be approved by the Commission before implementation. The Company shall only consider program options that will result in delivering value to all of its customers and will benchmark such programs to the last accepted proposal from the Company's utility scale REDI program.

13. Staff and the Company shall work together to address retirement study and other modeling issues. This process should begin within six months of the final order being issued in this proceeding and must conclude at least 12 months prior to the Company's filing of the 2019 IRP.

14. For purposes of the Company's IRP evaluations the long term Southern System planning reserve margin shall be raised to 16.25%. The Company shall meet with Commission Staff within 6 months of a final order in this case to discuss the timing of future Expected

Unserved Energy studies. The Company will report to Staff once all operating companies have approved for utilization the long term planning reserve margin adopted by this provision.

15. The Company agrees to minimize all capital expenditures on Plant McIntosh Unit 1 and Plant Hammond Units 1-4 through July 31, 2019. The Company agrees to annual limits on all capital expenditures of $1 million for McIntosh 1 and $5 million for Hammond 1-4[1]. The Company agrees to make a filing with the Commission prior to incurring expenditures that exceed the annual limit.

16. The measures taken to comply with the existing government imposed environmental mandates necessary for the Company to implement its environmental and compliance plan as presented in Technical Appendix Volume 2, Summary of Capital Expenditures, Closures, and O&M Expenses filed as part of the 2016 IRP are approved subject to the limits outlined in No. 15 above regarding Plant McIntosh Unit 1 and Hammond Units 1-4. This approval does not preclude the Commission from reviewing prudence of the actual expenditures made to effectuate the compliance plan.

17. The remaining net book values of Plant Mitchell Unit 3 shall be reclassified as a regulatory asset and the Company shall continue to provide for amortization expense at the same rate as determined in the Company's 2013 base rate case. Recovery of the remaining balance as of December 31, 2019 will be deferred for consideration in the Company's 2019 base rate case. The Stipulating Parties reserve the right to make any arguments, including policy and legal arguments, on the recovery mechanism and appropriate period in which the costs should be recovered if applicable. Parties may argue their respective positions on that issue in the 2019 base rate case.

    Any unusable M&S inventory balance remaining at the date of the unit retirement shall be reclassified as a regulatory asset and deferred for consideration in the Company's 2019 base rate case. The Stipulating Parties reserve the right to make any arguments, including policy and legal arguments, on the recovery mechanism and appropriate period in which the costs should be recovered if applicable. Parties may argue their respective positions on that issue in the 2019 base rate case.

18. Any over or under recovered cost of removal balances for each Retirement Unit shall be deferred for consideration until the Company's 2019 base rate case. The Stipulating Parties reserve the right to make any arguments, including policy and legal arguments, on the appropriate period in which the costs should be recovered. Parties may argue their respective positions on that issue in the 2019 base rate case.

[1] The Hammond Units 1-4 $5 million value represents the cumulative annual amount for all four units. This provision does not apply to expenditures required for retirement obligations.

19. The Company shall report to the Commission concerning progress on the dismantlement and remediation of the Plant Kraft generating plant site and the Company shall provide the Commission with appraised values of any land at that site that the Company would propose to donate to the Georgia Ports Authority, including information regarding whether the appraised value exceeds the Company's net book value of such land.

20. The decision whether to accept, modify or defer consideration of the Company's request for authority to capitalize additional costs to preserve new nuclear shall be a policy decision for the Commission. Adoption of this provision within this stipulation does not preclude any Party from making any argument for or against the Company's request in this regard, nor does this agreement or this provision within this agreement suggest that the Commission must or should (or should not) consider this question as part of this IRP.

21. When filing the 2019 IRP or when filing any updates to the IRP prior to the 2019 IRP filing, the Company agrees to provide the Commission Staff working copies of all models used in the development of that IRP, with each configured to replicate inputs used to derive results incorporated in its base case scenario within 10 days after the IRP or update to the IRP is filed.

22. In conjunction with the ongoing level of review and analysis required by this agreement, Georgia Power will agree to pay for any reasonably necessary specialized assistance to the Staff in an amount not to exceed $300,000 annually. This amount paid by Georgia Power under this paragraph shall be deemed as necessary cost of providing service and the Company shall be entitled to recover the full amount of any costs charged to the utility.

23. The Electric Transportation Initiatives and associated costs identified in the 2016 IRP are not, and have not been converted into, jurisdictional expenses that become the responsibility of ratepayers. Each party reserves the right to address these costs and the merits of the program through the Annual Surveillance Report process and future rate cases.

**Demand Side Plan**

1. The Company's 2016 Demand Side Management ("DSM") Plan and Application for Certification, Decertification and Amended DSM Plan is approved as amended by this Stipulation.

2. Georgia Power will continue to treat DSM as a priority resource in accordance with prior Commission precedent. For the calculation of long term percentage rate impacts, the Company will work with Commission Staff to come up with a methodology within 12 months of the issuance of the final order.

3. Georgia Power will enter discussions over the next three years with Staff and DSMWG members on the value of a Residential Mid-Stream Retail Products Program.

4. Georgia Power will develop a Technical Reference Manual prior to the Company's next IRP filing and will update it every three years thereafter. The Company will work closely with Staff and members of the DSMWG and DSMWG members may also propose new measures to be added at any point in the measure evaluation process. The DSM Program Planning Approach filed as Staff Exhibit BSK8 will otherwise remain unchanged other than "Technology Catalog" will be replaced with "Technical Reference Manual" and the dates will be updated to reflect 2017 through 2019.

5. Georgia Power will agree to the budget adjustments as provided in exhibit 8 attached to this Stipulation as amended.

6. Georgia Power will receive an Additional Sum equal to 8.5% of actual net benefits based on net energy savings from the Program Administrators Cost Test ("PACT"). Once the Additional Sum amount as calculated exceeds the annual program costs, the portion of the Additional Sum that exceeds the program cost shall be calculated based on 4% of the actual net benefits based on net energy savings from the PACT.

7. Georgia Power will work with Staff and the Company's implementation contractor for the Residential Behavioral Program to find ways to include more customers in the program.

8. The Company will make a concerted effort to obtain at least 25% of portfolio savings each year from the Residential sector.

9. Once a program implementer is selected and plans for all proposed programs are drafted and completed, the plans will be provided to Staff for review prior to implementation of the programs. The current review and approval process reached in an agreement between Staff and the Company in 2014 will continue, and the Company agrees to discuss further refinements and revisions to the process. In order to change the process both Staff and the Company must agree to the recommended changes.

10. The Company will provide detailed evaluation plans for each of the approved DSM programs within 120 days of the selection of Program Implementers for each of the certified programs. If necessary, the Company may request, and Staff may unilaterally grant, additional time to complete the detailed evaluation plans for each of the approved DSM proposals.

11. The Company will agree to a Commercial and Residential Building Usage Data awareness option at the cost of $300,000 for 2017 and $100,000 annually for 2018 and 2019, and such costs will be added to the DSM Consumer Awareness budget. This option will be available to customers within one year from the date of the final order in

this docket. There will be no assumed energy savings or goals attributed to this customer awareness option.

12. The Company and Staff agree to a $2.5 million annual pilot budget for DSM and energy efficiency pilot programs. Staff will be notified before the start of such pilots.

13. The Company agrees to the Staff recommendation for the Learning Power program annual budget to be $3 million.

14. The Company agrees to the Staff recommendation against shifting residential and commercial customer awareness to cross-cutting costs.

15. The current DSM true-up process filed in Docket No. 36499 on October 18, 2013, will continue through 2020. Although the DSM tariffs will remain at current levels until rates are adjusted in 2020, the true-up review process will continue on an annual basis.

Agreed to this 23rd day of June, 2016.

Jeffrey Stair

On behalf of the Georgia Public Service Commission
Public Interest Advocacy Staff

Brandon F. Marzo

On behalf of Georgia Power Company

[Additional Signatures]

On behalf of Clean Line Energy Partners LLC

David Berry
authorized person

On behalf of

On behalf of

On behalf of

On behalf of

On behalf of

On behalf of

On behalf of

[Additional Signatures]

Chad B. Jones, III

On behalf of Georgia Association
Of Manufacturers

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On behalf of Georgia Industrial
Group

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On behalf of

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On behalf of

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On behalf of

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Agreed to this 23rd day of June, 2016.

Jeffrey Stair

On behalf of the Georgia Public Service Commission
Public Interest Advocacy Staff

Brandon F. Marzo

On behalf of Georgia Power Company

on behalf of Georgia Industrial Group

[Additional Signatures]

On behalf of The Georgia Large Scale Solar Association

On behalf of

On behalf of

On behalf of

On behalf of

On behalf of

On behalf of

On behalf of

On behalf of

[Additional Signatures]

On behalf of Georgia State Building and Construction Trades Council

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On behalf of

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On behalf of

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On behalf of

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On behalf of

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On behalf of

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On behalf of

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On behalf of

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On behalf of

[Additional Signatures]

Bruce W. Burcat

On behalf of Southern Wind Energy Association

# EXHIBIT E

February 29, 2016

*Via Electronic Mail*

Supervisor Marc Harris
Power Plant NPDES Permitting, Industrial Wastewater Section
Florida Department of Environmental Protection

Re: *Bringing Florida Coal Plants Into Compliance With The New Effluent Limitations Guidelines*

Dear Supervisor Harris:

As you know, the U.S. Environmental Protection Agency ("EPA") updated the Effluent Limitations Guidelines ("ELGs") for steam electric power plants to protect our waters from the toxic pollutants in these generators' discharges.[1] Reflecting decades of advances in water quality science and control technology,[2] the ELGs became effective on January 4, 2016. Now coal-burning[3] power plants across the country must come into compliance with the ELGs "as soon as possible;" for many plants the deadline is November 1, 2018.[4] The undersigned groups and our tens of thousands of Florida members therefore urge you, as the supervisor of power plant NPDES permitting, to:

1. Promptly issue draft revised NPDES permits and fact sheets for Florida coal plants to require these plants to comply with the ELGs by November 1, 2018, unless you conclude that a later date is appropriate based on a well-documented justification that is consistent with EPA's guidelines in the final rule and the public interest in securing vital water protections as soon as possible.

2. Take public comment for no less than 60 days on draft NPDES permits and fact sheets for Florida coal plants that include your ELGs compliance determinations.

3. Work with the operators of the three Florida coal plants without NPDES permits or announced plans for retirement, and other stakeholders, to ensure that these plants achieve timely compliance with the applicable requirements in the ELGs.

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[1] U.S. EPA, *Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*, 80 Fed. Reg. 67,837 (Nov. 3, 2015), codified at 40 C.F.R. part 423.
[2] *See* 80 Fed. Reg. at 67,840.
[3] *See* 80 Fed. Reg. at 67,839, n. 1 ("power plants covered by the ELGs use nuclear or fossil fuels, such as coal, oil, or natural gas, to heat water in boilers, which generate steam." [emphasis added]).
[4] *See, e.g.*, 40 C.F.R. § 423.13(g)(1)(i) (establishing deadline for compliance with FGD wastewater standards; identical language appears in the provisions for other regulated waste streams).

4. Work with all Florida coal plant operators, fellow regulators, and other stakeholders to determine compliance obligations and timelines for all other applicable water-side requirements.

As we discuss below, timing is critical. Through the permit renewal process, making prompt compliance determinations will help attain and maintain safe water quality in Florida. Prompt compliance determinations will also allow fellow regulators to assess whether it is more prudent to retire—rather than spend huge sums of public monies to retrofit—these aging coal plants in the rapidly evolving regulations and market conditions concerning coal and carbon.

In short, our overarching request is that you take swift action to determine what it will take to bring *all* Florida coal plants into timely compliance with *all* applicable water-side requirements, set deadlines for the same, and meet with us to discuss the way forward.

## I. DEP Should Promptly Issue Draft Permits And Fact Sheets For Florida Coal Plants Incorporating The ELGs And Specifying The "As Soon As Possible" Compliance Deadline.

The ELGs impose stringent, technology-based effluent limitations on the discharges of several common types of effluent (i.e., waste streams) from coal plants, including fly ash and bottom ash transport waters, and wastewater from flue gas desulphurization ("FGD") systems.[5] Under the Clean Water Act, it is the responsibility of state permitting authorities to incorporate the ELGs into the NPDES permits for coal plants "as a floor or a minimum level of control."[6] Just as it is the responsibility of the coal plant operators to "immediately begin"—"even prior to the permit renewal process"—their ELGs compliance analyses, and convey to state authorities the information they need to complete independent evaluations.[7]

In particular, when revising permits for direct dischargers—facilities that discharge to surface waters—state permitting authorities must determine the compliance deadline for the ELGs, which is to be "as soon as possible beginning November 1, 2018, but no later than December 31, 2023." To be clear, the phrase "as soon as possible" means November 1, 2018, unless the permitting authority establishes a later date based on a well-documented justification and the

[5] *See* 40 C.F.R. § 423.13.
[6] 80 Fed. Reg. at 67,882.
[7] *Id.* at 67,882-83 ("Regardless of when a plant's NPDES permit is ready for renewal, the plant should immediately begin evaluating how it intends to comply with the requirements of the final ELGs. In cases where significant changes in operation are appropriate, the plant should discuss such changes with the permitting authority and evaluate appropriate steps and a timeline for the changes, even prior to the permit renewal process." [emphasis added]).

authority's case-by-case consideration of certain enumerated factors in the final rule, discussed further below.

The November 1, 2018, compliance deadline is achievable. EPA's rulemaking record shows that, depending on the scope of required retrofit at a particular coal plant, industry itself projects that the total time needed for fly ash and bottom ash system retrofits ranges from 27 to 36 months, from the start of conceptual engineering to final commissioning.[8] With appropriate planning and direction from state permitting authorities, many plants thus can and should be required to bring their operations into compliance by November 1, 2018, especially given that the updates to the ELGs were developed and thus anticipated by industry over several decades.

EPA rightly urges permitting authorities to "provide a well-documented justification for how [they] determined the 'as soon as possible' date in the fact sheet or administrative record for the permit," and to "explain why allowing additional time to meet the limitations is appropriate," if that is the authority's conclusion.[9] EPA specifies that any determination that a later date is appropriate should be substantiated by the public record and reflect consideration of the following factors:

- "Time to expeditiously plan (including time to raise capital), design, procure, and install equipment to comply with the requirements [in the ELGs]."[10] EPA explains that "the permitting authority should evaluate what operational changes are expected at the plant to meet the new BAT limitations for each waste stream, including the types of new treatment technologies that the plant plans to install, process changes anticipated, and the timeframe estimated to plan, design, procure, and install any relevant technologies."[11]

- Changes being made or planned to bring the coal plant into compliance with Clean Air Act requirements, as well as the requirements for the disposal of coal combustion residuals under Subtitle D of the Resource Conservation and Recovery Act.[12]

- For FGD wastewater requirements only, an initial commissioning period to optimize the installed equipment.[13] EPA explains that the "record demonstrates that plants installing

[8] Utility Water Act Group, *Comments on EPA's Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (Sept. 30, 2013), Attach. 11: Retrofitting Dry Bottom Ash Handling, Attach 13: Retrofitting Dry Fly Ash Handling.
[9] *See* U.S. EPA, Technical Development Document for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (Sept. 2015), at p. 14-11, *available at* http://goo.gl/PpzQ4F [hereinafter "TDD"].
[10] *Id.*
[11] *Id.*
[12] 40 C.F.R. § 423.11(t)(2).

the FGD technology basis spent several months optimizing its operation (initial commissioning period). Without allowing additional time for optimization, the plant would likely not be able to meet the limitations because they are based on the operation of optimized systems."[14]

- Other factors as appropriate.[15]

Consistent with these EPA guidelines and the public interest in securing vital water protections as soon as possible, you should incorporate the ELGs into the NPDES permits for eight Florida coal plants—Big Bend, Crist, Crystal River, Northside/St. Johns, Seminole, Stanton, Indiantown and Polk.

As you are aware, NPDES permits for the first six of these plants (Big Bend through Stanton) expire this year or next year. Therefore, you should be working with their operators to ensure that they do, in fact, "immediately begin" their ELGs compliance analyses, and are prepared to provide you and the public the information needed to evaluate and set the "as soon as possible" ELGs compliance deadline in their NPDES renewal permits.

Moreover, even if Indiantown and Polk's NPDES permits do not expire until 2019, their operators have the same responsibility to "immediately begin"—"even prior to the permit renewal process"—their ELGs compliance analyses, and, similarly, you should be working with these plant's operators to expeditiously set and achieve the "as soon as possible" ELGs compliance deadline.

Therefore, we urge you to make prompt compliance determinations for all eight coal plants, first, by collecting and making publicly available the information from their operators regarding their potential to comply with the ELGs by November 1, 2018, and, second, by closely scrutinizing and verifying this information as you revise NPDES permits and adjudicate any requests to extend the ELGs compliance deadline beyond November 1, 2018.

With respect to extension requests, we recognize that for other regulations, for instance, the Mercury and Air Toxics Standards, it has been the Department of Environmental Protection's ("DEP") practice to carefully review and grant such requests only in exceptional cases. Similarly, DEP should continue this practice here and use its broad information collection powers and stakeholder engagement process to help adjudicate the merits of any extension requests for ELGs compliance.

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[13] 40 C.F.R. § 423.11(t)(3).
[14] TDD at 14-11.
[15] 40 C.F.R. §423.11(t)(4).

## II. DEP Should Take Public Comment For No Less Than 60 Days On Draft NPDES Permits And ELGs Compliance Determinations For Coal Plants.

Because of the significance of the water protections in the ELGs and the findings you must make regarding the compliance date, as discussed above, we urge you to take public comment for no less than 60 days on these draft NPDES renewal permits and compliance determinations for the ELGs. Doing so is entirely consistent with DEP's mission to serve the public interest and to conduct its environmental oversight responsibilities with transparency.[16]

## III. DEP Should Work With Florida Coal Plant Operators That Do Not Have NPDES Permits, And Other Stakeholders, To Ensure That Their Plants Achieve Timely Compliance With The Applicable Requirements In The ELGs.

Three coal plants in Florida—C.D. McIntosh, Jr., Cedar Bay, and Deerhaven—are not covered by NPDES permits but nonetheless must assure that the toxic pollutants in their effluent are properly treated to meet the requirements in the ELGs. For example, the McIntosh plant in Lakeland discharges effluent containing toxic pollutants such as mercury to publicly owned treatment works. These discharges are subject to revised Pretreatment Standards for Existing Sources (PSES) in the ELGs.[17] The PSES are self-implementing, meaning these requirements apply directly, without the need for any permit revision, and must be met by the November 1, 2018, compliance deadline in the final rule.[18] Sierra Club provided McIntosh's operator, Lakeland Electric, with a compliance analysis specifying the implications of the PSES for this plant.[19] We urge you to work with the DEP PSES coordinator, the operators of all three plants, as well as other stakeholders, to ensure that they achieve timely compliance with the applicable requirements in the ELGs.

## IV. Timing Is Critical.

As we noted above, timing is critical. Through the water permit renewal process, you should make prompt ELGs compliance determinations for three key reasons:

First, prompt ELGs compliance determinations, including setting the "as soon as possible" deadline, are needed to secure safe water for Floridians. EPA updated the ELGs to address the "outstanding public health and environmental problem" related to the discharge of effluent containing toxic and other pollutants from power plants, including Florida's aging coal plants.[20]

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[16] *See, e.g.*, FDEP Mission Statement & Objectives, *available at* http://goo.gl/tTk3mp.
[17] *See* 40 C.F.R. § 423.16.
[18] *Id.*
[19] *See* Sierra Club letter to General Manager Ivy of January 26, 2016 and exhibits, on file with DEP.
[20] 80 Fed. Reg. at 67,840-41.

Indeed, the "ELGs that EPA promulgated and revised in 1974, 1977, and 1982 are out of date" and, as a result, permits issued to coal plants under those previous, outdated ELGs "do not adequately control the pollutants (toxic metals and other) discharged by this industry, nor do they reflect relevant process and technology advances that have occurred in the last 30-plus years."[21]

Furthermore, as you know, NPDES permits have a maximum term of five years.[22] The limited permit duration and the anti-backsliding requirement in the Clean Water Act aim to achieve gradual, iterative, but continual progress towards restoring the nation's waters. As the D.C. Circuit has explained, "[t]he essential purpose of this series of progressively more demanding technology-based standards was not only to stimulate but to press development of new, more efficient and effective technologies."[23] As pollution control technologies improve, higher standards are incorporated into the NPDES permits of existing facilities upon renewal. This makes timely renewal of NPDES permits a linchpin of the Clean Water Act, and an essential part of your office's responsibilities.

Second, prompt ELGs compliance determinations will help assure that coal plant operators do, in fact, reduce as soon as possible the toxic discharges into our waters, thus avoiding regulatory uncertainty and any avoidable delay in achieving these vital water protections.

Third, prompt ELGs compliance determinations will help level the playing field between coal plants with NPDES permits and those without them, so that all Florida coal plants achieve compliance with the ELGs as soon as possible.

For all these reasons, we urge you to make prompt determinations of what it will take to bring Florida coal plants into compliance with the ELGs, and promptly adjudicate any requests to extend the compliance deadline beyond November 1, 2018.

## V. DEP Should Do Its Part To Protect Consumers From Piecemeal Regulatory Compliance Decisions That Fail To Identify And Pursue Cost-Effective Alternatives To Spending Billions Of Dollars To Retrofit Florida's Aging Coal Plants.

As we noted above, fellow regulators are deciding whether to spend huge sums of public monies on retrofitting aging coal plants to meet several environmental regulations with fast-approaching compliance deadlines. Indeed, because burning coal is one of the most polluting and

[21] 80 Fed. Reg. at 67,840 [emphasis added].
[22] *See* 33 U.S.C. § 1342(b)(1)(B).
[23] *Natural Res. Def. Council v. U.S. Envtl. Prot. Agency*, 822 F.2d 104, 124 (D.C. Cir. 1987).

increasingly costly ways to generate electricity, regulators—and coal plant operators—will soon decide whether to take as much as 4 billion dollars from Floridian families and businesses for retrofits, alone, to these plants.[24] Yet there has not been any comprehensive accounting of just how much more Floridians may have to pay to rely on these plants to keep the lights on, much less a fair comparison to available alternatives such as retiring these plants and investing instead in modern clean energy resources such as solar, wind, energy efficiency, and storage that are at record low prices.[25] Indeed, while operators project coal plant retrofits may cost 4 billion dollars or more, they admit this huge sum does not account for all the costs and risks associated with relying on coal plants in the rapidly evolving regulations and market conditions concerning coal and carbon.[26]

We urge you to do your part to fill this acute information gap, first, by providing much needed clarity regarding ELGs compliance obligations and timelines for coal plants and, second, by providing the same for other applicable water-side requirements. For example, four Florida coal plants—Big Bend, Crist, Crystal River, Northside—use antiquated once-through cooling systems that needlessly harm millions of aquatic organisms, potentially including federally listed species. In fact, it has been unlawful to use such rudimentary cooling systems when building new power plants since 2001,[27] and generally none have been built since the 1980's precisely because of their adverse biological impacts.[28] To be sure, aging coal plants such as Big Bend, Crist, Crystal River, and Northside also must come into compliance with modern, species-protecting cooling standards under the Endangered Species Act and the Cooling Water Intake Structure Rule. Therefore, we urge you to work closely with the operators, fellow regulators, and other stakeholders to comprehensively identify Florida coal plants' water-side compliance obligations and timelines. The sooner, the better. As we discussed above, huge sums of public monies and vitally important water resources are at stake.

Thank you for your consideration, and we look forward to the opportunity to meet with you to discuss the way forward.

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[24] *See, e.g.,* Sierra Club letter of December 12, 2015, Table 1 (showing electric utilities' incomplete regulatory compliance costs estimates totaling 3-4 billion dollars through 2024), *available at* http://goo.gl/CT8l1j [hereinafter "2015 Letter"].
[25] *See generally id.*
[26] *See* 2015 TYSP First Supplemental Staff Data Request No. 38*, available at* http://goo.gl/nhBGEi; *see also* 2015 Letter, 7-8 (discussing incomplete nature of utility retrofit cost estimates).
[27] *See* 66 Fed. Reg. 65256 (2001) ("Phase I Rules"); *see also* 40 CFR §§125.80(a), 125.81(a) (2008).
[28] *See*, *e.g.*, 65 Fed. Reg. 49060, 49087 and 49094 (Aug. 10, 2000) ("Draft Phase I Rules") (noting that since the 1970's there has been extensive and increasing recycling and reuse of cooling water and that by the year 2000 most new industrial facilities used closed-cycle cooling systems).

Sincerely,

Diana Csank
Sierra Club

Alisa Coe
EarthJustice

Susan Glickman
Southern Alliance for Clean Energy

Kathleen E. Aterno
Clean Water Action

Jerry Phillips
Florida PEER

Dan Tonsmeire
Apalachicola Riverkeeper

Pete Harrison
Waterkeeper Alliance

Laurie Murphy
Emerald Coastkeeper

Neil A. Armingeon
Matanzas Riverkeeper

Justin Bloom
Suncoast Waterkeeper

Lisa Rinaman
St. Johns Riverkeeper

Rachel Silverstein, Ph.D.
Miami Waterkeeper

Harrison Langley
Collier County Waterkeeper

Cc: Paula Cobb, DEP
Greg Brown, DEP
Richard Tedder, DEP
Julie Brown, PSC
Mark Futrell, PSC
Tom Ballinger, PSC
J.R. Kelly, OPC

# EXHIBIT F

September 26, 2016

*Via email and postal mail*

Supervisor Marc Harris
Power Plant NPDES Permitting, Industrial Wastewater Section
Florida Department of Environmental Protection
marc.harris@dep.state.fl.us

**Re: Bringing coal burning operations at the Crystal Energy Generating Complex Units 4 and 5 into compliance with ground and surface water protection standards in the current NPDES permit renewal process (Permit No. FL0036366)**

Dear Supervisor Harris:

On behalf of our tens of thousands of Florida members and supporters and the undersigned groups, the Sierra Club respectfully submits these comments on the Draft Permit issued by the Florida Department of Environmental Protection ("DEP") for National Pollutant Discharge Elimination System Permit ("NPDES") Permit No. FL0036366. This permit governs discharges from Units 4 and 5 at Duke Energy Florida's ("DEF") Crystal River Energy Generating Complex ("CREC") into Crystal Bay, a Class II marine water and part of the Gulf of Mexico.

As stated in our prior letter of February 29, 2016,[1] we have a vital interest in bringing the toxic coal burning operations in Florida into compliance with the applicable public health and safety standards. Our comments here focus on the necessary changes to Permit No. FL0036366 to bring CREC into compliance with the revised effluent limitation guidelines for steam electric power plants ("ELGs")[2] and the new standards for coal combustion residuals ("CCR") [3] storage and disposal (the "CCR Rule").[4]

---

[1] Letter from Diana Csank, Sierra Club, to Marc Harris, Florida Department of Environmental Protection (February 29, 2016).

[2] U.S. EPA, *Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category; Final Rule*, 80 Fed. Reg. 67,838 (Nov. 3, 2015) (revising 40 C.F.R. Part 423) [hereinafter "ELGs"].

[3] Coal combustion residuals include "fly ash, bottom ash, boiler slag, and flue gas desulfurization materials generated from burning coal for the purpose of generating electricity by electric utilities and independent power producers." 40 C.F.R. § 257.53.

[4] U.S. EPA, *Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals From Electric Utilities; Final Rule*, 80 Fed. Reg. 21,302 (Apr. 17, 2015), as amended by Technical Amendments to the Hazardous and Solid Waste

# EXHIBIT 1

# Preparing for the U.S. Environmental Protection Agency's Coal Combustion Residuals Rule: Technical Assessment of Hydrogeologic Conditions and Groundwater Contamination at the Crystal River Energy Complex

August 28, 2016

By Mark Stewart, PhD, PG

## 1. EXECUTIVE SUMMARY

The Crystal River Energy Complex ("CREC") is located on unstable karst terrain, and the primary facility used for the storage and disposal of coal combustion residuals ("CCR") at CREC, the Ash Landfill, exhibits increasing contamination from toxic heavy metals associated with CCR waste. CCR disposal and storage at CREC puts local water resources at risk and fails to meet the new safety standards by the U.S. Environmental Protection Agency ("EPA") in December 2014 ("the CCR Rule") for several reasons:

- CREC is located in one of the country's most unstable areas, in karst terrain, and is under the influence of multiple sinkholes, including 24 reported sinkholes within 5 miles of CREC.

- The risk of limestone dissolution and sudden collapse beneath CREC's Ash Landfill is increased by many factors, including (a) having no impermeable liner; (b) having no cover to exclude precipitation from the exposed ash waste; and (c) CCR accumulating at the Ash Landfill increasing the static load on the underlying, unstable soils and rock.

- To assure the safety of CCR storage and disposal in such unstable areas, EPA's CCR Rule requires the detection and interception of (a) all of the possible conduits that allow piping of groundwater into underlying karst aquifers; (b) all of the possible shallow caves that could cause a sudden foundation collapse; and (c) all of the possible pathways for CCR constituents to be released from CCR storage and disposal facilities into karst aquifers. Consulting reports state that at CREC, "most [groundwater] flow is through solution cavities and conduits." These safety standards were not incorporated into the design of the Ash Landfill when it was built, and it is now nearly impossible to do so.

- The Ash Landfill was not built to structurally withstand the influence of sinkholes. It lacks the structural reinforcement that would be necessary, but may nevertheless be insufficient, to prevent a sudden foundation collapse. The Ash Landfill cannot be retrofitted now to be safe. Attempting a retrofit could trigger a sinkhole collapse that could rapidly spread CCR contamination in the underlying karst aquifers.

- To protect public waters, the CCR Rule requires (a) a distance of at least 5 feet between the base of CCR storage and disposal facilities and the uppermost aquifer, or (b) other measures that eliminate any hydraulic connection between CCR storage and disposal facilities and the aquifer—CREC Ash Landfill does not meet either standard. In fact, the available monitoring data are indicative of an ongoing hydraulic connection that allows CCR constituents, including arsenic and other heavy metals associated with CCR leachate, to reach the underlying karst aquifers.

- Water quality samples from wells downgradient from the Ash Landfill show consistent and increasing contamination since 2012 with toxic constituents associated with CCR, such as

arsenic, boron, molybdenum, manganese, selenium, sulfate, and thallium, indicating that the Ash Landfill has contaminated the Surficial and Floridan Aquifer at the site.

- Groundwater beneath CREC Ash Landfill, FGD Blowdown Ponds, and Percolation Ponds flows towards the seawater discharge canal, tidal wetlands, and Crystal Bay.

For these reasons, discussed in detail in the full report, the Ash Landfill cannot meet the safety standards in the CCR Rule. Additionally, as the CCR Rule requires corrective action to prevent further releases of CCR constituents into the environment, the CCR that have accumulated in the Ash Landfill should be removed and the site decontaminated. The only way to prevent such continued releases from the Ash Landfill is to remove the CCR that has accumulated and decontaminate the site.

## 2. INTRODUCTION

This is an assessment of coal combustion residuals ("CCR") storage and disposal at the Crystal River Energy Complex ("CREC"). This assessment evaluates hydrogeologic conditions at the Ash Landfill, FGD Blowdown Ponds, Gypsum Storage Pad, and Percolation Ponds, existing groundwater contamination at CREC, and compliance with the U.S. Environmental Protection Agency's ("EPA") new rule on the disposal of CCR from electric utilities ("CCR Rule," U.S. EPA 2015). More specifically, this assessment considers whether CREC's CCR facilities satisfy the safety standards in the CCR Rule for CCR disposal in karst terrain and away from the uppermost aquifer and for preventing groundwater contamination.

The karst-specific safety factors under CCR Rule can be summarized as follows:

1. The historical record of local sinkhole development;
2. The presence of a local hydraulic gradient that points downward at shallow depths;
3. The presence of subsurface conduits that allow piping of groundwater into the karst aquifer, or shallow conduits or caves that could cause sudden collapse of the structure's foundation; and
4. The use of engineering solutions to "prevent the kind of foundation collapse and settlement that could lead to sudden release to the environment of CCR with its toxic constituents and associated leachate." (U.S. EPA 2015).

As discussed below, these factors support the conclusion that CREC Ash Landfill cannot continue to safely receive CCR, nor can it meet the requirements of the CCR Rule.

Additionally, the CCR Rule requires (a) a distance of at least 5 feet between the base of certain CCR storage and disposal facilities and the uppermost aquifer, or (b) other measures that eliminate any hydraulic connection between the facilities and the aquifer. As discussed below, the Ash Landfill does not meet either of these standards.

Water quality samples from wells downgradient from the Ash Landfill show consistent and increasing contamination from common CCR constituents, such as arsenic, boron, molybdenum, manganese, selenium, sulfate, and thallium, indicating that the Ash Landfill has already contaminated the Surficial and Floridan Aquifer at the site.

The Ash Landfill cannot meet the safety standards in the CCR Rule. Additionally, as the CCR Rule requires corrective action to prevent further releases of CCR constituents into the environment, the CCR that have accumulated in the Ash Landfill should be removed and the site decontaminated. The only way to prevent such continued releases from the Ash Landfill is to remove the CCR that has accumulated and decontaminate the site.

## 3. ASSESSMENT

### A. CREC is in one of the country's most unstable areas, under the influence of multiple sinkholes

CREC is located in Citrus County, an active karst area under the influence of sinkholes (FGS 1985). The sandy sediment cover over the limestone in coastal Citrus County is thin, and sinkholes that form tend to be smaller, i.e., less than 10 feet ("ft") in diameter, and not as deep as in areas with thicker, more cohesive sediments covering the limestone. However, the near-surface limestone is deeply incised with solution channels and conduits that can cause small sinkholes to form as surficial sands move into the subsurface voids (Dames and Moore 1994).

#### a. Hydrogeology of coastal West Florida: Karst terrain, solution conduits, and sinkholes

Coastal Citrus County is a region that is underlain by a thick sequence of carbonate rocks, commonly called "limestone" (Miller 1986). These rocks can be dissolved by the chemical action of acidic groundwaters. This creates voids in the rock and a distinctive geologic terrain called karst.[1] Karst terrains are characterized by solution features such as caves and collapse features caused by surface materials falling into voids created by the solution of the underlying rocks. A vertical collapse or solution feature created by karst activity is called a sinkhole (Tihansky 2013).

Small sinkholes are common in western Citrus County (FGS 2016; Tihansky 2013). These voids or depressions at the surface are caused by the movement of unconsolidated surficial materials into pre-existing voids in the underlying limestone. Sinkholes can form rapidly by collapse or slowly by movement of surficial materials into underlying voids in the carbonate rock. Most sinkholes in coastal Citrus County are cover subsidence sinkholes. These sinkholes form when loose surficial sands migrate downward into solution cavities in the limestone. Cover subsidence sinkholes can form slowly, or abruptly, especially after heavy rainfall (Tihansky 2013).

[1] Geologists generally use the term "terrane" to refer to three-dimensional areas including the surface and subsurface, and "terrain" to refer to the surface configuration or topography only. This assessment uses "terrain" to refer to both surface and subsurface areas unless otherwise noted.

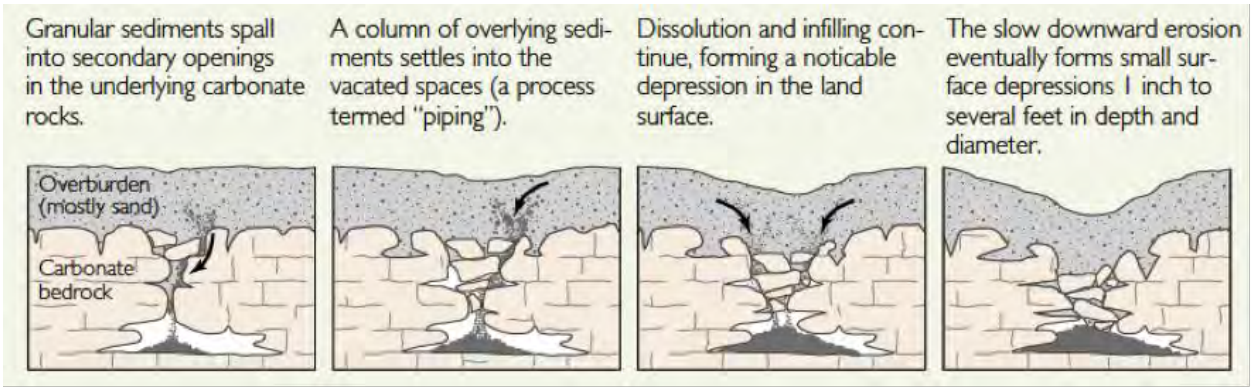


**Figure 1. Cover subsidence sinkhole schematic (Tihansky 2013)**

Paleosinks or paleo-sinkholes are also common in West Central Florida (Tihansky 2013). These are cover subsidence sinkholes that have been filled by sediments or water and do not have recognizable depressions at the surface. Such sediment-filled sinkholes can create a vertical column of permeable materials that allow contaminants introduced at the water table to reach the Floridan Aquifer. In addition to sinkholes, the limestone underlying CREC contains many solution enlarged fractures that form preferred conduits for groundwater flow and allow for downward movement of surficial sands into the underlying limestone (Dames and Moore 1994).

Groundwater, particularly groundwater in the Surficial and Floridan Aquifers,[2] supplies the region's public drinking water. The Floridan Aquifer is one of the largest and most productive sources of fresh groundwater in the world (Miller 1986). It is comprised of the carbonate rocks of Eocene to Miocene age in West Central Florida. In coastal western Citrus County, the Floridan Aquifer is unconfined and water table elevations represent the potentiometric surface of the Floridan Aquifer. This area is a recharge zone for the shallow Floridan Aquifer, which is at or within a few feet of land surface at CREC. More specifically, shallow groundwater flows downward from the water table and the shallow sands of the Surficial Aquifer into the Floridan Aquifer. Near CREC, the deeper and intermediate portions of the Floridan Aquifer are discharge zones, and groundwater has a component of flow toward the surface.

### b. Hydrogeology of CREC site

The Florida Geological Survey ("FGS") sinkhole database (FGS 2016) documents 24 reported sinkholes within 5 miles of CREC site. As the FGS sinkhole data are self-reported, the 24 reported sinkholes are the minimum number of sinkholes that have occurred in recent years near CREC site. The FGS database is biased toward residential and commercial areas where sinkholes are more likely to be reported than in rural areas and industrial sites. Most of the reported sinkholes near CREC site are reported along the U.S. Highway 19 corridor east of CREC site and associated residential areas. The reported sinkholes are smaller than sinkholes that occur in central Florida, generally less than 10 ft in

[2] The Surficial and Floridan Aquifers are U.S. EPA designated Underground Sources of Drinking Water, and Florida Department of Environmental Protection ("DEP") designated Type G-II (Surficial) and G-I (Floridan) groundwaters.

diameter and up to 10 ft in depth. Using the 24 sinkholes as a representative data set, 95% (two standard deviations) of reported sinkholes within 5 miles of CREC have diameters less than 7 ft. They are indicative of the extensive karst solution cavities that are present in the shallow subsurface in western Citrus County.

