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Dresden Nuclear Power Station, Units 2 and 3
Facility Operating License Nos. DPR-19 and DPR-25
NRC Docket Nos. 50-237 and 50-249

Quad Cities Nuclear Power Station, Units 1 and 2
Facility Operating License Nos. DPR-29 and DPR-30
NRC Docket Nos. 50-254 and 50-265

Subject: Additional Risk Information Supporting the License Amendment Request to Permit Uprated Power Operation at Dresden Nuclear Power Station and Quad Cities Nuclear Power Station

Reference: Letter from R. M. Krich (Commonwealth Edison Company) to U. S. NRC, "Request for License Amendment for Power Uprate Operation," dated December 27, 2000

In the referenced letter, Commonwealth Edison (ComEd) Company, now Exelon Generation Company (EGC), LLC, submitted a request for changes to the operating licenses and Technical Specifications (TS) for Dresden Nuclear Power Station (DNPS), Units 2 and 3, and Quad Cities Nuclear Power Station (QCNPS), Units 1 and 2, to allow operation with an extended power uprate (EPU). In a July 18, 2001, telephone conference call between representatives of EGC and Mr. L. W. Rossbach and other members of the NRC, the NRC requested additional information regarding these proposed changes. The attachment to this letter provides a portion of the requested information. The remainder of the requested information will be provided in a separate letter.

Should you have any questions concerning this letter, please contact Mr. A. R. Haeger at (630) 657-2807.

Respectfully,

K. A. Ainger

K. A. Ainger
Director – Licensing
Mid-West Regional Operating Group

A001

Attachments:

Affidavit
Attachment: Additional Risk Information Supporting the License Amendment Request to Permit Uprated Power Operation

cc: Regional Administrator - NRC Region III
NRC Senior Resident Inspector - DNPS Nuclear Power Station
NRC Senior Resident Inspector - QCNPS Nuclear Power Station
Office of Nuclear Facility Safety - Illinois Department of Nuclear Safety

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|---|---|---|
| **STATE OF ILLINOIS** | ) | |
| **COUNTY OF DUPAGE** | ) | |
| **IN THE MATTER OF** | ) | |
| **EXELON GENERATION COMPANY, LLC** | ) | **Docket Numbers** |
| **DRESDEN NUCLEAR POWER STATION, UNITS 2 AND 3** | ) | **50-237 AND 50-249** |
| **QUAD CITIES NUCLEAR POWER STATION, UNITS 1 AND 2** | ) | **50-254 AND 50-265** |

**SUBJECT:** Additional Risk Information Supporting the License Amendment Request to Permit Uprated Power Operation at Dresden Nuclear Power Station and Quad Cities Nuclear Power Station

**AFFIDAVIT**

I affirm that the content of this transmittal is true and correct to the best of my knowledge, information and belief.

K. A. Ainger

K. A. Ainger
Director – Licensing
Mid-West Regional Operating Group

Subscribed and sworn to before me, a Notary Public in and for the State above named, this 14th day of August, 2001.

Vicki L Farbo

Notary Public

OFFICIAL SEAL
VICKI L FARBO
NOTARY PUBLIC STATE OF ILLINOIS
MY COMMISSION EXP. NOV. 4, 2001

**Attachment**
**Additional Risk Information Supporting the License Amendment Request to Permit Uprated Power Operation**
**Dresden Nuclear Power Station, Units 2 and 3**
**Quad Cities Nuclear Power Station, Units 1 and 2**

This attachment contains responses to NRC Questions 1 through 9, 12, and 13. Responses to NRC Questions 10 and 11 will be provided separately.

<u>Question</u>
1. *There is a modification being implemented in parallel with the extended power uprate that will install an automatic recirculation system runback following a feedwater pump trip. What is the impact of a spurious recirculation system runback at full or low power and what is the impact of a failure of the recirculation pump to runback at full or low power? How have these new events been addressed in the extended power uprate probabilistic safety assessment (PSA) model and what are their expected impacts on the trip initiating event frequency?*

<u>Response</u>
A brief summary of the responses is provided in the following tabular display followed by a more detailed description.

| <u>Failure Mode</u> | <u>Impact</u> | <u>EPU PRA</u> | <u>Trip Frequency</u> |
|---|---|---|---|
| Spurious Initiation of Recirculation Pump Runback | Potential high reactor pressure vessel (RPV) water level, turbine trip, scram, and feedwater (FW) trip | Not quantitatively included; estimated as negligible | ~1E-4/yr |
| Failure to Runback | Potential low RPV water level scram and turbine trip | Failure Probability estimated at 5.2E-3 | None |

Recirculation pump runback has been added to the design to avoid plant trips on loss of a single condensate or feedwater pump. This results in reducing the trip frequency for the extended power uprate (EPU) condition by avoiding the "new" scrams which are estimated at frequencies of 5E-2/yr for Quad Cities Nuclear Power Station (QCNPS) and 0.21/yr for Dresden Nuclear Power Station (DNPS).

There are, however, increases in scram frequency introduced by the addition of this control circuit due to spurious scrams. However, the increase in scram frequency is estimated at 1E-4/yr, or approximately two orders of magnitude less than the scram reduction achieved by the addition of the runback circuit.

*<u>Spurious Recirculation System Runback</u>*
The recirculation pump runback is designed to be an energize to actuate logic. This design was chosen to reduce any possibility of spuriously causing an RPV water level transient. Therefore, the logic failure that would induce a recirculation runback is calculated to be approximately 1.3E-2/yr, characterized as an "OR" gate of two relay failures (one to spuriously energize and one to spuriously de-energize) and an operating crew miscalibration. Spurious recirculation pump

runback would lead to an RPV water level transient, which would challenge the feedwater control system. Spurious recirculation runback can be successfully mitigated by the feedwater control system maintaining RPV level below the high level scram setpoint to avoid a scram transient. Given a spurious recirculation system runback at full or low power, the feedwater control system is judged to adequately reduce feedwater flow to the RPV to match the decrease in recirculation flow. However, if the feedwater control system cannot reduce flow in sufficient time, the reactor would scram and the feedwater pumps would trip on high RPV level. The event would be similar to a turbine trip transient with the feedwater pumps remaining available to be restarted. Spurious runback is less likely at low power because the runback circuit is not enabled at power levels below current rated thermal power.

This combination of failures (spurious recirculation runback and failure of feedwater control) is estimated at 1E-4/yr.

The total turbine trip frequency is approximately 2.0/yr from all causes. Therefore, an increase of 1E-4/yr. is judged to be a negligible change to the initiating event frequency. Whether at full power or low power, spurious recirculation runback is a low frequency event that is subsumed by higher frequency initiating events already evaluated for the EPU condition (e.g., turbine trip).

*Failure of the Recirculation System Runback*
Failure of the recirculation system runback at full flow is explicitly evaluated for the EPU condition. Initial analyses indicated that the recirculation runback modification may not sufficiently reduce flow in the event of a feedwater or condensate/booster pump trip to prevent a low RPV water level scram. Therefore, the turbine trip initiating event frequency was increased to account for failure of any single feedwater or condensate/booster pump to result in a turbine trip. Based on plant specific analyses, the QCNPS turbine trip initiating event frequency increased from 2.0/yr to 2.05/yr and the DNPS turbine trip initiating event frequency increased from 1.14/yr to 1.35/yr. The risk associated with this initiating event frequency increase has been calculated and included in the delta risk calculations.

Subsequent analyses, however, indicate that the recirculation runback system would operate as designed and be able to prevent RPV level from reaching the low level scram setpoint given loss of a feedwater or condensate/booster pump (i.e., no increase in turbine trip initiating event frequency). Since the subsequent analyses was not available prior to completion of the EPU risk assessment, the increase in turbine trip initiating event frequency was incorporated into the base EPU risk model (see response to Question 3).

Failure of the recirculation pump runback at low flow is not explicitly evaluated for the EPU condition. When the reactor is at low power, the plant is likely to be operating in the pre-EPU condition with two of the three feedwater pumps and three of four condensate/booster pumps operating. For this condition, if a pump trips, the standby pump automatically starts and a low RPV level scram can be avoided.

