February 28, 2014

MEMORANDUM TO : Samuel Miranda, Senior Reactor Systems Engineer
Reactor Systems Branch
Division of Safety Systems
Office of Nuclear Reactor Regulation

FROM: Christopher P. Jackson, Chief ***/RA/***
Reactor Systems Branch
Division of Safety Systems
Office of Nuclear Reactor Regulation

SUBJECT: MAKING NON-CONCURRENCE NCP-2013-014 PUBLIC

As a part of the non-concurrence you have requested that NCP-2013-014 become publicly available. I support this request and also find the subject safety evaluation, that was referenced, may be made publicly available. Both documents will be enclosed via this memorandum.

I appreciate your help in resolving this issue.

Enclosures:
1. NRC Form 757 – Non-Concurrence Process Record for NCP-2013-014
2. Safety Evaluation

CONTACT: Shaun M. Anderson, NRR/DSS/SRXB
(301) 415-2039

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DATE	2/27/2014	2/28/2014

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U.S. NUCLEAR REGULATORY COMMISSION

NON-CONCURRENCE PROCESS

NCP TRACKING NUMBER
NCP-2013-014

SECTION A - TO BE COMPLETED BY NON-CONCURRING INDIVIDUAL

TITLE OF SUBJECT DOCUMENT SRXB Input for the Byron and Braidwood MUR Safety Evaluation	ADAMS ACCESSION NO. ML13267A080
DOCUMENT SIGNER Christopher Jackson	SIGNER PHONE NO.
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REASONS FOR NON-CONCURRENCE AND PROPOSED ALTERNATIVES

See Attachment 1

☐ CONTINUED IN SECTION D

SIGNATURE	DATE

SEE SECTION E FOR IMPLEMNATION GUIDANCE

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U.S. NUCLEAR REGULATORY COMMISSION

NON-CONCURRENCE PROCESS

NCP TRACKING NUMBER
NCP-2013-014

SECTION A - TO BE COMPLETED BY NON-CONCURRING INDIVIDUAL

TITLE OF SUBJECT DOCUMENT	ADAMS ACCESSION NO.
SRXB Input for the Byron and Braidwood MUR Safety Evaluation	ML13267A080

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REASONS FOR NON-CONCURRENCE AND PROPOSED ALTERNATIVES

See Attachment 1

☐ CONTINUED IN SECTION D

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DATE 12/12/2013

SEE SECTION E FOR IMPLEMNATION GUIDANCE

REASONS FOR NON-CONCURRENCE AND PROPOSED ALTERNATIVES

Reasons:

1. Failure to meet a written licensing commitment

ANS-N18.2-1973 [1], *Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants,* is cited in Chapter 15.5.1 of the UFSAR [2] for Exelon's Byron and Braidwood units. It states:

> *2.1.2.3 Design Requirement. Condition II events shall be accommodated with, at most, a shutdown of the reactor with the plant capable of returning to operation after corrective action.*
>
> *By itself, a Condition II incident cannot generate a more serious incident of the Condition III or IV type without other incidents occurring independently.*

Exelon's request for a license amendment to authorize a Measurement Uncertainty Recapture (MUR) power uprate [3], for their Byron and Braidwood units relies upon certain accident analyses (e.g., the inadvertent ECCS actuation at power event) that do not demonstrate fulfillment of their commitment to adhere to the design requirements of ANS-N18.2-1973.

In their MUR application, Exelon cites Regulatory Issue Summary (RIS) 2002-03 [4]; but does not mention RIS 2005-29 [5]. RIS 2005-29 is cited in the NRC's Standard Review Plan (SRP) section (ML070820081) that guides the staff's review of the inadvertent ECCS actuation at power event. RIS 2005-29 informs licensees of the NRC staff's position regarding acceptable and unacceptable means to demonstrate compliance with the aforementioned ANS design requirement. The current licensing basis (CLB) analysis of Byron and Braidwood's inadvertent ECCS actuation at power event has been unacceptable since the RIS was issued (2005), and the SRP was revised (2007). There is no indication, in Exelon's MUR application, that any modifications have been made to the CLB inadvertent ECCS actuation at power analysis to address the staff's concerns, which been outstanding, now, for eight years.

At the current power rating, the CLB analyses of the Byron and Braidwood units do not demonstrate that the ANS design requirements are satisfied. Now, the staff is requested to approve an increase in power level, by 1.63%, on the same flawed basis.

2. Incomplete licensing basis

The UFSAR states: *The most limiting case with respect to RCS pressure is an SI at Hot Full Power coincident with a reactor trip. Because of the pressure reduction from the reactor trip, the SI flow is maximized. The SI flow refills the pressurizer until the pressurizer is water solid, and the SI flow results in liquid discharge through the pressurizer safety relief valves.*

The underlying assumption here is that none of the PORVs open. This assumption may be due to the automatic control circuitry, which is not Class 1E with respect to the opening function. In general, the PORVs, which are set to open at a lower pressure than the pressurizer safety relief valves, will open before the pressurizer safety relief valves unless their opening control circuitry fails or their block valves are closed. A single open PORV will limit the RCS pressure to below the opening pressure setpoint of the pressurizer safety relief valves. There is no discussion of the PORVs, their operation, their qualification for water relief, or their effect upon the transient. Operation of the PORVs, and pressurizer spray, will cause the pressurizer to fill faster, since the RCS pressure will be maintained at a relatively lower level, where the ECCS can deliver more flow. Instead, the licensee's analysis relies solely upon operation of the pressurizer safety valves (PSVs), which are claimed to be qualified for water relief. Since they're qualified for water relief, the possibility of sticking open at least one of the three valves is not considered.

If the PSVs are applied, as the sole mitigating system, to prevent overpressurization of the RCS, then the analysis could include an assumed failure of one PSV to open. The other two will provide adequate protection against overpressurization.

If the PSVs are applied, as the sole mitigating system, to show that the inadvertent ECCS actuation will not develop into a small break LOCA, due to the sticking open of a PSV, then it can be assumed that the single failure of the PSV system will be one PSV failing to close. ANS N658/ANS-51.7 includes code safety valves as examples of components that are especially qualified for service, which may be considered exempt from active failure. Its example specifies the *opening of code safety valves*. It doesn't mention the closing of code safety valves. Therefore, even if the PSVs are qualified for water relief, one of the PSVs may be assumed to fail, as the system's single active failure. Consider, too, that the PSVs will be opening and closing many times. There are many opportunities to stick open. Therefore, a conservative licensing basis accident analysis that is based upon the operation of the PSVs cannot demonstrate compliance with the ANS design requirement, due to the requirement to assume single active failure.

There is also the question of the PSV opening setpoint that would apply to water relief. Normally, a 3% pressure accumulation is used for steam relief. In Westinghouse ATWS analyses [6], a 10% pressure accumulation was applied for water relief, and that was a best estimate value.

These issues were not considered in the licensing basis. Also, the UFSAR does not present plots of the inadvertent ECCS actuation transient. It is not known how long the PSVs would be predicted to be relieving water, or how much water would be expected to be spilled into the containment. Westinghouse's analysis of a loss of load ATWS, for a four-loop plant, predicts that water relief through the PSVs would occur for no more than 100 seconds. It is not known whether the licensee's analysis would show that the duration of water relief, for a Condition II event, would exceed the duration of water relief predicted for a similar plant that is experiencing a beyond- design-basis event. Operator action is required to terminate the ECCS flow, and thereby the PSV water relief. This could take more than 100 seconds.

The UFSAR states: *If the pressurizer safety relief valves do not reseat, then the transient will proceed and terminate as described in Section 15.6.1, "Inadvertent opening of Pressurizer Safety or Relief Valve." This event is also classified as an event of moderate frequency.*

The Inadvertent opening of Pressurizer Safety or Relief Valve, as reported in Section 15.6.1, is analyzed as an AOO to demonstrate that no fuel clad damage will occur. This event, also known as the RCS Depressurization, is treated as a reduction in thermal margin, since the depressurization, while operating at full power, will cause the DNB ratio to fall. The analysis is performed to show that the Overtemperature ΔT reactor trip protection logic will trip the reactor before DNB can occur. In fact, the MUR application states: *The criterion of interest for the accidental depressurization of the RCS analysis, which conservatively models the inadvertent opening of a PSV, is that the DNB design basis is satisfied.* The duration of the analysis covers the time of reactor trip (< one minute); there is no safety injection; and there is no water discharge through a PORV or PSV at any time during the reported analysis.

If the analysis of the Inadvertent opening of Pressurizer Safety or Relief Valve were to be extended past the time of reactor trip, without assuming operator action, then the RCS depressurization would eventually reach the low-low pressurizer pressure SI actuation setpoint. This (legitimate) signal would start the ECCS. The ECCS flow would be relatively high, due to the low RCS pressure, and the pressurizer would fill very rapidly (< five minutes). The water discharge, over a relatively long period, would soon cause the pressurizer relief tank (PRT) rupture disk to break open and allow RCS water to spill into the containment. The UFSAR states, for the inadvertent ECCS actuation event; but would apply to this scenario, as well: *Water relief from the pressurizer PORVs and safeties may result in overpressurization of the pressurizer relief tank (PRT), breaching the rupture disk and spilling contaminated fluid into containment. The radiological releases (offsite doses) resulting from breaking the PRT rupture disk are limited by isolation of the containment.* Recovery will require cleanup of the containment and repair or replacement of one or more pressurizer PORVs or PSVs. In 1988, the staff asked Commonwealth Edison (the licensee for Byron and Braidwood at that time) to develop and adopt plant procedures to inspect the PORVs and PSVs after each lift involving loop seal or water discharge. [7] This raises the question of whether the scenario qualifies as a Condition II event, according to the definition in the ANS standard. This scenario has not been evaluated.

The UFSAR states: *The performance of the pressurizer safety relief valve system and the loads on pressurizer safety relief valves, associated piping, and supports as a result of liquid discharge through the pressurizer safety relief valves, was determined to be acceptable.*

According to EGG-NTA-8028 [8], the PORVs and pressurizer safety relief valves were not tested for water discharge effects. The PSVs' qualification for water discharge, is not supported by test results.

EGG-NTA-8028 states: *4.2.3 Extended High Pressure Injection Event*

The limiting extended high pressure injection event is the spurious actuation of the safety injection system at power (Reference 7). For a four-loop plant, both the safety valves and PORVs will be challenged. Both steam and water discharges are expected. In this event, however, the safety valves or PORVs open on steam and liquid discharge would not be observed until the pressurizer becomes water solid. According to Reference 7, this would not occur until at least 20 minutes into the event which allows ample time for operator action. Thus the potential for liquid discharge in extended HPI events can be disregarded.

3. Flawed, poorly defined licensing basis

The UFSAR states: *American Nuclear Society standard 51.1/N18.2-1973 (Reference 2) describes example 15 of a condition II event as a "minor reactor coolant system leak which would not prevent orderly reactor shutdown and cooldown assuming makeup is provided by normal makeup systems only." In Reference 2, normal makeup systems are defined as those systems normally used to maintain reactor coolant inventory under respective conditions of startup, hot standby, power operation, or cooldown, using onsite power. Since the cause of the water relief is the ECCS flow, the magnitude of the leak will be less than or equivalent to that of the ECCS (i.e., operation of the ECCS maintains RCS inventory during the postulated event and establishes the magnitude of the subject leak). Therefore, the above example of a Condition II event is met.*

ECCS is an emergency system, not a normal makeup system. The charging pumps, when started by a safety injection signal, operate at maximum capacity for core cooling, not at a capacity that is controlled to maintain a programmed pressurizer level.

In the short term, the cause of the water relief is a hole in the pressurizer, not the ECCS flow. The water relief rate is determined by a critical flow calculation that is based upon the pressure difference between the RCS and the pressurizer relief tank or the containment. In the long term, it might be possible for the ECCS flow to maintain inventory, depending upon the RCS pressure and the number of PORVs and safety valves that are stuck open. Under such circumstances, the ECCS flow could well include flow from the safety injection pumps and accumulators. These are also not normal makeup systems. It would not be a Condition II event.

Exelon's MUR application states: *II.2.10 Chemical and Volume Control System Malfunction That Increases Reactor Coolant Inventory – UFSAR 15.5.2*
This event is bounded by the evaluation of the boron dilution event in Section II.2.8 and the analysis of the inadvertent ECCS operation at power event in Section III.11. Therefore, the conclusions presented in the UFSAR remain valid.

The Chemical and Volume Control System Malfunction That Increases Reactor Coolant Inventory is a mass addition event. The charging water does not cause a reactivity excursion, only a rise in RCS inventory. The analysis does not evaluate reactivity or criticality. The Boron Dilution event is analyzed to determine whether there is sufficient time for the operator to correct the situation before criticality can be reached. There is no consideration of pressurizer level.

4. The CLB analysis description (no plots are supplied) indicates that the licensee is relying upon water discharge through the PSVs for protection during an inadvertent actuation of the ECCS event. The PSVs are for overpressure protection during Condition III and IV events, and for ATWS. Using the PSVs in this manner is like relying upon the ECCS to shut down the reactor during a Condition II event.
5. The CLB analysis description indicates there could well be more water relief resulting from an inadvertent actuation of the ECCS event than for a loss of load ATWS. Is the staff prepared to accept the concept that a Condition II event will discharge more water into containment than will a Condition IV event?
6. The licensee's assertions that the PSVs are qualified for water relief are unsubstantiated by valve test results. The PSVs' qualification for water relief lies at the foundation of their CLB analysis.
7. The licensee's statements and comparisons, made in their CLB, indicate a perfunctory understanding of the accident analyses, their acceptance criteria, and how the analyses are constructed to demonstrate that the acceptance criteria are met.
8. There are some events that are not even evaluated.
9. Even if the PSVs are qualified for water relief, the assumed single failure would be one of the three PSVs failing to close. Thus, the ANS design criterion cannot be met.

Proposed Alternatives:

1. Transmit RAIs from SRXB, and give the licensee an opportunity to address the reviewers' concerns. One RAI that could be asked, for example, would be to see the 1983 EPRI report upon which the licensee bases its claim that the PSVs are qualified for water relief. [9]
2. Approve the MUR on condition that the licensee updates their licensing basis to correct the identified issues. In 2005, the NRC approved a license amendment that increased the licensed core power for FPL's Seabrook Station [10]. In addition to the increase in licensed core power, the license amendment imposed a license condition that required FPL Energy Seabrook to address the inadvertent actuation of the ECCS prior to startup from their next refueling outage.

Precedents:

Three plants are Westinghouse 4-loop plants with 1800 cu ft pressurizers, equipped with two PORVs, each capable of relieving 210,000 lbs/hr steam typically at 2335 psig[1], and three PSVs, each capable of relieving 420,000 lbs/hr steam at 2485 psig[2]. The fourth plant, Diablo Canyon, is equipped with a third PORV, also rated at 210,000 lbs/hr.

1. Salem [11]

[1] Copes-Vulcan diaphragm operated relief valve with a 2-inch orifice
[2] CrosbyHB-BP-86 6M6 safety valve with steam internals with a 2.154-inch orifice

How can both events be considered on a common basis, in order to conclude that one event will bound the other?

The Chemical and Volume Control System Malfunction That Increases Reactor Coolant Inventory is an event that is influenced by an MUR, since there is more decay heat present after the reactor trip. It is not analyzed.

Exelon's MUR application states: *Pressurizer Overfill*
The Inadvertent ECCS event results in an increase in the RCS inventory that leads to a water solid pressurizer. This event has been evaluated to assess its potential to progress into a SBLOCA event via a Pressurizer Safety Valve (PSV). The PSV's were qualified for water relief though EPRI testing performed in Reference III.11-3, which showed they would reclose following water relief.

The most limiting cases occur with the reactor at full power operation prior to the event. As the current evaluation is based on an NSSS power level of 3672.6 MWt, this evaluation remains bounding for the MUR power uprate, and the conclusions presented in the UFSAR remain valid.

Exelon continues to rely upon its licensing basis, which depends upon operation of the PSVs. Reference III.11-3 is EPRI Document NP-2770-LD, *EPRI/C-E PWR Safety Valve Test Report*, dated January, 1983. EPRI valve tests, conducted in 1988 [8], did not address the conditions of an Extended High Pressure Injection Event.

The licensee's reliance upon operation of the pressurizer PSVs seems to be inconsistent with PWR design principles. The PSVs, like the ECCS, are mitigation systems for Condition III and IV events. The ANS standard [1] indicates that Condition II events should be adequately protected by the reactor trip. In that vein, Condition I events (e.g., operational transients) are handled by the operator and the automatic control system. The PORVs are part of the automatic pressure control system, along with heaters and spray. This system, as well as other parts of the automatic control system, functions to maintain the plant within its acceptable operating range. The PORV opening setpressure is normally set to about 50 psi below the high pressurizer pressure reactor trip setpoint. The PORVs, along with spray, could limit pressurizer pressure to below the reactor trip setpoint, and thus avoid the reactor trip during Condition I and II transients. RCS pressurizations caused by AOOs should be handled by the PORVs (e.g., load rejection, turbine trip or loss of feedwater). PSVs should be required only during Condition III and IV events (e.g., locked rotor or feedline break), and by ATWS.

The PORV opening setpressure is normally set to about 150 psi below the PSV opening setpressure. It is seen, by accident analysis, that opening one PORV is sufficient to prevent the opening of any of the PSVs.

The licensee's reliance upon operation of the pressurizer PSVs for protection during a Condition II event implies that maybe the event is not in the Condition II category. It implies that their inadvertent ECCS operation at power event, which fills the pressurizer and causes the PSVs to open, is actually a Condition III event that originated as a Condition II event. One can conclude that the ANS design requirement is violated, and that the licensee is attempting to justify the violation by claiming that the PSVs are qualified for water relief.

4. Unjustified use of PSVs

The licensee relies upon operation of the PSVs to address the inadvertent ECCS operation event. The PSVs are the mitigation system for overpressurization events, not mass addition events. The inadvertent ECCS operation event is analyzed to show that it will not develop into a more serious event (e.g., a small break LOCA, created by a stuck-open valve). There is no question that the PSVs can prevent overpessurization. The licensee has not justified the use of PSVs, in this context, since the licensee has not evaluated the inadvertent ECCS operation event scenario in which three PSVs will open and close, repeatedly, under water relief conditions. The licensee has not shown that all the PSVs will always close with each demand. The licensee has also not addressed the single failure criterion to be applied to a mitigation system. In this case, it would be failure to close a PSV.

Finally, the licensee relies upon the assumption that none of the PORVs will operate. They will. Control grade equipment, like the PORVs, is assumed to operate if it aggravates the event. Otherwise, control grade equipment not assumed to operate. The licensee's analysis takes advantage of an assumption that the PORVs will not operate in order to apply the PSVs as the mitigation system for the inadvertent ECCS operation event.

Other plants, of similar design, have qualified their PORVs, not their PSVs) to perform safety functions by relieving water. This requires qualification for water relief, and upgrading the automatic control system circuitry. It also requires revising the tech specs to assure that the PORVs are not isolated during normal operation.

