INL/RPT-23-72105
Revision 0

Safety-Related Instrumentation and Control Pilot Upgrade: Conceptual - Detailed Design Phase Report and Lessons Learned

June 2023

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EXECUTIVE SUMMARY

The commercial nuclear sector faces unprecedented financial challenges. These circumstances, along with increasingly antiquated labor-centric operating models and analog technology, have forced the early closure of multiple nuclear facilities and placed a much larger population of nuclear stations at risk. To enable economic survival in current and forecasted market conditions, nuclear plants require an efficient and technology-centric operating model that harvests the native efficiencies of advanced technology, which is analogous to transformations that have occurred in other industries.

Historically, regulatory barriers have largely precluded the modernization of nuclear plant first-echelon safety-related (SR) instrumentation and control (I&C) systems to support this transformation. These barriers have now been largely addressed through collaboration between industry leaders and the Nuclear Regulatory Commission. These advances enable the modernization of key safety systems through the streamlined license amendment request alternate review process reflected in Digital Instrumentation and Controls Interim Staff Guidance #06 (DI&C-ISG-06), Revision 2, *Licensing Process* [1]. While regulatory advances have improved the environment for modernizing safety systems, the industry has remained reluctant to perform such I&C upgrades because of perceived regulatory and financial risks associated with being the first adopter of the Reference 1 alternate review process for highly critical reactor protection systems.

Constellation Energy Generation (CEG), with the support of the United States Department of Energy, is working to break this impasse through the SR I&C upgrade project at CEG's Limerick Generating Station (LGS). This project is being performed in accordance with industry processes that have been adapted to better support digital upgrades. These processes include IP-ENG-001, *Standard Design Process* [2], NISP-EN-04, *Standard Digital Engineering Process* [3], and Electric Power Research Institute (EPRI) Report 3002011816, *Digital Engineering Guide* (DEG)[4].

The Light Water Reactor Sustainability Program at the Idaho National Laboratory has been supporting this effort. Initial scoping phase activities as described in the EPRI DEG and associated lessons learned for this pilot project have been captured in INL/EXT-20-59809, "Safety-Related I&C Pilot Upgrade Initial Scoping Phase Implementation Report and Lessons Learned" [5]. These activities ultimately culminated in CEG management authorizing the project to proceed into the conceptual design and detailed design phases.

This research report describes the process followed during the SR I&C pilot project conceptual design phase and portions of the detailed design phase. It also captures associated lessons learned. It is recommended that reference 5 be reviewed prior to reading this document. Those already familiar with it should start their review of this document at Section 2, which summarizes conceptual design and detailed design activities through September 2022. Efforts are categorized as:

- Engineering and operations activities
- Licensing activities
- Project management and procurement activities.

Section 3 of this report summarizes lessons learned following a similar structure as Section 2. Sharing of these lessons learned is in keeping with the public-private partnership between the Department of Energy (DOE) and CEG to implement an SR I&C digital upgrade as a model for the industry. This research report makes no commitments for CEG.

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CONTENTS

FIGURES

TABLES

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ACRONYMS

ADS	Automatic Depressurization System
AEL	Affected Equipment List
AR	Alternate Review
AOT	Allowable Outage Time
ATWS	Anticipated Transient Without Scram
BTR	Bounding Technical Requirements
BWR	Boiling-Water Reactor
CCF	Common Cause Failure
CEG	Constellation Energy Generation
CFR	Code of Federal Regulations
Common Q	Common Qualified Platform®
CRS	Control Room Supervisor
CTA	Cognitive Task Analysis
CS	Core Spray
CV	Conceptual Verification
D3	Defense in Depth and Diversity
DI&C	Digital Instrumentation and Controls
DI&C-ISG-04	Digital Instrumentation and Controls Interim Staff Guidance #04
DI&C-ISG-06	Digital Instrumentation and Controls Interim Staff Guidance #06
DAS	Diverse Actuation System
DBD	Design Basis Document
DCS	Distributed Control System
DPS	Diverse Protection System
DEG	Digital Engineering Guide
DOE	Department of Energy
DOR	Division of Responsibility
EC	Engineering Change
ECCS	Emergency Core Cooling Systems[1]
EQ	Equipment Qualification
EPRI	Electric Power Research Institute
FAT	Factory Acceptance Test
FSSD	Fire Safe Shutdown
FMEA	Failure Modes and Effects Analysis
FOAK	First-of-a-kind

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[1] Comprised of separate functions for Core Spray (CS), High Pressure Coolant Injection, the Low Pressure Coolant Injection (LPCI) mode of Residual Heat Removal, and Automatic Depressurization System (ADS). The Reactor Core Isolation Cooling System (RCIC) also provides emergency core cooling capability. RCIC is identified as a separate system in plant design documentation. It is grouped with ECCS in this research document for convenience and incorporated into the Plant Protection System (PPS).

HFE	Human Factors Engineering
HSI	Human-System Interface
I&C	Instrumentation and Control
INL	Idaho National Laboratory
ISV	Integrated System Validation
LAR	License Amendment Request
LGS	Limerick Generating Station Units 1 and 2
LLC	Limited Liability Company
LWR	Light-Water Reactor
LWRS	Light Water Reactor Sustainability (Program)
LTR	Licensing Technical Report
MCR	Main Control Room
N4S	Nuclear Steam Supply Shutoff System
NEI	Nuclear Energy Institute
NRC	Nuclear Regulatory Commission (United States)
NSR	Non-Safety Related
OEM	Original Equipment Manufacturer
OI	Open Item
PPS	Plant Protection System
PRA	Probabilistic Risk Assessment
PRO	Plant Reactor Operator
PV	Preliminary Validation
RCIC	Reactor Core Isolation Cooling
RFI	Request for Information
RFP	Request for Proposal
RICT	Risk-Informed Completion Times
RO	Reactor Operator
RPS	Reactor Protection System
RRCS	Redundant Reactivity Control System
RSR	Results Summary Report
SAT	Site Acceptance Test
SER	Safety Evaluation Report
SHA	Software Hazard Analysis
SME	Subject Matter Expert
SR	Safety-Related
SRV	Safety Relief Valve
SSCs	Structures, Systems, and Components
SyDS	System Design Specification
SyRS	System Requirements Specification

TE	Turbine Enclosure
TCO	Total Cost of Ownership
TS	Technical Specification(s)
UCA	Unsafe Control Action
UFSAR	Updated Final Safety Analysis Report
VDU	Video Display Unit
VOP	Vendor Oversight Plan

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Safety-Related Instrumentation and Control Pilot Upgrade: Conceptual - Detailed Design Phase Report and Lessons Learned

1. INDUSTRY NEED AND UPGRADE STRATEGY

1.1. Problem Statement

Currently installed light-water reactor (LWR) first-echelon instrumentation and control (I&C) safety systems have performed their functions admirably. Costs associated with sustaining efforts for older systems, however, are rising rapidly. Unless this situation is addressed, it will be increasingly difficult to technologically sustain or economically justify the continued operation of existing LWRs for their current license durations and for subsequent extended license renewal periods.

To meet the industry need and overcome industry reluctance in performing first-echelon I&C safety related (SR) systems, the Light Water Reactor Sustainability (LWRS) Program at the Idaho National Laboratory (INL), in close coordination with Constellation Energy Generation (CEG), embarked on an SR I&C pilot upgrade project to demonstrate the viability of executing such an effort. At same time, the pilot upgrade effort endeavors to create a process and product roadmap for other utilities to follow.

1.2. Safety-Related Pilot Upgrade Strategy and Scope

1.2.1. Plantwide Concept of Operations

The LWRS Plant Modernization Pathway, with input from CEG, has developed a design concept for first-echelon boiling-water reactor (BWR) safety system I&C upgrades as a key enabler for a larger concept of operations that moves an existing plant from a labor-centric analog domain to a technology-centric digital domain, as illustrated in Figure 1.

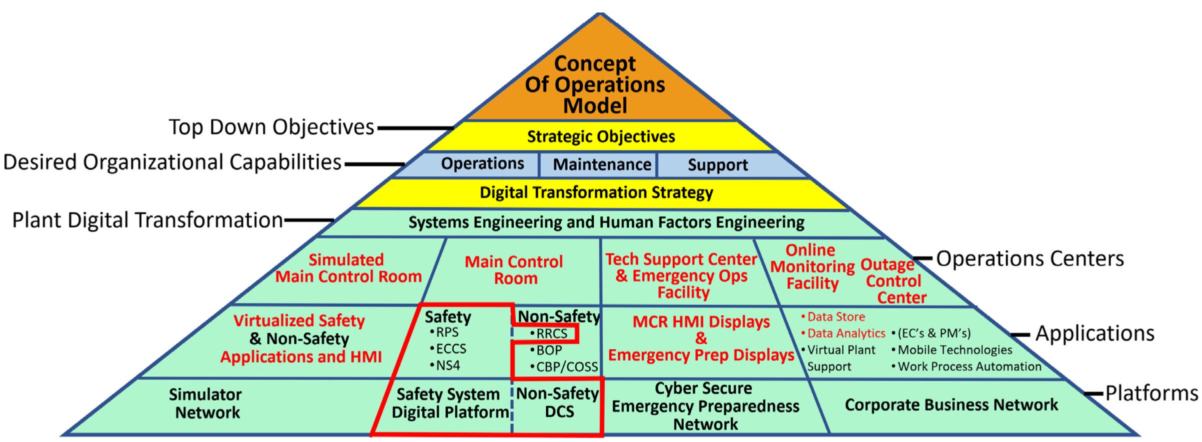


Figure 1. Advanced concept of operations model, with the safety-related I&C pilot scope outlined in red.

The advanced concept of operations model shown in Figure 1 establishes requirements and constraints for all plant and work function modernization efforts, ensuring strategic business objectives are achieved. Nuclear power plant budgets are created using a market-based electricity price point to derive total operating, maintenance, and support costs to support this price (top down). Work is also analyzed for opportunities to aggressively focus workload on essential functions that can be resourced within available budgets (bottom up). Work functions are then configured into the operating model. Process innovations and technologies are then applied as an integrated set by using systems engineering and human factors engineering (HFE). This promotes a business-driven digital transformation strategy that reformulates the traditional labor-centric model to a technology-centric model. This transformation lends itself to fewer onsite staff focused on daily operations, increasing plant safety, reliability, and situational awareness. The transformation strategy, along with process changes, supports employing centralized maintenance and support functions or outsourcing these functions to on-demand service models.

A tenet directing the larger digital transformation strategy in general and the SR I&C pilot upgrade project in particular is that the replacement of current equipment is not to simply to provide like-for-like functionality compared to the existing equipment. Instead, digital upgrades will fully leverage the capabilities of the technology as part of a holistic effort to establish a "new state" that reduces the total cost of ownership (TCO) for facilities that deploy them for the balance of the plant operating period.

1.2.2. Basic Safety-Related Instrumentation and Control Pilot Project Scope

The basic scope of the BWR SR I&C pilot upgrade project within the larger digital transformation strategy is outlined in red in Figure 1 and includes:

- A common, SR, plant protection system (PPS) platform that will implement the functions of the following BWR systems as applications:
  - Reactor protection system (RPS)
  - Nuclear steam supply shutoff system (N4S)—also referred to as the primary containment isolation system in other BWRs
  - Emergency core cooling systems (ECCS).
- A non-safety related (NSR) platform to host the existing SR redundant reactivity control system (RRCS) function. In accordance with 10 CFR 50.62, *Requirements for reduction of risk from anticipated transients without scram (ATWS) events for light-water-cooled nuclear power plants* [6], the RRCS must remain fully independent of the PPS (transmitters may be shared) but does not have to be constructed of SR components. Consequently, the RRCS will be upgraded using a NSR distributed control system (DCS). This DCS is expected to host most of the NSR functions in the unit. This includes a segment of the DCS to receive data from the PPS and perform the channel check function, alerting the operator to significant disagreement in PPS and RRCS inputs.

This basic scope was established at the pilot inception. As a result of the initial scoping phase activities [5], the project scope was expanded to include the LGS plant systems listed in Table 1.

Table 1. In-scope system list.

Plant System Code	Existing Primary System	Existing Subsystem I&C Electronics	Target Replacement Platform
001	N4S	Main Steam	PPS
025	N4S	Temperature Monitoring	PPS
026	N4S	Radiation and Meteorological Monitoring System	PPS
036	RRCS	RRCS	NSR DCS
041	ECCS	Main Steam/Automatic Depressurization System (ADS)	PPS
042	Common	Nuclear Boiler Instrumentation	PPS
044	N4S	Reactor Water Cleanup	PPS
046	RPS	Control Rod Drive	PPS
048	RRCS	Standby Liquid Control	NSR DCS
049	ECCS	Reactor Core Isolation Cooling (RCIC)	PPS
050	ECCS	ADS	PPS
051	ECCS	Residual Heat Removal	PPS
052	ECCS	Core Spray	PPS
055	ECCS	High-Pressure Coolant Injection	PPS
056	ECCS	High-Pressure Coolant Injection	PPS
059	N4S	Primary Containment Instrument Gas & Traversing Incore Probe Power Supply	PPS
071	RPS	RPS	PPS
072	N4S	N4S	PPS
076	N4S	Heating, Ventilation, and Air Conditioning (HVAC)	PPS
092	ECCS	Emergency Diesel Generators	PPS

In the initial scoping phase, a tenet was also established that both the PPS and NSR DCS will be expandable. The PPS and NSR DCS are intended to become the 'target platforms' onto which the functions of other obsolete I&C systems are migrated. Over time, the number of diverse I&C systems will be substantially reduced. This is shown in the simplified digital infrastructure diagram provided in Figure 2, which shows the PPS in red and the NSR DCS in green.

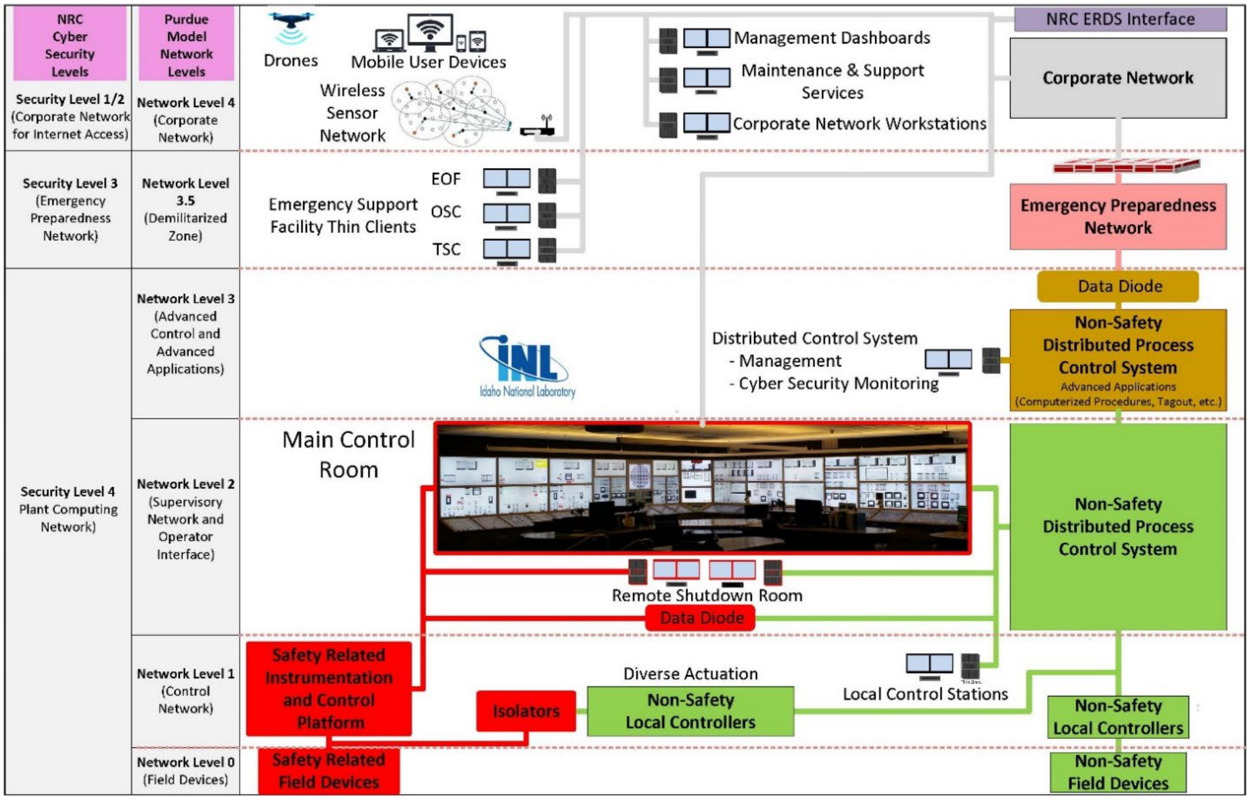


Figure 2. Simplified digital infrastructure generic framework for nuclear.

As shown in Figure 2 as taken from INL/EXT-21-64580, "Digital Infrastructure Migration Framework," digital I&C upgrades form the foundation for this larger digital infrastructure [7]. By digitizing I&C plant information and passing it unidirectionally to other data networks above them, as shown in Figure 2, remote monitoring and data analytics capabilities are enabled to further reduce the TCO. The digital infrastructure concept is more fully presented in Reference 7. Coordinating I&C technology upgrades with training simulator upgrades also reduces facility TCO. Data sharing opportunities and simulator coordination are reflected in the red text items in Figure 1.

1.2.3. Design Tenets as Applied to the Project Scope

Design tenets of the SR I&C pilot upgrade project upgrade strategy were also established during the initial scoping phase [5]. A truncated description of these tenets, as described in Reference 5 and implemented by CEG for LGS, are:

- Minimizing I&C upgrade development and implementation costs as well as technical and licensing risk by applying state-of-the-industry process control technology to the maximum extent practicable
    - CEG chose the Westinghouse Common Qualified (Common Q®) Platform as generically approved for first-echelon safety system use by the Nuclear Regulatory Commission (NRC). Using Common Q for the PPS enables use the streamlined alternate review (AR) process defined in DI&C-ISG-06, Revision 2, "Licensing Process."
    - CEG chose the Emerson Ovation® platform as provided through Westinghouse for their non-safety DCS.
- Leveraging the enhanced reliability of digital technology. Using the proven platforms above significantly reduces the potential for design errors in the platform software. Increased component reliability and component count reduction when transitioning from analog to digital will significantly improve system and plant reliability and availability.

- Leveraging the capability of Common Q and Ovation to digitally capture and correlate plant data for those systems serviced by the new digital I&C platforms. Augmenting the existing functionality provides data and control capability previously unavailable to operators in the main control room (MCR). This will eliminate actions remote operating stations (e.g., the auxiliary equipment room). Trending, diagnostic, and prognostic features enabled by the availability of this data can be used to improve plant performance and reduce time-based maintenance activities.
- Minimizing plant acquisition and lifecycle costs for modernization by eliminating diverse, legacy I&C systems by:
  - Consolidating the functions of the identified safety I&C systems on the PPS, which reduces the total system part count by ~75%. This, along with digital system design, reduces surveillance and calibration costs for maintaining the equipment as well as acquisition, installation, and lifecycle support costs.
  - Consolidating the RRCS anticipated transient without scram (ATWS) and any necessary PPS diverse actuation system (DAS) functionality on a diverse NSR DCS. By consolidating ATWS and DAS functionality on the single envisioned NSR DCS, there is no need for a separate system to host DAS functionality. Consolidating NSR I&C functionality, including DAS functionality, on a DCS has the same effect of reducing equipment count and diversity.
  - Providing a human-system interface (HSI) architecture for the PPS and DCS that provides a flexible solution for the MCR. During the conceptual design phase and portion of the detailed design phase of the project captured in this report, INL supported CEG in addressing planning and analysis phases of NUREG-0711, "Human Factors Engineering Program Review Model" [8].
- Standardizing designs. By using standard Common Q and Ovation building blocks, the number of disparate parts in the new platforms are reduced. A further migration of other legacy functions to the SR platform and NSR DCS not addressed by this upgrade will be able to use these standard building blocks and associated development tools, standardizing design processes while supporting further supply chain consolidation benefits.
- Reducing direct operating and maintenance costs associated with sustaining the replacement I&C systems for up to an 80-year plant life. Both Common Q and Ovation include advanced fault detection and self-diagnostics features to minimize operating and maintenance costs compared to current analog systems at LGS.
- Managing technology obsolescence. Digital equipment is also susceptible to technology obsolescence. Common Q and Ovation have obsolescence management strategies to maintain and refresh the digital capabilities they provide.
- Enabling a "design once, build many" approach. CEG plans to leverage the upgrade efforts performed on LGS Unit 1 on LGS Unit 2. Furthermore, engineering, licensing, and project management deliverables produced by the pilot will be made available to the nuclear industry to the maximum extent possible so that they can be leveraged to economically perform similar upgrade projects across the industry as a foundation for a larger digital transformation.

1.2.4. Pilot Project Execution Approach

The SR I&C pilot upgrade project is demonstrating the use of the latest industry guidance in the implement I&C upgrades. First-echelon SR I&C upgrade efforts led by CEG are employing the Standard Design Process [2], Standard Digital Engineering Process [3], and the Electric Power Research Institute (EPRI) Digital Engineering Guide (DEG) [4]. By using these industry standard processes, the concepts and methods become fully transportable to all nuclear plant owner-operators.

Figure 3, taken from Section 4 of EPRI DEG, visually represents the overall upgrade process.

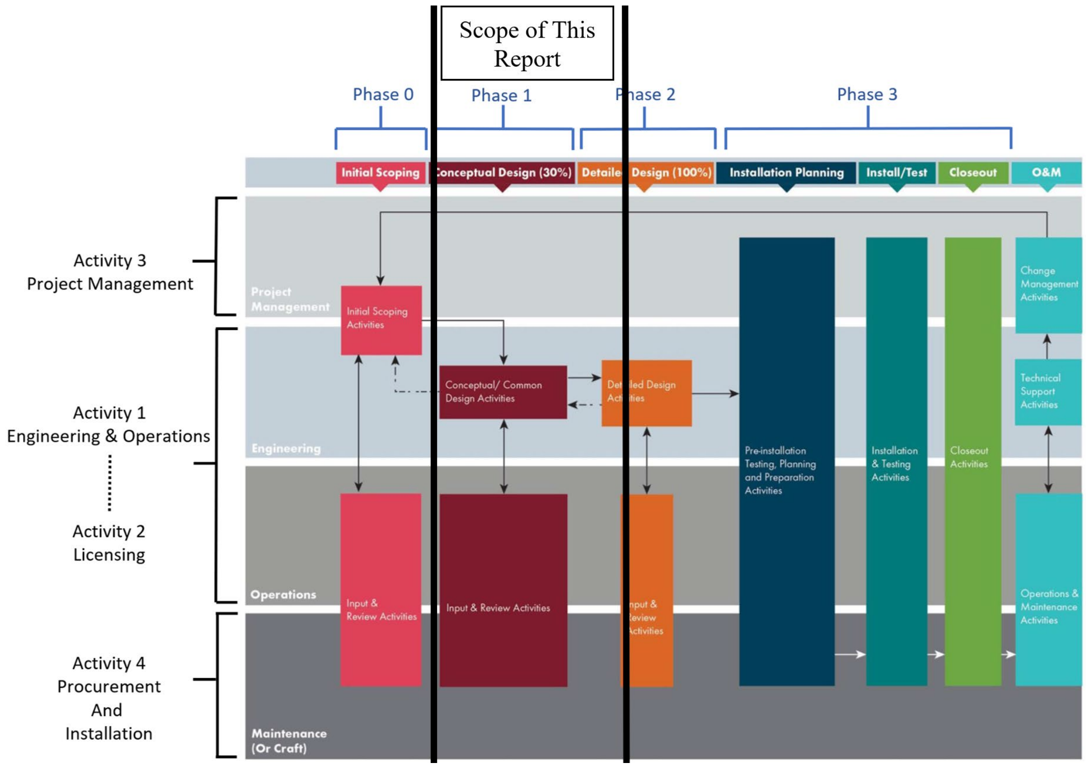


Figure 3. PPS and RRCS design change swimlane diagram.

Phases for the project directly follow this template and include:

- **Phase 0:** Initial Scoping
- **Phase 1:** Conceptual Design
- **Phase 2:** Detailed Design
- **Phase 3:** Implementation (which includes Installation Planning, Install/Test, and Closeout).

Project activities depicted in Figure 3 are performed as described in the EPRI DEG. This research report describes the activities taken and lessons learned associated with Phase 1 and 2 efforts through September 2022.

Subsequent research reports will describe the activities taken and lessons learned for Phase 2 and 3 efforts.

Project activities are grouped differently (as shown on the left of Figure 3) in this document for several reasons described below. Project phase activities are broken into four main categories:

- **Activity 1 – Engineering & Operations**: These two areas are very closely intertwined in this effort. Engineering services provided by vendors and subcontractors are also included here.
- **Activity 2 – Licensing**: While included with engineering in the EPRI DEG, licensing is broken out separately here as Activity 2 to more clearly define licensing deliverables and how these deliverables support using the DI&C-ISG-06, Revision 2, AR process.

- **Activity 3 – Project Management**: This activity guides all the others and is broken out separately as provided in the DEG. This also clearly defines key project management authorization milestones.
- **Activity 4 – Procurement and Installation**: This includes specific efforts associated with hardware and software procurement and installation. This activity is combined with project management for the scope of this report.

1.2.5. Pilot Project Licensing Approach

A prerequisite to implementing a first-echelon, SR I&C upgrade is to submit an license amendment request (LAR) to the NRC for approval. The process for LAR submission and approval provided in DI&C-ISG-06, Revision 2 [1] for the AR process is depicted in Figure 4 on the following page.

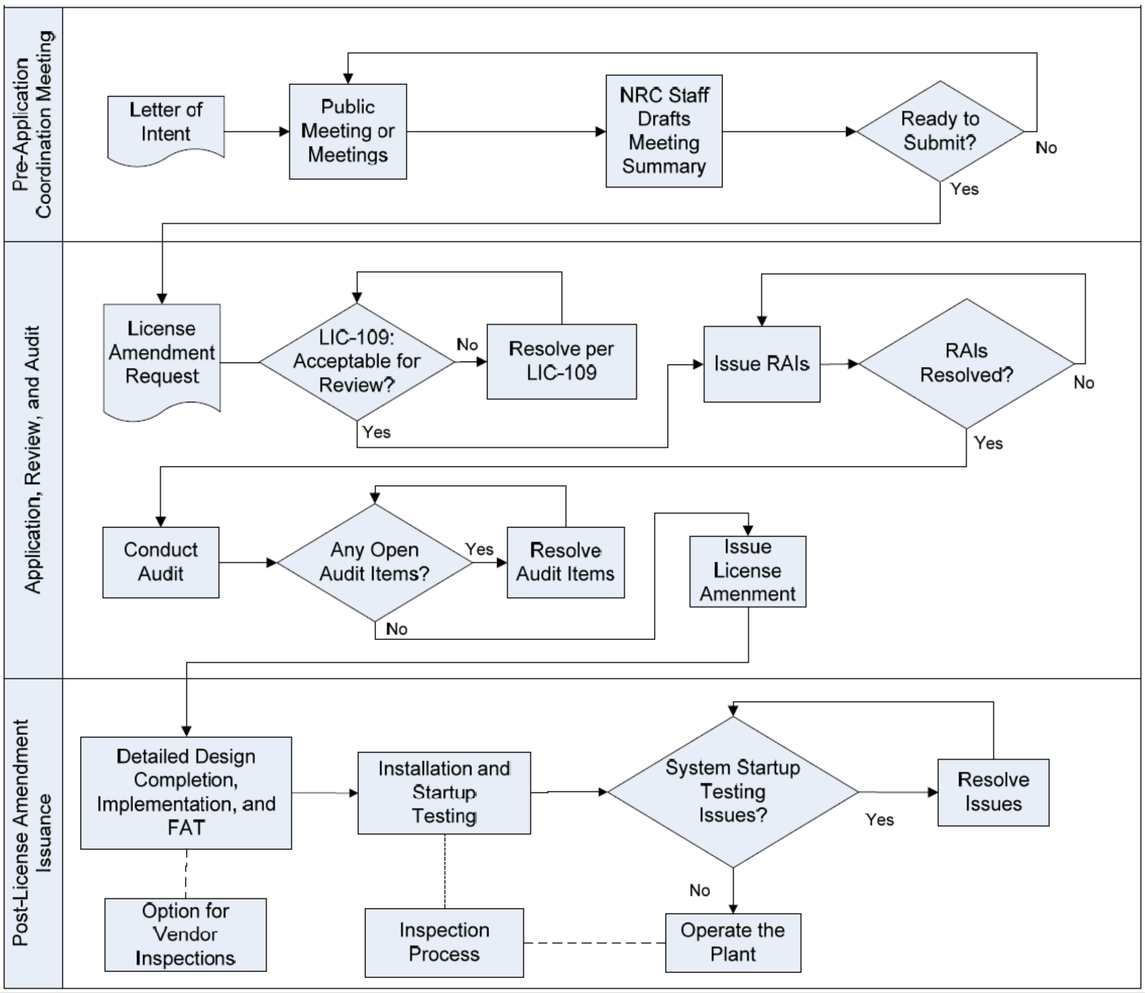


Figure 4. AR process from DI&C-ISG-06, Revision 2.

The LAR must describe how the use of the selected platform for the proposed design will meet design and licensing basis requirements. This pilot project requires a LAR for the SR PPS upgrade. No LAR is expected for the RRCS upgrade; however, the final RRCS design may impact existing technical specification (TS) wording, and these impacts may need to be included in the LAR. The RRCS upgrade will be performed pursuant with 10 CFR 50.69, *Risk-informed categorization and treatment of structures, systems and components for nuclear power reactors* [9] and 10 CFR 50.62 [6]. For the Phase 0, sufficient design concept and licensing strategy development occurred to establish implementing utility confidence to authorize proceeding to Phase 1.

Initial scoping phase licensing activities, in addition to supporting authorization to proceed with Phase 1, provided CEG with sufficient information to submit a letter of intent to proceed with the upgrade, as depicted in Figure 4.

Licensing activities from the completion of the initial scoping phase to September 2022 are presented in Section 2.2.

2. CONCEPTUAL DESIGN AND DETAILED DESIGN PHASES: ACTIVITIES AND DELIVERABLES

At the completion of the initial scoping phase, CEG authorized project conceptual design activities in December 2020. The conceptual design phase was declared complete in November 2021 and detailed design phase activities were authorized.

Conceptual design and detailed design phase I&C system design activities and associated products produced through September 2022 are described in Section 2.1. These were worked in parallel with licensing activities and associated products (Section 2.2) and project management activities and associated products (Section 2.3).

2.1. Engineering and Operations Conceptual Design and Detailed Design Phase Activities and Deliverables

Guidance regarding conceptual and detailed design phase engineering and operations activities is contained within Section 4.1 of the EPRI DEG and is best described by examining the systems engineering Vee model presented in Section 4 of the EPRI DEG [4]. The systems engineering Vee model is shown in Figure 5. Additional V-models exist within the process, such as the hardware and software V-models.

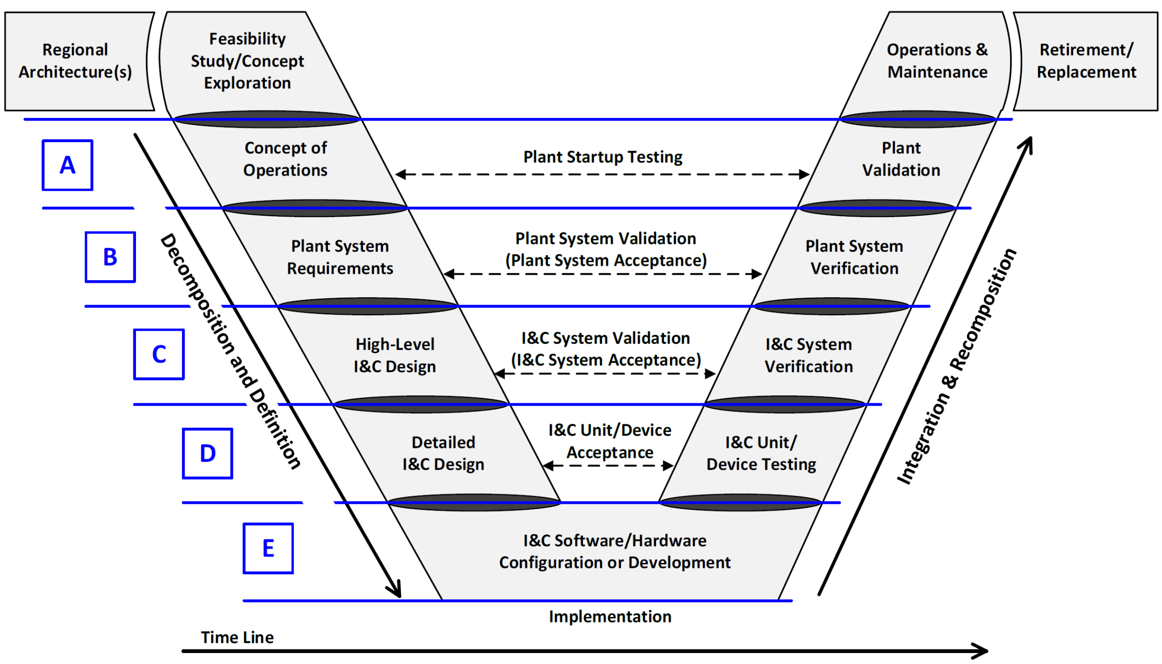


Figure 5. Systems engineering Vee model from the EPRI DEG [4].

The following subsections present in more detail how items on the left side of the EPRI DEG Vee model in Figure 5 were addressed by the engineering and operations activities. The conceptual design phase addressed Items A and B and culminated in Item C on the left side of Figure 5. Detailed design phase efforts through September 2022 are primarily addressing Item D.