Dames and Moore (1994) describe the geology and hydrogeology of CREC site. The following discussion is a summary of the geology and hydrogeology of CREC site from that report.

Dames and Moore report that the Upper Floridan Aquifer at CREC site contains abundant "solution enlarged fractures," "long linear depressions" in the limestone surface, and "underground channels and caverns." They also report that during removal of coal ash from the area of the former CREC south ash pond, "local superficial channels/sinkholes concealed by ash deposits had caused a continuous series of incidents and delayed removal/transportation activities." The report also states that "most flow is through the solution channels and cavities" and that the upper zone from the surface to a depth of about 30 feet contains many large interconnected solution cavities and channels that are highly permeable.

The surficial deposits at CREC consist of predominantly sandy, unconsolidated materials with some silt and clay. There is no distinct Surficial Aquifer at the site, and the Floridan Aquifer is within a few feet of the land surface. Water reaching the water table from the surface is effectively recharging the upper part of the Floridan Aquifer. The permeable surficial sediments are in direct hydraulic connection with the limestones of the Upper Floridan Aquifer. As a result of the lack of extensive low permeability surficial materials, the Floridan Aquifer at CREC site is an unconfined aquifer in direct hydraulic connection with the water table. Soils at the site typically have seasonal water tables within 1-2 ft of the land surface and are described as poorly drained. The undisturbed soils at CREC are subject to frequent and prolonged flooding.

The near-surface Floridan Aquifer units present at the site are the limestones of the Ocala Group, specifically the lower member of the Ocala Group, the Inglis Formation. The Inglis Formation is an Eocene limestone with extensive solution features. The Avon Park Formation underlies the Inglis Formation. The Avon Park Formation consists of limestones and dolostones and forms the bottom of the Upper Floridan Aquifer (Miller 1986). The permeability of the Avon Park decreases with depth. This results in enhancement of horizontal ground water flow in the Inglis Formation limestones. Dames and Moore (1994) report that most groundwater flow at the site is through "solution cavities and channels." In test borings that encountered voids, about 10% of the total aquifer volume is void space, generally within 50 ft of land surface. A zone in the Inglis Formation from land surface to a depth of about 30 ft consists of "many large solution cavities and channels that are highly permeable." A lower high permeable zone occurs between depths of about 40 to 60 ft at the contact between the Inglis and Avon Park Formations. Aquifer performance data suggest that the transmissivity of the Upper Floridan Aquifer at the site is about 2E05 $ft^2$/day, a very high value.

In a study to support installation of CREC Units 4 and 5 at CREC (ESE 1982), Dames and Moore (1994) report that test borings could be divided into "void" borings that encountered voids during

drilling, and “non-void” borings that encountered solid limestone. The eight void wells responded faster to recharge events and tides and were assumed to connect with solution cavities and channels. The water levels for the void group wells were found to “form a trough running northeast to southwest under the ash disposal site…this trough roughly coincides with the known subsurface cavities in this area and likely reflects a fracture zone of high permeability.” The general groundwater flow direction under the Ash Landfill indicated by the void and non-void wells is northeast to southwest, toward CREC intake and discharge canals and wetlands to west of CREC. Groundwater that flows under the Ash Landfill through the “trough” delineated by Dames and Moore (1994) flows toward the west-southwest and discharges into the seawater discharge canal, and ultimately into Crystal Bay.

The water table “trough” under the Ash Landfill reported by Dames and Moore (1994) includes monitor wells MWI-2R2, TWI-5, and TWI-3 (Figures 2 and 3). These three monitor wells are located on the west side of the Ash Landfill. As described further below, groundwater monitoring reports (DEP 2015) indicate that these three wells have been contaminated with arsenic, sulfate, thallium, selenium, molybdenum, manganese, and boron, all of which are contaminants associated with CCR leachate. This indicates that the Ash Landfill is in direct hydraulic connection with a highly permeable fracture zone in the Upper Floridan Aquifer, and that contaminants associated with CCR wastes have entered the Upper Floridan Aquifer.

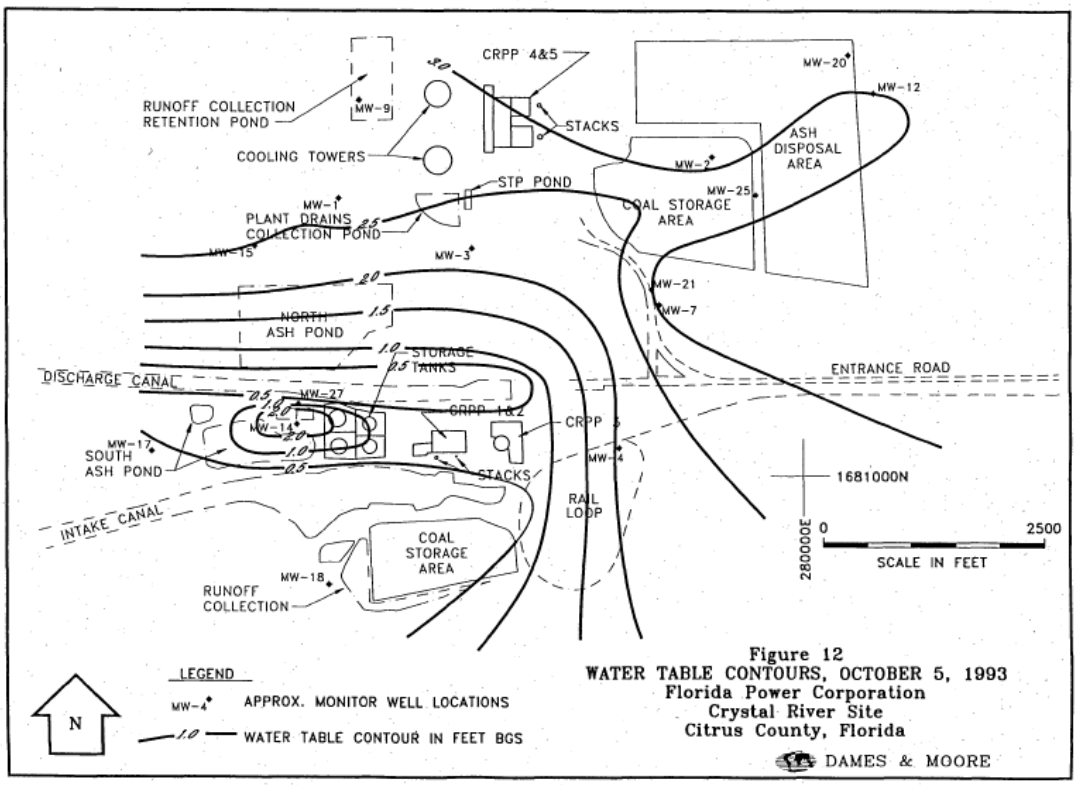


**Figure 2. Water table elevations under the Ash Landfill (Dames and Moore 1994)**

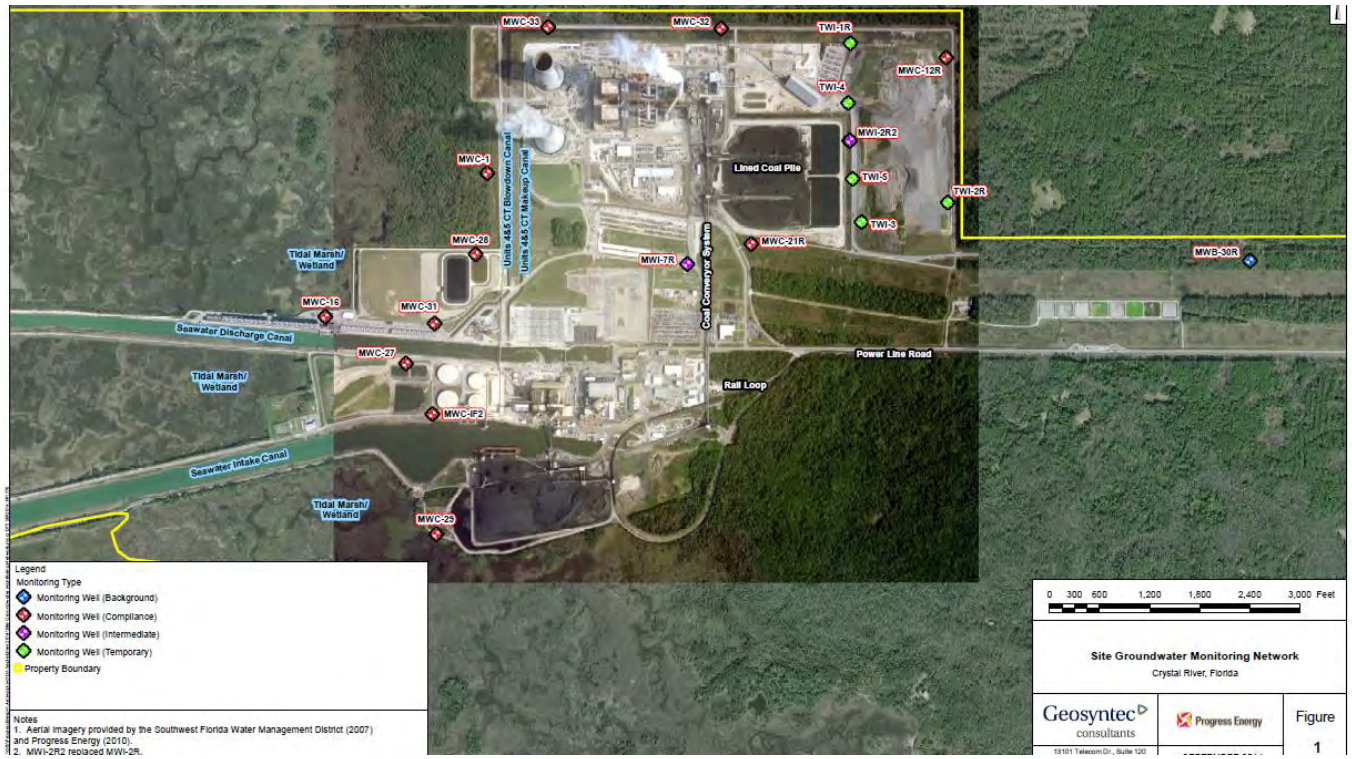


**Figure 3. Groundwater Monitoring Network at CREC (Geosyntec 2013)**

### B. CREC Ash Landfill cannot meet the CCR Rule's safety standards for unstable areas

Historical records of sinkhole activity in the region and reports prepared for CREC site clearly indicate that the site is within an active karst zone, with numerous, unlocated channels and voids. Consulting reports (Dames and Moore 1984; ESE 1982) state that at CREC "most [groundwater] flow is through solution cavities and conduits" and these reports document that the site contains numerous solution enlarged channels, voids, and caves, with one documented high permeability conduit located directly under the Ash Landfill (Dames and Moore 1994). These channels, conduits, limestone surface depressions, and voids create a sinkhole hazard for the Ash Landfill.

The Floridan Aquifer is at or near land surface at CREC site (Dames and Moore 1994) and any size sinkhole is likely to allow movement of unconsolidated materials under the CCR landfill into the voids, depressions, and caverns under the landfill will, and likely has (ESE 1982), allowed CCR materials to come into direct contact with the limestones and groundwater of the Upper Floridan Aquifer. The Ash Landfill does not have structural reinforcements or a liner[3] to prevent vertical movement of CCR materials into the Upper Floridan Aquifer, as occurred at the site of the former CREC south ash pond (ESE 1982).

[3] Only 5.5 acres of the 62-acre Ash Landfill are lined.

To ensure the safety of CCR storage and disposal in unstable karst areas, the CCR Rule requires the detection and interception of (a) *all* of the possible conduits that allow piping of groundwater into the underlying karst aquifers; (b) *all* of the possible shallow caves that could cause a sudden foundation collapse; and (c) *all* of the possible pathways for CCR constituents to be released from CCR storage and disposal facilities, such as the Ash Landfill, into the karst aquifers (U.S. EPA 2015).

These safety standards were not incorporated into the design of the Ash Landfill when it was built. Detection and interception of *all* possible conduits, depressions, voids, and shallow caves in a complex karst terrain such as CREC site is extremely difficult technically, if not practically and economically infeasible. With any currently known sinkhole remediation technology, the Ash Landfill cannot be "upgraded" to meet the CCR Rule requirements for facilities in karst terrains as it would be nearly impossible to determine that all conduits, voids, and caves had been detected and intercepted. As the Ash Landfill does not meet the CCR Rule's safety standards and instructions for engineering practices in karst areas, the CCR materials currently onsite should be removed and the groundwater and soils decontaminated.

In addition to the Ash Landfill, CREC site contains a Gypsum Storage Pad, which receives gypsum solids before disposal in the Ash Landfill or transport offsite, and FGD Blowdown Ponds and Percolation Ponds on the west side of the site, adjacent to the seawater discharge canal, that receive waste and wastewater from coal operations. The FGD Blowdown Ponds are lined with synthetic impermeable liners. However, the FGD Blowdown Ponds, Percolation Ponds, and Gypsum Storage Pad are in the same unstable karst environment as the Ash Landfill. There is a potential for failure of the FGD Blowdown Pond liner system or piping as result of sinkhole activity. If a sinkhole punctured the liner or caused a FGD pipe to leak, the FGD wastes would be introduced directly into the Upper Floridan Aquifer, discharging to the seawater discharge canal, tidal wetlands, and ultimately Crystal Bay. The liner system would need to be able to span sinkholes 10 ft in diameter or greater without failing to avoid contaminating the Upper Floridan Aquifer with FGD wastes. The Percolation Ponds are unlined and are in direct communication with the Upper Floridan Aquifer. The Percolation Ponds recharge the shallow groundwater aquifer and discharge into the seawater discharge canal, tidal wetlands, and Crystal Bay (Figures 2 and 3).

### C. The Upper Floridan Aquifer exhibits contamination from CCR Leachate at CREC

Contaminants such as sulfate, arsenic, selenium, thallium, boron, molybdenum, and manganese are common constituents of CCR leachate (EPRI 2004). The presence of several of these constituents, at any detectable level above background values, in groundwater downgradient from a CCR storage and disposal unit is overwhelming evidence that contaminants that have leached from the CCR materials have reached the water table and the aquifer. Groundwater sampling results from September 2012 for monitoring well MZ-3, which is in an upgradient, undisturbed area approximately one mile east of CREC facility, indicate that background arsenic concentrations in the shallow, intermediate, and deep portions of the aquifer are 2.1, 6.3, and <2.0 micrograms/liter, respectively (Geosyntec 2013). Arsenic levels in groundwater >10.0 micrograms/liter are indications of contamination of the aquifer system by CCR.

Dames and Moore (1994) state that the “void wells” near the Ash Landfill define a “trough” in the water table surface underneath the landfill (Figure 2). They attribute this water table trough to a “fracture zone of high permeability.” Three monitor wells on the west side of the Ash Landfill are located in or near this high permeability fracture zone: wells MWI-2R2, TWI-5, and TWI-3 (Figure 3).

Water samples from these three wells have regularly exceeded federal and state regulatory levels for arsenic, sulfate, thallium, selenium, molybdenum, manganese, and boron since 2012. For arsenic, boron, manganese, and molybdenum levels of these contaminants in groundwater in this fracture zone have trended upward from 2012 to 2015 (Figures 4, 5, 6, and 7). Water quality data obtained in January 2016, continue to show levels of contaminants in excess of groundwater standards in wells downgradient of the Ash Landfill in wells MWI-2R2, TWI-1R, TWI-3, and TWI-5 (DEP 2016).

These supporting lines of evidence, the definition of the water table trough, the presence of high permeability conduits at the site, and the presence of common CCR leachate constituents at increasing concentrations in wells downgradient from the Ash Landfill are overwhelming evidence that the landfill has contaminated local groundwater with toxic materials associated with CCR leachate. As the purpose of the standards enumerated under the CCR Rule is to prevent groundwater contamination from CCR facilities, the presence of these contaminants at the existing site is evidence that that the existing Ash Landfill does not meet the conditions specified in the rule.

Geosyntec (2013) has prepared a report that maintains that the arsenic found in groundwater downgradient from the Ash Landfill is the result of complex geochemical conditions and a natural source of arsenic. They note that arsenic was detected in borings at a proposed coal ash storage site east, and upgradient, of the current Ash Landfill, suggesting a natural source of arsenic. However, the concentrations of arsenic detected downgradient of the Ash Landfill are up to five times as high as the concentrations detected upgradient. In addition, the associated CCR contaminants sulfate, selenium, thallium, boron, molybdenum, and manganese have been detected in wells downgradient of the Ash Landfill. The Geosyntec report does not explain the presence of these CCR associated contaminants.

To prevent such contamination, the CCR Rule prescribes (a) a distance of at least 5 feet between the base of facilities containing CCR and the uppermost aquifer, or (b) other measures that eliminate the hydraulic connection between the base and the uppermost aquifer—safety standards that the Ash Landfill does not meet. According to public records, the base of the Ash Landfill has an elevation of 4 to 8 feet above sea level, while the water table near the Ash Landfill has reported elevations greater than 3 feet (Geosyntec 2013). This indicates that the base of the Ash Landfill is within 5 feet of the water table in the Surficial/Floridan Aquifer. The Ash Landfill is unlined, meaning that the CCR materials are in direct hydraulic connection with the Floridan Aquifer. Furthermore, natural soils at CREC site are poorly drained and flood seasonally (Dames and Moore 1994), indicating that the water table seasonally approaches the land surface.

As the CCR Rule requires corrective action to prevent further releases of CCR constituents into the environment, the CCR that have accumulated in the Ash Landfill should be removed and the site should be decontaminated.

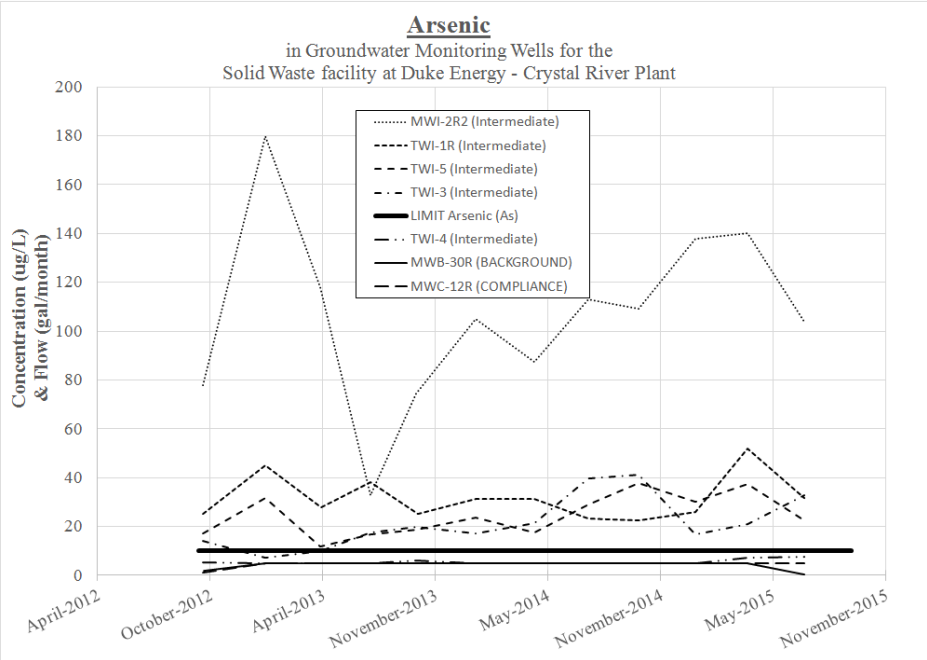


**Figure 4. Arsenic levels in groundwater samples from wells at CREC site, October 2012 to July 2015 (DEP 2015)**

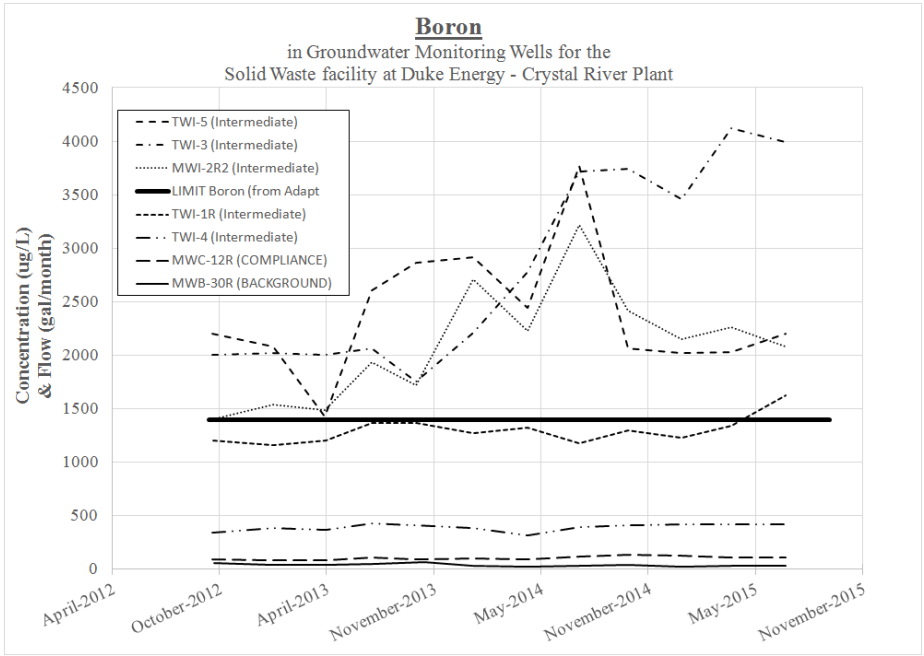


**Figure 5. Boron levels in groundwater samples from wells at CREC site, October 2012 to July 2015 (DEP 2015)**

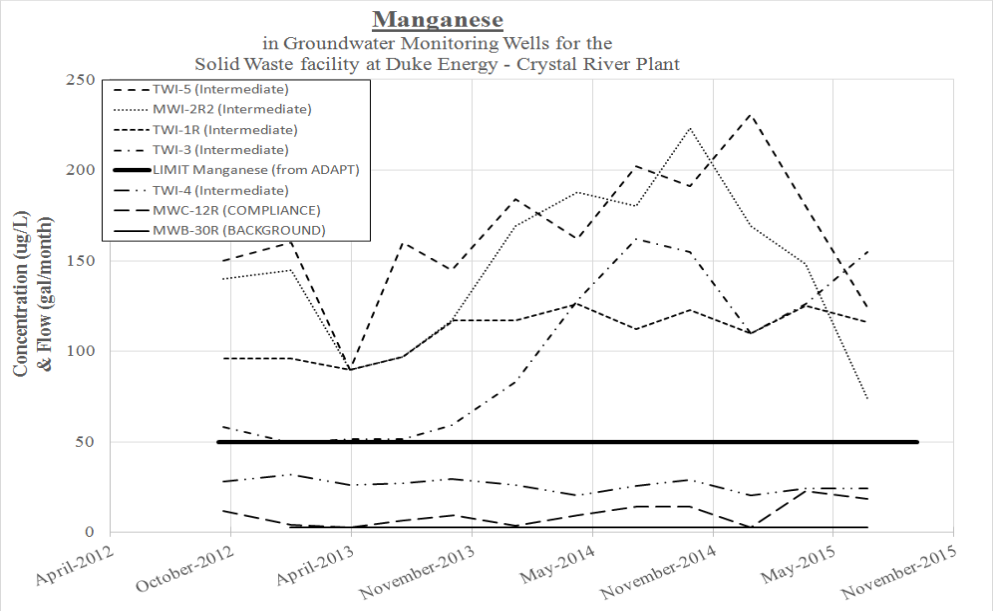


**Figure 6. Manganese levels in groundwater samples from wells at CREC site, October 2012 to July 2015 (DEP 2015)**

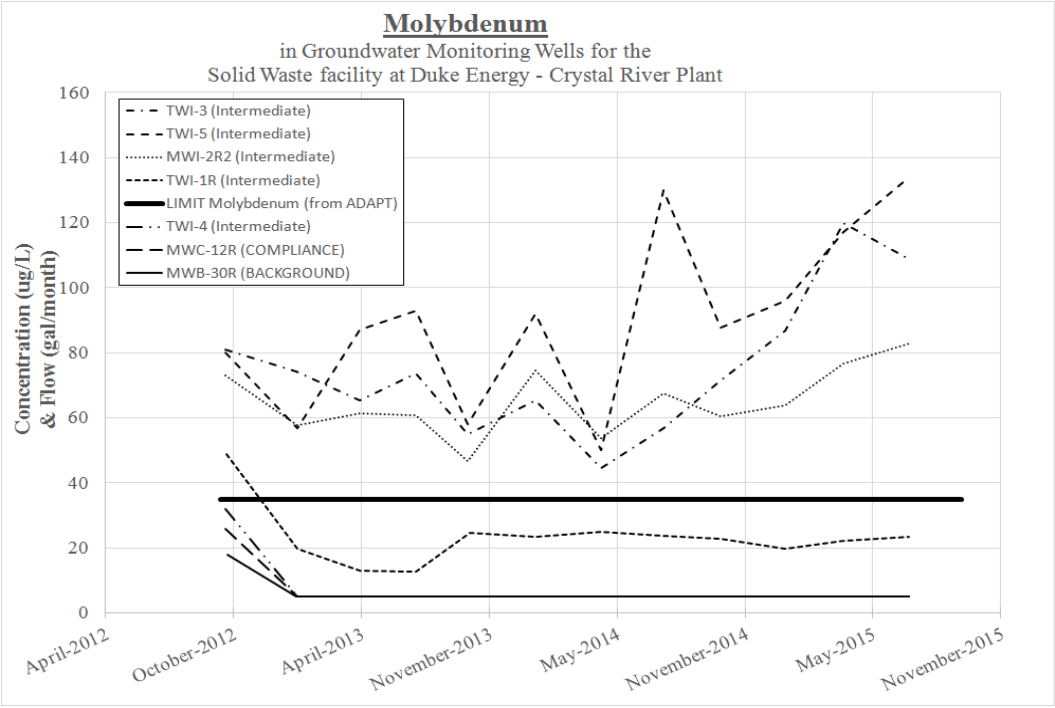


**Figure 7. Molybdenum levels in groundwater samples from wells at CREC site, October 2012 to July 2015 (DEP 2015)**

## 4. SUMMARY

CREC Ash Landfill does not meet the safety criteria for CCR landfills and impoundments enumerated in the EPA's CCR Rule. The facility is located in a documented unstable, karst area, putting local water resources at risk. It would be technically challenging, if not impossible to upgrade the Ash Landfill to meet the CCR Rule standards for active facilities in karst areas. In addition, there is overwhelming evidence that the Ash Landfill has contaminated local ground water with arsenic, selenium, molybdenum, manganese, boron, and thallium. The source of these contaminants is the Ash Landfill as documented by the presence of these contaminants in water samples from downgradient wells. The Ash Landfill is uncovered and open to infiltration of rainwater, the facility is unlined, and it is in direct hydraulic connection with the Upper Floridan Aquifer. The remedy to prevent further contamination of the aquifer and of Crystal Bay, is to remove the CCR materials currently on site and to decontaminate the Floridan Aquifer and local soils.

## 5. AUTHOR'S EXPERTISE AND QUALIFICATIONS

The author of this technical assessment, Dr. Mark Stewart, PhD, PG, is a Professor Emeritus at the University of South Florida School of Geosciences. Dr. Stewart is a registered Professional Geologist in the State of Florida. He has an extensive publication record and expertise in the hydrogeology of Florida, water resources management, karst hydrology, applied geophysics, and the geology of sinkholes. He has been qualified in hearings of the Division of Administrative Hearings and in State and Federal courts as an expert in hydrogeology, water resources management, karst hydrology, the geology of sinkholes, hydrologic modeling, and environmental geophysics. Dr. Stewart has an undergraduate degree in geological sciences from Cornell University, and graduate degrees in geology and water resources management from the University of Wisconsin-Madison.

The primary materials reviewed and used in the preparation of this assessment were Florida Department of Environmental Protection ("DEP") regulatory files, which include groundwater monitoring reports, reports on the geology and hydrogeology of CREC site, and reports on the construction and operation of waste material facilities and disposal of generated wastes, all of which were prepared by Duke/Progress Energy/FPC and their consultants and submitted to the DEP. Additional materials referenced for this report include: publications, data, and maps from the U.S. Geological Survey and Florida Geological Survey; peer-reviewed journal articles; and publically-available documents related to coal and coal combustion residuals, hydrogeology, sinkholes, and karst hydrology.

## 6. REFERENCES

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# EXHIBIT 1

# Preparing for the U.S. Environmental Protection Agency's Coal Combustion Residuals Rule: Technical Assessment of Hydrogeologic Conditions and Groundwater Contamination at the Crystal River Energy Complex

August 28, 2016

By Mark Stewart, PhD, PG

## 1. EXECUTIVE SUMMARY

The Crystal River Energy Complex ("CREC") is located on unstable karst terrain, and the primary facility used for the storage and disposal of coal combustion residuals ("CCR") at CREC, the Ash Landfill, exhibits increasing contamination from toxic heavy metals associated with CCR waste. CCR disposal and storage at CREC puts local water resources at risk and fails to meet the new safety standards by the U.S. Environmental Protection Agency ("EPA") in December 2014 ("the CCR Rule") for several reasons:

- CREC is located in one of the country's most unstable areas, in karst terrain, and is under the influence of multiple sinkholes, including 24 reported sinkholes within 5 miles of CREC.

- The risk of limestone dissolution and sudden collapse beneath CREC's Ash Landfill is increased by many factors, including (a) having no impermeable liner; (b) having no cover to exclude precipitation from the exposed ash waste; and (c) CCR accumulating at the Ash Landfill increasing the static load on the underlying, unstable soils and rock.

- To assure the safety of CCR storage and disposal in such unstable areas, EPA's CCR Rule requires the detection and interception of (a) all of the possible conduits that allow piping of groundwater into underlying karst aquifers; (b) all of the possible shallow caves that could cause a sudden foundation collapse; and (c) all of the possible pathways for CCR constituents to be released from CCR storage and disposal facilities into karst aquifers. Consulting reports state that at CREC, "most [groundwater] flow is through solution cavities and conduits." These safety standards were not incorporated into the design of the Ash Landfill when it was built, and it is now nearly impossible to do so.

- The Ash Landfill was not built to structurally withstand the influence of sinkholes. It lacks the structural reinforcement that would be necessary, but may nevertheless be insufficient, to prevent a sudden foundation collapse. The Ash Landfill cannot be retrofitted now to be safe. Attempting a retrofit could trigger a sinkhole collapse that could rapidly spread CCR contamination in the underlying karst aquifers.

- To protect public waters, the CCR Rule requires (a) a distance of at least 5 feet between the base of CCR storage and disposal facilities and the uppermost aquifer, or (b) other measures that eliminate any hydraulic connection between CCR storage and disposal facilities and the aquifer—CREC Ash Landfill does not meet either standard. In fact, the available monitoring data are indicative of an ongoing hydraulic connection that allows CCR constituents, including arsenic and other heavy metals associated with CCR leachate, to reach the underlying karst aquifers.

- Water quality samples from wells downgradient from the Ash Landfill show consistent and increasing contamination since 2012 with toxic constituents associated with CCR, such as

arsenic, boron, molybdenum, manganese, selenium, sulfate, and thallium, indicating that the Ash Landfill has contaminated the Surficial and Floridan Aquifer at the site.

- Groundwater beneath CREC Ash Landfill, FGD Blowdown Ponds, and Percolation Ponds flows towards the seawater discharge canal, tidal wetlands, and Crystal Bay.

For these reasons, discussed in detail in the full report, the Ash Landfill cannot meet the safety standards in the CCR Rule. Additionally, as the CCR Rule requires corrective action to prevent further releases of CCR constituents into the environment, the CCR that have accumulated in the Ash Landfill should be removed and the site decontaminated. The only way to prevent such continued releases from the Ash Landfill is to remove the CCR that has accumulated and decontaminate the site.

## 2. INTRODUCTION

This is an assessment of coal combustion residuals ("CCR") storage and disposal at the Crystal River Energy Complex ("CREC"). This assessment evaluates hydrogeologic conditions at the Ash Landfill, FGD Blowdown Ponds, Gypsum Storage Pad, and Percolation Ponds, existing groundwater contamination at CREC, and compliance with the U.S. Environmental Protection Agency's ("EPA") new rule on the disposal of CCR from electric utilities ("CCR Rule," U.S. EPA 2015). More specifically, this assessment considers whether CREC's CCR facilities satisfy the safety standards in the CCR Rule for CCR disposal in karst terrain and away from the uppermost aquifer and for preventing groundwater contamination.

The karst-specific safety factors under CCR Rule can be summarized as follows:

1. The historical record of local sinkhole development;
2. The presence of a local hydraulic gradient that points downward at shallow depths;
3. The presence of subsurface conduits that allow piping of groundwater into the karst aquifer, or shallow conduits or caves that could cause sudden collapse of the structure's foundation; and
4. The use of engineering solutions to "prevent the kind of foundation collapse and settlement that could lead to sudden release to the environment of CCR with its toxic constituents and associated leachate." (U.S. EPA 2015).

As discussed below, these factors support the conclusion that CREC Ash Landfill cannot continue to safely receive CCR, nor can it meet the requirements of the CCR Rule.

Additionally, the CCR Rule requires (a) a distance of at least 5 feet between the base of certain CCR storage and disposal facilities and the uppermost aquifer, or (b) other measures that eliminate any hydraulic connection between the facilities and the aquifer. As discussed below, the Ash Landfill does not meet either of these standards.

Water quality samples from wells downgradient from the Ash Landfill show consistent and increasing contamination from common CCR constituents, such as arsenic, boron, molybdenum, manganese, selenium, sulfate, and thallium, indicating that the Ash Landfill has already contaminated the Surficial and Floridan Aquifer at the site.

The Ash Landfill cannot meet the safety standards in the CCR Rule. Additionally, as the CCR Rule requires corrective action to prevent further releases of CCR constituents into the environment, the CCR that have accumulated in the Ash Landfill should be removed and the site decontaminated. The only way to prevent such continued releases from the Ash Landfill is to remove the CCR that has accumulated and decontaminate the site.

## 3. ASSESSMENT

### A. CREC is in one of the country's most unstable areas, under the influence of multiple sinkholes

CREC is located in Citrus County, an active karst area under the influence of sinkholes (FGS 1985). The sandy sediment cover over the limestone in coastal Citrus County is thin, and sinkholes that form tend to be smaller, i.e., less than 10 feet ("ft") in diameter, and not as deep as in areas with thicker, more cohesive sediments covering the limestone. However, the near-surface limestone is deeply incised with solution channels and conduits that can cause small sinkholes to form as surficial sands move into the subsurface voids (Dames and Moore 1994).

#### a. Hydrogeology of coastal West Florida: Karst terrain, solution conduits, and sinkholes

Coastal Citrus County is a region that is underlain by a thick sequence of carbonate rocks, commonly called "limestone" (Miller 1986). These rocks can be dissolved by the chemical action of acidic groundwaters. This creates voids in the rock and a distinctive geologic terrain called karst.[1] Karst terrains are characterized by solution features such as caves and collapse features caused by surface materials falling into voids created by the solution of the underlying rocks. A vertical collapse or solution feature created by karst activity is called a sinkhole (Tihansky 2013).

Small sinkholes are common in western Citrus County (FGS 2016; Tihansky 2013). These voids or depressions at the surface are caused by the movement of unconsolidated surficial materials into pre-existing voids in the underlying limestone. Sinkholes can form rapidly by collapse or slowly by movement of surficial materials into underlying voids in the carbonate rock. Most sinkholes in coastal Citrus County are cover subsidence sinkholes. These sinkholes form when loose surficial sands migrate downward into solution cavities in the limestone. Cover subsidence sinkholes can form slowly, or abruptly, especially after heavy rainfall (Tihansky 2013).

[1] Geologists generally use the term "terrane" to refer to three-dimensional areas including the surface and subsurface, and "terrain" to refer to the surface configuration or topography only. This assessment uses "terrain" to refer to both surface and subsurface areas unless otherwise noted.

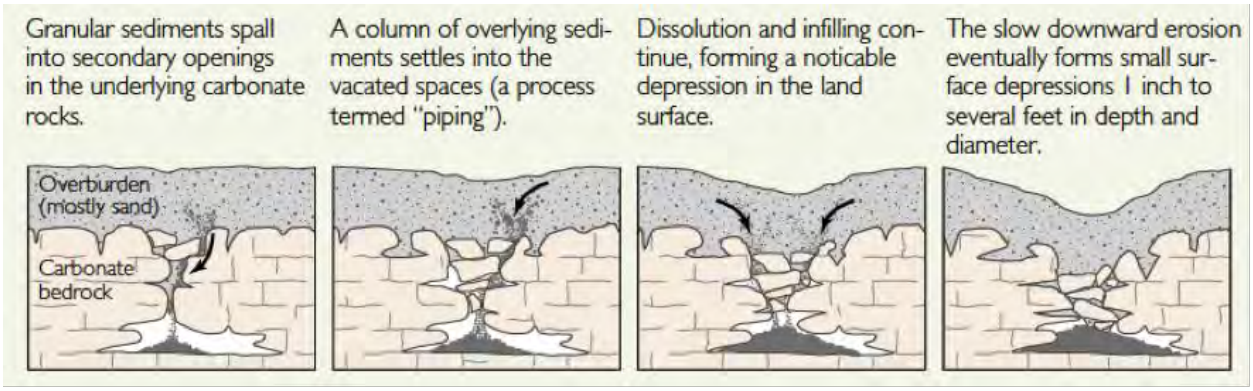


**Figure 1. Cover subsidence sinkhole schematic (Tihansky 2013)**

Paleosinks or paleo-sinkholes are also common in West Central Florida (Tihansky 2013). These are cover subsidence sinkholes that have been filled by sediments or water and do not have recognizable depressions at the surface. Such sediment-filled sinkholes can create a vertical column of permeable materials that allow contaminants introduced at the water table to reach the Floridan Aquifer. In addition to sinkholes, the limestone underlying CREC contains many solution enlarged fractures that form preferred conduits for groundwater flow and allow for downward movement of surficial sands into the underlying limestone (Dames and Moore 1994).