Issues Summary:

1. The staff erred in approving the licensee's CLB analysis of the inadvertent actuation of the ECCS event, more than a decade ago. Should the staff perpetuate the error by approving an MUR that is based upon this analysis?
2. The licensee had eight years to review RIS 2005-29 and make the necessary corrections before submitting their request for an MUR. There is no evidence that they consulted the RIS or the SRP in which it is referenced.
3. Other licensees have made corrections before submitting LARs, particularly for EPUs. Six plants have upgraded their PORVs to safety grade quality. Two have applied for TS changes associated with modifying their protection system logic to make the inadvertent actuation of the ECCS an incredible event. The staff made Seabrook's SPU approval conditional upon correction of their inadvertent actuation of the ECCS licensing basis analysis. Approving Byron and Braidwood's MUR without a similar condition could be construed as unequal treatment of licensees' applications by the staff.

In response to the Westinghouse Nuclear Safety Advisory letter (NSAL), NSAL 93-013, the licensee has determined that an inadvertent Safety Injection (SI) actuation at power could cause the pressurizer to become water solid and pressurizer safety valves lifting with water relief if the automatic operation of the PORVs is not made available for reactor coolant system depressurization early in the transient. The Salem pressurizer safety valves are not designed to relieve water. Thus, the water relief has the potential to cause the pressurizer safety valves to fail in the open position.

In the course of the review of the licensee's January 31, 1997 application, the NRC Staff noted that the pressurizer PORVs were not designed to "safety related" standards and thus could not be credited for mitigation of the inadvertent SI actuation at power incident when the PORV is operating in the automatic mode. In response to this observation, the licensee proposed an upgrade of PORVs as described in the March 14, 1997 and April 8, 1997 supplements, to eliminate the possibility that a single active failure of a PORV component could prevent the mitigation of the inadvertent SI actuation at power incident.

2. Seabrook [10]; UFSAR TABLE 5.4-16

   License Condition 2.K required that, prior to startup from refueling outage 11, Seabrook address the Inadvertent Actuation of the Emergency Core Cooling System either through reanalysis using NRC-approved methodology or by qualification of the pressurizer power-operated relief valves for water relief. On November 7, 2005, FPLE submitted to the NRC a reanalysis to address License Condition 2.K. This document is available in the Agencywide Documents Access and Management System under accession number ML053140139.

3. Diablo Canyon, 2003 [12]

   Unlike the others, Diablo Canyon is equipped with three PORVs, each capable of relieving 210,000 lbs/hr steam typically at 2335 psig, and
   three PSVs, each capable of relieving 420,000 lbs/hr steam at 2485 psig

   In summary, numerous analysis and operational issues have been identified since the original EPRI report was published, which have significantly impacted the SSI analysis results. Therefore, for LAR 01-08, PG&E has performed a more detailed modeling of operator actions, and also upgraded the pressurizer PORVs to Class I in order to credit them for mitigation of the SSI event.

4. Millstone Unit 3 [13]

   To provide added assurance that the pressurizer safety relief valves will not be damaged due to water relief during an ISI event, the licensee upgraded the PORV circuitry, added additional PORV surveillance requirements, qualified the PORVs and associated piping for water relief, and made EOP changes to allow plant operators additional time to terminate the event. The NRC has reviewed these changes and the staff's conclusions are documented herein.

<u>References:</u>

[1] ANS-N18.2-1973, *"Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants*

[2] UFSAR, Byron Units 1 and 2, and Braidwood Units 1 and 2, Rev 9, December 2002

[3] Exelon Nuclear, *Request for License Amendment Regarding Measurement Uncertainty Recapture (MUR) Power Uprate Measurement Uncertainty*, RS-11-099, dated June 23, 2011 (ML1117900030)

[4] NRC Regulatory Issue Summary (RIS) 2002-03, *Guidance on the Content of Measurement Uncertainty Recapture Power Uprate Applications*, dated January 31, 2002.

[5] NRC RIS 2005-29, *Anticipated Transients that Could Develop into More Serious Events,* dated December 14, 2005 (ML051890212).

[6] NS-TMA-2182, Letter from T.M. Anderson, Westinghouse, to S.H. Hanauer, NRC, ATWS Submittal, dated December 30, 1979 (ML041130109)

[7] Letter from L.N. Olshan, NRC, to H.E. Bliss, Commonwealth Edison, *NUREG-0737, Item II.D.1, Performance Testing on Relief and Safety Valves for Byron Station, Units 1 and 2,* dated August 18, 1988

[8] EGG-NTA-8028, *Technical Evaluation Report, TMI Action- NUREG-0737 (II.D.I), Byron Units 1 & 2*, dated January, 1988

[9] EPRI Document NP-2770-LD, *EPRI/C-E PWR Safety Valve Test Report*, January, 1983

[10] SBK-L-05226, FPL Energy, Seabrook Station, *Completion of License Condition 2.K,* dated November 7, 2005 (ML053140139)

[11] License Amendment Nos.194 and 177, *SALEM NUCLEAR GENERATING STATION, UNIT NOS. 1 AND 2,* NRC, June 4, 1997 (ML011720397)

[12] PG&E Letter DCL-03-152, Response to NRC Request for Additional Information Regarding License Amendment Request 01-08, *"Credit for Automatic Actuation of Pressurizer Power Operated Relief Valves,* November 21, 2003 (ML033360735)

[13] License Amendment No.161, *ISSUANCE OF AMENDMENT -MILLSTONE NUCLEAR POWER STATION, UNIT NO. 3,* June 5, 1998 (ML011800207)

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NON-CONCURRENCE PROCESS

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SECTION B - TO BE COMPLETED BY NON-CONCURRING INDIVIDUAL'S SUPERVISOR

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TITLE
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ORGANIZATION
Reactor Systems Branch, Office of Nuclear Reactor Regulation

COMMENTS FOR THE NCP REVIEWER TO CONSIDER
See the Attached --

☐ CONTINUED IN SECTION D

SIGNATURE

DATE
10/24/2013

SEE SECTION E FOR IMPLEMENTATION GUIDANCE

NCP-2013-014 - COMMENTS FOR THE NCP REVIEWER TO CONSIDER

The concerned individual makes four main points. The four points quoted directly are as follows:

1. Failure to meet a written licensing commitment
2. Incomplete licensing basis
3. Flawed, poorly defined licensing basis
4. Unjustified use of PSVs

Fundamentally I agree with each of the four points. As this issue has churned over the last seven months there has been collective agreement there is a valid technical and safety issue that needs to be addressed. Where we have disagreed is what process should be used to address the issue. The concerned individual's third point, "Flawed, poorly defined licensing basis," is correct and underscores the difficulty in drawing conclusions regarding the safety significance at the plant because the situation is unclear. Meaningful dialogue with the applicant is necessary to determine the safety significance and resolve the issue. Given the controversy over the scope of the review, we have not engaged the license in a meaningful way.

From reviewing the licensing basis two issues rise up as needing to be addressed. First the licensee claims the safety valves are qualified for water solid conditions. If this is accurate, as a safety-related component credited in the accident analyses, there needs to be Appendix B documentation demonstrating the valve will open and close under water solid conditions. Additionally the required valve testing needs to be conducted under water solid conditions. Although it is unclear if this is being done, this is relatively easy to verify. Second, the FSAR appears to accept the failure of a safety valve to close as an acceptable consequence to an Anticipated Operational Occurrence. This is not acceptable. A failed open safety valve is an un-isolable primary RCS leak in excess of the capacity of the make-up system. Safety systems would need to be relied upon to mitigate the accident and with an extensive recovery effort to clean-up primary containment to restart the unit would be necessary. This is clearly beyond the acceptance criteria of an AOO and would violate the escalation criterion in the plant's licensing basis. Recognizing that we do not understand the situation at the plant, this could be just a poorly documented licensing basis that should be corrected or it could be an actual safety issue and non-compliance that needs to be resolved.

I agree with the concerned individual that the most efficient and effective way to address the issue is through the licensing process (concerned individual Alternative 1 and 2). An error was made in the licensing process over 10 years ago, and there is no need to compound that error by granting another power uprate. It should be noted that reactor power is not a critical parameter in the consequences of this event so the small increase in reactor power associated with this amendment will not significantly impact the results. The review guidance for power uprates directs the staff to verify, among other things, that the existing accident analysis are valid and, had we chosen to, we could have reasonably interpreted the guidance to allow this issue to be in-scope for the licensing action. However, I fully acknowledge that there are other ways to achieve desired improvements in plant safety and in the licensing basis.

This issue has been resolved at several plants through the licensing process and I am confident that if we choose to adopt either of the concerned individual's two alternatives we will come to resolution quickly. However, recognizing that other approaches can also be effective, I recommend that two additional alternatives be considered. First, I recommend that we initiate an effort to correct the plant's licensing basis. We could proceed with a plant-specific backfit, we could initiate an inspection or we could engage in an open public dialog with the licensee. Second, I recommend that the RIS 2005-29 be revised to clarify to avoid the subjective in-scope/out-of-scope interpretations that are not conductive to predictable regulation.

Summary of Issues:

Based on the issues discussed in Section A of this non-concurrence process (NCP) package, the non-concurring individual chose not to concur on the Division of Safety System (DSS), Reactor Systems Branch (SRXB) evaluation input to the Byron Station Units 1 and 2 and Braidwood Station Units 1 and 2 measurement uncertainty recapture (MUR) power uprate. Those issues included:

1. The staff "erred" in previously approving the Byron/Braidwood current licensing basis (CLB) analysis of the inadvertent actuation of the emergency core cooling system (ECCS).
2. There is no evidence that Braidwood or Byron took action to address the issues identified in Regulatory Issue Summary (RIS) 2005-29, "Anticipated Transients that Could Develop into More Serious Events" or NUREG-0800, "Standard Review Plan - Inadvertent Operation of ECCS and Chemical and Volume Control System Malfunction that Increases Reactor Coolant Inventory."
3. Other licensees' have made corrections to their CLB before submitting license amendment requests (LAR's), particularly LARs for extended power uprates. Approving the Byron/Braidwood measurement uncertainty recapture (MUR) could be construed as unequal treatment of licensees by the staff.
4. The Byron/Braidwood CLB relies upon water discharge through pressurizer safety valves (PSVs) for protection during an inadvertent actuation of ECCS event; a function for which the PSVs are likely not designed.
5. The Byron/Braidwood CLB analysis description indicates that more borated water would be relieved to the containment, as a result of an inadvertent actuation of the ECCS, than would be during more significant plant events like a loss-of-load anticipated transient without a scram (ATWS).
6. The Byron/Braidwood CLB does not include a basis or analysis supporting the qualification of PSVs and their ability to relieve water.
7. The licensee's statements and comparisons, made in their CLB, indicate only a perfunctory understanding of their accident analysis and associated acceptance criteria.
8. There are some events that are not even evaluated.
9. Even if the PSVs were qualified to relieve water, the failure of a single SRV to close would not meet ANS single failure design criteria.

The non-concurring individual also proposed two alternatives be pursued in lieu of their not concurring with the SRXB evaluation input to the Byron and Braidwood MUR power uprate:

1. Transmit requests for additional information (RAIs) to the licensee, as part of the staff's review of the MUR LAR, and give them an opportunity to address the non-concurring individual's issues.
2. Approve the MUR on the condition that the licensee updates its licensing basis to correct the identified issues.

NRC FORM 757
NRC MD 10.158
(7-2011)

U.S. NUCLEAR REGULATORY COMMISSION

NON-CONCURRENCE PROCESS

NCP TRACKING NUMBER
NCP-2013-014

TITLE OF SUBJECT DOCUMENT
SRXB Input for the Byron and Braidwood MUR Safety Evaluation

ADAMS ACCESSION NO.
ML13267A080

SECTION C - TO BE COMPLETED BY DOCUMENT SPONSOR

NAME
Shaun M. Anderson

TITLE
Technical Assistant

PHONE NO.
(301) 415-2039

ORGANIZATION
Division of Safety Systems, Office of Nuclear Reactor Regulation

SUMMARY OF ISSUES

ACTIONS TAKEN TO ADDRESS NON-CONCURRENCE

On November 13, 2013, a meeting was held with the non-concurring individual, his supervisor, DSS senior management, and division senior level advisors, to ensure there was a common understanding of the safety significance of the identified issues, both individually and collectively. After a thorough discussion and review of the issues listed above, all parties agreed that the issues did not constitute a safety issue of sufficient significance to warrant immediate action be taken by the NRC to ensure the licensee addressed the identified issues. Additionally, as stated by the non-concurring individual's supervisor in Section B of the NCP package, "…reactor power is not a critical parameter in the consequences of this event so the small increase in reactor power associated with this amendment will not significantly impact the results." With the exception of the non-concurring individual, all other parties agreed that the identified CLB discrepancies and issues related to qualification of the PSVs could be pursued consistent with the requirements of 10 CFR 50.109, "Backfitting," in lieu of pursuing the matter through the MUR review process and issuing RAIs or otherwise conditioning the Byron/Braidwood operating licenses. However, the non-concurring individual continued to stand by their proposed alternatives for the reasons discussed in Section A of the NCP package.

Issues 1, 4, 5, 6, 7, 8, and 9 raised by the non-concurring individual will be evaluated consistent with the requirements of 10 CFR 50.109, "Backfitting," and NRR Office Instruction LIC-400, "Procedures for Controlling the Development of New and Revised Generic Requirements for Power Reactor Licensees."
(continued next page)

SIGNATURE--DOCUMENT SPONSOR	[signature]	TITLE Technical Assistant	
ORGANIZATION	Division of Safety Systems, Office of Nuclear Reactor Regulation		DATE 12/12/2013
SIGNATURE--NCP REVIEWER	[signature]	TITLE Deputy Director (Acting)	
ORGANIZATION	Office of Nuclear Reactor Regulation		DATE 12/18/13

NCP OUTCOME

Non--Concurring Individual: ☐ CONCURS ☒ NON-CONCURS ☐ WITHDRAWS NON-CONCURRENCE (i.e., discontinues process)

AVAILABILTY OF NCP FORM

Non--Concurring Individual: ☒ WANTS NCP FORM PUBLIC ☐ WANTS NCP FORM NON-PUBLIC

☑ CONTINUED IN SECTION D

SEE SECTION E FOR IMPLEMENTATION GUIDANCE

NRC FORM 757
NRC MD 10.158
(7-2011)

U.S. NUCLEAR REGULATORY COMMISSION

NON-CONCURRENCE PROCESS

NCP TRACKING NUMBER
NCP-2013-014

TITLE OF SUBJECT DOCUMENT
SRXB Input for the Byron and Braidwood MUR Safety Evaluation

ADAMS ACCESSION NO.
ML13267A080

SECTION D: CONTINUATION PAGE

CONTINUATION OF SECTION ☐ A ☐ B ☑ C

Issue 2, raised by the non-concurring individual, addresses concerns with the fact that the licensee had not taken action to address the issues identified in RIS 2005-29, and by way of reference, SRP 800. Although licensee's review NRC generic communications, including RIS', as part of their review of industry operating experience, a RIS (as a matter of policy) does not transmit any new requirements and does not require any specific action or written response on the part of an addressee. In this case, the licensee's handling of the issues discussed in RIS 2005-29 will be considered as the staff pursues this matter via the backfit process.

Issue 3, raised by the non-concurring individual, addresses concerns of inconsistent treatment of licensees stemming from the fact that some licensees' have made corrections to their CLB, to address the issues listed above, before submitting LAR's, particularly those supporting for extended power uprates. Historically, several licensees have taken proactive measures to address CLB discrepancies similar to those described above. Several more licensees have taken similar actions following the issuance of RIS 2005-29. However, the language in the RIS has recently led to confusion amongst the staff regarding when a licensee's accident analysis, including their evaluation of an inadvertent actuation of the ECCS, falls within the scope of the staff's review, thus opening the door for staff to ask accident-specific questions of a licensee via the RAI process. This confusion contributed to the lengthy review of the Byron/Braidwood MUR, as staff debated the merits of pursing the issues identified by the non-concurring individual via the RAI process. Consistent with the recommendations of the non-concurring individual's supervisor, the staff requested and received NRR Leadership Team concurrence to pursue the development of a revision to RIS 2005-29 to clarify when a licensee's accident analysis falls within the scope of staff review. Not only will this ensure licensees have a consistent understanding of when the staff will engage them on the issues discussed in the RIS, it will also alleviate future confusion amongst the staff thus support the timely review of future MURs and other similar LARs.

SEE SECTION E FOR IMPLEMENTATION GUIDANCE

NON-CONCURRENCE PROCESS

SECTION E - Implementation Guidance

Part 1 - Initiation of Non-Concurrence

Individual non-concurs on subject document and completes Section A, including identifying name and ADAMS accession number of document being non-concurred on, name of the subject document signer, and reasons for non-concurrence and proposed alternatives.

If more than one individual non-concurs, Section A should reflect the additional names and signatures.

Individual must request NCP tracking number prior to submitting NCP Form by emailing NCPPM.Resource@nrc.gov or calling (301) 415-2741.

Individual sends NCP Form to immediate supervisor, document signer, NCP PM, and OCWE Champion. (See Contacts on OCWE Web site.)

Part 2 - Staff Review of Non-Concurrence

Document Signer identifies Document Sponsor and forwards NCP Form to Document Sponsor to coordinate staff review. Document Signer may choose to act as Document Sponsor.

Individual's immediate supervisor completes Section B, including views of issues and proposed alternatives and any other information for management consideration and forwards to Document Sponsor.

Document Sponsor documents Summary of Issues (SOI) and emails to individual for comment and consensus. SOI ensures a common understanding of issues and should be agreed upon before NCP Form is evaluated by staff.

Document Sponsor serves to coordinate and document staff's review of the non-concurrence. Non-concurring individual should be included in discussions, when warranted, to maximize understanding and improve decision-making.

Document Sponsor completes Section C to reflect staff's review of issues and actions (if applicable), that were taken to address concerns. Documentation should be complete, on-point, factual, and focused on issues (not individuals).

Document Sponsor puts completed NCP Form in document package and returns package to concurrence.

Document Sponsor updates Section C, as necessary, to reflect any additional changes made during process to address issues.

Part 3 - Management Review of Non-Concurrence

Document Signer reviews NCP Form, may discuss with interested parties (including non-concurring individual), and may return NCP Form and subject document for additional action, prior to signing Section C as the NCP Reviewer and prior to issuance of subject document.

If Document Signer is Document Sponsor, NCP Reviewer is next level manager. Document Signer continues to sign subject document and NCP Reviewer is added to subject document concurrence.

If Document Signer is not SES manager, NCP Reviewer is first SES manager in organizational chain. Document Signer continues to sign subject document and NCP Reviewer is added to subject document concurrence.

Part 4 - NCP Outcome and Record-Keeping

Document Sponsor records outcome of NCP when process is complete (i.e., when subject document is issued) in Section C.