## Attachment
## Additional Risk Information Supporting the License Amendment Request to Permit Uprated Power Operation
## Dresden Nuclear Power Station, Units 2 and 3
## Quad Cities Nuclear Power Station, Units 1 and 2

Question

*2. There is a modification being implemented to trip the fourth running condensate pump during a loss of coolant accident (LOCA) to prevent an electrical overload. Is this modification being hardwired to a specific condensate pump? If the pump fails to trip or its breaker(s) fails to open, what is the impact on the electrical system? Were these new potential failure modes of the electrical system explicitly modeled? If not, please explain the basis for these failures modes being considered to have a negligible impact.*

Response

The modification will add a logic circuit to automatically trip condensate/booster pump "D" in the event of a LOCA while all four condensate pumps are running. The intent of the modification is to prevent a potential overload condition on the reserve auxiliary transformer (RAT) in the event of a LOCA with offsite power available. The LOCA would cause a unit trip, resulting in deenergizing the unit auxiliary transformer. Running loads would then transfer to the RAT. Without this modification, the starting of emergency core cooling system (ECCS) pumps could result in undervoltage on the 4kV buses. The undervoltage signal would then result in ECCS loads being powered from the emergency diesel generators, but the condensate and feedwater pumps would trip. Therefore, the condensate and feedwater pumps would not be available for injection without further operator action. Since offsite power can still be manually restored to the 4kV buses, this scenario would be bounded by the LOCA with loss of offsite power (LOOP).

There are two contact inputs from the LOCA detection circuits, each from a different division circuit, arranged in parallel. Failure of either contact to actuate on a LOCA will not prevent the desired trip of condensate pump motor "D." Multiple failures or a common cause failure (CCF) across two divisions would be required to prevent the receipt of the trip signal. Since failure of the trip circuit only results in ECCS loads being powered from the diesels as designed, additional failures must be postulated for this sequence to result in core damage.

The quantitative impact of the new failure mode was conservatively calculated as follows.

Core damage frequency (CDF) = (LOCA signal initiating event frequency) x (Failure to trip condensate/ booster pump "D" x (Single unit LOOP induced))[(1)] x (Failure to cross tie alternating current (AC) buses to opposite unit) x (Failure of all diesel generators + other failure combinations)

= (1E-2/yr) x (1E-3) x (1.0) x [(1.1E-2) x (1E-3) + 3E-6]

= 1.68E-10/yr

where failure to trip pump "D" can be due to failure of the logic or failure of the breaker to open.

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(1) This quantitative assessment conservatively assumes that the failure of the breaker to trip <u>will</u> cause a LOOP event with a 1.0 probability, AND no offsite AC power recovery is credited even though the RAT and offsite power remain available.

The screening analysis was performed as follows:

- The frequency of any initiating event that could result in a LOCA signal was summed to find the potential for the load shed signal. This includes the sum over all frequencies for LOCAs, loss of drywell cooling, loss of service water (SW), and loss of reactor building closed cooling water (RBCCW).

- The conditional probability that the condensate pump was not shed is estimated using a common cause miscalibration of the control system, plus relay failure, plus a circuit breaker failure to trip (8E-5 + 1E-4 +1E-3)

- The conditional probability that BOP systems are not available because of the unavailability of non-safety related power is assumed to be 1.0 for this screening analysis.

- The conditional probability of subsequent failures leading to core damage is dominated by the failure to supply alternating current (AC) power. This is characterized by the failure of all diesels capable of supplying the unit (~1E-3) and failure to supply AC power from the opposite unit (~1.1E-2). Other failure combinations represent approximately 30% of this conditional probability or 3E-6.

The additional CDF contribution of 1.68E-10/yr from this failure mode is negligible compared to the base CDF of 4.6E-6/yr for QCNPS and 2.6E-6/yr for DNPS. Therefore, this failure mode was not explicitly evaluated for the EPU probabilistic risk assessment (PRA) sensitivity quantification.

*Spurious Actuation Events*

In addition to the above failure mode of failure to successfully load shed, there could be a spurious condensate pump trip event due to a failure in the new circuit. Spurious trip of a condensate pump due to the relay energizing spuriously is 4.4E-3/yr.

This represents a negligible increase in the turbine trip frequency because of the following.

- Relay spuriously energizes ~4.4E-3/yr
- Condensate pump trips ~1.0
- Recirculation pump does not runback ~5.2E-3

This results in a 2E-6/yr turbine trip initiating event frequency increase. The scram frequency change is already adequately encompassed by the change included in the recirculation pump runback circuit addition (see response to Question 3).

Question

*3. The change in turbine trip initiating event frequency is stated to be the result of the need to operate the installed spare feedwater and condensate/condensate booster pumps.*

*3.1. How was the change in initiating event frequency determined? Was a plant-specific loss of feedwater initiating event model explicitly revised to include the potential failure of the required operating pumps or was the initiating event scaled to account for the additional failure modes? If the latter, please provide a justification for the applicability of the plant-specific initiating event data used in these calculations due to the change in operating conditions and configurations.*

*3.2. The DNPS information indicates that the loss of any single feedwater or condensate/condensate booster pump would lead to a reactor low level scram signal, but the QCNPS information indicates that this is estimated to occur only half of the time. Please explain why there is this difference between the DNPS and QCNPS loss of feedwater initiating event models.*

Response

*3.1 QCNPS*

For QCNPS, the turbine trip initiating event frequency change associated with the configuration change was developed with a plant specific fault tree model for the initiating event to account for the additional failure modes. A simplified fault tree model was developed to estimate the increase in the turbine trip initiating event frequency due to the modified feedwater/condensate configuration to support EPU.

The EPU configuration increases the number of normally operating feedwater pumps from two to three and the number of normally operating condensate pumps from three to four. Due to the increased feedwater flow rate to accommodate EPU, preliminary analyses indicated that the recirculation runback logic may not sufficiently reduce flow in the event of a feedwater or condensate/booster pump trip to prevent a low RPV level scram. Subsequent analyses, however, indicate that the recirculation runback system would operate as designed and be able to prevent RPV level from reaching the low level scram setpoint given loss of a feedwater or condensate/booster pump (i.e., no increase in turbine trip initiating event frequency). However, the analyses were not available prior to completion of the EPU risk assessment. Therefore, the risk assessment incorporated the increase in turbine trip initiating event frequency in the base EPU risk model.

The simplified model includes the following assumptions:

- Failure of any single feedwater or condensate pump to run during the year may lead to a plant trip. The plant trip is classified as a turbine trip and not a loss of feedwater event because, in most cases, one or more feedwater pumps will remain available. Failure of the recirculation runback logic to automatically reduce flow and prevent a trip is assigned a failure probability of 0.5.

- Failure to run rates for feedwater pumps (i.e., 2.59E-6/hr) and condensate pumps (i.e., 8.44E-7/hr) are taken from the QCNPS 1999 PRA update.

- The run time is assumed to be 8760 hours (i.e., 1 year) per pump.

- Additional component failures have not been included in this simplified analysis (e.g., feedwater heaters, condensate booster pumps, lube oil pumps). These failures are assumed to be subsumed by the feedwater and condensate pump failure rates

The fault tree model results estimate that the turbine trip initiating event frequency increases from the base QCNPS PRA value of 2.0/yr to approximately 2.05/yr due to the power uprate configuration.

*3.1 DNPS*
For DNPS, the turbine trip initiating event frequency was also developed to account for the additional failure modes. Similar to QCNPS, a simplified fault tree model was initially developed to estimate the increase in the turbine trip initiating event frequency due to the modified feedwater/condensate configuration to support power uprate. However, the failure to run rates for feedwater pumps (i.e., 2.5E-5/hr) and condensate pumps (i.e., 3.0E-5/hr), taken from the DNPS 1999 PRA update, are an order of magnitude higher than QCNPS. Therefore, the simplified fault tree methodology resulted in a calculated increase in turbine trip frequency that was judged to be unrealistically conservative. The higher feedwater and condensate pump failure rates are based on the DNPS IPE. The higher feedwater and condensate pump failure rates have a negligible impact on the base DNPS PRA model results.

As an alternate methodology for DNPS, plant specific data was reviewed to determine how many feedwater and condensate pump trips have occurred that did not result in plant scrams in the pre-uprate condition but would have resulted in plant scrams in the post-uprate condition if the recirculation system runback was ineffective. Based on this review, three additional turbine trips over a seven year period would have occurred. This equates to an initiating event increase of 0.43/yr/2 units, or 0.21 turbine trips per unit.

The plant specific data analysis estimates that the turbine trip initiating event frequency increases from the base DNPS PRA value of 1.14/yr to approximately 1.35/yr due to the power uprate configuration.