Groundwater, particularly groundwater in the Surficial and Floridan Aquifers,[2] supplies the region's public drinking water. The Floridan Aquifer is one of the largest and most productive sources of fresh groundwater in the world (Miller 1986). It is comprised of the carbonate rocks of Eocene to Miocene age in West Central Florida. In coastal western Citrus County, the Floridan Aquifer is unconfined and water table elevations represent the potentiometric surface of the Floridan Aquifer. This area is a recharge zone for the shallow Floridan Aquifer, which is at or within a few feet of land surface at CREC. More specifically, shallow groundwater flows downward from the water table and the shallow sands of the Surficial Aquifer into the Floridan Aquifer. Near CREC, the deeper and intermediate portions of the Floridan Aquifer are discharge zones, and groundwater has a component of flow toward the surface.

### b. Hydrogeology of CREC site

The Florida Geological Survey ("FGS") sinkhole database (FGS 2016) documents 24 reported sinkholes within 5 miles of CREC site. As the FGS sinkhole data are self-reported, the 24 reported sinkholes are the minimum number of sinkholes that have occurred in recent years near CREC site. The FGS database is biased toward residential and commercial areas where sinkholes are more likely to be reported than in rural areas and industrial sites. Most of the reported sinkholes near CREC site are reported along the U.S. Highway 19 corridor east of CREC site and associated residential areas. The reported sinkholes are smaller than sinkholes that occur in central Florida, generally less than 10 ft in

[2] The Surficial and Floridan Aquifers are U.S. EPA designated Underground Sources of Drinking Water, and Florida Department of Environmental Protection ("DEP") designated Type G-II (Surficial) and G-I (Floridan) groundwaters.

diameter and up to 10 ft in depth. Using the 24 sinkholes as a representative data set, 95% (two standard deviations) of reported sinkholes within 5 miles of CREC have diameters less than 7 ft. They are indicative of the extensive karst solution cavities that are present in the shallow subsurface in western Citrus County.

Dames and Moore (1994) describe the geology and hydrogeology of CREC site. The following discussion is a summary of the geology and hydrogeology of CREC site from that report.

Dames and Moore report that the Upper Floridan Aquifer at CREC site contains abundant "solution enlarged fractures," "long linear depressions" in the limestone surface, and "underground channels and caverns." They also report that during removal of coal ash from the area of the former CREC south ash pond, "local superficial channels/sinkholes concealed by ash deposits had caused a continuous series of incidents and delayed removal/transportation activities." The report also states that "most flow is through the solution channels and cavities" and that the upper zone from the surface to a depth of about 30 feet contains many large interconnected solution cavities and channels that are highly permeable.

The surficial deposits at CREC consist of predominantly sandy, unconsolidated materials with some silt and clay. There is no distinct Surficial Aquifer at the site, and the Floridan Aquifer is within a few feet of the land surface. Water reaching the water table from the surface is effectively recharging the upper part of the Floridan Aquifer. The permeable surficial sediments are in direct hydraulic connection with the limestones of the Upper Floridan Aquifer. As a result of the lack of extensive low permeability surficial materials, the Floridan Aquifer at CREC site is an unconfined aquifer in direct hydraulic connection with the water table. Soils at the site typically have seasonal water tables within 1-2 ft of the land surface and are described as poorly drained. The undisturbed soils at CREC are subject to frequent and prolonged flooding.

The near-surface Floridan Aquifer units present at the site are the limestones of the Ocala Group, specifically the lower member of the Ocala Group, the Inglis Formation. The Inglis Formation is an Eocene limestone with extensive solution features. The Avon Park Formation underlies the Inglis Formation. The Avon Park Formation consists of limestones and dolostones and forms the bottom of the Upper Floridan Aquifer (Miller 1986). The permeability of the Avon Park decreases with depth. This results in enhancement of horizontal ground water flow in the Inglis Formation limestones. Dames and Moore (1994) report that most groundwater flow at the site is through "solution cavities and channels." In test borings that encountered voids, about 10% of the total aquifer volume is void space, generally within 50 ft of land surface. A zone in the Inglis Formation from land surface to a depth of about 30 ft consists of "many large solution cavities and channels that are highly permeable." A lower high permeable zone occurs between depths of about 40 to 60 ft at the contact between the Inglis and Avon Park Formations. Aquifer performance data suggest that the transmissivity of the Upper Floridan Aquifer at the site is about 2E05 $ft^2$/day, a very high value.

In a study to support installation of CREC Units 4 and 5 at CREC (ESE 1982), Dames and Moore (1994) report that test borings could be divided into "void" borings that encountered voids during

drilling, and “non-void” borings that encountered solid limestone. The eight void wells responded faster to recharge events and tides and were assumed to connect with solution cavities and channels. The water levels for the void group wells were found to “form a trough running northeast to southwest under the ash disposal site…this trough roughly coincides with the known subsurface cavities in this area and likely reflects a fracture zone of high permeability.” The general groundwater flow direction under the Ash Landfill indicated by the void and non-void wells is northeast to southwest, toward CREC intake and discharge canals and wetlands to west of CREC. Groundwater that flows under the Ash Landfill through the “trough” delineated by Dames and Moore (1994) flows toward the west-southwest and discharges into the seawater discharge canal, and ultimately into Crystal Bay.

The water table “trough” under the Ash Landfill reported by Dames and Moore (1994) includes monitor wells MWI-2R2, TWI-5, and TWI-3 (Figures 2 and 3). These three monitor wells are located on the west side of the Ash Landfill. As described further below, groundwater monitoring reports (DEP 2015) indicate that these three wells have been contaminated with arsenic, sulfate, thallium, selenium, molybdenum, manganese, and boron, all of which are contaminants associated with CCR leachate. This indicates that the Ash Landfill is in direct hydraulic connection with a highly permeable fracture zone in the Upper Floridan Aquifer, and that contaminants associated with CCR wastes have entered the Upper Floridan Aquifer.

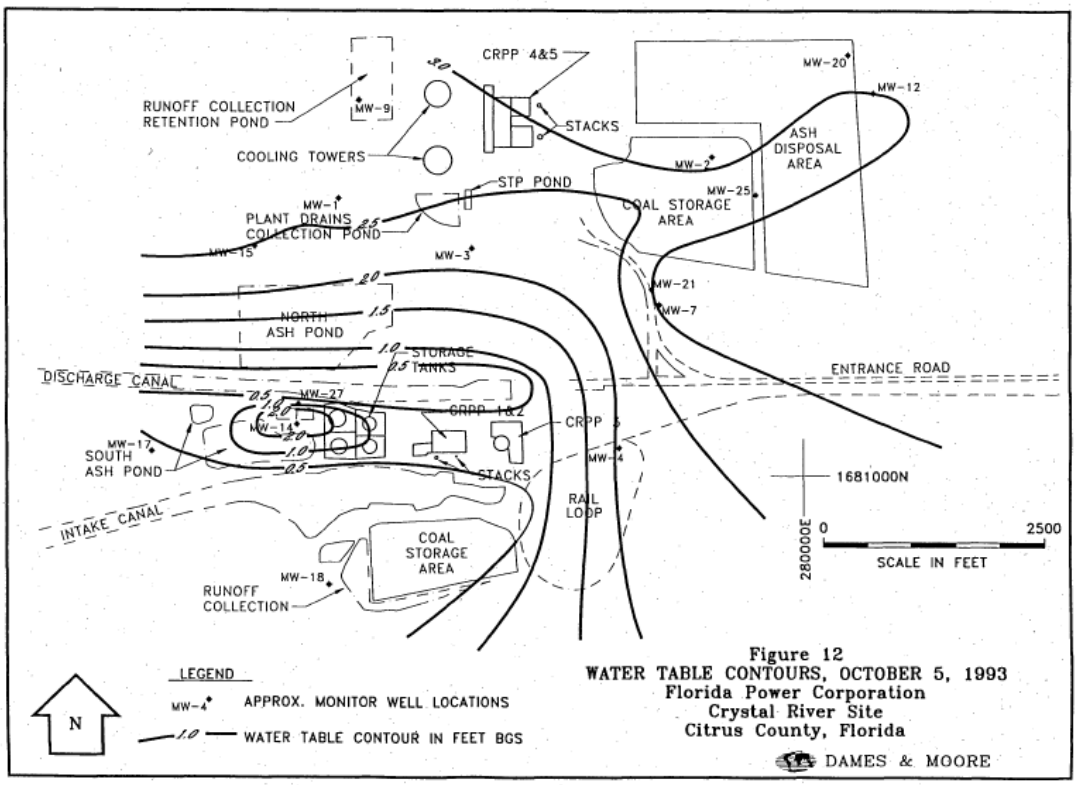


**Figure 2. Water table elevations under the Ash Landfill (Dames and Moore 1994)**

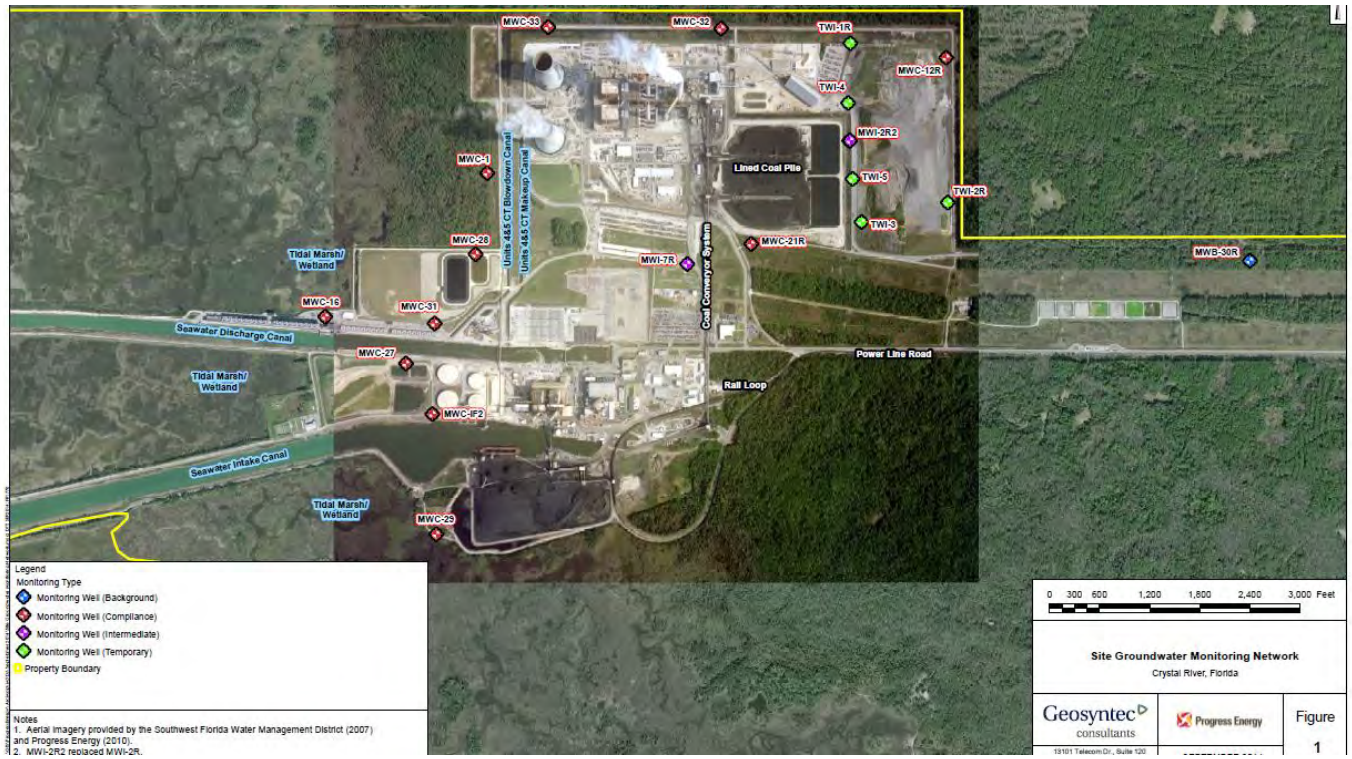


**Figure 3. Groundwater Monitoring Network at CREC (Geosyntec 2013)**

### B. CREC Ash Landfill cannot meet the CCR Rule's safety standards for unstable areas

Historical records of sinkhole activity in the region and reports prepared for CREC site clearly indicate that the site is within an active karst zone, with numerous, unlocated channels and voids. Consulting reports (Dames and Moore 1984; ESE 1982) state that at CREC "most [groundwater] flow is through solution cavities and conduits" and these reports document that the site contains numerous solution enlarged channels, voids, and caves, with one documented high permeability conduit located directly under the Ash Landfill (Dames and Moore 1994). These channels, conduits, limestone surface depressions, and voids create a sinkhole hazard for the Ash Landfill.

The Floridan Aquifer is at or near land surface at CREC site (Dames and Moore 1994) and any size sinkhole is likely to allow movement of unconsolidated materials under the CCR landfill into the voids, depressions, and caverns under the landfill will, and likely has (ESE 1982), allowed CCR materials to come into direct contact with the limestones and groundwater of the Upper Floridan Aquifer. The Ash Landfill does not have structural reinforcements or a liner[3] to prevent vertical movement of CCR materials into the Upper Floridan Aquifer, as occurred at the site of the former CREC south ash pond (ESE 1982).

[3] Only 5.5 acres of the 62-acre Ash Landfill are lined.

To ensure the safety of CCR storage and disposal in unstable karst areas, the CCR Rule requires the detection and interception of (a) *all* of the possible conduits that allow piping of groundwater into the underlying karst aquifers; (b) *all* of the possible shallow caves that could cause a sudden foundation collapse; and (c) *all* of the possible pathways for CCR constituents to be released from CCR storage and disposal facilities, such as the Ash Landfill, into the karst aquifers (U.S. EPA 2015).

These safety standards were not incorporated into the design of the Ash Landfill when it was built. Detection and interception of *all* possible conduits, depressions, voids, and shallow caves in a complex karst terrain such as CREC site is extremely difficult technically, if not practically and economically infeasible. With any currently known sinkhole remediation technology, the Ash Landfill cannot be "upgraded" to meet the CCR Rule requirements for facilities in karst terrains as it would be nearly impossible to determine that all conduits, voids, and caves had been detected and intercepted. As the Ash Landfill does not meet the CCR Rule's safety standards and instructions for engineering practices in karst areas, the CCR materials currently onsite should be removed and the groundwater and soils decontaminated.

In addition to the Ash Landfill, CREC site contains a Gypsum Storage Pad, which receives gypsum solids before disposal in the Ash Landfill or transport offsite, and FGD Blowdown Ponds and Percolation Ponds on the west side of the site, adjacent to the seawater discharge canal, that receive waste and wastewater from coal operations. The FGD Blowdown Ponds are lined with synthetic impermeable liners. However, the FGD Blowdown Ponds, Percolation Ponds, and Gypsum Storage Pad are in the same unstable karst environment as the Ash Landfill. There is a potential for failure of the FGD Blowdown Pond liner system or piping as result of sinkhole activity. If a sinkhole punctured the liner or caused a FGD pipe to leak, the FGD wastes would be introduced directly into the Upper Floridan Aquifer, discharging to the seawater discharge canal, tidal wetlands, and ultimately Crystal Bay. The liner system would need to be able to span sinkholes 10 ft in diameter or greater without failing to avoid contaminating the Upper Floridan Aquifer with FGD wastes. The Percolation Ponds are unlined and are in direct communication with the Upper Floridan Aquifer. The Percolation Ponds recharge the shallow groundwater aquifer and discharge into the seawater discharge canal, tidal wetlands, and Crystal Bay (Figures 2 and 3).

### C. The Upper Floridan Aquifer exhibits contamination from CCR Leachate at CREC

Contaminants such as sulfate, arsenic, selenium, thallium, boron, molybdenum, and manganese are common constituents of CCR leachate (EPRI 2004). The presence of several of these constituents, at any detectable level above background values, in groundwater downgradient from a CCR storage and disposal unit is overwhelming evidence that contaminants that have leached from the CCR materials have reached the water table and the aquifer. Groundwater sampling results from September 2012 for monitoring well MZ-3, which is in an upgradient, undisturbed area approximately one mile east of CREC facility, indicate that background arsenic concentrations in the shallow, intermediate, and deep portions of the aquifer are 2.1, 6.3, and <2.0 micrograms/liter, respectively (Geosyntec 2013). Arsenic levels in groundwater >10.0 micrograms/liter are indications of contamination of the aquifer system by CCR.

Dames and Moore (1994) state that the “void wells” near the Ash Landfill define a “trough” in the water table surface underneath the landfill (Figure 2). They attribute this water table trough to a “fracture zone of high permeability.” Three monitor wells on the west side of the Ash Landfill are located in or near this high permeability fracture zone: wells MWI-2R2, TWI-5, and TWI-3 (Figure 3).

Water samples from these three wells have regularly exceeded federal and state regulatory levels for arsenic, sulfate, thallium, selenium, molybdenum, manganese, and boron since 2012. For arsenic, boron, manganese, and molybdenum levels of these contaminants in groundwater in this fracture zone have trended upward from 2012 to 2015 (Figures 4, 5, 6, and 7). Water quality data obtained in January 2016, continue to show levels of contaminants in excess of groundwater standards in wells downgradient of the Ash Landfill in wells MWI-2R2, TWI-1R, TWI-3, and TWI-5 (DEP 2016).

These supporting lines of evidence, the definition of the water table trough, the presence of high permeability conduits at the site, and the presence of common CCR leachate constituents at increasing concentrations in wells downgradient from the Ash Landfill are overwhelming evidence that the landfill has contaminated local groundwater with toxic materials associated with CCR leachate. As the purpose of the standards enumerated under the CCR Rule is to prevent groundwater contamination from CCR facilities, the presence of these contaminants at the existing site is evidence that that the existing Ash Landfill does not meet the conditions specified in the rule.

Geosyntec (2013) has prepared a report that maintains that the arsenic found in groundwater downgradient from the Ash Landfill is the result of complex geochemical conditions and a natural source of arsenic. They note that arsenic was detected in borings at a proposed coal ash storage site east, and upgradient, of the current Ash Landfill, suggesting a natural source of arsenic. However, the concentrations of arsenic detected downgradient of the Ash Landfill are up to five times as high as the concentrations detected upgradient. In addition, the associated CCR contaminants sulfate, selenium, thallium, boron, molybdenum, and manganese have been detected in wells downgradient of the Ash Landfill. The Geosyntec report does not explain the presence of these CCR associated contaminants.

To prevent such contamination, the CCR Rule prescribes (a) a distance of at least 5 feet between the base of facilities containing CCR and the uppermost aquifer, or (b) other measures that eliminate the hydraulic connection between the base and the uppermost aquifer—safety standards that the Ash Landfill does not meet. According to public records, the base of the Ash Landfill has an elevation of 4 to 8 feet above sea level, while the water table near the Ash Landfill has reported elevations greater than 3 feet (Geosyntec 2013). This indicates that the base of the Ash Landfill is within 5 feet of the water table in the Surficial/Floridan Aquifer. The Ash Landfill is unlined, meaning that the CCR materials are in direct hydraulic connection with the Floridan Aquifer. Furthermore, natural soils at CREC site are poorly drained and flood seasonally (Dames and Moore 1994), indicating that the water table seasonally approaches the land surface.

As the CCR Rule requires corrective action to prevent further releases of CCR constituents into the environment, the CCR that have accumulated in the Ash Landfill should be removed and the site should be decontaminated.

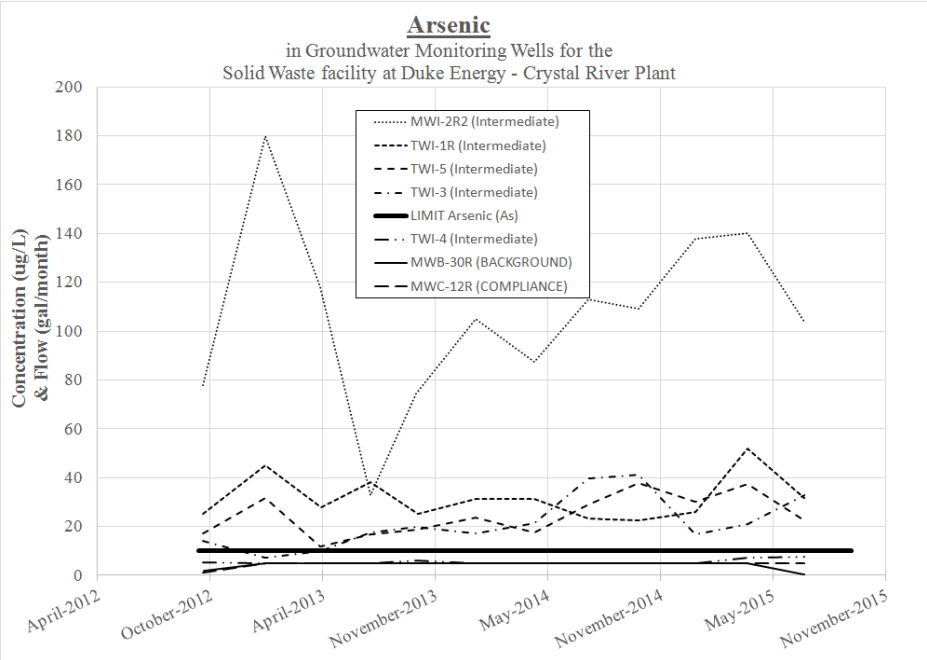


**Figure 4. Arsenic levels in groundwater samples from wells at CREC site, October 2012 to July 2015 (DEP 2015)**

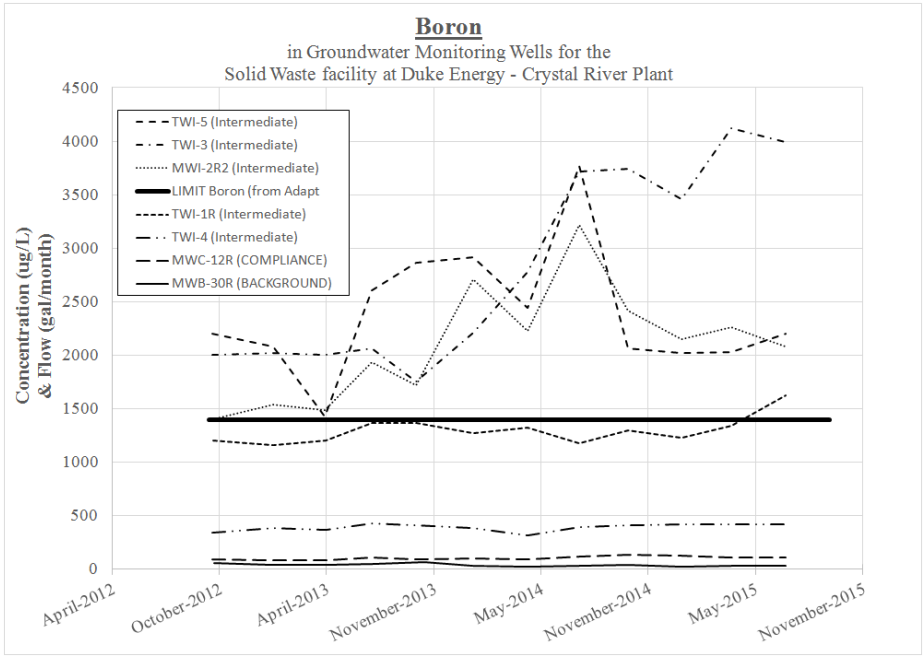


**Figure 5. Boron levels in groundwater samples from wells at CREC site, October 2012 to July 2015 (DEP 2015)**

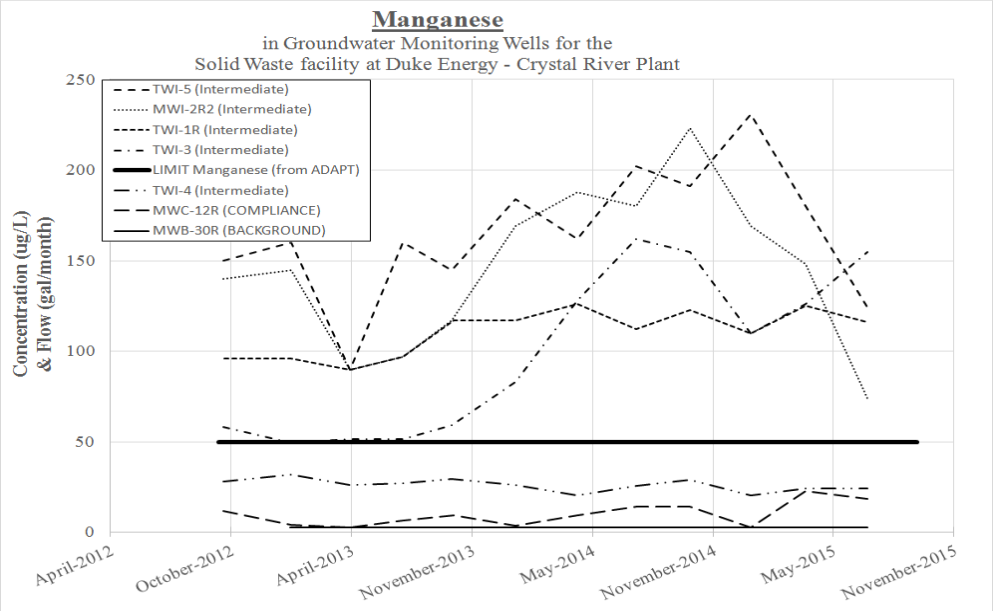


**Figure 6. Manganese levels in groundwater samples from wells at CREC site, October 2012 to July 2015 (DEP 2015)**

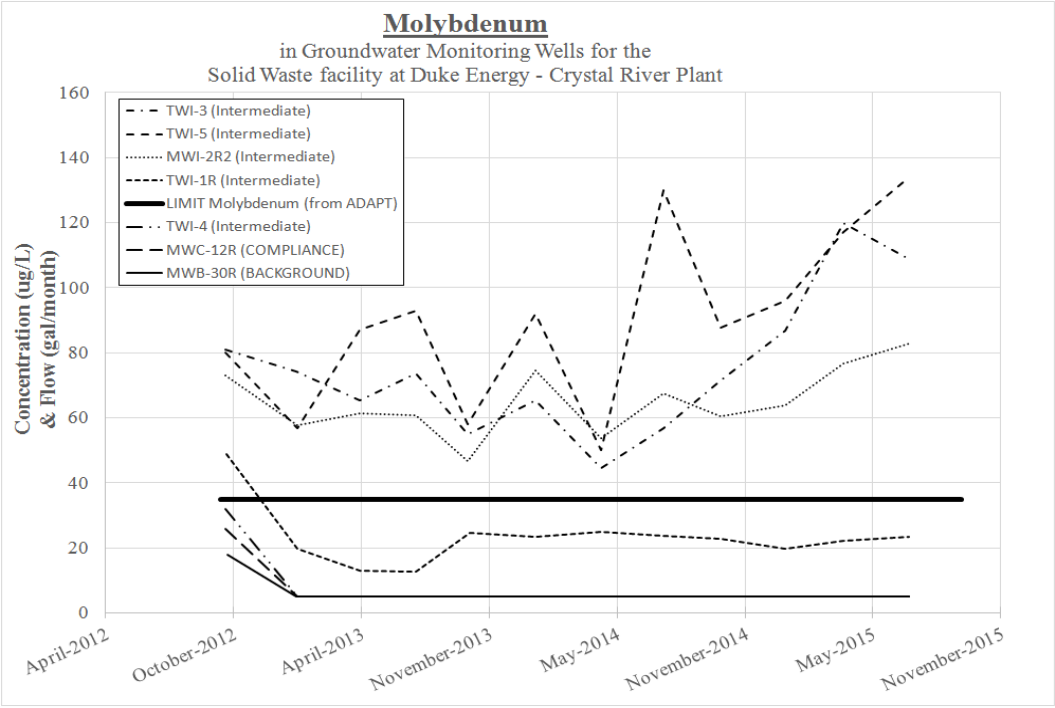


**Figure 7. Molybdenum levels in groundwater samples from wells at CREC site, October 2012 to July 2015 (DEP 2015)**

## 4. SUMMARY

CREC Ash Landfill does not meet the safety criteria for CCR landfills and impoundments enumerated in the EPA's CCR Rule. The facility is located in a documented unstable, karst area, putting local water resources at risk. It would be technically challenging, if not impossible to upgrade the Ash Landfill to meet the CCR Rule standards for active facilities in karst areas. In addition, there is overwhelming evidence that the Ash Landfill has contaminated local ground water with arsenic, selenium, molybdenum, manganese, boron, and thallium. The source of these contaminants is the Ash Landfill as documented by the presence of these contaminants in water samples from downgradient wells. The Ash Landfill is uncovered and open to infiltration of rainwater, the facility is unlined, and it is in direct hydraulic connection with the Upper Floridan Aquifer. The remedy to prevent further contamination of the aquifer and of Crystal Bay, is to remove the CCR materials currently on site and to decontaminate the Floridan Aquifer and local soils.

## 5. AUTHOR'S EXPERTISE AND QUALIFICATIONS

The author of this technical assessment, Dr. Mark Stewart, PhD, PG, is a Professor Emeritus at the University of South Florida School of Geosciences. Dr. Stewart is a registered Professional Geologist in the State of Florida. He has an extensive publication record and expertise in the hydrogeology of Florida, water resources management, karst hydrology, applied geophysics, and the geology of sinkholes. He has been qualified in hearings of the Division of Administrative Hearings and in State and Federal courts as an expert in hydrogeology, water resources management, karst hydrology, the geology of sinkholes, hydrologic modeling, and environmental geophysics. Dr. Stewart has an undergraduate degree in geological sciences from Cornell University, and graduate degrees in geology and water resources management from the University of Wisconsin-Madison.

The primary materials reviewed and used in the preparation of this assessment were Florida Department of Environmental Protection ("DEP") regulatory files, which include groundwater monitoring reports, reports on the geology and hydrogeology of CREC site, and reports on the construction and operation of waste material facilities and disposal of generated wastes, all of which were prepared by Duke/Progress Energy/FPC and their consultants and submitted to the DEP. Additional materials referenced for this report include: publications, data, and maps from the U.S. Geological Survey and Florida Geological Survey; peer-reviewed journal articles; and publically-available documents related to coal and coal combustion residuals, hydrogeology, sinkholes, and karst hydrology.

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Tihansky, A., 2013. Sinkholes, West Central Florida. In, Galloway, Jones, Ingebritsen, *Land Subsidence in the United States*, USGS Circular 1182, last modified 2013.

U.S. EPA, 2015. Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals From Electric Utilities, Final Rule, 80 Fed. Reg. 21,302 (Apr. 17, 2015), as amended by Technical Amendments to the Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals from Electric Utilities—Correction of the Effective Date, 80 Fed. Reg. 37,988 (Jul. 2, 2015); 40 C.F.R. §§ 257 and 261 ("CCR Rule").

To support our comments, we enclose two exhibits: Exhibit 1, by one of the state's preeminent hydrogeologists, Dr. Mark Stewart, assesses the coal disposal at CREC including the pathways for toxic contaminants in the Ash Landfill and Percolation Pond to leach into the Floridan aquifer and Crystal Bay. Exhibit 2, by Dr. Ranajit Sahu— an expert with over twenty-five years of experience in environmental, mechanical, and chemical engineering, including coal-fired power plants— examines the timeline for CREC Units 4 and 5 to achieve compliance with a zero discharge standard for bottom ash.

As detailed below and in the enclosed exhibits, per the ELGs, by November 1, 2018, the final permit should require DEF to eliminate all discharges of bottom ash and flue gas mercury control ("FGMC") wastewaters, and meet new limitations for pollutants in flue gas desulfurization ("FGD") wastewater and combustion residual leachate for the following reasons, again, detailed further below:

- The final permit should set November 1, 2018, as the "as soon as possible" deadline for DEF to eliminate bottom ash wastewater discharges from Units 4 and 5.[5] It is well documented that a zero discharge best available technology economically achievable ("BAT") standard for bottom ash wastewater can be readily achieved in 27 to 30 months, rather than the 44 months that DEF proposed and DEP has endorsed in the Draft Permit.[6] In fact, the permitting record here indicates that DEF is well-positioned to meet the standard in even less time, such that the default, November 1, 2018, deadline should apply.

- The final permit should include the applicable ELG provisions for CREC's FGMC and FGD wastewaters as they are discharged to groundwater in Percolation Ponds and directly hydrologically connected to Crystal Bay and the Gulf of Mexico, "waters of the United States."[7]

- The final permit should set November 1, 2018, as the deadline for DEF to meet the zero discharge standard for CREC's discharges of FGMC wastewater.[8] Additionally, before that deadline, the permit should require DEF to meet the best practicable control technology available ("BPT") limitations for total suspended solids ("TSS") and oil and grease effluent limits and begin monitoring flows daily.[9]

- The final permit should require the FGD wastewater to meet strict BAT effluent limits

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Management System; Disposal of Coal Combustion Residuals from Electric Utilities—Correction of the Effective Date, 80 Fed. Reg. 37,988 (Jul. 2, 2015) (revising 40 C.F.R. §§ 257 & 261) [hereinafter "CCR Rule"].

[5] *See* 40 C.F.R. § 423.11(t) (defining the phrase "as soon as possible" to mean Nov. 1, 2018, unless a later date is specifically justified); § 423.13(k)(1) (requiring compliance with bottom ash wastewater standards by Nov. 1, 2018 unless a later date up to Dec. 31, 2023 is specifically justified).

[6] *See* Exhibit 2.

[7] 33 U.S.C. §§ 1311(a), 1342(a), 1362(14); 40 C.F.R. § 423.13(g) and (i).

[8] 40 C.F.R. § 423.13(i)(1) (requiring compliance with FGMC wastewater standards by Nov. 1, 2018 unless a later date up to Dec. 31, 2023 is specifically justified).

[9] 40 C.F.R. § 423.12(b)(11).

for arsenic, mercury, selenium and nitrate/nitrite by December 2018, or even sooner if possible.[10] Additionally, the permit should require, effective immediately, FGD wastewater to meet the BPT TSS and oil and grease effluent limits and daily monitoring of the same.[11]

◊ The final permit should require combustion residual leachate to meet all applicable technology and water quality based effluent limits, not only for discharges that drain to the runoff collection system, but also for discharges to the seawater discharge canal and Crystal Bay.[12]

As detailed below and in the enclosed exhibits, per the CCR Rule, the final permit should require DEF to meet all of the applicable new safety standards for coal ash disposal. This includes the standards aimed at protecting groundwater and surface—here, most notably, the Floridan aquifer and Crystal Bay:

◊ Toxic coal ash contaminants associated with CCR—arsenic, boron, manganese, molybdenum, selenium, sulfate, and thallium—are exceeding state and federal safety limits at wells downgradient from the unlined Ash Landfill,[13] as DEP is aware and even predicted.[14] Because there is no protective barrier, CCR waste in the landfill is in direct contact with the Floridan aquifer and groundwater that is hydrologically connected to Crystal Bay.

◊ The CCR Rule requires cleanup of the CCR that has accumulated in the unlined Ash Landfill.[15] To prevent unauthorized discharges and further contamination, and to comply with federal and state waste and water quality regulations, the final permit should require DEF to take corrective action as soon as possible by removing all CCR from the Ash Landfill and decontaminating the site.

◊ CREC is in one of the country's most unstable areas, in karst terrain, and under the influence of multiple sinkholes, including 24 reported sinkholes within 5 miles of CREC. Siting CCR waste facilities here puts ground and surface waters at risk of releases of toxic CCR waste into the underlying aquifer, due to limestone dissolution and collapse.[16]

◊ DEF must comply with prohibitions, designed to protect public waters, on siting coal ash

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[10] *See* 40 C.F.R. §423.13(g)(1)(i) (requiring compliance with FGD wastewater standards by Nov. 1, 2018 unless a later date up to Dec. 31, 2023 is specifically justified).

[11] 40 C.F.R. § 423.12(b)(11).

[12] 40 C.F.R §§ 423.12(b)(11) and 423.13(l).

[13] *See* Exhibit 1 and Section G below; *see also* 40 C.F.R. §§ 141.62,141.66, 257.95(h); Fla. Admin. Code. R. 62-520.420 (2016).

[14] Memorandum from Don Kell to Hamilton Oven, Jr., July 15, 1981 at 3, 4, 7 (hereinafter "Ash Landfill Interoffice Memo").

[15] 40 C.F.R. §§ 257.95(g)(5); 257.96; 257.101(a).

[16] *See* Exhibit 1.

waste facilities in unstable areas (i.e., Florida's karst terrain).[17] To do so, DEF must move CCR disposal offsite if DEF fails to prove that the status quo—storing CCR in CREC's facilities—is somehow safe.[18] Because the Ash Landfill cannot meet the safety standards in the CCR Rule, and the facility cannot be effectively retrofitted, it cannot receive CCR after April 19, 2019. Instead, DEF will be required to close the landfill and move disposal offsite.

DEF applied to renew Permit No. FL0036366, governing surface water discharges from Units 4 and 5 in January 2016.[19] Notice of the Draft Permit was received by Sierra Club via email on Friday, August 26, 2016. The applicant's name is DEF Florida, LLC, and its address is 15760 Power Line St., Crystal River, FL 34428. The discharge covered by the proposed Draft Permit, File No. FL00036366-013-IW1S, is located in Citrus County.

We respectfully submit this material to help inform DEP's renewal of Crystal River's NPDES permit, to raise our concerns that the Draft Permit does not assure compliance with state and federal law, and to urge DEP to revise the Draft Permit and include requirements for CREC to comply with all applicable ground and surface water protection standards.

## BACKGROUND

The Crystal River Energy Generating Complex ("CREC") is located in Citrus County, Florida and is owned and operated by DEF. CREC Units 4 and 5 are pulverized coal-burning steam electric generating units that were placed into service in 1982 and 1984 respectively. The 4,729-acre coastal site in Florida's Big Bend is connected to Crystal Bay, a Class II[20] marine water and part of the Gulf of Mexico, via a seawater discharge canal that releases the plant's wastewater.

Crystal Bay is a shallow embayment of the Gulf of Mexico, midway between the Withlacoochee River to the north and the Crystal River to the south. Undeveloped portions of CREC include wetlands and salt marshes. Crystal Bay includes a variety of habitats that support vital aquatic resources, including the federally-listed species identified below. Open water habitats in Crystal Bay cover saltwater, tidally-influenced water, and tidal freshwater areas and include artificial structures, coastal tidal rivers and streams, oyster reefs, salt marshes, subtidal unconsolidated marine/estuary sediment habitats, and submerged aquatic vegetation habitats such as seagrasses and algae. The bottom of Crystal Bay provides benthic habitats, with characteristics dictated by salinity, tides, and substrate type.[21]

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[17] 40 C.F.R. § 257.64.

