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U.S. Nuclear Regulatory Commission
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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: Supplemental Information for Request for License Amendment for Power Uprate Operation

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

In the referenced letter, Commonwealth Edison (ComEd) Company requested changes to Facility Operating Licenses DPR-19, DPR-25, DPR-29, and DPR-30 and Appendix A to the Operating Licenses, the Technical Specifications (TS), for Dresden Nuclear Power Station (DNPS), Units 2 and 3, and Quad Cities Nuclear Power Station (QCNPS), Units 1 and 2. Subsequently, in a verbal conversation between Mr. L.W. Rossbach and Mr. A.R. Haeger on January 30, 2001, the NRC requested additional information. The requested information is provided in the attachment.

Should you have any questions related to this information, please contact Mr. Allan R. Haeger at (630) 663-6645.

Respectfully,

R.M. Krich
Director - Licensing
Mid-West Regional Operating Group

Attachment: Supplemental Information for Request for License Amendment for Power Uprate Operation

cc: Regional Administrator – NRC Region III
NRC Senior Resident Inspector – Dresden Nuclear Power Station
NRC Senior Resident Inspector – Quad Cities Nuclear Power Station
Office of Nuclear Facility Safety – Illinois Department of Nuclear Safety

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Attachment
Supplemental Information for Request for License Amendment for Power Uprate Operation

6.1 Changes in Emergency and Abnormal Operating Procedures

Question:
Describe how the proposed power uprate will change plant emergency and abnormal procedures.

Response:
The Emergency Operating Procedures (EOPs) remain symptom-based and thus the operator actions remain unchanged. The effect of Extended Power Uprate (EPU) on the EOPs is limited to revisions to previously defined numerical values. Some examples of these revisions are the maximum core thermal power and the heat capacity temperature limit of the Suppression Pool. The definition of these parameters has not been altered. Therefore, the scope and nature of the operator actions within the EOPs remain unchanged. The calculations to revise these values and the resulting procedure changes will be completed to support the operator training sessions conducted prior to EPU implementation.

Two Abnormal Operating Procedures (AOPs) will change as a result of modifications to plant equipment. One such change will be the required actions following a feedwater pump trip due to a modification which will install an automatic recirculation system runback. Similarly, the condensate pump circuitry is being revised to trip the fourth running pump during a Loss of Coolant Accident (LOCA) to prevent an electrical overload. No other significant AOP revisions are foreseen. However, all AOPs will be reviewed for EPU conditions and necessary revisions will be completed prior to EPU implementation.

These emergency and abnormal procedure changes will be addressed during operator training sessions prior to operation at EPU conditions.

All normal operating procedures are presently under review for revision. Procedures requiring revision will be presented to the operators prior to power ascension.

6.2 Changes to Risk-Important Operator Actions Sensitive to Power Uprate

Question:
Describe any new risk-important operator actions as a result of the proposed power uprate. Describe changes to any current risk-important operator actions that will occur as a result of the uprate. Explain any changes in plant risk that result from changes in risk-important operator actions.

(e.g., Identify operator actions that will require additional response time or will have reduced time available. Identify any operator actions that are being automated as a result of the power uprate. Provide justification for the acceptability of these changes.)

Response for Dresden Nuclear Power Station (DNPS)
Evaluations performed for the EPU project determined impacts on the existing plant Level 1 risk assessment in three areas: (1) reduced times available for effective operator actions; (2) changes in success criteria; and (3) changes in initial plant configuration. In addition, the potential impact of EPU on fire, seismic, and other event risks was reviewed. Each area is discussed below.

1. Effects of Changes in Operator Response Time

The reductions in certain operator action allowable times resulted in changes to human error probabilities (HEPs) due to the power uprate. The following actions and allowable times were identified in the risk assessment as the most significant in terms of core damage frequency (CDF) increase (i.e., those changes that individually cause a 1% or more increase in the base CDF).

The time to initiate late Standby Liquid Control (SBLC) injection following Anticipated Transient Without Scram (ATWS) is reduced from 20 minutes to 16 minutes. This reduction affects the HEP for this action. The base probability for failure to initiate was 3.3E-02. Due to the decrease in available time, the post-EPU HEP becomes 5E-02, resulting in a CDF increase of 1%.

The time to control reactor vessel level following ATWS decreases from 20 to 16 minutes. This case is similar to the previous one. The post-EPU HEP changes from 3.2E-02 to 5E-02, resulting in a CDF increase of 1%.

