DEF000003

July 7, 2016

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

Before the Commission

In the Matter of	)	
	)	
Duke Energy Florida, LLC	)	Docket Nos. 52-029 and 52-030
	)	
(Levy Nuclear Plant, Units 1 and 2)	)	

DUKE ENERGY FLORIDA'S RESPONSES TO PRE-HEARING QUESTIONS

In accordance with the Notice of Hearing[1] and the Commission's Order (Transmitting Pre-Hearing Questions) (June 24, 2016), Duke Energy Florida, LLC (Duke Energy) submits the following responses to each of the questions posed to it by the Commission.

Question 1. In its analysis of Seismic Seiches, the Safety Evaluation Report (SER) at 2-165 states: "Parameters for the maximum submarine landslide were determined for each of the provinces, except for the Campeche Escarpments where we are awaiting additional data."

New escarpment studies have recently been released (e.g., Monterey Bay Aquarium Research Institute, 2013) that map the escarpment in considerably more detail than studies that are reflected in SER Section 2.4. Did the Staff consider the more recent studies and their possible effect on the conclusions in the SER? If so what were the results?

December 2013, American Geophysical Union Fall Meeting Presentation, Poster P41F-1985. December 12, 2013. Multibeam mapping of the Cretaceous-Paleogene meteorite impact deposits on the Campeche Escarpment, Yucatán, Mexico. Roberto Gwiazda (presenter); Charles K. Paull; David W. Caress; Mario Rebolledo-Vieyra; Jaime U. Fucugauchi; Iza Canales; Esther J. Sumner; Xavier Tubau Carbonell; Eve M. Lundsten; Krystle Anderson.
Online: http://www.mbari.org/mapping-the-demise-of-the-dinosaurs-2/

Response:

The information presented in the LNP FSAR depended on an analysis of tsunami producing landslides/sloughs in the Gulf of Mexico in a report by the USGS (Brinks et al. 2007). The new reference referred to in the question above is linked to only sonar figures of the

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[1] Duke Energy Florida, LLC, Levy Nuclear Plant, Units 1 and 2, Combined License Application, Notice of Hearing, 81 Fed. Reg. 39,720 (June 17, 2016).

Campeche Escarpment without any assessments. However, it appears from the figures that the potential slough area is oriented toward Texas and Louisiana and that Florida would only receive peripheral wave action from a landslide along most of the Campeche Escarpment. The portions of Campeche Escarpment that do point toward Florida were not surveyed. The available bathymetry data from satellite imagery indicate that the northeast face of Campeche Escarpment is stable with no evidence of landslides.

There are no tsunamic landslide sources in the Campeche area being used for the Gulf of Mexico National Tsunami Hazard Mitigation Program (NTHMP) inundation mapping. A December 2015 update for historical record and sources was jointly published by NOAA and the USGS does not change the Gulf source data presented in the FSAR.

Question 3. Subsection 2.5.4.4.3.7, "Grouting of Karst Features," of the SER articulates that the purpose of the grouting program is to create a semi-impermeable barrier to reduce ground water inflow into the excavation, thereby reducing dewatering requirements during construction. The program will grout the eroded vertical joint sets and bedding planes through primary, secondary and if necessary through tertiary grouting to achieve the desired seepage cutoff. As noted in the subsection, the Staff has accepted that that the foundation system is designed to accommodate isolated voids up to 10 ft. in size, which is at least double the conservatively estimated lateral dimension of any actual void intercepted. Finally, the Staff acknowledges that the grout program is not intended to strengthen the foundation, but only reduce inflow into the excavation during construction. Filling of all the voids is therefore not required for stability. However, the Staff concludes, the proposed grouting in combination with the diaphragm wall, and the 35-foot Roller Compacted Concrete (RCC) bridging mat will improve the nuclear island basemat/foundation conditions.

What inspections, tests, and acceptance criteria will the applicant use to demonstrate that:

1. the grouted rock will perform its intended function over the life of the plant; and
2. potential sinkholes in the rock will be filled with grout to minimize the inflow of water over the life of the plant?

If none, why are they not necessary?

Response:

The RCC Bridging Mat is designed to bridge conservatively postulated voids without any credit given to grouting. The purpose of the grouting program is to reduce the ground water inflow during construction by creating a relatively impervious zone of limestone at the bottom of the NI excavation. This is not a safety-related function. However, the grouting program will be conducted under a quality program.

While grouting will have the beneficial effect of impeding flow through the uppermost Avon Park Formation and, thereby, minimize the potential for the initiation and/or growth of solution activity by diminishing porosity and reducing permeability, the maximum growth of solution activity was conservatively calculated to be less than 1/4 inch over the life of the plant without the benefit of grouting.

The grout does not have any safety-related function over the life of the plant. Therefore, no inspections, tests, or acceptance criteria are necessary.

Question 4. The uniqueness of the RCC bridging mat and grouted subgrade below the nuclear island has prompted the applicant (as presented in a slide to the Advisory Committee on Reactor Safeguards Subcommittee meeting of October 18, 2011) to consider a long-term monitoring program of the foundation system. Given the importance of the RCC bridging mat, as a Category I Structure, should the plant technical specifications include a condition/performance monitoring program with applicable surveillance and limiting condition for operation requirements?

Response:

Subsection 2.5.4.3 of the AP1000 DCD, Revision 19, describes the design requirements and considerations for settlement of the nuclear island and the nuclear island foundation that must be addressed by the Combined License applicant. In the LNP COL Application (COLA), Duke Energy provided site-specific information to address rock characteristics affecting the stability of the nuclear island including foundation rebound, settlement, and differential settlement (LNP COL 2.5-12), address provision for instrumentation for monitoring the performance of the foundations of the nuclear island, along with the location for bench marks and markers for monitoring the settlement (LNP COL 2.5-13), and address the verification that both total and differential settlements of the nuclear island, and the differential settlements between the nuclear island and other buildings do not exceed the AP1000 standard design (LNP COL 2.5-16). The FSAR states: "A monitoring program will be implemented after construction to monitor any long-term settlement. While long-term settlement is expected to be minimal, the settlement bench marks installed during the construction phase will be used post-construction to monitor settlement of the nuclear island structures" (FSAR Subsection 2.5.4.10.3.5). This is consistent with the ACRS presentation (slide 39) which indicated that a long-term monitoring program would be employed.

While the RCC bridging mat is important as a Category I Structure, including a limiting condition for operation and surveillance requirements in the technical specifications is unnecessary and inconsistent with regulatory standards and practice. A surveillance requirement in the technical specifications is unnecessary not only because of the existing commitment in the FSAR but also because the Maintenance Rule (MR) program will require monitoring of the RCC bridging mat. Duke Energy has incorporated NEI 07-02A, "Generic FSAR Template Guidance for Maintenance Rule Program Description for Plants Licensed Under 10 CFR Part 52," in Section 17.6 of the COLA Part 2 FSAR. As part of the MR scoping requirements in 10 CFR 50.65(b), all SSCs identified as risk-significant under the Reliability Assurance Program for the design phase (D-RAP) are included within the initial MR scope as high safety significance SSCs. This includes risk-significant SSCs identified as part of the design certification phase or follow-on COL applicant/holder phases of D-RAP.

In Section 17.4 of the COLA Part 2 FSAR, the RCC bridging mat is included in the D-RAP program as a site-specific SSC that is risk-significant. Table 17.4-201 identifies the rationale for including the bridging mat within the scope of D-RAP (e.g., SMA - Seismic Margin Analysis), along with the insights and assumptions applicable to this SSC.

As a result, the RCC bridging mat will be subject to the MR requirements for Preventive Maintenance (10 CFR 50.65(a)(2)), Periodic Evaluation of Monitoring and Preventive Maintenance (10 CFR 50.65(a)(3)), and Risk Assessment and Risk Management (10 CFR 50.65(a)(4)), as applicable. These MR activities are sufficient to ensure that settlement beyond the design criteria specified in the AP1000 DCD will be identified in a timely manner to preclude an impact to the safety of the Levy Nuclear Plant and preclude impact to the public health and safety.

Question 5. Alkali-carbonate reaction is observed in certain Dolomitic rocks. Dolomitic limestone may include up to 50% dolomite. As noted during the supplemental borings, the collected specimens indicated that the noted voids were filled with fragmented rock. Since grouting is expected to reduce the porosity and voids of the underlying rock, it is possible that during the process, the Calcium Hydroxide (Ca(OH)2) or Portlandite of the grout cement may react with the fragmented Dolomite (CaMg(CO3)2). The reaction (dedolomitization) and subsequent potential recrystallization to Brucite (Mg(OH)2) may cause considerable expansion.

Has the applicant looked at the potential for alkali- carbonate reaction? If so, has the applicant performed any petrographic examination of the recovered subsurface rock (especially those containing dolomite) to examine whether the findings would be a cause for concern during the grouting process?

Response:

As discussed below, Duke Energy has performed petrographic examination of twenty core samples which indicate that potential for alkali-carbonate reaction is not a significant concern.

In general, concrete aggregate (or rock in contact with grout, in this case) has the potential for expansive alkali-carbonate reactions if (1) the clay or insoluble acid residue content in the aggregate (or rock) is in the range of 5 percent to 25 percent; (2) the ratio of calcite-to-dolomite is approximately equal to 1; (3) the dolomite volume increases, up to the point at which interlocking texture becomes a restraining factor; and (4) the dolomite exists as small, discrete crystals in a clay matrix (Ozol, 2006). Small crystal size (in the latter characteristic) is in the range of 25 to 30 microns (μm) (Farny and Kerkhoff, 2007).

In an extended study of alkali-carbonate reactive and non-reactive limestones and expansion during rock cylinder and concrete prism expansion tests, Rogers (1986) and Rogers et al. (2000) further suggested that composition of potentially expansive rocks fell into a relatively distinct field when plotted as a ratio of calcium oxide (CaO) to magnesium oxide (MgO) relative to alumina (Al_2O_3) content.

Considered as a group, petrographic and x-ray fluorescence analyses completed on twenty select rock core samples from the Levy Site do not indicate significant potential for alkali-carbonate reaction. For example, results from the x-ray fluorescence testing suggest that clay content in the selected core samples (based on measured alumina weight percent) ranges from only 0.05 percent to approximately 0.50 percent. Petrographic analyses similarly suggest that clay content in the rock core samples is quite low.

Magnesium as $CaMg(CO_3)_2$ (dolomite) to calcium as $CaCO_3$ ratios in turn range from approximately 0.03 to approximately 0.2, and are also inconsistent with petrological or chemical conditions conducive to alkali-carbonate reactions. The chemical composition of the select core samples also suggests limited potential for alkali-carbonate reactivity, excepting two (2) samples (A7/SC-4 and A7/SC-9) from a single core location.

Also note that dolomite grain (or rhomb) size exceeds 30 μm in most of the twenty core samples (13 of 20). Moreover, samples containing relatively small (less than 10 μm) dolomite rhombs (i.e., dolomite grains more susceptible to reaction, per Ozol [2006]) seem to occur only at depths below the proposed grouting zone (El. -24 ft. NAVD88 to El. -99 ft. NAVD88). Petrographic analyses also suggest tight interlocking of dolomite grains in most core samples located in the grouting zone. As noted above, interlocking grains limit (or restrain) expansive alkali-carbonate reactions.

