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FOREWARD

These proceedings record the information presented at the 2nd International Conference on CANDU Maintenance held November 22-24, 1992 in Toronto Canada.

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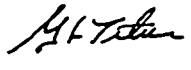
Honourary Chairperson's Message

The first CANDU Maintenance Conference held in 1987 generated a tremendous amount of interest within the Canadian nuclear industry. This second conference has shown an even higher interest level as can be seen in the expanded technical program, larger equipment display, new poster session and increased attendance. The conference has also drawn a significant international following with attendees and presenters from several countries and foreign utilities.

The relevance and importance of these conferences are exemplified by the fact that several of the key maintenance issues from 1987 are today major industry success stories. In the ensuing 5 years, some CANDU'S have been completely retubed and returned to very high levels of performance while the tremendous success of the CANDU 600 stations has been continued and expanded. Meanwhile, other issues such as steam generator maintenance and quality improvement programs have increased in importance and will be a focus at this conference.

This year's theme is "Maintenance in the 90's"; Strategy and Practice" with a program aimed at maintenance personnel, station management and technical staff, equipment suppliers and designers. The information and ideas that will be exchanged at this conference represent some of the best maintenance experience and wisdom that our industry has to offer. I am sure you will find it a very useful and enjoyable event.



G.L. Titus
President and CEO
New Brunswick Power

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Acknowledgements

Putting together this Second CANDU Maintenance Conference invclved the talents and efforts of a large number of people. Foremost are the authors and speakers who provided the basic working material without which we wouldn't have had a conference at all. Next are the attendees who through their participation in this forum have contributed to the vital information exchange that helps to keep our industry on the path of continuous improvement. On behalf of the Canadian Nuclear Society, I would like to thank all of them for their contribution.

Planning for this conference took place over a period of ten months. A great deal of work had to be done by the steering committee, in particular, three dedicated individuals who were critical to our success. George Fanjoy provided overall experience, wisdom and persuasion in putting together the important plenary session program that led off the conference. Dan Meraw and Doug Benton took on the daunting and time consuming task of assembling a program with over sixty papers and seeing it through to publication. The fact that George, Dan and Doug were on the steering committee for the last conference and so knew better than I what they were in for makes me all the more grateful!

Other members of our committee were Bill Schneider from Babcock Wilcox, Tim McLaughlin (our treasurer) from GE, Karl Mika from Ontario Hydro's Bruce site and Heiki Tamm from AECL who all provided important contacts and papers from their organizations. Lisa Anzil and Bryan Murdoch from Ontario Hydro put together the exhibits program. Isabel Franklin from AECL was responsible for all hotel arrangements and contracts. Sat Wadhwa from Ontario Hydro got out the proceedings. Sylvie Caron of the CNS handled registration. Finally, Kathy Murphy and the Canadian Nuclear Association made their staff and facilities available to us and provided guidance and support for this important undertaking. I thank them all for the effort that they expended on top of their already demanding schedules.

My last acknowledgements are to Alan Holt, past President of Ontario Hydro and to Elgin Horton, Vice President, Nuclear Operations who both recognize the critical importance of maintenance to keeping our stations running well and who both supported the idea of the conference from the beginning.

Tim Andreeff

Tim Andreeff
Conference Chair

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President
Canadian Nuclear Society

Plenary session paper not availble at the time of printing.

Keynote Speaker

G.L. Titus, President and CEO, New Brunswick Power

C# 9500130

MAINTENANCE - A DESIGN PERSPECTIVE

By

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AECL CANDU

November 1992

Abstract

A successful nuclear program requires a plant to have a long life and a high capacity factor for the duration of that life. As the plant matures, there is a need for a balancing and optimization among corrective, preventive and predictive maintenance programs depending on the age of the station.

However, design is the starting point, and a successful plant requires good design, attention to detail, and allowance for maintenance and rehabilitation, including facilitation of the replacement of some components.

The paper describes how AECL's new reactor design, the CANDU 3, has incorporated, at the design stage, maintenance requirements such as component accessibility, standardization, ease of replacement, reduction in the number of components, and simplified component design. Two processes that contributed greatly were the involvement of utility staff in the design, and the carrying out of formal design reviews, including a maintenance assessment. Such processes resulted in many changes to the CANDU 3 design, including numerous layout changes to improve maintenance access.

Existing plants must have excellent support when important components have to be replaced, refurbished or rehabilitated. AECL is playing a key role in the planned rehabilitation of Ontario Hydro's Bruce A nuclear generating station's four units. In addition to conceptual design and development, detailed design and analysis, procurement and site assistance, AECL's Sheridan Park Engineering Laboratory (SPEL) will provide important development and mockup facilities.

Research and Development also plays an important part in maintenance of station performance. A long term strategic plan is described whose objectives include the identification and characterization of aging and degrading mechanisms; the tailoring of developed products to plant requirements; and the identification of areas of international cooperation and information exchange.

It is clear that, from the designer's perspective, there is the requirement to consider the needs of maintenance throughout the complete life cycle of a nuclear plant, and to bring to bear the complementary aspects of their resources, be they design, test facilities, or R&D, as the plant matures.

MAINTENANCE - A DESIGN PERSPECTIVE

Elements of a successful nuclear power plant

- A successful nuclear program requires a high capacity factor due to its initial capital cost
- The plant must have a long life - at least 40 years - and hence maintenance is essential and rehabilitation is inevitable
- Plant lifetime performance leaders are new plants, but U.S. experience has shown that older plants can be made to work well

What is needed is a balancing and optimization between corrective, preventive and predictive maintenance programs that evolves from the short term needs of a recently commissioned station to the greater maintenance demands of a maturing plant.

The interdependence and the timely role of each component in such a maintenance program is shown in Table 1.

Table 1.

	Corrective	Preventive	Predictive
Short Term	Plant Maintenance	Planned Outage Maintenance/RCM	On-line Condition Monitoring of Critical Components
Long Term	Rehabilitation/ Replacement	Fatigue/Condition Monitoring for Critical Components	Condition Monitoring/ on all Non Replaceable Components

Many utilities have now recognized the need for proactive maintenance related programs such as:

- Improved inspection programs for assessing present state of components
- Upgraded preventive and reliability centred maintenance (RCM) programs

- Increased emphasis on predictive maintenance through use of surveillance and monitoring programs
- Component reliability trending programs to predict future reliability of critical components
- Updated component repair, refurbishment and replacement programs, including definition of need for substitute parts due to obsolescence or disappearance of suppliers
- Improved record and documentation programs
- Root cause analysis of equipment failures
- Increasing use of mockups, advanced tools and robotics

Features of Design for Maintainability

A successful plant requires good conceptual design with attention to requirements of:

- Constructability
- Safety philosophy
- Zoning
- Material handling
- Equipment access
- Equipment removal paths
- Personnel movement
- Human factors.
- Task link analysis
- Man rem uptake
- Application of ALARA
- Plant rehabilitation
- Decommissioning
- Utility input
- Planned outage

For the designs of CANDU 3 and 9, these requirements are addressed at the beginning of the conceptual design and have clear emphasis throughout the subsequent phases of design. These requirements are related directly or indirectly to an optimum maintenance plan.

- Constructability

  To achieve the short construction schedules targeted on all new designs this subject must be reflected in the plant layouts. Most structures are arranged to give access from a minimum of three sides with early consideration of construction crane access that does not block building access.

- Safety Philosophy

The clear interface between systems and structures engendered by the two group safety philosophy enables the designers and maintainers to avoid the maintenance mix between power production and safety equipment that existed in the past.

- Zoning

An early development of a zoning plan for the station assures the correct location of equipment and services thus avoiding "spotty" zoning. this gives the plant an efficient personnel and equipment movement pattern that leads naturally to enhanced maintainability.

- Material Handling

Once a plant is in operation, one of the major points in maintaining a high degree of availability is the quality of material handling. The main cranes of CANDU 3 and 9 in the reactor building (RB) and maintenance building (MB) have significantly enhanced capabilities over past plants. Of significant note is the direct grade level interface between the main airlock and the MB crane hall thus giving direct crane and road transporter access right up to the airlock.

In all structures cranes, monorails and hoists are chosen and located to best suit clearly defined maintenance tasks. An example is the use of jib cranes over valve stations to give a full arc of hook cover and thus avoid the off centre lifts that are associated with the past practice of using monorails.

- Equipment Selection and Access

As far as practicable, standard equipment is used to benefit from reduced spare part requirements, greater predictability of maintenance needs, and more efficient training of maintenance staff. All equipment has access envelopes defined and then modelled in CADDS. this assures that access is not blocked by later system designs. Additionally, the frequency of access and equipment required (both portable and fixed) is considered. Platforms or space for scaffolding etc are provided and frequent access results in the equipment being located in accessible areas. In general, systems/components are designed for 2 year continuous operation without major servicing.

- Equipment Removal Paths

  Any item of equipment that requires replacement has the frequency of replacement established and then a removal/replacement method and appropriate route are set. This information is recorded in a form that will be part of the station operating database.

- Personnel Movement, Human Factors and Task Link Analysis

  Personnel movement is the subject of early study and corridors, stairs, ladders, etc are located and sized as required. The human factors and task link analysis provides input to personnel movement planning and assures the development of an efficient plant. This is most noticeable in the main and secondary control areas where frequent testing and service activities are carried out and good access and communication between control, computer and control equipment areas is essential.

- Man rem Uptake and ALARA

  The new CANDUs improve upon their past good record of controlling and limiting personnel exposure to ionizing radiation. This is accomplished by a number of actions such as enhanced tritium control and the concept of internal structures that provide shielding as well as a support structure for equipment. This has resulted in a reactor building environment with greatly increased accessibility as compared to all previous CANDUs. The increased accessibility was utilized to provide access to locations and equipment that previously could not be serviced while on power. Examples would be the drives and controls for all shielding doors, and the ability to now access the shutdown cooling (SDC) valves pumps and motors.

  Equipment that previously required exposure to vault atmosphere and radiation is now housed outside the vaults such as SDC and bleed cooler heat exchangers. All of these improvements and many more like them improve maintenance activities and clearly demonstrate AECL's commitment to the ALARA (as low as reasonably achievable) principles.

- Plant Rehabilitation and Decommissioning

The new CANDUs are conceived with a 40 year design life with life extension to 60 years. the 40 years is the basis of equipment specification and economic evaluation. Included in the design life consideration is a plan for retubing after 24 years. The new designs provide very heavy lift crane access to the RB through the dome to replace large components such as steam generators in the event of premature failure or the decision to extend the plant life. Reactor building layout, fuel channel design, and replacement tooling design have been coordinated to facilitate quick and easy fuel channel replacement. Areas for fuel channel replacement facilities and space inside the RB to withdraw and install new channels are provided. All structures are accessible from a minimum of three sides usually to the outdoors. This greatly facilitates access for rehabilitation and decommissioning, as does the permanent heavy lift crane access.

- Utility Input

In order to benefit from the knowledge and experience of the utilities, input was solicited for the CANDU 3 design and was most notably provided by NB Power and Ontario Hydro. The utility input was both in design and in design review stages. This input concentrated on maintenance and resulted in suggestions and recommendations that were incorporated where feasible. Major areas of review comments, at the conceptual phase, by the utilities were the use of steel liner, the equipment hatch/airlock concept, size of the maintenance shops, steam generator removal, and the provision of an access shield door into the steam generator enclosure at the reactivity mechanism deck level. The review comments also addressed areas affecting the detailed design to be considered in that phase. CANDU 3 target operation costs are therefore more credible as a result of the input from utilities.

- Planned Outage

The planned outage for CANDU 3 is determined as 11 days in odd years and 18 days in even years of service. At 20 and 40 years of service an outage of 90 days is proposed. The total outage duration targets for single fuel channel replacement and for full fuel channel replacement are 7 and 185 days respectively.

Maintenance Assessment

The CANDU-3 project requirements include the capability to run for two years between planned shutdowns, with most components (except for the concrete structures and reactor assembly) replaceable within an outage of 90 days or less. Thus a maintenance assessment review was called during the conceptual design. There were five reviewers, including one from NB power and one from Ontario Hydro.

The initial review of the design package generated 157 comments. These were addressed by the designers and their responses given to reviewers prior to the review meeting; thus the meeting could concentrate on those responses given to reviewers where there was disagreement. In the end, each review comment was either accepted by the designer; answered to the satisfaction of the reviewer; or further action was assigned.

Some review comments could be addressed as part of the conceptual design; others would have to be resolved as part of the detailed design. An action list for each type was generated for followup. There were 165 actions assigned altogether. These actions are tracked periodically until completion.

A maintenance review is novel. A challenge to the reviewers was the lack of well-established criteria and the heavy reliance on experience and judgement - this made the utility presence even more important.

Examples of the concept phase comments from the review follow:

1. Use of anything less than a full steel liner for the containment building would require provisions for extensive external and internal inspection. [In the end, a full steel liner was chosen].

2. The proposal to substitute an equipment hatch for an equipment airlock could degrade maintainability. [The role was clarified: the main airlock was sized to accommodate all equipment and components required during operation; the hatch was for a long shutdown only].

3. The sizing of service maintenance shops, fuel handling shops, and waste handling was felt to be inadequate. [Revised].

4. If the boilers need replacing, it should be done by cutting holes in the steel-lined reinforced concrete dome. [Agreed].

Support to Existing Plant

CANDU nuclear plants have a nominal "design life" that forms the basis of equipment specification, economic evaluations and licensing for some jurisdictions. Some important components in the plant may require replacement, refurbishment and/or rehabilitation part way through the plant "design life" i.e. plant mid-life maintenance.

Ontario Hydro's Bruce A NGS is a four unit 3000 MWe station that came into service between 1977 and 1979. Since its startup, it has had an excellent overall record. However, in recent years, its performance has declined noticeably due to aging and wearout.

In order to restore capacity factors to the design target value of 85%, Ontario Hydro has initiated a $854M rehabilitation program over a projected nine-year period. The program comprises about 40 major projects to be undertaken in various areas of all the four reactor units.

Presently, AECL CANDU has a lead role in the design and development of four of these projects with additional assistance to Ontario Hydro in three projects. This translates into about 100 person years of work spread mainly from 1992 to 1994 for AECL.

These projects are:

- SDS #2 Liquid Injection Nozzles Replacement
- Boosters Lockout
- Safety Systems Monitoring Computers Replacement
- Moderator Heat Exchangers Replacement
- Station Main Control Computers Replacement
- Reactivity Mechanisms Deck Access Modifications
- Bleed Condensers Gasket Replacement

AECL participation includes conceptual design and development, detailed design and analysis, procurement and site assistance. In addition, several of these projects include development work and mockup construction at SPEL. These mockups are to prove the concepts and provide training for site staff to do the actual jobs manually or remotely in high man-rem environments.

One of these complex projects involves the replacement of the two out of seven liquid injection nozzles of the safety shutdown system #2 of each of the four reactor units. This replacement is required because of higher creep sag in the calandria tubes than predicted which may result in future interference between the calandria tubes and the

liquid injection nozzles. This could impact on safety system availability. AECL is able to bring to these kinds of jobs a unique combination of skills and experience in research and development, testing, component and tooling design to meet the specific requirements of each project.

An important extension of the design process is the need for development testing to verify and prove out design concepts. While true of design in general, this takes on a new emphasis for maintenance programs for which tooling and inspection equipment or operational programs must be demonstrated to facilitate quick installation, minimize station downtime, etc.

AECL's Sheridan Park Engineering Laboratory (SPEL) and other test facilities are being utilized for the support of station maintenance and operating programs.

For example, recent work on fuel bundle vibration problems and the evaluation of different designs of shield plugs required that these components be tested and evaluated under representative fuel channel operating conditions.

Prototype components have been tested in SPEL's fuel channel flow visualization facility before being installed in a test loop for endurance testing. The test loop supplies representative flow, temperature, pressure and pressure/flow pulsation conditions to a fuel channel. These programs require close cooperation between the design engineer and test engineer. The designer specifies his test requirements in accordance with design requirements and the test engineer develops the test plan and test procedures.

When the operation/maintenance program requires the design and development of specialized inspection and repair tooling then the design and test function literally become combined. Systems like SLAR and SLARette to locate and move the pressure tube spacers have been successfully developed in this manner, also tooling to replace the moderator inlet line pipe hanger at Pickering A, tooling to resupport the Pickering A ion chambers, long reach manipulator arms to inspect the calandria vaults at Pickering, Gentilly-2, and Pt. Lepreau are other examples of tooling developed by a synthesis of design and testing. This type of work also often involves building full scale mockups to aid in tool proving and operator training.

Large Scale Fuel Channel Replacement (LSFCR) is a major undertaking by CANDU owners; most existing CANDU stations have, or will undergo LSFCR as part of plant life assurance and/or extension.

AECL CANDU and other vendors provide a great deal of support in the planning, preparation, and implementation phases of fuel channel replacement programs. All four units at Pickering NGSA have now had their fuel channels replaced, and preparation for the Bruce A units is now underway.

As a vendor, AECL's support to Ontario Hydro has included an integrated design of the replacement reactor components, and tooling and equipment systems for their installation. The primary goals are to maximize post replacement design life while minimizing reactor down-time and radiation exposure to the personnel performing the replacement activities.

Major components of the program include:

- Preliminary studies to determine basic fuel channel replacement requirements, and participation in the project definition phase.
- Establishment of test facilities using representative reactor components and the actual tools and equipment (prototype and production) necessary to perform the work.
- Design and procurement of automatic and manual welding, inspection, and reactor component installation tooling and equipment.
- Integrated testing of components and equipment, with the participation of the utility's personnel who will lead the implementation phase.
- Support to vendor designed components and equipment during the implementation phase.

Other areas where AECL has been instrumental in providing assistance to operating stations have been the Operating Station Support initiative, and the CANDU Reactor Services group.

Research and Development

Research and Development has played a key role since the inception of the CANDU industry with the 25MWe Nuclear Power Demonstration unit (NPD) and throughout its commercialization cycle. Its mission continues as the industry matures to maintain CANDU's high performance, safety, reliability, to assure its design life and preserve the option of extending its life. Figure 1 illustrates such a mission. Recognizing the role of R&D in managing the impact of NPP age related degradation, a long term strategic

plan has been formulated by the CANDU Owners Group (COG) to be consistent with the maintenance strategy of the utilities. The main objectives of the R&D strategic plan are:

1. To identify and characterize aging and degradation mechanisms in an integrated and systematic manner so that methods, techniques, and facilities required to predict and manage plant life will be available when required.

2. To "custom tailor" developed products to nuclear plant operator requirements and site conditions, that is, master the process of "technology transfer" from researchers to operators.

3. To identify areas of international cooperation and information exchange.

The strategic plan also defines a number of key R&D areas. These include pressure vessels and piping, key components, concrete structures, electric equipment, development of inspection, surveillance and monitoring techniques, fitness for service guidelines and techniques for component repair, restoration and replacement.

The thrusts of the generic R&D programs in the strategic plan are:

1. Characterization of Aging Degradation Mechanisms for metals, concrete and elastomers with respect to:

   - vibration
   - fatigue
   - fretting wear
   - erosion - corrosion
   - thermal aging
   - neutron irradiation

   for applicability to critical and non critical components.

2. Development of guidelines for mitigating aging for pressure vessels, heat transfer equipment, piping, valves, cables, concrete structures, etc.

3. Development and validation of an integrated failure model approach for prediction of component remaining life based on state of the art inventory of data from insitu examination of plant components, and test data from naturally aged material samples from decommissioned reactors (NPD and Douglas Point).

4. Development of state of the art Inspection, Surveillance and Monitoring techniques, building on international development in the field and technological advancements made in other fields.

5. Fostering international cooperation and information exchange in all areas and building on successes made through ongoing cooperation in the Steam Generators, Heat Transport pump, erosion,corrosion fields, etc.

A phased approach on the Generic R&D has been adopted and supplemented by component and technology specific R&D programs funded by AECL and COG - Tables 2 and 3 identify the salient points of these programs.

Summary and Conclusions

AECL's pre-eminent position in both research and in CANDU design may have obscured in some people's minds its strong commitment to maintenance issues. This paper shows that research is essential to understanding aging processes, and that understanding is central to improved designs and reduced maintenance. It shows that an understanding by designers of maintenance issues leads to much improved designs. Another link from the design function to maintenance is the potential for new design features to be incorporated into existing plants.

Bruce unit 1 and 2 will solve a long-standing channel fretting concern when they incorporate new fuel channel design features during their planned retubing. The new fuel channel design grew out of ongoing design work in support of new reactors. Replacement control computers and monitoring computer designs for Bruce A are benefitting from design work on computer and display systems for new CANDUs. Specifications for possible Bruce A replacement steam generators have been written using the latest knowledge. There is a continuing parade of smaller improved components finding their way into existing plants as designers are consulted by site operating and maintenance staff.

In addition to designing new plants and new plant components based on maintenance considerations, design organizations are able to design and test special-purpose tools for maintenance operations. This work requires a combination of design skills, nuclear plant knowledge and access to good shop and testing facilities. AECL-CANDU, using its SPEL (Sheridan Park Engineering Laboratory) facilities is making continuing contributions to tool design, both for major programs such as large scale fuel channel replacement (LSFCR) and in response to many demands for immediate help with new maintenance challenges.

The key to a design organisation's ability to help with maintenance issues is the ability to bring designers close to the customers - the utilities. AECL-CANDU is determined to maintain and increase this customer focus to keep designers in touch with the important issues. This should in the future give even more visibility to AECL staff at the nuclear power plant sites as stronger partnerships are forged between designers and utilities.

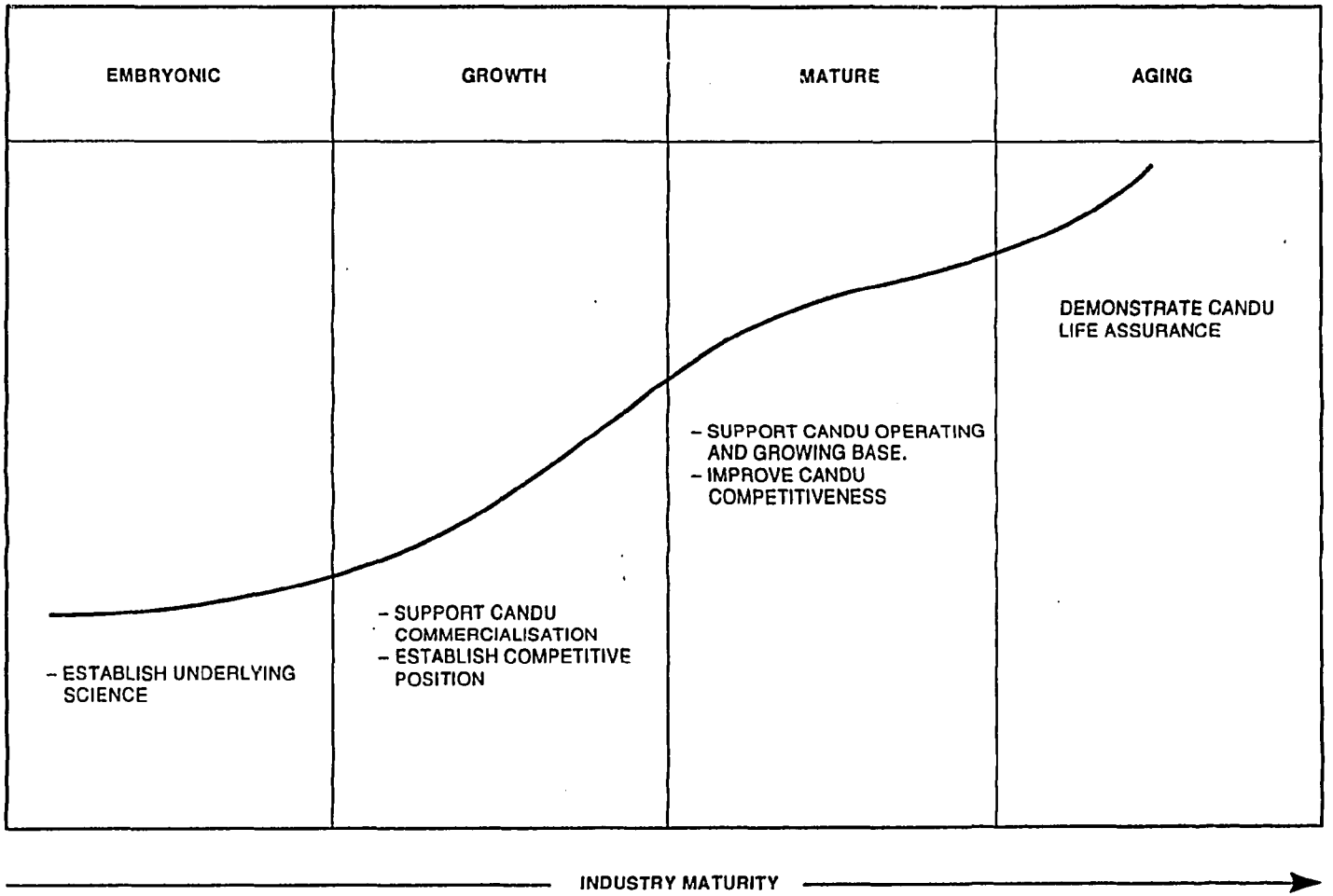

FIGURE 1 THE MISSION OF RESEARCH AND DEVELOPMENT AND THE CANDU INDUSTRY CYCLE

Table 2
Summary of COG Specific R & D Programs (current and planned)

CANDU Components	Degradation Mechanisms	Aging Data	Life Prediction	Maintenance Guidelines	Obsolescence (subcomponents)
Fuel Channels	X	X	X	X (Fitness for service guidelines)	
Steam Generators	X			X (Chemistry, Vibration, Thermal–hydraulics)	
Process and Safety Related Components (pressure vessels, heat exchangers, rotating machinery, etc.)	X		X	X	
Plant Piping/Elastomers	X	X			X
Concrete Structure		X		X	
Nuclear Cables	X	X			
Fuel Handling				X*	X*
Irradiated Fuel Bay Durability		X			

* Planned

Table 3
Inspection & Monitoring: Present R & D Programs

	Capability Development	Efficiency Improvement	Component Life Prediction
PHT Fatigue Monitoring			X
Valve Diagnostics	X		X
Motor Monitoring			X
Defect Sizing	X		
PHT Pump Monitoring	X		X
Erosion/Corrosion Susceptibility	X		X
ET Fretting Wear	X		
Pipe Flaws – Gauging		X	X
Real Time Radiography	X	X	
ET (for a wide range of CANDU materials)	X	X	

CA9500131

Plant Maintenance Experience in Wolsong # 1

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1.0 INTRODUCTION

Wolsong # 1 is the sole CANDU among 9 operating nuclear units in Korea. This plant began commercial operation in April 1983 and about 10 years has passed. At the beginning, we had a lot of difficulties due to lack of operating experience, shortage of quality manpower and incompatibilities with other PWR units in the country. Both plant management and operators have put great endeavors to overcome these initial difficulties. Now, the plant shows outstanding operating records.

Life-time capacity factor is as high as 84.6 %, which is far higher than other Korean nuclear units. In addition, on-power refuelling, the unique feature of CANDU has also made great contribution to stabilize the electric grid.

I want to point out that the performance of Wolsong # 1 has been one of the key factors for the KEPCO to decide to have three more CANDUs being built at Wolsong. As Wolsong # 1 means the name of excellence, I expect new units will do so again.

2.0 Basic Philosophy of Plant Maintenance

Ultimate goal of the plant maintenance is to assure high reliability and safety of the plant as well as to improve the plant capacity factor. Nuclear safety and reliability are the royal road to the public acceptance and to the successful development of nuclear electricity.

Based on high confidence on the plant safety and reliability, high capacity factor has to be pursued to keep nuclear electricity cheaper and more competitive than other energy resources.

2.1 Safety and reliability

KEPCO-Wolsong emphasizes the organized management and job activities in the following areas to assure the plant safety and reliability;

- plant improvement and modification,
- quality control program and activity,
- quality of maintenance crew,

- thorough periodic inspection, and
- safety audits.

2.2 Capacity factor

The so-called One-cycle-trouble-free or OCTF program is mobilized. The OCTF operation means continuous operation without any trip or shutdown of the plant between scheduled annual overhauls. In order to achieve OCTF operation, KEPCO-wide mind rehabilitation is encouraged as well as the following physical programs;

- preventive maintenance program,
- intensive monitoring of system and components with high risk
- periodic replacement of degrading components,
- block maintenance, and
- advanced diagnostic tools and equipment

3.0 Examples to improve safety and reliability

3.1 The activities to improve plant systems.

Many plant systems, equipment and components have been modified and upgraded.

The first example is steam generator modification. The performance test at 100 % power during the plant commissioning showed that the generator output was 646 MWe only, which was far below the design value of 678.6 MWe. The cause was the moisture contents as high as 15 % which far exceed the design value of 0.25 %. Therefore, second separators were installed in the steam generators, which lowered the moisture contents down to 0.16 % at full power operation.

The second example is the improvement of environmental condition around the exciter panel. The exciter panel of main generator is located close to feed water heater and condenser, which has elevated ambient temperature to cause early degradation and failure of control elements of the panel. Accelerated aging effect of the control elements has forced to reduce power frequently or to shutdown the plant. In order to eliminate these problems, an acrylic housing was erected over the excitor panel and the panel area was kept as clean as possible. After this modification, the malfunctioning of the panel has been drastically reduced.

The third example is to install additional support and hangers to the main steam pipes which penetrate the control equipment room. Plant commissioning operation has identified that the floor vibration of the control equipment room caused loose contacts between terminals and wiring in the central distribution frame which might lead to frequent plant malfunctions . Therefore, support and hangers are added to the main steam pipes routing the control equipment room and the turbine operating floor.

The fourth example is the modification of the raw service water system (RSWS) and recirculation cooling water system (RCWS). RSWS and RCWS are of single loop design. Any maintenance or inspection activity to the systems and components urged us to seek for an alternate heat sink in advance, which extended the maintenance duration and did not always result in adequate cooling. Therefore, these systems have been modified to have dual loop, which allows inspection and maintenance while operating the systems. These dual loops are believed very effective against the rupture of piping and heat exchanger, which is detrimental to reactor cooling and plant safety.

3.2 Quality control program and activity

There is no need to say that quality control is very important to the high safety and reliability. Therefore, Wolsong management has put high emphasis to quality control activities; Many Q.C. procedures have been written; Quality classification system has been set up; and all the operating and maintenance crew and supporting staff have been trained to have quality-mind.

A quality verification program is established for those systems which are critically related to the plant safety in order to not to allow any unwanted plant trip or power reduction. Repair jobs on these systems and components are done in accordance with this quality verification program. Some quality experts are selected to receive additional education and on-the-job training. They have developed and utilized witness and check list for safety systems to assure the best quality.

Besides, every year a quality rally is held, where slogans and quality-best crews are selected and awarded.

3.3 Qualification of maintenance crew.

It is very difficult to raise and maintain the quality of maintenance crew and. However, repeated training and education on their specialty and on advanced technology will assure higher quality. A qualification program is operated in order for maintenance crew to be exposed to new skills and deepen their specialty. Qualified crew are only allowed to perform maintenance activities of selected systems and equipment. In addition to this, various continued education and training programs are also available.

3.4 Thorough periodic inspection

In order to prevent unexpected failure or degradation of components and equipment, periodic inspections are performed in accordance with the plant technical specification.

Periodic Inspection Request is issued for the items whose inspection interval is 7 days or longer. The inspection results are analyzed and then integrated to forecast equipment failure or degradation. As many as 7,076 inspections are performed a year for 1,805 items.

Also available is a task force team, whose specialty is the

detail inspection of rotating machinery.

Periodic inspection is at present performed by disciplinary call-up system. In order to organize and obtain interdisciplinary interpretation of test results, and to manage human resources and tools more effectively, an integrated inspection program is being developed.

3.5 Safety audits

Wolsong # 1 has been subject to many safety audits from KEPCO-internal and external organizations and teams. These audits provide good opportunity to look into safety aspects of plant activities without prejudice and have been very effective to correct mistakes and errors which we may make without intention.

An example is the safety audit by a team of the OSART of the IAEA on the plant management in July 1989. The audit concluded that Wolsong has more than sufficient management and technical capability to assure the plant safety and reliability and recommended that some corrective actions have to be taken, which was accepted without hesitation by the KEPCO management.

With regard to the reactor safety and associated facilities, Korean Ministry of Science and Technology and the Korean Institute of Nuclear Safety perform audits during the annual overhaul.

Besides, KEPCO operates her own teams, which are responsible for safety audits from time to time to derive and correct safety problems.

4.0 Improvement of Plant Capacity factor

4.1 Preventive Maintenance

The best maintenance is not to correct the problem but to prevent such a problem may not occur. Therefore, general trend is the shift from the traditional corrective maintenance to preventive one. Our aim is that the preventive actions shall take place as high as 70 % of all maintenance activities. In order to meet this goal, under development is a systematic and integrated preventive maintenance program.

4.2 Intensive monitoring of risky systems and components

Plant statistics identified that major causes of the unscheduled plant shutdown or trip are equipment failure, external event, and human error.

Because ultimate goal of maintenance is continuous operation without any trip, weak and delicate points of each system are listed up, whose failure or degradation may lead to the system malfunctioning and even a plant trip. Based on this list, a special management program is developed to monitor and inspect these points.

For example, In order to protect the plant from external

events such as typhoon, heavy rain, and cold weather, established is a seasonal preventive maintenance program. Plant HVAC systems have to be wholly rehabilitated to cool down electric and electronic components which are very susceptible to high temperature in summer. Outdoor tanks, pumps, pipes and control panels are thermally insulated at due time to keep them from freeze and rupture during the winter season.

4.3 Periodic replacement of equipment and components

Control and instrumentation as well as the plant computer consist of many electronic elements, whose lifetimes are limited by their physical nature. They are also exposed to stressing environmental conditions such as temperature, humidity, vibration and etc. Thus their failure or degradation rates are much higher than that of other mechanical or electrical system components.

In-circuit testers are utilized to examine the performance of these elements and to provide technical basis to determine the time of change. Good examples of periodic replacement are potentiometer and aluminum electrolytic capacitors. Set point and gain of a potentiometer may drift during plant operation. Therefore, in order to assure the linearity and reproducibility of the variable resistance, potentiometers are replaced at regular interval. Electrolytic capacitor also has lifetime by its own nature, thus has to be replaced at a predetermined interval. The replacement interval is usually based on the manufacturers' recommendation and on the operating experience and environmental conditions.

4.4 Block maintenance

The advantage of block maintenance is to shorten the maintenance duration, to assure maintenance quality and to reduce radiation exposure to maintenance crew. It is natural, therefore, to enlarge the scope and items of block maintenance as far as possible.

But, at the beginning, there were many difficulties in securing spare parts of the blocks and in determining the items and size of a block. At present, 35 systems and equipment are selected in 4 areas, where block maintenance seems to assure higher reliability of the plant against malfunction. Up to now, 27 out of 35 selected blocks have been replaced. The items and scope of block maintenance will be further increased.

4.5 Advanced diagnostic tools and equipment

Precision tools and equipment are critical to the preventive and predictive maintenance. These tools and equipment are either purchased or developed by domestic institutions. Some examples of domestic development are protective relay testers, printed circuit board testers, computerized system to log and analyze the test results of standby generators.

5.0 Obstacles to Plant Maintenance

Major obstacles to plant maintenance at Wolsong # 1 can be categorized into following groups.

- inadequate supply of spare parts and system components,
- underdeveloped domestic technical capability, and
- poor access to some critical systems.

A few examples follow.

5.1 Plant control computer

The plant computer is specially designed for CANDU plant control, thus has little compatibility with other commercial products. Computer maintenance cannot be even thought of without overseas participation. It is almost impossible to modify or update the computing system without the designer and manufacturer's advice and participation. To make things worse, several spare parts are out of shelves and are not available any longer.
Furthermore, few program analysts are available to deal with ASSEMBLY language, in which computer software is written.

5.2 Fuelling machine

Ram ball screw, a critical component in fuelling machine, has a life time limitation. Therefore, every year, standby machine has to take the place of the operating one. Disassembling and reassembling job may result in internal radiation exposure of maintenance crew.

Custom-built head cable harness and catenary cable assembly have specific lifetime limits. Thus their replacement should have been made. Also DC power supply has been old enough to be placed. Because they are not available in manufacturer's warehouse, immediate actions are necessary to develop their substitutes.

5.3 Pressure tube integrity

At the beginning of the plant startup, there was intensive discussion whether the plant should have its own inspection and maintenance tools/technology in order to assure the integrity of pressure tubes. The result was to lease tools and manpower in a close cooperation with the Canadian entities, in order to lower economic burdens and to maintain technical compatibility with other CANDU units in the world,

However, Inspection and maintenance tools such as CIGAR, SLAR (Spacer Location and Repositioning), and SFCR (Single Fuel Channel Replacement) had not always been available when we absolutely needed them. Poor domestic capability does not allow us to develop the technology and to perform inspection activities by ourselves. Thus, the manufacturers including the AECL are required to take more positive attitudes for technology development and technical

support in this area.

5.4 Delayed neutron tube maintenance

Delayed neutron tubes are a part of failed fuel location system. These are installed at such an elevated height that it is not easy to install the lighting fixture for them. Furthermore, there exist many crossings and interferences among and between tubes. In other words, 380 tubes are installed without order, which makes the tube inspection and repair very difficult.

In addition, very high gamma and neutron doses not allow maintenance crew to work with sufficient time, which lowers the job quality.

5.5 Maintenance of ECCS Isolation Valves

In a CANDU plant, reactor coolant has to be maintained and circulated even during the plant overhaul in order to remove decay heat from the reactor. ECCS Isolation valves isolate the ECCS from the Primary Heat Transport System. If internal passing at the isolation valves or external passing through gland packing occur, it is very difficult or impossible to do any maintenance work for the primary systems.

6.0 Concluding Remarks

On-Power refuelling and the flexibility in electric grid management are the strong edges of CANDU over other reactor types, and will be the driving force to maintain very high capacity factor of CANDU in future as in the past.

Excellent performance of various control mechanisms at low pressure and temperature, low nuclear reactivity of reactor, and early detection and removal of failed fuels are only a few examples of CANDU unique safety features. Based on these features, CANDU is expected to be competitive with other reactor types.

To make good things more better, however, there are a few points that have to be improved through the concentrated effort of those who work for CANDU technology.

The first point is that data and information communication between utilities through COG network and the like is very limited compared to those of other reactor groups. This is largely due to the fact that there are only a few utilities which operate CANDU unit(s).

The second point is the inadequate supply of spare parts as described above. Production cease or run-out of stock shall be immediately informed to the utilities and power plants to allow some time to secure substitutes. Spare parts pools among power plants may be an idea to solve the problem.

The last but not the least problem area is the tools for inspection and maintenance of pressure tubes. The positive attitude for technology development and transfer is required.

Quality maintenance assures plant safety and reliability. Therefore, this conference is a good forum to deepen our mutual understanding and share unique experiences and new technology. Based on mutual understanding and cooperative spirit, combined effort by CANDU owners, manufacturers, and institutions will ensure betterment of CANDU and technical and economic edges of CANDU over other reactor types.

Industry and Utility Perspectives
H. Marais, Directeur Assistant
de la Gentilly II, Hydro-Quebec

Plenary session paper not available at the time of printing.

Industry Utility and Perspectives

A.R. Johnson, Station Manager
Point Lepreau G.S.
New Brunswick Power

Plenary session paper not available at the time of printing.

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QA INVOLVEMENT IN A LARGE STATION PROJECT - BRUCE NGS B EXPERIENCE

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ABSTRACT

To mitigate fretting of tubes in Bruce NGS B boilers the external contractor designed a complex repair process. This paper describes involvement of the Station QA Section during the design and realization phases of the project and summarizes experience gained. Both experience and conclusions drawn can be applied to any large scale project in a nuclear power plant.

QA INVOLVEMENT IN A LARGE STATION PROJECT - BRUCE NGS B EXPERIENCE

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INTRODUCTION

Boiler tube bundle repair project at Bruce B was undertaken to prevent further fretting problems experienced in these boilers. Technical details of the project are dealt with in a separate presentation by the Babcock and Wilcox staff in another session of this Conference. This presentation is focused on quality assurance aspects of the project and on the contribution of the Bruce B QA Section to the success of the project.

Station Management as well as the Atomic Energy Control Board put a strong emphasis on quality assurance aspects of the project. The efforts can be summarized into the QA axiom: do it right the first time.

It was decided that the station QA Section would be intensively involved in all phases of the project. It was the first time the Station QA Section was involved in this type and size of a project. Consequently, some valuable experience was gained by both the QA staff as well as other staff involved in the project.

PREPARATORY WORK

Objectives

The first step in the process of QA Section involvement was to establish objectives of that involvement. Two basic objectives were defined:

1. To provide an effective and independent feedback via audits and surveillance to the Station Management so that the mistakes are prevented.

2. To do efficient auditing and surveillance which would not cause any unnecessary delays and stoppages of the repair work.

Although both objectives seemed to be apparent, to meet them fully required a great deal of planning. In particular the second objective was a challenge. The project was on the critical path for the Unit outage and any unnecessary time losses were not acceptable. Liaising with the Outage Planners and Work Group Supervisors as well as attendance of coordination/planning meetings on a regular basis was necessary. QA surveillance was

then scheduled to fit the project schedule. This approach also had a positive effect on the relationship between the QA staff and the project staff. The final assessment of the project confirmed that both the objectives had been met.

Action Plan

The second step in the preparatory work phase was to prepare an Action Plan. The purpose of this plan was to list the major QA activities in a proper sequence and to assign completion dates to them. These activities were related to the following elements of QA involvement:

1. Design Quality Assurance
2. Station generated project documentation: Work Plan
3. Contractor generated documentation: Work Procedures
4. Training of Contractor Staff
5. Field work
6. History Docket.

The Action Plan was then submitted to the Station Management and to the Bruce B Office of the Atomic Energy Control Board and an approval in principle was obtained from both.

Responsibility Matrix

The next step in preparations for QA Section involvement in the project was to prepare and get an agreement on a Responsibility Matrix. This task was more complex than expected because of a large number of project participants. The parties who directly participated in the project were:

External Contractor
Head Office Maintenance and Inspection Group
Station Technical Group
Station Maintenance Group
Station Operations Group
Station Radiation Protection Group
Site Production Support Group
Station QA Group.

Indeed, basic responsibilities associated with the project had been known but they were not worked out to a sufficient detail required for the audit and surveillance activities. Another drawback was that only responsibilities for basic performance activities were known. The Responsibility Matrix prepared by the QA Section broke down the activities to a greater detail and also showed responsibilities for the verification and audit of performance activities. This process pointed out that in some cases there was an overlap in responsibilities and on the other hand there was no clear responsibility assignment for some detailed out activities.

Two meetings of involved parties were required to come to a clear picture of responsibilities. The clear and understood responsibility matrix proved to be indispensable during the field execution of the project.

AUDITING AND SURVEILLANCE

With all preparatory work completed it was possible to start performing audits and surveillance according to the Action Plan. The sequence of audits and surveillance corresponded with the sequence of project elements given in the paragraph on the Action Plan. The sequence is repeated here for convenience sake. The type of audit is indicated in the brackets.

1. Design Quality Assurance (documentation audit)
2. Station Work Plan (documentation audit)
3. Contractor Work Procedures (documentation audit)
4. Contractor Staff Training (field surveillance)
5. Repair Work on the Boiler (field surveillance)
6. History Docket (documentation audit)

As indicated above, some of the audits were documentation audits and some were field surveillance. It is in place to explain the meaning and differences between the terms "audit" and "surveillance" as they are used in this presentation. An audit is a concentrated, formal checking process which has all the following elements: pre-audit meeting in which the scope and objectives are discussed with the audited organization or an individual, auditing either of the documentation of the field work or both, post-audit meeting where a draft report is presented and actions committed, and the final report. Surveillance is a less formal form of checking. A formal pre-audit meeting is usually missing. The effort is usually not continuous and is more of an ad hoc character. However, a report is issued and actions are committed and recorded.

In the following paragraphs the approach and results of all audits and surveillance is discussed for each element separately. Experience gained in these audits is also mentioned.

Design Assurance

To mitigate fretting of boiler tubes, the contacted external organization designed a repair which in principle would stiffen and immobilize the boiler tubes. The design process was coordinated by the Ontario Hydro Head Office Design Organization. An integral part of the process was design quality assurance. The task of the Station QA Section was to satisfy themselves on behalf of the Station that QA principles and processes had been applied in the design phase. This was accomplished by the review of the evidence. The review confirmed that the quality assurance of the design had been properly planned and executed.

This audit was a formality since the Head Office Quality Engineering Group had been taking care of quality assurance and the involvement of the Station QA Section seemed to be a duplication of the effort. Consequently no significant experience was gained.

Work Plan

Any major work in the Station is controlled by a Work Plan. The Technical Section of the Station prepares a Work Plan which is then reviewed and accepted by all other Station Groups involved in the planned work. The QA Section was the last group to review the Plan. The QA Section looked at the Plan mainly from the point of view of the completeness of the Plan, coordination among the involved groups, radiological and conventional safety and verification and approval processes. A post-audit meeting was held and corrective actions committed.

Experience gained in this audit was that although the probability of having a subject expert in the QA Section is low, the QA Section can make contribution to the quality of the document and subsequent field work. In particular, suggestions with respect to radiological and conventional safety and coordination among the groups added to the quality of the Plan.

Contractor Work Procedures

Work procedures for the field repair work on the boiler were prepared by the Contractor. A total of six procedures had been prepared and all of them were reviewed by the Station QA Section. It was a demanding task because none of the members of the QA Section had had a solid previous experience with the involved Station systems under repair. Extra effort was required to overcome this drawback and some meaningful improvements were suggested and implemented. However, the emphasis of the QA review was on radiation safety, conventional safety and coordination between the Contractor and the involved Station groups. The total time spent by the QA Section staff on the review of the Contractor generated work procedures was 21 person days which by far was the most significant time expenditure of the whole QA Section involvement.

Once again the main lesson learned was that despite the lack of specific experience the QA staff made over 20 recommendations which all resulted in corrective actions. Some of them were simple semantic problems but many were significant improvements of safety and coordination.

Training of Contractor Staff

This element posed a difficulty for the Contractor. With the exception of management supervisors all maintenance staff for the project was hired from the Union Hall. The Contractor was limited

as far as selection of the suitable manpower was concerned. The labour laws dictate that only a limited number of hired staff can be selected. For the rest the seniority had to be taken into account. It was obvious that the training of the Contractor maintenance staff was of the paramount importance. Two members of the Station QA Section witnessed all important parts of the training process at the Contractor's premises on a mock up. Based on the observations the auditors made suggestions in the areas of training methodology, competence assessment, and radiological and conventional safety. A post-audit meeting was held immediately after the observations at the Contractor's premises and corrective actions were committed right there.

Experience gained at this phase was that in general the Ontario Hydro training expertise and requirements are high. The depth of the audit was enhanced by the fact that one of the auditors had had a significant experience in the Ontario Hydro training organization. The lesson here was that it would be advisable for the QA group to commission help from the training organization and have a member of that organization on the audit team.

Field Work

In the Action Plan discussed above the QA Section indicated the critical points of field execution at which it will do the surveillance. Eight important stages of the repair work were identified for surveillance. To prevent stoppages of work, QA Section were making frequent visits of job location to be sure of good timing for their committed surveillance. These more frequent visits resulted in a number of good observations and subsequent recommendations which made the next execution of the repair on a different boiler more efficient and safer. Some of the recommendations were acted on right away, some were implemented in the second repair of a different boiler six months later. A formal post-audit meeting was held after the outage and 16 recommendations were made and corresponding corrective actions were committed.

Experience gained during this phase was that it was possible by careful planning of surveillance to prevent adverse interference of surveillance activities into the flow of work. It was also obvious that more frequent observations can contribute to the quality of performance.

History Docket

The nature of the repair required the assembly of a History Docket. The History Docket was to be filed and stored in the QA Vault. In this phase the QA Section was asked to be an advisor to the Station Technical Section and identify the documents originated by the Contractor. These documents were then turned over to the Bruce B Generating Station. The QA Section checked the contents and the History Docket was then filed by the Records Unit in the QA Vault.

The only experience gained in this phase was that QA Section knowledge of QA requirements can be of benefit to other Station groups.

ASSESSMENT OF QA INVOLVEMENT

Because of the importance of the project and certain uniqueness of the QA Section involvement a report for the Station Management was prepared to summarize and discuss the QA Section involvement. The fact that in the future this repair may be repeated on all Bruce B boilers contributed to the issue of the summary report. The following are some important items from the report.

In total the QA Section staff spent 38 person-days on the project. Forty-nine recommendations made in audits and surveillance indicate that the involvement of the QA Section was effective. Indeed not all of these recommendations were significant but many of those made observing training and field work contributed significantly to the better performance. The involvement was also efficient. No critical time was lost due to auditing or surveillance.

One negative feature of the QA Section involvement was noticed. Because of a very visible presence of the QA Section during all phases of the project some supervisory staff felt that QA auditing and surveillance supplants supervisory duties and that there was no need for vigorous supervisory presence in the field. A similar observation was made of other staff involved in verification of work. These negative phenomena were discussed in the post-audit meeting.

The final endorsement of the QA Section involvement came when the second repair was done to a different boiler six month after the first one. In the first repair only so a called partial fix was done. The second repair was a full fix which meant a longer duration of the work and more complicated maintenance work in the boiler. The repair project was on the critical path for the Unit outage. It was completed before the scheduled time and with an excellent safety record. Although the intensity of the QA Section involvement was as strong as in the first repair there were no significant observations and all actions from the first turn were implemented and contributed to the success of the project. Logically not all of the success can be attributed to the QA Section involvement but the corrective actions suggested in the QA audits and surveillance visibly contributed to a well done job.

CONCLUSIONS

Involvement of the QA group in a large station project has a high potential to be effective and efficient. The areas of the most significant contribution of the QA group will most probably be:

coordination among various work groups
radiological safety
conventional safety
verifications and approvals
document control.

The absence of an intimate knowledge of the audited field does not seem to be an obstacle to a good audit. If there is a need for a deep narrow audit in some specialized field like for instance training or a specific technical field, it is better to have a specialist from that field on the audit team. The team would then consist, as a minimum, of a member from the QA group and a specialist. The QA member would provide the general audit expertise and the specialist would make the specific input.

The strong point of the QA group involvement is its independence and the ability to see things from the outside without being blinded by the pressures and customs of the job.

The weak point of the involvement is that the QA group is often perceived as another layer of supervision which is there to carry a part of the supervisory duties. That perception has to be guarded against by an aggressive broadcasting of the QA group function and by subsequent behaviour on the job.

The experience of the Bruce B QA Section with its involvement in the boiler repair project has been positive and gives it the confidence for similar future assignments.

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WORK SAMPLING STUDIES

BRUCE NUCLEAR GENERATING STATIONS 'A' AND 'B'

Ijaz Khan and Richard Robertson

Bruce Nuclear Power Development

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ABSTRACT

Work Sampling in Ontario Hydro's Nuclear Operations Branch (NOB) is one of the work programs that addresses human performance problems. Human performance is itself one of four key strategic areas addressed by the NOB maintenance strategy.

The work sampling methodology was designed to measure actual hands on tool time (wrench time) and other activities associated with station maintenance staff. Bruce Nuclear Generating Station 'A' (Bruce NGS 'A') developed a methodology for wrench time and work delays measurement and evaluated it by conducting a pilot study in April 1991. The Bruce NGS 'B' station and other departments, such as Bruce Site Services, have adopted the same methodology to conduct studies in their maintenance groups.

This paper describes the methodology and discusses the results of wrench time studies conducted at Bruce NGS. 'A' and 'B'. On the basis of the data collected from these wrench time studies, conclusions are drawn as to the usefulness of the work sampling technique.

WORK SAMPLING STUDIES
BRUCE NUCLEAR GENERATING STATIONS 'A' AND 'B'

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INTRODUCTION

Nuclear Operations Branch developed a maintenance strategy to improve performance in four strategic areas (Reference 4). Human performance is one of these strategic areas. A major issue in the area of human performance is maintenance labour productivity.

To improve maintenance labour productivity, the roadblocks that decrease productivity must be identified. These roadblocks have been measured at Bruce NGS 'A' and 'B' by a statistical sampling technique called work sampling. In addition, it has also been utilized to measure maintenance wrench time (actual hands on tool time) as well as to quantify maintenance delays (administrative procedures, work protection, equipment isolation, tools, spare parts, paperwork etc.).

The goal of work sampling is to identify and then to eliminate avoidable work delays without sacrificing personnel and plant safety. Work sampling, by identifying these work delays, can produce a decreased work backlog which in turn will increase the maintenance hours available to conduct preventive maintenance (i.e., do more work with the same staff levels).

Bruce NGS 'A' developed the methodology to conduct maintenance wrench time studies and completed a pilot study in April 1991 to evaluate it. The work sampling methodology is now widely accepted throughout the Nuclear Operations Branch. A number of departments within NOB have subsequently conducted wrench-time studies. Bruce NGS "B" conducted its initial wrench time study in January 1992.

This paper discusses the work sampling methodology and the two nuclear station wrench time studies that used it. The discussion of work sampling in this paper is presented in two parts. The first part of the paper describes the methodology and the second part discusses the results obtained from the studies conducted at Bruce NGS 'A' and 'B'.

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WORK SAMPLING

Work sampling is an easy to implement process that provides results with known accuracy. It operates without recourse to stopwatches or subjective judgments of performance. The data collected by work sampling is a visual snapshot of the various maintenance work activities. A work sampling observer determines what each individual is doing at an instant in time and then classifies that activity into one of several pre-defined categories. When a worker is observed working, the sampler makes no judgments as to:

1. Work pace - How hard is the person working;
2. Work method - How smart is the person working; and
3. Crew size - Are there too many people working on a job?

The work sampling methodology simply measures how well the management is utilizing its work force. More importantly, once an initial baseline study has been completed, future studies can be used to measure any progress made in worker utilization. The major reasons for using work sampling are to identify the possible causes of low work force utilization. These possible causes include:

1. management and organization;
2. planning - work is not well planned and coordinated;
3. lack of supervision - supervisors tied up in meetings and office work;
4. restrictive deficiency reporting (DR) systems;
5. inadequate enforcement of work rules;
6. unavailability of tools and material;
7. inadequate external support from engineering and technical work groups;
8. insufficient quantity of available work for assignment; and
9. lack of motivation and ownership.

METHODOLOGY

The Maintenance Support Unit at Bruce NGS 'A' developed the work sampling methodology used to conduct the maintenance wrench time studies. Cambridge Consulting Group of Cambridge Ontario provided the software and hardware for the wrench time studies. Bruce NGS 'A' and Cambridge Consulting Group worked together and customized the work sampling software.

Station wrench time studies using the work sampling methodology were designed to provide a 95% confidence level with ±3% accuracy on crew results. Therefore if the percentage of observed activity is 15%, there is a 95% probability, for 100% of the population, that the observed activity is carried out between 12 to 18 percent of the time.

To generate the data, work sampling defines sixty-two individual maintenance activities. These individual activities are grouped, for data entry and analysis, into ten separate activity categories (Appendix).

The work sampling software calculates the number of observations required to achieve the desired sampling accuracy and generates the random tour schedules used for work sampling. In the field, electronic data collectors record the observations made by the independent observers. This collected data is then transferred electronically to the work sampling software for data management and analysis.

Outside observers were used to take observations for both the Bruce NGS 'A' and 'B' studies. The observers used were provided by Cambridge Consulting Group and were experienced in the sampling process. The use of outside observers in the studies eliminated any bias in the data collection process. Line supervisors, or their delegates, guided the tours for their crews and provided work locations as well as identification of individual crew members.

Observations taken on the crew by crew basis accounted for each and every maintainer whether present or absent. Each crew had its own electronic data file. These data files were then combined to produce various higher order files for comparison and analysis. To avoid confusion during data logging and data analysis, a hierarchical file structure was defined before beginning the data collection process.

BRUCE NGS 'A' and 'B' DATA SUMMARY

Data Collection and Summary Headings

This section of the paper presents the measurements collected during the Bruce NGS 'A' study of April 1991 and the BRUCE NGS 'B' study of January 1992. The data collection period for both studies was seven days in length and 24 hours per day. During each of the studies the independent observers took approximately 4500 to 5000 field observations. This number of field observations gave a sampling accuracy of +/- one percent with a confidence limit, on overall station results, of 95 percent.

All field observations presented in this section are grouped into ten different categories. Each category representing the activities associated with a station's non-supervisory maintenance personnel. In addition , this section groups several of activity categories under three summary headings (i.e., productive, non-productive and unavailable to station). Table 1 lists the various activity categories and their respective summary headings.

Table 1
Activity Category Summary Headings

Summary Headings	Activity Categories
Productive	Wrench Time Support Work Work Related
Nonproductive	Delays Traveling Lost Time
Station Policy	Station Policy
Unavailable	Training Absent
Not Found	Not Found

The work sampling results presented in this paper have been adjusted by the removal of observations made for station maintenance personnel unavailable to the station because of vacation or sick leave. These modified results are a more

accurate representation of how maintenance personnel actually available to the station spend their time. As a consequence they provide a more effective measure of station maintenance personnel utilization.

Station Comparisons

Table 2 presents the station data in percent for productive, nonproductive, station policy and not found categories and summary headings. For each of the station studies conducted, the percentage of personnel unavailable to the station as a result of absent and training activity categories was 21.8 percent for Bruce NGS A's April 1991 study and 19.1 percent for Bruce NGS B's January 1992 study.

Table 2
Station Combined Shift Comparison

	BNGS 'A' April 1991	BNGS 'B' January 1992
Productive	42.6	40.2
Nonproductive	28.7	29.1
Station Policy	25.2	29.5
Not Found	3.0	1.1

Station Shift Comparisons

The Tables 3, 4 and 5 present the shift data in percent for productive, nonproductive and station policy activity categories and summary headings respectively. Shift data presented includes:

1. G Crew - 8 hour days Monday to Friday;
2. STU Crew - 12 hour seven day rotating day shift
3. Shift Days - days 12 hour rotating shift schedule; and
4. Shift Nights - nights 12 hour rotating shift schedule.

Table 3
Productive Shift Comparison

	BNGS 'A' April 1991	BNGS 'B' January 1992
G Crew	53.1	48.0
STU Crew	46.9	56.4
Shift Days	44.4	32.8
Shift Nights	32.4	31.3

Table 4
Nonproductive Shift Comparison

	BNGS 'A' April 1991	BNGS 'B' January 1992
G Crew	26.6	27.0
STU Crew	23.6	22.7
Shift Days	19.5	28.2
Shift Nights	39.8	34.0

Table 5
Station Policy Shift Comparison

	BNGS 'A' April 1991	BNGS 'B' January 1992
G Crew	14.7	21.9
STU Crew	26.8	19.6
Shift Days	34.2	38.0
Shift Nights	25.1	34.2

Station Productive and Nonproductive Breakdown

Table 6 and Table 7 provide a breakdown by percentage of the productive and nonproductive summary headings. All values displayed in the tables are for station combined shift results. The appendix to the paper provides a further

breakdown of the various activity categories by individual activity.

Table 6
Station Productive Activity Category Breakdown

	BNGS 'A' April 1991	BNGS 'B' January 1992
Wrench Time	15.9	18.3
Support Work	12.5	6.7
Work Related	14.2	15.2

Table 7
Station Nonproductive Activity Category Breakdown

	BNGS 'A' April 1991	BNGS 'B' January 1992
Delays	7.4	7.3
Traveling	16.0	14.1
Lost Time	5.3	7.7

Activity Category Breakdown

The tables 8 to 13 give in percent, except for wrench time, the breakdown of the various activity categories. The tables list only those activities that make a significant contribution to the respective categories. All remaining activities in the various categories are reported under the heading 'Other'.

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Table 8
Support Work Category Breakdown

	BNGS 'A' April 1991	BNGS 'B' January 1992
Observing and Inspecting	N/A	2.2
Documentation	N/A	1.6
Write/Update Procedures	N/A	1.5
Others	N/A	1.4

Table 9
Work Related Category Breakdown

	BNGS 'A' April 1991	BNGS 'B' January 1992
Writing Reports	N/A	3.8
Reading Drawings and Procedures	N/A	3.7
Helping Co-Workers	N/A	2.4
Receiving Instructions	N/A	2.0
Safety Precautions	N/A	1.2
Others	N/A	2.1

Table 10
Station Policy Category Breakdown

	BNGS 'A' April 1991	BNGS 'B' January 1992
Meals/Breaks	14.9	18.1
Showers and Lockers	6.9	5.2
Safety Meetings and Drills	3.0	4.4
Others	0.4	1.8

Table 11
Delays Category Breakdown

	BNGS 'A' April 1991	BNGS 'B' January 1992
Supervisor's Instructions	2.3	2.3
Operator Work Protection	2.2	1.5
Material from Stores	0.8	1.2
Others	2.1	2.3

Table 12
Traveling Category Breakdown

	BNGS 'A' April 1991	BNGS 'B' January 1992
New or Unfinished Job	2.9	6.0
For Material and Tools	6.1	3.5
To/From Break	5.1	3.3
Others	1.9	1.3

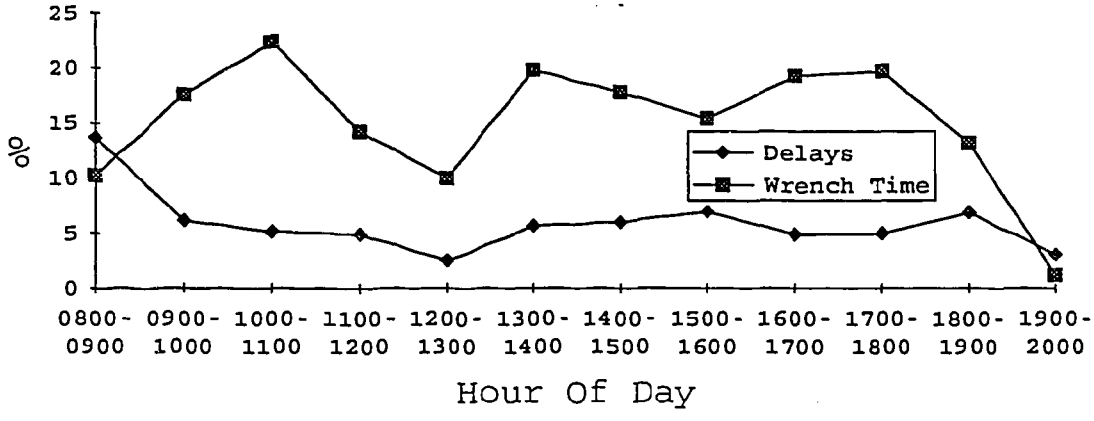
Table 13
Lost Time Category Breakdown

	BNGS 'A' April 1991	BNGS 'B' January 1992
Assigned but Idle	N/A	4.1
Unassigned	N/A	2.5
Others	N/A	1.1

Daily Variation - Wrench Time and Delay Categories

Figure 1 shows Bruce NGS B's wrench time and delay categories for the 12 hour period from 0800 hours to 2000 hours. Similar wrench time and delay data from Bruce NGS 'A', although collected, was unavailable.

Figure 1
BRUCE NGS B Wrench Time and Delay Categories



DATA INTERPRETATION

Station and Shift Comparisons

The two wrench time studies found no significant differences between stations. These studies, however, did indicate that day maintenance crews (G and STU) spend a greater portion of their time involved in productive activities versus nonproductive and station policy activities. The only exception to this was BRUCE NGS A's shift day crew.

Productive and Nonproductive Breakdown

Of the total productive time, approximately one third to one half consists of actual wrench time. The remainder of productive time is made up of support or work related activities. Under the support and work related activities, documentation related activities (writing procedures, reports etc.) are the most common.

Under the nonproductive activity summary heading, the traveling activity category makes up a significant portion of the nonproductive activities. In fact, traveling related activities are approximately equal to the sum total of delay and lost time activity categories.

In both studies station policy activities occupied approximately 25 to 30 percent of a maintainer time. Of the various station policy activities, the largest portion was reserved for meal and coffee breaks. A comparison of the station policy activities to wrench time indicates that approximately the same percentage of time is spent on lunch and breaks as on wrench time (i.e., 15 to 18 percent).

A review of the activity category breakdowns shows that the biggest delay causes are waiting supervisor's instructions, work protection and material from stores. In addition the category breakdowns show that traveling to and from the job as well as traveling to get parts are important causes of nonproductive time. By combining the data from the individual activities measured under the nonproductive summary heading, it can be concluded that:

1. lost time activities occupy 5 to 6 percent of a maintainer's time;

2. stores or material related delays and traveling make up 5 to 7 percent of a maintainer's time; and

3. showers and safety meetings comprise 9 to 10 percent of a maintainer's time.

Hourly Variations in Wrench Time and Delays

Figure 1 shows a portion of the hourly wrench time and delay activity category data. At the start of the shift (0800 hours) there is a relatively high percentage of delays. As the shift progresses, the level of delays become constant until the end of the day shift (2000 hours) when delays subsequently decline.

In contrast to the delays wrench time at the beginning of the day shift is relatively low. The wrench time data also indicates a reduction of wrench time during lunch (1200-1300 hours), at G Crew quitting time (1500-1600 hours) and after completion of the 12 hour day shift (1900-2000 hours). When putting the wrench time data in context of the overall maintenance operation, the data indicates that during the period of highest wrench time activity approximately one in four of available maintenance personnel are directly employed performing maintenance.

CONCLUSION

In comparing this wrench time data to that obtained from other work studies, it is important to consider the method used to collect data. The work sampling method used by Bruce NGS 'A' and Bruce NGS 'B' collects data for a pre-defined set of activities. Consequently, the wrench time data collected may not show wrench times as high as other "productivity studies" that use traditional stopwatch techniques to record wrench time.

Other departments within NOB such as Bruce Site Services have adopted the same methodology and have conducted similar wrench time studies. Pickering NGS and Bruce Heavy Water Plant are now in the process of planning to conduct their own studies using the same method. In all cases the results and target areas for these studies are similar to those of Bruce NGS 'A' and Bruce NGS 'B'. The five areas identified in these studies as needing improvements are:

1. field supervision;
2. extended use of day maintenance;
3. equipment ownership and specialization;
4. the planning process and possible use of "Integrated Operational" planning; and
5. spare part and tools availability.

Work sampling has been beneficial to the stations and work groups that have used it. It has provided quantitative data on maintenance personnel utilization and has helped identify the roadblocks that cause delays in maintenance. In so doing, it is helping to formulate the solutions that will eliminate roadblocks and that will increase maintenance productivity.

The work sampling software used in these studies is a flexible tool for data management and analysis. It can combine, modify and present collected data in a number of different ways. This ability makes it easier for the analyst to draw conclusions and to formulate recommendations for productivity improvements.

Although work sampling does not provide a direct measure of maintenance productivity, it is an effective method to determine the time maintenance personnel spend on a set of pre-defined activities. Work sampling's main benefit, as demonstrated by the studies at Bruce NGS 'A' and 'B', is its capability to identify areas where maintenance productivity can be improved.

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(2) KHAN I.U., "Maintenance Wrench Time Study", BGA-INF-09100-4 Bruce Nuclear Generating Station 'A', December 1991.

(3) ROBERTSON R.B., "Maintenance Wrench Time Study", BGB-MIR-08400.1 Bruce Nuclear Generating Station 'B', May 1992.

(4) Maintenance Strategy, Nuclear Operations Branch, Ontario Hydro, 1990

APPENDIX

CATEGORY ACTIVITIES

WRENCH TIME	SUPPORT WORK
Containment/ Confinement	Observing/ Inspecting
Balance of Plant	DR Assessment
Shop Machines	Write/Update Procedures
	Training
	Documentation
	Calibration of Standards
	Repair of Test Equipment
	Spares/Equipment

WORK RELATED	DELAYS
House Keeping	Waiting for Supervisor's Instructions
Helping Co-workers	Waiting for Permits, Authorization, Isolation, etc.
Reading Drawings/Procedures	Waiting for Technical Section's Input (specifications, drawings, work plans, written instructions, etc.)
Taking Safety Precautions	Waiting for Tools
Receiving Instructions	Waiting for Materials from Stores
Walking with Tools and Materials	Waiting for Equipment/Safety Equipment
Green Manning	Waiting for Transport
Working on BIMS	Waiting for Services Support (insulation/ scaffold)
Writing Work Reports on BIMS	Waiting for Quality Control Inspector
Decontaminating Tools	Waiting for Safety/Radiation Control Inspector
	Waiting for Co-worker
	Replacing Wrong Materials Supplied by Stores
	Computer Outage
	Repairing Tools Received from Tools Crib

APPENDIX

CATEGORY ACTIVITIES

TRAVELLING	LOST TIME
Travelling to New or Unfinished Job	Unassigned
Travelling to Stores to Get Materials	Assigned but Idle
Travelling to Tool Crib to Get Tools	Personal
Travelling to or from Lunch/Coffee Breaks	Late Arrival
Travelling to Check Other Equipment	
Travelling to Control Room for Work Protection	
Travelling to Supervisor's Office for Work Instructions	
Other Work-related travelling to Workshop	
Monitoring/ Decontaminating at Radiation Monitors	

TRAINING	STATION POLICY
WNTD	Medical/First Aid Break
Bruce 'A'/'B'	Lunch/Coffee Break
Other Location	Showers/Lockers
On the Job	Communication/Safety Meetings
	Union Business
	Safety Drills
	On Assignment

ABSENT	NOT FOUND
Long Term Disability	Unable to Locate
Long Terms Illness	
Lost Time Injury	
Vacation	
Sickness	

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IMPROVED MAINTENANCE PROCEDURES AT BRUCE NGS-B

PAT READY

ONTARIO HYDRO BRUCE NGS-B
TIVERTON, ONTARIO

and

D. PAUL AYOTTE

GE CANADA
PETERBOROUGH, ONTARIO

ABSTRACT

This paper considers the need for improved maintenance procedures brought about by changes in Health and Safety Regulations and Union Contracts and the turnover of experienced maintainers as a result of these changes. It outlines the creation of more comprehensive procedures based on the traditional Maintenance Manual.

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Our presentation falls into the category of a Human Performance Issue and we could probably simplify it under three headings:

What?

So what?

Now what?

What we have is an obvious need to limit unscheduled outages caused by system failures in the Nuclear Industry.

Keeping the fuel handling systems at peak operating efficiency is an important consideration at Ontario Hydro's nuclear generating stations. To minimize the number of unscheduled outages caused by system failure, Hydro has a program of preventive maintenance that it carries out at regular intervals.

At Bruce and Darlington, the fuel handling systems were supplied by GE Canada who also provided maintenance manuals for servicing them. The manuals cover every facet of the fuel handling system including the proprietary items supplied by GE's subcontractors. They recommend the frequency of maintenance and contain detailed instructions for dismantling the system, inspecting and servicing the component parts, reassembly, set-up, testing, and calibration. In a typical manual, the text is complemented by more than 100 exploded view illustrations in 3-D perspective and dozens of photographs to help the maintainers better understand how things come apart and go back together again. Pictures are also used to indicate lubrication points. The manuals are bound in durable 7-ring Peterson Case binders. Those who do the hands-on work get books with plasticized pages for easy clean up.

The Maintenance Manual is not intended to be a primer or training manual on fuel handling systems. It is aimed at trained maintainers who have received training in nuclear power plant operation. Personnel such as engineers experienced in power plant operation or technicians with technical school training (specializing in subjects relating to the application of this equipment) and a minimum of four years of power plant operating and/or maintenance experience with similar types of equipment would use them. Personnel without this training would not attempt to use the manual except with the assistance of the above mentioned experienced personnel.

It is not a complete textbook as a manual of this kind cannot address every contingency that could arise during installation, operation, and maintenance. Specialized information that is not normally required for the routine operation and maintenance of the equipment is not included.

During the preparation of the Manual it was decided to use cross-references for such things as fastener torques, lubrication data and vendor information. The main reasons for this decision were to reduce the bulk of the document and to eliminate the chance for error when revisions had to made. It was and is much easier to make the change in one place and know that every instance has been covered than trying to find the item throughout the different volumes of the Manual.

So what is the problem?

As ever, time marches on and through attrition valuable, experienced maintainers are lost to other parts of the corporation. This situation, when combined with Health and Safety efforts to reduce radiation exposure and the requirements in Union Contracts (5 rem/5 years), means that we face the fact that our crews are constantly turning over and we do not always have the experienced people available that we would prefer.

What this really means is that we had to improve the way we do things.

Reviewing the situation it was agreed the Maintenance Manual as it exists is a very useful document and has been the basis for maintenance procedures to this time.

The fuel handling systems are continually being revised and upgraded and the Bruce and Darlington maintenance manuals keep pace with this. On average, four revisions a year are published. To simplify and expedite the process, the texts have been computerized; soon the graphics will be computerized too. Eventually GE will be on-line with Ontario Hydro so that revisions can be fasttracked to the maintainers almost as quickly as GE can generate them.

However, situations have arisen where mechanical maintainers have spent undue time in general radiation fields while searching for information because they were not familiar with the manual. This lack of familiarty also led to the danger that the procedures were not being followed

adequately because new people did not know where to find the information they needed. The manuals themselves became contaminated and because they have to be reused required clean up.

When used in the office environment and with some degree of familiarity the Manual is, as stated earlier, a very useful tool but here are some examples to illustrate areas of the manual that could cause concern for new people in maintenance situations.

Cross-references exist in the manual for a reason but when you are in plastics with gloves on and you must leaf through the Manual to find a torque or a set-up dimension that reason seems somewhat vague.

Section 2–7 Maintenance Manual – Bruce GS–B Fuel Handling System
35213

Volume 1 – General Information

Fuelling Machine Head, and Head Suspension

F/M HEAD INTERNAL DRIVE COMPONENTS AND INPUT DRIVES

3.0 CHARGE TUBE AND RAM

3.4 ASSEMBLY AND INSTALLATION

3.4.2 Ram Drive Sleeve Rotation Check; Ram Input Drive Gear Mesh and Back–Lash Adjustment (Contd)

3.4.3.2 Procedure (Contd)

(f) Install the Back–Lash Indicator 29GBN35633–0019 (SCN 279N0803) to the input drive shaft and install a dial gauge to enable the back–lash to be measured. See Figure 2–7–14. Measure the back–lash with the ram drive sleeve at four different positions 90° apart. The back–lash should be 0.006 to 0.010 in. (0.15 to 0.25 mm). Back–lash correction is accomplished by adjusting the thickness of the spacer 38 behind the ram drive bevel gear 37 (see Figure 2–7–13). Decreasing the spacer thickness increases the back–lash at a ration of about 5:4, that is a 0.001 reduction is spacer thickness results in an increase of about 0.0008 in back–lash.

NOTE

Do not adjust the position of the input drive pinion gear to make back–lash corrections; adjustments to the pinion gear reflect only slight changes in back–lash as compared with the significantly greater effect they have on meshing.

(g) Remove the input drive. See Figure 2–7–1; at the top end of the input drive, bend up a tab on lockwasher 10 to secure the locknut 9.

(h) Remove the extension tube assembly.

(j) See Figure 2–7–13. Lubricate O–ring 88 with a light smear of DC–55M and install it on the end cap 59. Install the end cap and counterweights to the extension tube using lubricated capscrews 78. For the type of lubricant to use on the capscrew and for the torque refer to Section 2–4.

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Section 2–7
35213

Maintenance Manual – Bruce GS–B Fuel Handling System

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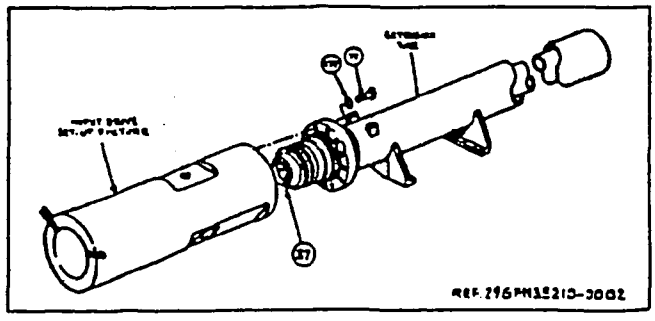
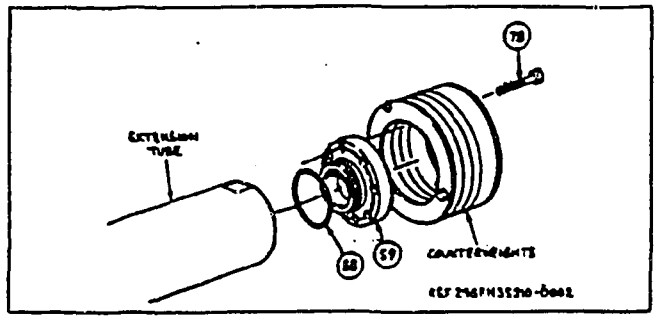
Field Maintenance Procedure – Bruce GS–B Fuel Handling System

4.0 ASSEMBLY

4.2 RAM DRIVE SLEEVE ROTATION AND GEAR ALIGNMENT CHECKS (29GFN35210–0002)

4.2.2 Procedure (Contd)





(g) Remove the extension tube and clean the teeth on the ram drive sleeve bevel gear 37 to remove any traces of duct seal or marking dye.

OPERATION COMPLETED BY ..... DATE .....

(h) Lubricate a new O–ring 88 with a light smear of DC–55M and install it on the end cap 59. Install the end cap and counterweights to the extension tube using capscrews 78 lubricated with Never–Seez NG–165. Torque the capscrews to 175 lb ft (240 Nm).

OPERATION COMPLETED BY ..... DATE .....

Drawings are not readily available when required and the exploded view illustrations are usually at the back of each section which requires leafing through the pages which can be cumbersome with gloves on. This can lead to a person making an assumption regarding the assembly process rather than taking the time to find the correct process, dimension, torque, or lubricant from the drawing.

Maintenance Manual – Bruce GS–B Fuel Handling System Section 2–8
35214

Volume 1 – General Information

Fuelling Machine Head, and Head Suspension

F/M HEAD HOMING AND LOCKING MECHANISM
AND GAP AIR SENSING PACKAGE

2.0 HOMING AND LOCKING MECHANISM (29GEN35214–0025 except where noted)

2.3 ASSEMBLY AND INSTALLATION (Figure 2–8–5) (Cont'd)

(j) Lubricate the needle bearing 12 as prescribed in Section 2–2 (Table 2–2–1) and insert, together with the retaining ring 14, in the housing 4, 29GEN35214–0024. Install the inner race 13 on the worm.

NOTE

If the inner race 13 is loose on the shaft, it should be retained on the worm shaft, with Loctite 242. Refer to Section 1, Subsection 5.0. Ensure both parts of the bearing are in line when assembled.

(k) Insert the worm and bearing assembly into the bearing housing 2, 29GDN35214–0034, and engage the worm gear. Install the housing 4, 29GEN35214–0024 on the end of the worm. Secure the bearing housing 9 using capscrews 62 and lockwashers 63. Place the dowel 16, 29GEN35214–0024, in position and secure housing 4, 29GEN35214–0024, using capscrews 14 and lockwashers 15, 29GEN35214–0024. Check that the end of the hole for dowel 16, 29GEN35214–0024, is peened over to retain the dowel. Also check that the inner and outer races of the needle roller bearing are in line.

(m) Insert the grease seal 7 in the bearing cover 8 and secure the cover with capscrews 82 and lockwashers 83. Install cover 11 using capscrews 64 and lockwashers 65 to housing 4, 29GEN35214–0024.

(n) Lubricate the pivot pins 122 and the pivot pin bushings 5 and 6, 29GEN35214–0079 in the jaw assembly, the rubbing surfaces on the locating blocks 38, and the clamping surfaces of the assembly 124 using the lubricants and procedure prescribed in Section 2–2, Table 2–2–1. Install hinge pins 122 and retaining rings 123.

(p) If removed, install the male elbow 107 to the lower jaw.

(q) Lubricate the threads of the clamping screw and nuts, 2, 3, and 4, 29GCN35214–0012, using the lubricant specified in Section 2–2 (table 2–2–1),and assemble the nuts to the clamping screw, equidistant from the centre of the screw.

(r) Lubricate pivot pins 43 and 110 and the pivot pin holes in the jaws with a light coating of the lubricant specified in Section 2–2, Table 2–2–1. Assemble the nuts and clamp screw to the jaws using pins 43 and 110. Secure the pins with capscrews 70 and lockwashers 71.(m) Insert the grease seal 7 in the bearing cover 8 and secure the cover with capscrews 82 and lockwashers 83. Install cover 11 using capscrews 64 and lockwashers 65 to housing 4, 29GEN35214–0024.

F/M HEAD HOMING AND LOCKING MECHANISM
AND GAP AIR SENSING PACKAGE

2.0 HOMING AND LOCKING MECHANISM (29GEN35214–0025 except where noted)

2.3 ASSEMBLY AND INSTALLATION (Figure 2–8–5) (Cont'd)

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NOTE
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(k) Insert the worm and bearing assembly into the bearing housing 2, 29GDN35214–0034, and engage the worm gear. Install the housing 4, 29GEN35214–0024 on the end of the worm. Secure the bearing housing 9 using capscrews 62 and lockwashers 63. Place the dowel 16, 29GEN35214–0024, in position and secure housing 4, 29GEN35214–0024, using capscrews 14 and lockwashers 15, 29GEN35214–0024. Check that the end of the hole for dowel 16, 29GEN35214–0024, is peened over to retain the dowel. Also check that the inner and outer races of the needle roller bearing are in line.

(m) Insert the grease seal 7 in the bearing cover 8 and secure the cover with capscrews 82 and lockwashers 83. Install cover 11 using capscrews 64 and lockwashers 65 to housing 4, 29GEN35214–0024.

(n) Lubricate the pivot pins 122 and the pivot pin bushings 5 and 6, 29GEN35214–0079 in the jaw assembly, the rubbing surfaces on the locating blocks 38, and the clamping surfaces of the assembly 124 using the lubricants and procedure prescribed in Section 2–2, Table 2–2–1. Install hinge pins 122 and retaining rings 123.

(p) If removed, install the male elbow 107 to the lower jaw.

(q) Lubricate the threads of the clamping screw and nuts, 2, 3, and 4, 29GCN35214–0012, using the lubricant specified in Section 2–2 (table 2–2–1),and assemble the nuts to the clamping screw, equidistant from the centre of the screw.

(r) Lubricate pivot pins 43 and 110 and the pivot pin holes in the jaws with a light coating of the lubricant specified in Section 2–2, Table 2–2–1. Assemble the nuts and clamp screw to the jaws using pins 43 and 110. Secure the pins with capscrews 70 and lockwashers 71.(m) Insert the grease seal 7 in the bearing cover 8 and secure the cover with capscrews 82 and lockwashers 83. Install cover 11 using capscrews 64 and lockwashers 65 to housing 4, 29GEN35214–0024.

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Maintenance Manual – Bruce GS–B Fuel Handling System Section 2–8
35214

Volume 1 – General Information

Fuelling Machine Head, and Head Suspension

F/M HEAD HOMING AND LOCKING MECHANISM
AND GAP AIR SENSING PACKAGE

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(p) If removed, install the male elbow 107 to the lower jaw.

(q) Lubricate the threads of the clamping screw and nuts, 2, 3, and 4, 29GCN35214–0012, using the lubricant specified in Section 2–2 (table 2–2–1),and assemble the nuts to the clamping screw, equidistant from the centre of the screw.

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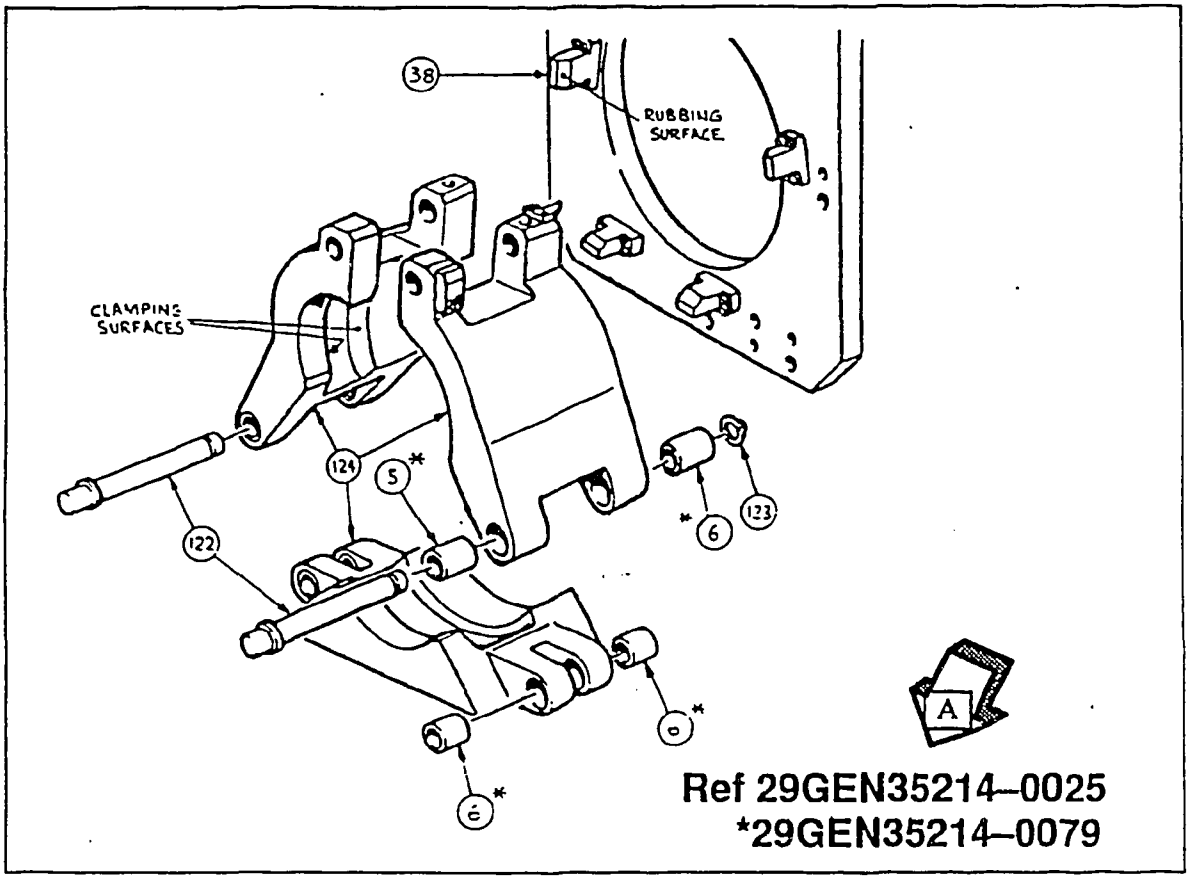
F/M HEAD HOMING AND LOCKING MECHANISM
AND GAP AIR SENSING PACKAGE

2.0 HOMING AND LOCKING MECHANISM (29GEN35214–0025 except where noted)

2.3 ASSEMBLY (Contd)



(m) Use APL 702 grease to lubricate the pivot pins 122 and the pivot pin bushings 5 and 6, 29 GEN35214–0079 in the jaw assembly, the rubbing surface of the locating blocks 38, and the clamping surfaces of the jaws 124. Install the hinge pins 122 and the retaining rings 123.

OPERATION COMPLETED BY ..... DATE.....

Information required for maintenance of vendor supplied components is contained in a separate volume of the manual and not readily available in the work areas. It also happens that mechanical, electrical, and control data is in separate sections of this volume and therefore could require additional time to locate.

Section 2–9
35216

Maintenance Manual – Bruce GS–B Fuel Handling System

Volume 1 – General Information

Fuelling Machine Head, and Head Suspension

F/M HEAD EXTERNAL DRIVES

3.0 GEARBOX (29GEN35216–0024 and Figure 2–9–4)

3.3 DISASSEMBLY

3.3.10 Differential (Contd)

(c) Withdraw the bearings 25 and 26 and remove spacers 54. Slacken the set screws 163 and remove the lock rings 53. Remove the compound gears 4 together with the bearings and spacers.

(d) Remove the Spirol dowel pins 139 and withdraw the bevel gear shafts 21 to release the bevel gears 5 from the spur gear 2.

3.3.11 Worm Shafts

(a) Remove the capscrews 143 and the bearing caps 76. Retain the shim sets 77 with the bearing caps. Discard the lockwashers 165, O–rings 46, and seals 51.

(b) Carefully withdraw the complete worm shaft assembly. Avoid damaging the worm or worm gear. Remove the bearings from the shaft as required.

3.4 INSPECTION AND SERVICING

3.4.1 Vendor Components

(a) For the inspection and servicing of vendor components, refer to Volume 6, Section 35210 (35216) and 63521.

(b) For the set–up, calibration, and check–out of the gearbox brakes and clutches, refer also to Section 2–3, Subsection 8.0.

(c) When reassembling the Stearns brakes –EM1–BK and –EM2–Bk to the head drive motors –E–M1 and –E–M2, the setscrews 16S* securing the hub 16* to the drive motor shaft, must be treated with an application of Loctite 242 and torqued to 70 lb in. (8.0 Nm). Refer to Section 1, Subsection 5.0 for the procedure for applying Loctite 242. For information on the brakes, refer to the Stearns Data Sheets in Volume 6, Section 63510 (B002).

3.4.2 Gears

Visually check all gears for wear and damage to the bore and keyways, for chipped and broken teeth, and for uneven wear on the teeth. Small nicks and burrs can be removed by light stoning.

* Stearns part numbers

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Maintenance Manual – Bruce GS–B Fuel Handling System

Volume 1 – General Information

Fuelling Machine Head, and Head Suspension

F/M HEAD EXTERNAL DRIVES

3.0 GEARBOX (29GEN35216–0024 and Figure 2–9–4)

3.3 DISASSEMBLY

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Section 2-9
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Maintenance Manual – Bruce GS–B Fuel Handling System

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Visually check all gears for wear and damage to the bore and keyways, for chipped and broken teeth, and for uneven wear on the teeth. Small nicks and burrs can be removed by light stoning.

* Stearns part numbers

Field Maintenance Procedure – Bruce GS–B Fuel Handling System

THE VENDOR INFORMATION REFERENCED HERE IS NOW CONTAINED IN THE FMP BINDER AND DOES NOT REQUIRE THE TECHNICIAN TO BREAK AWAY FROM THE MAINTENANCE OPERATION TO GET FURTHER INFORMATION.

Field Maintenance Procedure – Bruce GS–B Fuel Handling System

EXTERNAL DRIVES GEARBOX

4.0 INSPECTION AND SERVICING (Contd)

4.11 MOTOR BRAKES (–EM1–BK and –EM2–BK)

(a) If a brake is tagged for key replacement, remove the cover and notify the Technical Unit. If the brake is not tagged for key replacement, remove the cover and check for any signs of looseness between the brake hub and the key in the motor stub shaft – if looseness is found, contact the Technical Unit for a decision on key replacement. Oversize keys up to 0.25 in. (6.4 mm) are permissible.

(b) Check that the adjusting spring has not bottomed out. If there is not compression left, install a new one (SCN _____).

(c) Strip down the brake and inspect all parts. Check that the brake hub is the current 'toothed' configuration and not the original square shape. If it is square, remove it and the friction disc and replace them with new parts from Stores (SCN 423A4871 and 423A4885 respectively). Replace the oil seal in the end plate with a new one (SCN 565N7843).

(d) Check the friction disc for signs of wear, as evidenced by scuffing and by a large solenoid air gap, and replace it if necessary (SCN 423A4885). Check that the pressure plate is flat. If it is not, replace it (SCN _____).

(e) Check the solenoid air gap; it should be between 0.76 and 1.000 in. (between 19 and 25 mm). The procedure for setting the gap is given in the manufacturer's information in the FHS Maintenance Manual (NK29–WAN–35000–1001), Volume 6, Section 63521 (B004).

(f) When the brakes are being installed on the motors, treat the set screws that secure the hub to the drive motor shaft with Loctite 242 and torque them to 70 lb in. (8.0 Nm). The set screws are shown in items 16S on the illustration on the facing page.

Was it necessary to replace the friction disc in –EM1–BK?	Yes _____	No _____
Was it necessary to replace the pressure plate in –EM1–BK?	Yes _____	No _____
Was it necessary to replace the adjusting spring in –EM1–BK?	Yes _____	No _____
Was it necessary to replace the operating coil in –EM1–BK?	Yes _____	No _____
Was it necessary to replace the friction disc in –EM2–BK?	Yes _____	No _____
Was it necessary to replace the pressure plate in –EM2–BK?	Yes _____	No _____
Was it necessary to replace the adjusting spring in –EM2–BK?	Yes _____	No _____
Was it necessary to replace the operating coil in –EM2–BK?	Yes _____	No _____

OPERATION COMPLETED BY ..... DATE.....

TORQUE VERIFIED BY ..... DATE .....

Field Maintenance Procedure – Bruce GS–B Fuel Handling System

* SOME PROCEDURES ARE USED THROUGHOUT THE FMP'S AND ARE NOT REPRODUCED EACH TIME THEY ARE CALLED UP. THE TECHNICIAN IS ADVISED TO OBTAIN A COPY OF THIS DOCUMENT FOR REFERENCE AS PART OF THE ACCUMULATION PRIOR TO COMMENCING THIS MAINTENANCE OPERATION.

Now what we are doing is using a new style of manual for major equipment overhaul.

We are increasing the quality of maintenance by having procedures that are now user friendly.

Prepared by GE Canada and called Field Maintenance Procedures, they are formatted for the less experienced maintainer and lay out the step-by-step routines in more basic detail and with many more pictures. The training time for new people is reduced because of the completeness of thse new procedures.

The new procedures provide accurate records to ensure all activities have been completed and by which mechanical maintainer, as all operations are signed off by the maintainer doing the work and critical operations require second party verification.

A further benefit of the new procedures is reduced maintenance costs. This is accomplished because all the required information such as parts lists, SCN's, tooling lists and many more illustrations (average one per page) are included. The mechanical maintainer also knows what is needed for each procedure with regard to reference drawings and procedures, replacement parts that should be accumulated and consumables such as cleaners and lubricants that will be used from the accumulation pages at the front of each text.

We are finding reduced radiation exposure due to the reduced time spent working on active parts when using these accurate, high quality procedures . Lower radiation limits and the resultant manpower changes are not so much of a problem now.

When we decided that this was the direction in which we wished to go we determined that with the present manpower limitations it would be very difficult to use experienced maintenance people to write procedures. We also recognized that within our Mechanical Maintenance Department we had little or no capability to produce adequate exploded view illustrations. The natural thing to do was to turn to the designer-manufacturer:

-as the designers of the equipment GE Canada has all the required information to produce the procedures.

-GE Canada can produce high quality, user friendly procedures based on the Maintenance Manual.

-GE Canada has the capability to provide the required exploded view illustrations that are so beneficial to the mechanical maintainer.

-GE Canada has demonstrated an ability to liase with our mechanical maintainers and technical people to ensure that the procedures are correct and up to date. Revisions are issued promptly when required.

-GE Canada is in the process of installing a new computer publication system with the capability to electronically create, edit, and revise both text and graphics. This will insure that the technical people get up to date data quickly.

These new procedures are gaining broad favour at Bruce B with the mechanical maintainers. The next generation of maintenance manuals will almost certainly include a version of the Field Maintenance Procedures and will probably make provision for electronic sign-offs. It seems to be the wave of the future.

CA 9500135

INTEGRATED OPERATIONAL PLANNING

AT

BRUCE A NGS

V.S. Hutter

Technical Superintendent - Planning

Bruce A Nuclear Generating Station

Ontario Hydro

ABSTRACT

Over the past 2 years, staff at the 4 unit Bruce A nuclear generating station have been developing and implementing a new and innovative planning process. It's development has evolved from the need to significantly improve the daily coordination of maintenance work being performed on units in the operating state. The new technique has introduced to the station the use of multi-disciplinary planning teams, a 13 week rolling maintenance schedule, and comprehensive work packages. Following the successful pilot implementation on one unit, Bruce A has been proceeding with full implementation across the station. This paper describes the significant aspects of the overall planning process, the status of implementation, and the results which have been achieved to date.

INTEGRATED OPERATIONAL PLANNING AT BRUCE A NGS

V.S. Hutter
Technical Superintendent - Planning
Bruce A Nuclear Generating Station
Ontario Hydro

1.0 INTRODUCTION

Two years ago, staff at the Bruce A Nuclear Generating Station began development on a new planning process aimed at significantly improving the daily coordination of operating state maintenance work. A distinction is made between a unit in the operating versus outage state, since very different planning techniques are used. The new process is referred to as Integrated Operational Planning (IOP), and it has introduced 3 new concepts to operational maintenance planning at the station:

1. The use of Multi-Disciplinary Planning Teams, centrally coordinated by the Planning Section, but employing the skills of planners, tradesman and operators, working as dedicated unit teams, to provide planning support to the field trades.

2. The use of a Thirteen Week Rolling Maintenance Schedule, where each week is designated as a "blitz" period for certain functional equipment groups.

3. The use of Comprehensive Work Packages, which are provided to the field trades and contain all the essential information needed to promptly execute the required work.

The process was designed to complement a gradual restructuring of the station's entire maintenance organization (Figure 1) to accomodate:

- Performing planned maintenance on days rather than on shift, thereby leaving the shift crews with primary responsibility for addressing urgent unplanned work.

- Having unit dedicated field maintenance groups and multi-unit equipment specialty groups on days.

- Lead Trade Groups (Work Authorities) to ensure field accountability for the coordination and execution of scheduled work.

A little over a year ago, Bruce A began implementing this new planning process as a 3 month pilot on 1 of the 4 Bruce units. Success with the pilot prompted the decision to implement the process in a sequential manner on the remaining units. Sequencing was necessary in order to accomodate the required organizational restructuring. Currently, 2 units are fully implemented, with the other units in various stages of preparation. The first unit to see implementation has experienced a dramatic decrease in outstanding operating deficencies and a significant improvement in the completion of required preventive maintenance.

I have organized this presentation into 5 parts, each one addressing one of the following questions:

1. What prompted the need for planning process improvement?
2. How was the process developed?
3. What are the key process components?
4. What sort of measurable success has been achieved?
5. What are the future plans?

2.0 CONCEPT ORIGINS

It might be helpful to first provide a brief descriptive overview of Bruce A. It is one of two nearly identical 4 unit nuclear generating stations located at the Bruce Nuclear Power Development (BNPD) site in south-western Ontario. The reactor units are numbered 1 to 4. There is also a unit 0 comprising common process systems and fuel handling.

Each CANDU (pressurized heavy water) reactor unit is rated at a gross unit maximum continuous rating of 904 MW (electrical equivalent). First electricity was produced in 1976, and during the first 10 years of operation it was able to break world energy production records and maintain a capability factor in excess of 85%.

There are currently about 1000 staff employed at Bruce A. This includes about 250 operators, 200 control technicians and 200 mechanics. There are also about 100 service mechanics assigned to Bruce A for scaffolding, insulating, custodial work, etc.

Plant ageing has resulted in an increase the number of plant deficiencies occurring. Currently about 1600 deficiencies are generated per month, and the inability of the station to keep pace has resulted in a sizeable maintenance backlog. There are presently approximately 10,000 outstanding deficiencies which can be repaired with the units operating. Of these, approximately 6,000 represent true system deficiencies. The remainder are deficiencies to repair spare parts, to paint equipment, etc.

In January 1990, Bruce A staff from all sections and levels of the organization attended a workshop to identify problem areas seriously impeding station maintenance, and to develop a

comprehensive maintenance strategy for improving the overall maintenance effectiveness.

One of the clear problem areas identified was that the coordination of daily work being performed on units in the operating state was inadequate. As a result worker utilization was sub-standard. In effect, there were numerous roadblocks hindering the workers from getting on their tools to actually perform productive maintenance work. Because of this, workers were generally frustrated, morale was low, and it was generally perceived at all levels of the station organization, that the overall worker productivity was far below achievable levels.

A major contributor to this problem area was the process being used for the planning, scheduling and coordinating of maintenance activities. By using the workshop to conduct a thorough "problem analysis" of the process being used, it was concluded that some form of multi-disciplinary planning team approach was needed.

The Planning Section was therefore actioned to follow through with a "decision analysis" in order to determine how such a team should be structured, and how it should function. Several alternative structures (unitized vs systemized vs functional) were assessed against various criteria. It was generally agreed by the Planning staff that a dominantly unitized structure would yield the most benefits. It was therefore decided that such a proposal be recommended to the Maintenance Sub-Section.

Around this same time, in April 1990, Planning staff attended an On-Line Scheduling Process Conference in Arizona, sponsored by the Arizona Public Service. One of the workshops that drew the most attention presented a process referred to as Integrated Scheduling or the 13 Week Rolling Maintenance Schedule.

The basic concept was pretty straightforward. The year is broken up into quarters, thereby yielding four identical 13 week schedules. Each of the first 12 weeks is carefully assigned equipment "trains" or functional groups. The concept gives rise to buzz phrases like "Systems of the Week" and "Windows of Opportunity". Unless urgent or emergency work arises that would shut the unit down, all corrective maintenance DR's are deferred to their "Window of Opportunity". The 13th week is used as a catch-up week.

The base work for any one week is expected to be the preventive maintenance callups. Corrective work is then added and appropriate permits established. Generally, the higher priority work is scheduled in accordance with the actual resources available.

It was generally agreed by the Planning staff that dividing the station's systems into such a schedule, would nicely complement the multi-disciplinary teams. It was therefore decided that such a proposal should also be recommended to the Maintenance group.

3.0 CONCEPT DEVELOPMENT

As the concept proposals were prepared, it became clearly evident that potential benefits were not restricted to only the Maintenance Sub-Section. In July 1990, an "IOP Steering Committee" was established, consisting of management level supervisors from various sections (Figure 2). The Planning recommendations were accepted-in-principle by the committee. Later in the year, the union chief employee representatives were included on the committee to ensure that the concept principles were properly addressing employee interests and concerns.

In the Fall of 1990, it was further decided that an "IOP Concept Development Team" also be established. It consisted of largely first line union supervisory representatives from the various trade groups, since these individuals would be more in tune with the work coordination problems that needed to be rectified. One member of the steering committee was selected to act as team facilitator and to develop expectations, guidelines and tasks with the team.

The initial mandate of the team was to review the concept proposals, identify other related problem areas, provide recommendations, and develop the detailed procedures and processes that would eventually be implemented. In addition they would provide the necessary work direction, supervision and training required by individuals selected to staff the individual "Unit IOP Teams".

It's worth highlighting here that once full station implementation has been completed, the name "IOP Concept Development Team" will be changed to "Station IOP Coordination Team". This change is to reflect their revised mandate to provide an overall station coordination function within the process.

One of the first activities of the concept development team was a trip to the South Texas Project (nuclear) electric generating station. The purpose of the trip was to gain a better understanding of multi-disciplinary team planning and the 13 Week Rolling Schedule, from a utility that had implemented similar concepts. In this way the implementation problems could be identified and avoided.

Information was gleaned on various related topics, such as the advance scoping of work, the preparation of work packages, the timing and format of planning meetings, the close involvement of Stores representatives, etc. In addition, the team soon came to realize that assigning specific station systems to the various weeks was likely too complicated to work due to the complex interaction of systems. However, dividing equipment up into functional groups similar to the US utilities, was a viable alternative.

4.0 PROCESS FEATURES & OPERATION

Here is a brief explanation of the key process components, and how the overall planning process is currently working on a running unit.

4.1 The Unit Integrated Operational Planning Team

Prior to IOP implementation, all operational maintenance planning, scheduling and coordination on a unit was performed by a single planning technician, supported by a small station pool of mechanical assessors. No operator or control assessment was available. In addition, the ratio of non-supervisory tradespersons and operators to planning technicians was > 30 : 1.

This condition contributed to the planning technicians being unable to acquire valuable field experience and systems training necessary for them to effectively plan and schedule work. However, rather than simply increasing the number of available planning technicians, a more effective solution was seen in supplementing the existing planning technicians with production personnel who could bring their experience and skills to the initial planning process. The multi-disciplinary planning team that was agreed upon consists of 8 members (Figure 3). Its makeup is as follows:

- One Nuclear Operator (for assessing operator work and preparing work protection documents)
- Two Planning Technicians (for planning work package logic and preparing weekly plans/schedules on alternate weeks)
- Two Mechanical Assessors (for assessing mechanical work and preparing alternate week work packages)
- Two Shift Control Technicians (for assessing electrical and instrumentation work and preparing alternate week work packages)
- One Trades Management Supervisor (for assessing services work and preparing work packages)

Although the inclusion of a Stores/Supply Clerk on the team was originally specified, site resource constraints required that other alternatives be investigated.

The team members work together in the same geographic area. The various functions of each team member, and the justification for the numbers required, will be outlined during the explanation of the process operation. It is intended that about an 8 : 1 ratio of field workers to planning team members be achieved.

Some of the advantages in using these teams are:

- The expertise of other disciplines is immediately available.
- It allows for consultation between work groups without numerous memos, phone calls, and trips between the control room, the shops, and the planning office.
- It reduces the loss and delayed delivery of documents in the mail.
- It fosters team spirit and a feeling of working together toward a common goal.

4.2 The Thirteen Week Rolling Maintenance Schedule

All equipment in a unit which can be worked on while the unit is operating, is divided into Functional Equipment Groups (FEGs). These are groups of equipment which are within the same isolation boundaries or are functionally related such that they should be removed from service at the same time (Figure 4). It is these FEGs which form the basis for the plant corrective and preventive maintenance schedule. For a typical unit at Bruce A, the ANO on the concept development team has identified approximately 300 FEGs.

Each FEG is identified using a special 5 character code The first numeric character identifies the unit. The next 2 alpha characters identify broad categories of station systems. The remaining 2 numeric characters provide for distinguishing between equipment groups in a system.

The year is broken up into quarters, thereby yielding four identical 13 week schedules (Figure 5). Each of the first 12 weeks is then carefully assigned specific FEGs. While some FEGs will be assigned to the 13th week, it is primarily to be used as a catch-up week.

Each quarter, the schedule repeats itself. The weekly schedule for work on a unit is then produced by selecting work from any documents (Corrective Maintenance Deficiency Reports (DR), Preventive Maintenance Call-Ups (CU), Work Plans, etc) written against equipment with FEGs assigned to that particular week.

All the individual pieces of equipment associated with each FEG have been identified (Figure 6) and input to the equipment database of the Bruce Information Management System (BIMS).

All unit callups which can be performed with the unit operating, have either been assigned to an appropriate FEG, if isolation is required, or entered into a 52 week schedule, if no isolation and no channel rejection is required.

Some of the advantages in using the 13 Week Schedule are:

- All unit equipment is reviewed on a regular basis (at least 4X per year). It is relatively easy to determine when a particular piece of equipment will be scheduled for maintenance.
- Permitry requirements are reduced by working on all equipment within an isolation at the same time.
- It combines proactive, preventive and corrective maintenance to permit more efficient use of permitry, resources and dose budget.
- It reduces the administrative load for shift operating personnel (operators, trades, etc) by minimizing conflicts in scheduled maintenance.
- All deficiencies, including those of lower priority, are reviewed on a regular basis. In this way, no jobs are forgotten.

4.3 Scoping of Work

At Bruce A, a computerized Work Management System (WMS) resident in BIMS, is used to maintain and manage outstanding work documents (Figure 7). DR's are input to this system by the originator and then verified by the originator's supervisor. Work documents in WMS are referred to as Work Packages, regardless of whether the originating document was a DR, CU, work plan, etc. Work Packages are then assessed by the Unit IOP Team to identify the required resources, parts, work protection, scaffold, insulation, weld packages, etc.

When ordering parts using the BIMS - Material Management System, it is necessary to specify the date that the material is ordered for. In this way, the parts are reserved and should be available when needed. Using the 13 Week Schedule and the FEG that the work is related to, it is possible to specify the week before the work is to be executed. Following the assessment, the work package joins the pool of outstanding work (backlog).

Planning preparations for the execution of work during a weekly period commences 6 weeks in advance of the week occurring. In effect, planning preparations for work to be performed in say week 7, commences in week 1. The first planning activity consists of generating from the WMS a listing of all outstanding documents for FEGs assigned to the week selected. From this list is tentatively chosen an amount of work that is commensurate with the resources and skills that are forecast to be available from the dedicated unit field crews. It therefore accounts for vacation and training unavailability.

5 weeks in advance of the weekly plan execution, a work scope meeting is held. Work is jointly selected from the preliminary work scope list by the Unit IOP Team. Once this final work scope list has been produced, detailed work package preparation commences.

4.4 Comprehensive Work Package Preparation

Up to this point, work packages in WMS have merely been assessed. Detailed work package preparation by the Unit IOP Team, occurs from 5 weeks to 1 week before plan execution. It involves gathering documents and performing certain pre-requisite activities to ensure that the maintenance work to be performed can be executed efficiently. It is intended that the "comprehensive work packages" (CWP) which go to the field be as complete as possible. In this way the tradesman can go directly to work, without having to spend valuable time researching the job. The package that goes to the Lead Trade Group (Work Authority) contains items such as:

- A hard copy of the WMS work package which identifies the initiating deficiency or maintenance activity.
- A simple Logic Network Diagram showing the logical interconnection of all activities associated with executing the required maintenance, and the work groups responsible for completing the individual activities.
- Maintenance procedures, specifications, parts list, sketches, elementary drawings, manufacturers info, special tool requirements, etc.
- Work plans, Weld packages, technical attachments, etc.

The amount of information contained in the CWP is commensurate with the nature and complexity of the maintenance activity. CWPs are also prepared for the supporting work groups. The nuclear operator on the team, in cooperation with his counterpart on another unit team, prepares and checks the appropriate work protection packages.

4.5 Pre-Requisite Staging

During the week prior to execution of the weekly plan, several important pre-staging activites are performed.

- A final resource availability and qualification check is conducted to ensure that the appropriate amount of work is scheduled. The weekly plan also takes into account operator and support group requirements for performing Safety Sysyem Tests.
- Parts required for the various CWPs are delivered by stores to the station and deposited into individual unit staging/laydown areas. Access into these areas is controlled by trades supervisory staff and unit IOP teams.
- Scaffold installation and insulation removal for the upcoming work occurs in coordination with scaffold removal and insulation reinstallation resulting from the previousweeks work, using the limited service maintenance resources assigned to the unit.

- The unit IOP team members walkdown the upcoming work sites and laydown areas to ensure that scaffold, insulation, parts, and other pre-requisite requirements have been satisfied.
- The CWPs are delivered in specially marked black file folders to the various work group field offices.

4.6 Issuance of the Weekly Plan

The plan covers a 7 day period starting on #1 shift Monday. The plan is issued on the Friday dayshift prior to the week of execution. This permits review by the weekend crews, who are able to initiate early establishment of work protection if conditions and work load allows. The scheduling of operator routines and Safety System testing for #1 shift Monday has been significantly reduced in order to accomodate the establishment of required work protection. In addition, in order to provide an uninterrupted familiarization period for the incoming Monday dayshift duty crew, the plan largely schedules work not requiring work permits (maintenance callups, shop housekeeping, etc.) for the first 4 hours of #2 shift.

4.7 Weekly Plan Execution

Units on which the IOP process has been implemented have small dedicated trades crews (3-5 mechanics, 6-8 control technicians, 10-15 service mechanics) working days to execute the CWPs scheduled on the weekly plan. 2 shift mechanics and 1-2 shift control technicians are also dedicated to a unit making them available for urgent emergent work, for mandatory callups which can be linked to safety system tests, and for optionally scheduled work that it can be dropped at a moments notice.

Each weekday morning, members from the Station IOP Coordination Team contact the appropriate field supervisors to get an update of work progress relative to the plan. Any problems, concerns, issues, etc. which impact the weekly plan, are communicated back to the individual unit IOP teams, and daily addenda isssuedas required.

The Unit IOP Teams have been specially structured so that half the team is available to monitor and support the plan execution by responding to emerging issues (Figure 8). This is possible due to the weekly alternating of responsibilities for team members. As can be seen in Figure 8, which uses the 2 planning technicians (designated as "A" and "B") as an example, they alternate between preparation of weekly plans. This is also true for the mechanical and control maintenance assessors.

4.8 Forced Outages

In the event of a forced outage, the team members supporting the weekly plan execution redirect their efforts to support execution of the forced outage plan. The remainder of the team continues with operational planning as per the 13 week schedule. If it was fairly obvious that a long forced outage extension was inevitable, the entire team redirects it's efforts towards outage support. This continues until a fairly reliable startup date is forecast. While a forced outage is fairly disruptive to the 13 week schedule, it is no worse than the current transitions from outage to operational planning.

5.0 IMPLEMENTATION RESULTS

The IOP process was implemented on Unit 1 in July 1991, and on Unit 3 in July 1992. During the first few months, both units experienced an initial upsurge in the number of corrective maintenance DRs generated. This was due to the dedicated field trade crews taking ownership of the unit. On Unit 1 for example, the number of DRs generated and completed was approximately 150% higher than the other units, despite only having about 80% of the number of non-supervisory field staff compared to other units.

Over the past year the maintenance backlog on Unit 1 has steadily declined (Fig 9). From a July 1991 pre-IOP level of 1100 DRs it has dropped to 686 at the end of Sept 1992. Comparison to Units 2, 3, & 4 over the same time period illustrates the dramatic improvement. One can also begin to see the turnaround on Unit 3.

Closer scrutiny of the graphs also reveals that Unit 4 appears to have experienced some improvement even though IOP has not been implemented. This is attributable to the use of the 13 week rolling maintenance schedule on that unit. However, the improvement was not sustainable due to the lack of dedicated resources and other features of the IOP process.

Because of the effectiveness of the process in reducing mechanical work, the number of mechanics dedicated to Unit 1 was nearly halved after about 6 months. Around the same time, the services organization also experienced an almost total elimination of their work backlog. They have since pooled their Unit 1 dedicated team to look after 2 units.

As the backlog on Unit 1 decreases, the number of DRs generated and completed has also decreased because there is less operational work available to be done. The result is an increase in the amount of preventive maintenance callups being done on the unit. As is evident in Table 1, the callup completion rate has significantly improved. Not included in the figures shown are the signing off of callups that were due but could not be performed due to system conditions, seasonal considerations, etc. If included the values would have been very near to 100% completion.

Another indicator of improved performance is the degree of compliance to the weekly plan. This measures how closely the plan is being followed. Table 1 again shows that the completion of scheduled DRs, Callups, Work Plans, etc. has increased dramatically on U1. If the amount of unplanned work completed, arising from necessary carryover from the previous week and from urgent emerging work, is added to the amount of scheduled work completed, the resulting total exceeds the work scheduled by over 115%, on both units 1 & 3.

	Typical Unit Pre-IOP July 1991	Unit 1 IOP Sept 1992	Unit 3 IOP Sept 1992
Average Monthly Callup Compliance (Completed/Required)	40 - 50 %	74%	65%
Average Weekly Scheduled Work Compliance (Completed/Scheduled)	25 - 30 %	92%	72%

Table 1

The Unit 1 implementation was preceeded by a station-wide maintenance work sampling study designed to measure worker utilization. The study has accurately measured the fraction of available worker time utilized for actual "wrench time", and it provides a baseline from which to measure improvement. While a follow-up study was completed 1 year later, it occurred coincidently with Unit 1 having just come out of an outage. The disruption to plans that resulted left the results of the work sampling study on Unit 1 inconclusive as far as indications of improved performance. Another sampling study will be conducted after station-wide implementation is completed.

In 1991 Unit 1 experienced 6 forced outages. From January to mid October 1992, it has experienced only 1 forced outage. Although not totally attributable to IOP due to work completed during a comprehensive 1990 planned outage, it has certainly had a significant influence on the units improved performance.

6.0 FUTURE PLANS

Implementation on the remaining reactor units and on Unit 0 has been delayed because of lack of operator resources to support the IOP teams. Unit 2 implementation will take place this year as soon as possible after the restart of the unit following a prolonged forced outage. FEG identification on the systems unique to Unit 0 is proceeding but implementation has been delayed until

April 1993. Unit 4 implementation will occur in 1993 also, following restart of the unit after a long duration planned outage.

As the backlogs decrease, it is quite likely that both the unit IOP teams and the dedicated field trade crews will evolve to supporting unit pairs rather than individual units. Organizational restructuring to this end is already being investigated.

7.0 CONCLUSIONS

The Integrated Operational Planning process has proven it's potential to benefit all work groups at Bruce A.

For the Trades, greater "wrench time" has been achieved, although not yet conclusively measured. Preparatory delays experienced by the field crews due to the unavailability of parts, tools, procedures, scaffold, insulation, and work protection permitry, have been significantly reduced.

For the Operators, less work protection permitry preparation is now required. In addition, recognition and allowance for time spent performing routines and safety system testing is taken into account.

For the Planners, more credible and useful weekly plans have resulted. There is also instant access to the expertise of other disciplines.

For Technical staff, it is possible to predict when equipment is likely to be worked on. With trades assessors located together geographically, assessment and problem solving of work plans is facilitated.

For Station Management, more efficient and productive use of resources (people, dose, etc) has been realized. In addition, some of the intangible benefits such as improved morale has occurred. This is due to staff seeing delays progressively eliminated, and due to a feeling of ownership and teamwork on individual units. As a result of less outstanding (backlogged) work and more regular maintenance on all equipment, higher equipment reliability should result in:

- reducing the frequency and duration of forced deratings and outages.
- reducing the duration of planned outages.
- increasing the station's performance capability

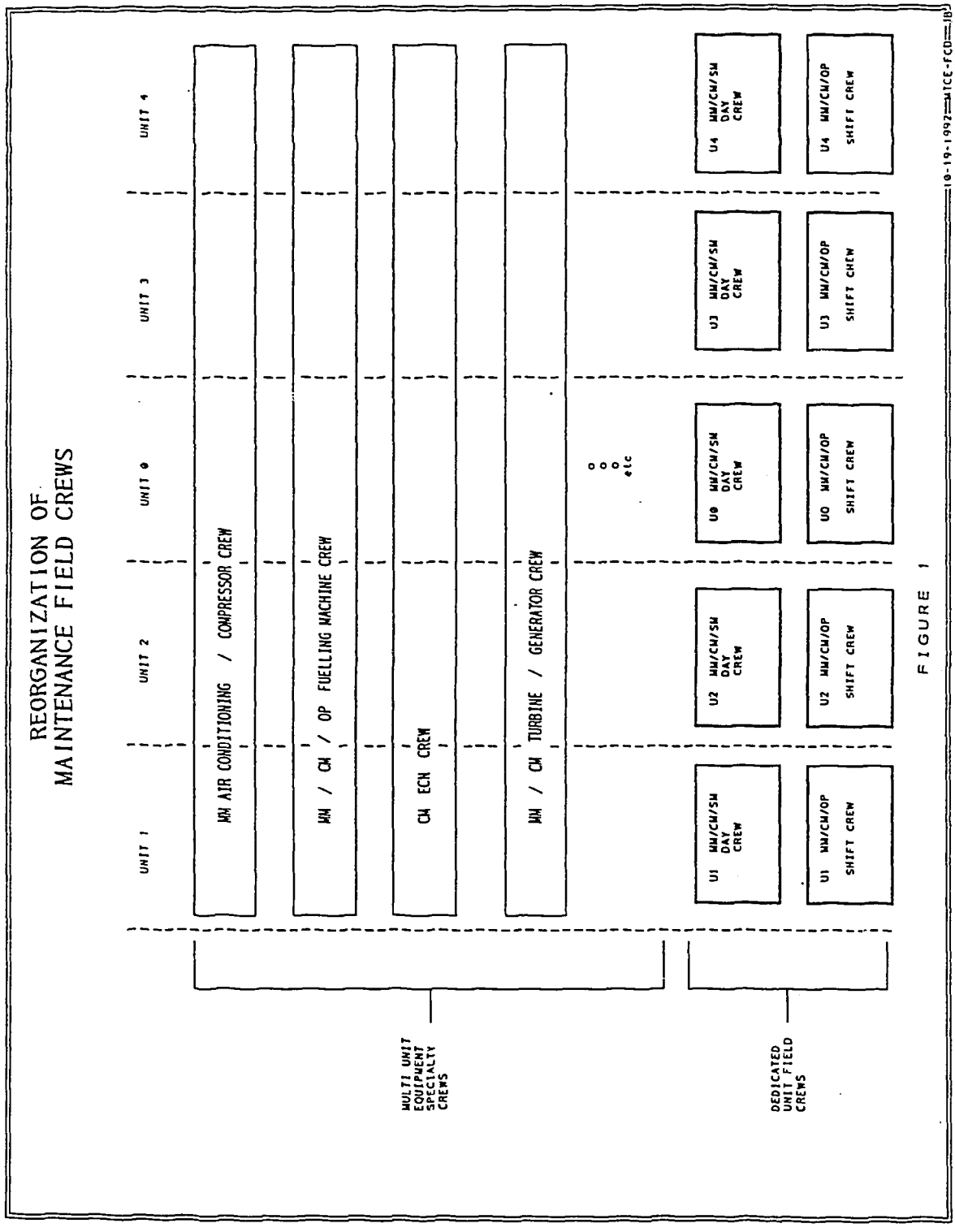

REORGANIZATION OF
MAINTENANCE FIELD CREWS
UNIT 1
UNIT 2
UNIT 0
UNIT 3
UNIT 4
MW AIR CONDITIONING / COMPRESSOR CREW
MW / CW / OP FUELLING MACHINE CREW
CW ECN CREW
MW / CW TURBINE / GENERATOR CREW
o
o
o
etc
U1 MW/CW/SW DAY CREW
U2 MW/CW/SW DAY CREW
U0 MW/CW/SW DAY CREW
U3 MW/CW/SW DAY CREW
U4 MW/CW/SW DAY CREW
U1 MW/CW/OP SHIFT CREW
U2 MW/CW/OP SHIFT CREW
U0 MW/CW/OP SHIFT CREW
U3 MW/CW/OP SHIFT CREW
U4 MW/CW/OP SHIFT CREW
MULTI UNIT EQUIPMENT SPECIALTY CREWS
DEDICATED UNIT FIELD CREWS
10-19-1992 MTCE-FCD 18

FIGURE 1

INTERGRATED OPERATIONAL PLANNING
(IOP)
DEVELOPMENT & IMPLEMENTATION ORGANIZATION

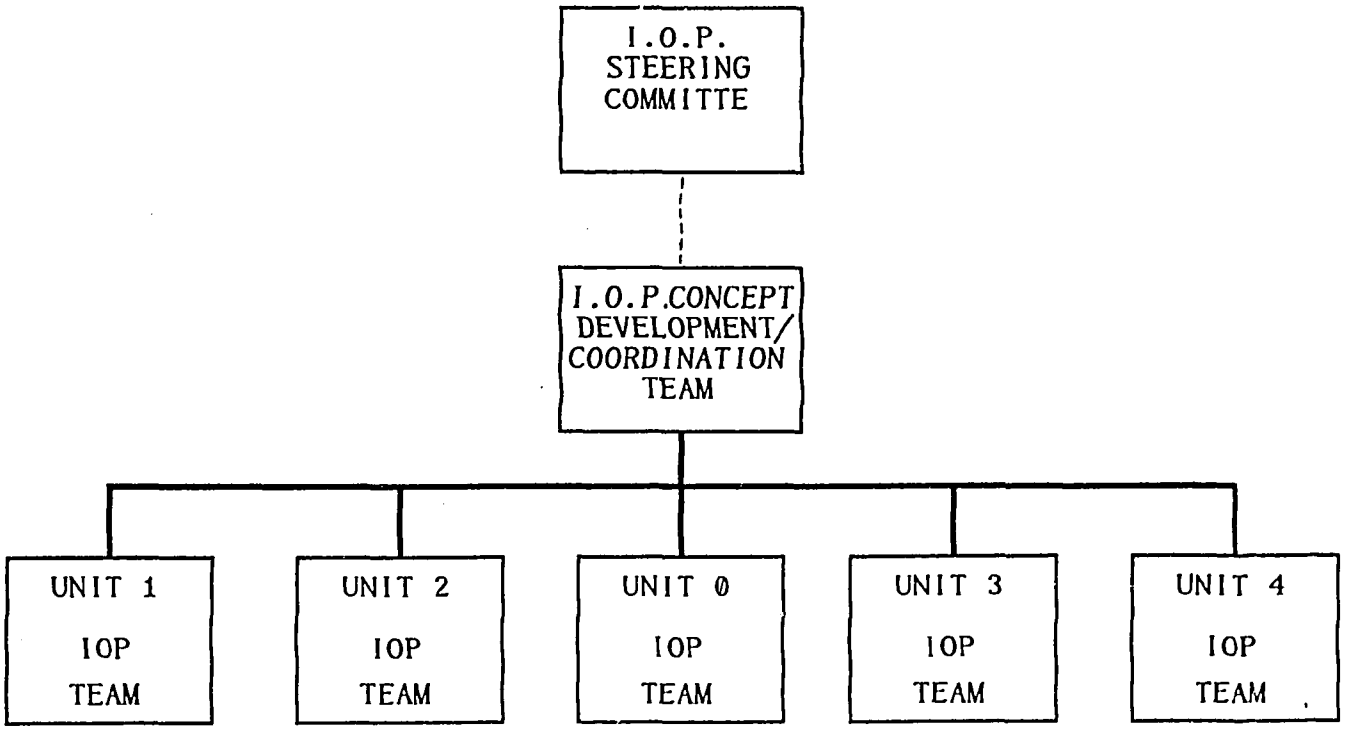


FIGURE 2

10-19-1992==IOP-FCD==JB

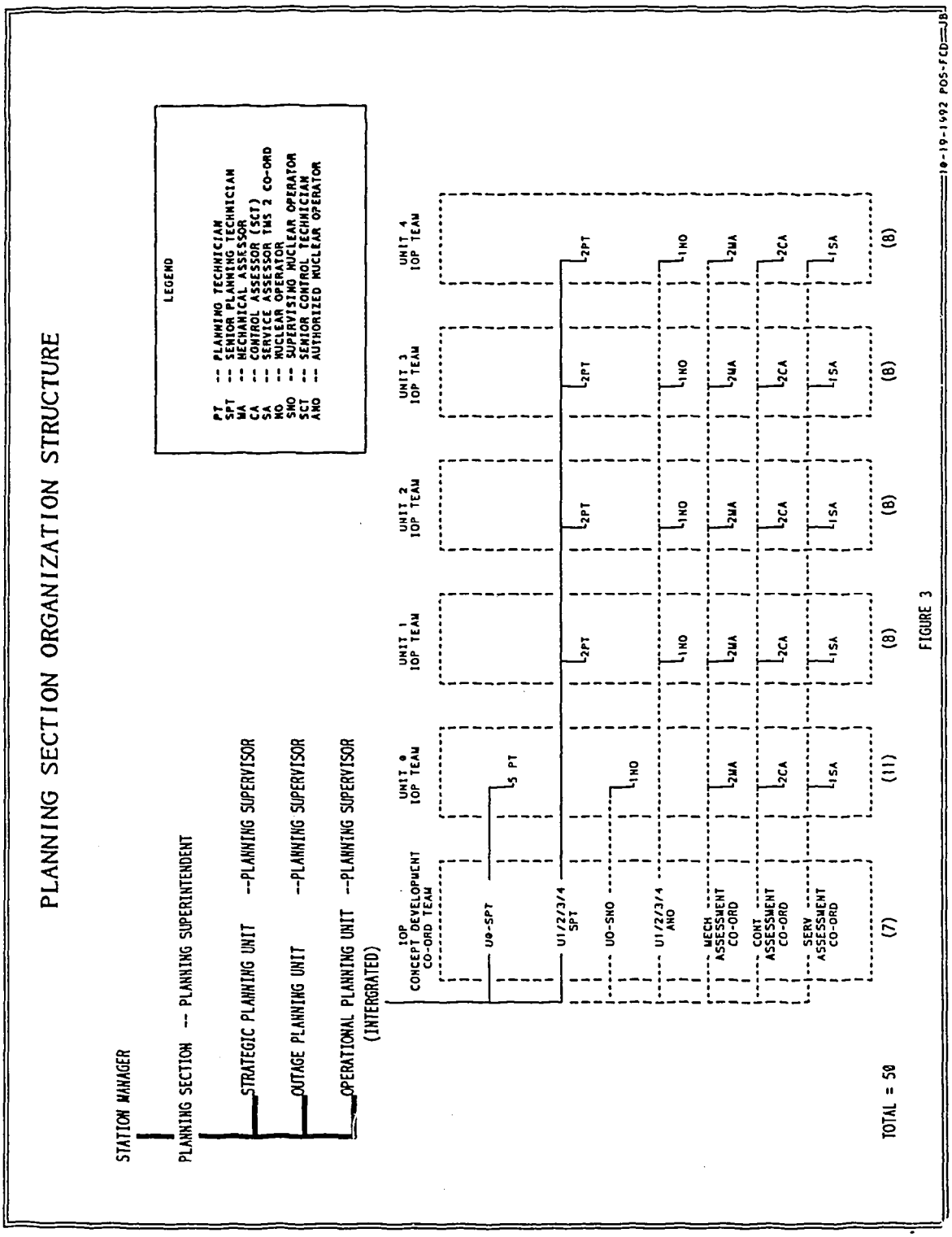

PLANNING SECTION ORGANIZATION STRUCTURE
LEGEND
PT -- PLANNING TECHNICIAN
SPT -- SENIOR PLANNING TECHNICIAN
MA -- MECHANICAL ASSESSOR
CA -- CONTROL ASSESSOR (SCT)
SA -- SERVICE ASSESSOR THIS 2 CO-ORD
NO -- NUCLEAR OPERATOR
SNO -- SUPERVISING NUCLEAR OPERATOR
SCT -- SENIOR CONTROL TECHNICIAN
ANO -- AUTHORIZED NUCLEAR OPERATOR
STATION MANAGER
PLANNING SECTION -- PLANNING SUPERINTENDENT
STRATEGIC PLANNING UNIT --PLANNING SUPERVISOR
OUTAGE PLANNING UNIT --PLANNING SUPERVISOR
OPERATIONAL PLANNING UNIT --PLANNING SUPERVISOR
(INTERGRATED)
IOP CONCEPT DEVELOPMENT CO-ORD TEAM
U0-SPT
5 PT
U1/2/3/4 SPT
U0-SNO
1NO
U1/2/3/4 ANO
MECH ASSESSMENT CO-ORD
2MA
CONT ASSESSMENT CO-ORD
2CA
SERV ASSESSMENT CO-ORD
1SA
UNIT # IOP TEAM
UNIT 1 IOP TEAM
2PT
UNIT 2 IOP TEAM
UNIT 3 IOP TEAM
UNIT 4 IOP TEAM
(7)
(11)
(8)
(8)
(8)
TOTAL = 50
10-19-1992 POS-FCD=JB

FIGURE 3

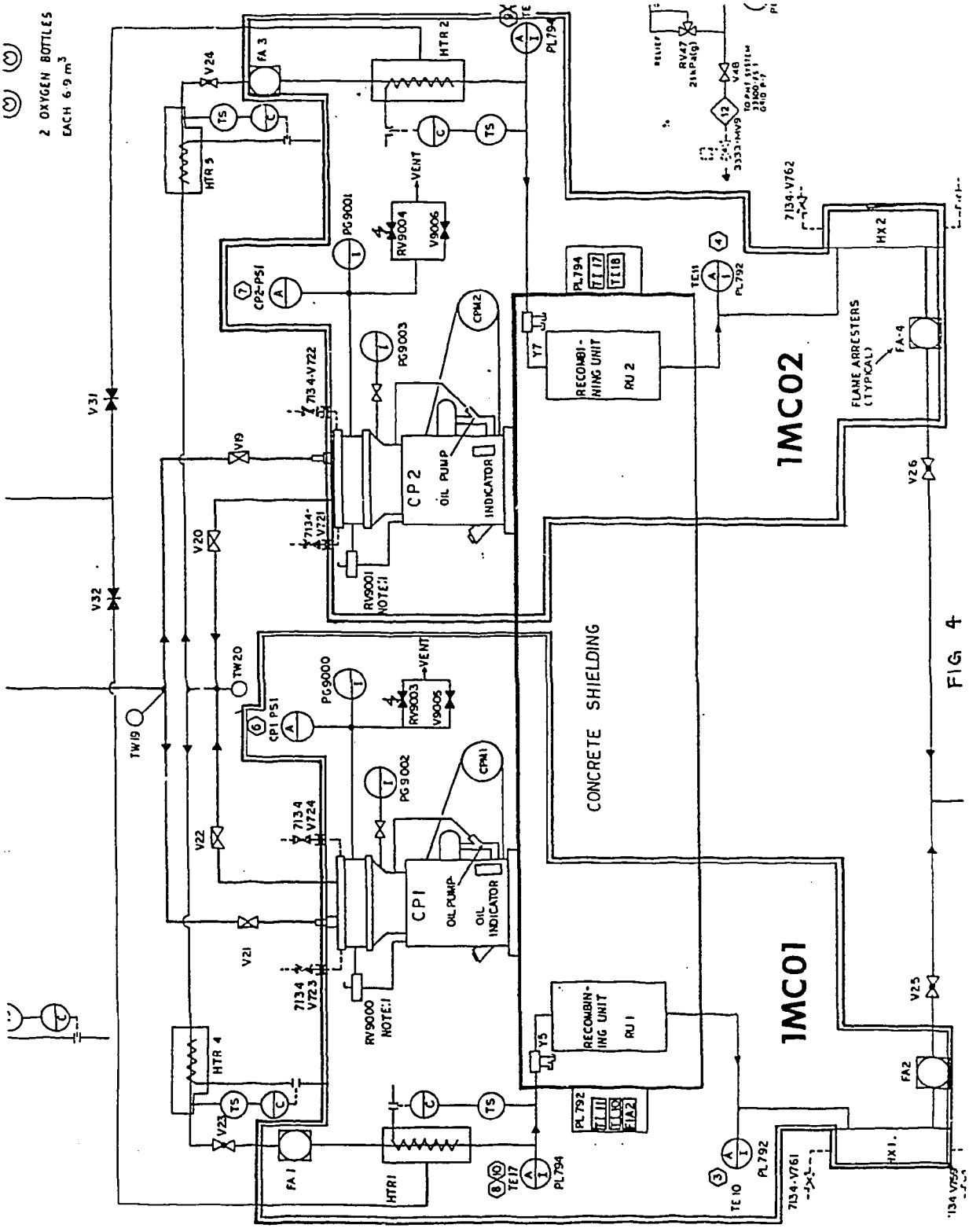

2 OXYGEN BOTTLES EACH 6.9 m³
CONCRETE SHIELDING
1MC01
1MC02
CP1
CP2
OIL PUMP
OIL INDICATOR
RECOMBINING UNIT RU 1
RECOMBINING UNIT RU 2
FLAME ARRESTERS (TYPICAL)
HTR 1
HTR 2
HTR 3
HTR 4
HTR 5
FA 1
FA 2
FA 3
FA 4
HX 1
HX 2
V19
V20
V21
V22
V23
V24
V25
V26
V31
V32
TW19
TW20
RV9000 NOTE 1
RV9001 NOTE 1
PL792
PL794

FIG 4

THIRTEEN WEEK ROLLING SCHEDULE

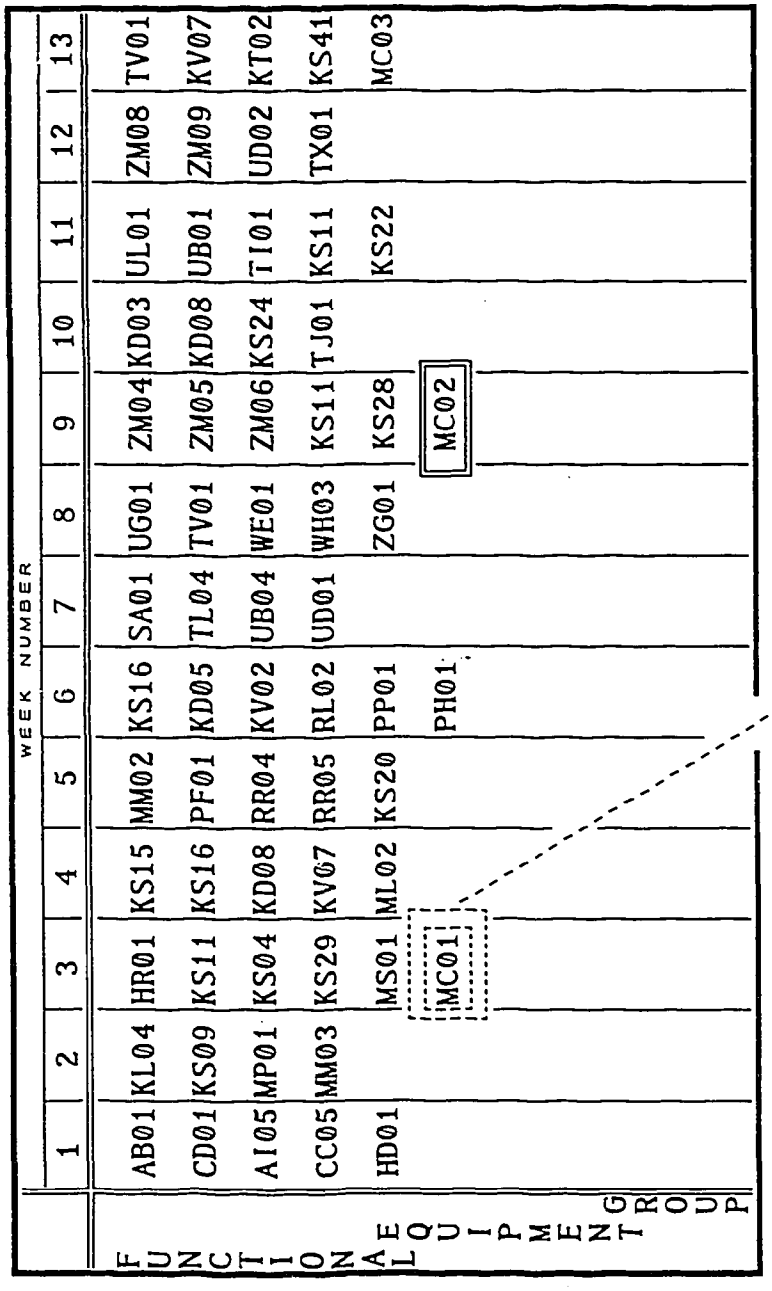


FIG 5

FEG COMPONENTS VS DOCUMENTS

FEG # : 1MC01

EQUIPMENT		DOCUMENT
32310	CP1	2-90-12468-00 (DR)
	FA1	
	HTR1	
	CPM1	
	Y5	2-91-00689-00 , 2-91-00689-01
	RV1	1-91-00345-01
	FA2	
	HX1	
	RV90000	1-91-00045-02 (CU)
	RV9003	
	V9005	
71340	V723	
	V724	
63231	TE17	2-90-16743-00
	TE10	
	TI10	
	TI11	
	FIA2	
	PG9002	
	PG9000	
	CP1-PS1	2-90-15689-00

FIG 6

INTEGRATED PLANNING PROCESS

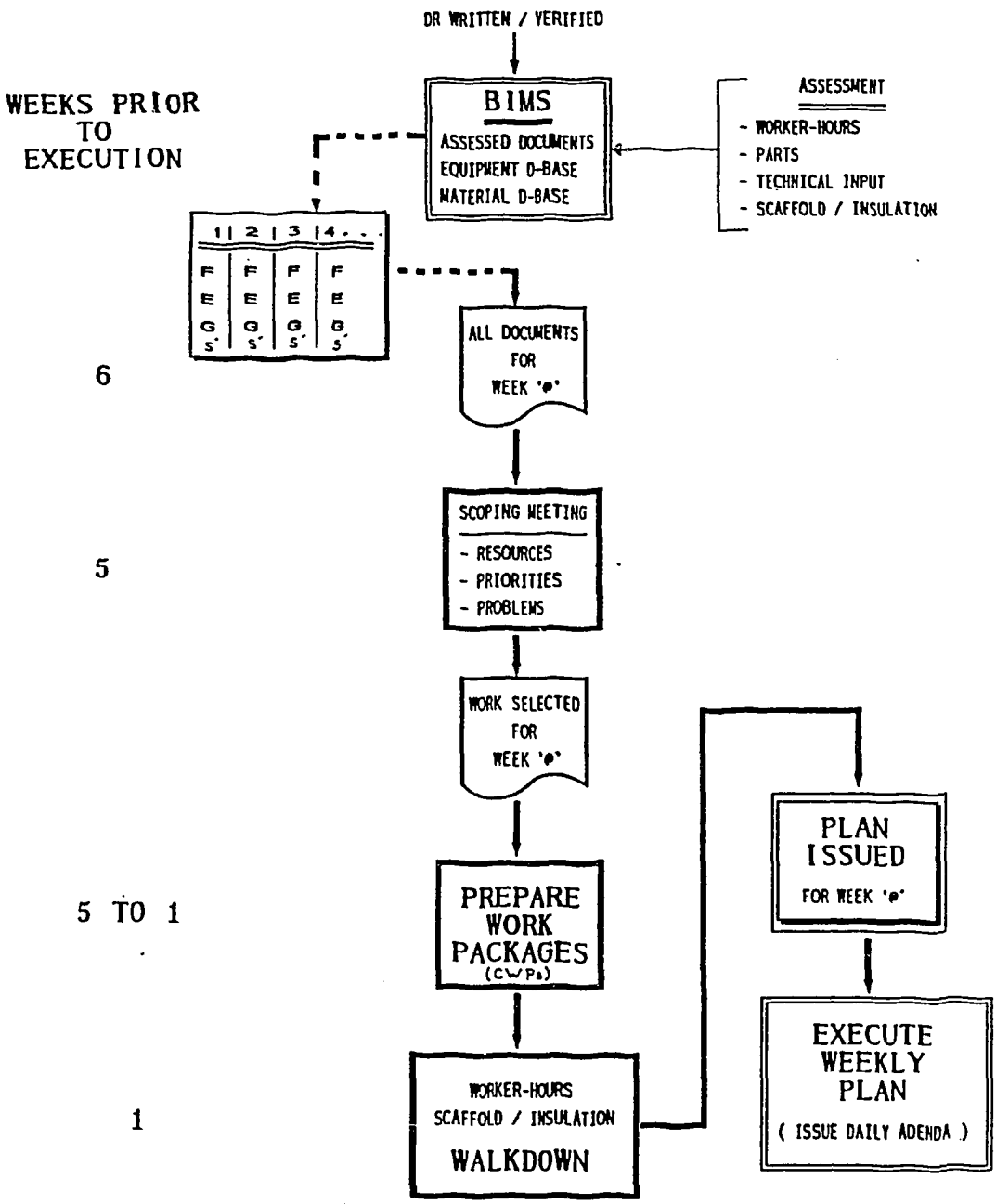


FIG 7

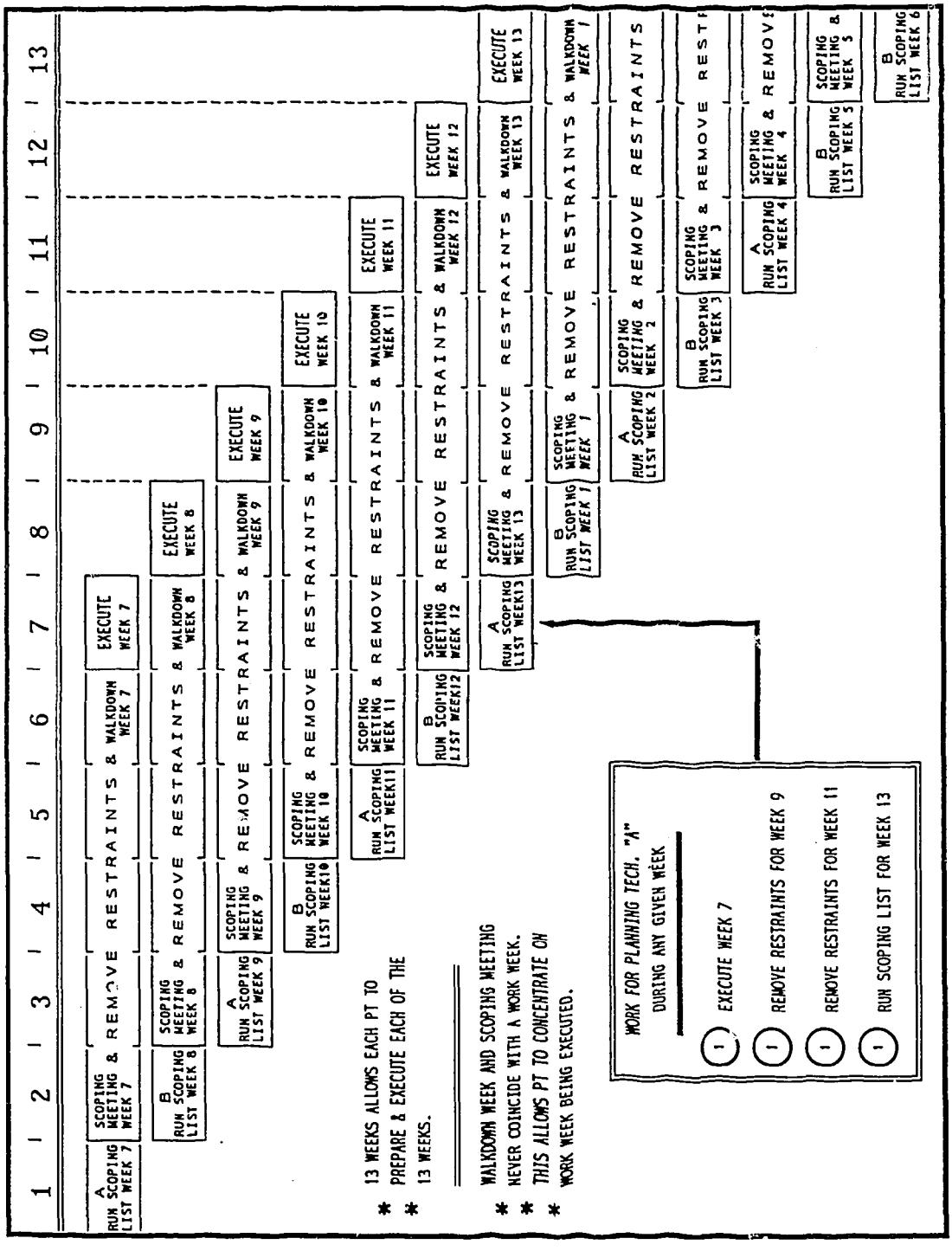
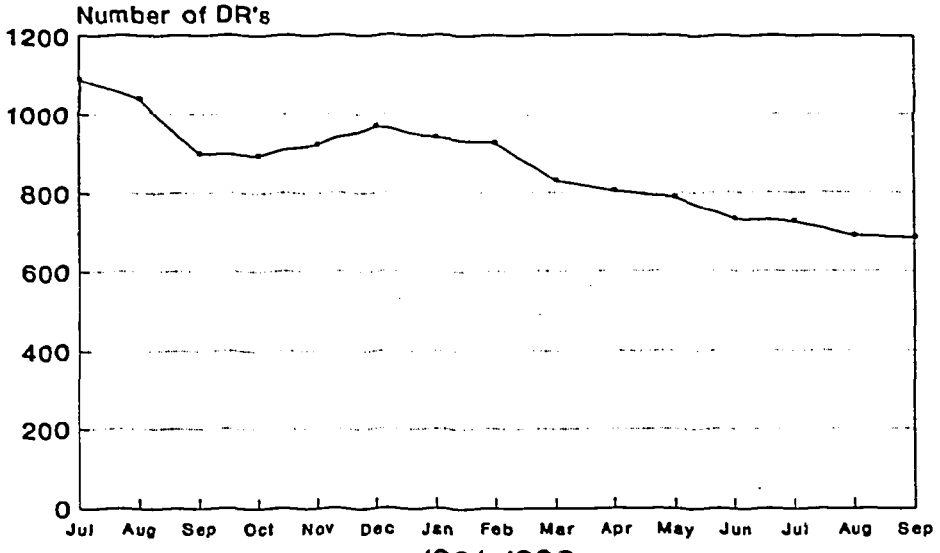

1 2 3 4 5 6 7 8 9 10 11 12 13
A RUN SCOPING LIST WEEK 7
SCOPING MEETING WEEK 7
& REMOVE RESTRAINTS & WALKDOWN WEEK 7
EXECUTE WEEK 7
B RUN SCOPING LIST WEEK 8
SCOPING MEETING WEEK 8
& REMOVE RESTRAINTS & WALKDOWN WEEK 8
EXECUTE WEEK 8
A RUN SCOPING LIST WEEK 9
SCOPING MEETING WEEK 9
& REMOVE RESTRAINTS & WALKDOWN WEEK 9
EXECUTE WEEK 9
B RUN SCOPING LIST WEEK10
SCOPING MEETING WEEK 10
& REMOVE RESTRAINTS & WALKDOWN WEEK 10
EXECUTE WEEK 10
A RUN SCOPING LIST WEEK11
SCOPING MEETING WEEK 11
& REMOVE RESTRAINTS & WALKDOWN WEEK 11
EXECUTE WEEK 11
B RUN SCOPING LIST WEEK12
SCOPING MEETING WEEK 12
& REMOVE RESTRAINTS & WALKDOWN WEEK 12
EXECUTE WEEK 12
A RUN SCOPING LIST WEEK13
SCOPING MEETING WEEK 13
& REMOVE RESTRAINTS & WALKDOWN WEEK 13
EXECUTE WEEK 13
B RUN SCOPING LIST WEEK 1
SCOPING MEETING WEEK 1
& REMOVE RESTRAINTS & WALKDOWN WEEK 1
A RUN SCOPING LIST WEEK 2
SCOPING MEETING WEEK 2
& REMOVE RESTRAINTS
B RUN SCOPING LIST WEEK 3
SCOPING MEETING WEEK 3
& REMOVE REST
A RUN SCOPING LIST WEEK 4
SCOPING MEETING WEEK 4
& REMOVE
B RUN SCOPING LIST WEEK 5
SCOPING MEETING WEEK 5
&
B RUN SCOPING LIST WEEK 6
* 13 WEEKS ALLOWS EACH PT TO PREPARE & EXECUTE EACH OF THE 13 WEEKS.
* WALKDOWN WEEK AND SCOPING MEETING NEVER COINCIDE WITH A WORK WEEK.
* THIS ALLOWS PT TO CONCENTRATE ON WORK WEEK BEING EXECUTED.
WORK FOR PLANNING TECH. "A" DURING ANY GIVEN WEEK
1 EXECUTE WEEK 7
1 REMOVE RESTRAINTS FOR WEEK 9
1 REMOVE RESTRAINTS FOR WEEK 11
1 RUN SCOPING LIST FOR WEEK 13

FIG 8

OUTSTANDING OPERATING DR's
UNIT 1



OUTSTANDING OPERATING DR's
UNITS 2,3,4

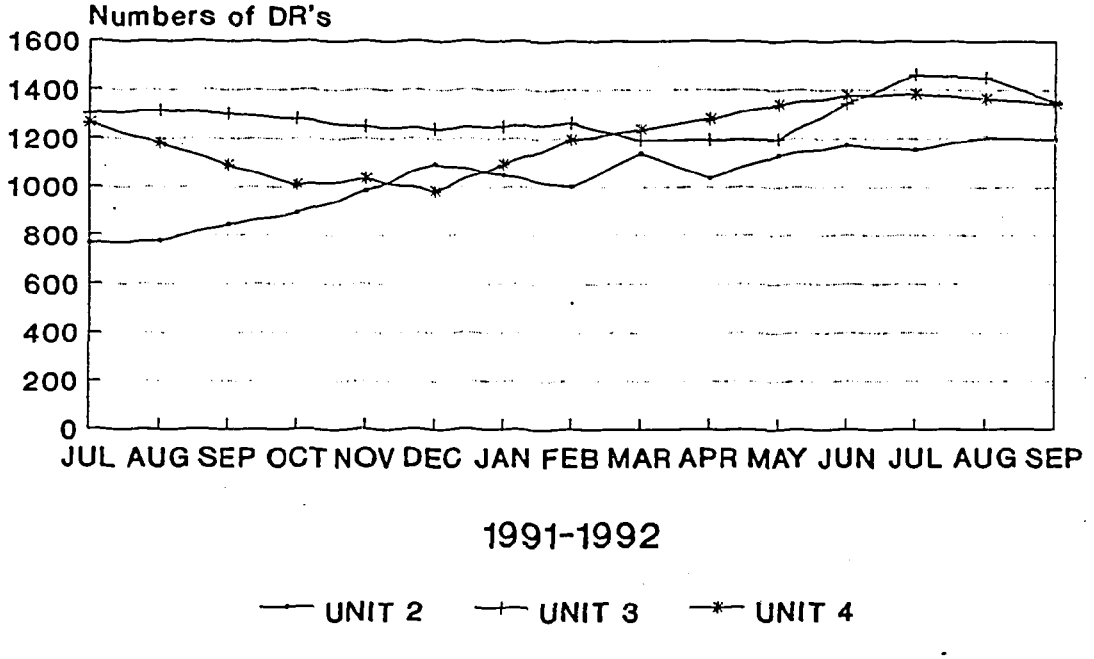


FIG 9

Maintenance Labour Forecasting in NOB of Ontario Hydro

A.K. Tanaka, Ontario Hydro
J.R., Tousignant

Session B paper not available at the time of printing.

Organization of Maintenance Program at Cernavode

L. Racoveanu, ICEMENERG, Romanian
Electricity Authority

Session B paper not available at the time of printing.

Please see Appendix A at back of book

CA9500136

LIFE CYCLE MANAGEMENT IN THE U.S. - STONE & WEBSTER'S EXPERIENCE

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ABSTRACT

Life Cycle Management (LCM) is a sound methodology that integrates plant operations, maintenance requirements and practices, capital improvements, radioactive waste strategies, decommissioning and life extension. It is a structured decision-making process for plant aging management and performance improvement. Stone & Webster has used this process for many fossil plants and is now using it at several nuclear plants. This paper discusses Stone & Webster's experiences with LCM programs at U.S. nuclear power plants.

LIFE CYCLE MANAGEMENT IN THE U.S. - STONE & WEBSTER'S EXPERIENCE

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Boston, Massachusetts

BACKGROUND

As recent premature shutdowns of operating nuclear power plants have demonstrated, nuclear power generating costs need to be competitive in the marketplace. Excess regional electric generating capacity, coupled with low prices of coal, oil, and natural gas and competitive pressure from Independent Power Producers (IPP), are expected to keep electricity rates at current levels over the next few years. In the meantime, nuclear power plant Operations & Maintenance costs and capital improvement needs, even though they have peaked recently, have risen sharply during the eighties (Figures 1 and 2). As nuclear power plants age, uncertainties related to the need for major component/systems replacement such as reactor pressure vessel, steam generator, and service water system are increasing. Uncertainties related to high level and low level waste disposal require utilities to decide whether to build on-site waste reduction, processing and storage facilities which add to the capital cost contribution to the electricity price. These costs are unwelcome, especially at a time in power plant life when the time left to recover these costs may be too short to be supported by the market price of electricity (Figure 3). One solution to these problems is to extend life, but that process also has not been tested yet; hence, this is also uncertain and is subject to external political influence.

Life cycle management (LCM), (Figure 4), looks at these issues strategically and plans a course of action that while minimizing the electricity generating cost also works towards preserving the life extension option. At this strategic level, the plan integrates plant operations and maintenance philosophies with capital improvements, waste management, and decommissioning strategies; and retains the option of life extension. LCM may also include other programs aimed at making the plant more cost competitive and reliable, such as power uprates, plant performance improvement, regulatory performance improvement, and plans for public acceptance of nuclear power.

LCM is a structured decision making process which addresses external and internal factors with associated uncertainties, supports economic analysis of major component/system replacement/refurbishment decisions, and remains a dynamic program over the life of the power plant.

The cornerstone of any effective maintenance program is to manage aging. In the U.S., both the Maintenance Rule and the License Renewal Rule require effective aging management. However, the real incentives for developing and implementing a comprehensive LCM program are not solely regulatory compliance. The implementation of a comprehensive LCM program can provide a more cost effective maintenance program, a more rational decision making process for plant/system and maintenance program upgrades and ultimately improvement in plant performance.

Stone & Webster had early involvement in numerous fossil power plant life extension projects, and in pilot and lead nuclear power plant life extension projects. Subsequently, Stone & Webster helped several utilities develop LCM strategies and worked on the implementation of some of the earliest LCM programs in the U.S. A wealth of experience has been gained on the successes and failures of such programs. This paper discusses some of these lessons learned, and case histories.

LCM PROGRAM DESCRIPTION

The LCM program for every utility is expected to be different because goals, objectives, problems, organization, power generation, plant design and performance of every utility is different. It is of utmost importance to first develop a long-term strategic program which addresses not only goals, objectives and technical issues, but also organizational issues such as how the program will be implemented, program financing, etc. A "buy-in" by the entire utility is essential to program success. At the implementation level, the LCM program must interface with all the major programs at a plant (Figure 5). LCM being shown at the center of the diagram does not mean that the LCM program becomes the key driver of all the other plant programs. However, a successful interaction is required which accounts for program improvements to meet the LCM objectives and needs. As an example, both the plant records and the configuration management system must provide sufficient, easily retrievable documentation to support LCM evaluations, and component replacement and upgrade programs consistent with LCM strategy.

As should be the case with any major program, the LCM program should be developed with deliberate speed and careful planning for a phased in process. A typical phased LCM methodology/process is described in Figures 6, 7, and 8.

The first phase consists of a reviewing plant performance and maintenance programs and practices with that of the industry. This comparative and detailed evaluation, coupled with the utilities LCM program goals, the economic impact of each system, structures and components (SSC) on plant life and performance, and the cost of electricity production will enable a prioritization of all SSCs.

During the second phase, several pilot SSCs are selected and the aging mechanisms applicable to the SSC are identified. A solid plant specific failure root-cause analysis program which can be integrated with the plant information management program is essential in determining plant specific aging mechanisms, their effects on systems, structures, and components, and the effectiveness of existing corrective/preventive measures. Where the plant specific failure history has not been well documented well in the past; industry data, available plant specific failure data and LCM experience can be used to establish SSC aging mechanisms. In addition, it is desirable to establish a comprehensive condition monitoring program. The data from the monitoring program should be integrated with industry experience with failure and aging data, and plant specific failure information, to establish age-related degradation matrix (ARDM) for systems, structures and components. The ARDMs, system/component designs, and existing maintenance programs and practices can be evaluated to determine where changes should be made to better address age management issues, improve plant reliability/availability, and ultimately reduce the cost of producing electricity. This evaluation results in determining which SSCs and programs meet LCM program requirements and which should be upgraded and/or added. An example of the SSC prioritization results, combined with ARDMs that are important to each SSC is provided in Table 1.

In the third phase, the SSCs design changes and age management program changes resulting from LCM program evaluations are reviewed to determine their cost effectiveness. Since typically several alternatives for upgrades are available to address the LCM Program objectives, an effective and consistent method for determining the cost/benefits of any proposed changes need to be established to support a rational decision making process.

Prioritization of modifications based on the largest impact on risk, cost, availability, plant performance, and reliability analyses are excellent tools that are available to support this process. Since much of the data used in the aging evaluations such as failure prediction, effect of preventive maintenance on component life, and the cost estimates have uncertainties associated with them, each of the inputs can be modeled using probablistic theories such that the reliability and sensitivity of the results can be evaluated.

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The cost benefit analysis was performed utilizing the present value of revenue requirements (PVRR) considering the effects of alternative course of action on total life cycle cost: capital expenditure, Operation & Maintenance expenditures (historical and estimated for remaining life), auxiliary additional power requirements, replacement (outage) power requirement, service life estimates (historical and estimated remaining life), failure effects (capitalized and/or expended cost to repair/replace; forced outage duration associated with failure), probablistic simulation of the effects of key variables to account for different level of confidence in maintenance/repair costs, capital cost, service life, consequence of failure, length of outage upon failure etc. These evaluations were going to be performed for 20 years of remaining life and also for 40 years of remaining life to see if the upgrade decisions are different for the two scenarios.
The component aging evaluations and cost-benefit analysis were integrated to produce a comprehensive Life Cycle management Plan for the system with supportable, cost-effective recommendations for improved system performance as well as the justification for operating the modified system for an additional 20 year license renewal period.

While a number of system and component modifications were considered, to illustrate the results of this evaluation, the summary cost benefit results of three pipe replacement options for the 40 years of remaining life case for above ground and underground major piping are presented in Tables 2 and 3. The results indicate that for above ground piping, even though rubber lined carbon steel initial capital cost is low, the PVRR life cycle cost was higher than other alternatives. However, if 20 years remaining life is assumed, the life cycle costs of the three pipe materials are nearly the same. For the underground piping, the slip inversion insitu-form lining process is the clear choice based on the calculated PVRR life cycle cost estimates. However, because this lining method is not a proven technology in a nuclear power plant application, the recommendation was made to follow industry developments, upgrade the current piping condition assessment and maintenance programs, and delay the pipe replacement decision as long as possible.

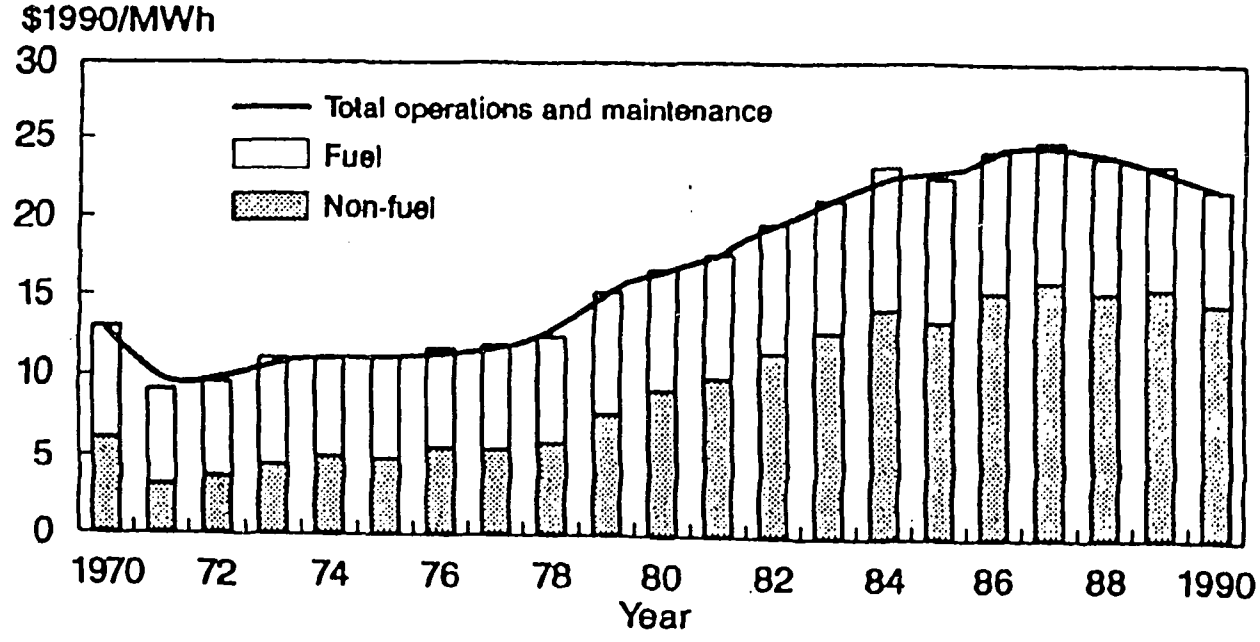
CONCLUSION

As can be seen from the case study, a LCM program needs to address not only technical issues but also financial issues and life extension strategies. A systematic development and implementation of LCM program plantwide provides for an integrated, structured process that leads to the most cost effective power production.

References:

1) "Evaluation of systems, structures and components for Life Cycle Management," by Messrs. N. E. Hanley, P. B. Woods, A. K. Banerjee of Stone & Webster, and Messrs. J. S. Perrin and F. A. Marian of Public Service Electric & Gas Company of New Jersey. Presented at American Nuclear Society Annual Meeting in Boston, Massachusetts in June 1992.

Operations & Maintenance Costs for U.S. Nuclear Plants

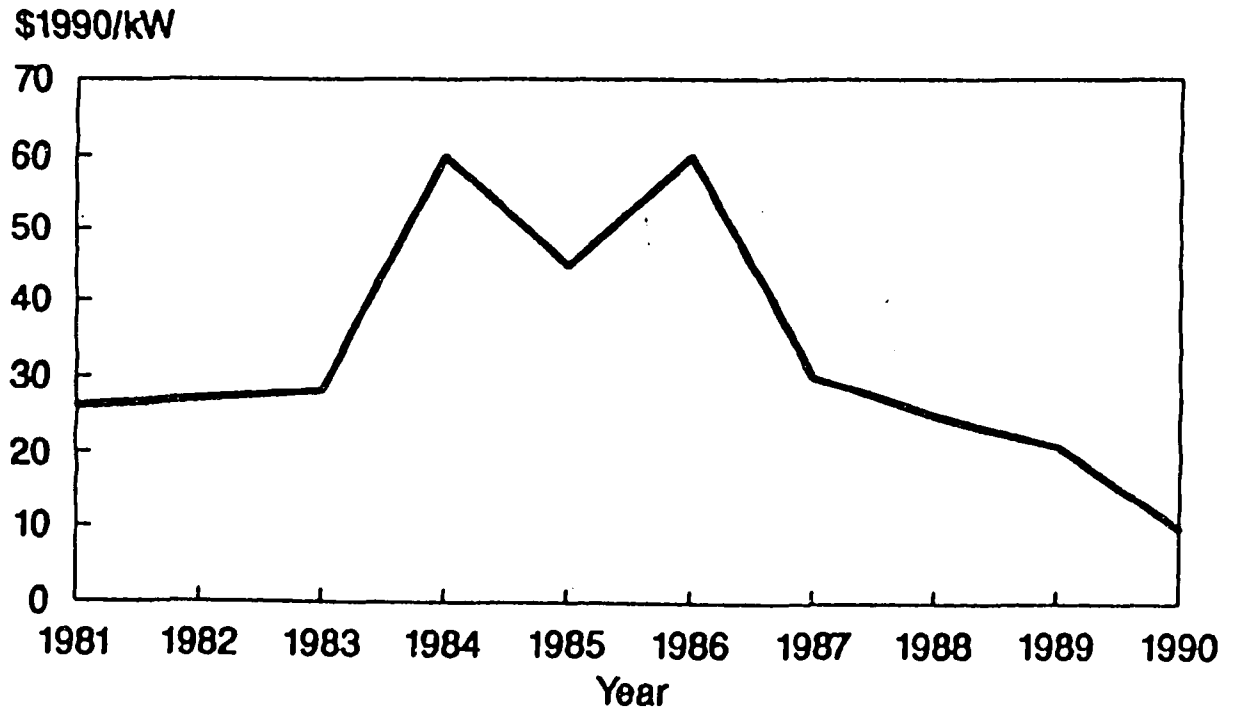


Note: Deflated by CPI

Source: UDI Utility Data Base, UDI-014-91

Figure 1

Capital Additions for U.S Nuclear Plants



Note: Deflated by CPI

Source: Nuclear Industry, 1st Quarter, 1992

Figure 2

Electricity Rate Required to Recover Total Capital Investment

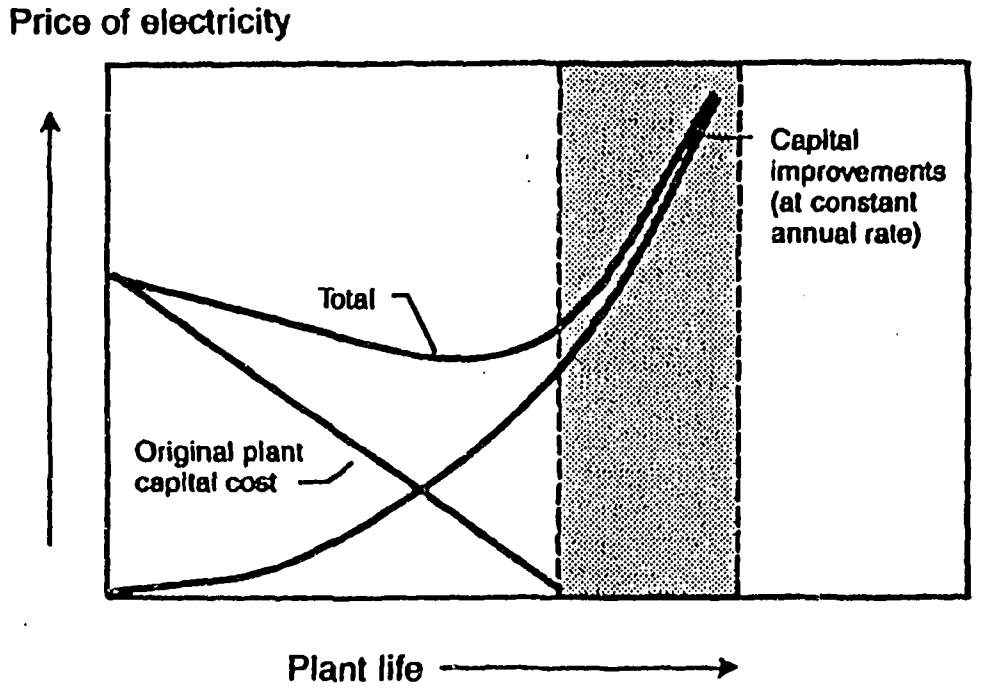


Figure 3

Life Cycle Management–Strategic Issues

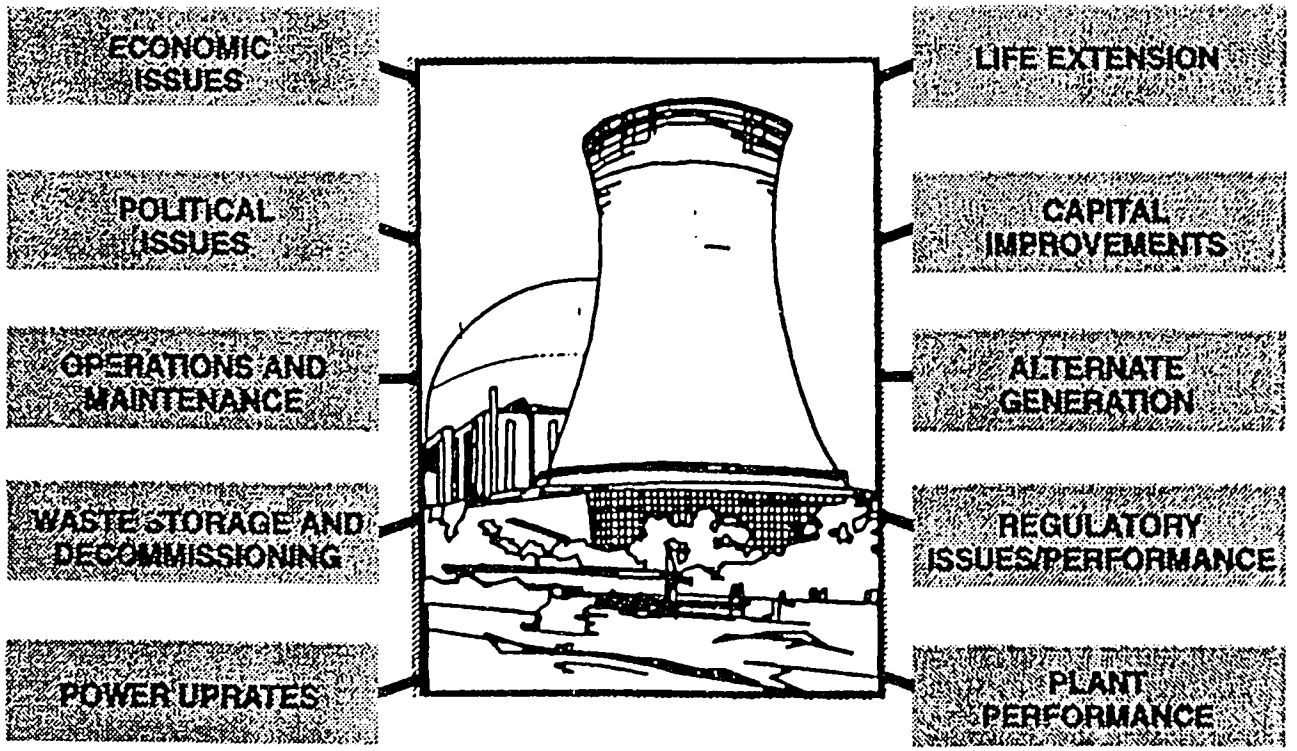


Figure 4

Life Cycle Management–Implementation Issues

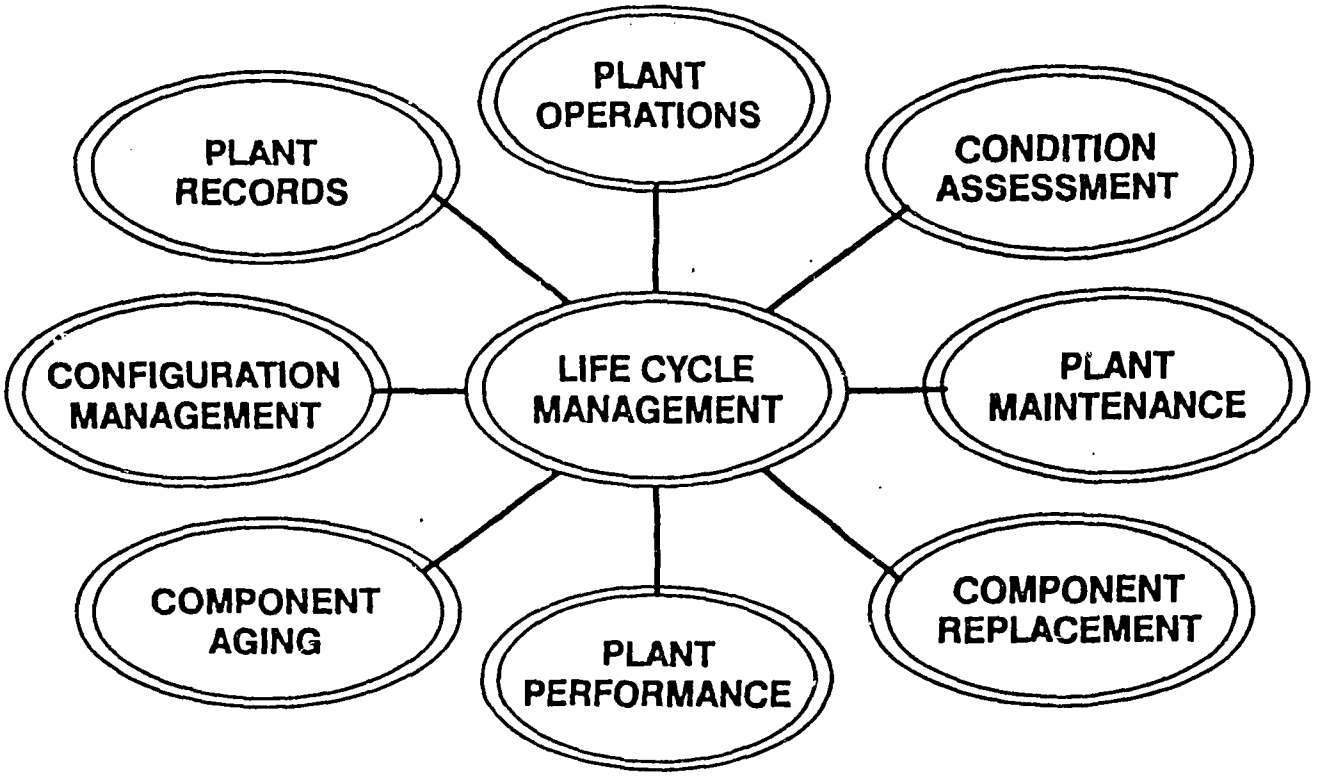
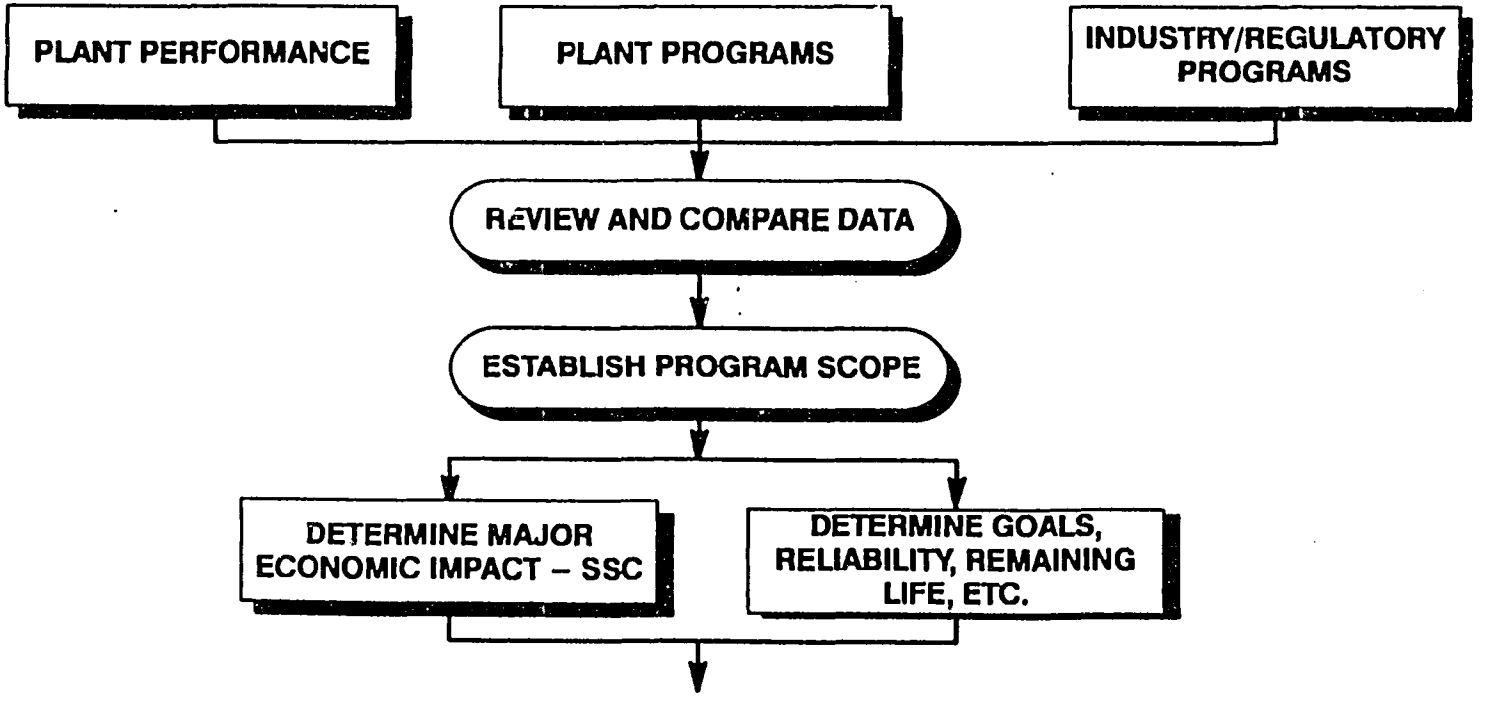


Figure 5

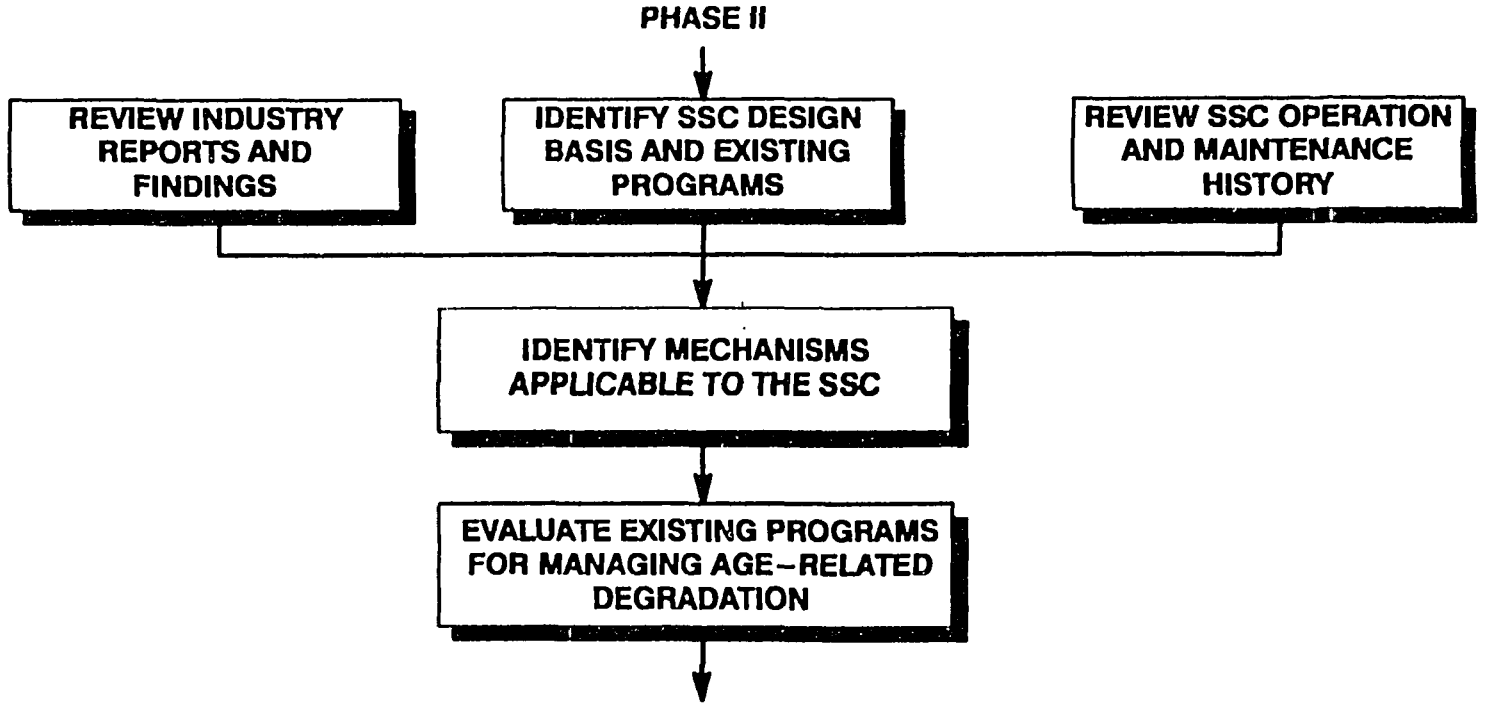
LCM Methodology – Phase I



RESULTS: List and prioritize all systems, structures, and components (SSC)

Figure 6

LCM Methodology – Phase II



RESULTS: Categorized list of SSC and programs to manage each during the plant life cycle

Figure 7

LCM Methodology – Phase III

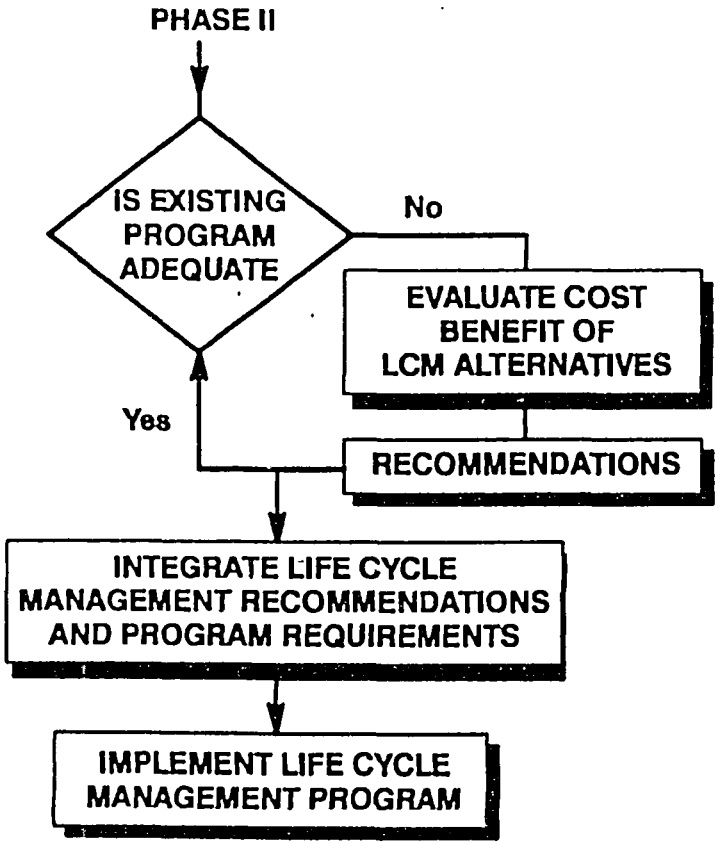


Figure 8

LCM Sample SSC List

LIST OF COMPONENTS	POTENTIAL DEGRADATION MECHANISMS			CATEGORY
	NEUTRON EMBRITTLEMENT	FATIGUE	CORROSION	
• Pressure vessel	X	X	X	2
• Closure studs	X	X	X	5
• Reactor vessel supports	X	X	X	1
• Stop valve	X		X	3
• Diesel generator		X	X	3
• Large heat exchangers		X	X	4

LCM categories

1. Judged unnecessary to replace or repair during plant life
2. High potential impact on life
3. Long life; nominal input on life
4. Impacts LCM cost; life time replacement needs to be determined
5. Limited life with recurring replacement

Table 1

Aboveground Piping

Option 1: Replace existing piping with Rubber–Lined Carbon Steel Spools

Option 2: Replace existing piping with 6 percent Moly stainless steel

Option 3: Replace existing piping with nickel alloy clad carbon steel

	Option 1	Option 2	Option 3
Present–day capital cost	$7,599,200	$9,203,450	$9,252,900
Best Estimate Differential total life cycle cost PVRR	Base	($3,594,000)	($3,534,000)
Expected value Differential total life cycle cost PVRR	Base	($5,119,000)	($5,061,000)
(Difference between Options 2 and 3)	–	Base	$58,100

Table 2

Underground Saltwater Piping

Option 1: Replace piping and distribution header using existing routing

Option 2: Replace piping along new route and replace distribution header in place

Option 3: Install InSituForm lining

	Option 1	Option 2	Option 3
Present–day capital cost	$10,027,500	$18,866,400	$11,550,000
Estimated outage	175 days(1)	161 days(1)	18 days
Best Estimate differential total life cycle cost PVRR	Base	$5,113,000	($40,208,000)
Expected Value differential total life cycle cost PVRR	Base	$4,982,000	($39,174,000)

(1) Cost of extended outage included in differential total life cycle PVRR

Table 3

CA9500137

AGING ASSESSMENT OF NUCLEAR GENERATING STATION CABLES

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Toronto, Canada

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ABSTRACT

A number of diagnostic techniques requiring micro samples for monitoring the condition of nuclear generating station cables have been identified. The cables studied were insulated with polyethylene (PE), cross-linked polyethylene (XLPE), ethylene propylene rubber (EPR), butyl rubber, styrene butadiene rubber (SBR), and polyvinyl chloride (PVC). The degradation was assessed by conventional elongation measurement, differential scanning calorimeter(DSC) oxidation induction time (OIT), DSC oxidation induction temperature (under high oxygen pressure), infrared carbonyl absorption, density, and swelling measurements. The sensitivities of the diagnostic techniques to measure oxidation and embrittlement were compared with the elongation results, and a criterion for monitoring the cable degradation was developed. Range of values obtained using diagnostic techniques are presented which can be used to assess the degradation state of commonly used insulating materials.

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1.0 INTRODUCTION

Cables are components critical to the safe operation of a nuclear power plant, and the substantial replacement cost of aged cables is an incentive to develop a management program to assess cable aging. Research results and operational experience indicate that power plant cable materials gradually embrittle and eventually crack, resulting in loss of dielectric strength. The major causes of aging include elevated temperature, mechanical stresses, humidity, hydrocarbon fluids, ozone, and radiation. These stresses act in conjunction with one another resulting in chemical and physical effects.

Elongation-at-break has been the conventional test method for measuring embrittlement. Traditionally a value of 50% absolute elongation has been selected as the end point criteria. This value will provide sufficient margin for the insulation to function without cracking, and has been used by several nuclear cable standards as the acceptance criteria.[1,2] The disadvantage of this destructive test is that a large sample size is required for analysis, and for many polymers elongation does not indicate the gradual decrease of physical properties. Rather, the elongation remains constant during the long induction period followed by a steep decline leading to embrittlement.

A study was initiated to improve or refine the traditional physical, and chemical testing methods for assessing degradation in cable insulation material. This study identifies chemical test procedures that can monitor the degradation of cables in lieu of elongation tests. Because the techniques evaluated in this study require only micro specimens for analysis, a small cable sample allowed investigators to conduct several tests.

In this study insulation specimens were aged at elevated temperatures until embrittlement, and the elongation-at-break values were measured as a function of aging time. Separate samples were Gamma irradiated up to 120 Mrad. The elongation results were compared with the values obtained in the physical and chemical properties using micro samples. The techniques evaluated were:

- DSC Oxidation Induction Time (OIT)
- Oxidation Induction Temperature (under high oxygen pressure)
- Fourier Transform Infrared Spectroscopy (FTIR)

- Gel Content
- Swelling Ratio
- Plasticizer Content
- Density

Cables insulated with cross-linked polyethylene (XLPE), polyethylene (PE), ethylene-propylene rubber (EPR), butyl rubber, styrene-butadiene rubber (SBR), and polyvinyl chloride (PVC) were evaluated in this study.

2.0 OBJECTIVES

1. To identify and assess promising diagnostic techniques for characterizing aging and degradation of nuclear power plant cable insulations.

2. To determine criteria for the life extension of nuclear power plant cables.

3.0 MATERIALS AND AGING CONDITIONS

All cables were aged with the conductors in place and, in one case, with the jacket. For PVC, samples also were aged without the conductors. Cable lengths of 30 cm and 5 m were prepared and the ends sealed with silicone tape. The specimens were aged in forced-air circulation ovens at the temperatures ranging from 105° to 140°C. The temperatures selected are typical aging condition used to provide accelerated aging and end-of-life (embrittlement) within 6 to 12 months. Samples were removed periodically and the physical and chemical properties were measured. Samples of EPR, XLPE and PVC were irradiated with a Cobalt 60 gamma source at a dose rate of 0.7 Mrad/h to a total of 120 MRad.

4.0 TESTS

4.1 Tensile Strength and Elongation-at-break

4.1.1 Experimental Procedure. Tensile and elongation tests were determined in accordance with CSA C22.2 0.3/ASTM D2633-82 using a Lloyd tensile testing machine. For cables greater than 10 mm in diameter, the insulation was buffed and Die 'C' specimens were prepared. For the smaller wire sizes tubular specimens were used with the conductors removed. The specimens were pulled at a crosshead speed of 50 mm/min. Typically three samples were tested and the data averaged to obtain the results used in the analyses.

4.1.2 Results.

4.1.2.1 Cross-Linked Polyethylene. The elongation-at-break (E_b) for XLPE insulation with thermal aging period are plotted in Figure 1. The insulation exhibits a long oxidation induction period, during which the E_b remained unchanged followed by a sharp decrease.

The results of E_b for PE, SBR and EPR were similar in that these materials showed a lengthy induction period followed by a significant decrease. In contrast, during irradiation the E_b values decreased gradually with total dose as shown in Figure 2.

The aging performance of butyl rubber insulations differs substantially (Figure 3) from other polymers evaluated. Butyl rubber lost 40% of its original elongation (460%) within 40 days of aging at 105°C. On further aging for 400 days, the elongation values remained at approximately 200% level, followed by a rapid decline when the butyl rubber started to depolymerize. Thus, E_b is not a good aging indicator for butyl rubber. However, the tensile strength decreased gradually from 6.8 MPa and reached zero after 390 days (Figure 4). The results clearly indicate that the tensile strength measurement is an effective measure of butyl rubber aging.

The elongation values for PVC with thermal aging are shown in Figure 5. The E_b trend was somewhat different from the other insulation materials in that there was no long induction period, rather the E_b value decrease continuously with aging until embrittlement. The progressive decrease of E_b throughout the aging period indicates that E_b values are effective in indicating PVC degradation.

4.2 DSC Oxidation Induction Time

4.2.1 Experimental Procedure. The oxidative stabilities of the polyethylenes and EPR insulations were measured using a Du Pont differential scanning calorimeter (DSC). A 10-mg sample was placed in an aluminum pan and the temperature raised to the test level in a nitrogen atmosphere[3]. When the temperature reached equilibrium it was maintained for 3 minutes, prior to changing the atmosphere to oxygen. The gas flow rates for the nitrogen and oxygen were 200 mL/min. The time to the onset of exothermic oxidation was the measure of the oxidative stability of the materials.

4.2.2 Results. The OIT values of XLPE and EPR are plotted as a function of aging in Figures 6 and 7. It can be seen that for XLPE the OIT decreased rapidly during the early stages of aging and then remained relatively unchanged for a long period, decreasing to less than 1 minute when the insulation began to embrittle. For EPR the OIT decreased progressively with aging time.

The OIT values for irradiated XLPE and EPR samples are plotted in Figures 8 and 9. The OIT values decreased rapidly with increased total dose. It is evident that the OIT technique is an extremely sensitive measurement for determining oxidative radiation or thermal damage. The decrease of OIT values indicate a depletion of antioxidants.

4.2.3 Correlation between Elongation and Oxidation Induction Time. Comparison of the OIT results with elongation results (Figures 10-11), indicates that the OIT measurement is an early indicator of oxidative aging of cable insulation materials; OIT decreased rapidly with aging period. Furthermore, a good correlation has been obtained between the end-of-life as indicated by elongation and OIT measurement. When the material attained OIT values of 1 minute or lower, the E_b values almost reached the end-of-life criterion of 50% absolute elongation. Whereas for irradiated XLPE and EPR sample, the E_b values decreased by approximately 60% of the as received values.

In almost all of the insulations studied, an OIT value of less than 1 minute indicated either that the insulations had reached the embrittlement stage or that the elongation had decreased significantly. When the OIT was greater than 1 minute, substantial additional aging was needed to reach embrittlement. Therefore, OIT values greater than 1 minute (at a properly selected measuring temperature) can be taken as the acceptance criterion for continued service of polyethylenes or EPR.

The recommended procedure to assess the condition of a field-aged cable taken from a harsh environment is to compare the OIT value with that of a cable found in a less harsh environment (such as air-conditioned control room). The close relationship between the end-point, determined by elongation values, and OIT indicates that even with a cable of unknown thermal history or radiation damage the OIT measurement alone can identify degraded insulations. An OIT of less than 1 minute for an insulation specimen indicates that the stabilizer effectiveness has been lost and the insulation has begun to oxidize and/or has reached the stage of embrittlement. This has been confirmed on field service samples.[4-5]

4.3 Oxidation Induction Temperature (under high pressure)

4.3.1 Experimental Procedure. For rubber insulations (SBR and butyl), oxidation induction temperature curves were obtained under a pressurized oxygen atmosphere. The normal procedure for running the DSC thermal analyzer was followed except that 1- to 2-mg specimens were heated at a rate of 10°C/min while under a 2 MPa oxygen atmosphere. The temperature of oxidation at the point of the exothermic reaction (oxidation) was measured. The oxidation induction temperature was taken as the point at which the extrapolated base line meets the extension of the oxidation peak (illustrated in Figure 12f).

The oxidation induction time measurements of rubber samples showed that the standard technique of using atmospheric oxygen pressure was not viable because no distinct exotherm was evident. However, using higher oxygen pressure in a high-pressure calorimeter, precise exotherms were obtained.

4.3.2 Results. Representative oxidation induction temperature curves of SBR are illustrated in Figure 12. It is evident that the induction temperature decreases on aging. The induction temperatures of SBR specimens are plotted as a function of aging time in Figure 13. For the unaged SBR, oxidation reaction occurred at 225°C. At the initial stages of aging, the effectiveness of the antioxidants was evident as the induction temperature decreased gradually. For completely oxidized rubbers the oxidation induction temperature was reduced by approximately 35°C. Similar results were obtained for butyl rubber.

4.3.3 Relationship between Oxidation Induction Temperature and Tensile Properties. The trends of oxidation induction temperature and tensile property of SBR insulations are compared in Figure 14. The results suggest that for SBR, oxidation temperature measurement is more sensitive to aging and deterioration than tensile test results. For example, after 27 days of aging the oxidation induction temperature slowly declined by 8° to 10°C and progressively decreased by another 30°C during 103 days of aging. In contrast, during the same period the elongation-at-break remained essentially unchanged.

The oxidation temperature of a polymer is dependent on factors, such as additives, degree of cure, level of aging, etc. To determine the condition of an unknown field-aged rubber insulated cable, the oxidation temperature of the unaged insulation should be known. Slightly aged or unaged samples could be obtained from stock or from areas operating at room temperature. Comparing the oxidation induction temperatures of specimens taken from the harsh area with those of unaged specimens would provide a reasonable indication of whether the cable insulation is adequately stabilized for further service.

4.4 Solubility Measurements

4.4.1 Experimental Procedure. The insoluble gel fraction (gel content) and swelling ratio were determined in accordance with the procedure described in ASTM D2765[6]. The solvents were xylene for XLPE, toluene for EPR, SBR, and butyl rubber, and tetrahydrofuran (THF) for PVC. Samples of approximately 100 mg were exposed to boiling solvent for 12 hours. After extracting the insoluble fraction in the corresponding solvents, the excessive solvent was removed from the surface and the insoluble part was weighed at room temperature. Then, the sample was dried and weighed again. Gel content and swell ratio were then calculated.

4.4.2 Results. Solubility (gel content) and swelling measurements can give an indication of whether a polymer has undergone chain scission or cross-linking. In a cross-linked system when a polymer undergoes additional cross-linking, gel content increases and swelling ratio decreases. Chain scission causes the opposite effects. In an uncross-linked system the initial soluble polymer will become less soluble with oxidative cross-linking reaction.

The gel content of PVC insulation is plotted as a function of aging time in Figure 15. The original PVC insulation was not cross-linked and was totally soluble in THF. On aging, the insulation exhibited a long induction period before showing rapid changes in the gel content and the material became insoluble. These measurements indicate that thermally aged PVC crosslinks. For butyl the insoluble fraction decreased as the material undergoes chain session.

Irradiated PVC samples showed a similar trend as illustrated in Figure 16. As the total dose increased the insoluble gel fraction increased showing that the predominant reaction was crosslinking.

For XLPE, EPR and SBR the gel content and swelling ratio remained essentially unchanged except close to the embrittlement point, the swelling ratio decreased drastically indicating crosslinking.

4.4.3 Relations with Tensile Measurements. Solubility data of PVC are compared with elongation properties in Figure 17. It can be seen that partial solubility and complete insolubility of PVC in THF can be taken as an indication of significant thermal degradation (E_b less than 50% of the as-received values).

For polymers undergoing chain scission, such as butyl rubber, tensile strength and degree of cross-linking (gel content) are parameters that can indicate degradation. The tensile strength and gel content values of butyl rubber insulations are compared in Figure 18. It is evident that significant changes in gel content or oxidation occurred only after 290 days of aging. At this point the insulation had lost 75% of its initial tensile strength and had soften.

4.5 Plasticizer Content

4.5.1 Experimental Procedure. The plasticizer concentration of PVC was measured after extraction of 100- to 200- mg specimens in boiling ethyl ether for 12 hours, in a Soxhlet apparatus[7]. After extraction, the sample was dried and reweighed.

4.5.2 Results. The plasticizer concentration of a typical PVC insulation formulation compound with aging at 120°C is shown in Figure 19. The results indicate that initially the plasticizer content decreases fairly rapidly loosing approximately two-thirds

of the total plasticizer within 60 days of aging. Thereafter, the plasticizer content remains constant without further loss.

The importance of plasticizer content to the physical properties is illustrated in Figure 20 where, it can be seen that during the early stages of aging the elongation values are directly related to the plasticizer content. After 60 days of aging, plasticizer concentration declined by 60% and the elongation value reduced by two-thirds of its original value. On further aging, the plasticizer content basically remained unchanged, whereas, the elongation value decreased further and reached the end-of-life criterion in 130 days. These results indicate that during the later stages the degradation mechanism was controlled by oxidation and dehydrochlorination rather than plasticizer loss.

The inference from these results is that a minimum level of plasticizer is required to prevent embrittlement of PVC. Therefore, plasticizer content is an important factor in determining the usability of PVC insulations, and the volatility rate of the plasticizer governs its longevity. However, for radiation exposure there is no direct relationship between plasticizer content and physical degradation[8].

The plasticizer content of a PVC insulation formulation is generally between 20 to 30% (by mass), depending on the type of plasticizer. Therefore, a plasticizer content below 15% indicates that the cable has been undergone thermal degradation. However, only a comparison with the same type of insulation subjected to a mild environment will provide a definitive indication of the actual loss during the service. This technique has been used extensively with good results to assess field service cables[9].

4.6 Density Measurements

4.6.1 Experimental Procedure. Sample density was measured using a density gradient column with water and isopropyl alcohol according to ASTM D1505[10]. The density measurements were performed using two density gradient columns covering ranges from 0.91 to 0.94 g cc^{-1} and 0.96 to 0.98 g cc^{-1}. Shavings from the outer surface of cross-linked polyethylene insulation specimens were used for the density measurements.

The density of butyl rubber, EPR, and PVC insulation was determined by the displacement method as described in ASTM D792[11]. A 5-g specimen was weighed in air to the nearest 0.1 mg, immersed in water, and weighed again.

4.6.2 Results. The density values of XLPE insulation samples versus aging time at 130°C are plotted in Figure 21. The density increased from 0.916 to 0.920 g cc^{-1} during 200 days of aging, and then increased sharply to 0.935 g cc^{-1}, the initial gradual increase in density appeared to have been essentially caused by oxidation effect. The colour change of the opaque unfilled XLPE

during aging provide further evidence that the material was being oxidized. The material turned yellow in 35 days, became light brownish in 200 days, and became dark brownish on further aging.

Density measurements have been extensively utilized by Gillen et al[12] to characterize oxidation in polyolefinic insulation materials that were subjected to gamma irradiation. For most insulations, a nearly linear increase in density was discerned as a function of dosage. An initial increase, followed by a decrease in density also has been observed for gamma irradiated XLPE[13]. The density increase has been attributed to a combination of weight increase by covalently bound oxygen and decrease of volume by release of gaseous products. It was pointed out that even small changes in density were readily detectable and that a change of only 1 to 2% was significant in terms of degradation[12].

The density values of PVC jacketing materials are shown in Figure 22. It can be seen that the change in the density was different from that of polyethylene. No induction period was observed. The density increased steadily from 1.287 to 1.419 g cc^{-1} in 96 days. A similar trend of density increases with aging were also found for EPR and butyl rubber.

The density increase in butyl rubber appears to be caused by a simple oxidation reaction. For PVC, the initial density increase was the result of plasticizer loss. The increase of density in EPR seems to be induced by a combination of oxidation and depletion of low molecular weight processing additives. Thermogravimetric (TGA) results confirm the presence of low molecular weight (low mass) additives that evolve at the accelerated aging temperatures.

4.6.3 Correlations with Tensile Measurements. The increase of density when samples are subjected to thermal environment suggests that the measurement of density can be a valuable tool for monitoring the degradation of XLPE, PVC, EPR, and butyl rubber insulated cables. In accelerated aged samples, limited diffusion of available oxygen to the bulk of the specimens are known to produce heterogeneously oxidized regions[12]. The outer surface, exposed to the air, oxidized at a faster rate and exhibited higher density than the inner region. Since field-aged cables are subjected to long-term aging, the effect of diffusion is not a significant factor. Therefore, for field-aged cables, density measured from an outer surface of the insulation is representative of overall insulation condition.

The density results for XLPE are compared with the elongation results in Figure 23. The density results appear to be more sensitive than the elongation results, showing detectable changes. For example, polyethylene cable insulations exhibited density changes in the second decimal place (0.01 g cc^{-1}) long before reaching their end of life. However, to predict the

condition of an unknown insulation using density measurements, its original density should be known.

For PVC and EPR the increase of density in the region of 0.01 g cc^{-1} did not cause detectable changes in the tensile properties. The early stage of PVC aging was primarily due to plasticizer loss, which resulted in a large density change, but not a corresponding decrease in elongation. Results indicate a density change in the region of 0.10 g cc^{-1} in PVC and 0.05 g cc^{-1} in EPR to be a suitable criterion for detecting degradation, which corresponded to a reduction of elongation by 50%.

4.7 FTIR Spectroscopy

4.7.1 Experimental Procedure. The structural changes associated with the aging process were determined with a Mattson Polaris Fourier Transform Infrared (FTIR) Spectrometer using the technique of Attenuated Total Reflection (ATR) Spectroscopy. An Anglia Scientific 200 series base sledge microtome was used to prepare 100-μm thick specimens for the study.

4.7.2 Results. Aged and oxidized polyolefins exhibit a characteristic carbonyl band at a wave number of 1730 cm^{-1}. The aging behaviour of the XLPE, PE, SBR and EPR were similar in that unaged specimens showed no carbonyl peak while aged specimens exhibited a strong carbonyl band after a lengthy induction period. Figure 24 shows typical FTIR Spectra for XLPE. The formation of the carbonyl band at 1730 cm^{-1} is clearly evident.

It was found that the carbonyl band could detect oxidation of irradiated XLPE samples but was less successful for EPR, SBR and PVC materials.

4.7.3 Correlation between Elongation and Carbonyl Group Formation. Carbonyl formation is a sensitive indicator of oxidative aging for XLPE and high density polyethylenes. In each instance the carbonyl formation preceded a steep decline in elongation. For EPR and SBR, the carbonyl formation coincided with the decrease of elongation that occurred after an induction period. In each case the formation of a carbonyl peak was well in advance of the material's embrittlement.

4.8 Assessment of Time to Embrittlement Using Various Diagnostic Techniques

The sensitivity of the diagnostic techniques to measure embrittlement (Table 1) was compared with elongation results. Diagnostic tests provide a conservative estimate of material degradation. For example, unfilled XLPE required 420 days of aging at 130°C to reach an absolute elongation value of 50%. However, an OIT value of less than 1 minute required 385 days aging. The density increased by 0.01 g cc^{-1} at the end of 250 aging days, whereas the carbonyl group formed after 200 days. Thus, signs of oxidation were detected by diagnostic tests before

embrittlement. This is true for all the insulations studied. These results suggest that a combination of diagnostic techniques employing micro samples can provide a good indication of cable insulation condition before mechanical failure.

4.9 Application of Diagnostic Techniques

The Table 2 illustrates the application of the diagnostic techniques to assess the condition of cable insulation and the recommended action. The data used to assemble the table was obtained from this and other studies[4,5]. To illustrate the application of the table to field service cables the following illustrations are presented:

EXAMPLE 1

Consider the case where a micro sample from a service cable insulated with XLPE is obtained. First measure the carbonyl peak using FTIR (a non destructive) test, and then obtain the OIT value (destructive test). If no carbonyl peak is detected and an OIT greater than 5 minutes is obtained the XLPE insulation can be considered as not having undergone significant degradation and can remain in service. If a larger sample is available elongation values should be determined. Elongation values meeting the minimum requirement found in cable standards would confirm that the insulation has not aged significantly.

EXAMPLE 2

A similar XLPE insulated cable can be considered significantly aged if: the elongation values are below CSA/ASTM minimum requirements; OIT value is in the region of 1 minute; a strong carbonyl peak is present. A reduction in the swelling ratio and an increase in density greater than 0.01 gcc^{-1} would confirm that the insulation has degraded. The recommendation would be that the cable be monitored frequently for embrittlement.

5.0 CONCLUSIONS

5.1 Elongation-at-break and Tensile Strength

As cables age there is a gradual embrittlement of the insulation material, leading ultimately to cracking at which stage the elongation value will be substantially lower than the standard minimum for new cable insulation. Elongation value obtained during the initial stages of aging and during the induction period is not a good indicator of the insulation condition for XLPE, EPR, PE and SBR. To assess the actual insulation condition during this period requires additional chemical tests.

The gradual decrease of tensile strength in butyl rubber and of elongation in PVC indicate that tensile measurement is still the best indicator of aging of these insulations.

Table 1
Comparison of Techniques to Assess XLPE, PE, EPR, Butyl Rubber, SBR, and PVC Insulation Degradation

	Aging Temp. (°C)	Induction Time for Significant Decrease in Percent Elongation	Induction Time for Significant Increase in Density	Time for Increase in Density by 0.01 g cc^{-1} Compared to Unaged Sample	Time for Increase in Density by 0.10 g cc^{-1} Compared to Unaged Sample	Time for Oxidation Induction Temperature to Increase by 15°C Compared to Unaged Sample	Time to Reach 15% (by Mass) Plasticizer Content	Induction Time for Increase/ Decrease in Gel Content	Induction Time for Carbonyl Group Formation	Time to Reach OIT of Less Than 1 Minute	Time to Increase/ Decrease Tensile Strength by 50%	Time to Reach 50% Absolute Elongation
Materials for Which the Tests are Applicable		XLPE, PE, EPR, SBR	XLPE, Butyl, PVC	XLPE, Butyl	PVC	SBR, Butyl	PVC	Butyl, XLPE, PVC	XLPE, PE, EPR, SBR	XLPE, PE, EPR	Butyl, PVC	All Insulators
		Aging Period (days)										
Unfilled XLPE	130	280	200	250		–		>385	≈ 200	385	–	420
Filled XLPE	130	320	>150	250		–		≈ 180	≈ 200	540	–	600
High Density PE	105					–		–	≈ 475	280	–	
EPR	140	35				–		–	≈ 62	40–45	–	120
Butyl Rubber	105	10		50		≈ 100		≈ 150	–	–	65	–
SBR	120	100				≈ 45		>126	≈ 100	–	–	≈ 135
PVC	120	–			≈ 60	–	20	62	–	–	40	≈ 150

Table 2
Assessment of Cable Condition Based on Physical and Chemical Tests

	ASSESSMENT TEST								
	Percent Elongation	Tensile Strength	*OIT (min.)*	*Oxidation Induction Temperature Under 2 MPa Oxygen*	*Infrared Carbonyl Absorption Peak @ 1720-1730 cm^{-1}*	*Density* *	*Gel Content* † *Swell Ratio*	*Plasticizer Content*	*Recommended Action*
	INSULATION TYPE								
Condition of Insulation	PE, XLPE, EPR, SBR, PVC	Butyl, PVC	PE, XLPE, EPR	SBR, Butyl	PE, XLPE, EPR, SBR	XLPE, Butyl, PVC, EPR	XLPE, PE, EPR, SBR, PVC, Butyl	PVC	
No Significant Degradation	Meet or above CSA/ASTM standard	Meet or above CSA/ASTM standard	>5-20	Same as unaged sample	No peak	Same as unaged sample	Gel content above 80%‡ Soluble §	20-30% (by mass)	No action required
Initiation of Degradation	Below CSA/ASTM requirement eg: 70-80% of the requirement	20-30% below the standard requirement ‡ 20-30% above the standard requirement	≈1	5°C below control specimen	Minor peak #	Same as control specimen Increased by 0.10 §, 0.05 g cc^{-1} Δ compared to control sample	In the vicinity of control specimen Gel content 5-10% † below control specimen Soluble §	10-20% below control sample	Periodic inspection to monitor aging
Significant Degradation	Below CSA/ASTM requirement eg: 50% of the requirement	50% below the standard requirement ‡ 50% above the standard requirement	<1	10-15°C below control specimen	Prominent peak #	Increased by 0.01 g cc^{-1} compared to control sample Increased above 0.10 §, 0.05 g cc^{-1} Δ compared to control sample	Swell ratio reduced Gel content 20-30% † below control specimen 5-10% gel content §	20-30% below control sample	Frequent monitoring required
Severe Degradation	≈50% absolute elongation	Soft and tacky ‡	<1	20-30°C below control specimen	Strong peak #	Increased more than 0.01 g cc^{-1} compared to control sample	Swell ratio reduced Soluble † Insoluble §	30-40% below control sample	Cable replacement recommended

Notes: * Measured within 5 minutes of water immersion for butyl rubber
† Solvent xylene for XLPE and PE, toluene for EPR, butyl rubber, and SBR, and THF for PVC
‡ Butyl rubber only
§ PVC only
# Only a comparison test if the control exhibits a peak in the carbonyl region
Δ EPR only

5.2 Oxidation Induction Time

The OIT measurement is a sensitive technique to measure the remaining oxidative stability in XLPE, PE, and EPR. Materials nearing embrittlement showed OIT values less than 1 minute. Well stabilized materials (as received and further aged) exhibited OIT values in excess of 5 minutes. No control sample is required to assess the condition of field-aged cable.

5.3 Oxidation Induction Temperature

The oxidation induction temperature measurement is a sensitive indicator of oxidative stability and aging in butyl rubber and SBR. Insulations that have undergone considerable aging oxidized at 15°C lower than the unaged specimen, when measured under 2 MPa oxygen. A reference sample for comparison is required for making a definitive assessment on the condition of a field-aged cable.

5.4 Solubility and Swelling Measurements

Solubility and swelling measurements are good indicators of changes accompanying the oxidative cross-linking/chain-scission process and good analytic tools for determining the condition of butyl rubber and PVC insulated cables. Significantly aged PVC showed reduced solubility in THF, and butyl rubber showed increased solubility in toluene. For PE, EPR, SBR, and XLPE with high initial gel content, the swelling measurements may show detectable differences only when the insulations near embrittlement.

5.5 Plasticizer Content

There is good agreement between the plasticizer loss and decrease in elongation of PVC. A minimum level of plasticizer is required to prevent embrittlement of PVC and it has been shown that a plasticizer level less than 15% by mass can indicate significant aging.

5.6 Infrared Carbonyl Analysis

Structural changes attributable to aging can be determined with FTIR. In this study, the aged insulations exhibited a carbonyl absorption band at 1730 cm-1 before changes were detected by elongation measurement. Additives such as antioxidants can interfere with the assignment of the carbonyl peak. In that case, comparison of the carbonyl peak area to a reference peak of a control sample can indicate whether the cable has been oxidized.

5.7 Density

Bulk density measurements of cable components show that density tends to increase with age. The limitation is that the density of a sample is dependent on the type of formulation, and hence

the test can only be a comparison test. Aged XLPE and butyl rubber exhibited density increases greater than 0.01 g cc^{-1}, whereas PVC and EPR showed density increases in the region of 0.10 and 0.05 g cc^{-1}, respectively.