Despite the change in response time for these ATWS actions, the probability of operator success in both cases remains high. The operators are trained specifically on these ATWS mitigation actions in the classroom and at the DNPS simulator.

The risk assessment reported in the licensing amendment request included a 1% CDF increase due to a conservatively estimated decrease in the time available to successfully initiate Isolation Condenser (IC) makeup. However, subsequent engineering analysis has found that 20 minutes would be available for this action post-EPU. This response time is longer than the Base PRA model assumption of 18 minutes. Consequently, the HEP values used in the Base PRA model for operators failing to initiate IC makeup remain conservative, and no change in those HEP values is required for the DNPS EPU risk assessment. Therefore, the previously reported CDF increase of 2.4E-07/yr (9% of the base CDF) has been revised to an increase of 2.1E-07/yr (8% of the base CDF). The risk impact of EPU on internal events is an increase in Base CDF from 2.61E-06/yr to 2.82E-06/yr.

The table on page 3 summarizes the effects of EPU operator response time changes on CDF. The important sequences are apparent from the event description and associated CDF increase. No new risk-important operator actions were identified as a result of EPU.

Attachment

Supplemental Information for Request for License Amendment for Power Uprate Operation

DNPS PRA MODEL CHANGES TO OPERATOR ACTION RESPONSE TIMES

Description	Basic Event ID	Base HEP	EPU HEP	Contribution to CDF Increase	Comment
Operator Fails to Reopen Turbine Bypass Valves to Restore Main Condenser as a Heat Sink (non-ATWS)	2MSOP-5699--TH--	0.1	0.1	N/A	Time available is estimated to be 40 minutes in Base PRA. The Base PRA HEP is documented to be 3.8E-4. However, an HEP of 0.1 was conservatively used in the quantification. No change is required for the EPU case.
Operator Fails to Initiate SBLC Makeup to reactor pressure vessel (RPV) During IC Operation	OP-ACT-SBLC-RV	0.2	0.2	N/A	Time available is estimated to be 30 minutes in Base PRA. Base PRA HEP was calculated in a conservative manner. The Base HEP is judged to apply to the EPU case also.
Operator Fails to Initiate RPV Depressurization (Medium LOCA)	2ADOP-DEPMADSH--	3.50E-03	3.50E-03	N/A	Time available decreases from 25 to 20 minutes. Base PRA conservatively uses 15 minutes. The same HEP will be used for the EPU.
Operator Fails to Inhibit Automatic Depressurization System (ADS) with Feedwater Available(ATWS)	2ADOP-INHIBHPH--	1.00E-02	1.30E-02	<1%	Time available decreases from 12 to 10 minutes (estimate)
Operator Fails to Initiate RPV Depressurization (ATWS)	2ADOP-ATWSADSH--	1.80E-02	2.30E-02	<1%	Time available decreases from 10 to 8.5 minutes (estimate)
Operator Fails to Initiate SBLC Injection During ATWS (Late)	2SLOP-IN-LATEH--	3.30E-02	5.00E-02	1.0%	Time available decreases from 20 to 16 minutes
Operator Fails to Control RPV/Power Level During ATWS (Late)	2SLOP-LATELVLH--	3.20E-02	5.00E-02	1.0%	Time available decreases from 20 to 16 minutes

2. Effects of Changes in Success Criteria

Two changes in the Level 1 Probabilistic Risk Assessment (PRA) success criteria were identified.

- The RPV depressurization success criteria changed from requiring one Electromatic Relief Valve (ERV) or Safety Relief Valve (SRV) to two ERVs/SRVs
- The number of Safety Valves (SVs)/SRVs/ERVs required to open for overpressure protection under failure to scram conditions increased from 11 of 13 to 12 of 13.

For sequences where RPV depressurization is currently required in the event tree sequence (e.g., transient events without a stuck open relief valve (SORV)), the change in RPV depressurization success criteria has a negligible quantitative impact. Failure to depressurize the RPV is dominated by operator action failure and common cause failure of the ERVs/SRVs to open.

For inadvertent open relief valve (IORV) or SORV sequences, RPV depressurization is not required for the pre-EPU configuration because a single open ERV/SRV satisfies the current success criteria for depressurization. For the post-EPU configuration where two ERVs/SRVs are required to open for success, RPV depressurization is required for IORV/SORV sequences. The increase in CDF due to the change in the RPV depressurization success criteria was calculated to be 5E-8/yr.

