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U.S.-KOREA ELECTRIC POWER GENERATION SEMINAR MISSION

October 24-26, 1994
Seoul, Korea

Volume I

PROCEEDINGS

DISCLAIMER

U.S.-KOREA ELECTRIC POWER GENERATION SEMINAR MISSION

October 24-25, 1994
Seoul, Korea

Volume I

PROCEEDINGS

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INTRODUCTION

Department of Energy
Washington, DC 20585

GREETINGS FROM THE DEPUTY ASSISTANT SECRETARY FOR SCIENCE AND TECHNOLOGY POLICY

It was an honor to lead the U.S. delegation of the U.S./Korea Electric Power Technologies Seminar to Seoul, Korea, October 24-28, 1994. The U.S. believes that such events provide important opportunities to build and expand positive business relationships and exchange information.

This seminar also provided the U.S. Government the opportunity to express strong support for increased trade with Korea. The United States is fully committed to work with Korea as partners in economic growth and responsible environmental stewardship.

The United States and Korea have many characteristics in common. Both countries have sophisticated, well-operated electric power systems. Both countries also share a growing need for an abundant supply of reliable, low-cost electricity. Most importantly, both countries want to meet the increasing demand for electricity on terms that are environmentally responsible and promote the health, safety and welfare of our citizens.

In conclusion, I want to stress that the United States Government and the Department of Energy encourage and promote cooperation between U.S. and Korean industry. The Korean market offers opportunities for U.S. firms to increase their exports. U.S. industry, in turn, offers opportunities for Korean power producers to utilize state-of-the-art, high-quality, and competitive U.S. products.

I look forward to working with my Korean counterparts as we support ongoing business relationships and seek new opportunities for expanded collaboration.

Jessie Harris

Jessie Harris

U.S./KOREA ELECTRIC POWER TECHNOLOGIES

SEMINAR MISSION

SEOUL, KOREA - OCTOBER 24-28, 1994

OPENING CEREMONY REMARKS

JESSIE J. HARRIS

DEPUTY ASSISTANT SECRETARY

OFFICE OF SCIENCE AND TECHNOLOGY POLICY

UNITED STATES DEPARTMENT OF ENERGY

INTRODUCTION

GOOD MORNING, LADIES AND GENTLEMEN. IT IS A GREAT PLEASURE FOR ME TO BE HERE TODAY AS HEAD OF THE U.S. DELEGATION TO THE U.S./KOREA ELECTRIC POWER TECHNOLOGIES CONFERENCE.

I BRING GREETINGS AND BEST WISHES FOR A MOST PRODUCTIVE CONFERENCE FROM WASHINGTON, AND THE SECRETARY OF ENERGY, HAZEL O'LEARY. I HAD AN OPPORTUNITY YESTERDAY TO SEE SOME OF YOUR BEAUTIFUL CITY AND AN OPPORTUNITY THIS MORNING TO MEET REPRESENTATIVES OF YOUR ELECTRIC POWER INDUSTRY. I AM DELIGHTED TO BE HERE AND VERY IMPRESSED WITH EVERYTHING I'VE SEEN.

EVENTS SUCH AS THIS ARE VERY IMPORTANT TO US IN THE UNITED STATES.

- THEY PROVIDE KOREAN OFFICIALS AND BUSINESSMEN AND WOMEN THE OPPORTUNITY TO LEARN ABOUT THE LATEST AND MOST ADVANCED U.S. ENERGY TECHNOLOGIES.

- THEY PROVIDE AN OPPORTUNITY FOR U.S. BUSINESSMEN AND WOMEN, IN TURN, TO LEARN ABOUT THE NEEDS AND REQUIREMENTS OF THE KOREAN ELECTRIC POWER SECTOR.

- THEY PROVIDE ALL OF US THE OPPORTUNITY TO BUILD AND DEVELOP U.S./KOREAN PERSONAL AND BUSINESS RELATIONSHIPS.

THIS CONFERENCE ALSO GIVES THE U.S. GOVERNMENT THE OPPORTUNITY TO EXPRESS ITS STRONG SUPPORT FOR INCREASED TRADE WITH KOREA. THE UNITED STATES IS FULLY COMMITTED AND EAGER TO WORK WITH ALL OF YOU AS <u>PARTNERS</u> IN ECONOMIC GROWTH AND RESPONSIBLE ENVIRONMENTAL STEWARDSHIP.

REPRESENTED HERE TODAY ARE U.S. MANUFACTURERS AND SUPPLIERS OF ELECTRIC POWER EQUIPMENT, PRODUCTS, CONSULTANT SERVICES, AND RESEARCH INSTITUTIONS. THEY ARE HERE TO LEARN FROM OUR KOREAN HOSTS THE BEST WAY TO SUCCESSFULLY CONDUCT BUSINESS IN KOREA.

THANKS

I WANT TO BEGIN BY THANKING THE MINISTRY OF TRADE, INDUSTRY, AND ENERGY, THE KOREA ELECTRIC POWER CORPORATION, THE STAFF OF THE KOREA POWER ENGINEERING COMPANY, INC. AND THE MEMBERS OF THE STEERING COMMITTEE FOR THIS SEMINAR MISSION FOR THEIR EXCEPTIONAL SUPPORT IN MAKING THESE MEETINGS POSSIBLE. I ALSO WANT TO THANK THE U.S. DEPARTMENT OF COMMERCE REPRESENTATIVES HERE IN KOREA, AND ESPECIALLY ROBERT CONNAN AND DAVID HUNTER AND THEIR STAFF FOR THE SUBSTANTIAL TIME AND EFFORT INVESTED IN PLANNING THIS CONFERENCE AND MAKING IT A REALITY.

KOREAN CONTEXT

THE REPUBLIC OF KOREA HAS DEVELOPED AN AMBITIOUS, IMPRESSIVE PLAN FOR INCREASING ITS ELECTRIC POWER CAPACITY. THE MINISTRY OF TRADE, INDUSTRY, AND ENERGY HAS RELEASED A DRAFT PLAN ON ELECTRICITY SUPPLY FOR THE NEXT 14 YEARS.

THE PLAN CALLS FOR CONSTRUCTING NEW SOFT COAL, NUCLEAR AND LIQUIFIED NATURAL GAS (LNG) POWER PLANTS HAVING A COMBINED GENERATION CAPACITY OF 36 MILLION KILOWATTS. NATIONAL POWER PRODUCTION IS EXPECTED TO DOUBLE BY THE YEAR 2006.

THIS IS A TESTIMONIAL TO THE STRENGTH OF THE KOREAN ECONOMY AND ITS POTENTIAL FOR GROWTH. I BELIEVE WE WILL HEAR MORE ABOUT THIS FROM OUR NEXT SPEAKER---DR. LEE.

COMMON CHARACTERISTICS

I WANT TO FOCUS NOW ON SOME OF THE CHARACTERISTICS OUR TWO COUNTRIES HAVE IN COMMON. BOTH COUNTRIES SHARE A GROWING NEED FOR AN ABUNDANT SUPPLY OF RELIABLE, LOW-COST ELECTRICITY. AS ALL OF US KNOW, OUR PRODUCTS COMPETE IN A GLOBAL ECONOMY. THE COST OF ELECTRICITY IS AN IMPORTANT FACTOR IN KEEPING OUR PRODUCTS COMPETITIVE.

WE BOTH HAVE SOPHISTICATED, WELL-OPERATED ELECTRIC POWER SYSTEMS. WE ALSO WANT TO MEET THE INCREASING DEMAND FOR ELECTRICITY ON TERMS THAT ARE ENVIRONMENTALLY RESPONSIBLE AND PROMOTE THE HEALTH, SAFETY AND WELFARE OF OUR CITIZENS.

FURTHERMORE, WE BOTH RECOGNIZE THE EXTREMELY HEAVY DEMANDS FOR ENERGY AND POWER THROUGHOUT THE DEVELOPING WORLD. ELECTRIC POWER IS A CRITICAL

COMMODITY. IT IS ESSENTIAL FOR HIGH-QUALITY ECONOMIC GROWTH.

AS MORE AND MORE DEVELOPING COUNTRIES REACH THE POINT OF RAPID INDUSTRIALIZATION, THE NEED TO FINANCE AND CONSTRUCT THE POWER PLANTS THAT FUEL GROWTH AND RISING STANDARDS OF LIVING WILL EXPAND DRAMATICALLY. I AM VERY PLEASED TO SEE THAT ONE OF THE ISSUES TO BE TAKEN UP IN THIS CONFERENCE IS KOREAN/U.S. <u>JOINT</u> MARKETING OF POWER PROJECTS IN THIRD- PARTY COUNTRIES ABROAD.

WHEN YOU LOOK FOR BUSINESS PARTNERS TO EXPAND ELECTRIC POWER PRODUCTION IN YOUR OWN COUNTRY, AND TO JOIN YOU IN PROJECTS IN THE OTHER COUNTRIES, I THINK YOU WILL BE VERY PLEASED AT THE CREDENTIALS OF THE U.S. ELECTRIC POWER INDUSTRY AND ITS EQUIPMENT SUPPLIERS.

U.S. STRENGTHS

LET ME ELABORATE ON U.S. STRENGTHS. THE U.S. ELECTRICITY INDUSTRY HAS A SIGNIFICANT RECORD OF ACHIEVEMENT IN RELIABILITY, UNIVERSAL ACCESS, AND SUPERIOR EFFICIENCY AND ENVIRONMENTAL COMPLIANCE AT COMPETITIVE COSTS.

IT HAS PROVIDED WORLD-CLASS RELIABILITY, WITH AN EXTENSIVE GRID INTERCONNECTING THE MAJOR REGIONS OF THE U.S. AND THE NEIGHBORING CANADIAN AND MEXICAN SYSTEMS. WE BELIEVE THAT THE U.S. SYSTEM IS THE MOST RELIABLE IN THE WORLD.

WE ALSO BELIEVE THAT IT IS AMONG THE MOST EFFICIENT AND COST-EFFECTIVE. U.S. ELECTRICITY PRICES IN CONSTANT DOLLARS, ARE THE LOWEST THEY HAVE BEEN IN 15 YEARS.

THIS IS DUE, IN PART, TO LOWER FUEL PRICES, BUT MORE IMPORTANTLY, TO A SUCCESSFUL EFFORT TO BUILD INCREASED EFFICIENCY, DIVERSITY, COST-REDUCTION PRACTICES, AND DEMAND-SIDE MANAGEMENT TECHNIQUES INTO THE ELECTRIC GENERATING SYSTEM.

THE ELECTRIC SECTOR IN THE U.S. HAS ACHIEVED GREATLY IMPROVED ENVIRONMENTAL PERFORMANCE. ELECTRICITY-RELATED AIR EMISSIONS HAVE DECREASED DRAMATICALLY IN RECENT YEARS, AS A DIRECT RESULT OF STRICT AIR QUALITY LEGISLATION ADOPTED BY THE U.S. CONGRESS.

EMISSIONS OF SULFUR DIOXIDE HAVE DROPPED OVER THE PAST DECADE, AND WILL BE REDUCED BY 50 PERCENT BY THE YEAR 2000. NITROGEN OXIDE EMISSIONS FROM THE ELECTRIC SECTOR WILL ALSO DECLINE, AS BOTH NEW AND EXISTING GENERATING CAPACITY IN THE U.S. BENEFIT FROM THE INTRODUCTION OF OUR NEW NITROGEN OXIDE CONTROL TECHNOLOGIES.

U.S. ELECTRIC UTILITIES ARE ALSO VOLUNTARILY REDUCING THEIR GREENHOUSE GAS EMISSIONS IN SUPPORT OF U.S. INTERNATIONAL CLIMATE CHANGE COMMITMENTS, WHILE AT THE SAME TIME IMPROVING EFFICIENCY AND REDUCING OVERALL COSTS.

NEW POWER PLANTS BUILT IN THE U.S. IN RECENT YEARS ARE STATE-OF-THE-ART PLANTS, EMPLOYING <u>HIGHLY ADVANCED TECHNOLOGY</u>. THESE PLANTS ARE TOP IN THEIR CLASS IN TERMS OF EFFICIENCY, HEAT RATES, AND EMISSIONS PERFORMANCE. NEW GAS-FIRED COMBINED-CYCLE UNITS CAN ACHIEVE A CONVERSION EFFICIENCY OF NEARLY 50 PERCENT. NEW, SUPER-EFFICIENT COAL-COMBUSTION TECHNOLOGIES OFFER A "CLEAN COAL" ALTERNATIVE.

SOME RENEWABLE TECHNOLOGIES, SUCH AS WIND TURBINES AND BIOMASS, HAVE BECOME INCREASINGLY COST-EFFECTIVE AND RELIABLE -- AND IN MANY LOCATIONS ARE NOW

COMPETITIVE WITH MORE MATURE GENERATING TECHNOLOGIES.

THESE ADVANCED TECHNOLOGIES ARE HERE TODAY, IN PART, BECAUSE OF A STRONG PARTNERSHIP BETWEEN U.S. INDUSTRY AND THE FEDERAL GOVERNMENT IN RESEARCH AND DEVELOPMENT.

THE UNITED STATES, THROUGH THE DEPARTMENT OF ENERGY, HAS MADE, AND IS CONTINUING TO MAKE, SUBSTANTIAL INVESTMENTS IN THESE ADVANCED TECHNOLOGIES.

EXAMPLES OF THIS CONTINUING COMMITMENT INCLUDE A COOPERATIVE EFFORT WITH INDUSTRY TO DEVELOP ADVANCED BATTERY TECHNOLOGY FOR AUTOMOTIVE APPLICATIONS, AND SUBSTANTIAL INVESTMENT IN ENVIRONMENTAL, EFFICIENCY AND RENEWABLE TECHNOLOGIES, AND NEW GENERATION NUCLEAR TECHNOLOGIES.

WE ARE NOW IN A POSITION TO TRANSFER TO OTHERS -- TO KOREA AND OTHER NATIONS -- THE FRUITS OF THAT CONSIDERABLE INVESTMENT.

WHOLESALE COMPETITION

WE BELIEVE THAT THE U.S. HAS MANY DISTINCT ADVANTAGES -- IN:

- RELIABILITY
- EFFICIENCY
- COST-EFFECTIVENESS
- ENVIRONMENTAL EMISSIONS
- ADVANCED TECHNOLOGY
- SUPPORTED BY STRONG INDUSTRY-GOVERNMENT RESEARCH PARTNERSHIPS.

ONE OF THE UNITED STATES' STRONGEST AND MOST UNIQUE ADVANTAGES, HOWEVER, IS THE RAPIDLY CHANGING ENVIRONMENT IN UTILITY REGULATION, AND INCREASED

RELIANCE ON COMPETITION AND MARKET FORCES IN POWER GENERATION.

THE GENERATION SECTOR OF THE U.S. ELECTRICITY INDUSTRY HAS BECOME INCREASINGLY COMPETITIVE OVER THE LAST DECADE, AS FEDERAL LEGISLATION AND REGULATION HAVE SPAWNED AN INDEPENDENT POWER SECTOR TO COMPETE WITH UTILITIES IN THE WHOLESALE MARKET.

INDEPENDENT POWER PRODUCERS ARE ENTITIES THAT DEVELOP AND OPERATE POWER PLANTS AND SELL POWER AT WHOLESALE COSTS TO INVESTOR- OR PUBLICLY-OWNED UTILITIES, WHO THEN RESELL IT TO RETAIL CUSTOMERS.

THE COMPETITIVE PRESSURES THAT THESE INDEPENDENTS HAVE PROVIDED WITH REGARD TO PRICE AND OTHER TERMS OF SERVICE, ALONG WITH BENEFITS OF DIVERSE INNOVATIONS AND TECHNOLOGICAL ADVANCES, HAVE HELPED TO BRING DOWN MARGINAL ELECTRICITY COSTS. THIS HAS PROMPTED

MORE AGGRESSIVE COST-CONTAINMENT PRACTICES BY UTILITIES AND OTHER POWER PROVIDERS.

MANY REGULATORS AT THE NATIONAL AND STATE LEVELS HAVE BECOME COMFORTABLE WITH THE FACT THAT COMPETITION AMONG ALTERNATIVE ELECTRICITY PROVIDERS ENABLES A LIGHTER STYLE OF REGULATION. THEY HAVE BEGUN TO FOCUS ON THE PRICE AND QUALITY OF SERVICE PROVIDED TO CUSTOMERS, RATHER THAN THE COSTS OR EARNINGS OF THE SERVICE PROVIDER.

MUCH OF THE SHIFT IN REGULATORY FOCUS -- AND MUCH OF THE PROGRESS WE HAVE MADE IN THE U.S. IN IMPROVING THE COST-EFFECTIVENESS OF ELECTRIC SERVICE -- IS ASSOCIATED WITH EMERGENCE OF INDEPENDENT POWER PRODUCERS IN U.S. MARKETS.

WE BELIEVE THAT THESE LEGISLATIVE AND REGULATORY CHANGES THAT MADE THIS GROWTH IN INDEPENDENT POWER

PRODUCTION POSSIBLE HAVE PLACED THE UNITED STATES IN A UNIQUE AND LEADING POSITION OVER OTHER COUNTRIES NOW CONTEMPLATING SIMILAR RESTRUCTURING.

THESE CHANGES HAVE CREATED A BROAD MARKET FOR ELECTRICITY TRADE. WE HAVE MANY COMPETITORS AND OPEN ACCESS TO TRANSMISSION SYSTEMS. OUR COMPANIES ARE FLEXIBLE AND ACCUSTOMED TO PUTTING TOGETHER THE BEST AND HIGHLY TAILORED DEALS. THE RESULT IS THAT MORE THAN HALF OF ALL NEW GENERATION IN THE UNITED STATES IS NOW BUILT BY NON-UTILITY GENERATORS.

WHAT DOES THIS ALL MEAN?

THIS EXTRAORDINARY PERIOD OF CHANGE IN THE UNITED STATES HAS CREATED EQUALLY EXTRAORDINARY OPPORTUNITIES FOR INNOVATION. THE DEVELOPMENT OF NEW ORGANIZATIONS, NEW WAYS OF BUYING AND SELLING POWER, DRAMATIC CHANGES IN THE NATURE OF REGULATION, AND

SIGNIFICANTLY INCREASED COMPETITION MAKE FOR VERY EXCITING TIMES. BY JOINING WITH U.S. COMPANIES, YOU TOO CAN SHARE IN THE ADVANTAGES THAT THESE OPPORTUNITIES BRING.

CONCLUSION

IN CONCLUSION, I WANT TO STRESS THAT WE ARE HERE TODAY TO ENCOURAGE AND PROMOTE COOPERATION BETWEEN OUR INDUSTRY AND YOURS. THE KOREAN MARKET OFFERS OPPORTUNITIES FOR U.S. FIRMS TO INCREASE THEIR EXPORTS. U.S. INDUSTRY, IN TURN, OFFERS OPPORTUNITIES FOR KOREAN POWER PRODUCERS TO UTILIZE STATE-OF-THE-ART, HIGH-QUALITY, AND COMPETITIVE U.S. PRODUCTS.

THE UNITED STATES GOVERNMENT, AND IN PARTICULAR THE DEPARTMENT OF ENERGY, IS VERY PLEASED TO ENCOURAGE GREATER COMMERCIAL COLLABORATION BETWEEN OUR TWO COUNTRIES.

SOME OF THE COMPANIES REPRESENTED ON THE U.S. DELEGATION HAVE BEEN DOING BUSINESS IN KOREA FOR MANY YEARS AND THESE RELATIONSHIPS REMAIN STRONG. THE PURPOSE OF THIS CONFERENCE IS TO ENHANCE THIS RELATIONSHIP AND EXTEND IT TO A LARGER NUMBER OF U.S. FIRMS.

WE ARE PLEASED THAT OUR KOREAN COLLEAGUES AND U.S. INDUSTRY HAVE BOTH INDICATED A STRONG INTEREST IN THIS EXPANSION. WE EXPECT TO SEE THIS INTEREST PRODUCE PRACTICAL RESULTS.

ON BEHALF OF THE U.S. GOVERNMENT AND ALL MEMBERS OF THE U.S. DELEGATION, I THANK OUR KOREAN HOSTS FOR THEIR EFFORTS TO DEVELOP STRONGER COMMERCIAL TIES WITH U.S. INDUSTRY. THANK YOU.

U.S./KOREA ELECTRIC POWER TECHNOLOGIES SEMINAR

"Electric Power Industry in Korea: Past, Present, and Future"

1994.10.

by

Hoesung Lee

President
KOREA ENERGY ECONOMICS INSTITUTE

I. Introduction

Electrical power is an indispensable tool in the industrialization of a developing country. An efficient, reliable source of electricity is a key factor in the establishment of a wide range of industries, and the supply of energy must keep pace with the increasing demand which economic growth creates in order for that growth to be sustained. As one of the most successful of all developing countries, Korea has registered impressive economic growth over the last decade, and it could be said that the rapid growth of the Korean economy would not have been possible without corresponding growth in the supply of electric power.

Power producers in Korea, and elsewhere in Asia, are to be commended for successfully meeting the challenge of providing the necessary power to spur what some call an economic miracle. The future continues to hold great potential for participants in the electrical power industry, but a number of important challenges must be met in order for that potential to be fully realized. Demand for electricity continues to grow at a staggering rate, while concerns over the environmental impact of power generating facilities must not be ignored. As it becomes increasingly difficult to finance the rapid, and increasingly larger-scale expansion of the power industry through internal sources, the government must find to meet the growing demand at least cost. This will lead to important opportunities for the private sector.

It is important, therefore, for those interested in participating in the power production industry and taking advantage of the newly emerging opportunities that lie in the Korean market, and elsewhere in Asia, to discuss the relevant issues and become informed of the specific conditions of each market.

II. Overview of Korean Power Industry

Historically an agrarian economy, Korea instituted a strong export drive in the 1970s and 1980s. Active central government planning and management of prices, interest rates, exchange rates and incentives have generated rapid economic growth and increased the country's market share of world exports. The Korean economy, with its key products being steel, petrochemicals, autos, industrial machinery, paper, computers and electronics, has become energy intensive and relies heavily on electric power to sustain its rapid growth.

Korea experienced hard times due to a severe shortage of electric power at earlier days. The electric power sector in Korea concentrated on implementing various projects to develop electric power resources to cope with the rapidly increasing demand for power, which was out-pacing annual economic growth due to the rapid development of industry. The country's power production, which reached 144,437 million KWh annually by 1993, had increased to 75 times that of 1961, when annual power production was only 1,770 million KWh. As of the end of 1993, the total number of customers stood at 11,499,368, a number 14.4 times greater than the 797,252 customers in 1961, and the country's electrification rate had almost reached 100 percent.

The demand for electricity has increased due to rapid economic growth and the improvement of living standards in Korea. The capacity of electric power generation has been increasing at an average annual rate of 10.7% from 2,508 MW in 1970 to 27,654 MW in 1993. The average load which was only 1,046 MW in 1970 increased to 16,488 MW in 1993, and the peak load increased 14 times from 1,555 MW in 1970 to 22,112 MW in 1993.

In addition, the consumption of electricity increased at an average rate of 11.1% annually during the decade since 1981. The industrial sector is the major consumer of electricity with a share of more than 60% of total consumption.

Since 1982, an increase in nuclear capacity and a decrease in oil prices have led to a gradual decline in the price of electricity in Korea. Electricity rates have declined by 20.6 percent from 1982 to 1993 while the consumer price index has risen by 83.8 percent. During this period per capita GNP has grown by 4.0 times. Electricity's share of total household expenditures changed from 2.0 percent in 1982 to 1.2 percent in 1993. At the same time, electricity's share of manufacturing costs reduced from 2.9 percent in 1982 to 1.5 percent in 1993.

In 1970, petroleum was the main fuel used in generating power, accounting for 76.6 percent of all fuel consumed for power generation. Domestic reserves of anthracite coal and hydropower played supplementary roles, accounting respectively for 11.2% and 12.2% of fuel consumed for power generation.

After the first oil crisis in 1973, the Korean economy faced difficulties because of its heavy dependence on oil, and the importance of fuel diversity was increasingly emphasized. In spite of this emphasis, however, Korea's reliance on petroleum had increased to 92% of all fuel consumed for power generation in 1976. Then in 1978, the Korean Electric Power Corporation (KEPCO) commissioned its first nuclear power plant.

The mix of fuel consumption for power generation by 1993 had changed drastically as a result of increased efforts for fuel diversification after the second oil shock. Korean power generating facilities achieved an impressive combined capacity of 27,654 MW, of which 27.5% came from nuclear power plants, 20.8% from coal, 20.2% from oil, 22.4% from LNG, and 9.1% from hydropower sources. This fuel mix represents a remarkable improvement of fuel diversity, compared to the heavy reliance on oil that prevailed until the late 1970's.

III. Problems Faced

The future of the energy sector in Korea is uncertain, even though continued strong growth provides a source of great opportunity. A number of obstacles must be overcome in order to take full advantage of this opportunity. These obstacles include the securing of low-cost capital to finance the continued rapid growth of the energy sector, the increasing difficulty in siting new plant facilities, and the need to address growing environmental concerns.

Although capacity growth in the future is expected to be more moderate than that of the last few decades, the Korean government, in consultation with KEPCO, will continue to pursue a significant construction program, with plans for more than 13,000 MW of new capacity from 26 new power plants until 2000.

The ambitious power plant construction program will require extensive capital. According to the Long-Term Financial Plan of KEPCO, investments in generating facilities will average $4.5 billion per year for the next decade. An additional $2.5 billion will be needed annually for transmission, distribution and other facilities. Capital requirements of the electricity sector are expected to total more than $70 billion by 2001.

Initial estimates indicate that for the next few years, KEPCO will generate approximately US$3 billion per year internally. At the current rate, KEPCO will face an estimated US$52.2 billion capital shortage during the period from 1992 to 2001. Provided that electricity prices were allowed to rise at the same rate as inflation, the shortage could be halved.

In any case, however, additional funds will need to be raised in Korean and foreign capital markets. Although KEPCO has been able to borrow funds in the Korean market at preferential rates, the scale of borrowing needed in the future will make it more difficult to secure all capital in this way. KEPCO has been regulated in borrowing funds directly from overseas by the government for the sake of the local money market balance. But this regulation will be changed some time near future, due to the seriousness of the shortage of finances.

The Korean government is now starting to consider the environmental problems created by rapid economic development, and realizes that electricity generation is a significant contributor to these problems. As a result, a series of measures have been recently introduced to reduce emissions from thermal power plants.

At the present time, there are no requirements to install Flue Gas Desulphurization (FGD) or other pollution control equipment in power plants. The Ministry of Environment has introduced new atmospheric emission standards, but there are no plans at the present time to set an upper limit for total emissions.

The future of the electrical power industry in Korea will be affected by the direction of the Climate Change Convention, which will require environmentally sound energy systems. The use of natural gas, nuclear power, and new and renewable energy should be increased more than currently projected and the competitiveness of clean energy should be bolstered. A comprehensive policy strategy should be developed to overcome the various difficulties in promoting a clean energy system.

Problems related to the siting of power plants are very important for a country with a small land area and large population like Korea. The further expansion of existing power plant sites and the addition of new sites are likely to face increasing public opposition. As the population becomes more environmentally aware and concerned about pollution and nuclear safety, the ability of KEPCO to procure adequate sites is becoming increasingly more difficult. The siting problem is neither unique to Korea, nor to nuclear power. But in Korea, the fact that nuclear siting decisions have been made between the government and KEPCO, without public participation, has added to the problem.

Korea has begun a program to increase public acceptance of nuclear power, including special financial incentives for communities located near a power plant. The program apparently has not yet sufficiently penetrated the communities whose support may be needed to solve the siting problems.

IV. Current Policy

The industry supplying electric power in Korea is regulated by the Ministry of Trade, Industry, and Energy (MOTIE) under the authority of the Electric Power Business Act. MOTIE is required to develop a long-term power development plan every two years that includes a demand and supply forecast (the current plan runs up to 2006). KEPCO is then expected to develop generating capacity in accordance with the long-term plan. The latest long-term plan was issued in November 1993. According to this plan, electricity demand is expected to grow an average of 6.4 percent per year between 1993 and 2006. Between 1993 and 1996, growth is expected to average 8.9 percent per year. Thereafter the growth rates are expected to decline slowly, from 6.2 percent between 1997 and 2001 to 4.3 percent between 2002 and 2006. These rates are substantially higher than the rates expected in OECD countries to 2010 (2.1 percent on average), and are reminiscent of growth rates observed in the 1960s and early 1970s.

The main strategies of the Long Term Power Development Plan are as follows:

- reduce peak demand by active implementation of a demand side management program

- maintain an optimum level of installed capacity with proper supply system reliability
- form an optimum capacity mix considering site, environmental degradation, and cost
- conform with tighter environmental regulations

To meet future demands for electricity, the long-term power development plan requires the building of 76 additional generating units between 1993 and 2006, with a combined capacity of 36,128 MW. These facilities will comprise 14 nuclear plants (12,800 MW), 25 bituminous coal-fired plants (13,170 MW), 12 LNG combined cycle plants (6,326 MW), 19 pumped storage power plants and hydropower plants (2,980 MW), 4 oil-fired plants (452 MW) and 2 anthracite coal-fired units (400 MW).

According to the plan, the installed capacity in 2006 will be 54,098 MW. Nuclear power will contribute 37 7 percent (20,416 MW), coal 29.8 percent (16,090 MW), LNG and residual oil 22.4 percent (12,115 MW), and hydropower and pumped storage power 10.1 percent (5,477 MW).

One of the objectives of Korea's energy policy is a reliable electricity supply at economic cost. The electricity rate structure is split into the six consumer categories: residential, commercial, school, industrial, agricultural, and street lighting, with some of these classes having further rate classification such as night time, vacation, or interruptible.

Under the Electricity Enterprise Act, electricity prices are determined by the government based on the principle that the price paid should not only reflect costs but also provide a "fair" return on the utility's investment (currently set at 8 percent). Under this Act KEPCO must apply to MOTIE for a rate change. The application is considered by the Price Stabilization Committee (chaired by the Minister for the

Economic Planning Board (EPB) and consisting of eight economic Ministers and nine consumer representatives), reviewed by the Cabinet and the President, and if passed by these groups, then formally announced by MOTIE. Issues such as the impact on economic growth and inflation of any proposed price increase are taken into account (by the EPB) in the decision making process.

In last June, the Korea Energy Economics Institute proposed that electricity rates be increased by between 5.5 and 6.5 percent to stabilize demand growth over the next several years, to cover KEPCO's existing costs, and to fund KEPCO's ambitious investment program. Such an increase, following on the heels of a 4 9 percent increase in June 1991 and a 6 percent increase in February 1992, has been necessitated by the inability of KEPCO to raise the funds needed. It should be noted here that electricity rates in Korea will still be moderate, even if the proposed rate hike takes effect, as the price of electrical power over the long term has been decreasing compared with other consumer prices in general.

The 1993 long-term power development plan invites the private sector to build and operate two 50 MW bituminous coal plants and two 40 MW LNG plants. Some procedural guidelines for the invitation of IPP participation stated in the plan are:

- secure fairness and objectivity in the selecting and licensing process
- provide a fair ground for competition between KEPCO and IPPs
- build a constructive business environment for private firms to participate actively

Some basic features of IPP operation stated in the plan are:

- an IPP will be selected through competitive bidding with the purchase price based on the cost of a similar KEPCO plant
- foreign investment will be allowed within the 50% stock ownership limit
- the rate of return and operation rate are guaranteed to equal those of KEPCO

One of the most serious problems with the plan is that it does not provide any long-term blue print for future capacity to be allocated to IPPs. However, the invitation of the private sector to power generation is not likely a passing phenomenon as the plan states the prospect of further private sector participation to be outlined in the 1995 plan.

In a normative sense, the most frequently cited rationale for introducing IPPs is raising efficiency through competition. A state monopoly is usually criticized for its lack of cost-minimizing and productivity-enhancing efforts, its bureaucratic and rigid business style, and other organizational failures.

An empirical study on the economies of scale in the Korean electrical power industry provides another justification for the participation of private firms. By estimating the cost function through translog functional form, Sonn and Jung (1993) show that the Korean electric power industry began to lose scale economies, as a whole, from 1990, and in the generation sector from 1985. Although this study does not comment on the privatization issue it has a clear message: The Korean electrical power industry should escape from a monopoly structure as the total generating capacity is expected to more than double to 54, 098 MW by 2006.

On the other hand, the real forces that resulted in the introduction of IPPs are different from the normative ones. The most plausible factor is that the Korean government has to secure enough funds to raise generating capacity by utilizing the financing ability of private firms. Behind this problem lies the low electricity rates that made it difficult for KEPCO to set aside enough funds for future investment in generating capacity. The difficulty with siting is another factor that made the IPP option more attractive.

The government offered applicant sites for public subscription in October 1991 and selected 7 of those sites for further in-depth study. The sites finally selected will be constructed as model villages through the implementation of plans for the development of plant surroundings. The government plans to use local cooperation agreements with representative organizations of selected sites in order to minimize residential opposition to the selecting of radioactive waste disposal sites.

For the efficient implementation of demand side management, an annual load management target will be set and electricity tariffs will be revised to have effects on the use of electricity An efficiency improvement program for electric appliances will be carried out, so as to effectively implement the load management program. Along with this, cold water storage systems and gas refrigeration systems will be recommended to replace electric air-conditioning systems.

V. Policy Issues and Prospects

As the energy industry changes to meet current demands, it is important that policy is formulated to keep up with the changes and provide a positive and progressive environment for a smooth transition. Policy makers should pay special attention to privatization, pricing, industry structuring and environmental issues.

Privatization is becoming widely accepted as one of the most efficient and cost-effective ways in which developing countries can increase their generating capacity. Experience shows that private sector participation in the power industry results in increased efficiency.

In December 1993, the Korean government announced a privatization plan that covers 61 public enterprises. Among these, important public energy firms such as Korea Gas Corporation is included. KEPCO was not included in the plan. A government review of management efficiency at KEPCO is presently being conducted.

This review, scheduled to be completed by mid 1995, will affect the government's decision on the privatization issue.

Another issue related to the privatization is the vertical unbundling of KEPCO. As the size of Korean power industry rapidly increases—its scale is expected to double by 2006—there are debates on horizontal and vertical unbundling. Partial unbundling of generation is already in progress. MOTIE also announced that non-utility generators can serve the local surrounding communities without selling electricity to KEPCO first. However, the main function of transmission and distribution of electricity needs to be handled by one dominant firm regardless of its ownership structure.

The price of electricity is currently below the long run marginal cost. As the current electricity price does not meet the need for sound growth of the industry, IEA recommends the following for an efficient price structure:

- take steps to ensure that the weight of social and industrial policy objectives is reduced and eventually eliminated from electricity pricing arrangements
- give serious consideration to developing a pricing approach that gives consumers and investors the right price signals
- carefully examine evidence of cross-subsidies (either in the form of rate differentials between consumer groups or low allowed rates of return on investment) and take steps to remove them. In conjunction with the government's private investment initiatives, market clearing prices could work
- increase the allowed rate of return to commercial levels while introducing some form of incentive rate making, if it is decided to retain the existing structure for KEPCO

A number of different approaches exist for ensuring that prices give proper signals about the costs of supply. While all aim to ensure that prices cover costs, there is an increasing move away from simple "cost plus" approaches, which do not encourage utilities to keep their costs to a minimum. New approaches which are being considered in Korea are "price caps" (which allow prices to move in line with the consumer price index, minus an efficiency factor) or "yardstick costs" (which allow the utility's prices to rise in line with a standard set of costs, so that if a utility's own costs are lower it gains a benefit). These approaches, collectively known as "incentive rate-making," are all designed to give utilities an incentive to keep their costs down and if implemented in Korea may help improve the operating environment.

Deregulation and reorganization of the industrial structure are the main theme under the new economic plan designed by the new administration. The electricity sector will be very much influenced by the new economic plan. As the structure of the power industry is changing through the adoption of partial privatization, new institutional arrangement needs to be considered. Currently, the Ministry of Trade, Industry, and Energy (MOTIE) is chiefly responsible for developing electricity policy in Korea, in consultation and close cooperation with the Economic Planning Board, the Ministry of Finance, KEPCO, and others.

Under a new regulatory regime of mixed entities of private and public firms, regulatory bodies are supposed to minimize the risks of private companies, reduce their costs and safeguard their interests, as well as protect consumer interests. Although free transaction and contract between economic agents backed by an appropriate legal system could supply detailed transactional arrangements, proper regulation by the government could meet this goal more effectively.

To this end, as the traditional regulator and owner of public utilities, the government must clearly define the role it will play in a newly emerging industry where public and private enterprises would coexist. More specifically, regulatory principles should be clearly issued through solid legal instruments and the regulatory agency should be established, staffed and provided with all required physical and technical facilities.

The need for an independent regulatory agency rises in inverse proportion to the deregulation of electricity pricing arrangements. Its functions are to assess system costs and oversee the tariff-setting process, to ensure that prices and tariff structures are based on sound economic principles. In order to minimize the monitoring and enforcement cost for the implementation of energy regulation as a whole, such a regulatory body could also be charged with monitoring the prices for other energy forms as well, including gas and oil.

Among those energy sources which do not emit CO_2, a cause of global warming, only nuclear power has been put to practical use and can be substituted with full supply capacity for fossil fuel. From a long-term standpoint, we must continue construction of nuclear power plants in order to maintain stability of fuel supply and to properly cope with global environmental regulations.

The government has increased investment for environmental technology development, and a total of US$1.0 billion will be invested in that area from 1992 to 2001. Investment will be made in such areas as clean coal technologies, anti-pollution technologies and high capacity incineration technologies. The government's support will reach 70% of the required finances.

VI. Concluding Remarks

Over the next decade Asia will prove to be the world's biggest and fastest growing market for electric power generation. It is estimated that some US$550 billion will be spent on generation, transmission, and distribution in Asia. Korea's role in the Asian market is significant for a number of reasons. First, its domestic market offers significant opportunities as it takes steps to allow the participation of IPPs and as continued rapid growth is projected. In addition, opportunity in Korea is further augmented by the very real possibility of joint North and South Korean power projects and eventual reunification of the two countries. Finally, Korean companies, along with those from other countries will be working to enter other key markets in Asia. Korea may serve as a stepping stone to other Asian markets as cooperation begun here may be expanded in other markets.

Nuclear Technologies Session

NUCLEAR POWER PROGRAM AND TECHNOLOGY DEVELOPMENT IN KOREA

OCT. 24, 1994

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Manager, Nuclear Fuel

Korea Electric Power Cooporation

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1. INTRODUCTION

Korea Electric Power Corporation (KEPCO) has currently 9 nuclear units in commercial operation. As of the end of 1993, the total nuclear capacity in Korea was 7,616 MWe which accounted for 28 percent of the total installed capacity.

In 1993, the nuclear power generation with 8 PWRs and 1 PHWR was 58,138 GWh representing 40.3 percent of Korea's electricty production.
The average capacity factor has been steadily maintained over the 70 percent level since 1984, and over the 80 percent level for the last 3 years.

The construction of 7 nuclear units (4 PWRs and 3 PHWRs) is progressing well and is on schedule. According to the long-term power development plan, additional 14 nuclear units including 7 units under construction will be on line by the year of 2006 with a total nuclear capacity of 20,416 MWe.

Along with the continuous increase of nuclear capacity, the stable and economical supply of nuclear fuel has been greatly encouraged. Accordingly, the supply sources of uranium concentrates, conversion and enrichment services are diversified through long-term supply contracts with U.S., U.K., Canada, France, Russia etc.
Since 1987, fuel fabrication technology has been successfully pursued in Korea.

In parallel with long-term nuclear development plan, intensive R & D programs that include the Next Generation Reactor (NGR) and advanced nuclear fuel are being implemented and will be extended to develop nuclear technology to the level of advanced countries by the early 2000s.

This paper describes the present status of nuclear power program and technology development in Korea.

2. OPERATION OF NUCLEAR POWER PLANTS

2.1 Status of Operation

Since the commercial operation of Kori Unit 1 in April 1978, KEPCO has achieved a steady growth in nuclear power development.

As of the end of 1993, KEPCO's total nuclear capacity was 7,616 MW with nine nuclear units in commercial operation. This accounted for 28 percent of the total installed capacity. In 1993, nuclear power generation with 8 PWRs and 1 PHWR was 58,138 GWh representing 40.2 percent of Korea's total electricity production, thereby played a leading role in the production of economical electricity.

The status of KEPCO's nuclear power plant is shown in Table 2-1.

Table 2-1 Status of Operating Nuclear Power Plants

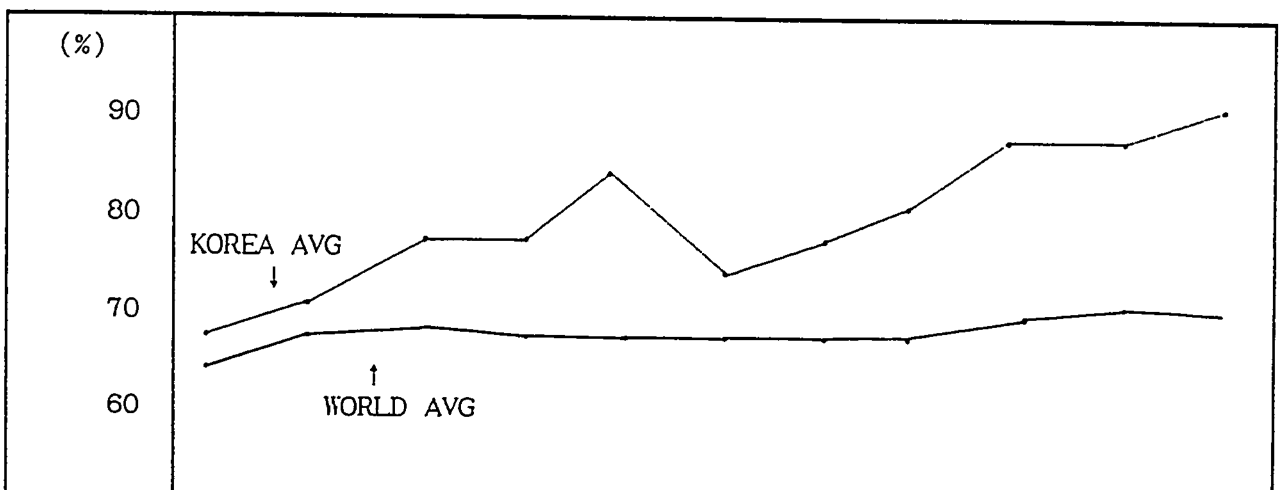
Plant		Reactor Type	Capacity (MWe)	Manufacturer		Commercial Operation
				Reactor	T/G	
Kori	Unit 1	PWR	587	W	GEC	April 1978
	Unit 2	"	650	"	"	July 1983
	Unit 3	"	950	"	"	Sep. 1985
	Unit 4	"	950	"	"	April 1986
Wolsong	Unit 1	PHWR	679	AECL	NEI Parsons	April 1983
Yonggwang	Unit 1	PWR	950	W	W	Aug. 1986
	Unit 2	"	950	"	"	June 1987
Ulchin	Unit 1	PWR	950	Framatom	Alsthom	Sep. 1988
	Unit 2	"	950	"	"	Sep. 1989

2.2 Operating Performance

KEPCO has made great efforts to improve the safety and reliability of nuclear power plants. As a result, the operating performance of Korea's nuclear power plants has shown remarkable improvement over previous years when compared to the world's average performance. For example, in 1993, the average capacity factor was 87.2% while the world's average achieved only 67.8%.

Since 1984, the average annual capacity factor has been consecutively maintained over the 70% level, and over the 80 percent for the last 3 years. In particular, Nucleonics Week noted Wolsung Unit-1 for having the top gross capacity factor (100.81%) in the world during 1993.

Figure 2-1 Trend of Capacity Factor



YEAR	'83	'84	'85	'86	'87	'88	'89	'90	'91	'92	'93
KOREA	66.6	70.1	78.7	78.1	81.5	73.0	76.2	79.3	84.4	84.5	87.2
WORLD	64.2	67.0	65.4	66.9	66.7	65.9	64.8	65.7	67.8	69.3	67.8

A reduction in unplanned shutdowns is one of the best ways to improve the economic benefits of nuclear power plants. Therefore, KEPCO has set the goal for OCTF (One Cycle Trouble Free) as a company catch phrase.

KEPCO has launched several improvement programs as follows :

○ Preventive maintenance

- Establishment of optimum maintenance plans
- Timely replacement of aged components and parts
- Preventive maintenance using the latest diagnostic technology

○ Human error prevention

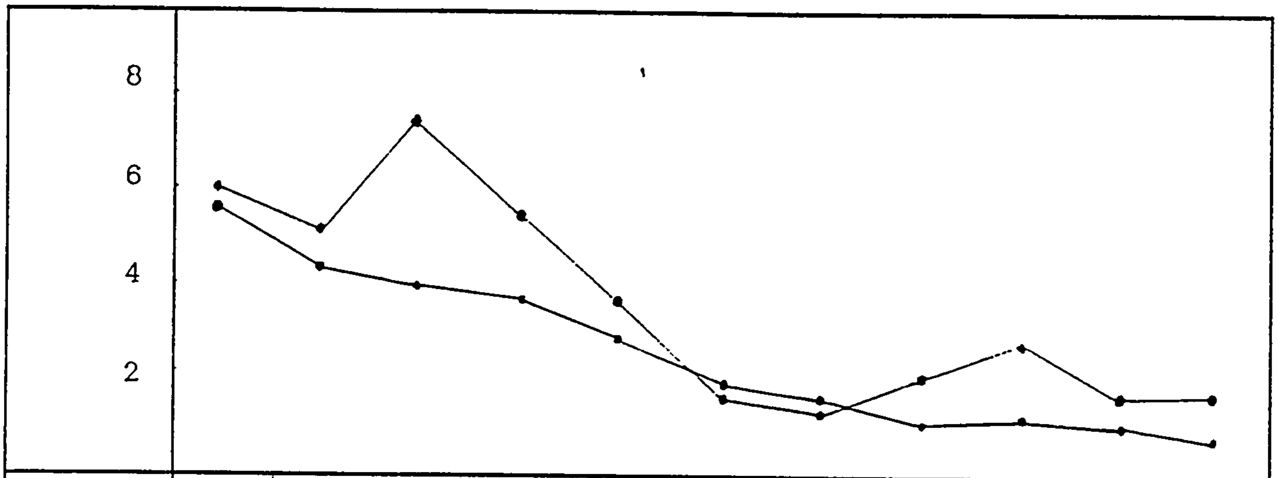
- Improved training program through use of a simulator
- Strengthening of operation shift organization (from 5 shifts to 6 shifts)
- Improvement of station work environment

○ Practical use of lessons learned from other plant

- Information feedback from other plants
- Application of intermediate maintenance work practices

Subsequent to the improvement program, the number of nuclear plant trips has been reduced continuously.
In 1978, there were 17 unplanned automatic or manual trips in Kori Unit 1. However the numbers rapidly decreased to 5.5 per reactor in 1985 and 1.6, and 1.4 per reactor in 1988, and 1989 respectively. In 1993, there were a total of 14 unplanned trips, averaging 1.6 occurrences per reactor-year.

Figure 2-2 Trend of Unplanned Trips (reactor-year)



YEAR	'83	'84	'85	'86	'87	'88	'89	'90	'91	'92	'93
KOREA	6.0	5.3	7.5	5.5	3.7	1.6	1.4	2.0	2.7	1.7	1.6
U.S.A	5.8	4.4	4.0	3.8	2.8	1.9	1.7	1.2	1.3	1.1	0.9

2.3 Nuclear Fuel Management

In order to implement our nuclear expansion program effectively, a stable and economical supply of nuclear fuel is of great importance. Accordingly the requirements of uranium concentrates are secured through long-term supply contracts with countries such as Canada, Australia, U.S and France. The supply sources of Conversion and Enrichment services are also diversified through mid or long-term contracts with U.S., U.K., France and Russia. Since 1987, most of the fuel fabrication services required for nuclear power plants has been supplied by local entities.

Along with the steady increase in operating nuclear power plants, by 1997 the current fuel fabrication capacity of 200 MTU/Yr for PWR and 100 MTU/Yr for PHWR will be expanded to 400 MTU/Yr for PWR and 400 MTU/Yr for PHWR.

The intensive R & D programs are being carried out to improve the economy of nuclear fuel toward improvement of uranium utilization, reduction of discharged spent fuel and enhancement of safety.

Table 2-2 Capacity of Fuel Fabrication Services

Organization	Reactor type	Capacity (MTU/Yr)	COD	Remarks
KAERI	PHWR	100	1987	
KNFC	PWR	200	1988	
	PHWR	400	1997	under planning
	PWR	200	1997	under planning

In addition, a longer refueling cycle scheme was adopted in the early 1990s to improve the capacity factor of nuclear power plants.

Currently, 8 operating PWRs are under longer fuel cycle operation.

For 600MW class plants, Kori Units 1 & 2 have adopted 15 month cycle operations since 1989 and 1987 respectively. Nuclear units with 950 MWe class capacity are or will be in 18 month operations cycle following 15 month transient cycle.

Currently, spent fuel and radwastes from all nuclear power plants are kept at each plant site. PWR spent fuel storage capacity is being doubled by adopting high-density storage racks. CANDU spent fuels are first cooled in a storage pool and then transferred to dry concrete canisters which were built in 1992. Under the government's policy, the interim away-from-reactor (AFR) storage facility for spent fuels is planned to be built in the future.

It is, however, somewhat difficult to secure the sites for radwaste disposal facilities. New locations for these facilites are being considered and will be announced soon by the government.

Once the AFR facility is available, all the spent fuels from nuclear power plants will be shipped to the facility.

3. CONSTRUCTION OF NUCLEAR POWER PLANTS

3.1 Status of Construction

The construction of 7 nuclear units (4 PWRs and 3 PHWRs) is progressing well and is on schedule. Yonggwang Unit 3 completed the initial core loading in September this year, and will be ready for commercial operation in March 1995. Yonggwang Unit 4 is also near completion, expecting the initical core loading next year.

By 1994, Wolsong Unit 2 will be 61.57 percent complete, and is scheduled for completion in June 1997. Wolsong Units 3 & 4 obtaincd construction permit in February 1994 and will be completed in June 1998 and 1999 respectively. Initial excavation of main building for Ulchin Units 3 & 4 began in May 1992. These units will have reached 44.98 percent complete with the construction of main building for reactor and turbine in December 1994. Commercial operation of these reactors is planned from 1998 to 1999.

Table 3-1 Status of Nuclear Power Plants under Construction

Plant		Reactor Type	Capacity (MWe)	Manufacturer		Commercial Operation
				Reactor	T/G	
Yonggwang	Unit 3	PWR	1,000	KHIC/CE	KHIC/GE	March 1995
	Unit 4	"	1,000	"	"	March 1996
Wolsong	Unit 2	PHWR	700	KHIC/AECL	KHIC/GE	June 1997
	Unit 3	"	700	"	"	June 1998
	Unit 4	"	700	"	"	June 1999
Ulchin	Unit 3	PWR	1,000	KHIC/CE	KHIC/GE	June 1998
	Unit 4	"	1,000	"	"	June 1999

3.2 Long-term Power Development Plan

Considering the increase in national economic growth, KEPCO expects that the annual growth rate of electricity sales will be 9.3 percent on an average in the short-term (1993 to 1996). The average growth rate from 1993 to 2006 is expected to be 6.4 percent per annun.

In order to meet future electricity demands, the long-term power development plan established in 1993 requires the building of additional generating units for 36,128 MWe from 1993 to 2006. According to this plan, the totlal installed capacity in 2006 will be 54,098 MWe, and nuclear power with an additional 14 units will contribute 37.7 percent (20,416 MWe) during this time.

Based on this long-term plan, the basic plans for the construction of Yonggwang Units 5 & 6 (PWR 1,000 MWe each) were finalized in July 1993. KEPCO is in the final process of negotiation for the main contracts. Currently, these units are scheduled for completion by 2001 and 2002 respectively.

In addition, ITB for Ulchin Units 5 & 6 (PWR, 1,000 MWe each) which are planned to be on line by 2003 and 2004 will be issued in the very near future.

Table 3-2 Long-term power development plan

	1993	1996	2001	2006
Nuclear	7,616 (27.5)	9,616 (29,3)	14,716 (32.7)	20,416 (37.7)
Coal-Fired	5,760 (20.8)	7,820 (23.9)	12,240 (27.2)	16,090 (29.8)
LNG-Fired	6,200 (22.4)	6,409 (19.6)	7,609 (16.8)	9,522 (17.6)
Oil-Fired	5,574 (20.2)	5,798 (17.7)	6,019 (13.4)	2,593 (4.8)
Hydro	2,504 (9.1)	3,108 (9.5)	4,477 (9.9)	5,477 (10.1)
Total	27,654 (100)	32,751 (100)	45,061 (100)	54,098 (100)

3.3 Community Activity and Nuclear PA

In September 1993, Korea Gallop Poll initiated a poll of 2,000 general people and 800 residents near nuclear power stations to investigate the public's opinion of nuclear power. According to the poll, 74.7 percent of the general people and 54 percent of people living near nuclear power stations recognized the need for additional construction of nuclear plants to meet energy needs. However, 55 percent still thought of nuclear power plants as an obstacle to the growth of the local community compared with 34.2 percent in favor of the plants. Although these results were better than in 1991, we had some difficulties, which may affect the promotion of the long-term nuclear power development, in securing sites for new power stations.

For this reason we are implementing more active community programs under a policy to return some benefits of nuclear power to the local community. These programs, for example, include financial support, medical care, scholarship fund and job offering program to local residents.

Along with the community cooperation, nuclear PA activities have also been strengthened to inform the public about nuclear power. These programs are designed to enhance the public's confidence in the safety and reliability of nuclear power plants.

4. NUCLEAR TECHNOLOGY DEVELOPMENT

In order to achieve the national goal of energy independence, the self-reliance program of nuclear technology has been greatly enhanced under the government policy through various efforts such as plant standardization and a long-term nuclear R & D program. KEPCO's policy is to allocate more than 3 percent of annual revenue to support technology development efforts and R & D related investment.

4.1 Plant Standardization

To develop nuclear technology effectively, KEPCO has completed 3 constructing stages of nuclear power plants.

During the early stage of nuclear power plant construction, the first three units were constructed on a turnkey basis.

To enhance our own technology, domestic companies participated in the areas of site civil and structural work.

During the second stage, KEPCO took the project management responsibility for site construction, while other Korean industries expanded their role in engineering and equipment supply. Six units under this stage were constructed by foreign prime contractors with increased participation by local companies.

On the basis of industrial growth, the third stage of plant construction began with Yonggwang Units 3 and 4. In this third stage, KEPCO's nuclear technology self-reliance program was also introduced.

Currently, KEPCO has the ultimate responsibility for plant construction and operation, while domestic companies participate as main contractors responsible for plant design and engineering, with main equipment being manufactured locally under the support of foreign sub-contractors.

In addition to the self-reliance plan, KEPCO has developed a standand nuclear plant design, promoted plant localization and reduced construction time and cost. The proposed standard design is a 1,000 MWe class PWR which will be developed by improving Yonggwang Units 3 & 4 design and incorporating the design enhancements and lessons learned from previous projects including installation of upgraded equipment and application of new regulatory requirements.

4.2 Nuclear R & D Program

Following the technology self-reliance and plant standardization program, the Korean government has estabilished a 10 year long-term nuclear R & D program with a total investment of 2.5 billion dollars, that requires the integrated efforts of the entire Korean nuclear community.

