APPENDIX A

Table 2 – Expanded Calculations

Emissions Based on Current Sulfur Concentrations

Facility		Diesel Storage Capacity (Full Tanks)		Sulfur Mass Concentration[15]		Mass of Fuel Bound Sulfur		Sulfur Molar Mass	Mole of Fuel Bound Sulfur		Sulfur Dioxide Molar Mass
				Facility	Rule	Facility	Rule		Facility	Rule	
		(gal)	(lb)	(ppm)		(lb)		(lb/ lbmol)	(lbmol)		(lb/ lbmol)
Byron		255,500	1,773,937	26		46.12	26.61		1.44	0.83	
Clinton		137,193	952,531	160		152.40	14.29		4.75	0.45	
Dresden	All Other Tanks	47,775	331,702	21	15	6.97	4.98	32.06	0.22	0.16	64.07
	Aux Boiler Tank	150,000	1,041,450	150		156.22	15.62		4.87	0.49	
	Total	197,775	1,372,458	--		163.18	20.60		5.09	0.64	
LaSalle		197,200	1,369,160	147		201.27	20.54		6.28	0.64	

Facility		Mass of Sulfur Dioxide Emissions					
		Facility	Rule	Difference	Facility	Rule	Difference
		(lb)			(tons)		
Byron		92.17	53.18	39.00	0.046	0.027	0.019
Clinton		304.57	28.55	276.02	0.152	0.014	0.138
Dresden	All Other Tanks	13.92	9.94	3.98	0.007	0.005	0.002
	Aux Boiler Tank	312.19	31.22	280.97	0.156	0.016	0.140
	Total	326.11	41.16	284.95	0.163	0.021	0.142
LaSalle		402.22	41.04	361.18	0.201	0.021	0.181
			Total =	1246.09 lb		Total =	0.622 tons

[15] The sulfur concentration used for each Facility represents the highest concentration of the largest tank at the Site, except for LaSalle Station, which uses the average concentration of the tanks. Exelon Generation used 21 ppm for Dresden Station's sulfur concentration. This figure excludes the estimated sulfur concentration of the auxiliary boiler tank because it has a limited history of sampling and the exact concentration is unknown. The other tanks fall in the 16-18 ppm range, so 21 ppm is a conservative estimate.

Table 3 – Expanded Calculations

Emissions Based on Compliance Plan Sulfur Concentration

Facility		Diesel Fuel Storage Capacity (Full Tanks)		Sulfur Mass Concentration		Mass of Fuel Bound Sulfur		Sulfur Molar Mass	Mole of Fuel Bound Sulfur		Sulfur Dioxide Molar Mass
				Facility	Rule	Facility	Rule		Facility	Rule	
		(gal)	(lb)	(ppm)		(lb)		(lb/lbmol)	(lbmol)		(lb/lbmol)
Byron		255,500	1,773,937	250	15	443.48	26.61	32.06	13.83	0.83	64.07
Clinton		137,193	952,531	250		238.13	14.29		7.43	0.45	
Dresden	All Other Tanks	47,775	331,702	250		82.93	4.98		2.59	0.16	
	Aux Boiler Tank	150,000	1,041,450	250		260.36	15.62		8.12	0.49	
	Total	197,775	1,373,152	--		343.29	20.60		10.71	0.64	
LaSalle		197,200	1,369,160	250		342.29	20.54		10.68	0.64	

Facility		Diesel Fuel Storage Capacity (Full Tanks)		Mass of Sulfur Dioxide Emissions					
				Facility	Rule	Difference	Facility	Rule	Difference
		(gal)	(lb)	(lb)			(tons)		
Byron		255,500	1,773,937	886.28	53.18	833.10	0.443	0.027	0.417
Clinton		137,193	952,531	475.89	28.55	447.34	0.238	0.014	0.224
Dresden	All Other Tanks	47,775	331,702	165.72	9.94	155.78	0.083	0.005	0.078
	Aux Boiler Tank	150,000	1,041,450	520.32	31.22	489.10	0.260	0.016	0.245
	Total	197,775	1,373,152	686.04	41.16	644.88	0.343	0.021	0.322
LaSalle		197,200	1,369,160	684.05	41.04	643.00	0.342	0.021	0.322
					Totals :	3,213.20 lbs		Totals :	1.607 tons

Assumes a density of 6.943 lb/gal

Table 4 – Expanded Calculations

Facility	Years Averaged	Historic Diesel Burned Annual Averages		Sulfur Mass Concentration		Mass of Fuel Bound Sulfur		Sulfur Molar Mass	Mole of Fuel Bound Sulfur		Sulfur Dioxide Molar Mass
				Facility	Rule	Facility	Rule		Facility	Rule	
		(gal)	(lb)	(ppm)		(lb)		(lb/ lbmol)	(lbmol)		(lb/ lbmol)
Byron	11-15	107,094	743,556	26	15	19.33	11.15	32.06	0.60	0.35	64.07
Clinton	11-15	27,218	188,973	160		30.24	2.83		0.94	0.09	
Dresden	11-15	33,211	230,584	21		4.84	3.46		0.15	0.11	
LaSalle	11-15	32,814	227,830	147		33.49	3.42		1.04	0.11	

Facility	Mass of Sulfur Dioxide Emissions					
	Facility	Rule	Difference	Facility	Rule	Difference
	(lb)			(tons)		
Byron	38.63	22.29	16.35	0.019	0.011	0.008
Clinton	60.42	5.66	54.76	0.030	0.003	0.027
Dresden	9.68	6.91	2.76	0.005	0.003	0.001
LaSalle	66.93	6.83	60.10	0.033	0.003	0.030
		Total =	133.97 lb		Total =	0.067 tons

APPENDIX B

Table 5

Byron Tank Sulfur Concentrations

Sample Date Range: October 2015-April 2016

Tank	Volume (gal)	Sulfur (ppm)
Outside Storage Tank	50,000	17
Security Diesel	500	132
0B SX M/U Pump	2000	230
1A DO Storage Tank	25,000	21
1B DO Storage Tank	25,000	22
1C DO Storage Tank	25,000	17
1D DO Storage Tank	25,000	26
2A DO Storage Tank	50,000	16
2B DO Storage Tank	50,000	16
1A DG FO Day Tank	500	21
1B DG FO Day Tank	500	22
2A DG FO Day Tank	500	33
2B DG FO Day Tank	500	17
1B AF FO Day Tank	500	17
2B AF FO Day Tank	500	17

Table 6

Clinton Tank Sulfur Concentrations

Sample Date Range: February 2014 – October 2015

Description	Volume (gal)	Sulfur (ppm)
Div 1 Diesel Fuel Oil Day Tank	731	122
Div 2 Diesel Fuel Oil Day Tank	731	110
Div 3 Diesel Fuel Oil Day Tank	731	160
Div 1 Diesel Fuel Oil Storage Tank	50,000	122
Div 2 Diesel Fuel Oil Storage Tank	50,000	110
Div 3 Diesel Fuel Oil Storage Tank	35,000	160

Table 7

Dresden Tank Sulfur Concentrations

Sample Date: March 2016

Tank	Volume (gal)	Sulfur (ppm)
Unit 2/3 Aux Heating Boiler Diesel Fuel Tank	150,000	< 150 This is an assumed value based on a limited history of sampling and the exact concentration being unknown.
Unit 2 Emergency Power Diesel Generator Day Tank	750	18
Unit 3 Emergency Power Diesel Generator Day Tank	750	16
Unit 2/3 Emergency Power Diesel Generator Day Tank	750	21
Unit 2/3 Emergency Diesel Driven Fire Pump	275	16
Emergency Power Security Diesel Generator Day Tank	100	21
Unit 2/3A Isolation condenser Cooling Water Supply Pump Diesel Generator Day Tank	75	16
Unit 2/3B Isolation condenser Cooling Water Supply Pump Diesel Generator Day Tank	75	16
Unit 2 Diesel Fuel Oil UST	15,000	17
Unit 2/3 Diesel Fuel Oil UST	15,000	16
Unit 3 Diesel Fuel Storage Tank	15,000	16

Table 8

LaSalle Tank Sulfur Concentrations

Sample Date: March 2016

Description	Volume (gal)	Sulfur (ppm)
Unit 1 Diesel Fuel Day Tank	750	211
Unit 2 Diesel Fuel Day Tank	750	208
Common Diesel Fuel Day Tank	750	104
EDG Unit 1 Diesel Fuel Storage Tank	40,000	These 3 tanks supply fuel to those 3 day tanks listed directly above, and thus it is understood the sulfur values in these three tanks mimic the sulfur content in the day tanks.
EDG Unit 2 Diesel Fuel Storage Tank	40,000	
EDG Common Diesel Fuel Storage Tank	40,000	
Diesel Fire Pump Day Tank “A”	550	These 2 tanks are fueled from the EDG Tanks and thus it is understood that the sulfur values in these two tanks mimic the sulfur content in the day tanks (which is representative of the EDG Tank)
Diesel Fire Pump Day Tank “B”	550	
Unit 1 HPCS Diesel Fuel Day Tank	1,700	73
Unit 2 HPCS Diesel Fuel Day Tank	1,700	138
Unit 1 HPCS Diesel Fuel Storage Tank	33,950	These 2 tanks supply fuel to the 2 day tanks listed directly above, and thus it is understood the sulfur values in these two tans mimic the sulfur content in the day tanks.
Unit 2 HPCS Diesel Fuel Storage Tank	33,950	
TSC/Security Diesel Fuel Storage Tanks (UST)	2000	These three tanks have a limited history of refueling, and therefore their sulfur content has not been tested regularly.
TSC Diesel Generator Day Tank	275	
Security Diesel Generator Day Tank	275	

APPENDIX C

Table 9

Fuel Replacement Cost Estimate

	Total Volume	Recycling of Fuel	Refill	Labor	Total
	Gal	-$0.40/Gal	$5/Gal	Cost	Cost
Byron	250,000	-$100,000	$1,250,000	$288,270	**$1,438,270**
Clinton	135,000	-$54,000	$675,000	$133,290	**$754,290**
Dresden Tanks	45,000	-$18,000	$225,000	$101,790	$308,790
Dresden Boiler	70,000	-$28,000	$350,000	$53,181	$375,181
LaSalle	187,900	-$75,160	$939,500	$209,165	**$1,073,505**
Total Cost[16]	687,900[17]	-$275,160	$3,439,500	$785,696	**$3,950,036**
Compliance Cost if Variance is Granted[18]					**$2,202,976**
Exelon Generation Savings if Variance is Granted[19]					**$1,747,060**

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[16] Cost to achieve compliance by January 1, 2017.

[17] This estimate excludes approximately 20,000 gallons contained in smaller diesel fuel storage tanks. Exelon Generation believes these tanks will come into compliance through dilution.

[18] Compliance Cost for fuel replacement at Clinton and LaSalle, as well as the auxiliary boiler tank at Dresden. The remaining tanks at Dresden and Byron will have time to achieve compliance through dilution. No costs are required for tanks that will come into compliance through dilution.

[19] Compliance Savings result from achieving compliance at Byron and Dresden through dilution over the additional time granted by the variance.

APPENDIX D

Table 10

On Road Vehicle Diesel Emission Estimate

Emission Source	Diesel fuel Burned By Heavy Duty On-Road Vehicles		Sulfur Mass Concentration	Mass of Fuel Bound Sulfur	Sulfur Molar Mass	Moles of Fuel Bound Sulfur	Sulfur Dioxide Molar Mass	SO_2 Emitted	
	(gal)	(lb)	(ppm)	(lb)	(lb/lbmol)	(lbmol)	(lb/lbmol)	(lb)	(ton)
Trucks	6,000	41,658	15	0.62	32.06	0.02	64.07	1.25	6.24E-04

Density: 6.943 lb/gal

Emission Source	Miles Traveled	Emission Factor		Emissions			
		NOx	PM10	NOx		PM_{10}	
	(mile)	(g/mile)		(lb)	(ton)	(lb)	(ton)
Trucks	40,000	8.613	0.219	759.54	0.38	19.31	0.010

0.0022046 lb/g (Unit Conversion)

*Emission Factors from EPA Document Titled: Average In-Use Emissions from Heavy-Duty Trucks, available at https://www3.epa.gov/otaq/consumer/420f08027.pdf

Exhibit A

Statement of Reasons

BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

IN THE MATTER OF:	)	
	)	R15-21
AMENDMENTS TO 35 ILL. ADM. CODE	)	(Rulemaking-Air)
PART 214, SULFUR LIMITATIONS, PART	)	
217, NITROGEN OXIDES EMISSIONS,	)	
AND PART 225, CONTROL OF EMISSIONS	)	
FROM LARGE COMBUSTION SOURCES	)	

RECEIVED
CLERK'S OFFICE
APR 28 2015
STATE OF ILLINOIS
Pollution Control Board

STATEMENT OF REASONS

I. INTRODUCTION

The Illinois Environmental Protection Agency ("Illinois EPA" or "Agency") submits this Statement of Reasons to the Illinois Pollution Control Board ("Board") pursuant to Sections 4, 10, 27, 28, and 28.2 of the Environmental Protection Act (415 ILCS 5/4, 10, 27, 28, and 28.2) and 35 Ill. Adm. Code 102.202 in support of the attached proposal of regulations. Generally, these regulations are proposed to control emissions of sulfur dioxide ("SO_2") in and around areas designated as nonattainment with respect to the 2010 SO_2 National Ambient Air Quality Standard ("NAAQS").

This proposed rulemaking includes several components. First, portions of the proposal are intended to meet certain obligations of the State of Illinois under the federal Clean Air Act ("CAA"), 42 U.S.C. § 7401 *et seq.* Such provisions are intended to satisfy Illinois' obligation to submit a State Implementation Plan ("SIP") to the United States Environmental Protection Agency ("USEPA") to address requirements under Sections 172, 191, and 192 of the CAA for sources of SO_2 emissions in areas designated as nonattainment with respect to the 2010 SO_2 NAAQS ("nonattainment area" or "NAA"). *See* 42 U.S.C. §§ 7502, 7514, and 7514a. Other portions of the proposal are not specifically federally required, but are intended to aid Illinois' attainment planning efforts with respect to future rounds of attainment designations for the SO_2 NAAQS. Finally, portions of the proposal are the product of stakeholder outreach efforts, and are intended to address stakeholder requests and concerns; while some of these provisions involve pollutants other than SO_2, they are related to Illinois' attainment planning efforts for the SO_2 standard and are thus included with this rulemaking proposal.

The Agency is proposing amendments that: 1) establish sulfur content limitations for liquid fuels used by fuel combustion emission units throughout the State; 2) establish SO_2 emission limitations for specific sources impacting an SO_2 NAA; 3) address the conversion of certain coal-fired electric generating units ("EGUs") located in or near an SO_2 NAA to fuel other than coal; and 4) correct or update various existing provisions. The proposed requirements are reasonable and cost effective. Included in this submittal are proposed amendments to 35 Ill. Adm. Code 214, Sulfur Limitations; 35 Ill. Adm. Code 217, Nitrogen Oxides Emissions; and 35 Ill. Adm. Code 225, Control of Emissions from Large Combustion Sources.

II. STATEMENT OF FACTS

The CAA establishes a comprehensive program for controlling and improving the nation's air quality via state and federal regulations. The USEPA is charged with identifying air pollutants that endanger the public health and welfare and with formulating NAAQS that specify the maximum permissible concentrations of those pollutants in the ambient air, pursuant to Sections 108 and 109 of the CAA. 42 U.S.C. §§ 7408-7409.

A. Sulfur Dioxide

Sulfur dioxide is one of a group of highly reactive gases known as "oxides of sulfur." The largest source of SO_2 emissions is fossil fuel combustion at electric utilities and other industrial facilities. Other sources of SO_2 include the extraction of metal from ore and the burning of sulfur-containing fuels by locomotives, large ships, and equipment utilizing diesel engines. *Final Primary National Ambient Air Quality Standard for Sulfur Dioxide*, 75 *Fed. Reg.* 35520, 35524 (June 22, 2010).

Short-term exposure to sufficient concentrations of SO_2 is associated with increased respiratory morbidity, including moderate to great decrements in lung function, bronchoconstriction, and a variety of respiratory symptoms. 79 *Fed. Reg.* 35520, 35525-26. Groups potentially at greater risk of experiencing adverse health effects from SO_2 include those with pre-existing respiratory disease, children and older adults, persons who spend increased time outdoors or at elevated ventilation rates, persons with lower socioeconomic status, and persons with certain genetic factors. *Id.* at 35527. USEPA has determined that "the considerable size of the population groups at risk indicates that exposure to ambient SO_2 could have a significant impact on public health in the United States." *Id.* at 35527.

On June 22, 2010, USEPA finalized revisions to the primary SO_2 NAAQS, replacing the previous 24-hour and annual standards with a 1-hour standard of 75 parts per billion. 75 *Fed. Reg.* 35520. USEPA designated two areas in Illinois as nonattainment for the SO_2 NAAQS: 1) the Lemont NAA, which includes Cook County (partial-Lemont Township) and Will County (partial-DuPage and Lockport Townships); and 2) the Pekin NAA, which includes Tazewell County (partial-Cincinnati and Pekin

Townships) and Peoria County (partial-Hollis Township). 40 CFR § 81.314. Final designations became effective on October 4, 2013. *Final Air Quality Designations for the 2010 Sulfur Dioxide (SO_2) Primary National Ambient Air Quality Standard*, 78 *Fed. Reg.* 47191, 47192 (Aug. 5, 2013).

In its final designations for the Lemont and Pekin areas, USEPA explained that it intends to address in "separate future actions" designations for all other areas of the State. 78 *Fed. Reg.* 47191.[1] Subsequently, on May 13, 2014, USEPA proposed a "Data Requirements Rule" in which it set forth criteria for identifying the sources around which air agencies will eventually need to characterize SO_2 air quality, as well as a process and timetables for characterizing air quality through ambient monitoring and/or modeling and for submitting the data to USEPA. USEPA indicated that it will use this data in "future rounds of area designations" for the 2010 SO_2 standard. *Proposed Data Requirements Rule for the 1-Hour Sulfur Dioxide (SO_2) Primary National Ambient Air Quality Standard (NAAQS)*, 79 *Fed. Reg.* 27446 (May 13, 2014).

B. Clean Air Act Requirements for Sulfur Dioxide

Under Section 110 of the CAA and related provisions, states are required to submit for the USEPA's approval SIPs that provide for the implementation, maintenance, and enforcement of standards established by USEPA through control programs directed to the sources of the pollutants involved. 42 U.S.C. § 7410. The CAA also requires that states address provisions specific to areas designated as nonattainment with respect to a NAAQS, including such requirements as reasonably available control measures

[1] USEPA explained, "At this time, the EPA is designating as nonattainment most areas in locations where existing monitoring data from 2009–2011 indicate violations of the 1-hour SO_2 standard. The EPA intends to address in separate future actions the designations for all other areas for which the agency is not yet prepared to issue designations and that are consequently not addressed in this final rule." 78 *Fed. Reg.* 47191.

("RACM") and reasonably available control technology ("RACT"). *See* 42 U.S.C. § 7502.

Specifically, Section 172 of the CAA, addressing general requirements for areas designated as nonattainment, provides in pertinent part:

> (c) Nonattainment plan provisions
>
> The plan provisions (including plan items) required to be submitted under this part shall comply with each of the following:
>
> > (1) In general
> >
> > Such plan provisions shall provide for the implementation of all reasonably available control measures as expeditiously as practicable (including such reductions in emissions from existing sources in the area as may be obtained through the adoption, at a minimum, of reasonably available control technology) and shall provide for attainment of the national primary ambient air quality standards.

42 U.S.C. § 7502(c)(1). Rather than describing specific control systems to be used to address the necessary SO_2 reductions, USEPA has interpreted the terms RACT and RACM for purposes of Section 172(c)(1) requirements as "the level of emissions control that is necessary to provide for expeditious attainment of the NAAQS within a nonattainment area." *Withdrawal of the Prior Determination or Presumption that Compliance with the CAIR or the NO_x SIP Call Constitutes RACT or RACM for the 1997 8-Hour Ozone and 1997 Fine Particle NAAQS*, 79 *Fed. Reg.* 32892, 32894 (June 9, 2014). USEPA noted, "Courts have upheld this interpretation of the statute with respect to nonattainment SIPs." *Id.* (citing *Natural Resources Defense Council v. Environmental Protection Agency*, 571 F.3d 1245 (D.C. Cir. 2009)).