ACKNOWLEDGEMENTS

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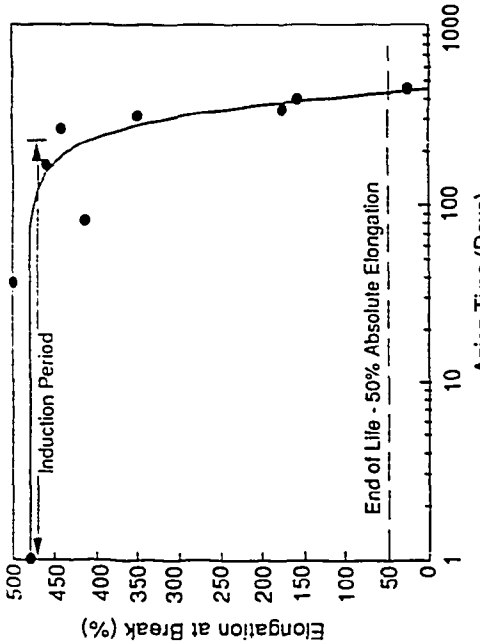

Figure 1

Effect of Oven Aging at 130°C on Tensile Elongation for Unfilled XLPE Insulation (Shielded Cable)

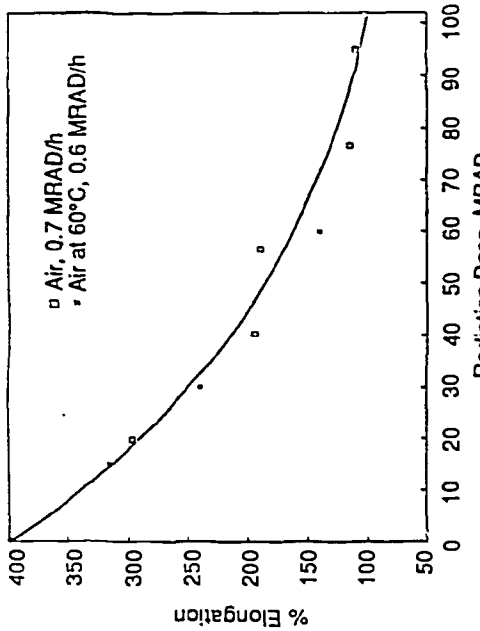

Figure 2

Elongation-at-break of FRXLPE Specimens as a Function of Dose. Irradiated in Air Atmosphere.

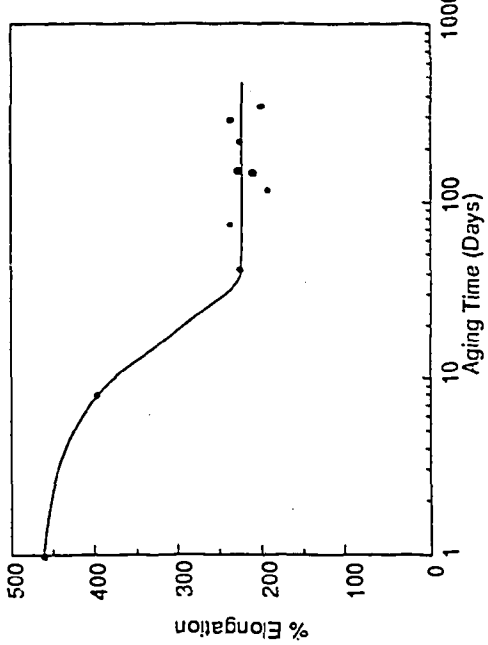

Figure 3

Effect of Oven Aging at 105°C on Tensile Elongation for Butyl Insulations

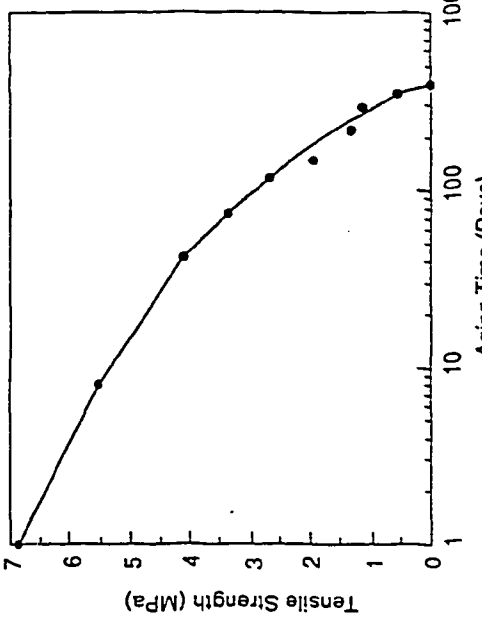

Figure 4

Effect of Oven Aging at 105°C on Tensile Strength for Butyl Insulation

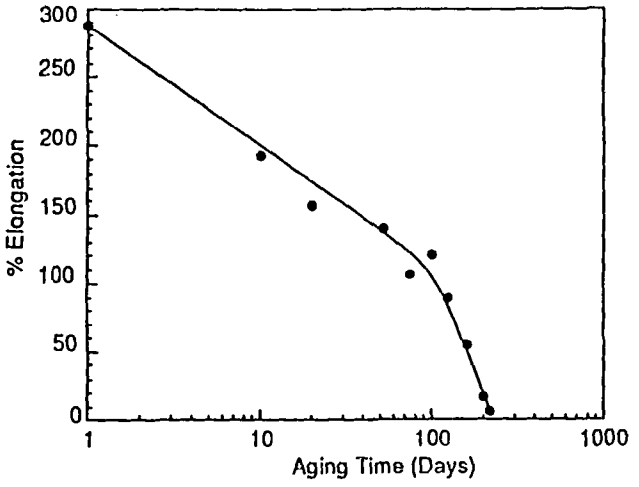

Figure 5

Effect of Oven Aging at 120°C on Tensile Elongation for PVC Insulations

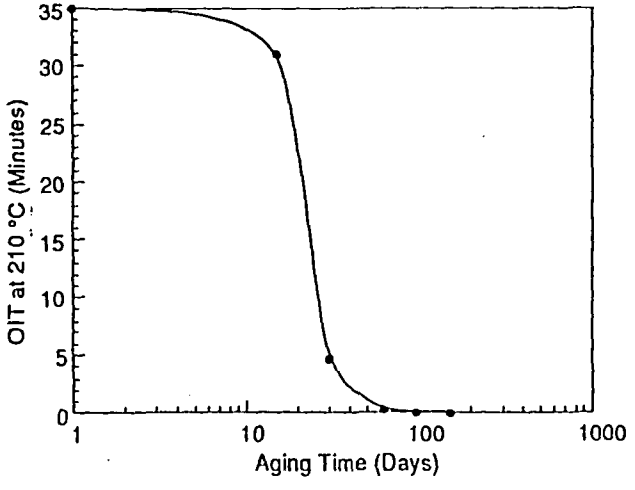

Figure 7

DSC Oxidation Induction Time at 210°C After Aging at 140°C for EPR Insulations

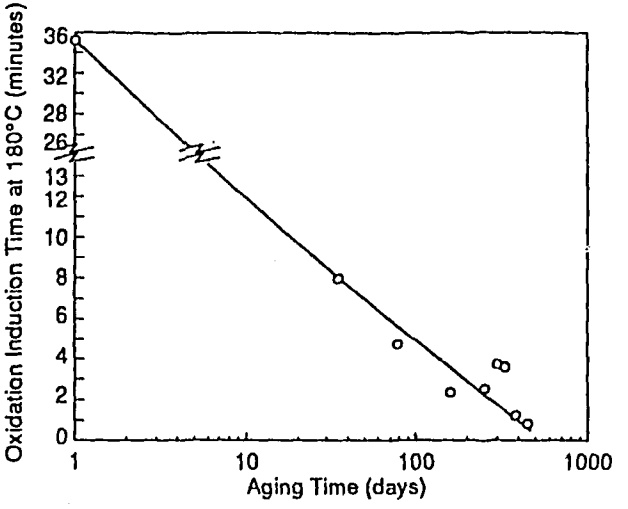

Figure 6

DSC Oxidation Induction Time at 180°C for Unfilled XLPE Insulations After Aging at 130°C

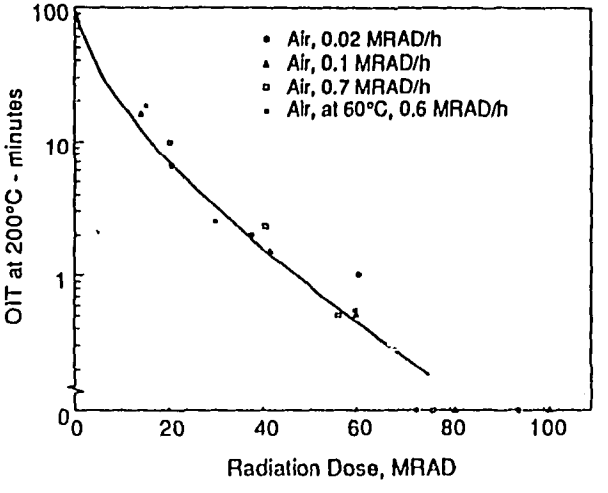

Figure 8

DSC Oxidation Induction Time at 200°C for FRXL PE Specimens as a Function of Dose, with Different Dose Rates

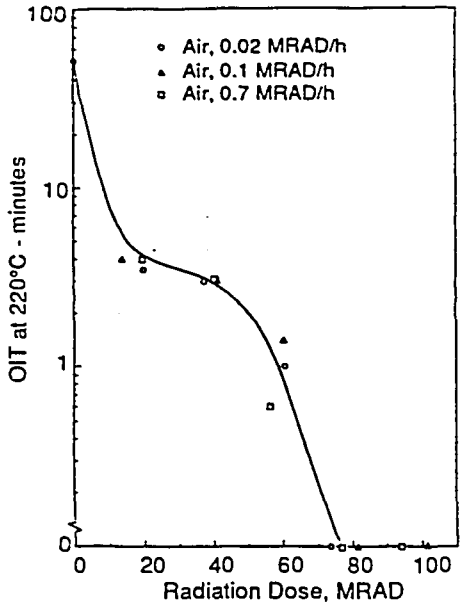

Figure 9

DSC Oxidation Induction Time at 220°C for FREPR Specimens as a Function Of Dose. Irradiated In Air with Different Dose Rates

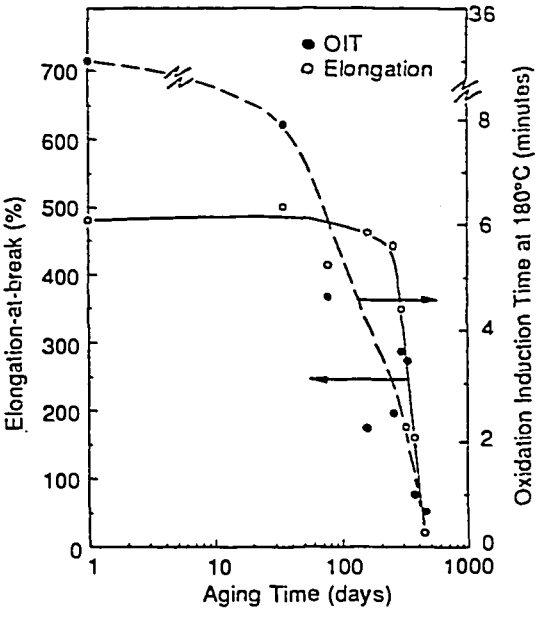

Figure 10

Correlation Between Elongation-at-break and Oxidation Induction Times of Unfilled XLPE Insulations Aged at 130°C

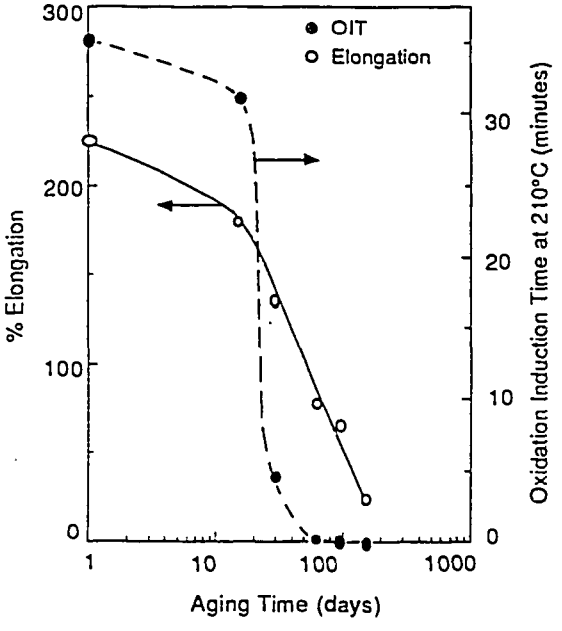

Figure 11

Correlation Between Elongation-at-break and Oxidation Induction Times of EPR Insulations Aged at 140°c

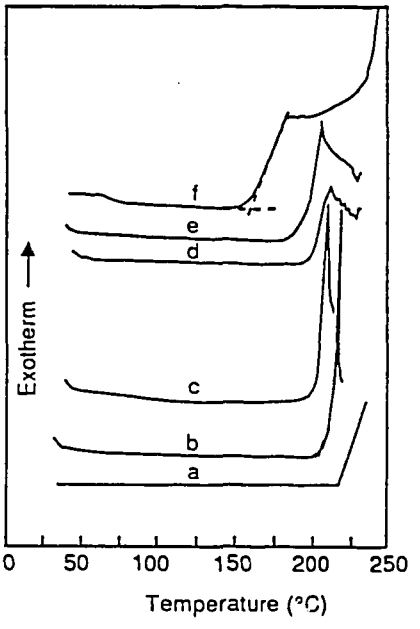

Figure 12

DSC Oxidation Induction Temperature Curves of SBR Under 2 MPa Oxygen Pressure(a) unaged material and insulations aged at 120°c for(b) 16 days; (c) 42 days; (d) 73 days; (e) 90 days; and (f) 126 days

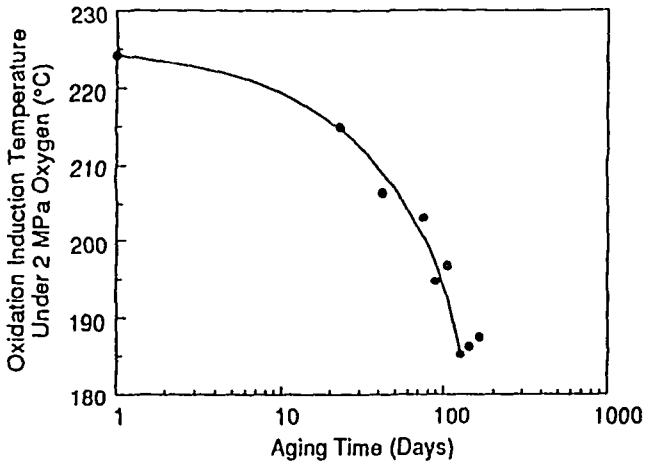

Figure 13

DSC Oxidation Induction Temperature under 2 MPa Oxygen Pressure versus Aging Time at 120°C for SBR Insulation

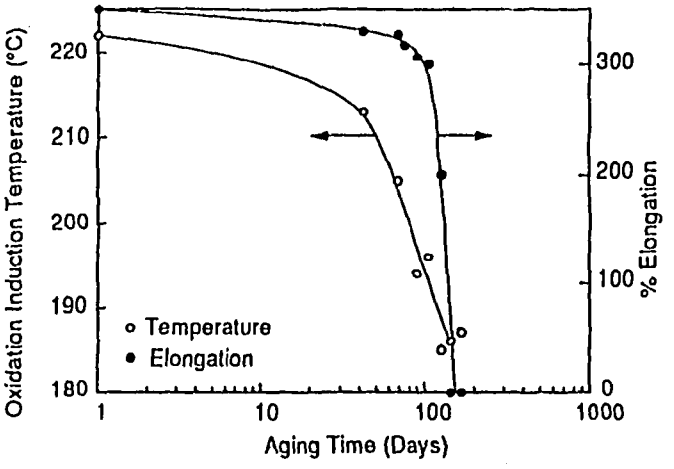

Figure 14

Correlation Between the DSC Oxidation Induction Temperature and the Elongation Values of SBR Insulations as a Function of Aging Time at 120°C

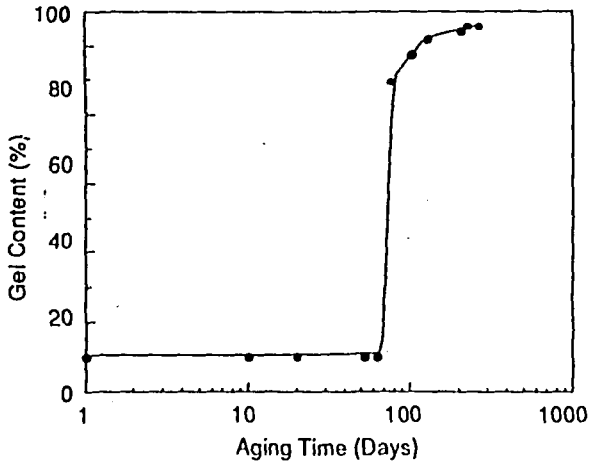

Figure 15

Gel Fraction versus Aging Time at 120°C for PVC Samples

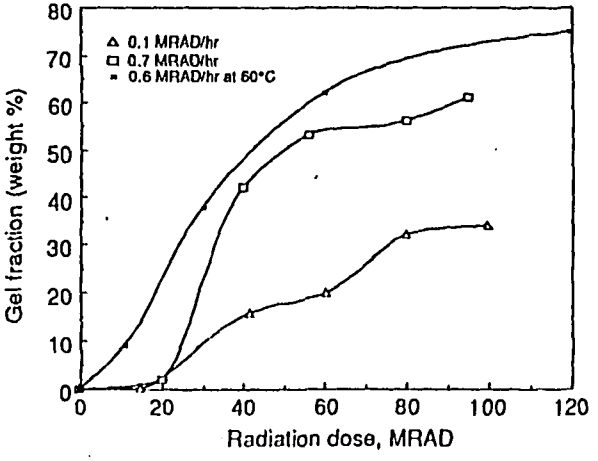

Figure 16

Gel Fraction of PVC Specimens Irradiated in Air Atmosphere With Different Dose Rates

Figure 18

Relationship Between the Gel Content and Tensile Strength in Butyl Insulations

Figure 20

Correlation Between the Elongation-at-break and the Plasticizer Content of PVC Insulations as a Function of Aging Time

Figure 17

Correlation Between the Elongation-at-break and the Gel Content of PVC Insulations as a Function of Aging at 120°C

Figure 19

Effect of Oven Aging at 120°C on the Plasticizer Concentration for PVC Samples

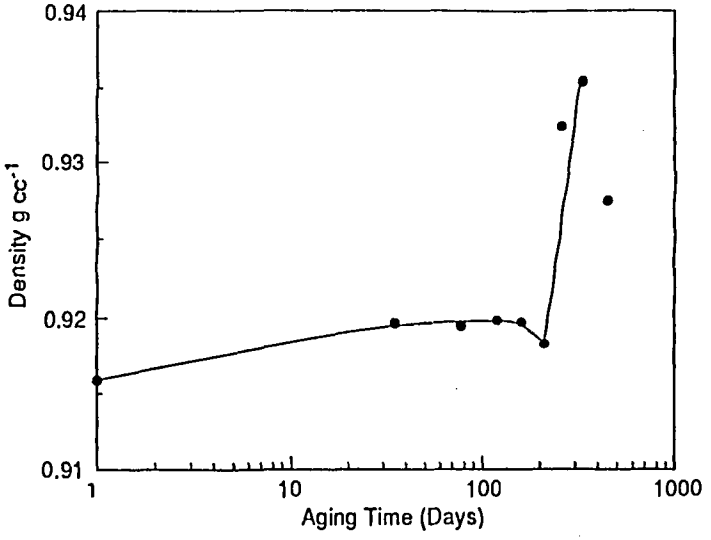

Figure 21

Density of Unfilled XLPE Insulations as a Function of Aging Time at 130°C

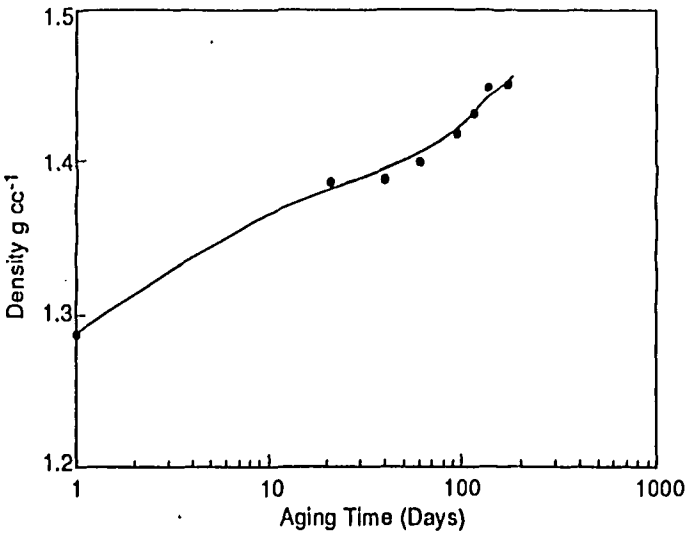

Figure 22

Density of PVC Jacket Specimens as a Function of Aging Time at 120°C

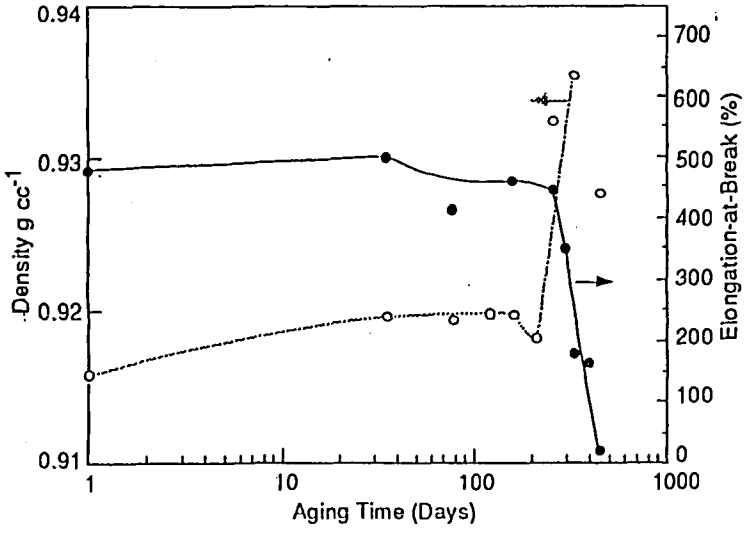

Figure 23

Relationship Between Density and Elongation-at-break in Unfilled XLPE Insulations

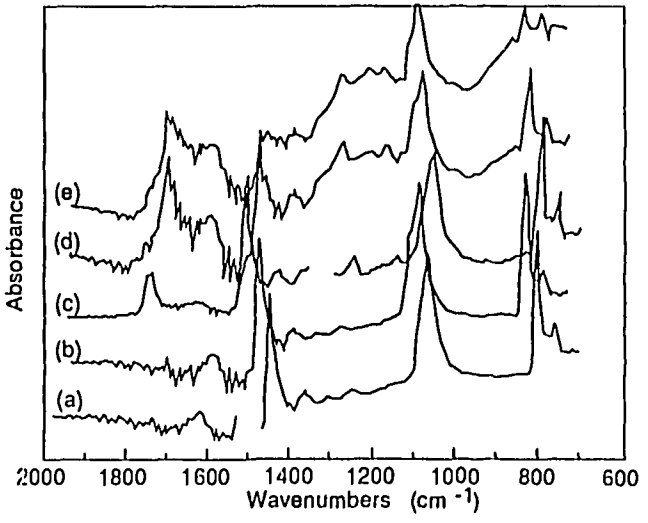

Figure 24

FTIR Spectra of Filled XLPE Insulations
(a) unaged material and insulations aged at 130°C for
(b) 99 days; (c) 235 days; (d) 330 days; and (e) 425 days

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NUCLEAR PLANT LIFE ASSURANCE SCOPING STUDY NUCLEAR & CONVENTIONAL PIPING

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ABSTRACT

The Ontario Hydro Nuclear Plant Life Assurance program offers a new dimension to plant maintenance. Conventional means of maintaining equipment reliability are preventive maintenance and inspection. These have been of limited effectiveness in managing aging degradation, which may proceed slowly and relentlessly without being apparent until its effects reach the point where there's a crisis to deal with. Being blindsided by unanticipated failure of major components is one of several 'destiny issues' identified by Ontario Hydro, and NPLA is intended to prevent it. NPLA is a key part of Ontario Hydro's plan to realize its strategic goal of achieving at least 40 years life with its nuclear generating stations.

Fifteen 'critical' components were identified in the initial phase of the NPLA program. Aging degradation issues for critical components in each plant are being identified and investigated in NPLA Scoping studies, to be completed in 1992. Implementation by the stations will follow. This paper discusses some issues identified in scoping studies done for nuclear and conventional piping systems.

NUCLEAR PLANT LIFE ASSURANCE SCOPING STUDY NUCLEAR & CONVENTIONAL PIPING

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INTRODUCTION

While the design life of Ontario Hydro's nuclear power plants is 30 years, a minimum 40 year life has been adopted as a strategic goal. Achieving that in a plant depends on achieving it with all major components essential to plant safety or operation. Experience indicates something more than preventive maintenance and inspection - the usual means of maintaining equipment reliability - is needed, however, to anticipate and manage aging degradation over the longer term.

The Nuclear Plant Life Assurance program is intended to provide the basis for managing each plant to achieve a minimum 40 year life, by developing and implementing aging management programs for major 'critical' components. The goal is basically to avoid surprises!

The NPLA methodology was developed in the initial phase of the program, which also identified 15 'critical' components essential to plant safety or operation and likely to cost more than $50 M, or a 6 month outage in the event of failure [1]. Nuclear and conventional piping are two of the 'critical' components included in the program.

The second phase of the program, NPLA scoping studies, explores and identifies life management issues for each 'critical' component in each plant. Potential aging degradation issues for nuclear and conventional piping are summarized in Table 1. System by system reviews of design and operating information were done for each plant, and compared with world experience in aging of similar equipment in other plants. That work was documented in scoping research reports. These were used as a basis for working documents - scoping compilation reports - assembled for each station.

The author has worked on the NPLA scoping studies for nuclear and conventional piping for much of the past 18 months, and at time of writing, most of the research is complete. The studies focus on the pressure boundary, and had to be guided by both the cost of piping replacement and the potential economic consequences of piping failure in deciding what should be considered relevant to NPLA. Piping system components such as pumps, valves, supports, restraints, snubbers, penetration seals, and insulation were considered insofar as they affect piping life, but were not treated in detail themselves. Heat exchanger shells and tubes

are cylindrical pressure boundaries similar in many ways to piping, but were not specifically included.

The purpose of this paper is to present and discuss significant issues identified. Your comments and suggestions are invited. The work is not yet complete and has had limited review. The technology should continue to evolve for some years.

Table 1
Summary of Aging Degradation Mechanisms

Principal Stressors	Degradation Mechanisms	Likely Consequences
Pressure Change, Temperature Change or Gradient Stress Raisers	Low Cycle Fatigue High Cycle Fatigue	Cracking, Leakage, Rupture
Temperature, Flow Velocity, Geometry, Water Chemistry, Trace Alloys	Erosion: - Cavitation - Liquid Impact - Single Phase - Solid Particle	Leakage, Rupture, Stress Raiser
Mechanical Loading: - Vibration, - Water Hammer - Steam Hammer Stress Raisers	Low Cycle Fatigue, High Cycle Fatigue, Fretting Wear, Rupture, Distortion	Cracking, Leakage, Rupture
Temperature, Water Chemistry, Strain, Silt Deposits	Various Corrosion Mechanisms	Leakage, Rupture, Stress Raiser
Zebra Mussels	Fouling	Pressure Drop, Silt Deposits

GENERIC PIPING ISSUES

ASME Code

Recent evidence indicates the ASME fatigue design procedures based on specimens tested in air are not as conservative as initially assumed for steel piping stressed in a water environment. The effect is referred to as corrosion-assisted fatigue [2,3] and is believed to correlate with trace sulfur content in the piping material. Low cycle fatigue life is reduced most in water service; low cycle fatigue cracks initiate early in the fatigue life and are therefore affected proportionately more by corrosion than high cycle fatigue cracks, which initiate late in the fatigue life and propagate relatively quickly. Another consequence of corrosion-assisted fatigue is that the concept of a dynamic stress level below which there is no fatigue damage (ie, the endurance limit) is not applicable to piping in water service as previously assumed, though it is well known to be valid in air.

The ASME Boiler and Pressure Vessel fatigue design curve will likely be changed soon. Even with the current safety factor of 20 on cycles to failure reduced to 10 (consistent with reduced uncertainty as to the environment) the overall effect might be a factor of about two reduction in fatigue life [2].

To achieve a 40 year life, Ontario Hydro plants will have to be re-qualified for operation beyond the 30 year design life. How changes to the Code will be used by Ontario Hydro and its regulators in evaluating cumulative fatigue usage in existing plants at the end of the 30 year design life remains to be determined. That's only ten years away for Pickering NGS-A; thinking about such issues before that time may help avoid surprises.

Transient & Fatigue Monitoring

Piping in Ontario Hydro nuclear plants was subject to fatigue analysis in design, but to various standards according to Code requirements in place when they were designed. The most heavily stressed welds in Bruce NGS-B are in the pressurizer vessel; several have design fatigue usages approaching 100 % in 30 years. Inlet nozzle welds on the BNGS-B bleed condenser shell have design fatigue usages approaching 100% in 38 years. Design fatigue usage in piping is generally much lower, but the stress calculations are based on assumptions that supports and restraints function as intended.

Aging by fatigue is inevitable throughout all plants. Extrapolating available information on plant transients (Table 2) indicates actual fatigue usage after 40 years life will be about 10 %. If changes to the ASME code halve the design fatigue life

Table 2
Summary: Pickering NGS-A Operating History [12]

Normal/Upset Transient	Design Number	Actual Number through Dec. 1991			
		P-1	P-2	P-3	P-4
1.1 PHTS Heat-up	500	19	13	21	18
1.2 Reactor Startup	1500	104	101	80	99
1.3 Reactor Shutdown	1000	67	58	49	55
1.4 PHTS Cooldown	500	18	12	20	17
1.5 Power Manoeuvre (deep)	10000	112	109	110	139
1.6 Frequency Control	1000	?	?	?	?
1.7 Hydrostatic Test	15	2	2	2	1
1.8 Test BECS	50	21	21	20	19
1.9 Turbine Trip	500	22	26	19	28
1.10 Reactor Trip	500	28	27	20	21
1.11 Loss of Class 4 Power	100	3	4	2	0
1.12 Crash Cooldown	50	0	0	0	1
1.13 PHTS Overpressure	500	0	1	0	0
1.14 Low Feedwater Temperature After Turbine Trip	10	0	0	0	0
1.15 Loss of feedwater pumps	100	0	0	0	0
1.16 Failure of Blowdown Line	2	1	0	0	0
1.17 Failure of BECS (Reheat Drains) Line	1	0	0	0	0
1.18 Steam Generator Thermal Upset	540	0	0	0	0
1.19 BECS	100	0	0	0	0
1.20 Feedwater Upset	180	?	?	?	?
1.21 Severe Feedwater Upset	30	?	?	?	?
2.1 SDCS Hydrostatic Test	15	1	1	1	1
2.2 Pressurize, warmup, cooldown, depressurize - type A	250	18	12	20	17
- type B	750				
2.3 Loss of PHTS Pressure Control	15	0	0	0	0
2.4 Rapid Cooldown	50	0	0	0	1
2.5 SDCS Isolation Valve Failure	25	0	0	0	0
3.1 Outside End-Shield Coupling Schedule	25	?	?	?	?

of piping and pressure vessels by the time Ontario Hydro plants reach their 30 year design life, the projected fatigue usage at 40 years will be about 20 %. That means Ontario Hydro nuclear plants might be capable of operating 200 years if fatigue is the only consideration. Re-qualifying all pipework for operation beyond the 30 year design life will require some credible means of verifying actual fatigue usage. A transient monitoring program supplemented by transient verification and fatigue monitoring at some locations is recommended.

Pickering NGS-A is now about 20 years old. Its need for such a capability should be considered urgent. Several years of transient monitoring data will be required to provide a good enough correlation with other data to extrapolate historical records and derive credible estimates of actual fatigue usage.

Pipe Support Inspection

A piping stress analysis is only valid if the piping is supported as assumed. Periodic and in-service inspection of Bruce NGS PHT pipe supports indicates their importance to the health of piping was not adequately reflected in construction and early operation. The main deficiencies were loose or missing locknuts on threaded fasteners, which caused the supports to get out of adjustment or even come apart. Once the problem was recognized, management began 100 % in-service inspection of pipe supports in systems subject to periodic inspection, and a mechanical maintainer accompanied the inspector to correct deficiencies immediately, while scaffolds were erected and insulation was removed.

Inspection of pipe supports was not included in the Pickering NGS-A periodic inspection program until after the first 10 year inspection cycle. A surprising number of deficiencies were found. The PNGS Equipment & Documentation unit recently began in-service inspection of pipe supports in systems not subject to periodic inspection. That looks like a good initiative! A similar approach is taken by Duke Power Co, which is understood to have a policy requiring system engineers to do annual walkdowns of all piping in their systems. Bruce NGS-B main steam pipe hangers are not readily accessible; simple inspection by binoculars is done on annual callups to check hanger integrity and spring scale setting. Doing that with all pipe supports in the plant seems a prudent way of avoiding surprises.

Analysis of Bruce NGS pipe support periodic inspection results for eight units over about 15 years demonstrates they can be used in a predictive mode to identify locations of relatively high vibration. Thus, spring hangers close to pumps were shown to age faster than elsewhere. Overall, the results provide positive evidence of low vibration levels in Bruce NGS PHT systems piping, which may be useful evidence in re-qualifying the plants for operation beyond the 30 year design life. One maintenance cooling system rigid pipe hanger was recently found broken for the second time in three

years. A report of a piping vibration investigation during commissioning indicated the hanger was observed to be vibrating excessively, and appeared to be in resonance with structurally transmitted excitation. Modifying the hanger to change its natural frequency was recommended, and was apparently not done effectively.

Station policies on pipe support inspection, documenting inspection done by station staff, and analysis of inspection reports were recommended to be reviewed. While Ontario Hydro keeps good records of pipe support inspection done by Central Division staff, inspection by station staff is not similarly documented and retrievable for verification and analysis. Having such data available may help avoid surprises some time in the future.

NUCLEAR PIPING ISSUES

Periodic Inspection

The ASME Boiler and Pressure Vessel Design Code has evolved over many years, and is very conservative. It has been deliberately developed to provide comfortable margins of safety without relying heavily on inspection to assure pressure boundary integrity. Periodic inspection was added to the ASME nuclear code in the early 1970s to monitor equipment for in-service (aging) degradation.

A substantial fraction of the periodic inspection investment is for ultrasonic volumetric inspection of a sample population of pipe welds in each plant. The criteria for selecting the samples mainly relate to fatigue as determined by design stress analysis, with some consideration for known weld defects.

The in-service inspection program for each station is reviewed at the end of each ten year inspection cycle and adjusted in accordance with experience. Recent US NRC reports indicate there has not yet been a failure or even discovered cracks in PWR reactor coolant piping [4]. That demonstrates the veracity of the design procedures and should not be a surprise, particularly since actual fatigue usage is typically about 10 % of the design rate.

It also leads one to question if the current financial and radiation exposure expenditures on periodic inspection are warranted, and if they might be more productively employed. One possibility is to substitute transient and fatigue monitoring for part of the inspection sample to provide ongoing verification of conformance with fatigue design assumptions. Another possibility is to select the inspection sample more on the basis of experience as to potential degradation mechanisms. For example, unintentional passing by isolation valves separating fluids of different temperatures and pressures has caused several fatigue fractures in LWR plants due to thermal stratification of the leakage flow [5]. Better value might be obtained if periodic inspection is directed at such potential stressors identified in NPLA scoping studies.

Pressurizer & Surge Line Stratified Flow

In the design of pressurizers and surge lines in Ontario Hydro plants, surge flow temperatures were assumed to be uniform and to vary smoothly with time and distance. Recent research indicates temperature stratification in pressurizers is more stable than previously believed [6]. The main consequences are increased pipe support loads and fatigue stress in piping and vessels caused by: 1) step changes in fluid temperature at some locations, and 2) stratified flow in some sections of surge lines. Excessive surge line movement and low cycle fatigue loading have caused problems in a number of PWRs throughout the world.

Fatigue is the main degradation mechanism in the Bruce NGS pressurizer and surge line now, and cumulative fatigue usage will undoubtedly be higher once the effects of stratification are properly accounted for in stress analysis. No damage to Bruce NGS pipe supports has been observed, but the likely effect of flow stratification would be to unload them. Persistent problems have been encountered in getting the valve at the middle of the surge line to seal, which may or may not be relevant. Re-qualifying these components at the end of 30 years service has to be considered uncertain until more is known about the effects of various plant transients on fatigue stress.

Instrument Tubing

Branch piping such as instrument and sampling lines is part of the pressure boundary and is prone to damage. Breaks in accessible areas of the plant are potential personnel hazards. PHT tubing breaks have the additional significance that they cause forced outages, and can potentially deplete the station D_2O inventory and actuate the ECI system if the leak is not detected and stopped soon enough. Branch piping is generally austenitic stainless steel tube of up to 0.5 inch (12 mm) size and is attached to equipment or process piping by weldolets. Some lines were fabricated by welding and have often been repaired or replaced with Swagelok fittings, which are preferred over welded connections.

Considerable difficulty has been experienced in Pickering NGS-A with fracture of small diameter stainless steel instrument, water sampling, and leakage collection lines due to stress corrosion cracking (SCC) and/or high cycle fatigue. The SSC generally results from residual or imposed strain and/or high levels of chlorine released by such materials as valve packings, gaskets, insulation, and wall penetration sealant. Fatigue fracture and fretting wear are often caused by excessive vibration due to inadequate support of the tubing, which is rectified in all units as deficiencies become apparent. Mechanical damage of small tubing due to accidental impact causes residual strain or interference with other equipment that can later lead to fracture or fretting wear.

The fragility of branch piping is an inevitable hazard all employees should be aware of. High priority should be put on root cause analysis of branch piping fracture and implementing corrective action at other locations in the station. All such incidents should be treated as significant.

Fuel Channel Feeder Coupling

Early experience in Douglas Point NGS indicated degradation of Grayloc feeder coupling seals by pipe reaction forces, and consequent erosion and wear. The coupling was modified to provide higher bolt loading in later reactors, and sufficient temperature and load cycling testing was done to provide assurance it should not be a chronic and possibly life-limiting problem. Pickering NGS-A has had a number of leaking Graylocs [7] with little evidence of damage other than light pitting corrosion near the sealing surface, attributed to crevice corrosion. Many of the failures were seals that had been replaced and not properly conditioned prior to service, so large scale fuel channel replacement has included hot conditioning. A number of similar Grayloc seal failures have occurred recently in Bruce NGS-A. It has not yet been determined if that is going to be a generic cause of forced outages.

PHT Feedline

'Thermal striping' in the Pickering NGS reactor outlet headers near the 2 inch size PHT feedline connection is a potential aging mechanism that has not been a problem to date. Feed flow is injected into the main circuit via thermal sleeves at reactor outlet headers 3312-HDR1,7. Part of the feed flow (called the reflux feed flow) is routed through the tube-side of the bleed condenser where it is heated to 215 C. It is then mixed with direct feed flow at 38 C, upstream of header 7. Feed flow to header 1 is direct feed flow only.

Injection of feed flow at temperatures as low as 38 C into the reactor outlet headers at 290 C might be expected to cause high cycle thermal fatigue cracks on the inside surface of the header in the vicinity of feedline nozzle, but would not cause them to propagate through the wall. Such cracks could act as stress raisers and would be difficult to inspect for. Thermal and vibration fatigue of the thermal sleeve in such nozzles has been experienced in other plants, and is another potential hazard to monitor [8].

Bruce NGS-A has had an extensive history of PHT feed piping problems attributed to digital control of the reflux feed flow at low feed rates causing large temperature oscillations. That problem has now been rectified, but it illustrates how aging degradation mechanisms can be overlooked for some years, then provide surprises.

CONVENTIONAL PIPING ISSUES

Secondary Systems

From a plant life assurance perspective, most secondary system piping is considered expendable, so the focus in NPLA was limited to issues with potential to cause extensive outages.

A substantial amount of world experience in nuclear power plant operation is relevant to aging degradation of steam and feedwater system piping. The principal degradation mechanism in main steam lines is liquid impact erosion at fittings and discontinuities. Fatigue usage in main steam piping designed to ANSI B31.1 is low despite the apparent potential for fatigue loading by vibration, thermal strain, and flow transients [3,9].

Carbon steel is widely used in secondary system piping and erosion corrosion at some locations is inevitable. It is a difficult degradation mechanism to manage because of the number of relevant parameters influencing it, the lack of visible symptoms, and the difficulty of inspecting for it. Recent experience at Bruce NGS-B showed how trace chromium content in carbon steel can influence erosion corrosion rates sufficiently to require applying the lead unit concept carefully in multi-unit stations.

All Ontario Hydro stations give high priority to in-service inspection programs managed by the station Equipment & Documentation units to monitor secondary system piping for wall thinning due to erosion. The CANDU Owners Group R&D program has provided technical support. Inspection locations are chosen in conjunction with piping designers on the basis of vulnerability to the various forms of erosion. Stations keep rolling ten-year plans for managing secondary system piping maintenance.

Two serious problems with boiler feedwater piping have been encountered by light water reactors throughout the world [9]. One, low cycle fatigue caused by temperature stratification in horizontal pipe runs is avoided in Ontario Hydro plants by electric heaters in the deaerator storage tank that maintain feedwater temperature during low power operation. The other, steam hammer caused by boiler water level dropping below the feedwater inlet nozzle, may be relevant in Bruce NGS-B but is precluded by boiler design in other Ontario Hydro stations. Actuation of the Pickering NGS-A Boiler Emergency Cooling system is expected to similarly cause steam hammer in the reheat condensate return lines, and was anticipated in the design.

Service Water Systems

These ultimately supply all reactor and conventional cooling water requirements, and are designed and operated to be high availability systems. While service water systems are low-profile, low-technol-

ogy equipment, they cannot be taken for granted; the principal systems are pervasive throughout the plant. System-wide replacement of piping would be a massive undertaking, partly because of the need to maintain adequate heat sinks.

World experience indicates fouling and corrosion are likely to be the dominant aging degradation mechanisms in 'open' service water system piping [10,11]. That seems to be the case in Ontario Hydro plants too, in spite of the high quality of Great Lakes water. Corrosion is likely worse in service water piping at Pickering and Darlington than at Bruce NGS; Lake Ontario is higher than Lake Huron in concentrations of silt, bacteria, and nutrients.

System-wide pitting up to 1.4 mm deep (15 % of wall thickness) was measured in stagnant service water piping at Pickering NGS-A after about seven years of operation (ie, 0.2 mm/a). Available evidence indicates silt deposits occur at stagnant locations throughout service water systems at Pickering. Ontario Hydro experience is that sulfate-reducing bacteria corrosion of carbon steel occurs under silt deposits and proceeds rapidly to some depth (less than about 6 mm) by which time the corrosion slows down markedly. Chlorination of Pickering NGS service water was begun in 1991, but may not affect bacteria under pre-existing silt deposits.

Ontario Hydro plants also have a certain amount of buried pipe which is liable to bacterial corrosion from the outside surface, and may not be adequately protected for a 40 year plant life. An investigation of buried stagnant service water piping at Bruce NGS-A after ten years indicated corrosion rates of 0.09 mm/a externally and 0.05 mm/a internally. On that basis, service life was estimated to be 35 years in both Bruce plants. Higher local corrosion rates might be caused by damage to the protective coating, stray electrical currents, differential aeration of the soil, and non-replacement of protective anodes (which are largely not accessible). Further investigations of buried piping at both Pickering and Bruce are to be done in the near future, and should probably be done every ten years or so to avoid surprises.

Corrosion is always significant from a plant life assurance perspective since damage is likely to be system-wide, rather than localized as with most damage mechanisms.

A design error was made in Pickering NGS-A, in not venting drains stacks (ie, vertical runs of piping with flow downward to drains conduits). The problem was recognized in High Pressure Service Water piping downstream of the shutdown coolers, in the early 1980s. Vacuum breakers were installed at a 23 m high stack, after replacing upstream pipework damaged by erosion caused by super-cavitating flow. Cavitation erosion has similarly occurred in connected piping from other coolers. Fatigue damage can initiate at erosion or corrosion sites that act as stress raisers, especially in small piping sizes.

A similar error seems to have been made in lower level stacks such as downstream of the moderator heat exchangers and the recirculated water coolers. These have a drop of about 7 m and may be purposely not vented in order to recover pumping power from the syphon effect. While the syphon head in those cases is less than the vapour pressure of the process fluid, the margins against cavitation are significantly reduced, and Low Pressure Service Water piping downstream of the recirculated water coolers is now being replaced because of cavitation erosion. Connected piping may be similarly damaged. In-service vibration tests indicated excessive cavitation in moderator cooling water piping when it was operated with the anti-cavitation trim removed from the temperature control valves. While the use of anti-cavitation valve trim may reduce or eliminate cavitation at control valves - usually the main flow obstruction - it does not remove the root cause, and provides no assurance that smaller scale cavitation capable of destroying piping but not detected in vibration tests, is not occurring at other flow obstructions such as elbows and pipe welds.

CONCLUDING REMARKS

NPLA scoping research studies of nuclear and conventional piping in Ontario Hydro nuclear generating stations are almost complete, and appear to have achieved the objective of identifying and exploring issues relevant to achieving 40 year plant lives. Hopefully no significant issue was missed, but that may be too much to expect. Further input is welcome. The findings are not revolutionary and were not expected to be, but they do provide a basis for planning ongoing activity that should contribute to plant productivity in the longer term. That's what NPLA is intended to do.

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COST EFFECTIVE MAINTENANCE

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ABSTRACT

This paper outlines the steps that have been taken at Nanticoke Thermal Generating Station to incorporate the need to be competitive into the maintenance strategy.

COST EFFECTIVE MAINTENANCE

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1.0 BACKGROUND - NANTICOKE T.G.S.

Nanticoke consists of 8 X 512 MW coal fired units, with overload capability of 560 MW's. The plant was originally designed to fire U.S. sub-bituminous coal, and was located on the shore of Lake Erie to be in close proximity to the coaling dock in Pennsylvania and Ohio. Since commissioning of the first unit in 1972, Nanticoke has undergone a number of significant changes, both in its role in the system, and in the management of maintenance. Our operating practices have also changed, and adapted to environmental legislation, in what has become a competitive market. To remain competitive, both now, and in the future, expenditure of O.M.& A. dollars on plant maintenance has become a significant influence.

At the same time as our operating environment, and the expectations of our customer was changing, we underwent a significant change in plant management structure. Without getting into great detail we switched from the traditional plant management structure covering eight units, to Location Management, establishing six Locations who would each have control over their own maintenance expenditures.

Four Locations - each having two operating units

Production Services

Fuels & Outside Services

An increasing emphasis on maintenance costs was taking place prior to our change in management pattern. As we were both involved in plant maintenance with the old and the new organizations, our presentation will span the full time frame of maintenance cost reduction initiatives.

2.0 SIGNIFICANT CHANGES AT NANTICOKE WHICH IMPACTED ON MAINTENANCE

The maintenance strategy at Nanticoke T.G.S. had a difficult

start and in retrospect there was no maintenance strategy. As the units were commissioned through the 1970's numerous design defects were encountered. These design defects coupled with a fast paced commissioning schedule dictated a maintenance strategy which was strictly corrective (i.e., "Fire Fighting").

After the last unit was commissioned, in December 1978, the corrective maintenance of the commissioning years was gradually being replaced with preventive maintenance programs. These preventive maintenance programs were based on the experience gained from eight years of corrective maintenance. Under normal circumstances a preventive maintenance program would have been implemented effectively but several other changes occurred at Nanticoke T.G.S. which impacted significantly on the emerging maintenance strategy. These changes were:

- Fuel Changes
- Two - Shift Operation
- Overload Operation
- Budget Reductions

2.1 Fuel Changes

Nanticoke T.G.S. was originally designed to burn U.S. bituminous coal. The Energy Crisis of the 1970's resulted in a decision to reduce the dependency on U.S. coal and introduce Western Canadian Coals to the Nanticoke boilers. The design of the Nanticoke boilers dictated that a blend of U.S. coal and Western Canadian coals would be necessary in order to maintain MCR. Subsequent testing established a blend of 50% U.S. and 50% Western Canadian coal.

The Western Canadian coal has a lower heating value and higher ash content than the U.S. bituminous coal. The lower heating value means more coal is burned and the high ash content means higher wear rates since the composition of the ash is largely quartz and silica.

2.2 Two-Shift Operation

At the beginning of 1985, Ontario Hydro had a dependable peak capacity of 27,000 MW of electrical generation and supplied 122.9 billion KW hours of electricity in 1984. This consisted of approximately equal portions of hydraulic, fossil and nuclear units. 7000 MW of nuclear capability was still under construction and planned to be in service in the next several years.

Technical and economic reasons dictate that the nuclear and hydraulic units carry the base load component of the system electrical demand, while the fossil-fired units take up the cycling (peaking) duties.

The cycling duties of Nanticoke required that each unit be

capable of coming off the line for a minimum of six hours, then resynchronizing after 1.5 hours from the initiation of the start sequence and then achieving MCR with two hours after synchronizing. This mode of operation is referred to as two-shifting.

This mode of operation required modifications to the boiler and turbine systems as well as a maintenance strategy to counter the predicted increase in incapability performance.

The key to effective two-shifting is the ability to match turbine temperatures during run up. In order to do this the boiler must be fired aggressively which introduces unwanted thermal stresses in both the boiler and turbine.

2.3 Overload

Overload operation involves raising the electrical output of the Nanticoke generators from MCR of 512 MW to 560 MW. This mode of operation reduces the thermal conversion efficiency of the unit but proves to be cost beneficial at displacing other forms of generation during high load periods. Overload operation is achieved by raising the boiler pressure above normal operating pressure and by shutting off the extraction steam to the 6th and 7th banks of feedwater heaters.

To accommodate overload operation a maintenance strategy should be in place that ensures that equipment normally spare for MCR operation is available for overload operation, i.e., condensate extraction pumps. Also the pressure boundary equipment must be maintained to allow for reliable overload operation, i.e., boiler drum safety valves.

2.4 Budget Reductions

Maintenance budgets have undergone close scrutiny over the past ten years in Thermal Generation as a result of tougher economic times. Coupled with this was a shift in the split between material and labour dollars. As wage settlements increased, the portion of the maintenance budget available for materials, equipment and purchased services fell to approximately 30% by 1990.

The effect that the maintenance budget has on maintenance strategy is create a priority system which ranges from essential work to nice-to-do work. Other areas to be looked into include alternative sources for materials (i.e., non OEM), improved procedures and techniques, and skills upgrading.

3.0 THERMAL PLANT FINANCES

Plant personnel are typically only concerned about a small portion of the total cost of the electricity generated. Generally this is the O.M.& A. budget. Maintenance staff have the impression that they do not have an impact on the other components of the total unit energy costs.

Maintenance strategies should be developed by considering the impact on the total costs rather than just considering the O.M.& A. costs.

The total cost of generation includes the interest and depreciation on the original capital as well as capital modifications, the fuel costs, overhead costs and the interest costs on the spare parts inventory.

By being aware of the total costs, maintenance strategies can be developed, to avoid capital projects (i.e., Rehab), to improve thermal conversion efficiency and reduce the spare parts inventory.

4.0 MAINTENANCE BUDGET

The maintenance budget for a thermal plant is comprised of work programs with each program being categorized as energy related or capacity related.

Capacity related work programs are intended to bring or hold a station in a specified state of readiness to generate as needed by PSOD.

- Labour from operations, fuel and ash and chem techs
- Management and administration
- Fixed costs
- Site, structure, and common services

Energy related work programs are required as a result of the station having been operated.

- Maintenance
- Technical support
- Stores staff
- A minimum of 5% capacity factor allowance to hold station in a state of readiness.

The maintenance budget for a thermal station is heavily influenced by the projected energy production and can vary significantly from year to year.

5.0 IMPACT OF CURRENT FINANCIAL SITUATION

In the current recession, tighter financial controls have been placed on O.M.& A. dollars, at the same time our T.W. hour production is being reduced, and two shifting is becoming the normal mode of operation. We have accepted the fact, that to remain in business we must adapt to the changing demands of our customer, provide two shifting capability, provide operating flexibility, and make every effort to improve conversion efficiency. This environment has been facing even closer scrutiny of maintenance expenditures, staffing levels, and productivity.

6.0 DOING MORE WITH LESS

In the current economic climate most businesses are striving to become more competitive to maintain or improve their market share. This need to be more competitive is evident in the electrical energy generation business as utililities find themselves competing with NUGS and purchases from other utilities.

At Nanticoke the need to be more competitive plays an important role in the overall maintenance strategy. The following strategies are in use at Nanticoke.

6.1 Planned Outage

The planned outage is a period when the unit is removed from service for several weeks so that major maintenance work can be completed to ensure that the unit remains available when needed. When the unit is removed from service a potential revenue source is unavailable, therefore it is vital that the work programs for planned outages are essential, and planned to minimize the planned outage duration. The following practices are employed at Nanticoke T.G.S.

6.1.1 Work Packages

When selecting work packages for planned outages only work that is necessary is selected. By reviewing the history of past planned outages it can be determined what inspections can be eliminated.

6.1.2 Maintenance Outages

Maintenance outages are short duration outages, typically one or two days, that are arranged on short notice. Typically maintenance outages for thermal units are arranged for weekends but can occur at other times when the load requirements are low.

A maintenance strategy that makes use of maintenance

outages can in some cases reduce the upcoming planned outage duration.

6.1.3 Planned Outage Frequency

A maintenance strategy should take into account the maintenance frequency cycle of the various systems and pieces of equipment and algin these frequencies to minimize planned outage time.

At Nanticoke T.G.S. the practice prior to 1990 was to schedule a six week planned outage annually for boiler work regardless of what turbine work was scheduled. Since the turbine work is scheduled on 2, 4, 6, and 8 year cycles it became obvious that the major boiler work should be scheduled for every other year.

The planned outages at Nanticoke T.G.S. for boiler work are scheduled every other year and the duration is eight weeks. During the off year a two week planned outage is scheduled to accomplish the regulatory inspections (i.e., pressure vessel recertification).

6.1.4 Control of P.O. Work

Most maintenance personnel have a habit of expanding the work to the outage duration, foremen and supervisors who want to do a good "maintenance" job are particularly prone to this. After all maintenance "owns" this plant which then allows operations to run. The result was over maintenance of boilers, the outage duration being controlled by major turbine generator work. In past years overhaul reports were reviewed to eliminate unnecessary inspections, or take the opportunity to extend the time between inspection. The effort now is to ensure that no work is added to a planned outage, once the outage is started, and that no work is dropped. In both cases any deviation from the plan must be justified. The key to this has been to change the attitude of maintenance staff because the unit is shut down, and manpower is available, can they justify the cost of performing inspections, and the associated non-labour costs.

6.2 Turbine Generator Maintenance

When the maintenance sections were first established at Nanticoke, Turbine-Generators were scheduled for major overhaul every four years - whether they needed it or not. The logic being eight units, so do two major overhauls per year - not the logic one would follow if there was only one

unit. Since this time turbine maintenance has evolved to planned outage work based on deterioration in cylinder efficiency, or component life cycle. H.P. turbines have been prone to efficiency deterioration, primary causes being increased interstage seal clearances, dirty blading, and minor blade damage. From experience we have found the greatest long term gains in cylinder efficiency have been achieved by blade cleaning (abrasive blasting), and removal of blemished in the steam path, rather than clearance restoration. Restored blading clearances, because of cylinder distortion have not proven to be long lasting. We have also established the optimum cylinder efficiency level, at which time remedial action should be taken, earlier cylinder rehabilitations were undertaken prematurely, the short term improvements in efficiency did not justify the cost of this work. Under our current philosophy, an H.P. turbine should last eight years between overhauls.

The I.P. turbines have seen very little drop off in cylinder efficiency, with very little gain in efficiency for remedial action taken. I.P. turbines are overhauled every eight years, mainly to repair damage, replace broken seal strips, and blading inspection. Depending on work load I.P. turbines could be allowed to go beyond eight years.

The L.P. turbines are opened up every six years, the life cycle being controlled by the life expectancy of the last row rotating blade erosion shields. At this time the L.P. spindle blading is cleaned and inspected. If we can extend the life of our erosion shields then we would extend the time between L.P. turbine overhauls - we are working on this.

Also being investigated, is boxed up, chemical cleaning of turbine blading. This has been carried out successfully by U.S. utilities, we are following up on this.

Since first operation, Nanticoke has been plagued with generator problems, we have suffered significant failures of both rotors and stators - we have a spare stator and spare rotor. Until upgrading of all generators has been completed, the generator will continue to set its own schedule. On the positive side, we have been able to extend the life of H_2 seals, and improve generator end door sealing, almost eliminating forced outages caused by these components.

6.3 Proactive Maintenance

Proactive maintenance requires that every event that results or has the potential to result in a forced outage or derating be investigated to determine the root cause. When the root cause has been determined, a maintenance strategy is developed to prevent a reoccurrence of the event.

An example of this is the practice of investigating boiler tube failures. When the root cause has been determined action is taken to prevent the failure from occurring again. If the failure was caused by flyash erosion then shields may be applied to the erosion sensitive areas to prevent further wear.

Whatever proactive action is decided upon is applied to all eight units.

6.4 Operator Involvement in Maintenance Decisions

The switch to Location Management has presented the opportunity for us to establish operator ownership of the equipment. Through our daily production meetings (which are chaired by the Production Supervisor - Operations), we involve the Shift Unit Supervisors in most maintenance decisions. This has been advantageous in eliminating conflict between operations and maintenance, and has provided a clear line of communication between maintenance and operations. Knowing that a particular piece of equipment will be scheduled for repair at the next opportunity, has resulted in operators willingly operating equipment that has significant, but not unsafe, defects.

In the same framework, we have drastically improved the working relationship between Control & Mechanical Maintenance. This team approach has resulted in the virtual elimination of repeat work orders where both groups were involved. Any reduction in repeat work orders, is a saving in maintenance resources, and an improvement in equipment reliability.

6.5 Labour Resourcing

As mentioned earlier, in section 4.0 "Maintenance Budget", the maintenance budget depends heavily on the projected energy production. When the production goes up the maintenance funding goes up and when the production goes down the maintenance funding goes down.

For the past several years the energy projection for Nanticoke has been quite variable. This situation results in Nanticoke being either under compliment or over compliment in maintenance staff depending on high or low energy production. In the late 1980's, the energy production from Nanticoke was projected to increase and as a result additional maintenance funds were made available. We then increased our maintenance staff levels through street hires and apprenticeships to meet the demand for increased maintenance. Since then, the energy production from Nanticoke has fallen and we now find ourselves overstaffed for maintenance.

Now that we have a staff compliment that is not funded we are faced with two options either layoff or find something else for them to do.

We choose the latter option, "find something else for them to do" for the following reasons.

1. Laying off staff has a negative impact on the morale of all staff.

2. The energy production variable could result in increased funding and we would be ready with trained staff.

3. Attrition will gradually reduce the numbers and if we lay people off we may not be able to rehire them when attrition reduces the staff numbers below compliment.

Now that we have made the decision to remain over compliment we must find ways to fund the extra staff. At Nanticoke we have been able to do this by assigning maintenance staff to MUCM's and CCP projects.

MUCM's, "major unforeseen corrective maintenance" are funded additional to our OM & A budget. Just recently our coal receiving dock hopper was relined with wear plates by Hydro Construction. Due to improper selection of materials the liner cracked and required replacement. MUCM funding was obtained for the warranty repairs and rather than contract the repairs to Hydro Construction it was decided to use our maintenance staff. By doing this we were able to direct several hundred labour hours away from our OM & A budget.

The same practice is used with CCP, "capital construction programs", work programs. Currently Nanticoke has two CCP projects released which we are resourcing with our own maintenance staff. These projects are Life Management Inspections and Asbestos Removal. By deploying this labour to these CCP projects we are able to reduce the impact on our OM & A budget by 15 - 20 people per year.

Other opportunities for reducing the impact on our OM & A budget would be to loan labour to other locations within Ontario Hydro such as Nuclear Operations Branch.

In summary, our strategy is to try and maintain the current level of staff so that when the energy production goes up we are ready with skilled staff and when the energy production stays low we look for other ways of funding the over compliment.

7.0 FUTURE PLANS

Future plans support the goal of Thermal Operations

Future maintenance strategies at Nanticoke are supportive of "Competitive Thermal Generating Station Strategies"

To work toward these goals and strategies, the following initiatives for maintenance continue at Nanticoke:

1. Expand on maintenance that is controlled by Predictive Techniques, or is driven by Equipment Performance.

2. Always look for better materials to extend the wear life of components, and improved tools and work methods which will reduce turn around time.

3. To remain competitive (cost of production per M.W. hour) look for improvements in conversion efficiency that are cost effective.

4. With eight identical units, whilst allowing each unit location freedom to have their individual strategies, not loose the economy of scale.

5. With the plant retirement date removed, actively pursue a policy of Life Management, which will avoid the impact of an extensive plant rehabilitation and consequent increase in production costs.

COMPETITIVE

THERMAL GENERATING STATION

STRATEGIES

CURRENT VIEW	EMERGING VIEW
LOAD DRIVEN & PRICE SETTING	MARKET DRIVEN & PRICE SETTING
PUBLIC UTILITY COST + RETURN = PRICE	INSTRUMENTS OF PUBLIC POLICY PRICE - COST = RETURN
MEET LOAD	CAPTURE MARKET SHARE
PRODUCE ELECTRICITY	SOLVE CUSTOMERS' ENERGY NEEDS
ECONOMIES OF SCALE	FLEXIBILITY
REPLACE/REHAB	LIFE MANAGE
RETIRE	EXTEND

THERMAL GOAL

TO MEET THE NEED OF POWER SYSTEM OPERATIONS DIVISION FOR ELECTRICAL CAPACITY AND ENERGY FROM THERMAL RESOURCES CONSISTENT WITH PROVIDING THE BEST LONG TERM VALUE FOR CORPORATION.

THERMAL OBJECTIVES

- DELIVERY PRODUCT
- RESOURCE PRODUCT
- MANAGEMENT PRODUCT
- COST EFFECTIVENESS
- COMPETITIVENESS

CA9500140

REVIEW OF BRUCE NGSA REHABILITATION PROJECTS AND THEIR FOCUS

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ABSTRACT

This paper details the role of projects in the Bruce NGSA Rehabilitation Program and their contribution to station performance improvement. The development of the BRUCE NGSA Rehabilitation Program is also reviewed.

REVIEW OF BRUCE NGSA REHABILITATION PROJECTS AND THEIR FOCUS

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The Bruce Nuclear Generating Station is located on the shores of Lake Huron as part of the Bruce Nuclear Power Development. It is one of 5 multi-unit pressurized heavy water reactor stations forming the Nuclear Operations Branch of Ontario Hydro.

BRUCE NGSA PERFORMANCE

The four Bruce A units are rated at 795 MWe and were brought into service between 1977 and 1979. Current running hours average 85,000 hrs. The operating performance of Bruce A has fallen since the mid 1980's.

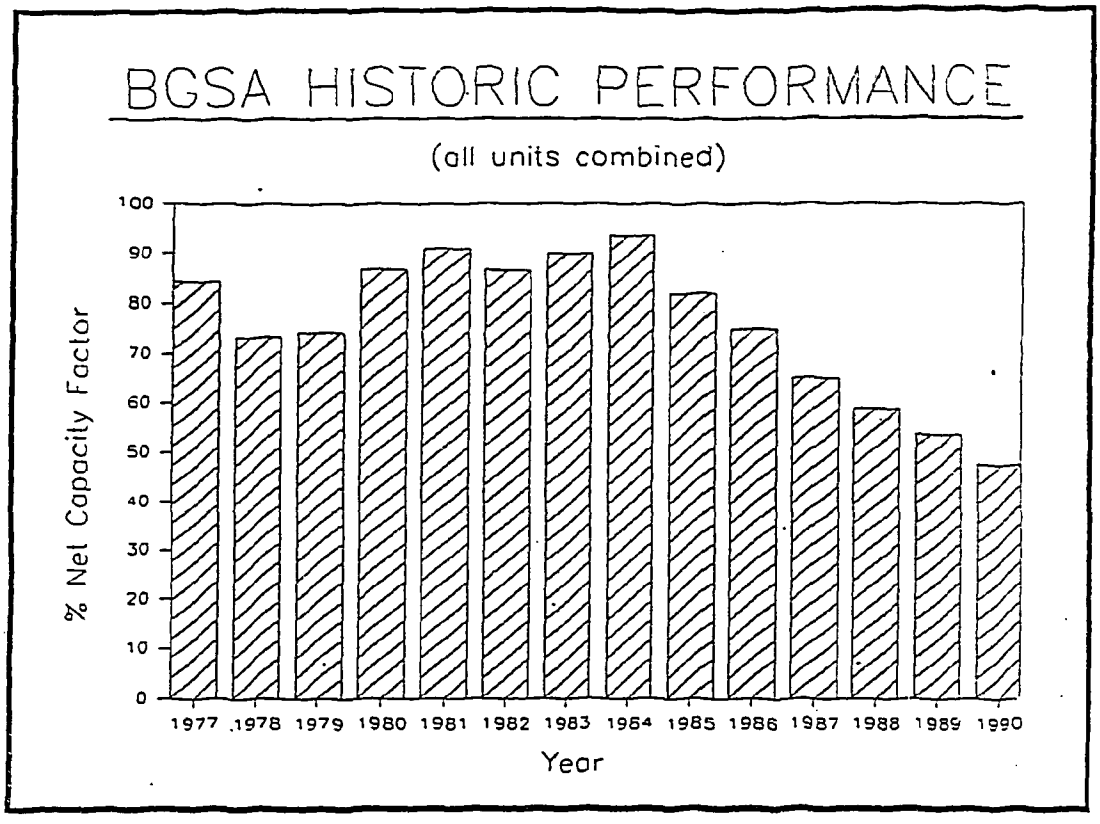
Contributing to this decline was the amount of outage time necessary to perform inspections and maintenance on reactor pressure tubes, which were approaching planned service life and associated change-out under the retubing program.

There were a number of other contributors which would prevent satisfactory operation and would not be corrected by retubing alone.

PERFORMANCE RESTORATION

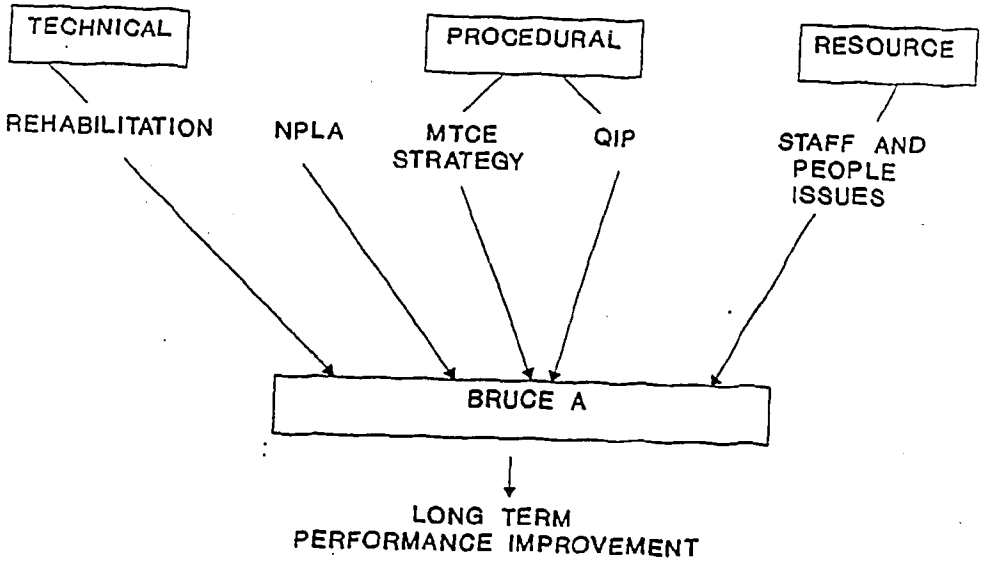
The decision was made in 1990 to scope out and commit a rehabilitation program on the balance of plant. The objective was (and is) the attainment of target 85% capacity factor for balance of plant life (to year 2018) by the implementation of both Retube and Rehabilitation Program.

In addition to these technically based programs, a revised approach to operation and maintenance has been under development to maintain satisfactory capacity factor levels through end of life. Major efforts in procedure improvement and resourcing support this area.



CAPACITY PIC

BNGS'A' PERFORMANCE IMPROVEMENT INITIATIVES



PROJECT MANAGEMENT

A parallel activity within the Rehabilitation Program involves iniatives to improve project management and meeting the customers needs. Poor performance in these areas affects the station through unexpected financial burdens and failure of the changes to meet performance targets.

Key to implementing improvements has been the use of teams at the project and program level. Most are 3 party teams (Engineering, Construction and Operations). Project teams became intimately involved in up-front problem definition, justification for release, and post release implementation with project accountability for cost, schedule and deliverables. Additional support teams were put together to deal with overall program concerns (Rehab Program Management Team, Planning and Control Team, Licensing Team, etc.).

This is a change from past practice which was a handoff process from one group to the other. There have already been definite benefits due to 3 party input to problem solving and ownership.

REHABILITATION PROGRAM

The Rehabilitation Program, as committed by the Board Of Directors of Ontario Hydro in June of 1991, contained 3 main components:

- Restorative Maintenance
- Life Assurance Inspections
- Rehabilitation Projects

Most activities are to be completed by the year 2000.

The details of the maintenance and inspection programs are being finalized at this time. The project portion of the program is the most advanced. It is this area that the rest of the paper will concentrate on.

REHABILITATION PROJECTS

The major part of BNGSA Rehabilitation Program as released consists of:

-40 station equipment/system change projects and
-a Training Simulator update project to reflect the changes.

The projects evolved from a "wish list" the Technical Section staff at Bruce A had been compiling in anticipation of the commitment of the Rehab program. The scope was fine tuned using a number of inputs:

- Technical and Operating Staff input
- Maintenance trends
- Inspection Results
- Third party reviews (more later)
- System Planning analysis
- Incapability analysis (past and projected)

The current station project list is in Appendix A. For each the problem identified and solution alternative is noted.

CAPABILITY FACTOR STUDY

It was easy to identify and justify projects for areas that had historically experienced incapability. It was more difficult making convincing arguments about things which has not caused outage time to date but showed unfavourable precursors. This challenge was addressed by an analytical capability factor project exercise (1).

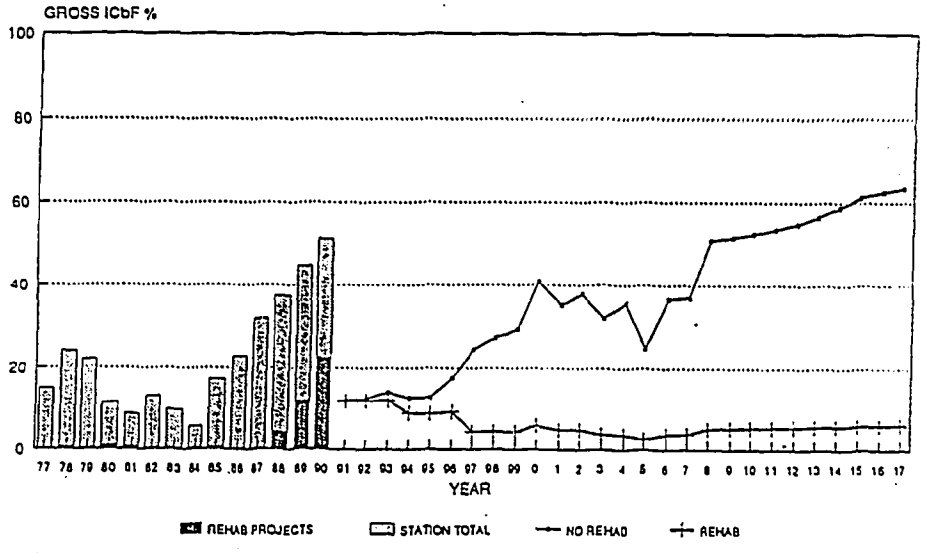
Using historical data and subject matter expert input, algorithms were generated which showed expected incapability for selected projects (one shown here for Feedwater Heaters), and when summed, the overall incapability projections under 2 scenarios implementation (the lower line) and "do nothing", the higher the line.

The analysis confirmed that not implementing the balance of plant rehabilitation program would prevent meeting capacity factor targets, by a significant amount.
Gains with respect to current performance levels would be about 12% but more importantly greater future incapability of could be avoided.

This type of analysis had not been attempted before. Therefore independent verification of the methodology was used to establish the credibility of the process.

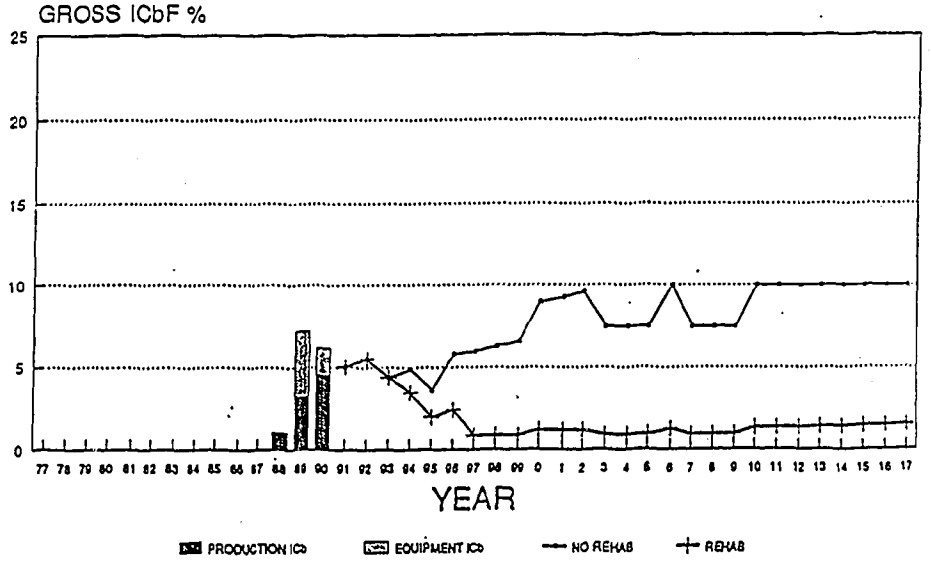
Further details of the method can be obtained from Ontario Hydro's Nuclear Operating Standards Department, which developed the approach.

BNGS A
INCAPABILITY HISTORY/FORECAST
REHAB PROJECTS



HISTORICAL & FORECAST DATA
FOR 9 REHAB PROJECTS

BNGS A
INCAPABILITY HISTORY-PROJECTION
FEEDWATER HEATERS



REHAB PROJECT: .59

PROJECT FOCUS

The Bruce NGS"A" Rehabilitation Program Capability Factor Study supported that eight of the current projects having significant capacity factor impact:

- Turbine Governor
- Control Computers
- Condenser Retubing
- Upgrade Fuel Handling Controls
- Feedwater Heater Retubing
- Inverter Replacement/ Enclosures
- Standby Generator Governors
- Replace Moderator Heat Exchangers

In all of the previous projects wearout and/or obsolescence of equipment are primary drivers.

The justifications for many projects go beyond these issues into other areas. These include:

System performance failing to meet targets.
-Upgrade All Airlocks

Anticipating/ Meeting Regulatory Limits.
-Active Liquid Waste Upgrade
-Boiler Emissions

Plant Complexity Issues
-Booster Lockout
-Main Control Room panel changes

Employee Safety
Conventional
-Noise Reduction,
-Reactivity Deck Modifications
Radiological
-Feeder Freezing Junction Box Overhaul
-D20 Sampling

Nuclear Plant Life Assurance
-Turbine Generator Fixed Vibration Monitoring
-Generator Condition Monitoring

Design Improvements
-Reheater Lid Flanges
-Bleed Condenser Gasket
-Turbine Water Induction

Support services
-Electrical Distribution Upgrade

Training
-A training plan supported by a Simulator Upgrade

In some cases several projects came together to contribute to a common goal. As an example the Boiler Protection strategy consists of six different projects to limit deposits in the boiler and provide protection in both operating and shutdown conditions.

-Boiler Protection
-Boiler Emission Control
-Feedwater Heater Retubing
-Condenser Retubing
-New Water Treatment Plant
-Retube Lay-up

SUMMARY

A Rehabilitation program to succeed it must go beyond current equipment problems and include in its scope any tangible factor that could affect performance to the end of station life. Successful management of the program can have significant impact on station performance as well.

References:

(1) T.A. Naeem/ G. Obuchowski, "Bruce NGS-A Rehabilitation Program Capability Factor Study", Ontario Hydro, NOCS-IR-00770-0001, January 1992.

APPENDIX A: REHAB PROJECT INFORMATION INDEX - OCTOBER 1992

A **SAFETY SYSTEM/REGULATORY**
- Upgrade All Airlocks
- Active Liquid Waste Upgrade
- Replace Moderator Heat Exchangers
- Booster Lockout
- Liquid Injection Nozzle Contact

B **FUEL HANDLING**
- Upgrade Reactor Bridge
- Upgrade Fuel Handling Controls
- Feeder Freezing Junction Box Overhaul

C **TRIP SETPOINT RESTORATION**
- Replace PHT Flow Orifices

D **BOILER PROTECTION**
- Boiler Protection
- Boiler Emission Control
- Feedwater Heater Retubing
- Condenser Retubing
- New Water Treatment Plant
- Retube Lay-up

E **CONTROL INTERFACE**
- MCR Panels/Cabinets
- Control Computers
- Computer Room Ventilation
- Replace SSMC's

F **STEAM/DRUM FEEDWATER**
- HT/Steam Drum Stress Minimization
- Deaerator Modifications
- Improve Feedwater Capacity
- Deaerator Nozzle

G **ELECTRICAL SYSTEMS**
- Inverter Replace/Enclosures
- Standby Generator Governors
- 250 Volt Relays/Switchgear
- Upgrade of Electrical Distribution System

H **TURBINE GENERATOR**
- Turbine Water Induction
- Turbine Governor
- Generator Condition Monitoring
- Turbine Generator Fixed Vibration Monitoring
- Reheater Lid Flanges
- Turbine/Condenser Joint

I **PRIMARY HEAT TRANSPORT**
- PHT Storage Tank
- Bleed Condenser Gasket
- PHT Sampling
- Replace/Refurbish In-Line Gas Chromatographs

J **EMPLOYEE SAFETY**
- Reactivity Deck Modifications
- Upgrade Vault Cooling
- Noise Reduction

SAFETY SYSTEM/REGULATORY

Airlock Upgrades

Problem Identified: Current design of airlocks and transfer chambers results in difficulty in meeting containment unavailability targets and is impacting on outage duration due to airlocks being out of service.

Selected Alternative Modify existing airlocks and transfer chambers.

- Relocate pneumatic components from airlocks and transfer chambers to remote instrument panels to make accessible during unit operation.
- Upgrade pneumatic components to decrease leakage and failure frequency.
- Change unit vault airlocks from fully automatic to manual.
- Provide dual air supply to door seals with each air reservoir to inflate one seal each on opposite doors.
- Remove slide type equalizing valves and refit with suitable equalizing valve to provide dual door containment boundary.

Active Liquid Waste Upgrade

Problem Identified Without extraordinary Active Liquid Waste (ALW) handling procedures, the ALW treatment system cannot meet existing federal radiological emission regulations nor provincial non-radiological water quality regulations.

Selected Alternative Replace existing system with Volume Reduction equipment (reverse osmosis / evaporation / solidification process). This will reduce both radiological and chemical emissions, to be consistent with current regulations and the upcoming MISA legislation.

Replace Moderator Heat Exchangers

Problem Identified HX Tube deterioration has been discovered by inspection program. Tube plugging is currently used to prevent radiological emissions to lake water. Reduced Moderator Outlet temperature operating limits result in unit deratings during 6 months of the year.

Selected Alternative Replace Moderator HX's with ones of larger size and improved tube materials.

SAFETY SYSTEM/REGULATORY

Booster Lockout

Problem Identified Boosters increase reactor operational complexity. Extensive re-analysis, design changes and resulting high costs are expected in meeting relicensing requirements. These costs outweigh benefits.

Selected Alternative Lockout boosters, removing mechanisms and associated process trips to reduce operational complexity.

Liquid Injection Nozzle/Calandria Tube Contact

Problem Identified Higher creep sag rate of calandria tubes will result in contact between some calandria tubes and horizontal Liquid Injection Nozzles.

Selected Alternative Replace 2 affected Liquid Injection Nozzles with those of Offset Liquid Injection Nozzle design.

FUEL HANDLING

Upgrade Reactor Area Bridges

Problem Identified Inadvertent drive actuations caused by operator or software, can result in undesirable horizontal or vertical motion of the reactor area bridge or carriage. Such an incident previously occurred at BNGSA in January 1990 while fuelling at Unit 4. The probability of reoccurrence is unacceptably high.

Selected Alternative Install electrical interlocks which are independent of computer or manual control, to the bridges of each of the four units. This would reduce probability of inadvertent movement of the bridge or carriage when the fuelling machine is locked onto a fuel channel.

Upgrade Fuel Handling Controls

Problem Identified The present equipment is obsolete and increasingly unreliable. This unreliability could result in fuelling machine or trolley unavailability.
The computer software is difficult to maintain and tedious to modify and audit.

Selected Alternative Replace computers with new computers and software. Incorporate current Software Quality Assurance standards.

FUEL HANDLING

Feeder Freezing Junction Box Overhaul

Problem Identified Damaged internal wiring and junction box connectors caused by high temperatures and radiation when the reactor is on power is presently causing delays in feeder freezing operations during maintenance and extended outages. Increased labour resulting from checking feeder freezing electrical connections is causing increased radiation exposure to staff.

Recommended Alternative Amalgamate twenty vault junction boxes into four per unit and relocate away from feeder cabinets. Replace wiring and connectors inside and outside the vault with more durable, heat and radiation resistant connectors.

TRIP SETPOINT RESTORATION

Replace PHT Flow Orifices

Problem Identified Primary Heat Transport flow orifices, used to measure fuel coolant flow in reactor shutdown safety systems, have eroded. Inaccurate flow measurement has resulted in an AECB action item, and conservative calibrations of signals and operation with reduced margin to trip.

Selected Alternative Replace orifices with a "tapered backedge" type of orifice. Installation of new accurate flow elements in the feeder pipes of the twelve fuel channels will permit SDS2 trip setpoint reduction logic to be placed in service.

BOILER PROTECTION

Boiler Protection

Problem Identified Corrosion products deposit and plug flow pathways in the support plates causing boiler level oscillations and the requirement for boiler lancing and cleaning programs. In addition, deposit build up on the tubesheets has the potential to cause boiler tube failure via under-deposit corrosion.

Recommended Alternative Install full-flow condensate filtration system (at the discharge of the main condensate pumps) with feedwater recirculation and boiler blowdown recovery.

BOILER PROTECTION

Boiler Emission Control

Problem Identified The present method of boiler wet lay-up, using temporary pumps and hoses is labour intensive and a safety hazard. Also, chemistry control is poor due to lack of recirculation. Lay-up chemicals, when no longer required, are released via CCW flow to the environment.

Selected Alternative Install new boiler set lay-up chemical addition and emission control system consisting of:
- permanently installed piping system
- recirculation pumps, and
- a chemical addition and recovery system

Feedwater Heater Retube

Problem Identified Feedwater Heat Exchanger copper alloy tubes are corroding under chemical attack by dissolved oxygen and residual ammonia from feedwater hydrazine. Corrosion products are carried over to the boiler causing deposits resulting in boiler level oscillation problems. Thinning of heat exchanger tubing results in tube failures and unit deratings to repair and plug tubes.

Selected Alternative Remove and replace all copper alloy tubes in all forty Feedwater Heat Exchangers with new replacement stainless steel tubes. HX's removed from station and retubing work done at manufacturers plant. Also inspect shells and heads and refurbish as required.

Condenser Retube

Problem Identified Presence of copper in the feedwater train contributes to deposits in the boilers and boilertube cracking mechanisms. These deposits also result in intermediate term unit deratings and the need for boiler cleaning.

Recommended Alternative Replace all brass tubes in the turbine condensers with stainless steel tubes.

New Water Treatment Plant

Problem Identified The quality and quantity of demineralized water produced by the current WTP does not adequately support the station.

Selected Alternative Build a new WTP to produce water in quantities required while meeting or exceeding current NOB standards.

BOILER PROTECTION

Retube Lay-up

Problem Identified During periods of construction or major outages secondary side chemical control capabilities are currently inadequate. Consequently, design changes are required to permit the implementation of lay-up procedures in order to enhance equipment preservation, improve water chemistry and for quicker start-up.

Recommended Alternative Identify locations where dryer equipment should be connected and provide installations.

A set of dryers of selected capacities to be provided in order to dry systems to required specification.

CONTROL INTERFACE

MCR Panels and Cabinets

Problem Identified Main control room lighting can be harsh and irritating. Control panels lack free space for future anticipated changes. Operators have identified several panel problems which can be addressed by replacing or moving some existing devices. The existing Operator desk and document storage is poorly configured and congested.

Selected Alternative Move/replace some existing panel meters and controls. Free up space on existing panels. Complete redesign of control room lighting. Replacement of Operator desk.

Control Computers

Problem Identified The Digital Control Computers and the Plant Display System hardware is obsolete and must be replaced before the unavailability of spare parts causes extensive unit incapability. Also, the Human-Machine interface presented by the existing Plant Display System causes operational difficulties.

Selected Alternative DCC's will be upgraded, with a functionally identical CPU, thus enabling existing process software to be used. A new Plant Display system with separate Unit 0 computer will also be installed.

Computer Room Ventilation

Problem Identified Computer room temperatures exceeding 27 C have caused operational problems with unit DCC's.

Selected Alternative Increase the existing air conditioning capacity and temperature control to reduce maximum room temperature to 20 C.

CONTROL INTERFACE

Replace SSMC's

Problem Identified The existing Safety System Monitoring Computer (SSMC) is obsolete. Future maintenance will be hampered by unavailability of spare parts and lack of manufacturers support. It has a very awkward user interface and designing and installing changes is difficult.

Selected Alternative Install new SSMC that provides improved display and maintenance interface. This hardware will have sufficient computing power to accommodate current and future needs.

STEAM/DRUM FEEDWATER

HT/Steam Drum Stress Minimization

Problem Identified There have been many System Operating Diagram (SOD) incidents. These have caused 20 days of equivalent lost production. Process constraints imposed by SOD's have contributed to operational complexity.

Selected Alternative Install expansion loop in PHT boiler outlet balance header making it more flexible and reducing stresses seen in this critical area and expanding SOD envelope. Provide computer displays to monitor and interpret all SOD parameters.

Deaerator Modifications/Pressure and Level Control

Problem Identified The deaerator level and pressure control system has been unable to prevent severe transients experienced by the deaerator and storage tank. These transients could damage the Deaerator, the Turbine and adjacent piping and equipment, with associated risk to operating staff.

Selected Alternative Improve level and pressure control system to control rapid level and pressure fluctuations. Modify boiler feed pump recirculation distribution system. Modify tray enclosure boxes and the extraction steam piping to the deaerator.

Improve Feedwater Capacity

Problem Identified The pumping capacity of the Main Boiler Feed Pumps has been reduced due to running at non-optimal pressure conditions. This has resulted in the need to run three Main Boiler Feed Pumps to meet operating requirements since the 1985 boiler pressure increase.

Selected Alternative Pump impellers to be redesigned to increase the pump discharge pressure. Thus, unit capacity will be met with only two pumps at their optimum point, leaving the third as a standby.

STEAM/DRUM FEEDWATER

Deaerator Nozzle Modifications

Problem Identified The outlet nozzle gusset plates of the Deaerator have regularly experienced cracking. The nozzles are currently inspected at every shutdown.

Selected Alternative Replace nozzle with new design with thicker walled pipe and supports able to resist the effects of vibration and prevent cracking.

ELECTRICAL SYSTEMS

Inverter Replace/Enclosures

Problem Identified The reliability of inverter systems at Bruce 'A' is an ongoing problem and is expected to deteriorate as the inverters near the end of their projected lives.

Selected Alternative Air conditioned rooms to be installed in each of the Units. New inverters are to be installed in these rooms in Bruce B configuration.

Standby Generator Governors

Problem Identified Governor problems are the major contributor to Standby Generator unavailability . To date, it has been possible to make quick repairs to the standby generators, but the unavailability of replacement parts in the future will make it impossible to make such quick repairs.

Selected Alternative Replace Governor Electronics and throttle actuator.

250 Volt Relay/Switchgear

Problem Identified Between 1985 and 1990 there have been 6 cases of loss of portions of the 250 Volt Class I system. All of these were caused by switchgear failures. These failures result in loss of protective relaying and capability to remotely operate breakers.

Selected Alternative Replacement of present switchgear with fuse gear and transfer switches.

Upgrade Electrical Distribution

Problem Identified Spare capacity for electrical supplies to support new BNGSA facilities, Rehab, and future projects does not exist.

Selected Alternative Expand current electrical distribution system to support above need.

TURBINE GENERATOR

Turbine Water Induction

Problem Identified Current water induction protection is not consistent with current industry standards.

Recommended Alternative Install all new drains from the steam pipes and run pipes individually to drain headers. Add new headers to accept an additional number of drainage pipes. Pipes and headers to be made of erosion/corrosion resistant material.

Modify Feedwater Heater level controls to limit level upsets.

Turbine Governor System

Problem Identified The current governing system is "one of a kind". System components are aging and replacement parts are not easily obtainable. In addition, technical support from the supplier is very limited. Problems with the governing system have had impact on unit incapability.

Selected Alternative Install a digital governing system, complete with modern replacements for outdated electrical relays, components and servo valves.

Generator Condition Monitoring

Problem Identified The existing system is old and slow to respond to changing conditions. For example, the sensitivity of stator cooling system waterboxes to cracking makes continuous stator temperature and pressure monitoring essential. Generator aging is also a concern.

Recommended Alternative Install a modern monitoring system which will provide data for many more variables than are presently measured. The trending of data will provide earlier indication of system problems and allow planned responses to prevent unplanned outages and reduce outage durations.

Turbine Generator Fixed Vibration Monitoring

Problem Identified The Turbine Generator Supervisory system provides insufficient vibration information to detect bearing and alignment problems. This hampers effective outage planning for turbine outages leading to outage extensions.

Recommended Alternative Install Turbine Generator Fixed Vibration Monitoring and Diagnostic System using fixed sensors.

TURBINE GENERATOR

Reheater Lid Flanges

Problem Identified The current design of Bruce 'A' reheaters has made them susceptible to steam leaks at the vessel flanges, creating a safety hazard to station employees and lost electrical production.

Selected Alternative Replace existing flange with thicker, stronger flanges and a spool piece to physically separate sealing and vessel support functions.

Turbine Condenser Joint

Problem Identified Current turbine condenser joints are of original installation. With continued service these joints are expected to fail, allowing air in-leakage to the condenser. To date, some units have already experienced minor air in-leakage.

Recommended Alternative Install a new elastomeric joint between each turbine and condenser to eliminate air in-leakage into the system.

PRIMARY HEAT TRANSPORT

PHT Storage Tank

Problem Identified Additionally, heavy water inventory and make-up capability is being reviewed against OP&P 33.6 which requires unit storage capacity to accommodate "leaks within the capacity of the D2O feed system".

Recommended Alternative Upgrade D2O transfer system or provide additional in-unit D2O storage capacity as required. Currently under study.

Bleed Condenser Gasket

Problem Identified Bruce N.G.S. 'A' has a chronic leakage problem with the bleed condenser tubesheet gasket arrangement. A total of 5 gasket repairs have been completed in the last 5 years and two units presently have inner gasket leaks to collection. Repair of a leaking gasket takes 700 manhours of labour, a dose commitment of 1.5 man-rem and a minimum outage time of two weeks.

Selected Alternative Review design of the gasket area to identify primary causes of premature leakage, assess adequacy of existing gasket material and assess whether currently used torque values are appropriate.

PRIMARY HEAT TRANSPORT

PHT Sampling

Problem Identified Sample lines have become plugged causing high radiological fields in tubing runs. Chemical Technicians have become wetted upon extracting D2O from current sample pots.

Recommended Alternative Replacement changes include: Installation of in-line analyzers; re-design sampling cabinet; provide datalogging capability and replace pressure reducing coils with pressure reducing valves.

Replace/Refurbish In-Line Gas Chromatographs

Problem Identified Gas chromatograph reliability and equipment wearout have become an increasing problem. PEER audit teams have highlighted the importance of the reliability of this instrument and have recommended that the system be replaced or refurbished.

Recommended Alternative Purchase new in-line gas chromatograph; a dedicated in-line deuterium analyzer and install local ventilation.

EMPLOYEE SAFETY

Reactivity Deck Modifications

Problem Identified The present deck configuration grating support design and congestion has been the cause of a number of minor accidents and near misses.

Selected Alternative Redesign reactivity mechanism deck grating support such that the grating remains secure when sections are removed.

Upgrade Vault Cooling

Problem Identified Vault coolers are suffering performance degradation and maintainability problems.

Recommended Alternative Improve vault cooling system by replacing cooling coils improving access, installing improved motors/fans installing monitoring of coil condition.

Noise Reduction

Problem Identified Noise mapping surveys confirm several work areas in the station with noise levels exceeding 90 dB(A) on a continuous basis.

Recommended Alternative Noise reduction by engineering controls. Scope as yet not defined.

CA 9500141

USE OF A PROJECT EVALUATION AND RANKING SYSTEM IN ONTARIO HYDRO NUCLEAR OPERATIONS BRANCH

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Ontario Hydro

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ABSTRACT

This paper describes a system developed to evaluate and rank projects in Ontario Hydro's Nuclear Operations Branch. This system involves determining the value of project induced changes using a simple questionnaire and computer spreadsheet, and then transferring the results to a master database for the ranking to be done on a benefit/cost basis. All capital projects in the branch are now being evaluated and ranked using this system.

Background

There is a greater emphasis today than ever before on maintaining and improving efficiency and reliability of our nuclear stations. At the same time, increasing regulatory demands require an ever increasing amount of resources. In trying to respond to both demands, budgets are becoming more and more strained.

Neither efficient, reliable operation, nor regulatory compliance can be sacrificed, yet we are unable to completely satisfy either due to limited financial and labour resources. To make good choices on the best use of funds to try and satisfy all requirements, we need a rigorous, yet simple, evaluation process that can judge all maintenance or modification projects using measures that would consider all aspects of station performance.

This evaluation process should not only ensure that funds are spent on the most beneficial projects at each station, but also that funds are properly allocated between the stations in the Nuclear Operations Branch.

Nature of the Problem

Maintenance and modification projects have been difficult to compare to each other due to the wide variation in the nature of the projects. Not only are they very technically different, but some are capital, some are OM & A. Some projects have "hard" dollar benefits, some have only "soft" dollar benefits. It is difficult to compare regulatory driven projects with cost saving or employee safety projects. It is even more difficult to compare projects from different stations.

For example, the following five jobs need to be done, but there is only enough money for three of them:

- restack the irradiated fuel bay for greater storage capacity
- upgrade the Abnormal Incident Manuals to reflect new AECB standards
- retube the condensers to avoid future leaks
- replace obsolete controllers with a new type to increase reliability
- implement a new computer based training program to increase productivity.

How do you decide which three to fund?

Clearly some type of ranking system is required to compare the projects and choose those with the biggest return on investment.

Ranking System Objectives

There are many objectives that should be satisfied by a thorough project evaluation and ranking system. Of prime importance is to best satisfy overall station and branch objectives by allocating resources to maximize benefits. This must be done within a constrained budget and a limited resource base.

Another key characteristic of a good project ranking system is that it considers both benefits and risks. All too often the benefits of a project tend to be used to justify a project without thoroughly looking at the negative aspects. There are many changes we have installed, that, had we looked at all the impacts on station performance, we probably would not have gone through with.

The process that is used must be visible so that everyone involved can readily understand the decision process. It must be defensible against technical and financial scrutiny, and so must be able to minimize the effect of individual biases on the results. It is essential that the assessment process be clear, consistent and comparable within and between different departments, otherwise the results will not be accepted as a means of choosing between competing projects. As well, both Hydro driven and regulatory driven projects should be comparable.

When used early enough in the life cycle of a project, the system can minimize expenditures before deciding to proceed. Yet, it should be useful throughout the project life cycle.

Sound financial methods consistent with branch practices must be used for assessing project value, to ensure that the system outputs are consistent with detailed project evaluations. Simple outputs are required to allow the broadest base of users to work with the evaluations. Dollar impact has been found to be the best common metric for evaluating projects on an equal basis, and is used by this system in ranking projects.

System Development

Ontario Hydro developed a Project Evaluation and Ranking System (PERS) together with Prof. R. Land of Penn. State University. This system was based on one used successfully over the last ten years by several US nuclear utilities. Only minor modifications were required to configure the system for a CANDU station and to incorporate Canadian financial details.

The first trial of the system was at the Bruce A station in late 1991. After the this successful trial, the system was adapted for the other stations in the Nuclear Operations Branch. Modifications to allow use at the Bruce Heavy Water Plant have permitted all project initiating departments in NOB to use a common system by early 1992.

Ownership of the evaluation part of the system rests with the station Technical Sections. Comptrollership Sections at the stations manage and control the master project databases that contain the project ranking lists.

Overall Process

The PERS system has several components. The Branch key result areas of public safety, personnel safety, production reliability, environmental protection and operating cost were the starting point. To provide further clarity in the identification of project value, two of these attributes are further subdivided into two subcategories. Public safety effects are divided into "quantifiable" changes in public risk from plant modifications or operation, and improvements in public safety resulting from the utility's actions to respond properly and promptly to important issues and concerns raised by the AECB, MOE, and other regulatory bodies. Plant costs are separated into costs associated with materials and supplies, and costs associated with worker productivity as reflected in work-hours spent.

However, since these Key Result Areas are too general and high-level to evaluate projects against, the KRAs were broken down into approximately thirteen separate sub-areas so that project induced effects could be better evaluated. For each sub-area, one or more specific questions was prepared to try and quantify the possible effects the proposed modification would have. In all, forty questions were found to cover all the significant change mechanisms that most projects could affect.

The evaluation questionnaire requires evaluators to first decide if a proposed project is expected to alter any of the forty specific aspects of plant or utility operation. If the answer to any of these questions is "yes," users are also asked to indicate whether the expected effect will cause an increase or decrease in the characteristic performance measures that define operation in the affected area (viz., change in person-rem of exposure for projects that alter radiation exposure, or changes in work-hours for projects that alter productivity). In addition to indicating direction of change, evaluators are asked to estimate how large the changes will be. However, this does not mean that unique and accurate estimates must be calculated for every effect of every project. Instead, the evaluation questionnaire includes five pre-defined impact levels for each performance measure. The impact levels range from "low" values, which approximate the smallest measurable change in the various performance measures, to "high" values which represent the largest "practical" magnitude of change that a single project is likely to produce.

Answers to the questions are input directly into an automated spreadsheet to evaluate the impact of project induced changes on station characteristics and performance. The spreadsheet has been preloaded with financial data, so that the answers to the questions are converted into a total benefit value. This benefit is calculated both on an annual and a lifetime basis for the station.

Knowing the cost of the project then allows calculating a benefit/cost ratio for each project, which is done in a separate database that also collects all projects for ranking and comparison.

Spreadsheet Details

The spreadsheet is currently in use is a Lotus 2.2 version that has been set up with macros so that even non-Lotus users can step through the process. The worksheet formulas automatically convert the answers from the questionnaire to dollar values of expected benefit (+$) or risk (-$) to plant operation. The worksheet produces a table of projected benefits AND risks identified both by the questions that give rise to them and by the key effectiveness areas affected. In addition to the breakdown by questions and effectiveness areas, the benefits and risks from all anticipated effects are summed to provide a net project benefit.

Some dollar conversions such as MW-h, work-hours, OM&A costs etc are relatively straightforward. Things like accident effects, regulatory concerns, reducing risk of lost time accidents or morale issues are more difficult. Despite the difficulty, values have been assigned based on the current best judgement of impacts (eg from PRA studies for public risk effects) or avoided costs. Though these values are sometimes debated, they have stood the test of time and are being used consistently across the branch.

The spreadsheet output consists of two pages that detail the answers to each question and the associated dollar benefit/risk. The summary at the bottom shows the net benefit or risk on an annual and lifetime basis. This output forms an easy to read, concise summary which highlights a projects expected benefits for managerial review. (See Figures 1,2 for examples of the spreadsheet outputs.)

The formulas in the spreadsheet employ simplified financial calculations using escalation and discount factors blended into a "levelized dollar" in order to speed up the calculations. Another approximation that is made is that one-time benefits or risks are adjusted to look like continual ones. Normally, benefits or risks will continue through the remainder of the station life, and this is taken as the default setting. The spreadsheet formulas and financial data are readily reviewed by anyone using the spreadsheet if desired, and all the information is documented in a basis document.

Database Details

The database, a dBase III plus application, is used to collect all the project evaluations generated using the questionnaire and the spreadsheet. The spreadsheet outputs are manually transferred to the database to allow for easier review and for data security control.

The calculation of benefit cost ratios and the ranking of the projects is preformed by the database. Projects can be ranked on either benefit/cost, total benefit, and/or net benefit. As well, projects can be ranked either by weighted or unweighted benefit cost ratios. This feature allows senior management some adjustment of strategic direction by emphasizing certain attributes of performance above others even though the dollar benefit may be equal. For example, rankings can be generated in which public safety benefits are valued twice as highly as other benefits.

Reports of various types can be viewed on screen or printed, allowing easy sensitivity evaluations. In addition to the various project ranking reports, the dollar value of a project's impact on individual Key Result Areas can be determined, and so projects can also be sorted by KRA.

Precautions in using PERS

It is very important when using a system such as this to ensure that results are not taken as absolutes, the system is primarily a ranking system. In many cases, especially where hard dollar benefits are involved, the outputs will be very close to full fledged financial evaluations. But, where soft dollar benefits are the prime result, this system may give different absolute benefit values. Given that the spreadsheet conversions and values are agreed upon though, comparisons of very diverse projects are valid.

Project interactions are not considered since there is no facility for connecting separate projects. Any interactions must be manually corrected for when evaluating and comparing projects.

Project reevaluations using the spreadsheet are required as better financial or design information becomes available. The system outputs should not be considered static. As with any system, especially computerized ones, better quality inputs gives better quality outputs.

Proper cost estimates are also a vital denominator to the ranking equations. The spreadsheet output only forms the numerator, ie the benefit of a project. Although the initial project evaluation may be done at the concept stage with very coarse cost values, release quality estimates should be used for budget or business planning decisions. Also, while ongoing operating and maintenance costs are factored in as project risks in the spreadsheet, one time installation costs such as radiation dose

or outage delays are not. These costs must be included as part of the overall project cost so that a true benefit/cost ratio can be calculated.

Summary

Using this methodical approach allows comparison of very diverse maintenance or modification projects such as employee safety, regulatory compliance or cost saving projects. This can be done both within a station and across different stations.

The evaluation questionnaire asks for impact assessments in terms that can be easily understood and estimated (eg. outage times, work hours). People are not required to try and judge values of complex factors such as public safety and regulatory impact. Instead, these values are all determined for them using a fixed and controlled process. The result is better, more consistent evaluations.

The system is easy and quick to use, yet still provides accurate, comprehensive, comparable, defensible and repeatable evaluations. As a result we can easily compare all projects to see which provide the best return on investment, before major expenditures occur, so that limited dollars are put to the best use.

ONTARIO HYDRO - NUCLEAR OPERATIONS BRANCH
BENEFIT & RISK EVALUATION WORKSHEET
PNGSA(or B)

Project number: 12345 PCA #:
Project name: EXAMPLE
Project engr: J SMITH
Units Affected: 4 Date: 7/10/91

QUES #	Y/N	SIGN 1=+ -1=-	IMPACT1 5=HI 1=LO	IMPACT2 3=HI 1=LO	TOTAL VALUE
Q_1	Y	-1	1	-----	$37,838
Q_2	N			-----	$0
Q_3	N			-----	$0
Q_4	N			-----	$0
Q_5	N			-----	$0
Q_6	N			-----	$0
Q_7	N			-----	$0
Q_8	N			-----	$0
Q_9	N			-----	$0
Q_10	Y	1	3	-----	($1,225,955)
Q_11	N			-----	$0
Q_12	N			-----	$0
Q_13	N			-----	$0
Q_14	N			-----	$0
Q_15	Y	-1	4	-----	$721
Q_16	N			-----	$0
Q_17	N			-----	$0
Q_18	N			-----	$0
Q_19	Y	-1	2	-----	$193
Q_20	N			-----	$0
Q_21	N			-----	$0
Q_22	N			-----	$0
Q_23	N			-----	$0
Q_24	N			-----	$0
Q_25	N			-----	$0
Q_26	N			-----	$0
Q_27	N			-----	$0
Q_28	Y	1	1	-----	($5,630)
Q_29	N			-----	$0
Q_30	N			-----	$0
Q_31	N			-----	$0
Q_32	Y	1	5	-----	$1,914,200
Q_33	N			-----	$0
Q_34	N			-----	$0
Q_35	N			-----	$0
Q_36	N			-----	$0
Q_37	N			-----	$0
Q_38	N			-----	$0
Q_39	Y	-1	3	2	$25,000
Q_40	N			-----	$0

ESTIMATED ANNUAL BENEFIT = $58,121
ESTIMATED LIFETIME BENEFIT = $1,569,267
WORKSHEET INPUTS CHECKED BY: _____

Figure 1 - Page 1 of Benefit-Risk Worksheet Report

ONTARIO HYDRO - NUCLEAR OPERATIONS BRANCH
BENEFIT & RISK EVALUATION WORKSHEET
PNGSA(or B)

Project number: 12345 PCA #:
Project name: EXAMPLE
Project engr: J SMITH
Units Affected: 4 Date: 7/10/91

QUES #	<-- PUBLIC SAFETY --> Publ Risk	Regl Intrf	Plt Reliab	<-- PLANT COSTS --> Matl Cost	Pers Prodct	Envr Prot	Wrkr Sfty
Q_1	$4		$37,834				
Q_2	$0		$0				
Q_3	$0		$0				
Q_4	$0		$0				
Q_5			$0				
Q_6			$0				
Q_7			$0				
Q_8			$0				
Q_9			$0				
Q_10			($1,225,955)				
Q_11			$0				
Q_12			$0				
Q_13			$0				
Q_14			$0				
Q_15			$721				
Q_16			$0				
Q_17				$0			
Q_18				$0			$0
Q_19				$193			
Q_20				$0			
Q_21				$0			
Q_22				$0			
Q_23				$0			
Q_24				$0			
Q_25				$0			
Q_26				$0			
Q_27				$0			
Q_28				($5,630)			
Q_29					$0		$0
Q_30					$0		$0
Q_31					$0		$0
Q_32					$1,914,200		
Q_33					$0		
Q_34							$0
Q_35							$0
Q_36							$0
Q_37							$0
Q_38		$0					$0
Q_39		$25,000					
Q_40						$0	
YR	$4	$25,000	($1,187,400)	($5,437)	$1,914,200	$0	$0
TOTL	$106	$675,000	($32,059,800)	($146,805)	$51,683,400	$0	$0

Figure 2 - Page 2 of Benefit-Risk Worksheet Report

Organizing Ownership in Multi Unit Stations

Y. Young, Ontario Hydro

This paper was not available at the time of printing.

CA9500142

QUALITY IMPROVEMENT IN PICKERING RETUBING/REHABILITATION OUTAGES

A.R. Lees

Ontario Hydro

Ontario

ABSTRACT

Retubing of the Candu Reactor has progressed from single channel replacements in the 1970s through to large scale replacement programs in the 1980s and 1990s. Significant changes in the approach to the task have taken place in order to make the outage duration, dose uptake and costs viable.

This was achieved by reducing radiation fields, designing shielding and planning to shorten the job on reactor.

The organization and roles of the work groups involved (Construction, Operations and Design) were carefully designed to ensure a focused team approach to the outage. The work to be done during the outage is carefully detailed and logically planned.

The outage itself involves many Operations activities to be completed before Construction begins it's work on the reactor. Once work begins all activities are monitored and controlled from the Retubing Control Centre. Removal of high radioactive components is done entirely by remotely controlled tools.

Once the reactor is retubed a program of restarting and testing of systems to ensure operating license requirements is carried out.

QUALITY IMPROVEMENT IN PICKERING RETUBING/REHABILITATION OUTAGES

The topic of my talk today is the Retubing of the Candu Reactor. There have been many papers already on this subject. These have often been focused on the engineering or construction aspects. Today, I will present the topic more from the Operations viewpoint of a major outage and will introduce some of the initiatives that allowed people working on the project to exercise some of the principles of quality improvement.

A key initiative was to have many people participate in the training on the principles of team building. This permitted an acceptance of Quality Improvement ideals.

The objective of this paper is to provide an insight into the enormous production effort that goes into the retubing job. Firstly, it will put into perspective the challenge to improve the techniques required to go from single channel replacement methods to the large scale program. Secondly, it will give some appreciation of how the synopsis and script for a major retubing show is developed. Finally, it will explain how the job actually happens once the show begins.

The analogy of a stage or screen production is used. The retubing job has been compared to a reactor heart transplant. The theatrical comparison is preferred because of the aspect of the people involved. In a heart transplant there are one or two skilled technicians, ie, the surgeons. In a reactor retube there are literally hundreds of skilled technicians. At the peak of activity about 500 people are involved. The challenge is to choreograph the whole show so that everybody gets on stage on cue and knows their lines.

What has to be done to improve our techniques and plans to go from single channel replacement to large scale fuel channel replacement programs?

The first pressure tubes were replaced in 1974 after leaks occurred as a result of the delayed hydride cracking phenomenon. The tooling available at that time meant that the dose to replace one pressure tube was 100 rem. It took about six weeks to do the job. When it became known that fifty two pressure tubes had to be replaced some major improvements were made. This allowed a pressure tube to be replaced for a dose expenditure of 16 rem. To retube a reactor with these techniques would take four years and 6000 rem.

From that time designers worked on tooling to do the job more effectively. Some very sophisticated equipment using the SPAR "space arm" concept was tried but abandoned. The current approach is simpler and was adopted following the sudden rupture of Unit 2 pressure tube G16 on August 1, 1983. It involves significant reactor face work by people using carefully designed tools. As well there are remote tools which deal with the high

dose parts of the job. The objectives for retubing 1 and 2 were to complete the job in 2.5 years with a dose expenditure of 1000 rem. They were retubed in 48 and 54 months with a total dose of 650 rem. Unit 3 was completed this year in 25 months and less than 400 rem. Our current target is to complete Unit 4 in 19 months with a dose expenditure of 370 rem. This is summarized in the table #1.

As you can tell the two key elements necessary for success in Retubing are dose and schedule. To minimize dose the usual, well known, techniques were employed. These include decontamination, shielding, and minimizing the time doing the job.

The decontamination employed the Candecon process. In the case of Unit 3 the general fields were reduced from 430 mrem/h to 200 mrem/h with one decontamination. In order to complete the retubing job within the dose target it was necessary to further reduce the general fields. The second Candecon brought the fields down to 84 mrem/h.

After decontamination of Unit 4 the general field at the reactor face is 50 mrem/h.

There were major delays on previous retubing outages because of the presence of C_{14} in the annulus between the pressure tube and calandria tube. To minimize exposure of the workers to C_{14} (a very fine particulate) the annulus was also decontaminated and 50 ci of C_{14} were removed. The outage was successfully completed with only minimal uptake of C_{14}.

Most of the work on the reactor face is done from within a shielded cabinet weighing 35 tons which is located on the fuelling machine bridge. Apart from channel beams which can be 30 Rem/h the general fields in the cabinet are less than 10 mrem/h. This cabinet is a very complex assembly as it provides not only shielding but also the audio visual communication systems, lighting for the worksite, and power for the tools. It also is the structure for the work tables, remote hoists and tool carriers that are used to transport the highly activated fuel channel components. All activities within the shield cabinet can be viewed from the Retube Control Centre. The operation of the remote devices is carried out from there.

The third way to reduce dose is to minimize time doing the work. This of course goes a long way to improving the job schedule too. The key to success was the construction of the Training and Mock-up Building. This contains a full scale reactor face, fuelling machine vault and shield cabinet. This gives the people designing the tasks and the people doing the tasks the facility to define the task completely under almost real conditions. The trades who will do the work are involved with the people who write the detailed procedures. Under these circumstances the

tools are proven and the radiation protection concerns can be identified. Once the tool proving is complete and the procedures are written, the crews who will do the work carry out full rehearsals wearing protective clothing. When they go onto the reactor face they are then fully prepared to minimize their dose and at the same time to do the job quickly.

The key to achieving improvements has been to create teams to be responsible for a number of discrete steps of the retubing process. These teams were redesigned after Unit 3 for the work on Unit 4. They examined the detailed procedures and proactively sought improvements. The teams were kept in place until the Unit 4 outage began and consequently developed good working relationships and a high level of ownership for their particular part of the project. Improvements were possible in many areas because the teams consisted of people from engineering, construction trades, operations and health physics. Consequently changes in tool redesign, tool handling, work sequencing, shielding methods etc. could be made. Since all the necessary authorities were present in the team, it was possible to empower the team to implement the changes it identified.

The basic technical approach to the retubing job was defined for Units 1 and 2. Prior to beginning the retubing outage for Unit 3 it was decided that the roles of the actors should be rewritten because there had to be a major improvement in the time for the outage. The three main actors in this show are Design, Construction, and Operations. Behind the scenes was valuable support from AECL and GE Canada. A much more focused team approach was adopted with people from each organization being dedicated to the project. Separate departments from each organization now function together and to a large extent occupy offices located very close to each other at the Training and Mock Up Building. For the most part this now involves Operations and Construction staff but the Design presence has also been very strong at site. This allowed a very quick and thorough response to the tooling changes that the Operations and Construction workers identified. A key change in roles is that Construction do all the high hazard work. On Units 1 and 2 they only did the low hazard installation of new fuel channels.

The basic process for retubing has been refined into a number of activities. Each of the major steps is called a "series". For example one of the main activities is to cut the pressure tube. Because it is done 390 times it is called the "Pressure tube cut" series. The task itself is broken down into smaller tasks. For each task a detailed work plan is prepared.

QUALITY IMPROVEMENT IN PICKERING RETUBING/REHABILITATION OUTAGES

The retubing work is about one half of the overall outage. The balance of the outage time is spent in preparing the unit for retubing and the restart after retubing is finished.

The first phase in retubing is called the "removal phase". The time taken to do this is about one quarter of the overall outage. This involves removing the shield plugs and closure plugs. The feeders are disconnected from the end fittings. The bellows between the calandria tube and end fitting is cut. The pressure tube is cut and separated from the end fitting. The end fittings and pressure tubes are then removed. For this the remotely controlled hoists are used. The operation is carried out using the controls and monitors in the Retube Control Centre. These highly activated components are remotely placed into shield flasks which are used to transport them from the reactor vault to the Irradiated Components Management System. This system facilitates transfer from the in-station shield flask to the Dry Storage Modules where they will remain indefinitely. On Unit 3 a major pressure tube sampling program was implemented. One or two 3 inch rings were cut from every pressure tube before it was placed in the storage module. These rings were sent to Chalk River and have provided extremely valuable information to the CANDU knowledge base on the behaviour of pressure tubes after 17 years in service.

The reactor vault work often appears as the main action under the spotlight at centre stage. In the wings there is also a tremendous amount of activity occurring at the same time. For example the removal tools undergo refurbishing and calibration. This requires the full time operation of a dedicated decontamination facility. All of the closure plugs are also rebuilt. This work is carried out in new workshops built specifically for that purpose.

The next part of the retubing job is called the Installation Phase. The duration of this is about one quarter of the total outage time. This involves checks and inspections of the calandria tube and the annulus gas piping. The bellows rings are dressed in readiness for the welded connections of the new fuel channel. One end fitting is fitted to the pressure tube to form a sub-assembly that is put together in the workshops. This means only one rolled joint has to be done in situ. This is an example of an opportunity taken to reduce dose and schedule. Prior to making this rolled joint the four garter springs are installed and checked. After this the bellows are welded and the feeders are reconnected.

All this sounds like fairly basic construction work however it must be remembered all this is done with construction workers hired in the union hall who have very little training in radiation protection. They will work in conditions that are potentially hazardous. The work has to be designed very

carefully to deal with these concerns. This has been achieved very successfully by the integration of Operations staff called "Series Coordinators". Their job is to maintain a high degree of attention to radiological concerns while working with the Construction.

Throughout the Retubing Outage the operating license for the reactor is held by the Operations Rehabilitation Manager. Operations staff on the team are employed to ensure that Radiation Protection Procedures, Radiation Protection Regulations, and the Operating Policies and Principles are all adhered in order to comply with the requirements of the Operating license. Throughout retubing Operations staff called Vault Supervisors work alongside Construction staff but with an independent role of ensuring the radiological safety concerns are always under control.

Series Coordinators and Vault Supervisors have difficult roles. They can be seen as being motivated in a direction counter to the production effort since they have a strong focus on safety. They have been successful only by everyone understanding key principles such as the need to focus on the situation, not the person, to maintain constructive relationships, understanding how to give constructive feedback and being able to support each other because each understood the others goals.

The basic objectives of the radiation protection program for retube outages is to prevent acute overexposure beyond the license limit, to prevent acute unplanned exposures, to minimize collective dose and prevent uncontrolled contamination.

There is a fairly complex organizational structure in place. To be successful this had to be clearly defined and communicated. Two major documents were written which govern the roles and responsibilities of the Operations and Construction organizations. One is called the Retube Radiation Protection Program which deals with the issues just referred to. The second is called the Retube Agreement. One key concept of this is that the reactor and adjacent areas are turned over to Construction and are called Retube Zones. This gives Construction complete independence subject only to the Operations responsibility for radiation safety.

The agreement also defines the role of Operations in supplying support services to Construction. For example Operations supplies the radiation protective clothing and removes the low level radioactive waste. These are significant matters that can impede the retubing work if not done well. For example there are more than 200 entries to the reactor building per day in protective clothing and many hundreds of tools are taken out for refurbishing. A significant amount of low level radioactive waste is generated. There have been a number of innovations

system progress in parallel with the decontamination. When the fuelling machines have finished defuelling they are modified to include drain lines so they can visit each channel once again to remove all the heavy water.

When all the heavy water has been drained the system is thoroughly dried out by drawing a vacuum on it while elevating the temperature in the reactor by allowing the moderator to warm up.

By the time all this work by Operations is finished the Construction team has transformed the fuelling machine vaults into the production facility for replacing pressure tubes. The shield cabinet is on the fuelling machine bridge, the lights are on, the television and headsets are all tested, the power supplies and remote tool carriers are all checked out and the show can begin.

The Construction workers start their shift by going to the Construction changerooms near Unit 8. There they dress in radiation clothing. They are then driven by bus to the other end of the site to Unit 4. They assemble in waiting rooms until their turn comes to work on the reactor face. Each shift crew is divided into small teams of four men. These teams rotate duty on the reactor face so that while some are working, others are resting or are having a meal break. In this way the work goes on continuously with four workers in the shield cabinet all the time.

When their turn comes the team will move off to dress in plastic suits and obtain their dosimetry from their radiation protection assistant. In the meantime their supervisor will have obtained approval from the Operations Vault Supervisor for the team to perform the job. If the Vault Supervisor is satisfied all the surveys have been completed, that everyone's current dose is low enough to allow them to work and they have procedures and training to do the job they will get approval to enter the shield cabinet and begin the task.

They will then work under the surveillance of their foreman from the Retube Control Centre, he will lead them though the detailed procedures. Their Radiation Protection assistant will work with them in the shield cabinet monitoring changing conditions as the team dismantles the fuel channels.

At the end of the shift the team returns by bus to the changeroom. Their dosimetry is collected and results are fed into a dose recording system so that depending upon their dose they can be assigned to an appropriate task on their next shift.

taken though to minimize the volume. For example the tools are no longer double wrapped in plastic before being transported from the reactor face. Re-usable plastic skids, which can be decontaminated are used instead of wooden ones. Mops have been eliminated by using a water spray and vacuum system for cleaning contamination from the shield cabinet.

As a result of all this attention to radiation protection the dose received on the Retube of Unit 3 was 397 rem. Nicely under the target 425 rem.

While discussing the preparation for Retubing there is one other important organization that must be mentioned. This is the Atomic Energy Control Board. Their involvement is crucial to a successful outage. Throughout the outage a high level of communication was maintained with them. Approval had to be gained for the organizational patterns documented to describe the roles of Operations and Construction. There were a number of modifications in the design of the fuel channel assemblies which were submitted for approval at the start of the work. There were other changes that became necessary, for example improvements to the flow characteristics of the annulus gas system that had to be submitted during the outage. It was as a result of keeping the staff of the AECB well informed of the issues as they arose that their approval was received in time to avoid any schedule delays. In addition to design changes the AECB was also required to approve the fuel channel inspection program, the quality assurance program and many other documents used to define the execution of the outage.

Going back to the analogy with a stage show or movie we now have a complete synopsis, the script is written and the stage is set. The show can now begin. This is where the Operations organization begins its role. From the day the unit is shutdown the defuelling operation begins. This takes two months to complete. The fuelling machines remove 4680 fuel bundles at a rate of 8 channels every day.

Throughout this period Operations staff are also busy working on other tasks in preparation for retubing. The cobalt adjuster rods are removed. This reduces the radiation fields experienced at the reactor face.

Preparations for the decontamination process have to be completed. The ion exchange resins have to be replenished and connections have to be made to the heat transport system to inject the chemicals and to add special filters. As soon as the last fuel bundle is removed from the reactor the decontamination will begin.

Before any retubing work begins the heat transport system must be drained. Preparations for draining the bulk heat transport

QUALITY IMPROVEMENT IN PICKERING RETUBING/REHABILITATION OUTAGES

The removal phase for Unit 4 began in December 1991 and was completed in June 1992. Installation continued then until October 1992.

During this period the Operations organization carried out a major program of work. This dealt with corrective and preventive maintenance, inspection programs, and modifications. For example new shut off rod mechanisms were be installed, and new safety system features such as a "flux tilt trip" were wired in. The turbine and generator rotors came out for inspection and tests. All relief valves were recalibrated, all rubber components replaced, major valve refurbishing done, all safety system wiring checked and many equipment deficiencies were corrected.

In order to gain the synergy available from various work groups, such as maintenance, technical, operations and planning, some particular initiatives were taken. The key to achieving this was to put effort into ensuring good communications, ensuring people were trained in teamwork principles and accepted the cultural changes implied in this. A lot of effort was put into ensuring the team was self sufficient by providing as far as possible the resources needed to get on with the job.

Once staff and supervisors bought into the direction the project management team had taken many initiatives were created to make things work better. Some examples of these initiatives are:

- To ensure good communications, the different trades supervisory staff offices were grouped together instead of being in different departments. They became a supervisory team.

- Adequate space was provided for planning meetings and communications meetings.

- Staff created and controlled local semi-permanent work shops to avoid trekking to the central shops. They have ownership of their own facility.

- Teams were created to deal with special projects such as replacement of flux monitoring rods using unproven tooling. This concept was expanded to embrace the outage program for systems. A team of the various work groups was created to examine the work necessary in the areas of modifications, maintenance, testing and on through the restart operations. These teams were called SPORTS (System Project Operations Rehabilitation Teams). This approach is similar to the Retube approach with the Retube Series Teams and succeeds in involving the people actually doing the work to good advantage.

QUALITY IMPROVEMENT IN PICKERING RETUBING/REHABILITATION OUTAGES

When the Retubing and the other outage work is complete the last phase of the outage begins. This is called Restart, the final quarter of the outage. It is basically the same process used to commission new plants. It begins with testing the integrity of the reactor building containment prior to loading new fuel and progresses through systematic checks of each system. All the checks are formally documented then presented to the Atomic Energy Control Board to demonstrate that the systems are available for service. The culmination of the process being the granting of permission to progress through the various milestones of the restart such as the adding of heavy water to the heat transport and moderator system, the approach to critical and the raising of power to various levels.

The retubing of Unit 3 was successful because some important principles were adopted and maintained.

- Firstly, there was well integrated project management within the three key organizations focused on a common goal.
- Secondly, there was a clear understanding of roles and responsibilities.
- Thirdly, there was a clear assignment of resources dedicated to the project.
- Fourthly, there was a great deal of attention paid to training and improvement to the processes of retubing.
- Finally and perhaps most importantly, there was an active promotion of team work concepts within and between the organizations.

As part of the team, we were pleased with the results and I might conclude with a statement from the AECB - they were impressed, with the sense of pride and ownership displayed by all involved staff. The team feels they have made a contribution to the people in Ontario.

QUALITY IMPROVEMENT IN PICKERING RETUBING/REHABILITATION OUTAGES

Table #1

YEAR	PROJECT	DURATION	DOSE
1974	1 Pressure Tube	6 weeks	100 rem.
1974	52 Pressures Tubes	6 months	832 rem.
1983/84	PNGS Unit 1/2 Retube Outage	4 years	650 rem.
1991	PNGS Unit 3 Rehabilitation-Retube Outage	2 years	400 rem.
1993	PNGS Unit 4 Rehabilitation-Retube Outage	1.5 years	370 rem.

Ontario Hydro SLAR Implementation Team For Gentilly 2 NGS

J.P. Mather, Ontario Hydro

This paper was not available at the time of printing.

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INNOVATIVE MAINTENANCE TECHNIQUES IN GENERATOR EXCITATION SYSTEM

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ABSTRACT

The use of higher power and larger equipments created new problems during the plant operation. One of these are the excessive abrasion in excitation collector rings and brushes. This study will be used to diagnose specific problems without major disassembly and physical inspections. This document describes in detail the excitation system collector ring and brushes and its requirements and controls, showing the results of one on going program to monitor abrasion on its components.

INNOVATIVE MAINTENANCE TECHNIQUES IN GENERATOR EXCITATION SYSTEM

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A. Introduction

A.1. Analysis procedure to determine the abrasion presence is the most powerful technique available for abrasion analysis. During maintenance this study was very important because the information obtained indicates the magnitude of abrasion in the positive collector ring and brushes. Data reading for all the measurements are represented in figures : 15 - 17 - 19 - 20 - 21 - 22 - 23 - 24 .
The primary objectives of the abrasion control in collector rings and brushes are :
[1]- To achieve acceptable operating conditions.
[2]- Extend collector rings life ,(Critical components in general can not be easily replaced).
[3]- Reduce excitation system failures.
[4]- To assure long-term reliability during the nominal service.
[5]- Lower maintenance costs (The collector rings are a critical components because the cost of replacement is very high).

A.2. In general the techniques used were :
[1]- A complete machine analysis during standard operating conditions.
[2]- The abrasion brushes were measured and then compared to standard. Then it, was possible to detect any problem that may arise.
[3]- If a problem should appear , it's important to detect its severity.
[4]- This analysis was the procedure of measuring the abrasion presented in the collector ring and brushes. Analized the characteristics of that abrasion we could determined the cause. Abrasion was the signal that revealed the presence of a ionization problem, a current density problem, or a temperature problem.
[5]- Each time that a fault was revealed, a careful analysis was carried out to identify the problem.

A.3. Revalidation checks. (Considerations).
[1]- Degradation mechanism is produced by the ring pitting due to frictional forces, unequal brush hardness, presence of foreign materials, ring overheating, frictional heating and high environment temperature, unequal surface brush pressure in many points.
[2]- During the revalidation checks, the ring thickness and ring slot will be measured to indicate the rings rate use and its remaining life time.

[3]- It's recommendable to maintain slipring temperature within operational limits , allowing operation within the established capability diagram.
[4]- If this is not possible, rotor reactive loading will be restricted to avoid overheating the slipring.
[5]- It's necessary to check the ventilation system to supply cooling air to the collector ring and brushes.
[6]- A significant change in temperature in turbine generator collector ring, indicates that further attention may be required.

A.4. General considerations :
[1]- The temperature collector ring works is over the ionization limit.The positive turbine generator collector ring is also included here.
[2]- The collector ring and brushes lives are inverse exponential function of temperature. Reducing the operating temperature the collector ring and brushes efficiency will be higher.
[3]- In the "ANSALDO" maintenance manual, the normal allowed abrasion brush is from 4.5 mm to 6 mm for 1000 hours of generation.

A.5. Generator problem.
During 1986 outage, the surface abrasion measured in the positive collector ring was 3.5 mm as maximun value by the second trace brush, this effect could be originated by current density, ionization effect, and temperature, as shown figure 3 and figure 5.
The average brushes abrasion was in that year of 9mm for 1000 hours of generation in the positive collector ring, and was 14 mm as maximun value brush abrasion.
If that problem could not be solved the collector ring could be destroyed in a short time.

A.6. After six years of maintenance investigation we solved this problem as follows.
[1]- In general, contact pressure brush holders were not optimal, because the position of the spring on the brush head does not support propperly. To solve this inconvenience, we use a brush with a U-design on top, in order to position the spring exactly on the brush head.
[2]- To increase surface contact between brush and ring, we have done one slot first and two after, on the running surface of the brushes.
]3]- Due to these changes, we've corrected the effect of the current density, ionization problem and temperature, in the following sections those will be discussed.

B. Study methodology.

B.1. Pressure brush verification.
(See table 1 and table 2).

B.2. Peripheric speed verification.

Collector ring diameter : 55 cm
L = 2 x π x r = 2 x 3.14 x 27.5 = 172.7 cm
Revolution rotor 1500 r.p.m., equal at :1500/60 r.p.s.
Peripheric speed = 172.7 cm x (1500/60 r.p.s.)

[Peripheric speed = 43.175 m/s.]

Collector ring type : C98KU (UNI 2955-68) Ansaldo

B.3. Surface density current.
Surface of contact between collector ring and brush.
Surf. of cont. = 2.5 x 3.7 = 9.25 cm2
Current admissible for brush = 9 A/cm2 x 9.25 cm2 = 83 A
Current admissible for collector ring = 48 brushes x 83 A = = 4000 A
Nominal generator characteristic :
Max.exc.current 3543 A (H2 = 4.21 kg/cm2 - 763.5 Mva).

B.4. Type of brushes.
In the study we used two different type of brushes:
[1]- L.F.C.557 - Le Carbone Lorraine.
[2]- Grade F19 - Schunk Sebe Gmbh - Germany

Le Carbone Lorraine brush

Type	Current-density	Peripheric-speed	Pressure	Hard-Shore
LFC-501	6 - 10 A/cm2	75 m/sec.	180 gr/cm2	14
LFC-557	6 - 10 A/cm2	75 m/sec.	180 gr/cm2	18

As reference we have taken : (*)

Russian Brush

Type	C.-density	Peripheric-Speed	Pressure	Hard-Shore
Electro-graphite 83	9 A/cm2	45 m/sec.	195-220 gr/cm2	15-32

B.5. Analysis done for current density theory.
When the total measurements were performed, the first action was surface collector ring laping as shown figure 7 and figure 8.
The second action we have done,to test with eleven brush holders only, the idea was to have more exactly distribution of surface density current in the brushes, and with this to reduce punctual temperature contact between slipring and surface brushes.

11 brush-holders x 4 brushes = 44 brushes
44 brushes x 83 A = 3652 A
Max.exc.current = 3543 A

But, after 200 hours of generation the abrasion detected was very high as shown figure 17.

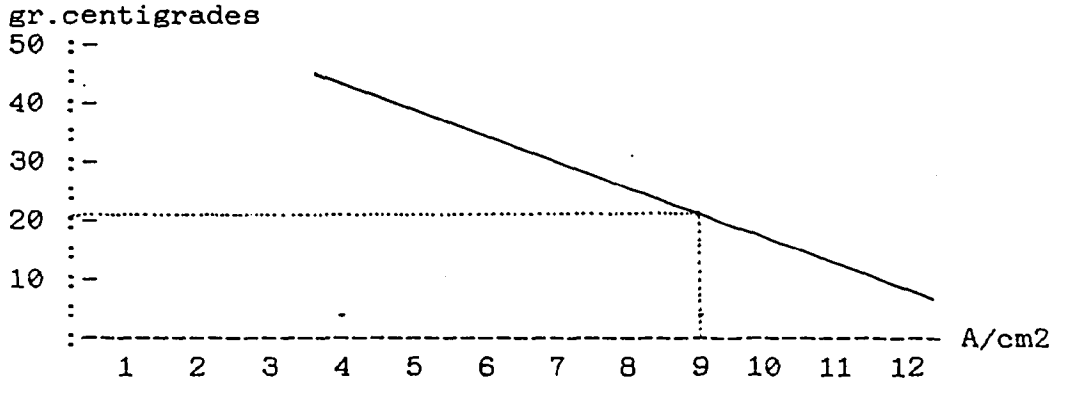
The conclusion after this test was that the higher abrasion was produced for excessive current concentration because the distribution current is not uniform. In general,contact pressure brush holder are not optimal, because the position of the spring on the brush head is indefinited.
At the second trace brush, the surface abrasion measured in the positive collector ring was (3.5 mm) as maximun value. This effect, could be originated by a punctual current density concentration.

B.6. Analysis done with the ionization theory.
With the analysis indicated in point (B.5) the excessive abrasion has not been eliminated.The abrasion in the positive collector ring can be analyzed with the ionization theory.
In the synchronous machine,the working temperature in collector ring is over the ionization limit.
In the positive collector ring,the ionization contact is produced at 9 A/cm2 with a temperature approximate of 22 grades centigrades if the temperature is higher, the ionization begins with a lower density. (See table 4).

Experimental values for contact ionization are the following:

8 grades centigrades 12 A/cm2
43 grades centigrades 4 A/cm2

With this experimental values we can approximatively plot this graphic :



The first measurement was the brush contact surface temperature (See tables 5, 6 and 7).
The second measurement was the air cooling system at the inlet and outlet.

Temperature instrument used:

[a] - Fluke 8024 a (Multimeter).

[b] - Rayneger 2 - U.S.A. - Mod. R2PCFSC1

C. Conclusion:

The abrasion in the positive collector ring was produced due to :

[1]- High temperature in the surface contact between brushes and collector ring.

[2]- The high temperature and abrasion was produced for :
(a)- High punctual current density
(b)- Current distribution not uniform.
(c)- Excess of pressure on the brushes.

[3]- Temperature at which positive collector ring operates (between 70 and 90 grades centigrades) is higher than the admissible ionization temperature of 22 grades for a current density of 9 A/cm2.

D. Corrective actions.

To reduce abrasion in the positive collector ring according with points (C.1), (C.2) and (C.3) we have done in the first study one slot on the brush surface.(Years 1989 and 1990 , see figure 21 and figure 23).
After, during the second study two slots on the brush surface were done.(Years 1991-1992 , see figure 22 and figure 24)

D.1. First study.

The average abrasion for 1000 hours of generation was in years 1989-1990.

$$\text{Total average abrasion} = \frac{\frac{\sum_{i=1}^{12} u_{1i}}{12} + \frac{\sum_{i=1}^{12} u_{2i}}{12} + \frac{\sum_{i=1}^{12} u_{3i}}{12} + \frac{\sum_{i=1}^{12} u_{4i}}{12}}{4}$$

Total average abrasion = 5.554 mm

This total average abrasion was acceptable, but the average abrasion was acceptable only in positions : 1 , 2 and 4. This average was:

$$\text{Average abrasion positions (1 , 2 , 4)} = \frac{\frac{\sum_{i=1}^{12} u_{1i}}{12} + \frac{\sum_{i=1}^{12} u_{2i}}{12} + \frac{\sum_{i=1}^{12} u_{4i}}{12}}{3}$$

Average abrasion positions (1 , 2 , 4) = 4.4 mm

In position 3 the average abrasion was not acceptable

$$\text{Average abrasion position 3} = \frac{\sum_{i=1}^{i=12} u_{3i}}{12} = 9.04 \text{ mm}$$

D.2. Second study.
To reduce the abrasion in position 3 we have done two slots in the brush surface. The average abrasion in this new study for 1000 hours of generation was.

$$\text{Total average abrasion} = \frac{\frac{\sum_{i=1}^{i=12} u_{1i}}{12} + \frac{\sum_{i=1}^{i=12} u_{2i}}{12} + \frac{\sum_{i=1}^{i=12} u_{3i}}{12} + \frac{\sum_{i=1}^{i=12} u_{4i}}{12}}{4}$$

Total average abrasion = 5.6267 mm

But in position 3 the average abrasion was acceptable.

$$\text{Average abrasion position 3} = \frac{\sum_{i=1}^{i=12} u_{3i}}{12} = 5.307 \text{ mm}$$

With these two studies we can conclude that the best corrective actions is to do one surface slot in brushes of positions 1,2,and 4, and two surface slots in brushes of position 3.- (See figure 25 and figure 26)

D.3. Slots :
The slots produce brush surface temperature reduction of 10 grades or more, and therefore, we don't find any more high punctual current density, because distribution current is more uniform in the brush surface.

D.4. References :

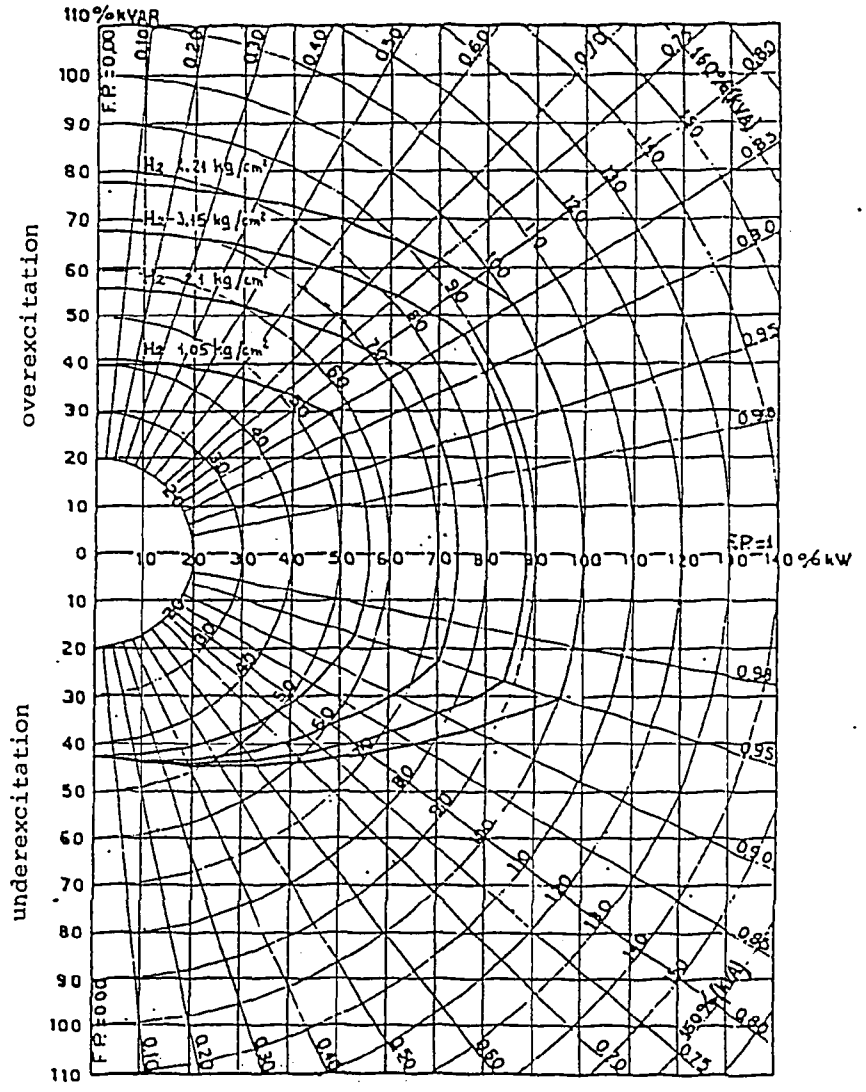
(*) - " ELECTRICAL MACHINES "
M. Kostenko and L. Piotrovsky
Polytechnic Institute "Kalinin"
(Leningrado)
Year 1968 - page 186

CAPABILITY CURVES

100 % = 763.530 Kva in H_2 = 4.1 kg/cm^2

Max.exc.current = 3543 A (H_2 = 4.1 kg/cm^2 - 763.530 Kva - 22 Kv - 50 Hz - F.P. 0.85)

Min.exc.current = 2815 A (H_2 = 1.05 kg/cm^2 - 427.580 Kva - 22 Kv - 50 Hz - F.P. 0.85



MEASURED PRESSURE BRUSHES - (STANDAR PRESSURE IS 185 gr/cm^2)

Brush-Holder / Brush	13	14 gr/cm^2	15 gr/cm^2	16 gr/cm^2	17 gr/cm^2	18 gr/cm^2	19 gr/cm^2	20 gr/cm^2	21 gr/cm^2	22 gr/cm^2	23 gr/cm^2	24 gr/cm^2
1		216	248	259	238	238	238	227	227	227	227	216
2		248	238	248	238	248	227	238	238	216	216	216
3		248	227	270	238	238	216	216	227	238		216
4		238	248	238	238	248	216	216	238	238	216	216

TABLE 1

MEASURED PRESSURE BRUSHES - (STANDAR PRESSURE IS 185 gr/cm^2)

Brush-Holder / Brush	1 gr/cm^2	2 gr/cm^2	3 gr/cm^2	4 gr/cm^2	5 gr/cm^2	6 gr/cm^2	7 gr/cm^2	8 gr/cm^2	9 gr/cm^2	10 gr/cm^2	11 gr/cm^2	12 gr/cm^2
1	216	235	202	232	229	216		224	256	224	229	310
2	237	248	202	229	224	243		229	216	229	240	297
3	216	256	216	256	248	256		248	216	243	264	259
4	216	243	216	243	216	224		216	235	243		270

TABLE 2

AIR COOLING SYSTEM - MEASURE WAS DONE IN SUMMER
INGRESS AIR TEMPERATURE : 37 °C
EXIT AIR TEMPERATURE : 46 °C

TABLE 3

MEASURED TEMPERATURE COLLECTOR RINGS (YEAR 1990)
POSITIVE COLLECTOR RING : 67 °C
NEGATIVE COLLECTOR RING : 59 °C

TABLE 4

Positive collector ring - Year 1986

BRUSH-HOLDER	BRUSHES : Surface temperature			
	1	2	3	4
3	68 °C	72 °C	83 °C	75 °C
5	78 °C	82 °C	84 °C	74 °C

TABLE 5

Positive collector ring - Year 1.987.-

BRUSH-HOLDER	BRUSHES : Surface temperatu			
	1	2	3	4
16	80 °C	80 °C	90 °C	85 °C
15	78 °C	88 °C	96 °C	91 °C

TABLE 6

MEASURED TEMPERATURE SURFACE BRUSH

POSITIVE COLLECTOR RING YEAR 1990

BRUSH-HOLDER	BRUSH 1	BRUSH 2	BRUSH 3	BRUSH 4
1	58 °C		70 °C	
2			66 °C	
3		60°C	69 °C	
4			72 °C	
5			72 °C	63 °C
6			75 °C	
7	59 °C		71 °C	
8		60°C	75 °C	
9			68 °C	63°C
10	58 °C	58 °C	68 °C	58°C
11				
12				

TABLE 7

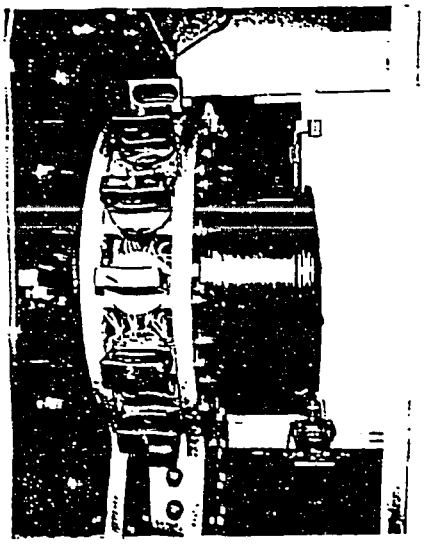


figure 1

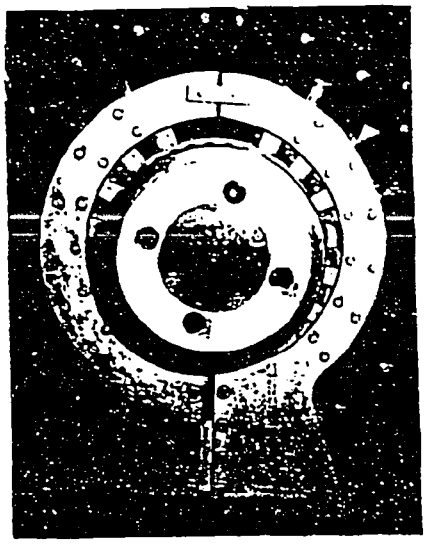


figure 2

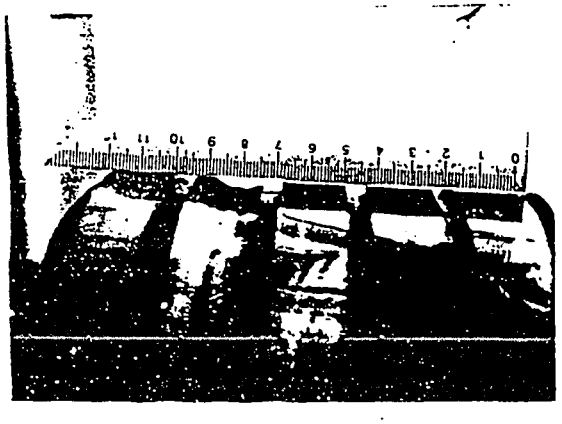


figure 3

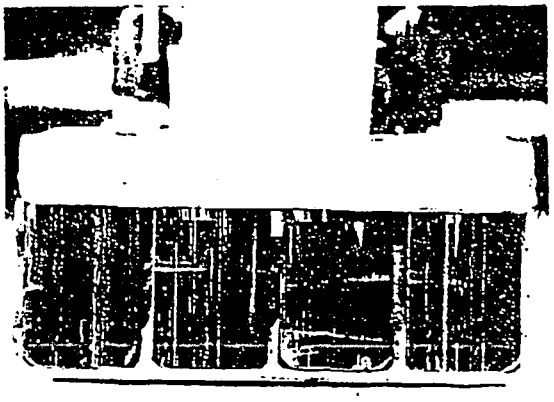


figure 4

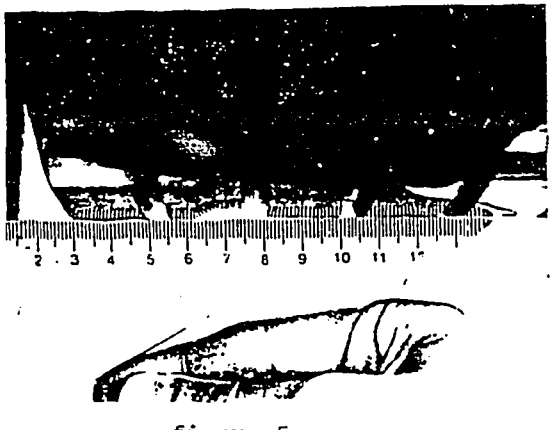


figure 5

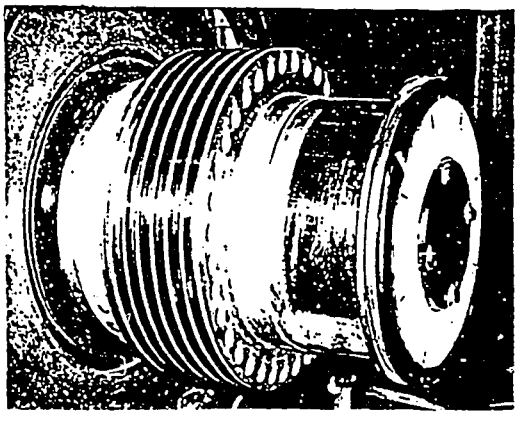


figure 6

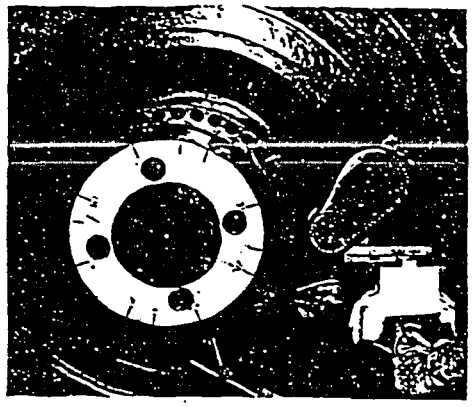


figure 7

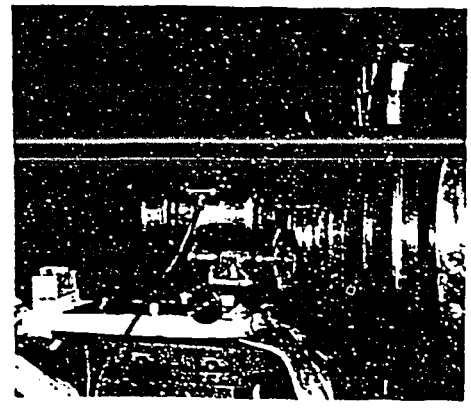


figure 8

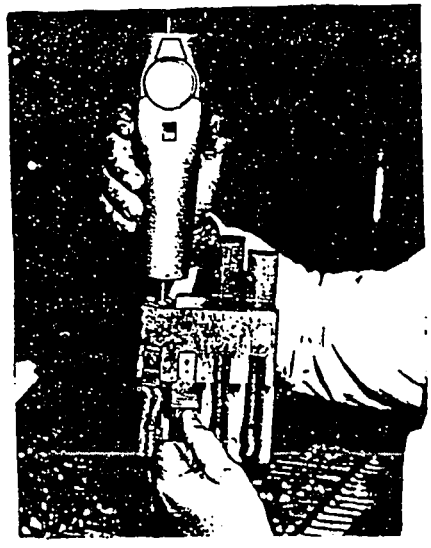


figure 9

figure 10

figure 11

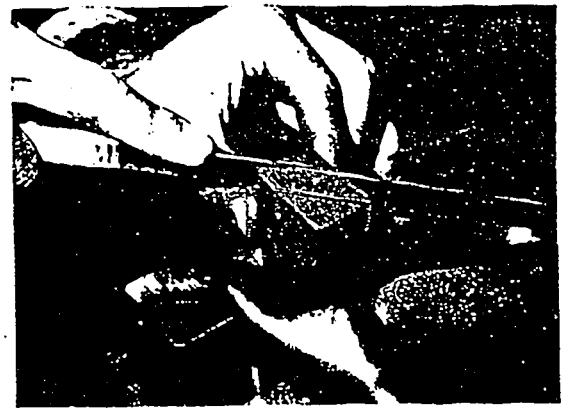


figure 12

SURFACE BRUSH WITH ONE SLOT - STUDY MADE IN YEARS 1989 - 1990
5064 HOURS OF GENERATION

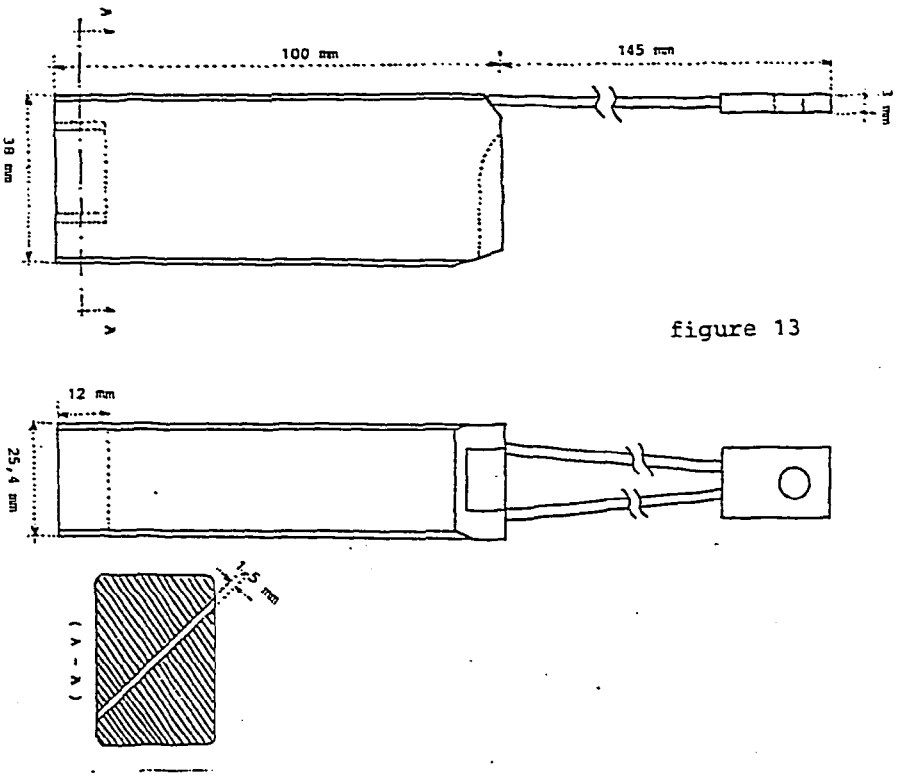


figure 13

SURFACE BRUSH WITH TWO SLOT - STUDY MADE IN YEARS 1991 - 1992
4176 HOURS OF GENERATION

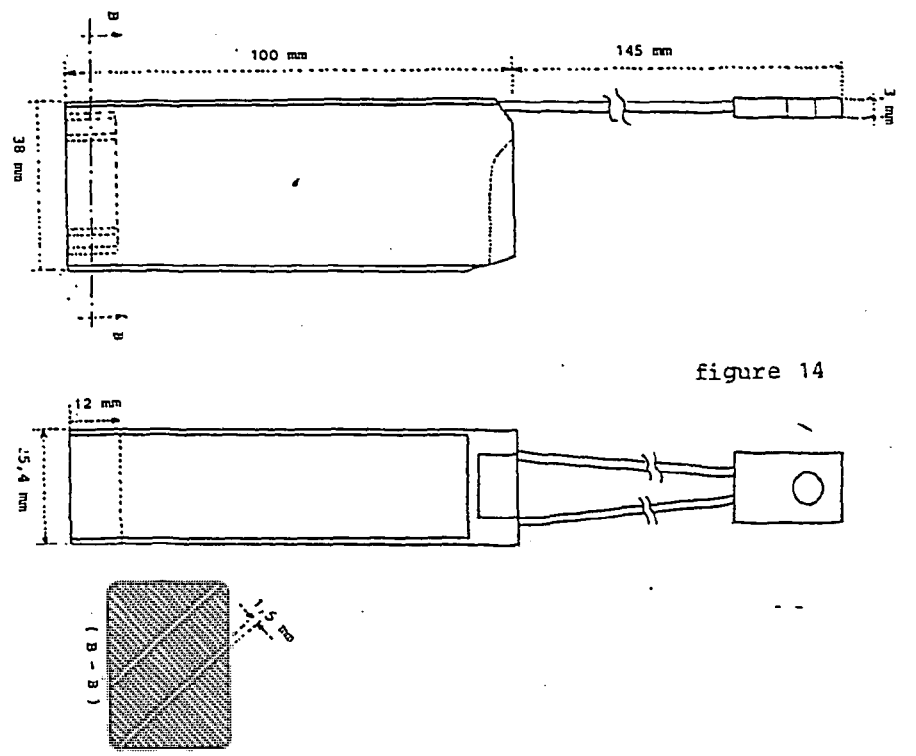


figure 14

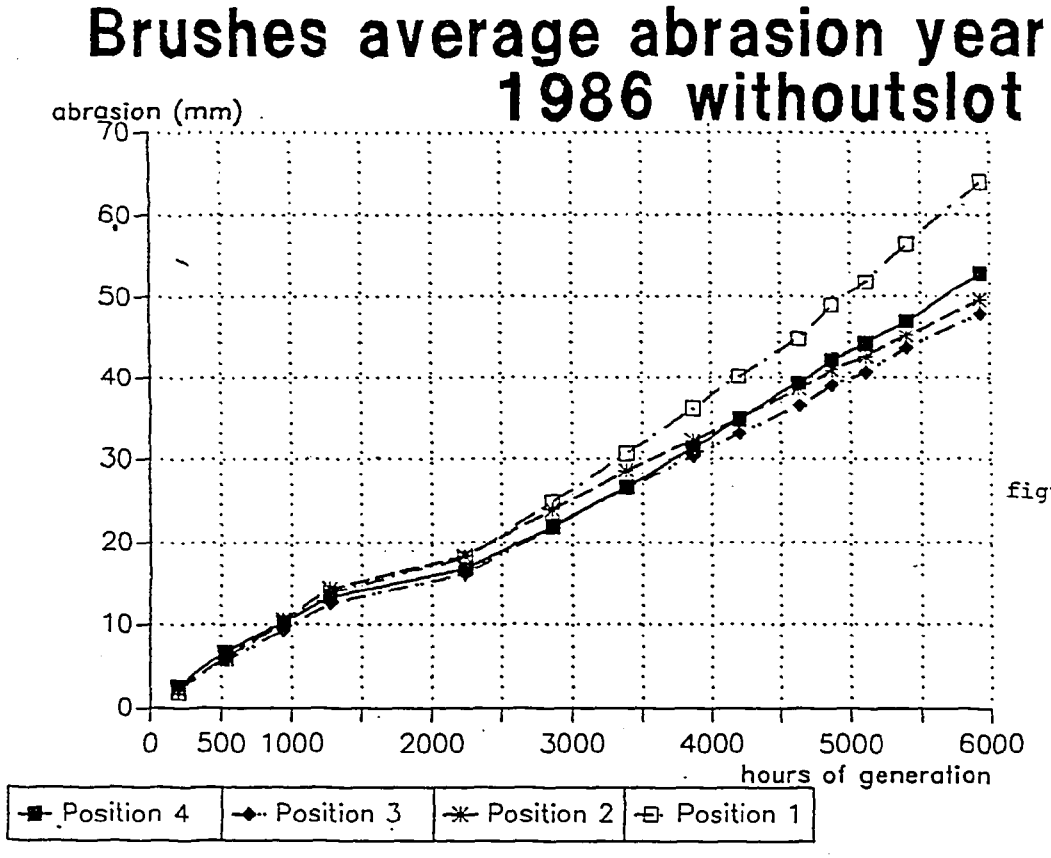


figure 15

POSITIVE COLLECTOR RING POSITION AND NEGATIVE COLLECTOR RING POSITION IN THE STUDYS IN YEARS: 1986, (1989-1990) and (1991-1992)

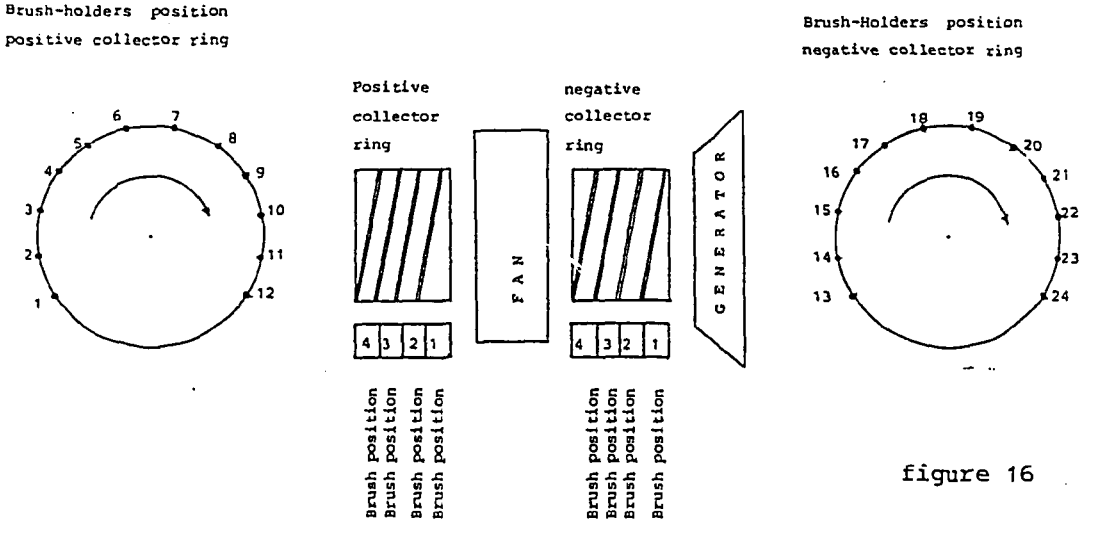


figure 16

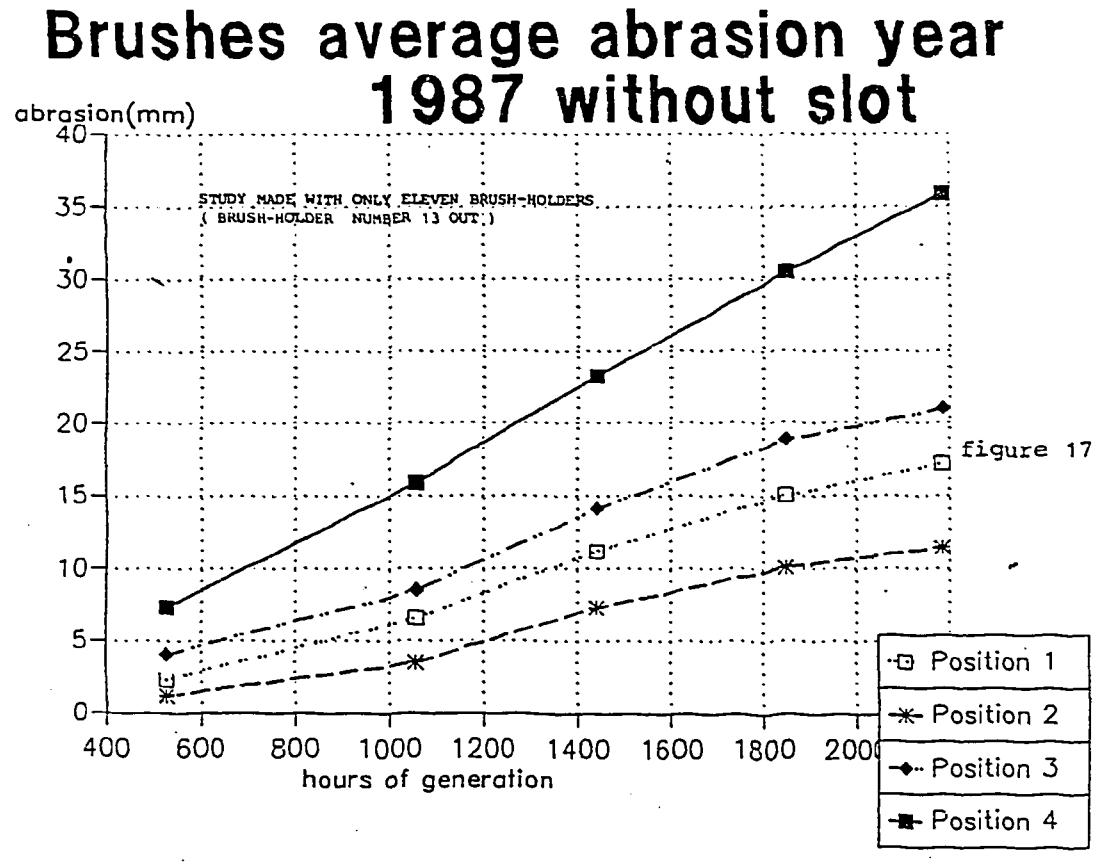


figure 17

POSITIVE COLLECTOR RING POSITION AND NEGATIVE COLLECTOR RING POSITION IN THE STUDY IN YEAR: 1987

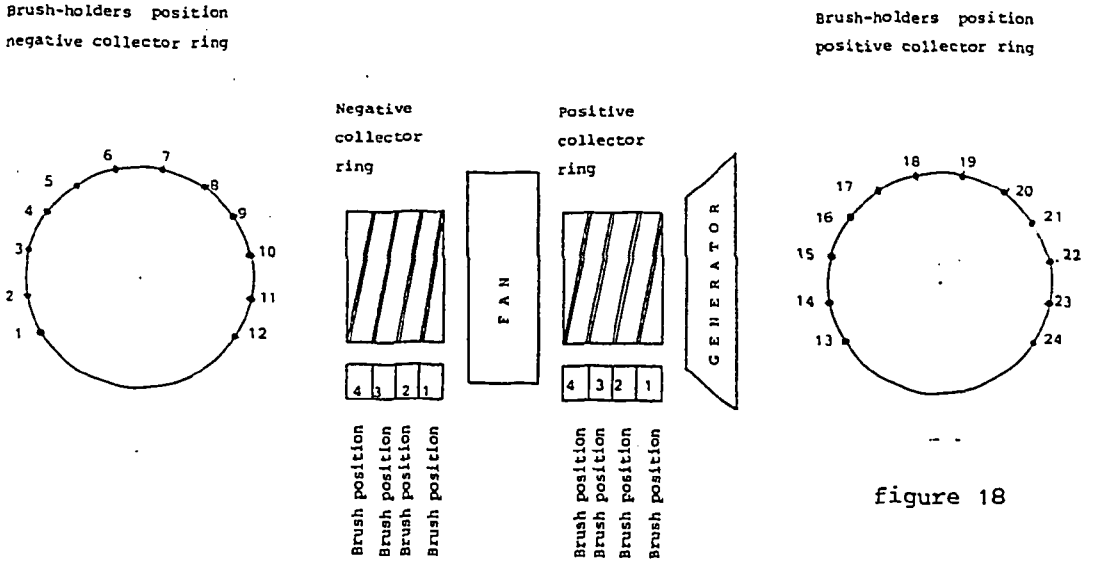


figure 18

Abrasion brushes for 1000 hours of generation (surface brush without slot)- Year 1986

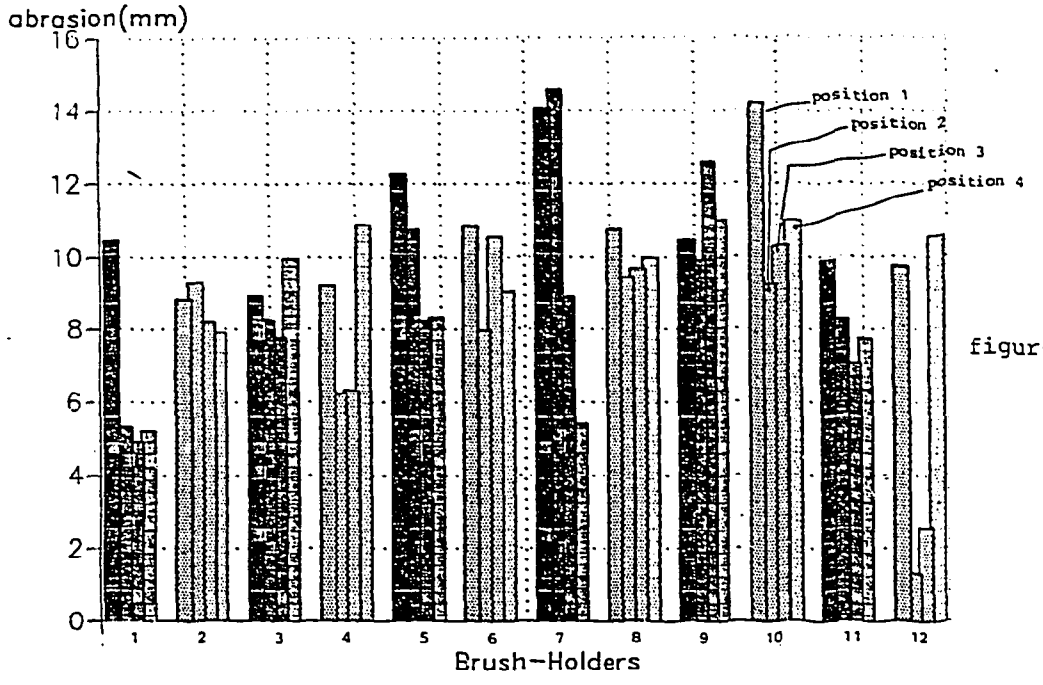


figure 19

Abrasion brushes for 1000 hours of generation (surface brush without slot)- Year 1987 brush-holder 13 out

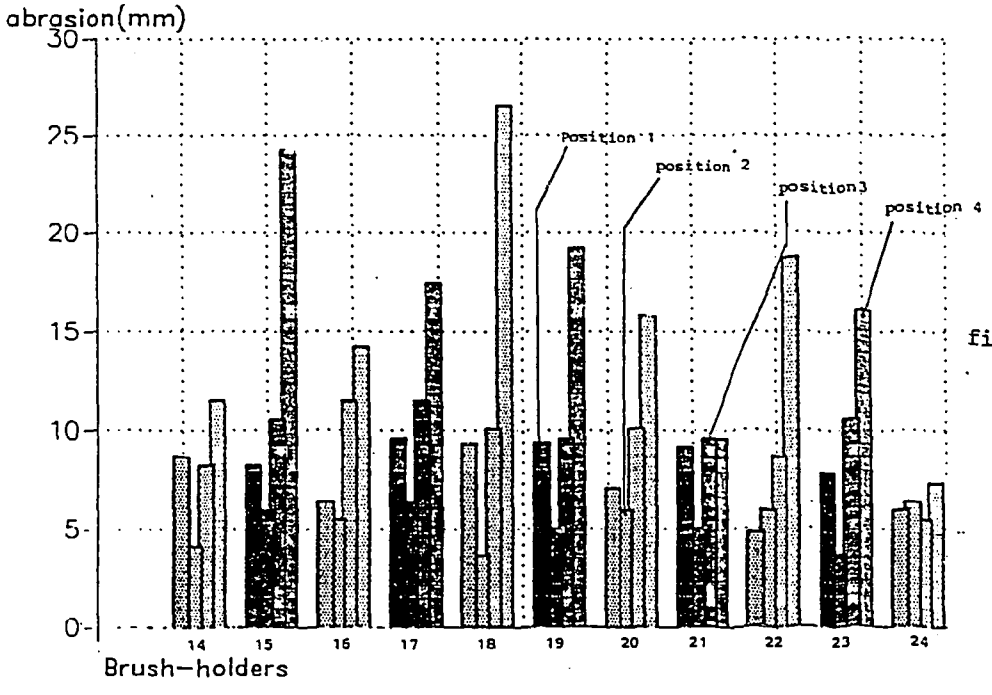


figure 20

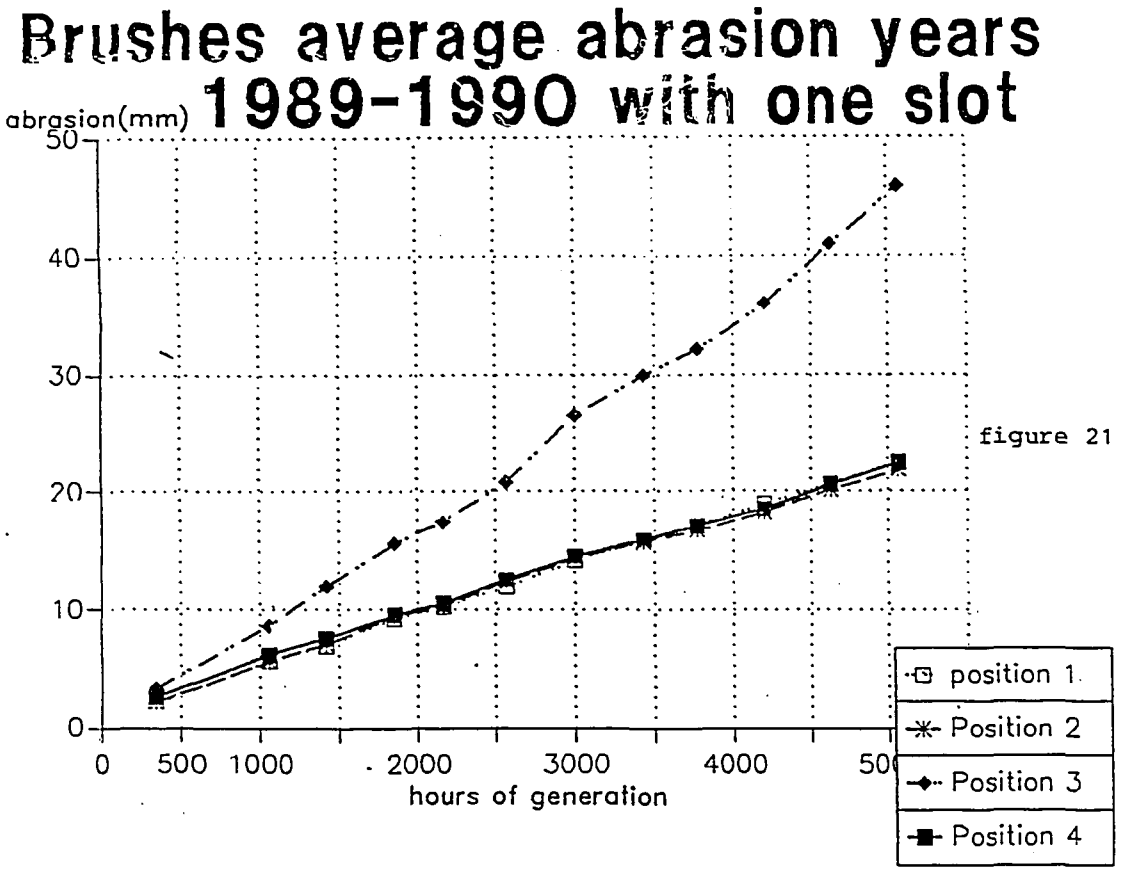


figure 21

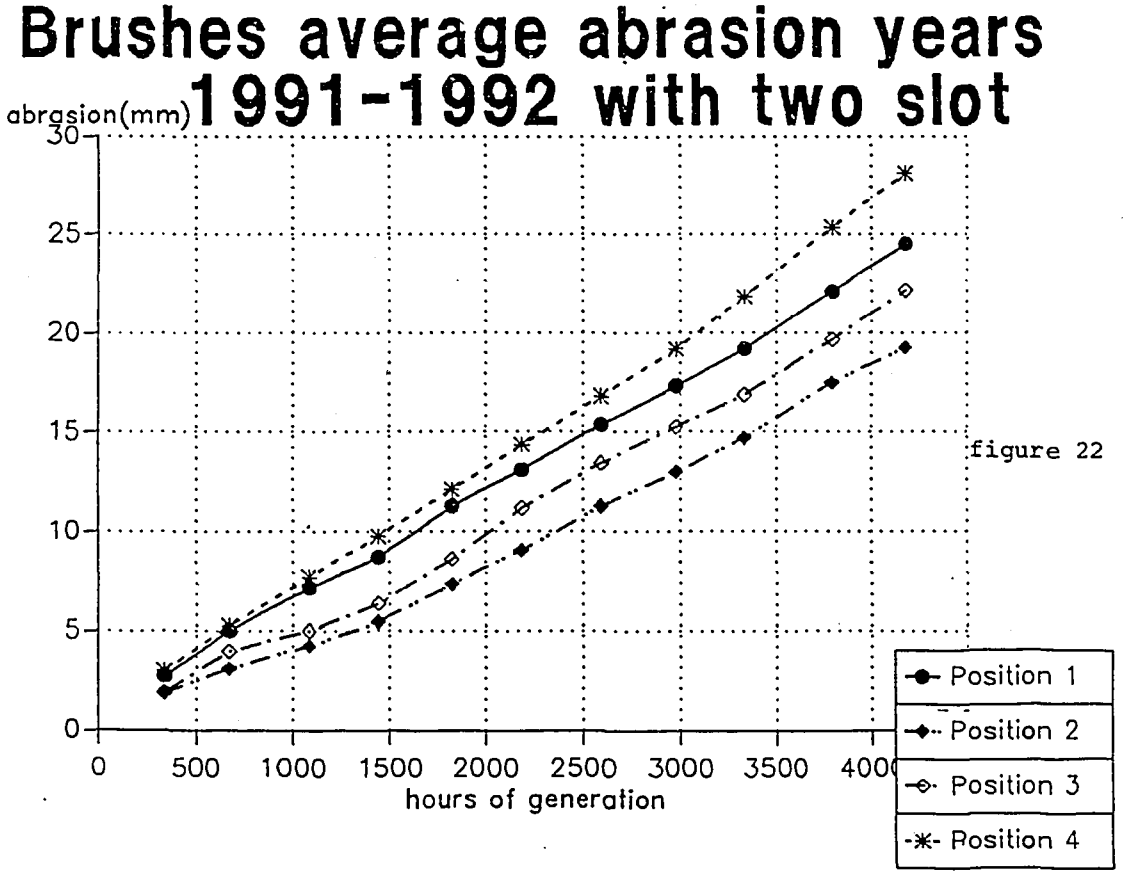


figure 22

Abrasion brushes for 1000 hours of generation (surface brush with one slot)
Years 1989-1990

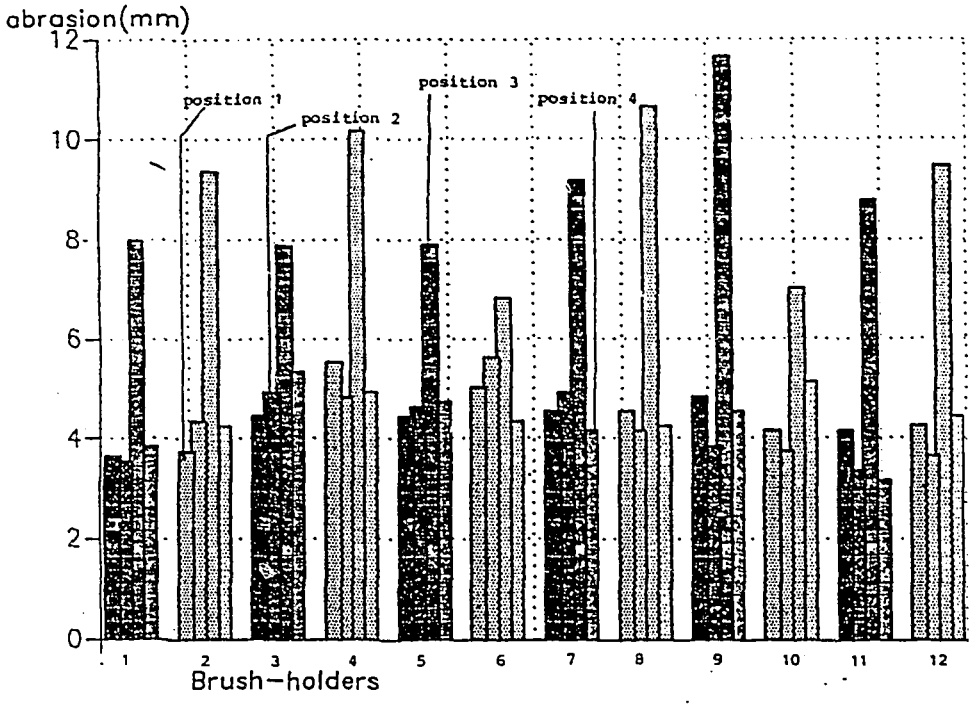


figure 23

Abrasion brushes for 1000 hours of generation (surface brush with two slot)
Years 1991-1992

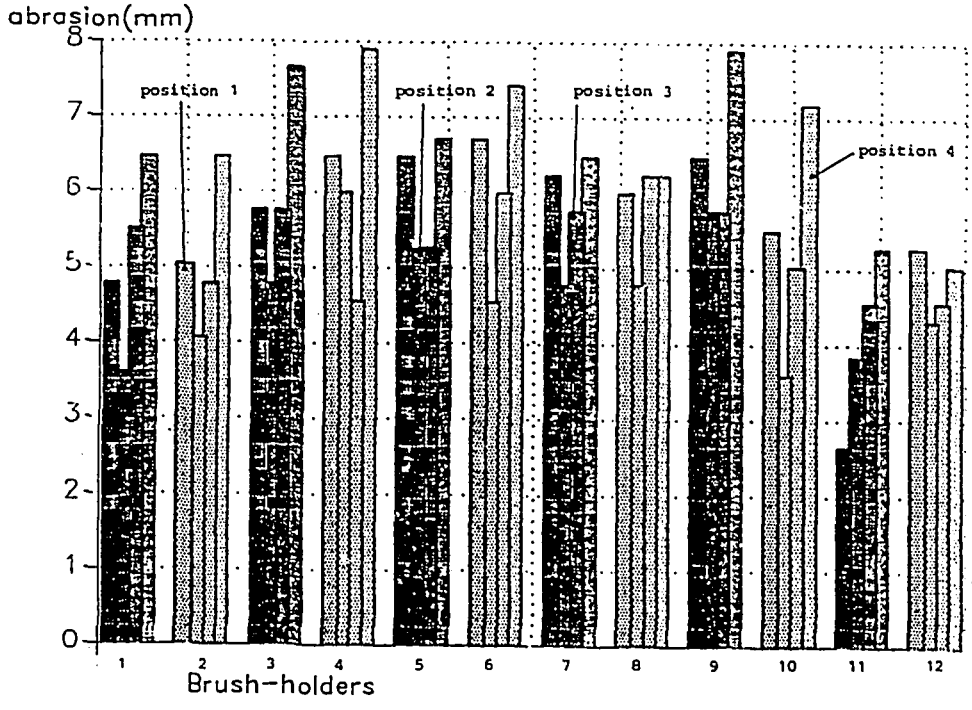


figure 24

CONCLUSION:"Future abrasion brushes" (Position 1,Position 2 and Position 4 with one surface slot, Position 3 with two surface slot).

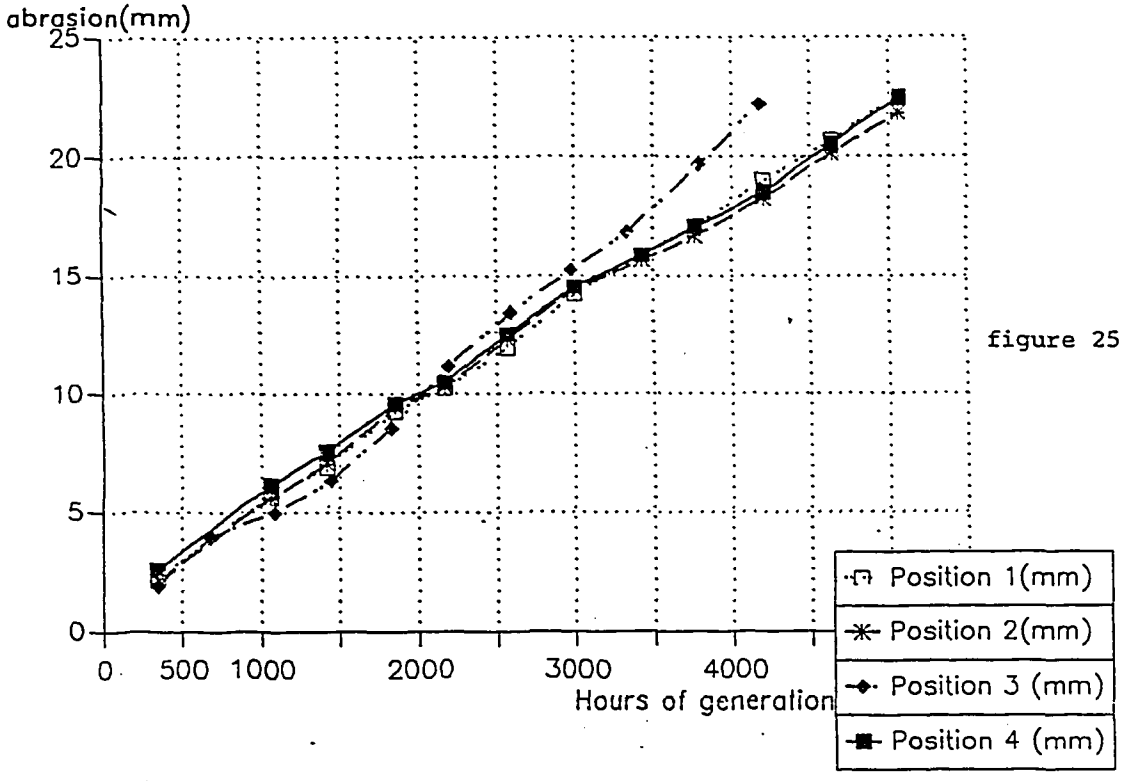


figure 25

CONCLUSION:"Future abrasion brushes" (Position 1,Position 2 and Position 4 with one surface slot, Position 3 with two surface slot).

Hours of generation	Position 4 (mm)	Position 3 (mm)	Position 2(mm)	Position 1(mm)
336.00	2.58	1.93	2.13	2.25
672.00	.	4.00	.	.
1,056.00	6.17	.	5.63	5.67
1,080.00	.	5.00	.	.
1,416.00	7.58	.	7.04	6.92
1,440.00	.	6.38	.	.
1,824.00	.	8.58	.	.
1,848.00	9.58	.	9.46	9.25
2,160.00	10.50	.	10.29	10.25
2,184.00	.	11.17	.	.
2,568.00	12.50	.	12.29	11.92
2,592.00	.	13.42	.	.
2,976.00	.	15.25	.	.
3,000.00	14.50	.	14.38	14.17
3,336.00	.	16.83	.	.
3,432.00	15.88	.	15.67	15.88
3,768.00	17.04	.	16.67	17.08
3,792.00	.	19.66	.	.
4,176.00	.	22.16	.	.
4,200.00	18.50	.	18.25	18.96
4,632.00	20.54	.	20.13	20.67
5,064.00	22.42	.	21.79	22.50

TOTAL AVERAGE ABRASION,years:"1986","1987","1989/90","1991/92"
FUTURE ABRASION (Positions 1-2-3 with one slot,Position 3 with two)

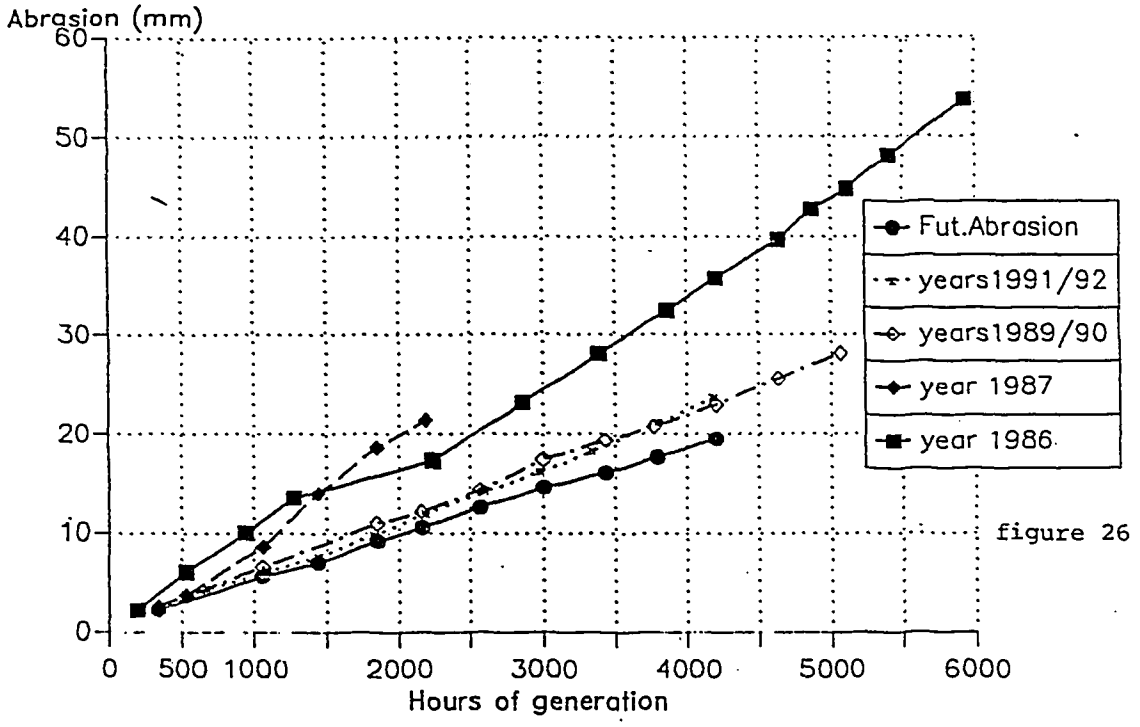


figure 26

TOTAL AVERAGE ABRASION,years:"1986","1987","1989/90","1991/92"
FUTURE ABRASION (Positions 1-2-3 with one slot,Position 3 with two)

Hours of generation	year 1986	year 1987	years1989/90	years1991/92	Fut.Abrasion
192.00	2.20				
336.00			2.57	2.32	2.22
528.00	6.06	3.73			
672.00				4.33	
936.00	10.02				
1,056.00		8.60	6.53		5.62
1,080.00				6.02	
1,272.00	13.54				
1,440.00		13.97		7.56	6.98
1,824.00				9.81	
1,848.00		18.59	10.97		9.22
2,160.00			12.11		10.55
2,184.00		21.38		11.90	
2,232.00	17.26				
2,568.00			14.36		12.53
2,592.00				14.19	
2,856.00	23.09				
2,976.00				16.17	
3,000.00			17.38		14.57
3,336.00				18.12	
3,384.00	28.07				
3,432.00			19.33		16.07
3,768.00			20.74		
3,792.00				21.12	17.61
3,864.00	32.43				
4,176.00				23.50	
4,200.00	35.71		22.92		19.47
4,632.00	39.69		25.56		
4,872.00	42.69				
5,064.00			28.13		
5,112.00	44.80				
5,400.00	48.02				
5,928.00	53.59				

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MAINTENANCE APPLICATIONS OF THE THERMAL SPRAY PROCESS

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Ontario Hydro, NOWD

Tiverton, Ontario

ABSTRACT

This paper will offer a brief introduction into the thermal spray process followed by a description of the administration and application of spray coatings to conventional and nuclear components/parts for repair or corrosion coatings. This will include a practical discussion of equipment requirements, application methods, operator qualification, coatings used, finishing techniques and documentation for various components.

MAINTENANCE APPLICATIONS OF THE THERMAL SPRAY PROCESS

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Tiverton, Ontario

INTRODUCTION

The Production Support Department (PSD), part of the Nuclear Operations Western Division (NOWD), Bruce Nuclear Power Development, provides a repair/overhaul service offered through a number of successful work programs. In addition to the Thermal Spray work program these include tube welding, portable stress relief, heat treatment, overhead doors, elevators, calibration lab, cranes, valve repair and thermography. The programs are run through a work program support group which administers and provides technical support as required.

The Thermal Spray work program was started in the mid eighties using a combustion flame spray system. Additional new equipment purchases, a wire arc spray system, enable a variety of material applications.

FUNDAMENTALS (1)

Thermal Spraying

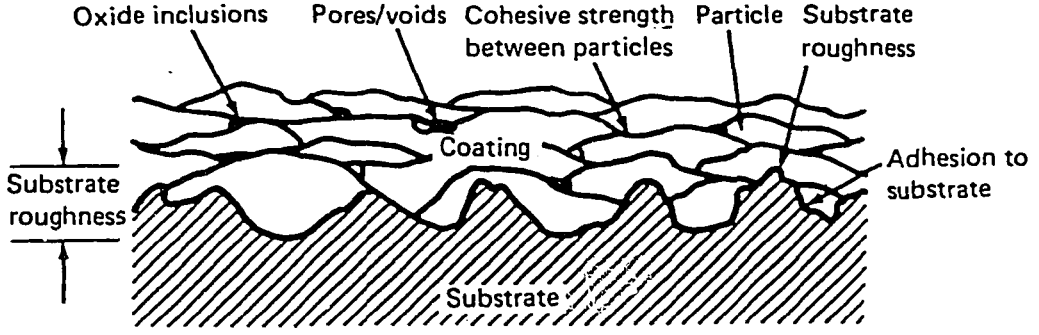
Thermal Spraying is a group of processes in which finely divided metallic or nonmetallic surfacing materials are deposited in a molten or semimolten condition on a prepared substrate to form a spray deposit. The processes are flame spray, wire arc spray and plasma arc spray. The spray material may be in the form of wire, powder or rod.

The thermal spraying gun generates the necessary heat by using combustion gases or an electric arc. As the materials are heated, they change to a plastic or molten state, and are accelerated by a compressed gas. The confined stream of particles is conveyed to the substrate. The particles strike the surface, flatten and form thin platelets (splats) that conform and adhere to the irregularities of the prepared surface and to each other. As the sprayed particles impinge upon the substrate, they cool and build up, particle by particle, into a lamellar structure, to form the coating.

The deposited coating structure and chemistry of coating sprayed in ambient air are different from those of the same material in the wrought or pre-sprayed form (Fig. 1). The differences are due to the incremental nature of the coatings, the reaction with process gases, and the atmosphere surrounding the material while

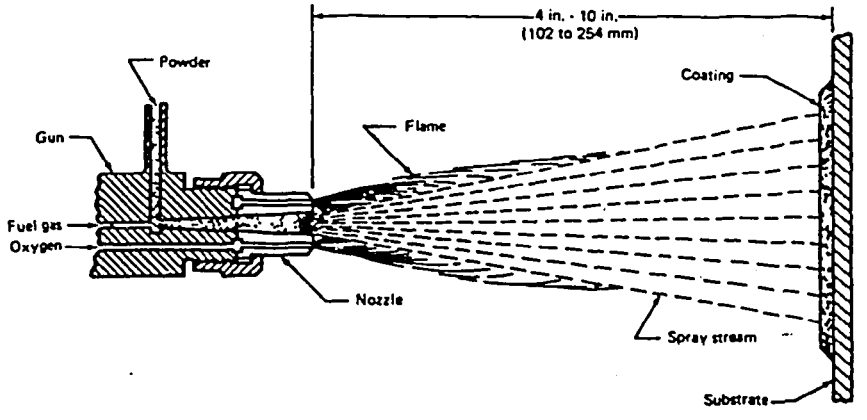
in the molten state; i.e. Oxides of the applied material are formed and become part of the coating, metal coatings tend to be porous and brittle and have a hardness different from that of the original coating. However, the as-sprayed structure of the coatings will be similar in their lamellar nature, exhibiting varying characteristics, depending on the particular spraying process used, process parameters, technique employed, and material applied.

Fig.1
Typical coating cross section to illustrate lamellar structure of oxides and inclusions (1)



Flame Spraying. Flame spraying is the process in which coatings are sprayed from rod, wire or powder stock. The material is delivered to an oxy-fuel flame where it is heated to a molten or semi-molten state. The flame is surrounded with a stream of compressed gas used to atomize the molten metal and propel it onto the substrate, Fig. 2. On impact the adhesive bond that

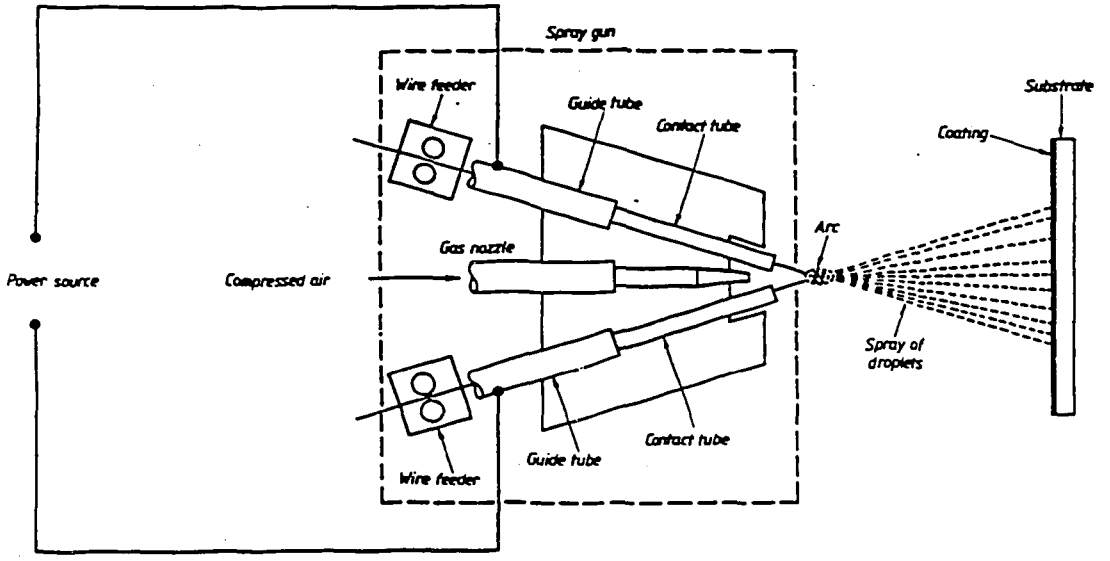
Fig. 2
Cross section of a powder flame spray gun (1)



occurs is generally mechanical in nature,in which the particles interlock with the roughened surface and/or other deposited particles.

Wire Arc Spray Equipment. Wire arc spraying is a process in which two consumable wire electrodes, that are first insulated from each other, automatically advance to meet at a point in an atomizing gas stream. A potential difference is applied across the wires which initiates an arc that melts the tips of the wire electrodes. An atomizing gas is directed across the arc zone, shearing off the molten droplets which are propelled onto the substrate. On impact, the bond that occurs is generally mechanical in nature. Fig. 3 shows a cross section of a wire arc spray gun.

Fig. 3
Schematic of a wire arc spray gun (4)



Substrate Preparation

Surface preparation is the most critical step in a thermal spray operation. Coating adhesion is directly related to the cleanliness and the roughness of the substrate surface.

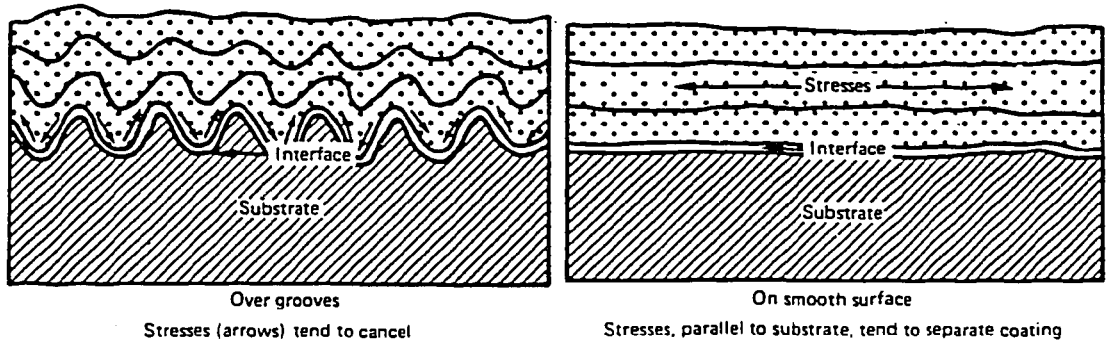
Preliminary machining or undercutting is carried out, if required, to remove surface defects and provide a space for the thermal spray deposit, primarily where the reclaimed surface is a seat, housing, or location surface. Three main methods are used by the PSD to give maximum coating adhesion:

Grit Blasting. Abrasive grit blasting is the most commonly used roughening technique. For the majority of small items which can fit into a hand blasting booth, #24 Aluminum oxide grit material is used. Suitable masking is used to protect areas that can be damaged by the blast.

For larger items and those with a base material hardness which exceed 37 Rockwell "C", it is necessary to use bond coat preparation, see section following.

Rough Threading. Rough cutting consists of cutting deep, closely spaced striations to produce a torn jagged thread form. This grooving helps restrict the shrinkage stresses, increase the bond surface area, and produce folds in the layers of the coating to limit internal stresses, Fig. 4.

Fig. 4
Sprayed metal (1)



Bond Coat Preparation. Certain materials adhere to clean, smooth surfaces forming strong coating-to-substrate bonds. A thin layer of bonding material serves as an anchoring subcoat for subsequently applied coating layers. Grit blasting with iron grit thoroughly cleans the surface and provides a satisfactory base.

EQUIPMENT & PROCEDURES

Thermal Spray Equipment

Flame Spray Equipment. The PSD uses the Metco 6P-II Flamespray System. Powder is fed to the gun from a powder feed unit which provides constant feed and feed monitoring capability. Oxy-acetylene gas is used for combustion to melt the powder, which is

carried by the flame onto the substrate.

Wire Arc Spray Equipment. The PSD uses the Hobart-Tafa Model 8830,200 amp, Arc Spray System. Spray wire is pulled from the feed rolls by wire-drive rollers in the spray gun. The control unit sequences the power and air supply on and off through the spray gun trigger, Fig. 3.

Equipment Optional Features. Optional features have been purchased to improve the versatility of the system.

1) Autofeed. Permits operation of the torch up to 9 m from the power supply. Extensions up to 15 m are available.

2) Inside Diameter Gun. An add on feature that allows spraying into pipes and small spaces only 75 mm in diameter and 1 m long. Extensions up to 2.5 m long are available.

Advantages/Disadvantages of Flame Spray vs Wire Arc Spray

1) Arc spray gun has fewer process variables to control resulting in more reproducible coatings requiring less operator judgement.

2) Less energy is consumed with the arc spray gun, approx 1/9 that of a flame spray system..

3) A higher particle temperature is achieved with the wire arc with complete melting.

4) Wire arc can only be used with materials that can conduct electricity and be drawn into wire form. Flame spray can be used with metals and alloys in the form of powder, cord, or wire, and ceramics as power, cord or rod provided the material,does not sublime and melts at a temperature less than 2760°C.

5) Cost to process material into powder form for flame spray is much more expensive than processing the same material into wire form.

6) Wire arc is generally considered to be a "dirtier" spray operation. Compressed air used to break up the molten material tends to create more small fines than the injection of the powder into a flame.

Finishing Equipment

The accepted practices and techniques used to grind, machine and polish materials in their wrought form do not apply to the same

materials when sprayed. Spray coatings are composed of well defined particles and have poor thermal conductivity compared to the same material in wrought form. Heat transfer away from the point of grinding is slow. The bond between the particles is primarily mechanical, therefore individual particles can pull out if cutting pressure is excessive.

Turning. At the PSD, the preferred method for initial material removal is turning. Turning of sprayed materials is very similar to turning a cast material. Carbide tipped tools recommended for grey cast iron give good results.

Cuts are generally light, not exceeding 0.13 mm, with traverse speeds between 0.10 and .015 mm per revolution. Overspray material is removed by machining outward from the spray area. After a few cuts the overspray will generally fall away from the masking compound.

Grinding. Generally all sprayed materials can be ground and for those materials which cannot be turned, grinding is utilized. The Metco 136F chromium oxide powder, used on the repair of PHT pump sleeves with macrohardness of 65 Rockwell "C", is the main spray material used by the PSD requiring grinding.

A tool post grinder with a 150 grit diamond wheel is used to rough grind to within 0.13mm of final diameter, followed by honing with diamond stone and diamond paste.

Lapping/Superfinishing. A Supfina superfinishing machine is used in the final step to improve the surface finish. As the part rotates, the superfinish abrasive stone oscillates and moves across the part. The lubricant is a determining factor in the amount of cutting accomplished by the abrasive. As viscosity is increased, cutting action is reduced producing finer finishes with minimal stock removal. Finishes to 8 RMS can be achieved on some spray coatings.

Handling Equipment

A variety of handling equipment can be used in conjunction with thermal spraying to provide process mechanization and help consistently reproduce quality coatings. Manipulation of the part rather than the spray gun produces higher quality coatings and is generally easier to achieve, due to the gun connections and attachments.

Lathe. For smaller cylindrical parts, i.e. valve stems, pump seal sleeves & shafts, a lathe can provide the rotary motion required, with a variety of speeds.

Turntable/Positioner. Large parts, i.e. heat exchanger channels, require a rotary table or positioner capable of handling the size and weight. The choice of one over the other depends on operator accessibility and/or shop ability to set up for semiautomatic spray gun manipulation.

System Automation. The use of a simple manipulator arm for spray gun handling allows for vertical or horizontal tracking. In conjunction with a positioner a pattern can be formed on a flat surface. The addition of a 'Cat' track allows for additional contour spraying.

Ventilation

Proper ventilation is required while performing grit blast and thermal spray operations. Factors to consider are the volume of space to be vented, evolution of hazardous fumes, gases or dust, heat generated by the spray process and the presence of volatile solvents. All vented air should be filtered/cleaned to meet industrial standards as set out and approved by the Ministry of the Environment or other local authorities.

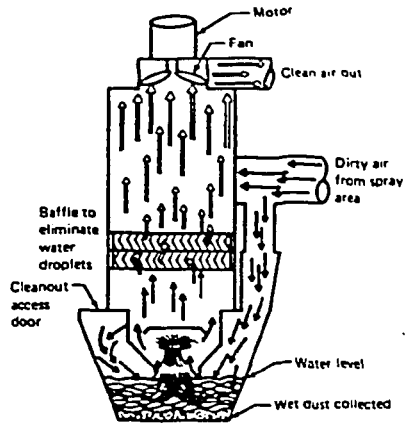
Industry standard type hand blast booths can be used for the majority of items requiring blasting, i.e valve stems, pump shafts and seal sleeves. Large items may require a walk-in type spray booth.

Thermal spray operations preformed on a lathe should be equipped with an exhaust hood. This hood can be mounted on the carriage to allow travel with the gun, or be permanently installed, and sized to enclose the repair items. Capture velocity at the face of the hood opening should be 1 m/sec to 1.5 m/sec. The spray equipment is operated within the face of the hood and directed into it.

Large repair items require a spray booth or room. The booth can be sized to totally enclose the repair item, rotary positioner and manipulator arm. Proper lighting along with a dust collection /ventilation system is required.

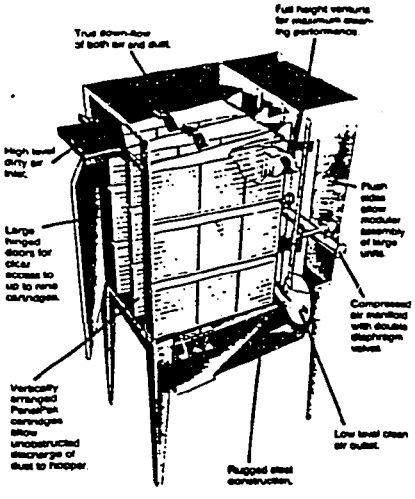
Both dry and wet dust collection systems are available for use with spray ventilation. In the past, dry filter systems were not recommended due to the volume of dust generated, the large content of fines and peculiar dust properties tended to clog the filter surfaces. The PSD uses a rotocyclone type of wet collector (Fig. 5). Specially designed passages mix the dust laden air with water, ensuring proper dust wetting and collection. Typical water wash systems are 70 to 75% efficient. Due to tightening requirements for environmental emissions PSD is investigating the new types of dry filter media being introduced in the last few years. These dry systems utilize a compressed air manifold to back-pressure and clean the filter

Fig. 5
Rotocyclone wet collector system (1)

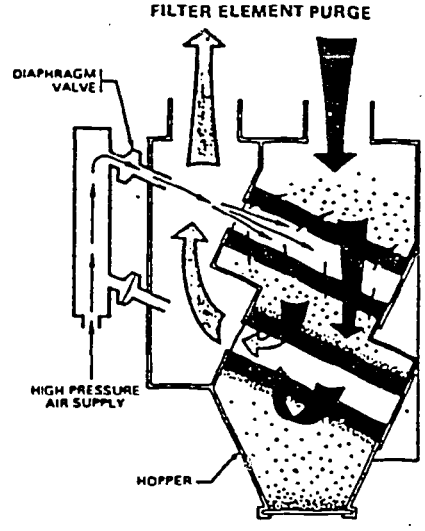


elements as the dust cake forms (Fig. 6). System efficiencies can reach 99.9+%. Dry filter systems tend to be 2 to 3 times more expensive than a comparably sized wet system.

Fig. 6
Dry cartridge collectors



AAF PulsePak II



Metco Dry Collector

OPERATOR QUALIFICATION (1)

The operator is relied upon to produce a quality coating. This applies not only to the deposition process but also to the prepatory process, and ultimately, the end product.

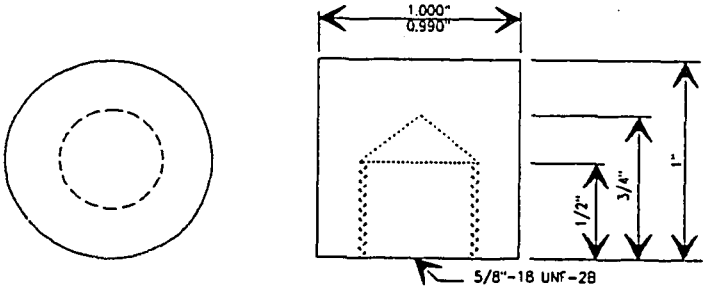
Operators should have a working knowledge of basic safety, equipment and tool handling, and have a good familiarity with manuals and instructions. Additional training in the thermal spray process should include:

- Process description
- Safety practices
- Use of gun and control equipment
- Self study (reading/hands-on)
- Equipment construction and assembly
- Trouble shooting.

There is no satisfactory None Destructive Examination (NDE) method to test the bond strength of thermal spray coatings, each step in the repair process must be controlled to ensure standard conditions for the prepared surface, as sprayed coating appearance, and finish. As a result, thermal spray coupons are tested to determine bond strength acceptance criteria, and qualifications, for thermal spray operators.

The standard test for thermal spray coatings is a tensile test set out in the American Society for Testing Materials (ASTM) Specification C633 Standard Method for 'Adhesive or Cohesive Strength of Flame-Sprayed Coatings'. In this test a 'button ' coupon (Fig. 7) is prepared and sprayed. A matching button is

Fig. 7
Spray Button Coupon



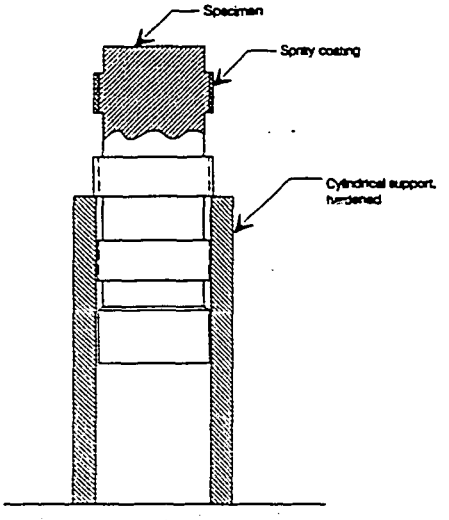
then bonded with adhesive to the sprayed button and the assembly is tensile loaded until coating failure. A target bond strength of 70% of the manufacturers claimed ideal bond strength, obtained

under controlled laboratory spraying, has been set for the Production Support thermal spray operators.

An additional European test is available for the Testing of Thermally Sprayed Materials, DIN 50 161 'Determination of the Adhesive Shear Strength in Shearing Test'. The shearing test is used to determine the adhesive shear strength of thermally sprayed metallic coats on metallic base material under a shearing stress on the adhesion face.

A cylindrical test specimen is prepared and sprayed. Rings are cut into the specimen which are then sheared using a hardened cylindrical support (Fig. 8). This test can be used to monitor metal spraying operations or to assess the effect of the base material and the sprayed-on material, the pretreatment of the surface of the workpiece and of the spraying conditions on the adhesive strength in shear of the sprayed-on coat.

Fig. 8
Cylindrical support with test specimen, the lowest sprayed on ring of which has already been sheared off



COATINGS/APPLICATIONS

Thermal spraying is deposited on machine components to reclaim worn or mis-machined surfaces, and to impart desirable surface characteristics such as wear resistance and improve corrosion resistance.

The suitability of the thermal spray process for any particular application may be determined according to the following

fundamental principles (2):

1 No strength is imparted to the base material by the sprayed metal deposit. It is essential that the component to be sprayed, in its prepared form, be able to withstand any mechanical loading to which it will be subjected in service.

2 If the area to be sprayed on a component or any section of the total area is subject to shear loading in service, then it is not a suitable subject; i.e., gear teeth, splines, threads.

3 A point loading with line contact on a metal sprayed deposit will eventually spread the deposit causing detachment; i.e., needle and roller bearing seats.

Subject to the above, almost any metal or alloy surface may be sprayed. Typical applications are:

1 Seats & Housings. These are usually bearing seats, gear and pinion seats, etc. The bearings or other components may be press fits, interference fits or sliding fits.

2 Location Surfaces.

3 Bearing Surfaces. The selection of the material to be sprayed will be governed by the type of bearing material in contact with the sprayed surface.

4 Bushings.

5 Gland & Oil Seal Contact Areas.

6 Corrosion Resistant Coatings.

A wide variety of coatings are available to meet the ever-widening range of applications. These include coatings for wear resistance, heat and oxidation resistance, atmosphere and immersion corrosion resistance, electrical conductivity or resistivity, restoration of dimension for salvage or build-up, and for chemical control resistance.

The PSD carries a number of standard coatings to cover the majority of the repair requests which come to the facility. These include:

1 Metco 442 Self Bonding "Stainless" Composite Powder. It produces a hard stainless type coating with excellent wear resistance and very good corrosion resistance properties for wear resistance and hard bearing applications. With a Rockwell "C" hardness of 35 it is used in the repair of 400 series stainless steel valve stems, small pump seal sleeves and as a general repair

build-up material. Coating thickness is limited to 2.5mm.

2 Metco 444 Self Bonding "Stainless" Composite Powder. It produces a machinable stainless type coating with good wear and excellent corrosion resistance properties for hard bearing applications. With a Rockwell "B" hardness of 80 it is used primarily in the repair of 300 series stainless steel valve stems. Coatings to 7.6 mm thick can be applied.

3 Metco 136 Chromium Oxide-silica Composite Powder. It was designed to produce coatings which are hard, dense and extremely wear resistant. This material has a Rockwell "C" of 65. Finishing is done with a diamond wheel grinder and diamond paste lapping. Due to finishing costs, to date the PSD has used it exclusively to repair the Primary Heat Transfer pump seal sleeves. These sleeves cost approx. $16k each to purchase. Repair costs are approx. $5k to refurbish.

4 Hobart-Tafa 60T, 13% Chrome Steel Wire. This is the most widely used reclamation wire because of its low shrink. Typical hardness is 40 to 43 Rockwell "C". It is recommended when a hard coating is desired, preferably requiring some corrosion resistance, because of its durable qualities -- high strength, high elongation and low shrink. Coating thickness to 3.8mm can be applied. It is used as the primary repair material for valve stems and general pump sleeves.