As noted for QCNPS, subsequent analyses indicate that the recirculation runback system would operate as designed and be able to prevent RPV level from reaching the low level scram setpoint given loss of a feedwater or condensate/booster pump (i.e., no increase in turbine trip initiating event frequency). However, the analyses were not available prior to completion of the EPU risk assessment. Therefore, the risk assessment incorporated the increase in turbine trip initiating event frequency in the base EPU risk model with no credit for the recirculation pump runback.

Therefore, on a realistic basis the increase in risk associated with this turbine trip frequency increase should be removed, i.e., the quantified QCNPS EPU CDF risk would decrease by approximately 1% from 5% to 4%. Similarly, the DNPS EPU CDF would decrease by approximately 2.5% from 9% to 6.5%.

*3.2 QCNPS and DNPS*
For QCNPS, a value of 0.5 was used to estimate that the recirculation runback system would fail to prevent a low level scram signal given failure of a feedwater or condensate/booster pump. The value of 0.5 is based on a conservative judgement because preliminary analyses indicated that the recirculation runback system might not be capable of preventing a low level scram signal. Using a value of 1.0 instead of 0.5 for failure of the recirculation runback system for QCNPS would have resulted in a CDF and large early release frequency (LERF) increase of less than an additional 1% over the base EPU case.

The DNPS analysis was performed later and used a value of 1.0 to estimate that the recirculation runback system would fail to prevent a low level scram signal. The value of 1.0 was used to account for the additional uncertainty associated with using engineering judgement to determine if the failed feedwater or condensate/booster pump described in the event reports would lead to a scram in the post-uprate condition.

For both plants, failure of the recirculation runback system is modeled conservatively because subsequent analyses indicate that the recirculation runback system would function as designed to prevent a low RPV level scram signal given loss of a feedwater or condensate/booster pump. The use of the conservative values yielded acceptably small increases in the risk.

Question
*4. It is expected that the time to initiate standby liquid control (SBLC) early would also be impacted, as well as its late initiation, but this impact is not identified. What was the impact on early SBLC initiation as a result of the extended power uprate in terms of available time and associated human error probability (HEP) and what was its overall impact on core damage frequency (CDF)?*

Response
*DNPS and QCNPS*
The manual initiation of SBLC has been divided into two time phases. The two time phases are defined solely be for the purpose of characterizing the following.

- "Early" time phase is a condition corresponding to the expected operating crew response to follow procedures and take prompt action as specified by the symptom based procedures. This results in a more controlled response to the anticipated transient without scram (ATWS) event and the ability to avoid a demand for emergency depressurization due to exceeding the heat capacity temperature limit (HCTL).

- "Late" time phase that characterizes the absolute latest time when crew action can be taken to prevent core damage. The plant condition would have deteriorated substantially and increased difficulty in controlling RPV injection is modeled to prevent core damage.

From a probabilistic risk assessment standpoint, the "early" success paths are more reliable. The demarcation time for the early time phase was conservatively represented in the pre-EPU PRA. The deterministic calculations performed as part of the EPU assessment indicated this time to be adequate and therefore no change was made to the timing or HEP associated with "early" SBLC initiation. The deterministic calculations show that the "late" time phase which was realistically assessed in the pre-EPU case does decrease for the post-EPU case.

The time available to initiate SBLC (early), prior to the condition where HCTL cannot be prevented, is estimated based on generic boiling water reactor (BWR) analysis to be approximately 6 minutes. The Modular Accident Analysis Package (MAAP) calculations for the power uprate configuration for QCNPS and DNPS confirm that SBLC initiation at 6 minutes is adequate to prevent reaching HCTL. Therefore, no change to the HEP for early SBLC initiation was required.

<u>Question</u>
*5. The success criteria is stated to change in two areas: number of electromatic relief valves (ERVs) or safety relief valves (SRVs) required for reactor pressure vessel (RPV) depressurization and number of safety valves (SVs), ERVs, or SRVs required for overpressurization protection.*

*5.1. It is noted that the RPV depressurization sequences without a stuck open relief valve are dominated by operator action failures and common cause failures (CCFs). However, the CCF modeling, and thus its contribution, will be impacted due to the change in success criteria. Was the CCF modeling and associated values changed to reflect the change in success criteria for the post-uprate model? If so, what were the CCF values used in the pre- and post-uprate models and what was the quantified change in CCF contribution? If not, what is the basis for the conclusion that the impact is negligible?*

*5.2. The ATWS overpressure protection success criteria changes from 11 of 13 to 12 of 13 SVs, ERVs, or SRVs, which is stated to have a negligible impact on the results because it is dominated by CCF. Note that the post-uprate model would have to consider the CCF of any two valves, which was not considered in the pre-uprate model (it modeled the CCF combination of any three valves). Thus, the CCF contribution will be impacted due to this change in success criteria. Was the CCF modeling and associated values changed to reflect the change in success criteria? If so, what were the CCF values used in the pre- and post-uprate models and what was the quantified change in CCF contribution? If not, what is the basis for the conclusion that the impact is negligible?*

<u>Response</u>

*<u>5.1 QCNPS</u>*

The success criteria for RPV depressurization for a transient without a stuck open relief valve (SORV) are the following:

| Plant Condition | Depressurization Success Criteria[1] ERVs/SRVs | Failure Combination Required ERVs/SRVs |
|---|---|---|
| Pre-EPU | 1 of 5 | All 5 |
| Post-EPU | 2 of 5 | Any 4 |

[1] QCNPS includes 4 ERVs and 1 Target Rock SRV for depressurization.

The common cause treatment requires the failure combinations noted in the table. The data used for the common cause evaluation is based on Multiple Greek Letter (MGL) data contained in INEL 94/0064 (Reference 1), (including the identification of an additional failure mode noted in precursor events due to inadvertent insulation coverage on the valve top works), which is the predecessor to NUREG/CR-5497 (Reference 2).

These result in the following CCF probabilities used for QCNPS:

| Plant Condition | ERV MGL CCF Probability 4 of 4 | Precursor Failure Probability Failure of All SRVs/ERVs 4 of 5 | Total Hardware Failure Probability[1] |
|---|---|---|---|
| Pre-EPU | 2.8E-4 | 1.47E-4 | 1.47E-4 (5 of 5) |
| Post-EPU | 2.8E-4 | 1.47E-4 | 4.27E-4 (Any 4) |

[1] Random contributions are neglected.

Class IA and IIIB (i.e., high pressure core damage) is increased by this change in CCF probability resulting in an increase in Class IA and IIIB of 1%. This change was identified in the risk evaluation performed to support the EPU.

The change in CDF remains relatively small because of the large diversity in high pressure makeup systems for QCNPS. The dominant contributors to Class IA and IIIB are related to DC power system failures that affect multiple ERVs and the SRV and multiple high pressure injection sources.

*DNPS*
The ERV/SRV configuration and success criteria are similar between DNPS and QCNPS. The dominant failures of the ERV/SRVs to depressurize the reactor at DNPS are also similar to QCNPS. Therefore, the results for DNPS are approximately the same (i.e., a 1% increase in CDF). The impact on CDF at DNPS is lessened by an isolation condenser (IC) that acts as a method to maintain RPV inventory and avoids challenging RPV makeup systems.

*5.2 QCNPS and DNPS*
The success criteria for RPV overpressure protection for an ATWS are the following:

| Plant Condition | Overpressure Protection Success Criteria ERVs/SRVs/SVs | Failure Combination ERVs/SRVs/SVs |
|---|---|---|
| Pre-EPU | 11 of 13 | 3 |
| Post-EPU | 12 of 13 | 2 |

The common cause treatment requires the failure combinations noted in the table. The data used for the common cause evaluation is based on NUREG/CR-5497 and its predecessors. NUREG/CR-5497 and its predecessors do not have CCF of the relief mode of BWR SRVs. Other estimates were used because the NUREG/CR-5497 evaluation found that the data identified no BWR safety valve CCF events and provided no other guidance.