Document Sponsor gets input from non-concurring individual on interest of availability of NCP Form.

If individual wants NCP Form public, Document Sponsor assists in releasability review in accordance with the NRC Policy For Handling, Marking, and Protecting Sensitive Unclassified Non-Safeguards Information (SUNSI) and MD 3.4, "Release of Information to the Public."

NCP Form should be profiled in ADAMS using ADAMS Template NRC-006.

Document Sponsor will email NCP PM and OCWE Champion when process is complete.

NCP PM will post NCP Form and issued subject document on internal Web site and OCWE Champion will highlight to staff, as warranted.

December 9, 2013

MEMORANDUM TO: Travis L. Tate, Chief
Plant Licensing Branch III-2
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

FROM: Christopher P. Jackson, Chief ***/RA/***
Reactor Systems Branch
Division of Safety Systems
Office of Nuclear Reactor Regulation

SUBJECT: REACTOR SYSTEMS BRANCH SAFETY EVALUATION INPUT TO BYRON STATION UNITS 1 AND 2 AND BRAIDWOOD STATION UNITS 1 AND 2 MEASUREMENT UNCERTAINTY RECAPTURE POWER UPATE

By letter dated June 23, 2011, Exelon Generation, the licensee for Braidwood Station Units 1 and 2 and Byron Station Units 1 and 2, submitted a License Amendment Request (LAR) to revise the Operating License and Technical Specifications (TSs) as necessary to increase the licensed core power level by approximately 1.63% from the Current Licensed Thermal Power (CLTP) of 3586.6 MWt to 3645 MWt.

The proposed power uprate is based on a redistribution of analytical margin originally required of Emergency Core Cooling System (ECCS) evaluation models performed in accordance with the requirements set forth in Title 10 of the *US Code of Federal Regulations*, Part 50, Appendix K, and "ECCS Evaluation Models." The Reactor Systems Branch (SRXB) has reviewed the request using the guidance contained in Regulatory Issue Summary (RIS) 2002-03, "Guidance on the Content of Measurement Uncertainty Recapture Power Uprate Applications."

Based on our detailed review, the SRXB finds that the requested amendment is acceptable. A Safety Evaluation (SE) presenting the staff's findings is enclosed. This completes SRXB review efforts.

Enclosure:
Safety Evaluation Input

Contact: Joshua R. Miller, NRR/DSS/SRXB
301-415-8398

December 9, 2013

MEMORANDUM TO:	Travis L. Tate, Chief Plant Licensing Branch III-2 Division of Operating Reactor Licensing Office of Nuclear Reactor Regulation
FROM:	Christopher P. Jackson, Chief */RA/* Reactor Systems Branch Division of Safety Systems Office of Nuclear Reactor Regulation
SUBJECT:	REACTOR SYSTEMS BRANCH SAFETY EVALUATION INPUT TO BYRON STATION UNITS 1 AND 2 AND BRAIDWOOD STATION UNITS 1 AND 2 MEASUREMENT UNCERTAINTY RECAPTURE POWER UPATE

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Contact: Joshua R. Miller, NRR/DSS/SRXB
301-415-8398

<u>DISTRIBUTION:</u> CJackson JMiller SWhaley WLyon

ADAMS ACCESSION: ML13267A080 **Non-concurrence *via email NRR-106

OFFICE	**DSS/SRXB****	**DSS/SRXB**	**DSS/SRXB***	**BC/DSS/SRXB**
NAME	**SMiranda**	**JMiller**	**WLyon**	**CJackson**
Date	**9/25/13**	**9/24 /13**	**9/24/13**	**12/9/13**

OFFICIAL RECORD COPY

REACTOR SYSTEMS BRANCH

SAFETY EVALUATION INPUT TO BYRON STATION UNITS 1 AND 2

AND BRAIDWOOD STATION UNITS 1 AND 2 MEASUREMENT

UNCERTAINTY RECAPTURE POWER UPATE

1.0 INTRODUCTION

By letter dated June 23, 2011, Exelon Generation, the licensee for Braidwood Station Units 1 and 2 and Byron Station Units 1 and 2, submitted a License Amendment Request (LAR) to revise the Operating License and Technical Specifications as necessary to increase the licensed core power level by approximately 1.63 percent from the Current Licensed Thermal Power (CLTP) of 3586.6 Megawatts Thermal (MWt) to 3645 MWt (Reference V). An audit was also performed to verify information necessary to the completion of this evaluation.

The proposed amendment is based on the use of the Cameron Leading Edge Flow Measurement (LEFM) CheckPlus ultrasonic, multi-path, transit time flowmeter system that would decrease the uncertainty in the measurement of feedwater flow, thereby decreasing the power level measurement uncertainty from 2.0% to 0.37%.

The proposed power uprate is based on a redistribution of analytical margin originally required of Emergency Core Cooling System (ECCS) evaluation models performed in accordance with the requirements set forth in Title 10 of the *US Code of Federal Regulations*, Part 50, Appendix K, and "ECCS Evaluation Models" (Reference 3). Appendix K mandated consideration of 102% of the licensed power level for ECCS evaluation models of light water reactors. The U.S. Nuclear Regulatory Commission approved a change to the requirements of 10 CFR 50, Appendix K, on June 1, 2000. The change provided licensees with the option of maintaining the 2% power margin between the licensed power level and the assumed power level for the ECCS evaluation, or applying a reduced margin for ECCS evaluation based on the accounting of uncertainties due to instrumentation error.

In large part, the basis for acceptability of this proposed amendment is that the Measurement Uncertainty Recapture (MUR) power level conditions are bounded by the current analyses of record.

The Office of Nuclear Reactor Regulations (NRRs) Reactor Systems Branch (SRXB) has responsibility for review of Ultrasonic Flow Meters (UFMs) thermal-hydraulic, certain mechanical aspects, accident analysis, and related topics that potentially affect UFM performance. NRRs Instrumentation and Controls Branch (EICB) covers instrument uncertainty and everything from the electrical and mechanical connections at the spool piece to and including the displays that indicate FW flow rate. This Safety Evaluation (SE) is limited to the thermal hydraulic aspects of the CheckPlus UFM, including some aspects of the transducers that may influence the perceived flow profile, accident analysis and consideration of the associated uncertainty.

ENCLOSURE

2.0 REGULATORY EVALUATION

Early revisions of 10 CFR 50.46, and Appendix K to 10 CFR 50, required licensees to base their Loss-Of-Coolant Accident (LOCA) analysis on an assumed power level of at least 102% of the licensed thermal power level to account for power measurement uncertainty. The NRC later modified this requirement to permit licensees to justify a smaller margin for power measurement uncertainty. Licensees may apply the reduced margin to operate the plant at a level higher than the previously licensed power. The licensee proposed to use a Cameron Leading Edge Flow Meter (LEFM) CheckPlus system to decrease the uncertainty in the measurement of feedwater flow, thereby decreasing the power level measurement uncertainty from 2.0% to 0.37%.

The licensee developed its LAR consistent with the guidelines in NRC Regulatory Issue Summary (RIS) 2002-03, "Guidance on the Content of Measurement Uncertainty Recapture Power Uprate Applications".

3.0 TECHNICAL EVALUATION

3.1 Background

Nuclear power plants are licensed to operate at a specified core thermal power. The uncertainty of the calculated value of this thermal power is a significant input into the probability of the plant exceeding the power levels assumed in the design-basis transient and accident analyses. In this regard, Appendix K, "ECCS Evaluation Models," to Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50, "Domestic Licensing of Production and Utilization Facilities," originally required LOCA and ECCS analyses to assume that the reactor had been operating continuously at a power level at least 102.0 percent of the licensed thermal power to allow for uncertainties such as instrument error. To reduce an unnecessarily burdensome regulatory requirement and to avoid unnecessary exemption requests, the Commission published a revised rule in the *Federal Register* (65 FR 34913; June 1, 2000). This rule amended the requirement in Appendix K to allow applicants the option of justifying a smaller margin for power measurement uncertainty by using more accurate instrumentation to calculate the reactor thermal power.

In existing nuclear power plants, the neutron flux instrumentation continuously indicates the reactor core thermal power. This instrumentation must be periodically calibrated to accommodate the effects of fuel burnup, flux pattern changes, and instrumentation setpoint drift. The reactor core thermal power generated by a nuclear power plant is determined by steam plant calorimetry, which is the process of performing a heat balance around the nuclear steam supply system (called a calorimetric). The accuracy of this calculation depends primarily upon the accuracy of Feedwater (FW) flow rate and FW net enthalpy measurements. As such, an accurate measurement of FW flow rate and temperature is necessary for an accurate calibration of the nuclear instrumentation. Of the two parameters, flow rate and temperature, the most important in terms of calibration sensitivity is the FW flow rate.

The originally installed instruments for measuring FW flow rate in existing nuclear power plants were usually a venturi or a flow nozzle, each of which generates a differential pressure proportional to the FW velocity in the pipe. Of the two, the venturi was the most widely used because of relatively low head loss. However, error in determination of flow rate is introduced due to venturi fouling and, to a lesser extent, flow nozzle fouling, the transmitter, and the analog-to-digital converter.[1]

Because of the desire to reduce flow instrumentation uncertainty to enable operation of the plant at a higher power while remaining within the licensed rating, the industry assessed alternate flow rate measurement techniques and found that UFMs are a viable alternative. UFMs are based on computer-controlled electronic transducers that do not have differential pressure elements that are susceptible to fouling. Caldon, Inc.[2] developed a UFM called a "leading edge flow meter" and named it the LEFM Check system. It followed this with the LEFM CheckPlus system, which consists essentially of two Check systems in the same spool piece and provides a more accurate FW flow measurement than the Check system. Both of these UFMs have demonstrated better measurement accuracies than the differential pressure type instruments and provide on-line verification to ensure that the UFM is operating within its uncertainty bounds.

Caldon submitted an engineering report, ER-80P (Reference A), in March, 1997, that describes the LEFM, includes calculations of power measurement uncertainty using a Check system in a typical two-loop pressurized-water reactor or a two-FW-line boiling-water reactor, and provides guidance for determining plant-specific power calorimetric uncertainties. The U.S. NRC staff approved this report for an exemption to the 2 percent uncertainty requirement in Appendix K to 10 CFR Part 50 and approved a 1% power uprate for using the LEFM (Reference B). Following publication of the amendment to Appendix K that allowed for an uncertainty less than 2 percent, Caldon submitted a supplement to ER-80P, ER-160P (Reference C) that the NRC staff approved in Reference D for up to a 1.4% power uprate. Subsequently, the NRC staff approved ER-157P, Revision 5, (Reference E) for up to a 1.7% power uprate using the CheckPlus system (References E and F) and recently approved ER-157P, Revision 8 (References G and H). Revision 8 corrects minor errors in Revision 5, provides clarifying text, and incorporates revised analyses of coherent noise, non-fluid delays, and transducer replacement. It also adds two new appendices, Appendix C and Appendix D, which describe the assumptions and data that support the coherent noise and transducer replacement calculations, respectively.

Byron and Braidwood were originally designed with FW flow and temperature instrumentation consisting of venturis, differential pressure transmitters, and thermocouples. Modifications required for the MUR power uprate include installation of the CheckPlus system. Existing FW flow and temperature instrumentation will be retained and used for comparison monitoring of the LEFM system and as a backup FW flow measurement when needed.

The FW flow measurement system to be permanently installed is a Cameron LEFM CheckPlus ultrasonic 8-path transit time flowmeter. As discussed above, the CheckPlus design is addressed in Topical Reports ER-80P, ER-160P, and ER-157P that have been approved by the NRC. It will be used for continuous calorimetric power calculation determination by providing FW mass flow and FW temperature input data to the plant computer system that is used for automated performance of the calorimetric power calculations.

---

[1] "Venturi" will generally be used in the remainder of this document to reference both venturis and flow nozzles.

[2] Caldon Ultrasonics is now part of Cameron Measurement Systems.

The CheckPlus system is stated to consist of one flow element (spool piece) installed in each of the Steam Generator (SG) FW flow headers. The FW piping configurations are stated to have been explicitly modeled as part of the CheckPlus meter factor and accuracy assessment testing performed at Alden Research Laboratories (ARL). The planned installation location of each CheckPlus is stated to conform to the applicable requirements in Cameron's Installation and Commissioning Manual and Cameron Topical Reports ER-80P and ER-157P and the bounding uncertainty analysis is stated to be addressed by ER-800, ER-801, ER-802, and ER-803 (Reference N).

3.2 Acceptance Criteria

General acceptance criteria apply to all aspects of testing in a certified facility, transfer from the test facility, initial operation, and long-term in-plant operation. These criteria are:

- Traceability to a recognized national standard. This requires no breaks in the chain of comparisons, all chain links must be addressed, and there can be no unverified assumptions.
- Calibration.
- Acceptable addressing of uncertainty beginning with an initial estimate of the bounding uncertainty and continuing through all aspects of initial calibration in a certified test facility, transfer to the plant, initial operation, and long-term operation.

For CheckPlus, meeting these criteria includes documenting:

- Design and characteristics information,
- Calibration testing at a certified test facility,
- any potential changes associated with differences between testing and plant operation including certification that initial operation in the plant is consistent with pre-plant characteristics predictions, and
- in-plant operation.

When it originally approved ER-80P and ER-157P, the NRC established four criteria that applicants were to address. The criteria and the applicant responses in Reference V are as follows:

> **Criterion:** Discuss maintenance and calibration procedures that will be implemented with the incorporation of the LEFM, including processes and contingencies for inoperable LEFM instrumentation and the effect on thermal power measurements and plant operation.
>
> **NRC Staff Comments:** Implementation should include developing the necessary procedures and documents required for LEFM maintenance and calibration. Plant maintenance and calibration procedures should include Cameron's maintenance and

calibration requirements prior to declaring the CheckPlus system operational and raising power above approximately 90% of the licensed thermal power. Preventive maintenance scope and frequency should be based on vendor recommendations. Maintenance should be performed by personnel qualified on the CheckPlus system. Maintenance and test equipment, setting tolerances, calibration frequencies, and instrumentation accuracy should be accounted for within the thermal power uncertainty calculation. Uncertainty should be at the 95% probability and 95% confidence level.

Applicant Response: "Implementation of the MUR power uprate license amendment will include developing the necessary procedures and documents required for continued calibration and maintenance of the LEFM system. Plant maintenance and calibration procedures will be revised to incorporate Cameron's maintenance and calibration requirements prior to raising power above the CLTP of 3586.6 MWt. The Byron and Braidwood Station Technical Requirement Manuals (TRM) will be revised as discussed in Sections I.1.G and H below, and in Attachment 1 to the LAR to address contingencies for inoperable LEFM instrumentation. "

"Preventive maintenance will be performed based on vendor recommendations. The preventive maintenance program and LEFM CheckPlus system continuous self-monitoring feature ensure that the LEFM remains bounded by the Topical Report ER-80P (Reference I-1), as supplemented by ER-157P (Reference I-2), analysis and assumptions. Establishing and continued adherence to these requirements assures that the LEFM CheckPlus system is properly maintained and calibrated. The preventive maintenance activities will be identified via the associated plant modification package. Typical activities performed include power supply checks, pressure transmitter checks, and clock verifications. Maintenance of the LEFM system will be performed by personnel who are qualified on the LEFM."

"Instrumentation, other than the LEFM system, that contributes to the power calorimetric computation will be periodically calibrated and maintained using existing site procedures. Maintenance and test equipment, tolerance settings, calibration frequencies, and instrumentation accuracy were evaluated and accounted for in the thermal power uncertainty calculation."

NRC Staff Assessment: The licensee response included references to Cameron reports and discussed how the licensee will install and maintain the LEFMs at the four plants. The licensee referenced operation and contingences for inoperable LEFM later in the LAR and it is discussed below in 3.5.2.1. The applicant has acceptably addressed Criterion 1.

Criterion: For plants that currently have LEFMs installed, provide an evaluation of the operational and maintenance history of the installation and confirmation that the installed instrumentation is representative of the LEFM system and bounds the analysis and assumptions set forth in Topical Report ER-80P.

Applicant Response: "At the time of this submittal, only Byron Station Unit 1 and Braidwood Station Unit 2 have installed the LEFM CheckPlus systems. Based on the results of the modification and commission testing the LEFM CheckPlus system as installed is in conformance with the analysis and assumptions given in Cameron's

Topical Report ER-80P (Reference I-1), ER-157P (Reference I-2), and the Byron and Braidwood unit specific "Bounding Uncertainty Analysis for Thermal Power Determination Reports" (References I-7a through d), as well as the performance parameters identified in the Alden Laboratory Meter Factor Calculation and Accuracy Assessments (References I-5a through 5d). As of June 17, 2011, there have been no performance, operational, or maintenance issues that would indicate any non-conformance with the above."

NRC Staff Assessment: The licensee provided the above response. The staff also audited an occurrence at the Byron Station Unit 1 with comparisons of the UFM and the venturi and plant parameter data. This is detailed in Section 3.8. Based upon the above response and the staff audit of information provided by the licensee, the licensee has acceptably addressed Criterion 2.

Criterion: Confirm that the methodology used to calculate the CheckPlus uncertainty in comparison to the current FW instrumentation is based on accepted plant setpoint methodology (with regard to the development of instrument uncertainty). If an alternative approach is used, the application should be justified and applied to both venturi and ultrasonic flow measurement instrumentation installations for comparison.

NRC Staff Comments: The applicant should address the calculation of uncertainty. For example, CheckPlus system uncertainty calculation methodology is usually based on a Square-Root-Sum-of-Squares (SRSS) calculation for independent contributors to uncertainty with addition of uncertainties associated with dependent contributors to uncertainty.

Applicant Response: "Cameron has performed Unit specific bounding uncertainty analysis for Byron and Braidwood Stations, Unit 1 and 2 (References I-7a through 7d). Copies of these analyses are provided in attachments 8a through 8d of the LAR. The calculations in these analyses are consistent with Cameron's Topical Report ER-80P (Reference I-1), as supplemented by ER-157P (Reference I-2), ISA-RP67.04.02-2000, "Methodologies for the Determination of Setpoints for Nuclear Safety-Related Instrumentation" (Reference I-8) and Exelon standard NES-EIC-20.04 (Rev. 5). This approach has been approved by the NRC in References I-3 and I-4. The core thermal power uncertainty calculation which takes into account the uncertainty associated with the feedwater flow venturis is performed in accordance with Exelon standard NES-EIC-20.04 (Rev. 5) and is consistent with ISA-RP67.04.02-2000 (Reference I-8).
The fundamental approach used is to statistically combine inputs to determine the overall uncertainty. Channel statistical allowances are calculated for the instrument channels. Dependent parameters are arithmetically combined to form statistically independent groups, which are then combined using the square root of the sum of the squares approach to determine the overall uncertainty."

NRC Staff Assessment: The applicant has acceptably addressed Criterion 3.