Engineering and operations design activities address two specific but related disciplines. The first is the design of the I&C systems themselves. This effort ensures that the functions to be performed by the selected platforms for the PPS (Common Q) and DCS (Ovation) are identified and that these systems are properly configured to support necessary monitoring and control features needed to enable plant function. This I&C system design effort also addresses all the other aspects associated with physically interfacing the PPS and DCS to the rest of the plant. This includes accounting for sensor and actuator connectivity, needed space for platform equipment, supplying power to the equipment, cable routing, system redundancy requirements, environmental requirements, seismic qualification, etc. These efforts are described in Section 2.1.1.

The second engineering and operations design discipline is HFE. The I&C systems being modernized as part of this upgrade also have to optimally interface with the operators that will use them to monitor and control the plant. The HSIs designed for the upgrade need to not only enable plant operators to utilize the specific capabilities provided by the new I&C systems but also ensure that the new HSIs can support the larger concept of operations of the plant through the careful integration of the new HSIs with existing HSI in the MCR. These efforts are described in Section 2.1.2.

2.1.1. Instrumentation and Control

This subsection describes I&C engineering & operations activities for the conceptual design and detailed design phases that occurred through September 2022.

- Section 2.1.1.1 describes the development of a division of responsibility (DOR), which is unique to the conceptual design phase.
- Section 2.1.1.2 of this report addresses multiple activities undertaken during the conceptual design phase, as identified in Section 4.2 of the EPRI DEG [4].
- Section 2.1.1.3 of this report addresses activities undertaken during the detailed design phase in Section 4.3 of the EPRI DEG. Section 4.3 shows that the seven listed activities are to "perform or confirm" activities that were initiated in Section 4.2 of the EPRI DEG. Section 2.1.1.3 of this report addresses those efforts performed during the detailed design phase of the LGS SR I&C Upgrade Project through September 2022.

2.1.1.1. Division of Responsibility

As identified in Section 4.2.1 of the EPRI DEG [4], a DOR for project participants and vendors is developed in the conceptual design phase. This is necessary to properly allocate responsibility to complete project activities. While DOR development is a project management activity, it, along with the project schedule, governs all project activities.

Attachment A, "Activity Applicability and DOR Worksheet," from the EPRI DEG was leveraged and adapted to develop a detailed DOR for this project, which has been revised and updated as necessary as the project has progressed. The current detailed DOR is provided as Attachment A and is summarized as:

- CEG:
    - Overall project management.
    - Provision of design-related information to support drawings, specifications, and setpoints.
    - Joint support of input and output definition (units, ranges, sensor types, transmitters, etc.).
    - Review and approval of vendor documentation.
    - Provide power feeds and upstream protective device information, design conduits, raceways, and specifications for new field (plant) ground, power, and instrumentation cable.
    - Observation of factory acceptance test (FAT), site acceptance test (SAT) execution, and modification acceptance test development and execution.

- Develop utility design change packages. Complete required documentation for facility changes not included in LAR and licensing technical report (LTR) in accordance with 10 CFR 50.59, "Changes, tests and experiments" [41].
- HFE program development and execution as supported by INL.

- Westinghouse:
  - Project management of activities contracted to Westinghouse.
  - Development of systems requirements specifications and system design specifications (SyDSs) based on CEG inputs.
  - Design and integration activities for the PPS (Common Q) and non-safety DCS (Ovation).
  - Development of a defense in depth and diversity (D3) analysis for the PPS.
  - Delivery and configuration of hardware and software for the PPS and DCS.
  - Electrical and mechanical interface support to permit installation of Westinghouse-provided hardware at LGS.
  - Development of HSIs as directed by CEG design inputs and HFE program activities.
  - FAT procedure development and FAT execution for the PPS and DCS.
  - SAT procedure development for the PPS only.
  - LAR support activities.
- Sargent & Lundy as engineer of choice organization
  - Prepare, review, and identify all affected equipment list (AEL) changes in the LGS document management tool (Passport), which includes the identification and disposition of all current and newly generated records.
  - Prepare and review all impacted drawing revisions, which includes drawings to be voided and drawings which require changes.
  - Process all new vendor documents, including adding the CEG title block to each drawing and processing of information to records for document creation in Passport.
  - Prepare updates for all impacted design basis documents (DBDs) as significant rewrites will likely be necessary for each impacted DBD, such as the high-pressure coolant injection, reactor RCIC, CS, residual heat removal, RRCS, post-accident monitoring, ADS, and electrical systems as well as any other impacted DBDs.
  - Review, evaluate, and revise all impacted LGS updated final safety analysis report (UFSAR) [20] sections.
  - Coordinate all UFSAR owner reviews and completion of UFSAR forms.
  - Draft the engineering change (EC) design attribute review and manage the ECs in Passport, including AEL screens and affected document list screens in support of the work above. CEG and Westinghouse engineering will provide technical input into the design attribute review. Format this input into the EC disposition. Write work planning instructions in support of EC preparation. Create and manage the majority of EC required forms in Passport. CEG engineering will support obtaining necessary reviews and approvals for the necessary forms, and CEG personnel will sign all prepare, review, and approval signatures required in Passport.
  - Process all changes to vendor manuals, which includes manuals to be deleted, revised or new manuals.

- Prepare all cable changes, including deleted, abandoned, rerouted, repurposed, and modified cables as well as the addition of all new cables that must be added though CEG will own all cable routing and provide cable routes. Sargent & Lundy is responsible for any cable overfill evaluations that may be required.
- Revise any fire safe shutdown calculations associated with impacted cables.

- INL
  - Project management of HFE activities performed by INL.
  - Development of an HFE Program Plan using NUREG-0711 [8] as a model for the project for review and acceptance by CEG.
  - Support the execution of the HFE Program Plan through the completion of the planning and analysis phase, as described in the HFE Program Plan, including the planning and facilitation of workshops at INL and production of requisite reports that will be reviewed and accepted by CEG.
  - Support the execution of the HFE plan through the completion of the design and verification & validation phases, as described in the HFE Program Plan, including the planning and facilitation of the Conceptual Verification (CV) and Preliminary Validation (PV) Workshops at INL and production of requisite reports and the planning, assessing, facilitation, and production of requisite reports associated with Integrated System Validation (ISV).
- Jensen Hughes
  - The Limerick Digital Modernization Project reconfigures and replaces the reactor parameter inputs signals to the ECCS systems, RCIC, and ADS, which introduces new equipment and cables into the fire safe shutdown (FSSD) analysis and multiple spurious operation analysis that were not previously evaluated. The modification also removes equipment and cables previously credited for FSSD. Jensen Hughes performs a preliminary assessment of this portion of the upgrade, which evaluates the potential impacts of crediting the equipment and circuits for transmitters.

2.1.1.2. Conceptual Design Activities

2.1.1.2.1. Bounding Technical Requirements

The bounding technical requirements (BTR) were developed from existing plant documentation and design basis documents. This documentation was originally used to develop a site-specific performance specification. The performance specification was used to solicit bidders and then was conformed with the awarded bidder (Westinghouse). The BTR performance specification bounded the design that will be installed at LGS.

2.1.1.2.2. Synthesized Design

The Limerick Digital Modernization Project consists of the PPS and a non-safety DCS. The two systems operate independently, but they share information between the systems. Each is described in the subsections below.

2.1.1.2.2.1. Plant Protection System

The PPS performs the necessary SR signal acquisition, calculations, setpoint comparison, coincidence logic, RPS/N4S/ECCS actuation functions, and component control functions to achieve and maintain the plant in a safe shutdown. Unless otherwise noted, ECCS within this document includes RCIC functions. The PPS contains maintenance and test functions to verify proper operation of the system and is also responsible for meeting Class 1E post-accident monitoring and display requirements.

The PPS consists of four divisions, designated 1, 2, 3, and 4. Divisions are provided to satisfy single-failure criteria and improve plant availability. Interdivisional communication is accomplished through optically coupled unidirectional datalinks that maintain independence and prevent fault propagation across divisions.

Following completion of the BTR performance specification, the awarded vendor developed WNA-DS-04899-GLIM, "Limerick Generating Station Units 1&2 Plant Protection System Digital Modernization Project System Requirements Specification" [37], which provides the requirements for the PPS safety system targeted for replacement and provides the:

- Specification of the system design requirements (including the utility design requirements)
- Specification of the system interface requirements
- Specification of the system HSI requirements
- Specification of the external interface requirements
- Specification of the cybersecurity requirements.

The PPS system requirements specification (SyRS) synthesized the utility requirements into a design artifact (an LTR) that supports the development of the LAR submission to be reviewed and approved by the NRC staff. This LTR follows aspects of the structure in Revision 2 of DI&C-ISG-06 [1], that is those aspects that pertain to the AR process as described in Section C.2 of DI&C-ISG-06.

2.1.1.2.2.2. Distributed Control System

Following completion of the BTR performance specification, the awarded vendor also developed WNA-DS-05080-GLIM, "Constellation Energy Generation Limerick 1& 2 Distributed Control System Functional Design Specification" [38], which is referred to here as the DCS SyRS. The Limerick DCS expands the existing Ovation turbine control and protection functions by adding the RRCS, diverse protection system (DPS), and a datalink interface to the PPS. The MCR interface to these new functions includes three operator consoles, four large panel displays to present the PPS division and channel status, and five annunciator displays to alert the operators of the PPS status.

The DCS SyRS provides similar information to that provided in the PPS as described above. The requirements for the digital implementation of the control system, defined throughout this document, are:

- Control system classification
- Control system design basis of replacement
  - Performance requirements
  - Regulatory requirements
- Control system functional logic
- Control system attributes
- Control system qualification
- Control system test and calibration.

The majority of the DCS design, testing, and installation is being performed under 10 CFR 50.59 [41]. The DPS segment of the DCS and a datalink interface to the PPS is being performed under the auspices of the LAR.

2.1.1.2.3. Confirm, Verify, and Validate Requirements, Architecture, and Implementation

2.1.1.2.3.1. Key Item Assessment to Complete the Conceptual Design Phase

To complete the concept design phase in the CEG change process, the following key items were addressed for both the PPS and DCS:

- All functions are listed to a "final" level of detail
- System diagrams are at a near piping and instrumentation diagram level of detail
- All credible malfunctions are listed with design mitigation (what makes the system or plant failure tolerant to the malfunction)
- 95% of the potentially affected functional diagrams and affected calculations are known
- Sufficient detail exists for a definitive estimate of the remaining design work.

Items below were considered before exiting the conceptual design phase:

- Basic system and equipment functions
- Performance requirements
- Physical constraints
- Detailed review of critical calculations for potential margin impacts, including:
    - Determination of associated interfacing calculations
    - Review of outstanding change paper to be incorporated
- Material specification development
- Verification of critical and unverified assumptions
- Identification and elimination of project risks
- Accessibility concerns
- Licensing impact
- Digital aspects (disaster recovery and cybersecurity)
- Walkdown plans, especially for normally inaccessible areas
- Drawing markups to cable block diagrams and termination details
- System and equipment interfaces
- Installation power requirements.

The results of these assessments were ultimately captured in the SyDSs, as described in Section 2.1.1.3.2.

2.1.1.2.3.2. Hazard and Consequence Analysis for Digital Systems

An EPRI-developed report titled "HAZCADS: Hazard and Consequence Analysis for Digital Systems" [13], provides a practical risk-informed engineering process for digital systems. It assesses the digital system as a "controlling system" that manipulates and controls the "controlled system," which is the fluid, mechanical, and electrical elements of the nuclear facility. HAZCADS is designed to determine the contributions digital systems play in overall plant risk via a variety of causal factors. These causal factors include software failures, design flaws, cyberattacks, human error, and implementation errors.

Previous EPRI research has shown that a systems-theoretic process analysis (STPA) is effective in identifying unsafe control actions in digital systems and that a fault tree analysis is effective in identifying random hardware failures in digital systems and their sensitivity relative to top events. HAZCADS expands upon this prior work, producing a practical approach to addressing the risk of digital systems within a systems-oriented approach that leverages both STPA and fault tree analysis methods.

As the SR I&C upgrade pilot at LGS is leveraging the EPRI DEG, CEG decided to explore the application of HAZCADS in this project in the conceptual design phase for the PPS. CEG and INL personnel attended a week-long training course on STPA. A subject matter expert (SME) from the Massachusetts Institute of Technology taught the STPA course and facilitated several working meetings on the application with LGS operations and engineering personnel. A separate HAZCADS training was also provided by EPRI personnel.

During the training sessions, both CEG and INL personnel saw the potential value of applying HAZCADS to the project. HAZCADS leverages the logical and structured STPA approach to methodically analyze the controlling system by:

- Identifying stakeholder losses and hazards that can cause a stakeholder loss.
- Developing a control structure that provides a model of controllers and related control actions as well as system elements needed for control actions to be successful.
- Identifying how control actions can be unsafe, that is lead to a hazard, which, in turn, can lead to a loss.

The HAZCADS process does not directly accomplish the fourth step of STPA, which identifies loss scenarios that can cause an unsafe control action (UCA) to occur. This is accomplished via separate topical guidance identified by EPRI.

HAZCADS requires design information as identified in the EPRI DEG before the analysis can begin. In accordance with the DEG, hazard analysis can support both the conceptual and detailed design phases. HAZCADS is a diagnostic tool designed to promote discovery of hazards and related UCAs.

HAZCADS was applied in this project for the PPS as a voluntary activity. LGS engineering and operations personnel performed this effort with Massachusetts Institute of Technology SME facilitation support. HAZCADS was used as a tool where losses and hazards impacted or potentially created by the LGS SR I&C Upgrade Project were identified. Basic PPS system and component functions, performance characteristics, and necessary plant interfaces were identified, which could contribute to those losses or hazards. These were then further explored and refined through the development of hierarchical control structure models that define control loops and enforce constraints on the behavior of PPS functions. A simplified control structure loop is depicted in Figure 6. More complicated, hierarchical control structure examples were also developed and leveraged.

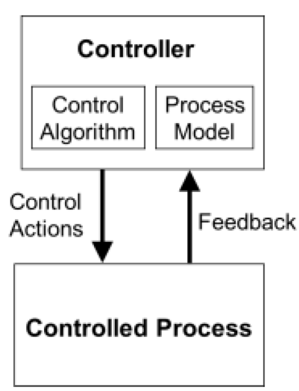


Figure 6. Simplified control structure loop.

This process was used to identify UCAs during the conceptual design. Loss scenarios and associated UCA's were also checked against the LGS probabilistic risk assessment (PRA) [29] to provide conceptual design insights.

Lessons learned with regards to HAZCADS use are captured in Section 3.1.1.4.1.

2.1.1.3. Detailed Design Activities

2.1.1.3.1. Bounding Technical Requirements

No additional bounding technical requirements were identified in detailed design efforts performed through September 2022.

2.1.1.3.2. Synthesized Design

Detailed design activities up through September 2022 focused on the development of SyDSs for the project. This included the development of:

- WNA-DS-04900-GLIM, "Limerick Generating Station Units 1&2 Plant Protection System Digital Modernization Project System Design Specification," (the PPS SyDS) [39]
- WNA-DS-05079-GLIM, "Constellation Energy Generation Limerick Units 1&2 Distributed Control System Design Specification," (the DCS SyDS) [40].

2.1.1.3.2.1. Plant Protection System

The PPS SyDS describes the design of the PPS safety system targeted to replace the existing legacy systems and provides the following information:

- System architecture diagram (as needed)
- Description of the functionality and architecture at the system, cabinet, and subsystem levels and of mapping the functionality to those levels
- Description of the external interfaces to the system
- Description of the internal communications to the subsystem level
- Specification of the hardware configuration
- Definition of the hardware requirements for the system components
- Description of time response requirements and performance
- Description of accuracy requirements and performance
- System spare capacity analysis—analyzes the spare capacity of the selected system design
- Safety system auxiliary system requirements—analyzes the cabinet heat load and inrush characteristics
- Required HSI formats (e.g., input screen formats, printed report formats)
- Definition of the plant computer interface that will enable the completion and verification of the plant computer interface design
- Description of cybersecurity compliance
- Unit-specific database configuration.

2.1.1.3.2.2. Distributed Control System

The DCS SyDS [40] provides details of the system design, system scope and key requirements for the DCS. The DCS SyDS provides the following information:

- The overall DCS system requirements and major system components used
- The HSI system components used to support plant operations in controlling and monitoring the plant processes, which includes the operator workstations, shared resource workstations (domain server, process historian, software server, and database server), display graphics, MCR switches and indicators, manual and auto stations, alarm presentation, and printers.
- The communications-level infrastructure components used to support communications between the operator control and monitoring level components and the process level controllers, which also includes communication interfaces to external equipment, such as the plant computer.
- The process control functions and the allocation of the major control loops to the controllers, which includes cabinet level modifications and the description of the equipment used for the upgrade implementation.
- The requirements for the input and output module arrangement and interface considerations to the existing plant sensors and actuating devices.

Figure 7 provides a pictorial representation of the information provided above.

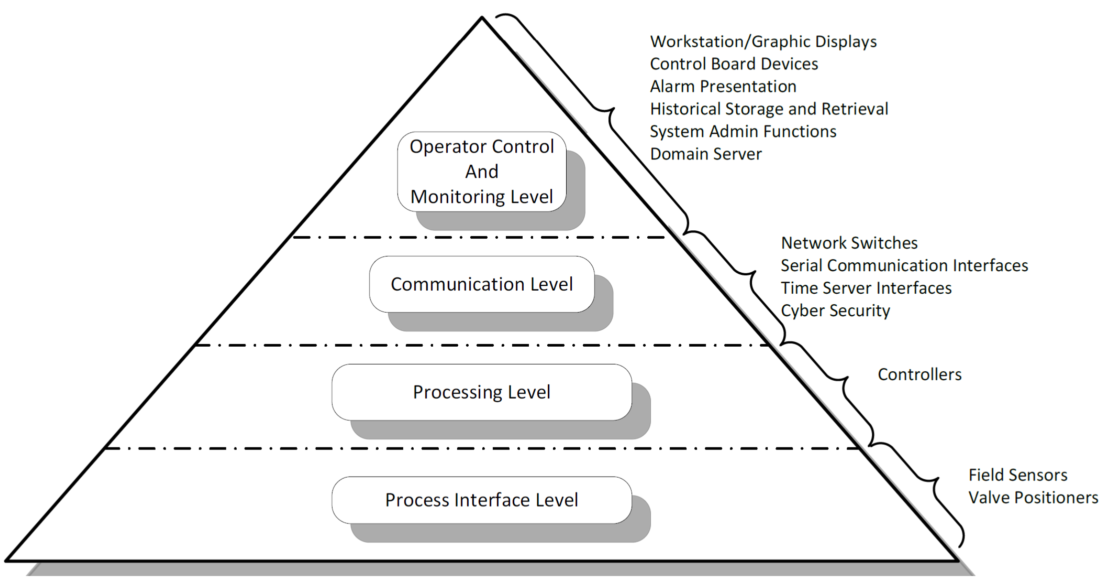


Figure 7. DCS architecture levels.

2.1.1.3.3. Confirm, Verify, and Validate Requirements, Architecture, and Implementation

2.1.1.3.3.1. Defense in Depth and Diversity Analysis

WNA-AR-01074-GLIM-P, “Defense in Depth and Diversity Common Cause Failure Coping Analysis” [11] documents three analyses that were performed on the LGS PPS being implemented as part of the LGS Digital Modernization Project. The PPS will be implemented using the Common Q platform, which is a digital platform that has been reviewed and generically approved by the NRC for use with SR systems, as documented in WCAP-16097-NP-A, Revision 5, “Nuclear Safety Related Common Qualified Platform Topical Report” [36].

The three analyses performed for the particular application of Common Q to LGS included:

1. A common cause failure (CCF) coping analysis that evaluates, for each LGS UFSAR [20] Chapter 15 event, the plant coping ability with the assumption that the Common Q portion of the PPS is not available due to a CCF. This analysis defines the DPS functions needed to meet acceptance criteria. It considered the NUREG/CR-6303 guidelines to create a block diagram for identifying which aspects of the architecture are susceptible to a CCF. The D3 analysis [11] identifies which portions of the PPS architecture are susceptible to a CCF.
2. CCF spurious actuation analysis.
3. An analysis defining the set of displays and controls located in the MCR for the manual, system-level actuation of critical safety functions and monitoring of parameters that support the safety functions. The displays and controls will be independent and diverse from the PPS Common Q system.

These analyses identified required functionality of the DPS. Following these analyses, this document compared the diversity attributes between the Common Q digital platform and the Emerson Ovation platform that will implement the DPS functions.

2.1.1.3.3.2. Plant Protection System Failure Modes and Effects Analysis

A failure modes and effects analysis (FMEA) was performed for this project as documented in WNA-AR-01050-GLIM, "Limerick Generating Station Units 1&2 Digital Modernization Project Failure Modes and Effects Analysis," for the PPS [12]. The FMEA revealed potential PPS single-failure modes from the viewpoint of hardware-failure-initiated events. The Institute of Electrical and Electronics Engineers (IEEE) Guide for General Principles of Reliability Analysis of Nuclear Power Generating Station Safety Systems, ANSI/IEEE 352-1987, identifies the purposes of an FMEA as follows:

- To assist in selecting design alternatives with high reliability and high safety potential
- To ensure that all conceivable failure modes and their effects on the operational success of the system have been considered
- To list potential failures and identify the magnitude of their effects
- To develop early criteria for test planning and the design of test and checkout systems
- To provide a basis for quantitative reliability and availability analyses
- To provide historical documentation for future references to aid in the analysis of field failures and consideration of design changes
- To provide input data for tradeoff studies
- To provide a basis for establishing corrective action priorities
- To assist in the objective evaluation of design requirements related to redundancy, failure detection systems, fail-safe characteristics, and automatic and manual override.

The FMEA was generated based upon the system requirements as contained in PPS SyDS [39]. The FMEA was applied to the electronic portions of the PPS and includes an analysis of the RPS, N4S, and ECCS functions. An analysis of the safety video display units (VDUs) and associated confirmation switches was also included. The analysis does not include switch inputs, which consist of RPS manual scram pushbuttons, reactor mode switches, and hand switch inputs for N4S. Particular attention was paid to failure modes that may affect the time response of the safety functions to determine the extent to which time response testing must be performed during the plant operation.

The FMEA demonstrates that the PPS design is capable of performing its protective functions for all of the single failures considered in the analysis. The analysis also demonstrates that the system provides protection with the presence of a single failure and the concurrent presence of a legitimate bypass of one channel in the PPS.

2.1.1.3.3.3. Plant Protection System Software Hazard Analysis

WNA-AR-01051-GLIM, “Limerick Generating Station Units 1&2 Digital Modernization Project – Plant Protection System Preliminary Software Hazard Analysis,” [42] is based on the detailed PPS design as shown in the PPS Architecture attachment to the PPS SyDS [39] and WNA-LD-01578-GLIM, “Exelon Generation Limerick Units 1 & 2 - Distributed Control System Architecture & Layout,” [43] and the software design, implementation, validation, and verification activities performed in accordance with WCAP-16096-P-A, “Software Program Manual for Common Q™ Systems” [44].

The software hazard analysis (SHA) [42] is part of the PPS software lifecycle plan in accordance with the software program manual [44]. At a minimum, an analysis will be performed iteratively for each software baseline release. Any portion of the SHA may be revisited at any time during the software lifecycle to account for overlooked or new software impacts to system hazards.

This analysis considers only those failure modes and consequences that impact the PPS software used to implement protection functions. Therefore, the protection class portion of the digital computer system is the primary focus, including the analysis of the software architecture and communication paths. During the concept phase only, important-to-safety class software is also assessed for potential hazards and any impacts on the protection class software; this provides an additional means to verify that the software classification and integrity level was assigned correctly. This analysis is restricted to the safety inputs, communication paths, and impacts on the software. The emphasis is on the programmable logic controller software to demonstrate that potential software hazards have been identified and compensating design features are being addressed.

The preliminary SHA confirmed that, with adequate document review, code inspection, software testing, independent verification and validation (V&V), system validation testing, and administrative inspection, the PPS software can perform the safety functions as designed. As described in the D3 analysis [11], a CCF of the PPS software in all four divisions is mitigated by the DCS diverse backup protection functions including the DPS and RRCS. The DCS is implemented using the non-safety, diverse, and separate Ovation platform.

The preliminary SHA identifies and confirms that all potential software hazards have been mitigated. The analysis demonstrates that the PPS software provides a low probability of creating hazards even when it fails. It also shows that a single failure in the plant does not create software hazards. The PPS design is capable of performing its protective functions with high reliability.

2.1.2. Human Factors Engineering Activities and Deliverables (NUREG-0711 Planning and Analysis Phase)

INL was selected by CEG to lead the HFE effort through completion of the NUREG-0711-defined planning and analysis phase activities [9]. INL worked with other project organizations to disposition HFE planning and analysis phase activities as described in NUREG-0711. These efforts are described in the subsections below. These efforts also address HFE as presented in the pertinent portions of Section 4.2 and 4.3 of the EPRI DEG [4].

2.1.2.1. *Human Factors Engineering Program Plan and Scope of Activities Addressed by This Report*

INL/RPT-22-68693, "Human Factors Engineering Program Plan for Constellation Safety-Related Instrumentation and Control Upgrades," [14] was developed by INL and reviewed and accepted by CEG. The HFE Program Plan is being used by CEG as it modernizes I&C systems in the Limerick Generating Station (LGS) as part of its SR I&C upgrade project. The MCR and local HSIs will be impacted by this upgrade. While this plan is specific regarding its application, the methodology presented herein is generic. CEG may choose to use the HFE Program Plan as a model for future I&C and associated MCR upgrades at the LGS and other nuclear power plants within its fleet.

The HFE Program Plan applies an appropriate level of HFE to changes affecting both the safety and non-safety I&C modifications scoped within the SR I&C upgrade project, reflecting the importance of HFE to plant reliability, safety, and economic operation. A graded approach is applied that is intended to support the project design objectives while meeting regulatory requirements and expectations to ensure a high level of plant safety and reliability is maintained as changes are made that impact HFE-related activities.

The HFE phases discussed in Reference 14 are described in NUREG-0711 [8]. Each phase (see Figure 8) consists of one or more elements. Each element as presented in Reference 8 contains a description of the review criteria applied by the NRC HFE staff to assess the acceptability of an applicant's submittal regarding safe plant operation.

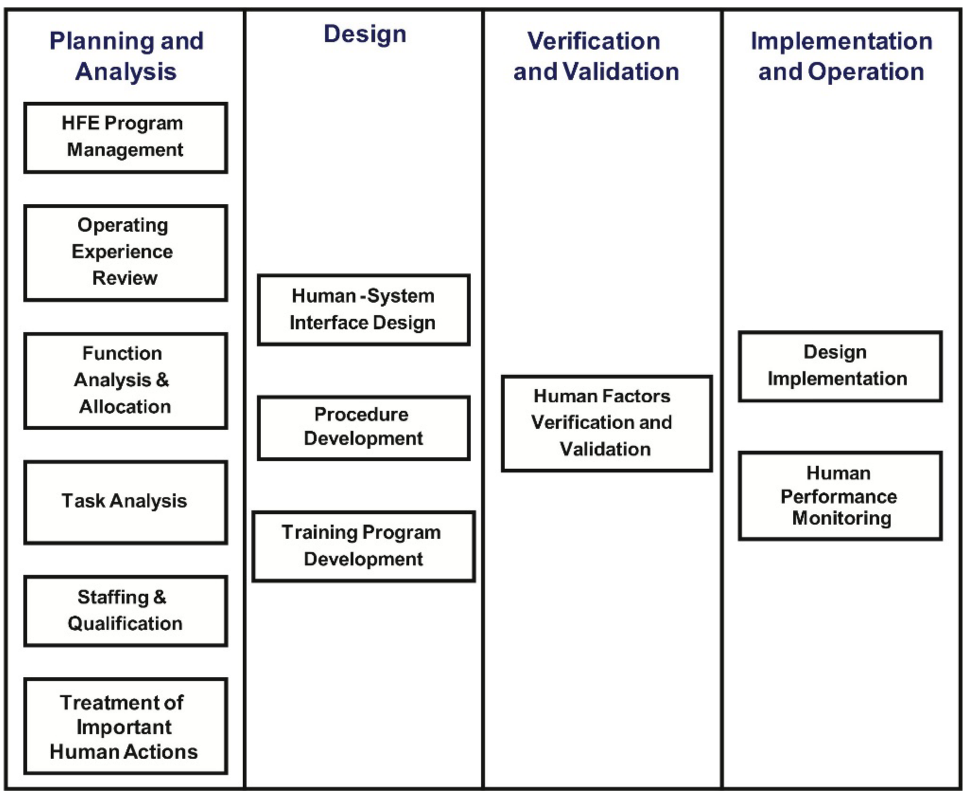


Figure 8. HFE phases covered by NUREG-0711, Rev. 3 [8].

Reference 14 provides guidance regarding all 12 elements described in NUREG-0711 [8] and includes industry best practices. Sections of Reference 14 include:

1. Introduction and Overview
2. Background
3. HFE Program Plan Objectives
4. HFE as Integral Part of the Modernization Process
5. Summary of LGS Safety-Related Instrumentation and Control HFE Activities
6. HFE Activities (with associated references which address each element in more detail)
    - 6.1 HFE Program Management [14]
    - 6.2 New State Vision for Instrumentation and Control Upgrades [15]
    - 6.3 Concept of Operations* [15]
    - 6.4 Operating Experience Review [16]
    - 6.5 Functional Requirements Analysis and Function Allocation [15]
    - 6.6 Project Screening and Task Analysis [15]
    - 6.7 Staffing and Qualification Analysis [15]
    - 6.8 Important Human Actions [15]
    - 6.9 Verification and Validation: Simulator Strategy* [15]
    - 6.10 Human-System Interface Style Guide [17]
    - 6.11 Conceptual Design Human-System Interface Display and Navigation Strategy* [15]
    - 6.12 Vendor Human-System Interface Design, Oversight, and HFE Issues Tracking
    - 6.13 Evaluation of Impacts to Procedures
    - 6.14 Evaluation of Impacts to Training
    - 6.15 Verification and Validation: Detailed Execution Plan for ISV
    - 6.16 Human Factors Verification and Validation
    - 6.17 Human Performance Monitoring
7. Second Unit Delta Analysis
8. References

Section 6 of Reference 14 includes additional activities (denoted with an * above) that are not specifically called out in NUREG-0711 but complement the NUREG-0711 elements.

A graded approach to NUREG-0711, as applied by Reference 14, includes the disposition of NUREG-0711 items and activities associated with element completion in a manner consistent with IEEE-1023, "Recommended Practice for the Application of Human Factors Engineering to Systems, Equipment, and Facilities of Nuclear Power Generating Stations and Other Nuclear Facilities," [18] by either:

- Applying a NUREG-0711 [8] item or activity to the upgraded I&C and HFE design as deemed appropriate and practicable
- Performing similar or alternate activities that meet the intent of the item or activity identified in NUREG-0711
- Justifying why a NUREG-0711 item or activity is not applicable or otherwise not being performed as part of the HFE effort.

NUREG-0711 was used as a tool to develop the HFE Program Plan [14] and identify the pertinent HFE activities to perform for the project. LGS is obligated to meet their regulatory and license basis HFE requirements, which are most explicitly defined in:

- Generic Letter 82-33 (NUREG-0737 Supplement 1) [19]
- The LGS UFSAR [20] Section 1.13
- Detailed Control Room Design Review (DCRDR) program plan [21], the initial Limerick Plant Control Room Design Review Final Report [22], and associated supplemental reports [23] and [24].

The conclusions in the NRC's safety evaluation report (SER) for the LGS LAR are to be based on these requirements.

While the HFE Program Plan [14] provides guidance for the design organization on all 12 NUREG-0711 elements, not all 12 HFE elements strictly relate to the requirements in NUREG-0737, Supplement 1, Item I.D.1. The additional HFE activities performed per NUREG-0711, Revision 3 for the structures, systems and components (SSCs) and procedures affected by the LGS Modernization Project, beyond those required by NUREG-0737, Supplement 1, Item I.D.1, only expands the LGS HFE licensing basis for those specific SSCs and procedures.

HFE activities performed during project conceptual design and design activities through September 2022 included dispositioning all of the planning and analysis phase activities as shown on the left of Figure 8. These activities include those described in Section 6.1–6.11 from Reference 14 as listed above.

Table 2 captures project efforts associated with all HFE planning and analysis phase activities as identified in the HFE plan [14].

Table 2. HFE planning and analysis activities.

HFE Plan [13] Document Section	HFE Planning and Analysis Activities	Section in This Document that Summarizes Activity-Related Efforts
6.1	HFE Program Management	2.1.2.1
6.10	HSI Style Guide	2.1.2.2
6.4	Operating Experience Review	2.1.2.3
6.5	Functional Requirements Analysis and Function Allocation (FRA & FA)	2.1.2.4.1
6.6	Project Screening and Task Analysis (TA)	2.1.2.4.2

HFE Plan [13] Document Section	HFE Planning and Analysis Activities	Section in This Document that Summarizes Activity-Related Efforts
6.2	New State Vision for I&C Upgrades	2.1.2.4.3
6.3	Concept of Operations	
6.7	Staffing and Qualification Analysis	
6.8	Important Human Actions (HAs)	
6.9	Verification & Validation: Establish Simulator Strategy to Support ISV	
6.11	Conceptual Design HSI Display & Navigation Strategy	

This report summarizes HFE planning and analysis phase efforts as presented in Table 2 because of integrated nature of executing these activities as outlined in NUREG-0711 [8] and the LGS HFE plan [14].

2.1.2.2. Human-System Interface Style Guide

INL/RPT-22-68693, "Human-System Interface Style Guide for Limerick Generating Station," [17] was developed by INL and reviewed an accepted by CEG. This design-specific HSI style guide was developed for the LGS SR I&C Upgrade Project in accordance with Section 6.10 of the HFE Program Plan for CEG SR I&C upgrades [14]. The HSI style guide provides specific guidance to design new and modified HSIs included as part of this effort while promoting consistency in HSI designs across the MCR panels to the extent possible. The HSI style guide addresses the organization and presentation of information on individual display pages on physical video display units, organization and navigation between those display pages, the design of display fonts and symbols, use of color-coding and labeling, and the design of touch capability to provide for operator input of decisions if this type of HSI is determined to be desired. The style guide also provides instructions for its use in the overall design process.