5 Hobart-Tafa 80T, 18/8 Stainless Wire. This stainless has a typical hardness of 93 to 97 Rockwell "B" and is used where maximum corrosion resistance is required. The deposits have a high shrinkage and should not be used for coating thicknesses above 2mm. Where greater thicknesses are required, it is better to first spray 13% chrome steel and then finish with the higher shrinkage 18/8 material.

6 Hobart-Tafa 88T, UltraMachinable Stainless Wire. This is a specially developed stainless steel with a hardness of 29 Rockwell "C". It has very high corrosion resistance and excellent machinability. Because of high shrinkage, it should not be used for coatings over 2mm. Where greater thicknesses are required, it is advisable to first spray with 13% chrome steel and finish with the higher shrinkage 88T material. This material is applied in a 0.5mm coating on heat exchanger channels and heads for the Bruce Heavy Water Plant. It is used for corrosion protection on the process side of the exchangers, which see hydrogen sulphide.

A number of other materials are available from the manufacturer including copper, 80/20 nickel chrome, nickel, brass, monel,

carbon steels, aluminum coatings, and various other specialty coatings.

We are also investigating the use of our Metco flame spray system for application of Low Temperature Plastics (thermoplastic). Applications could include enviromental corrosion coatings, pipe coatings, exterior industrial coatings, and architectural structures.

DOCUMENTATION

All items received at the PSD for thermal spray repair/refurbishment are inspected by technical to determine extent of damage and coating material requirements. A Thermal Spray Specification and Record Sheet is filled out outlining the job description, material specification (base & coating), base preparation, and final coating finish.

Nondestructive examination technique is specified. This is typically a liquid dye penetrant test preformed after machining, prior to rough threading or blasting, to ensure all defects are removed. The operator records the spray parameters used.

For nuclear grade items additional information is included in the final documentation. A Certified Material Test Report (CMTR) for the coating material used and the thermal spray material qualification sheet, which shows the tensile test results for that particular batch of material.

SAFETY (1)

The general requirements for the protection of thermal spray operators are the same as for welders, with special attention to respiratory and ear protection. As well local, provincial and federal health standards should be thoroughly understood for proper compliance.

Respiratory Protection

Most spray operations require that a properly approved respiratory protective device be used by the operator. When spraying in the open or in a well ventilated work area, additional respiratory protection may not be necessary. A mechanical filter respirator, approved for use against dust and metal fumes, may be required. Spraying in a confined or semi-confined area requires an air supplied respirator.

Ear Protection

The thermal spray process can generate excessive noise levels. It

is mandatory under the Occupational Health and Safety Act to limit employee exposure to these noise levels through the use of hearing protection or by limiting the exposure time within regulatory limits.

Typical arc spray noise levels run to 116 dBA and flame spray operations to 110 dBA.

Thermal Spray Equipment Operation

Wire arc spray uses high voltage and amperages not found in other thermal spray equipment. Operators should be instructed and trained by qualified personnel in the operation of the equipment before use. Familiarity with the operating and safety recommendations in the instruction manuals, and at the same time observing standard, safety precautions taken with electrical equipment, is imperative.

CONCLUSION

In recent years the thermal spray process has become widely accepted throughout industry through broad range utilization in maintenance as a reliable means of repairing worn parts. Superior coating properties can extend the life of a component, providing an economical alternative to component replacement.

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CA9500145

LEAK SEALING ON ANCILLARY COOLING CIRCUITS OF CANDU REACTORS

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ABSTRACT

Initially developed to cure problems in the cooling systems of the pre-stressed concrete pressure vessels of UK reactors, a sealant has been used to repair leaking bioshield pipework on six CANDU reactors.

This paper describes the evolution of the sealants used, the qualification and testing programme and their application to CANDU reactor systems.

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LEAK SEALING ON ANCILLARY COOLING CIRCUITS OF CANDU REACTORS

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INTRODUCTION

This paper discusses the remote plugging of leaks in inaccessible pipework with main reference to small leaks which frequently appear in ancillary cooling water circuits of nuclear reactors.

In themselves, and in the short term, such small leaks (say 1 mm effective diameter giving a leak rate of 48 litres per hour at a system pressure of 200 kPa) do not represent a safety hazard. But a nuclear reactor represents a major capital investment and these leaks initially no more than a minor inconvenience can ultimately have a significant financial impact if nothing is done. The leaks may

- cause corrosion to components that are intended to be dry
- may interfere with essential instrumentation
- if left unsealed grow and challenge the make-up water plant
- lead to non radioactive cooling water finding its way into radwaste streams, giving to the cost of waste processing

THE EVOLUTION OF THE PROCESS

In 1968, during final construction and commissioning of a Magnox power station, an NNC company encountered problems with water leaks in the cooling circuit of the reactor's pre-stressed concrete pressure vessel. Typically such constructions are cooled by an array of carbon steel pipework (Figure 1) of square or round cross section pipework welded to, or situated close to, the carbon steel liner of the pressure vessel. Much of this pipework is fabricated at site prior to casting of the concrete. The water leaks into the concrete were traced to pinholes in welds in the pipework which were completely inaccessible after casting in a minimum thickness of 3.4m of concrete. These defects, about 0.1 mm effective diameter, would be barely detectable by pressure testing during fabrication and in the event were not plugged by the concrete during casting.

All available techniques for sealing such leaks remotely were reviewed and evaluated in the laboratory.

Automobile radiator sealants were found to be unsatisfactory. These proprietary preparations are near-saturated solutions of insoluble salts which seal by exuding through cracks and forming a crust on the external surface of the heat exchanger in the relative dry air flow. These sealants produced only temporary seals in wet concrete and damp, humid environments. Latex and paint emulsions were tried with some success but, as their sealing mechanism was by internal coating of pipework which impaired heat transfer and coolant flow, they were rejected. Further such coatings could flake off and impair pumps, valves and instrument lines etc. Similarly fibrous materials only produced temporary seals that were readily dislodged by pressure and flow fluctuations.

The laboratory programme discovered that application of an aqueous suspension of a refined mineral clay could seal these defects. Moreover, a detailed study of the rheology of the suspensions optimised the preparation and application techniques such that, eventually, cracks up to 0.5 mm wide could be sealed by a relatively simple process.

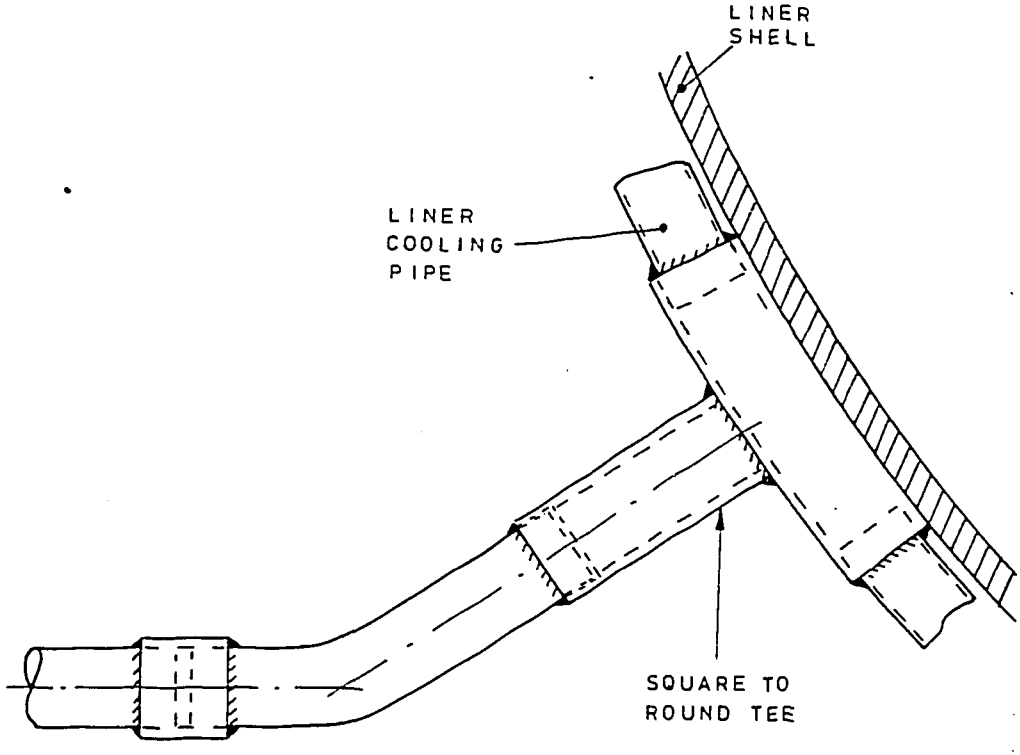

Figure 1 TYPICAL ARRANGEMENT OF LEAKING PIPEWORK

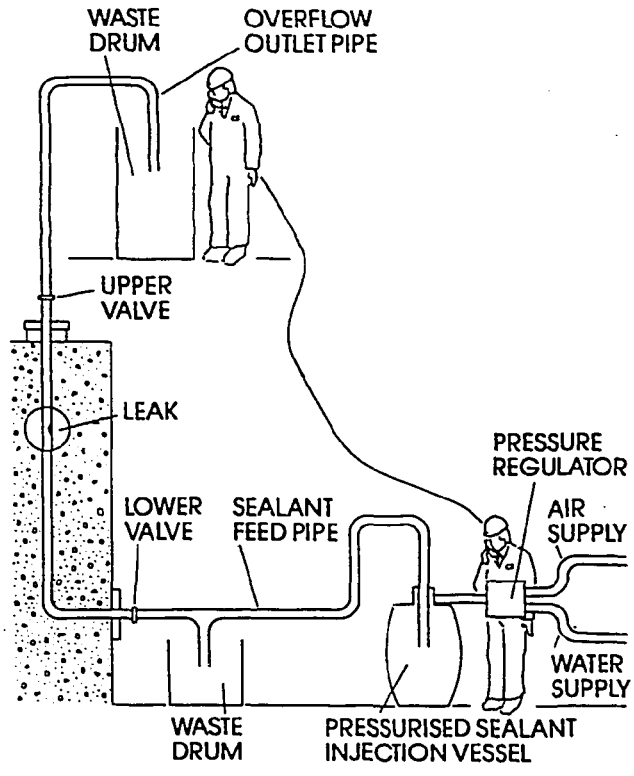

Figure 2 APPLICATION OF SEALANT (Schematic)

The formulation was mixed and applied to the water side of the isolated system where it was pressurised into the crack or hole responsible for the leak (Figure 2). The special properties of the sealant are that it staunches flow through the defect and forms a plug within the wall thickness of the pipe. The high water content of the mixture ensured that excess material was readily flushed from the pipework without coating the internal walls. Also because these flushing characteristics gave assurance that groups of pipes of various complexities could be treated, a large scale mixer blender (Figure 3) and associated filter unit were designed and manufactured so that up to 100 m^3 of mineral sealant could be applied to the entire circuits of some Advanced Gas Cooled Reactors. In principle this equipment enables reactors to be treated on-load. The seals first effected in 1968 have remained tight and have not required retreatment.

In the early 1980s, leaks began to appear in socket welds in pipework associated with pre-stressed concrete pressure vessels. The welds were subject to cyclic flexure and the

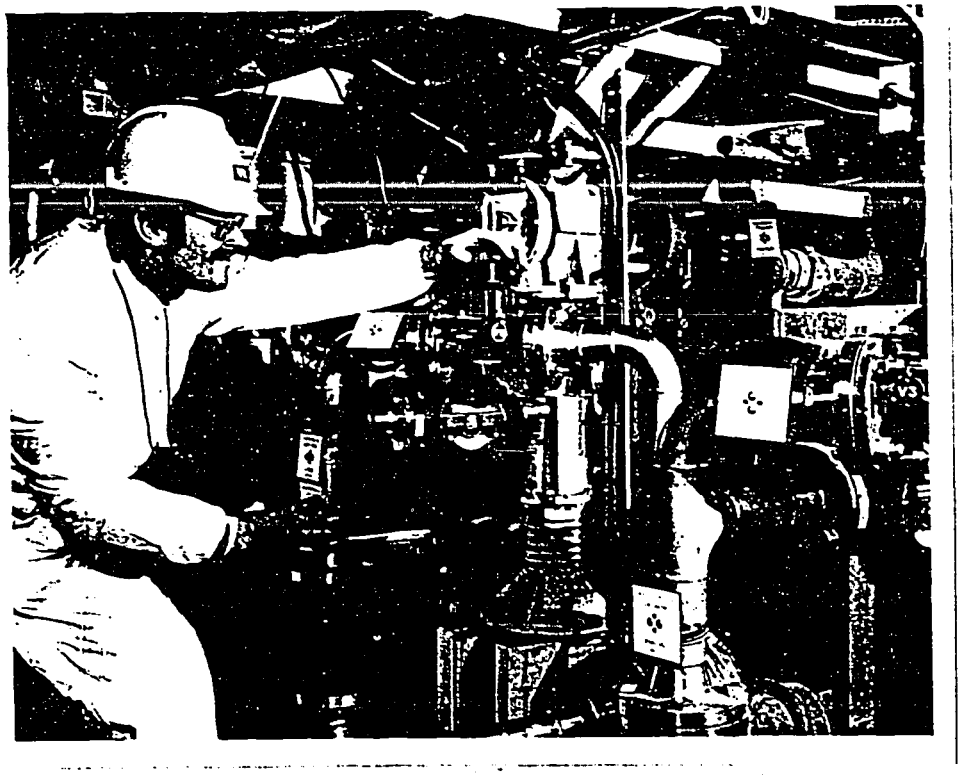

Figure 3 LARGE SCALE SEALANT MIXER/BLENDER

defect size, calculated from the leak rate, was of the order of 3 mm diameter (if present as round holes - e.g. corrosion pits). However, it was more likely that the defects were actually cracks some 15 mm long by 0.5 mm wide, which could give the same leak rate. The system here was treated using a water dispersible epoxy resin chosen for its resistance to radiation and for its adhesive properties. Again, considerable development of application skills using a specially built rig (Fig 4) demonstrated that the new water-based sealant could be safely applied to reactor pipework that had no redundancy. In 1985 this formulation was applied to a defective cooling water pipe in the prototype Thorium High Temperature Reactor, Schmehausen, Germany, which enabled it to proceed to commercial operation.

Contemporary with application of epoxy resin sealants to reactors, a development programme was on hand to combine the best features of the mineral sealant and the adhesive properties of epoxy resin. The result was the "ZORIC" range of sealants which are water based. These sealants, unlike epoxy resins, cannot set to a hard glassy mass and block pipework.

However, there was always a need to extend capabilities even further and, for the CANDU reactors at Pickering 'A' (see below) an additional, compatible radiation resistant filler was found which gave NNC the capability to seal defects considerably wider than any to date, including large round holes. Development continues to the present time.

QUALIFICATION TESTING

In addition to the testing of candidate sealants and their application methods, laboratory data have been accumulated to confirm the suitability of the sealants for reactor use.

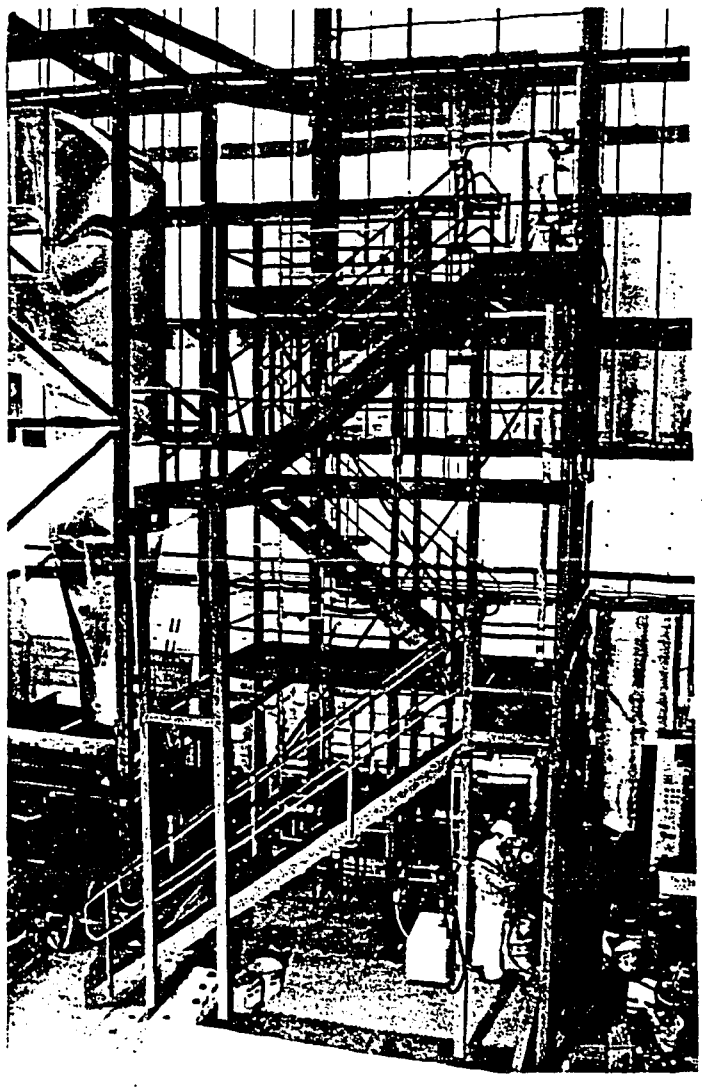

Figure 4 APPLICATION RIG

These include:

Resistance to Pressure and Pressure Cycling

These sealants were initially designed to operate in low development pressure cooling circuits at up to 1.5 MPa (g). However, laboratory tests have shown that the ZORIC formulation withstands up to 4 MPa (g) and further development have been tested beyond 10 MPa (g) without failure. For leak tightness, a seal is routinely tested at about 1.5 times the working pressure. The resin component of ZORIC was selected to ensure good adhesion and rig work has demonstrated that seals withstand rapid pressure fluctuations of ±0.5 MPa.

Temperature and Temperature Cycling

Customarily, seals have been effected in pipework designed to operate between 20 and 70°C. The ability of seals to withstand temperature beyond this is broadly in line with the expected softening characteristics of the resins but temperatures up to about 95°C do not normally present a problem. Sealing has been carried out in systems at about 85°C and the hottest seal "in the field" operates at about 120°C.

On a temperature cycling rig, test seals have withstood diurnal temperature cycles of ±25°C for more than five years.

Tensile and Flexural Properties

The elastic properties of the sealant were confirmed by conventional tensometry on cast specimens and by lap-shear tests on 12 mm x 12 mm areas of sealant bonded to stainless steel tags.

In addition a test rig has been built (Figure 5) to optimise the sealant recipe to withstand repeated flexure. Seals in simulated corrosion pits, up to 2 mm diameter, have exceeded the equivalent of a reactor lifetime of 160 bending cycles at up to 1% deflection (tensile) at deflection rates of up to 1% per second at 45°C and 0.5 MPa (g) pressure.

Radiation Properties

The formulation has been subjected to gamma irradiation trials and neutron activation analysis. Test seals in steel have withstood pressure testing after more than 650 MGy gamma irradiation under water immersion. This dose by far exceeds the expected lifetime dose to gas reactor pressure vessel concrete of about 10 MGy.

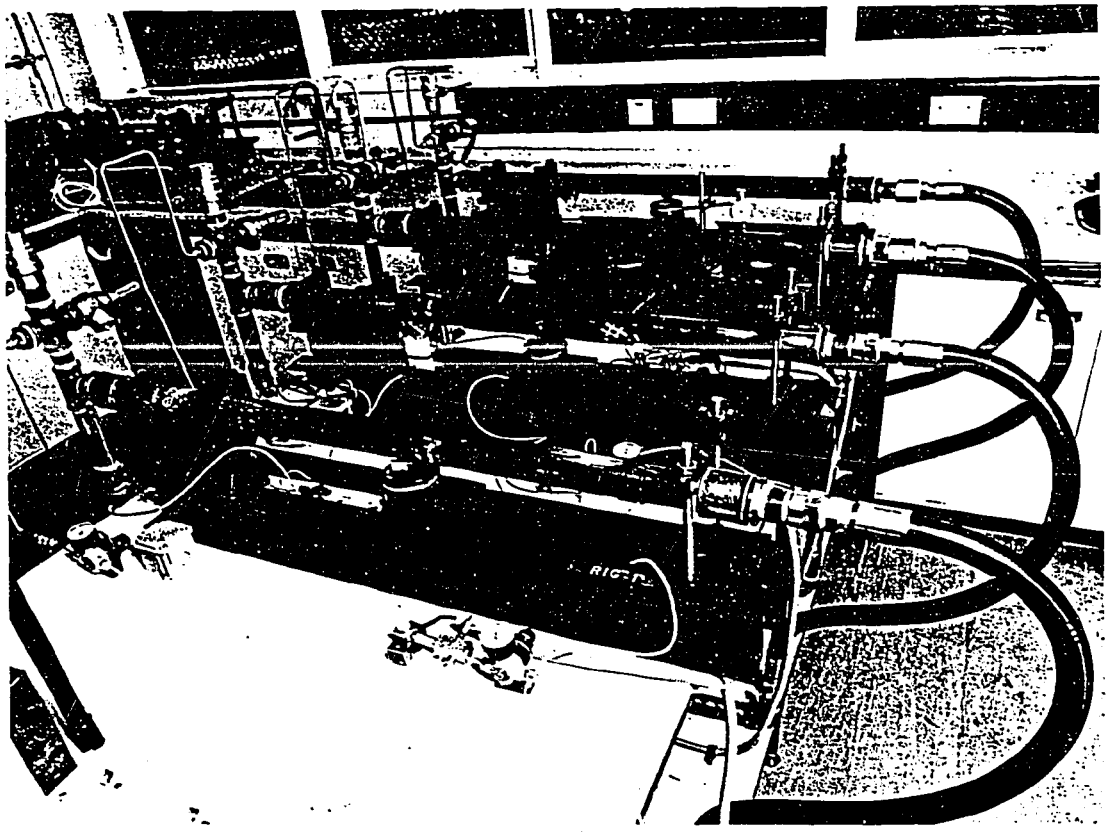

Figure 5 FLEXURAL TESTING OF SEALS

Neutron activation analysis, following exposure to a flux in a UK materials test reactor confirmed a very low persistent activation profile consistent with the chemical and mineralogical analysis of the sealant. The only truly detectable isotope was short-lived ^{24}Na resulting from the small natural sodium content of the mineral component.

Chemical Compatability

Detailed chemical analysis of the sealant and its feed stocks are routinely carried out. There is an inevitable small halogen (chloride) content by virtue of the chemical synthesis of one of the resin components. This is minimised by selection of resins to a level broadly in line with nuclear requirements (Ref 1). Heavy and low-melting point metals content are similarly evaluated and found to be very low.

Durable seals have been effected in carbon steel, stainless steels, aluminium, copper and brass and this confirms the chemical compatibility of the sealant. Seals have also been tested for their ability to withstand corrosive agents such as nitric acid, hydrazine, wet carbon dioxide and methanol.

APPLICATION TO CANDU REACTORS

The first application of the sealant to CANDU reactors was at Pickering 'A' NGS (Ref 2). All four units were suffering leaks to biological shield pipework exposed to the air filled reactor vault (Figure 6). Each reactor vault has 40 individual segments of the pipe emerging from and re-entering the vault wall, exposing about 4 metres of pipe per segment. Some of these forty pipes feed the Ring Thermal Shield (RTS). Each RTS circuit consists of four interconnected box section segments forming an 8 m mean diameter semi-circle. There are four such semi-circles per reactor unit suspended within the calandria vault. The box section segments contain a 40 cm x 2.5 cm channel for cooling water flow. Leaks within these box sections and their supply and return water lines represented a somewhat different configuration from previously treated systems. Consequently a full mock up simulation of one of the semi-circles was fabricated in a workshop close to Pickering NGS.

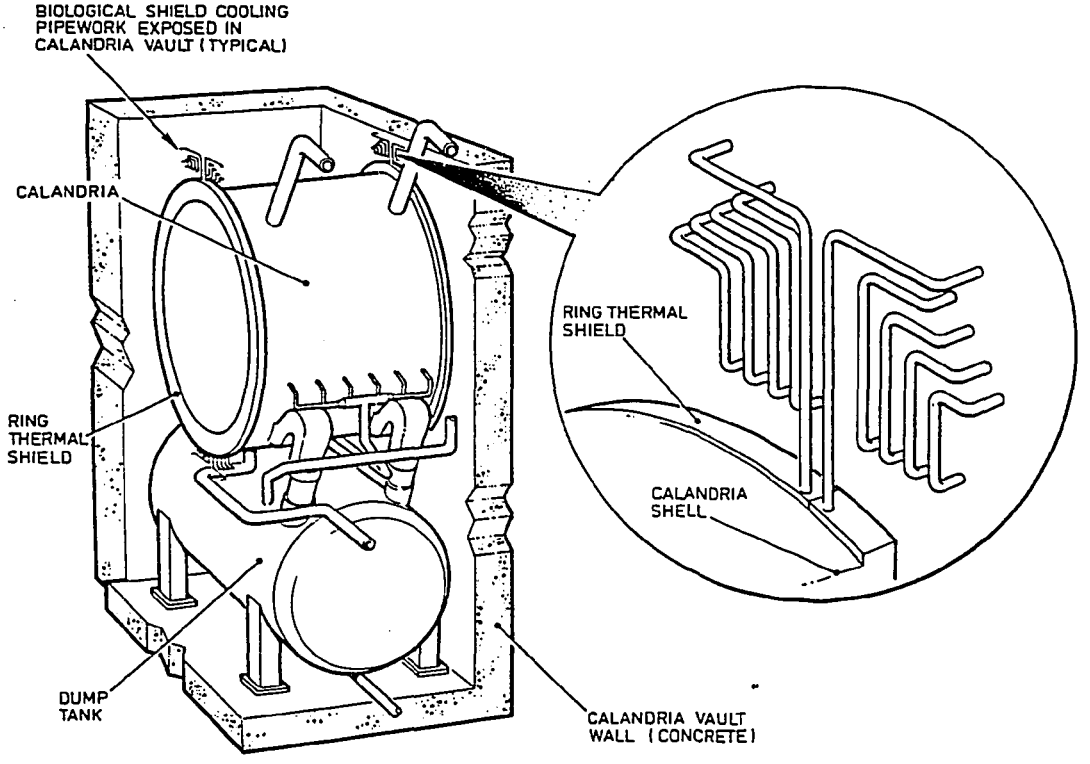

Figure 6 PICKERING NGS-A CALANDRIA VAULT

The mock-up was used to modify and confirm the procedures for sealant application and flushing. Once a technique had been confirmed a sample defect containing a 3mm diameter hole fully countersunk from the outside was subject to the sealing procedure. This defect was chosen to represent the suspected worst type of corrosion defect on the reactors and was successfully sealed.

Application to the reactors at PNGS 'A' proved equally successful. 10 leaks ranging from 0.2 to 3.7 mm equivalent diameter were sealed during schedule shutdowns by a joint NNC/Ontario Hydro team. During the application, a remotely operated arm with three degrees of freedom was deployed via 25 cm ports through the bioshield wall. Mounted on this was video and lighting equipment to enable close visual examination of the pipework being treated - the criteria for a successful seal involved hydrostatic testing with no visible seepage of water through the defect area. In addition, as a precautionary measure the area within the vault was sprayed with water by an arm also deployed via the 25 cm ports to eliminate any possible risk of chemical contamination of the stainless steel reactor vessel and calandria tank by the sealant.

NNC has now transferred its leak sealing to Ontario Hydro and the methods, materials and procedures are a part of Ontario Hydro's maintenance and repair expertise.

NNC has also sealed leaks on two CANDU reactors outside Canada. These leaks both occurred in buried cooling water pipework within the calandria wall. The leaks occurred in a bifurcated serpentine array of pipework buried in the concrete of the side wall and roof of the vault. The defect sizes and types were not dissimilar to those previously experienced by NNC in UK pre-stressed concrete pressure vessels and no development work nor mock-up rig proving work was considered necessary.

OTHER DEVELOPMENTS

Elsewhere sealant has been successfully applied to various systems: 18 other nuclear power plants, 2 conventional plants including the aluminium heat exchangers of a dry cooling tower, 3 materials test reactors and 2 high energy physics facilities.

Developments and upgrades of the sealant are ongoing and recent attention has focussed on efficient waste treatment.

ACKNOWLEDGEMENT

The authors would like to thank their colleagues in NNC, Ontario Hydro and elsewhere who collaborated in this work and the Directors of NNC Ltd for permission to publish this paper.

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CA9500146

PICKERING "A" ION CHAMBER ADDITIONAL SUPPORT

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ABSTRACT

Two cantilever type beams were designed and installed semi-remotely to provide additional support to the Ion Chamber. These beams were required to bear the full weight of the Ion Chamber should the original support structure fail due to corrosion. This is to ensure that the Ion Chamber instrumentation remains active under all operating conditions. The design life of the additional support is to be equal to the remaining plant life.

PICKERING "A" ION CHAMBER ADDITIONAL SUPPORT

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PICKERING "A" ION CHAMBER ADDITIONAL SUPPORT

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3.0 INTRODUCTION

Examination of the Pickering "A" calandria vaults revealed corrosive attack of many carbon steel components due to the presence of moisture in the vault. This condition raised the concern (due to the consequence of failure) about the integrity of the ion chamber support structure. See Fig. (1). The movement of the ion chambers relative to the calandria structure affects the signal output of the instrumentation. The relative positions of the ion chambers and the calandria has to be maintained during all normal and postulated accident conditions. Any change in their relative position could adversely affect the performance of the reactor safety shutdown systems. To preserve the integrity of this system it was decided to design and install an additional structure to support the weight of the ion chamber (11 tons) in the event that the existing structure should fail. See Fig. (2).

The additional support consists of two stainless steel rectangular hollow box beam assemblies which contain jacking and clamping mechanisms contained within the beam to ensure positive contact with the ion chamber. See Fig. (2). These beam assemblies are inserted horizontally through two 18" pre-drilled holes in the vault south wall. The beams were firmly grouted into position and the jacking and clamping mechanisms were activated remotely to secure the beam under the ion chamber.

The ion chamber additional supports were successfully installed in all four reactor units. The design, manufacture and testing of all the additional supports including the development of the installation procedure took 12 weeks. The installation of the additional support in each of the four reactor units took approximately two weeks.

4.0 DESIGN REQUIREMENTS AND CONSTRAINTS

The beam assemblies will be of a simple cantilever design, requiring no additional bracing from either the vault wall inside face or any components present in the vault. Any jacking and clamping mechanisms required as part of the assembly shall be fully contained within the beam cross-section during insertion through the vault wall and then activated remotely to effect positive contact with the ion chamber housing.

4.1 Loading on Vault Wall

The support beam assemblies shall not cause unacceptable stress levels or instability in the vault wall either during installation or under any subsequent operating or accident conditions which may be encountered.

4.2 Loading on Ion Chamber Housing

As the condition of the ion chamber housing cannot be determined with a high degree of certainty, jacking and clamping mechanisms shall be designed such that the load paths through the ion chamber housing will minimize the risk to the housing.

4.3 Position and Orientation

The beam assemblies will be inserted through two holes to be provided in the south vault wall. These holes will be oriented such that the supports can be installed horizontally, at right angles to the wall inside face. The beams must be aligned with the lower face of the ion chamber housing in the most outboard space between the ribs protruding from this face.

4.4 Size

Three factors limit the cross-sectional dimensions of the beam:

a. The holes penetrating the vault wall cannot interfere with the ion chamber penetrations above them.
b. The spacing between the ribs on the ion chamber housing is 12.75 inches.
c. Two 1/4-inch D_2O lines run parallel to the vault wall at a nominal elevation of 272 feet 8 1/2 inches at distances 5 feet and 5 feet 6 inches from the inside face of the wall. This provides a nominal clearance of 12 7/8 inches between these lines and the ion chamber housing. It should be noted however, that these lines were installed as field run, so the actual clearance must be determined for each unit. The support beam height must be minimized to provide the greatest scope possible to accommodate the unknown in the position of these lines relative to the ion chamber housing.

4.5 Vault Atmosphere

The beam assemblies will be installed in a corrosive environment that may be highly humid and which, when combined with the high radiation fields present in the vaults, results in the formation of nitric acid vapour and a liquid of pH2. This condition may be present from time to time until the vault air-drying system is installed and moisture ingress is prevented. All materials exposed to this condition must not corrode or otherwise degrade.

4.6 Radiation Fields

All materials used in the fabrication of the support beam assemblies must be able to withstand the radiation fields present in the vault during normal operating conditions without exhibiting any significant change in properties or dimension. Any materials (lubricants, seals etc.) used during installation must not degrade into harmful byproducts during reactor operation.

5.0 SYSTEM DESCRIPTION

The additional support system consists of two cantilever support beams which are inserted through penetrations in the south wall of the vaults immediately below the level of the ion chambers (Figure 2). The system is capable of fully supporting 11 ton weight of the ion chamber. Although the beams will only be preloaded to take a small portion (about 1,000 lbs) of weight. The beams are sufficiently stiff to ensure that the alignment of ion chamber with the calandria will be maintained in the event that the existing support structure fails, and are designed to support any transient loading which may occur without adversely affecting the response of the instrumentation.

The beams are grouted into sleeves, which are in turn grouted into the seven foot thick concrete wall at their outboard end. Jacking mechanisms at the inboard end of the beams are used to preload the system. Mechanisms at the inboard end of the beams are used to hold the ion chamber by clamping it between its inboard and outboard sides.

5.1 Mounting Plate

A two inch thick carbon steel plate (Figure 3) is mounted to the outside of the concrete wall. It acts as the template for boring the holes, mounting the boring equipment, and aligning the outboard end of the steel sleeves containing the jig for measuring the location of the ion chamber, and, eventually, the steel sleeves containing the support beams.

In addition to the two 18" diameter templates for the holes, the plate has mounting holes around the circumference of the holes (for attaching the drilling equipment and steel sleeves) and has steel doors which provide shielding from the radiation beam emitting from the holes during various installation stages.

5.2 Embedment Liner Sleeves

Two carbon steel sleeves were made to line the 18" holes which were drilled in the concrete wall at the South end of the vault. See Fig. (2). The purpose of the sleeves is to protect the concrete against any damage caused by the loads exerted by the beams. The sleeves were made of 18" standard pipe 7' long.

At the outboard end, a standard 18" pipe flange was welded to secure the sleeve to the mounting plate. See Fig. (3). To position the sleeves in the holes, three bearing pads were welded at each end of the sleeve. See Fig. (4). A hard rubber gasket was installed on the outside of the liner sleeve approximately 1" away from the inboard end. The purpose of the gasket is to seal the annulus between the sleeve and the hole so that grout can be pumped in without it extruding into the calandria vault. Once the grout is in place, there is no concern for the integrity of the gasket. For this reason the radiation resistance of the organic gasket material was not a constraint.

5.3 Support Beams

The two support beams are fabricated from 1" thick 304L stainless steel plate. The material was chosen for its resistance to the vault environment, its strength and ductility properties and its weld ability. A sketch of the beam is shown in (Figure 5).

The beam is of composite box design, the outboard 11.5 feet has an 8-1/2" w x 10" h outside cross section. The inboard 7.5 feet has an 8-1/2" w x 8" h cross section. To provide sufficient horizontal and vertical stiffness to withstand transient loads, 1" plate has been bolted to the outside of the beam in selected locations.

The primary reason for the composite configuration is to provide as much clearance as possible for the beam to be inserted through the nominal 14-1/2" window between the bottom of the ion chamber and the top of two moderator spray cooling lines which run along the vault below the holes.

The beam was fabricated using full penetration welds, in accordance with the requirements for ASME Sub Section NF, Class 1 Nuclear Supports, however, it was not a requirement to register the beam with the MCCR.

5.4 Jacking Mechanisms

Two jacking mechanisms are located at the inboard end of each beam, under the inboard and outboard sides of the ion chamber housing (Figure 6). The pads on top of the jacks are mounted in spherical seats, so that they are self aligning with the ion chamber housing. The jacks are driven up (and down) by a worm gear mechanism, turned by a drive shaft which runs through the centre of the box beam. The material of the jacks is 17-4 Ph stainless steel. All components in the load path have been fabricated to meet the intent of ASME Subsection NF Class 1, Nuclear Supports. There was no requirement to register the components with the MCCR.

5.5 Clamping Mechanisms

The inboard end of each beam also contains two clamping mechanisms which hold the ion chamber housing by clamping it between its inboard and outboard sides (Figure 6). The inboard clamp is recessed within the body of the beam during installation, to avoid interference with the bottom of the ion chamber housing. Once the beam is in place, the clamp is raised into position by its cam follower mechanism. The outboard clamp is in a fixed (vertical) location, above the top plate of the beam. The two clamps are independently driven by drive shafts extending through the centre of the beam.

6.0 SYSTEM INSTALLATION

The installation sequence is as follows:

1. A remote video inspection is made of the vault to confirm that there is adequate clearance and no unexpected obstructions that would prevent the installation of the support structure. Suitable working platforms and facilities are provided in the south accessible area for performing the installation of the beams.

2. The mounting plate (Fig. 3), is attached to the south wall using site standard mounting methods. Mounting holes have been provided in the plate.

3. The two 18" diameter holes are bored through the seven foot thick concrete south vault wall. Allowance has been made for hole misalignment, however, there are certain tolerances which must be met during boring.

4. Holes are flame cut in the three layer thermal shield steel plate (Fig. 2), on the inboard side of the south wall.

5. A steel sleeve identical to the embedment sleeve is inserted in the hole. This sleeve contains measuring equipment to determine the precise location of the ion chamber housing in relation to the penetrations. The reference location for the sleeve is determined by the mounting plate (at its outboard end) and the pads welded on the outside of the sleeve at its inboard end.

6. The measurements taken are used to position the beams within the embedment sleeves. This operation is performed prior to the insertion of the sleeve/beam assembly into the holes. The embedment sleeve is positioned vertically, with the beam inside of it. See Fig. (7). The beam is positioned axially by shims. The position of the sleeve is adjusted relative to the beam to provide the correct alignment. The beam is then grouted inside the sleeve. The inside of the beam is also grouted up to a level of seven feet from the flange. The tolerance on the entire measurement and grouting process is

such that the 1-1/2" travel of the jacks can adequately load the ion chamber structure.

7. The sleeve/beam assembly (Figure 7), is then inserted into its hole. In-vault cameras are used during the installation process to ensure proper alignment.

8. The jacks and clamps are actuated to just contact the bottom and sides of the ion chamber housing by turning the drive rods at the outboard end of the beam. See Fig. (8). The sleeve is then grouted in place.

9. After the grout has dried, the jacks and clamps are actuated to their final load, as determined by the load cells in the mechanisms. The drive rods are then positively locked in place by welding.

10. The outboard ends of the beams are then plugged with a lead filled box to provide proper shielding (equivalent to the existing wall) during reactor operation.

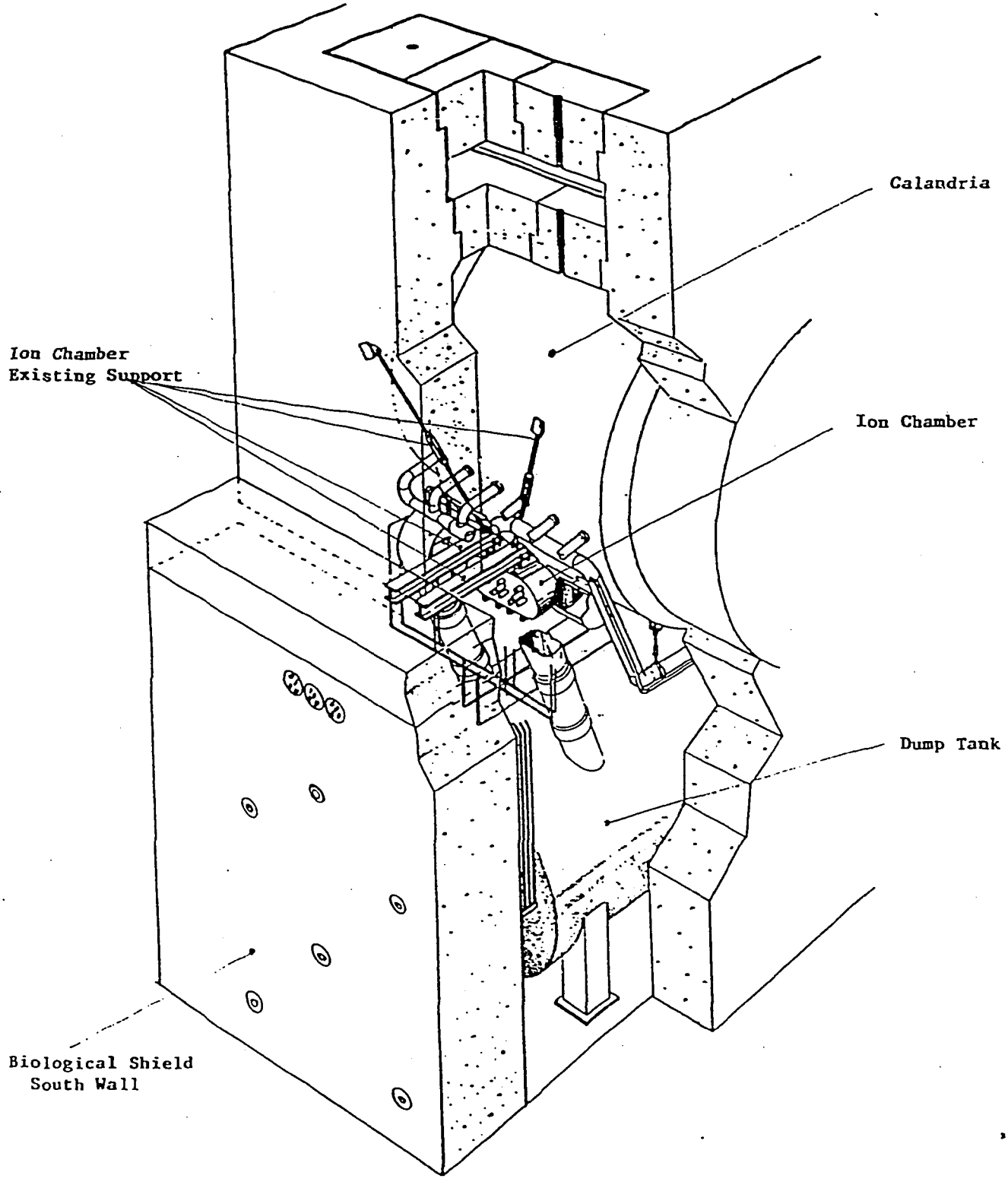
7.0 SYSTEM MAINTENANCE

The system was designed and built so that no maintenance will be required once the beams are installed and grouted in place.

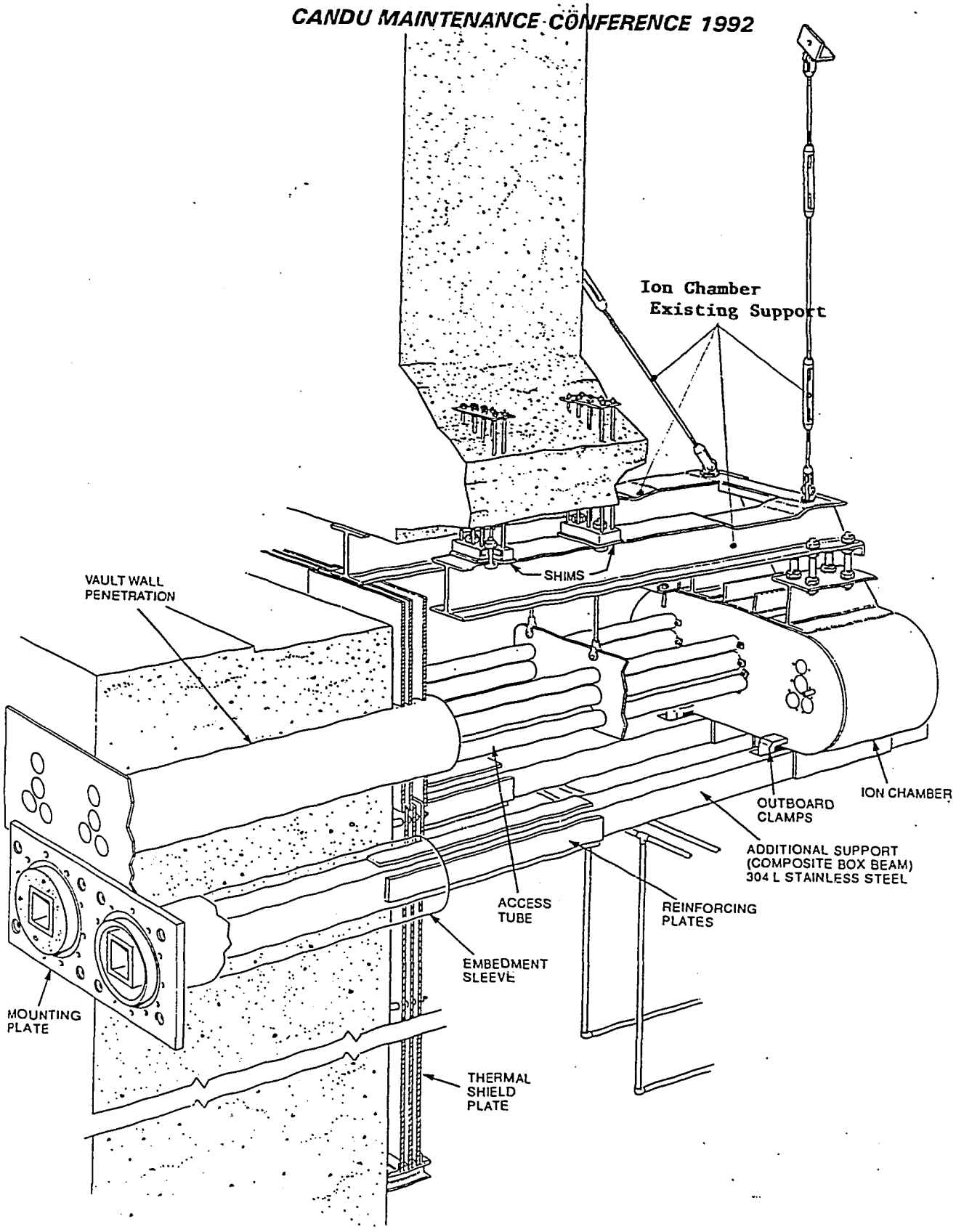
8.0 CONCLUSION

The Ion Chamber Additional Supports were installed in all four reactors at Pickering Nuclear Generating Station 'A'. The installation work was completed according to the procedure without any major problems. It took two weeks to install the new supports in each reactor unit. Installation work was done by a team from Ontario Hydro Construction and AECL Sheridan Park Engineering Laboratory.

9.0 ILLUSTRATIONS

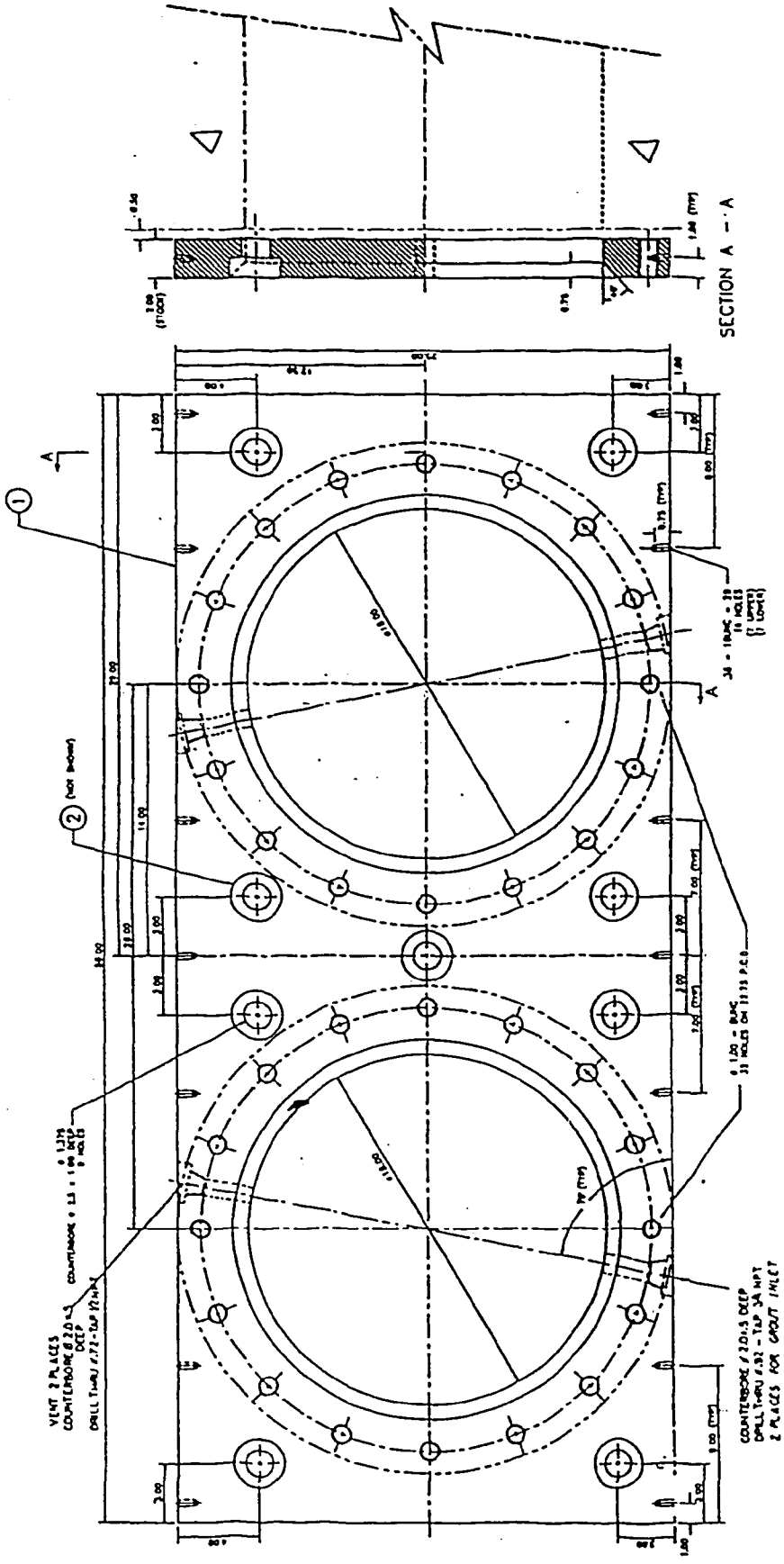


Pickering 'A' Calandria Vault
Fig. (1)

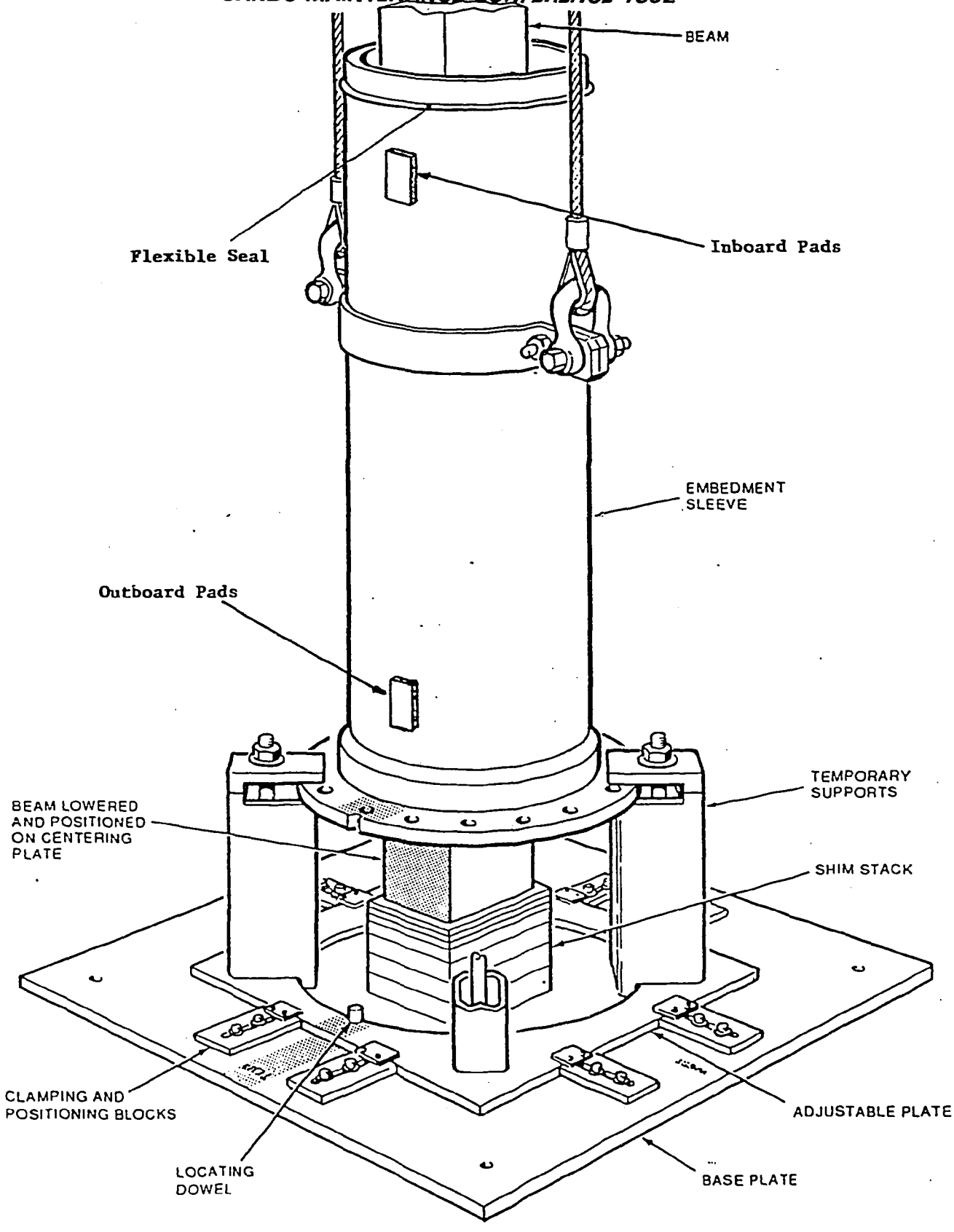


ION CHAMBER AND ADDITIONAL SUPPORTS

FIG (2)

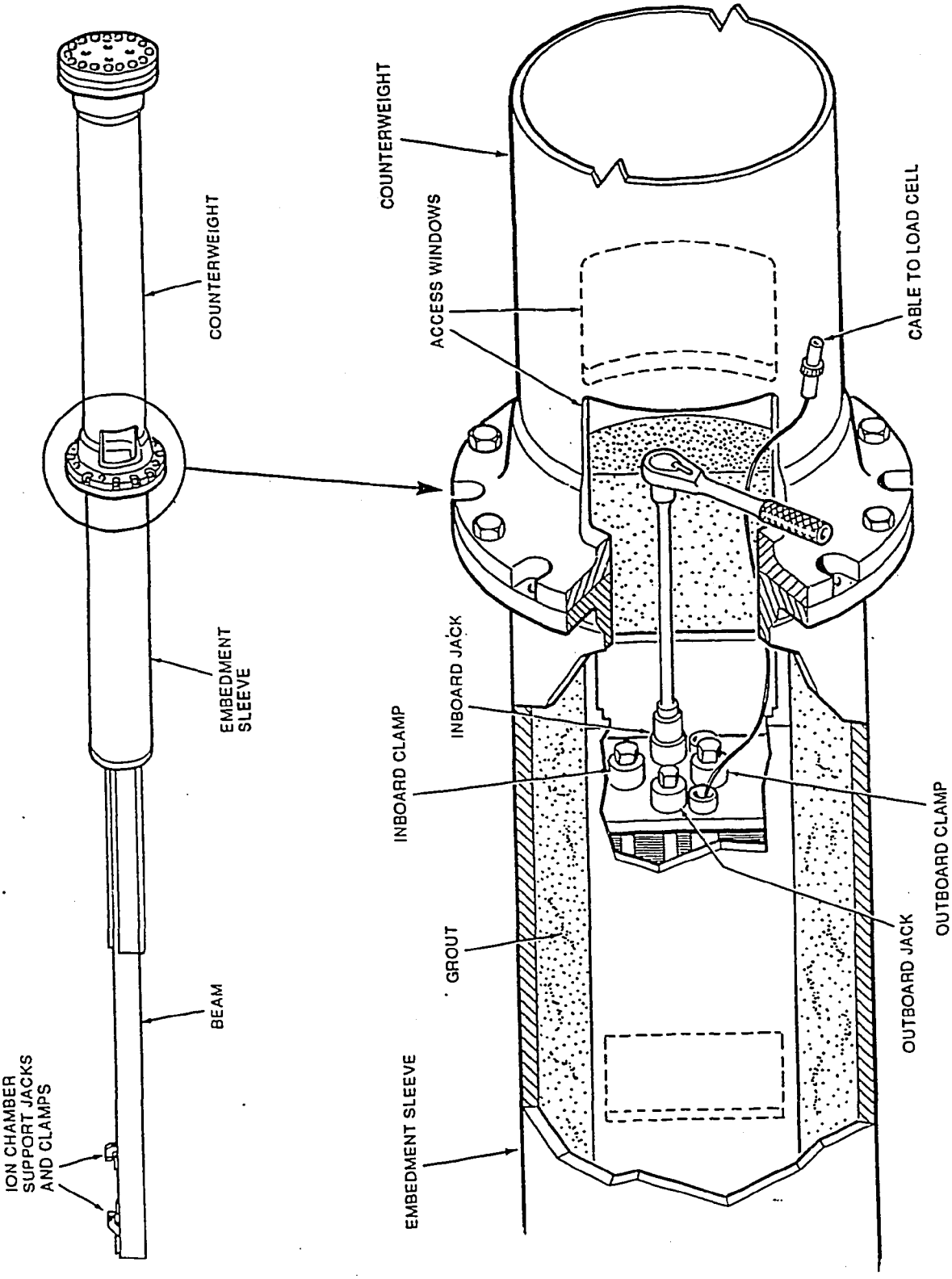


WALL MOUNTING PLATE FOR NEW I.C. SUPPORTS
FIG. (3)



BEAM/SLEEVE INSTALLATION

FIG (4)



BEAM CLAMPING AND JACKING CONTROLS

FIG (5)

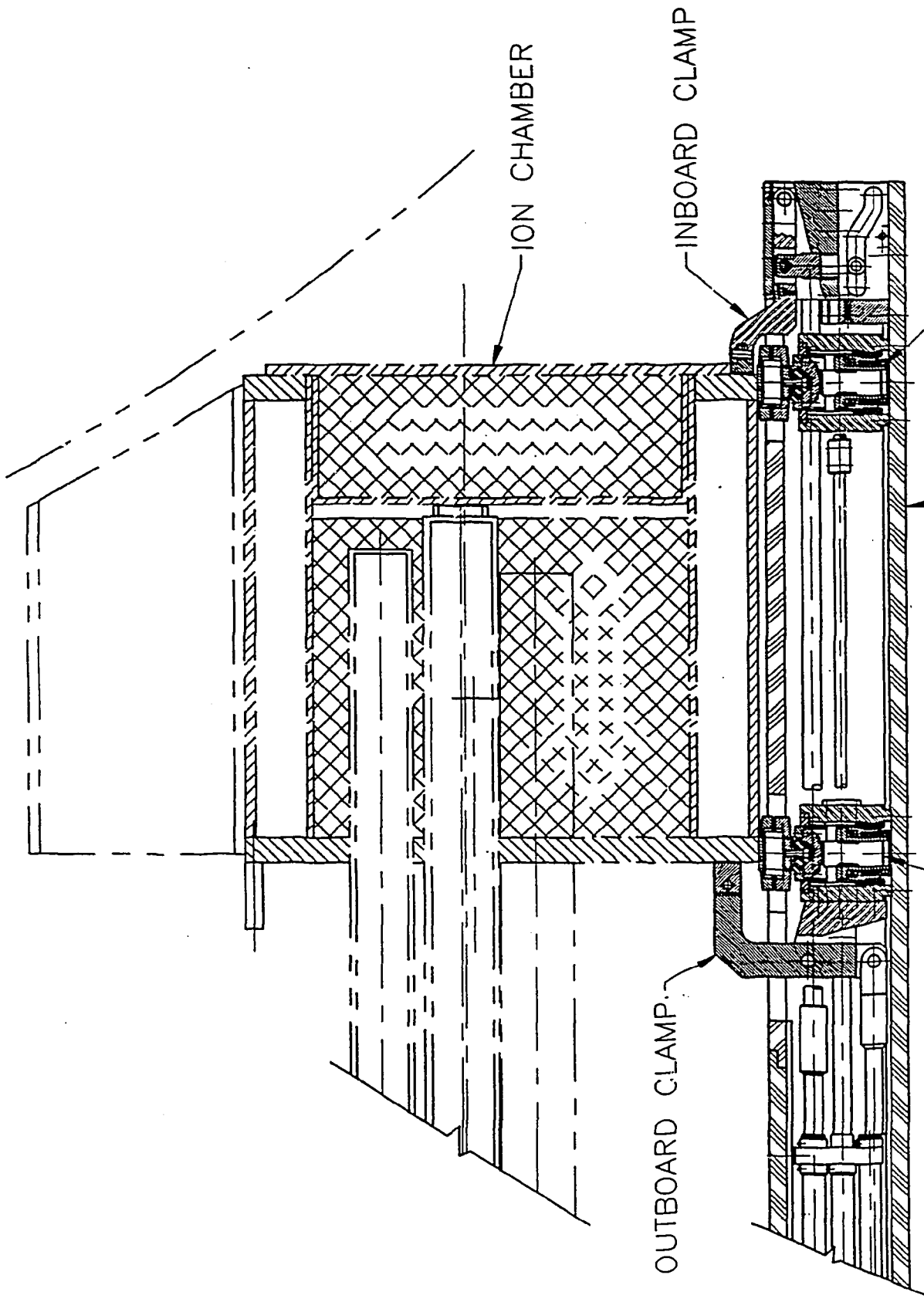
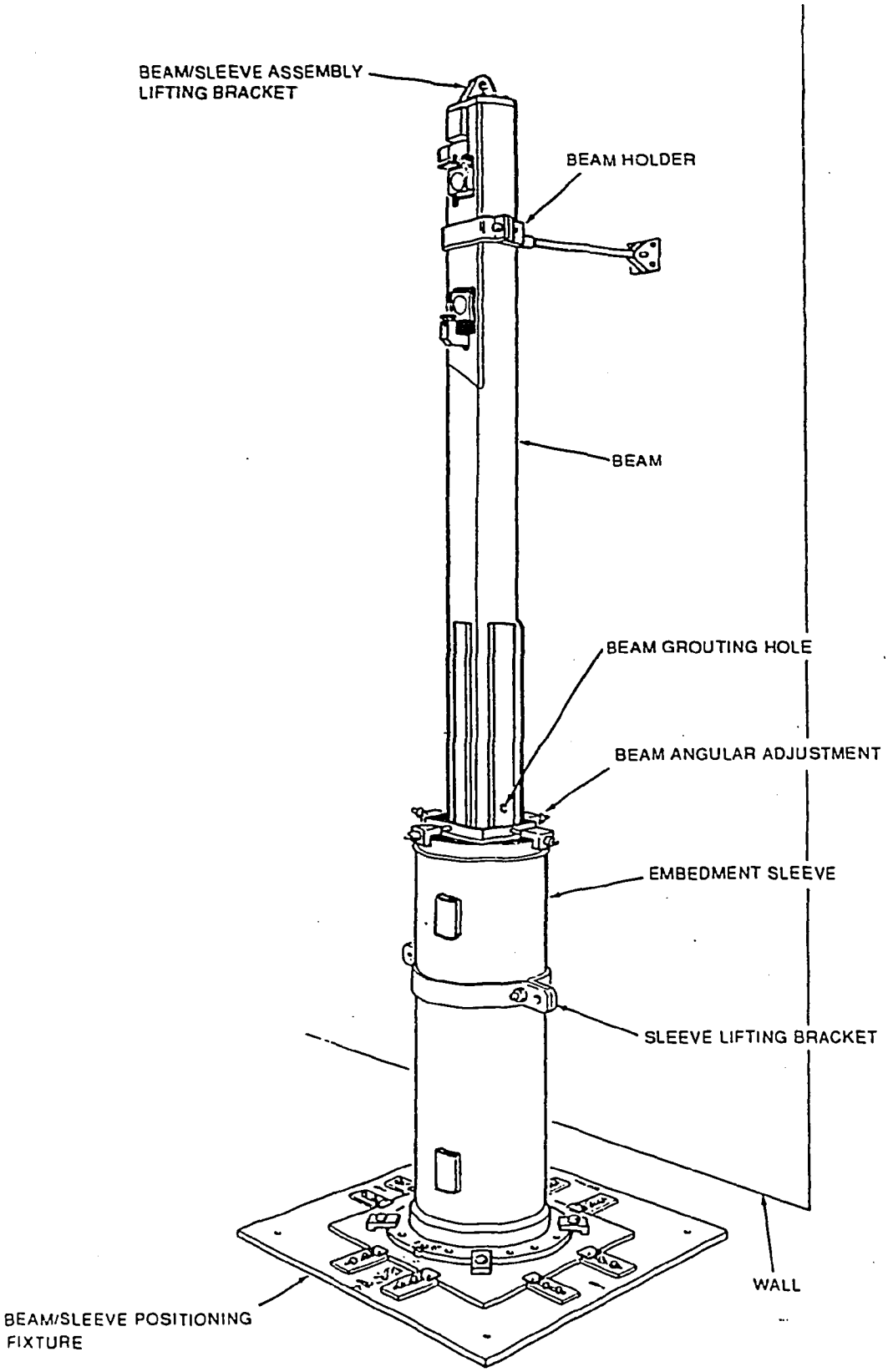

ION CHAMBER
INBOARD CLAMP
JACK
SUPPORT BEAM
JACK
OUTBOARD CLAMP

FIG. 6



BEAM/SLEEVE POSITIONING, ALIGNMENT AND GROUTING

FIG (7)

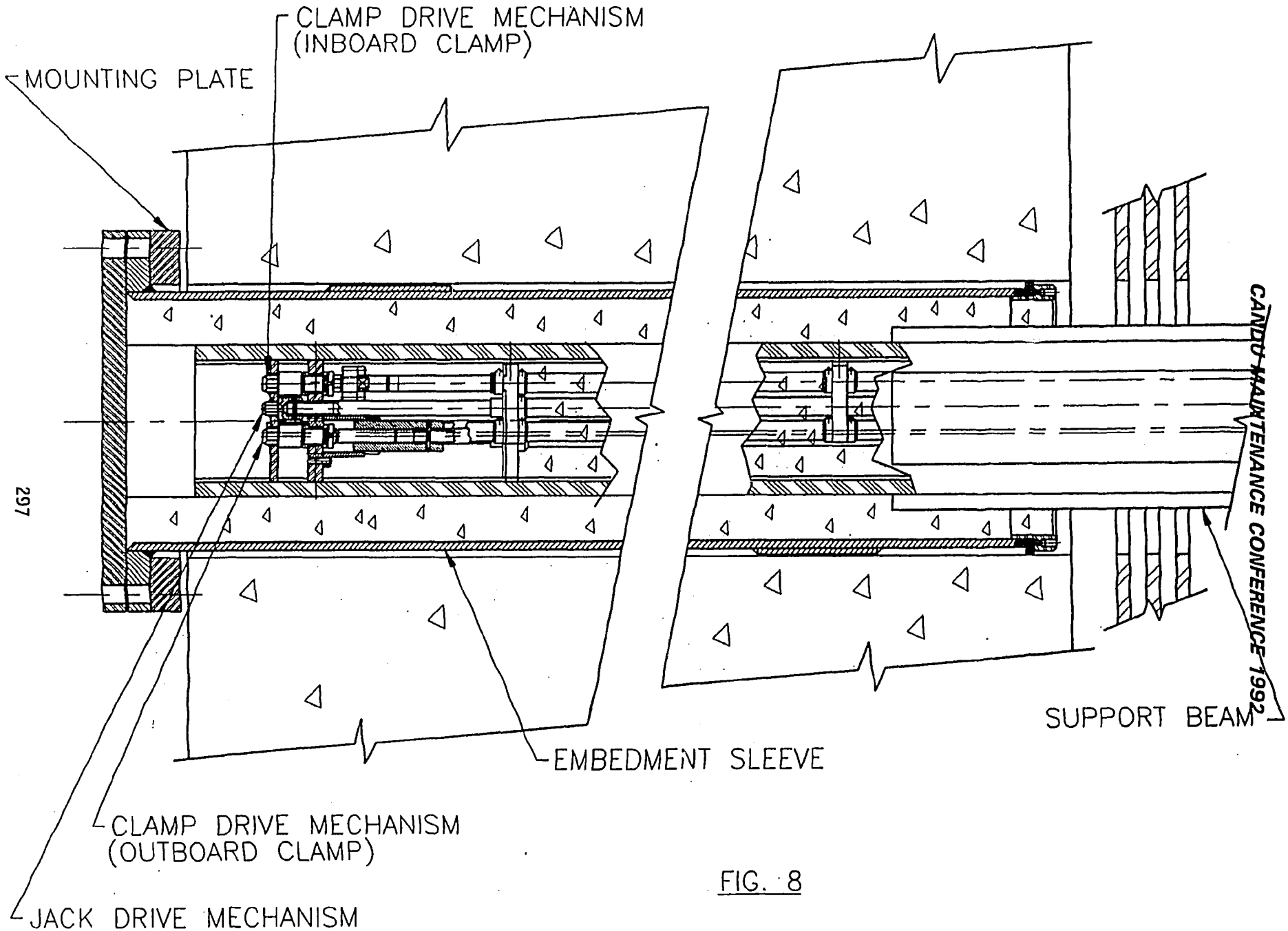

CLAMP DRIVE MECHANISM
(INBOARD CLAMP)
MOUNTING PLATE
SUPPORT BEAM
EMBEDMENT SLEEVE
CLAMP DRIVE MECHANISM
(OUTBOARD CLAMP)
JACK DRIVE MECHANISM

FIG. 8

10.0 APPENDIX

ION CHAMBER RESUPPORT

Installation Procedures

1.0 Install lower half of platform in the South accessible area.

2.0 Install temporary scaffold below "CU" inspection port.

3.0 Perform initial measurements to establish the actual location of the Ion Chamber and the horizontal cooling lines.

4.0 Remove temporary scaffold.

5.0 Install upper half of platform.

6.0 Install overhead monorails and hoists.

7.0 Mark position of the two new holes on wall using measurements derived from the I.C. location.

8.0 Install wall plate and shielding doors (shielding doors closed).

9.0 Drill the first 18" hole through wall and thermal shield plates.

10.0 Install shielding doors.

11.0 Install counter-weight carriage and trolleys on platform, align trolleys with center line of hole, and secure carriage to platform.

12.0 Open shielding door and partially insert gauging sleeve into hole using the overhead hoist.

13.0 Assemble gauging system counter-weight on trolleys.

14.0 Couple counter-weight and gauging sleeve end-to-end by bolting their flanges together.

15.0 Push gauging sleeve/counter-weight assembly into hole until sleeve flange is in contact with wall plate.

16.0 Bolt sleeve flange to wall plate.

17.0 Disconnect counter-weight from gauging sleeve and remove counter-weight from trolley.

18.0 Install gauging tool through the gauging sleeve.

19.0 Perform gauging as per procedure and record measurements.

20.0 Remove gauging tool.

21.0 Re-assemble counter-weight on trolleys.

22.0 Couple counter-weight with gauging sleeve end-to-end by bolting their flanges together.

23.0 Withdraw counter-weight/gauging sleeve assembly partially out of hole until the center of gravity of the sleeve itself can be reached by the overhead hoist.

24.0 Hang gauging sleeve by its center of gravity using overhead hoist.

25.0 Disconnect counter-weight from gauging sleeve, and remove counter-weight from trolleys.

26.0 Withdraw gauging sleeve completely from hole using overhead hoist.

27.0 Close shielding doors.

28.0 Set up beam/sleeve positioning mechanism in an area of minimum 30' x 30', and transfer beam and beam sleeve to this area.

29.0 Anchor plate of beam/sleeve positioning mechanism to floor.

30.0 Install appropriate quantity of shim plates onto base plate based on measurements taken in Step 19.

31.0 Install beam sleeve vertically on top of beam/sleeve positioning mechanism.

32.0 Hoist and lower beam vertically into beam sleeve.

33.0 Secure top of beam to wall using the provided clamp and check both beam and beam sleeve for level.

34.0 Position beam sleeve relative to beam in accordance with the gauging measurements obtained in Step 19.

35.0 Clamp sleeve flange to base plate.

36.0 Fill cavity between beam and sleeve with heavy concrete; fill the lower section of the beam with grout up to a height of 7 ft from the sleeve flange. Allow to cure.

37.0 Insert camera viewing equipment in the upper East and West inspection ports to view the beam insertion operation.

38.0 Transport beam/sleeve assembly to platform, and partially insert into hole using overhead hoist.

39.0 Assemble beam counter-weight on trolleys.

40.0 Join counter-weight and beam/sleeve assembly end-to-end by bolting their flanges together.

41.0 Push the counter-weight/beam/sleeve assembly into hole until the sleeve flange is in contact with wall plate. Watch operation using cameras in the UE and UW inspection ports.

42.0 Bolt sleeve flange to wall plate.

43.0 Actuate the two jacks to contact the Ion Chamber side plates (50-100 lbs load).

44.0 Clamp inboard and outboard clamps to the Ion Chamber side plates.

45.0 Fill the cavity between hole and sleeve with grout and allow to cure.

46.0 Disconnect counter-weight from sleeve and remove counter-weight from trolleys.

47.0 Actuate the two jacks to load the Ion Chamber (1,000 lbs).

48.0 Torque the clamp to final positions.

49.0 Weld drive shafts of jacks and clamps to outboard bulkhead plate.

50.0 Install lead filled shielding box in the outboard end of the beam.

51.0 Remove shielding doors.

52.0 Install blank flange on to the embedment sleeve.

Remote Handling Innovation From Fusion

J.W.F. Millard, Sparatsg
R.A. MacDonald, Sparatsg

This paper was not available at the time of printing.

CA9500147

RECENT USES OF ROBOTICS FOR REMOTE INSPECTION AND MAINTENANCE

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Inspection , Maintenance and Metallurgy Department
Nuclear Operations Central Division

ABSTRACT

This paper documents some of the recent uses of robotics for inspection and maintenance activities in Ontario Hydro's Nuclear Power Plants in areas other than Fuel Channels and Steam Generators.

RECENT USES OF ROBOTICS FOR REMOTE INSPECTION AND MAINTENANCE

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Nuclear Operations Central Division (NOCD)

1.0 INTRODUCTION

Steam generator and fuel channels are presently the largest user of remote equipment for inspection and maintenance within our nuclear power plants. However, other power plant areas are also in need of remote tooling and these applications are on the increase. This is mainly due to:

(1) Power plant and component aging.
(2) Increased regulatory requirements.
(3) Preventive maintenance activities.
(4) Declining allowable radiation expenditures.
(5) Increasing radiation fields.
(6) Inaccessibility.

The above factors necessitate the use of remote tooling and robotic equipment within many areas of our nuclear power plants. The following are examples of robotic equipment recently used or under development in these nontraditional areas by Inspection, Maintenance, and Metallurgy Department (IMMD), NOCD staff.

2.0 ANDREA AND CALVIN

Pickering NGS-A (PNGS-A), unlike the majority of CANDU-designed reactors, has a dry air-filled calandria vault environment (reference Figure 1). (This is very different from the immersed calandria shell within a shield tank CANDU design). This unique design requires cooling of the thick, heavy concrete walls via imbedded carbon steel piping within the walls known as biological shield cooling. This necessitates a number of hanger and support structures for the above system , as well as for other instrument lines, moderator lines, dump tank structure, ion chamber, etc.

Many of the components in the Calandria Vaults are made of Carbon Steel. PNGS-A has experienced leaks in the carbon steel biological shield cooling piping. Inspections for the vault component's integrity have been ongoing since the mid-1980s. Access to the calandria vault is restricted in two ways as follows:

(1) Radiation levels at shutdown can be up to 1,000 R/hr.

(2) Physically, access is limited via specific porthole entries from the south accessible area and from the boiler room floor.

The portholes consist of specially contoured plugs that can be removed during a unit outage. The size of the portholes range from the narrowest 100 mm diameter in the boiler room (three in total) to the 230 mm diameter portholes in the south accessible area (six in total).

Given the above physical and radiation constraints, numerous remote tools have been developed over the last decade to perform remote inspection and maintenance activities. Two of the latest and most complex items are the ANDREA and CALVIN teleoperated inspection arms manufactured by Babcock and Wilcox Canada (B&W), Cambridge, Ontario.

2.1 ANDREA (Automated Nuclear Device for Remote Extraction Applications) (Reference Figure 2)

ANDREA is a hydraulically-based, teleoperated maintenance arm manufactured in 1989 for the removal of biological shield piping in PNGS-A Unit 4 from the upper south accessible area portholes. The arm is approximately 7.9 m long x 175 mm in diameter. It is put together in equal sections, and has an elbow/wrist combination with a rotatable wrist and gripper fingers. When assembled, the arm weighs less than 500 kg and is suspended in the south accessible area from specially positioned hoists. ANDREA has pop-out mini black and white video cameras and lights and a two-function (open/close, rotatable) gripper with a 7 kg lift capability. ANDREA is designed to be operated in the horizontal position only in a cantilevered state within the calandria vault. This arm is primarily used for maintenance tasks.

Various end effectors have been developed which can mate to the ANDREA gripper fingers to perform specific tasks. Prior to usage, the tasks to be performed have been tested at AECL-SPEL labs on the lower calandria vault mock-ups. This allows proof of concept training, as well as operator training.

The ANDREA arm, since 1989, has been specifically used or targeted in PNGS-A for the following tasks:

(1) Biological shield cooling pipe removal.

(2) Moderator hanger replacement.

(3) Ring thermal shield bracket thickness measurements.

(4) Visual inspections.

(5) Potential NDE inspections using a specially designed jig (yet to be performed).

2.2 CALVIN (CALandria Vault INspection)
(Reference Figure 2)

CALVIN is a hydraulically-based, teleoperated inspection arm manufactured in 1990. CALVIN was developed as a general purpose calandria vault inspection arm. It is used for full visual inspection coverage of the calandria vault from the horizontal or vertical orientation. As such, the back sections of the arm are of different diameters , depending on the orientation. The inspection arm, when fully assembled (in sections), is 14.6 m long and 100 mm to 175 mm in diameter, depending on orientation. The first section, common to both orientations, is 4.9 m long, 100 mm in diameter, and consists of a 1 m long wrist and a longer elbow section. The wrist is rotatable, and contains lighting and a radiation tolerant Rees R93 black and white video camera with zoom capability. In addition, water-jet cleaning (< 7,000 kPa pressure) is possible using nozzles on the arm's wrist and station demineralized water supply . A second wrist is available that can be interchanged , allowing a limited two-function gripper (2 kg payload) that has been used for other NDE inspections and with other cleaning end effectors.

Since this arm is primarily a visual inspection arm, less mock-up work is required, and this arm has been used extensively in the past few years as follows:

(1) Visual inspections of the calandria vault and its components from the boiler room and south accessible area portholes. This includes water-jet cleaning of components for a better view.

(2) Ring thermal shield bracket thickness measurements.

(3) Vacuuming deposition from specific calandria vault locations.

(4) Detailed visual inspection of ring thermal shield bracket welds.

(5) Back-up arm used during planned maintenance activities.

3.0 ROVVER (REMOTELY OPERATED VEHICLE FOR VISUAL EXAMINATIONS AND RETRIEVAL) (REFERENCE FIGURE 3)

ROVVER is a trademark name for a very small tracked remote vehicle purchased from Visual Inspection Technologies in Flanders, New Jersey. IMMD has two of these vehicles, both with pan-tilt colour video cameras and auxiliary lights. The older version has a single-function gripper arm that can be used for retrieval of debris and can be operated in a moist or damp environment. The newer version is fully waterproof and has been used in underwater inspections.

The ROVVER vehicle weights less than 7 kg, and its dimensions are approximately 150 mm long x 150 mm high x 80 mm wide. The original version was purchased in 1990 with a second unit being received early in 1992. Other attachments available to the ROVVER vehicle are a 6X zoom lens attachment, focus or spot lights (35 watt), cerated steel wheels for better traction and magnetic wheels for climbing inclines.

ROVVER has been used for a wide variety of inspections and retrievals in piping and other confined or difficult to access locations. Examples of some inspection locations in which ROVVER was used are:

(1) Turbine HX cooling piping.

(2) HT piping (post SG inspection and maintenance).

(3) Calandria vault floor (PNGS-A side only) examinations.

(4) Conventional water supply pipe inspections.

(5) Steam line inspections at Lakeview TGS.

ROVVER's limitations are that it cannot be used in the vertical orientation and has a maximum of 30 m umbilical between vehicle and controller. In an emergency, the umbilical can be used for retrieval of ROVVER.

4.0 SIGMUND (SUBMERSIBLE INSPECTION GRIPPER FOR UNDERWATER APPLICATIONS) (REFERENCE FIGURE 4)

SIGMUND is a small, remotely-operated vehicle. It can be used in a dry, moist, or underwater environment. SIGMUND (or SEAMOR - commercial name) can be used as a submersible (with propellers) or as a pipecrawler (with attached tracks). SIGMUND has a built-in colour video camera and

lighting on a pivotal base. SIGMUND's dimensions as a submersible are 350 mm long x 270 mm wide x 230 mm high. As a pipecrawler, the port and starboard thrusters are replaced by two tank-type tracks, adding 150 mm height to the system. SIGMUND weighs approximately 14 kg as a pipecrawler (air), neutral in water. It has a 51 m long umbilical cord between the controller and vehicle that is used for placement and retrieval from water to surface. IMMD has three SIGMUND vehicles along with a two-function (open/close and rotatable) gripper arm. SIGMUND and attachments was manufactured by INUKTUN Services in Nanaimo, British Columbia.

SIGMUND, because of its larger size, has been used in Ontario Hydro's nuclear sites as a pipecrawler, with ROVVER piggybacked on it in PNGS Unit 4, on conventional water supply lines (> 0.9 m in diameter). As a submersible, some examples of its use are:

(1) PNGS shield tank inspections and repair attempts .

(2) Zebra mussels examinations.

5.0 FERRET (REFERENCE FIGURE 5)

FERRET is a unique pipecrawler system presently under development by AECL-SPEL staff. It is intended to be used in 1993 at PNGS Unit 8 to find and retrieve a broken annubar (flow transducer) suspected to be located within the inner moderator lines near the calandria shell. The FERRET crawler, lighting and tooling modules will be able to conform to the size and orientation of pipes. As such, it will be able to travel through various diameter size pipes, through T and Y junctions, in the horizontal or vertical orientation.

Its principle of operation is that it will have two fibreglass bodies with scissor-like braking mechanisms attached via a metal rail. Both modules have independent motor drives such that one module can set itself in the pipe (braked via scissor locks) and move the other module forward or backward on the metal rail. The module in motion comes to a predetermined stop, locks itself in via scissor locks, and now the other module is brought forward or back on the rail system. The front module will have its own video cameras, lights, and end effector tools.

The FERRET design is presently being tested at a plexiglas mock-up of the PNGS moderator lines (with T's, elbows, 45° and 90° bends, and varying diameters) at AECL-SPEL laboratories .

The equipment should be ready for use by early 1993.

nuclear generating sites. It was recently received from INUKTUN Services in Nanaimo, British Columbia. ETHEL or CIRCUMSPECTOR (commercial name) consists of a remote head colour low light video camera (ELMO) and lights mounted in line with a highly dextrous pan and tilt assembly. The camera wrist is located on a telescoping pole (2.6 m to 5.7 m). The camera can get into spaces < 32 mm. ETHEL is controlled via a simple toggle switch control and will be able to be used in a horizontal or vertical orientation. The complete assembly is made of black matted, anodized aluminum with built in slip clutches and brakes. The housing is o-ring sealed for easy water washing decontamination.

7.0 CONCLUSION

This is just an example of some of the unique remote tools developed or procured by IMMD. These tools are being used in the nontraditional maintenance areas of our nuclear sites. Tools being used in the nuclear and conventional side for remote and semi-remote inspections due to safety, access and/or radiation concerns.

8.0 ACKNOWLEDGEMENTS

Acknowledgements to the following individuals for their assistance :

.1 N. Shamoon of NOCD for his technical review of this paper.

.2 J. Vandenberg of B&W , Cambridge for ANDREA and CALVIN information .

.3 D. Scott and S. El Nesr of AECL-SPEL for PNGS Calandria Vault Mock-up and FERRET information.

.4 J. Drost of V.I.T. in Flanders , New Jersey for ROVVER information.

.5 J. Johns of REES Instruments in Atlanta , Georgia for information regarding Radiation resistant cameras.

.6 C. Roper and T. Knight of INUKTUN Services in Nanaimo , B.C. and W. H. Lam of NOCD for information about the SIGMUND and ETHEL equipment.

.7 C. Fromme of REDZONE Robotics in Pittsburgh , Penn . for FRED equipment information.

.8 S. McNabb , W.K. Chan of O.H. Research for photographs and information of the above equipment.

6.0 FRED AND ETHEL

FRED and ETHEL are two separate remote tools custom-built for IMM Department. The purpose of the tools are to perform semi-remote visual inspections of the upper and lower feeder cabinet components at all of Ontario Hydro's nuclear generating sites. These inspections are performed as in-service and regulatory periodic inspection program items. Presently, the inspections are performed manually. However, due to increasing radiation fields (>3 R/hr contact possible), and the lowering of allowable radiation exposures, semi-remote tooling is required .

6.1 FRED (Feeder Cabinet Remote Examination Device) (Reference Figure 6)

FRED is a modular, remotely operated vehicle that will be capable of travelling via a tracked base (from INUKTUN Services) on the feeder cabinet catwalks. FRED was recently procured from Redzone Robotics in Pittsburgh, Pennsylvania, and is still being commissioned at the TMB mock-ups near PNGS.

FRED has three low-light colour cameras and lighting systems. One general purpose pan-tilt overview camera, one stationary video camera, and a mini Elmo video camera on a Brooks pan-tilt wrist. The wrist is attached to a 1.8 m long (fully extended) telescoping arm. The arm can be folded in remotely and stowed during travel. The arm runs remotely vertically up and down on an enclosed ball screw arrangement, and can be tilted in various orientations. The arm's ball screw module is attached to a fully-rotatable table, such that FRED can inspect perpendicular or to the side of its direction of travel. It can telescope above, below, or at its side at various orientations. It has sensors informing the operator of any tilt in the mechanism, allowing for corrections, so it will not tip over. Its dimensions in a stowed position are approximately 1.4 m high x 0.4 m long x 0.32 m wide. When fully assembled it weighs approximately 90 kg but is assembled in modules weighing less than 23 kg per module. FRED is made of black matted, anodized aluminum and is water resistant for ease of decontamination (water washable). The crawler can climb a slight incline, and has a 30 m umbilical between the vehicle and controller.

6.2 ETHEL (Extendable Tool for Horizontal Examinations in Lower Feeder Cabinet) (Reference Figure 7)

ETHEL is a semi-remote, hand-held inspection tool to assist with visual exams of lower feeder cabinet components at all

Figure 1 -Pickering NGS Calandria Vault

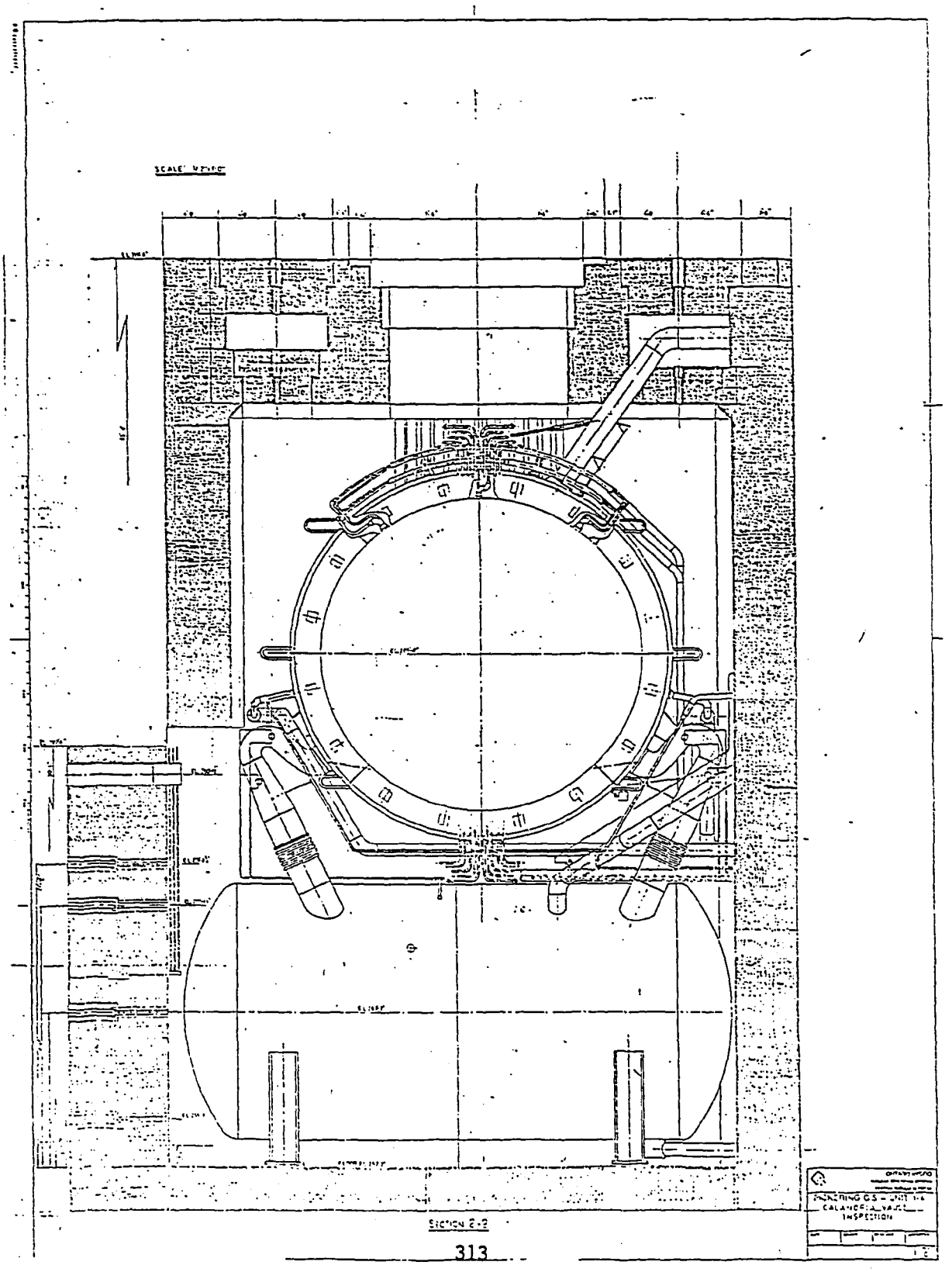


Figure 2 - PNGS Calandria Vault Remote Equipment

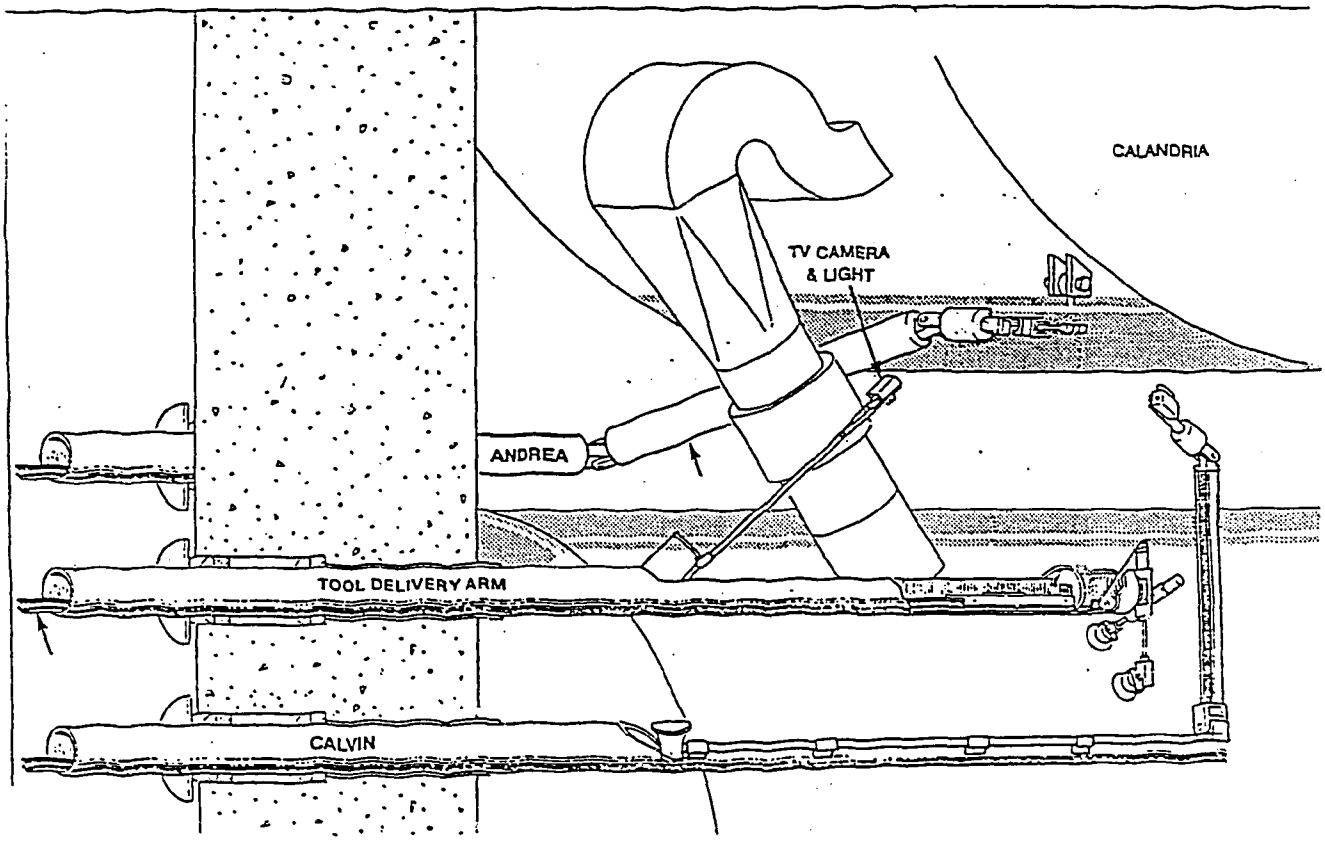
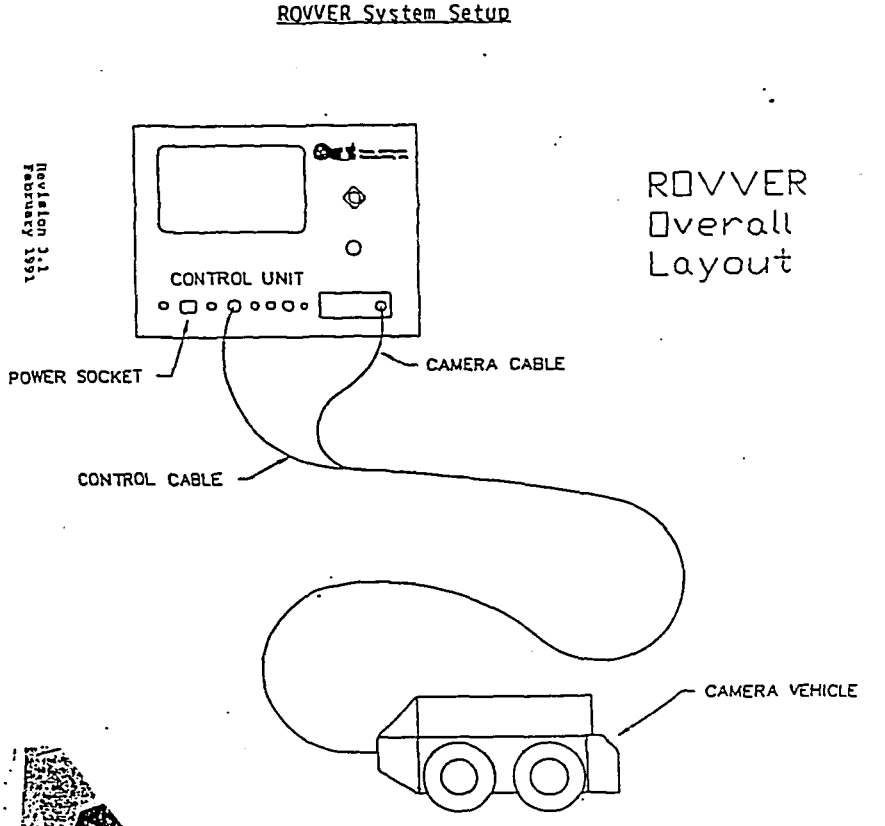


Figure 3 - ROVVER



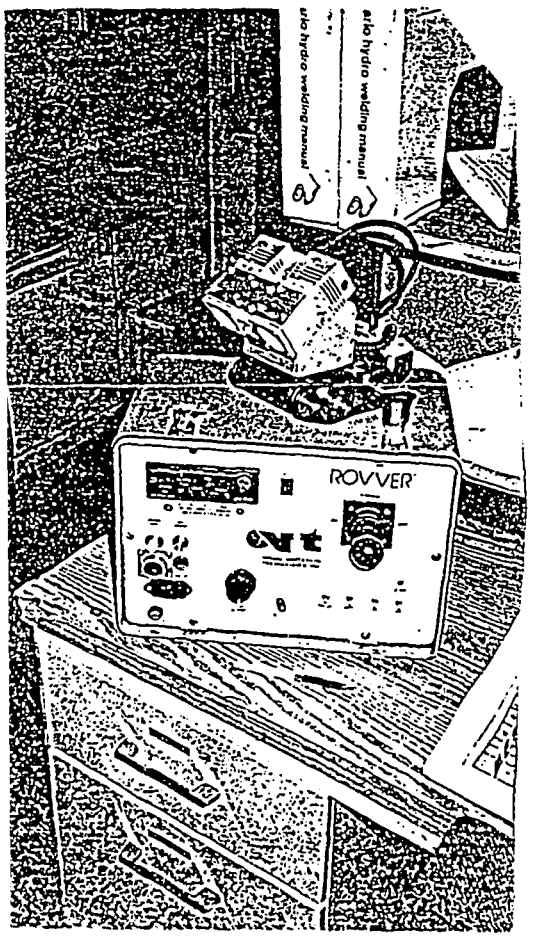
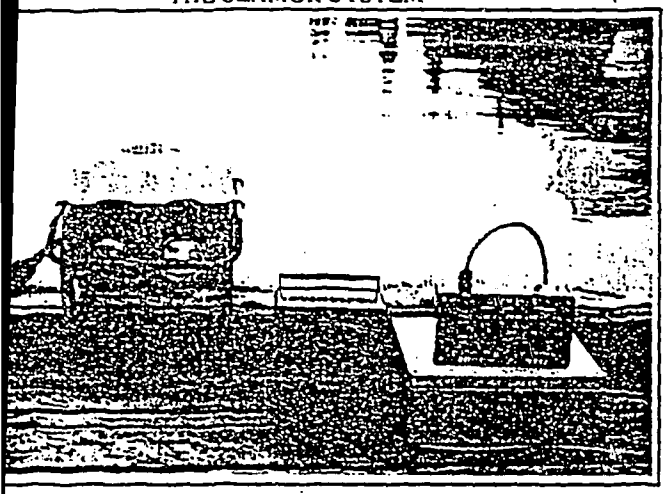
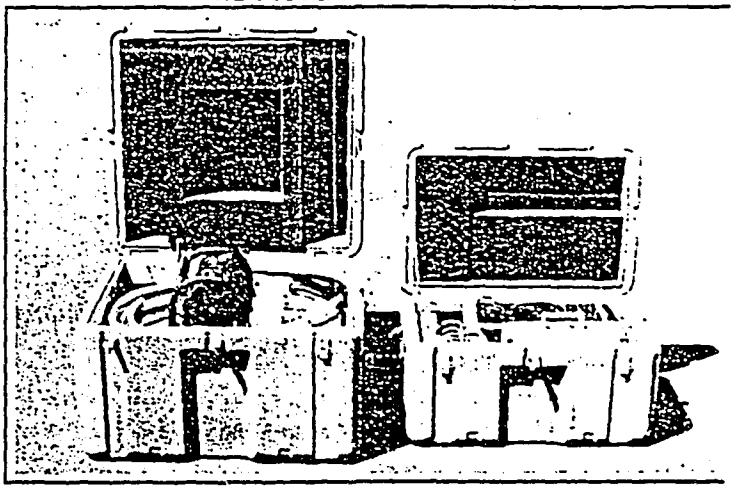


Figure 4 - SIGMUND

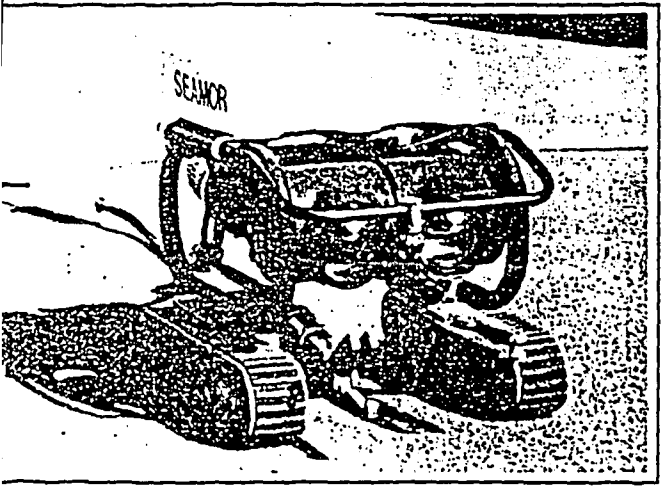
THE SEAMOR SYSTEM



THE SYSTEM READY TO SHIP



TED WITH A SET OF UNDERWATER TRACTOR TRACKS



FITTED WITH AN I.T.C. STEREO VISION SYSTEM

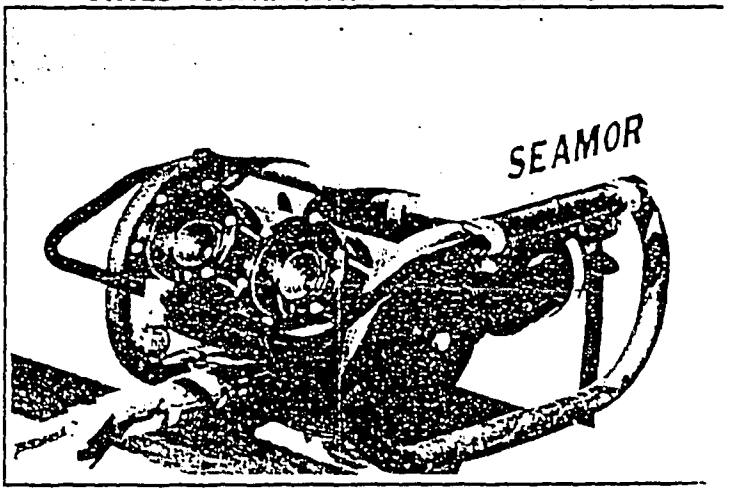
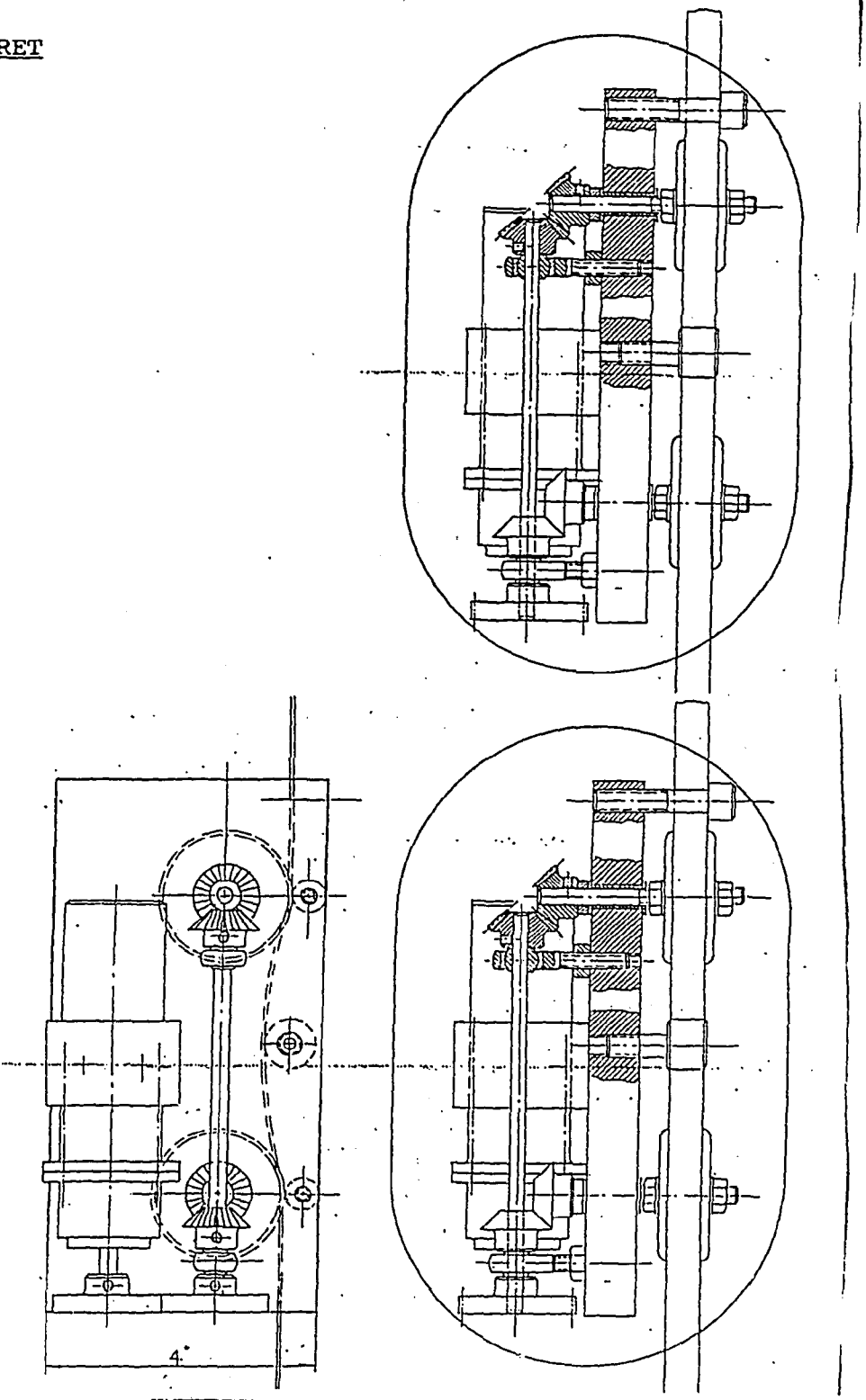


Figure 5 - FERRET



SIDE VIEW ---

Figure 6 - FRED

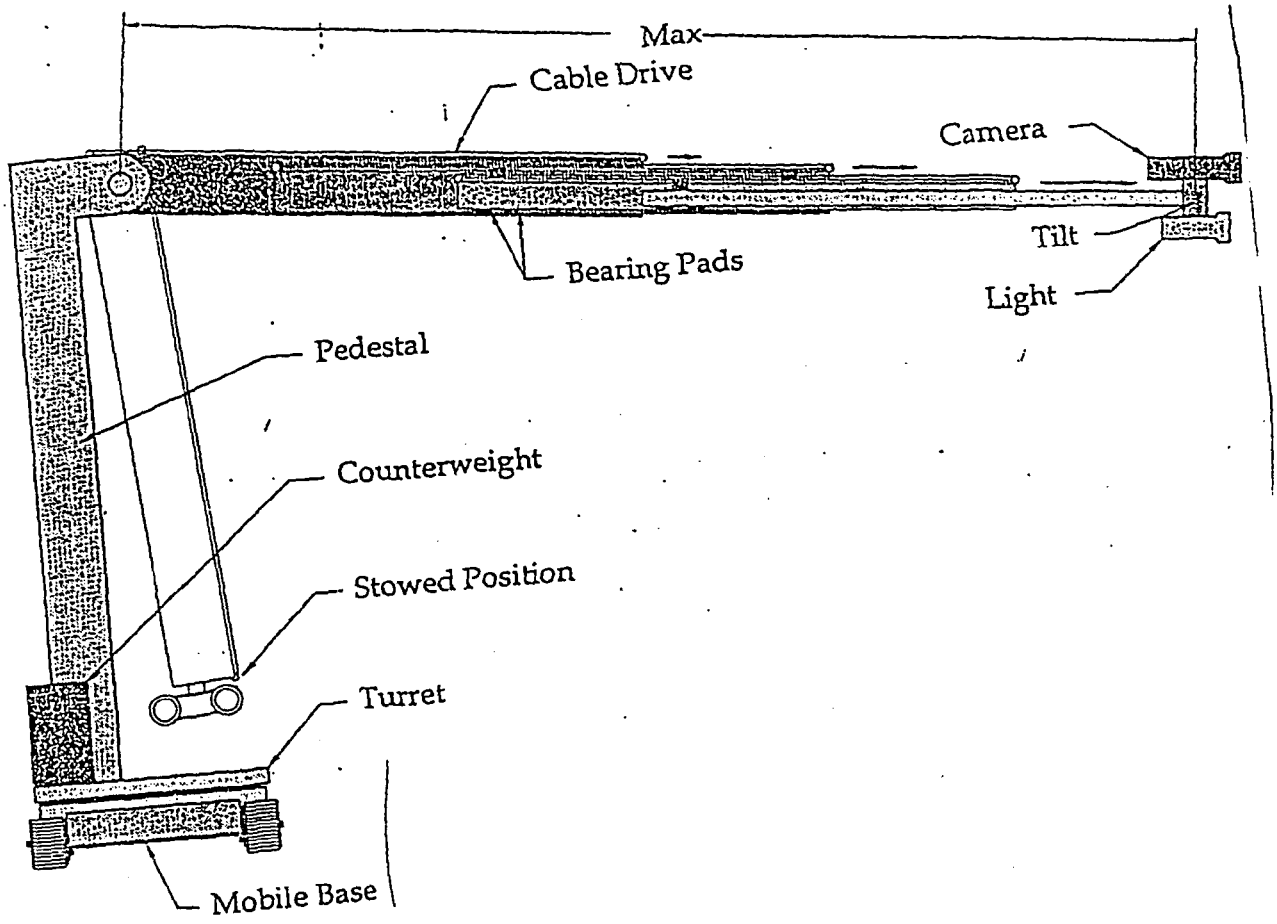
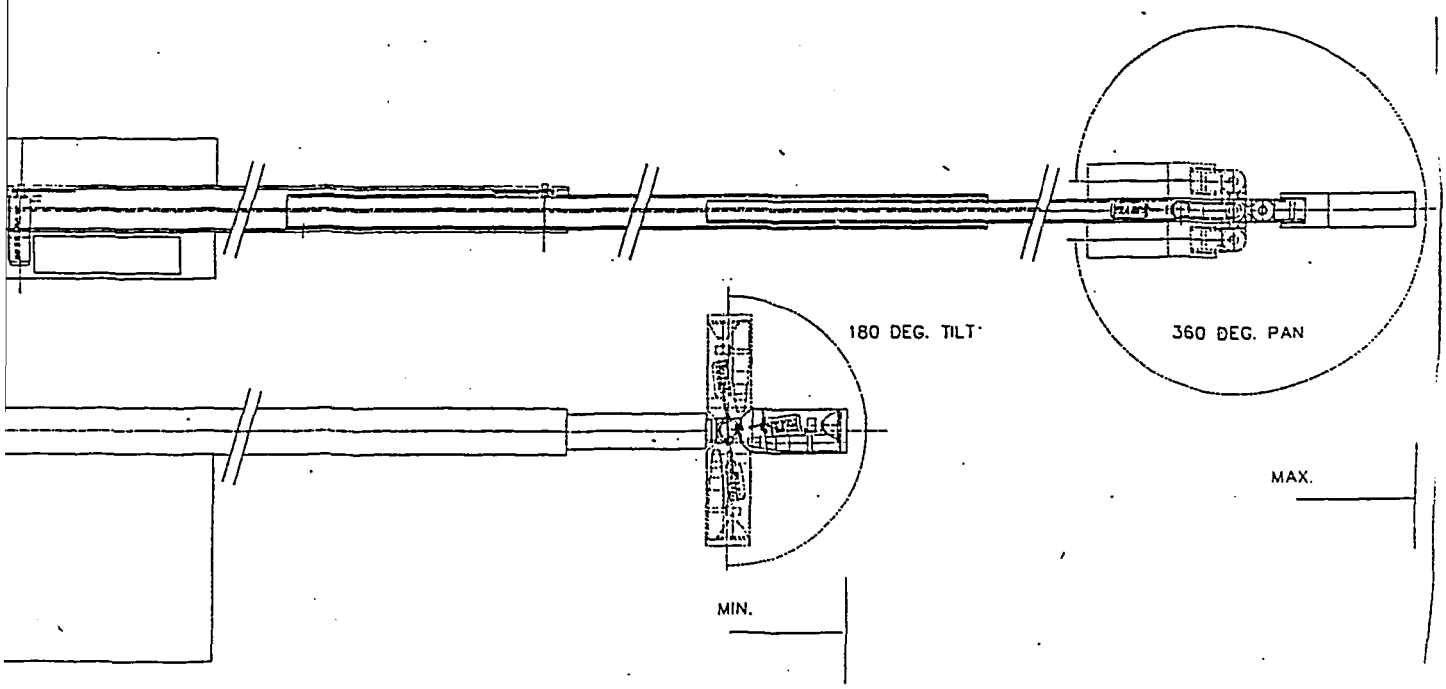


Figure 7 – ETHEL



CA9500148

PICKERING NGS-A REACTIVITY MECHANISM DECK MAINTENANCE

T. E. Smart & M. R. Lougheed

Ontario Hydro

ABSTRACT

This paper reviews the extensive reactivity mechanism deck maintenance that has taken place during the current pressure tube replacement outage on Pickering NGS-A Unit 4. This maintenance has included replacement of in-core components such as Neutron Flux Monitors and Adjuster Rods, as well as replacement of obsolete Shutoff Rod drive mechanisms with modern replacements. The problems encountered and the lessons learned during this maintenance work will also be discussed.

PICKERING NGS-A REACTIVITY MECHANISM DECK MAINTENANCE

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INTRODUCTION

During the course of the current Pickering NGS-A Unit 4 pressure tube replacement outage, a considerable amount of maintenance work has been undertaken on the reactivity mechanisms deck. This work has involved both the equipment situated on the deck proper, as well as the replacement of in-core components associated with the deck (such as Neutron Flux Monitors, Shutoff Rods and Adjuster Rods).

This work was undertaken by the staff of the Operations Rehabilitation Section, who are responsible during the outage for all maintenance and modification work on the unit (apart from the pressure tube replacement work).

This paper will present an overview of the various aspects of the maintenance/modification work performed during the outage, along with specific details when they serve to illustrate the lessons learned during the outage. After addressing the individual system work in turn, the general lessons learned will be presented.

ADJUSTER RODS

Maintenance and Modifications

Until recently, the adjuster rods at Pickering NGS-A were composed primarily of cobalt. The rods must be replaced periodically in order to ensure that the safety limits on cobalt irradiation are not exceeded. For both economic and worker safety reasons, it has been decided that the Pickering NGS-A cobalt adjuster rods will be replaced with stainless steel rods. These rods will not require periodic replacement, thus largely eliminating the economic costs and worker hazards associated with the handling of highly irradiated cobalt rods.

In order to maintain neutronic equivalency, the stainless steel rods weigh approximately four times as much as the cobalt rods. During pre-installation testing at the station on the reactivity

mechanisms deck rehearsal facility, it was discovered that the existing adjuster rod drive mechanism motor is not capable of reliably driving the heavier steel rod. Following procurement of a stronger motor, it was discovered the combination of heavier rod and stronger motor resulted in an unacceptable rate of wear of the worm gear assembly. Furthermore, it was found the settings of the existing motor protection (thermal overload) and control (current sensing) relays were no longer appropriate given the characteristics of the new motors.

New worm gear assemblies and motor circuit relays were obtained, and the entire assembly was then found to work well together.

In addition to the above work associated with the new steel rods, all of the existing adjuster rod cables on the deck were replaced during the outage. These motor and potentiometer cables were replaced from the drive mechanism to the local junction box in order to ensure reliable service for the remainder of the generating station's life.

Lessons Learned

Altering a single key component in a system may introduce a cascade of unforeseen additional modifications. The change from cobalt to stainless steel rods was initially seen as a simple and uncomplicated change to a mature and relatively trouble-free adjuster rod system. Instead, a number of unanticipated "weak links" in the existing design were uncovered by pre-installation testing at site. This illustrates the need to:

-consider all related system components when a change is introduced. If possible, this should involve consideration of the change by the various Design disciplines whose components *might* be affected by the change.

-perform pre-installation testing as early as possible, and in an environment which models field conditions as closely as possible. In this example, the use of a duplicate motor control and protection circuit made possible the timely discovery of the inadequacy of the existing relays.

-know where to look to see early evidence of an inadequate design. In this example, it was the detailed knowledge of adjuster rod drives gained during the earlier Unit 3 pressure tube replacement outage which lead to the discovery of premature worm gear wear. The staff knew from Unit 3 experience that the worm gears might be nearing the end of their useful life, after about 20 years of service. This lead them to anticipate possible problems on Unit 4 given the increased service demands on the worm gears.

NEUTRON FLUX MONITORS (NFMs)

Maintenance and Modifications

The eight existing in-core NFM assemblies were removed during the outage, and replaced with six HESIR (Hybrid Encapsulated Straight Individually Replaceable) units. Two sites were left empty since detectors in these sites were no longer required by the Shutdown System. This replacement was done due to concerns with on-going operational failures of the old NFMs, as well as anticipated widespread failures during the pressure tube replacement process (due to accelerated corrosion because of a lack of chemistry control in the calandria). The new 'encapsulated' NFMs do not require continuous D2O cooling, so the D2O supply lines to the assemblies were cut back to the D2O ring header and capped.

For earlier NFM removals on units undergoing pressure tube replacement, the highly irradiated portions had been transported to the Irradiated Fuel Bay (IFB) for interim storage. This was recognized as being less than satisfactory, since it cluttered the IFB and incurred future dose commitments for the final disposal of the NFMs.

On Unit 4, the highly irradiated portions were flasked in the Boiler Room, transported out of the Reactor Building, and then cut into short (0.5 m) lengths using a newly developed remote cutting tool. After being cut, the short lengths were placed into an interim flask to await transport to Bruce Nuclear Power Development (BNPD) for final storage.

In addition to the above work, the existing coaxial cables (running from the reactivity mechanisms deck to the amplifiers in the accessible area of the Reactor Building) were replaced with new triaxial cables. This was done to ensure continued reliable operation.

Lessons Learned

It is useful to carefully consider the interfaces between new equipment and remaining original equipment. This applies equally to mechanical and electrical/control aspects of a job. To illustrate:

-specialized wiring kits were required to allow an acceptable connection to be made from the new triaxial cables to the existing coaxial connections on the NFM amplifiers. This was done in favour of modifying the amplifiers in order to keep the amplifiers on all four Pickering NGS-A units identical (note Units 1 and 2 did not replace cables during their pressure tube replacement outages).

-the underside of the deck shielding plates needed to be machined out by about 3 cm in order to accommodate the higher profile of the new NFM assemblies.

Some aspects of a job may appear to be well defined since existing equipment is being replaced. For example, when replacing cables, the new cables will usually follow the same routing as the old cables (unless a concern with inadequate channelization has been identified). However, when the adjuster rod, shutoff rod and NFM cables were being replaced, it was not immediately clear if the original routing was the right routing. There are only two small cable pans circling the Pickering NGS deck, separated vertically by about 30 cm. These pans must carry:

-channel D, E, and F shutdown system cables
-channel A and B regulating system cables
-odd and even power cables
-odd and even instrumentation cables (some carrying picoAmpere currents)

In light of unclear or nonexistent design documentation, it was necessary to carefully consider the various aspects of channelization, and separation of control and power cables, to determine the optimum routing for the cables. Indeed, it was necessary to route the channel F cables in conduit instead of the pans.

With regards to the removal of the highly irradiated portions of the NFMs, the keys to success were planning and rehearsals. In the Operations Rehabilitation Section, a particularly rigorous approach to the preparation for high hazard radioactive jobs is enforced. For example, two separate proactive System Safety Analysis techniques must be used; one of them being a planning technique (such as Job Safety Analysis or Job Steps & Conditions Charting) and the other a focused technique (such as Energy-Barriers Traces or Change Analysis). Just as important as the technique being employed, the team members doing the analyses are the staff who will be doing the actual job. Technical/engineering staff, Production Unit personnel and Health Physics representatives work together to ensure a safe job.

Following the System Safety Analysis, rehearsals of the job were performed. On Unit 4, special attention was paid to the cutting of the highly irradiated NFMs using the remote cutting tool. Lessons learned in this area included:

-make the rehearsal setup as close to the reactor environment as possible. For example, spare NFM assemblies were used to practice cutting.

-try to anticipate the ways in which your rehearsal setup *doesn't* duplicate reactor conditions. If you know the differences, you can compensate. For example, the old Pickering NFM assemblies have unencapsulated wires wrapped around a central support rod. When the assembly is cut into short segments, the wires have a tendency to "spring" out, creating a possibility of jamming the remote cutting tool. It was unclear how irradiation would affect the properties of the NFM wires, and therefore there was some

uncertainty about how closely the rehearsal NFMs' behaviour would match that of the irradiated NFMs. It was necessary to ensure that the cutter mechanism would remain unjammed regardless of the behaviour of the wires when cut.

-give adequate time for your analysis team to do its job right. Two days is often required for a complex job. During the analysis, encourage "black hat" thinking by team members as they think of ways in which the job could go wrong; this kind of thinking must be regarded as a positive input to the job planning, not as nit-picking and criticizing.

SHUTOFF RODS

Maintenance and Modifications

New Mark III shutoff rod mechanisms were installed in place of the original Mark I mechanisms, in order to improve shutoff rod reliability and performance. The original mechanisms were just below deck level, in individual pits, while the new mechanisms were installed at deck level via the use of extension flanges. While this new location measurably improves access to the mechanisms during maintenance, the deck has become considerably more crowded.

As with the new NFM assemblies, the new Mark III mechanisms do not require D2O; the original mechanisms needed D2O for lubrication. The D2O lines were cut back to the ring header and capped. In order to enhance rod performance, the Mark III rods have accelerator springs.

Since the original rods were not compatible with the new Mark III mechanisms, the old shutoff rods were removed from core and flasked. The flasked rods were lowered out of the Boiler Room onto a cutting platform in the accessible area of the Reactor Building. The rods were then cut into 5 segments, and dropped into a flask for shipment to BNPD.

As with the adjuster rods, new power and control cables were installed from the drive mechanisms to the local junction boxes. Also, it was found during pre-installation testing that new thermal overload relays would be necessitated by the new stronger drive motors.

As part of the Mark III drives, new 'rod ready' indicators were installed to provide positive indication that the rods are truly poised. To accommodate the required odd/even separation of the two 'rod ready' channels, new junction boxes were installed on the east and west sides of the deck. The routing of these cables has already been discussed earlier in the NFM section of this paper.

During testing it was found that the phasing was incorrect for all of the new Mark III motors. Unfortunately, unlike the old motors, there was no connection box mounted locally on the motor itself to

permit easy switching of phases. Instead, a special pin removal tool was obtained to permit the reversal of the phases by altering the configuration of pins inside the Cannon connector.

Lessons Learned

A key to success during the shutoff rod work was flexibility in scheduling. As work paused in one area due to problems, other work was accelerated to take advantage of the free time on the deck. This was accomplished via frequent meetings with the affected staff (Technical/engineering, Production, and Planning), and cooperation from all groups.

Another major contributing factor was the use of a dedicated team of Mechanical Maintenance staff to perform the entire job. This included commissioning of the equipment, rehearsals, participating in high hazard reviews, and the actual removal job itself. The detailed equipment knowledge gained by the team led to time savings in all aspects of the job. For example, when problems arose during rehearsals with the safety interlocks provided as part of the equipment design, the team was able to improvise and develop alternative methods of ensuring safe operation. The adequacy of these alternative solutions was, of course, rigorously assessed using system safety analysis techniques.

Anther useful item was a post-job review meeting. This meeting allowed all of the staff involved in the process to gather together and discuss all concerns associated with the job. At a multi-unit station such as Pickering NGS-A, improvements suggested at the post-job review will be particularly useful as this same job is performed on the other three units.

D2O SUPPLY HEADER

Maintenance and Modifications

Circling the reactivity deck are two headers supplying D2O cooling flow to the deck mechanisms and assemblies. Due to the accumulation of activated corrosion products in these headers, general fields in some areas of the deck approached 400 mRem/hr. Fortunately, as described earlier, the new Mark III shutoff rod mechanisms and the new HESIR NFM assemblies do not require D2O flow for cooling or lubrication, unlike their predecessors. Because of this, it was possible to remove the header which supplies the SA rods and NFMs (the AA rods being supplied from the other header).

Lead blankets were placed over the high dose portions of the headers, and the low dose piping was cut out and disposed of in 45 gallon drums. The remaining high dose piping was disposed of in lead-lined drums with the lead blankets still wrapped around the pipework.

Following the job, the general fields dropped from 400 mRem/hr to about 120 mRem/hr, resulting in a considerable drop in dose expenditure for the remaining deck jobs.

Lessons Learned

Although a significant amount of dose was expended to remove the header (on the order of 1 Rem), this was more than compensated for by the reduced doses during the rest of the deck maintenance and modification work. Besides overall dose reduction, higher quality work was possible due to a less confined working space.

It is also relatively easy to maintain a heightened safety awareness when performing a high hazard job such as the header removal. It is less easy to do so over an extended period of several months when doing a multitude of maintenance and modification jobs in the area of the deck. Removing the header, therefore, contributes to a reduced risk of an unplanned radiation exposure.

By carefully considering the complete scope of work to be performed in an area, it is possible to make a reasoned judgement about the value of removing obsolete equipment.

SUMMARY

Based on experience on previous unit outages, it was decided to stage the deck work in three phases:

-remove old equipment (rods, NFMs, cables); roll back and protect cables not being replaced (Mark II shutoff rods)
-install new mechanical equipment (rods, NFMs)
-install new instrumentation and cables

This approach served to minimize dose, and to reduce the chance of less robust cabling being damaged during the installation of heavy mechanical components.

No job proceeds in isolation; it is necessary to consider the entire job environment when assessing the timing, manpower requirements, etc. For example, the Boiler Room crane experienced innumerable periods of unavailability, leading to delays in the mechanical portions of the work. This in turn resulted in delays to the instrumentation portions of the job.

With the multitude of jobs being performed on and around the deck, planning was essential. Each activity was assigned a target date, and progress versus these dates closely monitored. In essence, the deck work was completed on time because each of the individual jobs was finished on time.

In summary, a team approach to the entire reactivity mechanism deck job proved to be successful. This was true for both the

coordination of the overall deck rehabilitation as well as for the highly challenging individual system tasks.

Flux Detector Replacement Tooling Procedures

E.P. Ahearn, Point Lepreau, New Brunswick Power

This paper was not available at the time of printing.

Measurement of Calandria Tube to LISS Nozzle Proximity at Bruce NGS-A

A.B. Mitchell, R.P.C., New Brunswick

This paper was not available at the time of printing.

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FUEL CHANNEL INSTALLATION TOOLING FOR RETUBING BRUCE REACTORS

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ABSTRACT

Installing replacement fuel channels in CANDU reactors as part of a large scale fuel channel replacement program ("retubing") involves the use of a large number and variety of highly specialized tools. During the retubing of the Pickering reactors, the tooling proved to be a key factor in outage time, dose consumption and the final quality of the installed channels.

As the Pickering A units were successively retubed, the tools underwent continuous development and refinement. Today, many of these tools form the basis of a new generation of tools currently being developed for retubing the Bruce A reactors.

1. GENERAL

The actual work performed at the reactor face to retube a CANDU reactor is divided into two main phases, namely, the complete removal of all fuel channels in the vessel and the installation of new channels. This paper is concerned only with tooling used during the installation phase.

Installation of the new channels is carried out by personnel working in large elevating shield cabinets, one of which is located at each end of the reactor (see Figure 1). Each cabinet is equipped with a retube tool carrier (RTC) used for craning tools and components. Two work tables are provided in each cabinet for tool support and alignment.

2. FUEL CHANNEL INSTALLATION SEQUENCE

The basic sequence for installing replacement fuel channels is to complete the installation on one row before moving onto the next. As each channel is removed, a temporary shield plug and an extension sleeve are inserted into the lattice tube of the empty site. The extension sleeve allows tools to be transported between the shield cabinet and the lattice site and provides support for the loose feeders.

The main installation steps for each fuel channel of each row are as follows:

1. Clean the lattice tube and remove any debris from the calandria tube;

2. Visually inspect the lattice site (including the calandria tube);

3. Install the replacement pressure tube as a subassembly (Each subassembly includes the replacement west end fitting and the garter springs);

4. Position the garter springs at the correct locations on the pressure tube and confirm the location of the springs;

5. Weld the west end fitting to the existing stop collar;

6. Install the replacement east end fitting;

7. Roll the east joint; and

8. Weld the east end fitting to the existing bellows.

3. CLEANING AND REFURBISHING

The main cleaning operation involves brushing and vacuuming the bore of each lattice tube. This is accomplished using a combined vacuum and brushing tool which is cantilevered from a carriage mounted on a work table, as shown in Figure 2. The carriage is used to insert and extract the tool from the lattice tube at each lattice site.

The tool incorporates a rotating brush head with suction ports which vacuum debris and dust as the lattice site is brushed. The brush head, designed specifically for the cleaning tool, is comprised of a set of nylon bristles tipped with 1/2 inch diameter carbide balls. As the brush is rotated, the abrasive carbide tips remove surface debris from the lattice tube and the bearing surfaces while leaving a honed finish equal to or better than the original surface finish.

Refurbishment of the lattice site is limited to a manual deburring of the leading edge of the stop collar and bellows. The burrs are a result of removal operations and could prevent full insertion of a new end fitting. The tools used are simple hand tools equipped with hard tipped cutters that scrape the burrs away during manual rotation of the tools. Burr removal is confirmed by the use of plug gauge tools which are inserted into each bellows and stop collar.

4. INSPECTION AND MEASURING

Three visual inspections are carried out during retubing. These are: forward viewing down the length of each lattice tube and calandria tube; right angle viewing of the calandria tube insert and inboard bearing sleeve; and right angle viewing in the region of the new pressure tube rolled joint.

Visual inspection is carried out using closed circuit television (CCTV) cameras mounted in special housings. Unlike the Pickering video inspection tools, which were entirely custom built, each Bruce tool is of a completely new design which incorporates a pre-packaged nuclear camera system which can be controlled from outside the shield cabinet. The camera systems used in these tools are built by the supplier specifically for the rigorous environment of nuclear maintenance. The cameras are housed in rugged casings and are supplied with integral lights, lenses, right angle prisms, cables, etc. The control units are not dedicated to specific cameras. This allows several cameras to be controlled by one control unit while eliminating the necessity of readjusting the equipment when alternating from one camera to another. The control unit, along with a CCTV monitor, is mounted on a rail in the shield cabinet.

4.1 Forward Viewing Inspection

Once the cleaning of the lattice tube has been completed, visual inspections of the lattice tube and calandria tube bores are carried out using the forward viewing tool. The forward viewing tool has been designed to travel down the lattice tube as far as the calandria tube insert, allowing personnel to view down the length of a lattice tube and calandria tube in search of loose debris.

The forward viewing tool is initially supported in a housing which is attached to a rail inside the shield cabinet, as shown in Figure 3. The design of the housing attachment allows the tool to be moved horizontally along the rail to any fuel channel site.

The forward viewing tool operation involves aligning the housing with an open site and connecting it to a lattice tube extension sleeve already installed in the major bore of the lattice tube. A trolley containing the camera is driven out of the housing and down the lattice site. The camera, equipped with remote focus and zoom control, can detect objects as small as 1/8 inch diameter from a distance of 20 feet.

Among the design requirements for installation tooling is the necessity that each tool be capable of coping with a calandria tube sag of up to 2 inches. The forward viewing tool satisfies this requirement by incorporating a powered tilt mechanism which

allows the camera to view the sagged bottom of a calandria tube.

4.2 Right Angle Viewing

With the exception of a right angle viewing head, the right angle viewing tools use the same video components as the forward viewing tool. Areas that cannot be viewed with the forward viewing tool, those in the vicinity of the calandria tube insert and the inboard lattice tube bearing, are inspected using the first of two right angle viewing tools. During this inspection, the tool is required to first detect and then retrieve loose debris. A vacuum nozzle on the inboard end of the tool is used to capture any visible debris, and is capable of retrieving particles as large as a 1 inch length of broken garter spring. A schematic of the arrangement is shown in Figure 4.

The second right angle viewing tool is used to inspect the condition of the east pressure tube rolled joint of the newly installed fuel channel. The purpose of the inspection is to search for possible damage in the rolled joint region and to confirm that the joint has been formed in the correct axial location. This tool uses the same major components as the tool used for right angled viewing of the lattice tube bore.

Each right angle viewing tool is mounted on a work table trough and is advanced into a lattice site using the powered axial drive of the trough. When used for viewing the rolled joint, the outer sleeve of the tool used for viewing the lattice tube bore is removed and replaced with a smaller diameter sleeve which allows the tool to fit inside the end fitting.

5. FUEL CHANNEL INSTALLATION TOOLING

Fuel channel installation tooling, which comprises the majority of the tooling, is used to insert, support, align and clamp replacement fuel channel components (pressure tubes, garter springs and end fittings) during installation of the components at each lattice site. Also included in fuel channel installation tooling is the detection equipment necessary for confirming the locations of the garter springs.

5.1 Subassembly Installation

A prefabricated subassembly is prepared which includes the replacement pressure tube and the west end fitting. The subassembly is inserted from the west end of the reactor using a special fixture attached to the RTC. The fixture, which is essentially a structural steel beam, is bolted to the RTC with the subassembly underslung from the beam by means of a carriage and roller support system.

5.2 Garter Spring Installation

To protect the pressure tube during installation, a nylon tube is placed over the full length of the pressure tube. Attached to the pressure tube protective sleeve, at the end fitting end, is a magazine device containing the four new garter springs. As the sleeve is pulled off of the pressure tube from the east end, after the subassembly has been inserted into the fuel channel, each garter spring is automatically ejected from the magazine at the appropriate axial location along the pressure tube.

The tooling that pulls the sleeve off of the pressure tube also includes the detection equipment used to confirm and record the position of each garter spring. As each spring is deposited on the pressure tube, the detection system confirms the correct location of the spring before the next spring is ejected from the magazine. Schematic arrangements of this tooling are shown in Figures 5 and 6.

5.3 End Fitting Installation

Once the subassembly and garter springs have been installed, the replacement end fitting can be installed at the east end of the reactor. An installation mandrel, which extends the full length of the replacement end fitting, is inserted into the bore of the end fitting. Once the end fitting is mounted on the mandrel, the end fitting and the mandrel are transported to the reactor face using the RTC. At the reactor face, the end fitting mandrel assembly is attached to a carriage mounted on the work table. When attached to the carriage, the installation mandrel provides a cantilevered support for the end fitting. The carriage provides axial motion to advance the end fitting into the lattice site.

Close to the rolled joint region of the end fitting, a set of electronic measuring probes is mounted in the mandrel. These probes are used immediately prior to the pressure tube entering the end fitting bore to measure any angular misalignment between the end fitting bore and the leading end of the pressure tube. A schematic arrangement is shown in Figure 7. It is particularly important that the angular misalignment between the two components be minimised. Misalignment of these components can make insertion of the pressure tube into the end fitting bore difficult and can lead to higher residual stresses in the finished rolled joint. In the event that the misalignment is outside the permissible tolerance, a small straightening tool is inserted into the pressure tube from the opposite (west) end of the reactor. The straightening tool is actuated until an acceptable alignment is achieved, at which point the pressure tube can be fully inserted into the end fitting bore. The straightening tool remains actuated in the pressure tube until the rolled joint has been made.

6. ROLLED JOINT TOOLING

Rolling of the east pressure tube joints for the Bruce retube involves several significant changes to both the geometry of the joint and the tooling required to roll the joint. The reasons for the changes are two fold. The first of these is the desire to reduce the time required to install fuel channels. The second is to increase the support provided to the inlet fuel bundle by the pressure tube. Each of these is briefly discussed below.

Rather that installing a liner assembly in an end fitting at the reactor face after rolling of the pressure tube, by installing a liner assembly in each east end fitting off of the reactor face prior to pressure tube rolling, both the time and dose required to install a fuel channel can be reduced. However, until now, installation of the liner assemblies in end fittings prior to rolling of the pressure tube has not been carried out at Bruce. This is due to the fact that, for the geometry of the rolled region of Bruce fuel channels, during the initial phase of rolling, the rollers will roll the liner assembly prior to rolling the pressure tube. To prevent rolling of the installed liner assembly, the geometry of the rolled joint and liner assembly has been modified. By shifting the axial position of the joint inboard by approximately one half inch, and lengthening the end of the liner assembly by the same amount, the inboard end of the liner assembly can be stepped to allow the rollers to pass without interference, as shown if Figure 8. The step does not affect the support provided to a fuel bundle by the liner.

In a conventional rolled joint, the wall thickness in a region at the end of a pressure tube is reduced by rolling. This results in the rolled region of the pressure tube being of a larger bore than the remainder of the tube. Historically, the enlarged bore of the rolled region of the inlet end of each pressure tube, has provided poor support for the outermost fuel bundle at the inlet end of the fuel channel. For the Bruce retube, on the inlet end only, the joint will be rolled in such a way as to eliminate the enlarged bore. Thus, after rolling, the rolled region of the pressure tube will be of the same diameter, that is, flush with the unrolled portion of the tube, as shown in Figure 9. The result of this is that, with the enlarged bore eliminated, the flush rolled joint improves the support provided by the inlet joint to the inlet fuel bundle.

Tooling used to make the flush rolled joint is similar to that used for the conventional joints. However, the flush rolled joint is slightly longer than the conventional joint and consequently the rollers in the rolling tool are longer. Also, the setting of the rolling tool diameter and the axial position of the joint are different from conventional joints. Since the flush rolled joint is made only on every other fuel channel (inlet ends only), alternating with conventional joints, the

rolling tools will be colour coded to ensure that the correct tooling is inserted into each channel.

7. CONCLUSION

Installing replacement fuel channels in CANDU reactors as part of a large scale fuel channel replacement program requires many specialized tools. While the tools developed during the retubing of Pickering form a basis for the tools to be used during the retubing of Bruce, the tools continue to evolve as part of the effort to improve the quality of the replacement fuel channels and reduce the time required to perform the retube. The number of tools newly developed for use at Bruce represents a significant contribution to that effort.

Funding for tooling development has been provided by Ontario Hydro as part of the Bruce A large scale fuel channel replacement program.

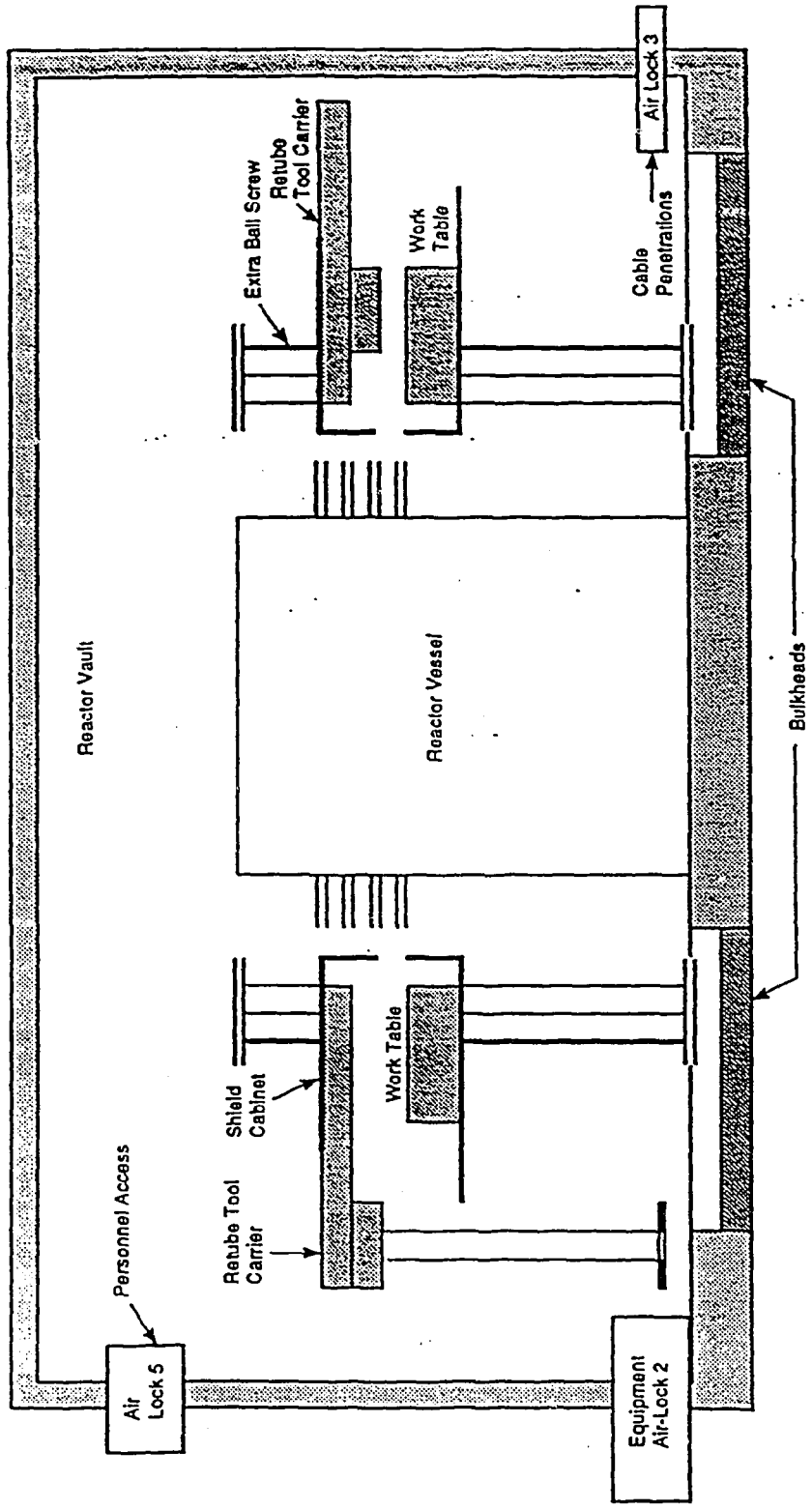

Figure 1
Retube Vault Arrangement

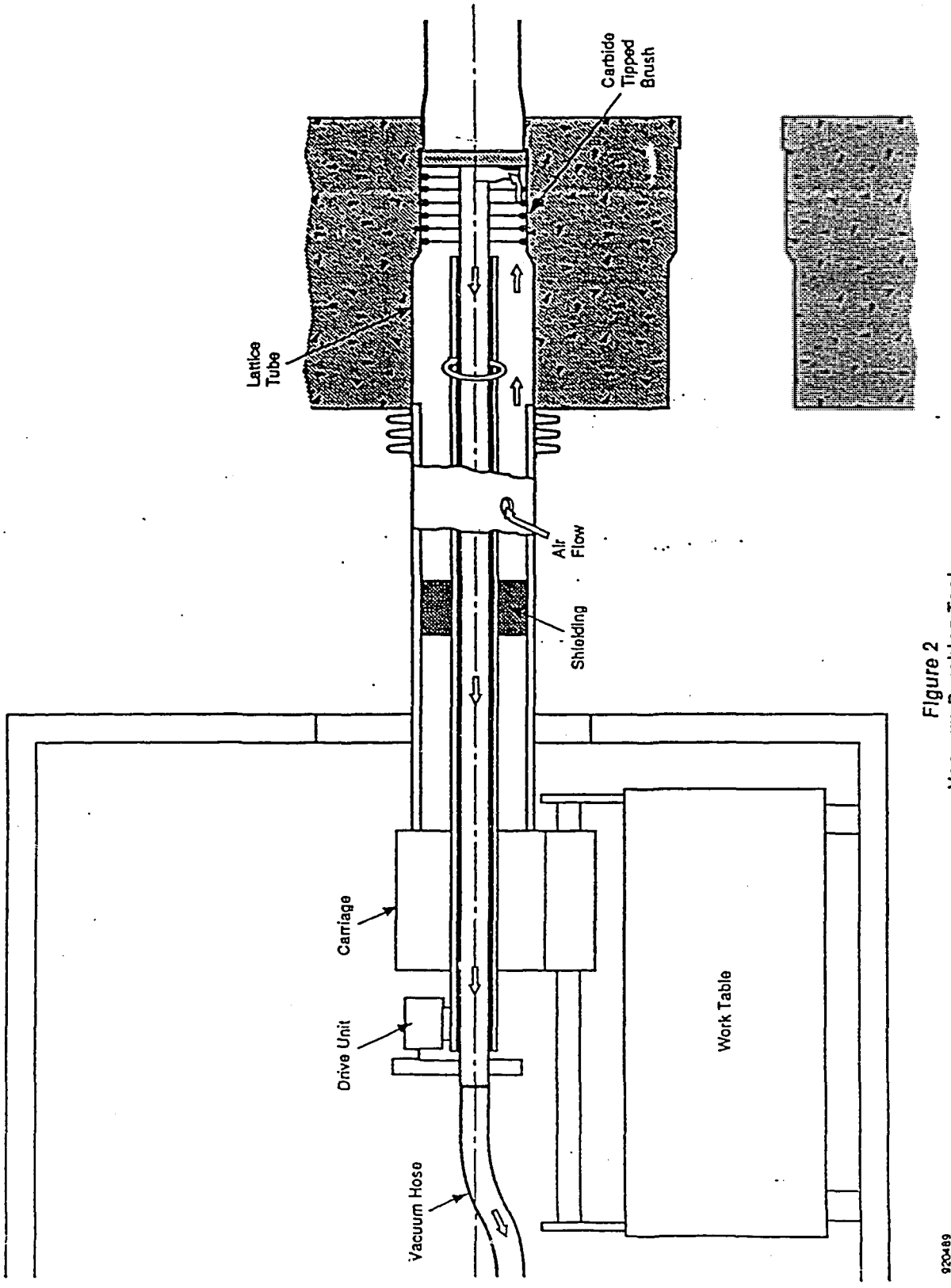

Figure 2
Vacuum Brushing Tool

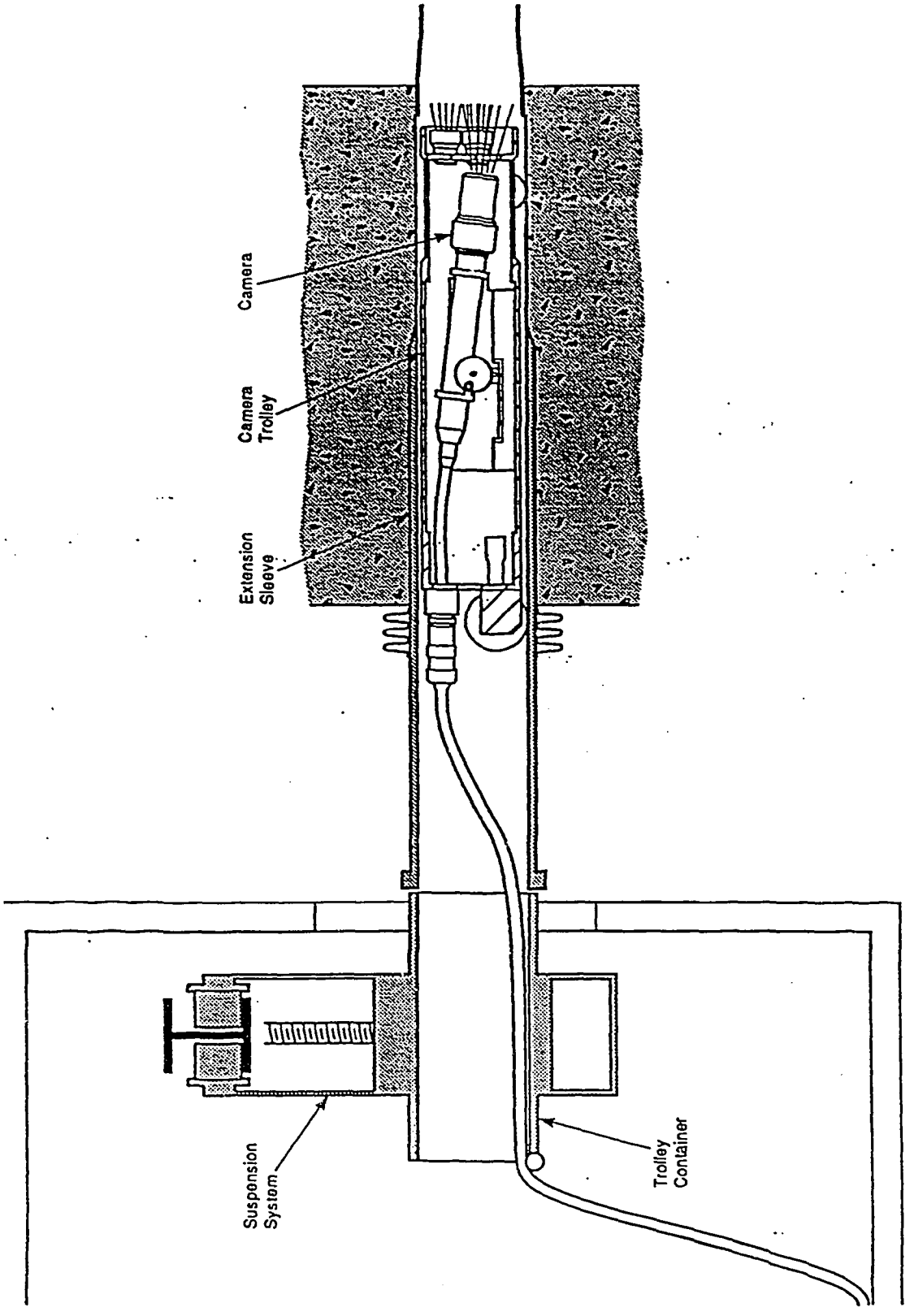

Figure 3
Forward Viewing Tool

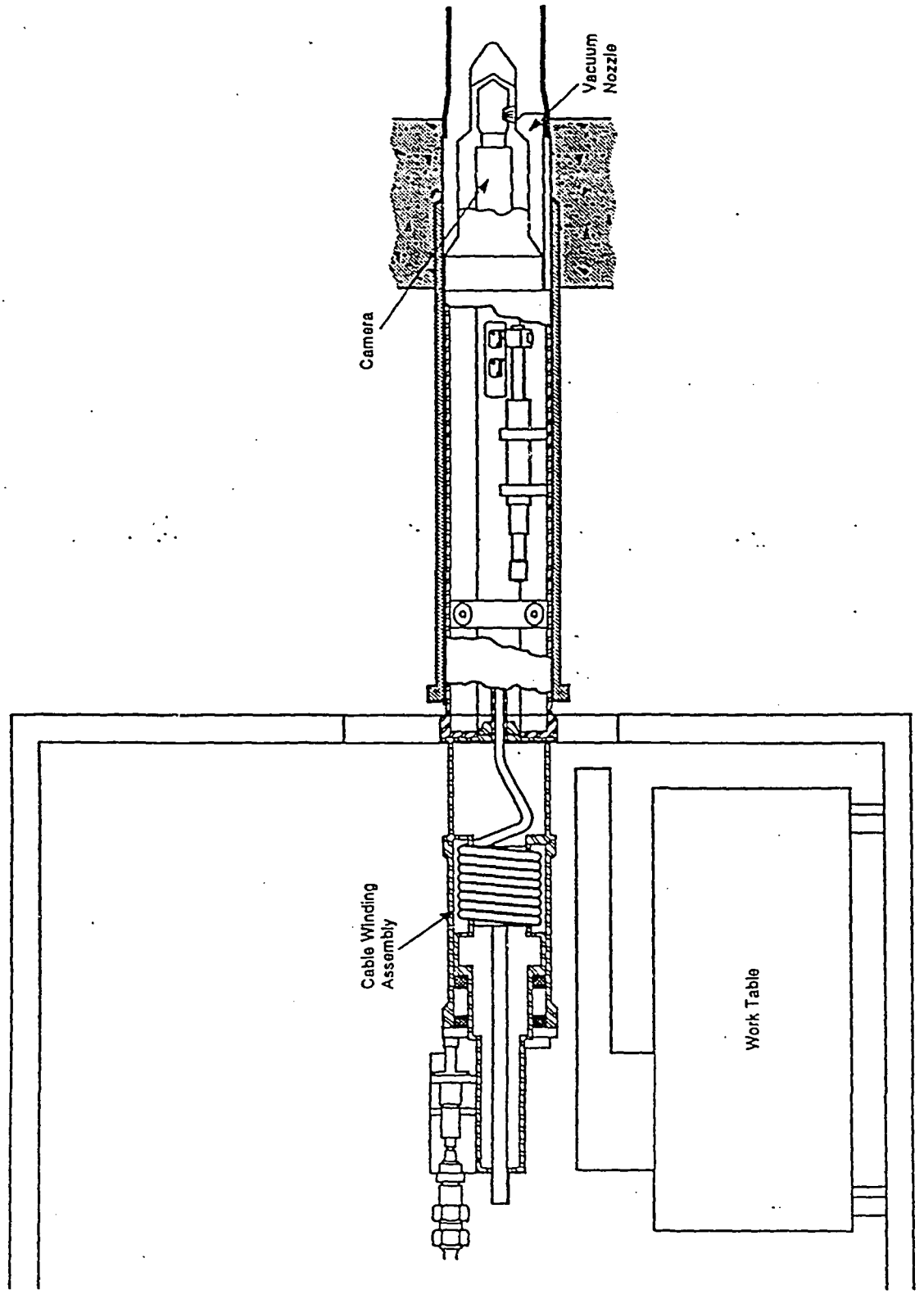

Figure 4
Right Angle Viewing Tool

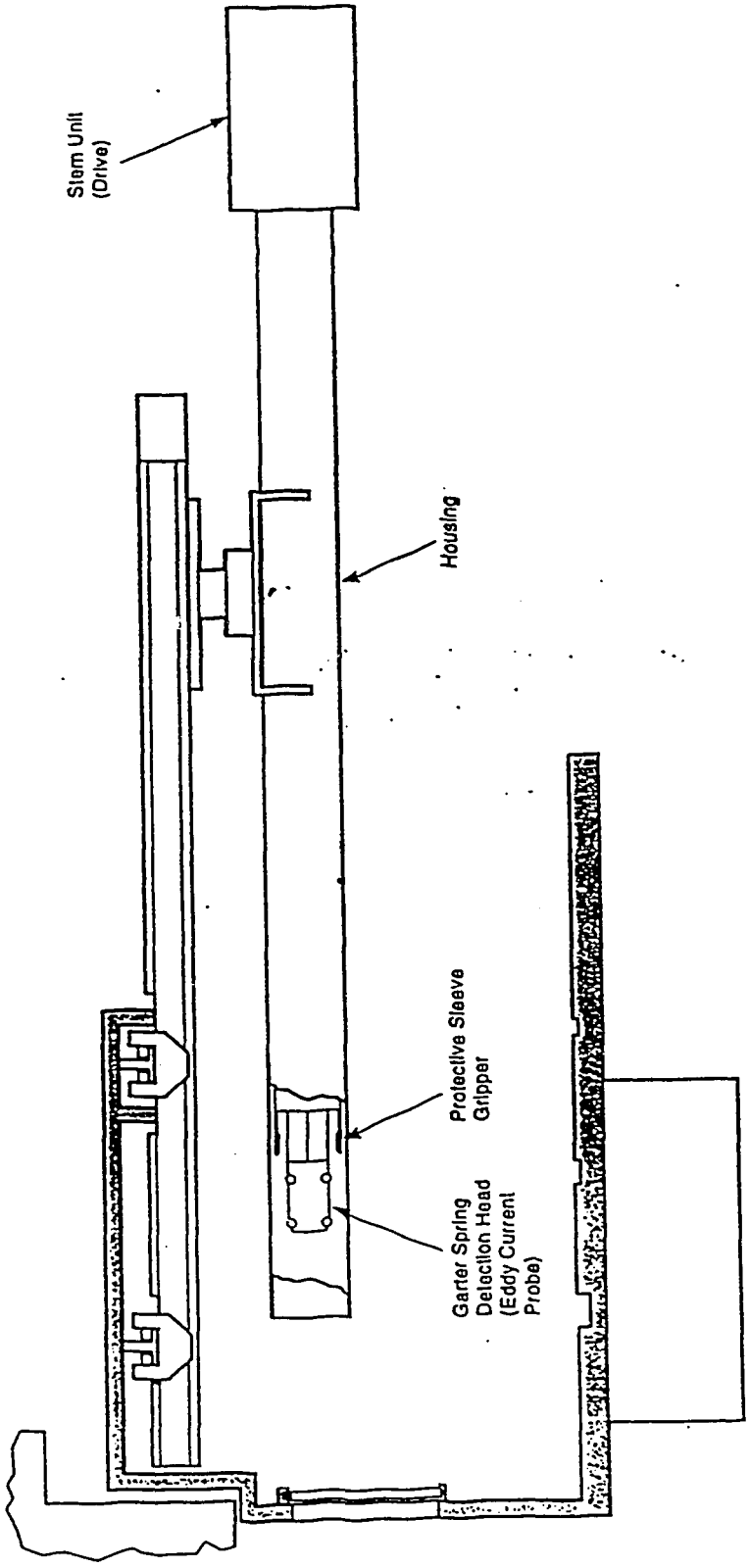

Figure 5
Protective Sleeve Removal Tool (East End)

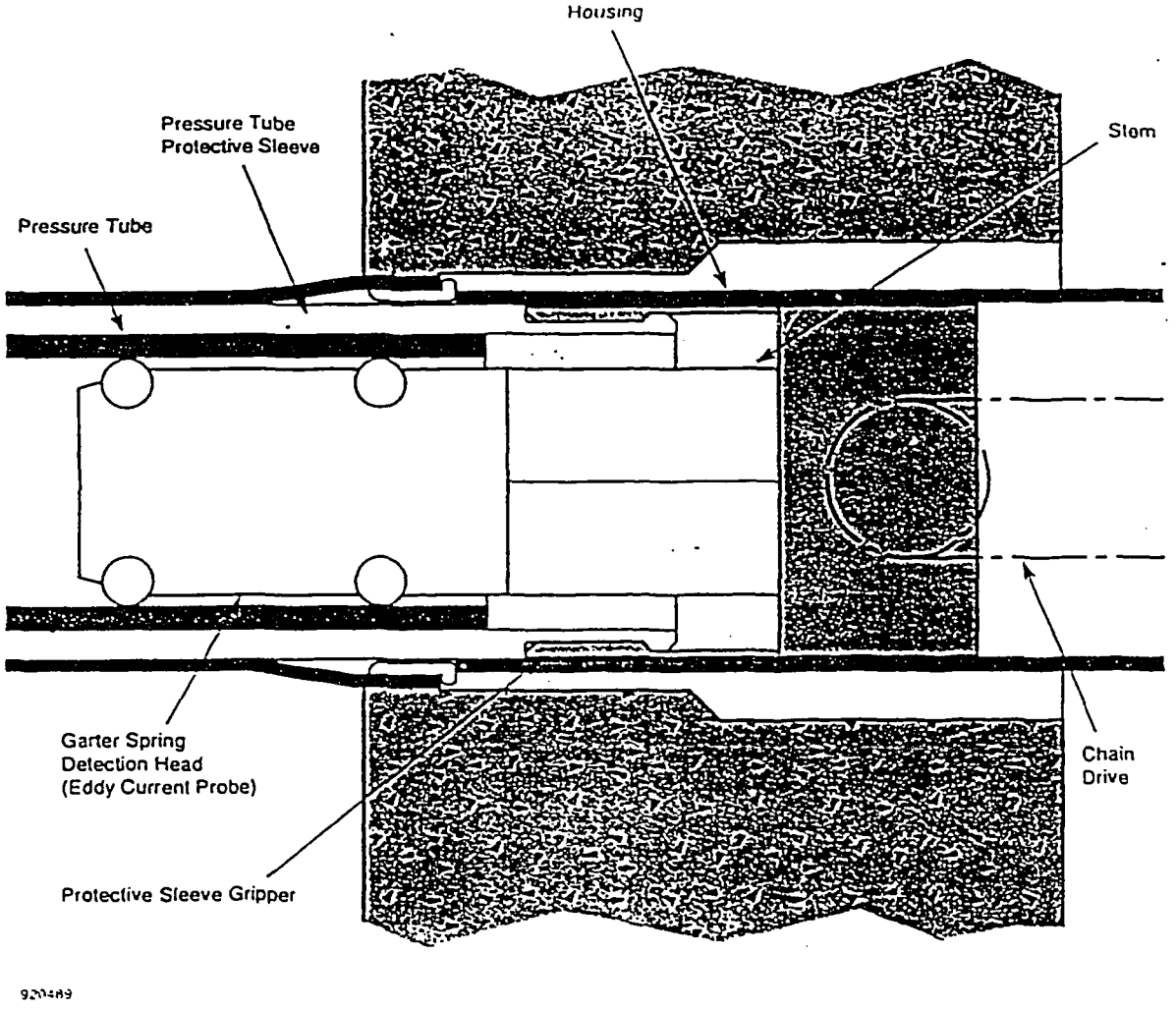

Figure 6
Protective Sleeve Removal and Garter Spring Detection

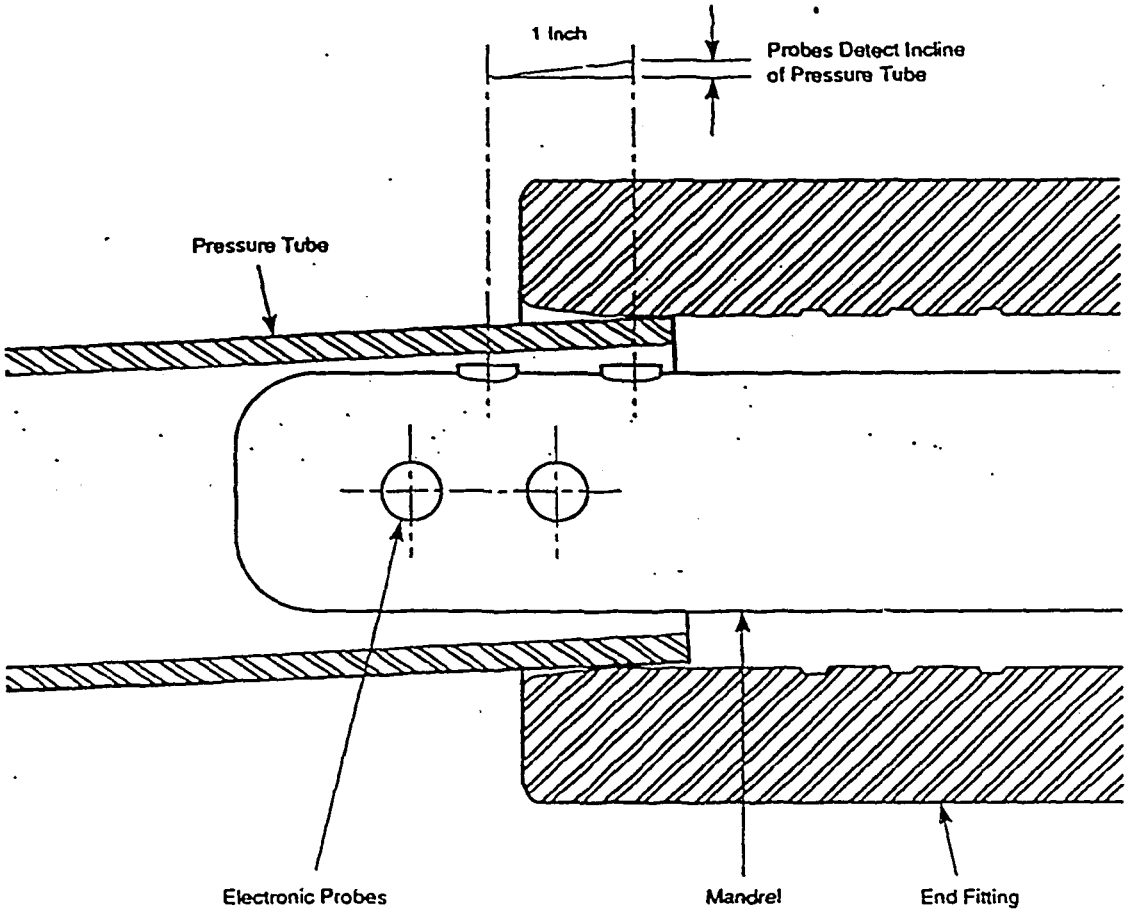

Figure 7
Pressure Tube Alignment

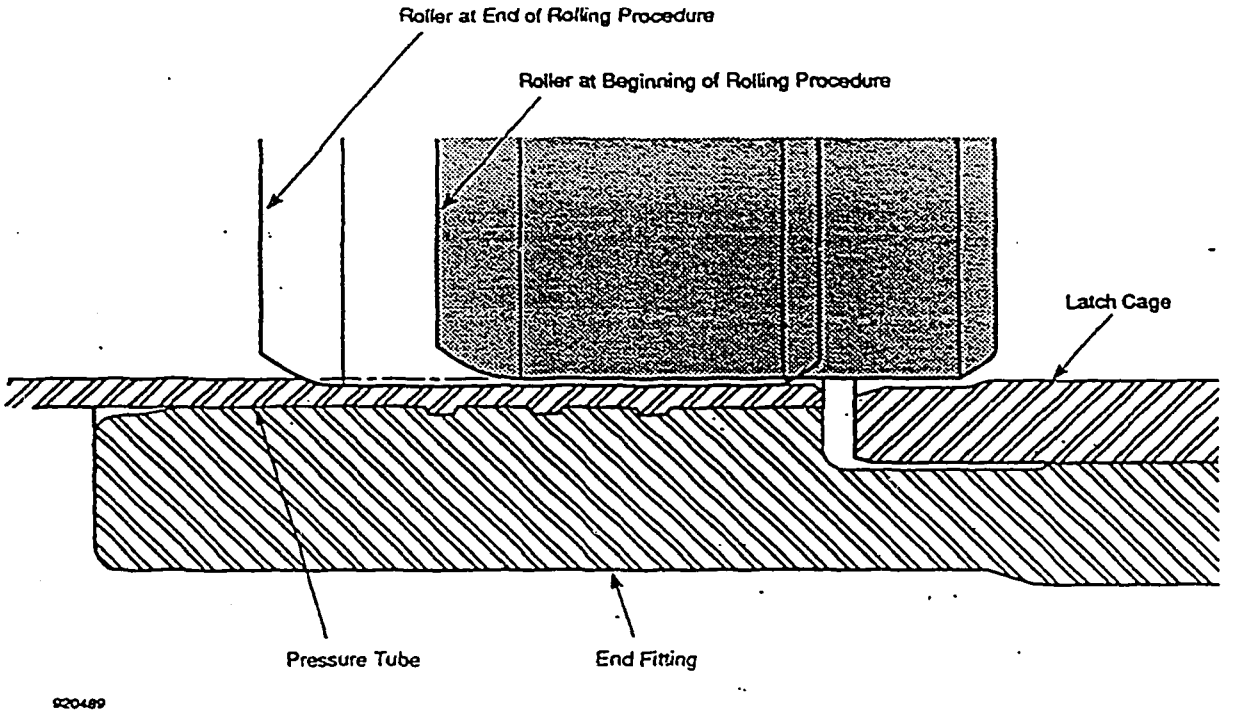

Figure 8
Conventional Rolled Joint

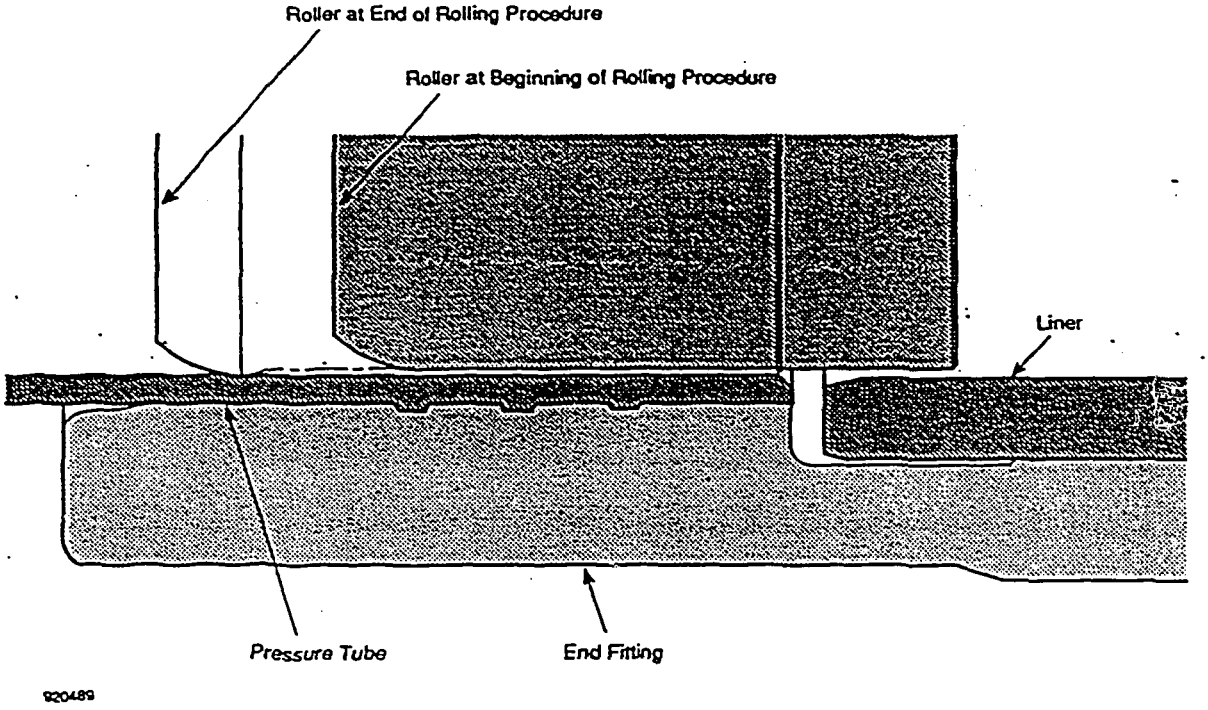

Figure 9
Flush Rolled Joint

CA9300150

THE IMPROVED INDUCTION HEATING TECHNIQUE FOR CALANDRIA TUBE ROLLED JOINT SEPARATION

M.Cenanovic, M.Ng, T.Malkiewicz, J.Lee, J.Morcom, D.Pritchard

Ontario Hydro

ABSTRACT

The Fast Induction Heating technique was developed for the single fuel channel replacement program. This technique was successfully used in separating the calandria tube-calandria tube insert-rolled joints in both the Pickering "A" NGS (P2G16) and the Bruce "A" NGS (B2N06).

This paper describes two major improvements in the induction heating technique which is used for rolled joint separation: equipment and process.

The improvements described herein simplify the rolled joint separation technique and make it more attractive for both single and large scale fuel channel replacement.

THE IMPROVED INDUCTION HEATING TECHNIQUE FOR CALANDRIA TUBE ROLLED JOINT SEPARATION

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INTRODUCTION

During the 90's rehabilitation of nuclear reactors will be one of Ontario Hydro's highest priorities. The Research Division, in cooperation with the Nuclear Support Services Division and the Bruce ENCON Services Division, is committed to meeting this corporate priority. It will do so in the nuclear reactor rehabilitation field by further developing electromagnetic techniques for reactor maintenance and repair.

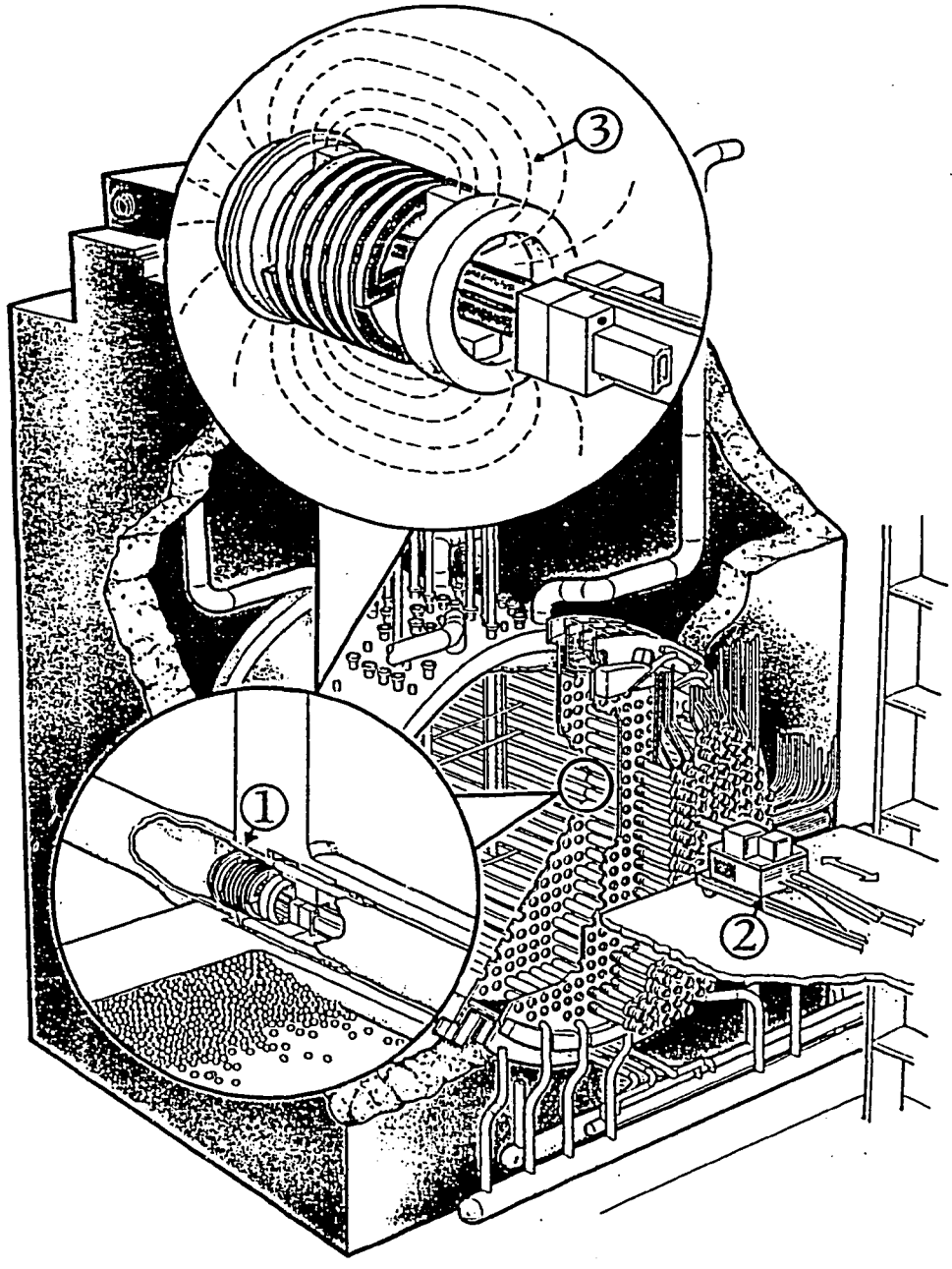
The Fast Induction Heating technique was developed for the single fuel channel replacement program. This technique was successfully used in separating the calandria tube-calandria tube insert-rolled joints in both Pickering "A" NGS (P2G16) and Bruce "A" NGS (B2N06)/1/ as illustrated in Figure 1.

This paper describes two major improvements in the induction heating technique which is used for rolled joint separation:

- equipment
- process.

The prototype of the new solid state Fast Induction Heating equipment described in this paper represents state-of-the-art equipment that has pushed the upper frequency limit of induction heating solid state technology. The compact size, modular assembly and the substantially reduced weight of the newly developed equipment offers numerous advantages over past systems. New possibilities for the efficient use of the Fast Induction Heating process for rolled joint separation are opened. The new equipment allows arrangements not possible in the past. Only the transmission line and the small load matching unit need to be placed on the reactor maintenance platform. They are connected by the flexible radio frequency power cable to the power supply unit which is located outside the reactor vault.

The principal objective of the single fuel channel replacement program was to release a small number of calandria tube-rolled joints on an emergency basis. Optimization of the process was secondary. However, for the large scale fuel channel replacement



The process of removing a calandria tube in a CANDU reactor is as follows: The rolled joint (1), which holds the calandria tube firmly in place, is rapidly heated but cannot expand in the cold surrounding tubesheet. After cooling, the calandria tube shrinks and can be readily removed. The carefully controlled induction heating process is performed with the old vacuum tube high-frequency power generator (2) and a water-cooled induction coil (3).

Figure 1

Calandria Tube Rolled Joint Separation Process

program, in which a large number of calandria tube-rolled joints need to be released, substantial time savings can be achieved from the improved process. Process optimization significantly reduces reactor downtime and man-rem exposure. Thus substantial dollar savings will be realized. As a result of the optimization program, the rolled joint separation process, which previously required one hour and eleven minutes per rolled joint, can be shortened to fewer than five minutes.

The improvements described herein also simplify the rolled joint separation technique and make it more attractive for both single and large scale fuel channel replacement.

EQUIPMENT OPTIMIZATION

Requirements

A Fast Induction Heating process for rolled joint separation requires special equipment that can induce rapid heating by generating high power in the shallow inner layer of a rolled joint without damaging the remaining reactor components such as the tube sheet. This is achieved by selecting a sufficiently high frequency (120 KHz and higher) to match physical dimensions and material properties of the rolled joint.

The critical equipment arrangement for the Fast Induction Heating system is the one in the reactor vault, especially the one on the reactor maintenance platform. The major impact of this development described in this paper focuses on this issue.

Old Equipment

In the past, the frequency at the required power level could be generated only by a very large and cumbersome oscillator tube generator system. This high frequency generation portion of the old equipment had to be placed as close to the load as possible, ie on the reactor maintenance platform.

New Equipment

State of the art, solid state induction heating equipment was developed specifically to meet the critical equipment arrangement requirements. To meet our process requirements, the upper limit of commercially available solid state technology had to be advanced.

This new solid state equipment is based on a concept in which the high frequency generation takes place outside the reactor vault. The high frequency power is transferred via a special flexible radio frequency cable to the lightweight front-end components on the reactor maintenance platform.

The compact size and substantially reduced weight of the solid state equipment offer numerous advantages for in-reactor use. A volume comparison of the reactor portion of the new solid state system with the old oscillator tube radio frequency generator system is illustrated in Figure 2. The corresponding reduction in weight is even greater, since the new equipment does not require a heavy trolley for the controlled movement.

INDUCTION HEATING SYSTEM
for the Separation of Calandria Tube Rolled Joint

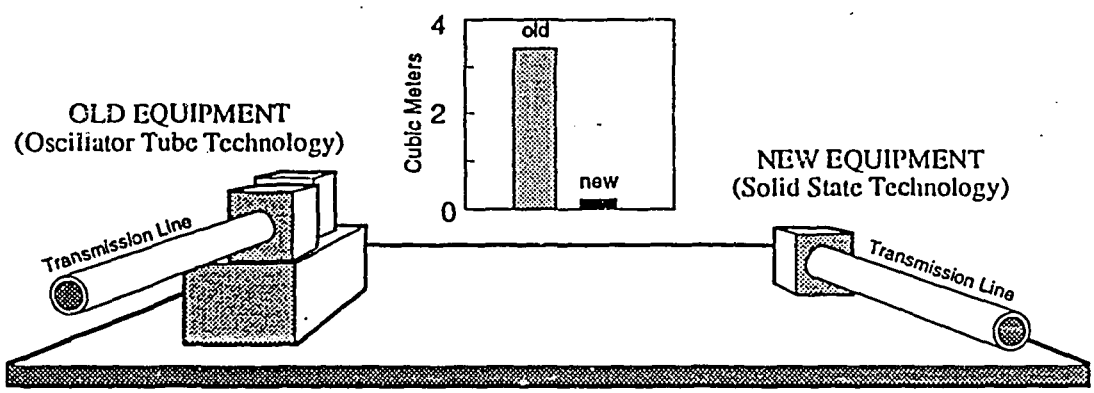


Figure 2

Comparison of the Equipment on the Reactor Maintenance Platform

This smaller, lighter and more mobile new equipment will replace the old equipment denoted by ② in Figure 1

Additional important features of the new solid state equipment are virtually instant power rise to the required level and no warm up time. These features offer new opportunity for process optimization.

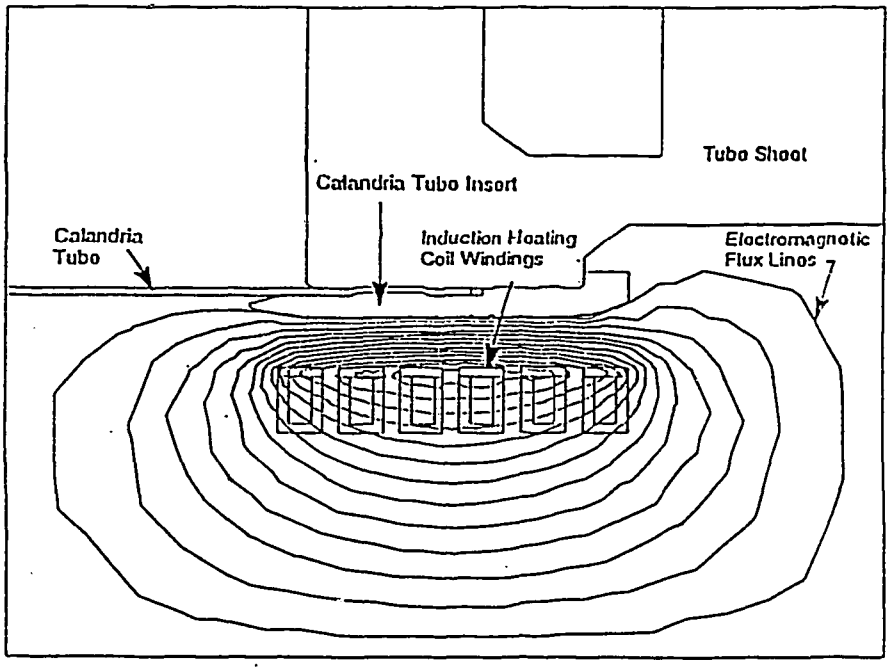


FIGURE 3

A TYPICAL ELECTROMAGNETIC FLUX PROFILE IN THE C/T ROLLED JOINT AREA

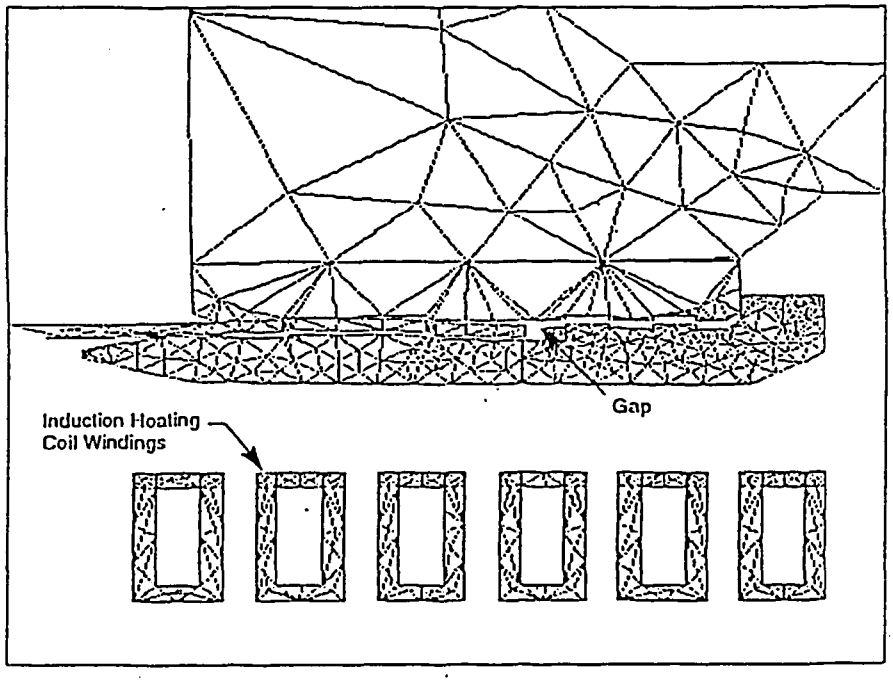


FIGURE 4

GEOMETRY OF THE C/T ROLLED JOINT AFTER THE HEATING CYCLE
(Please Note the Gap Between the T/S and Other C/T Rolled Joint Components)

PROCESS OPTIMIZATION

To optimize the process, a development program was undertaken in cooperation with Nuclear Supp. Division and the Bruce E&CS Division. The program consisted of both theoretical and experimental simulation and analysis of the calandria tube-rolled joint separation process. The results are summarized below:

Theoretical Studies

Computer modelling was used to study the shrinkage mechanism involved in the Fast Induction Heating process for calandria tube-rolled joint separation. A finite element based system was used to model the Fast Induction Heating process. The model included the induction heating coil and appropriate fuel channel components, and employs the typical Fast Induction Heating process parameters as inputs. It performs the analyses on the electro-heating and thermal stress. A typical electromagnetic flux profile is shown in Figure 3. The geometry of the calandria tube-rolled joint after a heating cycle is simulated in Figure 4. Modelling provided a means to visualize the shrinkage process. The results of the analysis were found very useful in optimizing the Fast Induction Heating process parameters for calandria tube-rolled joint separation.

Experimental Studies

The aim of this study was to minimize the duration of the calandria tube-rolled joint separation process.

In order to meet the time constraint, all hardware developed for the single fuel channel replacement program was left unchanged. Since the process optimization program was carried out in parallel with the induction heating equipment optimization program, the old oscillator tube induction heating system (Lepel 250kW system) was used for the process optimization program.

As a result of this program, a simple and reliable calandria tube-rolled joint separation process was developed, which significantly reduces the process duration from one hour and eleven minutes to less than five minutes as illustrated in Figure 5. The optimized process parameters developed using the oscillator tube induction heating system are as follows:

- 6 1/2-Turn induction heating coil (1/2 turn longer than the original coil)
- induction heating coil positioning of nominal +1/8" inboard (1/8" further inboard than the original position).

	HP Computer Power Setting	Duration	Power at Calorimeter
Heating	130	28 seconds	37 kW
Cooling	0	4 minutes	0 kW
Heating	130	17 seconds	37 kW

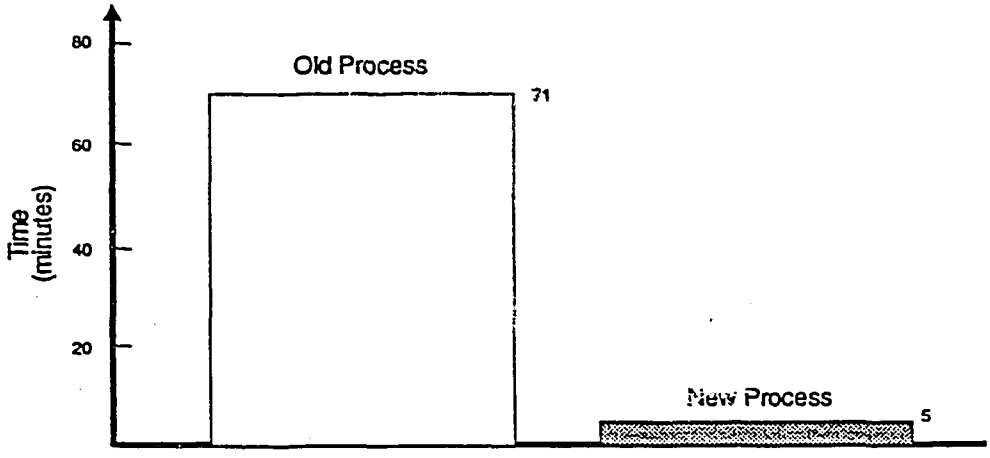


Figure 5

Comparison of the Old & the New Process Duration for Calandria Tube-Rolled Joint Separation

To ensure the quality of the tube sheet bore, four tube sheets separated by the optimized process parameters were sent to Atomic Energy of Canada Limited for bore diameter measurements and metallurgical examination. The results concluded that the condition of the tube sheet bores after shock heating is considered acceptable for further development.

With the acquisition of the compact solid state induction heating system, the optimized process parameters developed using the oscillator tube induction heating system were carefully matched and transferred to the new solid state induction heating system.

Three new Bruce type calandria tube-rolled joints were separated using the new solid state induction heating system. The results are comparable to that using the oscillator tube induction heating system.

CONCLUSION

The Fast Induction Heating technique for the calandria tube-rolled joint separation was improved for future single fuel channel replacement and large scale fuel channel replacement programs by:

- developing a new state of the art compact solid state Fast Induction Heating system
- optimizing the Fast Induction Heating process to release the calandria tube-rolled joint in less than five minutes.

These improvements should significantly reduce the reactor down time needed for rolled joint separation and fuel channel replacement in CANDU reactors.

OUTLOOK AND FUTURE WORK

Advances in technology have provided industry with the capability to function more effectively with respect to both cost and safety. Future development will focus on optimization of the electromagnetic technology, using where appropriate, up-to-date technology in order that maximum benefits can continue to be derived. Fast electromagnetic techniques, which offer the potential to be automated, offer important advantages in minimizing repair process times, radiation exposure and process reliability. The challenge facing CANDU maintenance groups is to adopt and advance this technology to suit the unique environment of a Nuclear Generating Station.

In the case of the induction heating technology for rolled joint separation, the advances in high frequency solid state technology and computer simulation software were utilized to achieve the described improvements.

Further work should be done to:

- prepare the described system for calandria tube-rolled joint separation for field implementation
- optimize the pressure tube rolled joint separation process/2,3/ using the new compact solid state equipment arrangement for potential cost reduction in future retubing schemes
- develop robotics schemes in conjunction with the new compact induction heating equipment for rolled joint separation./4,5/

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CA9500151

QUALITY IMPROVEMENT FOR STOP COLLAR AND BELLOWS WELDING ON BRUCE RETUBE

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ABSTRACT

This paper addresses current developments in welding process technology and considers their application to reactor maintenance operations during Large Scale Fuel Channel Replacement. An overview of prototype equipment developed for the retube of Bruce Units 1 and 2 is presented.

INTRODUCTION

With fewer new CANDU reactors under construction and aging of the first units built in the sixties and seventies, more emphasis is placed on efficient reactor maintenance and life extension programs. Whether routine maintenance or repair/replacement of major reactor components is needed, critical welds are often required where access to parts is extremely restricted (e.g. feeder repairs, fuel channel replacement). Cost factors are significant in these operations because the components are expensive and the work is usually very time consuming. This demands the highest quality and reliability of the welding process in order to minimize exposure of personnel and avoid costly rework.

Driven by these economic incentives and safety aspects, efforts must continue in further improvements in welding applications to achieve the lowest possible weld defect rate to reduce costs and operator exposures. One of the welding systems under development at AECL-CANDU incorporates current advances in welding technology such as microprocessor control, video arc monitoring and data acquisition to achieve improvements in welding performance and quality during remote welding operations.

WELDING PROCESS BACKGROUND

The Gas Tungsten Arc Welding (GTAW) process, more widely known as TIG welding, is often chosen for critical reactor maintenance applications because it is a versatile and stable process which is easily automated. The process, illustrated in Figure 1, uses a constant current type power supply to establish an arc between a non-consumable electrode and the workpiece; the arc region is shielded from atmosphere with a continuous flow of inert gas (argon, helium, or mixtures) which prevents contamination of the weld pool and also helps to maintain arc stability. The main process parameters which influence the weldability and the weld quality during GTAW include:

- welding current amplitude and mode
- arc voltage amplitude
- shielding gas composition
- gas flow rate
- arc travel speed
- wire filler additions
- rate of wire feed

In addition to the process parameters, other variables also have a significant bearing on the welding process, such as material composition, joint geometry, welding current mode (AC, DC or pulsed), the electrode condition, and the cleanliness of the material. Generally a procedure is established through trial techniques which takes into account all these variables as well as possible constraints related to material thickness, heat input restrictions, distortion, joint orientation etc.

Although simple in concept, the welding process is complex considering the number of variables that must be controlled in order to produce acceptable results. In orbital welding applications, such as the bellows welding during fuel channel replacement, process control is even more difficult since weld pool sag due to gravitational effects, results in non-steady state conditions as the weld progresses around the circumference. Under tight spatial constraints, typical in most reactor repair operations, and with variation in factors that are difficult to control (such as fit-up, distortion, environment), maintaining the welding process stability can be a challenging task.

PROCESS CONTROL APPROACHES

Traditional methods of quality control use the model illustrated in Figure 2. In this approach, defects are detected after the process has been completed. Statistical quality control principles, illustrated in Figure 3, incorporate process monitoring to assess real time performance so that changes in the process can be detected and parameter adjustments made, or other corrective action taken, to prevent producing defective output.

Welding can be considered as a small scale 'factory' process having inputs and outputs as shown in Figure 4. Two types of process input and process output can be identified; inputs can be controlled and uncontrolled; outputs occur as intermediate and final conditions. Controlled inputs with the GTA welding operation include: current, wire feed rate, gas flow, and arc travel speed. Occasionally arc voltage may also be a controlled variable if the equipment has an automatic voltage control (AVC) capability. If these parameters are not controlled properly and go beyond a tolerance range during welding, the following types of defects could occur:

- current high: blowholes, pool instability
- current low: incomplete penetration, fusion defects
- wire high: short circuit to electrode, poor profile
- wire low: insufficient weld volume, poor profile
- gas high: porosity due to turbulence
- gas low: weld porosity, electrode contamination
- travel high: incomplete penetration
- travel low: excess weld volume, pool instability

Proper parameter settings, however, are usually confirmed prior to welding, so excursions from the set conditions are due to the influence of uncontrolled inputs which interfere with the normal operation. Uncontrolled inputs could be variation in joint location or joint geometry, line voltage fluctuations, air flow disturbances and physical constraints which cause gas flow or wire feed restrictions. Weld defects resulting from these disturbances would be mainly fusion or penetration defects and porosity.

In practice, welding procedures are not 100% repeatable due to factors such as human error, equipment faults, equipment deterioration, and primarily uncontrolled variables which influence the process. Weld process monitoring, therefore is an effective tool to minimize the influence of unpredictable and uncontrolled disturbances.

Generally sensors are available to monitor any of the variables mentioned. Even joint variation can be sensed in real time using laser tracking/scanning devices, but space constraints in the work envelope determines the number and type of sensors that are practical in a welding application.

Intermediate outputs from the welding process such as arc length (if AVC is not used), arc stability, pool size, pool stability, and wire melting rate also provide some indication of the overall process equilibrium. Arc length, which is proportional to voltage, can be monitored with good accuracy. Other intermediate outputs are not easily monitored using sensors and the most practical ways of obtaining feedback on these conditions is to view them directly as an operator would do in a manual or automated process where space constraints are not a factor. This is achieved with miniature video cameras that are mounted on the weld head body allowing a view of the process dynamics in the weld pool and the arc vicinity. Machine operators then have visual feedback on the process and can terminate the process at initial indications of the onset of porosity for example. In some situations, adjustments to process parameters may also be a practical corrective action to bring the process under control.

In this way, weld repairs can be eliminated or at least limited in severity to reduce the overall repair effort. The essential requirement for successful implementation of arc video information is to have trained welding staff who can recognize indications which can lead to weld defects so that corrective action can be taken at the incipient stage before gross defects occur.

WELDING PROCESS DATA ACQUISITION

Data which has relevance to quality control, documentation, calibration, procedure modification as well as process control can also be acquired during the welding process. The traditional approach to data acquisition applied to welding operations, depicted in Figure 5, does not allow in-process control. Its main use is as a quality check after the fact similar to a visual post-weld inspection.

As a result of improvements in microprocessor technology, modern data acquisition systems allow effective real-time control where data is analyzed as it is collected, checked against parameter tolerance limits, and control signals output to alter the process or warn the operator for action. This approach is illustrated in Figure 6 and can be implemented using commercial microprocessor based data acquisition devices designed for welding applications or customized in a computer based or industrial PLC control systems. The systems can be programmed to monitor if the parameters are within allowable tolerances. Fault conditions can be established during welding procedure development and the system programmed to correct some parameters or initiate controlled shut down of the welding process (or indicate a fault) when a particular parameter is out of tolerance.

Table 1 illustrates a print-out of parameter data that can be collected from a pulsed current welding operation; the parameters recorded were elapsed time, gas flow, current and voltage (peak, background and average values) and pulse frequency. In this example, a temporary decrease in gas flow was induced at 18 seconds elapsed time. This type of information could be used for quality assurance purposes (to produce statistical process control data) or in trouble-shooting for defect causes if welding problems occur.

ASPECTS OF WELDING PROCEDURE OPTIMIZATION

While automation can be applied to welding processes to improve production, quality and repeatability, it is important not to ignore the fundamental aspects of the process which are essential to the overall success of automation efforts. In welding, the process stability is influenced by the welding parameters and the conditions under which they are applied. Fixed position circumferential welding, for example, is one of the most difficult applications to control because: a) gravity influences the weld pool differently as the weld progresses around the circumference, and b) preheat increases in the base metal as the weld progresses.

Traditional practice with older equipment uses a single-level weld schedule to complete the joint. Improved technology in microprocessor controlled power supplies, however, allows multi-level sequences within a schedule. This is beneficial in counteracting the changing conditions (preheat, gravity, distortion) as the weld progresses.

Pulsed current welding, typical for orbital welding applications, such as welding the bellows during fuel channel replacement, introduces other variables related to the waveform of the curre pulses. In pulsed welding, the weld penetration is achieved during the peak amplitude while the lower background amplitude allows partial solidification of the pool. This enhances process stability by preventing the weld pool from getting too large to control, however the process tolerance to disturbances can be affected by the structure of the pulse waveform. Parameter optimization therefore is an important part of the procedure development effort.

ECONOMIC BENEFITS

During CANDU reactor maintenance programs, the economic penalty for power replacement amounts to hundreds of thousands of dollars per day, and even small weld repairs can have a significant impact on costs; in addition, penalties exist in higher personnel exposure and replacement cost of expensive components. Consequently, reducing the frequency or extent of weld repairs even a small amount can quickly pay back the investment made for improvements to the welding process.

SUMMARY

Typically, welding during CANDU reactor maintenance efforts involves remote welds under conditions where access and visibility are poor. In these circumstances, defective welds are exceptionally difficult to correct. Improvements to the current welding methods in reactor maintenance are possible by direct arc monitoring using small video cameras and increased use of data acquisition to feedback information or process stability. A conceptual representation of these enhancements during a fuel channel replacement operation is shown in Figure 7 where an operator in a clean, remote area can support the weld monitoring function while the local operator in the radiation environment supports the mechanical operating requirements of the equipment.

Process improvements such as these, are the basis of a welding system under development at AECL-CANDU which, together with appropriate welding procedures, will reduce weld repairs and increase productivity during reactor maintenance welding operations.

ACKNOWLEDGEMENT

The authors would like to acknowledge the assistance provided by the CANDU utilities, in particular Ontario Hydro, Retube Engineering Department, in support of welding development at AECL CANDU. Design and support staff at AECL CANDU are also acknowledged for their valuable contributions to this effort.

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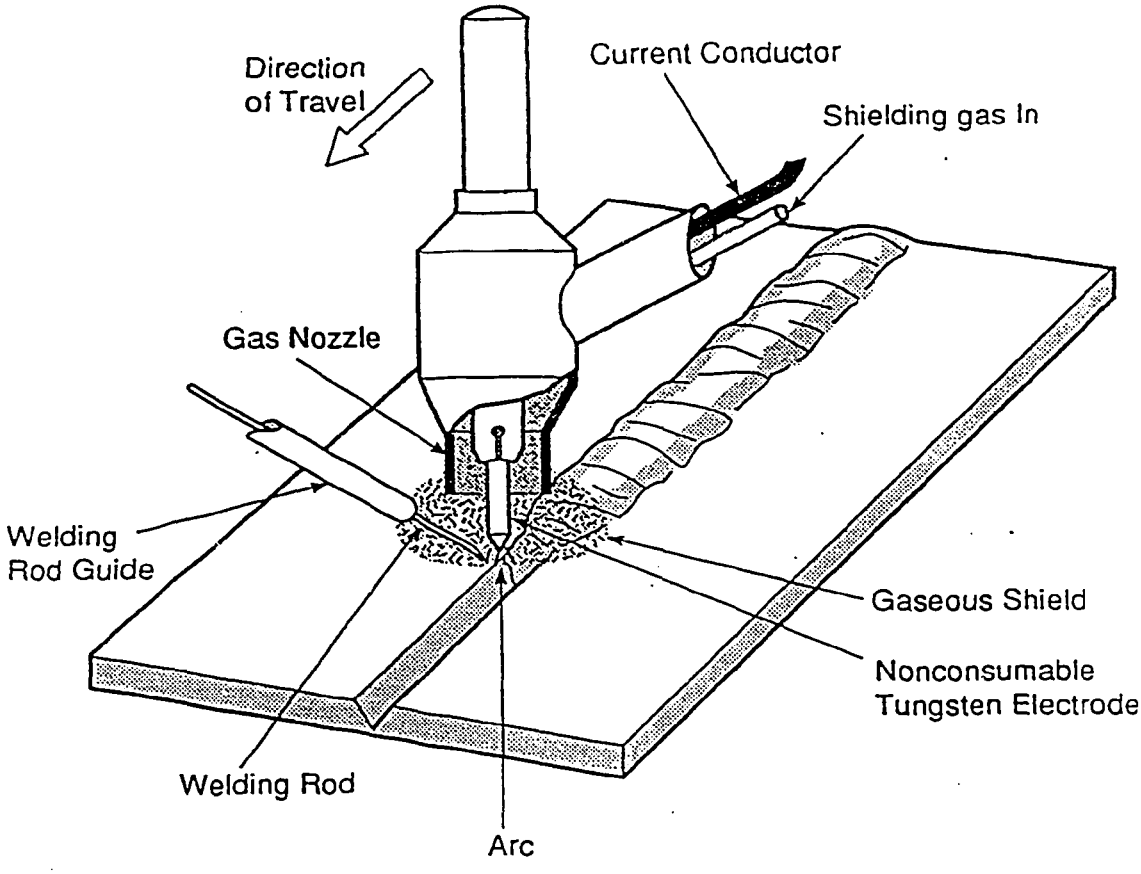

Figure 1
The Gas Tungsten Arc Welding (GTAW) Process

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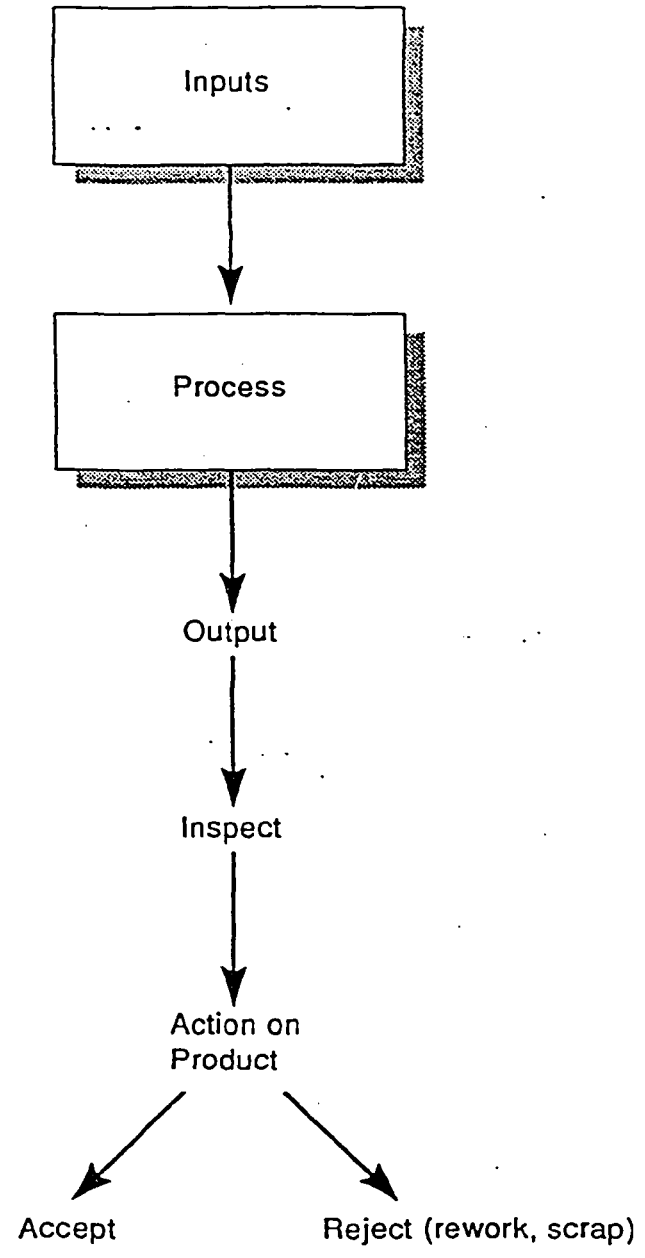

Figure 2
920453 Traditional Method of Quality Control in Welding

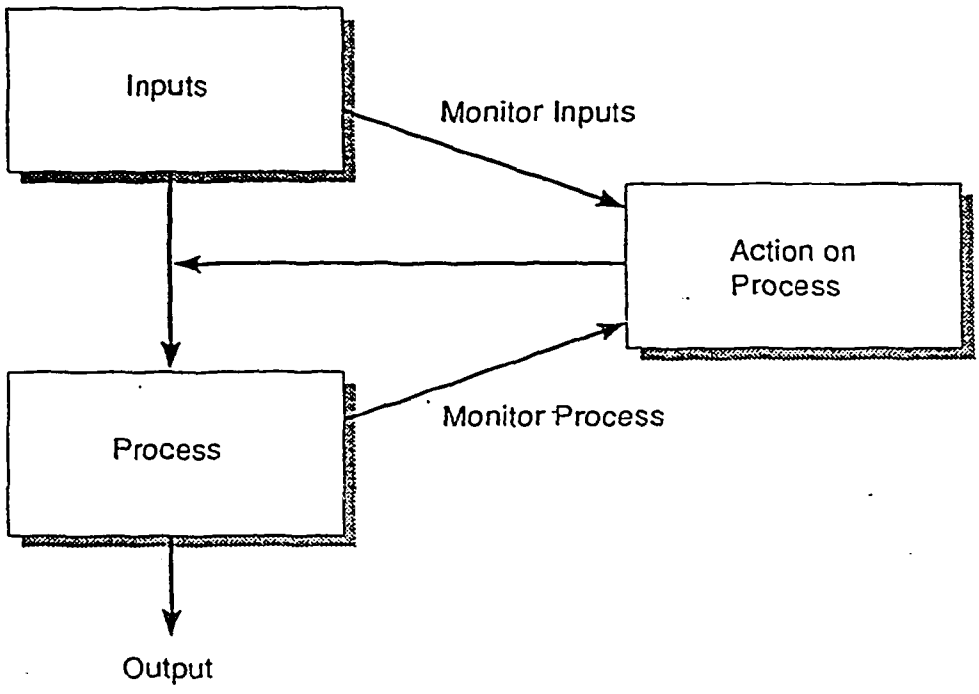

Figure 3
Welding Quality based on In-process Control Principals

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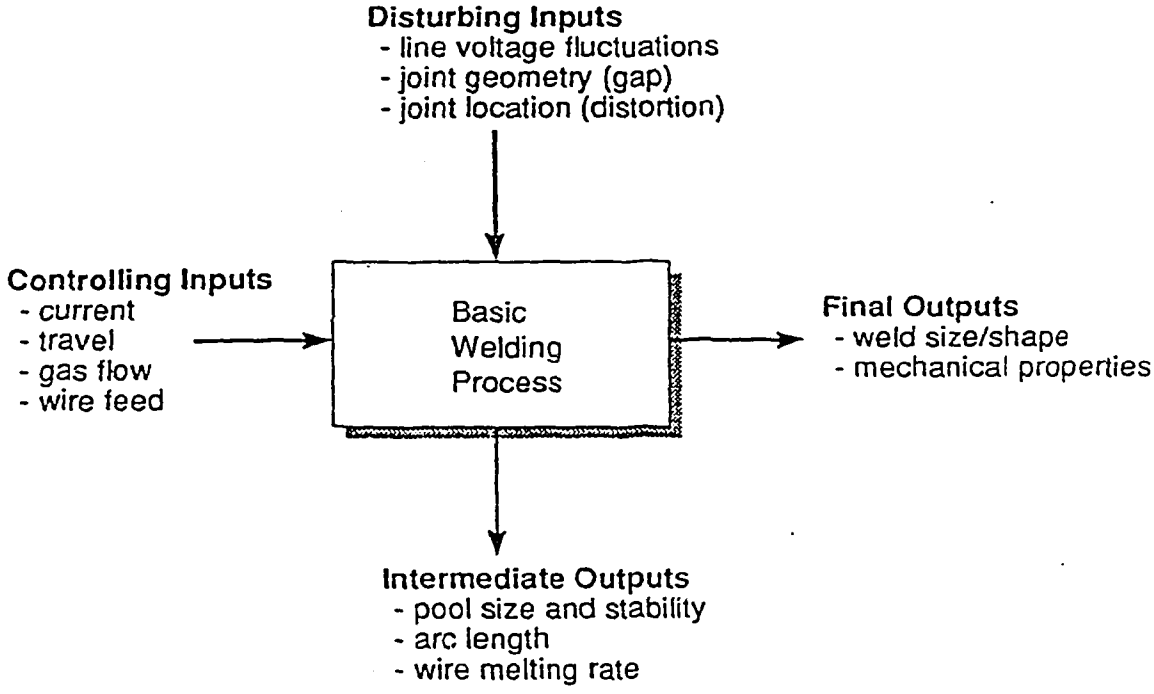

Figure 4
The Basic Welding Process Inputs and Outputs

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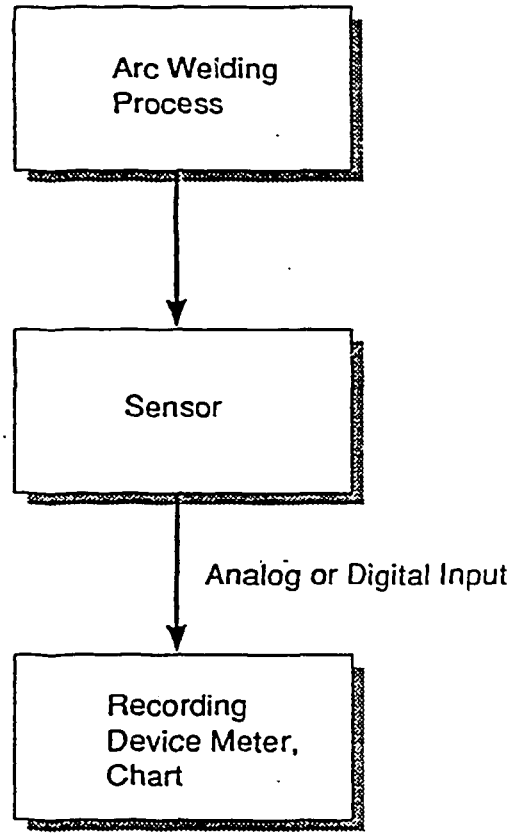

Figure 5
920453 Traditional Data Acquisition with Simple Recording Devices

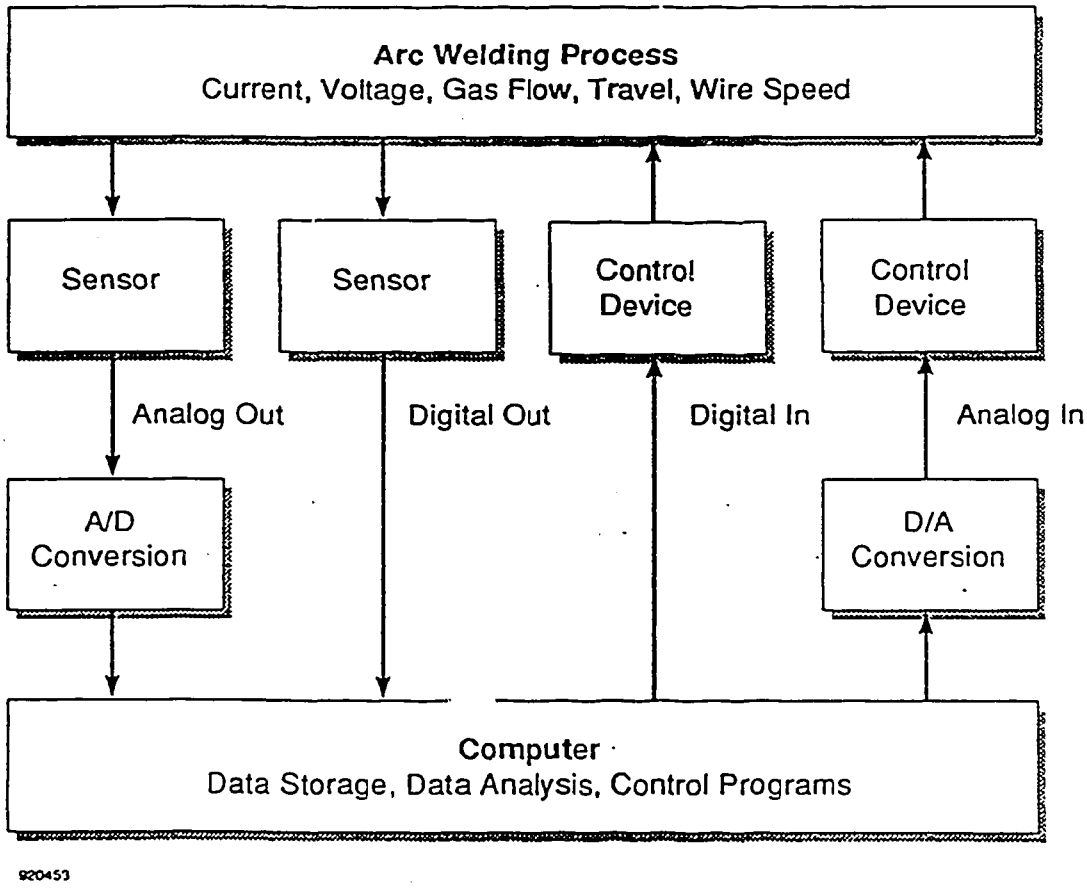

Figure 6
Data Acquisition and Control using Computers in Welding Applications

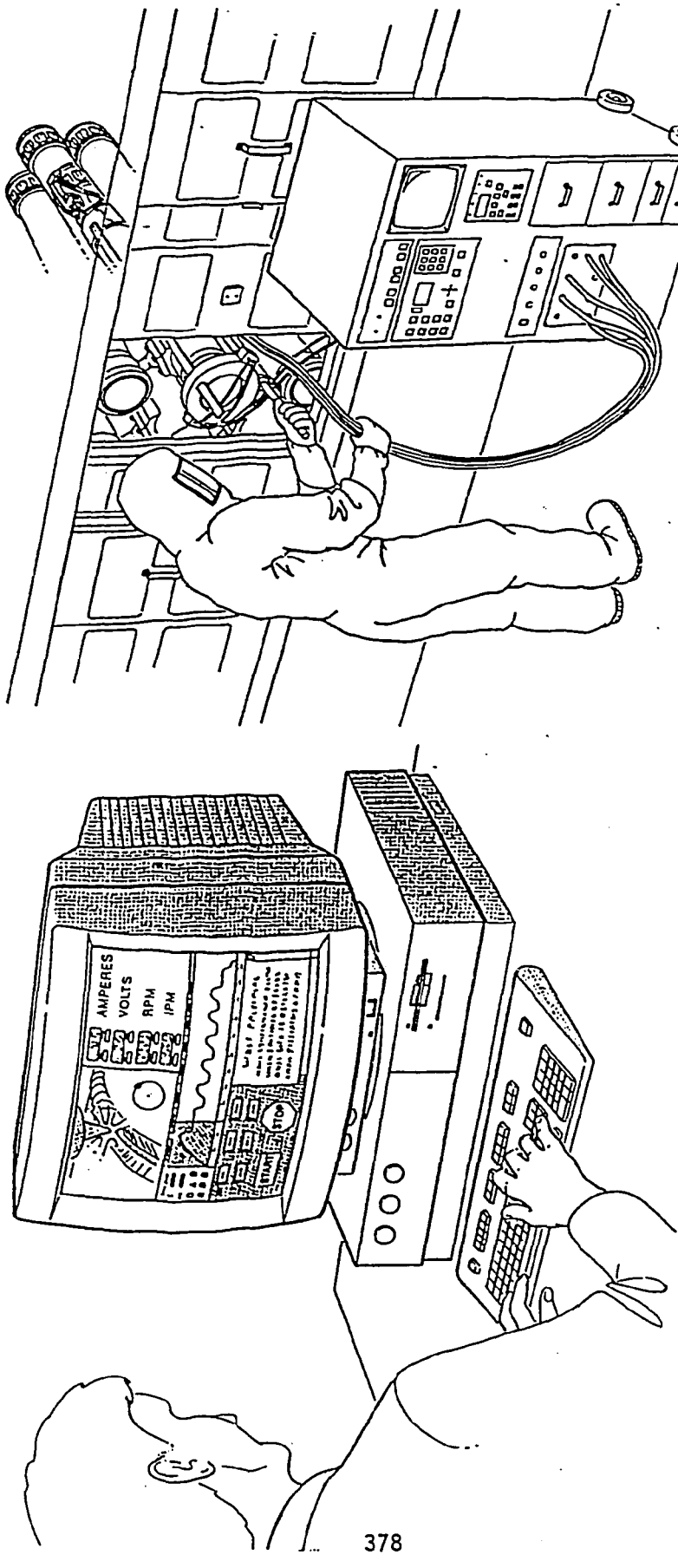

Figure 7
Conceptual View of Remote Weld Monitoring during LSFCR of CANDU Reactor

Table 1
Welding Process Data Acquisition

**** ADM(tm) Weld Data - Weld Schedule 1 ****

ADM(tm) Station Number: 100
Date: 05/31/89 Time: 13:35:13
Operation: CANDU Maintenance Unit 9-Bellows Weld

TIME sec	GAS cfh	TRAVEL ipm	WIRE ipm	VOLT vdc	AMP amp	HEAT kj/in	TEMP Deg F	PKAMP amp	BKAMP amp	PKVOLT vdc	BKVOLT vdc	FREQ hz
8.3	13	.0	0	9.8	149	.0	0	182	92	10.0	9.1	2.5
9.1	14	.0	0	9.7	121	.0	0	177	94	10.1	9.6	5.3
10.1	14	.0	0	10.7	164	.0	0	180	98	10.8	10.7	5.1
11.2	14	.0	0	10.2	103	.0	0	181	94	10.6	10.2	2.5
12.2	14	.0	0	10.8	172	.0	1	181	97	10.8	10.6	5.0
13.1	13	.0	0	9.4	106	.0	1	176	98	10.8	9.6	2.5
14.2	13	.0	0	9.6	140	.0	1	183	92	10.0	8.9	5.0
15.2	13	.0	0	9.9	140	.0	0	182	95	10.6	9.5	2.5
16.2	13	.0	0	9.1	124	.0	0	185	91	10.0	8.8	2.5
17.2	13	.0	0	9.8	164	.0	0	185	95	10.1	9.2	2.5
18.2	9	.0	0	9.5	110	.0	0	181	90	10.4	9.4	2.5
19.1	7	.0	0	10.0	169	.0	0	184	97	10.5	9.1	2.5
20.2	6	.0	0	9.2	110	.0	1	175	91	10.5	8.9	2.5
21.1	7	.0	0	10.4	165	.0	1	180	95	10.2	8.3	5.2
22.1	13	.0	0	9.1	132	.0	1	181	94	10.4	8.8	5.1
23.2	18	.0	0	9.8	123	.0	1	184	92	10.6	9.4	2.5
24.1	15	.0	0	9.8	155	.0	0	184	91	10.3	9.2	5.3
25.2	15	.0	0	8.8	115	.0	0	186	91	10.0	8.5	5.1

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OPERATING EXPERIENCE WITH WESTINGHOUSE STEAM GENERATORS

J. N. Esposito and M. J. Wootten

Steam Generator Technology and Engineering
Westinghouse Electric Corporation
Pittsburgh, PA, USA

ABSTRACT

Westinghouse has designed and manufactured steam generators which have been in commercial operation since the early 1960's. Certain technical issues have been identified for some operating steam generators and these issues will be discussed in this paper.