Criterion: For plants where the ultrasonic meter was not installed and flow elements calibrated to a site-specific piping configuration (flow profiles and meter factors not representative of the plant specific installation), additional justification should be provided for its use. The justification should show that the meter installation is either independent of the plant specific flow profile for the stated accuracy, or that the installation can be shown to be equivalent to known calibrations and plant configurations for the specific installation including the propagation of flow profile effects at higher Reynolds numbers. Additionally, for previously installed calibrated elements, confirm that the piping configuration remains bounding for the original CheckPlus installation and calibration assumptions.

NRC Staff Comments: Caldon has always performed pre-installation calibration tests of each CheckPlus at ARL before installation. The tests are performed at room temperature and sometimes at flow rates that are lower than will be obtained in the plant installation. Consequently, the Reynolds Number may differ between the test and plant conditions by approximately a factor of five to ten. This raises the possibility that the flow profile and meter factors (calibration factor) may not be representative of the plant values.

Criterion 4 allows for installation of a previously calibrated UFM where the calibration was performed at lower Reynolds numbers if acceptable justification is provided. Historically, Caldon has acceptably addressed propagation of flow profile effects at the higher Reynolds numbers. It also conducts additional confirmatory in-plant tests following installation as part of the final acceptance/commissioning process that provides the final positive confirmation that actual performance in the field meets the uncertainty bounds established for the instrumentation.

The process sometimes involves submission of a pre-test estimate of uncertainties. In Reference I, Cameron addressed the likelihood that testing would fail to confirm the bounding uncertainty parameters. They showed that the meter factor uncertainty was 0.22 percent on the basis of over 94 CheckPlus UFMs subjected to over 2045 calibration tests of over 409 test configurations, with a higher uncertainty of about 0.32 percent for a single meter that was less than 10 pipe diameters downstream of a tubular flow straightener[3]. Typically, without flow straighteners upstream of a CheckPlus, the differences between the pre-test bounding uncertainties and post-test uncertainties have been between 0.002 and 0.003 percent with the pre-test uncertainties greater. Consequently, it is unlikely that initial estimates of uncertainties will fail to bound test results.

Applicant Response: "Criterion 4 does not apply to Byron or Braidwood Stations, Units 1 or 2. Byron and Braidwood Stations LEFM CheckPlus systems were calibrated at Alden Research Laboratory. Cameron engineering reports for each of the Units evaluating the calibration test data from Alden Research Laboratory have been completed and are provided in LAR Attachments 8a through 8d (Appendix A.3). The calibration factors used for each Units LEFMs are based on the analysis contained in these reports."

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[3] There is less experience with flow straighteners upstream of a CheckPlus. SRXB recommends this configuration be avoided because flow straighteners are known to affect CheckPlus calibration. If this configuration is necessary, then the review process must be conducted with an in-depth review of the test and plant configurations and data to ensure the CheckPlus is operating within its stated uncertainty bounds.

NRC Staff Assessment: This is an acceptable response. The applicant provides in-depth coverage of the ARL testing and CheckPlus installation in the plant as reviewed within this SE.

3.3 Initial Design and Characteristics

To determine volumetric flow rate, the Caldon UFM transmits an acoustic pulse along a selected path and records the arrival of the pulse at the receiver. Another pulse is transmitted in the opposite direction and the time for that pulse is recorded. Since the speed of an acoustic pulse will increase in the direction of flow and will decrease when transmitted against the flow, the difference in the upstream and downstream transit times for the acoustic pulse provides information on flow velocity. Once the difference in travel times is determined, the average velocity of the fluid along the acoustic path can be determined. Therefore, the difference in transit time is proportional to the average velocity of the fluid along the acoustic path.

The CheckPlus provides an array of 16 ultrasonic transducers installed in a spool piece to determine average velocity in 8 paths. The transducers are arranged in fixtures such that they form parallel and precisely defined acoustic paths. The chordal placement is intended to provide an accurate numerical integration of the axial flow velocity along the chordal paths. Using Gaussian quadrature integration, the velocities measured along the acoustic paths are combined to determine the average volumetric flow rate through the flow meter cross section. Note that this process assumes a continuous velocity profile in the flow area perpendicular to the spool piece axis. Although the velocity profile can be distorted, the distortion cannot be such that the Gaussian quadrature process no longer provides an acceptable mathematical fit to the profile, such as may occur if the profile is distorted in a way that is not recognized by the CheckPlus due to an upstream flow straightener.

To obtain the actual average flow velocity a calibration factor is applied to the integrated average flow velocity indicated by the UFM. The calibration factor for the Caldon UFMs is determined through meter testing at ARL and is equal to the true area averaged flow velocity divided by the flow velocity determined from the average meter paths to correlate the meter readings to the average velocity and hence to the average meter volumetric flow. The mass flow rate is found by multiplying the spool flow area by the average flow velocity and density. The mean fluid density is obtained using the measured pressure and the derived mean fluid temperature as an input to a table of thermodynamic properties of water. Typically, the difference between an uncalibrated CheckPlus and ARL test results is less than 0.5 percent. This close agreement means that obtaining a correction factor for a CheckPlus is relatively insensitive to error for operation under test conditions. Further, as discussed in this SE, correction factor is not a strong function of the difference between test and plant conditions and the same conclusion applies.

Use of a spool piece and chordal paths improves the dimensional uncertainties including the time measurement of the ultrasonic signal and enables the placement of the chordal paths at precise locations generally not possible with an externally mounted UFM. This allows a chordal UFM to integrate along off-diameter paths to more efficiently sample the flow cross section. In addition, a spool piece has the benefit that it can be directly calibrated in a flow facility, improving measurement uncertainty compared to externally mounted UFMs that were historically installed in nuclear power plant FW lines.

The applicant acceptably addresses the above aspects of its proposed use of CheckPlus UFMs. Flow straighteners are not used immediately upstream of the installations and other potential distortions of the flow profile are either absent or acceptably addressed in ARL testing. Coverage of other aspects of the proposed use is addressed in other sections of this SE.

3.4 Test Facility Considerations

3.4.1 Test Facility Qualification

Calibration testing at a qualified test facility and at the plant involves traceability to a national standard, facility uncertainty, and facility operation. At www.aldenlab.com, ARL states that "Alden in the largest independent supplier of National Institute of Standards and Technology (NIST) traceable Flow Meter Calibration Services in the country." The NRC staff audited testing at ARL in 2006 as reported in References J and K and verified ARL's statement with respect to traceability to NIST. The NRC's audit found that ARL's processes and operation were consistent with the claimed facility uncertainties. The NRC staff also observed testing during a visit to ARL in 2009 (References L and M) and observed some improvements in test facility hardware. The NRC staff judged these changes would not change its previous conclusions regarding test operations and results. In References N and O, Cameron restated that "all elements of the lab measurements ... are traceable to NIST standards." Consequently, the references provide an acceptable basis for concluding that ARL meets the stated testing criteria.

All CheckPlus installations to date have been calibrated at ARL. The audit also confirmed that ARL was providing acceptable test data for the configurations under test. Consequently, the qualification of ARL does not need to be investigated further or confirmed with respect to CheckPlus testing provided test conditions remain consistent with the referenced conditions.

3.4.2 Test Fidelity and Test Range

Test fidelity, such as test versus planned plant configuration, test variations to address configuration differences, and potential effects of operation on flow profile and calibration, should be addressed on a plant-specific basis. Applicant requests must provide a comparison of the test and plant piping configurations with an evaluation of the effect of any differences that could affect the UFM calibration. Further, sufficient variations in test configurations must be tested to establish that test-to-plant differences have been bracketed in the determination of UFM calibration and uncertainty. Historically, calibration testing has acceptably covered upstream effects by applying a variation of configurations to distort the flow profile. Further, if the spool piece may be rotated during plant installation from the nominal test rotation, the effect of rotation should be addressed during testing.

Plant piping configuration drawings must, at a minimum, include isometrics with dimensional information that describe piping, valves, FW flow meters, and any other components from the FW pumps to at least 10 pipe diameters downstream of the FW flow meter that is most distance from the FW pump. Preferable are scale three dimensional (3D) drawings in place of isometrics that show this information. Test information must include 3D drawings of the test configuration including dimensions.

Reference O provides test configuration. The licensee provided an attachment of the typical installation locations drawings for the LEFMs at each of the four units. The LEFMs will be installed upstream of the venturis in the plants and downstream of the common feedwater header. There are no flow straighteners being installed. Distances between the exit of the CheckPlus spool pieces and the downstream venturis in the tests and plant are sufficient such that there will be no effect on the LEFM. As discussed in Section 3.5.2.5, below, this separation distance is large enough that there will be no effect on UFM calibration.

Weigh tank tests were run at different flow rates for each simulated feedwater loop. Tests included 100% and lower flow rates through the CheckPlus and some tests included an eccentric orifice upstream in the feedwater pipes containing the CheckPlus. Most test results were included in the reported main feedwater calculation.

3.5.1 Transfer from Test to Plant and In-Plant Installation

Each applicant for a power uprate must conduct an in-depth evaluation of the UFM following installation at its plant that includes consideration of any differences between the test and in-plant results and must prepare a report that describes the results of the evaluation. This should address such items as calibration traceability, potential loss of calibration, cross-checks with other plant parameters during operation to ensure consistency between thermal power calculation based upon the LEFM and other plant parameters, and final commissioning testing. The process should be described in written documentation and a final commissioning test report should be available for NRC inspection.

To date, the only UFM calibration traceability associated with transfer from the test facility to United States nuclear power plants that has been acceptably demonstrated is that provided by the Check and CheckPlus UFMs due to the ability to provide the flow distribution/velocity profile as a function of radius and angular position in the spool piece, the small calibration correction necessary to fit test data to UFM indication, and the demonstrated insensitivity to changes in operation associated with transfer changes and plant changes. Although other means have been used to obtain flow rate, such as use of tracers in the feedwater, they have not been demonstrated to provide the small uncertainty obtainable with a CheckPlus. Experience to date is that a UFM must provide flow profile information and calibration traceability when extrapolating from test flow rate and temperature conditions to plant conditions. Transfer uncertainty is associated with any changes due to installation in the plant such as mechanical and operating conditions. Mechanical perturbations include such items as transducer installation, mechanical misalignment, and fidelity between the test and plant. Changes in operating conditions involve consideration of such potential effects as noise due to pumps and valves, changes in flow profile, including swirl, flow rate, and temperature.

As previously identified, the test facility configuration and test parameters are expected to provide a basis for providing fidelity between the test and plant. However, an exact correspondence is probably not possible. Potential differences are expected to have been addressed and the UFM is expected to provide a capability to both identify differences and to address them during operation.

The applicant addressed uncertainty in References N and O. As stated in Section 3.4.2, above, the facility uncertainty is acceptable. Reference N is referenced for transducer installation uncertainty. The content is essentially identical to Appendix D of Reference H that the NRC staff found acceptable. Consequently, the applicant's treatment of transducer installation uncertainty is acceptable. The applicant showed that LEFM commissioning will include verification of ultrasonic signal quality and evaluation of actual plant hydraulic flow profiles as compared to those documented during the ARL testing. These parameters will be incorporated as required into the LEFM during commissioning. This is acceptable.

3.5.2 In-Plant Operation

Many of the calibration aspects associated with transfer from a test facility to the plant apply during operation as valve positions change, different pumps are operated, and physical changes occur in the plant. The latter include such items as temperature changes, preheater alignment and characteristics changes, pipe erosion, pump wear, crud buildup and loss, and valve wear. Further, potential UFM changes, such as transducer degradation or failure, may also occur and the UFM should be capable of responding to such behavior. Either the UFM must remain within calibration and traceability must continue to exist during such changes or the UFM must clearly identify that calibration and traceability are no longer within acceptable parameters. Experience is that the CheckPlus is capable of handling these operational aspects. Further, as stated above, UFM operation should be cross-checked with other plant parameters that are related to FW flow rate. Should such checking identify abnormal behavior, it should be identified to the NRC, the validity of the final commissioning test report should be confirmed, and the final commissioning test report should be updated as necessary to reflect the new information. Further, the UFM must be considered inoperable if its calibration is no longer established to be within acceptable limits.

Section I.1 of Reference V provides coverage of training, calibration, maintenance, procedures, entry into the corrective action program, and procedures to ensure compliance with the requirements of 10 CFR Appendix B. In-plant operation coverage is acceptable.

3.5.2.1 Operation with a failed Component

A brief description should be provided that covers system self-testing features, channel checks, control room alarms, and plant process computer functions. The following should be addressed to cover conditions if the CheckPlus system becomes degraded or inoperable:

(1) Operator response.

(2) Changes in FW flow input to the core thermal power calculation.

(3) Allowed outage time (AOT)[4]: Time when continued operation at full power is permitted and time when power must be reduced, including specification of the reduced power level.

(4) Justification for the AOT with respect to such topics as calibration of FW venturis, venturi fouling or defouling, monitoring of other indications of core thermal power such as average power range monitors, steam flow rate, feed flow rate, turbine first stage pressure, and main generator output.

(5) Response if the plant computer system is not operable.

[4] The NRC has typically approved an AOT of 72 hours if acceptably justified.

ER-157P Rev. 8 (Reference G) states that "The redundancy inherent in the two measurement planes of an LEFM CheckPlus also makes this system more resistant to component failures" when compared to the Check. "For any single component failure, continued operation at a power greater than that prior to the uprate can be justified with a CheckPlus system ... since the system with the failure is no less than an LEFM Check." This is acceptable subject to two qualifications:

(1) Continued operation at the pre-failure power level for a pre-determined time and the decrease in power that must occur following that time are plant specific and must be acceptably justified.

(2) The only mechanical difference that potentially affects the quoted statement is that the CheckPlus has 16 transducer housings interfacing with the flowing water whereas the LEFM Check has 8. Consequently, a CheckPlus operating with a single failure is not identical to an LEFM Check. Although the effect on hydraulic behavior is expected to be negligible, this must be acceptably quantified if an applicant wishes to operate as stated. An acceptable quantification method is to establish the effect in an acceptable test configuration such as can be accomplished at ARL.

Sections I.1.G-I.1.H of Reference V addresses allowed outage time, monitoring of CheckPlus status, and operational processes associated with a degraded or non-operational CheckPlus. The difference between a degraded CheckPlus and a Check is covered by the ARL test results.

To operate above the CLTP of 3586.6 MWt, the licensee proposes to use the Cameron LEFM CheckPlus System in the normal mode. In the normal mode of operation, both planes of transducers are in service and system operations are processed by both central processing units (CPUs). The LEFM reading will be used as input for the feedwater flow in the calorimetric. The licensee plans to respond to single path or single plane failures in the same way that they will respond two a whole system failure. In the event of a failure of a single path or single plane or other system failure the licensee will declare the system inoperable. The requirement will be to restore the system to operable within 72 hours or the plant will be required to reduce power to the CLTP or 3586.6MWt any time the plant is above the CLTP. If the plant is below the CLTP of 3586.6MWt when the LEFM is declared inoperable, the plant will not be allowed to increase power above the CLTP of 3586.6MWt.

The licensee provided justification for the proposed 72 hour TLCO action time. This justification included the statements as follows:

> "There has been no evidence of feedwater flow venturi fouling at Byron or Braidwood Stations. This is based on a review of historical work orders that document this observation as part of a procedural requirement performed every refueling outage. In addition, historical data was gathered over the last several years where feedwater venturi flow was analyzed. This data indicated that there was no divergence in feedwater flow indication that would suggest venturi fouling."
>
> "a typical power measurement uncertainty calculation for a two-loop PWR to be approximately 1.4%. The systematic error associated with feed flow nozzle differential pressure in this calculation is shown to be approximately 1.0%.

> Assuming this was calculated based on an 18-month cycle; this would represent a maximum potential drift in the differential pressure measurement of less than 0.002% per day. Over a 72-hour period, this would have an insignificant effect on the feedwater flow measurement. Feedwater flow differential pressure instrument drift history at Byron and Braidwood is consistent with the assumptions of this typical calculation. "

The staff agrees that under normal operating conditions the drift of a venturi over a 72 hour period would be minimal. The reference above as well as previous precedent of plants with similar operating experience and approved outage time provides reasonable assurance that the plant will operate safely for the 72 hour outage time and maintain the licensed power level.

These actions are to be covered in the LEFM operability requirements contained in the Byron and Braidwood TRM Technical Limiting Condition for Operation (TLCO). The NRC staff finds that operation with an inoperable (non-functional) CheckPlus has been acceptably addressed.

Planned operation with a failed CheckPlus component is acceptably addressed.

3.5.2.2 Spool Piece Dimensional Effects on UFM Response

ER-157P Appendix A (References E - H) addresses the effect of variation in such spool piece dimensions as as-built internal diameter and sonic path lengths, path angles, and path spacing. The applicant's description for addressing these effects is acceptable.

3.5.2.3 Transducer Installation Sensitivity

Transducers may be removed after ARL testing to avoid damage during shipping the spool piece to the plant. Further, transducers may be replaced following failure or deterioration during operation. Replacement potentially introduces a change in position within the transducer housing that could affect the chordal acoustic path. ER-157P Appendix D (Reference G) addresses replacement sensitivity by describing tests performed at the Caldon Ultrasonics flow loop and provides a comparison of test results to analyses of potential placement variations that shows that the test results are bounded by predicted behavior. One would expect an uncertainty associated with the test loop even if nothing was changed. This is not addressed in the ER-157P information. Rather, all of the test uncertainty is conservatively assumed to be due to transducer replacement. Further, as stated, the analyses predict a larger uncertainty than obtained during testing, and the analysis uncertainty is used for transducer replacement uncertainty. This approach is judged to be sufficient to cover the inability of the test loop to achieve flow rates comparable to those obtained in plant installations and to cover any analysis uncertainty associated with applications with pipe diameters that differ from the tests. Consequently, transducer replacement has been acceptably addressed and the ER-157P Rev. 8process for determining transducer replacement uncertainty is acceptable.

3.5.2.4 The Effects of Random and Coherent Noise of LEFM CheckPlus Systems

Appendix C of ER-157P (Reference G) provides a proprietary methodology for test- and plant-specific calculation of the contribution of noise to CheckPlus uncertainty. Review of this methodology has established that applicants may use this methodology in their MUR requests.

References N, O, and V show that critical performance parameters, including signal to noise ratio, are continually monitored for every individual meter path and alarm setpoints are established to ensure corresponding assumptions in the uncertainty analysis remain bounding. Signal noise will be minimized via strict adherence with Cameron design requirements. LEFM commissioning included verification of ultrasonic signal quality.

In Reference O, the applicant reported test signal to ratios for random and coherent noise that were within specifications and that uncertainty attributable to the electronics and signal to noise ratio are included in the overall meter factor uncertainty.

The test results and the above References N and O coverage of noise are sufficient to ensure that this topic is acceptably addressed.