The ATWS overpressure control requirement has been increased from 11 of 13 ERVs/SRVs/SVs to 12 of 13 as the result of power uprate. This change in success criteria was judged to have a negligible impact on the quantitative results because overpressurization is dominated by common cause failure of the ERVs/SRVs/SVs to open.

3. Effects of Changes in Plant Configuration

The additional principal changes that affect the Level 1 CDF include the following.

- Changes in the Turbine Trip initiating event frequency
- Changes in the SORV probability

The change in Turbine Trip event initiating frequency is a result of running the installed spare feedwater and condensate/condensate booster pumps at EPU conditions. This change is due to the conservative assumption that loss of any single pump will lead to a reactor low level scram signal. This conservative assumption alone accounts for a 2.5% increase in the base CDF, primarily due to ATWS sequences. Independent of the EPU risk analysis, a plant modification will be implemented to initiate a reactor recirculation runback on loss of a feedwater pump in combination with a reactor low level alarm. This modification is expected to prevent reaching the reactor scram setpoint with a high degree of success, such that the calculated increase in CDF bounds the actual post EPU plant conditions.

Changes in SORV probability are due to the predicted increase in valve cycles following postulated transients. Increased cycling is postulated due to the increase in decay heat resulting from EPU. This change had a very minor effect on the base CDF (less than 1%).

Changes to the Level 1 CDF due to EPU plant configuration are summarized in the table on page 6.

Attachment
Supplemental Information for Request for License Amendment for Power Uprate Operation

DNPS PRA MODEL CHANGES TO REFLECT EPU PLANT CONFIGURATION

Description	Basic Event ID	Base Prob.	EPU Prob.	Contribution to CDF Increase	Comment
Turbine Trip Initiating Event Frequency	%TT	1.14E+00	1.35E+00	2.5%	Increased number of Turbine Trips due to revised number of normally operating Feedwater and Condensate pumps.
SORV for Turbine Trip (non-ATWS)	2PLSVSORV-TT-K–	1.50E-02	1.80E-02	<0.1%	Increased number of SRV/SV cycles increases SORV probability. This event is ANDed with a basic event for SRV failing to reclose at low pressure (non-ATWS only).
SORV for MSIV Closure (non-ATWS)	2PLSVSORV-NTTK--	4.50E-02	5.40E-02	<1%	Increased number of SRV/SV cycles increases SORV probability. This event is ANDed with a basic event for SRV failing to reclose at low pressure (non-ATWS only).
SORV for Turbine Trip (ATWS)	2ADSV-SRVFTCTF--	1.80E-02	2.10E-02	<0.1%	Increased number of SRV/SV cycles increases SORV probability.
SORV for MSIV Closure (ATWS)	2ADSV-SRVFTC-F--	3.90E-02	4.20E-02	<0.1%	Increased number of SRV/SV cycles increases SORV probability.

4. Impact of EPU on Fire, Seismic, and Other External Events

Fire Risk

An evaluation of the top ten fire scenarios in terms of CDF contribution for each unit was performed. In each case, it was concluded that the power uprate would have only a minor effect on the current Individual Plant Examination of External Events (IPEEE) fire risk. The dominant DNPS scenario in terms of fire risk is a severe Control Room fire with evacuation. Analyses performed for EPU indicate that the time available for the operator to initiate the IC for this fire is reduced from 35 to 32 minutes. The fire risk update assumed that the conditional core damage probability (CCDP) for the Control Room evacuation scenario was 0.5, which is a very conservative assumption. Although the specific HEP may increase slightly due to the reduction in operator response time, such an increase would have no effect on fire risk because the conservative CCDP used in the IPEEE bounds any realistic HEP.

The fire risk for non-Control Room evacuation scenarios is dominated by loss of decay heat removal sequences. The operator action important for mitigating these scenarios are long term and the power uprate would have minor impact on the time available for those actions.

Based upon this assessment, a negligible change in the baseline CDF of 1.69E-5 for Unit 2 or 2.97E-05 for Unit 3 due to fire is judged to result from EPU implementation.

Seismic Risk

The DNPS seismic risk analysis was performed as part of the IPEEE. The seismic portion of the IPEEE program was completed in conjunction with the Seismic Qualification User's Group (SQUG) program. DNPS performed a seismic margins assessment (SMA) following the guidance of NUREG-1407, "Procedural and Submittal Guidance for the Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities," and EPRI NP-6041, "A Methodology for Assessment of Nuclear Power Plant Seismic Margin." The SMA is a deterministic evaluation process that does not calculate risk on a probabilistic basis. No core damage frequency sequences were quantified as part of the seismic risk evaluation.