The HSI style guide is informed by generic guidance provided by NUREG-0700, "Human System Interface Design Review Guidelines," [25] and proprietary HSI-related information from the selected vendor. CEG has selected Westinghouse as the I&C vendor and the Emerson Ovation® and Common Q vendor platforms for the LGS SR I&C upgrade. The selected platforms were used in the Westinghouse AP1000® for SR and non-SR I&C applications, including HSIs in the AP1000 MCR. The HSI style guide leverages the native capabilities of these platforms as much as practicable while addressing specific issues when applying them to LGS. This not only supports better HSIs that support improved operator performance but also supports a simplified HSI implementation, reduces associated implementation costs that would be associated with performing customizations outside the accepted practice employed for AP1000 and supported by Ovation and Common Q, and enables more efficient lifecycle management.

The application of this style guide is specific to the LGS SR I&C Upgrade Project. CEG may use this document as an overarching standard for future MCR modifications made as a result of digital upgrades so that the overall MCR HSI suite is optimized.

Since the AP1000 design leverages the same platforms being installed at LGS, portions of AP1000 HSI design guidelines document [45] can be employed at LGS. Since the AP1000 HSI design guidelines developed to apply to a scope of work far beyond that identified for the LGS SR I&C Upgrade Project, only certain portions of the AP1000 HSI design guidelines are applicable in the development of the Reference 17 HSI style guide. These portions are specifically identified in Reference 17. Where there are inconsistencies between the AP100 HSI design guidelines and LGS conventions, these guidelines are identified, and a resolution path is provided. Where there are exceptions to guidance due to differences between AP1000 and LGS, these guidelines are also identified, and supplementary guidance is given. Finally, there are general comments in Reference 17 that provide illustrative examples or additional guidance to supplement the content in the AP1000 HSI design guidelines and are intended to further enhance its interpretation and application. Figure 9 outlines the inputs and outputs of Reference 17 and its relationship to other HSI design activities.

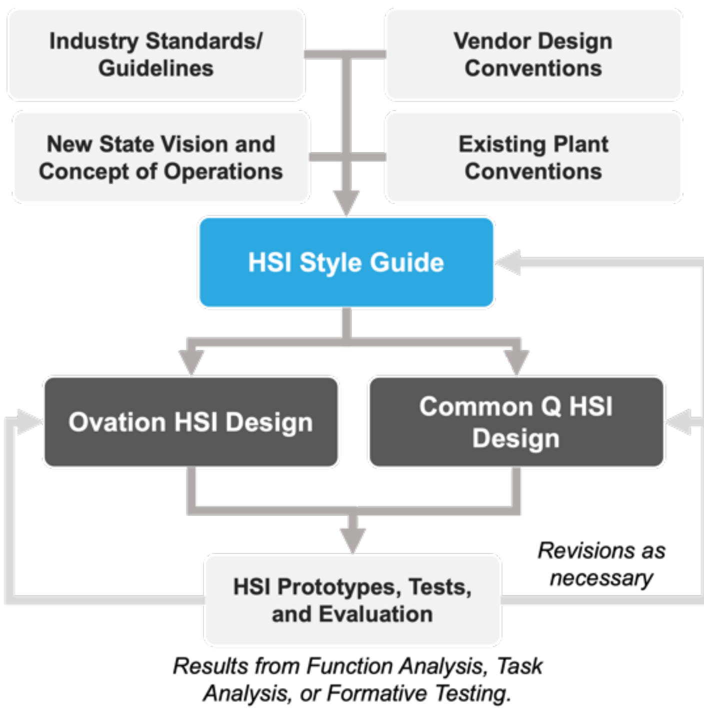


Figure 9. HSI style guide application to vendor design and HSI design and testing activities.

2.1.2.3. Operating Experience Review

INL/RPT-22-68693, "Human Factors Engineering Operating Experience Review of the Constellation Limerick Control Room Upgrade: Results Summary Report," [16] was developed by INL for the LGS SR I&C Upgrade Project in accordance with Section 6.4 of the HFE Program Plan for CEG SR I&C upgrades [14] was and reviewed an accepted by CEG.

The operating experience review (OER) methodology applied was based on NUREG-0711, Rev. 3 [8] review criteria, guidance in EPRI 3002004310, "Human Factors Guidance for Control Room and Digital Human-System Interface Design and Modification: Guidelines for Planning, Specification, Design, Licensing, Implementation, Training, Operation, and Maintenance for Operating Plants and New Builds," [26], and the process and results from prior INL operational experience (OE) studies with several other utilities. The OER methodology is shown in Figure 10.

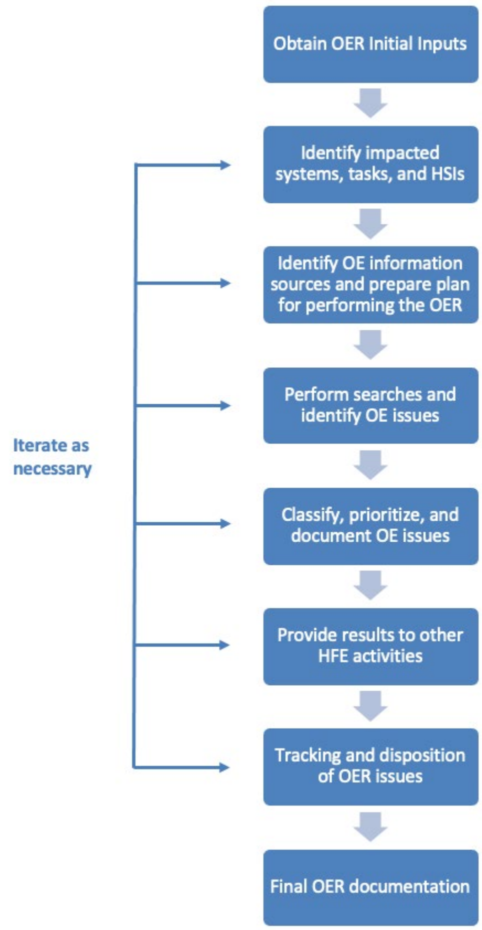


Figure 10. OER methodology.

An implementation plan describing the methodology for the OER is included in Reference 16. Reference 16 presents the OER results summary report (RSR), along with appendices containing detailed OE descriptions, which contain findings and dispositional recommendations related to existing and potential human performance issues impacting the proposed SR I&C upgrade design as may impact future LGS control room operations. The appendices included in the OER RSR contain pertinent HFE OE information obtained from:

- The LGS Condition Report Database.
- Operational experience and lessons learned from the SR I&C upgrade at the Oconee nuclear plant.
- Keyword searches of the Institute of Nuclear Plant Operations Consolidated Events Database.
- A review of recognized industry HFE issues identified in NUREG-1275 (Volumes 8 and 14) and NUREG/CR-6400.

- Keyword searches of the NRC Licensee Event Reports Database.
- Issues identified by LGS control room personnel were also captured through a survey and a face-to face OER workshop held on August 31, 2021, in the LGS training and simulation facility. This workshop facilitated the identification of potential issues in the MCR and elsewhere at the site as impacted by the upgrade. Operations SMEs from LGS-developed scenarios for the functions and tasks impacted by the SR I&C upgrade. Each scenario grouped the impacted tasks together in a contextually appropriate way. For instance, tasks are rarely performed in isolation. In many cases, the functions and tasks to be performed are part of a broader plant event (e.g., managing an ATWS). Using scenarios, the analysis of impacted functions and tasks account for different operational contexts that are important when understanding how any given function or task affects related tasks.

  This workshop supplemented the other OE information gathered as described in the other bullets directly above with information gathered from several group discussions with control room operators, engineers, instructors, and other staff.

The objectives of this effort were to acquire OE information specific or relevant to nuclear power plant I&C and associated control room modernization, preliminarily evaluate it regarding potential impact on design and operational considerations, and make it available for subsequent HFE analysis, design, and V&V elements for the LGS upgrade that is being pursued. HFE-related safety and availability events, issues, and information on past operational performance at CEG's LGS were examined, along with similar input from other United States nuclear power plants.

The results of this work support follow-on HFE analyses focused on control room modernization, as well as on current and future design decision-making on the part of CEG. Existing and potential human-system performance issues identified early in the design process through an OER can be formally tracked and addressed, thereby becoming significantly less likely to be overlooked in the overall systems engineering process. The relationship between HFE elements and OER item classification is shown in Table 3.

Table 3. OER item classification.

HFE Element	OER Item Classification
FRA and FA	Basis for initial requirements
	Basis for initial allocation
	Identification of need for modification
TA, Treatment of Important Human Actions, and Staffing and Qualifications	Important human actions and errors
	Problematic operations and tasks
	Instances of staffing shortfalls
HSI, Procedures, and Training Development	Trade study evaluations
	Potential design issues
	Potential design solutions
Human Factors V&V	Tasks to be evaluated
	Event and scenario selection
	Performance measure selection
	Issue resolution verification

Each OER item was prioritized as shown in Figure 11, which is derived from Reference 26 and captured in a table in the OER [16]. A graded approach was used to prioritize each item. Relevance to the new system was the first criterion, where OE not relevant to the new system would be graded as low relevance. If the OE was relevant to the new system, but was only an I&C issue, it was recorded in a separate appendix for record-keeping purposes but was no longer processed through the HFE graded approach procedure. For OE items that were human factors or I&C and human factors related, they were then coded as a globally or specifically relevant issue to the planned upgrades. The final criterion in the graded approach was whether the OE item was linked to safety or production goals. If yes, the OE item was graded as highly relevant. If no, the OE item was graded as moderately relevant.

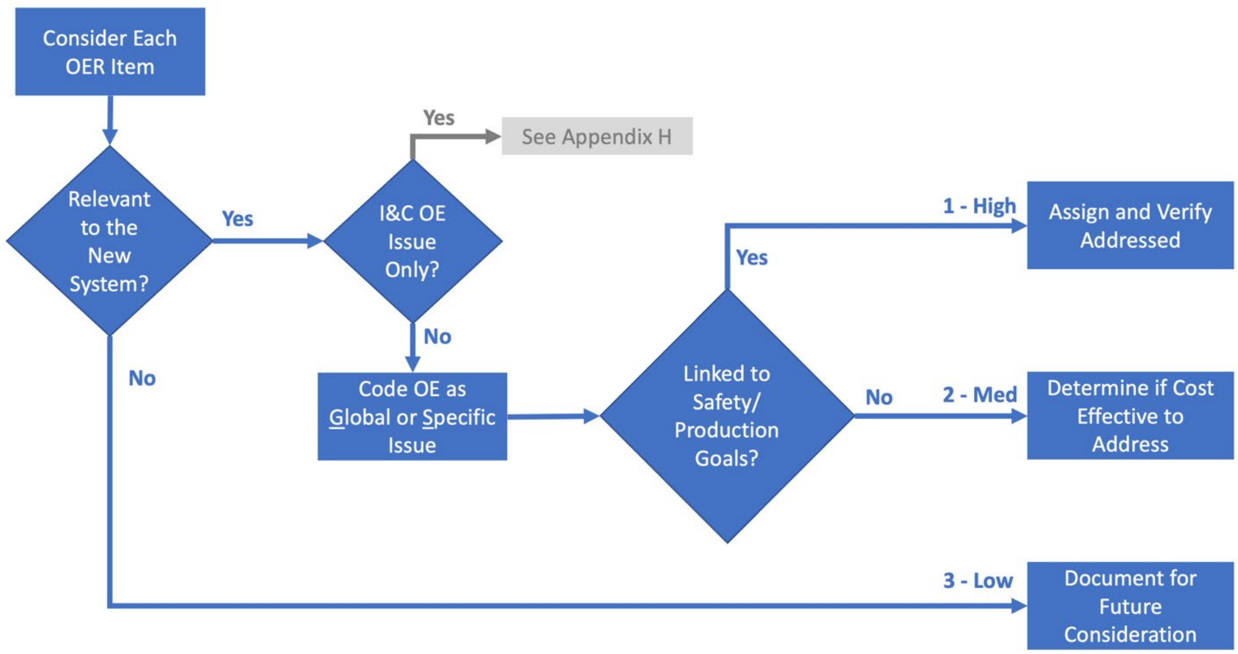


Figure 11. OE item prioritization method.

LGS SR I&C upgrade OER results were applied to activities associated with the functional requirements analysis and function allocation (FRA&FA) and task analysis (TA) elements of the LGS HFE Program Plan [14]. OE issues identified in the current report also impact subsequent HFE elements, such as the treatment of important human actions, HSI design, and V&V. OE results may also need to be considered when performing other elements, such as procedure and training program development. The OER report [16] does not attempt to resolve the OE issues that it identifies nor is any control room design or operational guidance provided. Each OE item should be assigned to the one or more HFE teams responsible for the element to which the item applies for resolution and disposition.

2.1.2.4. Combined Functional Requirements Analysis and Allocation & Task Analysis Summary Report

INL/RPT-22-68995, "Human Factors Engineering Combined Functional Requirements Analysis, Function Allocation, and Task Analysis for the Limerick Control Room Upgrade: Results Summary Report," [15] was developed by INL for the LGS SR I&C Upgrade Project in accordance with the HFE Program Plan for CEG SR I&C upgrades [14]. Reference 15 has also been reviewed and accepted by CEG.

This document is an RSR that provides a description of activities performed and the results from performing the remaining NUREG-0711 planning and analysis phase activities not addressed by the LGS HFE plan itself (Section 2.1.2.1), the project HSI style guide (Section 2.1.2.2), and the project OER (Section 2.1.2.3). The activities addressed in Reference 15 not only include the FRA&FA and TA efforts for the LGS Unit 1 SR I&C upgrades and their impacts on the MCR but also the other remaining planning and analysis activities that were completed in concert with them. These efforts are further summarized in the subsections below.

2.1.2.4.1. Functional Requirements Analysis and Allocation

2.1.2.4.1.1. Objective

The objectives of the FRA & FA element are to identify and define new and changed control functions resulting from the modernization effort that are required to satisfy plant safety and availability goals and to allocate responsibilities for those functions to personnel and automation in a way that takes advantage of human and automation strengths and avoids human and automation limitations and weaknesses. The FRA determines the objectives, performance requirements, and constraints of the HSI design and sets a framework for understanding the role of personnel and automation in controlling plant processes impacted by the LGS SR I&C Upgrade Project. FRA is the assignment of functions to personnel (manual control), automatic systems (automated control), and a combination of both (shared control). Taking advantage of functional capabilities provided by the modernized safety platform (Common Q—being used for the PPS) and non-safety platform (Ovation—being used for the DCS platform) and allocating these functions appropriately between manual and automated control will reduce human errors and inappropriate actions, resulting in improved system safety and economic performance.

2.1.2.4.1.2. Method

Figure 12 provides an overview of the FRA&FA process.

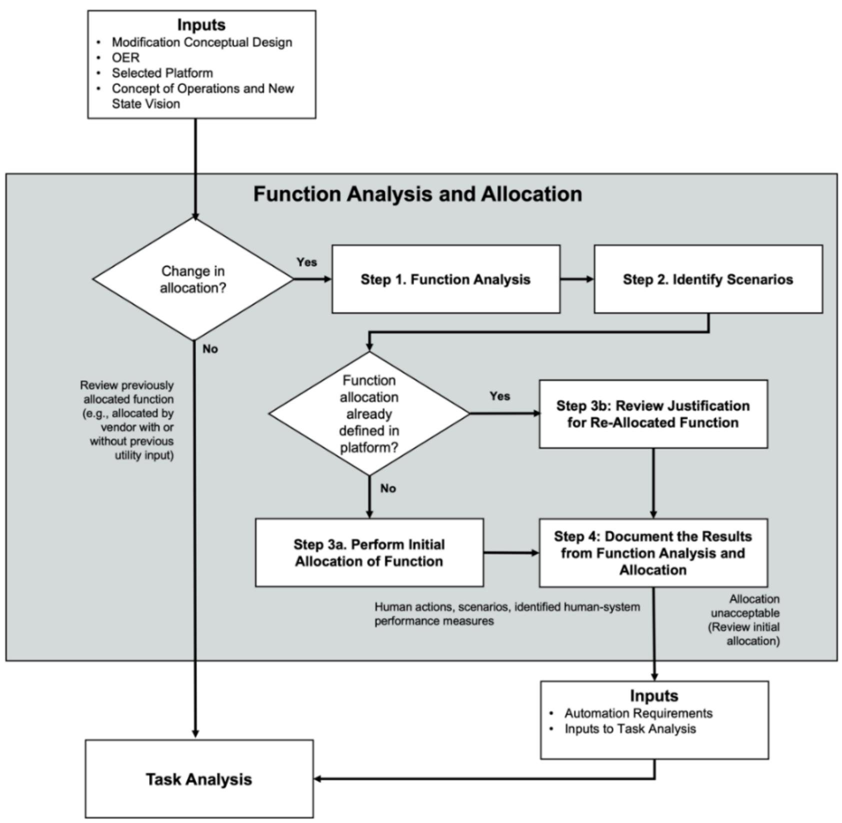


Figure 12. Overview of FRA&FA.

The activity of each shape presented in Figure 12 is described in detail in Reference 15. These activities were performed within the context of performing this activity being enabled using a dynamic FRA&FA workshop using the existing LGS MCR training simulator:

- FRA of project inputs to this effort, including:
  - The project scope as bounded by CEG (through preliminary design documents)
  - An understanding of the new state expected to be achieved by the upgrade
  - The capabilities of the selected I&C vendor (Westinghouse)
  - The OER as discussed in Section 2.1.2.3
  - An initial understanding of the MCR concept of operations through discussion with LGS operations personnel
  - Identifying, screening, and prioritizing plant tasks impacted by the upgrade with the assistance of LGS operations personnel. Screening and prioritization of tasks impacted by the upgrade was based on task difficulty, importance, and frequency scores as provided by LGS.
- Identifying scenarios using impacted tasks as a guide. Each scenario grouped the impacted tasks together in a way that was contextually appropriate. Using scenarios, the analysis of impacted functions and tasks accounts for different operational contexts that are important when understanding how any given function and task affects related tasks.

  A total of nine scenarios were identified by LGS SMEs. To aid in the proper allocation of functions within the HSI design and associated tools used by operating personnel, the following activities were performed for scenario identification:

  - Identify significant events, scenarios, and procedures impacted by the LGS Unit 1 SR I&C upgrade scope in which functions and operator tasks will change
  - Evaluate the large number of events, scenarios, and procedures expected to be identified, and select the ones expected to have the largest positive and negative impacts on operator and system performance
  - Describe the events, scenarios, and procedures in sufficient detail that they can be evaluated.

  Criteria considered during the selection of scenarios included:

  - Providing the greatest operator error traps and opportunities for human error and poor performance
  - Offering the greatest opportunity for improved safety and economic performance
  - Involving changes from manual to shared or automatic functions
  - Involving the most changes in operator roles and responsibilities
  - Involving increased operator workload and reduction in operator action times.

  These scenarios are documented in detail in simulator exercise guides (SEGs). The TA activities described in Section 2.1.2.4.1.2 also used these scenarios as the basis for analysis. It is expected that these scenarios will be carried forward into ISV to have a baseline to assess the maturing design's capability as the HFE program is performed.

- Performance of the FRA&FA workshop. This was accomplished on the LGS MCR training simulator. The scenarios identified by the FRA were run in the simulator with a fully qualified MCR watchteam. INL HFE SMEs collaborated with LGS simulator training personnel to run the scenarios.

- Documentation and use of results. INL captured observations in real time when observing the individual scenarios and also captured operator inputs through surveys and interviews after each scenario and at a wrap-up session at the end of the workshop. Observations and operational difficulties, key decision points, and impacts of the modification in the context of scenario execution were discussed.

2.1.2.4.1.3. Results Summary

Key findings from the FRA&FA workshop as captured in Reference 15 are:

1. The plant is highly dynamic, and operator actions often occur in parallel (particularly during casualty events).
2. In many situations, operators can achieve successful plant safety and operational outcomes in more than one way when following the same set of procedures.
3. Operators leverage the existing “flat topology” of indications and controls to enable the capability identified by Finding 1 and 1.
4. The new HSIs provided by the project need to maintain and enhance the existing MCR and plant concept of operations by creating HSIs that support the capabilities described in Finding 1, 1 and 2.
5. Many of the existing controls and indications are dispersed (i.e., across the MCR and sometimes in the field), which inhibits optimal MCR personnel performance by requiring operators and supervisors to ping-pong across the MCR to access appropriate indications and controls to diagnose issues and take proper control actions.
6. There are highly manual tasks (e.g., controlling pressure via safety relief valves (SRVs) where operators are required to remain in a particular location at the control board, which inhibits optimal operator and watchteam performance.
7. There is little rate of change and trending available related to the existing fixed analog displays, so the digitization of plant data by the upgrade needs to provide rate of change and trending to improve the mental model of the plant to enable improved performance.

Additionally, through observing scenario execution and operator response using existing LGS HSIs and operating procedures, it was identified that the initial MCR concept of operations as understood to be the target by INL researchers was not appropriate. INL researcher experience to date has been focused on pressurized-water reactor (PWR) technology. Recent PWR digital upgrades have more of a layered, hierarchical HSI topology and more linearly oriented procedures. LGS is a BWR. The current MCR concept of operation for LGS for casualty response is based on the MCR watchteam having access to a HSI that is characterized as a flat topology. In this flat topology, BWR operators have direct access to all system- and component-level indications and controls through the MCR panels and benchboard HSIs. Operator actions, as observed through FRA & FA workshop scenario execution, are accomplished by the dynamic execution of parallel procedure paths based upon the watchteam’s knowledge, judgement, and experience while using the flat topology HSIs.

While the LGS flat topology HSIs and parallel procedure processing methods observed were different from those previously observed by INL researchers, both work well in concert and are well understood by the MCR watchteam. They also enabled a level of performance that was at least equally acceptable when compared to INL researcher observations of PWR MCR performance.

Since LGS MCR operator training is based upon this BWR concept of operations and the supporting HSI flat topology, it was determined by LGS operations and agreed to by INL researchers that applying a PWR hierarchical HSI structure and associated concept of operations at LGS as originally envisioned would be unwise. This decision to change the initial direction regarding the concept of operations and HSIs design as described above is consistent with the iterative nature of establishing a MCR concept of operation as described in the HFE Plan [14]).

More detailed findings are also captured in Reference 15. FRA&FA findings had a direct impact on the planning and performance of TA activities summarized in the next section.

2.1.2.4.2. Task Analysis

2.1.2.4.2.1. Objective

The TA activity analyzes the functions assigned to plant personnel to satisfy the requirements for successful performance. TA identifies the specific tasks needed to accomplish HAs and the information, control, and task support required to complete those tasks. The TA results are a primary consideration in designing the HSIs, revising procedures, and training provided to plant personnel as part of the LGS SR I&C digital upgrade project.

2.1.2.4.2.2. Method

TA is a collection of different data collection, visualization, and analysis techniques that all have a common purpose. Within the context of nuclear power plant modernization, TA is the analysis of functions assigned to plant personnel to satisfy the requirements for successful performance. The actions personnel must do to accomplish functions assigned to them are called “tasks.” Generally, task refers to a group of activities with a common purpose. The fundamental basis of TA is a decomposition of tasks into the constituent activities to accomplish a goal. The degree of decomposition varies depending on the purpose of the TA. Figure 13 illustrates the decomposition of tasks as demonstrated by TA.

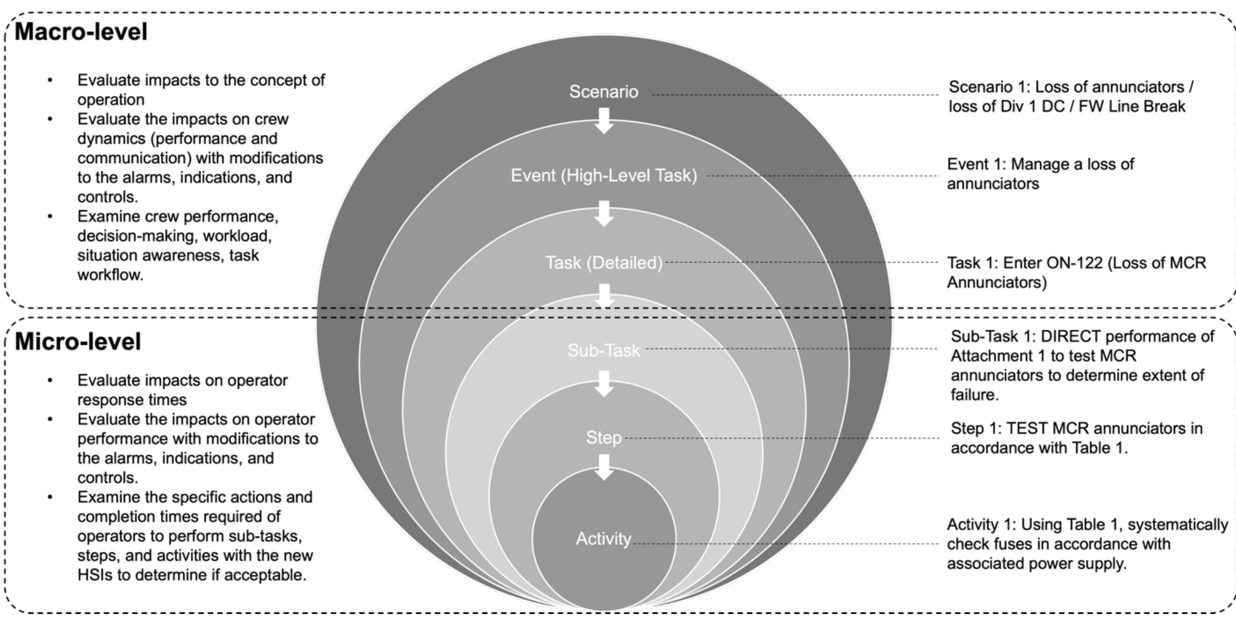


Figure 13. Decomposition of tasks for performing TA.

As seen in Figure 13, a top-down approach is taken by developing scenarios that comprise one or more events (i.e., high-level tasks), which are logically grouped in terms of accomplishing a goal. The individual tasks are contained within a scenario and event to accomplish these goals. The benefit of performing TA in this way is that tasks can be evaluated naturalistically. The influence of other tasks being performed in succession or in parallel can be properly analyzed in this manner. Further, by analyzing tasks from scenarios and events, the HFE can understand how modifications to the HSIs needed to perform these tasks can influence "macrolevel" HFE considerations, such as how the specific modifications impact crew performance and decision-making, situation awareness, workload, and overall task workflow. Put differently, these macrolevel HFE considerations are important when understanding how the modifications impact the concept of operations.

As the design matures and specific HSIs and design features are identified, the TA can be iterated upon and the scenarios, high-level tasks, and tasks can be further decomposed and analyzed to understand the impacts to microlevel HFE considerations that are concerned with the interaction with specific design features from the HSIs. It is here that the TA can examine the time required to perform specific tasks, subtasks, steps, and activities tied to important HAs with the defined HSIs via operational sequence analysis (OSAs) and operational sequence diagrams (OSDs) as described in NUREG-0800, Chapter 18, Attachment A, "Guidance for Evaluating Credited Manual Operator Actions" [27], and leverage the guidelines for using timelines to demonstrate sufficient time to perform the actions as provided in Appendix A of NUREG-1852, "Demonstrating the Feasibility and Reliability of Operator Manual Actions in Response to Fire" [28].

The approach taken here for TA was to begin with macrolevel considerations to define the impacts to the concept of operations and resulting impacts to the alarms, indications, decision processes, control actions, communication, workload, and interaction of tasks in addressing specific events. While some microlevel TA methods, such as cognitive modeling, have been used to analyze interactions with the new HSIs, it was expected that the TA will be iterated upon by the HFE team in later activities, as described in the HFE Program Plan [14], including the static (conceptual verification—CV) and dynamic (preliminary validation—PV) workshops in which the HSIs will be further defined and the application of OSAs and OSDs can be appropriately performed. Moreover, the identification of any new tasks credited in the accident analysis can be better identified at this time, at which point TA can address these new tasks at a macro- and microlevel, respectively. It is assumed that subsequent HFE activities described in the HFE Program Plan [14] will further enable TA iteration and that more detailed microlevel analyses will be performed to further support detailed HSI design, procedure design, training, and V&V (e.g., task support verification).

Collectively, the requirements developed in TA are a primary consideration in designing the HSIs, procedures, and training provided to plant personnel. TA evaluates personnel tasks in sufficient detail to identify the requirements for task performance, including the alarms, information, controls, procedures, and training needed to perform the tasks. TA results hence have many uses in subsequent analyses, including staffing, error analysis, HSI and procedure design, training, and V&V. The methodology followed here for performing TA is based on an EPRI HFE guidelines report [26]. The major activities are shown in Figure 14.

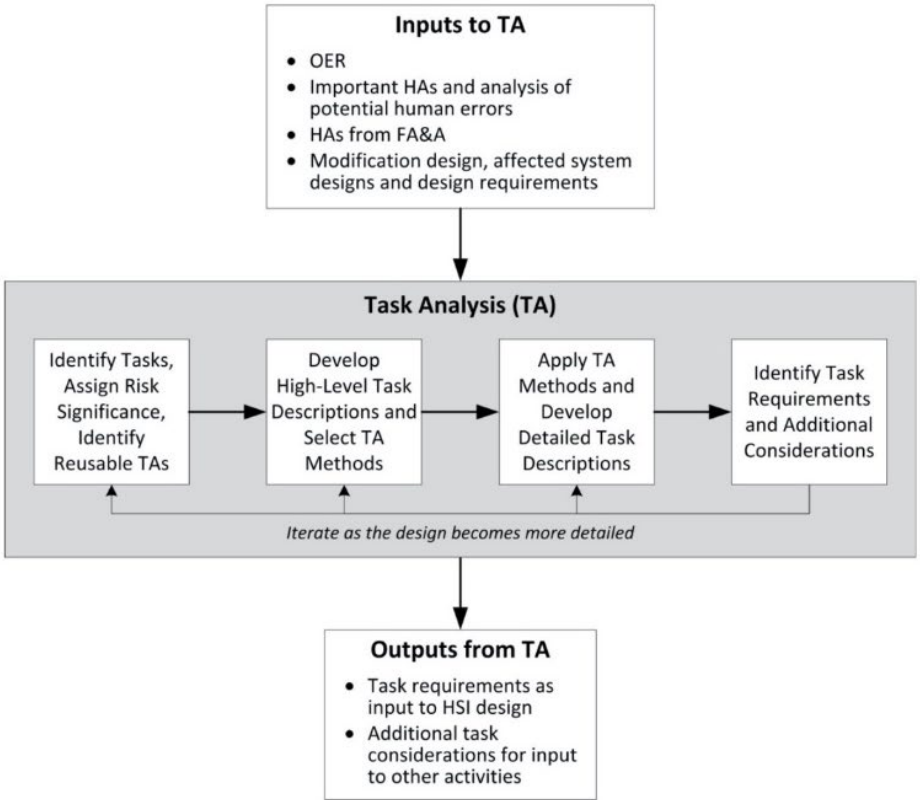


Figure 14. TA overview.

TA inputs included:

- The modification scope (Section 1.2.2).
- OER results (Section 2.1.2.3).
- FRA&FA results (Section 2.1.2.4.1).
- The MCR concept of operations (as modified during the FRA & FA as described in the results summary in Section 2.1.2.4.1.3).
- HAs credited in the D3 analysis performed to address potential PPS CCF [11] as well as the HAs credited in the LGS UFSAR [20] and Limerick Generating Station PRA Summary [29] for accident mitigation.
- Three dimensional (3D) MCR modeling. 3D MCR models supported both the FRA&FA and TA. When performing FRA&FA and TA knowledge elicitation activities, the models served as a visual reference to the MCR Unit 1 to enrich the discussion, identify human error traps, and drive development of the optimal placement of HSIs for the upgrade.

  The 3D model shown in Figure 15 below was based on LGS operations and engineering input during the FRA&FA workshop and in the lead up to the TA workshop.

Figure 15. 3D model showing pre-TA modifications and 5th percentile female reach envelope.

- Prototype HSI displays and an associated navigation strategy. Prototype HSI displays for both the PPS (Common Q) and Ovation (DCS) were rendered by INL along with a notional navigation strategy. These displays and navigation strategy were developed through a collaboration between personnel from LGS (engineering, operations, and training personnel), Westinghouse, and INL to reflect the latest HSI design concepts. Based on the revision of the concept of operations, as captured in Section 2.1.2.4.1.3, the conceptual PPS and DCS displays were formulated to maximize the use of available VDU space provided by both systems and to support, augment, and improve on the HSI flat topology currently used in the LGS MCR.

The result of these efforts was then loaded on the INL Human-Systems Simulation Laboratory (HSSL). The HSSL provides operators with the ability to view the notional displays and exercise the navigation strategies on representative VDUs. For the workshop, a mix of computer workstations and HSSL bays were used to represent the new VDUs. The layout of the upgrade VDUs from Figure 15 and the prototype display functionality presented on them was reflected in the HSSL configuration for the TA workshop and is shown in Figure 16 below.

Figure 16. Configuration of HSSL for the TA workshop.

Identification of Tasks and Assigning Risk Significance

- **Initial HFE Project Screening and Assignment of Project Risk Significance:** The SR I&C upgrade project was initially screened to determine the extent of potential HFE impacts. Changes considered in project screening included those that impacted operator HSIs. Changes that did not modify HSIs but could have other potential impact on operator tasks were also considered. The project screening process followed was based on guidance given in EPRI HFE guidance [26] and is depicted in Figure 17. This process first determined if any important HAs related to nuclear safety (i.e., identified from the LGS UFSAR [20], D3 analysis [11], and PRA [29]) may be impacted by the modification as an input to the initial screening.