3.5.2.5 Evaluation of the Effect of Downstream Piping Configurations on Calibration

The turbulent flow regimes that exist when the plant is near full power result in limited upstream flow profile perturbation from downstream piping. Consequently, the effects of downstream equipment need not be considered for normal CheckPlus operation provided changes in downstream piping, such as the entrance to an elbow, are located greater than two pipe diameters downstream of the chordal paths. However, if the CheckPlus is operated with one or more transducers out of service, the acceptable separation distance is likely a function of transducer to elbow orientation. In such cases, if separation distance is less than five pipe diameters, it should be addressed.[5] [6]

As discussed in Section 3.4.2, above, separation from downstream components is needed so that CheckPlus operation will not be affected. The in plant separation from downstream piping components such as elbows and venturis is acceptable and will not affect CheckPlus operation.

3.5.2.6 Evaluation of Upstream Flow Straighteners on CheckPlus Calibration[7]

Operation with an upstream flow straightener is known to affect CheckPlus calibration to a greater extent than most other upstream hardware. If an applicant proposes this configuration, it must provide justification.

A previously undocumented effect of upstream tubular flow straighteners on CheckPlus calibration was discovered during ARL testing while NRC staff members were at the site on August 24, 2009, that did not appear to apply to any previous CheckPlus installations. As follow-up, additional tests were conducted with several flow straighteners and two different pipe /spool piece diameters to enhance the statistical data basis and to develop an understanding of

[5] This was the case, for example, with a Calvert Cliffs application that the NRC found acceptable (References Q and R). In that installation, the distance between the spool piece exit is 15 inches from the downstream elbow and the chordal paths are 2.7 diameters upstream of the entrance to the piping bend.

[6] Although this is not addressed in ER-157P Rev. 8, it is addressed in the Reference H safety evaluation.

[7] This is not addressed in ER-157P Rev. 8 (Reference G) but is addressed in the Reference H safety evaluation.

the interaction between flow straighteners and the CheckPlus. The results are provided in the proprietary Reference P.[8]

Cameron concluded that two additional meter factor uncertainty elements are necessary if a CheckPlus is installed downstream of a tubular flow straightener and provided uncertainty values derived from the test results. The data also provide insights into the unique flow profile characteristics downstream of tubular flow straighteners and a qualitative understanding of why the flow profile perturbations may affect the CheckPlus calibration.

Cameron determined that the two uncertainty elements are uncorrelated and therefore combined them as the root sum squared to provide a quantitative uncertainty. The Cameron approach is judged to be valid, but there is concern that the characteristics of existing tubular flow straighteners in power plants may not be adequately represented by samples tested in the laboratory. Any applicant that requests an MUR with the configuration discussed in Section 3.5.2.6 should provide justification for claimed CheckPlus uncertainty that extends the justification provided in Reference P.

No flow straighteners are installed in the applicant's feedwater lines and flow straightener effects are not a concern.

3.6 Other Thermal Power Calculation Considerations

3.6.1 Steam Moisture Content

Some modern separators and dryers deliver steam with moisture content in the 0.05 percent range and these applicants often assume a zero moisture content that is conservative since the calculated power will be greater than actual power for such cases. No uncertainty is necessary if no moisture is assumed.

Reference C discusses an analysis in which the uncertainty in thermal power due to measurement of all variables excluding moisture is assumed to be normally distributed with two standard deviations of 0.3357 percent, essentially the aggregate uncertainty of all contributors excluding moisture for the CheckPlus system. The contribution of uncertainty due to moisture content was then calculated by multiplying a second, uniformly distributed random number times the uncertainty band assumed in Reference C's Table A-1 and Monte Carlo calculations of total power uncertainty were obtained. The results are summarized in Reference C's Figure 1. The author "concluded that applicants assuming large uncertainties in steam moisture content should have an engineering basis for the distribution of the uncertainties or, alternatively, should ensure that their calculations provide margin sufficient to cover the differences shown in Figure 1." This was stated to be an acceptable approach in Reference H.

3.6.2 Deficiencies and Corrective Actions

The applicant identified its process for addressing Cameron deficiency reports as well as reporting deficiencies to the manufacturer. In each case Byron and Braidwood Stations will use their corrective action program. In the case of receiving deficiency reports, Byron and

[8] The results do not apply to the Check UFM. Consequently, the findings do not apply to a Check that is installed downstream of a tubular flow straightener.

Braidwood stations will document and address applicable deficiencies in its corrective action program as well.

3.6.3 Reactor Power Monitoring

Applicants should identify guidance to ensure that reactor thermal power licensing requirements are not exceeded. Proposed guidance was addressed by NRC in Reference S.

The EICB assessment provided in its review, and the applicant response to Criterion 1, as summarized above, provides an acceptable description to ensure operation consistent with the Reference S guidance to prevent overpower operation.

3.7 Uncertainty

EICB provided an assessment that addressed uncertainty. The following discussion in Section 3.7 provides supplemental information.

Cameron considers flow rate uncertainty associated with the test facility, measurement (including transducer installation), extrapolation from test conditions to plant operating conditions, modeling, and data scatter.

3.7.1 Test Facility Uncertainty

The budgeted test facility uncertainty is consistent with past NRC staff evaluations and the Reference J value. This uncertainty is acceptable.

3.7.2 Measurement Uncertainty

The applicant addresses uncertainty due to such contributors as thermal expansion; dimensions; temperature, pressure, and density determination; and transducer installation. The contribution of some of these contributors was discussed in the above report sections. Overall, measurement uncertainty is acceptably addressed.

3.7.3 Extrapolation Uncertainty

Although calibration tests were performed, they were conducted at room temperature. This resulted in Reynolds numbers about a factor of ten less than would occur in the plant and an extrapolation is necessary to obtain in-plant calibration factor. A positive aspect of the CheckPlus is that the calibration factor is close to one and small errors in the extrapolation do not significantly affect extrapolation accuracy. Another aspect is that the Check and CheckPlus characteristics permit an alternate extrapolation approach that is typically less sensitive to error than a Reynolds number extrapolation. This involves the flatness ratio (FR), which for the CheckPlus is defined as the ratio of the average axial velocity at the outside chords (chords 1, 4, 5, and 8) to the average axial velocity at the inside chords (chords 2, 3, 6. and 7)[9]:

$$FR = (V1 + V4 + V5 + V8) / (V2 + V3 + V6 + V7)$$

[9] Details of this method are proprietary. This discussion is taken from the non-proprietary References T and U.

Where FR is a function of Reynolds number, pipe wall roughness, and the piping system configuration.

The effect of the configuration is evaluated in laboratory tests. The effect of Reynolds number is deduced from the fully developed flow inverse power law profile which may be written in several forms including the following:

$$\frac{V}{V_{max}} = \{X|R\}^{\frac{1}{n}}$$

where X = radial location, R = pipe radius, and the exponent *n* varies with Reynolds number and is determined from experimental data. The advantage of this approach is that a plot of FR versus calibration factor is linear and the calibration factor is insensitive to variation in FR. These results are consistent with analytic predictions and have been confirmed via ARL tests of many plant configurations. Further, minor changes in calibration factor observed in different hydraulics configurations are predictable and can be confirmed analytically. Therefore, if plant conditions result in a change in FR, the calibration factor may be adjusted to reflect the change in FR.

Cameron also uses swirl rate, defined as:

$$\text{Swirl Rate} = \text{Average}\left[\frac{V_1 - V_5}{2 - y_S}, \frac{V_8 - V_4}{2 - y_S}, \frac{V_2 - V_6}{2 - y_L}, \frac{V_7 - V_3}{2 - y_L}\right]$$

Where y_S and y_L are normalized chord locations for outside/short and inside/long paths.

Cameron also uses swirl rate to characterize behavior obtained during ARL tests.

The applicant provided experimental data of calibration factor as a function of FR and swirl rate for each of the CheckPlus instruments in Reference O.

Cameron includes an uncertainty term for extrapolation from laboratory conditions to plant conditions that is computed from empirical equations to account for change in Reynolds number and other effects such as a difference in pipe wall roughness. The calibration factor is shown to change in the fifth significant figure over a factor of ten change in Reynolds number between the test and plant conditions. With respect to extrapolation uncertainty, some of the uncertainty was likely already addressed by parametric testing over Reynolds numbers and FRs.

3.7.4 Modeling Uncertainty

Cameron uses FR and swirl rate to characterize the velocity distribution and to validate the experimentally determined calibration factor when installed in a plant. In Reference U, it discussed application of calibration data obtained at ARL for 330 hydraulic configurations with 75 CheckPlus UFMs with an average calibration factor of 1.002 with a standard deviation of ± 0.0039.

Cameron discussed its experience in calibrating over 100 UFMs with 500 different test configurations since typically 4 or 5 configurations were tested for each UFM. An approach is discussed where different numbers of subsets of configurations were considered applicable to the applicant's installation and modeling sensitivity was computed using that information.

The applicant's method for determining modeling uncertainty is acceptable.

3.7.5 Data Scatter Uncertainty

The precision with which the calibration factor is determined includes all calibration data for each CheckPlus and 95% confidence limits are calculated. The applicant's determination of data scatter uncertainty is acceptable.

3.8 Evaluation of Measurement Uncertainty Recapture Power Uprate Request for Byron Unit 1[10]

3.8.1 Introduction to and Summary of NRC Audit and Licensee Response to Byron Station Unit 1 LEFM vs. Plant Parameter Discrepancies

The LEFMs were installed at Byron Unit 1 during refueling outage B1R17. Following the outage, in late April, 2011, poly acrylic acid (PAA) was injected to control SG crud buildup.[11] Multiple indications showed a rise in thermal power when thermal power was held constant by controlling via the LEFMs from May to September 19, 2011 (Byron, September 19, 2011.), and an extensive troubleshooting effort was initiated to investigate the discrepancy between the LEFMs and other multiple indications. The troubleshooting investigation was conducted by Exelon, Cameron, and Dominion Engineering and subjected to an in-depth review by MPR Associates, ILD Inc., and Dominion Engineering. Troubleshooting was completed in April, 2012 (Borton, October 9, 2012, Attachment 2) and did not clearly identiy the cause of the observed behavior. Byron Unit 2 and the Braidwood units did not exhibit as large a discrepancy and no other plants had a similar discrepancy. The licensee reported that no other plants used PAA injection.

The NRC staff has audited the troubleshooting investigation and has conducted independent calculations based on data provided by Exelon and Cameron. One aspect of the trouble shooting was a determination that there was no significant deposit on the LEFM aperatures. The NRC staff did not agree with the assumptions and analysis approach but confirmed the conclusion via independent analysis.

On the basis of observed flatness ratio (FR)[12] data and the assumption that the power law or the modified Reichardt equation represented the flow profile, and study of operating data, the NRC

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[10] Most quantitative data are proprietary and are not provided in this non-proprietary evaluation.

[11] Industry experience had shown that PAA could reduce iron oxide accumulation on secondary side SG surfaces and that it could remove previously deposited iron-based corrosion products from secondary plant surfaces.

[12] The CheckPlus determines average flow velocities along straight line paths of two lengths. FR is the ratio of the measured velocity via the shorter path to the measured velocity via the longer path. Flow rate is determined by multiplying each velocity by the flow area it is assumed to represent and correcting for the angle between the measurement and the direction of flow.

staff determined that the effective change in CheckPlus calibration was less than 6×10^{-4} percent and therefore was negligible.

Estrada (March, 2012) concluded that analyses from all elements of the LEFM algorithm were in the range of + 0.05 percent to + 0.079 percent, in the opposite direction of the postulated LEFM drift that would be consistent with the best estimate based on other plant variable trends that indicated a LEFM change of about - 0.4 percent. He also concluded that the difference between LEFM indication and the best estimate was within the root sum square of the ± 0.3 percent LEFM uncertainty and the best estimate uncertainty of ± 0.55 percent.

The average difference between the LEFM and other parameters that can be used to determine feedwater flow rate or thermal power was about 0.25 percent at the end of the increased difference that occured from May, 2011 to September, 2011. Operating parameters from October, 2011 to May, 2013 established that differences had stabilized and were no longer increasing. The requested increase in thermal power corresponds to a power uncertainty of 0.37 percent, the calculated bounding value for system mass flow rate uncertainty was < 0.3 percent and the thermal power uncertainty was < 0.4 percent. The observed differences are smaller than the uncertainties that Caldon calculated that were part of the basis for the LAR. On this basis alone, the observed differences between LEFM and other plant indications are not sufficient to invalidate the feedwater flow rate indicated by the LEFMs. Further, the NRC staff's review supports a conclusion that the LEFMs are not affected by PAA injection and the observed deviation in thermal power and feedwater flow rates are not due to the LEFMs.

Examination of the data strongly supports a conclusion that the venturis are affected by PAA injection although the reasons are not as clear nor are the differences between Byron 1 and Byron 2 fully understood.

Reasons for deviation in other plant parameters have been postulated but these are not accepted by all licensing personal and are not sufficiently supported to lead to firm conclusions.

3.8.2 Discussion

Information provided during an audit conducted at Cameron's headquarters on May 14, 2013 was that Byron and Braidwood are the only stations that use PAA injection in feedwater. Thus, Byron considered that there was a lack of data concerning possible impact of PAA on LEFM operation. With respect to feedwater venturis and steam flow rate indications, PAA was known to have an impact.

Byron initiated an extensive troubleshooting plan when an upward trend in secondary parameters occurred that indicated Byron 1 thermal power was increasing in contrast to LEFM indications that thermal power was constant. This included securing PAA injection for two months and injecting PAA at an increased concentration after that. Securing PAA was accomplished to see if the upward trend would be reversed. Increasing PAA concentration was to discern if accumulation of PAA or PAA byproducts occurred that would cause secondary parameters to reach a higher magnitude.

3.8.2.1 Observed power behavior

During the time between May, 2011 and September, 2011, Byron Unit 1 was operated so that flow rate indicated by the LEFMs was essentially constant and other plant parameters indicated an increasing flow rate. The Byron observations of the effect on thermal power, and NRC staff estimates of the changes, were as follows:

Item	Percent Change	
	Byron	NRC estimate from Data
Impulse Pressure	0.21	0.20
First Stage Pressure	-	0.29
SG Steam Flow	0.20	0.25
LEFM Temperature	-	0.02
Pump Flow	0.23	0.20
RCS Differential Temperature	0.26	0.49[13]
Core Thermal Power	0.25	-
Venturi Thermal Power	0.27	-
LEFM Thermal Power	0.01	-
LEFM Flow Rate	~0.05[14]	0.04

The largest change in the difference between flow rates occurred between the LEFMs and venturies. The correspondence of multiple indications of an increasing flow rate and thermal power with a close-to-constant LEFM indication raised questions regarding LEFM calibration drift and accuracy.

3.8.2.2 Byron troubleshooting program

3.8.2.2.1 Summary

The LEFMs were installed at Byron Unit 1 during refueling outage B1R17 that ended in late April, 2011. Following start-up, PAA was injected to control SG crud buildup. Multiple indications showed a gradual rise in thermal power when thermal power was held constant by controlling via the LEFMs from May to September 19, 2011 (Byron, September 19, 2011.), and Byron initiated an extensive troubleshooting effort to investigate the discrepancy. The troubleshooting investigation was conducted by Exelon, Cameron, and Dominion Engineering and subjected to an in-depth review by MPR Associates, ILD Inc., and Dominion Engineering. Troubleshooting was completed in April, 2012 (Borton, October 9, 2012, Attachment 2) and did not identiy the cause of the observed behavior. Byron Unit 2 and the Braidwood units did not exhibit as large a discrepancy and no other plants had a similar discrepancy.

Key results of the troubleshooting program and the NRC staff findings included the following:

- Cameron used many diagnostic indicators to conclude that there were no LEFM anomalies. It concluded that LEFM performance was within its design basis. The NRC staff agrees.

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[13] Hot leg streaming changes will influence this parameter and could cause significant error.
[14] Cameron estimate of maximum bias (Ultrasonics, May 14, 2013).

- PAA build-up or PAA byproducts on LEFM surfaces were determined not to be a cause. The NRC staff did not identify any phenomenon that would contradict this conclusion.

- No anomalies were identified where hydraulic impacts, secondary parameter instrumentation drift, erosion/corrosion, or calorimetric program errors were identified that would result in the observed secondary parameter drifts. The NRC staff identified some anomalies that were not explained and Cameron identified interactions that it posited could explain the behavior.

Byron provided the following observations based on further study:

- A best estimate methodology based on five power system conversion measurements (secondary parameters) was used to calculate thermal power. Byron concluded that current thermal power was consistent with the previous two cycles that operated on the venturis at 100 percent power. NRC staff review of a comparison of indicated thermal power (ITP) versus Best Estimate Thermal Power (BETP) established the following:

  - BETP > ITP from April 2008 to Refueling Outage B1R17 in 2011.

  - BETP < ITP in May, 2011 and gradually increased to equal ITP in September, 2011. Operation was with LEFM controlling IPT.

  - BETP > ITP for several following months when operating under venturi control.

  - BETP = ITP subsequently until February, 2012 when operating under LEFM control.

- Comparison with Byron 2 and Braidwood 2 startups in 2011 failed to show similar upward trends in secondary parameters. The NRC staff confirmed this conclusion by examining the data.

- Review of industry operating experience did not identify differences between LEFM and venturi indication that occurred at Byron 1. The NRC staff did not review this Byron review.

- Byron found no significant issues or errors in inputs to the plant calorimetric that would result in the observed drifts.

- Byron did not identify any power plant failure mechanisms that would explain the drifts.

With regard to the last two items, the NRC staff notes that Cameron believes it identified reasons for drifts in steam flow rate and venturi behavior. The Cameron conclusions and additional unexplained anomolies identified by the NRC staff are discussed below.

NRC staff review of operating parameters from October, 2011 to May, 2013 established that differences had stabilized and were no longer increasing. This is important because it eliminates a potential concern that continued drift could raise questions regarding LEFM operating outside its uncertainty limits.

3.8.2.2.2 Discussion of selected aspects of troubleshooting program

Byron's troubleshooting investigation was described in Reference X and updated during an audit conducted at the Cameron offices on May 14, 2013. Potential failures, Byron conclusions, and NRC staff comments (**in bold to differentiate from licensee discussion**) were as follows:

(1) "Installation configuration results in hydraulic impacts causing the LEFM to read lower than actual."

- There were no significant differences in piping configurations between trains and UFM installation was consistent with specifications.
- There were no upstream obstructions that could affect the LEFMs

Review complete and determined not to be a cause.

(2) "Plant process computer (PPC) interface to LEFM is causing errors in the data."

- LEFM flow indication was determined to be accurately communicated to and displayed on the PPC.
- Modeling of programs and flow calculations to handle net flow and tempering line flows were determined to be correct. **See Item (6), below.**

Review complete and determined not to be a cause.

(3) "LEFM problem causing erroneous readings."