Based on a review of the DNPS IPEEE, the conclusions of the SMA are judged to be unaffected by the 17% power uprate. The power uprate has no impact on the seismic qualifications of the systems, structures and components (SSCs). Specifically, the power uprate results in additional thermal energy stored in the RPV, but the additional blowdown loads on the RPV and containment given a coincident seismic event are judged not to alter the results of the SMA.

Other external events are not impacted by changes due to EPU.

Level 2 PRA

The Level 2 PRA calculates the containment response under postulated severe accident conditions and provides an assessment of the containment adequacy. Changes of 17% in power represent relatively small changes to the overall challenge to containment under severe accident conditions. The timing to containment failure may be reduced by on the order of 5 to 30 minutes as measured over accident times of 6 to 30 hours. This is judged to be a minor change in the Level 2 PRA assessment. In addition, the success criteria for

RPV depressurization was modified similar to the modification in the Level 1 assessment. This change in success criteria has a minor impact on the conservative assessment of Level 2 Large Early Release Frequency (LERF) using the DNPS Level 2 PRA model.

Based on the changes to the Level 1 model as input to the Level 2, the LERF increased from the base value of 1.44E-6/yr to 1.58E-6/yr (i.e., an increase of 10%). The dominant scenarios for this LERF increase are the same as described above for CDF.

PRA Quality

The NRC reviewed the DNPS IPE relative to the requirements in NRC Generic Letter 88-20, "Individual Plant Examination For Severe Accident Vulnerabilities." The NRC Staff Evaluation Report issued in October 1997 (Reference 1) stated that, "...the staff finds that the licensee's IPE is complete with regard to the information requested by GL 88-20 (and associated guidance, NUREG-1335) and concludes that the licensee's IPE process meets the intent of GL 88-20." The NRC concluded in its summary, "The licensee explicitly addressed the staff's concerns in the modified IPE submittal." The NRC did note that Common Cause Factors (CCF) were lower than generic values. DNPS has since enhanced the DNPS PRA by incorporating generic CCF data from the NRC-sponsored database in NUREG/CR-5497, "Common-Cause Failure Parameter Estimations," and by modifying the containment analysis to follow the guidance given in NUREG/CR-6595, "An Approach for Estimating the Frequencies of Various Containment Failure Modes and Bypass Events," which is explicitly accepted for regulatory applications in Regulatory Guide 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis."

DNPS has significantly upgraded the DNPS PRA since the NRC Staff Evaluation Report on the IPE was issued in October 1997. Much of this upgrade was based on the results of the Boiling Water Reactor Owner's Group (BWROG) PRA Certification Peer Review of the DNPS PRA in January 1998. Enhancements included conversion to linked fault trees, addition of special initiators, update of initiating events data, revision of human reliability analysis, update of equipment failure rate, unavailability data and Common Cause Factors and upgrading Event Tree Analysis.

A second PRA peer review of the DNPS PRA was performed in November 2000. The peer review team used the March 15, 2000, Nuclear Energy Institute (NEI) draft, "Probabilistic Risk Assessment Peer Review Process Guidance," as the basis for the review. This peer review process was adapted from the review process originally developed and used by the BWROG. That original process was provided to the rest of the industry by the BWROG through the NEI Risk Based Applications Task Force (RBATF). Technical information exchanges regarding the PRA peer review process have taken place, both directly and through the NEI RBATF, with all of the domestic light water reactor owner's groups.

The PRA peer review process assesses a PRA in eleven functional elements. Each element is graded on a scale of 1 to 4. A grade of 3 indicates that risk significance determinations made by the PRA are adequate to support regulatory applications, when combined with deterministic insights. A grade of 4 indicates that the PRA is usable as a primary basis for developing licensing positions, however, it is expected that few PRAs would currently have many elements eligible for this grade. The DNPS PRA was graded 3 in ten of the PRA elements and 4 in the eleventh.

Exelon Generation Company (EGC), formerly Commonwealth Edison Company, maintains and updates each of its PRAs to be representative of the respective as-built, as-operated plant. A PRA Model Update Procedure formalizes the PRA update process. The procedure defines the process for regular and interim updates for issues identified as potentially affecting the PRA. This process assures that the present PRA reflects the current plant configuration and plant procedures.