The CCF estimates are based on industry data:

$\lambda$ = 3E-3 (NUCLARR data)
$\beta$ = 6.0E-2 (ALWR data)
$\gamma$ = 1.0 (ALWR data)

The approach taken in the modeling is a BETA factor approach. If two valves fail, all valves are assumed to fail. Therefore, the probability of three valves failing due to common cause had conservatively already been assumed to be as high as the probability of two valves failing due to common cause. Multiplying these values results in the following failure probabilities for QCNPS and DNPS.

| Plant Condition | ERV/SRV/SV MGL CCF |
|---|---|
| Pre-EPU 3 of 13 | 1.8E-4 |
| Post-EPU 2 of 13 | 1.8E-4 |

<u>Question</u>
*6. The DNPS (QCNPS) value for CDF is stated to change from 2.61E-6/year (4.61E-6/year) to 2.82E-6/year (4.85E-6/year) and the value for LERF is stated to change from 1.44E-6/year (3.30E-6/year) to 1.58E-6/year (3.43E-6/year). Typically, it is expected that the LERF value would be nearly an order of magnitude below the CDF value. Please explain why the LERF values at these sites are less than a factor of two below the CDF values.*

<u>Response</u>
<u>*QCNPS and DNPS*</u>
DNPS and QCNPS have BWR Mark I containments. The NRC and the industry in the IPEs have evaluated these containments in the past (Reference 3). In nearly all the analyses, the failure modes associated with BWR Mark I containments that can lead to large releases have been quantified to have relatively high conditional probabilities. As an example, consider the results of the NRC evaluation of risk at a Mark I containment performed as part of NUREG-1150:

> "The important conclusions that can be drawn ... [are]: (1) there is a high mean probability (i.e., 50%) that the Peach Bottom containment will fail early for the dominant plant damage states; (2) early containment failures will primarily occur in the drywell structure resulting in a bypass of the suppression pool's scrubbing effects for radioactive material released after vessel breach; and (3) the principal cause of early drywell failure is drywell shell melt through. The data further indicate that the early containment failure probability distributions for most plant damage states are quite broad."

Quantitatively, NUREG-1150 cites the following:

> "...the mean conditional probability from internally initiated accidents of (1) early wetwell failure is about 0.03, (2) early drywell failure is about 0.52, (3) late failure of either the wetwell or drywell is about 0.04, and (4) no containment failure is about 0.27."

The containment failure analysis for QCNPS and DNPS, while resulting in slightly higher containment failure probabilities than those in NUREG-1150, are within the uncertainty ranges alluded to in the NUREG-1150 evaluation. The specific items that have impacted the QCNPS and DNPS calculations are as follows:

A. The analysis follows the simplified and conservative approach described in NUREG/CR-6595 (Reference 4). This introduces some conservatism into the analysis.
   - Dependencies are treated conservatively.
   - No credit is given to the reactor building for a decontamination factor on the release fraction.
   - No additional deterministic calculations were performed to support lower releases.

B. The use of drywell (DW) sprays with the latest severe accident management guidelines (SAMGs) (implemented after the PRA freeze date) has not been factored into the analysis. Therefore, the drywell shell melt through effect is higher than at other BWRs with the SAMGs included.

C. The ATWS induced failures of containment have been treated as LERF.
   - The frequency is based on the old ATWS conditional probabilities from NUREG-0460 (Reference 5), instead of the latest NUREG/CR-5500 (Reference 6) estimates. Because the QCNPS and DNPS CDF is relatively low, the ATWS fraction represents a substantial fraction of the overall CDF and release and these are all treated as LERF.
   - No deterministic calculations were performed to support lower releases under certain ATWS scenarios.

In summary, the QCNPS and DNPS evaluation of LERF is judged to be conservative. The reported conditional probability of LERF using the streamlined approach from NUREG/CR-6595 is at the high end of the spectrum of uncertainty for Mark I containments. There are, however, no unique or unusual plant configurations or hardware that make either QCNPS or DNPS more susceptible to LERF than other free-standing steel Mark I containments in the U. S.

<u>Question</u>
*7. The response to the Human Factors RAIs implies there are different values used for HEPs at the different units at the same site, but this is not clear since the information provided seems to be primarily for one unit and only one set of CDF and LERF values is provided for a site. Are there different PRA models and data used for the individual units at each site or is a common model and data employed for both units at each site?*

<u>Response</u>
<u>*QCNPS*</u>
Different operator actions and HEPs are not used in the EPU analysis. The HEPs used in the QCNPS EPU analysis are representative of operating crew interactions on both QCNPS Units 1 and 2. The calculated changes in CDF and LERF are approximately the same for both units; only Unit 1 results are quoted.

<u>*DNPS*</u>
The same holds true for the DNPS Units 2 and 3 EPU evaluations, i.e., only a single unit is assessed.

Question

*8. Did the licensee re-perform the thermal hydraulic code analysis to establish the post-uprate PSA model success criteria and did this re-evaluation consider the numerous setpoint changes (e.g., reactor low water level, main steam line high flow, condenser vacuum), operational changes (e.g., recirculation pump runback feature, all feedwater and condensate pumps operating), and condition changes (e.g., higher decay heat load, higher ATWS peak pressures)? Did the evaluation specifically include the consideration of the operability of pumps (e.g., NPSH) that take suction from the torus, which will have a higher temperature condition as part of the extended power uprate? Please describe the supporting thermal hydraulic evaluations performed to determine the post-uprate PSA success criteria.*

Response

*DNPS and QCNPS*

The MAAP is used to calculate changes in the thermal hydraulic profile for specific issues (e.g., boildown timing). The boildown time decreases as a result of increasing the power from 2511 megawatt-thermal (MWth) to 2957 MWth. The value of 2957 MWth represents the licensed power uprate. A thermal hydraulic analysis has been performed for a value of 2898 MWth that equates to the desired heat output of 912 MWe. This value comes from the heat balance developed for the EPU condition. For the power uprate configuration, the plant will be operated at 2898 MWth. Therefore, the MAAP runs performed to support the power uprate use a value of 2898 MWth instead of the licensed uprate value of 2957 MWth.

For the EPU project, the MAAP evaluations were performed for QCNPS as the base case for both QCNPS and DNPS, since the thermal hydraulic parameters are the same for the two sites.

MAAP is an industry recognized thermal hydraulics code used to evaluate design basis and beyond design basis accidents. MAAP (Version 3.0B) has been used to support the PRA for performing best estimate calculations. The QCNPS plant description is based on the plant specific MAAP parameter file Q1SIR10.PAR dated January 7, 1993. This parameter file contains plant specific parameters representing the primary system and containment.

The EPU changes were examined qualitatively to identify those that would potentially modify success criteria, timing, or equipment operability (e.g., net positive suction head (NPSH)). The result of that qualitative evaluation was the identification that:

- Emergency depressurization success criteria could be affected. Therefore, a special MAAP calculation was performed to support the revised success criteria used for EPU.
- ATWS overpressure success criteria was identified as another possible impact. General Electric (GE) calculations for EPU were used to support modification of the success criteria, not MAAP calculations.
- Timing for some operator crew actions were identified that could change or influence the HEP calculation. Therefore, selected MAAP runs were performed to support the changes in available time. These were all performed at the EPU initial power level.

The NPSH for pump operability has been evaluated in the PRA. It is not limiting in the severe accidents evaluated except for those complete loss of decay heat removal (DHR) sequences with either a failed or vented containment. No change in this is found for the EPU conditions. Small changes in torus temperature do not impact pump operability due to NPSH.

MAAP is used for the power uprate evaluation to calculate the impacts of increased power level and changes to operating procedures (e.g., HCTL curve). Specifically, MAAP was used to calculate the revised accident timings or confirm existing success criteria for the following.

- Determine number of SRV/SVs required to be available for pressure control success criteria (transient and ATWS)
- Determine if 1 ERV/SRV is sufficient for emergency depressurization success criteria (transient and ATWS)
- Calculate time available for operator for emergency depressurization (transient, LOCA and ATWS)
- Verify for medium water break LOCA that initial HPCI/RCIC operation is sufficient for RPV depressurization success criteria.
- Verify that operator action time to initiate SBLC (early) and RPV level/power control (early) is sufficient to prevent reaching the HCTL
- Calculate the operator action time to initiate SBLC "late" and RPV level/power control "late" is sufficient to maintain suppression pool temperature below 260°F (the assumed containment failure criteria for ATWS)

Extensive analysis has also been performed to support the licensing and ATWS basis for EPU. The specific items are addressed as follows.

- Setpoint changes in main steam line flow and condenser vacuum are addressed in response to Question 13.
- The reactor low water level scram setpoint is discussed below.
- The recirculation runback feature is discussed in response to Question 1.
- The operation of all feedwater and condensate pumps is discussed in response to Question 3.
- The higher decay heat level was included in the revised thermal hydraulic calculations at the higher power level of 2898 MWth (full power).
- The higher peak ATWS pressures were explicitly evaluated using GE proprietary codes. These results were then factored into the revised EPU success criteria (see response to Question 5).
- The NPSH was monitored in the updated calculations to assess pump operability in the severe accident sequences as described in the above response.