[18] 40 C.F.R. §§ 257.64(5), 257.101(b)(1) (surface impoundments), 257.101(d)(1) (landfills).

[19] *See* Duke Energy Florida, Inc., Application to Renew NPDES Permit for Crystal River Units 4 & 5, Permit No. FL0036366, January 12, 2016.

[20] *See* Fla. Admin. Code. R. 62-302.400(16)(b)(9) (2016) (classifying "all coastal waters and tidal creeks" within Citrus County as Class II waters).. The Surface Water Quality Criteria are designed to to "protect fish consumption, recreation and the propagation and maintenance of a health, well-balanced population of fish and wildlife." Fla. Admin. Code. R. 62-302-400(4) (2016). Florida has set Surface Water Quality Criteria).

[21] U.S. Nuclear Regulatory Commission, Draft Environmental Impact Statement for Crystal River Unit 3, at 2-42

Water-related industries, such as commercial fishing and tourism, make up a large sector of the employment base in Citrus County.[22] These sectors of the local economy "depend upon the resources of the coastal fisheries and the West Indian (Florida) manatee."[23] Over ninety species of fish have been identified near CREC.[24]

Federally-listed threatened or endangered species in the vicinity of the CREC include, but are not limited to, the Gulf sturgeon, smalltooth sawfish, green turtle, hawksbill turtle, Kemp's ridley turtle, leatherback turtle, loggerhead turtle, the American alligator, the wood stork, the bald eagle, and the Florida manatee.[25] Manatees are known to dwell in Crystal River effluent and intake canals during the spring and fall[26] and nearby Crystal River/Kings Bay, an Outstanding Florida Water, is the largest winter refuge for manatees on the Florida Gulf Coast.[27]

As detailed in Exhibit 1, the CREC is located in one of the country's most unstable areas with 24 known sinkholes within a 5 mile distance. Indeed, coastal Citrus County is an active karst area with sandy sediment cover over limestone.[28] The near-surface limestone is deeply incised with solution channels and conduits that can cause additional sinkholes to form as surficial sands move into subsurface voids.[29] The permeable surficial sediments allow access to the shallow, unconfined aquifer below through solution cavities and along fractures. Groundwater at CREC flows towards Crystal Bay and the Gulf of Mexico via the seawater discharge canal, and tidal wetlands.

Wastewater from Units 4 and 5 includes runoff from coal, gypsum, and limestone storage handling areas and the Ash Landfill, overflow bottom ash sluice water, FGD wastewater, FGMC wastewater, and cooling tower blowdown. These wastewaters are combined and released into the seawater discharge canal, which connects the plant to Crystal Bay.

Bottom ash generated at CREC Units 4 and 5 is sluiced to handling tanks and dewatering bins, where bottom ash solids are separated out from the wastewater.[30] Overflow bottom ash

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(2011) (citing Florida Fish and Wildlife Conservation Commission (FWC, 2005)).).

[22] *See e.g.*, Tommy Thompson, *Time to Join the Crystal River Circus*, Florida Sportsman, February 1, 2006, *available at* http://www.floridasportsman.com/2006/02/01/fishing_crystal_river_powerplant/

[23] Citrus County Comprehensive Plan, Chapter 4, 4-13, October 28, 2014, *available at* https://www.citrusbocc.com/plandev/landdev/comp-plan/chapter-4.pdf.,

[24] U.S. Nuclear Regulatory Commission, Draft Environmental Impact Statement for Crystal River Unit 3, at 2-5.

[25] Duke Energy Florida, Inc. Crystal River Unit 3 Post-Shutdown Decommissioning Activities Report, at 25 (Dec. 2013) *available at* http://www.duke-energy.com/pdfs/3f1213-02_psdar.pdf.

[26] *See* Citrus County Comprehensive Plan, Chapter 13, October 28, 2014, *available at* https://www.citrusbocc.com/plandev/landdev/comp-plan/chapter-13.pdf.

[27] Southwest Florida Water Management District, *Crystal River/Kings Bay, Citrus County* https://www.swfwmd.state.fl.us/springs/kings-bay/

[28] See Exhibit 1.

[29] *Id.* at 4 (citing Dames and Moore 1994).

[30] Duke Energy Florida, Ash Storage/Disposal Area Operations Plan at 2, 5 (Dec. 2013); Duke Energy Florida, Response to Request for Additional Information, May 20, 2016 (hereinafter "RAI #2").

wastewater from the dewatering bins is permitted to flow through internal Outfall I-CH0, which is released through the main discharge canal at Outfall D-001 to Crystal Bay.

Fly ash and bottom ash solids from Units 4 and 5 are taken to CREC's Ash Landfill for disposal or storage. The 62-acre, unlined Ash Landfill began operating alongside Units 4 and 5 in the 1980's and receives a mixture of bottom ash, fly ash, gypsum, pyrites, FGD blowdown solids, mill rejects, and other CCR. [31] The Ash Landfill is unlined[32] as well as uncovered,[33] allowing water, such as precipitation, to enter and mix with the wastes inside, and subsequently leach CCR contaminants into the groundwater beneath the Ash Landfill, and then into the runoff collection system, the seawater discharge canal, and the waters of Crystal Bay.

Units 4 and 5 use a wet scrubber system for sulfur dioxide removal, which produces FGD wastewater as a byproduct. This wastewater is discharged to the plant's FGD Blowdown Ponds, two 1.5- and 4.5-acre solids settling ponds that became operational in 2010.[34] Solids are settled out in the FGD Blowdown Ponds and the remaining liquid is pumped to CREC's unlined Percolation Ponds to be absorbed into groundwater. FGMC wastewater is generated via the plant's mercury control system and is injected into the FGD absorber before also being discharged to the Percolation Ponds.[35] Gypsum solids are conveyed to the concrete-lined Gypsum Storage Pad and stored before disposal in the Ash Landfill or transport offsite for sale.

## LEGAL REQUIREMENTS

The wastewater and solid waste byproducts of burning coal at CREC fall under two new U.S. Environmental Protection Agency ("EPA") rules: the ELGs and the CCR Rule. These rules advance vital public health and environmental safeguards against the toxic metals and other pollutants found in CREC's waste streams.

CREC Units 4 and 5 discharge wastewater into Crystal Bay and are therefore required, pursuant to section 402 of the Clean Water Act ("CWA"), to obtain a NPDES permit. In enacting the CWA, Congress established as a national goal the elimination of all discharges of pollution into waters of the United States.[36] To this end, the Act's implementing regulations establish the NPDES permitting program. Under the program, no pollutant may be discharged from any "point source" without a permit, and failure to comply with such a permit constitutes a violation of the CWA.[37] The CWA defines a "point source" as "any discernible, confined and

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[31] Ash Storage/Disposal Area CCR Landfill Annual Inspection Report, December 2015; Florida Department of Environmental Protection Inspection Report, July 28, 2015.

[32] The 62-acre landfill is unlined with the exception of a 5.5-acre horizontal expansion in June 2010 which used a geosynthetic clay liner. RAI #2.

[33] Approximately 11 acres of the landfill has been covered with a geosynthetic clay liner, 24-inches of protective soil cover, and sod. *Id.*

[34] Record Documentation of Units 4 and 5 FGD Blowdown Ponds Construction Quality Assurance (January 2010).

[35] RAI #2.1

[36] 33 U.S.C. § 1251(a)(1).

[37] 33 U.S.C. §§ 1311(a) and 1342(a); 40 C.F.R. § 122.41(a).

discrete conveyance, including but not limited to any pipe, ditch, channel, tunnel, conduit, well, discrete fissure, [or] container … from which pollutants are or may be discharged."[38]

The CWA authorizes EPA to establish national, technology-based effluent limitations guidelines for discharges from categories of point sources, and requires that NPDES permits include effluent limits based on the performance achievable through the use of statutorily-prescribed levels of technology that "will result in reasonable further progress toward the national goal of eliminating the discharge of all pollutants."[39]

The ELGs became effective on January 4, 2016, and must be included in NPDES permits for such generators going forward. The ELGs impose technology-based effluent limitations—reflecting decades of advances in water quality science and control technology—on discharges of several common types of effluent (i.e., waste streams) from coal-burning power plants, including fly ash and bottom ash transport waters and wastewater from FGD and FGMC systems.

Under the CWA, it is the responsibility of state permitting authorities, such as DEP, to "incorporate the ELGs into NPDES permits as a floor or a minimum level of control."[40] November 1, 2018, is the default deadline for all coal-burning[41] power plants across the country.[42] Because we submitted comments to you in February detailing DEP's implementation responsibilities, we will not repeat ourselves here, but instead incorporate those comments by reference.[43]

EPA's CCR Rule, effective October 19, 2015, establishes national minimum requirements for the safe disposal of coal combustion residuals, or CCR, the solid waste byproducts of burning coal, commonly known as "coal ash." CCR contain toxic metals that for years have contaminated groundwater and put public drinking water supplies and surface waters at risk.[44] The CCR Rule advances public health and environmental safeguards, including enhanced groundwater monitoring, location restrictions for siting CCR waste facilities, liner and leachate collection requirements, and corrective action for cleaning up groundwater contamination.

Unlike the ELG requirements for direct dischargers, the CCR rule is self-implementing. EPA explains: "The federal standards apply directly to the facility (are self-implementing) and facilities are directly responsible for ensuring that their operations comply with these

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[38] 33 U.S.C. § 1362(4).

[39] 33 U.S.C. § 1311(b)(2)(A)(i), *see also* § 1311(b)(1)(A);)

[40] 80 Fed. Reg. at 67,882.

[41] *Id.* at 67,839, n. 1 ("power plants covered by the ELGs use nuclear or fossil fuels, such as coal, oil, or natural gas, to heat water in boilers, which generate steam." [emphasis added]).

[42] *See, e.g.*, 40 C.F.R. § 423.13(g)(1)(i).

[43] Letter from Sierra Club et al. to Supervisor Marc Harris, Power Plant NPDES Permitting, DEP Industrial Wastewater Section Re: *Bringing Florida Coal Plants Into Compliance With The New Effluent Limitations Guidelines*, (Feb. 29, 2016), *available at* http://blog.cleanenergy.org/files/2016/05/2016-02-29-Letter-re-Water-Side-Reqts-for-Fla-Coal-Plants-vfin.pdf.

[44] 80 Fed. Reg. 21,396; *see also* 80 Fed. Reg. 21,326: EPA identified 157 cases of proven or potential groundwater contamination from CCR in states across the nation.

requirements."[45] To ensure full and timely compliance with the CCR Rule, states can adopt the applicable standards in NPDES permits.[46] Likewise, states and citizens can enforce the federal standards under the citizen suit authority of the Resource Conservation and Recovery Act ("RCRA").

## COMMENTS

In this section, we explain the changes DEP should make as it finalizes Permit No. FL0036366 to bring the CREC into compliance with the applicable public health and safety standards in the ELGs and the CCR Rule.

### A. DEP Should Require Compliance with a Zero Discharge Standard for Bottom Ash Wastewater No Later Than November 1, 2018

Under the ELGs, the BAT standard for bottom ash wastewater is zero discharge. DEP should require the CREC to meet this zero discharge standard by November 1, 2018. As Dr. Sahu explains in his enclosed report, and we repeat here for emphasis, nothing in the permitting record justifies any later compliance deadline; in fact, the record shows that DEF is well-positioned to meet the default compliance deadline:

- DEF has already spent more than three years planning to convert to dry bottom ash handling at the CREC to comply with the ELGs, and has not documented any possible reason for needing additional time to plan, nor for why planning was slated to begin in June 2016 in the proposed schedule. DEF admits that compliance options are readily available.

- Duke Energy has publicly reported projected costs for ELG compliance at CREC Units 4 and 5 since at least 2014, which required conceptual or detailed engineering evaluations and studies in order to develop cost estimates. An additional 6 months for budget approval is unnecessary.

In fact, while DEF has long anticipated a "late 2018" compliance deadline,[47] DEF proposed almost five more years—to December 31, 2023—to reach compliance—without any justification for such a huge delay.[48] DEP should reject DEF's unsubstantiated and improper extension request.

As Dr. Sahu explains, it is clear that a November 1, 2018, compliance deadline for the BAT standard is readily achievable: most of the planning is finished, procurement should take little to no time and DEF admits construction takes 18 months.

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[45] 80 Fed. Reg. 21,311.

[46] Additionally, states can continue to enforce state regulations under their independent state enforcement authority.

[47] Exhibit 1.

[48] Response to RAI 2, Attachment 1

Dr. Sahu concludes that Units 4 and 5 can convert to dry bottom ash handling in approximately 27 to 30 months, instead of the 44 months projected by DEF, reaching compliance by August to November 2018 at the latest.

Indeed, EPA's rulemaking record and comments from the Utility Water Act Group ("UWAG")[49] show that, depending on the scope of the required conversions (a.k.a., retrofits) at a particular coal plant, industry itself projects that the total time needed for bottom ash system retrofits ranges from 27 to 36 months, from the start of conceptual engineering to final commissioning.[50]

At Duke Energy's own Mayo Plant in North Carolina, a wet-to-dry bottom ash handling system conversion was completed in under a year and a half.[51] At the South Carolina Electric & Gas Company Wateree plant, for example, conversion to a closed-loop bottom ash handling system was completed in two and a half years.[52] Conversion to a closed-loop bottom ash handling system was completed in two and a half years at the South Carolina Electric & Gas Company Wateree plant.[53] In 2010, the BL England Station retrofitted a recycle system on two coal burning units (one is 125-MW, the other is 155-MW) as well as a 170-MW oil-burning unit in less than two years from award of contract to operation of the new system.[54]

Delaying compliance with the zero discharge standard for bottom ash wastewater beyond November 1, 2018, is unnecessary and puts public and environmental health at risk. Bottom ash wastewaters are known to contain a number of toxic metals in both suspended and dissolved form, including arsenic, cadmium, chromium, copper, iron, lead, mercury, selenium, and zinc.[55] In one example of the public and environmental health threats posed by CCR waste, EPA estimates that reductions in arsenic loadings from the final ELGs will reduce cancer risks to humans that consume fish exposed to steam electric power plant discharges—such as those caught in Crystal Bay.[56] Against this backdrop, DEP has all the more reason to require CREC to comply with the zero discharge standard by the November 1, 2018, deadline.[57]

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[49] Duke Energy is a UWAG member.

[50] Utility Water Act Group, *Comments on EPA's Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (Sept. 30, 2013), Attach. 11: Retrofitting Dry Bottom Ash Handling.

[51] *See* DEF Progress, Inc., Mayo Steam Electric Generating Plant, Quarterly Progress Report (January – March 2015) ("Dry bottom ash handling system began construction on December 14, 2012. As of March 31, 2014, construction of this system was 100% complete.").

[52] DCN SE03779. Final Notes from Site Visit at South Carolina Electric & Gas Company's Wateree Station on January 24, 2013, *available at* http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OW-2009-0819-1917.

[53] *See* Final Notes from Site Visit at South Carolina Electric & Gas Company's Wateree Station on January 24, 2013, EPA-HQ-OW-2009-0819-1917, at 2. Check, from SELC comments, change text

[54] Dennis Del Vecchio and Robert G. Walsh, Wet to Dry Bottom Ash Disposal Conversion Project - BL England Station, Power-Gen, December 2011, February 2008 - February 2010.

[55] *See e.g.*, U.S. EPA, *Steam Electric Power Generating Point Source Category: Final Detailed Study Report*, EPA 821-R-09-008, 3-19 (Oct. 2009), (hereinafter "EPA Detailed Study"); U.S. EPA, *Development Document for Final Effluent Limitations Guidelines, New Source Performance Standards, and Pretreatment Standards for the Steam Electric Point Source Category*, Table V-33 (Nov. 1982).

[56] 80 Fed. Reg. 67,874 (Nov. 8, 2015).

[57] 80 Fed. Reg. at 67,840-41.

### B. The ELGs Apply to FGD Wastewater and FGMC Wastewater From Units 4 and 5, Which Discharge to Crystal Bay and the Gulf of Mexico via Hydrologically Connected Groundwater

Steam electric power plants must meet strict new standards in EPA's revised ELGs for contaminants in FGD wastewater—including arsenic, mercury, selenium, and nitrate/nitrite—and a zero discharge standard for FGMC wastewater. Because Unit 4 and 5's FGD and FGMC wastewaters discharge to waters of the United States, these waste streams must meet the standards in EPA's revised ELGs, and DEP must include permit limits in the renewed NPDES permit for CREC Units 4 and 5.

As Dr. Stewart explains in his enclosed report, contaminants from the unlined Percolation Ponds travel through the aquifer into Crystal Bay. FGD and FGMC wastewaters from Units 4 and 5 are thus discharged to the Percolation Ponds and absorbed into groundwater, as DEP is already aware.[58] The Percolation Ponds are unlined, in direct communication with the Upper Floridan aquifer, and connected to Crystal Bay and the Gulf of Mexico.[59] The Percolation Ponds recharge the shallow groundwater aquifer, which conveys pollutants into the seawater discharge canal, tidal wetlands, and Crystal Bay.[60]

The Percolation Ponds and groundwater are hydrologically connected to "waters of the United States"—that is, Crystal Bay and the Gulf of Mexico—and therefore, by discharging pollutants into the Percolation Ponds, DEF is discharging to waters of the United States *via* the Ponds and the groundwater. The Percolation Ponds and groundwater are conduits to waters of the United States. Discharging the FGD and FGMC wastewater to the Percolation Ponds puts these waste streams under the jurisdiction of the CWA, and the Units 4 and 5 NPDES Permit, because the wastewaters, and pollutants, migrate from the pond directly into Crystal Bay through an underground "conveyance" or "conduit."[61]

When groundwater is a conduit for pollutants, CWA liability may attach to a discharge to that groundwater.[62] "[I]t would hardly make sense for the CWA to encompass a polluter who discharges pollutants via a pipe running from the factory directly to the riverbank, but not a polluter who dumps the same pollutants into a man-made settling basin some distance short of the river and then allows the pollutants to seep into the river via the groundwater."[63] EPA has asserted that its authority under the CWA extends to hydrologically connected groundwater.[64]

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[58] See e.g., Duke Energy Florida, Inc., Application to Renew NPDES Permit for Crystal River Units 4 & 5, Permit No. FL0036366, January 12, 2016; RAI #2,

[59] Exhibit 1 at 9.

[60] *Id*.

[61] 33 U.S.C. § 1362(14).

[62] *See Haw. Wildlife Fund v. Cnty. of Maui*, 24 F. Supp. 3d 980, 996 (D. Haw. 2014).

[63] *N. Cal. Riverwatch v. Mercer Fraser Co.*, No. C-04-4620 SC, 2005 U.S. Dist. LEXIS 42997, *7-*8 (N.D. Cal. Sep. 1, 2005).

[64] 66 Fed. Reg. 2960, 3015 (Jan. 12, 2001); 73 Fed. Reg. 70,418, 70,420 (Nov. 20, 2008); 55 Fed. Reg. 47990, 47997 (col. 3) (Nov. 16, 1990)

The courts agree and have held, definitively, that the CWA covers groundwater that is hydrologically connected to waters of the United States. [65] Eleventh Circuit jurisprudence, governing Florida, also suggests that CWA jurisdiction extends to discharges like those to CREC Percolation Ponds.[66]

In sum, the FGD and FGMC wastewaters from Units 4 and 5 are discharged to surface waters *through* groundwater, and since the groundwater under the Percolation Ponds is directly hydrologically connected to surface water, discharges to the percolation ponds are a discharge to waters of the United States and must be regulated under the CWA. Therefore— just as DEP has included ELG limits for leachate that migrates through groundwater to the runoff collection system (see Section E below)—the ELGs apply to discharges of FGD and FGMC wastewaters and must be included in the revised NPDES permit.

### C. DEP Should Require Compliance with a Zero Discharge Standard for FGMC Wastewater No Later Than November 1, 2018

Under the ELGs, FGMC wastewater at CREC must be monitored and subject to new effluent limits. Effective immediately, this discharge is subject to a BPT TSS effluent limit of 100/30 mg/L (daily max./30 day avg.) and oil and grease effluent limit of 20/15 mg/L (daily max./30 day avg.) and after November 1, 2018, a zero discharge standard applies.[67]

As explained above in Section B, FGMC wastewater at the plant is discharged to waters of the United States—Crystal Bay and the Gulf of Mexico—through hydrologically connected groundwater and must be regulated under the ELGs. Although the FGMC wastewater combines with FGD wastewater at CREC Units 4 and 5, the zero discharge standard still applies: "Whenever flue gas mercury control wastewater is used in any other plant process or is sent to a treatment system at the plant, the resulting effluent must comply with the [zero] discharge limitation in this paragraph."[68]

The final permit therefore must include BPT limits for FGMC wastewater until a zero discharge BAT standard applies after November 1, 2018. Again, the revised ELGs apply starting

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[65] *See e.g., Waterkeeper Alliance, Inc. v. U.S. EPA*, 399 F.3d 486, 514-515 (2d Cir. 2005) (upholding EPA's requirements for the discharge of pollutants to surface water via groundwater to be regulated, "as necessary, on a case-by-case basis."); *Dague v. City of Burlington*, 935 F.2d 1343, 1347 & 1355 (2d Cir. 1991), rev'd in part on other grounds, 505 U.S. 557 (1992) (finding the city liable for allowing groundwater to flow through a landfill and into a pond and wetlands that were waters of the United States); *U.S. Steel Corp. v. Train*, 556 F.2d 822, 852 (7th Cir. 1977) (the CWA "authorizes EPA to regulate the disposal of pollutants into deep wells, at least when the regulation is undertaken in conjunction with limitations on the permittee's discharges into surface waters"), overruled on other grounds by City of West Chicago v. U.S. Nuclear Regulatory Comm'n, 701 F.2d 632, 644 (7th Cir. 1983).

[66] *U.S. v Banks,* 115 F.3d 916 (11th Cir. 1997) (District Court not clearly erroneous in deciding that wetlands are adjacent to a waterbody because of a hydrological connection where a hydrological connection is largely through groundwater and a surface flow only appears during storms); *United States v. Tilton*, 705 F.2d 429, 431 (11th Cir. 1983) (a hydrological connection exists when flowing mainly through groundwater, even where surface water only connects at extreme high tides such as in hurricanes).

[67] 40 C.F.R. § 423.13(l).

[68] 40 C.F.R. § 423.13 (i)(1)(i).

November 1, 2018, or "as soon as possible" based on a well-documented justification of a later date and DEP's consideration of certain factors enumerated in the final rule.

Until the zero discharge BAT standard is met, DEP should incorporate monitoring requirements for the FGMC wastewater into revised NPDES permit and Conditions of Certification ("COC"). To meet both monthly average and daily maximum limits, quarterly monitoring is wholly inadequate. A daily maximum limit cannot be effectively enforced with monitoring conducted on a monthly basis. Monitoring frequency should be daily in order to effectively enforce these limits to meet both monthly average and daily maximum limits for TSS and oil and grease. Sampling should be performed prior to mixing with the FGD wastewater.

### D. DEP Must Require Compliance with New Limits on FGD Wastewater Pollutants No Later Than December 2018

DEP must include effluent limits for FGD wastewater in the revised NPDES permit. Effective immediately, this discharge is subject to a BPT TSS effluent limit of 100/30 mg/L (daily max./30 day avg.) and oil and grease effluent limit of 20/15 mg/L (daily max./30 day avg.).[69] After November 1, 2018, DEF must meet strict new BAT effluent limits for arsenic, mercury, selenium, and nitrate/nitrite for the untreated FGD wastewater that is discharged to the Percolation Pond and waters of the United States. [70] DEP must incorporate the ELGs for FGD wastewater into the revised NPDES permit, immediately apply BPT and monitoring requirements, and ensure that DEF meets the BAT standard by December 2018 or as soon as possible.

The revised ELGs set daily maximum and monthly average limits on arsenic, mercury, selenium, and nitrate/nitrite in discharges of FGD wastewater.[71] These limits are based on technology using chemical precipitation and an anoxic/anaerobic fixed-film biological treatment system.[72] The chemical precipitation achieves most of the mercury and arsenic reductions, while the biological reactor removes selenium and nitrogen and other dissolved heavy metals.

DEF is currently completing "construction of a new wastewater treatment system that will use chemical precipitation and a bioreactor" for treatment of FGD wastewater from Units 4 and 5 and will complete the project by December 2018.[73] DEF "evaluated several treatment options…and selected a strategy that uses a physical/chemical treatment system with a bioreactor treatment system to treat Flue Gas Desulfurization ("FGD") blowdown wastewater with discharge to surface water or percolation ponds."[74]

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[69] 40 C.F.R. § 423.12(b)(11).

[70] 40 C.F.R. § 423.13(g)(1)(i).

[71] *Id.*

[72] 80 Fed. Reg. at 67,850.

[73] Third Amendment to Consent Order, OGC No. 09-3463D, at ¶4; *see also* Duke Energy Florida, Inc., Application to Renew NPDES Permit for Crystal River Units 4 & 5, Permit No. FL0036366, January 12, 2016 at Attachment 4 p.2.

[74] Duke Energy Florida's Petition for Approval of Environmental Cost Recovery True-Up and 2017 Environmental Cost Recovery Clause Factors, Docket No. 160007-EI, Environmental Cost Recovery Clause Form 42-SP at 7 (August 31, 2016). 07181-16, PSC ECRC filing

In November 2011, DEP entered into a Consent Order[75] with the former CREC owner Progress Energy Florida ("PEF") following exceedances of groundwater standards for gross alpha standard, radium 226/228, and arsenic. In the third amendment to the Consent Order in March 2016, DEF agreed to complete construction of a new wastewater treatment system using chemical precipitation and a bioreactor for treating FGD wastewater by December 31, 2018.[76] Within 30 days following completion of the treatment system, DEF will remove all accumulated CCR from the FGD Blowdown Ponds.[77]

The Consent Order constitutes an additional and separate legal obligation (from the ELGs) to complete construction of the FGD wastewater treatment system by December 2018. Nevertheless, DEP is required to include the new effluent limits in the revised NPDES and to ensure that DEF's new treatment system meets the federal BAT standards for arsenic, mercury, selenium, and nitrate/nitrite—which are not specified in the Consent Order— "as soon as possible beginning November 1, 2018."

It is imperative that DEP ensure that DEF meets this timeline and its legal obligations and begins operating the new system and treating toxic FGD wastewater by December 2018 at the latest. DEF is on its way to meeting these new standards and anticipated[78] meeting the revised ELG requirements for FGD wastewater, in addition to its Consent Order obligations.

Attachment H— Groundwater Monitoring, Operation, and Maintenance Requirements—of CREC COC authorizes DEF to discharge a variety of wastewaters, including FGD wastewater from Units 4 and 5, to the Percolation Ponds.[79] Quarterly reporting is required for FGD wastewater flows at sampling point EFF-2, the discharge pipe into the Percolation Ponds.[80] However, no limits are imposed on the FGD wastewater flows. DEP must incorporate monitoring requirements for arsenic, mercury, selenium, nitrate/nitrite, and TSS into the revised NPDES permit, as well as the COC. Monitoring should be required twice weekly. For final limits, where both monthly average and daily maximum limits are set, quarterly monitoring is wholly inadequate. A daily maximum limit cannot be effectively enforced with monitoring conducted on a monthly basis. Monitoring frequency should be daily to effectively enforce these limits.

### E. Combustion Residual Leachate from the Ash Landfill is Subject to Technology and Water Quality Based Effluent Limits

[75] Consent Order, File No. 09-34652, Permit No. FLA016960, OGC File No. 09-3463 (Nov. 2011).

[76] Third Amendment to Consent Order, OGC No. 09-3463D ¶4 (March 22, 2016).

[77] Third Amendment to Consent Order, OGC No. 09-3463D ¶5 (March 22, 2016).

[78] Duke Energy Florida, Inc., Application to Renew NPDES Permit for Crystal River Units 4 & 5, Permit No. FL0036366, January 12, 2016 at Attachment 4 p. 1.

[79] Florida Department of Environmental Protection, Conditions of Certification: Duke energy Florida Crystal River Energy Complex, PA 77-09R, Attachment H, April 29, 2016.

[80] *Id.*

Combustion residual leachate ("CRL") is now a separately regulated waste stream under the revised ELGs. Leachate from coal ash and other CCRs that are discharged to waters of the United States must be included in the NPDES permit and subject BPT limits in TSS and oil and grease, as well as technology and water quality based effluent limits.

CREC has no leachate collection system for the unlined Ash Landfill, and instead of being discharged to surface waters through a permitted outfall, most leachate seeps into the groundwater, as discussed further below in Section G and in Exhibit 1. The "majority of the coal combustion residual leachate is discharged to ground water"[81] as "by design, the leachate generated in the [Ash Landfill] infiltrates to the groundwater underneath the [Ash Landfill]."[82] EPA correctly notes that "[u]nlined impoundments and landfills usually do not collect leachate, which would allow the leachate to potentially migrate to nearby ground waters, drinking water wells, or surface waters."[83]

Since groundwater beneath the Ash Landfill is hydrologically connected to surface waters, CRL wastewater discharging from the Ash Landfill to groundwater constitutes a discharge to waters of the United States. DEF's groundwater modeling shows that CRL from the unlined Ash Landfill at times flows towards portions of the runoff ditch at Units 4 and 5.[84] Following, DEP has incorporated new BPT limitations for oil and grease and TSS in the Draft Permit at monitoring well TWI-1R, in order to differentiate CRL from storm water collected in the runoff collection system.[85]

Additionally, as described in Dr. Stewart's assessment, groundwater under the Ash Landfill "flows toward the west-southwest and discharges into the seawater discharge canal, and ultimately into Crystal Bay."[86] Indeed, monitoring data shows that toxic pollutants from CCR leachate[87]—including arsenic, boron, manganese, molybdenum, selenium, and sulfate—are migrating from groundwater beneath the Ash Landfill and flowing to Crystal Bay.

Like CRL leachate that migrates through groundwater to the runoff collection system, and for the reasons articulated above in Section B for FGD and FGMC wastewater, the discharges of leachate to groundwater beneath the Ash Landfill and into the seawater discharge canal, and then Crystal Bay, are also subject to the CWA. The CWA prohibits the discharge of pollutants from a point source" — "any discernible, confined and discrete conveyance, including but not limited to any pipe, ditch, channel, tunnel, conduit, well, discrete fissure, [or] container … from which pollutants are or may be discharged"[88]—to waters of the United States, except as

[81] Draft Permit at 12.

[82] RAI #2 p. 9.

[83] 80 Fed. Reg. at 67,847.

[84] RAI #2.

[85] Draft Permit p. 12.

[86] Exhibit 1 at 6.

[87] *See* TDD Table 6-13. Pollutants of Concern – Combustion Residual Leachate.

[88] 33 U.S.C. § 1362(4); *see also, e.g.*, *Dague v. City of Burlington*, 935 F.2d 1343, 1347 & 1355 (2d Cir. 1991), rev'd in part on other grounds, 505 U.S. 557 (1992) (finding the city liable for allowing groundwater to flow through a landfill and into a pond and wetlands that were waters of the United States).

in compliance with a NPDES permit.[89] Thus, CRL from the Ash Landfill that is discharged to Crystal Bay via groundwater must be also regulated in the revised NPDES permit, and meet new BPT requirements as well as other water quality based requirements.

DEP must also conduct a reasonable potential analysis and determine whether additional water quality-based effluent limits ("WQBELs") are required for the CRL from the Ash Landfill, in order to protection of aquatic life and human health. After application of the most stringent treatment technologies available under the BAT standard, if a discharge causes or contributes, or has the reasonable potential to cause or contribute to a violation of water quality standards, the permitting agency must include any limits in the NPDES permits necessary to ensure that water quality standards (both narrative and numeric) are maintained and not violated.[90] EPA regulations require permitting authorities to characterize all effluents in order to determine the need for WQBELs in the permit.[91]

Ultimately, as explained below, the only way to prevent further contamination of ground and surface waters from the Ash Landfill is likely to remove all accumulated CCR from the Ash Landfill and decontaminate the site.

### F. There is No Barrier Between the Unlined Ash Landfill and Percolation Ponds and the Underlying Groundwater, Allowing Toxic Coal Ash Contaminants to Pollute the Floridan Aquifer and Crystal Bay

The Ash Landfill and Percolation Ponds are unlined, with no protective barrier between toxic coal ash and wastewater and the underlying groundwater. Additionally, there is no intermediate confining unit between the highly permeable soils onsite and the Floridan aquifer, signifying an elevated risk of groundwater contamination. As a result, the toxic CCR waste and wastewaters that are disposed of in the unlined Ash Landfill and Percolation Ponds are in direct hydraulic connection with the Floridan aquifer and with groundwater draining into Crystal Bay.

Sierra Club retained one of the state's preeminent hydrogeologists, Dr. Mark Stewart, to evaluate conditions at CREC and application of the technical requirements in the CCR Rule. As explained in his accompanying report, Exhibit 1, the Floridan aquifer at CREC is unconfined and in direct hydraulic connection with the water table. The area is a recharge zone for the shallow aquifer. The underlying Floridan aquifer, one of the largest and most productive sources of fresh groundwater in the world,[92] lies within a few feet of the land surface. Thus, the unlined Ash Landfill sits less than 5 feet from the water table in the Floridan aquifer.[93] Because the Ash

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[89] Section 301(a) of the Clean Water Act, 33 U.S.C. § 1311(a).

[90] *See* 40 C.F.R. § 122.44(d). "[T]he permit must contain effluent limits" for any pollutant for which the state determines there is a reasonable potential for the pollutant to cause or contribute to a violation. *Id.* 40 C.F.R. § 122.44(d)(1)(iii); *see also Am. Paper Inst. v. EPA*, 996 F.2d 346, 350 (D.C. Cir. 1993); *Waterkeeper Alliance, Inc. v. EPA*, 399 F.3d 486, 502 (2d. Cir. 2005).

[91] 40 CFR § 122.44(d).

[92] Exhibit 1 at 5 (citing Miller 1986).

[93] Exhibit 1..

Landfill and Percolation Pond are unlined, and because of the shallow, unconfined aquifer at CREC, these two facilities are in direct connection with underlying groundwater and Floridan aquifer.[94]

To protect groundwater from contamination from CCR wastes, the CCR Rule prescribes (a) a distance of at least 5 feet between the base of facilities containing CCR and the uppermost aquifer, or (b) other measures that eliminate the hydraulic connection between the base and the uppermost aquifer—safety standards that the Ash Landfill, a CCR landfill[95], does not meet. CCR surface impoundments and new or expanded landfills must be constructed with a base that is located no less than five feet above the upper limit of the uppermost aquifer, or must demonstrate that there will not be an intermittent, recurring, or sustained hydraulic connection between any portion of the base of the CCR unit and the uppermost aquifer due to normal fluctuations in groundwater elevations (including the seasonal high water table).[96] While the Ash Landfill is exempt from this common-sense restriction as an "existing landfill"—although any future expansions and new facilities would not be—and the Percolation Ponds do not fall under the CCR Rule,[97] it is clear why these safety standards have been promulgated and that the close proximity of the unlined facilities to the aquifer are contaminating the Floridan aquifer and Crystal Bay.

Groundwater monitoring data showing contamination at the unlined Ash Landfill and Percolation Pond are further evidence of a hydraulic connection between the unlined Ash Landfill and the underlying aquifer. Groundwater pollution at the site, as described next in Section G, indicates that the Ash Landfill is in direct hydraulic connection with a highly permeable fracture zone in the Upper Floridan aquifer and that toxic contaminants are leaching from the Ash Landfill, as well as the Percolation Ponds, into the groundwater beneath, and moving towards Crystal Bay.

### G. The Unlined Ash Landfill and Percolation Ponds Are Leaching Coal Ash Contaminants Into Groundwater and Crystal Bay

Groundwater contamination from toxic coal ash contaminants has been repeatedly documented at wells downgradient from the Ash Landfill. In fact, data from DEF's own groundwater monitoring wells downgradient of the unlined Ash Landfill have consistently shown contamination at levels that far exceed background levels and federal, state, and permit limits.[98] This threatens the Floridan aquifer and waters of Crystal Bay and the Gulf of Mexico.

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[94] Exhibit 1.

[95] The CREC Ash Landfill is an "existing CCR landfill," subject to regulation under the CCR Rule. It is an "area of land or an excavation that receives CCR and which is not a surface impoundment, an underground injection well, a salt dome formation, a salt bed formation, an underground or surface mine, or a cave" that received CCR both before and after October 19, 2015. 40 C.F.R. § 257.53.

[96] 40 C.F.R. § 257.60.

[97] *See* 40 C.F.R. § 257.53.

[98] *See* Florida Department of Environmental Protection, Conditions of Certification: Duke energy Florida Crystal River Energy Complex, PA 77-09R, Attachment H, April 29, 2016; 40 C.F.R. §§ 141.62 and 141.66; Fla. Admin. Code. R. 62-520.420 (2016).

Wells downgradient from the unlined Ash Landfill have regularly exceeded regulatory for toxic coal ash contaminants—arsenic, boron, manganese, molybdenum, selenium, sulfate, and thallium—since 2012.[99] Levels of arsenic, boron, manganese, molybdenum, and sulfate, in particular, have trended upward since that time and continue to exceed protective groundwater standards. Concentration of arsenic at wells downgradient from the Ash Landfill are *five times* higher than at wells upgradient from the facility.

The presence of these common coal ash contaminants at monitoring wells downgradient from the unlined Ash Landfill, in combination with groundwater flow direction at the site and high permeability conduits, is, in Dr. Stewart's view, "overwhelming evidence" that contaminants have leached from the CCR materials have reached the water table and the Floridan aquifer.[100]

Contaminants from the unlined Percolation Ponds are also being absorbed to groundwater, which flows towards the Gulf of Mexico. Arsenic in groundwater near the ponds has been associated with the FGD wastewater that is discharged to the ponds, thus driving the installation of the new FGD wastewater treatment system.[101]

DEP is currently investigating groundwater contamination from the Ash Landfill.[102]A July 2015 DEP inspection noted adverse impacts to water quality from the operation of the Ash Landfill and that "[g]roundwater trending data for background and intermediate groundwater monitoring wells indicates impacts to groundwater, specifically for Arsenic, Boron, Manganese, and Molybdenum."[103] Steps have been taken to address contamination at the Percolation Ponds under CREC's November 2011 Consent Order.[104]

While alarming, the groundwater contamination at the Ash Landfill is not at all surprising given that the facility is unlined and lacks a protective barrier, that the CCR materials within it are in direct hydraulic connection with the Floridan aquifer, and given the shallow, unconfined aquifer. In fact, DEP predicted that serious groundwater contamination would occur from the operation of the Ash Landfill:

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[99] Exhibit 1; Florida Department of Environmental Protection ("DEP"), 2015. Groundwater Review, WAVS UD 97667, Amaury Betancourt, Nov. 30, 2015; Florida Department of Environmental Protection ("DEP"), 2016. FDEP Automated Data Evaluation. Duke Energy (FKA PEF) Crystal River Energy Complex. February 1, 2016

[100] Exhibit 1 at 9.