Based on the results of past NRC reviews and the PRA peer reviews, the level of detail and quality of the DNPS PRA fully supports its use in the risk assessment of the DNPS EPU project.

Response for Quad Cities Nuclear Power Station (QCNPS)
Evaluations performed for the EPU project determined impacts on the existing plant Level 1 risk assessment in three areas: (1) reduced times available for effective operator actions; (2) changes in success criteria; and (3) changes in initial plant configuration. In addition, the potential impact of EPU on fire, seismic, and other event risks was reviewed. Each area is discussed below.

1. Effects of Changes in Operator Response Time

The reductions in certain operator action allowable times resulted in changes to HEPs due to the power uprate. The following actions and allowable times were identified in the risk assessment as the most significant in terms of CDF increase (i.e., those changes that individually cause a 1% or more increase in the base CDF).

The time to initiate RPV depressurization following a medium LOCA is reduced from 25 to 20 minutes. This is a conservative estimate. This reduction affects the HEP for this action. The base probability for failure to initiate was 7.00E-04. Due to the decrease in available time, the post-EPU HEP becomes 1.1E-03, resulting in a CDF increase of 1.4%.

The time to initiate late SBLC injection following ATWS is reduced from 20 minutes to 16 minutes. This reduction affects the HEP for this action. The base probability for failure to initiate was 3.2E-02. Due to the decrease in available time, the post-EPU HEP becomes 4.9E-02, resulting in a CDF increase of 1%.

The time to control reactor vessel level following ATWS decreases from 20 to 16 minutes. This case is similar to the previous one. The post-EPU HEP changes from 3.2E-02 to 5E-02, resulting in a CDF increase of 1%.

Despite the change in response time for these operator actions, the probability of operator success in all cases remains high. The operators are trained specifically on these mitigation actions in the classroom and at the QCNPS simulator.

The table on page 10 summarizes the effects of EPU operator response time changes on CDF. The important sequences are apparent from the event description and associated CDF increase. No new risk-important operator actions were identified as a result of EPU.

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Supplemental Information for Request for License Amendment for Power Uprate Operation

OCNPS PRA MODEL CHANGES TO OPERATOR ACTION RESPONSE TIMES

Description	Basic Event ID	Base HEP	EPU HEP	Contribution to CDF Increase	Comment
Operator Fails to Initiate RPV Depressurization (Medium LOCA)	1ADOP-DEPMADSH--	7.00E-04	1.10E-03	1.4%	Time available decreases from 25 to 20 minutes (estimate)
Operator Fails to Inhibit ADS with Feedwater Available (ATWS)	1ADOP-INHIBHPH--	1.40E-02	1.40E-02	N/A	Time available decreases from 10 to 8.5 minutes (estimate). Conservative estimate is being used in the base PRA model. The same HEP will be used for the EPU.
Operator Fails to Initiate RPV Depressurization (ATWS)	1ADOP-ATWSADSH--	1.70E-02	2.20E-02	<0.1%	Time available decreases from 10 to 8.5 minutes (estimate)
Operator Fails to Initiate SBLC Injection During ATWS (Late)	1SLOP-IN-LATEH--	3.20E-02	4.90E-02	1.0%	Time available decreases from 20 to 16 minutes
Operator Fails to Control RPV/Power Level During ATWS (Late)	1SLOP-LATELVLH--	3.20E-02	5.00E-02	1.0%	Time available decreases from 20 to 16 minutes
Operator Fails to Initiate SPC During ATWS	1RHOPSPC-ATWSH--	2.80E-03	3.80E-03	<1%	Time available decreases from 20 to 16 minutes
Operator Fails to Inhibit ADS with Feedwater Available (ATWS)	2ADOP-INHIBHPH--	1.00E-02	1.30E-02	<1%	Time available decreases from 12 to 10 minutes (estimate)
Operator Fails to Initiate RPV Depressurization (ATWS)	2ADOP-ATWSADSH--	1.80E-02	2.30E-02	<1%	Time available decreases from 10 to 8.5 minutes (estimate)

2. Effects of Changes in Success Criteria

Two changes in the Level 1 PRA success criteria were identified.

- The RPV depressurization success criteria changed from requiring one ERV/SRV to two ERVs/SRVs
- The number of SVs/SRVs/ERVs required to open for overpressure protection under failure to scram conditions increased from 11 of 13 to 12 of 13.