Given the rather limited potential for alkali-carbonate reaction between the Levy Site rock and grout, expansion is not expected. Further, should some expansive reactions occur, the foundation engineering impacts would be insignificant. Rogers et al. (2000) indicate that concrete made from the most expansive dolomitic limestones (i.e., from rocks exhibiting each of the characteristics favorable to expansive reactions) can result in field expansions of up to 1.2 percent in 3 years. Such limited volumetric expansion in the grouted zone will not result in significant overall heave in the rock, and would be compensated by expected settlement. Moreover, the considerable confining stresses present at grouting zone depths will further limit the potential for expansion and subsequent impact on foundations or structures.

References:

Farny, J.A., and B. Kerkhoff, 2007, "Diagnosis and Control of Alkali-Aggregate Reactions in Concrete," Portland Cement Association Research and Development Serial No. 2071b, 26 p.

Ozol, M.A., 2006, "Alkali-Carbonate Rock Reaction," In Significance of Tests and Properties of Concrete and Concrete-Making Materials, ASTM STP 169D, J.F. Lamond and J.H. Pielert, eds., ASTM International, West Conshohocken, Pennsylvania, 2006, pp. 410-424.

Rogers, C., P.E. Grattan-Bellew, R.F. Hooton, J. Ryell, and M.D.A. Thomas, 2000, "Alkali-Aggregate Reactions in Ontario," Canadian Journal of Civil Engineering, Vol. 27, No. 2, pp. 246-260.

Rogers, C.A., 1986, "Evaluation of the Potential for Expansion and Cracking of Concrete Caused by the Alkali-Carbonate Reaction," Cement, Concrete, and Aggregates, Vol. 18, No. 1, pp. 13-23.

Question 6. The applicant plans to use a sheet-type waterproofing system for the below grade exterior walls exposed to flood and groundwater under seismic Category I structures. Section 3.4.1.1.1 of the AP1000 design control document (DCD) states:

> The COL applicant will use a waterproofing system for foundation mat (mudmat) and the below grade exterior walls exposed to flood and groundwater that will demonstrate a friction coefficient ≥ 0.55 with all horizontal concrete surfaces. This friction coefficient is maintained for the life expectancy of the plant and will not introduce a horizontal slip plane increasing the potential for movement during an earthquake. . . . The waterproof function of the membrane is not safety-related; however, the membrane between the mudmats must provide adequate shear strength to transfer horizontal shear forces due to seismic (SSE) loading. This function is seismic Category I.

Section 3.8.5.4, "Technical Evaluation," of the SER states:

> In a letter dated September 23, 2010, the LNP applicant proposed identifying, as LNP COL 2.5-17, the information in Section 3.8.5.1 addressing the type of waterproofing system to be used for the below grade exterior walls exposed to flood, and groundwater under seismic Category I structures. The applicant provided a waterproofing material to be used for the below grade, exterior walls exposed to flood and groundwater under seismic Category I structures. The applicant stated that a sheet type waterproofing membrane will be used for both the horizontal and vertical surfaces under Seismic Category I structures. The performance requirements to be met by the COL applicant for the waterproofing material are described in Section 3.4.1.1.1.1 of the AP1000 DCD. Thus, the NRC Staff considers LNP COL 2.5-17 to be resolved.

The applicant has selected a waterproofing membrane to support the functions of the nuclear island during the life of the plant. The applicant defined the waterproof function of the membrane to be nonsafety related. Its sliding, however, was defined as safety related. Its failure to function as a watertight barrier could impact the performance of the nuclear island basemat.

1. For the applicant: Explain how the consequences of potential damage, anticipated aging, and creep were factored in when selecting and qualifying the membrane as a watertight barrier. For the Staff: how were these effects evaluated in the Staff's review?

2. Is Table 3.8-3, "Waterproof Membrane, ITAAC," sufficient to demonstrate that its safety and non- safety functions will be maintained for the life of the plant? Is a license condition appropriate to ensure these functions?

Response:

From the approved waterproofing systems described in AP1000 Design Control Document (DCD) Subsection 3.4.1.1.1.1, Duke Energy will select one of the sheet-type membrane waterproofing systems for use on the horizontal and vertical below-ground surfaces of seismic Category I structures. The specific material to be used in that application has not yet been chosen. The material selection and qualification will be conducted as a construction activity after the start of construction at Levy. Benefitting from the construction experience at AP1000 plants already under construction, Duke Energy will choose a product that is rugged enough to withstand the construction process without significant damage, and that will exceed the required coefficient of friction throughout its service life. As a relatively simple construction phase procurement and qualification activity, we are confident that the proposed Waterproof Membrane ITAAC is sufficient to ensure the Levy Nuclear Plant (LNP) waterproofing system will adequately perform its seismic Category I safety functions for the life of the plant by ensuring the required coefficient of friction for all conditions. The waterproofing function of the membrane is not safety-related and will not be a part of the safety-related procurement and qualification activities. As the waterproofing function is not safety related, an ITAAC is not required for this function.

Duke Energy envisions that the Levy construction-phase procurement and qualification activities for the waterproof membrane will be similar to those for AP1000 projects under construction and using the sheet-type membrane waterproofing system. For the AP1000 currently in construction, a Commercial Grade Dedication process was employed to qualify a commercial membrane product for seismic Category I application. The process included design review and identification of Critical Characteristics for design, followed by material qualification testing, and then by material procurement and dedication. Since the waterproof function of the membrane is not safety-related, that function was not identified as a Critical Characteristic, and was not addressed in the qualification program. The service life selected for the qualification program included the anticipated construction duration, the DCD-specified design service life, and a further allowance for possible future plant license extension. The membrane qualification included testing of samples of the base material and lap / weld seams, and the simulated aging process included both wet and dry conditions. The effects of aging were evaluated for a number of material properties, including the coefficient of friction for the intended plant configuration. Samples were tested in both wet and in dry conditions, ensuring that the qualification results reflect conditions where the membrane may have failed its non-safety waterproofing function. In no case did the aged or un-aged samples fail to meet the required coefficient of friction for the tests, which was set at a value conservatively higher than the 0.55 value specified in the DCD, thereby ensuring significant design margin. As demonstrated in LNP FSAR Subsection 3.7, further site-specific margin is also available since the site-specific seismic demands are less than those considered in the DCD.

The horizontal portion of the waterproofing membrane is installed between two unreinforced layers of the mudmat, before reinforcing bars are introduced into the excavation. The waterproofing membrane will be inspected just prior to placement of the upper mud mat, and will remain visible until covered by concrete. There is high confidence that no significant damage to the membrane will occur during the placement of the second mudmat layer. During later periods, the mudmat provides protection for the membrane from incidental contact during construction. Since the membrane is then captured between the two mudmat layers, there is no opportunity for changes to the material as a result of creep.

Based on construction experience at other AP1000 projects, we fully expect that the Levy construction-phase qualification and procurement activities, and their results, will demonstrate that the waterproof membrane material will perform its seismic Category I function by confirming the coefficient of friction between the membrane and the mudmat concrete for all conditions. The Waterproof Membrane ITAAC is sufficient to ensure that the in-place LNP waterproofing system will adequately perform its seismic Category I safety related function (transfer of horizontal shear forces) for the life of the plant.

Question 7. Given that the grouting program will diminish but not eliminate ground water infiltration, proper compaction of the Roller Compacted Concrete (RCC) bridging mat layers during construction is of utmost importance.

The LNP will use unreinforced RCC placed in layers as a bridging mat over karst. Karst geological features include limestone and dolomite rocks that would still be exposed to the existing ground water. Additional rainwater seeping into nearby surface joints and could adversely affect unmitigated underlying carbonate rocks. This could lead over the life of the plant to additional geologic discontinuities (e.g., caverns, sinkholes) and less than desirable future substrate environments that could affect the performance of RCC bridging mat. The importance of proper and adequate compaction is captured in American Concrete Institute standard ACI 309.5R-00, which states:

> As the water content increases from the optimum level, the workability increases until the mixture will no longer support the mass of a vibrating roller. As the water content decreases from the optimum level, sufficient paste is no longer available to fill voids and lubricate the particles, and compacted density is reduced.

How will the applicant control the consistency of the in situ compaction of individual lifts of the RCC bridging mat to be optimal, so that potential seepage paths and poorly bonded lifts are eliminated?

Response:

A full scale RCC Test Pad will be constructed prior to construction of the Bridging Mat. The Test Pad will be used to validate the methodology that will be used to construct the Bridging Mat and develop construction plans and specifications. Samples of the as-placed material taken from the Test Pad will be used to perform compression, split tension, and direct shear strength testing. Samples will also be taken from the Test Pad to perform free-free testing to determine the shear wave velocity of the material.

During construction of the RCC Test Pad, RCC will be transported, placed, spread, and compacted in a similar manner as will be used during Bridging Mat construction. Vibratory rollers are expected to be used to compact the RCC, although other compaction methods may be used in areas adjacent to the forms. A construction dewatering system with shallow wells and sumps will prevent excess water seepage from impacting construction of the Bridging Mat. Such dewatering systems have worked effectively at previous major construction sites including large dams constructed with RCC.

The RCC will be compacted in place to a specified average density or 98 percent of the theoretical air-free density, whichever is greater. Density will be measured using single-probe nuclear density gages in accordance with ASTM C 1040. The average density will be determined by taking a minimum of three readings at the bottom, middle, and three inches from the top at each test location. A minimum of four test locations will be measured for each lift of RCC. The average density will therefore be determined from a minimum of twelve test readings per lift.

The compacted lift of RCC will be evaluated for compliance with the batch quantities, Joint Maturity Values (JMVs), and compaction before the next lift of RCC will be placed.

Final recommendations for RCC production testing will be determined as an outcome of the RCC Test Pad construction. Construction specifications will be developed as a result of Test Pad construction, and conformance to these specifications will be verified with a Quality Control Inspection Program (QCIP) implemented during Bridging Mat construction.

Question 8. The applicant states that lateral stiffness of the drilled shaft is governed by the soil properties in the top 10 to 16 feet. However, Figure 3.7-226 of the FSAR shows that some of the drilled shafts are located almost adjacent to the nuclear island diaphragm wall (minimum distance of 1 foot).

Both the applicant and the Staff considered the implications of lateral movements and interactions between the nuclear island structures, the adjacent structures, and their foundations, concluding that the provided seismic gap is adequate to minimize any potential interactions between buildings. In addition, the applicant states in the FSAR that the top of the diaphragm wall and the controlled low strength material fill between the diaphragm wall and the NI wall are below the individual building mat foundations and therefore there are no concerns of damage or interaction. There is no discussion, however, as to the effects of lateral movement of the annex, turbine, and radwaste building mats or drilled shafts on the engineered fill. Proper compactness of the engineered fill at all times ensures its design strength, compressibility, and permeability will be maintained ensuring compliance for its intended function.

1. Were the effects of lateral loads from drilled shafts on the engineered fill, if any, considered in the applicant's evaluation or the Staff's review?
2. Following a seismic event, what measures, if any, will be taken or required to ensure continued compliance of engineered fill to specifications?

Response:

The effects of lateral loads on engineered fill from the drilled shafts were considered in the site-specific seismic analysis of the building-soil-drilled shaft system. Because of significant margin demonstrated by the site-specific seismic analysis, no special measures to confirm the post-earthquake properties of the engineered fill are required.