*Scram Setpoint*
The reduction in scram setpoint on low RPV water level was not initially examined as part of the EPU PRA evaluation since it had not been identified as a change to the plant prior to the EPU PRA evaluation. This change has recently been evaluated consistent with the process used to

evaluate identified plant modifications for PRA impact and has resulted in the following.

*Initiating Events:* Added margin to prevent a scram is obtained. This should decrease the initiating event frequency. Other hardware changes may increase the frequency of low RPV water level challenges. The net effect may be a zero impact (unquantifiable).

*Success Criteria:* The successful prevention of a scram given a transient such as loss of a single condensate pump may be improved. This would prevent initiating event scrams and reduce overall risk.

*Accident Sequences:* No new sequences or changes in sequence probability are identified.

*Human Reliability Analysis:* The time available for the crew to prevent scrams increases by a very small amount. Following a scram, the time for crew response to initiate make-up or RPV depressurization decreases by a very small amount. These effects are considered negligible.

*Data:* No quantifiable impact at this time.

*Dependency:* No dependency changes are identified.

*Level 2:* No quantifiable impact on severe accident progression or timing is identified.

<u>Success Criteria and Accident Timing</u>
The delay in scram on low RPV water level may result in slightly reduced operating crew action times for:

- RPV make up initiation
- Depressurization
- Time for DHR initiation

However, the change in setpoint of eight inches is judged to represent such a small incremental change that the impact on the system success criteria or operator error rate is not considered measurable.

A summary of the MAAP results to support EPU is provided in Table 8-1.

Table 8-1

SUMMARY OF THERMAL-HYDRAULIC RUNS FOR QCNPS AND DNPS 17% POWER UPRATE

| Case ID | T-H Run Description | Purpose | Core Uncovered(3) | Max Core Temp (°F) | HCTL(2) (160°F) | Comments |
|---|---|---|---|---|---|---|
| Case QC1A1 | Main steam isolation valve (MSIV) closure, no high pressure (HP) injection, delayed emergency depressurization (ED) at minimum steam cooling water level limit (MSCWLL)(1) and 1 containment spray (CS) pump<br>• MSIV closure at t=0<br>• Only 3 SVs/ERVs available for initial pressure transient which operated as designed<br>• No HP injection<br>• ED at minimum steam cooling water level limit (using only 1 ERV)<br>• Initiate 1 CS pump at low pressure (LP) interlock | • Verify 3 SVs/ERVs are still OK for pressure control to prevent exceeding RPV pressure operability limits (success criteria)<br>• Verify that 1 ERV is still OK for RPV ED (success criteria) | 39 min | 1740 | 2.5 hrs. | Peak RPV pressure of 1130 psig<br>ED at 37 min<br>CS begins to inject at 59 min when shutoff head is reached |

Table 8-1

SUMMARY OF THERMAL-HYDRAULIC RUNS FOR QCNPS AND DNPS 17% POWER UPRATE

| Case ID | T-H Run Description | Purpose | Core Uncovered[3] | Max Core Temp (°F) | HCTL[2] (160°F) | Comments |
|---|---|---|---|---|---|---|
| Case QC1A2 | MSIV Closure, no HP Injection, delayed ED (at 1/3 core height), and 1 CS pump<br>• MSIV Closure at t=0<br>• Only 3 SVs/ERVs available for initial pressure transient<br>• No HP injection<br>• ED at 1/3 core height (using only 1 ERV)<br>• Initiate 1CS pump at LP interlock | • Verify that 1 ERV is still OK for RPV ED (success criteria)[4]<br>• Verify time allowable for manual initiation of automatic depressurization system (ADS) HEP (1ADOP-DEP-ADSH)[5] | 40 min | Melt<br>(> 4000°F) | 2.28 hr | Peak RPV pressure of 1130 psig<br>ED at 1.16 hr<br>CS begins to inject at 1.4 hr when shutoff head is reached |
| Case QC1A3 | Same as QC1A1 except:<br>• 1 low pressure coolant injection (LPCI) instead of 1 CS<br>• ED at –164" instead of –134" | | 40 min | 2630 | 2.7 hr | LPCI flow > 0 at 1.1 hr<br>ED at 45 min |
| Case QC1A4 | Same as QC1A2 except:<br>• 1 LPCI instead of 1 CS | | 40 min | Melt | 1.9 hr | LPCI flow > 0 at 1.5 hr<br>ED at 1.2 hr |

Table 8-1

SUMMARY OF THERMAL-HYDRAULIC RUNS FOR QCNPS AND DNPS 17% POWER UPRATE

| Case ID | T-H Run Description | Purpose | Core Uncovered(3) | Max Core Temp (°F) | HCTL(2) (160°F) | Comments |
|---|---|---|---|---|---|---|
| Case QC3B1 | Medium water break LOCA, high pressure coolant injection (HPCI) available, 1 LPCI pump, and no ED<br>• MLOCA 0.05 $ft^2$ (3" ID water break) at t=0<br>• HPCI auto cycling until RPV pressure below 100 psig<br>• No ED<br>• Initiate 1 LPCI pump when RPV pressure below shutoff head | • Verify viability of LP injection for MLOCA with HPCI and no ED (MLOCA ET success criteria) | N/A | Normal | 3.4 hr | Peak RPV pressure of 1130 psig<br>HPCI tripped when RPV pressure below 100 psig at 2.4 hrs<br>HPCI level control between initiation level and +2 ft<br>Operation of HPCI decreases RPV pressure<br>LPCI flow > 0 at 18.8 min |
| Case QC3B2 | Medium water break LOCA, no HP injection available, delayed ED (at 1/3 core height) and 1 LPCI pump<br>• MLOCA 0.05 $ft^2$ (3" ID water break) at t=0<br>• No HP injection<br>• ED at 1/3 core height (using only 1 ERV) | • Verify time allowable for manual initiation of ADS HEP (1ADOPMDEP-ADSH) for MLOCA | 7.8 min | 2250 | 3.4 hr | ED at 20 min due to 1/3 core height<br>Peak RPV pressure of 1130 psig<br>LPCI flow > 0 at 28 min |

Table 8-1

SUMMARY OF THERMAL-HYDRAULIC RUNS FOR QCNPS AND DNPS 17% POWER UPRATE

| Case ID | T-H Run Description | Purpose | Core Uncovered(3) | Max Core Temp (°F) | HCTL(2) (160°F) | Comments |
|---|---|---|---|---|---|---|
| | • Initiate 1 LPCI pump when RPV pressure below shutoff head | | | | | |
| Case QC4A1 | Isolation ATWS, water controlled with HPCI, early SBLC injection<br>• MSIV closure ATWS at t=0<br>• Recirculation pump trip (RPT) successful if high dome pressure reached<br>• All SVs/ERVs available(6)<br>• HPCI only injection source<br>• Level controlled between top of active fuel (TAF) and TAF + 5' at 6 mins<br>• SBLC w/2 pumps initiating at 6 min<br>• Decay heat removal with 1 RHR loop (1 RHR pump and RHRSW pump) initiated at 10 min<br>• DW sprays not available<br>• All other presented actions in | • Verify time available for actions to initiate early SBLC and control RPV water level such that ED on HCTL is avoided(7) | 3 min | Normal | 15 min | Peak RPV pressure of 1870 psig<br>ED on HCTL at 15 min<br>Peak torus pressure of 22 psig<br>To model effect of SBLC injection, power assumed to linearly decay from whatever level is predicted by Chexal-Layman correlation at 6 minutes and the time to shutdown of |

Table 8-1

SUMMARY OF THERMAL-HYDRAULIC RUNS FOR QCNPS AND DNPS 17% POWER UPRATE

| Case ID | T-H Run Description | Purpose | Core Uncovered(3) | Max Core Temp (°F) | HCTL(2) (160°F) | Comments |
|---|---|---|---|---|---|---|
| | EOPs to be taken e.g.:<br>- RPV depressurization when HCTL<br>- Vent containment at PCPL | | | | | 6 + 24 = 30 min<br>(24 minutes based on estimated time to inject SBLC inventory)<br>RPT at 12 sec due to high RPV pressure<br>Maximum pool temperature of 200°F |
| Case QC4A2 | Same as Case QC4A1 except control RPV level with simultaneous FW and HPCI injection<br>• FW injection until hotwell depleted<br>• HPCI automatically initiated and cycling on level | • Verify time available for actions to initiate early SBLC and control RPV water level such that ED on HCTL is avoided(7) | 3 min | Normal | 14 min | Peak RPV pressure of 1940 psig<br>ED at 14 min<br>Peak torus pressure of 22 psig<br>RPT at 13 sec due to high RPV press<br>Maximum pool temperature of 200°F |