For sequences where RPV depressurization is currently required in the event tree sequence (e.g., transient events without a SORV), the change in RPV depressurization success criteria has a negligible quantitative impact. Failure to depressurize the RPV is dominated by operator action failure and common cause failure of the ERVs/SRVs to oper

For IORV or SORV sequences, RPV depressurization is not required for the pre-EPU configuration because a single open ERV/SRV satisfies the current success criteria for depressurization. For the post-EPU configuration where two ERVs/SRVs are required to open for success, RPV depressurization is required for IORV/SORV sequences. The increase in CDF due to the change in the RPV depressurization success criteria was calculated to be 5E-8/yr.

The ATWS overpressure control requirement has been increased from 11 of 13 ERVs/SRVs/SVs to 12 of 13 as the result of power uprate. This change in success criteria has a negligible impact on the quantitative results because overpressurization is dominated b common cause failure of the ERVs/SRVs/SVs to open.

3. Effects of Changes in Plant Configuration

The additional principal changes that affect the Level 1 CDF include the following.

- Changes in the Turbine Trip initiating event frequency
- Changes in the SORV probability

The change in Turbine Trip event initiating frequency is a result of running the installed spare feedwater and condensate/condensate booster pumps at EPU conditions. This change is due to the conservative assumption that loss of any single pump will lead to a lo reactor level scram signal in half of the events. This conservative assumption still results i a less than 1% increase in the base CDF, primarily due to ATWS sequences. Independen of the EPU risk analysis, a plant modification will be implemented to initiate a reactor recirculation runback on loss of a feedwater pump in combination with a reactor low level alarm. This modification is expected to prevent reaching the low level scram setpoint with a high degree of success, such that the calculated increase in CDF bounds the actual post EPU plant conditions.

Changes in SORV probability are due to the predicted increase in valve cycles following postulated transients. Increased cycling is postulated due to the increase in decay heat resulting from EPU. This change had a very minor effect on the base CDF (i.e., less than 0.1%).

Changes to the Level 1 CDF due to EPU plant configuration are in the table on page 13.

QCNPS PRA MODEL CHANGES TO REFLECT EPU PLANT CONFIGURATION

Description	Basic Event ID	Base Prob.	EPU Prob.	Contribution to CDF Increase	Comment
Turbine Trip Initiating Event Frequency	%TT	2.00E+00	2.05E+00	<1%	Increased number of Turbine Trips due to revised number of normally operating Feedwater and Condensate pumps.
SORV for Turbine Trip (non-ATWS)	1PLSVSORV-TT-K--	1.50E-02	1.80E-02	<0.1%	Increased number of SRV/SV cycles increases SORV probability. This event is ANDed with a basic event for SRV failing to reclose at low pressure (non-ATWS only).
SORV for MSIV Closure (non-ATWS)	1PLSVSORV-NTTK--	4.50E-02	5.40E-02	<0.1%	Increased number of SRV/SV cycles increases SORV probability. This event is ANDed with a basic event for SRV failing to reclose at low pressure (non-ATWS only).
SORV for Turbine Trip (ATWS)	1ADSV-SRVFTCTF--	1.80E-02	2.10E-02	<0.1%	Increased number of SRV/SV cycles increases SORV probability.
SORV for MSIV Closure (ATWS)	1ADSV-SRVFTC-F--	3.90E-02	4.20E-02	<0.1%	Increased number of SRV/SV cycles increases SORV probability.

4. Impact of EPU on Fire, Seismic, and Other Events

Fire Risk

An evaluation of the top ten fire scenarios in terms of CDF contribution for each unit was performed. In each case, it was concluded that the power uprate would have only a minor effect on the current IPEEE fire risk. The QCNPS fire risk is dominated by loss of decay heat removal sequences. The operator actions important for mitigating these scenarios are long term and the power uprate would have minor impact on the time available for those actions.

Based upon this assessment, a negligible change in the baseline CDF of 6.6E-5 for Unit 1 or 7.3E-05 for Unit 2 due to fire is judged to result from EPU implementation.

Seismic Risk

The QCNPS seismic risk analysis was performed as part of the IPEEE. The seismic portion of the IPEEE program was completed in conjunction with the SQUG program. QCNPS performed an SMA following the guidance of NUREG-1407 and EPRI NP-6041. The SMA is a deterministic evaluation process that does not calculate risk on a probabilistic basis. No core damage frequency sequences were quantified as part of the seismic risk evaluation.