The effects of lateral load from the drilled shaft on the engineered fill (i.e., the reaction of the side soils to resist the lateral movement of the drilled shafts during a seismic event) were considered in the building-soil-drilled shaft seismic response analysis. The lateral loads due to seismic excitation of the building are transmitted to the building basemat and then to the supporting drilled shaft. The resulting lateral displacement of the drilled shafts is resisted by the soil (engineered fill) on the side of the drilled shafts. The lateral load causes the soil-drilled shaft-building system to displace laterally. The soil-drilled shaft-building seismic interaction analysis for the adjacent Annex Building (AB), Radwaste Building (RB), and Turbine Building

(TB) show that the specified engineered fill properties are adequate to limit the lateral displacement of the adjacent buildings to preclude any adverse seismic II/I interaction between the Nuclear Island (NI) and the adjacent AB, RB, and TB for the SSE (GMRS) with significant margins as described in FSAR Sections 3.7.2.8.1, 3.7.2.8.2, and 3.7.2.8.3 respectively.

There is significant margin in the design of the AB, RB, and TB drilled shaft-soil (including engineered fill) system not to require measures to ensure continued compliance of engineered fill to specifications for seismic events equal to less that the GMRS (SSE). The High Confidence Low Probability Failure (HCLPF) capacity for no seismic interaction between the drilled shaft supported AB, RB, and TB and the NI is >1.67*GMRS as described in FSAR Section 3.7.2.8.4.

The minimum distance from the NI wall to the drilled shafts (Figure 3.7-226) is approximately 8.5 feet. The non-safety related perimeter diaphragm wall is not a part of the NI structure. The perimeter diaphragm wall serves as a temporary excavation support to facilitate NI foundation excavation and dewatering of the excavation during construction (FSAR Section 2.5.4.5.1). Once the construction of the below grade NI walls are completed and the Controlled Low Strength Material (CLSM) backfill is in place, the diaphragm wall is no longer needed. The diaphragm wall is left in place since there will be no adverse effect on the load carrying capacity of the drilled shaft foundations or the NI walls.

Question 9. LNP COL 2.5-13 states:

> Settlement bench marks will be installed within the subgrade mudmat . . . and monitored before and periodically during construction of the nuclear island basemat and sidewalls prior to placement of backfill materials. Additional bench marks will be installed approximately 1 m (3 ft.) above site grade . . . and connected to the sidewalls of the nuclear island, directly above the deeper benchmark locations described previously. These bench marks will be monitored

> during backfilling operations and, periodically, during and after construction of the nuclear island structures.

Since the RCC is classified as a seismic Category I, safety-related structure, how would the applicant monitor RCC bridging mat deformations beyond those induced from settlements (e.g., material reactivity based, DEF, etc.)?

Response:

The roller compacted concrete bridging mat has specific design and construction considerations that are discussed in the FSAR, NRC RAI responses, and responses to Pre-Hearing Questions 7 and 21. During construction, thermocouples or thermistors will be used to monitor Joint Maturity Value, and thermal controls will prevent deformations due to heat of hydration while the concrete matures.

Beyond these construction considerations, deformation of the RCC bridging mat is monitored by evaluating any settlement of the subgrade mudmat placed immediately atop the RCC bridging mat and beneath the nuclear island basemat. The settlement of the limestone subgrade is the predominant contributor to nuclear island basemat settlement. For Levy Units 1 and 2, finite element modeling, corroborated by methodology from AASHTO 2002 and elastic theory, shows that total basemat settlement is less than 0.3 inches as noted in FSAR Subsection 2.5.4.10.3. This is much smaller than the AP1000 DCD allowable settlement of 3 inches described in FSAR Subsection 2.5.4.10.3.3. Axial deformation of the RCC bridging mat due to AP1000 SSE loading is insignificant compared to the foundation settlement and the 3 inch allowable settlement.

A monitoring program will be implemented after construction to monitor any long-term settlement as noted in the response to Pre-Hearing Question 4.

Material reactivity is not credible for the RCC bridging mat that is constructed to Levy specifications.

No other monitoring is needed or planned.

Question 10. A proposed ITAAC in Table 3.8-2 states that, "during construction, inspection of the physical properties of the rock socket for each drilled shaft will be performed in accordance with LNP Inspection of the as-built drilled shaft foundation physical arrangement will also be performed." The acceptance criterion for the ITAAC is that a "report exists that reconciles the during construction physical properties of the rock socket for each drilled shaft and the as-built physical arrangement of the Turbine, Radwaste, and Annex Buildings' drilled shaft foundations with design specifications and drawings. The report concludes that the as-built drilled shaft foundation conforms to the design commitment." It is not clear how the applicant will confirm load carrying capacity of the drilled shafts. The karst rock may have voids below the rock socket for drilled shafts.

The applicant provides explanation in the FSAR on how the design and installation of the drilled shafts would be implemented. The SER does not appear to address LNP SUP 3.8-2.

1. Please further explain why the proposed construction methodology in LNP FSAR 3.8.5.9, "Drilled Shaft Foundations Design and Installation" is acceptable.

2. How would the performance of the shafts be verified?

Response:

Each drilled shaft derives its vertical load carrying capacity entirely from the rock socket; most of this capacity is from the sidewall of the rock socket. The bearing capacity of the drilled shafts was calculated using laboratory data derived from Levy site geotechnical explorations and by applying methodologies from AASHTO and NAVFAC, the average of the two values calculated from these methodologies was used as the design value.

For the AASHTO method, bearing capacity resistance was calculated using correlations to the RMR/RQD values and the uniaxial compressive strength (in addition to drilled shaft dimensions). The lowest average compressive strength (from laboratory UCS tests) of the rock layers across both Units was taken as the compressive strength. The compressive strength was correlated to the side resistance based on a correlation given in AASHTO.

For the NAVFAC method, bearing capacity was calculated using correlations to the rock type encountered at the Levy site, as well as the UCS of the rock (in addition to drilled shaft dimensions). Again, the lowest average compressive strength (from laboratory UCS tests) of the rock layers across both Units was taken as the compressive strength.

The average value from the two methodologies was taken. The bearing capacities of the drilled shafts were therefore conservatively calculated using site-specific data.

The calculations supporting the conceptual design of the drilled shaft socket, based on the methodology described above, confirmed that a 10 ft. socket length is sufficient for current loading provided that the rock has a minimum RQD of 25 percent. Prior to the construction of each drilled shaft, a pilot hole will be drilled to verify the capacity of the rock to resist the imposed loads. Due to the wide variation in RMR/RQD values identified during Levy site geotechnical explorations, a pilot hole will be drilled to verify the RQD and demonstrate that there are no voids present beneath the rock socket, to a depth of at least 2 socket diameters below the tip of each drilled shaft. If the pilot hole indicates that the rock socket does not meet design requirements, the rock socket will be extended to a new design depth based on the core obtained from the pilot hole.

A qualified engineer or geologist will perform inspection. For 6 ft. diameter drilled shafts, the inspecting engineer/geologist will inspect the side wall rock of the socket to verify that it meets the RQD requirements. For 3 ft. and 4 ft. diameter drilled shafts, the RQD determination may be made from the material excavated from the pilot hole. The drilled shaft construction methods and construction inspections and testing will follow guidance in ACI 336.1-01 and ACI 336.3R-93.

The bearing capacity performance of the drilled shafts and design of the drilled shaft sockets will be verified based on the evaluation of the rock cored from the pilot hole in accordance with the requirements given above, as well as the inspection of the rock socket by a qualified engineer/geologist. No additional performance verifications are needed.

Question 11. Recent modifications to the reactor pressure vessel internals indicate the addition of a flow skirt to the vessel bottom head. In addition, neutron panels have also been added. Additions and vessel modifications invariably also involve added bolted or welded connections. A perennial problem in vessel internals has been irradiation-enhanced stress relaxation, creep, and swelling which could result in dimensional instabilities, loss of preload (i.e., loosening of bolts), fasteners, keyed and/or pinned connections resulting possibly in increased vibrations and further deterioration of the connections.

How has the applicant demonstrated that the fasteners of the added flow skirt and neutron panels can be maintained through the expected life of the facility?

Response:

The flow skirt and neutron panels were incorporated into the AP1000 standard design as part of Revision 16 to the AP1000 Design Control Document (DCD) (May 2007). These changes were reviewed and approved as part of Supplement 2 to NUREG-1793 (September 2011), and are part of the AP1000 certified design (10 CFR 52, Appendix D, amended December 2011). No changes were made to the certified standard design of the reactor internals for the Levy Nuclear Project.

Flow Skirt

The reactor vessel flow skirt (RVFS) and its attachment welds were qualified by analysis in accordance with the flow skirt design specification, including stress, fatigue, and vibration analyses for all design and service conditions over the full design life of the plant. Design qualification was performed in accordance with the requirements of the ASME Code, Section III, Division 1 – Subsection NG (DCD Tier 2, Section 3.9.5.3). The RVFS and attachment welds were screened for the effects of void swelling and radiation embrittlement and found to be acceptable (DCD Tier 2, Section 3.9.8.2). The RVFS and attachment welds are included in the AP1000 Comprehensive Vibration Assessment Program (CVAP) (DCD Tier 2, Sections 3.9.2.3

& 14.2.9.1.9), including vibration analysis and inspections before and after hot functional testing (HFT). The RVFS and attachment welds are examined as part of the overall reactor vessel in-service inspection (ISI) program, in accordance with Section XI of the ASME Code.

Neutron Panels

Design qualification of the neutron panel assemblies (neutron panels, dowel pins, and fasteners) was demonstrated by analysis in accordance with the reactor internals design specification, including stress, fatigue, and vibration analyses for all design and service conditions over the full design life of the plant. This analysis accounted for irradiation relaxation in the evaluation of fatigue, vibration, and joint integrity of the fasteners. Design qualification was performed in accordance with the ASME Code, Section III, Division 1 – Subsection NG (DCD Tier 2, Section 3.9.5.3). The neutron panel assemblies were screened for the effects of void swelling and radiation embrittlement and found to be acceptable (DCD Tier 2, Section 3.9.8.2). The neutron panel assemblies are included in the AP1000 CVAP (DCD Tier 2, Sections 3.9.2.3 & 14.2.9.1.9), including vibration analysis and inspections before and after hot functional testing (HFT). The neutron panel assemblies are examined as part of the overall core support structure in-service inspection (ISI) program, in accordance with Section XI of the ASME Code.

Question 12. As stated on page 8-19 of the SER, the Staff relied on the request for additional information (RAI) responses in letter dated March 21, 2014 (ADAMS accession No. ML14010A421) (Response to RAI 114), to conclude that the supplemental information provided by the applicant to address the open phase condition of the offsite electric power system, as described in Bulletin 2012-01, "Design Vulnerability in Electric Power System" (ML12074A115), is acceptable. The Staff stated that the Final Safety Analysis Report (FSAR) and the ITAAC supplemental texts included in the SER are those provided in the RAI responses. However, the ITAAC texts in the SER (page 8-24) differ from the ITAAC texts in the RAI responses (Response to RAI 114, at 16).

Explain how the ITAAC texts changed from the version contained in the RAI responses to the version in the SER.

Response:

Duke Energy compared the referenced ITAAC text contained on page 8-24 of the Final Safety Evaluation Report for Combined Licenses for Levy Nuclear Plant Units 1 and 2 (FSER) with the ITAAC text provided to the NRC in our letter NPD-NRC-2014-009, "Levy Nuclear Plant, Units 1 and 2, Docket Nos. 52-029 and 52-030, Supplement 2 to Response to NRC RAI Letter 114 - SRP Chapter 8.0, Electrical Power" on page 16 of 16 of the Enclosure. This ITAAC was added as a new line item 7 in ITAAC Table 2.6.12-1. For completeness, the review and comparison also included the incorporation of the subject ITAAC into the Levy COL Application Part 10, License Conditions and ITAAC, Revision 8, as presented on page LC-B22.