- Commissioning changes such as software changes; cable lengths; and alarm, hydraulic, and setup configurations were determined to not significantly affect LEFM readings.
- No significant differences were found between trains or with respect to Alden Labs test results. **The NRC staff notes that Train B FR decreased from May to September, 2011 whereas Trains A, C, and D increased. This difference has not been explained beyond an observation that the changes are within expectations and do not significantly affect MF. The overall effect is to decrease change in the average FR and change in the already small MF change when the four loops are averaged.**
- Environmental conditions were within specifications.
- Operating experience (OE) review found no new applicable information.
- Power supplies were within specifications.

- Pressure and temperature inputs have not drifted which eliminates bad sensor input as a cause.

- No significant integration errors were found with internal integration.

- Evaluation of transfer to Venturi control and observance of trends to identify potential LEFM problems did not identify errors.

Byron concluded that no anomalies were identified and this failure mode was not a cause.

(4) "Venturi calibration or drift issue is causing the descrepancy."

- Byron stated there were no unexplained drifts or deviations. **The NRC staff observed that there were unexplained differences between venturi and other indications. It also observed that venturi differential pressures for A, B, and D decrease by about one inch from May to September, 2011 while C increased by the same amount. Byron provided information during the audit that venturis were known to be affected by PCC injection (see Item (5), below). Cameron and the NRC staff reached the same conclusion.**

- No secondary calibrations of the flow elements or correction factors have been applied to the venturies that would cause large bias or uncertainty.

- No significant diverging trends were found in the LEFMs compared with other balance of plant (BOP) parameters. **Diverging trends were evident from the plant data. The key is whether or not they were significant. This is addressed below.**

- Venturi bypass flow has been stable and there are no gaps to allow bypass flow. **This is important and is often not addressed. Note also that tempering flow bypasses both the LEFMs and venturis.**

- Newly developed discharge coefficients were correctly implemented and the discharge coefficient extrapolation method was determined not to be in error.

Byron concluded that no anomalies were identified and this failure mode was not a cause.

(5) "External interaction with venturi / LEFM spools by either PAA or erosion / corrosion."

- PAA injection was expected to cause an indicated 0.2% increase in flow rate indicated by the venturies. An uncertainty of 0.3% was added to the calorimetric to compensate for the increase. Byron concluded that the impact on the venturies did not change. Further, it stated that PAA injection was not expected to affect the LEFMs. **This is addressed furher below.**

Byron concluded that no anomalies were identified and this failure mode was not a cause.

(6) "Calorimetric input or program fault."

- FW flows, SD flow, FW temperature, steam temperature, and steam pressure calorimetric inputs were verified as correct. However, two issues were identified:

- Tempering lines normally are expected to pass about 40,000 lbs/hr per loop of feedwater flow that bypasses the LEFMs and venturis (160,000 lbs/hr total). These lines were individually isolated with the expectation that measured feedwater flow would increase by about 40,000 lbs/hr for each isolation. This occurred with Loops A, B, and C with a nearly identical decrease within something less than 2000 lbs/hr per loop but Loop D isolation caused an indicated increase in feedwater flow of 46,000 lbs/hr in contrast to a pre-isolation flow rate of 41,000 lbs/hr, a difference of 5000 lbs/hr.. Byron stated that this anomaly would represent a 0.03 percent change in thermal power based on a total feedwater flow rate of 16 X 10^6 lbs/hr and would not be the cause of the observed drifts in secondary parameters.

  Since bypass flow is measured, the NRC staff understands it is included in the heat balance, and the unexpected behavior should not significantly impact the heat balance.

- **The unexpected behavior is not judged to be significant with respect to the observed discrepancy between indicated LEFM flowand other plant parameters and is not required to be addressed with respect to the subject LAR. However, it should be addressed in case it is an indication of a tempering flow error that should be corrected.**SG blowdown flow was isolated with the expectation that feedwater flow rate indicated by the venturis and the LEFM would decrease by the same amount from individual blowdown flows of 18,000 lbs/hr. Most loops showed a nearly identical decrease within < 2000 lbs/hr but Loop B decreased by ~ 28,000 lbs/hr, a change from expectations of 10,000 lbs/hr or a change of 0.063 percent based on total feedwater flow. Byron concluded that this change would have a conservative impact of core thermal power in contrast to the change in the opposite direction that was observed when LEFM flow was held constant and other plant parameters indicated an increase in power.

  The unexpected behavior is not a reason for the observed discrepancy between indicated LEFM flow and other plant parameters and is not required to be addressed with respect to the LAR. However, it should be addressed in case it is an indication of a blowdown flow error that should be corrected.

- Program was reviewed against plant parameters and verified to correctly calculate thermal power.

Byron concluded that this failure mode was not a cause. **The NRC staff agrees.**

3.8.2.2.3 Effect of changing PAA injection concentration

PAA was injected following startup from Refueling Outage B1R17 in late April, 2011 until November, 2011. The venturis and other secondary side parameters that can be related to thermal power showed a linear increase relative to the LEFMs from May, 2011 until September, 2011 while the LEFMs were used to control feedwater flow rate and thermal power to a steady state. A power reduction then occurred after which the venturi to LEFM ratio appeared to stablize at a value slightly larger than before the reduction. PAA injection was stopped for two months starting in November, 2011. Within about a day of stopping PAA, the venturi indication decreased relative to the LEFMs. There was no further change in the difference between the venturis and LEFMs while PAA was stopped. Upon re-initialization of PAA, the venturi indication increased by about 0.15 percent in less than a day relative to the LEFM; a reversal of the behavior when PAA was stopped.

PAA injection rate was increased in Byron 1 in February, 2012. With one exception, there was no change in the venturi to LEFM comparison through mid-March, 2012. The exception was a short time when PAA injection stopped. During this time, the ratio changed as described in the above paragraph.

PAA injection was increased in Byron 2 in February, 2012. LEFM and venturi tracked closely into March, 2012 with a slightly closer correspondence in March. This convergence was more pronounced when compared to other plant parameters with an initial relative correspondence of about 0.998 and a March correspondence of 0.999.

The above venturi behavior with variation in PAA injection is a clear demonstration that PAA affected the Byron 1 venturis.

Several investigators concluded that PAA had no impact on the LEFMs. The NRC staff agrees.

3.8.2.2.4 Best estimate (BE) comparisons

A BE methodology can be developed that combines independent variables on the basis of including their individual uncertainties as weighting factors to obtain an estimate with an uncertainty that is less than any of the individual variables. Three BE methodologies were developed by different investigators and applied to compare indicated thermal power to BE thermal power from April, 2008 to February, 2012. From 2008 until B1R17, indicated power was less than BE power, a comparison that continued following B1R17 until LEFMs were used to control thermal power. At this time, LEFM thermal power reversed and was greater than BE thermal power. The two then converged until September, 2011 when power control was changed to the venturis and the pre-B1R17 behavior was observed. A change back to LEFM control resulted in close correspondence that continued into February , 2012 when the Byron report comparison terminated.

3.8.2.3 Assessment of LEFM

The NRC staff elected to independently examine aspects of the observed behavior. This examination is summarized in Section 3.8.2.3.

3.8.2.3.1 Dimensional information

(Spadaro, July, 2010) provided drawings of the Alden test configurations that specified spool piece dimensions and Cameron provided tolerances and as-built dimensions during the May 14, 2013 audit that established that the as-built LEFMs were within tolerances. As-build wall thicknesses were measured in May, 2010 and again in March, 2012 following 11 months of operation (Estrada, March, 2012). Neglecting measurement uncertainty, Cameron calculated that the change would introduce a net change in internal diameter of – 0.024 percent and a flow error of + 0.012 percent (Ultrasonics, May 14, 2013). Dimensional changes are not a likely cause of the observed behavior.

3.8.2.3.2 Effect of deposit in transducer apertures

Estrada reported that the drift from May, 2011 to November, 2011 due to a postulated corrosion layer in the apertures was ruled out on the basis of measurements that established that there was little wall thickness change and a rationale that a small deposit on aperture walls "is not sufficiently thick to transmit acoustic energy and therefore not capable of altering the effective sound velocity in the aperture."

The NRC staff does not agree with Cameron's rationale. First, Cameron concluded that evidence of little change in spool piece diameter established that there was no deposit on the spool piece walls and, therefore, there was no deposit in the apertures. While the NRC staff agrees that there was no significant change in diameter based on the measurements, this is not justification regarding deposits in the apertures. It is possible for a deposit to form in the apertures while the spool piece walls remain deposit-free. While Cameron's conclusion that a small deposit on the aperture walls is not thick enough to transmit acoustic energy may be correct, this does not address the effect of a deposit on the aperture window that reduces the measured time from one transducer to another due to decrease in transmission distance and the change in velocity of sound between water and a deposit in the volume where the deposit displaced water.

Assuming a deposit affects all apertures equally, the Cameron LEFM can indicate the effect of a deposit on the transducer housings in the apertures because there will be a larger effect on the measured short path sound velocity in comparison to the long path sound velocity. This can be expressed in terms of the "flatness ratio," FR, defined by the following equation:

$$FR = \frac{V_1 + V_4 + V_5 + V_8}{V_2 + V_3 + V_6 + V_7}$$

where V_1, V_4, V_5, and V_8 are velocities measured along the outside chords (the short paths) and V_2, V_3, V_6, and V_7 are velocities measured along the inside chords (the long paths)

A change in FR can be approximated by the following equation:

$$\frac{y_s'}{y_l'} = \frac{y_s}{y_l} + \Delta FR$$

where: y_s = short path length
y_l = long path length

and the prime indicates the new path length.

If an effective deposit thickness, x, increases on the transducer window surfaces that is identical on all windows and has the properties of water, then:

$$y_s - y'_s = 2x \qquad y_l - y' = 2x$$

and:

$$y_s - y'_s = y_l - y'$$

so that:

$$y_l' = \frac{y_s - y_l}{\frac{y_s}{y_l} + \Delta FR - 1}$$

Estrada provided FR changes during a seven month period starting in May, 2011. Using these data, the NRC staff estimated the predicted thickness changes would change flow rate by less than 0.01 percent, in agreement with Cameron's conclusion. This is not a likely cause of the observed behavior.

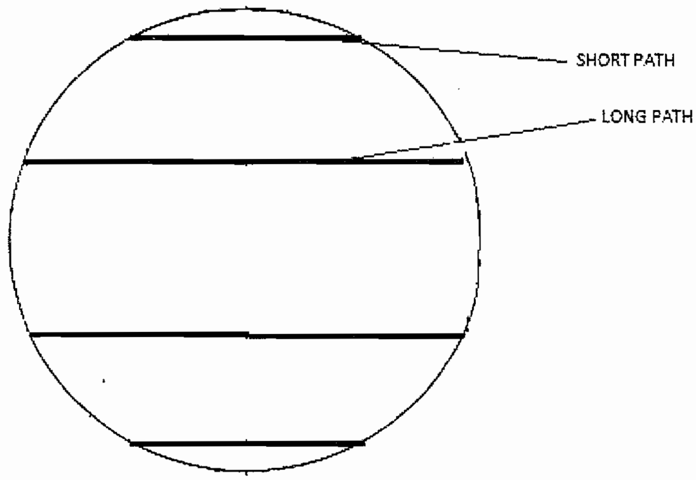
3.8.2.3.3 Effect of flatness ratio (FR) change on meter factor (MF)

Flatness ratio, as discussed above, is defined as:

$$FR = \frac{V_1+V_4+V_5+V_8}{V_2+V_3+V_6+V_7} = \frac{V_S}{V_L}$$

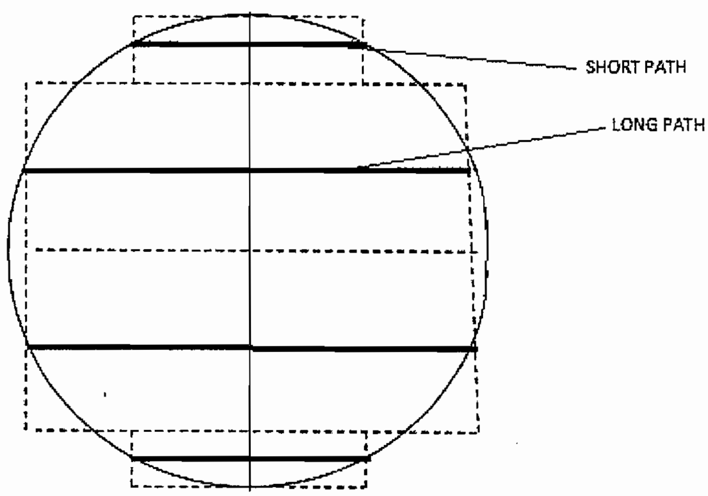
where V_1, V_4, V_5, and V_8 are velocities measured along the outside chords (the short paths), V_2, V_3, V_6, and V_7 are velocities measured along the inside chords (the long paths), V_S is the mean short part velocity, and V_L is the mean long path velocity. The paths are illustrated by the horizontal lines in the following figure that correspond to the paths between the CheckPlus transducers[15]:

[15] Measurements are at an angle with respect to pipe length. Velocities are translated into this configuration for calculation purposes.



FR can be determined experimentally, such as by testing at Alden Labs where the CheckPlus will provide the velocity data.

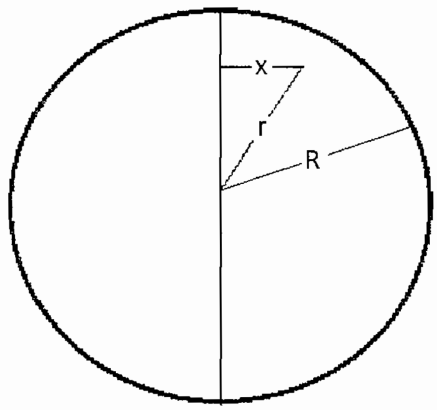
Once the V's are determined, the flow rate determined by the CheckPlus can be calculated by multiplying the rectangular vertical widths (weighting factors) indicated in the following figure by the dash lines by the corresponding velocities times two:



Cameron uses the same weighting factors for all of its nuclear applications. As is demonstrated below, this does not appear to be consistent with theoretical analyses when FR is compared to MF in an analysis of the Alden Lab data obtained with the Byron 1 LEFMs.

Once the CheckPlus flow rate has been calculated, MF can be determined by comparing the CheckPlus flow rate to the experimentally determined data.

FR and MF can also be calculated using an assumed symmetric velocity distribution that is a function of pipe radius, expressed as V(r), where r is the reduced radial position with the origin at the pipe centerline and $0 \leq r \leq 1$. Since the CheckPlus determines a mean velocity along the path, the calculation must be based on the same path, as illustrated by the "x" dimension in the following figure:



where the mean velocity is calculated by 1/X where x= X at r = R and V(x) is determined from the assumed V(r) where the relationship between x and r is obtained from the geometry illustrated in the figure.

The calculations define MF as the flow rate calculated by 2π divided by the calculated LEFM flow rate obtained by two times over the short and long path lengths multiplied by the corresponding weighting factors.

Spadaro described the velocity profile by the power law:

where V is the velocity normalized to the maximum value, and n is a function of Reynolds number and pipe roughness that changes the shape of the profile. FR and MF were calculated using an Excel spreadsheet with the calculation based on dividing the dimension spans into 1000 increments to provide an accurate calculation that addresses profile changes near the LEFM wall. The NRC staff used the same approach except it assumed the increment size was ten times smaller in the last 20 steps near the wall, a total of 1018 increments. The NRC staff assessed the calculation accuracy by changing the number of increments with the results summarized in the following table for a typical FR where the comparisons were obtained using the NRC staff methodology:

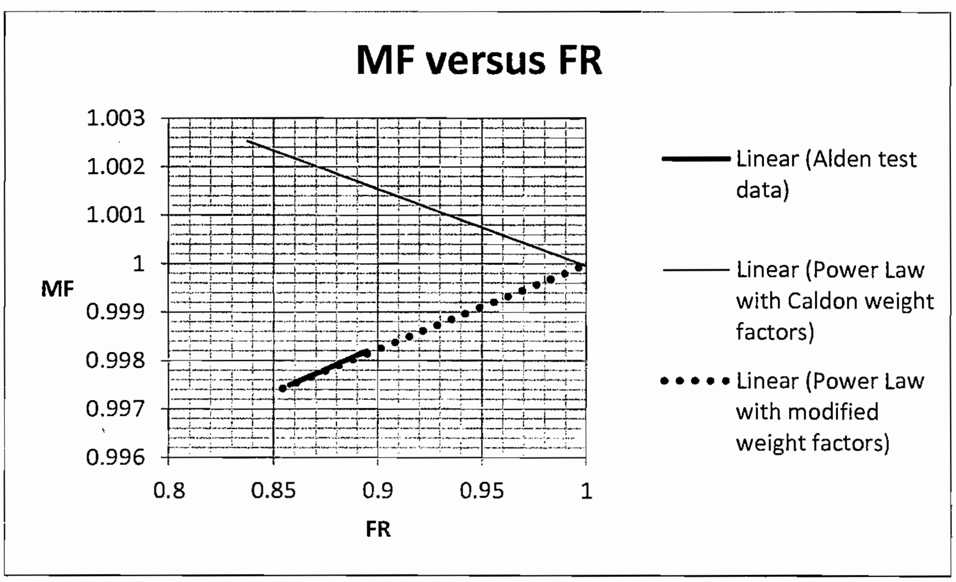
Nominal number of increments	Calculated relative short path velocity	Calculated relative long path velocity	Calculated relative FR	Calculated relative MF
1000	1.0000	1.0000	1.0000	1.0000
500	1.0000	1.0000	1.0000	1.0000
250	1.0001	1.0001	1.0000	1.0001

Clearly, the calculations using 1000 increments do not introduce a significant numerical error.

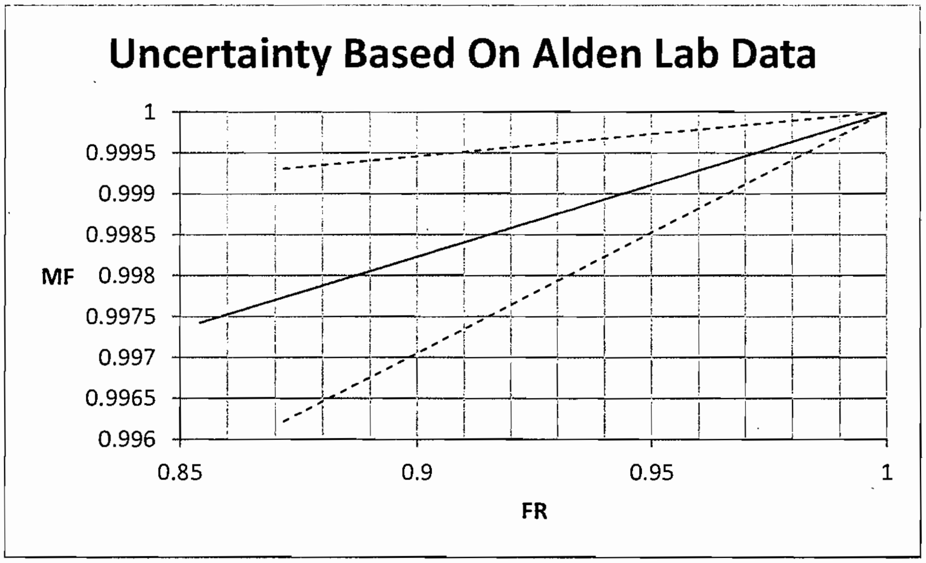
Estrada (Estrada, January, 2002) used the power law and weighting factors determined by Caldon to calculate MF as a function of FR and found that the calculations could be fitted by a straight line. All MF's were greater than one for FR < 1 and the results converged to MF = 1 at FR = 1. The NRC staff does not understand the rationale for fitting Alden data where MFs were less than one to a line where the MFs were greater than one. The comparisons are illustrated below.