Based on a review of the QCNPS IPEEE, the conclusions of the SMA are judged to be unaffected by the 17% power uprate. The power uprate has no impact on the seismic qualifications of the SSCs. Specifically, the power uprate results in additional thermal energy stored in the RPV, but the additional blowdown loads on the RPV and containment given a coincident seismic event, are judged not to alter the results of the SMA.

Other External Events
Other external events are not impacted by changes due to EPU.

Level 2 PRA

The Level 2 PRA calculates the containment response under postulated severe accident conditions and provides an assessment of the containment adequacy. Changes of 17% in power represent relatively small changes to the overall challenge to containment under severe accident conditions. The timing to containment failure may be reduced by on the order of 5 to 30 minutes as measured over accident times of 6 to 30 hours. This is judged to be a minor change in the Level 2 PRA assessment. In addition, the success criteria for RPV depressurization was modified similar to the modification in the Level 1 assessment. This change in success criteria has a minor impact on the conservative assessment of Level 2 LERF using the QCNPS Level 2 PRA model.

Based on the changes to the Level 1 model as input to the Level 2, the LERF increased from the base value of 3.3E-6/yr to 3.43E-6/yr (i.e., an increase of 4%).

The dominant scenarios for this LERF increase are the same as described above for CDF.

PRA Quality

The NRC Staff reviewed the QCNPS IPE relative to the requirements in NRC Generic Letter 88-20. The July 9, 1997, addendum to the NRC Staff Evaluation Report (Reference 2) stated that, "The licensee made several revisions in its analysis to address the Staff's concerns in both submittals and incorporated several plant modifications in the updated IPE, including the addition of two SBO diesel generators. On the basis of its review of the modified IPE and the updated IPE submittals, the Staff concludes that the QCNPS IPE has met the intent of GL 88-20."

EGC has significantly upgraded the QCNPS PRA since the addendum to the NRC Staff Evaluation Report was issued. Much of this upgrade was based on the results of the BWROG PRA Peer Review/Certification of the DNPS PRA in January 1998. The upgrade of the QCNPS PRA was done in parallel with an upgrade of the DNPS PRA and has produced PRAs of comparable quality. QCNPS and DNPS are sister plants with similar designs. EGC had essentially the same personnel working on each of the PRA upgrades. Common enhancements to both plants PRAs included conversion to linked fault trees, addition of special initiators, update of initiating events data, revision of human reliability analysis, update of equipment failure rate, unavailability data and Common Cause Factors, and upgrading Event Tree Analysis. The BWROG PRA Certification Peer Review of the QCNPS PRA took place in November, 1999.

The BWROG PRA Peer Review/Certification process assesses a PRA in eleven functional elements. Each element is graded on a scale of 1 to 4. A grade 3 indicates that risk significance determinations made by the PRA are adequate to support regulatory applications, when combined with deterministic insights. A grade of 4 indicates that the PRA is usable as a primary basis for developing licensing positions. However, it is expected that few PRAs would currently have many elements eligible for this grade. The QCNPS PRA was graded 3 in ten of the PRA elements and 4 in the eleventh.

EGC maintains and updates each of its PRAs to be representative of the respective as-built, as-operated plant. A PRA Maintenance and Update Procedure formalizes the PRA update process. The procedure defines the process for regular and interim updates for issues identified as potentially affecting the PRA. This process assures the present PRA reflects the current plant configuration and plant procedures.

Based on the results of past NRC reviews and the BWROG PRA Certification Peer Reviews, the level of detail and quality of the QCNPS PRA fully supports the QCNPS EPU project.

Attachment
Supplemental Information for Request for License Amendment for Power Uprate Operation

6.3 Changes to Control Room Controls, Displays, and Alarms

Question:
Describe any changes the proposed power uprate will have on the operator interfaces for control room controls, displays and alarms. For example, what zone markings (e.g. normal, marginal and out-of-tolerance ranges) on meters will change? What set points will change? How will the operators know of the change? Describe any controls, displays, alarms that will be upgraded from analog to digital instruments as a result of the proposed power uprate and how operators were tested to determine they could use the instruments reliably.