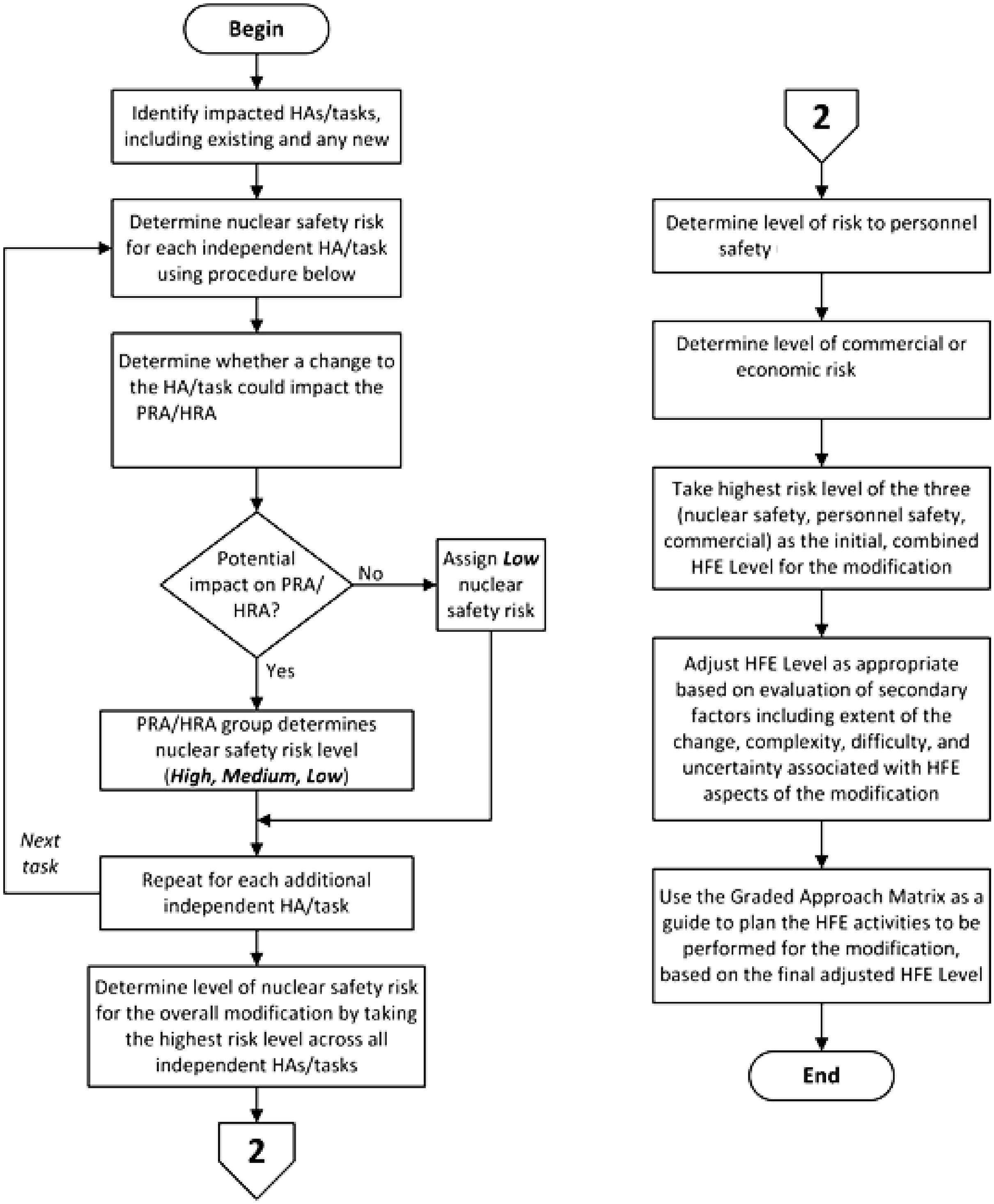
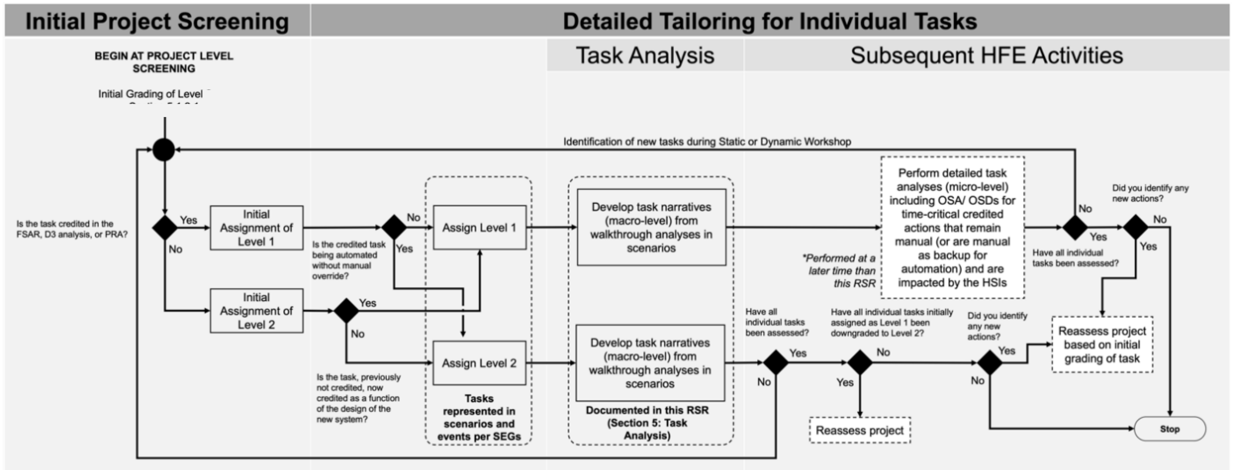


Figure 17. Process for determining HFE level of activity through project screening.

- **Detailed Tailoring of Specific, Individual Tasks in the HSI Design Phase:** Figure 18 illustrates the process followed for specific task identification and tailoring the TA following a graded approach.



Note. Tasks not impacted by SR Upgrade were noted as a Level 3 (little to no impact) and were not considered for subsequent HFE analysis.

Figure 18. Detailed task screening and tailoring process for TA.

- The first step was to identify the specific tasks impacted by the modification. The task identification and screening process was accomplished by engaging with LGS training SMEs who identified all the known tasks performed inside and outside the MCR from an Institute of Nuclear Plant Operations required methodology that identifies and lists specific LGS tasks and related difficulty, importance, and frequency scores. The screening of these specific tasks was based on whether these tasks were impacted by the SR I&C upgrade project using criteria such as:
  - Impacts to the operator HSIs inside the MCR
  - Changes to workplaces where operators use HSIs, if the changes could impact human performance
  - Changes that do not modify HSIs but could have other potential impacts on operator tasks (e.g., system changes that reduce the amount of time available for an operator to perform a task).
- Individual tasks were then evaluated through the process shown in Figure 18 to tailor the graded approach at an individual task level using the following criteria:
  - Level 1—High potential nuclear safety risk and economic risk
  - Level 2—Medium potential nuclear safety risk and economic risk
  - Level 3—Low potential nuclear safety risk and economic risk, which were not considered in the detailed task screening and tailoring process for the TA.

Develop High-Level Task Descriptions and Select Task Analysis Methods

A common approach to TA is to develop high-level task descriptions that can be further decomposed to the level of detail necessary to identify task performance requirements; this decomposition is reflected in Figure 13. TA is generally considered to extend from the results documented in FRA&FA. Thus, the task identification and risk significance assignment were used to develop and refine scenarios described previously in Section 2.1.2.4.1.2. Each scenario contained higher-level tasks (i.e., managing specific plant events) in which the specific tasks were grouped in a logical manner by LGS operations and training SMEs to ensure the context in which each task performed was considered. The higher-level tasks and scenarios were documented in SEGs and served as the basis for a detailed TA.

1. Task identification and risk significance assignments from above were used to develop and refine scenarios used during the FRA&FA workshop, as described in Section 2.1.2.4.1.2. Each of the nine scenarios developed for FRA&FA workshop and refined for the TA workshop contained higher-level tasks (i.e., managing specific plant events) in which the specific tasks were grouped in a logical manner by LGS operations and training SMEs to ensure the context in which each task performed was considered. The higher-level tasks and scenarios were documented in SEGs (also in Section 2.1.2.4.1.2) and served as the basis for detailed TA.

These higher-level tasks served as a goal-oriented approach in managing the plant in a way that required performing specific tasks. The benefit of this approach was added contextual accuracy in which the specific tasks were observed. That is, specific tasks are often not performed in isolation but are generally performed to accomplish a particular goal that can be characterized through events and scenarios. A group of related tasks used to accomplish a goal (high-level task) is considered an event. Related events can be further grouped into scenarios. Furthermore, the scenario-based approach allowed the team to sample tasks based on their uniqueness and level of impact by the modification. For example, while there are several different tasks associated with maintenance testing of the impacted systems, it was possible to sample a single task that was representative of the entirety of tasks associated with maintenance testing, as the specific changes to these tasks were similar in nature. The primary selected TA methods are documented in Table 4.

Table 4. HFE TA method selection.

Level 3 Task	Level 2 Task	Level 1 Task
Primary TA Methods		
Expert evaluation	Hierarchical task analysis (grouping tasks by events and scenarios in SEGs) Cognitive walkthrough	Hierarchical task analysis (Grouping tasks by events and scenarios in SEGs) Cognitive walkthrough *OSA and OSD
Primary TA Activities		
Screened out of SEGs Review of previous TA	Screened-in SEGs and evaluated via cognitive walkthroughs with scenarios Develop task narratives to address macrolevel task impacts	Screened-in SEGs and evaluated via cognitive walkthroughs with scenarios Develop task narratives to address macrolevel task impacts Identify credited manual tasks from UFSAR, D3 analysis, and PRA *Evaluate credited tasks in later HFE activities to address microlevel considerations such as time required and time available to perform tasks
Primary TA Outputs		
No formal TA outputs	Task narratives	Task narratives List of important HAs *OSA and OSDs for credited tasks
* The method will be performed in later HFE activities such as the dynamic (PV) workshop.		

All Level 1 and 2 tasks were grouped into specific scenarios that contained individual higher-level tasks or events. This composition of tasks and events were documented in SEGs in which the hierarchical relationship was clearly defined through a tabulated hierarchical task analysis format. Cognitive walkthroughs were performed at the HSSL simulator facility with two licensed operators (a control room supervisor (CRS) and a reactor operator (RO) and facilitated by human factors engineers. The specific methodology is described in the next section. Level 1 tasks will be further analyzed in later HFE activities using OSA and OSDs when the design is matured.

Apply Methods, Identify Task Requirements, and Identify Additional Considerations

The primary TA method was a series of walkthroughs from the nine developed scenarios in the HSSL glasstop simulator testbed. The HSSL was configured as shown in Figure 16 to present both the current boards and new, conceptual HSIs to allow operators to discuss the impacts of changing the HSIs in performing the identified tasks. The MCR arrangement was faithfully represented to match the board configuration of the actual MCR. The walkthroughs were performed by one CRS and one RO from LGS and were facilitated by a human-factors engineer at INL and a training SME from LGS. Additionally, there were several other key staff available from CEG (i.e., training and engineering), as well as the vendor (i.e., Ovation and Common Q).

The walkthroughs were facilitated by presenting the key impacted tasks, including important HAs, to operators and having the training SME facilitate the key events from the scenarios in which the impacted tasks would be performed. During the walkthroughs, operators walked through key tasks within the defined events and scenarios from the SEGs. Operators demonstrated and discussed what specific tasks they would need to perform to address each event with both the existing and new state MCR. The crew also had access to hardcopies of their procedures, including transient response implementation plan procedures.

The HSSL simulator was stopped at steps in the procedure where new functions were added, eliminated, or changed. The operators and others in attendance were asked to discuss these possible changes from existing practices. INL human factors staff collected verbal and observational data in the data logger while also facilitating the think-aloud technique per scenario. Both the existing and new states were presented to allow operators to discuss how they perform tasks now and how the upgrades will impact these tasks. Human factors staff collected observational and self-reported data from the walkthroughs using a combination of recording devices.

Post-scenario discussions were performed in concert with the walkthrough analysis. During the post-scenario discussion, INL human factors staff facilitated a semi-structured set of questions. The 3D model was also used, showing the planned modifications, to focus the discussion where needed.

After the nine scenario walkthroughs were completed, a static display review was completed. The review focused on the overview Ovation and PPS displays. The display review was facilitated by INL human factors staff where each display was presented on a large monitor and operators provided comments, based on their experience in the walkthroughs, regarding the completeness and format of the displays. Ovation and Common Q SMEs were available to provide feedback on the design characteristics of these platforms.

2.1.2.4.2.3. Results Summary

A total of 16 TA key findings were captured in Reference 15 and are listed below.

1. Walkthroughs and reviews were performed for all scenarios from the FRA&FA workshop. Specific tasks requiring manual actions were reviewed in the context of the HSSL and prototype VDU displays and display navigation. Those in the workshop with operating experience determined that those actions could be properly performed using the design concept presented in a manner that enabled correct, more informed, and more timely operator actions than the current design.

2. New PPS and DCS operator VDUs need to be grouped together in a way that facilitates their coordinated use. The workshop participants determined that there should be two groups of the four divisional PPS VDUs, with each group having a collocated DCS (Ovation) VDU. Each of these two groups was euphemistically called a “5 pack,” as shown in Figure 19.

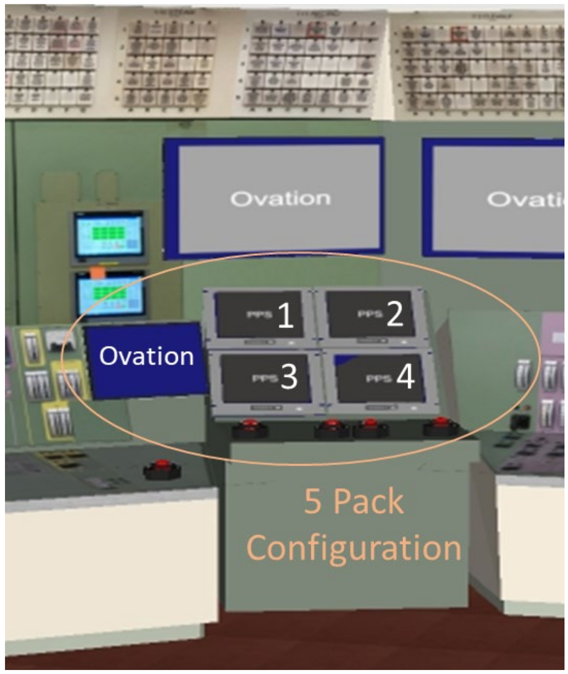


Figure 19. 5 Pack PPS and DCS (Ovation) workstation in current concept design location (as mocked up during the TA workshop).

3. The primary (RO) 5 pack needs to be specifically located to allow for coordinated PPS and other safety system controls. The resultant configuration along with the in-scope automated operator aids will allow the RO to perform the majority of his responsibilities from this location.
4. The primary group of PPS VDUs need to be mounted in a way that it:
    a. Provides for the functionality of Finding 3
    b. Does not obstruct the ability of the RO to view information on the back panels of the MCR in front of them
    c. Optimizes the use of the Ovation group-view displays
    d. Facilitates the use of both touchscreen and pointing device use by the operator
    e. Is optimized as much as possible to meet the goal of providing proper ergonomics for the 5^{th} percentile female and the 95^{th} percentile male (per NUREG-0700 [25])
    f. Allows for the RO and plant reactor operator (PRO) to coordinate their actions
    g. Allows for the CRS to best oversee the RO and PRO actions
    h. Following the LGS procedure, an SME in panel construction needs to be added to the team to help establish the MCR arrangement to ensure that the optimized design takes considers not only I&C and HFE attributes but also reflects panel structural concerns (e.g., fitment, seismic).

5. The secondary (PRO) PPS and Ovation VDU 5 pack needs to be located such that:
   a. The PRO can use this location to perform monitoring and control actions during casualty and complex operating conditions
   b. It can be separated from the RO 5 Pack VDU location to prevent congestion during both casualty and complex plant evolutions
   c. It can be located such that the CRS and Shift Technical Advisor
      i. Can observe and direct operator actions at the PRO VDU 5 pack
      ii. Can use the PRO 5 Pack PPS VDUs as a “group view display” in the event that Ovation is not functional (loss of the Ovation VDU functionality)
      iii. Can have access to RG 1.97 variable information—either “continuously viewable” or “continuously available”—more on this in Finding 8) [30].
6. PPS and DCS VDUs in the 5 Pack for both the RO and PRO need to support both touchscreen and pointing device functionality. Touchscreen enables rapid casualty response (display page navigation and rapid control action). The pointing device will provide an augmented capability for CRS oversight of routine and non-casualty RO and PRO operations.
7. To best address Finding 2–6 together, the conceptual layout provided in Figure 20 was developed.

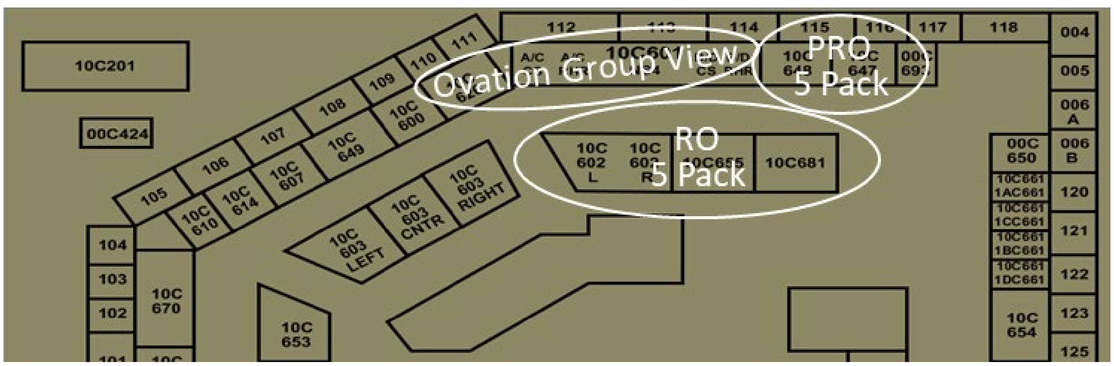


Figure 20. PPS and DCS workstations overlaid on the MCR layout drawing.

This conceptual layout:

a. Locates the RO 5 pack to a location within the oval shown above that would be driven by efforts to minimize the project cost and provide for necessary structural modifications to the panel
b. Identifies Ovation DCS group view displays as currently located in the upgrade design concept
c. Places the PRO 5 pack (as already described in Finding 5) as shown above.

Notional 3D model arrangements showing approximate VDU locations as depicted in Figure 20 are shown in Figure 21.

Figure 21. Notional MCR layout incorporating TA key findings.

Note that this notional arrangement:

- Provides optimized ergonomics that better addresses the guidance for the 5th percentile female and 95th percentile male
- Supports better coordinated control and supervision of PPS and DCS (Ovation) functionality for the current modification
- Supports better coordinated control and supervision of PPS and DCS (Ovation) functionality any future modifications that would migrate obsolete I&C functionality to either PPS or DCS.

The notional arrangement provided in Figure 21 is for illustrative purposes only. It has not been evaluated from a constructability point of view and may not represent the final MCR layout implemented by the LGS SR I&C Upgrade Project.

8. PPS VDUs:
    a. Have the capability to continuously present certain key variables (in the display headers or footers) and navigate to others
    b. Are limited in number (two per safety division, eight total)
    c. Are required to be able to provide MCR operators with sufficient capability to supervise and control the plant in the event of a loss of Ovation DCS.

This mix of capabilities, limitations, and requirements for the PPS VDUs raises a question regarding legacy RG 1.97, "Criteria for Accident Monitoring Instrumentation for Nuclear Power Plants," [30] licensing commitments for continuously presenting certain variables (continuously viewable). In the legacy design, these continuously viewable indications are largely provided with single point devices (meters, gauges, strip chart recorders, etc.). For such legacy variables subsumed within the PPS, it may be more advantageous for plant operation to make some or all these variables continuously available to the operator through simple navigation. There could also be separate displays (software images) developed for presentation on PPS VDUs that contain these variables. Instead of one or more of these displays being fixed to particular VDU(s), and thus severely limiting the usefulness of the limited number of PPS VDUs, their presentation could be controlled by policy and procedure based upon plant conditions. Both an operations and a licensing evaluation need to be made with regard to making RG 1.97 [30] variables continuously available vs. continuously viewable.

There is precedence for the use of "continuously available indications and alarms" as well as for a "limited number of fixed position controls" in the AP1000 Design Control Document, Section 18.12 "Inventory" in Section 18.12.2, "Minimum Inventory of Main Control Room Fixed Displays, Alarms, and Controls" [31].

9. Replication of the subset of PPS displays used to monitor and control the plant on the DCS (Ovation). The CRS identified that it would be advantageous (and easiest) to replicate the subset of PPS displays used by the RO to operate the plant and diagnose casualties on Ovation. That way, the CRS would be able to independently navigate to see the same information in the same format that the RO is seeing. It was stated to that the effort to reformulate the presentation of such PPS information on Ovation would be significant and of limited additional value. Deciding exactly which PPS displays will be replicated is a future activity.

10. Need to identify how valid "offscale – low" and "offscale – high" sensor values are presented on HSIs for this upgrade. There are operating conditions where sensors will detect such values from the field. This expected operational functionality is differentiated from a sensor producing an offscale – low or offscale – high due to a sensor failure or communication failure to the sensor. Such a sensor or communication failure typically would appear in Ovation as "bad quality" (magenta). This is a general issue for indications that can show either offscale – low or offscale – high without showing bad quality.

11. The ability of the upgrade to provide field data previously unavailable in the MCR will reduce RO, PRO, and CRS uncertainty regarding these values. This will also improve operator time response to plant conditions.

12. RO and PRO will be performing actions currently performed in the MCR along with actions currently performed by operators outside the MCR, which tends to increase RO workload (at least for short periods of time) but should speed up the overall response to the casualty in the MCR. This also frees up operators outside the MCR to pursue casualty response actions to aid in control and recovery.

13. The conceptual layout limited the ping-pong movements of the RO in the MCR during the scenarios because the upgrade tends to centralize indications and controls (RO 5 pack). It is expected that the PRO 5 pack will similarly reduce the ping-pong motions of the PRO.

14. MCR operators need to be trained on the failure modes of the Common Q and Ovation platforms. These failures would be induced by the partial and complete loss of power to portions of Ovation or Common Q, specific postulated malfunctions within each platform (e.g., loss of an Ovation server), loss of actuator power to a controlled component, or loss of separate whetting power to indications that feed Ovation and Common Q. Some scenario discussions were truncated and left open-ended because the detailed platform failure modes and how they will present themselves in the MCR have yet to be clearly defined in the I&C design.

15. Operators participating in the workshop did not have a full understanding of the detailed operational boundaries of the modification. This will need to be rectified as the HSI design effort continues forward.
16. The current use of the MCR wall panel provides MCR operators with significant operation awareness that supports a common mental model at a distance. This is accomplished based on the location of physical system mimics and equipment status indications (lights, meters, digital indications, strip charts, etc.). In most cases, operators can glean significant and valuable plant status information at a distance without having (or being able) to read the associated labels on the panel or the gradations on particular indicators. Plant operators at the workshop identified that the Ovation and Common Q VDUs located on the MCR wall panel could similarly provide such information on "overview displays" on the MCR back wall panels. If VDU display information were properly grouped and arranged and with sufficient training, this "at a distance" assimilation of information could be significantly augmented. Text and indications on these overview displays would likely be provided in two different sizes.
    a. Large text readable at a distance would provide global context for the "overview" displays along with a minimum set of "important" data that would also be directly readable at a distance. Simplified system mimics with an indication of active components in those systems would be provided. The use of pictograms (e.g., level indication bars, trend lines) instead of text values would also be preferred. These indications would meet the guidelines from NUREG-0700 [25] for viewing at a distance consistent with the RO and CRS watchstanding positions.
    b. Detailed information, such as labels for components, gradients for indicators, etc., would be provided so that they could be read at a closer distance from the panel standing at arms reach from the overview displays. This would allow for closer inspection during normal operation or, if necessary, during the recognition phase of a plant transient and casualty. Noun names for components may also be considered if they can provide clear and unambiguous identification.

More detained findings are described in an appendix to Reference 15.

2.1.2.4.3. Remaining Planning and Analysis Phase Human Factors Engineering Activities

2.1.2.4.3.1. Examination of Important Human Actions

As stated in Section 6.8 of the HFE Program Plan [14], the important HA element is concerned with HAs that are the most important to safety. HFE efforts for the LGS SR I&C Upgrade Project are to address important HAs enveloped within the project, as identified by CEG. Since this project is performing a modification of an existing plant, the identification of important HAs is not done from a "clean sheet." Rather, the important HAs for the existing design are known. Furthermore, the existing important HAs impacted by the upgrade are a subset of those.

The examination of important HAs for this project started during the FRA & FA, as discussed in Section 2.1.2.4.1.2. Task screening commenced during FRA & FA. Screening included not only whether tasks were impacted by the modification but also on tasks that address operator actions as identified either as part of the D3 analysis [11] or that are considered "risk important tasks" from the LGS UFSAR [20] Chapter 15 or the PRA [29]. The TA effort as discussed in Section 2.1.2.4.2.2 leveraged the results of the FRA & FA effort as inputs. Using the same scenarios for the TA as were used in the FRA & FA allowed the design team to assess how the aggregate HSI conceptual design presented in the TA workshop would permit operators to properly execute the scenarios and perform specific tasks related to specific important HA as identified by CEG.

For each TA scenario walkthrough, the specific important HA identified for that scenario was specifically discussed. For all scenarios, operations representatives stated that all critical tasks for each were discussed. Operators concluded that the notional HSI functionality as presented for each scenario would either not negatively impact or improve operator response for these tasks.

While evaluating important HAs is complete for the planning and analysis phase for NUREG-0711 [8], important HAs will be iteratively addressed during the design and V&V phases. As stated in Section 6.12.1.1. of the Project HFE Plan [14], HSI design static (CV) and dynamic (PV) workshops are planned to facilitate focused prototype display usability testing. This is a continuation of the TA activity into the design phase.

2.1.2.4.3.2. Main Control Room Staffing and Qualifications

As stated in Section 6.7, “Staffing and Qualification Analysis,” of the HFE Plan [14], it was not expected that the LGS SR I&C upgrade will fundamentally impact the staffing and qualification requirements for plant personnel. During the performance of the other planning and analysis activities as documented in this report, there was no indication from operations personnel that there would be any need to modify the staffing levels of MCR operators or alter their basic qualifications as a result of performing the upgrade as scoped.

2.1.2.4.3.3. Verification & Validation: Establish Simulator Strategy to Support Integrated System Validation

There are several V&V activities that build on each other that culminate in performing ISV that are summarized as:

1. Using the findings of HFE efforts to date and the prototype displays and navigation strategy developed to support the TA workshop, more refined displays will be developed that will ultimately be used for ISV. Working with operations, the types and number of displays necessary to accomplish ISV will be bounded and developed using the same prototyping tools. This will support initial tabletop reviews of displays by the geographically dispersed design team. In parallel with display development, necessary procedure changes to enable the use of these displays will also be made. As these coordinated efforts converge, task support verification can begin. While portions of task support verification may likely be performed in a tabletop environment, CV of the HSI design will occur during the static HSI workshop. Scenario walkthroughs will be performed using navigable, static displays on a simulator that can support this purpose.
2. After the static workshop (CV), additional refinements to the ISV-related displays and procedures will be made as necessary to address identified issues. The resultant displays will be dynamically connected to a simulator plant model to present simulator data on the displays. Scenario walkthroughs will be performed using navigable, dynamic displays on a simulator that can support this purpose. Standalone computer equipment may be used to evaluate the display capabilities in conjunction with procedure use. The satisfactory completion of such displays with procedures constitutes a task support verification. The dynamic workshop will be used to perform PV on the HSI’s developed for this upgrade, following the guidance of Attachment A, “Guidance for Evaluating Credited Manual Operator Actions,” to NUREG-0800, Chapter 18 [27]. OSAs and associated OSDs will be developed and validated for these manual actions, consistent with the review criteria.
3. Any final modifications needed to either the ISV-related displays or procedures will be made based upon the PV workshop. This will be the final input to rendering the PPS displays using the software application associated with Common Q and the DCS displays using the software application package for Ovation. CEG will provide an MCR simulator of sufficient fidelity to perform ISV for the upgrade. Development activities to ready this simulator for ISV (physical modifications driven by the design of new and modified HSIs, loading of HSI and control system software, and necessary simulator infrastructure modifications to enable this software to support an ISV) are incorporated within the project schedule for the upgrade.

A detailed ISV implementation execution plan, as described in the HFE Plan, Section 6.15 [14] will be developed to govern the ISV. Approximately two months before ISV, a readiness review of the CEG-provided simulator will be performed using the ISV implementation plan as a guide. Key readiness items to be assessed during the ISV readiness review are captured in Section 6.16.2 of the HFE Plan [14].

2.2. Licensing Activities and Deliverables

Licensing activities are described in the EPRI DEG process at an abstract level. These regulatory-oriented activities and products support implementing utilities by providing an avenue to develop technical information associated with the envisioned upgrades in a way that maps to the DI&C-ISG-06, Revision 2 [1] AR process.

In the initial scoping phase, CEG licensing activities included:

- Participation in the research and design team meetings and review of documentation
- Meetings with DOE including the NRC staff to keep them abreast of pilot project activities
- Support of LAR framework document development by INL, which is available for utility use in conjunction with their own licensing process and procedures to develop the final LAR submitted to the NRC
- Development of strategy and timeline to begin a formal LAR process using the DI&C-ISG-06, Revision 2, AR process.

Licensing activities from the completion of the Initial Scoping Phase Report [5] to the issuance of this report are described in the subsections below. A schedule of post LAR submittal activities through installation of the SR I&C Upgrade is also provided.

2.2.1. Letter of Intent and Licensing Amendment Timeline

As planned as described in the Initial Scoping Phase Report [5], a letter of intent to submit a LAR to the NRC for the SR I&C Upgrade at LGS Unit 1 was submitted by CEG to the NRC on December 11, 2020 [35]. The purpose of this letter was to inform the NRC that Exelon Generation Company, LLC (Exelon) (now CEG) intended to submit a LAR for a DI&C modification at LGS. The LGS Digital Modernization Project LAR would be developed and submitted in accordance with the DI&C-ISG-06, Revision 2, AR process [1].

The LGS Digital Modernization Project would replace the existing control logic hardware of the RPS, N4S, and ECCS. Concurrently, the RRCS would be upgraded and may be added to the scope of this LAR later depending on the final evaluation of the changes. The new digital system (RPS/N4S/ECCS) would be renamed the PPS.

Westinghouse had been selected to provide the new digital system. The new digital system will be based on the Common Q platform, which has been approved by NRC as captured in the Common Qualified Platform Topical Report [36].

2.2.2. License Amendment Presubmittal Meetings

In accordance with the DI&C-ISG-06 Revision 2 [1] AR process shown in Figure 4, preapplication coordination meetings (also called presubmittal meetings) were held between CEG and the NRC staff. These meetings, held in accordance with Section C.3 of Reference 1, served as a mechanism for CEG to present the LGS SR I&C upgrade design concept and NRC staff to provide feedback on critical aspects of the proposed design that are likely to affect the NRC staff's evaluation. A total of 12 meetings have been held since the letter of intent was issued to the NRC. Three of these dealt with the D3 analysis [11] and are discussed in Section 2.2.4. Each of the other nine meetings is summarized in the subsections below.

2.2.2.1. June 12, 2020, Presubmittal Meeting

CEG and NRC staff conducted a public teleconference with stakeholders to discuss the status of the proposed project. CEG communicated that they expected to submit the LAR in the third quarter of 2022 after the presubmittal meetings have concluded. This time frame, as communicated, supports the installation of the modification during the LGS refueling outages starting with Unit 1 in Spring 2024 and Unit 2 in Spring 2025.

Other topics covered during the meeting included:

- Introduction of the project team and their roles
- Potential consideration of a fee waiver by the NRC
- Project description
- Current and proposed architecture
- Use of the AR process for LAR review and approval
- NRC lessons learned associated with digital projects
- Closing remarks and suggested topics for the next presubmittal meeting.

The meeting objectives were met in that the NRC staff had a better understanding and overview of the project scope and key schedule milestones after the meeting. CEG gained insights on NRC lessons learned from previous digital LARs, including:

- Each of the key topics listed in DI&C-ISG-06, Revision 2, should be addressed in a preapplication meeting
- Early preapplication meetings are essential to ensure an efficient NRC staff review
- Changes to the schedule should be promptly communicated to the NRC to ensure staff can align the necessary resources to complete the review
- The licensee should engage the NRC staff in advance concerning any complex digital designs, first-of-a-kind technical approaches, and deviations from referenced NRC-approved topical reports or guidance.

NRC staff expressed the desire to observe at least two of CEG audits of Westinghouse as part of the vendor oversight plan (VOP).

2.2.2.2. March 16, 2021, Presubmittal Meeting

The licensee provided an overview of the planned SR I&C Upgrade Project at LGS and an overview of the planned LAR. The planned project would upgrade analog I&C systems and integrate the existing safety-related RPS, N4S, and ECCS into a single system that will be known as the PPS. Additionally, the redundant RRCS would be upgraded. As part of the upgrade, the PPS and DCS HSIs would be installed, and some TS surveillances would be replaced. The licensee plans to include the following in its LAR:

- Required information listed in Enclosure B, "Information Provided in Support of a License Amendment Request for a Digital Instrumentation and Control Modification," of DI&C-ISG-06 [1]
- An LTR
- Description of TS changes
- Description of PPS SyRS [37]
- Description of PPS SyDS [39]
- FMEA to support TS surveillance eliminations

- Equipment qualification summary report
- Summary of human factors
- Summary of VOP
- Regulatory commitments
- Conceptual LGS UFSAR [20] markups (information only).