The comparison did not reveal any differences in the wording contained in the Design Commitment column, the Inspections, Tests, Analyses column, or the Acceptance Criteria column, other than the addition of the word "and" in the title of the second column (e.g., Inspections, Tests and Analyses) in the FSER (page 8-24).

Question 13. Page 8-19 of the SER sets forth the Staff's position for an acceptable approach for passive designs to address the open phase condition, which includes four elements. The first element is a dedicated automatic detection of one and two open phase conditions of the offsite power system with and without a high impedance ground fault condition on the high voltage (HV) side of the main power transformer under all loading and operating configurations.

The supplemental text to the FSAR states: "The system detects an open phase condition (with or without a concurrent high impedance ground on the HV side of the transformer) on one or more phases under all transformer loading conditions." The supplemental text for the ITAAC in the SER states: "The credited GDC [General Design Criterion] 17 offsite power source is monitored by an open phase condition monitoring system that can detect the following at the HV terminals of the transformer connecting to the offsite source, over the full range of transformer loading from no load to full load: (1) loss of one of the three phases of the offsite power source (with or without a high impedance ground fault condition), or (2) loss of two of the three phases of the offsite power source (with or without a high impedance ground fault condition)."

Confirm that the open phase monitoring system will automatically detect one or two open phase conditions (with or without a high impedance ground fault condition) at the HV side of the main power transformer under all electrical system configurations and loading conditions.

Response:

Duke Energy confirms that the open phase monitoring system will automatically detect one or two open phase conditions (with or without a high impedance ground fault condition) at the high-voltage side of the main power transformer under all electrical system configurations and loading conditions.

Question 14. The second element of the Staff's position is an alarm in the control room, which activates upon detection of an open-phase condition, for operators to take manual actions if the standby diesel generators are not automatically connected to the auxiliary alternating current buses (ES-1 and ES-2). The supplemental text to the FSAR states: "The open phase condition monitoring system provides an alarm to the operators in the control room should an open phase condition occur on the high voltage source to the main step-up transformers. [….] Operator actions and maintenance and testing activities are addressed in procedures […] Plant operating procedures, including off-normal operating procedures associated with the monitoring system will be developed prior to fuel load."

1. Confirm that the plant procedures will specify operator actions for connecting the standby diesel generators to the ES-1 and ES-2 buses if they are not automatically connected.

2. Explain why the applicant was not required to include in the FSAR that operators will take manual actions if the standby diesel generators are not automatically connected to the ES-1 and ES-2 buses.

Clarify what the "high voltage source to the main step up transformers" is.

Response:

A set of Abnormal Operating Procedures (AOPs) has been developed for the AP1000 standard plant. It includes an AOP for Loss of AC Power which provides instructions to the operator to connect the standby diesel generators to ES-1 and ES-2 buses if they are not automatically connected. The Levy AOP for Loss of AC Power will be based on this standard plant procedure and include these instructions.

There are many important manual actions taken by operators in response to the failure of equipment to automatically actuate. These actions are accomplished through extensive operator training and procedural instructions including standard operating procedures, alarm response procedures, abnormal operating procedures, and emergency operating procedures. Operator actions are directed by procedures and not normally contained in the FSAR.

The "high voltage source to the main step up transformers" is the 500kV transmission line connecting each unit to the 500 kV buses in the switchyard as shown in FSAR Figure 8.2-201.

Question 15. 10 C.F.R. Part 50, Appendix E, § I.3, footnote 1 requires a plume exposure pathway emergency planning zone (EPZ) that consists of an area about 10 miles in radius. The regulation also provides that the actual size and shape of the EPZ will vary depending on demography, topography, land characteristics, access routes, and jurisdictional boundaries. Figure Intro-3 of the emergency plan shows the Levy Nuclear Plant (LNP) EPZ to be consistent with these requirements, with the apparent exception of an area on the southeast side of the EPZ within Citrus Springs. The defined EPZ boundary has about a 1.5- to 2-mile reduction in the EPZ periphery in this area. A review using a satellite view in Google Maps and StreetView shows that this excluded area contains residences.

1. How many people reside in this excluded area?
2. Why was the current boundary selected, given the existence of roads not far outside of the 10- mile radius that could have been used as a boundary for this area?

Additional reference: 44 Fed. Reg. 61,123 (Oct. 23, 1979).

Response:

The LNP Emergency Planning Zone (EPZ) and subzones called Protective Action Zones (PAZs) were developed in conjunction with off-site agencies from the state of Florida and the associated counties of Citrus, Levy, and Marion.

The boundary of the LNP EPZ for PAZ C4 crosses through the community of Citrus Springs. This boundary was developed in conjunction with the offsite agencies along well-defined features (major roadways for the most part) that would be easily identifiable to area residents and that would conform to an EPZ radius of about 10 miles. It was not deemed practical by the offsite agencies to include all of Citrus Springs as it extends well beyond the 10 mile radius.

The PAZ C4 boundary is defined by the following features:

- Bound on the north by the Citrus/Levy and Citrus/Marion county boundaries
- Bound on the east by US Highway 41, the Citrus Springs town boundary, and Elkcam Road
- Bound on the south by the Pine Ridge town boundary
- Bound on the west by the previous Crystal River Nuclear Plant 10-mile EPZ boundary

Data from the website "City-Data.com" indicates that the population in an area that encompasses and is slightly larger than the area in question is 2,273. The 2010 population for the entire community of Citrus Springs is listed as 8,622 on the same website.

Question 16. LNP Technical Specification 16.1 for the Containment Leakage Rate Testing Program states:

> A program shall be established to implement the leakage rate testing of the containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B, *as modified by approved exemptions*. This program shall be in accordance with the guidelines contained in Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program, dated September 1995," *as modified by approved exceptions*.

Does the applicant intend to exempt certain containment pressure boundary components from leak rate testing? If so, which components?

Response:

This Technical Specification, LNP Technical Specification 5.5.8, is adopted verbatim from the generic technical specifications in Chapter 16 of the AP1000 Design Control Document approved for incorporation by reference by the AP1000 Design Certification Rule, 10 CFR Part

52, App. D, § III.A. The language in the LNP technical specification is thus standard and as approved in the AP1000 Design Certification Rule, and does not signify any intent by Duke Energy to exempt containment pressure boundary components from leak rate testing.

Question 17. Section B.5.1 of the LNP emergency plan states that there is a technical support center (TSC) and operational support center (OSC) for each unit. It also specifies that in the event of a site-wide emergency (e.g., security event or natural phenomenon) Unit 1 will take the lead and that only the TSC and OSC of the lead unit will be activated.

1. Would the lead stay with Unit 1 if the event resulted in a substantial challenge to the fission product barriers at Unit 2?

2. Would the onsite response continue to be implemented from one of the TSCs/OSCs or would both TSCs and OSCs be staffed and activated to respond to the event in the respective units?

Response:

The text in the LNP Emergency Plan describing activation of Unit 1 TSC and Unit 1 OSC for a site-wide event is the LNP standard response to a site-wide event. If a unit specific event or challenge occurs during this site-wide condition, the Emergency Coordinator would determine what other facilities to activate and which facility would be the lead on a case by case basis.

Additional facilities would be staffed and activated based on the Emergency Coordinator's evaluation of events in progress and site/unit radiological and environmental conditions.

Question 18. In its discussion of the emergency news center (ENC), in SER § 13.3C.7.5 and the emergency operations facility (EOF) in SER § 13.3C.8.22 and SER § 13.3C.8.26, the Staff determined that the Crystal River-3 (Crystal River) ENC and EOF for LNP were acceptable because:

- The NRC performs oversight of emergency preparedness, including the ENC and EOF, by monitoring performance indicators;

- The ENC and EOF are inspected periodically during routine inspections, drills, and exercises; and

- Any changes to the ENC and EOF are reviewed in accordance with the established inspection program and requirements for operating reactors.

Given recent activities, including the Commission's issuance of exemptions that, in addition to other relaxations, remove the requirement for the identification of a physical location for dissemination of information from the Crystal River licensing bases, the facts underlying the Staff's assessment may have changed. In addition, Crystal River has submitted a certification of permanent cessation of operations. Because of that certification, Crystal River was removed from the reactor oversight process, eliminating monitoring of performance indicators and shifting from IMC 2515, "Light-Water Reactor Inspection Program- Operations Phase," to IMC 2561, "Decommissioning Power Reactor Inspection Program." Emergency preparedness is not a core inspection module under IMC 2561. There will be no further inspections on the Crystal River ENC and EOF. Changes to the Crystal River ENC and EOF would no longer trigger the 10 C.F.R. § 50.54(q) change process.

How, if at all, do these changes at CR-3 affect the Staff's acceptance of the Crystal River ENC and EOF for LNP as described in the SER?

Response:

The impact of Crystal River 3 (CR3) decommissioning on Levy emergency preparedness was evaluated by Duke Energy and the NRC staff. Some LNP EP Inspections, Tests, Analyses, and Acceptance Criteria (ITAAC) changes were determined to be necessary based on the future status of the CR3 EOF.

EP ITAAC for performance criteria associated with the EOF and ENC functions were already in the LNP COLA Part 10. No additional ITAAC or ITAAC revisions were considered necessary for the ENC based on the impacts of CR3 decommissioning. However, EP ITAAC revisions were considered necessary relative to the LNP EOF not remaining active for CR3 use. Three additional ITAAC acceptance criteria related to the EOF were added to proposed EP ITAAC in Part 10 of the LNP COLA as follows:

- The EOF is structurally built in accordance with the Uniform Building Code. (7.2.3)
- The EOF is environmentally controlled to provide room air temperature, humidity, and cleanliness appropriate for personnel and equipment. (7.2.4)

- The EOF is provided with industrial security when it is activated to exclude unauthorized personnel and when it is idle to maintain its readiness. (7.2.5)

In addition, the 'Inspection, Tests, Analyses' text for EP ITAAC 7.2 in LNP COLA Part 10 was revised and now states: An inspection of the as-built EOF will be performed, including a test of the capabilities. The EOF will meet the criteria of NUREG-0696 and NUREG-0737.

Duke Energy considers the LNP COLA Part 10 EP ITAAC and LNP Emergency Plan adequate to confirm the LNP EOF and ENC will be acceptable and meet the associated regulatory requirements.

Question 19. Emergency Plan § H.4 (SER §§ 13.3C.8.4 (TSC), 13.3C.8.28 (EOF)) discusses activation and staffing of the emergency response facilities. This discussion establishes a "goal" of 60 minutes for the emergency response organizations (EROs) to achieve minimum staffing of the emergency operations facility (EOF) following the notification of an Alert (Site Area Emergency or general emergency). The discussion further states that applicable emergency response facilities will be operational within 15 minutes of achieving minimum staffing. The SER discussion states that the LNP plan is acceptable because it conforms to the guidance in NUREG-0654 and Supplement 1 to NUREG-0737.

While compliance with the regulatory guidance is not required, please further explain the regulatory basis of the proposed alternatives for the following deviations from the following guidance:

- NUREG-0737, Supplement 1, § 8.2.1.j states that the TSC will be "staffed by sufficient technical, engineering, and senior designated licensee officials to provide needed support and be *fully operational within approximately 1 hour*." Specifically, how will the Staff enforce this criterion when it appears to be treated as a goal, rather than an explicit licensee commitment?

- NUREG-0654 evaluation criterion B.5 states that "the licensee must be able to augment on-shift capabilities within a short period *after declaration* of an emergency." Specifically, the applicant states that the clock start time is the notification of the ERO.