The objective of this program is to develop nuclear technologies to the level of advanced countries by the early 2000s.
The program mainly focuses on the development of Next Generation Reactor (NGR) and Advanced Nuclear Fuel.

4.2.1 Korean Next Generation Reactor Project

The objective of this project is to complete a standardized Next Generation Reactor (NGR) design by 2000. This project consists of three phases of development activities for which overall funding is $ 354 million in a nine-year period (1992 to 2000).

The first phase comprises the development of Korea Utility Requirements Documents (KURD) and the development of information to be used in the selection of design for the reference plant. A higher level of safety and improved economy are specified in draft KURD as of May 1994, which is being developed under the leadership of KEPCO.

In the second phase (Jun. 1994 ~ Feb. 1998), plant design will be completed to the level of detail necessary to obtain design certification, which will result in approximately 20% of plant design being completed.

During the third phase (Feb. 1997 ~ Feb. 2000) it is estimated that approximately 60% of the engineering scope of design can be completed beyond the design certification. As a first-of-a-kind engineering (FOAKE) in Korea, it is required to develop the entire plant design to achieve a reliable cost and construction schedule estimate.

The engineering performed in these phases will be partially applicable to the new twin-unit project which is expected to be in operation in 2005 and in 2006 respectively.

In addition, Korea is in the process of reviewing a development program for future reactor in order to achieve optimal utilization of uranium resources and to develop nuclear power system with inherent safety and breeding characteristics over the long-term.

4.2.2 Fuel Cycle Technology

One of the nuclear fuel cycle components localized in Korea is fuel fabrication services.

Since 1987, fuel fabrication technology of PWR and PHWR has been successfully developed by Korea Nuclear Fuel Company (KNFC) and Korea Atomic Energy Research Institute (KAERI).

As the nuclear generation capacity and fuel requirements increase, economical and reliable supply of nuclear fuel becomes of great importance. Therefore, intensive R & D programs are being carried out jointly with KNFC and KAERI to develop the advanced fuel that focuses on improvement of uranium utilization, reduction of the discharged spent fuel and enhancement of safety.

Under this strategy, region average discharge burnup of PWR fuel will reach about 45,000 MWD/MTU in 1996. According to the basic development plan for PWR fuel, advanced high burnup fuel with 50,000 MWD/MTU and 55,000 MWD/MTU will be developed by 1999 and 2004 respectively.

For PHWR fuel, in 1991, KAERI/AECL with participation of U.S. government undertook a new feasibility study of DUPIC (Direct Use of PWR fuel in CANDU) which would employ only mechanical processing technology instead of more politically sensitive wet chemical process. PWR spent fuel rod would be mechanically processed and assembled into CANDU fuel bundles. Such a topic is one subject to be studied more.

Since Korea operates both PWR and CANDU reactors, and has very limited energy resources, development of the DUPIC technology is of interest in order to improve urainum utilization and to reduce spent fuel volume.

The other development activities related to advanced PHWR fuel, called CANFLEX, are being performed jointly by KAERI and AECL.
Natural uranium, slightly enriched uranium and recycled uranium can be used as a nuclear fuel for CANFLEX. The increased number of fuel rod and smaller pin diameter reduce peak linear power ratings for both natural and enriched uranium by 10% to 20% compared to conventional PHWR fuel.

According to the development shedule, CANFLEX-NU (Using Natural Uranium) will be developed by 1998 and CANFLEX-SEU/REU (Using Slightly Enriched Uranium or Recovered Uranium) developed by 2006.

Table 4-1 Summary of Advanced Nuclear Fuel Program

Fuel	Organization	Target
High-burnup	KNFC/KAERI/KEPCO	50,000 MWD/MTU by 1999 55,000 MWD/MTU by 2004
CANFLEX	KAERI/AECL	CANFLEX-NU by 1998 CANFLEX-SEU by 2006
DUPIC	KAERI/AECL/U.S	Under feasibility study

5. CONCLUSION

KEPCO has successfully implemented the construction and operation of nuclear power plants since the early 1970s, and will continue to build safer and more efficient nuclear plants in the future in accordance with the nuclear power development plan previously established.

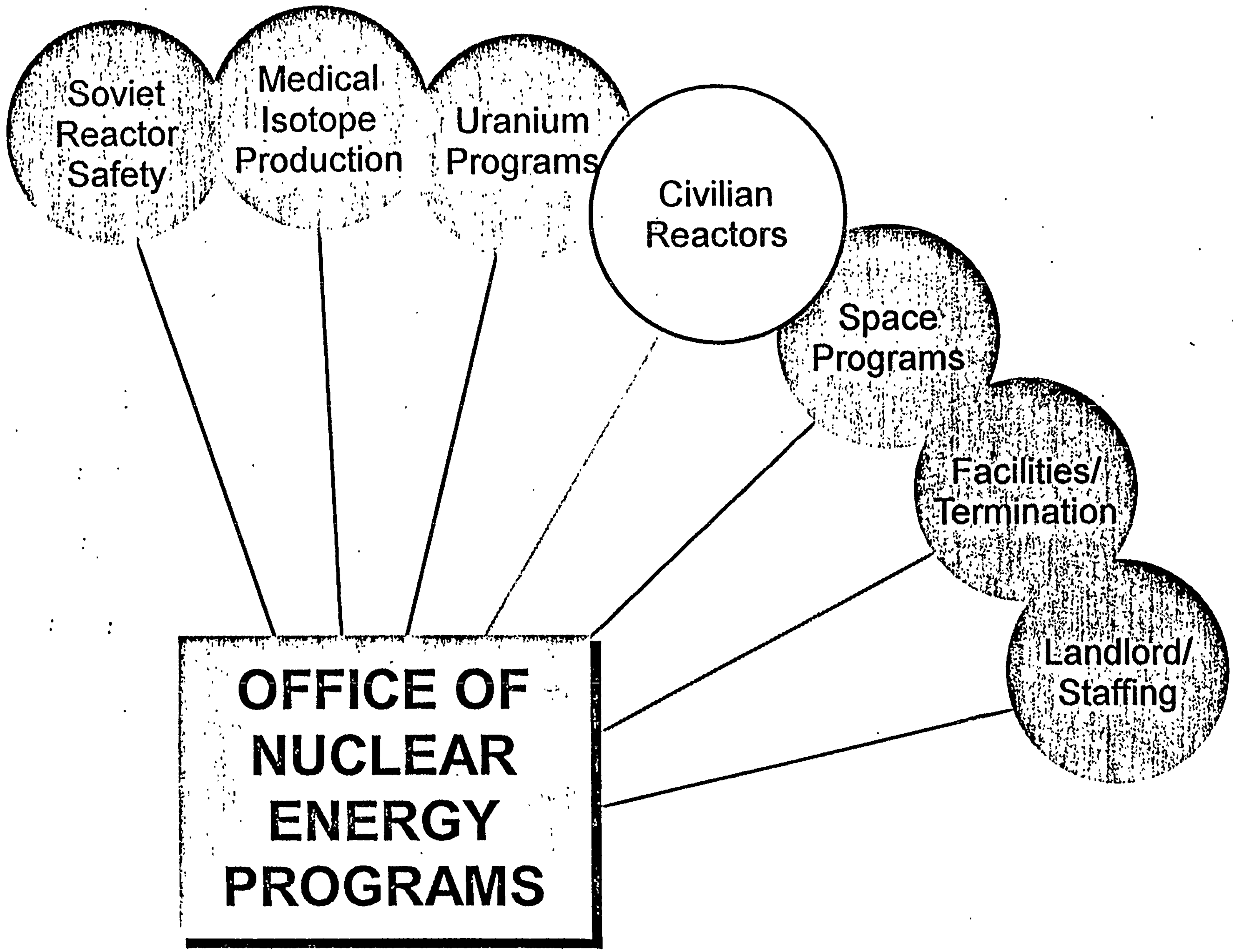
KEPCO will also make every effort to enhance nuclear safety and obtain the public's acceptance for nuclear power.

We are, however, facing the same difficulties, as United States and other countries have, in strengthened regulatory requirements, public acceptance, radwaste disposal, and acquisition of new plant sites despite an active nuclear power program.
Story of Ted Turner, CNN; "It ain't as easy as it looks". Yes ! It is difficult. But we will cope with these issues so that we can promote the nuclear power development and continue to supply a highly economical and clean energy to the world.

In this regard, it is my sincere wish that each organization participating in the nuclear industry, especially Korea and United States strengthen their ties and help each other so that we together can successfully accomplish our goals.

LIGHT WATER REACTOR PROGRAM

Sterling M. Franks
U.S. Department of Energy



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Light Water Reactor Program

Scope of Program

- Design certification of evolutionary plants:
  - General Electric ABWR/Combustion Engineering System 80+
- Design, development, and design certification of simplified passive plants:
  - General Electric SBWR/Westinghouse AP600
- First-of-a-kind engineering to achieve commercial standardization
  - General Electric ABWR/Westinghouse AP600
- Plant lifetime improvement
- Advanced Reactor Severe Accident Program

General Electric ABWR Certification Program

Status

- NRC Final Safety Evaluation Report was issued in May 1994
- NRC Final Design Approval obtained in July 1994 (completed six weeks behind schedule)
- Design Control Document to be issued by GE in September 1994 (completed on schedule)
- Design certification expected in December 1995

ABB-Combustion Engineering System 80+

Certification Status

- NRC issued Advanced Final Safety Evaluation on February 28, 1994
- NRC Final Design Approval (FDA) obtained in July 1994 (completed 2 months ahead of schedule)
- Design certification expected in December 1995

Westinghouse AP600 Design Certification Program

Status

- Standard Safety Analysis Report (SSAR) revision submitted in January 1994
- Matrix testing completed on a number of facilities.
  - Integrated system tests at Oregon State University completed 3 months ahead of schedule. Facility turnover to NRC being arranged.
  - Core Makeup Tank (CMT) testing - essentially complete
  - SPES integral systems testing - matrix testing underway
  - Automatic Depressurization System (ADS testing) - matrix testing underway
- Responses provided to about 2000 out of 2100 requests for Additional Information (RAIs)
- Future activities will focus on analysis of test results and responses to the Draft Safety Evaluation Report (DSER)
- NRC Final Design Approval (FDA) expected in September 1996
- Certification expected 15 to 18 months after FDA

General Electric SBWR Design Certification Program

Status

- Program redirected to obtain NRC acceptance of test and analysis activities by June 1995
- NRC licensing activities deferred until June 1995
- Testing completed:
  - Gravity driven cooling system tests
  - Passive containment cooling system tests
  - University condensation tests
- Testing to complete in 1994:
  - Prototype passive cooling condenser test
  - Vacuum breaker testing
- To complete in 1995:
  - Prototype isolation condenser test
  - Containment systems tests
- NRC Final Design Approval expected in May 1995
- Certification expected 15 to 18 months after FDA

First-Of-A-Kind Engineering Program

Objectives:

- Complete the designs of selected ALWR plants
  - Support commercial standardization
  - Define firm cost estimates and construction schedules
  - Prepare for construction

- Commercial standardization goal is to complete all of the design, except for design work that depends on the specific site, component procurement or construction work

Status:

- Cooperative cost-shared program with nuclear industry and Advanced Reactor Corporation

- DOE funding of $100 million, and industry funding of about $170 million

- ARC selected two designs for the program in January 1993: General Electric ABWR and Westinghouse AP600

- Programs scheduled for completion:
  - ABWR - 12/96
  - Westinghouse AP600 - 12/97

Plant Lifetime Improvement Program

Objectives:

- Support establishment of regulatory standards and criteria for license renewals by developing the technical bases for justifying continued operation of plants from forty to sixty years.
- Support development of technology and methods to predict and mitigate the effects of age-related degradation of key plant equipment and structures in order to support operation during the renewal term.

Status:

- Completed generic evaluations of key safety equipment and structures
- Continue commodity type evaluations for equipment and structures that are important to long term operation
- Initiate cost-shared project to demonstrate annealing of reactor pressure vessel
- Support utility owner groups' vendor-specific evaluations of critical equipment that is necessary for license renewal applications
- Support Industry and NRC in the development and implementation of a revised license renewal rule and regulatory guidance documents

Advanced Reactors Severe Accident Program (ARSAP)

Objective:

- The ARSAP objective is to prevent unresolved severe accident issues from becoming an obstacle to ALWR certification
- A important benefit of this program is the transfer of severe accident technology from DOE labs to the industry

Status:

- ARSAP provides severe accident expert assistance to the reactor vendors for probabilistic risk assessment
- ARSAP participates in internationally sponsored research programs that provide specific data for severe accident issue resolution

Contractors:

- Idaho National Engineering Lab, Sandia National Lab, Oak Ridge National Lab, Argonne National Lab

Korea's Choice of a New Generation of Nuclear Plants

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To support future economic expansion, Korea has turned to long-term, comprehensive energy planning that relies on a variety of technologies including fossil fuels, nuclear, and renewable energy. Nuclear energy is increasingly attractive to nations that are concerned about meeting their growing power needs without damaging the environment. Because its burns nothing, nuclear power is the world's largest source of clean electricity. Korea generated more than 40% of its electricity from nuclear power in 1993, and plans indicate nuclear power will provide over one-third of the additional 36,000 megawatts of electricity it will need by 2006[1]. Faced with the selection of nuclear power plant designs available today, Korea must decide which design it will adopt to meet its immediate energy needs as well as investigate nuclear plant designs suitable to meet future energy requirements.

GE would like to recommend that Korea solicit competitive bids for an advanced reactor for the next available nuclear site. Today's advanced reactors are superior to their predecessors through larger power ratings, higher levels of safety, improved economics and advanced technologies. By opening up the bidder's market, the suppliers of advanced plants will have the opportunity to present their designs to Korea for consideration as the country's first advanced plant, and Korea will insure itself of having the most competitive design proposals necessary to make the best decision for its people. By early next century, Korea could be at the forefront of advanced reactor technology.

In addition, Korea can become a pioneer in the nuclear reactor industry by joining forces with a design team to develop a next generation large, passive advanced plant. In choosing a suitable partner for such an endeavor, Korea needs to consider the technology base, experience, dedication, and expertise of its team member. GE is uniquely positioned as the only company in the world to be developing both large and passively safe advanced plants, the ABWR (advanced boiling water reactor) and the SBWR (simplified boiling water reactor). These advanced designs provide the technology base for developing the next generation of nuclear plants. These plants will have outputs of 1300 MWe or higher, use passive safety systems, introduce "smart" technology, and have fuel cycle flexibility. A GE/Korea partnership will provide the means to embark on an improved advanced reactor design for the next century, positioning Korea as a world leader in the nuclear power industry.

The ABWR Advantage

GE's advanced reactor design, the ABWR, has several advantages over ABB-CE's System 80+, a pressurized water reactor. Starting from the obvious, two ABWR units are under construction in Japan, with the lead ABWR to start commercial operation in 1996, and Japan plans to construct up to 19 more ABWRs. The System 80+ is not under construction anywhere in the world, and there are currently no commitments to do so. The ABWR is the lead plant in the 1300 MWe class of the U.S. industry's First of a Kind Engineering program.

The System 80+ has not been selected for inclusion in any comparable program. Extensive factory tests are currently being performed on key components, such as the reactor internal pumps and fine motion control rod drives, prior to installation in the Japan K-6/7 units in 1995. The System 80+ has no equivalent activities. In short, the ABWR is a proven design which is setting the standard for the next generation advanced nuclear power plant.

Safety features

The ABWR safety performance is superior to that of the System 80+. The capability to prevent severe reactor accidents from occurring, and the ability to withstand a severe accident in the unlikely event that one should occur, is evaluated with a probabilistic risk assessment (PRA). The result of the PRA is a core damage frequency (CDF). The CDF for the ABWR is 10^{-7}/year and for the System 80+ is 10^{-6}/year. This demonstrates that the ABWR has more redundant and diverse safety features to provide a higher degree of safety.

In contrast to the System 80+ safety systems and severe accident mitigation features which use active components (uses AC power and requires operator action), the ABWR incorporates both active and passive systems. Additionally, in the ABWR, responses to all accidents have been automated such that no operator action is required for 72 hours. In the System 80+ design, there are four mechanically separate trains of safety systems, where the trains are grouped in pairs. In each pair, the piping of the trains is cross-connected and they share the same source of electricity, including an emergency diesel generator (EDG). If that source of electricity or EDG is lost, then one system is lost. With only one pair of trains left to operate, the plant would have to be shut down until the other pair was repaired. On the other hand, the ABWR has three completely independent divisions of safety. They are mechanically, electrically and physically separated. They do not share piping, and each has its own source of electricity and a dedicated safety grade EDG. Even with one division lost, two divisions remain to protect the reactor and plant operation is uninterrupted.

Economics

The ABWR has a clear economic advantage over the System 80+. For example, the System 80+ nuclear island footprint (15,000 m^2) is more than twice the size of the ABWR footprint (6,900 m^2). This demonstrates the superior design of the ABWR which features a simplified and compact nuclear steam supply system and containment yielding a significant cost savings. Savings are also realized through the detailed design of the ABWR from FOAKE and the experience gained from having two plants nearing completion in Japan. Future ABWR plants will benefit from an experienced delivery and procurement team resulting in a compacted construction schedule and subsequent lower costs.

The ABWR and System 80+ also have cost differences as a result of their differing technology base. Both the BWR and PWR are challenged by the corrosive environment within the reactor, although the location of the stress corrosion cracking (SCC) differs. For the BWR, there are a number of plants that have experienced cracking of the stainless steel recirculating system piping and reactor internals. For the PWR plants, many have experienced the failure of the steam generator tubes, and in some cases, cracks have been found in the reactor head and control rod drive penetrations.

To prevent the problem in the ABWR, the external recirculation piping has been eliminated, and improved materials and better water chemistry are employed. The response of GE to the SCC problem demonstrates its willingness to not only acknowledge the problem but to find a solution to ensure that future designs will not be similarly burdened. For the PWR plants, the problem with steam generators still remains. The fundamental PWR design has not changed over the past twenty years, and only steps to mitigate the SCC problem have been taken -- by introducing a new material (Alloy 690 Thermally Treated) that has yet to be proven.

When the failure of the steam generator tubes is severe, the steam generators themselves must be replaced. About 40 steam generators in fourteen PWRs have now been replaced. An estimated 100 additional steam generators will be replaced within the next ten years. The cost is enormous -- about $185M in the U.S. per steam generator. The expected outage time is 150 days and the average occupational exposure is about 500 manrem.

The ABWR compares very favorably with the System 80+ in other areas as well. More information is provided in the Appendix.

A Large, Passive Advanced Plant

The nuclear plant for the next century will provide large outputs for cost efficiency, passive safety features for public security, and incorporate advanced technology not available at the time today's advanced plants were designed. GE's ABWR and SBWR provide the platform for introducing the next generation advanced plant. Combining and improving the desired features of both designs, as illustrated in Figure 1, is the next logical step in reactor technology advancement.

GE/Korea Partnership

A GE/Korea development team working side-by-side can ensure that the ideas and technology best-suited for a Korean large,

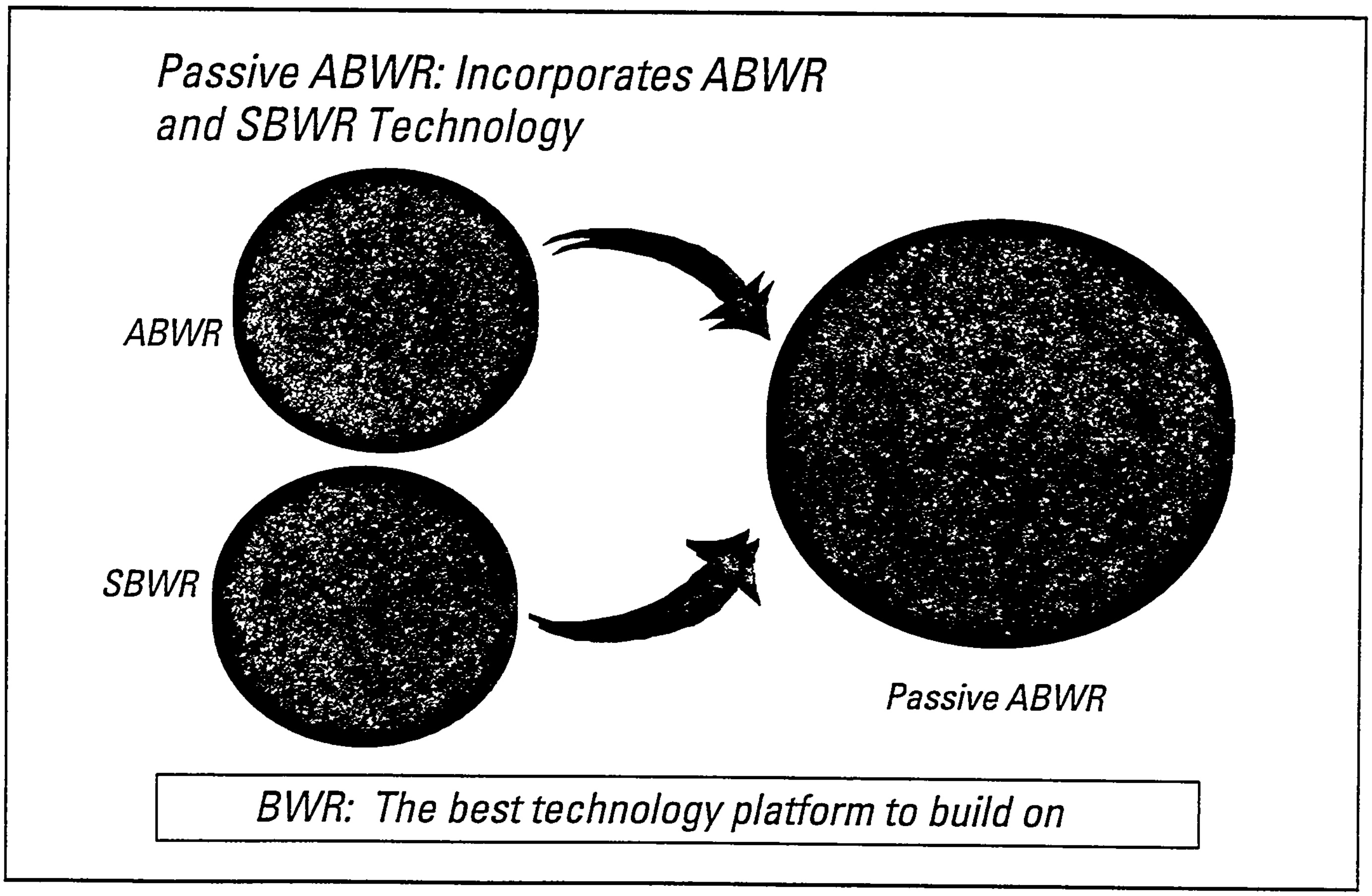


Figure 1: Combine ABWR & SBWR features for a large size, Passive Advanced Nuclear Power Plant

passive advanced reactor design becomes a reality. The partnership will aim at the evolution of the ABWR and SBWR by combining and improving the features of the two advanced designs to meet Korean requirements for an improved advanced reactor design. Like the GE/Japan and GE/Europe development teams, the GE/Korea team will share technology and work together to develop a next generation reactor incorporating country specific features. This joint design could be commercially deployed in 2005.

To serve the immediate energy needs of Korea, GE proposes that the units designated "New Nuclear Units 5 and 6" be Advanced BWRs. These ABWRs would be constructed at the next available site and enter commercial operation as early as 2002 and 2003. In this way, Korea can immediately acquire an Advanced Nuclear Plant and receive the advantages of higher output, safety and economies while concurrently developing its own next generation design.

Through its superior proven design and U.S. and Japan endorsement, the ABWR is setting the standard for advanced plants today. By constructing ABWR units at the next available Korea nuclear site, Korea will place itself at the forefront of advanced reactor technology. By concurrently participating in the GE/Korea partnership, Korea positions itself to set a new standard in the nuclear industry.

GE/Korea Technology Transfer

A GE/Korea partnership paves the way for a mutually beneficial technology transfer. GE has demonstrated its willingness to transfer its nuclear reactor technology through successful technology transfer programs with Japan and European countries. Korea has the opportunity to master the BWR technology and gain the results of the many years of dedication GE has invested into its advanced reactor programs.

Manufacturing

To build an ABWR in Korea, GE would rely heavily on Korean manufacturers to supply the ABWR components and equipment. A cooperative partnership with GE will provide Korean manufacturers with access to worldwide markets. Advanced plants built in Korea will be the same as future plants built in other countries. Korean factories and construction companies will have the experience and knowledge to sell equipment and components by participating in the construction of nuclear plants outside of Korea.

Currently, HANJUNG has the capability of manufacturing BWR components. Last year, in a step towards building a partnership with Korea, GE placed HANJUNG on the "approved nuclear suppliers list". Within the next one to two years, HANJUNG could be regularly producing BWR equipment/components, so that when Korea embarks on their plans to build the next generation of nuclear reactors, HANJUNG will be well positioned to manufacture equipment/components for BWRs, in addition to PWRs.

Engineering

The cost of engineering a new nuclear plant is a substantial amount, representing about 25% of the total capital cost of the first unit. For an ABWR to be built in Korea, most of this cost can be avoided because of the substantial amount of engineering which has already been done. The "U.S." version of the ABWR, which is what GE is proposing for Korea and its customers in other countries (besides Japan), has been designed by using the Japanese ABWR design and adapting it to U.S. requirements, by licensing the ABWR in the U.S., and by completing the detailed engineering in the First of a Kind Engineering (FOAKE) program sponsored by DOE and U.S. utilities. A summary of these costs are:

Table 1: Engineering Costs

Engineering of Japanese ABWR	$250 M
U.S. licensing	$ 50 M
FOAKE program	$100 M
Post FOAKE engineering	$125 M
TOTAL	$525 M

"Post FOAKE" engineering refers to the engineering needed to adapt the design to site specific conditions and to vendor specific equipment designs. This is, in effect, the cost of introducing the ABWR to Korea. Thus, for only $125M, Korea can acquire the design of an Advanced Nuclear Plant. This represents a savings of $400M, or 75% of the total engineering cost.

This is in sharp contrast to the engineering costs to be expected for the System 80+ which is not under construction and for which there is no program comparable to FOAKE. Taking this into account, the first System 80+ in Korea would have an additional cost of approximately $475 M or $350/kw just due to engineering.

GE would be able to provide the ABWR design to its partners in Korea in electronic form. The ABWR is being captured electronically on POWRTRAK, the most advanced Information Management System in the world. No other nuclear supplier in the world has anything comparable to POWRTRAK. This information management tool greatly increases the productivity of the engineering process and would be the basis from which the Korea specific engineering would be performed. POWRTRAK is also used to prepare procurement and construction packages and has been used in non-nuclear applications to greatly reduce construction costs and schedules. GE's technology transfer program would include the use of POWRTRAK.

Status of Advanced BWRs

The ABWR is the first of the next generation of advanced light water reactors to be commercially deployed. Two lead ABWR units are currently under construction by the Tokyo Electric Power Co. (TEPCO) at its Kashiwazaki-Kariwa site.

Excavation for Kashiwazaki Unit 6, the lead ABWR unit, began in September 1991. As of August 1994, K-6 was 70% complete, and the reactor pressure vessel was installed. Fuel loading will begin in August 1995. Following a 51-month construction schedule, K-6 will enter commercial operation in 1996. K-7, the second ABWR unit, will enter commercial operation in 1997.

To meet future generation needs, four Japanese electric utilities have announced plans to construct up to nineteen (19) new ABWR generating units. Only two new units are planned to be APWRs. The ABWR is clearly emerging as the standard plant in Japan.

In the United States, the ABWR has been adapted to the needs of U.S. utilities through the Advanced LWR Requirements Program as documented in the Utility Requirements Document. The ABWR, for example, was reviewed and found to be in conformance with these utility requirements.

In July 1994, the U.S. Nuclear Regulatory Commission issued a Final Design Approval (FDA), making the ABWR the first advanced LWR to successfully complete the NRC's "one-step" licensing process. Following that, public hearings will begin, during which public scrutiny of the design is encouraged. At the end of public hearings, which should take 12 to 18 months, a Design Certification will be issued.

With receipt of the FDA, the ABWR is the only advanced plant in the world to have received regulatory approval in two countries -- the U.S. and Japan.

In early 1993, DOE and the Advanced Reactor Corporation selected GE's ABWR as one of two advanced nuclear plants for inclusion in the U.S. industry's First of a Kind Engineering (FOAKE) program. The ABWR is the lead plant in the 1300 MWe class. A contract was signed in June 1993 and work is now well underway. Completion is expected in late 1995.

The purpose of the FOAKE program is to complete the detailed engineering of the ABWR, thereby creating the procurement and construction packages needed to build the plant and to establish firm costs and schedules. The designs would be ready for commercial application in the world. The ABWR FOAKE program is a $110M program funded by DOE and the Advanced Reactor Corporation (ARC), which consists of 15 nuclear utilities.

The SBWR conceptual design was completed in 1990. Development of the SBWR design was accompanied by extensive testing of its new features. Since 1990, GE and its SBWR team members, which includes 44 worldwide organizations, have been improving the SBWR and performing the detailed engineering needed for its licensing review. Over 50 engineers from GE's international partner have been working side-by-side with GE engineers in San Jose to ensure that the best ideas and technology are incorporated in the SBWR design.

In August 1992, the 21-volume Standard Safety Analysis Report (SSAR) was submitted to the NRC. The NRC review of the SSAR continues concurrently with the completion of SBWR test programs. GE is working with Japanese team members on a Japanese variant of the SBWR, and with the European members on a European variant. U.S. certification is important to both of these programs, but the technology base is the backbone of these programs. The Final Design approval (FDA) of the SBWR is expected in 1998.

The SBWR design and certification program is a $160 million effort. The U.S. Department of Energy is providing $48.5 million and the Electric Power Research Institute is supplying $22.5 million. GE and its team members are responsible for the balance of the funding.

Conclusion

The ABWR and SBWR design, both under development at GE, provide the best platform for developing the next generation advanced plants. The ABWR, which is rapidly setting the standard for new nuclear reactor plants, is clearly the best choice to meet the present energy needs of Korea. And through a GE/Korea partnership to develop the plant of the next century, Korea will establish itself as a leader in innovative reactor technology.

❑

References

1. "Asia Seizes Nuclear-Energy Growth Initiative As Europe, U.S. Mark Time, Analysis Indicates", Nuclear Energy Institute News Release, June 1994

The Advanced BWR Nuclear Plant: Safe, Economic Nuclear Energy

John R. Redding

GE Nuclear Energy

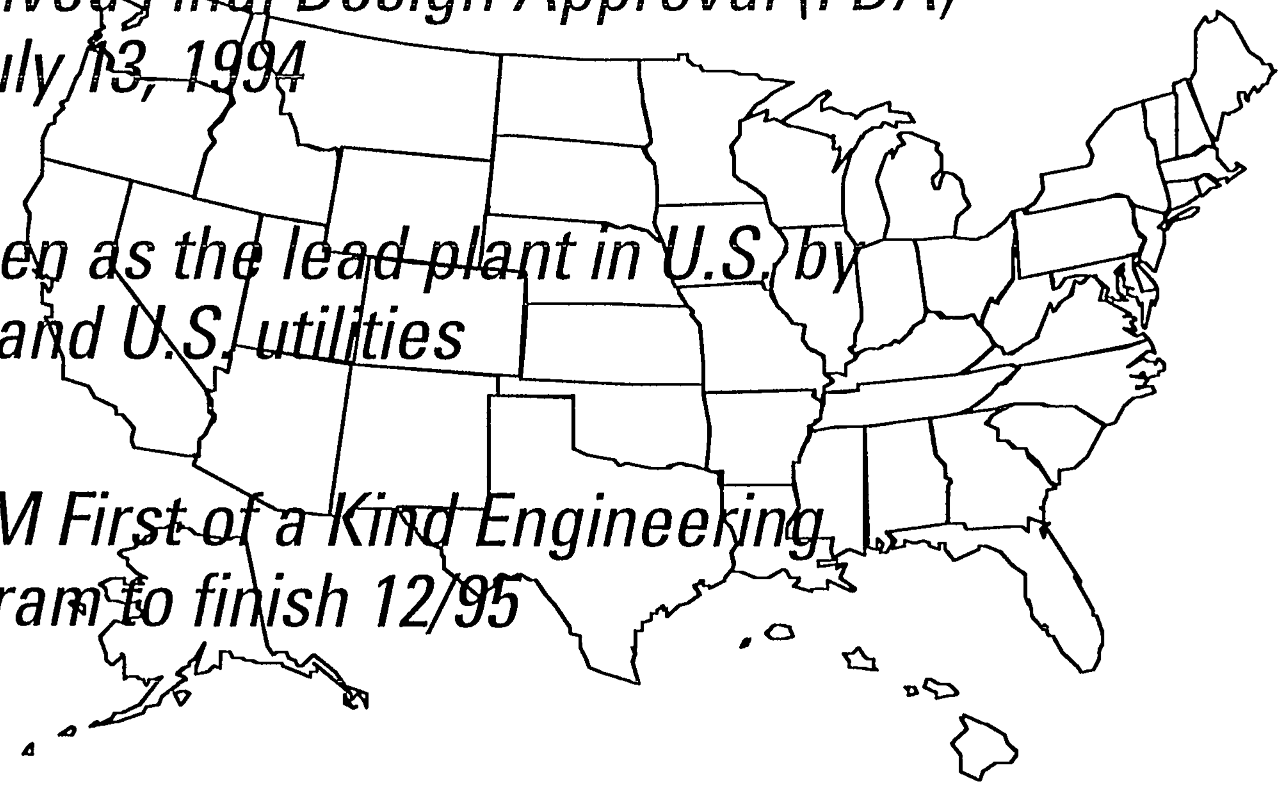
Appendix: ABWR Conformance to Korean ALWR Design Requirements

KOREAN ALWR DESIGN REQUIREMENT (KADR) DESCRIPTION	KADR SPECIFICATION	ABWR CONFORMANCE
Plant type and size	3000 to 4000 MWt	3926 MWt
Plant siting envelope	SSE : 0.3g	SSE : 0.3g, all soils
Plant life time	Goal : 60 yrs	60 yrs
Thermal margin	10 to 15%	>15%
Time to operator action required	> 30 min	72 hours
LOCA protection	No fuel damage for up to 15cm break	No core uncovery from worst postulated break
ECC system	4 mechanical trains	3 completely (mech., elect. and physically) independent safety divisions
Reactor depressurization system	Prevention of Direct Containment Heating	Yes; standard feature of BWRs
Man-machine interface	Maximize MMI using top-down approach	Yes; in use at Kashiwazaki-Kariwa units 6 and 7
Instrumentation and control	Maximize proven digital technology	Yes; in use at Kashiwazaki-Kariwa units 6 and 7
Occupational Radiation Exposure (ORE)	Accumulative exposure dose : 100 man-rem/yr	-Design ORE : < 100 man-rem/yr -ALARA concept
Containment	Cylindrical type / double containment	Cylindrical type / double containment with steel liner
Construction time	48 months	48 months
Capacity factor	90%	90%
Unplanned scrams	0.8 times/yr	< 1.0 times/yr
Refueling interval	18 months	18 to 24 months
Emergency planning	Designed for simplified planning	Yes; meets USNRC Severe Accident requirements- no offsite release

Outline

- ABWR Programs: Status in U.S. and Japan
- ABWR Competitiveness: Safety and Economics
- SBWR Status
- Combining ABWR and SBWR: the Passive ABWR
- Korean/GE partnership

ABWR Status in U.S.



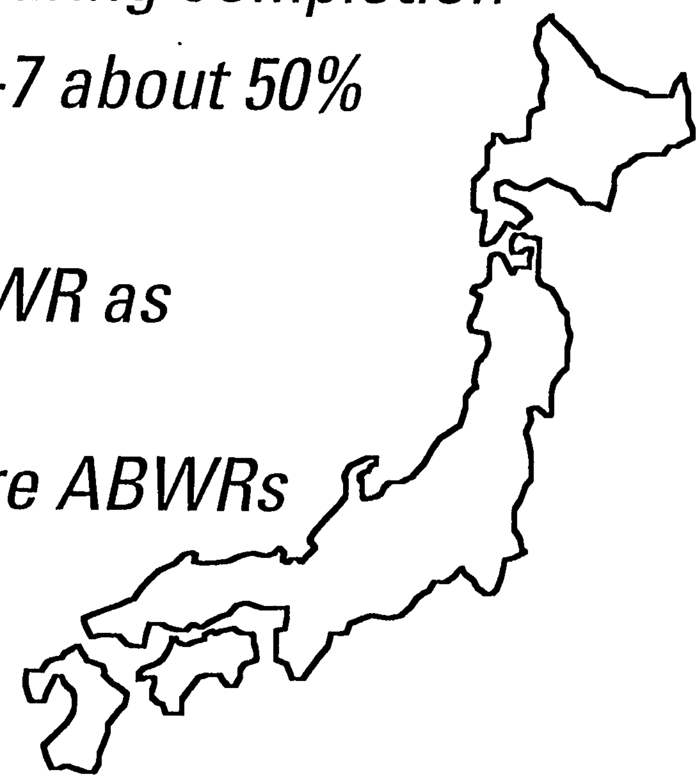
- Received Final Design Approval (FDA) on July 13, 1994
- Chosen as the lead plant in U.S. by DOE and U.S. utilities
- $110M First of a Kind Engineering Program to finish 12/95

ABWR to be the next generation plant for the U.S.

40475.3

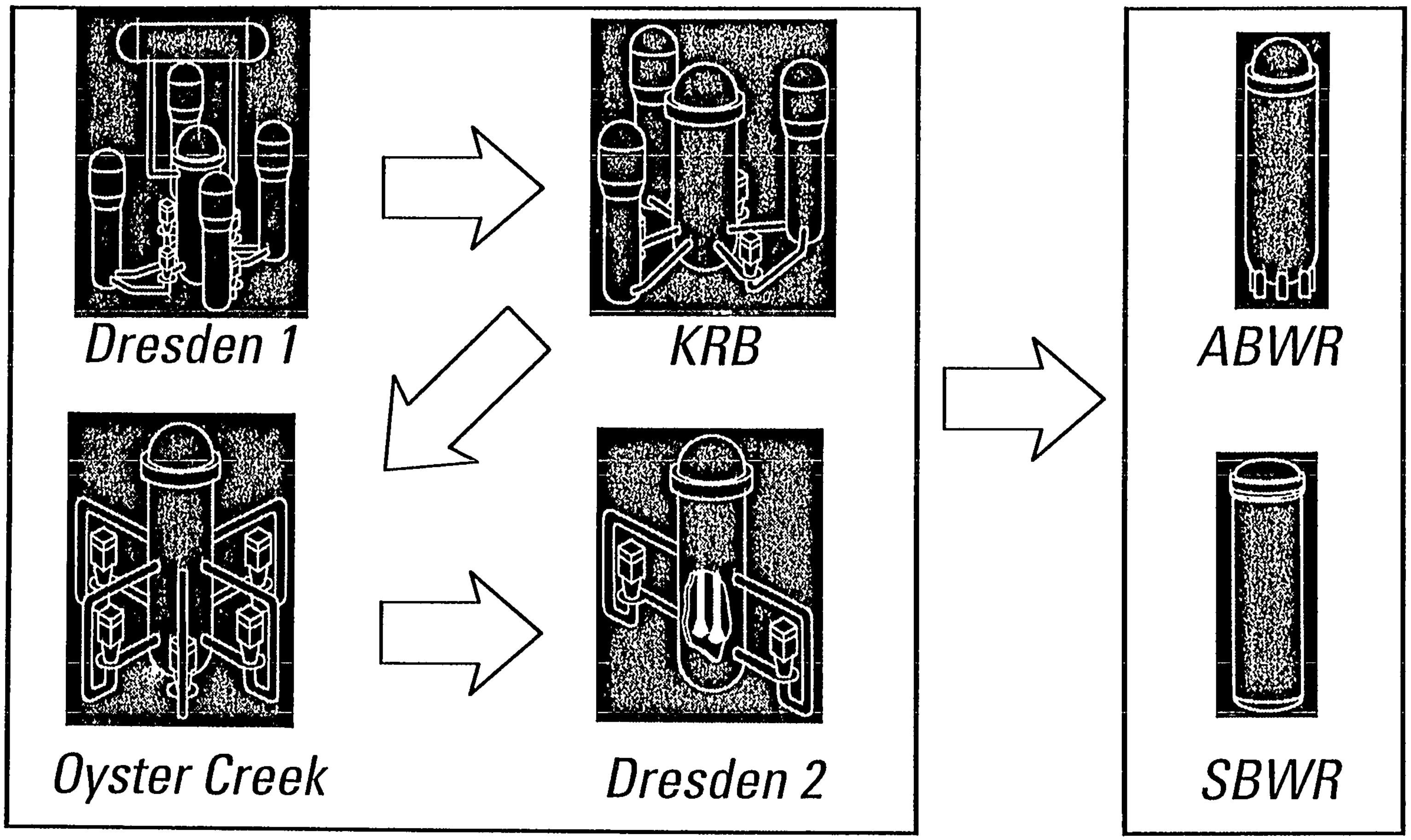
ABWR Status in Japan

- Kashiwazaki-Kariwa units nearing completion
  - K-6 over 70% complete, K-7 about 50%
  - Both units on schedule
- Japanese utilities chose ABWR as ALWR of the future
  - Of 21 plants planned, 19 are ABWRs
  - Only two are APWRs



ABWR is the next generation standard plant in Japan

Evolution of BWR Reactor Designs



Evolution towards simplicity

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ABWR vs System 80+ : Safety

	ABWR	System 80+		
Total core damage frequency	10^{-7}	10^{-6}	→	ABWR has higher degree of safety
Completely independent safety divisions	3	2*	→	ABWR's higher redundancy allows for N-2 capability
Severe accident mitigation features	Passive	Active	→	ABWR: offsite release extremely unlikely ($< 10^{-9}$ probability)

*S80+: 4 trains independent mechanically, but rely on only 2 electrical divisions

ABWR has a clear advantage in safety

ABWR vs System 80+ : Economics

	ABWR	System 80+		
Nuclear island footprint (S80+ = 1.0)	0.45	1.0	→	ABWR design requires significantly less bulk commodities
Existing design/ construction experience	FOAKE, Japan	-	→	ABWR to see significant cost reduction from strong learning curves
Large expected capital additions	-	Steam generators	→	ABWR has no foreseeable large capital additions
State of the art information management system	POWRTRAK	-	→	Enhanced procurement and delivery team achieves lower cost

ABWR has clear economic advantages

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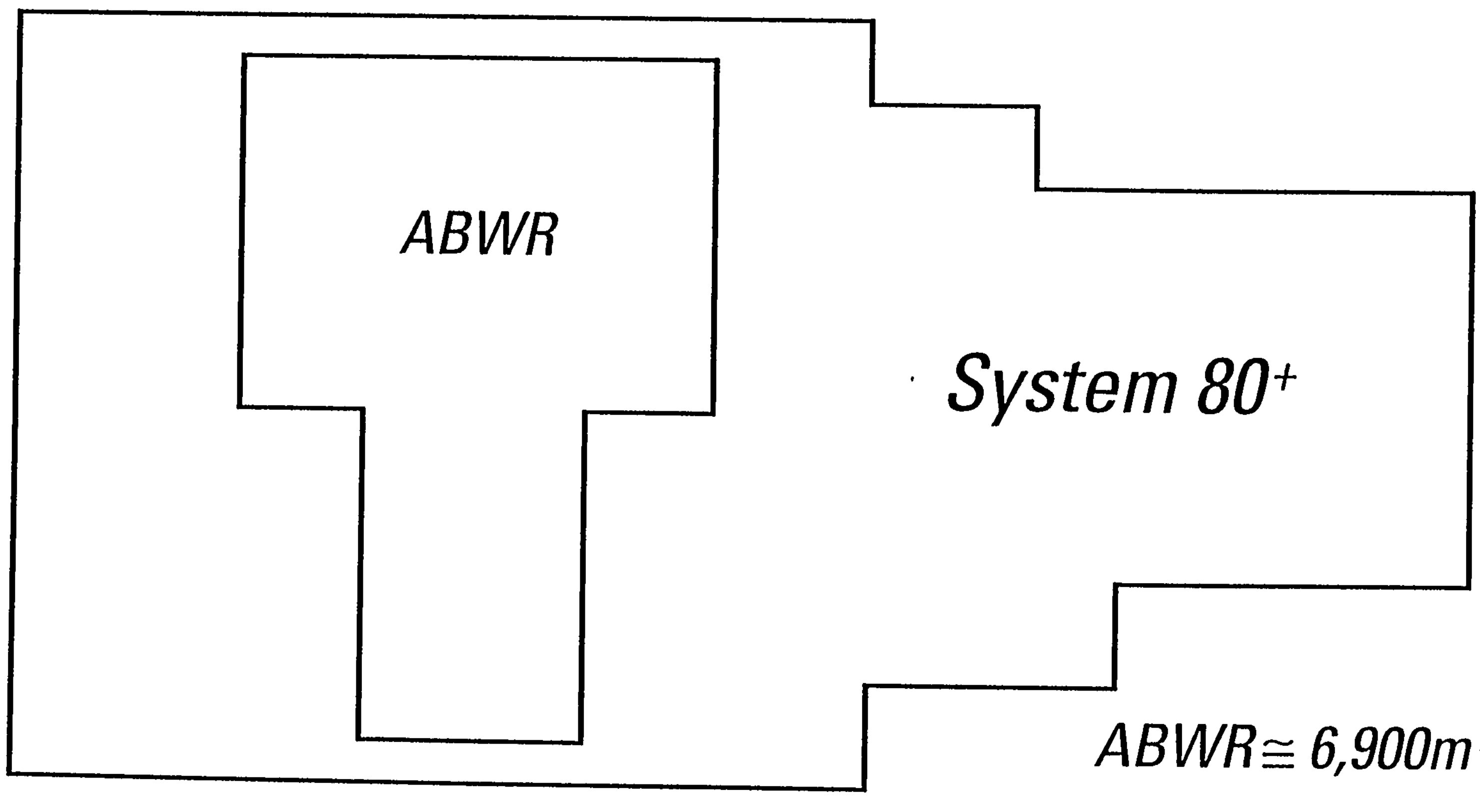
ABWR vs System 80+
Nuclear Island Footprint Comparison



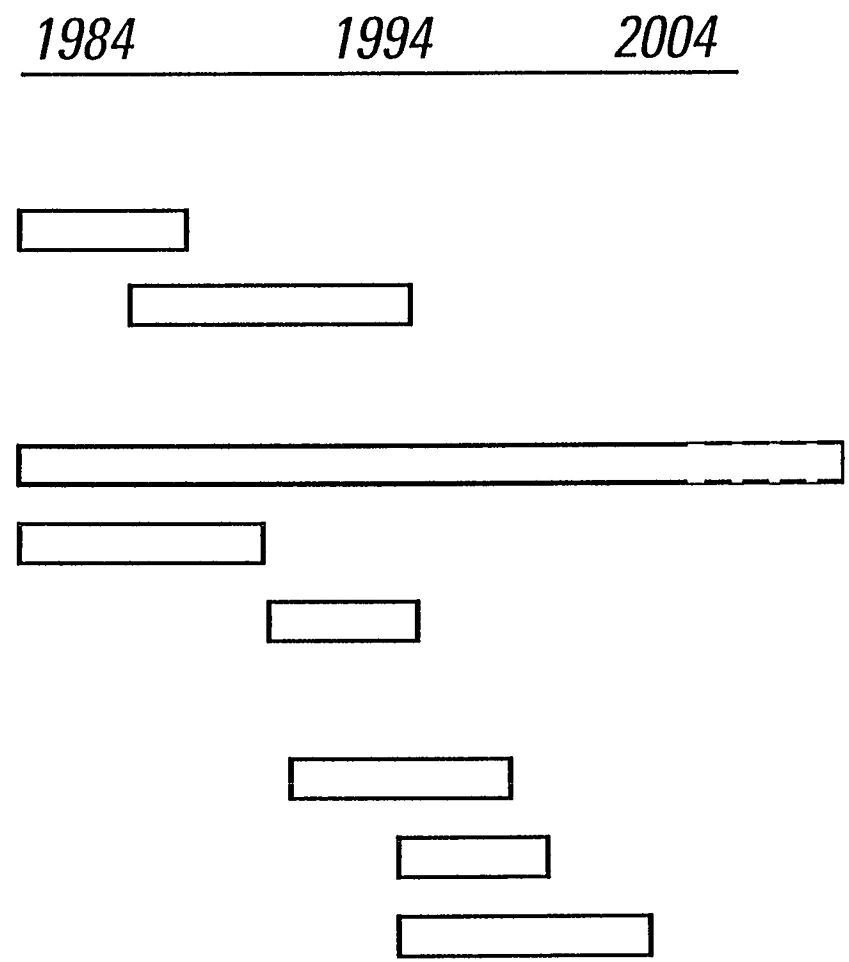
ABWR ≅ 6,900m²

System 80+ ≅ 15,000m²

ABWR design requires significantly less bulk materials

SBWR Program Plan

- Design definition
  - Key features selection
  - Feasibility/design optimization
- Technology and development
  - ABWR/operating plant base
  - Feasibility testing
  - Additional testing
- Commercial application
  - U.S. certification
  - Economic evaluations
  - Detailed design



Solid technology base for passive safety

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SBWR Passive Safety Systems

- Gravity Driven Cooling System (GDCS)
  - Method of passively providing water to keep core covered during a loss of coolant accident
- Passive Containment Cooling System (PCCS)
  - Method of passively removing heat from the containment
- No operator action needed for 72 hours

SBWR safety systems completely passive

ABWR – A Proven Plant Design

- Under construction and up to 19 more planned in Japan
- Licensed in two countries
- FOAKE program in U.S.
- Improved key design features
  - Based on U.S., Japan and European experience
- 17 confirmatory ABWR test programs to date worth $250M
  - Reactor internal pumps
  - Fine motion control rod drives
  - Reinforced concrete containment vessel
- Lead ABWR commercial operation in 1996

ABWR is proven technology

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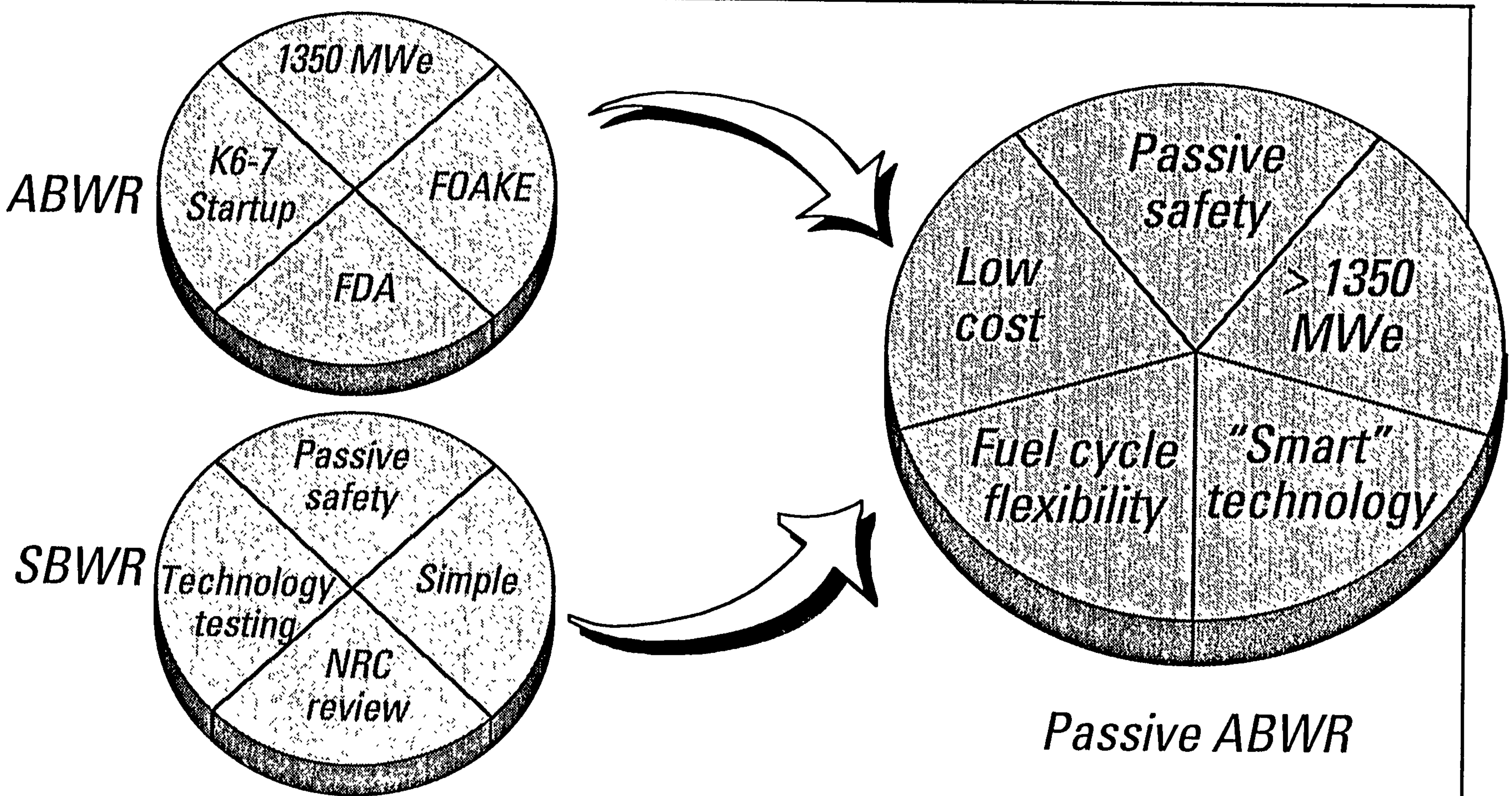
Passive ABWR: Incorporates ABWR and SBWR Technology



BWR: The best technology platform to build on

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GE and Korea – Partners in PABWR

- GE and Korean industry form a design team
- Combine ABWR and SBWR to meet Korean requirements for a large, passive ALWR
- Take advantage of worldwide BWR programs and operating experience
- Build upon proven technology and new technological advances

Broaden existing GE/Korea technology relationship

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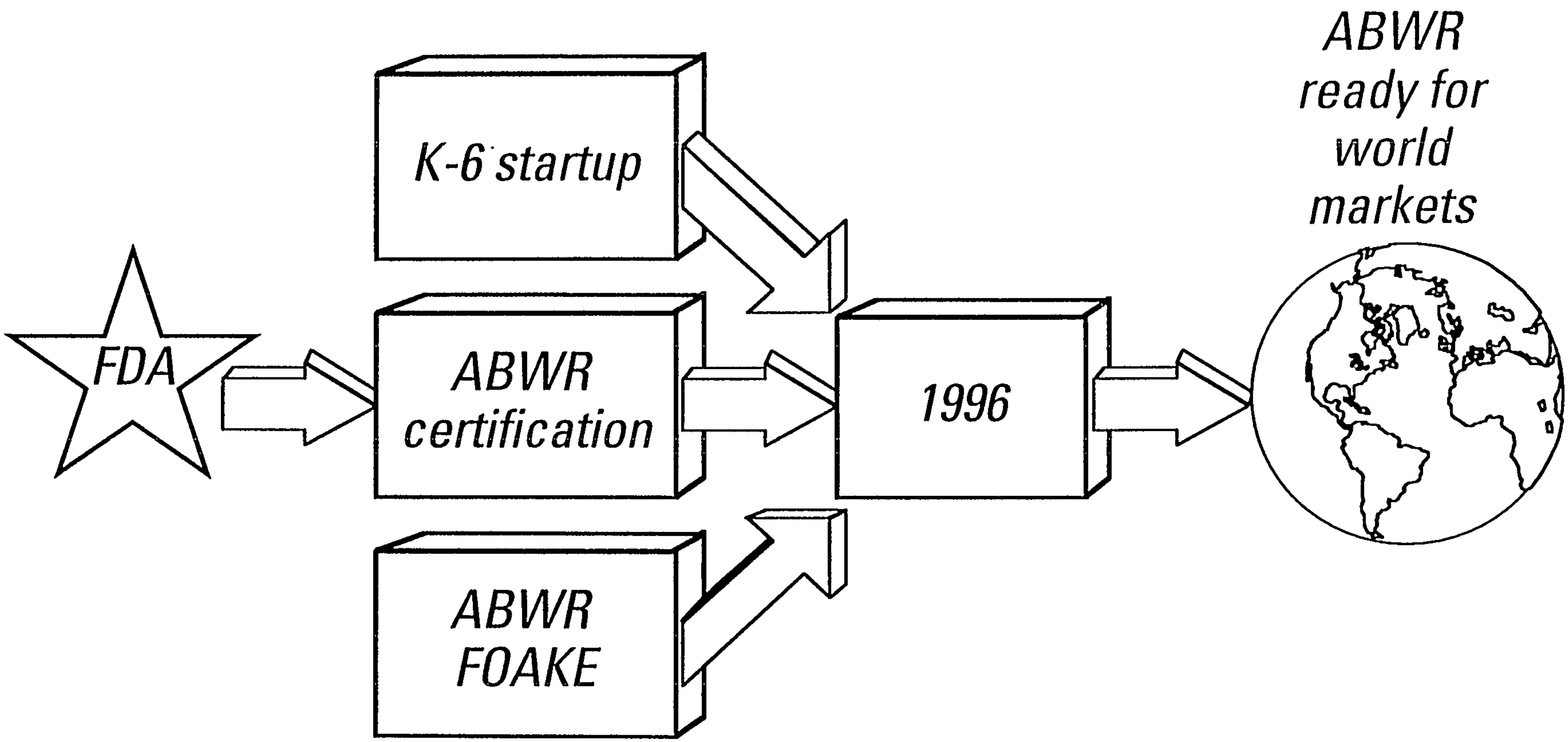
Introduction of ALWR Technology to Korea

- Introduce 1350 MWe ABWRs to next available nuclear site
  - Commercial operation in 2005 and 2006
  - Gain ABWR experience
- Form a joint GE/Korean industry design team to develop a Korean large, economical, passive advanced plant
  - Build upon proven technology
  - Incorporate country-unique features
  - Commercial operation in 2007

ABWR is worldwide standard for next generation advanced nuclear power plant

ABWR–Setting the Standard



ABWR ready for deployment in Korea

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ABB COMBUSTION ENGINEERING NUCLEAR TECHNOLOGY

Regis A. Matzie
ABB Combustion Engineering Nuclear Systems

ABB Combustion Engineering's Nuclear Technology

ABB Combustion Engineering has a long history in the nuclear energy field. We are the world's largest manufacturer of reactor pressure vessels, having supplied more than 140 to many of the world's nuclear vendors. Our history of manufacturing heavy nuclear components started with the first commercial nuclear unit at Shippingport, Pennsylvania, in 1954. Currently, ABB Combustion Engineering has 15 nuclear energy units in operation in the United States. Many of these units have set world records, including the three unit Palo Verde Nuclear Generating Station in Arizona, which has generated more electric energy in a single year than any other nuclear power station in the world. In addition, we have four units with ABB Combustion Engineering nuclear steam supply systems (NSSS) under construction in the Republic of Korea, with the lead unit currently in startup testing. As part of these projects, we have provided extensive technology transfer to Republic of Korea companies in the design and manufacturing of nuclear systems and components. This technology transfer has been uniquely successful in providing an extremely high level of technology self reliance to the Korean nuclear industry in a very short time.