Westinghouse recommended, in 1974, an all volatile treatment water chemistry operation for steam generators. In addition, the application of boric acid as a contributor to corrosion inhibition for denting and alkaline induced stress corrosion cracking environments has also been recommended.

In 1980, the first Model F-type steam generator designed and manufactured by Westinghouse began operation with advanced features to address corrosion concerns that were observed in the industry. The Model F-type steam generator is a proven design with 84 units in commercial operation, and over 400,000 tubes and 2.3 million "tube years" of service. Operating plant data demonstrates the effectiveness of the design enhancements in the Model F-type units which have operated with no indications of systemic corrosion.

INTRODUCTION

The Westinghouse PWR steam generator design contains a vertical, inverted U-bend tube bundle that is joined to a tubesheet that channels the primary system reactor water through two plenums, referred to as the hot leg and the cold leg channel heads. On the secondary side, the steam generator tube bundle is supported by a series of tube support plate structures and a series of anti-vibration bars that provide structure and support the tube bundle against the forces created by the flows of secondary side water and steam. The steam is separated from the steam-water mixture by moisture separators that remove the water and return it to the bulk secondary water while the steam flows to the turbine.

The steam generator feedwater is admitted to the steam generator through a feedwater ring located above the tube bundle for some models of steam generators and in the lower portion of the tube bundle for the preheater steam generator models. All of the steam generators recirculate the bulk water on the secondary side and have provisions for sampling the water for chemical analysis purposes and controlling the blowdown from the steam generators to provide a "feed and bleed" chemistry control. A typical example of the feedring design is schematically illustrated in Figure 1.

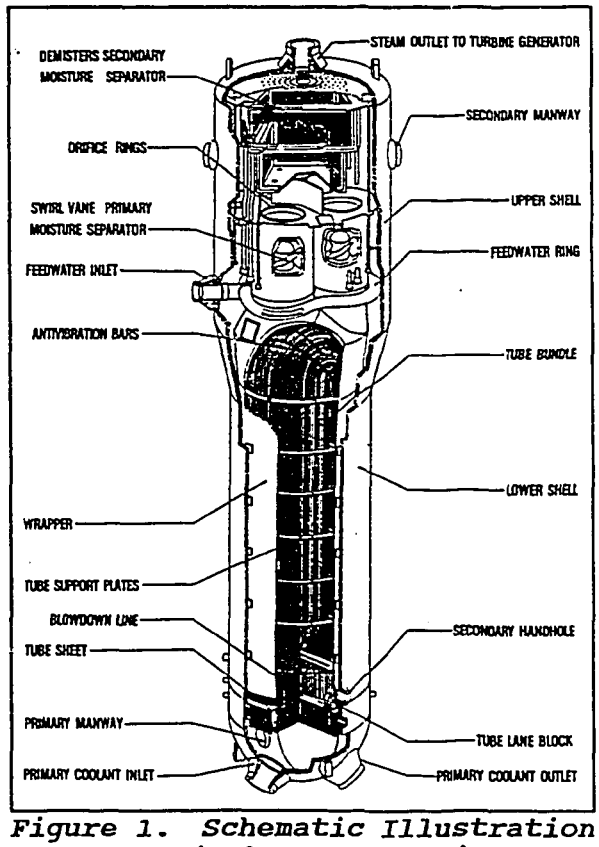

Figure 1. Schematic Illustration of a Westinghouse Feedring-Type Steam Generator

The operating experience of these early design recirculating steam generators has been the subject of other reports (1,2). The modes of steam generator degradation include denting, which represents corrosion of the support structure material, various modes of degradation from the outer diameter (OD) of the tubing, and stress corrosion cracking that initiates from the primary side of the tubing. A brief discussion of these modes of degradation and the specific remedial measures which have been implemented will follow.

In addition, the operating experience of steam generators of the Model F-type design has been accumulating since the

early 1980's and continues to indicate a high degree of corrosion resistance (3).

PRIMARY WATER STRESS CORROSION CRACKING (Early Design Steam Generators)

Primary water stress corrosion cracking (PWSCC) is the term associated with cracking of the steam generator tubing material from the inner diameter of the tubing in regions of the tubing where sufficiently high stresses may be present. This form of degradation has been reported in the tubesheet expansion region in tubes with either mechanical roll expansion or explosive expansions, the small radius U-bend transition region or locations of denting at the tube support plate region.

Cracking that has been observed in the region of the tubesheet can be placed in two categories with respect to the need for plugging or other repair actions. One classification is for cracking that is located relatively deep within the tubesheet region for tubes that have been expanded for the full tubesheet depth. Such cracks, as illustrated in Figure 2, are well contained within the tubesheet and pose no threat of leakage that could significantly affect the operation of the steam generator. If such cracks are located below a given depth from the top of the tubesheet they may be qualified, based on a plant specific analysis, to be left in service. The application of this basis for plugging of tubes has been supported by Westinghouse with a number of plant specific submittals to the United States Nuclear Regulatory Commission in support of U.S. utility requests. Cracks that may form from the primary side and are located in the region above the plant specific exempt region are presently repaired according to the plant technical specification requirements.

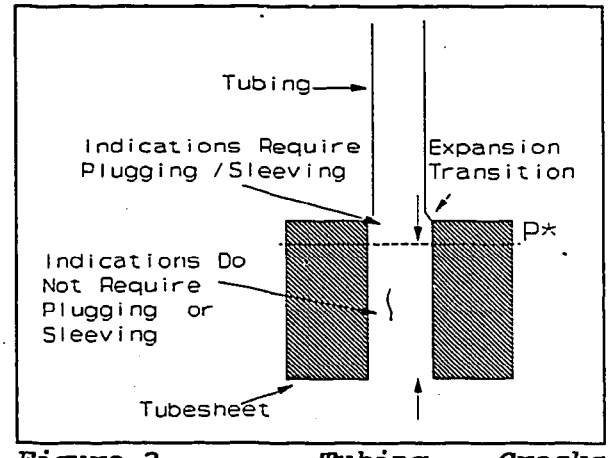

Figure 2. Tubing Cracks Contained within the Tubesheet Region

Axial cracks that are indicated in the expansion transition region have been observed to be of a limited length that is directly related to the stressed region of the roll transition. Such cracks are characteristically short and display no particular tendency to leak, Figure 3. In addition, numerous evaluations of tubes removed from operating steam generators have shown that the cracks generally have little effect on reducing the strength of the tubing as demonstrated by burst testing. Extensive data collection efforts at some European plants have

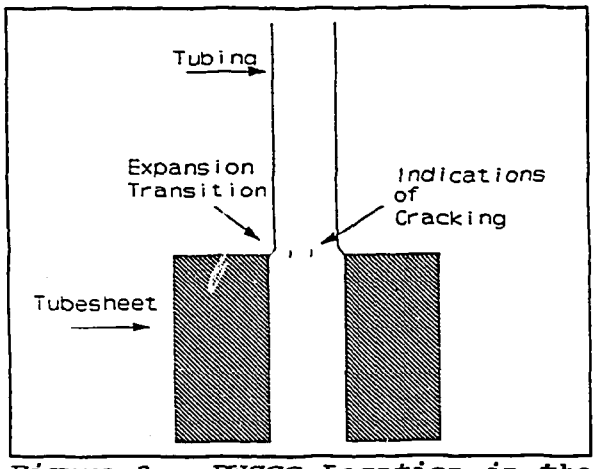

Figure 3. PWSCC Location in the Expansion Transition Region of Full Tubesheet-Depth Expanded Tubes

demonstrated this strength to the extent such that cracks have been permitted to remain in service, provided that a regular follow program to monitor potential crack growth is in place. Efforts to establish a data base and analytical evaluations that will permit equivalent plugging criteria to be established in the United States are in progress.

Although detection and monitoring of such primary side initiated degradation is anticipated to duplicate the efforts in Europe and provide the basis for an alternate plugging criterion for the tubesheet region, other actions have been initiated to avoid the occurrence of primary water stress corrosion in existing steam generators of early design. These steps include local stress modification techniques and a more general system wide application of a chemical agent that has been demonstrated in laboratory tests to provide an effective reduction in general and stress corrosion cracking propensity. The tube plugging that has occurred for indications of PWSCC is believed to have been reduced as a result of development programs and the subsequent implementation of qualified field actions. These efforts are described in the following subsections.

Local Stress Modification

Since stress corrosion cracking is associated with tensile stresses in the steam generator tubing material, substantial modification of the stresses would be expected to provide some measure of benefit. Efforts were accordingly directed toward the qualification of both mechanical and thermal techniques for stress modification.

Mechanical Stress Modification. Peening was selected as the method to modify the tubesheet expansion transition region. This mechanical method of inducing a compressive stress layer on the inner diameter of the tubing in a localized region can be accomplished in a controlled manner with minimal side effects. The two methods of mechanical stress modification that have been applied in operating units are rotopeening and shotpeening.

Shotpeening has been most extensively applied, but both methods have been determined to be capable of producing the desired compressive stress layer with the objective of avoiding the initiation of stress corrosion cracking. Qualification of the

peening process proceeded with the utilization of testing methods that determined the appropriate amount of stress modification to apply to the surface of the tubing using stress corrosion cracking testing correlations. In conjunction with this, the process control techniques that would provide controlled field application were developed. Such process controls in the Westinghouse system are based both on equipment monitoring and on the periodic verification that the desired stress modification has occurred by direct measurement of the compressive layer induced using the in-process equipment.

An example of the shotpeening equipment set-up, as applied in a field situation, is illustrated in Figure 4. Recent development activity within Westinghouse has resulted in field utilization of the shotpeening equipment with the fully robotic Remotely Operated Service Arm III assembly (ROSA III).

All Westinghouse steam generator hot leg locations with full depth mechanically rolled tubing have been mechanically stress modified using either rotopeening or shotpeening.

Units with Alloy 600 mill annealed tubing and the Westinghouse Explosive Tube Expansion (WEXTEX) process have lower stress levels in this region as compared to the mechanical expansion process. Shotpeening, however, has also been qualified for application in the WEXTEX transition region.

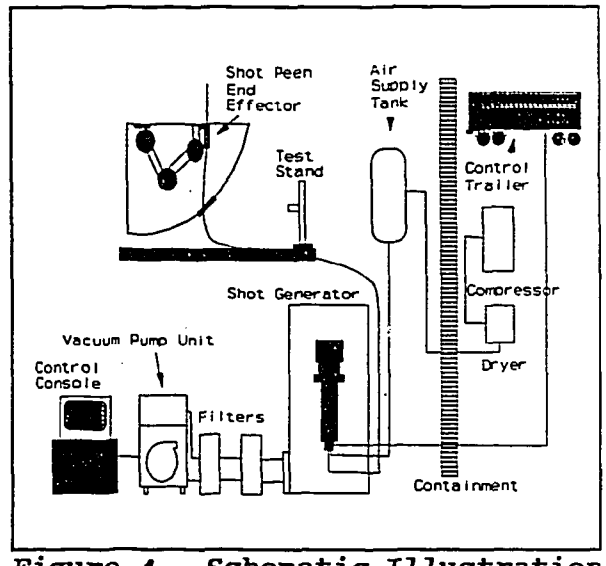

Figure 4. Schematic Illustration of Field Configuration of Shotpeening Equipment

Thermal Stress Modification. Cracking of the transition region U-bends was observed in the tighter radius U-bends of some tubes in some of the steam generators manufactured with mill annealed Alloy 600 steam generator tubing. Since the radius of curvature and the length of tubing to be treated made mechanical stress modification less practical, the thermal stress relief technique was developed for the small radius U-bends.

This technique consists of inserting a resistance heater through the U-bend region and heating the entire U-bend to an appropriate temperature for stress relief as determined on the basis of laboratory testing. Approximately 100 steam generators have been treated with U-bend stress relief.

Chemical Control of PWSCC. As part of a laboratory program to

evaluate chemical means of minimizing primary water stress corrosion cracking, Westinghouse observed that the addition of zinc borate provided substantial benefits for general corrosion control of Alloy 600 and also for specific stress corrosion cracking reduction of highly stressed specimens of susceptible heats of mill annealed Alloy 600 exposed to simulated primary coolant.

The preliminary results of this experimentation were reported previously and showed substantial reductions in general corrosion and corrosion product release (4). Such a general reduction has been calculated to result in a corresponding substantial reduction in the source term radiation levels. In addition, stress corrosion laboratory tests indicate that an additional substantial benefit can be anticipated relative to the occurrence of PWSCC.

Currently, the Westinghouse testing and qualification program has progressed to the point of plant specific consideration for field application on a demonstration basis[1].

DENTING

The phenomenon of tube denting, illustrated in Figure 5, was first observed in the mid-1970's as an obstruction to passage of the eddy current probes used for field in-service inspections of the steam generator tubing. Subsequent investigations, including the removal of tube-tube support plate intersections from operating plants revealed that the denting was due to corrosion products of the carbon steel support material. This corrosion product formed in the local tube-tube support plate crevice region as a result of local concentration of aggressive species present in the bulk steam generator water. Numerous studies were devoted to this phenomenon by Westinghouse and others (5, 6, 7). These studies into the mechanism of denting clearly showed that this form of corrosion occurred due to excursions in the secondary side chemistry, with

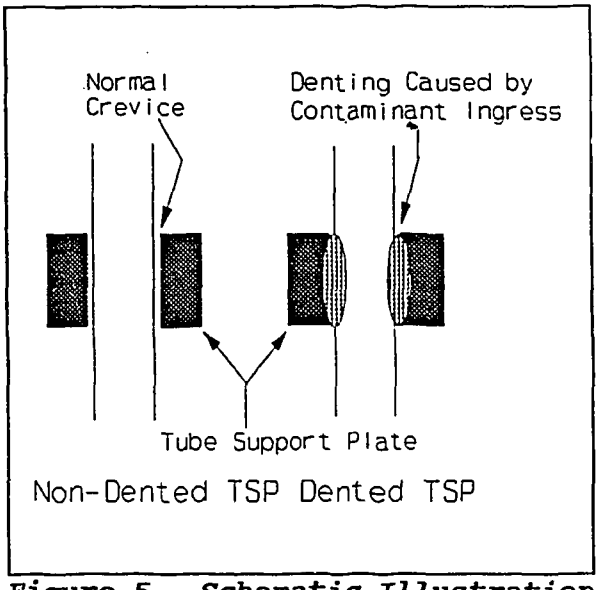

Figure 5. Schematic Illustration of Corrosion Leading to Tube Denting

[1]The support of the Westinghouse Owner's Group is acknowledged for a portion of the test program.

particular aggressiveness observed in situations that produced acid chloride environments through the incursion of chloride species, particularly in the presence of poor oxygen control or the concurrent ingress or presence of oxidized copper species. (It is interesting to note that essentially the same chemical environment, i.e. acid chloride, may also result in pitting of steam generator tubing materials such as Alloy 600. Significant amounts of pitting, however, have not been observed in dented intersections. This observation may be consistent with laboratory studies that indicate that pitting may occur more readily at low temperatures relative to plant operation.)

Appropriate measures were subsequently identified that avoided denting based on operating chemistry control. In addition, the application of boric acid was qualified by Westinghouse as an additive that contributed to denting control. At present approximately 17 plants in the United States have applied boric acid on the secondary side. Many of the plants that initiated boric acid application in the late 1970's and early 1980's for the specific purpose of aiding in the control of denting, have continued with boric acid application for the purpose of assisting in control of outer diameter initiated stress corrosion cracking as discussed later.

One of the important factors that was evaluated in the initial test program conducted in the late 1970's considered the effect of boric acid on the steam side balance of plant system. This portion of the program was conducted due to the known volatility of boric acid in steam at PWR operating conditions. These tests, conducted in cooperation with the Westinghouse Steam Turbine Division, showed that the boric acid did not produce detrimental effects provided that boric acid application guidelines were followed and that other steam chemistry control parameters were maintained within the approved limits.

The measures to prevent denting and, if it should occur, arrest its progression, have been largely successful.

Tube degradation issues arising from denting are minimal at most plants and denting progression has been largely eliminated. One plant, however, has experienced subsequent primary water initiated stress corrosion cracking at some dented locations. This illustrates that denting type deformation can contribute to PWSCC and that such locations should be monitored for the occurrence of such degradation.

Stress modification could be considered as a remedial measure for dented tubing at tube support locations and accordingly Westinghouse has developed a process for thermal stress relief of dented tube support locations.

OUTER DIAMETER INITIATED STRESS CORROSION CRACKING

Instances of outer diameter stress corrosion cracking (ODSCC) of

mill annealed Alloy 600 tubing were first observed in tubesheet crevice regions and the tubesheet sludge pile region. More recently, tube degradation from ODSCC has been reported at tube support plate locations with the concurrent plugging, or sleeving, of significant numbers of steam generator tubes at some plants.

This cause of cracking has been the subject of considerable field investigation and has been the focus of laboratory programs with respect to causative mechanisms, corrective and remedial measures, and engineering evaluations in support of defect specific plugging criteria. The latter point addresses the need for effective and safe plugging criteria without the burden of plugging tubes with modes of degradation that are inconsequential with respect to safe operation of the steam generators.

The following subsections provide some general examples of the degradation that has been observed, the causative and remedial measures that may be applied to avoid the initiation and propagation of ODSCC, and the evaluations that establish effective measures for the disposition of such degradation with consideration of the more sensitive inspection criteria that result in significantly increased reporting of ODSCC, even in circumstances where the initiation and progression of such degradation is quite modest.

Field Observations of ODSCC

An example of ODSCC as it may be observed on tubes removed from field operated steam generators is shown in Figure 6. It may be noted that such occurrences of field degradation are generally characterized as intergranular stress corrosion cracking that is confined within the TSP crevice region. The cracks, as they are detected by the in-service inspection technique of bobbin coil eddy current analysis, are characterized by an amplitude (voltage) and phase angle (depth) of the eddy current signal at that particular location. Specialized techniques, such as eddy current rotating pancake coil or ultrasonic test evaluations, that provide further characterization, are available and are being used with increasing frequency.

The inspection methodology associated with the reporting of ODSCC has become increasingly important since recent information associated with correlating tube degradation and eddy current signals has shown that low amplitude signals, previously thought to be uninterpretable due to signal-to-noise considerations, may be representative of actual tube degradation. As this information has become established in the inspection procedures it has resulted in an increased reporting of degradation type signals.

The changes in eddy current equipment and interpretation guidelines, Figure 7, can result in some units producing an "inspection transient" of tube plugging that suggests an increase

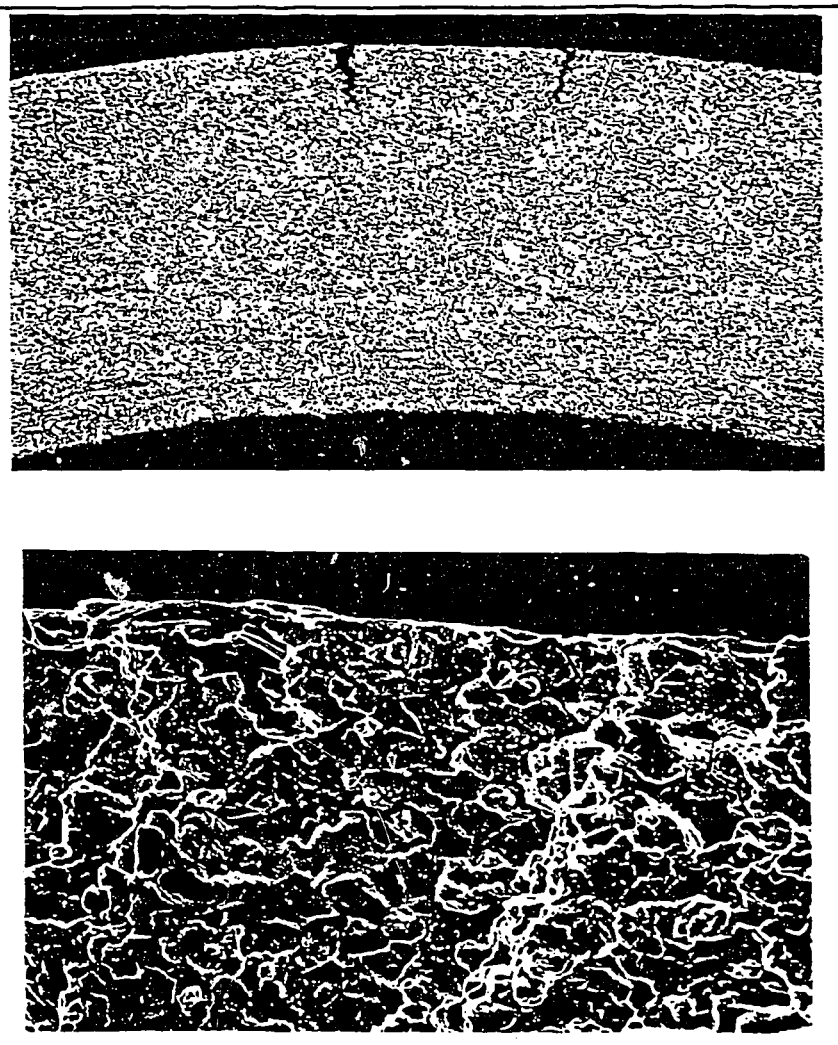

Figure 6. Example of ODSCC Observed on a Removed Steam Generator Tube

in corrosion rate, even if no significant progression of existing tube cracking has occurred and even if the indications being reported have no impact on the safe operation of the steam generators. The needless plugging of many tubes is detrimental in that it may reduce plant operating efficiency and accrue unnecessary radiation exposure. Accordingly, Westinghouse has developed alternate plugging criteria that permit tubes to remain in service provided they have no impact on the safe operation of the plant. Such criteria, as will be discussed in a following section, are presently being evaluated by the United States Nuclear Regulatory Commission on a plant specific basis.

Mechanism of ODSCC. Laboratory test programs conducted over a period of time by Westinghouse and by others concerned with the

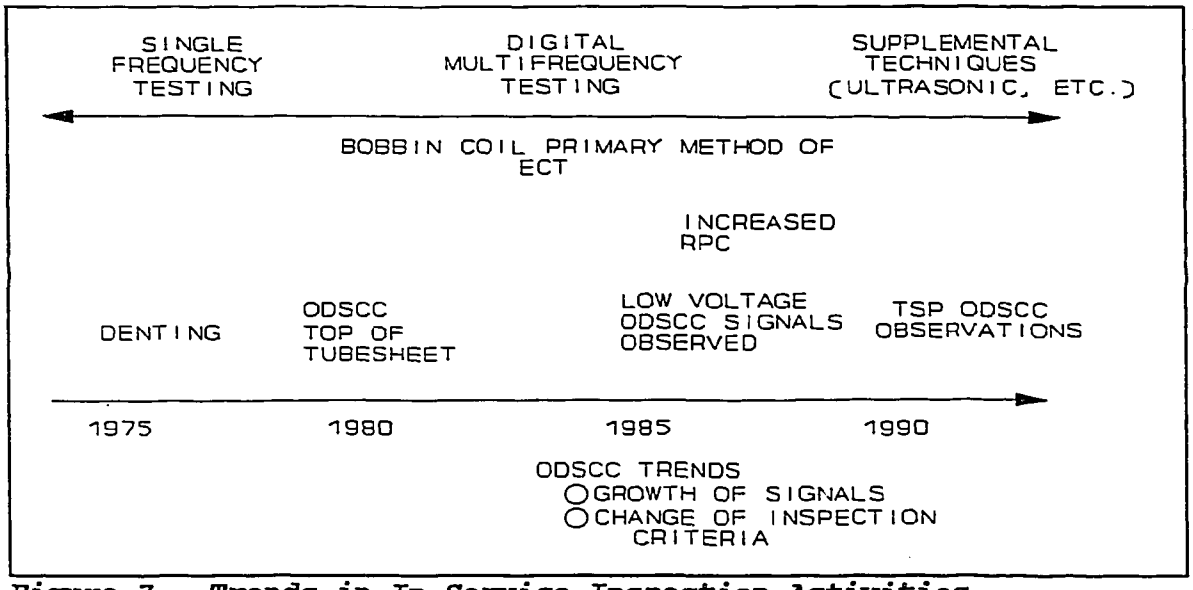

Figure 7. Trends in In-Service Inspection Activities

corrosion of steam generator tubing materials have established that Alloy 600 tubing materials may develop intergranular stress corrosion cracking in alkaline environments. Westinghouse model boiler cracking programs established that synergistic effects involving materials, such as sodium hydroxide, in conjunction with oxidizing materials, could result in accelerated initiation and propagation of stress corrosion cracking.

In particular, it was established that the synergistic action of copper oxide materials, which could occur as a contaminant in a steam generator, and sodium carbonates, which could also occur as a steam generator contaminant, resulted in 100% through wall cracking of model boiler tubing specimens in as little as two weeks if present in relatively high concentrations. Reducing the concentration of contaminants confirmed the direct relationship of cracking to environmental contamination by resulting in proportionally longer times to cracking. Detailed evaluation of the model boiler crack specimens and those obtained from the field were identical in that intergranular stress corrosion cracking was the consistent mode of degradation. In addition, the detailed evaluation of field chemistry data and microanalytical evaluation of various pulled tube specimens generally indicated that alkaline causing conditions were being produced in the field. Recent observations of OD initiated cracking associated with a very shallow surface marking on the tubes in question are presently under evaluation. The specific mechanism of degradation has not yet been identified.

Means of Controlling the Progression of ODSCC. The establishment of a reference model boiler ODSCC test provided the opportunity to evaluate the capability of boric acid additions to influence the initiation and propagation of stress corrosion cracking

induced by aggressive chemistry environments.

The initial series of model boiler tests established two facts:

1. the presence of boric acid, in an appropriate concentration for the contaminants added in the test, could prevent the initiation of stress corrosion cracking for the test exposures evaluated, and

2. the addition of boric acid following the formation of incipient cracking in an aggressive model boiler environment, could significantly delay the time for occurrence of through-wall cracking.

These test results provided the initial impetus for the addition of boric acid as an supplemental chemistry control measure for field instances of alkaline environment ODSCC.

Subsequent laboratory investigation into the direct effect of boric acid on the crevice chemistry environment was evaluated in a separate series of model boiler tests using a special test configuration known as the Heat Transfer Electrode. This device, which is schematically illustrated in Figure 8, accomplished the electrical isolation of a particular tubing section of a model boiler. This electrical isolation, which was accomplished using high temperature insulating films of zirconium oxide, permitted the measurement of crevice potentials in the section of tubing so isolated.

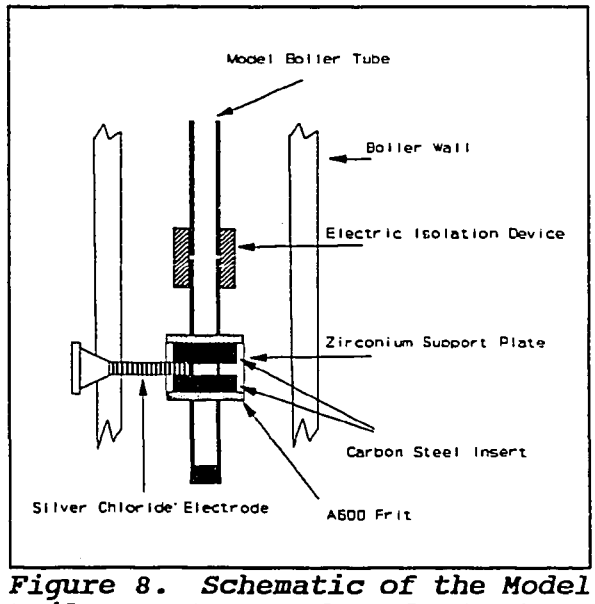

Figure 8. Schematic of the Model Boiler Heat Transfer Electrode

A typical experiment consisted of fitting the section of model boiler tubing with a concentrating device in the form of a tube support plate crevice configuration that was equipped with a high temperature electrode. Following operation of the model boiler to establish baseline conditions the injection of aggressive alkaline species was initiated. It was observed that the crevice potential dropped to levels where accelerated corrosion would be expected. It was also observed that the subsequent addition of boric acid caused the crevice potential to increase to more benign levels with the magnitude of that shift dependent on the relative concentrations of the aggressive contaminant and boric acid, Figure 9. The availability of such results directly refute concerns that the

volatility of boric acid prevents its influencing the tube support plate crevice environment and indicate that substantial value may be gained by the application of boric acid for units that may have alkaline crevice environments.

Although boric acid application is expected to provide a benefit for the avoidance of ODSCC, the main deterrent to the initiation of this mode of degradation would be the prevention of aggressive corrosive environments by appropriate chemistry control.

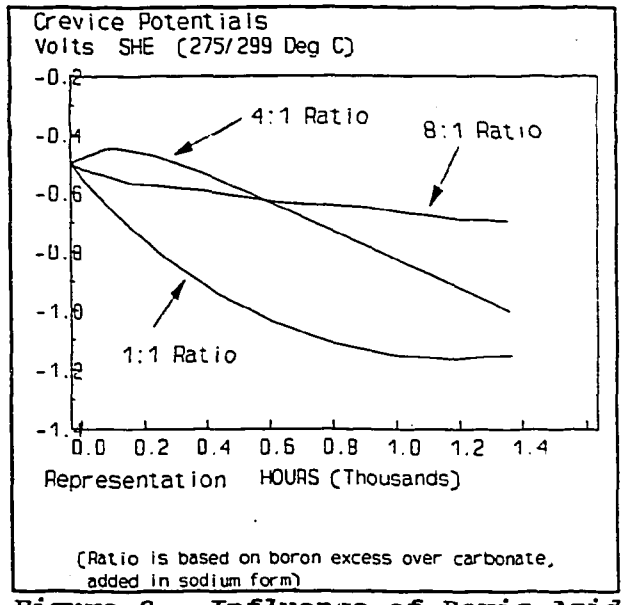

Figure 9. Influence of Boric Acid Application on Model Boiler Crevice Potentials Resulting from a Contaminated Environment

Alternate Plugging Criteria. The concept of Alternate Plugging Criteria (APC), as a means of defect specific degradation management, was developed based on correlations that were observed during tube examinations of field specimens and evaluation of laboratory produced instances of tubing degradation. In these programs data were developed on the leakage expected from a given tube whose degradation was subsequently characterized in considerable detail using metallographic techniques. Correlation of these data with the eddy current and burst resistance of the tubing clearly indicated that tubes were being removed from service even though they could meet all practical criteria for operation.

Correlations, such as those schematically illustrated in Figure 10, established a voltage limit of the bobbin coil signal which, if not exceeded, would indicate adequate integrity for the tubing under all normal, transient and fault conditions of plant operation. This data base is supplemented with the additional knowledge of the plant specific tube degradation mechanism as established through data gained from pulled tube evaluation, and the growth in the eddy current signal amplitude as determined using standardized techniques of signal calibration. The overall data base could then be applied to the existing population of indications remaining in a steam generator, to project the magnitude and characteristics of leakage over the next operational cycle.

The benefit of such a voltage based plugging criterion can be illustrated by consideration of the population of voltage indications that were recently observed in an operating plant and

were either plugged or repaired. These data display a characteristic lognormal distribution of voltage sizes, with the population mean occurring well below a technically justifiable voltage plugging limit, Figure 11.

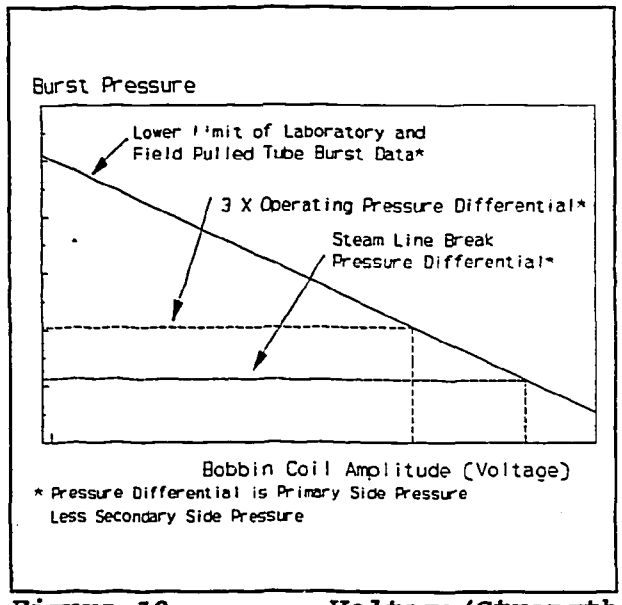

Figure 10. Voltage/Strength Correlations Contribute to Basis for Alternate Plugging Criteria

Of course, a structurally and operationally acceptable voltage population at the initiation of an operating cycle is necessary, but not sufficient, to justify operation for the following cycle. It must also be demonstrated that the voltage progression of the population remains within acceptable limits at the conclusion of the operating cycle. This is accomplished by the careful measurement of voltage growth, Figure 11, for the indications present in prior inspections and the use of that information in estimating the tube bundle condition at the next outage.

It is interesting and important to note that voltage growth studies on steam generators from several different plants show that the majority (in some cases all) of the indications were present at the prior inspection, Figure 12, and that the growth rate is quite modest. These data clearly show that plugging decisions and the initiation and rate of progression of degradation frequently do not occur in the same time frame and suggest caution in the use of plugging data for the purposes of projecting future performance.

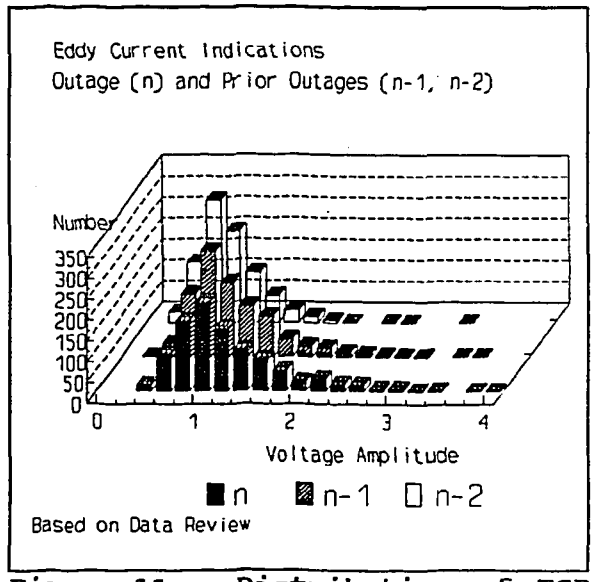

Figure 11. Distribution of TSP Voltage Indications Observed from Field ISI Data

The low voltage progression rates observed may also indicate the effectiveness of remedial measures such as chemistry control and boric

acid, and suggest that further enhancements in water chemistry control may indeed result in cessation of crack growth.

GENERAL REMEDIAL AND REPAIR ACTIONS TO ADDRESS TUBE DEGRADATION

In addition to corrosion control and alternate plugging criteria as qualified means to avoid or eliminate needless tube plugging, various repair options have been implemented in field service. In addition, other techniques are under detailed investigation in anticipation of potential field demonstrations. Two examples of these techniques are described in the following sections.

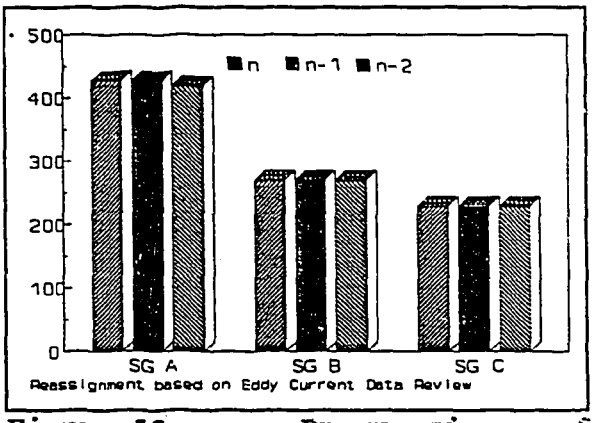

Figure 12. Progression of Signals to Additional Locations Based on Field NDE Results

Laser Welded Sleeving

The laser welded sleeving process offers the advantages of a replacement tube insert in the region where tubing degradation may have occurred, regardless of the reason. The major requirement is an area of non-degraded tubing at the region of the tube-to-sleeve joint. Sealing of the tube-to-sleeve occurs using a laser as a heat source and provides a sound metallurgically welded joint as illustrated in Figure 13.

The field equipment for laser welded sleeving is schematically illustrated in Figure 14. This equipment is capable of producing both tube support plate and tubesheet region sleeves as illustrated in Figure 15.

Direct Tube Repair. A spin-off development of the laser welded sleeving process is presently the focus of an intensive laboratory investigation and qualification program. This process, known as Direct Tube Repair (DTR), utilizes a focused laser beam as an energy source for remelting the tube in regions where the tubing may have experienced cracking. The laboratory effort to date has demonstrated that joining of two sections of tubing and the closure of laboratory produced stress corrosion cracks can be readily accomplished using a specially designed, automated weld head that is accommodated within the ID of the tubing. Field trials of the DTR technology are scheduled for late 1992.

Other Ameliorative Activities

In addition to the direct repair actions that may be taken in

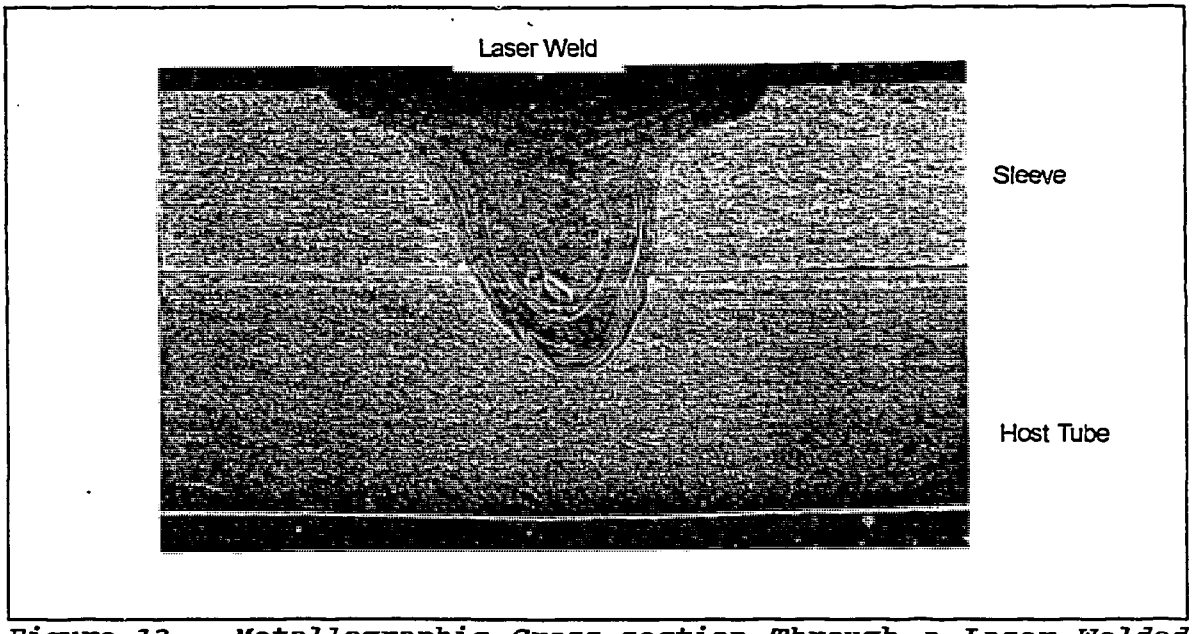

Figure 13. Metallographic Cross-section Through a Laser Welded Sleeve

situations of tube degradation, it is also desirable to implement additional measures to remove contamination from the steam generators and provide an enhanced environment for subsequent operations. Among such desirable activities are pressure pulse cleaning combined with chemical cleaning agents, and the monitoring and data management associated with a complete water chemistry control program.

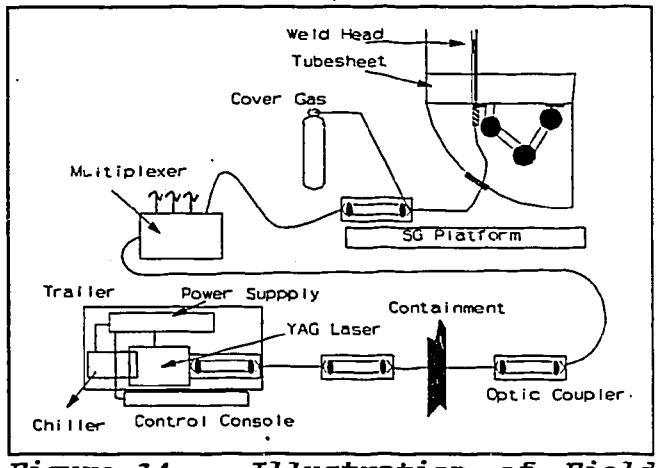

Figure 14. Illustration of Field Tooling Configuration for Laser Welded Sleeving

Pressure Pulse-Chemical Cleaning. Prior development has resulted in a technique to release a gas discharge pressure pulse into the steam generator during shutdown conditions. This pressure pulse, as a result of the pressure transient and the associated water surge which results from the gas expansion, serves to mechanically loosen deposits and flush soluble contaminants from otherwise flow restricted regions. This process has been applied at several plants and has been demonstrated to enhance the removal of sludge and dissolved solids.

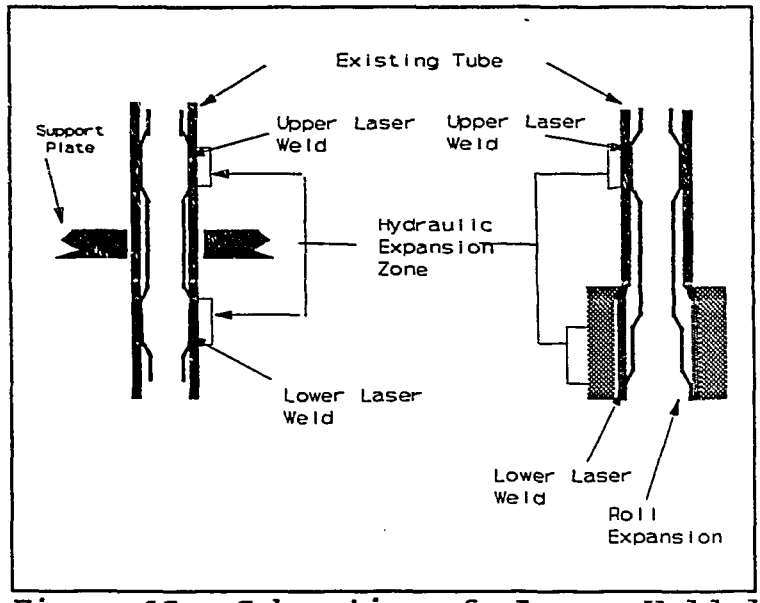

Figure 15. Schematic of Laser Welded Sleeving Configurations at the TSP and Tubesheet Locations

Chemical cleaning is the process of applying chemical agents with the dissolution capability to bring iron, copper and/or similar species into solution to aid in the removal of such species. Since the chemicals must be aggressive enough to bring iron oxides, such as magnetite, into solution and since the carbon steel and low alloy steel structural materials of the steam generator are protected from corrosion by a passivating iron oxide film, a certain amount of carbon steel or low alloy steel corrosion is inevitable with any effective chemical cleaning process. Dilute chemical cleaning agents, however, may be consumed relatively quickly and may not be able to migrate through surface deposits to desired locations prior to depletion of active chelation capability.

The goals and capabilities of the pressure pulse and chemical cleaning processes are the same, i.e. a cleaner steam generator, and the processes themselves are complementary. It is expected that pressure pulse application will eliminate one of the previously major difficulties associated with chemical cleaning, i.e. agitation. With effective agitation it is expected that the chemical cleaning reagent utilization will be more effective, and, with chemical loosening of the tube and crevice deposits, the mechanical removal capabilities of the pressure pulse technique will be significantly enhanced.

Chemistry Monitoring and Control. There are numerous examples in the chemical process control industry where the chemical interactions have been subjected to unanticipated synergistic reactions, or where periodic chemistry control activities have not been able to provide the continuous data stream necessary for effective process control. This issue is exacerbated when one of the components in the system is a heat transfer device that itself modifies the concentration and often modifies the chemistry of species that enter the system.
This is the situation with the monitoring and control of secondary side chemistry. The hideout which occurs with all boiling heat transfer devices causes a reduction in the concentration of soluble species in the bulk water and may, in

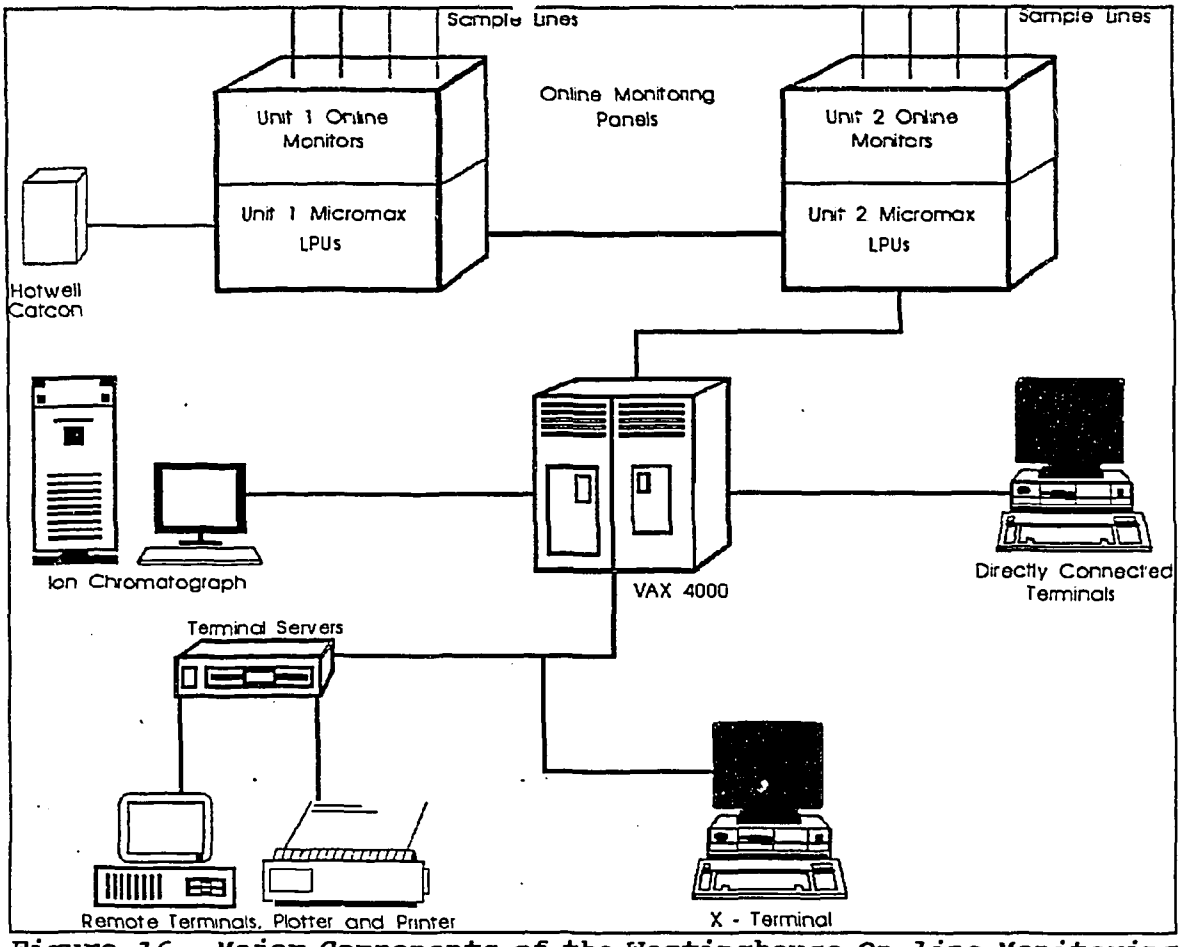

Figure 16. Major Components of the Westinghouse On-line Monitoring and Data Management Systems

cases with inadequate monitoring capabilities, provide a false reassurance that chemistry conditions are benign. The incorporation of an on-line chemistry monitoring and data management system provides a significant capability for the continuous monitoring and evaluation of this important plant chemistry data. Figure 16 illustrates some of the components the Westinghouse approach to this data management challenge.

ENHANCED STEAM GENERATOR PERFORMANCE CHARACTERISTICS

The first of the Model F-type steam generators came on line in 1980. Since then there have been additional Model F-type steam generators placed in service until today there are 84 of these steam generators in operation at 25 sites.

The design enhancements present in the Model F-type steam generators include quatrefoil broached tube support plate holes in Type 405 stainless steel tube support plates, hydraulically

expanded tubesheet joints, the use of thermally treated Alloy 600 or 690 steam generator tubing and other features.

Figure 17 summarizes the operating experience of all Model F-type steam generators. Westinghouse has furnished Models 44F, 51F and 54F replacement steam generators which utilize features typical of the Model F steam generator. Other replacement designs are currently being offered and differ by tube surface area and, in some instances, by tube size and tube pitch. Of the 25 Westinghouse replacement steam generators in operation, 17 employ thermally treated Alloy 600 tube material. This population of steam generators has operated for an average of 9.9 years. In that time the total number of tubes that have been plugged is 39. This is equivalent to 1 plugged tube per steam generator every 4.3 years of operation. In addition, eight operating Westinghouse replacement steam generators are tubed with thermally treated Alloy 690. These steam generators have operated for an average of 3.5 years with no tubes plugged.

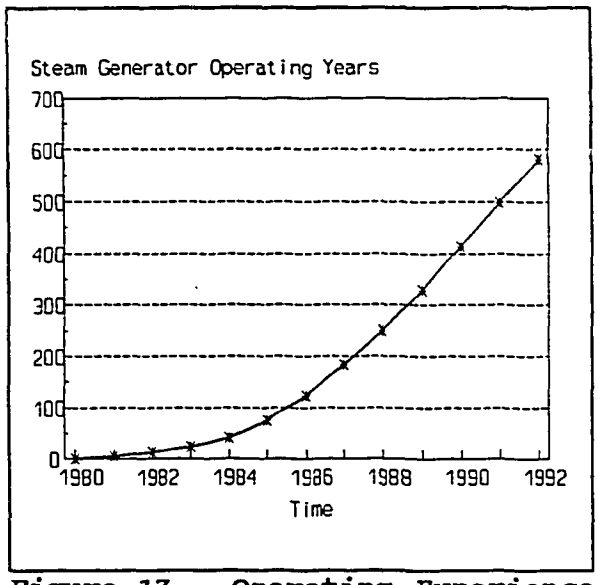

Figure 17. Operating Experience of Model F-Type Steam Generators

For all Model F-type steam generators, in the period from 1980 to the end of June 1992, a total of 730 tubes have been plugged; this corresponds to approximately 0.18% of the more than 400,000 tubes in operation, with more than 580 steam generator-years of operating experience. This is equivalent to 1 tube plugged per steam generator for every 1.3 years of operation. Figure 18 shows graphically the Model F-type steam generator tube plugging by cause from 1980 through 1991.

The two cases where tube plugging has been notable, i.e., one plant with unusual AVB wear and one plant with free length tube denting, are considered anomalies in that they clearly lie far beyond the bounds of behavior of the Model F-type steam generator population. If the plugging statistics for these two cases are regarded separately from the overall data base, the percent of tubes plugged in the 79 remaining Model F-type steam generators is 0.1% or equivalent to 1 tube plugged per steam generator for every one year of operation.

In Figure 18 the "other" category for tubes plugged consists of a variety of causes including foreign object wear, random eddy current signals not relevant to steam generator tubing

degradation, and indications due to local geometric anomalies.

SUMMARY

Specific modes of degradation occurring in the early models of U-bend design steam generators for the Westinghouse PWR system have been identified as a result of field inspection programs. These modes of degradation have a variety of origins that have been systematically addressed through a program of water chemistry modifications including the use of boric acid as an additive that aids in the control of stress corrosion cracking and denting.

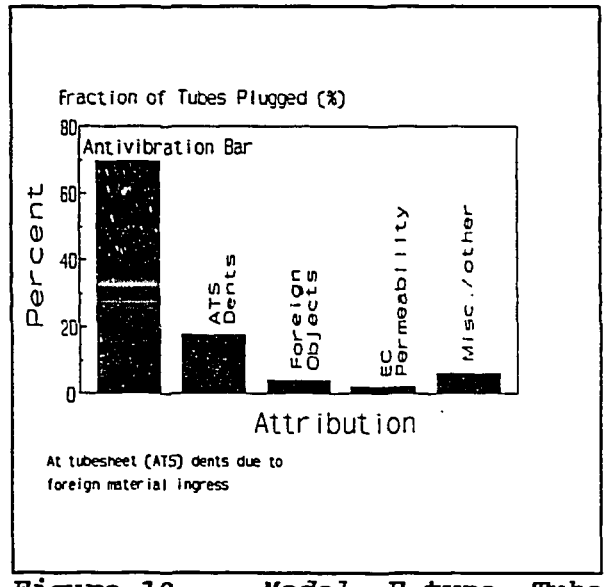

Figure 18. Model F-type Tube Plugging by Attribution

More recent laboratory test programs have identified that addition of zinc borate to simulated primary system environments should result in significantly lower corrosion rates that are expected to result in lower radiation fields and reduced instances of stress corrosion cracking.

The experience of the Model F-type steam generators has been essentially free of tube corrosion issues except for one occurrence believed to be due to the ingress of substantial quantities of foreign material.

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PROACTIVE HEAT EXCHANGER PROGRAM

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ABSTRACT

This paper describes the proactive heat exchanger program at Pickering NGS. The program objectives, methodology, benefits and costs are presented. Examples of initial results are included.

INTRODUCTION

Heat exchangers at Pickering Nuclear Generating Station (PNGS) have been a significant contributor to station incapability (Figures 1 & 2)(1). Cumulative production losses due to heat exchangers since the beginning of operation until 1991 have amounted to 300 unit days or nearly 1 unit year (equivalent to approximately 90 M$ energy replacement cost today). Heat exchanger tube failures and resulting leaks have occurred due to a variety of reasons, although pitting corrosion of tubing materials under lake Ontario cooling water deposits has been the dominant degradation mechanism.

In recent years, this negative impact on station performance has been significantly reduced, despite an increasing number of heat exchangers affected by degradation as the plant ages.

This paper describes the development, implementation and results to date of the proactive heat exchanger program presently being applied at PNGS. Similar programs are in place or are planned for other key equipment at the station, such as piping, valves, pumps.

OBJECTIVE OF THE PROGRAM

The objective of the program is to minimize heat exchanger tube degradation and its impact on station performance during the remaining plant life. Typical areas of impact are product cost, reliability and emissions to environment, often all three in a single event.

For example a leak in a moderator heat exchanger will result in a spill of tritiated heavy water to Lake Ontario via the service water cooling system. To stop the leak and enable repairs of the leaking heat exchanger the unit has to be shut down for a minimum of 10 days. The resulting cost of replacement energy (ie. to replace nuclear generation with more costly fossil generation or purchases) is approximately 3 M$ (300 k$ per day for a PNGS unit) for such an outage.

METHODOLOGY

The methodology applied to the heat exchanger program is generic for all equipment programs. It can be summarized in the following three basic steps.

1. Identify critical heat exchangers based on risk to station performance.

2. Develop programs for these critical heat exchangers.

3. Revise the programs as needed based on new information.

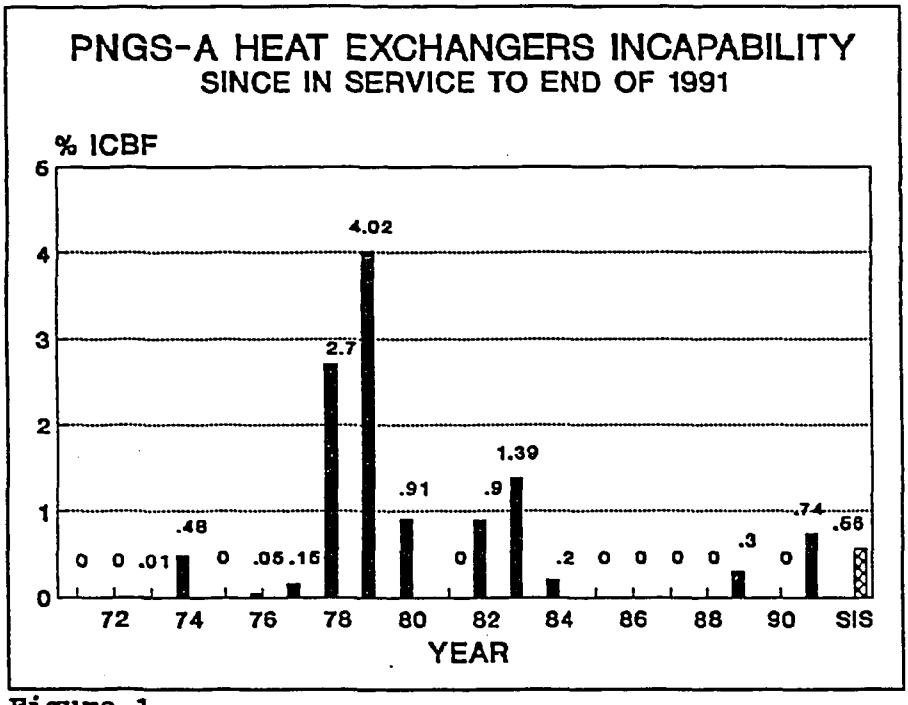

Figure 1

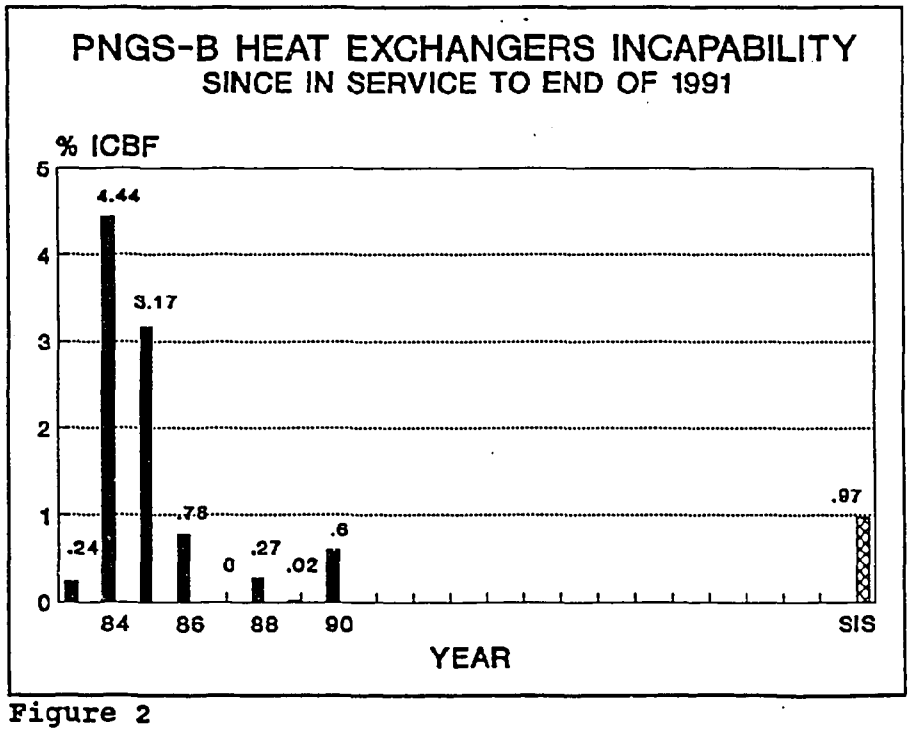

Figure 2

Each of these steps is discussed in more detail below.

Identifying Critical Equipment

To ensure the effectiveness of the program it is important to limit its scope to heat exchangers which are critical to station performance.

There are approximately 1100 heat exchangers in approximately 150 distinct applications in the 8 units of PNGS. Risk assessment helps prioritize this large number to ensure that limited resources are applied to a smaller number of heat exchangers with the greatest potential for impact on station performance.

Risk assessment is based on the well known formula:

risk = consequence x probability

Thus both the consequence and the probability of failure are evaluated for each distinct heat exchanger type.

Consequence of failure. A number of factors need to be considered to determine the consequence of failure of a heat exchanger, ie. its impact on station performance, including the following:

- function of the system to which heat exchanger belongs;
- impact of heat exchanger unavailability on the system;
- impact of tube leak on heat exchanger/system performance.

Heat exchangers with consequence of failure insignificant to station performance are eliminated from further consideration.

Probability of Failure. The probability of failure is assessed based on evaluation of known and potential degradation mechanisms for each heat exchanger type. Again, a variety of factors need to be considered, such as:

- previous PNGS operating and maintenance history;
- other Candu station and external utility experience with similar heat exchanger applications;
- modifications to operating regime, system configuration, etc. which may change future performance of heat exchanger.

Detailed surveillance and maintenance history is maintained for each critical heat exchanger.

As a result of the above described selection process 33 different types, representing population of 332 heat exchangers are currently covered by the program (approximately 30% of station heat exchanger population). They range from such major

components as moderator coolers and main condensers to much smaller and less expensive, but potentially critical heat exchangers, like fire resistant fluid (FRF) coolers and isolated phase bus (IPB) coolers.

Program Development

To minimize the impact of heat exchanger tube degradation on station performance, the program has to optimize surveillance and maintenance activities.

Program development is based on evaluation of alternative measures, such as cleaning, leak testing, inspections, tube plugging, retubing/replacement for each critical failure mode identified.

The program is documented in an Equipment Strategy Manual (ESM).

The ESM provides a 10-year program to facilitate long term planning. The main focus, however, is on the current year activities. The following is provided to support each recommended activity:
- rationale;
- priority;
- identification of outage work;
- estimate of labour by work group.

Program Revisions

In order to maintain and improve the effectiveness of the program it is reviewed periodically to assess the impact of relevant developments, such as:
- destructive & non-destructive examination results;
- test program results;
- unforseen equipment deficiencies & failures;
- outage schedule changes.

Each ESM is revised at the end of each year and whenever a significant revision is required.

RESULTS

Major Impacts Avoided

The proactive approach leads to early identification of degradation, before failures occur. The knowledge of the condition of critical station heat exchangers allows us to avoid or minimize the impact their degradation would otherwise have on station performance, as illustrated by the following examples.

Moderator Coolers. The cost of a single leak event (over 3 M$) approximates the cost of replacing both moderator coolers on a unit. Early detection of degradation is critical to avoiding significant production losses, in particular considering the impact of simultaneous degradation on 4 units and a 2-year procurement cycle for the replacements.

The **PNGS-A coolers** have replacement 70/30 copper/nickel tube bundles, which were installed in 1983-84. The original tube bundles, made of the same material, degraded due to tube vibration and fretting. A monitoring inspection was performed in 1990 to confirm lack of degradation in the new bundles. It showed that the tubes were thinning due to lake water silt erosion (2), a mechanism previously not observed in these heat exchangers. Our current strategy is to monitor the rate of thinning with sample inspections and destructive examinations of tubes removed to ensure timely replacement (anticipated in 1995-97).

The **PNGS-B coolers** have replacement tube bundles made of Incoloy-825 (Units 5 & 6) and Sanicro-28 (7 & 8), installed in 1985-87. They were expected to degrade due to pitting under lake water deposits, providing 10-12 years of service. The first monitoring inspection, performed on Unit 5 in 1989 (after 4 years in service) identified one pit measured at 12% through wall (3). A full scale inspection performed in 1991 on the same unit found 29 pitted tubes, including three with pit depths above 75%. All tubes with pit indications are plugged. A 1992 inspection on Unit 7 found two pits, one of which measured 98% through wall. A replacement program was initiated in 1991. Replacement heat exchangers with Ti tube bundles will be expected to last to the end of plant life. Installation is scheduled for 1993-1995. Until the replacement heat exchangers become available, inspections and preventive plugging are planned for each planned outage. No leaks due to pitting have occurred to date.

Turbine Lube Oil Coolers. Copper tubes in these coolers are degrading due to pitting under lake water deposits. A tube leak will result in emissions of oil to the lake. Our strategy, starting in 1990, has been to prevent oil emissions with tube inspections and preventive plugging, and to replace tube bundles when plugging limit is reached. Six of 12 coolers in PNGS-B have been inspected to date, resulting in 10% of all inspected tubes (860 tubes), with defects greater than 50% through wall, being plugged. The worst tubes examined had almost through wall defects; all that remained was tin plating on the tube outside diameter (4). Inspections and preventive plugging will continue until replacement bundles are installed, currently planned for 1993-94. No oil emissions due to tube defects have occurred to date.

Equipment Service Life Extension

Tube cleaning to prevent or slow down degradation in critical heat exchangers is another important aspect of the program. It is expected that periodic cleaning will reduce the build up of lake water deposits and thus reduce the rate of under deposit pitting, in particular in copper and 90/10 copper/nickel tubes. All critical heat exchangers cooled by lake water flowing through the tubes are cleaned every four years. That includes all turbine and generator heat exchangers.

CONCLUSION

The proactive program helps minimize the impact of equipment degradation on plant performance. It is also apparent that the costs of the program, thanks to its focus on critical equipment only, are not significant when compared with its benefits.

The annual cost of the proactive heat exchanger program including tube cleaning, inspections, plugging and technical support is approximately 70 k$ per unit. This is roughly equivalent to 6 hours of unit downtime. The total cost of the program for all 8 units in the first three years of its existence is about one half of the cost of a single moderator heat exchanger tube leak event.

Long term program costs can be expected to decline as the rate of degradation stabilizes with proper maintenance and expected replacements.

ACKNOWLEDGEMENT

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REPLACEMENT NUCLEAR STEAM GENERATORS

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Abstract

This paper reviews past and current practices in the replacement of nuclear steam generators. Plants where steam generator replacement has occured are reviewed to see what changes are made in the replacement hardware and how the evolving technology for site changeout activity has significantly reduced outage time and man-rem exposures. Current preferences in equipment design and material are reviewed.

REPLACEMENT NUCLEAR STEAM GENERATORS

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INTRODUCTION

One common feature of Pressurized Water Reactors (PWR) and CANDU heavy water reactors is steam generators. Between operating PWR and CANDU plants, there are more than 1000 steam generators currently in operation. Steam generators have been subject to a variety of problems, mainly corrosion related damage to the tubing. In a growing number of cases, the damage is becoming extensive enough to prompt complete replacement of the steam generators. This paper traces steam generator replacement from its beginnings in the 1970's up to current day practices and trends.

HISTORY OF STEAM GENERATOR PROBLEMS

All steam generators are designed and put into operation with an anticipated life expectancy of the full design life of the plant (e.g. 40 years). However, by the early 1970's, it was becoming apparent that steam generators were subject to a variety of tube failure mechanisms; some corrosion related, some of a mechanical nature (e.g. vibration and fretting). Figure 1 (1) shows, year by year, the predominant causes of steam generator tube failures. In the 1970's, the predominant causes were tube wastage, and tube denting, both of which were brought largely under control by changes in plant water chemistry practices. By the 1980's, however, the predominant tube failure mechanism had become stress corrosion cracking. This phenomenon can occur in pure water, and hence cannot be corrected through plant water chemistry. It is largely a deficiency in the tube material, and is most prevalent in mill annealed alloy 600 material. Mill annealed alloy 600 material was widely used in PWR steam generators in the US and other countries where U.S. steam generator technology was used under license.

A significant portion of those steam generators with mill annealed alloy 600 tubing, world-wide, have either been replaced, or are in planning for replacement.

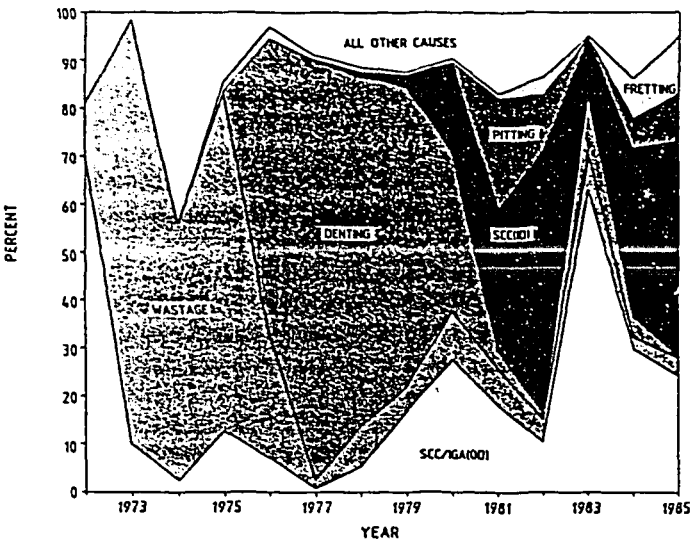

Figure 1. History of tube Failure Mechanisms

Stress corrosion cracking of mill annealed alloy 600 tubing is not the only cause of steam generator replacement, but at the present time, it is the largest contributor. In the absence of preventative measures against SCC (e.g. stress relief of U-bends, peening of expanded tube sections in tubesheets), it is highly likely that SCC will appear, widespread throughout the steam generator, with only a small variation in rate of initiation and propagation depending on plant operating temperatures.

REPLACEMENT PROJECTS

The first two plants to replace steam generators were the Surry (2 3-loop reactors) and Turkey Point (2 3-loop reactors) plants in the U.S. In both cases, the predominant cause of steam generator tube failure was denting. All four reactors had 20% or more of their steam generator tubes plugged at the time of replacement. Insofar as tube failure mechanisms were becoming well recognized by the mid-to-late 1970's, the replacement steam generators contained a number of provisions aimed at eliminating known problems. These were:

Table 1 - Surry and Turkey Point Steam Generator Comparison

Feature	Original Steam Generators	Replacement Steam Generators	Problem to be solved
Tubing	Mill annealed alloy 600	Thermally Treated alloy 600	SCC
Tube Supports	Solid carbon steel	Stainless steel broached	Denting
Tube / TS Crevice	Open	Full depth expanded	Crevice IGA
Feedwater Header	Downward Drain	J-Tubes	Waterhammer

While steam generator technology itself was becoming mature by the late 1970's, the technology of steam generator replacement was new. As this was the first case of major component replacement in PWR's, the work was done cautiously and meticulously and a certain amount of experimentation was done. The units were successfully brought back on line, regulatory acceptance was achieved, and the replacement steam generators have performed well since. However, by today's standards the outage durations were very long, and man-rem exposures were very high. Table 2 compares results from Surry and Turkey Point with more recent replacement projects at Ringhals 2 in Sweden, and Dampierre, in France, both of which are also 3-loop PWR plants.

Table 2 S.G. Replacement Time/Exposure Comparison

Plant	Replacement Year	Replacement Type	Shutdown Duration (Days)	Exposure (man-rem)
Surry 2	1979/80	Lower Sec's	303	2140
Surry 1	1981	Lower Sec's	209	1758
Turkey Pt.3	1981-82	Lower Sec's + Channel Cut	210	2151
Turkey Pt.4	1982/83	(as for TP3)	183	1305
Ringhals 2	1989	Entire SG	72	290
Dampierre 1	1990	Entire SG	99*	220

*Per Framatome, actual S.G. replacement time 70 days, outage extended by parallel non-steam generator activities.

In total, steam generator replacement, at time of this writing, has been completed at 12 reactors with a 13th (Millstone II) underway. The detailed changeout performance in each case can be seen in Table 3, but in all cases it is bounded by the performances listed in Table 2.

The drastic improvements in outage time and exposure are the result of significant technological advances in areas such as:

- automated pipe cutting and welding
- laser techniques for measurement and alignment of equipment and piping, reducing the number of welds to be performed and the complexity of weld fitup
- there is a significant advantage to full steam generator replacement (as in the case of Ringhals and Dampierre) vs partial (lower section) replacement at Surry and Turkey Point in terms of significant reduction in field welding to pipe welds only (readily adaptable to automated welding) vs vessel welds which are largely manual
- current decontamination and shielding technology, combined with remote, automatic tooling, have contributed to the nearly one order of magnitude reductions in man-rem exposures
- with experience being gained constantly in steam generator replacement, the various Contractors are constantly developing new methods, and the regulatory bodies are increasingly accepting steam generator replacement as a practice at nuclear power plants. Regulatory focus is not on the process as a whole for acceptability, but merely the minimized impact on overall reactor operation and safety, and ALARA considerations in the changeout itself. Several recent U.S. steam generator replacement projects (Indian Point III, Millstone II) have been carried out under US. 10 CFR 50.59 rules, which categorize the entire change of the steam generators as a "repair" not requiring license amendment.

CURRENT TRENDS IN REQUIREMENTS

With both the steam generator manufacturing industry and the steam generator changeout industry having now reached levels of maturity, the Utilities can expect significantly improved steam generators, and fast, low exposure changeouts. Reviewing all worldwide experience with nuclear steam generators, 46 failure mechanisms have been identified in numerous studies carried out by EPRI, US Nuclear Regulatory Commission and others. These are summarized in Figure 2. In terms of current specifications from Utilities to suppliers, the trend is to specify that design and material selections are largely left to the supplier, but the supplier must convince the Utility that his design addresses and

solves all identified steam generator problems. Two interesting trends which are arising out of the growing Utility confidence of:

a) regulatory acceptance for steam generator replacement

b) the Utility's own ability to judge designs against requirements of the specifications, are as follows:

1. There is a strong move towards lattice grid-style steam generators

	Prior to 1992	During 1992
# of replacement steam generators ordered with broached tube support plates.	55*	12
# of replacement steam generators ordered with lattice grid tube supports.	12	33

* Including 18 ordered by EDF for ongoing replacement program in French 900MWe plants.

2. There is a trend, driven partly by the lattice grid issue listed above, to order steam generators from other than the original manufacturer

	Prior to 1992	During 1992
# of steam generators ordered from OEM	57*	9
# of steam generators ordered from supplier other than OEM	10	36

* Including 18 ordered by EDF.

Recognition for the operating performance of lattice grid steam generators in PWR's in Germany, and CANDU reactors in Canada has resulted in the significant turn of ordering patterns in favour of suppliers of the lattice grid-type steam generators from those countries.

Another trend which has evolved in the equipment area over the years is in tube material selection. Since 1983, no replacement steam generators have been ordered with alloy 600 tubing, even the thermally treated (TT) variety. The alternatives are alloy 800, again used extensively in Germany and Canada, and alloy 690

TT, a more recent development. The following is a comparison of ordering trends, in terms of number of steam generators:

	Upto 1983	1984-1991	1992
Alloy 600TT	23	0	0
Alloy 800	2	3	12
Alloy 690 TT	0	39	33

Alloy 690TT and Alloy 800 both perform well in laboratory corrosion testing when compared with alloy 600. Alloy 800 has shown a tendency towards chloride and caustic SCC in the laboratory, but this has not been experienced in extensive operation of this material. Alloy 800 has experienced some limited pitting under aggressive tube deposits in one CANDU plant, and has experienced wastage under phosphate deposits in Germany. Alloy 690 has relatively little operating history. Alloy 690, however, offers other advantages when considered as a replacement material for alloy 600:

- conductivity is closer to that of alloy 600 than is conductivity of alloy 800 (per data from Inco (3), alloy 690, 9% lower, alloy 800 14% lower).

- per the ASME Code, the strength of alloy 690 (allowable stress) is equal to alloy 600, alloy 800 has lower strength. A Code Case allows mechanical modification of alloy 800 to enhance strength, but residual stress raises SCC concerns.

Between the above two (2) factors, a replacement-in-kind type of steam generator can be more readily developed and licensed using alloy 690TT tubing.

CONCLUSIONS

Steam generator replacement has been going on since the 1970's, and will continue mainly with the replacement of steam generators with mill annealed alloy 600 tubing. The replacement of steam generators has now received widespread regulatory acceptance as a necessary operation for the safe, efficient long-term operation of the affected reactors. There is a strong trend in recent ordering towards lattice grid type steam generators, and a strong trend towards alloy 690 TT tubing. Steam generator replacement technology has advanced significantly in its first 10 years, with close to an order of magnitude reductions being realized in both length of shutdown and total man-rem exposure. Although the process can be complex and costly, it is not insurmountable and most Utilities are choosing replacement over complete shutdown when severe steam generator problems occur.

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Figure 2
STEAM GENERATOR INDUSTRY-WIDE PROBLEM AREAS

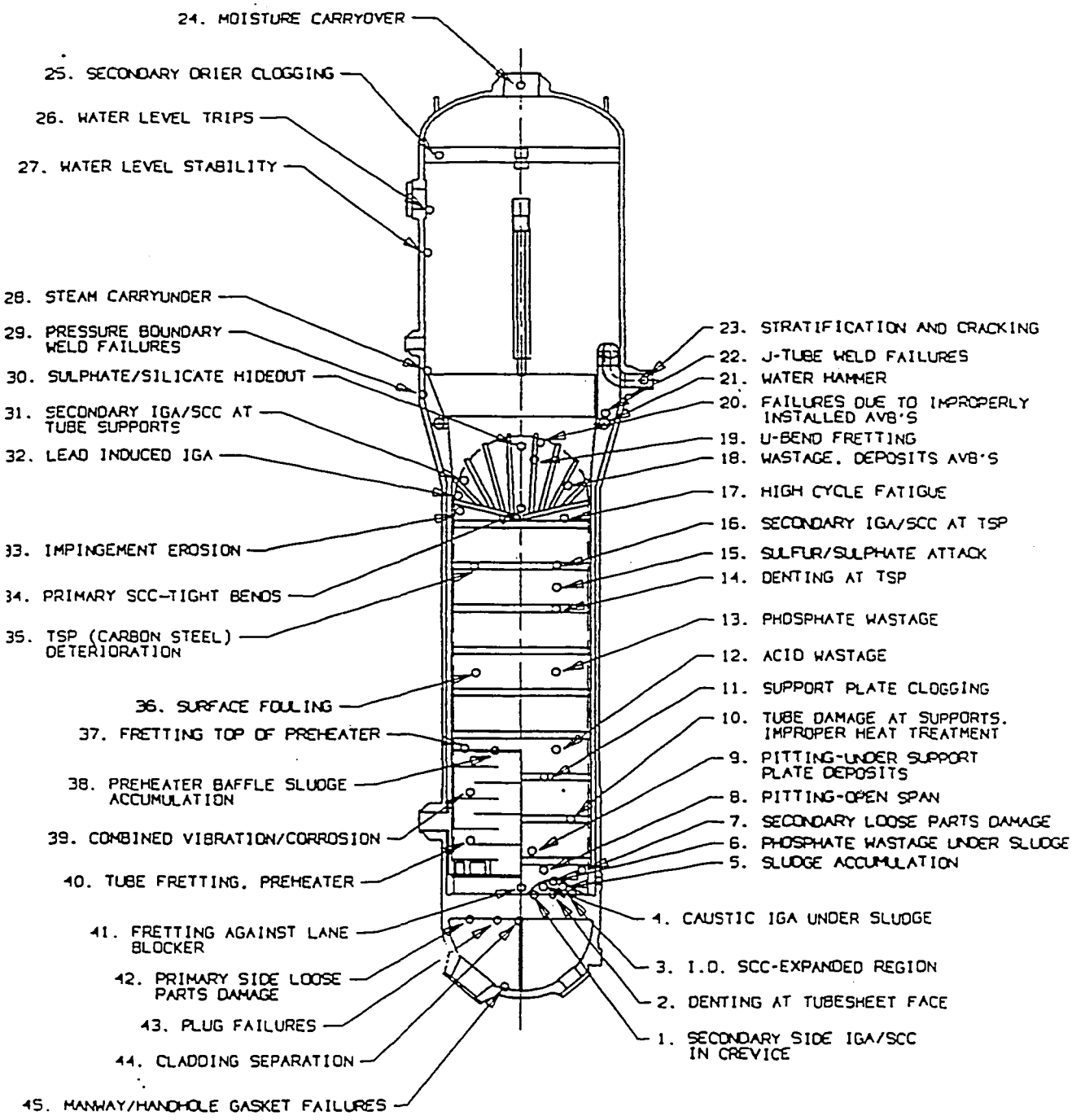

Table 3
Steam Generator Replacement Complete or
Planned with S.G.'s Ordered

Plant	Initial Operation	# of SG's Repl SG Type*	Date of Repl.	Orig/Repl SG Suppl'r **	Repl SG Tubing	Outage (MO)	Man Rem
Surry 1	1972	3 B	1981	W/W	600T	10	1758
Surry 2	1973	3 B	1980	W/W	600T	11	2141
Turkey PT3	1972	3 B	1982	W/W	600T	10	1305
Turkey PT4	1973	3 B	1983	W/W	600T	8	2151
Palisades	1971	2 L	1990	C/C	600MA	4	487
PT Beach 1	1970	2 B	1984	W/W	600T	5	580
Robinson	1971	3 B	1984	W/W	600T	7	1206
Obrigheim	1969	2 L	1983	K/K	800	3.5	690
Ringhals 2	1975	3 L	1989	W/K	690T	2.5	290
DC Cook 2	1978	4 B	1989	W/W	690T	7	561
Ind PT 3	1976	4 B	1989	W/W	690T	5	550
Ind PT 2	1974	4 B	Indef.	W/W	600T	---	---
Beznau 1	1969	2 B	1993	W/F	690T	---	---
Dampierre 1	1980	3 B	1990	F/F	690T	2.5	220
Millstone 2	1975	2 L	1992	C/B	690T	Under	way
Doel 3	1982	3 L	1993	W/K	800	---	---
N.Anna 1	1978	3 B	1993	W/W	690T	---	---
V.C. Summer	1984	3 B	1995	W/W	690T	---	---
St. Lucie 1	1976	2 L	1997	C/B	690T	---	---
McGuire 1	1981	4 L	1995	W/B	690T	---	---
McGuire 2	1984	4 L	1997	W/B	690T	---	---
Zion 1	1973	4 L	1998	W/B	690T	---	---
Farley 2	1981	3 B	1998	W/W	690T	---	---
Farley 1	1980	3 B	2005	W/W	690T	---	---
ASCO 1	1984	3 L	1995	W/K	800	---	---
Almaraz 1	1981	3 L	1995	W/K	800	---	---
ASCO 2	1985	3 L	1997	W/K	800	---	---
Almaraz 2	1983	3 L	1997	W/K	800	---	---
Tihange 1	1975	3 B	1995	W/M	690T	---	---
Catawba 1	1985	4 L	1996	W/B	690T	---	---
Ringhals 3	1981	3 L	1995	W/K	690T	---	---
North Anna 2	1980	3 B	1996	W/W	690T	---	---

* L = Lattice B = Broach

** W = Westinghouse F = Framatome
K = KWV/Siemens M= Mitsubishi
B = B&W (Canada)

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Canadian Nuclear Society
Société Nucléaire Canadienne

Proceedings

2nd International Conference on CANDU Maintenance

VOLUME 2 OF 2

Co-sponsored by

November 22-24, 1992

Toronto, Canada

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BRUCE 'A' UNIT 4 FUEL CHANNEL FEEDER COUPLING LEAKAGE

C.T. Ropponen and B.P. Cheung

AECL CANDU

Mississauga, Ontario

ABSTRACT

Candu Reactor fuel channels are connected to the Primary Heat Transport System by mechanical joints known as feeder couplings (feeder connections) which overall have performed well in many reactors over many years of operation. Occasionally, minor leaks have occurred in the couplings. In 1991 three feeder coupling leakages were discovered in Bruce A Unit 4. These leakages became large enough to exceed the operating limits and required the unit to be shut down for repair. Although existing repair methods are available to eliminate the leakage, an investigation, coupled with lab tests, was undertaken to gain an understanding as to the possible cause(s) of the leakage in that unit in order to eliminate or reduce future leaks.

The investigation has identified that the leakage at the feeder coupling was caused by a small "separation" of the couplings at the connections. One or more of the following factors might have been involved in causing the separation: a) marginal installation torque of capscrews, b) variation of capscrew preload for a given installation torque, c) alignment of feeder pipe with respect to end fitting port, d) decrease in capscrew load (capscrew loosening) during reactor operation and e) seal ring lip relaxation.

In the beginning of 1992, six more leaks which did not exceed the operating limits, were discovered in the same reactor unit. This paper covers only the investigation of the three leaks in 1991. The investigation of the six leaks found in 1992, which is still on-going, is to find out if there are similarities among all leakages.

BRUCE 'A' UNIT 4 FUEL CHANNEL FEEDER COUPLING LEAKAGE

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Design Engineers
AECL CANDU
Mississauga, Ontario

BACKGROUND

There were a few feeder coupling leakages that occurred at Bruce A Unit 4. These leaks were detected at power and the leakage magnitude was large enough that the unit had to be shut down for repair.

Each leak requiring a shut down affected the capacity factor of the reactor. Therefore, an investigation was initiated to investigate the cause(s) of the leaks with a view to preventing them in the future. This investigation involved reviewing site data on each leak, inspection of some of the available components, dimensional checks etc. Tests were also conducted at AECL CANDU's Sheridan Park Engineering Laboratory (SPEL) to simulate the large leaks, to assess the factors required to get such leaks and to confirm some of the early theories.

FEEDER COUPLING DESIGN AND REPAIR

A feeder coupling assembly essentially consists of a hub (welded to a feeder pipe), a flange, a seal ring, an end fitting feeder coupling port and four capscrews. The coupling connects the feeder pipe to a fuel channel end fitting as shown in Fig. 1. A typical assembly is shown in Fig. 2.

The seal incorporates an interference fit between the seal ring lip and the sealing surfaces of the end fitting port and the grayloc hub when the hub is bolted against the end fitting port. At this point the gap between the seal ring rib, the hub and the end fitting port should be zero as shown in Fig. 3. The rib provides for a predetermined amount of lip deflection with a high compressive force to affect a seal. In addition the rib provides for an overall stability to the assembly when the assembly is subjected to mechanical loading.

The repair to a leaky connection involves the use of "grafoil" tape and a motorized lapping fixture. The lapping fixture restores the hub sealing surface by removing a small amount of material from the surface as well as pitting, scratches or erosion marks that were causing the leaks. The grafoil tape is essentially a graphite material bonded to a tape for ease of installation. The tape is to provide additional assurance against leakage by filling up any extremely small defects still left after the lapping. The grafoil installation method and a motorized lapping fixture are shown in Fig. 4.

LEAKAGE INVESTIGATION

Possible leakage causes were identified and analyzed. Although the investigation involved a large study in various areas; such as reviewing history dockets, sources of components, comparison to other similar units, previous tests results, etc.; the important results can be briefly described as follows:

- When the leaking feeder coupling data obtained from site was reviewed, it was found that some of the capscrews removal torques were much lower than the installation torque specified of 163 N.m Previous experience showed just the contrary, i.e. capscrews were normally more difficult to remove than to install, after some time in operation. This indicated that some of the capscrew preload was reduced. On these leaking connections, the capscrew load reduction could be caused by capscrew loosening during operation, seal ring relaxation, or other factors.

- Capscrew material of Bruce A and Pickering A is carbon steel which limited the installation torque to 120 ft-lb. All other reactors have higher strength stainless steel material for their capscrews and have higher installation torques.

- Computer enhanced images of the seal areas in the hub revealed that it was not a corrosion problem. Only a few erosion marks existed (Fig. 5).

- Physical measurements, metallurgical examination, chemical analysis and observation of all components; seal rings, flanges and capscrews; were conducted. The results showed that there was some small erosion marks, but no corrosion, on the seal ring lips (Fig. 6). The erosion was the result and not the cause of leakages. However the erosion marks were also too small to cause the amount of leakage recorded when the unit was finally shut down. This was determined by analysis and later by test.

  There were shiny marks of about 120 degrees on the edge of all seal ring ribs (Fig. 7) and leakage marks were on the rest of the area. This indicated that hubs might have tilted causing the contact between hub and seal ring rib at one side but not at the other. There is no direct evidence that the feeders were installed outside the specifications. There was evidence on one seal ring of a shift or change in the seal area during operation.

  The inner diameter or the bore of the seal rings was found to be "barrel" shaped (concave shape - Fig. 8). This suggested that the seal ring lips were slightly relaxed.

The overall analysis suggested that the leakage was caused by a slight separation between the hub and the lip of the seal ring. The investigation has identified that the separation was due to the

loosening of the joints and that one or more of the following factors are involved, a) marginal installation torque specified for the capscrews, b) variation of capscrew preload for a given installation torque, c) alignment of feeder pipe with respect to end fitting port, c) decrease in capscrew load (capscrew loosening) during reactor operation and d) seal ring lip relaxation.

TEST REQUIREMENTS

The main objectives of the tests were to duplicate the feeder coupling leakage under site conditions (operating pressures, temperatures and loads) at the time of the leakage occurrence and to confirm the suspected causes described above.

The initial test requirements were to duplicate the site leakage by assembling the feeder coupling with a low installation torque in one of the four capscrews as measured during removal at site. The objective was to simulate the feeder coupling conditions at the leak site at the time of leaking. However, the feeder coupling of the first test could not duplicate the site leakage. The details of the later test requirements evolved as the tests progressed and we learned what other factors, such as relaxed seal rings etc., were also required to generate such leaks of the magnitude observed at site.

TEST PROGRAM

The program consisted of leakage tests, gap measurements and comparison of capscrew preload torque by a torque wrench and an ultrasonic bolt gauge.

Leakage Tests

Three assemblies were subjected to cyclic mechanical, thermal and hydrostatic loading to reflect reactor operational start ups and shut downs. A typical test assembly is shown in Fig. 9.

A cycle was comprised of a heating up and cooling down of the assembly. The heating process was initiated with hot water introduced into the assembly, with the water chemistry similar to site heat transport system water chemistry. The assembly temperature (sensed via a thermocouple clamped to test inlet pipe) rose from 38°C. to 260°C. at a rate of 93°C. per minute. During this time the water pressure was maintained at 10.0 Mpag.

The cooling process commenced with the venting of the test assembly volume and the introduction of demineralized water into the assembly. The assembly temperature controls were set to provide a cooling rate of 93°C. per minute from 260°C. to 38°C. with water pressure at 0.27 Mpag.

Concurrent with the heating and cooling processes, were mechanical

loadings imparted to the coupling. The loading is illustrated in Fig. 10.

The maximum loading values used during the tests were:

- axial load (separating load along assembly axis) = 934 N.
- radial load (perpendicular to feeder pipe) = 2,046 N.
- bending moment (opening moment) = 3,227 N.m
- torsional moment (about feeder pipe axis) = 1,030 N.m

The mechanical loads were transferred to the coupling via a loading flange and a hub extension. The mechanical loads simulated the loads the coupling experience as a result of initial coupling installation and fuel channel creep during the reactor life of a fuel channel.

The leakage from the joint was determined by passing nitrogen gas from a bottle through a tightly sealed metal shroud encasing the coupling and through anhydrous copper sulphate desiccant. Periodic weighing of the desiccant provided weight gain due to moisture pick up (seal leakage). For large leaks such as site equivalent leakage (100 Kg/hr), the shroud outlet was connected to a condenser.

Assembly No. 1. The components were assembled with the four capscrews lubricated and torqued to specified 163 N.m torque. In one test, one of the capscrew torques was reduced to 68 N.m to simulate a site condition where one of the capscrews was not torqued to specified torque value. In another test the capscrews were torqued to 190, 190, 190 and 95 N.m. Each test comprised of 200 cycles.

Assembly No. 2. The capscrews were torqued to 122, 122, 122, and 54 N.m, to see if this rotation could be achieved with lower capscrew loads and the assembly tested to 562 cycles. The capscrews were lubricated as in Assembly No. 1.

Assembly No. 3. The capscrews were unlubricated to simulate site conditions where the lubricant had dried. In addition, shims were used to reflect feeder pipe misalignment. One of these tests involved the use of a seal ring that had experienced gross leakage at site. Another one of the tests included a test assembly that had been heated for 6 hours at 288°C. and 24 hours at 593°C. This "baking" at elevated temperature was performed to provide an equivalent to long time residence at site as operative temperature.

Gap Measurement

Four different seal rings were loosely placed between an end fitting hub and a feeder pipe hub (ref. Fig. 3). The gaps between the seal rib, feeder pipe hub and end fitting hub were measured

indicating the amount of permanent set of seal lip that had occurred at site as well as during the tests.

Capscrew Preload

After the tests, capscrews were torqued to 163 N.m, using lubrication and to 190 N.m, using no lubrication. The installed tensile load (actual preload) in the capscrews were determined using an ultrasonic bolt gauge.

TEST RESULTS

Leakage Tests

Assembly No. 1. The capscrew removal torques were 149, 102, 129 and 75 N.m, for the first test. For the second test, the removal torques were 183, 176, 176 and 95 N.m. The maximum leakage was measured to be 6.58×10^{-4}g/min. This leakage was below the allowable leakage of 7.5×10^{-4}g/min.

Assembly No. 2. Since site equivalent leakage was not achieved with Assembly No. 1, the capscrews of Assembly No. 2 were torqued to a lower value in the hope of getting hub and seal ring separation and a subsequent higher leakage. Visual examination of components indicated that the feeder pipe hub had rotated with respect to the end fitting hub resulting in galling marks on seal rib and hub. The rotation had also resulted in wear of knurled area of the flange. The amount of leakage reached a maximum rate of 1.62×10^{-2}g/min.

Assembly No. 3. The major portion of the leakage tests involved Assembly No. 3. The results are contained in Table 1. Different sizes of shims were added between the hub and the seal ring rib to simulate feeder hub misalignment. Conditions of the second last test of Table 1 (0.51 mm shim, baked seal ring and 7, 176, 176, 176N.M torque) simulated the leak which was observed at site.

Gap Measurements

The gap measurements are shown in Table 2.

Capscrew Preload

The preload values are contained in Table 3.

DISCUSSION

The following discussion briefly summarizes the key points of the investigation and the test results that confirmed those points.

- Lubricant that was cured and dried increased the capscrew removal torques. This explains why the capscrew removal torques at site were usually higher than the installation torques. Low removal torques indicated capscrew preload was reduced.

- The test indicated that low capscrew installation torques would allow the hub to rotate due to insufficient friction between the flange and the hub, when external loads are applied by the feeder pipe. The shiny marks of the seal ring ribs appear to be caused by the rotation of the tilted hub on the seal ring rib. Similar shiny marks on the reactor seal ring ribs suggested that hubs had contacted with the seal ring rib over an arc of the circumference, but was not contacting entirely over the whole circumference.

- Capscrew preloads that were measured by bolt gauging equipment confirmed a significant variation in capscrew preload value using mechanical torque wrench and a set torque.

- The test showed that the small erosion on the lip of the seal ring which was from the leak site, could not cause the amount of leakage experienced at site unless there was also a separation between the hub and the seal ring. It was demonstrated in the test that a combination of a small misalignment of the hub (perhaps within spec), a used seal ring and capscrews with reduced capscrew loads (loose capscrews) caused a small separation leading to a large leakage.

- The gap measurements in the test provided an insight into the seal ring behaviour when exposed to long term residence at reactor conditions. Both the baked and the reactor seal ring (K-13) had a smaller gap (Ref. Fig. 3) at the bottom and at the top than both a new seal ring and the seal ring from the Assembly No. 3, indicating that the seal ring lips were possibly relaxed during operation. If the seal rings relaxed, there would be less sealing contact force (less interference fit between the seal ring lips and the other two components).

- The leak which was observed at site was "duplicated" in the test when low capscrew loads were used in conjunction with a deformed (baked) seal ring and at least a small angular misalignment. This suggested that a relaxed seal ring combined with other factors, such as high external loads, could reduce the capscrew load and cause the capscrews to become loose. A slight misalignment of the feeder hub of a loose joint could cause a separation of the connection and leakage could occur.

SUMMARY/CONCLUSIONS

A total of nine feeder couplings have leaked to date. They were repaired and the Unit was quickly put back on power. Three leaks which exceeded the operating limits were discovered in 1991 and the other six leaks (which did not exceed the operating limits) were found in 1992. An investigation was initiated to identify the root cause(s) of these leakages in order to eliminate or reduce the future leaks.

The investigation described in this paper covers only the three leaks found in 1991, while the investigation of the leaks found in 1992 is still on-going. Results of the investigation has so far identified that the joints which have leaked have loosened causing a small separation between the hub and the seal ring. One or more of the following factors might have been involved: a) marginal installation torque of capscrews, b) variation of capscrew preload for a given installation torque, c) alignment of feeder pipe with respect to end fitting port, d) decrease in capscrew load) (capscrew loosening) during reactor operation and e) seal ring lip relaxation.

Based on the above results, the initial assessment is that it is unlikely the feeder coupling leakage in Bruce-4 is a generic issue, mainly because the later reactors have higher strength capscrews, higher installation torques and differences in other areas. A number of factors appear to be necessary to develop such leaks and it is unlikely that all these factors exist on other units, especially more recent reactors. For the future, further improvements are being considered for the seal ring and capscrew material and more accurate capscrew preload measurements to improve margins in the feeder connection. The final recommendations will depend on the findings from the investigation of the most recent leaks.

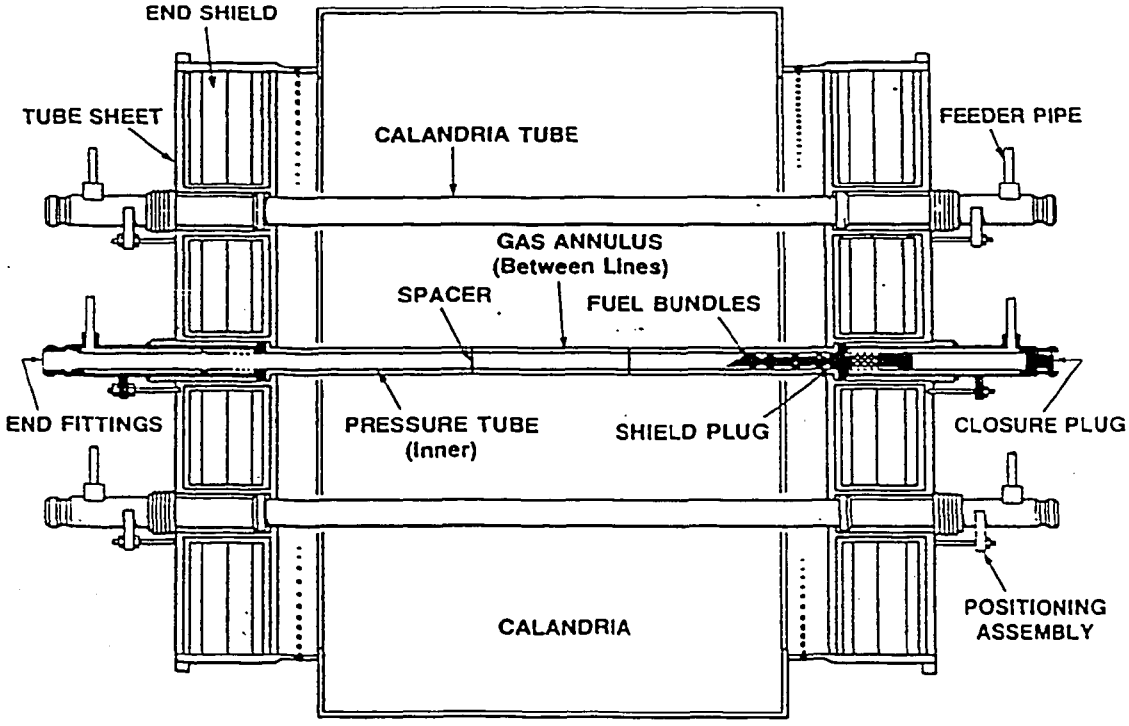


Fig. 1 Reactor Core Schematic

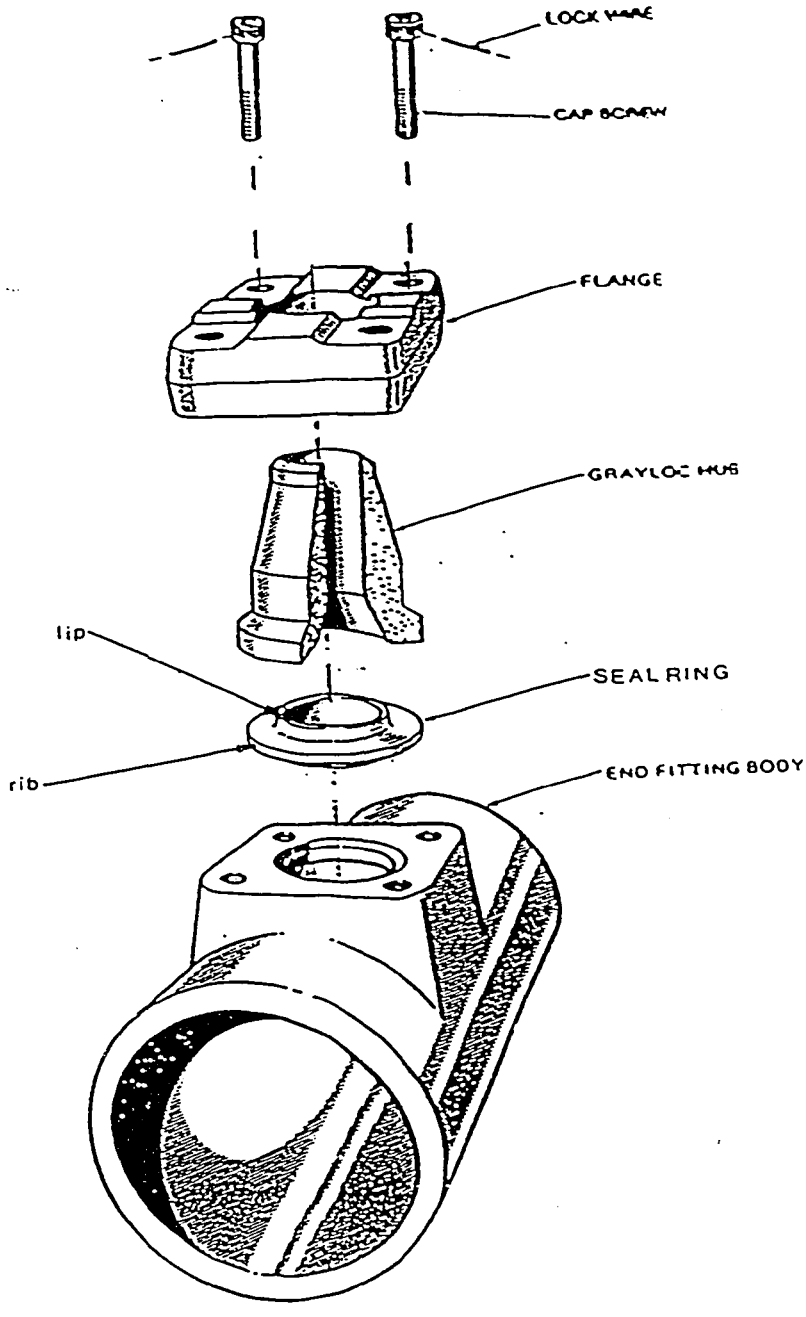
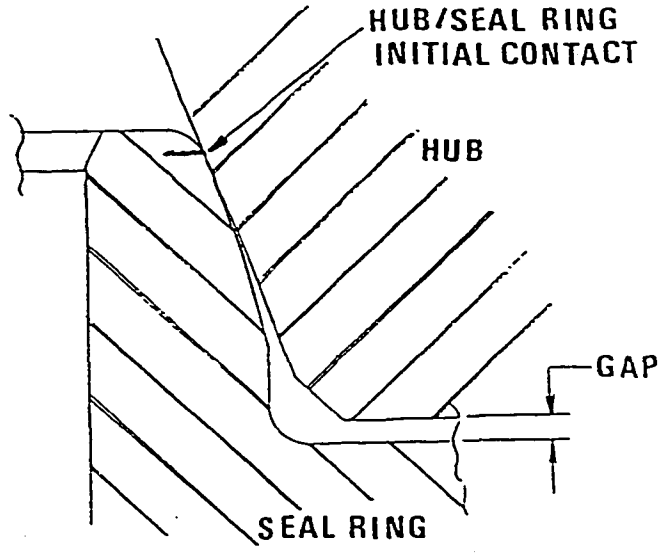
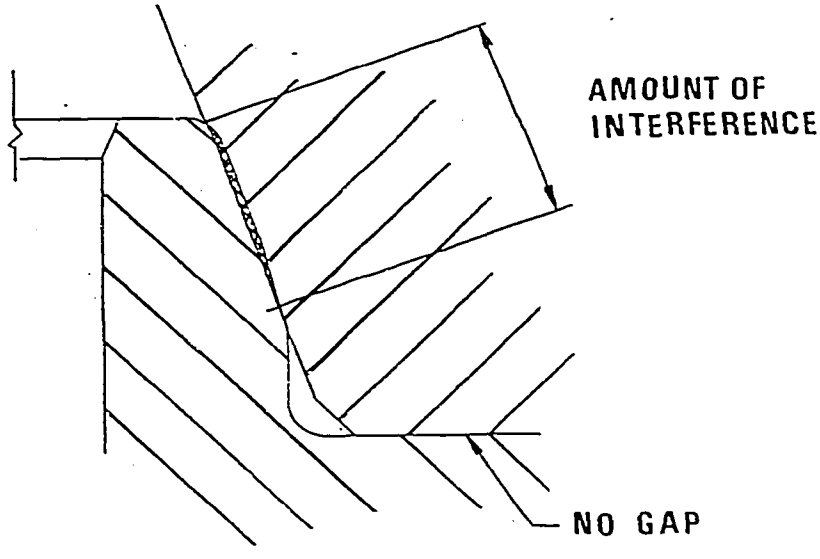


Fig. 2 Feeder Coupling

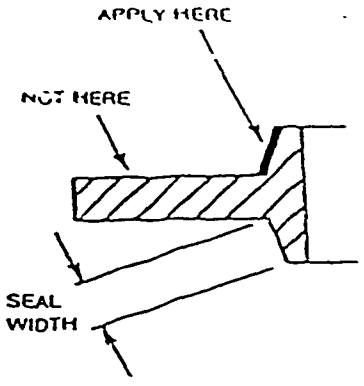


HUB AND SEAL RING BEFORE TIGHTENING

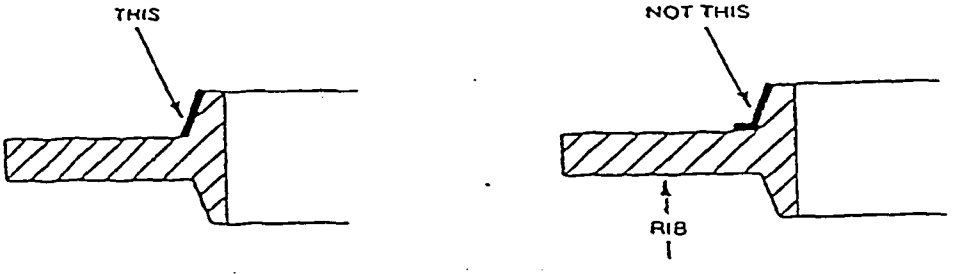


HUB AND SEAL RING AFTER TIGHTENING

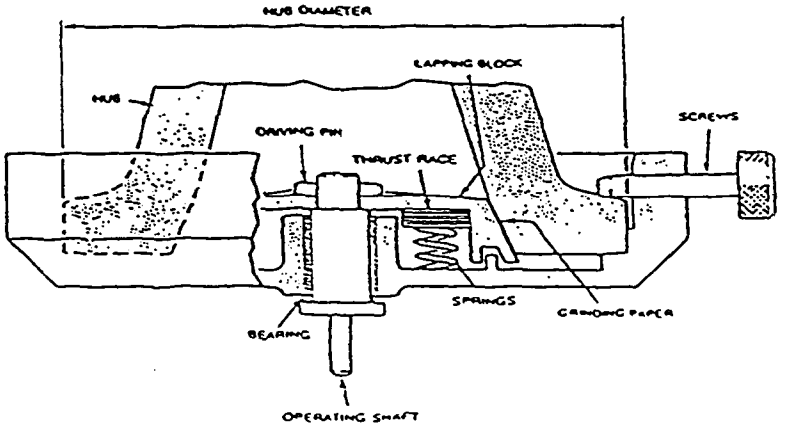
Fig. 3 Development of Seal



APPLICATION AREA FOR "GRAFOIL"



METHOD OF APPLICATION OF GRAFOIL TO SEAL RING



MOTORIZED LAPPING FIXTURE

Fig. 4 Repair Methods for Grayloc Hub and Seal Ring

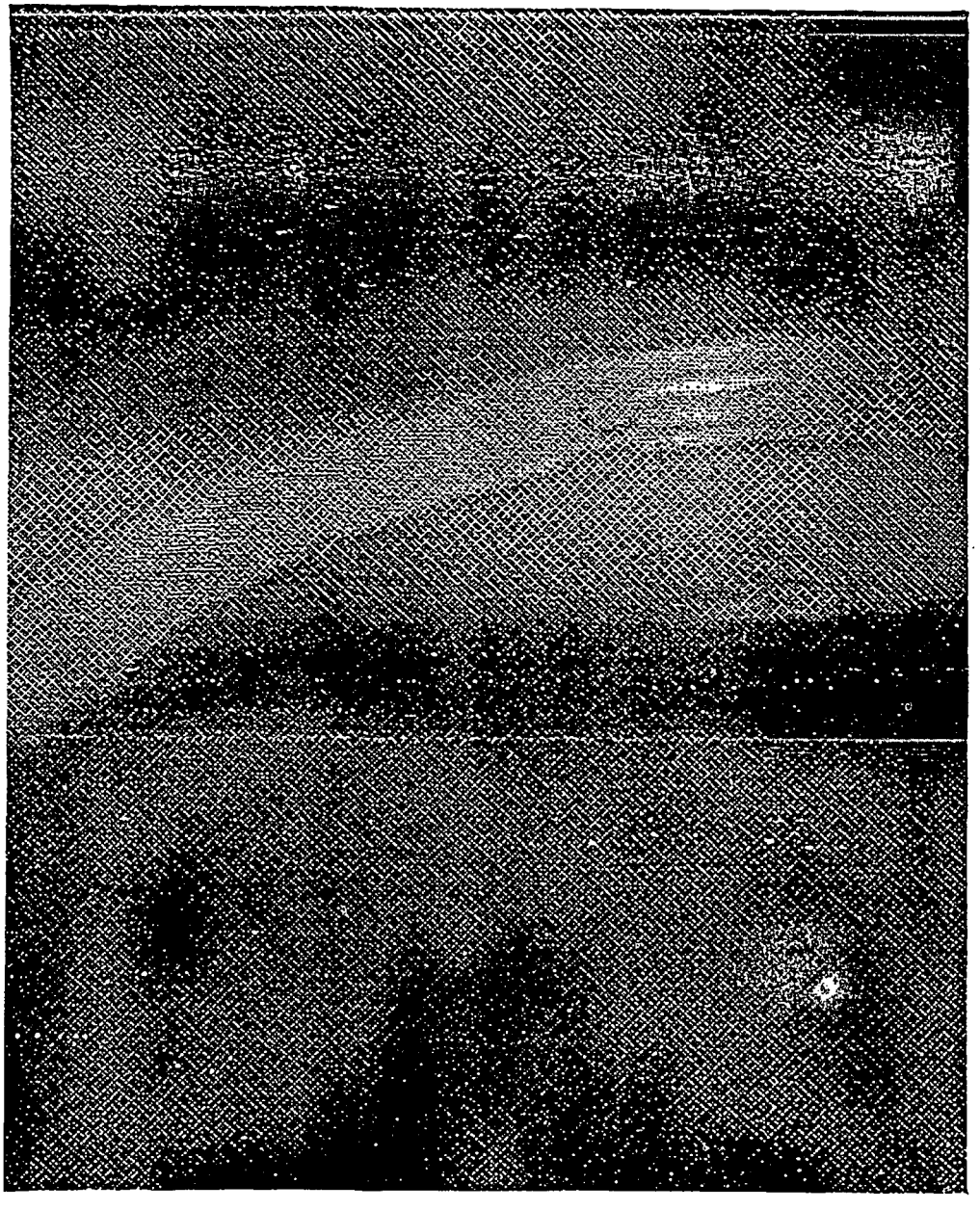


Fig. 5 Feeder Hub K-13W

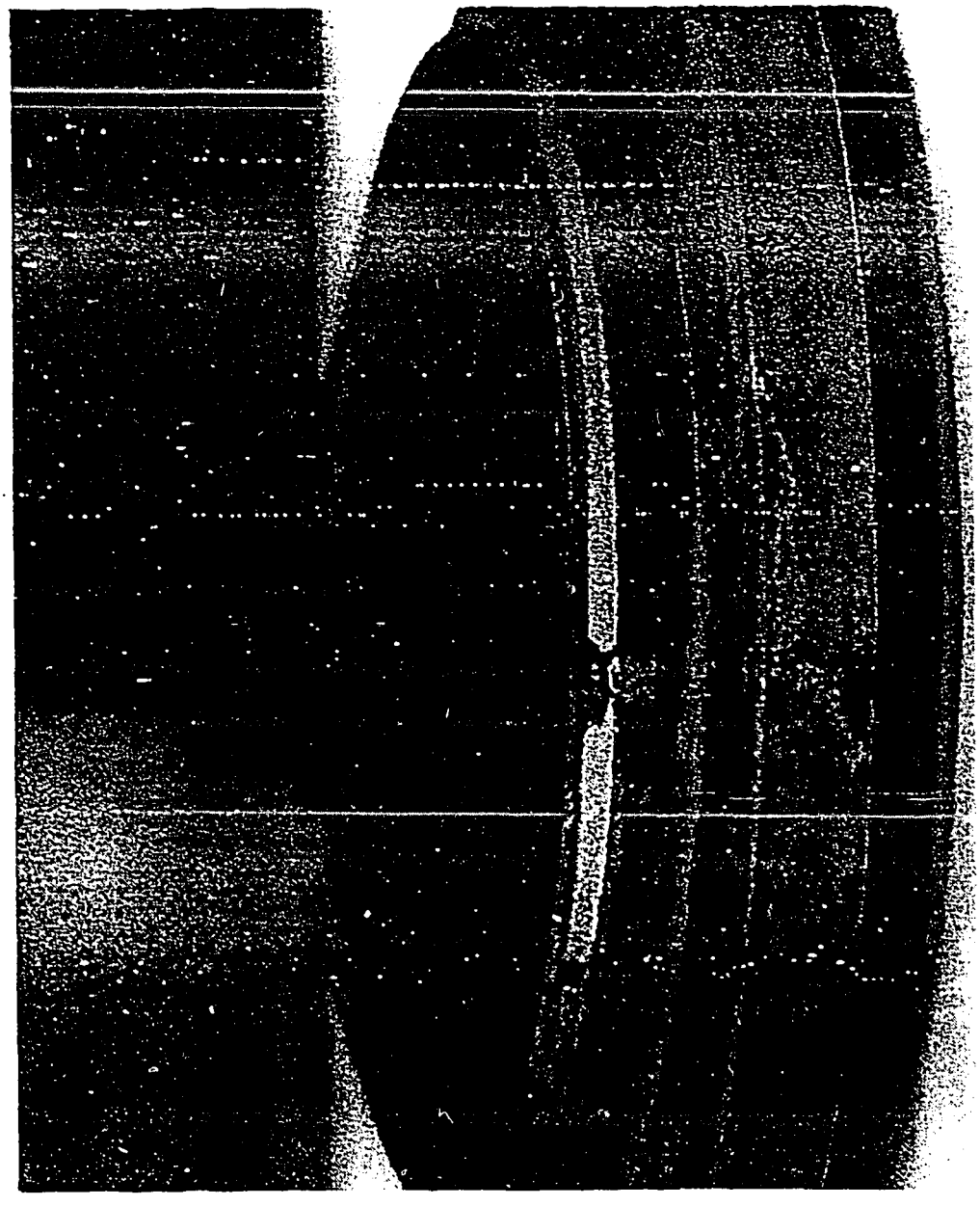


Fig. 6 K-13 Seal Ring

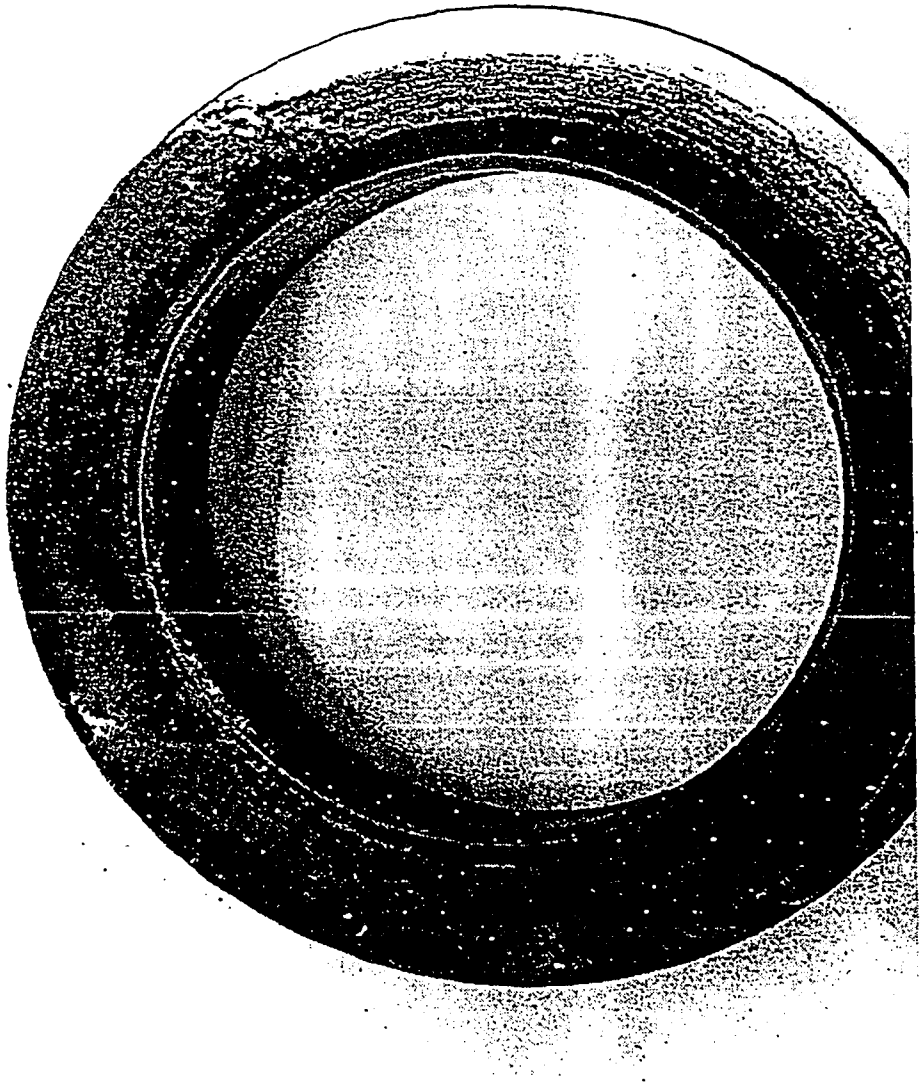


Fig. 7 K-13 Seal Ring

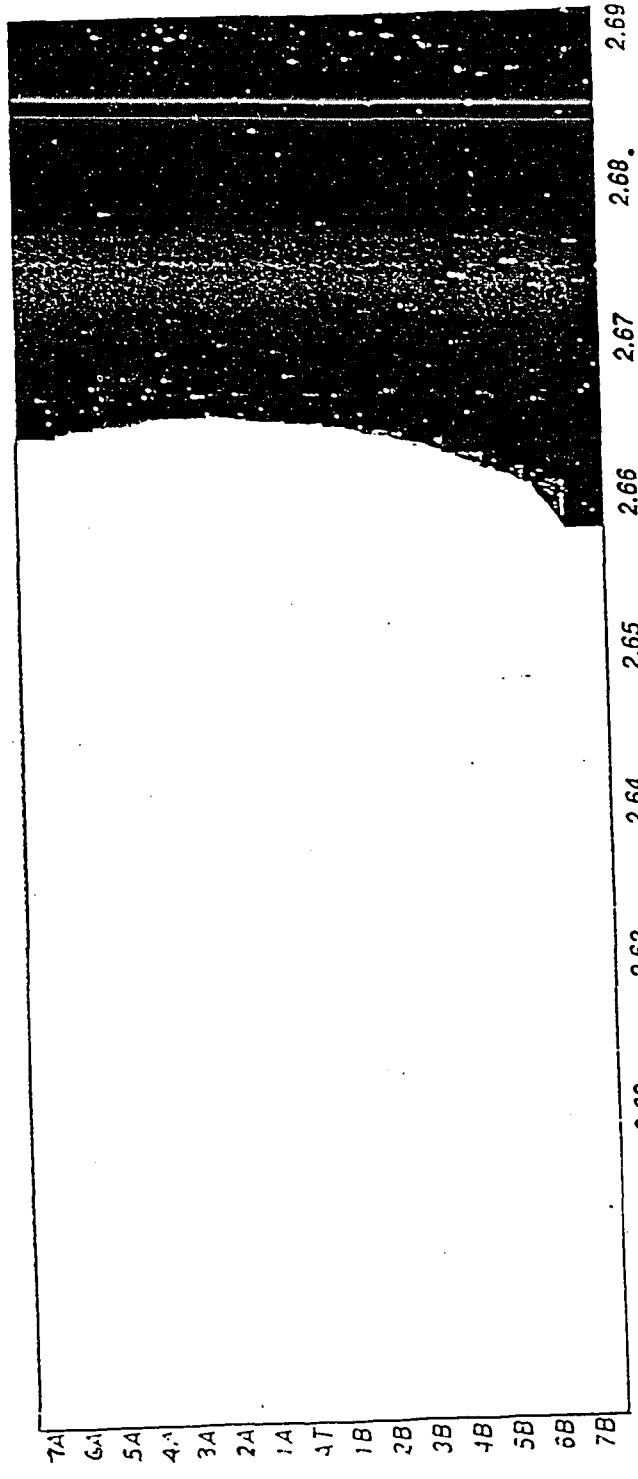


Fig. 8 Seal Ring N16-E Bore Diameter at 0° Location

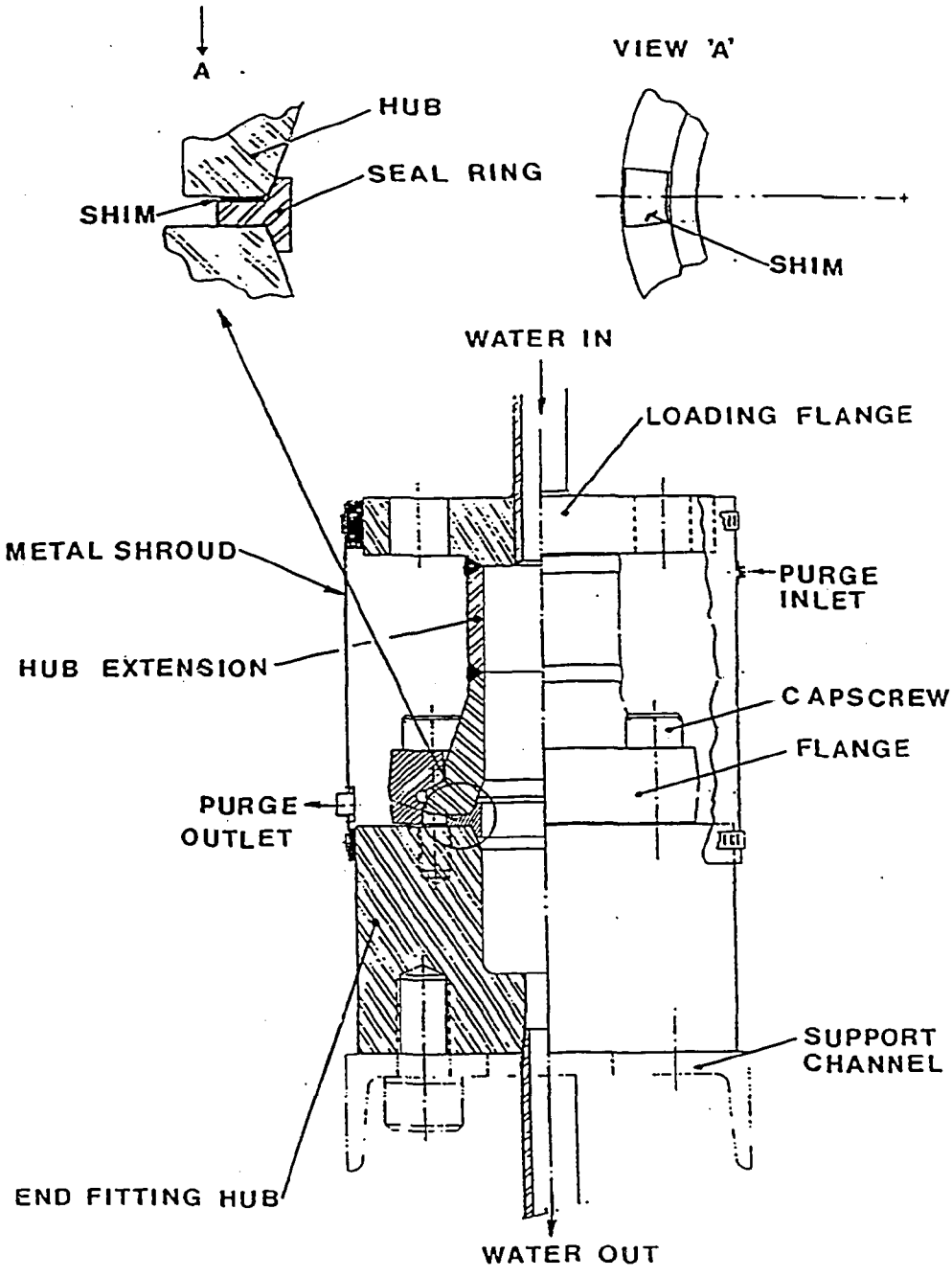


Fig. 9 Test Assembly

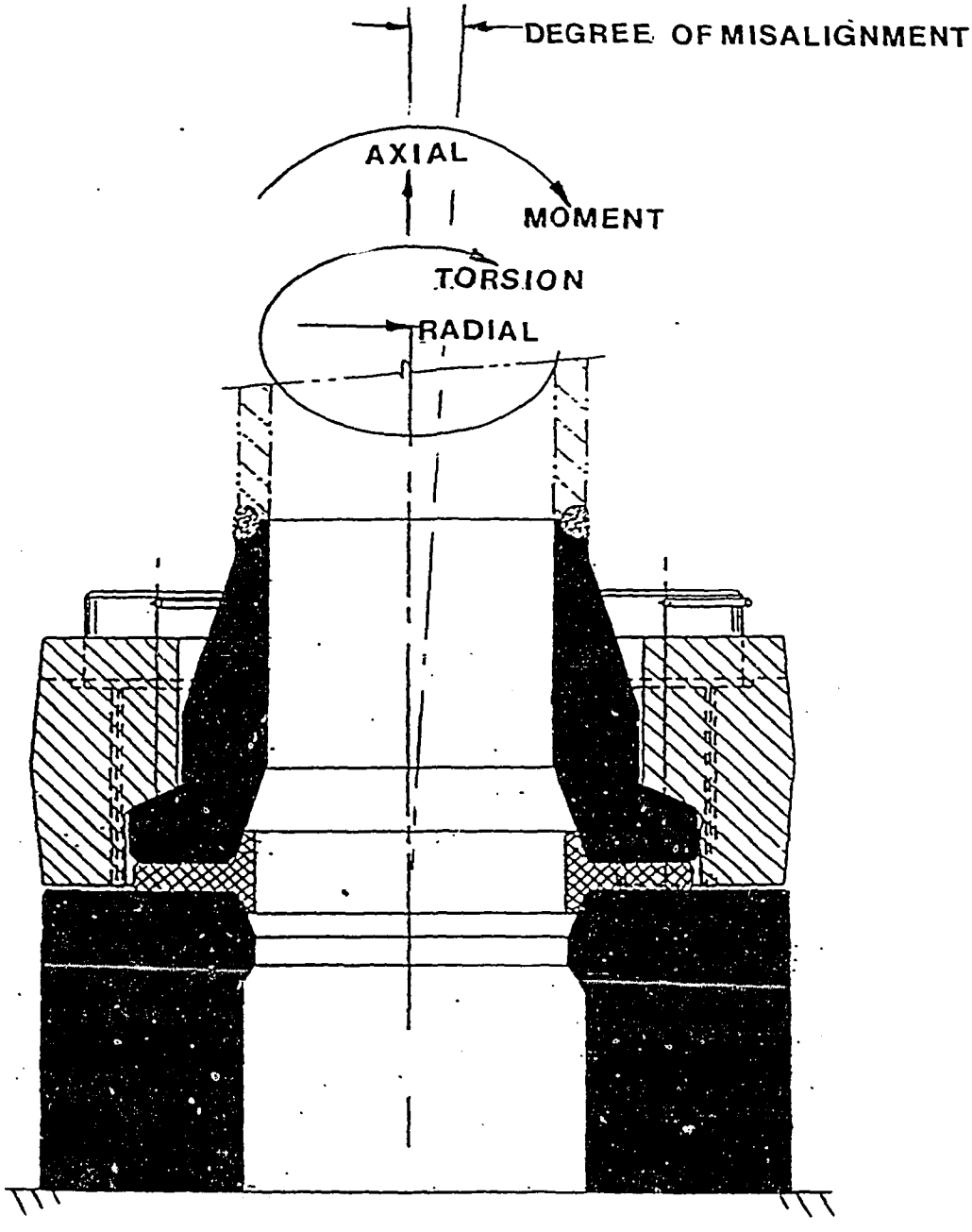


Fig. 10 Mechanical Loading

TABLE 1

Test Results for Assembly No. 3

SEAL RING	SHIM (mm)	CAPSCREW TORQUE (N.M)								ASSEMBLY LOADING	LEAKAGE (KG/HR) H_2O @27°C
		INSTALLATIONS				REMOVAL					
		#1	#2	#3	#4	#1	#2	#3	#4		
New Seal	1.27	68	230	130	230	NOT TAKEN (N.T.)				No mechanical or thermal loading T=27°C	0.96
K-13 (Unit 4 Site)	NO	81	230	230	230	95	244	230	244	12 mechanical load cycles 4 thermal cycles	6.9 x 10
New Seal	0.76	81	230	230	230	10 8	271	203	258	no mechanical or thermal loading T=27°C 0 - 8 Cycles (Thermal + Mechanical) 9 - 21 Cycles (Thermal + Mechanical	Nil None Taken 3.8 x 10-4
From Test #3	1.02	81	230	230	230	N.T.				No mechanical or thermal loading T=27°C 0 - 5 Cycles (Thermal + Mechanical) 6 - 15 Cycles (Thermal + Mechanical) 16 - 25 Cycles (Thermal + Mechanical) 16 - 35 Cycles (Thermal + Mechanical) 36 - 45 Cycles (Thermal + Mechanical)	Nil 6.2 7 6.9 7 .5
New Seal	1.22	81				N.T				No mechanical or thermal loading T=22°C	2.400
From Test #4	1.27	81	230	230	230	N.T.				No mechanical or thermal loading T=260°C 0 - 9 Cycles (Thermal + Mechanical) Mechanical loading, no thermal cycling T=260°C 10 - 19 Cycles (Thermal + Mechanical) Mechanical loading, no thermal cycling T=260°C 20 - 29 Cycles (Thermal + Mechanical) Mechanical loading, no thermal cycling T=260°C 30 - 39 Cycles (Thermal + Mechanical) Mechanical loading, no thermal cycling T=260°C	3 43.3 5.6 57.4 5.2 58.4 5.2 60.4 5.6
From Test #6	1.27	7	230	230	230	68	190	190	149	No mechanical or thermal loading T=27°C 0 - 4 Cycles (Thermal + Mechanical) Mechanical loading, no thermal cyling T=260°C	400 138.5 60 (for 4 min. only)
From Test #7	1.02	7	230	230	230	N.T.				Mechanical loading no thermal cycling T=22°C	Few Drops per Second
From Test #8	1.27	7	230	230	230	N.T.				No mechanical loading, no thermal cycling T=27°C	Massive (Too large in measure)
From Test #9	1.02	7	230	230	230	N.T.				No mechanical loading, no thermal cycling T=27°C	Few drops per second
"Baked Seal" From Test #1	0.51	7	230	230	230	N.T.				Mechanical loading no thermal cycling T-22°C 0 - 4 Cycles (Thermal + Mechanical)	15 Not Taken
From Test #11	0.51	7	176	176	176	N.T.				No mechanical loading, no thermal cycling T=27°C 0 - 1 Cycles (Thermal + Mechanical)	139.8 22.8
From Test #11	0.25	7	176	176	176	N.T.				Mechanical loading no thermal cycling T=27°C 0 - 1 Cycles (Thermal + Mechanical)	Nil Nil

Pressure Loadings for Table 1 Range from 6.9 to 9.7 Mpas.

TABLE 2
Seal Ring Gaps

SEAL RING	TOP GAP (mm)	BOTTOM GAP (mm)
New Seal Ring	0.60	0.60
"Baked" Seal Ring	0.24	0.24
Seal Ring (Site, K-13)	0.28	0.32
Seal Ring from assembly No. 3, as per Test #10	0.48	0.44

TABLE 3
Capscrew Preload
Capscrews Installed with Lubrication & 163 N.m Torque

BOLT #	TYPE #	LENGTH mm	ELON. mm	LOAD N	STRESS mpa
1	15255	66.182	0.079	56,024	397
2	15255	66.170	0.079	56,024	397
3	15255	66.170	0.099	70,482	500
4	15255	66.172	0.084	59,639	423

Capscrews installed without Lubrication & 190 N.m Torque

BOLT#	TYPE #	LENGTH mm	ELON. mm	LOAD N	STRESS mpa
1	15255	66.175	0.066	46,988	333
2	15255	66.177	0.084	59,659	423
3	15255	66.167	0.109	77,711	551
4	15255	66.172	0.107	75,904	538

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CANDU MAINTENANCE CONFERENCE 1992

REFURBISHING OF A DAMAGED END FITTING SEALFACE ON CANDU REACTORS

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ABSTRACT

This paper discusses the refurbishing of an End Fitting Sealface on Candu Reactors. It describes the design of tooling required for a successful refurbishing and design details to achieve a satisfactory result.

REFURBISHING OF A DAMAGED END FITTING SEALFACE ON CANDU REACTORS

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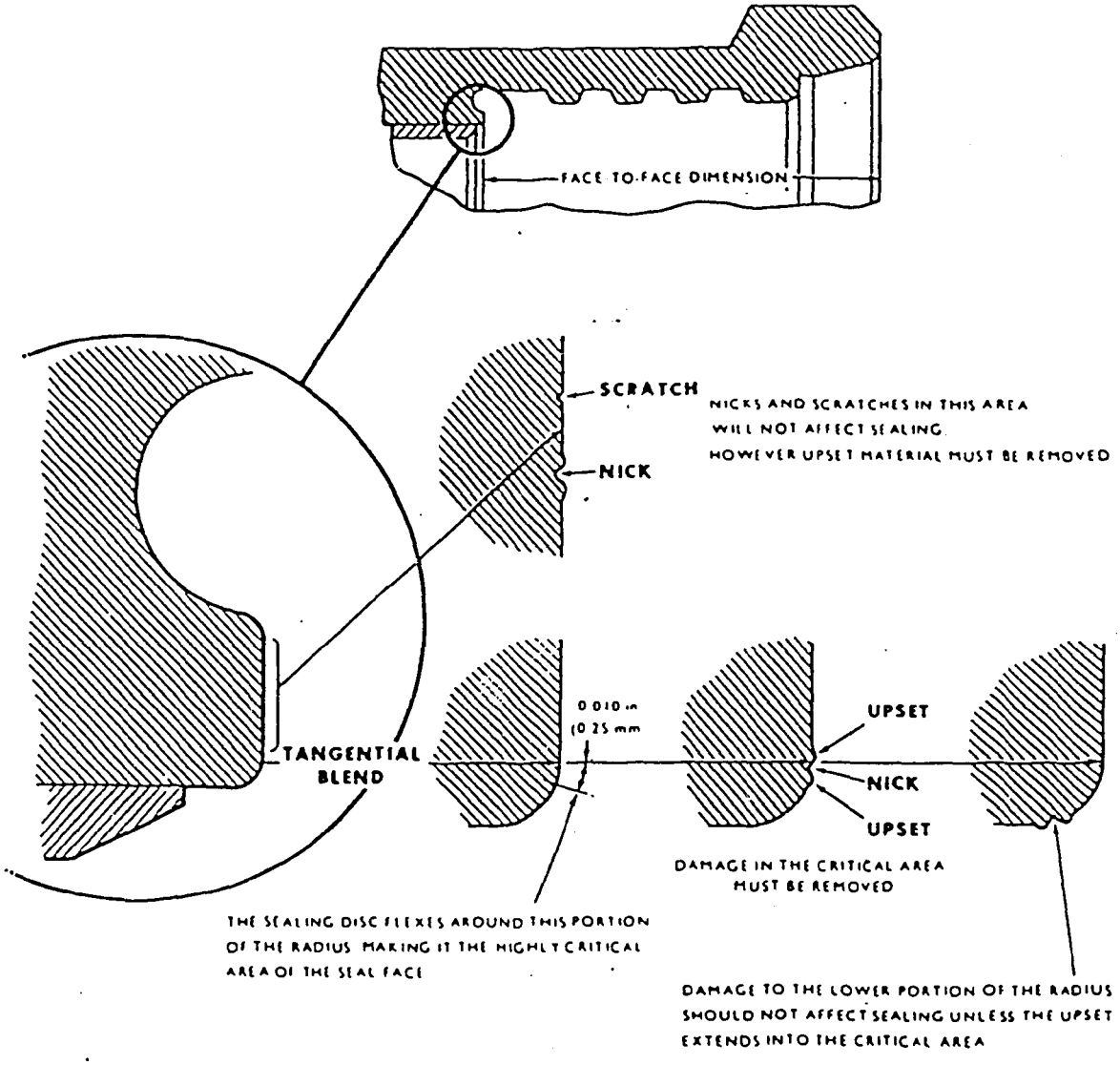
An end fitting sealface can become damaged through various activities - during installation - with inspection equipment - corrosion - loose particles and objects in the system - therefore creating an unacceptable leak on a channel.

FIG. 1 Examples of Minor Damage



REFURBISHING OF A DAMAGED END FITTING SEALFACE ON CANDU REACTORS

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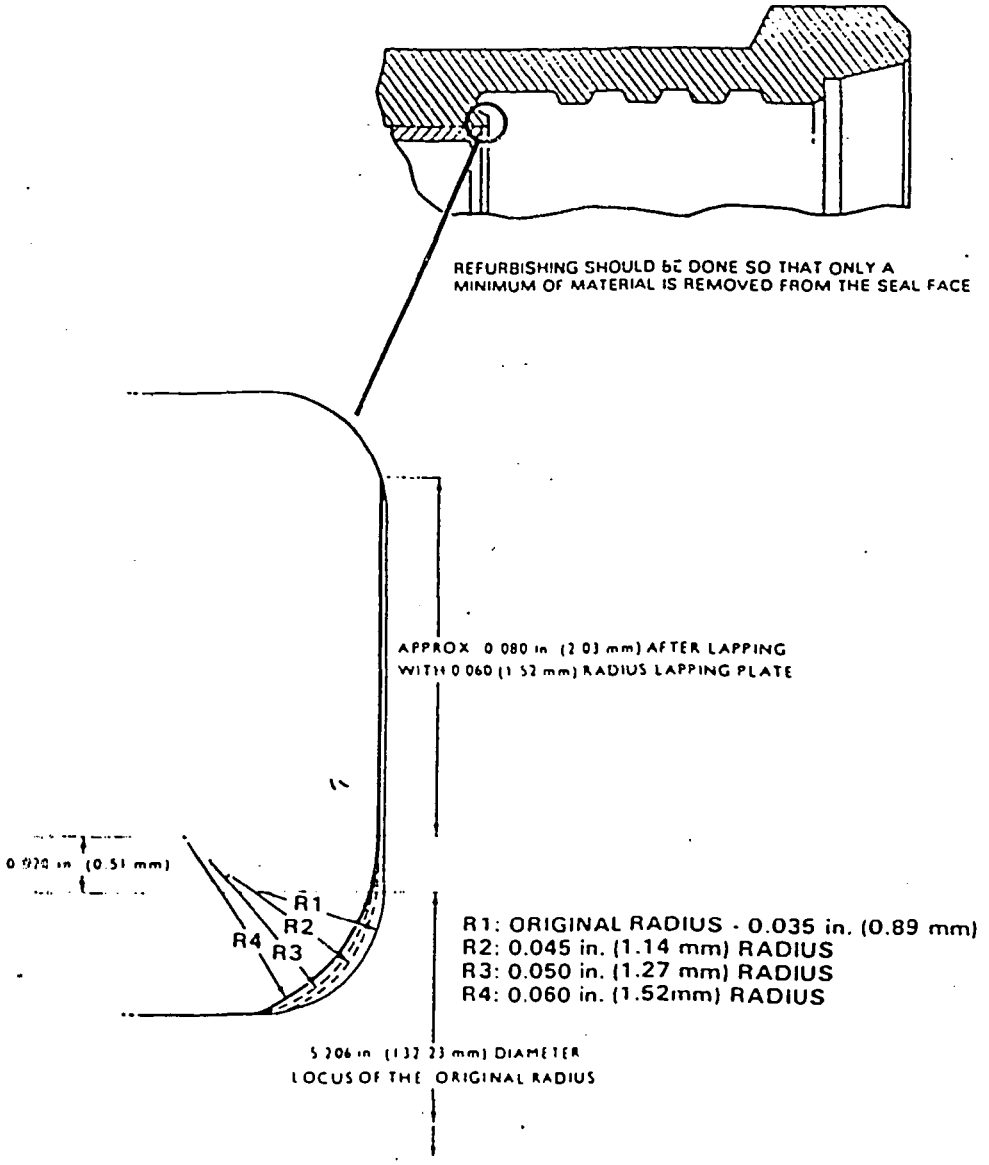
A damaged seal face can be refurbished by lapping for minor damage (.002 inch, .05 m/m or less).
Various lapping plates are used to achieve the repairs necessary, FIG. 2.

FIG. 2 Refurbishing Minor Damage



REFURBISHING OF A DAMAGED END FITTING SEALFACE ON CANDU REACTORS

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Damage in excess of .002 inch (.05 m/m) necessitates machining of the sealface using the End Fitting Sealface Refurbishing tool. FIG. 3.

Machining the sealface can restore a channel to new condition in a very short time.

Below are some examples of repaired channels and the amount removed.

Darlington Unit 2 Q12 channel Fuel Tube Sheeting (.006 inch, .015 m/m)
Darlington Unit 3 M1 channel Manual Fuel Load Damage (.005 inch, .012 m/m)
Bruce B Unit 8 J19 channel Temperature Probe (.030 inch, .76 m/m) and others.

The intention of this paper is to describe in greater detail the design of the E/F sealface refurbishing tool and details of design to successful regenerate the profile of the sealface.

Various means are employed estimating the damage on a sealface to help in the preparation for the repair (visual, Video camera, mould impressions and other).

A mockup for operator training consisting of an E/F outboard stub with replaceable seal rings is part of our tooling package, therefore all situations of a sealface refurbishing operation can be duplicated in a clean environment.

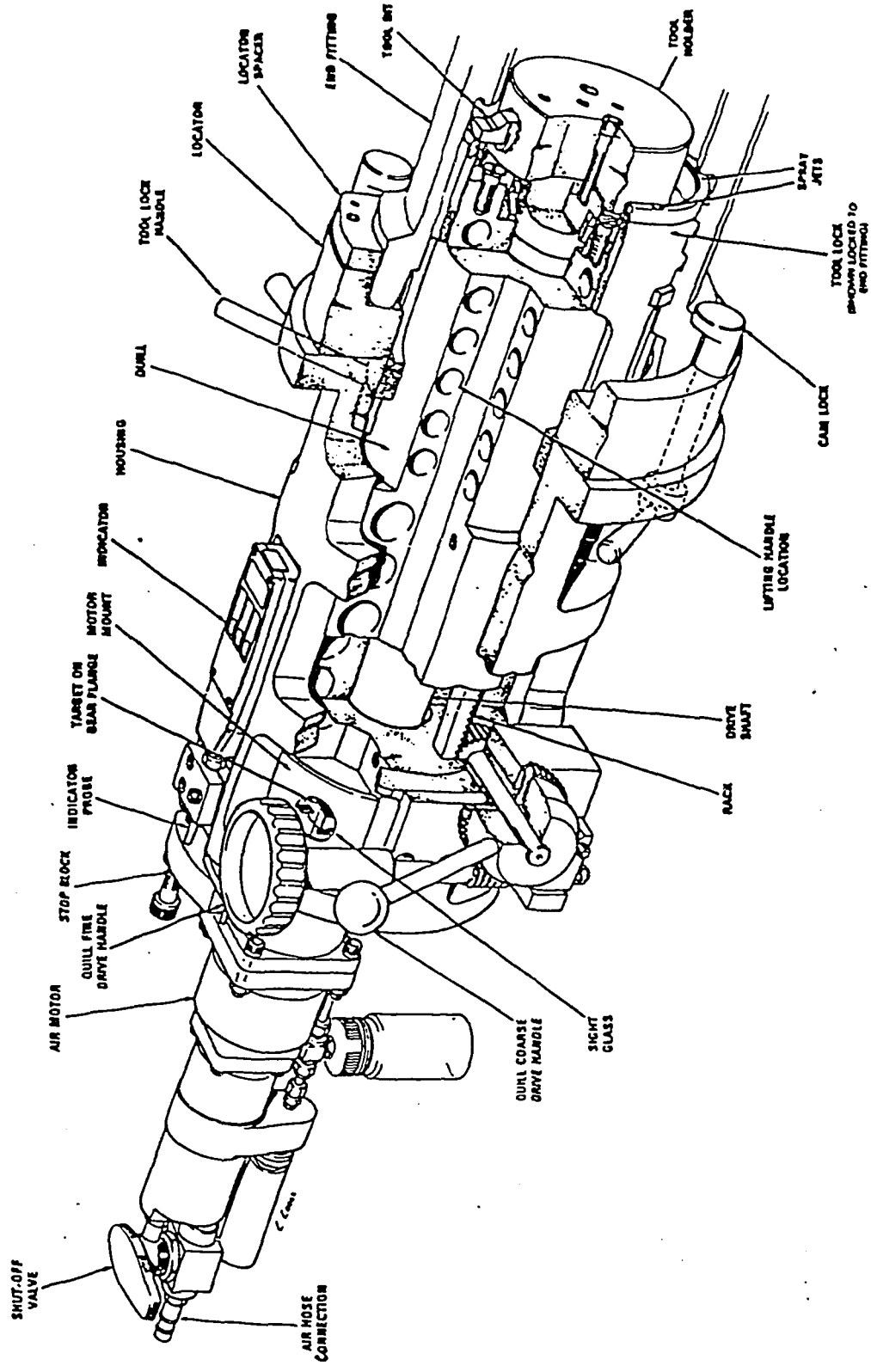
LOCATOR SPACER
END FITTING
TOOL BIT
TOOL HOLDER
LOCATOR
TOOL LOCK HANDLE
SPRAY JETS
TOOL LOCK (SHOWN LOCKED TO END FITTING)
QUILL
HOUSING
CAM LOCK
INDICATOR
LIFTING HANDLE LOCATION
MOTOR MOUNT
TARGET ON GEAR FLANGE
DRIVE SHAFT
INDICATOR PROBE
RACK
STOP BLOCK
QUILL FINE DRIVE HANDLE
AIR MOTOR
QUILL COARSE DRIVE HANDLE
SIGHT GLASS
SHUT-OFF VALVE
AIR HOSE CONNECTION

FIG. 3

REFURBISHING OF A DAMAGED END FITTING SEALFACE ON CANDU REACTORS

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Design Details

The machine tool is a self contained lightweight unit supported on the end fitting outboard end. The design was dictated mainly by the Breechlock and sealface dimensions.

To have a good lock-up to the E/F and also achieve the squareness requirements a tool-attachment was designed to:

a) primary center and lock up on the E/Face with 4 clamps and the cutting tool retracted,

b) to extend the cutting tool into the breechlock, and support the tool head as close as possible to the sealface using the tool lock. This tool lock is the main guide during the cutting cycle and supports the quill movement within 1 inch (25 millimeter) of the sealface.

Part of the refurbishing operation is to preset the required depth for repair. To do this we installed a digital indicator and a "hardstop". The depth is set with a setting fixture representing the E/F seal face dimension of 4.625 inch (117.48 m/m) and the indicator at "ZERO". The hardstop is used to prevent overtravel. All repair dimensions are taken from "ZERO". The Z-motion of the tool is controlled manually by rack and pinion and has a worm drive attachment for fine feed.

The tool head is driven through a 2 inch (50 m/m) diameter meter solid spindle supported by two 3 inch (80 m/m) tapered roller precision bearings.

By using a air motor and gear reduction we arrived at 40 SFPM (12 SMPM) or approx. 30 RPM. A shut off valve can throttle the spindle down to 5 RPM to help us achieve a surface finish to drawing requirement.

All the above details have given us a very well supported Tool head, a chatterfree cutting action and a high quality finished sealface.

REFURBISHING OF A DAMAGED END FITTING SEALFACE ON CANDU REACTORS

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Cutting Tools

In metal removal, prime consideration must be given to the cutting tool.

Important points are a) material to be cut
b) cutting tool quality
c) cutting tool geometry

To machine the end fitting sealface (410 Stl.Stl) a tool blank made of powdered metal (PM) High speed steel (HSS) was used.

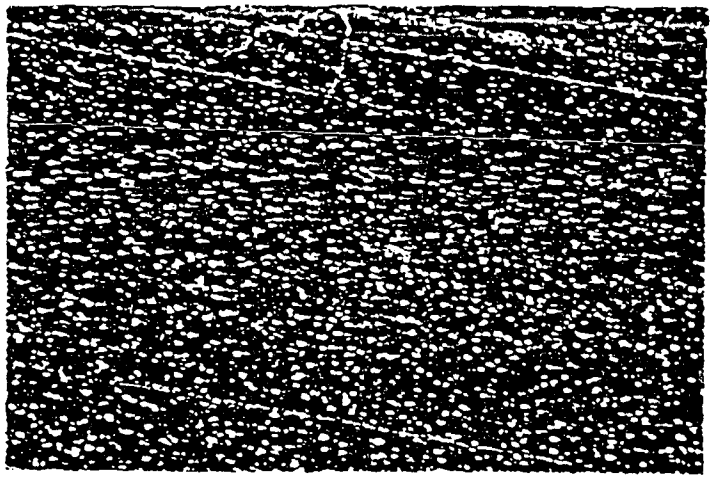
The advantage of PM/HSS tooling is the ability to maintain a very keen edge due to the microfine grain structure. FIG. 4 (Other advantages of PM/HSS tooling are in the manufacture and grinding of the tools).

The cutting edge geometry was designed with a 3° side cutting edge together with a 20° positive rake angle.

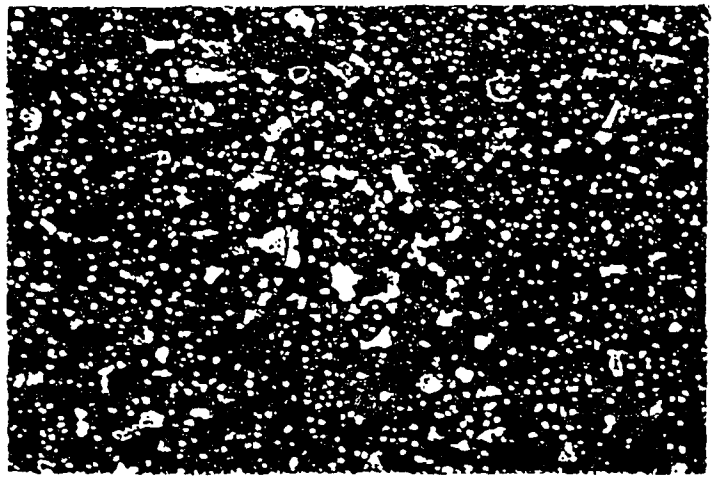
One of the main reasons for cutting tool failure is the heat generated through either the wrong rake angle, surface speed or both.

To assist also in maintaining a good tool edge a cutting fluid spray mist is part of the machine tool and is directed onto the sealface during the cutting cycle. The air motor exhaust is used to force the liquid through six .04 inch diameter (1 m/m) holes not only lubricating, but also cooling the cutting surface.

FIG. 4



TYPICAL POWDERED METAL HIGH SPEED STEEL GRAIN STRUCTURE



REGULAR HIGH SPEED STEEL GRAIN STRUCTURE

REFURBISHING OF A DAMAGED END FITTING SEALFACE ON CANDU REACTORS

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Figure 5 explains various scenarios of damages and the appropriate tooling used to achieve good results. The lapping operation after machining is optional and depends on the surface finish achieved.

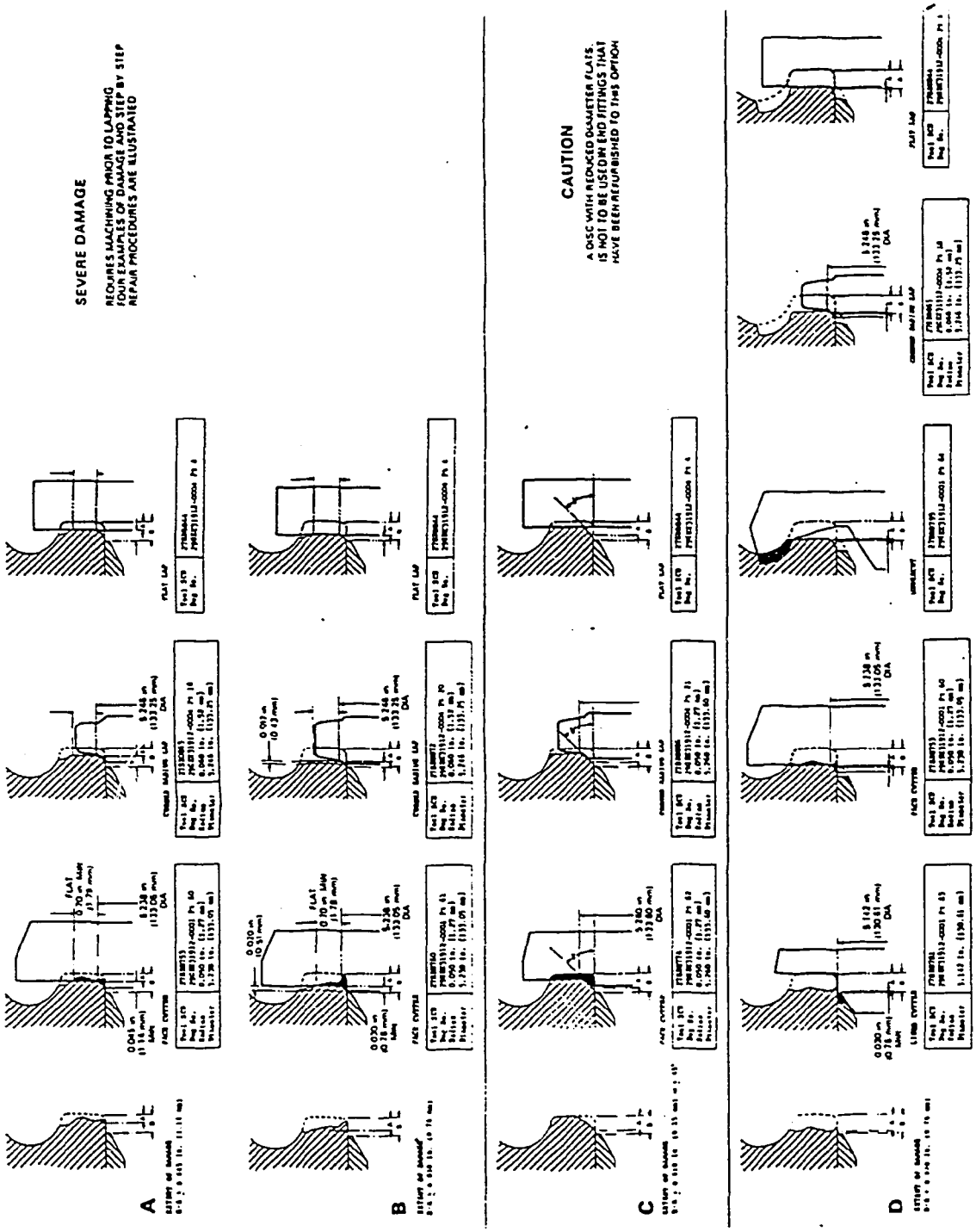
SEVERE DAMAGE
REQUIRES MACHINING PRIOR TO LAPPING
FOUR EXAMPLES OF DAMAGE AND STEP BY STEP
REPAIR PROCEDURES ARE ILLUSTRATED
CAUTION
A DISC WITH REDUCED DIAMETER FLATS
IS NOT TO BE USED ON END FITTINGS THAT
HAVE BEEN REFURBISHED TO THIS OPTION
A
B
C
D

FIG. 5

REFURBISHING OF A DAMAGED END FITTING SEALFACE ON CANDU REACTORS

E.J. SCHARTINGER
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The refurbishing tooling package is complimented with a variety of accessories like

STORAGE CART to hold all tooling including electrical outlet, an air filter and lubricator and a hose reel with 15 ft (5 m) of air line.

GAGE to lock into the end fitting and take readings of the sealface on 4 locations simultaneously.

SETTING FIXTURE for presetting the tool head to a "ZERO" reading.

CUTTING TOOLS for various options.

LAPPING PLATES, to compliment the cutting tools.

MOCK UP END FITTING STUB as mentioned before with replaceable seal rings for training.

A tool operating and instruction manual includes all the details necessary for tool operation and a successful repair.

CA 9500159

NUCLEAR OPERATIONS BRANCH OUTAGE MANAGEMENT STRATEGY

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ABSTRACT

In 1991, partly in response to declining nuclear performance in Ontario Hydro, six priority areas were chosen where improvement efforts should be focused. Of these, outage management has the greatest potential for increasing near-term electrical generation. Many initiatives are being undertaken to improve our performance in this key area. The outage management strategy is intended to focus these improvement efforts and put outage management at Ontario Hydro's nuclear generating stations on a more predictable and business-like basis. This paper outlines the strategic planning process and provides an overview of the outage management strategy.

NUCLEAR OPERATIONS BRANCH OUTAGE MANAGEMENT STRATEGY

W.M.C. Knowles and T. Andreeff

Ontario Hydro
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INTRODUCTION

In 1991, partly in response to declining nuclear performance in Ontario Hydro, six priority areas were chosen where improvement efforts should be focused. Of these, outage management has the greatest potential for increasing near-term electrical generation. Planned outages result in the need for approximately $350 million annually in replacement energy costs and represent a large fraction of total station incapability. The work performed during outages is also a significant part of the operating and maintenance cost and is essential if the plants are to operate well between outages.

Most stations now recognize outage management as a distinct function and have full-time outage management positions. The new outage superintendents are producing many innovative improvements. The outage management strategy is intended to focus these improvement efforts and put outage management on a more predictable and business-like basis.

This paper outlines the strategic planning process and provides an overview of the outage management strategy.

STRATEGIC PLANNING PROCESS

The strategic planning process has evolved in three phases: Consultation, Scoping and Implementation. The overall process is illustrated in Figure 1. The first phase included the initial staff work to identify and gain agreement on the broad issues in outage management within the Nuclear Operations Branch. Extensive research of our outage management practices was conducted which included interviews with key personnel in the field, observation of outages and a review of applicable literature (1).

The Scoping phase built on the results of the consultation activities with the objectives to:

a. identify the issues for which immediate action can be taken and develop the necessary implementation plans;

b. identify key performance gaps requiring further analysis and diagnosis of the root-causes; and

c. define the process required to reduce the key performance gaps.

The outage management strategy therefore represents a starting point for improvements in this key area. It is a living document and will be periodically updated as new issues are identified and as new innovations and ideas are tried.

STRATEGIC ENVIRONMENT

Safety

Our performance in terms of public and worker safety during outages appears comparable to that during normal operations. However, there is growing recognition that some of the periods of highest risk may involve shutdown configurations for which procedural and programmatic controls are minimal. Risk assessments in the US and France have shown that the contribution to the overall risk of core damage from shutdown operation is significant. In response to these concerns, NUMARC initiated a Shutdown Plant Issues Working Group which concluded that (2):

"Proper outage planning and control, with a full understanding of the major vulnerabilities that are present during shutdown conditions, is the most effective means of enhancing safety during shutdown."

An increased emphasis on reactor safety during outages will mean that the outage scope will need to be defined earlier and rigorously controlled to allow for the necessary reviews of the overall outage schedule and detailed work plans.

Financial

We are all well aware of the recent large electricity rate increases. Though our rates are still competitive by North American standards, the gap is narrowing. As a result, Ontario Hydro continues to focus on improving its financial performance. In this climate, it is unlikely that significant new sources of funding could be devoted to the nuclear program. Most new programs or initiatives, therefore, will need to be supported from existing resources by trading off work of less importance.

Generation Reliability

Outage management practices effects generation reliability in several areas:

- the inspections and preventive maintenance undertaken during planned outages helps reduce forced incapability.
- extensions to planned outages contribute directly to overall station incapability.
- the amount and of work performed during planned outages and the available resources governs the duration of the outage.

International experience has shown that careful outage management linked to an effective maintenance strategy is a major reason for good overall performance. Several countries, including France and Japan, have been successful in implementing strategies which emphasize the effective use of planned outages. The results of these strategies have been a steady decrease over time of both planned and forced unavailability. This is illustrated in Figure 2.

In contrast, our overall performance has shown the opposite trend with both forced and planned outage time increasing over a similar period. While station capability remains high for the first 8-10 years, this initial period of high performance has been followed by a rapid decrease in capability. Although some of this may be attributed to fuel channel problems on Pickering NGS A, other aging factors are beginning to contribute to this decline. This type of performance, however, is not an inevitable consequence of plant aging. Top performing light water reactors have shown consistently improving performance up to 15 years service and beyond.

As illustrated in Figure 3, experience has shown that, on average, our outages have taken 35% longer to complete than originally scheduled. A clear majority of these outage extensions result from deficiencies in planning and preparation. If current performance levels are maintained, replacement power for outage extensions could cost approximately $100 million annually. Fortunately, the trend has improved over the past couple of years but we will have to see if this is permanent.

For a typical good performing light water reactor, approximately 150,000 man-hours of work are completed during planned outages. At Point Lepreau NGS, about 60,000 man-hours of work are executed during annual planned outages. Although we have had planned outages in which 100,000 man-hours of work have been completed, these are the exception and the large majority of our outages have less than 35,000 man-hours of work. Consequently, more inspection, maintenance and refurbishment work will likely be required to improve performance levels on the older stations as well as to prevent deterioration of the high levels of performance currently being achieved on the newer stations.

The number of planned outage days we schedule per year per unit is consistent with the rest of the world. To accommodate additional maintenance and inspection work and reduce planned outage durations, we will have to do more work on each of these days if we want world-class performance. This means that planned outages will need to be more effectively and efficiently planned and executed and better resourced. As illustrated in Figure 4, Ontario Hydro significantly lags most international utilities in the ability to mobilize and control personnel resources to maximize the number of maintenance man-hours completed per day. On average, we execute approximately 1000 maintenance man-hours per day (on individual outages we have achieved up to 2000) as compared to an international average of 5000 maintenance man-hours per day. One reason for this is that we staff outages using relatively small numbers of regular staff; almost everyone else employs large numbers of contract staff (typical peak numbers of contract staff are on the order of 500-800).

Organizing for Ownership

Although there are many individual Quality Improvement initiatives, one which will significantly affect outage management is the Organizing for Ownership initiative. The aim of this initiative is to increase the sense of ownership at the nuclear generating stations through the use of a more decentralized organization. The organization being proposed by the Organizing for Ownership design team is evolving towards a unit-pair concept. Under this concept, technical, maintenance and operations resources would be aligned under a single manager to support two units.

This re-structuring initiative affects outage management in two areas:

a. Organization - the outage planning/management function may be the responsibility of the unit-pair. At most stations, this will double the number of outage management teams; and

b. Resources - means will have to be devised so that maintenance and operator resources are transferred to the unit-pair with the planned outage.

OUTAGE MANAGEMENT STRATEGY

Overview

The overall mission of outage management may be stated as:

To manage planned outages in Nuclear Operations Branch so that:

- *the long-term needs for plant upgrades, inspection and maintenance are clearly known.*
- *resources to carry out outages are identified and planned for both inside and outside the Branch.*
- *outages are executed according to plan and execution improves with time with due regard to safety and the environment.*
- *the plants run well between planned outages.*

In order to accomplish this mission, a strategy has been developed which focuses on four key result areas. In each key result area, objectives have been set and major initiatives identified to improve outage management performance. Where appropriate, specific action plans have been prepared.

The overall strategy is summarized in Table 1. To gain a better appreciation of the strategy and how it is being implemented, the main issues and initiatives in each key result area will be examined.

Key Result Area #1

As previously noted, station capability factors have been declining with plant age and a large fraction of the resulting outage time is unplanned.

Much of this incapability has resulted from lengthy shutdowns to correct the unforeseen degradation of critical components, eg., fuel channels and steam generators. To reduce the likelihood of further nasty surprises in the future, long-term proactive strategies need to be developed for selected critical components. These will minimize the impact of component aging on key station performance objectives, and effectively manage station life, ie., assure safety and reliability during the nominal service life and preserve the option of life extension. Nuclear Plant Life Assurance (NPLA) is one technique that is being used to assess the level of understanding of aging degradation and the adequacy of existing research, inspection and maintenance programs. From this review, recommendations are being made for additional inspection, maintenance and surveillance activities, changes to operating and maintenance practices or mitigating programs such as overhauls, replacements and modifications.

While these lengthy shutdowns certainly receive a lot of attention and resources, the effects on station performance of equipment breakdowns cannot be overlooked. Despite the existence of preventive maintenance programs at all stations, our overall approach to maintenance remains largely reactive; less than 40% of our overall maintenance effort is devoted to preventive maintenance. In addition, the basis for many of the preventive maintenance tasks appears questionable and so completion of scheduled call-ups remains low. To address these problems, programs have been initiated at Bruce NGS A and Bruce NGS B to improve their PM program using a technique borrowed from the commercial airline industry, Reliability Centred Maintenance.

As we gain better confidence in the work needed to ensure that our plants operate safely and reliably between outages, we also need to consider how this work should be integrated into a stable and predictable pattern of planned outages. While all stations have developed some form of standard outage cycle, the current basis for duration and frequency is subjective. A standard cycle of CANDU planned outages that repeat with frequencies designed to level station workload and maximize long-term capacity factors needs to be more rigorously defined. Both Bruce NGS A and Bruce NGS B have recently taken a closer look at their long-range outage plans.

Key Result Area #2

Experience has shown that, on average, our outages have taken 35% longer to complete than originally scheduled. If continued, this level of performance would result in about 3-5% station incapability. Fortunately, significant improvements have been made in this area over the last couple years. It is expected that our target Planned Outage Management Factor will be better than the target of 1.1 in 1992.

Much of the credit for this improved performance can be attributed to the establishment of outage management organizations at the stations. The composition of this organization varies

from station to station and sometimes from outage to outage. Most of the positions are filled on a temporary basis; however, permanent positions are planned. The organization works as a team under the direction of an outage superintendent or director who is responsible for the success of the planned outage. Included on the team are experienced maintenance personnel who act as trade group coordinators, operators who coordinate work protection and authorization, Planning Section staff who provide specialist planning services and other support staff who act as coordinators for some critical work group or function. This team develops a strong sense of ownership for the outage and has proven effective in meeting the outage objectives.

Successful execution of an outage is also highly dependent on the quality of the outage planning and preparation. Although good planning, by itself, cannot guarantee a successful outage, poor quality planning will generally result in a failure to meet the outage objectives. The quality of outage planning and preparation depends largely on the early definition and control of outage scope and on the development of detailed work plans.

Late identification of work can be very disruptive and results in poor quality planning. Consequently, most utilities specify planning milestones or freeze dates for work identification and work plan preparation. We have not been consistent in adhering to planning freeze dates and this has been a major contributor to extensions of planned outages. Jobs are frequently identified at the last minute and detailed work plans may not arrive until the outage has begun. All stations have administrative processes to deal with these situations that usually involve a manager's approval; however, there is a tendency to accommodate late work.

Similarly, major repair work discovered during the course of an outage can be very disruptive if it is completely unexpected. Discovery work has contributed to 10-15% of outage extensions. On average the amount of work identified after the start of the outage has represented approximately 20-25% of the total outage work; however, this figure has been as high as 40-50% for some outages. To reduce the impact of discovery work on the outage it needs to be anticipated and where appropriate effective contingency plans developed.

A key to improving the effectiveness of detailed job planning is to create a sense of ownership for the job. This has been achieved in several utilities by allowing the work groups responsible for performing the work to develop the detail plans. At Diablo Canyon, the duration of refuelling outages dropped from over 120 days to 55 days. They credited the use of High Impact Teams (HIT) as the most effective management improvement. These teams are composed of representatives from all groups involved in selected major tasks. Bruce NGS A is experimenting with this concept and the preliminary results are very encouraging. Pickering Construction also invested heavily in the planning of re-tubing activities by having workers evaluate each reactor series and suggest areas for improvement. The result has been dramatically reduced outage lengths for Units 3 and 4.

Key Result Area #3

As noted, Ontario Hydro significantly lags most international utilities in the ability to mobilize and control personnel resources to maximize the number of maintenance man-hours completed per day. Hence, we don't achieve the shortest possible critical path and the minimum overall outage cost for a given scope of work. This becomes even more critical if planned outages increase in scope to incorporate additional plant maintenance and inspections.

The number of maintenance man-days worked per day on our outages is much lower than industry averages. At Olkiluto in Finland, significant reductions in outage duration have been achieved through increased resource levels. Increased Central Maintenance Facility staff at BNPD and establishment of an outage crew at Pickering NGS will improve our situation. Even with these steps, our ability to assign maintenance resources to outages will still be far below industry averages.

In order to achieve the types of reductions in outage duration realised by other utilities, we will have to further increase resource levels. This could be done in essentially three ways:

a. increased maintenance staff in the Branch, likely at the Branch or Division level in centralized maintenance organizations (would require up to 1000 extra maintenance staff);

b. the use of external contractors to perform large blocks of outage work, eg., steam generator inspections and turbine generator inspection and overhaul; or

c. a hybrid approach involving the use of Ontario Hydro Engineering and Construction Services.

Each option has its own merits and disadvantages and would take several years to fully implement. The new mid-term agreement on purchased services presents a vehicle through which this opportunity can be explored so that rational decisions on the resourcing of various outage tasks can be reached.

Key result Area #4

Safety while the reactor is shutdown is receiving increasing international attention. There is growing recognition that some of the periods of highest risk may involve shutdown configurations for which procedural and programmatic controls are minimal. This and other regulatory initiatives, eg., with respect to ALARA, will lead to greater scrutiny of outage plans.

The Reactor Safety groups within the stations are playing an increasingly important role during outages which includes:

a. defining heat sink requirements;

b. defining testing requirements for safety-related equipment; and

c. assessing outage logic and work plans.

Worker safety is also being emphasized. Hazard assessments are being conducted for specific jobs. The inclusion of safety officers on the outage management team has also been found to be effective.

CONCLUSION

An outage management strategy is essential if a coordinated approach is to be taken to improve performance in this area and contribute to overall improvements in nuclear station performance. This paper has outlined the steps taken in developing this strategy and has outlined its key areas and initiatives.

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2. "Guidelines for Industry Actions to Assess Shutdown Management"; Numarc 91-06.

Table I: Outage Management Strategy Summary

Key Result Area	Objectives	Measure	Quantitative Target	Actions
Ensure that the outage scope contributes to long-term reliability and safety.	1.1 To have effective preventive and predictive maintenance programs. 1.2 To have effective inspection programs. 1.3 To have long-term strategies for critical components. 1.4 To control and manage plant modifications. 1.5 To develop a rational standard outage cycle.	• Preventive Maintenance *Enhancement Programs conducted* at all stations. • Inspection program requirements have been reviewed and rationalized. • NPLA scoping studies completed and recommendations implemented. • Modifications are evaluated for their cost-benefit and are included in long-term plan. • A rational standard outage cycle exists.	To be determined.	<u>High Priority Actions</u> #1: Optimize Preventive Maintenance Programs #4: Long-Term Component Strategies (NPLA) #8: Standard Outage Cycle <u>No Plan Required</u> #5: Control Plant Changes - Outage Work Priority #6: Control Plant Changes - Strategic Planning #7: Control Plant Changes - Value Ranking <u>Deferred Actions</u> #2: PM Tasks During Outages #3: Rationalized Inspection Program
Complete defined outage work on time and within budget.	2.1 To have an outage organization with a clear structure and well defined responsibilities for outage planning and execution. 2.2 To systematically define and control outage scope. 2.3 To effectively plan outage work in sufficient detail and complete necessary preparatory work in time. 2.4 To effectively organize and coordinate outage work execution so that the necessary levels of work quality are achieved. 2.5 To prepare and maintain effective contingency plans for forced outages.	• Comparison of actual to scheduled duration. • Degree planned work completion. • All stations have permanent outage management teams. • High degree of compliance with freeze dates - TBD. • Discovery work as fraction of total outage work - TBD. • Rework measure - TBD. • Effective forced outage plans exist.	Planned Outage Management Ratio: 1.05. Work Completion: 100%. Outage Scope Control: TBD. Discovery Work: guideline 20-25% (TBD). Rework: TBD.	<u>High Priority Actions</u> #9: Optimum Organization Structure #11: Outage Scope Control #14: Planning Resources - HIT Trial #17: Readiness for Forced Outage <u>No Plan Required</u> #12: Discovery Work - Anticipation #13: Discovery Work - Contingency Planning #15: Operator Effectiveness - Operator Assessment #16: Minimize Rework <u>Deferred Actions</u> #10: Inter-Branch Roles & Responsibilities

Table I: Outage Management Strategy Summary - Continued

Key Result Area	Objectives	Measure	Quantitative Target	Actions
Plan and execute the defined outage work efficiently to minimize outage duration and cost.	3.1 To maximize effectiveness of existing maintenance and operations resources. 3.2 To increase the average maintenance manhours executed per outage day in accordance with industry norms. 3.3 To have standard work plans and logic for major repeatable outage tasks. 3.4 To have an effective lesson transfer program in the Branch. 3.5 To have a consistent set of outage performance indicators.	• Operator time as fraction of total decreasing - TBD. • Maintenance wrench time - TBD. • Maintenance labour-loading - TBD. • Libraries of standard work packages exist and are being optimized. • Effective lesson-transfer programs exist.	To Be determined.	High Priority Actions #19: Operator Effectiveness - Capability #20: Labour Loading Strategy #23: Post-Outage Follow-up #24: Information Exchange #26: Performance Indicators No Plan Required #18: Operator Effectiveness - Work Protection #22: Standard Work Packages Deferred Actions #21: Outage Financial Structure #25: Structured Plant Visits
Safely plan and execute the defined outage work to minimize the risk to workers and the public.	4.1 To ensure that nuclear safety requirements are effectively integrated with outage planning 4.2 To ensure that worker safety requirements are effectively integrated with outage planning and execution.	• To be determined		High Priority Actions No Plan Required #27: Outage Reactor Safety Deferred Actions

Figure 1: Strategic Planning Process

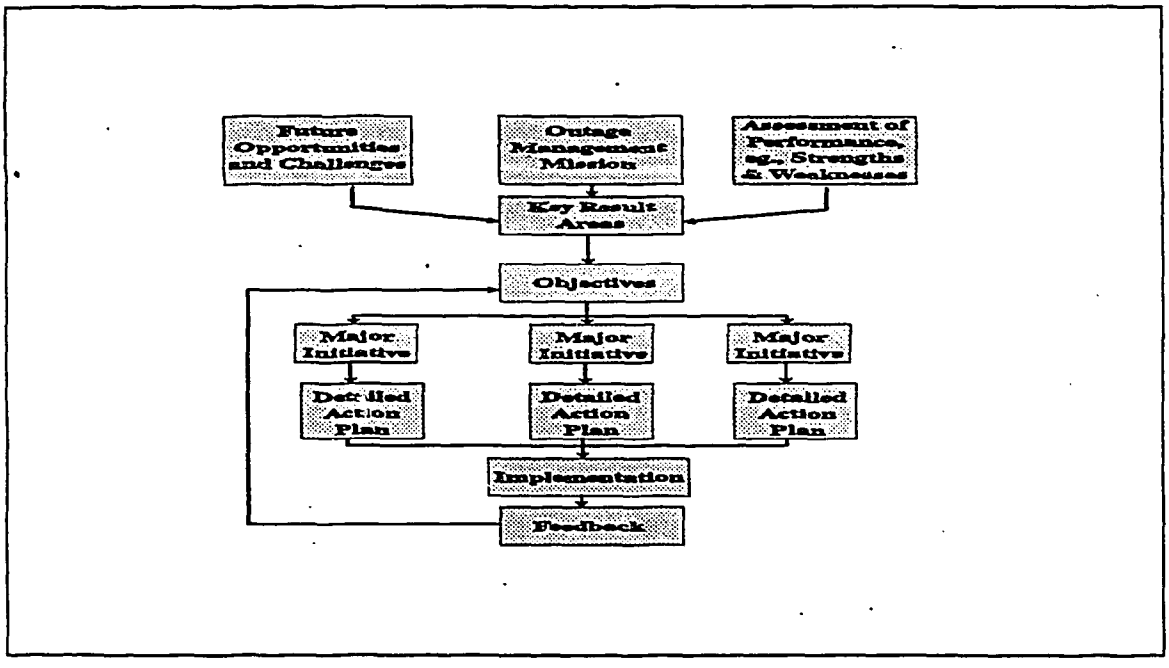


Figure 2: Outage Effectiveness

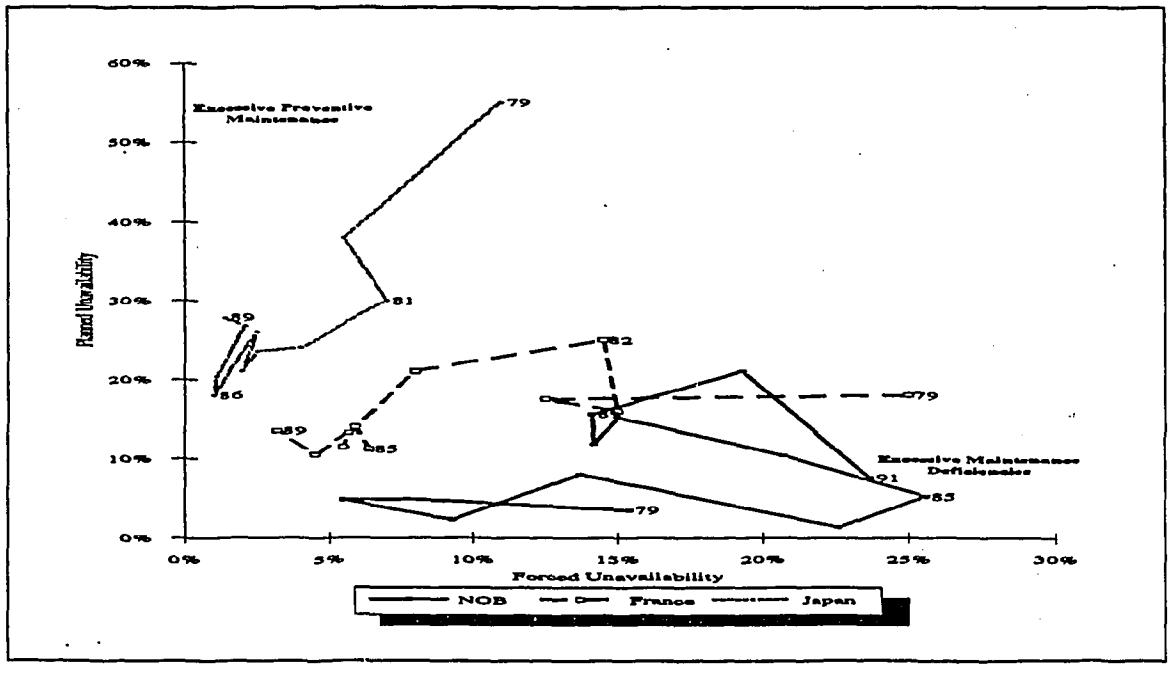


Figure 3: Planned Outage Management Factor

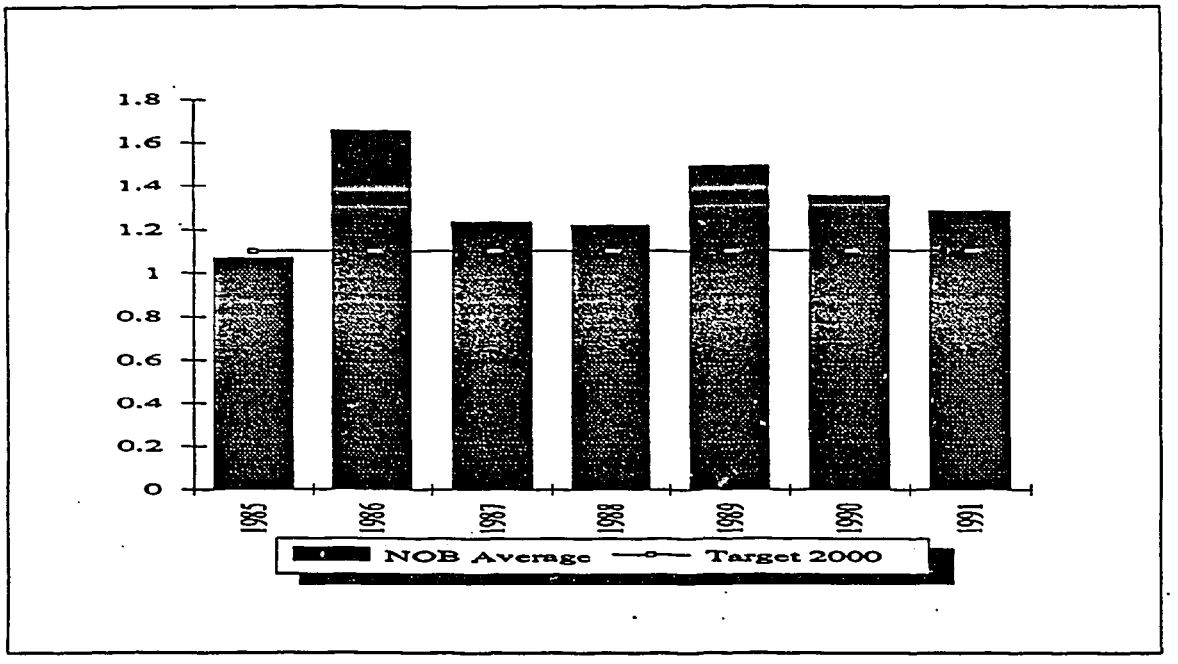
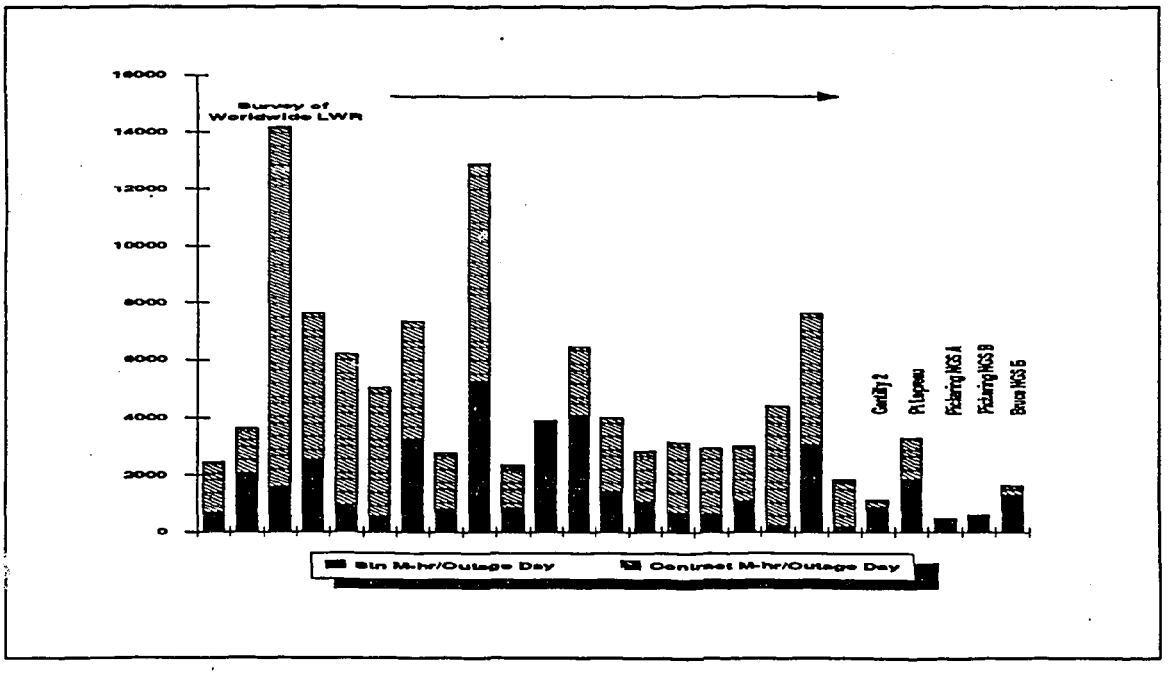


Figure 4: Outage Maintenance Labour Loading



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POINT LEPREAU GENERATING STATION
FLUX DETECTOR REPLACEMENT COORDINATION AND PLANNING

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ABSTRACT

This paper gives an overview of the planning effort to replace the twenty six vertical and seven horizontal flux detectors at Point Lepreau Generating Station during the 1992 annual outage. It discusses the strategy used for outage preparation, outage control, and how the flux detector replacement program was managed within the outage.

FLUX DETECTOR REPLACEMENT COORDINATION AND PLANNING

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Introduction

Point Lepreau Generating Station is a single unit 680 MWe (630 MWe net) CANDU PHWR owned by New Brunswick Power Corporation. It provides approximately 27% of the electricity used in the province. Because of the high replacement energy costs ($25/MW-h) great emphasis is placed on outage planning and scheduling. Each year the annual outage is scheduled in mid April to take advantage of the spring run off for hydro generation.

Planning Department

The Planning Department at Point Lepreau consists of seven members, a Planning Superintendent, two Senior Planners, two planners and two scheduling clerks. There are two sub sections as shown in Fig.1, one of which is responsible for short term planning and the other for outage and long term planning.

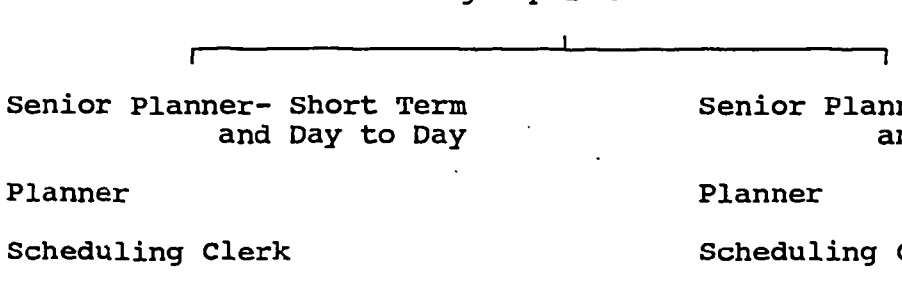

Fig.1 Planning Unit Organization

Outage Preparation

Preparation for the annual outage begins in September of the previous year. A member of the Planning Department meets with every System Engineer in the Technical Unit to discuss outage work and develop a list of proposed work for the annual maintenance outage. This list is then presented to Management for review. Once this review is complete the scope of the outage is defined. The target to have the outage scope defined is four months prior to outage start.

The 1992 annual outage was scheduled to start on April 14, with a scheduled duration of 32 days. Major work included;

1) Generator inspection and replacement of rotor end bells
2) SLARETTE of 5 and SCRAPE of 10 pressure tubes
3) Replacement of horizontal (7) and vertical (26) flux detector assemblies
4) Repair of Boiler #1 tube leak
5) Lancing of two boilers

The critical path for this outage was through the generator inspection program. (31.5 days)

Outage Control

A major contributor to achieving outage control is the assignment of an outage manager with a team of operations personnel. This group consists of a Shift Supervisor, three licensed operators and three second operators. They are taken off shift approximately two months prior to the start of the outage. They review outage logic, outage work plans, and ensure that all work permits (tag outs) are ready for issue prior to the outage. During the outage this group support the duty shift supervisor by managing the work protection effort and providing the hour to hour coordination needed to keep the outage on schedule.

The tool used at Point Lepreau for outage control is the Network Scheduling System. This is an in house developed project management system using critical path methodology. Logic networks are developed for individual systems and all the tasks associated with that system are logically linked. Logical ties are then applied between systems to provide an overall logic network for the outage. These ties (links) are used to ensure that we maintain adequate heat sink and process systems availability during the plant shutdown. The logic preparation and review process is an ongoing one that starts in the early stages of outage preparation and continues up to and through the outage as plant conditions and job status change.

Once agreement has been reached between the Maintenance Groups, Operations Outage Group, System Engineers, and Planning that the logic in the Network Scheduling System is correct, calendars, durations, skills, and skill levels are assigned to each individual task. If task duration is longer than 24 hours it is broken down into two or more tasks of a shorter duration. This is done to ensure control is maintained on long duration activities. A critical path is then determined, float values are calculated for the non critical activities, and the project is resource levelled.

Flux Detectors Replacement Project - Outage Preparation

Replacement of the flux detectors was proposed as a project for the 1992 annual outage in meetings held with the Technical Unit in October of 1991. It was realized that this was a large project and would require a considerable amount of our resources during the outage. A Senior Maintenance person was assigned from each of the Mechanical and EI&C departments to become familiar with the project during the pre outage period. They were responsible for identifying and ensuring completion of pre-requisite work that would expedite the project during the outage.

A flux detector replacement program was carried out at the Gentilly 2 station in November 1991. Members of our maintenance and technical groups visited Gentilly 2 site at this time to observe their work methods and videotaped the actual replacement of both horizontal and vertical flux detectors. The information obtained during this visit provided the Flux Detector replacement team with a good starting point for our project. The videotape was viewed by all personnel involved with the replacement. As a result of this visit Point Lepreau staff:

1) Borrowed some of the tools required from Gentilly 2.
2) Modified some of our tools to improve their operation
3) Decided to use a throw away flask for each horizontal flux detector assembly to eliminate the Carbon 14 problem.
4) Modified horizontal flux detector working platforms to facilitate positioning for change out of each assembly.
5) Modified the horizontal flux detector flasks to allow remote cutting of the detector during removal. This to reduce the dose received during the four active cuts required on each assembly.
6) Purchased video equipment to allow each assembly to be cut remotely to reduce radiation exposure.
7) Modified piping in vicinity of the horizontal flux detector assemblies to allow easier flask access.
8) Changed vertical flux detector flasks tilting assembly from a manual to an air operated system.
9) Modified procedure to dispose of active vertical flux detector assemblies in the spent fuel bay such that only the snout of the flask contacted the water. This reduced the decontamination requirements considerably.
10) Developed a training program for EI&C covering assembly and remake of the flux detector cable connections.
11) Determined that separate work teams would be assigned and trained for replacement of the horizontal and vertical flux detectors.
12) Ordered materials and stocked separate job kits with material and test equipment required for horizontal and vertical detectors replacement.

The Technical Unit initiated an extensive work program to develop the procedures required to install the new detectors and provide

the commissioning plans for the start up. This involved the preparation, review and issue of eighteen detailed coordination work plans and as many detailed maintenance procedures. They arranged for the installation of a high speed datalogger for data collection during the start up. They ensured the site AECB officers were kept informed of the status of the project.

Logic was developed in the Network Scheduling System by the Planning Department for the Mechanical and EI&C aspects of the project and the commissioning program as defined by the Technical Unit. Because of the complexity of the project and the importance of maintaining control during the outage the logic was very detailed. Following review of the logic by the Technical and Maintenance departments, and the Operations outage management team, actual man hours and skill profiles were assigned to each step. This logic was then linked into the overall outage network.

It immediately became apparent that congestion in the area of the detectors would be a problem. To resolve this the following was agreed to:

1) For horizontal flux detectors, mechanical maintenance would have access to the area on the north face of the reactor for the first twelve (12) days of the outage. The EI&C department would not start work until the mechanical portion of the replacement was complete.

2) The vertical flux detectors are accessed from the reactivity mechanism deck on the top of the reactor. For the removal of the twenty six old assemblies and installation of twenty two new assemblies, mechanical maintenance departments would work a 4pm to 4am shift. The EI&C department would work from 4am to 4pm.

Appropriate calendars and resource profiles were assigned in our Network Scheduling System. With this information, schedules were developed indicating the project could be managed in this way and not exceed the outage critical path duration of 31.5 days through generator maintenance.

Flux Detector Outage Control

Every day during the outage, the Planning Department issued a daily schedule listing the work for the next 48 hour period. This schedule listed all work assigned to a foreman on an hour to hour basis. The work associated with flux detector replacement was assigned to the Senior Maintenance personnel who had been involved in completion of the outage pre-requisites and developed the detailed procedures. A member of the Technical department was assigned to provide around the clock support for the duration of the project.

The flux detector project had approximately three days float (slack) at the start of the outage. Generally the work went as planned. Detailed work plans and procedures developed during the preparation stages were executed with few problems. Each day a representative from the Planning Department met with the maintenance departments responsible for executing the tasks scheduled in the previous 24 hours to determine the status of the work. The feedback from the flux detector work and all other work scheduled for the period were then fed to the Network Scheduling System and the effect on the critical path was determined.

There were times when the flux detector replacement project fell behind schedule. Because the individual maintenace departments were not working both shifts on this project, they would assign personnel in the non scheduled work period to complete the work necessary to bring the project back on schedule.

Problems Experienced

Although the outage schedule was maintained, the following problems were encountered:

1) One vertical flux detector assembly was damaged when it was dropped during installation. No spares were available and the assembly had to be returned to the manufacturer in Ontario for repairs. Turn around time for this was six days including transportation with no impact on our overall outage schedule.

2) Numerous problems were experienced with the operation of the airlock doors during flask removal and return to the Reactor Building.

3) Because of the length of the replacement detector assemblies, considerable difficulty was experienced in transporting the new assemblies to the reactivity mechanism deck area.

4) The new detector assemblies were slightly larger than the original assembly. Fifty percent of the guide tubes had to be reamed to allow installation of the new assembly. Unknown to us one guide tube had been repaired during initial installation and reaming was required in this area.

5) Problems were experienced with the cranes used for moving the flasks. This resulted in unexpected delays.

6) Although tritium was expected to be a problem, the procedure used to depressurize moderator cover gas during the replacement of detectors kept the levels to a minimum.

7) Station policy on hours of work limited resource availability near the end of the outage. This resulted in delays to the project schedule.

8) The data acquisition facilities did not provide the data in the format desired by the physics and analysis groups.

Summary

The overall flux detector replacement program involved a dedicated effort from many different work groups. In all 95 people were involved from 15 different disciplines.

The execution of the outage portion of this project took approximately thirty days and involved 16 maintenance personnel full time. The commissioning program to verify the integrity of the new detectors and return to near full power took another two weeks. This required the support of two EI&C technicians. Both the Maintenance and Technical departments felt the visit to Gentilly 2 was the greatest contributor to the success of the project.

Point Lepreau staff are often asked what contributes to our success in execution of outages and we believe the greatest contributors are:

1) Management support for the planning effort

2) Pre-outage planning: Twice the effort put into planning outage than executing it

3) Teamwork: Group of individuals dedicated to the project

4) Grass roots involvement: Each team member has input

5) Buying in: Ownership in the plan

6) Planning the work & then working the plan (critical path calculated daily during outages)

7) Quality work plans (extensive review process)

8) Planning detail to match level of control

9) Operations based outage management team

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3) R.M. Crawford' "Strategies To Keep A Plant Young At Heart". Presented at the 32nd Annual Conference Canadian Nuclear Association. June 7-10, 1992

Maintenance Planning and Management at KANUPP

J.A. Hashmi, Karachi, KANUPP

This paper was not available at the time of printing.

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STEAM GENERATOR WATER LANCING

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Babcock & Wilcox

ABSTRACT

The tubesheet and tube support plate deposits in CANDU steam generators are notable for their hardness. Also notable is the wide variety of steam generators access situations. Because of the sludge hardness and the difficulty of the access, traditional water lancing processes which directed jets from the central tube free lane or from the periphery of the bundle have proven unsuitable. This has led to the need for some very unique intertube water lancing devices which could direct powerful waterjets directly onto the deposits. This type of process was applied to the upper broached plates of the Bruce A steam generators which had become severely blocked. It has since been applied to various other steam generator situations. This paper describes the flexlance equipment development, qualification, and performance in the various CANDU applications.

STEAM GENERATOR WATER LANCING

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Babcock & Wilcox

INTRODUCTION

Water lancing of tubesheet deposits has been performed in PWR systems for some time. CANDU steam generators have however provided special challenges and some very difficult constraints.

BACKGROUND

Deposit buildup at the tubesheet, the tube supports and on the tubes themselves occurs to some degree in all PWR and PHWR steam generators. Typically, the deposits are distributed with about 80% as a thin fouling layer on the tube, about 15% as a concentrated deposit on the tubesheet and about 5% at the tube supports.

The effects of these deposits are; (i) tube deposits reduce heat transfer and may encourage under deposit corrosion; (ii) the tubesheet deposits which may be many inches deep can be a strong contributor to under deposit tube corrosion and (iii) tube support deposits can encourage under deposit attack. Tube support deposits can also restrict the secondary side flow so as to cause operating restrictions.

Water lancing of tubesheet sludge deposits has been performed for some time in various PWR steam generator systems. The process involves lancing from the tubesheet central no-tube-lane (NTL) with a lance which directs oscillating jets along the inter-tube lanes (the gaps between the rows of tubes). By this process, tubesheet deposits which were relatively soft could be flushed to the edge of the bundle and removed by suction. A variant of this approach involves jetting from the edge of the bundle inward.

Efforts to apply this process to CANDU steam generators met with unsurmountable difficulties (1). Tube bundle access proved to be very difficult. In the first trial which was at Pickering A, it was necessary to devise a lance which was very compact yet able to jet along tube lanes at a 60° angle (rather than 90°) to the lance body. A very unique articulating lance head was devised. Despite some difficulties, this articulated lance did operate successfully. The real revelation of this work was the toughness of the deposits to be removed and the depth of the tubesheet deposits. The tubesheet sludge pile extended over most of the width of the SG hot leg and to a maximum depth of about 16 inches. Repeated lancing along selected tube lanes resulted in a reduction of the near side of the pile height by 2 to 3 inches.

A subsequent water lancing operation at the Point Lepreau plant had a similar result (1). In these SG's the deposits covered a smaller area and were less deep. As shown in Figure 1, they covered about 10% of this tubesheet and had a maximum depth of about 6 inches. They were, nevertheless, very hard. Lancing was performed on all four SG's - albeit with some difficulties

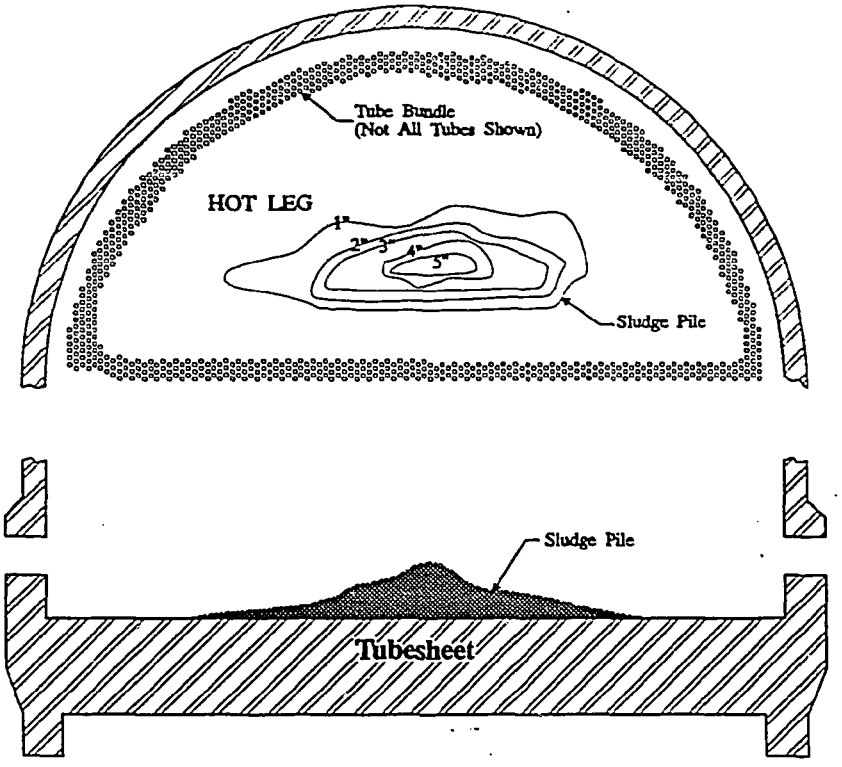

Figure 1: Location of Point Lepreau Tubesheet Deposits

in the operation of the prototype equipment. The operation was successful in removing only a limited amount of sludge from the near side of the pile. The balance remained in place.

From these trials and from various inspections and deposit testing, it was clear that in CANDU SG's generally, the tubesheet deposits were exceedingly tough. Typically, only the recently deposited upper layer of one or two inches is soft. Why deposits in these SG's should be so hard is not entirely clear although some combination of deposit composition, deposition dynamics and time is undoubtedly involved. Various tests were performed to try to further develop lancing from the NTL for hard deposits. Ultimately it was determined that (i) the best jets could not cut hard deposits at the necessary distances from the NTL (even without interference from the tubes), (ii) passage through the narrow intertube gaps rapidly dissipated even the best jets, (iii) the intensity of the jet with distance was extremely sensitive to alignment of the jet with the centre of the lane, and (iv) additives can enhance the cutting efficiency of the jet but do not reduce its sensitivity to misalignment and can make it erosive to the tubes except at relatively low pressure. The ultimate conclusion was that NTL lancing is effective if the deposits are very soft or as a bundle flushing process. NTL lancing however could not be developed for cutting the very hard sludges.

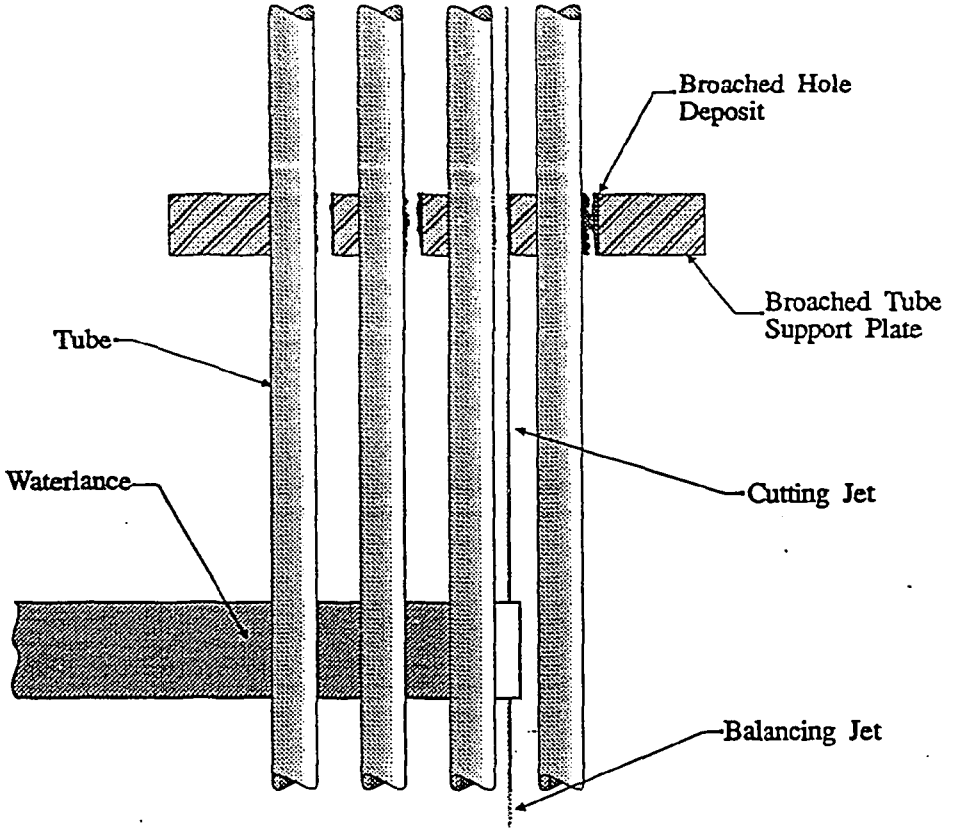

Figure 2: Bruce A Tube Support Plate Waterlancing

BRUCE UNIT 2

In the 1986-88 time period, Steam Generator #3 of Bruce Unit 2 was observed to have a very large apparent water level variation during operation. This turned out to be a variation in water level indication due to an instability in the secondary side circulation flow. Flow measurements indicated that variations in the downcomer flow were occurring at high power levels at which condition the flow varied at regular, seven second intervals between about zero and 120%. Analysis (2) indicated that this type of instability could be due to support plate blockage. In general instability is most sensitive to severe blockage of the upper plates and less sensitive to blockage lower down in the SG. The analysis showed that instability would occur at about 77% blockage of the upper most support or at overall blockage of about 70%. Subsequent flow measurements and inspections revealed that such blockage did exist.

Blockage of broached plates had been previously observed in PWR Once Through Steam Generators. Those deposits were successfully reduced by a process called "Waterslap" and were ultimately removed by chemical cleaning. Application of the Waterslap process to U2 SG3 was

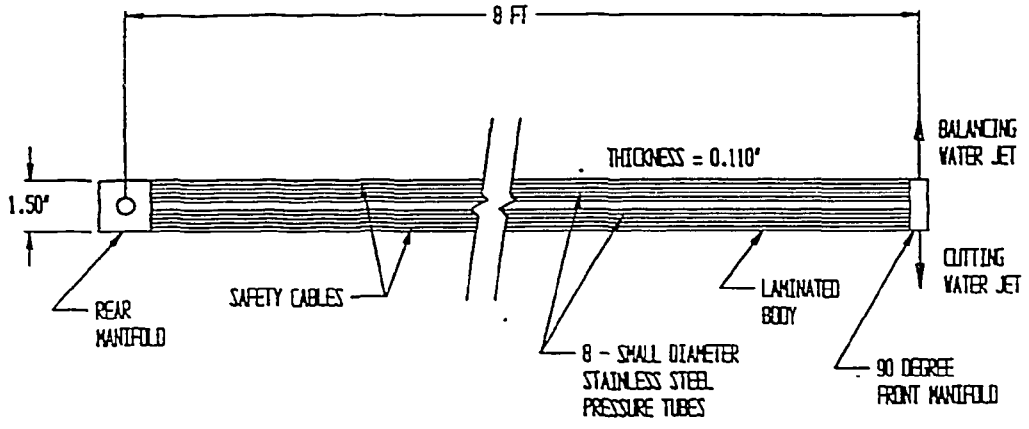

Figure 4: Bruce 2 Waterlance

and installation of inspection ports and the deployment of personnel.

The degree of deposition before and after lancing was determined by fibreoptic inspection from below using a 2 mm fibreoptic probe. The fibreoptic probe was delivered by a fibreoptic guide (Figure 6) which was designed to be positioned by the water lance manipulator. The fibreoptic provided a view of the individual broached openings along a tube lane. The degree of blockage was estimated for individual openings and from that, the blockage of the entire plate was estimated. The pre-water lancing blockage inspection result for Support Plate #6 of SG #3 is shown in Figure 7.

Contrary to initial expectations, the deposits proved to be very hard. They also proved to be very extensive. Table 1 is a typical list of aggregate TSP blockages on Unit 1. Inspection showed that

- all plates inspected had deposits at all locations.
- numerous passages were totally blocked.
- some plates had extensive areas of total blockage.
- in some regions, deposits not only extended right through the passage but on top of the plates as well.
- U2 SG3 had deposits which were particularly extensive and tough.