- NUREG-0696 § 4.3 states, with regard to the EOF, "designated personnel shall report directly to the EOF *to achieve full functional operation within 1 hour.*" Specifically, the applicant states that the facility will be operational within 15 minutes of achieving minimum staffing.

Response:

The 30 or 60-minute response times for the minimum staffing positions listed in LNP Emergency Plan Table B.1 together with the 15-minute facility activation time after minimum staffing is achieved are explicit commitments providing the time criteria for the emergency response facilities to be fully operational. The facility activation time reflects the need to brief the responders on the situation and conduct a proper turnover. The guidance in NUREG-0737, Supplement 1 (ML102560009) referenced in the question (8.2.1.j) states that the TSC should be fully operational within "approximately" 1 hour. The FSER concludes that the provisions for timely staff augmentation and activation of the TSC conform to the guidance in Supplement 1 to NUREG-0737. FSER at 13-126.

The augmented staff response times in Table B.1 of the LNP Emergency Plan are comparable to the augmented staff response times in existing nuclear plant emergency plans. Further, LNP has additional on-site resources available to respond to an emergency prior to the arrival of augmented resources since the minimum shift size for two units listed in LNP Emergency Plan Table B.1 exceeds the minimum shift size in Table B.1 of NUREG-0654.

The LNP time to achieve fully operational status for the EOF is consistent with the EOF activation/fully operational times in existing nuclear plant emergency plans approved by the NRC for both new and operating plant sites. The 30 or 60-minute response times for the minimum staffing positions listed in LNP Emergency Plan Table B.1 together with the 15-minute facility activation time after minimum staffing is achieved provide time criteria for the EOF to be fully operational. NSIR/DPR-ISG-01, Interim Staff Guidance – Emergency Planning for Nuclear Power Plants, which supplements or replaces previous guidance, modifies the guidance in NUREG-0696 to state that "Upon EOF activation, designated personnel shall report directly to the EOF to achieve full functional operation as specified in the licensee's emergency plan" rather than within 1 hour. (NSIR/DPR-ISG-01, Section IV.1, Emergency Operations Facility - Performance-Based Approach, page 45.)

Question 20. Emergency Plan § J.12 "Registering and Monitoring Evacuees," states that LNP has the means for registering and monitoring all evacuees at relocation centers and that personnel and monitoring equipment will be made available to monitor all residents and transients. (This is not a responsibility assigned to the licensee; hence, it is not addressed in the SER.)

1. This section appears to establish that the applicant has taken the responsibility for registering and monitoring evacuees. Is this correct?

2. Neither these personnel nor the equipment to be used have been previously identified in the emergency plan. Where are these resources being obtained from? In what time frame would they become available?

3. Has the Federal Emergency Management Agency reviewed these arrangements? If so, what was the result of its review?

Response:

The text in section J.12 of the LNP Emergency Plan is not intended to establish the applicant as responsible for registering and monitoring evacuees. Rather, LNP Emergency Plan Appendix 8, NUREG-0654 Cross Reference, Criteria J.12 comments specify that the "… respective state and county plans" contain the information to satisfy this criteria.

The State and associated counties are responsible for registering and monitoring evacuees as stated in the response to item 1 above. Therefore, no Duke Energy personnel or equipment are identified for registering and monitoring evacuees in the LNP Emergency Plan.

The FEMA Interim Finding Report for Reasonable Assurance for LNP (ML16070A213) delineates the State and counties as responsible for performing activities associated with criterion J.12 and concludes that the State and county plans reviewed are adequate to satisfy this criterion.

Question 21. Section 3.8.5.4 of the SER outlines how the RCC lifts are to be bonded and the bonding to be verified through testing. The ITAAC, however, in "Design Commitment," "Inspection, Test, and Analysis," and Acceptance Criteria" as described in Table 3.8-1, "Roller Compacted Concrete ITAAC," does not stipulate that the RCC Bridging Mat should be designed and perform for life as a monolithic section to avoid relative movements and sliding of individual lifts.

How will cohesion between lifts be assured, so that there is reasonable assurance that the RCC will behave as a monolithic structure following a safe-shutdown earthquake? Has this been inadvertently omitted from Table 3.8-1 "Roller Compacted Concrete ITAAC"?

Response:

Monolithic behavior of the RCC Bridging Mat is ensured by horizontal shear stresses across the bedding plane being less than code allowable stress for the SSE load combination. RCC Test Pad testing and RCC mix design will ensure that the RCC Bridging Mat satisfies code shear strength requirements for monolithic behavior across lift joints. As described in the Response to Pre-Hearing Question 7, a full-scale RCC Test Pad will be constructed to validate the methodology that will be used to construct the Bridging Mat and develop construction plans and specifications. During the construction of the RCC Test Pad, a 4,000 psi high-slump (7-to 9-inch slump) Bedding Mix will be placed between compacted lifts of RCC. This material will be batched using a maximum ¾-inch aggregate. The bedding layer will be placed in a minimum of ¾-inch thick layer immediately prior to placement and compaction of the next lift of RCC.

The RCC lifts/bedding layer joints will be created at Joint Maturity Values (JMVs) of approximately 2,500 degree hours and at approximately 4,700 degree hours. The temperature will be recorded and stored by temperature recording devices. A minimum of two temperature recording devices will be used per lift of RCC. The data will be downloaded to a monitoring device and evaluated. When the RCC reaches the required maturity, the lift surface will be prepared, the bedding layer will be applied, and the next lift of RCC can be initiated.

To bound all expected construction conditions, the Contractor will practice lift surface treatment for both “warm” joints (approximately 2,500 degree hours) and “cold” joints (approximately 4,700 degree hours). The “warm” joint will be prepared for the subsequent bedding layer placement by removing laitance (if any), loose debris, and contaminants from the entire surface by compressed air and vacuum. The “cold” joint will be prepared by water/air jetting to expose but not undercut the aggregate. The industry term for this type of joint preparation is a “green cut.” After green cutting, the entire surface will be cleaned of any remaining loose debris and excess moisture by compressed air and/or vacuum.

After a curing period, one foot by one foot block samples consisting of two adjacent lifts and the bedded joint will be cut from the Test Pad to perform direct shear testing. Direct shear testing will evaluate the shear strength along lift surfaces by measuring the cohesion and friction angle for the peak load and the residual cohesion and friction angle. The peak values are obtained by testing the specimen to failure and continuing to test until the specimen has been displaced 0.5 inches. The residual cohesion and friction angle are calculated at several points along the displacement. Data from these tests will be used to verify that USACE EM 1110-2-2006 specified shear strengths are achieved across lift joints.

Final recommendations for production testing during construction of the Bridging Mat will be determined as an outcome of the RCC Test Pad construction. Construction specifications will be developed as a result of the RCC Test Pad construction, and conformance to these specifications will be verified with a Quality Control Inspection Program (QCIP) implemented during Bridging Mat construction.

There is no omission from the ITAAC. Acceptance Criteria i and ii of the ITAAC ensure that all design requirements are met. This includes code compliance of the RCC, its constituents, and that calculations show that the RCC Bridging Mat stresses are below code allowable. Horizontal shear stress across the lift joints is one of stresses checked for the SSE load combination. Satisfying these acceptance criteria confirm that the RCC Bridging Mat performs as a monolithic structure.

<u>Question 23</u>. Chapter 21.0 concludes with the statement, "The staff finds that the cumulative risk impact of these design changes and departures is acceptable."

For the Staff: Please describe further how the Staff assessed the cumulative risk impact of these design changes and departures from AP1000 Design Control Document Rev. 19?

For the applicant: Has the applicant assessed the cumulative risk impact of the five design changes and departures listed in Chapter 21 of the SER as compared to AP1000 Design Control Document Rev. 19? If so, what were the results?

<u>Response:</u>

The AP1000 design certification PRA is based on assumptions that are consistent with the plant design as modified by these departures, (because these departures predominantly restored intended capabilities). The proposed changes assure that these elements of the AP1000 design are now compatible with the PRA calculations and therefore no changes to the design certification PRA were needed to account for these departures. None of them have any impact on the quantification of core damage frequency or large release frequency. The success criteria that were used in developing the PRA are unchanged and the reported results of the PRA are not changed.

Evaluations also determined that these changes involved no significant hazards considerations. These evaluations determined that the changes did not increase the probability or consequences of an accident previously evaluated, create the possibility of a new or different kind of accident from any accident previously evaluated or significantly reduce a margin of safety.

Since these changes were implemented to restore the design to comply with licensing basis assumptions and there is no impact to core damage frequency, large early release frequency, PRA or significant hazards considerations from any of them, their cumulative risk impact is deemed insignificant.

Question 24. The Staff states the guidance in Regulatory Guide (RG) 1.82, Rev. 3, dated November 2003 and NEI-04-07, Rev. 0 were used in conducting the review of STD-COL 6.3-1. Regulatory Guide 1.82, Rev. 4, dated March 2012 was issued prior to the 2014 applicant-proposed changes in DEP 6.3-1 and specifically incorporated developments and lessons learned in the implementation of NEI-04-07, Rev. 0.

Please explain the rationale for using RG 1.82, Rev. 3 instead of Rev. 4 for this departure and exemption request. Did the applicant's submission and Staff's review incorporate lessons learned from implementation of NEI-04-07?

Response:

There is no direct relationship between STD COL 6.3-1 and LNP DEP 6.3-1. STD COL 6.3-1 addresses the Containment Cleanliness Program, which is found in DCD Subsection 6.3.8.1 and LNP FSAR 6.3.8.1 as closure to the Combined License Item. The Containment Cleanliness Program was reviewed by the NRC as described in Section 6.3 of the Levy Units 1 and 2 FSER and found to be acceptable because the containment cleanliness program complies with the guidance in RG 1.82. As stated in the FSER, the evaluation of the containment cleanliness program was performed using RG 1.82, Rev. 3, because this was the revision in effect six months prior to submittal of the Levy COL Application on July 28, 2008, based on the guidance set forth in RG 1.206. As stated in the introduction to RG 1.82, "This guide describes methods that the staff of the U.S. Nuclear Regulatory Commission (NRC) considers acceptable for use in implementing requirements regarding the sumps and suppression pools that provide water sources for emergency core cooling, containment heat removal, or containment atmosphere cleanup systems. It also provides guidelines for evaluating the adequacy and the availability of the sump or suppression pool for long-term recirculation cooling following a loss-of-coolant accident (LOCA)."

LNP DEP 6.3-1 relates to the capability of the PRHR HX to meet GDC 34 and GDC 44 requirements using the closed loop cooling mode of PRHR HX operation during a postulated non-LOCA event (e.g., loss of feedwater along with a loss of all AC power throughout the transient). This departure is unrelated to the subject of RG 1.82 (or NEI 04-07), which are directed towards long-term recirculation cooling following a LOCA. In particular, LNP DEP 6.3-1 deals specifically with defining the period in which closed loop cooling using the PRHR HX can be maintained assuming a postulated non-LOCA event (e.g., loss of feedwater along with a loss of all AC power throughout the transient) as greater than 14 days, as opposed to the original statement in the AP1000 DCD Revision 19 that closed loop cooling could be maintained indefinitely. The list of subsections affected by LNP DEP 6.3-1, as found in LNP FSAR Table 1.8-201, does not include any revisions to Subsection 6.3.8.1.