Sections 191 and 192 of the CAA set forth requirements specific to areas designated as nonattainment for lead, nitrogen dioxide, or sulfur oxides. Section 191 requires that states with an SO_2 NAA submit to USEPA a SIP satisfying CAA requirements within 18 months of being designated as nonattainment. 42 U.S.C. § 7514. Section 192 requires that the SIP provide for attainment of the SO_2 NAAQS as expeditiously as practicable but no later than 5 years from the date of the nonattainment designation. 42 U.S.C. § 7514a.

Designation of the Lemont and Pekin areas as nonattainment for the SO_2 NAAQS triggered the above CAA provisions, requiring that Illinois adopt regulations that reduce emissions sufficiently to demonstrate attainment of the SO_2 standard in those areas. Illinois was required to make its SIP submittal by April 6, 2015. The SIP must contain provisions that provide for attainment of the SO_2 NAAQS in the Lemont and Pekin NAAs by October 4, 2018. 78 *Fed. Reg.* 47191, 47192-93.

III. PURPOSE AND EFFECT OF THE PROPOSAL

A. Part 214 Revisions

The bulk of the Agency's proposed revisions to Part 214 have been prepared to satisfy Illinois' obligation to submit a SIP to USEPA to address the requirements under Sections 172, 191, and 192 of the CAA, as described above, for areas designated as nonattainment with respect to the SO_2 NAAQS. *See* 42 U.S.C. §§ 7502, 7514, and 7514a. The proposal aims to achieve SO_2 emission reductions in Illinois, particularly in SO_2 NAAs.

First, the proposal requires that fuel combustion emission units throughout the State comply with sulfur content limitations of 1000 parts per million for residual fuel oil and 15 parts per million for distillate fuel oil, with certain specified exceptions. Owners or operators of subject emission units must maintain records demonstrating compliance with the limitations.

Applying these provisions to fuel combustion emission units impacting the Lemont and Pekin NAAs is needed to address the CAA requirements discussed above. Applying these provisions to units not currently impacting the Lemont and Pekin NAAs is intended to aid attainment planning efforts regarding future attainment designations for the 2010 SO_2 standard. As previously discussed, USEPA intends to engage in at least two additional rounds of attainment designations for the SO_2 standard based on monitoring and/or modeling data submitted by states, which may result in additional NAAs in Illinois. Rather than imposing fuel sulfur content limitations piecemeal as additional areas are designated nonattainment, the Illinois EPA proposes establishing such limits statewide. These limits will assist the State's attainment planning efforts in future NAAs, and could even potentially help certain areas avoid a nonattainment designation. Statewide regulation is therefore appropriate, particularly as fuel complying with the Agency's proposed limitations is widely available in Illinois and is in fact already used by the majority of commercial and industrial sources in Illinois.

Next, the proposal creates a new Subpart AA requiring that particular sources contributing to nonattainment in an SO_2 NAA comply with SO_2 emission limitations for specified emission units. These emission limitations are based on extensive computer modeling conducted by the Agency that evaluated the SO_2 emission reductions necessary to demonstrate attainment of the SO_2 NAAQS. Certain emission units must utilize a continuous emissions monitoring system ("CEMS") or an alternative monitoring method available under 40 CFR 75 to demonstrate compliance with the emission limitations, while other units must either utilize a CEMS or conduct performance testing in compliance with specified testing provisions. All sources are required to comply with recordkeeping and reporting requirements. All provisions in the proposed Subpart AA are intended to address the CAA requirements described above.

January 1, 2017, is the proposed compliance deadline for most sources subject to the Part 214 sulfur content limitations for fuel oil,[2] and is the proposed compliance deadline for all sources subject to the requirements in Part 214, Subpart AA. USEPA identified this date as the latest compliance deadline it expects will be acceptable to USEPA, as the deadline will ensure at least one full calendar year of air quality monitoring data prior to the October 2018 attainment deadline, enabling USEPA to evaluate whether the State's plan is in fact providing for attainment. *Guidance for 1-Hour SO_2 Nonattainment Area SIP Submissions*, pp. 10-11 (April 23, 2014).[3]

B. Part 217 and Part 225 Revisions

The Agency's proposed revisions to 35 Ill. Adm. Code Parts 217 and 225 are the product of the Agency's stakeholder outreach efforts, and are intended to address stakeholder requests and concerns.

1. Regulatory Background

Subparts C, D, E, F, G, H, and M of Part 217, known as Illinois' NO_x RACT Rule, control nitrogen oxides ("NO_x") emissions from various source categories. Subpart M establishes NO_x emission limitations for EGUs: 0.06 lbs/mmBtu for natural gas-fired

[2] Certain specified sources have until January 1, 2019, to comply with the proposed sulfur content limitations for distillate fuel oil. One specified source, subject to a less stringent sulfur content limitation for distillate fuel oil, is required to comply by January 1, 2016. These exceptions were taken into account in the Agency's modeling and will not interfere with attainment.

[3] Available at http://www.epa.gov/airquality/sulfurdioxide/pdfs/20140423guidance.pdf.

EGUs; 0.10 lbs/mmBtu for liquid-fired EGUs; and 0.12 lbs/mmBtu for solid fuel-fired EGUs. 35 Ill. Adm. Code 217.344. Subpart M, however, exempts from these limitations coal-fired EGUs complying with the Illinois Mercury Rule through the Combined Pollutant Standard ("CPS") (discussed in more detail below), as such EGUs are already subject to NO_x limitations under the terms of the CPS. 35 Ill. Adm. Code 217.342(b) ("the provisions of this Subpart [M] do not apply to a coal-fired stationary boiler that commenced operation before January 1, 2008, [and] that is complying with 35 Ill. Adm. Code 225.Subpart B through the . . . combined pollutant standard").

Subpart B of Part 225, known as the Illinois Mercury Rule, controls emissions of mercury from coal-fired EGUs. Section 225.230(a) of Subpart B sets forth mercury emission standards for EGUs at existing sources. The CPS, set forth in Sections 225.291-299 of Subpart B, provides specified EGUs an alternative means of compliance with these mercury emission standards through permanent shut-down, installation of activated carbon injection equipment, and compliance with specified control requirements and/or emission standards for SO_2, NO_x, particulate matter, and mercury. *See generally* 35 Ill. Adm. Code 225.291. Pertinent to this rulemaking proposal, EGUs under the CPS must comply with a CPS group average NO_x emission limitation of 0.11 lbs/mmBtu on both an annual and ozone season basis. 35 Ill. Adm. Code 225.295(a).

2. Proposed Amendments

As discussed in Section VI *infra*, the Illinois EPA engaged in extensive outreach on its proposal. During the course of discussions with potentially impacted sources, Midwest Generation, LLC ("Midwest Generation") approached the Agency regarding the company's plans to potentially convert several coal-fired EGUs located in or near the

Lemont NAA (Units 6, 7, and 8 at the Joliet station ("Joliet 6, 7, and 8"), and Unit 3 at the Will County station ("Will County 3")) to combust only fuel other than coal, such as natural gas or distillate fuel oil. Midwest Generation, however, requested regulatory certainty that the conversions would not change the NO_x emission limitations applicable to such units. All of the above units are currently subject to the Illinois Mercury Rule in Part 225 and all currently comply with the rule via the CPS. As discussed above, the EGUs are therefore subject to the NO_x emission limitations in the CPS and are exempt from the NO_x emission limitations in Subpart M of Part 217.

Once the EGUs permanently cease combusting coal, however, an argument could arise as to whether the units are still subject to the Illinois Mercury Rule/CPS and still eligible for the Subpart M exemption. If the units are no longer exempt from Subpart M, they would be required to comply with the appropriate NO_x limitation in Subpart M, depending on the type of fossil fuel combusted. Midwest Generation expressed concerns about the uncertainty the company believes this could cause and the related possible change in the company's expectations, as well as concerns that the converted EGUs would not be able to meet the applicable Subpart M NO_x limitations. These concerns arise from the age of the units being converted, the cost of installing NO_x control equipment on those units, and the cost effectiveness of controls for units that are projected to operate at a relatively low capacity factor.

The Agency strongly supports the conversion of the above units to natural gas or diesel fuel, as such conversions would significantly reduce SO_2 emissions in the Lemont NAA, aiding the Agency's efforts to demonstrate attainment of the SO_2 NAAQS in that area. The conversions would also result in significant reductions in emissions of particulate matter and greenhouse gases such as carbon dioxide, and likely significant reductions in emissions of NO_x. These reductions will aid the State's planning efforts to address regional haze, interstate transport issues related to the Cross-State Air Pollution Rule, and USEPA's recently proposed Clean Power Plan for the control of greenhouse gases from the power sector.

The Agency's proposal therefore addresses the potential conversion of the above units and specifies the NO_x limitations that will be applicable to these units. The Agency proposes amendments to Parts 214 and 225 that collectively require the above units to permanently cease combusting coal. In Subpart AA of Part 214, the Agency proposes emission limitations for the units that reflect combustion of fuel other than coal. In Part 225, the Agency proposes establishing deadlines after which these units are no longer allowed to combust coal. The proposal addresses applicable NO_x emission limitations by amending the Illinois Mercury Rule to specify that EGUs in the CPS (as listed in Appendix A to Part 225) remain subject to the Illinois Mercury Rule/CPS, including the NO_x limitations in the CPS, regardless of the type of fuel combusted. The proposal also provides, both in the CPS and in Subpart M of Part 217, that EGUs subject to the CPS are exempt from the NO_x emission limitations in Subpart M, regardless of the type of fuel combusted.

The proposal addresses collateral issues related to the above as well. First, as mercury emissions are not a concern for units combusting fuel other than coal, and particulate matter emissions are a significantly lower concern for such units, the Agency proposes amending Part 225 to specify that EGUs that permanently cease combusting coal are no longer required to comply with the mercury or particulate matter control technology requirements set forth in the CPS or the mercury-related emission rates, monitoring, recordkeeping, notice, analysis, certification, or reporting requirements set forth in the Illinois Mercury Rule/CPS. The Agency also proposes specifying that EGUs that convert to fuel other than coal are not subject to the CPS group average annual SO_2 emission rate set forth in Section 225.295(b) of the CPS. Such units will instead be subject to unit-specific SO_2 emission limitations under the proposed Subpart AA in Part 214.

During discussions, Midwest Generation also indicated its intent to continue combusting coal at Unit 4 at the Will County station ("Will County 4"). The CPS currently requires that Midwest Generation install flue gas desulfurization ("FGD") equipment on Will County 4 on or before December 31, 2018. 35 Ill. Adm. Code 225.296(b). In light of the significant SO_2 emission reductions that will result from the conversion of Joliet 6, 7, and 8 and Will County 3 to natural gas or diesel fuel, Midwest Generation requested that Will County 4 be exempted from the requirement to install FGD equipment in lieu of Joliet 6 having such exemption.[4] The Agency's proposal implements this request, both in Part 225 and in the proposed emission limitation applicable to Will County 4 in Part 214.

Finally, Midwest Generation requested changes to provisions in the CPS that permit the sale or trade of NO_x and SO_2 allowances to the Homer City, Pennsylvania,

[4] Currently, the CPS exempts Joliet 6 (ambiguously identified by boiler reference as "Joliet 5" in the CPS) from the requirement to install FGD equipment. As Joliet 6 will be converting to natural gas or diesel fuel, the Agency proposes replacing the exemption for Joliet 6 with an exemption for Will County 4.

generating station, due to a change in Midwest Generation's affiliation with such station.[5] The Agency's proposal implements this request.

The Agency's proposed revisions to the CPS are not intended to alter the variances recently granted by the Board to Midwest Generation regarding certain provisions set forth in the CPS. In *Midwest Generation, LLC-Waukegan Generating Station v. Illinois Environmental Protection Agency*, PCB12-121, the Board granted Midwest Generation relief from the requirement in Section 225.296(a)(1) to install FGD equipment on Unit 7 at the Waukegan station by December 31, 2013, as well as relief from the requirement in Section 225.296(c)(1) to convert the hot-side electrostatic precipitator on such unit by December 31, 2013; the Board granted Midwest Generation's request for a delay in such requirements until December 31, 2014. (8/23/12 Board Order). In *Midwest Generation, LLC v. Illinois Environmental Protection Agency,* PCB13-24, the Board granted Midwest Generation relief from the system-wide average annual SO_2 emission rates set forth in Section 225.295(b) from January 1, 2015, through December 31, 2016, as well as relief from the requirement in Section 225.296(a)(2) to install FGD equipment on Unit 8 at the Waukegan station, or shut down the unit, by December 31, 2014; the Board granted Midwest Generation's request for a delay of such requirement in Section 225.296(a)(2) until May 31, 2015. (4/4/13 Board Order). The relief granted by

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[5] According to Midwest Generation, when the CPS was originally established, EME Homer City Generation, LP ("EMEHC"), which was an affiliate of Midwest Generation, operated the Homer City station and obtained emission allowances from Midwest Generation for use by the Homer City station. Ownership was financed through a sale-leaseback arrangement with General Electric Capital Corporation ("GECC"). In March 2012, EMEHC transferred its interests in the Homer City station to GECC. At that point, no Midwest Generation affiliate had any involvement with the Homer City station. GECC selected NRG Energy Services to handle operations and maintenance ("O&M") of the Homer City station in 2012. In April 2014, NRG Energy, Inc., the ultimate parent company of NRG Energy Services, acquired ownership of Midwest Generation. The NRG Energy Services O&M arrangement is still operative, but NRG and its affiliates do not have any ownership interest in the Homer City station and do not make any bidding or dispatch determinations. Accordingly, Midwest Generation requested that references to trading with the Homer City station be removed from the CPS.

the Board in each variance was subject to certain conditions, specified in the Board's final order.

The Agency's proposed revisions are not intended to abrogate in any way the relief granted by, or the conditions imposed by, the Board in either of the proceedings described above.

3. Other Revisions to Part 217

The Agency proposes revising Section 217.394 in Subpart Q of Part 217. Subpart Q controls emissions of NO_x from stationary reciprocating internal combustion engines and turbines. A regulatory oversight was recently brought to the Agency's attention regarding the initial performance testing provisions in Section 217.394(a)(3); the current provision fails to specify an alternate testing deadline for new units that meet the criteria in such subsection. The Agency therefore proposes amending this Section to specify a deadline.

The Agency does not intend for this rulemaking to be a "clean-up" of Part 217, but as sources could currently be impacted by this error, the Agency proposes amending this provision as part of this rulemaking proposal.

C. SIP Revisions

Three Illinois SIPs are implicated by the Agency's proposal—Illinois' SIP for the 2010 SO_2 NAAQS, Illinois' Regional Haze SIP, and Illinois' NO_x SIP Call Phase II SIP. The Agency anticipates submitting to USEPA portions of the Agency's proposal for each SIP.

First, as previously discussed, the Illinois EPA intends to submit to USEPA all revisions to Part 214 as part of Illinois' SIP for the 2010 SO_2 NAAQS.

Second, the Illinois EPA intends to submit to USEPA revisions to Sections 225.291, 225.292, 225.293, 225.295, and 225.296 (except 225.296(d)) of Part 225, and Appendix A to Part 225, as revisions to Illinois' Regional Haze SIP. On June 24, 2011, the Illinois EPA submitted the provisions listed above to USEPA for approval as part of Illinois' plan to address the visibility protection requirements of Section 169A of the CAA, 42 U.S.C. § 7491, and the Regional Haze Rule, as codified in 40 CFR § 51.308. On July 6, 2012, USEPA approved the provisions as part of Illinois' Regional Haze SIP. *Approval and Promulgation of Air Quality Implementation Plans; Illinois; Regional Haze*, 77 *Fed. Reg.* 39943 (July 6, 2012). The Illinois EPA is therefore required to submit to USEPA subsequent amendments to these sections as revisions to the Regional Haze SIP. *See* 40 CFR § 51.104. The Agency's proposal should not negatively impact Illinois' Regional Haze SIP, as the proposed amendments to Part 225 will result in significant reductions in emissions of SO_2, and likely NO_x as well.

Third, the Illinois EPA intends to submit to USEPA revisions to Subpart Q of Part 217 as revisions to Illinois' NO_x SIP Call Phase II SIP ("Phase II SIP"). On October 23, 2007, the Illinois EPA submitted Section 217.394 of Subpart Q (along with other provisions not amended in this rulemaking proposal) to USEPA for approval as part of Illinois plan to satisfy USEPA's NO_x SIP Call Phase II Rule. On June 26, 2009, USEPA approved the provision as part of Illinois' Phase II SIP. *Approval and Promulgation of Air Quality Implementation Plans; Illinois; Oxides of Nitrogen Regulations, Phase II*, 74 *Fed. Reg.* 30466 (June 26, 2009). The Illinois EPA is therefore required to submit to USEPA subsequent amendments to this section as revisions to the Phase II SIP. *See* 40

CFR § 51.104. As the proposed amendment simply adds a testing deadline for new units, it will not negatively impact Illinois' Phase II SIP.

The Illinois EPA does not currently intend to submit to USEPA: 1) revisions to sections of Part 225 other than those described above; or 2) revisions to Subpart M of Part 217, as Subpart M is not currently part of Illinois' SIP.

IV. GEOGRAPHIC REGIONS AND SOURCES AFFECTED

The proposed fuel sulfur content limitations in Part 214 apply statewide, and are expected to affect both new and existing fuel combustion emission units. Appendix A to the *Technical Support Document for Proposed Rule Revisions Necessary to Demonstrate Attainment of the One-hour NAAQS for Oxides of Sulfur* ("TSD"), included in this rulemaking proposal, lists the sources potentially affected by these proposed amendments.

The proposed SO_2 emission limitations in Subpart AA of Part 214 impact the two areas designated as nonattainment for the SO_2 NAAQS: 1) the Lemont NAA, which includes Cook County (partial-Lemont Township) and Will County (partial- DuPage and Lockport Townships); and 2) the Pekin NAA, which includes Tazewell County (partial-Cincinnati and Pekin Townships) and Peoria County (partial-Hollis Township). 40 CFR § 81.314. The proposed limitations are intended to affect only those sources listed in Subpart AA, all of which are either located in the Lemont or Pekin NAAs or have been determined to be contributing to nonattainment in one of those areas.

The proposed revisions to Part 225 and to Subpart M of Part 217 impact only those EGUs that are subject to the CPS. Such EGUs are listed in Appendix A to Part 225.

The proposed revisions to Subpart Q of Part 217 are expected to impact new stationary reciprocating internal combustion engines and turbines that are subject to Subpart Q and that meet the criteria in Section 217.394(a)(3).

V. TECHNICAL FEASIBILITY AND ECONOMIC REASONABLENESS

A. Part 214

The Agency's proposed amendments to Part 214 are both technically feasible and economically reasonable. Fuel complying with the Agency's proposed fuel sulfur content limitations is already widely available in Illinois and is in fact already used by the majority of commercial and industrial sources in Illinois. The proposed emission limitations in Subpart AA are achievable through a variety of SO_2 control measures, including fuel switching and the use of well-known desulfurization technologies such as wet and dry scrubbers and dry sorbent injection systems.

A more detailed discussion of technical feasibility and economic reasonableness is set forth in the Agency's TSD.

B. Part 217 and Part 225

The Agency's proposed amendments to Subpart M of Part 217 and Part 225 are also technically feasible and economically reasonable. These amendments were requested by Midwest Generation, the only source impacted by such revisions. Based on consultations with Midwest Generation, the conversions of Joliet 6, 7, and 8 and Will County 3 to fuel other than coal are both feasible and cost effective.

The Agency's proposed amendment to Subpart Q of Part 217 imposes no additional requirements upon sources subject to Subpart Q, but rather clarifies the deadline to conduct an initial performance test for new units that meet the criteria in

Section 217.394(a)(3). The amendment requires that such units conduct a test once within the five-year period following the date the unit commenced operation. This time frame is consistent with the amount of time originally provided to units for initial performance testing under this subsection, and is both technically feasible and cost effective.

VI. COMMUNICATION WITH INTERESTED PARTIES

The Illinois EPA engaged in extensive outreach on this proposal. During development of the proposed revisions to Part 214, the Illinois EPA met with representatives from individual sources impacted by the proposed Subpart AA, engaged in subsequent conference calls and correspondence with source representatives regarding the proposal, and held an informational meeting for source representatives regarding the Agency's modeling efforts. The Agency provided draft amendments to Part 214 to the Illinois Environmental Regulatory Group for comment, and included an article in the Small Business Environmental Assistance Program's "Clean Air Clips," an electronic newsletter sent to associations, legislators, etc., explaining the proposed statewide fuel sulfur content limitations. The Agency also solicited comments on its proposed fuel standards in the August 2014 issue of the *Small Business Connection*, a publication provided to certain small businesses, chambers of commerce, business associations, trade groups, and legislators.