After the initial operation, it became apparent that enhanced lance performance was required to cut through the tough deposits in some of the SG's. From the initial cutting head operating at 6000 psi with demineralized water, the lance development progressed through numerous enhancements including

- many refinements to the cutting head design.
- reduction of lance body thickness from 0.125" to 0.110" to allow passage through the

not successful since these deposits were not soft nor fragile as was initially hoped.

By October 1988, U2 had been derated to 73% power in order to avoid operation with flow instability. It became essential to develop a direct means of removing the deposits from the broached tube support plate flow passages.

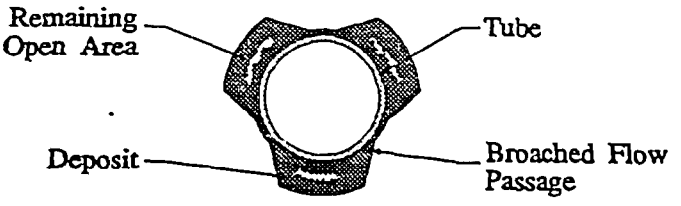

Figure 3: Severely Blocked Broached Hole

The Bruce A (Units 1-4) steam generators incorporate 4200 Alloy 600 U-tubes on 0.800 inch triangular pitch. The tubes are positioned by 7 tube support plates (TSP's) within trilobal broached holes and by three sets of scalloped bar U-bend supports (UBS's). The tubesheet and lower supports are virtually inaccessible due to the containment. Access to the upper supports was achieved by adding 2½ inch inspection ports at the NTL 7 inches below each of the upper 2 or 3 support plates. Internal access was further complicated by four tie rods in the NTL. The broached TSP's with deposits are shown in Figures 2 and 3.

Removal of the TSP deposits required a device which could act directly on the deposits within the broached openings. The idea of using some form of waterlancing to clean the broached openings was promoted by Ontario Hydro (3). This was a novel approach for which no experience or tooling existed. The response to this challenge was the development of a flexible water lance which could access individual tube lanes and jet directly onto the deposits. The prototype was developed from scratch and operated at site within a 12 week period in the winter of 1989. Various enhancements, tests, program adjustments and some difficulties ensued.

The Bruce 2 waterlances (Figure 4) incorporate front and rear manifold blocks interconnected by 8 stainless steel tubes encased in a polycarbonate body. A lance is typically 0.110" thick x 1½" wide x 8 ft long. The front manifold incorporates a flow collection chamber which feeds two nozzles of 1 mm diameter - one directed upward and one downward. The rear manifold incorporates a pressure fitting for connection to a high pressure pump.

The lances were designed to pass along the NTL via a manipulator which articulated to direct the lance into an individual tube lane (Figure 5). Access to the SG was via special 2½" inspection ports positioned about 7" below the individual support plate. By accessing holes at each end of the NTL, with special flexible manipulators, both the hot leg (HL) and cold leg (CL) could be lanced from the two opposing 30° directions. In this way - allowing for the various inaccessible areas - about 60% of the plate could be lanced. By accessing the top two or three support plates, sufficient lancing was done to resolve the instability problem.

Development and deployment of this equipment required considerable effort. This included the preparation of designs and manufacturing techniques for the intricate parts, performance and qualification testing, preparation of pumping systems, development of inspection tooling, design

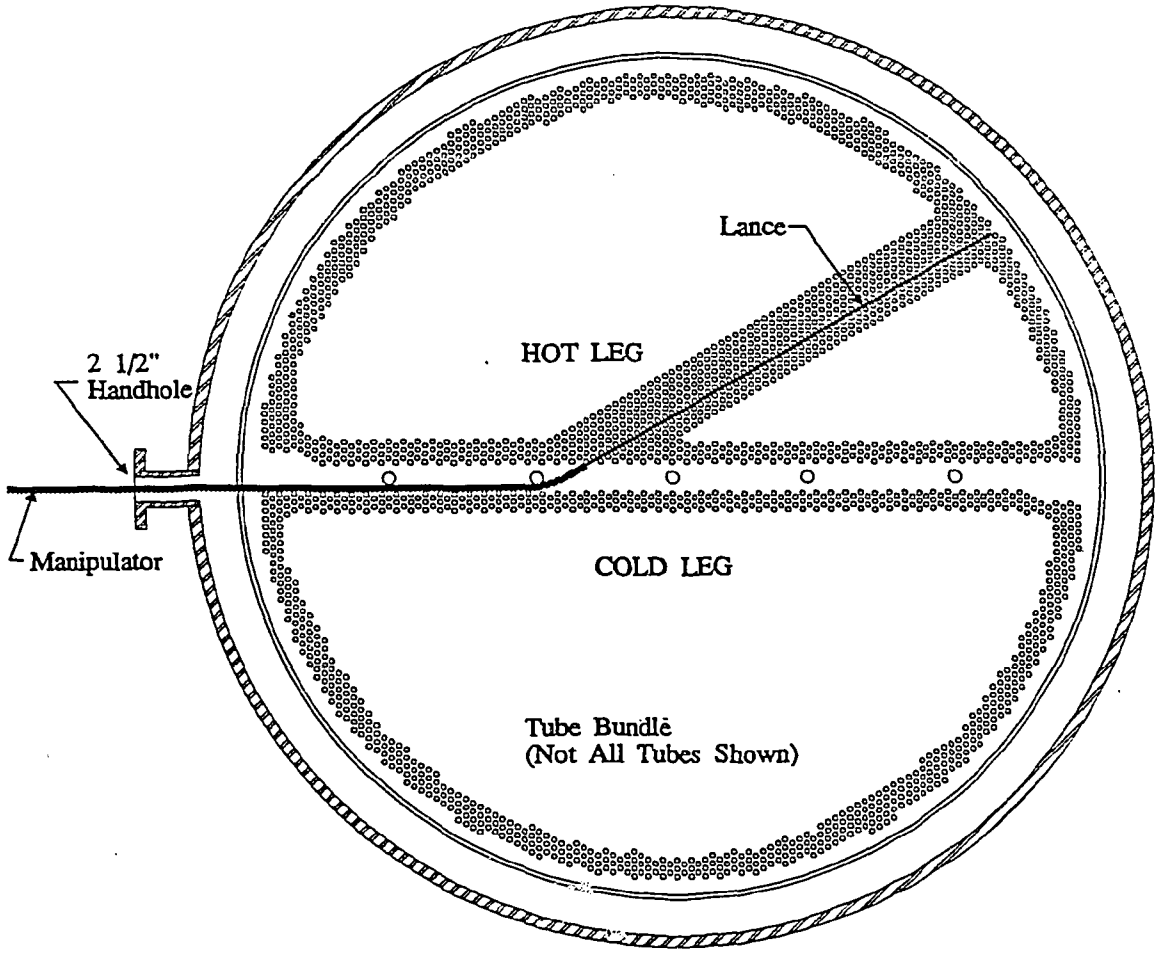

Figure 5: Bruce A Waterlance and 30° Manipulator

tight inter tube gaps.

- a forward jetting lance to remove tube deposits to improve lance access
- a lancing pressure increase from 6000 to 10-12000 psi.
- lancing medium changed to a Superwater solution - Superwater is a water additive which improves jet focus at distance.

Lance qualification tests were performed at each stage of development, or after any change of nozzle design, jet performance, lancing medium or SG impingement geometry condition. Tests were performed to;

(i) Verify Jet Performance. These tests were done by cutting commercial bricks (calcium silicate) in comparative tests. The best Superwater jet could cut through a brick when

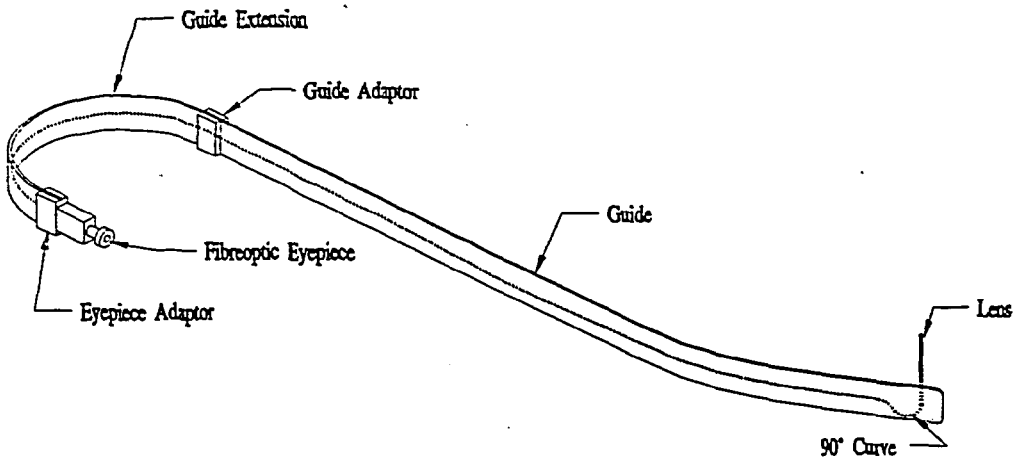

Figure 6: Fibreoptic Inspection Probe And Guide

traversing at 6 in/min at 7 in standoff distance and 10000 psi pressure. While the bricks are not as tough to cut as the hardest deposits, they have served as a convenient standard for testing and comparison.

(ii) Determine Limits for Tube Erosion. Erosion tests were set up to determine the safe operating pressure for the specific lancing conditions. Tests were arranged to simulate lancing parallel to the tubes, lancing with abrasive entrainment and lancing with impingement on the U-bend curve above the top support. Tests were set to conservatively cover exposure durations.

The erosion tests were performed to a test matrix and criteria established by Ontario Hydro who also examined the resultant tube erosion test specimens. The criteria were set (3) to require:

- tube samples receive 30 minutes exposure (versus a minute or so actual exposure for multiple passes)
- tests simulate the exposure geometry conservatively
- tests simulate entrained deposits
- erosion not to exceed 10% of wall thickness (the criteria actually applied on examination was basically to accept light buffing (including light peen marks from grit) but to not accept significant loss of material or any pitting type of damage). Loss never exceed 10 microns (< 1% wall).

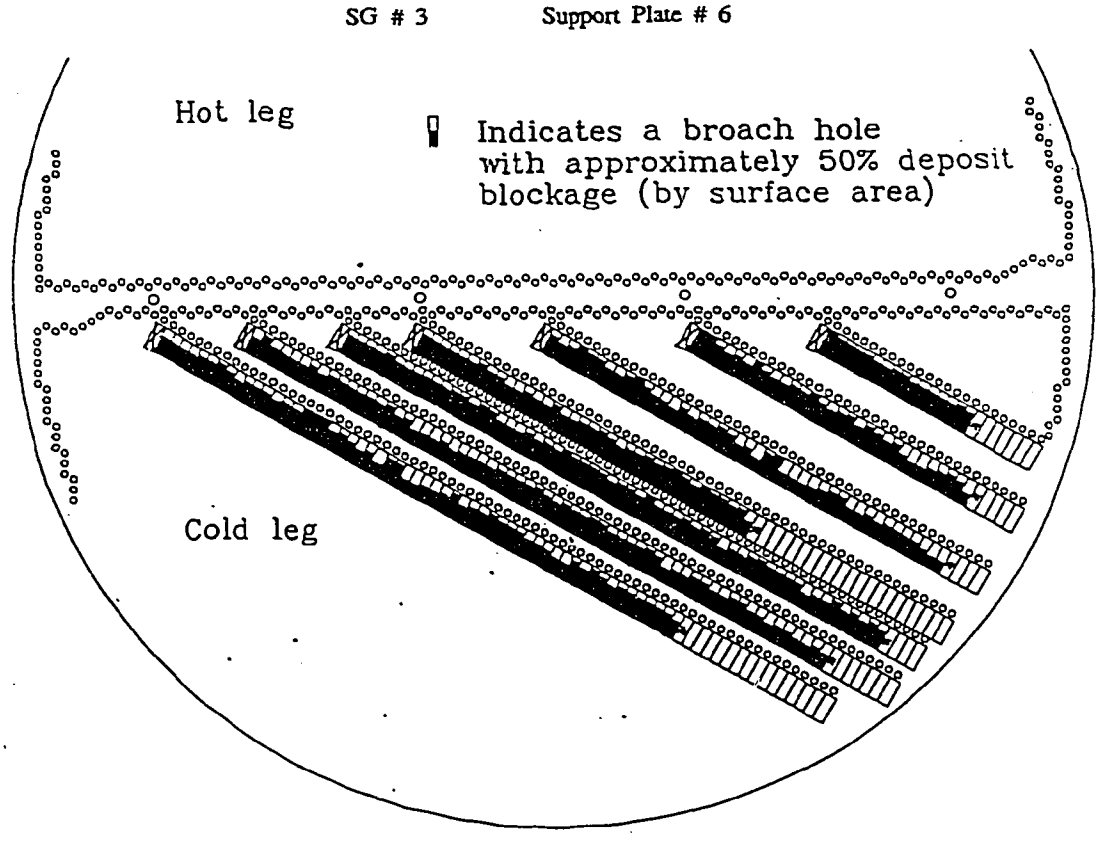

Figure 7: Bruce Unit 2 Pre-lancing Inspection Result

The result of the Bruce 2 lancing program was relatively effective at cleaning the accessible 60% of the upper two supports of 7 of the 8 SG's. The remaining SG (#3) had particularly tough deposits. Despite repeated efforts with increasingly effective lances, the hot leg deposits were only partially removed (the CL deposits were effectively lanced).

The unit was subsequently returned to service and was able to operate at full power with no limitation due to instability.

Table 1
TSP Blockage for Unit 1 SG's

	% Avg. Blkg. Before Lancing	% Avg. Blkg. Where Lanced	% Overall Aggregate Blkg. After Lancing
	Min/Max	Min/Max	Min/Max
TSP 7	80/90	< 10/20	30/50
6	60/90	< 10/10	30/40
5	20/90	< 10/10	10/40
4 *	20	20	20
3 *	45	45	45
2 *	45	45	45
1 *	45	45	45

* estimated from pressure drop measurements on U2 SG 3.

BRUCE UNIT 1

After Unit 2 had returned to service, Unit 1 underwent a very severe power limitation due to oscillation. By early 1990, five of the 8 SG's were oscillating at high power. The plant ultimately had to be limited to 55% power. While Unit 1 had not had the oscillation problem for as long as Unit 2, the blockage was even greater and the oscillation was occurring on more boilers. A listing of blockage in Unit 1 SG's is provided in Table 1. A renewed program of support water lancing was undertaken covering;

- lancing the upper TSP's of all 8 SG's.
- 30° lancing from both directions of both the HL's and CL's.
- lancing with Superwater as required.
- inspection before and after of representative lanes.

The renewed effort for Bruce 1 evolved from the experience at Bruce 2. Further work was done to refine the cutting ability of the lance. The lance head flow passages were modified to overcome some of the restrictions on jet quality caused by the very small head size. The lance was developed for still smaller lanes to overcome access restrictions due to tube deposits and tube misalignment. The complete set of qualification tests was redone - a necessity after each lance or process refinement.

The operation at site involved four sets of equipment lancing simultaneously the support plates of one bank of four SG's. Prior to lancing, two inspection holes were added by O.H. at each of the TSP's to be lanced. Extensive broached hole inspections were performed by O.H. in

parallel with the lancing.

Results (4) of pre lancing inspection on Unit 1 SG's (Table 1) showed that;

- pre-lancing aggregate blockage was in the 60% to 90% range for the upper plates.
- 5% to 9% of the holes were totally blocked before lancing.
- some of the SG's had more deposits on the cold leg side than on the hot leg side.

After lancing, essentially all of the deposits were removed from the accessible areas (ie. from the approximately 60% of the TSP area which was accessible). This removed the instability problem and substantially restored secondary side flow circulation. The effect of blockage on circulation was subsequently analyzed. The result is shown for a typical SG (U1 B6) in Table 2. The as-designed, as-blocked and as-lanced cases are addressed. Note that in the as-blocked case, the flow is severely reduced. In the as-lanced case the flow was restored to a value much closer to the as-designed case. The effect of increased circulation (as caused by deposit lancing) is a slight increase in bundle velocities but a large increase in mass flow and density. After lancing, the unit was restored to operation without power limitation due to deposits.

Table 2

Effect of Blockage on Circulation - U1 SG6

	As-Designed	As-Blocked	As-Lanced
Circulation Ratio	5.9	1.2	4.5

POINT LEPREAU AND GENTILLY 2

The Point Lepreau (PLGS) and Gentilly 2 (G2) plants have operated very successfully due in part to the vigilance of the operators in assessing the condition of their steam generators and in endeavouring to minimize formation of deposits. There has nevertheless been a degree of deposition which has resulted in a reduction of heat transfer efficiency and the buildup of sludge piles on the tubesheets (1).

In 1987, an effort was made to remove the PLGS tubesheet sludge by conventional NTL water lancing. This process had limited success and confirmed that the deposits were exceedingly hard.

Later, after discovery of the Bruce 2 broached plate deposits, an inspection of several upper plates at PLGS showed that there was very little deposition in that area. There was however severe deposition on the lowermost hot leg broached plate in the local area of the bundle immediately above the centre of the sludge pile.

In 1991, both PLGS and G2 performed intertube water lancing trials to determine the feasibility of removing their sludge piles. Lancing trials verified that most of the sludge depth could be removed by intertube lancing.

In 1992, a full tubesheet lancing program was performed for all four of the PLGS steam generators. The lancing program was expanded from two to four steam generators after work initiation at site when it was discovered that under deposit pitting had occurred on some tubes within the sludge pile area.

At that stage the sludge pile was still concentrated primarily in the central HL "kidney" shaped region which covered about 7% of the tubesheet. In this area, the sludge pile varied in depth to a maximum of about 6 inches. The composition was generally very hard but with a softer layer forming the top 1 or 2 inches. The broached plate area directly above the sludge pile had significant blockage including some passages which were totally blocked. The tubes directly above the sludge pile also had significant deposits. Beyond the main sludge pile area, the tubesheet was relatively clean and deposition on tubes and the first broached plate was very light.

Lancing was performed along the 30° (to the NTL) HL lanes via access from both ends of the NTL. This provided a cross over pattern which reached about 75% of the hot leg area. The main sludge pile area could be lanced from both directions so as to maximize sludge removal in this critical area and to maximize coverage of the shadow areas behind tie rods within the bundle.

The water lancing was performed with S.S. tubed lances accessing the 30° lanes and jetting at angles (to the lance body) of 90° and 60°. The lance could be manipulated to the horizontal position at which point the lance nozzle was about 8 inches from the tubesheet - or to "zero standoff" in which case the nozzle was very close to the tubesheet or sludge pile. Lancing was performed at 6000 psi with demineralized water.

Prior to lancing at site, qualification tests were performed to verify the operating range relative to erosion concerns. Erosion testing was performed with the best cutting lance and with various conditions of jet impingement and deposit entrainment. The Alloy 800 tube samples were submitted to test conditions, visually examined and then forwarded to the utility's analyst for detailed examination. Any evidence of pitting or net loss of metal was cause for rejection and for restriction of the operating parameters. The selected conditions were qualified for up to 30 minutes exposure at any one point. Prior to delivery and during operation at site, individual lances were tested to verify their operation and to confirm that the operating lance fell within the range of the qualification test parameters.

After completion of the intertube lancing, a flushing pass was performed with a fixed multi tube lance operating from the NTL.

The result of the lancing operation was verified by fibreoptic inspection and by a special depth probe. The results showed:

- the tubesheet beyond the main kidney was essentially clean after lancing.
- the sludge in the kidney area was reduced from a typical depth of approximately 4 inches to about 1 inch.
- the broached plate deposits were effectively removed by the tubesheet lancing - even though the upper nozzle was a "balancing jet" (ie. of less quality than the nozzle directed at the tubesheet) and the jetting distance was about 17 inches (vs. 8 inches to the tubesheet).
- the flushing was effective in removing loosened material from the NTL and the annulus of the SG.

The PLGS steam generators have now been returned to operation.

PICKERING B

Pickering 5, the first of the Pickering B units, has been in-service since 1983. As a result of the experience with support deposits at Bruce 2 and 1, there was a concern that there may be similar upper support plate deposits and instability problems at Pickering B. Waterlancing equipment was developed and mobilized to Unit 5 SG 4 in May, 1991 to investigate and deal with the upper support deposition. Upper support plate deposition was found not to be significant on that unit. Deposits which did exist could be monitored and addressed later.

At the same outage it was decided to look at the tubesheet and the lowermost support plate. The examinations showed that deposition in the tubesheet region was quite severe. In particular, deposition at the 1st support (lowermost hot leg broached plate) was very heavy. Blockage was observed to be of the order of 80%. Heavy deposits had accumulated on the tubes and the tubesheet sludge pile had grown to about 6 inches deep.

Unit 5 SG tube inspections showed that the tubes had experienced a number of under deposit pitting type defects in the lower hot leg area of the SG. Indications were observed under the tubesheet sludge pile, under deposits at the first and second supports and even under deposits on the tubing free span below the first support.

With such deposits there was a great potential for ongoing corrosion of the tubing. There was also the question of how the SG would operate with restricted circulation to the hot leg area - the area where heat flux is highest and the potential for chemical concentration is greatest.

In order to return to service, the tubes were 100% inspected in the lower region and significant indications noted. A number of tubes were plugged at that time.

In April, 1992, Unit 5 was taken out of service as a result of a tube leak after only 4 months of additional operation. Both the defect which caused the leak and other defect indications had grown at an unacceptably rapid rate in the intervening period.

On April 29, the station dictated that water lancing and chemical cleaning must be undertaken on an urgent basis and be completed before returning the unit to operation. The requirement was that (i) tubesheet lancing of 30° lanes with S.S. tubed lances begin by June 10, (ii) lancing of 90° lanes with composite tubed (Kevlar reinforced) lances begin by July 1, and (iii) chemical cleaning begin by August 1. This was an extremely urgent demand considering that

- the lancing internal access (below the preheater NTL divider plate) was extremely difficult and only a very flexible type of device would be able to operate there.
- no water lancing manipulator design existed to do that.
- steel tubed water lances would have to be redeveloped for this application to reduce their size and improve their flexibility and cutting performance.
- no composite lance of any type existed beyond the Bruce prototype which was not yet fully developed and which was totally unproven. This type of lance was needed to access the tube lanes at 90° to the NTL in order to improve tubesheet coverage.
- extensive design, development and deployment of auxiliary equipment and preparation of personnel were required.

The equipment and procedures required for the program included

- fibreoptic inspection guides and manipulators for inspection along the 90° tube lanes at both the tubesheet sludge pile and the first broached plate. The fibreoptic guide is a narrow strip incorporating a 1.5 mm fibreoptic which is capable of sweeping through 90° tube lanes in order to view either the TSP or the tubesheet surface. The images are recorded and later analyzed. From these images are determined percentage blockage of the broached TSP openings, the nature of the tube deposits and the appearance of the sludge pile.

- depth gauges for measuring sludge pile profile. These gauges are inspection strips which incorporate a probe by which the surface of the consolidated pile can be gauged and recorded.

- water lances with stainless steel pressure tubing suitable for lancing tube lanes at 30° to the NTL. This type of lance must be; flexible enough to navigate a 6 inch radius to get into the 30° lane; of 1¼" height to get below the preheater obstruction; of 0.100" thickness to get through narrow crudded tube lanes; able to operate at 15000 psi; produce a high quality jet in at least one direction; and be reasonably durable.

- flexible manipulators able to access the NTL from beneath the preheater obstruction and to deliver a S.S. lance to the correct 30° tube lane.

- 90° manipulator head able to deliver an inspection manipulator (or 90° lance) to a 90° tube lane.

- 100 h.p. electrically driven pumps to supply lancing water at 15000 psi, 11 gpm.

- air-water suction pumps for removal of lancing water and sludge. The water level in the

SG must be kept very low in order to avoid destroying the effectiveness of the jet.

- drives for traversing the lance over the sludge pile.

- water lances with composite Kevlar reinforced tubing for lancing at 90° to the NTL. This type of lance was needed to access the 90° lanes in order to increase coverage from about 50% of the hot leg (with a 30° lance) to 90% or more. The 30° lance is restricted by tie rod blockage as well as by having no access to an outer segment of the bundle. The composite lance must navigate a radius of about 1½" in order to get into the 90° lanes. This puts severe shear stress on the lance body. It also severely distorts the rigid head of the lance as it navigates the manipulator. The lance body must have a 0.100" x 1¼" cross section and a very compact lance head which is efficient at cutting deposits. It must also be able to operate at 6-12000 psi and have an acceptable operating life. Achieving these requirements from a standing start proved very difficult as described below. In due course, lances were made which were able to cut deposits and last for several shifts. Completion of the lancing operation required numerous lances to offset their very short life. Ultimately, the lancing operation was completed so that other operations (chemical cleaning) could proceed.

- manipulators for positioning the 90° composite lances to the 90° lanes.

- flushing lances for removal of the insoluble residue from the tubesheet after the full bundle chemical cleaning operation.

- manipulators for delivery of inspection guides (and composite lances) to the second TSP (beside the preheater).

- engineering and tooling for positioning of inspection holes for the second TSP.

- equipment and personnel for simultaneous 7 days per week lancing on 3 SG's with three sets of crews on rotating 12 hour shifts.

Lance development under the severe time constraint pursued several avenues in parallel ie. (i) design of a new 30° (S.S. tubed) lance with a compact head and a body narrow enough to get below the preheater, (ii) design of the totally new 90°, Kevlar tubed, composite lance, (iii) developing suppliers for the multiplicity of small, specialized parts including custom made tubing, nozzle blocks, ferrules etc., (iv) development of manufacturing techniques for the final lance assembly, (v) performance testing of the prototype lances, (vi) erosion testing, (vii) preparing for the manufacture of the anticipated production of about 12 copies of each type of lance.

Production lancing was now undertaken at site. The lancing program at site called for a period of 30° lancing with S.S. tubed lances followed by 90° lancing with composite lances.

Lancing of the 90° lanes with composite lances was to proceed after completion of the 30° lancing on the first three SG's. Considerable difficulty was experienced with the development

of these lances which had not existed even in concept at the start of the job. Three types of difficulty were experienced;

- lance cutting effectiveness was unexpectedly low. This was traced largely to the fact that the lances were severely downsized for this application. Downsizing resulted in unusually high velocities and therefore high turbulence upstream of the nozzles. A number of cycles of refinement were necessary to deal with this difficulty - an effort which continued into the time of operation at site. The result was lances which had reasonably good cutting ability.

- lance durability was exceedingly low. Because of the confined NTL space, the lance had to bend through a 1.5 inch radius within the manipulator. It also had to bend in at least two directions outside the SG. This bending and the 10000 psi operating pressure put the lance components under severe stress. Many failures were experienced as a result.

- lance manufacture at the start of the project was strictly a development activity. The intent was to expand it enough to provide the 12 or so lances which would be needed. Because of the durability problem, the need for replacement lances required that production be expanded substantially.

As the 90° lancing got underway, the degree of difficulty and its impact became fully apparent. Composite lances which had been expected to last for a large part of the job were failing within hours. With the initial 2 day replacement cycle crews were at times left with no equipment.

Efforts were doubled and redoubled to improve the effectiveness of durability of the lances and to expand production. By the end of the tubesheet lancing program, production was at the rate of 2 to 3 lances per day.

Ultimately, tubesheet lancing program was completed for all twelve steam generators. The results were

- the tubesheet sludge pile in the accessible regions was reduced from about 6 inches to less than 1 inch. The remaining deposits were very hard and were not being reduced by further lancing.

- lancing coverage of the tubesheet area was approximately 70-75%. This compares to about 40% with 30° lancing alone.

- the deposits on the first TSP's (which were initially about 80% blocked) were totally removed from the accessible regions by the balancing jet on the reverse side of the lance. While the balancing jet is typically not very intense, it was able to remove these deposits.

- deposition at the second TSP was inspected and found to be minimal and consequently was not lanced. Access to the second TSP was exceedingly difficult and limited to 30° lanes.

- the entire program including development of equipment, mobilization and the lancing of twelve steam generators at site was completed in a period of 19 weeks.

The initial Pickering 5 tubesheet lancing has now been completed. The program was successful in removing a large portion of the deposits from the tubesheet and the first TSP. Removal of these deposits was critically important to achieving clean steam generators at the end of the subsequent chemical cleaning program. That could not have been done by any process other than inter tube waterlancing.

CONCLUSION

The CANDU tube support and tubesheet sludge waterlancing program is characterized by the hardness of the deposits and the awkwardness of the access. Each new task has required advancements in tooling to overcome access limitations and to enhance cutting ability. Considerable progress been made. Further challenges remain.

ACKNOWLEDGEMENTS

The achievements of the support plate and tubesheet waterlancing program has depended upon the contributions of many different people. Special mention should be made of the pro-active technical support and project direction provided by J. Malaugh of Ontario Hydro; of the program leadership of W.R. Symmons and W. Papailias of Ontario Hydro, K. Verma of NB Power and A. Marchand of Hydro Quebec; and of the site direction provided by B. King and S. O'Neill of BNGS and M. Arnone of PNGS; and of the Inspection reporting of R. Adams and H. Carbajales; of the development, manufacturing and operations contribution of the B&W people and finally of R. Dyck of Ontario Hydro who actively promoted the idea of cleaning support plates using waterlancing in the first place.

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STEAM GENERATOR MAINTENANCE PROGRAM AT POINT LEPREAU N.G.S.

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ABSTRACT

This paper addressed the issues which contribute to successful Steam Generator maintenance at the Point Lepreau N.G.S. It outlines the significant maintenance related activities and some of the modifications to station equipment to facilitate the Boiler inspecion, cleaning and maintenance tasks. Steps taken to address associated heat sink, radiation control and outage management issues are considered.

STEAM GENERATOR MAINTENANCE PROGRAM AT POINT LEPREAU N.G.S.

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INTRODUCTION

The Point Lepreau Generating Station has been in service since 1982 and has operated well with a lifetime capacity factor above 91%. A major factor in minimizing station unavailability is the effort put into planning, managing and executing annual maintenance outages. These shutdowns have been dominated by Turbine-Generator, Fuel Channel and Steam Generator inspection and maintenance activities. A rising Reactor Inlet Header Temperature and under deposit tube attack will increase the annual Boiler outage activities in the next few years. It is likely that this Boiler work will establish the critical path in these shutdowns.

The maintenance departments have supported a wide variety of Boiler activities. These activities are often not as technically demanding as those on other large pieces of equipment in the station. Replacing a hydrogen seal on the Generator, for example, poses a greater demand on the maintainers skill. Steam Generator work, however, provides the challenge of conducting maintenance while dealing with a variety of radiological hazards within the limitations posed by the need to react very quickly to potentially changing station heat sink demands.

The purpose of this paper is to outline the Boiler maintenance activities which have supported the various Steam Generator inspections, tube leak searches and repairs, Boiler modifications and cleaning operations through the years. Initiatives used to address the radiological and heat sink demands will be presented. In addition, maintenance strategies planned to deal with the future expanded scope of Boiler work will be discussed.

The success of Steam Generator maintenance is strongly dependent on the preparation of the staff and the planning of the job. "Good practices" which are credited with enabling Boiler maintenance to be completed effectively and on schedule at Point Lepreau will be listed.

THE BOILER

The Point Lepreau Steam Generators (Figure 1) were manufactured by Babcock & Wilcox Canada. Characteristics of the design and associated equipment which have a bearing on maintenance are listed in Table 1.

FIGURE 1 - POINT LEPREAU STEAM GENERATOR

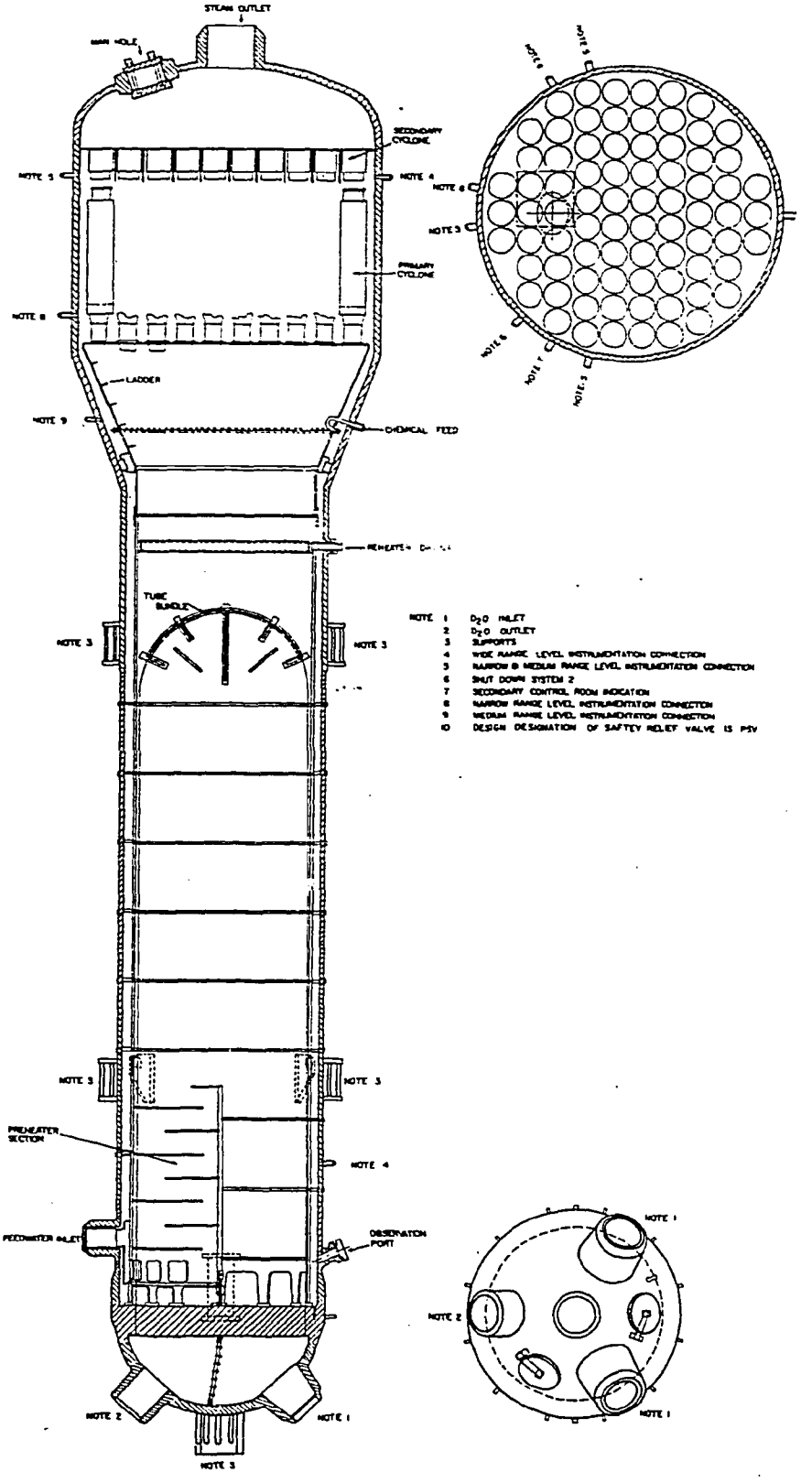


Table 1

Some Design Specifications Which Influence Maintenance

Tubes: 3550 per vessel. I800 material. 5/8" OD triangular pitch.

Support Plates: trilobal broach holes. Material is 410 stainless except for the preheater thermal plate and 2 preheater support plates which are carbon steel.

Shell: some of the shell "cans" have greater than 0.25% carbon content which, by code, requires welds of attachments (inspection ports etc.) to be heat treated.

Isolation Valves: isolation valves are not provided in the primary side (heavy water) piping nor in the secondary side (light water) steam lines.

Insulation Cabinet: the lower third of the vessel is surrounded by a large insulation cabinet which must be cooled before access is possible to the Boiler primary side mandoors. The dimensions of the cabinet restrict some maintenance activities.

Boiler Maintenance History

A chronological listing of the major inspection results and significant maintenance events is provided in Table 2. This includes water jet lancing (to remove tubesheet sludge deposits) activities and tube leak information.

Maintenance Heat Sink Issues

The Boilers are required to provide fuel cooling during outages in the event that the primary heat removal system becomes ineffective. This requirement imposes significant limitations on the maintenance staff as all activities must be conducted in such a way that the Boiler primary and secondary side water inventories can be reestablished.

To permit the flow of primary coolant through the Boiler being worked on, the maintainers must remove the contents of the primary head and install temporary manway covers within 5 minutes of loss of the heat sink.

Sixty minutes are available to box up the secondary side of the Steam Generators being worked on. Within this time, maintenance, inspection and cleaning equipment must be removed or secured, a temporary main steam line bung removed (in tube leak search cases) and inspection ports and temporary secondary side manway covers installed.

Table 2
POINT LEPREAU NUCLEAR GENERATING STATION
BOILER OPERATING CHEMISTRY
CHRONOLOGY

EFPD	CONDITIONS	SIGNIFICANT EVENTS	INSPECTIONS
0 - 1325 (83-86)	S/G - PO4 Control FW - pH 9.8 N2H4 100-200 ppb Fe 3 ppb RIHT 262.7 - 265.7 ΔT 3°C	440 - EC Inspection Boiler 4 (84) 1000 - Tube Leak Boiler 3 1120 - Defect tube removed (86) (D20 = [illegible])	Kidney-shape sludge pile on T/S < 1 inch Centre of hot leg - 1 inch above TSP 1. Pitting - agent unknown. Iron phosphate sludge. 4-6 inches sludge pile at centre of hot leg. Lancing ports installed.
1325-1810 (86-88)	S/G - PO4 Control FW - pH 9.5 N2H4 10-20 ppb Full flow CP NH4OH cycle Fe 8 ppb RIHT 265.7 - 265.7 ΔT 0°C	1482 - Water lanced 4 Boiler T/S (87) (From no tube lane) Specimen tube and sludge removed 1700 - Tube Leak Boiler 1 1810 - Defect tube removed (88) (D20 = $0.5 E6)	10-11 kg sludge per S/G removed SG#1 - 12 hrs. SG#3 - 30 hrs. SG#2 - 48 hrs. SG#4 - 30 hrs. removed. Iron phosphate sludge. Tube corrosion - nil. Centre of hot leg - at or above TSP 1 pitting - agent unknown. CuCl2, O2 and Cl all suspected
1811-3210 (88-92)	S/G - PO4 Control FW - pH 9.5 N2H4 10-20 ppb Full flow CP C4H8NHO Cycle Fe < 2 ppb RIHT 265.4 - 267.2 ΔT 1.8 °C	2150 - Boiler 3 TSP lancing/ (90) inspection holes drilled 2850 - Intertube gap lancing (91) demonstration for Boiler 3 3148 - Tube Leak Boiler 1 3210 - Defect Tube Plugged (92) (D20 = $0.2E6) - Specimen tubes removed (Boiler 1,3) - 10 tubes plugged Boiler 1 7 tubes plugged Boiler 3 - Water lanced 4 boiler T/S (intertube gap)	TSP 9 - 9 slants HL - 5 slants CL TSP 6 - 2 slants CL All broaches clean Partial inspection of T/S lanes and TSP's Upper TSP's clean Centre of Hot leg - at or just above tubesheet pitting? Pre-lance inspection shows Boilers 2/4 less sludge than 1/3. ECT/UT shows localized indications in boiler 1/3 sludge pile regions. No indications boiler 2/4. 1-1.5 inches sludge remaining in centre of hot leg after lancing. Boiler #1 - #4 TSP#1 fouled at maximum sludge pile region. Boiler #3 TSP#5 - 1 slant TSP#6 - 5 slants HL, 6 slants CL — no fouling TSP#9 - 6 slants HL — 3 plugged broaches 5 slants CL — clean
3210- (92-	S/G - PO4 Control FW - pH 9.5 N2H4 20-40 ppb Full-flow CP C4H8NHO Cycle Fe <2 ppb RIHT 267.6		

Boiler Maintenance Dose Rates

In addition to the confined space entry concerns the maintainers also must deal with the radiological issues. Typical dose rates encountered while performing work local to the Boilers are listed in Table 3.

Table 3

Typical Lepreau Boiler Dose Rates (msv/h = Milli Sieverts per hour)

Primary head before decontamination:
- Hot leg: general fields 4.5 msv/h Beta, 1.5 msv/h Gamma
- Cold leg: general fields 8-10 msv/h Beta, 5 msv/h Gamma

Primary head following decontamination:
- Hot leg: general fields 2-4 msv/h Beta, 1 msv/h Gamma
- Cold leg: general fields 5-8 msv/h Beta, 4.5-5 msv/h Gamma

General fields in the boiler cabinet area outside the primary manway doors: 0.2 - 0.25 msv/h

Fields on top of the tube U bend:
General fields 2-3 msv/h
Tube contact fields 9 msv/h

BOILER MAINTENANCE RELATED EVENTS

A variety of events will be covered here. Vendor support to date has been provided exclusively by Babcock Wilcox Canada who on occasion has subcontracted portions of work to others (Buoy Clean for 1987 water lancing and Babcock & Wilcox U.S. for 92 inspection).

Tube Leaks

A very effective tube leak location procedure has been developed and used to locate each of the 3 leaking tubes encountered to date. In each case the tube was identified within minutes of pressurizing the secondary side fluid. The defects in all 3 tubes were pits which, unlike cracks, do not tend to close up when the tube cools. The smallest leak located was .08 kg/hr at operating conditions.

Leak Search. The technique used has the secondary side water (spiked with a fluorescent tracer) pressurized and the leaking tube located by black light inspection of the tube ends from the primary head. The tracer is readily seen as it drips down from the hole in the tube.

Pressurization of the secondary side water may be accomplished by using large air compressors to increase the pressure of the entire volume of the steam space from the Boilers to the Turbine stop valves. In this case the entire length of the main steam lines is pressurized. The Point Lepreau main steam lines run outside from the Reactor to the Turbine Building. The brittle fracture characteristics of this length of pipe (exposed to the cold April annual outage temperatures) precluded the use of this procedure.

An aluminum bung was developed to be installed in the Boiler main steam line nozzle to isolate the leaking vessel from the remainder of the system. This bung (rated for 900 kPa) is transported into the Boiler in two pieces via the secondary side manway door and is supported, once installed into the nozzle, by a jacking system which sits on the separator cyclone deck. A temporary secondary side manway door equipped with air supply connections is then installed. The small volume of air space above the water in the Boiler can then be pressurized in a matter of minutes via a small compressor located in the Reactor Building. The time expended to install the bung is offset by the time saved in pressurizing the smaller air space.

Leak Repair. The flawed length of two of the three leaking tubes were pulled from the Boiler to be analyzed. Prior to 1992 all tubes taken from service had the tube ends or tubesheet holes (vacated by pulled tubes) plugged explosively. Tubes plugged but not pulled were severed. Seventeen tubes were taken out of service in the 92 outage, two of these had sections pulled for analysis. In this case all tube ends were plugged with manually welded plugs and no plugged tubes were severed.

Contamination control is an issue when explosively plugging tubes. The particles coating the inside of the tubes (now dry after sitting in an empty vessel for several hours) become airborne as a result of the explosion shocks. Temporary primary manway door covers equipped with flexible ventilation ducts are used to exhaust the primary head air via an air mover through a HEPA filter. This has been successful in removing the airborne contamination hazard.

Water Lancing

Two methods have been used to remove sludge which has laid down on the tubesheet in the centre of the hot leg of each Boiler. In 1987, 3000 psi water sprayed from the tube free lane succeed in removing about 30% of the pile. In 1992 a lance "snaked" through the tube nest to a location right at the sludge pile surface was used. This water, jetted at a pressure of 6000 psi, removed about 60% of the remaining sludge. It is believed that the remaining 5-10 cm of hard phosphate sludge will not be completely removed by water lancing. This continues, however, to be an effective method of limiting sludge pile volume by periodically flushing away the newly laid down soft upper layer of the pile. Significant modifications were required to permit the lancing equipment to access the tubesheet sludge.

Boiler Insulation Cabinet. Doors were manufactured in the cabinet at the Boiler tubesheet level. These, when opened, provide sufficient room to operate the reamer used to drill the lancing ports in the Boiler shell also to operate the water lancing equipment. A second benefit of these doors is the increased cooling rate of the Boiler cabinet, realized due to the cross air flow they provide. These doors are opened with long handled tools immediately after station shutdown and have reduced the time to gain entry to the cabinets to start Boiler maintenance from 24 to 8 hours.

Lower Lateral Restraints. The lower Boiler lateral restraints are attached to the walls of the vessel just above the tubesheet at either end of the tube free lane. This unfortunately is the same location as the water lancing ports. The restraints were lifted during the drilling of the lancing ports. To eliminate the need to repeat this during more frequent lancing exercises, the lateral supports were modified (Figure 2). In the modified configuration, the restraint pin and bracket plates can be removed leaving the lateral support in place. The weight of the support is carried by a jack which is used to drop the component a few centimetres to line up the restraint pin hole and lancing port. At this point the lancing or inspection equipment can access the port through the removed restraint pin. The elimination of the requirement to remove the restraint saves significant maintenance time and effort.

Tubesheet Lancing Ports. A magnetic base drill was used to ream the 10 cm. diameter ports at each end of the tube free lane in all 4 Boilers. The gasket surface and bolt holes were machined into the "thick shell". No leakage from any of these joints has been experienced.

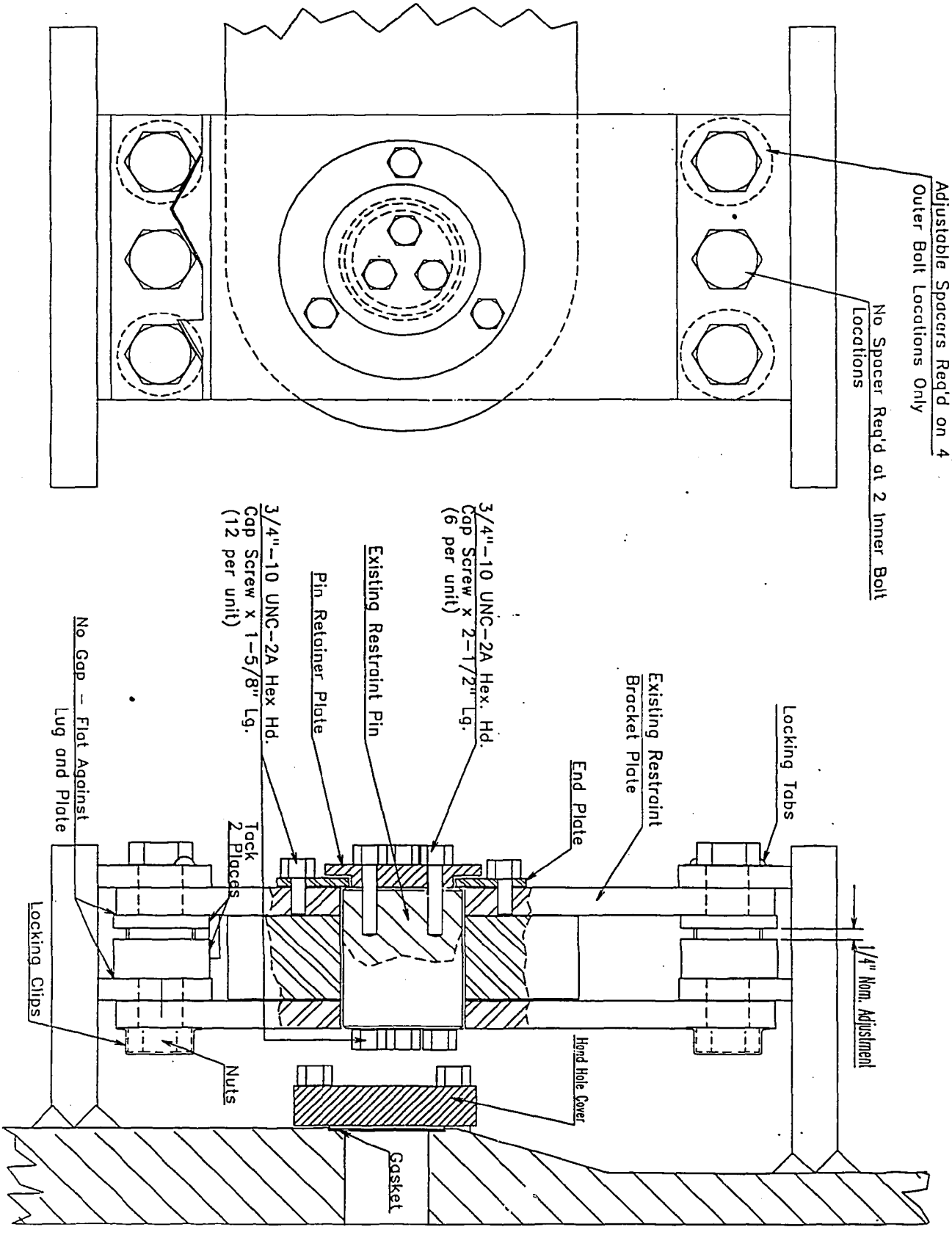
Support Plate Broach Hole Lancing Ports. Broach hole sludge plugging has been observed in the first and second support plates of Lepreau Steam Generators. Reacting to Ontario Hydro experience it was also decided to determine if broach hole plugging was occurring in the upper support plates. Three 5 cm. diameter ports were machined in Boiler 3 to permit inspection of broach holes in 3 of the upper support plates. Holes were reamed in the shell and the shroud. A saddle was welded to the Boiler wall and a gasketed cover provided. To prevent leakage from the riser to the downcover through the holes in the shroud, plugs supported by the flange cover were installed. No support plate fouling was observed and therefore no lancing was required. No flange leakage has been experienced.

Primary Head Activities

Primary access has been required to accomplish the following tasks:

- tube inspection (EC & UT)
- tube leak search
- tube removal (up to 2nd support plate)
- tube sheet and support plate sludge video camera inspection

FIGURE 2 - LOWER LATERAL RESTRAINT AND LANCING HAND HOLE



via space vacated by removed tube
- tubesheet sludge sampling using a rotating cutter inserted through the space vacated by removed tube
- tube explosive and manual weld plugging

Primary Nozzle Bung. When the Boiler is drained for primary side work the heavy water level is maintained in the headers just below the Boiler primary head. The hydraulics of the circuit are such that a single Shutdown Cooling pump trip causes the water level to rise into the head. This poses a hazard to the individual working in the Boiler also will cause heavy water to rise above the open manway level. The Mechanical Maintenance Department developed a nozzle bung to block the rise of D20 in such an event.

This bung is locked in placed by a series of pointed fingers which dig into the nozzle wall (pressure from the smaller to wider side of the nozzle). An inflatable seal is located around the periphery of the aluminum bung to achieve leak tightness. The design is such that the device can be depressurized, the fingers retracted and the bung removed in a matter of seconds in the event of a loss of heat sink.

Primary Manways. Opening and closing these doors are generally critical path activities. Each manway has an inner and outer door which is swung into or out of position by a manipulator mounted on the outside of the vessel. Seating the doors properly on the gasket surface while working in plastic suits in a confined space is a challenge. It is necessary to complete these activities efficiently to reduce the impact on the outage schedule yet it is crucial to complete the tasks effectively to avoid a future outage (with system drain down) in the event that a gasket leaks excessively.

To date each of the manway activities has been performed by crews staffed by Lepreau maintainers who have field experience installing the doors. This ties up experienced and radiation qualified staff who are needed to progress other Zone 3 work during shutdowns. A mock up will be purchased before the 93 outage to enable crews supplemented by tradesmen from the local union hall to better prepare for this task. In addition, a lighter door manipulator with greater flexibility of movement has been purchased.

Tube Bundle "U" Bend Inspection

Access to the top of the tube bundle is achieved by removing the secondary side manway door, the four removable secondary cyclones and four primary cyclones. The end of one section of dousing pipe was flanged so it could easily be moved to permit the cyclones to be lifted through the manway. The procedure has worked well. Administrative procedures are instituted to insure that tools or contents of maintainers pockets do not fall down into the tube nest. Security is provided outside the manway to limit access, to insure that equipment is logged in and out, that tools are tied off and pockets are empty or taped up.

BOILER MAINTENANCE SUPPORT ISSUES

One major component in the successful maintenance of Point Lepreau equipment is the thorough preparation and equipping of the work crews. The outage planning and management aspect of this will be described later. This section focuses on the measures taken to insure that each maintainer assigned to Boiler maintenance activities knows how to complete the specific tasks and how to react to contingencies.

Procedures

Maintenance procedures to accomplish each of the major Boiler activities are prepared by experienced mechanics. These are reviewed and modified as necessary by a Maintenance Foreman and the Technical Unit Engineer responsible for Steam Generators.

The designated primary and back up fuel cooling methods vary from outage to outage depending on the equipment being taken out of service. A comprehensive heat sink procedure is prepared for each annual outage. This procedure specifies what role the Boilers play in fuel cooling during each stage in the shutdown. It also states what steps the operations and maintenance personnel must take, in what time frame, to return the Boilers to a condition in which they may be used as a heat sink. A maintainer trained in the box up procedure is to be stationed in a low radiation field area near the Boiler at all times when a manway is open. The balance of the crew is summoned to the area by a alert signal and PA announcement on loss of heat sink. An operator is sent to the field to accept surrender of the permit when box-up is complete to expedite initiation of Boiler refill.

The Health Physics procedures used to support Boiler maintenance work are also outage specific. The Radiation Control department works with the Maintenance, Technical and Operations groups to scope the work and provide detailed procedures to deal with dose control, dose monitoring and contamination control. Specific responsibilities of Maintainers and Protection Assistants are given. Details of the access routes, rubber stations, ventilation, dosimetry, methods of decontaminating, required protective equipment and procedures for moving equipment in and out of the area are among the subjects addressed.

Training

Prior to the outage the people assigned to work on Boiler activities are attached to day or night crews. Each crew typically has representatives from the Maintenance Department, Radiation Control, Protection Assistants, a team coordinator generally an individual associated with the Boiler from the Technical Unit and often a Senior Operator assigned to deal with perimetry issues. These crew teams train together.

Training includes the following:

- mock up training on actions required to return the Boiler for heat sink use (ex. evacuation of the primary head and box up). This is made as realistic as possible and includes PA announcements and field deployment
- training and walk through on all the details of the Radiation Control procedure
- classroom training and discussion dealing with what specific tasks are to be undertaken, what the purpose of each task is and what is happening from a system perspective in each contingency. In this way the mechanics gain an appreciation for what their efforts contribute to the whole scope of the outage work. Furthermore, concerns with respect to their safety in loss of heat sink events, for example, are dealt with. Comments on procedures are solicited and incorporated when warranted. This activity has been invaluable in building team knowledge and spirit.

BOILER MAINTENANCE OUTAGE MANAGEMENT

The Point Lepreau Maintenance organization is described in Reference 1 and work planning and maintenance management in Reference 2. The preparation for and completion of Boiler outage activities represents significant commitment from the Technical, Operations and Maintenance staff. To date the Steam Generator work has been completed expeditiously and has not caused an outage to be extended.

A great deal of effort goes into work preparation to make this possible. The maintenance team approach alluded to earlier and described in more detail in Reference 3 brings the people required together. In this forum they are well prepared with the appropriate training and procedures to tackle the tasks. The team is further supported by the following outage management initiatives which contribute to a timely completion of Boiler work and good quality of maintenance.

Maintenance Shops Do Assessment of Each Job/Task to be Done.

During the pre outage period, almost as many maintainers are involved in preparing work packages for the outage as are actively maintaining the station. Each work order is assessed and a complete package identifying the maintenance procedure, parts, tools, scaffolding, etc. is prepared. The packages are usually developed with input from the Boiler Supplier and System Engineer who in turn obtains maintenance input to the work plan when it is required.

Contingency Planning.

Jobs are "thought through" with a view to preparing strategy and arranging equipment and resources in case events do not unfold as planned. A helium leak detection procedure was developed in the event that more traditional Boiler tube leak detection methods were unsuccessful, etc.

Maintenance Support Equipment Addressed Prior to the Outage.

Cranes are inspected, tooling tested and calibrated, bungs and inspection equipment organized and placed local to the job sites, etc.

The Plant is Modified to Expedite Boiler Work.

Cranes to lift equipment to and from the Boiler cabinet and permanent working platforms are added as required, systems are modified to permit jobs to go in parallel rather than series.

Pre-Packaging of Boiler Work.

As requested by the associated assessment, scaffolding is prepared and stored in a local accessible area, parts taken from stores and packaged for each job etc. all ready to be deployed at the earliest opportunity.

Maintenance Shops are Involved with the Planning Department in Developing and Reviewing the Logic Diagrams Pertinent to the Boiler Jobs.

Each activity, especially critical path and low float jobs are "critically assessed" with respect to estimated event durations. Correct sequencing of activities and potential interferences are addressed.

Licensing Issues and Heat Sinks are Rationalized to Optimize Maintenance Flexibility.

Radiation Protection Issues are Addressed in the Assessment Stage.

The number of Protection Assistants required to support contractor work and the specific role of the Assistants for each task is defined. Radiation protection safety work plans are developed, specific training provided and equipment procured. Approximately 90% of the maintenance staff are qualified to the green badge (highest) level. An efficient Primary Heat Transport Purification System and attention to the Delayed Neutron and Gaseous Fission Product Systems identifying failed fuel for early removal have kept the boiler shutdown fields relatively low.

The Outage Management Team is Put in Place Early.

The Outage Manager (a duty Shift Supervisor) and three Outage Coordinators (Senior Operators) are taken off their shift assignments 4 and 2 months before the shutdown respectively. This team reviews job plans and job packages and works with Planning to build the outage logic and with the Licensing Group to establish the heat sink criteria. This Operations team also works with the Maintenance Shop and 4 off shift outage Permit Coordinators to pre-package work permits for each job.

Liberal Attitude Towards Hiring of Knowledgeable Experts to Support Work Crews in Job Preparation and Implementation.

Babcock and Wilcox and experienced Ontario Hydro personnel have been used to prepare our staff prior to "first of a kind" Steam Generator maintenance jobs.

The Seniors and Foremen Know the Jobs for Which They are Responsible.

The Senior Maintainers (crew leaders) work directly for shop Foremen. On each of the day and night shifts there are typically 3 Foremen one for each of the Turbine/Generator, Reactor Building/BOP and Special Projects (such as Boiler jobs). The Foremen and Seniors know all jobs they are responsible for and thoroughly review the assessed work packages prior to the outage. Furthermore the Senior reviews the jobs, work locations, specific safety/radiation issues and procedures with the off site workers in their crews 1 to 2 days before the actual start of work.

Operations Support is Integrated Into the Maintenance Shops.

One Shift Supervisor or Senior Power Plant Operator is assigned to each shop working for the shop supervisors to help achieve their objectives.

This individual performs the following major functions
- helps expedite work permits and clear permitry problems
- provides Operations and systems knowledge and perspective while problem solving or deciding on best redirection in the light of new or changing information
- helps coordinate the return of maintained equipment in a sequence which is consistent with Operations needs to return systems and resupply services

Scheduling Feedback.

We actually do know on a given day whether the outage is on time and what activities must be expedited to keep the outage on time.

The progress of each crew is established by obtaining feedback on the status of each activity from the Foremen and Senior Maintainers before 7 AM. This progress, or lack of it on the major activities,

is reviewed by senior site staff at the morning planning meeting at 9 AM. Redirection of resources and technical discussion of problems are initiated at this time.

The Maintenance Group, Planning and Outage Management senior people meet at the 1 PM meeting to further update progress, schedule work for the next 24 hours and arrange for upcoming services from other groups. This is the most significant and detailed of the planning meetings, attended by people "in the know" and by field supervision sufficiently senior in the organization to make things happen.

FUTURE BOILER MAINTENANCE ACTIVITIES

Two phenomena will necessitate an expanded Boiler inspection and maintenance program in the years to come.

Reactor Header Inlet (RIH) Temperature Rise.

The licensing analysis which supports the stations operation in accident conditions was conducted using a maximum RIH temperature of 268° C. Fouling of the Boiler tube surfaces has reduced the heat transfer capability and resulted in a steady rise in RIH temperature of about 0.5° C per year. The current temperature is 267.5° C.

Boiler Tube Attack (Pitting Corrosion) Under Sludge Deposits.

Tube inspection during the 1992 outage indicated that the sludge deposits in the 1st and 2nd tube support plate broach holes and on the tubesheet (hot leg side) has started to attack some of the tubes. A number of tubes show pitting type of wall loss indications and 17 of these had sufficient wall reduction to require them to be removed from service.

Activities to Address These Issues.

A program is underway to establish the rate of tube attack, to sleeve severely damaged tubes and to remove the tube deposits. This program will place increased demand on the Boiler maintenance staff both in routine activities (more boiler entries) and new tasks (sleeving and chemical cleaning). Supplier and process evaluation is ongoing to have manipulator inspection capability by the 1993 outage, sleeving capability as early as 1993 and to conduct a chemical cleaning (full bundle potentially followed by a tubesheet clean) as early as the 1994 shutdown.

CONCLUSION

Steam Generator maintenance, to date, at Point Lepreau has been successful in supporting the required Boiler injection and cleaning activities. This success has been achieved through a combination of strong vendor support, good maintenance practices, establishment of a team approach in accomplishing Boiler projects and an effective outage management strategy.

Tube deposit related difficulties have expanded the scope of Boiler work planned for the next few years. It is anticipated that the approach to Steam Generator maintenance which has served us so well, to this point, will continue to permit efficient and effective completion of the tasks necessary to support the upcoming work.

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BRUCE NGS B
U-BEND SUPPORT STABILIZATION

G. McClellan, P. Gowthorpe, W. Schneider

Babcock & Wilcox

ABSTRACT

The steam generators at Bruce NGS B have experienced a degree of tube fretting at the U-bend scalloped bar support locations. Investigation attributed the tube fretting to flow induced vibration induced wear as a result of U-bend supports which were too widely spaced (compared to current criteria) and insufficiently rigid. The paper describes the problem, the development of a stabilization configuration, its qualification, its installation tooling and procedures and the installation of the initial trial assemblies.

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U-BEND SUPPORT STABILIZATION

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INTRODUCTION

The steam generators of the Bruce B generating station have experienced a degree of fretting at the U-bend support locations. Investigation of the problem, the development of a stabilization device and its trial installation was as follows.

BACKGROUND

The Bruce B steam generators each have 4200, Alloy 600, ½ inch tubes supported by carbon steel broached support plates at seven levels. The U-bends are supported by carbon steel, scalloped bar supports at three locations ie. at 40°, 90° and 40° to horizontal (Figure 1).

The scalloped bars are made by stacking rectangular bar stock and then drilling at the parting lines in such a way that each bar has "half holes" along its upper and lower surface. After drilling, the holes are "hourglassed" (conically relieved from both sides) so that the net tube support land is 0.10" wide over the circumference of the hole. On installation successive bars are then positioned between successive tube rows. The bar dimensions are such that if they are stacked in line (as drilled and as installed at Bruce A), they form a solid stack. The freedom of the tubes in this case is then limited to the tube to tube hole clearance which is nominally 15 mils diametral. The successive bars at Bruce B were offset from each other as shown in Figure 2, but the tube positioning remained the same. In this way the tube to hole clearance was maintained throughout the assembly. Because the bars were out of line, the tubes could move slightly within their clearances in the bar holes but the bars could also move slightly.

The objective in offsetting the U-bend bars was to provide a more open U-bend support which would allow some flow to pass through the assembly and to thereby minimize the potential for deposit build up and the potential for under deposit corrosion. A further objective was to make the individual tubes more free to absorb tube to support thermal motions during heat up and cooldown.

The U-bend support bar stacks are supported by the tubes and restrained by three tined bars or "forks" which keep the scalloped bars from moving along the tubes. The three bar stacks are spaced relative to each other by peripheral "tie bars" which are parallel to the tubes. There is no connection between the U-bend support assemblies and the shroud so that the U-bend assembly as a whole supports itself under handling or seismic loads.

During inspection of the Bruce B - Unit 6 steam generators in 1989, it was noted that the U-bend support bars appeared to be surprisingly loose and free to move about within their constraints. This observation led to further visual and eddy current testing which revealed that

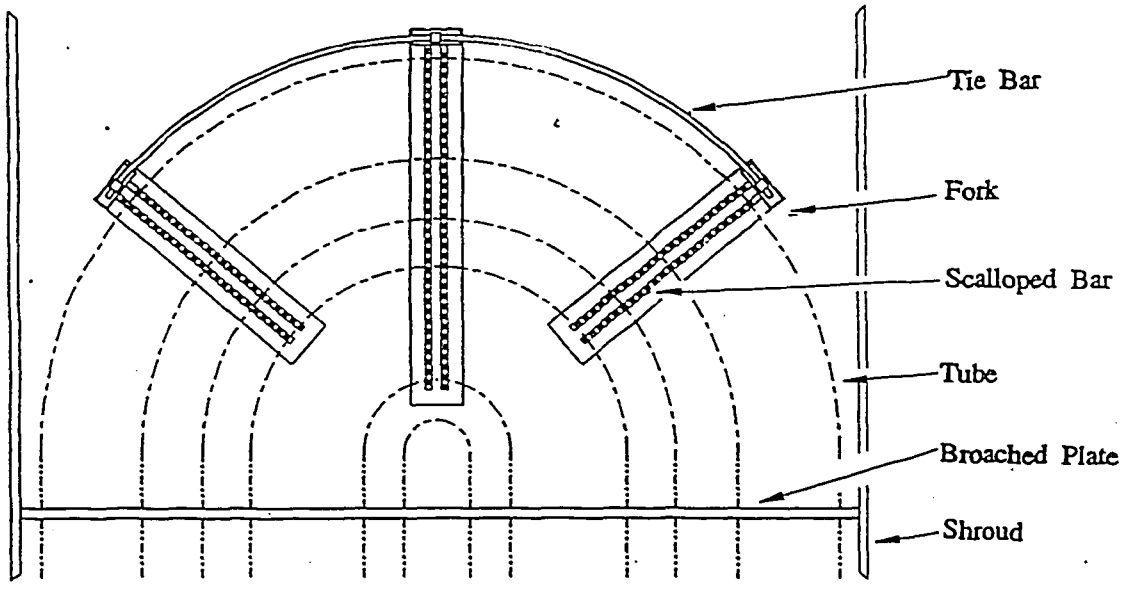

Figure 1: Bruce B SG Existing U-Bend Support

a significant number of large radius tubes had experienced some degree of fretting at the U-bend support locations.

Extensive inspection of the Bruce B steam generators was performed in the ensuing months. The results generally showed

- fretting damage had occurred at the U-bend support locations in a large number of tubes in the outer 15 rows
- a number of additional indications occurred deeper into the bundle
- no indications were seen at the broached support plates
- all four reactor units had indications despite variations in operating time
- a small number of indications exceeded 40% through-wall. None exceeded 60%.

VIBRATION

The presence of fretting at the tube support locations is a clear indication of the presence of flow induced vibration (FIV). Flow induced vibration may result from an inadequate number or location of supports or from ineffective supports.

The positioning of the supports is determined by FIV analysis. FIV analysis includes analysis of flow rates and flow distribution using a 3D thermal-hydraulic code, the analysis of mode

shapes and the determination of response to random turbulence in the flow (RT) and susceptibility to fluid elastic instability (FEI). This is a linear analysis and assumes idealized supports ie. supports which are rigid and either pinned or fixed. The adequacy of a design is judged in terms of not exceeding certain RT response and FEI criteria.

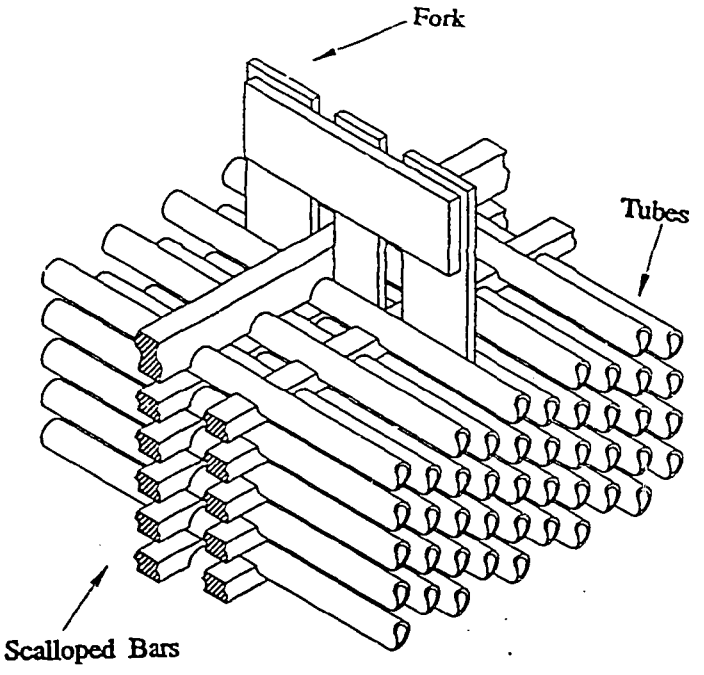

Figure 2: Existing U-Bend Support Detail

The Bruce B support locations were set in 1976 based on the apparent adequacy of the Bruce A design. Bruce A supports were confirmed by what was in effect the prototype FIV analysis performed in 1971. That analysis (1) used methods which were much the same as current methods. There are however very significant differences of detail. In particular, the Bruce A analysis used an average U-bend flow distribution. Current analysis (3) is based on detailed 3D flow analysis (2) which predicts very high local velocities just below the 40° U-bend supports. In addition, current FIV analysis uses a much lower damping value than the earlier work. As a result, while the original Bruce A analysis showed the design to be adequate, the current analysis shows the support locations to be inadequate ie. inadequate in that the current design criteria are exceeded.

The above assumes idealized, effective supports which are rigid and with small controlled clearances. The Bruce B supports proved not to be fully effective. Because of the offset bar arrangement and the larger than anticipated tube to bar and bar to fork clearances, the bars were free to move about somewhat. In this situation, the tubes and bars were both able to respond to the flow either individually or in some sort of combined response. In this situation, the tubes are not effectively supported. Furthermore, both tubes and bars may be responding to the flow simultaneously.

The existence of this combined type of tube and bar response was demonstrated in testing at Chalk River Laboratories (CRL) (4). These tests simulated two phase (air-water) flow conditions over Bruce B type U-bends with various support conditions. Tests were performed with rigid (ideal) scalloped bars, loosely restrained bars (looser than at site) and loosely restrained bars but with flat bar supports added. The first test showed that with rigid supports, the tubes responded at the expected frequencies and within narrow frequency bands. The second test showed that with loosely held bars, the response was of a higher magnitude and a very

broad band ie. the response occurred over a wide frequency range and included a large amount of low frequency rattling. The test also showed that at high flows, the bars would move about and even levitate in the flow. This test verified the ineffectiveness of loose supports and showed that some kind of combined tube/bar response could occur. The first test showed that stabilizing the bars would reduce the response and restore the expected mode shapes.

The third test with flat bars added showed that the response level was reduced below that for one rigid scalloped support and that the frequency levels were shifted upward. It still exhibited some of the low frequency rattling because the scalloped bars were still loose. Unfortunately the fourth case of rigid scalloped bars with flat bars added was not run. This would have verified the performance of the combined scalloped bar stabilization/flat bar addition concept which was ultimately selected.

Given the above and the extent of the observed fretting indication, several stabilization concepts were developed. In the early stages it was felt that doing anything to correct the looseness of the scalloped bars would be impractical - particularly at the 40° supports which are much more difficult to get at than the 90° supports.

In the first concept which evolved, the 90° supports would be somehow stabilized and flat bar supports would be added above and below the 40° support. These corrections would be extended from tube row 95 at the bundle O.D. down to about row 55. In this way most but not all of the defects would be covered. The defects not covered were expected to benefit from the general stiffening of the bundle.

As work progressed, the feasibility of stabilizing the scalloped bars was seen to improve and the awkwardness of adding anything below the 40° supports became more apparent. Ultimately two stabilization concepts evolved - the partial fix and the full fix. The partial stabilization concept consisted of stabilizing the scalloped bars at the 40° and 90° locations. This was done by inserting the rather unique auxiliary forks so as to restrain and space the scalloped bars. The intent of the partial fix is to restore the FIV effectiveness of the existing scalloped bars by making them rigid and by correcting the tube to support clearances. While improving support effectiveness, it will not bring the support positioning within current design parameters. It is nevertheless possible that it will stop the problem given that there is a degree of conservation in the design methods and criteria.

The full fix incorporates the stabilization of the partial fix along with the addition of an assembly of flat bar U-bend supports at the 55° location. The flat bar assembly consists of two sets of flat alloy bars which are inserted between the U-tubes at the 55° points ie. one set above each of the two 40° supports. The flat bars extend in to row 55. The bar thickness (.173") is selected to provide a small tube to bar clearance (0.006" nominal). The bars are clamped at their outer ends by an arch bar assembly which controls the bar positioning and spacing. The flat bar/arch bar assemblies and the existing scalloped bar supports are positioned by new heavier tie bars. The full fix restores the effectiveness of the supports and it also brings the support positioning within the current design criteria.

In order to evaluate the above, a partial and a full fix were qualified and installed as described

below. The existing defects in these SG's and in other unmodified SG's are being monitored to determine the need for installation of any type of fix and also to determine the effectiveness of these two candidate fix concepts.

STABILIZATION SYSTEM CONFIGURATION

The full fix hardware (Figure 3) is designed to provide additional tube support locations at 55° and to make the existing supports at 90° and 40° more effective. The hardware is designed to be mounted off the original U-bend support system in a very tight space envelope in a minimum amount of time in order to limit radiation exposure to installation personnel. In addition, the design was to include features that make removal practical, (which precluded a fully welded structure). The new hardware incorporates several design features to accomplish this.

The new support system consists of the following main components and assemblies:

auxiliary forks, Figure 6
tie tube/connecting tower assemblies, Figures 4 and 6
arch bar assemblies, Figures 4 and 5
stainless steel flat bars, Figures 3 and 5

The auxiliary forks are designed to be installed adjacent to the terminal points (Figures 3 and 6) formed by the removal of the original 1/2" diameter tie bars. There are six terminal points for each of the three scalloped bar supports. The auxiliary forks re-space the scalloped bars and stabilize them. They are also important in carrying the dead weight of the new hardware.

The tie tube assemblies (Figure 4) are equipped with adjustable connecting tower assemblies (Figure 6) so that the new tie rod assemblies can be mounted to the 18 terminal points even if the existing forks have moved as much as 1/4" relative to each other from their original design positions.

The arch bar assembly (Figure 5) is equipped with adjustable tie tube connection lugs for attachment to the tie tube assemblies and to allow for lateral adjustment so that the flat bar slots in the arch bars can be aligned with the tube bundle lanes below. The flat bars are thus aligned for installation into the lanes between rows of tubes.

The design of the arch bar assembly minimizes the potential for loose parts. The assembly, complete with all fasteners and locking devices, is factory assembled. Only the tie tube connecting lug bolts need be assembled while inside the steam generator.

The arch bar design provides for flat bar insertion, tightening of flat bar locking screws and positive locking of the locking screws by remote tooling from above.

All other fasteners are equipped with locking tabs affixed to the main assemblies to preclude loose parts falling into the bundle during assembly. All flat bars and auxiliary forks are equipped with design features so that they cannot, if they become loose during assembly, slide too far into the bundle.

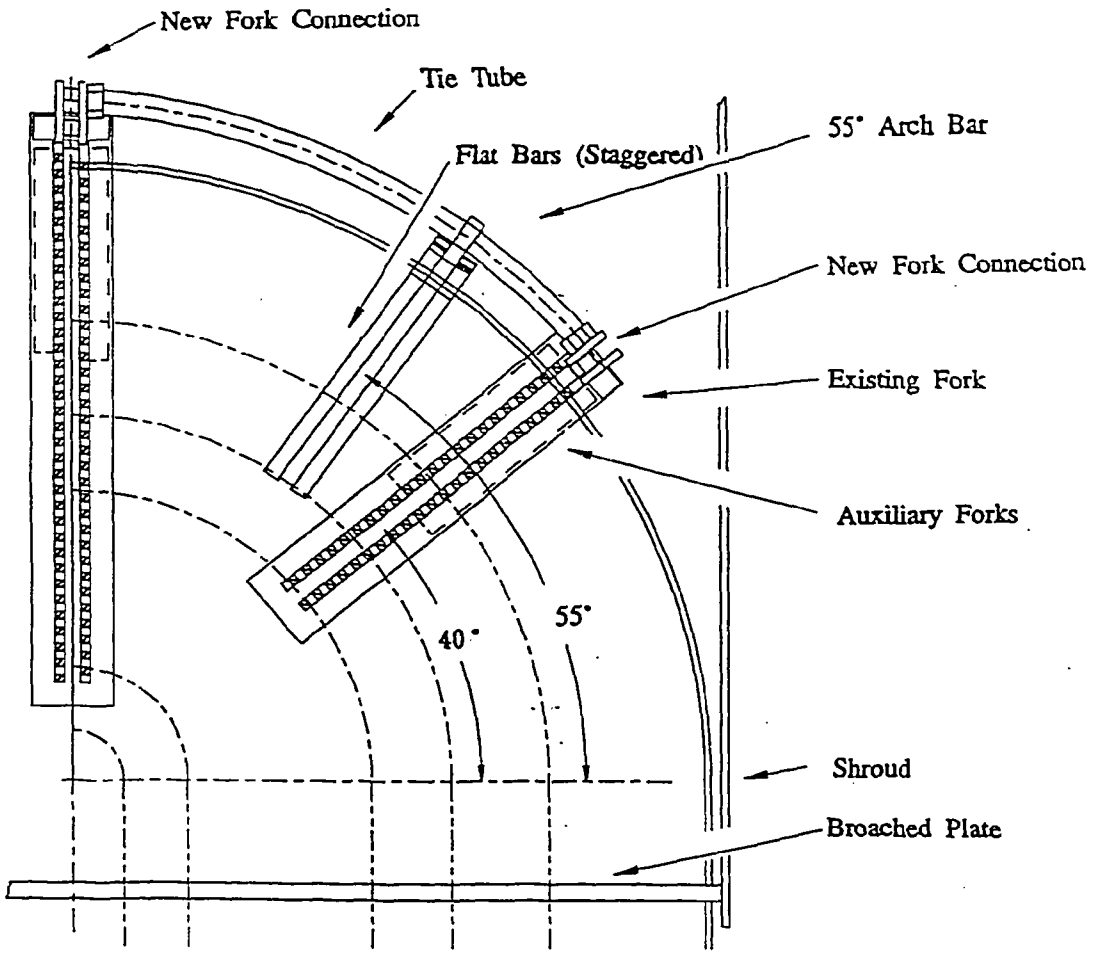

Figure 3: Stabilization Arrangement

ANALYTICAL QUALIFICATION

The addition of the full fix hardware adds a considerable amount of extra weight to the U-bend region of the steam generator (860 lbs). This raises concerns with respect to the structural integrity of the new U-bend support structure as well as for the existing structure and of the U-tubes themselves. With respect to the tubing it is known that significant tube fretting already exists and therefore any analytical consideration of the tubing should take into account the original tubing condition as well as the degraded condition.

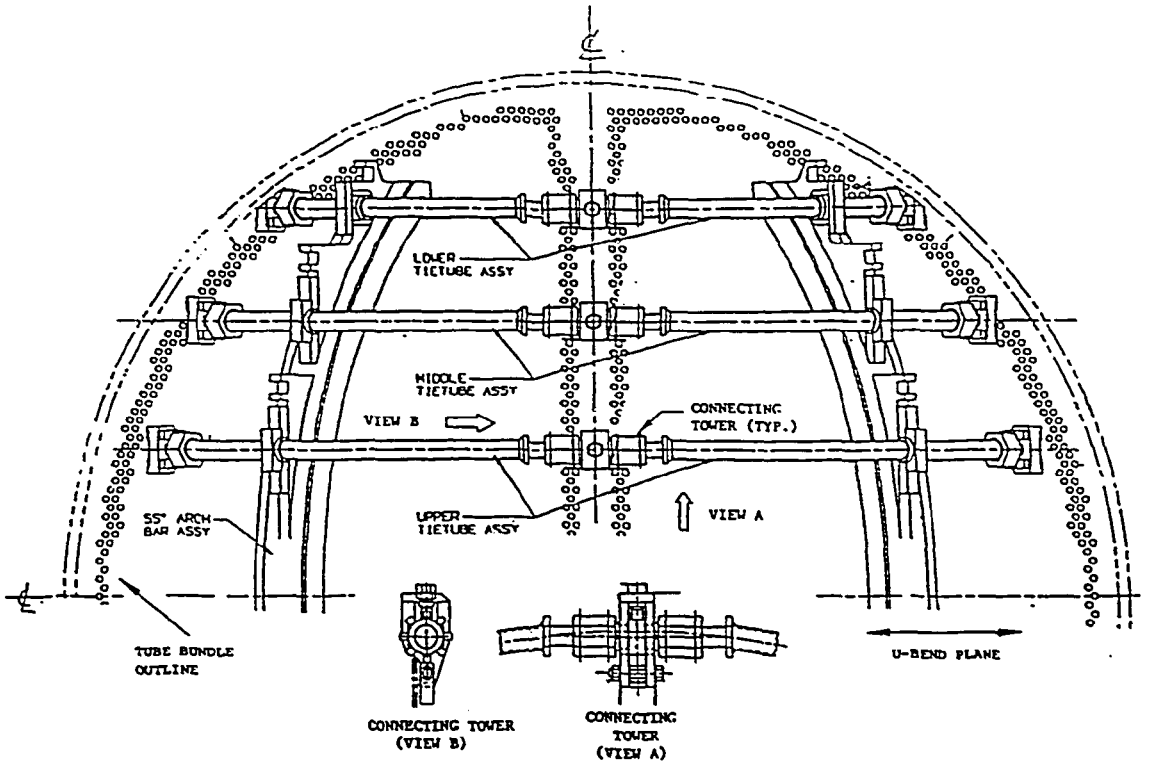

Figure 4: Arch Bar / Tie Bar Assembly

In order to qualify the U-bend support system modification a complete structural analysis was carried out to evaluate the structural strength of the fix hardware and the U-bend tubing in its original and degraded conditions.

The acceptance criteria used for the added hardware was that support components must sustain all service loading, including seismic and burst pipe loading, without damaging the tubing and that no loose parts be created.

It was also a requirement that tube to scalloped bar clearance in the U-bend region must not increase significantly during operation due to weight added. With respect to the latter this was a matter of distributing the dead weight to as many tubes as possible. Placement of the auxiliary forks adjacent to the existing forks was found to be a very important factor in spreading these point loads to many tubes and in controlling scalloped bar stresses to acceptable levels.

Although the U-bend support hardware components are not pressure boundary, the acceptance criteria and general methods of ASME Section III Div. 1 Subsection NB were used as a means of showing that the support components met the criteria of "no tube damage" consistent with the acceptance criteria of the original steam generator design analysis. Components stressed higher than these limits were considered acceptable if it was shown by test or otherwise that no tube damage would occur and no loose parts were created as a consequence of the overstress condition.

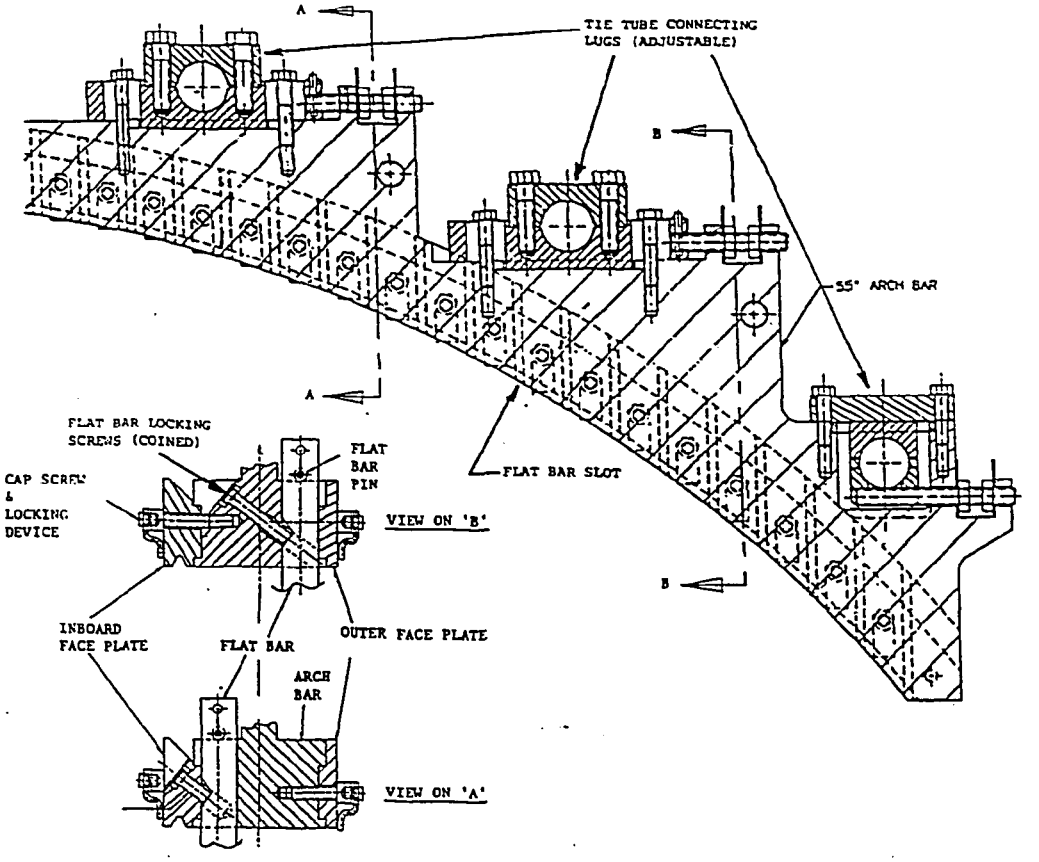

Figure 5: View of 55° Arch Bar Assembly

The acceptance criteria used for the tubing in the degraded condition was ASME Section III, Div. 1, Subsection NB.

The loading considered includes:

(1) Design loading caused by weight added.

(2) Seismic loading from DBE (Design Basis Earthquake).

(3) Burst steam line loading which may result from ruptured steam outlet nozzle piping.

(4) Thermal differential expansion loads during warm-up and start-up.

(5) In-service/Out-of-service (IS/OOS) tubes.*

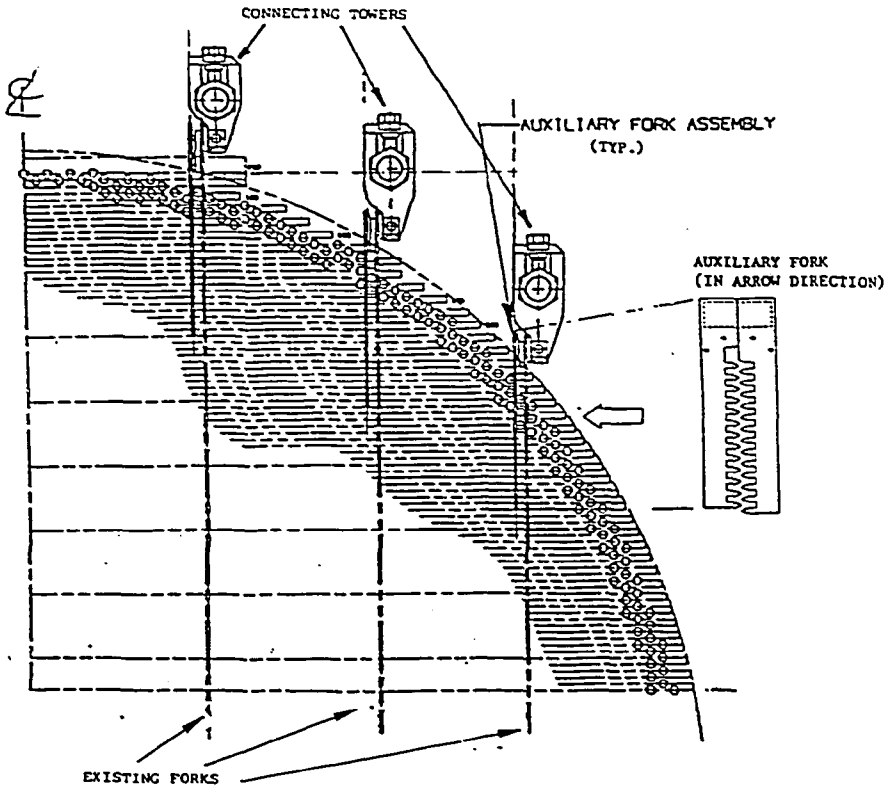

Figure 6: Tie Tube / Tower / Fork Assembly

The components that were analyzed include the following:

- scalloped bars
- scalloped bar fork assemblies
- auxiliary forks
- U-bend tie tube assemblies
- flat bars
- arch bar assemblies
- all connecting lugs, clamps, and bolting
- tubes in the original and degraded (fretted) condition

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* IS/OOS loads were not considered in the degraded case since no tubes were plugged adjacent to fretted tubes.

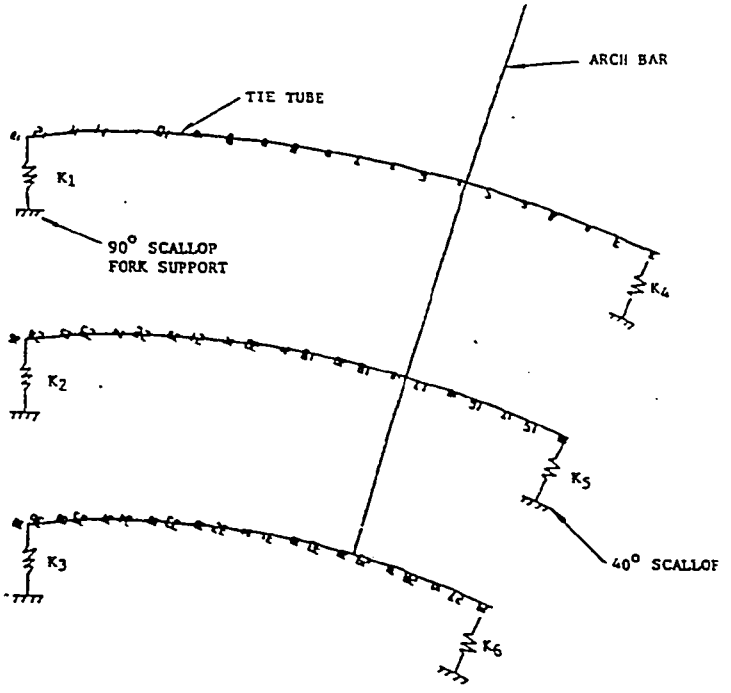

Figure 7: Quarter Symmetric Model of Stabilization Arrangement

The tube bundle and the new U-bend support system form a complicated structure with many components. Relatively simple but conservative 2-D and 3-D finite element models were utilized to simulate the interaction between the tube bundle and support system caused by the loading conditions.

Of particular interest is the distribution of the 860 lbs of deadweight into the bundle. This is a considerable increase in the weight to be carried by the U-tubes. Its distribution into the bundle must be accomplished without overstressing scalloped bars and U-bend tubes involved in the load path. Figure 7 is a quarter symmetric finite element beam model of the 'fix' hardware. It is made up of one half of an arch bar connected to three half tie-tube assemblies. The deadweight of the flat bars is modelled by distributing their weight over the arch bar. Springs K_1 through K_6 are located at the terminal points discussed earlier and represent the flexibilities of the scalloped bars, auxiliary forks and U-tubes involved in the load path.

In distributing the 860/4 lbs of deadweight of the model, the tie tubes undergo bending deflections and the springs K_1 through K_6 deflect (compress) vertically. The springs K_1 through K_6 thus model the movement, under dead load, of the terminal points. The determination of the stiffness of K_1 through K_6 takes into account deflections of scalloped bars and the sharing of the load by the tubes along scalloped bars represented by the forces in springs K_{tube} as well as tubes

deep into the bundle represented by the force in $K_{auxfork}$. Using unit deflection δ on the models of Figure 8 yields the values of K_1 through K_6. From the analysis it was shown that the main load path is through $K_{auxfork}$ since the auxiliary forks Figure 6 distribute the load deep into the bundle to many scalloped bars and tubes directly below the terminal points.

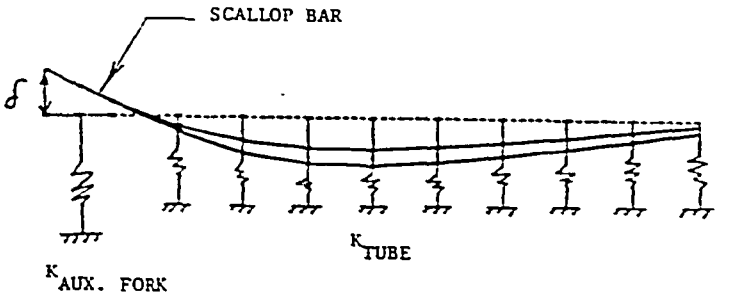

Figure 8: Scalloped Bar Deflection Model

Using the forces from K_1 through K_6 the scalloped bar stresses and stresses in degraded tubes caused by deadweight were calculated and found to be acceptable.

FABRICATION

Components

All of the components for the Bruce NGS "B" U-bend fix were fabricated in the Babcock & Wilcox (B&W) main shop to a CSA Z299.3 quality assurance standard. In order to comply with the relevant codes and B&W's own standards, strict quality assurance procedures were followed through out the entire process. Each component is supported by documentation in the manufacturing history docket including material test reports, material inspection data, route sheets and the relevant non conformance reports. With the fix installation, a complete history docket was given to the customer containing all of the above for each component.

Due to the complexity of the components, a great deal of engineering had to be put into the tooling used for the manufacture. Of all the components in the U-bend fix, the arch bar assembly (Figure 5) was by far the most complex. Three arch bars were manufactured so that the tool engineering department could perfect the process on one arch bar before fabricating the two needed for the full fix. By the time the process was perfected, each arch bar needed seven jigs to create the very impressive final product.

The auxiliary forks (Figure 6) were also complex to manufacture. In order to find the best process for their manufacture, drawings were taken to several local vendors. The vendors who claimed they could hold the tolerances and provide a product to the strict requirements were given the opportunity to produce several trial pieces. One vendor used a laser cutting method while the other vendor used a travelling wire EDM process. The laser cutting was unable to hold the tolerances to the desires values. The EDM product was excellent. All of the tolerances were met and the quality was well within standards. For the production forks, B&W supplied a CAD file to the vendor which he used to manufacture the parts. Upon completion, each fork was inspected by a quality assurance inspector. Very few pieces were rejected.

At the same time that the real components were being made, a complete set of mockup components were fabricated by local machine shops. The only components that were not fabricated as mock ups were the arch bars and the auxiliary forks. The arch bar that was used to set up the process and the forks that were out of tolerance became training tools. The use of mockup components was very critical to the development of tooling.

U-Bend Mockup

In order to effectively simulate the work environment, a full sized steam generator U-bend mock up was fabricated. The mockup scope consisted of the entire region from the seventh support plate up to the primary cyclone support deck. The mockup tube bundle incorporated approximately 1000 tubes with one half of the mockup extensively tubed and the other half having only peripheral tubes. The mockup proved to be invaluable as a training and design tool.

The fabrication of the mockup took place in B&W's main shop using many of the original steam generator drawings. During assembly, a great deal of care was taken to recreate the support conditions of the scalloped bars including the scalloped bar looseness due to assembly clearance. This looseness was crucial for tooling development. The one major difference between the actual generators and the mockup was in the support plate. In the mockup the U-bend tubes are expanded into drilled tube holes. The actual steam generator has a broached plate that acts as a guide only and not as a fixed support. This difference was unavoidable but does not affect the tooling significantly. The shroud was made according to actual generator drawings and included the complete primary cyclone support deck and a chute that simulated the access through the steam drum manway and the steam separators. This was needed in order to create the actual access conditions to the work area which enabled personnel to get an accurate picture of the space available. The entire mockup was completed in approximately four weeks from support plate drilling to final assembly.

Work Platform

During the initial stage of contract negotiation, it was evident that some form of platform was needed for two reasons; (i) to act as a level work surface; (ii) to reduce the amount of radiation exposure to personnel working in the U-bend area. One of the main challenges in designing the platform was how to fit a 6' diameter platform through a 18"x22" oval manway. The solution was a segmented design that could be assembled inside the boiler.

The body of the platform is constructed from curved channels situated around a central beam. Each connection is pinned for ease of assembly. Inside each of the frame openings, are a series of bottom plates, two layers of 1/4" thick lead cut to match the shape of the plates and a series of top plates. Multiple plates were used so that the weight of any one plate was kept to a minimum. In addition, the multi-plate design allows for the removal of a minimal amount of shielding in order to gain access to the work area, so that maximum radiation protection is maintained.

One of the most important concepts behind the platform is the method of installation. The procedure for the installation was laid out in such a manner that the radiation exposure is kept

to a minimum. As the platform is assembled, a shielded work space is created which increases in size as the assembly progresses.

Tooling

The tooling design component of the contract was very challenging. Each tool was custom designed for its application and designed in such a way as to minimize radiation exposure. For this tooling development, the full sized mockup was invaluable. The mockup became the ultimate test for any design; ie. is it a practical approach; does it fit as expected; does it work?

One of the most unique tools, developed for the fix, was the 40° auxiliary fork insertion tool (Figure 9). A major concern with this tool was the location in which it had to be used. The middle 40° auxiliary fork location comes within 4" of the generator shroud. As with all of the tools, the 40° auxiliary fork insertion tool was modeled with the U-bend on a three dimensional CAD system so that any interferences could be found prior to manufacture. Further development of this tool was accomplished by testing through the platform on the mockup.

The 40° insertion tool needed to be able to supply a large force to the auxiliary forks so that they would be pressed into place. The most effective way to do this turned out to be hydraulic force. The space constraint meant that the tool could not be placed directly over the fork location but had to fit within the shroud. In order for the auxiliary forks to be inserted correctly, they had to be brought together linearly which contradicted the motion needed to get the tool into the location. This problem was overcome by the pivoting jaw design. The jaw pivots until the tool can be positioned over the existing forks, then by engaging the linear bearings, the tool clamps linearly to press the forks into position.

Many other types of tools, ranging from saws to nut runners, were developed to complete the installation of the full and partial fixes. Each tool was modeled in three dimensions and then tested and refined on the mockup. In addition to the custom tooling, a large quantity of camera equipment was developed and used for the site work. Cameras were used to verify locations and fits as well as to provide a view of the work taking place. In many instances during installation, the cameras allowed supervision and problem solving to be done from outside of the steam generator.

INSTALLATION

During November of 1991, the first installation of U-bend fix components occurred. This first installation was a partial fix installed in Unit 6 Steam Generator 7 and consisted of only the scalloped bar stabilization components. Prior to mobilization for site work, all of the personnel involved were subjected to an intensive training program. Each person on each crew was given a complete set of the procedures and expected to read and learn the steps. The procedure steps were reinforced by hands on training. For two weeks, the crews practised the complete job on the mockup. The platform was assembled, removed and then reassembled until every person had confidence in the task. Auxiliary fork tooling was used during the training as it would be at site. Due to the awkward weld locations, all welders were required to practice the welds they would be expected to perform. The training was intensive and largely responsible for excellent

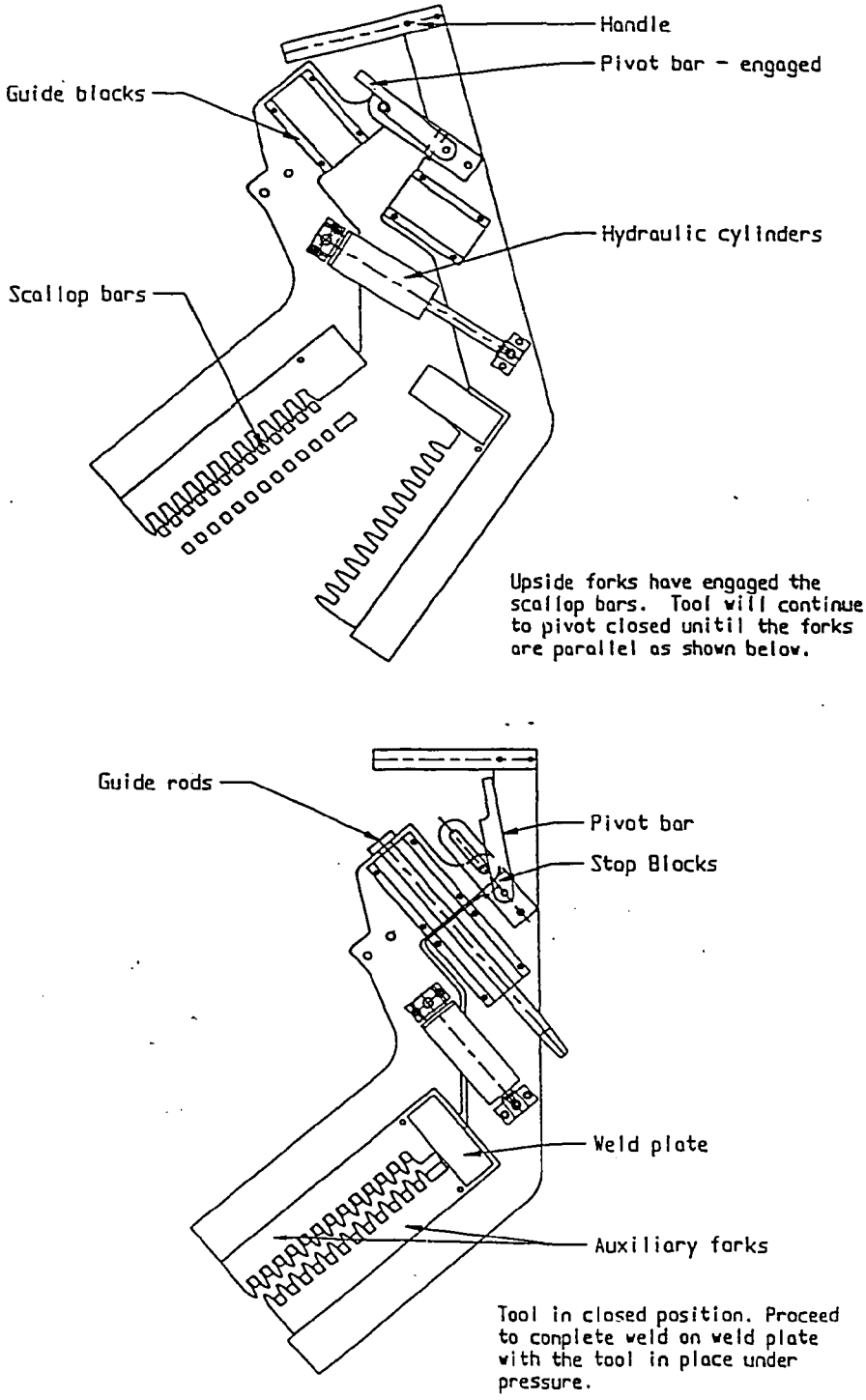

Figure 9: 40° Auxiliary Fork Insertion Tool

progress on the job. The installation was completed without any significant problems in less than a week. A major reason that the job progressed flawlessly, was the fact that all of the people involved had a large amount of training on the U-bend mockup using all of the installation tooling.

In April 1992, a full U-bend fix was installed in Unit 5 Steam Generator 6. As with the partial fix, the full fix installation progressed reasonably smoothly thanks mainly to the same type of intensive training used for the partial fix. Over the entire job only two minor non conformance reports (NR) had to be filed. One related to one of the existing forks which could not be properly restored to its original position. The other was a result of the first. A small amount of material had to be removed from a 40° tower so that it would fit on to the fork. Apart from these two minor incidents, the job proceeded as planned. The work was completed in ten (10), twenty four (24) hour days, which was considerably quicker than was expected. By completing the job at an accelerated pace, the total dose uptake was also kept to a minimum.

With all site work, there can be significant time and dose savings as the job progresses due to the natural learning curve. For the full fix, this was quite evident. Many of the steps laid out in the fix installation procedures are repetitive and could be refined as the job progressed. It became clear that changing the position used to perform a task or placing lead shielding on the bundle in the work area would keep the dose uptake to a minimum. The estimated dose uptake was over 16 Rem for the job but through common sense and awareness of ALARA principles, dose uptake was kept below 10 Rem.

CONCLUSION

In response to the fretting which has been observed in the Bruce NGS B steam generator U-bends, two stabilization concepts have been developed. The two concepts, referred to as the partial and the full fix concepts, have now been designed, analyzed, manufactured and installed. They are now under ongoing observation to track the development of the problem with and without these additional supports and to determine whether or not the partial fix is sufficient.

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VALVE PACKING QUALIFICATION FOR IMPROVED PLANT AVAILABILITY

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ABSTRACT

The success of using live-loaded valves in CANDU NGS is well documented; however, the specified packing material was JC-187I. The loss of asbestos-based packing products, such as JC-187I, generated a renewed effort by AECL and Ontario Hydro to review the valve packing specifications. The increased pressure to improve plant availability and the uncertainty of the new packing products being developed by the packing manufacturers required immediate action by AECL and the CANDU Owners Group (COG) to address this issue.

This paper describes the successful proactive approach taken by AECL and Ontario Hydro to improve plant availability of CANDU Nuclear Generating Stations through an integrated valve packing retrofit program. The paper provides details on the packing qualification efforts for combi- nation die-formed graphite for single- and double-packed config- urations including functional performance parameters of stem friction, leakage and in-service consolidation.

VALVE PACKING QUALIFICATION FOR IMPROVED PLANT AVAILABILITY

J.A. Aikin[1], C.R. Lade[1], R.G. McCutcheon[2], B.W. Bagshaw[3]

INTRODUCTION

There is a growing concern throughout industry regarding the consequences of valve stem packing leakage. Environmental concerns and clean air legislation require improvements in valve stuffing box performance. The cost of shutting down revenue-producing equipment to repack key valves is high. In normally inaccessible or hazardous areas, the cost of valve maintenance and repair in terms of safety and radiation and toxic gas exposure is even higher. The need for reduced plant emissions requires changes in the way industry approaches valve maintenance.

The restricted use of asbestos-based valve packing products provided investment incentives for the packing manufacturers to develop replacement products. This necessitated increased testing and qualifying of non-asbestos-based packing products [1-4]. These studies have shown that, with proper application, a five-ring combination die-formed graphite packing set (three die-formed rings bracketed by two braided end rings) is capable of providing reliable sealing for a wide range of valve and stuffing box designs (Figure 1).

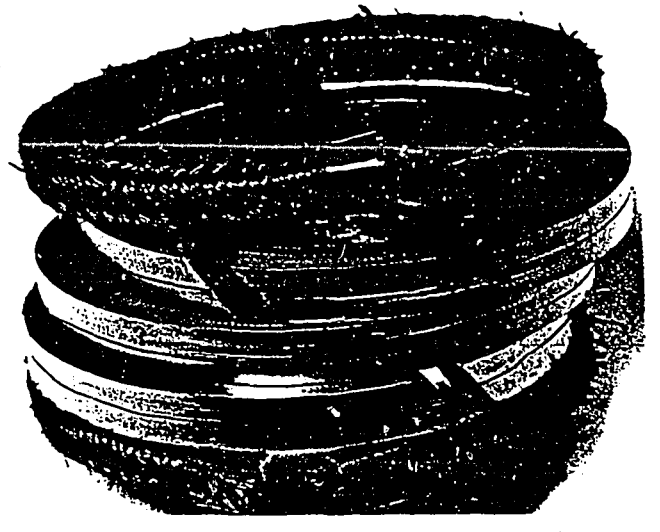

FIGURE 1:
Photo of a Standard 5-Ring Combination Die-Formed Graphite Packing Configuration with Braided End Rings.

[1] AECL Research, Chalk River Laboratories, Chalk River, Ontario

[2] Ontario Hydro, 700 University Avenue, Toronto, Ontario

[3] Ontario Hydro, Bruce NGS-B, Tiverton, Ontario

CANDU Nuclear Generating Stations (NGS) pose a special valve packing challenge. The standard five-ring combination graphite packing arrangement will not fit existing double-packed stuffing box depths. These were designed for three rings of JC-187I below the lantern ring and two rings above (Figure 2). Therefore, there is a need to identify and qualify available non-asbestos products to replace the asbestos packings used in the primary heat transport (PHT) valves in CANDU NGS.

This report outlines the work done on these products by AECL Research, Chalk River. A brief statement on braided non-asbestos products is provided. The focus of the text is on the qualification testing done with combination die-formed flexible graphite configurations. The report includes studies funded by AECL Research, the CANDU[4] Owners Group (COG), participating packing manufacturers and utilities. A description of the test programs and a summary of the performance results on selected die-formed graphite configurations is provided.

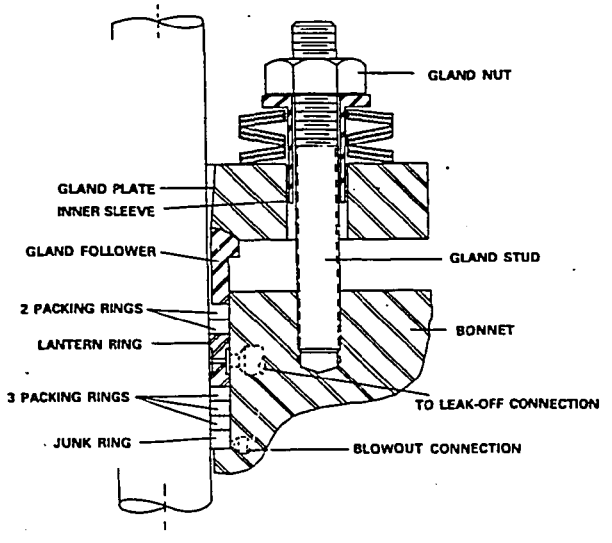

Figure 2:
Standard Double-Packed Configuration Used In CANDU PHT Valves.

PACKING MATERIAL QUALIFICATION

Valve packing qualification can be viewed as a first step towards leak-free valve performance. Historically, packing recommendations by some packing manufacturers have been unreliable, and there are no standards for comparing manufacturers' claims.

[4] CANada Deuterium Uranium. Registered trademark.

Therefore, there is a need to verify manufacturer's claims.[5] To address this need, AECL Research and Ontario Hydro (OH) established functional performance testing specifications for valve stem packing materials[5,6]. The purpose of the qualification testing is to ensure that the following requirements are met:

(a) Packing rings must not induce unacceptable levels of corrosion of the valve stem, stuffing box or gland follower.

(b) Packing rings must not introduce excessive amounts of corrosive materials into the system fluid.

(c) Packing rings must be compatible with heavy water at operating conditions of 10.3 MPa (1500 psi) and 295°C (560°F). Expected radiation exposure will exceed 2×10^5 Rads.

(d) Packing rings must retain elasticity (not harden) when exposed to the operating conditions given in (c) above.

(e) Packing rings must show minimum relaxation with time. Exposure to pressure, temperature and operating loads must not cause them to collapse.

(f) Packing rings must not induce excessive stem friction at operating conditions and under effective sealing loads.

In the future, all packing used for critical service in CANDU stations must be qualified to these standards. The qualification tests are performed at a facility acceptable to the station and include a bake test, load testing, chemical analysis and corrosion testing. Packing products that meet the specified qualification test requirements are then tested in a valve packing endurance test rig for short- and long-term stroke testing.

Valve Packing Endurance Test Rig

The AECL Research rig used in qualification testing simulates two large gate valves. It is designed to allow accelerated life-cycle testing of various packing systems, with and without live-loading, under controlled and repeatable conditions (Figure 3). The rig is fully instrumented, and all critical parameters are monitored to provide engineering data for quantifying performance. The stem diameter, for the qualification tests, is 76.2 mm (3 in.), and the stuffing box can accommodate a compressed packing height of 102 mm (4 in.) of 9.5 mm (3/8-inch) packing. The stem is actuated hydraulically and has a maximum stroke length of 35.6 cm (14 in.). The two endurance rigs are identical and designed for independent operation, allowing simultaneous evaluation of the packing to be conducted

[5] A packing qualification procedure that qualifies valve packing by valve size is being reviewed by the Manufacturers Standardization Society (MSS).

(using the same or different packing and the same or different test conditions).

Operation of the test rig and data collection are handled by a Keithley 500 Scientific Work Station, a microcomputer-based system. The workstation is programmed for two modes of data acquisition: "dynamic" and "static". During the cycling (dynamic) mode of the endurance test, the system will monitor key data, including packing consolidation, stem actuation forces and packing leakage. During the static or shutdown mode, the work-station controls and/or monitors system conditions, packing consolidation, and leakage.

The operating conditions simulate nominal CANDU PHT conditions (10 MPa (1450 psi) at 295°C (563°F)). The gland pressure is set at 26.2 MPa (3800 psi). (Applied gland pressure above 26.2 MPa has been demonstrated to cause fracture of end ring materials.) The test fluid is distilled lithiated water at pH of 10.5, O_2 < 100 ppb.

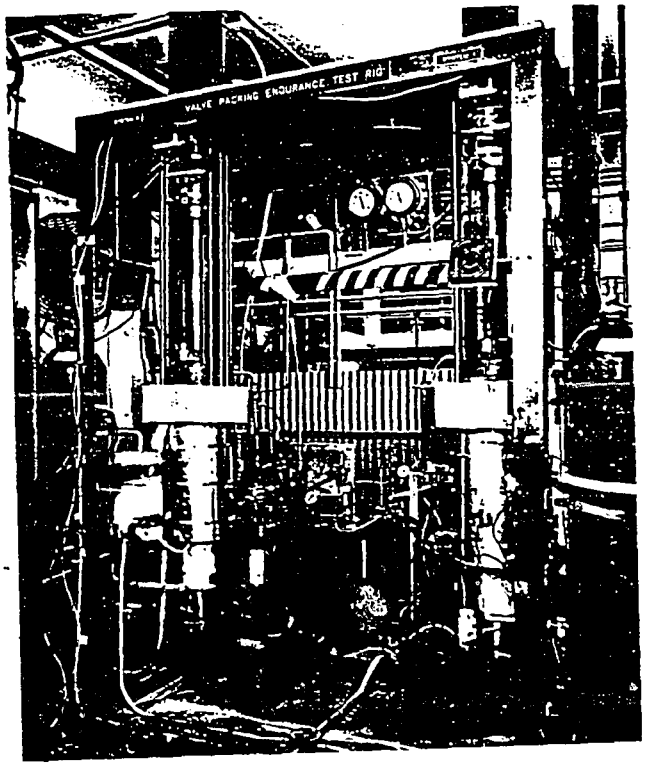

Figure 3:
Photo of the Valve Packing Endurance Test Rig.

Installation

All internal components are cleaned and inspected prior to installing packing sets. The procedures used for the qualification tests require loading of the packing to 40% of the specified load, stroking of the valve stem, re-torquing of the

gland nuts to 75% of load, re-stroking of the stem and re-torquing of the gland nuts to the final applied gland load. Stem stroking and torque adjustments are repeated until the reduction in the torque on the gland nuts after stroking is less than 5% of the specified full load, and the packing does not exceed specified pre-service consolidation limits.

NOTE: The revised installation procedure loads the packing set to full load prior to stem stroking. This has been found to be more cost effective for field application.

Stem Cycling

The specified cycling rate is once every 15 minutes. The 15-minute cycle includes an in-stroke of 70 seconds, a dwell of 5 minutes in the closed or down position, a return stroke or out-stroke of 70 seconds and a dwell of about 8 minutes in the up or open position. The dwell periods are included to allow for thermal growth and contraction of the stem between strokes, as occurs in some field situations. It has been found that this places greater demands on the packing than does continuous stroking. Stem cooling is provided by a small fan blowing air over the stem just above the gland plate. After the stem has cycled for 300 strokes, the stem is left in the up position to measure static leakage. Static leakage is measured for a 24-hour period at hot conditions, then the process is repeated. Variations of this cycling sequence are used to evaluate other parameters, such as break-away friction.

QUALIFICATION RESULTS

The results from the testing have been beneficial in verifying performance requirements and identifying acceptable products. Test results are described below.

Braided Non-Asbestos Materials

AECL has attempted to qualify more than twenty braided non-asbestos valve packing materials for use in PHT systems. None of the products tested fully meets the performance requirements[5] to maintain and improve CANDU NGS availability. The problems with the packing concern blocking agents and fibre size. Since the fibre size is larger than asbestos, voids between the fibres are larger. These voids are filled with various blocking agents, such as polytetrafluoro- ethylene (PTFE), which tend to extrude or burn off at PHT operating temperatures. The other concern with the fibre is that it fractures at relatively low gland loads, 27.6 MPa (4000 psi), and with relatively low numbers of stem cycles (Figure 4).

Currently, few non-asbestos braided products have been approved, and those approved have been limited to low-temperature systems

Figure 4:
A Fractured 3-Ring Braided Non-Asbestos Packing Configuration After 150 Stem Strokes at a Gland Pressure of 34.5 MPa.

<150°C (300°F). These are Garlock 1298, with graphite, and Burgmann 6011/A. To perform satisfactorily, these products must:

i) be live-loaded,
ii) not use gland loads >26.2 MPa (3800 psi), and
iii) have an anti-extrusion ring at the bottom of the packing set [7].

Combination Die-Formed Graphite

AECL and OH have had much more success qualifying available combination die-formed graphite packing configurations. Qualification testing has been completed on products from three different packing manufacturers[8-10]. The testing programs were funded in whole or in part by the supplier and participating utilities. All testing was done using the AECL endurance test rig, at live-loaded gland loads of 26.2 MPa (3800 psi) and operating conditions of 10 MPa (1450 psi) at 295°C (563°F).

The approved products under this program (arranged alphabetically) are:

- Argo 6300J, Argo Style 524 and Argo 6000 Composite,
- Burgmann 0901-B6 and Burgmann 6030, and
- Garlock Graph-Lock, Garlock G-700 and Garlock EVSP-9000 ("cup & cone").

Note: A.W. Chesterton Style 5300, Style 5350 and Style 1 have been approved by OH based on the EPRI-funded work reported in EPRI NP-5697.

Leakage. Leakage performance of the packing sets is important in reducing emissions and improving plant efficiency. Valve stem leakage is monitored by condensing the leaking fluid from the leak-off port and collecting the condensate in a small bottle connected to a load cell. Leakage is monitored continuously, both during the dynamic and the static testing mode.

All of the combination graphite products tested provided leak-free packing seals through 1500 stem cycles (i.e, < 1 g/d). All of the leakage for the combination graphite packing sets tested occurred during stem cycling; there was no detectable leakage from any of the packing arrangements in the static mode. This is desirable because most valves spend their life in the rest or static position.

Friction. Packing friction is becoming increasingly important to valve maintenance, due to recent regulatory requirements in setting up valve actuators. The changes in packing materials and related loading requirements have hampered some existing actuators from performing as originally designed. The actuators, in some cases, may not have sufficient thrust to seat the valve.

The packing friction is calculated as the difference between measured stem thrust, using the stem/actuator load cell, and the hydraulic force on the stem, derived from the system pressure transducer. By convention, the 'down-stroke', or valve closing force, is defined as a positive friction, and the 'up-stroke', or valve opening force, as negative friction.

Figure 5 plots the change in average down-stroke friction force vs stem cycles for some of the packing arrangements tested. The composite configuration was installed and loaded by Argo Packing; the other configurations were installed and loaded by AECL Research. All packing configurations were loaded to a nominal gland load of 26.2 MPa (3800 psi) and used the same disc spring arrangements.

The revised valve packing specification states that the average down-stroke friction should not exceed the initial cold friction and the friction coefficient must not be greater than 0.15. The products tested under the qualification program meet these requirements.

The friction profile for the 5-ring set with braided end rings is the average of selected products tested at Chalk River. The stem friction from the braided end rings shows higher friction than that measured for the other packing materials configurations.

Packing configurations that can reduce stem friction without reducing the applied gland load or increasing stem leakage would be a benefit to actuator set-up and design. Figure 5 shows that 5-ring sets using composites and a "cup & cone" arrangement approach this requirement.

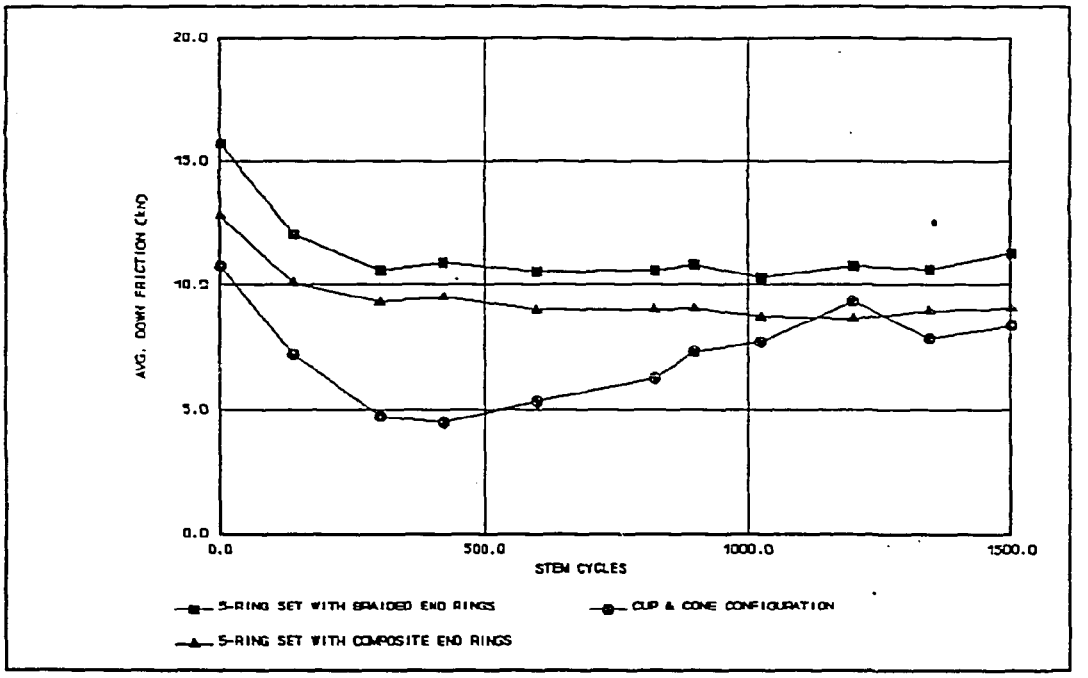

Figure 5:
Average Down-Stroke Friction Force vs Stem Cycles

Both the composite and "cup & cone" configurations have been designed to cause a more effective transfer of the axial load to radial load to achieve better sealing at a given gland load without significantly increasing stem friction.

In-Service Consolidation. In-service packing consolidation is measured using a displacement transducer mounted to the gland stud. This allows the spring-loaded arm to follow the gland plate movement during stem cycling. Figure 6 shows percent in-service consolidation with respect to free packing height vs stem stroke. (The plot for the 5-ring set with braided end rings is an average of selected product lines.) The majority of the packing consolidation occurs in the initial start-up and is attributed to temperature effects.

These temperature effects are believed to be the combined result of direct change and different thermal expansion between the valve components, with the latter being the dominant influence. The rapid rise, then drop, in consolidation is due to expansion of the packing set. The slow increase in percent change or volume loss is believed to be due to normal wear and loss of lubricants and other blocking agents. The data is presented this way to provide a more meaningful measure of material consolidation for those sets with braided end rings, when designing for live-loading applications.

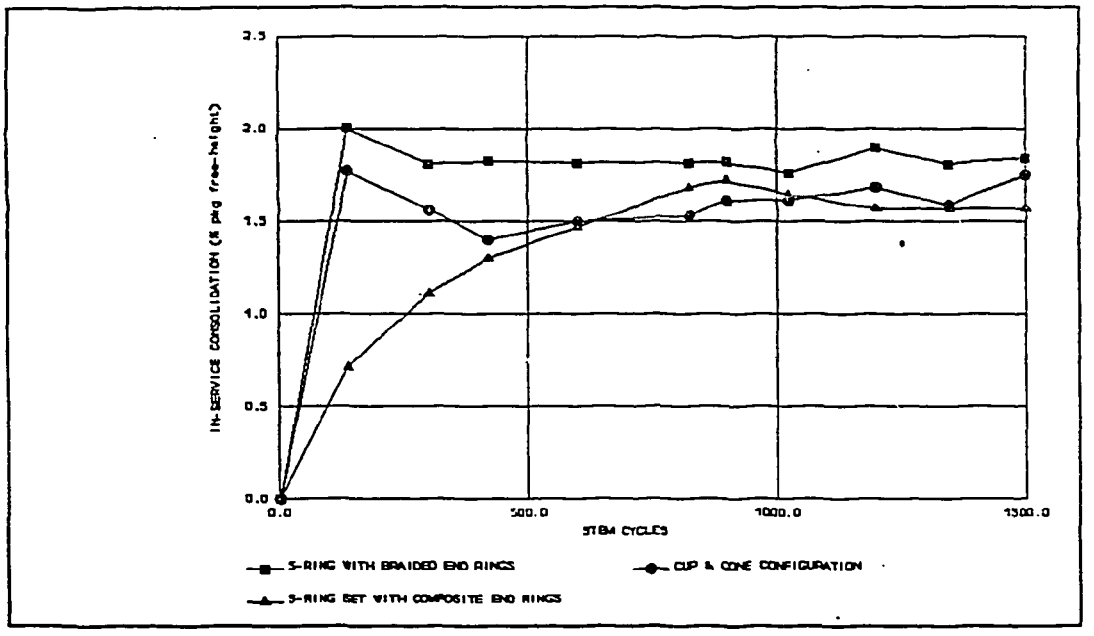

Figure 6:
In-Service Consolidation For Selected Packing Arrangements.

The revised valve packing specification for CANDU stations states that the in-service consolidation must not exceed 2.5% of the initial free height of the packing set. The packing configurations tested meet this requirement.

MECHANICAL SPECIFICATIONS

The lack of specifications governing stuffing box design has been a problem in the valve industry for years. Fortunately, this has been recognized by the valve and packing industry, and new specifications are being drafted by the Manufacturers Standardization Society (MSS).

The revised live-loading specifications for combination graphite packing issued in Canada by Ontario Hydro and AECL CANDU reflect a desire to assure performance and plant availability of existing and new stations. The specifications are the result of a joint effort among AECL Research, Ontario Hydro and valve packing suppliers. It is beyond the scope of this paper to provide all the details from the specifications, but a few points are worth mentioning.

Disc Springs

Disc springs are the key component for a live-loaded valve. Unfortunately, there is no ASME specification similar to DIN specifications 2092 and 2093 for disc springs. Although good manufacturing practices are followed by disc spring manufacturers, catalogue spring-loading information is not reliable enough for good live-loading.

To address this, the revised AECL/OH specifications call for fully-machined disc springs. All springs must be deburred to a surface finish of 1.6 μm arithmetic average (63 micro inches CLA) and compressed completely flat once prior to shipment. The height-to-thickness ratio of disc springs should not exceed 1.4 to 1. The recommended spring material is ASTM A564, Type 631 stainless steel (17-7 PH) in the TH1050 condition or approved equivalent. It is strongly recommended that a load approved deflection curve be provided with each lot of springs. When installing a spring set, the lubricant used on the springs must be free of molybdenum disulphide.

When installed, the spring stack should not be loaded to flat or to become solid. On large valves, the induced thermal taper on the hot stem is sufficient to generate a significant volume change in the stuffing box. On the return stroke or valve opening, this volume change translates into an increased load on the packing. Loading the spring set flat does not allow the gland follower to effectively accommodate the volume and load change; premature stem packing failure could result.

Stem Material

Packing materials have various additives and blocking agents. These additives can cause stem corrosion, particularly in 400 series stainless steels. To reduce this risk, all stem materials for new valves and replacement stems for CANDU NGS (operating conditions 10 MPa (1450 psi) and 290°C (563°F)) call for ASTM A564, Type 630, H1075 or H1100 (17-4 PH stainless steel). There are other suitable materials, and corrosion resistance is not the only requirement. The use of 17-4 PH stainless steel is not recommended for applications above 345°C, due to toughness limitations. The stem finish is important to reduce wear. The AECL/OH specifications call for 0.4 μm arithmetic average (16 micro inches CLA) or better.

Stuffing Box Internal Components

The newer valve packing products are much less forgiving than braided asbestos packing in accommodating machining errors of the stuffing box and of related internal components. Diametral clearances must be tighter for today's packings to avoid extrusion. As a general guideline, to avoid stem galling, the diametral clearance between the stem and those components not in contact with the packing should be 1.15-1.25 mm (0.045-0.050 in.). Those in contact with the packing sets should have a diametral clearance of 0.15-0.20 mm (0.006-0.008 in.) on the outside diameter and 0.55-0.65 mm (0.020-0.025 in.) on the inside diameter. Tighter tolerances may be required for certain other packing products and applications.

R&D FIELD SUPPORT

With any emerging technology, R&D support is critical to provide a degree of confidence that the directions taken are beneficial. AECL Research is working closely with the Integrated Valve Actuator Program (IVAP) Valve Packing Steering Committee to

determine the R&D support beneficial in addressing station valve packing concerns.

Double-Packed Testing

Qualification testing at AECL Research identified acceptable products for use in combination die-formed graphite packing configurations. However, the testing only considered single-packed configurations. The IVAP-Valve Packing Steering Committee has now requested testing of double-packed configurations that could be used in field applications. To date, four double-packed configurations have been evaluated. The configurations evaluated are a full-size set (5-rings plus 3-rings) for Pickering-A applications and a reduced-size set for applications in Bruce designs (4-rings plus 3-rings).

Test Description. The cycling sequence for the double-packed configurations is similar to previous single-packed tests. However, two different cycling rates are used: 4 cycles per hour and 10 cycles per hour. The 4 cycles per hour allows for thermal growth and contraction of the stem between strokes as occurs in some field situations. This places greater demands on the packing than continuous stroking. The 10 cycles per hour rate simulates control valve action and has less stem thermal taper induced effects. After the stem has been cycling for about 300 strokes, the stem is left in the up position to measure static leakage. Static leakage is measured for about 24-hours at hot or cold conditions, then the identified stem cycling is repeated.

All testing is done at 10 MPa (1450 psi) and 290°C (560°F). The full height packing configurations are installed as complete sets and loaded as described for qualification testing. The reduced height configurations are installed in two steps; the primary set is loaded to full load (with stem stroking) and then the secondary set is loaded to full load (with stem stroking).

Double-Packed Test Results. The results from the double-packed tests are summarized in Table 1. The most significant find was the higher than expected in-service consolidation and leakage. Previous tests with single-packed arrangements had shown no leakage, and in-service consolidations of less than 1.7%.

Comments

a) The higher than expected in-service consolidation seen for both full and reduced height packing tests is believed to be the result of the split composite ring trying to roll axially in the stuffing box. With repeated cycles the inside edges of the composite ring start to fracture, allowing the laminations on the die-formed ring to move into the space. This process continues to crumble the composite material and with repeated stem cycles accelerates the erosion (i.e., higher leak rates and in-service consolidation). Figure 7 shows the outboard composite ring and adjacent die-formed ring for the 9.5 mm reduced-height primary

TABLE 1:
Test results of double-packed configurations after 1500 stem strokes.

PACKING WIDTH (mm) (HEIGHT)	STEM DIAMETER (mm)	CUMULATIVE LEAKAGE (g)	AVERAGE DOWN FRICTION (kN)	IN-SERVICE CONSOLIDATION (% of free-height)
6.35 (FULL)	25.4	341	2.17	2.38
12.7 (FULL)	50.8	218	10.23	1.01
7.9 (REDUCED)	25.4	312	2.09	2.99
9.5 (REDUCED)	50.8	378	3.49	2.42
9.5 STANDARD 5-RING SET (reference)	76.2	0	9.3	1.7

packing set. Note the composite ring broken on the inside corner, and the delamination of the die-formed ring. There is evidence from station field experience that tighter clearances are required when using composite end rings. The clearances for carbon bushings stated in M-729 may be sufficient because there was no observed degradation of the composite rings in the secondary set nor in single-packed tests where carbon bushings were used.

Figure 7:
Outboard Composite and Adjacent Die-Formed Ring of the Primary Packing Set of the Reduced-Height Double-Packed Packing Configuration.

b) The cumulative leakage, although significant with respect to zero leakage, is 600 times less than with the existing asbestos products now in use.

c) The double-packed configurations, as tested, require more investigation to make the outboard anti-extrusion ring of the primary set stiffer.

d) The height to width ratio for split-composites should not be less than 1.0.

Conventionally-Loaded Configuration

The IVAP-Valve Packing Steering Committee requested that testing be conducted on AECL/OH approved valve packing products, conventionally loaded (i.e., without live-loading). The purpose of the testing is to obtain packing performance data (i.e., leak rates and stem friction) for use with valves that do not have actuators and are not live-loaded. The majority of conventionally-loaded valves in power stations are hand-operated and are on the secondary side. Therefore, access to the valve is available for retorquing on-line. These valves are also stroked infrequently, less than once a month, and therefore the number of stem strokes for the test can be reduced from the standard 1500 stem cycles to 650 stem cycles.

Operating Conditions. The two packing configurations tested were a five-ring set consisting of two die-formed rings bracketed by three composite end rings (6300J/6000), two on the outboard and one on the bottom, loaded to 34.5 MPa (5000 psi), and a seven-ring set consisting of 5 cup-and-cone die-formed rings bracketed by braided end rings (9000-EVSP) loaded to 26.2 MPa (3800 psi). The packing installation procedures and guidelines followed were those described in the Bruce Valve Packing Procedures BGB-MMP-76510-027. The procedure used full loading to the packing set prior to any stem stroking. All torque adjustments during installation and testing were made with the stem in the down or closed position.

Test Results. The total cumulative leakage from the 5-ring combination set (6300J/6000) was 1154 g, and from the 9000-EVSP set, 282 g. The stem friction force for the two packing products was near 10 kN at operating temperature (290°C). Leakage collected during the test of the 6300J/6000 configuration showed significant evidence of composite end-ring degradation (Figure 8). The 9000-EVSP performed better at conventionally-loaded conditions than the 6300J/6000 configuration.

Comments

a) The test results indicate that under the test conditions, conventionally-loaded combination die-formed graphite with composite end rings (6300J/6000) does not have sufficient stored energy to handle relatively small stuffing box volume changes caused by thermally induced stem tapers.

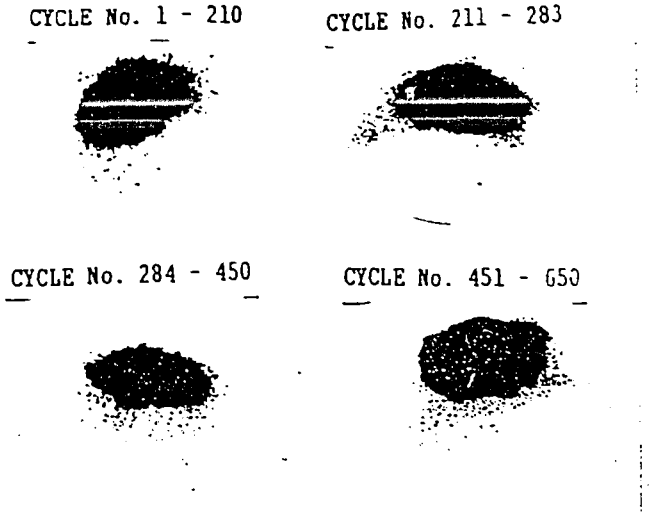

Figure 8:
Photo of Collected Composite End-Ring Material After Conventional Load Test at 34.5 MPa.

b) The 6000 composite end-rings tested showed significant material degradation at gland pressures of 34.5 MPa (5000 psi). This is a concern because moving to higher gland loads was one of the possible solutions to improve the performance of double-packed combination graphite packing configurations.

c) The leakage observed during initial stem stroking is sufficient to justify review of packings in large valves that are not live-loaded.

d) The preferred packing configurations for conventionally-loaded valves are those using braided end rings or a configuration such as the 9000-EVSP Simplified Set.

CONCLUSIONS

The R&D support in valve packing qualification has provided numerous benefits for CANDU maintenance, including:

- the identification and qualification of available combination die-formed graphite products suitable for PHT systems,

- the issuing of standard specifications for combination graphite valve packing products.

This work has produced a highly motivated valve packing team with members drawn from design, operations and R&D. The acknowledge-

ment, through peer reviews, that the packing retrofit program at Bruce NGS-B is providing improved plant availability is a tribute to this team's effectiveness.

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[4] Aikin, J.A., Doubt, G.L., and Lade, C.R., "A Summary of the Chalk River Valve Packing Evaluation Program 1985 - 1990", AECL Report AECL-10298, 1990 December.

[5] Ontario Hydro Standard Specification, "Graphite Stem Packing and Associated Components", M-724-91/Rev. 01.

[6] 'Live-Loading of Stem Packing for Valves", AECL Technical Specification 74-30830-TS-003, REV. 0/9105-31.

[7]* Aikin, J.A. and Doubt, G.L., "Benefits and Hazards of using Live-Loaded Teflon and Teflon Impregnated Packings in Nuclear Valves", COG-90-147, 1991 January.

[8]+ Aikin, J.A., "Evaluation of a Composite Anti-Extrusion Ring", AECL Research Report CI-V-71, 1990 September.

[9]+ Aikin, J.A., "Evaluation of Garlock Combination Graphite Packing Graph-Lock/G-700 and Style 9000 EVSP", AECL Research Report ET-V-74, 1991 December.

[10]+ Aikin, J.A., "Evaluation of Burgmann Combination Graphite Set 0901-B6/6030 End Rings and Style 6011/A", AECL Research Report ET-V-75, 1992 January.

* Restricted report; property of the CANDU Owners Group (COG). To obtain a copy contact COG Information Exchange at (416)590-3149.

\+ Restricted report. To obtain a copy contact AECL Research at (613)584-3311 Ext 3726.

CA9500163

BRUCE "B" VALVE IMPROVEMENT PROGRAM

Brian Bagshaw

Ontario Hydro, BNGS"B"
Shift Maintenance Supervisor
Tiverton, Ontario

ABSTRACT

The Bruce "B" Valve Improvement Program began in 1987 based on the results of Unit 6 start up. In the past Bruce "B" used 187-I and 127-A asbestos packing materials both conventional and live loaded with good results. Bruce "B" experienced packing failures on a number of valves after units were shutdown for regular maintenance. On start up of the units the number of leaks sometimes surpassed the leaks repaired during the shutdown.

Our challenge is to make operation of our equipment meet and exceed today's accepted performance. Part of this program was the elimination of asbestos materials, and the testing of non-asbestos packing.

BRUCE "B"
VALVE IMPROVEMENT PROGRAM

Brian Bagshaw

Ontario Hydro, BNGS"B"
Shift Maintenance Supervisor
Tiverton, Ontario

OBJECTIVE

Valves are the single most numerous component in a power plant. Any extension of packing service life will have a significant benefit for our maintenance cost. We have, as our goal, to reduce outage cost and time, to conserve heat, to maintain configuration control and finally involve manufacturers in our leak control program.

EXPERIENCE

During the period from 1987 to 1989, Bruce "B" tried different packing material from a variety of manufacturers. These were logged on data sheets and checked after start up and during the first year of operation. Bruce "B" still experienced packing failures during this period due to some of the following problems (see Appendix I).

a) Large number of packing rings (20 rings +)

b) Stem finish

c) Not torquing gland nuts

d) Large consolidation

e) No training

f) No procedure.

Bruce "B" surveyed the valves of similar make and model across all four (4) units and compiled a list and percentage of leakers. These lists were the bases for the Valve Improvement Program indicating certain manufactures and sizes had a large percentage of packing leaks.

The program concentrated on these valves first (Rain Forest areas) all valves were packed even the non-leakers. During the Valve Packing Program, maintenance also inspected the seats and wedges for damage. The results of this program were very noticeable after the unit was placed in service. Leaks did not exist in areas repaired by the program.

ALTERNATE VALVE PACKING MATERIALS

During the 1989 Peer Evaluation, finding MA 2-1 stated: Numerous steam, water and oil leaks, damaged or missing insulation, and defective equipment or instrumentation reflects the need for a more aggressive approach to the identification and correction of deficiencies. Maintenance Support investigated U.S. Facilities that had highly rated Valve Programs. Susquehanna Station was selected and Bruce "A" and Bruce "B" visited the station to closely look at their Valve Improvement Program. They worked on the team approach to equipment failures, one being the valve packing manufactures (see Appendix II). The relationship was constructed so as to achieve a working relationship between the valve packing manufacturer and the plant so that a leak free environment will exist.

Bruce "B" invited the same manufacturer to site so to investigate the use of graphite packing.

GRAPHITE VALVE PACKING PROGRAM

This program concentrated on chronic leakers such as: boiler blow-off, main steam isolators, various boiler feed valves and some reheat valves. These valves were live loaded with graphite and yarn material using a four (4) or five (5) ring set, the extra spare was taken up by a spacer carbon bushing. Approximately five hundred (500) valves were packed during the first outage using both yarn end rings and composite materials. Each unit shutdown after this approximately three hundred (300) to six hundred (600) valves were packed with a trained team of 10 journeypersons.

Our first nuclear double packed valve was a Fisher, feed bleed and relief valve which was packed with composite material in 1989. Since then six (6) other double packed valves on the nuclear side have been successfully packed.

The method to maintain design control and configuration control is a valve data base. All valve information is input into this program plus the appropriate packing arrangement drawing is added (see Appendix III).

The data sheets are field copies initiated by the maintenance assessors showing the expected nominal dimensions for the size of valve and manufacturer. These sheets are then returned to Maintenance Support upon the completion of the job task so changes can be input.

The program was successful and during the 1991 Peer Evaluation a good practice stated: The program to repack valves at Bruce "B" has proven effective in minimizing steam leaks and has contributed to an improvement in plant material condition (see Appendix IV).

REDUCED HEIGHT COMPOSITE AND GRAPHITE RINGS

The unique feature of these rings are that they can be supplied in any height, this is important in valves with undersized actuators or double packed valves. Our maintenance cooling and ECI valves require reduced height rings both below and above the lantern ring (see Appendix V).

VALVE PACKING QUALIFICATIONS AND SPECIFICATIONS

Packing qualification is an integral part of the packing program, this testing has been carried out at A.E.C.L. Chalk River. A.E.C.L. and Ontario Hydro head office have produced a packing specification that can be used in the purchase of packing material.

TRAINING

All maintenance staff at Bruce "B" have had valve packing training supplied by the packing manufacturer. This training was also given to the Central Maintenance Facility crews that pack valves at Bruce "B". The technical unit was given an update on graphite packing materials and how they can be used to reduce station leaks.

VALVE STEM REFURBISHMENT

Many valve stems when removed have been found to be pitted due to corrosion. These stems are made from 410 stainless steel and can be refurbished in our Central Maintenance Facility.

The stems are machined and cracked checked before they are welded. After welding the stem is machined back to the original size and polished to a finish of 14 RMS.

VALVE DIAGNOSTIC EQUIPMENT

Bruce "B" has successfully used and purchased two diagnostic systems, one for motor operated valves (Liberty Votes) and one for control valves (Fisher unit).

CONCLUSION

To support a successful valve packing program all groups must be on board:

a) Research labs (packing qualifications)

b) Design (specifications)

c) Purchasing (Focus on quality)

d) Managers (View on long term P/M programs)

e) Maintenance (execute repairs).

All these groups are responsible for the success of the Bruce "B" Valve Improvement Program.

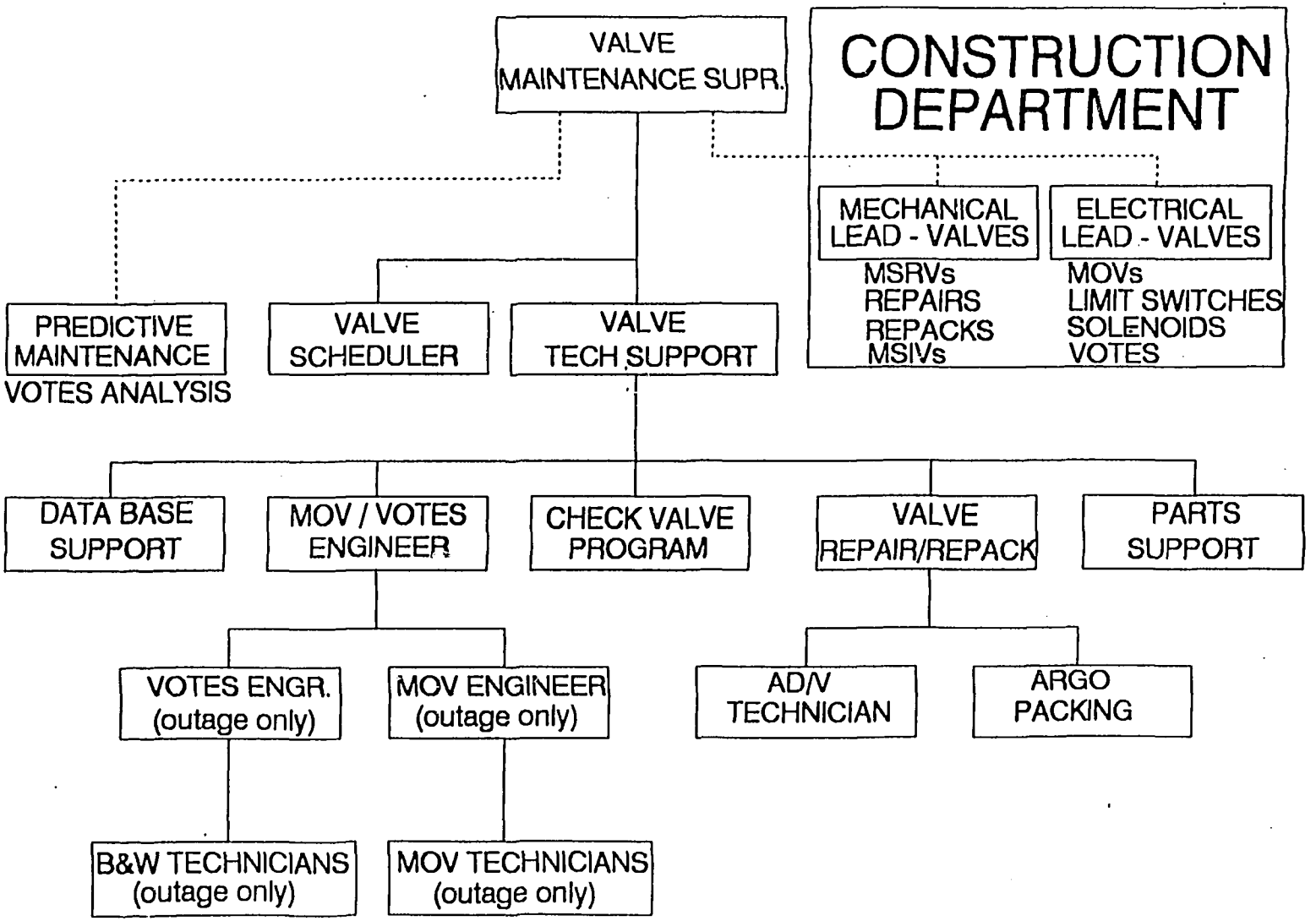
BNGS "B"
MECHANICAL MAINTENANCE

VALVE STATUS REPORT

NOTE: Please indicate if valve is OK, had to be tightened, or leaked after tightened.

USI	DR #	Valve Number	Packing Type	Check #1 First Steam	Check #2 1 Week Fullpower	Check #3 1 Month	Comments
41100		V-16	287I	OK	OK	OK	
41150		MV-17	127A	OK	Adjusted	OK	
41180		V-7	287I	OK	OK	OK	
41180		V-8	127A	OK	OK	OK	
41180		V-9	287I	OK	OK	OK	
41180		V-10	127A	OK	OK	OK	
41180		V-11	287A	OK	OK	OK	
41180		V-12	287A	OK	OK	OK	

MAINTENANCE VALVE TEAM



APPENDIX III - BRUCE 'B' VALVE IMPROVEMENT PROGRAM

MECH MTCE UPDATE CHECK SHEET

GENERAL

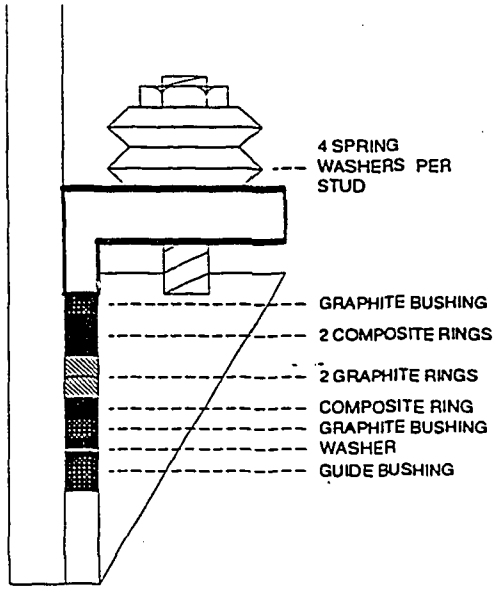
CURRENT RECORD

UNIT:	7	ROOM NO:		SCAFFOLD (Y/N):	
USI:	36140	ELEVATION:	696	LAST UPDATE:	Sep 30 1992
VALVE NO:	CV1	COLUMN:	7D9	FLOWSHEET/GRID:	36110-0001 B-3

VALVE INFO

VALVE SCN:	543D4411
MAKE:	MASONEILAN
MODEL:	71-40413
SIZE:	8
RATING:	600
SEAT MATL:	STELLITE
SEAT HELD BY:	COMPRESS.
BELLOW SEAL (Y/N):	
VALVE TYPE:	PLUG
OPERATOR MAKE:	MASONEILAN
OPER MODEL:	C SIZE
VALVE STROKED 5 TIMES (Y/N)	
PACKED BY:	

DWG_FIG: V701



NOTE: IF THERE IS A "JUNK" RING PRESENT, REINSTALL RING WITH NEW PACKING.

PACKING INFO

STEM DIA:	1.000
GLAND DIA:	1.6250
GLAND DEPTH:	5.000
LEAKOFF I.D.:	
LEAKOFF PRT DPTH:	
STUD DIA:	.5000
NUMBER OF STUDS:	2
NUT SIZE:	.8750
GLAND TORQUE(FT /lbs):	17
GLAND LOAD:	
UPPER BUSH. HT.:	1.000
LOWER BUSH HT.:	2.000
LANTERN RING HT.:	
JUNK RING HT.:	
LIVE LOAD (Y/N):	Y
SPRING NO.:	50M177
PACKING TYPE:	COMPOSITE
ESTIMATED FRICTION:	
PACKING DATE:	Apr 20 1991
TIMES PACKED:	3
TIMES STEM REPAIRED:	0
GASKET DATE:	Apr 20 1991
TIMES GSKT REPAIRED:	1

COMMENTS/HAZARDS:

GUIDE BUSHING IN BOTTOM OF STUFFING BOX 1.500" LONG (REINSTALL).

Return completed MECH MTCE UPDATE CHECK SHEET to MTCE SUPPORT.

APPENDIX IV

MAINTENANCE

MAINTENANCE ORGANIZATION AND ADMINISTRATION

RFORMANCE OBJECTIVE: The maintenance organization and administration should sure effective implementation and control of maintenance activities.

od Practice MA.1-1 The program to repack valves at BNGS-B has proven effective in minimizing steam leaks and has contributed to an improvement in plant material condition. Elements of the program include:

a) Industry research.

b) Vendor selection.

c) Product testing.

d) Training and field support of maintenance workers.

e) Establishment of historical data base.

Live loading and graphite packing materials were used to correct chronic valve leaks. When chronic leakers were identified similar valves were repacked preemptying future steam leaks.

DIX V - BRUCE 'B' VALVE IMPROVEMENT PROGRAM

MECH MTCE UPDATE CHECK SHEET

GENERAL

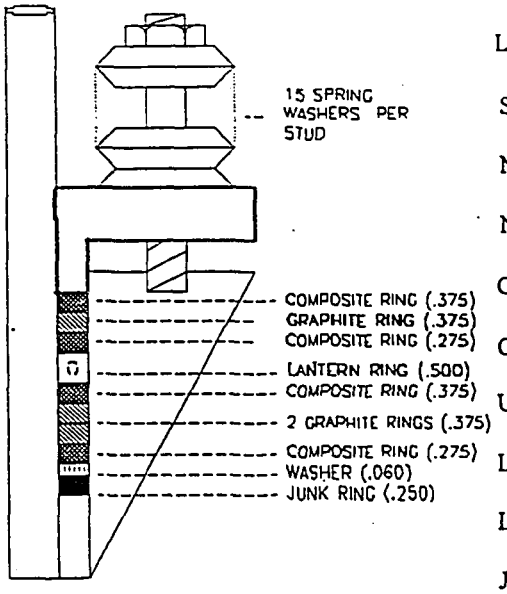
CURRENT RECORD

UNIT:	7	ROOM NO:		SCAFFOLD (Y/N):	
USI:	34720	ELEVATION:		LAST UPDATE:	Sep 30 1992
VALVE NO:	MV1	COLUMN:		FLOWSHEET/GRID:	34720-0001-A1

VALVE INFO

VALVE SCN:	542N4801
MAKE:	VELAN
MODEL:	M2-3639
SIZE:	12
RATING:	900
SEAT MATL:	DELORO 50
SEAT HELD BY:	WELD
BELLOW SEAL (Y/N):	
VALVE TYPE:	WEDGE
OPERATOR MAKE:	LIMITORQUE
OPER MODEL:	SMB3-100
VALVE STROKED 5 TIMES (Y/N)	
PACKED BY:	

DWG_FIG: V713



NOTE: IF THERE IS A "JUNK" RING PRESENT, REINSTALL RING WITH NEW PACKING.

PACKING INFO

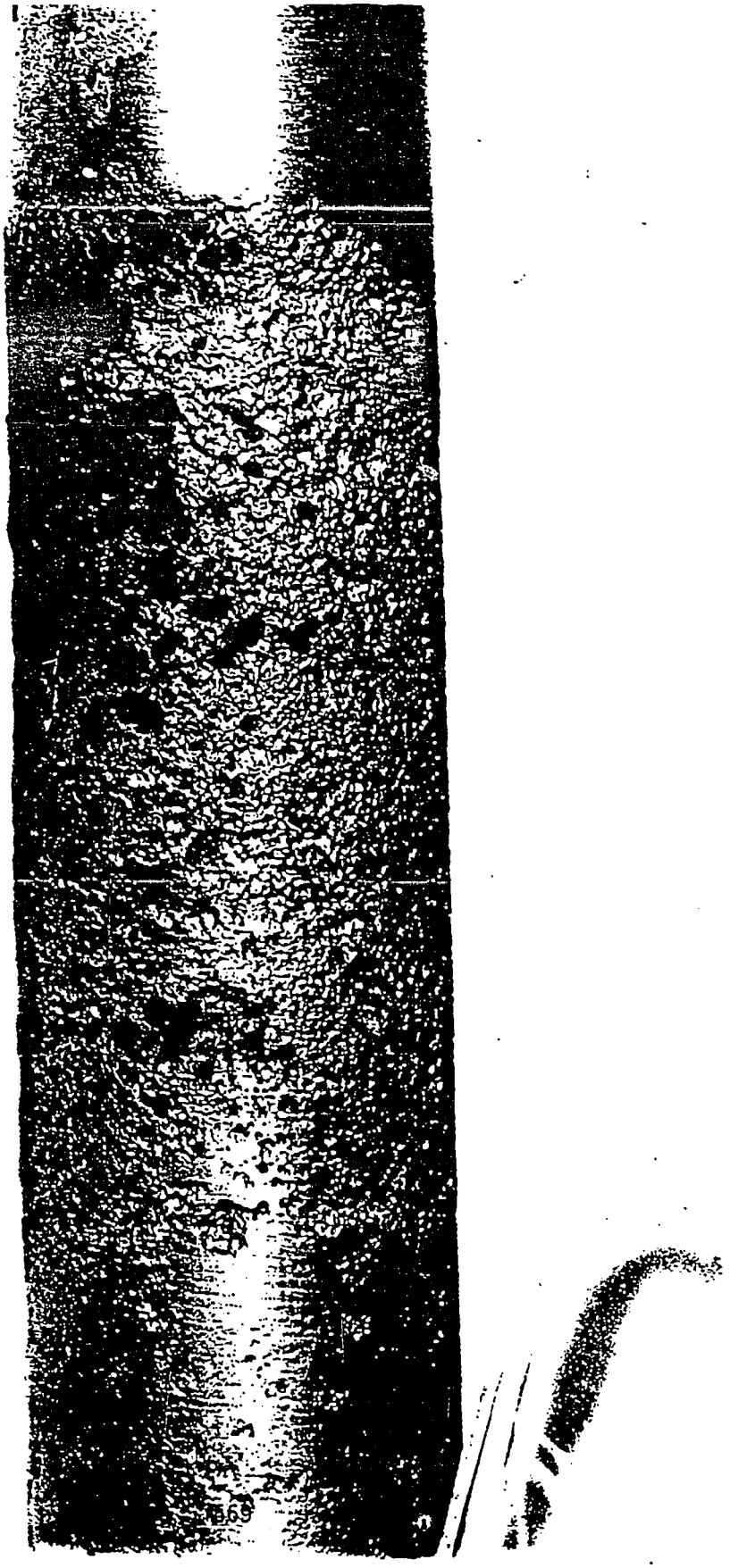
STEM DIA:	2.750
GLAND DIA:	3.500
GLAND DEPTH:	3.500
LEAKOFF I.D.:	
LEAKOFF PRT DPTH:	
STUD DIA:	1.125
NUMBER OF STUDS:	2
NUT SIZE:	1.812
GLAND TORQUE(FT /lbs):	138
GLAND LOAD:	7363
UPPER BUSH. HT.:	
LOWER BUSH HT.:	
LANTERN RING HT.:	
JUNK RING HT.:	
LIVE LOAD (Y/N):	
SPRING NO.:	
PACKING TYPE:	COMPOSITE
ESTIMATED FRICTION:	
PACKING DATE:	Dec 24 1991
TIMES PACKED:	1
TIMES STEM REPAIRED:	0
GASKET DATE:	
TIMES GSKT REPAIRED:	0

COMMENTS/HAZARDS:

JUNK RING .25" "LANTERN RING .500" LEAK OFF PORT SIZE .1875". BOTTOM OF BOX TO CENTRE OF LEAK PORT 1.625". BONNET TORQUE 3075 FT/LBS. LANTERN RING TAPPED HOLE 10/24. JUNK RING TAPPED HOLES 8/32.

Return completed MECH MTCE UPDATE CHECK SHEET to MTCE SUPPORT.

APPENDIX VI



CA9500164

PNGS-A UNIT 4
COMPOSITE GRAPHITE VALVE PACKING PROGRAM

F.Meaney

Ontario Hydro, Pickering Nuclear Generating Station
Pickering Ontario

L939700CA

ABSTRACT

During the PNGS-A Unit 4 retube/rehabilitation outage, a composite graphite packing program was completed on 100 conventional valves and 50 nuclear valves. This paper will detail the repacking program for the nuclear valves by describing component refurbishment, related maintenance and manpower requirements.

PICKERING NGS-A UNIT 4
COMPOSITE GRAPHITE PACKING PROGRAM

INTRODUCTION

A large number of valves on the Pickering NGS-A units use asbestos based packing (in particular Garlock 127A and John Crane 187I). Ontario Hydro and AECL undertook to identify and test alternate packing materials for two reasons - these packing materials are becoming less available and also to eliminate the use of asbestos based packing. Composite graphite packing was identified as the preferred alternative. Composite graphite packing has several advantages over asbestos packing, as listed below:

- superior leakage reduction
- reduced stem friction
- less consolidation (compression/shrinkage)

The Pickering NGS-A Unit 4 retube/rehabilitation outage presented an ideal time to begin a major valve repacking program on the unit. The valves chosen for repacking (100 conventional and 50 nuclear) were chronic leakers and others that are difficult to isolate during a normal shutdown. The nuclear valves chosen were on the Heat Transport System (HTS) - 14" boiler isolators, 14" HT pump discharge valves, 10" shutdown cooling isolators and several miscellaneous valves on the HTS. This paper will focus on repacking of the HTS valves, although the repacking program for the conventional valves was essentially the same.

To accommodate retubing and maintenance, the HTS was drained and dried. With the HTS dried, the valve bonnets could be removed and repacked outside the Reactor Building. Removing the bonnets had a number of advantages. First, the maintenance personnel did not have to repack the valves while wearing a plastic suit, in high field conditions, or in cramped areas. Second, extremity dose could be minimized by totally disassembling the valve for decontamination. Third, with a valve disassembled, the stem, stuffing box, lantern ring and gland follower could be completely refurbished.

This paper will describe the various aspects of the Unit 4 valve repacking program. Specific packing configurations will not be described since there are numerous factors to consider when selecting packing for a individual valve (number of end rings and packing rings, dimensions of packing rings, lantern rings, bushings, and washers, allowable tolerances).

Figure 1 is a sketch of the various components related to valve packing. Many of these components will be referred to in the body of this paper.

PICKERING NGS-A UNIT 4
COMPOSITE GRAPHITE PACKING PROGRAM

VALVE REHABILITATION

To ensure all composite graphite packing purchased meets an acceptable and consistent standard, Ontario Hydro has issued Standard Specification (M-724-91). The specification identifies the necessary tests, materials, dimensions, tolerances and documentation for qualified composite graphite packing. This specification was used to establish the scope of the valve repacking program.

The surface finish of the valve components (particularly the stem and stuffing box) are very important when using graphite packing. Therefore, for each valve, the stem was refurbished, the stuffing box bored out, new lantern ring and gland follower fabricated and composite graphite packing installed. The Unit 4 valve repacking program was, in effect, a complete valve rehabilitation.

Preliminary Work

Prior to any rehabilitation work being completed on a valve, the actuator and bonnet were removed. With the bonnet separated from the valve, the stem and existing packing could be easily removed. The bonnet was then decontaminated in a parts washer. The stems were manually decontaminated and shipped to the Bruce Central Maintenance Facility (CMF).

Stem Refurbishment

Most of the valve stems (46 of 50) had some degree of pitting and corrosion. In general, this damage was in the area where the lantern ring and gland follower sit with the valve in the fully open position. Design and the MCCR reviewed/approved a process for thermal spray repair of the valve stems.

At Bruce CMF, the stems were undercut to remove the corroded material. After a liquid penetrant inspection was completed, the base metal was blasted with aluminium oxide. The undercut area was then built up using the thermal spray process (Hobart-TAFA 60T Arc Spray Wire) and finished to 16 μinches or better, with a tolerance of +0.0"/-0.002" on the stem diameter. A visual inspection was completed after the final machining.

PICKERING NGS-A UNIT 4
COMPOSITE GRAPHITE PACKING PROGRAM

Stuffing Box Refurbishment

After decontamination of each valve bonnet, a survey sheet was completed (see Figure 2). The survey sheet detailed information related to the stuffing box, gland follower, glands studs, lantern ring, junk ring and bushings.

For the 40 boiler isolators and HT pump discharge valves, the as found stuffing box diameters ranged from 3.000" to 3.152". For consistency and to minimize the number of different packing sets required to be kept in stock, it was decided to bore the stuffing boxes to one common diameter (3.187"). This required increasing the diameter of the stuffing boxes by a maximum of 3/16". As with stem refurbishment, this machining was reviewed with Design and the MCCR.

The two HT interconnect valve stuffing box diameters were measured at 2.005" and 2.151". These stuffing boxes were bored out to 2.187" (a maximum diameter increase of 3/16").

The as found stuffing box diameters for the 8 shutdown cooling (SDC) valves were reasonably consistent (2.750" to 2.762"). Therefore, machining of the SDC valve stuffing boxes was not required. These were new valves which were installed in 1989 as part of ECI modifications.

Fabricate Lantern Rings and Gland Followers

After machining of the stuffing boxes, the clearances between the stuffing box and lantern ring/gland follower exceeded those specified in Ontario Hydro Specification M-724-91. As a result, new lantern rings and gland followers were fabricated. The gland followers were fabricated from carbon steel. The new lantern rings were machined from Waukesha.

Repacking

The valve survey sheet described earlier was forwarded to the packing supplier, who used the information to propose an optimum packing configuration. A valve datasheet detailed the proposed configuration and was reviewed by PNGS Maintenance Engineering and the Shift Maintenance Supervisor. After the packing configuration was approved, the supplier provided an individual packing set for each valve in a labelled container. Each container had an upper and lower packing set, and any necessary bushings, graphite washers and Belleville washers.

PICKERING NGS-A UNIT 4
COMPOSITE GRAPHITE PACKING PROGRAM

After the stems were refurbished at Bruce CMF, the stuffing boxes machined and new lantern rings and gland followers fabricated, the valves were ready for repacking.

A comprehensive procedure, specific to composite graphite packing, was prepared which detailed the steps required to repack single and double packed valves. (Note: all of the nuclear valves were double packed - i.e. packing above and below a leak-off line). The first draft of this procedure was an amalgamation of information obtained from Bruce NGS-A, Darlington NGS and ARGO Packing. The procedure was then refined to incorporate comments received from the Maintenance personnel during field testing of the procedure. The packing supplier was contracted to provide on site training to Maintenance and Technical personnel during the early part of the repacking program. It is important to note that a dedicated mechanical maintenance crew was responsible for the packing installation.

The following is a very brief description of the procedure used to repack a double packed valve:

- install the bottom packing set and lower the lantern ring onto the packing
- torque the gland nuts to a specified value and consolidate (compress/settle) the packing by stroking the valve 5 times
- relax the torque on the gland nuts and install the top packing set
- again, torque the gland nuts to a specified value and consolidate the packing by stroking the valve 5 times

After the packing was installed, the information from the datasheet was input to a database. The database contains all relevant information related to packing a particular valve (packing configuration, dimensions, gland load, etc.). The database is Windows based and was developed by the Computer Services Group of PNGS Operations Rehabilitation. Anyone who has access to the Rehabilitation local area network can browse the database.

PICKERING NGS-A UNIT 4
COMPOSITE GRAPHITE PACKING PROGRAM

Manpower Requirements

The valve packing program required the involvement of numerous groups. However, the primary groups were Mechanical Maintenance (valve rehabilitation and repacking) and Control Maintenance (disconnect/reconnect electrics and set-up limitorque actuators). Based on the actual work completed to date and the outstanding work, it is estimated that the manpower requirements for the maintenance groups to repack 50 valves is:

Mechanical Maintenance	4000 hours (80 hours/valve)
Control Maintenance	1075 hours (22 hours/valve)

In support of the maintenance personnel, the following groups were also involved in the repacking program:

- Unit 4 Rehabilitation Technical Unit: coordinate the involvement of various groups and track the progress of the program
- Maintenance Engineering: review/approve packing arrangements and spring stack requirements, arrange for project funding
- Maintenance assessors: arrange for stem repairs, and other material as required
- Service Maintenance: bonnet decontamination
- Purchasing/Supply: administer contract for purchase/delivery of packing material
- Packing Manufacturer/Supplier: supply materials, technical assistance and training
- Design: technical assistance related to packing configuration, stem repair and stuffing box machining
- Bruce CMF: thermal spray weld repair to valve stems
- PNGS-MCCR contact and MCCR representative: approval of stem repairs and machining of stuffing boxes
- AECL Chalk River: qualification/testing of packing materials and various packing configurations

PICKERING NGS-A UNIT 4
COMPOSITE GRAPHITE PACKING PROGRAM

RELATED MAINTENANCE ITEMS

The valves selected for the repacking program have been inservice for almost 20 years. There has been minimial maintenance required on these valves over that time. As described below, a number of additional maintenance items were completed during the repacking program to completely rehabilitate the valves.

Wedge Guides

During the retube portion of the outage a piece of metal debris was found in a feeder. This piece of debris was later identified as part of a missing wedge guide from a 14" Velan HT pump discharge valve. The remaining piece of the wedge guide was found near a restricting orifice on another feeder. An inspection of other HT pump discharge valves identified another wedge guide with 2 of 6 welds cracked. The missing/damaged wedge guides were repaired according to a procedure provided by the valve manufacturer and Design. The repair procedure also required MCCR approval.

Leakoff Lines

Each valve had a leakoff pipe stub which was approximately 6" long. The length of this pipe stub made it difficult to remove the bonnet nut directly below the stub. To ease installation and future maintenance, these pipe stubs were cut back to approximately 3" long. A short length of tubing and Swagelok fittings were used to extend the pipe stub to the original length.

During the leakoff line modifications, one of the lines was found to be plugged with packing. This line was cleaned out and all the lines were blown down to the D2O collection tank to confirm they were clear.

Stem Lubrication

Composite graphite packing does not require the valve stem to be lubricated. In fact, lubrication may cause the graphite packing to break down. Therefore, maintenance call-ups were revised to indicate that only the threaded portion of the stem should be lubricated.

Independent of the valve packing program, Design recommended using Esso Nebula EP1 to lubricate the valve stems. Previously, the valve stems were lubricated with molykote, which has the potential to cause stress corrosion cracking.

PICKERING NGS-A UNIT 4
COMPOSITE GRAPHITE PACKING PROGRAM

Rotors in Limitorque Actuators

Some of the existing rotors in the limitorque actuators were cracked and others were not radiation qualified. The PNGS Environmental Qualification Group identified a suitable replacement rotor (radiation resistant - brown or grey). The rotors were inspected and replaced as required during set-up of the actuators.

Bonnet Studs

A number of bonnet studs were stripped/damaged prior to or during the repacking program. Design required that replacement studs be fabricated from nuclear grade material. The new studs were fabricated by an external company using chrome molybdenum meeting ASME Section III requirements.

SUMMARY

During the PNGS-A Unit 4 Retube/Rehabilitation outage, 50 nuclear valves and 100 conventional valves were repacked with composite graphite packing. The success of the program can only be proven after the HTS has been refilled (November 1992) and operated for a period of time. However, by using a dedicated, trained maintenance crew and completely rehabilitating the valves, there is confidence that the program will provide long term benefits of reduced packing leakage and valve maintenance.

PICKERING NGS-A UNIT 4
COMPOSITE GRAPHITE PACKING PROGRAM

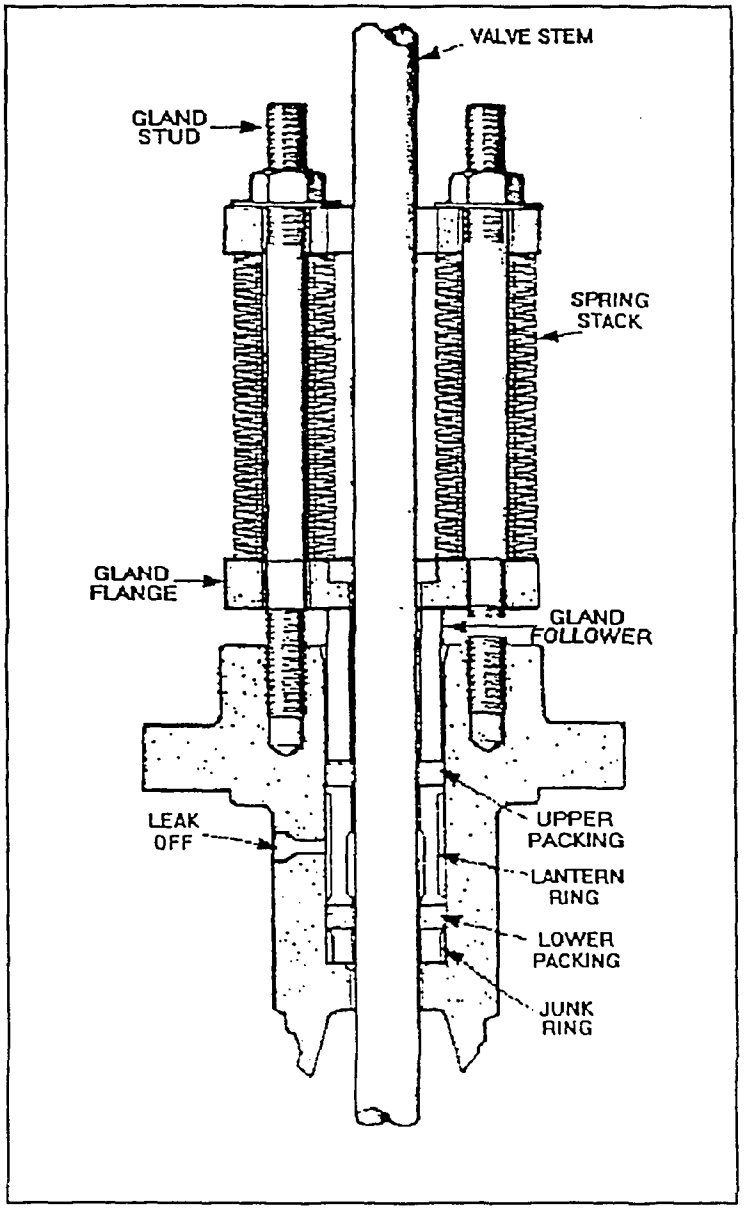


Figure 1
Typical Valve Packing Components

SURVEY SHEET FOR VALVES

DR REF.: _____
VALVE NO: _____
DATE: _____
SURVEY BY: _____

THE FOLLOWING INFORMATION IS REQUIRED TO SELECT COMPONENTS IN LIVE LOADED AND NON-LIVE LOADED VALVES. USE AN ADDITIONAL SHEET IF REQUIRED

GENERAL:
STATION: _____
USI/SIC: _____
SYSTEM NAME: _____
SYSTEM PSI: _____
SYSTEM MEDIA: _____
CYCLE HISTORY: _____

VALVE INFORMATION
MAKE/MODEL: _____
SIZE: _____
PSI RATING: _____
TYPE: _____
OPER. MAKE/MODEL: _____
VALVE NO./SCN: _____
VALVE ORIENTATION: _____

COMMENTS: _____

STUFFING BOX DATA:
A: STEM - DIAMETER ____/____/____
- ROUNDNESS ____/____/____
- STRAIGHTNESS ____/____/____
B: BOX DIA: ____/____/____
C: BOX DEPTH: _____
F: EXISTING PACKING SIZE: _____
NO. OF RINGS: _____
TYPE: _____
G: LEAKOFF: DEPTH FROM TOP OF BOX _____
: DIA. INSIDE OF BOX _____
P: DIA- OPENING @ BOTTOM OF BOX _____
ANGLE AT BOTTOM OF BOX: _____

BUSHING(s) YES: __ NO: __
MATERIAL: _____
INSIDE DIA: _____
OUTSIDE DIA: _____
HEIGHT: _____

GLAND FOLLOWER DATA
A: INSIDE DIA: _____/_____
B: OUTSIDE DIA.: _____
H: TOTAL LENGTH: _____
I: PUSHER LENGTH: _____
J: WASHER CLEARANCE/THK: _____/_____
FOLLOWER TOP & BOTTOM FLAT? YES: __ NO: __

STUD DATA
NO. OF STUDS: _____
K: STUD DIA: ALL THREAD: _____
SWING: _____
HEX. HEAD: _____
L: RADIAL CLEARANCE: _____
M: AXIAL CLEARANCE: _____
N: EXISTING STUD LENGTH: _____
O: MAX. LENGTH OF NEW STUDS: _____

LANTERN RING YES: __ NO: __
INSIDE DIA: _____
OUTSIDE DIA: _____
HGT/LANDING: _____

JUNK RING YES: __ NO: __
INSIDE DIA: _____
OUTSIDE DIA: _____
HEIGHT: _____

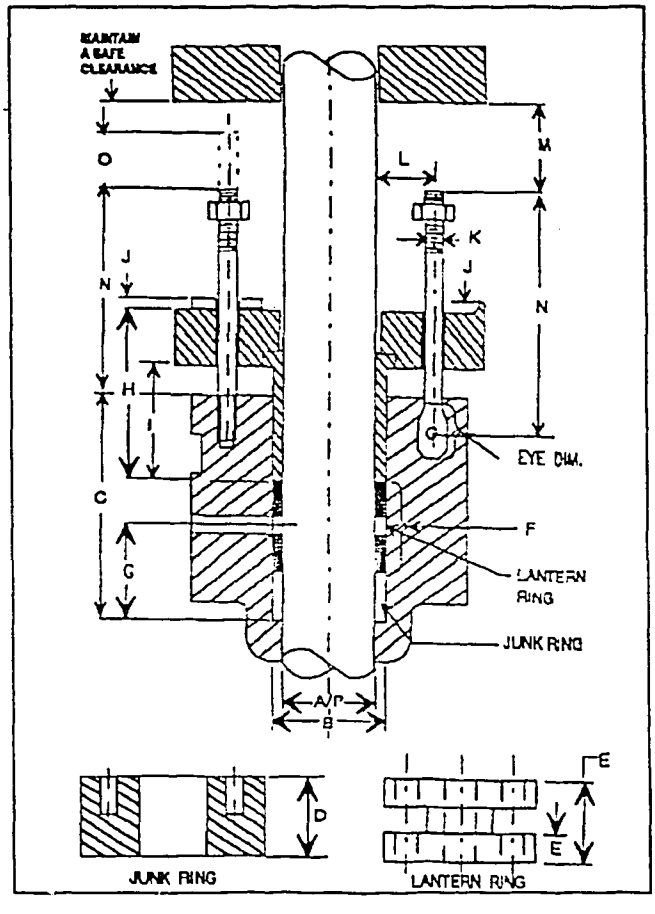


Figure 2 - Valve Survey Sheet

CA9500165

DEVELOPMENT OF RADIATION HARDENED ELECTRONICS

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ABSTRACT

This paper concerns the development of radiation hardened electronics for ITER/NET (International Thermonuclear Experimental Reactor \ Next European Torus) produced by Spar Aerospace Ltd for CFFTP (Canadian Fusion Fuels Technology Project). It describes the development and radiation proving of circuitry required to eventually build a device for multiplexing control and diagnostic signals, initially for ITER/NET. Further applications for radiation hardened electronics are seen as being in data acquisition and, robotic telemetry and control for both electrical and robotic systems employed in radioactive environments

1.0 INTRODUCTION

This paper describes the development and radiation proving of circuitry required to eventually build a device for multiplexing control and plasma diagnostic signals for ITER/NET. Further applications for radiation hardened electronics are seen as being in data acquisition and, robotic telemetry and control for both electrical and robotic systems employed in radioactive environments.

2.0 WORK OVERVIEW

The design, development and proving work of the key radiation hard circuitry was carried out in three phases: phase 1, a conceptual design feasibility study; phase 2, prototype design, manufacture and development; and phase 3, irradiation testing. In Phase 1 a concept design and feasibility study of a Radiation Hardened Multiplexer for ITER/NET was carried out. The primary function of the multiplexer is to reduce the quantity of wiring required for control of the ITER/NET reactor, thereby minimizing the associated penetrations through the vacuum vessel (cryostat) surrounding the torus. In this way the cost, complexity and leakage potential of these penetrations can be reduced. During Phase 1 operational and environmental requirements were established, together with guidelines for equipment design and a conceptual design for the multiplexer. In addition a survey of available component sources was undertaken including both European and North American manufacturers.

Phase 2 built upon the concept design study work to cover additional applications and to produce and develop prototype designs of key circuit elements. The prototype design used all the key circuit elements in an example board with each circuit element being assembled in at least two ways with parts from alternative suppliers.

In Phase 3; gamma and neutron irradiation of a batch of prototype designs was started in September 1992. Results for this were positive, proving that a rad-hard multiplexer device with a life of at least 10^6 integrated Rads can be built using the parts and compensation elements tested. Results of the testing are being analyzed with a view to planning a device with an even higher irradiation life. Figures 1 and 2 show the boards in the hot cell period of irradiation testing.

3.0 DESIGN PHILOSOPHY

The following is a brief description of the I/O multiplexer device and the context of its intended application.
The ITER/NET fusion reactor is to be housed in a 26 metre diameter evacuated cryostat. Since it is basically a research device, there are expected to be as many as 100,000 signals to be conveyed from the reactor torus to the control centre outside the cryostat. Figure 3 shows a typical cross section of the ITER/NET 2 reactor concept.

Obviously this requires a vast amount of cabling to pass through the cryostat wall with each penetration (whether single wire or bundle) impinging on the integrity of the cryostat wall.
Some cables are unavoidable, such as power supplies and ground connections. However, many of the data signal lines can be time division multiplexed, in other words the same physical signal path is switched between different electrical signals over a discrete time interval. A telephone exchange is an example of time division multiplexing signals along a single cable.

To this end the ITER/NET Radiation hardened multiplexer has been conceived. Whilst time division multiplexing is well developed and is widely used in a variety of applications, there are special considerations with respect to the ITER/NET environment which must be addressed.

3.1 Environment Factors

Radiation. The ITER/NET environment calls for gamma and neutron radiation tolerance well in excess of susceptibilities typically bearable by commercial electronic equipment. ITER/ NET radiation levels are closer to those driving military requirements than, for example, typical Space flight requirements. Certain military products conceived in the early 1980s and onwards can survive to fairly high radiation dosage levels with public domain test data available for many of these electronic devices. The more tolerant of these devices have been used where ever possible in this rad-hard electronics multiplexer design.
There is an important difference in testing/ proving practice to note. Experimental radiation data for electronic devices spawned from military requirements is generally for passive radiation, ie the radiation dose is applied whilst the device under test is turned off. Reactor control and plasma diagnostics, as well as use in nuclear manipulators, require that the multiplexer, and therefore the components within it, operate whilst being irradiated.

Pressure. The ITER/NET multiplexer is destined for operation in a vacuum (in-cryostat conditions). Considerations have been made for this in the choice of components, eg. selecting ceramic pack and hermetically sealed devices. Whilst the irradiation testing of circuitry is being carried out at Standard Temperature and Pressure (STP), cooling considerations have been borne in mind for any production units.

Magnetic Fields. Depending upon the final location of the multiplexer within the cryostat, high magnetic fields may be experienced from magnetic plasma containment coils. This means that care in designing a power supply and the selection of some component will be necessary.

Electric Fields. Electric fields induced in the reactor signal cabling may be as high as 2.5kV. Because of this floating front end data acquisition amplifiers are employed and signal outputs are via opto-isolators.

3.2 Design Criteria

In designing the rad-hard electronics to meet the above conditions, the principal risk is in coping with the expected radiation environment. In particular, there are several features regarding performance during test that are unconventional when compared with other designs based purely on 'passive' irradiation of individual components.

a) We are designing for system performance of the multiplexer, in that the overall circuit performance from input to output is being proved. This is in contrast to simply testing the individual components that make up the device. This is a

particularly valuable exercise since data on passive irradiation performance of most key individual components can be obtained from various existing sources.

b) A "radiation effects correction" technique is being used during irradiation. This attempts to correct for irradiation induced effects within the electronics design during the course of actual irradiation. The intent of this design feature with regards to production units is twofold. First it allows for periodic self-calibration to take place. Second, by monitoring the amount of offset correction needed, it allows us to predict and carry out the change-out of equipment before end of life is reached, ie thus actively performing preventative maintenance.

c) The multiplexer is powered up and results are taken whilst the electronics are being irradiated. This proves the performance in conditions representative of its intended application.

4.0 COMPONENT CHOICE & DESIGN GUIDELINES

Each sensor circuit is isolated by means of opto-isolators. Signals from the front-end are filtered, multiplexed, offset corrected and then converted to a 12-bit digital representation via a sample-and-hold amplifier and analogue-to-digital converter. The components used in the demo are principally restricted to devices which have been previously radiation characterized in order to reduce cost and design time. Device technology plays an important part in radiation tolerances and preference has been given to those devices with triple passivation and isolated structures. Horizontal PNP transistors have been avoided. The circuit design has been based on the following techniques:

- Low impedances to minimize the effects of bias current degradation.
- Split total gain between multiple stages to minimize the effect of a reduction in the open loop gains of devices (otherwise noise performance could be degraded).
- Ultra low noise power devices to minimise the effects of power supply rejection loss, and adequate decoupling and filtering of all power parts.
- Derating of all device dynamic parameters, e.g. voltage swing, slew rate, settling time, and conversion time.
- Provisions for adjusting gain and offset.
- Use of instrumentation grade passive components in particular, signal conditioning resistors and capacitors.
- Circuit and cable layouts which keep loops to a minimum,

given the high magnetic fields that might be encountered.

- Magnetic shielding in the form of low reluctance packaging.
- Gamma and neutron shielding.
- Sensor over sampling to facilitate downstream signal processing.

5.0 DEVICE SPECIFICATION

Sensitivity

Input signals can be voltage or current; the current input circuitry has a minimum sensitivity of 5μV

Frequency Response

Up to 10kHz (dependent on the number of inputs to be multiplexed versus the frequency response required)

Gain Range

25-1000 V/V

CMR (Common Mode Rejection)

125dB @ G=100

Noise

4.9nV/$\sqrt{Hz}$ typical

Number of Inputs

Thirty-two 1kHz signal inputs (oversampled at 2kHz) routed to a single output. This represents a single multiplexer module. More may be combined to give more channels at 1 kHz. Or, conversely, the less the frequency response needed per channel (eg for temperature sensors or strain gauges) the more inputs per single module are available. This is because there is a trade-off between input frequency response and the number of inputs for a given maximum sampling rate.

Radiation

Designed to meet a gamma 1 x 10^6 Rads (Si) total dose at a fluence of 8.6 x 10^7 gammas/cm^2/sec and a neutron total dose of 1 x 10^{12} neutrons per cm at a fluence of 1 x 10^8 neutrons cm^2/sec. Testing has shown an operational total integrated dose of 1 MRad for the device with a suitable factor of

safety applied. Neutron shielding is required to satisfy the neutron total dose requirement of 1×10^{15} neutrons cm^2 and this is achieved by the use of boronated polyethylene.

6.0 CIRCUIT DESCRIPTIONS

A block diagram of the circuitry is shown in Figure 4. From the initial concept and feasibility work the following functional blocks have been incorporated into the design of the radiation hardened electronics circuitry:

Instrumentation Amplifier

The design is based on a three operational amplifier configuration. It also includes a shield driver to improve the rejection of common mode signals.

Active Filter

Their are two different bandwidths selectable: 1kHz and 10kHz. This is accomplished by selecting appropriate values of integrating capacitors.

Opto-Isolator

The design utilizes a commercially available opto-isolator to provide a signal link with a linearity of greater than 12 bits. The opto-isolator consists of a GaAs emitter and PIN diode detectors, yielding a radiation tolerant configuration.

Multiplexer (MOS Switches)

The circuit provides two levels of multiplexing to yield an overall ratio of 16:1. Two level multiplexing reduces the impact of switch capacitance on bandwidth as well as increasing the effective isolation. Two different commercial MOS switches have been evaluated during the irradiation tests.

Digital-to-Analogue (D/A) Converters

Two commercially available D/A converters are being evaluated. They can be used both for output circuits and to provide a dynamic offset correction to a selected signal channel during operation.

Analogue-to-Digital (A/D) Converter

The A/D converter is used to digitize (to 12 bits) the analogue signal from the sensor front end amplifiers, after being stabilized for the conversion time by a sample-and-

hold circuit. There are three A/D Converters being evaluated, two of which are commercially available, the third of which is a custom Spar design based on discrete components.

Sample-and-Hold

Two sample-and-hold designs are being evaluated, one a commercial product, the other a Spar design. The Spar design includes two buffers with a FET feeding the sample capacitor. Compensation circuitry is included.

7.0 FUTURE PLANS

The current application is intended for multiplexing control and data signals in experimental fusion reactor designs. In the fusion industry medium gamma radiation levels are expected for most applications, ie 10^3 to 10^6 Rads total dose. This level is similar to that for fission plant retubing, refurbishment, fuel handling, decommissioning, reprocessing and waste management. The higher radiation levels predicted for much remote handling work will require a further generation of development. R&D work is underway at Spar to produce radiation hardened electronics suitable for meeting this challenge.

SPAR are also considering other possible applications of the current design. One option may, for example, consist of I/O Modules to form a system as per figure 5.

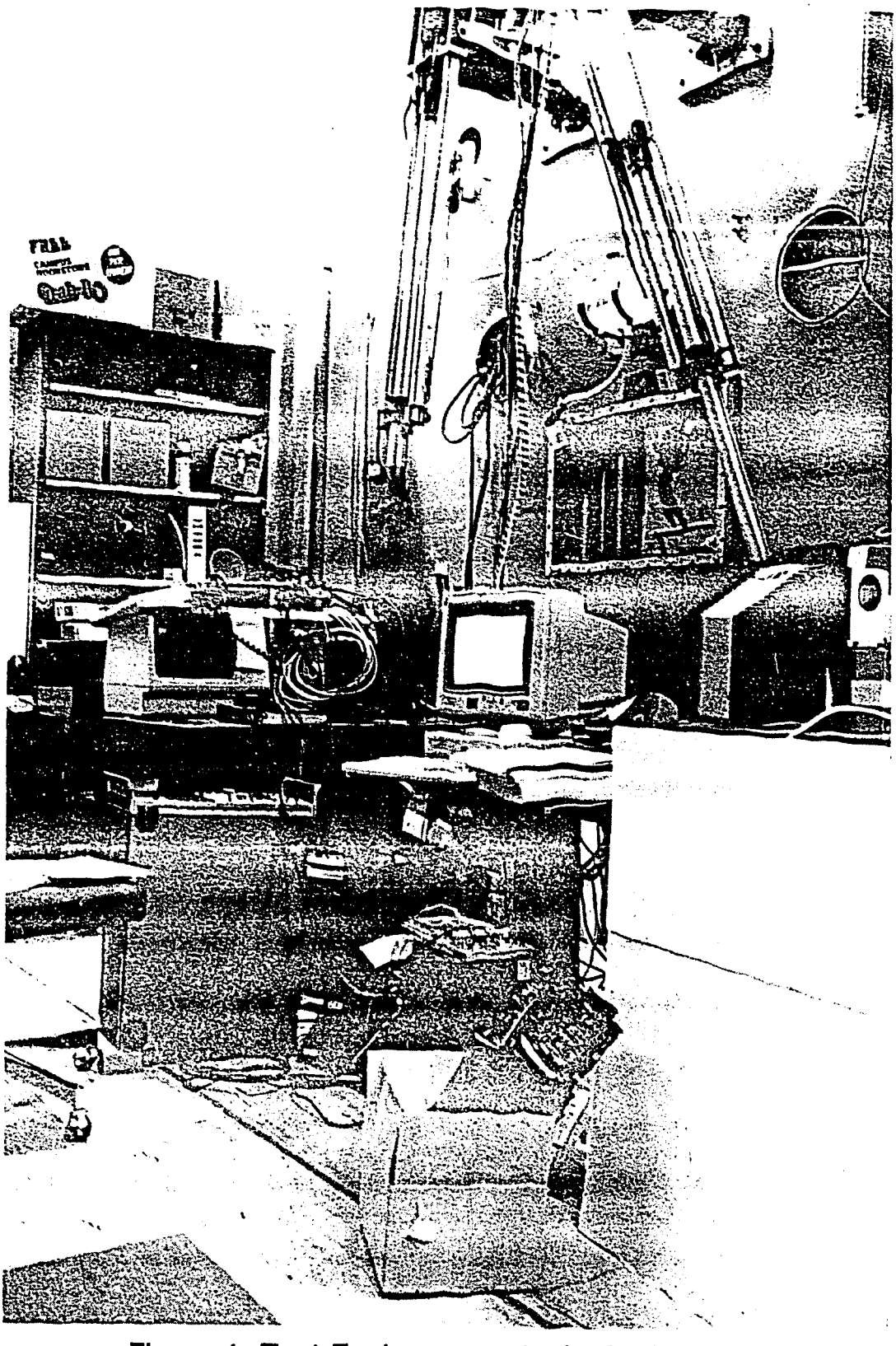

Figure 1 Test Equipment outside the Hot Cell

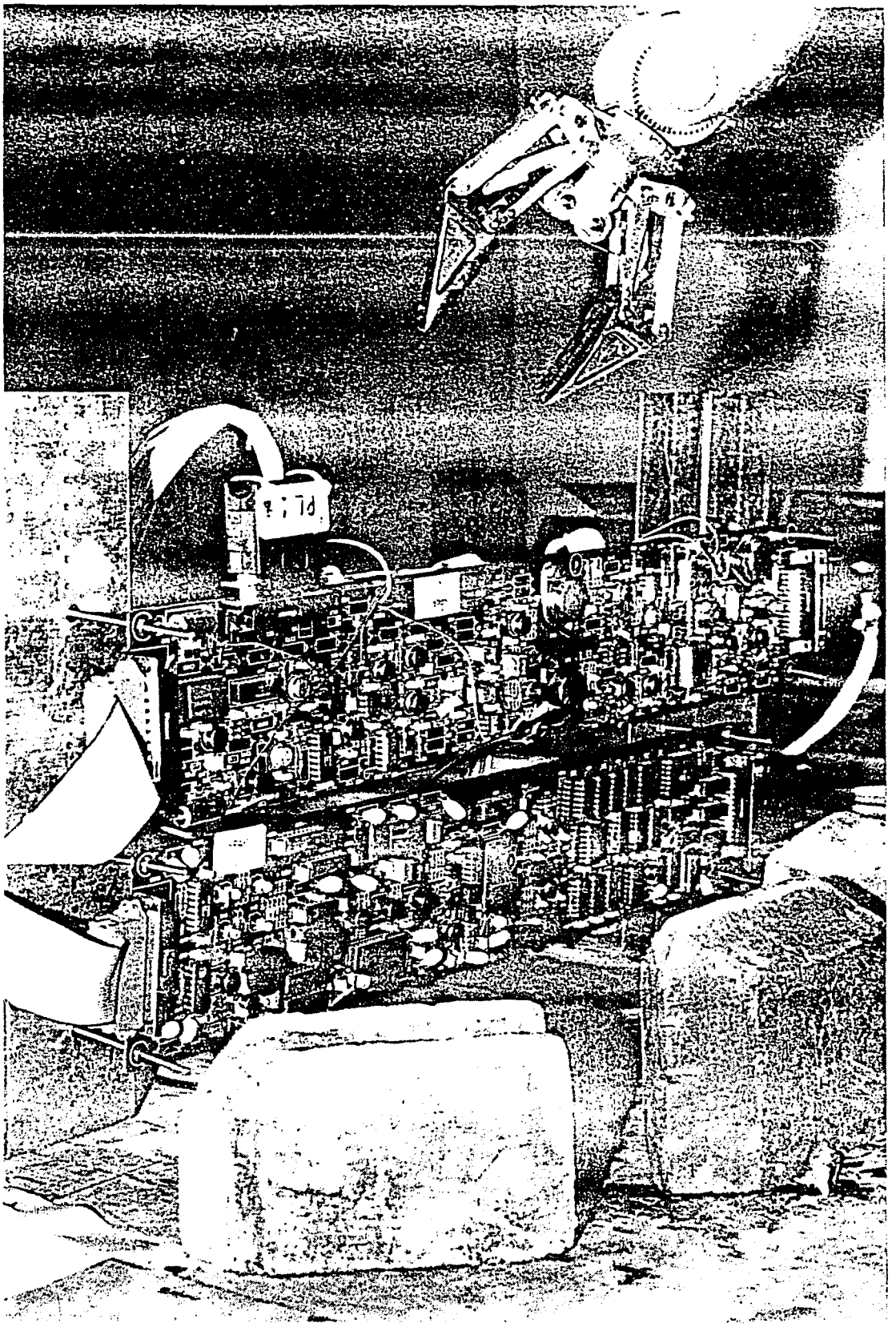

Figure 2 Test Boards inside the Hot Cell

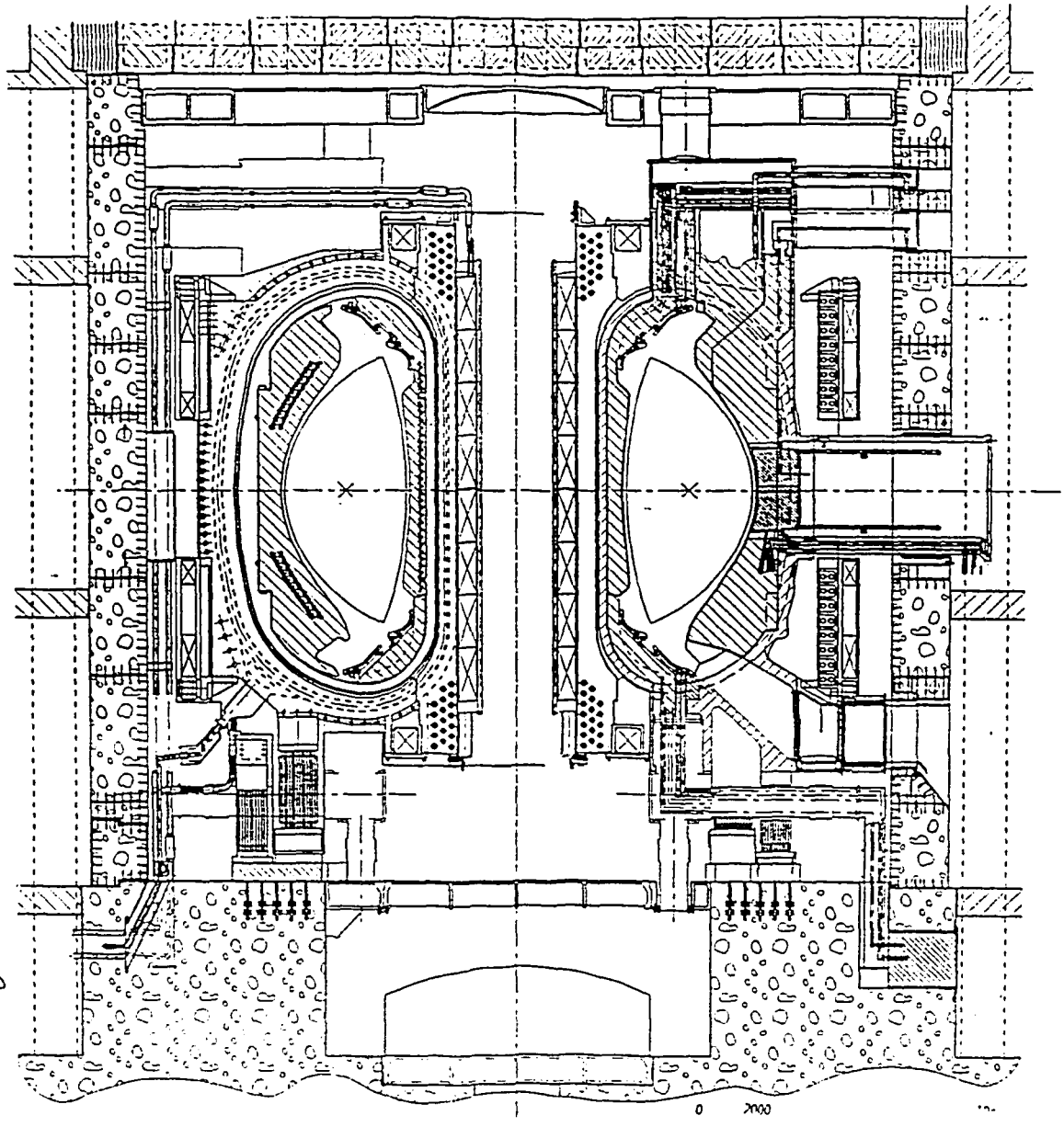

Figure 3 ITER/NET 2 typical Reactor cross section

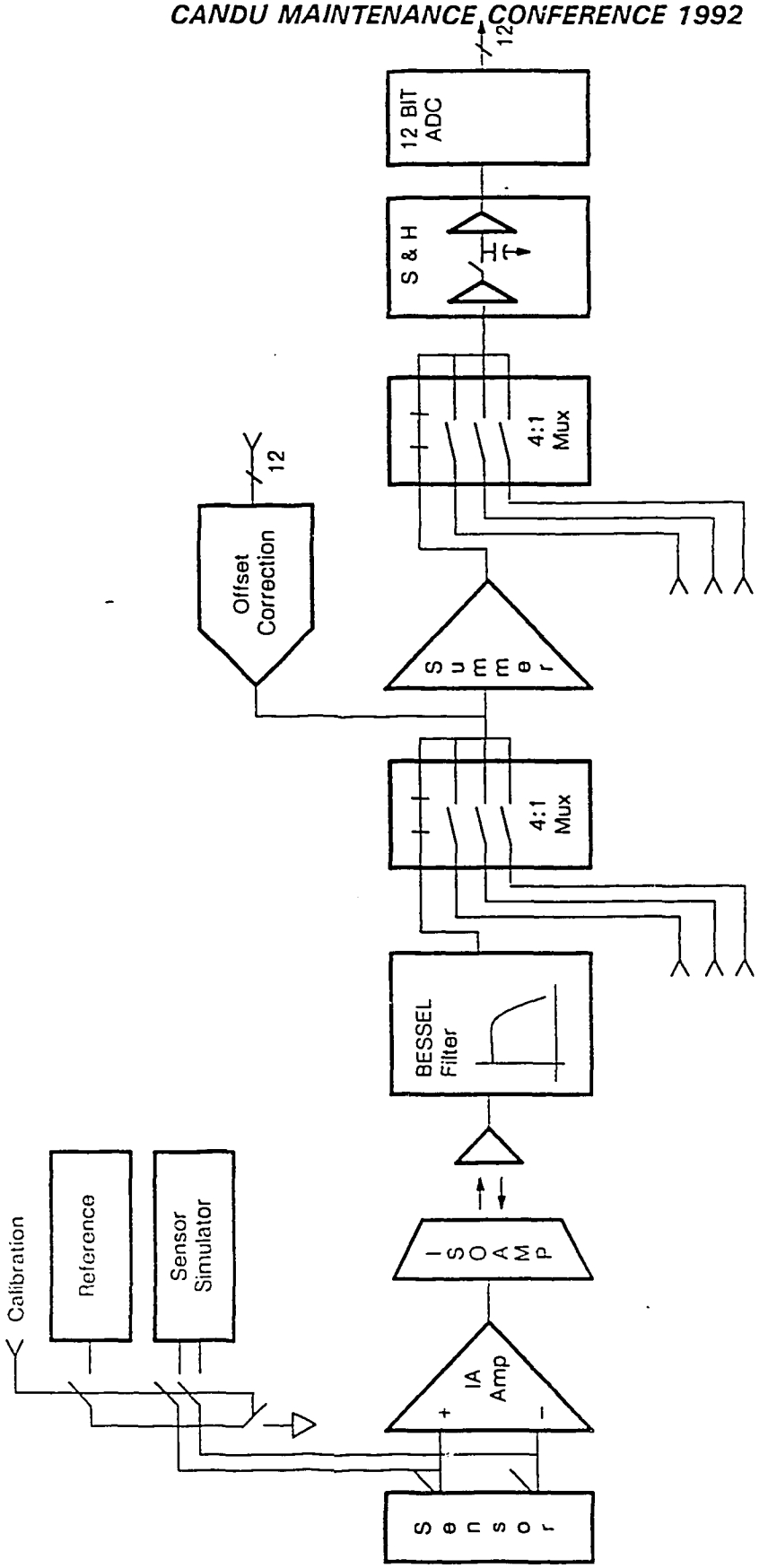

Figure 4 Radiation Hard Multiplexer Block Diagram

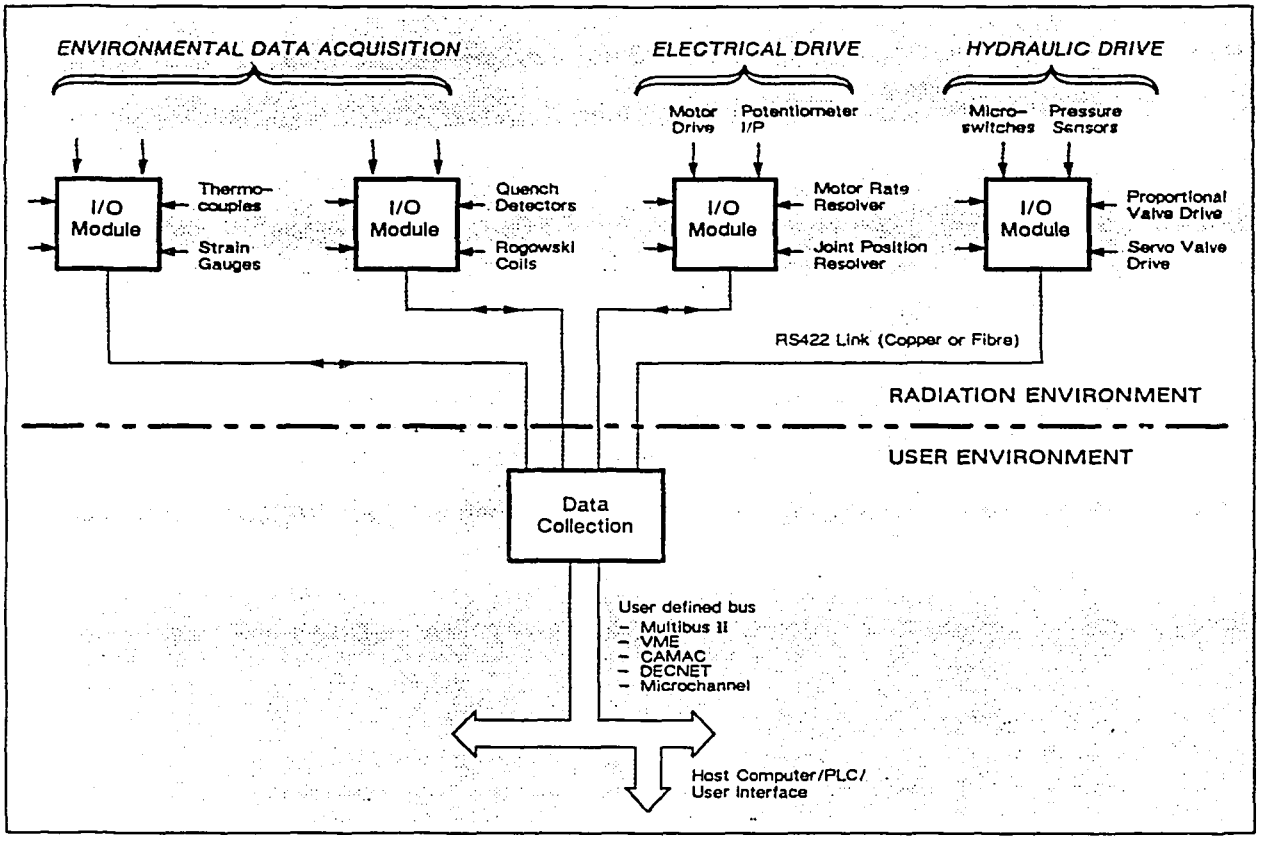

Figure 5 Typical Rad-Hard I/O System

Uses of the system may include the following:

Environmental Data Acquisition
- Sensor Data Collection, such as strain gauges, thermocouples, Rogowski Coils, Quench detectors

Robotic Telemetry and Control

Electrical Drive:
- Rate and position sensing via resolvers, inductosyns, encoders or potentiometers.
- Motor Drive Amplifiers
- Microswitch Inputs

Hydraulic Drive:

- Rate and position sensing via resolvers, inductosyns, encoders or potentiometers.
- Pressure sensors
- Servo valve drives
- Proportional valve drives

8.0 ACKNOWLEDGEMENTS

The authors acknowledge the valuable contributions made to this work by colleagues at Spar, CFFTP and NET.

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ROBOTICS FOR STEAM GENERATOR MAINTENANCE

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Nuclear Operations Central Division

ABSTRACT

This paper documents the recent use of robotics to perform steam generator tube plugging in Ontario Hydro's nuclear power plants.

ROBOTICS FOR STEAM GENERATOR MAINTENANCE

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1.0 INTRODUCTION

Ontario Hydro operates five, four unit CANDU nuclear power stations. The 542 Mw Pickering A and 540 Mw Pickering B units are located on Lake Ontario east of Toronto, and have 12 steam generators per unit, each with approximately 2600 tubes. The 904 Mw Bruce A units are located northwest of Toronto on Lake Huron, and have 8 steam generators per unit , each with 4200 tubes. The 915 Mw Bruce B units are on the same site as Bruce A and have similar generators. The 935 Mw Darlington units are located east of the Pickering station and have four steam generators per unit, each with approximately 4600 tubes. All steam generators are Babcock and Wilcox Canada recirculating boilers with U-tubes. Overall, Ontario Hydro has 196 steam generators with 593,000 tubes in operation.

The steam generator designs with relatively small primary bowl, and tube size has resulted in a need for compact manipulators and associated tooling.

This paper will describe the manipulators and tooling recently acquired by Ontario Hydro to plug steam generator tubes remotely at Bruce and Pickering NGS's.

2.0 BACKGROUND

Pickering - Design Data

The Pickering steam generator (S.G.) tubing is fabricated from seamless, cold worked and annealed Monel 400. The nominal tube outside diameter is 12.60 mm (0.496 in.) with a 1.24 mm (0.049 in.) wall thickness. The S.G. primary bowl internal radius is approximately 813 mm (32 in.). The round manway cover rests in the bottom of the primary bowl during plugging operations. The plug designed for the Pickering application is manufactured from Monel 400 material to the requirements of ASME SB164. The plug design and weld was analyzed for all conditions as specified in the original S.G. design requirements. Although the plug is not a registered component with the jurisdiction, the welding procedure must be registered and the welding operators must be qualified to the procedure to meet jurisdictional requirements.

Bruce - Design Data

The Bruce steam generator tubing is fabricated from seamless cold worked and annealed Inconel 600. The nominal tube outside diameter is 12.95 mm (0.510 in) with a 1.12 mm (0.044 in.) wall thickness. The S.G. primary bowl radius is approximately 1067 mm (42 in.). The round Bruce A manway cover rests in the bottom of the primary bowl during plugging operations while the oval Bruce B manway cover can be removed and is therefore not an internal obstacle to remote manipulators.

The plug designed for the Bruce application is manufactured from INCO 82. The plug design and weld was analyzed for all conditions as specified in the original S.G. design requirements. Although the plug is not a registered component with the jurisdiction, the welding procedure must be registered and the welding operators must be qualified to the procedure to meet jurisdictional requirements.

Darlington - Design Data

The Darlington steam generator tubing is fabricated from seamless cold worked and annealed Incoloy 800. The nominal tube outside diameter is 15.88 mm (0.625 in.) with a 0.99 mm (0.039 in.) minimum wall thickness and a 1.19 mm (0.047 in.) maximum wall thickness. The S.G. primary bowl radius is approximately 1626 mm (64 in.) from a point centred approximately 8 " above the secondary side of the tubesheet. This results in a vertical clearance of 965 mm (38 in.) at the divider plate. The oval manway cover can be removed and is therefore not an internal obstacle to remote manipulators.

Further steam generator design information which affects some of the tooling design features is illustrated and listed in Figure 1 and Table 1.

Background

The early tube plugging that was performed on the steam generators was performed manually using either explosive plugs or manual TIG (Tungsten Inert Gas) welding. Manual operation was acceptable for the following reasons:

(1) Only minimal maintenance was required due to excellent performance of steam generator tubes (only 67 tubes plugged in-service prior to Dec. 1990, see Figure 2 for plugging history) .

(2) Relatively low initial radiation fields in the steam generator primary head (375 to 475 mrads/hr gamma and 600 to 800 mrads/hr. beta).

(3) Primary head decontamination techniques were successful in further reducing the radiation field (dose reduction factor of 2 for gamma and 4-5 for beta radiation).

(4) Radiation dose uptake limits were high (5 rem/year, 3 rem/quarter).

(5) Manual techniques were cost effective for small scale plugging jobs.

More recently, the manual techniques have become unacceptable for the following reasons:

(1) S.G. tube performance deteriorated resulting in a larger number of tubes to be plugged. (see Figure 2 for plugging history)

(2) The radiation dose uptake limits were reduced (1 rem/year averaged over a 5 year period).

(3) The number of personnel that could be easily trained to perform manual tube plugging was limited.

(4) Remote techniques were more cost effective for large scale plugging jobs.

In early 1990 Ontario Hydro awarded a contract to ABB-Combustion Engineering to design and build remotely welded tube plugging equipment for the Bruce steam generator design. The specific need at the time was to have the capability to plug large numbers of steam generator tubes due to fretting damage at Bruce B. The same tooling has been subsequently used for plugging at Bruce A and modified to work in the both PNGS A and B steam generator designs.

3.0 PROCESS DESCRIPTION - PLUGGING

The steps and tools required to install a remotely welded tube plug are:

1.) Identify and mark the tube
2.) Brush the tube
3.) Size roll the tube entrance
4.) Insert the water plug (if required)
5.) Swab the tube
6.) Insert the plug
7.) Weld the plug
8.) Visually inspect the weld

These steps are performed with four tools:

1.) Rolling motor
2.) Plug inserter
3.) Weld head
4.) Visual inspection camera

The steps required to remove a welded plug are:

1.) Machine to remove weld
2.) Grip the plug and pull it out of the tube

These steps are performed with the following tools:

1.) Milling Tool
2.) Hydraulic Plug Remover

To control the tools described above three main control components are required: The control panel, solenoid box and welding power supply/pendant. The tool operator controls all of the tools from outside containment and is normally located in a trailer. The operator controls all tool operations except for plug welding at the control panel. The welding power supply pendant is located in the trailer and is used to control the welding power supply located in containment, which in turn controls the weld head. The solenoid box is located near the steam generator manway . All of the tools except for the plug welding tool are directly connected to the solenoid box. The solenoid box is in turn controlled by the control panel located in the trailer. Figure 2 shows the block connection diagram for remote tube plugging.

4.0 PLUGGING TOOLS

The following is a listing of the various tools which may be used during plugging operations:

4.1 CONTROL PANEL

The control panel is used to control the remote tooling via corresponding switches on the panel. The panel contains the power supplies which power the solenoid box, tool cameras, and the milling machine. The control panel also contains video monitors and a VCR.

Video switches are mounted on the panel to allow viewing of up to four video images: two tool cameras and two auxiliary cameras.

4.2 SOLENOID BOX

The solenoid box is an electrical pneumatic junction box. The solenoid box contains 1.) Air regulator, moisture separator and air lubricator assembly, and 2.) solenoid valves which control pneumatic equipment: rolling motor, plug inserter, etc.

4.3 TOOL COUPLER

The tool coupler incorporates a lock/unlock function which is controlled by the control panel. One limit switch is used to indicate when the maximum vertical travel has been reached by any tool while working on or near the tubesheet.

4.4 ROLLING MOTOR

The rolling motor is a pneumatic motor with a right angle head and a quick change chuck. The rolling motor provides power for brushing and size rolling the tube.