ABB Combustion Engineering is not resting on its successes of the past. We have a highly successful development program for our advanced light water reactor (ALWR), the System 80+ Standard Plant Design, which is an evolutionary enhancement of the System 80 design under construction in Korea. Development of the System 80+ Standard Plant Design reached a major milestone this past summer with the completion of the technical review by the U.S. Nuclear Regulatory Commission and the issuance of the Final Design Approval. ABB Combustion Engineering is actively pursuing the final phase of licensing in the United States by pursuing generic rulemaking which will lead to design certification by the end of 1995.

Because of the firm regulatory bases established by the Final Design Approval and the confidence which ABB Combustion Engineering has in the technical quality of its advanced design, the System 80+ Standard Plant has been bid in the Republic of China for the Lungmen Project. This design offers the highest possible level of safety, economy, and operability of any plant in the world. Not only does it build on the very good experiences of the System 80 design, but it also

ABB Combustion Engineering's Nuclear Experience and Technologies

Dr. Regis. A. Matzie
Vice President, Nuclear Systems Engineering

U.S./Korea Electric Power Technologies
Seminar Mission

Seoul, Korea
October 24-28, 1994

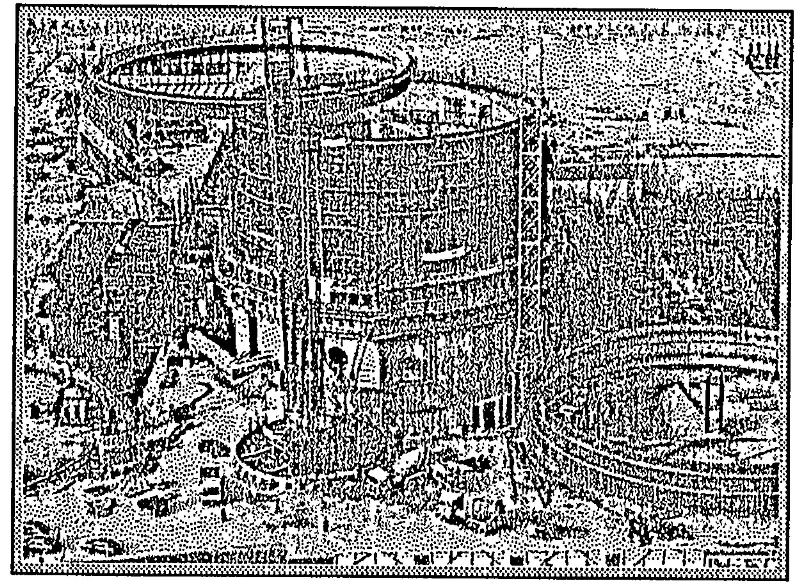
ABB

incorporates the desires of future owners by conforming to the EPRI ALWR Utility Requirements Document. Furthermore, it meets all current and anticipated regulatory requirements, including severe accidents.

ABB Combustion Engineering believes in continuous improvement of this design and the design process. We continue to evaluate potential improvements to meet new requirements both of the public and the regulator, so that our designs meet the highest standards world-wide. We will make advancements as necessary to meet market needs and to ensure the highest level of performance in the future.

System 80+™ Standard Plant Evolutionary Advanced LWR

- It is an evolution of the proven System 80 design in operation at Palo Verde in Arizona and under construction in Korea
- Balance of plant design based on Duke Power Co. Cherokee/Perkins plant design
- Standardized design for the complete plant - Nuclear Island, Turbine Island, support systems and structures
- Approved by U.S. Government (Nuclear Regulatory Commission - NRC)



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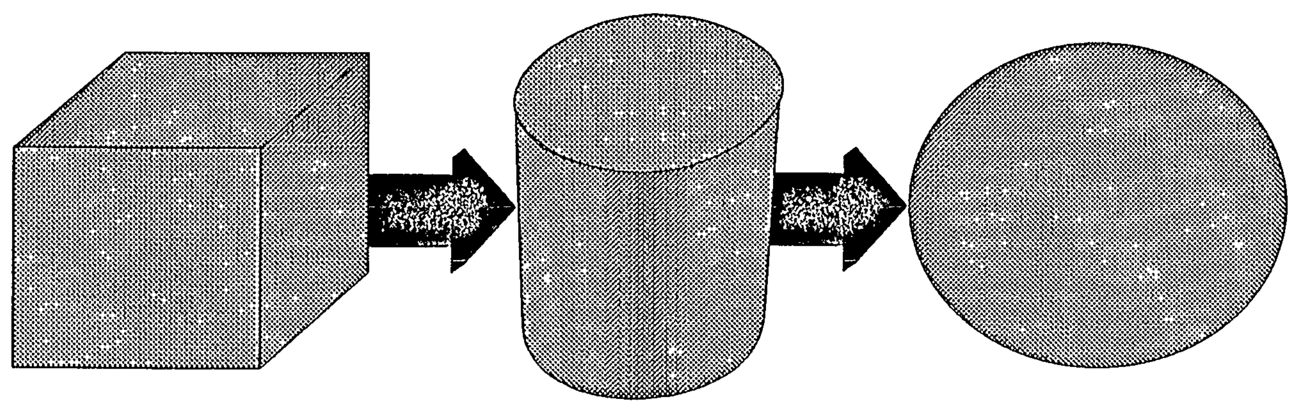
Benefits of Evolutionary Approach

- Predictable performance based on experience
- Availability of proven equipment and manufacturing capability
- No proof of principle demonstrations or verification testing required
- Assured licensability
- Confidence in plant cost and construction schedule



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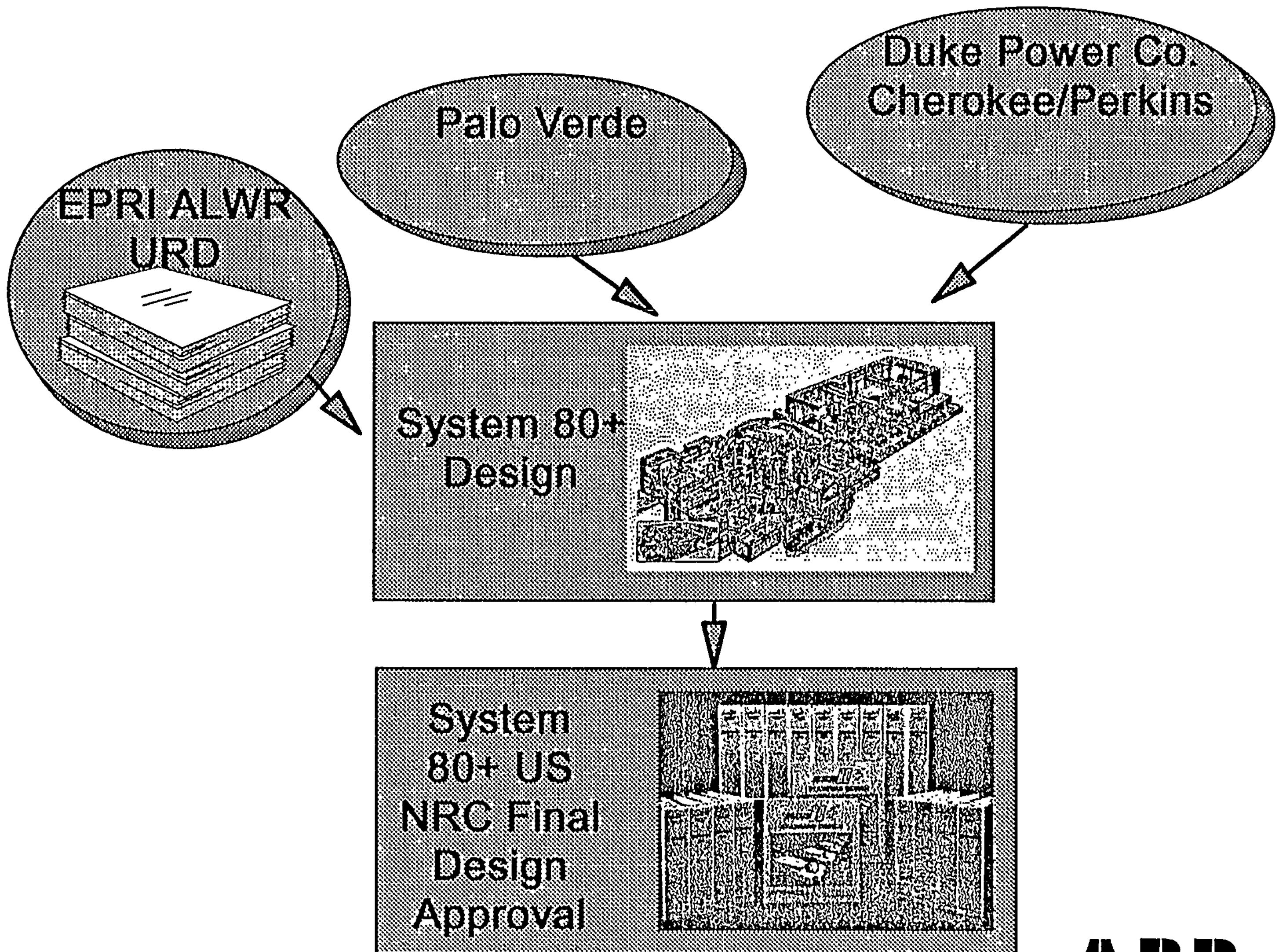
Evolutionary Development of System 80+

EVOLUTIONARY FEATURE	YGN 3&4 1987	UCN 3&4 1991	YGN 5&6 1994	SYSTEM 80+ 1994
Ring forged vessels	X	X	X	X
Larger pressurizer	X	X	X	X
Advanced fuel design	X	X	X	X
More secondary system margin	X	X	X	X
Safety depressurization & vent system	X	X	X	X
Emergency feedwater system changes	X	X	X	X
Digital balance of plant control system	X	X	X	X
Alternate power source	X	X	X	X
Delete chemical additives to containment spray	X	X	X	X
Increased cavity floor area		X	X	X
Non-safety multiplexing		X	X	X
Video display unit monitoring		X	X	X
Digital NSSS control system			X	X
Centrifugal charging pumps & CVCS changes			X	X
Dedicated RCP seal injection system			X	X
Reactor drain tank increased size			X	X
Steel, dual spherical containment				X
Nuplex 80+ Advanced Control Complex				X
Incontainment refueling water tank				X
Severe accident systems				X
Letdown heat exchanger in containment				X
Inconel 690 steam generator tubes				X
Mid-loop narrow range HJTC level measuremt.				X
Inter-system LOCA changes				X
N-16 monitoring				X
Hydrogen igniters				X

System 80+ Development



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System 80+ Design Approach

- Integrated design team for entire plant
- Evolutionary design changes to meet EPRI ALWR Requirements Document and NRC criteria
- Utility input for total plant design and operations
- Emphasis on plant safety and cost competitiveness

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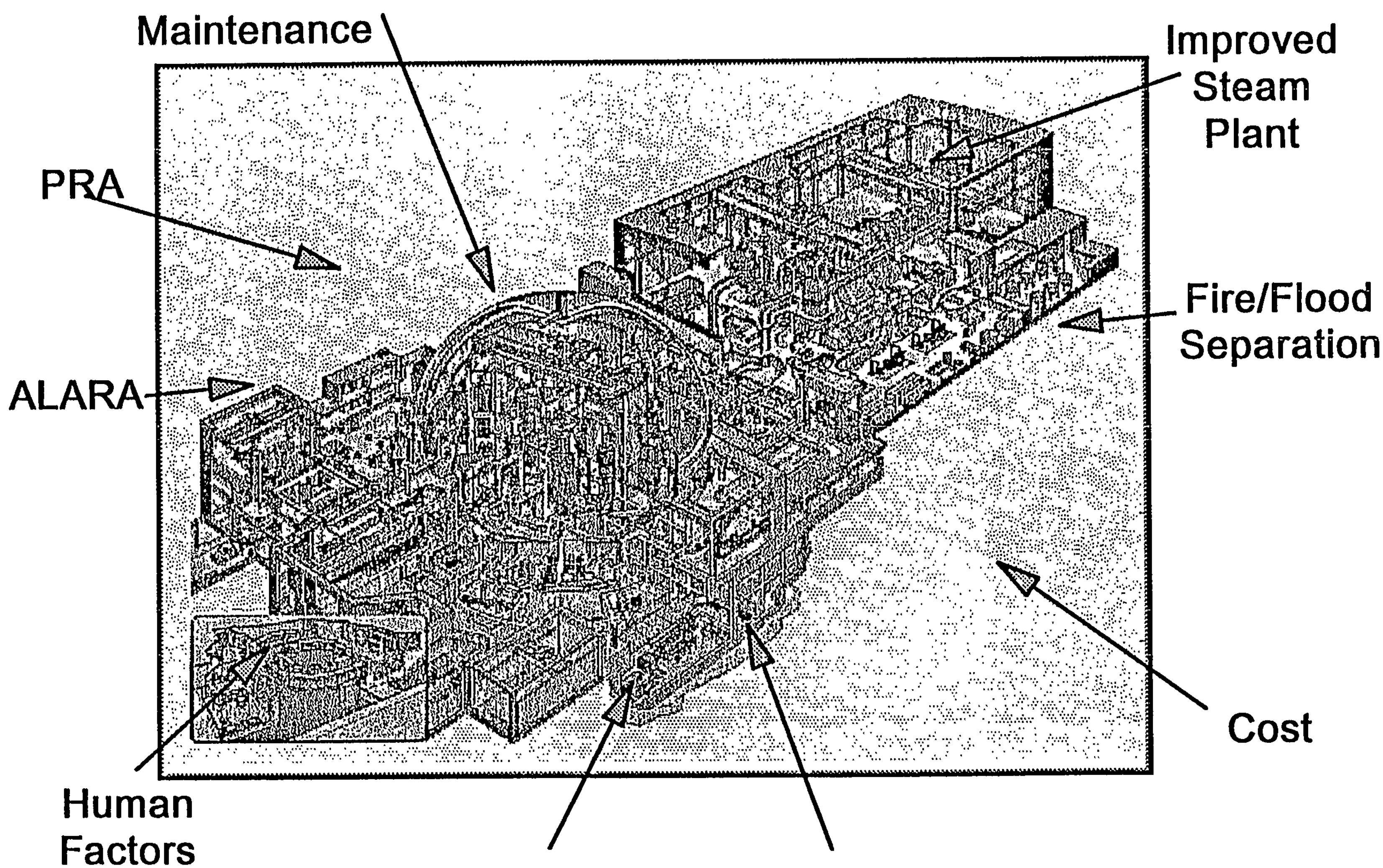
Integrated Design Approach Balances Competing Considerations



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Defense-In-Depth for Safety Philosophy

- Problem prevention
  - Improved materials
  - Redundant equipment
- Margins for operations and plant transients
  - Thermal margin
  - Component sizes
  - Human factors engineering
- Accident mitigation
  - Redundancy
  - Diversity
  - Severe accident design features
- Analyses to confirm safety improvement
  - Design basis accidents
  - Probabilistic Risk Assessment (PRA)

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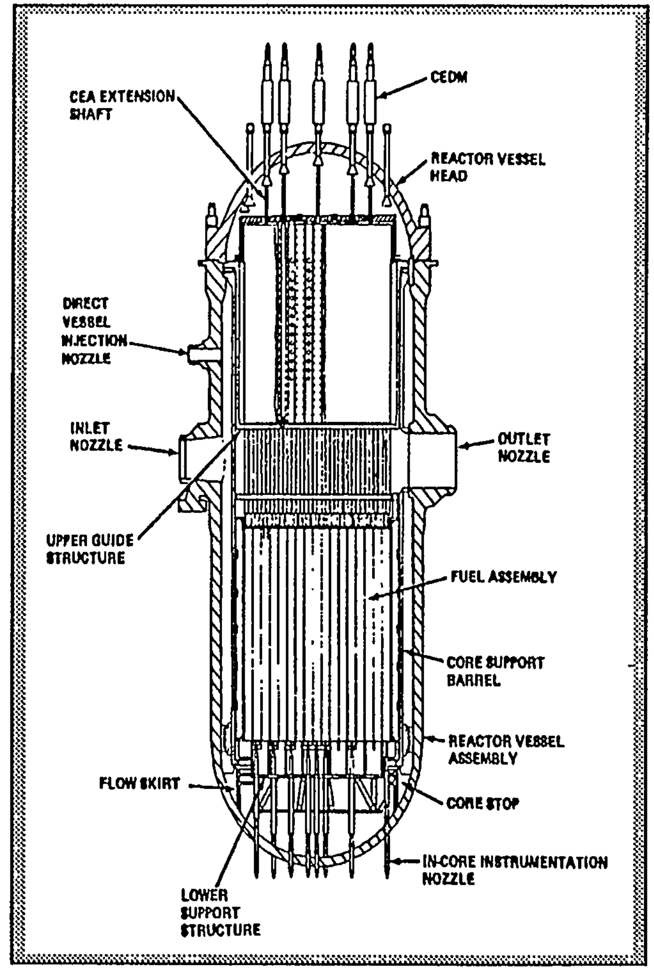
Example of Problem Prevention Reactor Vessel Design

- Improved material specifications provide for a 60 year design life
- Ring-forged reactor vessel eliminates welds
- Twelve additional nozzles for control rods, safety injection, and level monitoring



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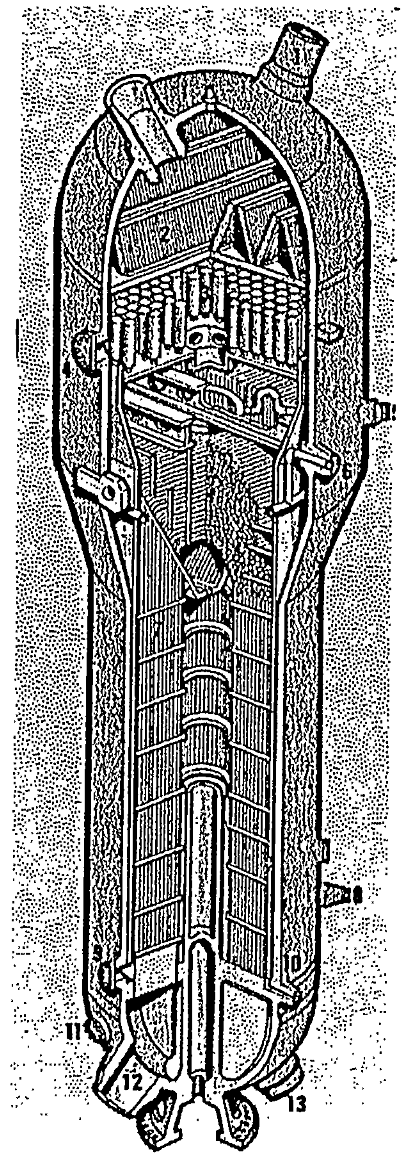
Example of Increased Margins Improved Steam Generator Design

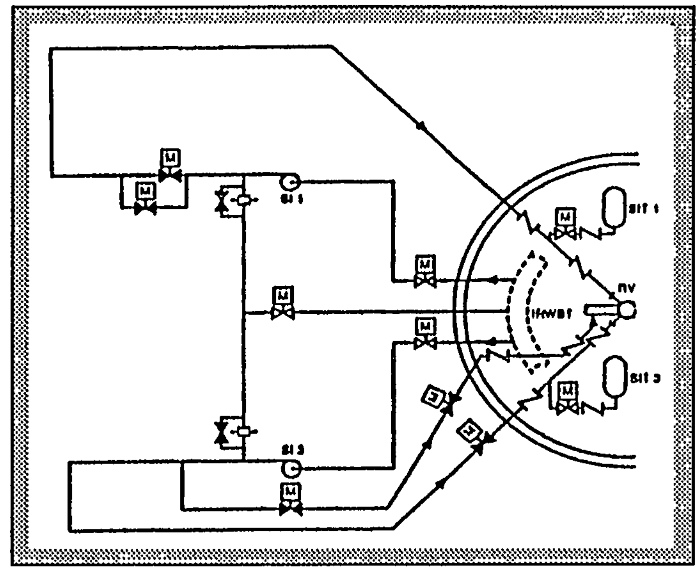


- Increased secondary volume
- Inconel 690 tubes
- 10% tube plugging margin
- Improved maintenance access
- Improved dryers
- Capability to improve secondary side chemistry during wet layup

ABB

Example of Accident Mitigation Safety Injection System

- 4 train (100%) redundancy for small break loss of coolant accident
- Direct Vessel Injection
- In-containment refueling water storage tank - no automatic recirculation actuation
- No fuel damage for breaks less than 25 cm. diameter
- Full flow testing while operating



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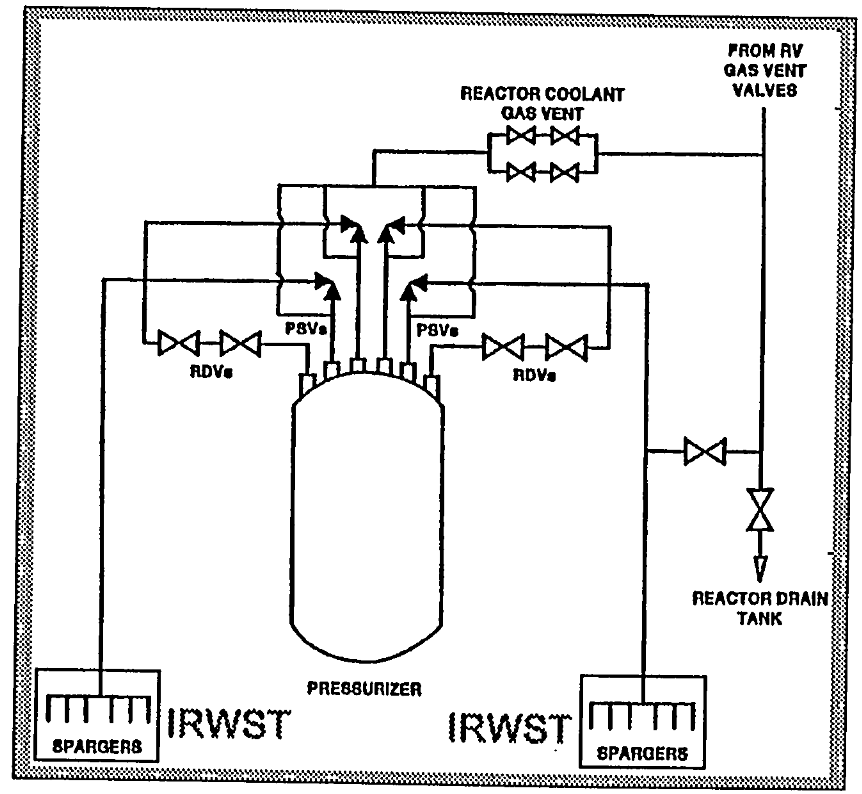
Example of Accident Mitigation Safety Depressurization System

- Venting noncondensibles
- Alternative if pressurizer spray is unavailable
- Depressurization to initiate feed and bleed core cooling
- Depressurization during severe accident
- Vented reactor coolant scrubbed of radioactivity in IRWST



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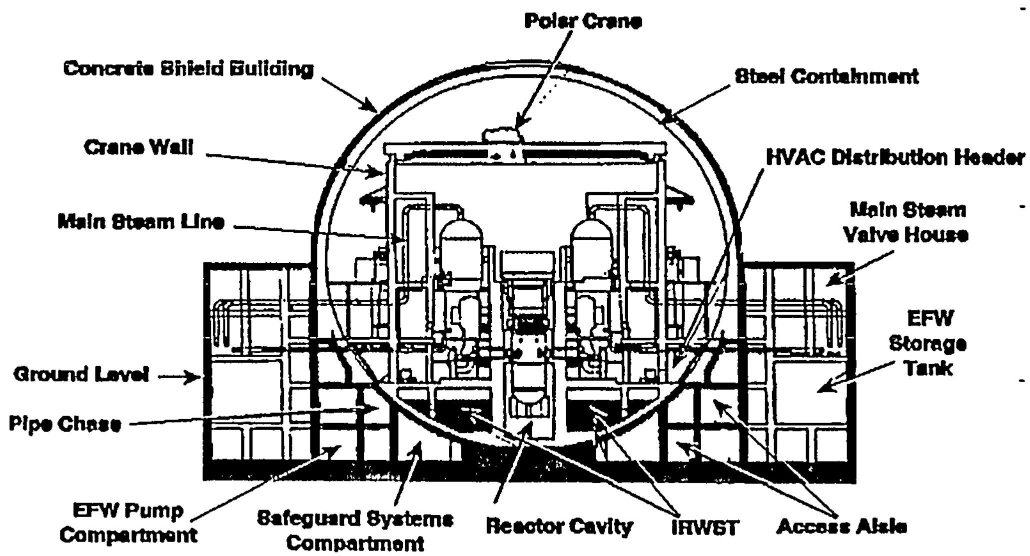
Steel Dual Containment

- 61m diameter steel sphere (4.45 cm thick)
- 0.91m thick shield building (with 1.52m annulus space)
- Design pressure of 365 kPa
- Allowable leak rate: 0.5% per day
- Increased space for maintenance access
- Designed to mitigate severe core damage
- Subsphere region houses safety systems



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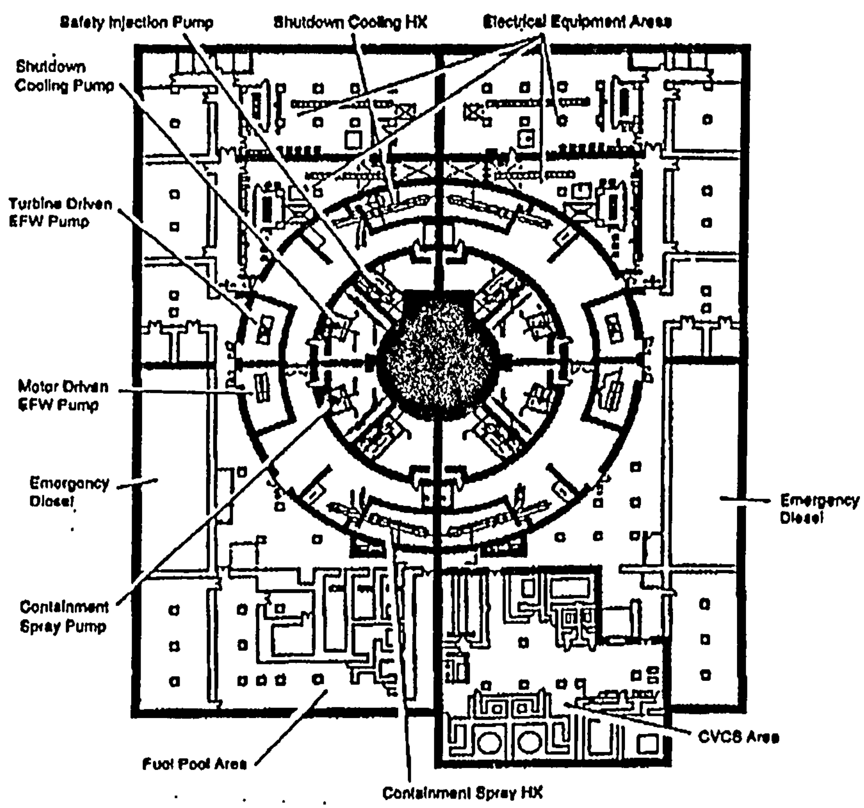
General Arrangement of containment and Nuclear Annex (Basemat level)

- Strict divisional separation for entire nuclear annex
- Quadrant separation in subsphere region



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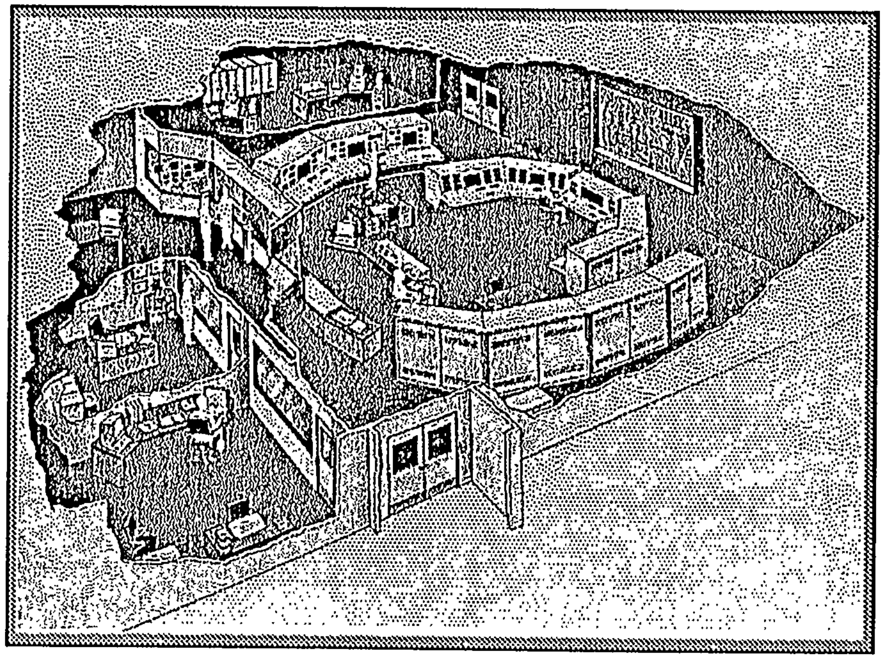
Severe Accident Protection Provided in System 80+

- Large dry containment with excellent natural circulation
- Ultimate containment strength approximately three times design pressure
- Cavity design to permit core debris spreading and retention
- Cavity flood system to cool core debris
- Hydrogen control system to prevent uncontrolled burn
- Safety depressurization system to prevent high pressure ejection

System 80+ Advanced Control Complex - Nuplex 80+

- A complete integration of I&C systems and control panels for nuclear plants
- Employs modern software based I&C technology in all areas:
  - Distributed microprocessor technology
  - Serial data communication techniques
  - Video based man-machine interfaces



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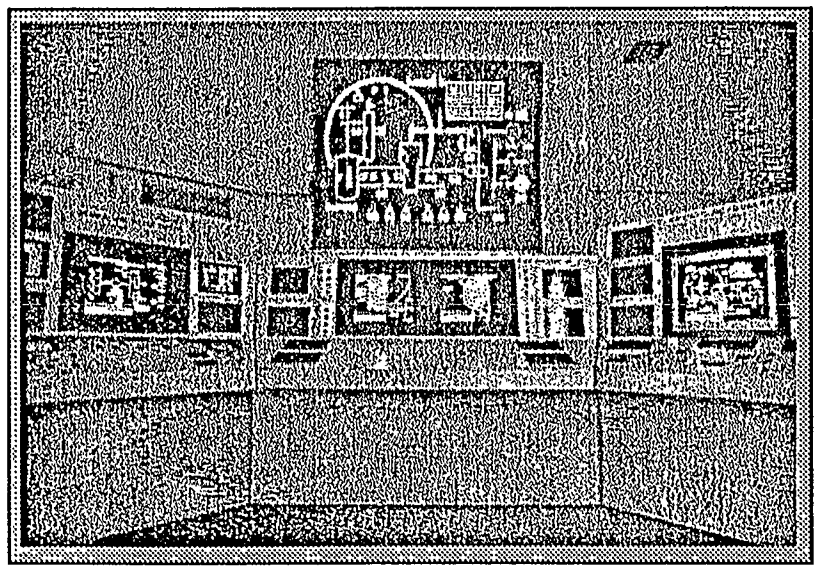
Advanced Control Room

- Large Overview Display Screen
- Touch-sensitive CRT and plasma displays
- Microprocessors reduce operator burden
- Mode-dependent, prioritized alarms
- Self-testing and fault-tolerant features
- Multiplexing and fiber optical cable



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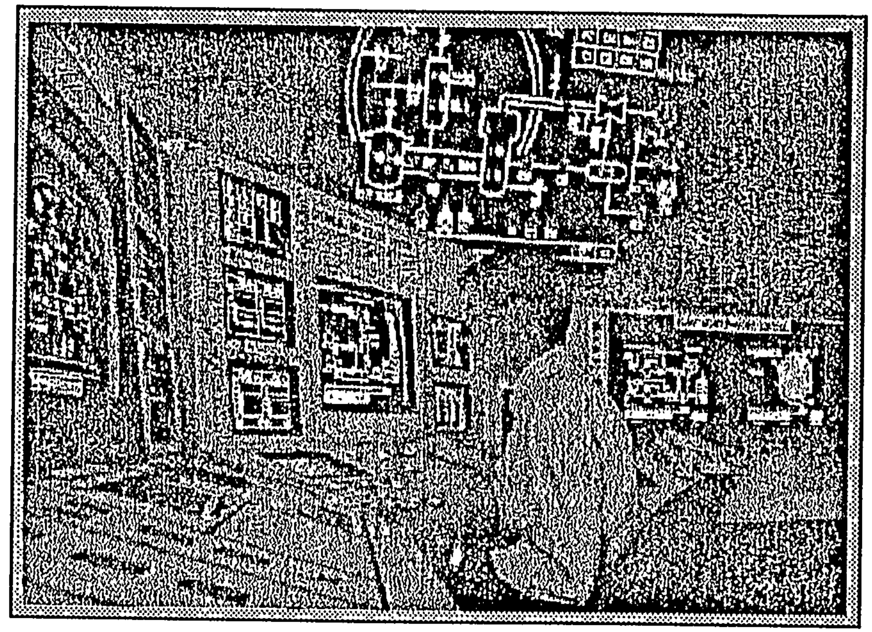
Nuplex 80+ Advanced Control Complex

- Nuplex 80+ uses modern technology to:
  - Improve plant safety and performance
  - Improve man-machine interaction
  - Reduce construction and installation costs and schedule
  - Improve maintenance and testing



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Probabilistic Safety Assessment

- Core Damage Frequency

-Internal Events:	1.7 E-6 events/year
-External Events:	0.3 E-6 events/year
-Shutdown Risk:	0.8 E-6 events/year
Total:	2.8 E-6 events/year

- Containment Integrity, given a severely damaged core, is 99%
- Large offsite release frequency (25 Rem) is 2.9E-8 events/year
- The best-estimate dose at site boundary for the first 24 hours is 0.3 Rem (protective action guideline for emergency planning is 1 Rem)

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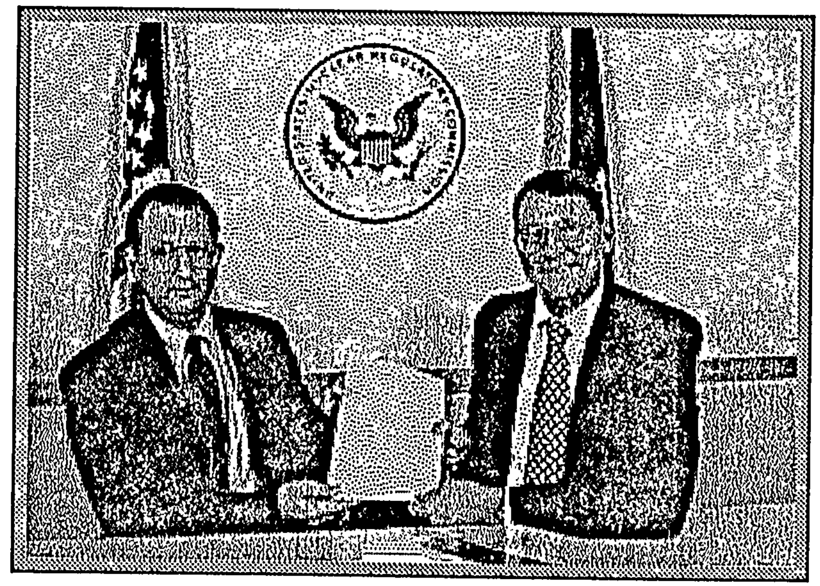
U.S. Government Approves System 80+

- U.S. Nuclear Regulatory Commission issues Final Design Approval (FDA) on July 26, 1994
- "...ABB-CE has completed the technical review stage of design certification..."
- "This FDA allows the System 80+ standard design to be referenced in an application for a construction permit or operating license..."

  – William T. Russell, Director Office of Nuclear Reactor Regulation



U.S. NRC presents Final Design Approval to ABB Combustion Engineering Nuclear Systems!

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Assuring Success

- Evolutionary approach using proven technology
- Substantial improvement to plant safety
- Utility perspective up front in developing design
- Integrated design from inception
- Very competitive plant cost
- Focus on operability and maintainability
- Commitment to standardization
- Completed U.S. NRC technical review (Final Design Approval issued July 1994)

System 80+ ready to proceed with commercialization

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OPTIMIZATION OF LIFE CYCLE MANAGEMENT COSTS

TECHNICAL PAPER

by

A. K. Banerjee

Presented at
US/KOREA ELECTRIC POWER TECHNOLOGIES SEMINAR
Seoul, Korea
October 23-28, 1994

Stone & Webster

OPTIMIZATION OF LIFE CYCLE MANAGEMENT COSTS

By

Ajoy K. Banerjee

Stone & Webster Engineering Corporation
Boston, Massachusetts

BACKGROUND

Economic factors have recently resulted in the decision to shutdown Yankee Rowe, San Onofre Unit 1, and Trojan Nuclear Plants. In the case of San Onofre 1 and Trojan, this decision also was influenced by the uncertainties associated with possible future steam generator replacements. In all cases, the rising costs associated with operations and maintenance and capital improvements coupled with the currently low prices of coal, oil, and natural gas made these plants less competitive in today's marketplace. Furthermore, pressures from Independent Power Producers (IPP), are expected to keep electricity rates at current levels over the next few years. Nuclear power plant operations and maintenance and capital improvements costs, which peaked in the late 1980's, have leveled off through the actions of utility management. These actions include staff reductions, prioritization of capital improvements, and plant performance improvements (Figures 1 and 2). As nuclear power plants age, uncertainties related to the need for major component/ systems replacement and high and low level waste storage/disposal may add significantly to the capital cost contribution to the price of electricity. 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 uncertain. External political influence which on one hand forces utility owners to factor such things as steam generator replacement into their least cost plan will not on the other hand allow credit for cost recovery into the license renewal period.

Life cycle management (LCM) (Figure 4) is a structured decision making process which addresses external and internal factors with associated uncertainties, supports economic analysis of major component/system replacement and refurbishment decisions, and remains a dynamic program over the life of the power plant.

LCM 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 also may 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.

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. Reliability centered maintenance (RCM) and risk based maintenance have been proposed and implemented at several plants in order to prioritize and potentially reduce overall maintenance activities and costs. Predicted and preventive maintenance programs also are implemented to improve plant reliability and to reduce maintenance costs. LCM is not just a maintenance program in the same sense as these programs, but integrates the maintenance strategy with other issues such as capital improvement, radwaste generation, and plant life extension to optimize overall plant cost.

The real incentive for developing and implementing a comprehensive LCM program is not solely for regulatory compliance, but to 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 and operating costs.

Stone & Webster had extensive experience 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. 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 the 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 systems are selected, and the design and licensing basis and aging mechanisms applicable to the system are identified. Each structure and component in the system is evaluated to determine if it is important to license renewal or important to power production. Life cycle program objectives should establish the level of evaluation for each type of component. 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 plant-specific failure history has not been well documented in the past, industry data, available plant specific failure data, and LCM experience can be used to establish SSC aging mechanisms and failure rates. 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 and 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 probabilistic theories such that the reliability and sensitivity of the results can be evaluated.

Based on the result of the cost benefit and sensitivity analysis, the most effective upgrade consistent with LCM program objectives is determined. Implementation is typically performed by the appropriate plant group and additional SSCs are considered based on the lessons learned from the pilot program. It is important to remember that plant performance and station programs are dynamic i.e., continue to change. Thus, the LCM program which by definition is a long-term program, also must be dynamic such that it can interface with other plant programs that are in progress and continue to change.

IMPLEMENTATION EXAMPLES

As discussed earlier, Stone & Webster has performed many LCM evaluations. The ones performed for the life extension pilot plant Surry Unit 1, license renewal lead plant Yankee Rowe and the EPRI/NUMARC industry topical reports, focus primarily on technology and process development for nuclear plant life extension. In a recent LCM strategy development for a large multi-plant, multi-site nuclear power plant utility, the focus was to assess the utility's corporate maintenance and condition assessment programs, compare them with industry initiatives, programs and priorities, and to suggest improvements.

For a utility with a multi-unit (BWR & PWR) site, the LCM strategy again was to compare the industry initiatives, programs and priorities to existing plant programs and to suggest improvements. This LCM program has progressed further and has evaluated intake structures, reactor vessel supports, containment liner, containment structure (below grade), instrument air, RHR, and service water (buried portion). The evaluations to date have been primarily technical and have not indicated a need for any major upgrades which require cost benefit analyses (Reference 1). The recommended upgrades have been primarily associated with condition monitoring and improved maintenance in cases where condition monitoring show degradation. This LCM program is in the process of being further enhanced to include a cost benefit analysis of all recommended major changes. The utility will soon select a major component or system as a pilot for evaluation where the cost benefit analysis method will be used.

The LCM evaluation of a service water system of a two unit nuclear plant that has been in operation for 20 years will be discussed here in more detail. The scope of work for this project was to evaluate age-related degradation mechanisms (ARDMs) of components important to power production and/or safety; assess existing programs for effective age management; define alternatives to improve system availability and life expectancy in the most cost effective fashion either through program or hardware changes; and perform a cost benefit analysis of suggested alternatives. The scope also included the reliability and availability analysis (RAM) of system as currently designed and as upgraded. The RAM analysis quantified the projected incremental change in system availability resulting from the alternatives proposed to improve system availability and life expectancy. The results of the cost-benefit and RAM analyses provide the critical information necessary to justify the optimum/cost-effective, long-term solutions to existing LCM and availability problems in the saltwater system.

The service water system at the plant is a once-through sea water system which cooled two closed loop cooling water systems and ECCS room cooler systems. A service water system was provided for each unit and one train in each system can be inoperable for a maximum period of only 72 hours under technical specification limiting conditions. The original above ground concrete lined carbon steel piping had experienced numerous leaks and in some areas had been replaced with rubber lined carbon steel piping. A large portion of the system large diameter concrete line ductile iron supply headers were buried beneath existing structures. The condition of these sections of piping were inspected infrequently and thus unknown. Heat exchanger fouling and material failures were contributing to reliability and availability problems and also would potentially impact the system life.

The service water system has been experiencing numerous problems with reliability, and was chosen as the first system to study because of the large impact on overall plant performance and O&M costs. The utility had already decided to modify the system design to address the historical age related failures in heat exchangers and piping and the LCM evaluation and cost-benefit analysis was to demonstrate the adequacy of the LCM process in determining the best and most cost effective upgrade program. Early in the project scoping process it was determined that because some portions of the salt water system needed to be replaced with an alternate design, the LCM evaluation should not evaluate all of the existing components through the Integrated Plant Assessment (IPA) of the SCCs and their aging mechanisms. Therefore, the replacement options for each of the problem components were determined and then evaluated through a cost-benefit process in order to determine the most cost effective life cycle options. The remainder of the SCCs were evaluated under the normal IPA process and the age mechanism and effective age management programs determined.

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. The implementation of the cost-benefit analysis forces the review of all life cycle considerations. This, therefore forces the consistent addressing of LCM, life cycle cost, and technical issues.

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) yielding the replacement frequencies and costs, failure effects (capitalized and/or expended cost to repair/replace; forced outage duration associated with failure), probabilistic simulation of the effects of key variables to account for different level of confidence in maintenance/repair costs, capital cost, service life, con-sequence of failure, length of outage upon failure etc. These evaluations were performed for 20 years of remaining life and also for 40 years of remaining life (corresponding to a license renewal scenario) to see if the upgrade decisions are different for the two scenarios.

For each of the replacement alternatives, several technical solutions were identified that would potentially solve the reliability and availability problems of the component or system portion under consideration. These technical solutions involved differences in pipe routings, materials, component designs and configurations. Because it was not practical either from the cost or schedule standpoint, to address each of the technical solutions through the entire cost-benefit process, preliminary capital costs, life expectancies, and O&M costs were developed for each of the technical solutions. This technical and cost "brainstorming" process resulted in the early elimination of several technical solutions because of large differences in the initial capital and replacement frequencies/cost and the associated O&M costs when compared against other technical solutions.

While several equipment trains were identified as having a significant effect on reliability or availability, to illustrate the results of the LCM evaluation, the cost benefit methodology and results of two replacement alternatives will be discussed.

Above Ground and Below Ground Service Water Piping Replacement

Above Ground Piping Saltwater Piping - Failure of the concrete lining was exposing the carbon steel piping to sea water. The corrosion of the base piping was resulting in through-wall leakage. The scope of the LCM evaluations ultimately considered the following solutions to correct the life cycle management issue:

- Replacement of the above ground piping with new piping made of a corrosion resistant piping material (6% Molybdenum alloy and titanium were considered). Because all pipe supports were being replaced as part of each alternative/option, the cost-benefit analysis included the cost of the additional supports required by the higher alloy piping material.

- Replacement of the existing carbon steel concrete lined spools with spools of similar material and the lining of the piping with a corrosion resistant coating (rubber lined or alloy clad).

The pipe replacement options for the 40 years of remaining plant life case for above ground piping are presented in Table 2. The results indicate that 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 plant life is assumed, the life cycle costs of the three pipe materials are nearly the same. The cost-benefit analysis compared the total installed and operating cost of rubber-lined carbon steel piping, 6 percent molybdenum alloy, and clad carbon steel pipe. Because the expected installed cost of titanium would exceed the cost of the 6 percent molybdenum alloy, and both materials had acceptable corrosion resistance for the saltwater system service, a detailed cost-benefit analysis was not developed for the titanium design. Therefore, the titanium material was technically evaluated for this application and general cost comparisons performed. Based on the results of the cost benefit and technical evaluations, the rubber-lined piping material has the highest life cycle cost. The 6 percent molybdenum alloy design has a slight advantage in terms of the total life cycle cost over the nickel alloy clad piping material.

The existing concrete-lined and rubber-lined pipe used in the above ground service water system has a limited life and may not survive the current remaining license period of 20 years. Further, based on the results of the cost-benefit analysis, neither material provides the lowest life cycle cost, regardless of whether license renewal is sought. Because there was a lack of failure data for the rubber lined pipe, additional cost benefit cases were run to evaluate the sensitivity of the failure probability and hence the replacement frequency for the above ground rubber lined piping. The cases considered a 15-year and 20.5-year piping life (Table 2). In the case of the 15-year life, the piping failure required the replacement of the piping twice through the end of the renewal term (40 years additional plant life). The 20.5-year assumption necessitated one replacement. Based on the results of the cost benefit sensitivity analysis the lower replacement frequency was insufficient to offset the higher rubber lined piping O&M costs. Six percent Molybdenum still had a lower total life cycle cost compared to the rubber lined piping.

While the cost benefit analysis clearly defined the best life cycle decision based on the application of the cost benefit analysis and probabilistic simulation of the cost benefit input variables, the final choice for the above ground service water piping modifications also had to consider other additional factors and non-economic criteria.

- Positive plant experience with rubber lined piping and existence of nearly complete modification change packages and procurement efforts to install rubber-lined piping in some areas of the plant.

- Uncertainty in accurate failure data based on the small failure data base

- Uncertainty associated with extending plant life

- Positive plant experience with titanium in other applications

Based on these considerations, for the above ground piping the decision was ultimately made to continue the replacement efforts with rubber lined piping in all but one area where space and radiation concerns made the potential of a second replacement cycle undesirable. Therefore, at this location titanium piping will be used.

No matter which material is selected, chemical treatment is required to prevent biofouling in the Saltwater Service System.

Underground Salt Water Piping - The inspections and service experience with the above ground, concrete lined piping, led to the concern regarding the condition of the underground piping which was concrete lined ductile iron pipe. The underground piping was routed beneath existing structures which made its inspection, repair, and replacement extremely difficult and costly. The piping was to be inspected during an outage following the completion of the LCM studies. The following technical solutions were identified for resolving the potential degradation of the underground piping and the implementation of which were dependant on the results of the piping inspection.

- Installation of a new closed loop system independent of bay water. (Note: the brainstorming cost and

  O&M estimates eliminated this option from consideration during the detailed cost benefit analysis based on its initial high capital cost and the large O&M exposure due to the addition of cooling towers and additional safety related equipment.)

- Replacement of under-ground piping with above ground piping routed through existing structures.

- Replacement of the underground piping with a superior design

- Repair of the piping in place. This option was only feasible if the future piping inspection showed that the base piping material was in "good" condition.

- Coating of the existing piping with a corrosion resistant lining such as slip lining/inversion techniques (InSitu Form). As in the repair option noted above, this option was only technical possible based on limited piping corrosion.

The pipe replacement options for the underground piping are presented in Table 3. The InSitu Form Lining has the lowest life cycle cost whether the 20-year remaining plant life or the 40-year plant life assumption is considered. The InSitu Form Lining option was only considered as a repair option and was therefore dependent on the structural integrity of the existing underground piping. Based on the results of the above ground piping cost benefit analysis, the conceptual design and the cost benefit analysis for the underground piping replacement options only considered the 6 percent molybdenum alloy piping. The 6 percent molybdenum and clad pipe are acceptable from a corrosion perspective to last through the additional 20-year license renewal period, but do not have the implicit corrosion margin of the titanium. From a technical standpoint, the underground piping should have the greatest margin against corrosion and other degradation modes. No matter which material is selected, chemical treatment is required to prevent biofouling in the Saltwater Service System.

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.

Service Water Heat Exchanger Replacement

The existing service water and to a lesser extent the component cooling water heat exchangers were highly susceptible to macro-fouling which limited heat transfer capability and required frequent cleaning. Because each system design included only two heat exchangers and both were needed to satisfy technical specification requirements, a single heat exchanger could not be removed for cleaning without entering a limiting condition of operation (LCO). Maintenance on the service water heat exchanger also impacted diesel generator availability. Heat exchanger shell and tube material selections were not ideal for the seawater application and tube replacements were required at approximately 10-year intervals. System portion isolation valves also were not ideal technical selections and were not adequate for complete component isolation.

The following technical solutions were identified for correcting this LCM concern.

- Continue to retube the existing heat exchanger at defined intervals. Replace the existing isolation valves with a better technical design and install dedicated isolation valves in lieu of relying on control valves for heat exchanger isolation.

- Replacement of the current heat exchangers with plate and frame heat exchangers (PFHX) constructed of a more corrosion resistant material. Depending on the available space constraints within the heat exchanger rooms consider the installation of a maintenance spare to alleviate LCOs.

The conceptual designs and cost-benefit analysis considered 6 percent molybdenum piping material because it proved to have had the lowest life cycle costs based on the cost-benefit analysis of the aboveground piping.

The LCM evaluation of the heat exchanger rooms needed to consider interesting and at times conflicting considerations. The LCM evaluation considered PFHX primarily because of the excellent heat transfer characteristics and the resulting compact size. The PFHX option is additionally preferable for long-term maintenance and availability because the reduced size of the PFHX allows the installation of a common swing maintenance spare, thus facilitating heat exchanger maintenance without impacting availability/LCOs. Both the heat exchanger rooms were affected by space constraints in terms of the installation requirements and space available for spare maintenance components. An additional advantage in terms of the physical modification effort was the ability to assemble the PFHX on site thereby reducing the rigging and installation and demolition efforts. The PFHX also had advantages relative to there ease of cleaning. Highly corrosion resistant materials could be selected thereby enhancing the expected trouble free life expectancy and reliability of this system portion.