On February 18, 2015, the Agency provided a draft of its proposed revisions, including proposed amendments to Parts 214, 217, and 225, to potentially impacted sources, public interest groups, and USEPA Region 5, soliciting comments on the proposal.

The Illinois EPA received several comments on the draft rule, and this proposal incorporates many of the concerns and suggestions set forth in those comments. Such comments can generally be categorized into the following areas: availability of exclusions from the statewide fuel sulfur content limitations, availability of averaging to meet certain emission limitations, emission unit descriptions in Subpart AA of Part 214, the necessity of certain monitoring and recordkeeping/reporting provisions, requests for clarification, inquiries into the Agency's modeling methodologies, and inquiries regarding the Agency's proposed revisions to Part 225. These regulations are being proposed after the interested parties have had an opportunity to review the proposal and discuss any issues with the Illinois EPA.

VII. SYNOPSIS OF TESTIMONY

The Illinois EPA anticipates calling Rory Davis, Environmental Protection Engineer, Air Quality Planning Section ("AQPS"), Illinois EPA's Bureau of Air ("BOA"), as a witness at hearing. Mr. Davis will testify regarding the amendments proposed by the Agency. Written testimony will be submitted prior to hearing in accordance with the Board's procedural rules. Mr. Davis will be available for questions, as will David Bloomberg, Manager of AQPS, BOA; and Jackie Sims, Regulatory Unit Manager, AQPS, BOA.

VIII. THE ILLINOIS EPA'S PROPOSAL

The Illinois EPA proposes the following amendments to Parts 214, 217, and 225.

35 Ill. Adm. Code 214, Sulfur Limitations

SUBPART A: GENERAL PROVISIONS

Section 214.101 Measurement Methods

Update abbreviations throughout the Section.

Amend subsection (a) to acknowledge that a certified emissions monitoring system is an acceptable method of measuring sulfur dioxide emissions.

Amend subsection (b) to correct a spelling error and to acknowledge controlled condensate methods as acceptable methods of measuring sulfuric acid mist and sulfur trioxide.

Correct a typographical error in which two subsections are identified as subsection (e).

Section 214.102 Abbreviations and Units

Amend subsections (a) and (b) with updated abbreviations.

Section 214.103 Definitions

Amend this Section to acknowledge definitions contained elsewhere in this Part, including in Subpart AA.

Section 214.104 Incorporations by Reference

Amend subsection (a) to include additional test methods under 40 CFR 60.

Amend subsections (b) and (d) to incorporate 2014 versions of the regulations.

Add subsections (e) and (f) to incorporate by reference 40 CFR 75 and a USEPA guideline document, respectively.

SUBPART B: NEW FUEL COMBUSTION EMISSION SOURCES

Section 214.121 Large Sources

Update abbreviations throughout the Section.

Amend subsection (b) to specify sulfur content limitations for residual and distillate fuel oil used by new fuel combustion emission sources that burn liquid fuel exclusively and that exceed the specified size threshold. On and after January 1, 2017, the owner or operator of such sources must comply with the limits and with specified recordkeeping and reporting requirements.

Section 214.122 Small Sources

Update abbreviations throughout the Section.

Amend subsection (b) to specify sulfur content limitations for residual and distillate fuel oil used by new fuel combustion emission sources that burn liquid fuel exclusively and that do not exceed the specified size threshold. On and after January 1, 2017, the owner or operator of such sources must comply with the limits and with specified recordkeeping and reporting requirements.

SUBPART D: EXISTING LIQUID OR MIXED FUEL COMBUSTION EMISSION SOURCES

Section 214.161 Liquid Fuel Burned Exclusively

Amend subsection (a) to update abbreviations and to specify that the limitations in this subsection apply prior to January 1, 2017.

Add subsection (b) to specify sulfur content limitations for residual and distillate fuel oil used by existing fuel combustion emission sources burning liquid fuel exclusively. On and after January 1, 2017, the owner or operator of such sources must comply with the limits and with specified recordkeeping and reporting requirements.

Add subsection (c) to specify an exemption from the sulfur content limitation for distillate fuel oil set forth in subsection (b)(2) of this Section for distillate fuel oil used by specified units at Caterpillar Inc. Technical Center in Mossville, Illinois, for purposes of research and development or testing of equipment intended for sale outside of Illinois. The exemption is limited to a combined total of 150,000 gallons of distillate fuel oil per calendar year; the sulfur content of such oil cannot exceed 500 ppm. The owner or operator must comply with specified recordkeeping and reporting requirements.

Add subsection (d) to specify an exemption from the sulfur content limitation for distillate fuel oil set forth in subsection (b)(2) of this Section for existing EGUs at certain Midwest Generation electric generating stations. The owner or operator of such EGUs must not purchase distillate fuel oil with a sulfur content exceeding 15 ppm from January 1, 2016, through December 31, 2018; must not use distillate fuel oil with a sulfur content exceeding 500 ppm from January 1, 2017, through December 31, 2018; and must not use distillate fuel oil with a sulfur content exceeding 15 ppm on and after January 1, 2019. The owner or operator must comply with specified recordkeeping and reporting requirements.

Add subsection (e) to specify an exemption from the sulfur content limitation for distillate fuel oil set forth in subsection (b)(2) of this Section for existing fuel combustion emission units at Caterpillar's facility in Montgomery, Illinois. On and after January 1, 2016, the owner or operator of such units must not purchase distillate fuel oil with a sulfur content exceeding 15 ppm, and must not use distillate fuel oil with a sulfur content exceeding 500 ppm. The owner or operator must comply with specified recordkeeping and reporting requirements.

Section 214.162 Combination of Fuels

Amend subsection (d) to update abbreviations and to account for new sulfur content limitations.

SUBPART F: ALTERNATIVE STANDARDS FOR SOURCES INSIDE METROPOLITAN AREAS

Section 214.201 Alternative Standards for Sources in Metropolitan Areas

Amend this Section to update abbreviations and to clarify that nothing in this Section excuses a source subject to Subpart AA from complying with the requirements set forth in Subpart AA.

SUBPART K: PROCESS EMISSION SOURCES

Section 214.301 General Limitation

Amend this Section to clarify that the 2000 ppm limitation is on a dry basis when averaged over a one-hour period. This revision is not intended to change existing requirements related to this limitation, but rather clarify existing requirements and codify the Agency's longstanding interpretation of such requirements.

SUBPART Q: PRIMARY AND SECONDARY METAL MANUFACTURING

Section 214.421 Combination of Fuels at Steel Mills in Metropolitan Areas

Amend subsection (d) to update abbreviations and to account for new sulfur content limitations.

SUBPART AA: REQUIREMENTS FOR CERTAIN SO_2 SOURCES

Section 214.600 Definitions

Add this Section to set forth definitions applicable to this Subpart.

Section 214.601 Applicability

Add subsection (a) to specify the sources that are subject to this Subpart.

Add subsection (b) to specify that once a source is subject to this Subpart, it is always subject to this Subpart.

Add subsection (c) to clarify that nothing in this Subpart excuses a source from complying with air quality standards in 35 Ill. Adm. Code 243 or with other applicable requirements in Part 214.

Section 214.602 Compliance Deadline

Add this Section to establish January 1, 2017, as the compliance deadline for all requirements in this Subpart.

Section 214.603 Emission Limitations

Add this Section to set forth the emission limitations applicable to specified emission units at specified sources. The limitations are expressed in terms of pounds of SO_2 emitted per clock hour. For the specified emission units located at Midwest Generation Powerton, compliance will be determined on a 30-operating day rolling average basis.

Section 214.604 Monitoring and Testing

Add subsection (a) to require that sources demonstrate compliance with the applicable emission limitations in Subpart AA via the monitoring and testing requirements set forth in this Section.

Add subsection (b) to require that the sources listed in this subsection utilize CEMS for the measurement of SO_2 emissions in accordance with 40 CFR 75 (except provisions in Part 75 regarding missing data substitution) and subsection (d) of this Section, or utilize an alternative monitoring method that would be available to the pertinent emission unit under Part 75.

Add subsection (c) to require that all sources not listed in subsection (b) of this Section either conduct performance testing in accordance with subsection (e) of this

Section or utilize CEMS for the measurement of SO_2 emissions in accordance with 40 CFR 60 or 40 CFR 75 (except provisions in Part 75 regarding missing data substitution), and subsection (d) of this Section.

Add subsection (d) to specify requirements for sources demonstrating compliance via CEMS. Sources may utilize a single CEMS for emission units served by a common stack. If an emission unit changes the method of demonstrating compliance from performance testing to use of a CEMS, the owner or operator must begin operating the CEMS on or before the performance testing deadline determined in accordance with subsection (e)(2) of this Section. This subsection also restates that the missing data substitution provisions in 40 CFR 75.31-34 must not be used to demonstrate compliance with the requirements in this Subpart.

Add subsection (e) to specify requirements for sources demonstrating compliance through performance testing. These requirements regard testing deadlines, submittal of testing protocols and notifications to the Agency, and the methods to be used for each performance test.

Section 214.605 Recordkeeping and Reporting

Add subsection (a) to specify the records that must be submitted to the Agency by January 1, 2017, including a certification that the source will be in compliance by that date, documentation specific to the method the source is using to demonstrate compliance, and a description of the methods the source will use to comply with all emission limitations in this Subpart.

Add subsection (b) to specify that owners or operators of sources must keep and maintain records demonstrating ongoing compliance with the requirements in this

Subpart, including performance test reports, a log of parametric monitoring conducted, information specific to sources utilizing CEMS, information related to malfunctions of emission units or SO_2 control equipment, information related to SO_2 control equipment, and information specific to emission units utilizing a 30-day average.

Add subsection (c) to require that sources demonstrating compliance through performance testing submit the results of all tests conducted pursuant to Section 214.604(e) of this Subpart within 60 days after completion of the test.

Add subsection (d) to establish requirements applicable to owners or operators of emission units changing the method of demonstrating compliance between performance testing and CEMS.

Add subsection (e) to specify that the owner or operator of a source must notify the Agency within 30 days after discovery of deviations from any of the requirements in this Subpart or any exceedance of an emission limitation in this Subpart. Such notification must describe the deviations, possible causes, corrective actions taken, and preventative measures taken.

Add subsection (f) to require that sources maintain all records required by this Section at the source for a minimum of 5 years and provide copies to the Agency within 30 days of receipt of a request by the Agency.

35 Ill. Adm. Code 217, Nitrogen Oxides Emissions

SUBPART M: ELECTRICAL GENERATING UNITS

Section 217.342 Exemptions

Amend subsection (b) to eliminate the reference to the CPS, as the CPS is addressed in the new proposed subsection (c).

Add subsection (c) to specify that the provisions of Subpart M do not apply to a fossil fuel-fired stationary boiler that is subject to any of the requirements in the CPS, regardless of the type of fossil fuel combusted.

SUBPART Q: STATIONARY RECIPROCATING INTERNAL COMBUSTION ENGINES AND TURBINES

Section 217.394 Testing and Monitoring

Amend subsection (a) to specify an initial performance testing deadline for new units that meet the criteria in subsection (a)(3) of this Section.

35 Ill. Adm. Code 225, Control of Emissions from Large Combustion Sources

SUBPART B: CONTROL OF MERCURY EMISSIONS FROM COAL-FIRED ELECTRIC GENERATING UNITS

Section 225.205 Applicability

Amend this Section to specify that the stationary boilers listed in Appendix A to Part 225 are subject to the requirements in this Subpart, regardless of the type of fuel combusted.

Section 225.210 Compliance Requirements

Amend subsection (b) to acknowledge proposed changes to the CPS that eliminate some of the requirements set forth in this Section for EGUs in the CPS that permanently cease combusting coal.

Section 225.240 General Monitoring and Reporting Requirements

Amend this Section to acknowledge proposed changes to the CPS that eliminate some of the requirements set forth in this Section for EGUs in the CPS that permanently cease combusting coal.

Section 225.265 Coal Analysis for Input Mercury Levels

Amend this Section to acknowledge proposed changes to the CPS that eliminate some of the requirements set forth in this Section for EGUs in the CPS that permanently cease combusting coal.

Section 225.290 Recordkeeping and Reporting

Amend this Section to acknowledge proposed changes to the CPS that eliminate some of the requirements set forth in this Section for EGUs in the CPS that permanently cease combusting coal.

Section 225.291 Combined Pollutant Standard: Purpose

Amend this Section to add the conversion of an EGU to fuel other than coal as one of the alternative means of compliance with the mercury emission standards in Section 225.230(a) for EGUs in the CPS.

Section 225.292 Applicability of the Combined Pollutant Standard

Amend subsection (a) to add "the."

Amend subsection (b) to provide that a specified EGU is an EGU listed in Appendix A to Part 225, regardless of the type of fuel combusted by the EGU.

Section 225.293 Combined Pollutant Standard: Notice of Intent

Add subsection (d) to require that the owner or operator of a specified EGU that, on or after January 1, 2015, changes the type of primary fuel combusted by the unit or the control device(s) installed and operating on the unit must notify the Agency of such change by January 1, 2017, or within 30 days of the completion of such change, whichever is later.

Section 225.294 Combined Pollutant Standard: Control Technology Requirements and Emissions Standards for Mercury

Amend subsection (a) to specify that the requirements in this subsection apply only to coal-fired EGUs.

Amend subsection (b) to specify that on and after the date an EGU permanently ceases combusting coal, it is not required to install, operate, or maintain activated carbon injection equipment.

Amend subsection (c) to specify that EGUs that permanently cease combusting coal are not required to comply with the mercury emission standards set forth in this subsection.

Amend subsection (d) to eliminate the requirement that Will County 3 comply with the mercury emission standards in subsection (c) of this Section and to specify that on and after April 16, 2015, Will County 3 must not combust coal. The deadline after which Will County 3 must not combust coal is also included in proposed amendments to Section 225.296.

Amend subsection (e) to specify that on and after the date an EGU permanently ceases combusting coal, it is not subject to the requirements in subsections (g), (h), (i), (j), and (k) of this Section.

Amend subsection (g) to remove two misplaced parentheticals in (g)(1)(c)(iii). Also, the current version of (g)(2) contains a strikethrough of the number "4"; the "4" should be removed.

Add subsection (m) to provide that the requirements in Sections 225.240 through 225.290 of this Subpart, and any other mercury-related monitoring, recordkeeping, notice, analysis, certification, and reporting requirements set forth in this Subpart, including in the CPS, will not apply to a specified EGU on and after the date the EGU permanently ceases combusting coal.

Section 225.295 Combined Pollutant Standard: Emissions Standards for NO_x and SO_2

Amend subsection (a) to specify that the NO_x emission rates set forth in this Section apply to all EGUs in the CPS regardless of the type of fuel combusted, and that EGUs in the CPS are not subject to the requirements in Subpart M of Part 217, including the NO_x emission standards in Section 217.344.

Amend subsection (b) to specify that, for purposes of this subsection only, the CPS Group includes only those specified EGUs that combust coal. This subsection requires that the CPS Group comply with group average annual SO_2 emission rates set forth in this subsection.

Amend subsection (d) to correct errors in the equation.

Section 225.296 Combined Pollutant Standard: Control Technology Requirements for NO_x, SO_2, and PM Emissions

Amend subsection (b) to specify the dates on and after which Will County 3 and Joliet 6, 7, and 8 are not permitted to combust coal, and to provide that all other specified EGUs (except Will County 4) must either permanently shut down, permanently cease combusting coal, or install FGD equipment, on or before December 31, 2018.

Amend subsection (c) to eliminate the requirement that Will County 3 comply with the control technology requirements for particulate matter in this subsection, as the unit is converting to natural gas or diesel fuel. Also amend this subsection to change the compliance deadline for Waukegan 7 to reflect the variance granted by the Board in *Midwest Generation, LLC-Waukegan Generating Station v. Illinois Environmental*

Protection Agency, PCB12-121, discussed in Section III, *supra*; this amendment is intended to avoid any confusion caused by the Agency's reorganization of subsection (c).

Section 225.298 Combined Pollutant Standard: Requirements for NO_x and SO_2 allowances

Amend subsection (a) to eliminate the provision permitting EGUs in the CPS to sell, trade, or transfer SO_2 and NO_x emission allowances to the Homer City, Pennsylvania, generating station.

225.APPENDIX A Specified EGUs for Purposes of the CPS (Midwest Generation's Coal-Fired Boilers as of July 1, 2006)

Amend the title of this Section to remove the reference to Midwest Generation.

ILLINOIS ENVIRONMENTAL
PROTECTION AGENCY

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DATED: April 27, 2015

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Exhibit B

LaSalle Technical Specification 3.8.3

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in UFSAR, Chapter 6 (Ref. 4) and Chapter 15 (Ref. 5), assume Engineered Safety Feature (ESF) systems are OPERABLE. The DGs are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that fuel, reactor coolant system, and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.5, Emergency Core Cooling (ECCS) and Reactor Core Isolation Cooling (RCIC) System; and Section 3.6, Containment Systems.

Since diesel fuel oil and starting air subsystems support the operation of the standby AC power sources, they satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Stored diesel fuel oil is required to have sufficient supply for 7 days of rated load operation for Division 1 and 2 DG, and for 7 days of maximum expected load profile for Division 3 DG. It is also required to meet specific standards for quality. This requirement, in conjunction with an ability to obtain replacement supplies within 7 days, supports the availability of DGs required to shut down the reactor and to maintain it in a safe condition for an anticipated operational occurrence (AOO) or a postulated DBA with loss of offsite power. DG day tank fuel requirements, as well as transfer capability from the storage tank to the day tank, are addressed in LCO 3.8.1, "AC Sources—Operating," and LCO 3.8.2, "AC Sources-Shutdown."

The starting air system is required to have a minimum capacity for five successive Division 1 and 2 DG starts and three successive Division 3 DG starts without recharging the air start receivers. While each air start receiver set has the required capacity, both air start receiver sets (and associated air start headers) per DG are required to ensure OPERABILITY of the DG.

APPLICABILITY

The AC sources (LCO 3.8.1 and LCO 3.8.2), are required to ensure the availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an AOO or a postulated DBA. Since stored diesel fuel

(continued)

Exhibit C

NRC Regulatory Guide 1.160

U.S. NUCLEAR REGULATORY COMMISSION

May 2012
Revision 3

REGULATORY GUIDE

OFFICE OF NUCLEAR REGULATORY RESEARCH

REGULATORY GUIDE 1.160

(Draft was issued as DG-1278, dated September 2011)

MONITORING THE EFFECTIVENESS OF MAINTENANCE AT NUCLEAR POWER PLANTS

A. INTRODUCTION

This Regulatory Guide endorses Revision 4A to Nuclear Management and Resources Council (NUMARC) 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," issued April 2011 (Ref.1), which provides methods that are acceptable to the U.S. Nuclear Regulatory Commission (NRC) staff for complying with the provisions of Section 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," of Title 10, of the *Code of Federal Regulations*, Part 50, "Domestic Licensing of Production and Utilization Facilities" (10 CFR Part 50) (Ref. 2). 10 CFR 50.65 requires that power reactor licensees monitor the performance or condition of structures, systems, and components (SSCs) against licensee-established goals in a manner sufficient to provide reasonable assurance that such SSCs are capable of fulfilling their intended functions. Revision 4A to NUMARC 93-01 incorporates guidance previously contained in Regulatory Guide 1.182, Revision 0, "Assessing and Managing Risk before Maintenance Activities at Nuclear Power Plants," issued May 2000 (Ref. 3). Therefore, this revision to Regulatory Guide 1.160 supersedes Regulatory Guide 1.182, Revision 0.

The NRC published 10 CFR 50.65 (commonly referred to as the maintenance rule) on July 10, 1991. The NRC's determination that a maintenance rule was needed arose from the conclusion that proper maintenance is essential to plant safety. As discussed in the Statements of Consideration for this rule, there is a clear link between effective maintenance and safety as it relates to such factors as the number of transients and challenges to safety systems and the associated need for operability, availability, and reliability of safety equipment. In addition, good maintenance is also important in ensuring that failure of other than safety-related SSCs that could initiate or adversely affect a transient or accident is minimized. Minimizing challenges to safety systems is consistent with the NRC's defense-in-depth

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The NRC issues regulatory guides to describe and make available to the public methods that the NRC staff considers acceptable for use in implementing specific parts of the agency's regulations, techniques that the staff uses in evaluating specific problems or postulated accidents, and data that the staff needs in reviewing applications for permits and licenses. Regulatory guides are not substitutes for regulations, and compliance with them is not required. Methods and solutions that differ from those set forth in regulatory guides will be deemed acceptable if they provide a basis for the findings required for the issuance or continuance of a permit or license by the Commission.