[101] Geosyntec, 2013. Arsenic and radionuclide plan of study addendum, Crystal River Energy Complex, Crystal River, Florida, Rpt. No. FR2061/03, April 2013; Consent Order No. 09-34652. This groundwater contamination (under NPDES Permit No. FLA016960) remains unresolved, five years later. Further review of arsenic contamination is required, but not until December 31, 2017, and a plan to evaluate arsenic impacts on downgradient surface waters is required by June 30, 2018. Full compliance with arsenic limits is required by December 31, 2019. DEP should reopen NPDES Permit No. FL0036366 pending results of the required studies and strictly enforce corrective action to clean up groundwater contamination at the CREC.

[102] Email from Amaury Betancourt, P.E., Florida Department of Environmental Protection to Mr. Bob Stafford, Duke Energy, February 15, 2016.

[103] *See* Florida Department of Environmental Protection Inspection Report, July 28, 2015.

[104] Consent Order No. 09-34652.

> 'The highly transmissive characteristic of the shallow aquifer zone should provide and environment for the rapid dispersion of leachate which might infiltrate from the ash disposal site into the shallow aquifer.'…
>
> [Former CREC owner and applicant] FPC's application demonstrates succinctly that point at which such economico-politico maneuvering leads to very serious consequences when 1000 tons per day of truly hazardous wastes, generated each day that Units 4 and 5 would operate (for 30 years or more), would be dumped, for all practical purposes into the Floridan aquifer. …
>
> Thus leachate from the proposed ash disposal area can (on the basis of the data implicating the existing dump as a source of ground water pollution) be expected to flow into the Floridan aquifer at such rates that a number of WQ standards would be violated short term. (Perhaps many more violations would occur long term as pollutant activities build up on the ecosystem). Should the leachate move through existing or through induced Karst structures into deeper zones of the aquifer where hydraulic head may be reduced (or only appear to equal or even "slightly exceed" shallow depth heads by reason of statistically inadequate data or by greater density due to higher salinity or loading of leachate itself), then so much the worse for the Floridan aquifer.[105]

As Dr. Stewart explains in his assessment, there is no adequate liner or natural barrier to prevent CCR constituents from seeping out of the Ash Landfill into the underlying aquifer and eventually into Crystal Bay and the Gulf of Mexico. Until DEF removes the existing CCR material from the Ash Landfill and decontaminates the site, it will continue to leach toxic CCR contaminants into ground and surface waters. Furthermore, as explained next in Section H, as the CCR Rule requires corrective action to prevent further releases of CCR constituents into the environment, the CCR that have accumulated in the Ash Landfill should be removed and the site decontaminated.

## H. The CCR Rule Requires Corrective Action to Address the Groundwater Contamination from the Unlined Ash Landfill

Where coal ash contaminants from CCR units have leached into the environment in excess of federal regulatory limits, the CCR Rule requires corrective action to prevent further releases. Monitoring data at CREC show levels of arsenic, molybdenum, and thallium at wells downgradient from the Ash Landfill exceeding federal groundwater protection standards and triggering clean up requirements for DEF.

To ensure compliance with the CCR Rule and to prevent further releases of CCR constituents into Floridan waters, DEP should require DEF to immediately take action to remove the CCR that has accumulated and decontaminate the Ash Landfill.

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[105] Ash Landfill Interoffice Memo at 3, 4, 7 (emphasis original).

Owners and operators of CCR units must install a system of groundwater monitoring wells and establish a monitoring program to detect the presence of hazardous constituents and other monitoring parameters from covered CCR units.[106] Where groundwater monitoring shows exceedances of groundwater protection standards[107] for Appendix IV constituents—including arsenic, molybdenum, and thallium—the owner or operator must initiate corrective action, retrofit, and/or close the unit.[108]

For these Appendix IV CCR constituents of concern, "immediately upon detection of a release from a CCR unit" the owner/operator "must initiate an assessment of corrective measures to prevent further releases, to remediate any releases and to restore affected area [*sic*] to original conditions."[109] Then, the owner/operator must select and implement remedies certified by a qualified engineer to be consistent with the standards set out in the CCR Rule. Specifically, the "remedies must"

(1) Be protective of human health and the environment;

(2) Attain the groundwater protection standard as specified pursuant to §257.95(h);

(3) Control the source(s) of releases so as to reduce or eliminate, to the maximum extent feasible, further releases of constituents in Appendix IV to this part into the environment;

(4) Remove from the environment as much of the contaminated material that was released from the CCR unit as is feasible, taking into account factors such as avoiding inappropriate disturbance of sensitive ecosystems; and

(5) Comply with standards for management of wastes as specified in §257.98(d).[110]

The requirement to "immediately" initiate an assessment of corrective measures is triggered by the detection of a release at any time after the effective date of the CCR Rule, October 19, 2015. This includes but is not limited to detection pursuant to a pre-existing groundwater monitoring program and/or the enhanced groundwater monitoring program that is required by the CCR Rule. The "zone of discharge" exemption to water quality standards under Florida law do not apply; "the point of compliance is the waste boundary" of CCR units.[111]

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[106] 40 C.F.R. § 257.94(a).

[107] Groundwater protection standards for Appendix IV constituents detected are based on either (1) the maximum contaminant limit ("MCL") established at 40 C.F.R. §§ 141.62 and 141.66; or (2) the background concentration for the constituent, where there is no MCL or where the background concentrations are higher than the MCL. 40 C.F.R. § 257.95(h).

[108] 40 C.F.R. §§ 257.95(g)(5); 257.101(a).

[109] 40 C.F.R. § 257.96.

[110] 40 C.F.R. § 257.97.

[111] EPA, Comment Summary and Response Document, Docket #EPA-HQ-RCRA-2009-0640, Volume 9: Groundwater and Corrective Action at 47; *see also* 40 C.F.R. § 257.53 (defining "waste boundary"); § 257.91 (requiring groundwater

Groundwater monitoring data for the Ash Landfill following October 19, 2015, show exceedances of groundwater protection standards[112] for arsenic, molybdenum, and thallium, all Appendix IV constituents, at wells downgradient from the Ash Landfill, an existing CCR landfill under the CCR Rule. With this knowledge, DEF is obligated to immediately begin an assessment of corrective measures and implementation of appropriate remedies. To meet the corrective action requirements in the CCR Rule, and to "eliminate, to the maximum extent feasible, further releases of constituents," Dr. Stewart recommends ceasing onsite CCR storage and disposal, which can exacerbate the ongoing contamination problem. The only way to effectively prevent such continued releases from the Ash Landfill is to remove the CCR that has accumulated and decontaminate the site.

## I. CREC is Located in Sinkhole-Prone Karst Terrain, Putting Ground and Surface Water Resources at (Further) Risk and Requiring Compliance with the CCR Rule's Location Restriction for Unstable Areas

Coastal Citrus County is an active karst area, marked by limestone and under the influence of sinkholes. As detailed in Dr. Stewart's assessment, the onsite and local hydrogeological conditions make CREC an inherently unstable area, under the influence of multiple sinkholes, including 24 reported sinkholes within 5 miles.

Most sinkholes in the region are cover subsidence sinkholes, whereby loose surficial sands migrate downward into solution cavities in the limestone and which can occur either slowly or abruptly. Because the Floridan aquifer is at or near land surface at CREC, sinkholes of any size would allow the movement materials under the CCR landfill into the voids, depressions, and caverns underneath, allowing materials, such as CCR waste in the Ash Landfill, to come into direct contact with the limestones and groundwater of the Floridan aquifer.

DEP is aware of the unstable nature of CREC and accompanying risks to ground and surface waters from the sinkhole-marked terrain. For example, in a staff analysis, DEP described CREC as "characterized by sinkholes and flowing springs" and concluded that:

> Due to the nature of the geologic formation under this area there will always be a chance of a sinkhole forming under the plant or its related facilities….
>
> It is not apparent that FPC has adequately considered the impact that future solution cavities may have on the operation of the coal piles, the ash disposal landfill, and related ditches. Acidic leachates can hasten formulation of solution cavities which could result in

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monitoring at the waste boundary); § 257.94 (requiring enhanced groundwater monitoring for detected increases in certain CCR constituents at the waste boundary).

[112] There is no MCL for molybdenum; instead the groundwater protection standard is the background level. A background well (MWB-30R) at the CREC shows molybdenum levels of 18 mg/L. In contrast, the intermediate monitoring well and temporary monitoring wells around the Ash Landfill have exhibited molybdenum levels ranging from 44.5 – 135 mg/L—*seven times higher* than background levels.

subsidence of the land surface and allow for rapid contamination of ground and surface waters.[113]

Later, DEP rightly questioned the sensibility of locating a coal ash landfill at CREC:

> Already a piece of heavy machinery has fallen into a sinkhole on site which collapsed beneath the weight of the machine. What would be the effect of the much greater loading due to 60 or more feet of stacked ash materials spread over some 100 acres? Even if a massive collapse did not take place, allowing direct introduction of the wastes into the aquifer, [studies] clearly indicate the high permeability of the upper …[114]

There is copious evidence, as documented in Dr. Stewart's assessment, DEP records[115], and other sources, showing sinkhole activity at and around CREC. There can be no question that CREC is in unstable, sinkhole terrain and that, as described next in Sections J and K, CREC cannot meet CCR Rule's safety standards for onsite storage and disposal.

## J. After April 19, 2019, the CCR Rule Prohibits Adding—Even On a Temporary Basis—CCR To CCR Units in Unstable Areas, Such As Florida's Karst Terrain, Unless a Qualified Engineer Can Certify That it is Safe To Do So

After April 19, 2019, the CCR Rule prohibits adding, even on a temporary basis, CCR to CCR units in unstable areas, such as Florida's karst terrain, unless a qualified engineer can certify that it is safe to do so by October 17, 2018.[116] Specifically, this is a certification "that recognized and generally accepted good engineering practices have been incorporated into the design of the CCR unit to ensure that the integrity of the structural components of the CCR unit will not be disrupted."[117] This location restriction applies to all existing and new CCR units.

EPA defines unstable areas as:

> a location that is susceptible to natural or human-induced events or forces capable of impairing the integrity, including structural components of some or all of the CCR unit that are responsible for preventing releases from such unit. Unstable areas can include poor foundation conditions, areas susceptible to mass movements, and karst terrains.[118]

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[113] "1978 Staff Analysis, at 44, (STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL REGULATION, ELECTRIC POWER PLANT SITE CERTIFICATION REVIEW FOR FLORIDA POWER CORPORATION CRYSTAL RIVER UNITS 4 AND 5, CASE NO. PA 77-09, STAFF ANALYSIS. September 15, 1978) (emphasis added).

[114] Ash Landfill Interoffice Memo at 4.

[115] Florida Department of Environmental Protection, Conditions of Certification: Duke energy Florida Crystal River Energy Complex, PA 77-09R, Attachment H, April 29, 2016;; Ash Landfill Interoffice Memo; 1978 Staff Analysis; Terry Witt, Citrus County Chronicle, July 23, 2007 and July 30, 2007 articles, *in* "Proposed Haul Road Letter"; FGD Blowdown bond 2010 report.

[116] 40 C.F.R. §§ 257.101(b)(1) and 257.101(d)(1).

[117] 40 C.F.R. § 257.64(a).

[118] 40 C.F.R. § 257.53.

"Structural components" are defined as:

> liners, leachate collection and removal systems, final covers, run-on and run-off systems, inflow design flood control systems, and any other component used in the construction and operation of the CCR unit that is necessary to ensure the integrity of the unit and that the contents of the unit are not released into the environment."[119]

In the final CCR Rule, EPA enumerates safety factors that should be addressed in the certification of CCR units in Florida's karst terrain:

> For areas where the solution-weathered limestone is close to the surface (e.g., Florida) recognized and generally accepted good engineering practices dictate that there must be no conduits beneath the CCR unit that allow piping of groundwater into the karst aquifer, or shallow caves that could cause sudden collapse of the unit foundation. …
>
> Karst hydrogeology is complex, since contaminant flows can occur along paths and networks that are discreet and tortuous, and groundwater monitoring wells must be capable of detecting any contaminants released from the CCR unit into the karst aquifer. …
>
> Therefore, the owner or operator will need to ensure, with verification by a qualified professional engineer, that monitoring wells installed in accordance with § 257.91 will intercept these pathways. Verification will usually necessitate the use of tracers to track groundwater flow towards offsite seeps or springs from the uppermost aquifer beneath the facility. Any engineered solution employed to mitigate weak ground strength in karst areas must be able to prevent the kind of foundation collapse and settlement that could lead to sudden release to the environment of CCR with its toxic constituents and associated leachate. …
>
> However, such engineered solutions are complex and costly, and the best protection is not to site CCR landfills and surface impoundments in karst areas.[120]

In short, this safety certification is a tall order in Florida's karst terrain. Elsewhere in the rulemaking docket, EPA noted that it might even be "impossible" to obtain the safety certification for a CCR unit that has already been constructed without adequate safeguards.[121]

These safety standards were not incorporated into the design of the Ash Landfill when it was built, as discussed in Dr. Stewart's assessment. The Ash Landfill does not have structural reinforcements nor a liner that could help prevent movement of CCR materials into the

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[119] *Id.*

[120] 80 Fed. Reg. 21,368 (emphasis added).

[121] U.S. EPA, Comment Summary and Response Document, Volume 4: Location Restrictions, Docket # EPA-HQ-RCRA-2009-0640, December 2014, *available at* http://goo.gl/QVAXRi.

Floridan aquifer. Dr. Stewart explains that certain factors at the Ash Landfill even increase the risk of limestone dissolution and sudden collapse, such as including having no impermeable liner; having no cover to exclude precipitation from the exposed CCR waste; and CCR accumulating and increasing the static load on the underlying, unstable soils.

Moreover, the Ash Landfill cannot effectively, nor economically, be retrofitted using existing technologies to meet the CCR Rule's safety standards: it would be nearly impossible to ensure that all conduits, voids, and caves beneath the Ash Landfill were had been detected and intercepted. Attempting a retrofit of the Ash Landfill now could even trigger a sinkhole collapse.

CREC FGD Blowdown Ponds and Gypsum Storage Pad also lie on unstable karst terrain and a qualified professional engineer must make a demonstration showing "that recognized and generally accepted good engineering practices have been incorporated" into the design of these units by October 17, 2018 in order for them to continue operation. Although these units are at least lined, providing some measure of protection unlike the Ash Landfill, if a sinkhole were to rupture the liners or pipes at the FGD Blowdown Ponds, for example, the CCR wastes would be released into the Floridan aquifer, and flow into the seawater discharge canal, tidal wetlands, and Crystal Bay.

DEF reports that a preliminary assessment of the stability at the Ash Landfill has been performed and that the "preliminary conclusion is no karst remediation will be required."[122] This conclusion seems remarkable given the geological characteristics and history of the region and CREC site, as encapsulated above in Section I and in Dr. Stewart's review. Regardless of this conclusion, however a thorough evaluation must still be completed under the CCR Rule.

The CCR Rule location restriction and safety factors are designed to protect public waters from the risks of sinkhole and unstable terrain. To comply with federal regulations and protect the Floridan aquifer and waters of Crystal Bay, DEP must ensure that DEF completes the required engineering certifications. Because CREC's CCR units cannot be certified as safe under the CCR Rule, DEF will have to change its current practices of onsite CCR storage and disposal by the April 19, 2019 deadline in the CCR Rule.

### K. DEP Should Extend The Proposed Schedule for Permit Issuance To Allow For Meaningful Consideration of Public Comments

Finally, we urge DEP to revise its own proposed schedule for permit issuance to allow for meaningful consideration of and response to public comments. Under the proposed schedule,[123] DEP would submit the proposed permit to EPA on September 30th, only *one day* after the close of the public comment period on September 29, 2016. This plainly is not enough time for the Department to review let alone meaningfully consider and respond to all comments

[122] Duke Energy Florida's Petition for Approval of Environmental Cost Recovery True-Up and 2017 Environmental Cost Recovery Clause Factors, Docket No. 160007-EI (August 31, 2016). Recent PSC filing – 07181-16

[123] Draft Permit at 14.

in writing.[124] As we explained in our February 29, 2016, letter, due to the importance of the water impacts and protections at issue in this permit renewal, DEP should go above and beyond its routine public participation practices, not truncate them.

## CONCLUSION

For all the foregoing reasons, we respectfully ask that, in issuing Crystal River Unit 4 and 5's renewed NPDES permit, DEP:

1. Set a technology-based zero discharge standard for bottom ash wastewater and require compliance with the standard no later than November 1, 2018;

2. Set a technology-based zero discharge standard for FGMC wastewater and require compliance with the standard no later than November 1, 2018;

3. Set technology-based limits on arsenic, mercury, selenium and nitrate/nitrite in FGD wastewater and require compliance with the standard no later than December 2018;

4. Establish technology-based BPT effluent limits and daily monitoring requirements for FGD and FGMC wastewater flows, effective immediately;

5. Apply BPT limits to discharges of CRL from the Ash Landfill to the runoff collection system and to Crystal Bay, and conduct a reasonable potential analysis to determine whether WQBELs are needed for greater protection;

6. Require clean up and corrective action, as mandated by the CCR Rule, to swiftly address ongoing groundwater contamination from the unlined Ash Landfill and to take all measures necessary to protect against further leaching of toxic metals into ground and surface waters including, retrofitting or closing the unit; and

7. Require compliance with the CCR Rule's prohibition on siting CCR units in unstable areas, so as to further protect ground and surface waters.

Timing is critical: To meet the deadlines for implementing ground and surface water protections—which also protect the public use of those waters—DEF will have to undertake changes to coal operations at CREC Units 4 and 5. DEF must not delay, or be excused by DEP through extensions or deferrals to future permit renewal cycles, for which there is no justification let alone a well-documented one in this permitting record.

Thank you for your consideration.

Sincerely,

[124] Draft Permit at 15.

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# EXHIBIT 1

# Preparing for the U.S. Environmental Protection Agency's Coal Combustion Residuals Rule: Technical Assessment of Hydrogeologic Conditions and Groundwater Contamination at the Crystal River Energy Complex

August 28, 2016

By Mark Stewart, PhD, PG

## 1. EXECUTIVE SUMMARY

The Crystal River Energy Complex ("CREC") is located on unstable karst terrain, and the primary facility used for the storage and disposal of coal combustion residuals ("CCR") at CREC, the Ash Landfill, exhibits increasing contamination from toxic heavy metals associated with CCR waste. CCR disposal and storage at CREC puts local water resources at risk and fails to meet the new safety standards by the U.S. Environmental Protection Agency ("EPA") in December 2014 ("the CCR Rule") for several reasons:

- CREC is located in one of the country's most unstable areas, in karst terrain, and is under the influence of multiple sinkholes, including 24 reported sinkholes within 5 miles of CREC.

- The risk of limestone dissolution and sudden collapse beneath CREC's Ash Landfill is increased by many factors, including (a) having no impermeable liner; (b) having no cover to exclude precipitation from the exposed ash waste; and (c) CCR accumulating at the Ash Landfill increasing the static load on the underlying, unstable soils and rock.

- To assure the safety of CCR storage and disposal in such unstable areas, EPA's CCR Rule requires the detection and interception of (a) all of the possible conduits that allow piping of groundwater into underlying karst aquifers; (b) all of the possible shallow caves that could cause a sudden foundation collapse; and (c) all of the possible pathways for CCR constituents to be released from CCR storage and disposal facilities into karst aquifers. Consulting reports state that at CREC, "most [groundwater] flow is through solution cavities and conduits." These safety standards were not incorporated into the design of the Ash Landfill when it was built, and it is now nearly impossible to do so.

- The Ash Landfill was not built to structurally withstand the influence of sinkholes. It lacks the structural reinforcement that would be necessary, but may nevertheless be insufficient, to prevent a sudden foundation collapse. The Ash Landfill cannot be retrofitted now to be safe. Attempting a retrofit could trigger a sinkhole collapse that could rapidly spread CCR contamination in the underlying karst aquifers.

- To protect public waters, the CCR Rule requires (a) a distance of at least 5 feet between the base of CCR storage and disposal facilities and the uppermost aquifer, or (b) other measures that eliminate any hydraulic connection between CCR storage and disposal facilities and the aquifer—CREC Ash Landfill does not meet either standard. In fact, the available monitoring data are indicative of an ongoing hydraulic connection that allows CCR constituents, including arsenic and other heavy metals associated with CCR leachate, to reach the underlying karst aquifers.

- Water quality samples from wells downgradient from the Ash Landfill show consistent and increasing contamination since 2012 with toxic constituents associated with CCR, such as

arsenic, boron, molybdenum, manganese, selenium, sulfate, and thallium, indicating that the Ash Landfill has contaminated the Surficial and Floridan Aquifer at the site.

- Groundwater beneath CREC Ash Landfill, FGD Blowdown Ponds, and Percolation Ponds flows towards the seawater discharge canal, tidal wetlands, and Crystal Bay.

For these reasons, discussed in detail in the full report, the Ash Landfill cannot meet the safety standards in the CCR Rule. Additionally, as the CCR Rule requires corrective action to prevent further releases of CCR constituents into the environment, the CCR that have accumulated in the Ash Landfill should be removed and the site decontaminated. The only way to prevent such continued releases from the Ash Landfill is to remove the CCR that has accumulated and decontaminate the site.

## 2. INTRODUCTION

This is an assessment of coal combustion residuals ("CCR") storage and disposal at the Crystal River Energy Complex ("CREC"). This assessment evaluates hydrogeologic conditions at the Ash Landfill, FGD Blowdown Ponds, Gypsum Storage Pad, and Percolation Ponds, existing groundwater contamination at CREC, and compliance with the U.S. Environmental Protection Agency's ("EPA") new rule on the disposal of CCR from electric utilities ("CCR Rule," U.S. EPA 2015). More specifically, this assessment considers whether CREC's CCR facilities satisfy the safety standards in the CCR Rule for CCR disposal in karst terrain and away from the uppermost aquifer and for preventing groundwater contamination.

The karst-specific safety factors under CCR Rule can be summarized as follows:

1. The historical record of local sinkhole development;
2. The presence of a local hydraulic gradient that points downward at shallow depths;
3. The presence of subsurface conduits that allow piping of groundwater into the karst aquifer, or shallow conduits or caves that could cause sudden collapse of the structure's foundation; and
4. The use of engineering solutions to "prevent the kind of foundation collapse and settlement that could lead to sudden release to the environment of CCR with its toxic constituents and associated leachate." (U.S. EPA 2015).

As discussed below, these factors support the conclusion that CREC Ash Landfill cannot continue to safely receive CCR, nor can it meet the requirements of the CCR Rule.

Additionally, the CCR Rule requires (a) a distance of at least 5 feet between the base of certain CCR storage and disposal facilities and the uppermost aquifer, or (b) other measures that eliminate any hydraulic connection between the facilities and the aquifer. As discussed below, the Ash Landfill does not meet either of these standards.

Water quality samples from wells downgradient from the Ash Landfill show consistent and increasing contamination from common CCR constituents, such as arsenic, boron, molybdenum, manganese, selenium, sulfate, and thallium, indicating that the Ash Landfill has already contaminated the Surficial and Floridan Aquifer at the site.

The Ash Landfill cannot meet the safety standards in the CCR Rule. Additionally, as the CCR Rule requires corrective action to prevent further releases of CCR constituents into the environment, the CCR that have accumulated in the Ash Landfill should be removed and the site decontaminated. The only way to prevent such continued releases from the Ash Landfill is to remove the CCR that has accumulated and decontaminate the site.

## 3. ASSESSMENT

### A. CREC is in one of the country's most unstable areas, under the influence of multiple sinkholes

CREC is located in Citrus County, an active karst area under the influence of sinkholes (FGS 1985). The sandy sediment cover over the limestone in coastal Citrus County is thin, and sinkholes that form tend to be smaller, i.e., less than 10 feet ("ft") in diameter, and not as deep as in areas with thicker, more cohesive sediments covering the limestone. However, the near-surface limestone is deeply incised with solution channels and conduits that can cause small sinkholes to form as surficial sands move into the subsurface voids (Dames and Moore 1994).

#### a. Hydrogeology of coastal West Florida: Karst terrain, solution conduits, and sinkholes

Coastal Citrus County is a region that is underlain by a thick sequence of carbonate rocks, commonly called "limestone" (Miller 1986). These rocks can be dissolved by the chemical action of acidic groundwaters. This creates voids in the rock and a distinctive geologic terrain called karst.[1] Karst terrains are characterized by solution features such as caves and collapse features caused by surface materials falling into voids created by the solution of the underlying rocks. A vertical collapse or solution feature created by karst activity is called a sinkhole (Tihansky 2013).

Small sinkholes are common in western Citrus County (FGS 2016; Tihansky 2013). These voids or depressions at the surface are caused by the movement of unconsolidated surficial materials into pre-existing voids in the underlying limestone. Sinkholes can form rapidly by collapse or slowly by movement of surficial materials into underlying voids in the carbonate rock. Most sinkholes in coastal Citrus County are cover subsidence sinkholes. These sinkholes form when loose surficial sands migrate downward into solution cavities in the limestone. Cover subsidence sinkholes can form slowly, or abruptly, especially after heavy rainfall (Tihansky 2013).

[1] Geologists generally use the term "terrane" to refer to three-dimensional areas including the surface and subsurface, and "terrain" to refer to the surface configuration or topography only. This assessment uses "terrain" to refer to both surface and subsurface areas unless otherwise noted.

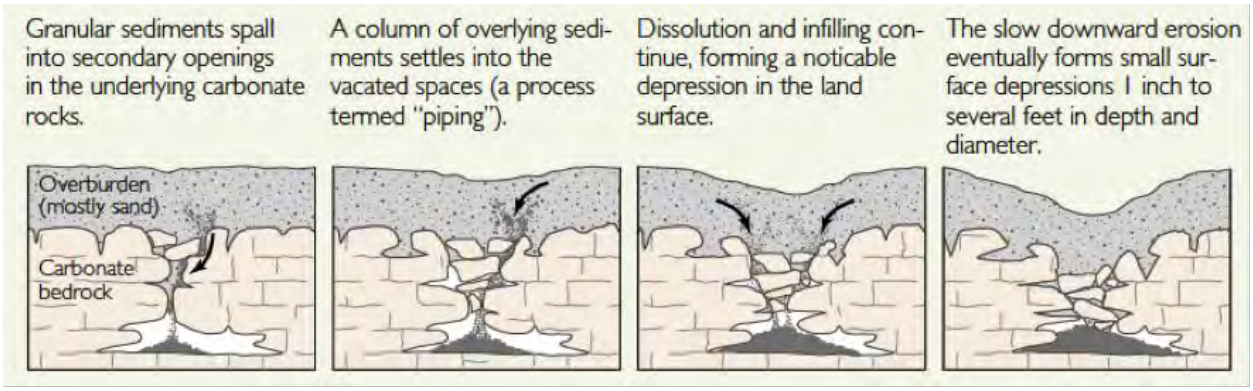


**Figure 1. Cover subsidence sinkhole schematic (Tihansky 2013)**

Paleosinks or paleo-sinkholes are also common in West Central Florida (Tihansky 2013). These are cover subsidence sinkholes that have been filled by sediments or water and do not have recognizable depressions at the surface. Such sediment-filled sinkholes can create a vertical column of permeable materials that allow contaminants introduced at the water table to reach the Floridan Aquifer. In addition to sinkholes, the limestone underlying CREC contains many solution enlarged fractures that form preferred conduits for groundwater flow and allow for downward movement of surficial sands into the underlying limestone (Dames and Moore 1994).

Groundwater, particularly groundwater in the Surficial and Floridan Aquifers,[2] supplies the region's public drinking water. The Floridan Aquifer is one of the largest and most productive sources of fresh groundwater in the world (Miller 1986). It is comprised of the carbonate rocks of Eocene to Miocene age in West Central Florida. In coastal western Citrus County, the Floridan Aquifer is unconfined and water table elevations represent the potentiometric surface of the Floridan Aquifer. This area is a recharge zone for the shallow Floridan Aquifer, which is at or within a few feet of land surface at CREC. More specifically, shallow groundwater flows downward from the water table and the shallow sands of the Surficial Aquifer into the Floridan Aquifer. Near CREC, the deeper and intermediate portions of the Floridan Aquifer are discharge zones, and groundwater has a component of flow toward the surface.

### b. Hydrogeology of CREC site

The Florida Geological Survey ("FGS") sinkhole database (FGS 2016) documents 24 reported sinkholes within 5 miles of CREC site. As the FGS sinkhole data are self-reported, the 24 reported sinkholes are the minimum number of sinkholes that have occurred in recent years near CREC site. The FGS database is biased toward residential and commercial areas where sinkholes are more likely to be reported than in rural areas and industrial sites. Most of the reported sinkholes near CREC site are reported along the U.S. Highway 19 corridor east of CREC site and associated residential areas. The reported sinkholes are smaller than sinkholes that occur in central Florida, generally less than 10 ft in

[2] The Surficial and Floridan Aquifers are U.S. EPA designated Underground Sources of Drinking Water, and Florida Department of Environmental Protection ("DEP") designated Type G-II (Surficial) and G-I (Floridan) groundwaters.

diameter and up to 10 ft in depth. Using the 24 sinkholes as a representative data set, 95% (two standard deviations) of reported sinkholes within 5 miles of CREC have diameters less than 7 ft. They are indicative of the extensive karst solution cavities that are present in the shallow subsurface in western Citrus County.

Dames and Moore (1994) describe the geology and hydrogeology of CREC site. The following discussion is a summary of the geology and hydrogeology of CREC site from that report.

Dames and Moore report that the Upper Floridan Aquifer at CREC site contains abundant "solution enlarged fractures," "long linear depressions" in the limestone surface, and "underground channels and caverns." They also report that during removal of coal ash from the area of the former CREC south ash pond, "local superficial channels/sinkholes concealed by ash deposits had caused a continuous series of incidents and delayed removal/transportation activities." The report also states that "most flow is through the solution channels and cavities" and that the upper zone from the surface to a depth of about 30 feet contains many large interconnected solution cavities and channels that are highly permeable.

The surficial deposits at CREC consist of predominantly sandy, unconsolidated materials with some silt and clay. There is no distinct Surficial Aquifer at the site, and the Floridan Aquifer is within a few feet of the land surface. Water reaching the water table from the surface is effectively recharging the upper part of the Floridan Aquifer. The permeable surficial sediments are in direct hydraulic connection with the limestones of the Upper Floridan Aquifer. As a result of the lack of extensive low permeability surficial materials, the Floridan Aquifer at CREC site is an unconfined aquifer in direct hydraulic connection with the water table. Soils at the site typically have seasonal water tables within 1-2 ft of the land surface and are described as poorly drained. The undisturbed soils at CREC are subject to frequent and prolonged flooding.

The near-surface Floridan Aquifer units present at the site are the limestones of the Ocala Group, specifically the lower member of the Ocala Group, the Inglis Formation. The Inglis Formation is an Eocene limestone with extensive solution features. The Avon Park Formation underlies the Inglis Formation. The Avon Park Formation consists of limestones and dolostones and forms the bottom of the Upper Floridan Aquifer (Miller 1986). The permeability of the Avon Park decreases with depth. This results in enhancement of horizontal ground water flow in the Inglis Formation limestones. Dames and Moore (1994) report that most groundwater flow at the site is through "solution cavities and channels." In test borings that encountered voids, about 10% of the total aquifer volume is void space, generally within 50 ft of land surface. A zone in the Inglis Formation from land surface to a depth of about 30 ft consists of "many large solution cavities and channels that are highly permeable." A lower high permeable zone occurs between depths of about 40 to 60 ft at the contact between the Inglis and Avon Park Formations. Aquifer performance data suggest that the transmissivity of the Upper Floridan Aquifer at the site is about 2E05 $ft^2$/day, a very high value.

In a study to support installation of CREC Units 4 and 5 at CREC (ESE 1982), Dames and Moore (1994) report that test borings could be divided into "void" borings that encountered voids during

drilling, and “non-void” borings that encountered solid limestone. The eight void wells responded faster to recharge events and tides and were assumed to connect with solution cavities and channels. The water levels for the void group wells were found to “form a trough running northeast to southwest under the ash disposal site…this trough roughly coincides with the known subsurface cavities in this area and likely reflects a fracture zone of high permeability.” The general groundwater flow direction under the Ash Landfill indicated by the void and non-void wells is northeast to southwest, toward CREC intake and discharge canals and wetlands to west of CREC. Groundwater that flows under the Ash Landfill through the “trough” delineated by Dames and Moore (1994) flows toward the west-southwest and discharges into the seawater discharge canal, and ultimately into Crystal Bay.

The water table “trough” under the Ash Landfill reported by Dames and Moore (1994) includes monitor wells MWI-2R2, TWI-5, and TWI-3 (Figures 2 and 3). These three monitor wells are located on the west side of the Ash Landfill. As described further below, groundwater monitoring reports (DEP 2015) indicate that these three wells have been contaminated with arsenic, sulfate, thallium, selenium, molybdenum, manganese, and boron, all of which are contaminants associated with CCR leachate. This indicates that the Ash Landfill is in direct hydraulic connection with a highly permeable fracture zone in the Upper Floridan Aquifer, and that contaminants associated with CCR wastes have entered the Upper Floridan Aquifer.

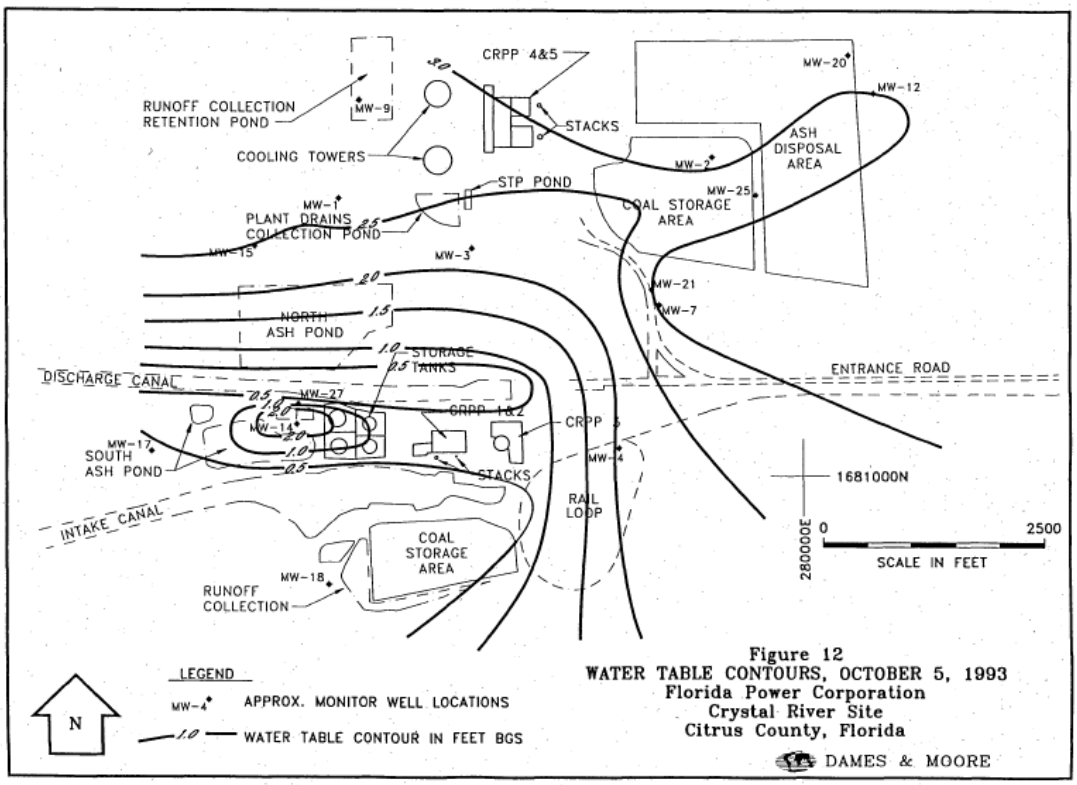


**Figure 2. Water table elevations under the Ash Landfill (Dames and Moore 1994)**

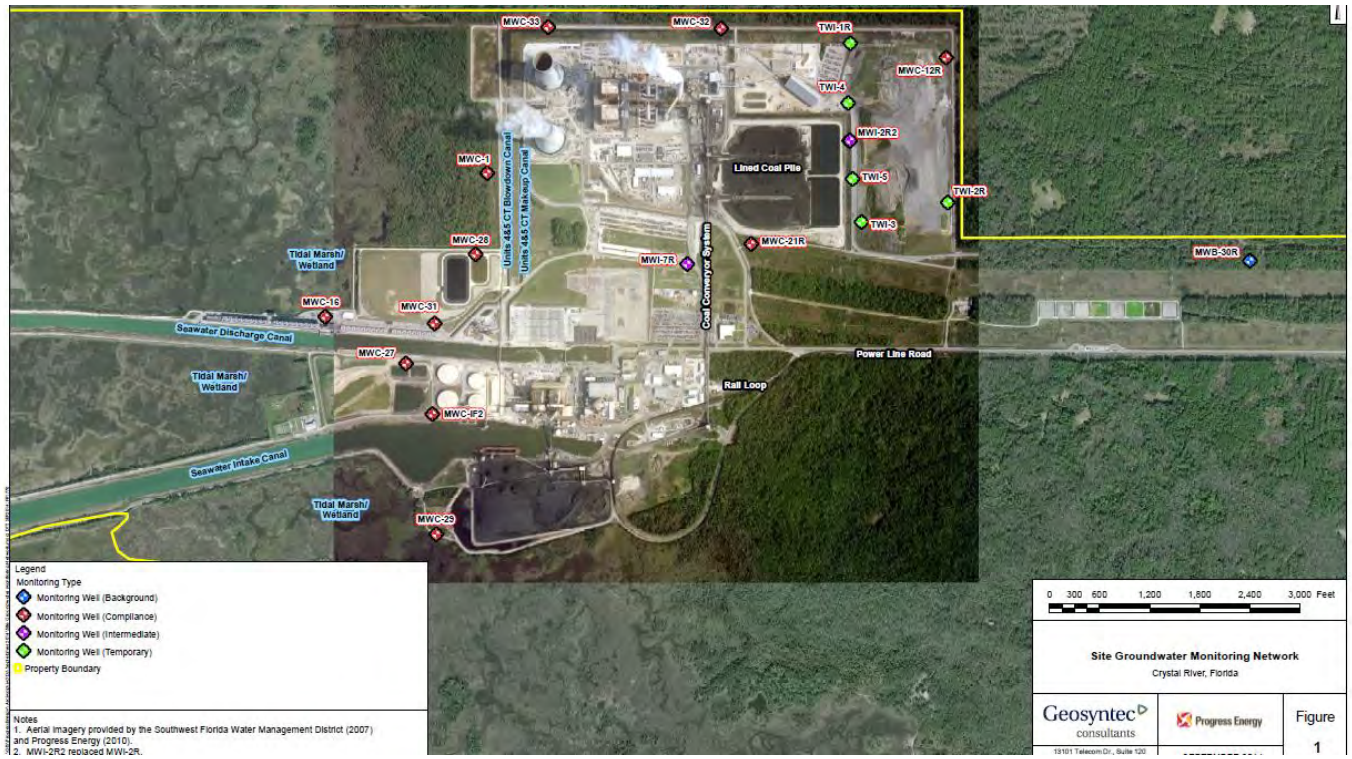


**Figure 3. Groundwater Monitoring Network at CREC (Geosyntec 2013)**

### B. CREC Ash Landfill cannot meet the CCR Rule's safety standards for unstable areas

Historical records of sinkhole activity in the region and reports prepared for CREC site clearly indicate that the site is within an active karst zone, with numerous, unlocated channels and voids. Consulting reports (Dames and Moore 1984; ESE 1982) state that at CREC "most [groundwater] flow is through solution cavities and conduits" and these reports document that the site contains numerous solution enlarged channels, voids, and caves, with one documented high permeability conduit located directly under the Ash Landfill (Dames and Moore 1994). These channels, conduits, limestone surface depressions, and voids create a sinkhole hazard for the Ash Landfill.