Table 8-1

SUMMARY OF THERMAL-HYDRAULIC RUNS FOR QCNPS AND DNPS 17% POWER UPRATE

| Case ID | T-H Run Description | Purpose | Core Uncovered(3) | Max Core Temp (°F) | HCTL(2) (160°F) | Comments |
|---|---|---|---|---|---|---|
| | | | | | | FW tripped off when hotwell depleted at 30 sec |
| Case QC4A3 | • All SVs/ERVs available<br>• FW until hotwell depleted<br>• HPCI automatically initiated and cycling on level<br>• ED on HCTL<br>• Level controlled between TAF and + 5ft at 20 min using 1 LPCI pump<br>• SBLC w/2 pumps initiated at 20 mins<br>• Decay heat removal with 2 RHR loops (1 RHR pump and 1 RHRSW pump per loop) initiated at 10 mins<br>• DW sprays not available<br>• All other presented actions in EOPs to be taken e.g., | • Verify time available for delayed SBLC injection and RPV water level control(8) | 3 min | Normal | 11 min | Peak RPV pressure of 1940 psig<br>ED on HCTL at 11 min<br>Peak torus pressure of 39 psig<br>RPT at 13 sec due to high RPV pressure<br>Maximum pool temperature of 280°F<br>FW tripped off when hotwell depleted at 30 sec |

Table 8-1

SUMMARY OF THERMAL-HYDRAULIC RUNS FOR QCNPS AND DNPS 17% POWER UPRATE

| Case ID | T-H Run Description | Purpose | Core Uncovered[3] | Max Core Temp (°F) | HCTL[2] (160°F) | Comments |
|---|---|---|---|---|---|---|
| Case QC4A3 cont'd | - RPV depressurization when HCTL<br>- Vent when pressure reaches vent pressure | | | | | |

Table 8-1

SUMMARY OF THERMAL-HYDRAULIC RUNS FOR DRESDEN AND QUAD CITIES 17% POWER UPRATE

| Case ID | T-H Run Description | Purpose | Core Uncovered[3] | Max Core Temp (°F) | HCTL[2] (160°F) | Comments |
|---|---|---|---|---|---|---|
| Case QC4A4 | • Same as QC4A1 except pre-uprate power of 2511 MWt | | 3.4 min | Normal | 13.8 min | Peak RPV pressure of 1630 psig<br>ED at 13.8 min<br>Peak pool temperature of 199°F |
| Case QC4A5 | • Same as QC4A2 except pre-uprate power of 2511 MWt | | 17 min | Normal | 9.5 min | Peak RPV pressure of 1230 psig<br>ED at 9.5 min<br>Peak pool temperature of 225°F |
| Case QC4A6 | • Same as QC4A3 except pre-uprate power of 2511 MWt | | 25.4 min | Normal | 9.1 min | Peak RPV pressure of 1230 psig<br>ED at 9.1 min<br>Peak pool temperature of 240°F |

Table 8-1

SUMMARY OF THERMAL-HYDRAULIC RUNS FOR DRESDEN AND QUAD CITIES 17% POWER UPRATE

| Case ID | T-H Run Description | Purpose | Core Uncovered[3] | Max Core Temp (°F) | HCTL[2] (160°F) | Comments |
|---|---|---|---|---|---|---|
| Case QC4A7 | • Same as QC4A1 except HCTL assumed at 190°F | • Verify time available for actions to initiate early SBLC and control RPV water level such that ED on HCTL is avoided[7] | 2.6 min | Normal | N/A | Peak RPV pressure of 1870 psig<br>No ED<br>Peak pool temperature of 185°F |
| Case QC4A8 | • Same as QC4A7 except pre-uprate power of 2511 MWt | • Verify time available for actions to initiate early SBLC and control RPV water level such that ED on HCTL is avoided[7] | 3.2 min | Normal | N/A | Peak RPV pressure of 1630 psig<br>No ED<br>Peak pool temperature of 187°F |

Notes to Table 8-1

(1) MSCWLL in the QCNPS general abnormal procedures (DNPS emergency operating procedures) is approximately -164"; however, the fuel zone water level instruments read high for these hot pressurized cases by 30" to 60". Therefore, ED can be anticipated to be called for at -134" to -104". Used -134" in the MAAP calculation as the most conservative representation.

(2) HCTL of 160°F based on a pool level of 14 ft at normal RPV operating pressure.

(3) Core uncovered when collapsed downcomer level drops below TAF (-142").

(4) Given that 1 ERV for ED results in core melt for Case QC1A2, the PRA conservatively assumes that 2 ERVs are required for the ED success criteria for the EPU configuration.

(5) For Case QC1A2, the time to core uncovery is 40 minutes. If 2 ERVs are credited for ED, the RPV is assumed to depressurize in sufficient time to allow low pressure injection and prevent core melt. The human reliability analysis (HRA) conservatively used a time estimate of 31 minutes for RPV depressurization. Case QC1A2 confirms that 31 minutes is still conservative.

(6) It would be more appropriate if Case QC4A1 used the number of valves available that is consistent with the ATWS success criteria. However, the purpose of this MAAP calculation is not to confirm the RPV overpressure success criteria. MAAP is not an accurate tool to use for calculating peak RPV pressure. The ATWS RPV overpressure success criteria is based on ODYN calculations and engineering judgement. Assuming that all SVs/ERVs are available should not significantly impact the results of the MAAP calculation (e.g., containment temperature).

(7) Case QC4A1 shows that the HCTL is reached at 15 minutes when the HCTL is conservatively set at 160°F. Subsequently, Case QC1A7 was developed to increase the HCTL to 190°F. The 190°F represents the HCTL if the operators manually depressurized to follow the HCTL curve. For Case QC1A7, the HCTL is not reached and confirms that the early SBLC initiation timing is adequate for the EPU configuration.

(8) The results of Case QC4A3 show that SBLC injection at 20 minutes results in a peak suppression pool temperature of 280°F. This is greater than the ATWS containment failure criteria of 260°F in the pool. The PRA conservatively assumes that SBLC must be initiated within 16 minutes to maintain pool temperature below 260°F and prevent containment failure.

Question
*Based on the recent QCNPS inspection report 2001-05, the staff has questions on how the licensee assures that the plants PSA models and associated data adequately reflect the plants current operating conditions, configurations, and practices.*

*9.1. Please describe how the plants assure that the system/equipment performance criteria as part of the maintenance rule implementation and the assumptions, data, and equipment unavailabilities (e.g., maintenance/testing, demand failure rates, etc.) used in the plants PSA are consistent with one another. Also include how the methodology implemented by the plants for establishing or revising performance criteria is consistent with Regulatory Guide 1.160, which indicates that the number of maintenance preventable functional failures allowed per evaluation period should be consistent with the assumptions of the PSA.*

*9.2. Does the PSA used in support of the extended power uprate also reflect, and is it consistent with, the current maintenance rule performance criteria? Please explain any differences between the performance criteria and the pre- and post-uprate PSA models and associated data.*

*9.3. Station procedures recommend updating the PSA every two years. Please state when the PSA models and the data were last updated, describe the major changes that have occurred since the last update, and discuss the potential impact of these changes on the PSA models and data, including consideration of the extended power uprate plant conditions.*

*9.4. The recent inspection findings indicate that there has been an increase in on-line maintenance activities, which is a programmatic change. This programmatic change, which may make past operating experience invalid in establishing maintenance unavailabilities, should be reflected in the PSA. How have the plants reflected this programmatic change in the PSA models for determining the unavailabilities of systems and equipment; specifically in determining the equipment maintenance unavailabilities? In addition, how has this change been reflected in the on-line risk monitoring tool used by the licensee to meet the maintenance rule a(4) criteria and how does this programmatic change affect other operating modes such as shutdown operations?*

Response
9.1. Exelon Generation Company (EGC) assures the NRC Maintenance Rule reliability performance criteria (RPC) is consistent with the assumptions found in the PRA through the use of EPRI methodology. This methodology is described in the following EPRI documents:

- Monitoring Reliability for the Maintenance Rule, EPRI Technical Bulletin 96-11-01, November 1996
- Monitoring Reliability for the Maintenance Rule - Failures to Run, EPRI Technical Bulletin 97-3-01, March 1997

The methods use a statistical basis to determine when a failure rate experienced in the plant is significantly outside what would be expected based on the failure rate used in the PSA.