4.5 PLUG INSERTION TOOLS

Plug insertion is accomplished using the plug carousel and the plug inserter. The carousel is a storage device which holds up to 25 plugs. The carousel is locked to the S.G. tubesheet by a gripper which grips the I.D. of a S.G. tube. The carousel installation is accomplished by mounting the carousel on the plug inserter and transported to a convenient location with the manipulator arm.

The plug inserter is a pneumatic impact hammer which drives the plug into the steam generator tube.

The carousel and single plug inserter are powered and controlled through the solenoid box via the control panel.

4.6 WELDING POWER SUPPLY & WELD HEAD

The welding process is an Autogenous (Tungsten Inert Gas) process with Argon used in the Bruce application and a Helium/Argon mixture for Pickering.

The orbital weld head is delivered to the tube location by the flexivera manipulator. The weld head has a local elevator which is used to perform the weld mandrel insertion in the vertical direction. The use of this elevator has helped eliminate some of the earlier problems associated with using the manipulator elevator to perform this fine motion. Final control of the weld head is performed via the weld head pendant. The pendant is remotely located in the plugging trailer. During the first several plugging campaigns the welding operator was required to sit in containment next to the welding machine. The equipment was modified to control the welding operation from the remote trailer location. This system modification has resulted in reduced radiation dose uptake and increased plugging rates.

The welding machine is an ARC Machine, model 215. The welding machine and cover gas bottle are located within 35 metres of the S.G.

The weld head design does not allow for plugging in rows 1-3 at either Pickering or Bruce. These are the first three rows next to the primary bowl divider plate.

4.7 VISUAL INSPECTION TOOL

The visual inspection tool is an inspection device designed to inspect the interior, exterior and frontal views of a weld fusing the tube plug to the S.G. tube. This tool consists of a colour CCD camera, two mirror assemblies and a light source. The light intensity and camera focus are remotely controlled from the trailer. When properly situated the I.D. mirror reflects a panoramic image of the weld fusion line and heat affected zone on the interior surface of the tube plug to the camera. With minimal adjustment of light intensity and focus the O.D. mirror will reflect a panoramic image of the weld fusion line and heat affected zone on the exterior of the steam generator tube as well as part of the tubesheet fillet weld. Also with minimal adjustment the frontal view of the fusion weld may be viewed. The weld magnification is approximately 10X.

Approval was required from the local Boiler and Pressure Vessel jurisdictional authority (MCCR) to use a visual inspection technique in lieu of a dye penetrant inspection which was previously used for manual welds. The use of this remote inspection technique also contributed to overall radiation dose reduction during tube plugging.

4.8 MILLING TOOL

The milling tool uses a pneumatic motor to power the cutter. The cutter motor assembly is positioned using an electric motor feed assembly. Both of these motors are controlled from the control panel in the plugging trailer. The tool feed rate is controlled by adjusting the current supply to the motor. Two pneumatic outboard grippers are used to align the cutter with the tube/plug centre line during plug removal as well as transfer any resultant torques to the tubesheet instead of the manipulator arm. The grippers are also fitted with limit switches to activate a level light on the control panel. Cutting collars are used to provide a positive stop to prevent milling any further than required.

4.9 PLUG REMOVAL TOOL

This is a tool which hydraulically grips and extracts a tube plug prepared for removal from a tube by the previous application of the milling tool. A gripper assembly is inserted into the plug I.D. The gripper is expanded with a mandrel/cam and the plug is extracted with any reaction load being transferred to the tubesheet between tubes.

4.10 TOOL CAMERA

The tool camera used is a Sony HVM-42C, with auto iris lens and a microphone. The camera is installed in a fixture equipped with an adjustable fuse light. The camera is set a fixed focal length for all tools and provides a local view of each tool as it enters the tube in the tubesheet.

The operation of tooling can be monitored by use of the camera's audio capabilities. Volume control is located on the control panel.

4.11 TUBESHEET PAN & TILT CAMERA

The tubesheet pan & tilt camera assembly is used to watch any plugging operation in progress in the S.G. and monitor the position of the manipulator arm, leg and any associated cabling/hoses or tools.

The camera assembly is remotely installed by the manipulator, will grip the interior of a steam generator tube and support itself there. The camera/lens functions include low light capability, remote manual iris, remote manual focus, remote manual zoom, and remote light intensity control. All the preceding features as well as pan and tilt are controlled from the plugging trailer via a single coaxial cable and multifrequency control.

4.12 TUBE MARKING TOOL

The marking tool attaches to the rolling motor and uses soapstone as the marking agent. The marking tool is spring loaded and when rotated at a tube location, a white ring is produced on the fillet weld around the selected tube. The white soapstone ring stands out clearly against the black magnetite layer which adheres to the tubesheet.

4.13 ECT PROBE GUIDE

The ECT (Eddy Current Testing) probe guide assembly can be used to deliver ECT probes or for the installation of flexible tube stakes with the flexivera manipulator. The probe guide is also fitted with a tool camera.

5.0 MANIPULATOR

The Flexivera remotely controlled manipulator used for plugging operations is designed and built by Vermatt Technics BV of the Netherlands with specific modifications by ABB-Combustion Engineering.

The Flexivera Manipulator designed for Ontario Hydro was initially sized and built for the Bruce S.G. design and has

been subsequently modified to fit into the Pickering S.G. design.
The manipulator offers the following features:

-Four computer controlled degrees of freedom
-An absolute accuracy of +/- 2 mm
-A repeatable accuracy of +/- 0.1 mm
-Weight of arm with cabling is 17 kg
-Weight of leg with cabling is 34 kg
-The tool speed is adjustable up to 250 mm/sec.
-Tube to tube transit time is 1-3 sec.

The Manipulator system includes the following components:

5.1 IN CONTAINMENT COMPONENTS

The leg and arm and the associated control cabling are the only in-bowl components of the manipulator system. The existing leg designs require unique legs for both Pickering and Bruce bowl designs. The same arm can be used at both Pickering and Bruce but it does require some minor modification to the joint lengths to ensure that the longer Bruce arm will fit and work in the PNGS bowl. The modification to the arm can be performed in approximately 2-4 hours.

The leg and arm do not require entry into the bowl for installation. Installation is performed with the use of an installation rod and a tackle device.

The temporary tackle is inserted in a previously marked tube and secured by a hydraulic finger. The leg is attached to the opposite end of the tackle and then pulled into the S.G. and located in its proper position with hydraulic fingers in the tubesheet and a pneumatic cylinder which actuates a foot at base of the leg.

The arm can be installed in a similar manner by using the tackle or if the dose rate is sufficiently low it is relatively simple to manually reach into the bowl to hang the arm from the leg.

The Leg/Arm installation process is relatively short and only takes 5-10 minutes. This is the time period commencing with tackle installation until the arm is hanging from the leg. Typically it takes 1 hour to move the manipulator from one side of the S.G. to the opposite side. This requires the efforts of two people working next to the steam generator and one person at the control station in the plugging trailer.
The majority of the tubes can be accessed from one manipulator position for both Pickering and Bruce. However to get access to all tubes the manipulator must be relocated.

The remainder of the in containment components are a junction box for cabling interconnects, manway control box for locally

controlling the leg functions and a hydraulic pump to supply the leg.

5.2 OUTSIDE CONTAINMENT COMPONENTS

The computer/monitor/keyboard, the control console and a control cabinet are the out of containment components. Effectively the operator has two separate means of manipulator control. The first method of control being the computer and the associated software. The second method is the control console with a joy stick and control switches.

The description of the control system can be quite extensive so only some of the basic operational features will be described.

For manipulator movements the operator makes use of a CRT display which depicts either the primary or secondary side view of the tubesheet, the row/column position of the tube which is being worked on and a trace on the CRT of all motions made in the x-y plane. The additional information used for manipulator motion is the tool camera view as well as the tubesheet camera view. Generally operators make use of a combination of computer and control console motions. The choice of which mode of operation used will depend on the motion required. Where a gross motion is required like moving from tube to tube, computer control will generally be used but when fine motion control is required like inserting the visual inspection tool into a welded plug then a manually controlled motion will be used via the control console. The operators spend approximately half their time making use of computer controlled motions and the other half in manual control.

6.0 OPERATIONAL EXPERIENCE

The benefits that were anticipated when remote tube plugging was initiated was a reduction in the absorbed dose and no reduction in the plugging efficiency.

A reasonable comparison of dose reduction were two separate plugging campaigns at Pickering NGS. In the first plugging campaign (PNGS Unit 5, 1991) remote tube plugging capability was not present and 172 tubes were plugged manually with a commitment of 20 rem shared by all non-station staff. Remote tube plugging was later introduced (PNGS UNIT 5, 1992) and 1145 tubes were plugged remotely with a commitment of 7.4 rem shared by all non-station staff. The comparison indicates that manual techniques will require 116 mrem/tube compared to 6.5 mrem/tube using remote techniques. Additionally the manual technique will be more sensitive to increasing dose rates or local radiation hot spots.

The original design criteria applied to remote tube plugging was 2 plugs installed per hour. During the Pickering remote

tube plugging project plugging rates of 4 plugs per hour were achieved and occasionally 6 plugs per hour. This plugging performance has met and exceeded our requirements for large scale plugging efficiency.

The drawback to remote tube plugging is the plugging efficiency when only several tubes must be plugged per steam generator. There is an initial commitment to laying of cables in containment as well as a commitment to set up and perform functional checks on all associated equipment.

One of the additional benefits achieved through the application of remote tube plugging has been the weld quality consistency. The weld quality is much less dependent upon an operator's skill at working in a confined space and more dependent upon the proper operation of hardware and process control variables. One of the techniques implemented to provide assurance of proper welding control is the production of weld quality control samples just outside the S.G. head at preset intervals or when the job supervisor has identified that a major component must be changed. The Q.C. weld samples are sectioned in the plugging trailer and etched in the station chemistry lab. The weld quality is then ascertained and minimum leak path measured in the plugging trailer by Q.C. personnel.

7.0 OTHER APPLICATIONS

This Flexivera manipulator has also been used for Eddy Current inspections, for flexible tube stake installations and for identifying locations where tubes have been plugged previously.

8.0 ACKNOWLEDGEMENTS

The authors would like to acknowledge contributions to this paper from S. Crabtree and E. Williams of ABB-Combustion Engineering and C.C. Maruska, M.S. Upton, R.M. Guy, Y. Sakuma, B. Whalen and K. Braun of Ontario Hydro.

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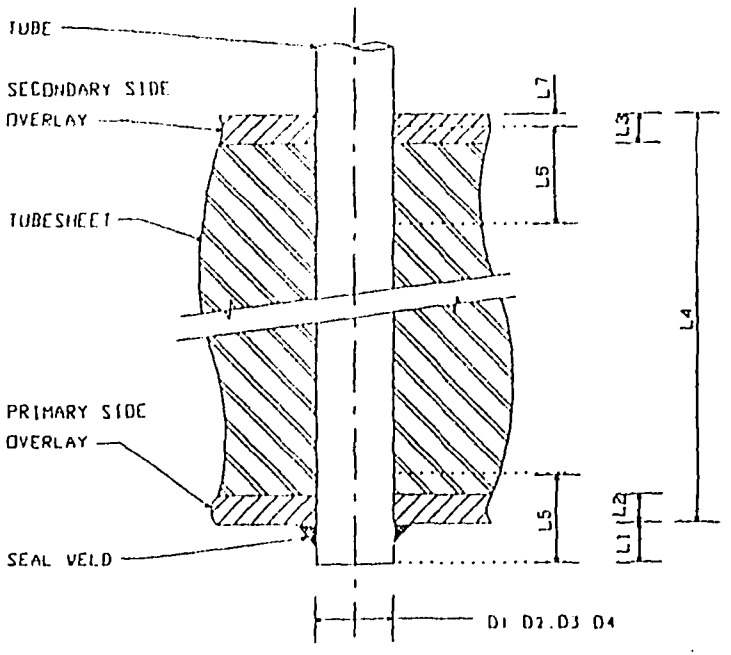
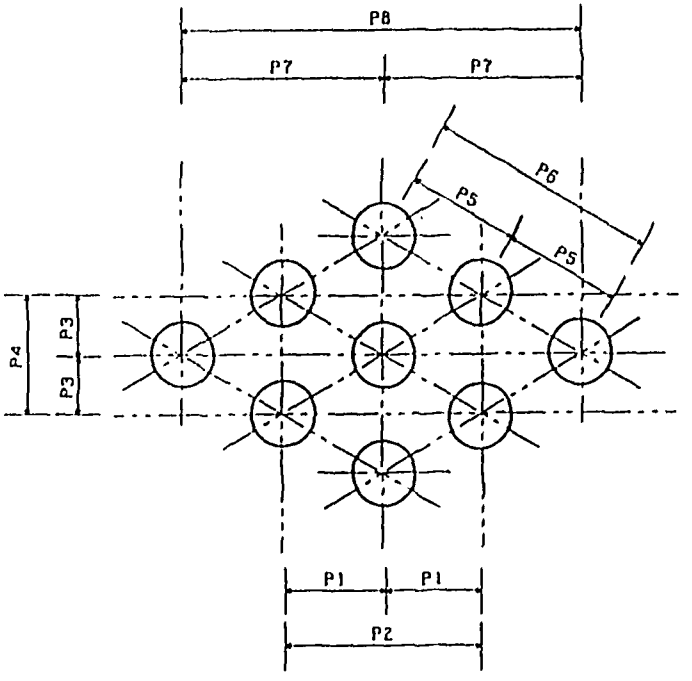


TUBE EXPANSIONS



TUBE PATTERN

SKETCHES OF TUBE PATTERN AND TUBE EXPANSION IN THE STEAM GENERATOR TUBESHEET

FIGURE 1

TABLE 1

	Item	Pick A	Pick B	Bruce A	Bruce B	Darl
P1	Tube Spacing	0.6495	0.6495	0.693	0.693	0.8357
P2	Tube Spacing	1.299	1.299	1.386	1.386	1.6714
P3	Tube Spacing	0.375	0.375	0.4	0.4	0.4825
P4	Tube Spacing (Pitch)	0.75	0.76	0.8	0.8	0.965
P5	Tube Spacing	0.75	0.75	0.8	0.8	0.965
P7	Tube Spacing	1.299	1.299	1.386	1.386	1.6714
L1	Tube Protrusion	0.1875	0.186/0.25		0.218	0.150/0.210
L2	Primary Overlay Depth	0.25	0.312	0.31	0.297	0.414
L3	Secondary Overlay Depth	0.25	0.187	none	none	none
L4	Tubesheet Thickness	11.5	12.129	14.8	14.25	19.02
L5	Primary Expansion Length	1.25	1.125			5
L6	Secondary Expansion Length	1.25	1.125			0.75
L7	Secondary Crevice Depth	0.125	0.125	0.125	0.125	0.125
D1	Tube Outside Diameter	0.496	0.496	0.51	0.51	0.625
D2	Tube Thickness	0.049	0.049	0.044	0.044	0.0445
D3	Tube Hole Diameter, max		0.511		0.525	0.643
D4	Tube Hole Diameter, min		0.504		0.516	0.633
	Number of Tube Supports	8	9	7	7	11
	Tube Support Type	Lattice	Trefoil	Trefoil	Trefoil	Lattice
	Tube Support Material	CS	CS	CS	CS	410S
	Tube Material	Monel 400	Monel 400	Inconel 600	Inconel 600	Incoloy 800
	Tube Straight Length, max (ft)		31.7	27.5	27.5	

STEAM GENERATOR DIMENSIONS - INCHES

STEAM GENERATOR TUBE PLUGGING HISTORY

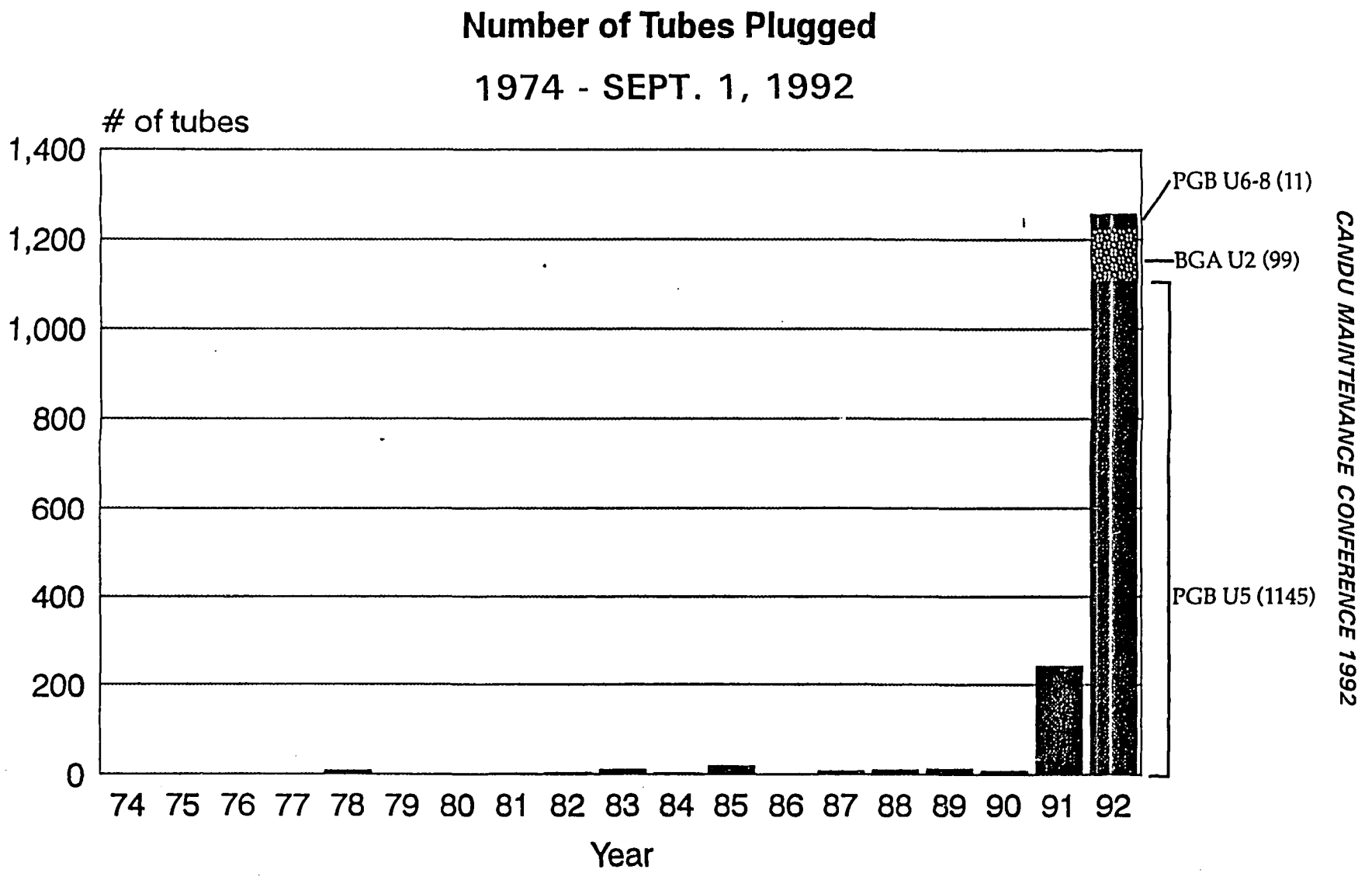
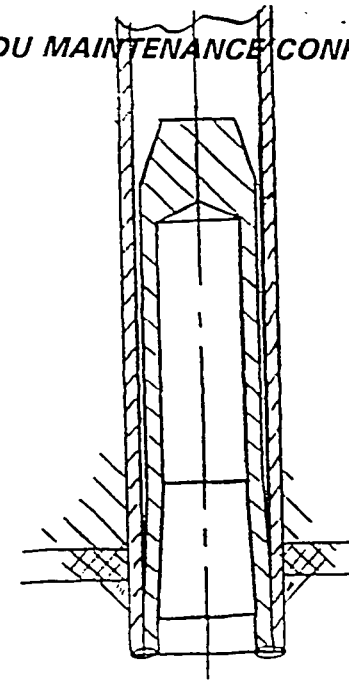
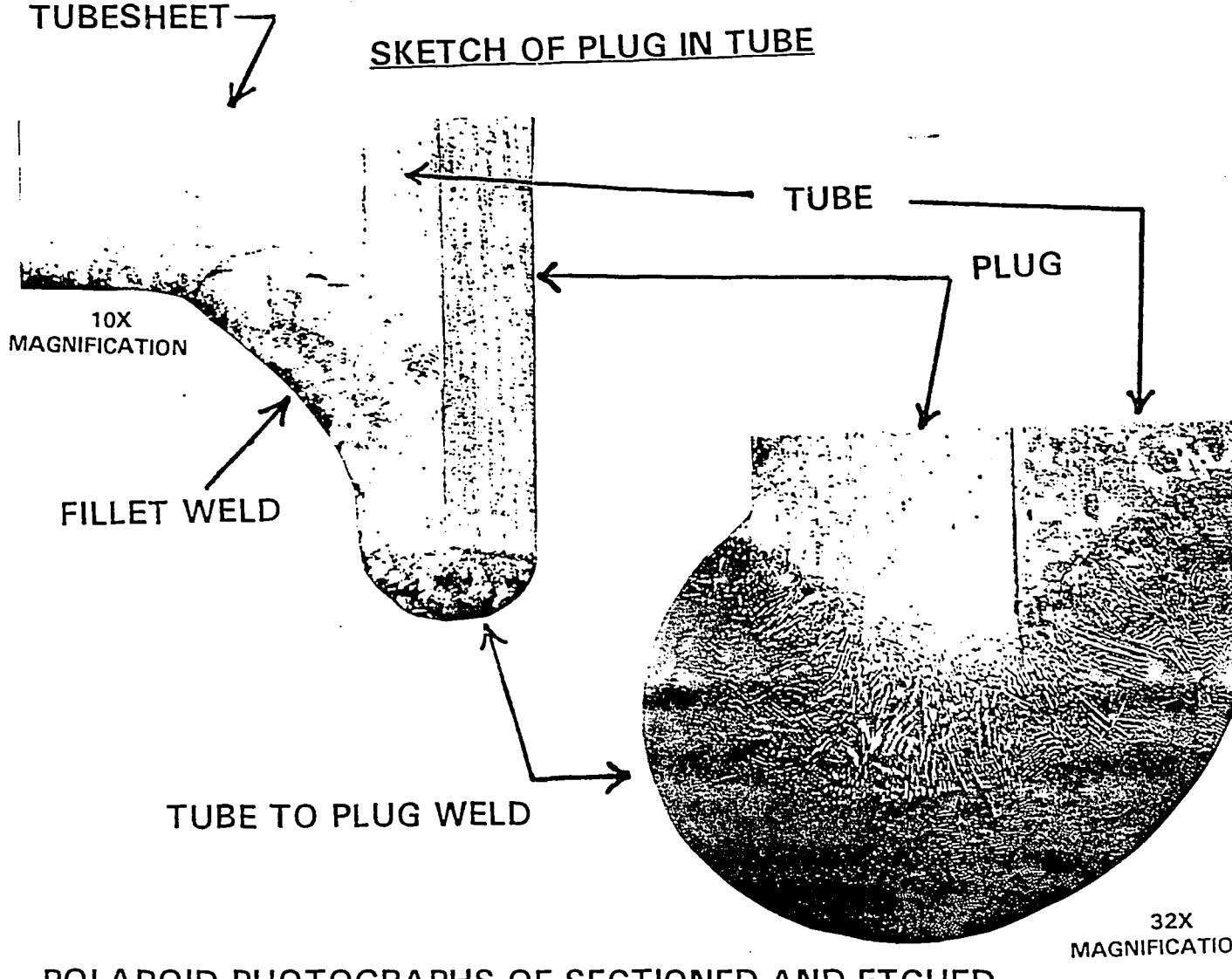


FIGURE 2

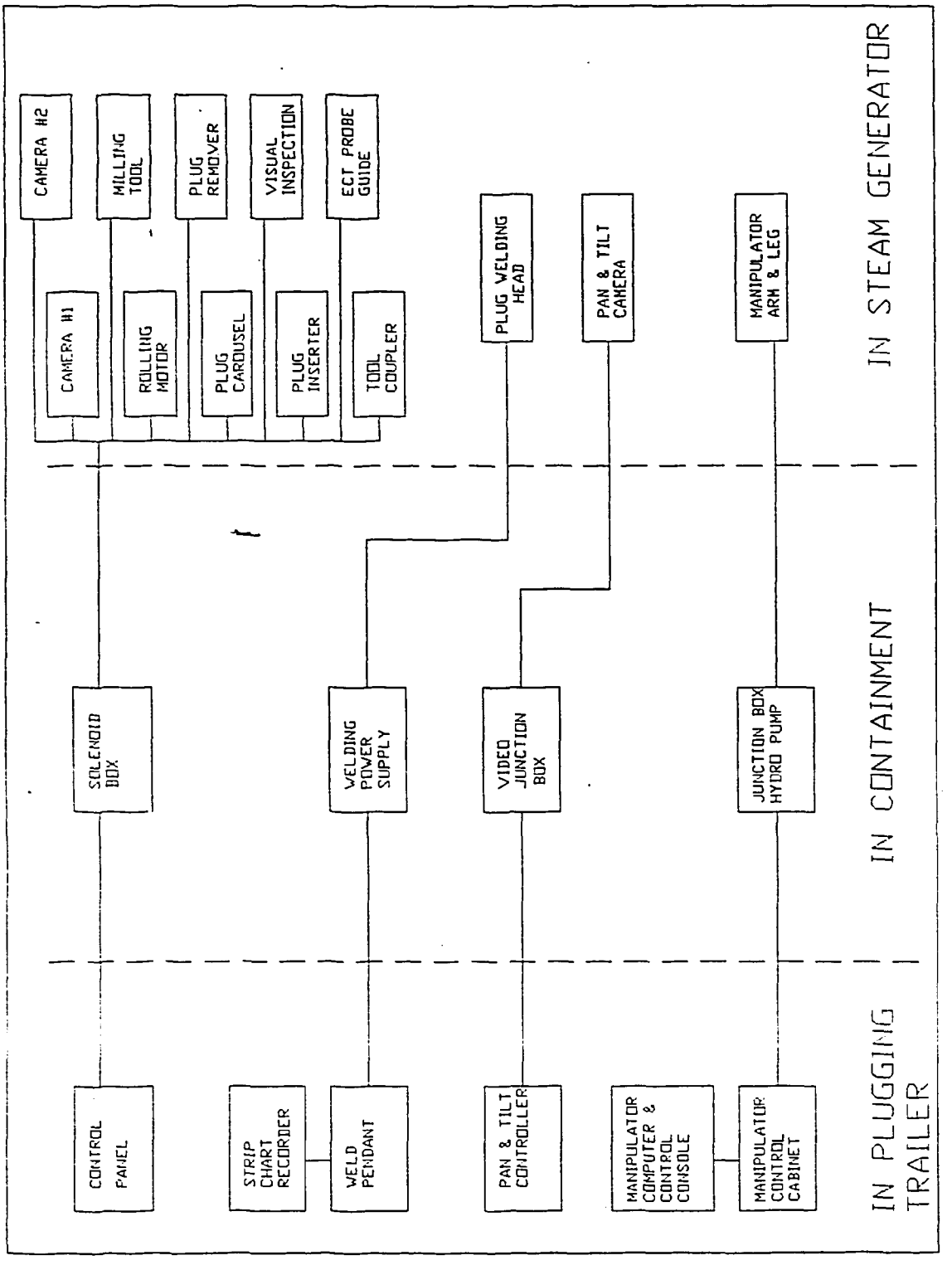


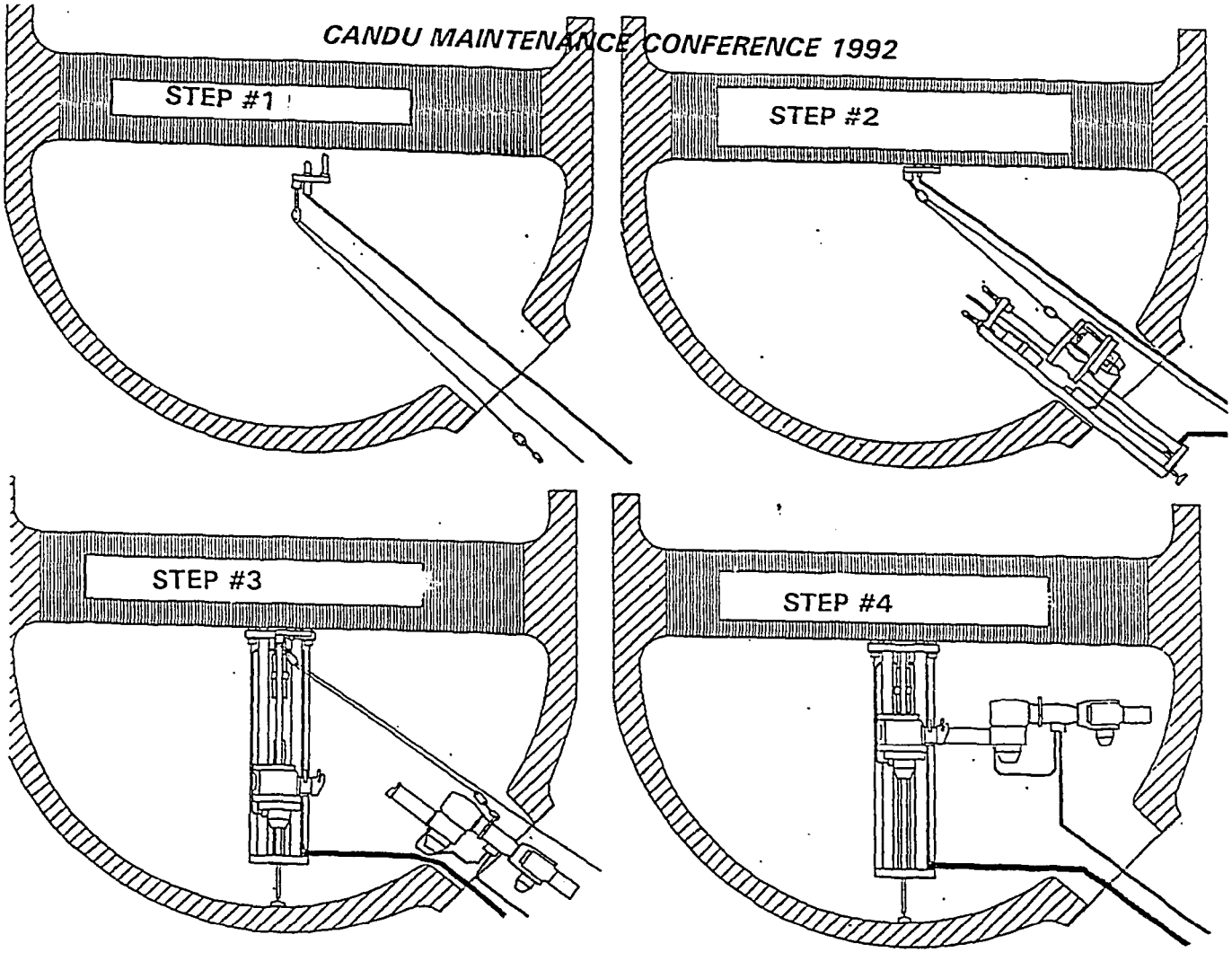
SKETCH OF PLUG IN TUBE



POLAROID PHOTOGRAPHS OF SECTIONED AND ETCHED TUBE TO PLUG WELDS - FIGURE 3

REMOTE TUBE PLUGGING SYSTEM - FIG. 4





STEP #1 - INSTALL TACKLE IN TUBE SHEET

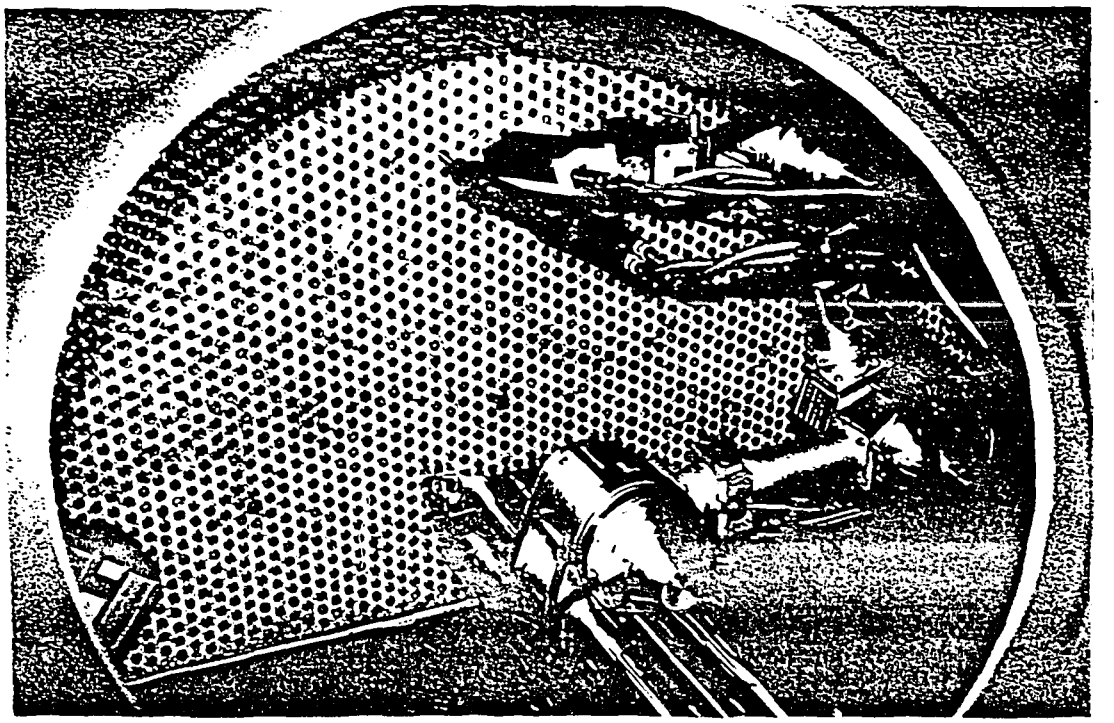
STEP #2 - TACKLE IS USED TO PULL LEG INTO BOWL, FINGERS ARE THEN INSERTED INTO TUBESHEET AND WHEN LEG IS LEVEL THE FOOT IS EXTENDED

STEP #3 - TACKLE CAN BE USED TO PULL ARM INTO BOWL AND THEN ARM IS LOCKED TO LEG ELEVATOR

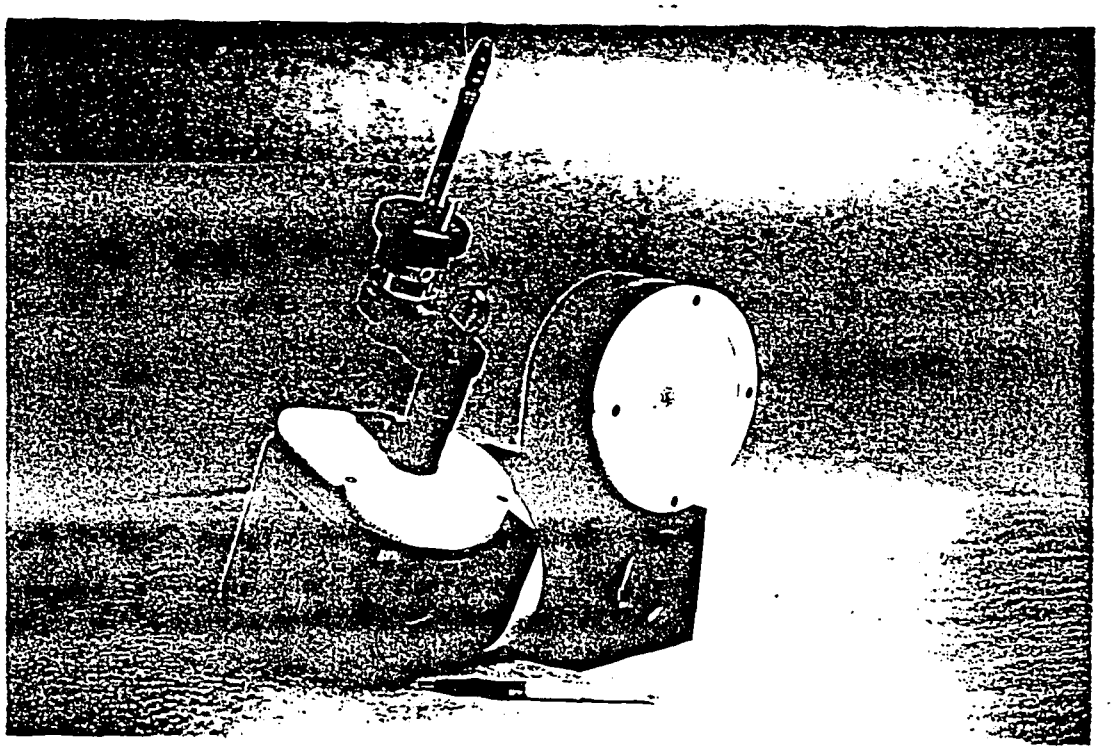
STEP #4 - AFTER ARM AND LEG INSTALLATION, TACKLE IS REMOVED, AND TOOLS CAN THEN BE ATTACHED TO THE ARM TO COMMENCE PLUGGING

INSTALLATION OF FLEXIVERA MANIPULATOR IN STEAM GENERATOR BOWL

FIGURE 5

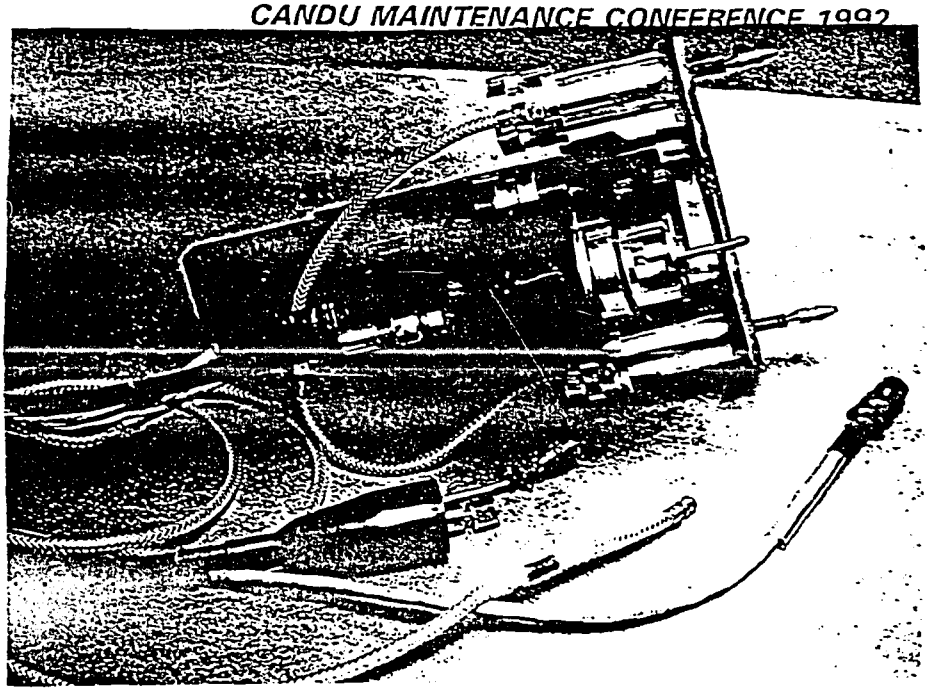


MANIPULATOR WITH ROLLING MOTOR & TOOL CAMERA
IN BRUCE NGS STEAM GENERATOR MOCK-UP

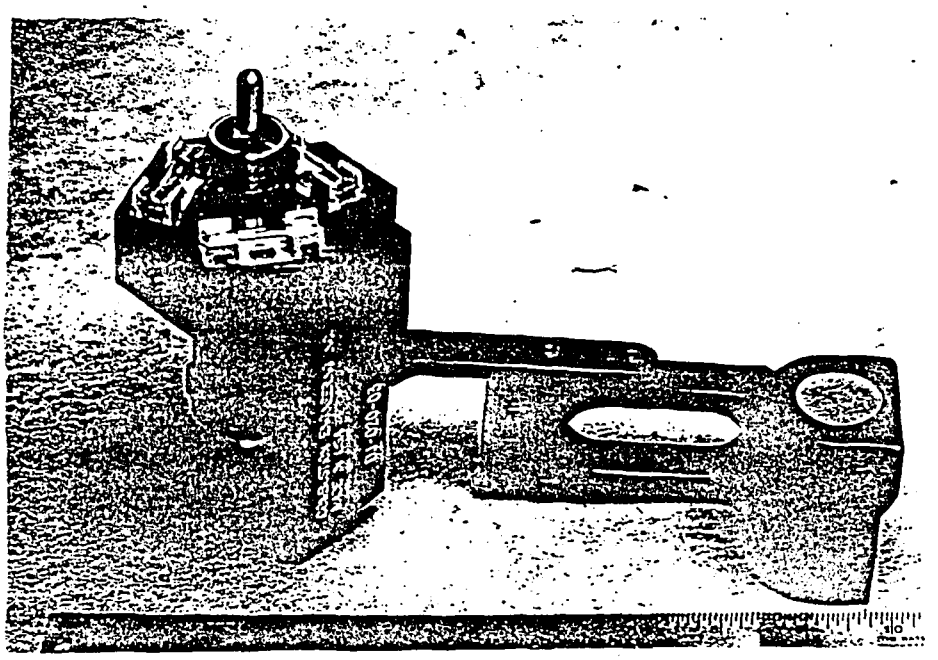


PAN & TILT CAMERA

FIGURE 6



WELD HEAD



VISUAL INSPECTION TOOL

FIGURE 7

CA9500167

ORBITING TOOLS FOR CUTTING, CLEANING AND WELDING CANDU REACTOR COMPONENTS

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ABSTRACT

This paper discusses the development of specialized tools used to sever welds or components related to removal of old fuel channel end fittings (E/F), and to perform the activities required to weld new end fittings in place. It includes discussions of various options considered, the reasons for the chosen solution and the operation of the tools.

ORBITING TOOLS FOR CUTTING, CLEANING AND WELDING CANDU REACTOR COMPONENTS

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INTRODUCTION

One of the primary operations in the Large Scale Fuel Channel Replacement (LSFCR) at Ontario Hydro's Bruce Nuclear Generating Station "A" involves precisely severing the End Fittings (E/F) from their attachment points to the tube sheet on the face of the reactor. The area to be cut is a weld on the outboard side of the expansion bellows assembly on the east side and through a thin steel shell (stop collar assembly) on the west side (Fig.1). Once the cutting and other related operations are complete, the old E/F is removed and a new one is installed and welded at the location of the cut. Access is difficult because of the physical restrictions of surrounding lattice sites, feeder pipes and the obstructions on the target E/F itself.

The LSFCR at Bruce is divided into two categories; Removal and Installation. The removal phase includes all work associated with removing old reactor components which primarily encompass the end fittings (E/F) and pressure tubes (P/T). The installation phase includes all work associated with installation of new pressure tubes and the east and west variations of the end fittings.

REMOVAL PHASE - DEVELOPMENT OF THE CUTTING PROCESS

In previous LSFCR's at Ontario Hydro's Pickering Nuclear Generating Station, the E/F's were removed in a two piece process where one tool coarsely severed the outboard section of the E/F and a second tool removed the bellows weld (Fig 2). Removing the outboard section eliminated the obstruction presented by the feeder port so that a relatively simple tool could cut the bellows weld. While adequate, this method involved removing the old E/F in two pieces thereby requiring an extra cutting operation as well as doubling the number of pieces to be handled.

The requirement to rethink the process arose with the Bruce LSFCR because there are significant differences in the Bruce E/F's both in size and configuration such that the Pickering tooling cannot be used.

The fuel channels at Pickering are essentially the same on each end of the reactor, and use the same tooling to cut the bellows weld. The Bruce fuel channels are different from end to end and the E/F's are larger in diameter. The east end has a bellows much

the same as Pickering, and except for size, E/F removal could be made using the same two piece method, however the west end has a "stop collar" assembly which requires a radial cut that the Pickering method cannot accommodate (Fig.1).

"High Torque" vs. "Low Torque" Cutting

Two different cutting concepts have historically been used for LSFCR and general reactor maintenance work; these are the so called "high torque" and "low torque" methods.

High torque cutting involves a single point cutting tool that rotates about the E/F and is advanced axially into the weld material. In the case of Pickering, with the outer portion of the old E/F removed, the tool could simply be slipped over the end of the stub to gain access to the weld to be cut. Other tools have had single point cutters mounted on "orbiter" shells that were assembled around the projections of the E/F. In all cases a relatively high torque had to be applied to drive the cutter and some mechanism for advancing the cutter had to be designed. Unfortunately, high torque cutting is best suited to axially advanced cutting and is not readily adaptable to the Bruce requirement for a radial cut through the stop collar.

"Low Torque" cutting involves the use of a small tool with a circular saw typically in the range of 2.5" diameter which is "plunged" into the area to be cut and then rotated around the periphery of the channel. The tool must be small enough to fit in the space between the E/F's. It is normally carried on "orbiter" shells which take relatively low torque to drive.

To perform the cuts, still using the two piece removal method, a number of concepts were considered, ranging from a redesigned high torque tool for the east end to a one piece "low torque" tool for the west end. Because of the difficulty in adapting high torque to the west end, and the desire to use common tooling if possible, attention became focused on the "low torque" method.

One Piece E/F Removal

During the course of the study, it became apparent that reactor downtime and worker radiation exposure could be reduced if the low torque tooling system could be developed sufficiently to allow the E/F to be removed in one piece. One piece removal required the development of an orbiter and cutting system that was fast enough to compete with two piece removal.

Removal Orbiter. The first essential requirement for one piece E/F removal was for a removal series orbiter that could be assembled around the obstructions on the E/F quickly as well as meeting the running accuracy requirements. Several concepts were considered, but the eventual choice was a design that split

horizontally and assembled on the E/F in two pieces (Fig. 3). The orbiter, when assembled, has two main components; the stationary ring which is anchored to the E/F using a hydraulic clamp, and the rotating ring which carries the cutting tool and is driven by an electric motor. The two rings are connected together using a series of spring loaded stud and shoe assemblies such that when they are split horizontally, they can be assembled in two pieces.

An important element of the system are the "inserters" which are the tools used to insert and assemble the orbiter. The central feature of the inserter system is a "support ring" that clips onto the outboard face of the E/F and provides a support point for the orbiter. With it, the orbiter halves are supported by the E/F, rather than by the operator, during the assembly phase.

Cutting Tools. The second essential element of one piece E/F removal is for "low torque" cutting tools that operate quickly. Previous reactor maintenance tools had used pneumatically powered cutters with qualified success; they cut successfully but were typically slow and underpowered because the available space was too small for suitably powerful motors. In order to make the cutting system viable, the cut times had to be reduced to less than 5 minutes.

The only form of motor with suitable power density was found to be hydraulic. It offered the possibility of putting much greater power in the same volume such that fast cuts could be made. The motors employ the same type of oil as used in the fueling machines at Pickering. During testing, it was found that hydraulic powered bellows weld cuts could typically be completed in 2 minutes, representing a definite improvement over anything pneumatic powered tools had been able to achieve.

Each cutting tool includes a hydraulic motor, a hydraulic plunge cylinder, inserter attach point, the cutter head and support bracket. They may include a reduction gearbox if a right angle drive is required (Fig.4).

As with the orbiter, an important part of the cut tool is the "inserter" used to attach the tool to the orbiter. Because of size constraints, the cut tool has to be attached to the orbiter in a separate operation. With previous tooling, there had been problems with controlling the services to the tool. They had been manually fed by the operator and through over or under control the cable would sometimes "snag" and cause problems. To address the situation, and to take the operator "out of the loop", an automated cable feed system was developed. The cable is driven in or out by a motor which drives a long lead screw to which the cables are attached. The cable drive is slaved to the orbiter drive to maintain a pre-set amount of slack. For some tools, the first portion of the drive also "wrists" the tool (Fig.5), which means that it goes from the low profile shape needed to be inserted past the feeder port to the aligned position ready to

attach to the orbiter.

The tools must operate in a very small swept volume (Fig 6) defined radially by the clearance between adjacent fuel channels, and axially by the feeders on the outboard side and the bellows (east) or annulus gas system (west) on the inboard side. In addition there are a number of special sites near the periphery that have even more restrictive obstructions from feeder support brackets.

Assembly. To assemble the orbiter, the first orbiter half, with its inserter supported from the support ring in a sliding block, is passed through the space opposite the feeder port and then rotated behind the feeder port. The second half, which includes the drive motor, has an inserter with a fulcrum block that clips to the support ring and then slides along the E/F until it is mated with the first half. When the two joint screws are tightened, assembly is complete. To prepare for tool acceptance the assembly is slid forward and temporarily locked in position using a hydraulically actuated clamp.

Next, the fulcrum point for the cutting tool/inserter is clipped to the support ring and the assembly slid forward until in the vicinity of the toolmount on the orbiter. For some tools, the tool is "wristed" (Fig.5) into alignment before being attached to the toolmount using a captured bolt. The correct axial position of the orbiter/tool is set by releasing the orbiter clamp and sliding the assembly forward until a probe on the inserter touches the reference surface on the tubesheet. The clamp is then reapplied. The inserter is released from the tool and pulled back to its parked position where it attaches to the rear of the orbiter. The system is now ready for operation.

Operation. Before cutting, the tool and its service cables are pre-wound around the fuel channel. For the Bruce LSFCR, this is done automatically with the cable feed being synchronized to the orbiter rotation. Once in position, the cutting tool motor is started and the plunge cylinder forces the cutter into the surface. The orbiter is then rotated, unwinding the cables as the tool cuts a groove in the surface until the component is completely severed.

Baseline Approach

With these designs proven in concept, a considerable savings in outage time and dose was projected, and as a result, the "low torque" cutting tools became the baseline approach for the retube.

INSTALLATION PHASE

After the old E/F is removed, several intervening operations take place to refurbish and repair the lattice site before new E/F's are installed and prepared for welding. The weld operation involves cleaning using a wire brush tool, followed by welding and inspection. In the event of a weld defect, contingency repair tools that cut or grind the problem area can be installed on the orbiter.

As the end fittings for the installation phase are installed in one piece, an orbiter is the only appropriate type of tool to carry the welding tools. A design study was carried out to investigate the most appropriate design which ranged from orbiting shells that remained in place as permanent reactor components to removable shells.

Permanent orbiters held some initial attraction on the assumption they could be used for future single channel repair work, but were eventually rejected because of mechanical interference problems.

Also considered, were relatively simple orbiters that would require preassembly on the E/F's and dismantling by a quick release mechanism. These orbiters could not easily be reinstalled on a site once removed and additional specialized tooling would be required for repair work. This type of orbiter was used with good success at Pickering but were not appropriate for Bruce because the larger E/F diameter combined with the same lattice spacing resulted in insufficient room to have orbiters on adjacent channels when feeders were inbetween (Fig.6). Because of feeder management complications, this would have forced the installation to proceed along a rigid path of installing and completely finishing a particular row or column of sites before the next could be done.

In response to the Ontario Hydro planners' desire for a system that allowed a flexible approach to the installation sequence, a somewhat more complex orbiter was developed that could either be preinstalled outside the vault or installed in-situ on the face. It fulfilled all the design requirements, as well as having a minimal effect on the processing operations on the face. Having an orbiter in place on the new fuel channel still prevents another channel from being installed on an adjacent site if a feeder lies inbetween, however it can be quickly be removed and reinstalled at a more appropriate time as the situation warrants. If for instance the number of E/F's to be installed is restricted by interference with orbiters, the orbiters can be stripped off and replaced later as required, whereas an entire shift's production might have been lost otherwise. The ability to be removed and replaced easily allows shift supervisors to respond to unusual situations in a way that might not have been available with other tooling.

Installation Tools

The installation orbiter is similar in concept to the removal series orbiter, but has been changed in detail to reflect the requirement for being capable of pre- or in-situ installation (Fig 7). It has the same concept of a stationary and rotating ring that split horizontally, but does not have the motor built in because of interference with E/F installation tooling and because there is a requirement for hand rotation during the installation phase. The orbiter is anchored in place using a mechanical clamp, rather than the hydraulic version on the removal orbiter because it would not be practical to maintain hydraulic pressure for preinstalled orbiters. Seven dovetailed slots are arrayed around the periphery of the stationary ring to accept either the motor, a handcrank, positioning tools or the orbiter inserters as the situation warrants. The 7 slots are situated to accept the motor/handcrank or the inserters at any of the 12 different site groupings that occur on the reactor face (Fig 8 & 9).

Several functions are required during the installation including wire brushing to clean the area to be welded, pre-inspection using an orbiter mounted video camera, the actual welding operation plus post weld inspection. In the event the weld is defective, cutting or grinding tools are used to remove the defective weld material so it can be rewelded. Tasks such as cleaning with a the wire brush tool may be performed by hand control whereas the welding requires a closely controlled speed feedback to an electric motor.

The orbiter mounted video camera is unique in that it incorporates a low powered laser that emits a thin plane of light inclined at an angle to the weld preparation area such that variations in the height of the surface can be detected. This is useful to detect the radial "fit up" of weld preparations as well as whether a completed weld is "concave" or "convex". Normally these features cannot be detected with video cameras alone.

Assembly of the orbiter can be done in the component preparation area, thereby saving both critical path outage time on the reactor face as well as reducing the dose accumulation. This would normally be the preferred solution, but complication arising from other operations could also result in savings if assembly is done on the face. Face assembly is much the same as with the removal orbiters except the motor/handcrank is separate and the inserters are removed. It still uses the support ring concept on the end of the E/F to support the orbiter components or the tools.

The installation system must allow the tools to access weld locations that are axially out of position. In previous retube operations, the orbiter was fixed axially which usually meant that each tool interfacing to the orbiter had to have a built-in axial adjustment, which had to be carefully controlled. The new

orbiter is designed such that the entire orbiter can be readjusted axially and the design of all tools that attach to the orbiter are controlled by an interface specification such that the distance from the orbiter to the weld is the same. Therefore if the axial adjustment is correct for one tool, it will be correct for all. The axial position is quickly readjustable with micrometer accuracy using an attachment to the support ring.

Axial alignment of the orbiter is set using a positioning tool that sets the orbiter in position relative to the end fitting attachment ring (EFA ring) on the east end and the weld preparation groove on the west end. The positioning tool fits into one of the 7 dovetail slots and a probe is rotated into place. The orbiter clamp is then released and the orbiter is slid along the E/F until the correct position is achieved. The clamp is then reapplied.

SUMMARY

The tooling described above is being produced for the Bruce LSFCR and has undergone extensive testing on reactor mock-ups. The status at the time of writing is the removal series tools are being produced for the Bruce LSFCR and the installation tools are undergoing design acceptance testing.

The above approach to the replacement of End Fittings has evolved based on the experience from four Large Scale Fuel Channel Replacements at Pickering NGS, the West Shift operation at Bruce NGS as well as many single channel replacement operations. All tooling has been developed using the procedures laid out by Ontario Hydro's "Program of Quality Engineering for Fuel Channel Replacement Tooling and Equipment".

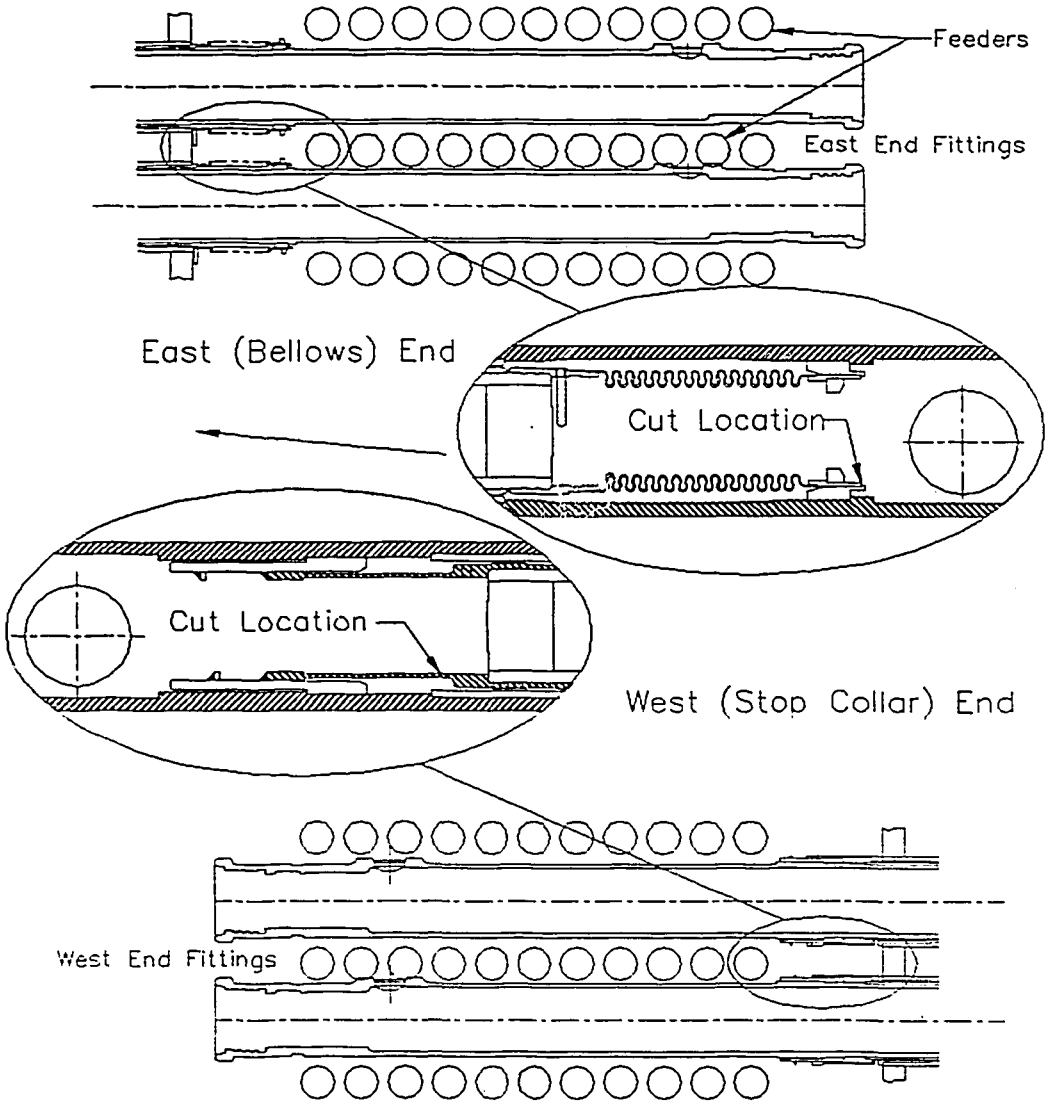

Fig. 1 Bruce NGS LSFCR Cut Locations

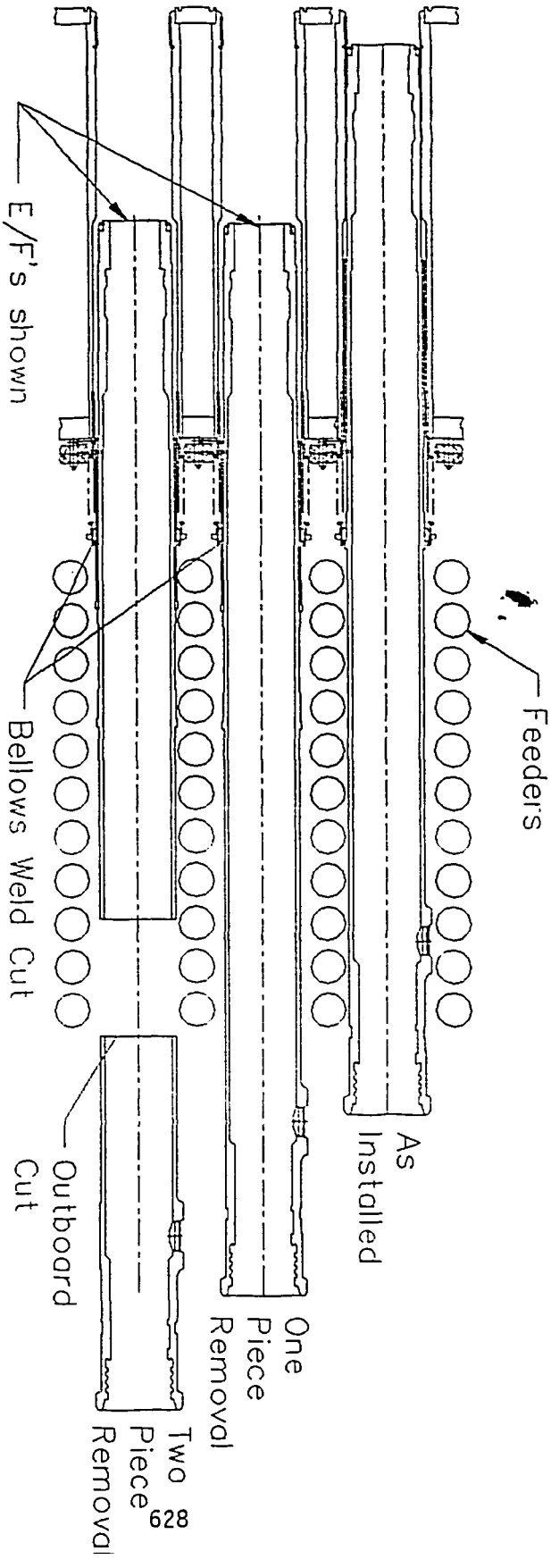

Fig. 2 One Piece vs. Two Piece End Fitting Removal

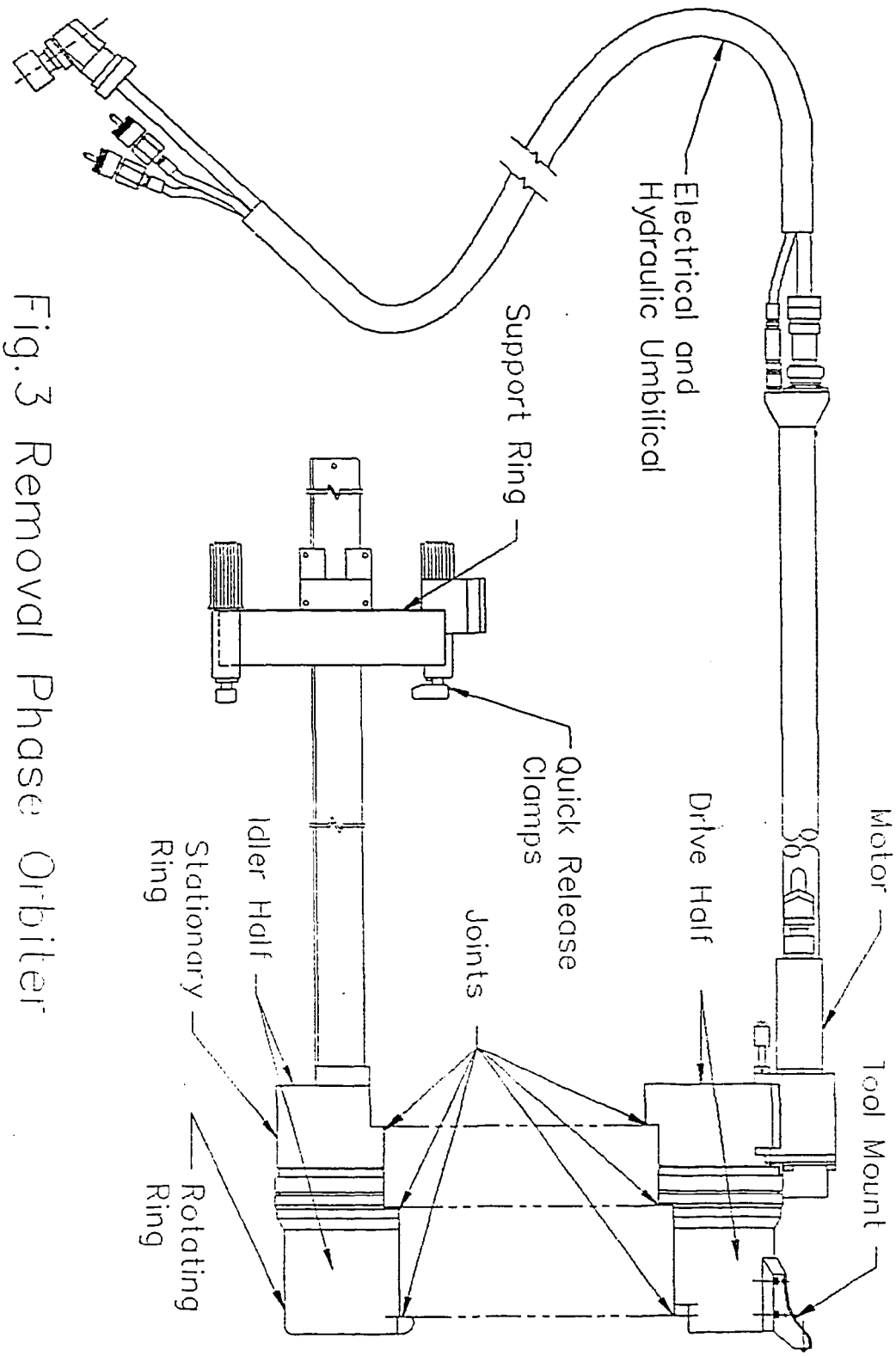

Fig.3 Removal Phase Orbiter

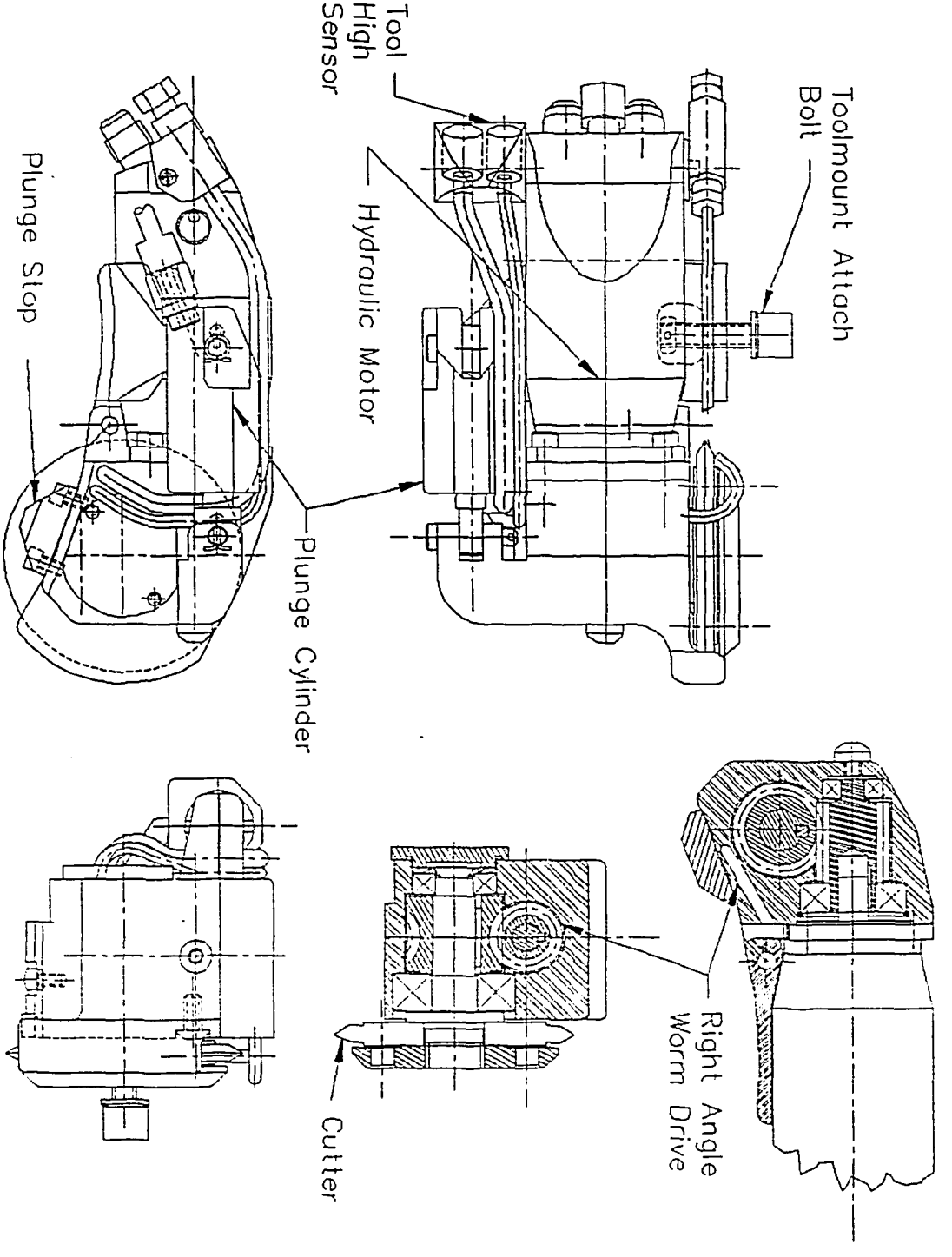

Fig. 4 East (Bellows) Cutting Tool

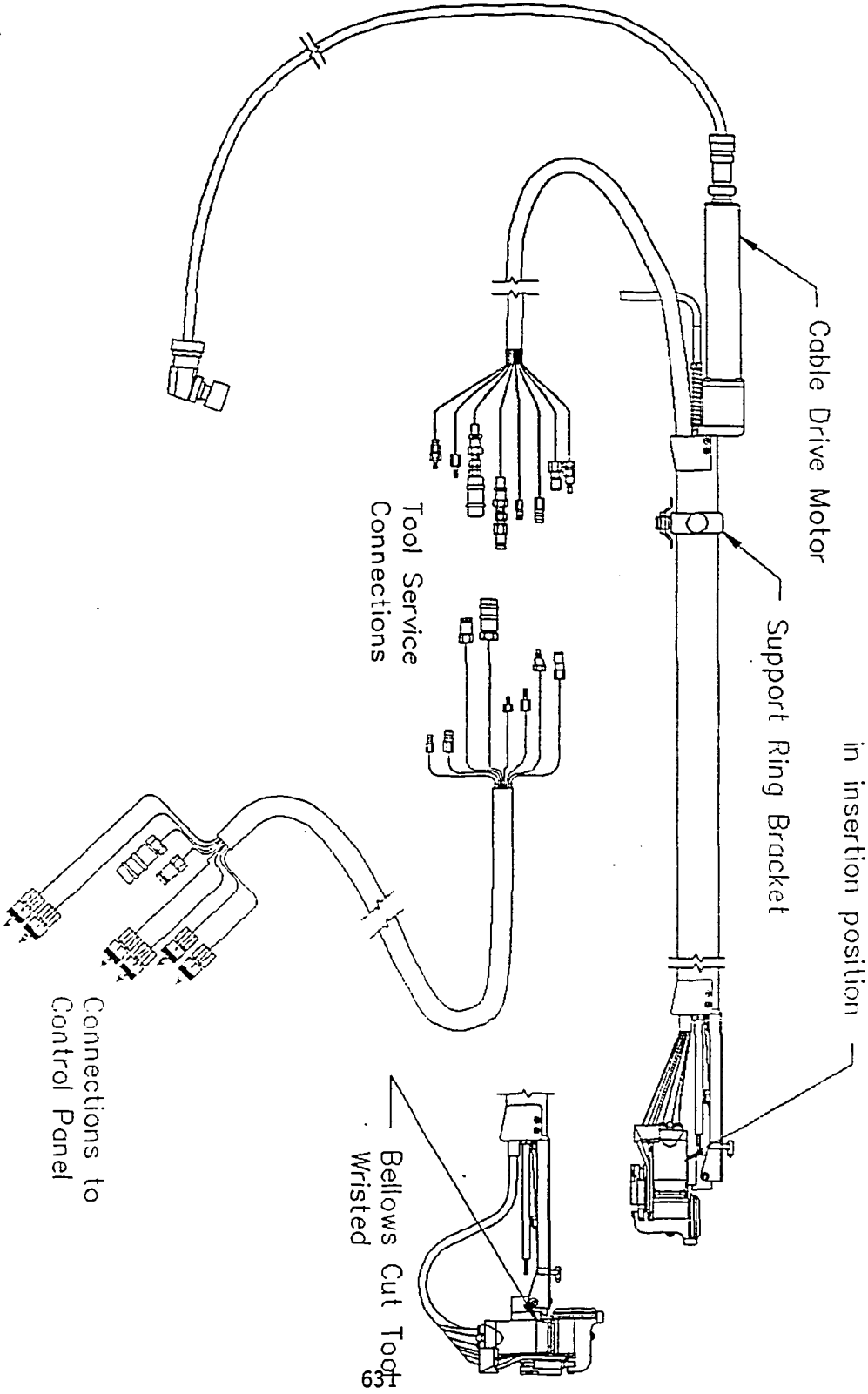

Fig. 5 Cut Tool and Inserter

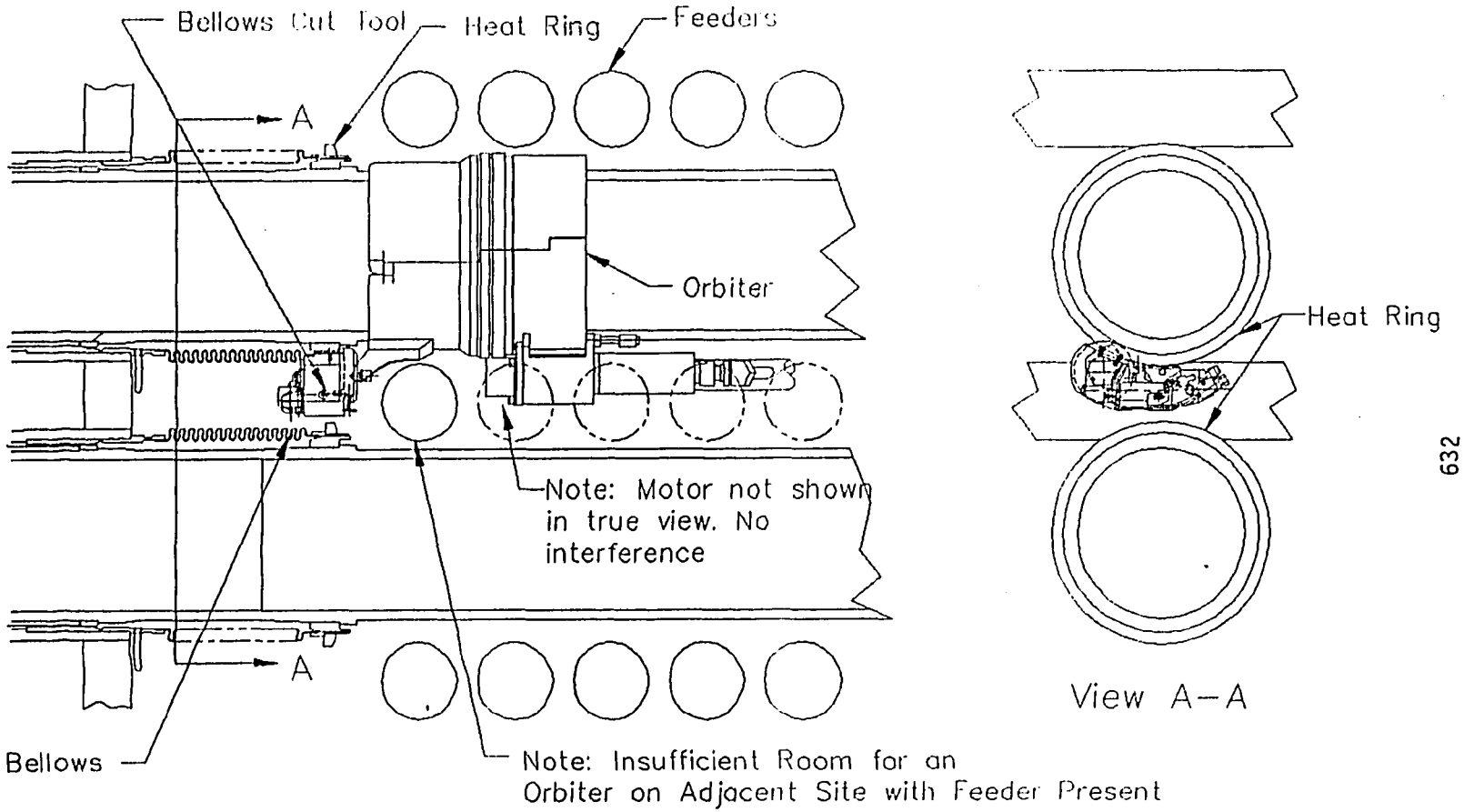

Fig. 6 Orbiter and Bellows Cut Tool

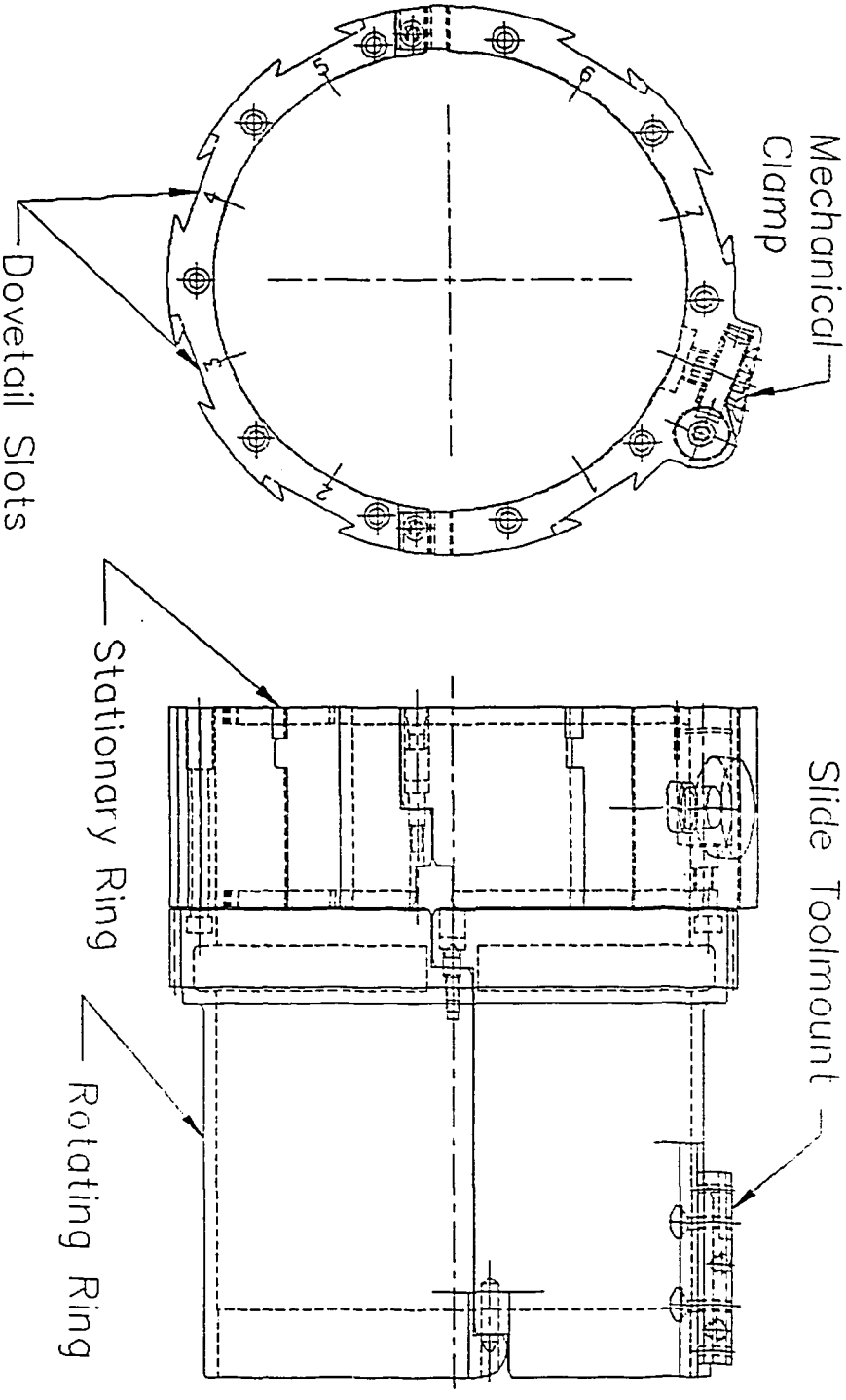

Fig. 7 Installation Orbiter

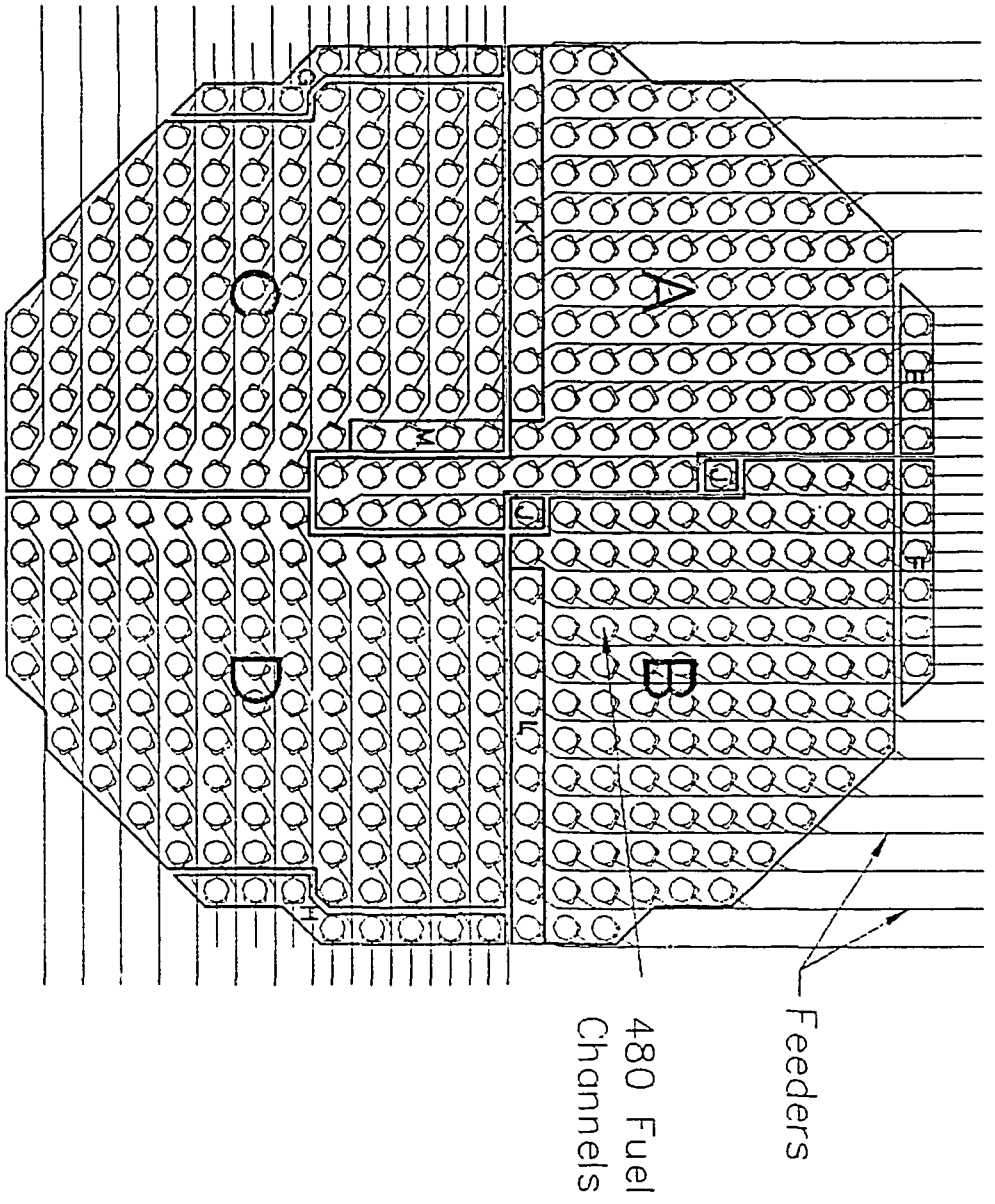

Fig. 8 Reactor Face Site Groupings

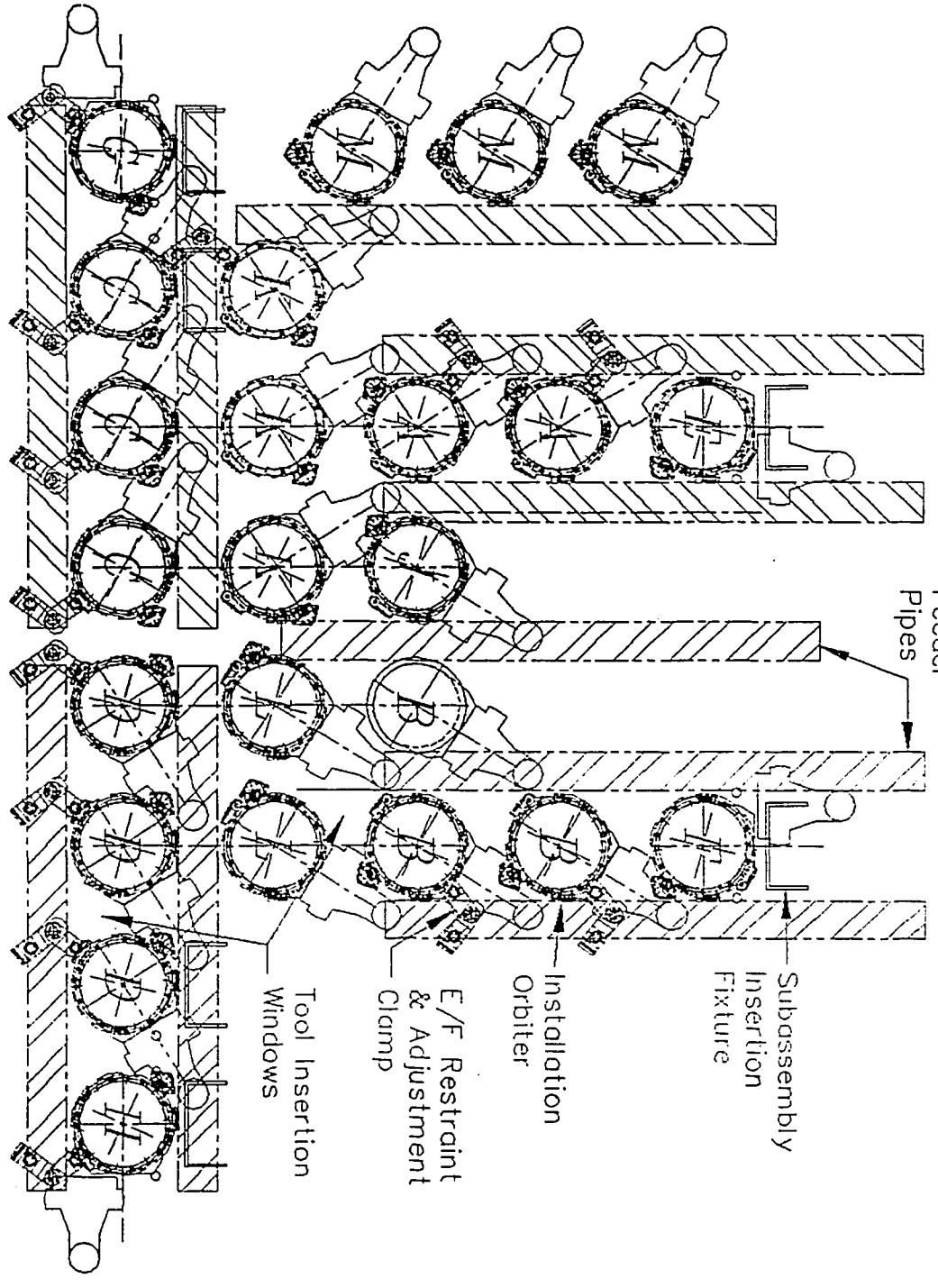

Fig. 9 Montage of Site Groupings

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HARDWARE AND SOFTWARE MAINTENANCE STRATEGIES FOR UPGRADING VINTAGE COMPUTERS

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ABSTRACT

The paper focuses on the maintenance of the computer hardware and software for Digital Control Computers (DCC's). Specific design problems related to various maintenance strategies are reviewed. A foundation was required for a reliable computer maintenance and upgrading program to provide operation of the DCC's with high availability and reliability for 40 years. This involved a carefully planned and executed maintenance and upgrading program involving complementary hardware and software strategies. The computer system was designed on a modular basis with large sections easily replaced to facilitate maintenance and improve the system availability. Advancements in computer hardware have made it possible to replace DCC peripheral devices with reliable, inexpensive and widely available components from PC-based systems. By providing a high speed link from the DCC to a PC, it is now possible to use many commercial S/W packages to process data from the plant.

H/W & S/W MAINTENANCE STRATEGIES FOR UPGRADING VINTAGE COMPUTERS

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1.0 INTRODUCTION

Due to the rapid evolution in new computer technology, computer hardware becomes obsolete and goes out of production quickly. Mature computer systems that are performing adequately for the application as designed, suffer from a lack of spare parts. Also, the capabilities of new computer systems create a desire to upgrade systems.

Complete replacement of computer systems not only is costly but also, since they are an integral part of the plant, creates a major disruption in production.

The problem can be alleviated, both by care in the original design and by refitting existing computers with new compatible equipment. Proven methods for doing this will be presented in this paper.

2.0 HARDWARE DESIGN STRATEGIES

2.1 General Philosophy

The key to establishing hardware longevity lies in following an established quality program. The program must include design verification and review, component quality assurance, workmanship quality inspection and full documentation of the process. The effectiveness of the QA program is judged by the trouble-free effectiveness of the end product.

All systems must operate with high availability and reliability for years. They must be meticulously designed, constructed, and commissioned. They also require a precisely planned on-going rehabilitative maintenance program.

Control systems should be designed on a modular basis with vital sections easily replaceable to speed up maintenance and reduce down time. Key modules, such as disk drives, used for diagnostic functions should have redundant functional devices. Since computers have short product life spans, strategies must be developed to deal with these requirements.

To achieve the required levels of functionality and reliability the system designer must take a conservative but thorough system level design approach. Rather than striving for leading edge technology, the designer must consider reliability, performance and maintainability. System designers must remain broadly focused on the new technological solutions. They must also have clearly defined requirements based on a firm understanding of the end use for the computer product.

2.2 System Requirements

The designer should analyze the system requirements and then specify and purchase a system which meets these requirements exactly. Design specials should only be used where it is impractical to make an off-the-shelf product suit his needs. If unique or custom design work is necessary, this should be accurately and thoroughly documented.

Convenience options, such as built in back-up tape drives, should only be bought if they are going to be used. They should increase the complete system availability or functionality and decrease its overall cost significantly. Options, such as key locks, which are included in a system but are never activated can only add to the maintenance burden, and should, if possible be removed from the system.

2.3 System Configuration Guidelines

The designer must allow for future functional power and signal Input/Output (I/O) expansion. A system designed to manage this must be put in place in the conceptual design phase which will predict, review and control the use of computer resources and I/O.

Hardware documentation must be purchased with the computer system to ensure maintainability. This documentation should provide fabrication details. Most vendors are hesitant to supply this type of documentation, so it must be negotiated as part of the purchase order.

The computer system must be an expandable, modular design. Computer system components should be readily accessible for regular or call up maintenance, and easy to replace. This modular approach will reduce the regular maintenance costs. This will also reduce the cost of replacements due to future equipment obsolescence.

Overall simplicity of the system is the foremost requirement. This implies a minimum parts count, direct and logical interconnections, and clear documentation. Savings in material cost, maintenance effort and training time, as well as more reliable operation will result.

There is a new computer design concept called, open architecture. This is used in the latest distributed systems, which run on a standardized data highway between self-sufficient devices. This has the flexibility to support a large variety of devices now and in the future. This may be the answer to a large number of existing obsolescence issues.

2.4 Design Standards

In any complex design it is beneficial to make full use of standardized equipment. Adhering to hardware design standards especially where they apply to open architecture I/O bus structures, or open systems will increase the likelihood of future parts supplies. However, use of standard computer bus structures will not guarantee extended computer system life.

Power plant life cycles are commonly planned for 30 to 40 years; computer standards may stay current for only 3 or 4 years. Therefore, the design should not be made significantly more complicated for the sake of incorporating standard bus structures.

2.5 Maintenance Computers

A separate maintenance computer is an essential resource in achieving overall system availability. It should be a scaled-down version of the process computer consisting of at least one of each module type configured to run the on-line system.

The maintenance computer is an ideal facility to test new computer parts. This complete computer can execute complex programs written to diagnose and test specific pieces of hardware. New design changes can also be safely tested on the maintenance computer. Again, since time is not a constraint, modifications can be completely validated after which they can be installed in the on-line computers.

The maintenance computers are bought early in the design stage, when they are required for software development and plant commissioning, and used throughout the equipment service life.

2.6 Spare Parts

Overall management of computer spares for the plant lifetime begins in the design phase. It is up to the system designers to include spares in the initial purchase and to be sufficiently familiar with the computer equipment to recommend an appropriate inventory.

Process computer sparing for 40 year plant lifetimes involves unique problems. Spares must be at the exact same revision level as those identified in original contract. This ensures that they will all work as specified, or conversely, if they are all wrong in function or design, they will exhibit common failure symptoms, simplifying the task of design trouble-shooting.

After the computer system has been delivered, maintenance staff and designers must become involved in the training and early testing phase of the work. They will get actual hands-on experience which will allow them to make key technical judgments on spares purchased. These decisions will allow further expansion or refinement of the spare parts inventory. This should include a systematic review of failures, to allow design deficiencies to detected and corrected early. This must continue to the point when the computer is replaced.

3.0 EQUIPMENT REFURBISHING

This section outlines methods that may be employed to provide replacement equipment when the original is no longer being manufactured and sources of spares have been exhausted. Details of actual refurbishing projects will be given as examples.

3.1 General Philosophy

The overall objective is to maintain the function performed by the original equipment.

In a mature system, equipment obsolescence due to a lack of replacements or high costs is a serious concern. It may not be practical to disrupt plant production unless computer refurbishing is tied in with major plant rehabilitation. Therefore, a replacement module or subsystem as a replacement for an obsolete item must be designed for minimum changeover time.

In a nuclear application, it is generally advisable to retain the controlling elements of the computer system because confidence in them has been established. These include the CPU and memory, and the controlling input and output circuits. Fortunately these elements are less subject to wear out than peripherals.

3.2 Reasons for Refurbishment

These are the situations where replacement of components becomes mandatory:

a. When original equipment becomes mechanically worn out and replacement parts can not be obtained.

b. When maintenance of a piece of equipment consumes an inordinate amount of staff time.

c. When performance deteriorates due to aging.

Most high-technology devices follow the traditional bathtub failure curve. There is early mortality, the random failure period, then the wear out region. This all ends in technological death where it is no longer technically or financially practical to maintain the device. The wear out portion of the failure curve on some computer equipment frequently begins before the end of the plant lifespan. This usually starts with equipment that has mechanical moving parts such as printers and disc drives.

3.3 Replacement Strategies

Experience shows that adding new products to vintage computers requires a great deal of technical creativity. The challenge lies in the requirement to simplify a custom design. The design must be prototyped, tested and burned in the host computer. This is done before going into final production.

A modular design in the original equipment greatly simplifies the replacement.

When replacing an existing piece of equipment there are choices and compromises where the connection to the new equipment could be made:

a. Connecting Internally to the Existing Equipment.

   This approach is valid where one component of the device presents a maintenance problem. The component can be a single integrated circuit or a whole subsystem.

b. Connecting to the original equipment cable or port.

   The safest and most cost-effective replacement strategy is often to provide an emulator which links the existing interface to the new device. It makes use of the existing controller or adaptor and assures that no software need be changed. The emulator must fully mimic all the characteristics of the original, whether these are documented or not. Performance improvement will usually not be gained.

c. Interfacing to the Computer I\O Bus.

Making a replacement directly to the computer bus presents a greater risk of interference (electrical or logical) but also creates an opportunity to optimize the design in terms of overall simplicity, performance and removal of obsolescent components. The new device will be a custom design, but can be made to operate with existing software. An example is the fixed head disc replacement at Bruce NGS B. The DDC disc was replaced by a Megaram storage device, and original disc controller was removed as well. The parallel, rather than serial data transfer and random access achieved with the new device greatly improved the bulk memory access rate.

3.4 Validation Testing of New Computer Products

All new devices must be subjected to a type testing, which exercises the device in every known operating mode and condition. This can be done on the spare or maintenance computer if such is available. In addition, it is advisable to perform environmental and electrical stress tests on the device in an attempt to shake out marginal performance. To gain full confidence, error free performance alone may not be sufficient. The design should be carefully reviewed and internal measurements made to ensure adequate timing, signal and voltage margins. Final checkout should consist of extended runs (3 to 6 months) on an on-line computer while carefully monitoring system performance.

4.0 UPGRADING

This section outlines ways of connecting new equipment to vintage computers when new functions are required. Again, details of actual upgrading projects will be given as examples.

4.1 General Philosophy

The objective is to add new function with a minimum disruption to the existing system. Unlike the refurbishing situation, the original equipment is fully operational without the intended upgrade. As in equipment replacement, it may not be practical to disrupt plant production unless computer upgrading is tied in with major plant rehabilitation. This is especially true since new equipment will involve operator familiarization. Ideally the upgrade module must be designed for minimum changeover time and fall back provisions in case of problems.

We must ensure that additional expansion capacity is added to the retrofit. Focus on eliminating or reducing the number of moving parts installed in a computer. Increase the system bus transfer rates if possible. Expand the storage capacity. The design should take advantage of the on-going miniaturization of electronics. The new equipment can not be considered in isolation, but as part of the overall new and existing control and monitoring strategy.

4.2 Reasons for upgrading

The following reasons for adding new equipment may arise:

a. New facilities are required for operator information or control,

b. Performance of existing equipment is inadequate.

c. Safety considerations

d. Record keeping requirements.

4.3 Potential Problems

Fitting new equipment always has the potential of disrupting the existing system. This can be electrical or signal disruption, as well as operator interference due to false or conflicting indications. The rehabilitation work must be carefully managed.

4.4 Interfacing Strategies

Most of the vintage computers we are concerned with do not have the standard expansion boards available that we have become accustomed to for personal computers, as they were designed before the advent of such standards as RS232 and IEEE-488. If a completely new piece of equipment is to be added, a custom design will be called for and it will require some software development.

On the other hand, in fitting new components to a system, the designer is not constrained by any existing ports or devices as would be the case in refurbishing. There is still a choice of connecting points, but the closer to the computer bus the connection is made, the greater the danger of interference with existing operation.

The following interface connections are possible:

a. Standard process digital inputs and outputs.

If system security is of paramount importance, the safest method is to interface the new equipment through added digital inputs and outputs. These can be electrically isolated if required. The new equipment is treated as a field device, and will conform to existing software structures. No special interface protocol is required, but communications will be slow.

b. General purpose I/O adapter.

A parallel digital interface card (such as the BIOC for the Varian) if such is available can form the new port. The new equipment will need to conform to the interface protocol of the adapter, but the host computer side can use software that has been established for other applications. These existing cards have established performance records, hence they are unlikely to cause bus problems.

c. Modified Existing I/O Controller.

If an interface controller to other devices exists and can be adapted to the new equipment, suitable modification will serve the new function with a minimum of development. This allows the use of existing software, although new functions will require appropriate modification to it.

d. Custom Interface Module.

A complete custom interface module can be designed to serve as a gateway to the host computer. The card and its driving software will comprise a one-time design effort that then can be utilized in various applications. An example of this is the Parallel Data Link Controller (PDLC) designed by AECL CANDU for the Varian computers. See figure 1. This general purpose high-speed parallel data link connects Varian Computers to IBM PCs. This makes it possible to add the abundance of off-the-shelf PC software and hardware products to a computer systems widely used in CANDU and acts as a buffer to prevent the PC from impacting the performance of the DCC.

5.0 SUMMARY OF HARDWARE STRATEGIES

Careful design and maintenance coupled with a comprehensive and well-enforced quality program, and a complete spare parts inventory can extend the life of a control computer system. This can be extended for the design life of the station with refurbishment of unserviceable parts and upgrading of essential functions.

6.0 SOFTWARE STRATEGIES

In recent years, the rapid advancement in computer hardware has drastically reduced the cost/performance ratio. The cost and quality of computer software, however, has become the dominant focus for many computer based systems, especially for safety critical applications.

With the proven record of the CANDU reactors, it is more prudent to keep most of the existing system running. However, obsolete computer components may be replaced with more reliable and lower priced components, during the scheduled plant shutdowns. Since the upgrade is done on a modular basis, the impact on the software is minimal and incremental. Likewise, a new device can also be added to include new functions for enhancing the system performance.

Software maintenance involves mainly the following activities:

a. Making corrections to existing software designs.

b. Software design changes to improve or to add functions on the existing software programs.

c. Software design changes due to hardware replacement or to emulate one of the hardware components.

d. Enhancements to improve system performance or supplement the operator's activities, by adding monitoring or data acquisition functions or data links with other systems.

e. Verification and testing of the software design changes.

f. Changes in the documentation and descriptions for the software design changes.

While performing these activities over the extended period of time covering the expected life of the systems, the main focus of issues for the software maintenance work are as follows:

a. Changes in licensing requirements and regulations.

b. The retention of skills and training on the system.

c. Equipment costs for the maintenance facility, involving capital investments, computer maintenance, a software library and the software tools.

d. Availability of the facility and software tools to software design personnel.

e. Configuration control of the software changes.

f. Software quality control regarding the functions intended, their interfaces, program code structure, design comments and system error handling.

g. Optimization of the hours and schedule required for development, testing and installation.

6.1 General Philosophy

The software tools require the ability to develop and run software for the various types of DCC programs. They are to be used to design, modify, assemble, link, test and analyze application programs and to maintain a library of the latest program versions. Some improvements have been made to the original software tools but a new set of tools that perform these functions faster and at lower costs for processing and storage are available on PC computers. Much of the software coding and preliminary testing, up to as much as 75% of the work, can now be performed on MS-DOS machines. In addition, commercial packages for program design and editing are available at comparatively low prices and are well supported by the PC industry. Generally, much of the maintenance and development can be done on the PC and only the final testing is required to be done on the target machine.

Initially, a DCC serial transfer utility, which used commercial PC serial programs, was developed to transfer files back and forth reliably. This resulted in an immediate cost saving and improvement in the source program quality by allowing edits to be done on PC-based editors. Productivity increased since edits did not require booking time on the target machine and there was less chance of losing work due to disk crashes. Work stations were then available on everyone's desk for program editing. Transfers were much faster with the PDLC link and later the transfer program was further refined so that now even the largest programs take little time.

It was then recognized that similar savings could be realized by doing the program assembly debugging and printouts on the IBM-PC. A Varian code cross-assembler was developed for this purpose operating under MS-DOS. It was made to duplicate the action of the DCC assembler exactly and has been in operation for many years. It is now being used on the Wolsong-2 project on the five IBM-PC work stations for all the DCC programs, including the real-time Executive. Again an improvement in productivity and less use of the target machines provided development cost savings.

A fully compatible Varian code linker operating under MS-DOS was then developed to generate the executable DCC code completely on the IBM-PC, ready for execution on the DCC. This meant the total process of editing, assembly and linking could be achieved and debugged on the desk-top work stations. The cross-linker is able to handle all absolute and relocatable code identical to the DCC linker.

To provide control over the listings generated on the PC, an editor was added for this purpose to format the output to the DCC standard. Further, the editor, cross-assembler and cross-linker were made to operate under batch control to allow quick rebuilding of a program after editing and to provide records.

Eventually, more commercial IBM-PC tools were added to handle version control, configuration management and window based editing and debugging. The DCC software production and control process has improved to the extent that ratios of between 1:5 and 1:10 in the hours required are now attained compared with years ago.

The benefits of doing tests on the IBM-PC were also investigated and a Varian code emulator and a step-debugger were developed to provide a code module testing facility on each desk-top work station. Any self-contained program or parts of programs may be tested with these tools, including Executive I/O call.

On new projects, a fundamental part of the project plan includes the use of desk-top work stations thereby reducing the capital outlay and dependency on the DCC equipment and its maintenance. The DCC's are only required for the real-time testing. The development work can proceed on schedule, far ahead of the delivery of the DCC. Initial training in DCC program design, coding and testing for team members utilise these work stations.

6.2 On-line Plant Monitor System

Recent developments in micro-computer designs and commercial software for micro-computers allow the DCC to be designed to off-load certain functions, such as display and monitoring systems, to other computers. Only the control functions remain, making the DCC more efficient, while the parallel processing power of the micro-computers can be directed to the non-control functions.

The plant monitor system is a real-time system that periodically transfers field data from a DCC, via a PDLC, to a PC server, which is linked to a local area network. The PC server stores the received data in a database that can be used for trend displays, printouts or long term data storage. In addition, the data collected may be broadcast over the local area network to user work stations, in real-time. Thus the plant status becomes readily accessible in the offices of the technical support staff, while maintaining the DCC system integrity.

6.3 Moving Arm Disk Replacement

The Moving Arm Disk (MAD) replacement unit is a PC-based drive system, using the PDLC for data transfers, which offers a direct replacement for the Hawk, Diablo or Pertec disk drive, as is shown in the system block diagram in Figure 1. The following design features are considered for the Emulated MAD (EMAD) disks:

- It is fully compatible with the existing disk drive system.
- Its performance is equal to or better than the existing disk drive system.
- It is less susceptible to obsolescence through a combined software and hardware solution, rather than a hardware only replacement.
- It maintains existing flexibility (e.g. it is easy to change a disk pack).
- It is an open system design, therefore it is easy to expand.
- It maintains EMAD disk integrity.

Based on these requirements, it was decided that an MS-DOS logical drive could be designated as an EMAD disk. Once an MS-DOS logical drive is formatted via the **FORMAT** command and re-built by the EMAD disk utility's **BUILD** command into an EMAD disk, it is protected from the MS-DOS file system so that EMAD data can not be accidentally destroyed (e.g. by the MS-DOS **COPY** command). There is no restriction on the disk size. However only 16 Mbytes are accessible via the MS-DOS in the current design. The number of EMAD disks which one can have is subject to the MS-DOS configuration. Note that any logical drive can be used as an EMAD disk, except the c: drive where the MS-DOS system is stored.

The advantage of the software-based over the hardware-based approach is that the EMAD disk is not tied to any particular type of disk or drive interface. Hence, disk drive obsolescence is no longer a major maintenance problem. The PC hard disk interface has already changed several times in the past few years and more changes are expected in the future.

The performance of the EMAD has been demonstrated to be comparable to the Hawk disk using a 386 based PC-AT system. During the course of development, several disk media and different interfaces have been tested: from the 360 Kbyte floppy diskette to a 640 Mbyte optical disk (partitioned into 64 Mbyte disks). They all performed in a satisfactory manner. The performance of the RAM-based EMAD disk far exceeds the original MAD disk.

Changing from one EMAD disk to another is as easy as changing an MS-DOS drive via one simple command from the keyboard.

6.4 High Speed File Transfer

High speed file transfers (source, object and core image files) between a DCC and PC are possible via a PDLC. Software utilities are now available for copying the entire disk image from a MAD disk to an EMAD disk or vice versa. This serves as a disk duplication tool. The MAD archiving utility allows the entire MAD disk (bootable or non-bootable) to be archived in the PC as an MS-DOS file for permanent archiving or disk backup.

6.5 Printer Replacement System

The printer replacement system offers a replacement for the line printer and video hard-copy printer unit as shown in the System Block Diagram given in Figure 1. It replaces the current unit (e.g. Statos printer) with a Centronics compatible line printer interface and an RS-170 compatible video printer interface driven by a printer controller that is connected to an IOBIC.

The software change involves the replacement of the on-line printer driver in the DCC Executive and relinking all the off-line DOS programs with the new DOS printer driver.

Since the Centronics compatible printer interface is in wide use, a variety of printers can be selected and installed. This also means that any future printer replacement which is Centronics compatible does not require a software change.

6.6 Fixed Head Disk Management

The Fixed Head Disk that holds the image of the on-line system can now be managed easily on an EMAD disk. All core image files can be directly transferred from the EMAD disk to the Fixed Head Disk and can be modified with the new Fixed Head Disk Library program linked with the new EMAD disk driver.

A new PC based Fixed Head Disk management program is also available to list the Fixed Head Disk directory.

6.7 Desk-top Maintenance of EMAD System

Traditionally, the computer software librarian had to maintain a source master disk, a source master backup disk and a working disk for all issued software. A copy on the paper tape was also required. Since the DOS system is command driven only, and available tools were limited, configuration control was a time consuming task.

With the EMAD disks, the entire disk is readily accessible through MS-DOS functions. A user friendly, menu driven File Access System (FAS) is now available for the user of the EMAD disk to view or access quickly any file on an EMAD disk directly in the PC. Programs developed, assembled and linked in MS-DOS can be transferred to an EMAD disk on the PC and then be taken to the DCC to be executed directly from that EMAD disk.

The File Access System has all the functions needed to build, backup and manage the EMAD disk. The software librarian can execute the traditional library functions with greater ease and speed as well as utilize the much higher density storage on the PC media. The need for many office cabinets has been reduced to be only a few disk filing drawers.

7.0 SOFTWARE DEVELOPMENT

A complete series of PC based desk-top software tools has been developed to optimize the use of commercially supported and low-priced PC equipment and tools for DCC software maintenance. They further increase programmer's productivity by having a work station for each designer, using PC software tools and using the larger memory and disk capacities on these systems. An increase in software quality, such as better commenting, documentation, desk-top testing and more thorough reviews can also be realized cost-effectively.

7.1 Development Platform

The MS-Windows multiple task environment and windowing system permits rapid switching between tasks. This is now in use to move rapidly from task to task as required during development, to view the results of each step and to repeat these steps quickly as may be required. The many individual tasks performed in the past over long periods of time by exiting and re-entering them are available at the click of a mouse button, which provides an integrated design platform. The development tools currently support batch (or macro) processing within the integrated environment also.

The control system resources can now be best used for actual final system integration test.

The following functions are now performed at individual work stations:

- Source file editing and design documentation.
- Program listing printouts.
- Assembly and linking (absolute as well as relocatable codes).
- Module debugging and testing.
- Test data generating.
- Program testing using simulator for overlay programs.
- Control system configuration managing.
- Program file storing, archiving and issuing on magnetic or optical disk media.

7.2 Software Quality Project Plan

Current licensing requirements and software design practices require a software development process which ensures that the programs and their revisions comply with the design specifications. The standard adopted to achieve this defines a Software Quality Project Plan to govern the development. The purpose of this plan is to provide a systematic approach and to solicit commitments from the developer's organization for the development of the control computer software such that the software conforms to the technical requirements. The plan is applicable to design, coding and verification of the software.

7.3 Software Quality Assurance

The quality assurance standards being consulted for Digital Control Computer software are those based on the standards CAN/CSA Q396.2.1-89, "Quality Assurance Program For The Development Of Software Used In Noncritical Applications", and CAN/CSA Q396.2.2-89, "Quality Assurance Program For Previously Developed Software Used In Noncritical Applications", dated January 1989. These standards require independent verification and QA audits at various stages during development of new software.

The software standards jointly prepared with Ontario Hydro for the development and maintenance of software on the Ontario Hydro projects classify the software according to the criticality of its application as follows:

a. Category 1 applies to Safety System software.

b. Category 2 applies to Control System software.

c. Category 3 applies to Monitor System software.

Present practices on control and monitor software design are being reviewed in light of the recent work on the Category 2 & 3 software standards, which are being developed.

Where the Digital Control Computer software change is performed by revising existing modules, the program changes need to be verified only according to the revisions or additions in the specifications. Verification of the interactions of these changes with other modules is also required. Integration tests are to be performed to verify changes to the key functions and interfaces.

7.4 Organization

The developer's organization is to be clearly identified in its supporting role for the development of the software on each Project. These will involve the following facilities:

a. Computer work stations

b. DCC test facilities

c. Design concepts and specification preparations

d. Software design

e. Software verification

f. Software design manual preparations

g. Software library facility and version control

h. Software design recor facility

i. Quality assurance monitoring

j. Software design Q.A. audits

7.5 Software Development Life Cycle

The conventional software development life cycle applies, which follows a systematic approach, composed of the following phases:

a. Requirements Analysis phase

b. Design Specification Phase

c. Detailed Design and Coding Phase

d. Program Testing Phase

e. Integration Testing Phase

f. Operation

7.6 Software Verification

The design and documents produced by the software development shall be reviewed at various stages to verify that they conform to the requirements and design standards. The verification shall be performed by qualified individuals in the software design group who did not perform the design or make decisions on the design changes.

The types of verification that shall be used on the software development are Review and Comment (RAC), Independent Design Review (IDR) and Supervisory Compliance Review (SCR). All reviews are intended to verify compliance with the functional requirements and standards. Test tool design documents and test data shall also be verified as being applicable for the tests intended.

7.7 Software Design Documentation Records

The software documentation serves to record the requirements, development, features and verification performed at the various stages of the development cycle. The record services department provides a computerized record and index of all documents produced for the project.

The official filing and archiving system for the software, containing the design standards, tools, source references, design records, source codes, binary code images and program listings, shall be maintained by the software library facility. Optical disks are used for mass storage of the software and its formal documents.

7.8 Software Configuration Management

The program source codes, assembled listings, object modules and binary code images shall be subject to configuration management to control the version to be issued, to control any changes to the issued versions and to control their identification. This is to ensure that only changes approved by formal revision to the specifications shall be incorporated.

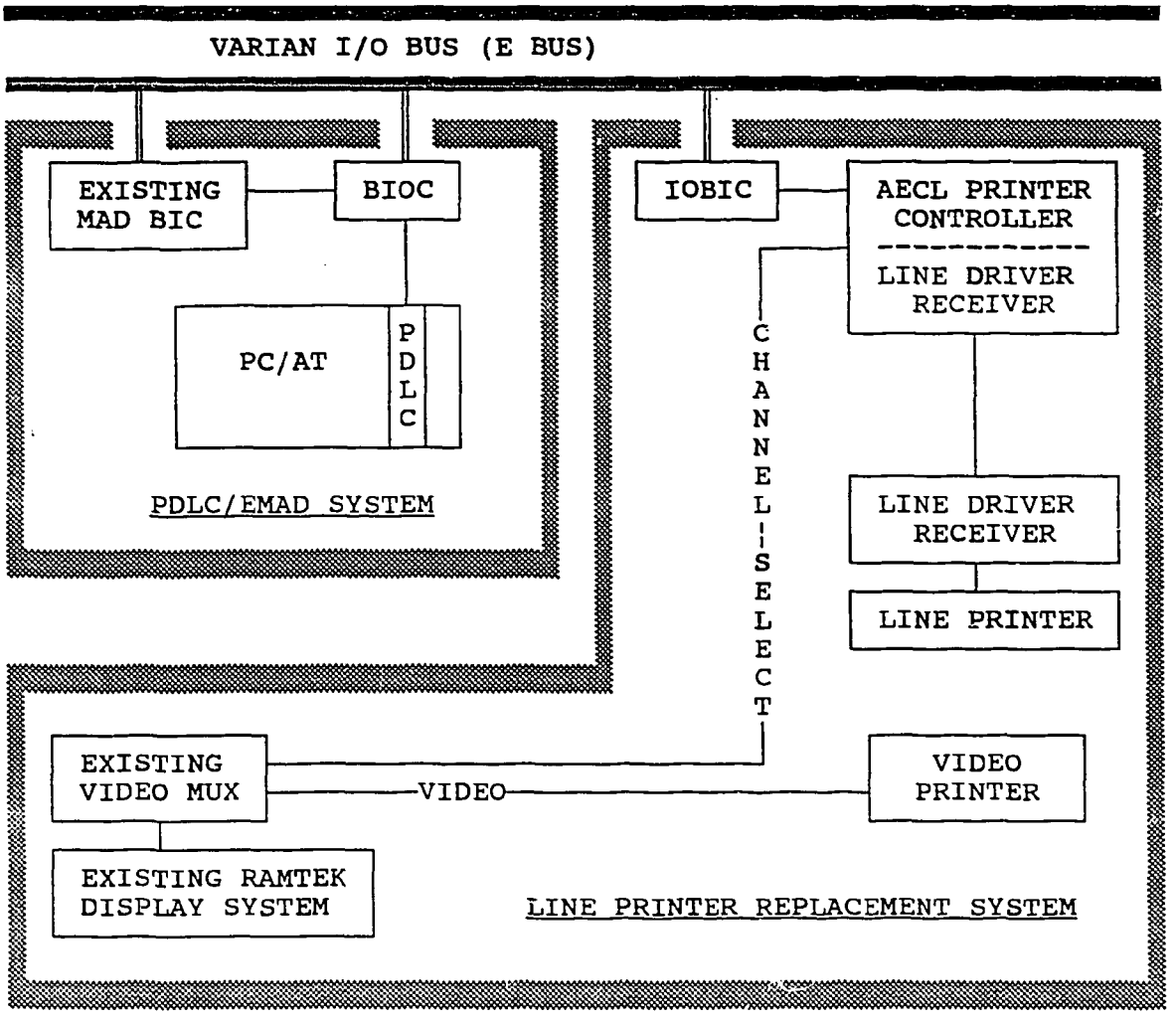
8.0 SUMMARY OF SOFTWARE STRATEGIES

With the new software tools available and more exacting quality requirements, the software user should have a high level of confidence that the software changes can be made cost-effectively and with a low probability of error.

9.0 GLOSSARY OF TERMS

BIC	Block interlaced controller device
BIOC	Block input/output controller device
Bus	Interface with the processor for computer components
CPU	Central processor chip (Unit) in a computer
CSA	Canadian Standards Association
DCC	Digital Control Computer
DISK	Magnetic storage media in disk form
DOS	Control computer disk operating system programs
EMAD	PC-based magnetic disk storage device, emulating DCC
Executive	Control computer real-time operating system by AECL
FAS	PC-based file access utility for EMAD disks
FHD	Fixed-head high speed magnetic storage device
H/W	Computer hardware equipment
I/O	Computer system input and output signal components
IOBIC	Input/Output block interlaced controller device
MAD	Magnetic disk storage device
Megaram	RAM disk high speed storage device in place of FHD
PC,PC-AT	IBM compatible personal computer system
PDLC	Parallel data link controller between DCC and PC
MS-DOS	Personal computer disk operating system by Micro-Soft
QA	Quality Assurance monitoring
RAM	Random access computer memory chips
S/W	Computer software programs

Figure 1
System Block Diagram



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CANADIAN NUCLEAR SOCIETY
SECOND INTERNATIONAL CONFERENCE ON CANDU MAINTENANCE
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ABSTRACT

DIGITAL CONTROL COMPUTERS' CABLE REPLACEMENT AT THE HYDRO-QUEBEC GENTILLY 2 NUCLEAR POWER STATION

30762000CA

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During the 1990 annual outage, the Preventive Maintenance Program inspections on the Gentilly 2 Digital Control Computers (DCCs) revealed that approximately 20% of the cable connector assemblies inspected showed signs of degradation. These findings raised the concern of an increased risk of signal failure by short-circuit.

Despite the excellent reliability of the gentilly 2 DCCs and their inherent design robustness, it was decided to proceed with the replacement of all cable connector assemblies within a reasonable time frame.

The degradation of the insulation was traced to a material incompatibility problem originating during cable manufacture. A migration of the plastifier contained in the PVC of the transparent sheats, surrounding many of the conductors, resulted in the chemical attack of the conductor insulation.

All assemblies of DCCX and DCCY were replaced during 1991 annual outage and during late 91 early 92 forced outage, respectively. The new cable assemblies were built by CAE, using the Raychem process which lacked the faulty material. Also the opportunity was taken to modify the ground network while the computer systems were stripped of their main components.

This work turned out to be a time-costly project needing an overall investment of over 900 thousand dollars (including taxes, interests and administrative charges). Nevertheless the planning and execution of the work was nearly flawless and the project a complete success. Integrity of cable insulation should not be a concern for the rest of the plant's life term.

Introduction

THIS PRESENTATION SHOULD GIVE YOU SOME ANSWERS TO THE...

- WHATS?
- WHYS?
- WHENS?
- HOWS?

ON THE REPLACEMENT OF INPUT/OUTPUT CABLES OF THE DIGITAL CONTROL COMPUTERS AT HYDRO-QUÉBEC' GENTILLY 2 NUCLEAR POWER STATION.

What?

WHICH COMPUTERS?

WHAT KIND OF CABLES ARE YOU TALKING ABOUT?

WHAT SORT OF DEGRADATION?

HOW MANY OF THOSE CABLES?

What?

WHICH COMPUTERS?

Configuration

1. TWO COMPUTERS (DCCX/DCCY) IN MASTER/SLAVE CONFIGURATION
2. DCCX IS IN CONTROL WHEN IT IS ON LINE
3. DCCY IS IN CONTROL WHEN DCCX IS OFF LINE
4. CONTROL IS PASSED BY ELECTRICALLY SWITCHING OUTPUTS

VARIAN DATA MACHINE: V73 SERIES

16 BITS MEMORY/IO/DATA/BUS

64 BITS MICROCODE

64 KB CORE MEMORY

2 MB SEMICONDUCTOR MASS MEMORY

What?

WHICH COMPUTERS? (CONTINUED)

I/O chassis

1856/1608	A/Is	64	A/Os
608/1152	D/Is	336/752	D/Os
2048	C/Is	32	EXT. INT.

Display system

RAMTEK FS-2000

Main functions

CONTROL OF PLANT PROCESSES
ANNUNCIATION OF ALARMS
DATA ACQUISITION
LOGGING

What?

WHAT KIND OF CABLES?

Connecting what?

PRINTED CIRCUIT BOARDS (PCB) TO TERMINAL BLOCS
PCB TO PCB

Cable assembly

MULTI-CONNECTOR-TB ASSEMBLIES:
TB/4C, 1C/1C, 1C/2C, 1C/8C

AMOUNT OF CABLES/CONNECTORS/TERMINALS

	DCCX	DCCY
CABLE ASSEMBLIES	**78**	**95**
CONNECTORS	**220**	**227**
TERMINAL BLOCKS	**97**	**126**

Why?

IDENTIFICATION OF PROBLEM

REPLACEMENT DECISION

SCALE OF PROBLEM

ROOT CAUSE

Why?

IDENTIFICATION OF PROBLEM

June 22 1989

FIRST AND ONLY I/O FAULT LINKED TO DEGRADATION OF INSULATION
SHORT BETWEEN TWO WIRES WITHIN CONNECTOR

July 1989

INSPECTION OF 67 CABLE ASSEMBLIES ON DCCZ OFFLINE COMPUTER
SEVERAL ASSEMBLIES SHOW SYMPTOMS
3 ASSEMBLIES SHOW BARE WIRES

Why?

IDENTIFICATION OF PROBLEM (CONTINUED)

September 1990 annual outage

- 33 ASSEMBLIES INSPECTED ON DCCX: 7 BAD, 4 REPLACED
- 27 ASSEMBLIES INSPECTED ON DCCY: 5 BAD, 3 REPLACED

- A.E.C.B. AND C.O.G. ARE INFORMED
- I.R.E.Q. IS GIVEN MANDATE TO EXPERTIZE PHENOMENON
- DECISION TO GO AHEAD WITH STARTUP OF PLANT AND TO PLAN REPLACEMENT OF CABLES WITHIN A REASONNABLE TIME FRAME.

Why?

REPLACEMENT DECISION

Impact on plant

NO IMPACT ON SAFETY NOR ON ENERGY PRODUCTION

Impact on availability of computers

- THEORETICAL INCREASE IN THE PROBABILITY OF FAILURE DUE TO SHORT CIRCUITS BETWEEN TWO WIRES
- HISTORICALLY NO OTHER COMPUTER FAULT WAS EVER RELATED TO PROBLEM
- HISTORICAL DATA SHOWED THAT PERFORMANCE IS MORE DIRECTLY LINKED TO MAINTENANCE THOROUGHNESS AND FREQUENCY
- NOT ENOUGH INFORMATION TO MEASURE RATE OF PROGRESSION OF PROBLEM

Why?

REPLACEMENT DECISION (CONTINUED)

Decision process

- GOOD CONFIDENCE THAT COMPUTER AVAILABILITY CAN BE MAINTAINED ON A SHORT PERIOD OF TIME (ROUGHLY ONE YEAR)
- NO ACCEPTABLE ALTERNATIVE (REPAIR OF BAD SECTIONS)
- INTERIM INSTRUCTIONS WERE GIVEN TO CURTAIL MAINTENANCE ACTIVITIES INVOLVING CABLE DISTURBANCE, AND TO BUILD SPARE CABLES OF DIFFERENT TYPES FOR EMERGENCY REPLACEMENTS

Action

REPLACEMENT OF ALL CABLE ASSEMBLIES WAS PLANNED FOR THE 1991 ANNUAL OUTAGE (LAST QUARTER)

Why?

SCALE OF PROBLEM

OUT OF THE 493 CONNECTORS INSPECTED ON DCCX

4 SYMPTOMS WITHIN OR NEAR CONNECTOR LOGGED:

53%	262	GREEN DEPOSITS INSIDE SHORT PVC SLEEVES
40%	197	WHITE POWDER ON SHORT PVC SLEEVES
35%	172	DISCOLOURING OF WIRE INSULATION
13%	**66**	**PHYSICAL BRAKE UP OF WIRE INSULATION**

31%	152	NO APPARENT DEGRADATION

Why?

ROOT CAUSE

Expertise

- IREQ
- CANADA WIRE (FOR CAE)

Common conclusions

- DETERIORATION DUE TO INCOMPATIBILITY OF MATERIAL
- POLYPROPYLENE INSULATION CHEMICALLY ATTACKED BY CHLORINE (HCL)
- HCL LIBERATED BY PLASTIFIER WHICH MIGRATED FROM PVC SLEEVES
- PHENOMENON ACCELERATED BY HUMIDITY & TEMPERATURE

Why?

ROOT CAUSE(CONTINUED)

Divergent theses for migration of chlorine

IREQ: PVC INHERENT INSTABILITY (15 YEARS LONGEVITY)

CAE: TRAPPED TRICHLOROETHYLENE UNDER PVC SLEEVES

Some Facts

- PHENOMENON ENCOUNTERED AT OTHER STATIONS, ALTHOUGH NONE AS SEVERE AS G2
- TEMPERATURE ENDURANCE TEST FOR ALL CANDU STATION COMPUTERS
- G2 SUBJECTED TO TWO TEMPERATERE ENDURANCE TEST (35°C FOR 2 DAYS)
- INADEQUATE ROOM TEMPERATURE CONTROL FOR SEVERAL YEARS

When?

REPLACEMENT WAS DONE:

DCCX:	LATE 91 DURING ANNUAL OUTAGE
DCCY:	EARLY 92 DURING A FORCED OUTAGE
DCCZ:	MID 92

How?

HOW MUCH DID IT COST?

HOW LONG DID IT TAKE?

HOW DID YOU DO IT?

How?

HOW MUCH...

DIRECT COSTS

MATERIAL	509K$	(CABLES, TERMINAL BLOCKS,...
MANPOWER	44K$	(CAE PERSONNEL)
TOTAL	**610K$**	

How?

How long (person/hours)

DOING THE JOB	DCCX		DCCY		TOTAL	
Disconnecting & removal	6%	103	8%	158	7%	261
Replacement of cables	60%	1008	67%	1274	64%	2282
Reconnecting with field	13%	220	9%	170	11%	390
Recommissioning	21%	359	16%	300	18%	659
TOTAL	**100%**	**1690**	**100%**	**1902**	**100%**	**3592**

PLANNING THE JOB					TOTAL	
Technical unit						450
Maintenance unit						125
TOTAL						**575**

GRAND TOTAL	4167

How?

HOW DID YOU DO IT

PREPARATION

REPLACEMENT

COMMISSIONING

RESULTS

How?

PREPARATION

Cable index Update

- COMPARING INDEX WITH EXISTING INSTALLATIONS: TEDIOUS BUT MOST IMPORTANT TASK
- DOCUMENTATION NOT ACCURATE

How?

PREPARATION (CONT'D)

Fabrication of material by C.A.E.

- CABLE ASSEMBLIES INCLUDING TERMINAL BLOCKS
- FULL ID. AT BOTH ENDS OF CABLES
- CONDUCTOR IDENTIFICATION STRIPS
- SPARE SETS OF CABLES ASS. OF MAXIMUM LENGTH
- COPY OF REPRODUCTIBLES OF ALL DRAWINGS
- CONSISTENT WITH CSA Z299.3 STANDARD

How?

REPLACEMENT

- POWERING DOWN COMPUTER
- DISCONNECTING FROM FIELD
- WITHDRAWAL OF EQUIPMENTS FROM CABINETS
- WITHDRAWAL OF EXISTING CABLES
- INSTALLATION OF NEW CABLES
- VERIFICATION OF INSTALLATIION
- RECONNECTING TO FIELD
- VERIFICATION OF FIELD CONNECTIONS
- REINSTALLATION OF EQUIPMENTS

How?

COMMISSIONING

TESTING OF A/C & D/C POWER SUPPLIES
TESTING OF POLARITIES OF A/Os, D/Is AND EXTERNAL INTERRUPTS
TESTING OF COMPUTER, PERIPHERALS AND I/O DEVICES
SYSTEM HEALTH MONITORING

How?

RESULTS

Problem encountered

- GROUND WIRES WERE TOO SHORT
- ID. STRIP ON TERMINAL WERE TOO LONG
- CONNECTIONS ON TERMINALS WERE A BIT LOOSE AND WERE TORKED TO 6 LB-IN
- 12 WRONG FIELD CONNECTIONS (OUT OF 13600) BETWEEN TERMINAL AND FIELD (BOTH COMPUTERS)
- A FEW CABLE ASSEMBLIES WERE EITHER TOO LONG OR TOO SHORT
- 2 CONNECTORS HAD BROKEN PINS
- A FEW CABLE ASSEMBLIES HAD WRONG ID.
- WRONG TYPE OF PINS/POLARITY ON 48VDC CONNECTORS
- 1 PAIR OF WIRES WAS INVERSED ON A TERMINAL

How?

RESULTS, WORST CASE

THE WORST PROBLEM DURING COMMISSIONING WAS FOUND ON DCCX AND HAD NOTHING TO DO WITH REPLACEMENT OF THE CABLES:

BAD CONTACT ON PCB IN POWER SUPPLY (P/S) OF COUNT DOWN REGISTER CHASSIS CAUSING OVERLOADING OF COMPUTER AND FAILURE OF PROGRAMS. THE OUTPUT OF THE P/S WOULD GO DOWN WHENEVER A PERIODIC PROGRAM WAS SWITCHED ON.

How?

OVERALL

Overall evaluation of work

- PROBLEMS ENCOUNTERED WERE MINOR
- CABLE ASSEMBLIES DELIVERED BY C.A.E. WERE OF EXCELLENT QUALITY
- WORK DONE BY C.A.E.'s PERSONNEL WAS WELL FINISHED AND PROFESSIONNAL
- PINS OF CONNECTORS (FROM EDAC) USED IN RAYCHEM PROCESS ARE WEAK AND CAN BRAKE OFF EASILY IF CABLES ARE NOT SECURED PROPERLY

Conclusion

- PHENOMENON WAS JUDGED SEVERE ENOUGH AT G2 TO REPLACE ALL CABLES
- PHENOMENON IS PRESENT AT SEVERAL STATIONS WITH DIFFERENT SEVERITY
- REPLACEMENT IS COSTLY, TIME CONSUMING AND KEEPS COMPUTER DOWN FOR SEVERAL WEEKS
- REPLACEMENT AT G2 IS A SUCCES AND OUR EXPERTISE CAN BE READILY TRANSFERED ON DEMAND TO ANY PARTY IN NEED
- SUCCESS IS BASED ON GOOD PLANNING, TRIMMED PREPARATION, QUALITY MANUFACTURING AND MANPOWERE BY C.A.E. AND THOROUGH COMMISSIONING

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MAINTENANCE PROBLEMS WITH SPECIALIZED INSTRUMENTATION USED ON CANDU SYSTEMS, AND METHODS USED TO IMPROVE EQUIPMENT AVAILABILITY

H. Toby

Ontario Hydro

Bruce Nuclear Generation Station "B"

ABSTRACT

This paper describes several maintenance problems, and solutions, associated with specialized instrumentation. Because some of this equipment was manufactured for a laboratory type of environment, it couldn't perform the functions it was designed for when exposed to a nuclear plant environment.

Sample delivery systems supplying samples to analytical instrumentation are cumbersome and very maintenance prone due to the high equipment failure rate, or loss of sample to the instrument.

Maintaining radiation detection equipment is very time consuming due to the regular testing requirements and repairs. It's also costly due to the high detector failure rate.

Admittedly, we've had to learn to live with some maintenance problems. But for the most part, Bruce NGS B has surmounted the difficulties associated with maintaining special instrumentation in a CANDU environment.

MAINTENANCE PROBLEMS WITH SPECIALIZED INSTRUMENTATION USED ON CANDU SYSTEMS, AND METHODS USED TO IMPROVE EQUIPMENT AVAILABILITY

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Ontario Hydro
Bruce Nuclear Generation Station "B"

Abstract

1 Off the Shelf Fixed Instrumentation and their Common Problems when Placed in a CANDU Reactor Environment

2 Equipment Access and Maintainability

3 Non-standard Maintenance Programs on Specialized Equipment

MAINTENANCE PROBLEMS WITH SPECIALIZED INSTRUMENTATION USED ON CANDU SYSTEMS, AND METHODS USED TO IMPROVE EQUIPMENT AVAILABILITY

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SECTION 2: OFF THE SHELF FIXED INSTRUMENTS AND THEIR COMMON PROBLEMS WHEN PLACED IN A CANDU REACTOR ENVIRONMENT

Not all off the shelf instruments are suitable for their selected application. Instruments used in a CANDU plant environment that are not located in a special instrument room will be subjected to air drafts, dust, fluctuating and higher than normal operating temperatures, humidity, vibration, electrical magnetic inductions (E.M.I.), power excursions and power supply problems.

- Air drafts can cause instrument calibration to drift, while dust will impair a computer's floppy disk drives.

- Dust will also prevent instruments from dissipating heat. High instrument operating temperatures caused by dust or high ambient temperature will lead to calibration drift and premature electronic component failures.

High instrument operating temperature problems include:

A. The non-contaminated noble gas stack monitors at Bruce B initially were located near an outside air ventilation louvre, in an unheated room. The daily and seasonal temperature changes made it impossible to maintain an adequate calibration. Contaminated stack monitors were located on 691' elevation beside the air duct fans. In the summer, the temperature on this floor level can become very high causing calibration to drift. This results in erroneous radiation release rates indication. We also experienced a high level of equipment failures.

   The maintenance on these monitors ranged from difficult to impossible and a solution to the problem had to be found. It was decided to put the non-contaminated and contaminated monitors together in one air conditioned instrument room (see Fig. 1). The instrument room was built in the contaminated stack area and most of the above problems disappeared. The equipment failure rate is now acceptable and equipment availability is greatly improved.

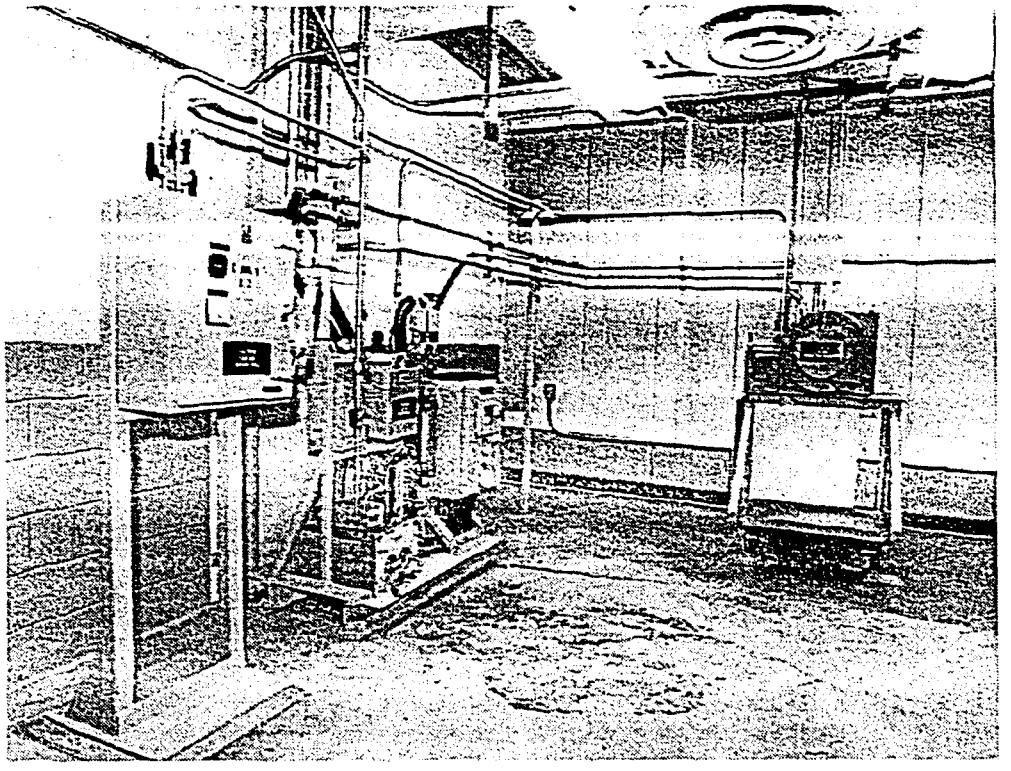

Fig. 1
Tritium Collector, Particulate and Iodine, and Noble Gas Monitor at Bruce B

B. Containment monitors (commonly referred to as box-up monitors) have problems with temperature changes as well. A Unit containment monitor has a live zero and the output signal to Digital Control Computers (DCC) will drop below zero reading, causing a box-up of the containment monitors due to large temperature changes. A small radiation check source which can be activated from the control room to initiate a box-up monitor functional test becomes stuck during seasonal temperatures change. It requires a small adjustment on the check source mechanism to ensure enough counts are being received to pass the test.

C. Hand and foot monitors located at or beside an outside door will have operating problems due to the fluctuating temperatures. We have seen an increase of maintenance on these monitors during winter months.

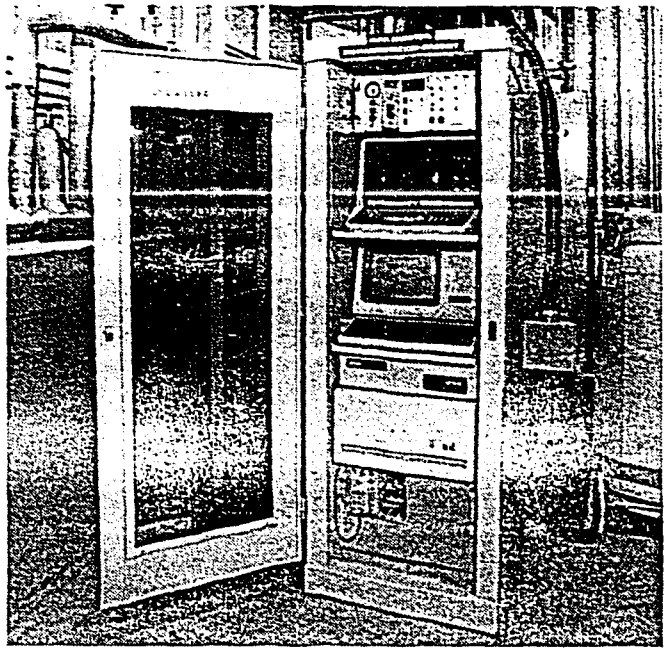

Fig. 2
Heat Transport System Radioactivity Monitor
(Gaseous Fission Product Monitor)

D. The Gaseous Fission Product (GFP) at Bruce B is located in the field and is packaged in a standard size equipment cabinet (see Fig. 2). The cabinet is filled with instruments that dissipate a considerable amount of heat. Some cooling fans were installed on the top of the cabinet to increase the air circulation, as we thought this would keep the inside temperature from over-heating the instruments. However, this was inadequate as we encountered a high electronic component failure rate, especially in the multi-channel analyzer instrument. Opening the door somewhat lowered the inside temperature but allowed dust into the cabinet. This led to several problems; floppy disk drive failures or sections of the floppy disk damaged, which caused program errors.

Because it was a very high maintenance item, the equipment availability was low. After attaching an air conditioning unit to the outside of the cabinet the equipment operated satisfactorily with low maintenance requirements.

Summary of Temperature Effects on Station Equipment

At Bruce B, we were successful in eliminating some of the equipment problems caused by high operating temperature, by controlling the environment with air conditioning.

Comments

An overly high operating temperature can become a control technician's nightmare. Initially, you will experience calibration problems and then intermittent faults. When the equipment is then removed for shop repair, it cools down and the fault disappears!

Humidity's Effects on Instruments

A. Humidity will have an adverse effect on electronic printed circuit boards, especially on high voltage supply boards in radiation detection equipment. The hand and foot monitors high voltage power supply boards showed tracking of the high voltage when the humidity increased. This tracking results that a lower then normal operating voltages is available to the GM (Geiger Moeller) tube, which made the GM tube output drop. When a control technician went to troubleshoot the monitor for low count and measured the HV supply, he found it lower than required. The control technician then cranked the high voltage up, getting the monitor operating satisfactorily.

   If the humidity in the atmosphere drops, the tracking will reduce, resulting in an increase of the voltage. If the increase in voltage exceeds the GM high voltage threshold, the GM tube will go into a counting avalanche and destroy itself. Sealing the high voltage printed circuit boards with Humiseal (a protective coating for electronic application) to prevent high voltage tracking connected this phenomenal.

B. Humidity also had an effect on some of the hand and foot monitor printed circuit board component sockets. We learned that the Eproms started to develop intermittent problems as their pins had started to oxidize. This oxidation was caused by some residual acid in the eprom sockets. It was determined that the sockets were not sufficiently washed after being electroplated. We replaced all sockets (440) with one of better quality, thus eliminating this problem.

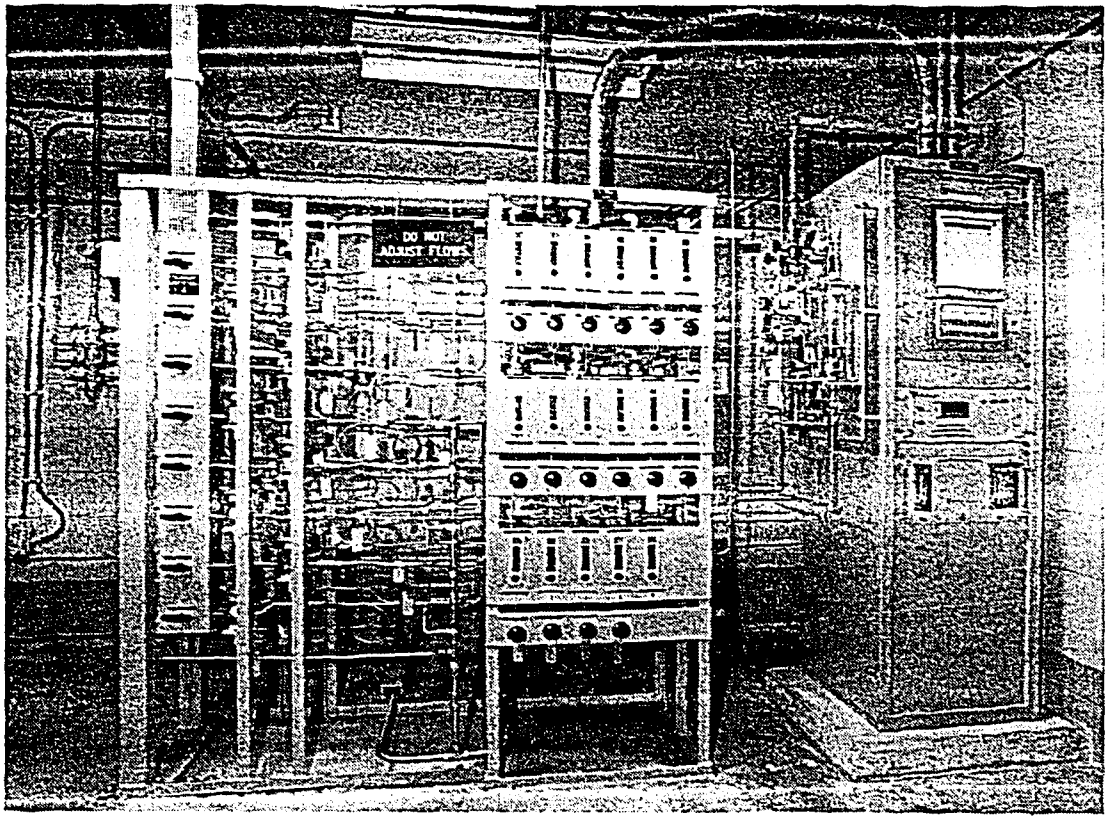

Figure 3
Boilers: D_2O - H_2O Analyzers

C. High humidity has also had an affect on the operation of the D_2O in H_2O analyzers. Whenever the air conditioning of the instrument room fails, the humidity in the room increases severely influencing on the instrument accuracy. (see Fig 3).

Vibration Effects

Vibration problems in the station range from affecting instrumentation calibration and processing equipment failures, to failure of radiation detectors.

Examples of equipment failures are:

A. Wiring connectors and printed circuit boards' edge connectors become loose, causing intermittent problems and finally resulting in failures. Control wiring (solid conductor type especially) breaks at terminal strips.

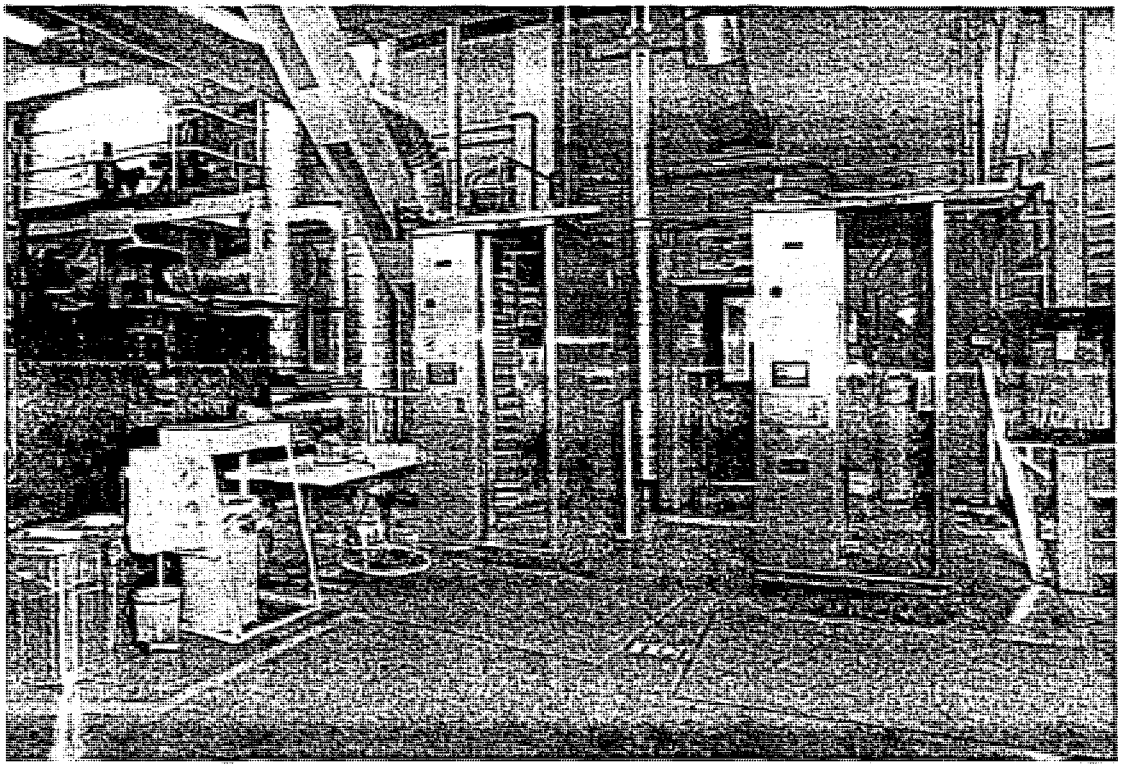

Fig. 4
Whole Body Monitors

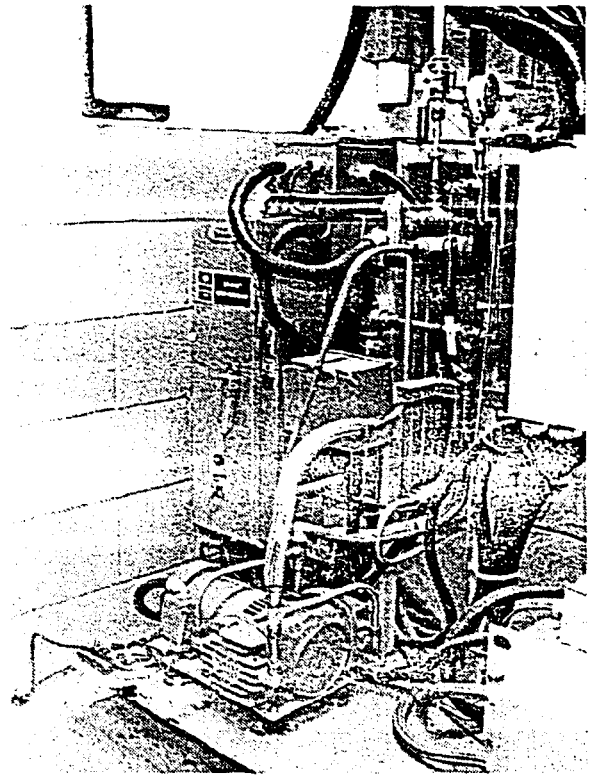

Fig. 5
Iodine & Particulate Monitors

B. At Bruce B, we were finding a lot of pin holes in the mylar covering the large size gas flow proportional counters in the whole body monitors. These monitors are in the vicinity of the Unit 6 boiler level control valves. Vibration analysis showed that the monitors suffered from vibration exposure, causing fretting of the counters' mylar window which in turn caused an abnormally high amount of pin holes. These pinholes increased the detector failure rate significantly. The monitors had to be placed on shock absorbers to reduce their high failure rate.

C. The Unit's gas chromatographs have Metal Bellows sample delivery pumps. These are located on the same skid as the gas chromatograph and bearing failure on these pumps will cause vibration of the pump. This vibration is transferred into the skid and the thermoconductivity detector of the gas chromatograph, altering the baseline of the instrument and causing incorrect local and control room readings, see fig.4.

D. The particulate and iodine stack monitors at Bruce B have a bellow type sample delivery pump located on the equipment skid. These 24-hour duty cycle pumps will periodically start to vibrate before they fail. When the vibration increases, the monitor begins having electronic problems. It also has trouble maintaining a steady sample flow and its output becomes erratic. (Refer to Figure 5).

ELECTRICAL MAGNETIC INDUCTION

Electromagnetic fields in and around a generating facility are very much a concern in all systems and present functional problems with the most sensitive of equipment. Radiation measuring instruments, by their nature, are among those which can be easily influenced by noise since the detector signals are often fast pulses which resemble noise. This makes it difficult to separate the noise from the signal.

A. One such example are the containment monitors in the vacuum building control instrument room. Every so often, a burst of pseudo-radiation was reported by each of the two monitors simultaneously. Each monitor was, however, fed from separate power supplies from separate class 2 power busses, and shared no common control circuitry. An indepth analysis of the problem found that spurious bursts were predominantly 590 kHz in frequency and could be found in the instrument room on everything; including metal cabinets and the station ground. The bursts lasted approximately 10 seconds and occurred every 2-6 hours. They could not be traced to the startup of any piece of equipment nor could they be linked to radio transmitters.

The solution to the problem was then to mask or hide the burst by increasing the signal level, heightening the signal to noise ratio. The noise burst still exists, but is of insignificant amplitude with respect to the signal (see Fig. 6).

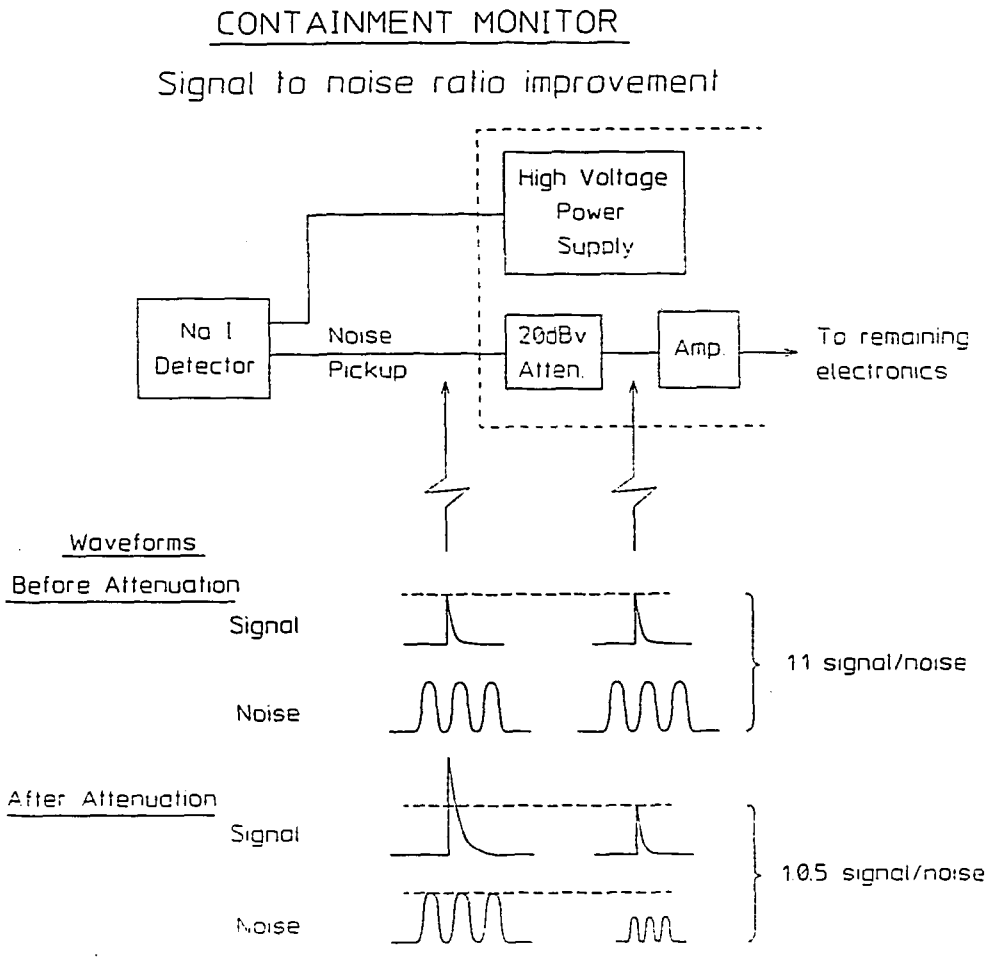

Fig. 6

B. The particulate and iodine monitors also encountered noise induced pseudo-radiation. This problem was overcome by the use of additional AC line filters. Power line voltage drops also presented an obstacle in the commissioning of these monitors. The drops were overcome by increasing the voltages at the source; the transformer.

C. The hand, foot and frisker monitors we have are another such example. Power bumps (largely due to instrument AC supply line switching) would make the monitors lose their calibration data, necessitating a recalibration. The problem lies in the original design of the instruments. In the event of a power failure, no provisions were incorporated to bring the cpu to an orderly shutdown. As it was the cpu would perform a memory cycle and all of a sudden control and data lines would become erratic. The solution to this problem was to incorporate into the circuitry a lightly filtered 5V power supply which would decay much quicker than the main 5V supply and connect it to the cpu's highest priority non-maskable interrupt (TRAP). The code residing at this interrupt vector consisted of a disable all interrupts and a halt. The cpu would then not perform any memory cycles until a power fail restart pulse was generated by the power supply.

SECTION 3: EQUIPMENT ACCESS AND MAINTAINABILITY

Bruce B is fortunate in that almost all of our instruments are outside the containment area. This increases the ability to maintain the equipment versus some other nuclear power plants that have instrumentation within containment areas. We thus get away from the time consuming procedures involved in getting into and out of containment areas which can significantly reduce productivity. This also decreases the dose rate received by the control technicians working on the equipment.

Being able to gain easy access to the equipment increases its maintainability, consequently improving the equipment's availability. But having relatively easy access to instruments will not always result in better maintainability. Some equipment is, by design, difficult to work with due to its complexity. Other instruments are a regular pain in the neck to deal with, or very time consuming to maintain.

Very high maintenance prone instruments are, for example, the D_2O in H_2O monitors (refer to Fig. 3). This is a simple type of electronic spectrometer that measures D_2O in H_2O in parts per million. Each Unit has two systems, one system to sample surface cooling water, the other to sample water of each boiler. The sample delivery system to these monitors consumed an abnormal amount of the maintenance time, especially the one that samples the surface water systems. It delivers a sample via filters to a very small holding tank with a level probe. When the level is high enough, a small micro pump will start, delivering the sample via a second filter to the analyzer. Normally this pump runs steadily, only stopping when the level becomes low. The cost of parts to refurbish the little pumps due to wear and tear of fine sand in the cooling water, and the cost of the filters which are regularly replaced to prevent the analyzer from clogging up, is absurd. Because the analyzers at Bruce B seem to drift below their zero setting (148 ppm) they need a control technician's visit bi-weekly to re-zero them. It takes a control technician on a four unit station about eight hours each time he does the regular routines(this includes re-zeroing each instrument). In addition to the twice weekly regular routines, there are quarterly and yearly call-ups to maintain this equipment.

SECTION 4: NON-STANDARD MAINTENANCE PRACTICES ON SPECIALIZED EQUIPMENT

To increase equipment reliability certain test programs were developed. Not only did the equipment reliability increase, but the maintenance department benefitted as well. At Bruce B we use three of these programs extensively; the DCC X and Y Self Check Program, the testing of inverter drive control loop in the Fuel Handling Area, and the whole body data acquisition system.

The following is a short description of each of these programs and an explanation of why they enhance certain maintenance programs. They also could be used as examples for reducing costs on other high maintenance systems.

A. Each Unit has two digital control computers, called DCC X and Y. In order to meet the safety and reliability requirements of the dual computer system, a comprehensive self-checking scheme is provided. The self check program (CHECK) is designed to monitor the performance of the computer and its peripheral (input/output) equipment. If a system malfunction is detected, the CHECK program will alert the operator through the annunciation system and alarm recorder.

On detection of a very serious failure within the computer system, the CHECK program can force a stall of the failing computer system, and a safe transfer of control to the standby computer.

The check program is an unswitched periodic program which runs every two seconds. It is normally on all the time. If the check program is turned off, the executive program initiates an alarm message informing the operator that check is off.

The check program runs 11 different tests. A few are:

- Buffered Input/Output Controller Test
- Digital Input/Output System Test
- Analog Input System Test, etc.

Each test provides error messages and, where possible, the expected and received data from the test.

Besides increasing the safety and reliability of the computer system, the check program provides control maintenance personnel with messages indicating the following:

- potential faults
- immediate failures.

The alarm messages generated by the check program will allow a control technician to break the computer system down into segments which can be readily analyzed for fault diagnosis. The check program also ensures the computer's accuracy, and whenever it deviates from a set value it will initiate an error message. This assists a control technician in taking prompt and correct action to eliminate the problem.

B. DATA ACQUISITION SYSTEM FOR WHOLE BODY COUNTERS

The new generation of very sensitive whole body monitors is composed of many detectors. These flow proportional detectors have a very thin mylar cover that is easily punctured. Because we have 27 of these monitors spread throughout the station, and an additional 16 one-step monitors coming, it would take a considerable amount of manpower to ensure they operate correctly. Taking into consideration the factors causing a monitor to go into a malfunction mode, a self check system with central annunciating and failure reporting was developed. The central reporting is done in the control maintenance shop where a PC based system audits all monitors (see Fig. 7). The Data Acquisition System (DAS) was developed by Herfurth, the monitor's manufacturer, and the installation at Bruce B is the first of its kind. Two separate and distinct functions are performed by the DAS - Data Acquisition and Maintenance.

The data acquisition portion, coupled with a badge reader, is used by Radiation Control to track people who are contaminated, looking mainly for where they picked up the contamination.

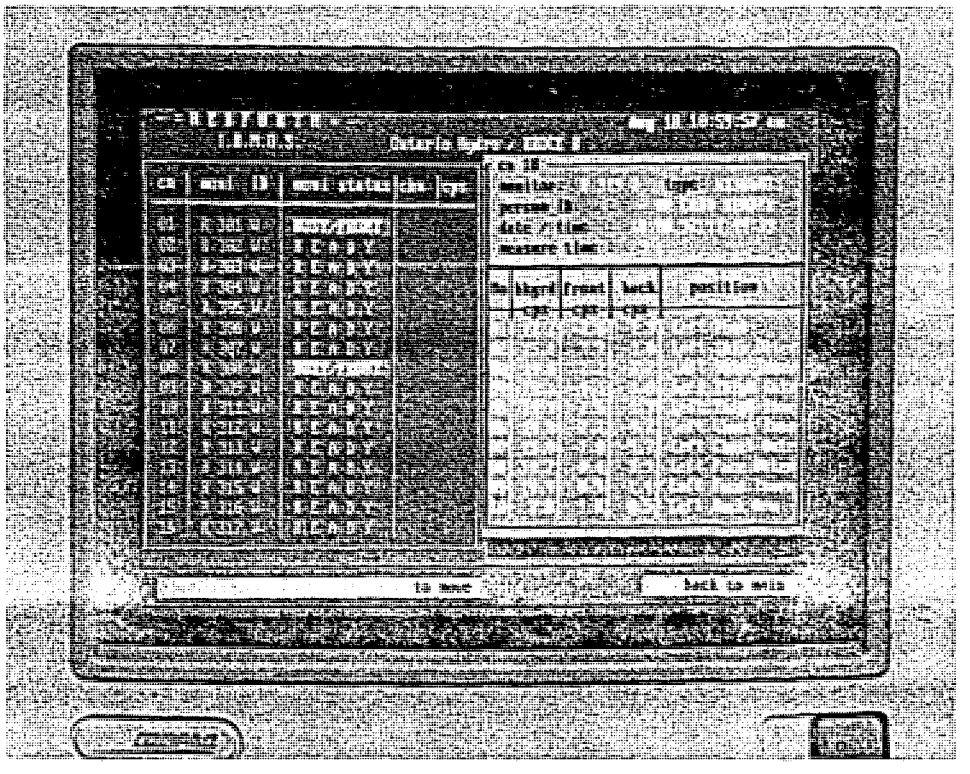

Fig. 7
Whole Body Monitors

The maintenance portion allows the control technicians to look at all parameters associated with the monitors from a central location. This obviously eliminates the necessity of having technicians visit every monitor for correct operation, therefore saving a considerable amount of their time. It also aids in minimizing monitors down time in case of equipment failure or loss of gas used in the proportional gas counters. Besides, it allows the maintenance department to closely watch all the monitors for a downward trend in performance, thus increasing response time.

The DAS system computer has four status screens available. The administration screen shows the status of all the monitors (refer to Fig. 6). It also shows all the monitors' identification numbers and their status. The status indicators are:

Ready	(monitor is fully operational and not in use)
Not Ready	(a fault condition exists)
Busy Front	(front of a person is being checked)
Busy Back	(back of a person is being checked)
Clean	(no contamination found)
Contaminated	(contamination found)
Time Out	(communication between the monitor and computer has been lost)

Any fault condition can be analyzed by calling up the next computer driven screen. This screen will display all available alarm conditions, such as low gas, high or low counts of each detector, etc. More screens are available to aid control technicians in obtaining information to determine the status of a faulty monitor before going into the field to repair it.

C. TESTING OF INVERTER DRIVE CONTROL LOOP AT BRUCE B

Background

The fuelling machine system requires several different sized motors from 1/2 horsepower to 40 horsepower. Operating at variable speeds and torques, they perform the required physical motions of the fuel changing system. A simple and rugged three-phase squirrel cage induction motor, fed by static inverters, was the designer's choice to meet the requirements.

The speed of each motor is dependent upon the supply frequency, while the torque output of each motor is related to the supply voltage which affects the magnetic flux level in the motor. The static inverter is an extremely effective motor controller, accomplishing both frequency and voltage adjustment.

The fuelling operation normally occurs in full automatic mode under computer control. The digital control computers interface via multiplexers to the field devices. The computers provide control inputs to the inverters to determine:

- the state of the inverter - on or off
- phase rotation of the inverter-controls motor direction
- frequency output - controls motor torque
- voltage output - controls motor torque

A custom designed inverter monitor samples the output of the inverter and provides feedback signals relative to the inverter frequency and voltage to the digital computers. These feedbacks are used in the controlling software, ensuring drives are not operated at unacceptably high speeds or torques.

The command signals sent from the digital control computers to the inverters are set at a level which allows continuous automatic operation of the fuelling system with no danger of stressing any mechanical components or risking fuel damage. The signal levels are set just high enough to reliably operate drives if the drives are experiencing normal friction levels, and the inverter is providing the correct frequency and voltage for the given input. Therefore, if any mechanical degradation of the drive occurs which results in more drive friction, or if the inverter output is low, the mechanical drive will stall.

Problem

When mechanical stalls of the drives occur, many different components of the complex mechanical drive or inverter drive control loop could have caused the failure. Solid failures of either the mechanical drive or the inverter drive loop are rare. Most stalls are due to some component in the electrical or mechanical part of the drive drain being marginal. Tracking down the exact cause of the stall can be difficult.

Any mechanical drive troubleshooting is performed in a radioactive environment where workers must wear protective clothing. A penalty of dose expenditure and reduced efficiency of maintainers is experienced. The logical course of action in the absence of an obvious mechanical failure is to prove all components of the inverter drive control loop are operating in tolerance. This entails calibration checks on the:

- analog output section of the computer,
- inverter,
- inverter monitor,
- analog input section of the computer.

The original method of performing detailed calibration checks on these devices required two technicians for approximately eight hours. A diagnostic tool has been developed which very quickly tests the inverter drive control loop tolerances.

Solution

An off line software package called Inverter Tests (INVTST) was provided by GE Canada and refined by Bruce B Operations. This software simulates normal inverter drive loop control with the exception of actually running the motor. Analog outputs and inputs of the computers and the inverter and monitor are checked, as a loop, at eighteen "critical operation" levels. These "critical operation" levels were chosen to match the drive requirements of the fuelling machine drives historically proven to be most prone to stalls.

Information provided by the test included:

- hertz and torque input command levels
- hertz and torque output feedback tolerance range
- hertz and torque actual output feedback
- hertz and torque output failure indication (low or high)

The software can be loaded, run, and the results analyzed in less than fifteen minutes!

If a "clean" run (no lows or highs) is achieved, it can be reasonably inferred the stall is being caused by the mechanical portion of the drive or the drive motor itself. (See example 1 for "clean" run.)

If running the test shows a "dirty" inverter, (any lows or highs reported) the detailed calibration procedure mentioned earlier must be performed to determine the faulty component. See example 2 for a "dirty" run.

We have found this program to be a very effective diagnostic tool when faced with fuelling machine drives stalls.

O-63599 DSW: INVERTER TWO TEST
FUEL HANDLING INVERTER CALIBRATION RECORD

1) If any HZ or V2-H2 limits are exceeded, a full inverter and monitor calibration is necessary as per CMP 63599.3 and 63599.2 respectively.

2) If no limits are exceeded, the inverter and monitor are within specification, however, it is still required to measure the manual bus power supply in the control equipment room, and the inverter DC bus capacitor rank capacity.

A) PS2 READING
SEE CMP 63599.3, 4.0(A) INSTRUMENT # _____

_____ VDC EXPECTED VALUE 14.0 +- .1 VDC

B) DC BUS CAPACITY
SEE CMP 63599.3 SECTIONS 3.2, 3.4 AND 4.0 (C)
INSTRUMENT # _____

_____ MFD _____ MFD
READING 1 READING 2
READING 1 AND 2 MUST BOTH BE > 18 MFD

TEST PERFORMED BY: _____ _____

TEST VERIFIED BY CT III: _____

HZ OUTPUT COUNTS	V/HZ OUTPUT COUNTS	HZ FDBK LIMITS	HZ FDBK ACTUAL	HZ TEST LOW-HIGH	V2/HZ FKBK LIMITS	V2/HZ FCBK ACTUAL	V2/HZ TEST LOW-HIGH
0135	0460	0260-0350	0267		0165-0320	0216	L
0135	0530	0260-0350	0266		0250-0405	0232	L
0135	0610	0260-0350	0266		0350-0530	0317	L
0135	0640	0260-0350	0266		0405-0600	0355	L
0135	0730	0260-0350	0266		0540-0750	0473	L
0135	0757	0260-0350	0265		0615-1020	0536	L
0140	0550	0270-0360	0306		0305-0465	0272	L
0140	0650	0270-0360	0306		0455-0640	0116	L
0150	0120	0320-0405	0327		0150-0305	0152	
0150	0520	0320-0405	0327		0260-0440	0527	L
0150	0570	0320-0105	0327		0350-0555	0342	L
0150	0600	0320-0405	0326		0370-0575	0355	L
0250	0430	0620-0710	0617	L	0350-0565	0342	L
0250	0470	0620-0710	0617	L	0455-0710	0441	L
0300	0250	0720-1010	0720		0105-0270	0117	
0520	0260	1605-1677	1532	L	0300-0535	0304	
0520	0310	1605-1677	1532	L	0110-0670	0404	L
0777	0325	2640-2727	2536	L	1000-1270	1013	

O-63599 DSW: INVERTER TWO TEST
FUEL HANDLING INVERTER CALIBRATION RECORD

1) If any HZ or V2-H2 limits are exceeded, a full inverter and monitor calibration is necessary as per CMP 63599.3 and 63599.2 respecitvely.

2) If no limits are exceeded, the inverter and monitor are within specification, however, it is still required to measure the manual bus power supply in the control equipment room, and the inverter DC bus capacitor rank capacity.

A) PS2 READING
SEE CMP 63599.3, 4.0(A) INSTRUMENT # _____

_____ VDC EXPECTED VALUE 14.0 +- .1 VDC

B) DC BUS CAPACITY
SEE CMP 63599.3 SECTIONS 3.2, 3.4 AND 4.0 (C)
INSTRUMENT # _____

_____ MFD _____ MFD
READING 1 READING 2
READING 1 AND 2 MUST BOTH BE > 18 MFD

TEST PERFORMED BY: _____ _____

TEST VERIFIED BY CT III: _____

HZ OUTPUT COUNTS	V/HZ OUTPUT COUNTS	HZ FDBK LIMITS	HZ FDBK ACTUAL	HZ TEST LOW-HIGH	V2/HZ FKBK LIMITS	V2/HZ FCBK ACTUAL	V2/HZ TEST LOW-HIGH
0135	0460	0260-0350	0267		0165-0320	0216	L
0135	0530	0260-0350	0266		0250-0405	0232	L
0135	0610	0260-0350	0266		0350-0530	0317	L
0135	0640	0260-0350	0266		0405-0600	0355	L
0135	0730	0260-0350	0266		0540-0750	0473	L
0135	0757	0260-0350	0265		0615-1020	0536	L
0140	0550	0270-0360	0306		0305-0465	0272	L
0140	0650	0270-0360	0306		0455-0640	0116	L
0150	0120	0320-0405	0327		0150-0305	0152	
0150	0520	0320-0405	0327		0260-0440	0527	L
0150	0570	0320-0105	0327		0350-0555	0342	L
0150	0600	0320-0405	0326		0370-0575	0355	L
0250	0430	0620-0710	0617	L	0350-0565	0342	L
0250	0470	0620-0710	0617	L	0455-0710	0441	L
0300	0250	0720-1010	0720		0105-0270	0117	
0520	0260	1605-1677	1532	L	0300-0535	0304	
0520	0310	1605-1677	1532	L	0110-0670	0404	L
0777	0325	2640-2727	2535	L	1000-1270	1013	

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1.0 EXECUTIVE SUMMARY

The Three Mile Island Nuclear Station Unit One (TMI-1) Once-Through Steam Generators (OTSG's) were chemically cleaned during the period of October 18 - November 1, 1991 by the B&W Nuclear Service Company (BWNS). This secondary side cleaning was accomplished through application of the EPRI/SGOG chemical cleaning iron removal process. BWNS also performed on-line corrosion monitoring to verify safe process application.

The primary objective of the chemical cleaning was to remove magnetite (Fe_3O_4) deposits from the tube support plate (TSP) broached holes. These deposits caused an increase in the secondary side pressure drop resulting in increasing OTSG downcomer water levels. These rising downcomer water levels had forced TMI-1 to reduce power by various amounts during the three previous fuel cycles. Upon shutdown for the October 1991, outage, TMI-1 was limited to 96% power. TMI-1 returned to 100% power operation on November 17, 1991, after completion of the 9R outage and chemical cleaning. OTSG pressure drop after startup returned to values observed during initial startup of the new OTSGs in 1974.

General Public Utilities Nuclear (GPUN) had estimated a total deposit loading of 3400 lbs per OTSG by calculating total feedwater iron transport. The actual amount of deposits removed from each generator was very close to this estimate:

	OTSG "B"	OTSG "A"
Chemical Cleaning	3157 lbs	3128 lbs
Sludge Lancing	118 lbs	128 lbs
TOTAL	3275 lbs	3256 lbs

OTSG material corrosion was monitored during process application through the use of free and galvanic corrosion electrodes and coupons placed in the lower handholes of each generator.

Corrosion of key OTSG materials and welds was low and well within established limits:

COMPONENT	ALLOWANCE (mils)	OTSG "B" (mils)	OTSG "A" (mils)
TSP Land	3.0	1.02	0.78
Shroud	10.0	1.31	1.12
Wedge Block	10.0	1.03	0.83
Various	50.0	1.69	1.34

On-line corrosion values predicted by the BWNS Corrosion Monitoring Data Acquisition System (CMS) were within a maximum difference of 12% of the actual corrosion values calculated by electrode weight loss.

OTSG chemical cleaning was completed four and one-half days ahead of schedule and was performed off critical path. BWNS performed the cleaning with a mobile chemical cleaning system that utilized flexible hosing for a majority of the process runs. All outside-containment equipment was set up and checked out prior to plant shutdown. This approach greatly simplified in-containment system installation and checkout during the outage.

The EPRI/SGOG chemical cleaning process was applied to the OTSGs using a fill/soak/drain scenario. This process was performed sequentially on both OTSGs over an 11-day period (including one-day changeover from OTSG "B" to OTSG "A"). OTSG "B" heatup started at 1900 on October 18. Six fill-soak-drain cycles were applied to OTSG "B" and five cycles were applied to OTSG "A". An intermediate reheat of each OTSG was also required to maintain proper process temperature. Cooldown of "A" OTSG was completed on October 30.

EVENT	START	FINISH	ELAPSED
OTSG "B" Cleaning	1900, 10/18	0110, 10/25	6.3 days
Changeover to "A"	0110, 10/25	1901, 10/25	0.7 days
OTSG "A" Cleaning	1901, 10/25	0156, 10/30	4.3 days
		TOTAL	**11.3 days**

Sludge lancing was then performed on each OTSG to remove residual loose deposits that had fallen onto the lower tubesheet. Before startup, TMI-1 Operations performed two cold fill and drains of each OTSG to remove residual chemicals. Establishment of OTSG chemistry during startup was completed with existing plant systems and did not cause any startup delays. The close coordination between GPUN and BWNS in the planning and execution of the cleaning resulted in actual person-rem exposure 50% below estimates.

A total of 51,300 gallons of solvent waste and 41,500 gallons of rinse waste was generated during the chemical cleaning. This liquid waste was stored in Frac tanks at TMI-1 and was processed by BWNS in April 1992. The amount of rinse waste produced was 20,500 gallons less than the expected 62,000 gallons due to the exceptional performance of the chemical cleaning system. There was never a need to cross-connect the separate solvent and rinse flow path and the use of procedures that minimized cross contamination of rinse and solvent streams are the primary reasons for the low rinse volume.

2.0 INTRODUCTION

Increased steam generator secondary side pressure drop (delta P) forced GPUN to operate TMI-1 at reduced power levels. Increased delta P across the TSPs results in an increase in feedwater downcomer level that can result in thermal hydraulic instability: when this occurs plant power output must be reduced.

The increase in steam generator water levels is attributed to the following mechanisms:

- Slow increase in secondary side flow resistance caused by magnetite deposit buildup in TSP broached openings.
- Rapid increase in secondary side flow resistance caused by tube deposit (flakes) spalling from tubes to block TSP broached openings.

As did other OTSG utilities experiencing delta P problems, GPUN initiated actions to address the cause and/or symptoms. Inspection ports were installed in the OTSG "A" shell and wrapper to allow secondary side inspection and deposit sampling. Water slap and sludge lancing were utilized but with only short-term success. During Cycle 7 TMI-1 switched to morpholine chemistry in the secondary system. A reduction in the rate of iron transport to the OTSG and hence a reduction in the rate of pressure drop increase during the fuel cycle was observed after initiation of the chemistry change.

However, subsequent to the January 1990 8R refueling outage, the unit was initially unable to go beyond approximately 75% power due to the redistribution of secondary side deposits. In parallel with non-chemical cleaning remedial efforts, GPUN continued toward implementing a chemical cleaning process that could resolve the delta P problems (if non-chemical cleaning means continued to be of limited success) at TMI-1.

In February 1989, GPUN decided to move forward with their chemical cleaning program and directed BWNS to commence the site specific qualification program and preliminary system design. Since non-chemical cleaning actions continued to have only limited success, GPUN decided in September 1990 to proceed with the chemical cleaning. The details of this chemical cleaning are provided in the sections that follow.

3.0 PROCESS QUALIFICATION

GPUN selected the generic Electric Power Research Institute/Steam Generator Owners Group (EPRI/SGOG) chemical cleaning process to perform the cleaning of the TMI-1 OTSGs. Since all steam plants differ in design, materials of construction, plant operating history, fouling characteristics, and deposit composition, some plant specific testing and evaluation was required prior to application of the process. The TMI-1 specific qualification program included deposit dissolution testing, an OTSG material evaluation, structural analyses and corrosion estimates, development of a process specification and preparation of a 10CFR50.59 evaluation. Optimization of the chemical cleaning process was based on the following criteria (listed in order of priority):

1. Minimize Corrosion - The process application parameters were selected to minimize the weld and base metal corrosion of the TMI-1 OTSGs.

2. Maximize Effectiveness - The chemical cleaning application parameters were optimized to ensure that all TSP broached openings were sufficiently cleaned to restore OTSG operating levels to or near to those achieved at original plant startup.

3. Minimize Waste Volumes - Different application scenarios were evaluated and equipment requirements defined to minimize waste volumes.

The following sections summarize the TMI-1 specific program.

An initial dissolution test was performed using deposits obtained during the 7R Refueling Outage (October 1988). This test did not completely evaluate the effects of morpholine on deposit dissolution as these deposits were only exposed to 6 weeks of morpholine treatment. Additional deposits were obtained during the 8R Refueling Outage (February 1990). These deposits were exposed to one full cycle (18 months) of morpholine chemistry. A second dissolution test was performed. These results demonstrated the ability of the EPRI solvent to effectively dissolve greater than 94% of the TMI-1 deposits.

B&W's extensive EPRI/SGOG solvent corrosion response data base was used to estimate the expected corrosion and to identify any previously untested materials. The material evaluation identified 10 untested welds deemed potentially susceptible to higher than normal corrosion induced by chemical cleaning. A structural analysis of these welds was performed to better define the allowable corrosion loss for chemical cleaning. Several weld geometries, which bounded the corrosion response of all untested materials, were made into corrosion coupons and placed in the generator during the cleaning to obtain actual corrosion data. The most critical (lowest corrosion allowance) and most susceptible (will suffer the greatest corrosion during the cleaning) welds and base metals were also chosen for corrosion monitoring.

Electrodes were used for on-line measurement of galvanic corrosion (via a zero resistance ammeter) and free corrosion (via linear polarization) and for weight loss determination of corrosion. Coupons were galvanically coupled to the OTSG and were used for weight loss determination of corrosion and visual examination of weld intersections.

A process specification was prepared to define the implementation of the EPRI/SGOG chemical cleaning process at TMI-1. This process specification incorporated the TMI-1 qualification program results with experience gained during the EPRI/SGOG program development, the cleanings at Oconee Units 1 and 2, other industry information, and BWNS R&D programs. The following general cleaning sequence was specified for application of 24,500 gallons solvent for removal of 3400 pounds of deposit per generator (Note all times were measured at or above the 7th TSP):

1. Check-out Rinse
2. Heatup Rinse
3. Magnetite Dissolution

   * Cycle 1 - 1.5 hours
   * Cycle 2 - 2.5 hours
   * Cycle 3 - 6.5 hours
   * Cycle 4 - 8.0 hours

4. Reheat Rinse

5. Magnetite Dissolution

   * Cycle 5 - 8.0 hours
   * Cycle 6 - 6.5 hours

6. OTSG Rinse
7. Passivation/Cooldown

The objective was to achieve a minimum solvent contact time of at least 33 hours at or above the 7th TSP while keeping the solvent contact time below 40 hours at the lower tube sheet (LTS). This was done by minimizing the time for filling and draining the generators.

A 10CFR50.59 Safety Evaluation was prepared to show that unreviewed safety questions did not exist in the application of the OTSG chemical cleaning.

4.0 SYSTEM DESIGN

4.1 CHEMICAL CLEANING SYSTEM

The BWNS mobile chemical cleaning system was designed to meet the application requirements outlined in the Chemical Cleaning Process Specification.

Rinse and solvent were stored and recirculated through separate tanks, lines and pumps to minimize cross contamination of the rinse water with solvent. Some process lines were common and required blowdown between rinse and solvent steps.

Eight 22,000 gallon Frac Tanks were used to hold reserve rinse water early in the process and waste streams later in the process. Wastes were segregated to maximize waste processing efficiency and reduce processed waste volume and cost.

The use of four inch flexible hose was maximized to reduce system installation time. Hose material was tested to verify compatibility with the cleaning solvent. Stainless steel pipe was used primarily for vertical runs and direct connections to the OTSGs.

All potentially contaminated out-of-containment equipment was contained in a bermed area to contain any spills. All external hose, not in the bermed area, was sleeved.

4.2 CORROSION MONITORING SYSTEM

The BWNS Corrosion Monitoring Data Acquisition System (CMS) is designed to provide on-line free and galvanic corrosion rate and integral corrosion data during the chemical cleaning. The major components include:

LP Probe Holders - Used to position five free corrosion probes (3 electrodes per probe) at the lower 5 inch handholes.

Two holders were placed in each OTSG for redundancy.

ZRA Probe Holders - Used to position six galvanic corrosion probes and four galvanic corrosion coupons at the lower 5 inch handholes.

Two holders were placed in each OTSG for redundancy.

The four galvanic coupons were used to simulate the following weld regions:

* Shell to lower tube sheet weld intersection.
* Shroud to shroud weld intersection.
* Wedge block to tube support plate weld.
* Tack welded carbon steel bolt head.

Data Acquisition System (DAS) - Forced air cooled cabinet containing components that acquire and measure corrosion rate data. This cabinet was placed inside containment within 150 feet of the generator.

System Computer - A HP computer system was designed to:

* Acquire digital signals from A/D drawer
* Calculate mean rate and cumulative integral corrosion data for each electrode
* Display data for control and monitoring
* Save all data

The computer was located outside containment and was connected to the DAS by a 750 foot signal data cable.

5.0 PRE DEPLOYMENT ACTIVITIES

5.1 PROCEDURE PREPARATION

The chemical cleaning was performed with procedures and was controlled by specific valve-by-valve operations. Examples of these operations include:

* Solvent Preparation
* Rinse Preparation
* OTSG Fill
* OTSG Drain
* OTSG Vent
* Solvent Recirculation & Heatup

Each of these procedures was sequenced by an overall controlling procedure ("Chemical Cleaning Sequence Control Procedure").

In addition, the following contingency operations were covered by procedure:

1. Loss of a Process Pump
2. Loss of Site Power
3. Loss of a Diesel Generator
4. Loss of Nitrogen Supply
5. Loss of Process Ventilation
6. Chemical Spill/Leak

Solvent formulation and process implementation decisions were guided by the "Process Chemistry and Corrosion Control Procedure. This procedure included sampling requirements and specified procedures for interfacing with the system operators and TMI-1 chemistry personnel.

5.2 TRAINING

5.2.1 CHEMICAL CLEANING SYSTEM OPERATORS

Operator training included both classroom and hands-on training. Key areas addressed in the training of equipment operators included:

* Corrosion fundamentals and corrosion monitoring
* Chemical cleaning objectives and general process description
* Chemical cleaning system design and system operating philosophy
* Normal operating procedures required to complete the chemical cleaning process
* Contingency plans required to recover from abnormal events
* Safety procedure requirements, including clothing and respiratory requirements
* Watchstanding duties and logkeeping

5.2.2 CORROSION MONITORING SYSTEM OPERATORS

Operator training included both classroom and hands-on training. Key areas addressed in the training of CMS operators included:

* Chemical cleaning objectives and general process description
* Corrosion monitoring objectives
* System configuration
* Normal operating procedures required to complete the chemical cleaning process
* Contingency plans required to recover from abnormal events

5.2.3 PROCESS ENGINEERS

BWNS and GPUN Process Engineers completed detailed training on the "Process Chemistry and Corrosion Control Procedure." This training also included evaluating options for abnormal events.

5.2.4 GPUN CHEMISTRY TECHNICIANS

TMI-1 chemistry technician training included both classroom and hands-on training. Approximately three days were spent learning new analysis methods and performing blind sample analyses. In addition, a two hour seminar was presented to familiarize the chemistry technicians with the chemical cleaning process.

New analysis methods were developed to determine free and total EDTA concentrations. Practical training was also given to prepare the chemistry analyses technicians for specific adjustments to existing analyses techniques to accommodate the chemical cleaning matrix.

5.3 CHEMICAL PROCUREMENT

The following chemicals were procured to support formulation of the cleaning solutions:

CHEMICAL	CONCENTRATION
Diammonium EDTA	40 w%
Hydrazine	35 w%
Ammonium Hydroxide	30 w%
CCI-801 Corrosion Inhibitor	--

These chemicals were all procured using BWNS prepared and GPUN approved specifications. These specifications required assay and contaminant analysis of a sample of each chemical prior to shipment and defined the maximum acceptable level for contaminants. The results of the analyses were compared to the vendor supplied certificate of analysis.

6.0 SYSTEM INSTALLATION

System installation was performed in two phases: out-of-containment installation and in-containment installation.

6.1 OUT-OF-CONTAINMENT INSTALLATION

The chemical cleaning equipment started to arrive on-site on July 19, 1991. A full operational leak test and checkout of the yard system was completed on September 17, 1991.

6.2 IN-CONTAINMENT INSTALLATION

The chemical cleaning crew returned to site on October 1 to coordinate in-containment installation. Both OTSGs were connected to the chemical cleaning system to minimize changeover time after completion of the first generator. CMS probe holders were also inserted into both OTSGs. Use of flexible hoses and short connection pieces allowed routing the system piping around unanticipated obstructions. In-containment installation was completed on October 13. System leak testing and functional checkout was finished on October 17, two days ahead of schedule.

7.0 CLEANING PROCESS APPLICATION

The following sections will detail specific areas of the process application and discuss the planned versus actual application along with the lessons learned in each area.

7.1 SOLVENT/RINSE FORMULATION

Based on the development and qualification testing, the following solutions were selected for use at TMI-1:

Magnetite Solvent

- 130 g/l EDTA
- 10 g/l Hydrazine (N_2H_4)
- 10ml/l CCI-801 (Corrosion Inhibitor)
- pH 7 adjusted with ammonia (NH_4OH)

Rinse and Passivation Solution

- 300 ppm N_2H_4
- pH 10.2 adjusted with NH_4OH

All formulations were made by metering in the appropriate amount of concentrated chemicals into the mix and rinse tanks. Plant demineralized water was used in the formulation of the solutions. After formulation, the mix and rinse tanks were recirculated to thoroughly mix the solutions.

7.2 OTSG "B" Application

7.2.1 APPLICATION DESCRIPTION

The SOAK cycle lengths for OTSG "B" are summarized in Table 7-1.

TABLE 7-1: OTSG "B" CYCLE LENGTHS

CYCLE	SCHEDULED DURATION (7TH TSP)	REVISED DURATION (7TH TSP)	ACTUAL DURATION (9TH TSP)	ACTUAL DURATION (LTS)
1	1.5 hrs	1.5 hrs	0.0 hrs	2.0 hrs
2	2.5 hrs	4.0 hrs	0.0 hrs	6.5 hrs
3	6.5 hrs	6.5 hrs	6.4 hrs	7.0 hrs
4	8.0 hrs	8.0 hrs	7.8 hrs	8.5 hrs
5	8.0 hrs	8.0 hrs	7.9 hrs	8.6 hrs
6	6.5 hrs	8.0 hrs	7.9 hrs	8.6 hrs
TOTAL	33.0 hrs	36.0 hrs	29.9 hrs	38.9 hrs

7.2.2 CHEMISTRY RESULTS

The solvent chemistry changes followed predicted trends. A summary of solvent chemistry is provided in Table 7-2.

TABLE 7-2: OTSG "B" CYCLE SOLVENT CHEMISTRY

STEP	FREE EDTA (g/l)	FE (g/l)	N2H4 (ppm)	pH
INITIAL	145.8	0	8740	7.47
CYCLE 1	129.0	2.31	8610	7.82
CYCLE 2	86.0	5.28	8108	8.17
CYCLE 3	78.8	8.80	7935	8.25
CYCLE 4	66.0	9.88	7790	8.37
CYCLE 5	60.0	10.30	7192	N/A
CYCLE 6	59.0	10.56	6831	8.42

The actual and predicted pounds of deposit removed after every step (including iron in the rinse water and undissolved deposits removed during sludge lancing) is summarized in Table 7-3:

TABLE 7-3: OTSG "B" DEPOSITS REMOVED PER CYCLE

STEP	PREDICTED REMOVAL (POUNDS)	ACTUAL REMOVAL (POUNDS)
CYCLE 1	1122	648
CYCLE 2	833	835
CYCLE 3	680	988
CYCLE 4	374	303
CYCLE 5	150	119
CYCLE 6	91	72
RINSES	N/A	192
SLUDGE LANCE	150	118
TOTALS	3400	3275

7.2.3 CORROSION RESULTS

The average total corrosion, as measured by CMS on-line data, for all monitored materials was well below specified cleaning allowances:

COMPONENT	ALLOWANCE (mils)	OTSG "B" (mils)
TSP Land	3.0	1.02
Shroud	10.0	1.31
Wedge Block	10.0	1.03
Various	50.0	1.69

The OTSG "B" electrode free and galvanic corrosion rates followed expected trends.

7.3 OTSG "A" Application

7.3.1 APPLICATION DESCRIPTION

Five soak cycles were applied to OTSG "A" instead of the six applied to OTSG "B". This was achieved by increasing the Cycle 1 and 2 soak durations.

The SOAK cycle for OTSG "A" are summarized in Table 7-4.

TABLE 7-4: OTSG "A" CYCLE LENGTHS

CYCLE	SCHEDULED DURATION (7TH TSP)	REVISED DURATION (7TH TSP)	ACTUAL DURATION (9TH TSP)	ACTUAL DURATION (LTS)
1	3.0 hrs	3.0 hrs	0.0 hrs	3.6 hrs
2	6.0 hrs	6.0 hrs	5.9 hrs	6.4 hrs
3	8.0 hrs	8.0 hrs	7.9 hrs	8.5 hrs
4	9.0 hrs	9.0 hrs	8.9 hrs	9.6 hrs
5	9.0 hrs	9.0 hrs	8.9 hrs	9.5 hrs
TOTAL	35.0 hrs	35.0 hrs	31.6 hrs	37.6 hrs

7.3.2 CHEMISTRY RESULTS

The solvent chemistry changes followed predicted trends. A summary of solvent chemistry is provided in Table 7-5.

TABLE 7-5: OTSG "A" CYCLE SOLVENT CHEMISTRY

STEP	FREE EDTA (g/l)	FE (g/l)	N2H4 (ppm)	pH
INITIAL	137.5	0.37	9365	6.85
CYCLE 1	115.0	4.78	8142	7.47
CYCLE 2	86.3	8.55	7850	7.93
CYCLE 3	91.3	9.64	7350	8.00
CYCLE 4	91.0	9.71	6934	8.10
CYCLE 5	75.0	10.23	6508	8.13

The actual and predicted pounds of deposit removed after every step (including iron in the rinse water and undissolved deposits removed during sludge lancing) is summarized in Table 7-6:

TABLE 7-6: OTSG "A" DEPOSITS REMOVED PER CYCLE

STEP	PREDICTED REMOVAL (POUNDS)	ACTUAL REMOVAL (POUNDS)
CYCLE 1	1690	1306
CYCLE 2	824	1119
CYCLE 3	459	320
CYCLE 4	184	23
CYCLE 5	93	156
RINSES	N/A	204
SLUDGE LANCE	150	128
TOTALS	3400	3256

7.3.3 CORROSION RESULTS

The average total corrosion, as measured by CMS on-line data, for all monitored materials was well below GPUN specified cleaning allowances:

COMPONENT	ALLOWANCE (mils)	OTSG "A" (mils)
TSP Land	3.0	0.78
Shroud	10.0	1.12
Wedge Block	10.0	0.83
Various	50.0	1.34

7.4 CHEMICAL CLEANING EVALUATION

The TMI-1 chemical cleaning produced several interesting results in the areas of rinse waste reduction, OTSG temperature control, the effect of iron dissolution on corrosion, performance of solvent/rinse chemistry analyses, and person-rem exposure. These areas are discussed in more detail in the following sections.

7.4.1 RINSE WASTE REDUCTION

Contamination of the rinse solution with the solvent chemicals (EDTA, Fe, N_2H_4, CCI-801) causes an increase in the rinse solution corrosion rates and the chemicals left in the OTSG after rinse operations. The Oconee 1 and 2 chemical cleanings each generated 90,000 gallons of rinse waste to process because fresh rinse solutions were prepared prior to each passivation step. One of the objectives of the TMI-1 chemical cleaning was to reduce rinse waste volumes by reusing rinse water. Several equipment design and procedural features were factored into BWNS' application of the chemical cleaning to reduce cross contamination of solvent and rinse solutions. These features included:

* Designing the system vent and drain capabilities to maximize draining of process lines.
* Blowdown of process lines between solvent and rinse steps.
* Performance of a 3,000 gallon low volume rinse after process line blowdown to dilute residual solvent in process lines and on the OTSG tubesheet.
* Reuse of 10,000 gallons of OTSG "B" rinse water for OTSG "A" solvent preparation.
* Reuse of OTSG "A" half-rinse solution for OTSG "A" passivation solution preparation.

These steps resulted in generation of only 42,000 gallons of rinse waste instead of the pre-outage estimated 62,000 gallons of rinse waste. Minimizing cross contamination kept rinse solution chemistry (N_2H_4, EDTA, and FE concentrations) within acceptable levels.

7.4.2 TEMPERATURE CONTROL

Performance of the fill/soak/drain process without constant recirculation and heating resulted in solvent and generator cooldown during application. A minimum solvent temperature of 195°F was specified to maintain effective deposit dissolution. Several actions were taken to minimize the possibility for performance of an intermediate reheat step:

- Maximize initial OTSG stored heat by heatup of the OTSG to the maximum temperature allowed and until upper head shell temperatures stabilized.
- Maximize the amount of insulation on the OTSG during the cleaning.
- Ensure the upper and lower head manway openings were covered to prevent occurrence of the "chimney effect".
- Minimize the time duration between solvent drain and fill (the OTSG experiences rapid cooldown during periods without solvent).
- Maximize solvent temperature just prior to fill.
- Minimize the number of fill/soak/drain cycles and therefore the amount of time during which the OTSG was drained.

7.4.3 DISSOLUTION/CORROSION COMPARISON

The OTSG "A" and "B" chemical cleaning deposit dissolution rates were very similar to those rates observed during laboratory testing.

The chemical cleaning data also indicate a strong relationship between corrosion and deposit dissolution. These data indicate that amount of material corrosion is dependent on the total amount of deposits dissolved.

7.4.4 PERFORMANCE OF CHEMISTRY ANALYSES

TMI-1 Chemistry performed the following analyses in support of chemical cleaning: Free and Total EDTA, Hydrazine, pH, dissolved Iron, Specific Conductivity, Specific Gravity, Ammonia titrations and Gamma Isotopic analysis. Free EDTA concentration was measured by ion specific electrode using an electrometric titration with copper sulfate and a copper electrode. Total EDTA concentrations were performed spectrophotometrically using percent transmittance. The Total EDTA method was modified from ASTM No. D3113-87 method A. Hydrazine concentration was also analyzed spectrophotometrically per ASTM D1385-78. Iron concentrations were measured by atomic absorption with a flame method. A total of 103 samples were taken and analyzed to support the chemical cleaning.

7.4.5 PERSON-REM EXPOSURE

The actual radiation exposure during the chemical cleaning is summarized in Table 7-7.

TABLE 7-7: RADIATION EXPOSURE DURING CHEMICAL CLEANING

TASK DESCRIPTION	EXPOSURE (PERSON-REM)
Chemical Cleaning	6.944
Sludge Lancing	4.046
Sub-Total	10.990
Remove and Install Manway and Handhole Covers	.213
Radcon Support	.480
Total	11.683

This total exposure is well below the estimated 15-25 person-rem.

7.4.6 CHEMICAL CLEANING SCHEDULE

The chemical cleaning was completed four and one-half days ahead of the schedule and was performed off critical path. All outside-containment equipment was set up and checked out prior to plant shutdown. This approach greatly simplified in-containment system installation and checkout during the outage.

8.0 POST CHEMICAL CLEANING ISSUES

8.1 STEAM GENERATOR LEVELS

On November 17, 1991, TMI-1 returned to 100% power operation after chemical cleaning. These values are comparable to values observed during initial startup of the new OTSGs in 1974.

8.2 START-UP CHEMISTRY

It was anticipated that residual chemical cleaning solution would create problems for feedwater chemistry during start-up. To minimize this effect the "B" OTSG was filled, recirculated and drained twice, during wet layup, to remove as much solution as possible. The "A" OTSG was filled and drained twice without recirculation.

TMI-1 additionally prepared a carbon-based powdex resin overlay as a contingency to remove high concentrations of organic contaminants. This resin overlay was not used because of the low feedwater Total Organic Carbon (TOC) levels measured during startup.

During start-up, feedwater chemistry was maintained within the specified limits with the exception that cation conductivity increased significantly during the OTSG boil down and following the transition to "once through" operation. The cation conductivity was attributed to the carry over of the break-down products of the residual chemical cleaning solution that remained in the OTSGs.

OTSG contaminants, although higher than the 1 ppm limit during start-up, were still significantly lower than those seen during the refueling shutdown and the previous outage. This reduction is credited to the multiple flushes performed. Establishment of start-up chemistry did not impact the start-up critical path.

8.3 SLUDGE LANCING

BWNS performed the sludge lancing of the TMI-1 Unit 1 steam generators. Work was performed after chemical cleaning. Sludge lancing started October 25, 1991, and was completed on November 4, 1991.

A total of 246 pounds of deposit was removed from the TMI-1 OTSGs (128 pounds from OTSG "A" and 118 pounds from OTSG "B").

8.4 STORAGE/DISPOSAL OF SPENT CHEMICAL CLEANING SOLUTIONS

The chemical cleaning spent solvent and rinse solutions were transferred to 22,000 gallon fractional (Frac) tanks for storage. In April 1992 BWNS processed the spent solutions for burial.

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CHEMICAL CLEANING OF THE BRUCE A STEAM GENERATORS

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ABSTRACT

Deposits consisting mostly oxides and salts and copper metal in the secondary side of the steam generators at the Bruce A Nuclear Generating Station have caused instability in steam flow and loss of heat capacity, resulting in derating of the units and reduction in power production. Attempts to remove the deposits by pressure pulsing were unsuccessful. Water lancing succeeded in restoring stability but restrictions on access prevented complete lancing of the tube support plate holes. Chemical cleaning using a modified EPRI-SGOG process has been selected as the best means of removing the deposits. A complete chemical cleaning system has been designed and fabricated for Ontario Hydro by Pacific Nuclear, with support from AECL CANDU and their suppliers. The system consists of self contained modules which are easily interconnected on site. The whole process is controlled from the Control Module, where all parameters are monitored on a computer video screen. The operator can control motorized valves, pumps and heaters from the computer key board. This system incorporates all the advanced technologies and design features that have been developed by Pacific Nuclear in the design, fabrication and operation of many systems for chemical decontamination and cleaning of nuclear systems.

CHEMICAL CLEANING OF THE BRUCE A STEAM GENERATORS

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INTRODUCTION

The performance of the steam generators at Bruce Nuclear Generating Station "A" (BNGS-A) has been affected by tube fouling and sludge deposition on the broach-hole support plates. This fouling and deposition has led to rising reactor inlet header temperatures and steam generator secondary side water level instability.

After a thorough examination of the conditions of the secondary side of the steam generators, it was determined that cleaning was necessary. The options considered included water lancing and chemical cleaning. Water lancing was performed to remove oscillations in the short term. Chemical cleaning of the full height of the tube bundle is planned to remove as much of the fouling deposit as possible.

In this paper, the nature of the problem is briefly reviewed and the chemical cleaning system design and proposed operation are described. It is expected that results will be available for presentation at the next CANDU Maintenance Conference.

DEGRADATION OF STEAM GENERATORS

During October 1986, the wide range drum level measurement on Bruce A Unit 2 Steam generator #3 indicated that an apparent oscillation was occurring in the water level of steam drum #1. The oscillation only occurred at elevated powers.

Three possible causes for these oscillations are:

- downcomer/flow oscillations,
- downcomer/riser leak path,
- change in flow resistance.

An analytical model was built to simulate these effects. The most probable cause was identified as partial blockage of the upper tube support plate broached flow holes.

In addition to the level oscillations in steam generators, reactor inlet header temperatures have been observed to increase in time at both BNGS-A and BNGS-B. These increases were caused by several factors, including fouling of the steam generators and preheaters, causing a reduction in the efficiency of the heat rejection from the heat transport system.

Due to the immediate oscillation problem causing reactor power reductions, a two phase solution was sought, the first phase to prevent the oscillations and the second phase to deal with the longer term problem of lower heat transfer rates.

SHORT TERM SOLUTION

Similar experiences with steam generator oscillations in the USA have led to the development of "water-slapping" techniques which have been used with some success. In addition, water lancing techniques have been developed to remove sludge which builds up on steam generator tube sheets.

Both of these techniques became candidates for a short term solution to the oscillation problem, and both techniques were developed for use on steam generator #3.

The water-slap technique was tried first, but due to the internal design of the Bruce steam generators, the necessary forces could not be developed to dislodge the broach hole sludge.

In parallel, a lancing technique was developed that was successful in clearing enough broached holes in the upper support plates to correct the oscillation.

The lancing technique was used to clear the upper support plates in all steam generators in Bruce Unit 2 and Bruce Unit 1. This resulted in both units reattaining full power, but the lancing technique does not clean the deposit from the steam generator tubes. Also, access restrictions prevented all the broach holes from being cleared. Therefore a longer term, more extensive solution was needed to meet the requirement of returning the steam generators to long term full power operation.

LONG TERM SOLUTION

The steam generators at Bruce A were inspected during the lancing program and estimates were made of the deposit loading. The estimates predicted up to 6000 kg of sludge per steam generator with approximately 75% coating the tubes, 15% in the broached holes and on the tube support plates and 10% on the tube sheet as a sludge pile.

For long term full power operation, it was necessary to provide a process that would remove the tube deposits and the broached hole blockages that still remained following lancing. It was decided that a full height chemical clean had good potential to successfully achieve that objective.

Because the Bruce A steam generator design includes an integral steam drum attached to each bank of four steam generators, a process had to be used that could clean four steam generators in parallel to avoid gross steam generator temperature gradients and would also be effective below 100°C.

After investigating the available processes, the EPRI-SGOG process was chosen for further refinement and application to Bruce A steam generators. This process was developed by a cooperative industry effort funded by the Electric Power Research Institute - Steam Generator Owners Group. The decontamination and chemical cleaning division of United Nuclear Corporation, which later became the Plant Services Division of Pacific Nuclear, was responsible for the chemical formulation development. The process uses a reducing solvent to remove the iron-based deposits and an oxidizing solvent to remove the copper-based deposits. Alternating steps of copper and iron solvents are applied until the soluble constituents in the deposit are all dissolved.

BASIC OPERATIONS

The iron and copper solvents are applied to the steam generators alternately. More than one iron or copper step may be applied in sequence, depending upon the amount of iron or copper deposits in each bank of steam generators. The steam generators are rinsed between solvent cycles to reduce cross contamination of the different solvents, which could result in reduced solvent effectiveness and dissolution capacity. One or more low volume rinses will be used to flush residual solvent from the base of the steam generator. This is followed by a full volume rinse with on-line filtration and ion exchange applied to completely flush spent solvent from the internal surfaces of the steam generators. The spent iron and copper solvents and the low volume rinse solutions will be sent to the iron or copper waste hold-up tank as appropriate for subsequent transfer to the waste treatment facility. The full volume rinses will be cleaned up by ion exchange resins for reuse in the process.

The design criteria for the cleaning system are based upon applying the modified SGOG process to one bank of 4 steam generators at a time. As an option, one, two, or three steam generators in a bank can be cleaned simultaneously. In the event that the solvent chemistry needs to be adjusted during the application, chemicals can be added directly to the recirculating solvent.

DESIGN OF THE CHEMICAL CLEANING SYSTEM

The design of the system incorporates features evolved by Pacific Nuclear from the design and fabrication of many systems for the application of chemical cleaning and decontamination processes. Also, the use of the different cleaning systems at many different nuclear plants has revealed opportunities for improvements in design, which have been incorporated into this latest design of equipment for Ontario Hydro. The basic design concepts and drawings were prepared by Pacific Nuclear, converted to detailed drawings by AECL CANDU, and approved by Ontario Hydro. The equipment fabrication drawings were usually prepared by the Canadian fabricators, E.S. Fox Ltd of Niagara Falls and Hooper Welding Enterprises Ltd of Oakville, and approved by Pacific Nuclear.

The single most important feature of the design concept is the division of the system into discrete, self-contained weather protected modules. These modules can be easily interconnected on site, thereby minimizing the on-site effort and time required for installation.

The second significant feature is the built-in ion exchange (IX) cleanup system. The IX system provides on-line and off-line capability for purifying rinse water waste solutions. This feature enables immediate reuse of the rinse water, thereby significantly reducing the waste storage requirements and the usage of demineralized water. Experience has shown that effective rinsing between iron and copper dissolution steps is mandatory to ensure that proper chemistry and corrosion control is achieved and that solvent effectiveness and capacity is optimized.

The third important feature is the computerized control of the system. All important parameters are measured and sent to the control centre by a computerized PLC board control system. Information is displayed in the control centre on duplicate CRT screens. The total system or individual process operations can be displayed. Different colours are used to depict the levels and flows of fluids in the system. The operator in the control centre can operate motorized valves, pumps and heaters and perform all essential control functions from the computer terminal.The layout of the various modules in the system is shown in figure 1. A simplified flow diagram is shown in figure 2.

The level in each steam generator as well as the process flow and temperature can be adjusted by the cleaning system. Brief descriptions of the various cleaning system modules follows.

Tanker Module.

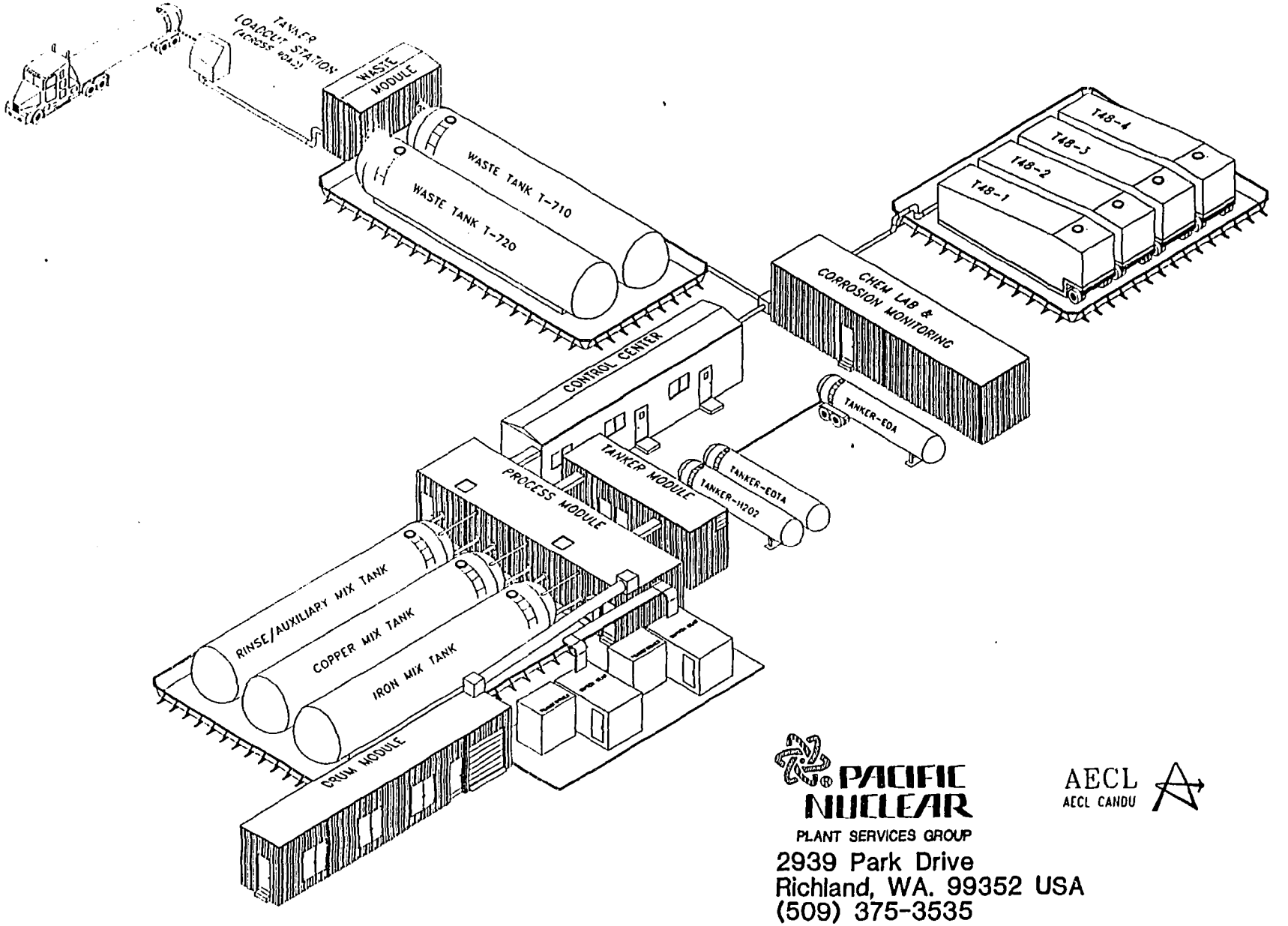
Chemicals that are required in large quantities, such as EDTA, EDA and hydrogen peroxide, will arrive on site in tanker trucks. The function of the Tanker Module is to transfer chemicals from the tanker trucks to the appropriate mix tank, via the process module. The Tanker Module is really two separate modules in one structure; the pumping systems for the EDTA and EDA and the hydrogen peroxide are completely separate, with a steel dividing wall between them which has no doors or other penetrations. Access to each of the two sections is by separate external doors. The Tanker Module is provided with appropriate pumps and flow meters as well as an environmental spill barrier and closed ventilation for personnel safety and worker protection.

Drum Module.

Chemicals that are required in smaller quantities, such as hydrazine, ammonia and the corrosion inhibitor, arrive on site in cylindrical drums or rectangular totes. They are put onto pallets in the Drum Module and measured quantities of each chemical are transferred into the system via the Process Module. The Drum Module also contains a facility for transferring fresh ion exchange resins (needed for purification of spent rinse solutions) from their transport containers to the two ion exchange columns in the Process Module. The Drum Module is designed for chemical handling, with forced ventilation and air extraction, explosion proof lights, heaters, pumps and electrical fittings. It is equipped with a personnel shower and eye-wash station. Like all the modules, the interior has a dike to contain any spills. It also has a sloping floor beneath a floor grating to facilitate clean-up of any spillage that should occur.

Mix Tanks.

Three large (approximately 36,000 US gallons; 136,000 L) horizontal, cylindrical tanks are supplied for preparation of the iron solvent, copper solvent and rinse solution. They are contained in a sealed dike, with a pumping system to remove rain water or any spilled chemicals. The insulated mix tanks contain flow distributors and level instrumentation and gauges. Individual recirculation pumps, heaters and bulk chemical addition manifolds for each mix tank are contained in the Process Module. Each solution is brought to the correct chemical composition and temperature before being injected into the steam generators.



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AECL CANDU

Figure 1 Layout of the Chemical Cleaning Modules at Bruce A NGS.