The Floridan Aquifer is at or near land surface at CREC site (Dames and Moore 1994) and any size sinkhole is likely to allow movement of unconsolidated materials under the CCR landfill into the voids, depressions, and caverns under the landfill will, and likely has (ESE 1982), allowed CCR materials to come into direct contact with the limestones and groundwater of the Upper Floridan Aquifer. The Ash Landfill does not have structural reinforcements or a liner[3] to prevent vertical movement of CCR materials into the Upper Floridan Aquifer, as occurred at the site of the former CREC south ash pond (ESE 1982).

[3] Only 5.5 acres of the 62-acre Ash Landfill are lined.

To ensure the safety of CCR storage and disposal in unstable karst areas, the CCR Rule requires the detection and interception of (a) *all* of the possible conduits that allow piping of groundwater into the underlying karst aquifers; (b) *all* of the possible shallow caves that could cause a sudden foundation collapse; and (c) *all* of the possible pathways for CCR constituents to be released from CCR storage and disposal facilities, such as the Ash Landfill, into the karst aquifers (U.S. EPA 2015).

These safety standards were not incorporated into the design of the Ash Landfill when it was built. Detection and interception of *all* possible conduits, depressions, voids, and shallow caves in a complex karst terrain such as CREC site is extremely difficult technically, if not practically and economically infeasible. With any currently known sinkhole remediation technology, the Ash Landfill cannot be "upgraded" to meet the CCR Rule requirements for facilities in karst terrains as it would be nearly impossible to determine that all conduits, voids, and caves had been detected and intercepted. As the Ash Landfill does not meet the CCR Rule's safety standards and instructions for engineering practices in karst areas, the CCR materials currently onsite should be removed and the groundwater and soils decontaminated.

In addition to the Ash Landfill, CREC site contains a Gypsum Storage Pad, which receives gypsum solids before disposal in the Ash Landfill or transport offsite, and FGD Blowdown Ponds and Percolation Ponds on the west side of the site, adjacent to the seawater discharge canal, that receive waste and wastewater from coal operations. The FGD Blowdown Ponds are lined with synthetic impermeable liners. However, the FGD Blowdown Ponds, Percolation Ponds, and Gypsum Storage Pad are in the same unstable karst environment as the Ash Landfill. There is a potential for failure of the FGD Blowdown Pond liner system or piping as result of sinkhole activity. If a sinkhole punctured the liner or caused a FGD pipe to leak, the FGD wastes would be introduced directly into the Upper Floridan Aquifer, discharging to the seawater discharge canal, tidal wetlands, and ultimately Crystal Bay. The liner system would need to be able to span sinkholes 10 ft in diameter or greater without failing to avoid contaminating the Upper Floridan Aquifer with FGD wastes. The Percolation Ponds are unlined and are in direct communication with the Upper Floridan Aquifer. The Percolation Ponds recharge the shallow groundwater aquifer and discharge into the seawater discharge canal, tidal wetlands, and Crystal Bay (Figures 2 and 3).

### C. The Upper Floridan Aquifer exhibits contamination from CCR Leachate at CREC

Contaminants such as sulfate, arsenic, selenium, thallium, boron, molybdenum, and manganese are common constituents of CCR leachate (EPRI 2004). The presence of several of these constituents, at any detectable level above background values, in groundwater downgradient from a CCR storage and disposal unit is overwhelming evidence that contaminants that have leached from the CCR materials have reached the water table and the aquifer. Groundwater sampling results from September 2012 for monitoring well MZ-3, which is in an upgradient, undisturbed area approximately one mile east of CREC facility, indicate that background arsenic concentrations in the shallow, intermediate, and deep portions of the aquifer are 2.1, 6.3, and <2.0 micrograms/liter, respectively (Geosyntec 2013). Arsenic levels in groundwater >10.0 micrograms/liter are indications of contamination of the aquifer system by CCR.

Dames and Moore (1994) state that the “void wells” near the Ash Landfill define a “trough” in the water table surface underneath the landfill (Figure 2). They attribute this water table trough to a “fracture zone of high permeability.” Three monitor wells on the west side of the Ash Landfill are located in or near this high permeability fracture zone: wells MWI-2R2, TWI-5, and TWI-3 (Figure 3).

Water samples from these three wells have regularly exceeded federal and state regulatory levels for arsenic, sulfate, thallium, selenium, molybdenum, manganese, and boron since 2012. For arsenic, boron, manganese, and molybdenum levels of these contaminants in groundwater in this fracture zone have trended upward from 2012 to 2015 (Figures 4, 5, 6, and 7). Water quality data obtained in January 2016, continue to show levels of contaminants in excess of groundwater standards in wells downgradient of the Ash Landfill in wells MWI-2R2, TWI-1R, TWI-3, and TWI-5 (DEP 2016).

These supporting lines of evidence, the definition of the water table trough, the presence of high permeability conduits at the site, and the presence of common CCR leachate constituents at increasing concentrations in wells downgradient from the Ash Landfill are overwhelming evidence that the landfill has contaminated local groundwater with toxic materials associated with CCR leachate. As the purpose of the standards enumerated under the CCR Rule is to prevent groundwater contamination from CCR facilities, the presence of these contaminants at the existing site is evidence that that the existing Ash Landfill does not meet the conditions specified in the rule.

Geosyntec (2013) has prepared a report that maintains that the arsenic found in groundwater downgradient from the Ash Landfill is the result of complex geochemical conditions and a natural source of arsenic. They note that arsenic was detected in borings at a proposed coal ash storage site east, and upgradient, of the current Ash Landfill, suggesting a natural source of arsenic. However, the concentrations of arsenic detected downgradient of the Ash Landfill are up to five times as high as the concentrations detected upgradient. In addition, the associated CCR contaminants sulfate, selenium, thallium, boron, molybdenum, and manganese have been detected in wells downgradient of the Ash Landfill. The Geosyntec report does not explain the presence of these CCR associated contaminants.

To prevent such contamination, the CCR Rule prescribes (a) a distance of at least 5 feet between the base of facilities containing CCR and the uppermost aquifer, or (b) other measures that eliminate the hydraulic connection between the base and the uppermost aquifer—safety standards that the Ash Landfill does not meet. According to public records, the base of the Ash Landfill has an elevation of 4 to 8 feet above sea level, while the water table near the Ash Landfill has reported elevations greater than 3 feet (Geosyntec 2013). This indicates that the base of the Ash Landfill is within 5 feet of the water table in the Surficial/Floridan Aquifer. The Ash Landfill is unlined, meaning that the CCR materials are in direct hydraulic connection with the Floridan Aquifer. Furthermore, natural soils at CREC site are poorly drained and flood seasonally (Dames and Moore 1994), indicating that the water table seasonally approaches the land surface.

As the CCR Rule requires corrective action to prevent further releases of CCR constituents into the environment, the CCR that have accumulated in the Ash Landfill should be removed and the site should be decontaminated.

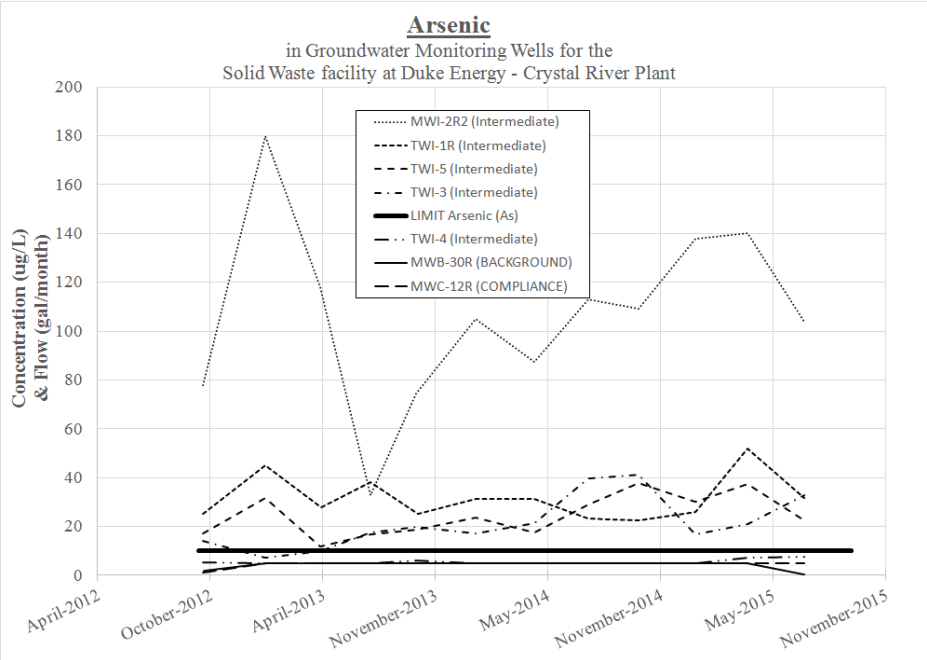


**Figure 4. Arsenic levels in groundwater samples from wells at CREC site, October 2012 to July 2015 (DEP 2015)**

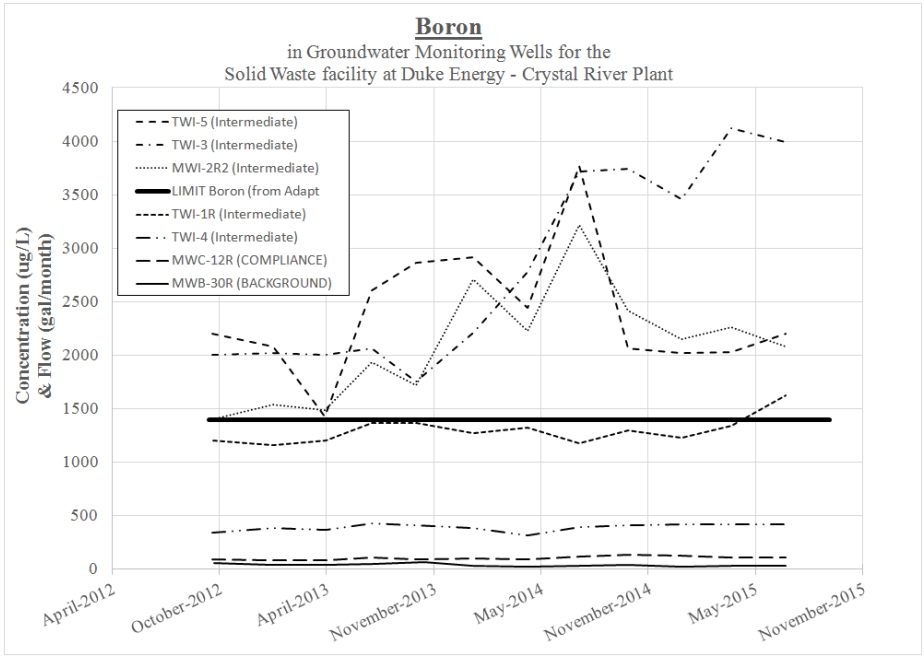


**Figure 5. Boron levels in groundwater samples from wells at CREC site, October 2012 to July 2015 (DEP 2015)**

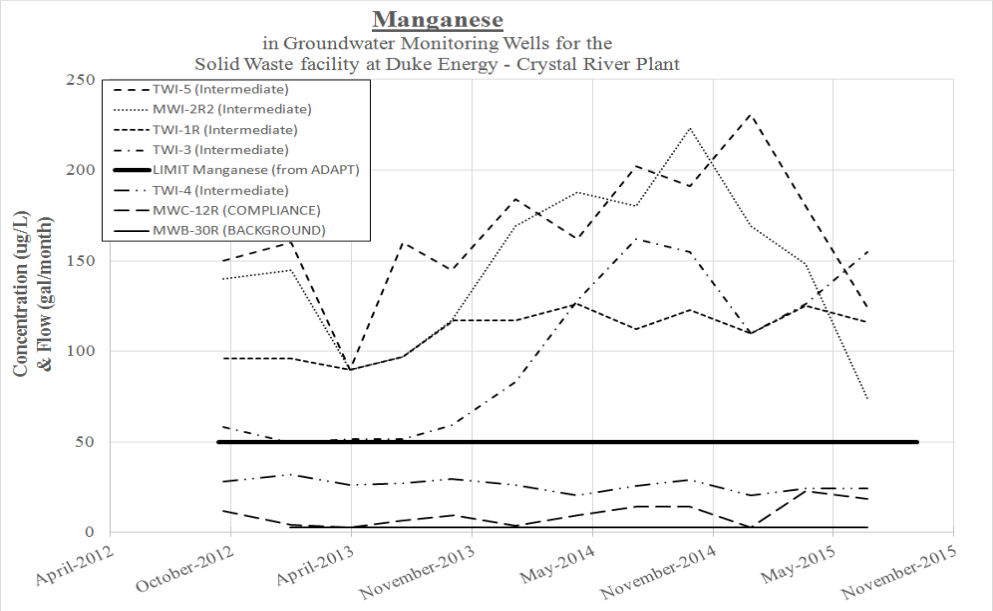


**Figure 6. Manganese levels in groundwater samples from wells at CREC site, October 2012 to July 2015 (DEP 2015)**

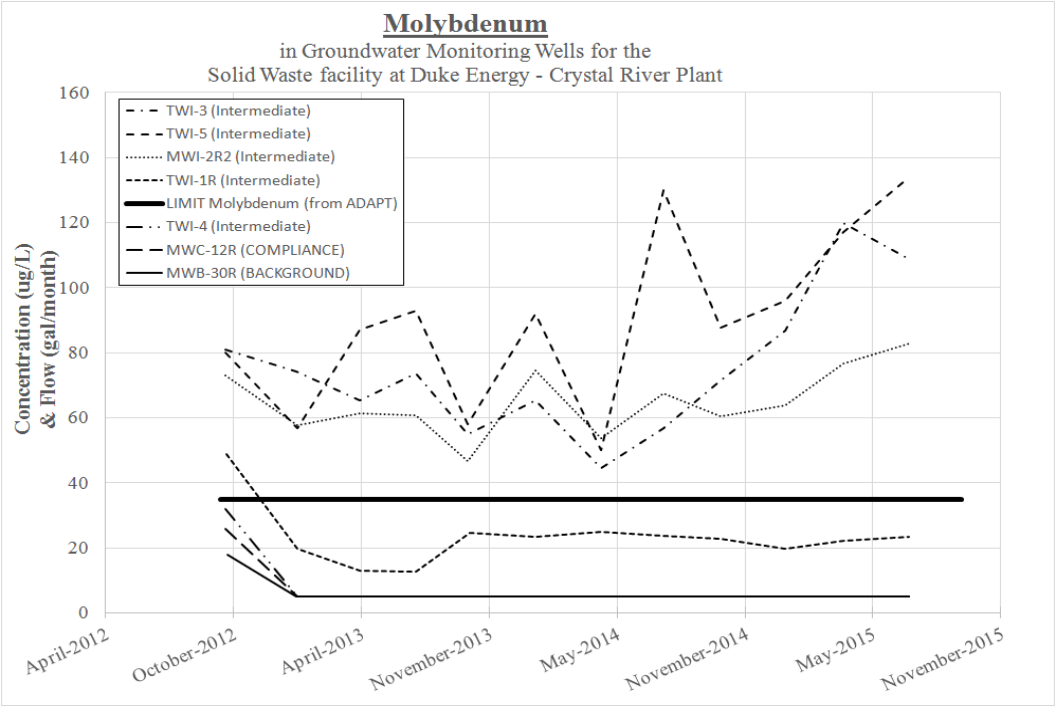


**Figure 7. Molybdenum levels in groundwater samples from wells at CREC site, October 2012 to July 2015 (DEP 2015)**

## 4. SUMMARY

CREC Ash Landfill does not meet the safety criteria for CCR landfills and impoundments enumerated in the EPA's CCR Rule. The facility is located in a documented unstable, karst area, putting local water resources at risk. It would be technically challenging, if not impossible to upgrade the Ash Landfill to meet the CCR Rule standards for active facilities in karst areas. In addition, there is overwhelming evidence that the Ash Landfill has contaminated local ground water with arsenic, selenium, molybdenum, manganese, boron, and thallium. The source of these contaminants is the Ash Landfill as documented by the presence of these contaminants in water samples from downgradient wells. The Ash Landfill is uncovered and open to infiltration of rainwater, the facility is unlined, and it is in direct hydraulic connection with the Upper Floridan Aquifer. The remedy to prevent further contamination of the aquifer and of Crystal Bay, is to remove the CCR materials currently on site and to decontaminate the Floridan Aquifer and local soils.

## 5. AUTHOR'S EXPERTISE AND QUALIFICATIONS

The author of this technical assessment, Dr. Mark Stewart, PhD, PG, is a Professor Emeritus at the University of South Florida School of Geosciences. Dr. Stewart is a registered Professional Geologist in the State of Florida. He has an extensive publication record and expertise in the hydrogeology of Florida, water resources management, karst hydrology, applied geophysics, and the geology of sinkholes. He has been qualified in hearings of the Division of Administrative Hearings and in State and Federal courts as an expert in hydrogeology, water resources management, karst hydrology, the geology of sinkholes, hydrologic modeling, and environmental geophysics. Dr. Stewart has an undergraduate degree in geological sciences from Cornell University, and graduate degrees in geology and water resources management from the University of Wisconsin-Madison.

The primary materials reviewed and used in the preparation of this assessment were Florida Department of Environmental Protection ("DEP") regulatory files, which include groundwater monitoring reports, reports on the geology and hydrogeology of CREC site, and reports on the construction and operation of waste material facilities and disposal of generated wastes, all of which were prepared by Duke/Progress Energy/FPC and their consultants and submitted to the DEP. Additional materials referenced for this report include: publications, data, and maps from the U.S. Geological Survey and Florida Geological Survey; peer-reviewed journal articles; and publically-available documents related to coal and coal combustion residuals, hydrogeology, sinkholes, and karst hydrology.

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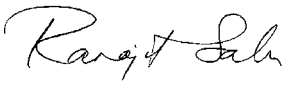
# EXHIBIT 2

Technical Assessment of Converting a Zero Discharge Standard for Bottom Ash Wastewater at the Crystal River Energy Complex:

Expert Report by Dr. Ranajit (Ron) Sahu



September 26, 2016

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## 1. EXECUTIVE SUMMARY

This is an assessment of Duke Energy Florida's ("DEF") plans for achieving compliance with the U.S. Environmental Protection Agency's ("EPA") revised effluent limitations guidelines ("ELGs") for bottom ash wastewater generated at DEF's Crystal River Energy Generating Complex ("CREC") Units 4 and 5. Specifically, this assessment evaluates DEF's contention that February 1, 2020, should be the deadline for these units under the ELGs.

DEF's 44-month schedule to achieve compliance with the bottom ash BAT standard is simply unsupported. CREC can achieve a zero discharge standard for bottom ash wastewater within 27 to 30 months, roughly August to November 2018.

Construction time for bottom ash retrofits at Units 4 and 5 are anticipated to take, with a built in contingency, only 18 months. Other, related, tasks for achieving compliance should take significantly less time than DEF proposes, particularly as DEF began planning for and evaluating strategies to comply with the revised ELGs as far back as 2012. Beginning in 2014, Duke Energy began publicly reporting projected compliance costs, suggesting that conceptual or detailed engineering evaluations and studies were undertaken and that Duke Energy's Board has been aware of these changes and costs for some time.

DEF does not need until February 1, 2020, to achieve compliance with a zero discharge standard for bottom ash wastewater at CREC Units 4 and 5. Rather, compliance can be achieved by November 2018 if not sooner. The Florida Department of Environmental Protection ("DEP") should carefully review the unsupported schedule provided by DEF and require that Units 4 and 5 comply with a zero discharge bottom ash standard by no later than November 2018.

## 2. INTRODUCTION

This is an assessment of Duke Energy Florida's ("DEF") plans for achieving compliance with the U.S. Environmental Protection Agency's ("EPA") revised effluent limitations guidelines ("ELGs") for bottom ash transport water[1] or "wastewater" generated at DEF's Crystal River Energy Generating Complex ("CREC") Units 4 and 5. Specifically, this assessment evaluates DEF's contention that February 1, 2020, should be the deadline for these units' under the ELGs.

## 3. BOTTOM ASH HANDLING AND WASTEWATER AT CREC UNITS 4 AND 5

[1] 40 C.F.R. § 423.11(f) (defining the term "bottom ash" as "the ash, including boiler slag, which settles in the furnace or is dislodged from furnace walls. Economizer ash is included in this definition when it is collected with bottom ash); § 423.11(p) (defining the term "transport water" as "any wastewater that is used to convey fly ash, bottom ash, or economizer ash from the ash collection or storage equipment, or boiler, and has direct contact with the ash. Transport water does not include low volume, short duration discharges of wastewater from minor leaks (e.g., leaks from valve packing, pipe flanges, or piping) or minor maintenance events (e.g., replacement of valves or pipe sections)."

CREC is operated by DEF and is located adjacent to Crystal Bay, part of the Gulf of Mexico, in Citrus County, Florida. Units 1 (built in 1966, rated at 395 MW), 2 (built in 1969, rated at 520 MW), 4 (built in 1982, rated at 769 MW), and 5 (built in 1984, rated at 767 MW) are Duke Energy's only coal-fired units in Florida.[2] DEF applied to renew the NPDES Permit No. FL0036366 for Units 4 and 5 in January 2016.[3]

As described by DEF, Units 4 and 5 produce bottom ash wastewater that discharges from dewatering bins to an intenral canal and then to Crystal Bay via a discharge canal:

> The bottom ash handling system collects and removes bottom ash from Crystal River North Unit 4 & 5. Bottom ash collected in ash hoppers beneath the steam generator is periodically removed with ash sluice water to a transfer tank. From the transfer tank, an ash slurry pump transports slurry to a selected dewatering bin where bottom ash is separated from the transport water. When dewatered, bottom ash is either directly sent for beneficial reuse or deposited in an ash storage area for later beneficial reuse. All transport water from the dewatering bin is sent to a surge tank where it is pumped back to the ash hoppers to transport more bottom ash. Several process streams also feed into the bottom ash transport water system. While they provide needed make-up water, these sources may also, at times, cause the surge tank to overflow. The overflow runs into the coal area stormwater runoff ditch which discharges infrequently through NPDES internal outfall I-CHO.[4]

DEF further describes:

> The facility currently utilizes a wet-sluicing system for bottom ash, in which most of the bottom ash transport water is reused after exiting the dewatering basins. However, due to water balance issues at the facility, an overflow structure is used to discharge excess water from the dewatering basins into the runoff collection system, and then through Internal Outfall I-CHO to eventually Internal Outfall I-0CO, Outfall D-001 and waters of the State.[5]

Additional details are provided in the NPDES permit renewal application and other documents in the permitting record.[6]

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[2] *See Coal-Fired Plants*, Duke Energy, https://www.duke-energy.com/power-plants/coal-fired.asp (last visited Sep. 26, 2016).

[3] Duke Energy Florida, Inc., Application to Renew NPDES Permit for Crystal River Units 4 & 5, Permit No. FL0036366, January 12, 2016.

[4] Duke Energy Florida, Response to Request for Additional Information, Attachment 1 at 1, May 20, 2016.

[5] Draft Permit at 12.

[6] *See e.g.*, DEF's Coal Combustion Product (CCP)/Solid Waste Materials Management Plan, Revision 6, December 2013.

## 4. THE ELGS

After many years of work,[7] EPA finalized the ELGs in November 2015.[8] The ELGs revise and strengthen technology-based effluent limitations guidelines and standards for wastewater discharges from steam electric power plants, including coal-fired units such as CREC Units 4 and 5.

The final ELGs set federal limits on the discharge toxic metals and other harmful pollutants from wastewater at steam electric power plants. The ELGs are based on technology improvements in the steam electric power industry over the last three decades and establish new requirements for wastewater streams from the following processes and byproducts associated with flue gas desulfurization, fly ash, bottom ash, flue gas mercury control, and gasification of fuels such as coal and petroleum coke.

The ELGs require a zero discharge best available technology ("BAT") standard for bottom ash wastewater to be achieved by November 1, 2018, or "as soon as possible."[9] The phrase "as soon as possible" means November 1, 2018, unless permitting authorities, such as the Florida Department of Environmental Protection ("DEP"), establish a later date based on a well-documented justification.[10]

## 5. CONSULTATION WITH VENDORS AND INDUSTRY REGARDING BOTTOM ASH CONVERSIONS

### A. Vendor Experience and Discussions During ELG Rulemaking

As EPA has stated, "to gather information on handling fly ash and bottom ash, EPA … contacted several ash handling and ash storage vendors. The vendors provided the following types of information for EPA's analyses:

- Type of fly ash and bottom ash handling systems available for reducing or eliminating ash transport water;
- Equipment, modifications, and demolition required to convert wet-sluicing fly ash and bottom ash handling systems to dry ash handling or closed-loop recycle systems;
- Equipment that can be reused as part of the conversion from wet to dry handling or in a closed-loop recycle system;

---

[7] As EPA noted in the preamble to the final ELG Rule, "….EPA initiated a steam electric ELG rulemaking following a detailed study in 2009. EPA published the proposed rule on June 7, 2013, and took public comments until September 20, 2013." 80 Fed. Reg. 67,844.

[8] The Final ELG Rule was published in the Federal Register on November 3, 2015. 80 Fed. Reg. 67,838.

[9] *See* 40 C.F.R. § 423.11(t) (defining the phrase "as soon as possible" to mean Nov. 1, 2018, unless a later date is specifically justified); § 423.13(k)(1) (requiring compliance with bottom ash wastewater standards by Nov. 1, 2018 unless a later date up to Dec. 31, 2023 is specifically justified).

[10] 40 C.F.R. § 423.11(t) (emphasis added).

- Outage time required for the different types of ash handling systems;
- Maintenance required for each type of system;
- Operating data for each type of system;
- Purchased equipment, other direct, and indirect capital costs for fly ash and bottom ash conversions;
- Specifications for the types of ash storage available (*e.g.*, steel silos or concrete silos) for the different types of handling systems;
- Equipment and installation capital costs associated with the storage of fly ash and bottom ash; and
- Operation and maintenance costs for fly ash and bottom ash handling systems."[11]

The vendor community has been well aware of the rule requirements and participated fully in the rulemaking. There are numerous well-qualified U.S. vendors (and foreign vendors that are active in the U.S. market) that are capable of providing equipment and services for ash handling and conversion of bottom ash transport water at coal-fired units such as Units 4 and 5. Major vendors include United Conveyer Corporation ("UCC"),[12] Clyde Bergemann,[13] and Magaldi.[14] Others such as GE, Veolia, Nalco, Aquatech, Heartland, LB Industrial Systems, and many others also have potential capabilities and solutions for specific aspects of ash handling. The ELGs docket shows that EPA consulted expensively with at least UCC and Clyde Bergemann with respect to bottom ash transport water and handling during rule development.[15].

That the vendor community is robust is not surprising given that the US coal-fired power plant fleet is over 800 units strong, with each one generating copious amounts of bottom ash that must be handled and managed. Further, as the ELGs rulemaking record shows, a significant portion of the U.S. coal fleet already meets the ELGs BAT standard for bottom ash wastewater and are dry systems. These vendors already have many technology solutions and offerings for achieving

---

[11] Technical Development Document for the Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category, U.S. Environmental Protection Agency, EPA-821-R-15-007 at p. 3-21 and 3-22 (Sep. 2015).

[12] UCC offers various hydraulic, mechanical, pneumatic, and vibratory systems for dry bottom ash handling.

*See Bottom Ash*, United Conveyor Corporation, http://unitedconveyor.com/bottom_ash/ (last visited Sep. 26, 2016).

[13] Clyde Bergemann offers a trademarked "DRYCON" system for dry bottom ash handling.

*See DRYCON*, Clyde Bergemann Power Group, http://www.cbpg.com/en/products-solutions-materials-handling-bottom-ash/drycon%E2%84%A2 (last visited Sep. 26, 2016).

[14] Magaldi offers a dry ash handling system called MAC. A variant of this system appears to have been installed in either CREC Unit 1 or 2 or both.

*See Magaldi Solutions for Ash Handling*, Magaldi, http://www.magaldi.com/en/magaldi_solutions_for/Ash-Handling-Mac__9_11.php#tab_fototab (last visited Sep. 26, 2016).

[15] See, for example, EPA-HQ-OW-2009-0819-0580 (pertaining to EPA and its contractor's discussions with UCC) (*available at* https://www.regulations.gov/document?D=EPA-HQ-OW-2009-0819-0580) and EPA-HQ-OW-2009-0819-6232 (pertaining to EPA and its contractor's discussions with Clyde Bergemann) (*available at* https://www.regulations.gov/document?D=EPA-HQ-OW-2009-0819-6232).

a zero discharge bottom ash standard. As the preamble to the ELG Rule states:

> …technologies for control of bottom ash transport water are demonstrably available. Based on survey data, more than 80 percent of coal-fired generating units built in the last 20 years have installed dry bottom ash handling systems. In addition, EPA found that more than half of the entities that would be subject to BAT requirements for bottom ash transport water are already employing zero discharge technologies (dry handling or closed-loop wet ash handling) or planning to do so in the near future.[16]

Thus, DEF has a good selection of experienced vendors to select from to achieve compliance with the bottom ash ELGs. As discussed below, the record also shows that DEF and previous CREC owner Progress Energy Florida ("PEF") appear to have actively consulted with at least one vendor, UCC, with regards to bottom ash dry conversion systems, as far back as 2012.

## B. Vendor Discussions Pertaining to DEF and CREC in the Rulemaking Docket

The ELG rulemaking docket indicates that DEF already consulted vendors regarding the conversion to bottom ash dry conversion systems. Specifically, the docket shows that DEF has a long-standing relationship with one of the vendors, Magaldi,[17] and has been discussions with another vendor DRYCON™.[18] In addition, the docket shows DEF has experience with other vendors through its pursuit of dry systems at its other plants/units. Moreover, DEF and its predecessor, Progress Energy Florida (PEF), have been engaged for years in developing a compliance strategy for bottom ash transport water for Units 4 and 5. As EPA notes in a memorandum provided by its contractor ERG in May 2012:

> UCC noted the wet to dry conversions in the recent past or in process:
>
> …
>
> - Duke Energy's Gibson plant is in the process of converting their wet sluicing system to a dry fly ash handling system;
>
> …
>
> - Progress Energy's Mayo plant is planning to convert their current bottom ash handling system to a PAX system (100 percent dry

[16] 80 Fed. Reg. 67,852.

[17] *See* Final Seminole Site Visit Notes, EPA-HQ-OW-2009-0819-1891 (Jan. 2013) (*available at* https://www.regulations.gov/document?D=EPA-HQ-OW-2009-0819-1891).

[18] *See* Memorandum to the Steam Electric Rulemaking Record: Ash Handling Documentation from Comunications with Clyde Bergemann Power Group, EPA-HQ-OW-2009-0819-6232 (Sep. 2015) (*available at* https://www.regulations.gov/document?D=EPA-HQ-OW-2009-0819-6232).

> vacuum), which is currently scheduled to be commissioned in 2013;
> …
>
> UCC explained that Duke Energy's plants (i.e., Marshall, Allen, Wabash, and Gibson) are going dry to avoid violations, or risks of violations, with NPDES permits. Additionally, Duke Energy is exploring ash handling technologies in anticipation of changing regulations. Additionally, UCC reports that Gibson engaged UCC for quotes for a bottom ash handling conversion.
>
> UCC also reported that Progress Energy wants to convert ash handling systems to dry to get ahead of the industry. UCC stated that Progress is likely going with a PAX bottom ash handling system for the plants that still operate wet sluicing systems. UCC stated that this system because [*sic*] operational at Crystal River 15 years ago.[19]

These notes show that DEF/PEF has already made significant progress on dry conversion for its plants/units, including not only installing such a system at its Mayo plant in 2013, but also for its other plants including CREC where only Units 4 and 5 use wet bottom ash sluicing. Moreover, the fact that these discussions took place in mid-2012 show that significant development work was completed on or before by that time—more than four years ago. The discussions also show significant preparations by DEF parent company to convert to dry handling systems in anticipation of the ELGs.

### C. Utility Water Act Group (UWAG) Comments During the ELG Rule Development

Lastly, while numerous parties provided comments to the EPA during its ELG rulemaking, it is particularly important to note certain relevant portion of comments provided by the Utility water Act Group ("UWAG"), an industry consortium, which includes almost all utilities as its members.[20] Duke is a member of UWAG as was PEF.

In its comments, pertaining to bottom ash conversions, UWAG states that

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[19] *See* Teleconference Notes Between Kevin McDonough & Mike Kippis, United Conveyor Corporation, Ron Jordan and Jezebele Alicea-Virella, USEPA, TJ Finseth, Elizabeth Sabol, ERG, Inc., EPA-HQ-OW-2009-0819-0580 (May 24, 2012) (*available at* https://www.regulations.gov/document?D=EPA-HQ-OW-2009-0819-0580) (emphasis added).

[20] As UWAG's comment's note, "UWAG is a voluntary, *ad hoc*, non-profit, unincorporated group of 198 individual energy companies and three national trade associations of energy companies: the Edison Electric Institute, the National Rural Electric Cooperative Association, and the American Public Power Association. The individual energy companies operate power plants and other facilities that generate, transmit, and distribute electricity to residential, commercial, industrial, and institutional customers." Utility Water Act Group Comments on EPA's Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, at 1 n.1.

> [I]n the case study presented in the attachment, it would take 30-36 months to convert from a wet bottom ash hopper to a dry bottom ash hopper for a large unit…..Another case study for adding a remote wet ash hopper and submerged flight conveyor would take 27-33 months.[21]

The project implementation timeframes referenced in this section, which are already considerably shorter than what DEF has proposed (i.e., 44 months, as discussed in Section 7), are relevant for situations in which no initial planning or assessment has been completed. However, since, as shown next, there are clear indications that Duke Energy and PEF have undertaken significant, multi-year efforts to begin planning for a conversion to dry bottom ash handling, and that the implementation schedule at CREC Units 4 and 5 should be shorter.

## 6. DUKE ENERGY'S PUBLIC STATEMENTS AND PLANNING TO COMPLY WITH THE BOTTOM ASH ELGS

Public statements from Duke Energy corroborate that DEF has already evaluated options and developed likely costs for compliance with the ELGs at CREC Units 4 and 5, and that implementation can and should occur more quickly than in the schedules proposed by DEF and DEP.

### A. Duke Energy's 2013 Annual Report and SEC Form 10-K Filing

In a brief discussion in its 2013 Annual Report, Duke Energy provided the following general statement, (although no cost estimates) regarding compliance with the then-proposed revised ELGs for steam electric power plants:

> *Steam Electric Effluent Limitation Guidelines*
>
> On June 7, 2013, the EPA proposed Steam Electric Effluent Limitations Guidelines (ELGs). The EPA is under a court order to finalize the rule by May 22, 2014. The EPA has proposed eight options for the rule, which vary in stringency and cost. The proposed regulation applies to seven waste streams, including wastewater from air pollution control equipment and ash transport water. Most, if not all of the steam electric generating facilities the Duke Energy Registrants own are likely affected sources. Compliance is proposed as soon as possible after July 1, 2017, but may extend until July 1, 2022. The Duke Energy Registrants are unable to predict the outcome of the rulemaking, but the impact

[21] *Id.* at 84.

could be significant.[22]

## B. Duke Energy's 2014 Annual Report and SEC Form 10-K Filing

Again in 2014, Duke Energy considered compliance with the proposed ELGs, this time offering cost estimates:

> *Steam Electric Effluent Limitation Guidelines*
>
> On June 7, 2013, the EPA proposed Steam Electric Effluent Limitations Guidelines. The EPA is under a revised court order to finalize the rule by September 30, 2015. The EPA has proposed eight options for the rule, which vary in stringency and cost. The proposed regulation applies to seven waste streams, including wastewater from air pollution control equipment and ash transport water. Most, if not all, of the steam electric generating facilities the Duke Energy Registrants own are likely affected sources. Requirements to comply with the Final rule may begin as early as late 2018 for some facilities.
>
> *Estimated Cost and Impacts of Rulemakings*
>
> …
>
> The following table provides estimated costs, excluding AFUDC, of new control equipment that may need to be installed on existing power plants, including conversion of plants to dry disposal of bottom ash and fly ash, to comply with the above regulations over the five years ended December 31, 2019
> …

| (In millions) | Estimated 5 Year Cost |
|---|---|
| Duke Energy | $ 1,850 |
| Duke Energy Carolinas | 675 |
| Progress Energy | 525 |
| Duke Energy Progress | 475 |
| Duke Energy Florida | 50 |
| Duke Energy Ohio | 75 |
| Duke Energy Indiana | 575 |

[23]

[22] Available at https://www.duke-energy.com/investors/financials-sec-filings/annual.asp.