Electronic copies of this guide and other recently issued guides are available through the NRC's public Web site under the Regulatory Guides document collection of the NRC Library at http://www.nrc.gov/reading-rm/doc-collections/ and through the NRC's Agencywide Documents Access and Management System (ADAMS) at http://www.nrc.gov/reading-rm/adams.html, under Accession No. ML113610098. The regulatory analysis may be found in ADAMS under Accession No. ML113610101.

This guide was issued after consideration of comments received from the public. The public comments and NRC staff response to them may be found in ADAMS under Accession No. ML12136A011.

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philosophy. Maintenance is also important to ensure that design assumptions and margins in the original design basis are maintained and are not unacceptably degraded. Therefore, nuclear power plant maintenance is important to protecting public health and safety.

In 10 CFR 50.65(a)(1), the NRC requires that power reactor licensees monitor the performance or condition of SSCs against licensee-established goals in a manner sufficient to provide reasonable assurance that such SSCs are capable of fulfilling their intended functions. Such goals are to be established commensurate with safety and, where practical, take into account industrywide operating experience. When the performance or condition of an SSC does not meet established goals, appropriate corrective action must be taken. For a nuclear power plant for which the licensee has submitted the certifications specified in 10 CFR 50.82(a)(1) (i.e., plants undergoing decommissioning), 10 CFR 50.65(a)(1) applies only to the extent that the licensee must monitor the performance or condition of all SSCs associated with storing, controlling, and maintaining spent fuel in a safe condition, in a manner sufficient to provide reasonable assurance that such SSCs are capable of fulfilling their intended functions.[1]

In 10 CFR 50.65(a)(2), the NRC states that monitoring as specified in paragraph (a)(1) is not required when it has been demonstrated that the performance or condition of an SSC is being effectively controlled through the performance of appropriate preventive maintenance, such that the SSC remains capable of performing its intended function.

In 10 CFR 50.65(a)(3), the NRC requires that performance and condition monitoring activities and associated goals and preventive maintenance activities be evaluated at least every refueling cycle provided the interval between evaluations does not exceed 24 months. The evaluations shall take into account, where practical, industrywide operating experience. Adjustments shall be made where necessary to ensure that the objective of preventing failures of SSCs through maintenance is appropriately balanced against the objective of minimizing unavailability of SSCs due to monitoring or preventive maintenance.

In 10 CFR 50.65(a)(4), the NRC requires that before performing maintenance activities (including but not limited to surveillances, postmaintenance testing, and corrective and preventive maintenance), the licensee shall assess and manage the increase in risk that may result from the proposed maintenance activities. The scope of the assessment may be limited to SSCs that a risk-informed evaluation process has shown to be significant to public health and safety.[2]

In 10 CFR 50.65(b), the NRC states that the scope of the monitoring program specified in 10 CFR 50.65(a)(1) is to include safety-related and nonsafety-related SSCs as follows.

(1) Safety-related structures, systems, and components that are relied upon to remain functional during and following design basis events to ensure the integrity of the reactor coolant pressure boundary, the capability to shut down the reactor and maintain it in a safe shutdown condition, or the capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposure comparable to the guidelines in §50.34(a)(1), or §50.67(b)(2), or §100.11 of this chapter, as applicable.[3]

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[1] The specific requirements for decommissioning plants became effective on August 28, 1996 (Ref. 4).

[2] This paragraph (a)(4) of the maintenance rule was added on July 19, 1999 (Ref 5).

[3] This paragraph (b)(l) of the maintenance rule was changed in the final rulemaking for "Reactor Site Criteria Including Seismic and Earthquake Engineering Criteria for Nuclear Power Plants" (Ref. 6).

(2) Nonsafety related structures, systems, or components:

(i) That are relied upon to mitigate accidents or transients or are used in plant emergency operating procedures (EOPs); or

(ii) Whose failure could prevent safety-related structures, systems, and components from fulfilling their safety-related function; or

(iii) Whose failure could cause a reactor scram or actuation of a safety-related system.

In 10 CFR 50.65(c), the NRC states that licensees are to implement the rule provisions no later than July 10, 1996.

The NRC issues regulatory guides to describe to the public methods that the staff considers acceptable for use in implementing specific parts of the agency's regulations, to explain techniques that the staff uses in evaluating specific problems or postulated accidents, and to provide guidance to applicants. Regulatory guides are not substitutes for regulations and compliance with them is not required.

This regulatory guide contains information collection requirements covered by 10 CFR Part 50 and 10 CFR Part 52 that the Office of Management and Budget (OMB) approved under OMB control number 3150 0011 and 3150-0151, respectively. The NRC may neither conduct nor sponsor, and a person is not required to respond to, an information collection request or requirement unless the requesting document displays a currently valid OMB control number. This regulatory guide is a rule as designated in the Congressional Review Act (5 U.S.C. 801-808). However, the NRC has determined this regulatory guide is not a major rule as designated by the Congressional Review Act and has verified this determination with the OMB.

The International Atomic Energy Agency (IAEA) has established a series of safety guides and standards constituting a high level of safety for protecting people and the environment. IAEA safety guides present international good practices and increasingly reflects best practices to help users striving to achieve high levels of safety. Pertinent to this regulatory guide, IAEA Safety Guide NS-G-2.6, "Maintenance, Surveillance, and In-service Inspection in Nuclear Power Plants," issued October 2002, provides guidance and recommendations on maintenance, surveillance and in-service inspection activities to ensure that safety related SSCs are available to perform as designed. This regulatory guide incorporates a similar philosophy to maintenance of nuclear power plants in the United States and its guidelines are consistent with the basic safety principles provided in IAEA Safety Guide NS-G-2.6.

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B. DISCUSSION

Objective

The objective of 10 CFR 50.65 (referred to hereafter as the maintenance rule or the rule) is to require monitoring of the overall continuing effectiveness of licensee maintenance programs to ensure that (1) safety-related and certain nonsafety-related SSCs are capable of performing their intended functions, and (2) for nonsafety-related equipment, failures will not occur that prevent the fulfillment of safety-related functions, and failures resulting in scrams and unnecessary actuations of safety-related systems are minimized.[4] Additional objectives of the maintenance rule are to require that (1) licensees assess the impact of equipment maintenance on the capability of the plant to perform key plant safety functions, and (2) licensees use the results of the assessment before undertaking maintenance activities at operating nuclear power plants to manage the increase in risk caused by those activities.[5]

Development of Industry Guideline NUMARC 93-01

In May 1993, the nuclear industry developed NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants" (Ref. 8), which provides guidance to licensees on implementation of the maintenance rule. NUMARC prepared this document by conducting a verification and validation effort, with NRC staff observation, to test the guidance document on several representative systems. Changes were made to the NUMARC guidance document based on the results of the verification and validation effort. The NRC staff reviewed this document and found that it provided acceptable guidance to licensees. In June 1993, the NRC staff issued Regulatory Guide 1.160, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," which endorsed the May 1993 version of NUMARC 93-01. In January 1995, the NRC staff issued Revision 1 to Regulatory Guide 1.160 to reflect the amendment to 10 CFR 50.65(a)(3) that changed the requirement for performing the periodic evaluation from annually to once per refueling cycle, not to exceed 24 months between evaluations.

From September 1994 to March 1995, the NRC staff conducted nine pilot site visits to verify the usability and adequacy of the draft NRC maintenance rule inspection procedure and to determine the strengths and weaknesses of the implementation of the rule at each site that used the guidance in NUMARC 93-01. NUREG-1526, "Lessons Learned from Early Implementation of the Maintenance Rule at Nine Nuclear Power Plants," issued June 1995 (Ref. 9) describes the findings. The NRC staff concluded that the requirements of the rule could be met more consistently across the industry if some clarifying guidance was added to NUMARC 93-01 to address the findings noted in NUREG-1526. The NRC staff met with industry representatives in a series of public meetings to discuss proposed revisions to NUMARC 93-01 that would address the findings of the site visits. Revision 2 to NUMARC 93-01 in April 1996 (Ref. 10) resulted from these meetings.

By July 1998, maintenance rule baseline inspections at all U.S. nuclear power plant sites were complete. The findings are described in NUREG-1648, "Lessons Learned from Maintenance Rule Baseline Inspections," issued October 1999 (Ref. 11). NRC staff experience during the baseline inspections indicated that all licensees had developed programs to implement the recommended premaintenance assessment provision of the original 10 CFR 50.65(a)(3). However, the baseline inspections identified instances in which these assessments were not performed (including some that caused a significant increase in risk) and identified weaknesses in licensees' programs that could result in

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4 NRC Statements of Consideration for 10 CFR 50.65 (Ref. 7).

5 NRC Statements of Consideration for 10 CFR 50.65 (Ref. 5).

failures to perform adequate assessments before maintenance activities. Partly because of these inspection findings, the Commission approved an amendment to the maintenance rule, adding a new paragraph (a)(4) to ensure that licensees assess and manage increases in risk associated with maintenance activities.

In a series of public meetings, the NRC staff met with industry representatives to discuss the change in the rule in relation to proposed revisions to Section 11, "Assessment of Risk Resulting from Performance of Maintenance Activities," of NUMARC 93-01 (Ref. 12). In May 2000, the NRC staff issued Regulatory Guide 1.182, which endorsed the February 2000 revision to Section 11 of NUMARC 93-01.

From December 2009 to March 2011, the NRC staff met with industry representatives in a series of public meetings to discuss additional revisions to NUMARC 93-01 that would improve implementation of the maintenance rule throughout the industry. Revision 4A to NUMARC 93-01 resulted from those meetings.

Definition of Maintenance

As discussed in the *Federal Register* notice, "Final Commission Policy Statement on Maintenance at Nuclear Power Plants," dated March 23, 1988 (Ref. 13), maintenance is defined as the aggregate of those functions required to preserve or restore safety, reliability, and availability of plant SSCs. Maintenance includes not only activities traditionally associated with identifying and correcting actual or potential degraded conditions (i.e., repair, surveillance, diagnostic examination, and preventive measures) but extends to all supporting functions for the conduct of these activities.[6] The activities that form the basis of a maintenance program are also discussed in "Final Commission Policy Statement on Maintenance at Nuclear Power Plants."

Timeliness

NUMARC 93-01 states that activities such as cause determinations and moving SSCs from the 10 CFR 50.65(a)(2) to the (a)(1) category must be performed in a "timely" manner. Some licensees have requested that the NRC staff specify a period that would be considered "timely." To be consistent with the intent of the maintenance rule to provide flexibility to licensees, the NRC staff does not consider providing a specific timeliness criterion appropriate. Licensees should undertake and accomplish activities associated with the maintenance rule in a manner commensurate with the safety significance of the SSC and the complexity of the issue being addressed.

Plant, System, Train, and Component Monitoring Levels

The extent of monitoring may vary from system to system depending on the system's importance to safety. Some monitoring at the component level may be necessary; however, the staff envisions that most of the monitoring can be done at the plant, system, or train level. SSCs with high safety significance and standby SSCs with low safety significance should be monitored at the system or train level. Except as noted in Section C of this guide, normally operating SSCs with low safety significance may be monitored through plant-level performance criteria, including unplanned scrams, safety system actuations, or unplanned capability loss factors. For SSCs monitored in accordance with 10 CFR 50.65(a)(1), additional parameter trending may be necessary to ensure that the problem that caused the SSC to be placed in the 10 CFR 50.65(a)(1) category is being corrected.

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6 53 FR 9430, March 23, 1988.

Use of Existing Licensee Programs

The NRC staff encourages licensees to use, to the maximum extent practicable, activities currently being conducted, such as technical specification surveillance testing, to satisfy monitoring requirements. Such activities could be integrated with, and provide the basis for, the requisite level of monitoring. Consistent with the underlying purposes of the rule, maximum flexibility should be offered to licensees in establishing and modifying their monitoring activities.

Use of Reliability-Based Programs

Licensees are encouraged to consider the use of reliability-based methods for developing the preventive maintenance programs covered under 10 CFR 50.65(a)(2); however, the use of such methods is not required.

Safety Significance Categories

The maintenance rule requires that goals be established commensurate with safety. To implement this requirement, NUMARC 93-01 establishes two safety significance categories, "risk-significant" and "non-risk-significant." Section 9.0 of NUMARC 93-01 describes the process for placing SSCs in either of these two categories. The Statements of Consideration for the rule use the terms "more risk-significant" and "less risk-significant." NRC Inspection Procedure 71111.12, "Maintenance Effectiveness" (Ref. 14), uses the terms "high safety significance" and "low safety significance." After discussions with industry representatives, the NRC staff determined that the preferred terminology is "high safety significance" and "low safety significance."

Some licensees may elect to define other safety significance categories or may elect to define more than two categories, which would be acceptable if these alternative categories are defined in the licensee's procedures and used consistently.

Safety-Significance Ranking Methodology

The NRC staff endorses the use of the SSC safety significance ranking methodology described in NUMARC 93-01 as an acceptable method for meeting the requirements of the maintenance rule. However, because of some unique aspects of the maintenance rule, including the fact that standby SSCs of low safety significance are treated the same as SSCs of high safety significance, this endorsement for purposes of the maintenance rule should not be construed as an endorsement for other applications. The NRC staff discussed these issues in SECY 95-265, "Response to August 9, 1995, Staff Requirements Memorandum Request to Analyze the Generic Applicability of the Risk Determination Process Used in Implementing the Maintenance Rule," dated November 1, 1995 (Ref. 15).

Use of Probabilistic Risk Assessments

NUMARC 93-01 contains multiple references to the use and application of a probabilistic risk assessment (PRA) or a probabilistic safety assessment (PSA) in a licensee's implementation of the maintenance rule. The NRC staff endorses the use and application of these risk analyses as described in NUMARC 93-01. Like other types of engineering analyses used to support the regulatory process, risk analyses must be sound and technically defensible. Sound and technically defensible risk analyses help increase confidence in and the consistency of decisionmaking. When a PRA is used in a licensee's implementation of the maintenance rule, the technical adequacy of the base PRA should be sufficient to provide the needed confidence in the results being used in the decision.

Applicability of Appendix B to 10 CFR Part 50

With regard to the scope of the maintenance rule, as stated in 10 CFR 50.65(b), the NRC understands that balance of plant (BOP) SSCs may have been designed and built with normal industrial quality and may not meet the standards in Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants," to 10 CFR Part 50. It is not the intent of the NRC staff to require licensees to generate paperwork to document the basis for the design, fabrication, and construction of BOP equipment (i.e., BOP equipment need not meet the requirements of Appendix B to 10 CFR Part 50).

Each licensee's maintenance efforts should minimize failures in both safety-related and BOP SSCs that affect safe operation of the plant. The effectiveness of maintenance programs should be maintained for the operational life of the facility.

Maintenance Risk Assessments

The intent of 10 CFR 50.65(a)(4) is to require licensees to conduct assessments before performing maintenance activities on SSCs covered by the maintenance rule and to manage the increase in risk that may result from the proposed activities. The results of these assessments are to be used in conjunction with other regulatory requirements and, therefore, cannot be used as justification for performing activities that may not comply with other regulations.

Performing the assessment discussed in Section 11.0 of NUMARC 93-01 does not relieve the licensee from compliance with its license (including technical specifications) and applicable regulations. The intent of this section of NUMARC 93-01 is to eliminate overlapping requirements for assessments that could be considered to exist under 10 CFR 50.65(a)(4) and 10 CFR 50.59, "Changes, Tests and Experiments." This clarification applies to temporary alterations directly related to and required in support of the specific maintenance activity being assessed. (Note that when a maintenance activity to restore a degraded condition is planned, a compensatory measure already in place addressing that condition would have to be considered in the assessment under 10 CFR 50.65(a)(4) if the measure is to remain in place during the maintenance activity.)

Switchyard Maintenance Activities

As noted in Regulatory Position 4 of this guide, there may be a need to address maintenance activities that occur in the switchyards that could directly affect plant operations. Plant management should be aware of and have the ability to control these activities.

Emergency Diesel Generators

Industry- and NRC-sponsored PRAs have shown the safety significance of emergency alternating current (ac) power sources. The station blackout rule (10 CFR 50.63, "Loss of All Alternating Current Power") requires plant-specific coping analyses to ensure that a plant can withstand a total loss of ac power for a specified duration and to determine appropriate actions to mitigate the effects of a total loss of ac power. During the station blackout reviews, most licensees (1) committed to implementing an emergency diesel generator reliability program in accordance with NRC regulatory guidance but reserved the option to later adopt the outcome of Generic Issue B-56 resolution, and (2) stated that they had an equivalent program or will implement one. Subsequently, utilities docketed commitments to maintain their selected target reliability values (i.e., maintain the emergency diesel generator target reliability of 0.95 or 0.975). Those values could be used as a goal or as a performance criterion for emergency diesel generator reliability under the maintenance rule.

Emergency diesel generator unavailability values were also assumed in plant-specific individual plant examination analyses. These values should be compared to the plant-specific emergency diesel generator unavailability data regularly monitored and reported as industrywide plant performance information. These values could also be used as the basis for a goal or performance criterion under the maintenance rule. In addition, in accordance with 10 CFR 50.65(a)(3), licensees must periodically balance the unavailability and reliability of the emergency diesel generators.

C. STAFF REGULATORY GUIDANCE

1. NUMARC 93-01

Revision 4A to NUMARC 93-01 (Ref. 1) provides methods that are acceptable to the NRC staff for complying with the provisions of 10 CFR 50.65 with the following provisions and clarifications.

1.1 Maintenance-Preventable Function Failures as an Indicator of Reliability

NUMARC 93-01 states that performance criteria for SSCs of high safety significance should be established to ensure that reliability and availability assumptions used in the plant-specific safety analysis are maintained or adjusted. NUMARC 93-01 further allows the use of maintenance-preventable functional failures (MPFFs) as an indicator of reliability. The maintenance rule requires that the performance of SSCs be monitored commensurate with safety; however, the maintenance rule does not require that the assumptions in the safety analysis be validated. Licensees who choose to use their safety analyses as described in NUMARC 93-01 must be able to demonstrate how the number of MPFFs allowed per evaluation period is consistent with the assumptions in the risk analysis. For standby SSCs, this would require, at a minimum, a reasonable estimate of the number of demands during that period.

If a licensee desires to establish a reliability performance criterion that is not consistent with the assumptions used in the risk analysis, adequate technical justification for the performance criterion must be provided. For some SSCs, an MPFF performance criterion may be too small to be effectively monitored and trended as required by the rule. In these cases, the licensee should establish performance or condition monitoring criteria that can be monitored and trended so that the licensee can demonstrate that maintenance is effective.

1.2 Monitoring Structures

The maintenance rule does not treat structures differently from systems and components. Experience with the rule and NUMARC 93-01 during the pilot site visits and the initial period following the effective date of the rule indicated that specific guidance for monitoring the effectiveness of maintenance for structures was needed, as structures present a different situation than do systems and components. The primary difficulty in implementing the rule for structures using NUMARC 93-01 was in establishing appropriate criteria for performance and monitoring structures under 10 CFR 50.65(a)(1) instead of (a)(2).

The effectiveness of maintenance can be monitored by using performance criteria or goals, or by condition monitoring. Although it is acceptable to use performance criteria or goals, most licensees have found it more practical to use condition monitoring for structures. With certain exceptions (e.g., primary containment), structures do not have unavailability, and rarely have demands placed on their safety significant functions (e.g., maintain integrity under all relevant design basis events), which makes reliability monitoring impractical.

In accordance with the rule, structural monitoring programs must provide reasonable assurance that in scope structures are capable of fulfilling their intended functions. An acceptable structural monitoring program for the purposes of the maintenance rule should have the attributes discussed in Section 9.4.1.4 of NUMARC 93-01. Structures monitored in accordance with 10 CFR 50.65(a)(1) would continue to be monitored until the degradation and its cause have been corrected. For these structures, there would be additional degradation-specific condition monitoring and increased frequency of assessments until the licensee's corrective actions are completed and the licensee is assured that the structure can fulfill its intended functions and will not degrade to the point that it cannot fulfill its design basis.

Consistent with the intent of the rule, licensees should use their existing structural monitoring programs (e.g., those required by other regulations or codes) to the maximum extent practical.