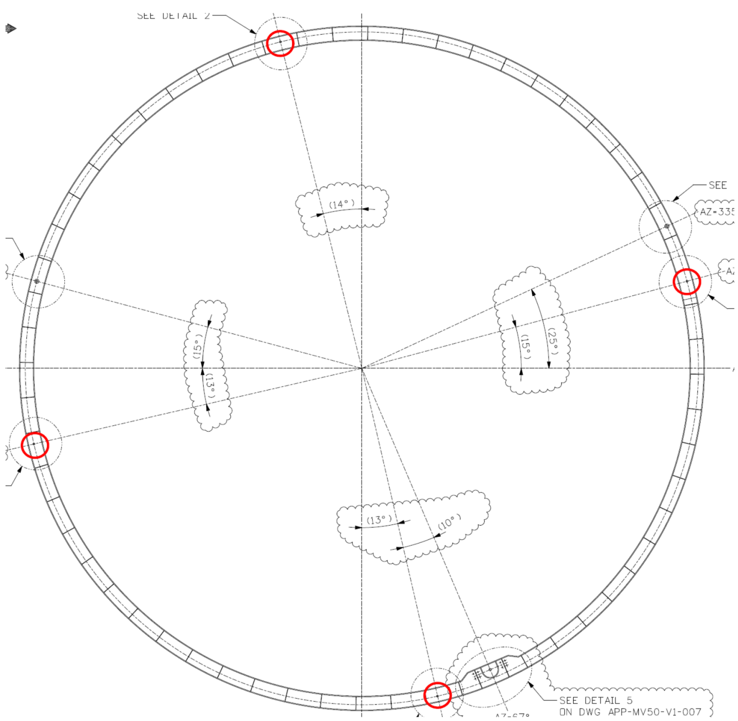
LNP DEP 6.3-1 only requires a departure and is not specifically part of an exemption. The exemption associated with the capability of the PRHR HX to meet GDC 34 and GDC 44 requirements is in LNP DEP 3.2-1.

Question 25. As a part of LNP DEP 3.2-1 and LNP DEP 6.3-1, the applicant describes the addition of protective screens to the downspouts to protect the passive residual heat removal heat exchanger (PRHR HX) from debris. Has the applicant or the Staff investigated whether the screens could be subject to clogging phenomena similar to what is considered by Generic Safety Issue 191 (GSI-191)? Has the applicant performed any analysis to determine how long the PRHR HX can remain functional with degraded return flow to the in- containment refueling water storage tank (IRWST)?

Response:

When designing the downspout system and screens which interface with the polar crane girder (PCG) and the internal stiffener, plugging of one of the downspout screens was taken into consideration to meet single failure criteria. Design calculations support downspout sizing and screen sizing considering a single failure (plugging of a downspout screen), and flowrates are shown to support adequate pressure drop to avoid overflowing at any one location while avoiding the potential for flashing in the system piping.

Related to their location in containment, the polar crane girder and internal stiffener are not easily accessible and are not located in high traffic areas which may result in potential cleanliness issues that may plug any of the screens. The four screens added at the polar crane girder and internal stiffener are evenly spaced around containment to provide separation between each of the downspout connections. The figure below provides detail as to the location of the screens at the internal stiffener elevation.



Downspout Screen Location

The screens were designed to have a relatively coarse mesh meant to prevent larger debris from entering the downspout piping, which may pose a risk to clogging the pipe entrance.

Finer debris that is more likely to be transported will pass through these screens as the holes provided in the screen design are 1 inch in diameter. It is not expected that significant debris bed formation on this screen design would be a concern, resulting in plugging of multiple screens at the same time.

Generic Safety Issue 191 (GSI-191) concerns are tied to debris blockage in parts of Emergency Core Cooling Systems (ECCS) as a result of a series of events which had occurred in the industry. The concern is related to debris blockage on strainers in ECCS and containment spray systems, resulting in additional pressure drop that has the potential to cause the loss of net positive suction head margin which in turn impacts pump performance. The purpose of the downspout screens supporting condensate return and PRHR HX functionality is solely to prevent large debris from plugging an entire pipe resulting in insufficient flow capacity that causes the polar crane girder or internal stiffener to overflow.

A qualitative consideration of GSI-191 was taken when designing the downspout screens, though there are few parallels between the application of the generation and transport of debris during a LOCA to the containment sump suction strainers and the design function of the downspout screens. An extended loss of AC power with loss of feedwater is the limiting event for PRHR HX operation with respect to the condensate return design basis. This event does not involve a pipe rupture inside containment. Thus, there is little potential for significant debris located at the polar crane girder and internal stiffener which could result in plugging of the screens. Therefore, the downspout screens located at the polar crane girder and internal stiffener are not considered to be susceptible to the same clogging mechanisms as experienced during containment flooding and the resulting ECCS injection through the sump screens. As a result, this screen design is considered to be adequate to support PRHR HX functionality. The piping and screens were designed for peak condensation flowrates to the containment vessel shell, on the order of several hundred gallons per minute, which are much lower than in pumped flow ECCS systems. The screens and piping were sized to result in reduced pressure drop, and prevent overflow at the polar crane girder or internal stiffener locations. As decay heat reduces with time during prolonged PRHR HX operation, the steaming rate also reduces and flowrates become less in the long term. Therefore as the transient progresses, the downspouts have increasing margin as a result which gives further capacity to support condensate return flow. Contrary to many ECCS or containment spray systems, the downspout piping system does not have any significant choking points in its flowpath such as throttle valves, spray nozzles, fuel assemblies, etc. that could potentially allow debris which had passed through the screen to result in clogging of the entire piping flow area.

In addition, Technical Specifications further minimize the likelihood of clogging of the gutter and downspout screen system. Surveillance Requirement (SR) 3.5.4.7: "Verify by visual inspection that the IRWST gutter and downspout screens are not restricted by debris" (24 months). The Technical Specification 3.5.4.7 Bases states: "This surveillance requires visual inspection of the IRWST gutter and downspout screens to verify that the return flow to the IRWST will not be restricted by debris. A Frequency of 24 months is adequate, since there are no known sources of debris with which the gutter or downspout screens could become restricted."

<u>Question 26</u>. In RAI 7439, the Staff inquired about the applicant's use of extrapolated predictions of condensate return losses. SER § 21.1.4 states that "the NRC staff remains unconvinced as to the validity of the applicant's temperature scaling argument, especially given the relative variance in the test results," although the Staff went on to find that the treatment of condensate losses over the attachments to the containment shell was acceptable due to conservatism in the extrapolation.

1. For the applicant, please discuss further the justification for using extrapolated predictions.

2. For the Staff, please explain the Staff's justification for the finding that "the treatment of film losses over attachments to the containment shell" is acceptable.

Response:

Testing performed to substantiate the magnitude of losses in the condensate return analysis was conservative as it yielded thicker liquid flow (refer to Figure 2 and scaling analysis of response to RAI 7439) which promoted higher measured losses. Elevated liquid temperatures in the AP1000 plant would result in lower viscosity and surface tension within the liquid flow compared to the test. This would lead to a decrease in liquid flow thickness and would thus yield lower condensate losses in the AP1000 plant relative to the test. In addition to a thinner liquid flow, elevated temperatures in the AP1000 plant would suppress the transition of falling liquid condensate flow from film regime to the rivulet regime (refer to the scaling analysis in response to RAI 7439) which would also reduce the losses as the rivulet regime would result in a thicker liquid flow compared with the film regime at the same total mass flow rate of condensate. Hence, these phenomena result in a larger percentage of attachment plate condensate losses in the condensate return test facility (thicker condensate flow translates into larger condensate losses at attachment plates) compared with the AP1000 plant. As the condensate losses in the test bound AP1000, no extrapolation of condensate losses from the test to the AP1000 plant related to elevated liquid temperature is necessary.

Question 27. As part of the exemption for DEP 3.2-1 related to the passive core cooling system (PXS) containment condensate return, Technical Specification (TS) Surveillance Requirement 3.5.4.7 was added to require a visual inspection of the IRWST gutter and downspout screens to verify that the return flow to the IRWST will not be restricted by debris.

The Staff's technical evaluation of the exemption request and departure states, "Condensate return is one of the primary factors influencing the performance of the PRHR HX." The Staff further explains that the PXS downspout piping network was added at the polar crane girder and stiffener with four specific collection points located on both the upper portion and the lower flange of the polar crane girder. While in use during refueling or forced outages the polar crane can be positioned at any point on the girder.

Does the final polar crane bridge position on the girder (relative to the 8 downspout screens on the polar crane girder and internal stiffener) affect the rate of return of condensate from the polar crane bridge via the gutter system or is the rate of condensate return unaffected by polar crane bridge position?

If the final polar crane bridge position on the girder affects the rate of return of condensate to the IRWST, please explain why a TS Surveillance Requirement for polar crane position is unnecessary to ensure that the quality of systems and components is maintained and the limiting conditions for operation will be met for the PXS.

If the final polar crane bridge position on the girder affects the rate of return of condensate to the IRWST, are restrictions on polar crane position relative to TS operational MODES required?

Response:

The position of the polar crane on the girder has no impact to the rate of condensate return. The rail that the polar crane rides on is located several feet from the containment vessel shell, and goes around the entire circumference of containment. The dam which was added on the polar crane girder is located between the containment vessel shell and the polar crane girder rail. Therefore, any condensation which occurs on the containment vessel shell and travels down the shell to the polar crane girder collection location will be separated by the dam from any interaction with the polar crane itself. Any condensation which occurs on the polar crane and/or the polar crane structure that spans from one side of containment to the other will not be captured by the gutter system. This is accurately modelled in WGOTHIC as a heat sink, and therefore no credit is taken for capturing this lost condensation. The Figure below shows an image of the continuous dam and also the rail for the polar crane.

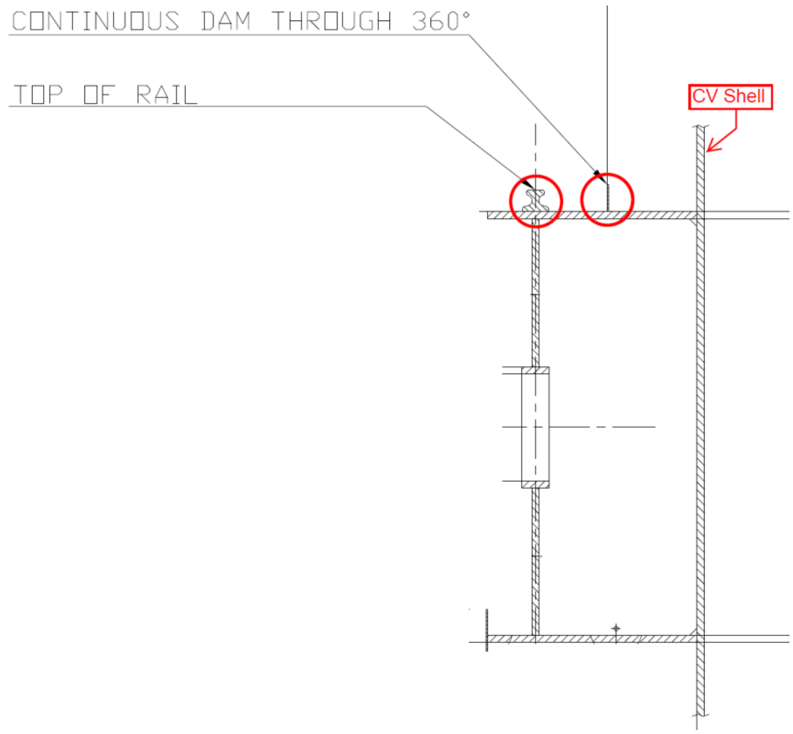


Figure: Polar Crane Rail and Dam

In the Figure above, the polar crane rail and the continuous dam are circled. The containment vessel shell is pictured at the right of the figure. Therefore, based on the orientation of the polar crane circumferential dam, there is no need for a Technical Specification or Surveillance Requirement restricting the polar crane bridge position on the girder.