The recommended RPC is provided to the Maintenance Rule Program manager. In some cases, the system engineer, through the Maintenance Rule Program manager may request a higher RPC, in which case, a PRA sensitivity study is performed. This sensitivity study is performed in conjunction with setting the availability performance criteria (APC) as described below.

For APC, a sensitivity study is used to evaluate the risk impact of all of the performance criteria. Proposed APC values are obtained from system engineering. These proposed APC's along with RPC's (if any) that are set above the recommended value obtained using the EPRI methodology are converted to probabilities and input to the PRA. The PRA model is exercised to determine the resulting risk of core damage if all equipment were actually at their RPC and APC limits.

The APC and RPC are considered consistent with the PRA model if the quantitative screening criteria for permanent risk increases specified in the EPRI PSA Applications Guide are met.

The NRC Maintenance Rule inspection reports for the QCNPS Follow-up Inspection, LaSalle Baseline Inspection, and Braidwood Baseline Inspection indicate regulatory review and acceptance of this methodology. This methodology ensures that these RPC and APC are consistent with failure probabilities assumed in the PRA.

9.2 The PRA used in support of the EPU is consistent with the PRA used to support the NRC Maintenance Rule performance criteria as explained above. The NRC Maintenance Rule does not require that PSA models reflect the performance criteria. The NRC Maintenance Rule guidance is that the performance criteria are to be consistent with the PSA. The answer to Question 9.1, above, describes the analysis to show that the performance criteria are consistent with the base PSA. A similar analysis has not been performed for the PSA used for EPU, but given the small impacts of EPU on PRA parameters, EPU will have negligible impact on Maintenance Rule performance criteria. It should be noted that maintenance rule criteria will be reviewed following the next update.

9.3 Procedure ER-AA-600, Revision 2 (as well as previous revisions of ER-AA-600) recommends a 2 year update period, with completion permitted within 3 years. EPU risk assessments and the NRC Maintenance Rule performance criteria are based on the latest model revisions, which were completed in 1999. The 1999 models include updated equipment performance data for selected systems. All values used in the updates were reviewed for consistency with generic data. EGC risk management processes provide for ongoing review of plant design changes, procedure changes, and formal calculations, to ensure that PRA personnel are aware of actual and pending changes to the plant. Plant changes with potential impact on the PRA are recorded in a database called the Update Requirements Evaluation (URE) database, along with an assessment of whether immediate model change is required. For DNPS, there are approximately 175 entries in the URE database. For QCNPS, there are approximately 150. In no case was it concluded that an immediate model change is required. No URE issues to date, including plant changes, have been identified as having a major impact on the PRA requiring an immediate change.

9.4 Maintenance practices that have been introduced in recent years are reflected in the PSA models to the extent that data updates have captured these changes. Selected system unavailability basic events were updated in the 1999 update. If key systems are being made unavailable over significantly longer period of times than estimated, overall risk would trend significantly higher than the baseline risk. Such trends would be identified through the following process.

The plant engineers trend overall risk as part of the Maintenance Rule Program. In 2000, station engineers began quarterly evaluations of the 12 month rolling average CDF. Risk increases or decreases with respect to the base CDF are evaluated against the quantitative screening criteria for permanent risk increases as specified in the EPRI PSA Applications Guide (the guide recommends also applying these criteria to risk decreases). To date, the risk increases or decreases for either the periodic assessment period or the 12 month rolling average period have been in the "non-risk-significant" region specified by the EPRI PSA Applications Guide. These results indicate that the PRA model adequately reflects the current maintenance practices.

A 2-year rolling average data is currently available for Maintenance Rule equipment. EGC plans to utilize, for risk-significant equipment, the latest unavailability data from the Maintenance Rule database when a 3-year update is performed in 2002.

The online maintenance tool uses the "zero maintenance" PRA model, and, therefore, is unaffected by changes in the amount of hours unavailable from online maintenance. That is, on-line risk calculations reflect only the actual equipment out-of-service at the time of maintenance. Shutdown risk is assessed on an ongoing basis during outages using the deterministic Outage Risk Assessment and Management (ORAM) model. These models are based on defense-in-depth for key shutdown safety functions and are not affected by equipment unavailability values in the PRA model. Regardless, increased on-line maintenance reduces the need for equipment out-of-service during maintenance and refueling outages, thus reducing risk of those outages.

<u>Question</u>
*12. What is the impact of the extended power uprate on other modes of operations; specifically shutdown operations? Please describe the impacts on these operations and provide an estimate of the impact on shutdown risk (i.e., CDF and LERF).*

<u>Response</u>
<u>*QCNPS and DNPS*</u>
The CDF and LERF changes due to EPU have been evaluated qualitatively using the insights derived from the shutdown risk management tool used for QCNPS and DNPS and the insights gained in the application of a quantitative shutdown risk model to both sites.

The conclusion from these insights are that the changes in CDF and LERF due to EPU are negligible compared with the shutdown risk levels that are present in the pre-EPU case. Some of the insights which support this evaluation are discussed below.

**Attachment**
**Additional Risk Information Supporting the License Amendment Request to Permit Uprated Power Operation**
**Dresden Nuclear Power Station, Units 2 and 3**
**Quad Cities Nuclear Power Station, Units 1 and 2**

The functional impacts of the EPU on shutdown risk are similar to the impacts on the at-power Level 1 PRA with the exception that reactivity additions have a different nature in the shutdown condition compared with the at-power condition.

The risk contributors include the following:

- loss of shutdown cooling
- RPV water makeup/injection failures
- Reactivity control failures

The first two functional challenges are similar in nature to the at-power risk assessment. The reactivity control functional impact at shutdown is related to mis-loaded fuel or mis-located fuel, as opposed to failure to scram issues for the at-power evaluation. The shutdown reactivity control issues are not a function of EPU and therefore their contribution to changes in CDF or LERF is assessed as zero.

The other areas of review for the shutdown risk evaluation included the following:

- Initiating Events
- Success Criteria
- Human Reliability Analysis

The following qualitative discussion applies to the shutdown conditions of Hot Shutdown (Mode 3), Cold Shutdown (Mode 4), and Refueling (Mode 5). The EPU risk impact during the transitional periods such as at-power (Mode 1) to Hot Shutdown and Startup (Mode 2) to at-power are subsumed by the at-power Level 1 PRA.

Important initiating events for shutdown include RPV draindown and loss of shutdown cooling, however, no new initiating events or increased potential for initiating events during shutdown (e.g., loss of DHR train) have been identified based on the EPU configuration. The at-power change which leads to a possible increase in the turbine trip initiating event frequency due to the need to operate the installed spare feedwater and condensate/condensate booster pumps (see response to Question 3) does not apply during shutdown conditions because the turbine has been already tripped.

The impact of the EPU on the success criteria during shutdown is similar to the Level 1 PRA. The increased power level decreases the time to boildown. However, because the reactor is already shutdown, the boildown times are relatively long compared to the at-power PRA. The boildown time is approximately 1 hour at 2 hours after shutdown (e.g., time of Hot Shutdown) and approximately 2-4 hours at 12-24 hours after shutdown (e.g., time of Cold Shutdown). The changes in the boildown time when comparing the pre-EPU cases with the EPU cases are small fractions of the total boildown time. These small changes in timing have a negligible effect on the calculated HEPs, which are found to be dominated by the Cause Based methodology inputs, and not the Time Reliability Correlation contribution.

The increased decay heat loads associated with the EPU impacts the time when low capacity DHR systems such as fuel pool cooling (FPC) and reactor water cleanup (RWCU) can be considered successful alternate DHR systems. The EPU condition delays the time after shutdown when FPC or RWCU may be used as an alternative to shutdown cooling (SDC). However, shutdown risk is dominated during the early time frame soon after shutdown when the decay heat level is high and FPC and RWCU would not be viable DHR systems for either pre-EPU or EPU conditions. QCNPS and DNPS assess the time in each outage when various DHR systems are viable. The RWCU and FPC systems would not be included in the defense-in-depth evaluation until the EPU decay heat level was sufficiently low for these systems to be successful. Therefore, the impact of the EPU on the FPC and RWCU success criteria has a negligible risk impact.