1.3 Definition of Standby

In NUMARC 93-01, standby SSCs of low safety significance must have SSC-specific performance criteria or goals, similar to SSCs of high safety significance. NUMARC 93-01 provides a definition of standby. Some licensees have improperly interpreted this definition to mean that SSCs that are energized are normally operating. As stated in NUMARC 93-01, if the SSC performs its intended function only when initiated by either an automatic or manual demand signal, the SSC is in standby.

Normally operating SSCs are those whose failure would be readily apparent (e.g., a pump failure results in loss of flow that causes a trip). Standby SSCs are those whose failure would not become apparent until the next demand, actuation, or surveillance. Only those SSCs of low safety significance whose failure would be readily apparent (because they are normally operating) should be monitored by plant-level criteria.

SSCs may have both normally operating and standby functions. To adequately monitor the effectiveness of maintenance for the SSCs associated with standby functions, licensees should develop SSC-specific performance criteria or goals, or condition monitoring.

1.4 Normally Operating SSCs of Low Safety Significance

1.4.1 Cause Determinations

For all SSCs that are being monitored using plant-level performance criteria (i.e., normally operating SSCs of low safety significance), the NRC staff's position is that a cause determination should be performed whenever any of these performance criteria are exceeded (i.e., failed) in order to determine which SSC caused the criterion to be exceeded or whether the failure was a repetitive MPFF. As part of the cause determination, it would also be necessary to determine whether the SSC was within the scope of the maintenance rule and, if so, whether corrective action and monitoring (tracking, trending, goal setting) under 10 CFR 50.65(a)(1) should be performed.

1.4.2 Establishing SSC-Specific Performance Criteria

The maintenance rule requires that licensees monitor the effectiveness of maintenance for all SSCs within the scope of the rule. NUMARC 93-01 allows licensees to monitor SSCs of low safety significance with plant-level criteria. NUMARC 93-01 notes that some normally operating SSCs of low safety significance cannot be practically monitored by plant-level criteria. Licensees should ensure that the plant-level criteria established do effectively monitor the maintenance performance of the normally operating SSCs of low safety significance, or they should establish SSC-specific performance criteria or goals or use condition monitoring.

For example, a licensee determined that the rod position indication system and the spent fuel pool pit cooling system were within the scope of the maintenance rule because they were safety-related at the licensee's site. None of the three plant-level performance criteria described in NUMARC 93-01 (unplanned scrams, unplanned capability loss factor, or unplanned safety system actuations) would monitor the effectiveness of maintenance on these systems. Therefore, licensees should establish additional plant-level performance criteria or system-specific performance criteria.

1.5 Clarification of Maintenance Preventable Functional Failures Related to Design Deficiencies

The third paragraph of Section 9.4.5 of NUMARC 93-01 provides guidance on the licensee's options following a failure and on whether, as a result of the licensee's corrective actions, subsequent failures would be considered MPFFs. In particular, this paragraph addresses failures caused by design deficiencies. Ideally, licensees would modify the design to eliminate the poorly designed equipment. However, if the licensee determines that such an approach is not cost effective (e.g., the cost of modification is prohibitive), the licensee has two options:

(1) Replace or repair the failed equipment and adjust the preventive maintenance program as necessary to prevent recurrence of the failure. Subsequent failures of the same type that are caused by inadequate corrective or preventive maintenance would be MPFFs, and could be repetitive MPFFs.

(2) Perform an evaluation that demonstrates that the equipment can be run to failure (as described in Section 9.3.3 of NUMARC 93-01). If the equipment can be run to failure, the licensee may replace or repair the failed equipment, but adjustments to the preventive maintenance program are not necessary and subsequent failures would not be MPFFs.

1.6 Scope of the Hazards to be Considered During Power Operations

NUMARC 93-01 provides guidance to licensees on the scope of hazard groups to be considered for the 10 CFR 50.65(a)(4)assessment provision during power operating conditions. Section 11.3.3 of NUMARC 93-01 specifically considers internal events, internal floods, and internal fires for assessment. Section 11.3.4.2 of NUMARC 93-01 also considers weather, external flooding, and other external impacts if such conditions are imminent or have a high probability of occurring during the planned out-of-service duration. The NRC staff considers these two sections of NUMARC 93-01 to encompass the scope of hazards that licensees should consider during power operation in order to perform an adequate assessment of the potential impact of risk that may result from proposed maintenance activities.

1.7 Scope of Initiators to be Considered for Shutdown Conditions

NUMARC 93-01 provides guidance to licensees on the scope of hazard groups to be considered for the 10 CFR 50.65(a)(4) assessment provision during shutdown conditions. Section 11.3.6 of NUMARC 93-01 specifically considers internal events for assessment as well as weather, external flooding, and other external impacts if such conditions are imminent or have a high probability of occurring during the planned out-of-service duration. The NRC staff considers this section of NUMARC 93-01 to encompass the scope of hazards that licensees should consider during shutdown conditions in order to perform an adequate assessment of the potential impact of risk that may result from proposed maintenance activities.

1.8 Fire Scenario Success Path(s)

The last paragraph of Section 11.3.3.1 of NUMARC 93-01 states that some fire scenarios have no success paths available. The NRC does not agree with this statement within its context in NUMARC 93-01. Each plant is required by 10 CFR 50.48, "Fire Protection" to identify one train of safe-shutdown capability free of fire damage, such that the plant can be safely shut down in the event of a fire. When maintenance activities are conducted on the protected train, the staff's position is that licensees should follow the guidance in Section 11.3.4.3 of NUMARC 93-01.

1.9 Establishing Action Thresholds Based on Quantitative Considerations

In Section 11.3.7.2 of NUMARC 93-01, the authors suggest the value "10^{-3}/year" as a ceiling for configuration-specific core damage frequency. At this time, the NRC neither endorses nor disapproves of the 10^{-3}/year value.

1.10 SSCs Considered under 10 CFR 50.65(a)(1)

In 10 CFR 50.65(a)(1), the NRC requires that goal setting and monitoring be established for all SSCs within the scope of the rule except for those SSCs whose performance or condition is adequately controlled through the performance of appropriate preventive maintenance as described in 10 CFR 50.65(a)(2). NUMARC 93-01 initially places all SSCs under 10 CFR 50.65(a)(2) and only moves them to consideration under 10 CFR 50.65(a)(1) if experience indicates that the performance or condition is not adequately controlled through preventive maintenance, as evidenced by the failure to meet a performance criterion or by experiencing a repetitive MPFF. Therefore, the 10 CFR 50.65(a)(1) category could be used as a tool to focus attention on those SSCs that need to be monitored more closely. It is possible that no (or very few) SSCs would be handled under the requirements of 10 CFR 50.65(a)(1). However, the rule does not require this approach. Licensees could also take the approach that all (or most) SSCs would be handled under 10 CFR 50.65(a)(1) and none (or very few) would be considered under 10 CFR 50.65(a)(2). Licensees may take either approach.

During the pilot site visits, licensees asked whether the NRC would consider a large number of SSCs monitored under 10 CFR 50.65(a)(1) as an indicator of poor maintenance performance. The NRC staff assured the licensees that NRC management would not use the number of SSCs monitored under 10 CFR 50.65(a)(1) as an indicator of maintenance performance nor would it be used in determining the systematic assessment of licensee performance grade in the maintenance area. The staff continues to assert that the number of SSCs monitored under 10 CFR 50.65(a)(1) will not be used as an indicator of licensee performance under the Reactor Oversight Process. The number of SSCs monitored under 10 CFR 50.65(a)(1) can vary greatly because of factors that have nothing to do with the quality of the licensee's maintenance activities. For example, two identical plants with equally effective maintenance programs could have different numbers of SSCs monitored under 10 CFR 50.65(a)(1) because of differences in the way system boundaries are defined (e.g., a system with three trains may be defined as one system at one plant while the same system may be defined as three separate systems at an identical plant) or because of differences in the way performance criteria are defined at the two plants (e.g., a licensee that takes a very conservative approach to monitoring against the performance criteria would have more SSCs in the 10 CFR 50.65(a)(1) category). The NRC staff also cautioned licensee managers that they should not view the number of SSCs in the 10 CFR 50.65(a)(1) category as an indicator of performance because that attitude might inhibit the licensees' staff from monitoring an SSC under 10 CFR 50.65(a)(1) when a performance criterion has been exceeded or a repetitive MPFF has occurred. If there is some doubt about whether a particular SSC should be monitored under 10 CFR 50.65(a)(1) or (a)(2), the conservative approach would be to monitor the SSC under 10 CFR 50.65(a)(1).

1.11 Use of Other Methods

Licensees may use methods other than those provided in Revision 4A to NUMARC 93-01 to meet the requirements of the maintenance rule. The NRC will determine the acceptability of other methods on a case-by-case basis.

1.12 NUMARC 93-01 References to 10 CFR 50.65

NUMARC 93-01 contains references to the language in 10 CFR 50.65. These references are not exact quotations of the regulations. Since the rule language has been updated (e.g., to include licensees under 10 CFR 52), licensees should reference 10 CFR 50.65 for exact regulatory language.

2. Consideration of Risk from Internal Fires in Maintenance Rule (a)(4) Activities

Previous versions of NUMARC 93-01 provided no guidance on how licensees should consider the risk from internal fires in the conduct of maintenance rule (a)(4) activities unless these fires were imminent or were considered to have a high probability of occurring during the planned out-of-service duration. During public interactions, the staff and industry agreed that additional guidance was necessary to adequately assess and manage the risk from internal fires in the conduct of activities required by 10 CFR 50.65(a)(4). Consequently, industry included guidance in Revision 4A to NUMARC 93-01, which states methods licensees can use to identify equipment which is important to mitigation of risk of core damage from fire initiators, describes approaches to developing and implementing appropriate risk management actions, and discusses the tools for effective implementation of the guidance.

In developing this guidance, the industry evaluated and identified the specific efforts essential to ensure effective implementation of the activities necessary to appropriately consider the risk from internal fires in (a)(4) assessments. Specifically, industry identified a project plan and associated timeline for piloting and implementing the guidance. This project plan identifies December 1, 2013 as the date by which all licensees shall have fully implemented the changes necessary to effectively consider the risk from internal fires in the conduct of maintenance rule (a)(4) activities. The staff has reviewed the project plan and concluded that it is an acceptable approach for adequately considering the risk from internal fires in maintenance rule (a)(4) activities. Licensees should consider the risk from internal fires upon completion of the specific efforts necessary to ensure effective implementation of the industry guidance, but no later than December 1, 2013.

3. Other Documents Referenced in NUMARC 93-01

The NRC's endorsement of NUMARC 93-01 should not be considered an endorsement of other documents referenced in NUMARC 93-01.

4. Inclusion of Electrical Distribution Equipment

The monitoring efforts under the maintenance rule, as defined in 10 CFR 50.65(b), encompass those SSCs that directly and significantly affect plant operations, regardless of which organization actually performs the maintenance activities. Maintenance activities that occur in the switchyard can directly affect plant operations; as a result, electrical distribution equipment out to the first intertie with the offsite distribution system (i.e., equipment in the switchyard) should be considered for inclusion as defined in 10 CFR 50.65(b).

D. IMPLEMENTATION

The purpose of this section is to provide information on how applicants and licensees may use this guide and information regarding the NRC's plans for using this regulatory guide. In addition, it describes how the NRC staff complies with the Backfit Rule (10 CFR 50.109) and any applicable finality provisions in 10 CFR Part 52.

Use by Applicants and Licensees

Applicants and licensees may voluntarily use the information in this regulatory guide to develop applications for initial licenses, amendments to licenses, requests for exemptions, or NRC regulatory approval. Licensees may use the information in this regulatory guide for actions that do not require prior NRC review and approval (e.g., changes to a facility design under 10 CFR 59.59 that do not require prior NRC review and approval). Licensees may voluntarily use the information in this regulatory guide or applicable parts to resolve regulatory or inspection issues (e.g., by committing to comply with provisions in the regulatory guide).

Current licensees may continue to use the guidance that was found acceptable for complying with specific portions of the regulations as part of their license approval process.

A licensee who believes that the NRC staff is inappropriately imposing this regulatory guide as part of a request for a license amendment or request for a change to a previously issued NRC regulatory approval may file a backfitting appeal with the NRC in accordance with applicable procedures.

Use by NRC Staff

The NRC staff does not intend or approve any imposition or backfitting of the guidance in this regulatory guide. The staff does not expect any existing licensee to use or commit to using the guidance in this regulatory guide in the absence of a licensee-initiated change to its licensing basis. The NRC staff does not expect or plan to request licensees to voluntarily adopt this regulatory guide to resolve a generic regulatory issue. The NRC staff does not expect or plan to initiate NRC regulatory action that would require the use of this regulatory guide (e.g., issuance of an order requiring the use of the regulatory guide, requests for information under 10 CFR 50.54(f) as to whether a licensee intends to commit to use of this regulatory guide, generic communication, or promulgation of a rule requiring the use of this regulatory guide) without further backfit consideration.

During inspections of specific facilities, the staff may suggest or recommend that licensees consider various actions consistent with staff positions in this regulatory guide. Such suggestions and recommendations would not ordinarily be considered backfitting even if prior versions of this regulatory guide are part of the licensing basis of the facility with respect to the subject matter of the inspection. However, unless this regulatory guide is part of the licensing basis for a plant, the staff may not represent to the licensee that the licensee's failure to comply with the positions in this regulatory guide constitutes a violation.

If an existing licensee seeks an amendment or change in an already approved area of NRC regulatory concern and (1) the NRC staff's consideration of the request involves a regulatory issue directly relevant to this new or revised regulatory guide and (2) the specific subject matter of this regulatory guide is an essential consideration in the staff's determination of the acceptability of the licensee's request, then, as a prerequisite for NRC approval of the license amendment or change, the staff may require the licensee to either follow the guidance in this regulatory guide or to provide an equivalent alternative method that demonstrates compliance with the underlying NRC regulatory requirements. This is not considered backfitting as defined in 10 CFR 50.109(a)(1) or a violation of any of the issue finality provisions in 10 CFR Part 52.

Conclusion

This regulatory guide is not being imposed upon current licensees and may be voluntarily used by existing licensees. In addition, this regulatory guide is issued in conformance with all applicable internal

NRC policies and procedures governing backfitting. Accordingly, the issuance of this regulatory guide by the NRC staff is not considered backfitting, as defined in 10 CFR 50.109(a)(1), nor is it deemed to be in conflict with any of the issue finality provisions in 10 CFR Part 52.

REFERENCES[1]

1. NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," Revision 4A, Nuclear Energy Institute, Washington, DC, April 2011. Electronic copies of this document are available through ADAMS at http://www.nrc.gov/reading-rm/adams.html, under Accession No. ML11116A198.

2. 10 CFR Part 50, "Domestic Licensing of Production and Utilization Facilities," U.S. Nuclear Regulatory Commission, Washington, DC.

3. Regulatory Guide, 1.182, "Assessing and Managing Risk before Maintenance Activities at Nuclear Power Plants," U.S. Nuclear Regulatory Commission, Washington, DC.

4. 61 FR 39278, "Decommissioning of Nuclear Power Reactors," *Federal Register*, Volume 61, Number 146, p.39278, Washington, DC, July 19, 1996.[2]

5. 64 FR 38551, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," *Federal Register*, Volume 64, Number 137, p. 38551, Washington, DC, July 19, 1999.

6. 61 FR 65157, "Reactor Site Criteria Including Seismic and Earthquake Engineering Criteria for Nuclear Power Plants," *Federal Register*, Volume 61, Number 239, p. 65157, Washington, DC, December 11, 1996.

7. 56 FR 31306, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," *Federal Register*, Volume 56, Number 132, p. 31306, Washington, DC, July 10, 1991.

8. NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," Nuclear Management and Resources Council, Washington, DC, May 1993.[3]

9. NUREG-1526, "Lessons Learned from Early Implementation of the Maintenance Rule at Nine Nuclear Power Plants," U.S. Nuclear Regulatory Commission, Washington, DC, June 1995.

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[1] Publicly available NRC published documents are available electronically through the NRC Library on the NRC's public Web site at: http://www.nrc.gov/reading-rm/doc-collections/. The documents can also be viewed on-line or printed for a fee in the NRC's Public Document Room (PDR) at 11555 Rockville Pike, Rockville, MD; the mailing address is USNRC PDR, Washington, DC 20555; telephone 301-415-4737 or (800) 397-4209; fax (301) 415-3548; and e-mail pdr.resource@nrc.gov.

[2] All *Federal Register* notices listed herein were issued by the NRC, and are available for inspection or copying for a fee from the NRC's PDRoom at 11555 Rockville Pike, Rockville, MD; the PDR's mailing address is USNRC PDR, Washington, DC 20555; telephone (301) 415-4737 or (800) 397-4209; fax (301) 415-3548; e-mail pdr.resource@nrc.gov. Many are also available electronically through the Federal Register Main Page of the public GPOAccess Web site, which the U.S. Government Printing Office maintains at http://www.gpoaccess.gov/fr/index.html.

[3] This document is available for inspection or copying for a fee in the NRC PDR at 11555 Rockville Pike, Rockville, MD; the mailing address is USNRC PDR, Washington, DC 20555; telephone 301-415-4737 or (800) 397-4209; fax (301) 415-3548; and e-mail pdr.resource@nrc.gov.

10. NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," Revision 2, Nuclear Energy Institute, Washington, DC, April 1996. Electronic copies of this document are available through ADAMS at http://www.nrc.gov/reading-rm/adams.html, under Accession No. ML101020415.

11. NUREG-1648, "Lessons Learned from Maintenance Rule Baseline Inspections," U.S. Nuclear Regulatory Commission, Washington, DC, October 1999.

12. Section 11 of NUMARC 93-01, "Assessment of Risk Resulting from Performance of Maintenance Activities," Nuclear Energy Institute, February 2000. Electronic copies of this document are available through ADAMS at http://www.nrc.gov/reading-rm/adams.html, under Accession No. ML101020466.

13. 53 FR 9430, "Final Commission Policy Statement on Maintenance at Nuclear Power Plants," *Federal Register*, Volume 53, Number 56, p. 9430, Washington, DC, March 23, 1988.

14. Inspection Procedure 71111.12, "Maintenance Effectiveness," U.S. Nuclear Regulatory Commission, Washington, DC.

15. SECY 95-265, "Response to August 9, 1995, Staff Requirements Memorandum Request to Analyze the Generic Applicability of the Risk Determination Process Used in Implementing the Maintenance Rule," U.S. Nuclear Regulatory Commission, Washington, DC, November 1, 1995.

16. Draft Regulatory Guide 1020, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," U.S. Nuclear Regulatory Commission, Washington, DC, November 1992.

17. Draft Regulatory Guide 1082, "Assessing and Managing Risk before Maintenance at Nuclear Power Plants," U.S. Nuclear Regulatory Commission, Washington, DC, December 1999.

Exhibit D

NRC Regulatory Guide 1.155

U.S. NUCLEAR REGULATORY COMMISSION

August 1988

REGULATORY GUIDE

OFFICE OF NUCLEAR REGULATORY RESEARCH

Reissued to correct Tables 1, 5, and 6.

REGULATORY GUIDE 1.155
(Task SI 501-4)

STATION BLACKOUT

A. INTRODUCTION

Criterion 17, "Electric Power Systems," of Appendix A, "General Design Criteria for Nuclear Power Plants," to 10 CFR Part 50, "Domestic Licensing of Production and Utilization Facilities," includes a requirement that an onsite electric power system and an offsite electric power system be provided to permit functioning of structures, systems, and components important to safety.

Criterion 1, "Quality Standards and Records," of Appendix A to 10 CFR Part 50 includes a requirement for a quality assurance program to provide adequate assurance that structures, systems, and components important to safety will perform their safety functions.

Criterion 18, "Inspection and Testing of Electric Power Systems," of Appendix A to 10 CFR Part 50 includes a requirement for appropriate periodic testing and inspection of electric power systems important to safety.

The Commission has amended its regulations in 10 CFR Part 50. Paragraph (a), "Requirements," of § 50.63, "Loss of All Alternating Current Power," requires that each light-water-cooled nuclear power plant be able to withstand and recover from a station blackout (i.e., loss of the offsite electric power system concurrent with reactor trip and unavailability of the onsite emergency ac electric power system) of a specified duration. Section 50.63 requires that, for the station blackout duration, the plant be capable of maintaining core cooling and appropriate containment integrity. It also identifies the factors that must be considered in specifying the station blackout duration.