Each of the four CheckPlus LEFMs installed at Byron 1 was tested at Alden Labs. There were three test piping configurations in additional to a configuration to model the plant installation for each CheckPlus. More than one flow rate was included in each configuration test. The configuration variations were, for example, to introduce swirl to bracket any variations that would be encountered in the plant. The test report (Spadaro, July, 2010) provided FR versus MF for each of the 16 test configurations. All MF's were less than one yet, as stated above, the results were plotted on Estrada's straight line where the line is limited to MF > 1. This was achieved by offsetting the MF for each meter such that the average MF was on the predicted curve. The off-set "data" correspondence to the straight line was an excellent fit. Caldon explained that the purpose of this work was to illustrate the dependence of MF on FR and, in this case, the change was small, as is discussed below.

The NRC staff calculated MF behavior using the power law and the Caldon weighting factors and compared it to a straight line fit of the Alden Labs test results for the four LEFMs installed at Byron 1. The comparison is shown in the following figure where the upper solid line is the calculation and the lower solid line is a straight line fit to the data. There is effectively no correspondence. The NRC staff also modified the weighting factors so that the power law reproduced the mean MF and FR of the 16 Alden Lab test results and, using the modified weighting factors, repeated the calculation to obtain the dash line. The fit of the power law to the data line is excellent.



The above calculations were based on nominal test values without considering the Alden flow rate uncertainty. There is significant scatter in the 16 data points, in part due to testing different configurations to bracket possible variations introduced in the plant installation. Simply obtaining the standard deviation, σ, without considering variation in FR, approximating uncertainty as two times σ, and applying the uncertainty at the mean FR of the data provided the following approximation of the data scatter. Note that the upper extreme never reaches



MF = 1 except at FR = 1 in contrast to the Caldon extrapolation of the data to the Caldon calculation that Caldon used to evaluate MF sensitivity. Further note that Caldon's approach results in a reduction in MF with increasing FR whereas the Alden data establishes that MF increases with increasing FR. In contrast, the absolute magnitude of the MF changes is identical due to the mirror image of the two calculations with respect to MF = 1.

The NRC staff used it's Excel spreadsheet to calculate the velocity distributions and effect on MF that corresponded to the observed FR's provided by Estrada for the May, 2011 to November, 2011 FR's. The conclusion was that, regardless of which curve applies, the change in FR that occurred between May and September of 2011 is predicted to introduce a maximum change in MF of about 6 X 10^{-6} which is negligible. Stated differently, the CheckPlus calibration is not calculated to have changed by more than about 6 X 10^{-4} percent. Further, an important consideration is that the test data included the expected plant configuration and modifications that caused swirls that were greater than observed during plant operation.

3.8.2.3.4 Effect of thermal expansion

The coefficient of thermal expansion is a multiplier on both the numerator and denominator in calculation of MF and therefore thermal expansion has no effect on MF assuming there are no other effects that perturb the calculation.

3.8.2.3.5 Effect of a change in speed of sound of FR

A change in the speed of sound affects the numerator and denominator equally and therefore has no effect on FR assuming there are no other effects perturbing FR.

3.8.2.3.6 Coherent noise

Cameron investigated the interaction of coherent noise that can interact with the acoustic signals and can affectt transit time measurements. Cameron concluded that coherent noise did not account for the LEFM trend in comparison with other plant parameters. The NRC staff agrees.

3.8.2.3.7 LEFM conclusions

No cause of a change in LEFM characteristics was identified that would indicate a significant measurement error was caused by the LEFMs. Further, the above information supports the conclusions that the LEFMs are not affected by the PAA and LEFM characteristics remain within the initially established uncertainty bounds.

3.8.2.4 Cameron's examination of other indicators of flow rate[16]

Thermal power increased by about 0.5 percent from May, 2011 to September, 2011 by using the LEFM indications for control. Thus, for discussion purposes, thermal power based on LEFM indications may be treated as constant when assessing other parameters that may be used to determine thermal power. During this time, venturi flow, turbine pressure indicators, and total steam flow all indicated that thermal power was increasing at a greater rate. The venturies indicated a rate increase larger than the other indicators. Consequently, one may conclude that either the LEFM or the other indicators were providing erroneous information. As discussed above, LEFM changes appear to have been eliminated. The conclusion is that the other parameters have changed.

3.8.2.4.1 Venturis

The venturis are located downstream of the PAA injection location. Cameron stated that PAA is a dispersant that leads to a feed stream that contains colioidal corrosion products. These can be electochemically attracted to the stainless steel surface in the venturi throat since the high throat velocity sweeps away the neutralizing free electrons. Cameron stated that this causes verturi fouling that, in turn, makes the venturis indicate a flow rate that is higher than actual.

Cameron also identified that PAA interaction that affected venturi calibration was observed before LEFM installation and pointed out that a brief cessatin of PAA injection led to an immediate shift of 2 percent in indicated verturi flow indication relative to all other indicators of feedwater flow rate.

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[16]Discussion based on information provided in the May 14, 2013 audit (Ultrasonics, May 14, 2013) unless otherwise stated.

Cameron concluded that PAA changed feedwater calibration by approximately 3 percent or more and could explain the observed discrepency between the LEFM and venturi flow rate indications.

The NRC staff observed that there were differences between venturi indications. However, when each venturi flow rate was compared to the corresponding LEFM flow rate, all venturis exhibited a similar upward trend with approximately the same slope from May to September, 2011.

3.8.2.4.2 Turbine pressure indicators and mean steam flow

There are two water paths to the SGs, feedwater flow that is measured by the LEFMs and venturies, and tempering flow that is also measured but bypasses the LEFMs and venturis. Tempering flow rate was approximately one percent of feedwater flow rate during the comparison period and was stated to be constant. As identified in Section 2.2.2, above, an anomaly was idenfied that the NRC staff believes should be investigated

There are two flow paths that exit the SGs, main steam flow and blowdown flow. Blowdown flow rate is measured and was about 0.5 percent of total flow into the SGs during the comparison period. The NRC staff observes that an anomaly in blowdown flow was identified in Section 3.8.2.2.2, above, that should be further investigated.

Thus SG steam flow is equal to tempering flow plus main feed flow minus blowdown flow.

Most of the steam flow enters the turbine with about 5 percent entering the second stage reheater. Cameron stated that there was no evidence that steam flow to the second stage reheater changed significantly as a fraction of total steam flow. Changes in SG steam flow in the comparison period were stated to be less than 0.1 percent.

First stage pressure is a measure of vapor flow rate and Cameron stated that, for practical purposes, is not affected by change in moisture content. Therefore Cameron concluded that if feedwater, blowdown, and tempering flow rates are constant, a decrease in steam moisture will increase vapor flow rate and first stage pressure. Cameron also stated that, "Because the steam flow and first stage pressure instruments respond differently to changes in moisture content, their indications can be used to estimate trends in moisture content." It also stated that changes in differential pressure across steam flow nozzles and first stage pressure "can be used to calculate the change in moisture carryover." A Cameron moisture trend calculation showed a moisture decrease "approximately equal to the discrepancy between turbine flows and LEFM flow. This was considered "plausible" because PAA caused a steam pressure increase "apparently due to removal of corrosion products from the SG tube surface" and "reduction of deposits on separator cans by a similar mechanism could lead to a reduction in moisture."

3.8.2.4.3 Cameron conclusion

Cameron concluded that:

- "The process change in moisture carry-over is the most plausible explanation consistent with all of the data."

- "The change in moisture carry-over should be expected given the effects intended with the PAA addition."

- "The investigation is therefore complete."

3.8.2.5 Recent plant characteristics

PAA was restored in January, 2012 during steady state operation after an extended period when PAA was not injected. Exelon provided data normalized to one after an initial tranient that followed re-initiation of PAA. Upon re-initiation, steam flow indication immediately decreased by 0.5 percent and venturi indication increased by 0.16 percent before reaching a relative value of one while LEFM, best estimate core thermal power, impulse pressure, and MWt were unchanged. Although there were numerous power transients following re-initiation, indications that apply to flow rate remained consistent after the initial transient until the plant was shut down for Refueling Outage B1R18 in August, 2012. Byron identified that a divergence in steam mass flow rate occurred previously when PAA was isolated and an upward trend occurred that was attributed to likely occurrence of new deposits on secondary steam separator surfaces or the SG outlet nozzle venturi surfaces. These deposits were postulated to have cleared when PAA was restored in January, 2012. The NRC staff considers this experience as supporting a conclusion that PAA affects both SG flow rate and venturi indication. Further it observes that PAA caused indicated SG flow rate to decrease and venturi flow rate to increase. The former is opposite to the 2011 behavior and twice as large whereas the venturi indicated flow rate change is essentially identical to the change that occurred in 2011. In both of these cases, the change was immediate in contrast to the change that occurred over several months from May to September in 2011.

After startup following Refueling Outage B1R18 in October, 2012 until May, 2013, the parameters were essentially unchanged during full power operation. This indicated that whatever was causing the parameter divergence was no longer occurring. Byron stated that it plans to continue to perform detailed trending assessments following Refueling Outage B1R19.

3.8.3. CONCLUSIONS

As summarized in Section 3.8.2.1, above, the average difference between the LEFM and other parameters that can be used to determine feedwater flow rate or thermal power was about 0.25 percent at the end of the increased difference that occured from May, 2011 to September, 2011. Operating parameters from October, 2011 to May, 2013 established that differences had stabilized and were no longer increasing. The requested increase in thermal power corresponds to a power uncertainty of 0.37 percent, the calculated bounding value for system mass flow rate uncertainty was < 0.3 percent and the thermal power uncertainty was < 0.4 percent. The observed differences are smaller than the uncertainties that Caldon calculated that were part of the basis for the LAR. On this basis alone, the observed differences between LEFM and other plant indications are not sufficient to invalidate the feedwater flow rate indicated by the LEFMs. Further, the NRC staff's review supports a conclusion that the LEFMs are not affected by PAA injection and the observed deviations in thermal power and feedwater flow rates are not due to the LEFMs.

Examination of the data supports a conclusion that the venturis are affected by PAA injection although the reasons are not as clear nor are the differences between Byron 1 and Byron 2 fully understood.

Reasons for deviation in other plant parameters have been postulated but these are not accepted by all licensing personal and are not sufficiently supported to lead to firm conclusions.

3.9 Conclusions

The above review covers the aspects of the requested 1.63 percent MUR thermal power uprate that are specific to the CheckPlus installations and are within the areas of SRXB review responsibility. SRXB concludes that the requested MUR thermal power uprate of 1.63 percent is acceptable for the topics that are within SRXB's UFM review responsibility.

3.10 Accident Analyses

3.10.1 Accident Analyses Bounded by Current Analysis of Record

Although the licensee generally concluded that existing analyses were bounding of uprated plant operation with reduced uncertainty, the analyses were shown to be bounding in one of three different ways:

- For analyses that assume steady-state plant operation with a core power of 3672 MWt, there is a 2% margin for power measurement uncertainty at the CLTP, 3586.6 MWt. These analyses are bounding also of plant operation at the MUR RTP of 3645 MWt_t, with operating margin.

- For analyses that assume steady-state plant operation with a core power of 100%, the licensee evaluated accident or transient, and reanalyzed as necessary.

- Zero-power transients were not reanalyzed.

The licensing basis transients and accidents within the scope of SRXB review are summarized in Table 3-1.

Regulatory Issue Summary 2002-03, "Guidance on the Content of Measurement Uncertainty Recapture Power Uprate Applications," states the following:

In areas (e.g., accident/transient analyses, components, systems) for which the existing analyses of record do bound plant operation at the proposed uprated power level, the staff will not conduct a detailed review.

The NRC staff therefore finds the licensee's analyses that were performed at 102% of the CLTP level acceptable without detailed review.

Table 3-1 – Accident and Transient Analyses

Transient/Accident	Analytic Power Level (% CLTP)	Review Comments
Main Steam Line Break Mass and Energy Releases Outside Containment	102	Acceptable
Natural Circulation Cooldown	102	Acceptable
Feedwater System Malfunctions Causing a Reduction in Feedwater Temperature	100	Reanalyzed See 3.10.2.1
Feedwater System Malfunctions Causing an Increase in Feedwater Flow	100	Reanalyzed See 3.10.2.1
Excessive Increase in Secondary Steam Flow	100	Reanalyzed See 3.10.2.2
Inadvertent Opening of a Steam Generator Relief or Safety Valve	NA	Bounded by other Analysis Acceptable
Steam System Piping Failure at Zero Power	0	Reanalyzed See 3.10.2.3
Steam System Piping Failure at Full Power	100	Reanalyzed See 3.10.2.4
Steam Pressure Regulator Malfunction or Failure that Results in Decreasing Steam Flow	NA	No such regulator at the plants
Loss of External Load/Turbine Trip/Inadvertent Closure of Main Steam Isolation Valves/Loss of Condenser Vacuum and Other Events Causing a Turbine Trip	RCS Overpressure 102 Transient 100 MSS Overpressure NA	See 3.10.2.5
Loss of Nonemergency AC Power to the Plant Auxiliaries (Loss of Offsite Power)	102	Acceptable
Loss of Normal Feedwater Flow	102	Acceptable
Feedwater System Pipe Break	102	Acceptable
Partial Loss of Forced Reactor Coolant Flow	100	Reanalyzed See 3.10.2.6
Complete Loss of Forced Reactor Coolant Flow	100	Reanalyzed See 3.10.2.7

Reactor Coolant Pump Shaft Seizure (Locked Rotor)/Reactor Coolant Pump Shaft Break/Locked Rotor with Loss of Offsite Power	PCT/ RCS Overpressure 102 100	Bounded Reanalyzed See 3.10.2.8
Uncontrolled Rod Cluster Control Assembly Bank Withdrawal from a Subcritical or Low Power Startup Condition	0	Acceptable
Uncontrolled Rod Cluster Control Assembly Bank Withdrawal at Power	8 (limiting case) 100 60 10	See 3.10.2.9
Rod Cluster Control Assembly Misoperation	100	Acceptable
Startup of an Inactive Reactor Coolant Pump at an Incorrect Temperature	NA	TS Precludes Acceptable
Chemical and Volume and Control System Malfunction that Results in a Decrease in Boron Concentration in the Reactor Coolant	NA	Not Power Dependent Acceptable
Spectrum of Rod Cluster Control Assembly Ejection Accidents	102 0	Acceptable
Inadvertent Operation of Emergency Core Cooling During Power Operation	102 (Peak Pressurizer Volume) 100	See 3.10.2.10
Chemical and Volume Control System Malfunction that Increases Reactor Coolant Inventory	NA	Bounded by other analysis including Inadvertent ECCS Acceptable
Inadvertent Opening of a Pressurizer Safety or Relief Valve	100	Reanalyzed See 3.10.2.11
Failure of Small Lines Carrying Primary Coolant Outside Containment	NA	Bounded Acceptable
Steam Generator Tube Rupture	102	Reanalyzed See 3.10.2.12
Loss of Coolant Accident Resulting from a Spectrum of Postulated Piping Breaks Within the Reactor Coolant Pressure Boundary (Best Estimate LOCA)	102	Acceptable

Small Break LOCA Analysis	102	Acceptable
Post-LOCA Long-Term Core Cooling/Subcriticality	102	Acceptable
Anticipated Transients without Scram (ATWS)	100	Reanalyzed

3.10.2 Accident Analysis Not Bounded by Current Analysis of Record

The licensee reviewed their current analysis of record and reanalyzed the accidents that were not bounded by the proposed MUR power level. The licensee also reanalyzed some accidents for other issues that they found and adjusted them for the proposed MUR power level. The licensee also proposed to adopt VIPRE subchannel analysis code. The reanalysis using the VIPRE code used a core power level of 3648MWt for the MUR DNB analyses. This is a 1.7% increase to the CLTP and is consistent with Revised Thermal Design Procedure (RTDP). The VIPRE usage as well as the RTDP methodology is reviewed by SNPB

WCAP-14565-P-A SER Conditions

The staff reviewed the four conditions of the SER for the staff approval of the WCAP-14565 topical report for the use of the VIPRE-01 code. The staff reviewed the conditions and the licensee responses to them.

Condition 1: *Selection of the appropriate critical heat flux (CHF) correlation, DNBR limit, engineered hot channel factors for enthalpy rise and other fuel-dependent parameters for a specific plant application should be justified with each submittal.*

The licensee provided the limits in their response. It included the WRB-2 correlation limit of 1.17 for the VIPRE DNBR calculations for the VANTAGE+ fuel. The licensee also stated that the fuel design will not change for the MUR and therefore the fuel dependent parameters in the DNBR calculations are unchanged.

Condition 2: *Reactor core boundary conditions determined using other computer codes are generally input into VIPRE for reactor transient analyses. These inputs include core inlet coolant flow and enthalpy, core average power, power shape and nuclear peaking factors. These inputs should be justified as conservative for each use of VIPRE.*

The licensee stated that the boundary conditions are all generated by NRC approved codes and analysis methodologies. They also stated that reactor core boundary conditions are unchanged from currently justified values besides the increase in the nominal core power of 1.7%.

Condition 3: *The NRC Staff's generic SER for VIPRE (Reference III.1-21) set requirements for use of new CHF correlations with VIPRE. Westinghouse has met these requirements for using WRB-1, WRB-2 and WRB-2M correlations. The DNBR limit for WRB-1 and WRB-2 is 1.17. The WRB-2M correlation has a DNBR limit of 1.14. Use of* *other CHF correlations not currently included in VIPRE will require additional justification.*

The licensee stated the limit for the WRB-2 correlation is 1.17. the licensee also stated that the ABB-NV DNBR limit is 1.13 and the WLOP DNBR limit is 1.18 and both were previously approved for use with the VIPRE code.

Condition 4: *Westinghouse proposes to use the VIPRE code to evaluate fuel performance following postulated design-basis accidents, including beyond-CHF heat transfer conditions. These evaluations are necessary to evaluate the extent of core damage and to ensure that the core maintains a coolable geometry in the evaluation of certain accident scenarios. The NRC Staff's generic review of VIPRE (Reference III.1-21) did not extend to post CHF calculations. VIPRE does not model the time-dependent physical changes that may occur within the fuel rods at elevated temperatures. Westinghouse proposes to use conservative input in order to account for these effects. The NRC Staff requires that appropriate justification be submitted with each usage of VIPRE in the post-CHF region to ensure that conservative results are obtained.*

The licensee response stated that the MUR power uprate application of VIPRE replaces the THINC and FACTRAN codes and is not used in the post-CHF region.