As part of the cost benefit analysis it was determined that preliminary equipment layouts were required in order to substantiate the constructability and operability of the system. The preliminary layouts also formed the basis for detailed material takeoffs in order to have accurate cost inputs to the cost benefit computer model. The layouts also demonstrated that although the PFHXs were in themselves very compact compared to equivalent shell and tube heat exchangers, the installed system including the multiple heat exchangers, large quantity of connecting piping and valves (2 PFHX were required to replace each shell and tube design; in order to maintain PFHX fouling to a minimum recirculation piping and large in-line process strainers were required; each PFHX required two inlet and two outlet pipes) increases the required space envelope substantially. The extent of the new components (all new piping, PFHX, valves, and strainers) had a large impact on the initial capital cost and the annual operating and maintenance costs.

The heat exchanger replacement options for the 40 years of remaining life case for are presented in Table 4. The results indicate that retaining the existing heat exchangers had the lowest life cycle cost. The PVRR life cycle cost was lower than the PFHX option. Retaining the existing heat exchangers (Option 1) has a "best estimate" present day capital cost of $9,490,950. Option 2 has a "best estimate" cost of $33,068,250. The large difference in life cycle cost was mainly because of the large capital investment of the PFHX and related strainers and piping. O&M expenses contribute relatively little to total PVRR in this analysis, and such expenses are similar for both options.

The results of the RAM analysis of the Saltwater System determined that the replacement of the existing piping and heat exchangers (including the maintenance spare) would increase the probability that the system would be operational from 90.23 percent to 99.34 percent which corresponds to approximately 33 days per year. This availability increase would indicate a large reduction in the LCOs caused by the Saltwater System. The majority of the availability increase arises from the installation of the PFHX. However, because the RAM analysis considers any failure as the loss of availability and the failure may not require a shutdown (exceed the 72-hour time limit for the LCO) the RAM results do not define a cost (penalty) to the cost-benefit analysis. Adding the PFHXs would be important with respect to limiting the entry into LCOs. Reducing the number of entries into LCOs by the Saltwater System also lowers the unavailability of the emergency diesel generators (EDGs) reported to INPO as a safety system performance indicator (SSPI).

While the cost-benefit analysis cannot justify the installation of the PFHX on cost, consideration of the impact of the modification on the number of LCOs generated could have had an effect. The utility however, did not find the decrease in LCOs and the increase in diesel generator availability was a factor which would offset the higher life cycle cost of the PFHX option.

In addition to retaining the existing heat exchangers it was recommended that an effective chemical treatment program be instituted to reduce the fouling potential. Coating of the intake structure to reduce the biofouling carryover into the system also would improve the availability and heat transfer margin thus reducing maintenance costs and the potential unavailability concerns. These as well as the results of the cost benefit program assisted the utility in the determination of the most cost effective and technically acceptable methodology to correct age degradation issues.

CONCLUSION

As can be seen from the case studies, a LCM program needs to address and integrate, in the decision process, technical, political, licensing, remaining plant life, component replacement cycles, and financial issues. As part of the LCM evaluations, existing plant programs, ongoing replacement projects, short and long-term operation and maintenance issues, and life extension strategies must be considered. The development of the LCM evaluations and the cost benefit analysis identifies critical technical and life cycle cost parameters. These "discoveries" result from the detailed and effective use of a consistent, quantifiable, and well documented methodology. The systematic development and implementation of a plant-wide LCM program provides for an integrated and structured process that leads to the most practical and effective recommendations. Through the implementation of these recommendations and cost effective decisions, the overall power production costs can be controlled and ultimately lowered.

REFERENCE:

1) "Evaluation of Systems, Structures and Components for Life Cycle Management," Hanley, N. E.; Woods, P. B.; and Banerjee, A.K., Stone & Webster Engineering Corporation and Perrin, J. S. and Marian, F. A., Public Service Electric & Gas Company of New Jersey. Presented at American Nuclear Society Annual Meeting, Boston, Massachusetts, June 1992.

Operations and Maintenance Costs for U.S. Nuclear Plants

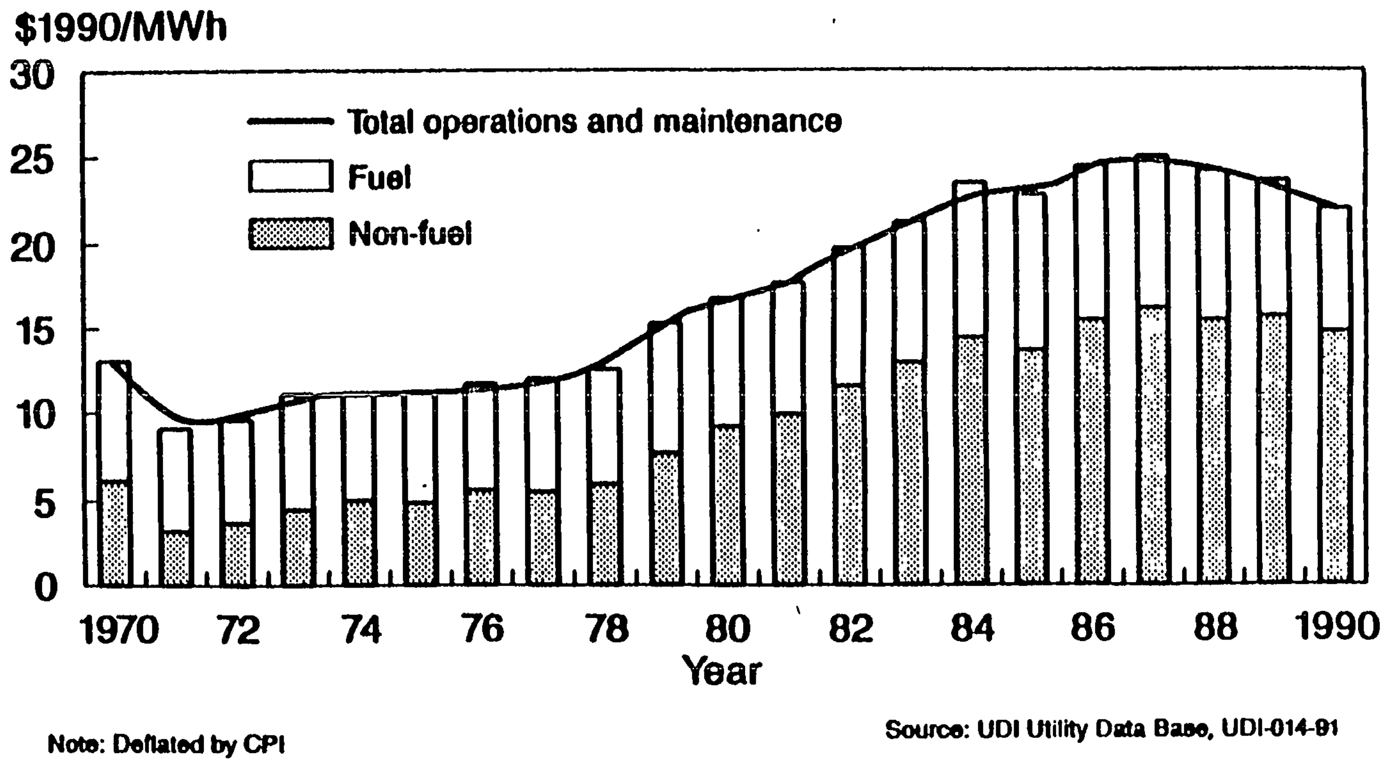
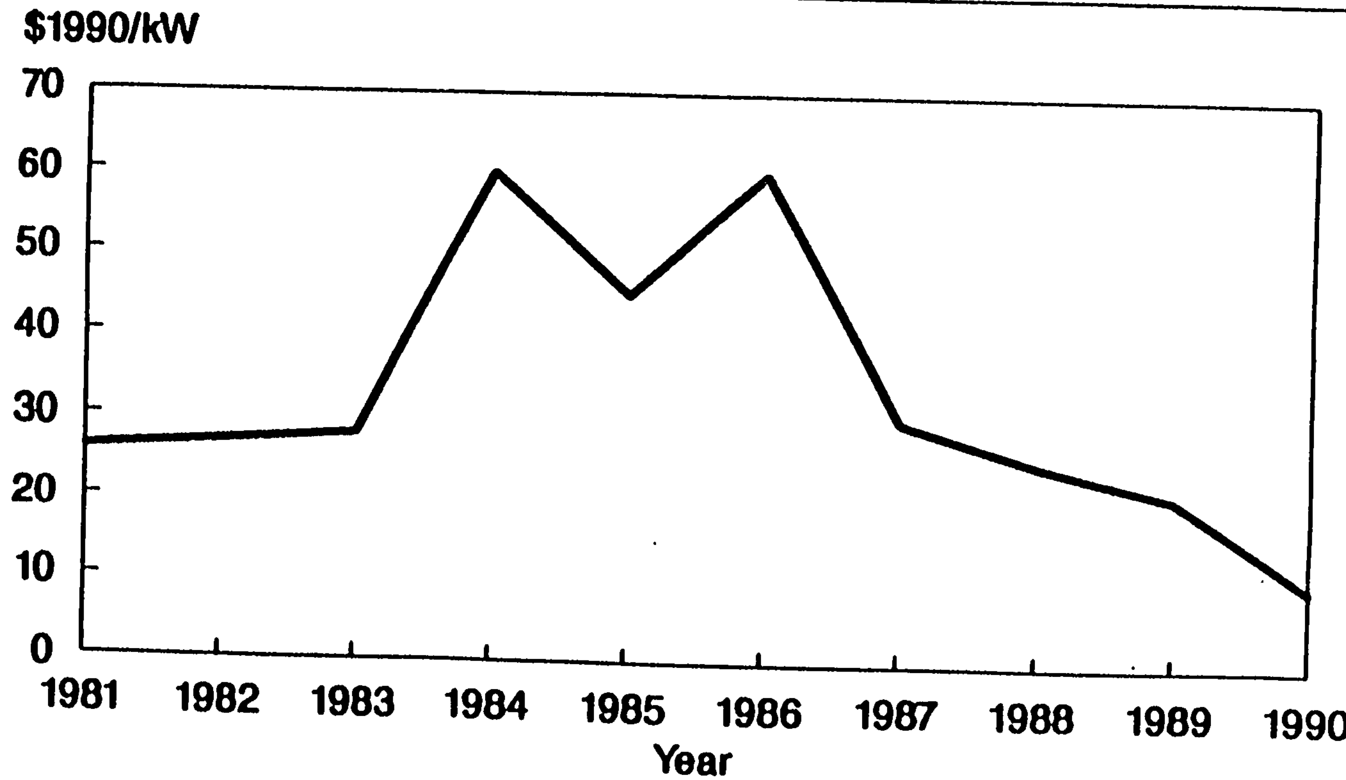


FIGURE 1

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

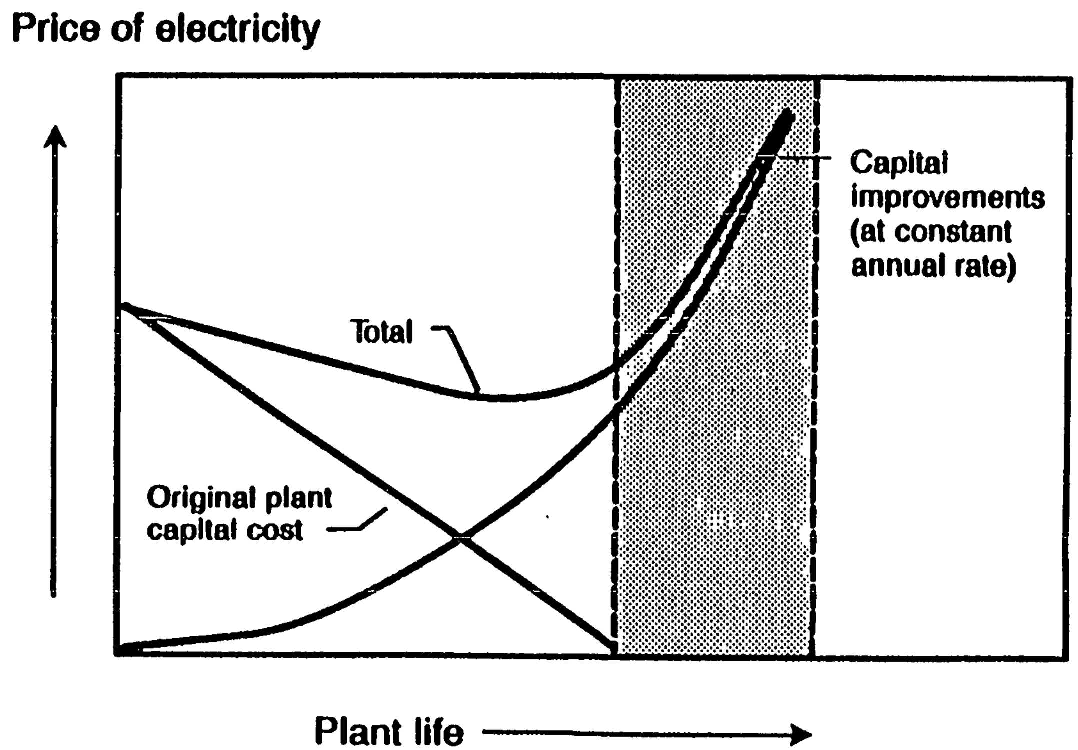


FIGURE 3

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■ nA66.134

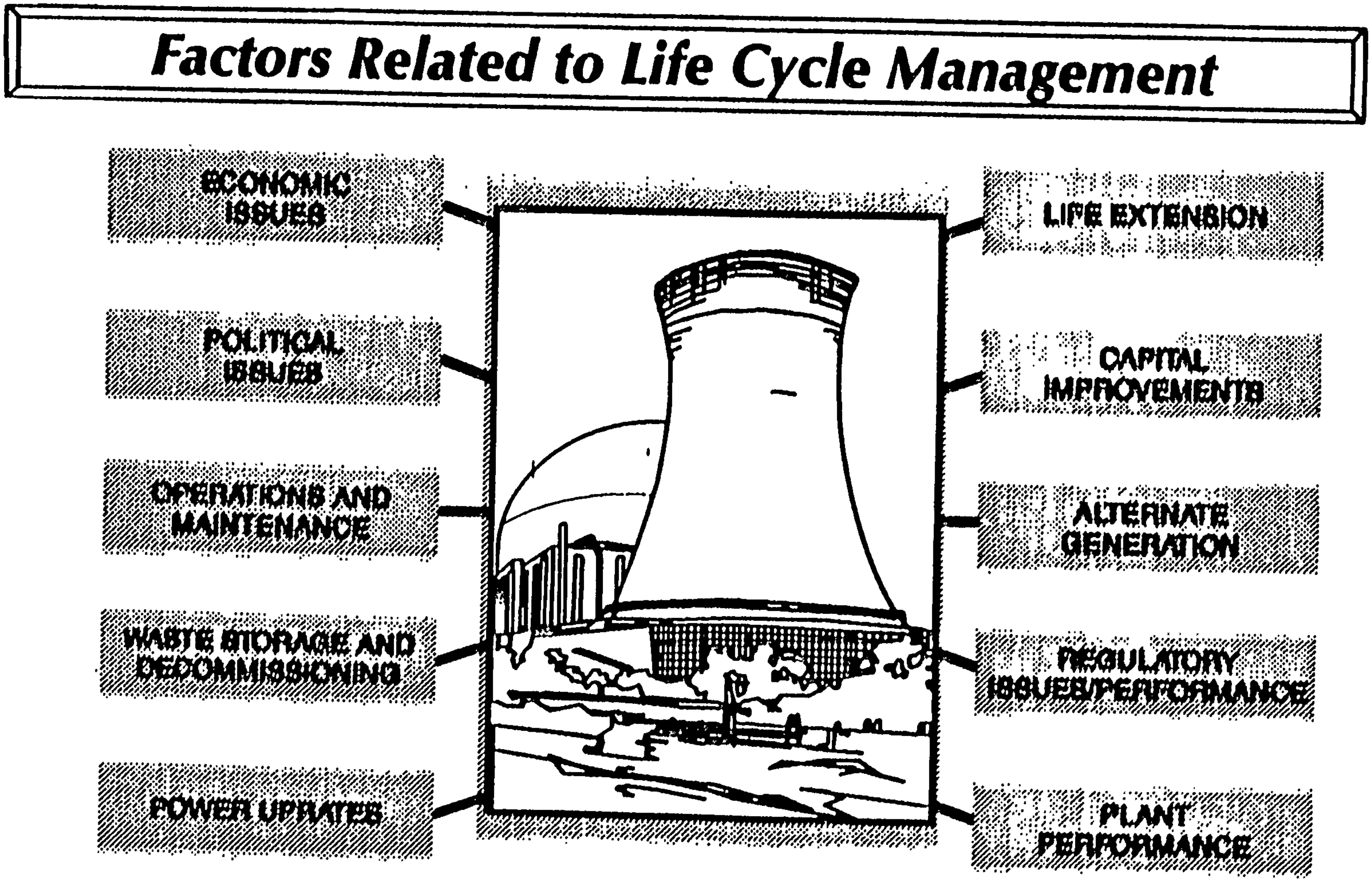
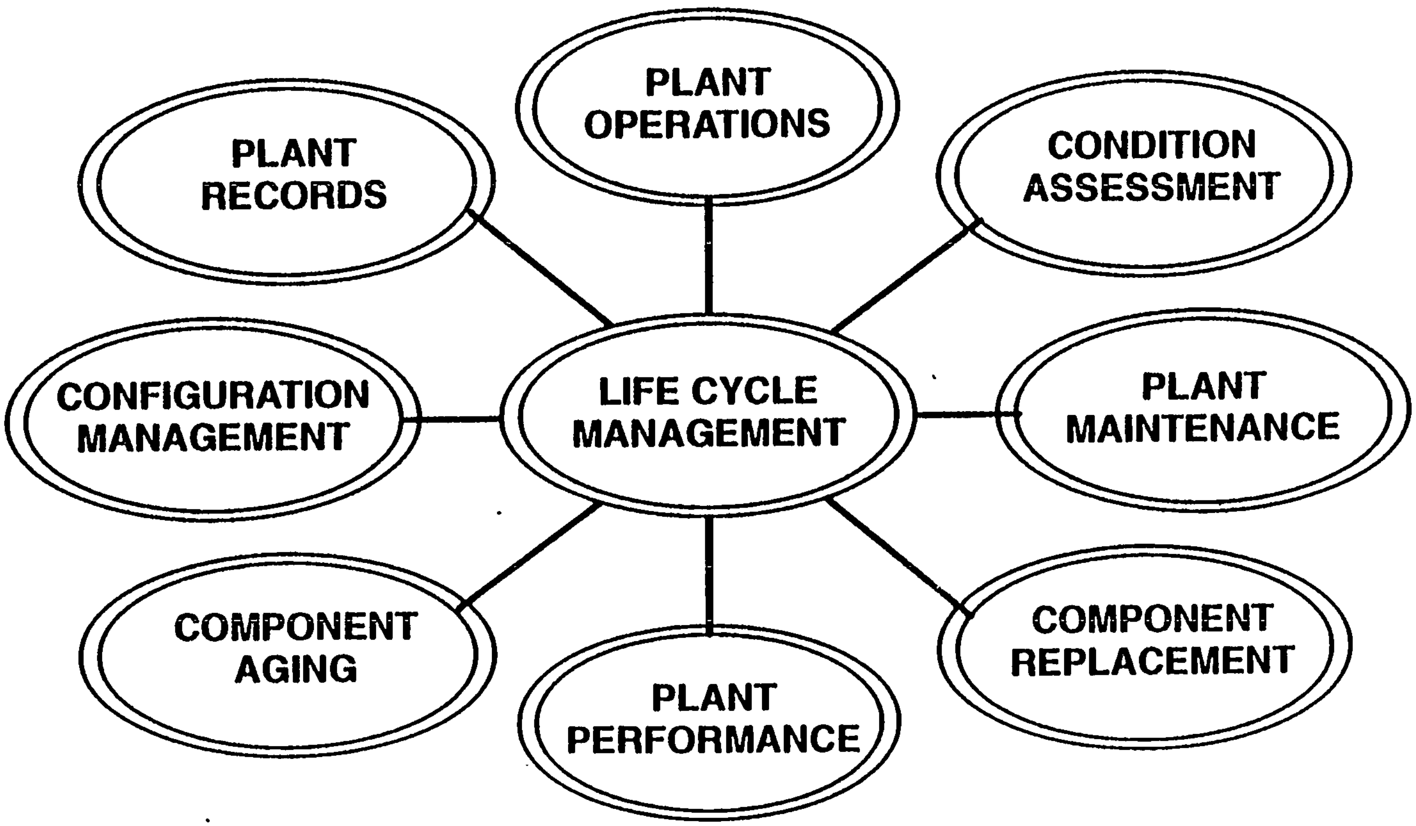

Factors Related to Life Cycle Management
ECONOMIC ISSUES
POLITICAL ISSUES
OPERATIONS AND MAINTENANCE
WASTE STORAGE AND DECOMMISSIONING
POWER UPRATES
LIFE EXTENSION
CAPITAL IMPROVEMENTS
ALTERNATE GENERATION
REGULATORY ISSUES/PERFORMANCE
PLANT PERFORMANCE

FIGURE 4

Life Cycle Management



0137 bep
5

FIGURE 5

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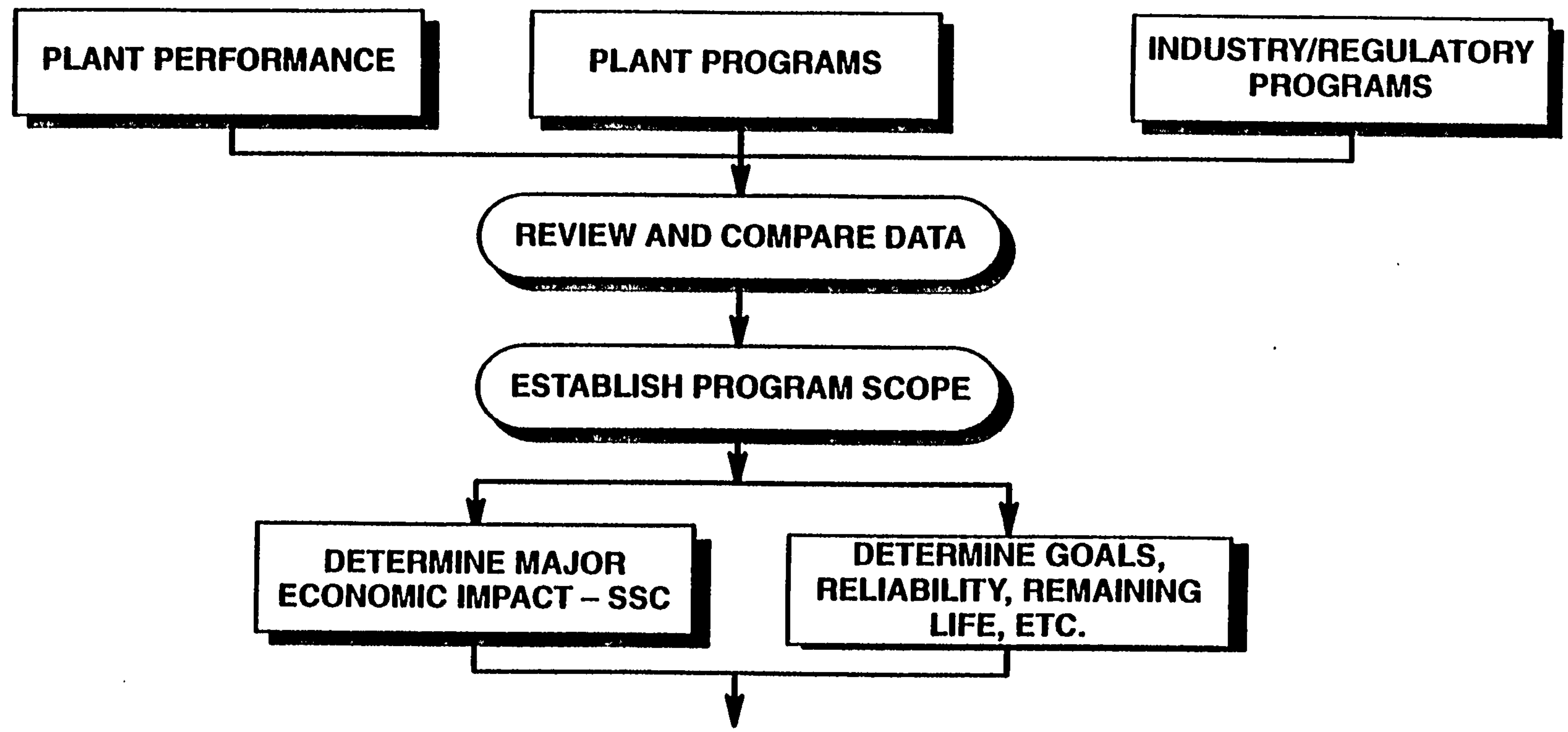
LCM Methodology – Phase I



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

0137lep
6

FIGURE 6

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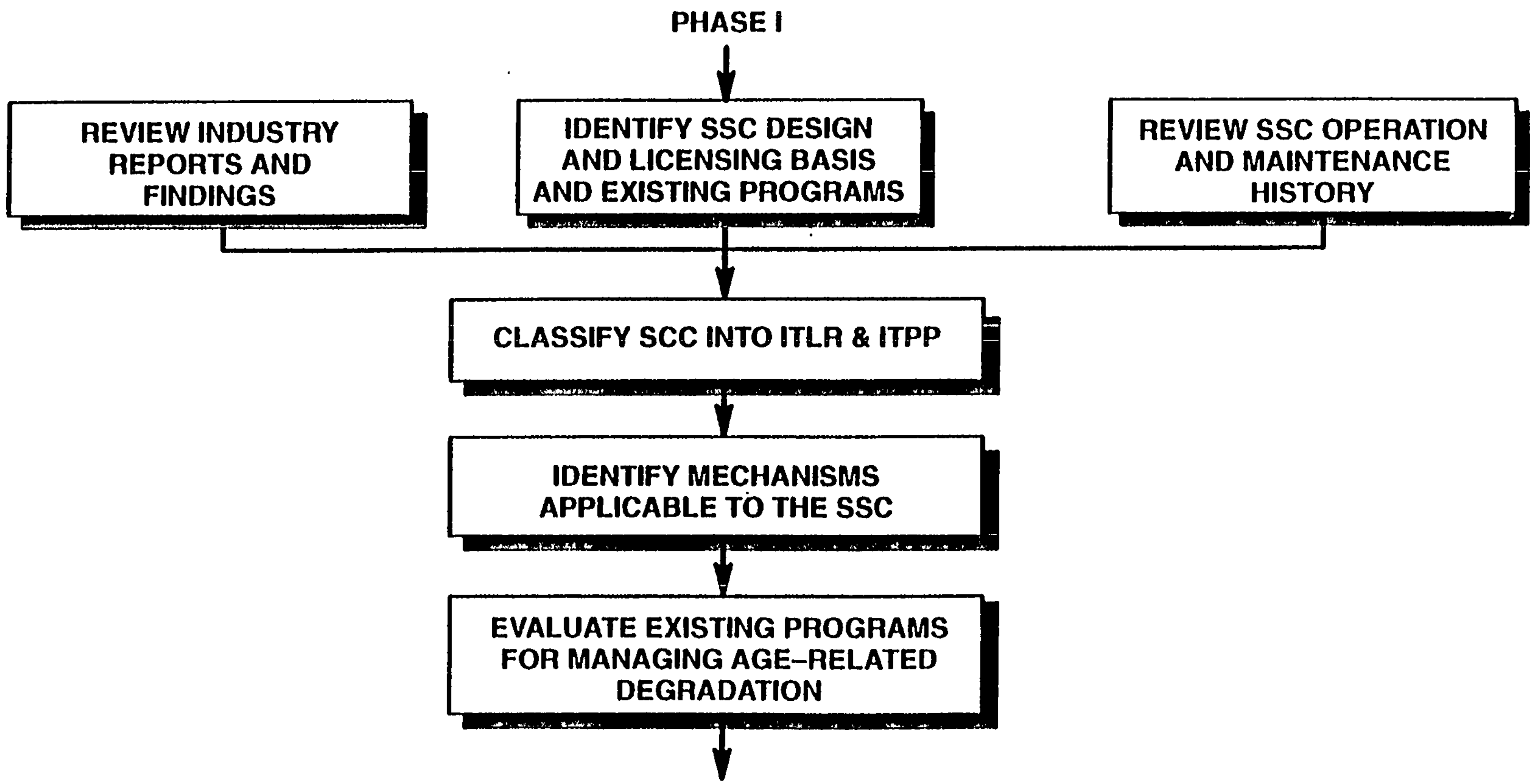
LCM Methodology – Phase II

Integrated Plant Assessment



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

0137 bcp
7

FIGURE 7

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LCM Methodology – Phase III

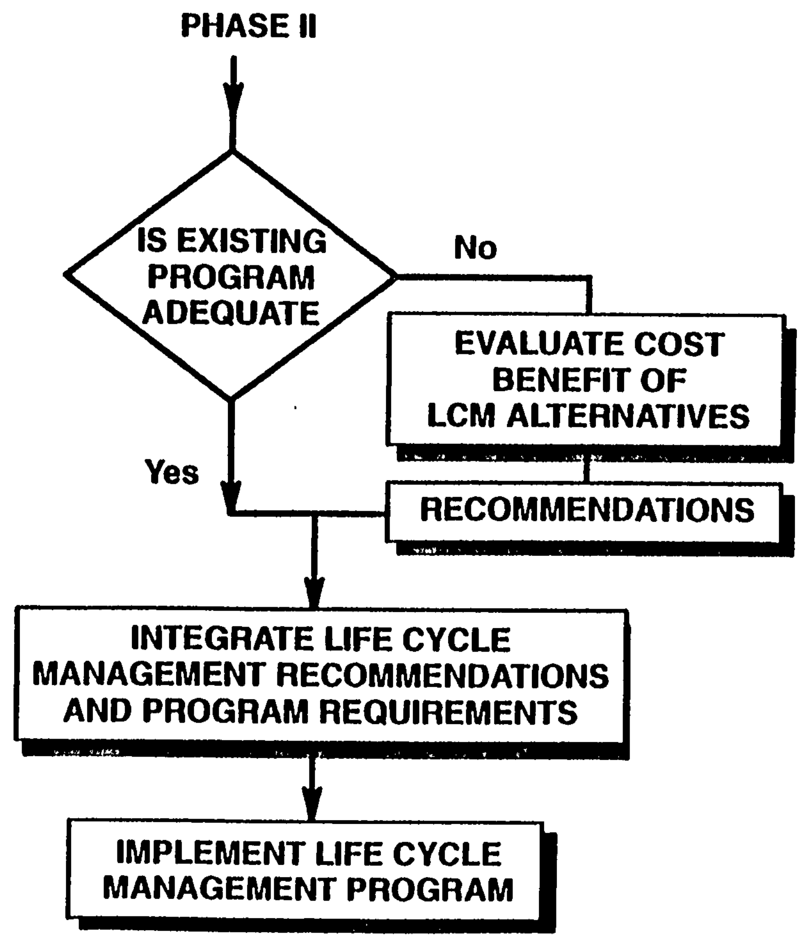

FIGURE 8

Table 1

LCM Sample SSC List

LIST OF COMPONENTS	POTENTIAL DEGRADATION MECHANISMS			LCM 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

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9

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Table 2

Aboveground Piping
(40 Year Remaining Plant Life)

Option 1A: Replace existing piping with Rubber–Lined Carbon Steel Spools (Assume 15 year life)

Option 1B: Replace existing piping with Rubber–Lined Carbon Steel Spools (Assume 20.5 year life)

Options 2A & B: Replace existing piping with 6 percent Moly stainless steel

Options 3A & B: Replace existing piping with nickel alloy clad carbon steel

	Option 1A (15 year pipe replacement)	Option 2A	Option 3B	Option 1B (20.5 year pipe replacement)	Option 2B	Option 3B
Present–day capital cost	$7,599,200	$9,203,450	$9,252,900	$7,599,00	$9,203,000	$9,253,000
Best Estimate Differential total life cycle cost PVRR	Base	($3,594,000)	($3,534,000)	Base	($1,277,000)	($1,218,000)
Simulation Results Expected value Differential total life cycle cost PVRR	Base	($5,119,000)	($5,061,000)	Base	($3,224,000)	($3,163,000)

0137 bep
17

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Table 3

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 InSitu Form lining

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

(2) Cost estimate to test sensitivity of capital cost on total lifecycle PVRR; analysis considered higher than expected capital cost

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18

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Table 4

Plate and Frame Heat Exchanger

	Option 1 (Retain Hx/Modify Valving)	Option 2 (Replace with PFHX)
"Best Estimate"		
Base Scenario	Base	+ $27,504,000
No Renewal	Base	
Simulation Results		
Expected Value	Base	+ $27,776,000
Maximum	Base	+ $29,506,000
Minimum	Base	+ $26,006,000
Probability of Positive Differential	–	100%
Availability	90.23%	99.34% (33 additional days over option 1)

ADVANCED MAINTENANCE, INSPECTION & REPAIR TECHNOLOGY FOR NUCLEAR POWER PLANTS

Presented by ABB Combustion Engineering Nuclear Operations

Bruce M. Hinton

October 1994

ABB CE Nuclear Operations

ABB

AGENDA

- The ABB Group
  - ABB Nuclear Power
  - ABB Combustion Engineering Nuclear Operations
- Technology for:
  - Reactor Systems
  - Steam Generators
  - Balance of Plant
- Summary

ABB Group

- Business Segments
  - Power
  - Power T & D
  - Industrial & Building
  - Transportation
  - Financial Services
- 50 Business Areas
- 1300 Companies
- 206,000 Employees
- 140 Countries

- 1993 Financial Results
  - Orders = $29.4B
  - Revenue = $28.3B
  - Earnings = $1.19B
  - R&D = $2.27B

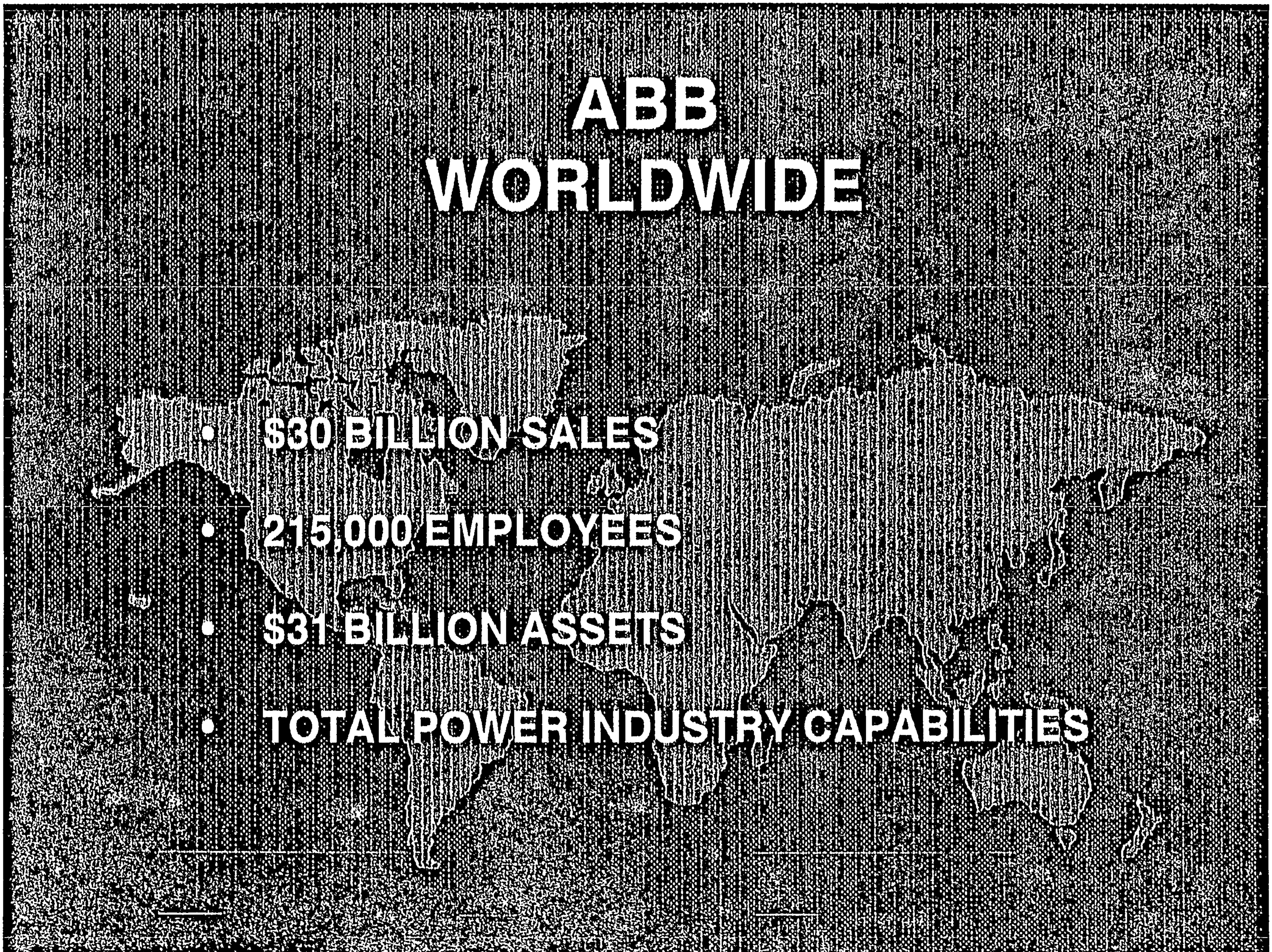


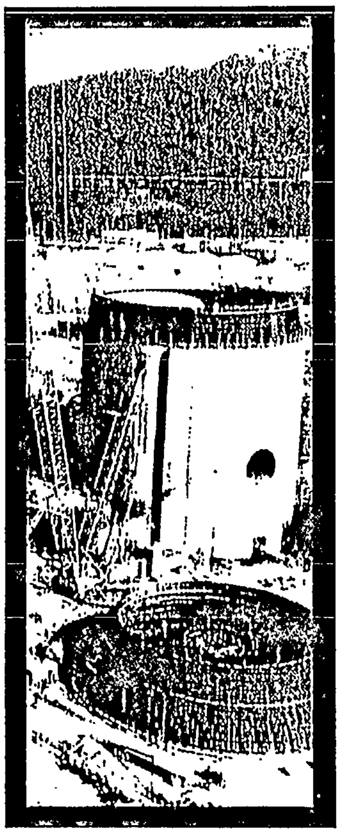
ABB
WORLDWIDE
• $30 BILLION SALES
• 215,000 EMPLOYEES
• $31 BILLION ASSETS
• TOTAL POWER INDUSTRY CAPABILITIES

Nuclear Power Products and Services

Nuclear Power

MMF 1103-1

ABB PWR's in Korea



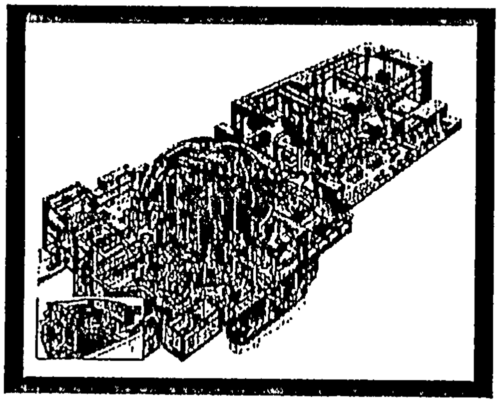
- Four 1000 MWe System 80 nuclear steam supply systems under construction commercial operation 1995-99
- Two more bid est. award 3rd quarter 1994
- Two more will be bid in 1995
- Transition to 1350 MWe units in 1998 (next-generation reactor based on System 80+)
- Full technology transfer and participation in next-generation reactor program are cornerstones

Nuclear Power

MMF 1103-12

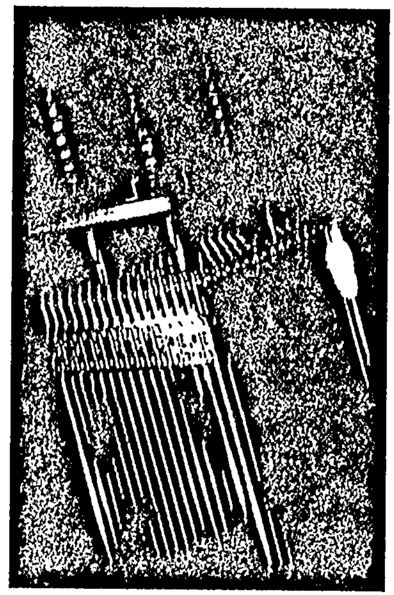
ABB

Product Lines

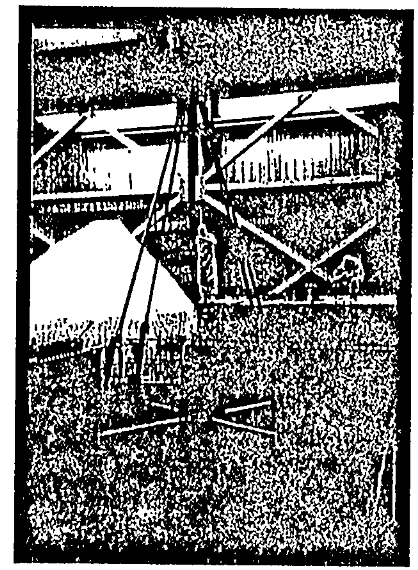


New Plants/
Systems

Fuel



Operating
Plant Services



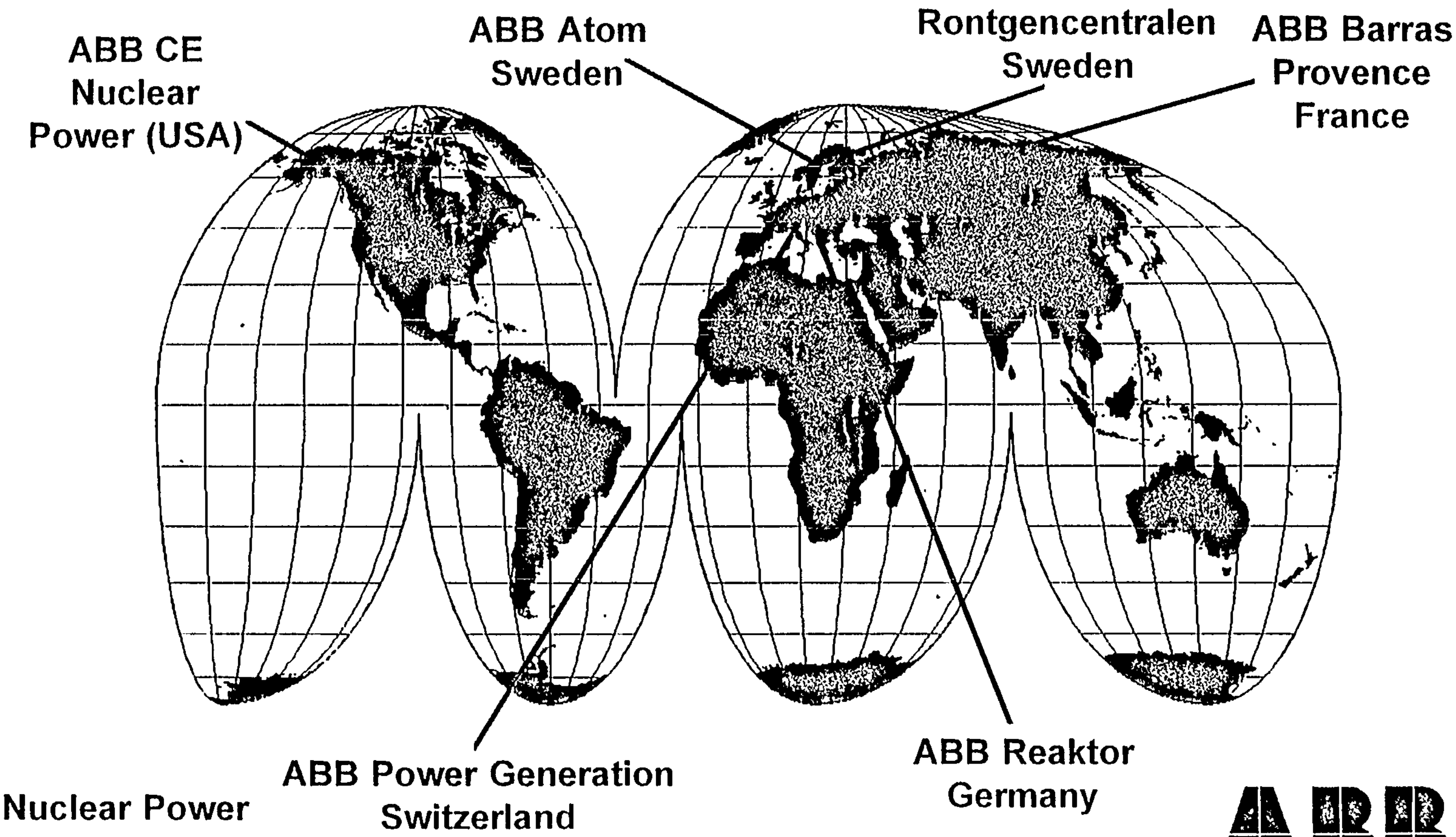
Nuclear Power

MMF 1103-2

ABB

ABB Nuclear BA Today

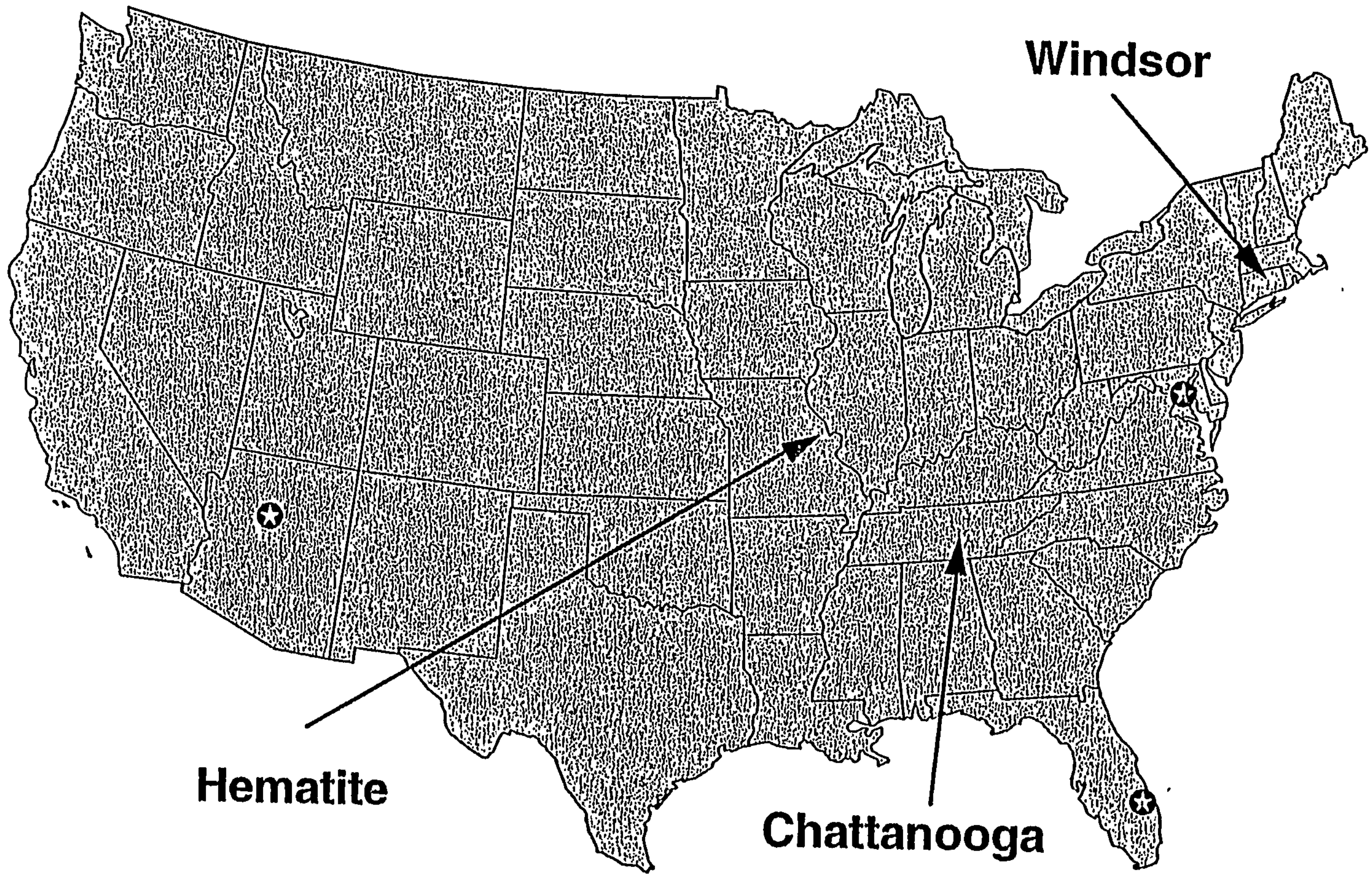
Significant Geographical Presence



Nuclear Power

MMF 1103-3

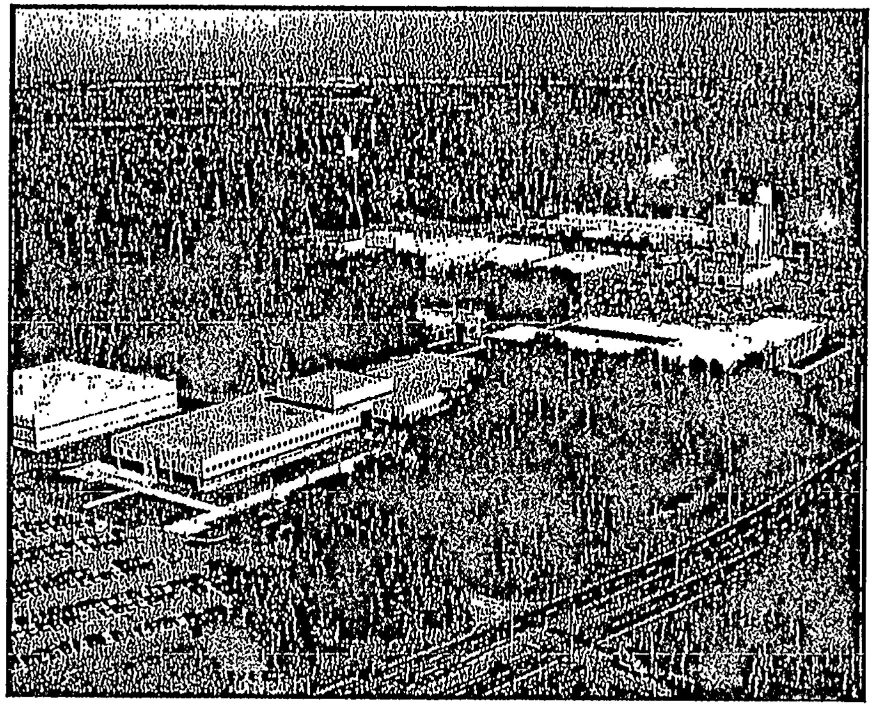
ABB CE Nuclear Operations - Major Facilities



✪ Engineering Site Offices

SRK2-10

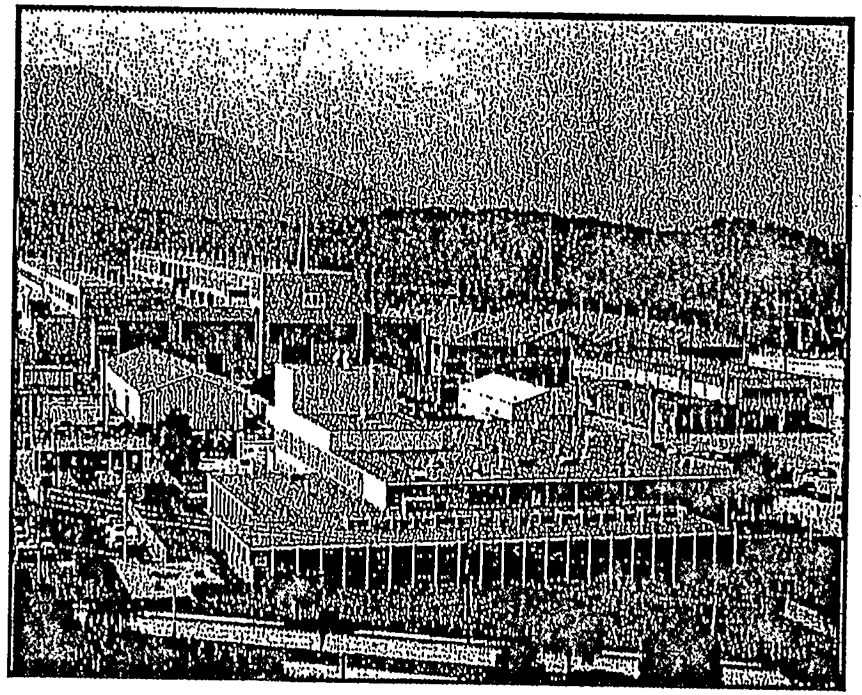
Windsor - Main Site



- 500 ABB CE Nuclear Operations employees
- Plant equipment; parts warehouse; engineering operations; technology development; test facilities; laboratories; field services' equipment repair and maintenance, decontamination; administration

SBK2-20

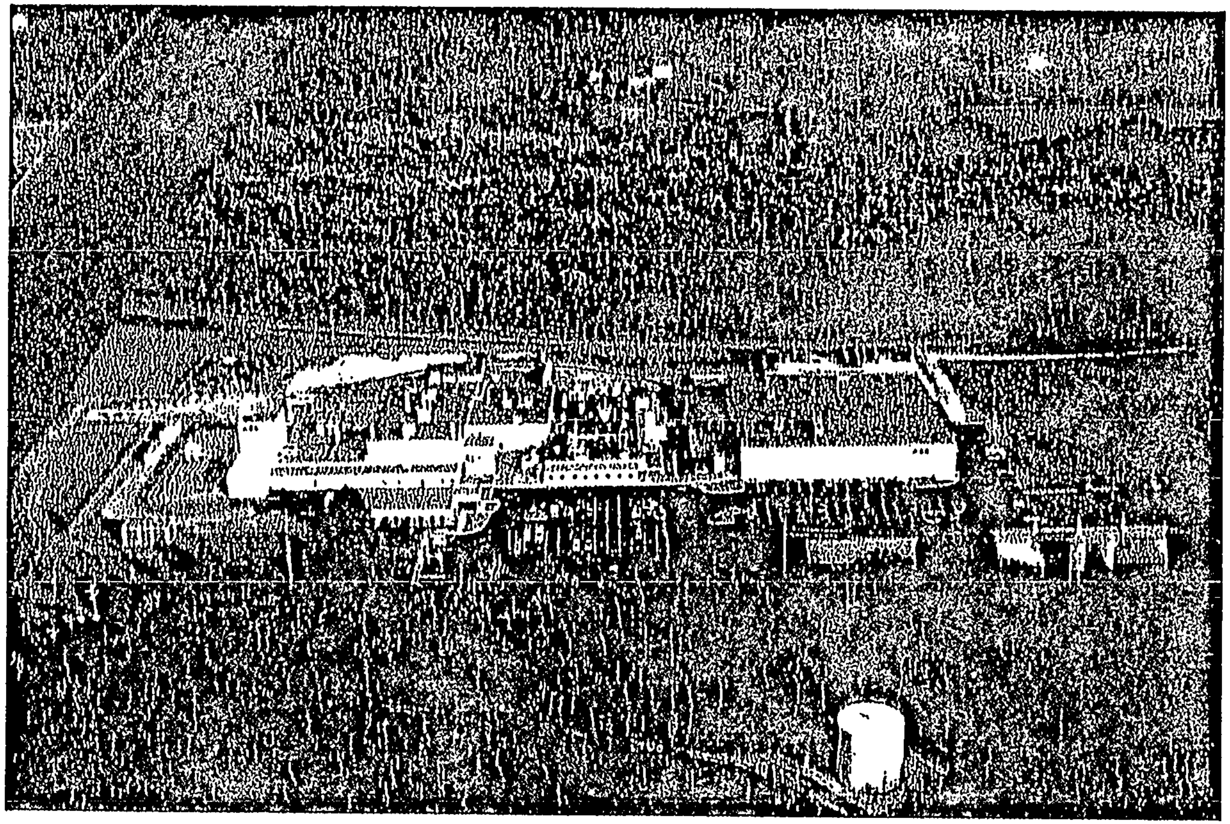
Chattanooga



- 100 employees
- Southeast Nuclear Service and Training Center:
  - Development, testing & qualification of personnel & equipment to perform maintenance, repairs and modifications at PWR and BWR plants
  - Invessel & undervessel mockups