Criteria 1 and 18 of Appendix A to 10 CFR Part 50 apply to safety-related equipment needed to cope with station blackout and other safety functions. Appendix A of this regulatory guide provides quality assurance guidance for non-safety systems and equipment used to meet the requirements of § 50.63.

This guide describes a method acceptable to the NRC staff for complying with the Commission regulation that requires nuclear power plants to be capable of coping with a station blackout for a specified duration. This guide applies to all light-water-cooled nuclear power plants.

The Advisory Committee on Reactor Safeguards has been consulted concerning this guide and has concurred in the regulatory position.

Any information collection activities related to this regulatory guide are contained as requirements in the revision of 10 CFR Part 50 that provides the regulatory basis for this guide. The information collection requirements in Part 50 have been cleared under the Office of Management and Budget Clearance No. 3150-0011.

B. DISCUSSION

The term "station blackout" refers to the complete loss of alternating current electric power to the essential and nonessential switchgear buses in a nuclear power plant. Station blackout therefore involves the loss of offsite power concurrent with turbine trip and failure of the onsite emergency ac power system, but not the loss of available ac power to buses fed by station batteries through inverters or the loss of power from "alternate ac sources." Station blackout and alternate ac source are defined in § 50.2. Because many safety systems required for reactor core decay heat removal and containment heat removal are dependent on ac power, the consequences of a station blackout could be severe. In the event of a station blackout, the capability to cool the reactor core would be dependent on the availability of systems that do not require ac power from the essential and nonessential switchgear buses and on the ability to restore ac power in a timely manner.

The concern about station blackout arose because of the accumulated experience regarding the reliability of ac power supplies. Many operating plants have experienced a total loss of offsite electric power, and more occurrences are expected in the future. In almost every one of these loss-of-offsite-power events, the onsite emergency ac power supplies have been available immediately to supply the power needed by vital safety equipment. However, in some instances, one of the redundant emergency ac power supplies has been unavailable. In a few cases there has been a complete loss of ac power, but during these events ac power was restored in a short time without any serious consequences. In addition, there have been numerous instances when emergency diesel generators have failed to start and run in response to tests conducted at operating plants.

The results of the Reactor Safety Study (Ref. 1) showed that, for one of the two plants evaluated, a station blackout event could be an important contributor to the total risk from nuclear power plant accidents. Although this total risk was found to be small, the relative importance of station blackout events was established. This finding and the accumulated diesel generator failure experience increased the concern about station blackout.

In a Commission proceeding addressing station blackout, it was determined that the issue should be analyzed to identify preventive or mitigative measures that can or should be taken. (See Florida Power & Light Company (St. Lucie Nuclear Power Plant, Unit No. 2) ALAB-603, 12 NRC 30 (1980); modified CLI-81-12, 13 NRC 838 (1981).)

The issue of station blackout involves the likelihood and duration of the loss of offsite power, the redundancy and reliability of onsite emergency ac power systems, and the potential for severe accident sequences after a loss of all ac power. References 2 through 7 provide detailed analyses of these topics. Based on risk studies performed to date, the results indicate that estimated core melt frequencies from station blackout vary considerably for different plants and could be a significant risk contributor for some plants. In order to reduce this risk, action should be taken to resolve the safety concern stemming from station blackout. The issue is of concern for both PWRs and BWRs.

This guide primarily addresses the following three areas: (1) maintaining highly reliable ac electric power systems, (2) developing procedures and training to restore offsite and onsite emergency ac power should either one or both become unavailable, and (3) ensuring that plants can cope with a station blackout for some period of time based on the probability of occurrence of a station blackout at a site as well as the capability for restoring ac power in a timely fashion for that site.

One factor that affects ac power system reliability is the vulnerability to common cause failures associated with design, operational, and environmental factors. Existing standards and regulatory guides include specific design criteria and guidance on the independence of preferred (offsite) power circuits (see General Design Criterion 17, "Electric Power Systems," and Section 5.1.3 of Reference 8) and the independence of and limiting interactions between diesel generator units at a nuclear station (see General Design Criterion 17, Regulatory Guide 1.6, "Independence Between Redundant Standby (Onsite) Power Sources and Between Their Distribution Systems," Regulatory Guide 1.75, "Physical Independence of Electric Systems," and Reference 9). In developing the recommendations in this guide, the staff has assumed that, by adhering to such standards, licensees have minimized, to the extent practical, single-point vulnerabilities in design and operation that could result in a loss of all offsite power or all onsite emergency ac power.

Onsite emergency ac power system unavailability can be affected by outages resulting from testing and maintenance. Typically, this unavailability is about 0.007 (Reference 5), which is small compared to the minimum emergency diesel generator reliability specified in Regulatory Position 1.1 of this regulatory guide (i.e., 0.95 or 0.975 reliability per demand). However, in some cases outages due to maintenance can be a significant contributor to emergency diesel generator unavailability. This contribution can be kept low by having high-quality test and maintenance procedures and by scheduling regular diesel generator maintenance at times when the reactor is shut down. Also, limiting conditions for operation in the technical specifications are designed to limit the diesel generator unavailability when the plant is operating. As long as the unavailability due to testing and maintenance is not excessive, the maximum emergency diesel generator failure rates for each diesel generator specified in Regulatory Position 1.1 would result in acceptable overall reliability for the emergency ac power system.

Based on § 50.63, all licensees and applicants are required to assess the capability of their plants to maintain adequate core cooling and appropriate containment integrity during a station blackout and to have procedures to cope with such an event. This guide presents a method acceptable to the NRC staff for determining the specified duration for which a plant should be able to withstand a station blackout in accordance with these requirements. The application of this method results in selecting a minimum acceptable station blackout duration capability from 2 to 16 hours, depending on a comparison of the plant's characteristics with those factors that have been identified as significantly affecting the risk from station blackout. These factors include redundancy of the onsite emergency ac power system (i.e., the number of diesel generators available for decay heat removal minus the number needed for decay heat removal), the reliability of onsite emergency ac power sources (e.g., diesel generators), the frequency of loss of offsite power, and the probable time to restore offsite power.

Licensees may propose durations different from those specified in this guide. The basis for alternative durations would be predicated on plant-specific factors relating to the reliability of ac power systems such as those discussed in Reference 2.

The information submitted to comply with § 50.63 is also required to be incorporated in an update to the FSAR in accordance with paragraph 50.71(e)(4). It is expected that the applicant or licensee will have available for review, as required, the analyses and related information supporting the submittal.

Concurrent with the development of this regulatory guide, and consistent with discussions with the NRC staff, the Nuclear Management and Resource Council (NUMARC) has developed guidelines and procedures for assessing station blackout coping capability and duration for light water reactors (NUMARC-8700, Ref. 10). The NRC staff has reviewed these guidelines and analysis methods and concludes that NUMARC-8700 provides guidance for conformance to § 50.63 that is in large part identical to the guidance provided in this regulatory guide. Table 1 of this regulatory guide provides a section-by-section comparison between Regulatory Guide 1.155 and NUMARC-8700. The use of NUMARC-8700 is further discussed in Section C, Regulatory Position, of this guide.

C. REGULATORY POSITION

This regulatory guide describes a means acceptable to the NRC staff for meeting the requirements of § 50.63 of 10 CFR Part 50. NUMARC-8700 (Ref. 10) also provides guidance acceptable to the staff for meeting these requirements. Table 1 provides a cross-reference to NUMARC-8700 and notes where the regulatory guide takes precedence.

1. ONSITE EMERGENCY AC POWER SOURCES (EMERGENCY DIESEL GENERATORS)

1.1 Emergency Diesel Generator Target Reliability Levels

The minimum emergency diesel generator (EDG) reliability should be targeted at 0.95 per demand for each EDG for plants in emergency ac (EAC) Groups A, B, and C and at 0.975 per demand for each EDG for plants in EAC Group D (see Table 2). These reliability levels will be considered minimum target reliabilities and each plant should have an EDG reliability program containing the principal elements, or their equivalent, outlined in Regulatory Position 1.2. Plants that select a target EDG reliability of 0.975 will use the higher level as the target in their EDG reliability programs.

The EDG reliability for determining the coping duration for a station blackout will be determined as follows:

1. Calculate the most recent EDG reliability for each EDG based on the last 20, 50, and 100 demands using definitions and methodology in Section 2 of NSAC-108, "Reliability of Emergency Diesel Generators at U.S. Nuclear Power Plants" (Ref. 11), or equivalent.[1]

2. Calculate the nuclear unit "average" EDG reliability for the last 20, 50, and 100 demands by averaging the results from step 1 above.

3. Compare the calculated "average" nuclear unit EDG reliability from step 2 above against the following criteria:

   Last 20 demands > 0.90 reliability
   Last 50 demands > 0.94 reliability
   Last 100 demands > 0.95 reliability

4. If the EAC group is A, B, or C AND any of the three evaluation criteria in step 3 are met, the nuclear unit may select an EDG reliability target of either 0.95 or 0.975 for determining the applicable coping duration from Table 2.

   If the EAC group is D and any of the three evaluation criteria in step 3 are met, the allowed EDG reliability target is 0.975.

5. If the EAC group is A, B, or C and NONE of the selection criteria in step 3 are met, an EDG reliability level of 0.95 must be used for determining the applicable coping duration from Table 2. Additionally, if the "averaged" nuclear unit EDG reliability is less than 0.90 based on the last 20 demands, the acceptability of a coping duration based on an EDG reliability of 0.95 from Table 2 must be further justified.

   If the EAC group is D and NONE of the three evaluation criteria in step 3 are met, the required coping duration (derived by using Table 2) should be increased to the next highest coping level (i.e., 4 hours to 8 hours, 8 hours to 16 hours).

1.2 Reliability Program

The reliable operation of onsite emergency ac power sources should be ensured by a reliability program designed to maintain and monitor the reliability level of each power source over time for assurance that the selected reliability levels are being achieved. An EDG reliability program would typically be composed of the following elements or activities (or their equivalent):

1. Individual EDG reliability target levels consistent with the plant category and coping duration selected from Table 2.

2. Surveillance testing and reliability monitoring programs designed to track EDG performance and to support maintenance activities.

[1]This EDG reliability is not suitable for probabilistic risk analyses for design basis accidents because of the differing EDG start-reliability requirement that would be applicable for such probabilistic risk analyses.

3. A maintenance program that ensures that the target EDG reliability is being achieved and that provides a capability for failure analysis and root-cause investigations.

4. An information and data collection system that services the elements of the reliability program and that monitors achieved EDG reliability levels against target values.

5. Identified responsibilities for the major program elements and a management oversight program for reviewing reliability levels being achieved and ensuring that the program is functioning properly.

1.3 Procedures for Restoring Emergency AC Power

Guidelines and procedures for actions to restore emergency ac power when the emergency ac power system is unavailable should be integrated with plant-specific technical guidelines and emergency operating procedures developed using the emergency operating procedure upgrade program established in response to Supplement 1, "Requirements for Emergency Response Capability" (Generic Letter No. 82-33),[2] to NUREG-0737, "Clarification of TMI Action Plan Requirements" (Ref. 12).

2. OFFSITE POWER

Procedures should include the actions necessary to restore offsite power and use nearby power sources[3] when offsite power is unavailable. As a minimum, the following potential causes for loss of offsite power should be considered:

- Grid undervoltage and collapse
- Weather-induced power loss
- Preferred power distribution system faults[4] that could result in the loss of normal power to essential switchgear buses

3. ABILITY TO COPE WITH A STATION BLACKOUT

The ability to cope with a station blackout for a certain time provides additional defense-in-depth should both offsite and onsite emergency ac power systems fail concurrently. Regulatory Position 3.1 provides a method to determine an acceptable minimum time that a plant should be able to cope with a station blackout based on the probability of a station blackout at the site as well as the capability for restoring ac power for that site. Each nuclear power plant has the capability to remove decay heat and maintain appropriate containment integrity without ac power for a limited period of time. Regulatory Position 3.2 provides guidance for determining the length of time that a plant is actually able to cope with a station blackout. If the plant's actual station blackout capability is significantly less than the acceptable minimum duration, modifications may be necessary to extend the plant's ability to cope with a station blackout. Should plant modifications be necessary, Regulatory Position 3.3 provides guidance on making such modifications. Whether or not modifications are necessary, procedures and training for station blackout events should be provided according to the guidance in Regulatory Position 3.4.

3.1 Minimum Acceptable Station Blackout Duration Capability

Each nuclear power plant should be able to withstand and recover from a station blackout lasting a specified minimum duration. The specified duration of station blackout should be based on the following factors:

1. The redundancy of the onsite emergency ac power system (i.e., the number of power sources available minus the number needed for decay heat removal),

2. The reliability of each of the onsite emergency ac power sources (e.g., diesel generator),

3. The expected frequency of loss of offsite power, and

4. The probable time needed to restore offsite power.

A method for determining an acceptable minimum station blackout duration capability as a function of the above site- and plant-related characteristics is given in Table 2. Tables 3 through 8 provide the necessary detailed descriptions and definitions of the various factors used in Table 2. Table 3 identifies different levels of redundancy of the onsite emergency ac power system used to define the emergency ac power configuration groups in Table 2. Table 4 provides definitions of the three offsite power design characteristic groups used in Table 2. The groups are defined according to various combinations of the following factors: (1) independence of offsite power (I), (2) severe weather (SW), (3) severe weather recovery (SWR), and (4) extremely severe weather (ESW). The definitions of the factors I, SW, SWR, and ESW are provided in Tables 5 through 8, respectively. After identifying the appropriate groups from Tables 3 and 4 and the reliability level of the onsite emergency ac power sources (determined in accordance with Regulatory Position 1.1), Table 2 can be used to determine the acceptable minimum station blackout duration capability for each plant.

[2] Modifications or additions to generic technical guidelines that are necessary to deal with a station blackout for the specific plant design should be identified as deviations in the plant-specific technical guidelines as required by Supplement 1 to NUREG-0737 (Ref. 12) and outlined in NUREG-0899, "Guidelines for the Preparation of Emergency Operating Procedures" (Ref. 13).

[3] This includes such items as nearby or onsite gas turbine generators, portable generators, hydro generators, and black-start fossil power plants.

[4] Includes such failures as the distribution system hardware, switching and maintenance errors, and lightning-induced faults.

3.2 Evaluation of Plant-Specific Station Blackout Capability

Each nuclear power plant should be evaluated to determine its capability to withstand and recover from a station blackout of the acceptable duration determined for that plant (see Regulatory Position 3.1). The following considerations should be included when determining the plant's capability to cope with a station blackout.

3.2.1. The evaluation should be performed assuming that the station blackout event occurs while the reactor is operating at 100% rated thermal power and has been at this power level for at least 100 days.

3.2.2. The capability of all systems and components necessary to provide core cooling and decay heat removal following a station blackout should be determined, including station battery capacity, condensate storage tank capacity, compressed air capacity, and instrumentation and control requirements.

3.2.3. The ability to maintain adequate reactor coolant system inventory to ensure that the core is cooled should be evaluated, taking into consideration shrinkage, leakage from pump seals, and inventory loss from letdown or other normally open lines dependent on ac power for isolation.

3.2.4. The design adequacy and capability of equipment needed to cope with a station blackout for the required duration and recovery period should be addressed and evaluated as appropriate for the associated environmental conditions. This should include consideration as appropriate of the following:

1. Potential failures of equipment necessary to cope with the station blackout,

2. Potential environmental effects on the operability and reliability of equipment necessary to cope with the station blackout, including possible effects of fire protection systems,

3. Potential effects of other hazards, such as weather, on station blackout response equipment (e.g., auxiliary equipment to operate onsite buses or to recover EDGs and other equipment as needed),

4. Potential habitability concerns for those areas that would require operator access during the station blackout and recovery period.

Evaluations that have already been performed need not be duplicated. For example, if safety-related equipment required during a total loss of ac power has been qualified to operate under environmental conditions exceeding those expected under a station blackout (e.g., loss of heating, ventilation, and air conditioning), additional analyses need not be performed. Equipment will be considered acceptable for station blackout temperature environments if an assessment has been performed that provides reasonable assurance that the required equipment will remain operable.

3.2.5. Consideration should be given to using available non-safety-related equipment, as well as safety-related equipment, to cope with a station blackout provided such equipment meets the recommendations of Regulatory Positions 3.3.3 and 3.3.4. Onsite or nearby alternate ac (AAC) power sources that are independent and diverse from the normal Class 1E emergency ac power sources (e.g., gas turbine, separate diesel engine, steam supplies) will constitute an acceptable station blackout coping capability provided an analysis is performed that demonstrates the plant has this capability from the onset of station blackout until the AAC power source or sources are started and lined up to operate all equipment necessary to cope with station blackout for the required duration.

In general, equipment required to cope with a station blackout during the first 8 hours should be available on the site. For equipment not located on the site, consideration should be given to its availability and accessibility in the time required, including consideration of weather conditions likely to prevail during a loss of offsite power.

If the AAC source or sources meet the recommendations of Section 3.3.5 and can be demonstrated by test to be available to power the shutdown buses within 10 minutes of the onset of station blackout, no coping analysis is required.

3.2.6. Consideration should be given to timely operator actions inside or outside the control room that would increase the length of time that the plant can cope with a station blackout provided it can be demonstrated that these actions can be carried out in a timely fashion. For example, if station battery capacity is a limiting factor in coping with a station blackout, shedding nonessential loads on the batteries could extend the time until the battery is depleted. If load shedding or other operator actions are considered, corresponding procedures should be incorporated into the plant-specific technical guidelines and emergency operating procedures.

3.2.7. The ability to maintain "appropriate containment integrity" should be addressed. "Appropriate containment integrity" for station blackout means that adequate containment integrity is ensured by providing the capability, independent of the preferred and blacked-out unit's onsite emergency ac power supplies, for valve position indication and closure for containment isolation valves that may be in the open position at the onset of a station blackout. The following valves are excluded from consideration:

1. Valves normally locked closed during operation,

2. Valves that fail closed on a loss of power,

3. Check valves,

4. Valves in nonradioactive closed-loop systems not expected to be breached in a station blackout (this does not include lines that communicate directly with containment atmosphere), and

5. Valves of less than 3-inch nominal diameter.

3.3 Modifications To Cope with Station Blackout

If the plant's station blackout capability, as determined according to the guidance in Regulatory Position 3.2, is significantly less than the minimum acceptable plant-specific station blackout duration (as developed according to Regulatory Position 3.1 or as justified by the licensee or applicant on some other basis and accepted by the staff), modifications to the plant may be necessary to extend the time the plant is able to cope with a station blackout. If modifications are needed, the following items should be considered:

3.3.1. If, after considering load shedding to extend the time until battery depletion, battery capacity must be extended further to meet the station blackout duration recommended in Regulatory Position 3.1, it is considered acceptable either to add batteries or to add a charging system for the existing batteries that is independent of both the offsite and the blacked-out unit's onsite emergency ac power systems, such as a dedicated diesel generator.

3.3.2. If the capacity of the condensate storage tank is not sufficient to remove decay heat for the station blackout duration recommended in Regulatory Position 3.1, a system meeting the requirements of Regulatory Position 3.5 to resupply the tank from an alternative water source is an acceptable means to increase its capacity provided any power source necessary to provide additional water is independent of both the offsite and the blacked-out unit's onsite emergency ac power systems.

3.3.3. If the compressed air capacity is not sufficient to remove decay heat and to maintain appropriate containment integrity for the station blackout duration recommended in Regulatory Position 3.1, a system to provide sufficient capacity from an alternative source that meets Regulatory Position 3.5 is an acceptable means to increase the air capacity provided any power source necessary to provide additional air is independent of both the offsite and the blacked-out unit's onsite emergency ac power systems.

3.3.4. If a system is required for primary coolant charging and makeup, reactor coolant pump seal cooling or injection, decay heat removal, or maintaining appropriate containment integrity specifically to meet the station blackout duration recommended in Regulatory Position 3.1, the following criteria should be met:

1. The system should be capable of being actuated and controlled from the control room, or if other means of control are required, it should be demonstrated that these steps can be carried out in a timely fashion, and

2. If the system must operate within 10 minutes of a loss of all ac power, it should be capable of being actuated from the control room.

3.3.5. If an AAC power source is selected specifically for satisfying the requirements for station blackout, the design should meet the following criteria:

1. The AAC power source should not normally be directly connected to the preferred or the blacked-out unit's onsite emergency ac power system.