<u>Question 28</u>. The Staff discusses the tube plugging assumption used for DBA analyses along with the analysis of the Loss of AC Power to Plant Auxiliaries (LOAC). The Staff notes that the analyses of the LOAC event demonstrate that the top horizontal portion of the PRHR heat exchanger becomes uncovered.

Did the tube plugging assumptions conservatively assume that the plugged tubes were not within the top horizontal portion of the PRHR heat exchanger that becomes uncovered? If not, please explain why this additional conservatism was unnecessary.

<u>Response:</u>

The analysis for most limiting DBA (LOAC) did not assume that all plugged tubes in the Passive Residual Heat Removal Heat Exchanger (PRHR HX) were below the uncovered portion of the tubes. An average reduction in the heat transfer area of the tubes in the heat exchanger was assumed in the analysis. Additional conservatism is unnecessary, because the location of the plugged tubes would not alter the analyzed ability of the PRHR HX to remove the full decay heat load over the required 72 hour period. During the entire 72 hours considered for the DBA case, the PRHR HX is able to match decay heat.

The PRHR HX is "C" shaped. Each tube runs horizontally from the inlet tubesheet located at the top of the heat exchanger. The tubes then turn 90 degrees down to a vertical run. Each tube finishes with another 90 degree turn to a second horizontal run to the outlet tubesheet.

As the top horizontal portion of the heat exchanger uncovers, the transient continues to match decay heat regardless of the location of the plugged tubes. Sensitivities run on tube plugging for the DBA case showed almost no impact on the DBA results within the 72 hour time frame. This is due to the fact that the DBA acceptance criteria are only challenged when decay heat generation no longer matches decay heat removal - which would not occur until the bottom portions of the heat exchanger begin to uncover. It should also be noted that the bottom portion of the top horizontal tube bundle contains the shortest PRHR HX tubes, therefore it is expected that plugging the bottom tubes would have the smallest impact on heat transfer area.

It is noteworthy that, as stated in SER § 21.1.4.B.1.2.1 (Page 21-18), the DBA analyses assume 8 percent tube plugging in the PRHR HX (in terms of heat transfer area) for scenarios where minimizing heat removal is bounding (such as LOAC). However, the design allowable number of plugged tubes is equivalent to just 5 percent of the heat transfer area.

Question 29. The design requirement of establishing an initial long term safe shutdown condition within 36 hours (i.e., reaching an average reactor coolant system (RCS) temperature less than 420°F in 36 hours) following an event with a safety grade decay heat removal system is established in the EPRI utility requirements document (URD) and SRM-SECY-94-084. SECY-94-084 states that after the passive residual heat removal system affects the initial shutdown condition, a non-safety- grade reactor shutdown cooling system will be available to bring the plant to cold shutdown conditions for inspection and repair.

In SER § 21.1.4.B.1.2.5, "Safe Shutdown," the Staff discusses the safe shutdown criteria for reaching an average RCS temperature of less than 420°F in 36 hours. In SER § 21.1.4.B.1.3, "Non-Safety Design Basis," the Staff states that the PRHR heat exchanger long-term shutdown condition for 14 days in a closed loop mode of operation are non-safety related operational requirements.

In FSAR § 6.3.1.2.1, "Nonsafety Design Basis-Post Accident Core Decay Heat Removal," the applicant describes both establishment of the reactor coolant temperature of 420°F in 36 hours and a long-term shutdown condition of 14 days at 420°F as non-safety related. In an April 5, 2016, presentation (slide 15) to the Advisory Committee on Reactor Safeguards on the PXS condensate return, the applicant again stated that the PRHR establishment of the reactor coolant temperature of 420°F in 36 hours and a long-term shutdown condition of 14 days at 420°F are "nonsafety" design basis licensee performance goals.

While not a Chapter 15 design basis accident safety requirement, the establishment of the reactor coolant temperature of 420°F in 36 hours appears to be a safe shutdown safety-related requirement from SER § 21.1.4.B.1.2.5, with criteria as discussed in SECY-94-084. Please explain the discrepancy between the Staff's SER and applicant's FSAR regarding whether the performance criteria for the initial establishment of the reactor coolant temperature of 420°F in 36 hours is a safe shutdown safety-related equipment performance requirement or a non-safety design basis requirement. Were the calculations and analyses performed by the applicant/vendor completed as part of a 10 C.F.R. Part 50, Appendix B program?

Response:

Duke Energy does not believe that there is a discrepancy between the Staff's FSER and the applicant's FSAR. As discussed below, the performance criteria for the initial establishment of the reactor coolant temperature of 420°F in 36 hours is not part of the "safety design basis" which is used to connote those criteria that must be demonstrated under Chapter 15 accident conditions.

The applicable regulatory requirement in the NRC rules is contained in General Design Criterion (GDC) 34, "Residual heat removal," which requires in pertinent part:

> A system to remove residual heat shall be provided. The system safety function shall be to transfer fission product decay heat and other residual heat from the reactor core at a rate such that specified acceptable fuel design limits and the design conditions of the reactor coolant pressure boundary are not exceeded.

The GDC "establish the necessary design . . . and performance requirements for structures, systems and components important to safety, that is, for structures, systems and components that provide reasonable assurance that the facility can be operated without undue risk the health and safety of the public." 10 C.F.R. Part 50, App. A, Introduction at ¶ 1. Thus, the specified acceptable fuel design limits (known as SAFDLs) and design conditions of the reactor coolant system (RCS) pressure boundary are the acceptance criteria that, under the NRC rules, should not be exceeded to demonstrate reactor safety.

FSER § 21.1.4.B.1.2 is consistent with this regulatory requirement. FSER § 21.1.4.B.1.2 identifies four safety-related functions of the passive core cooling system (PXS) – (1) emergency decay heat removal,(2) emergency reactor makeup/boration, (3) safety injection, and (4) containment pH control – which are discussed in FSER §§ 21.1.4.B.1.2.1-21.1.4.B.1.2.4 respectively. With respect to the emergency decay heat removal function, FSER § 21.1.4.B.1.2.1 states that the passive residual heat removal heat exchanger (PRHR HX) is designed to maintain acceptable reactor coolant system conditions for a minimum of 72 hours following a non-LOCA event, and that applicable post-accident evaluation criteria are specified in Chapter 15. FSER at 21-16. The Chapter 15 acceptance criteria are stable or decreasing RCS temperatures, heat removal from PRHR exceeding core decay heat, no liquid relief through the pressurizer safeties, and fuel safety limits and pressure boundary design limits not challenged (DCD Rev. 19, Section 15.2.6.2). FSER § 21.1.4.B.1.2 states that applicable Chapter 15 design basis safety evaluation criteria are met over the 72-hour period during which the PRHR HX must remain operational following a non-LOCA event. FSER at 21-17.

FSER § 21.1.4.B.1.2.5, which goes beyond the four safety-related functions identified in FSER § 21.1.4.B.1.2, addresses long term safe shutdown conditions defined in DCD Section 7.4

and derived from the URD and the SECY-94-084 – *i.e.*, cooling the RCS temperature to 420 °F in 36 hours. As that section indicates, this design requirement was evaluated, in both the DCD and the departure in the FSAR, in Chapter 19 using best estimate (conservative but non-bounding) values and is not demonstrated by a Chapter 15 analysis. FSER at 21-23 to 21-24. “The use of nominal and best-estimate values for reactor power and decay heat remains consistent with the shutdown temperature evaluation supporting the design certification as verified by the staff during an audit of the original calculation.” Id. at 21-24. The FSAR refers to this capability as a non-safety design basis and as non-safety related because the supporting analyses utilized nominal and best-estimate values for reactor power and decay heat instead of the more conservative inputs required for a safety design basis analysis.

The FSAR characterization of the shutdown capability is consistent with the NRC’s discussion before the ACRS. *See, e.g,*, Advisory Committee on Reactor Safeguards - AP1000 Subcommittee: Open Session Transcript at 77-78 (April 15, 2016) (ADAMS Accession No. ML16106A099).

The analyses demonstrating compliance with both the safety design basis in GDC 34 and non-safety related design requirements were conducted under a 10 CFR Part 50 Appendix B quality assurance program.

Question 30. The main control room (MCR) radiation monitors are de- energized on either a High-2 radiation signal (MCR emergency habitability system (VES) actuation) or a low battery charger input voltage for greater than 10 minutes. Therefore, following an actuation of the High-2 radiation signal, the MCR radiation monitors no longer function to provide operators in the control room with real-time radiation readings.

Continuous MCR radiation measurements with automatic alarm setpoints available to operators during an accident ensure the control room provides a safe environment for operators under accident conditions and that operators know the MCR emergency habitability system (VES) filtration system is properly functioning following a valid actuation.

Additionally, Emergency Action Level "AA3" for an ALERT due to abnormal radiation levels in the NRC endorsed NEI 07-01, Rev. 0, describes an example emergency action level threshold dose rate of greater than 15 mRem/hour in the AP1000 MCR. The emergency action level basis description states the value of 15 mRem/hour is derived from the General Design Criteria 19 value of 5 Rem in 30 days.

Are continuous MCR radiation monitors needed to determine whether an Emergency Action Level is met in the AP1000 MCR under all conditions?

Please explain why de-energization of the MCR radiation monitors following a High-2 radiation signal or a low battery charger input voltage for greater than 10 minutes is acceptable.

Response:

Continuous MCR radiation monitors are not needed to determine whether the threshold for Emergency Action Level AA3 has been reached. While, under the certified design, the MCR radiation monitors are deenergized on either a High-2 radiation signal or a low battery charger input voltage (i.e. loss of ac power) for greater than 10 minutes, these conditions also isolate the MCR and actuate the safety-related emergency habitability system (VES). Thereafter, the VES design and its automatic actuation on a High-2 signal will maintain MCR operator doses below the 5 Rem TEDE dose criterion in GDC 19.

While the MCR radiation monitors are deenergized on a High-2 signal or loss of AC power resulting in MCR isolation and VES actuation, radiation levels during passive VES operation will be assessed using portable instrumentation and onsite analysis as determined necessary based on actual event conditions. During a declared emergency, on-site surveys are conducted by Emergency Response Organization personnel. On-site surveys using portable instrumentation can be efficiently performed by trained personnel with or without AC power available.

When the VES is not actuated, the non-safety nuclear island non-radioactive ventilation system (VBS) protects the main control room personnel, and radiation monitor set points initiate

VBS supplemental filtration mode to ensure that the GDC-19 dose criterion is not exceeded. Both the MCR area monitor and the MCR supply air radiation monitors remain available during VBS operation. As reflected in NEI 07-01, Rev. 0 by the reference to RMS-JE-RE010 (which is the AP1000 designation for the MCR area monitor) in the Example EAL Threshold for AA3, the MCR area monitor provides the means of determining whether the EAL threshold is met when the MCR is not isolated. The MCR supply air radiation monitors are available to provide backup information for determining the magnitude of release of radioactive materials and continuously assessing such releases during VBS operation.

Question 31. Stage 1 load shed de-energizes large screen displays used for weather and the non-safety-related MCR area radiation monitor. The applicant and the Staff conclude that the stage 1 load shed does not affect operational decision making or plant control.

Please explain further the effect, if any, that the stage 1 load shed has on operational decision making in the context of emergency plan implementation by operators with the loss of large screen displays for weather and the non-safety-related MCR area monitor.