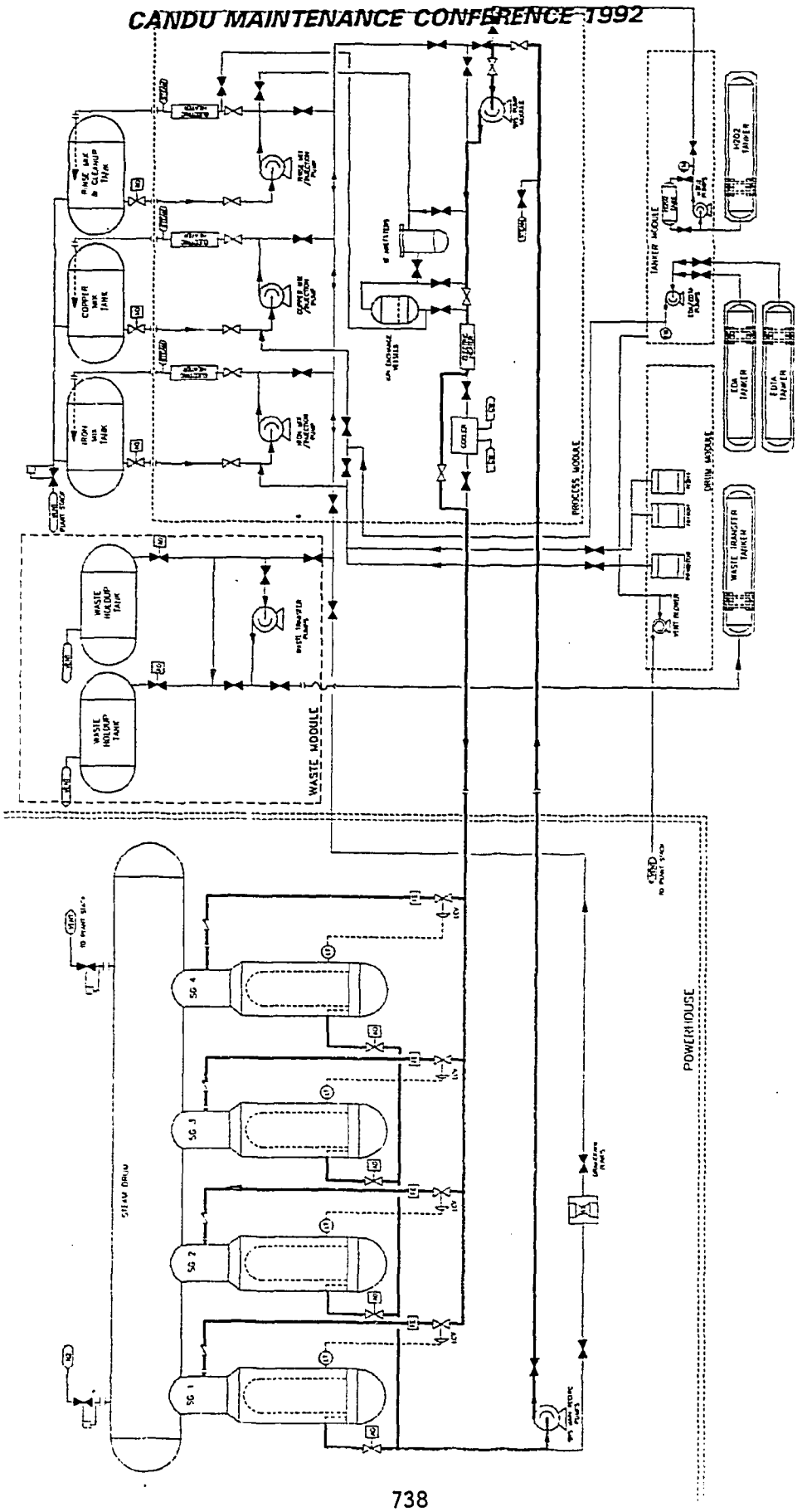

FIGURE 2
SIMPLIFIED FLOW DIAGRAM

Process Module.

The Process Module is the heart of the system. It contains piping and equipment for transferring the bulk chemicals from the Tanker and Drum Modules to the Mix Tanks, recirculating and heating the chemicals in each Mix Tank, and transferring the process solutions to the steam generators in the power house. The filters and ion exchange columns for rinse water purification are also contained in the Process Module, along with a plate heat exchanger, steam heater and chemical sampling station.

SRS Pump Skid and SRS Distribution Skid.

Inside the power house are located the SRS (Solvent Recirculation System) pump and distribution skids. The skids control the solution flow to each of the systems being cleaned, as well as maintaining the same liquid level in each steam generator in a bank of four.

Interim Waste Tanks and Waste Module.

There are two large Waste Tanks where the concentrated waste solutions are stored temporarily before being transported in chemical tankers to the waste treatment facility. Heat to prevent the waste solutions from freezing in winter and pumps to recirculate the solutions through the heaters and transfer them to the waste tanker trucks are provided in the Waste Module.

Contingency Waste Tanks.

The waste solutions from cleaning the secondary side of the steam generators is expected to be free from radioactive contaminants. However, against the circumstance that the first cleaning solution may contain more radioactivity than the de minimus level below which the waste is considered non-radioactive, four Contingency Waste Tanks of approximately 20,000 US gallons each (76,000 L) are provided in a diked area.

Electrical Power.

The electrical power for the system is provided by two 2.5 MW, 600 volt transformers. This provides much more power than will be needed to operate the system, but contains provision for future expansion and use of the power source for other station requirements.

Control Centre/Office Module.

The Control Centre is in a separate module, which also contains office facilities for the staff who will be installing, operating and maintaining the cleaning system. The whole process is monitored and controlled from this station. The Control Centre operator can change process flows, temperatures and pressures from the computer keyboard. Communication with each of the modules and with other staff members in the field is provided by telephone, a hard-wired intercom system and radio transmission.

Chemistry/Corrosion Module.

A separate module is provided for the performance of chemical analyses and corrosion monitoring. A monitor screen from the main control room computer is provided for information of the staff in this module. Process control is not possible from this terminal.

CURRENT STATUS

At the time of presentation of this paper, the system is installed at the Bruce A site and is fully tested and commissioned with the exception of connection to the steam generators. The installation and commissioning proceeded exceptionally smoothly. This easy set up is attributable to the innovative design, the high quality of the design and manufacture and the comprehensive quality control which was maintained throughout the engineering design and fabrication stages of the project.

The first application is expected to be to Unit 4, starting in March, 1993.

SUMMARY

The performance of the steam generators at Bruce Nuclear Generating Station "A" has been affected by an accumulation of metal oxide deposits (primarily magnetite and metallic copper) causing tube fouling and blockage of the broached-holes in the tube support plates. This has led to rising reactor inlet header temperatures and fluctuations in the steam generator secondary side water level.

A thorough examination of the conditions of the secondary side of the steam generators revealed the necessity to remove the deposits. The options considered included water slap, water lancing and chemical cleaning. Water slap was ineffective at Bruce, water lancing provided a short term amelioration of the condition but was restricted in its benefit by limited access.

Chemical cleaning is currently planned to remove as much of the iron and copper deposits as possible. The process to be used is based on the EPRI-SGOG formulations. Alternating steps of iron- and copper-removing solvents will be applied by a sophisticated chemical cleaning system.

The chemical cleaning system is based on proven designs used successfully in the past by Pacific Nuclear, and incorporates features identified as desirable during previous applications of cleaning processes.

To minimize the time and effort required at site, the system is based on self contained modules. Each module was operated and commissioned at the manufacturer's shop. The modules were easily interconnected at site. These features resulted in the on-site commissioning proceeding exceptionally smoothly with the minimum of effort.

Bulk chemicals will be transferred from tanker trucks, totes and drums to large mix tanks where the chemical composition and temperature of each solvent are adjusted before injection into the steam generators. A solvent recirculation system will distribute the solvents into four steam generators which will be cleaned simultaneously. All major parameters are displayed and recorded in the system control centre. The control centre operator can perform all essential process control functions through the computerized control system. Chemical analyses and corrosion monitoring will be performed throughout the operation in a separate chemistry module.

Waste solutions will pass to interim storage tanks before being shipped to an on site waste storage and processing facility.

Currently, the system is installed on site, fully commissioned apart from connection to the steam generators.

First application is planned for Unit 4, starting in March, 1993.

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BENEFITS OF INTEGRATING CHEMICAL AND MECHANICAL CLEANING PROCESSES FOR STEAM GENERATOR SLUDGE REMOVAL

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ABSTRACT

This paper discusses the benefits of performing in-bundle tubesheet sludge lancing in conjunction with chemical cleaning of PWR and PHWR steam generators in which a hard sludge pile is known to exist. The primary benefits of in-bundle lancing are to: (1) increase the exposed area of the sludge pile by cutting furrows in the surface thereby enhancing sludge pile dissolution, (2) reduce the volume of solvents required since material removed by lancing does not have to be dissolved chemically, (3) improve rinsing and removal of residual solvent between iron and copper dissolution steps, and (4) allow for verification of process effectiveness by providing high quality in-bundle visual inspection. The reduction in solvent volumes can lead to a significant reduction in solvent costs and waste processing. A case study which includes an economic evaluation for a combined chemical/mechanical cleaning shows a potential cost savings of up to $300,000 (USD) over use of chemical cleaning alone.

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INTRODUCTION

The deposition of corrosion products, metals and other insoluble impurities on the secondary side of recirculating-type steam generators in pressurized water reactors (PWRs) and pressurized heavy water reactors (PHWRs) is well documented. These materials exist in the steam generators as scale on heat transfer tube surfaces, coatings on structural parts, and piles on the steam generator tubesheet. The deposits consist primarily of magnetite and other iron oxides, zinc and copper oxides, and copper metal. The source of the deposits is generally thought to be the corrosion of equipment and piping in the feedwater and condensate systems. All deposits regardless of their composition, morphology or location on the secondary side of the steam generator are known as *sludge*. Figure 1 depicts the locations of sludge accumulations in a typical steam generator.

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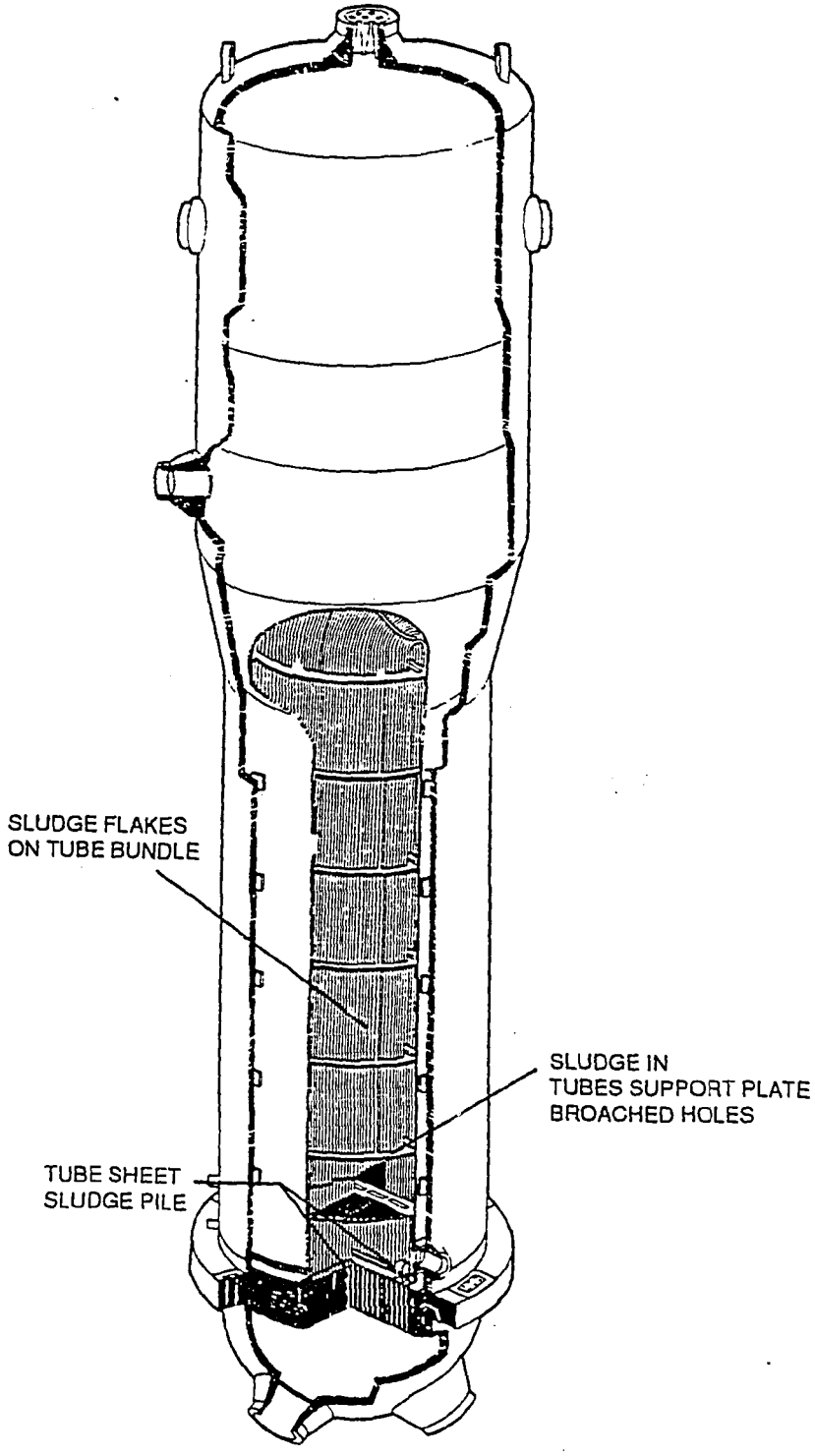

Figure 1. Sludge Accumulation in a Steam Generator

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Despite design lifetimes of forty years, steam generators in both the United States and Canada experience significant operational problems and can become maintenance burdens after as little as ten years of operation. Many of the operational problems have been attributed to the accumulation of sludge. Sludge deposits on tubes and tube support plates are reducing primary-to-secondary side heat transfer[1,2], blocking flow through tube support plates[3,4], and accelerating corrosion of steam generator structures[5]. In addition, sludge piles on the tubesheet and sludge in the tube-to-support plate annular crevices lead to the formation of concentration cells adjacent to the steam generator tubes. The presence of these concentration cells can promote pitting, stress corrosion cracking/intergranular attack (SCC/IGA)[6] or other forms of corrosion of the tube and support plate materials[7]. In addition, copper metal deposits on tube surfaces can also mask those eddy current thickness (ECT) signals associated with tube degradation[8].

SLUDGE MANAGEMENT OPTIONS

Faced with the premature degradation of steam generator integrity or efficiency, a utility often resorts to one or more *sludge management* activities. The candidate activities vary widely with respect to cost and potential for success. Each is discussed below.

Steam Generator Replacement — One option available to a utility is to remove the existing steam generators and replace them with models which incorporate features which better withstand the long term effects of sludge. Such features include (1) more corrosion resistant tube materials, (2) increased heat transfer area to provide additional margin in the event of forced tube plugging, (3) corrosion resistant support plate materials, and (4) broached hole support plates which reduce the potential for crevice corrosion. About a dozen plants in the US have already replaced or plan to replace steam generators in the next ten years. Despite the high probability that replacement will restore the operational reliability of the plant, the Portland General Electric Company (PGE) board of directors recently decided to shut down the Trojan Nuclear Power Plant in Oregon rather than replace the plant's four steam generators. The reason cited for shutdown was the prohibitive cost of replacement, which can exceed $200 million dollars (USD).[9]

Improved Feedwater Chemistry Control — In order to reduce the accumulation of sludge in a steam generator, the concentration of contaminant species in the feedwater can be reduced. Even with concentrations of iron and copper well below industry guidelines (in the 2 to 20 ppb range) the tremendous flowrate of feedwater will still result in transport of hundreds of pounds of sludge per year. Feedwater chemistry control can also be improved to reduce corrosion of feedwater and condensate system components and piping. Although reducing the accumulation of sludge is certainly prudent, most steam generators already contain hundreds and even thousands of pounds of sludge. As such, utilities often choose to remove as much of the existing sludge as possible, as discussed below.

Mechanical Techniques for Sludge Removal — A utility can choose from two basic lancing options for mechanical removal of sludge from the steam generators: (1) conventional sludge lancing which involves directing water jets at the tubesheet sludge pile from the annulus or the no tube lane of the steam generator, and (2) manual or robotic in-bundle sludge lancing which involves insertion of a flexible water jet lance deep in the tube bundle.

Conventional sludge lancing systems direct high pressure water jets at the sludge pile from distances of up to several meters. Since the energy of the water jet diminishes rapidly away from the jet nozzle, conventional sludge lancing is not an effective process for removing hard sludge located deep within the bundle. On average, conventional sludge lancing removes only 50% of the sludge from the tube sheet region.[10]

On the other hand, advanced mechanical intertube lancing systems such as the CECIL system use a flexible lance to enter the tube bundle and place the water jet nozzles close to the hard deposits. Intertube lancing has been shown to remove most of the tube sheet region sludge including the hard sludge around the tubes, hard scale on tubes just above the tubesheet ("tube collars") and sludge in the space between tubes or in the *shadow zones*. The CECIL in-bundle robotic system is shown in Figure 2. The development and performance of the CECIL system are discussed elsewhere.[11]

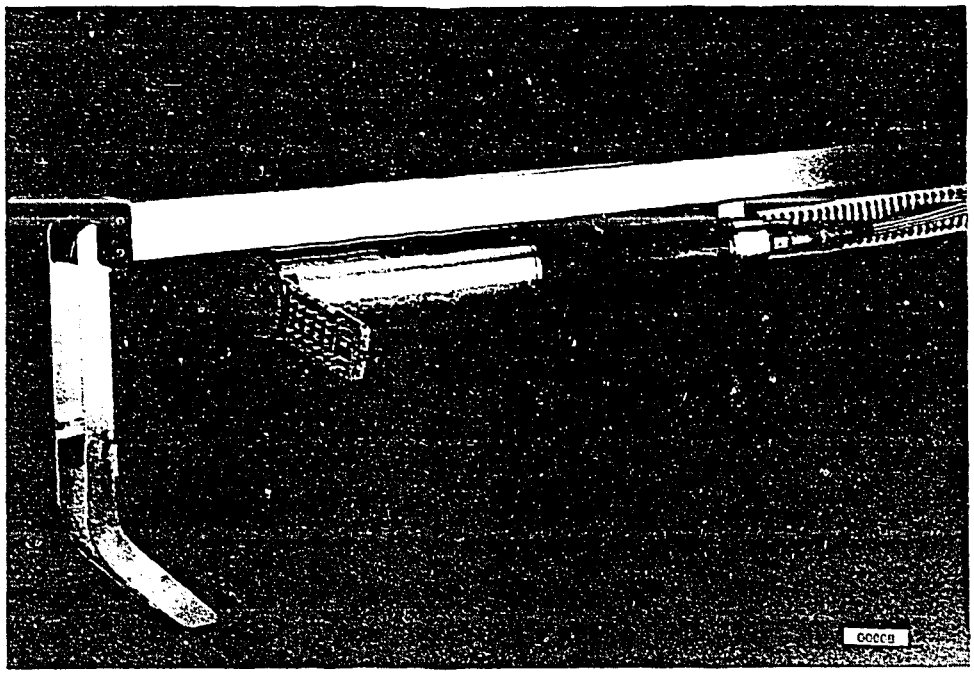

Figure 2. CECIL In-bundle Sludge Lance System

Demonstrations of the CECIL system at Consolidated Edison's Indian Point 2 plant showed that intertube lancing can be twice as effective as conventional lancing. The results of the CECIL trials at Indian Point are summarized in Table 1. Advanced in-bundle mechanical lancing systems can also be operated remotely which results in a reduction in personnel radiation exposure. In addition, an in-bundle lance can be u to provide high resolution video inspection of the tubesheet region so that the extent of the sludge pile and the progress being made toward its removal can be monitored.

Chemical Cleaning — Chemical cleaning is a multi-step process which involves soaking the secondary side with either an oxidizing (copper-dissolving) or reducing (magnetite-dissolving) solvent to dissolve sludge constituents.

Chemical cleaning is generally recognized as an effective means for removing tube scale deposits and partial blockages of tube support plate openings. Dissolution of deep and dense tubesheet sludge piles is complicated by the small surface area to volume ratio. Insoluble particles (such as silicates) are not dissolved. Large and heavy particles are not flushed out while draining the solvent.

Table 1. Sludge Removal Data from Indian Point Unit 2 — March 1989

Steam Generator No.	Weight (lb)	Method
21	418	Advanced intertube lancing
22	168	Conventional
23	131	Conventional
24	265	Conventional
Total	982	

Because of the ability of chemical solvents to reach all regions of the steam generator, and the particular capabilities of an in-bundle lancing system in removing hard sludge piles on the tube sheet, it appears reasonable that use of both processes together would represent an improved overall sludge removal strategy.

In order to quantify the potential benefits of the sludge lancing-chemical cleaning approach, this paper includes a summary of the results of a case study for an operating PHWR plant. The case study begins with a summary of the assumed sludge loadings.

SLUDGE ACCUMULATIONS IN THE STEAM GENERATORS

The example uses a PHWR with twelve steam generators which are similar in configuration to recirculating steam generators common in the US. The Canadian steam generators are smaller than comparable US designs, with heat transfer surface areas of 1831m^2. The case study steam generators include six broached hole support plates and 2573 U-tubes with a diameter of 12.6mm. The diameter of the tube bundle is approximately 1.5m.

Some Ontario Hydro steam generators are known to contain a significant quantity of sludge. Visual inspections have confirmed the presence of a kidney shaped hard sludge pile, partially blocked broached holes in the tube support plates, and relatively thick tube scale deposits. For the purpose of the present case study, the following assumptions have been made regarding sludge distribution and loading:

Average Tube Scale Thickness:	0.3mm
Average Broached Hole Blockage:	70%
Maximum Sludge Pile Height:	30cm

Based on the above, a sludge loading of 3500kg per steam generator can be calculated based on a sludge density of 4.7g/cm^3.

The sludge is assumed to consist of only magnetite, copper, and insoluble material. Table 2 summarizes the assumed compositions for the tube scale, broached hole deposits and the sludge pile. The proportion of insoluble material is higher than that normally found in sludge in US PWR steam generators.

During chemical cleaning, the insoluble material will be liberated from the sludge matrix and either settle out by gravity or be pumped out of the steam generator with spent solvent or rinse water. Large dense particles would have the greatest tendency to settle on the tube sheet while small light particles would likely be pumped away. Published analyses have shown that velocities of at least 0.6 to 1 meters per second are required to sweep the material particles across the tubesheet and into suction lines or the blowdown system[12]. Some large insoluble particles will remain on the tubesheet.

Table 2. Assumed Sludge Compositions

	% Iron Oxides	% Copper	% Insolubles
Broached Hole Deposits	45.0	45.0	10
Tube Scale	47.5	47.5	5
Tubesheet Sludge Pile	37.5	37.5	25

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CHEMICAL CLEANING PROCESS EFFECTIVENESS

The chemical solvents and the associated application procedures in use today in the US and Canada were developed in the 1980's under sponsorship of the Steam Generator Owners Group (SGOG) of the Electric Power Research Institute (EPRI). Laboratory trials using the EPRI/SGOG solvents and process have shown that the iron dissolution solvent can theoretically hold well over 20 grams per liter of iron metal. The copper solvent can hold over 10 grams per liter of copper. For the present analysis, it is assumed that loadings for the iron and copper solvents would be 20 and 10 grams per liter, respectively.

Based on industry experience[1], chemical cleaning of the steam generators at the sample plant should result in complete removal of material from the tube surfaces. Chemical cleaning should clear sludge from broached openings in tube support plates if exposure times are sufficient[13]. On the other hand, the tubesheet sludge pile is not expected to completely dissolve because of the large proportion of insolubles and the limited surface area of the pile. In addition, insoluble layers have been known to form on the exposed surface of sludge piles during chemical cleaning and further retard the dissolution process[14].

Despite the potential for formation of such an insoluble layer, it is assumed that each copper or iron step reduces the sludge pile height by two centimeters.

Based on complete dissolution of tube scale, broached hole deposits, and tube sheet pile, a total of 70,000 liters of iron solvent and 140,000 liters of copper solvent would be required for chemical cleaning each of the twelve steam generators. Of the 700 kg of insolubles in the steam generator, about 350 kg will be washed out with the solvent. Another 350 kg of large, heavy insoluble particles will remain on the tubesheet.

ADDITION OF IN-BUNDLE TUBE SHEET SLUDGE LANCING

The exact sequence of alternating between in-bundle sludge lancing and chemical cleaning solvent steps would be determined during site specific qualification of the combined process; however, the first step in an integrated mechanical/chemical cleaning would be to inspect the steam generator.

One unique feature of the CECIL lances is high resolution fiberscope. This is used to inspect the tubes, the tubesheet, and possibly the first tube support plate. The next step would be to lance the tubesheet. If the in-bundle system could not remove all of the sludge pile, grooves or furrows would be cut into the pile and increase its surface area. At a steam generator with two 30 cm high sludge piles in roughly kidney shaped regions on the hot and cold leg sides, the surface area of the piles would be increased by a factor of ten if 5 cm deep furrows could be cut into the surface. Field results and laboratory investigations have shown that cutting furrows of such depth are within the capability of the CECIL system (described earlier), even for sludges with high compressive strengths.

After the initial inspection and lancing, one or more chemical cleaning solvent steps would be completed. The in-bundle system would be reintroduced to continue sludge lancing and provide inspection capability so that the progress of the chemical cleaning can be verified. Periodic reintroduction of the in-bundle system would also allow insoluble materials which fell on the sludge pile from the tube bundle to be removed.

Alternating between lancing and chemical cleaning steps could be repeated several times. It may also turn out to be desirable to limit the last few chemical steps to a partial fill cleaning of the tubesheet region if it is found through visual inspection that the tubes and first tube support plate are clean and the last vestiges of sludge are at the tubesheet level.

High pressure water jets directed at the sludge pile would provide enhanced removal of residual solvent. This is important as the copper solvent and iron solvent, often used sequentially, are incompatible. Enhanced solvent rinsing will reduce the amount of residual solvent.

In summary, use of an in-bundle lancing system in conjunction with chemical cleaning would:

- increase the exposed surface area of the sludge pile, thereby increasing the rate of dissolution of the sludge pile;

- reduce the amount of sludge which would have to be dissolved chemically, as any portion of the sludge pile removed during lancing would not need to be dissolved with solvents;

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- remove those insolubles liberated from dissolved tube scale and broached hole deposits which settle on the sludge pile;

- provide enhanced rinsing of the tubesheet; and

- inspect before, during and after cleaning.

The case study analyses showed that a combined process would result in a reduction in copper and iron solvent volumes of between 50,000 to 60,000 liters. Perhaps more important is that while chemical cleaning alone would probably not result in complete removal of the tubesheet sludge pile, addition of the in-bundle lancing system should allow complete cleaning of the tubesheet region.

With assumed costs for chemicals and waste processing of $5.30 (USD) per liter, a $250,000 to $300,000 (USD) savings could be realized for the chemical cleaning operation.

RECENT EXPERIENCE

The nuclear power industry is beginning to combine advanced mechanical in-bundle lancing with chemical cleaning. The CECIL in-bundle lancing system was recently used by Electricité de France at Fessenheim Unit 2 before and after chemical cleaning. The results were very favorable. Quantitative data on the enhanced removal of sludge from the steam generators is expected to be published soon.

CONCLUSIONS

Advanced mechanical in-bundle lancing and chemical cleaning have been shown to be synergistic processes. The primary benefits of the combined process would be: (1) a reduction in the volume of solvent required to dissolve sludge, (2) a reduction in waste volumes, and (3) enhanced inspection of the tubesheet region to verify the effectiveness of the process.

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FEEDWATER HEATERS FUNCTIONAL ANALYSIS AT EMBALSE NGS

R. R. LOLIS

EMBALSE NUCLEAR POWER PLANT - CNEA -ARGENTINA.

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ABSTRACT

This study considers a feedwater heaters functional analysis to detect a particular actual equipment failure or a bad trend, beyond certain normal limits accepted according with the operative experience. When these situations are defined, preventive or corrective maintenance must be done.

FEEDWATER HEATERS FUNCTIONAL ANALYSIS AT EMBALSE NGS

R. R. LOLIS

EMBALSE NUCLEAR POWER PLANT - CNEA - ARGENTINA

1 GENERAL

The feedwater heaters main design targets are:

- To obtain a high feedwater flow, and
- To approach it as near as possible to the saturated temperature, before entering into the boilers

To get this, installations with certain complexity are required:

- A large heaters quantity, and
- Related auxiliaries

For Embalse Plant, we have twelve heaters and three forward pumps associated.

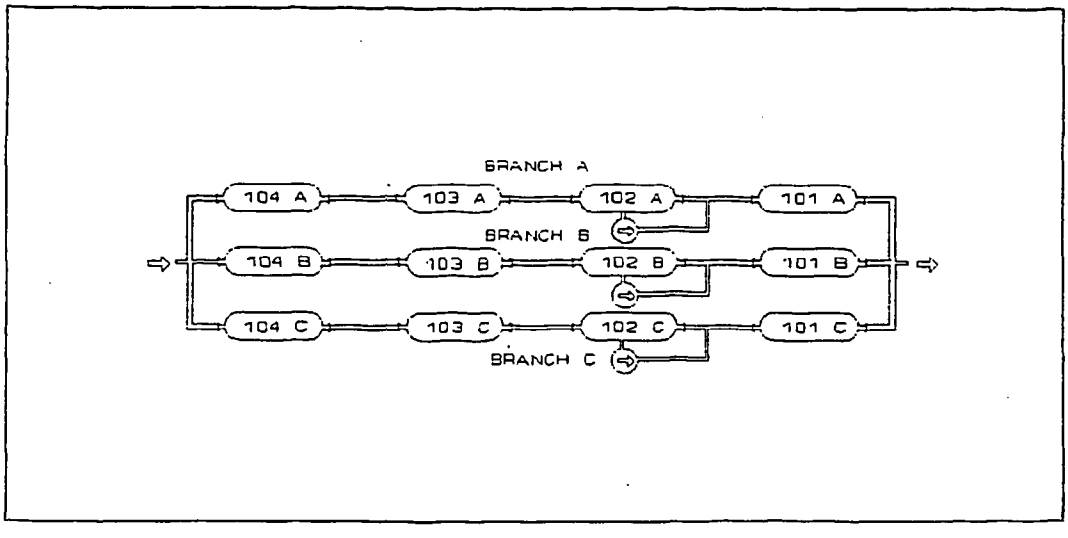

FIGURE N° 1

As result of this huge installation, if all parameters were pretended to be instrumented to have their readings in the Main Control Room, it should be very expensive and difficult.

Then local readings in the field for our purposes are applied when certain special checks are carried out.

So, for the developed method it was considered: the use of minimum data, and readings already instrumented to be taken throughout Control Computers.

2 METHOD BASES

2.1 There are two operational cases in the presented installation:

- Nine heaters, in which the shell side condensed steam discharges to the turbine condenser.

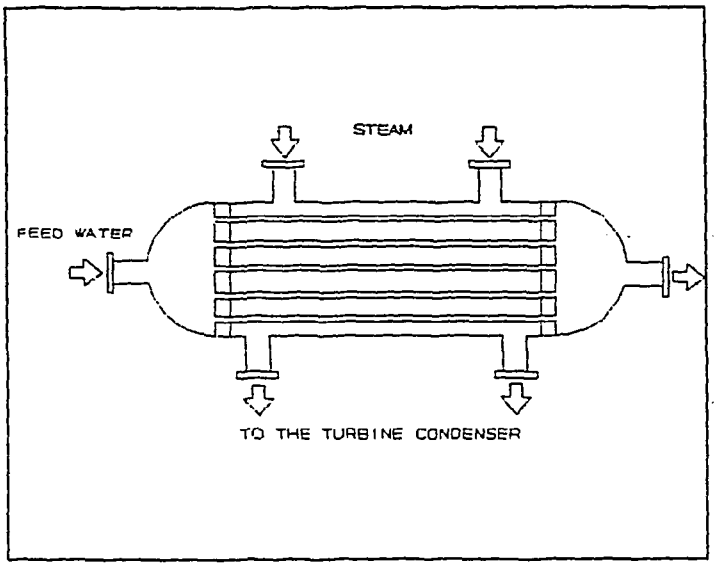

FIGURE N° 2

- Three heaters in which there is a reflow from the shell side condensed steam to the next heater tube side by means of the forward pumps.

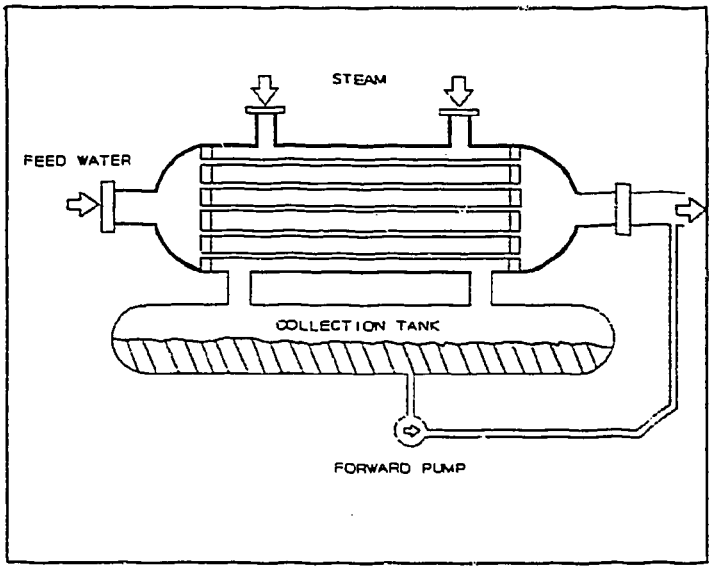

FIGURE N° 3

In both cases, calculations will be the same, but the forward pumps contribution to the thermal cycle, have particular details to be discussed latter.

2.2 To perform calculations, the first thing to have in mind is that the data acquisition has a main requirement for proper use: readings must be always done for the same Station percentage of full power.

Then, when associated with other reading groups to perform the same calculations, results will belong to the same Station operational condition, and will be compatible.

If it is not noticed, the 100 % of full power will be the normal Plant operational condition.

2.3 The required data for calculations are fifteen (inlet and outlet) temperatures. For each component:

tin = inlet heater feedwater temperature in °C
tout = outlet heater feedwater temperature in °C

2.4 Once having the tin and tout for a heater, it's very easy to obtain:

hin = inlet heater feedwater enthalpy in Kcal / Kg
hout = outlet heater feedwater enthalpy in Kcal / Kg

2.5 Using the inlet and outlet enthalpies, for the heater under consideration, a Functional Indicator can be calculated:

$$FI = \frac{hout - hin}{hout}$$

2.6 Each value for the heater FI, varies in accordance with:

- Lake water temperature
- Heater functional status

As an example, for heater 101 A, values for FI are:

Summer

tin = 116.00 °C, hin = 116.204 Kcal / Kg
tout = 151.00 °C, hout = 152.252 Kcal / Kg

$$FI = \frac{152.252 - 116.204}{152.252} = 0.23677$$

Winter

tin = 115.30 °C, hin = 115.487 Kcal / Kg
tout = 151.20 °C, hout = 152.148 Kcal / Kg

$$FI = \frac{152.148 - 115.487}{152.148} = 0.24096$$

Normal functioning

tin = 115.60 °C, hin = 115.794 Kcal / Kg
tout = 151.20 °C, hout = 152.148 Kcal / Kg

$$FI = \frac{152.148 - 115.794}{152.148} = 0.23894$$

This indicates that:

- There is a minimum FImin for summer.
- There is a maximum FImax for winter.
- For normal functioning FImin ≤ FI ≤ FImax.

2.7 Before to make graphic representations, it's required to define another variable, which will be called Reading Number N and may be associated with a sample date for better classification.

2.8 Resuming the required data and calculations for the above example:

N	Date mm-dd-yy	tin	tout	hin	hout	FI
1	11-05-90	116.00	151.30	116.204	152.252	0.23677
2	04-01-91	115.60	151.20	115.794	152.148	0.23894
3	08-01-91	115.30	151.20	115.487	152.148	0.24096

2.9 A complete graphic is shown for reference:

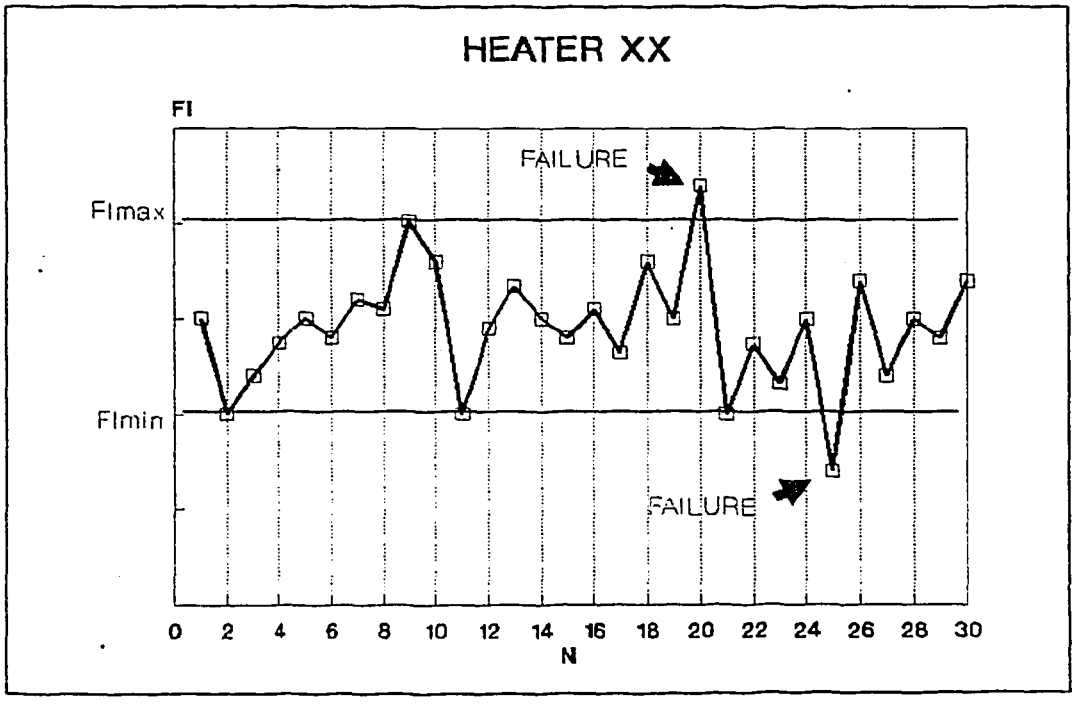

FIGURE N° 4

- Verify if FImin corresponds for a summer time.

- Verify if FImax corresponds for a winter time.

- If one of the two last or both values doesn't correspond, must be discarded for the analysis and another FIminand/or FImax must be chosen.

The origin of these atypical FI values could be because:

- A Station power maneuvering before or during temperature readings.

- A refuelling operation before or during temperature readings.

- An associated pump or system malfunctioning.

3 RESULT INTERPRETATIONS

4.1 When the twelve FI, N graphics are obtained (one per heater), the abnormal situations must be considered.

Here all FI > FImax or FI < FImin are detected and measured. Then, a classification is obtained as a result of the deviation magnitudes.

This establishes a heater priority for planning a preventive or corrective maintenance actions.

4.2 For equipment malfunctioning, if for a certain heater it's observed:

$$FI > FImax, \text{ or}$$
$$FI < FImin$$

It does not mean that the equipment must be shut-down immediately for reparations.

If:

- A very high tout in a heater is observed, or

- A very high level in a collection tank, or

- A very bad operational symptom,

then that particular heater should require to be repaired very soon.

Generally if the detected malfunctioning does not causes any of the above particular situations, it can last until the next Station shut-down.

All FI > FImax or FI < FImin is considered as an equipment failure.

- If FI > FImax, a tubes or tube-plate leak happens.
- If FI < FImin, is a thermal blockade due to rust or crude builded on the tubes wall.

Generally the most common circumstance is FI > FImax.

2.10 If average statistics from June of 1989 up to May of 1992 are observed for the twelve heaters:

HEATER	tin	tout	hin	hout	FI
104 A	36.4568	61.9968	36.4438	61.9340	0.41185
103 A	61.9968	88.4588	61.9340	88.4194	0.29968
102 A	88.4588	115.5544	88.4194	115.7478	0.23608
101 A	115.5544	151.3208	115.7478	152.2756	0.23977
104 B	36.4568	66.3416	36.4438	66.2716	0.45113
103 B	66.3416	88.4896	66.2716	88.4635	0.25089
102 B	88.4896	111.4800	88.4635	111.6178	0.20723
101 B	111.4800	157.6400	111.6178	158.8123	0.29739
104 C	36.4568	61.6192	36.4438	61.6032	0.40922
103 C	61.6192	92.4420	61.6032	92.4366	0.33334
102 C	92.4420	111.4320	92.4366	111.5692	0.17181
101 C	111.4320	152.4920	111.5692	153.4914	0.27312

TABLE N° 1

Must be noticed that for the same heaters branch, FI is going down from the first heater to the last one, where goes up again a little.

2.11 More method requirements:

To select the FImin and FImax for a certain readings quantity, for a particular heater, it's required:

This sort of failure detection is considered as a part of a corrective maintenance planning.

4.3 In the following figure a typical equipment bad trend is observed.

This sort of failure detections are considered as a part of a preventive maintenance planning.

Here also, immediate actions are not required.

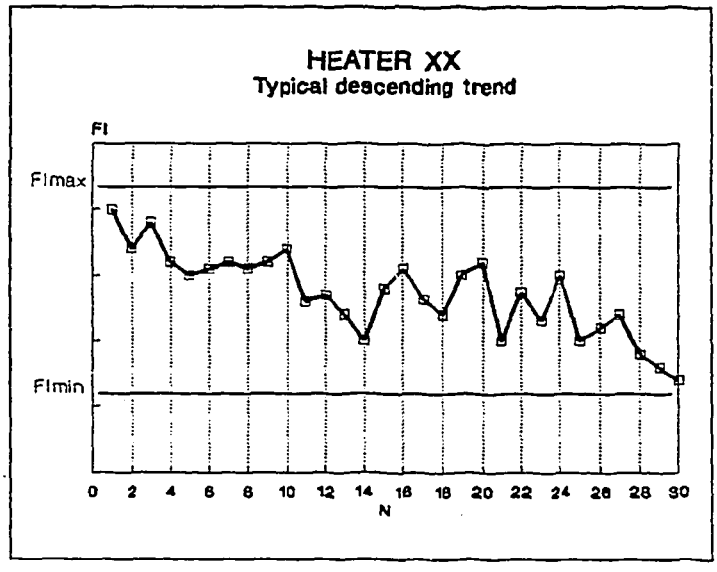

FIGURE N° 5

4.4 As an example for our Station, the following graphics will be shown:

(a) A heater without any failure.
(b) Malfunctioning or bad trend heaters.
(c) A heater presenting atypical values.

The considered period will be from June of 1989 up to May 1992.
Latter, one of these graphics will be described in detail.

(a) A heater without any failure

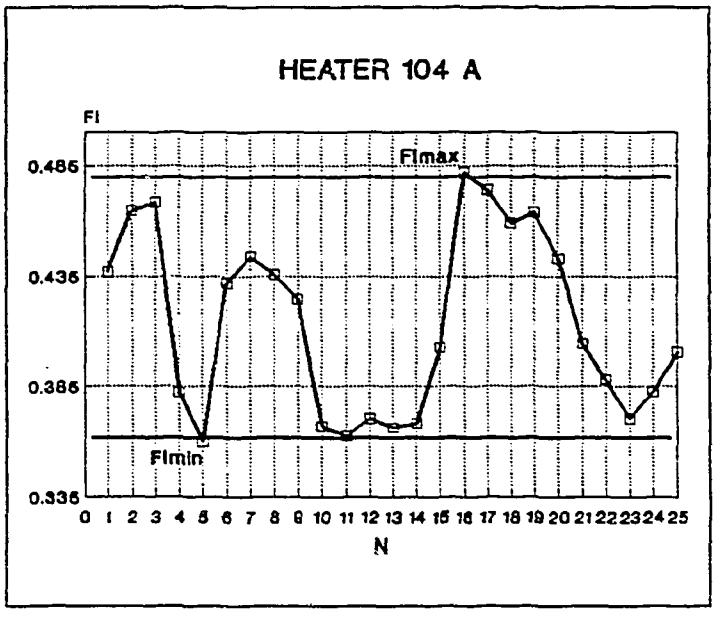

FIGURE N° 6

(b) Malfunctioning or bad trend heaters

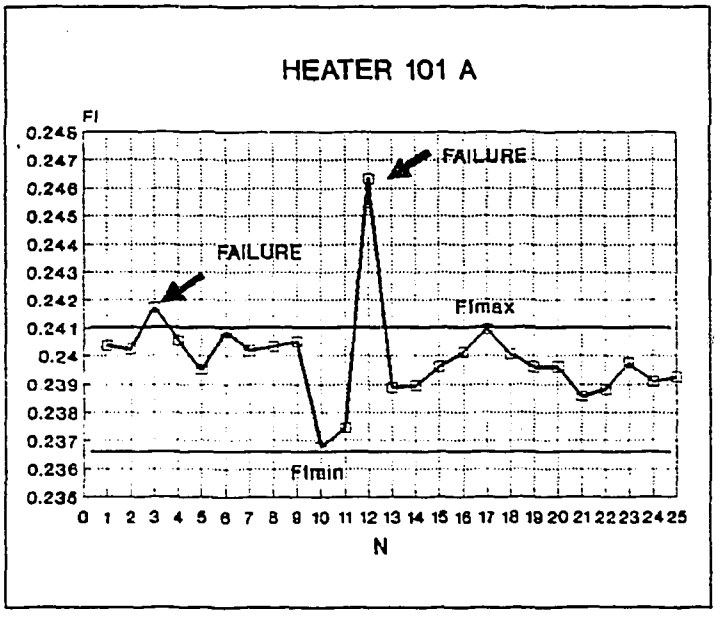

FIGURE N° 7

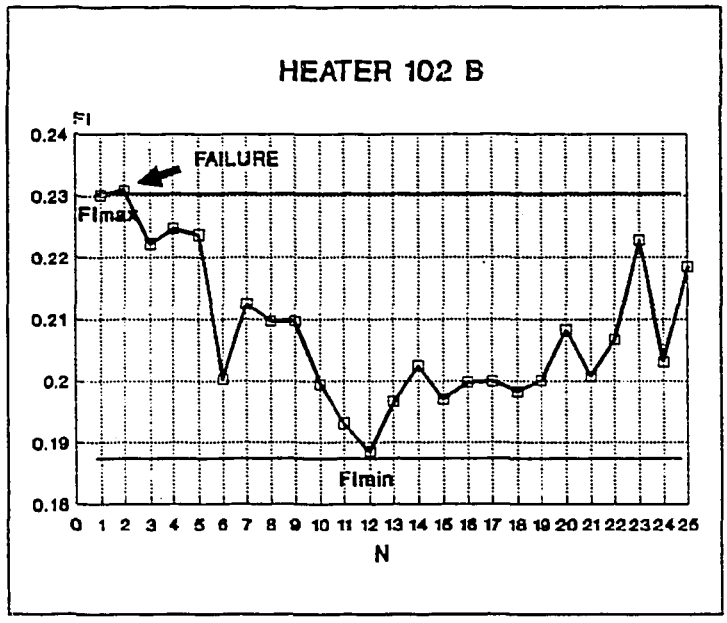

FIGURE N° 8

The following heater presents besides of an internal failure a bad trend:

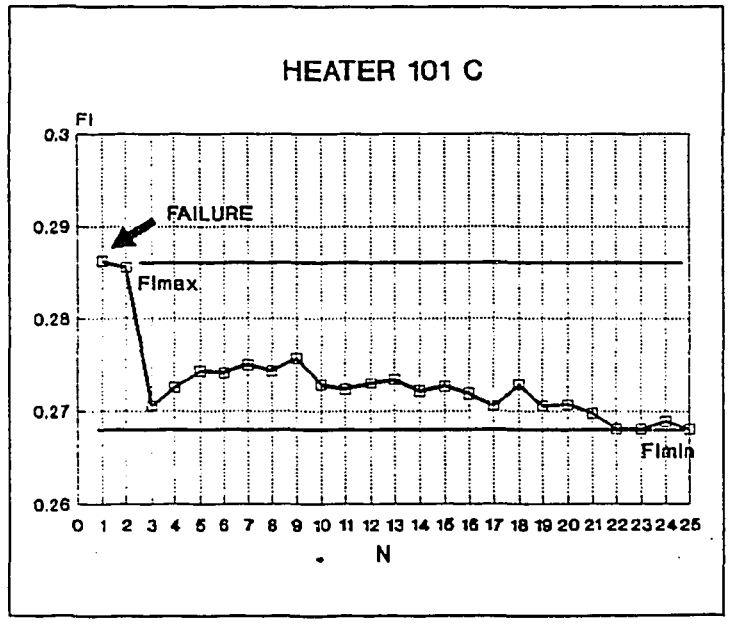

FIGURE N° 9

(c) A heater presenting atypical values

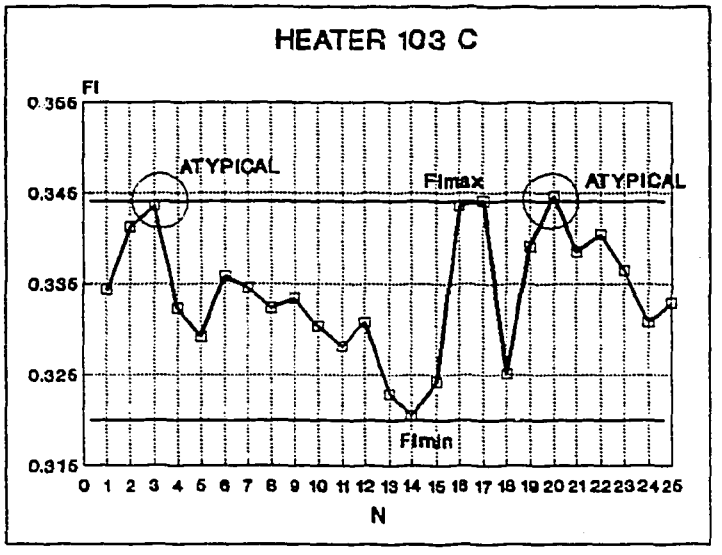

FIGURE N° 10

The pointed values are atypical because numerically correspond to FImax, temperature readings do not belong to winter.

N	Date mm-dd-yy	tin	tout	hin	hout	FI
3	09-08-89	61.00	92.84	60.837	92.837	0.34360
20	11-04-91	60.91	92.86	60.848	92.857	0.34471

Must be noticed that:

- In all cases when a failure is repaired, FI goes back again to normal values between FImin and FImax.
- Time to time, FImin and FImax values must be updated because the equipment oldness advance.
- In graphics as like FIGURE N° 7, where a failure appears for N = 3, the FImax was calculated before the considered period of N = 25. The calculated FImax for N = 17, is an updated value which coincides with the previous one.

5 METHOD APPLICATIONS

5.1 Coming back again to the heater 101 A, a detailled consideration will be carried out.

The complete data and calculations for N = 25 readings are:

N	DATE mm-dd-yy	tin	tout	hin	hout	FI	Remarks
1	05-06-89	115.00	150.70	115.180	151.628	0.24038	
2	04-07-89	115.10	150.80	115.282	151.732	0.24023	
3	08-09-89	115.80	152.00	115.999	152.980	**0.24174**	**Tubes leak**
4	03-01-90	115.90	151.90	116.102	152.876	0.24055	
5	01-03-90	115.90	151.70	116.102	152.668	0.23951	
6	04-06-90	115.70	151.70	115.897	152.668	0.24086	
7	17-07-90	115.80	151.70	115.999	152.668	0.24019	
8	07-09-90	115.70	151.60	115.897	152.564	0.24034	
9	03-10-90	115.60	151.50	115.794	152.460	0.24050	
10	05-11-90	116.00	151.30	116.204	152.252	0.23677	**FImin**
11	04-12-90	115.90	151.30	116.102	152.252	0.23744	
12	04-02-91	114.99	151.84	115.170	152.814	**0.24634**	**Tube-plate leak**
13	01-03-91	115.67	151.28	115.866	152.231	0.23888	
14	01-04-91	115.60	151.20	115.794	152.148	0.23894	
15	02-05-91	115.50	151.20	115.692	152.148	0.23961	
16	01-07-91	115.50	151.30	115.692	152.252	0.24013	
17	01-08-91	115.30	151.20	115.487	152.148	**0.24096**	**FImax**
18	02-09-91	115.20	150.90	115.385	151.836	0.24007	
19	08-10-91	115.50	151.20	115.692	152.148	0.23961	
20	04-11-91	115.50	151.20	115.692	152.148	0.23961	
21	03-12-91	115.50	151.00	115.692	151.940	0.23857	
22	30-01-92	115.50	151.00	115.692	151.990	0.23882	
23	03-03-92	115.40	151.10	115.590	152.044	0.23976	
24	03-04-92	115.50	151.10	115.692	152.044	0.23908	
25	03-05-92	115.40	151.00	115.590	151.940	0.23924	

TABLE N° 2

FImax = 0.24096 for N = 17

(a) First failure for N = 3, FI = 0.24174

Deviation = σ_1 = | 0.24174 - 0.24096 | = 7.8×10^{-4}

(b) Second failure for N = 12, FI = 0.24634

Deviation = σ_2 = | 0.24634 - 0.24096 | = 5.38×10^{-3}

$\left| \sigma_2 > \sigma_1 \right|$ ≈ 7 times

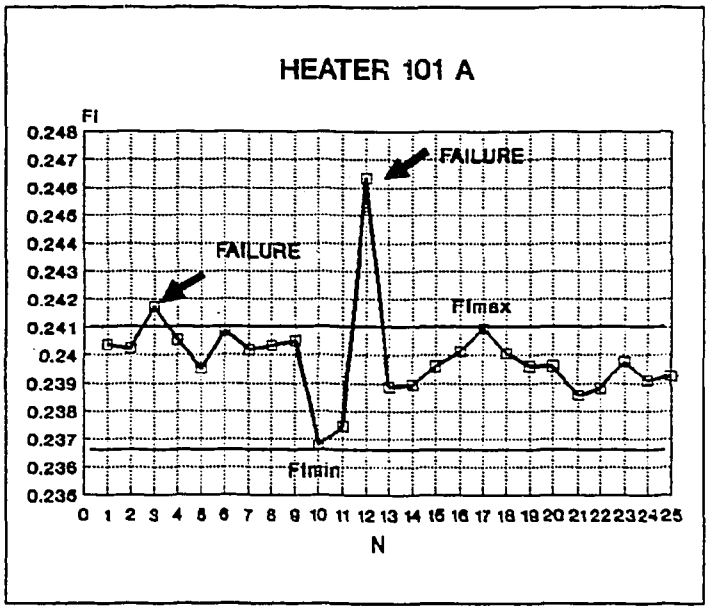

FIGURE N° 11

In practice, it was verified that for the first failure a tube leak existed, and for the second one a tube-plate leak (greater than the other).

That's why: $\sigma_2 > \sigma_1$

For planning purposes, when the 12 heaters have theirs individual Deviations already calculated:

$$\sigma_n > \sigma_{n-1} \quad \ldots\ldots\ldots > \sigma$$

Then, heaters reparation priorities are automatically established for corrective maintenance.

5.2 For preventive maintenance, priorities can be estimated calculating the slope trend angles.

Looking again to the heater 101 C graphic:

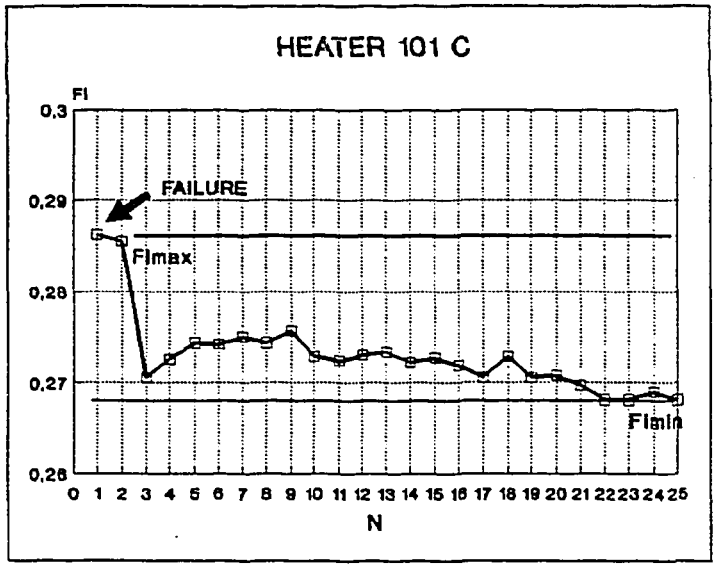

FIGURE N° 12

Functional Indicator trend will be:

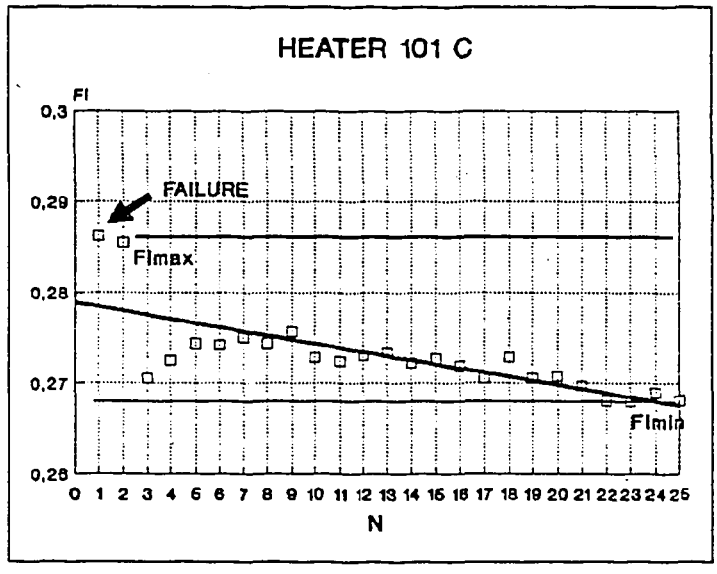

FIGURE N° 13

Having more than two trends (ascsnding or descending), inspections are classified from bigger to smaller slope angules.

5.3 In TABLE N° 1, it was established the Functional Indicator variations for each feedwater branch system, from the first heater to the last one.

Such as variations for C branch are:

Heater	FI
104 C	0.40922
103 C	0.33334
102 C	0.17181
101 C	0.27312

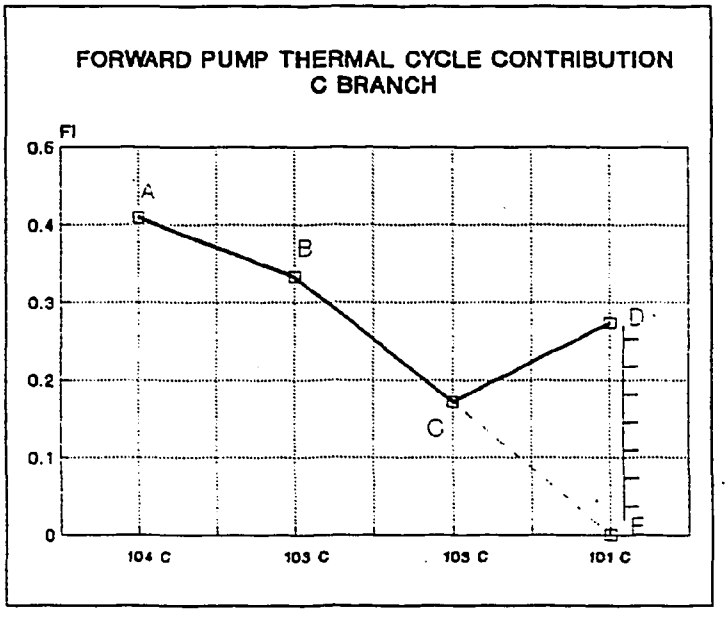

FIGURE N° 14

The ABCD curve are the normal FI variations along the C branch. If the C forward pump is shut-down, the FI variations are almost the ABCE curve.

Then it's possible to calibrate the DE distance, which indicates when maximum forward pump contribution to the thermal cycle is taking place.

When the forward pump does not work at full, the FI value for heater 101 C, will indicate the FI variation due to the pump functional change.

This is an approximate way to measure the forward pump work.

6 EQUIPMENT REPARATIONS RATE

For the 12 heaters, and for about 3 years of samples period, 4 equipment reparations were required. Then:

$$4/3 = 1.33 \text{ equip. rep. / year}$$

It is the actual required feedwater heaters reparations rate after 9.5 years of the Station operation.

Normally, because of the method result interpretations, 2 and no more than 3 heaters are selected to be inspected per year.

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INTEGRATED INSPECTION PROGRAMS AT BRUCE HEAVY WATER PLANT

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ABSTRACT

Quality pressure boundary maintenance and an excellent loss prevention record at Bruce Heavy Water Plant are the results of the Material and Inspection Unit's five inspection programs. Experienced inspectors are responsible for the integrity of the pressure boundary in their own operating area. Inspectors are part of the Technical Section and along with unit engineering staff, they provide technical input before, during and after the job. How these programs are completed and the results achieved are discussed.

INTEGRATED INSPECTION PROGRAMS AT BRUCE HEAVY WATER PLANT

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INTRODUCTION

Inspections are performed to assess the condition of the pressure boundary, to find corrosion before failures occur and to assure quality maintenance is performed. At Bruce Heavy Water Plant, (BHWP) the Materials and Inspection (M&I) Unit manages five inspection programs to accomplish the above task. This paper will describe how M&I is organized to carry out these programs. The description of the programs will focus on how they are integrated to encourage inspector ownership for their operating area.

BACKGROUND TO BHWP CORROSION MECHANISMS

The corrosive properties of hydrogen sulphide (H_2S), and the sheer size of the plant, present an inspection challenge at BHWP. The following describe corrosion mechanisms associated with operating a heavy water plant.

1. Hydrogen sulphide, H_2S is used in a dual temperature exchange process with water to concentrate heavy water. It is both a toxic and corrosive chemical. When it reacts with oxygen, polythionic acids and/or sulphuric acid form and corrosion rates of 2 mm per month on carbon steel are not uncommon.

2. Both carbon steel and stainless steel (the principal materials of construction) are susceptible to sulphide stress corrosion cracking unless proper metallurgical properties are specified and controlled.

3. With 25,000 flanges in H_2S service, gasket leaks occur on a small percentage. Once H_2S reacts with oxygen, it corrodes the flange studs and weakens the strength of the joint.

4. BHWP is an outdoor plant, similar to a refinery, with approximately 17 kilometres of insulated and steam traced piping in H_2S service. Steam tracing can exacerbate corrosion in two ways:

   4.1. Steam tracing leaks soak insulation and leach out chlorides from the insulation. Chlorides can initiate stress corrosion cracking and increase the corrosion rate on external surfaces.

   4.2. Stagnant fluid in piping (eg. deadlegs and isolated systems), heats and boils if the steam tracing is left

on. The resulting high temperature and loss of protective iron sulphide scale cause corrosion rates to increase exponentially.

5. Loss of protective iron sulphide scale occurs in areas of high fluid velocity or turbulence. Accelerated rates of corrosion result in pressure vessels or piping where these conditions are present.

6. Traditional power plant corrosion mechanisms such as two phase condensate erosion/corrosion and oxygen pitting in cooling water also require attention.

MATERIALS AND INSPECTION ORGANIZATION

Materials and Inspection (M&I) is a unit within the BHWP Technical Section with the following goal:

> "To provide inspection, quality control and materials expertise to ensure the integrity of the BHWP pressure boundary and structural assets allowing BHWP to be operated safely and efficiently within regulatory requirements. An inspection service is also provided to other departments."

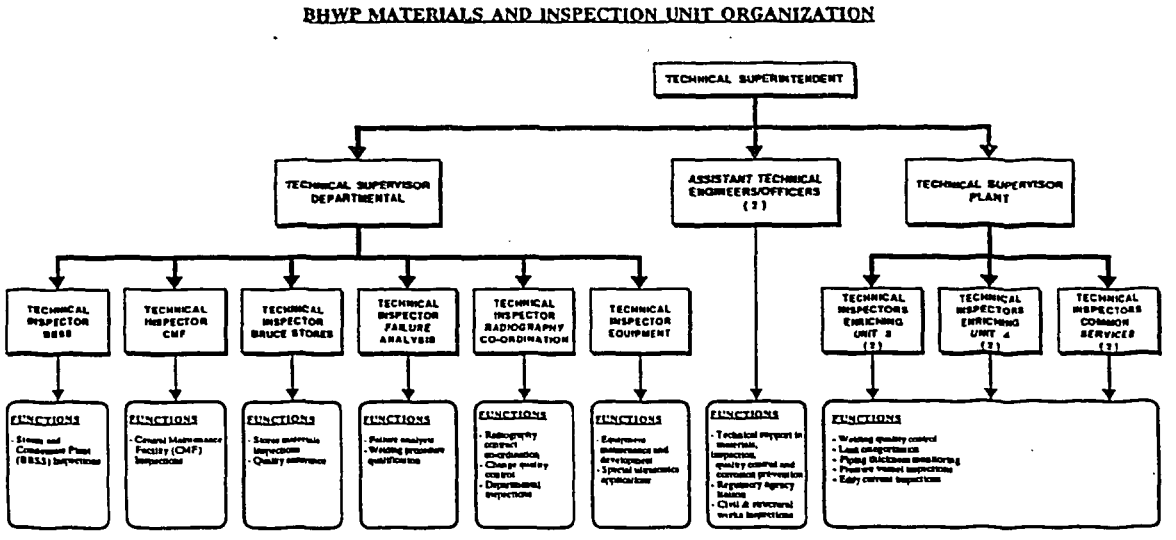
The staff currently consists of twelve technical inspectors, two contract radiographers, two engineers, two supervisors and a superintendent.

BHWP is divided into three operating areas; Enriching Unit #3, Enriching Unit #4 and a Common Services area. Inspection services are also provided to three other departments at The Bruce Nuclear Power Development site; The Central Maintenance Facility, (CMF), Central Stores and The Steam and Condensate Plant, (BBSS).

The Organization Chart in figure 1 below describes the function of each position. The Technical Inspectors in the Enriching Units and Common Services have ownership for the inspection programs in their area. Inspection and quality assurance support to BHWP is provided by the inspectors in the other positions. Only the Technical Inspector at the Steam and Condensate Plant works independently of BHWP.

Technical Inspectors all work to the same job description document and rotate between different positions. The rotation criteria was developed by the inspectors based on yearly preferences. Rotations broaden the experience of the inspectors which benefits the plant during maintenance outages and provides back-up flexibility for all positions.

Figure 1



All Technical Inspectors at BHWP have more than 10 years experience in non-destructive testing. Each inspector is certified to Canadian General Standards Board Level II in magnetic particle and liquid penetrant inspection. Six are certified to Level II radiography, six to Level II ultrasonics, and two to Level II eddy current. The experience and breadth of knowledge required by BHWP Technical Inspectors is important to the success of the M&I program. Experienced staff work with enough independence that the performance of the M&I Unit is not sensitive to changes in supervision.

INSPECTION PROGRAMS

There are five programs managed within M&I:

1. Quality Control/Assurance Inspection Program
2. In-service Inspection Programs (3):
   - 2.1 Internal and External Pressure Vessel Inspection Program
   - 2.2 Piping Thickness Monitoring Program
   - 2.3 Flange Leak Inspection Program
3. Failure Analysis Program

1. Quality Control Inspection and Quality Assurance Program:

M&I performs both quality control and quality assurance functions. It has been said M&I acts as the "conscience" of the plant. BHWP has specifications more stringent than ASME codes because of the corrosive properties of H_2S. The specifications require material and weld traceability, along with high inspection standards. All repairs and new pressure boundary fabrication must meet the quality control and quality assurance standards as written in the Bruce Heavy Water Plant Quality Control Manual.

The BHWP Quality Control Manual was written to comply with the requirements of the Ministry of Consumer and Commercial Relations (MCCR) as outlined in Canada's Pressure Vessel and Piping Code, CSA B51. It is reviewed annually, and is issued and administered by M&I. Each revision must be concurred with by the MCCR.

All liaison at BHWP with the Authorized (Government) Inspector is through M&I. Over the years a respectful relationship has been developed. BHWP is exempt from the requirement to contact the Authorized Inspector prior to proceeding with certain types of pressure boundary repairs during off-hours or when the he/she is unavailable. Most hydrotests at BHWP are witnessed by Technical Inspectors, as delegated by the MCCR. These are time saving privileges when performing critical path repairs.

Quality assurance for pressure boundary components starts with purchasing and traceability of the correct materials. The Technical Inspector at Bruce Stores reviews all internal supply requests to ensure purchasing clauses specify the level of quality control and quality assurance required by the codes and the BHWP Quality Control Manual. When material is received, the same Technical Inspector checks that the documentation meets the purchase order, and in some cases quality control inspections such as hardness and dimensional measurements are performed.

The next stage begins when a repair package is forwarded to M&I. Technical Inspectors, with help when required from the unit engineers, provide technical input before, during and after all pressure boundary welding jobs. All welding work packages, whether pressure boundary or not, are reviewed by the area Technical Inspector and his supervisor before the job starts. This review of an engineer's work package is a check to ensure consistency and quality in the pressure boundary work packages.

A weld quality control directive sheet is completed by the inspector to specify the welding procedure and any inspection hold points for the work package. If it is a pressure boundary job, a higher level of quality assurance is required. For pressure boundary work, each weld is assigned a unique number that traces the inspection results and the welder's identification.

As the job proceeds, the area Technical Inspector is often in the field with the welders and fitters. He provides technical input to

ensure fit-ups, welding techniques, materials, and documentation all meet the quality/inspection standards specified in the work package.

After the work is completed, and tested, the inspector must review the work package to ensure the necessary documentation is available, and the job was performed as specified. This package must then be presented to the MCCR Authorized Inspector for acceptance.

In summary, the Inspector is involved in pressure boundary welding jobs from start to finish. This involvement makes the Technical Inspector accountable for work in his area, contributing to area ownership and ultimately greater job satisfaction. As a result, consistently high quality pressure boundary work is performed at BHWP.

2. In-service Inspection Programs

The three in-service inspection programs and the failure analysis program at BHWP represent a comprehensive surveillance effort to effect loss control, (ie. safe efficient operation).

2.1 Internal and External Pressure Vessel Inspection Program:

There are 360 registered pressure vessels in service at BHWP. As a commitment to our insurer, Factory Mutual, internal inspection of most pressure vessels is mandatory once every six years. In may cases, vessels are internally inspected more frequently, depending on corrosion rates.

There are two exceptions to the mandatory inspection rule. Vessels too small to enter are externally thickness monitored or radiographed in lieu of entry. The other exception is for identical equipment in the same service, (eg. ten seal oil filters), where a representative sample of vessels is inspected internally. M&I's target is to achieve 100% compliance with the planned mandatory inspection program each year. Meeting this target requires a team effort and commitment to the inspection program from the Plant Management Team.

Internal Inspections: Technical Inspectors look for areas of general corrosion, pitting, erosion, cracking, hydrogen blistering and mechanical damage. Thickness measurements are always taken with pit gauges and handheld thickness meters. The condition of the scale is noted, and scale samples are taken if required. Some vessels have protective coatings and liners which require assessment.

Where required, tower internals are dismantled to allow visual access to the walls, or packing is removed. For most inspections, the internals are high pressure water cleaned to remove all loose scale. For surface inspections such as wet fluorescent magnetic

particle, areas are sandblasted to remove scale.

On occasion the following NDE techniques are used:

Wet Fluorescent Magnetic Particle examination is a sensitive surface inspection used to detect tight cracks, such as those associated with hydrogen induced cracking.

Eddy current inspection is used to detect flaws in stainless steel heat exchanger tube bundles.

Ultrasonic inspection using straight beam or shear wave probes is used to detect and measure subsurface flaws. Specialized ultrasonic probes were designed within M&I and used to measure wall thickness in boiler tubes up to 50 mm in diameter.

After performing the internal inspection, deficiencies are immediately reported. A complete formal report is issued within 3 months, complete with recommendations, and the next scheduled inspection date. A comprehensive equipment filing system is maintained within the M&I Unit to provide good inspection and maintenance history.

Area Outages: Every two years each enriching unit has a planned outage when most of the planned maintenance and internal inspections for the year are performed. Inspection activity is high; 60 to 70 internal pressure vessel inspections are performed and many piping repairs require quality control inspections .

For the typical two week maintenance window, all 12 Technical Inspectors are employed in the single area. No extra contract staff are used. All inspectors are familiar with the inspection programs, the equipment being inspected and the standard of inspection required. This team effort results in a highly productive period of inspection.

Effective pre-job planning is important to successful outages. Preliminary inspection plans for an Enriching Unit outage are issued 7 months in advance. For each vessel inspected, the history is reviewed prior to the outage to identify the extent of inspection and prerequisites, (scaffold, cleaning, lighting). The Technical Inspectors and M&I Engineers put together an inspection package for each pressure vessel to ensure the information required for inspection during the high activity period is concise.

External Inspections: External inspections are performed using ultrasonic thickness gauges or radiography. Permanent inspection ports are located on vessels corresponding to known areas of corrosion or hydrogen blistering to allow for periodic ultrasonic thickness monitoring. Data loggers allow the inspector to enter the data electronically in the field and download the result into a computer. These programs calculate the mean thickness and the lowest thickness to compare with previous

results. After each inspection, the inspector issues an inspection bulletin and schedules the next inspection date.

To enhance external inspections, an automated ultrasonic "patch scanner" is being developed with Ontario Hydro Research. This scanner will crawl along a vessel and download thousands of data points to provide a reproducible 'C' scan printout. A 'C' scan is like a topographical map of the steel thickness. This will allow visual comparison of corroded or blistered areas over time, to better estimate blister, or corrosion growth rates.

2.2 Piping Thickness Monitoring Program:

Two types of piping inspection techniques are used: ultrasonic thickness and shadow radiography. For piping 200 mm in diameter or less, radiography is the preferred technique. The advantages to using radiography are; the insulation usually does not have to be removed, and a better picture of the type of corrosion is provided. BHWP has a database of 6500 locations for radiography corrosion monitoring. Each year, approximately 2500 shots are taken.

There are over 500 inspection ports for larger diameter piping, monitored using ultrasonic thickness gauges. Typically 120 of these are monitored each year. Since there are 17 kilometres of H_2S piping at BHWP, achieving even 1% inspection coverage would be very costly. Choosing the most representative locations to inspect is an important part of the surveillance programs. Surveillance of the piping systems is a complex task, and an ongoing process.

To ensure this surveillance program is effective, the inspection locations are identified and prioritized on the basis of:

Propensity to corrosion: There are known corrosion or erosion mechanisms associated with certain piping configurations and process operating conditions.

Locations non-isolatable from large pressure source: Piping which is non-isolatable from large vessels pose a much greater safety risk if they fail. An unplanned shutdown results if they fail.

Safety risk: H_2S leaks are more hazardous than water leaks. Piping prone to large areas of corrosion are of greater risk than piping with pitting corrosion.

Previous history: Learning from past failures and applying failure analysis recommendations to similar conditions is a valuable surveillance tool.

Accessibility: To get a random representative 'picture' of a system, when possible, locations are chosen in the most accessible location to save on time and temporary access (scaffold) costs.

Redundancy: Locations are chosen on one system, which may be

identical to others in the plant in all respects, to provide a representative inspection.

Cost factor: Some non-H_2S systems are not inspected because the consequence of a material failure does not warrant the cost of inspection.

Using all the above criteria, the Technical Inspectors with the help of M&I Engineers choose monitoring points, evaluate the findings, then decide when (or if) to inspect the same location again. Surveillance requests also come from other technical staff.

Surveillance inspections are more effective when adding new locations and changing inspection frequencies is easily done. Inspectors follow guidelines which do not require supervisor approval to add inspection locations or change inspection frequencies. Because the inspectors are mostly responsible for identifying inspection locations, accountability is promoted increasing their sense of ownership to their operating area.

The In-Service Inspection Program at BHWP is very similar in structure to requirements as outlined in the International Atomic Energy Agency Publication "In-Service Inspection of Nuclear Power Plants, Safety Series No. 50-P-2". The details of the BHWP surveillance program are contained in BHWP Technical Section Procedure 43.

Use of Corroded Equipment: As inspections are carried out, inevitably piping or vessels are found with corrosion beyond the corrosion allowance.

To keep equipment in service that is corroded beyond the corrosion allowance, a "fitness for service" assessment is done. A managed "Use of Corroded Equipment (UCE)" system is in place at BHWP to record and monitor all corroded equipment in service. A replacement (expiry) date for each corroded component is committed to, depending on the corrosion rate and the next planned maintenance window.

Every UCE raised, represents corrosion found prior to a failure. Tracking the number of UCE's provides an indicator for the effectiveness of the surveillance program.

Comparing the number of UCE's raised to the number of failures provides a pro-active measure of the inspection program at BHWP. A higher ratio of UCE's to failures indicates more corroded equipment is being identified prior to failure. Figures 2 and 3 show that BHWP's performance in this area is improving.

Figure 2

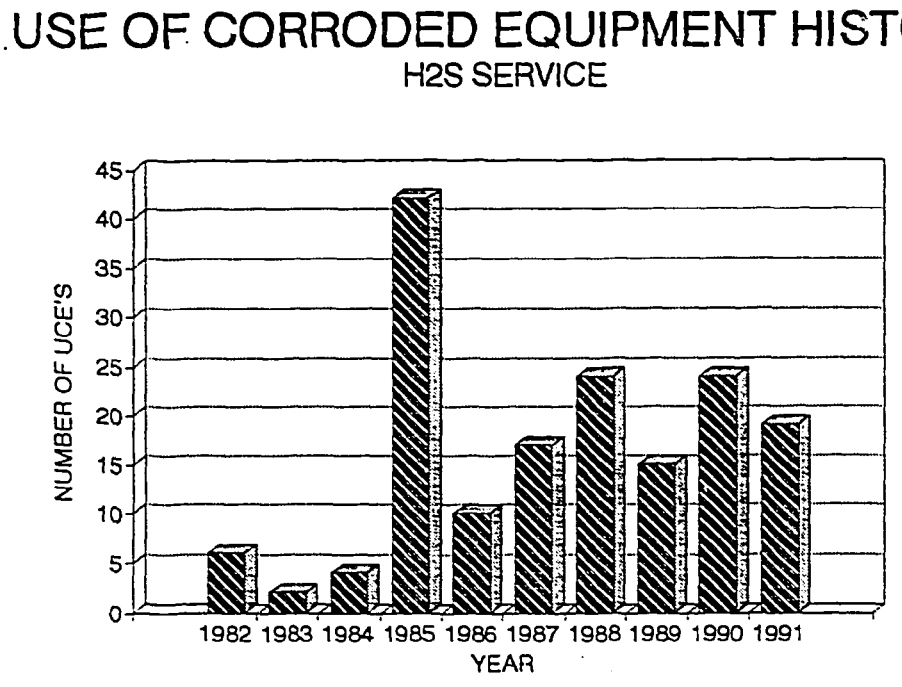
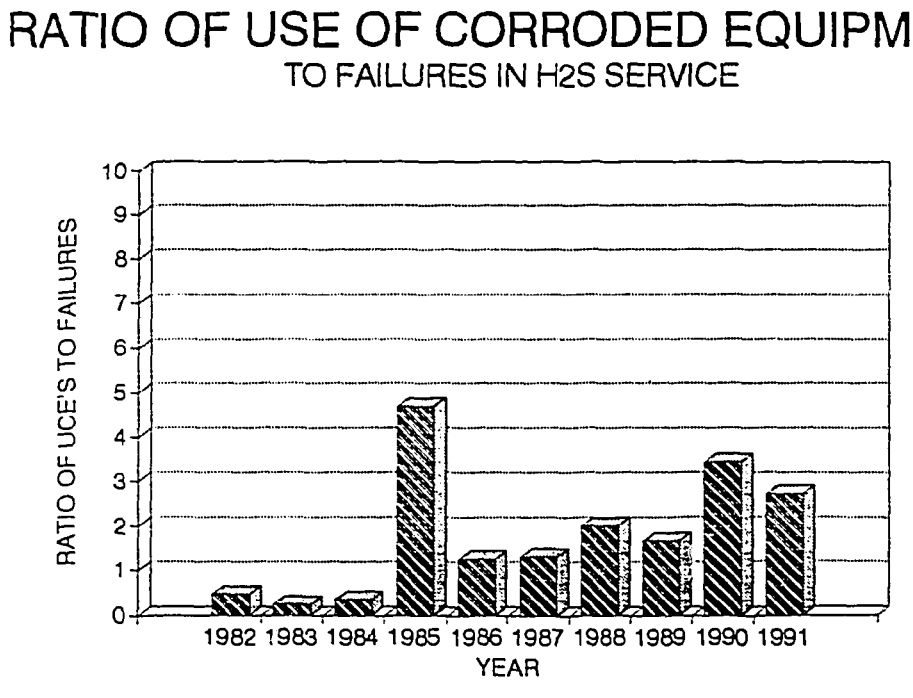


Figure 3



2.3 H_2S Flange Leak Inspection Program:

This inspection program is driven by the need to monitor the condition of 25,000 flanged joints because of the corrosiveness of H_2S. Flange studs corrode rapidly when a leak develops, and if repair of the leak requires a unit shutdown, the flange must be inspected periodically until the repair is effected. The Technical Inspector categorizes the extent of corrosion on the studs and decides if the stud should be replaced or schedules the next inspection. Typically before an outage there are between 200 and 300 flange leaks. **Stud maintenance receives a very high plant priority.** If the corrosion is beyond the thread root on a critical number of studs in a flange, repair is effected within 24 hours. Particularly in the months before a unit shutdown, H_2S leak inspections consume up to 25% of an area inspector's time.

3. Failure Analysis Program:

The M&I failure analysis laboratory is equipped to perform metallurgical investigations. A Technical Inspector trained in metallographic specimen preparation and examination performs the analyses. The lab has the capability to prepare specimens for metallographic analysis, using photomicrographs, microhardness testing, and field replication. The surveillance inspection programs benefit from timely information on failures or corrosion studies.

Engineers with mechanical or metallurgical backgrounds provide technical support for most corrosion, metallurgy and inspection problems. For specialized requests, or longer term studies, support is also available from Ontario Hydro Research Division in Toronto.

OWNERSHIP

The Technical Inspectors' work, like "General Practitioners" in the Medical Field involves maintaining the "health" or integrity of the pressure boundary through quality assurance and quality control (inspection), and surveillance. To do this they perform a variety of tasks from welding inspection to report writing. Ownership, i.e. accountability for their operating area, is fundamental to their job.

The Technical Inspector's daily work involves team work with the system engineers, the mechanical foreman, area planners and operators. All area pressure boundary work including welding, machining, pressure testing, inspection or flange leaks requires input from the inspector.

Daily communication meetings with their supervisor updates the status of the operating areas and helps to focus on plant priorities. This meeting also provides a forum to discuss inspection findings, or any technical or administrative problems

of immediate interest.

Through area ownership, the inspector is confronted with a variety of concerns, from an inexperienced welder in the shop to generic corrosion problems in the field. This range of duties requires the inspector to assess his own priorities. That may mean spending more time with a new welder, or specifying new areas to inspect for the piping surveillance program. By having the field inspectors accountable for their operating area from the planning stage, to completion of the documentation, targets to find corrosion, prevent leaks and maintain good quality control are achieved.

Appendix 1 illustrates how ownership works on a day to day basis by looking at the day in the life of an inspector at BHWP.

ARE WE SUCCESSFUL?

The success of an inspection unit is difficult to directly quantify because most of the activities are pro-active. Quality control influences the safety and reliability of the plant, as does surveillance. Surveillance inspections also contribute to a predictive maintenance program. The following quantitative and subjective evidence supports the success of the M&I organization and its integrated inspection program:

1. Bruce Heavy Water Plant 'B', has operated for 11 years with an excellent safety record and average capacity factor of 70.7%.

2. Our failure rate[1] in H_2S service has improved over the years. Typically, unattended piping corrodes to the point where leaks grow in number and extent, exponentially with time. The lessons learned from previous heavy water plant corrosion problems and an effective inspection program contributes to the trend shown in figure 4.

3. One of the key performance targets for the M&I Unit is a broad base indicator of the inspection program effectiveness. The yearly target is to have three or less unpredicted failures[2] (both in H_2S and non-H_2S service) which cause a significant event report or an event report to be raised.

   The history of this target is shown in figure 5. While the target has not been met every year, it indicates if the inspection program is focusing on the correct areas.

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[1] A failure is defined as a penetration (leak) in the pressure boundary of any size.

[2] An unpredicted failure is defined as "a pressure boundary failure on a system where a risk of failure due to corrosion or incorrect material has not been previously identified by M&I to the Plant Management Team.

Figure 4

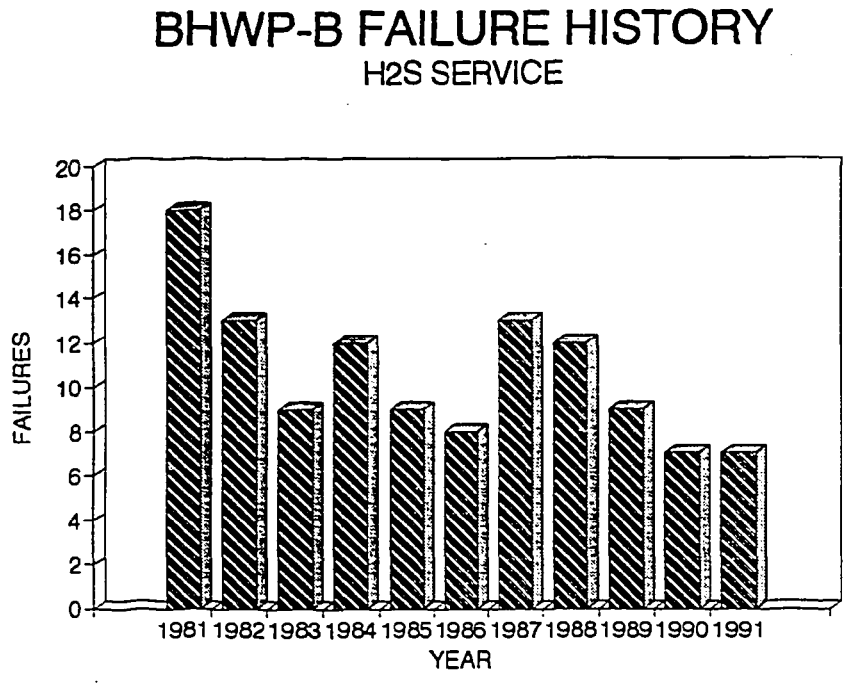
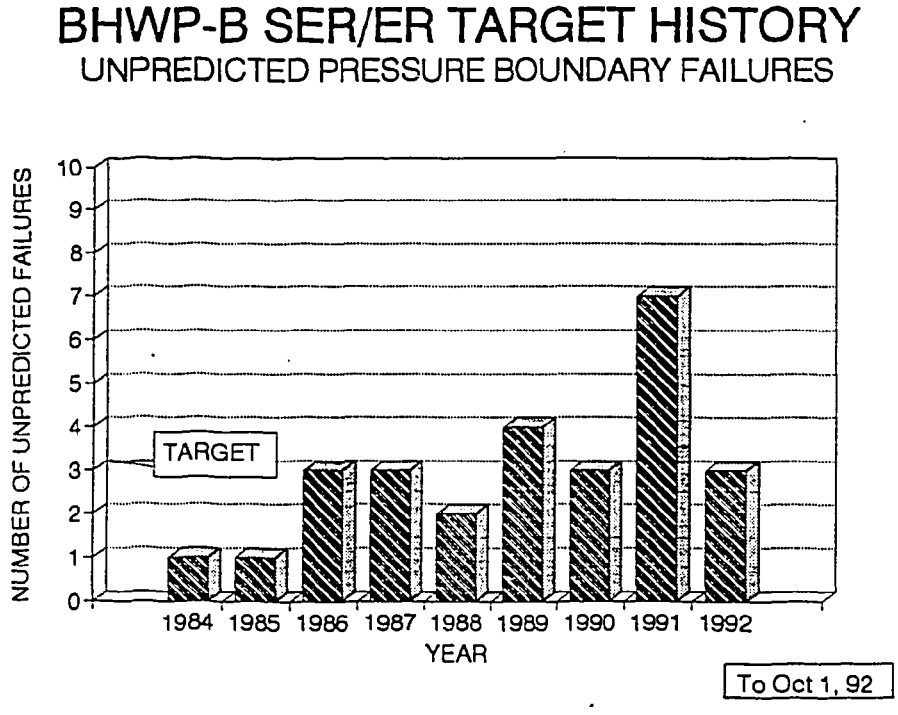


Figure 5



4. The M&I Unit's program has endured the scrutiny of numerous auditing bodies, without directives and in many cases with praise. The following are quotes from recent audits:

4.1 1988 Joint AECB/MCCR audit

"The audit covered a general overview of the quality control program and a dedicated examination of those elements controlling inspection and specific special processes. ... The audit findings indicate that the degree of implementation of those program elements audited was very good. It was evident that quality control personnel are qualified, capable and often exceed the minimum requirements of the Quality Control Manual."

4.2 1988 and 1992 Factory Mutual Insurance Audits

"Plant Management is interested in loss prevention. This was evident by an excellent inspection and maintenance program for all pressure vessels located in this plant... Excellent records of inspection and maintenance activities for all pressure vessels are maintained." (1992)

"Good operation, maintenance, testing including documentation reflects excellent management interest towards loss prevention." (1988)

4.3 1990 Ontario Hydro Peer Evaluation Report

The M&I Unit was identified as a strength at BHWP with the following comments:

"Maintenance and inspection of pressure boundary components is well controlled and documented....Welding packages and M&I Unit response in the field give effective support to welders....Inspections are carried out on schedule and are thoroughly and effectively performed."

5. BHWP is the only nuclear facility within Ontario Hydro with an exemption under Section 32(3) of the Boilers and Pressure Vessels Act of Ontario. This allows specified pressure boundary work to proceed at specified times without prior written concurrence of the Authorized Inspector representing the Ministry of Consumer and Commercial Relations (MCCR).

SUMMARY

Organization for ownership, and the five inspection programs have been described. As a result, M&I is aware of, and concerned about the condition of plant components and their safe operation. The experience, range of duties and responsibilities of the Technical Inspectors contribute to quality pressure boundary maintenance and an excellent loss prevention record at BHWP.
Two axioms, area ownership and involvement of the inspectors from conception to documentation of all inspections form the basis of the inspection organization.

APPENDIX 1

A Day in the Life of a BHWP Technical Inspector

8:00 An H_2S leak inspection has been scheduled with the Insulators. A leaking flange on a small diameter plug valve requires that the studs be assessed for corrosion. The inspection result is entered into the computer to schedule the next inspection.

8:30 Surveillance radiographs on heat exchanger J-drains are assessed for corrosion. The results are documented, and the next inspection date is recommended.

9:30 A call by the mechanical foreman is taken to witness a hydrotest on a field weld.

10:15 The daily communication meeting with the supervisor, other area inspectors and unit engineers is held. Plant status is provided, along with discussions about recent inspection results, safety concerns and administrative items. The inspectors outline what they intend to accomplish for the day.

10:30 A welding quality control directive sheet for a work package is prepared to replace a section of process drain piping.

There is question about the bill of materials provided with the package. It calls for the use of a schedule 160 elbow with a schedule 40 pipe, and the inspector is concerned about fit up. The inspector calls up the area engineer to discuss the alternatives and suggests the engineer specify a heavier wall pipe.

11:00 A flare knock-out drum requires thickness monitoring as part of a pressure vessel surveillance program. This inspection requires two inspectors in the unit as a buddy team.

12:30 A bulletin is written with the results of the thickness monitoring. At the same time the inspector discusses the results with the engineer to establish when the inspection should be rescheduled. The next inspection date becomes a recommendation on the bulletin.

1:00 Weekly H_2S leak checks; 15 leaking flanges in the unit are inspected to assess the condition of the studs. The inspectors visit the area planner's office after completion to inform him that one of the flanges is a category 'C' leak which requires 'A' priority scheduling for maintenance to replace 6 corroded studs.

The results of the flange leak inspections are entered into the computer to reschedule them.

3:00 A report on an internal inspection of a condensate drum in the area has come back from typing and must be reviewed for corrections.

3:15 A stainless steel weld-o-let on a sample station line being welded in the shop is ready for a dye penetrant inspection, as specified on a welding quality control directive sheet. The inspector responds to the mechanical foreman's request, performs the inspection and documents the acceptable result.

4:00 Two completed pressure boundary welding packages require review. The inspector reviews them, ensuring the quality control requirements were met and documented, then forwards the package for acceptance by the local government inspector.

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THE RELIABILITY CENTERED MAINTENANCE PROGRAM AT ONTARIO HYDRO'S BRUCE NUCLEAR GENERATING STATION 'A'

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ABSTRACT

This paper discusses the key factors which led us to pursue the use of Reliability Centered Maintenance (RCM) techniques for improvement of the Station Preventive Maintenance (PM) program. The paper also describes program development and changes to the Station PM program necessary to establish an Integrated PM program. Finally, the paper provides an overview of the benefits of the RCM evaluations on four pilot systems and full Station implementation of an Integrated PM (IPM) program. This work resulted in a coordinated and controlled PM program using RCM methods for defining and evaluating the PM activities.

INTRODUCTION

Since mid 1980's a number of nuclear power stations across the United States have conducted Reliability Centered Maintenance (RCM) studies. Some of these stations are now successfully using RCM methodology to optimize their Preventive Maintenance (PM) program.

The Electric Power Research Institute (EPRI) took the lead in performing initial Research and Development work in order to transfer this technology from the airline industry to the nuclear power industry.

Bruce N.G.S. 'A' started its PM improvement plan in August 1991. It began as a Pilot Project for the Nuclear Operations Branch (NOB) in order to evaluate RCM as a PM program optimizing technique. Specifically, at Bruce NGS "A", declining capacity factor and increasing backlog of maintenance activities had added to the keen interest in maintenance optimization technique such as RCM. RCM is viewed as a key element in holding maintenance costs down through development of an appropriate and cost-effective PM program.

Bruce NGS "A" had no prior RCM experience. We, therefore, selected a consultant, HALLIBURTON NUS Corporation, to help us in program development. Consultant selection was based on their ability to meet the following requirements:

1. 100% of work must be done on site
2. complete technology transfer to Ontario Hydro personnel must occur
3. EPRI RCM methodology must be used to develop/optimize PM program

Our PM improvement effort also coincided with EPRI's search for host utilities to beta test EPRI's new software for performing RCM analysis,"the RCM Workstation." EPRI offered Bruce NGS "A" an opportunity to use the RCM Workstation for system analyses. Station staff worked with EPRI in testing their software and suggested many enhancements that have been incorporated in the final release version of the code.

This paper explores the program development work and significant results achieved through RCM evaluations on four pilot systems. This work had two key components:

1. Development of Reliability Centered Maintenance program
2. Establishing and maintaining an Integrated Preventive Maintenance program

PROGRAM DEVELOPMENT

At Bruce N.G.S. 'A' we have developed and implemented a unique approach to Reliability Centered maintenance, which we feel is an improvement on current nuclear utility practice. Our review of US RCM experience indicated that implementation was the major problem area for successful use of RCM methodology. Many of the lessons learned from RCM implementation difficulties in the US utility industry and the ideas which promote implementation of RCM results have been incorporated as key elements of our approach. This is shown in Figure 1.

Our first step was to review and assess:

1. The current PM organization and responsibilities.
2. The state of our existing PM program
3. Our predictive maintenance capabilities

This assessment allowed us to identify shortfalls and their remedies, ie.

1. Areas where improvements can be made
2. How RCM analysis can be made a key element of the PM program
3. How implementation of RCM recommendations can be accomplished
4. How the overall PM program can be controlled and made a living program

Based on above, we established a procedural framework to make RCM and the PM Living program part of the Station Maintenance program. The objective was to ensure that mechanisms were in place beforehand to support RCM system evaluations and implementation of RCM based PM tasks. It is essential that complete implementation plan and strategy be in place before RCM analysis begins.

THE INTEGRATED PREVENTIVE MAINTENANCE PROGRAM

The poor state of our existing preventive maintenance practices and the need to ensure implementation of RCM recommendations resulted in developing the Integrated Preventive Maintenance (IPM) program and establishing a PM Engineering Group. The procedural framework is shown in Figure 2. The procedures which we developed before analysis began, describe completely how the program will function throughout the Station's life cycle. This is done by defining program strategy, staff roles and responsibilities, RCM methodology, current predictive maintenance capabilities and effectiveness monitoring, feedback and evaluation of PM program activities. The main elements of the IPM program are:

1. The PM Engineering Group defines controls and implements the Station PM program

2. Develop a PM program, system by system, using the RCM analysis technique
3. Integrate periodic and predictive maintenance activities and results
4. Maintain quality and keep the program current by continuous monitoring the effectiveness of the PM program

The PM Engineering organization is shown in Figure 3. The PM Engineering Group is a composite Work Group which includes engineers, senior mechanics, senior control technicians and an operator. The composite nature of the work group ensures that all aspects of the PM program are continuously monitored. It also ensures that smooth interfaces exist between various Station organizations. This group has the responsibility for RCM analysis, implementation and PM administration. The PM Engineering Group is also responsible for effectiveness monitoring, feedback and evaluation (EMFE) of PM activities. This is the key to maintaining a living PM program.

Figure 4 shows PM program improvement process that includes RCM evaluation, new revised PM task evaluations and long term PM program upgrading activities. This will force all PM tasks within the program to undergo constant review to ensure their appropriateness and effectiveness.

RCM EVALUATIONS

RCM evaluations were undertaken on four plant systems. We chose these systems to fully test RCM methodology on mechanical, electrical and control components, and components in standby and continuous operation. The systems include: D.C. Power; Main Moderator; Moderator Auxiliaries; and Moisture Separator/Reheat. The RCM evaluation process included the following technical steps:

1. Determine system boundaries
2. Identify important system functions and functional failures
3. Determine dominant failure modes of system components
4. Identify consequences of component failure and determine component criticality
5. Identify dominant causes of critical component failure modes
6. Assign appropriate and cost-effective PM tasks to address the causes of critical component failure modes
7. Reconcile RCM recommended tasks with current PM task activities to determine final PM task results for system components

We used the EPRI RCM Workstation to perform RCM analysis. The workstation allows the RCM evaluator to accomplish the system review and maintenance task selection activities with efficiency and technical consistency. The software makes maximum use of computerized maintenance-related data at the plant to reduce manual records review and to maintain consistency in evaluation results. Plant maintenance experts reviewed maintenance tasks that are part of the generic reference database in the RCM workstation. This was done to ensure that those tasks were acceptable to the plant staff.

Some streamlining techniques were used in order to determine their applicability as part of the RCM program. The techniques included using RCM experience to select components for RCM review while excluding others known to be insignificant with respect to failure consequences for the system of plant.

The following are some of the insights we obtained through review of the plant systems:

D.C. Power

1. Critical voltage indicator/alarm components had no preventive maintenance tasks assigned. Failure of these components could lead to Operator confusion or delayed Operator response.

2. RCM recommended tasks included thermographic analysis techniques on circuit breakers. This predictive maintenance technology was available on-site but not utilized on 250 VDC breakers.

3. Critical circuit breakers had no preventive maintenance tasks. Failure of these components could result in loss of control/monitor power for 4kV switchgear.

Main Moderator

1. Work history for the past seven years on main moderator pumps was used to help specify appropriate maintenance tasks emphasizing use of vibration analysis to address the causes of pump failures.

2. Assessment of failure consequences of system MOVs, AOVs and check valves showed that many of these components have critical failure modes; however, no PM tasks were in place. These components also experienced significant corrective maintenance in the recent past. New condition monitoring and preventive maintenance tasks were specified to address the causes of critical failure modes of these components.

3. For numerous components, duplicate and ineffective PM tasks were in place. These tasks were recommended for deletion after verification of consequences. More appropriate and cost-effective tasks were recommended to address the causes of critical failures.

Moderator Auxiliaries

1. A review of the CM history and the existing PM program showed: extensive CM history on cover gas compressors and diaphragm valves; limited PM on system components, including lack of routine instrument calibrations; and no use of predictive maintenance.

2. Routine instrument calibrations were recommended to avoid (corrective maintenance) calibration of instrumentation in response to plant problems. Failure in temperature instrument loops for heaters caused malfunctions in the past resulting in overheating and excessive moisture in helium cover gas. This in turn resulted in recurring compressor diaphragm failures due to water accumulation in the compressors or overheating.

3. AOV diagnostic/monitoring was recommended for all AOVs with critical failure modes. These AOVs had no PM tasks in place.

Moisture Separator/Reheat

1. No preventive maintenance was in place for system AOVs. Maintenance history showed problems with these valves and failure consequences identified then as "critical." Condition monitoring was recommended for all critical AOVs in the system.

2. Maintenance history showed fluctuations in reheater drain tank level that could lead to water carryover to the reheater. Routine tank level instrumentation calibrations were recommended.

3. MOVs controlling main steam supply to reheaters had little preventive maintenance in place. Condition monitoring was recommended for critical MOVs in the system.

IMPLEMENTATION

In order to ensure successful implementation of RCM recommendations, we developed a plan for implementation as part of the initial procedural framework. This is shown in Figure 5. The implementation plan was tested out even before completion of RCM analysis on four systems. This was done by performing technical evaluations of new open PM tasks waiting for verification and approval and implementing the results as per

plan shown in Figure 5. The evaluation was done using RCM principles (task based analysis). Figure 6 shows the results of these evaluations. This task is now an on-going activity.

These evaluations served the following purposes:

1. Tested out RCM analysis implementation approach
2. Built management and system engineering support for RCM by providing actual results and benefits
3. Familiarized Station staff with actual changes that will take place as a result of RCM analysis
4. RCM implementation team received on-the-job training

Figure 7 compares RCM recommended PM tasks with existing tasks for Moderator Auxiliaries System. Many revisions, deletions and additions took place to the existing PM program for the system.

BENEFITS OBTAINED

As noted, there are a number of benefits obtained as a result of the RCM evaluations. These benefits include:

1. Identifying causes of component failure and assigning appropriate PM tasks
2. Adding essential PM tasks where none previously existed
3. Adopting more cost-effective predictive tasks to avoid costly CM and component rebuilds
4. Eliminating duplicate and unnecessary PM tasks
5. Modifying existing PM tasks to ensure that they address the causes of component failures

We anticipate that some of the benefits of the RCM program related to maintenance effectiveness and system reliability/availability many not be fully realized until perhaps two years after completing the system studies.

Bruce NGS "A" can be expected to save approxmately 30 million dollars per year after plant-wide implementation of RCM. These savings represent roughly 9 million dollars in maintenance cost and 21 million dollars attributable to improved plant generating capability. These estimates are based on results of the four pilot system analysis using RCM, and historical data on maintenance preventable forced outages. The maintenance cost saving estimates take into consideration that appropriate and effective preventive maintenance tasks will reduce costly corrective maintenance work.

The RCM program also resulted in general benefits that will likely be of great significance over the life of the plant. These benefits include:

1. Establishing control over the PM program to maintain its integrity

2. Effectiveness monitoring, analysis and evaluation of PM activities as part of an overall integrated PM program to upgrade the PM program on continuous basis
3. Expanding the use of predictive maintenance techniques
4. Establishing technical basis for PM tasks

An important control put into place is a mechanism for regulating the growth of new PM tasks. This control ensures that PM tasks developed outside of PM Engineering Group get evaluated using RCM principles. This ensures consistency and that duplicate and ineffective PM tasks are not allowed into the RCM-enhanced PM program.

SUMMARY AND CONCLUSIONS

Bruce N.G.S. 'A' has successfully completed a pilot RCM program development. The major accomplishments are:

1. Development and establishment of an integrated PM program with RCM as a key strategic element to optimize PM activities
2. Station management has agreed to pursue full plant implementation of RCM
3. A new group, PM Engineering, has been establish within the maintenance department to define, implement and control the PM program
4. System engineering, operations and other key Station organizations provide support to RCM implementation in the form of resources for system evaluation and review of technical results
5. RCM recommended PM activities on four pilot systems have been implemented
6. Our regulator, The Atomic Energy Control Board of Canada, views RCM implementation at Bruce NGS "A" as a positive step toward effective PM program management (reference 3)

As the RCM program at Bruce NGS "A" continues to evolve and mature, the Station will begin to see additional long term benefits. Such as, actual dollar savings in maintenance costs and improvements in plant reliability and availability. This will also result in improvements to the program necessary to respond to the ever-changing needs of the maintenance program.

The RCM program developed at Bruce NGS "A" can be applied to Ontario Hydro's other nuclear power stations with some changes to suit to their unique requirements. Our sister station Bruce NGS "B" has already started a PM improvement program based on this methodology.

References:

(1) KHAN IU, SCHWAN C, FERGUSON BJ, GEORGE TC, "Reliability Centered Maintenance (RCM) Program Development at Ontario Hydro's Bruce Nuclear Generating Station "A", Inter-RAM Conference August 1992, Philadelphia PA.

(2) KHAN IU, FERGUSON BJ, "Reliability Centered Maintenance Implementation at Bruce Nuclear Generating Station "A", ERUG Meeting June 1992, Philadelphia PA.

(3) ATOMIC ENERGY CONTROL BOARD, AECB Staff Review of Bruce NGS "A" Operation for 1991, April 1992.

OVERALL PROGRAM DEVELOPMENT APPROACH

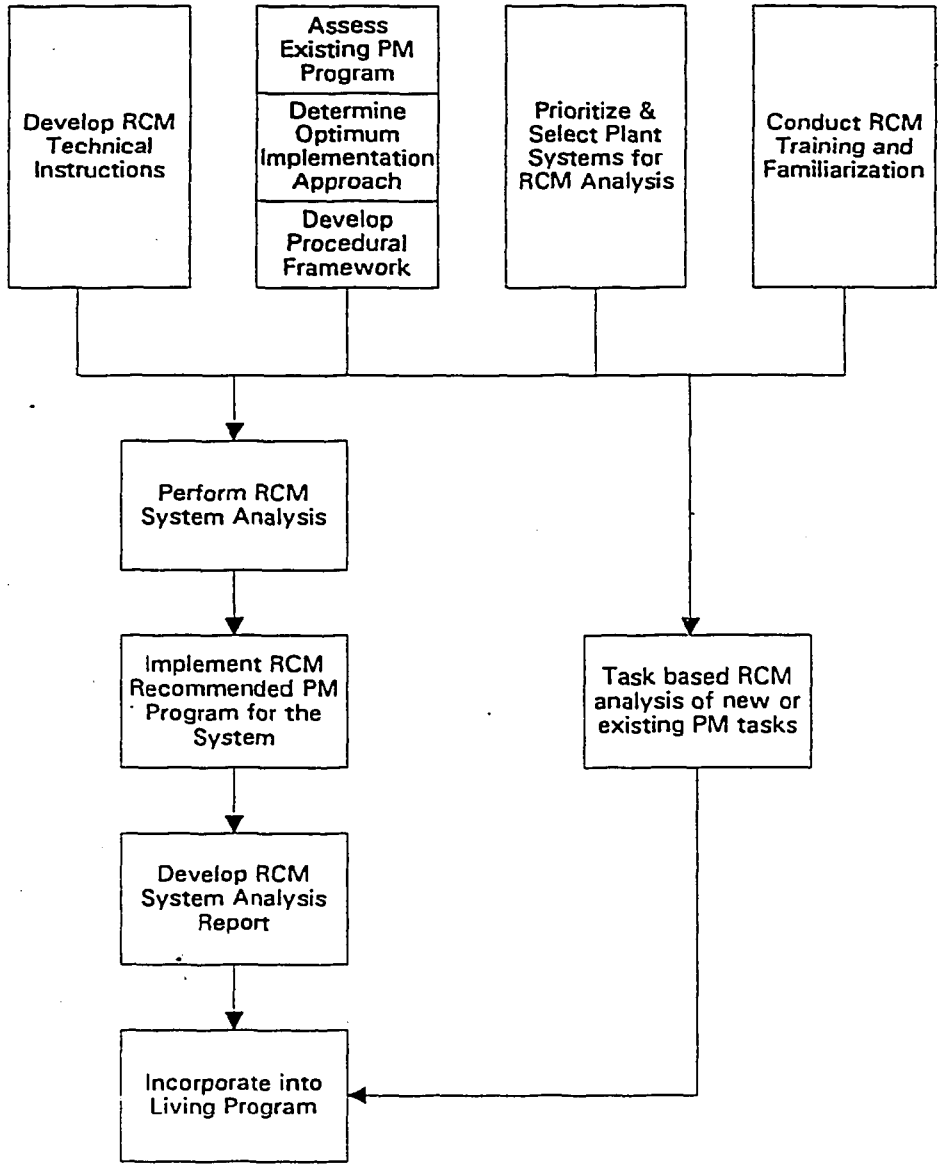


Figure 1

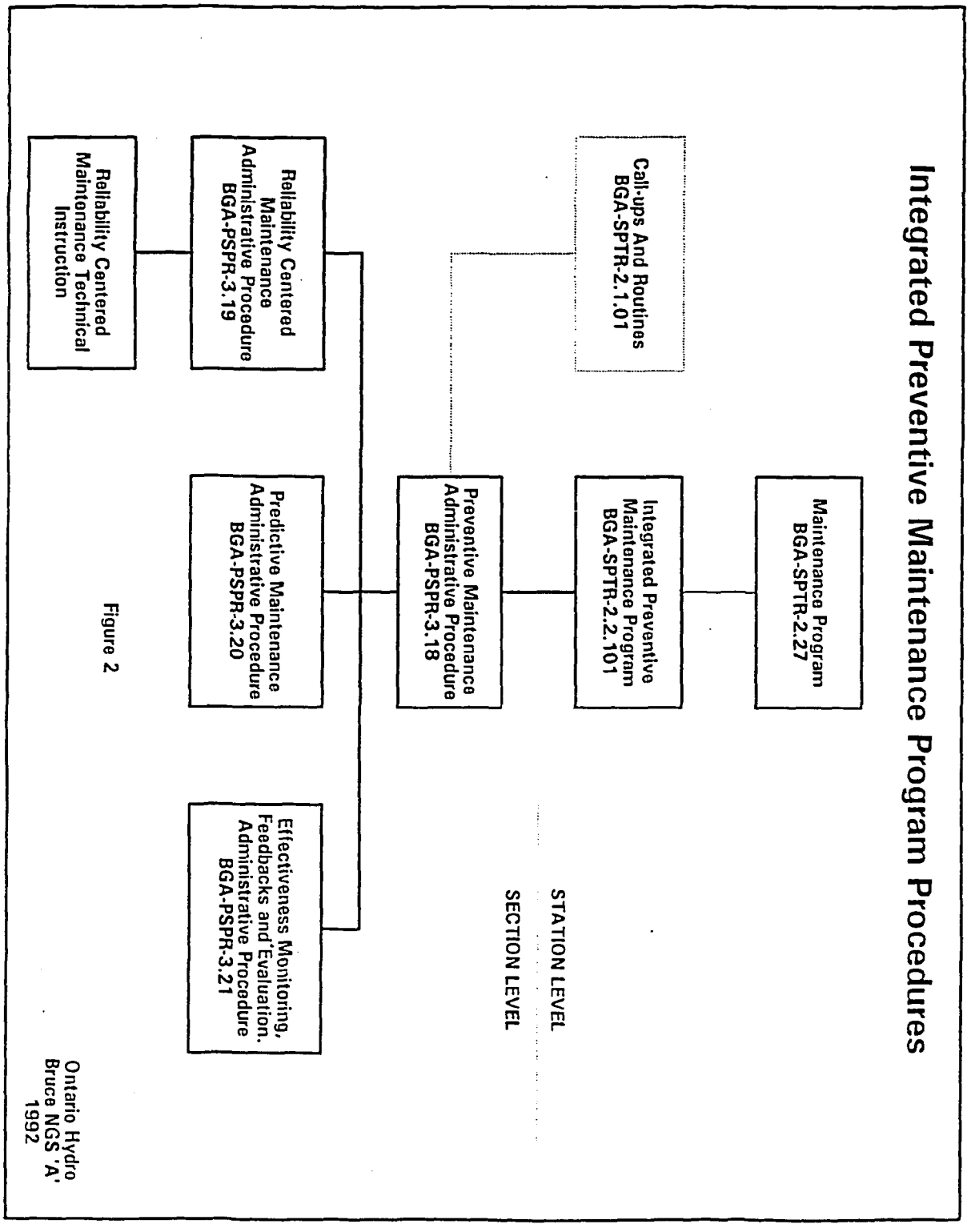

Integrated Preventive Maintenance Program Procedures
Maintenance Program BGA-SPTR-2.27
Integrated Preventive Maintenance Program BGA-SPTR-2.2.101
Call-ups And Routines BGA-SPTR-2.1.01
Preventive Maintenance Administrative Procedure BGA-PSPR-3.18
Predictive Maintenance Administrative Procedure BGA-PSPR-3.20
Effectiveness Monitoring, Feedbacks and Evaluation, Administrative Procedure BGA-PSPR-3.21
Reliability Centered Maintenance Administrative Procedure BGA-PSPR-3.19
Reliability Centered Maintenance Technical Instruction
STATION LEVEL
SECTION LEVEL
Ontario Hydro
Bruce NGS 'A'
1992

Figure 2

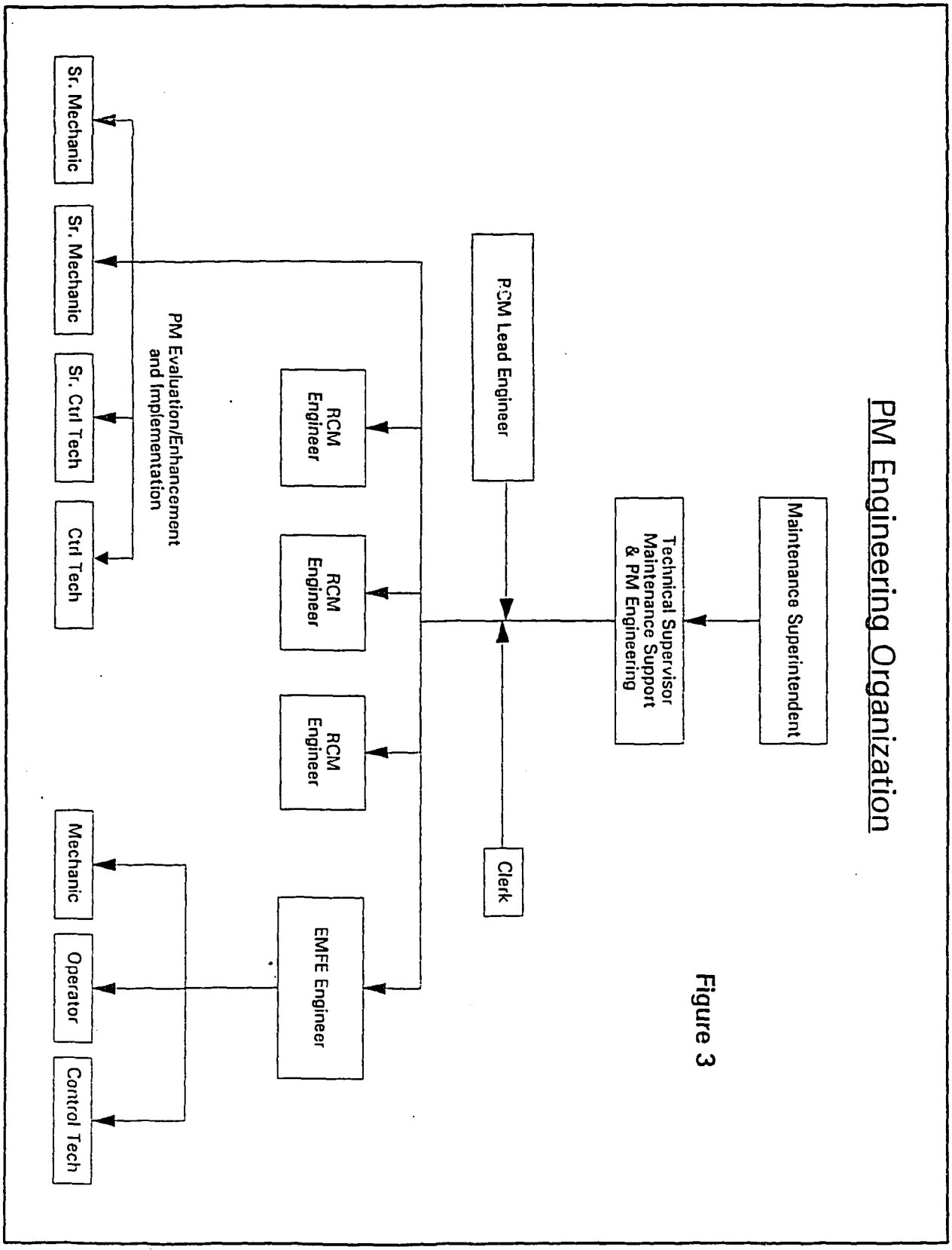

PM Engineering Organization
Maintenance Superintendent
Technical Supervisor Maintenance Support & PM Engineering
RCM Lead Engineer
Clerk
RCM Engineer
RCM Engineer
RCM Engineer
EMFE Engineer
Mechanic
Operator
Control Tech
PM Evaluation/Enhancement and Implementation
Sr. Mechanic
Sr. Mechanic
Sr. Ctrl Tech
Ctrl Tech

Figure 3

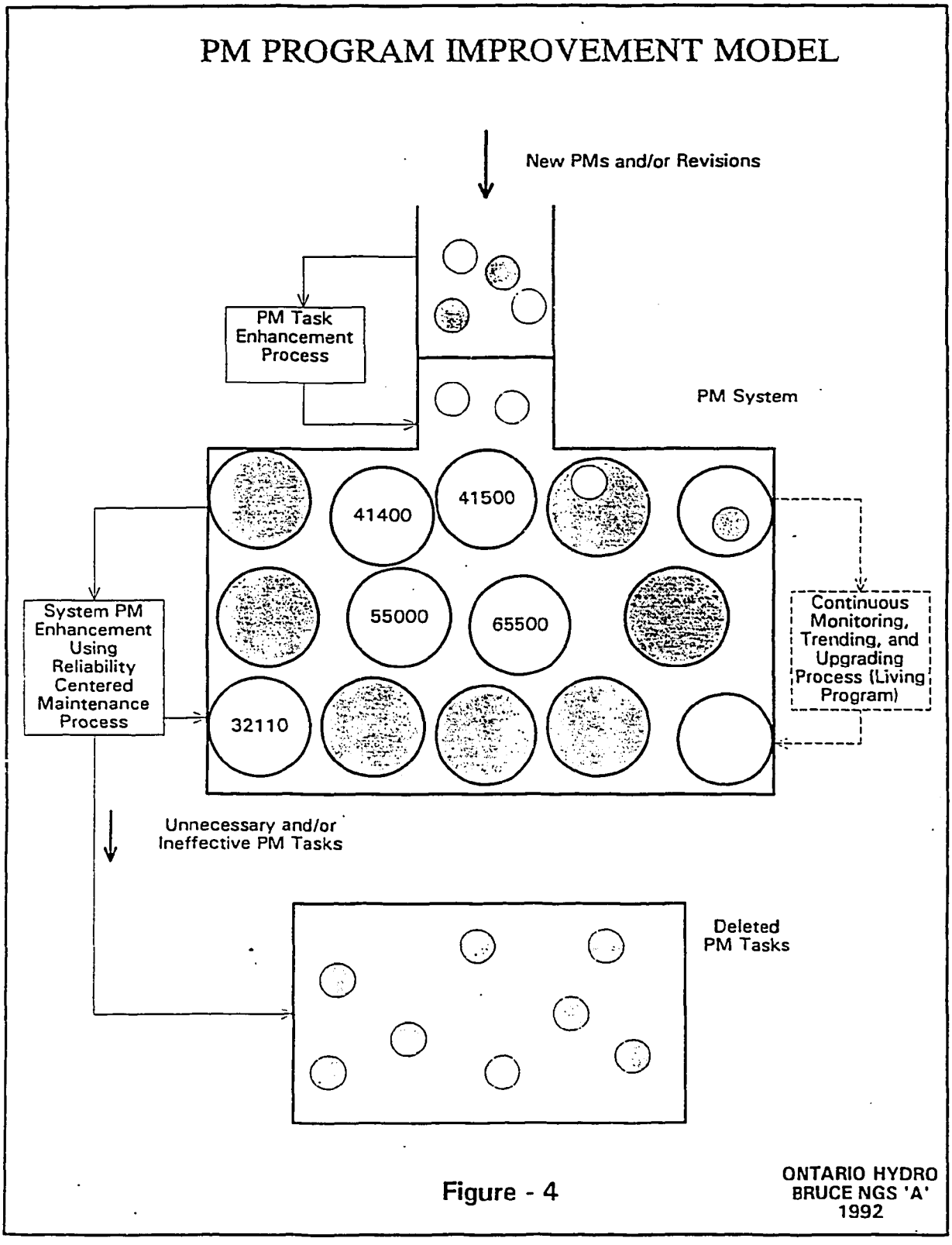
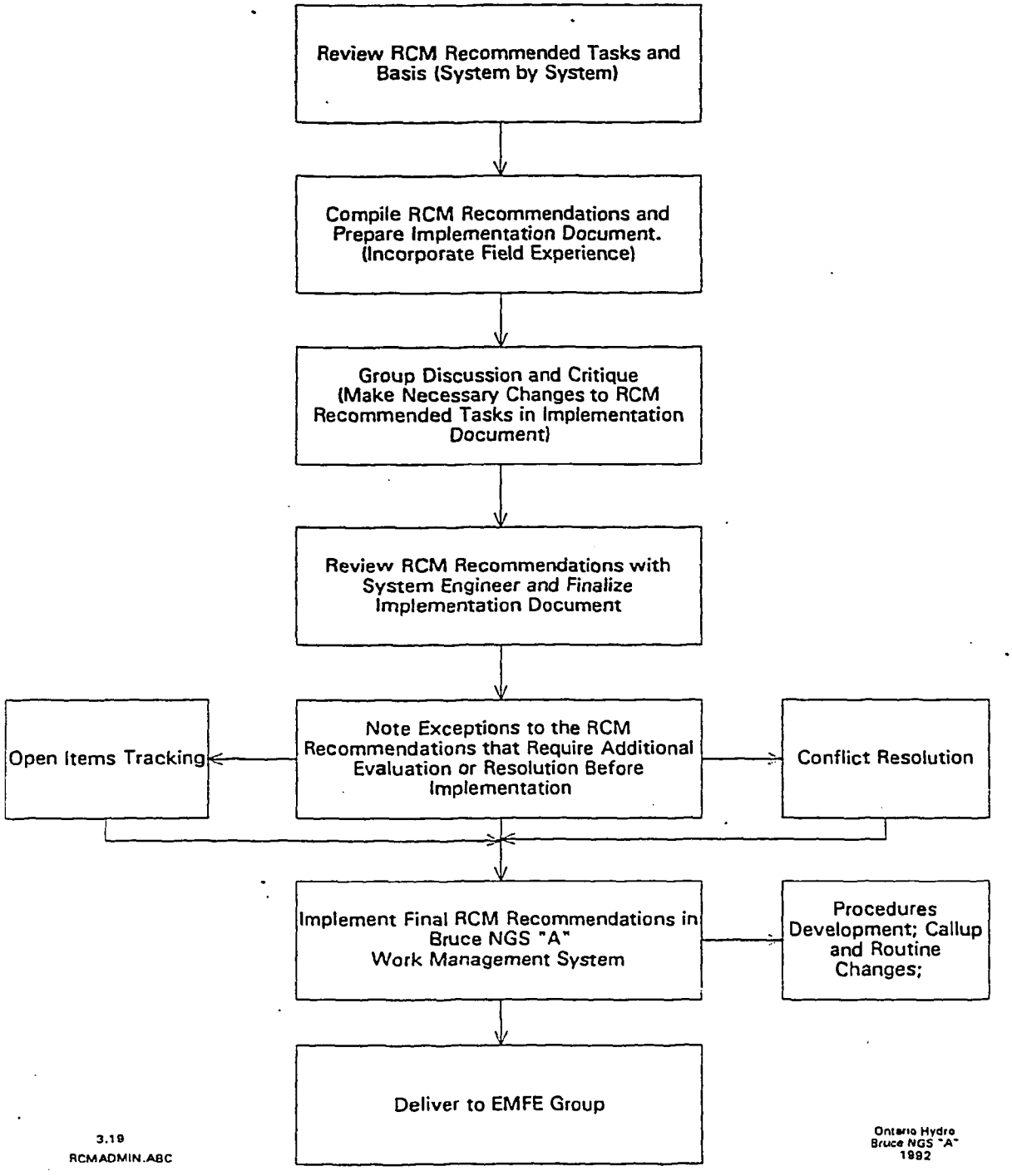

PM PROGRAM IMPROVEMENT MODEL
New PMs and/or Revisions
PM Task Enhancement Process
PM System
41400
41500
55000
65500
32110
System PM Enhancement Using Reliability Centered Maintenance Process
Continuous Monitoring, Trending, and Upgrading Process (Living Program)
Unnecessary and/or Ineffective PM Tasks
Deleted PM Tasks
ONTARIO HYDRO
BRUCE NGS 'A'
1992

Figure - 4

Figure - 5

Implementation Plan



CALL-UP EVALUATION/ENHANCEMENT

(Year to Date, 1992)

	NUMBER OF CALL-UPS REVIEWED	NUMBER OF CALL-UPS DELETED	NUMBER OF CALL-UPS ENCHANCED	MAN HOURS SAVED/YR	MATERIALS $ SAVED PER YEAR
MECHANICAL MAINTENANCE	579	230	349	1564	2892
CONTROL MAINTENANCE	107	9	98	423	0
TOTAL	686	239	447	1987	2892

Figure - 6

Figure - 7

SUMMARY OF PRELIMARY RCM ANALYSIS RESULTS MODERATOR AUXILIARIES SYSTEM

	EXISTING	RETAIN AS IS	REVISION	NEW ADDITION	DELETION	MANHOURS	
						PRE	POST
MECHANICAL	20	-	8	7	12	226	224
CONTROL	6	-	5	13	1	34	79
OPERATOR	8	8	-	3	-	8	46
Total	34	8	13	23	13	268	349

ONTARIO HYDRO
BRUCE NGS 'A'

CA9500177

Canadian Nuclear Society

Second International Conference on CANDU Maintenance

November 22-24, 1992 Toronto, Canada

AIR OPERATED VALVE DIAGNOSTICS
"AN INTEGRAL PART OF AN INTEGRATED PREVENTIVE MAINTENANCE PROGRAM"

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ABSTRACT

This paper outlines the evolution of the Integrated Preventive Maintenance Program from the Reliability Centered Maintenance pilot program at Bruce Nuclear Generating Station 'A' (Bruce N.G.S.'A'). The Integrated Preventive Maintenance Program provides the means for taking control of the Bruce N.G.S.'A' Preventive Maintenance Program.

In addition, the development of the Bruce N.G.S.'A' Air-Operated Valve Preventive Maintenance is reviewed.

1.0 INTRODUCTION

Until the late 1980's performance of Ontario Hydro's nuclear units met or exceeded our standards and compared favourably with world standards. Since that time we have seen a gradual increase in our average nuclear incapability factor, as illustrated by Figure 1, a plot of average nuclear incapability factor versus year for all of our nuclear units.

In response Ontario Hydro has developed a Maintenance Strategy to improve the conduct of maintenance at all of it's nuclear facilities. The strategy focuses our improvement efforts in four main areas:

- resource management,
- human performance,
- outage management, and
- equipment performance.

Bruce Nuclear Generating Station 'A' has taken the lead in equipment performance improvement for the Corporation by developing and implementing a Preventive Maintenance Optimization Program. This program has two components:

1. Reliability Centered Maintenance (RCM) analysis, and
2. establishment of the Integrated Preventive Maintenance Program (IPMP).

Together they will provide effective control over our existing Preventive Maintenance (PM) program.

This paper will describe the Integrated Preventive Maintenance Program and the development of an Air-Operated Valve (AOV) Preventive Maintenance Program within the IPMP.

2.0 INTEGRATED PREVENTIVE MAINTENANCE PROGRAM

Improving equipment performance requires us to move away from performing "breakdown" or corrective maintenance and to focus more maintenance effort on preventive maintenance, where we can detect degrading performance and repair or replace critical components before failure occurs.

The state of Preventive Maintenance in our plant (and I suspect many others), prior to this program, can be described diagrammatically by Figure 2, i.e. the PM program is inconsistent, lacks a technical basis, and many PM tasks are neither applicable nor effective.

The PM improvement plan began as a pilot to evaluate the use of Reliability Centered Maintenance (RCM) as a PM program optimization methodology for four station systems (main moderator, moderator auxiliaries, DC power, and moisture separation/reheat). All analysis was carried out using the EPRI "RCM Work Station". This software was made available to Ontario Hydro as a "Beta" test version and is now in general release to EPRI members.

A short time after the project started, it became apparent to us that RCM analysis alone was not going to accomplish the desired PM program optimization because we did not have proper control of our existing PM program as illustrated in Figure 2. Consequently, it was necessary for us to develop the concept of the Integrated PM Program in order to provide a framework within which PM program improvement could occur. This integrated approach was necessary to ensure successful implementation of RCM analysis and to maintain the program over the life of the Station.

The IPMP has two components:

1. A procedural framework as shown in Figure 3, and
2. The PM Engineering Organization as illustrated in Figure 4.

The five procedures completely describe how the program will operate throughout the Station's life cycle by defining program strategy, staff roles and responsibilities, RCM methodology, current plant predictive maintenance capabilities and feedback and trending of PM program activities.

The PM Engineering Organization establishes single point responsibility for the total PM program. This group has responsibility for RCM analysis, PM task administration and feedback, trending and analysis of equipment performance. Performance trending is the key to maintaining a "living" PM program.

Figure 4 shows the total resource requirements for plant wide implementation of the Integrated Preventive Maintenance Program. The net result of the IPMP will be an improved PM program with the three enhancement recirculation loops as shown in Figure 5 (the Khan model). This will force all PM tasks within the program to undergo constant review to ensure their applicability and effectiveness. The pilot phase of the IPMP (i.e., analysis and implementation of the four previously noted systems) is now complete. Full plant implementation will be completed by the end of 1994.

3.0 AIR OPERATED VALVE PREVENTIVE MAINTENANCE PROGRAM

3.1 Introduction

Traditionally, Air-Operated Valves (AOV) have received little attention by our maintenance staff. Valve maintenance has been predominantly corrective and calibration/setup of AOVs has been looked upon as an art, not a science.

Recent developments in diagnostic analysis of AOV performance by at least three vendors (Fisher Controls, ABB Combustion Engineering, and ITI MOVATS) have been able to provide us with a new diagnostic technique for determining the condition of Air-Operated Valves. An AOV PM program based on the use of AOV diagnostics is now being

incorporated into the Bruce N.G.S.'A' Integrated Preventive Maintenance Program. The AOV PM program has been in evolution for approximately two years. A previous paper (3) describes our early experience with AOV diagnostics.

3.2 Diagnostic System

The diagnostic system in use at Bruce N.G.S.'A' measures a number of characteristic parameters (or signature) of an AOV's response to an instrument input signal during a full stroke cycle of the valve. The parameters include valve stem travel, instrument air pressure to the positioner, supply air pressure, and actuator air pressure. It can indicate:

- bench set and actuator spring rate,
- valve stroke length and friction,
- condition of bearing and guide surfaces,
- valve stroke time,
- seat load and seat condition,
- stem nut adjustment,
- air supply pressure,
- positioner calibration, linearity and hysteresis, and
- I/P calibration, linearity and hysteresis.

Figure 6 shows a typical signature that the diagnostic system records for an AOV. Assessment of valve condition requires both analysis of the signature trace and software generated parameters such as stroke length, valve friction, seat load, etc. Comparison of subsequent diagnostic signatures with the initial (or baseline) signature valve condition permits trending of valve performance and condition.

3.3 Full Program Evolution

The AOV diagnostic pilot program (3), mentioned previously, examined a population of about 50 valve/actuator combinations (valves - Posiseal, Fisher, Masoneilan, Rockwell, Hattersly-Newman-Hender; actuators - Bettis, Masoneilan, and Fisher) and successfully demonstrated that:

1. AOV diagnostics can non-intrusively assess condition of a complete valve/actuator assembly and as a consequence is a useful predictive maintenance tool.
2. AOV diagnostic equipment can dynamically calibrate and setup AOVs.
3. Station maintenance staff can quickly develop skills in AOV diagnostic analysis.

As a result of these positive findings we proceeded with development of an Air-Operated Valve Preventive Maintenance Program.

Three key elements of the program are as follows:

1. Organization,
2. Valve priority ranking, and
3. Preventive and corrective maintenance work flow.

3.3.1 Organization

A full time "Valve Diagnostic Team" has been dedicated to this program. It's structure is shown in Figure 7. This team is responsible for both the AOV and MOV PM programs and is a specialist "Day Only" crew composed of both control (electrical/I&C) and mechanical maintainers. Their duties include:

1. Collection, interpretation and storage of valve signature data.
2. Repair, calibration and setup of valves in the program.

Program management and engineering support is provided by the PM Engineering Unit and Technical Section.

3.3.2 PM Priorities

Currently there are approximately 60 valves (per unit) in the PM program. They have been selected by the following criteria:

1. Valves inside reactor building,
2. Problem valves identified by operators or engineering, and
3. Valves identified by RCM analysis.

Priority ranking of valves within the program will be provided by RCM analysis.

Inspection frequency has been set at once per year. However, as RCM analysis proceeds and trend data accumulates, frequencies will be refined to reflect failure history and service conditions.

3.3.3 Preventive and Corrective Maintenance Work Flow

The flow of AOV diagnostics and repair work within the maintenance department is described by a flowchart in Figure 8. It addresses two paths:

1. Corrective, and
2. Preventive maintenance (or call-ups).

In the case of corrective maintenance it is important to note that:

- AOV deficiencies can be initiated by maintenance or operations staff.
- AOV work is usually assigned to the Valve Diagnostic Crew but in the case of emergency Duty Shift maintenance personnel can perform troubleshooting and repairs. However, an "as left" signature of the valve must be taken by the Valve Diagnostic Team.

All preventive maintenance is performed by the Valve Diagnostic Team. This includes performing "as found" and "as left" diagnostics, repair and calibration for each valve.

3.4 Results

To date, a population of about 100 valves has been tested (Bruce N.G.S.'A' has approximately 400 AOVs per unit). Figure 9 is a plot of % occurrence versus fault type found with the valve population tested using the diagnostic equipment. The bar chart shows both initial and follow up calibration results. The follow up calibration represents the second diagnostic visit to the valve population and indicates a trend to improved valve performance except in the case of the I/P transducers where we have seen an increase in faults primarily due to "zero drift" problems.

It must be stressed that the deficiencies listed are of varying degrees. Not all require immediate action of repair.

Three specific examples of valve signatures where valve performance deficiencies have been identified are as follows:

1. Bleed and Relief Circuit
   CV 22 and 23 are identical valves in over pressure relief service on the Unit 1 Primary Heat Transport Pressurizer. Figure 10 (actuator pressure vs stem travel) shows the effect of a loose stem inside the split coupling. Figure 11 (stem travel vs I/P output pressure) illustrates a positioner fault. Subsequent inspection showed that the signal bellows/beam was loose.
2. Auxiliary Boiler Feedwater System
   FCV 2 is an auxiliary boiler feed pump recirculation valve. Operators reported flow problems but the valve appeared to be functioning properly. In Figure 12 (actuator pressure vs stem travel) the peaks after opening and before seating are indicative of a plug/stem separation.

4.0 CONCLUSIONS

Development and implementation of the Integrated Preventive Maintenance Program has enabled us to begin to take control or our Preventive Maintenance Program at Bruce N.G.S.'A' and with the use of RCM analysis we have begun to develop a technical basis for all PM tasks. Full implementation is expected to have a major positive impact on safe, reliable, cost effective operation of Bruce N.G.S.'A'.

We have also developed and implemented an AOV preventive maintenance program based on the successful results of the Bruce N.G.S.'A' AOV diagnostic pilot program.

REFERENCES

1. Fisher Controls, "Automated Trouble Shooting of Pneumatically Operated Control Valves"
2. Walker, I., 1991, "Ontario Hydro's Nuclear Maintenance Strategy", American Nuclear Society - 15th Biennial Reactor Operations Topical Meeting, Bellevue, WA
3. Ferguson, B.J., and Cooper, D., 1991, "Air Operated Valve Diagnostics", EPRI - Fluid Systems Testing and Analysis Forum, Philadelphia, PA

Nuclear Incapability Factor (ICbF%)
(Does not include retubing)

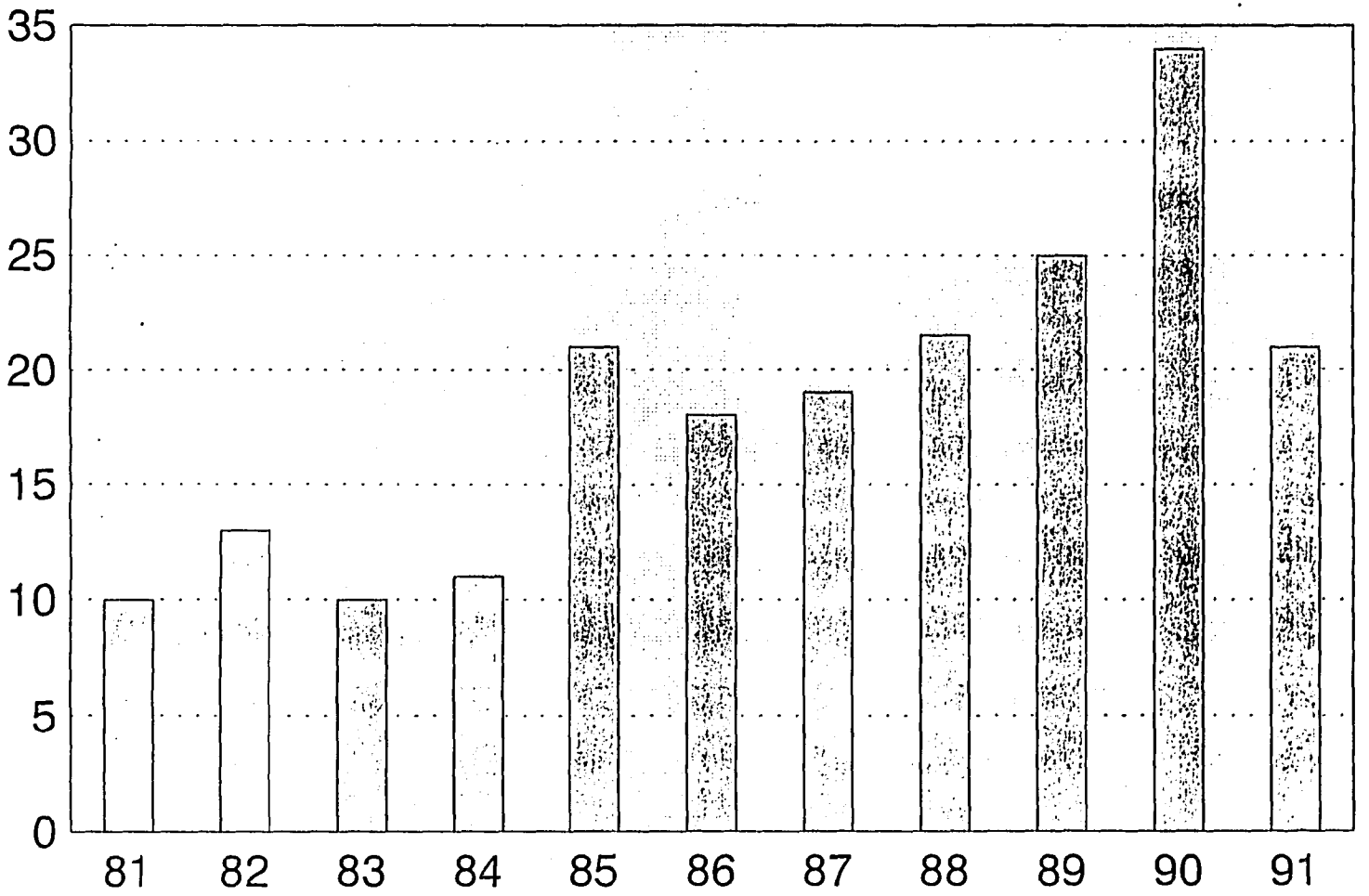
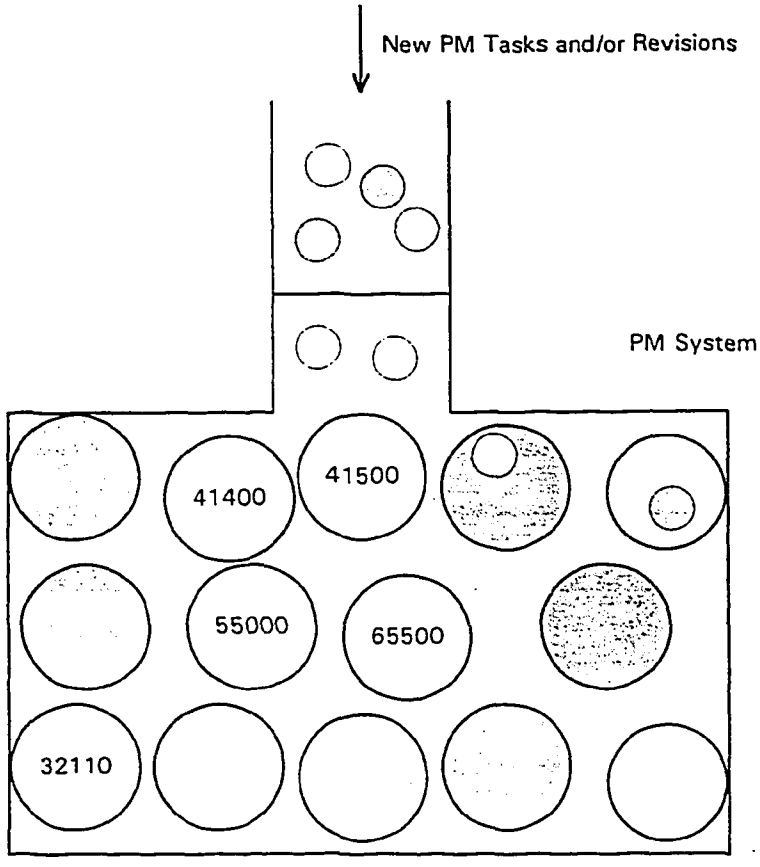


Figure 1.

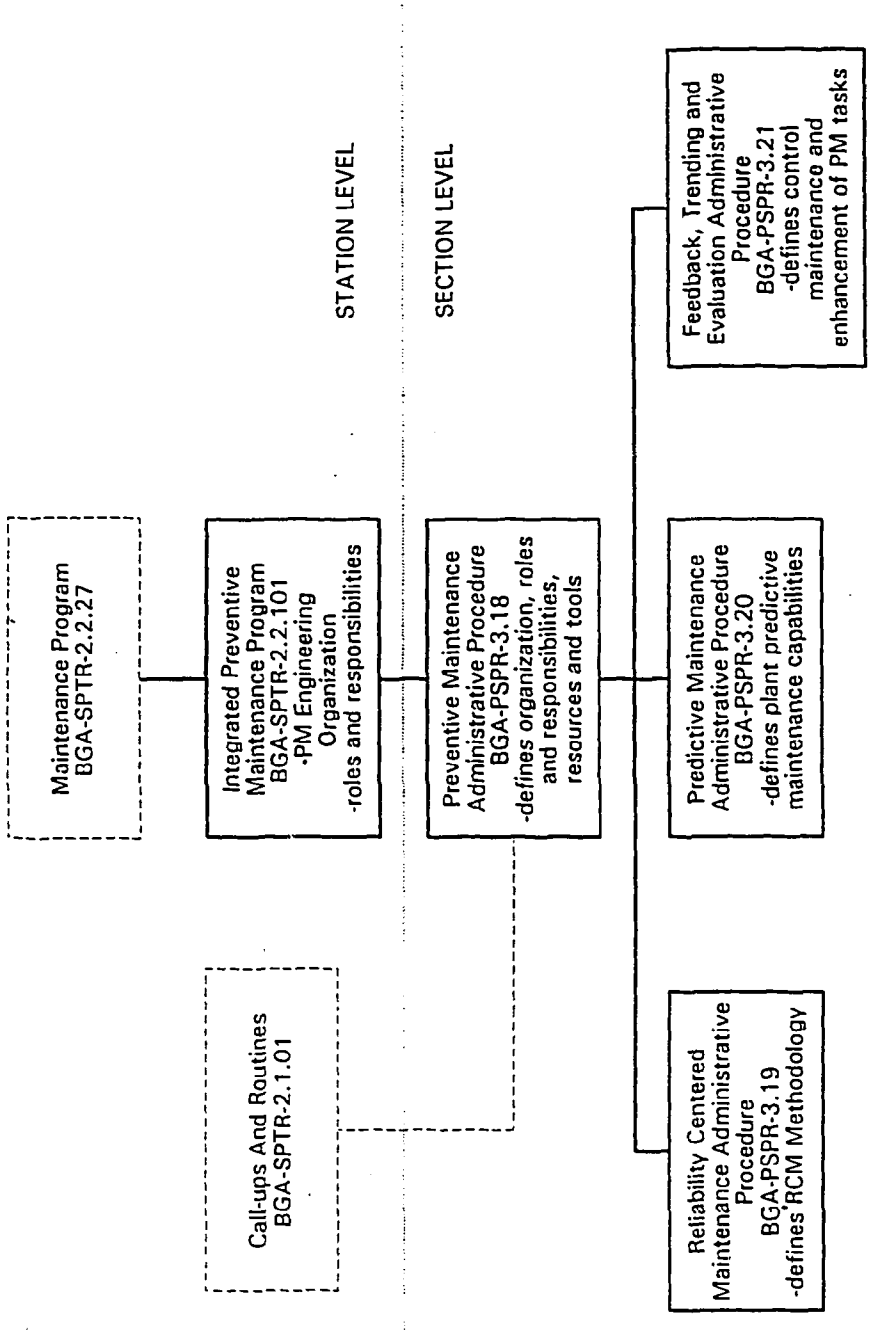
Figure 2

CURRENT STATE OF PM PROGRAM



- inconsistant
- no technical basis
- boundary fixed by O & M Budget
- some tasks neither applicable nor effective

Figure 3: Integrated Preventive Maintenance Program Procedure Heirarchy



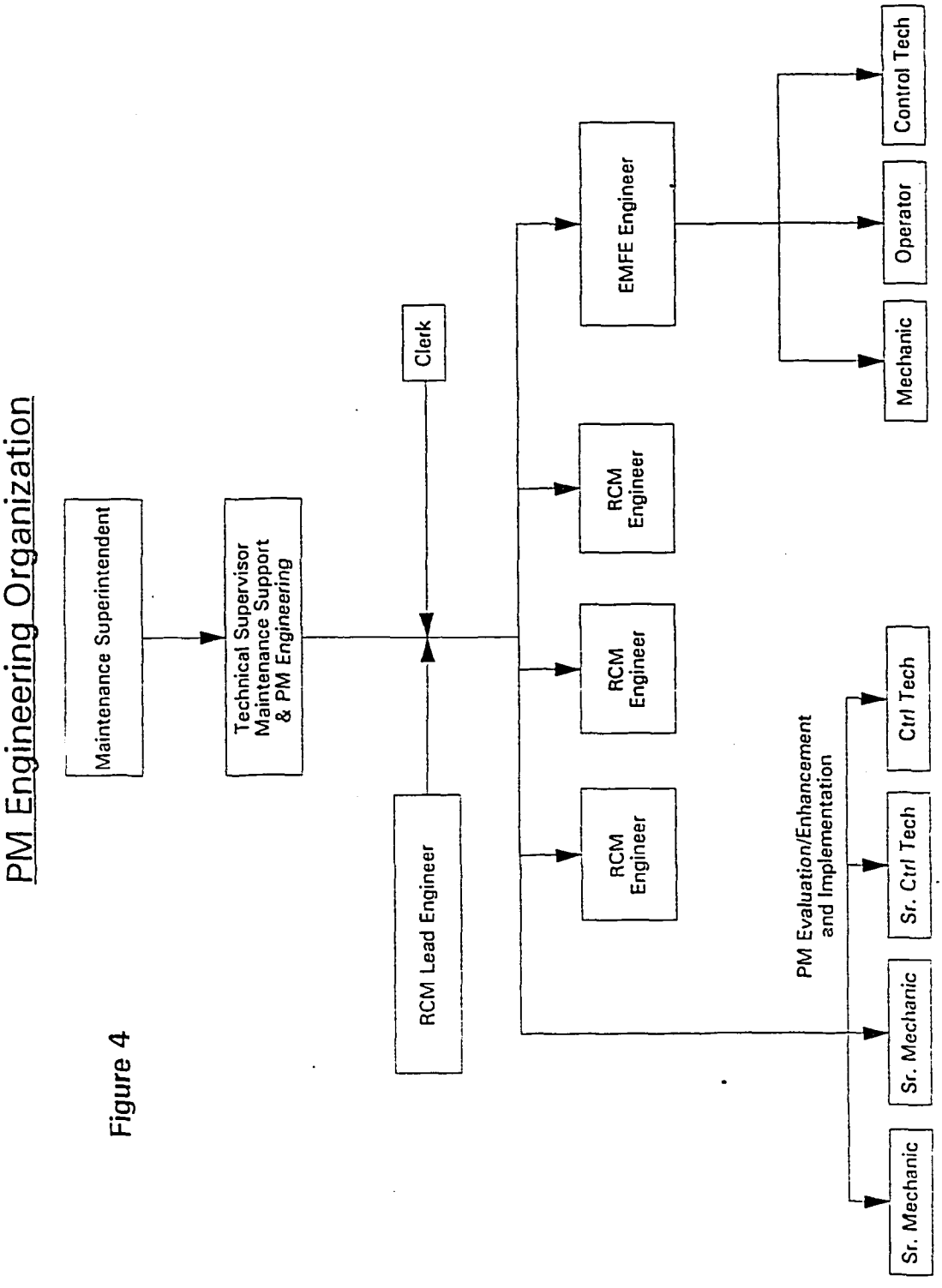
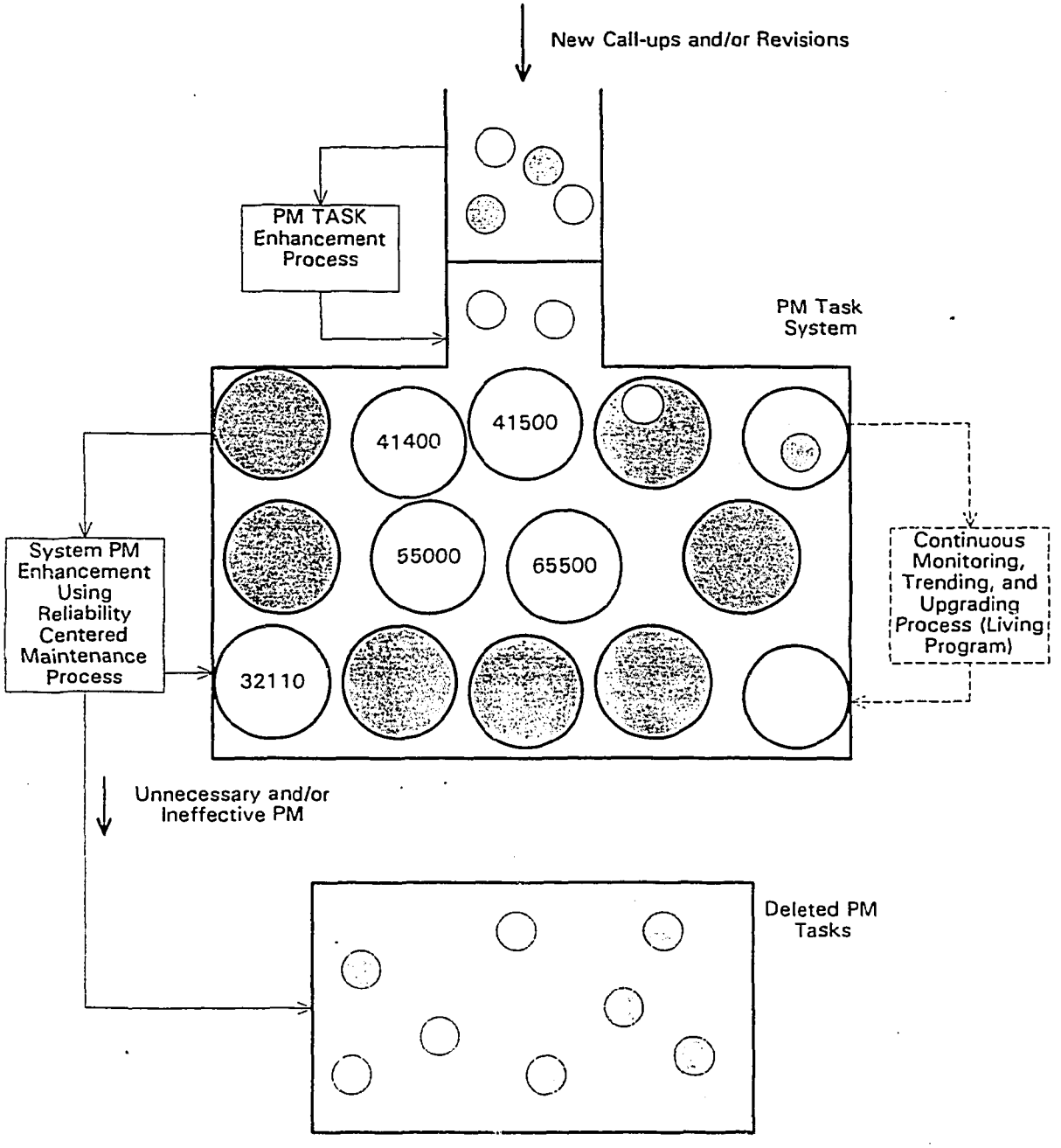

PM Engineering Organization
Maintenance Superintendent
Technical Supervisor Maintenance Support & PM Engineering
Clerk
RCM Lead Engineer
RCM Engineer
RCM Engineer
RCM Engineer
EMFE Engineer
Control Tech
Operator
Mechanic
PM Evaluation/Enhancement and Implementation
Ctrl Tech
Sr. Ctrl Tech
Sr. Mechanic
Sr. Mechanic

Figure 4

Figure 5

KHAN MODEL FOR PM PROGRAM IMPROVEMENT



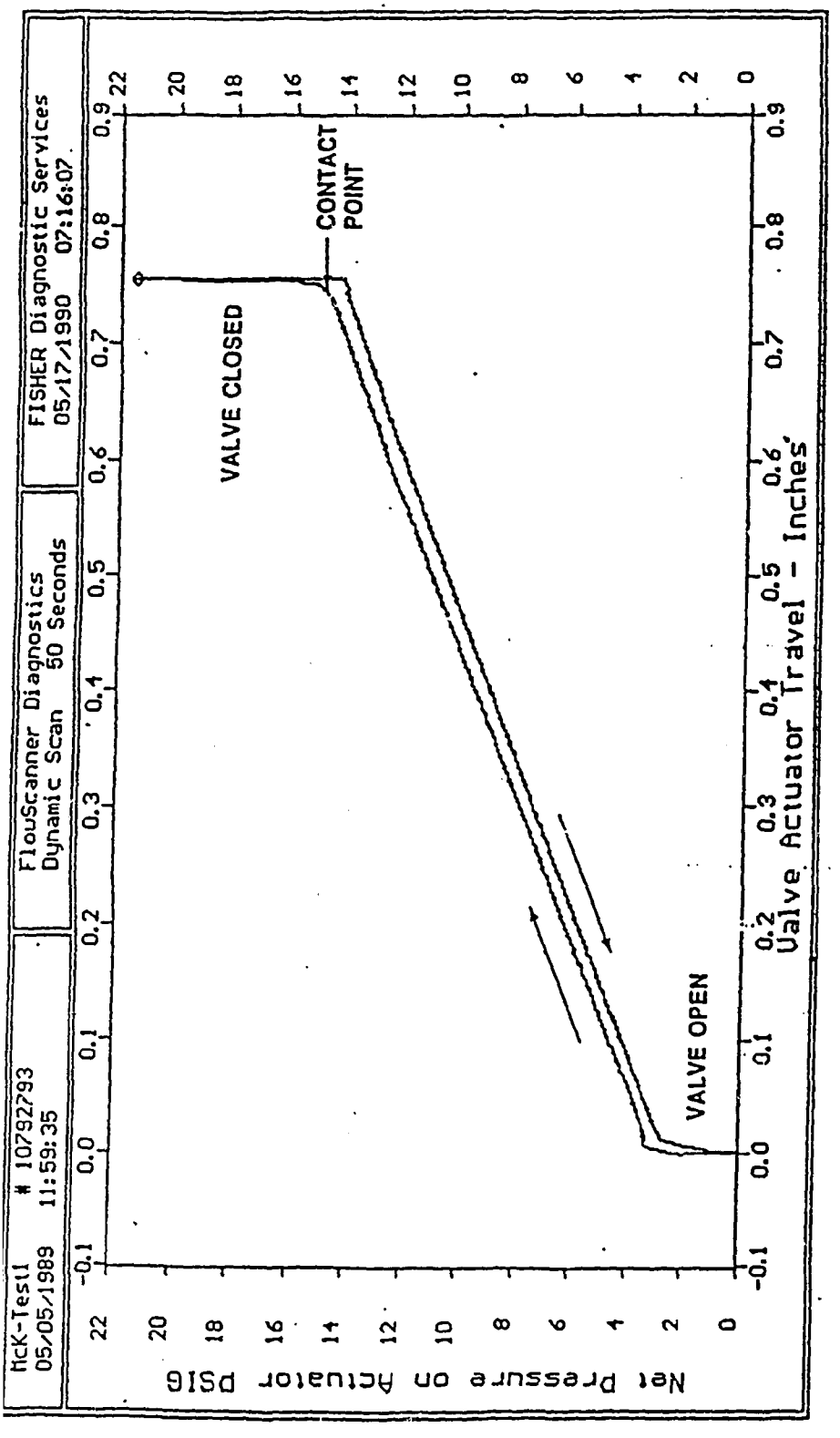

McK-Test1 # 10792793
05/05/1989 11:59:35
FlowScanner Diagnostics
Dynamic Scan 50 Seconds
FISHER Diagnostic Services
05/17/1990 07:16:07
Net Pressure on Actuator PSIG
Valve Actuator Travel - Inches
VALVE CLOSED
CONTACT POINT
VALVE OPEN

Figure 6

VALVE DIAGNOSTIC TEAM ORGANIZATION

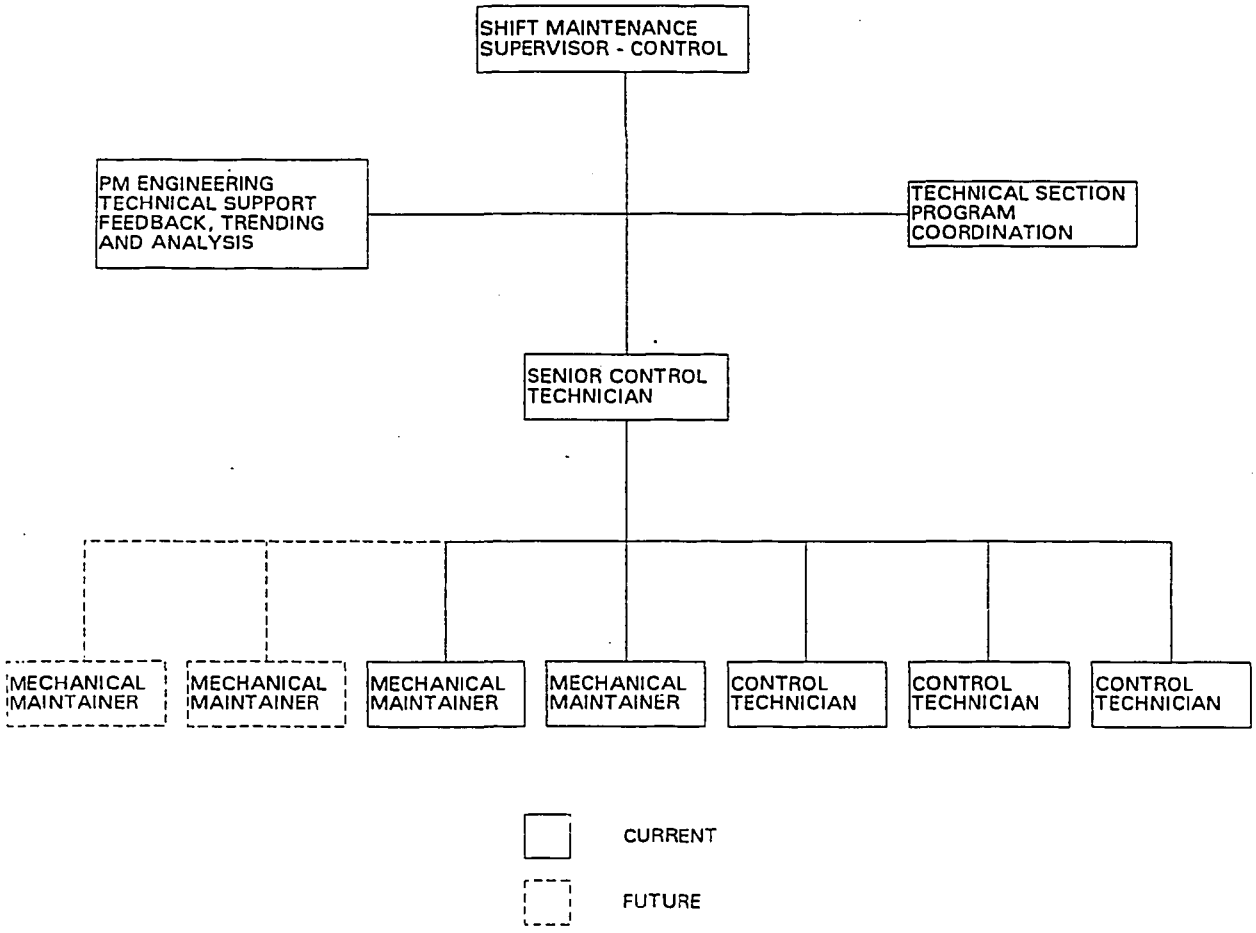


Figure 7

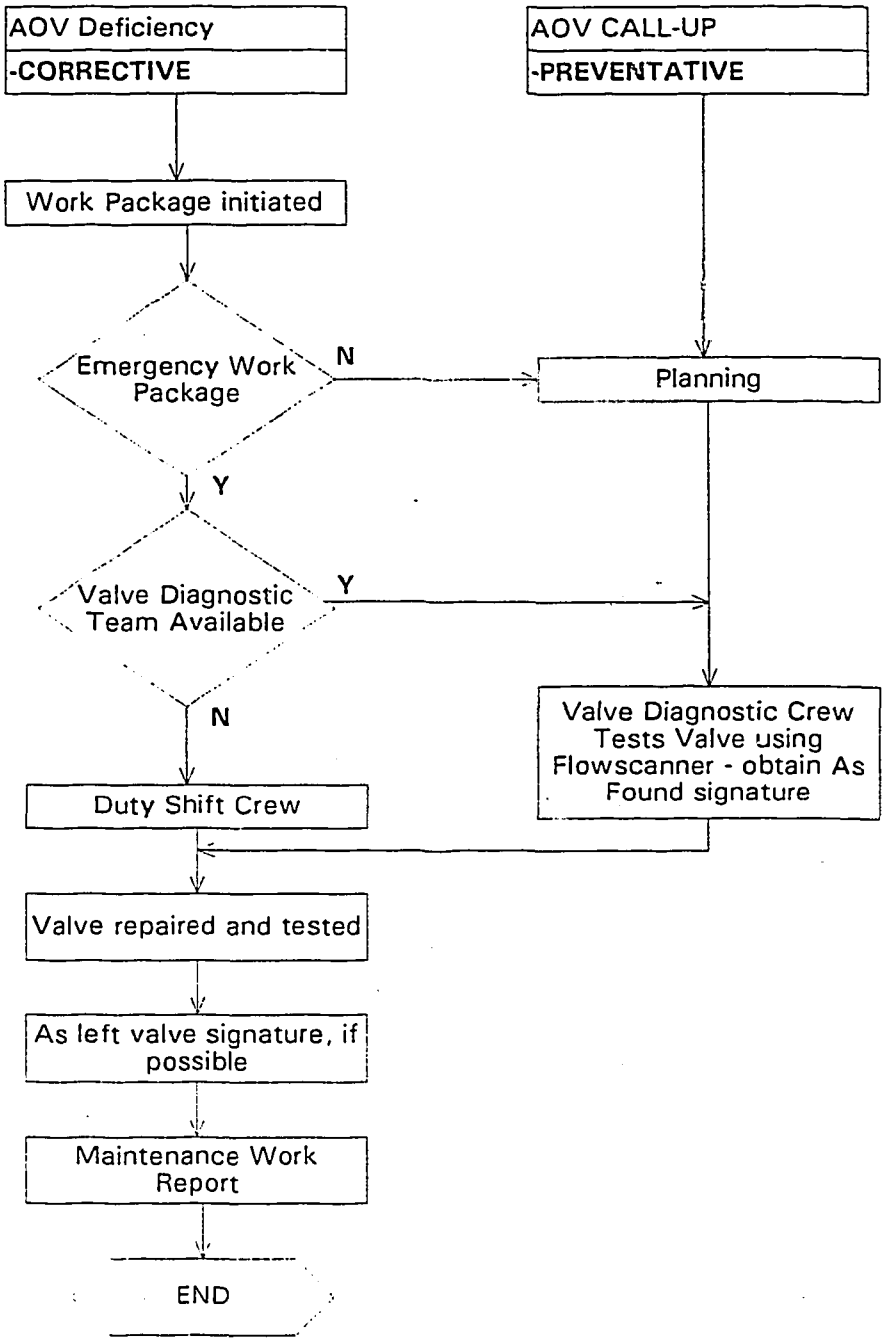

AOV Deficiency
-CORRECTIVE
AOV CALL-UP
-PREVENTATIVE
Work Package initiated
Emergency Work Package
N
Planning
Y
Valve Diagnostic Team Available
Y
N
Valve Diagnostic Crew Tests Valve using Flowscanner - obtain As Found signature
Duty Shift Crew
Valve repaired and tested
As left valve signature, if possible
Maintenance Work Report
END

Figure 8

Deficiency Frequency Distribution

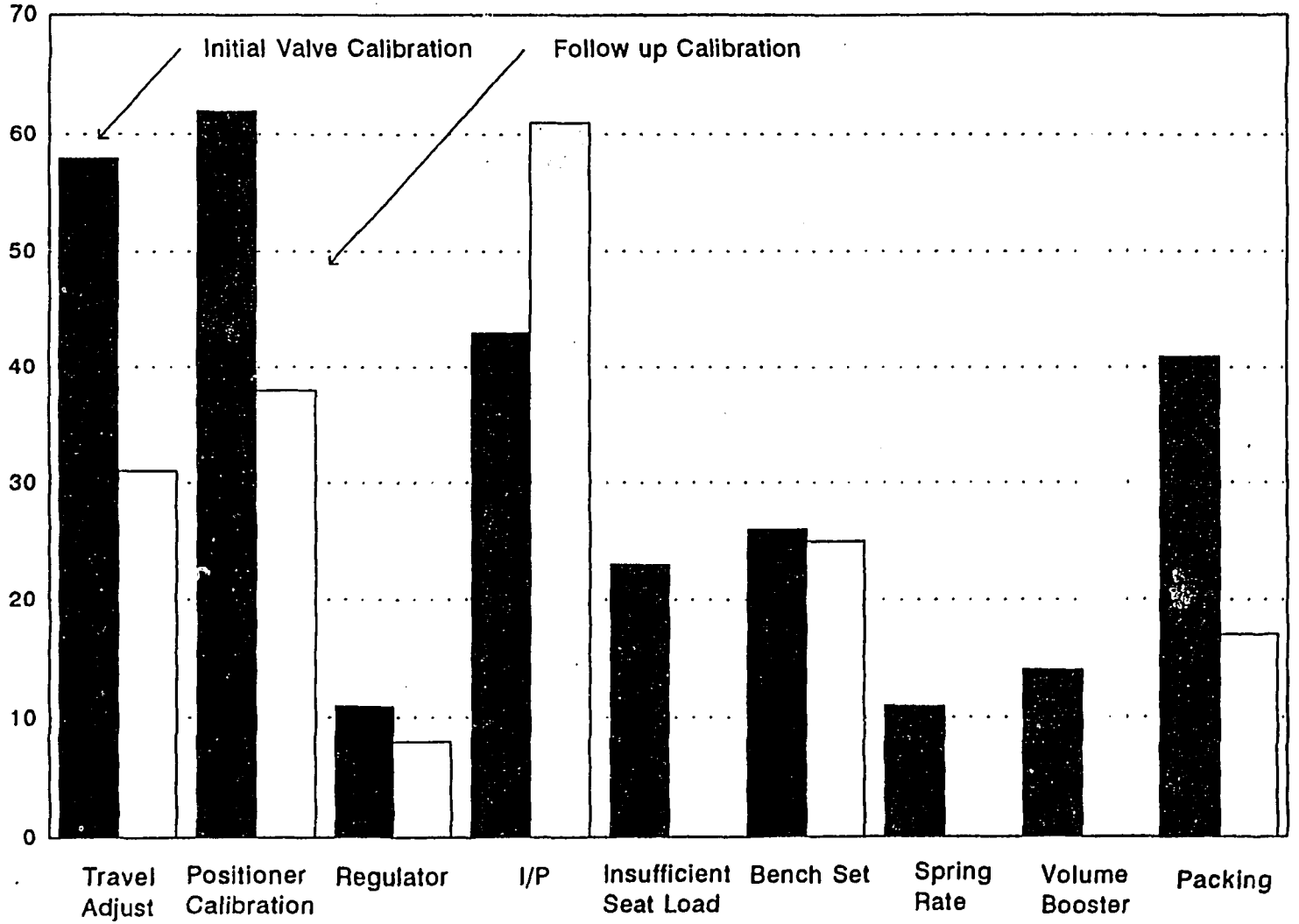


Figure 9

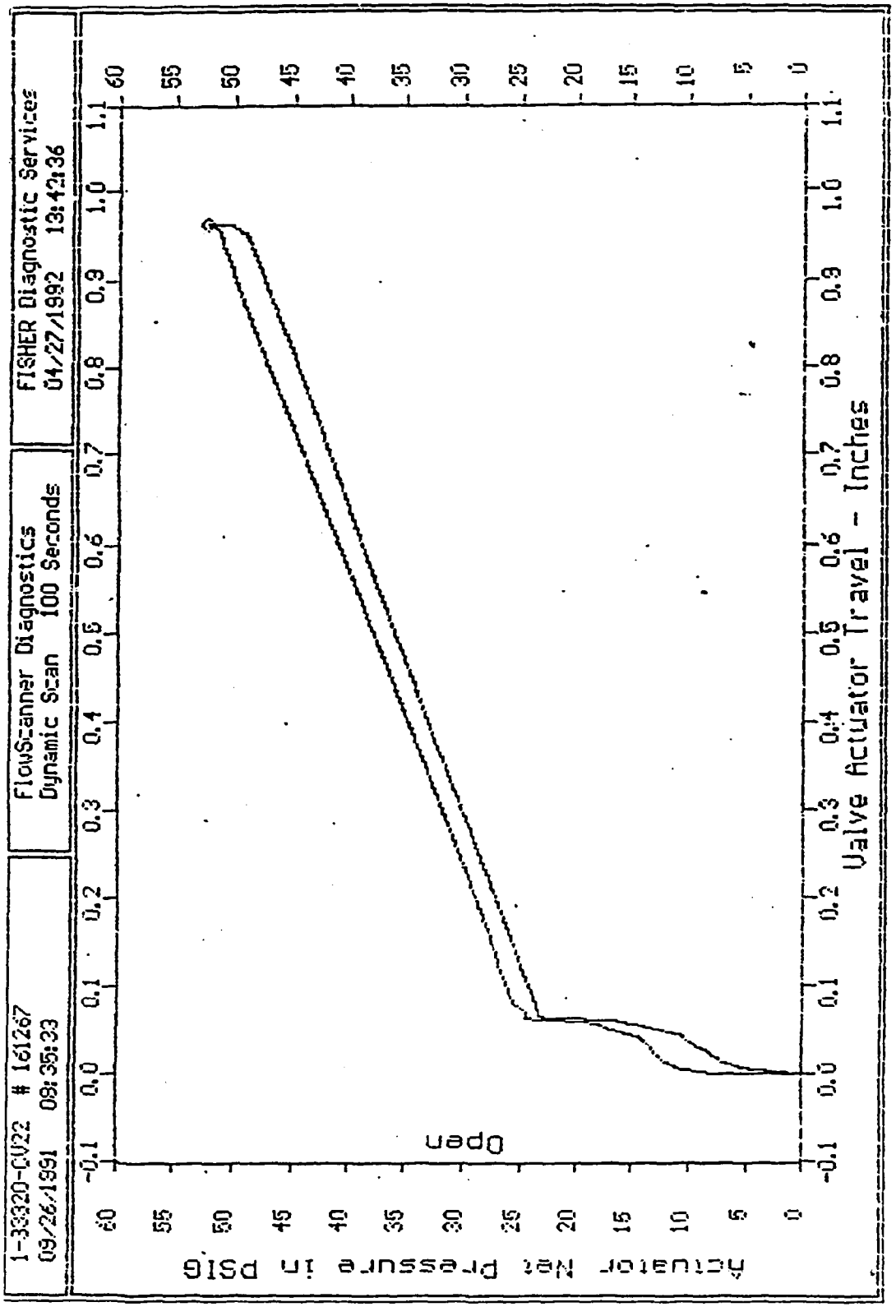

1-33320-CV22 # 161267
09/26/1991 08:35:33
FlowScanner Diagnostics
Dynamic Scan 100 Seconds
FISHER Diagnostic Services
04/27/1992 13:42:36
Actuator Net Pressure in PSIG
Valve Actuator Travel - Inches
Open

Figure 10

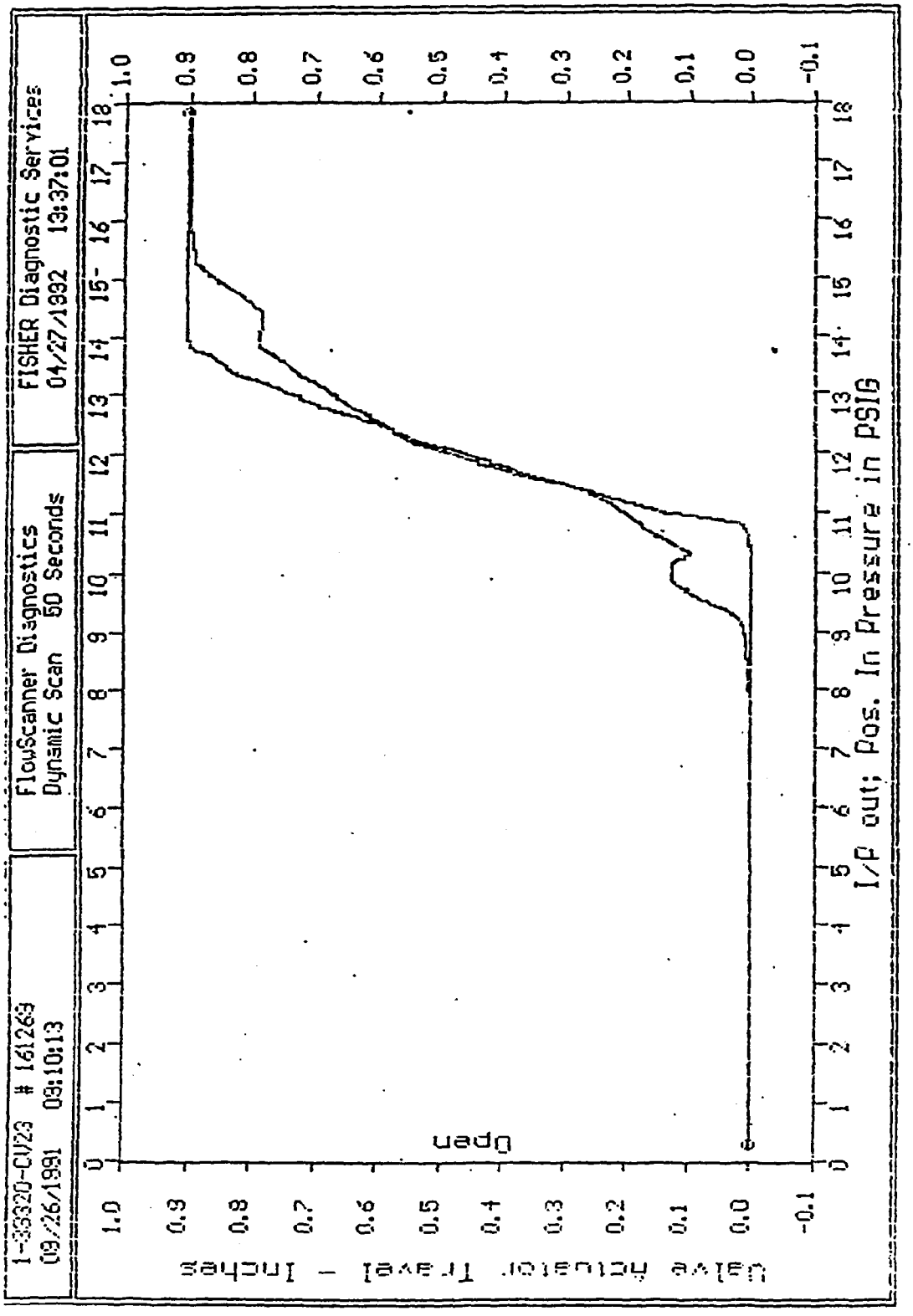

1-33320-CV23 # 161263
09/26/1991 08:10:13
FlowScanner Diagnostics
Dynamic Scan 60 Seconds
FISHER Diagnostic Services
04/27/1992 13:37:01
Valve Actuator Travel - Inches
I/P out; Pos. In Pressure in PSIG
Open

Figure 11

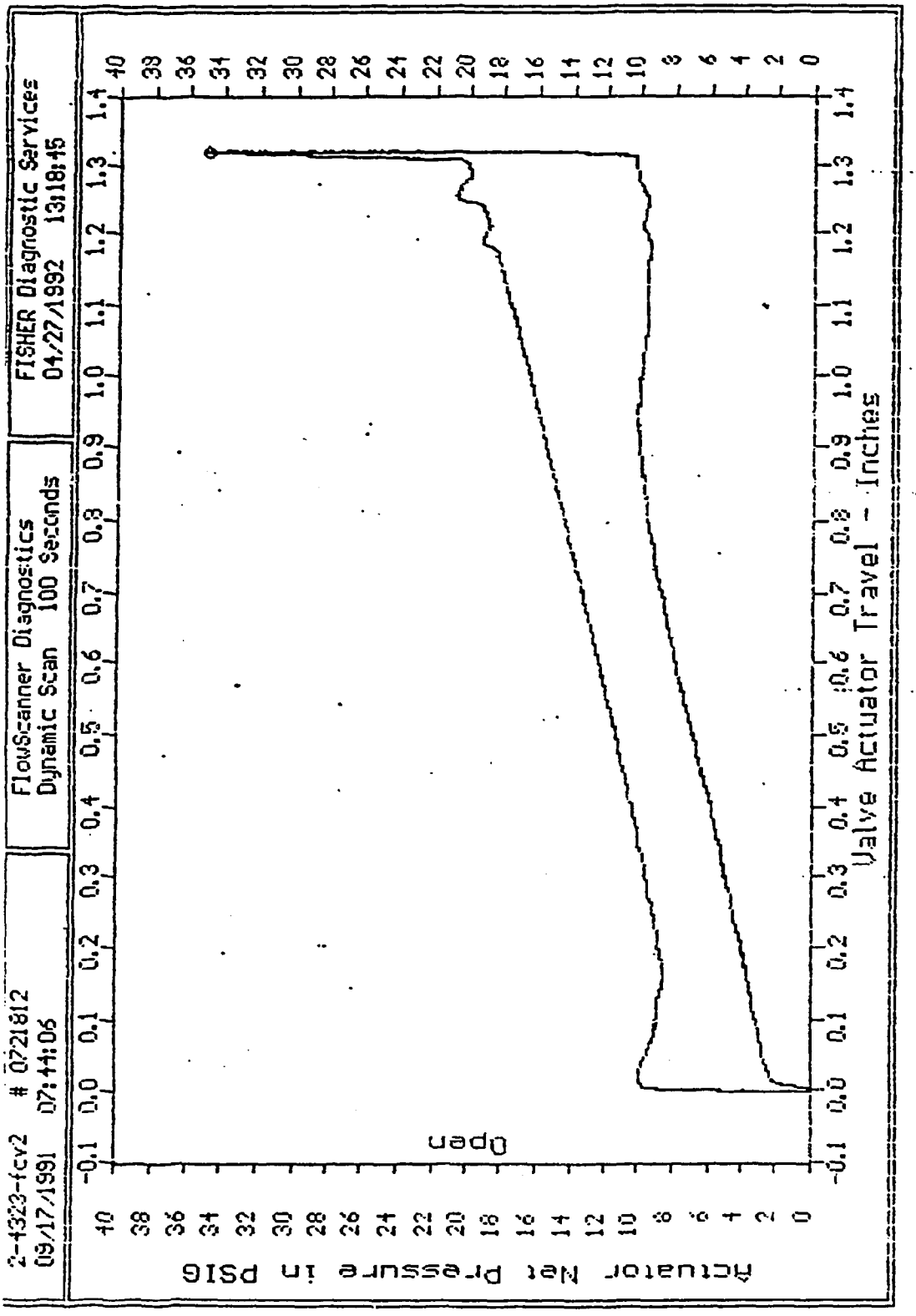

2-4323-fcv2 # 0721812
09/17/1991 07:44:06
FlowScanner Diagnostics
Dynamic Scan 100 Seconds
FISHER Diagnostic Services
04/27/1992 13:18:45
Actuator Net Pressure in PSIG
Valve Actuator Travel - Inches
Open

Figure 12

CA9500178

MOV PREDICTIVE MAINTENANCE PROGRAM AT DARLINGTON NGS

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ABSTRACT

This paper details the MOV Predictive Maintenance Program, at Darlington NGS. The program encompasses the use of diagnostics tooling in conjunction with more standard maintenance techniques with the goal of improving overall performance of station MOV's. This paper discusses the advantages of such a program. The MOV problems encountered and the solutions developed during the first two phases of this program are presented, along with proposed actions for the final trending phase of the program. Although termed as an MOV predictive maintenance program, this paper also touches upon the preventative and corrective maintenance aspects of an overall MOV maintenance program.

MOV PREDICTIVE MAINTENANCE PROGRAM AT DARLINGTON NGS

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Ontario Hydro
Darlington NGS, Bowmanville, Ontario

DARLINGTON NGS

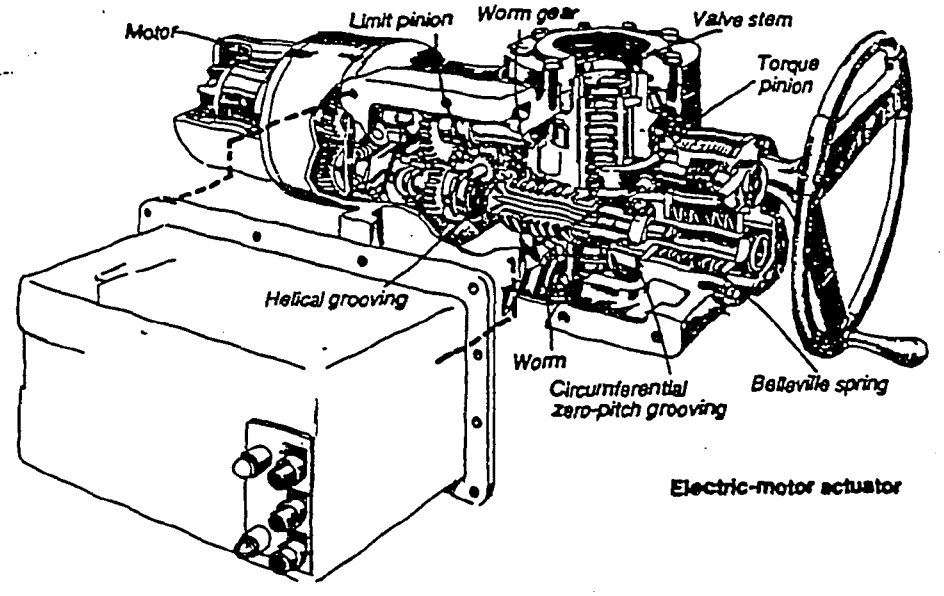
Darlington NGS is a four unit CANDU nuclear generating station, located on the shores of Lake Ontario, approx 70km east of Toronto. The CANDU design is a Pressurized Heavy Water Reactor (PHWR), each unit at Darlington is designed to produce 940MWe.

Darlington presently has one unit in service, with two other units nearing the end of their commissioning phase. The last unit is reaching the end of construction and starting into its commissioning phase.

BACKGROUND

A Motor Operated Valve (MOV) is simply a valve with an actuator attached to it. This actuator enables the valve to be operated remotely upon receipt of the appropriate control signal. This control signal can originate from a number of sources; a handswitch operation in the control room, a process control signal or a safety related control signal from safety system logic.

For the purposes of this paper, the term MOV will describe only those valves with geared actuators driven by electric motors. (See fig1.)



Electric-motor actuator

The learning curve for maintenance and operation of MOV's has in recent years been increasing at an almost exponential rate.

The motivation behind this search for knowledge, in such a very specific equipment area, can be credited to three very important influences;

- Recognition of the high frequency of MOV failures and the possible effects of such failures, given that many of the MOV's perform important safety related functions. (1) (2)

- The associated costs for maintaining these failure prone pieces of equipment.

- Regulation from the US Nuclear Regulatory Commission (NRC), eg. Generic letters 85-03 and 89-10. (3)(4)

Much of the latest research in this field of engineering, stems from the US Nuclear utilities and the associated engineering community. The increasing number of MOV failures was recognised by the NRC (prior to 1985) as an area requiring improved performance.

The NRC set about attaining this improved performance by regulating its requirements in the form of Generic Letters supplemented by numerous Information Notices. These documents passed on the NRC's requirement for each US Nuclear utility to implement a detailed and complete maintenance program for the safety related MOV's installed in their plant.

This started an enormous expenditure of resources by the utilities to try and define the program requirements and to set about implementing their programs as cost effectively as possible. With the Generic letter 89-10, the NRC imposed a very tight timetable for implementation of these maintenance programs. This timetable allowed the utilities up to 5 years to define, document and implement their programs with the goal of proving to the NRC that their safety related MOV's would operate under all required safety related conditions.

Applicability of US Experience to CANDU Stations

The applicability of the experience and knowledge gained by the US utilities can be linked to our CANDU stations through the following key areas;

High Frequency of MOV Failures. The US utilities have a computerized system (NPRDS), for monitoring the failure of safety related equipment within their stations. This system was one of the key indicators to the NRC of the increasing number of MOV failures occurring at these US plants. Further high profile

examples of MOV failures such as the Auxiliary Feedwater MOV's at Davis Besse, the Power Operated Relief Valves (PORV) - Block valves at H.B. Robinson and the Reactor Core Isolation Cooling Throttle Valves at Peach Bottom, etc. served only to underline the background information being fed to the NRC by this industry database.

The AECB report (1) detailed similar valve failure information for a number of the Canadian CANDU stations. The frequency of failures mirrors the US experience which prompted the NRC to issue its generic letters.

Many CANDU stations having gone back independently and reviewed their MOV maintenance histories are confirming the high failure rates, repeat failures, etc. as identified by the US and Canadian regulatory bodies.

Safety Related Functions. MOV's identified as having safety related functions have additional operating requirements, over and above their "normal' process and maintenance operations.

These safety related functions are many and varied;

1. Requirement to Close. Some valves are required to close. This may be under line break conditions to ensure the system fluid inventory is maintained, and/or perhaps to maintain the containment boundary.

2. Requirement to Open. Other valves are required to drive open to ensure access to a heat sink is maintained or to valve in an alternate heat sink.

3. Different Operating Requirements. Some valves are required to drive both open and closed under different accident/emergency conditions. (ie. a combination of 1. and 2. above)

4. Maintain Position. Other valves are required to maintain their normal operating position, ie. stay in their normal operating position open or closed, thereby controlling fluid flow as needed by the accident/emergency conditions.

5. Pressure Boundary. For some valves their safety related function is to of act as a pressure boundary, ie. the valve body, packing, gaskets etc. thus the valve body must maintain structural integrity.

All of the examples of safety related functions given above apply equally well to US Nuclear (BWR, PWR, etc) and to CANDU stations. Therefore any concerns over the ability of these safety related MOV's to perform their safety related functions would also be applicable to both US stations and CANDU stations.

MOV Equipment Used in US and CANDU plants. The majority (approx. 95%) of MOV actuators in use at US nuclear stations are manufactured by Limitorque. A few US utilities have used other manufacturers for safety related applications, eg. Duke Power has some stations where Rotork actuators are being used, but these are very much in the minority.

In CANDU stations the mix of actuator manufacturers used in safety related applications is much greater (Table 1.), however Limitorque and Rotork account for the majority of the actuators used.

Table 1
Actuator Manufacturers in use at (OH) Candu Stations

Actuator Manufacturer	DNGS	BNGSA	BNGSB	PNGS
Limitorque	Yes	Yes	Yes	Yes
Rotork	Yes	Yes	Yes	Yes
Hopkinson	No	Yes	Yes	Yes
EIM	Yes	Yes	Yes	No
Jones-Tate	No	No	No	No

The Rotork and Limitorque actuators in use at US and Canadian stations are, for all essential purposes, of the same design. Therefore any equipment based problems identified in the US are expected to be seen here in Canada too.

Failure Modes. The experience in the US identified a number of common equipment related failures, it further identified concerns with the engineering used during the equipment specification and selection.

1. Equipment Failures. Typical MOV problems are identified in the numerous NRC and INPO information notices. These notices give failures specific to Limitorque actuators, though not specific to any particular model of actuator.

Darlington experience has verified many of the failures modes detailed in the US experience. Further it has identified others, some of which are applicable only to Darlington and some of which are now being highlighted in the latest US experience and their latest research work. (Table 2.)

The Darlington experience on MOV failures is not limited to Limitorque actuators. The other makes also suffer from many of the common problems identified on table 2., as well as having some which are unique to their own design.

TYPICAL PROBLEMS FOUND DURING OPERATION & MAINTENANCE OF MOV'S

TABLE 2. (Pg. 1 OF 3)

ITEM #	PROBLEM ID'D IN US BY INPO AND NRC REPORTS	PROBLEM ID'D BY OPG'S MOV PROGRAM IN 1990	TYPE OF PROBLEM	DESCRIPTION OF PROBLEM
1	NO	YES	DESIGN	LONG CONTACTOR DROPOUT TIME (CDOT)
2	YES	YES	DESIGN	UNDERSIZED ACTUATORS
3	YES	YES	DESIGN	INCORRECT INSTALLATION INSTRUCTIONS
4	NO	YES	DESIGN	NON SEISMIC ACTUATORS SPECIFIED
5	YES	YES	DESIGN	NON NUCLEAR ACTUATORS SPECIFIED
6	YES	YES	DESIGN	NON FAIL SAFE LOGIC
7	NO	YES	DESIGN	OH180 (PLC) LOGIC ERRORS
8	YES	YES	DESIGN	NO TORQUE SWITCH BYPASS FUNCTION
9	YES	YES	DESIGN	NO TORQUE SWITCH LOCKOUT FUNCTION
10	NO	YES	DESIGN	INCORRECT THERMAL OVERLOADS/FUSES
11	NO	YES	DESIGN	MISSING DESIGN DATA
12	NO	YES	DESIGN	INCORRECT CONTROL PHILOSPHY
13	YES	YES	DESIGN	OVERSIZED ACTUATORS
14	YES	YES	MANFR'G	WRONG SPRING PACKS
15	YES	YES	MANFR'G	WRONG TORQUE SWITCH ASSEMBLIES
16	YES	YES	MANFR'G	NON STANDARD COMPONENTS INSTALLED
17	NO	YES	MANFR'G	SPRING PACK GAP
18	YES	YES	MANFR'G	LOOSE LOCK NUTS
19	YES	YES	MANFR'G	INCORRECT ACTUATOR SHIMMING
20	NO	YES	MANFR'G	WRONG SPARE PARTS SPECIFIED
21	YES	YES	MANFR'G	WRONG UPPER HOUSING GASKETS INSTALLED
22	NO	YES	MANFR'G	WRONG STEM PACKING LOADS
23	NO	YES	MANFR'G	WRONG DRIVE SLEEVE BEARINGS
24	NO	YES	MANFR'G	IMPROPER MODIFICATION OF ASSEMBLY
25	YES	YES	MANFR'G	INACCURATE MACHINING OF HOUSING/COMPONENTS
26	NO	YES	MANFR'G	ASSY DIDNT MEET SPECIFICATIONS
27	YES	YES	EQUIPT FAILURES	MOTOR FAILURES
28	YES	YES	EQUIPT FAILURES	HIGH MOTOR CURRENTS
29	NO	YES	EQUIPT FAILURES	HIGH RUNNING LOADS
30	YES	YES	EQUIPT FAILURES	MANUAL SELECT/OPERATION FAILURES
31	YES	YES	EQUIPT FAILURES	ACTUATOR HOUSING FAILURES
32	YES	YES	EQUIPT FAILURES	BENT STEMS
33	YES	YES	EQUIPT FAILURES	DISC/SEAT WEAR & DAMAGE
34	YES	YES	EQUIPT FAILURES	TORQUE & LIMIT SWITCH FAILURES
35	YES	YES	EQUIPT FAILURES	HYDRAULIC LOCKUP/DAMPENING IN SPRING PACK
36	YES	YES	EQUIPT FAILURES	STEM PACKING
37	NO	YES	EQUIPT FAILURES	DRIVE SLEEVE FAILURES
38	YES	YES	OTHERS	STEM LUBRICATION
39	YES	YES	OTHERS	ACTUATOR LUBRICATION
40	YES	YES	OTHERS	LOOSE ACTUATOR MOUNTING BOLTS
41	YES	YES	OTHERS	VALVE STEM SCORING

TABLE 2. (Pg. 2 OF 3)

TABLE 2. (Pg. 3 OF 3)

2. Engineering and Equipment Specification Errors. Advances in the understanding of MOV operation, valve packing and valve dynamics, have allowed the US utilities to better understand the requirements for a valve to overcome its various operating loads; ie. packing drag, line pressure and delta p's across the valve.

These loads are further complicated by many other phenomena including; temperature effects such as thermal binding, calibration effects such as hydraulic lockup of the actuator spring pack, friction effects at the valve stem threads and at the valve disk (where applicable), etc.

Some of these phenomena are still not fully understood, issues such as rate of loading, gate friction factors, etc. continue to receive much attention from the engineering community.

The requirements for these valves to operate are the same for both US and CANDU stations, similarly the phenomena which affect their operation are also equally applicable to US and CANDU stations.

One of the major areas of benefit to the Darlington NGS program, was, and is, the sharing of information on these engineering advances. The area of MOV engineering and MOV specification and selection has allowed Darlington NGS to identify specific and generic problems in how its MOV's were specified, and it has allowed engineering solutions to be developed to overcome those shortfalls.

Maintenance Verification and MOV Diagnostics. Problems with how MOV maintenance was being performed and the verification of that maintenance performance were also identified by the NRC.

Further the NRC identified concerns with the suitability of the maintenance tasks and the test operations being performed, to verify the ability of an MOV to perform its specific safety related function under the worst operating conditions.

The interest shown by the NRC in this field of plant engineering and maintenance led to developments in a number of areas related to the issues listed above. One of the more important developments was in the area of equipment diagnostics.

Henze-MOVATS were the early leaders in this area and setup a MOVATS users group, which grew into what is today the MOV Users Group (MUG); North American Nuclear Utilities who are addressing the issues and concerns associated with operation of MOV's.

Although the availability of MOV Diagnostics has not fully answered the NRC's concerns over operability, it has allowed the utilities to verify and document the condition of their safety related MOV's.

Many CANDU stations have adopted the use of these diagnostics systems (Table 3.) for the same reasons; verification and documentation of MOV condition. Therefore any developments in the use of such diagnostics is equally of interest to these CANDU stations.

Table 3
MOV Diagnostics Systems in Use at CANDU Stations

Station	Diagnostics System Used
DNGS	MOVATS 3000 System
BNGSA	VOTES System
BNGSB	VOTES System
PNGS	VOTES System
Point Lepreau	MOVATS & VOTES (Contracted Services)

Other US Nuclear Industry Initiatives. US initiatives into type testing, sharing of test results through industry wide databases, development of alternatives to full DP testing, etc. continue to address the NRC's concerns over operability.

The reason for shying away from full DP testing is the costs associated with the testing. This reason would equally apply to CANDU stations, therefore any US initiatives which would preclude our having to perform such tests are to be welcomed.

The many problems overcome and those yet to be tackled by the US utilities are outside the scope of this paper except to say that the MOV program at Darlington NGS, has gained much from the progress made thus far. (eg. Rotork Thrust report. (5))

DARLINGTON MOV PROGRAM

At Darlington NGS, there are in excess of 1200 MOV's, with electrically driven actuators. Implementation of an MOV maintenance program at Darlington started during commissioning of first reactor units. This has allowed the identification and resolution of many problems early in the life of the MOV's.

Program Scope

At present 322 of these MOV's are included in the scope of the full MOV predictive maintenance program. These valves are singled out for this special attention, due to of the safety related functions they are required to perform.

The remaining 880 MOV's are not safety related valves, (or have a safety related function which does not require them to operate under a design basis event. Although not included in the full program, they still receive the benefits of the program through implementation of generic modifications. Also from the use of diagnostics tooling to assist in troubleshooting of problem valves.

Three Program Phases - Engineering, Field Implementation, Trending

There are three phases to the program at Darlington NGS. The program is modelled after the MOVATS MOV program (6), with the major differences related to the program resources, to differences in program depth and to priorities associated with the age and operating status of the station. The three phases are;

Engineering Phase. The engineering phase has been entered in parallel to the field implementation phase given the construction, commissioning and operating schedules for the various units at DNGS. Elements of this phase include; outlining the program scope, identifying program MOV's and determining resources required to implement the program. The status of the individual program areas is shown on figure 2.

Field Implementation Phase. The field implementation phase is presently underway on all units at Darlington NGS. Elements of this phase include; training of maintenance staff, scheduling of diagnostics testing and analysis/documentation of test results. The status of the individual program areas is shown on figure 3.

Trending Phase. The trending phase is due to get underway at Darlington within the next 6 months (Figure 3.). Elements of this phase include; reviewing preventative maintenance, coordination post maintenance and periodic testing, comparison of previous and latest test results and identification of trends. Some of these long term program aspects are in the planning stage.

Some of the key aspects of the DNGS MOV program are discussed below in some detail.

Diagnostics Testing at Darlington

Darlington uses the diagnostics system developed by Henze-MOVATS.

Presently there are two MOVATS (Motor Operated Valve Analysis and Testing Systems) 3000 systems in use at DNGS, with full time control maintenance and engineering staff working on the program as described above. Other resources, such as design and mechanical maintenance, are called in as required, to meet the needs of the program.

Figure. 2

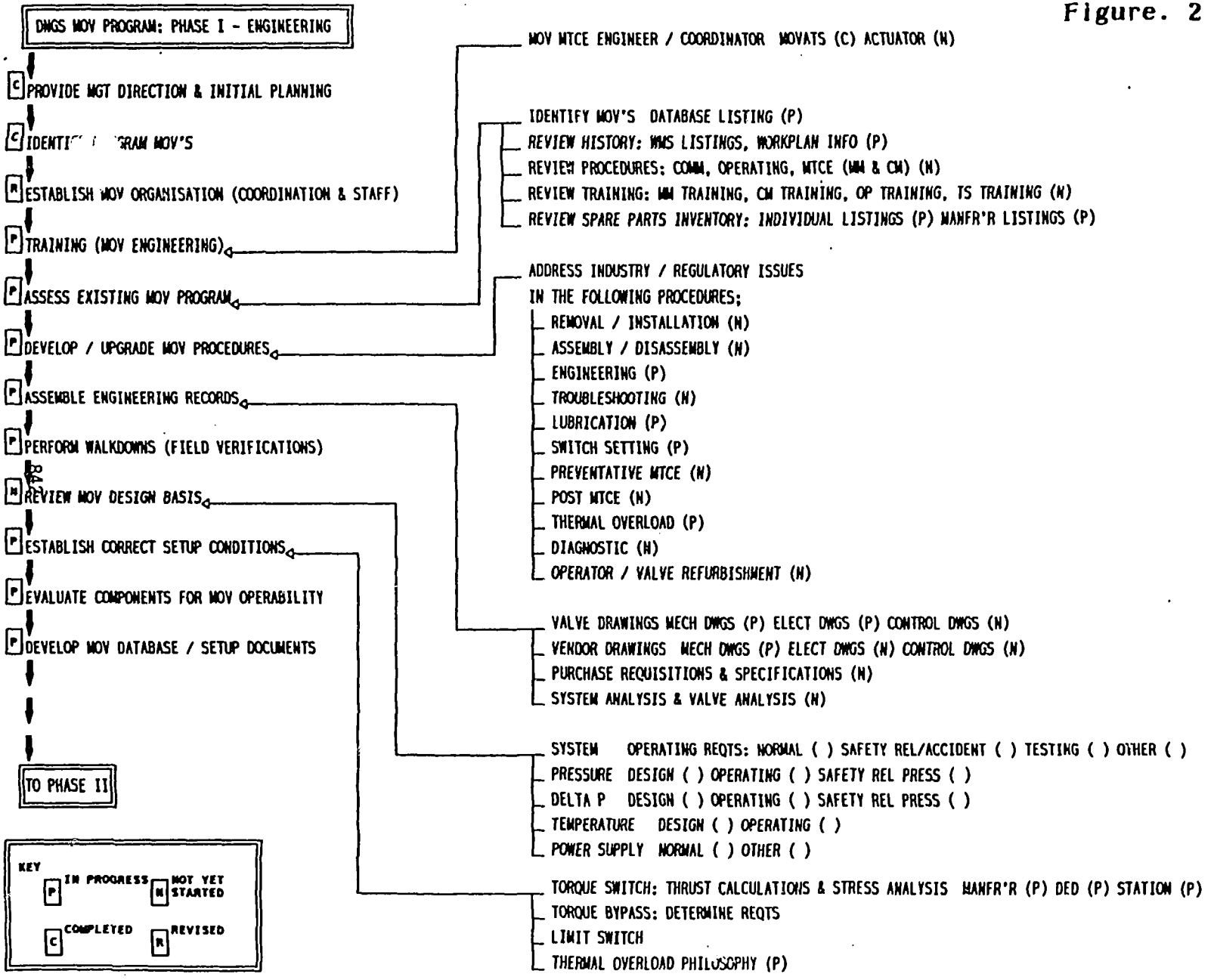
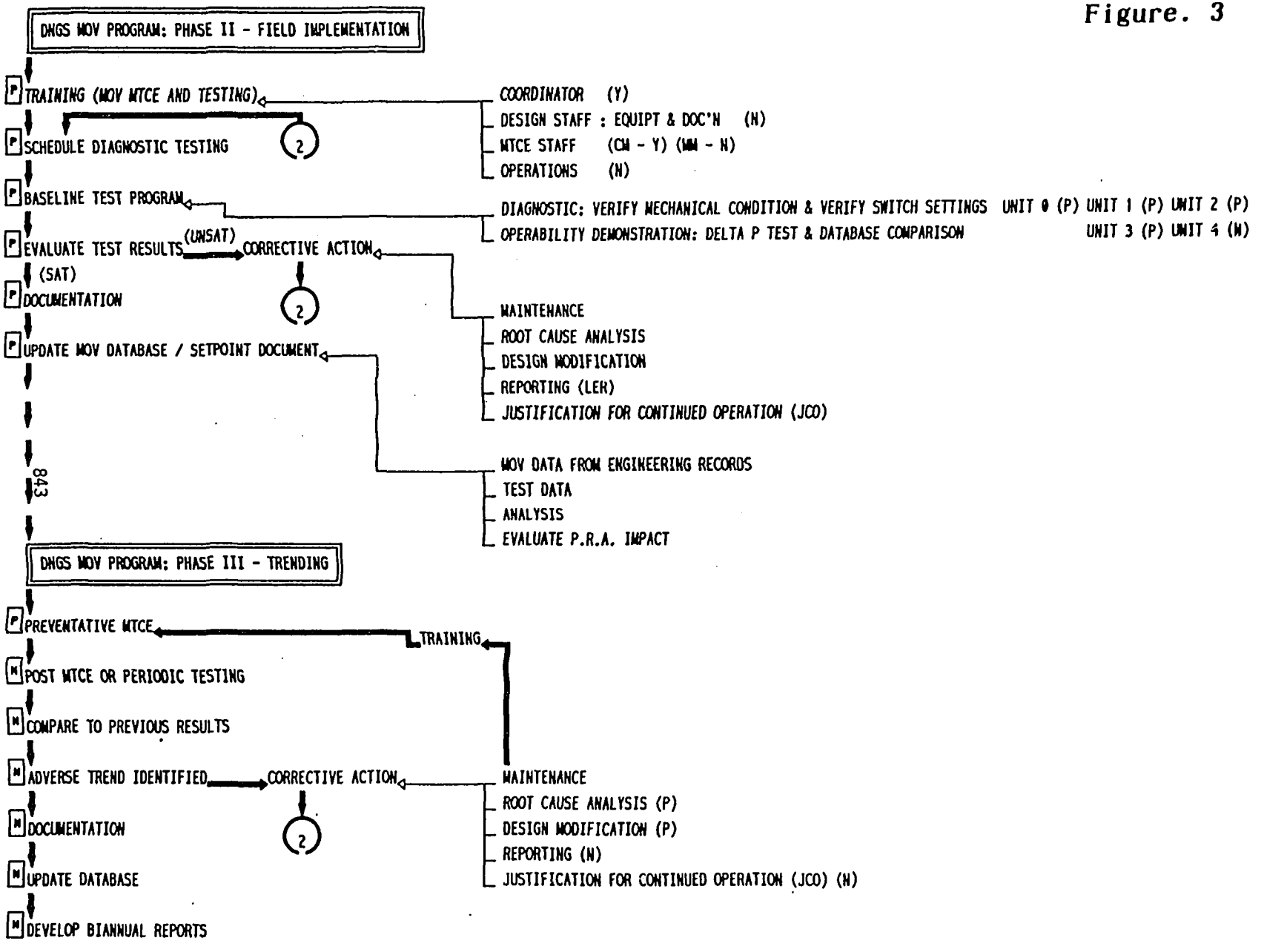

DWGS MOV PROGRAM: PHASE I - ENGINEERING
C PROVIDE MGT DIRECTION & INITIAL PLANNING
C IDENTIFY PROGRAM MOV'S
R ESTABLISH MOV ORGANISATION (COORDINATION & STAFF)
P TRAINING (MOV ENGINEERING)
P ASSESS EXISTING MOV PROGRAM
P DEVELOP / UPGRADE MOV PROCEDURES
P ASSEMBLE ENGINEERING RECORDS
P PERFORM WALKDOWNS (FIELD VERIFICATIONS)
N REVIEW MOV DESIGN BASIS
P ESTABLISH CORRECT SETUP CONDITIONS
P EVALUATE COMPONENTS FOR MOV OPERABILITY
P DEVELOP MOV DATABASE / SETUP DOCUMENTS
TO PHASE II
KEY
P IN PROGRESS
N NOT YET STARTED
C COMPLETED
R REVISED
MOV MTCE ENGINEER / COORDINATOR MOVATS (C) ACTUATOR (N)
IDENTIFY MOV'S DATABASE LISTING (P)
REVIEW HISTORY: WMS LISTINGS, WORKPLAN INFO (P)
REVIEW PROCEDURES: COMM, OPERATING, MTCE (MM & CM) (N)
REVIEW TRAINING: MM TRAINING, CM TRAINING, OP TRAINING, TS TRAINING (N)
REVIEW SPARE PARTS INVENTORY: INDIVIDUAL LISTINGS (P) MANFR'R LISTINGS (P)
ADDRESS INDUSTRY / REGULATORY ISSUES
IN THE FOLLOWING PROCEDURES;
REMOVAL / INSTALLATION (N)
ASSEMBLY / DISASSEMBLY (N)
ENGINEERING (P)
TROUBLESHOOTING (N)
LUBRICATION (P)
SWITCH SETTING (P)
PREVENTATIVE MTCE (N)
POST MTCE (N)
THERMAL OVERLOAD (P)
DIAGNOSTIC (N)
OPERATOR / VALVE REFURBISHMENT (N)
VALVE DRAWINGS MECH DWGS (P) ELECT DWGS (P) CONTROL DWGS (N)
VENDOR DRAWINGS MECH DWGS (P) ELECT DWGS (N) CONTROL DWGS (N)
PURCHASE REQUISITIONS & SPECIFICATIONS (N)
SYSTEM ANALYSIS & VALVE ANALYSIS (N)
SYSTEM OPERATING REQTS: NORMAL ( ) SAFETY REL/ACCIDENT ( ) TESTING ( ) OTHER ( )
PRESSURE DESIGN ( ) OPERATING ( ) SAFETY REL PRESS ( )
DELTA P DESIGN ( ) OPERATING ( ) SAFETY REL PRESS ( )
TEMPERATURE DESIGN ( ) OPERATING ( )
POWER SUPPLY NORMAL ( ) OTHER ( )
TORQUE SWITCH: THRUST CALCULATIONS & STRESS ANALYSIS MANFR'R (P) DED (P) STATION (P)
TORQUE BYPASS: DETERMINE REQTS
LIMIT SWITCH
THERMAL OVERLOAD PHILOSOPHY (P)

Figure. 3


DNGS MOV PROGRAM: PHASE II - FIELD IMPLEMENTATION
P TRAINING (MOV MTCE AND TESTING)
COORDINATOR (Y)
DESIGN STAFF : EQUIPT & DOC'N (N)
MTCE STAFF (CM - Y) (MM - N)
OPERATIONS (N)
P SCHEDULE DIAGNOSTIC TESTING
2
P BASELINE TEST PROGRAM
DIAGNOSTIC: VERIFY MECHANICAL CONDITION & VERIFY SWITCH SETTINGS UNIT 0 (P) UNIT 1 (P) UNIT 2 (P)
OPERABILITY DEMONSTRATION: DELTA P TEST & DATABASE COMPARISON UNIT 3 (P) UNIT 4 (N)
P EVALUATE TEST RESULTS
(UNSAT)
CORRECTIVE ACTION
(SAT)
P DOCUMENTATION
2
MAINTENANCE
ROOT CAUSE ANALYSIS
DESIGN MODIFICATION
REPORTING (LER)
JUSTIFICATION FOR CONTINUED OPERATION (JCO)
P UPDATE MOV DATABASE / SETPOINT DOCUMENT
MOV DATA FROM ENGINEERING RECORDS
TEST DATA
ANALYSIS
EVALUATE P.R.A. IMPACT
843
DNGS MOV PROGRAM: PHASE III - TRENDING
P PREVENTATIVE MTCE
TRAINING
N POST MTCE OR PERIODIC TESTING
N COMPARE TO PREVIOUS RESULTS
N ADVERSE TREND IDENTIFIED
CORRECTIVE ACTION
MAINTENANCE
ROOT CAUSE ANALYSIS (P)
DESIGN MODIFICATION (P)
REPORTING (N)
JUSTIFICATION FOR CONTINUED OPERATION (JCO) (N)
N DOCUMENTATION
2
N UPDATE DATABASE
N DEVELOP BIANNUAL REPORTS

The MOVATS system allows for the monitoring of various MOV parameters including; motor current, motor load, applied thrust (at the valve stem), switch operation (torque and limit switches) and spring pack response. The spring pack calibrates the torque output of the actuator, therefore any malfunction of the spring pack results in a malfunctioning actuator.

The diagnostics system develops "signatures" of the MOV operation, by collecting and storing the parameter information for display and measurement. The diagnostics function comes from analysing these signatures for recognizable discrepancies.

These discrepancies allow identification of many common faults; eg. spring pack problems which can be identified include hydraulic lockup/dampening, spring pack gaps, incorrect spring pack range (through mis-assembly or through installation of the wrong components).

Many of the problems identified using the diagnostics equipment would not be found until they had caused the MOV to fail, hence the "Predictive" nature of the test program. Table 4 gives examples of hidden problems.

Table 4.
Hidden MOV Problems

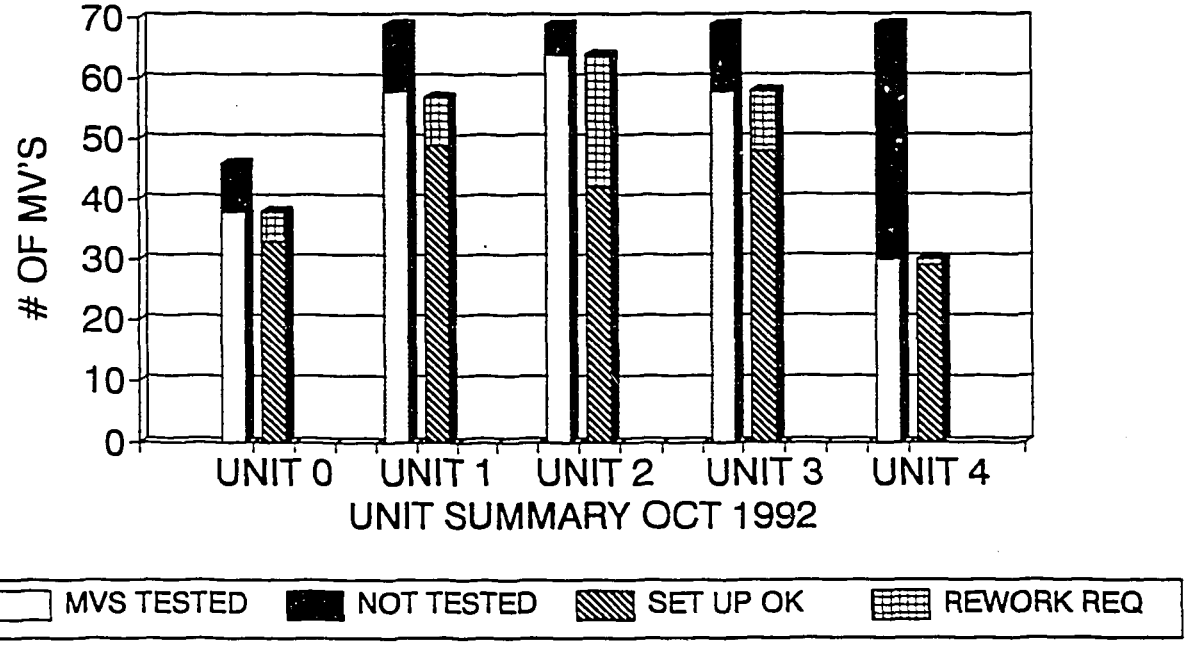
TYPE OF PROBLEM	EFFECT ON THE MV	HOW WAS IT FOUND BY DIAGNOSTICS
SPRING PACK GAP	IMPROPER SETUP CAUSING VALVE FAILURE	CHANGES IN RUNNING LOAD AFTER HAMMER BLOW.
SHEARED DRIVE SLEEVE	VALVE FUNCTIONED O.K. DURING A STATIC SETUP	DIAGNOSTICS SHOWED REDUCED THRUST OUTPUT AND LOWER RUNNING CURRENTS THAN OTHER SIMILAR VALVES DIS-ASSEMBLY REVEALED THE REAL PROBLEM.
GREASE IN SPRING PACK	EXCESSIVE OUTPUT THRUST	INCONSISTENT K-FACTORS DURING SPRING PACK VERUS THRUST. CALIBRATION STROKES.
FULL SPRING PACK COMPRESSION	LOCKED ROTOR ON THE MOTOR AND POSSIBLE VALVE DAMAGE	COMPARISON OF THRUST DEVELOPED VERUS SPRING PACK MOVEMENT.
BACK SEATING	LEAKAGE PROBLEMS AND POSSIBLE DISC SEPARATION FROM THE STEM.	A SLIGHT INCREASE IN THRUST CAN BE SEEN AT THE END OF A CLOSE TO OPEN STROKE.
EXCESSIVE INERTIA	HIGH UNSEATING LOADS AND/ OR A BENT STEM.	INCREASING LOAD CAN BE SEEN EVEN AFTER THE TORQUE SWITCH HAS TRIPPED.
INCORRECT SPRING PACK	VALVE FAILS DURING A DIFF: PRESSURE STROKE.	INSUFFICIENT THRUST AT TORQUE SWITCH TRIP EVEN THOUGH THE SWITCHES WERE SET TO THE VALUES GIVEN BY THE MANUFACTURER.
LOOSE STEM NUT LOCKNUT	VALVE FAILS TO OPEN OR CLOSE COMPLETELY.	EXCESSIVE TIME BETWEEN HAMMER BLOW AND VALVE UNSEATING.
BENT STEM	LEAKAGE AT THE PACKING GLAND DUE TO UNEVEN WEAR. INCREASED MOTOR LOAD AND POSSIBLE INADVERTENT TORQUE SWITCH TRIPS.	INCREASED LOADING CAN BE SEEN AS THE BENT PORTION OF THE STEM MOVES THROUGH THE DRIVE NUT.