Even though the ELGs had not yet been finalized, Duke Energy recognized that the rule would likely be final by September 2015 and had already developed cost estimates for compliance. Duke Energy necessarily would have had to complete considerable planning and engineering work in the 2013-2014 time period to be able to share such cost estimates.

The statement above also shows that Duke anticipated that compliance would be required "as early as late 2018" which is consistent with EPA's final compliance schedule beginning in November 2018.

Specific to CREC units, the cost estimate of $50 million presented to shareholders and the SEC for DEF relate directly to Units 4 and 5, since these are DEF's only non-retired coal units.

### C. Duke Energy's 2015 Annual Report and SEC Form 10-K Filing

Finally, in 2015, Duke Energy again projected compliance dates and costs for the ELGs:

> *Steam Electric Effluent Limitations Guidelines*
>
> On January 4, 2016, the final Steam Electric Effluent Limitations Guidelines (ELG) rule became effective. The rule establishes new requirements for wastewater streams associated with steam electric power generation and includes more stringent controls for any new coal plants that may be built in the future. Affected facilities must comply between 2018 and 2023, depending on timing of new Clean Water Act permits. Most, if not all, of the steam electric generating facilities the Duke Energy Registrants own are likely affected sources. The Duke Energy Registrants are well-positioned to meet the requirements of the rule due to current efforts to convert to dry ash handling.
>
> *Estimated Cost and Impacts of Rulemakings*
>
> Duke Energy will incur capital expenditures to comply with the environmental regulations and rules discussed above. The following five-year table provides estimated costs, excluding AFUDC, of new control equipment that may need to be installed on existing power plants primarily to comply with the Coal Ash Act requirements for conversion to dry disposal of bottom ash and fly ash, MATS, Clean Water Act 316(b) and ELGs, through December 31, 2020.

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[23] Duke Energy 2014 Annual Report at 59 *available at* https://www.duke-energy.com/investors/financials-sec-filings/annual.asp.

| (in millions) | Five-Year Estimated Costs |
|---|---|
| **Duke Energy** | **$ 1,350** |
| Duke Energy Carolinas | 625 |
| Progress Energy | 350 |
| Duke Energy Progress | 300 |
| Duke Energy Florida | 50 |
| Duke Energy Ohio | 100 |
| Duke Energy Indiana | 275 |

"[24]

The 2015 filing does not change the 2014 cost estimate of $50 million for DEF's compliance with the ELGs, indicating no significant alterations in its compliance strategy. Notably, Duke Energy states that "[t]he Duke Energy Registrants are well-positioned to meet the requirements of the rule due to current efforts to convert to dry ash handling."[25] This statement is not surprising and is consistent with DEF's ability to meet a compliance deadline of late 2018.

## 7. CRITIQUE OF DEF'S PROPOSED COMPLIANCE SCHEDULE

As detailed above, Duke Energy and DEF have made considerable progress in preparations for compliance with the bottom ash wastewater provisions in the ELGs. Nothing in the record suggests that Units 4 and 5 cannot achieve compliance with the BAT requirements for bottom ash wastewater by November 1, 2018. Yet DEF has, surprisingly, proposed February 1, 2020, as the compliance deadline for the bottom ash BAT standard at CREC Units 4 and 5.

In its initial NPDES permit renewal application, DEF proposed the following schedule for "[e]valuation of the Dry Bottom Ash Dewatering system to eliminate the water overflows" and stated that "Duke Energy is in the process of conducting this evaluation:"[26]

- Complete evaluation of the Dry Bottom Ash Dewatering System and submit to the Department a list of actions with deadlines – July 31, 2018.
- Completion of actions and compliance with the ELG Rule no later than December 31, 2023.[27]

---

[24] Duke Energy 2015 Annual Report at 63 *available at* https://www.duke-energy.com/investors/financials-sec-filings/annual.asp (emphasis added).

[25] *Id.*

[26] Duke Energy Florida, Inc., Application to Renew NPDES Permit for Crystal River Units 4 & 5, Permit No. FL0036366, January 12, 2016, at attachment 4 p.1-2.

[27] *Id.*

In other words, DEF did not commit to compliance before December 31, 2023, the final deadline for compliance with the revised ELGs, nor provide any support for why it would take until late 2023, eight years after the finalization of the ELGs.

Subsequently, in reponse to Florida DEP's request for additional information, DEF amended its initial proposed schedule for compliance and stated that:

> DEF intends to promptly initiate the formal planning process on June 1, 2016, based on an assumption that the enclosed additional information will result in a complete application and no significant modification to DEF's compliance plans. Due to time needed for planning, procurement, permitting, construction and testing, DEF is requesting that the Department approve a date of completion February 1, 2020, 44 months from June 1, 2016.[28]

DEF now proposes February 1, 2020, as the compliance deadline for the zero discharge standard for bottom ash wastewater. While this is an improvement over the previous, unsupported December 31, 2023, compliance date proposal, this is still too long, and not supported by an justificaiton, as describe next.

As support for a project duration of 44 months, DEF provided a project schedule, shown below.[29]

Table 1- CRN Unit 4 & 5 : Dry Bottom Ash

| Task Number | Task Name | Duration (Months) |
|---|---|---|
| 1 | Bottom Ash Water Balance | 6 |
| 2 | Review Bottom Ash Modification Options | 2 |
| 3 | Finalize Bottom Ash Modification Options | 3 |
| 4 | Project Budget Approval | 6 |
| 5 | Detailed Engineering of Selected Modifications | 3 |
| 6 | Implementation of Modifications | 18 |
| 7 | Review of Modifications/Contingency | 6 |
| **Total** (months - excluding task overlaps) | | 44 |

DEF's discussion of each Task Number, as shown in the schedule in F is provided below in

[28] Duke Energy Florida, Response to Request for Additional Information at 1, May 20, 2016.

[29] Duke Energy Florida, Response to Request for Additional Information, at attachment 1, May 20, 2016.

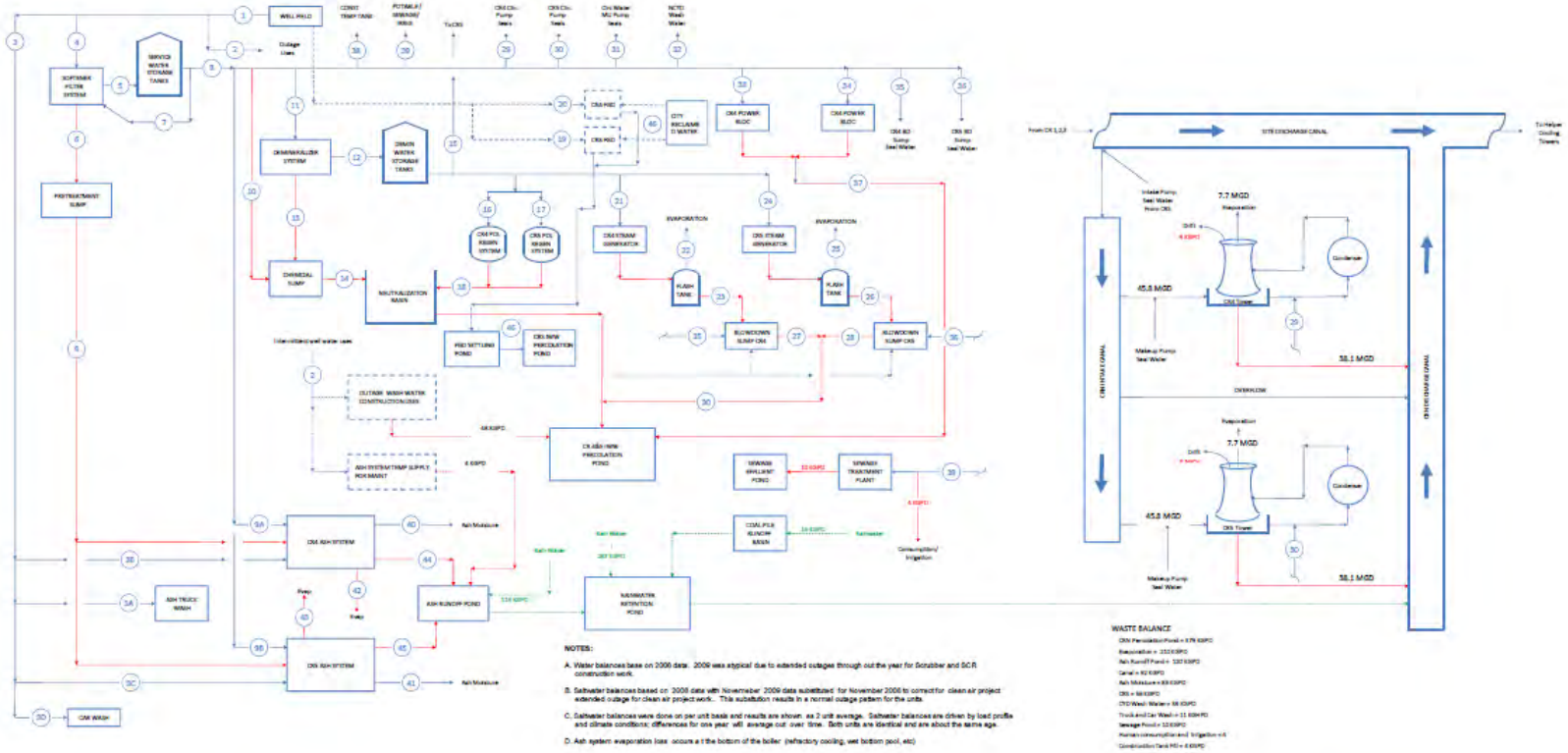
italics followed by critique and commentary:

- ***Task 1 - Bottom Ash Water Balance Review***

*An internal water balance was developed on the bottom ash system several years ago and identified water streams and approximate amounts contributing to the bottom ash system. Review of the information on the on bottom ash system water balance will include verifying all streams indicated, data verification, and review of system as pertains to new ELG regulation. Approximately six (6) months are necessary to perform these actions, which provides time if additional information is required for the evaluation.*

DEF asserts that an internal water balance must be developed, yet in its January 2016 application for NPDES permit renewal, just months ago, DEF provided a detailed water balance, as reproduced below.

The January 2016 renewal application was required be accurate and complete. Unless DEF failed to meet that requirement, which DEF has not indicated it has, DEF already has developed an accurate and complete water balance and should not need another six months to redevelop such a balance. Any verification needed can be made in a shorter time frame—and in parallel with the tasks described next. Thus, the six months built into the schedule for this task are a significant and unnecessary slack.




NOTES:

A. Water balances base on 2006 data. 2009 was atypical due to extended outages through out the year for Scrubber and SCR construction work.

B. Saltwater balances based on 2006 data with November 2009 data substituted for November 2006 to correct for clean air project extended outage for clean air project work. This substition results in a normal outage pattern for the units.

C. Saltwater balances were done on per unit basis and results are shown as 2 unit average. Saltwater balances are driven by load profile and climate conditions; differences for one year will average out over time. Both units are identical and are about the same age.

D. Ash system evaporation loss occurs at the bottom of the boiler (refractory cooling, wet bottom pool, etc)

WASTE BALANCE

CR4 Percolation Pond = 376 GDPD
Evaporation = 222 GDPD
Ash Runoff Pond = 120 GDPD
Canal = 82 GDPD
Ash Moisture = 69 GDPD
CR5 = 66 GDPD
CR5 West Water = 36 GDPD
Truck and Car Wash = 11 GDPD
Sewage Pond = 12 GDPD
Human consumption and Irrigation = 6
Combination Tank PD = 6 GDPD

## CRYSTAL RIVER UNITS 4 AND 5 WATER BALANCE

| STREAM NO. | 1 | 2 | 3 | 3A | 3B | 3C | 3D | 4 | 5 | 6 | 7 | 8 | 8A | 8B | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 | 25 | 26 | 27 | 28 | 29 | 30 | 31 | 32 | 33 | 34 | 35 | 36 | 37 | 38 | 39 | 40 | 41 | 42 | 43 | 44 | 45 | 46 | 47 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| FLOW (GDPD) | 1008 | 82 | 83 | 4 | 12 | 12 | 4 | 924 | 924 | 102 | 102 | 822 | 38 | 38 | 6 | 822 | 876 | 87 | 4 | 66 | 19 | 19 | 82 | 1200 | 1200 | 565 | 66 | 79 | 146 | 84 | 79 | 82 | 82 | 86 | 55 | 22 | 66 | 4 | 4 | 6 | 6 | 82 | 6 | 14 | 82 | 60 | 69 | 94 | 14 | 460 | 460 |
| FLOW (GPM) | 701 | 69 | 29 | 3 | 8 | 8 | 2 | 642 | 642 | 71 | 71 | 571 | 64 | 64 | 4 | 285 | 260 | 26 | 3 | 94 | 13 | 13 | 21 | 834 | 834 | 325 | 69 | 55 | 101 | 58 | 55 | 57 | 57 | 24 | 24 | 15 | 24 | 3 | 3 | 4 | 4 | 57 | 4 | 10 | 57 | 42 | 27 | 37 | 40 | 320 | 320 |

- ***Task 2 - Review Bottom Ash Modification Options***

*After review and finalization of a bottom ash water balance, a review of inputs and outputs will be performed. The review will indicate options available for managing the streams in the process. This could include a review of switching mechanical seals on pumps from wet to dry seals, evaluating rerouting streams to other locations, and system modifications required to meet the ELG regulations. The review of bottom ash modification options will last approximately two (2) months and will entail a review of possible pipe reroutes, potential changes in system operations, and system modifications required for ELG compliance.*

- ***Task 3 - Finalize Bottom Ash Modification Options***

*Once DEF outlines the modification options, the next step is to determine which modifications and piping reroutes will needed. A three (3) month schedule is proposed for this activity, which includes review of modifications and reroutes from an economical, operational, and environmental standpoint with DEF's management team members with responsibility over these different functional areas. Additional time is included to resolve unexpected questions or missing data that may arise when finalizing the modification options considered in Task 2.*

DEF's proposed 5-month duration for Tasks 2 and 3 to review and finalize bottom ash modification options is inexplicably long. So much time may be reasonable for a plant that has never before undertaken such reviews, but that is not the case here. Duke Energy already reported costs to the SEC and its shareholders for such modifications. It would be inconsistent with Duke's SEC and shareholder reporting obligations to report such costs without analytic support. Similar to Task 1, any further confirmation of Duke's options can be done in much less time. More specifically, if such confirmation is done in parallel with Task 1, any competent consultant, in-house engineer, or vendor should be able to complete Tasks 1-3 in no more than 2 to 3 months, including development of a budget estimate, as discussed next.

- ***Task 4 - Budget Approval***

*The final modification plan will include appropriate budgetary estimates. In accordance with company fiduciary duties, DEF will conduct an in-depth financial review of these budgetary estimates prior to securing the requested funds. Depending on the budgetary amount required and the number of modifications necessary, several review stages may be required prior to fund approval. The project budget approval time is anticipated to last six (6) months.*

DEF has already developed a budget estimate and Duke Energy has publicly reported this estimate since 2014. It is therefore unnecessary to schedule 6 additional months for budget approval. As Duke Energy's filing indicates, its Board has long been aware of the need to spend $50 million for ELG compliance at CREC. Anticipated cost expenditures reported to shareholders are typically based on appropriate engineering and planning studies and analyses, including budgetary quotes obtained from vendors for equipment and labor. This is especially true for publicly traded corporations such as Duke

Energy, which have significant legal obligations in its SEC filings. As a result, it is unreasonable to allow six additional months for internal budget approval.

- ***Task 5 - Detailed Engineering of Modifications***

*Once the modifications are selected and the budgetary approval finalized, the project will enter a detailed engineering design phase. This phase will likely include, but not limited to, pump sizing, pipe rerouting, vessel sizing, building additions or modifications, chemical sizing, system sizing, etc. An engineering firm may need to be identified and hired to help facilitate detailed engineering of the required modifications. DEF estimates it will take three (3) months to select an engineering firm with the requisite expertize and then work with the firm to finalize the detailed engineering design.*

If DEF were to hire the same engineering firm or consultant to confirm Tasks 1, 2, and 3, Task 5 can be run in parallel with those tasks, saving more time. Alternatively, Duke could save as much if not even more time if DEF were to complete Tasks 1, 2, 3, and 5 with in-house engineering staff and/or Duke's corporate engineering staff.

- ***Task 6 - Implementation of Modifications***

*Depending on bottom ash system modifications selected, construction or implementation may or may not be an extensive process. The ideal modifications selected would have minimal capital and operational and maintenance cost associated with them. However, lead times on components and routing of streams to alternative locations may nevertheless prolong the estimated duration, as well as, any unforeseen circumstances such as weather. Some modifications may require a unit outage to complete. Recognizing the current uncertainty associated with implementing plant modifications that have not yet been conceived, DEF conservatively estimates that eighteen (18) months will be required to retain a labor and construction firm to perform the selected modifications from Task 5 and includes time to implement modifications that may require a long term outage.*

Depending on the option selected, "implementation may or may not be an extensive process…" Thus, the possibility that this task will take 18 months, is a worst case estimate, with enough contingency already built in. For example, if DEF chooses to not replace the current almost closed loop system with a complete dry system, and instead chooses to engineer and build additional margin so that there is no possibility of any overflow of the bottom ash transport water under any circumstances to receiving waters, then implementation will likely take significantly less time.

- ***Task 7 - Review of Modifications/Contingency***

*Approximately six (6) months have been added to the compliance schedule for review of system modifications and/or contingency needed due to unforeseen events that may arise in other tasks. If the dry bottom ash system modifications have unintended or undesirable impacts on other processes or do not obtain satisfactory results, then additional modifications and reviews may be required to resolve.*

DEF's proposal of six months of additional contingency, on top of the contingency already built into Task 6, is simply unjustified additional slack in the schedule.

In summary, Tasks 1-5 can be reasonably completed in 6 to 9 months, if not less. Even assuming that Task 6 takes all of 18 months, which is highly unlikely, and allowing for a reasonable contingency of 3 months in Task 7, the overall project duration should be in the range of 27 to 30 months, instead of the 44 months projected by DEF, a saving of 17 months. This would allow compliance to be achieved by roughly August to November 2018. DEP should carefully review the unsupported schedule provided by DEF and, reasonably, require that Units 4 and 5 achieve bottom ash wastewater BAT compliance by no later than November 2018.

## 8. COMPARISON OF DEF'S COMPLIANCE SCHEDULE WITH THAT OF OTHER LARGE PROJECTS

DEF's 44-month schedule to achieve compliance with the bottom ash wastewater BAT provisions of the ELGs is simply unsupported. In part, this is due to DEF's unjustified and long projected timelines for certain tasks, particularly given the strong evidence of DEF and Duke's prior planning for compliance with these provisions, which began as far back as mid-2012.

Additionally, in comparison to other major projects at coal-fired units, the 44-month schedule proposed by DEF for bottom ash ELG BAT compliance is simply unreasonable and too long. Here, comparisons are made using the expected timelines for implementing complex,air pollution control projects at coal-fired boilers. These include the installation of wet or dry flue gas desulfurization ("FGD") or scrubbers for $SO_2$ control and the installation of Selective Catalytic Reduction ("SCR") for NOx control. These projects, for units of similar size to CREC Units 4 and 5, often cost hundreds of million dollars. Yet, while often complex and challenging to implement, timelines for such projects are in the range of 3 to 5 years—starting from conceptual engineering through completion during scheduled outages.

Three example timelines are shown below—for dry FGD, wet FGD, and SCR projects, respectively—as developed by a contractor for MISO, the independent system operator for the U.S..[30] These timelines are generally conservative– i.e., the timelines shown are generally high, reflecting the most complex installations, with typical projects capable of implementation in less time. Nonetheless, as the charts below show, the expected durations for implementing dry FGD or SCR are around 46 months and the same for wet FGD is around 56 months.

Given the far greater complexity associated with these projects, DEF's assertion is untenable that the relatively much simpler conversion of Unit 4 and Unit 5's wet sluicing bottom ash system to a dry system will take 44 months. If DEF decides to achieve compliance without

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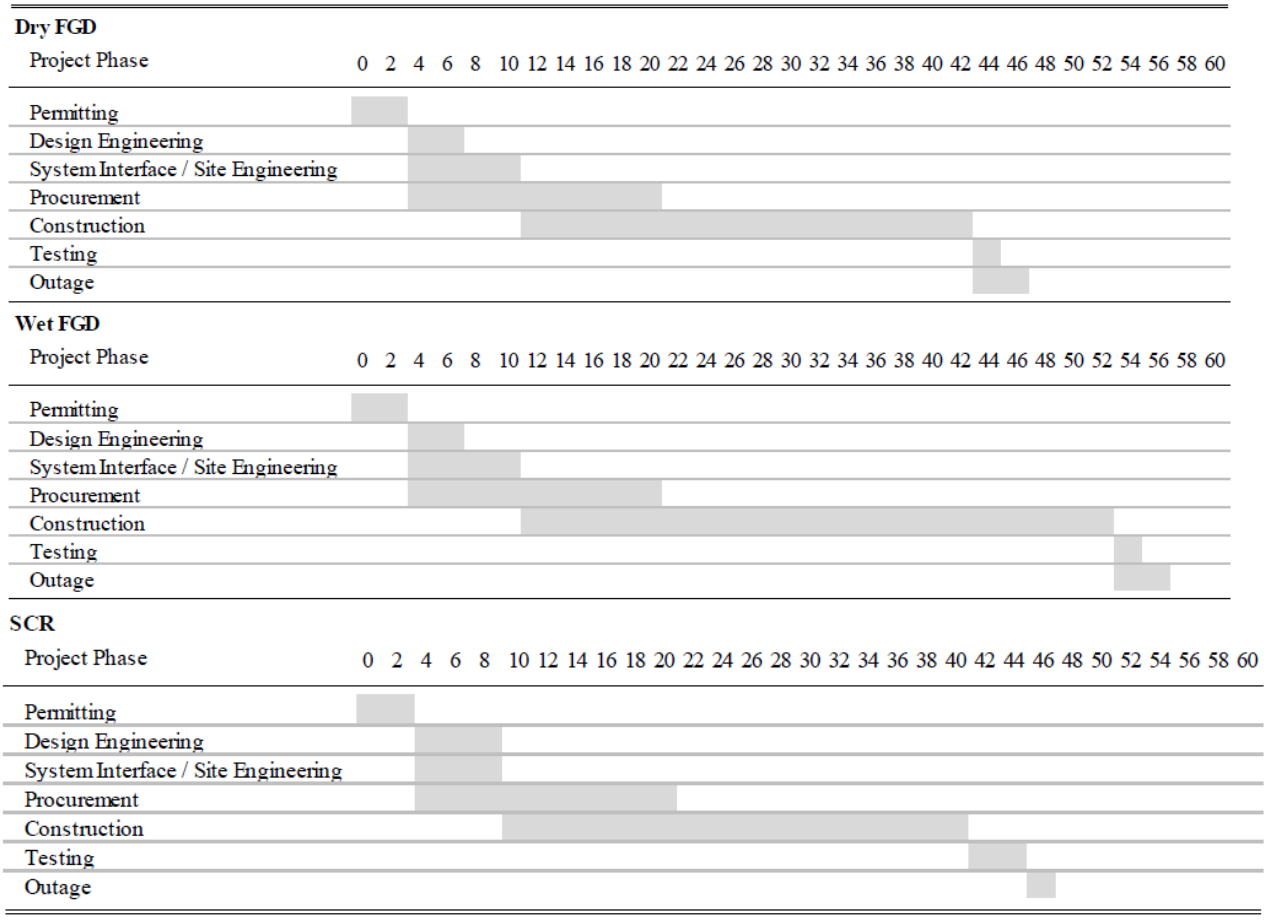
[30] The Brattle Group, *Supply Chain and Outage Analysis of MISO Coal Retrofits for MATS*, Appendix A (May 2012) (available at http://www.brattle.com/news-and-knowledge/news/brattle-economists-identify-challenges-for-miso-s-coal-fleet-to-comply-with-epa-s-mats-rule).

switching to a dry system, implementation times will be even shorter.

**Typical Timelines for Dry FGD, Wet FGD, DSI and ACI Retrofit Projects**




## 9. CONCLUSIONS

DEF does not need till February 1, 2020 to achieve compliance with a zero discharge standard for bottom ash wastewater at CREC Units 4 and 5. Rather, compliance can be achieved by November 2018, if not sooner.

Construction for bottom ash retrofits at Units 4 and 5 is anticipated to take, with a built in contingency, only 18 months. Other proposed tasks for acheving compliance should take signficiantly less time than DEF forecasts, particularly as DEF began ancticipating and planning for the revised ELGs as far back as 2012. Beginning in 2014, Duke Energy began publicly reporting projected compliance costs, suggesting that conceptual or detailed engineering evaluations and studies were undertaken and that Duke Energy's Board has been aware of these changes and costs for some time.

DEF's 44-month schedule to achieve compliance with the bottom ash BAT standard is

simply unsupported. Comparisons to similar retrofits and other large-scale, more complex projects at coal-burning units show far shorter timelines and demonstrate that DEF's proposed schedule is inflated. Moreover, as DEF is aware, there is a robust vendor community with experience in handling the types of retrofits needed to achieve compliance.

The available evidence does not support a 44-month timeline for eliminating bottom ash wastewtater discharges at CREC Units 4 and 5. In renewing the NPDES permit for CREC Units 4 and 5, DEP should require DEF to achieve compliance with the bottom ash wastewater ELGs no later than November 2018.

## 10. AUTHOR'S EXPERTISE AND QUALIFICATIONS

Dr. Ranajit Sahu has over twenty-five years of experience in the fields of environmental, mechanical, and chemical engineering including: program and project management services; design and specification of pollution control equipment for a wide range of emissions sources; soils and groundwater remediation including landfills as remedy; combustion engineering evaluations; energy studies; multimedia environmental regulatory compliance (involving statutes and regulations such as the Federal CAA and its Amendments, Clean Water Act, TSCA, RCRA, CERCLA, SARA, OSHA, NEPA as well as various related state statutes); transportation air quality impact analysis; multimedia compliance audits; multimedia permitting (including air quality NSR/PSD permitting, Title V permitting, NPDES permitting for industrial and storm water discharges, RCRA permitting, etc.), multimedia/multi-pathway human health risk assessments for toxics; air dispersion modeling; and regulatory strategy development and support including negotiation of consent agreements and orders.

Over the last twenty-three years, Dr. Sahu has consulted on several municipal landfill related projects addressing landfill gas generation, landfill gas collection, and the treatment/disposal/control of such gases in combustion equipment such as engines, turbines, and flares. In particular, Dr. Sahu has executed numerous projects relating to flare emissions from sources such as landfills as well as refineries and chemical plants. He has served as a peer-reviewer for EPA in relation to flare combustion efficiency, flare destruction efficiency, and flaring emissions.

A significant portion of Dr. Sahu's educational background and consulting experience deals with addressing environmental impacts due to coal-fired power plants including all aspects of air emissions from such plants but also environmental impacts from water/waste water, cooling water, and solid/hazardous wastes at such plants and impacts due to coal mining, transportation, and stockpiling.

Dr. Sahu holds a B.S., M.S., and Ph.D., in Mechanical Engineering, the first from the Indian Institute of Technology (Kharagpur, India) and the latter two from the California Institute of Technology (Caltech) in Pasadena, California. His research specialization was in the combustion of

coal and, among other things, understanding air pollution aspects of coal combustion in power plants as well as the formation of ash during combustion.

The opinions expressed in the report are Dr. Sahu's and are based on the data and facts available at the time of writing. Should additional relevant or pertinent information become available, Dr. Sahu reservesthe right to supplement the discussion and findings.

## ATTACHMENT A - RESUME

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### EXPERIENCE SUMMARY

Dr. Sahu has over twenty five years of experience in the fields of environmental, mechanical, and chemical engineering including: program and project management services; design and specification of pollution control equipment for a wide range of emissions sources; soils and groundwater remediation including landfills as remedy; combustion engineering evaluations; energy studies; multimedia environmental regulatory compliance (involving statutes and regulations such as the Federal CAA and its Amendments, Clean Water Act, TSCA, RCRA, CERCLA, SARA, OSHA, NEPA as well as various related state statutes); transportation air quality impact analysis; multimedia compliance audits; multimedia permitting (including air quality NSR/PSD permitting, Title V permitting, NPDES permitting for industrial and storm water discharges, RCRA permitting, etc.), multimedia/multi-pathway human health risk assessments for toxics; air dispersion modeling; and regulatory strategy development and support including negotiation of consent agreements and orders.

Specifically, over the last twenty-three years, Dr. Sahu has consulted on several municipal landfill related projects addressing landfill gas generation, landfill gas collection, and the treatment/disposal/control of such gases in combustion equipment such as engines, turbines, and flares. In particular, Dr. Sahu has executed numerous projects relating to flare emissions from sources such as landfills as well as refineries and chemical plants. He has served as a peer-reviewer for EPA in relation to flare combustion efficiency, flare destruction efficiency, and flaring emissions.

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He has over twenty-three years of project management experience and has successfully managed and executed numerous projects in this time period. This includes basic and applied research projects, design projects, regulatory compliance projects, permitting projects, energy studies, risk assessment projects, and projects involving the communication of environmental data and information to the public. Notably, he has successfully managed a complex soils and groundwater remediation project with a value of over $140 million involving soils characterization, development and implementation of the remediation strategy including construction of a CAMU/landfill and associated groundwater monitoring, regulatory and public interactions and other challenges.

He has provided consulting services to numerous private sector, public sector and public interest group clients. His major clients over the past twenty three years include various steel mills, petroleum refineries, cement companies, aerospace companies, power generation facilities, lawn and garden equipment manufacturers, spa manufacturers, chemical distribution facilities, and various entities in the public sector including EPA, the US Dept. of Justice, California DTSC, various municipalities, etc.). Dr. Sahu has performed projects in over 44 states, numerous local jurisdictions and internationally.

In addition to consulting, Dr. Sahu has taught numerous courses in several Southern California universities including UCLA (air pollution), UC Riverside (air pollution, process hazard analysis), and Loyola Marymount University (air pollution, risk assessment, hazardous waste management) for the past seventeen years. In this time period he has also taught at Caltech, his alma mater (various engineering courses), at the University of Southern California (air pollution controls) and at California State University, Fullerton (transportation and air quality).

Dr. Sahu has and continues to provide expert witness services in a number of environmental areas discussed above in both state and Federal courts as well as before administrative bodies.

**EXPERIENCE RECORD**

2000-present **Independent Consultant.** Providing a variety of private sector (industrial companies, land development companies, law firms, etc.) public sector (such as the US Department of Justice) and public interest group clients with project management, air quality consulting, waste remediation and management consulting, as well as regulatory and engineering support consulting services.

1995-2000 Parsons ES, **Associate, Senior Project Manager and Department Manager for** Air Quality/Geosciences/Hazardous Waste Groups, Pasadena. Responsible for the management of a group of approximately 24 air quality and environmental professionals, 15 geoscience, and 10 hazardous waste professionals providing full-service consulting, project management, regulatory compliance and A/E design assistance in all areas.

Parsons ES, **Manager for Air Source Testing Services**. Responsible for the management of 8 individuals in the area of air source testing and air regulatory permitting projects located in Bakersfield, California.

1992-1995 Engineering-Science, Inc. **Principal Engineer and Senior Project Manager** in the air quality department. Responsibilities included multimedia regulatory compliance and permitting (including hazardous and nuclear materials), air pollution engineering (emissions from stationary and mobile sources, control of criteria and air toxics, dispersion modeling, risk assessment, visibility analysis, odor analysis), supervisory functions and project management.

1990-1992 Engineering-Science, Inc. **Principal Engineer and Project Manager** in the air quality department. Responsibilities included permitting, tracking regulatory issues, technical analysis, and supervisory functions on numerous air, water, and hazardous waste projects. Responsibilities also include client and agency interfacing, project cost and schedule control, and reporting to internal and external upper management regarding project status.

1989-1990 Kinetics Technology International, Corp. **Development Engineer.** Involved in thermal engineering R&D and project work related to low-NOx ceramic radiant burners, fired heater NOx reduction, SCR design, and fired heater retrofitting.

1988-1989 Heat Transfer Research, Inc. **Research Engineer**. Involved in the design of fired heaters, heat exchangers, air coolers, and other non-fired equipment. Also did research in the area of heat exchanger tube vibrations.

## EDUCATION

1984-1988 Ph.D., Mechanical Engineering, California Institute of Technology (Caltech), Pasadena, CA.

1984 M. S., Mechanical Engineering, Caltech, Pasadena, CA.

1978-1983 B. Tech (Honors), Mechanical Engineering, Indian Institute of Technology (IIT) Kharagpur, India

## TEACHING EXPERIENCE

Caltech

"Thermodynamics," Teaching Assistant, California Institute of Technology, 1983, 1987.

"Air Pollution Control," Teaching Assistant, California Institute of Technology, 1985.

"Caltech Secondary and High School Saturday Program," - taught various mathematics (algebra through calculus) and science (physics and chemistry) courses to high school students, 1983-1989.

"Heat Transfer," - taught this course in the Fall and Winter terms of 1994-1995 in the Division of Engineering and Applied Science.

"Thermodynamics and Heat Transfer," Fall and Winter Terms of 1996-1997.

U.C. Riverside, Extension

"Toxic and Hazardous Air Contaminants," University of California Extension Program, Riverside, California. Various years since 1992.

"Prevention and Management of Accidental Air Emissions," University of California Extension Program, Riverside, California. Various years since 1992.

"Air Pollution Control Systems and Strategies," University of California Extension Program, Riverside, California, Summer 1992-93, Summer 1993-1994.

"Air Pollution Calculations," University of California Extension Program, Riverside, California, Fall 1993-94, Winter 1993-94, Fall 1994-95.

"Process Safety Management," University of California Extension Program, Riverside, California. Various years since 1992-2010.

"Process Safety Management," University of California Extension Program, Riverside, California, at SCAQMD, Spring 1993-94.

"Advanced Hazard Analysis - A Special Course for LEPCs," University of California Extension Program, Riverside, California, taught at San Diego, California, Spring 1993-1994.

"Advanced Hazardous Waste Management" University of California Extension Program, Riverside, California. 2005.

Loyola Marymount University

"Fundamentals of Air Pollution - Regulations, Controls and Engineering," Loyola Marymount University, Dept. of Civil Engineering. Various years since 1993.

"Air Pollution Control," Loyola Marymount University, Dept. of Civil Engineering, Fall 1994.

"Environmental Risk Assessment," Loyola Marymount University, Dept. of Civil Engineering. Various years since 1998.

"Hazardous Waste Remediation" Loyola Marymount University, Dept. of Civil Engineering. Various years since 2006.

University of Southern California

"Air Pollution Controls," University of Southern California, Dept. of Civil Engineering, Fall 1993, Fall 1994.

"Air Pollution Fundamentals," University of Southern California, Dept. of Civil Engineering, Winter 1994.

University of California, Los Angeles

"Air Pollution Fundamentals," University of California, Los Angeles, Dept. of Civil and Environmental Engineering, Spring 1994, Spring 1999, Spring 2000, Spring 2003, Spring 2006, Spring 2007, Spring 2008, Spring 2009.

International Programs

"Environmental Planning and Management," 5 week program for visiting Chinese delegation, 1994.

"Environmental Planning and Management," 1 day program for visiting Russian delegation, 1995.

"Air Pollution Planning and Management," IEP, UCR, Spring 1996.

"Environmental Issues and Air Pollution," IEP, UCR, October 1996.

## PROFESSIONAL AFFILIATIONS AND HONORS

President of India Gold Medal, IIT Kharagpur, India, 1983.

Member of the Alternatives Assessment Committee of the Grand Canyon Visibility Transport Commission, established by the Clean Air Act Amendments of 1990, 1992-present.

American Society of Mechanical Engineers: Los Angeles Section Executive Committee, Heat Transfer Division, and Fuels and Combustion Technology Division, 1987-present.

Air and Waste Management Association, West Coast Section, 1989-present.

## PROFESSIONAL CERTIFICATIONS

EIT, California (# XE088305), 1993.

REA I, California (#07438), 2000.

Certified Permitting Professional, South Coast AQMD (#C8320), since 1993.

QEP, Institute of Professional Environmental Practice, since 2000.

CEM, State of Nevada (#EM-1699). Expiration 10/07/2017.

## ATTACHMENT B – LIST OF PUBLICATIONS AND PRESENTATIONS

**PUBLICATIONS (PARTIAL LIST)**

"Physical Properties and Oxidation Rates of Chars from Bituminous Coals," with Y.A. Levendis, R.C. Flagan and G.R. Gavalas, *Fuel*, **67**, 275-283 (1988).

"Char Combustion: Measurement and Analysis of Particle Temperature Histories," with R.C. Flagan, G.R. Gavalas and P.S. Northrop, *Comb. Sci. Tech.* **60**, 215-230 (1988).

"On the Combustion of Bituminous Coal Chars," PhD Thesis, California Institute of Technology (1988).

"Optical Pyrometry: A Powerful Tool for Coal Combustion Diagnostics," *J. Coal Quality*, **8**, 17-22 (1989).

"Post-Ignition Transients in the Combustion of Single Char Particles," with Y.A. Levendis, R.C.Flagan and G.R. Gavalas, *Fuel*, **68**, 849-855 (1989).

"A Model for Single Particle Combustion of Bituminous Coal Char." Proc. ASME National Heat Transfer Conference, Philadelphia, **HTD-Vol. 106**, 505-513 (1989).

"Discrete Simulation of Cenospheric Coal-Char Combustion," with R.C. Flagan and G.R.Gavalas, *Combust. Flame*, **77**, 337-346 (1989).

"Particle Measurements in Coal Combustion," with R.C. Flagan, in "**Combustion Measurements**" (ed. N. Chigier), Hemisphere Publishing Corp. (1991).

"Cross Linking in Pore Structures and Its Effect on Reactivity," with G.R. Gavalas in preparation.

"Natural Frequencies and Mode Shapes of Straight Tubes," Proprietary Report for Heat Transfer Research Institute, Alhambra, CA (1990).

"Optimal Tube Layouts for Kamui SL-Series Exchangers," with K. Ishihara, Proprietary Report for Kamui Company Limited, Tokyo, Japan (1990).

"HTRI Process Heater Conceptual Design," Proprietary Report for Heat Transfer Research Institute, Alhambra, CA (1990).

"Asymptotic Theory of Transonic Wind Tunnel Wall Interference," with N.D. Malmuth and others, Arnold Engineering Development Center, Air Force Systems Command, USAF (1990).

"Gas Radiation in a Fired Heater Convection Section," Proprietary Report for Heat Transfer Research Institute, College Station, TX (1990).