SBK2-24

Hematite

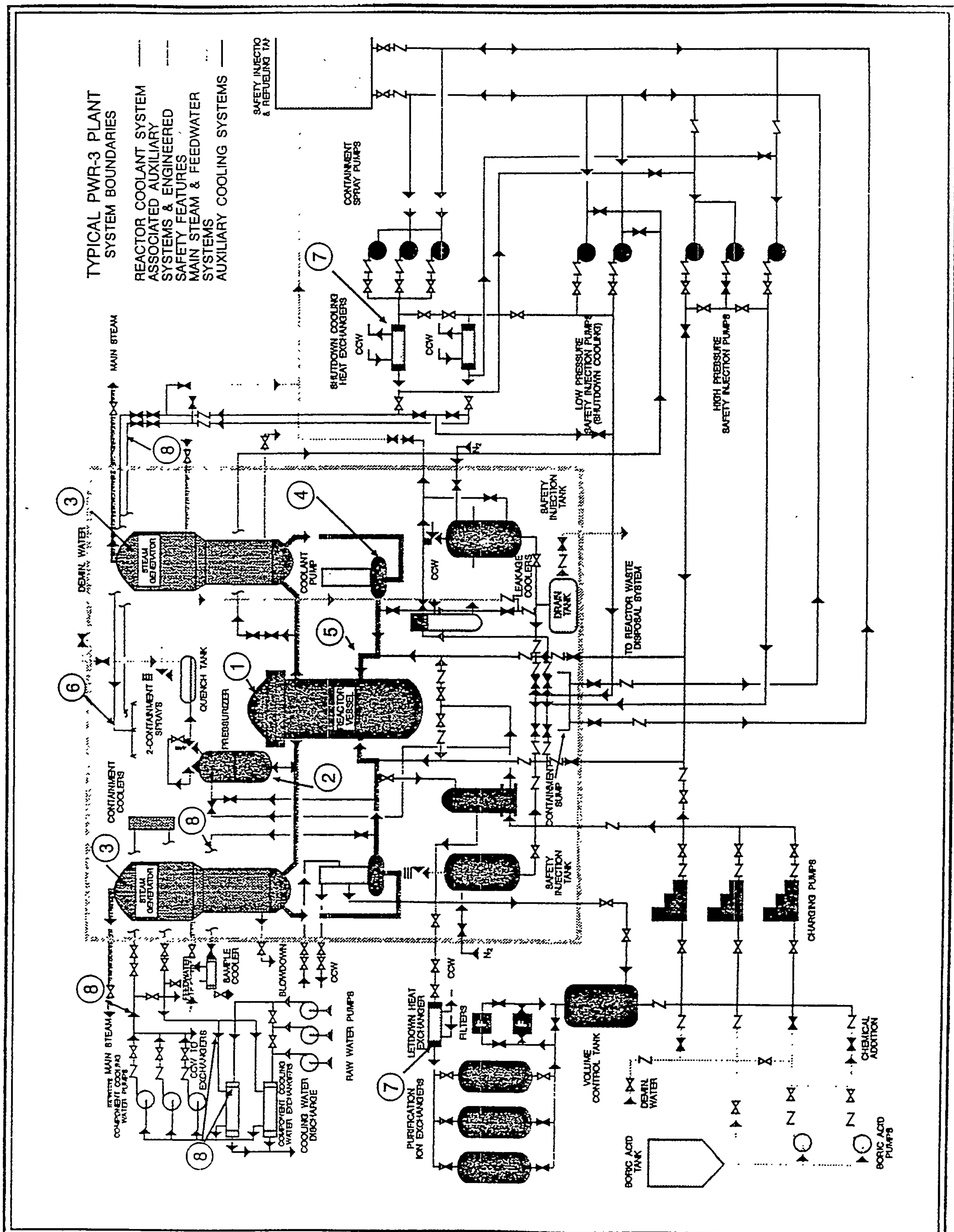


- 150 employees
- Conversion, pelletizing, fuel rod manufacture and fuel bundle assembly

SBK2-23

Technology for Reactor Systems

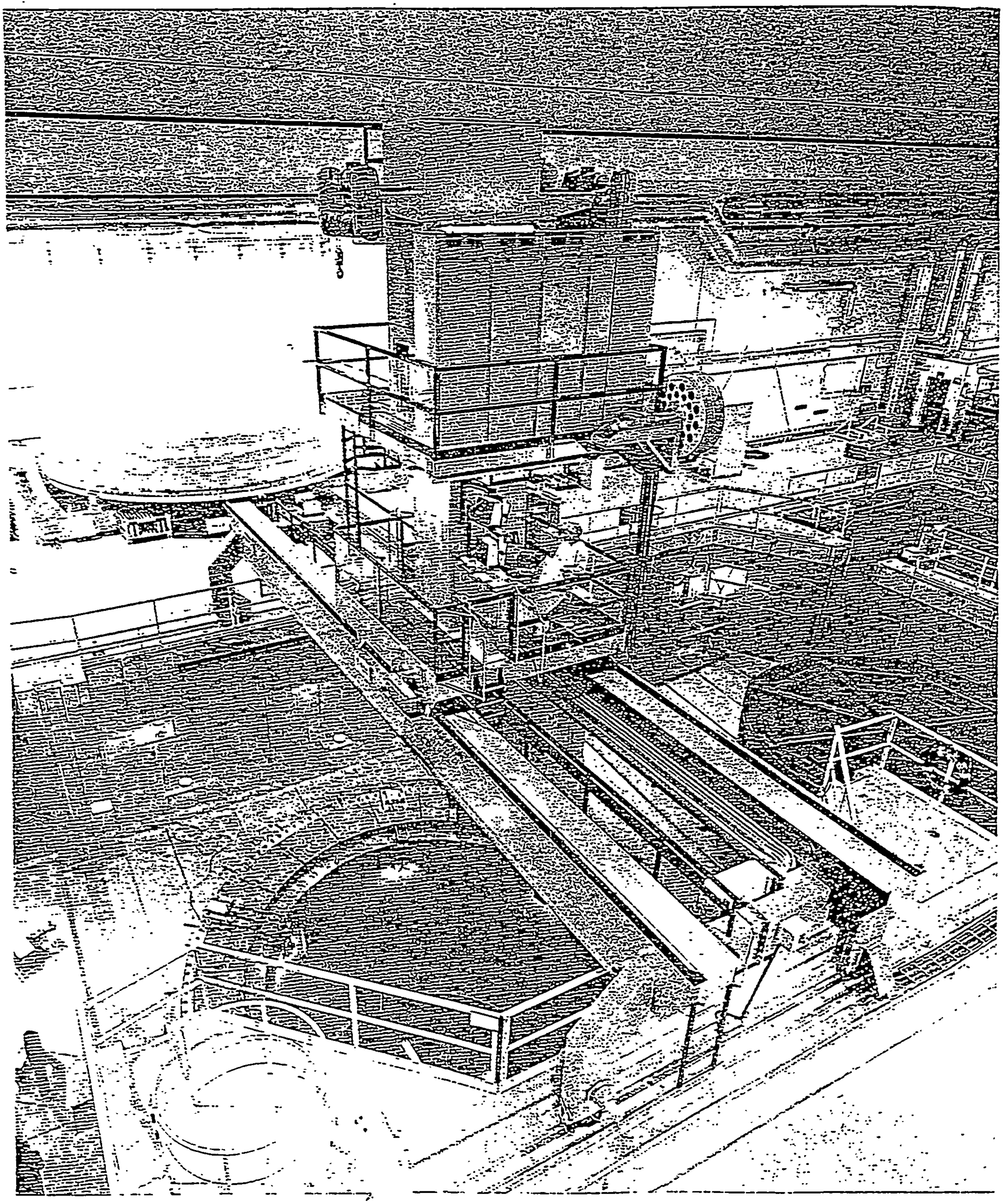
- Refueling Bridges
- Fuel Inspections
  - UT Inspections
  - In-mast Sipping
- Fuel Shuffling Software
- Fuel Reconstitution
- CEA/RCCA/CRA Inspection
- CRDM canopy seals
- Vessel/Head Inspections
  - CRDM Nozzle Inspection
- Reactor Internals Repair Problems
  - Fuel Alignment Pin Inspection & Replacement
  - Core Baffle Bolt Inspection & Replacement
- Stud Tensioning
- Stud/Nut Cleaning
- EDM Machining
- Mineral Insulated cable
- Core exit T/C assemblies


TYPICAL PWR-3 PLANT
SYSTEM BOUNDARIES
REACTOR COOLANT SYSTEM
ASSOCIATED AUXILIARY SYSTEMS & ENGINEERED SAFETY FEATURES
MAIN STEAM & FEEDWATER SYSTEMS
AUXILIARY COOLING SYSTEMS
SAFETY INJECTION & REFUELING TANK
CONTAINMENT SPRAY PUMPS
SHUTDOWN COOLING HEAT EXCHANGERS
CCW
LOW PRESSURE SAFETY INJECTION PUMPS (SHUTDOWN COOLING)
HIGH PRESSURE SAFETY INJECTION PUMPS
MAIN STEAM
DEMIN. WATER
STEAM GENERATOR
COOLANT PUMP
SAFETY INJECTION TANK
LEAKAGE COOLERS
DRAIN TANK
TO REACTOR WASTE DISPOSAL SYSTEM
2-CONTAINMENT SPRAYS
QUENCH TANK
PRESSURIZER
REACTOR VESSEL
CONTAINMENT COOLERS
CONTAINMENT SUMP
CHARGING PUMPS
FEEDWATER
SAMPLE COOLER
BLOWDOWN
RAW WATER PUMPS
COMPONENT COOLING WATER PUMPS
CCW TO EXCHANGERS
COMPONENT COOLING WATER EXCHANGERS
COOLING WATER DISCHARGE
LETDOWN HEAT EXCHANGER
FILTERS
PURIFICATION ION EXCHANGERS
VOLUME CONTROL TANK
CHEMICAL ADDITION
BORIC ACID TANK
BORIC ACID PUMPS
N_2
1
2
3
4
5
6
7
8

Reactor Refueling Bridge

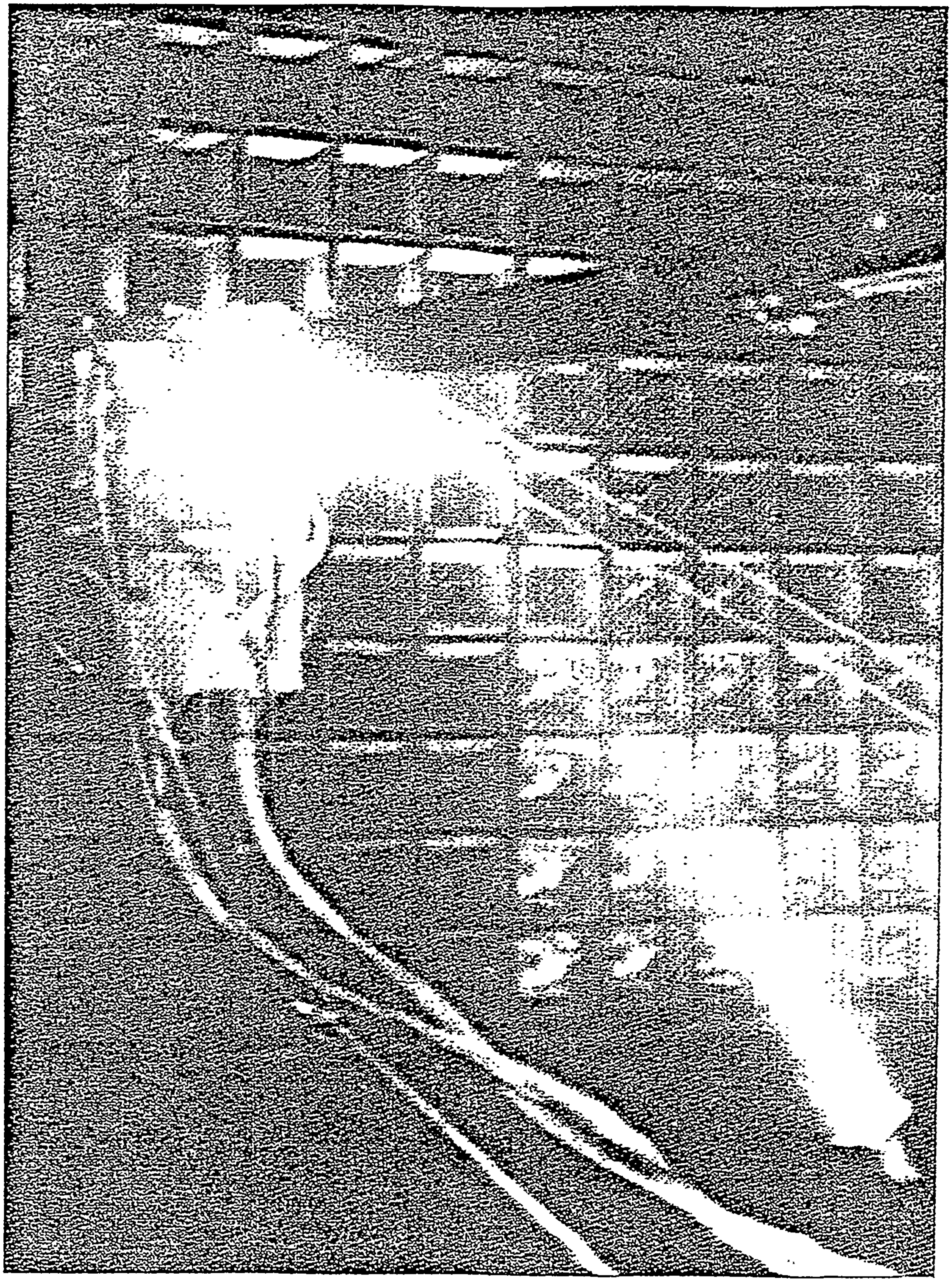
- Refueling Bridge reliability and ease of use directly affect influence outage critical path time
  - Average downtime over 16 outages is 2 hours & 11 minutes
  - Dual wheel drives; electronic control & alignment
  - Compatible with Computer-based fuel movement tools
  - User friendly control system

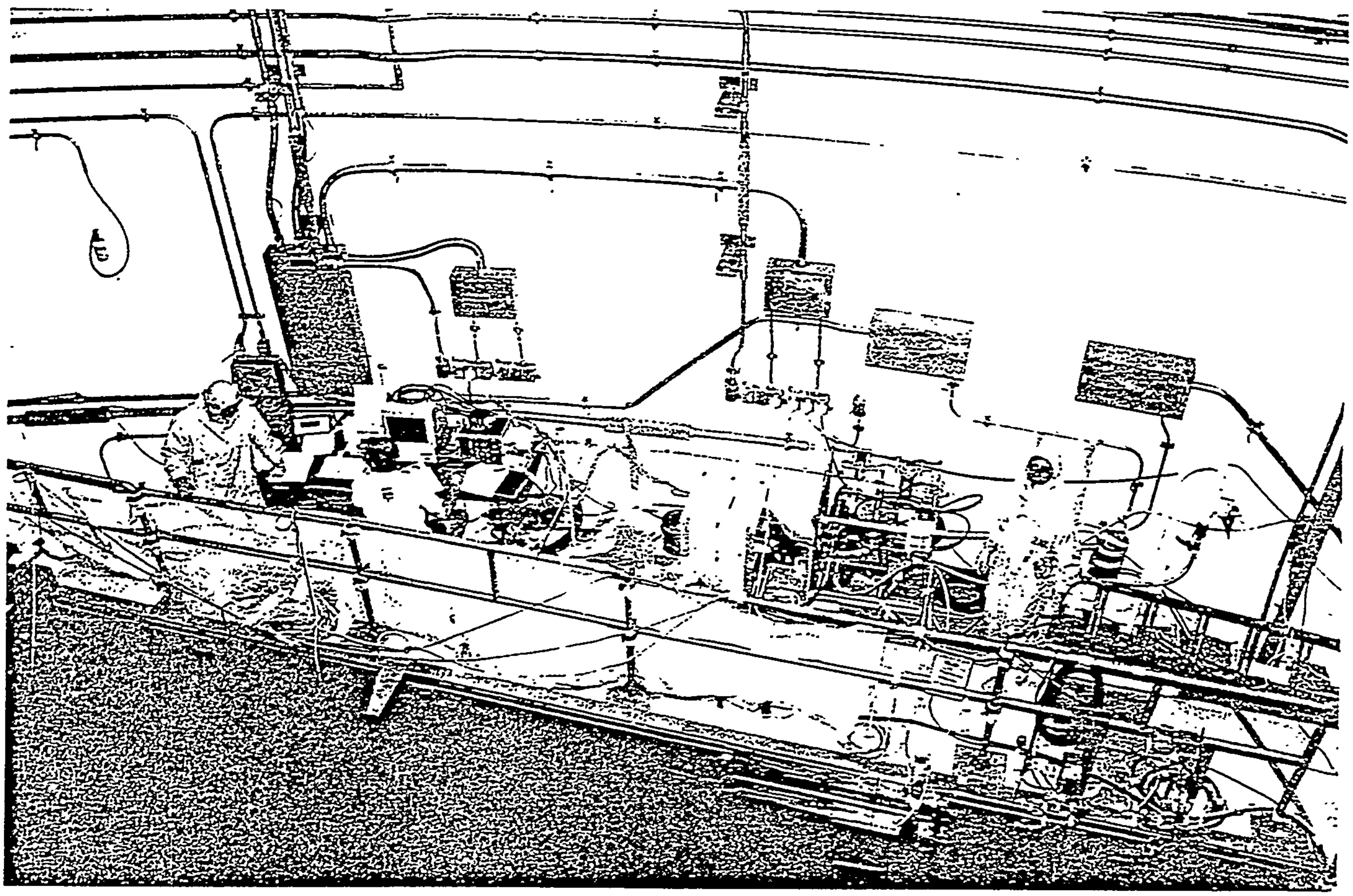
TYPICAL ABB REFUEL PLATFORM



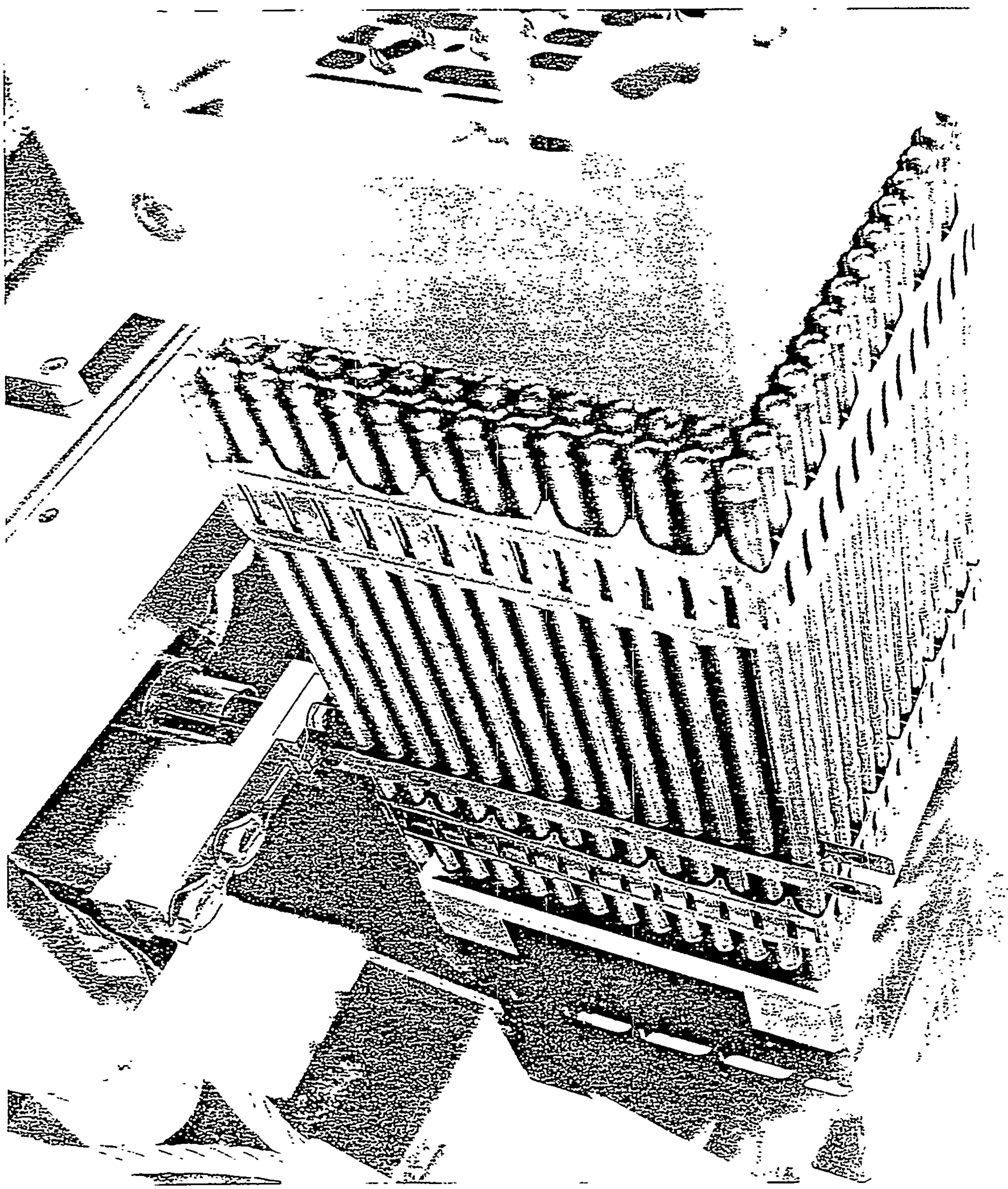
Fuel Inspection Systems

- In-Mast Fuel Sipping System
  - Identifies defective fuel bundles
  - Performed during fuel bundle movement
  - 3 minutes per bundle typical
- Failed Fuel Rod Detection system
  - Identifies defective fuel pins
  - Proven on all vendors PWR fuel
  - Quick, remote, accurate inspections
  - Does not require bundle disassembly





Failed Fuel Rod Detection System : FFRDS



Fuel Shuffling Software

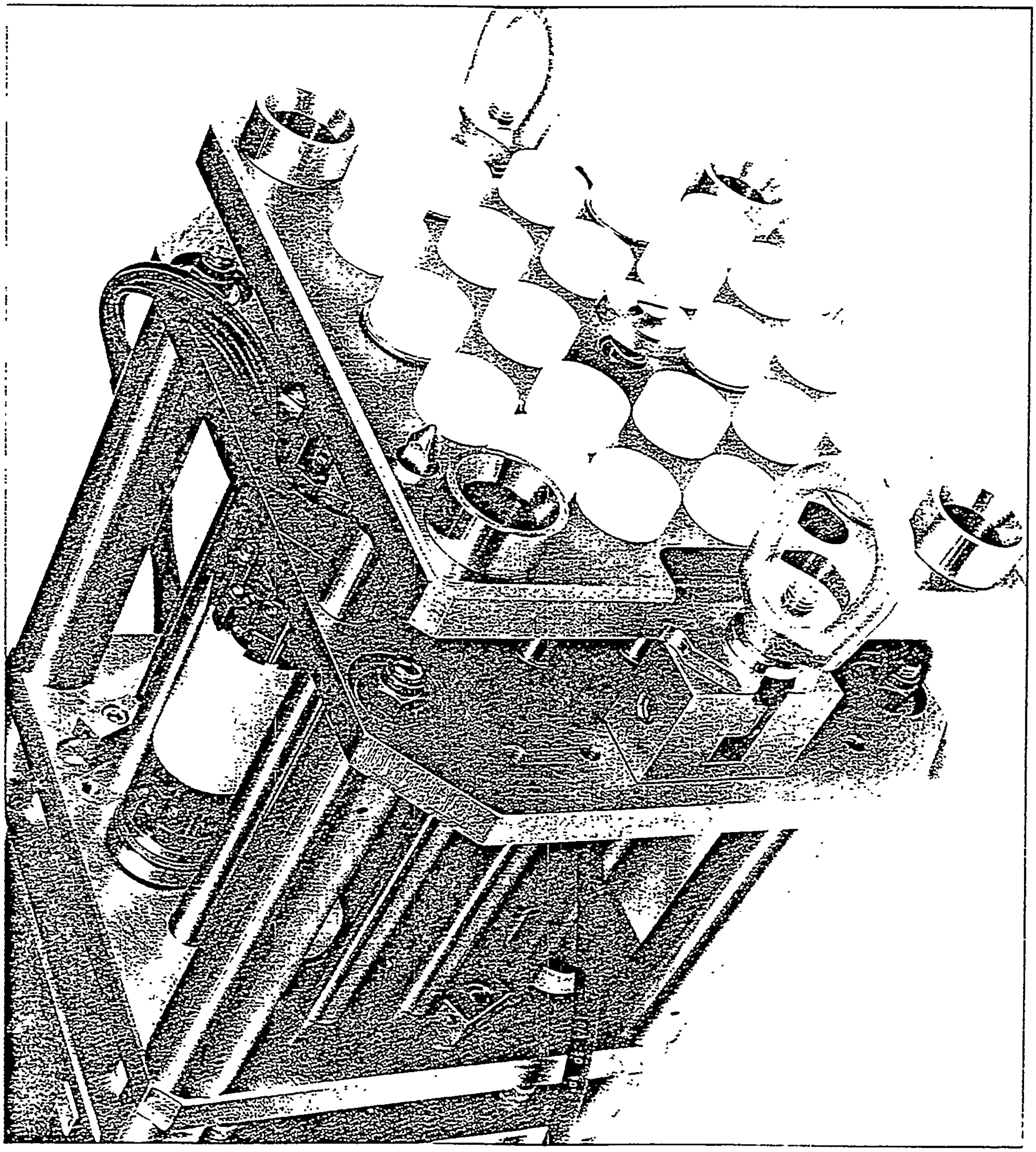
- Shuffleworks ™
  - PC-based Artificial Intelligence application
  - Automatic component movement sequence sheets
  - Ability to include plant specific requirements
  - Provides real-time status of fuel movements
  - Allows “what if” planning sessions
  - Excellent training tool
  - Improved record keeping

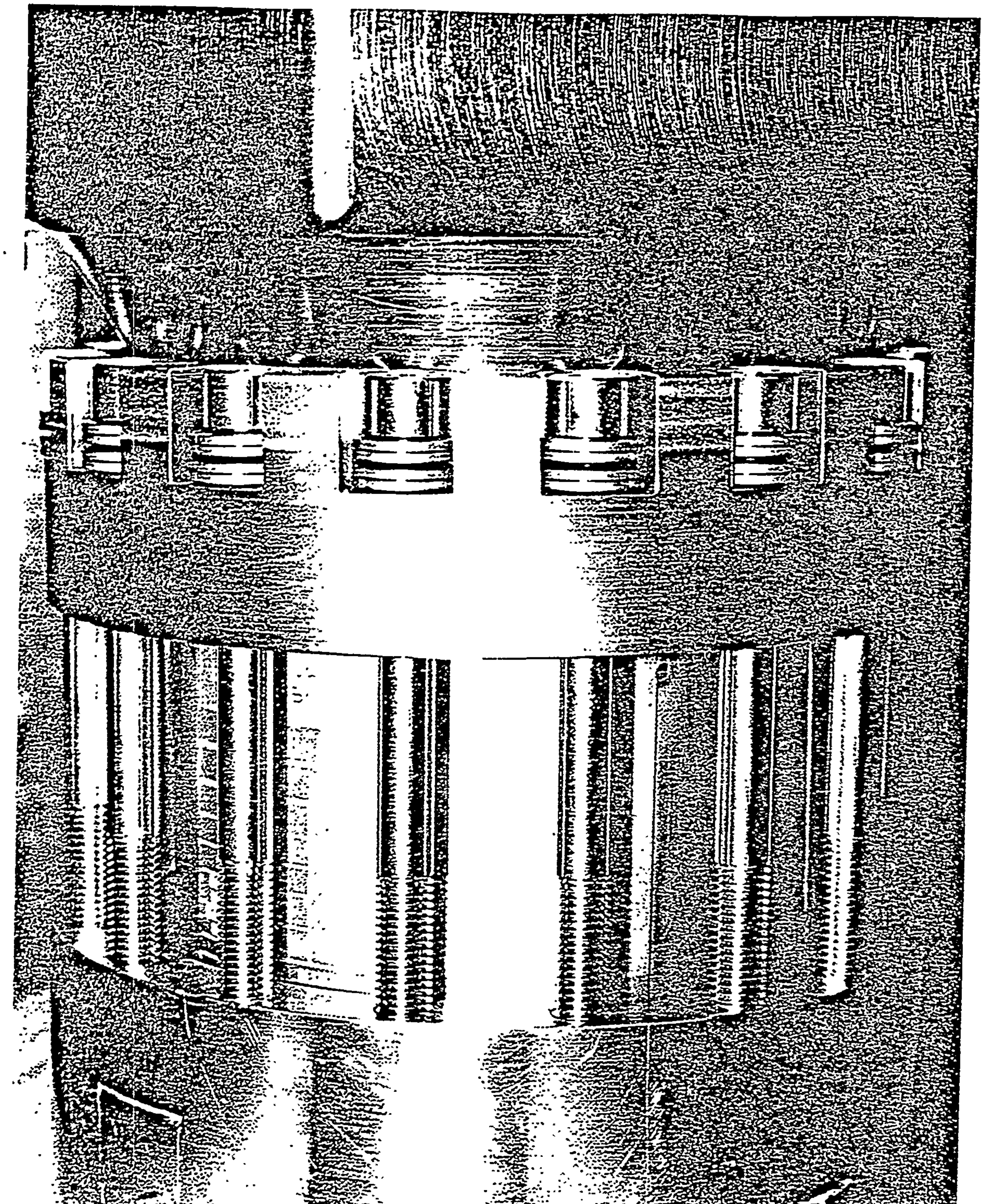
Fuel Reconstitution

- Reconstitution maitains a clean core and reduces fission products throughout the plant
- Prevents more serious problems
- Custom tooling adapted to plant specific conditions optimizes the process
- Lightwieght graphite tools
- Typical program - 12 days
  - Involves 5 assemblies
  - 5 - 10 failed fuel rods
  - 1 grid cage change

CEA/RCCA/CRA Inspection

- UT Axial Profilometry + Encircling Coil ECT
  - Detects wear, cracks and swelling
- Immediately available, highly accurate
- On-line monitoring of test variables
- No direct contact with rods; water coupling
- High speed data acquisition
- Maximizes control assembly life



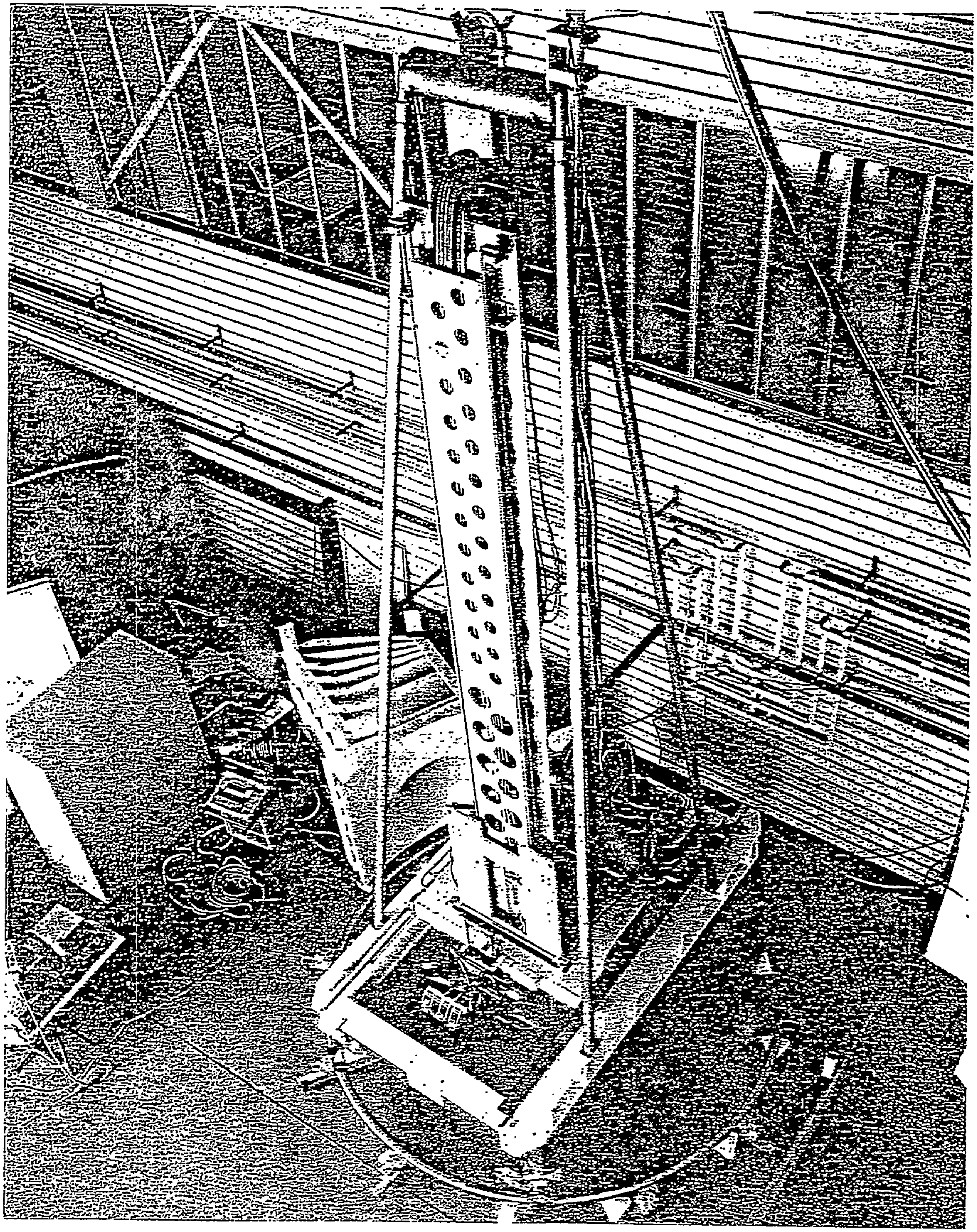


Vessel Inspection Capabilities

- Advanced underwater, robotic manipulators for both OD and ID inspections via EC, UT and visual methods
- Mast Manipulator System for PWR RV's
  - Rotation frame
  - Telescopic mast
- State-of-the-art data acquisition and flaw imaging systems

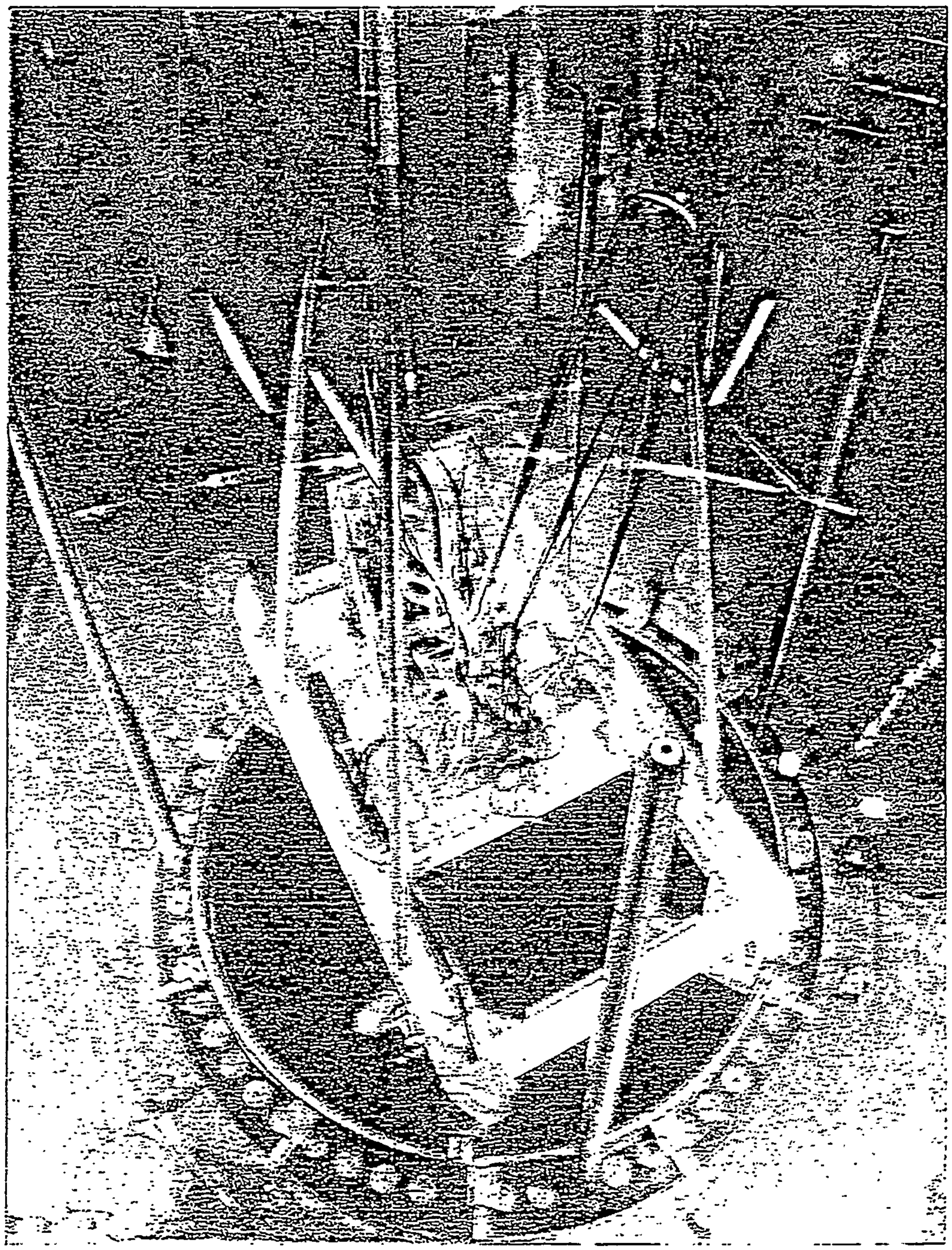
PWR MAST MANIPULATOR

Telescopic Mast on Rail Ring



PWR MAST MANIPULATOR

Manipulator and Ring Placed on Vessel Flange



CRDM Inspection and Repair

- Advanced Robotic Delivery System
  - Reduced ManRem (2-4 per 100% inspection)
- ECT Gap Scanner (Sleeve-housing area)
  - Successfully used on over 20 units
- MRPC, UT and Flourescent Methods
  - Confirms crack location, size and geometry
- Crack removal by both Grinding and EDM
- Qualified sleeve removal/replacement and crack removal techniques

Reactor Internals Repair technology

- Fuel Alignment Pin Problem
  - Rail-based manipulator with 4-axis control system
  - Custom-designed probes and TV camera control and monitor the progress from a pool-side workstation
  - Improved replacement pin design
- Core Baffle Bolting Problem
  - Rotating work platform; multiple manipulators
  - Self-aligning probe; 1mm flaw resolution
  - Repair system uses most inspection components

Fig. 2
View into the reactor pressure vessel with core barrel, lower grid plate and a fuel element dummy

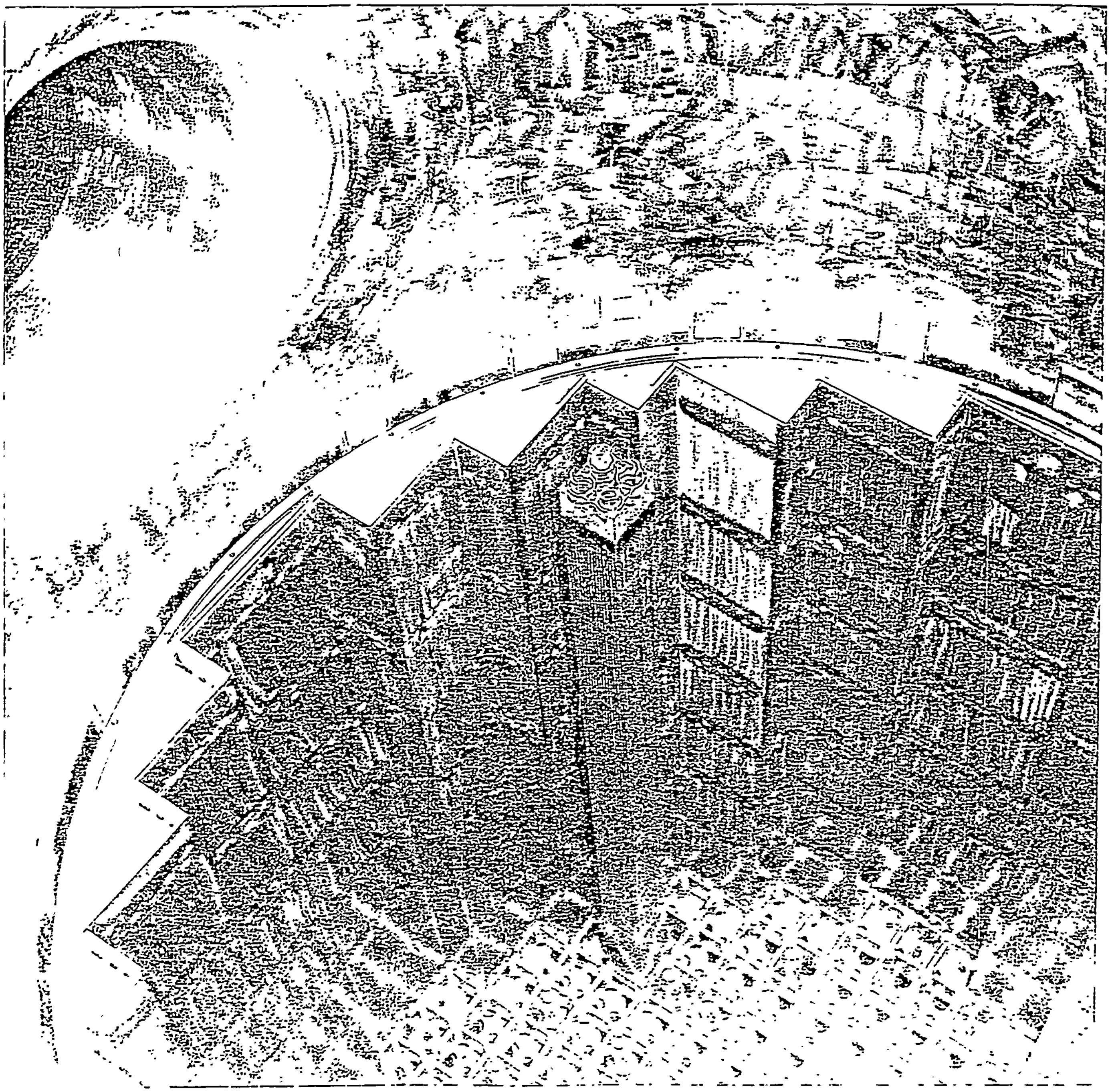
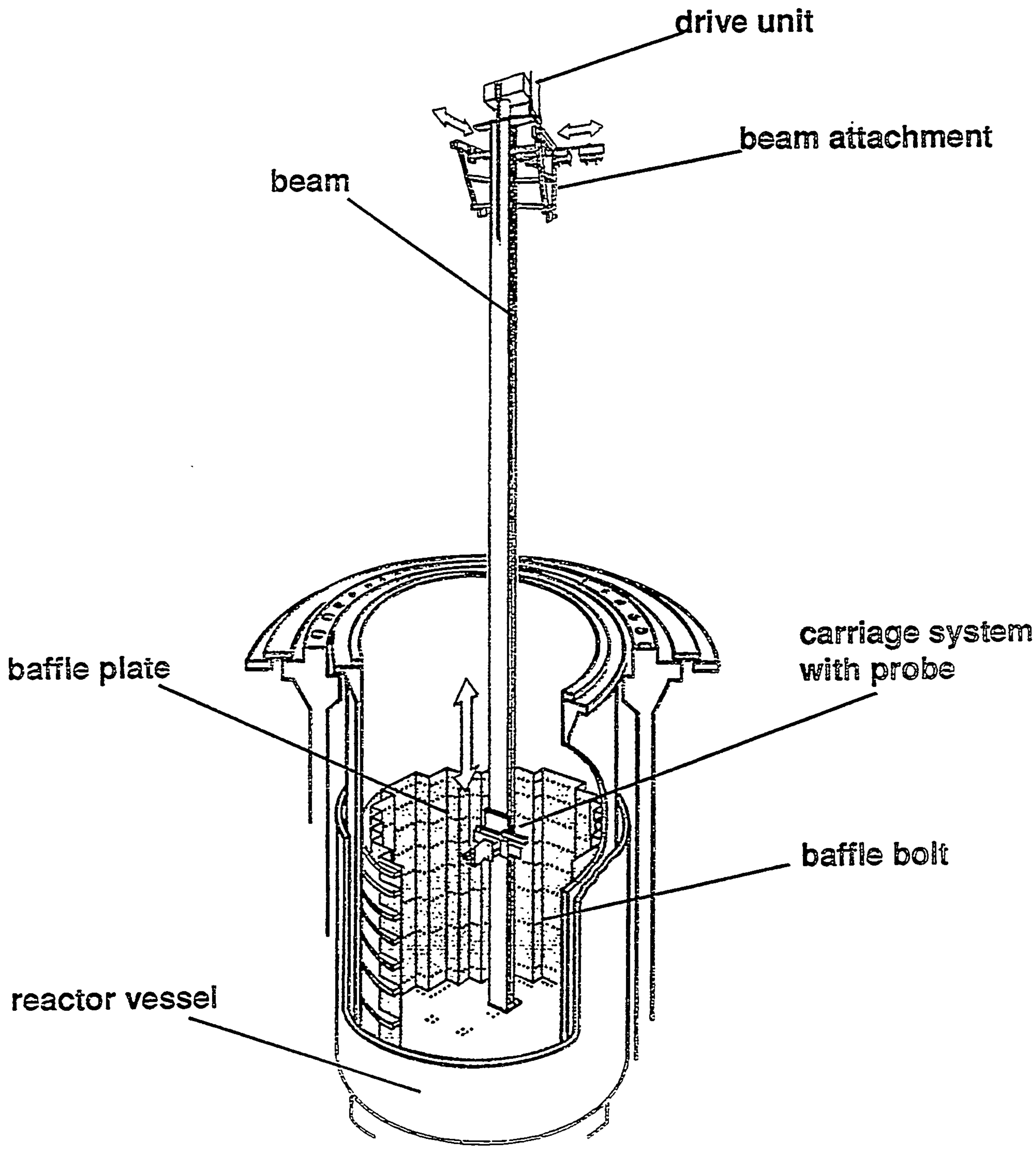
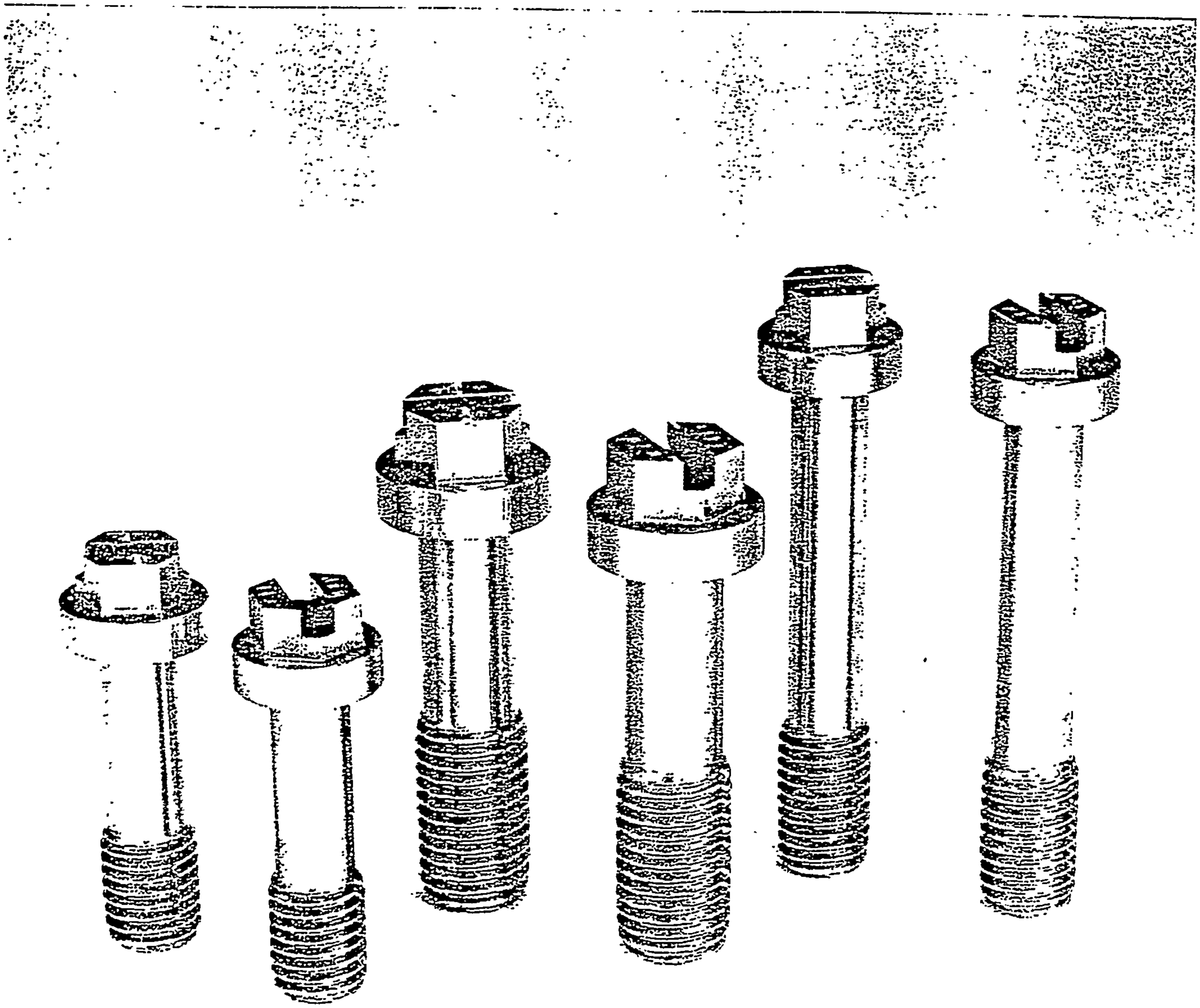