Response:
The primary impacts of power uprate on control room operation involve changes to the power-to-flow relationship and a need to have all feedwater and condensate pumps in service to achieve the required flows. There are no major physical changes required to the control room controls, displays, or alarms as a result of power uprate. Some changes are required to control board indicator spans, alarm settings, and automatic actuation setpoints to accommodate increased process conditions due to power uprate. In addition, the existing zone banding (green, yellow, and red) on all control board indications will be reviewed for acceptability and revised as necessary prior to power uprate operation.

Control board changes that are being implemented for power uprate include an increase in the indicator span for both Feedwater and Main Steam Flow and the addition of an annunciator and reset pushbutton associated with the Reactor Recirculation Runback on Loss of FW Pump feature which is being added.

The following setpoints are being changed as a result of power uprate. These are described in Section 5, "Instrumentation and Controls," of the Power Uprate Safety Analysis Report (PUSAR), which is attachment E of the License Amendment Request (Reference 3).

APRM Flow Biased Scram and Rod Block Setpoints
Main Steamline High Flow MSIV Isolation Setpoint
Turbine Trip Scram Bypass Setpoint
RWM Low Power Setpoint
Condenser Low Vacuum Alarm and Scram Setpoints
Off Gas System High Temperature Alarm Setpoints
Reactor Low Water Level Alarm and Scram Setpoints
IC Initiation Time Delay Setpoint
Feedwater Pump Runout Protection (Maximum Flow) Setpoints

With regard to control system upgrades, a new programmable logic controller (PLC) is being added to existing local control panels in conjunction with the Condensate Demineralizer addition at QCNPS and the Condensate Pre-Filter addition at DNPS.

These changes are being implemented as design changes in accordance with approved change control procedures. The change control process includes an impact review by operations and training personnel. Training and implementation requirements are identified and tracked, including simulator impact. Verification of training is required as part of the design change closure process.

6.4 Changes in the Safety Parameter Display System

Question:
Describe any changes the proposed power uprate will have on the Safety Parameter Display System. How will the operators know of the changes?

Response:
The analog and digital inputs for the Safety Parameter Display System (SPDS) were reviewed to determine the impacts from EPU. The inputs to SPDS are not affected. There is one change to the SPDS alarms to reflect the revised low reactor water level scram function. This change will not affect human factors because the display and function of the system are unchanged. The setpoint changes for EPU are listed in Section 5 of the PUSAR.

The changes to the SPDS computer will be completed prior to power ascension above EPU conditions. Additionally, this change will be discussed as part of the operator training program for EPU.

6.5 Changes to the Operator Training Program and the Control Room Simulator

Question:
Describe any changes the proposed power uprate will have on the operator training program and the plant reference control room simulator, and provide the implementation schedule for making the changes.

Response:
An operator lesson plan will be developed to teach plant changes as a result of the EPU and existing lesson plans will be revised to reflect the changes. The plant changes are described in the PUSAR. The EPU lesson plan will be presented to all licensed/certified operations personnel before startup is initiated for operating at extended power conditions. EPU changes will be incorporated in continuing training lesson plans, as applicable.

Operator training for power uprate conditions will be performed on the simulator prior to operating at uprated conditions. This training will consist of comparisons of plant conditions between the current maximum power level and the uprated power level, the normal operating procedural actions to achieve the uprated power level, selected transients and accidents that present the greatest change from previous power levels, such as feedwater pump trip and condensate pump trip.

The plant simulator will contain a software module that reflects the major plant systems and reactor changes as a result of EPU. This module will be used for training, test preparation and operator training conducted prior to EPU implementation. These initial simulator changes will be implemented prior to the operator training session before power uprate is initiated. Simulator revalidation will be accomplished in two stages. First, the simulator performance will be validated against the EPU expected system response. Second, post-startup data will be collected and compared with simulator performance data, allowing any necessary adjustments to simulator model performance. This simulator performance validation for EPU will be performed in accordance with ANSI/ANS 3.5-1985, Section 5.4.1 "Simulator Performance Testing"

References

1. Letter from U.S. NRC to I. Johnson (ComEd), "Dresden, Units 2 and 3, Modified and Updated Individual Plant Examination (IPE) Submittal - Internal Events," dated October 2, 1997

2. Letter from U.S. NRC to I. Johnson (ComEd), "Quad Cities, Units 1 and 2, Modified and Updated Individual Plant Examination (IPE) Submittal - Internal Events," dated July 9, 1997

3. Letter from R.M. Krich (ComEd) to U.S. NRC, "Request for License Amendment for Power Uprate Operation," dated December 27, 2000