Testing Status. MOV diagnostics testing at Darlington NGS is underway in all four reactor units, units 1 to 4, and in the common services unit, unit 0. Approximately 250 MOV's have been tested to date, within successful setup achieved on over 200 of these MOV's. To date there are only 6 MOV assemblies which cannot presently be tested (Due to valve or actuator design restrictions).

Figure 4. shows the status of this testing as of October 1992, the total number of valves tested includes those requiring rework to meet the required acceptance criteria.

FIG. 4 MOVATS TESTING STATUS

DNGSA SAFETY RELATED MV'S



Acceptance Criteria. This acceptance criteria is developed and/or verified by the station. If manufacturer information is made available which details the original calculations for equipment sizing and selection, it is reviewed and modified to allow for changes in the accepted thinking for the sizing of the MOV valves and actuators.

Margins for operation are added to the manufacturers calculations and these are issued to the field in the form of Acceptance Criteria sheets. (Figure 5.)

Tool Development It is important to note that the mix of butterfly, wedge gate and globe valves is as listed in Table 5.

Table 5
Valve Types used in MOV's at DNGS

Valve Type	% of MOV's at DNGS
Butterfly	11
Globe	40
Wedge Gate	40
Parallel Slide	0.5
Ball	4.5
Other	4.0

The MOV design; valve type coupled with the actuator type, has resulted in the need to develop tooling on site to meet the needs for testing of particular valve assemblies.

The most important such development at Darlington has been the Split Nut Load Bar (SNLB), which was developed by the staff involved in the MOV program at DNGS. This tool is presently being marketed jointly by Ontario Hydro and ITI-Movats.

The SNLB was developed originally to allow the testing of Rotork actuators. However, it actually allows the calibrated testing of all actuator makes in both the open and closed directions.

The tool as illustrated in figure 6. allows load cells to be reacted against the gland studs while driving closed, and against the valve yoke when driving open. This gives a calibration for the corresponding spring pack movements against a corresponding stem thrust measurement, whilst the valve is stroking open and closed.

The differences in open and closed calibration factors was identified early on in the Darlington program. These differences are related to differences in machining of the geared and threaded components, differences in the lubricated surfaces, etc.

This requirement for performing Open and Closed calibrations is the first example of the Darlington MOV Program leading the US research efforts into MOV operation.

ACCEPTANCE CRITERIA FOR : 3-34320-MV268 TO MV271

PREPARED BY:

VERIFIED BY:

Figure 5.

REV. 0

PREVIOUS SETUP : NONE

EXPERIENCE FROM UNITS 1,2 : THESE MV'S CANNOT BE SETUP FULLY DUE TO PACKING DRAG AND CDOT PROBLEMS. THE SAFETY REL. FUNCTION IS TO OPEN, THEREFORE THE MV'S SHALL BE SET WITH THE FINAL CLOSED THRUSTS WITHIN RATINGS. THE OPEN THRUST AT TST WILL BE EQUAL TO OR GREATER THAN THE CLOSED THRUST AT TST. (IF FINAL OPEN THRUST EXCEEDS THE RATING THEN IT WILL BE ACCEPTED UTIL SOME REWORK CAN BE PERFORMED TO IMPROVE THE OPERATING MARGINS.)

REWORK DONE: ECN 2650 (INSTALLED) (TS BYPASS/LOCKOUT)
ECN 2681 (INSTALLED) (TOL SETTINGS)
ACTUATOR SPRINGPACK MODIFICED (INSTALLED) (HYDRAULIC LOCKUP PROBLEM)

REWORK REQD: VALVE PACKING CHANGE
CDOT MOD (ECN 3057)

CLOSED SETUP GUIDELINES

MANUFACTURERS RECOMMENDED THRUST FOR CLOSING = 43179 # (FROM MANFR DATA SHEET)
(ASBESTOS PACKING)

DNGSA RECOMMENDED THRUST @ TST (INCL DEGRADATION ALLOWANCE; 30%) = 56133 # (FROM MV DATABASE)

VALVE THRUST RATING = 66440 #
(ACTUATOR RATING 70000 # +10%)

PREFERRED SET UP

- FINAL THRUST LESS THAN RATING (66400#) AND THRUST AT TST SET AS NEAR TO DNGSA RECOMMENDED CLOSING THRUST (56133#) AS IS POSSIBLE.
- THIS ALLOWS FOR THE OPTIMUM AMOUNT OF OPERATING MARGIN (IE. ALLOWS AS MUCH AVAILABLE THRUST AS POSSIBLE (AFTER PACKING DRAG & STEM BLOWOUT) TO OVERCOME THE GATE DRAG DUE TO DELTA P EFFECTS.

ACCEPTABLE SETUP

- FINAL THRUST LESS RATING (66440#), AND THRUST AT TST IS GREATER THAN MANFR'S RECOMM. THRUST (43179#).

OPEN SETUP GUIDELINES

MANUFACTURERS RECOMMENDED THRUST FOR OPENING = 47497 # (IE. 10% GREATER THAN CLOSED)

DNGSA RECOMMENDED THRUST AT TST (INCL DEGRADATION ALLOWANCE) = CLOSING THRUST (@ TST)

VALVE THRUST RATING = 66440 # (FROM VELAN DATASHEETS)

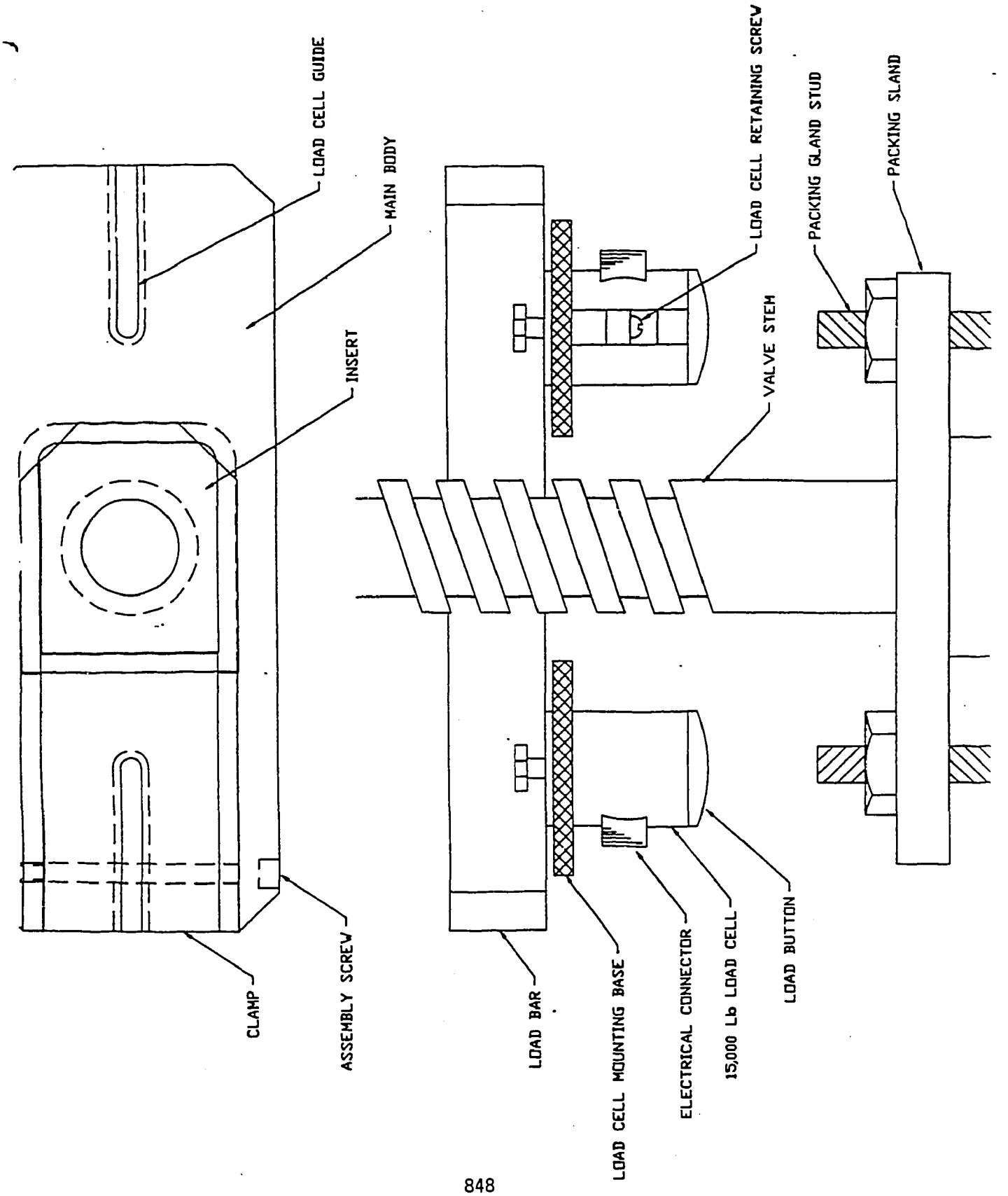
PREFERRED SET UP

- THRUST AT TST SET ABOVE THE AS LEFT CLOSED THRUST (@ TST) AND THE FINAL THRUST LESS THAN RATING (66440#).
- WITH THE INSTALLATION OF THE TS BYPASS FEATURE (ECN 2650) THE FUNCTION OF THE OPEN TS BECOMES THAT OF A BACKUP TO THE LS FAILING TO STOP THE VALVE TRAVEL AT THE END OF THE OPEN STROKE. (IE. THERE IS NO NEED TO ENSURE A SIGNIFICANT DIFFERENCE FROM THE CLOSED TS SETTING FOR UNSEATING THE VALVE)

ACCEPTABLE SET UP

- THRUST AT TST IS EQUAL TO / GREATER THAN THE AS LEFT CLOSED THRUST (@ TST), & FINAL THRUST IS GREATER THAN RATING (66440#).
  IF FINAL THRUST > 66440# THEN A LONG TERM FIX SHOULD BE INITIATED TO RESOLVE THIS PROBLEM.

Figure 6. Split Nut Load Bar



The differences in Open and Closed calibrations are now being acknowledged in the US as being very significant in predicting the operation of MOV's.

The use of the SNLB removes this concern as calibration signatures are taken for both stroke directions.

Common MOV Problems

Table 2. listed typical MOV problems found during US work on MOV's and during work on the DNGS MOV program.

These typical problems can be broken down to four main categories;

Design. These problems include incorrect MOV specifications (eg. Non Nuclear or Non Seismic), Control Circuit or Logic errors (eg. Non fail safe logic, switch functions omitted or incorrectly used), Protection devices incorrectly specified (eg. Thermal Overloads, Fuses), etc.

Manufacturer Quality Control. These problems include such things as non standard components installed, erroneous components, incorrectly installed components, out of tolerance components, etc.

Equipment Failures. These problems include such things as motor failures, declutch mechanism failures, etc.

Installation and Maintenance. These problems include such things as incorrect MOV installation (eg. orientation), incorrect lubrication, etc.

These typical problems identified at Darlington, now number 41 problems.

MOV Rework

The numerous problems have led to the development of both specific modifications and generic modifications which are now being implemented at the station to rework the MOV's. (Table 6.)

Specific Modifications. These modifications deal with the specific operating problems an individual MOV may have. Some examples include; customized spring packs, actuator upgrades (motor replacement), valve packing replacement.

Generic Modifications. These modifications deal with problems common to many or all of the MOV's as specified for and installed at DNGS. Some examples include; Contactor Dropout Time reductions (CDOT), Torque Switch Bypass Function, Torque Switch Lockout Function.

Table 6.
MOV Modifications

Action	Results
Customized Spring Packs Replacement Spring Packs	Allows calibration range of the actuator to be selected to meet output thrust reqt's.
Hydraulic Lock Up	Prevents grease build up in the actuator spring pack, ensuring repeatable operation.
Actuator Upgrades	Costly fix, also allows for actuator output thrust to match requirements.
Contactor Dropout Time (CDOT)	Minimizes the thrust developed after the torque switch trips.
Stem Lubrication	Temporary fix, as lubricating effect degrades with time.
Torque Switch Bypass	Ensures valve can overcome unseating loads.
Torque Switch Lockout	Ensures valve does not hammer when tripped on torque switch. (This can happen with non self locking gear sets)
Valve Packing Replacement	Reduces the amount of packing drag, allowing more thrust for overcoming system pressures.
Revised System Conditions	If valves are not required to operate under the most severe operating conditions, then these perhaps can be relaxed. This will reduce the thrust requirements.

Engineering Justification for Operation. Not all of the rework is achieved through replacement parts, substitute parts or upgrading actuators. One such example is the thrust report which Duke Power contracted Rotork to produce. This required Rotork perform thrust and torque testing on its actuators to identify allowable increases in the maximum thrust limits for the actuators.

Darlington recently purchased this report and is using it to justify increased settings for a number of MOV's which were previously identified as "undersized". Initial estimates of savings from not having to purchase upgraded actuators is of the order of 300K$.

Configuration Management

Given the number of modifications undertaken on these MOV's and the complex engineering information of the original assemblies, a good database system is a must. DNGS has been using a Dbase programs and files to maintain all of the data management functions (except for the configuration management functions).

New database facilities are being developed to give this configuration management feature, this will be done in the short term using Superbase programs and files, with a long term database facilities using SQL based programming.

The long term plans for the database stem from an Integrated Valve and Actuator Task Force (IVAP) initiative. This project is being funded by CANDU Owners Group (COG).

Preventive and Corrective Maintenance

Preventive and corrective maintenance tasks are being included in the overall MOV maintenance program. Some examples are MOV lubrication checks (stem and actuator housing), valve packing adjustment and replacement, actuator to valve bolt tightness, equipment qualification inspection and motor control centre inspection.

Future Program Work

The program is reaching the trending phase, all of the MOV's will have undertaken their "baseline" testing and will then be tested on a routine basis for signs of degradation. Some new areas to be worked on include;

Spare parts. There is a need for spare parts which are qualified (and in some cases modified) to meet the needs of the various MOV assemblies. This requirement is already raising administrative concerns with the equipment suppliers which must be addressed by the industry as a whole.

Post Maintenance Testing. A station reference document is planned which will identify requirements for post maintenance testing on MOV's (and other equipment). This requires identification of the maintenance tasks which require testing to be performed afterwards. Further it requires definition of the appropriate level of testing for each of the maintenance tasks. This area has been looked in the US by MUG and NMAC with various documents which give more of the detailed requirements.

Trending Test Techniques. The purpose of this work is to minimize the amount of "field intrusion" of the test equipment, perhaps to the point where a full diagnostics can be run from the motor control centre.

Test Equipment Maintenance and Calibration This area was recently identified at DNGS as a priority requirement.

This priority stemmed from a previously undetected equipment failure, requiring the review and retest of some of the program MOV's. This equipment failure identified the requirement to treat the diagnostics equipment like "class 1" measuring equipment, requiring traceability to the MOV's which have been tested with this diagnostics systems. Having more than one MOVATS system in use at DNGS, makes this even more important.

SUMMARY

The DNGS MOV Program has identified many MOV problems, which if they had gone undetected would have resulted in the operational failure of the associated MOV's at some point in their life.

The knowledge attained in implementing this program has allowed the station to identify problem MOV's prior to failure and to identify suitable rework which removed the problems.

The variation in the rework performed has allowed this work to proceed in a cost effective manner.

The MOV program when first initiated went through a stage of identifying problem, after problem, after problem. This caused a certain resentment towards the program from technical, operating and maintenance staff alike.

However having progressed to the stage where the problems are being resolved (mainly by the MOVATS team) and the ability of the MOVATS team to generate "fixes" has become well known, we are now at the stage where the MOVATS team is overloaded by requests from these same work groups, to work on problem valves, which are not included in the original program scope.

References.

1. AECB Report # INFO-0303, "Aging and Malfunction of Valves in CANDU Special Safety Systems", Numet Engineering Ltd and Spectrum Engineering Corp. Ltd. March 1989.

2. NRC Report #AEOD/C203 "Survey of Valve Operator related Events Occurring During 1978, 1979 and 1980.", May 1982.

3. NRC IE Bulletin # 85-03 "Motor Operated Valve Common Mode Failures during Plant Transients Due to Improper Switch Settings"

4. NRC Generic Letter # 89-10 ""Safety Related Motor Operated Valve testing and Surveillance (generic Letter no. 89-10) - 10 cfr 50.54(f)", June 1989.

5. Rotork Technical Report #TR3178, "Valve Actuator Thrust Testing for the Nuclear Power Industry", April 1991.

6. Henze-Movats "Integrated Motor Actuator Program" Description Document.

CA9500179

MOV OPERABILITY DETERMINATION

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9530978 US

ABSTRACT

This paper presents a technical approach for meeting the operability requirements of NRC GL 89-10. This technical approach will determine the design-basis requirements, verify equipment, determine the required forces to operate the MOV, evaluate the capability of the MOV, establish a target window that the MOV can operate, and justify operability. Alternatives are provide for justifying operability, and a sample operability review is provided for review. This paper is applicable for gate and globe valves with Limitorque operators.

BACKGROUND

The NRC issued GL 89-10 to ensure operability of MOVs and position-changeable MOVs in all safety-related fluid systems. NRC's staff evaluation of the data obtained from IEB 85-03 indicated that, unless additional measures are taken, failure of safety-related MOVs and position-changeable MOVs to operate under design-basis conditions will occur much more often than had previously been estimated.

PURPOSE

The purpose of this paper is to describe a methodology for meeting the operability requirements of GL 89-10.

METHODOLOGY

MOV operability can be determined by performing the following tasks:

- Design Basis Evaluation
- Hardware Verification
- MOV Capability Analysis
- Establish Target Windows
- MOV Diagnostic Testing
- Justification of MOV Operability

DESIGN BASIS EVALUATION

The first step in determining operability is establishing the design basis for the operation of each MOV. The design basis review shall consider all facets of operation which include:

- Function
- System
- Power Distribution System
- Electrical Controls

The basis for the reviews will be the plant configuration as defined in the current design basis documentation. Though not limiting, the following list contains those documents expected to define the current design:

- FSAR
- Tech Specs
- System Descriptions
- Operating Procedures (Normal, Abnormal, Emergency, Accident)
- P&IDs
- Piping Isometrics

Function Review

MOVs may have multiple functions. This review shall determine the safety function and normal operating function for each MOV.

System Review

The system review will determine the design-basis conditions for which the MOV has to perform its function. The safety-related operation of the MOV does not necessarily indicate the design-basis condition. Therefore all operational functions must be reviewed. The following conditions are evaluated:

- Differential Pressure
- Line Pressure
- Temperature
- Flow

In addition, the NRC has requested that evaluations on mispositioning and recovery from mispositioning be included. Mispositioning is considered for any MOV in a safety-related system that is not blocked from inadvertent operation from either the control room, the motor control center, or the valve itself.

Power System Distribution Review

This review will determine the minimum voltage requirements at the MOV terminals. This degraded voltage is normally based on the diesel generator load carrying capability during sequencing. Sometimes it is based on degraded grid conditions. Though not limiting, the following evaluations should be included:

- Length of cable
- Losses thru TOLs
- Motor losses due to ambient temperature

Electrical Controls Review

This review will determine the functional controls (interlocks, annunciators, indicators, etc) required for the MOV to perform its function.

HARDWARE VERIFICATION

The purpose of this task is to verify the existing hardware configuration for each MOV. This task would be accomplished by reviewing vendor drawings, original equipment specifications, existing databases, and walkdown data sheets. The information gathered during the hardware verification would also be used in performing the MOV capability analysis.

Additional verifications required are as follows:

- Control Logic
  This will ensure that the logic for the torque switch and position limit switch, and the circuitry for the interlock, annunciator, and indication switches are appropriate for the application.
- Thermal Overloads
  This will ensure that the overloads are properly sized or configured.
- Cable Sizing
  This will ensure that the power supply and cable sizes are adequate to provide the high starting currents needed for MOV operation.

MOV CAPABILITY ANALYSIS

Determining the capability of the MOV requires the following actions:

- Perform Required Thrust Calculation
- Determine Valve Limits
- Evaluate Operator Limits

Required Thrust Calculation

Required thrust calculations for gate and globe valves are performed using the classical industry equation:

$ST = DPL + PL + PE$

ST = total stem thrust

DPL = differential pressure load.

$DPL = VF \times A_o \times DP$

VF = valve factor
= 0.3 Gate Valve
= 1.1 Globe Valve
These valve factors represent the classical values typically used by the valve manufacturers. Actual valve factors may vary due to wear, aging, and maintenance.

A_o = seating contact area

DP = differential pressure

PL = packing load
The packing load force is the drag on the stem created by friction as the stem moves through the packing material.

PE = piston effect
The piston effect is the line pressure force acting on the stem. This effect may be positive, negative, or non-existence dependent on the operation (open or close) of the MOV.

Piston effect for globe valves:

$PE = A_s \times (LP - DP)$

A_s = stem area

LP = line pressure

Piston effect for gate valves:

$PE = A_s \times LP$

Valve Limits

The valve limit is evaluated under two conditions:

- Seismic
- Weak Link

The seismic limit represents the maximum amount of stem load that can be applied to the valve during the design basis seismic event.

The weak link limit represents the maximum amount of stem load that the weakest component of the valve can withstand before damage can occur, in both the open and close direction.

Operator Limits

The limiting component for the operator is identified by evaluating the following operator parameters:

- Operator Thrust Rating
- Operator Torque Rating
- Spring Pack Capability
- Motor Capability

The operator thrust/torque rating are obtained from the operator vendor.

The spring pack capability is evaluated by calculating the corresponding stem thrust value from the minimum and maximum spring pack torque values. The spring pack torque values can be obtained from the operator vendor or by performing an actual spring pack test.

The motor capability is evaluated at the following conditions:

- 100% Voltage
- Undervoltage
- Stall

ESTABLISH THRUST WINDOW

A thrust window is established which represents an operating range for the MOV based on the above evaluations. The window is comprised of three values:

- Min CST
- Max CST
- Max TT

The Min CST (control switch trip) is equal to the required stem thrust (ST).

The Max CST is the thrust level at which the motor must be de-energized. The Max CST is

the lessor of the following limits:

- Valve Seismic Limit
- Valve Weak Link Limit
- Operator Ratings
- Maximum Spring Pack Capability
- Motor Capability @ Undervoltage

The Max TT (Total Thrust) is the maximum thrust that can be experienced with inertia. The Max TT is the lessor of the following limits:

- Valve Seismic Limit
- Valve Weak Link Limit
- Operator Ratings

Establishing the target window will also require that both torque switch repeatability (TSR) and diagnostic accuracies (DA) be taken into account. The TSR is defined as the variance in actual output torque from test run to test run for a given torque switch setting. The DA is defined as the variance in data output attributed to error inherent to the diagnostic hardware. Since these two events are not dependent on each other, they are combined by the square root of the sum of the squares method.

MOV DIAGNOSTIC TESTING

After the thrust window is established, setpoint selection and adjustments can be verified based on setup and operability testing. The purpose of the tests is to reduce uncertainties which affect the selection of the setpoints (friction coefficients, spring pack characteristics, rate of loading, stem factor) and to demonstrate that the setpoints selected will ensure proper MOV performance over the anticipated range of operating conditions. There are two basic types of setup and operability tests:

- Static
  Static tests obtain MOV information such as the functional characteristics of the specific valve and motor operator under static conditions. It's main purpose is to allow switch settings to be established delivering the desired thrust output, as well as to identify operator and valve anomalies.

- Dynamic
  Dynamic tests provide information related to the performance of the MOV under actual system operating conditions.

JUSTIFICATION OF MOV OPERABILITY

GL 89-10 requires that each MOV should be demonstrated to be operable by testing it at the design basis conditions. In cases where such testing in situ is not practicable, alternative methods can be developed. In addition, each MOV should be stroke tested, to verify that the MOV is operable at no-pressure or no-flow conditions even if testing at design-basis conditions cannot be performed.

As stated in GL 89-10, "Alternatives to testing a particular MOV in situ at design-basis pressure or flow, where such testing cannot practicably be performed, could include a comparison with appropriate design-basis tests results on other MOVs, either in situ or prototype. If such information is not available, analytical methods and extrapolations to design-basis conditions, based on best data available, may be used until test data at design basis conditions become available to verify operability". The NRC has identified this as the two-step approach.

In determining whether testing of a MOV in situ under design-basis conditions is practicable, an evaluation of the safety implications should be performed. This would include evaluation of the potential for damage to the MOV or other plant equipment. If the test of the MOV would require violation of plant technical specifications or procedures, alternatives to testing the MOV in situ under design-basis conditions may be necessary.

If testing at design-basis conditions is not practicable, the following alternatives are available as the best data available until test data at design-basis conditions become

available to verify operability:

- Identify Adequate or Sufficient Margin
- Extrapolation of Partial Design-Basis Tests
- INEL Test Data
- Prototype testing

Identify Adequate or Sufficient Margin

When the results of a MOV capability analysis indicate a large thrust window between the Min CST and Max CST, it would indicate that the MOV has excessive capability for its application. Two methods could be utilized in justifying operability.

- Set-up switches near the upper limit (Max CST).
- Recalculate required thrust using a worst case valve factor.

Extrapolation of Partial Design-Basis Tests

The design-basis test would be performed as close as possible to the design-basis conditions. In addition, two interim data points would be chosen to establish any relationships with a change in the design-basis conditions. The following information would be gathered from each partial design-basis test:

- Differential Pressure
- Line Pressure
- Thrust at Flow Cut-Off
- Thrust at Unseating
- Packing Load
- Stem Torque

Using the above information and the required stem thrust equation from the MOV capability analysis, the actual valve factor could be calculated. Then recalculate the required stem thrust using the calculated valve factor from the test results and the design-basis conditions.

A disadvantage is that INEL test data shows thrust can be non-linear with increasing DP. This would identify certain valves as being "unpredictable", and very hard to justify and set limits on extrapolation.

Prototype Testing

Prototype is defined, by the NRC, as an MOV that will perform in such a manner that its test results are applicable to the MOV being demonstrated to be operable under design-basis conditions. The prototype MOV may be identical to the MOV in question or similar in nature of the MOVs, and may be located in the same plant, in another nuclear power plant, at a test facility, or at any location where the MOV could be adequately tested. The prototype test data may be obtained from several MOVs in order to increase the reliability of the data.

A disadvantage is that prototypes cannot accurately represent any given valve. In addition, the valve would have to be tested at the design basis conditions and orientation of the valve as a minimum.

INEL Test Data

The Idaho National Engineering Laboratory (INEL) provided research for the NRC in their efforts to address Generic Letter 87, "Failure of HPCI Steam Line Without Isolation". INEL's research examined the methods used by the industry to predict the required stem force of a valve, and provide guidelines for the extrapolation of in-situ test results to design basis conditions. Conclusions of their testing indicated that regardless of fluid conditions, the valves tested required more thrust for opening and closing under various differential pressure and flow conditions than would have been predicted from standard industry calculations and typical friction factors. As a result of the testing, INEL developed an equation to predict the forces required to close the valve at design-basis conditions.

A disadvantage is that the equation is only valid for flexwedge gate valves in the closing direction that have been shown to be predictable.

SUMMARY

This paper addresses one approach to determining operability. Other approaches are available and it is up to the utilities to determine which approach best fits their needs. Design-basis testing is the only method approved for determining operability, however alternatives are available to evaluate operability with the best data available until design-basis testing becomes available. Which ever method the utilities use, data must be provided to justify their operability determination.

REFERENCES

NRC Generic Letter 89-10, *Safety-Related Motor-Operated Valve Testing and Surveillance*, issued June 28, 1989

Supplement 1 to Generic Letter 89-10, *Results of the Public Workshops*, issued June 13, 1990

NMAC/EPRI NP-6660-D, *Application Guide for Motor-Operated Valves in Nuclear Power Plants*.

NUMARC 91-01, *Industry Guidance in Responding to NRC Generic Letter 89-10*.

Limitorque Corporation, 1988, *Limitorque Selection Guide*.

NRC Generic Issue 87, *Failure of HPIC Steam Line Without Isolation*.

NRC Information Notice 90-40, *Results of NRC-Sponsored Testing of Motor-Operated Valves*, issued June 5, 1990.

J.C. Watkins, R. Steel, K.G. DeWall, *NRC Test Results and Operations Experience Provide Insights for a New Gate Valve Stem Force Correlation*, INEL

SAMPLE
OPERABILITY REVIEW AT PARTIAL DESIGN BASIS

This example will illustrate the operability review of a MOV using extrapolation of partial design-basis testing.

VALVE DATA

The valve used in this example is as follows:

Type:	Gate
Size:	4"
Seat Dia.:	3.5"
Stem Dia.:	1.375"
Operator:	Limitorque
Size:	SB-0-25
DP:	1750 psi
LP:	1750 psi
Undervoltage:	80%

MOV CAPABILITY ANALYSIS

Calculate the required thrust: (close direction)

$$ST = (VF \times A_o \times DP) + PL + (A_s \times LP)$$

where: $VF = 0.3$
$A_o = 9.62\ in^2$
$A_s = 1.48\ in^2$
$PL = 1500$ lbs

$ST = 9150$ lbs

Determine the valve limit:

The valve vendor has provided the following valve limits:

Seismic:	25000 lbs
Weak Link:	45000 lbs

Determine the operator limits:

Operator Thrust Rating:	24000 lbs
Operator Torque Rating:	500 ft-lbs
Spring Pack Capability:	
Max:	39106 lbs
Min:	4860 lbs
Motor Capability:	
100% voltage:	32475 lbs
80% voltage:	20784 lbs
Stall:	44653 lbs

ESTABLISH THRUST WINDOW

Based on the above evaluations:

Min CST: 9150 lbs

Max CST: 20784 lbs (80% voltage)

MAx TT: 24000 lbs (operator thrust rating)

Accounting for Torque Switch Repeatability (TSR) and Diagnostic Accuracies (DA):

TSR: 5.0%
DI: 9.2%

Using the square root of the sum of the squares method:

Accuracy: 10.47%

Thrust window based on equipment accuracies:

Min CST: 10220 lbs

Max CST: 18814 lbs

Max TT: 21725 lbs

MOV TESTING

Testing was not practicable at design-basis conditions, therefore testing was performed at less-than severe design-basis conditions.

Test Conditions:

DP: 1580 psi
LP: 1580 psi

Figure 1 shows the force trace taken from a full cycle design-basis test using the VOTES diagnostic system.

Figure 2 is a zoom of the trace in the open direction to locate the force needed to open the valve.

Force @ Unseating: 7111 lbs

Figure 3 is a zoom of the trace in the close direction to locate the force needed for flow cut-off.

Force @ Flow Cut-off: 11242 lbs
Force @ CST: 16693 lbs
Force @ TT: 18250 lbs

OPERABILITY EVALUATION

Operability evaluation will be based on the worst-case condition (closing direction). Additional data taken from the trace is the packing load.

Packing Load: 1000 lbs

Using the required thrust equation the actual valve factor can be calculated:

$$VF = \frac{ST - PL - (A_S \times LP)}{A_0 \times DP}$$

$$VF = 0.52$$

Using the revised VF, the required thrust at design-basis conditions can be calculated:

$$ST = (VF \times A_0 \times DP) + PL + (A_S \times LP)$$

where: $VF = 0.52$
$A_0 = 9.62\ in^2$
$A_S = 1.48\ in^2$
$PL = 1500$ lbs
$DP = 1750$ lbs
$LP = 1750$ lbs

$$ST = 12884 \text{ lbs}$$

Static testing was also performed to evaluate rate of loading. The following data was recorded:

Force @ CST: 16518 lbs

Comparing the static test results with the dynamic test results indicates a difference of 1% which is less than the 5% error for TSR. Therefore, rate of loading is not a factor for this valve. If the difference between the static and dynamic tests resulted in a value greater than TSR, then rate of loading effects would need to be evaluated.

Based on the revised required stem thrust calculation and equipment accuracies:

Min CST: 14346 lbs

CA9500180

ORGANIZATION OF THE MAINTENANCE PROGRAM AT THE CERNAVODA NGS

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ABSTRACT

The first part of the paper considers the maintenance related provisions of the agreements concluded by the Romanian Electricity Authority with Atomic Energy of Canada Limited and General Electric-USA, ANSALDO-Italy - Consortium for the Cernavoda Nuclear Generating Station. The main actions, carried out in keeping with these provisions and with the practice gained within Romanian electric power stations, are reviewed as well. The organization chart established for the maintenance department is also shown.

The second part of this paper deals with the maintenance related stipulations within the contract concluded by Romanian Electricity Authority with Atomic Energy of Canada Limited and ANSALDO Consortium for the completion and operation of the Cernavoda Nuclear Generating Station's Unit 1. The actions so far performed and the established organization chart are also included in this paper.

The third part of the paper presents studies and works under way within the Romanian Electricity Authority's research and design institutes, in order to train and specialize engineer staff capable to properly solve maintenance problems.

APPENDIX A

ORGANIZATION OF THE MAINTENANCE PROGRAM AT THE CERNAVODA NUCLEAR GENERATING STATION

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1. INTRODUCTION

The Cernavoda Nuclear Generating Station ("Cernavoda NGS") is a 5 units of 660 MWe each CANDU nuclear generating station located at about 70 km west of the city of Constantza, Romania. The Cernavoda NGS is being constructed by cooperation of the Romanian Electricity Authority ("Owner") with Atomic Energy of Canada Limited ("AECL"), ANSALDO Italy ("ANSALDO"),and with General Electric USA ("GE").

Between 1979-1991 the co-operation was developed based on the contracts concluded by the Owner with AECL for the Nuclear Part and with ANSALDO-GE Consortium for the Conventional Part, AECL having the role of the General designer. The contracts concern design, construction, installation, commissioning and initial operation of the first unit and equipment licences, equipment procurement and manufacturing. According to the provisions of these contracts, ultimately,the Romanian party would have been in a position of designing, constructing, installing, commissioning, operating and also manufacturing the equipment for CANDU 600 unit stations. The first part of the paper considers the maintenance related provisions of the contracts and the main actions carried out in keeping with these provisions and with the practice gained within the Owner's electric power stations. The organization chart established for the maintenance department is also shown.

In August 1991 the Owner contracted with AECL-ANSALDO Consortium ("AAC") within the Project Management Contract(PM Contract) that AAC perform, in the Owner's name and on its behalf, the management of the engineering, construction,commissioning and an 18 month initial operation of the Station's Unit 1. The second part of the paper deals with the maintenance related stipulations contained by this contract. The actions, so far performed, and the established organization chart are included in this paper as well.

The third part of the paper presents studies and works under way within the Owner's research and design institutes, in order to train and specialize engineer staff capable to properly solve maintenance problems.

2. PROVISIONS OF THE INITIAL CONTRACTS WITH AECL, GE AND ANSALDO CONCERNING MAINTENANCE

In accordance with the referred contracts, the foreign partners

have been assigned tasks within three main areas: personnel training, providing of procedures and manuals and assurance of technical assistance within the plant.

As for the maintenance personnel's training, the foreign partners are held responsible for:

- Providing a training program for the Cernavoda NGS staff in Canada, USA and Italy in accordance with an agreed schedule.
- Providing the Romanian station staff with a training for the positions they will be assigned within the plant. This kind of training will assure the availability of the key staff required for the proper operation of the station and will also make possible the training, in Romania, of the remaining personnel needed for the station.
- Assisting the basic trained Cernavoda NGS staff in the preparation of the programs and manuals for training the remaining staff required for the station.

As concerns maintenance programs, procedures and manuals, the contracts provide the following responsibilities for the foreign partners:

- Preparation of the program.
- Preparation of maintenance procedures and manuals.

As regards the technical assistance in the maintenance area, the contracts stipulate technical assistance in order to:

- Bring Cernavoda NGS to perform the commissioning and initial operation.
- Prepare final issues of maintenance procedure and manuals.

3. ACTIONS UNDERTAKEN

Considering that the effective maintenance is essential for the safe operation of a nuclear power plant, the Owner, technically assisted by AECL, ANSALDO and GE, has undertaken certain actions concerning the maintenance area, in accordance with the provisions of the Guide 50-SG-07, Maintenance of Nuclear Power Plants.

The selection of the required maintenance staff has been strongly emphasized. As a result, experienced staff of the conventional plants have been selected for the key positions. This staff has been preliminarily trained in our country (classroom training for about a year before starting training in Canada). They also ended their expert training abroad for the following positions: production manager, mechanical maintenance supervisor, control and instrumentation supervisor, planning chief, computer engineers (4), process system engineers (2), electrical maintenance engineer, training engineers (2). As for the Nuclear Part, a training for about 320 man-months have been provided, out of which about 170 man-months have been performed, while for the

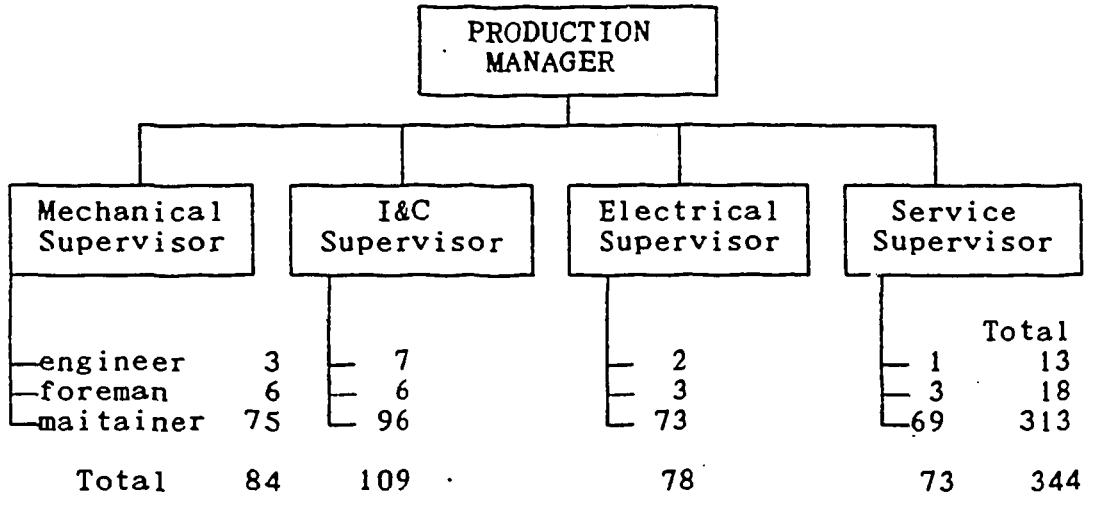
Conventional Part, a training of about 80 man-months have been provided, out of which 24 man-months have been performed so far.

All these engineers, on site, have been involved in:

- Establishing the training programs for the remaining staff within three modules in accordance with the Canadian practice.
- Selecting the rest of the staff (till 1990, the selection of the maintenance staff was performed in proportion of about 70%).
- Fulfilling the training program for the staff to be trained in our country.
- Establishing the programs for preparing maintenance procedures and manuals.
- Preparing maintenance procedures and manuals.
- Reviewing the design from a maintenance point of view in order to cover the following: access to plant items, space available for in situ work, interference with operation and maintenance areas of other structures and systems, provision for shielding and access control drainage and ventilation facilities on active systems, easiness of maintenance.

Our group of key maintenance engineers trained in Canadian Nuclear Generating Stations, technically assisted by AECL have established organization structure and number of the maintenance staff, using CANDU Stations,' as well as Romanian Conventional Stations', organization charts and also maintenance guides and regulations applied by the Owner. All these have been adapted and modified in order to answer the specific requirements and to apply to the specific features of the Cernavoda NGS.

The maintenance department is organized as shown in the organization chart below:



The maintenance department is organized in four sections under four supervisors, each professional engineer. Other professional

engineers are included in each section to perform such maintenance engineering functions as liaison with the Technical Unit for procedures and tool development. As one can see, there is a large staff number (344 persons) as against the number of staff in the Canadian CANDU- Station (about 145 persons at Point Lepreau NGS). We point out that choosing this large staff number was required by the specific conditions in Romania during that period of time, namely: non-existence of certain organizations specialized in maintenance areas, non-acceptance of the equipment manufacturers providing equipment repair services as well as the usage of repairing equipments and their component parts within the nuclear power station's own workshops and not having them replaced by new ones. As an example, we specify that in an Owner's conventional electric power of 550 MW, the staff number is of about 300 persons.

Till 1990, 70% of the maintenance staff were selected by the Owner and were included in the classroom training programs for about a year before starting on - the - job training. They ended the class room training course materials for Module I and Module II courses. The course materials for the Module I courses consist of training lessons in use by a Canadian utility for the training of comparable staff. Module II courses cover CANDU 6 systems and equipment.

In order to elaborate a "Maintenance Program" in accordance with the provisions of the Safety Guide No.50-SG-07, Maintenance of Nuclear Power Plant, the Owner has also resorted, based on contracts, to the services of the Owner's research and desing organizations having experience in maintenance and repair of conventional stations.

It is worth mentioning that, despite enthusiasm and professionalism manifested in preparing and finalizing a maintenance program which to cover all the areas set out by IAEA Safety Guide series No.50-SG-07, the outcome was not satisfactory either at the requirements level or at the possibilities level. This fact was due to the lack of professionalism demonstrated by the peak decision making leaders of the Romanian authority who, till 1987, imposed the personnel, trained in Canada for maintenance, involve in other different areas. Since 1989 a part of the key staff, although trained in Canada for maintenance activities, moved to other activities in the Nuclear Power Plant or to other organizations outside the Cernavoda NGS.

In conclusion, as far as preparation of maintenance is concerned, the contracting stipulations mentioned above have been partly fulfilled both by the foreign partners and by the Owner.

4. PROVISIONS OF THE RENEL AND AAC CONTRACT, 1991, CONCERNING MAINTENANCE

The contract between the Owner and AAC stipulates, as mentioned

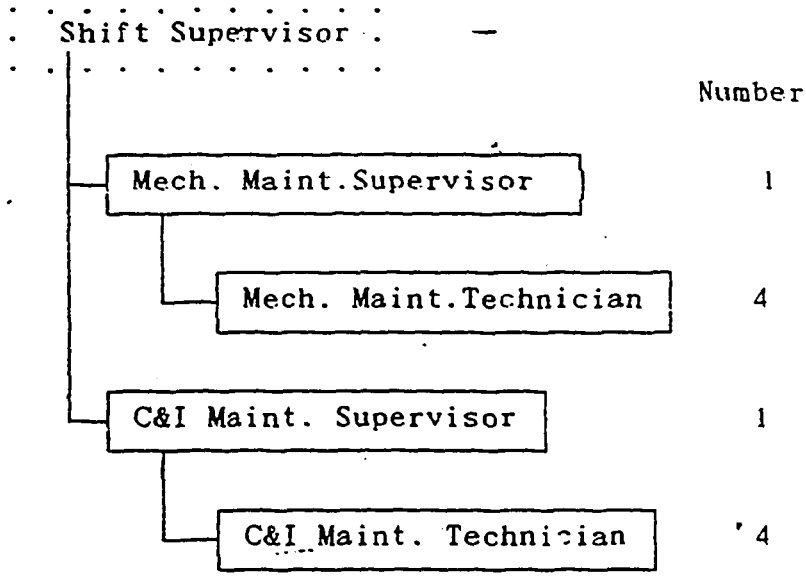
above. AAC's full responsibility for management of engineering, construction, commissioning and an 18 months initial operation of the Station's Unit 1.

Related to maintenance, the contract provides for AAC the following responsibilities:

- Developing of the maintenance and repair concept for the station, as normally developed for CANDU 6 nuclear power station, taking into consideration the requirements of the IAEA Safety Guide 50-SG-07.
- Developing, in consulation with the Customer, of a comprehensive Staffing Plan for recruiting, training and deploying the Operations Staff for Unit 1. The Staffing Plan's objective is a full complement of Operations Staff for Unit 1 trained and available for participation in commissioning of Unit 1 not later than 18 months prior to the scheduled connection of the Unit 1 to the Grid. The Plan shall identify and specify requirements for all Operations Staff positions, including academic, training and occupational experience requirements and descriptions for each position in the organization. The Plan shall include a schedule for the recruitment, training and deployment of the Operations Staff.
- Development, as part of the Project Management Work and in consultation with the Customer, of the criteria for the selection of the Operations Staff and assistance of the Customer in screening and selecting Operations Staff.
- Developing and providing training programs for the Operations Staff. The training services and programs shall be presented in two parts.Preliminary Training shall be completed in Romania prior to the selection of trainees for subsequent training off - shore as set out in the contract. The Customer shall present the Preliminary Training based on course materials to be provided by the AAC. Advanced Training shall be conducted by the AAC off - shore at operating CANDU reactor, reactor simulator and training centre sites to be established, as set out in the contract. Training periods for the individual positions shall last between 4 and 20 months.
- Establishing of a maintenance plan and implementation of the maintenance plan in Commissioning Phase and in the Operating Phase.
- Preparation and issuance, with the assistance of the Operations Staff (Owner's Personnel), of the selected maintenance procedures in English on the basis of documents originally issued by AECL, ANSALDO, GE and Romanian designers and suppliers..
- Preparation of a list of consumables required during commissioning and initial operation:
- Preparation of spare parts lists for commissioning and initial operation.
- Management of all Project materials, including procurement, warehousing and preservation of all material and equipment at Site, maintaining recording and control of quantities,

availabilit: ..d storage conditions of material and equipment.

- Management of the organization and implementation of maintenance and training of Customer's Personnel.
- Assignment of the AAC Maintenance Personnel shown on the NSP / BOP Commissioning and Operations organization chart, during the commissioning and operations phases, as shown below:



- Establishing and leading of the implementation of a document control system for commissioning and operations documents (including maintenance).
- Leading, supervising and performing, with the support of the Customer's Personnel, of the maintenance, including in - service inspection, making all required technical matters related to commissioning and operations.
- Monitoring of maintenance for compliance with the approved procedures.
- Training of the Operations Staff in Operating Cernavoda NGS as they develop the capability of, independently making decisions without AAC Personnel's support.
- Transfer by the AAC Operation Personnel of the leadership and supervision on a person - by - person basis to the Operations Staff (including maintenance), as they become trained and capable.

For the Customer the contract provides the following:

- Making available a full complement of Operations staff for participation in commissioning and operation under the technical direction of AAC Personnel.
- Assisting AAC Operations Personnel in preparing documents as required.
- Ensuring that the Operations Staff (Customer Personnel)

are available for their assignments.
- Preparing and submitting of licensing doc nts to the Romanian Licensing Authority, as required, in order to permit operation of Unit 1.
- Ensuring of the availability of required spare parts, consumables, tools and instruments.
- Providing of all local supplies and stationery required for preparation and control of documents.

5. ACTIONS UNDERTAKEN IN ACCORDANCE WITH RENEL-AAC CONTRACT OF 1991

A first priority action, both for the Owner and for AAC, was the assurance of the selection of the maintenance staff intended to be trained in Canada, as provided by the new contract. With this end in view, it was aimed at the completion of the preliminary training, at Cernavoda, of the potential candidates. Further, based on interviews organized by AAC and the Owner, the following engineers provided to be trained in Canada, were selected: mechanical maintenance engineer, mechanical maintainers (2), F/H mechanical maintenance engineer, F/H mechanical maintainer, F/H electrical and C& I maintenance engineer, SR F/H electrical and C & I maintainer, C & I maintenance engineer, SR C & I maintainers (2). These ones started their training in May 1992 at the Point Lepreau NGS, based on the training programs set out by AAC.

According to the contract's provisions, AAC drafted the concept of the Maintenance and Repair Program, taking into account the requirements of IAEA Safety Guide 50-SG-07. This draft is to be detailed and finalized by AAC.

Based on the contract's provisions, AAC has proposed the organization chart for the maintenance department shown in Appendix 1.

As one can see, the organization chart is similar to the organization structures used at Point Lepreau NGS. The provided staff number is also close to that of the Point Lepreau NGS but it is reduced as against that provided by the Owner, technically assisted .in this respect, by AAC during the period between 1989-1990. This problem is to be solved by taking advantage of the Canadian experience as well as of the special features of the Cernavoda NGS.

All the activities required for creating a well organized maintenance department properly provided with documentation and necessary material resources shall be managed by AAC. These activities shall be correlated with the construction schedule.

6. OTHER ACTIVITIES REGARDING THE MAINTENANCE PROGRAM

As far back as in the period when the Customer was responsible

for the completion of the Maintenance Program. he involved, based on contracts. his research and design organizations in activities preparing the maintenance for the Cernavodă NGS. Related to the that:

- One of the characteristics featered by the Cernavodă NGS is that four distinct technologies are being used (the basic equipment of the plant is designed and manufactured under Canadian. American. Italina and Romanian licences).
- Another feature of the Cernavoda NGS is the lack of appropriate experience in addressing maintenance problems that are connected. mainly with the NSP but also with the BOP insofar as the latter implies a leap in technology and power (the biggest power group in Romania is 33o MW)
- AAC contract provides as a task for AAC the preparation of the selected maintenance procedures only. not of all the procedures.
- And last but not least due to the limited financial resources of our country in this period of economic transition the management of RENEL has decided that the research and design institutes (ISPE-ON.ICEMENERG- BUCHAREST and ICN PITESTI) be involved in the activities related to the maintenance program for. Nuclear Power Plants. on the contracts basis.Through the works under way we pursue the following objectives:

- To get thorough knowledge about the types of defects. by families of equipment.
- To maintain and improve the reliability of components. equipment, systems.
- To cut down the number of defects (and hence the number of shutdowns).
- To cut down the operation costs.
- To reduce the integrated dose, by applying modern techniques and correct procedures.

The principles we will adopt in the organization of the maintenance activity will consider the Romanian experience with conventional power plants. the Canadian experience in the field as well as strict observance of the requirements of IAEA standards.

In order to address these categories of problems we think it is necessary to solve the following:

- The present status of Cernavoda Unit 1 (instalation finalization) does not allow for an integral defining of the maintenance program (surveillance activities. preventive. predictive. corrective maintenance. in- service inspections etc.) without a preliminary analysis of the type of systematic defects occuring with CANDU reactors. the location. frequency and remedy of such defects.
- Undoubtedly. each category of equipment (considering the four categories of technological licences) has its own "sicknesses" and the designer's position versus this

situation is rather to replace the equipment.

These elements reflecting the real, present state of things at Cernavoda lead us to the conclusion that for the beginning the elaboration of a maintenance concept based - a priori - on predictable defects, prediction methods and related repair techniques is an acceptable approach.

Nevertheless we are aware of the fact that these are only "early reflections" that will maturate as far as we get experience in the operation of nuclear power units and that only a thorough analysis of our own experience in this field will let us establish a maintenance strategy of an optimum technical - economic level.

In establishing the maintenance program that represents the plant's reference plan (covering the organization of the maintenance activities, responsibilities, implementation, scheduling and control methods) we shall pursue the following objectives:

- To gather data on equipment behaviour in operation and maintenance (by recording the "history" of equipment operation).
- To analyse the evolution of the operating parametres of equipment in order to predict defects and determine the opportunity of taking the equipment out of operation in order to perform the maintenance works.

We would like to draw attention - expecting critical comments to the following areas and types of systematic defects occurring with the main systems and the ways of solving these problems, as we envisage at this moment.

Nuclear Steam Supply System- the areas subject to testing and in-service inspections shall be selectively (not exhaustively) selected considering the presence of special erosion, corrosion, mechanical and thermal fatigue conditions. Consequently, the maintenance staff shall focus attention to:

- Areas that present geometrical singularities to which the common designing criteria cannot be easily adapted.
- Areas where the fracture and toughness of materials could have an unpredictable evolution due to the existente of a strong field of radiations and to significantly increased pressure and temperature conditions.
- Areas where the corrosion and/or erosion process can be very active.
- Manufacturing defects the repair of which does not provide the required level of confidence.

At present we are examining the possibility:

- To procure a complete system for multiple control and in-service inspection ot the pressure tubes - CIGAR type.

- To procure only the control tools with possibilities for ultrasonic detection, eddy current, televisual detection and determination of the pressure tube deflection.
- To use the canadian service team for inaugural and in-service inspection.
- At the same time the F/M head simulator is almost finalized and for the same system ultrasonic and ultraacoustic techniques are under study.

Steam Generator - two main objectives are associated with the maintenance of the bundle of tubes:

- From nuclear safety point of view: maintaining the probability for a pipe to break at approximately the same probability as designed.
- From the point of view of the availability in operation: limiting the number of shutdowns caused by abnormal D_2O losses.

The steam generator defects are mainly located with:

- The small bend radius pipes, at the return zone, susceptible of corrosion under strain.
- The peripheral pipes susceptible of defects resulting from friction against impurities in the secondary system.
- The pipes located in regions with low circulation rate: corrosion under strain as well as classical corrosion.
- The pipes in the transition chucking region: corrosion under strain, longitudinal or circumferential, simple or multiple cracks.

Given the aforementioned, the maintenance staff should permanently "master" the leaks before pipe breakage may occur. This concept shall be based on the knowledge and application of a number of data and actions:

- Location- detection methods and techniques;
- Characteristics of design, manufacture, installation and operation.

At the present stage we are examining the endowment of the maintenance department with:

- Helium leak detection techniques.
- Eddy-current, non-distructive examination system; training of teams of specialists able to perform tests and to interpret the results of tests.

We are also considering the studying of the tube post welding heat treatment "in situ", the possibility for eliminating (reducing) residual strains in the transition ares of the tubes in the tubular plate as well as the preparation of repairing mothods for the tubes in this area.

Saturated Steam Large Turbines - the statistical information in

this area estimate that these are not available at 1% of the theoretical producible energy: this figure could be reduced through an apropriate preventive maintenance.
The main actions of maintenance carried out on inlet parts as review of the records relating to the vibration surveillance systems. tightness control. verification of functional backlash. verification of rod deflection. visual and liquid penetrant examination of rods. large elements and stelite coated element. Also the actions of maintenance have been carried out on rotors and housings as verification of rotors movement in the turbine housings. verification of rotors alignment in the turbine housings. analysis of the vibration parametres of the turbine rotors, ultrasonic and magnetoscopic examination of the studs of the high pressure unit. magnetoscopic examination of the mobile blades. ultrasonic and magnetoscopic examination in the connection areas of the shafts. ultrasonic examination of the fretted disks and shafts of the low pressure rotors. ultrasonic examination of the stiffening wires of the last pressure stages.

At this stage we are examining offers regarding the procurement of systems for measuring. monitoring and analysing the vibration parametres with a view to performing the vibrodiagnosis of turbine rotating machinery in general: a group was formed in this respect (consisting of two engineers) who will perform vibration measurements and analyses.

Ultrasonic and magnetoscopic examainations will be provided by our own forces or will be contracted with other specialized companies.

For large operations (rotor aliagnment. centering) within the planned repair works or the preventive maintenance activities specialists from the traditional suppliers of equipment will be contracted.

Also in an advanced stage of elaboration there is an on/line method for determining the outstanding lifetime of turbines (the method also applies to other kinds of equipment) based on numeric analysis of the tridimensional fields of mechanical and thermal strains using izoparametric finite elements.

A distinct place in our preocupation is held by the organization of a data base (event file) containing statistic reliability data and presenting the feedback from the experience gained inoperation and maintenance. In order to create a data base to define the maintenance concept and support the maintenance activities carried out in the NPP a number of works are under preparation:

- A study into the modern methods of planning. organizing and perfoming repairs in NPP; the adaptation of a modern system for the Cernavoda NPP.
- A study concerning the setting-up of a maintenance base at the NPP.
- Maintenance lists for equipment in the NPP.

- Maintenance process sheets for equipment in the NPP.
- Maintenance procedures for equipment in the NPP.

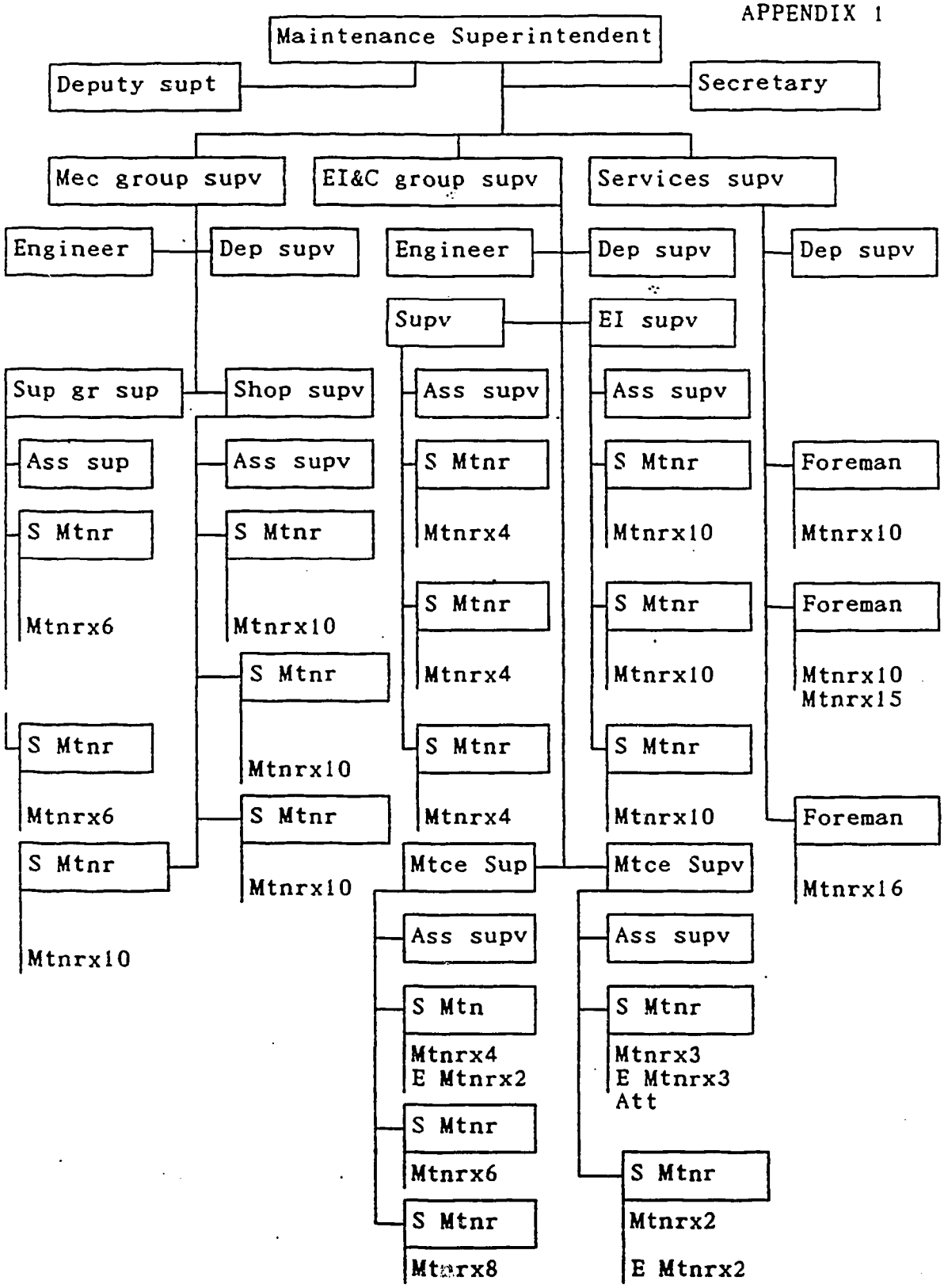
As regard the NPP, the following regulations have been prepared:

- Lists of test and inspection on CANDU-type mechanical equipment.
- List of inspection and tests on electrical , instrumentation and control equipment in CANDU-type plants.
- Other regulations concerning NPP specific activities that have to be aligned to the international standards in the nuclear field are under preparation.

In Appendix 2 there are given the main legal regulations in force, regarding the maintenance activities in the Owner's conventional plants.

Based on the activities being carried on at present, we shall pursue the fulfilment of two objectives: on one hand to make available, for the Cernavoda NGS, certain"tools"(methods, technologies) necessary for applying a substantial maintenance program (out of which some of them have been mentioned before): on the other hand we shall dispose of an engineer body expert in maintenance, which shall contribute to a more reliable and economical operation of the Cernavodă NGS.

APPENDIX 1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Secretary
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APPENDIX 2

LIST OF REGULATIONS APPLICABLE TO MAINTENANCE ACTIVITIES IN THE OWNER'S CONVENTIONAL POWER PLANTS

1. PE 016/84 - Technical norm for the repair of power equipment and installations.

2. PE-016-7/88 - Department technical norm for the repair of apparatuses and installations for the detection of defects in cables.

3. PE-027/86 - Instructions for the acceptance of the technical revision, current repair and capital repair works in electric power plants.

4. PE 116/84 - Norm for tests and measurements on electrical equipment and installations - 4th amendment - 1990.

5. PE 116-2/88 - Norm for tests and measurements on automation installations in the electrical system of the plants and stations.

6. PE 211/80 - Norm for test and in-service inspections on thermal and hydrodynamic equipment in thermal power plants.

7. PE 005/85 - Rules for the analysis and evidence of operation incidents in installations for the generation, transport and distribution of electric energy and heat.

8. PE 013/84 - Norm concerning the methods and elements for the calculation of the safety operation in the of the power equipment.

9. PE 028/87 - Guide on the reliability indicators for the main products used in power installation.

10. - Repair process sheets for mechanical, electrical, I&C equipment used in the electric power plants in Romania (368 - repair process sheets").

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REMOTE HANDLING INNOVATION FROM FUSION

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Abstract

In the following paper we will show a proactive approach to remote maintenance involving design of plant to be remote handling friendly, design of retro fit systems, use of graphical computer simulation tools to look at maintenance options and the integration of state of the art technology as warranted. Work on magnetic confinement fusion, inertial confinement fusion and for the US Environmental Restoration Program performed by SPAR ATSG will be used to illustrate the approach.

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1.0 INTRODUCTION

In Fusion research and on the US Environmental Restoration program a large amount of work has been done on planning for maintenance, especially in Remote Handling which is a key need in former waste facilities and future fusion plants. This work when supplemented by relevant practical experience has many parallel applications within the CANDU community.
SPAR work in Fusion has a long history with direct involvement in JET, NET, TFTR, CIT/BPX, ITER and PILOT magnetic fusion programs and the Prometheus Inertial confinement fusion program. Some of this work is and has been in conjunction with the Canadian Fusion Fuels Technology Project. In the US Environmental Restoration program SPAR is an active player with involvement including test bed work for the Hanford tank remediation program using a SPAR 2500 manipulator arm originally developed for CANDU use.
This paper looks at the application of that experience to the maintenance of large power plants.
In maintenance of large power plant down time costs are such that potential savings in shut down maintenance justify a highly proactive stance in looking at maintenance impact. Maintenance planning that should actively consider the relevant usage of both manual hands on and remote handing as part of the maintenance menu. For new facilities it becomes economically viable to consider future maintenance costs during the design process and do off line investigation of tasks long before they are anticipated to be needed. In existing facilities changing regulatory environments, the emergence of materials related and other problems unforseen during the original plant design and the emergence of new technologies cause a similar proactive process to become viable. In parallel to this investigation of maintenance tasks it is also advisable to actively investigate emerging technologies to reap any benefits they may give to maintenance.

2.0 OVERVIEW OF PROBLEMS

Before looking at the maintenance challenges in CANDU power stations it is a good idea to consider the wealth of exploitable experience from related areas. This includes the historical perspective from other mature nuclear programs, some of the problems encountered in Environmental restoration of former nuclear research facilities and research directed toward future power sources like Fusion. The civil nuclear power programs in the UK, USA and France, having all had power plants go through full life cycle, have been a steady source of exploitable experience. Much of this is now public knowledge with many published accounts and papers [1]. Relevant experience from other areas like the US environmental restoration program and Fusion research is less well known in the CANDU community and is thus used to illustrate this paper.
The US environmental restoration program has been going on for a number of years mainly concerning the cleanup of transuranic and related wastes from 'former classified sites'. The changes in regulatory environment together with accumulation of a greater knowledge of the effects of the materials involved has resulted in the need to plan and perform remediation tasks on former work sites and storage facilities. This involves an array of tasks in inspection, surveying, remediation planning as well as the actual remediation activity with work in a full spectrum methods from hands on to full remote operation.
Fusion research has been going on for over 60 years at a gradually escalating level, though the technical and materials challenges involved mean that commercial utilisation will not occur for another 20 years. Work is generally centred in 3 areas, theoretical research, design and usage of major international fusion test facilities (eg JET, ITER), and studies looking at the economics and technical feasibility of the commercial reactors which will derive from the research work. SPAR has a long history of involvement in the latter two activities making use of our expertise in materials, reliability analysis, maintenance planning, remote handling planning and remote handling operations. Currently proposed fusion research reactors like ITER (see figure 1) and studied commercial fusion power plants like

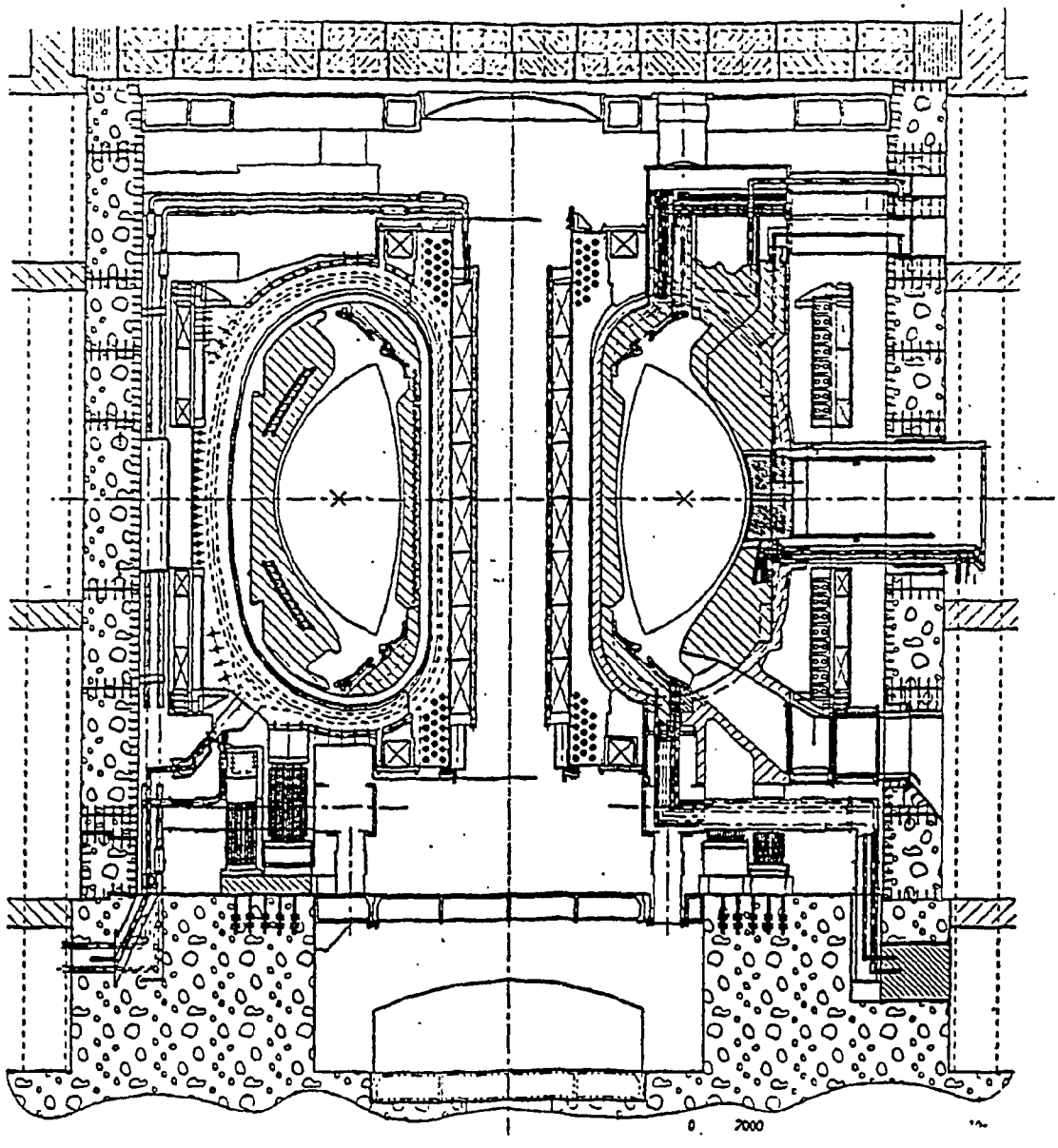

Figure 1 ITER Fusion Reactor typical cross section

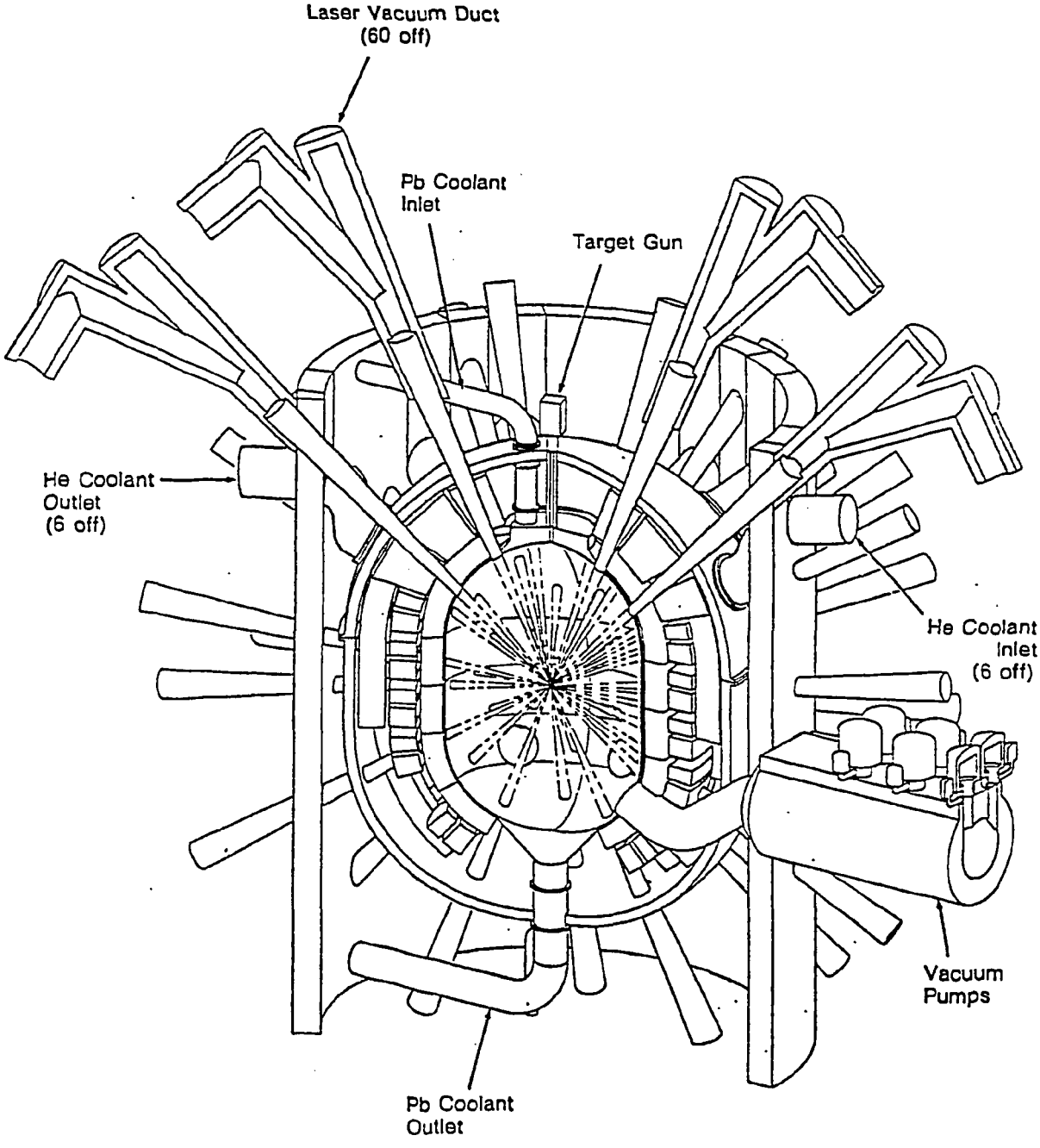

Figure 2 Prometheus Reactor Vessel (Laser drivers)

Prometheus (see figure 2) are physically very large with key areas off limits to humans due to the high radiation levels as well as other factors, like the use of inert gas atmospheres to stop contamination of vacuum areas. The novelty of the reactor hardware together with the size, access and atmosphere factors has meant that a significant body of planning work is needed [ref 2,3,4] as well as the more normal maintenance support during actual usage.

3.0 TASK ANALYSIS

In maintenance of large power plant down time costs are such that potential savings in shut down maintenance justify a highly proactive stance in looking at maintenance impact. It becomes economically viable to consider future maintenance costs and do off line investigation of possible repair tasks long before they are anticipated to be needed. While this is easily the case for new plants it is also becoming increasingly proven for use with retrofit systems for existing plants. This investigation of future tasks can be used to quickly check that potential problems will not have a significant economic effect on plant operation. In doing this it is also necessary to actively investigate emerging technologies to reap any benefits they may give to maintenance as well as checking any negative effects from changing regulatory limits.

3.1 Task Analysis on Prometheus

In the PROMETHEUS study of a 1000 MW Inertial fusion power plant all the principle plant items were identified and their relationship from an availability standpoint was identified. The inherent reliability of these plant items was then calculated using a combination of factored past data and expert analysis. Scheduled maintenance requirements for these items were then investigated with key maintenance tasks, both scheduled and failure related, analyzed to produce a total plant availability. When combined with a safety assessment this allowed the relative importance of the scheduled and failure case tasks to be assessed with effort expended to further analyze the most critical.
For the reactor, excluding drivers (Note: the drivers are the energy sources used to trigger the fusion process in the reactor chamber), the key tasks identified were as follows;

-target injector replacement
-first wall panel replacement
-heat transfer blanket replacement
-lead coolant pump replacement
-lead waste stream pump replacement
-helium coolant pump replacement
-vacuum pump replacement

4.0 EQUIPMENT SELECTION OPTIONS

Having looked forward to identify probable future maintenance tasks it is then advisable to investigate human and equipment needs for both those and the ever present unplanned failure cases. This identification may not necessarily be concerned with purchase or design but simply to investigate options and the times needed to get and train human resources and procure hardware. There are essentially three ways maintenance may be carried out.

Hands On Maintenance	This includes regular contact maintenance or contact maintenance in a controlled area with a partial or full change of clothing which may includes a ventilated or "Bubble Suit".
Semi-Remote Maintenance	Maintenance using long handled tools or maintenance from behind temporary shielding.
Fully Remote Maintenance	Maintenance is carried totally remote from the work place using manipulators or robotic devices.

The type of procedure adopted will be determined in part by ALARA guidelines and in part by the degree of protection necessary because of the radiation levels present. In general there is a time penalty to be paid when maintenance is carried out semi or fully remote. However, if the task involves many repetitive operations this time can be recovered by the use of automation if the fully remote devices are programable.
Having decided on the maintenance method then requirements for manpower, protective equipment and remote equipment can be started to be assessed. Before making a final decision however it is usually a good idea to look at what equipment options exist as these can often drive the maintenance approach.

The following sub-sections review the equipment areas that are considered pertinent to the maintenance task.

4.1 Inspection Devices

Inspection devices range from simple viewing and sensing instruments to complex work space surveying and mapping devices. Inspection equipment is used to better assess the condition of the plant items and generally includes visual inspection devices, radiological sensors, Non Destructive Examination (NDE) sensors like ultrasonics ,and materials sampling probes. In some cases surveying equipment will then be deployed like 3D coordinate measurement devices to measure wear and displacement. Examples of surveying equipment include the mechanical probe based channel measurement device used to measure the changes in fuel channel alignment in UK Magnox reactors due to graphite shrinkage and the more complex laser cameras being tested for Fusion and Environmental Restoration use for mapping wall profiles. While single sensors have been available commercially for many years the thrust of investigation in both Fusion and Environmental restoration involves the 'fusing' of signals from more than one sensor to create a composite image that shows more information.An example of this for Fusion has magnetic and position sensor readouts fused together on a computer to show the alignment of the magnetic containment fields to the reactor walls.

4.2 Payload Handling Devices

Payload handling devices have evolved from simply being hoists and trolleys to cover a range of newer variants which can cover more eventualities with varying degrees of automation. These include trolleys which vary from those pushed by humans through more complex powered trolleys to a range of automatic guided vehicles which are remotely controlled. Overhead devices range from simple fixed hoists through a range of deployable hoists to more complex mast based cranes which can use manipulators to perform fixing operations on payloads which the mast is supporting. In between these two types of device are a range of more specialised items like legged robots being developed to handle stairs, and crawlers designed to deploy tools and sensors along ducts and pipes.
Examples of these in Fusion use are many with developments including a range of truss based deployable cranes that can be stored in a central location and deployed in a variety of locations were it is uneconomic to leave fixed cranes both from a radiation life and usage stand point.

4.3 Manipulators

Manipulators were first developed for nuclear use in the 40s and range from simple open loop devices through mechanically linked master slave manipulators (MSMs) through to more complex electrically and hydraulically linked dexterous devices. While all these device types are in general power station use in Europe, in North America however the power industry has been mainly using more crude open loop devices along with mechanically linked MSMs. More complex manipulators have been gaining more acceptance due to the large safety and productivity benefits available. A number of current Environmental restoration and Fusion development projects have extensive remote handling capabilities which can be looked at as examples of state of the art. Figure 3 shows the ITER In Vessel Vehicular System [5]. Though the ITER reactor does not yet exist a number

A	SHOULDER PITCH	+/- 120°	(SHOWN AT -90°)
B	SHOULDER ROLL	+/- 12°	(SHOWN AT 0°)
C	MAST	5m	(FULLY RETRACTED)
D	WRIST YAW	+/- 180°	(SHOWN AT 0°)
E	WRIST PITCH	+/- 15°	(SHOWN AT 0°)
F	WRIST ROLL	+/- 100°	(SHOWN AT 0°)

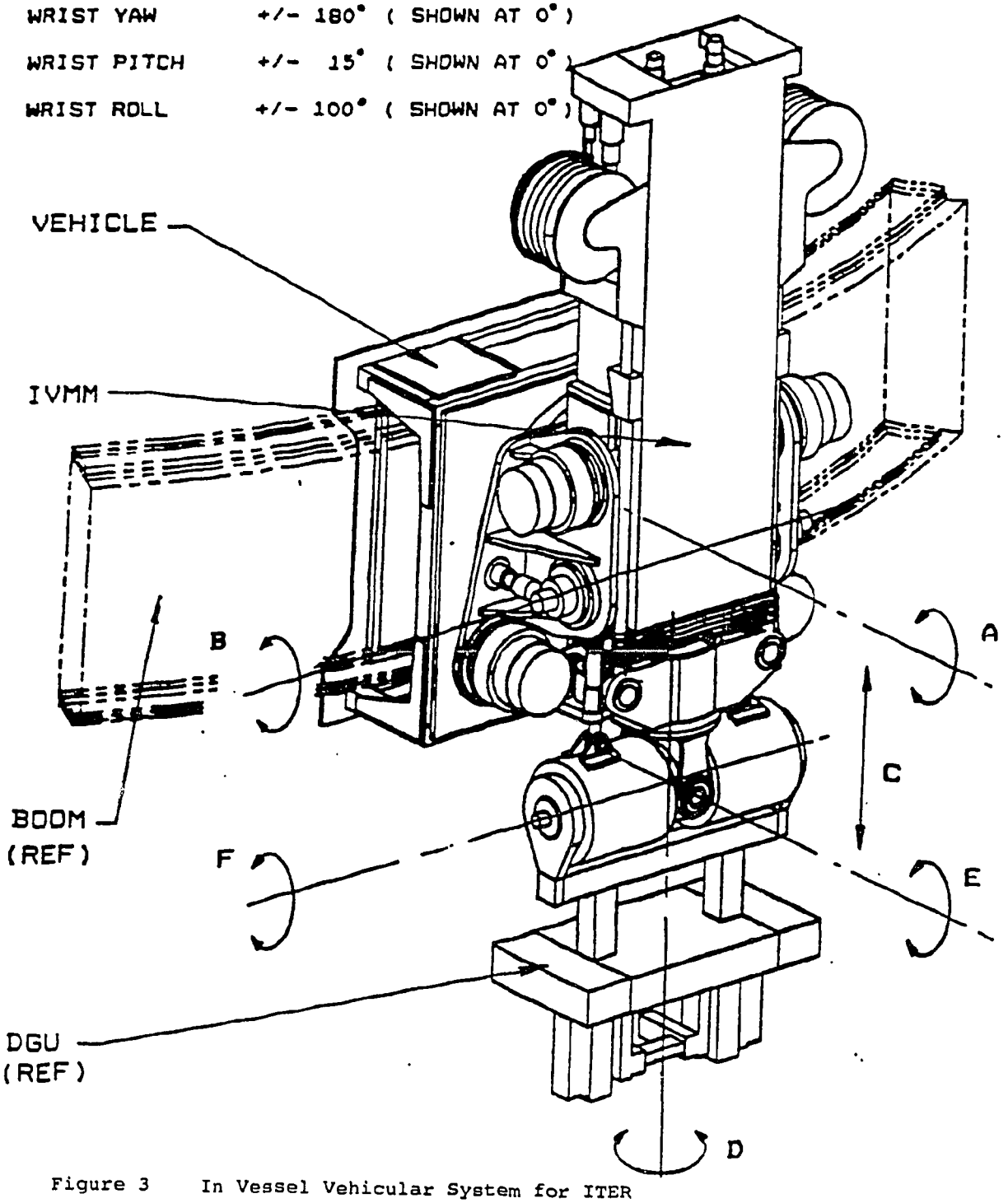

Figure 3 In Vessel Vehicular System for ITER

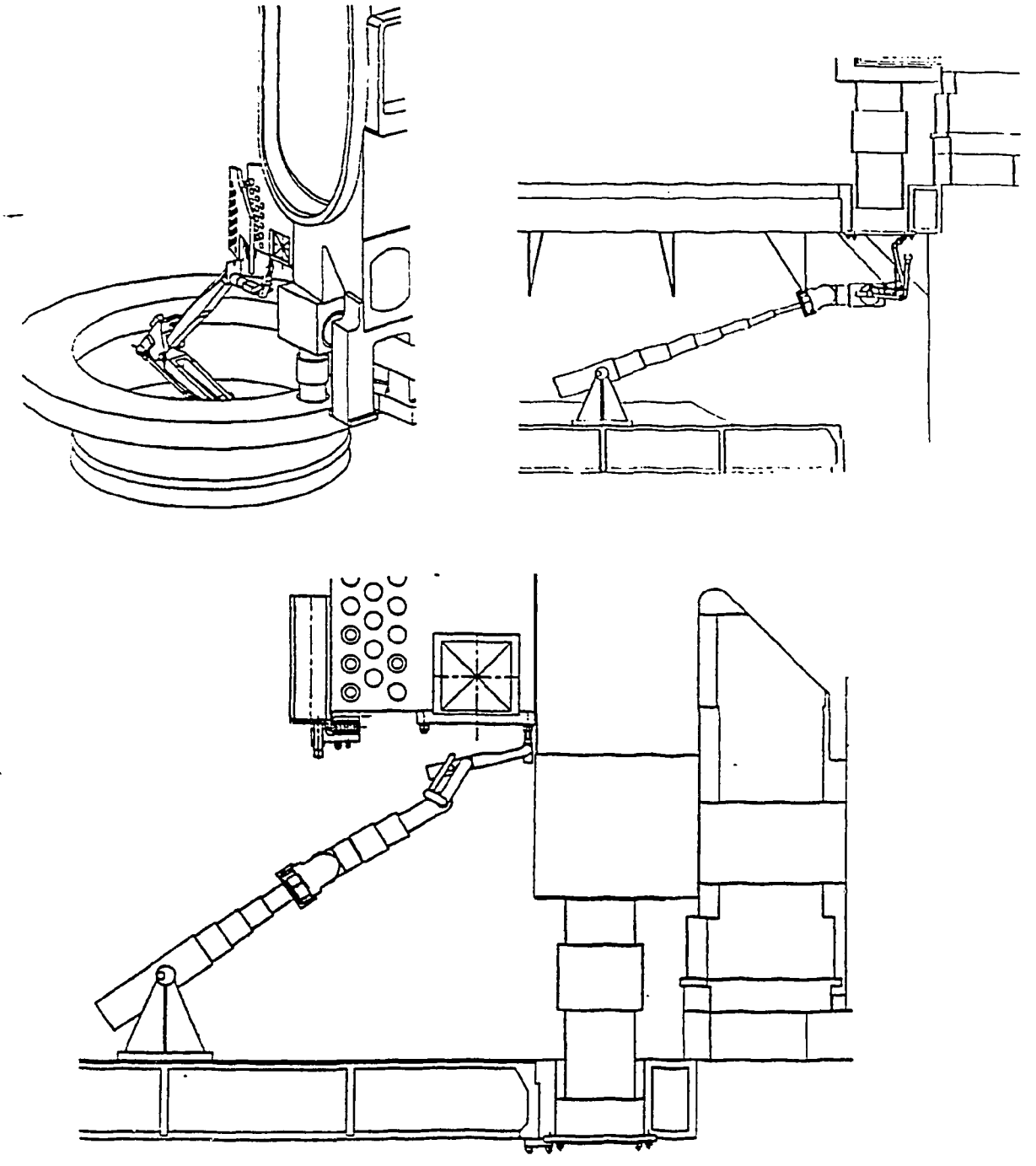

Figure 4 NET Lower vessel Maintenance

of prototypes of this device are under construction. It has a deployable rail on which 1 tonne payload telescopic manipulators run round to perform maintenance tasks like divertor replacement. Figure 4 shows various manipulators working in the lower vessel area of the ITER machine on typical tasks. The small manipulators shown are the Mascot and RD 500 with the large manipulators being the SPAR telescopic and 2500 devices.

5.0 TASK/ INTERVENTION PLANNING

The detailed planning of future tasks has been done in many industries from some time. From experience with other fission power programs it would appear that the innovations in Fusion research in this area are of relevance to CANDU in both their power and economic advantages.
In order to minimise down time during repair both diagnosis time and repair time should be considered. Built in test systems for fault diagnosis are becoming increasingly more powerful. They are designed to minimise the diagnostic skills needed at the repair site and ensure that the repair time is minimised by allowing correct replacement parts and the relevant repair specialist to be at the site immediately the fault is detected. Built in test systems like this have been proven in defence systems like the US Navy ANSAR8 surveillance system. For analysis of repair time tasks can be looked at off line using mock ups though with modern CAE tools this effort can be greatly speeded up and streamlined. Modern CAE tools, like IGRIP, are used in kinematic and dynamic analysis of tasks allowing design requirements and concepts to be more quickly and accurately developed. Manipulator concept development can be aided greatly by comparing different manipulators on the same task. By using existing equipment device models the task analysis work can be fine tuned with real testing feedback to 'calibrate' estimates and prove the dynamic models.

5.1 Prometheus Task Analysis

In the Prometheus study the reactor vessel, due to its relative importance, was the area chosen for most complete maintenance analysis. The laser driver option was used as the principle example due to its more onerous access problems. The sixty laser beam lines spread round the vessel causing far more challenges than the Heavy Ion beams which are bunched into two locations. The reactor design was heavily tailored to suit repair and replacement during use with an overall vertical maintenance scheme chosen. The top of the vessel is designed to be removed with all internal parts removable upwards so that the only access from the bottom is for access to the lead coolant outlet pipe and the contaminated lead outlet pipe. Since the worst contamination is associated with the contaminated lead stream from the front of the first wall this contamination can be flushed down into the vessel during maintenance from whence it will simply pass down the pipe work provided to the contaminated lead cleanup area in the tritium building.
Though most maintenance activities involve work inside the reactor, like the replacement of first wall panels every five years, some external access is needed. Access to work on driver ducts, helium ducts and pipe connections is accomplished using a combination of long reach manipulators from above and mobile devices from below.

The general procedure for dismantling the reactor for internal work is as follows

(a) The lead coolant system is drained and the first wall flushed out.

(b) To provide access the shield slabs in the floor of the upper access chamber are removed and the remote maintenance equipment moved into position.

(c) The sections of pipe providing coolant into the top of the reactor are removed to provide clear access to the top of the vessel.

(d) Sections of driver duct at the top of the vessel are cut and moved clear.

(e) the target gun is moved clear of the top of the vessel.

(f) the top of the reactor vessel is unbolted at its flange joint with any seal weld cut.

(g) The reactor top is lifted clear into the upper access tunnel.

(h) The helium manifolds are disconnected from the down pipes at the joint.

(i) The first (top) blanket ring is removed after its support ties are released.

(j) The second blanket ring is removed after its support ties are released revealing the first wall dome.

(k) The upper first wall dome panel is released and lifted off.

(l) Further blanket rings and first wall panels removed as required.

Figure 6 shows the sequence of reactor dismantling with figure 5 showing a trial hot cell assembly of replacement reactor core parts.

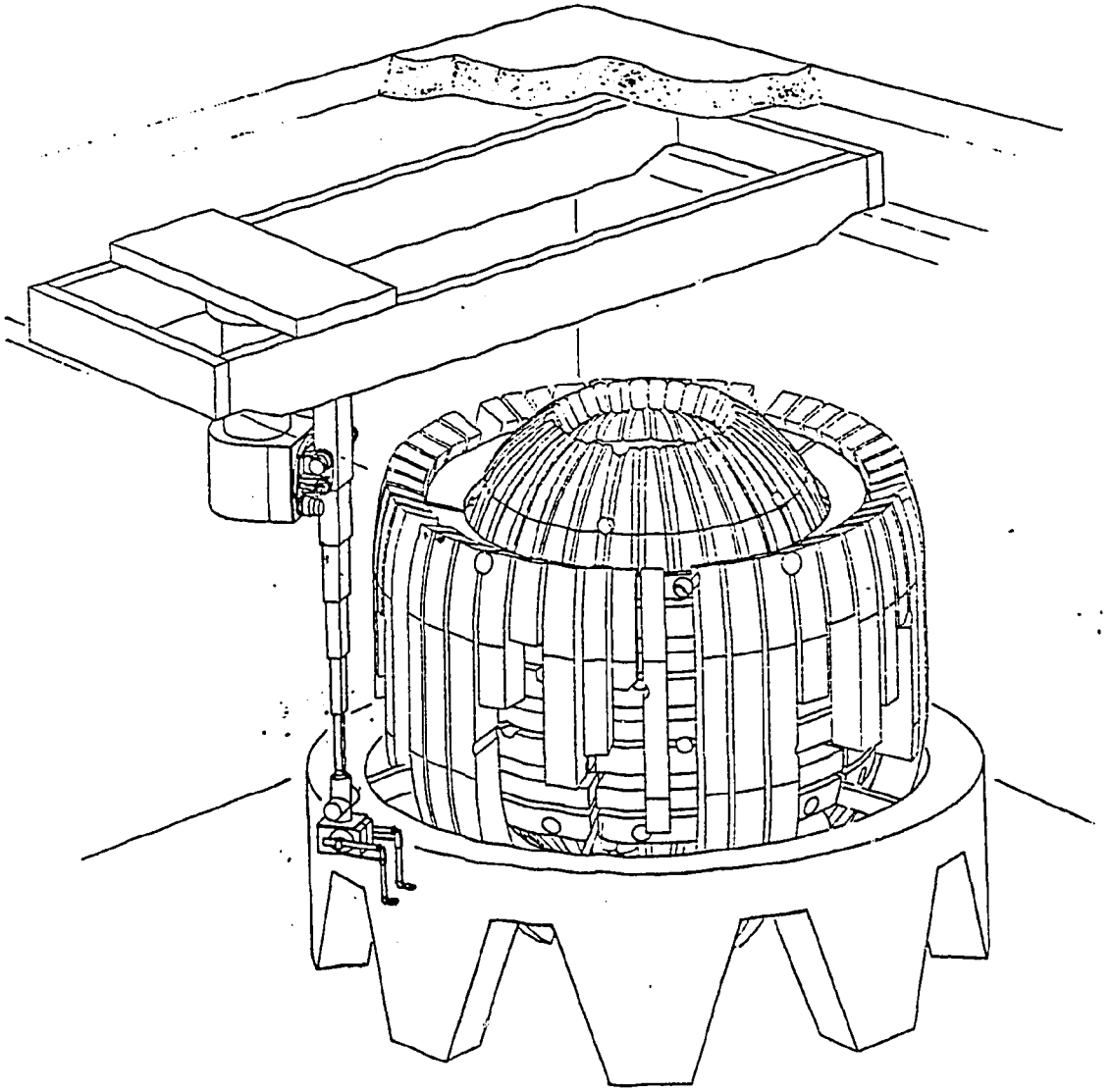

Figure 5 ICF Reactor core trial assembly in Hot Cell

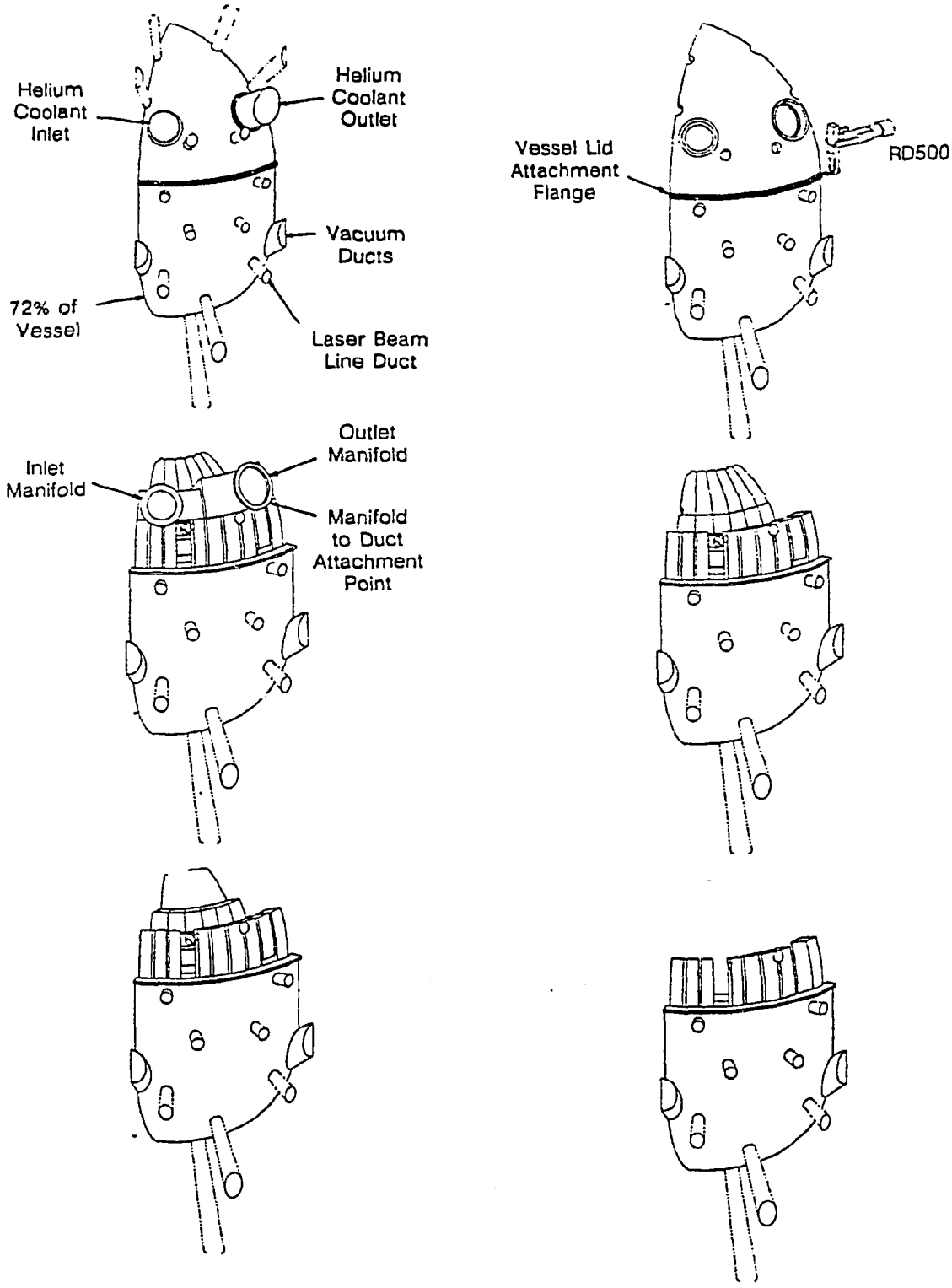

Figure 6 ICF Reactor dismantling sequence

6.0 TEST BED USAGE

Test beds are made use of in much of the nuclear industry to plan intervention tasks and train operators. These test beds vary in complexity from the UK Nuclear Electric Littlebrook facility with its multiple full size reactor mock ups with associated computer simulators to far more simple temporary mock ups. In many facilities these test beds are not only used for task planning but are also used for equipment development and selection. In the fusion and Environmental restoration fields the following two examples of SPAR involvement help describe typical usage of advanced test beds.

The Joint European Torus (JET) is a multi-national fusion experiment sited in the UK. Next to the reactor hall in the JET facility is a linked hall with common cranage used for preassembly of parts and as a test bed site for intervention planning. The test bed activities [7] involve both trials in an old sector of torus and computer based simulations on a graphical simulation program. Figure 7 shows the Joint European Torus TARM and Articulating Boom Manipulators together with supporting mobile trolleys and mater slave teleoperated manipulators in the test bed location.

The U.S. Department of Energy (DOE) has created a test bed for the development, testing and evaluation of robotic technologies for waste retrieval from underground storage tanks [6]. Spar and Ontario Hydro have supplied a Spar 2500 manipulator to DOE for use in the test bed. The Spar 2500 was originally designed for retubing CANDU reactors but has approximately the payload and reach required for waste retrieval operations. Figure 8 shows the test bed which includes a partial mock-up of a storage tank, a central control system, multiple robotic manipulators (Spar 2500 and Schilling Titan), sensors, and surveillance systems. The test bed allows present technologies to be evaluated and developed for possible use in future full-scale retrieval systems.

7.0 CONCLUSIONS

CANDU maintenance can be aided through the use of technology and experience from other areas. The body of knowledge being gained and technology developed in the Fusion and Environmental restoration fields has been shown to be CANDU relevant and worthy of further examination to aid future CANDU maintenance work.

8.0 ACKNOWLEDGEMENTS

The authors would like to acknowledge the valuable contribution made by colleagues at NET, CFFTP , the Prometheus team and at SPAR Aerospace Ltd. Prometheus work supported by US DOE contract DE-AC02-90ER54101. Cleared for public release, Export Authority:22 CFR 125.4(b)(13) applies.

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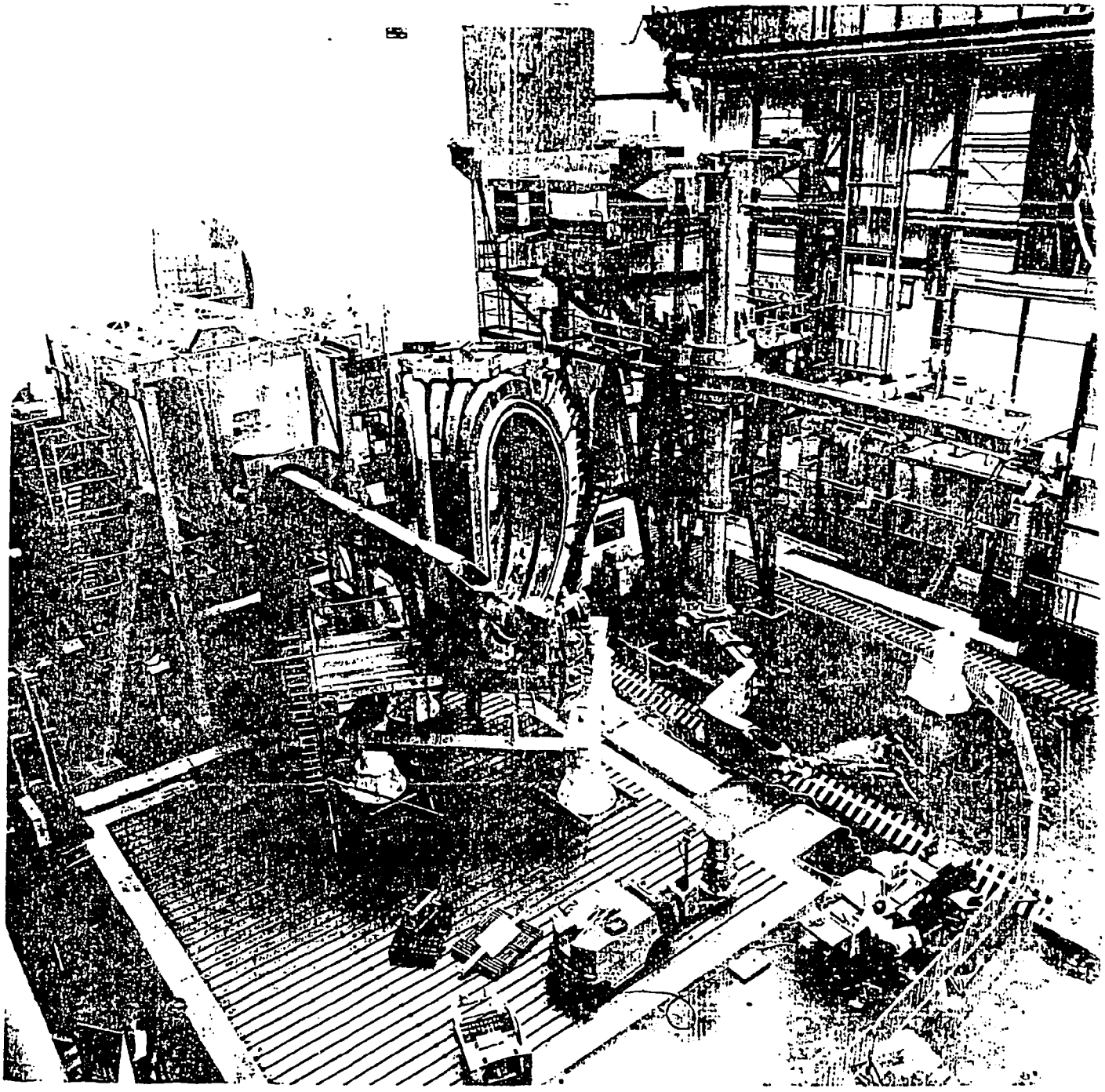

Figure 7 JET Test bed with Manipulators and AGV

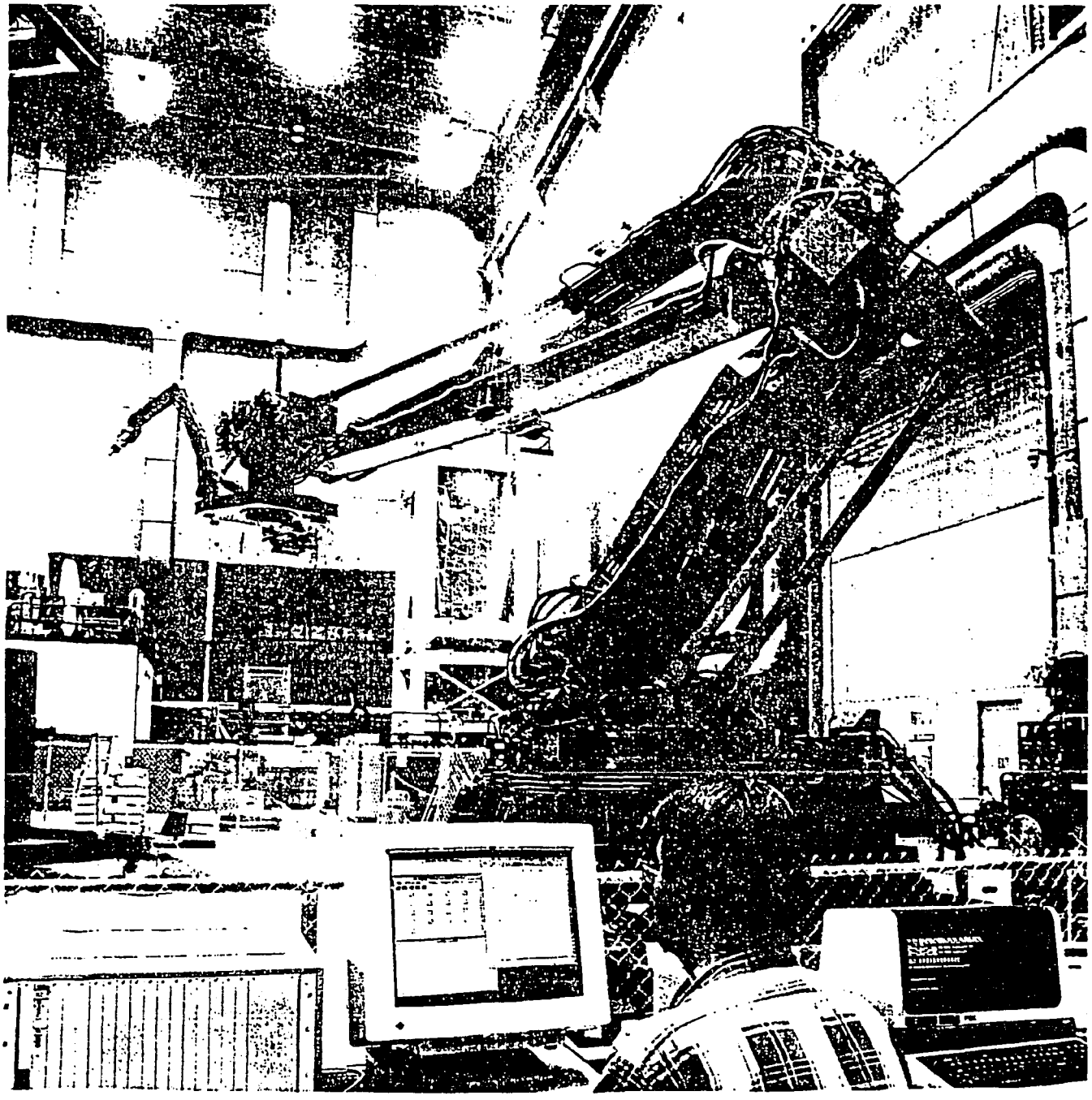

Figure 8 Hanford UST Technology Test Bed

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DARLINGTON REACTOR MAINTENANCE STUDY

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ABSTRACT

This paper describes a study which was carried out by E.H. Farris, General Electric Canada Inc., to provide a framework for a reactor maintenance program at the Darlington Nuclear Generating Station. The study contained two parts; the first, a description of existing reactor maintenance programs at the Pickering and Bruce Nuclear Generating Stations and the second, reactor maintenance program requirements for Darlington.

DARLINGTON REACTOR MAINTENANCE STUDY

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BACKGROUND

In the push to get new reactors up and running, often not enough attention is given to reactor maintenance. When it comes to the allocation of resources, priority is given to getting the station built, commissioned and operating.

It has long been recognized that there are decided advantages to taking a good look at reactor maintenance early in the construction phase and establishing a reactor maintenance program in time for start up. But this goal was not fully realized on Ontario Hydro's Bruce and Pickering Reactors. At Darlington, Peter Walsmley was determined to get started on the right foot, but he too was finding it difficult to allocate the needed resources to make it happen.

At a Darlington fuel handling meeting in April 1989 Peter happened to express concern about the lack of progress in the preparation of a reactor maintenance program for Darlington. Syd Waldron and Ernie Farris of GE Canada lent a sympathetic ear and suggested that if a person with knowledge of, and contacts at, the Ontario Hydro reactor stations could be dedicated to the task, that progress might be made. It was proposed that Ernie Farris be the dedicated person and he carry out a study in two parts. The purpose of the first part was to identify the existing reactor maintenance programs and responsibilities at Pickering and Bruce. The purpose of the second was to identify the reactor maintenance requirements for Darlington.

The work went ahead and Ernie published the first part of the study in March 1991 and the second in July 1991. A brief summary of the study follows:

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PART 1 - EXISTING REACTOR MAINTENANCE PROGRAMS AT BRUCE AND PICKERING.

Part 1 of the Darlington Reactor Maintenance Study identified two main categories of reactor maintenance work at Bruce A, Bruce B and Pickering:

1. Fuel Channel Maintenance.
2. Reactivity Mechanism Maintenance.

There were two basic kinds of reactor maintenance:

1. Routine - lubricate, change oil, check set-ups, rebuild closure plugs, inspect pressure tubes, refurbish closure seal faces, change cobalt, measure fuel channel lengths and gaps, etc.

2. Developmental - pressure tube, calandria tube and reactivity mechanism replacement, correct feeder leakage, etc.

There were some differences in implementation at the 3 reactor sites but basically there were 3 levels of responsibility:

A. Reactor Maintenance Technical Section

- overall responsibility for program
- identify routine maintenance work and schedules
- identify development work and schedules
- secure funding
- provide technical support for all work
- arrange outside assistance

B. Maintenance Superintendent

- direct responsibility for defined tasks
- provide manpower to perform tasks
- provide supervision for work
- provide procedures for work
- maintain tools and equipment used for work
- implement training programs

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C. Mechanical SMS (Shift Maintenance Supervisor)

- perform work to schedules provided
- arrange training and maintain records
- prepare mechanical procedures
- document all work and problems
- feed back problems and solutions to technical section
- report progress of work

Staffing at Bruce A, Bruce B and Pickering:

All three reactor sites had permanent Reactor Maintenance Technical Section staffs with temporary assistance as required.

At Bruce A, dedicated reactor maintenance crews were divided between fuel channel replacement and reactivity mechanism work with many mechanics often borrowed from fuel handling.

At Bruce B there was a small dedicated reactor maintenance staff supplemented as required by fuel handling mechanics.

At Pickering A and B there were no maintainers or SMS dedicated to reactor maintenance. The work was carried out by the fuel handling staff.

Location of Reactor Maintenance Facilities:

Generally the reactor maintenance programs have had to make do with whatever space could be found. For example at Bruce A the mock-up, training and storage area was first located on the turbine hall floor with very high noise and temperature levels. The reactor maintenance storage area and work shop were then established in the reactor auxiliary bay between units 1 and 2 and the fuel channel rehearsal facility was located in the reactor auxiliary bay at the east end of unit 4. The booster flask storage area was at the end of the unit 1 turbine bay where there was a crane large enough to lift the 28 ton flask.

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PART 2 - REACTOR MAINTENANCE PROGRAM FOR DARLINGTON

Part 2 of the Darlington reactor maintenance study reported on the following 17 topics:

1. Maintenance Responsibilities and General Categories of Maintenance.
2. Types of Maintenance Work.
3. Manpower Required.
4. Personnel Responsibilities.
5. Training Facility.
6. Special Tools and Equipment.
7. Closed Circuit Television (CCTV) and Communications.
8. Flasks and Shielding.
9. Access to the Vault and Reactor Face. (Complete with 3 binders of photographs and 4 Video Tapes).
10. Tool Control.
11. Decontamination.
12. Quality Assurance Program.
13. Estimated Expenditures and Manpower Required.
14. Responsibilities of AECL and OH.
15. Proposed Involvement of Outside Expertise.
16. Sources of Expertise in Design and Manufacturing.
17. General Schedule.

Some of the more significant topics are discussed as follows:

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1. Maintenance Responsibilities and General Categories of Maintenance

For Darlington it was recommended that a Reactor Maintenance Group be set up. This group would work closely with the Reactor Instrumentation and Control Group who would handle servicing of electrical and control devices. There would be 3 categories of maintenance:

1. Fuel Channels.
2. Reactivity Mechanisms.
3. Flux Detectors and Liquid Injection Shutdown System.

2. Types of Maintenance Work

As with the other stations there would be the same two kinds of reactor maintenance work:

2.1 Routine Reactor Maintenance. Lubricate and set-up reactivity mechanism drives, change reactivity mechanism control materials, refurbish end fitting seal faces, inspect pressure tubes, adjust fuel channel restraint hardware, refurbish closure plugs, inspect feeder clearances and do other minor servicing.

2.2 Reactor Maintenance Development. Nine reactor components were identified for this type of maintenance. Development programs would identify and perfect the required tooling and procedures and establish training programs. Depending on the complexity of the technology, outside assistance could be brought in. For each component the development requirements were identified. These included; mock-up, tooling, inspection equipment, flasks and procedure.

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2.2 Reactor Maintenance Development (cont'd)

The nine reactor components were:

- Fuel Channels
- Flux Detectors
- Shut-Off Rods
- Ion Chambers
- Liquid Zone Control Units
- Control Absorbers
- Adjusters
- Cobalt (If it should be installed)
- Liquid Injection Nozzles

3. & 4. Manpower Requirements and Responsibilities

It was recommended that the Reactor Maintenance Technical Section be a sub unit of the Fuel Handling Technical Section. It would have 'A' level responsibilities as was the case at Bruce and Pickering. Ultimately four people from the Technical Section would be required when the reactor maintenance facility became fully operational.

The Mechanical Maintenance Reactor Section would have the 'B' and 'C' level responsibilities with the following 4 titles:

Mechanical Maintenance Superintendent
Mechanical Maintenance Supervisor
Shift Maintenance Supervisor (SMS)
Technical Maintenance Supervisor (TMS)

The TMS would be the only full time position and it would be backed up by six full time mechanics.

5. Training Facility

Provision of an adequate training facility was stressed in the study and a state-of-the-art facility was recommended as part of a proposed 3 bay annex on the east end of the turbine building. Based on the Bruce and Pickering experience such a facility would contribute to the success of the reactor maintenance program.

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5. Training Facility (cont'd)

With funding problems, it was decided not to provide the 3 bay annex but to utilize the two bay (18 metre) extension which was added to the turbine building when the station was built. The training facility would occupy the ground floor (elevation 100 metres) with a length of 54 metres and a ceiling height of about 7 metres. A concrete wall would be built to isolate the area so that it could be made Zone 3. The area would access the main reactor corridor and hence the equipment airlocks of all reactors. When the station was built the need for vertical reactivity mechanism mock-ups was foreseen and penetrations were provided through the two floors above the 100 metre floor. A simulated reactivity mechanism deck would be about 1 metre above the turbine hall floor (elevation 115 metres). The turbine hall crane, with a hook height of about 25 metres above the floor, would be used to install and remove reactivity mechanisms from the mock-ups. A horizontal mock-up would be located on the 115 metre floor.

At the present time a temporary reactor maintenance training facility has been established in the components building which was used for new fuel channel installation during construction. Layouts are being made of the new facility in the turbine building extension and major features and services are being identified. Included is a clean room assembly area, a crane to service one of the 9 x 54 metre bays, a truck loading area and a combined office for the mechanical maintainers and the technical unit.

7. Closed Circuit Television (CCTV) and Communications

With the Bruce and Pickering reactors, the normal practice was to set up a temporary enclosure to act as a monitoring and control centre for reactor service work. Such an enclosure was often constructed of 2x4's and plastic and was usually noisy and hot or cold.

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7. Closed Circuit Television (CCTV) and Communications (cont'd)

For Darlington a specially equipped trailer was recommended to house the CCTV and communication equipment and to provide a control centre for reactor maintenance work. The trailer would also serve as a permanent storage location for the equipment. Such a trailer was purchased and used to great advantage in the replacement of two fuel channels in Unit 2 (K13 November 1991 and N12 June 1992).

The trailer provided a place for the directors and supervisors involved in the project to view the TV monitors and exercise control through the communications hookup to the vault. It provided a noise free temperature controlled environment. This resulted in a very successful operation which was better controlled, safer, and less stressful.

8. Flasks and Shielding

The study recommended more shielding for reactor face work such as single fuel channel replacement. A unique shielding canopy was eventually designed and supplied.

9. Access to the Vault and Reactor Face

This section proved to be one of the most useful of the study. Photographs were taken of the vault access ways starting with access to the reactor auxillary bay, leading to the large equipment airlock, through the airlock and into the east and west reactor vaults. Many restrictions were identified and dimensioned. These included fences, doorways, brackets, cables, ventilation ducts, junction box support frames, stairway columns, feeder cabinets, air ducts, piping, cable trays; breathing air stations, stairways, air lines, conduit and the airlocks themselves.

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9. Access to the Vault and Reactor Face (cont'd)

Tests showed that a cylinder 152 mm in diameter and 6474 mm long could be brought through the equipment air lock at a diagonal; replacement pressure tubes and calandria tubes fall within these limits. The maximum size rectangular body that could be brought into the east vault was 2170 mm high x 1900 mm wide x 4780 mm long. For the west vault the length and height were the same but the width was only 1640 mm.

The vaults were equipped with fairly large permanent stairwells to give access to maintenance platforms at any level. The size and position of the stairwell made movement around the vault difficult and an innovative and more compact egress system has been proposed.

In addition to the photographs, four videos were made of the vault access ways, vertical and horizontal reactivity mechanisms and fuel channels. These along with the photographs, which were mounted in three large binders, provide a good permanent record of the access conditions.

12. Quality Assurance Program

The work performed under reactor maintenance must meet the same quality standards that were required when the reactors were built. The jurisdiction is the ASME Boiler and Pressure Vessel Code, Section III, Class 1 and CSA Standard CAN 3-N286.3. Detailed plans and written procedures are required for all quality related functions. This includes gauge control and calibration.

SINGLE FUEL CHANNEL REPLACEMENT (SFCR)

The reactor maintenance study was barely issued in 1991 when the need arose to replace a fuel channel in unit 2. Even though implementation of the recommendations had only begun, the study produced a number of advantages which should undoubtedly strengthen the argument for its timely implementation.

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SINGLE FUEL CHANNEL REPLACEMENT (SFCR) (cont'd)

The access study had shown that a new pressure tube could be taken through the airlock using a lifting fixture to hold the tube on the diagonal. Also it showed that the width of the flasks would have to be reduced to miss various restrictions. With this prior knowledge it was possible to make preparations ahead of time and avoid last minute problems. The SFCR tool list in section 6 proved very helpful in getting the program off to a good start.

As with many single fuel channel replacements there was very little time to prepare. This dictated making use of resources from any available sources. Hence tooling was borrowed from Bruce A and Bruce B. SFCR experience was already on hand in the person of Ernie Farris and he was given a free hand to apply this experience. Early in the preparation period the Darlington core crew went to Bruce A to see a demonstration of SFCR. The Darlington crew pulled together very well. Supervision created a very good atmosphere; everyone was expected to play an important role and efforts were well recognized. The learning curve was very short and the replacement of the first fuel channel went very smoothly and quickly. A second fuel channel was replaced successfully in a manner similar to the first.

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Canadian Nuclear Society

DU 22 AU 24 NOVEMBRE 1992 / NOVEMBER 22-24, 1992
Toronto, Canada

La maintenance à Gentilly 2
à l'heure de la qualité totale

Gentilly 2 Maintenance
in a Total Quality Environment

Michel H. ROSS
Conseiller / Sr Advisor
Henri MAROIS
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Gestion du nucléaire
Hydro-Québec

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GENTILLY 2 MAINTENANCE IN A TOTAL QUALITY ENVIRONMENT

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SUMMARY

The station's maintenance policy aims at ensuring equipment availability through a management process seeking to balance resources and requirements. This policy has led to the implementation of comprehensive preventive maintenance programs.

Based on almost ten years of station operation, quality indicators provide a good measurement of how well customer needs and expectations are satisfied.

The commitment to total quality provides a strict management approach based on performance improvement and total customer satisfaction.

To improve overall performance to an annual availability factor of 90%, planned outages must be limited to 21 days a year and the preventive maintenance program must be upgraded. A quality improvement team is already involved in supporting this initiative. This team will seek to bring a new balance to the program and, eventually, optimize it using reliability-centered maintenance techniques.

INTRODUCTION

Hydro-Québec declared in service Gentilly 2, a CANDU 6 station, in October 1983. Eventhough it is one of the largest power utilities in North America, Hydro-Québec operates only one conventional thermal power plant and one nuclear power plant.

Presently, 96% of all the energy it produces is hydraulic. It is expected that the utility will continue to focus on the development of its hydraulic resources through various projects in northern Québec.

The ageing of nuclear stations, including Gentilly 2, is accompanied by growing maintenance-related concerns. These concerns relate to increases in actual maintenance costs as well as energy replacement costs due to station unavailabilities. Even more important is the growing influence of maintenance on the safe and reliable operation of an ageing station. Ultimately, a station's service life is determined to a great extent by maintenance.

The utility's maintenance policy has spawned comprehensive preventive maintenance programs. After almost ten years of operation, the time has come to look closely at maintenance indicators and to evaluate their results. Through its commitment to total quality and its related management approach, the utility is able to increase its overall performance and carry out corrective actions where necessary.

MAINTENANCE POLICY

Gentilly 2 adopted Hydro-Québec's maintenance policy for production facilities. This policy is designed to ensure equipment availability through maintenance actions on systems and components. This policy is based on five main principles:

- customer satisfaction;
- public and employee health and safety;
- compliance with legislation and commitments, such as agreements and labour contracts;
- environmental protection;
- optimizing corporate profitability by minimizing costs and maximizing equipment availability.

This policy is structured around two main themes. The first is equipment availability and the second is maintenance management.

Equipment availability is ensured by maintaining components in a specified state based on design criteria, operating conditions and maintenance practices. Accordingly, preventive maintenance, modification, overhaul and replacement programs are implemented to minimize the frequency of component failures. Also, maintenance practices are established to minimize the impact of outages and defective components, and components are modified to facilitate maintenance actions.

Maintenance management is applied in such a way as to balance committed resources with equipment operation requirements. Appropriate preventive or corrective maintenance is identified for each component. This management approach takes into consideration the following factors: planning, organization, performance, control, feedback and applied research.

Maintenance actions are listed in fig. 1 and types of maintenance in fig. 2.

Maintenance

Maintenance refers to a series of activities designed to maintain a piece of equipment or a component in a specified state. These activities include servicing, overhauling, modification, component replacement, as well as recommissioning following maintenance. Two types of maintenance are used: corrective and preventive.

Corrective Maintenance

Corrective maintenance activities are used to return a defective component to an operational state.

Preventive Maintenance

Preventive maintenance activities are designed to prevent a component's failure or degradation. They may be time-based or condition-directed.

Time-based activities are performed according to a schedule based on time or number of units of use.

Condition-directed activities are dependent on predetermined events symptomatic of a component's state.

Modification

A modification can be a preventive or a corrective maintenance activity. It is used to change a component's specified state to a new state.

Overhauling

An overhaul can be a preventive or a corrective maintenance activity. It is used to bring a component back to its specified state.

Recommissioning

Recommissioning is a maintenance activity used to test a component's specified state following another maintenance activity.

Replacement

A replacement can be a preventive or a corrective maintenance activity. It restores compliance to a specified state by substituting a suitable component for one that is no longer suitable.

Servicing

Servicing is a preventive maintenance activity used to influence the evolution of a component's actual state or a corrective maintenance activity designed to return a damaged or degraded component to its operational state.

MAINTENANCE PROGRAM

The Gentilly 2 maintenance program was implemented in compliance with Hydro-Québec production facilities' maintenance policy and also with the Operations quality assurance program for nuclear generating stations.

This maintenance program includes the following: organization and administration of maintenance, training and qualification of personnel, controls and calibration, planning and scheduling, maintenance records, maintenance procedures, post-maintenance testing, designing and implementing modifications, documentation control, procurement and inventory management, and radiological control.

More specifically, preventive maintenance encompasses the six programs described below.

Preventive Maintenance

The station's preventive maintenance program encompasses all maintenance activities designed to keep components in their operational state with high operational reliability.

In-Service Inspections

The in-service inspection program includes all inspection-related activities designed to confirm the proper operation and integrity of systems and components critical to reactor shutdown and fuel cooling operations throughout the life of the station.

Pressure Vessels

The quality control program for pressure vessels covers all activities relating to the inspection, repair and modification of pressure vessels.

Safety Valves

The safety valve certification program encompasses all activities related to the prevention, detection and correction of safety valve defects.

Vibration

The vibration program includes all activities relating to the measurement and analysis of equipment and rotating machinery vibrations; it is aimed at preventing catastrophic failures, reducing forced outages and optimizing equipment use while lowering costs.

Prescribed Testing

The prescribed testing program encompasses all testing and preventive maintenance activities credited in the reliability studies used in the safety assessment of the station.

As Gentilly 2 is the utility's only nuclear power plant, and because it did not grow out of a conventional thermal power program, all personnel were following a training cycle, as it were, during the early years of operation. This cycle is now complete.

A good hands-on experience base in operation and maintenance has been gained. This allows us to take a critical look at the programs.

Several of them, such as the in-service inspection program, the pressure vessel program, the safety valve program and the vibration program, are generally satisfactory. However, specific improvements have been and are still being made in areas such as pressure tubes, steam generators and secondary side inspection.

The prescribed testing program underwent a thorough review a few years ago and is now adequate.

The original preventive maintenance program was developed by commissioning engineers based on current regulations and specifications, recommendations from designers and suppliers, results from special studies and on experience gained by operators of similar equipment. This program underwent relatively few changes through the years; it has been shown to produce inconsistent results and is in need of major improvement. For example, it has been established that this program requires upgrading in order to be in a position to shift more activities carried out during shutdown to a time when the station is on power and to eliminate unproductive preventive maintenance activities.

Figure 3 shows a standard relationship between the overall cost of maintenance and the volume of preventive maintenance. The cost curve reflects the optimum condition sought by all. A thorough review of the preventive maintenance program, carried out by a quality improvement team, is a step in the right direction.

MAINTENANCE INDICATORS

Maintenance indicators are used to measure how well customer needs and expectations are met. In other words, it measures the level and frequency of compliance with a valid requirement. Based on a given non-compliance value, it is relevant to consider any discrepancy between what is and ought to be, between actual performance and customer requirements. These indicators provide a measurement of the current situation, its evolution and the efforts required to generate improvement.

Quantitative Indicators

The most significant quantitative indicator is the equivalent availability factor. It measures the probability that the station will be able to fulfill its function, which is providing electrical power to its customer (the power grid) at any given time and in accordance with current specifications, including those related to nuclear safety.

As shown in fig. 4, the station's lifetime average equivalent availability factor was 79.3% at the end of October 1992. This result, although satisfactory, must be further improved. The goal for 1995 is to gradually raise the annual equivalent availability factor to 90.0% full power. This is the station's main improvement target.

Due to Québec weather, demand from the power grid soars during the winter months. Except for the 91-92 winter, the station has always succeeded in satisfying its customer with an average availability factor of 97.7% between December and April with an average of less than one forced outage per year.

Fig. 5 shows that planned outages account for nearly 60% of all unavailabilities. Fig. 6 displays the station's time-related unavailability structure. Unavailabilities caused by forced outages are often more costly. Planned outages can be scheduled during periods when the customer enjoys an energy surplus, i.e. during spring runoff. Also, actions are better planned and parts and materials are available. Forced outages are always disruptive, and their consequences must be controlled.

As shown in fig. 7, yearly planned outages last 39 days on average. Except for 1986, when the constraint was directly related to the power grid, the duration of annual shutdowns has always been dependent on the work required on the turbine generator.

It is made clearer by showing unavailability factors for each year in fig. 8. Since technical problems related to the turbine generator are now under control, an overall unavailability factor of 10% for 1995 is a challenging but achievable goal, as long as labour peace holds.

Qualitative Indicators

Availability indicators do not measure customer satisfaction qualitatively. For example, having an excellent availability factor during annual peak periods is satisfying, but having a fairly large number of forced outages translates into a non-compliance with regard to customer expectations. As a consequence, the power grid must maintain an adequate power reserve to deal with these outages. The maintenance of such a reserve is costly. Also, each outage, planned or forced, puts additional stress on the equipment. As time goes on, the effects of these transients add up and eventually restrict the equipment's service life. Finally, each outage increases the possibility of human error and additional equipment failures during both the shutdown and restart phases.

Other maintenance indicators used to characterize the quality of the station are those related to radiation safety. Figure 9 shows excellent dosimetric results. These values are among the best in the world and are indicative of the station's commitment to respect people and to control work processes involving radiation. Similarly, the exceptionally low volume of low-level radioactive waste shown in fig. 10 is evidence of the station's focus on this aspect of operation.

As for maintenance costs, they have remained virtually constant during the last nine years. The current ratio of preventive maintenance to corrective maintenance is only slightly above 1. As a means of controlling maintenance costs in an ageing station, a gradual increase of this ratio to 1.5 is being contemplated.

PERFORMANCE CHALLENGE

In 1990, the company committed itself to total quality through its Performance Challenge project. The implementation of Performance Challenge is being phased in over a five-year period. Implementation has started this year at Gentilly 2. Seven quality teams are already at work out of an expected total of 22.

The total quality management approach is designed to fully satisfy customer needs, at the lowest cost, through the involvement of all employees and the control of work processes. This is not only a philosophy aimed at introducing basic values, but also a technique in the sense that it formalizes, through scientific methods, a strict management style.

To support total quality management, the utility is introducing a new management model involving four basic principles and three management action streams, as well as quality teams dedicated to performance improvement. Fig. 11 shows the interaction between the four basic principles implemented through management streams.

This management model, made up of stringent tools used to ensure performance improvement and total customer satisfaction, is based on the following principles :

- *Customer satisfaction* – The utility's actions are all directed toward the satisfaction of external customers' needs. External customer satisfaction hinges on internal customer satisfaction; therefore, customer satisfaction becomes the working aim of every employee.
- *Respect for people* – It is based on the premise that the company's most important resource is its human capital. The company can capitalize on the full potential of all its employees by showing them respect and getting them to support common goals. If they are allowed to fully assume their responsibilities, they will rediscover satisfaction and pride in their work.
- *Management by fact* – Decisions should be based on objective and measurable data, not on intuition or feelings.
- *Continuous improvement* – It refers to a constant and systematic quest for customer satisfaction based on the Deming Wheel or the PDCA work cycle (Plan, Do, Check, Act).

These basic quality principles generate concrete actions in the following management streams :

- *Improvement targets* are used to focus the company's actions and resources on total customer satisfaction, based on a restricted number of targets specified by customers.
- *Working processes* describe how each activity is to be carried out in order to achieve the expected results. Quality improvement is highly dependent on the existence of systematically documented working processes.
- *Quality assurance* is used by the company to confirm that all its activities are performed in a way that fully satisfies customer needs and expectations. It means making sure that every step included in these activities is performed correctly the first time around, at the lowest cost possible.
- *Quality teams* are at the centre of the Performance Challenge. They are responsible for solving one or more problems by applying stringent methods. They foster employee mobilization in support of quality improvement and the pursuit of excellence.

The approach used by quality improvement teams refers specifically to the problem solving process included in Performance Challenge. Known as the Quality Approach, it is used to systematically identify and solve problems by collecting and analyzing factual data. As shown in fig. 12, it includes seven steps :

1. *Improvement need.* The quality team identifies an improvement topic, a problem area, then it states the reasons for acting.
2. *Improvement objective.* The team selects a specific problem under this topic and an improvement objective.
3. *Causes of the problem.* The team identifies and validates the primary cause(s) of the problem.
4. *Corrective action.* The team selects and tries out corrective actions needed to eliminate the primary cause(s) of the problem.
5. *Results.* The team evaluates the effectiveness of the corrective actions by measuring the extent to which the improvement objective was reached.
6. *Standardization.* The team permanently includes the corrective actions into the working process.
7. *Review and Outlook.* Team actions and responses are reviewed in order to identify outstanding issues and to anticipate the next step.

At each step, the team systematically conducts a whole series of well defined activities.

POSSIBILITIES FOR IMPROVEMENT

The station's main performance target is increasing the equivalent availability factor by 10% full power over a four-year period without incurring additional maintenance costs.

Personnel-related unavailabilities should not be a recurring event as long as labour peace is maintained.

Two other conditions are required to achieve the set goal: maintaining frequency and duration of forced outages to present record, despite the fact that the station is ageing, and reducing average annual planned outage duration from 39 to 21 days. These two conditions can only be met through the optimization of the preventive maintenance program.

Positive Factors

During the last ten years, a great deal of experience has been gained. We are putting out fires less and less, and most of the major problem areas have been circumscribed.

For instance, reactive maintenance on fuel handling systems has, for over a year, given way to a time-based and condition-directed preventive maintenance program. The unavailabity rate for such systems, which are critical to reactor operation, has been substantially reduced in the process.

The important condition-directed maintenance program on reactor pressure tubes is now considered adequate, although it still could be modified. With the channel inspection and monitoring program and with the garter spring location and repositioning program (SLAR), the evolution of these critical components' condition will be controlled and a satisfactory service life can be achieved.

Time-based and, increasingly, condition-directed preventive maintenance on steam generators has already produced positive results. In fact, thus far, no steam generator tube has had to be plugged as a result of a failure. At present, indications are that these critical components will operate in a safe, reliable and economical manner until the end of the station's service life.

Duration of planned outages has almost always been dependent on work required on the turbo-generator. These outages were required to carry out alignment checks, to perform rotor re-aligments or to repair the machine. The machine's continuous misalignment is caused by a chemical reaction in the concrete foundation called alkali-silicate reaction, which causes the concrete to expand and results in unacceptable machine component shifts. Also, strong generator vibrations are caused by the foundation's inherent flexibility. After more than fifteen years, a relative stabilization of the foundation has, at last, been achieved. Also, an improvement in follow-up procedures on the foundation and the machine itself will make it possible to target maintenance actions more efficiently. Time-based preventive maintenance is being replaced by condition-directed preventive maintenance. Inspections are being performed on a sectional instead of an overall basis. As early as next year, annual outage duration will be down to 21 days. This could only be achieved through a relative stabilization of the foundation and significant local and external operating experience feedback.

Planned outage management is now under control. Through the years, a major experience feedback process took place, specifically on operation, planning and scheduling, internal and external resource management, work preparation and performance follow-up.

Preventive Maintenance Program

The preventive maintenance program must be optimized. A new balance is being sought. A quality team applying the Quality Approach is already at work. This team includes personnel from all groups involved in maintenance: engineers, operators, foremen, technicians, tradesmen, planners.

One of the problems identified, a pressing improvement need, comes from the fact that the current preventive maintenance program calls for multiple activities during a reactor shutdown. So far, this did not cause any major problem, on

account of the relatively lengthy average annual outage, but 21-day outages will create new difficulties.

Another improvement need identified by the team is the optimization of the preventive maintenance program using reliability-centered maintenance techniques. The program must be capable of systematically integrating operating and maintenance feedback, focussing maintenance actions in the right places, giving components attention commensurate with their importance based on risk and economic losses, and taking into consideration most probable failure modes for maintenance action prioritization.

Having two problems to deal with, the quality team will have to twice go through the various steps in the Quality Approach.

Without speculating on the quality team's conclusions, a project to improve the component reliability data gathering system has been in place for some time. The introduction of this system via Maintenance Management System softwares, compatible with external data banks, will greatly facilitate the systematic analysis of component failure and degradation mechanisms. These new tools will also be very useful in the conduct of plant life assurance and plant life extension studies.

CONCLUSION

Maintenance programs have already yielded good results. Proactive preventive maintenance, more specifically condition-directed, is continuously gaining in importance as the programs are updated. On the other hand, everyone being committed to total quality will lead to an increase in our overall performance. Achieving an equivalent availability factor of 90% full power by 1995 is our main performance target.

The total quality management approach is designed to fully satisfy customer needs, at the lowest cost, through the involvement of all employees and the control of working processes.

Specifically, the preventive maintenance program is scrutinized by a quality team in order to bring a new balance to this program and, eventually, optimize it through the use of reliability-centered maintenance techniques. The quest for excellence is endless.

BIOGRAPHY

Michel H. Ross is Senior Nuclear Advisor with the Nuclear Management Directorate. Amongst his tasks, he analyzes and handles complex technical and/or administrative files falling within the field of nuclear operations. In his work, he deals with plans, orientation and development of the nuclear function and what concerns prospects, strategies and corporate interests in this field.

Mr. Ross is a graduate in Nuclear Engineering from the Nuclear Engineering Institute of the Montreal Polytechnic. He has great experience of commissioning and operating CANDU plants. As a reactor physicist, he actively participated in the Gentilly 1 NGS commissioning. He became head of the Technical Division of Gentilly 1, and, subsequently, chief engineer responsible for mothballing the plant. He then was put in charge of commissioning of the Gentilly 2 plant. He directed the Operations and Planning Division of Gentilly 2 over the first years of its operation.

Henri Marois is Assistant Director – Nuclear Management Directorate. As such, he assists in the managing of all Hydro-Québec nuclear-related activities. More specifically, he seconds the Director who sees that the operation of Gentilly 2 plant is carried out in a reliable, economical and safe manner, and that the development of nuclear technical know-how meets the needs.

After completing his engineering training, he held various engineering positions with Hydro-Québec, at the head office, at Manicouagan and at Gentilly. As the commissioning of the Gentilly 1 nuclear power plant was getting under way, he joined the Atomic Energy Control Board (AECB) as on-site representative with Gentilly 1 and, later, Gentilly 2. He then returned to Hydro-Québec where he chaired the Committee for the Safety of Nuclear Installations and concurrently held the position of Radioprotection Manager. He was subsequently appointed Maintenance and Radioprotection Manager, and finally Assistant Plant Manager.

Figure 1

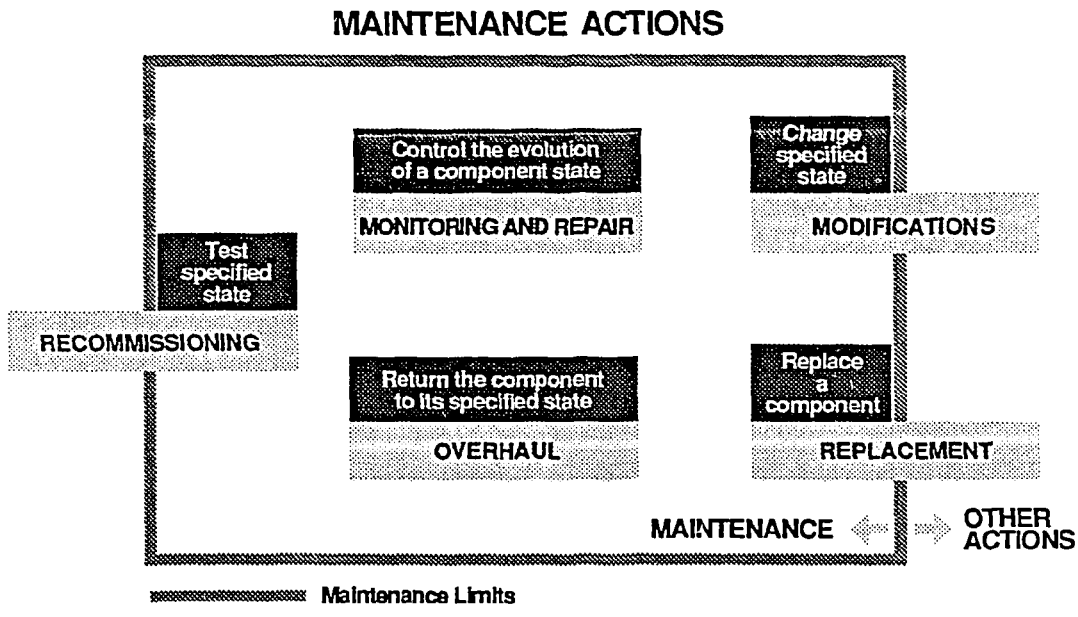


Figure 2

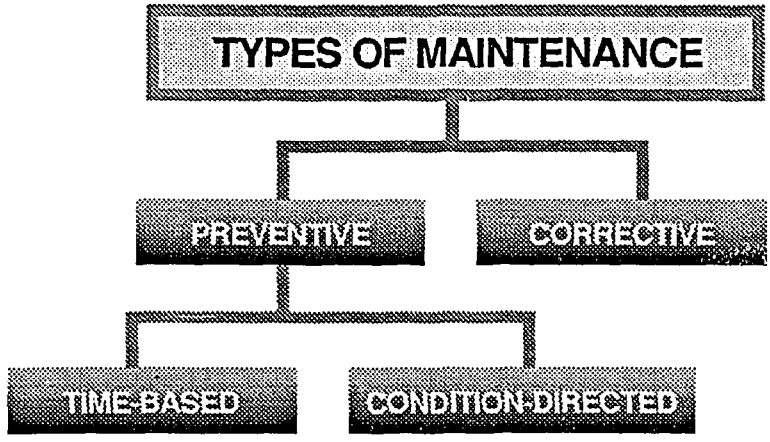
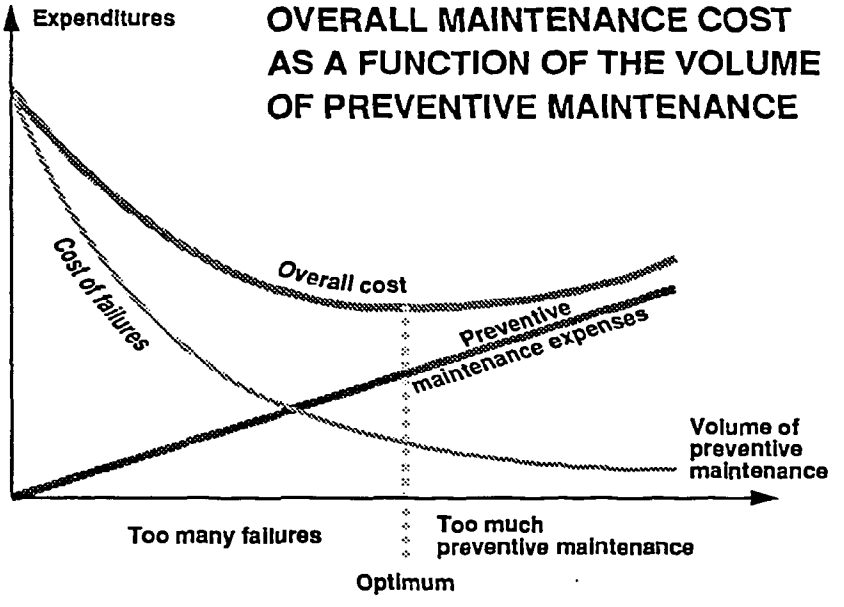


Figure 3



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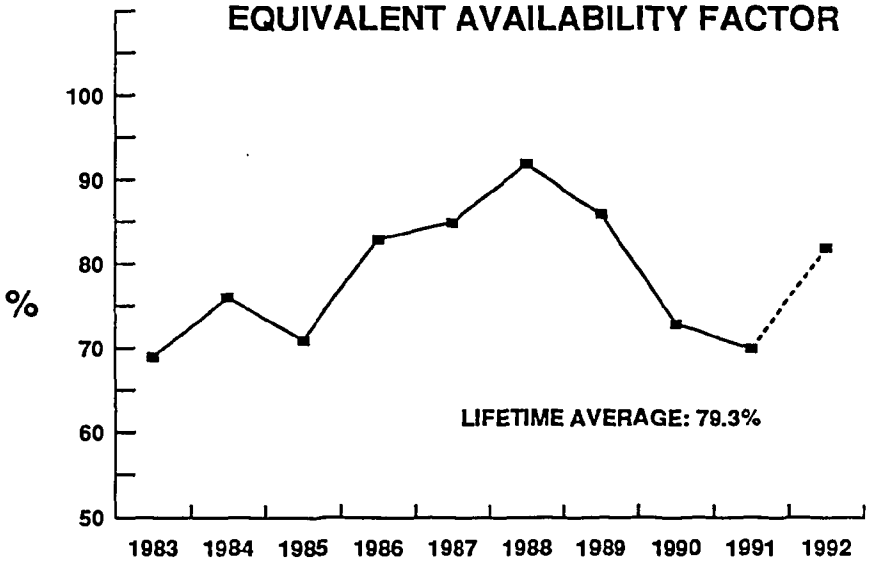

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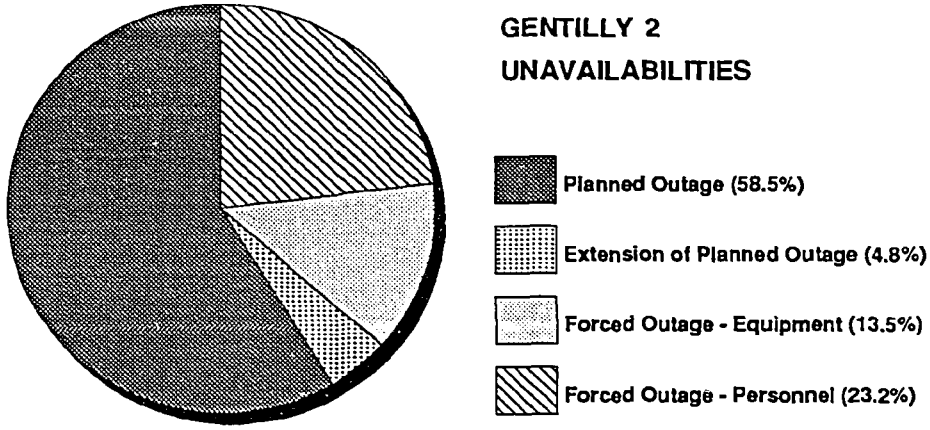


Figure 6

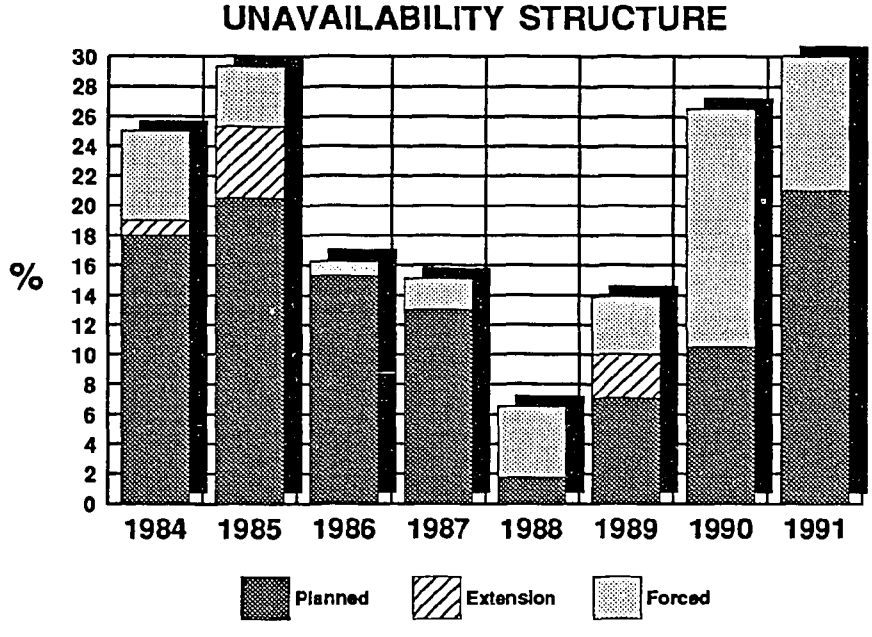


Figure 7.

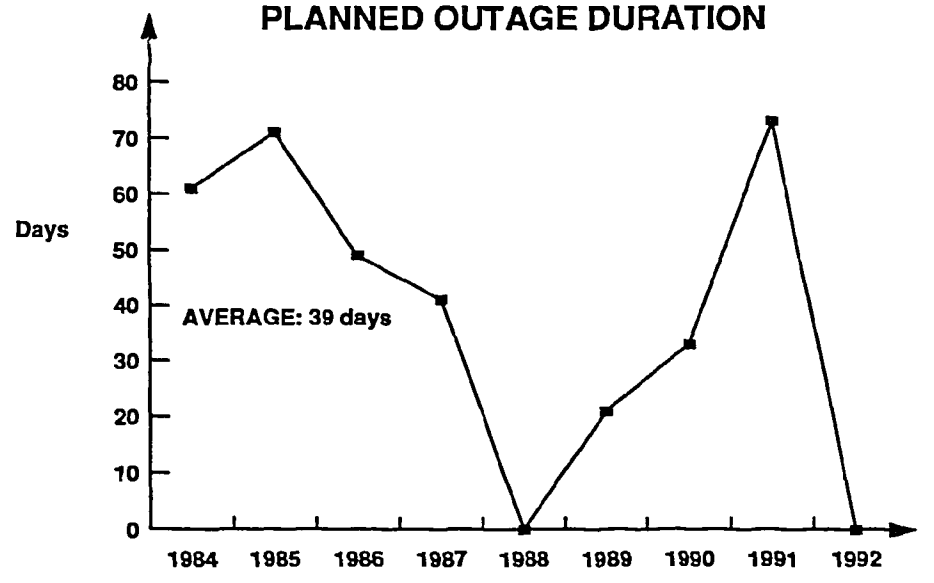


Figure 8

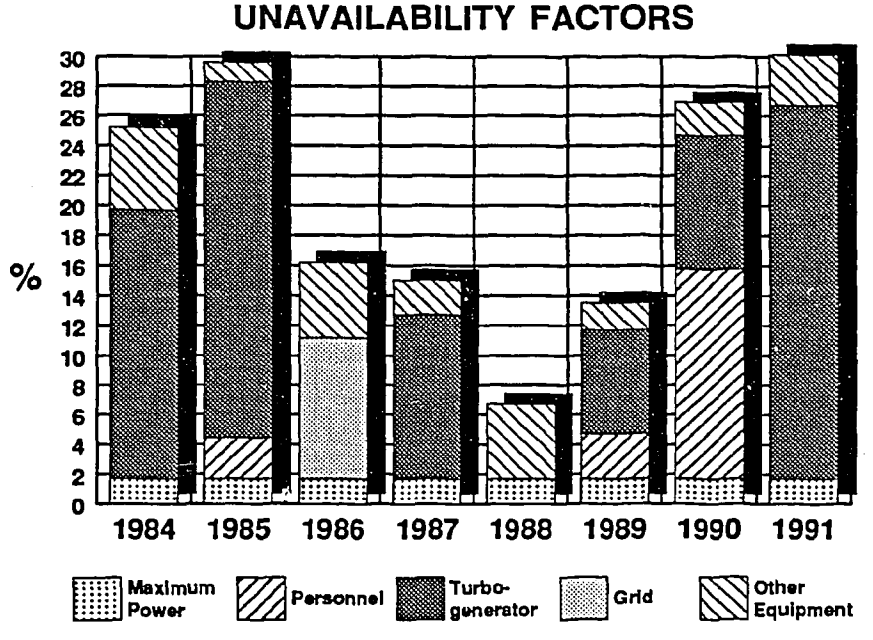


Figure 9

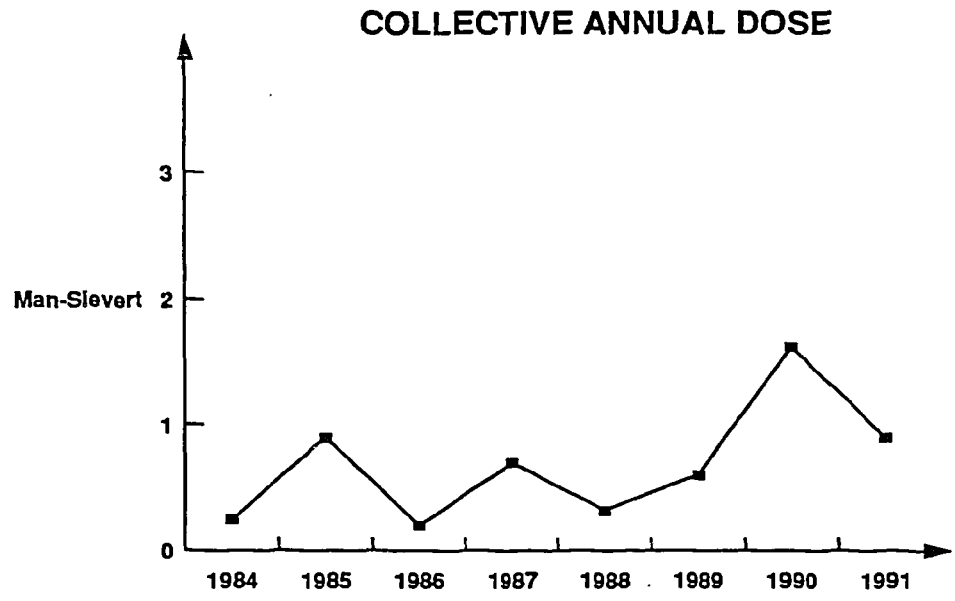


Figure 10

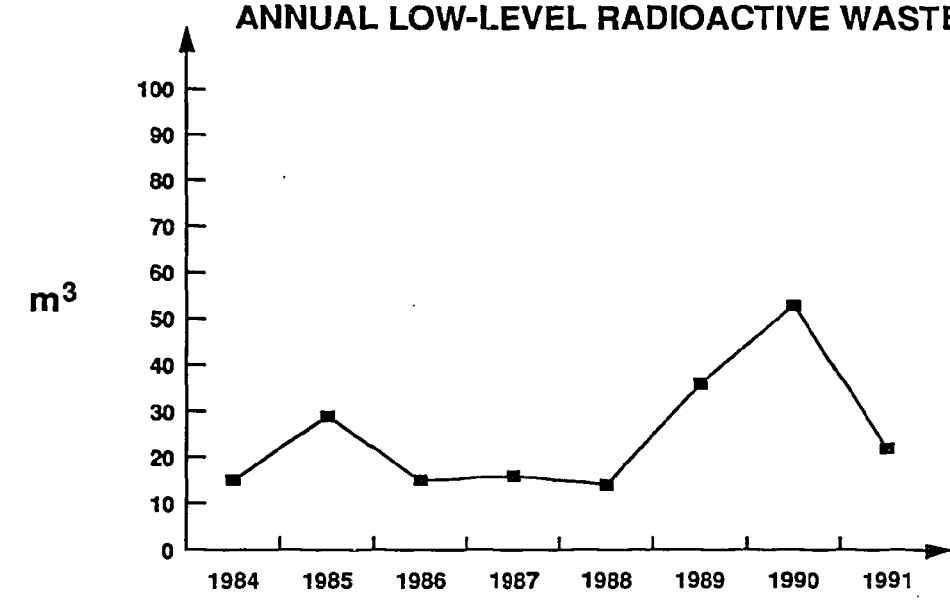
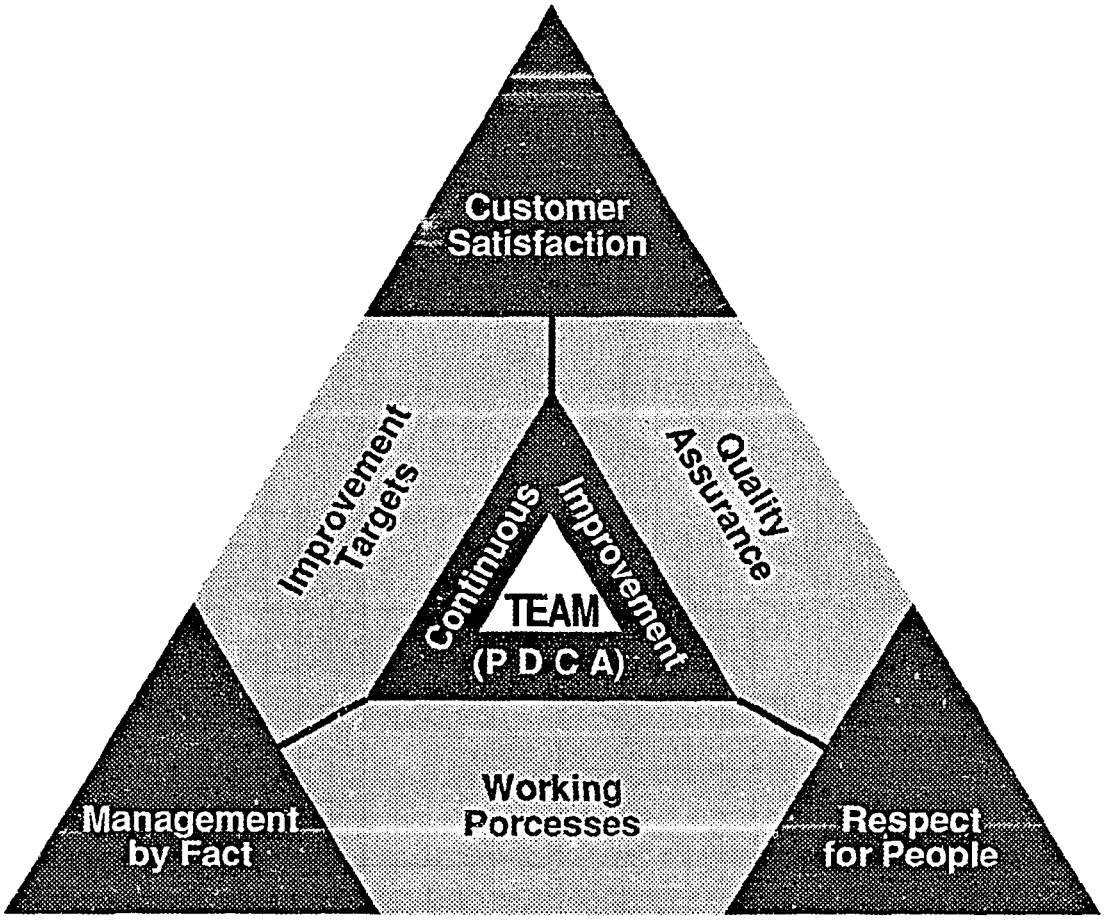
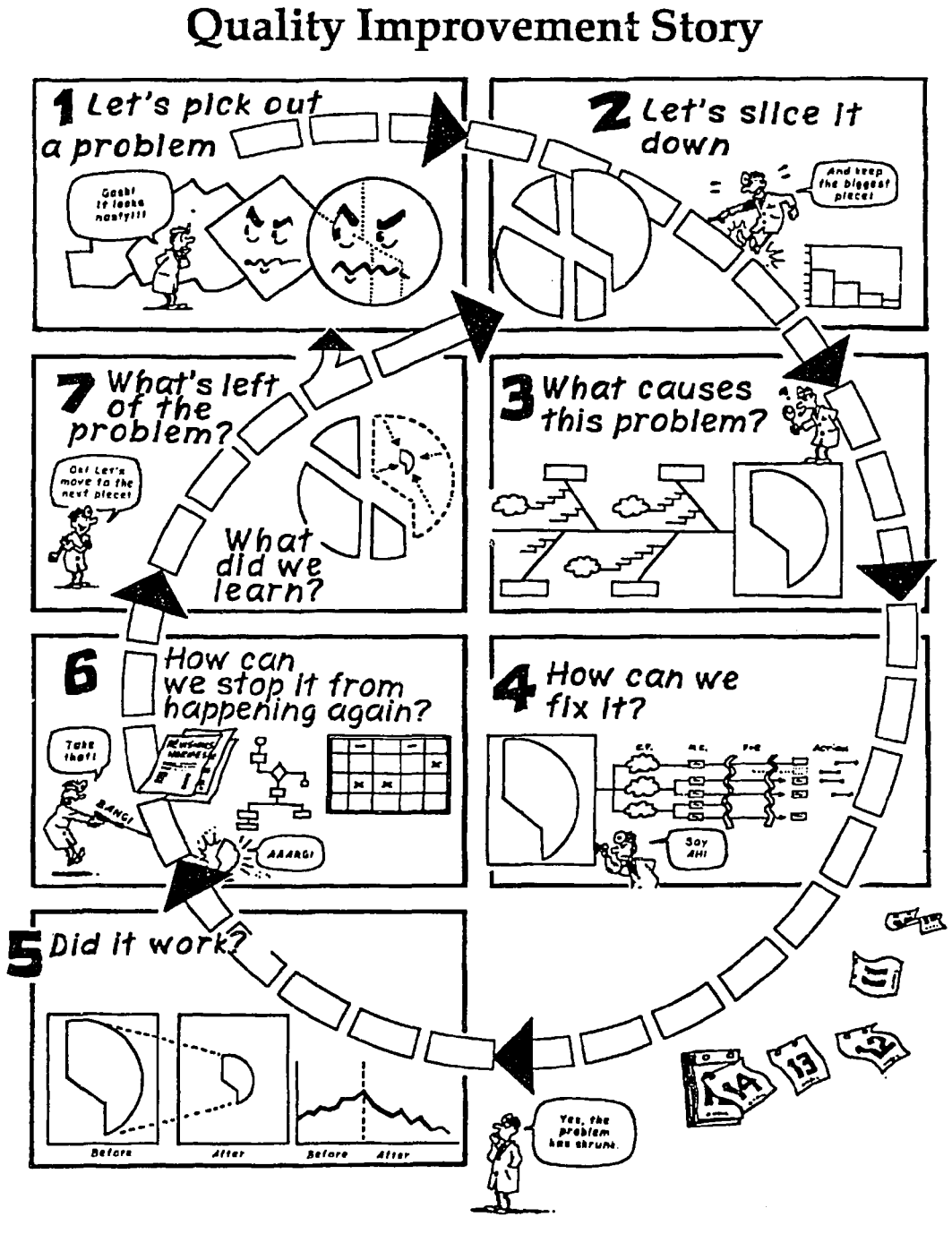


Figure 1.1



TOTAL QUALITY MANAGEMENT PROCESS

Figure 12


Quality Improvement Story
1 Let's pick out a problem
Gosh! It looks nasty!!!
2 Let's slice it down
And keep the biggest piece!
3 What causes this problem?
4 How can we fix it?
Say AH!
5 Did it work?
Before
After
Before
After
Yes, the problem has shrunk.
6 How can we stop it from happening again?
Take that!
BANG!
AAARGI
7 What's left of the problem?
Ok! Let's move to the next piece!
What did we learn?

LA MAINTENANCE À GENTILLY 2 À L'HEURE DE LA QUALITÉ TOTALE

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RÉSUMÉ

La politique de maintenance de l'entreprise prend appui sur un appareil de gestion qui vise à assurer la disponibilité des installations, et ce de manière à optimiser l'adéquation entre les ressources et les exigences. Cette politique a donné lieu à la mise en place de programmes élaborés de maintenance préventive.

Après bientôt une dizaine d'années d'exploitation de la centrale, les indicateurs de qualité permettent de mesurer le degré de réussite atteint en matière de satisfaction des besoins du client et de ses attentes.

Le virage de la qualité totale s'accompagne d'une approche de gestion mettant en jeu l'intégration d'outils rigoureux d'amélioration de la performance et de satisfaction totale des clients.

Avec pour objectif une disponibilité annuelle de 90 %, l'augmentation de la performance globale passe par la limitation des arrêts planifiés annuels à une durée de 21 jours et par l'optimisation du programme d'entretien préventif. Une équipe d'amélioration de la qualité travaille déjà en ce sens. Cette équipe verra à apporter un nouvel équilibre au programme et, éventuellement, à l'optimiser en misant sur la fiabilité.

INTRODUCTION

En octobre 1983, Hydro-Québec a déclaré que Gentilly 2, centrale de la série CANDU-6, avait débuté son exploitation commerciale. Bien qu'elle soit une des principales compagnies d'électricité en Amérique du Nord, Hydro-Québec n'exploite qu'une seule centrale thermique classique et qu'une seule centrale nucléaire.

Dans l'ensemble, l'énergie qu'elle produit est à 96 % d'origine hydraulique. Il est à prévoir que l'entreprise continuera de faire porter ses efforts sur la valorisation de ses ressources hydrauliques par la mise en oeuvre de divers projets dans le Grand Nord québécois.

L'âge moyen des centrales nucléaires, dont Gentilly 2, augmente sensiblement, de pair avec les préoccupations engendrées par la maintenance. Au nombre de ces préoccupations figurent les coûts croissants de la maintenance proprement dite, de même que ceux de l'énergie de remplacement lors des indisponibilités de centrale. Plus important encore est l'incidence de la maintenance sur l'exploitation sûre et fiable de la centrale vieillissante. À long terme, la durée de vie de la centrale est, en bonne partie, fonction de la maintenance.

La politique de maintenance de l'entreprise a donné lieu à la mise en place de programmes élaborés de maintenance préventive. Après bientôt dix années d'exploitation, l'heure est maintenant venue de scruter les indicateurs de maintenance et d'en évaluer les résultats. En s'engageant sur la voie de la qualité totale, l'entreprise s'est dotée d'un appareil de gestion qui lui permet d'augmenter sa performance globale et d'apporter les correctifs qui s'imposent.

LA POLITIQUE DE MAINTENANCE

La politique de maintenance des installations de production d'Hydro-Québec vise à assurer la disponibilité des installations par des actions de maintenance appliquées à leurs éléments et à leurs composants. Elle s'appuie sur cinq principes généraux indissociables :

- la satisfaction des besoins des clients;
- la santé et la sécurité du public et du personnel;
- le respect de la législation et des engagements, tels les ententes et les conventions collectives;
- la protection de l'environnement;
- la rentabilité optimale de l'entreprise, par la minimisation des coûts et la maximisation de la disponibilité des installations.

Cette politique s'articule autour de deux grands axes. Le premier a trait à la disponibilité des installations et le second à la gestion de la maintenance.

La *disponibilité des installations* est assurée en maintenant leurs éléments dans un état spécifié, lequel est établi d'après les critères de conception, les conditions d'utilisation et les pratiques de maintenance. Dans ce but, des programmes préventifs d'entretien, de modification, de réfection et de remplacement sont mis en oeuvre de façon à minimiser la fréquence de défaillance des éléments des installations. Aussi, on établit des pratiques de maintenance qui minimisent l'impact d'une interruption de fonctionnement ou d'une détérioration des éléments des installations, et on modifie les éléments des installations de façon à faciliter les actions de maintenance.

La *gestion de la maintenance* est réalisée de manière à optimiser l'adéquation entre les ressources qui y sont affectées et les exigences relatives au bon fonctionnement des installations. Le mode de maintenance préventif ou correctif approprié est déterminé pour chaque élément des installations. Cette gestion tient compte des facteurs suivants : la planification, l'organisation, la réalisation, le contrôle, la rétroaction et la recherche appliquée.

La figure 1 présente les diverses actions de maintenance et la figure 2 les modes de maintenance.

Maintenance

La maintenance est un ensemble d'actions exécutées dans le but de maintenir une installation ou un élément d'une installation dans un état spécifié. Ces actions comprennent l'entretien, la réfection, la modification et le remplacement d'éléments ainsi que leur remise en service consécutive à ces actions. La maintenance peut être réalisée selon le mode correctif ou préventif.

Mode correctif

Les actions de maintenance réalisées en mode correctif visent à rétablir le fonctionnement d'un élément suite à sa défaillance.

Mode préventif

Les actions de maintenance réalisées en mode préventif visent à prévenir la défaillance ou la détérioration d'un élément. Elles peuvent être déclenchées de façon systématique ou de façon conditionnelle.

De *façon systématique,* l'action de maintenance est effectuée en fonction d'un calendrier établi selon le temps ou le nombre d'unités d'usage.

De *façon conditionnelle,* l'action de maintenance est subordonnée à un type d'événement prédéterminé, révélateur de l'état d'un élément.

Modification

La modification est une action de maintenance réalisée de façon préventive ou corrective visant à changer l'état spécifié d'un élément pour un nouvel état.

Réfection

La réfection est une action de maintenance réalisée de façon préventive ou corrective visant à restaurer un élément conformément à l'état spécifié.

Remise en service

La remise en service est une action de maintenance visant à éprouver l'état spécifié d'un élément suite à une autre action de maintenance.

Remplacement

Le remplacement est une action de maintenance réalisée de façon préventive ou corrective visant à rétablir la conformité à l'état spécifié par voie de substitution d'un élément conforme à un autre qui ne l'est plus.

Entretien

L'entretien est une action de maintenance visant, en mode préventif, à maîtriser l'évolution de l'état réel d'un élément ou, en mode correctif, à remettre en état de fonctionnement un élément endommagé ou détérioré.

Telle est la politique en vigueur à la centrale.

LE PROGRAMME DE MAINTENANCE

En accord avec la politique de maintenance des installations de production d'Hydro-Québec et en accord avec le programme d'assurance de la qualité d'exploitation de la centrale, le programme de maintenance de Gentilly 2 a été mis en place.

Ce programme de maintenance s'étend notamment à l'ensemble des éléments suivants : organisation de la maintenance et de l'entretien, qualification du personnel, fonction de vérification, étalonnage, planification, dossiers d'entretien, procédures d'entretien, essais et mise en service, préparation et implantation des modifications, contrôle de la documentation, gestion des approvisionnements et des stocks, et contrôle radiologique.

Plus spécifiquement, la maintenance préventive englobe les six programmes suivants.

Entretien préventif

Le programme d'entretien préventif des équipements de la centrale regroupe l'ensemble des activités d'entretien visant à garder les équipements en état de remplir leurs fonctions avec un maximum de fiabilité.

Inspection périodique

Le programme d'inspection périodique regroupe l'ensemble des activités d'inspection visant à garantir le bon fonctionnement et l'intégrité des systèmes et éléments essentiels à l'arrêt du réacteur et au refroidissement du combustible durant toute la vie de la centrale.

Appareils sous pression

Le programme de contrôle de la qualité des appareils sous pression regroupe l'ensemble des activités d'inspection, de réparation et de modifications touchant les appareils sous pression.

Soupapes de sûreté

Le programme de maintien de la certification des soupapes de sûreté regroupe l'ensemble des activités de prévention, de détection et de correction des non-conformités des soupapes de sûreté.

Vibrations

Le programme de contrôle des vibrations regroupe l'ensemble des activités de mesure et d'analyse des vibrations des équipements et machines tournantes visant à prévenir l'occurrence de bris catastrophiques, à réduire les arrêts imprévus et à assurer une utilisation optimale des équipements tout en permettant une réduction des coûts.

Essais prescrits

Le programme des essais prescrits regroupe l'ensemble des activités d'entretien préventif et des essais dont il est tenu compte dans les études de fiabilité pour garantir la sûreté de la centrale.

Comme Gentilly 2 est la seule centrale nucléaire de l'entreprise, et qu'elle n'est pas issue d'un programme thermique classique, l'ensemble de son personnel amorçait ni plus ni moins un cycle d'apprentissage au cours des premières années d'exploitation. Ce cycle arrive à maturité maintenant.

Un bon historique de fonctionnement et d'entretien des équipements et une vaste expérience acquise en matière d'exploitation nous permettent de jeter un regard critique sur tous ces programmes.

Plusieurs d'entre eux, tels les programmes d'inspection périodique et de contrôle des appareils sous pression, des soupapes de sûreté et des vibrations ont été peu retouchés et produisent les résultats attendus.

Le programme des essais prescrits a été révisé en profondeur il y a quelques années et est maintenant au point.

Le programme initial d'entretien préventif a été défini par les ingénieurs de mise en service d'après la réglementation et les spécifications techniques en vigueur, les recommandations du concepteur et du fournisseur, les résultats

d'études particulières et l'expérience acquise par les exploitants d'équipement semblable. Ce programme, qui a été relativement peu modifié au cours des années, se révèle aujourd'hui de qualité inégale et laisse amplement place à l'amélioration.

La figure 3 présente la relation classique entre le coût total de la maintenance et le volume d'entretien préventif. La courbe de coût présente un optimum que tous recherchent. La revue en profondeur du programme d'entretien préventif par une équipe d'amélioration de la qualité est une démarche en ce sens.

LES INDICATEURS DE MAINTENANCE

Les indicateurs de qualité sont des mesures du degré de réussite atteint en matière de satisfaction des besoins du client et de ses attentes. Il s'agit, en d'autres termes, de la mesure du degré de conformité, de façon qualitative aussi bien que quantitative, à une exigence valable. En se fondant sur une valeur donnée de non-conformité, il y a lieu de s'attarder sur l'écart entre ce qui est et ce qui devrait être, entre la performance actuelle et les exigences du client. Les indicateurs donnent une mesure de la situation actuelle, de son évolution et des efforts à consentir en vue de son amélioration.

Indicateurs quantitatifs

Le principal indicateur quantitatif est le coefficient de disponibilité équivalente. Celui-ci permet de mesurer selon quelle probabilité la centrale est apte à accomplir sa mission, soit produire de l'électricité pour son client qui est le réseau, en tout temps et selon les spécifications, y compris celles touchant la sûreté nucléaire.

La figure 4 permet de visualiser l'évolution de cet indicateur. À la fin octobre 1992, la valeur moyenne à vie de la disponibilité équivalente de la centrale était de 79,3 %. Cette valeur, quoique satisfaisante, doit être améliorée. Ainsi l'objectif pour 1995 est d'augmenter graduellement la disponibilité équivalente annuelle à 90,0 %. Il s'agit là de la principale cible d'amélioration de la centrale.

À cause du climat québécois, la demande sur le réseau est beaucoup plus élevée au cours des mois d'hiver. À l'exception de l'hiver 91-92, la centrale a toujours pu satisfaire son client avec une disponibilité de 97,7 % de décembre à avril de chaque année, et, en moyenne, moins d'un arrêt imprévu par an.

La figure 5 montre que les arrêts planifiés comptent pour près de 60 % des indisponibilités. La figure 6 détaille la structure des indisponibilités dans le temps. Les indisponibilités causées par les arrêts imprévus sont souvent plus coûteuses. Les arrêts planifiés peuvent être prévus dans une période où le client, autrement dit le réseau, est en période de surplus énergétique, soit au moment de la crue printannière des eaux attribuable à la fonte des neiges. De plus, les interventions sont mieux préparées et le matériel disponible. Un arrêt imprévu est toujours un élément perturbateur important dont il faut réduire les conséquences.

La durée moyenne des arrêts annuels planifiés est de 39 jours, comme l'illustre la figure 7. Sauf pour l'année 1986 où la contrainte est venue directement du réseau, la durée des arrêts annuels a toujours été conditionnée par les travaux reliés au turbo-alternateur.

Ceci devient plus clair à la vue de la figure 8 qui illustre les facteurs d'indisponibilité pour chaque année. Les problèmes techniques reliés au turbo-alternateur étant dorénavent sous contrôle, il est permis de croire que l'objectif d'indisponibilité totale de 10 % pour 1995 est réaliste, dans la mesure où la paix industrielle persiste.

Indicateurs qualitatifs

Les indicateurs de disponibilité ne permettent pas de qualifier la satisfaction des besoins du client. Par exemple, le fait d'avoir une très bonne disponibilité en période de pointe annuelle du réseau est un élément de satisfaction alors qu'un nombre relativement élevé d'arrêts imprévus devient une non-conformité par rapport aux attentes du client. En effet, le réseau doit maintenir une réserve de production adéquate pour faire face à ces arrêts. Le maintien de cette réserve est coûteux. De plus, chaque arrêt, planifié ou imprévu, impose des contraintes aux équipements. Ces transitoires s'additionnent avec le temps et deviennent éventuellement un facteur limitatif de la vie utile des équipements et

systèmes. Enfin, chaque arrêt augmente les possibilités d'erreurs hmaines et de défaillances additionnelles des équipements au cours de l'arrêt et du démarrage subséquent de la centrale.

D'autres indicateurs de la qualité de la maintenance à la centrale sont ceux qui sont reliés à la radioprotection. Ainsi, la figure 9 fait voir les excellents résultats obtenus en dosimétrie. Ces valeurs sont parmi les meilleures au monde et résultent de l'engagement de l'entreprise à respecter les personnes et à maîtriser les processus de travail mettant en jeu la radioactivité. De même, les volumes exceptionnellement bas de déchets faiblement radioactifs montrés à la figure 10 viennent confirmer l'attention portée à cet aspect de la production de l'usine d'électricité qu'est la centrale.

En ce qui a trait aux coûts de la maintenance, ceux-ci demeurent à toutes fins utiles égaux depuis neuf ans. Le rapport actuel de l'entretien préventif à l'entretien correctif n'est que très légèrement supérieur à 1. Afin de contenir les coûts de maintenance alors que la centrale commence à vieillir, il est envisagé d'augmenter progressivement ce rapport à environ 1,5.

LE DÉFI PERFORMANCE

En 1990, l'entreprise s'est engagée sur la voie de la qualité totale au moyen de son projet défi Performance. L'implantation du défi Performance s'échelonnera sur une période de cinq ans.

L'approche de gestion de la qualité retenue vise à satisfaire totalement et au moindre coût les besoins des clients par une plus grande mobilisation des ressources humaines et par la maîtrise des processus de travail. Il s'agit non seulement d'une philosophie qui permet l'implantation de valeurs fondamentales, mais aussi d'une technique en ce qu'elle formalise, par des méthodes scientifiques, un style de gestion rigoureux.

Pour soutenir la gestion de la qualité, l'entreprise s'est donné un nouveau modèle de gestion qui met en jeu quatre principes et trois axes de gestion, de même que des équipes de travail vouées à l'amélioration de la performance. La figure 11 illustre l'interdépendance des quatre principes de la qualité mis en oeuvre par le moyen des axes de gestion.

Ce modèle de gestion, qui allie des outils rigoureux d'amélioration de la performance et de satisfaction totale des clients, s'appuie sur des principes fondamentaux :

- L'*orientation client* a pour objet d'orienter chacune des actions de l'entreprise en fonction de la satisfaction des besoins des clients externes. La satisfaction des clients externes découle de la satisfaction des clients internes; la satisfaction des clients devient ainsi la finalité du travail de chacun des employés.

- Le *respect des personnes* est fondé sur le principe que la plus importante ressource de l'entreprise est son capital humain. C'est par le respect de l'employé et l'obtention de son adhésion à un projet commun que l'entreprise parviendra à tirer le maximum des possibilités de chacun. Ainsi, en permettant à chacun d'assumer pleinement ses responsabilités, le personnel retrouvera la satisfaction du travail bien fait et la fierté qui en découle.

- La *gestion en fonction des faits* permet d'appuyer les décisions prises sur des données objectives et quantifiées, et non sur des opinions ou des impressions.

- L'*amélioration continue* est la recherche constante et systématique de la satisfaction des clients selon la roue de Deming ou le cycle de travail PFVA (Planifier, Faire, Vérifier, Agir).

Ces principes de la qualité débouchent sur des interventions concrètes dans les axes de gestion suivants :

- Les *cibles d'amélioration* visent à orienter l'ensemble des actions et des ressources de l'entreprise vers la satisfaction totale des clients, compte tenu d'un nombre restreint de cibles indiquées par les clients.

- Les *processus de travail* décrivent comment chaque activité doit être exécutée pour obtenir les résultats recherchés.

L'amélioration de la qualité dépend étroitement de l'existence de processus de travail systématiquement documentés.

- L'*assurance de la qualité* vise à mettre en place les éléments assurant l'entreprise que toutes ses activités sont réalisées de façon à satisfaire totalement les besoins et les attentes des clients. Il s'agit de faire en sorte qu'à chaque étape de leur réalisation, ces activités soient bien faites du premier coup, et au moindre coût.
- Les *équipes d'amélioration* sont au coeur même du défi Performance. Elles ont le mandat de résoudre un ou des problèmes selon une méthode rigoureuse. Elles favorisent la mobilisation de tous les employés en vue de l'amélioration de la qualité dans l'entreprise et de la recherche de l'excellence.

Le défi Performance est implanté progressivement à Gentilly 2 au même rythme que dans l'ensemble de l'entreprise.

Les équipes d'amélioration de la qualité adoptent une démarche qui réfère spécifiquement au processus de résolution de problèmes du défi Performance. Baptisée démarche Qualité, il s'agit d'une méthode systématique de recherche et de résolution de problèmes, fondée sur la cueillette et l'examen de données factuelles, qui comporte sept étapes, comme l'indique la figure 12 :

1. *Besoin d'amélioration.* L'équipe identifie un thème d'amélioration, une zone problématique, et précise les raisons de l'intervention.
2. *Objectif d'amélioration.* L'équipe sélectionne un problème précis à l'intérieur du thème et un objectif d'amélioration.
3. *Causes du problème.* L'équipe détermine et valide la ou les causes premières du problème retenu.
4. *Mesures correctives.* L'équipe sélectionne et expérimente les mesures correctives qui visent à enrayer la ou les causes premières du problème.
5. *Résultats.* L'équipe évalue l'efficacité des mesures correctives en mesurant le degré de réalisation de l'objectif d'amélioration.
6. *Standardisation.* L'équipe intègre de façon définitive les mesures correctives au processus de travail.
7. *Bilan et perspective.* On passe en revue les travaux de l'équipe et le déroulement de la démarche afin de se pencher sur les questions en suspens et de prévoir la démarche suivante.

À chacune de ces étapes, l'équipe procède systématiquement à toute une série d'activités bien définies.

LES VOIES D'AMÉLIORATION

La principale cible d'amélioration de la centrale sur quatre ans est une augmentation graduelle du facteur de disponibilité équivalente de 10 %, sans augmentation des coûts de maintenance.

Les indisponibilités causées par les problèmes reliés au personnel ne devraient pas être récurrentes, dans la mesure où la paix industrielle persiste.

Pour toucher la cible, deux autres conditions sont nécessaires : contenir le nombre et la durée des arrêts imprévus à leurs valeurs actuelles, alors que la centrale commence à vieillir, et réduire la durée moyenne des arrêts annuels planifiés de 39 à 21 jours. Ces deux conditions passent par une optimisation du programme d'entretien préventif.

Conditions facilitantes

Au cours des dix dernières années, beaucoup d'expérience pratique a été gagnée. On éteint de moins en moins de feux, et la majorité des zones de problèmes importants ont été circonscrites.

Ainsi, par exemple, la maintenance réactive des systèmes reliés à la manutention du combustible a cédé le pas depuis plus d'un an à un programme de maintenance préventive systématique et conditionnelle. Les indisponibilités de ces systèmes critiques pour le maintien du réacteur en marche ont été réduites de façon très substantielle.

L'important programme de maintenance conditionnelle des tubes de force du réacteur, bien qu'il puisse toujours être modifié, peut

maintenant être considéré comme étant au point. Ce programme d'inspection, de surveillance et de remise en place des ressorts d'espacement permettra de maîtriser l'évolution de l'état de ces éléments essentiels et d'obtenir une durée de vie utile satisfaisante des canaux de combustible.

Le programme de maintenance préventive systématique, et de plus en plus conditionnelle, des générateurs de vapeur a déjà porté fruits. En effet, jusqu'à ce jour, aucun tube des générateurs de vapeur n'a dû être bouché pour cause de défaillance. Tout porte à croire que ces équipements critiques vont fonctionner de façon sûre, fiable et économique jusqu'à la fin de la vie utile de la centrale.

La durée des arrêts planifiés a presque toujours été dictée par les travaux relatifs au groupe turbo-alternateur. Ces arrêts ont été requis pour vérifier l'alignement, pour aligner les arbres ou pour réparer le groupe. Le désalignement continuel de la machine est causé par une réaction chimique dans le béton, appelée alcali-agrégat, qui fait gonfler le béton et qui engendre des déplacements inacceptables des composants de la machine. D'autre part, les fortes vibrations de l'alternateur sont dues à une trop grande flexibilité de la fondation le supportant. Après plus de quinze ans, il y a enfin une stabilisation relative des déplacements de la fondation. De plus, l'amélioration des moyens de suivi de la fondation et de la machine elle-même va permettre de mieux cibler les interventions. La maintenance préventive systématique est remplacée par de la maintenance préventive conditionnelle. Les inspections deviennent sectionnelles au lieu d'être totales. Dès l'année prochaine, l'arrêt annuel pourra être comprimé à 21 jours. Ceci n'a été rendu possible que grâce à la stabilisation relative de la fondation et un important retour d'expérience interne et externe.

La gestion des arrêts planifiés est maîtrisée. Au fil des ans, un important retour d'expérience a eu lieu, notamment en ce qui a trait à la conduite, à la planification, à la gestion des ressources internes et externes, à la préparation des travaux et au suivi de l'exécution.

Le programme d'entretien préventif

Le programme d'entretien préventif doit être optimisé. Un nouvel équilibre est recherché. Une équipe d'amélioration mettant en pratique la démarche Qualité est déjà à pied d'oeuvre. Cette équipe est constituée de personnel venant de tous les groupes dont les activités sont liées à la maintenance : ingénieurs, opérateurs, contremaîtres, techniciens, gens de métier, planificateurs.

Un des problèmes cernés, soit le besoin d'amélioration, réside dans le fait que le programme d'entretien préventif actuel fait appel à de multiples interventions alors que la centrale est à l'arrêt. Jusqu'à ce jour, ceci n'a pas causé de difficultés importantes en raison de la durée moyenne relativement longue des arrêts annuels, mais des arrêts raccourcis à 21 jours font naître une nouvelle problématique.

Un autre besoin d'amélioration identifié par l'équipe est l'optimisation de l'entretien par la fiabilité. Le programme doit pouvoir intégrer de façon systématique le retour d'expérience, faire porter l'effort de maintenance au bon endroit, accorder aux divers éléments une attention proportionnelle à leur importance en ce qui a trait à la sûreté et à la production de la centrale et tenir compte des causes les plus probables de défaillance dans l'ordonnancement des interventions de maintenance.

Puisqu'il y a deux problèmes, l'équipe d'amélioration devra franchir chacune des différentes étapes de la démarche Qualité à deux reprises.

Sans présumer des conclusions de l'équipe d'amélioration, il existe déjà depuis quelque temps un projet d'amélioration du système de collecte des données de fiabilité des composantes. L'implantation de ce système intégré aux logiciels du système de gestion d'entretien (SGE) compatible avec les banques de données externes va grandement faciliter l'analyse systématique des mécanismes de défaillance et de dégradation des divers éléments. Ces nouveaux outils seront aussi d'une grande utilité dans les études du projet Durée de vie.

CONCLUSION

Les programmes de maintenance ont déjà donné de bons résultats. L'importance de la composante proactive, c.-à-d. la maintenance préventive conditionnelle, progresse continuellement au fur et à mesure que les programmes sont mis à jour. Par ailleurs, l'engagement de chacun à l'égard de la qualité totale permet d'augmenter notre performance globale. Le principal objectif visé pour 1995 est un facteur de disponibilité équivalente de 90 % annuellement.

L'approche de gestion axée sur la qualité totale vise à satisfaire totalement et au moindre coût les besoins des clients par une plus grande mobilisation des ressources humaines et par la maîtrise des processus de travail.

En particulier, le programme d'entretien préventif est scruté par une équipe d'amélioration de la qualité afin de lui redonner un nouvel équilibre et, éventuellement, de l'optimiser par la fiabilité. La marche continue vers l'excellence n'a pas de cesse.

BIOGRAPHIE

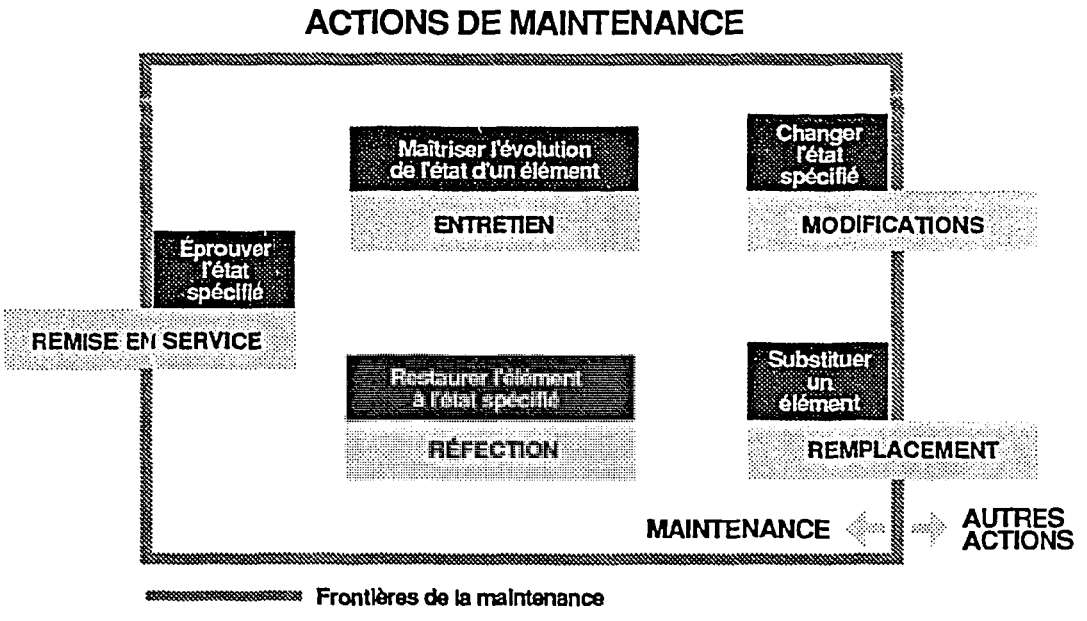
Michel H. Ross est conseiller principal - Dossiers nucléaires à la direction Gestion du nucléaire. À ce titre, il analyse et traite des dossiers techniques ou administratifs complexes liés à l'exploitation de l'énergie nucléaire. Son travail porte sur les encadrements, les orientations et l'élaboration de la fonction, et plus particulièrement sur les perspectives, les stratégies et les intérêts de l'entreprise dans le domaine.

Diplômé en génie nucléaire de l'Institut de génie nucléaire de l'École Polytechnique de Montréal, il a acquis une vaste expérience en matière de mise en service et d'exploitation des centrales CANDU. Il a participé à la mise en service de la centrale Gentilly 1 en qualité d'ingénieur physicien. Il a ensuite occupé les postes de chef de la division Technique de cette centrale, puis d'ingénieur chef chargé de sa mise en état de conservation, après quoi il est devenu responsable de la mise en service de Gentilly 2, centrale dont il a également dirigé la division Conduite et Planification pendant ses premières années d'exploitation.

Henri Marois est directeur adjoint – Gestion du nucléaire. À ce titre, il participe à la gestion de l'ensemble des activités d'Hydro-Québec reliées au nucléaire. Plus précisément, il seconde le directeur qui voit à l'exploitation fiable, économique et sécuritaire de la centrale nucléaire Gentilly 2, ainsi qu'au développement de l'expertise technique nucléaire que commandent les besoins de la centrale.

Après ses études en génie, il cumule différentes fonctions à Hydro-Québec à titre d'ingénieur au siège social, à Manicouagan et à Gentilly. Alors que la mise en service de la centrale nucléaire Gentilly 1 débute, il entre au service de la Commission de contrôle de l'énergie atomique (CCEA) à titre de responsable, sur place, de Gentilly 1, puis Gentilly 2. Il revient à Hydro-Québec où il préside le Comité de la sûreté des installations nucléaires en même temps qu'il est nommé chef de service Radioprotection. Après quoi, il devient chef de service Entretien et Radioprotection, puis directeur adjoint.

Figure 1



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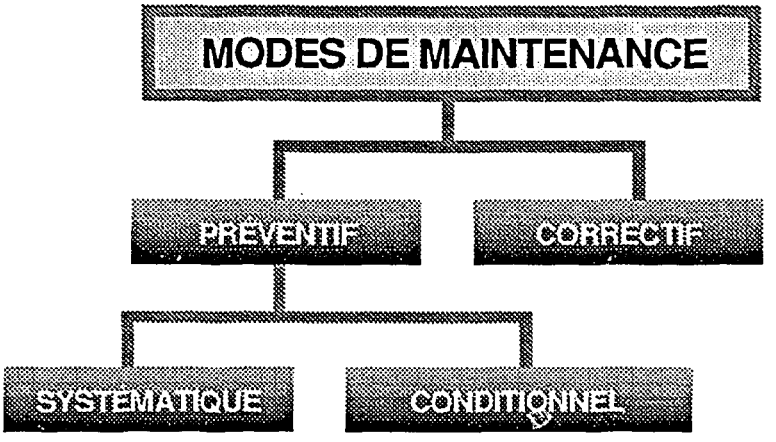

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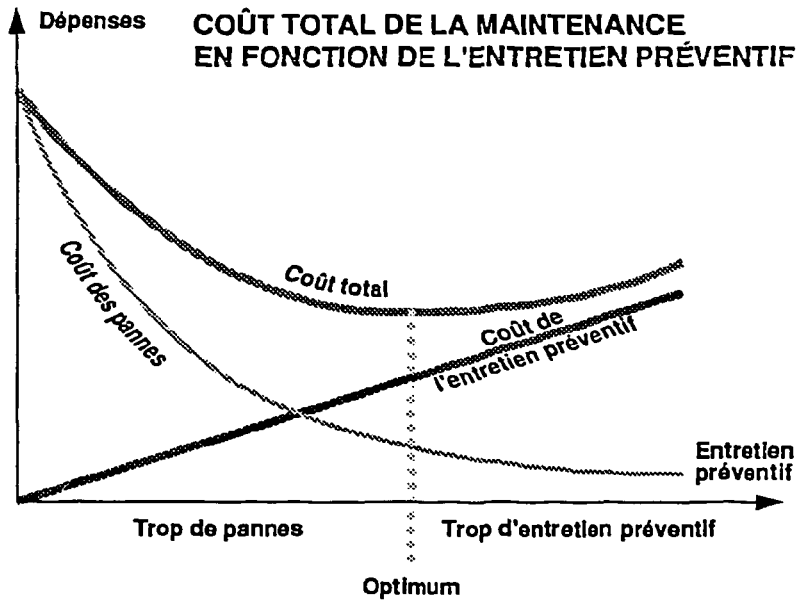

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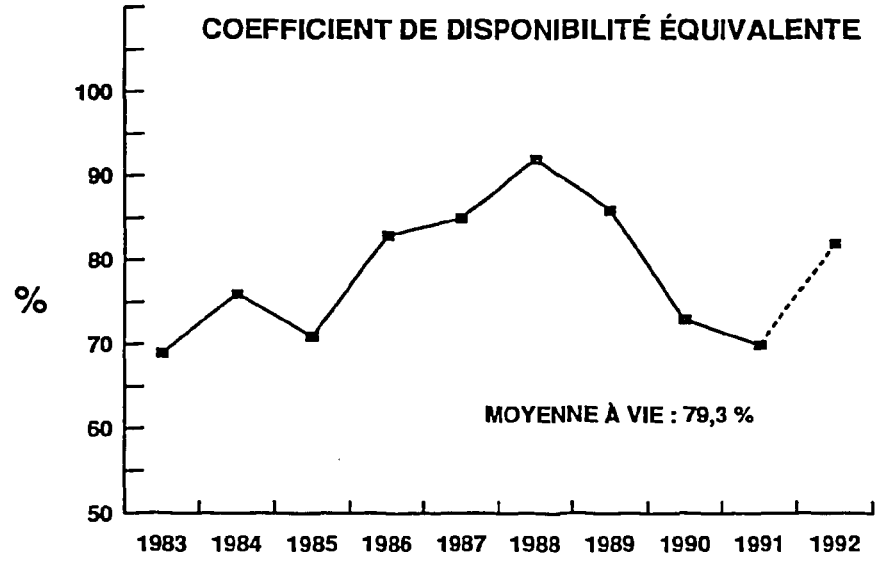

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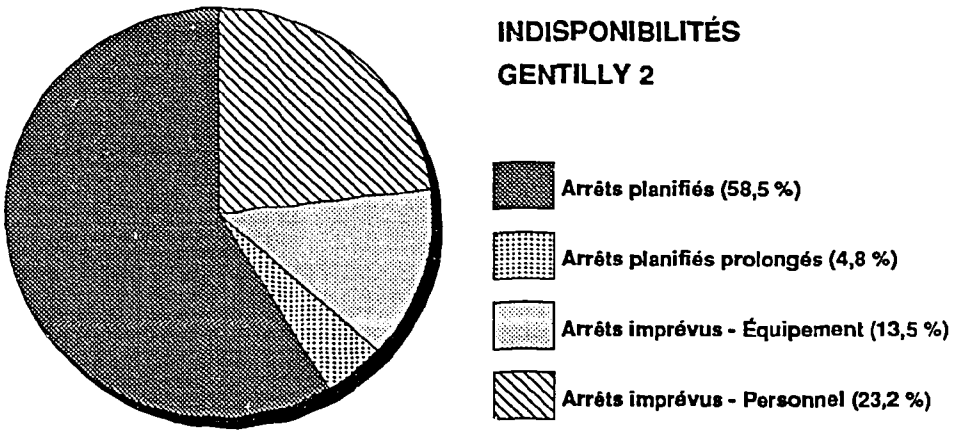

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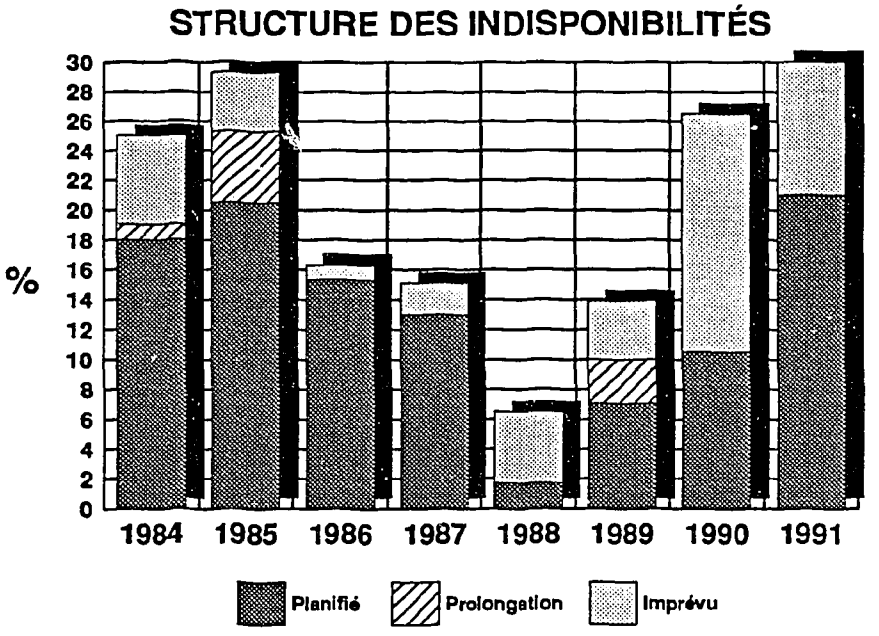

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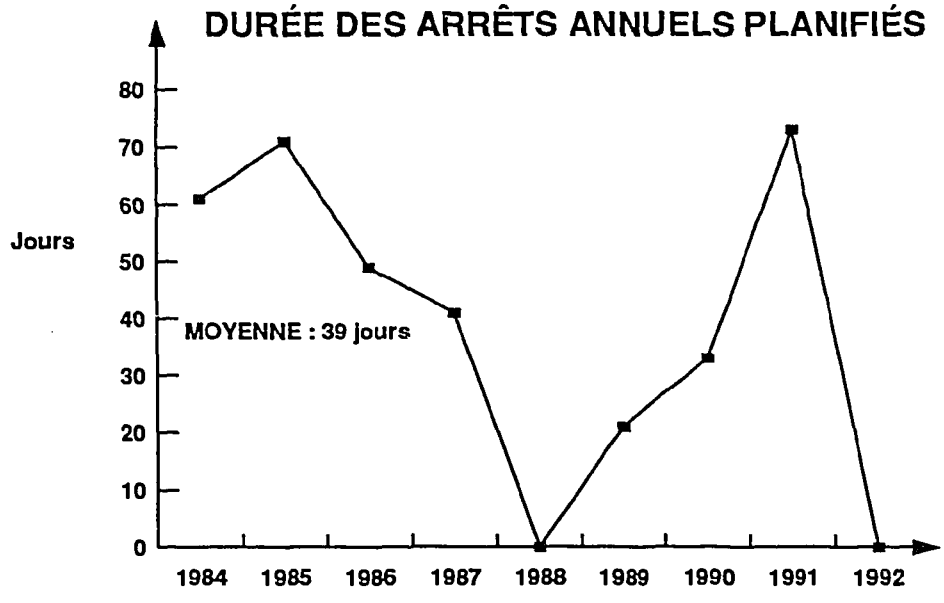

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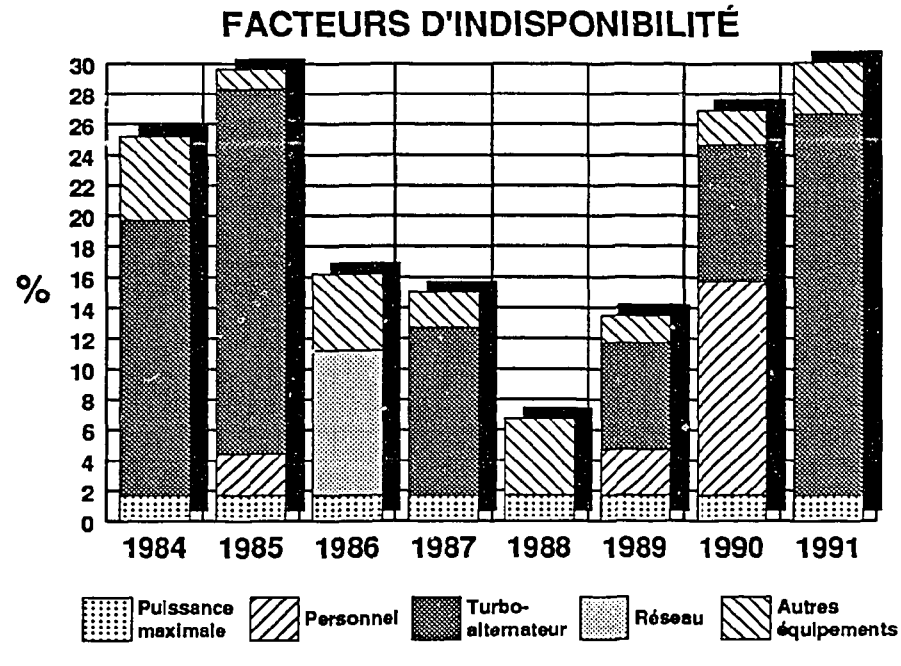
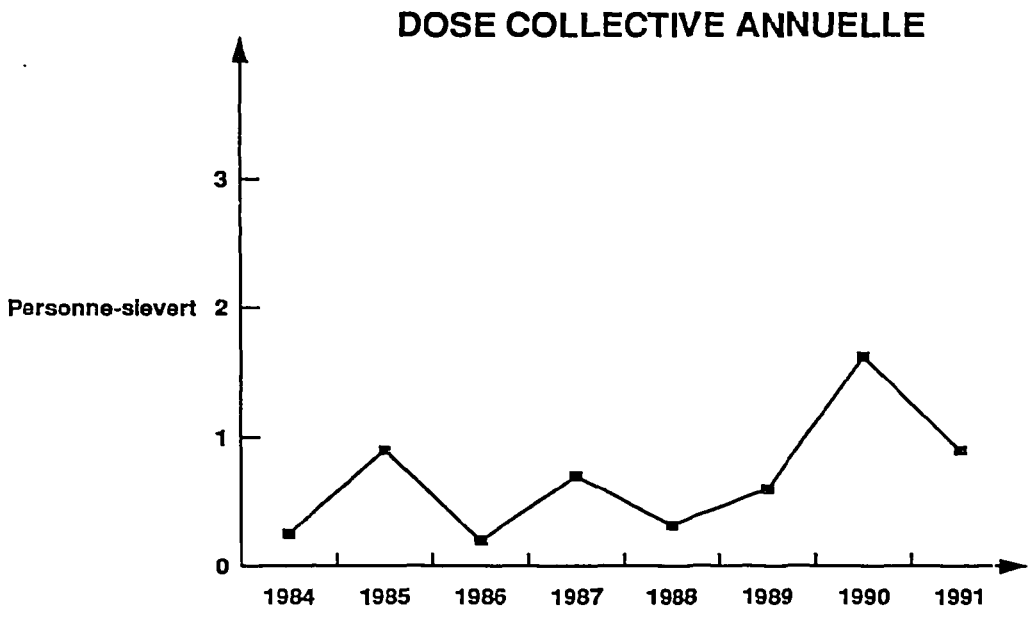


Figure 9



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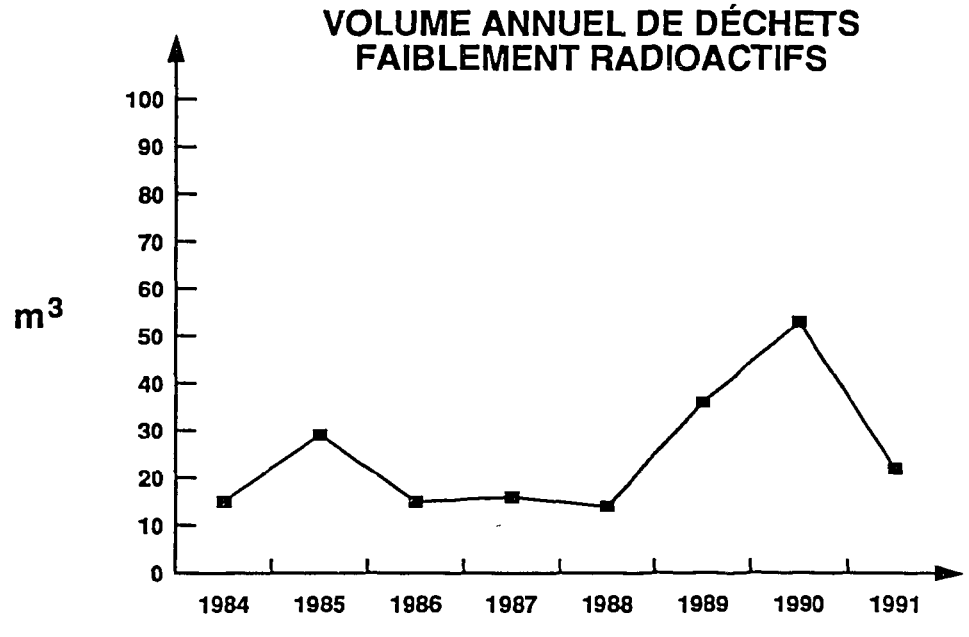

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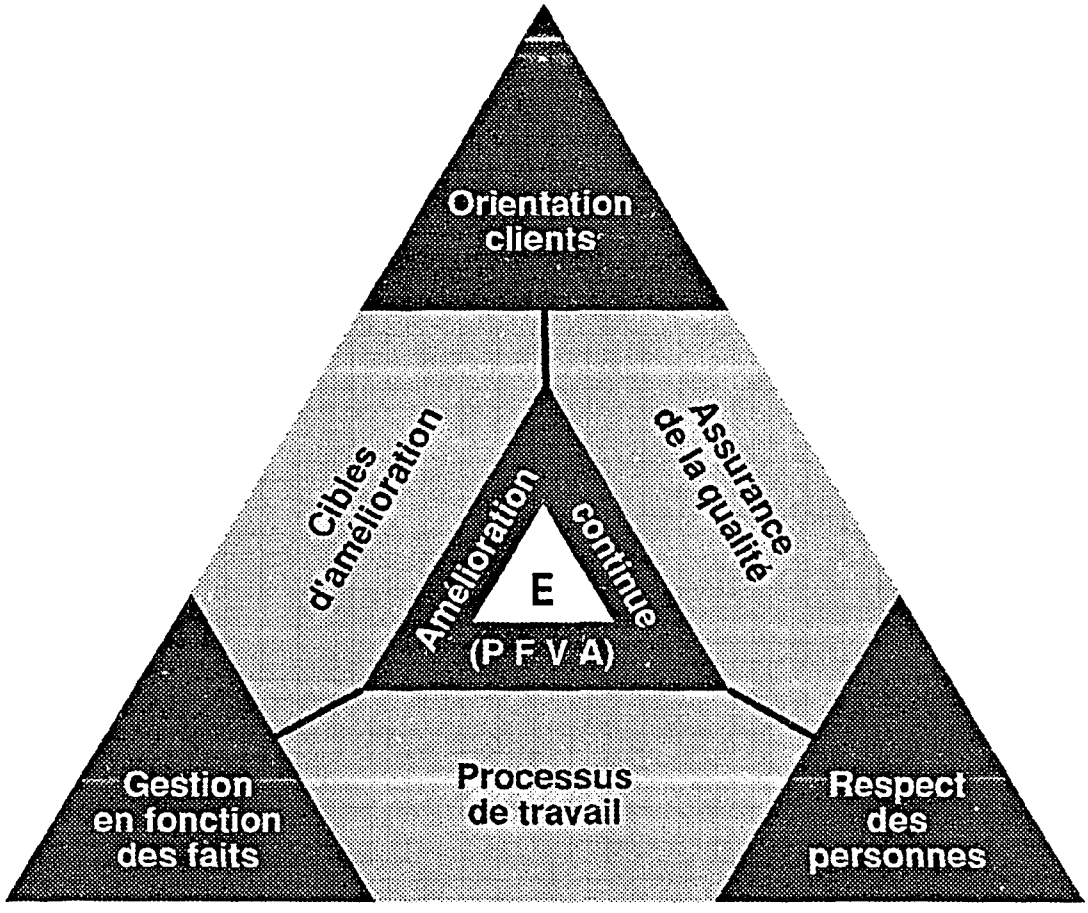
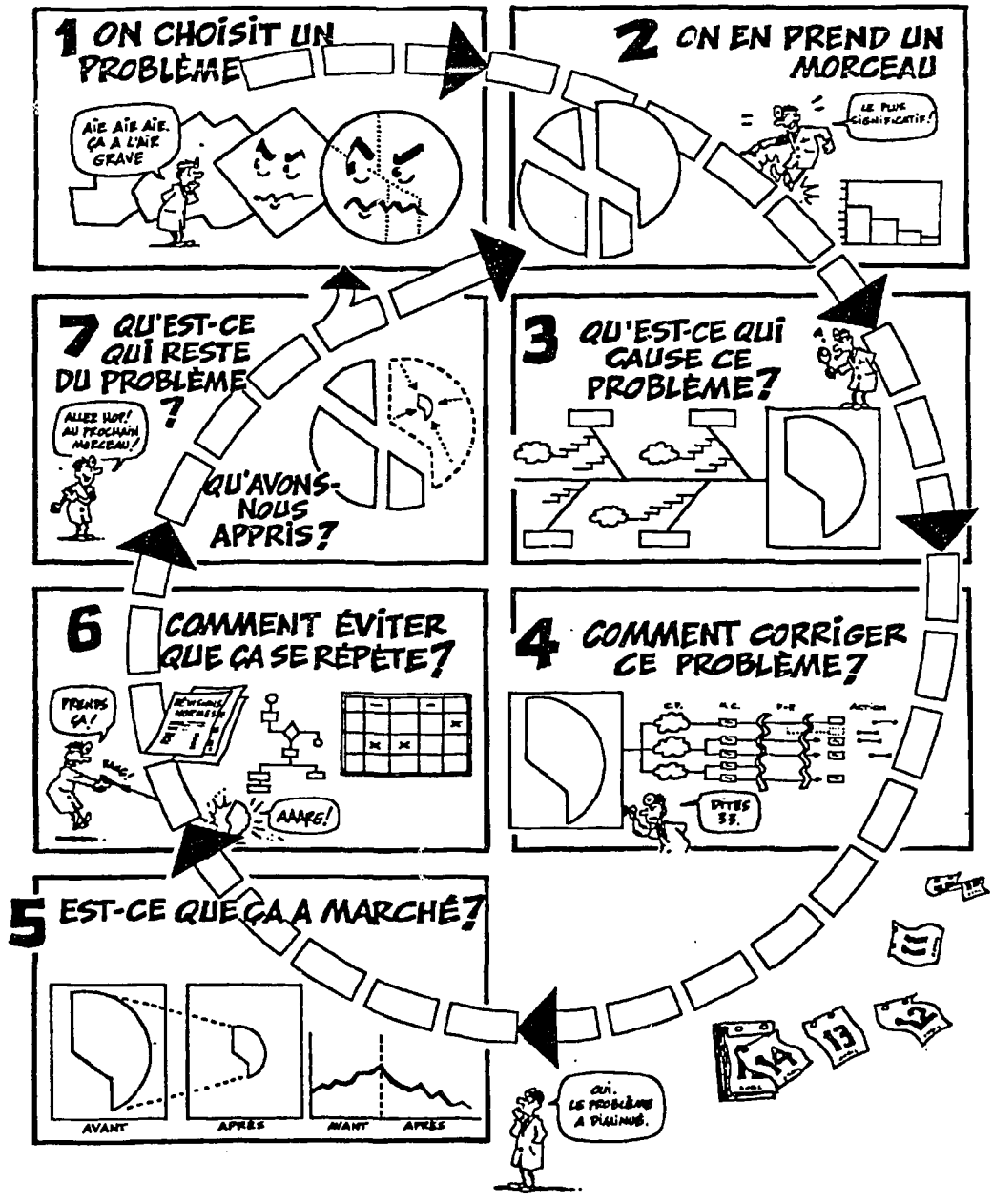


PROCESSUS DE GESTION DE LA QUALITÉ TOTALE

Figure 12

La Démarche qualité en abrégé