Response:

The FSER (pages 21-72 and 21-73) describes the Stage 1 load shed which includes the "large screen displays used for weather or plan of the day information." However, weather data will continue to be available in the MCR at each operator and the SRO desk top console until the Stage 2 load shed and will remain available at the SRO desk top console after the Stage 2 load shed. Real time meteorological data will also be available in the EOF and TSCs, as indicated in the LNP Emergency Plan.

Control room radiation readings would be provided by in-plant radiation surveys conducted by on-site Emergency Response Organization (ERO) personnel with the loss of the non-safety-related MCR area radiation monitor.

Question 32. The Staff concludes that "there is reasonable assurance that Scenarios 4, 5, and 9 will not occur because of the low probability of concurrent independent failures, recognizing many of the scenarios may be considered beyond design basis.

Please provide additional information on the expected probability of occurrence of the scenarios presented in Table 21.3-1 and a further explanation of why there is reasonable assurance Scenarios 4, 5, and 9 will not occur.

Response:

The probabilities of occurrence of all the scenarios in Table 21.3-1 have not been quantitatively calculated.

Scenarios 1, 2, and 3 - Station Blackout and Loss of Offsite Power (LOOP) have been evaluated in other portions of the license application and these three scenarios do not postulate additional VES or VBS failures. Therefore, the probabilities of occurrence of these scenarios are not changed.

Scenarios 6, 7, and 8 - These scenarios all begin with the LOCA design basis event which has been evaluated elsewhere in the license application. Each scenario also depends on additional, concurrent failures. Therefore, the probabilities for the combination of the LOCA and additional failures in each scenario will be lower than those of the LOCA.

Scenario 4 - This scenario contemplates the spurious actuation of VES due to simultaneous, independent component failures. However, VES is a safety related system and the inputs that can initiate VES are safety related. Safety related equipment utilizes design features including redundancy, separation, isolation, and independence. These design features provide a reasonable assurance that this scenario will not occur.

Scenario 5 - This scenario assumes ". . . simultaneous, independent VBS component failures." Section 9.4.1.1.1 of the AP1000 Design Control Document says:

> The nuclear island nonradioactive ventilation system is designed to provide a reliable source of heating, ventilation, and cooling to the areas served when ac power is available. The system equipment and component functional capabilities are to minimize the potential for actuation of the main control room emergency habitability system or the potential reliance on passive equipment cooling. This is achieved through the use of redundant equipment and components that are connected to standby onsite ac power sources.

This VBS use of redundant equipment and components provides a reasonable assurance that this scenario will not occur.

Scenario 9 - This scenario begins with "LOCA with fuel failure and leakage from containment at an adjacent plant . . ." and requires additional, multiple concurrent failures to occur in VBS. LOCA with leakage from containment is a beyond design basis event, and as noted in Scenario 5 above, VBS is designed to be reliable with ". . . the use of redundant equipment and components. . . ." The improbable, beyond design basis initial event combined with the VBS use of redundant equipment and components provides a reasonable assurance that this scenario will not occur.

Question 34. For the Staff: How is the NRC Staff keeping track of and considering changes that have occurred since publication of the final environmental impact statement (FEIS) (April 2012) to determine whether to supplement the FEIS?

- Describe the process the Staff is using to monitor and evaluate changes that may occur during the time period between publication of the FEIS and the Commission licensing decision, which has spanned several years.

- Do any events—such as the Duke Energy- Progress merger, the overall delay in LNP's construction and commercial date of operation schedule, or the closure of Crystal River— present a seriously different picture of the environmental impact of the issuance of the COLs from what was previously envisioned?

For the applicant: How has the applicant kept track of changes that have occurred since publication of the FEIS and kept the Staff apprised of these changes?

Response:

Duke Energy identifies and evaluates changes that have occurred since publication of the FEIS in accordance with a procedure for evaluating New and Significant Information. The procedure defines the type of information to be evaluated, qualifications of investigators, and the evaluation and reporting methods and timing. It includes an information evaluation checklist and tracking system. If new information is deemed to be potentially significant, the procedure requires it to be reported to the NRC. Duke Energy conducts the procedure at least semi-annually, or any time a new and potentially significant change becomes apparent. The NRC Staff audited this process and Duke's evaluations of new information in February 2016, and concluded the audit in March 2016 after completing research on the new information identified by the applicant and follow-on teleconferences. The Staff did not find that any information was significant such that there was a need to supplement the FEIS.

Question 62. Please provide additional summary information on the costs of refurbishment and environmental impacts of operating refurbished coal-fired units.

Response:

Refurbishment of coal -fired units is not a feasible alternative. The current economic and regulatory environment does not lend itself to the refurbishment.

Due to the adoption of new air regulations (Mercury Air Toxics rule), Duke extended the retirement date of the coal fired Crystal River (CR) Units 1 and 2 from 2016 to 2018 and established a plan for replacement power via combined cycle generation to be in-service by 2018. The new Citrus County Combined Cycle (CCC) facility being constructed will replace the generation from CR Units 1 and 2. CCC permit obligations (Air Permit and Power Plant Siting Act Certification) require these coal fired units be retired and as a result they are not available for refurbishment.

Assuming a refurbished coal fired plant could be successfully permitted, the costs would be considerable. The cost of refurbishing CR 1 and 2 (870 MW combined) was estimated in 2012 to be over $1.6 billion. Environmental impacts of operating a refurbished coal plant would be comparable to the operational impacts of coal fired generation discussed in Section 9.2.3.1 of the Environmental Report and 9.2.2.1 of the FEIS, and greater than a baseload nuclear plant, including demands for cooling water, impacts to wetlands, and emissions of regulated air pollutants, such as SO_2, NO_x, particulate matter, mercury, and other constituents. Further evaluation of coal as a source of power production was considered environmentally unacceptable due to the production of carbon-derived gases and their potential contribution to climate change. Other environmental impacts associated with coal-fired plants include production and disposal of coal ash, which can affect land-use and groundwater quality.

Question 65. Clarify whether the Highlands site requires 6,725 (9-151) or 2,000 acres (9-161) for the transmission line corridor and whether the Putnam site requires 6,212 (9-196) or 2,150 acres (9-206) for the transmission line corridor.

Response:

The larger acreage figures (6,725 acres for Highlands, 6,212 acres for Putnam) represent the total acreage required for the transmission corridor, while the smaller acreage figures (2,000 acres for Highlands and 2,150 acres for Putnam) represents the acreage expected to be disturbed within the corridor.

Question 66. What additional actions would the applicant need to take to acquire water rights to the Kissimmee River for the Highlands site alternative since "no additional surface water will be allocated from [South Florida Water Management District]-controlled surface-water bodies over and above existing allocations?"

Response:

Duke would have to acquire existing permit allocations to obtain water rights in this subwatershed. Because Florida considers water as public property and the state regulates its use for the benefit of the citizens, existing permits on purchased land could be transferred to Duke, or additional water use permit holders could agree to transfer their permit allocations to Duke, and SFWMD would need to concur. Some of the land to be purchased may already have water use permits and a combination of surface and groundwater could be used to generate sufficient makeup cooling water. Another action that could be taken includes seeking a variance from the South Florida Water Management District.

Question 68. The FEIS estimates that the Dixie site would disturb approximately 5,468 acres of land (9-103), the Highlands site would disturb about 4,068 acres of land (9-151), and the Putnam site would disturb around 4,218 acres of land but that the Levy site would only disturb roughly 2,525 acres of land (4-17). Nonetheless, Table 9-31 lists the cumulative impacts for land use at all of these sites as MODERATE. Does the significant difference in disturbed land between the LNP site and these alternative sites provide further support for the Staff's conclusion that none of the alternative sites are environmentally preferable to the proposed LNP site? (9-243)

Response:

Yes, the differences in potentially disturbed acres support the selection of LNP as the preferred site given that the Levy site would disturb less acreage than the alternative sites considered. The conclusion in the FEIS that none of the alternative sites are environmentally preferable to LNP for land use is based on the impact characterization (MODERATE for all sites), rather than the magnitude of difference in disturbed acres. MODERATE environmental effects are considered (based on Council of Environmental Quality guidelines) sufficient to alter noticeably, but not to destabilize, important attributes of the resource. An alternatives analysis conducted for the USACE also determined that the LNP is the Least Environmentally Damaging Practicable Alternative (LEDPA), using factors defined in the Section 404(b)(1) analysis in the Clean Water Act (Title 40 Code of Federal Regulations [C.F.R.] Part 230). These factors included land use analysis.

Question 69. Have there been significant energy or environmental regulatory or policy changes at the state or federal level that alter the viability of the various alternatives evaluated in the FEIS?

Response:

Duke Energy has an established procedure for identifying and evaluating New and Significant Information. Energy and environmental regulatory or policy changes are monitored regularly under this process. For example, regulatory or policy changes that have been evaluated include changes in FEMA maps, Waste Confidence Rule, Clean Water Rule on Waters of the United States, Florida Fish & Wildlife Conservation Commission proposed rules for threatened and endangered species, and USFWS rules regarding critical habitat. Duke Energy has not identified any significant energy or environmental regulatory or policy changes that alter the viability of the various alternatives evaluated in the FEIS.

Question 70. One of the reasons that the applicant provided for selecting the Levy 2 area as its proposed site instead of the Crystal River site was that adding new nuclear generating capacity at Crystal River would result in a significant concentration of the applicant's generating assets in one location. According to the applicant, this would make its system overly vulnerable to a major hurricane or other natural or man-made disaster. Further, in its Section 404(b)(1) Alternatives Analysis the applicant concluded that the Crystal River site would not meet the purpose and need of the project. Has the decision not to restart Crystal River Unit 3 changed this analysis? Has this decision affected the USACE's determination of the LEDPA?

Response:

The decision not to restart Crystal River Unit 3 has not changed the results of the alternative sites or 404(b) analysis. Duke Energy is currently constructing the Citrus County Combined Cycle Plant (CCC) adjacent to the Crystal River Energy Complex (CREC). At the time this asset comes online, CREC Units 1 and 2 will be retired. The retirement of Units 1, 2, and 3 represent 1730 MW of generating capacity that would be removed from CREC, but the CCC will add 1640 MW of generating capacity to effectively replace the lost capacity. Therefore, the CREC site's generating capacity will be similar to its capacity before the closure of Units 1, 2 and 3. Due to reliability concerns based on the concentration of energy production at a single site and the associated vulnerabilities summarized in the question above and described in the FEIS, the Crystal River site is not preferable to the Levy site. The closures of Crystal River 1, 2, and 3 were considered by the USACE in their determination that Levy was the LEDPA site.

Respectfully submitted,

/Signed electronically by David R. Lewis/

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Dated: July 7, 2016

CERTIFICATION

I, Robert H. Kitchen, am responsible for the responses to the above questions. I certify that these answers were prepared by me or under my direction, and I adopt the answers as part of my sworn testimony in this proceeding. I hereby certify under penalty of perjury that the forgoing is true and complete to the best of my knowledge, information, and belief.

/Executed in Accord with 10 C.F.R. § 2.304(d)/
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Dated at Charlotte, NC, the 7th day of July, 2016

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

Before the Commission

In the Matter of	)	
	)	
Duke Energy Florida, LLC	)	Docket Nos. 52-029 and 52-030
	)	
(Levy Nuclear Plant, Units 1 and 2)	)	

CERTIFICATE OF SERVICE

I hereby certify that the foregoing Duke Energy Florida's Responses to Pre-Hearing Questions, and accompanying Certification, have been served through the E-Filing system on the participants in the above-captioned proceeding, this 7th day of July, 2016.

/Signed electronically by David R. Lewis/

David R. Lewis