In the closed portion of the meeting, the licensee discussed the design principles for the planned project and its planned approach to D3. The format set up (open meeting first and second closed meeting for proprietary vendor information) was established at this meeting and was used throughout subsequent presubmittal meetings.

2.2.2.3. June 29, 2021, Presubmittal Meeting

In the open portion of the meeting, the licensee provided an overview of the LGS digital modernization design and licensing timeline, its VOP, work that would be completed that does not require prior NRC approval and planned HFE efforts. In a presentation, the NRC staff described the HFE regulatory guidance that the NRC staff would use to review human actions and control room modifications that the licensee should consider for the planned modifications to the LGS main control room. In the closed portion of the meeting, the licensee described the planned architecture of the digital modification, reduction of sensors, soft controls, approach to D3, proposed approach to address spurious actuation, proposed approach for independent and diverse displays and controls, and planned software design process.

The NRC staff mentioned to the license that the licensee's proposed timeline appeared to be closer to the Tier 1 review process than the AR process that the licensee plans to ask the NRC staff to use during the review. The licensee responded that the content of the preliminary design and timeline would be discussed in more detail at a subsequent meeting. The NRC staff shared lessons learned from reviewing VOP summaries from other amendment requests with CEG, including:

- Licensees identifying and describing the process and procedures for accepting design artifacts in the VOP summary
- Licensees making a clear distinction between licensee and vendor verification efforts in the VOP summary
- Licensees identifying key design characteristics in the VOP summary that will be verified
- Licensees describing the process that will be used to modify the VOP in the VOP summary.

The licensee stated that INL would be assisting with HFE for the planned modification, and in response to an NRC staff question, stated that INL would be covered by the VOP for the planned digital modification at LGS. The NRC staff asked the licensee about ISV using the LGS simulator and when the simulator would be available for ISV. The licensee responded that those topics would be discussed in more detail at a subsequent meeting.

2.2.2.4. October 20, 2021, Presubmittal Meeting

The licensee provided an overview of the SR I&C Upgrade Project at LGS and an overview of the planned LAR. In addition to replacing analog safety systems with a digital safety system, the licensee plans on replacing and combining the RPS, N4S, and ECCS into a single digital PPS using Westinghouse Common Q technology. The licensee discussed details of the proposed I&C architecture, including the combination of systems, reduction in sensors, D3, spurious actuation, and PRA [29].

The licensee’s LAR will include the following required information:

- Cover letter
- Required information per DI&C-ISG-06, AR Process, Section C.2 [1]
- Description and reason for the proposed TS changes
- SAT description
- System engineer and operations actions supporting TS surveillance reduction
- Regulatory commitments (currently none)
- LTR proprietary and nonproprietary versions
  - FMEA to support TS SR eliminations
  - Conceptual LGS UFSAR [20] markups (info only)
  - RRCS reclassification per 10 CFR 50.62 justification.
- D3 analysis [11] conclusions
- TS markups and clean pages
- TS bases markups (info only)
- Initial equipment qualification summary report
- Description of PPS SyRS [37]
- Description of PPS SyDS [39]
- PPS requirements traceability matrix (requirements phase)
- Component interface module diversity analysis
- Summary of equipment qualifications
- Human factors evaluation
- VOP summary.

In the closed portion of the meeting, the licensee discussed proprietary details of the Common Q technology, planned system integration, sensor allocation, D3 approach, and spurious actuation analysis. Also, the licensee specifically addressed the questions NRC staff sent to the licensee prior to the meeting on the consolidation of systems, reduction in sensors, and PRA [29]. During the discussion of the SR I&C upgrade project, the NRC staff informed the licensee that planned review duration assumption should be 2 months for the acceptance review and 15 months for the detailed review. In response to a question from the NRC staff, the licensee stated that its D3 analysis and evaluation [11] will be provided to the staff early in the first quarter of Calendar Year 2022 (it was provided on February 14, 2022) and will discuss TS changes in a separate meeting with the staff later. In response to a question from the NRC staff, the licensee representative stated that the PPS is designed to have a power supply that is not susceptible to common cause failure and that each cabinet will have a redundant power supply. The licensee stated that it will discuss the details of cabinet power supply configuration in the next presubmittal meeting. The NRC staff informed the licensee that the following should be included in its application:

- Either the reliability goal for the proposed system or a comparison of the reliability of the current systems and proposed system in the planned LAR
- A summary of the planned reliability analysis in the planned LAR.

2.2.2.5. *December 7, 2021, Presubmittal Meeting*

During the meeting, the licensee provided an overview of the I&C section (i.e., Section 3.3) in the current LGS TS and proposed changes to that section. The licensee stated that the proposed changes would make the I&C section of the LGS TS more consistent with the improved standard TS described in NUREG-1433 and better reflect the planned upgraded digital design discussed at previous public meetings (ADAMS Accession Nos. ML21300A277, ML21301A161, ML21123A136, and ML20175A240). The proposed changes included:

- Moving trip setpoints and response time limits from LGS TS to a document under the licensee's control
- Reorganizing Section 3.3 of the LGS TS (see licensee's presentation for a more complete description of changes)
- Requiring only three sensor channels—not four sensor channels—be operable for most four-channel functions.

The NRC staff informed the licensee that the following should be described in more detail at a future public meeting and in the planned LAR:

- Describe how three channels (i.e., two-out-of-three channel logic vs. two-out-of-four channel logic) meet all design requirements.

  The two-of-three condition may represent a system capable of performing its safety functions; however, there remains a question of whether a system in this state continues to meet all design requirements. In particular, the single-failure criteria of IEEE 603 or IEEE 279 in conjunction with surveillance testing requirements does not appear to be satisfied with a system in this condition.

- Describe how three channels provide lowest functional capability of the system.

  In absence of a limiting condition for operability, operation of the system with only three functioning channels would need to demonstrate not only functional capability but would also have to show compliance with the performance criteria of IEEE 279 or IEEE 603, which includes maintaining single-failure criteria during periodic surveillance testing activities during which only two channels would remain operable.

  During the meeting, the NRC staff referred to several TS examples for plants with similar designs that include limiting conditions for operability that must be considered during the time in which the safety system is in a two-of-three logic condition. Though the time to take the required action varies significantly between plants, all the example TSs include descriptions of actions that must be considered when the system is in a two-of-three configuration.

- Reestablish the basis for the continued elimination of previously removed response times from the TS.

  During the meeting, the NRC staff pointed out that, if the licensee wants to retain the existing exception from time response testing provisions, they should review the bases for these exceptions. If the replacement system diagnostic functions are to be credited in lieu of the current calibration and functional test surveillance tests as described in the licensee's presentation, a new basis for these time response test exceptions may need to be established. If a basis for these exceptions is not reestablished in the LAR, the TS test exceptions may become invalid and new test requirements would be needed.

- Describe any changes to allowable values and setpoints with regards to protecting allowable values.

2.2.2.6. January 11, 2022, Presubmittal Meeting

During the meeting the licensee discussed TS changes that the licensee plans to submit as part of a planned LAR. This meeting was a continuation of a public meeting on the same topic held on December 7, 2021. During the meeting, the licensee presented information in response to NRC staff feedback from the public meeting held on December 7, 2021, regarding proposed changes to the TS for LGS that were intended to reflect the digital design and improve consistency with the standard TSs. The licensee addressed the following topics in its presentation in response to NRC staff feedback from the December 7, 2021, public meeting:

- How Limerick's proposed protection system meets design requirements.
- How Limerick's proposed protection system provides lowest functional capability of the system.
- Reestablishing the basis for the continued elimination of previously removed response times from the TS.
- Potential impacts on limiting conditions for operation and surveillance requirements for engineered safety features actuation system and ECCS.
- Potential impacts associated with the surveillance requirements for the manual initiation functions at the system level for each subsystem of ECCS and the nuclear steam supply shutoff system.
- Additionally, the licensee presented a change from the December 7, 2021, meeting regarding the proposed TS changes. The licensee previously stated the proposed TS change would include TS 3.3.3, "Reactor Trip Units," which would provide requirements on the trip system from the division reactor trip matrix through the scram valves. The licensee suggested existing requirements in TS 3.1.3.1, "Control Rod Operability," and surveillance requirements in TS 3.3.2, "Plant Protection System Divisions," would provide end-to-end verification of the operability of the reactor trip system.
- A key discussion was presented that explained how the PPS design meets the single-failure criteria with only three out of four operable channels and was the key for not having any limiting conditions for operation when one of the four channels was inoperable.

The NRC staff informed the licensee that the following should be described in more detail at a future public meeting and in the planned LAR:

- A description of the limiting condition for operation and associated action statements entered for each reduction in the number of channels available in the PPS. To better understand how the proposed system complies with the criteria of IEEE 603, the NRC staff requested a description using a staged approach to loss of channels and associated example action statements in the information request following the December 7, 2021, public meeting. That information was not able to be made available at the January 11, 2022, meeting.
- A description of how channels out of service will impact operability of the actuated systems. The NRC staff pointed out that the operability of the PPS would impact actuated equipment. The licensee stated the proposed TS will have actions that recognize the impact of inoperable divisions on actuated equipment and that the LAR will describe and justify that the TS have appropriate mitigating actions for the specific degradation. The staff suggested an additional discussion on those actions prior to LAR submittal may be helpful in preparing for the review.

The next presubmittal was planned to be held in March 2022.

2.2.2.7. March 31, 2022, Presubmittal Meeting

CEG provided the following information to the NRC staff during the open portion of the meeting:

- LAR progress and proposed schedule for LAR submittal
- Proposed LAR content and expected post-submittal supplements
- Separate risk-informed completion time (RICT) LAR
- Response to previous NRC staff questions related to TS 2.2.1 (Limiting Safety System Settings) and LGS 3.3.1 (Plant Protection System Instrumentation Channels)
- Outage installation strategy and required TS revisions.

CEG provided the following information to the NRC staff during the closed portion of the meeting:

- DPS and RRCS architecture
- Sensor consolidation
- Reliability analysis
- HFE evaluation
- LGS plant power distribution and PPS cabinet power distribution
- RICT LAR update.

2.2.2.8. June 9, 2022, Presubmittal Meeting

CEG provided the following information to the NRC staff during the meeting:

- LAR progress and proposed scope and schedule for submittal (these are described more in Section 2.2.3):
  - Digital modernization LAR
  - Outage installation LAR
  - RICT LAR
- A discussion concerning HFE evaluation and ISV
- Response to previous NRC staff questions related to the HFE validation and verification process and the D3 coping analysis [11].

2.2.2.9. September 8, 2022, Presubmittal Meeting

CEG provided the following information to the NRC staff during the open portion of the meeting:

- Detailed LAR schedule for submittal and expected post-submittal supplements and project activities through the initial outage installation
- Summary of DI&C-ISG-06, Revision 2, Enclosure B matrix and post-LAR submittal and supplements
- VOP and summary
- HFE follow-up from June 9, 2022 presubmittal meeting
  - Project compliance with key guidance for HFE Program Plan
  - Expected CV, PV, ISV, and FAT results timing
  - Glass top and ANSI 3.5 simulator details

- Elimination of turbine enclosure main steam line tunnel high-temperature isolation function
- Outage Installation Support LAR overview (see Section 2.2.3.2).

CEG provided the following information to the NRC staff during the closed portion of the meeting:

- LAR content relative to PPS SyRS [37] and PPS SyDS [39] and alignment with DI&C-ISG-06 [1] requirements
- Equipment qualification (EQ) summary report and timing of specific EQ reports PPS and DCS cabinet power supplies.

2.2.3. License Amendment Request Strategy Refinement

Initial licensing plans for the LGS SR I&C Upgrade Project accounted for submitting one Digital Modernization Project LAR to the NRC for the entire effort. This one LAR was intended to include all necessary NRC approvals to accomplish the upgrade. To support the LGS Unit 1 SR I&C Upgrade LAR approval schedule using the DI&C-ISG-06 [1] AR process within the larger overall project schedule, this one-LAR approach was determined to be lacking. A total of three LARs are now being submitted to support the project. Each is described below.

2.2.3.1. Digital Modernization Project License Amendment Request

The proposed changes will revise the LGS licensing and design basis to incorporate a planned digital modification at LGS (i.e., the LGS Digital Modernization Project). Incorporation of the modification into the LGS licensing and design basis will also result in changes to the LGS TS.

The LGS Digital Modernization Project replaces the existing analog control logic hardware of the RPS, N4S, ECCS, RCIC system, and end-of-cycle recirculation pump trip instrumentation with the new PPS.

The scope of the PPS modification also includes upgrading the RRCS with the Westinghouse Ovation controller platform. The RRCS performs the functions required to comply with the ATWS rule (i.e., 10 CFR 50.62 [6]) and is currently classified as SR. The proposed change reclassifies RRCS to non-safety related, consistent with the system classification requirements of 10 CFR 50.69 [9]. Any additional diverse actuation functions that are needed as a result of the D3 CCF coping analysis [11] will be implemented in the new Ovation-based RRCS.

In addition, based on historical RRCS operational issues at LGS that have challenged plant operations and have the potential to complicate reactor level control during an ATWS, CEG has chosen to eliminate the automatic RRCS feedwater runback function as part of the PPS modification, while retaining the manual feedwater pump trip function.

Similarly, based on the potential for ambient temperature swings in the turbine enclosure (TE) for reasons other than actual main steam leaks, which could potentially result in exceeding the TE main steam line tunnel area temperature setpoint and cause an unnecessary Group I isolation, CEG has elected to include the elimination of the automatic isolation function for TE—main steam line tunnel temperature—high in the modification and the addition of TS-required manual actions.

The Digital Modernization LAR was submitted to the NRC on September 26, 2022. As of the writing of this report, the current project schedule is to support LGS unit 2 installation during its April 2025 refueling outage and LGS unit 1 installation in its April 2026 refueling outage.

2.2.3.2. *Installation Support License Amendment Request*

The Installation Support LAR and exemption request facilitates the installation of the new PPS system within the given outage duration. It is needed to:

- Support preoutage RRCS demolition activities 30 days prior to outage. To accomplish this, a request for a temporary, one-time allowable outage time (AOT) extension for TS Section 3.3.4.1, "ATWS Recirculation Pump Trip System Instrumentation," Actions D and E, from 72 hour to 30 days and 1 hour to 30 days, respectively. This will be supported with a temporary one-time AOT extension for TS Section 3.3.4.1, "ATWS Recirculation Pump Trip System Instrumentation," Actions D and E, from 72 hour to 30 days and 1 hour to 30 days, respectively.
- Provide temporary relief from compliance to 10 CFR 50.62 [6] since the RRCS function will be inoperable during the 30-day demolition. A temporary exemption request is required from 10 CFR50.62(c)(3), (4), and (5) since the alternate rod insertion system, automatic standby liquid control system, and automatic ATWS recirculation pump trip will be inoperable.
- Implement TS task force reactor pressure vessel water inventory control enhancements (Technical Specifications Task Force 582) to facilitate TS compliance during outage installation configurations.
- Support a TS change to facilitate mode switch and manual scram function inoperability issues, which come into play because of the modification work (which includes core modifications).

Technical Evaluation of the Installation Support LAR is not linked or dependent on the Digital Modernization LAR. The Installation Support LAR was summited to the NRC on February 17, 2023, with a requested one-year NRC review.

2.2.3.3. *Risk-Informed Completion Time License Amendment Request*

LGS has implemented a RICT program. The RICT LAR was made necessary because a decision to remove RICTs associated with instrumentation limiting conditions for operation impacted by the changes from the Digital Modernization LAR. This was done to facilitate the timely review of the Digital Modernization LAR. The PRA [29] analysis needed to modify RICTs requires detailed design information that is not planned to be available in the time frame to support combining this information in the Digital Modernization LAR. The PRA model update changes started in December 2022 with the submittal of the RICT LAR forecast for December 2023 with a requested one-year NRC review. This would facilitate restoring instrument-related RICTs at the end of the 2025 refueling outage for LGS Unit 2. Technical evaluation of the RICT LAR is linked to the Digital Modernization LAR. The NRC staff has indicated that such a linkage may be appropriate as part of the LAR AR, as discussed with NRC staff in several presubmittal meetings.

2.2.4. Early Submittal of Defense in Depth and Diversity Analysis

CEG chose to submit the D3 analysis [11] as described in Section 2.1.1.3.3.1 to the NRC during the presubmittal process. This occurred on February 14, 2022. CEG thought that this would enable NRC staff to allow the NRC to complete the Digital Modernization LAR review in under 17 months. NRC staff have been reviewing the D3 analysis [11] and providing input on the approach used. Three LAR presubmittal meetings were held with NRC staff on this subject, which are summarized below.

2.2.4.1. May 18, 2022, D3 Presubmittal Meeting #1

The first D3 presubmittal meeting provided an overview of the D3 audit process and the OI list and how it would be used for the D3 analysis [11]. The original OI list included 37 questions and 14 additional document requests. The NRC staff and licensee went through several items on the list, notably including items 5, 6, 7, 8, 25, and 37, among a few others. NRC staff informed the licensee that seven questions had inadvertently been left off the OI list and would be forwarded following the meeting. A few items were marked as closed and there were several items that were identified as needing more information or initial answers from the team.

2.2.4.2. June 16, 2022, D3 Presubmittal Meeting #2

The second D3 presubmittal meeting went further into the OI list and opened with some higher-level discussions and questions about the function of the list. Items 1, 2, 3, 7, 9, 14, 15, and 41 were discussed between NRC staff and CEG, among others. The response designation of "confirm" was explained and would be used when the NRC staff had enough information for the moment and would confirm the information in the formal submittal. A few items were moved to confirm status and a few were moved to "closed." There were back and forth discussions between NRC staff and the licensee, and CEG would continue to work on getting more answers completed before the next D3 presubmittal meeting.

2.2.4.3. July 22, 2022, D3 Presubmittal Meeting #3

The third D3 presubmittal meeting continued with the OI list. Different responsible NRC team members asked questions on their respective areas and licensee item owners provided their best answers or told the NRC staff they would gather more info and get back to them. Items 1, 4, 5, 11–13, 16, 17, 20–39, 41–46, and 51 were discussed among others. Almost all of those discussed were moved to the confirm or closed status. NRC staff were also informed that, in the meeting held on June 16, 2022, Westinghouse presented an error captured in the D3 analysis provided to the NRC (ML22164A808). Subsequently, Westinghouse self-discovered this error and submitted a revised D3 analysis to the NRC to close out the OIs and self-discovered issue.

2.2.5. Schedule of Post-License Amendment Request Submittal Key Licensing Activities Through Project Completion

During the September 8, 2022, presubmittal meeting with NRC staff concerning this LAR, CEG indicated that the following documents associated with the LAR would be submitted. As of May 2023, the documents and the latest dates associated with their submittal are listed below:

- The PPS SyDS [39]: Revision 3 was submitted in February 2023.
- HFE Conceptual Verification RSR: Submitted in February 2023.
- The CV RSR will document the verification that the HSI design meets acceptance criteria identified therein. This will include an assessment of credited manual human actions.
- HFE PV RSR: Submitted in March 2023.
- The PV RSR will document the completion of PV activities, including HSI design and validation of credited manual actions, as described in NUREG-0800, Chapter 18, Attachment A [27].
- Seismic EQ Summary Report, Revision 0: Forecast date of November 22, 2023.
- Environmental EQ Summary Report, Revision 1: Forecast date of January 24, 2024.
- Electromagnetic Compatibility EQ Summary Report, Revision 2: Forecast date of January 24, 2024.

The EQ summary reports listed above will provide the required information specified in DI&C-ISG-06, Section D.3.1, "Information to Be Provided," including:

- Codes and standards
- Equipment tested or analyzed
- Summary details of testing performed
- Reference to detailed test report(s)
- Associated results
- Installation restrictions (if any)
- Conclusions.

2.3. Project Management and Procurement: Activities and Deliverables

2.3.1. Stage-Gate Approval Process – Project Initiation to Conceptual Design Approval

As described in the Project Initiation Phase Lessons Learned Report [5, Section 2.6], the following were produced as an input to the conceptual design phase stage-gate approval process:

- A project plan commensurate with the level of project complexity was developed to ensure all project objectives and deliverables required to execute the project are defined and in place.
- A risk management plan and associated risk register were developed to identify potential risks, identify methods to address those risks (e.g., accept, mitigate, transfer) as appropriate, and estimate project impacts if potential risks are realized.
- A project procurement plan was also developed in accordance with Section 5.1.1, "Develop or Apply a Procurement Strategy," of the EPRI DEG [4], and CEG procedure PC-AA-1005, "Projects Implementation" [10]. For the SR I&C pilot upgrade, the type of procurement will consist of both "system" and "services," as identified in the EPRI DEG. Vendor selection, an element of the project procurement plan, was performed using a CEG-developed initial performance specification (bounding project scope) along with objective evaluation criterion as specified in the EPRI DEG to review the PPS request for proposal submittals, characterize the vendor suitability technically and financially, and document the results. Results were communicated to internal stakeholders to ensure that the down-select results were challenged and that the best-fit selection was aligned upon prior to the contract award.
- An initial project DOR
- A Level 2 project schedule to bound key deliverables and milestones
- An order of magnitude estimate, with a certainty range of -50–75% for an initial scoping phase project.

As enabled by the above, CEG management provided Concept Design – Phase 1 Authorization to Proceed for this project in December 2020. Associated project management activities for the conceptual design phase and detailed design phase activities through September 2022 are described below.

2.3.2. Conceptual Design and Detailed Design Project Management Activities

Once authorization of conceptual design activities had been obtained, efforts to fully fund and stand-up the project to execute commenced in earnest. These efforts are described in the remainder of this section.

2.3.2.1. Department of Energy Engagement

Coincident with the CEG concept design phase authorization, project management pursued a continuation application for Budget Period 2 (2022) and finalized all award documentation under DE-NE0009042 to permit project concept design activities to commence. The successful completion of the PPS and DCS common conceptual design was a go- or no-go decision point for the project. The detailed design authorization, by CEG and DOE leadership, demonstrated that the business case and go forward costs were still in alignment with initial assessments, satisfying the merit criteria to continue the project.

2.3.2.2. Contracting and Budgeting

The CEG Supply organization uses a formal bidding and evaluation process to select vendors and award project-related scopes of work (and in accordance with 2CFR200, DOE contract DE-NE0009042 and all CEG management model policy). Prospective vendors are issued a technical scope of work within a request for proposal for each vendor to consider in development of their respective approach to proposing the scope of work and associated cost basis. Each bidder's proposal has been evaluated (or scored if you will) against many merit criteria, ranging from technical content, diversity, cost profile, organizational risk, related success of similar work performance, and personnel expertise and experience. The bid evaluation criteria cited previously is not all inclusive but is a representative of general evaluation criteria. The bid evaluation criteria can be customized to the type of services solicited and weighted individually based on project needs to arrive at a meaningful numerical result to support the vendor selection activity. Any unique attributes used in the bid evaluation process and vendor selection will be discussed in the following sections.

2.3.2.2.1. Idaho National Laboratory

INL was chosen as the lead organization to bound the scope of the HFE program within the larger LGS SR I&C Upgrade Project, coordinate its execution, and document the results. The reputation of INL in HFE is well established. INL HFE personnel produce methodologies and tools to support industry implementation of HFE, directly assist utilities in that implementation, and provide HFE training to both industry and to NRC personnel.

INL and CEG entered into a cooperative research and development agreement to provide a contracting vehicle for INL to support the project. For the HFE planning and analysis phase as defined in NUREG-0711 [8], INL created necessary budgets, developed an execution schedule, and integrated that schedule within the larger project schedule managed by CEG. Funds were provided directly to INL by CEG and by DOE to complete HFE planning and analysis activities. INL also entered into a non-disclosure agreement with Westinghouse to facilitate necessary data exchanges for the benefit of LGS to support the development of HSIs.

INL will continue to be involved in continued HSI detailed design efforts. INL will also guide HSI verification and validation efforts, including CV and PV of MCR HSI resources as well as supporting ISV preparation and execution. INL will provide facilities, such as the HSSL, as well as qualified resources to support CEG's completion of HFE efforts for the project.

2.3.2.2.2. Westinghouse

While bid evaluation and OEM selection for the new safety-related plant protection system followed the generic process discussed in Section 2.3.2.2, additional activities were necessitated, due to the financial and technical significance of the project scope. CEG used, in addition to a request for proposal (RFP) with each prospective OEM, a request for information (RFI), from each OEM requiring each to provide a detailed plan to accomplish the scope of work and provide a conceptual design approach for retrofitting modern digital controls into an existing operational BWR nuclear plant. This permitted early insights into each OEM's novel approach to the technical design challenges and capabilities and open a channel of dialogue with each OEM for addressing CEG RFI-related questions. All questions and answers were conducted publicly, meaning all vendor and CEG questions and answers were shared with all vendors, unless the vendor response to a question used proprietary information embedded within the response(s). The RFI was not included in the formal bid evaluation process but influenced each vendor's RFP response.

Once all OEM's remitted their RFP response, each were evaluated against predetermined bid evaluation criteria and scored accordingly. The bid evaluation team was comprised of a cross-functional group of individuals from the project team representing plant operations, design engineering, plant engineering, project management, and supply to ensure a diversity of scoring. Final scoring results were tallied, reviewed, and presented to leadership (at CEG and DOE) for alignment in the down-selection process, results, and acknowledgement of award to the successful OEM. Westinghouse prevailed out of seven candidates that participated in the bid event.

2.3.2.2.3. Sargent & Lundy and Other Vendors

Selecting Sargent & Lundy as engineer of choice, as well as all other project support contracts also followed the same request for proposal, bid event, and evaluation process as the OEM down-select described in Section 2.3.2.2.2.

2.3.2.3. Detailed Division of Responsibility

With contracts in place, CEG worked with its collaborators to refine and add details to the project DOR developed in the project initiation phase. This is consistent with Section 4.2.1 of the EPRI DEG [4] and is captured in Section 2.1.1.1.

The DOR worksheet as provided in Attachment A of the EPRI DEG was used as a starting point for detailed DOR development and adapted as necessary by the project to meet its specific needs. The current DOR is provided as Attachment A to this report.

2.3.2.4. Scheduling of Detailed Project Activities

As required for projects in the conceptual design phase, a Level 3 schedule was developed that provided additional granularity to the Level 2 schedule developed during the project initial scoping phase. The Level 3 schedule extended through installation planning, as shown in Figure 3, to gauge schedule adherence and performance to outage targets. Vendor activities were incorporated into the Level 3 schedule to enable the tracking of their efforts as well.

2.3.3. Stage-Gate Approval Process – Detailed Design and Ongoing Activities

As the conceptual design phase was completing, CEG management and DOE authorization was required for the project to continue into the detailed design phase. The necessary items making up the detailed design project authorization package were updated based upon the conceptual design project management efforts described in Section 2.3.1, including:

- The project plan, commensurate with the level of project complexity, was updated to ensure all project objectives and deliverables required to execute the project are defined and in place.
- The risk management plan and associated risk register were updated to update risks, identify new risks, and identify methods to address those risks (e.g., accept, mitigate, transfer) as appropriate and estimate project impacts if potential risks are realized.
- The project DOR was refined to support the detailed design phase, incorporating new cross-functional site support teams and project contractors. The current DOR is provided in Attachment A to this report.
- The Level 3 project schedule was updated to bound key deliverables and milestones.
- The budgetary estimate was refined to provide a certainty range of -25–25% for the detailed design phase of the project.

The detailed design phase of the project was authorized on December 13, 2021, and is anticipated to complete for the lead unit on or before calendar of Q3 of 2024. The completion of the follow unit detailed design is anticipated on or before Q3 of 2025. Project management will pursue CEG management and DOE approval to authorize the installation planning, installation, test, and closeout phase as shown in Figure 3.

3. LESSONS LEARNED

To facilitate the identification and capture of lessons learned, face-to-face meetings were held with key CEG project participants, including:

- **Engineering and Operations**
  - Mark Samselski, Responsible Engineer
  - George Bonanni, Engineering
  - Paul Krueger, Operations
  - Scott Schumacher, Engineering
- **Licensing**
  - Frank Mascitelli, Senior Licensing Engineer
  - Ashley Rickey, Principal Licensing Engineer
  - Jim Berg, Senior Regulatory Engineer
  - George Budock, Principal Regulatory Engineer
- **Project Management**
  - Jerry Segner, Principal Project Manager
  - Steven Hesse, Project Director
  - David Molteni, Senior Manager Digital Modernization

Individuals from INL also participated in the generation of this report and provided lessons learned primarily in the HFE area of engineering and operations, including:

- **Human Factors Engineering**
  - Jeffrey Joe, Human Factors Scientist
  - Casey Kovesdi, Human Factors Scientist and Engineer
  - Paul Hunton, Senior Research Scientist

  All the above individuals contributed to this report.

3.1. Engineering and Operations Activities

3.1.1. Instrumentation and Control Design

3.1.1.1. Project Scoping and Execution

3.1.1.1.1. Structural Inertia: Replacement-Oriented Thinking and Sustaining Engineering

When examining conceptual and detailed project scope refinement in hindsight, it became apparent to both engineering and operations personnel that such efforts were initially oriented toward providing "like-for-like" replacements of existing system functionality using new digital equipment. Project scoping efforts during the initial scoping phase as captured in the associated lessons learned report [5] presented a robust use of technology to provide improvements in functionality and data analysis to reduce plant TCO.

The following is stated in the Initial Scoping Phase Lesson Learned report [5]:

> This Project intends to engage the vendor as early as possible to establish a collaborative relationship between the utility and the vendor. This collaboration is expected to evaluate and refine information communicated in the initial performance specification and develop more detailed requirements, specifications, and system configuration instructions. Through such a collaborative and iterative Conceptual Design Phase and Detailed Design Phase effort, Project costs will be more closely controlled, final products will provide the maximum benefit, and lifecycle support strategies will be refined to lower TCO.

As the project has progressed, it has had to overcome a "structural inertia" within the nuclear industry that impedes realization of this concept. The nuclear industry relies predominantly on legacy system documentation and understanding of existing system properties to bound the capabilities of the new two-platform I&C solution (separate safety and non-safety platforms) being pursued by LGS. The causes of this include:

1. Nuclear project identification and approval processes and procedures are oriented toward addressing particular issues with existing systems and either repairing them or pursuing like-for-like replacements, particularly for SR I&C systems. Industry guidance, such as the Institute of Nuclear Plant Operations AP-913, "Equipment Reliability Process Description," [46] and use of the Mitigating System Performance Index on SR systems, drives such thinking. This in no way is meant to impugn these processes and procedures from the perspective of their obvious contribution to plant safety and reliability over the years. However, as many I&C systems are operating at or beyond their original design lifetime, they are increasingly difficult and uneconomical to sustain. Further investment in antiquated and fragmented I&C systems also provides no opportunities for leveraging the capabilities of new technologies.

2. Industry has little remaining experience in implementing digital I&C upgrades in a strategic manner across a nuclear facility or a fleet of such facilities. Plant I&C system engineers at a nuclear site are primarily responsible for maintaining current systems. These system engineers are assigned to support existing, specific I&C systems in the plant. They track system performance, identify any deficiencies with the system, and identify methods to address those deficiencies. Activities to address those deficiencies as directed by station procedures and processes that do not require an engineering design change to accomplish are typically addressed by system engineers. Examples of plant I&C system engineers activities include identifying the need for calibration of equipment, replacement of failed components with available (or obtainable) exact replacements, etc.

   Utilities also have I&C design engineering departments with highly qualified design engineering personnel. I&C design engineers are engaged when a design change needs to be made to I&C systems. Examples of design changes directed by these design engineers include reverse engineering replacement parts that provide the same form, fit, and function as failed legacy parts, enabling new capabilities through software program changes to existing digital systems, designing new systems that provide like-for-like functionality of existing obsolete systems, or designing new systems that provide enhanced functionality when compared to functions (such as eliminating single point vulnerabilities and automating existing manual functions).

   Many utilities do not have I&C system or design engineers who are familiar with or capable of performing a systems-engineering function as outlined in the EPRI DEG. To fulfill the role of a digital systems engineer requires detailed knowledge of and familiarity with new digital system technology, its capabilities, and its long-term lifecycle support strategies. Such systems engineers also have the capability to envision how these modern digital systems can be applied holistically across a nuclear plant. Such applications can provide not only existing I&C functionality, but can integrate and augment existing functionality plantwide to provide new capabilities enabled by new digital systems. For example, new SR and NSR digital I&C platforms can be optimally applied for maximum aggregate benefit at the lowest TOC across an entire nuclear plant for its remaining operational life.

   The systems engineering skills to envision, integrate, and strategically apply new I&C systems and capabilities holistically across the enterprise that were once resident at many utilities during and immediately after the construction of nuclear plants in the United States in many cases no longer exist. This, along with the technology gap between existing nuclear plants and the modern industrial control system industry outside impedes fully leveraging the capabilities which can be enabled by nuclear digital I&C modernization. Current utility I&C system and design system engineers can read and conceptually understand the systems engineering process as described in the EPRI DEG, but in most cases they lack the technical knowledge of new digital systems and practical experience in specifying their use and implementing them to fill the systems engineer role. This is discussed more in Section 3.3.2.

Early input from operations and other stakeholders was also pursued and provided to develop project scope as is good practice. Engagement, however, was largely based on a “piece-parts” review of specification sections focused largely on the new digital systems providing like-for-like” functionality. Stakeholders did not have an opportunity early in the process to understand a larger picture where capabilities beyond those available on current system could be leveraged. More specific lessons learned regarding operations involvement in project scoping are provided in Section 3.1.1.1.4.

As the project has and continues to progress, the project team led by CEG is overcoming this structural inertia. Improved collaboration and improved communication within CEG and between CEG, and its subcontractors has resulted in leveraging available digital technology enabled capabilities more fully, more in line with the new-state vision that those who initiated and approved the project are intending to achieve. A lesson learned is that similar projects would benefit from more clearly defining and communicating this vision to foster earlier stakeholder understanding and buy-in to translate these ideas earlier and more concretely in the initial project scope.