2. There should be a minimum potential for common cause failure with the preferred or the blacked-out unit's onsite emergency ac power sources. No single-point vulnerability should exist whereby a weather-related event or single active failure could disable any portion of the blacked-out unit's onsite emergency ac power sources or the preferred power sources and simultaneously fail the AAC power source.

3. The AAC power source should be available in a timely manner after the onset of station blackout and have provisions to be manually connected to one or all of the redundant safety buses as required. The time required for making this equipment available should not be more than 1 hour as demonstrated by test. If the AAC power source can be demonstrated by test to be available to power the shutdown buses within 10 minutes of the onset of station blackout, no coping analysis is required.

4. The AAC power source should have sufficient capacity to operate the systems necessary for coping with a station blackout for the time required to bring and maintain the plant in safe shutdown.

5. The AAC power system should be inspected, maintained, and tested periodically to demonstrate operability and reliability. The reliability of the AAC power system should meet or exceed 95 percent as determined in accordance with NSAC-108 (Ref. 11) or equivalent methodology.

An AAC power source serving a multiple-unit site where onsite emergency ac sources are not shared between units should have, as a minimum, the capacity and capability for coping with station blackout in any of the units.

At sites where onsite emergency sources are shared between units, the AAC power sources should have the capacity and capability to ensure that all units can be brought to and maintained in safe shutdown (i.e., those plant conditions defined in plant technical specifications as Hot Standby or Hot Shutdown, as appropriate). Plants have the option of maintaining the RCS at normal operating temperatures or at reduced temperatures.

Plants that have more than the required redundancy of emergency ac sources for loss-of-offsite-power conditions, on a per nuclear unit basis, may use one of the existing emergency sources as an AAC power source provided it meets the applicable criteria for an AAC source. Additionally, emergency diesel generators with 1-out-of-2-shared and 2-out-of-3-shared ac power configurations may not be used as AAC power sources.

3.3.6. If a system or component is added specifically to meet the recommendations on station blackout duration in Regulatory Position 3.1, system walk downs and initial tests of new or modified systems or critical components should be performed to verify that the modifications were performed properly. Failures of added components that may be vulnerable to internal or external hazards within the design basis (e.g., seismic events) should not affect the operation of systems required for the design basis accident.

3.3.7. A system or component added specifically to meet the recommendations on station blackout duration in Regulatory Position 3.1 should be inspected, maintained, and tested periodically to demonstrate equipment operability and reliability.

3.4 Procedures and Training To Cope with Station Blackout

Procedures[5] and training should include all operator actions necessary to cope with a station blackout for at least the duration determined according to Regulatory Position 3.1 and to restore normal long-term core cooling/decay heat removal once ac power is restored.

3.5 Quality Assurance and Specification Guidance for Station Blackout Equipment That Is Not Safety-Related

Appendices A and B provide guidance on quality assurance (QA) activities and specifications respectively for non-safety-related equipment used to meet the requirements of § 50.63 and not already covered by existing QA requirements in Appendix B or R of Part 50. Appropriate activities should be implemented from among those listed in these appendices depending on whether the non-safety equipment is being added (new) or is existing. This QA guidance is applicable to non-safety systems and equipment for meeting the requirements of § 50.63 of 10 CFR Part 50. The guidance on QA and specifications incorporates a lesser degree of stringency by eliminating requirements for involvement of parties outside the normal line organization. NRC inspections will focus on the implementation and effectiveness of the quality controls described in Appendices A and B. Additionally, the equipment installed to meet the station blackout rule must be implemented such that it does not degrade the existing safety-related systems. This is to be accomplished by making the non-safety-related equipment as independent as practicable from existing safety-related systems. The non-safety systems identified in Appendix B are acceptable to the NRC staff for responding to a station blackout.

D. IMPLEMENTATION

The purpose of this section is to provide information to applicants and licensees regarding the NRC staff's plans for using this regulatory guide. Except in those cases in which the applicant or licensee proposes an acceptable alternative method for complying with specified portions of the Commission's regulations, the method described in this guide may be used in the evaluation of submittals by applicants for construction permits and operating licenses (as appropriate) and will be used to evaluate licensees who are required to comply with § 50.63, "Loss of All Alternating Current Power," of 10 CFR Part 50.

[5] Procedures should be integrated with plant-specific technical guidelines and emergency operating procedures developed using the emergency operating procedure upgrade program established in response to Supplement 1 of NUREG-0737 (Ref. 12). The task analysis portion of the emergency operating procedure upgrade program should include an analysis of instrumentation adequacy during a station blackout.

TABLE 1

CROSS-REFERENCE BETWEEN REGULATORY GUIDE 1.155 AND NUMARC-8700

Regulatory Position in R.G. 1.155	Section in NUMARC-8700
1.1	3.2.3, 3.2.4
1.2	Appendix D
1.3	4.2.1, 4.3.1
2	4.2.2, 4.3.2
3.1	3
3.2.1	2.2.1, 2.2.2
3.2.2	2.9, 7.2.1, 7.2.2, 7.2.3
3.2.3	2.5
3.2.4	2.7, 4.2.1, 4.2.2, 7.2.4, Appendices E and F
3.2.5	7.1.1, 7.1.2, Appendices B and C
3.2.6	4.2.1, 4.3.1, 7.2.1, 7.2.2, 7.2.3
3.2.7	2.10, 7.2.5
3.3.1	7.2.2
3.3.2	7.2.1
3.3.3	7.2.3
3.3.4	2.5
3.3.5	2.3.1, 7.1.1, 7.1.2, Appendices A, B, and C
3.3.6	None (Use Regulatory Guide 1.155)
3.3.7	4.2.1(12), 4.3.1(12), Appendices A and B
3.4	4
3.5	None (Use Regulatory Guide 1.155)
Appendix A	None (Use Regulatory Guide 1.155)
Appendix B	None (Use Regulatory Guide 1.155

TABLE 2

ACCEPTABLE STATION BLACKOUT DURATION CAPABILITY (HOURS)[a]

	Emergency AC Power Configuration Group[b]						
	A		B		C		D
	Unit "Average" EDG Reliability[c]						
Offsite Power Design Characteristic Group[d]	0.975	0.95	0.975	0.95	0.975	0.95	0.975
P1	2	2	4	4	4	4	4
P2	4	4	4	4	4	8	8
P3	4	8	4	8	8	16	8

[a]Variations from these times will be considered by the staff if justification, including a cost-benefit analysis, is provided by the licensee. The methodology and sensitivity studies presented in NUREG-1032 (Ref. 2) are acceptable for use in this justification.

[b]See Table 3 to determine emergency ac power configuration group.

[c]See Regulatory Position 1.1.

[d]See Table 4 to determine groups P1, P2, and P3.

TABLE 3

EMERGENCY AC POWER CONFIGURATION GROUPS[a]

EAC Power Configuration Group	Number of EAC Power Sources[b]	Number of EAC Power Sources Required To Operate AC-Powered Decay Heat Removal Systems[c]
A	3[d]	1
	4	1
B	4	2
	5	2
C	2[d]	1
	3[e]	1
D	2[f]	1
	3	2
	4	3
	5	3

[a]Special-purpose dedicated diesel generators, such as those associated with high-pressure core spray systems at some BWRs, are not counted in the determination of EAC power configuration groups.

[b]If any of the EAC power sources are shared among units at a multi-unit site, this is the total number of shared and dedicated sources for those units at the site.

[c]This number is based on all the ac loads required to remove decay heat (including ac-powered decay heat removal systems) to achieve and maintain safe shutdown at all units at the site with offsite power unavailable.

[d]For EAC power sources not shared with other units.

[e]For EAC power sources shared with another unit at a multi-unit site.

[f]For shared EAC power sources in which each diesel generator is capable of providing ac power to more than one unit at a site concurrently.

TABLE 4

OFFSITE POWER DESIGN CHARACTERISTIC GROUPS

Group	Offsite Power Design Characteristics			
	Sites that have any combination of the following factors:			
	I[a]	SW[b]	SWR[c]	ESW[d]
P1	1 or 2	1 or 2	1 or 2	1 or 2
	1 or 2	1	1 or 2	3
	1 or 2	3	1	1 or 2
P2	All other sites not in P1 or P3.			
	Sites that expect to experience a total loss of offsite power caused by grid failures at a frequency equal to or greater than once in 20 site-years, unless the site has procedures to recover ac power from reliable alternative (nonemergency) ac power sources within approximately one-half hour following a grid failure.			
	or			
	Sites that have any combination of the following factors:			
P3	I	SW	SWR	ESW
	Any I	5	2	Any ESW
	Any I	1,2,3, or 4	1 or 2	5
	Any I	5	1	Any ESW
	Any I	4	2	1,2,3, or 4
	1 or 2	3	2	4
	3	3	2	3 or 4

[a]See Table 5 for definitions of independence of offsite power (I) groups.

[b]See Table 6 for definitions of severe weather (SW) groups.

[c]See Table 7 for definitions of severe weather recovery (SWR) groups.

[d]See Table 8 for definitions of extremely severe weather (ESW) groups.

TABLE 5

DEFINITIONS OF INDEPENDENCE OF OFFSITE POWER GROUPS

Category	I		
	1	2	3
1. Independence of offsite power sources	1. All offsite power sources are connected to the plant through two or more switchyards or separate incoming transmission lines, but at least one of the ac sources is electrically independent of the others. (The independent 69-kV line in Figure 1 is representative of this design feature.) OR	1.a. All offsite power sources are connected to the plant through one switchyard. OR 1.b. All offsite power sources are connected to the plant through two or more switchyards, and the switchyards are electrically connected. (The 345- and 138-kV switchyards in Figures 2 and 3 represent this design feature.) AND	AND
2. Automatic and manual transfer schemes for the Class 1E buses when the normal source of ac power fails and when the back-up sources of offsite power fail. a. The normal source of ac power is assumed to be the unit main generator.	2.a. After loss of the normal ac source, (1) There is an automatic transfer of all safe-shutdown buses to a separate preferred alternate power source. (2) There is an automatic transfer of all safe-shutdown buses to one preferred power source. If this preferred power source fails, there is another automatic transfer to the remaining preferred power sources or to alternate offsite power source. OR	2.a. After loss of the normal ac power source, there is an automatic transfer of all safe-shutdown buses to one preferred alternate power source. If this source fails, there may be one or more manual transfers of power source to the remaining preferred or alternate offsite power sources. OR	2.a. If the normal source of ac power fails, there are no automatic transfers and one or more manual transfers of all safe-shutdown buses to preferred or alternate offsite power sources. OR There is one automatic transfer and no manual transfer of all safe-shutdown buses to one preferred or one alternate offsite power source.
b. If the Class 1E buses are normally designed to be connected to the preferred or alternate power sources.	2.b. Each safe-shutdown bus is normally connected to a separate preferred alternate power source with automatic or manual transfer capability between the preferred or alternate sources.	2.b. The safe-shutdown buses are normally aligned to the same preferred power source with either an automatic or manual transfer to the remaining preferred or alternate ac power source.	

TABLE 6

DEFINITIONS OF SEVERE WEATHER (SW) GROUPS

SW Group	Estimated Frequency of Loss of Offsite Power Due to Severe Weather, f (per Site-Year)*
1	$f < 3.3 \times 10^{-3}$
2	$3.3 \times 10^{-3} \leq f < 1 \times 10^{-2}$
3	$1 \times 10^{-2} \leq f < 3.3 \times 10^{-2}$
4	$3.3 \times 10^{-2} \leq f < 1 \times 10^{-1}$
5	$1 \times 10^{-1} \leq f$

*The estimated frequency of loss of offsite power due to severe weather, f, is determined by the following equation:

$$f = (1.3 \times 10^{-4})h_1 + (b)h_2 + (0.012)h_3 + (c)h_4$$

where h_1 = annual expectation of snowfall for the site, in inches

h_2 = annual expectation of tornadoes (with wind speeds greater than or equal to 113 miles per hour) per square mile at the site

b = 12.5 for sites with transmission lines on two or more rights-of-way spreading out in different directions from the switchyard, or

b = 72.3 for sites with transmission lines on one right-of-way

h_3 = annual expectation of storms at the site with wind velocities between 75 and 124 mph

h_4 = annual expectation of hurricanes at the site

c = 0 if switchyard *is not* vulnerable to the effects of salt spray

c = 0.78 if switchyard *is* vulnerable to the effects of salt spray

The annual expectation of snowfall, tornadoes, and storms may be obtained from National Weather Service data from the weather station nearest to the plant or by interpolation, if appropriate, between nearby weather stations. The basis for the empirical equation for the frequency of loss of offsite power due to severe weather, f, is given in Appendix A to Reference 2.

TABLE 7

DEFINITIONS OF SEVERE WEATHER RECOVERY (SWR) GROUPS

SWR Group	Definition
1	Sites with enhanced recovery (i.e., sites that have the capability and procedures for restoring offsite (nonemergency) ac power to the site within 2 hours following a loss of offsite power due to severe weather).
2	Sites without enhanced recovery.

TABLE 8

DEFINITIONS OF EXTREMELY SEVERE WEATHER (ESW) GROUPS

ESW Group	Annual expectation of storms at a site with wind velocities equal to or greater than 125 miles per hour (e)*
1	$e < 3.3 \times 10^{-4}$
2	$3.3 \times 10^{-4} \leq e < 1 \times 10^{-3}$
3	$1 \times 10^{-3} \leq e < 3.3 \times 10^{-3}$
4	$3.3 \times 10^{-3} \leq e < 1 \times 10^{-2}$
5	$1 \times 10^{-2} \leq e$

*The annual expectation of storms may be obtained from National Weather Service data from the weather station nearest to the plant or by interpolation, if appropriate, between nearby weather stations.

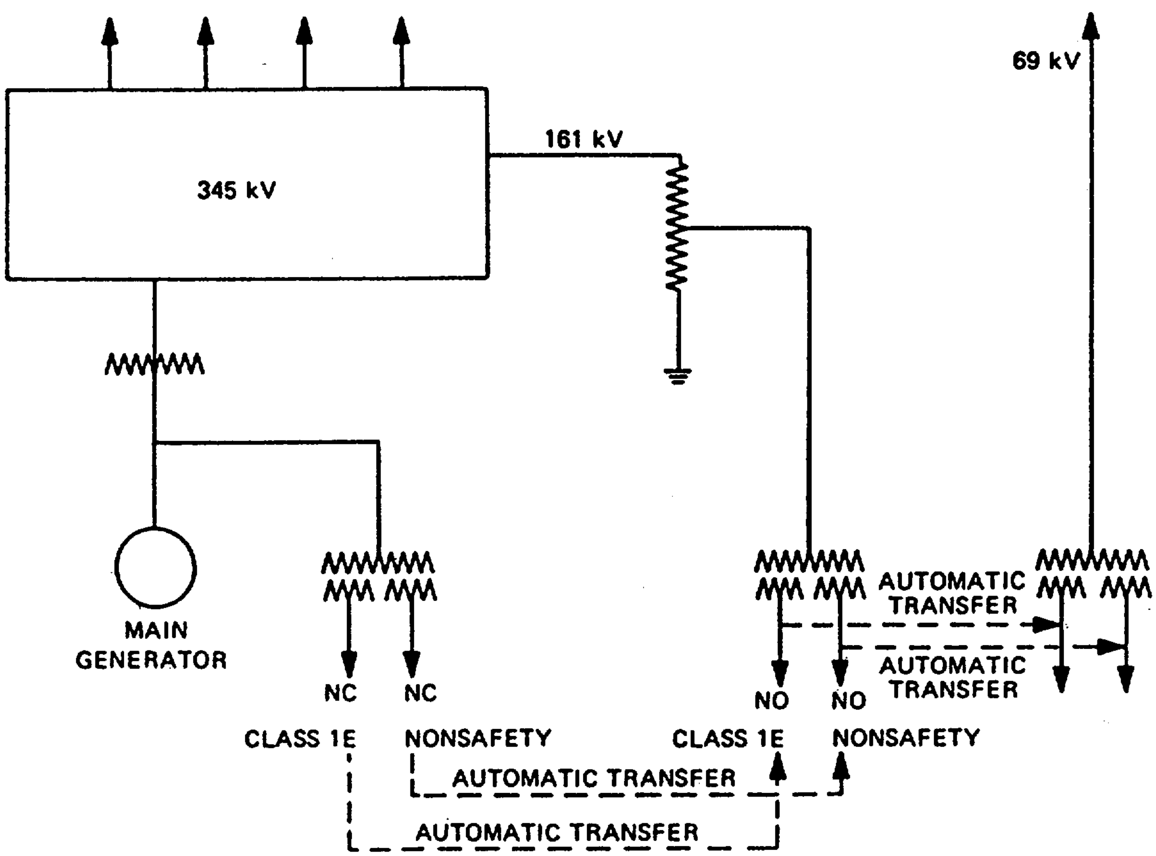

Figure 1. Schematic Diagram of Electrically Independent Transmission Line

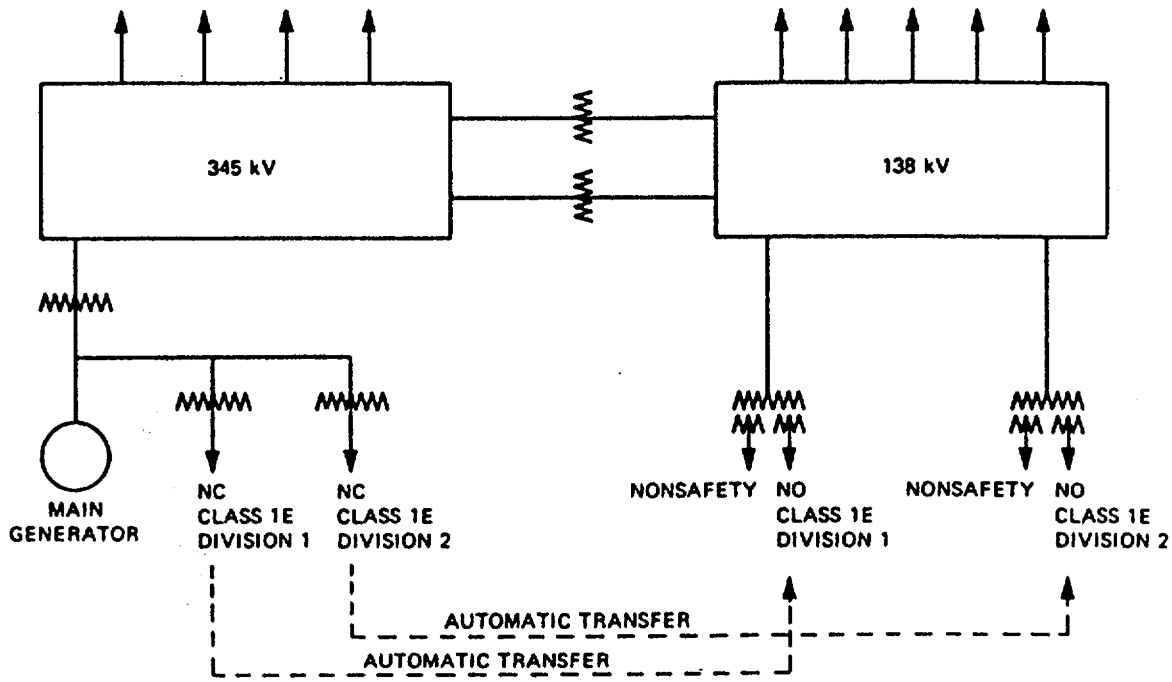

Figure 2. Schematic Diagram of Two Switchyards Electrically Connected (One-Unit Site)