It is recognized in the shutdown risk quantifications that the SDC equipment is operating continuously for a significant portion of the outage. Therefore, for the post-EPU case, SDC would be required to run for a longer time than in the pre-EPU case before other systems with lower heat removal capacity are adequate for decay heat removal. These generally are very low risk periods during the outage. Therefore, for those low risk situations when FPC or RWCU could provide a backup in the pre-EPU case, they would become marginal in the post-EPU case for some short period of time. The time differential between the pre- and post-EPU conditions when FPC and RWCU may not be adequate alone as decay heat removal methods, is approximately 12 days in the time frame from 26 to 38 days following a shutdown based on conservative assumptions (e.g., no decay heat loss to structures or the environment). Because the shutdown risk profile is dominated by the risk at early times in the outage (i.e., 0 to 10 days), increasing the time when shutdown cooling is the only adequate decay heat removal system (during which the risk is low due to low decay heat) has a minor impact on the overall shutdown risk. With QCNPS and DNPS outages lasting less than 20 days, this change in success criteria has no impact on the integrated shutdown risk.

Other success criteria are marginally impacted by the EPU. The EPU has a minor impact on shutdown RPV inventory makeup requirements because of the low makeup requirements associated with the low decay heat level. The heat load to the suppression pool is also lower because of the low decay heat level such that the margins for suppression pool cooling capacity are adequate for the EPU condition.

The EPU impact on the success criteria for blowdown loads, RPV overpressure margin, and SRV actuation is estimated to be minor because of the low RPV pressure and low decay heat level during shutdown.

Similar to the at-power Level 1 PRA, the decreased boildown time decreases the time available for operator actions. The significant, time critical operator actions impacted in the at-power Level 1 PRA are related to RPV depressurization, SBLC injection, and SBLC level control. These operator actions do not directly apply to shutdown conditions because the RPV is at low pressure and the reactor is subcritical.

The risk significant operator actions during shutdown conditions include recovering a failed DHR system or initiating alternate DHR systems. However, the longer boildown times during shutdown results in the EPU having a minor impact on the shutdown HEPs associated with recovering or initiating DHR systems because the available time is relatively long and the HEPs are dominated by the Cause Based HRA performance shaping factors.

Based on a review of the potential impacts on initiating events, success criteria, and HRA, the EPU configuration will have a minor impact on shutdown risk.

Any quantitative impact on the EPU on shutdown risk is performed using the ORAM software. ORAM evaluates the planned plant configuration including systems available, RPV water level, RPV and containment status, and decay heat level (for calculating time to boil or time to uncover fuel). ORAM evaluates the planned outage schedule to ensure that adequate defense in depth is maintained throughout the outage. With respect to the EPU, based on the increased decay heat level, ORAM will be able to identify how much longer SDC needs to operate (e.g., 12 days longer) before alternate DHR systems (e.g., FPC and RWCU) could be placed in service.

<u>Question</u>
*13. The allowable values for main steam isolation flow are raised variously as 120%/125% (DNPS Unit 2); 120%/140% (DNPS Unit 3); 138%/254.3 psid (QCNPS). The stated bases in NEDC-32424P-A is to keep the same basis (expressed as a percentage of steam flow) to assure that reactor trip avoidance is maintained. Thus, the setpoints will have the effect of significantly increasing the maximum size of steam line breaks that will go unisolated due to the increased steam flow under extended power uprate conditions. What analyses have been performed for the additional impact of this range of steam line breaks (e.g., on CDF or on HELB analyses)? How does this condition impact the accident progression for an unisolated main steam line break (e.g., how much quicker to core damage)?*

<u>Response</u>
<u>*QCNPS and DNPS*</u>
Any steam line break large enough to depressurize the main steam line will result in an isolation signal on low steam line pressure. Breaks passing from 120%-140% flow are therefore still automatically isolated after EPU, even though they do not result in reaching the high flow setpoint.

There is a narrow window of main steam line breaks that could occur and not cause a high steam flow isolation signal. The setpoint changes do not significantly increase the maximum size of steamline breaks that could not receive a high steam flow logic isolation signal. The maximum change in break size that would not trigger the high steam flow logic for MSIV isolation is 3.6 inches in diameter of a break. The DNPS Unit 2 change in size is 1.2 inches in diameter. These are not considered as "significantly increasing" the maximum size of the steam line breaks that will go unisolated due to increased steam flow under EPU conditions. For example, a catastrophic break would clearly cause an isolation signal due to high steam flow and be unaffected by the small change in setpoint. In addition, the MSIVs are also isolated by high temperature sensors that would initiate an isolation given a steam break in the steam lines inside the steam tunnel for a large spectrum of steam line breaks. Further, low steam line pressure and low RPV water level logic also introduce additional MSIV isolation signals that provide diverse isolation capability.

*High Energy Line Break (HELB)*
The HELB evaluation is the subject of PUSAR Section 10.1.1.1. The results show no impact on the PRA.

*PRA*
The PRA characterizes the main steam line break as follows:

- The pipe failure frequency is characterized by a rupture frequency with a flow rate greater than 100 gpm equivalent.
- The effect of the break is characterized as the maximum break size.
- The failure to isolate is assessed to include the CCF of the isolation valves (where applicable) or a single valve when the break is inside the MSIV. The logic failure probability evaluation includes only the high temperature logic to initiate the isolation, not the high steam flow logic.

The failure to successfully isolate the main steam lines given a break is composed of the following failure modes:

- Logic failure that prevents the automatic signal to close the MSIVs
- Operator failure to back up the logic failure (assumed to be 1.0 failure probability in this analysis)
- Valves fail to close when signaled due to either valve fault or induced failure

The failure mode of interest in the RAI question requires failure of the following logic to prevent an isolation signal from reaching the MSIVs:

- Failure of the high temperature steam line break logic
- Failure of the high steam flow logic
- Failure of the low RPV water level logic (Level 2)
- Failure of the low RPV pressure logic

The logic will be effective over the spectrum of breaks that can also cause significant failures of equipment outside containment. Considering all the possible logic to cause MSIV closure on a steam line break, explicit modeling of the steam line break logic was not required because the core damage sequences were dominated by the valve failure to close probability.

Therefore, the change in the steam flow setpoint that would slightly increase the steam line break size that would not be isolated by high steam flow logic has no impact on the calculated CDF associated with this break outside containment (BOC) quantification.

*QCNPS*
Based on the QCNPS 1999 PRA results, the main steam BOC contribution to CDF is as follows:

CDF ($BOC_{Mainsteam}$) = 2.0E-11/yr

*DNPS*
The same approach was used for DNPS except the calculated CDF is different for DNPS due to the use of plant-specific data. Based on the DNPS 1999 PRA results, the main steam BOC contribution to CDF is as follows:

CDF ($BOC_{Mainsteam}$) = 1.5E-10/yr

*Summary*
No change in risk was calculated for QCNPS or DNPS because the change in isolation actuation failure probability was assessed as negligible. The change in risk could be estimated by assuming that one half the break frequency would not initiate a high flow isolation trip. This leaves the low steam line pressure trip, the low RPV water level trip and the high steam tunnel temperature logic to provide break detection and MSIV isolation. The failure probability of the actuation logic can be estimated for the two cases as follows:

Pre-EPU: P(logic)= 2E-3 x 2E-3 x 2E-3 x 2E-3 = 1.6E-11

Post-EPU: P(logic)= 2E-3 x 2E-3 x 2E-3 x 0.5 = 4E-9

The change in the logic failure probability is delta P(logic) = 3.98E-9

This causes a change in the initiating event frequency and CDF of

(3.98E-9/2E-3) = 2E-6 = 0.0002%

where, 2E-3 is the value for random failure of an MSIV to isolate credited in the base PRA model. The value 3.98E-9 represents the additional isolation failure probability (post EPU) over the base value of 2E-3. A ratio of the additional isolation failure probability to the base isolation failure provides an estimate of the small potential increase in CDF.

*Time to Core Damage*
The time to core damage has been evaluated for the large break LOCA event outside containment in the main steam line with no RPV injection and no MSIV isolation. The following summarizes the results of the comparison:

Large Break LOCA in Main Steam Line

| Condition | Time to Core Damage |
|---|---|
| Pre-EPU | 21 min |

| | |
|---|---|
| Post-EPU | 18 min |

No operator actions are credited for accident mitigation during this time period.

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