3.1.1.1.2. Locking In Preliminary Design Concepts as Project Requirements

As is necessary in larger and complicated projects, preliminary design and project execution concepts are typically created to frame the project for direct project participants and management. Such concepts developed by this project were directed toward preliminary architectures, MCR layouts, installation techniques, outage scheduling, etc. Some of these preliminary concepts (such as the installation of the upgrade taking two outages to compete), tended to be malleable as the project progressed and more information was made available. In other cases, initial design concepts intended to be illustrative only became more locked in even though it was well known that necessary analyses had yet to be performed on them.

An example of this was the MCR preliminary design concept pictured in Figure 22.

Figure 22. Preliminary general arrangement for the upgraded Limerick MCR.

Figure 22 was generated by the project responsible engineer early in the project. It was very helpful in communicating the portions of the MCR to be impacted by the modification. It also provided generalized depiction of the Common Q PPS and Ovation VDUs that will be necessary to allow operators to supervise and control plant functions hosted by these systems. This helped communicate the project scope within CEG and to NRC staff.

As the conceptual design of the project was initiated and advanced, the Figure 22 depiction became the de facto control room arrangement. It was used to bound the number and size of the Common Q and Ovation VDUs. It also tended to drive the thinking that locations of those VDUs in the final design would be as shown. This was all occurring even though no formal HFE evaluation had been performed to inform the Figure 22 arrangement. The principal engineer was fully aware of this and was communicating that planned HFE efforts would impact the MCR arrangement, but other project needs were driving that design attributes be established for estimating purposes.

As project HFE activities were initiated and progressed, it became apparent that there were significant HFE issues that made portions of the preliminary MCR arrangement concept unworkable. NUREG-0700 human-system interface design review guidelines had not been fully considered in the Figure 22 arrangement. Three-dimensional modeling of the MCR by INL began identifying issues with sight lines, accessibility by operators of different sizes (e.g., 5th percentile female and 95th percentile male), and missing interface equipment (e.g., pointing devices). Several alternative arrangements were developed and used to move the HSI aspect of the conceptual design forward. The latest MCR arrangement as of the writing of this document is shown in Figure 21.

As HFE planning and analysis phase activities as identified in NUREG-0711 [8] continued, the MCR layout continued to evolve through the performance of the FRA&FA and task analysis efforts captured in Section 2.1.2.4 above. Despite these efforts, there was still resistance to use these HFE results because of efforts to minimize changes to the project scope, which was based on the preliminary MCR layout from Figure 22..

3.1.1.1.3. Bounding New System Installation Impacts to the Plant

In addition to challenges in bounding requirements in a method conducive with leveraging design capabilities of the pre-engineered platforms selected for use in this project, there were also challenges when addressing how these new platforms would be installed in the plant. MCR interfacing constraints in the MCR, as discussed in Section 3.1.1.1.2, are impacted not only by HFE considerations but also by physical constraints associated with the panels and consoles. Wiring constraints such as cable separation requirements and cable pull lengths as impacted to relocate indications and controls to accommodate new HSIs provided by the project need to be considered. Physical constraints, regarding mounting new VDUs either on or within the structure of existing panels and consoles to meet seismic requirements, also must be addressed. Such modifications come at a cost. Tradeoffs must be weighed. For example, a choice between implementing “ideal” HFE-driven HSI concepts as opposed to “acceptable” HSI attributes that maintain or improve performance may be driven by the costs associated with each. The early conceptual HSI design is intended to help aid in refining the project scope in this area. To the degree that the MCR conceptual layout was locked in early in the project, it was more challenging to adapt modernized HSIs into the MCR panels and consoles.

This installation impacts issue also extends beyond the MCR. Initial concepts to retain cabinet structures and install new equipment within them changed to replacing cabinets and providing interface plates for them. System redundancy, cable routing, and fire protection design constraints also presented themselves

Project personnel were well aware that there would be installation impacts when replacing legacy analog systems with the new digital PPS and DCS. When retrofitting new digital systems into an existing plant, more significant, early investments in bounding and validating installation impacts with knowledge of the attributes of the replacement systems will minimize project risks and costs. This is not to say that this did not occur during this phase of the project, but that improvements in this area, as enabled by earlier and clearer communication of new-state vision (as discussed above), would provide benefit to future projects.

3.1.1.1.4. Engagement with Various Station Disciplines

As was briefly mentioned in Section 3.1.1.1.1, input from plant operations was solicited early and often in the conceptual design phase and in detailed design efforts to date. The engineering-driven replacement-oriented thinking in the conceptual design phase as described in Section 3.1.1.1.1, however, had a more pervasive impact on the project. While new system capabilities were generally discussed with operations and multidisciplinary teams were established, the ingrained nuclear culture of like-for-like replacements suppressed viewing the project from an oblique perspective that considers the wealth of experience and knowledge of operating issues regarding current system issues. Figure 23 better visualizes this challenge.

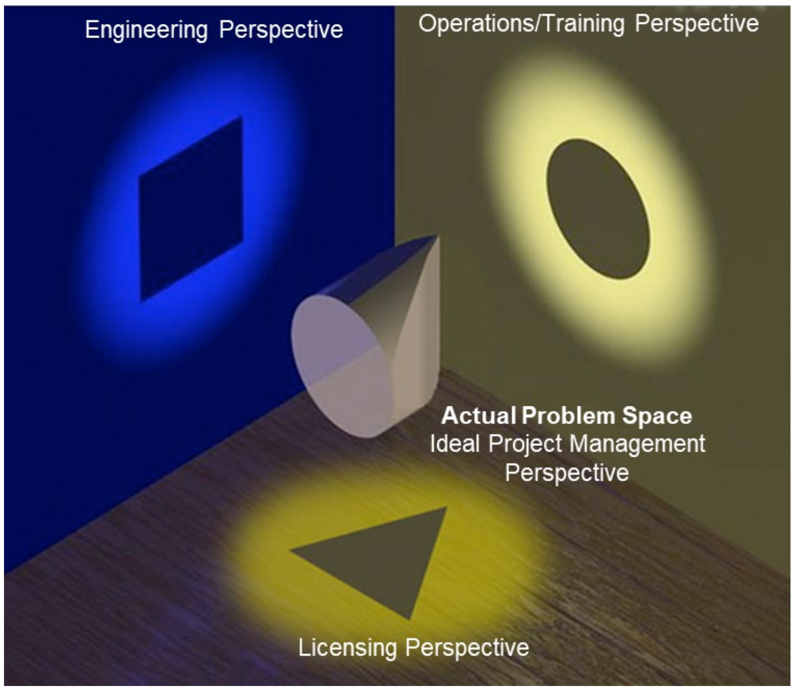


Figure 23. Different perspectives of the project.

It is important to note that each of the three, different, two-dimensional perspectives in Figure 23 are not wrong. Each is correct from its own vantage point. But by not fully considering the other perspectives, the true nature of the project scope shown in the center is not fully and mutually understood.

By being constrained in looking at the problem primarily from the engineering perspective that started with a like-for-like replacement point of view, operations did not fully recognize that there was a window to address operational issues associated with the legacy systems being replaced by the upgrade. The use of available new platform features, such as automation capabilities, were not substantively explored. Consequently, the early feedback provided by operations did not provide a significant value add to the project.

As conceptual and detailed design activities progressed, operations as well as training and maintenance personnel recognized that the opportunity to address existing issues and employ new functionality to improve operator and plant performance while reducing human errors in the project scope. As a practical example, with regard to training operators on the legacy SR I&C system designs, the associated training exam bank as well as operating procedures (with associated notes, cautions, and warnings) contain a wealth of knowledge of operational issues associated with these systems. Many exam questions and procedure notes, cautions, and warnings are the direct result of operating experience where plant upsets or other operational issues occurred either in whole or in part because of the attributes of the legacy I&C system design. By examining these with an eye toward addressing them in the new design, not only will the plant operate better, but procedures and training can be simplified. From a maintenance perspective, personnel also started to look outside of the box with regard to addressing true requirements that maintain plant safety as opposed to just perpetuating the status quo. This resulted in leveraging design aspects to reducing TS surveillances.

To add to this point, engaging training simulator personnel as part of operations provides a wealth of practical operating experience regarding operational issues and workarounds to address them. This is because simulator training is continuously occurring and exercising a far wider range of procedures and associated operator actions, including interfacing with HSIs, than is possible in the plant.

As the window opened to propose design changes, additional automated features, such as automated reactor pressure vessel pressure control using SRVs, were proposed by operations and eventually incorporated into the design.

As a final note regarding operations involvement, assertive personalities and the degree of openness to change are key attributes that need to be sought out when engaging operations personnel. They are the ultimate customers for the SR I&C digital upgrade project. They live with the operational capabilities and limitations of existing systems. Ownership by operations for the project is key to ultimate project success. Strong input from LGS operations, including training simulator personnel, has been and continues to provide strategic project direction. Retaining continuity of operations personnel as much as possible through the remainder of the project will enhance their ultimate impact.

These learnings for this project provide the industry with a model for iterative design and collaborative stakeholder engagement. The earlier this type of engagement can be achieved to include all project stakeholders, the sooner the structural inertia challenges identified in Section 3.1.1.1.1 can be more completely addressed.

3.1.1.2. Vendor Engagement

3.1.1.2.1. Instrumentation and Control System Vendor Engagement: Challenges with Iterative Design and Agile Development Processes

When developing the vendor performance specification as a tool for the vendor selection process and when placing the contract with the selected vendor, the requirements contained therein were intended to be written agnostically, that is, it was intended to focus on what the replacement systems needed to do and less on how the replacement systems actually would perform the needed functions. This was intended to allow the vendor to have flexibility when providing a design solution. It was agreed when discussing lessons learned with LGS engineering personnel that this is generally good practice. During those same discussions, it was revealed that, in hindsight, the performance specification and contracting scoping information were written with a backwards-compatible mentality with a bias toward maintaining the functionality of the legacy systems. This is captured in Section 3.1.1.1.1.

When the vendor was more formally engaged in the project iterative design activities consistent with systems engineering approach outlined in the EPRI DEG [4] were requested. In digital system development, this is often characterized as an Agile development process. A primer on the Agile process along with associated tenets can be found online at https://www.agilealliance.org/agile101/. This approach is intended to foster collaboration to produce the intended technical results more rapidly while promoting project cost and schedule efficiencies.

Generically speaking, current nuclear industry thinking in engineering space is that contract documents are taken as proscriptive and bounding in scope. This is antithetical to one of the tenets of the Agile process that puts "customer collaboration over contract negotiation." This is not to say contracts are not important and are not to be followed. But when applying and configuring fully designed digital platforms to a legacy plant design when the detailed platform capabilities and their applicability are not collaboratively understood by the customer and the vendor, using a "compliance model" for requirements is premature. Reverting into a compliance model mindset in conceptual design and early detailed design tends to overemphasize familiar legacy linear processes and tools in nuclear for engineering and project management over less familiar Agile processes that are more collaborative and iterative. This tends to violate another tenet of the Agile process: "individuals and interactions over processes and tools." This is not to say that both processes and tools should not be followed or used. Rather, the overemphasis on them over collaboration (the structural inertia from Section 3.1.1.1.1) can lead to a thought process that stifles collaboration.

The net result of this for industry is that the intended technical benefits and cost and schedule efficiencies afforded by an optimal implementation of an iterative Agile-like design process are not being fully realized. The nuclear industry needs to focus on necessary cultural changes to enable such processes while not creating processes that tend toward engineering verbatim compliance. Consideration should be made in changing the contracting model for digital I&C upgrades to promote an iterative, Agile conceptual design and requirements development process. These aspects of employing iterative processes throughout digital I&C upgrade projects are further discussed in Section 3.3.

3.1.1.2.2. Simulator Vendor Engagement

Simulator vendor engagement should go hand-in-glove with I&C vendor engagement. Ultimately, the simulator vendor must be able to either incorporate or replicate the HSI and I&C functional characteristics of the I&C upgrade being developed and installed in the target plant. This must also be done in a way that supports simulator-specific functionality, such as freeze and backtrack. The relationship between these two vendors is a microcosm of the larger overall "systems integration" effort for a complete I&C upgrade project, including the MCR simulator. How the interface between these two is managed is important. Unless an organization is clearly identified with total simulator integration responsibility, there can be challenges in obtaining necessary functionality in a timely manner to support the project and follow-on operator training and qualification needs. This relationship needs to be formalized in contract space (e.g., through proprietary information nondisclosure agreement or other contracting vehicles between the involved parties) early in projects such as the LGS SR I&C upgrade.

For the SR I&C upgrade project, simulator vendor engagement was delayed. This was made evident during the work up to the LGS HFE Task Analysis Workshop for this project. To support this workshop, as well as future HSI development activities, INL was able to receive and load the LGS simulator software in the INL HSSL. This was an early success in the project that others should emulate. It was intended to dynamically link prototype displays developed by INL with input from CEG with the LGS simulator software to provide a substantially "live" capability when walking through operational scenarios during the Task Analysis Workshop. While it was shown as a proof of concept that such dynamic linking was possible, INL was unable to present the desired degree of dynamic performance due to difficulty in mapping engineering values from the LGS simulator model to digital HSI displays. The LGS HFE Task Analysis Workshop was still held and met project objectives, but it could have been improved had the dynamic linking capabilities been more developed. As of the writing of this report, contracting vehicles to integrate the simulator vendor within the LGS I&C SR I&C upgrade project were still being negotiated.

3.1.1.3. Boiling-Water Reactor Plants Are Different

3.1.1.3.1. Design-Related Changes: Benefits and Challenges

For the LGS SR I&C Upgrade Project, not only is digital I&C technology employed, the fundamental system architecture and protection logic are being upgraded. By incorporating the functionality of modern SR I&C digital systems the large number of duplicated sensors that provide inputs to each of these three separate systems can be significantly reduced. This results in cost savings since these sensors will no longer need to be calibrated or maintained.

All the digital SR systems evaluated for application for PPS for the LGS upgrade support replacing the existing one-out-of-two logic systems taken twice I&C voting protection logic with a true four-channel, four-division digital logic system. Each of the four divisions employs two-out-of-four (2oo4) voting logic for each specific protective action. This eliminates the possibility of many inadvertent scram scenarios when compared to the existing one-out-of-two logic systems. It also allows for taking single channel inputs out of service (due to failure or other reasons), without impacting operations or technical specifications (when updated). The logic simply becomes two out of three in such a scenario.

While these benefits are very beneficial, some design aspects necessary to fully enable the benefits when transferring to the new logic schema were not fully considered when scoping the project. To fully leverage the flexibility and robustness of the 2oo4 channel and division logic of the new PPS, two new SR power supply busses are necessary. Because this was not identified until later in the project, the level of effort to provide these power supplies was not included in the original business case analysis on the project.

3.1.1.3.2. Operations Specific Properties Challenges of a Boiling-Water Reactor

As stated in the FRA &FA allocation results summary in Section 2.1.2.4.1.3, the initial MCR concept of operations as understood to be the target by INL researchers was not appropriate. The current LGS MCR concept of operation response is based upon the MCR watchteam having direct access through the flat topology of system- and component-level indications and controls provided by MCR panels and benchboard HSIs. Parallel operator actions as observed through FRA & FA workshop scenario execution are accomplished by the dynamic execution of parallel procedure paths based upon the watchteam's knowledge, judgement, and experience while using the flat topology HSIs.

During lessons learned interviews with operations personnel, it was stated that Limerick's BWR MCR modernization needs to be approached from the perspective of creating a mission control space. The new digital HSIs need to be integrated in a way to support this perspective. The following points that were offered to communicate this concept include:

- Large DCS VDUs need to be provided with select safety-related and non-safety related plant data. This data must be organized and formatted in such a way as to provide overall supervisory and operator situational awareness. These large VDUs are used at a standoff distance by all MCR personnel to establish and reinforce a common mental model to inform individual operator actions often taken in parallel.
- Enough VDU real estate and spacing needs to be provided to supplement the large VDU information to enable parallel processing when taking specific actions at individual operator PPS and DCS workstations (which include existing PPS and DCS VDUs and collocated physical switches).

Such a deliberate allocation of functionality to the large VDUs and the VDU-enabled operator workstations is necessary to support and enhance the BWR parallel processing operations model. This functional allocation at the same time negates issues that would otherwise present themselves. Without such a mission control space view, providing like-for-like HSI capabilities on new VDUs would likely create an artificial segmentation of functions by PPS and DCS functional boundaries from an operations point of view.

3.1.1.4. Analyses Performed During the Conceptual and Detailed Design Phase

3.1.1.4.1. Hazard and Consequence Analysis for Digital Systems

CEG saw the objective value of applying HAZCADS [13] to digital upgrades in the concept design phase as described in Section 2.1.1.2.3.2. Benefits and deltas observed when working to apply HAZCADS to the LGS SR I&C Upgrade Project scope as identified by CEG are that:

- The training on the process was high quality. Attending the training promoted general understanding of the concept and helped develop a mindset that it is necessary to identify losses, hazards, UCAs, and methods to eliminate or mitigate them. Attending the training and working through examples, however, did not impart a level of experience to participants to enable them to be subject matter experts who could perform the analyses in a systematic and repeatable fashion. A part-time facilitation of project-specific analyses added value. Full-time facilitating during HAZCADS analysis meetings would have been better, but it would not have made up for the lack of process execution runtime. Participants felt that, to be proficient to perform HAZCADS, practitioners would need to develop the requisite skills during many iterations over time and maintain them through continuous use.
- Tied to the previous point, utility operations and engineering personnel felt that an application of HAZCADS is better suited for a clean-sheet I&C design solution. For the LGS SR I&C Upgrade Project, most of the desired functions and licensing basis functions have already been bounded by the larger plant design. While HAZCADS was seen as having a potential benefit where a new I&C functionality was being considered, participants felt that most of the system hazards and constraints for the bounded scope had already been identified and evaluated.
- Utility operations and engineering personnel noted that they felt they brought preconceived biases into the HAZCADS effort that tended to skew the results. Some stated that HAZCADS was being used to analyze and confirm their assumptions and produce results that were understood beforehand based upon their understanding of analyses of the existing systems.
- Project schedule and budget constraints coupled with perceived utility qualification and experience shortcomings resulted in a situation where the pilot utility could not fully commit to the HAZCADS process. Similarly, the I&C vendor did not have the resources or time in their contract with the utility to engage in the STPA HAZCADS process. Performing a HAZCADS effort was seen by the vendor as more of a utility effort to define requirements rather than a collaborative effort to identify UCAs that could cause hazards and result in losses.
- Utility personnel could only engage in the HAZCADS as a part-time activity due to other work assignments related to the pilot project. This also inhibited its application.
- Ultimately both operations and engineering identified that HAZCADS would be best executed as a hand-in-glove collaborative effort with vendor involvement.

These items are likely reflective of the first-of-a-kind (FOAK) use of HAZCADS in this industry pilot. Use of HAZCADS across the industry could be enhanced by developing individuals and groups (either at larger utilities or other industry-supporting organizations [e.g., EPRI, INL, etc.]) who establish and maintain HAZCADS proficiency.

3.1.2. Human Factors Engineering

INL HFE researchers have been involved in the LGS SR I&C Upgrade Project from the start. Project work directly performed in support of this project cross-pollenates INL HFE with research efforts performed by the same personnel. As part of DOE-funded INL HFE research, the LWRS Plant Modernization Pathway produced and issued a public-facing research report that captured many HFE lessons learned during LGS I&C upgrade conceptual and detailed design activities. This report, INL/RPT-22-68472, is titled "Demonstration and Evaluation of the Human-Technology Integration Function Allocation Methodology," [32]. Section 6 of Reference 32 presents those lessons learned. They are summarized here to promote completeness of this report. Each HFE lesson learned as presented in the subsections below is numbered to allow for cross-referencing.

3.1.2.1. Team Composition and Dynamics

1. **Early involvement and regular communication between operations, training, and HFE is critical in planning and coordinating HFE activities.**

   The early involvement of a multidisciplinary team of CEG engineering, operations, and training personnel along with INL HFE researchers resulted in the effective identification of scenarios that were used for the FRA&FA workshop as well as the TA workshop. The multidisciplinary team also worked together to design early MCR and HSI concepts, to identify key considerations to address, and to address logistical considerations with simulator integration and workshop planning. Regular communication between the team members was critical to achieve these ends. CEG operations and training personnel, while tasked with many other activities, made the time as supported by their management to support project efforts. This is especially important in managing some of the challenges described in Section 3.2.1.

2. **A clear division of responsibility between parties is important for effective collaboration.**

   A DOR enabled the entire design team. Having well-defined roles for each discipline ensured that planning activities were completed efficiently and that each team member effectively contributed using their domain expertise. Having a team lead across each area if there are multiple staff in a single discipline was useful when coordinating between organizations.

   The DOR was also used in planning specific HFE-related activities. Establishing clear roles for HFE staff supported workshop planning, which involved scheduling, team coordination, protocol and tool development, scenario development, simulator integration, management of facility security protocols, and other administrative tasks.

3.1.2.2. Methodological Considerations

3. **A risk-driven scenario-based approach to evaluating impacted functions and tasks provides an effective way to evaluate the impacts to tasks naturalistically and capture task interdependencies for the most critical impacted human actions (HAs).**

   A scenario-based approach allowed evaluating macrolevel (e.g., concept of operations) and microlevel (e.g., specific interactions with HSIs) task considerations. The use of scenarios allowed the HFE team to evaluate impacted tasks in a naturalistic manner to which their interdependencies could be effectively addressed by added context of use. As such, macrolevel considerations, such as impacts on teamwork, communication, and overall crew performance, were examined with the proposed modifications, compared to the existing MCR concept of operations. The scenario-based approach enabled additional benefits captured in HFE Lessons 4–11 below. Moreover, the scenarios will be reused in later HFE activities like V&V for ISV. As such, a key lesson learned is to identify scenarios (key use cases), driven by a graded approach (i.e., view risk analyses), early so that the impacted tasks can be evaluated in planning and analysis HFE activities when design input can be best leveraged.

4. **Applying a "baseline" evaluation of the existing state offers value in benchmarking human-system performance and can be used as a reference in future HFE activities.**

   This work performed benchmark testing of the existing MCR configuration at the LGS training simulator. The simulator was used for both the OER and FRA&FA workshop. The benefit to this, beyond capturing observational data of existing challenges, was collecting baseline performance, workload, and situation awareness data. These measures can be compared to the later iterations of the new configuration to provide a data-driven approach in ensuring that these HFE considerations are not being negatively impacted. These results agree with earlier guidance from INL research that identified potential activities supplementing the existing HFE activities described in NUREG-0711 [8] to better support modifications at existing nuclear power plants. One of these added elements in planning and analysis is the benchmark test.

5. **Having access to a digital glasstop simulator is instrumental in collecting early feedback during planning and analysis activities like task analysis.**

   Without a glasstop simulator, human-in-the-loop simulation, and rapid prototyping of HSI concepts cannot be faithfully represented and evaluated. The use of a glasstop simulator is instrumental in applying an empirical approach to HFE evaluation, especially early in the project lifecycle. The HSSL at INL enabled early testing through rapid prototyping to collect early design feedback for the LGS SR I&C Upgrade Project. A facility like the HSSL, or an equivalent, is recommended when embarking on any major digital modification. This guidance is necessary to enable Lesson 3 and to evaluate scenarios and impacted tasks in a naturalistic way.

6. **Focusing on knowledge elicitation via qualitative measures is pertinent to the success of addressing human-technology integration requirements.**

   Methodologically, early HFE activities benefit significantly by implementing qualitative approaches that focus on knowledge elicitation in understanding operators' rationale (i.e., the why) when performing actions, making decisions, and coordinating as a team. Applying observational and interview techniques enabled a balance between objective and knowledge elicitation. This recommendation falls on the premise that design decisions should go beyond asking operator opinion. While preference data is important, understanding the rationale and bases on which operators act on the information they receive in the MCR is pertinent in designing new digital systems; the use of qualitative measures addresses this need.

7. **Advanced frameworks can complement simulation and modeling techniques applied to FRA&FA and TA.**

   Frameworks used included using decision ladders from cognitive work analysis and cognitive task analysis (CTA) techniques (cognitive walkthroughs). These approaches allowed an evaluation of the cognitive processes required of the crew and individual operators when performing the impacted tasks. It is recommended that someone experienced in HFE and with a background in cognitive science facilitate the use of these methods (e.g., see NUREG-0711 [8] Appendix – Composition of the HFE Team). Guidance from INL/EXT-21-64320, "Development of an Assessment Methodology That Enables the Nuclear Industry to Evaluate Adoption of Advanced Automation" [33], EPRI 3002004310 [26], and associated references listed in these documents can be used in applying such approaches. Cognitive work analysis and CTA techniques are outlined in more detail in Sections 3.4.1.2 and 3.4.1.1 of Reference 32.

8. **A multidisciplinary team, including operations, training, simulator SMEs, engineering, vendor, and HFE personnel should be embedded in the execution of HFE workshop activities.**

   As mentioned in Section 3.1.2.1 Lesson 1 for HFE planning, a multidisciplinary team is needed in the execution of HFE activities. A level of team building and synergy that is difficult to quantify is needed for effective decision-making. Having the right people available allows the team to efficiently address design tradeoffs to make effective decisions. For example, during the operator walkthroughs, questions were elicited by operators during discussion with human factors engineers that only engineering personnel or the vendor could answer. Having this real-time coordination allows for quicker and more complete design decisions. This directly addresses challenges observed in Section 3.2.1.

   The ability of the multidisciplinary team to dynamically interact to identify issues and proposed solutions is paramount when developing and refining HFE concepts and associated designs. This allows ideas to be proposed, vetted, and dispositioned much more rapidly (orders of magnitude faster) than following a document-driven, linear process of concept and requirement development, rendering of HSIs based upon those written requirements, written comment creation and aggregation, and then written dispositions of comments and associated requirement updates.

   The interactive dynamics associated with bringing the multidisciplinary team together and working together as a team to converge ideas and concepts into workable solutions where team consensus is achieved was best executed during face-to-face team activities via FRA&FA and TA workshops. When geographical separation prevented true face-to-face interactions, bringing the team together via electronic means was leveraged. While this medium provided a somewhat diminished capability to create the full experience of true face-to-face meetings, it was still much more effective than asynchronous emails.

9. **Real-time 3D and digital human modeling can significantly improve design team decision-making.**

   The use of 3D models in combination with digital human models were used to support effective team decision-making. The models presented design changes to the MCR to help align stakeholders. Changes in many cases were made based on engineering and operations feedback and evaluated in near real time during meetings, not between meetings. These same models would then be further leveraged to evaluate HFE considerations, such as those in NUREG-0700 [25], using digital human models. The use of the 3D models was successfully applied through the key HFE activities to make iterative changes and come to a rapid consensus on the placement and location of safety and non-safety VDUs and workstations. Feedback provided by stakeholders (i.e., engineering and operators) was collected in a combination of a series of workshops and virtual meetings. HFE principles were then applied to the feedback to verify the acceptability of proposed changes to the MCR.

10. **Using a think-aloud protocol during scenario walkthroughs enables deeper knowledge elicitation and real-time design feedback that drive design decisions.**

    Applying a think-aloud protocol allowed for collection of verbal responses associated with design insights regarding decisions, workload consideration, and other cognitive considerations. This guidance correlates with Lesson 6 in which think aloud was used to elicit knowledge during the scenario walkthroughs to capture knowledge and design input. The think-aloud protocol is a technique well known in the HFE and usability engineering literature (e.g., Nielson, 1994 [34]). This approach is commonly used in early HFE activities that demand knowledge capture. Later staged efforts like ISV should not take on the think-aloud protocol.

11. **There is a benefit in presenting conceptual displays in tandem with the current boards to enrich design feedback.**

    By using a glasstop simulator (see Lesson 5), HFE staff were able to present both the existing state and the conceptual new state at once when performing the walkthroughs. This feature allowed the operators to provide targeted feedback on the specific indications presented on the HSI display concepts. Such feedback would be arguably more difficult to collect if not collected in tandem. This tandem approach offers a useful way of collecting data and is particularly beneficial in early HFE activities where knowledge elicitation is the focus (Lesson 6) and a think-aloud protocol (Lesson 10) is used.

3.2. Licensing Activities

3.2.1. Human Factors Engineering Within the DI&C-ISG-06 Alternate Review Process

A notable challenge encountered in this effort dealt with scheduling constraints of the larger project and implementing the HFE activities (i.e., FA&A and task analysis) within these constraints. One contributor of this challenge was the application of the DI&C-ISG-06 [1] AR process for LAR submittal and approval. The AR process as enabled by using a safety platform with a generic safety evaluation report creates efficiencies and reduces schedule, licensing, technical, and project cost risks from an I&C perspective. The expectations for HFE activities, however, are the same as the standard review process. This is clearly communicated in Section B.1.4, "Review Areas Outside the Scope of this Interim Staff Guidance," of DI&C-I&C-06, Revision 2 [1]. That section states:

> A modification described in an LAR may also impact other review areas. The NRC staff should review the information necessary to make a safety determination using the review criteria found in the SRP for all relevant review areas.
>
> For example, some DI&C equipment modifications may involve HFE considerations (e.g., HFE analyses and design processes). In these cases, an HFE safety evaluation should be performed in accordance with SRP Chapter 18, "Human Factors Engineering," NUREG-0711, "Human Factors Engineering Program Review Model," and NUREG-1764, "Guidance for the Review of Changes to Human Actions," with close coordination with the DI&C evaluation under SRP Chapter 7.

This communicates that HFE efforts are expected follow the normal progression described in NUREG-0711 [8]. The HFE design verification and ISV activities for HSIs as described in NUREG-0711 are in a sense the operational FAT testing of the HSIs. So, while the AR process enables the early submittal and approval of a LAR for the I&C aspects of the design (before FAT), there is a challenge when trying to complete NUREG-0711 HFE activities within the compressed project schedule otherwise enabled by the AR process. This also creates associated workload challenges. NRC staff is aware of this and has been working with industry to find ways to address the NUREG-0711 process compression to support timely and complete LAR submittals and subsequent SER issuance. This is a FOAK HFE effort that is running in parallel to support the FOAK implementation of the DI&C-ISG-06 Rev. 2 AR process.

Figure 24 shows this constraint in more detail over a typical HFE schedule (e.g., EPRI 3002004310 [26]). Primary HFE activities as described by NUREG-0711 can be executed from initial scoping through implementing and testing (i.e., including FAT). The standard review process approach (shown in yellow) allows for the completion of HFE activities through V&V, such as ISV. In the AR process (shown in red), the issuance of a license amendment comes *before* implementation and testing. HFE expectations are similar to that of the standard review process and therefore constrains the HFE portion of the project schedule, particularly in the planning and execution of V&V activities. The importance of *early* human-technology integration activities is therefore emphasized as being critical to address HFE issues well before the execution of V&V. The lessons learned described in Section 3.1.2 are integral in the sense of their importance in addressing this licensing consideration.

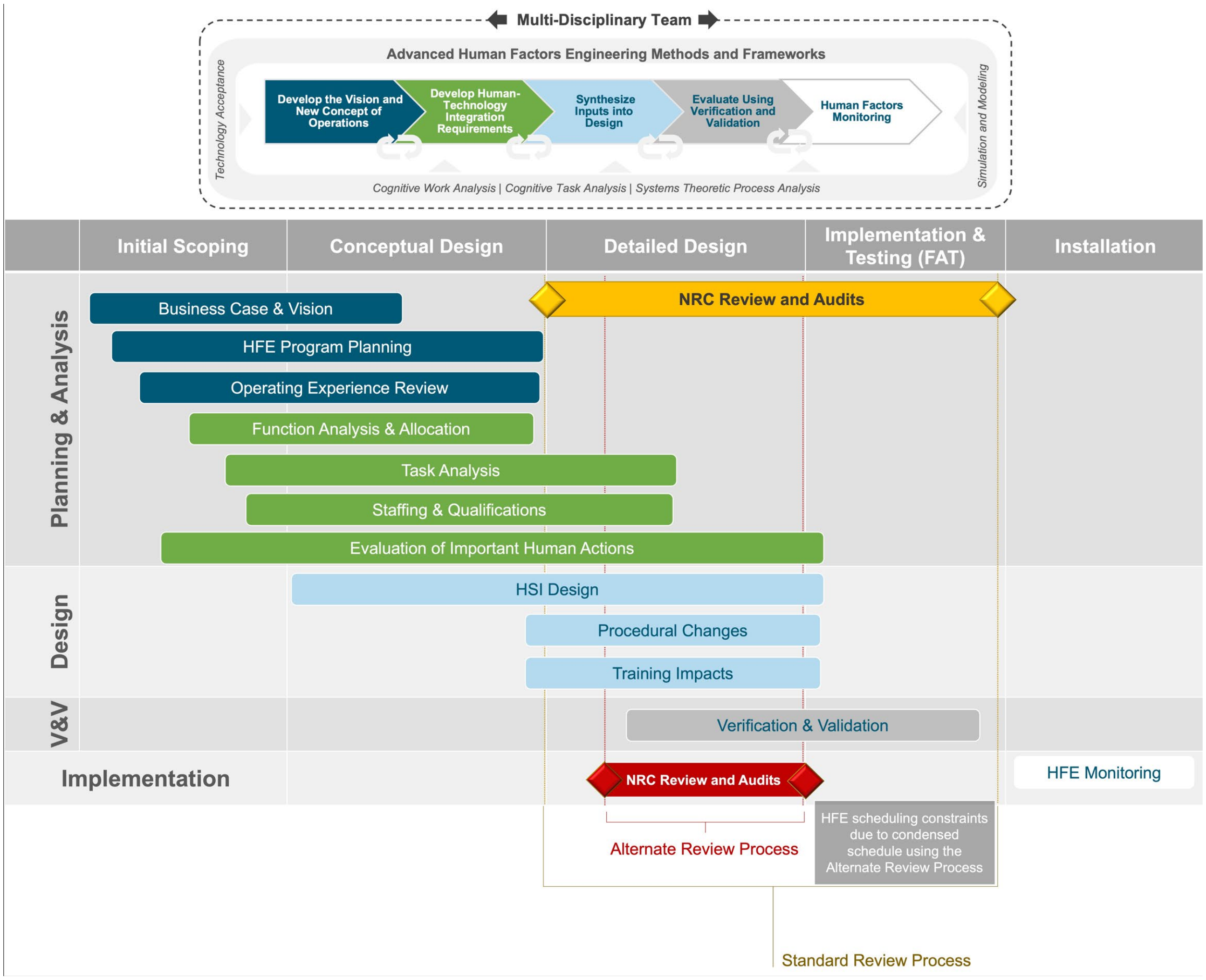


Figure 24. Typical HFE schedule overlaid with the standard review and AR processes.