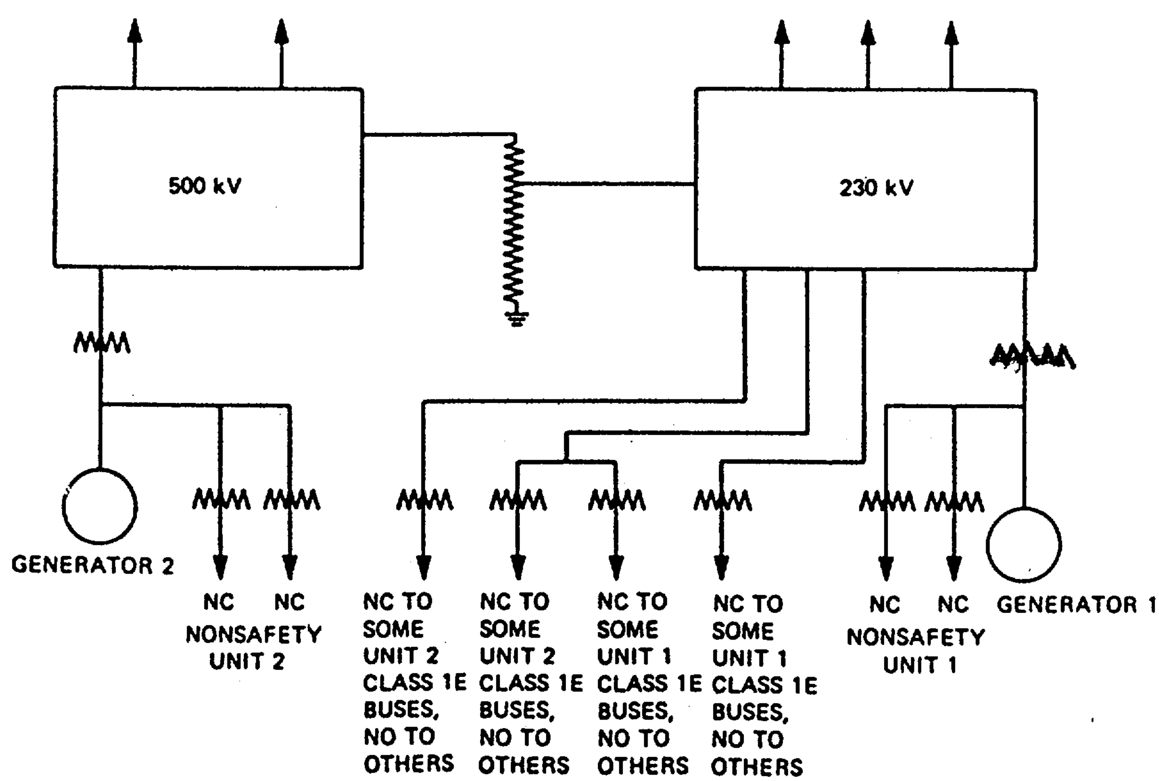

Figure 3. Schematic Diagram of Two Switchyards Electrically Connected (Two-Unit Site)

REFERENCES

1. U.S. Nuclear Regulatory Commission, "Reactor Safety Study," WASH-1400, October 1975.[1]

2. U.S. Nuclear Regulatory Commission, "Evaluation of Station Blackout Accidents at Nuclear Power Plants, Technical Findings Related to Unresolved Safety Issue A-44," NUREG-1032, June 1988.[1]

3. A. M. Rubin, "Regulatory/Backfit Analysis for the Resolution of Unresolved Safety Issue A-44, Station Blackout," U.S. Nuclear Regulatory Commission, NUREG-1109, June 1988.[1]

4. U.S. Nuclear Regulatory Commission, "Collection and Evaluation of Complete and Partial Losses of Offsite Power at Nuclear Power Plants," NUREG/CR-3992 (ORNL/TM-9384), February 1985.[1]

5. U.S. Nuclear Regulatory Commission, "Reliability of Emergency AC Power System at Nuclear Power Plants," NUREG/CR-2989 (ORNL/TM-8545), July 1983.[1]

6. U.S. Nuclear Regulatory Commission, "Emergency Diesel Generator Operating Experience, 1981-1983," NUREG/CR-4347 (ORNL/TM-9739), December 1985.[1]

7. U.S. Nuclear Regulatory Commission, "Station Blackout Accident Analyses (Part of NRC Task Action Plan A-44)," NUREG/CR-3226 (SAND82-2450), May 1983.[1]

8. Institute of Electrical and Electronics Engineers, "IEEE Standard for Preferred Power Supply for Nuclear Power Generating Stations," IEEE Std 765-1983, June 1983.[2]

9. Institute of Electrical and Electronics Engineers, "IEEE Standard Criteria for Diesel-Generator Units Applied as Standby Power Supplies for Nuclear Power Generating Stations," IEEE Std 387-1984, June 1984.[2]

10. Nuclear Management and Resources Council, "Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors," NUMARC-8700, November 1987.[3]

11. Electric Power Research Institute, "Reliability of Emergency Diesel Generators at U.S. Nuclear Power Plants," NSAC-108, September 1986.[4]

12. U.S. Nuclear Regulatory Commission, "Clarification of TMI Action Plan Requirements: Requirements for Emergency Response Capability" (Generic Letter 82-33), Supplement 1 to NUREG-0737, January 1983.[1]

13. U.S. Nuclear Regulatory Commission, "Guidelines for the Preparation of Emergency Operating Procedures," NUREG-0899, August 1982.[1]

[1]NRC publications may be obtained from the Superintendent of Documents, U.S. Government Printing Office, Post Office Box 37082, Washington, DC 20013-7082; or from the National Technical Information Service, Springfield, VA 22161.

[2]Copies may be obtained from the Institute of Electrical and Electronics Engineers Service Center, 445 Hoes Lane, P.O. Box 1331, Piscataway, NJ 08855.

[3]Copies may be obtained from the Nuclear Management and Resources Council, 1776 Eye Street NW., Washington, DC 20006.

[4]Copies may be obtained from the Electric Power Research Institute, Research Reports Center, P.O. Box 50490, Palo Alto, CA 94303.

APPENDIX A

QUALITY ASSURANCE GUIDANCE FOR NON-SAFETY SYSTEMS AND EQUIPMENT

The QA guidance provided here is applicable to non-safety systems and equipment used to meet the requirements of § 50.63 and not already explicitly covered by existing QA requirements in 10 CFR Part 50 in Appendix B or R. Additionally, non-safety equipment installed to meet the station blackout rule must be implemented so that it does not degrade the existing safety-related systems. This is accomplished by making the non-safety equipment as independent as practicable from existing safety-related systems. The guidance provided in this section outlines an acceptable QA program for non-safety equipment used for meeting the station blackout rule and not already covered by existing QA requirements. Activities should be implemented from this section as appropriate, depending on whether the equipment is being added (new) or is existing.

1. Design Control and Procurement Document Control

Measures should be established to ensure that all design-related guidelines used in complying with § 50.63 are included in design and procurement documents, and that deviations therefrom are controlled.

2. Instructions, Procedures, and Drawings

Inspections, tests, administrative controls, and training necessary for compliance with § 50.63 should be prescribed by documented instructions, procedures, and drawings and should be accomplished in accordance with these documents.

3. Control of Purchased Material, Equipment, and Services

Measures should be established to ensure that purchased material, equipment, and services conform to the procurement documents.

4. Inspection

A program for independent inspection of activities required to comply with § 50.63 should be established and executed by (or for) the organization performing the activity to verify conformance with documented installation drawings and test procedures for accomplishing the activities.

5. Testing and Test Control

A test program should be established and implemented to ensure that testing is performed and verified by inspection and audit to demonstrate conformance with design and system readiness requirements. The tests should be performed in accordance with written test procedures; test results should be properly evaluated and acted on.

6. Inspection, Test, and Operating Status

Measures should be established to identify items that have satisfactorily passed required tests and inspections.

7. Nonconforming Items

Measures should be established to control items that do not conform to specified requirements to prevent inadvertent use or installation.

8. Corrective Action

Measures should be established to ensure that failures, malfunctions, deficiencies, deviations, defective components, and nonconformances are promptly identified, reported, and corrected.

9. Records

Records should be prepared and maintained to furnish evidence that the criteria enumerated above are being met for activities required to comply with § 50.63.

10. Audits

Audits should be conducted and documented to verify compliance with design and procurement documents, instructions, procedures, drawings, and inspection and test activities developed to comply with § 50.63.

APPENDIX B

GUIDANCE REGARDING SYSTEM AND STATION EQUIPMENT SPECIFICATIONS

	Alternate AC Sources	Alternate Battery Systems
Safety-Related Equipment (Compliance with IEEE-279)	Not required, but the existing Class 1E electrical systems must continue to meet all applicable safety-related criteria.	Not required, but the existing Class 1E battery systems must continue to meet all applicable safety-related criteria.
Redundancy	Not required.	Not required.
Diversity from Existing EDGs	See Regulatory Position 3.3.5 of this guide.	Not required.
Independence from Existing Safety-Related Systems	Required if connected to Class 1E buses. Separation to be provided by 2 circuit breakers in series (1 Class 1E at the Class 1E bus and 1 non-Class 1E).	Required if connected to Class 1E battery systems. Separation to be provided by 2 circuit breakers in series (1 Class 1E at the Class 1E bus and 1 non-Class 1E).
Seismic Qualification	Not required.	Not required.
Environmental Consideration	If normal cooling is lost, needed for station blackout event only and not for design basis accident (DBA) conditions. Procedures should be in place to effect the actions necessary to maintain acceptable environmental conditions for the required equipment. See Regulatory Position 3.2.4.	If normal cooling is lost, needed for station blackout event only and not for accident conditions. Procedures should be in place to effect the actions necessary to maintain acceptable environmental conditions for the required equipment. See Regulatory Position 3.2.4.
Capacity	Specified in § 50.63 and Regulatory Position 3.3.5.	Specified in § 50.63 and Regulatory Position 3.3.1.
Quality Assurance	Indicated in Regulatory Position 3.5.	Indicated in Regulatory Position 3.5.
Technical Specification for Maintenance, Limiting Condition, FSAR, etc.	Should be consistent with the Interim Commission Policy Statement on Technical Specifications (Federal Register Notice 52 FR 3789) as applicable.	Should be consistent with the Interim Commission Policy Statement on Technical Specifications (Federal Register Notice 52 FR 3789) as applicable.
Instrumentation and Monitoring	Must meet system functional requirements.	Must meet system functional requirements.
Single Failure	Not required.	Not required.
Common Cause Failure (CCF)	Design should, to the extent practicable, minimize CCF between safety-related and non-safety-related systems.	Design should, to the extent practicable, minimize CCF between safety-related and non-safety-related systems.

APPENDIX B (Continued)

	Water Source (Existing Condensate Storage Tank or Alternative)	Instrument Air (Compressed Air System)	Water Delivery System (Alternative to Auxiliary Feedwater System, RCIC System, or Isolation Condenser Makeup)
Safety-Related Equipment (Compliance with IEEE-279)	Not required, but the existing Class 1E systems must continue to meet all applicable safety-related criteria.	Not required, but the existing Class 1E systems must continue to meet all applicable safety-related criteria.	Not required, but the existing Class 1E systems must continue to meet all applicable safety-related criteria.
Redundancy	Not required.	Not required.	Not required.
Diversity	Not required.	Not required.	Not required.
Independence from Safety-Related Systems	Ensure that the existing safety functions are not compromised, including the capability to isolate components, subsystems, or piping, if necessary.	Ensure that the existing safety functions are not compromised, including the capability to isolate components, subsystems, or piping, if necessary.	Ensure that the existing safety functions are not compromised, including the capability to isolate components, subsystems, or piping, if necessary.
Seismic Qualification	Not required.	Not required.	Not required.
Environmental Consideration	Need for station blackout event only and not for DBA conditions. See Regulatory Position 3.2.4. Procedures should be in place to effect the actions necessary to maintain acceptable environmental conditions for required equipment.	Needed for station blackout event only and not for DBA conditions. See Regulatory Position 3.2.4. Procedures should be in place to effect the actions necessary to maintain acceptable environmental conditions for required equipment.	Needed for station blackout event only and not for DBA conditions. See Regulatory Position 3.2.4. Procedures should be in place to effect the actions necessary to maintain acceptable environmental conditions for required equipment.
Capacity	Capability to provide sufficient water for core cooling in the event of a station blackout for the specified duration to meet § 50.63 and this regulatory guide.	Sufficient compressed air to components, as necessary, to ensure that the core is cooled and appropriate containment integrity is maintained for the specified duration of station blackout to meet § 50.63 and this regulatory guide.	The capacity to provide sufficient cooling water flow to ensure that the core is cooled in the event of a station blackout for the specified duration to meet § 50.63 and this regulatory guide.
Quality Assurance	As indicated in Regulatory Position 3.5.	As indicated in Regulatory Position 3.5.	As indicated in Regulatory Position 3.5.
Technical Specifications for Maintenance, Surveillance, Limiting Condition, FSAR, etc.	Should be consistent with the Interim Commission Policy Statement on Technical Specifications (Federal Register Notice 52 FR 3789) as applicable.	Should be consistent with the Interim Commission Policy Statement on Technical Specifications (Federal Register Notice 52 FR 3789) as applicable.	Should be consistent with the Interim Commission Policy Statement on Technical Specifications (Federal Register Notice 52 FR 3789) as applicable.
Instrumentation and Monitoring	Must meet system functional requirements.	Must meet system functional requirements.	Must meet system functional requirements.
Single Failure	Not required.	Not required.	Not required.

APPENDIX B (Continued)

	Water Source (Existing Condensate Storage Tank or Alternative)	Instrument Air (Compressed Air System)	Water Delivery System (Alternative to Auxiliary Feedwater System, RCIC System, or Isolation Condenser Makeup)
Common Cause Failure (CCF)	Design should, to the extent practicable, minimize CCF between safety-related and non-safety-related systems.	Design should, to the extent practicable, minimize CCF between safety-related and non-safety-related systems.	Design should, to the extent practicable, minimize CCF between safety-related and non-safety-related systems.

	RCS Makeup System (PWRs and BWRs Without RCIC)	Isolation Condenser (BWRs Without RCIC)	Instrumentation and Control Room Indications for Verification of RCS Natural Circulation (PWRs and BWRs Without RCIC)
Safety-Related Equipment (Compliance with IEEE-279)	Not required, but the existing Class 1E systems must continue to meet all applicable safety-related criteria.	Not required, but the existing Class 1E systems must continue to meet all applicable safety-related criteria.	Not required, but the existing Class 1E systems must continue to meet all applicable safety-related criteria.
Redundancy	Not required.	Not required.	Not required.
Diversity	Not required.	Not required.	Not required.
Independence from Safety-Related Systems	1. Safety-grade isolation devices required between this RCS makeup system and existing safety-related makeup water systems. 2. A malfunction of this non-safety-grade makeup system should not affect the design safety function of any safety-related systems.	1. Safety-grade isolation devices required between this system and existing safety-related systems. 2. A malfunction of this non-safety-related system should not affect the design safety function of any safety-related systems.	A malfunction of this instrumentation and monitoring system should not affect the design safety function of any safety-related instrumentation and monitoring systems powered by onsite or offsite ac power buses.
Seismic Qualification	Not required.	Not required.	Not required.
Environmental Consideration	Needed for station blackout event only and not for DBA conditions if normal cooling is lost. See Regulatory Position 3.2.4. Procedures should be in place to effect the actions necessary to maintain acceptable environmental conditions for the required equipment.	Needed for station blackout event only and not for DBA conditions if normal cooling is lost. See Regulatory Position 3.2.4. Procedures should be in place to effect the actions necessary to maintain acceptable environmental conditions for the required equipment.	Needed for station blackout event only and not for DBA conditions if normal cooling is lost. See Regulatory Position 3.2.4. Procedures should be in place to effect the actions necessary to maintain acceptable environmental conditions for the required equipment.
Capacity	Sufficient RCS makeup so that core temperatures are maintained at acceptably low values considering a loss of RCP water inventory through a postulated RCP seal failure during the specified duration of station blackout, with a minimum assumed RCP seal leakage of 20 gpm per RCP, unless a lower value is justified.	Provide sufficient capacity for decay heat removal. During the specified duration of station blackout, the isolation condenser pool side requires a water makeup system powered by sources independent from onsite and offsite ac buses.	Provide sufficient instrumentation and control room indications for parameters required for verification of RCS natural circulation during the specified duration of station blackout.
Quality Assurance	As indicated in Regulatory Position 3.5.	As indicated in Regulatory Position 3.5.	As indicated in Regulatory Position 3.5.

	RCS Makeup System (PWRs and BWRs Without RCIC)	Isolation Condenser (BWRs Without RCIC)	Instrumentation and Control Room Indications for Verification of RCS Natural Circulation (PWRs and BWRs Without RCIC)
Technical Specifications for Maintenance, Surveillance, Limiting Condition, FSAR, etc.	Should be consistent with the Interim Commission Policy Statement on Technical Specifications (Federal Register Notice 52 FR 3789) as applicable.	Should be consistent with the Interim Commission Policy Statement on Technical Specifications (Federal Register Notice 52 FR 3789) as applicable.	Should be consistent with the Interim Commission Policy Statement on Technical Specifications (Federal Register Notice 52 FR 3789) as applicable.
Instrumentation and Monitoring	Must meet system functional requirements.	Must meet system functional requirements.	–––
Single Failure	Not required.	Not required.	Not required.
Common Cause Failure (CCF)	Design should, to the extent practicable, minimize CCF between safety-related and non-safety-related systems.	Design should, to the extent practicable, minimize CCF between safety-related and non-safety-related systems.	Design should, to the extent practicable, minimize CCF between safety-related and non-safety-related systems.

*U.S. GOVERNMENT PRINTING OFFICE:1988-202-292:80149

REGULATORY ANALYSIS

A separate regulatory analysis was not prepared for this regulatory guide. The regulatory analysis prepared for the station blackout rule, NUREG-1109, "Regulatory/Backfit Analysis for the Resolution of Unresolved Safety Issue A-44, Station Blackout," provides the regulatory basis for this guide and examines the costs and benefits of the rule as implemented by the guide. A copy of NUREG-1109 is available for inspection and copying for a fee at the NRC Public Document Room, 1717 H Street NW., Washington, DC 20555. Copies of NUREG-1109 may be purchased from the Superintendent of Documents, U.S. Government Printing Office, Post Office Box 37082, Washington, DC 20013-7082; or from the National Technical Information Service, Springfield, VA 22161.

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NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555

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Exhibit E

Affidavit of Roland Beem

BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

EXELON GENERATION LLC,	)	
	)	
Petitioner,	)	
	)	
v.	)	PCB
	)	(Variance- Air)
ILLINOIS ENVIRONMENTAL	)	
PROTECTION AGENCY,	)	
	)	
Respondent.	)	

AFFIDAVIT OF ROLAND BEEM

I, Roland Beem, having first been duly sworn upon oath, depose and state as follows:

1. I am the Environmental Programs Manager for Exelon Generation. In that role, I am responsible for environmental policy and compliance. I joined the company as Environmental Programs Manager in December 2013.

2. My duties and responsibilities at Exelon Generation specifically include corporate responsibility for staff management and oversight of the Environmental Programs department, including such activities as the preparation of this Petition for Variance.

3. I participated in the development of the this Petition for Variance.

4. I have read the foregoing Petition for Variance, and based upon my personal knowledge, and information and belief after reasonable inquiry of others with more specific knowledge, the facts stated therein are true and correct.

Further affiant sayeth not.

County of DuPage)
State of Illinois) SS

Roland D. Beem

Roland Beem

Subscribed and sworn to before me this 12th day of May, 2016.

Carolyn V Polos

Notary Public

"OFFICIAL SEAL"
CAROLYN V POLOS
Notary Public, State of Illinois
My Commission Expires 1/26/2018

BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

EXELON GENERATION LLC,	)	
	)	
Petitioner,	)	
	)	
v.	)	PCB
	)	(Variance- Air)
ILLINOIS ENVIRONMENTAL	)	
PROTECTION AGENCY,	)	
	)	
Respondent.	)	

APPEARANCE OF BYRON F. TAYLOR

I hereby file my appearance in this proceeding, on behalf of Exelon Generation LLC.

Dated: May 18, 2016

/s/ Byron F. Taylor

Byron F. Taylor
SIDLEY AUSTIN LLP
One South Dearborn
Chicago, Illinois 60603
Phone: (312) 853-4717
bftaylor@sidley.com

BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

EXELON GENERATION LLC,	)	
	)	
Petitioner,	)	
	)	
v.	)	PCB
	)	(Variance- Air)
ILLINOIS ENVIRONMENTAL	)	
PROTECTION AGENCY,	)	
	)	
Respondent.	)	

APPEARANCE OF KATHARINE F. NEWMAN

I hereby file my appearance in this proceeding, on behalf of Exelon Generation LLC.

Dated: May 18, 2016

/s/ Katharine F. Newman

Katharine F. Newman
SIDLEY AUSTIN LLP
One South Dearborn
Chicago, Illinois 60603
Phone: (312) 853-2038
knewman@sidley.com

CERTIFICATE OF SERVICE

I, the undersigned, certify that on May 18, 2016, I electronically and by U.S. Mail, served the attached **Petition for Variance, Appearance of Byron F. Taylor** and **Appearance of Katharine Newman** on the following persons:

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Dana Vetterhoffer
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/s/ Katharine F. Newman_

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knewman@sidley.com

Dated: May 18, 2016