The staff reviewed the disposition of the four conditions laid out in the staff SER for WCAP-14565. The staff found that the licensee adequately addressed the conditions for the MUR LAR.

Review of Reanalyzed Events

The SRXB staff's review of the following accidents covered:

1. The description of the causes of the event and the description of the event itself
2. The initial conditions
3. The values of reactor parameters used in the analysis
4. The analytical methods and computer codes used
5. The results of the associated analysis

The staff used specific review criteria contained in NUREG-0800 SRP Section 15 and other guidance.

3.10.2.1 Feedwater System Malfunctions Causing a Reduction in Feedwater Temperature or an Increase in Feedwater Flow

An increase in feedwater flow or reduction in feedwater temperature will result in increased subcooling in the affected SGs. The increased subcooling will then create a greater load demand on the RCS which decreases the RCS temperature which can produce a reactivity insertion. The neutron overpower, overtemperature and overpower ΔT trips are designed to prevent power increases that could lead to DNBR becoming less than its limit value.

The staff reviewed the initial conditions that the licensee used for the event. The analysis uses a 1.5°F RCS average temperature bias and a minimum SG tube plugging level and maximum feedwater temperature.

The licensee used NRC approved codes LOFTRAN, VIPRE-W, and ANC as well as the RTDP to calculate DNBR. The current analysis was performed at 3600.6MWt and the proposed analysis was performed at 3672MWt.

The licensee chose a limiting case for the four plants which showed a reduction in feedwater temperature event with D5 SGs. The results showed that the resulting DNBR was greater than the safety analysis limit.

The staff reviewed the analysis and results and found them to be acceptable.

3.10.2.2 Excessive Increase in Secondary Steam Flow

An increase in secondary steam flow creates a mismatch between the reactor core and the SG load demand. The RPS signals that protect against this event include the low pressurizer pressure, overtemperature ΔT, and power range high neutron flux.

The licensee used NRC approved code LOFTRAN as well as the RTDP to calculate DNBR. The current analysis was performed at 3600.6MWt and the proposed analysis was performed at 3672MWt.

The staff reviewed the initial conditions for the event. The most limiting case assumed minimum reactivity feedback, automatic rod control and the Babcox & Wilcox International (BWI) SGs with zero tube plugging.

The analysis showed the worst case minimum DNBR and it gave more than 20% safety analysis margin. The staff reviewed the analysis and the results and found them to be acceptable.

3.10.2.3 Steam Supply Piping Failure at Zero Power

The steam break would result in an increase in steam flow initially which removes more energy from the RCS and causes a reduction in RCS temperature and pressure. The cooldown can result in an insertion of positive reactivity. The most reactive RCCA is assumed to be stuck in its fully withdrawn position and the possibility of returning to power exists.

The licensee used NRC approved LOFTRAN, VIPRE, and ANC case along with the Standard Thermal Design Procedure (STDP) to calculate the minimum DNBR and Peak Linear Heat Rate (PLHR). The licensee reanalyzed the even to address revised reactivity feedback coefficients associated with MUR power level.

The staff reviewed the initial conditions and assumptions for the event. The initial conditions included various conservative assumptions as well as the assumption that the maximum break size corresponds to the size of the flow restricting nozzle in the two SG types. Protective functions available to provide protection for a steamline break included the safety injection system, overpower trips, redundant isolation of the main feedwater lines, and trip of the fast acting steamline stop valves.

The limiting case was found to be with the Units 2 with a beak size of 1.4ft^2, AC power available and low T_{ave}. The minimum DNBR value is above the limit value of 1.18 and the maximum PLHR is below its limit value. The staff noted that there was a reduction in margin to the limits which the licensee stated occurred due to power uprate reactivity coefficients creating a more severe return to power as well as the analysis being performed in a more conservative manner to bound cycle to cycle variations in future reloads.

The staff reviewed the analysis and the results and found them to be acceptable.

3.10.2.4 Steam System Piping Failure at Full Power

The steam break would result in an increase in steam flow initially which removes more energy from the RCS and causes a reduction in RCS temperature and pressure. The cooldown can result in an insertion of positive reactivity which can cause a power excursion.

The licensee used NRC approved LOFTRAN, VIPRE, and ANC as well as the RTDP to calculate the minimum DNBR and Peak Linear Heat Rate (PLHR). The current analysis was performed at 3600.6MWt and the proposed analysis was performed at 3672MWt.

The staff reviewed the initial conditions and assumptions for the event. The initial conditions included maximum moderator reactivity feedback and least negative Doppler power feedback. The limiting break size that was found to bound all break sizes was 0.95ft^2. Protective functions that may be used to mitigate this event include the reactor trip, and safety injection.

Westinghouse applies the Condition II acceptance criteria such that damage to the fuel rods is precluded.

The limiting case shows that the power increases during the transient until the reactor trips on overpower ΔT. The minimum DNBR and PLHR were both found to be within the safety limits.

The staff reviewed the analysis and the results and found them to be acceptable.

3.10.2.5 Loss of External Load/Turbine Trip/Inadvertent Closure of Main Steam Isolation Valves/Loss of Condenser Vacuum and Other Events Causing a Turbine Trip

The turbine trip event is the event found to be bounding for this analysis. For the event the turbine stop valves close very rapidly which cuts off steam flow to the turbine. The steam dumps are initiated. The secondary temperature increases as well. The steam dumps and condenser normally accept the excess steam.

The licensee used the STDP for the maximum RCS and main steam system (MSS) pressure overpressure concerns. The RCS overpressure event was not reanalyzed as it is bounded by the AOR. The MSS overpressure event was analyzed based on the RCS overpressure case with automatic pressure control assumed and minimum SG tube plugging modeled . NRC approved LOFTRAN is also used for the overpressure event.

For the DNB case the licensee used NRC approved LOFTRAN and the RTDP to calculate DNBR. The current analysis was performed at 3600.6MWt and the proposed analysis was performed at 3672MWt. The DNB case assumed minimum SG tube plugging as well as the RCS flow rate corresponding to minimum measured flow.

The staff reviewed the initial conditions and assumptions for the event. One assumption is that the conditions in the reactor must cause the reactor trip there is no reactor trip on the turbine trip. No credit is taken for steam dump and main feedwater flow is terminated at the time of the turbine trip and no auxiliary feedwater is credited. Manual rod control is modeled for conservatisms. No credit is taken for the SG power-operated relief valves. The MSSVs are at or greater than the TS limit of 3%.

The results for the MSS overpressure event showed that the overpressure case came in under the pressure limit of 1318.5psia at about 1313.5psia for Units 1 and 1310.6psia for Units 2. The minimum DNBR event showed that the minimum DNBR was above the safety limit DNBR.

The staff reviewed the analysis and results and found them to be acceptable.

3.10.2.6 Partial Loss of Forced Reactor Coolant Flow

The partial loss of forced reactor coolant flow would occur from the failure of an RCP. When the reactor is at power the loss of an RCP would result in a loss of coolant flow and a rapid increase in the coolant temperature which could lead to DNB.

The licensee used NRC approved LOFTRAN and VIPRE codes along with the RTDP to calculate the minimum DNBR. The current analysis was performed at 3600.6MWt and the proposed analysis was performed at 3672MWt. The analysis is performed assuming the loss of two RCPs with four loops in operation.

The staff reviewed the initial conditions and assumptions for the event. The most negative Doppler-only power coefficient was modeled. The Low Reactor Coolant System Flow reactor trip is credit as being available to mitigate the event.

The results showed that the minimum DNBR was above the DNBR safety analysis limit.

The staff reviewed the analysis and the results and found them to be acceptable.

3.10.2.7 Complete Loss of Forced Reactor Coolant Flow

The complete loss of forced reactor coolant flow would occur with the loss of all four RCPs. The loss of the RCPs would cause immediate loss of coolant flow and a rapid increase in coolant temperature.

The licensee used NRC approved LOFTRAN and VIPRE computer codes as well as the RTDP methodology to calculate a minimum DNBR. The current analysis was performed at 3600.6MWt and the proposed analysis was performed at 3672MWt. Two cases were analyzed. One was the complete loss of all four RCPS and the other was the frequency decay event resulting in the complete loss of forced coolant flow.

The staff reviewed the initial conditions and assumptions for the event. The most negative Doppler-only power coefficient was modeled. The RCP power Supply Undervoltate or

Underfrequency and the Low Reactor Coolant System flow reactor trip functions are credited to mitigate this event.

The frequency decay event was shown to be the limiting case. The reactor trips on the underfrequency trip signal after the frequency decay of 5 Hz/sec occurs for 1.2 seconds. The minimum DNBR was shown to be above the DNBR safety analysis limit.

The staff reviewed the analysis and the results and found them to be acceptable.

3.10.2.8 Reactor Coolant Pump Shaft Seizure (Locked Rotor)/Reactor Coolant Pump Shaft Break/Locked Rotor with Loss of Offsite Power

When an instantaneous RCP shaft seizure occurs, the flow through the loop reduces rapidly with no RCP coastdown. The coolant in the primary side heats up and expands causing an insurge into the pressurizer. Pressure suppression including sprays and the PORVs would actuate to lower pressure.

The licensee used NRC approved LOFTRAN and VIPRE codes along with the RTDP methodology. The case that is performed as bounding is the locked rotor rods-in-DNB case. The codes and methodology are used to determine the percentage of fuel rods experiencing a DNBR. The current analysis was performed at 3600.6MWt and the proposed analysis was performed at 3672MWt. The locked rotor is analyzed as one locked rotor with four loops operating and a concurrent loss of offsite power at the time of the reactor trip.

The staff reviewed the initial conditions and assumptions for this event. The most negative Doppler-only power coefficient was modeled. The Low Reactor Coolant System Flow reactor trip is credited as available to mitigate the event.

The results showed that the percentage of fuel rods exceeding the DNBR limit is less than the 2% fuel rod failures for the radiological dose calculations.

The staff reviewed the analysis and the results and found them to be acceptable.

3.10.2.9 Uncontrolled Rod Cluster Control Assembly Bank Withdrawal at Power

This event occurs when an uncontrolled Rod Cluster Control Assembly (RCCA) is withdrawn from the core at power. This can occur due to operator action or malfunction in the rod control system. The result is an increase in the core heat flux and an increase in the RCS temperature. The RPS is designed to terminate this event before the limits are exceeded.

The Licensee used NRC approved LOFTRAN code and the RTDP methodology to analyze this event. The proposed analysis was performed at 3672MWt. There are a variety of automatic RPS features which are designed to prevent core damage during this event and they include: power range neutron flux, positive neutron flux rate, overtemperature ΔT, overpower ΔT, high pressurizer pressure, and high pressurizer water level reactor trips. In addition to the RPS features there are rod withdrawal blocks, that would limit this event, which include high neutron flux, overpower ΔT, and overtemperature ΔT.
The staff reviewed the initial conditions and assumptions for this event. Minimum and maximum reactivity feedback cases are analyzed. Reactor tips are assumed to be at their maximum

values. The reactor trip assumes the highest worth RCCA is stuck fully withdrawn. Power levels of 10%, 60%, and 100% are considered.

This event is considered a Condition II event. The results were shown for the range of considered conditions. The minimum DNBR was greater than the safety analysis limit for each of the analyzed events.

The staff reviewed the analysis and the results and found them to be acceptable.

3.10.2.10 Inadvertent Operation of the Emergency Core Cooling System During Power Operation

The inadvertent operation of the ECCS at power could be caused by operator error, test sequence error, or a false electrical actuation signal. If the actuation signal occurs the suction of the charging pumps changes to the refueling water storage tank (RWST). The charging pumps then are aligned to start pumping the borated RWST water into the RCS. The accumulators and low head injection systems are not able to inject into the RCS at normal pressure. This event is analyzed to (1) show that there is no fuel clad damage, as indicated by the calculated minimum of DNBR, and (2) to show that the event will not escalate into a more serious event. In the first case, the reactor is not assumed to trip from the SI signal.

For the DNBR analysis, the SI signal is considered to not cause a reactor trip in the analyzed event. The reactor power will decrease due to the injection of borated water and the pressurizer pressure and water level decrease. The reactor will eventually trip by low pressurizer pressure trip or a manual trip.

The licensee used NRC approved LOFTRAN code and the RTDP methodology to calculate the minimum DNBR. The current analysis was performed at 3600.6MWt and the proposed analysis was performed at 3672MWt.

The staff reviewed the initial conditions and assumptions for this event. The reanalysis was done for the DNB case. Some assumptions included: zero moderator temperature coefficient, low absolute value Doppler power coefficient, manual rod control, pressurizer heaters inoperable, reactor trip on low pressurizer pressure, no operator action, and no credit for the steam dump. This event is considered a Condition II event.

The results showed the power decreasing due to boron injection. The DNBR is shown to increase throughout the event. There was an expected decrease in the minimum DNBR due to the power increase from the initial conditions (MUR).

The staff reviewed the analysis and results and found them to be acceptable for the DNB case of the Inadvertent Operation of the ECCS during Power Operation event.

For the analysis to demonstrate the inadvertent ECCS operation does not escalate into a more serious event the analysis was done at 102% of CLTP. The current licensing basis (CLB) analysis is documented in the FSAR and dated 2002. The applicant states that this analysis continues to bound operation at the MUR power level. Since 2002, the NRC staff has issued a Regulatory Issue Summary (RIS 2005-29) regarding this event and the problems that can occur when the pressurizer is filled. The licensee's CLB analysis indicates the pressurizer is predicted to fill. However, the licensee has not updated its CLB analysis to address the concerns outlined in the RIS. Given that the applicant has not updated the analysis in response to the RIS, the issue was determined to be outside the scope of the MUR. The staff intends to pursue this issue generically by clarifying the expectations in the RIS and is also considering plant-specific actions to address the issue.

3.10.2.11 Inadvertent Opening of a Pressurizer Safety or Relief Valve

The inadvertent opening of PORV would cause depressurization of the RCS. The analysis uses the more conservative assumption of the conditions of a Pressurizer Safety Valve (PSV) opening because the PSVs have close to twice the steam flow rate relief capacity of the PORVs. The event initially starts with rapidly decreasing RCS pressure then the filling of the pressurizer.

The licensee used NRC approved LOFTRAN code and the RTDP methodology to calculate the minimum DNBR. The current analysis was performed at 3600.6MWt and the proposed analysis was performed at 3672MWt.

The staff reviewed the initial conditions and assumptions for this event. The cases were run to find the most limiting result between the Unit 1 and Unit 2 SGs. Maximum SG tube plugging and least negative Doppler-only power coefficient are assumed. The Low Pressurizer Pressure and Overtemperature ΔT reactor trips are credited to be available to mitigate the event. This event is considered a Condition II event.

The results showed the most limiting case being the Unit 2 SGs with maximum tube plugging and minimum feedwater temperatures. The results showed the depressurization and the nuclear power as well as the minimum DNBR. The reactor trip occurs on Low Pressurizer Pressure. The minimum DNBR was greater than the DNBR safety analysis limit.

The staff reviewed the analysis and the results and found them to be acceptable for the DNB event of the Inadvertent Opening of a Pressurizer Safety or Relief Valve.

3.10.2.12 Steam Generator Tube Rupture Margin to Steam Generator Overfill

The licensee performed the thermal and hydraulic analysis using LOFTTR2 program and methodology. The licensee looked at the failure of an intact SG PORV, failure of ruptured SG MSIV, and failure of ruptured SG feedwater control valve to determine the limiting single failure. The limiting single failure was determined to be the failure of an intact SG PORV was found to be limiting due to the increased cooldown time.

The staff reviewed the initial conditions and the assumptions for this event. For both Units the SG MTO considered the minimum operating temperature with the minimum main feedwater temperature. They both also assumed the maximum SG tube plugging. The failure of a PORV on an intact SG was used for the limiting case. The secondary side volume available for Unit 1 SG is 5122ft^3 and the secondary side volume available for Unit 2 SG is 5955ft^3. The licensee performed the analysis to show that the secondary side of the ruptured SG did not completely fill with water.

The event initiates with a tube rupture with water flowing from the primary to the secondary side of the SG. The RCS starts losing coolant and the pressurizer level and pressure are decreased. The reactor trip occurs on overtemperature ΔT trip signal. The reactor power decreases to decay heat and the turbine stop valves close. The steam dumps are unavailable due to assumed loss of offsite power. This also causes main feedwater flow to stop and the SG flow is provided by the AFW. The energy in the secondary side is released through the SG PORVS and safety valves. The pressurizer pressure signal starts the SI and flow is delivered to recover pressurizer level. The licensee assumes that the AFW flow to the ruptured SG will be isolated within 9 minutes and the MSIV for the same SG is closed at 18 minutes. Three minutes of operator action time are assumed before cooldown is started. The cooldown is performed with two of the intact SGs since one of the intact SG PORVs is the assumed failure. After the cooldown termination temperature is reached the cooldown is terminated and a 4 minute operator action time is assumed before RCS depressurization. The RCS depressurization is terminated when the RCS pressure is less than that of the ruptured SG and the pressurizer level was adequate. Three minute operator action time is assumed before the SI is terminated.

The results showed margin to overfill for both units. The maximum ruptured SG water volume for the Unit 1 case was shown to be 5068ft^3. The result was therefore 54ft^3 of margin to overfill. The maximum ruptured SG water volume for the Unit 2 case was shown to be 5685ft^3. The result was therefore 270ft^3 of margin to overfill.

The licensee will implement the following plant modifications to support the SG MTO assumptions:

1. Installing safety related air accumulator tanks to support AFW flow control
2. Increase the capacity of the Unit 1 SG PORVs
3. Modify Unit 2 SG PORVs to achieve analysis flow rates
4. Install uninterruptible power supplies on two of the four SG PORVs
5. Install a manual isolation valve upstream of each High Head Safety Injection valve

The staff reviewed the analysis and results and found them to be acceptable.

3.11 Conclusion

The NRC staff has reviewed the licensee's analyses of the above events and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of these events. Therefore, the NRC staff finds the proposed MUR LAR acceptable with respect to the events above.

4.0 CONCLUSION

The SRXB staff reviewed the reactor systems and thermal-hydraulic aspects of the LEFM as well as the accident analysis aspects of the proposed LAR in support of implementation of a MUR. Based on the considerations discussed above, the NRC staff determined that the results of the licensee's analyses related to these areas continue to meet applicable acceptance criteria following implementation of the MUR. The proposed amendment is based on the use of a Cameron LEFM Check Plus system that would decrease the uncertainty in the feedwater flow, thereby decreasing the power level measurement uncertainty from 2.0% to 0.37%. Therefore, the SRXB staff finds the proposed LAR acceptable in its area of review.

5.0 References

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