NRC staff has informed CEG that satisfactorily addressing HFE aspects of the design is the controlling path for issuing the SER for the LGS safety-related I&C upgrade. INL is working with industry, which is communicating methods to address this issue to the NRC. The current direction as of the writing of this report is to leverage PV as presented in NUREG-0800, Chapter 18, Attachment A [27], "Guidance for Evaluating Credited Manual Operator Actions." Attachment A states that when the utility believes that the PV analysis provides high confidence that the time required for operator action will satisfy the success criteria for ISV, the complete analysis, which provides time available and time required, and the supporting analysis, will be submitted for NRC review. This analysis will be submitted as part of the LAR. When the NRC reviewers have high confidence that the manual operator actions will be accomplished correctly reliably, and within the time available, NRC staff will make a safety determination as part of the safety evaluation report on the associated licensing actions.

Industry and the NRC need to be closely coordinated and communicating to ensure that the DI&C-ISG-06, Rev. 2 AR process can be leveraged as intended by the NRC to accelerate safety-related digital upgrades while sufficiently addressing HFE.

3.2.2. Clarification of Project Use of NUREG-0711 - HFE Program Plan

Over the past 20 years, both industry and the NRC have come to better understand the practical nature HFE activities and their relationship to the design and implementation of I&C system upgrades as described in NUREG-0711 [8]. The Standard Review Plan NUREG-0800, Chapter 18 [27] is structured around NUREG-0711. Yet, the licensing bases for most nuclear plants in the HFE area do not invoke NUREG-0711 since it was developed after plant licenses were granted. Instead, licensees HFE commitments are generally captured in Generic Letter 82-33 (NUREG-0737 Supplement 1) [19] and associated LGS UFSAR [20] sections. NUREG-0737 Supplement 1 was developed as part of the NRC-directed activities after Three Mile Island (TMI). Other licensee HFE commitments are captured in DCRDR documents created through the implementation of NUREG-0737 Supplement 1.

Bridging the gap between leveraging NUREG-0711 concepts and techniques as understood by licensees and regulators while still addressing existing HFE licensing commitments has been a challenge. When CEG chose to engage INL to support HFE activities for the LGS SR I&C Upgrade Project, INL developed a NUREG-0711-based HFE Program Plan [14]. This is because INL's HFE research and associated collaborations with industry have been based on NUREG-0711.

It was INL's and CEG's understanding that NUREG-0711 could be used as a tool to address HFE aspects of the upgrade while not committing to making NUREG-0711 part of the licensing basis for the plant. In discussions with NRC staff during LAR presubmittal meetings for this project, it became apparent that:

- HFE attributes of the upgrade must either satisfy current license commitments or formally request any changes in the LAR.
- The path the licensee takes to satisfy current HFE licensing commitments is determined by the licensee, who can leverage any standard or guidance available (e.g., NUREG, IEEE, or other standards) or follow a method of their own to satisfy license commitments.
- The NRC staff will evaluate the LAR based upon current licensing commitments and the methods selected by the licensee to address HFE.

The practical result of this twofold:

1. If a licensee chooses to apply a standard beyond that currently included in the plant licensing basis for HFE (e.g., NUREG-0711), NRC staff will use that standard to evaluate the acceptability of the LAR HFE content. This expands the licensing basis to include the new standard for the scope of the upgrade.
2. The NRC staff is predispositioned to more readily review and accept LARs that have HFE content structured around the application of NUREG-0711. NUREG-0711 was developed to provide a more structured and complete HFE program and to address lessons learned from post-TMI HFE activities. It has served as the basis for NRC HFE staff activities for the last 20 years. It was suggested by the NRC staff during LAR presubmittal meetings that, for the LGS SR I&C upgrade, it may be more efficient to directly apply NUREG-0711 principles to this project and relate those activities to LGS HFE licensing commitments than to reach back close to 40 years to apply the original TMI-based HFE guidance.

As a result of the interactions with the NRC staff, the HFE Program Plan for CEG SR I&C upgrades [14] was revised to address NUREG-0711 use and existing HFE licensing commitments as follows:

A graded approach to NUREG-0711, as applied to this HFE Program Plan, includes the disposition of NUREG-0711 items/activities associated with element completion in a manner consistent with IEEE-1023 [18] by either:

- Applying a NUREG-0711 item or activity to the upgraded I&C/HFE design as deemed appropriate and practicable
- Performing similar or alternate activities that meet the intent of the item or activity identified in NUREG-0711
- Justifying why a NUREG-0711 item or activity is not applicable or otherwise not being performed as part of the HFE effort.

NUREG-0711 is being used as a tool to develop the LGS HFE Program Plan and identify the pertinent HFE activities to perform for the Project. LGS is obligated to meet their regulatory and license basis HFE requirements, which are most explicitly defined in:

- Generic Letter 82-33 (NUREG-0737 Supplement 1) [19]
- The LGS UFSAR [20] Section 1.13
- DCRDR Program Plan [21], the initial LGS Plant Control Room Design Review Final Report [22], and associated supplemental reports [23] and [24]

The conclusions in the NRC's SER for the LGS LAR are to be based on these requirements.

While this HFE Program Plan provides guidance for the design organization on all 12 NUREG-0711 elements, not all 12 HFE elements strictly relate to the requirements in NUREG-0737 Supplement 1, Item I.D.1. The additional HFE activities performed per NUREG-0711, Revision 3 for the SSCs and procedures affected by the LGS Modernization Project, beyond those required by NUREG-0737 Supplement 1, Item I.D.1, only expands the LGS HFE licensing basis for those specific SSCs and procedures.

3.2.3. Creation of Multiple Licensing Amendment Requests

Initial licensing plans for the LGS SR I&C Upgrade Project accounted for submitting one Digital Modernization Project LAR to the NRC for the effort. As discussed in Section 2.2.3, this one-LAR approach was determined to be suboptimal. Three LARs are now being submitted to support the project. This in itself is a lesson learned. An evaluation of the project scope, the overall project schedule, and how the LAR approval schedule (whether using the standard or the AR process in DI&C-ISG-06) needs to be made early in the process to determine if all aspects of a significant digital I&C upgrade project can be accomplished with one LAR.

Specific impacts associated with the transition from one LAR to three LARs are presented in the following subsections:

3.2.3.1. Digital Modernization Project License Amendment Request

Development, review, and approval of this LAR represents the majority of the licensing effort for this project. CEG has been working with NRC staff to establish necessary LAR content through a series of LAR presubmittal meetings as summarized in Section 2.2.2.

3.2.3.2. Installation and Support License Amendment Request

Performing such a significant SR I&C upgrade requires preplanning to ensure impacts that could negatively extend the outage in which they occur are minimized. LGS determined that they could decouple preoutage RRCS demolition activities planned to commence 30 days prior to the outage by obtaining a temporary, one-time AOT extension for TS. This LAR also obtains permission TS changes to facilitate necessary configurations during the outage to facilitate the installation of the new platforms.

Because of the way this LAR is written, its technical evaluation is not linked to or dependent on the Digital Modernization LAR. This should permit an accelerated review time for this LAR. This LAR was submitted to the NRC on February 17, 2023, with a requested one-year NRC review time frame.

3.2.3.3. Risk-Informed Completion Time License Amendment

The one LAR was intended to also address RICTs as discussed in Section 2.2.3.3. Significant effort was expended to incorporate RICT information into the one Digital Modernization Project LAR (as described in Section 2.2.3.1). It was then determined that the PRA analysis [29] needed to modify RICTs requires detailed I&C system design information. Compressing the project schedule (which is made possible in part by compressing the I&C LAR schedule when implementing the DI&C-ISG-06 AR process) resulted in a lack of necessary detailed I&C designs to perform RICT-related PRA calculations in a time frame to include this information in the Digital Modernization LAR. To satisfy the timeline to produce the Digital Modernization LAR and obtain NRC approval of the project schedule, it was determined that the RICT licensing changes be separated into their own LAR. This has increased project cost and impacted the schedule.

The architectural and associated logic changes being implemented in the LGS SR I&C Upgrade Project are expected to fundamentally change aspects of the RICT calculations. The new PPS design is fundamentally a four-channel, four-division system that supports a 2oo4 voting logic. LGS has been challenged to find a way to efficiently communicate this fundamental architectural change without having to repeat each RICT calculation at a detailed level. Identifying a way to efficiently communicate such issues to NRC staff early in the project could reduce efforts and associated costs.

3.2.4. Benefits and Challenges of Early Submittal of Information to the NRC

3.2.4.1. Early Submittal of Defense in Depth and Diversity Analysis

Early submittal of the D3 analysis [11] as described in Section 2.2.4 was helpful in providing CEG and Westinghouse with insights regarding the content necessary for this analysis. To capture NRC staff questions regarding the D3 analysis, an open item (OI) list was created. The OI list is intended as a communication vehicle for the NRC staff and CEG to reach a common understanding on the D3 analysis and to address other issues early to limit the number of more formal requests for additional information after Digital Modernization LAR submittal.

The NRC staff, however, did not shorten the LAR approval period as was envisioned.

3.2.4.2. Challenges of Early Submittal

While the use of the OI list as presented above has been helpful and may streamline the Digital Modernization LAR approval process in the future, it has taken significant and unplanned effort to address NRC staff questions early in the project. It is also unclear how the relatively new OI list resolution process will be leveraged going forward. Early industry experience with the Waterford Unit 3 I&C upgrade has shown this process can work well going forward. There have been indications, however, that this process may not efficiently scale up to support the larger scope of the LGS SR I&C digital upgrade project.

NRC staff supported this review by also performing an audit of the D3 process concurrent with the relatively new OI process. The net result of this extensive OI process and licensing engagement was an unplanned impact on engineering and licensing resources, taking them away from other conceptual and detailed design activities. While the early submittal of the D3 analysis [11] has facilitated positive communications with the NRC staff, it may have had the unintended consequence of essentially extending the NRC staff review period.

3.2.5. Presubmittal Meeting and License Amendment Request Development Level of Effort

The presubmittal effort as presented in Section 2.2.2 has been a significant and dynamic effort, involving all aspects of the project. These meetings required significant preplanning and preparation of materials in the areas of design engineering, operations, HFE, licensing, and project management. There has been a certain aspect of learning as you go, which has resulted in more time and effort being expended in this area than planned. As the project has been in the conceptual and early detailed design phases, there has been a degree of back and forth regarding FOAK design attributes of the new systems and how those need to address the licensing basis of LGS.

As an example, the LGS SR I&C Upgrade Project proposes the reduction of redundant sensors for individual existing subsystems (i.e., the RPS, the nuclear steam supply shutoff system (N4S)—also referred to as the primary containment isolation system in other BWRs—and the ECCS). This is accomplished when combining the functions of these systems on the new PPS. This concept was presented in detail at the June 29, 2021, presubmittal meeting. After this meeting, CEG personnel were under the impression that NRC staff understood what was being proposed and that from a conceptual perspective that the approach was sound. This was later determined to not be the case. Significant engineering, operations, and licensing resources had to then be redirected to provide a more detailed information on this concept along with further discussion of it at the October 20, 2021, presubmittal meeting.

The need for such iterative interactions with NRC staff regarding design elements made it difficult to determine at times when a convergence of understanding between LGS and NRC staff had actually been achieved.

3.2.6. Internal Utility Procedural Challenges When Following the Alternate Review Process

The NRC, working with industry, created the DI&C-ISG-06 [1] AR to address regulatory barriers that have largely precluded the modernization of nuclear plant first-echelon SR I&C systems. Internal utility processes and procedures for developing and reviewing safety-related DI&C LARs for submittal to the NRC, however, have not been similarly updated. Internal processes at CEG for LAR development and for review by the LGS Plant Operations Review Committee (PORC) are aligned with the standard DI&C licensing process and post-license amendment issuance process for Tiers 1, 2, and 3 as shown in Figure C.1 of [1] (and repeated as Figure 25).

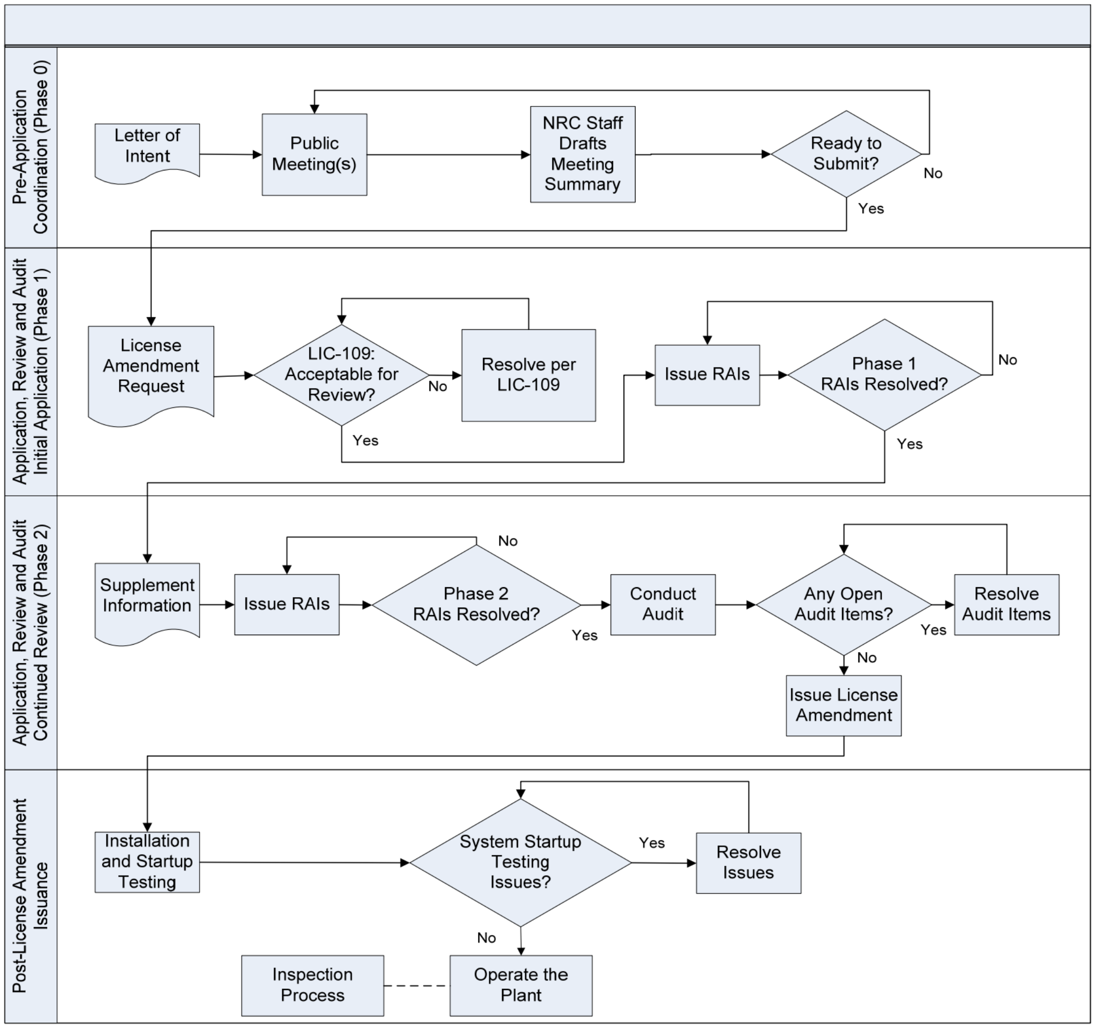


Figure 25. DI&C licensing process and post-license amendment issuance process for Tiers 1, 2, and 3.

In Figure 25, the LGS PORC would typically review and issue the Digital Modernization Project LAR at the end of Phase 2 as shown (prior to issuing a LAR). At this point, the design would be finalized, and FAT completed. As a result, there is a gap in expectations between the content of the Digital Modernization Project LAR being produced by LGS following the DI&C-ISG-06 AR process as compared to what the PORC typically reviews. As a result, an exception to the LGS PORC review procedure is being taken to support the AR process. This FOAK activity requires a change in mindset to accomplish within the compressed schedule the DI&C-ISG-06 [1] AR process is designed to promote.

3.2.7. Submittal of Draft LAR for NRC Comment and Associated Need for an Earlier and More Comprehensive Detailed Design Description

CEG initially developed a schedule to submit a draft version of the Digital Modernization Project LAR (Section 2.2.3.1) for comment prior to its formal submittal. In the future, it would be more beneficial to focus on the formal submittal instead. The development of draft submittal was very time consuming for CEG. NRC staff initial feedback on the CEG proposal to provide the draft LAR for comment also caused confusion at CEG. Working to address that feedback took time away from development of the formal LAR submittal. Ultimately, a draft version of the Digital Modernization LAR was not provided to NRC staff by CEG.

During the first few presubmittal meetings with NRC staff, CEG exerted substantial effort in communicating how the design would meet the DI&C-ISG-06 content requirements following the AR process. Furthermore, CEG was challenged in effectively presenting the high-level architecture of the proposed design and associated interfaces with existing plant systems in sufficient detail. As a result, the high-level architecture and plant interfaces had to be revisited with the NRC in several presubmittal meetings. It would be advantageous for utilities pursuing similar upgrades to develop and present information as described above to NRC staff so that they have a clear and concise understanding of the overall upgrade as early as possible in the presubmittal process. This would likely result in NRC staff having fewer questions during the presubmittal process, which could ultimately result in fewer presubmittal meetings for similar upgrades.

3.3. Project Management and Procurement Activities

3.3.1. Resource Management and Scheduling

When transitioning a project from the initial scoping phase into the conceptual and detailed design phases, personnel resource needs are identified, and more detailed work schedules are developed as a matter of course. Specific challenges that were encountered in these two related areas for the LGS SR I&C Upgrade Project are:

- **Resource management.** Nuclear facility staffing has been declining, largely through attrition, for a number of years. This trend has been driven by an aging workforce and the need for utilities to reduce operating costs to remain competitive in the marketplace. As a result, many utilities have moved to a "matrixed organization" model where a pool of qualified personnel is created that are then assigned to perform tasks in their area of qualification as needed. Consistent with project initial scoping phase lessons learned [5], project management continued to engage stakeholder resources as early as possible to minimize pilot project risks. A diverse and qualified resource pool was routinely consulted for input as early as practicable to converge conceptual and detailed design. This aided project execution. The matrixed organizational model and operational needs at LGS sometimes impacted the continuity of individuals being able to support the project. When this occurred, it tended to inhibit progress.
- **Scheduling.**

  Several other issues also impacted the project schedule. Initial development of the project integrated master schedule using the Primavera software tool was challenging. This required the synthesis and tracking of scheduled activities from all involved organizations. The integrated master schedule in Primavera was also linked to the "stage-gate" activity schedule for project execution. Maintaining this linkage was difficult to maintain as the project progressed. Delays in contracted delivery dates in key deliverables also manifested themselves during the conceptual and detailed design phase activities described in this report. All of these challenges together required the schedule to be re-racked multiple times to adjust to the reality of the situation. Challenges such as these are not novel to this project. Dealing with these issues while at the same time addressing FOAK issues in this pilot upgrade resulted in a less stable project schedule. Schedule execution was impacted by more frequent revisions. This impacted near-term work, kept focus more on near-term activities, and impacted the contracting and scheduling of future project work.

  During the multiple LAR presubmittal meetings with NRC staff as discussed in Section 2.2.2, several changes to project direction occurred as CEG worked with NRC staff to plot a course for this FOAK project. The development of products to the level of detail communicated as necessary by the NRC staff impacted when those documents were expected to be completed. Items such as the early submittal of the D3 analysis [11], as discussed in Sections 2.2.4 and 3.2.4, and the evolving understanding of what is necessary to incorporate HFE within the DI&C-ISG-06 AR process, as discussed in Section 3.2.1, also dynamically impacted the schedule.

The net effect of the challenges identified above was that the project schedule was being executed at the same time it was being written and revised. This not only impacted near-term work, but also kept the focus on near-term activities. This has also had an impact on the contracting and scheduling of future work to complete the project.

From all the work done in schedule space, there were positive aspects to these efforts as well. It obviously helped in coordinating project activities to advance the design and produce the creation and submittal of the LAR for the LGS SR digital I&C upgrades to the NRC. The early development of an outage installation strategy provided a degree of project-wide understanding of efforts needed to achieve it. The outage installation strategy shaped the licensing strategy of creating multiple LARs (Section 2.2.3). It also shaped the engineering strategy to make the outage strategy more achievable. Scheduling efforts also identified other project issues early. As an example, the need to perform simulator updates and coordinate project HFE efforts that use the simulator with other demands on that facility (e.g., operations training and operator qualifications) were identified earlier than in previous projects.

Schedules and resources (both internal to the utility and contracted work) need to be flexible to permit identifying, assigning, and addressing lessons learned during the iterative design process. Funding must also be allocated to account and project risks identified to account for iterative design. These topics are presented in other sections of this report (i.e., Sections 3.1.1.1, 3.1.1.2, 3.3.2, and 3.3.3).

3.3.2. Learning by Doing: Applying a Systems Engineering Approach

Changes to the project management model and associating contracting model for digital I&C upgrades must be made to promote an iterative conceptual design and requirements development process that incorporates Agile process concepts, as discussed in Section 3.1.1.2.1. The nuclear industry, being true to form, has been working on guides, processes, and procedures to direct these efforts. This, however, is not enough. Utilities and their selected vendors must be given an opportunity to gain practical experience in executing them.

Similarly, contract commitments by themselves do not guarantee that that either the utility or vendor will follow a collaborative, multidiscipline, iterative, systems engineering approach or process. Such commitments by themselves do not indicate that either the vendor or utility:

- Has procedures in place that mesh with the approach or process
- Fully understands how to implement the approach or process (due to a lack of training and particularly a lack of experience)
- Are willing to implement the approach or process
- Are willing to be held accountable for the approach or process.

There is a natural tendency for any organization, particularly ones regimented to a high degree, such as those that perform SR I&C system design, to revert to their legacy processes with which they are familiar. Again, this is not to impugn either the utility or vendor's desire or motivation to pursue a systems engineering approach. Both CEG and their I&C vendor have the desire and motivation. The challenge is that nuclear utility project management and engineering organizations as well as their vendors:

- Are regimented toward existing linear, once-through, stage-gate processes and procedures for project management and engineering developed over 30–50 years
- Have a corresponding bias toward a verbatim compliance procedural mindset

- Tend to emphasize multidiscipline impact reviews of design products following a checklist rather than collaborative design
- Have a siloed, short-term system engineer view of upgrades (discussed in Section 3.1.1.1.1) based on legacy plant I&C systems and the success that has been achieved to date to keep them operating well beyond their service life using plant-health processes that leverage the equipment reliability process description (AP-913 [46]) and use of the mitigating system performance index concept.

Project management, systems engineering (discussed in Section 3.1.1.1.1), and operations skills to envision and then apply new digital I&C systems and integrate them within a larger digital modernization of existing plants need to be developed and honed through experience. Defining the new-state target for either singular digital upgrades or for a set of related digital upgrades provides strategic direction. New guides, processes, and training can equip project participants with generic knowledge. Without this knowledge, they cannot contribute to project success. Only by experience in repeatedly using these tools when performing and integrating such upgrades and then maintaining and modernizing the upgrades can participants build the wisdom necessary to maximize their operational benefits across the nuclear industry. As a practical example, the EPRI DEG presents the concept of systems engineering and design iteration along with the value of both with a high degree of detail. The value of this presentation is manifest in the adoption of the EPRI DEG [4] by industry in NISP-EN-04 [3]. Many of the lessons learned in the LGS SR I&C Upgrade Project reflect the challenges of translating the theory of systems engineering and design iteration into practice as a skill-of craft capability within the existing culture and associated policies and procedures in the nuclear industry.

Utilities must look to building compact, qualified, singularly focused, and experienced digital teams that are kept that way through a continuous exercising of their skills. If digital upgrades are developed and implemented infrequently or by different teams each time, the ability to leverage the skill-of craft lessons learned, such as those captured in this report, to improve future project execution will be significantly limited.

It is expected that there will continue to be challenges as nuclear utilities and their vendors work to catch up with the rest of the process control industry outside of nuclear and capitalize on the capabilities of digital technology to maintain and improve plant safety and reliability while reducing TCO. Continued capture and communication of lessons learned when performing upgrades, such as the SR I&C Upgrade at LGS as documented in this report, are crucial. This will aid not only in developing and refining the guides, processes, and procedures for employing true systems engineering in nuclear, but also in identifying and communicating both correct paths and well-intended dead ends that can only be found (and avoided in the future) through experience.

3.3.3. Alternative Contracting Model

As stated in Section 3.3.3.1, the generic specification used for vendor selection for this project was based largely on existing system requirement documents and a limited set of existing SR system drawings. This generic specification was used, along with additional information, to formulate a contract with the selected vendor. This is consistent with normal nuclear industry practice.

A contracting model using such a specification has several challenges associated with it. In many cases, the historical documents that describe current I&C functions and their implementation do not differentiate the “what” (true functional requirements that the I&C system performs) and the “how” (specific legacy system design attributes that are not requirements but enable the implementation of the true functional requirements). Current system and I&C design engineers, in their sustaining role, are challenged to differentiate between the “what” and the “how” when they are developing true requirements to replace the current I&C systems.

While modern digital systems in most cases can be programmed and configured to perform the needed true requirements, the conflation of those true requirements with legacy I&C implementation details can result in a set of contracted requirements that are either difficult (and costly) to implement and maintain because they require design changes to the selected platform or are unimplementable on that platform. Many of those same engineers, limited by their sustaining role, are not intimately knowledgeable regarding the capabilities and operating characteristics of the modern digital systems that vendors offer. Consequently, such engineers may not write requirements that leverage these capabilities and operating characteristics in a way that provides enhanced performance.

Existing industry upgrade processes, identify the need for and value of design iteration to refine requirements as a collaborative effort between the utility and the vendor. Existing contracting models, however, are typically described and executed in a linear manner.

To address this issue, an alternate contracting model for digital I&C procurement and installation should be considered. It would allow the utility an opportunity to more fully understand how the selected digital platforms will meet their need. It would support collaboration and iterative design between the utility and vendor to tailor utility needs into true requirements that best leverage the selected digital platform. This alternative model is outlined in the subsections below. In must be noted that the development of artifacts needed to support non-engineering activities, such as project management and licensing, need to be considered and addressed in the project DOR and schedule. Such activities may not align with the alternative contracting model.

3.3.3.1. Initial Scoping Phase

During the project initial scoping phase, the utility would work internally to bound key replacement I&C platform performance characteristics, such as the number and type of I&C interfaces that must be supported, replacement platform operational characteristics (e.g., processing rates, HSI refresh rates, and network speed, latency, and deterministic properties), redundancy and failover requirements, HSI functional capabilities, and life cycle support capabilities. These characteristics would be identified based on what is understood by the utility to satisfy functional requirements at a minimum or to provide additional capabilities (such as the elimination of single point failures, automated diagnostics, etc.) The utility would share these performance characteristics with potential vendors and collaborate with them to establish which vendors are able to meet the utility need from a capability and cost perspective. It is expected that the utility and vendor would exchange information to bridge any gaps between identified key performance characteristics and available vendor solutions to achieve a mutual understanding that an implementable state is achievable. Solicitation of estimates to perform the work and vendor down-selection would occur at the end of the initial scoping phase. This information would then be used to obtain management approval to move forward into the conceptual design phase. Note that, at this point, more than one vendor may be identified as viable. Also, a detailed elucidation of function-by-function requirements is not intended to be fully developed at this point.

3.3.3.2. Conceptual Design and Vendor Contracting

Down-selected vendor(s) would be solicited to make detailed proposals for the conceptual design phase and to provide bounding estimates for the detailed design and implementation phase. It may be beneficial for a utility to select more than one vendor for the conceptual design phase to foster competition to achieve the optimal solution based upon technical merit and cost.

The scope the vendor(s) include in their proposal would be to collaborate with the utility to develop the design requirements enveloped withing bounding performance characteristics captured in the vendor contracts. Detailed scheduling and execution to produce these requirements are included in this phase. Bounding scope and schedules to complete the design and installation should also be provided for information to ensure that vendors can meet the overall project timeline through implementation. The utility works with the vendor(s) to identify and capture the true functional requirements from the existing design documentation within the project scope in such a way that the vendor platform(s) can be configured to achieve them. If more than one vendor is carried into the conceptual design phase, in the ideal case, the resultant functional requirements would be as vendor agnostic as practicable. Areas where the competing designs may diverge would likely inform the next vendor down-selection.

This collaboration is intended to promote the iterative design process as outlined in the EPRI DEG [4] by not being overly proscriptive in defining detailed requirements too early. Utility engineers become increasingly familiar with vendor technology, and the vendors have an opportunity to learn how to optimally apply their platforms to meet utility needs.

HFE planning and analysis phase activities following the guidance in NUREG-0711 [8] also need to be addressed during the conceptual design phase. The project HFE Program Plan should be written, and execution of activities described therein should begin. Authorship and execution of the HFE Program Plan should be accomplished by an organization with requisite experience. Ideally, planning and analysis HFE activities would be completed during the concept design phase so that they can provide inputs into HSI design. Depending upon project scheduling, these planning and activities may continue into the early portions of the detailed design phase.

As the conceptual design period approaches completion, the functional requirements for the project scope are intended to fully bounded and implementable. HFE planning and analysis activities are complete to a point to enable HSI detailed design in a way that is consistent with vendor platform capabilities. Ideally, the functional requirements would be vendor agnostic and could be competed between the remaining vendors. Solicitation of proposals to perform detailed design, implementation, and lifecycle support would occur. Final vendor down-selection would occur at the end of the conceptual design phase if it has not occurred previously. This information would then be used to obtain management approval to move forward into the detailed design phase.

At this point in the contracting effort, total lifecycle costs and vendor relationship attributes need to be carefully considered and included in the vendor request for proposals. If target platforms akin to the Common Q for the PPS and Ovation for the DCS at LGS are being selected by a utility as part of a comprehensive modernization strategy, this will likely be the start of a utility I&C vendor covenant relationship that may last 30–50 years. This is driven by several factors.

1. The initial implementation costs associated with the intellectual property investments made to fully leverage these systems at a multiunit site or fleet may run into the hundreds of millions of dollars and take up to 10 years to fully implement.

As high as the initial implementation costs might be for a particular vendor's initial implementation, the TCO to maintain needed functionality over the remaining period the utility intends to operate the unit(s) will be a significant, if not overriding, cost driver. Digital I&C system technology will also go obsolete.

If the selected vendor design does not include a detailed lifecycle strategy to either:

a. Fully support and maintain original platform equipment, firmware, and software for remaining plant life
b. Include a capability to address digital obsolescence by migrating intellectual property investments to new hardware, firmware, and operating systems and validating their performance when migration is complete the lifecycle costs to maintain such systems will most likely increase substantially over time. Letting the upgraded platforms become obsolete or switching vendors may result in all the initial implementation costs becoming sunk costs.

   The opportunity to enter a long-term lifecycle support contract also incentivizes the vendor to design the system(s) to control lifecycle costs. Utilities can also potentially negotiate service and support discounts with the vendor to lower TCO.

3.3.3.3. Detailed Design, Implementation, and Lifecycle Support Contract

Once the vendor is down-selected and placed under contract, hardware procurement by the vendor would be authorized. The vendor will develop I&C detailed design specifications and system configuration instructions for the platform(s) based upon the approved functional requirements. They will also develop all necessary software to enable the platform to accomplish the functional requirements. System testing up to and including factory acceptance will also be contracted along with post-modification installation test support.

Detailed HSI development following the HFE Program Plan will occur. Development of design and related HFE project activities include:

- Develop HSI detailed design to support design HSI design verification and validation
- Simulator integration for:
  - PV of HSIs
  - ISV as necessary based on upgrade impacts to the MCR
  - Long-term operator training support.

For large-scale digital modernizations that have a significant MCR impact, the development of a full “glasstop” MCR simulator should be considered. This would support early simulator integration in a separate facility that would not negatively impact operator training and qualifications, but also provide a capability to collaboratively develop HSIs, procedures, and control system concepts, not only for the initial installations of I&C upgrades, but also for additional upgrades going forward.

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42. WNA-AR-01051-GLIM, Rev. 0. “Limerick Generating Station Units 1 & 2 Digital Modernization Project - Plant Protection System Preliminary Software Hazard Analysis.” Westinghouse Electric Company, LLC.

43. WNA-LD-01578-GLIM. “Exelon Generation Limerick Units 1 & 2 - Distributed Control System Architecture & Layout.” Westinghouse Electric Company, LLC.