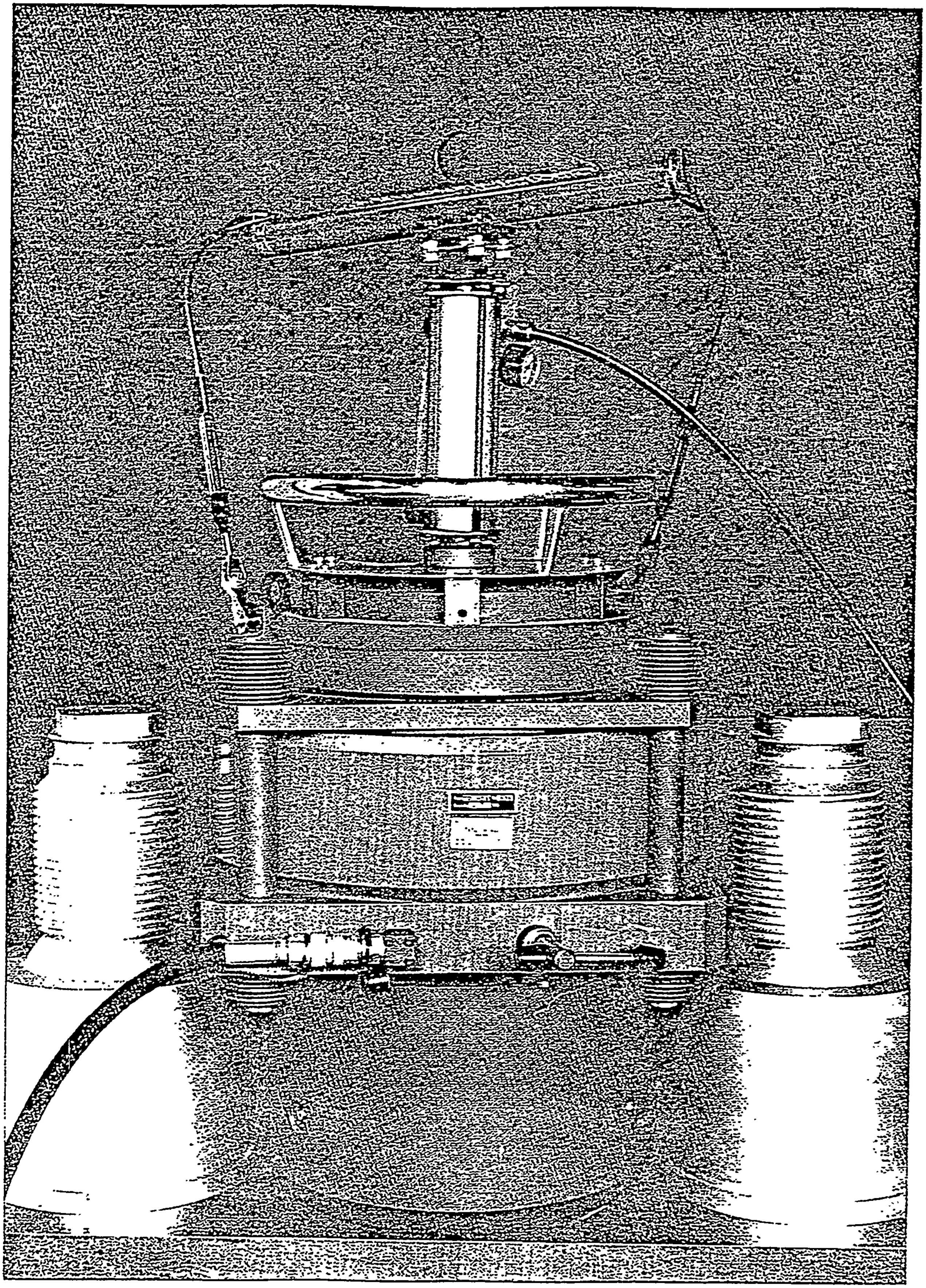
Fig. 3
Baffle bolt inspection system





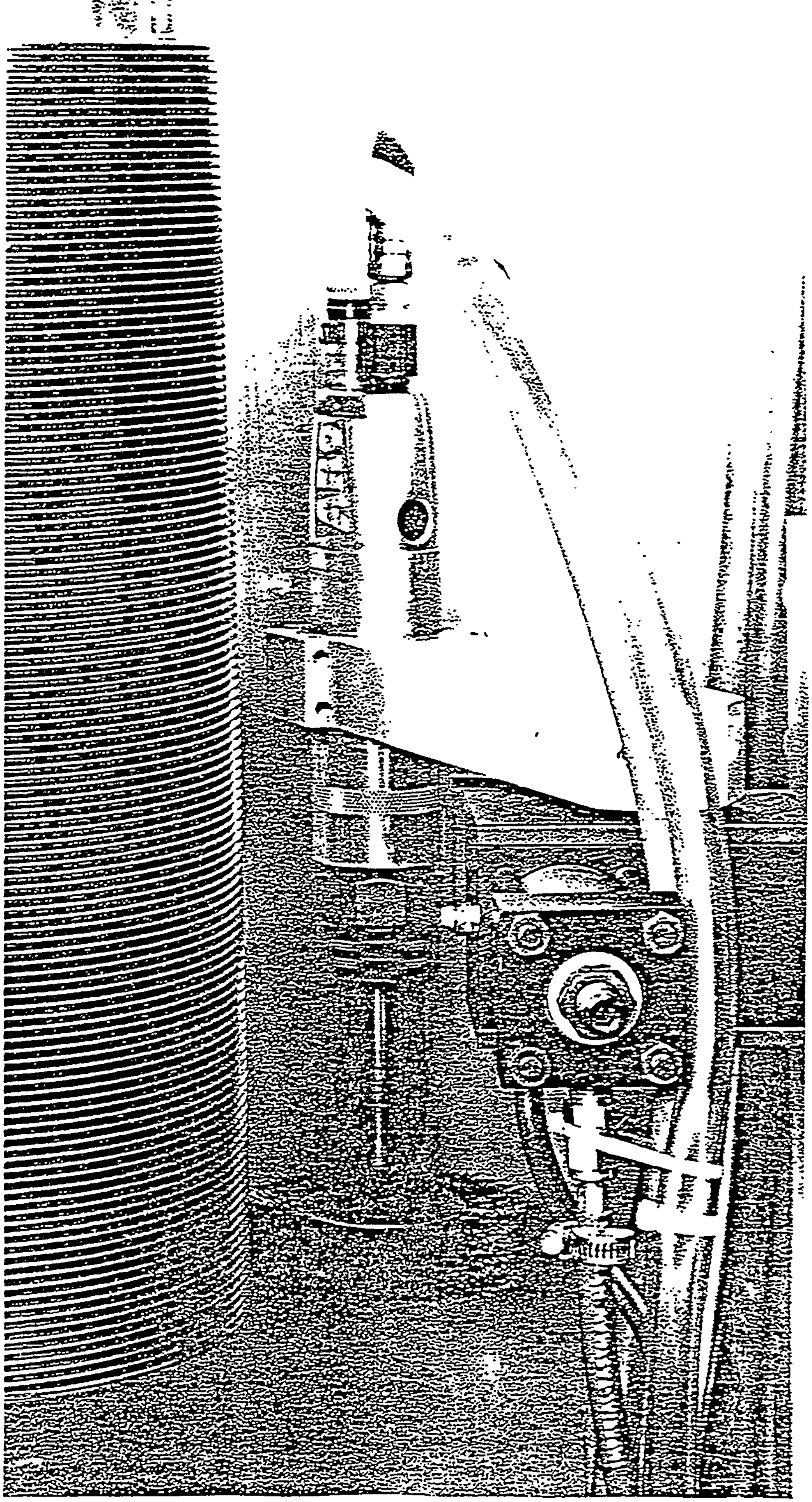
Stud Tensioning System

- Simplified design
  - Ease of use & maintenance
    - 40% lighter than other units
- Interfaces with existing systems
- Tensioning/Detensioning time reductions of 50% -70%
  - Shortens critical path time
- Fewer operating personnel required
  - Reduced ManRem exposure



Stud/Nut Cleaning System

- Automatic, thorough, uniform cleaning via pneumatically driven wire brush heads in 2 passes
- Stud lengths - 6” to any length
- Stud diameters - 5” to 7-1/2”
- HEPA filtered enclosure
  - Reduced waste generation
- 20 minute stud cleaning
- 10 minute nut cleaning

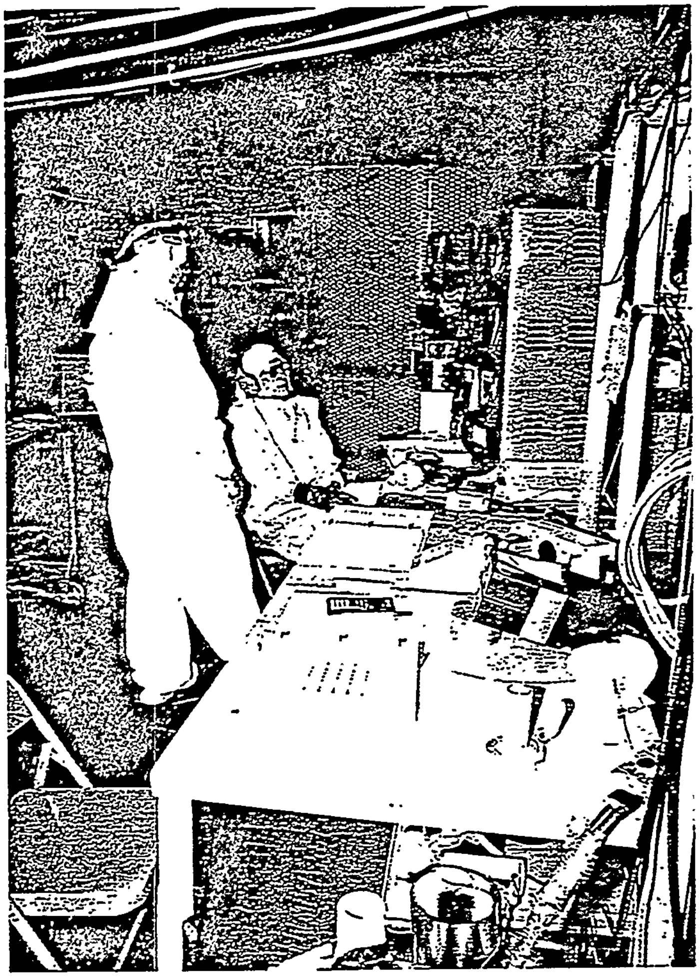


One of two wire brush heads

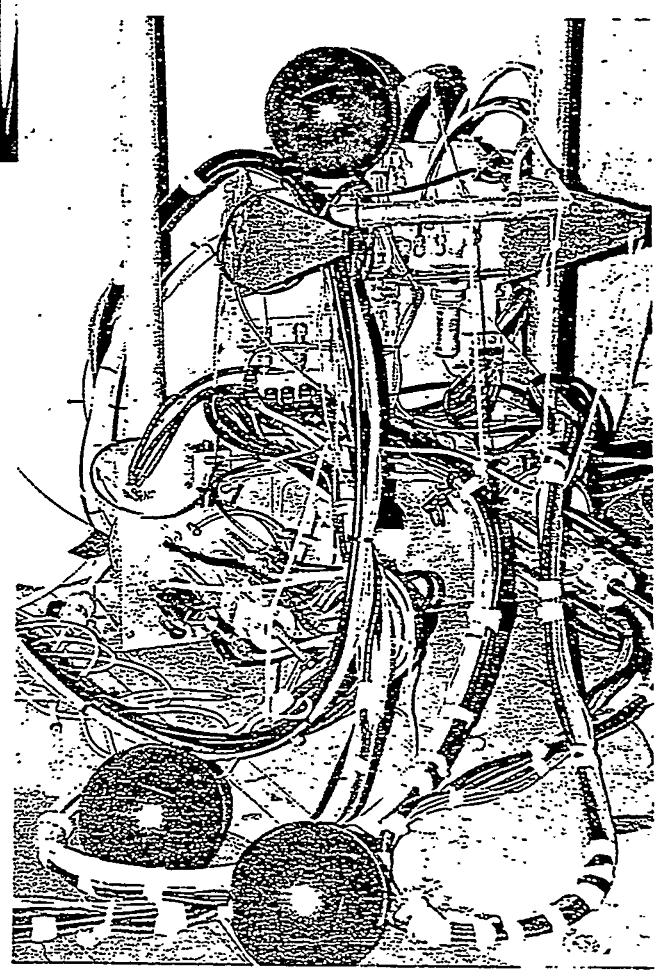
EDM Machining Technology

- Underwater <u>E</u>lectrical <u>D</u>ischarge <u>M</u>achining
- Custom designed 85 amp rotary EDM head
- Typical performance
  - 4 reactor FW nozzles in <12 days
  - 120 cu. in. metal removed
  - Diameter machined
    - 12.14" @ 5.13" deep
    - 10.35" @ 6.76" deep
  - 76 hours / nozzle (ave.)

MAINE YANKEE THERMAL SHIELD



TOOLING CONTROL STATION



UNDERWATER TOOL STATION

MI Cable Systems

- 40 year qualified, flexible, mineral insulated, Class 1E cable systems
  - LOCA/MSLB = 460F + 60psi
- Individual coaxial or twinaxial cables
- Stainless steel or Inconel sheathed
- All-welded, hermetically sealed construction
- Installed in 45 reactors

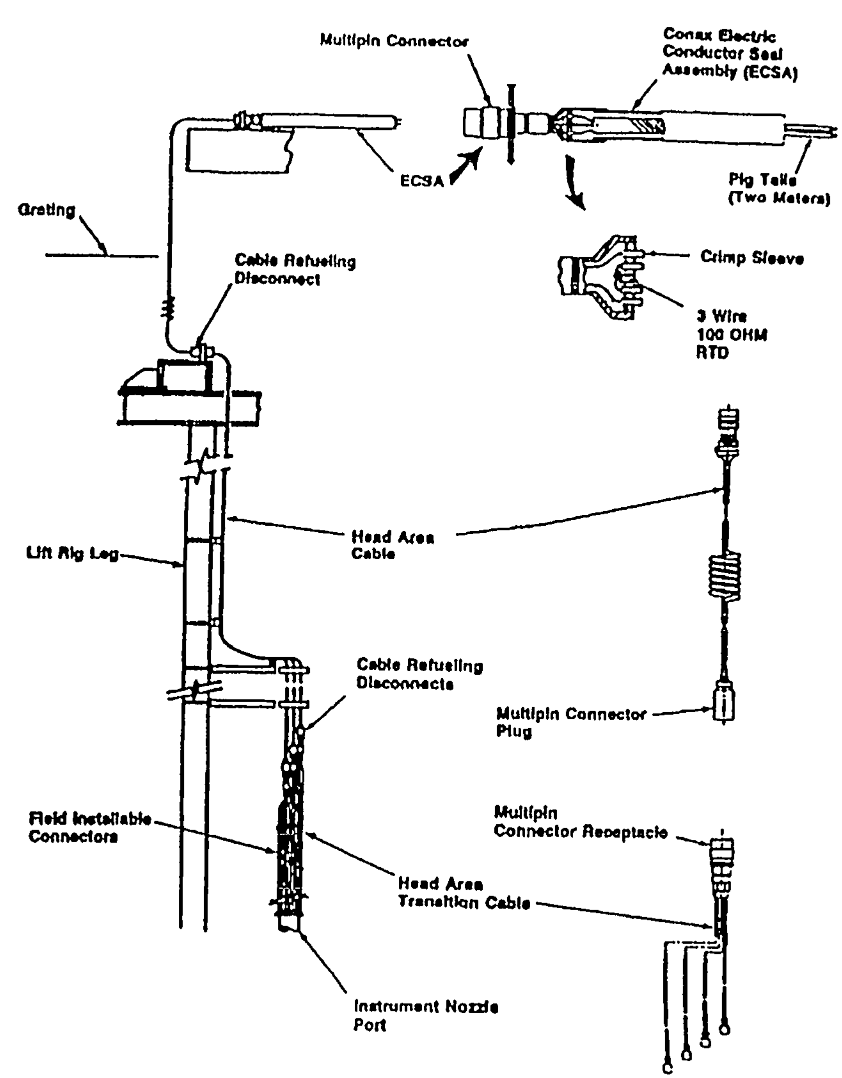
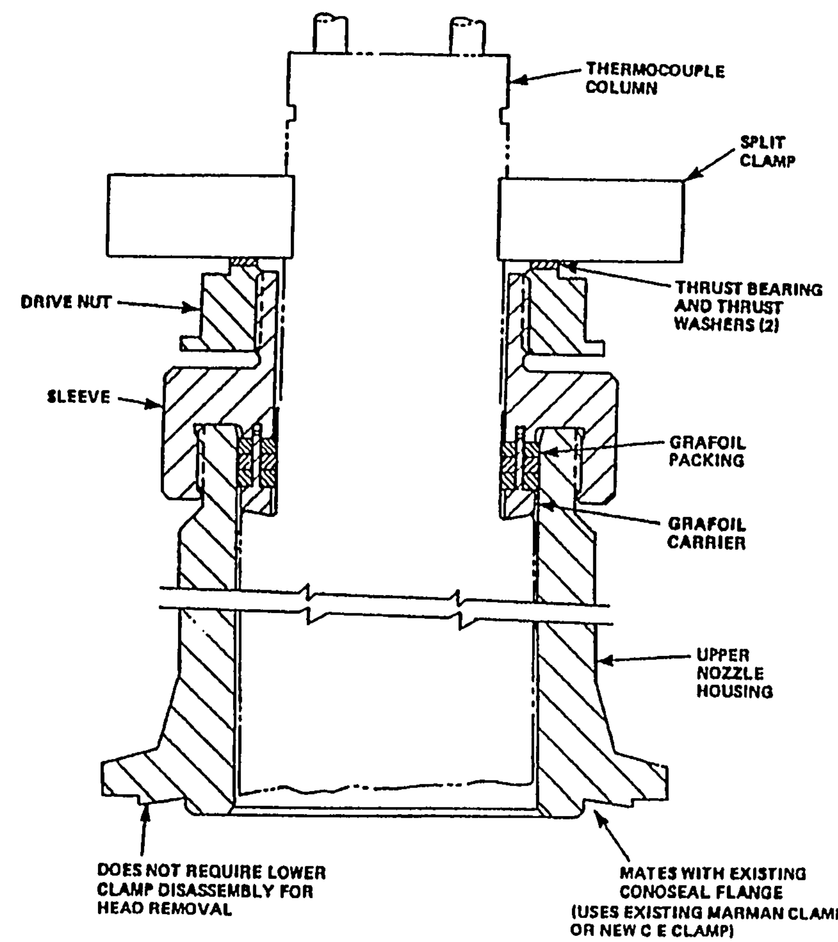


ABB CE Nuclear Operations

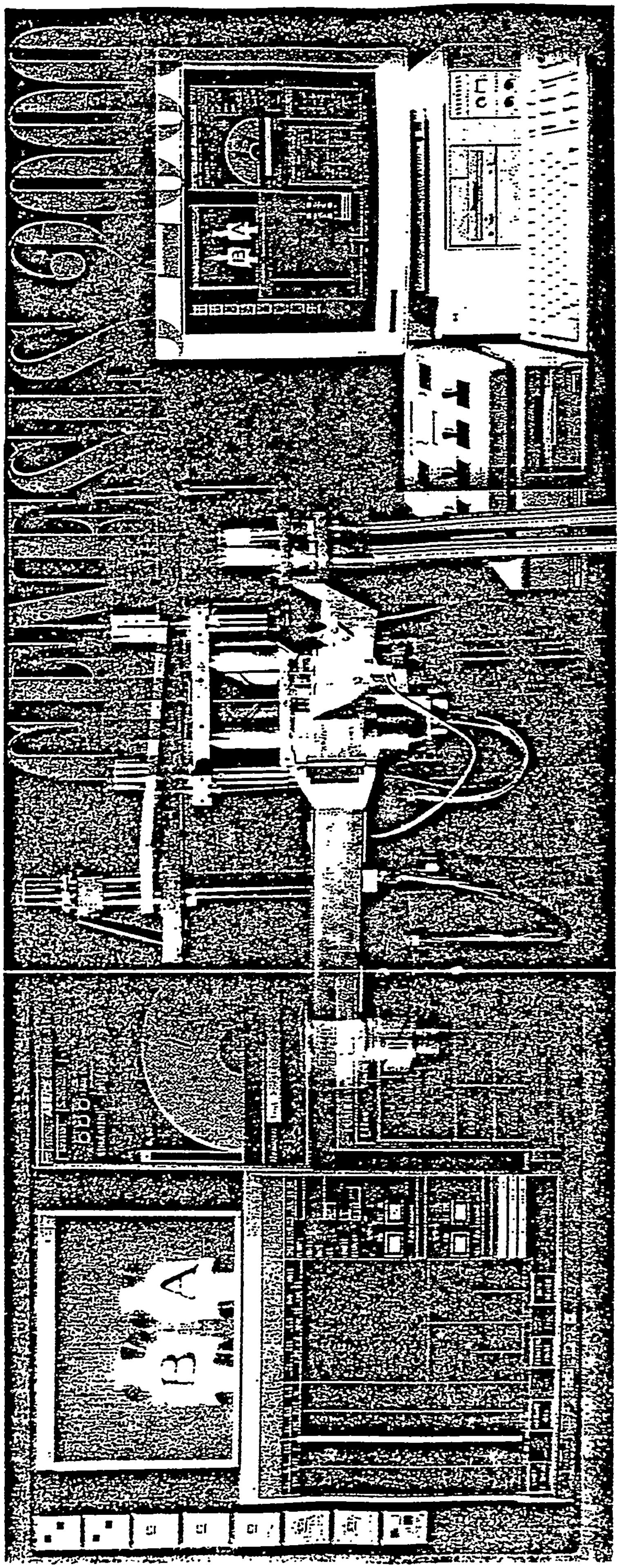
Core Exit T/C Nozzle Assemblies

- ABB CETNA reduces Personnel Exposure and Head Area Maintenance time
  - Reduces Seal Removal /Reinstallation from 2 to 1
- ASME Section III Component
- Inorganic, Grafoil packing rings
- Easily installed
  - No field cutting or welding
  - One-man operation
- Installed at 7 W-reactors since 1985 with no reported leakage



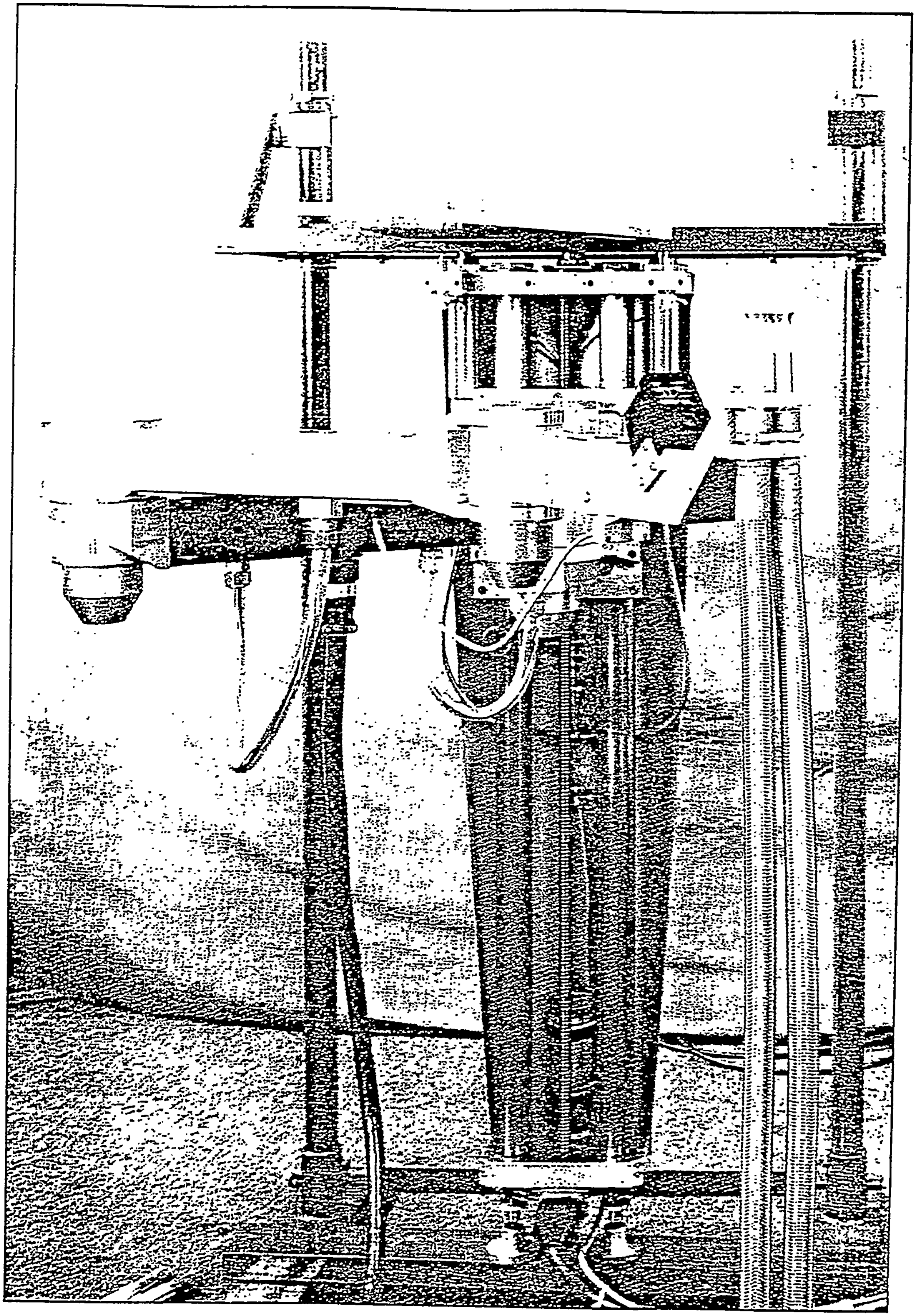
Technology for Steam Generators

- Steam Generator Inspection System
  - Genesis Manipulator System
  - EC, UT, Penetrant Inspections
- Steam Generator Repair System
  - Plugs
  - Sleeves
- Steam Generator Cleaning System



Genesis Manipulator System

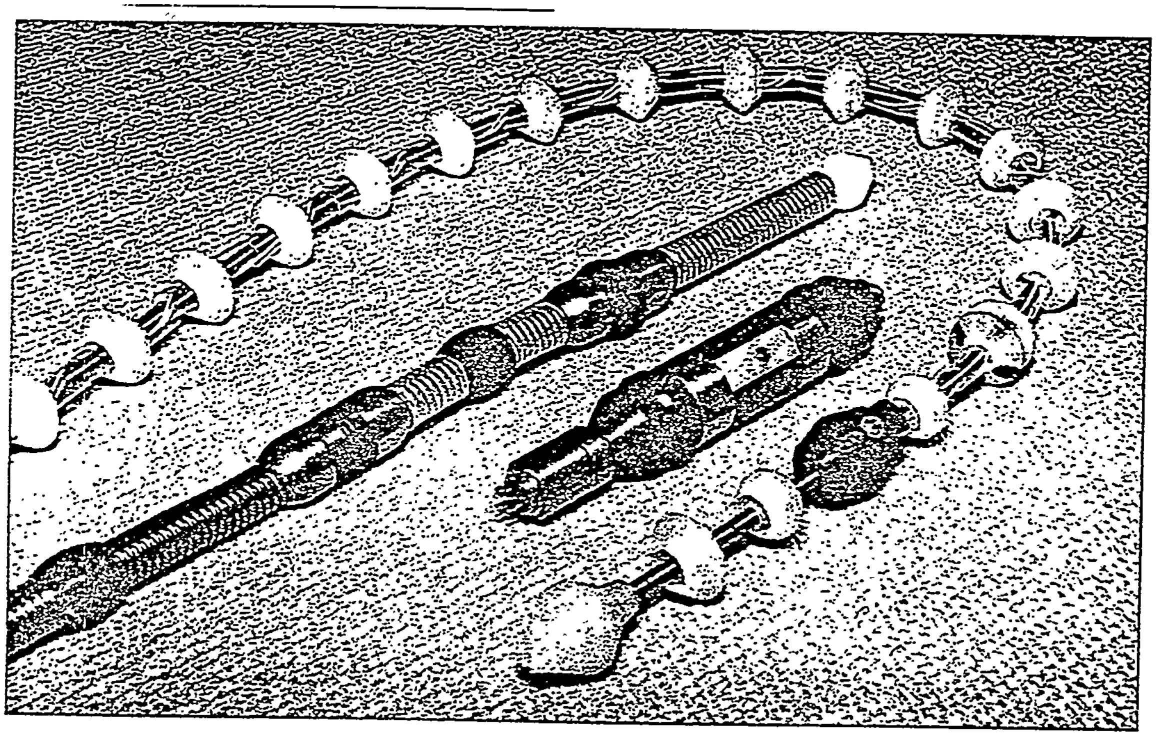
- Zero entry installation; reduced exposure
- Multi-service capability
  - Inspection/Plugging/Sleeving/Pulling/Staking
- Advanced control system integrates data acquisition (with 2, 3, or 4 probes) & manipulator motion via fiber optic link to single computer



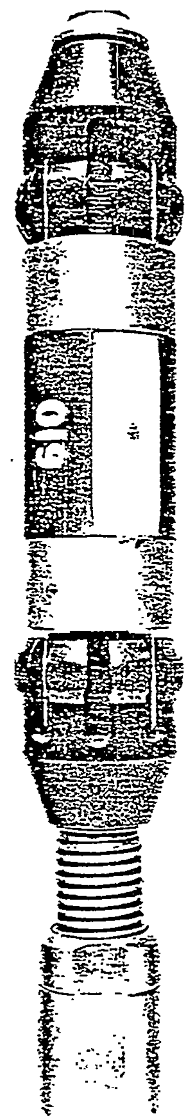
GENESIS remote manipulator with eddy current dual guide tube attached.

ECT, UT, Penetrant Inspections

- Advanced eddy-urrent probes
  - High-speed (2000 rpm), wear-resistant, MRPC probe
  - High resolution bobbin probe (300% increase)
- Ultrasonic testing probe in development
- Intraspect flaw imaging software
- Fluorescent penetrant testing
  - Minaturized, remote, fully qualified for imaging ID initiated cracks

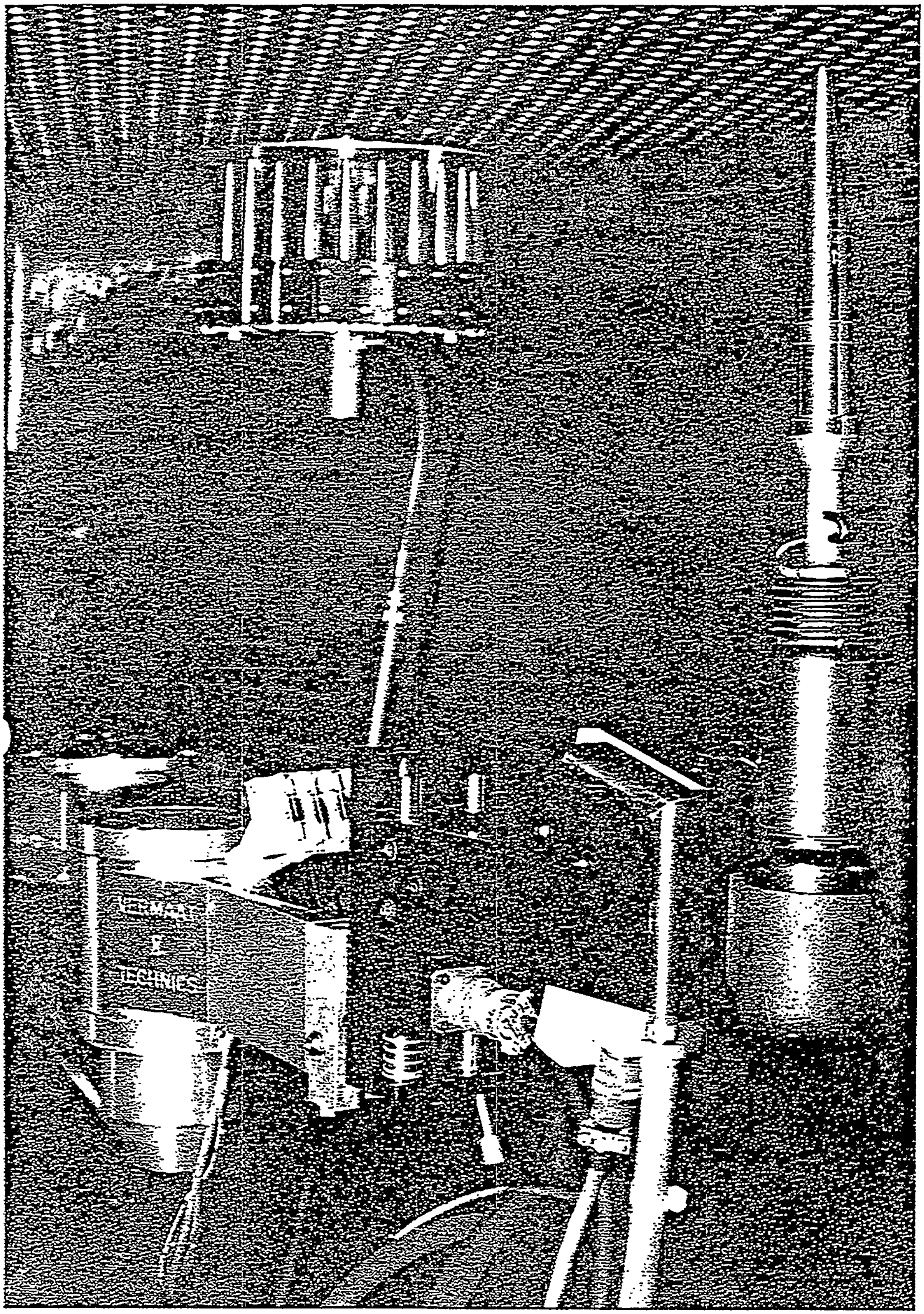


Four-segmented, MRPC U-bend and MRPC straight body probes

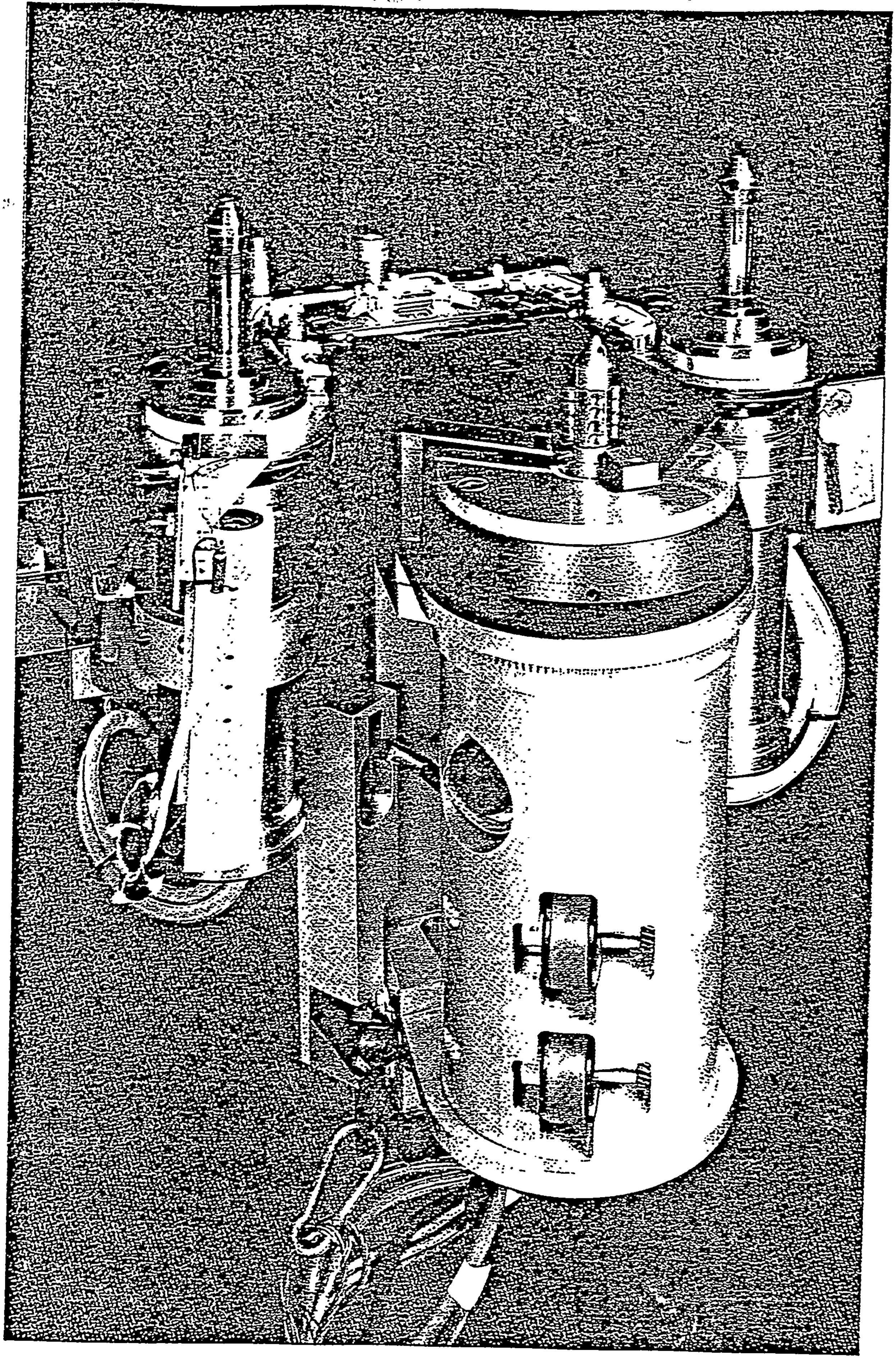


Steam Generator Repair System

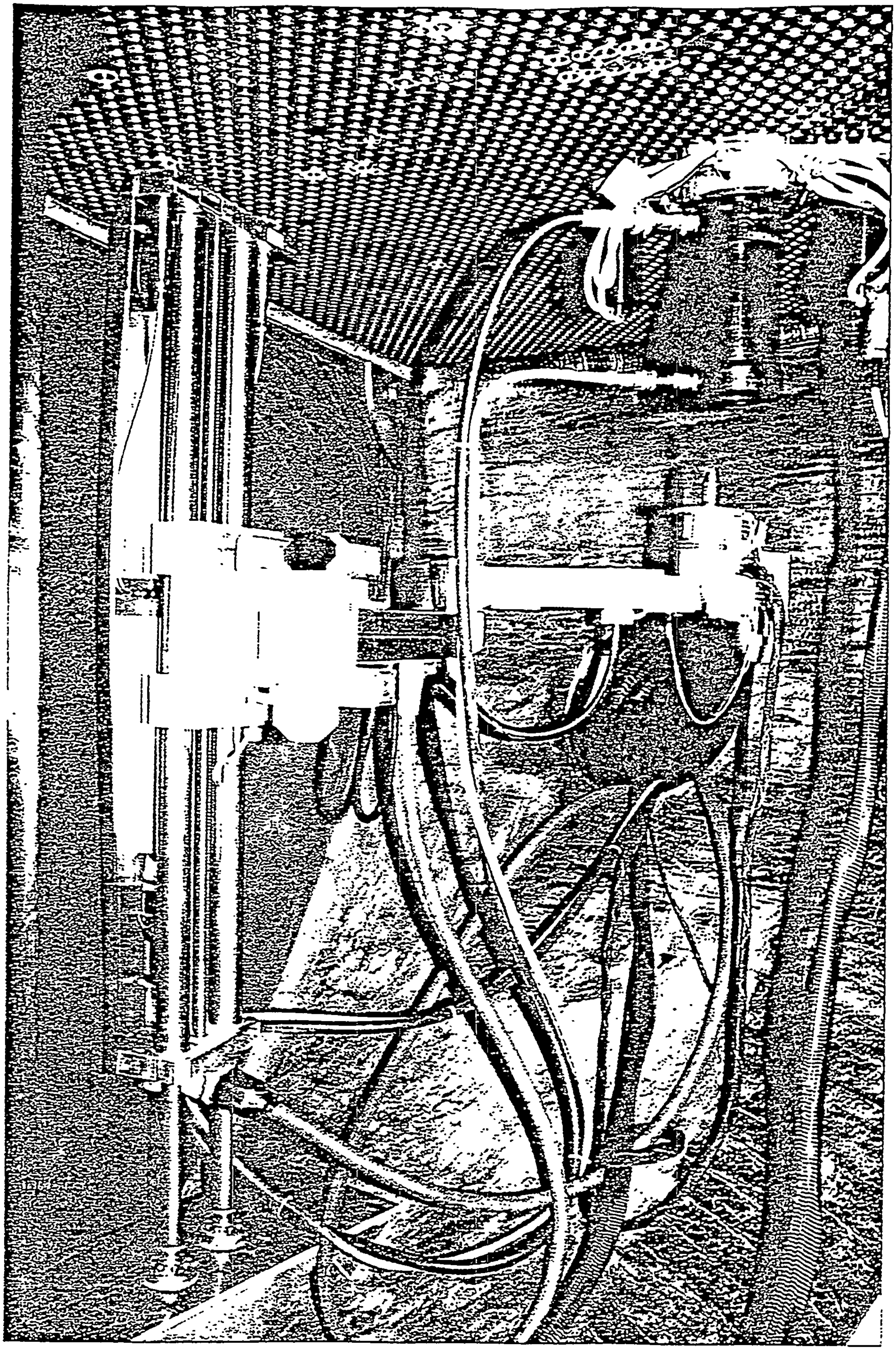
- Plugs
  - Thermally treated Inconel 690
  - Leaktightness via ductile plated band
  - Fully removable; no ID damage
  - Installation rates of 4-6 plugs/hour
- Sleeves
  - Thermally treated Inconel 690
  - Multiple lengths and diameters available
  - Sleeves for sleeved tubes
  - Low residual stress, no parent tube sensitization



Single plug inserter with carousel



Field-proven sleeve tooling permits welded sleeve installation in up to 99 percent of all tubes



Tube pulling equipment zero entry

Steam Generator Cleaning System

- EPRI/SGOG process
  - Iron removal step; crevice cleaning step; plant specific options
- Sludge lancing system
  - High pressure, multi-directional spray
  - Continuous video monitoring
  - Advanced filtration system
- Full-flow permanent magnet filter
  - 95%-98% magnetite removal

Technology for Balance of Plant

- Heat Exchangers
- Piping & Weld Inspections
- Turbo-Generators

ABB CE Nuclear Operations

Heat Exchangers

- Leaktight adhesive bonded rolled sleeve
  - ASME Section III compatible design
    - Extensive analysis & testing
  - Stress corrosion crack resistant UNS C70600 Copper alloy
    - Other materials possible
- Easily installed
- Field proven
- >10,000 installed in < 5 days

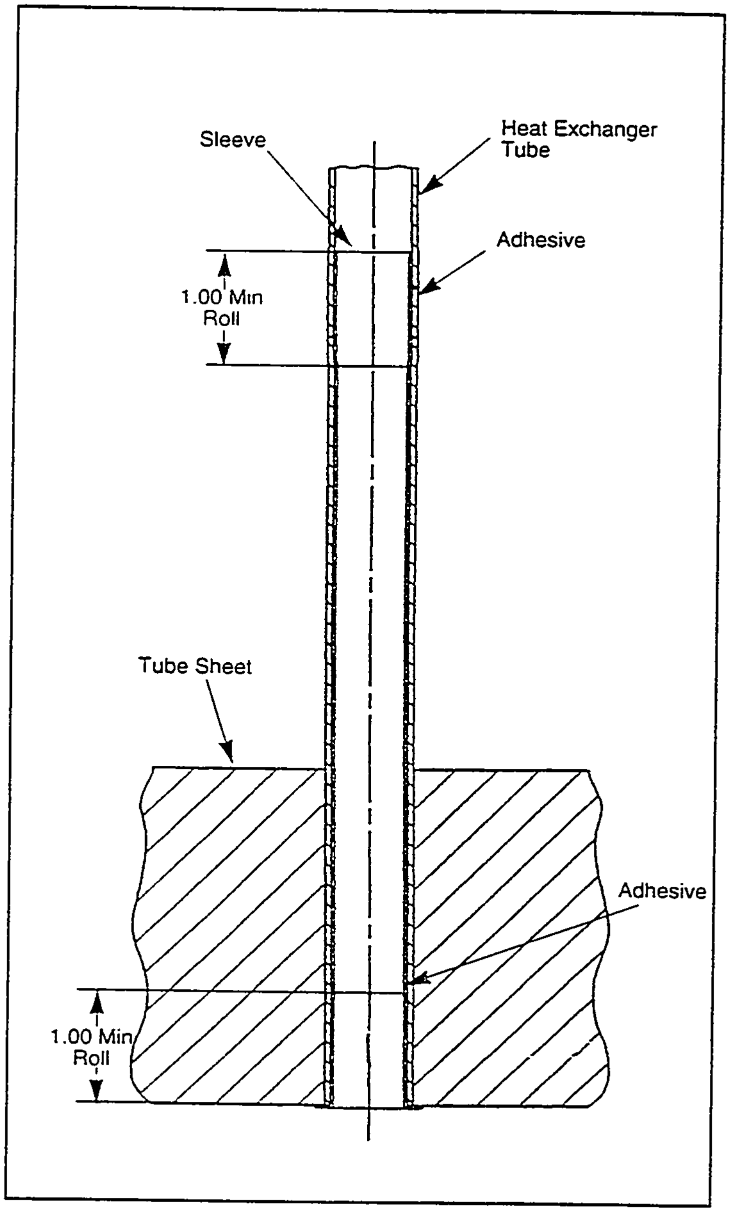


ABB Safety Grade Heat Exchanger Sleeve Installed in Tube

Benefits of the ABB Safety Grade Sleeve include:

- **Restoration of heat exchanger tubing to an as-new condition**

  The adhesive bonded rolled joint remains leaktight throughout the life of the heat exchanger and the sleeve can be installed in 100% of the heat exchanger tubes. The installed sleeve utilizes materials most capable of resisting the mode of tube attack.

- **Accommodates as-found tube conditions**

  The sleeve will accommodate tube ID, wall thickness, and ID and OD surface condition variations. The process is not affected by tubes locked at various support locations.

- **Minimizes impact upon existing tubes**

  During installation, tube diametral expansion is limited to minimize the residual stress in the parent tube to below that found at the tube-to-tubesheet roll transition zone.

- **Qualified, field proven process**

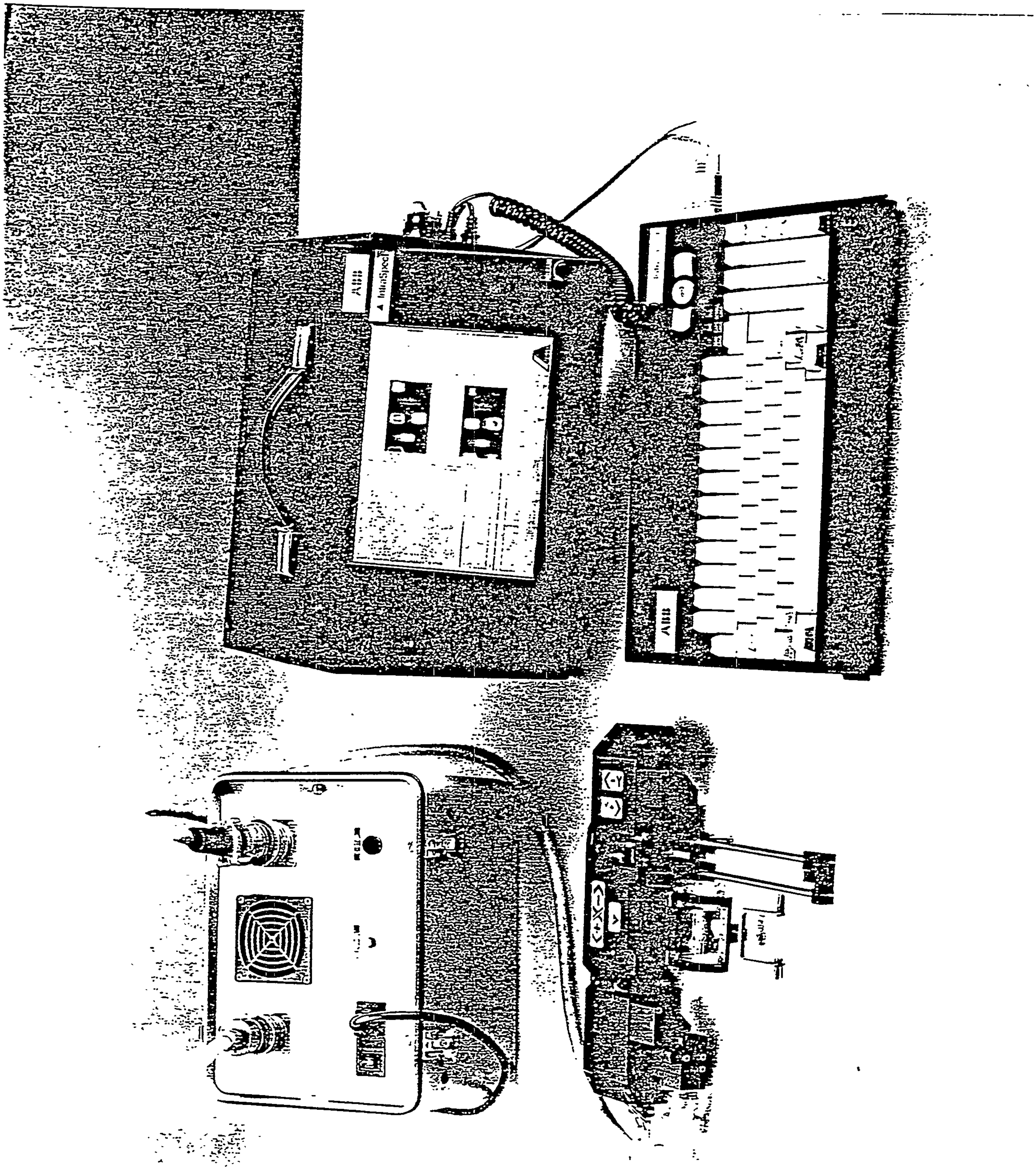
  The sleeve design, development, qualification and installation is in accordance with Section XI of the ASME code. The process is field proven, with over 10,000 sleeves in service.

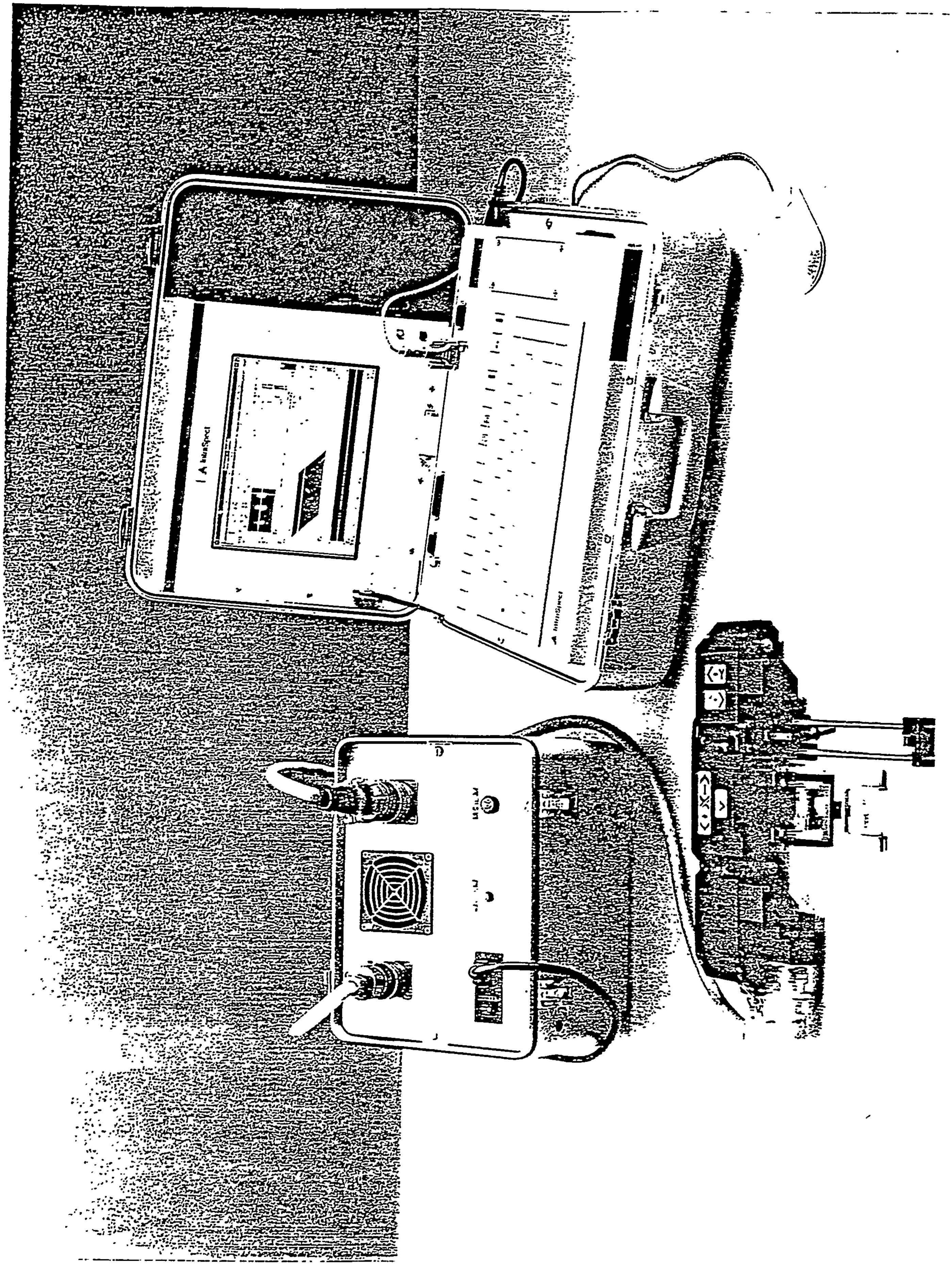
- **Rapid, flexible installation**

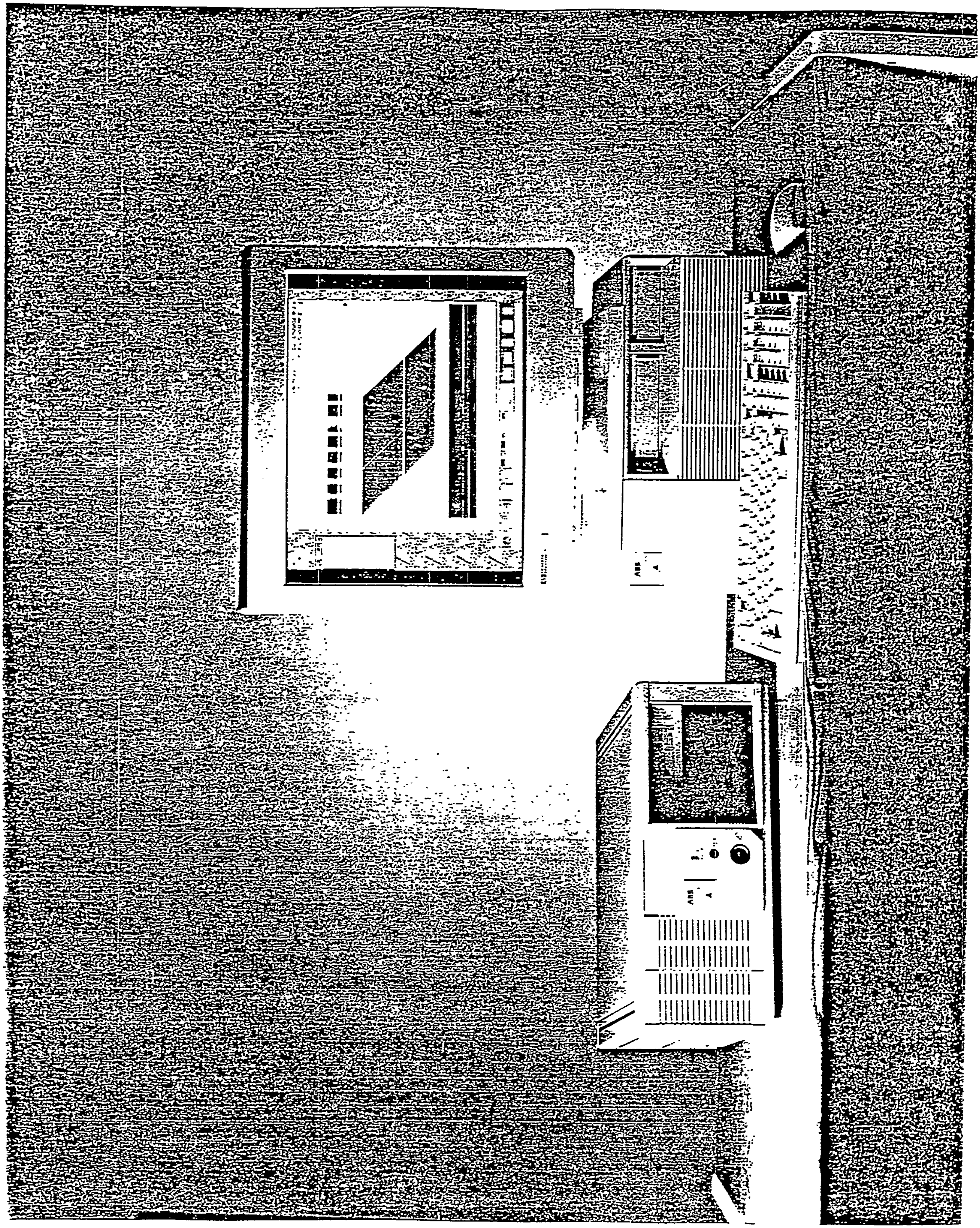
  Over 1300 sleeves per day per plenum can be installed. Alternate materials and deplugging to meet site specific conditions are available.