"Heat Transfer and Pressure Drop in NTIW Heat Exchangers," Proprietary Report for Heat Transfer Research Institute, College Station, TX (1991).

"NOx Control and Thermal Design," Thermal Engineering Tech Briefs, (1994).

"From Puchase of Landmark Environmental Insurance to Remediation: Case Study in Henderson, Nevada," with Robin E. Bain and Jill Quillin, presented at the AQMA Annual Meeting, Florida, 2001.

"The Jones Act Contribution to Global Warming, Acid Rain and Toxic Air Contaminants," with Charles W. Botsford, presented at the AQMA Annual Meeting, Florida, 2001.

**PRESENTATIONS (PARTIAL LIST)**

"Pore Structure and Combustion Kinetics - Interpretation of Single Particle Temperature-Time Histories," with P.S. Northrop, R.C. Flagan and G.R. Gavalas, presented at the AIChE Annual Meeting, New York (1987).

"Measurement of Temperature-Time Histories of Burning Single Coal Char Particles," with R.C. Flagan, presented at the American Flame Research Committee Fall International Symposium, Pittsburgh, (1988).

"Physical Characterization of a Cenospheric Coal Char Burned at High Temperatures," with R.C. Flagan and G.R. Gavalas, presented at the Fall Meeting of the Western States Section of the Combustion Institute, Laguna Beach, California (1988).

"Control of Nitrogen Oxide Emissions in Gas Fired Heaters - The Retrofit Experience," with G. P. Croce and R. Patel, presented at the International Conference on Environmental Control of Combustion Processes (Jointly sponsored by the American Flame Research Committee and the Japan Flame Research Committee), Honolulu, Hawaii (1991).

"Air Toxics - Past, Present and the Future," presented at the Joint AIChE/AAEE Breakfast Meeting at the AIChE 1991 Annual Meeting, Los Angeles, California, November 17-22 (1991).

"Air Toxics Emissions and Risk Impacts from Automobiles Using Reformulated Gasolines," presented at the Third Annual Current Issues in Air Toxics Conference, Sacramento, California, November 9-10 (1992).

"Air Toxics from Mobile Sources," presented at the Environmental Health Sciences (ESE) Seminar Series, UCLA, Los Angeles, California, November 12, (1992).

"Kilns, Ovens, and Dryers - Present and Future," presented at the Gas Company Air Quality Permit Assistance Seminar, Industry Hills Sheraton, California, November 20, (1992).

"The Design and Implementation of Vehicle Scrapping Programs," presented at the 86th Annual Meeting of the Air and Waste Management Association, Denver, Colorado, June 12, 1993.

"Air Quality Planning and Control in Beijing, China," presented at the 87th Annual Meeting of the Air and Waste Management Association, Cincinnati, Ohio, June 19-24, 1994.

## ATTACHMENT C – PREVIOUS EXPERT WITNESS TESTIMONY

**1. Occasions where Dr. Sahu has provided <u>Written or Oral testimony before Congress</u>:**

(a) In July 2012, provided expert written and oral testimony to the House Subcommittee on Energy and the Environment, Committee on Science, Space, and Technology at a Hearing entitled "Hitting the Ethanol Blend Wall – Examining the Science on E15."

**2. Matters for which Dr. Sahu has provided <u>affidavits and expert reports</u> include:**

(b) Affidavit for Rocky Mountain Steel Mills, Inc. located in Pueblo Colorado – dealing with the technical uncertainties associated with night-time opacity measurements in general and at this steel mini-mill.

(c) Expert reports and depositions (2/28/2002 and 3/1/2002; 12/2/2003 and 12/3/2003; 5/24/2004) on behalf of the United States in connection with the Ohio Edison NSR Cases. *United States, et al. v. Ohio Edison Co., et al.*, C2-99-1181 (Southern District of Ohio).

(d) Expert reports and depositions (5/23/2002 and 5/24/2002) on behalf of the United States in connection with the Illinois Power NSR Case. *United States v. Illinois Power Co., et al.*, 99-833-MJR (Southern District of Illinois).

(e) Expert reports and depositions (11/25/2002 and 11/26/2002) on behalf of the United States in connection with the Duke Power NSR Case. *United States, et al. v. Duke Energy Corp.*, 1:00-CV-1262 (Middle District of North Carolina).

(f) Expert reports and depositions (10/6/2004 and 10/7/2004; 7/10/2006) on behalf of the United States in connection with the American Electric Power NSR Cases. *United States, et al. v. American Electric Power Service Corp., et al.*, C2-99-1182, C2-99-1250 (Southern District of Ohio).

(g) Affidavit (March 2005) on behalf of the Minnesota Center for Environmental Advocacy and others in the matter of the Application of Heron Lake BioEnergy LLC to construct and operate an ethanol production facility – submitted to the Minnesota Pollution Control Agency.

(h) Expert Report and Deposition (10/31/2005 and 11/1/2005) on behalf of the United States in connection with the East Kentucky Power Cooperative NSR Case. *United States v. East Kentucky Power Cooperative, Inc.*, 5:04-cv-00034-KSF (Eastern District of Kentucky).

(i) Affidavits and deposition on behalf of Basic Management Inc. (BMI) Companies in connection with the BMI vs. USA remediation cost recovery Case.

(j) Expert Report on behalf of Penn Future and others in the Cambria Coke plant permit challenge in Pennsylvania.

(k) Expert Report on behalf of the Appalachian Center for the Economy and the Environment and others in the Western Greenbrier permit challenge in West Virginia.

(l) Expert Report, deposition (via telephone on January 26, 2007) on behalf of various Montana petitioners (Citizens Awareness Network (CAN), Women's Voices for the Earth (WVE) and the Clark Fork Coalition (CFC)) in the Thompson River Cogeneration LLC Permit No. 3175-04 challenge.

(m) Expert Report and deposition (2/2/07) on behalf of the Texas Clean Air Cities Coalition at the Texas State Office of Administrative Hearings (SOAH) in the matter of the permit challenges to TXU Project Apollo's eight new proposed PRB-fired PC boilers located at seven TX sites.

(n) Expert Testimony (July 2007) on behalf of the Izaak Walton League of America and others in connection with the acquisition of power by Xcel Energy from the proposed Gascoyne Power Plant – at the State of Minnesota, Office of Administrative Hearings for the Minnesota PUC (MPUC No. E002/CN-06-1518; OAH No. 12-2500-17857-2).

(o) Affidavit (July 2007) Comments on the Big Cajun I Draft Permit on behalf of the Sierra Club – submitted to the Louisiana DEQ.

(p) Expert Report and Deposition (12/13/2007) on behalf of Commonwealth of Pennsylvania – Dept. of Environmental Protection, State of Connecticut, State of New York, and State of New Jersey (Plaintiffs) in connection with the Allegheny Energy NSR Case. *Plaintiffs v. Allegheny Energy Inc., et al.,* 2:05cv0885 (Western District of Pennsylvania).

(q) Expert Reports and Pre-filed Testimony before the Utah Air Quality Board on behalf of Sierra Club in the Sevier Power Plant permit challenge.

(r) Expert Report and Deposition (October 2007) on behalf of MTD Products Inc., in connection with *General Power Products, LLC v MTD Products Inc*., 1:06 CVA 0143 (Southern District of Ohio, Western Division) .

(s) Expert Report and Deposition (June 2008) on behalf of Sierra Club and others in the matter of permit challenges (Title V: 28.0801-29 and PSD: 28.0803-PSD) for the Big Stone II unit, proposed to be located near Milbank, South Dakota.

(t) Expert Reports, Affidavit, and Deposition (August 15, 2008) on behalf of Earthjustice in the matter of air permit challenge (CT-4631) for the Basin Electric Dry Fork station, under construction near Gillette, Wyoming before the Environmental Quality Council of the State of Wyoming.

(u) Affidavits (May 2010/June 2010 in the Office of Administrative Hearings))/Declaration and Expert Report (November 2009 in the Office of Administrative Hearings) on behalf of NRDC and the Southern Environmental Law Center in the matter of the air permit challenge for Duke

Cliffside Unit 6. Office of Administrative Hearing Matters 08 EHR 0771, 0835 and 0836 and 09 HER 3102, 3174, and 3176 (consolidated).

(v) Declaration (August 2008), Expert Report (January 2009), and Declaration (May 2009) on behalf of Southern Alliance for Clean Energy in the matter of the air permit challenge for Duke Cliffside Unit 6. *Southern Alliance for Clean Energy et al., v. Duke Energy Carolinas, LLC*, Case No. 1:08-cv-00318-LHT-DLH (Western District of North Carolina, Asheville Division).

(w) Declaration (August 2008) on behalf of the Sierra Club in the matter of Dominion Wise County plant MACT.us

(x) Expert Report (June 2008) on behalf of Sierra Club for the Green Energy Resource Recovery Project, MACT Analysis.

(y) Expert Report (February 2009) on behalf of Sierra Club and the Environmental Integrity Project in the matter of the air permit challenge for NRG Limestone's proposed Unit 3 in Texas.

(z) Expert Report (June 2009) on behalf of MTD Products, Inc., in the matter of *Alice Holmes and Vernon Holmes v. Home Depot USA, Inc., et al.*

(aa) Expert Report (August 2009) on behalf of Sierra Club and the Southern Environmental Law Center in the matter of the air permit challenge for Santee Cooper's proposed Pee Dee plant in South Carolina).

(bb) Statements (May 2008 and September 2009) on behalf of the Minnesota Center for Environmental Advocacy to the Minnesota Pollution Control Agency in the matter of the Minnesota Haze State Implementation Plans.

(cc) Expert Report (August 2009) on behalf of Environmental Defense, in the matter of permit challenges to the proposed Las Brisas coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH).

(dd) Expert Report and Rebuttal Report (September 2009) on behalf of the Sierra Club, in the matter of challenges to the proposed Medicine Bow Fuel and Power IGL plant in Cheyenne, Wyoming.

(ee) Expert Report (December 2009) and Rebuttal reports (May 2010 and June 2010) on behalf of the United States in connection with the Alabama Power Company NSR Case. *United States v. Alabama Power Company*, CV-01-HS-152-S (Northern District of Alabama, Southern Division).

(ff) Pre-filed Testimony (October 2009) on behalf of Environmental Defense and others, in the matter of challenges to the proposed White Stallion Energy Center coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH).

(gg) Pre-filed Testimony (July 2010) and Written Rebuttal Testimony (August 2010) on behalf of the State of New Mexico Environment Department in the matter of Proposed Regulation 20.2.350 NMAC – *Greenhouse Gas Cap and Trade Provisions,* No. EIB 10-04 (R), to the State of New Mexico, Environmental Improvement Board.

(hh) Expert Report (August 2010) and Rebuttal Expert Report (October 2010) on behalf of the United States in connection with the Louisiana Generating NSR Case. *United States v. Louisiana Generating, LLC*, 09-CV100-RET-CN (Middle District of Louisiana) – Liability Phase.

(ii) Declaration (August 2010), Reply Declaration (November 2010), Expert Report (April 2011), Supplemental and Rebuttal Expert Report (July 2011) on behalf of the United States in the matter of DTE Energy Company and Detroit Edison Company (Monroe Unit 2). *United States of America v. DTE Energy Company and Detroit Edison Company*, Civil Action No. 2:10-cv-13101-BAF-RSW (Eastern District of Michigan).

(jj) Expert Report and Deposition (August 2010) as well as Affidavit (September 2010) on behalf of Kentucky Waterways Alliance, Sierra Club, and Valley Watch in the matter of challenges to the NPDES permit issued for the Trimble County power plant by the Kentucky Energy and Environment Cabinet to Louisville Gas and Electric, File No. DOW-41106-047.

(kk) Expert Report (August 2010), Rebuttal Expert Report (September 2010), Supplemental Expert Report (September 2011), and Declaration (November 2011) on behalf of Wild Earth Guardians in the matter of opacity exceedances and monitor downtime at the Public Service Company of Colorado (Xcel)'s Cherokee power plant. No. 09-cv-1862 (District of Colorado).

(ll) Written Direct Expert Testimony (August 2010) and Affidavit (February 2012) on behalf of Fall-Line Alliance for a Clean Environment and others in the matter of the PSD Air Permit for Plant Washington issued by Georgia DNR at the Office of State Administrative Hearing, State of Georgia (OSAH-BNR-AQ-1031707-98-WALKER).

(mm) Deposition (August 2010) on behalf of Environmental Defense, in the matter of the remanded permit challenge to the proposed Las Brisas coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH).

(nn) Expert Report, Supplemental/Rebuttal Expert Report, and Declarations (October 2010, November 2010, September 2012) on behalf of New Mexico Environment Department (Plaintiff-Intervenor), Grand Canyon Trust and Sierra Club (Plaintiffs) in the matter of *Plaintiffs v. Public Service Company of New Mexico* (PNM), Civil No. 1:02-CV-0552 BB/ATC (ACE) (District of New Mexico).

(oo) Expert Report (October 2010) and Rebuttal Expert Report (November 2010) (BART Determinations for PSCo Hayden and CSU Martin Drake units) to the Colorado Air Quality Commission on behalf of Coalition of Environmental Organizations.

(pp) Expert Report (November 2010) (BART Determinations for TriState Craig Units, CSU Nixon Unit, and PRPA Rawhide Unit) to the Colorado Air Quality Commission on behalf of Coalition of Environmental Organizations.

(qq) Declaration (November 2010) on behalf of the Sierra Club in connection with the Martin Lake Station Units 1, 2, and 3. *Sierra Club v. Energy Future Holdings Corporation and Luminant Generation Company LLC*, Case No. 5:10-cv-00156-DF-CMC (Eastern District of Texas, Texarkana Division).

(rr) Pre-Filed Testimony (January 2011) and Declaration (February 2011) to the Georgia Office of State Administrative Hearings (OSAH) in the matter of Minor Source HAPs status for the proposed Longleaf Energy Associates power plant (OSAH-BNR-AQ-1115157-60-HOWELLS) on behalf of the Friends of the Chattahoochee and the Sierra Club).

(ss) Declaration (February 2011) in the matter of the Draft Title V Permit for RRI Energy MidAtlantic Power Holdings LLC Shawville Generating Station (Pennsylvania), ID No. 17-00001 on behalf of the Sierra Club.

(tt) Expert Report (March 2011), Rebuttal Expert Report (June 2011) on behalf of the United States in *United States of America v. Cemex, Inc.*, Civil Action No. 09-cv-00019-MSK-MEH (District of Colorado).

(uu) Declaration (April 2011) and Expert Report (July 16, 2012) in the matter of the Lower Colorado River Authority (LCRA)'s Fayette (Sam Seymour) Power Plant on behalf of the Texas Campaign for the Environment. *Texas Campaign for the Environment v. Lower Colorado River Authority,* Civil Action No. 4:11-cv-00791 (Southern District of Texas, Houston Division).

(vv) Declaration (June 2011) on behalf of the Plaintiffs MYTAPN in the matter of Microsoft-Yes, Toxic Air Pollution-No (MYTAPN) v. State of Washington, Department of Ecology and Microsoft Corporation Columbia Data Center to the Pollution Control Hearings Board, State of Washington, Matter No. PCHB No. 10-162.

(ww) Expert Report (June 2011) on behalf of the New Hampshire Sierra Club at the State of New Hampshire Public Utilities Commission, Docket No. 10-261 – the 2010 Least Cost Integrated Resource Plan (LCIRP) submitted by the Public Service Company of New Hampshire (re. Merrimack Station Units 1 and 2).

(xx) Declaration (August 2011) in the matter of the Sandy Creek Energy Associates L.P. Sandy Creek Power Plant on behalf of Sierra Club and Public Citizen. *Sierra Club, Inc. and Public Citizen, Inc. v. Sandy Creek Energy Associates, L.P.,* Civil Action No. A-08-CA-648-LY (Western District of Texas, Austin Division).

(yy) Expert Report (October 2011) on behalf of the Defendants in the matter of *John Quiles and Jeanette Quiles et al. v. Bradford-White Corporation, MTD Products, Inc., Kohler Co., et al.,* Case No. 3:10-cv-747 (TJM/DEP) (Northern District of New York).

(zz) Declaration (February 2012) and Second Declaration (February 2012) in the matter of *Washington Environmental Council and Sierra Club Washington State Chapter v. Washington State Department of Ecology and Western States Petroleum Association,* Case No. 11-417-MJP (Western District of Washington).

(aaa) Expert Report (March 2012) and Supplemental Expert Report (November 2013) in the matter of *Environment Texas Citizen Lobby, Inc and Sierra Club v. ExxonMobil Corporation et al.,* Civil Action No. 4:10-cv-4969 (Southern District of Texas, Houston Division).

(bbb) Declaration (March 2012) in the matter of *Center for Biological Diversity, et al. v. United States Environmental Protection Agency,* Case No. 11-1101 (consolidated with 11-1285, 11-1328 and 11-1336) (US Court of Appeals for the District of Columbia Circuit).

(ccc) Declaration (March 2012) in the matter of *Sierra Club v. The Kansas Department of Health and Environment*, Case No. 11-105,493-AS (Holcomb power plant) (Supreme Court of the State of Kansas).

*(ddd)* Declaration (March 2012) in the matter of the Las Brisas Energy Center *Environmental Defense Fund et al., v. Texas Commission on Environmental Quality,* Cause No. D-1-GN-11-001364 (District Court of Travis County, Texas, 261st Judicial District).

(eee) Expert Report (April 2012), Supplemental and Rebuttal Expert Report (July 2012), and Supplemental Rebuttal Expert Report (August 2012) on behalf of the states of New Jersey and Connecticut in the matter of the Portland Power plant *State of New Jersey and State of Connecticut (Intervenor-Plaintiff) v. RRI Energy Mid-Atlantic Power Holdings et al.,* Civil Action No. 07-CV-5298 (JKG) (Eastern District of Pennsylvania).

(fff) Declaration (April 2012) in the matter of the EPA's EGU MATS Rule, on behalf of the Environmental Integrity Project.

(ggg) Expert Report (August 2012) on behalf of the United States in connection with the Louisiana Generating NSR Case. *United States v. Louisiana Generating, LLC*, 09-CV100-RET-CN (Middle District of Louisiana) – Harm Phase.

(hhh) Declaration (September 2012) in the Matter of the Application of *Energy Answers Incinerator, Inc.* for a Certificate of Public Convenience and Necessity to Construct a 120 MW Generating Facility in Baltimore City, Maryland, before the Public Service Commission of Maryland, Case No. 9199.

(iii) Expert Report (October 2012) on behalf of the Appellants (Robert Concilus and Leah Humes) in the matter of Robert Concilus and Leah Humes v. Commonwealth of Pennsylvania Department of Environmental Protection and Crawford Renewable Energy, before the Commonwealth of Pennsylvania Environmental Hearing Board, Docket No. 2011-167-R.

(jjj) Expert Report (October 2012), Supplemental Expert Report (January 2013), and Affidavit (June 2013) in the matter of various Environmental Petitioners v. North Carolina

DENR/DAQ and Carolinas Cement Company, before the Office of Administrative Hearings, State of North Carolina.

(kkk) Pre-filed Testimony (October 2012) on behalf of No-Sag in the matter of the North Springfield Sustainable Energy Project before the State of Vermont, Public Service Board.

(lll) Pre-filed Testimony (November 2012) on behalf of Clean Wisconsin in the matter of Application of Wisconsin Public Service Corporation for Authority to Construct and Place in Operation a New Multi-Pollutant Control Technology System (ReACT) for Unit 3 of the Weston Generating Station, before the Public Service Commission of Wisconsin, Docket No. 6690-CE-197.

(mmm) Expert Report (February 2013) on behalf of Petitioners in the matter of Credence Crematory, Cause No. 12-A-J-4538 before the Indiana Office of Environmental Adjudication.

(nnn) Expert Report (April 2013), Rebuttal report (July 2013), and Declarations (October 2013, November 2013) on behalf of the Sierra Club in connection with the Luminant Big Brown Case. *Sierra Club v. Energy Future Holdings Corporation and Luminant Generation Company LLC*, Civil Action No. 6:12-cv-00108-WSS (Western District of Texas, Waco Division).

(ooo) Declaration (April 2013) on behalf of Petitioners in the matter of *Sierra Club, et al., (Petitioners) v Environmental Protection Agency et al. (Resppondents),* Case No., 13-1112, (Court of Appeals, District of Columbia Circuit).

(ppp) Expert Report (May 2013) and Rebuttal Expert Report (July 2013) on behalf of the Sierra Club in connection with the Luminant Martin Lake Case. *Sierra Club v. Energy Future Holdings Corporation and Luminant Generation Company LLC*, Civil Action No. 5:10-cv-0156-MHS-CMC (Eastern District of Texas, Texarkana Division).

(qqq) Declaration (August 2013) on behalf of A. J. Acosta Company, Inc., in the matter of *A. J. Acosta Company, Inc., v. County of San Bernardino*, Case No. CIVSS803651.

(rrr) Comments (October 2013) on behalf of the Washington Environmental Council and the Sierra Club in the matter of the Washington State Oil Refinery RACT (for Greenhouse Gases), submitted to the Washington State Department of Ecology, the Northwest Clean Air Agency, and the Puget Sound Clean Air Agency.

(sss) Statement (November 2013) on behalf of various Environmental Organizations in the matter of the Boswell Energy Center (BEC) Unit 4 Environmental Retrofit Project, to the Minnesota Public Utilities Commission, Docket No. E-015/M-12-920.

(ttt) Expert Report (December 2013) on behalf of the United States in *United States of America v. Ameren Missouri*, Civil Action No. 4:11-cv-00077-RWS (Eastern District of Missouri, Eastern Division).

(uuu) Expert Testimony (December 2013) on behalf of the Sierra Club in the matter of Public Service Company of New Hampshire Merrimack Station Scrubber Project and Cost Recovery, Docket No. DE 11-250, to the State of New Hampshire Public Utilities Commission.

(vvv) Expert Report (January 2014) on behalf of Baja, Inc., in *Baja, Inc., v. Automotive Testing and Development Services, Inc. et. al*, Civil Action No. 8:13-CV-02057-GRA (District of South Carolina, Anderson/Greenwood Division).

(www) Declaration (March 2014) on behalf of the Center for International Environmental Law, Chesapeake Climate Action Network, Friends of the Earth, Pacific Environment, and the Sierra Club (Plaintiffs) in the matter of *Plaintiffs v. the Export-Import Bank (Ex-Im Bank) of the United States*, Civil Action No. 13-1820 RC (District Court for the District of Columbia).

(xxx) Declaration (April 2014) on behalf of Respondent-Intervenors in the matter of *Mexichem Specialty Resins Inc., et al., (Petitioners) v Environmental Protection Agency et al.,* Case No., 12-1260 (and Consolidated Case Nos. 12-1263, 12-1265, 12-1266, and 12-1267), (Court of Appeals, District of Columbia Circuit).

(yyy) Direct Prefiled Testimony (June 2014) on behalf of the Michigan Environmental Council and the Sierra Club in the matter of the Application of DTE Electric Company for Authority to Implement a Power Supply Cost Recovery (PSCR) Plan in its Rate Schedules for 2014 Metered Jurisdictional Sales of Electricity, Case No. U-17319 (Michigan Public Service Commission).

(zzz) Expert Report (June 2014) on behalf of ECM Biofilms in the matter of the US Federal Trade Commission (FTC) v. ECM Biofilms (FTC Docket #9358).

(aaaa) Direct Prefiled Testimony (August 2014) on behalf of the Michigan Environmental Council and the Sierra Club in the matter of the Application of Consumers Energy Company for Authority to Implement a Power Supply Cost Recovery (PSCR) Plan in its Rate Schedules for 2014 Metered Jurisdictional Sales of Electricity, Case No. U-17317 (Michigan Public Service Commission).

(bbbb) Declaration (July 2014) on behalf of Public Health Intervenors in the matter of *EME Homer City Generation v. US EPA* (Case No. 11-1302 and consolidated cases) relating to the lifting of the stay entered by the Court on December 30, 2011 (US Court of Appeals for the District of Columbia).

(cccc) Expert Report (September 2014), Rebuttal Expert Report (December 2014) and Supplemental Expert Report (March 2015) on behalf of Plaintiffs in the matter of *Sierra Club and Montana Environmental Information Center (Plaintiffs) v. PPL Montana LLC, Avista Corporation, Puget Sound Energy, Portland General Electric Company, Northwestern Corporation, and Pacificorp (Defendants)*, Civil Action No. CV 13-32-BLG-DLC-JCL (US District Court for the District of Montana, Billings Division).

(dddd) Expert Report (November 2014) on behalf of Niagara County, the Town of Lewiston, and the Villages of Lewiston and Youngstown in the matter of CWM Chemical Services, LLC New

York State Department of Environmental Conservation (NYSDEC) Permit Application Nos.: 9-2934-00022/00225, 9-2934-00022/00231, 9-2934-00022/00232, and 9-2934-00022/00249 (pending).

(eeee) Pre-filed Direct Testimony (March 2015) and Rebuttal Testimony (August 2015) on behalf of Friends of the Columbia Gorge in the matter of the Application for a Site Certificate for the Troutdale Energy Center before the Oregon Energy Facility Siting Council.

(ffff) Expert Report (March 2015) on behalf of Plaintiffs in the matter of *Conservation Law Foundation v. Broadrock Gas Services LLC, Rhode Island LFG GENCO LLC, and Rhode Island Resource Recovery Corporation (Defendants)*, Civil Action No. 1:13-cv-00777-M-PAS (US District Court for the District of Rhode Island).

(gggg) Direct Prefiled Testimony (May 2015) on behalf of the Michigan Environmental Council, the Natural Resources Defense Council, and the Sierra Club in the matter of the Application of DTE Electric Company for Authority to Increase its Rates, Amend its Rate Schedules and Rules Governing the Distribution and Supply of Electric Energy and for Miscellaneous Accounting Authority, Case No. U-17767 (Michigan Public Service Commission).

(hhhh) Expert Report (July 2015) and Rebuttal Expert Report (July 2015) on behalf of Plaintiffs in the matter of *Northwest Environmental Defense Center et. al., v. Cascade Kelly Holdings LLC, d/b/a Columbia Pacific Bio-Refinery, and Global Partners LP (Defendants)*, Civil Action No. 3:14-cv-01059-SI (US District Court for the District of Oregon, Portland Division).

(iiii) Declaration (August 2015, Docket No. 1570376) in support of "Opposition of Respondent-Intervenors American Lung Association, et. al., to Tri-State Generation's Emergency Motion;" Declaration (September 2015, Docket No. 1574820) in support of "Joint Motion of the state, Local Government, and Public Health Respondent-Intervenors for Remand Without Vacatur," *White Stallion Energy Center, LLC v. US EPA*, Case No. 12-1100 (US Court of Appeals for the District of Columbia).

(jjjj) Expert Report (November 2015) on behalf of Appellants in the matter of *Sierra Club, et al. v. Craig W. Butler, Director of Ohio Environmental Protection Agency ey al.,* ERAC Case No. 14-256814.

**3. Occasions where Dr. Sahu has provided oral testimony <u>in depositions, at trial or in similar proceedings</u> include the following:**

(kkkk) Deposition on behalf of Rocky Mountain Steel Mills, Inc. located in Pueblo, Colorado – dealing with the manufacture of steel in mini-mills including methods of air pollution control and BACT in steel mini-mills and opacity issues at this steel mini-mill.

(llll) Trial Testimony (February 2002) on behalf of Rocky Mountain Steel Mills, Inc. in Denver District Court.

(mmmm) Trial Testimony (February 2003) on behalf of the United States in the Ohio Edison NSR Cases, *United States, et al. v. Ohio Edison Co., et al.*, C2-99-1181 (Southern District of Ohio).

(nnnn) Trial Testimony (June 2003) on behalf of the United States in the Illinois Power NSR Case, *United States v. Illinois Power Co., et al.*, 99-833-MJR (Southern District of Illinois).

(oooo) Deposition (10/20/2005) on behalf of the United States in connection with the Cinergy NSR Case. *United States, et* al. *v. Cinergy Corp., et al.*, IP 99-1693-C-M/S (Southern District of Indiana).

(pppp) Oral Testimony (August 2006) on behalf of the Appalachian Center for the Economy and the Environment re. the Western Greenbrier plant, WV before the West Virginia DEP.

(qqqq) Oral Testimony (May 2007) on behalf of various Montana petitioners (Citizens Awareness Network (CAN), Women's Voices for the Earth (WVE) and the Clark Fork Coalition (CFC)) re. the Thompson River Cogeneration plant before the Montana Board of Environmental Review.

(rrrr) Oral Testimony (October 2007) on behalf of the Sierra Club re. the Sevier Power Plant before the Utah Air Quality Board.

(ssss) Oral Testimony (August 2008) on behalf of the Sierra Club and Clean Water re. Big Stone Unit II before the South Dakota Board of Minerals and the Environment.

(tttt) Oral Testimony (February 2009) on behalf of the Sierra Club and the Southern Environmental Law Center re. Santee Cooper Pee Dee units before the South Carolina Board of Health and Environmental Control.

(uuuu) Oral Testimony (February 2009) on behalf of the Sierra Club and the Environmental Integrity Project re. NRG Limestone Unit 3 before the Texas State Office of Administrative Hearings (SOAH) Administrative Law Judges.

(vvvv) Deposition (July 2009) on behalf of MTD Products, Inc., in the matter of *Alice Holmes and Vernon Holmes v. Home Depot USA, Inc., et al.*

(wwww) Deposition (October 2009) on behalf of Environmental Defense and others, in the matter of challenges to the proposed Coleto Creek coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH).

(xxxx) Deposition (October 2009) on behalf of Environmental Defense, in the matter of permit challenges to the proposed Las Brisas coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH).

(yyyy) Deposition (October 2009) on behalf of the Sierra Club, in the matter of challenges to the proposed Medicine Bow Fuel and Power IGL plant in Cheyenne, Wyoming.

(zzzz) Deposition (October 2009) on behalf of Environmental Defense and others, in the matter of challenges to the proposed Tenaska coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH). (April 2010).

(aaaaa) Oral Testimony (November 2009) on behalf of the Environmental Defense Fund re. the Las Brisas Energy Center before the Texas State Office of Administrative Hearings (SOAH) Administrative Law Judges.

(bbbbb) Deposition (December 2009) on behalf of Environmental Defense and others, in the matter of challenges to the proposed White Stallion Energy Center coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH).

(ccccc) Oral Testimony (February 2010) on behalf of the Environmental Defense Fund re. the White Stallion Energy Center before the Texas State Office of Administrative Hearings (SOAH) Administrative Law Judges.

(ddddd) Deposition (June 2010) on behalf of the United States in connection with the Alabama Power Company NSR Case. *United States v. Alabama Power Company*, CV-01-HS-152-S (Northern District of Alabama, Southern Division).

(eeeee) Trial Testimony (September 2010) on behalf of Commonwealth of Pennsylvania – Dept. of Environmental Protection, State of Connecticut, State of New York, State of Maryland, and State of New Jersey (Plaintiffs) in connection with the Allegheny Energy NSR Case in US District Court in the Western District of Pennsylvania. *Plaintiffs v. Allegheny Energy Inc., et al.,* 2:05cv0885 (Western District of Pennsylvania).

(fffff) Oral Direct and Rebuttal Testimony (September 2010) on behalf of Fall-Line Alliance for a Clean Environment and others in the matter of the PSD Air Permit for Plant Washington issued by Georgia DNR at the Office of State Administrative Hearing, State of Georgia (OSAH-BNR-AQ-1031707-98-WALKER).

(ggggg) Oral Testimony (September 2010) on behalf of the State of New Mexico Environment Department in the matter of Proposed Regulation 20.2.350 NMAC – *Greenhouse Gas Cap and Trade Provisions,* No. EIB 10-04 (R), to the State of New Mexico, Environmental Improvement Board.

(hhhhh) Oral Testimony (October 2010) on behalf of the Environmental Defense Fund re. the Las Brisas Energy Center before the Texas State Office of Administrative Hearings (SOAH) Administrative Law Judges.

(iiiii) Oral Testimony (November 2010) regarding BART for PSCo Hayden, CSU Martin Drake units before the Colorado Air Quality Commission on behalf of the Coalition of Environmental Organizations.

(jjjjj) Oral Testimony (December 2010) regarding BART for TriState Craig Units, CSU Nixon Unit, and PRPA Rawhide Unit) before the Colorado Air Quality Commission on behalf of the Coalition of Environmental Organizations.

(kkkkk) Deposition (December 2010) on behalf of the United States in connection with the Louisiana Generating NSR Case. *United States v. Louisiana Generating, LLC*, 09-CV100-RET-CN (Middle District of Louisiana).

(llllll) Deposition (February 2011 and January 2012) on behalf of Wild Earth Guardians in the matter of opacity exceedances and monitor downtime at the Public Service Company of Colorado (Xcel)'s Cherokee power plant. No. 09-cv-1862 (D. Colo.).

(mmmmm) Oral Testimony (February 2011) to the Georgia Office of State Administrative Hearings (OSAH) in the matter of Minor Source HAPs status for the proposed Longleaf Energy Associates power plant (OSAH-BNR-AQ-1115157-60-HOWELLS) on behalf of the Friends of the Chattahoochee and the Sierra Club).

(nnnnn) Deposition (August 2011) on behalf of the United States in *United States of America v. Cemex, Inc.*, Civil Action No. 09-cv-00019-MSK-MEH (District of Colorado).

(ooooo) Deposition (July 2011) and Oral Testimony at Hearing (February 2012) on behalf of the Plaintiffs MYTAPN in the matter of Microsoft-Yes, Toxic Air Pollution-No (MYTAPN) v. State of Washington, Department of Ecology and Microsoft Corporation Columbia Data Center to the Pollution Control Hearings Board, State of Washington, Matter No. PCHB No. 10-162.

(ppppp) Oral Testimony at Hearing (March 2012) on behalf of the United States in connection with the Louisiana Generating NSR Case. *United States v. Louisiana Generating, LLC*, 09-CV100-RET-CN (Middle District of Louisiana).

(qqqqq) Oral Testimony at Hearing (April 2012) on behalf of the New Hampshire Sierra Club at the State of New Hampshire Public Utilities Commission, Docket No. 10-261 – the 2010 Least Cost Integrated Resource Plan (LCIRP) submitted by the Public Service Company of New Hampshire (re. Merrimack Station Units 1 and 2).

(rrrrr) Oral Testimony at Hearing (November 2012) on behalf of Clean Wisconsin in the matter of Application of Wisconsin Public Service Corporation for Authority to Construct and Place in Operation a New Multi-Pollutant Control Technology System (ReACT) for Unit 3 of the Weston Generating Station, before the Public Service Commission of Wisconsin, Docket No. 6690-CE-197.

(sssss) Deposition (March 2013) in the matter of various Environmental Petitioners v. North Carolina DENR/DAQ and Carolinas Cement Company, before the Office of Administrative Hearings, State of North Carolina.

(ttttt) Deposition (August 2013) on behalf of the Sierra Club in connection with the Luminant Big Brown Case. *Sierra Club v. Energy Future Holdings Corporation and Luminant Generation Company LLC*, Civil Action No. 6:12-cv-00108-WSS (Western District of Texas, Waco Division).

(uuuuu) Deposition (August 2013) on behalf of the Sierra Club in connection with the Luminant Martin Lake Case. *Sierra Club v. Energy Future Holdings Corporation and Luminant Generation Company LLC*, Civil Action No. 5:10-cv-0156-MHS-CMC (Eastern District of Texas, Texarkana Division).

(vvvvv) Deposition (February 2014) on behalf of the United States in *United States of America v. Ameren Missouri*, Civil Action No. 4:11-cv-00077-RWS (Eastern District of Missouri, Eastern Division).

(wwwww) Trial Testimony (February 2014) in the matter of *Environment Texas Citizen Lobby, Inc and Sierra Club v. ExxonMobil Corporation et al.,* Civil Action No. 4:10-cv-4969 (Southern District of Texas, Houston Division).

(xxxxx) Trial Testimony (February 2014) on behalf of the Sierra Club in connection with the Luminant Big Brown Case. *Sierra Club v. Energy Future Holdings Corporation and Luminant Generation Company LLC*, Civil Action No. 6:12-cv-00108-WSS (Western District of Texas, Waco Division).

(yyyyy) Deposition (June 2014) and Trial (August 2014) on behalf of ECM Biofilms in the matter of the *US Federal Trade Commission (FTC) v. ECM Biofilms* (FTC Docket #9358).

(zzzzz) Deposition (February 2015) on behalf of Plaintiffs in the matter of *Sierra Club and Montana Environmental Information Center (Plaintiffs) v. PPL Montana LLC, Avista Corporation, Puget Sound Energy, Portland General Electric Company, Northwestern Corporation, and Pacificorp (Defendants)*, Civil Action No. CV 13-32-BLG-DLC-JCL (US District Court for the District of Montana, Billings Division).

(aaaaaa) Oral Testimony at Hearing (April 2015) on behalf of Niagara County, the Town of Lewiston, and the Villages of Lewiston and Youngstown in the matter of CWM Chemical Services, LLC New York State Department of Environmental Conservation (NYSDEC) Permit Application Nos.: 9-2934-00022/00225, 9-2934-00022/00231, 9-2934-00022/00232, and 9-2934-00022/00249 (pending).

(bbbbbb) Deposition (August 2015) on behalf of Plaintiff in the matter of *Conservation Law Foundation (Plaintiff) v. Broadrock Gas Services LLC, Rhode Island LFG GENCO LLC, and Rhode Island Resource Recovery Corporation (Defendants)*, Civil Action No. 1:13-cv-00777-M-PAS (US District Court for the District of Rhode Island).

(cccccc) Testimony at Hearing (August 2015) on behalf of the Sierra Club in the matter of *Amendments to 35 Illinois Administrative Code Parts 214, 217, and 225* before the Illinois Pollution Control Board, R15-21.

(dddddd) Deposition (May 2015) on behalf of Plaintiffs in the matter of *Northwest Environmental Defense Center et. al., (Plaintiffs) v. Cascade Kelly Holdings LLC, d/b/a Columbia Pacific Bio-Refinery, and Global Partners LP (Defendants)*, Civil Action No. 3:14-cv-01059-SI (US District Court for the District of Oregon, Portland Division).

(eeeeee) Trial Testimony (October 2015) on behalf of Plaintiffs in the matter of *Northwest Environmental Defense Center et. al., (Plaintiffs) v. Cascade Kelly Holdings LLC, d/b/a Columbia Pacific Bio-Refinery, and Global Partners LP (Defendants)*, Civil Action No. 3:14-cv-01059-SI (US District Court for the District of Oregon, Portland Division).