44. WCAP-16096-P-A. “Software Program Manual for Common Q™ Systems.” Westinghouse Electric Company, LLC (May 2021). https://www.nrc.gov/docs/ML2114/ML21146A203.pdf

45. APP-OCS-J1-002, Rev. 9. “AP1000 Human System Interface Guidelines.” Westinghouse Electric Company, LLC.
46. AP-913, Rev. 1 “Equipment Reliability Process Description.” Institute of Nuclear Plant Operations, (Nov.2001)

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Attachment A - Division of Responsibility

Limerick Digital I & C Modification - Division of Responsibility Matrix	
R	Responsible: Initial & Final submittal as well as overall development
S	Support: Provide input, documentation, draft reviews, insight as it relates Scope of Supply and Project Exhibits, Project Control Package for Customer and Vendor Projects.
A	Approve: Final Review and Concurrence
I	Inform: Be made aware of changes to, but not directly responsible for product
C	Consulting
	Note: Exelon in this document is now Constellation. 3/31/2023
	Posted 11/18/2022

Engineering Division of Responsibility

Item	Activity	Purchaser	AE	AE	Equipment Supplier	HFE	Install	Install	Licensing
		(Exelon)	(Exelon)	EOC	(WEC)	INL	WEC	MMC	
1.00	**General**								
1.01	Identify Basic System/Equipment Functions		R	S	S	S			
1.02	Develop Performance Requirements & Document in NE-402(3)		R		S	S			
1.03	Review outstanding change paper to be incorporated by design		R	S					
1.04	Verification of critical parameters	S	R	S	S	S			
1.05	Identify Unverified Assumptions		R	S					
1.06	Identify & Eliminate Project Risks	R	S	S	S	S	S	S	
1.07	Review Accessibility concerns		R	S					
1.08	Develop Interim Plant configurations	S	R	S	S	S			
1.09	Posted 11/18/2022	S	R	S	S	S	S	S	
1.10	Identify FAT configuration needs	S	A	S	R	S			
1.11	Evaluate Load and Travel Paths	S	R	S	S		S	S	
1.12	Document and Lead Walkdowns	S	R	S	S	S	S	S	
1.13	Identification of interferences	S	R	S			S	S	
2.00	**Specification Development & Vendor Interface**								
2.01	Equipment Specification Development	R	R	S	S	S			
2.02	Review Specification for NE 402 & 403	R	R	S	S				
2.03	Approve / Issue Specification	R	R						
2.04	Vendor Document Reviews	R	R	S					
2.05	Vendor Document Approval	S	R						
2.06	Finalize Vendor Documents for Issue to Records	S	S	R					
3.00	**Design Input**								
3.01	Designer Walkdown	S	R	R	S		S	S	
3.02	Compile Design Inputs (Review Vendor Data. Calculations, etc.)	S	R	R					
3.03	Provide Design Inputs to EOC / Vendor (TODI)	S	R	S					
3.04	Initial Equipment Selection	S	R						
3.05	Initial Equipment Selection	S	R						
4.00	**Electrical Calculations**								
4.01	DC System/ELMS		R		S				
4.02	GENESIS		R						
4.03	AC Load/Volt Drop		R		S				
4.04	Protective Device Setting		R						
4.05	Short Circuit Analysis		R						
4.06	Raceway (e.g. Conduit) loading design		S	R					
4.07	Other Calculations: (list)								
4.08	Calculation Reviews		R						
4.09	Calculation Approvals		R						
5.00	**I&C Calculations**								
5.01	Instrument Set Point	S	R		S				
5.02	Instrument Calibration End Points		R						
5.03	Other Calculations: (list)		R						
5.04	Calculation Reviews		R						
5.05	Calculation Approvals		R						
6.00	**Mechanical Calculations**								
6.01	Seismic Qual		R		S				
6.02	Seismic Mounting		R		S				
6.03	Heat Load/HVAC Evaluation		R		S				
6.04	Other Calculations: (list)		R						
6.05	Calculation Reviews		R						
6.06	Calculation Approvals		R						
7.00	**Structural Calculations**								
7.01	Eval of Cable Tray Hanger & Main Struc Steel		R	S					
7.02	Eval of Conduit/Junction Box & Main Struc Steel		R	S					

	Engineering Division of Responsibility								
Item	Activity	Purchaser	AE	AE	Equipment Supplier	HFE	Install	Install	Licensing
		(Exelon)	(Exelon)	EOC	(WEC)	INL	WEC	MMC	
7.03	Eval of Block Wall Loading		R						
7.04	Cut Rebar/Core holes/Slab		R	S					
7.05	Equip Foundations		R	S					
7.06	Equipment Mounting		R	S					
7.07	Other Calculations: (list)		R						
7.08	Calculation Reviews		R						
7.09	Calculation Approvals		R						
8.00	**Evaluations (Typically Documented in EC)**								
8.01	Cable/Equipment Evaluation		R						
8.02	Human Factors Evaluation		S			R			S
8.03	EMI/RFI Evaluation		R		S				
8.04	DCS FMEA Evaluation(s)	S	A		R				
8.05	PPS - FMEA Evaluation(s)	S	A		R				
8.06	Plant Level FMEA incorporates system FMEA.	S	R	S					
8.07	Digital/Cyber Review		R		S				
8.08	Other Evaluations (NFP 805, Alarm setpoints, etc.):		R						
8.09	Setpoint Coordination (PPS/DPS)		R	S	S				
8.10	Evaluation Reviews	S	R						
8.11	Evaluation Approvals		R						
9.00	**Design Documents (Drawings, Lists, etc.)**								
9.01	Electrical Schematic		S	R					
9.02	Elect/Mech Physicals (GA's, One Lines, etc.)		S	R					
9.03	Electrical Wiring		S	R					
9.04	Misc (Key Diagram, etc)		S	R					
9.05	Vendor Drawings - processing		S	R					
9.06	Loop Calibration Report		R	S					
9.07	P&ID		S	R					
9.08	C&ID		S	R					
9.09	Other (Foundations, etc.) - software configuration control		S	R					
10.00	**Software Configuration Control**								
10.01	Software Configuration Management Plan		S		R				
10.02	Software Release				Refer to WEC DOR				
11.00	**Licensing Activities**								
11.01	50.59 Screening Preparation	S	R		S				
11.02	50.59 Screening Review	S	R		I				
11.03	50.59 Evaluation Preparation	S	R		S				
11.04	50.59 Evaluation Review	S	R		I				
11.05	UFSAR/FPR/ITS changes (DRP/FDRP)	S	S	R	S				
11.06	LTR	S	S	S	R	S			
11.07	Review and Validate iaw/ Exelon Design Eng. Procedures for LTR		R			Also Refer to Licensing DOR			
11.08	LAR support	S	S	R	S	S			
11.09	Develop Presubmittal Presentations (5)		S		Refer to Licensing DOR				R/P
11.10	Review Vendor deliverables needed for LAR		S		Refer to Licensing DOR				R/P
11.11	Review and Concur iaw/ LS-AA-101-1000		R		Refer to Licensing DOR				R
11.12	RAI Provide/Obtain Responses		S		Refer to Licensing DOR				R/P
11.13	RAI Review and Concur with Response Letter		R		Refer to Licensing DOR				R/P
12.00	**Engineering Change**								
12.01	OE Review	S	R	S	S	S			
12.02	Design Summary - Conceptual (30%)	S	R		S	S			
12.03	DAR Attribute Review	S	R						
12.04	Conceptual (30%) Design Review	S	R		S	S			
12.05	CDO Conceptual (30%) Challenge	S	R		S	S	S	S	
12.06	ADL - Affected Document List		S	R					

Engineering Division of Responsibility

Item	Activity	Purchaser	AE	AE	Equipment Supplier	HFE	Install	Install	Licensing
		(Exelon)	(Exelon)	EOC	(WEC)	INL	WEC	MMC	
12.07	AEL - Affected Equipment List		S	R					
12.08	Design Summary - Detailed / Final		R	S					
12.09	Detailed (60 %) Design Review	S	R		S	S	S	S	
12.10	Designers Walkdown	S	R	S	S	S	S	S	
12.11	Installers Walkdown	R	S				S	S	
12.12	Bill of Material	S	S	R	S				
12.13	VTIP / vendor manuals		S	R	S				
12.14	Fire Protection Review	R	S	S	S				
12.15	Owner Acceptance Reviews	S	R						
12.16	Final internal Reviews	R	R		S				
12.17	Comment resolution and incorporation	S	S	R					
12.18	MAT - DCS & PPS	R	S		S				
12.19	SAT - DCS	R	S	S	S				
12.20	SAT - PPS	R	S	S	R				
12.21	FAT	S	S		R				
12.22	Acceptance Test criteria	S	R		S				
12.23	Testing Development	S	R	S	S				
12.24	Final (90%) Review Meeting	S	R		S	S	S	S	
12.25	Final EC Review and Approval (Include DRB hours if applicable)	S	R		S	S	S	S	
13.00	**Implementation & Close-out**								
13.01	NE-402 FAT-SAT Support		S		R				
13.02	NE-403 FAT-SAT Support		R		S				
13.03	Rigging Evaluations/Scaffold Plan	R	S				S	S	
13.04	Shielding Package				NA not Rad work				
13.05	Work Package Prep				Refer to WEC DOR Item 11.22				
13.06	Review and walk down work packages	S	R				S	S	
13.07	Site Procedure Writer Support (Review and Validate)	R	S						
13.08	Training Department Support	R	S		S				
13.09	Online Installation Support	R	S	S	S		S	S	
13.10	Outage Installation Support	R	S	S	S		S	S	
13.11	Drawing Issue	S	R	S					
13.12	Operations Briefing	S	R						
13.13	EC Closeout including EC Revision	S	R	S					
14.00	**OTHER**								
14.01	Installation Instructions		S	R	S				
14.02	Diagrams (Installation Related Documentation)		S	R	S				
14.03	Engineering Design Change		R	S	S				
14.04	Detailed Design (1st) Review meeting		R	S	S				
14.05	Detailed Design (2nd) Review meeting		R	S	S				
14.06	Design challenge review	S	R	S	S		S		
14.07	Data Collection/Provision of plant site data, drawings, plant procedures, training documents and OEM Data. Non Safety		R		S				
14.08	Data Collection/Provision of plant site data, drawings, plant procedures, training documents and OEM Data. Safety		R		S				
14.09	Hardware List BOM (Purchaser Provided Equipment)		R		S				
14.10	Identify Long Lead Items (Purchaser Provided Equipment)		R		S				
14.11	Consult / Markup plant interface system control & equipment drawings, schematics and wiring diagrams		S	R	S				

	Engineering Division of Responsibility								
Item	**Activity**	**Purchaser**	**AE**	**AE**	**Equipment Supplier**	**HFE**	**Install**	**Install**	**Licensing**
		(Exelon)	**(Exelon)**	**EOC**	**(WEC)**	**INL**	**WEC**	**MMC**	
14.12	Consult / Mark-up Plant System Existing Termination Drawings		S	R	S				
14.13	All Calculations including: HVAC, Electrical etc.		R		S				
14.14	Custom Metal work Design- AER Cabinet Bases		R		S				
14.15	Custom Metal Work Design- MCR Vertical panel and Bench board panel inserts.		R		S				
14.16	Custom Metal Work/brackets Design- All Control room equipment such as: Thin client, Node box, keyboard, Monitor, and Track ball, Backpanels, media converters, network hardware, etc.		R		S				
14.17	Operator and maintenance Procedures	R	S		S				
14.18	UFSAR/FPR/ITS changes (DRP/FDRP)		S	R	S				
14.19	VTIP / vendor manuals		S	R	S				

	I&C System Engineering Equipment Design, Installation Design, Delivery and Installation							
	Westinghouse Division of Responsibility							
Item	**Activity**	**Purchaser**	**AE**	**AE**	**Equip. Supplier**	**HFE**	**Installer**	**Installer**
		(Exelon)	**(Exelon)**	**EOC**	**(WEC)**	**INL**	**WEC**	**MMC**
1.00	**Project Management**							
1.01	Project Plan & Communications Document	R / A			S		S	
1.02	Project Schedule	R	S	S	S	S	S	S
1.03	Posted 11/18/2022	R	S	S	S	S	S	S
1.04	Project Risk Mitigation Plan	R	S	S	S	S	S	S
1.05	WEC Contract Change Notice (CCN)	S/A			R			
1.06	Exelon Project Change Request (PCR)	R	S	S	S	S	S	S
1.07	Integrated Kick-Off Meeting	Attend	Attend	Attend	Host	Attend	Attend	
1.08	Risk Management Planning	R	S	S	S	S	S	S
1.09	Project Quality Management planning	R	S	S	S	S	S	S
2.00	**Non-Safety System Design**							
2.01	Data Collection/Provision of plant site data, drawings, plant procedures, training documents and OEM Data							
2.02	Prepare Contract Requirements Traceability Matrix	S/A			R			
2.03	Integrated System Architecture Dwg	S/A	S	I	R		I	
2.04	I/O Database (Current Design)	R	S		I		I	
2.05	I/O Database (New Design – Initial Release)	S/A	S	I	R		I	
2.06	Equipment Cabinet layout and Design including infrastructure cabinets	I	I		R			
2.07	I&C System Wiring Diagrams	I	I		R		I	
2.08	Functional Design Specification	S/A	S		R			
2.09	Graphics Display Design Specification	I	I		R	S		
2.10	Human Factors – Requirement	I			S	R		
2.11	System Design Specification	S/A	S		R		I	
2.12	Software Design Specification	I	S		R			
3.00	**Safety System Design**							
3.01	Data Collection/Provision of plant site data, drawings, plant procedures, training documents and OEM Data							
3.02	Contract Requirements Traceability Table	S/A			R			
3.03	Field Termination Report	A	I		R			
3.04	Functional Logic Diagrams	A	I		R			
3.05	System Requirements Specification	A	I		R			
3.06	System Design Specification	A	I		R			
3.07	Software Requirement Specification	I	S		R			

	Westinghouse Division of Responsibility							
Item	Activity	Purchaser	AE	AE	Equip. Supplier	HFE	Installer	Installer
		(Exelon)	(Exelon)	EOC	(WEC)	INL	WEC	MMC
3.08	Standard Hardware Drawing Package	I	I		R			
3.09	Project Specific Hardware Drawing Package	I	I		R			
3.10	Software Design Description	I	I		R			
4.00	**I&C System Equipment Procurement (Safety/Non-Safety)**							
4.01	Procure I&C System, and simulator equipment	S/A	I		R			
4.02	Peripheral Equipment Supply & Delivery	I	I		R			
4.03	Hardware Assembled (cabinets, internal-cab wiring, etc.)	I	I		R			
4.04	Equipment List / Master BOM	S/A	S		R			
4.05	Hardware List BOM (Purchaser Provided Equipment)							
4.06	Procure Hardware List BOM (Purchaser Provided Equipment)	R	S		S			
4.07	Identify Long Lead Items	A	S		R			
4.08	Identify Long Lead Items (Purchaser Provided Equipment)							
4.09	Recommended I&C Spare Parts List	A	S		R			
5.00	**I&C SYSTEM SOFTWARE DEVELOPMENT**							
5.01	HMI Display Development	S/A	S		R	S		
5.02	Control Builder Diagrams (Ovation Logic) Development and Function Chart Builder (Common-Q) Development	S/A	S		R			
5.03	Workstation & System Security Configurations	S/A	S		R			
6.00	**I&C System 50.59 / LAR Development**							
6.01	50.59	Refer to Licensing DOR Tab						
6.02	Licensing Technical Report (LTR)	Refer to Licensing DOR Tab						
6.03	LAR	Refer to Licensing DOR Tab						
6.04	RAI Support	Refer to Licensing DOR Tab						
6.05	Tech Spec Markups	Refer to Licensing DOR Tab						
6.06	Deltas Document	R/A	I		R			
7.00	**Calculation / Analyses Documents**							
7.01	FMEA, Plant/System Specific (Ovation and Common-Q)	S/A	S		R			
7.02	Halogen Non Compliant Material Report	I	I		R			
7.03	Power Heat Load Calculation	S/A	S		R			
7.04	Software Hazards Analysis	S/A	S		R			
7.05	Susceptibility Analysis Report	S/A	S		R			

	Westinghouse Division of Responsibility							
Item	Activity	Purchaser	AE	AE	Equip. Supplier	HFE	Installer	Installer
		(Exelon)	(Exelon)	EOC	(WEC)	INL	WEC	MMC
7.06	System Reliability Analysis & MTBF Summary Report	S/A	S		R			
7.07	Cyber Analysis	S/A	S		R			
7.08	D3 Coping Analysis	S/A	S		R			
7.09	Update NE-402 & NE-403 based on Analyses & detailed design	Refer to Exelon Engineering DOR						
8.00	**Test Procedures & Test Program**							
8.01	System Test Plan	S/A	S		R			
8.02	Software In Loop Test Guidelines (Ovation)	S/A	S		R			
8.03	Energization Procedure (FAT)	I			R			
8.04	Base Hardware Test Procedure (FAT)	I			R			
8.05	Base Software Configuration Test Procedure (FAT)	I			R			
8.06	Communication Data Link Testing Procedure (FAT)	S/A	S		R			
8.07	System Integration Test Procedure	I	S		R			
8.08	Site Acceptance Test Procedure (SAT)	R/A	S					
8.09	Modification Test Procedure (MAT)	R/A	S		S			
8.10	Power Ascension Testing Procedure (PAT)	R/A	S		S			
8.11	SWIL test report- Ovation	S/A	S		R			
8.12	FAT test report- Ovation and Common-Q	S	S		R			
8.13	Safety Final Verification and Validation Report	I	I		R			
8.14	Equipment Qualification Report	A			R			
9.00	**Human Factors Engineering - See HFE Tab**							
9.01	HFE Program Plan		Refer to HFE DOR Tab					
9.02	HSI Style Guide		Refer to HFE DOR Tab					
9.03	Operating Experience Report		Refer to HFE DOR Tab					
9.04	Function Analysis & Allocation		Refer to HFE DOR Tab					
9.05	Task Analysis		Refer to HFE DOR Tab					
9.06	Staffing & Qualification Analysis		Refer to HFE DOR Tab					
9.07	Identify/Treat Important Human Actions		Refer to HFE DOR Tab					
9.08	Conceptual Design MCR Layout & Concept of Operations Doc		Refer to HFE DOR Tab					
9.09	Develop Conceptual Design Safety Displays & Navigation Strategies & produce Report		Refer to HFE DOR Tab					
9.10	Establish Simulator strategy to support ISV, operator training, and procedure development		Refer to HFE DOR Tab					

	Westinghouse Division of Responsibility							
Item	Activity	Purchaser	AE	AE	Equip. Supplier	HFE	Installer	Installer
		(Exelon)	(Exelon)	EOC	(WEC)	INL	WEC	MMC
9.11	Training Impact Evaluation (not currently listed as INL deliverable)		Refer to HFE DOR Tab					
9.12	Procedure Changes Evaluation (not currently listed as INL deliverable)		Refer to HFE DOR Tab					
10.00	**Data Communication**							
10.01	PPS to DCS Communication Advant to Ovation (AOI) Datalink				R			
10.02	DCS to PPC Communication OPC data Link	R/A			R			
11.00	**System Design Integration with Plant (Installation Design)**							
11.01	Consult / Markup plant interface system control & equipment drawings, schematics and wiring diagrams	Refer to Exelon Engineering DOR						
11.02	Consult / Mark-up Plant System Existing Termination Drawings	Refer to Exelon Engineering DOR						
11.03	All Calculations including: HVAC, Electrical etc.	S/A	R		S			
11.04	Custom Metal work Design- AER Cabinet Bases		R		S			
11.05	Custom Metal work Procurement- AER Cabinet Bases	R					I	
11.06	Custom Metal Work Design- MCR Vertical panel and Bench board panel inserts.	Refer to Exelon Engineering DOR						
11.07	Custom Metal Work Procurement- MCR Vertical panel and Bench board panel inserts.	R					I	
11.08	Custom Metal Work/brackets Design- All Control room equipment such as: Thin client, Node box, keyboard, Monitor, and Track ball, Backpanels, media converters, network hardware, etc.	Refer to Exelon Engineering DOR						
11.09	Custom Metal Work/brackets Procurement - All Control room equipment such as: Thin client, Node box, keyboard, Monitor, and Track ball, Backpanels, media converters, network hardware, etc.	R					I	
11.10	Consult / Mark-up of existing affected system technical manuals	I	R		S			
11.11	Existing OPS Procedures	R						
11.12	Existing Maintenance Procedures	R						
11.13	Existing Administrative Procedures	R						
11.14	Existing Site Cyber Admin Procedures	R						
11.15	Installation Instructions	Refer to Exelon Engineering DOR						

	Westinghouse Division of Responsibility							
Item	Activity	Purchaser	AE	AE	Equip. Supplier	HFE	Installer	Installer
		(Exelon)	(Exelon)	EOC	(WEC)	INL	WEC	MMC
11.16	Diagrams (Installation Related Documentation)	Refer to Exelon Engineering DOR						
11.17	Engineering Design Change	Refer to Exelon Engineering DOR						
11.18	Detailed Design (1st) Review meeting	Refer to Exelon Engineering DOR						
11.19	Detailed Design (2nd) Review meeting	Refer to Exelon Engineering DOR						
11.20	Design challenge review	Refer to Exelon Engineering DOR						
11.21	Issue planning and installation schedule	S	S		S		R	S
11.22	Prepare work packages	S	S		I		R	R
11.23	Review and walk down work packages	Refer to Exelon Engineering DOR						
11.24	Complete Constructability Checklists		S	S	S		R/A	R
11.25	Communicate Pre-outage Work Scope & Resource Requirements to Site	S	S				R	S
11.26	Communicate Outage Work Scope & Resource Requirements to Outage Manager	S	S				R	S
12.00	**I&C System Shipment**							
12.01	Complete Certificate of Conformance	A	I		R			
12.02	Ship I&C System Electrical/I&C Equipment	S	I		R			
12.03	Receive equipment and document condition – file shipment damage report if applicable	R	I		S			
12.04	Procure commodity items (wire, fiber-optic cable, terminal lugs, etc.).	R	S				S	S
13.00	**Simulator Upgrade and Testing**							
13.01	Provide the Plant Model Computer (PMC) equipment to the Equipment Supplier (WEC)	R			S			
13.02	Removing the existing control system logic that is being replaced and modify the simulation to incorporate any plant changes associated with the I&C updates .	R						
13.03	Simulator Factory acceptance testing	S			R			
13.04	Integration support at the Limerick site	R			S			
13.05	Ship I&C System hardware/software for the simulator	S			R			
13.06	Perform Limerick simulator hardware installation and modifications	R			S		S	
13.07	Plant Simulation & SAT Testing	R			S			
13.08	Ops simulator certification and training	R						
14.00	**Personnel Training**							
14.01	Overview Platform training	S	I		R			

	Westinghouse Division of Responsibility							
Item	Activity	Purchaser	AE	AE	Equip. Supplier	HFE	Installer	Installer
		(Exelon)	(Exelon)	EOC	(WEC)	INL	WEC	MMC
14.02	Engineering Training	S	I		R			
14.03	Technician Training	S	I		R			
14.04	Operator Training (Train the Trainer)	S	I		R			
15.00	**Non-Safety Cyber Security**							
15.01	License, Install, & Configure ePO suite (AV, AC, DC, PM)				R			
15.02	License, Install, & Configure Acronis Backup & Recovery				R			
15.03	License, Install, & configure SYSLOG agent on Windows				R			
15.04	Establish and Sustain strict configuration management of all equipment at the factory Cyber Secure Testing Facility (CSTF)	R			R			
15.05	Provide and configure Cyber Security System (CSS) firewall to limit traffic between CSS and the Emerson Ovation network	R						
15.06	Configure log forwarding to the DAE Interface -Windows computers (via SYSLOG agent) -SPAN Port for networking equipment	R			S			
15.07	Configure firewalls installed in the DAE Cyber Security to isolate the DAE Cyber Security network from the Emerson Ovation network	R			S			
15.08	EPRI Cyber Security Technical Assessment Methodology (TAM) -Provide site standard example and template for population -Review/comment on the provided populated drafts for the project scope equipment	R						
15.09	EPRI Cyber Security Technical Assessment Methodology (TAM) -Provided populated drafts using the customer-provided template for the project scope equipment				R			
16.00	**Site Testing**							
16.01	Deliver spare parts to site				R			
16.02	Remove old spare parts from all inventories for unit	R	S					
16.03	Deliver all unique test equipment to site	S			R			
16.04	I&C and Support Systems SAT Testing	R	S		S		S	

	Westinghouse Division of Responsibility							
Item	**Activity**	**Purchaser**	**AE**	**AE**	**Equip. Supplier**	**HFE**	**Installer**	**Installer**
		(Exelon)	**(Exelon)**	**EOC**	**(WEC)**	**INL**	**WEC**	**MMC**
16.05	Testing of system interfaces (Datalinks, Plant Computer)	R	S		S		S	
16.06	Power Ascension Testing	R	S		S		S	
16.07	Plant Installation and Startup Support.							
16.08	Return to Service	R	S				S	
17.00	**Closeout**							
17.01	Disconnect Services (Power, Network, Water, Sewer, etc.) for all Temporary Trailers	R	S				S	S
17.02	Remove all Temporary Trailers from site	R	S				S	
17.03	Post modification critique	R	S		S		S	
17.04	As Built Notices Issued/Incorporated	R	S		S		S	
17.05	Complete lessons learned	R	S		S		S	
17.06	I&C System Final Report	R	S		S		S	
17.07	Work Package Closure	S	S				R	R
17.08	Vendor NRC Audits	Refer to Licensing DOR Tab					R	
17.09	UFSAR Markups for LAR	Refer to Licensing DOR Tab					R	

	Human Factors Engineering (INL) Division of Responsibility							
1.00	**Deliverable**	**Exelon Engr.**	**Exelon Licensing**	**Exelon Ops**	**Exelon Training**	**EOC**	**WEC**	**INL HFE**
1.01	HFE Program Plan	S	S					R
1.02	HSI Style Guide	S		S	S		S	R
1.03	Operating Experience Report	S		S	S			R
1.04	Function Analysis & Allocation	S		S	S		S	R
1.05	Task Analysis	S		S			S	R
1.06	Staffing & Qualification Analysis	S	S	S				R
1.07	Identify/Treat Important Human Actions		S	S	S		S	R
1.08	Conceptual Design MCR Layout & Concept of Operations Doc	S	S	S	S		S	R
1.09	Develop Conceptual Design Safety Displays & Navigation Strategies & produce Report	S		S	S		S	R
1.10	Establish Simulator strategy to support ISV, operator training, and procedure development	S		S	R		S	S
1.11	Posted 11/18/2022		S	S	R			S
1.12	Procedure Changes Evaluation (not currently listed as INL deliverable)		S	R	S		S	S
1.13	Create/Maintain Human Factors Issues Tracking System (HFITS)	R	S	S			S	S

	Licensing.. Division of Responsibility									
	Sub Task	**Exelon PORC**	**Exelon Project Mgmt.**	**Exelon Site Eng.**	**Exelon Site Ops.**	**Exelon Site Reg.**	**Exelon Corp. Lic.**	**S&L (Golub)**	**WEC**	**CDO**
1.00	**Digital Vendor Licensing Technical Report (LTR)**									
1.01	Prepare Licensing Technical Report		S	S	S	S	S	S	R	
1.02	Review and Validate iaw/ Exelon Design Eng. Procedures	N/A	S	R	I	C	C	R	S	
1.03	- Engineering EN-DC-149 line-by-line review – Owner acceptance									R
1.04	Posted 11/18/2022							R		
1.05	- Exelon Lic – Review against WF3 site licensing basis						R			
2.00	**UFSAR**									
2.01	UFSAR Markups for LAR		S	S	S	S	S	S	R	S
2.02	Final UFSAR changes		S	S	S	S	S	S	I	R
3.00	**License Amendment Request**									
3.01	Develop Presubmittal Presentations (5)	N/A	S	S	S	S	R	R/P	P	
3.02	Develop TS / Bases markups	N/A	I	S	S	S	R	R/P	S	
3.03	Stakeholder (Ops, etc.) review of TS/Bases	N/A	I	I	R/P	R/P	S	S	I	
3.04	Develop VOP Summary	N/A	I	I	I	I	R	R/P	I	
3.05	Review Vendor deliverables needed for LAR	N/A	I	S	I	C	C	R/P	I	
3.06	Develop Draft LAR	N/A	S	S	S	S	R	R/P	I	
3.07	Coordinate Review Draft LAR	N/A	S	S	S	S	R/P	S	N/A	
3.08	Perform TVT	N/A	S	S	S	S	R/P	S	S	
4.00	**LS-AA-101-1000**									
4.01	Review and Concur iaw/ LS-AA-101-1000	N/A	R	R	R	R	R	S	S	
4.02	Arrange LAR site review	N/A	S	S	S	R/P	S	S	N/A	
4.03	Arrange/Present to PORC	N/A	S	S	S	S	R/P	S	N/A	
4.04	Approve LAR	R	C	C	C	S	R/P	S	N/A	
4.05	Submit LAR	N/A	I	I	I	I	R	I	S	
5.00	**RAI Responses**									
5.01	Manage Response Development	N/A	S	S	S	S	R/P	S	N/A	
5.02	Provide/Obtain Responses	N/A	R	S	S	S	R/P	S	S	
5.03	Develop Response Letter	N/A	S	C	C	S	R/P	S	N/A	
5.04	Review and Concur with Response Letter	N/A	R	R	R	R	R/P	S	S	
5.05	Execute Response Letter	N/A	I	I	I	I	R/P	I	N/A	
6.00	**NRC Audits**									
6.01	Manage On-site NRC Audits	N/A	S	S	S	R/P	S	S	S	
6.02	Vendor NRC Audits	N/A	S	S	S	S	S	S	R	
7.00	**TS Implementation**									
7.01	Identify Licensing Impacts *	N/A	S	S	S	R/P	I	I	I	
7.02	Implement LAR and Document Revisions LS-AA-101-1000*	N/A	S	S	S	R	R/P	I	I	
8.00	**50.59 Reports**									
8.01	50.59 Screens and Evaluations	Refer to Engineering DOR								

	Installation Division of Responsibilities									
	Item Description	**WEC**	**Exelon/ MMC**	**Exelon OPS**	**Exelon I&C**	**Exelon Engin.**	**Exelon Maint. Support**	**Exelon RP**	**Exelon DMP Project Team**	**Exelon NOS**
1.00	**Hardware/Equipment Logistics:**									
1.01	Delivery to LGS Training Center (LTC)	R	S		S				S	
1.02	PPS/DCS equipment setup for SAT	R	S		S				S	
1.03	Setup and control/communication wiring for SAT	R			S					
1.04	120VAC setup for SAT	S	R							
1.05	Posted 11/18/2022	S		S	S	R			S	
1.06	SAT demobe and packing for transport to site	R	S		S					
1.07	Delivery from LTC to Site staging area	S	R							
1.08	Unpacking, final staging for installation	R	S				S			
2.00	**Work Planning:**									
2.01	Demobe and Mobilization planning (by DOR)	R	R							
2.02	In Processing, Training and Qualification (by DOR)	R	R							
2.03	Staff augmentation (by DOR)	R	R							
2.04	Lead Installation Representative						R			
2.05	Craft Supervision (by DOR)	R	R							
2.06	Work order planning (by DOR)	R	R							
2.07	Pre-outage and outage activity planning and scheduling (by DOR)	R	R							
2.08	QA/QV - activity hold/witness points, quality checks	S	S							R
2.09	Vendor Oversight (by DOR)	R				R	R		R	R
2.10	Pre-Outage Work activity progress reporting (twice daily min)	R	R							
2.11	Outage Work activity progress reporting (max every 3hrs)	R	R							
2.12	Clearance Order(s) Development		S	R						
2.13	Clearance Holder (by DOR)	R	R							
2.14	Equipment Staging Areas	S					R		S	
2.15	Craft Muster Areas						R		S	
2.16	Laydown areas	S					R		S	
2.17	Radiological Work Permits							R		
3.00	**Tooling and Maintenance & Test Equipment (M&TE):**									
3.01	Specialty tooling (if not available from LGS M&TE)	R								
3.02	Lifting/Rigging/Hauling equipment		R				S			
3.03	Torquing Tools (if not available from LGS M&TE)	R								
4.00	**Support Work:**									

	Installation Division of Responsibilities									
	Item Description	**WEC**	**Exelon/ MMC**	**Exelon OPS**	**Exelon I&C**	**Exelon Engin.**	**Exelon Maint. Support**	**Exelon RP**	**Exelon DMP Project Team**	**Exelon NOS**
4.01	Development of Infrastructure Installation Design	S								
4.02	Development of Installation Design	S								
4.03	Development of Site Acceptance Test - L5 (enerization)/L6 (Network Software Load)	R								
4.04	Scaffolding - Install, Mod, Inspection, Removal	S	R							
4.05	Penetration work		R							
4.06	Pull Fiber Optic Infrastructure (cabling)		R							
4.07	Terminate Fiber Optic Cabling (including OTDR)	R								
4.08	Asbestos abatement (if needed)		R							
4.09	Lead paint remediation (if needed)		R							
4.10	Standing Fire Watch for Fire System impairment		R							
4.11	Temporary Power - Install, Maintain, Removal	S	R			S	S			
4.12	Free Release of Equipment and tooling	S	S					R		
4.13	Painting and touch-up		R							
5.00	**AER/MCR/Simulator Demo/Install:**									
5.01	AER/MCR Cabinet determ	R								
5.02	AER/MCR Cabinet reterm	R								
5.03	Cabinet interconnects (communication and control)	R								
5.04	Cabinet hardware (incl. adapter plates)	R								
5.05	Design/Procure MCR/Simulator Face Plates for VDU					R				
5.06	Install MCR/Simulator VDU faceplates and components	R								
5.07	Design/Procure MCR/Simulator Face Plates Keyboard/Mouse					R				
5.08	Install MCR/Simulator keyboard/mouse Components	R								
5.09	Old AER cabinet rigging, removal and delivery to dispose		R							
5.10	New AER cabinet rigging and placement		R							
5.11	AER cabinet/adapter bolting and torquing	R								
5.12	Temporary Control Panel(s) (TCP)- As required	R								

	Installation Division of Responsibilities									
	Item Description	**WEC**	**Exelon/ MMC**	**Exelon OPS**	**Exelon I&C**	**Exelon Engin.**	**Exelon Maint. Support**	**Exelon RP**	**Exelon DMP Project Team**	**Exelon NOS**
5.13	TCP Installation/Removal	R								
5.14	MCR HMI interface installation	R								
5.15	MCR existing control removal (physical control & wiring (abandon in place)	R								
5.16	MCR control console wiring - new equipment	R								
5.17	MCR control equipment installation	R								
5.18	AER power distribution and connection	S	R							
5.19	MCR power distribution and connection	S	R							
5.20	Design & Procure MCR Control Console face plates					R				
5.21	Install MCR control console face plates	R								
5.22	MCR control console HMI installation and connection	R								
5.23	Simulator Modifications	R								