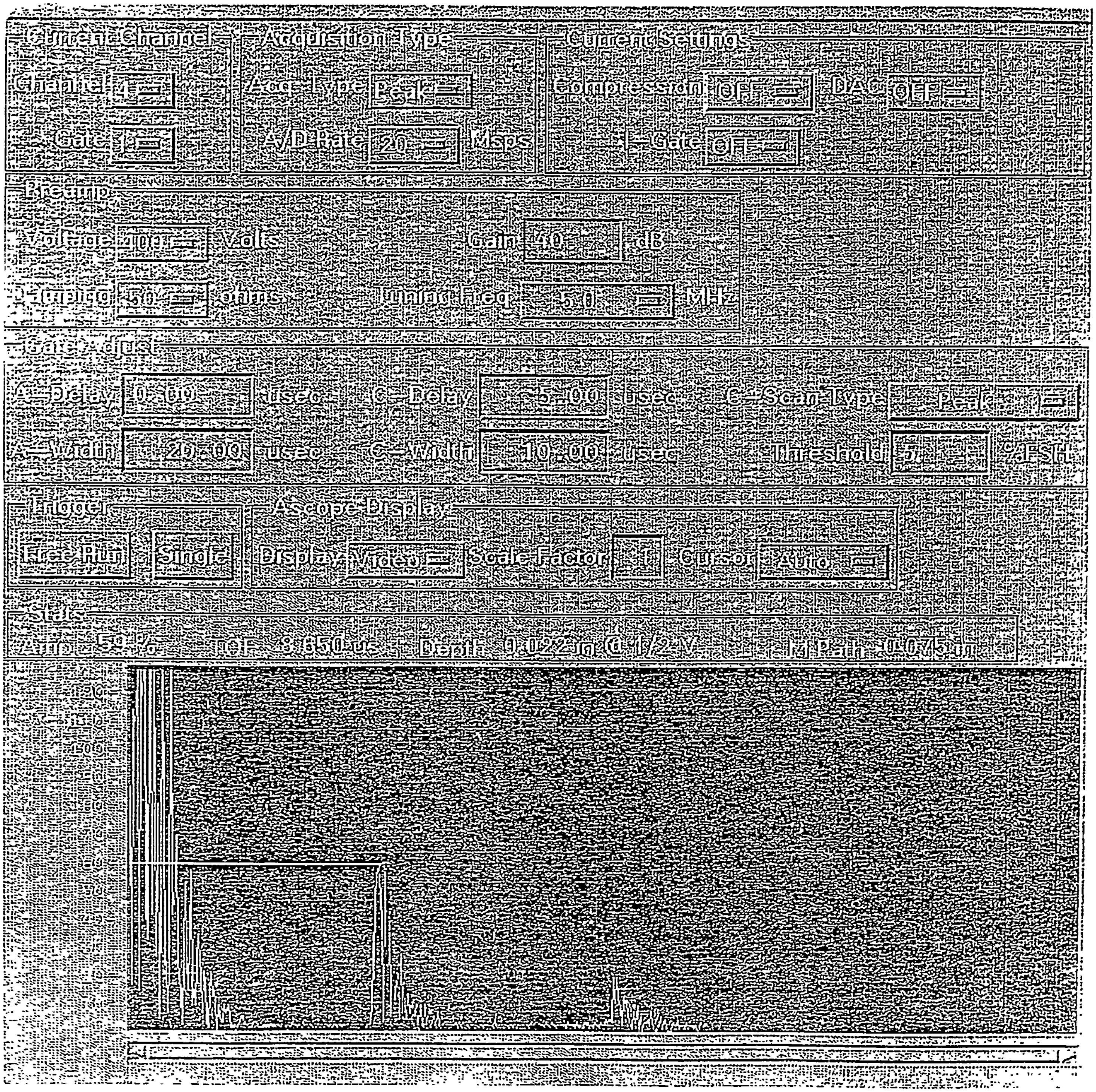
Piping & Weld Inspections

- Inegrated UT & ECT testing systems
  - Real-time, UNIX-based networkable computer
  - High-speed data acquisition (full RFA file)
  - Multi-channel, Expandable
- Flaw Evaluation
  - Forward tip diffraction; Signal deconvolution;
  - A, B, C scans; 3D modeling;
  - SAFT; TOFD; Delta technique
- Manual and automated scanners
- Pipe crawlers



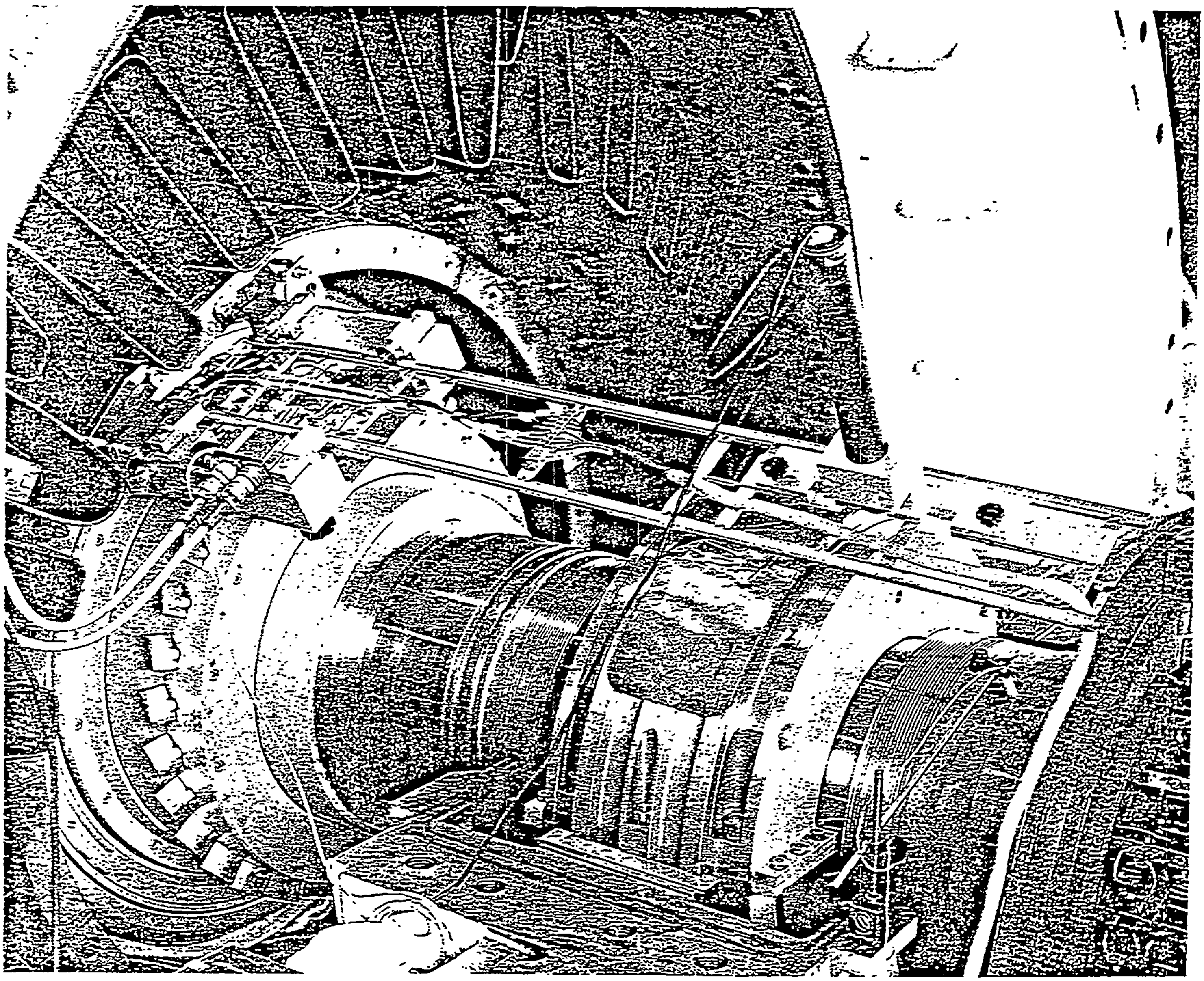


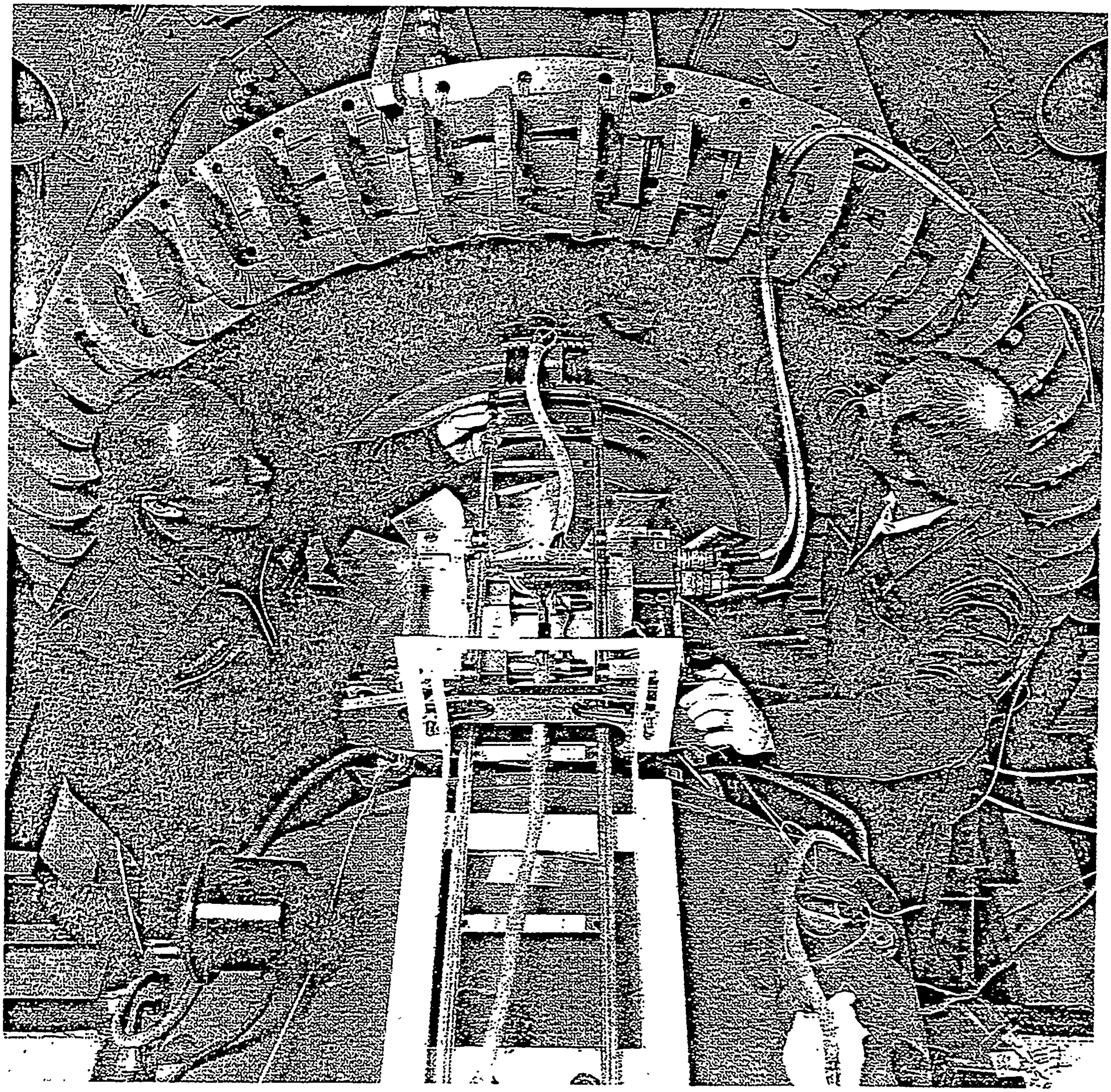



Current Channel
Channel 4
Gate 1
Acquisition Type
Acq Type Peak
A/D Rate 20 Msps
Current Settings
Compression OFF
DAC OFF
I-Gate OFF
Preamp
Voltage 100 Volts
Gain 40 dB
ohms
Tuning Freq 5.0 MHz
Gate Adjust
A-Delay 0.00 usec
C-Delay 5.00 usec
C-Scan Type Peak
A-Width 20.00 usec
C-Width 10.00 usec
Threshold 5 %FSH
Trigger
Free Run
Single
Ascope Display
Display Video
Scale Factor 1
Cursor Auto
Stats
Amp 59 %
TOF 8.650 us
Depth 0.022 in @ 1/2 V
Path 0.075 in

Turbo-Generators

- Wheels and disks - UT
- Blades - ECT & PT
- Retaining rings (in-situ) - UT, ECT & PT





Summary

- ABB CE Nuclear Operations provides -
  - NSSS Vendor developed and qualified technologies for aspects of primary and secondary systems
  - Standard and custom designed systems
  - Advanced software applications
  - On-site services
  - Training
  - Technology transfer

IMPROVED TECHNICAL SPECIFICATIONS

DONALD R. HOFFMAN
EXCEL Services Corporation

ITS CHRONOLOGY

1954	SECTION 182.a ATOMIC ENERGY ACT (ACT)
1968	10 CFR 50.36
1974	STANDARD TECH SPECS
1983	TASK GROUP
1987	NRC INTERIM POLICY STATEMENT
1988	NRC "SPLIT REPORT"
1989	OWNERS GROUPS DRAFTS
1991	NRC DRAFT ITS
1992	NRC ITS NUREGS REVISION 0 ISSUED
1993	NRC FINAL POLICY STATEMENT
1994(?)	NRC ITS RULE

OBJECTIVES

- IMPROVE SAFETY
- PROVIDE CLEARER UNDERSTANDING OF SAFETY SIGNIFICANCE
- EASE NRC AND INDUSTRY ADMINISTRATIVE BURDENS

IMPROVEMENTS

- SPLIT
- RULES
- FORMAT
- DETAIL
- BASES
- SPECIFICS (Technical Improvements)

SPLIT

CRITERION 1: Installed instrumentation that is used to detect, and indicate in the control room, a significant abnormal degradation of the reactor coolant pressure boundary.

CRITERION 2: A process variable, *design feature, or operating restriction* that is an initial condition of a DBA or Transient analysis that either assumes the failure of or presents a challenge to the integrity of a fission product barrier.

SPLIT

CRITERION 3: A structure, system, or component that is part of the primary success path and which functions or actuates to mitigate a DBA or Transient that either assumes the failure of or presents a challenge to the integrity of a fission product barrier.

CRITERION 4: A structure, system, or component which operating experience or probabilistic risk assessment has shown to be significant to public health and safety.

MORE SPLIT

In addition to those structures, systems, and components captured by the above criteria, it is the Commission's policy that licensees retain their Technical Specifications' LCOs, ACTION statements, and Surveillance Requirements for the following systems (as applicable) which operating experience and probabilistic risk assessment have generally shown to be important to public health and safety:

RCIC, RHR, SLC, RPT, and
Any risk significant system (PRA).

RULES

- Old "motherhood" rules 3.0/4.0
- LCO 3.0.4 improved on Generic Letter 87-09
- New LCO 3.0.5, 3.0.6 & 3.0.7
- SR 3.0.3 & 3.0.4 improved on GL 87-09
- Deletes old 3.0.5
- Relocates 4.0.5 to Administrative Control Program

- 1.2 Logical Connectors
- 1.3 Completion Times
- 1.4 Frequency

New LCO 3.0.5

Equipment removed from service or declared inoperable to comply with ACTIONS may be returned to service under administrative control solely to perform testing required to demonstrate its OPERABILITY or the OPERABILITY of other equipment. This is an exception to LCO 3.0.2 for the system returned to service under administrative control to perform the testing required to demonstrate OPERABILITY.

New LCO 3.0.6

When a supported system LCO is not met solely due to a support system LCO not being met, the Conditions and Required Actions associated with this supported system are not required to be entered. Only the support system LCO ACTIONS are required to be entered. This is an exception to LCO 3.0.2 for the supported system. In this event, additional evaluations and limitations may be required in accordance with Specification 5.8, "Safety Function Determination Program (SFDP)." If a loss of safety function is determined to exist by this program, the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists are required to be entered.

When a support system's Required Action directs a supported system to be declared inoperable or directs entry into Conditions and Required Actions for a supported system, the applicable Conditions and Required Actions shall be entered in accordance with LCO 3.0.2.

New LCO 3.0.7

Special Operations LCOs in Section 3.10 allow specified Technical Specifications (TS) requirements to be changed to permit performance of special tests and operations. Unless otherwise specified, all other TS requirements remain unchanged. Compliance with Special Operations LCOs is optional. When a Special Operations LCO is desired to be met but is not met, the ACTIONS of the Special Operations LCO shall be met. When a Special Operations LCO is not desired to be met, entry into a MODE or other specified condition in the Applicability shall only be made in accordance with the other applicable Specifications.

FORMAT

- Human Factored
- Applicability
- Actions - 3 column
- Surveillances - 2 column
- Tables - only one
- Logical order within section
- No. & Title in corner
- Bases significantly enhanced and improved

DETAIL

- SYSTEM
- OPERABILITY
- ACTIONS
- SURVEILLANCES

BASES

- MORE, MORE, MORE
- Every LCO
- Every Instrument Function
- Every Applicability
- Every Action
- Every Surveillance
- Every Note

3.6 CONTAINMENT SYSTEMS

3.6.1.4 Drywell Pressure

LCO 3.6.1.4 Drywell pressure shall be [≤ 0.75 psig].

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Drywell pressure not within limit.	A.1 Restore drywell pressure to within limit.	1 hour
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. <u>AND</u> B.2 Be in MODE 4.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.6.1.4.1 Verify drywell pressure is within limit.	12 hours

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.4 Drywell Pressure

BASES

BACKGROUND	The drywell pressure is limited during normal operations to preserve the initial conditions assumed in the accident analysis for a Design Basis Accident (DBA) or loss of coolant accident (LOCA).
APPLICABLE SAFETY ANALYSES	Primary containment performance is evaluated for the entire spectrum of break sizes for postulated LOCAs (Ref. 1). Among the inputs to the DBA is the initial primary containment internal pressure (Ref. 1). Analyses assume an initial drywell pressure of [0.75 psig]. This limitation ensures that the safety analysis remains valid by maintaining the expected initial conditions and ensures that the peak LOCA drywell internal pressure does not exceed the maximum allowable of [62] psig. The maximum calculated drywell pressure occurs during the reactor blowdown phase of the DBA, which assumes an instantaneous recirculation line break. The calculated peak drywell pressure for this limiting event is [57.5] psig (Ref. 1). Drywell pressure satisfies Criterion 2 of the NRC Policy Statement.
LCO	In the event of a DBA, with an initial drywell pressure ≤ [0.75 psig], the resultant peak drywell accident pressure will be maintained below the drywell design pressure.
APPLICABILITY	In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, maintaining drywell pressure within limits is not required in MODE 4 or 5.

(continued)

BASES (continued)

ACTIONS

A.1

With drywell pressure not within the limit of the LCO, drywell pressure must be restored within 1 hour. The Required Action is necessary to return operation to within the bounds of the primary containment analysis. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.1.1, "Primary Containment," which requires that primary containment be restored to OPERABLE status within 1 hour.

B.1 and B.2

If drywell pressure cannot be restored to within limit within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.4.1

Verifying that drywell pressure is within limit ensures that unit operation remains within the limit assumed in the primary containment analysis. The 12 hour Frequency of this SR was developed, based on operating experience related to trending of drywell pressure variations during the applicable MODES. Furthermore, the 12 hour Frequency is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal drywell pressure condition.

REFERENCES

1. FSAR, Section [6.2].

Table 3.3.7.1-1 (page 1 of 1)
[Control Room Fresh Air] System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION A.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
[1. Reactor Vessel Water Level — Low Low, Level 2	1,2,3, [(a)]	[2]	B	SR 3.3.7.1.1 SR 3.3.7.1.2 [SR 3.3.7.1.3] SR 3.3.7.1.4 SR 3.3.7.1.5	≥ [-43.8] inches]
[2. Drywell Pressure — High	1,2,3	[2]	C	SR 3.3.7.1.1 SR 3.3.7.1.2 [SR 3.3.7.1.3] SR 3.3.7.1.4 SR 3.3.7.1.5	≤ [1.43] psig]
3. Control Room Ventilation Radiation Monitors	1,2,3, (a),(b)	[2]	D	SR 3.3.7.1.1 SR 3.3.7.1.2 SR 3.3.7.1.4 SR 3.3.7.1.5	≤ [5] mR/hr

(a) During operations with a potential for draining the reactor vessel.

(b) During movement of irradiated fuel assemblies in the [primary or secondary containment].

SPECIFIC ITEMS

LINE ITEM IMPROVEMENTS

- Organization Charts — GL 88-06
- Fire Protection — GL 88-12
- Cycle Specific Limits — GL 88-16
- Radiological Effluents — GL 89-01
- 3.25 Surveillances — GL 89-14
- RV Material Specimens — GL 91-01
- Component Lists — GL 91-08

More SPECIFIC ITEMS

- Response Times GL 93-??
- Reduced Testing GL 93-??

- Extended AOTs OGs
- Extended STIs OGs
- MSL Hi Rad Scram/Isolation BWROG

More SPECIFIC ITEMS

- EDG common mode failure check
- Loss of offsite power requiring EDG starts
- Best of the Best
- Others

BASES

- MORE, MORE, MORE
- Every LCO
- Every Instrument Function
- Every Applicability
- Every Action
- Every Surveillance
- Every Note

IMPLEMENTATION

SUBMITTAL DEVELOPMENT

- PROCESS
- REVIEW
- SUBMITTAL

PROCEDURE REVISIONS

- APPROACHES

PROGRAM DEVELOPMENT

- RELOCATED ITEMS
- SAFETY FUNCTION DETERMINATION PROGRAM

TRAINING

ENIDINE

ENIDINE

VIBRATION AND SEISMIC ISOLATION

TECHNOLOGIES FOR

POWER GENERATION STATION

APPLICATIONS

Thomas A. Zemanek

ENIDINE

I. INTRODUCTION TO ENIDINE

ENIDINE Inc. is a world leader in the design and manufacture of shock and vibration mounts. Founded in 1966, the company has two manufacturing facilities, employs over 300 people and supports a worldwide network of distributors and representatives. ENIDINE Inc. is part of the ENIDINE Corporate Group which owns a number of companies that design and manufacture Hydraulic/Pneumatic cylinders, Electromechanical devices, Hydraulic Control Valves and a number of Industrial Distribution companies throughout Europe. In total, the ENIDINE Corporate Group has over 900 employees with annual sales of over $100 million.

ENIDINE shock and vibration mounts are used to isolated the vibration of missiles from their guidance systems, pumps from hospital operating equipment and off shore oil rigs, from the shock energy of waves in the North Sea. ENIDINE products can be found on all Boeing and McDonnell Douglas aircraft, as well as many electronic and weapons systems on board Navy ships.

II. ENIDINE MANUFACTURING

Worldwide, ENIDINE has over 200,000 square feet of manufacturing space. Orchard Park, New York is the design and research center for all ENIDINE shock and vibration mounts. Our manufacturing processes meet some of the most stringent Quality assurance standards in the world including: ISO 9001, DI-9000, (Boeing), Mil Q9858, mil Q 9858A, and MI 4508. In addition, ENIDINE has supplied components to the Nuclear Power industry under 10CFR 21 Appendix B.

The Orchard Park Facility consists of over 80,000 square feet of manufacturing space. Here we product most of our standard shock absorbers as well as wire rope isolators.

As stated earlier, ENIDINE is part of the ENIDINE Corporate Group. Included in this group is HYDROLINE INC., a Manufacturer of large hydraulic cylinders. Fluid dampers over 100 kip and up to 2,000 kip are manufactured in our 143,000 square foot facility in Rockford Ill..

ENIDINE

III. ENIDINE TECHNOLOGIES

ENIDINE energy absorption technologies are based around fluid filled shock absorbers and dampers, elastomeric and wire rope isolators. Over the years, ENIDINE has designed and manufactured products utilizing these technologies for Power Generating Stations; Nuclear and Fossil fuel alike. Pipe snubbers, Valve Actuators, pressure and limit switch failures are often caused by plant vibration. This vibration can be eliminated by isolating the component from the source. ENIDINE has also identified and isolated many of the *sources* of vibration; Piping, Recirculation Pumps, water pumps, emergency generators and turbines can be mounted on or around ENIDINE isolators to lessen the likelihood of vibration failures in the plant. ENIDINE products can isolate the vibration or shock from the largest to the smallest component.

In addition to component isolation, safety systems have been developed to lessen the damage caused by Earthquakes. The technologies developed at ENIDINE have applications individually and in combination to improve the safety of structural and non structural components alike in the event of a seismic event.

IV. HYDRAULIC DAMPERS

ENIDINE manufactures hydraulic shock absorbers and dampers from as small as a persons little finger to as large as a table top. Fluid filled shock absorbers and dampers enable the plant design engineer to dissipate large amounts of energy to protect plant and equipment. ENIDINE has perfected this technology over the years by using numerous types and blends of fluids, minimizing space for fluid reservoirs and valving, and using varied orifice schemes to manipulate the dissipation of energy through a given stroke. ENIDINE engineers have the products and expertise to cover a wide range of velocities and drive forces absorbing as much energy as possible in the smallest possible package.

ENIDINE hydraulic dampers have been designed in sizes up to 650 KIP. These units have been developed as building and bridge seismic isolators. Unlike Snubbers (lockup devices), dampers dissipate large amounts of energy produced during a seismic event. Damping curves can be manipulated to estimated velocities expected during an accident usually in the equation $F = C\text{-}V^n$. Turbines, Steam Generators Boilers etc. are candidates for seismic isolation.

V. WIRE ROPE ISOLATORS

Wire Rope Isolators are helical shaped loops of stainless steel cable, clamped in place by metal bars. The isolators serve a dual purpose and function as vibration isolators and shock absorbers. Energy is dissipated through the friction in the wire as the unit is compressed. The units can be oriented in different directions to the load; compression, 45 degree angles, shear and roll. The units are constructed of stainless steel. They will not rust or degrade with use if sized and applied correctly. There are no seals fluids or sliding surfaces and radiation is not a problem. These devices range in size from one inch in height to as large as necessary to meet the application.

Wire Rope Isolators have unparalleled durability and are maintenance free. They can survive the harshest environments. Many successful applications can be found on Navy ships withstanding extreme temperatures and continuous salt spray environments.

Typical applications are as a base isolator for Emergency Generators, all types of rotating equipment, piping, gauge and instrument isolation etc..

ENIDINE

VI. WEAR RESTRAINTS

The ENIDINE WEAR seismic restraint provides wire rope isolator technology and performance in a linear configuration. Developed primarily for pipeline shock and vibration, the unit provides optimal performance and dependability in a maintenance free package.

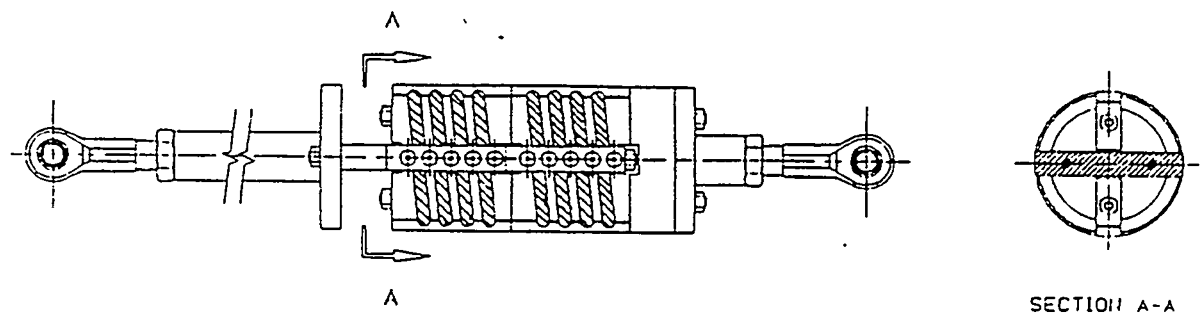
Technically the WEAR provides additional benefits to certain pipe restraint applications (as a snubber replacement) in that it also acts as a vibration isolator. Pipe vibration has been a cause of mechanical and hydraulic pipe snubber failures. The WEAR is capable of isolating continuous vibration as well as maintaining it's readiness as a restraining device to protect against seismic events or water hammer.

WEAR restraints are constructed of 100% stainless steel. The cable can be uncovered or covered depending on the desire of the design authority.

ENIDINE

ENGINEERING SOLUTIONS IN ENERGY ABSORPTION AND VIBRATION ISOLATION

WEAR™ PIPE RESTRAINT



*** NO OIL * NO SEALS * NO TESTING * NO MAINTENANCE ***

WEAR™ Pipe Restraint

ENIDINE'S WEAR™ (Wire Energy Absorbing Rope) Pipe Restraint eliminates the problems associated with complex failure prone snubbers. This new generation energy absorbing restraint is of simple construction and ideal for seismic and vibration control. The WEAR™ Restraint is available as a Linear, Bi-linear or Gapped spring which provides for a wide range of pipe thermal expansion. The wire rope windings exhibit excellent damping characteristics and eliminate the structural impact loads associated with conventional "gapped" supports when arresting transient events.

The wire rope isolator, which is the basic element of the restraint, has been utilized in military, satellite, warship, space shuttle, aircraft, and off-road vehicle applications for the past 25 years. Such uses have resulted in conformance to government and military specifications along with quality control requirements similar to those of the nuclear industry.

WEAR™ Design

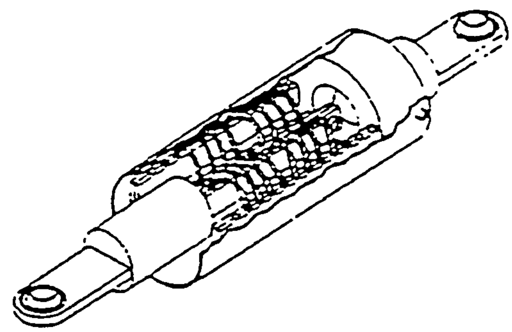
The energy absorbing element of the WEAR™ Restraint is composed of helical cable geometrically arranged such that the cable deflects when relative motion occurs between the pipe and structure. The restraint is designed to have specific response characteristics by varying the diameter of the wire rope, the number of strands, the cable length, the twist or lay, and the number of windings. The wire rope loops are configured such that they exhibit linear or bi-linear spring characteristics. Internal stops prevent overstressing the wire rope isolator. The overall geometry of the restraint is designed to allow existing snubber pin-pin dimensions to be met.

The WEAR™ Restraint is available in load capacities ranging from 500 to 100,000 lb The restraint can be supplied as a "gapped" spring which allows for unconstrained pipe thermal expansion. During a dynamic event, the device restrains the pipe by limiting deflections and imparting a significant amount of damping.

Damping is provided by flexure hysteresis due to friction associated with the rubbing and sliding between the strands of the wire rope. Damping values in the range of 15%-17% of critical are typical. The restraint has a high cyclic fatigue life making it an excellent choice for controlling steady state vibration.

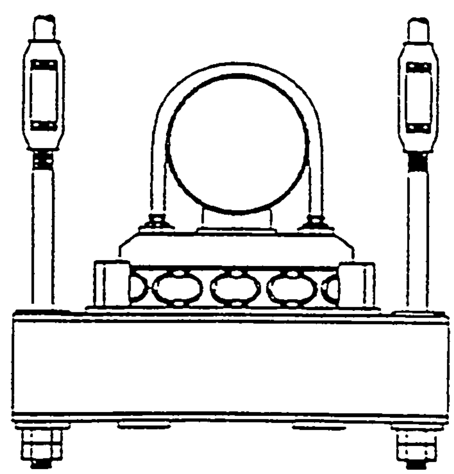
Controlling Pipe Vibration Using WEAR™ Restraints

WEAR™ restraints were installed at a midwest refinery to control a steady state pipe vibration. Flow disturbances originating in a batching tank resulted in 2-3 inch displacements of an 8-inch diameter oil process line. The resulting steady state vibration and 600°F operating temperature made WEAR™ the only choice for this punishing job. The high cycle fatigue life and simplicity in design of the WEAR™ Restraint provided the plant with a cost effective, maintenance free solution.



WEAR™ Supports Installed at the Byron Nuclear Plant

A portion of the Byron Reactor Feedwater piping system is supported by WEAR™ restraints to mitigate a floor vibration problem. Steady state vibration of the Feedwater system excited an overhead supporting floor slab. The resulting floor vibration was irritating and disruptive to the plant personnel who work in the area. WEAR™ supports were designed to dampen the pipe vibration and isolate it from the supporting floor slab. The WEAR™ supports were incorporated into existing support hardware at a minimum cost. Vibration data taken after the installation of the WEAR™ supports demonstrated that all floor vibration frequencies above 5 Hz were eliminated as predicted by analysis prior to their installation.



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REDUCING PIPE SHOCK & VIBRATION USING WIRE ENERGY ABSORBING ROPE (WEAR™) RESTRAINTS

PRESENTED
by
ENIDINE INC.

ABSTRACT

Flow induced vibration can be the source of unacceptable stress levels in piping systems. The use of Wire Energy Absorbing Rope (WEAR™) pipe restraints is investigated for application to a hydraulic transient problem. WEAR™ is an energy absorbing seismic and vibration suppression pipe restraint. The support is a combined spring-dashpot with a high cycle fatigue life. The restraint can be specified with bi-linear stiffness properties in order to accommodate the conflicting requirements of thermal expansion and vibration control. The basic element of the restraint has been used over the past twenty years as a means of controlling vibrations in various diversified industries.

A piping system analysis is performed in order to size the WEAR™ restraints. The paper also investigates the loads which WEAR™ restraints transfer to the structure.

INTRODUCTION

Elimination of the source of a flow induced transient is not always possible as in the case when large pressure drops must be taken in a system. An example is the flash tank drain line at Southern California Edison's Oxnard plant. During startup of the once through critical boiler, the pressure in the line must be dropped from up to 1000 psi to a vacuum as the fluid enters the condenser. Flashing of the liquid results in pressure waves which propagate through the piping system. The resulting piping response can cause an overstress condition and/or support failures if the system is not properly restrained against such flow induced transients.

The use of Wire Energy Absorbing Rope (WEAR™) pipe restraints is investigated for application to this problem. A WEAR™ restraint is a combined spring and dashpot. The patent pending device incorporates the use of helical wound wire rope into a compact shape. Energy is absorbed by the rubbing and sliding of the wire strands when deflected. Figure 1 shows the overall geometry of a WEAR™ restraint. A typical force-deflection curbe is shown in Figure 2. The support can also be supplied with bi-linear force-deflection properties to accommodate the conflicting requirements of pipe thermal expansion and vibration control. Figure 3 shows a typical WEAR™ bi-linear force-deflection curve.

The use of wire rope for controlling vibration has been successfully utilized for over 20 years in spacecraft, airplanes, offroad vehicles, rotating euqipment mountings and various military applications. WEAR™ supports have been installed in feedwater lines at PWR nuclear facilities to isolate pipe induced structural vibrations(1). WEAR™ pipe restraints have also been installed at oil refinery's to control a steady state pipe vibration problem.

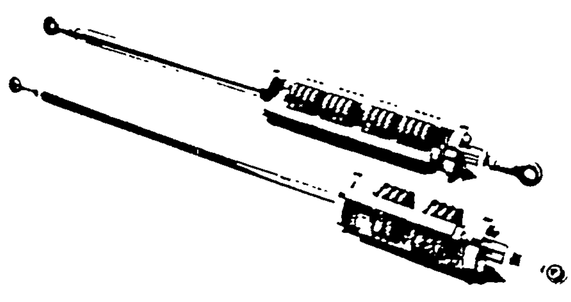

Figure 1 - WEAR Restraint

PROBLEM DESCRIPTION

An isometric of the piping system investigated is shown in Figure 4. The system is a 10-inch diameter drain line which runs between the flash tank and the condenser.

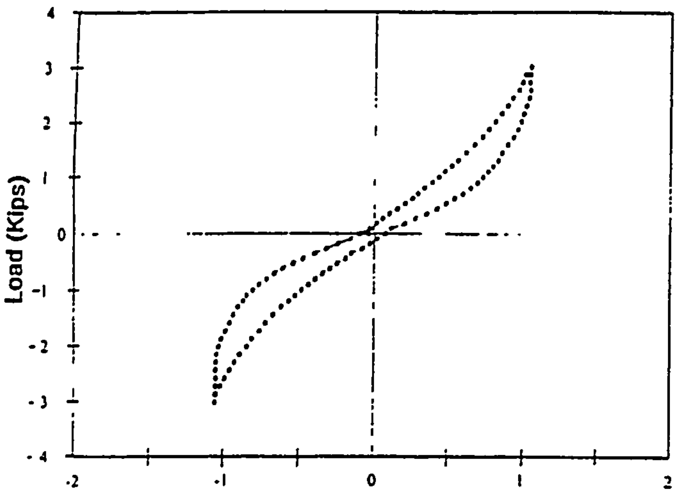

FIGURE 2 - TYPICAL WEAR™ FORCE DEFLECTION CURVE

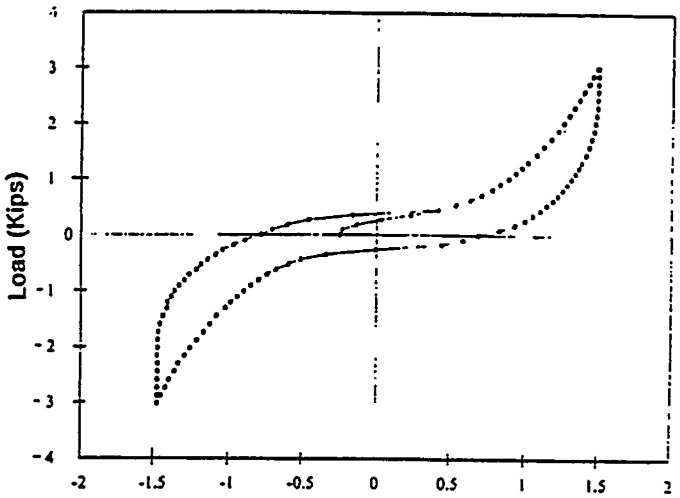

FIGURE 3 - TYPICAL WEAR™ BI-LINEAR FORCE DEFLECTION CURVE

The piping system has an overall vertical drop of 120 feet and horizontal runs totaling 60 feet. The Oxnard plant is a 750 MW non-enclosed oil and gas fired unit located on the sea coast. Corrosion is a factor for exposed supports. The system was originally restrained by 4 hydraulic snubbers at 3 locations, as shown in Figure 4. Corrosion and lack of maintenance due to inaccessibility has taken its toll on the existing hydraulic snubbers, making them non-functional. WEAR™ restraints were investigated as replacements because of their simplicity, no maintenance requirements, high cycle fatigue life, and their ability to absorb energy and minimize loads on the structure.

Transients occur in the line during boiler startup each time the valve to the condenser is cycled. The lack of functional snubbers has resulted in failed spring supports and damaged pipe insulation.

The system operates at 560°F and 1175 psi. Snubbers were originally located to carry pipe axial transient loads of $\pm$ 10,000 pounds. Replacement WEAR™ restraints were to maintain existing pin-pin dimensions and utilize existing pipe and structural attachments. Since WEAR™ restraints are spring elements, their effect on the thermal expansion behavior of the piping system must be considered. WEAR™ restraints are selected such that they are flexible enough to allow for pipe thermal expansion. They must also have sufficient stiffness to arrest the hydraulic transient. The selection of the proper WEAR™ restraints balances these two conflicting requirements.

Hydraulic transient forces act along the axis of each pipe segment. In general, the longer the pipe segment is, the larger the magnitude and duration time of the transient force. It is impractical to restraint every leg of a piping system for the transient loadings. Typically, the major runs are constrained and small transient displacements are acceptable. Unlike snubbers, WEAR™ restraints will quickly dampen out the transient pipe response. System damping equal to 9% of critical is achievable with the use of WEAR™ restraints[2]. Added damping is a desirable characteristic when trying to control pipe vibrations.

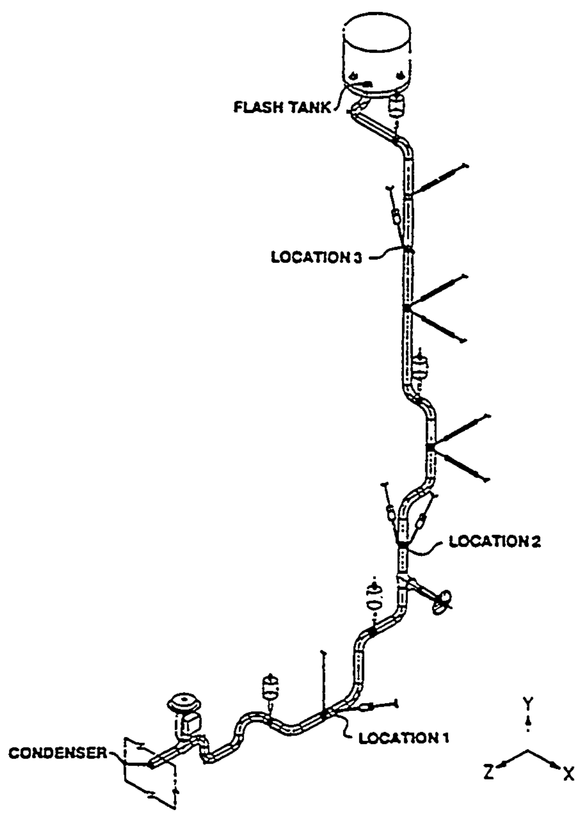

FIGURE 4 - ISOMETRIC OF FLASH TANK DRAIN SYSTEM

MINIMUM REQUIRED STIFFNESS

The minimum required stiffness of each WEAR™ restraint is governed by the code allowable for occasional loadings. In this case the material is A106 GrB and the sum of longitudinal pressure, dead weight and the transient load stresses must be less than 18,000 psi per ASME/ANSI B31.1. The determination of the required minimum stiffness of each WEAR™ restraint is found by performing static analysis using the design transient load. The design load is imposed in the direction of the WEAR™ restraint at each support location. The resulting pipe stiffnesses are computed from each of these runs. The maximum allowable pipe displacements, based on the code allowable are then determined from these analyses. This information is utilized to form the basis for the minimum WEAR™ stiffness required to limit transient displacements to code acceptable values.

In this example, the design load was imposed at the locations shown in Figure 5. Each of the three loads are analyzed separately. The results of the design load placed at WEAR™ restraint Location 1 show that a 10,000 pound load displaces the pipe along the restraint axis 5.2 inches. The resulting pipe stiffness is computed as:

$$K_1 = \frac{10{,}000}{5.2} = 1{,}923 \text{ lb/in} \qquad (1)$$

The maximum stress from application of this load is 51,750 psi and occurs in the first elbow adjacent to the condenser. The combined axial pressure plus dead weight stress at this location is 5,666 psi. The code allowable of 18,000 psi for occasional loading provides the following stress margin for the transient load:

$$\sigma_1 = 18{,}000 - 5{,}666 = 12{,}334 \text{ psi} \qquad (2)$$

Based on the design load analysis producing a displacement of 5.2 inches and a corresponding stress level of 51,750 psi, the maximum allowed displacement at the restraint location is:

$$\Delta_{1max} = \frac{(12{,}334)\ (5.2)}{51{,}750} = 1.24 \text{ inches} \qquad (3)$$

Since static methods are being utilized for analyzing a transient event, Δ_{1max} must be reduced by an appropriate dynamic load factor. A conservative value for a non-periodic forcing function is 2.[3] Thus the maximum allowed displacement is equal to one-half Δ_{1max} or .62 inches.

The required minimum WEAR™ stiffness for Location 1 may now be determined. The addition of the WEAR™ support results in a system of two springs in parallel where K_1 is the previously computed pipe stiffness and K_{w1} is the required WEAR™ stiffness at Location 1. Thus:

$$F = (K_1 + K_{w1})\ \Delta \qquad (4)$$

or

$$K_{w1} = \frac{F}{\Delta} - K_1 \qquad (5)$$

In this case, the design load is 10,000 pounds and the maximum allowed displacement is .62 inches. Thus:

$$K_{w1} \geq \frac{10{,}000}{.62} - 1{,}923 = 14{,}200 \frac{\text{lb}}{\text{in}} \qquad (6)$$

Performing the same computation using the analysis of design loads applied at WEAR™ restraint locations 2 and 3 results in the following minimum stiffnesses at these locations:

$K_{w2} \geq 6{,}300$ lb/in

$K_{w3} \geq 12{,}500$ lb/in

These stiffness values are on the conservative side since they were determined without consideration for the effect which adjacent WEAR™ restraints have on the pipe stiffness. This is particularly true for the WEAR™ restraints at Locations 2 & 3, since they both constrain vertical movement. Thus, the actual minimum required WEAR™ stiffnesses are somewhat less than the computed values.

WEAR™ restraints are available with standard load ratings and stiffness values. Custom sizes are also available. For this application, a model 19200 is chosen for Locations 1 and 3 and two models 9600 are chosen for Location 2.

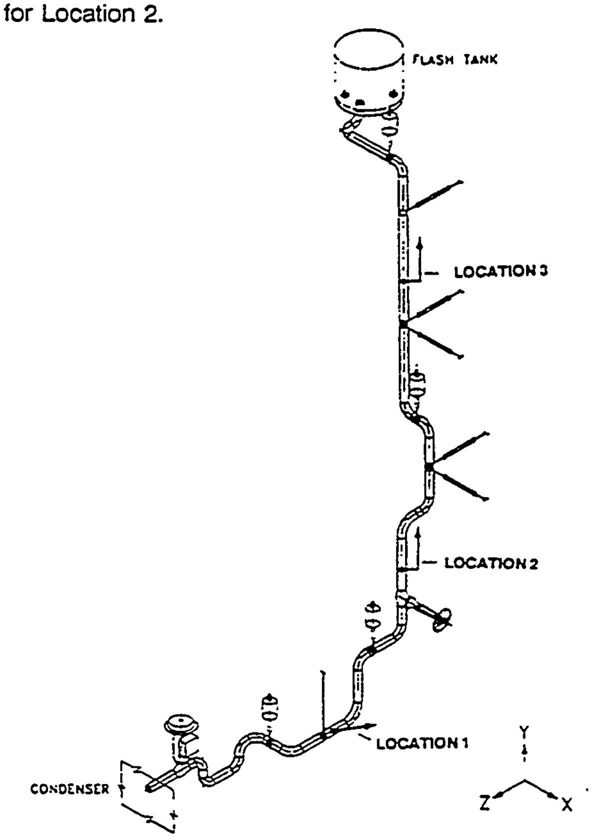

FIGURE 5 - LOCATIONS OF UNIT LOADS

These restraints have the following load ratings and nominal stiffness values:

Model No.	Load Rating(lb)	Stiffness(lb/in)
9600	9,600	8,000
19200	19,200	16,000

In order to verify the acceptability of the chosen WEAR™ restraint stiffnesses, the static analyses are rerun, this time with the chosen WEAR™ stiffnesses incorporated into the model. Since static methods are being used for a transient analysis, a dynamic load factor of two is conservatively applied to the design load of 10,000 pounds.

Computed deflections and maximum combined occasional load stresses for each of the three 20,000 pound analyses are:

Run No.	Load Location*	Restraint Travel(in)	Combined Stress(psi)
1	1	1.10	16,935
2	2	1.12	15,280
3	3	.77	15,017

* See Figure 5

As the results indicate, the initially chosen WEAR™ restraint stiffness values are sufficient for the applied dynamic loads.

THERMAL EXPANSION CRITERIA

Based on the chosen WEAR™ stiffness values, the system is checked for thermal expansion effects. In general, the added stiffness of the WEAR™ restraints will tend to increase the thermal stress level in the piping system.

The thermal analysis of the example system demonstrates that the code allowable stress is met with the chosen WEAR™ restraints. The maximum thermal stress with the WEAR™ restraints is 22,324 psi. This compares with a maximum thermal stress level of 18,030 psi without the WEAR™ restraints.

With the completion of the thermal analysis, all required information for the WEAR™ restraints is known. The final specification for the WEAR™ restraints at each of the three locations is as shown in Table 1.

The specified WEAR™ restraints will maintain the code allowables for the design transient load and thermal expansion. Their high damping characteristics will quickly dampen out the flow induced transient response of the piping system.

Loc	No. Req'd	Load Rating(lb)	Stiffness (lb/in)	WEAR™ Displacements (in) Thermal	Dynamic	Total
1	1	19,200	16,000	.20	1.10	2.40
2	2	9,600	8,000	.31	1.12	2.55
3	1	19,200	16,000	.05	.77	1.60

TABLE 1 - Final Specification for WEAR™ Restraints

If the results of the thermal expansion analysis were not acceptable, bi-linear restraints would be specified. This is accomplished by a simple factory adjustment of the standard WEAR™ restraint. The stiffness of the "soft" portion of the restraint is specified based on the maximum restraint stiffness which can be tolerated at each location. The range of the "soft" spring is dictated by the total thermal travel absorbed by the restraint. The restraint is typically installed with a cold preload. This preload is equal to the spring force associated with the thermal travel. This is shown in Figure 6 as point CP on the force-deflection curve. As the pipe expands, the restraint moves along the "soft" slope to point HP, also shown in Figure 6. The average stiffness as indicated by the broken line in Figure 6 must be sufficient to arrest the transient event and maintain the code allowable for occasional loadings.

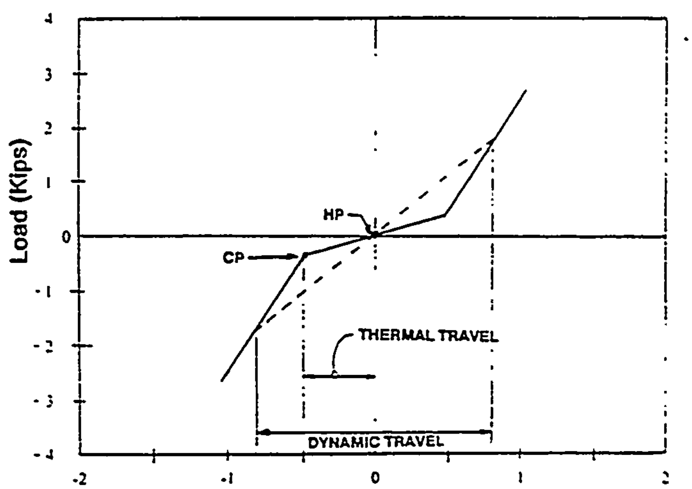

FIGURE 6 - HOT & COLD POSITIONS OF BI-LINEAR WEAR™ RESTRAINT

DYNAMIC PROPERTIES

WEAR™ restraints exhibit a number of desirable characteristics for dynamic load control. These include:

- Large Damping Characteristics
- High Fatigue Life
- Energy Absorption
- Simplicity
- Low Maintenance
- Low Structural Loading

The damping characteristic of the device was previously investigated by Loziuk[2]. The low structural loading attribute is investigated in this paper in terms of dynamic load factors.

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A dynamic load factor is the deflection ratio of a spring-mass system subjected to a static load versus a dynamic load of the same magnitude. The use of dynamic load factors allows one to evaluate a dynamic event using static methods. This is done by multiplying the static results (deflections, stresses, loads, etc.) by an appropriate dynamic load factor. In the example previously presented, a dynamic load factor of two was conservatively utilized in evaluating the piping system with WEAR™ restraints. Two is an upper bound for non-impact and non-cyclic loads.

An interesting phenomenon of dynamic load factors is that they are not always greater than unity. Figure 7 presents the dynamic load factor curve for a square pulse loading of magnitude F and duration time t_d. The dynamic load factor is a function of the duration time of the applied load and the natural period of the spring mass system. As Figure 7 indicates, the dynamic load factor decreases as the natural period increases relative to the load duration time.

The natural period of a spring mass system is equal to:

$$T = 2\pi\sqrt{M/K} \tag{7}$$

Thus, as the stiffness increases, the natural period decreases. This has the effect of increasing the dynamic load factor. Snubbers and struts are relatively stiff restraints and their use typically results in dynamic load factors which approach two. On the other hand, WEAR™ restraints are relatively soft and their use will tend to result in dynamic load factors less than two. To demonstrate this, the dynamic load factor for the flash tank drain line system is investigated.

In order to approximate the dynamic load factor, the load duration time, t_d, and the natural period, T, of the system must be determined. The load duration time may be approximated by assuming that the transient event results in the propagation of a square pressure wave down the piping system. The wave travels at the speed of sound in the media and is equal to about 4,000 feet/second for water[4]. If we consider a vertical segment of pipe equal to 50 feet long, the time which the unbalanced pressure force acts on the leg is equal to:

$$t_d = \frac{L}{C} = \frac{50}{4000} = .0125 \text{ sec.} \tag{8}$$

Where:

L = Length of the pipe segment

C = Speed of sound in the media

A modal analysis of the flash tank drain line system provides the natural periods and mode shapes of the system. A review of these results indicates that the system's response to vertical excitation is primarily associated with the fourth mode shown in Figure 8. The natural period of the fourth mode is equal to .24

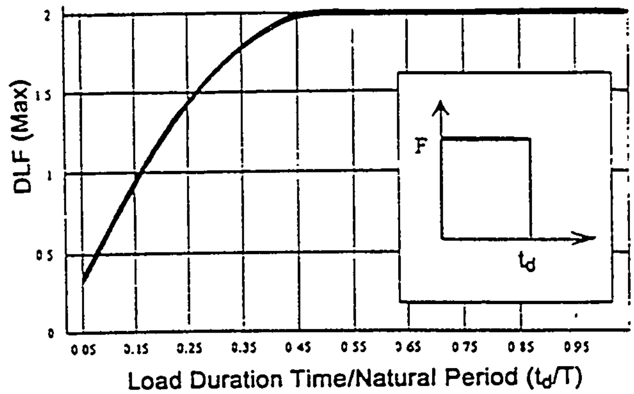

FIGURE 7 - DYNAMIC LOAD FACTOR CURVE FOR SQUARE PULSE LOAD

seconds. Thus, the ratio of the load duration time to the natural period is computed as:

$$\frac{t_d}{T} = \frac{.0125}{.24} = .052 \tag{9}$$

Referring to Figure 7, one finds that dynamic load factor for this case is less than .4. Thus, the response of the system will be significantly less than the design basis presented earlier in this paper. The applied 10,000 lb. dynamic load is seen by the system as 4,000 lbs. versus the 20,000 lbs. previously estimated.

Supporting a system using flexible restraints will typically result in lower loads on the structure than traditional rigidly supported systems. WEAR™ restraints offer this advantage.

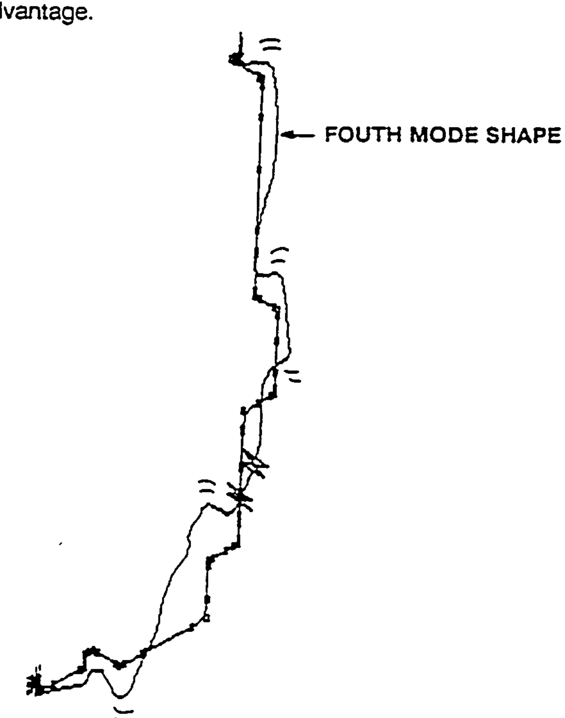

FIGURE 8 - FOURTH MODE SHAPE OF THE FLASH TANK DRAIN LINE

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A Versatile Electrical Penetration Design Qualified to IEEE Std. 317-1983

This paper presented by Tim Pelot at the
United States/Korea Electric Power Technologies Seminar

on October 25, 1994

in

Seoul, Korea

A Versatile Electrical Penetration Design Qualified to IEEE Std. 317-1983

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SUMMARY

Although worldwide demand for new construction of nuclear power stations has been on a decline, the available opportunities for the design and construction of qualified electrical penetrations continues to offer challenges, requiring a highly versatile design. Versatility is necessary in order to meet unique customer requirements within the constraints of a design basis qualified to IEEE Std. 317-1983.

This paper summarizes such a versatile electrical penetration designed, built and tested to IEEE Std. 317-1983. The principal features are described including major materials of construction. Some of the design constraints such as sealing requirements, and conductor density (including numerical example) are discussed.

The requirements for qualification testing of the penetration assembly to IEEE Std. 317-1983 are delineated in a general sense, and some typical test ranges for preconditioning, radiation exposure, and LOCA are provided.

The paper concludes by describing ways in which this versatile design has been adapted to meet unique customer requirements in a variety of nuclear power plants.

A VERSATILE ELECTRICAL PENETRATION DESIGN QUALIFIED TO IEEE STD 317-1983

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Introduction

An electrical penetration assembly is a device that provides the means for the passage of electrical conductors through the containment wall of a nuclear power plant while maintaining containment integrity. The electrical cable may be as large as 1000MCM (507mm^2) used primarily for circulation cooling pumps or as small as triax or coax used in radiation monitoring systems. The penetration assembly must be designed and manufactured to survive the nuclear plant's most severe postulated Design Base Event in its end of life condition (40 years), and maintain containment integrity, and where required, function electrically.

Construction of new nuclear plants is infrequent and those penetrations in operating plants have been installed for the lifetime of the facility. For the most part, purchases of new penetrations are limited to upgrade requirements or when the documentation provided with the original equipment does not satisfy new requirements. When these occasions arise, time should be spent reviewing the appropriate sections of the ASME Boiler Code and one of the penetration standards such as IEEE Std 317-1983 or IEC 772 prior to writing the design specification. The following is a review of some parameters to consider when writing an electrical penetration design specification using as a model, a versatile penetration assembly manufactured by Imaging & Sensing Technology (IST).

Penetration Design

The penetration assemblies manufactured prior to the early 1970's were primarily of the canister design. This design consisted of a carbon steel sleeve welded and sealed at both ends with stainless steel plates. Ceramic or glass to metal feedthroughs were brazed to the plates with the penetration pigtails crimped or soldered to the feedthroughs. This sleeve would then be welded to the containment nozzle. One of the shortcomings of this design is that if a failure were to occur (i.e. containment leak or significant electrical failures) it would be necessary to cut the assembly out of the wall.

The penetration assemblies being manufactured today are a modular design. Similar to the canister design, a sleeve welded to a stainless steel plate (bulkhead extension assembly) is welded to the containment nozzle. The penetration pigtails pass through the stainless steel plates sealed in removable modules or feedthroughs. Figure 1 is a drawing of an IST modular penetration assembly designed to be welded to a 12" nominal containment nozzle size. The drawing shows the bulkhead extension assembly, two modules and one plug, and retaining lugs that secure the modules in the bulkhead. These items when installed are part of the containment boundary and, therefore, are controlled by the requirements of the ASME Boiler Code. The pigtail conductors are sealed in the module, and the modules sealed in the bulkhead in a manner that will allow the leak tightness of these seals to be verified during plant operation and shutdown by observing the monitoring gauge. Without this feature, leak tightness can only be demonstrated during the total containment pressure test. This provision for leak rate monitoring is a requirement of IEEE Std 317-1983 for penetration assemblies containing double seals. The remaining items in the drawing are accessories that may or may not be provided by the penetration manufacturer.

Figure 2 is a cutaway drawing of an IST module. A bare solid copper conductor is provided for each pigtail. The cross sectional area of each copper conductor is equal to one AWG size larger than the pigtail to which it is crimped. Q-1 is a three part oven cured epoxy that develops sufficient compressive force on each copper conductor to maintain a hermetic containment seal during normal operation and severe accident conditions. Q-1 also provides electrical insulation between the bare copper conductors. After the pigtails are crimped to their copper conductors, the remaining module volume is filled with Q-2, an epoxy composed of the same three ingredients as Q-1 but in different percentages to permit room temperature curing. The function of Q-2 is to provide strain relief for the pigtail/copper conductor splice. The stainless steel module flange (header) contains four O-ring grooves for the sealing of the module into the finely machined bulkhead module holes. The monitoring space is a void in each module that connects with the volume between the pair of module O-rings and the monitoring gauge volume once the module is secured in the bulkhead. The pressurization of this interconnected monitoring volume with nitrogen permits the total leak rate of the module conductor seals and O-ring seals to be documented by recording any drop in pressure gauge reading.

The discussion thus far has described the design of the environmental sealing mechanism of an electrical penetration. The second half of the design addresses the specifying of cable sizes, quantity of cable, and ampacity. This is the area where people appear to have the most difficulty when writing a design specification. IEEE Std 317-1983 has included in its appendix some very useful information to assist in sizing the penetration cable configuration. It should be pointed out, however, that the preferred values tabulated in Part A1. and A2. of the standard are for penetrations in a 12 inch nozzle size and, therefore, may need to be adjusted for nozzles of different sizes. For this discussion the nozzle size is 12 inches. The maximum number of conductors of a given cable size in an assembly is based upon the cable diameter and minimum space required between conductors to hold off the rated and test voltages. Table 1 is a tabulation of the maximum number of cables in a standard 12 inch nozzle IST penetration assembly. An important consideration when specifying the size and number of penetration conductors is the rated continuous current. Rated continuous current is the value at which a penetration conductor in the assembly operates without exceeding the conductors qualified life design temperature or the nozzle/concrete interface temperature with all other conductors in the assembly operating at their rated continuous current. The maximum allowable interface temperature is normally 150°F (66°C). To illustrate how the rated continuous current is determined, a calculation for one conductor size is provided.

The cables used for pigtails in the IST penetrations have been qualified to the nuclear cable standard IEEE Std 383-1974 for 40 year life at 90°C. To determine the maximum rated continuous current of 750, #16AWG cables in a 12 inch nozzle, reference is first made to Table 310-17 of the National Electrical Code or its equivalent. The 1984 Edition indicates that #16AWG cable carrying 24 amps. of current in a 30°C ambient would have an insulation temperature of 90°C. This current is for a single conductor in air. Because in this example there are 750 conductors in a 12 inch diameter pipe, the current value must be derated. Because all 750 conductors will be operating at 90°C, we will derate to the highest ambient (71°C - 80°C) by multiplying the 24 amps by 0.41 for a current value of 9.8 amps.

It has been determined by test that if 30 watts/foot of power is dissipated in a 12 inch diameter pipe, the interface temperature between the pipe and the concrete in which it is imbedded will be 150°F when the ambient temperature outside the pipe is 123°F (50°C).

Using the ampacity equation and solving for I,

I^2RN = watts/foot

where $R = 5.55 \times 10^{-3}$ ohm (one foot length of #16AWG at 90°C.); N = 750 (#16AWG pigtails); watts/foot = 30

I = 2.6 amps.

These calculations are indicating that although the 750, #16AWG cables are capable of simultaneously operating continuously at 9.8 amps without exceeding the 90°C maximum insulation temperature, the current will be limited to 2.6 amps because of the 150°F interface temperature restriction.

If 9.8 amps is required, and again using the ampacity equation, the number of #16AWG conductors operating at any one time at that current would be restricted to 56. If more conductors are required operating at 9.8 amps, then a larger size conductor would have to be specified.

Qualified Life Testing

Once designed, the penetration performance must be verified not only at normal plant ambient conditions, but also during or after any of the accidents or events that may occur during, or at, the end of plant life.

IST has subjected representative samples of Medium Voltage Power, Low Voltage Power, Control and Instrumentation penetration assemblies to the Qualified Life Testing program described in Paragraph 6.3 of IEEE Std 317-1983.

Qualified life testing to IEEE Std. 317-1983 includes preconditioning and life testing to various conditions. The preconditioning portion includes Shipping and Storage, Thermal Operating Cycle, Thermal Aging, and Radiation Exposure.

Shipping and Storage, and Thermal Operating Cycle portions of the preconditioning are intended to provide conservative thermal cycling to the qualification units. Shipping and Storage varies from -20F to 150F (5 cycles), and the Thermal Operating Cycle must cover a temperature change of 100F (120 cycles). These cycles are easily tolerated by the penetration assemblies.

Thermal aging of the penetration assembly components follows the requirements of IEEE Std. 317-1983, and utilizes activation energies of the materials. Derivation of the IST proprietary epoxy compound activation energy was based on an extensive Arrhenius aging program to IEEE Std. 98-1984 and IEEE Std. 101-1972, which considered sealing performance and electrical integrity as failure criterion. The O-rings and epoxy were aged to an equivalent of 40 years at 70°C.

Radiation exposure preconditioning was performed by Cobalt-60, gamma radiation exposure to a certified minimum of 220 MRads. This includes normal service, plus accident, plus required margin. This was the minimum level of exposure on the penetration module. Electrical cables of the penetration received significantly higher doses because of unavoidable proximity to the source.

Functional electrical and containment leak testing of the penetrations was performed following preconditioning.

The assemblies were then subjected to the tests described in Paragraph 6.3.3 of IEEE Std 317-1983, summarized below:

(1) Short-Circuit Current and Short-Circuit Thermal Capacity Test

(2) Seismic Test

(3) Simulation Tests of the Most Severe DBE Environmental Conditions (See Figure 3)

(4) Rated Short-Time Overload Current and Duration During the Most Severe DBE Environmental Conditions.

(5) Rated Short-Circuit Current During the Most Severe DBE Environmental Conditions

(6) Rated Short-Circuit Thermal Capacity (I^2t) During the Most Severe DBE Environmental Conditions

The penetration assemblies passed all the required functional electrical and leak tests during and at the conclusion of the six tests listed above, thus demonstrating qualification to IEEE Std 317-1983.

Versatile Design

The penetration assembly described above will maintain containment integrity during normal operation and the accident conditions enveloped by the LOCA profile of Figure 3. There are, however, additional design configurations that must be considered to satisfy unique plant requirements.

In the BWR Perry Plant, a negative 0.40 inch WG pressure must be maintained in the annular space between the shield building and the containment vessel. The modular penetration described was adapted to this requirement by the addition of a second seal around the cables where they emerge through the outer wall of the shield building. Because of the mild environment at this location and the slight pressure differential requirement across the seal, the epoxy was potted directly to the cables rather than using the more complex design of the primary seal. To complete the installation, the secondary seal was O-ring sealed to a stainless steel plate that had been sealed to the outboard end of the nozzle.

This secondary seal design was used for the CANDU penetrations IST provided for the Ontario Hydro Darlington Station. The design specification required that the penetration design shall accept and contain sand by providing two filler plugs in a sand retaining plate on the inboard side. In this installation, the bulkhead extension assemblies containing the primary modules were welded to the outside containment end of the nozzle. The secondary seals were mounted to the stainless steel plate (sand retaining plate) which was sealed to the inboard end of the nozzle. The sand used for radiation shielding was then blown into this sealed nozzle volume completing the installation.

The most recent adaption of this basic design are the penetrations IST and licensee SKODA Nuclear Machinery are providing for the VVER-1000 design Temelin plants in the Czech Republic. The penetrations have been designed and successfully tested to a worst case DBE scenario, wherein the penetrations must remain leak tight after a 1000°C, 90 minute fire followed by a 0.56 MPa loss of coolant accident. The primary module is installed on the inside containment wall and the secondary module, constructed similar to the primary seal, on the outside containment wall. The nozzle volume between modules is filled with sand for radiation shielding.

In conclusion, IST's versatile modular electrical penetration design has been successfully tested for use in PWR, BWR, CANDU and VVER power plants.

TABLE 1

Maximum Number of Cable in a Standard 12 Inch IST Penetration Assembly

Conductor Size	Number of Conductors
#16AWG	750
#14AWG	654
#12AWG	561
#10AWG	399
#8AWG	255
#6AWG	165
#4AWG	153
#2AWG	111
#1/0AWG	59
#2/0AWG	39
#3/0AWG	39
#4/0AWG	39
250MCM	27
350MCM	27
500MCM	12
750MCM	9
1000MCM	9
#16STP (Shield Twisted Pair)	165
#16STT (Shield Twisted Triplets)	111
#16STQ (Shield Twisted Quad)	93
Coax	57
Triax	24

NFPA 70-1984, TABLE 310-17

1/C #16 AWG, 30° C Ambient

24 amps, 90° C insulation temperature

71° C - 80° C Ambient, 0.41 derate factor

24 amps x 0.41 = 9.8 amps

---

30 watts/foot, 12 inch nominal nozzle size

150° F (66° C) nozzle/concrete interface temperature

$I^2 RN = 30$ W/ft

I = rated current

$R = 5.55 \times 10^{-3}$ ohms (#16 AWG)

$N = 750$ (number of conductors at rated current)

$I = 2.6$ amps

Maximum number of conductors at 9.8 amps without exceeding the 150° F interface temperature:

$$N = \frac{30}{I^2 R} \qquad N = 56 \text{ conductors}$$

Table 2

Qualified-Life Tests

6.3.1 Initial Tests

A. Gas-Leak Rate/Pneumatic Pressure Test

B. Dielectric-Strength Test

C. Insulation-Resistance Test

D. Conductor Continuity and Identification

F. Partial Discharge (Medium Voltage only)

6.3.2 Preconditioning

A. Shipping and Storage Simulation
5 Cycles -28°C (-20°F) to 65.5°C (150°F) for 2 hr. dwell

B. Thermal Operating Cycle Simulation
120 cycles of 55°C (100°F) temperature change

C. Thermal Age Conditioning (40 years at 70°C (158°F) max.

D. Radiation Exposure (220M rads)

6.3.3 Test Requirements

A. Short Circuit Current/Thermal Capacity Test

B. Seismic Test

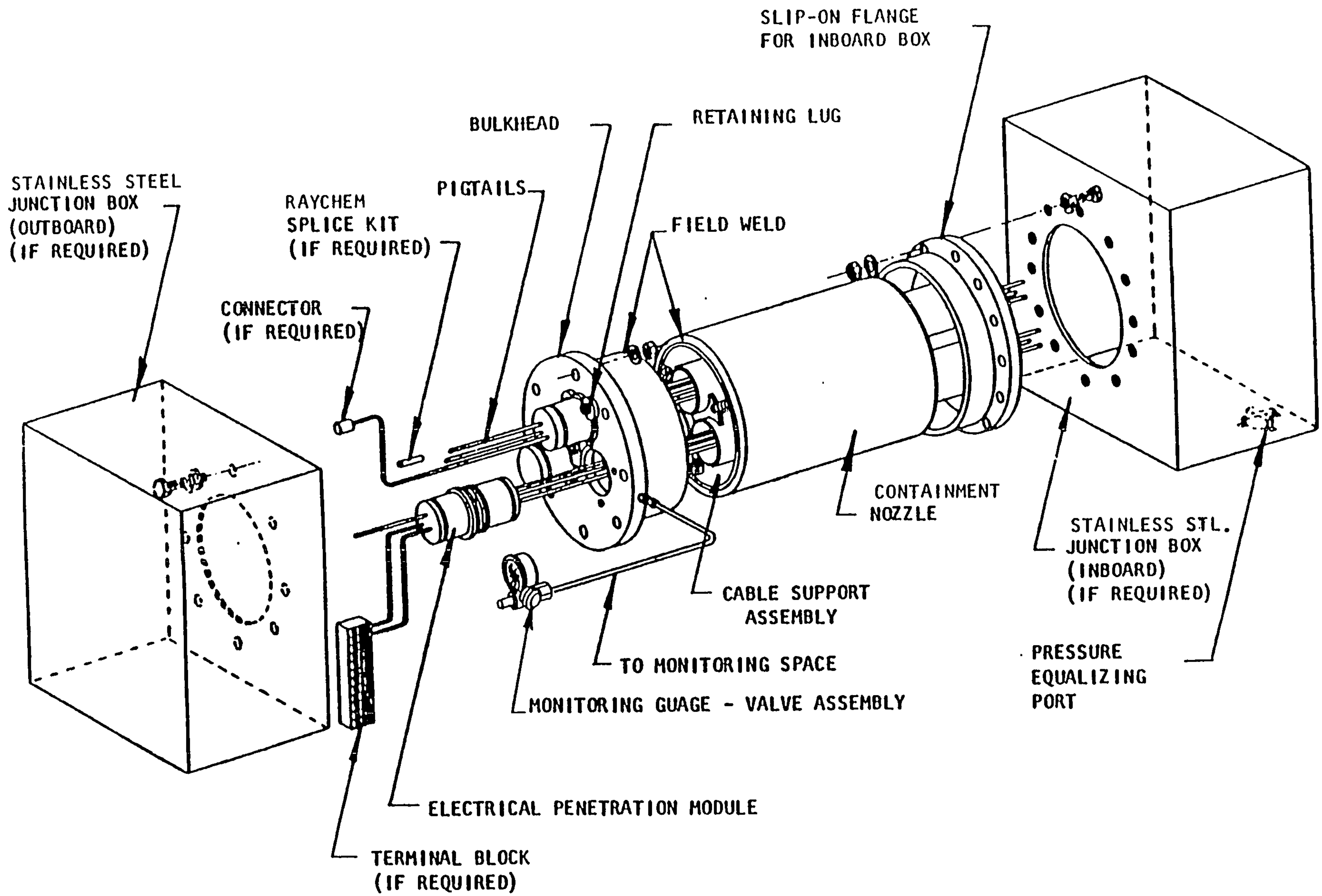
C. Most Severe DBE Environmental Conditions (Figure 3)

D. Rated Short-Time Overload Current and Duration
During the Most Severe DBE Environmental Conditions

E. Rated Short Circuit/Thermal Capacity (I^2t)
During the Most Severe DBE Environmental Conditions

Required Containment Leak Test and Electrical Tests Performed After Each Test Segment.

Table 3



IMAGING & SENSING TECHNOLOGY CORPORATION
HORSEHEADS, NY
WELDED BULKHEAD ELECTRICAL PENETRATION ASSEMBLY

Figure 1

MODULE CONSTRUCTION

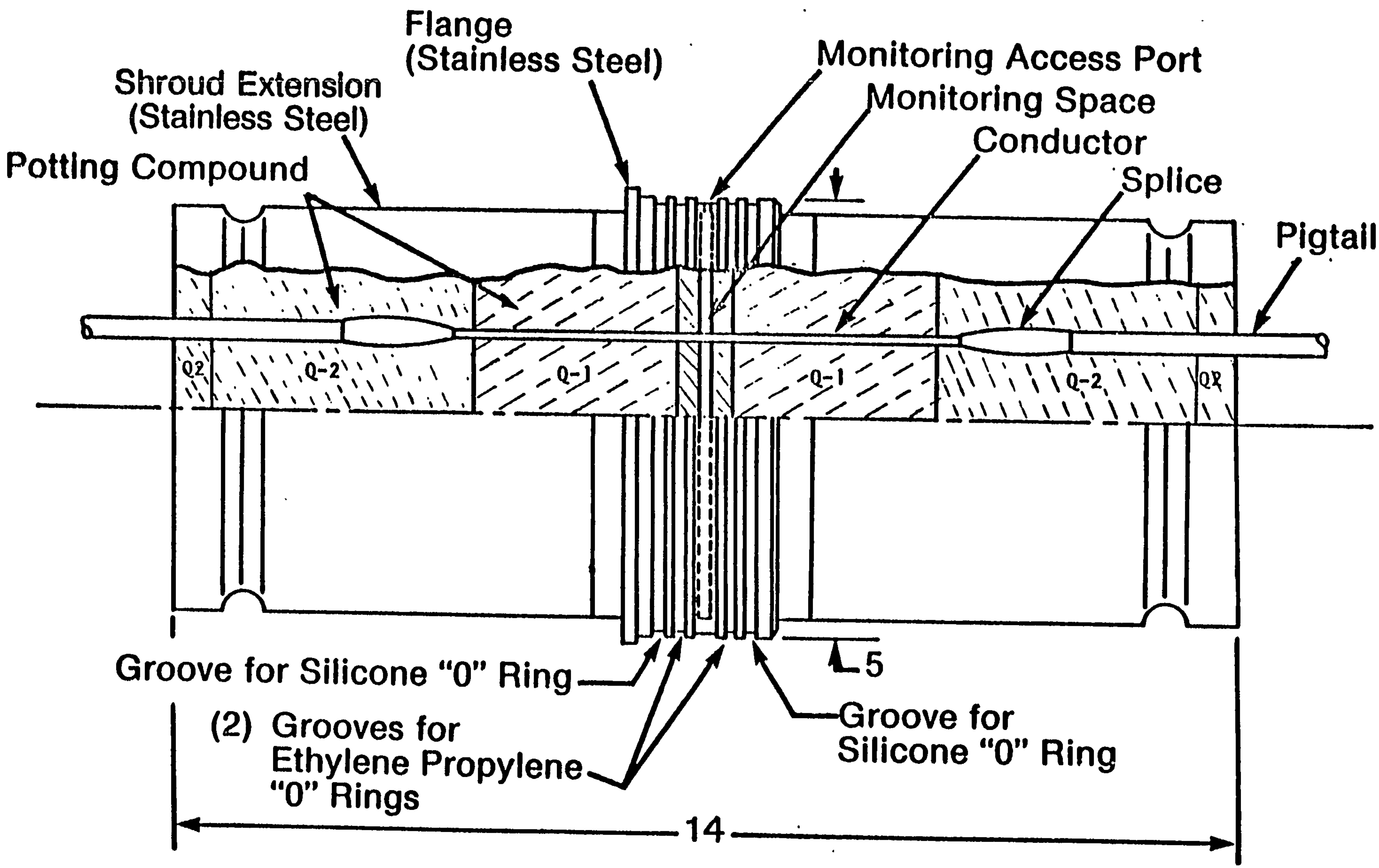
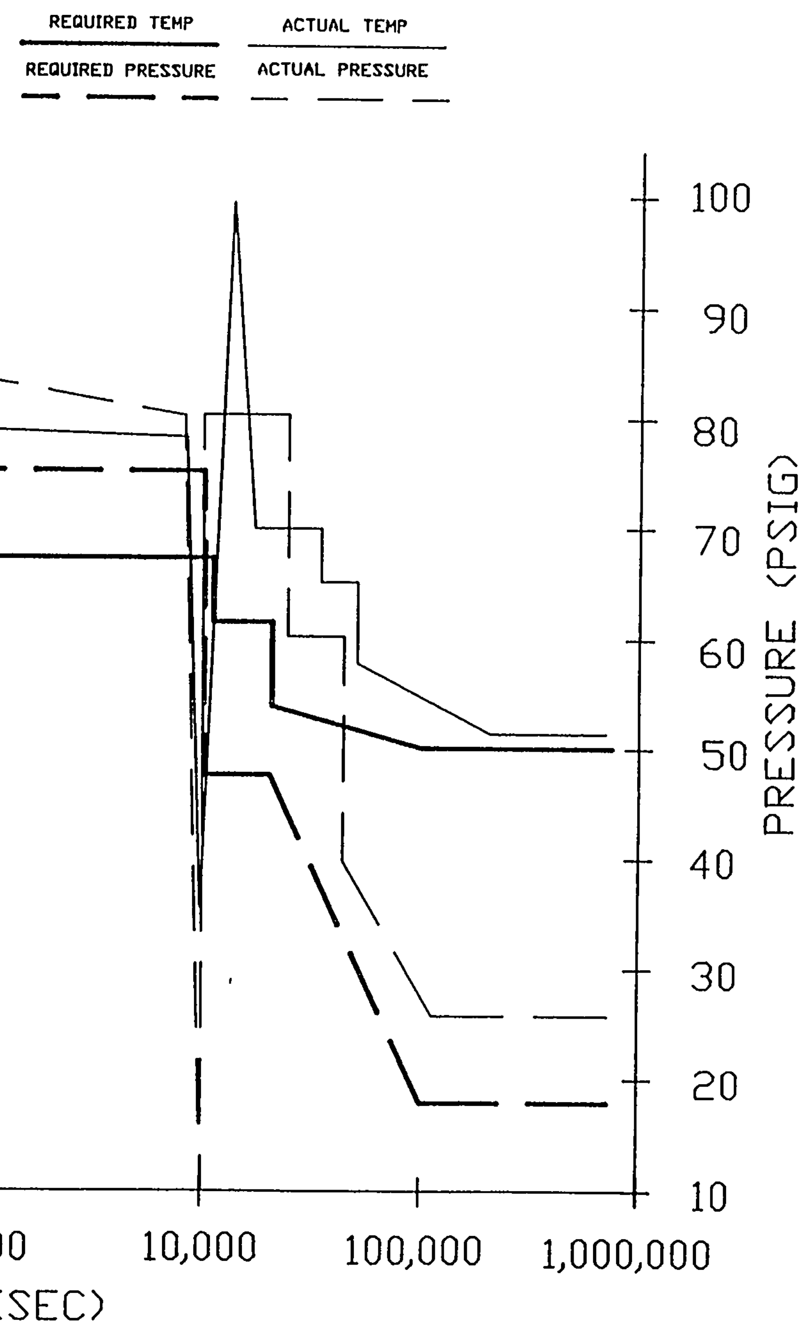
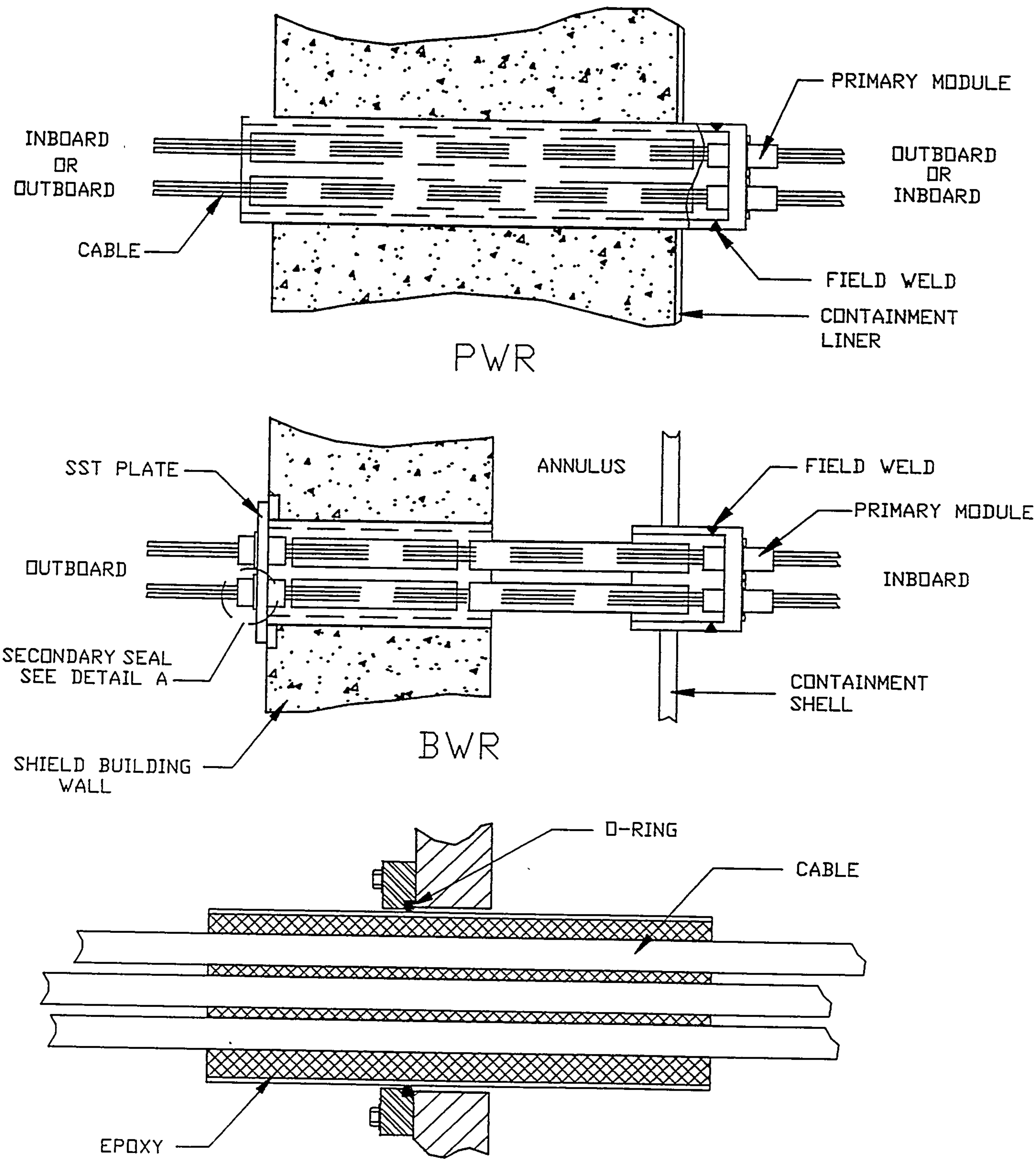


Figure 2

FIGURE 3

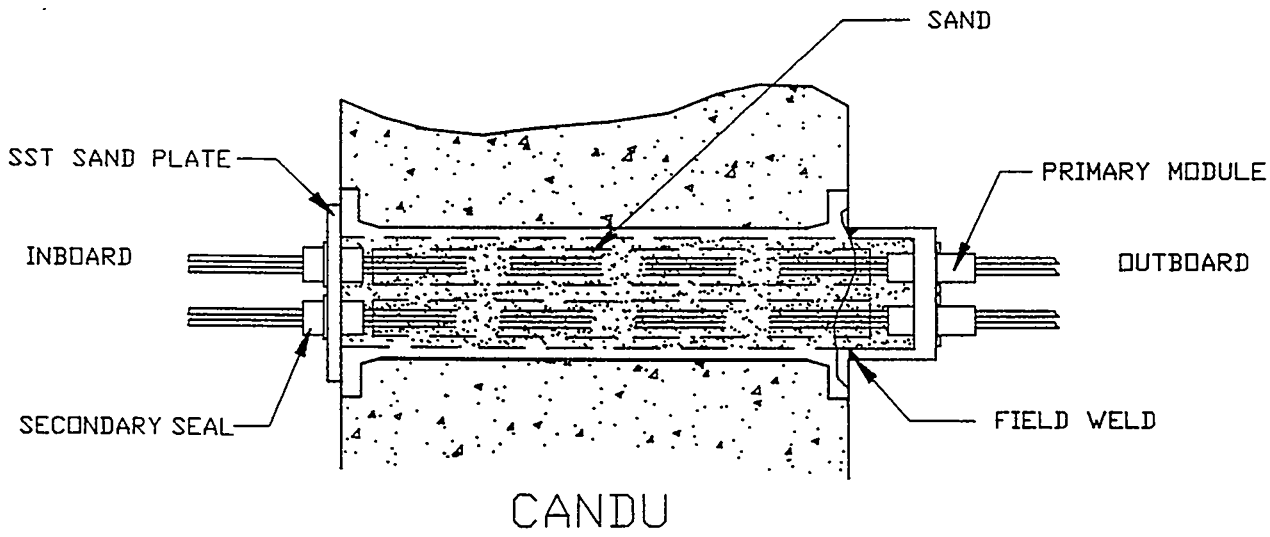
IST CORPORATION
LOCA PROFILE
IEEE 317-1983 QUALIFICATION

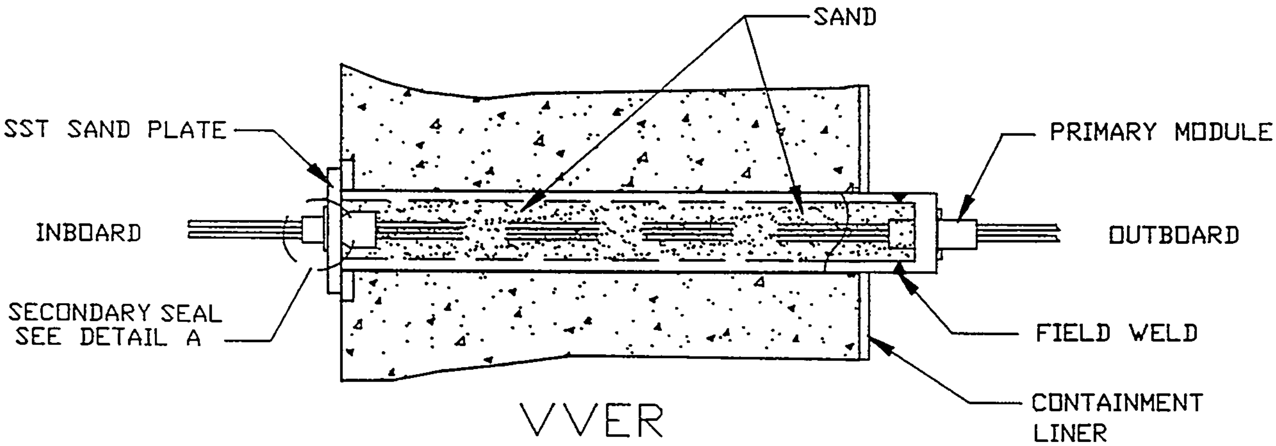




BWR SECONDARY SEAL
DETAIL A

FIGURE 4


SAND
SST SAND PLATE
PRIMARY MODULE
INBOARD
OUTBOARD
SECONDARY SEAL
FIELD WELD
CANDU


SAND
SST SAND PLATE
PRIMARY MODULE
INBOARD
OUTBOARD
SECONDARY SEAL
SEE DETAIL A
FIELD WELD
CONTAINMENT
LINER
VVER

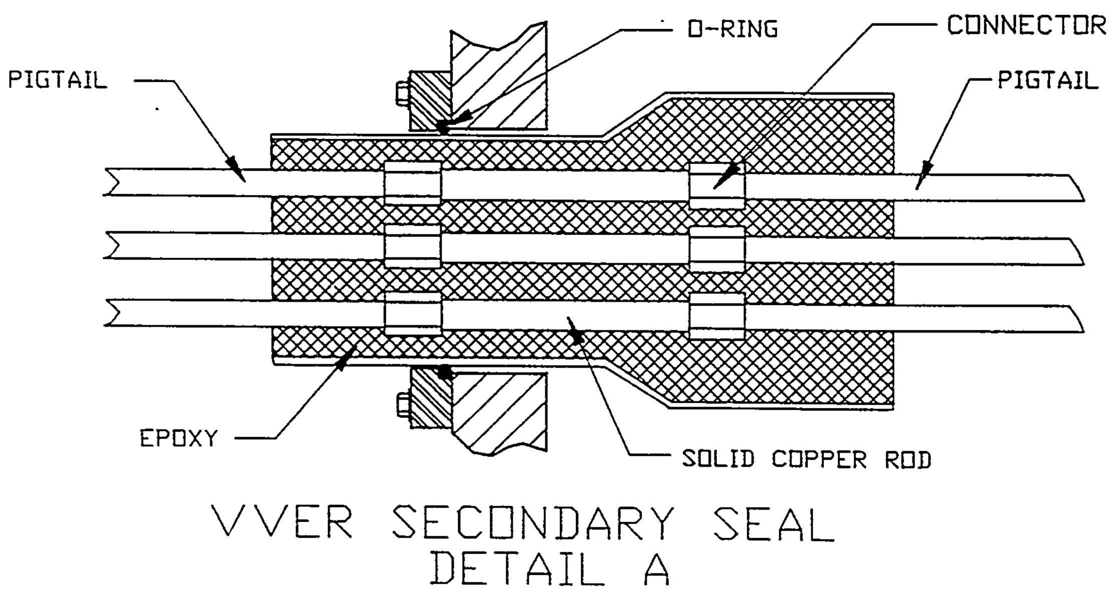

O-RING
CONNECTOR
PIGTAIL
PIGTAIL
EPOXY
SOLID COPPER ROD
VVER SECONDARY SEAL
DETAIL A

FIGURE 5

TESTING AND PLUGGING POWER PLANT HEAT EXCHANGERS

U.S./Korea Power Technology Seminar
Inter-Continental Hotel, Seoul, Korea
October 24-26, 1994

Mr. Fritz Sutor, Vice President

Expando Seal Tools, Inc.
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INTRODUCTION.

Heat Exchanger tubes fail for any number of reasons including but certainly not limited to the cumulative effects of corrosion, erosion, thermal stress and fatigue. This presentation will attempt to identify the most common techniques for determining which tubes are leaking and then introduce the products in use to plug the leaking tubes. For the sake of time I will limit the scope of this presentation to include feedwater heaters and secondary system heat exchangers such as Hydrogen Coolers, Lube Oil Coolers, and nuclear Component Cooling Water, Emergency Cooling Water, Regenerative Heat Recovery heat exchangers. (The subject of testing and plugging Nuclear Steam Generators and Power Plant Main Condensers is beyond the time limit for today's presentation.)

TUBE TESTING TECHNIQUES.

When a heat exchanger has been successfully isolated and allowed to cool the present group of testing techniques revolves around pressurizing the entire heat exchanger in a Shell Side Test or pressurizing each individual tube to determine the affected tubes. Within the past 5-10 years a new testing technique called Eddy Current Testing has been gaining attention as a tube testing "tool" for predictive maintenance. These methods are detailed below.

Shell Side Air or Water Test

This is the simplest and most common method for testing shell and tube heat exchangers for tube leaks. An operator simply floods the shell side of the heat exchanger with air or water and pressurizes the system. In an air test the operator detects leaks by running his/her hand across the face of the tubesheet "feeling" for leaks. In a shell side hydro test the leaking tubes would be indicated by water seeping from the end of the leaking tube. The drawback of this technique is that it indicates the tubes with the greatest leaks first. After those leaking tubes have been plugged, additional tests will be required to identify other leaking tubes. When hydro testing it is possible to wind up plugging more tubes than are actually necessary because of water trapped when the unit was cooled. This type of testing may be time consuming when looking for pinhole leaks.

Individual Tube Air/Hydro Test

This type of test is performed by using either test plugs or tube testing guns to isolate an individual tube and either pressurize or evacuate it. A loss of pressure or vacuum during the test indicates that the tube is leaking. Typically air tests are performed with pressures ranging from 0 to 125 psia (0 to 8.5 Bars). Individual tube hydro testing can be performed with pressures ranging from 50 to 6,500 psi (3.4 to 450 Bars). The maximum test pressure should be determined by the operating requirements of the heat exchanger, it's age, the type of tube failure mechanism and the type of test plugs available. The drawbacks of this technique are obvious. It requires additional testing equipment and will be very time consuming if each tube is to be tested.

Eddy Current Testing

Eddy Current Testing has been gaining in popularity over the past several years because of it's ability to identify more than just a leaking tube. Eddy Current Testing is performed by drawing a small probe through the individual heat exchanger tubes. As the probe travels through each tube it introduces a small electrical signal into the tube wall and measures the time it takes for the signal to return. This time difference is recorded and used to make a "map" or "plot" of the actual tube I.D. and tube wall. A trained operator, through careful interpretation of the plot, can identify interior and exterior tubewall anomalies such as leaks, pits, cracks, wall reduction, and scale buildup. Successive eddy current tests performed over months or years can be compared to determine the rate of change in the tube wall and may be used to establish a preventative tube plugging program - actually plugging the tube before it fails in an attempt to avoid a costly forced outage.

The drawbacks of this technique are the relatively high cost of the equipment and operator training. It is also fairly time consuming (about equal to individual tube testing). Because of the capital expense for equipment and training there are consulting companies which offer eddy current testing and tube failure analysis as a service. Eddy current testing is currently limited to non-ferrous alloy tubes. (I have heard of at least two companies that have begun to market a variation intended for testing ferrous alloy tubes but do not know much about their equipment)

Each of these testing methods has several positive features that make them worth considering. Field experience indicates that an effective tube testing program may best be accomplished by performing eddy current testing annually (or during consecutive planned outages) and judiciously using a combination shell side hydro testing and individual tube testing as needed when "unplanned" failures occur.

TUBE PLUGGING TECHNIQUES & PRODUCTS

Currently available tube plugs can be categorized into three areas.

1. Hammer-In Taper Plugs
2. Mechanical Tube Plugs
3. Explosive Tube Plugs

Hammer-In Tube Plugs

Probably the most common and the oldest type of tube plug in use today is a simple tapered pin that is hammered into the end of a leaking tube. In low pressure applications these plugs are just hammered-in and left alone. In high pressure applications, they are usually hammered-in and welded to the tube sheet.

The drawbacks of Hammer-in tube plugs are that they're limited to sealing only at the very end of the leaking tube and that their sealing surface area is fairly small and will be dependant on the amount of force used to hammer in the plug. Erosion and corrosion of the tube end will interfere with the ability of the taper plug to make an effective seal. To improve the effectiveness of taper plugs may be necessary to ream the tube with a tapered reamer and to hammer the plugs in with greater force. How much force does it take to install a hammer-in plug? If these plugs are not hammered in hard enough they may fall out of the tube during operation causing the leak to resume. If they are hammered in with too much force, they may flair the tube end, possibly cracking the tube, damaging the tube-to-tubesheet joint and cracking the tubesheet ligament.

In critical applications Tapered Plugs are usually welded directly to the tube and/or tubesheet after they have been hammered in. While this might appear to be a better solution it too has some drawbacks.

Heat exchangers are intended to carry water or some other liquid through the tubes. Moisture present at the time the seal weld is attempted will cause weld porosity or the formation of pinholes within the weld. Pinholes and weld porosity may lead to the formation of a worming leak. If left undetected, this type of leak may eventually wash out a large area of the tube sheet. Repairs to the damage caused by worming are extremely difficult and time consuming to repair.

Welding on some alloy tube sheets may cause the tube sheet to shrink as it cools drawing the tube sheet away from the tubes surrounding the newly plugged tube. This situation may ultimately lead to the formation of joint leaks in the adjacent tubes and the operator may end up "chasing leaks" across the tube sheet in subsequent outages.

Additionally, in the cramped confines of a power plant heat exchanger the welding operation becomes even more difficult and time consuming for a skilled welder.

While the taper plug itself and the cost of a welder may seem inexpensive at first once any of the problems associated with this technique occurs the cost escalates and other plugging alternatives may be more cost effective.

Another variation on this theme is a hammer-in and welded thimble plug. The thimble design is intended to compensate for thermal expansion and contraction of the tube and tubesheet as the heat exchanger cycles. This technique does not appear to be that widely used.

Two Piece Hammer-in Taper Plugs

The Two Piece Hammer-in Plug is an improvement to the hammer-in taper plugs discussed above. It is an attempt to provide greater sealing surface area by incorporating an internally tapered, sleeve with a smooth ring. Installation is essentially the same, the pin and sleeve assembly is inserted into the end of the leaking tube and the sleeve is expanded by hammering the tapered pin into the sleeve.

Unfortunately this method doesn't effectively consider the effects of tube end erosion and corrosion. The smooth sealing surface on the O.D. of the ring does not conform to even the most minor tube end imperfection making tube preparation even more important.

Two Piece plugs may be treated like taper pins and may be hammered-in with too much or too little force. In critical applications they are also seal welded. As such they will be subject to all the problems which plague taper plugs.

Mechanical Tube Plugs

Pop-A-Plug

Pop-A-Plugs are simple mechanical tube plugs that function like a combination anchor bolt and "pop" rivet. Each Pop-A-Plug is an assembly of three individual parts:

a. A tapered pin
b.. An internally tapered and both internally and externally serrated ring, and
c. A breakaway

Each breakaway has a specially designed undercut section that allows the breakaway to fail at a predetermined load.

The breakaway material is controlled and constantly tested during the manufacturing process. Controlling the ultimate breaking point allows for precise, repeatable plug installations and a working pressure rating of 6,000 psi (415 Bars). Controlling the breakaway load also assures that there is no damage to the tube wall, tubesheet and/or adjacent tube joints.

Pop-A-Plugs are installed by using a small hydraulic ram to draw the tapered pin through the ring which causes the ring to expand. As the ring contact the tube wall, the serrations on the ring begin to compress sealing the tube. Simultaneously, as the serrations compress the frictional load between the pin and the ring increases until the tensile strength of the breakaway is exceeded and the plug "pops". The entire installation time is less than 15 seconds. Incorporating a simplified tube preparation and sizing routine, total plugging time will be less than 5 minutes per tube end.

In addition to the speed with which these plugs can be installed, the Pop-A-Plug System has several other advantages including the following.

Pop-A-Plugs can be installed at any depth within the tube end provided that they remain within the tubesheet. A corollary to this is that under certain conditions, such as hydrogen and lube oil coolers, that Pop-A-Plugs can be passed through the tube to successfully seal the far end of the tube without having direct access to the far tube end.

Pop-A-Plugs are available in 8 different alloys and do not require welding.

Pop-A-Plug tube plugs are presently the only tube plugs available under both ANSI N45.2 U.S. Nuclear Quality Assurance and ISO-9001 International Quality Standards.

Torq'n Seal

Torq'n Seal plugs are mechanical tube plugs that are expanded by torquing a tapered, threaded plug into an internally tapered and threaded barrel. A small eccentric cam is used to counteract the torque applied and lock the plug in position. Torq'n Seal plugs are intended to be installed to a specific torque rating and can be installed at any depth in the near tube end. The problems associated with this type of plug are discussed below:

The eccentric cam may not adequately hold the plug against the installation torque allowing the plug to spin freely within the tube end and subsequently not seal the tube end.

Torq'n Seal Plugs are presently being supplied with a weld prep bevel on the near end and may actually require seal welding to ensure a more effective seal.

The sealing surface of the Torq'n Seal plug consists of four flat ridges over 5/16" [8mm] long region of the barrel. These flat surfaces may be subject to the same problems associated with the smooth ring of the two piece hammer-in plug.

Torq'n Seal plugs are designed to be installed to a specific torque value which changes with plug size and material. In an ideal world this would work. Unfortunately due to variables which are extremely difficult to control (e.g. friction) the actual outward force or installation load exerted by a Torq'n Seal plug against the tube wall may vary widely between plugs of the same size and material. The amount of installation load is directly related to the plugs ability to hold pressure and remain leak tight.

Presently Torq'n Seal plugs are available in only three materials and can be used in near end applications only.

Torq'n Seal plugs are similarly priced to the Pop-A-Plug.

Noe Alpha Plug

This mechanical tube plug is actually a variation of tube testing plug. Incorporating an expandable set of grips to restrain the plug, it uses three elastomer o-rings to seal off the end of the leaking tube. The correctly sized plug is installed into the end of the leaking tube, and a wrench is used to tighten a compression nut expanding the grips and setting the plug. After this step a thin hex key is inserted into the shaft of the plug and is used to tighten an internal nut expanding the o-rings. This plug is advertised as a removable, reusable, temporary tube plug.

The drawbacks of this technique center around the use of the elastomer o-rings for sealing. The design overlooks an important physical property of rubber compounds - compression set (the ability of the material to change shape over time to reduce internal stress). The expected service life of this plug is limited to 1-2 years. Elastomers are also limited by temperature. Even the most exotic elastomers are limited to continuous service at less than 450 degrees F (230 degrees C).

Noe Alpha Plugs are almost two times the cost of the other mechanical tube plugs and are available in only two materials. EPDM o-rings are standard but more exotic elastomers are available adding still more to the cost of an already expensive plug. Installing a temporary tube plug that will have to be replaced at some time in the future is questionable especially when there are equally as fast, less expensive, permanent tube plugs available.

Explosive Tube Plugs

There are presently two different types of explosive tube plugs offered - those that are explosively expanded and those that are explosively welded to the tube and/or tubesheet. Their method of operation is as the name implies. An explosive charge is detonated within the body of the plug. The shape of the charge and/or the shape of the plug body determines whether the plug expands into or is fusion welded to the tube wall.

These types of tube plugs have been known to swell the tube and tubesheet during installation. This can damage the tube-to-tubesheet joints of adjacent tubes and may be responsible for the propagation of tube and tube joint leaks over time, greatly reducing the life span of the heat exchanger.

Explosive tube plugs require special handling, permits and must be installed by trained technicians from the companies who promote them. This makes explosive tube plugs very expensive. Typically their cost is two to five times that of the average mechanical tube plug - excluding the cost of installation.

CONCLUSION

Of the tube plugging methods presently available the mechanical tube plugs, more specifically the Pop-A-Plug System appear to offer a greatest amount of flexibility and benefits at moderate expense.

It should be noted that regardless of the method selected tube preparation is vitally important toward improving the success of any of these methods.

This presentation is intended only as an overview of the most common tube testing and plugging techniques and equipment in use today.

Q & A

Presenter's Note: As a manufacturer of heat exchanger tube testing and plugging equipment I have tried to remain objective in my treatment of competitive methods and/or products. Any omission of a tube testing technique or plugging method is not intentional and I offer my apologies to the companies whose products may have been overlooked. I would appreciate being advised of any omission. Please feel free to contact me at the following address, telephone or fax numbers.

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Expando Seal Tools, Inc.
123 Keystone Drive
Montgomeryville, PA 18936-9638

Tel 1-215-643-7044
Fax 1-215-641-9765

Pop-A-Plug II Technical Specifications

1. **Size Range.** Pop-A-Plugs can be supplied to handle any tube I.D. from .400" up to 2.000" [10.2 mm to 50 mm] and cover .02" (.5mm) intervals. A correctly sized Pop-A-Plug should be .001" to .020" [.02mm to .5mm] smaller than the actual tube I.D.

2. **Plug Materials.** Pop-A-Plugs can be supplied in eight different alloys allowing the plug and tube material to be compatible.

Tube and tube plug material compatibility is important because it will reduce and possibly eliminate any possibility of galvanic action between the plug and the tube. It also minimizes the differences in the Thermal Coefficients.

a. Galvanic, or electrolytic, action is best described as the corrosive effect of dissimilar materials on one another.

b. The Thermal Coefficient is a number that relates the dimensional changes a material experiences as it undergoes changes in temperature. Similar coefficients of Thermal Expansion are important because the plug and tube material should expand and contract at roughly the same rate.

3. **Controlled Installation Load.** Pop-A-Plugs are installed with a known, predetermined amount of force every single time. The installation force, or load is such that it will not damage the tube, the tube to tube sheet joint, or any of the adjacent tubes.

a. All breakaway materials are tensile tested prior to and during manufacture. Breakaway diameter are cut according to guidelines established for each plug material and size range.

b. Pop-A-Plugs are designed to neither damage, nor penetrate the tube wall during installation. The design criteria for Pop-A-Plugs requires that the installation load used to install plugs shall be less than the yield strength of the tube material.

4. **Reliable.** Pop-A-Plugs have 4 to 6 pointed serrations along the exterior of the ring. These serrations are designed to provide an equal number of independent sealing surfaces along the interior of the tube.

5. **Maximum Operating Conditions.** The installation load generated by the breakaway at the time of installation is all that is required to keep the Pop-A-Plug in place during the operation of the heat exchanger. Pop-A-Plugs have a maximum operating pressure of 6,000 psi [410 bar] *without welding*. Maximum operating temperatures will be limited only by the limitations of the heat exchanger itself.

6. **Placement at Installation.** Pop-A-Plugs can be installed at any depth in the tube provided that they remain within the tube sheet area. This feature allows the following:

a. Pop-A-Plugs can be installed beyond the region of the tube end affected by tube end erosion and corrosion.

b. Under certain conditions, the operator may have the ability to pass Pop-A-Plugs through a straight through heat exchanger tube and install them in the far end of the tube without having direct access to that tube end. This technique called "Through the Tube Plugging" is unique to the Pop-A-Plug system and is ideal for floating head heat exchangers and applications where it is too time consuming [costly] to remove the tube bundle, or gain access by other means to the rear tubesheet.

7. **Speed of Installation.** Incorporating a simplified tube preparation and sizing routine, total plugging time will be less than 5 minutes per tube end.

8 **Preparation.** Pop-A-Plugs are supplied in kit form. Each kit contains ten individually packaged plugs, a tube preparation brush and a Go/No-Go sizing gauge. For tube ends with welded tube-to-tubesheet joints an additional tapered reamer may be required to quickly remove "weld droop" from the tube end prior to brushing and gauging. Tapered reamers are available from Expando Seal or from a mill supply house.

9. **Removability.** Pop-A-Plugs are removable.

a. The ease of removal will depend upon the plug material and the type of service in which the Pop-A-Plug has been installed.

b. The removal procedure is simple. Using a drift the operator drives the pin back through the ring disengaging the two pieces. The ring can then be extracted by using either a tube spear or threaded extractor. The pin may be retrieved either by magnet, expelling it with air, or it may be removed with the tube as the tube is extracted.

10. **Minimal Training Required.** Pop-A-Plugs can be installed by your own maintenance personnel. Expando Seal sales representatives are available to train and trouble shoot for any maintenance crew involved in tube plugging operations using the Pop-A-Plugs system. Field Service Technicians may be provided directly from the factory, if desired.

11. **Reliable.** Pop-A-Plugs are presently in service in almost 400 Thermal and Nuclear Power Plants throughout North America and Europe.

12. **Quality Assurance.** All Pop-A-Plugs are manufactured under a quality program certified to the international quality standard ISO-9001. Pop-A-Plugs are also available under several U.S. Nuclear Industry Quality Standards including ANSI N45.2, 10CFR50 Appendix B, 10CFR21, and/or NQA-1.

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U.S.-KOREA ELECTRIC POWER GENERATION SEMINAR MISSION
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Lotus Room, Hotel Inter-Continental, Seoul

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TRANSMISSION & DISTRIBUTION SYSTEMS

TECHNOLOGY SESSION

OVERVIEW OF U.S. ELECTRIC UTILITIES

TRANSMISSION AND DISTRIBUTION SYSTEMS

BY

RONALD D. BROWN, P.E.
DIRECTOR, PLANNING & ENGINEERING DIVISION
EAST KENTUCKY POWER COOPERATIVE, INC.
WINCHESTER, KENTUCKY

PRESENTED AT

U.S./KOREA ELECTRIC POWER TECHNOLOGIES SEMINAR

SEOUL, SOUTH KOREA

OCTOBER 24, 1994

Good afternoon. Welcome to the "Electric Power Technologies Seminar". I am very pleased to see so many here for what I believe will be a very interesting and informative Transmission and Distribution workshop.

The presentations which will be given in this workshop will provide an opportunity for U.S. companies to share their ideas and research in this important segment of the overall electric utility operations. As an introduction, I will summarize for you a few facts about the U.S. electric utility industry in general and transmission and distribution in particular, some of the industry's current concerns, and a brief summary of related ongoing research.

By way of comparison, the U.S. is a country about 90 times as large in land area as South Korea. The population of the U.S. is about six times as large.

Overview

Electric power and energy is available to over 99 percent of the U.S. population and is provided by approximately 3,200 electric utilities, consisting of municipally or publicly owned, cooperatives (member-consumer owned), investor owned (privately owned), and federal government affiliated entities. They range in size from very large utilities with 150,000 square miles of service territory, several million customers, sales of over 100,000,000 MWh, 10,000-20,000 employees, and over 30,000 miles of high voltage transmission line, to small municipal systems serving a few square miles with only a few hundred customers and a handful of employees.

Total peak electrical load demand in the U.S. was about 581,000 MW in 1993 and is projected to increase to around 678,000 MW in 2003. This represents an annual load growth of approximately 2.9 percent. Electric generating capacity is projected to increase from about 694,000 MW to 776,000 MW during the same period as shown in Table 1. Generation reserves decrease from 19.5 percent of load to 14.5 percent by 2003. Of the 82,000 MW of new capacity, 58 percent is peaking or combined cycle and will burn oil and/or natural gas.

Coal-fired generating capacity is the largest source of energy at over 50 percent of total production followed by nuclear at 20 percent. Hydro provides about 8 percent, oil and gas ranges from 1 to 4 percent, with non-utility sources providing between 6 and 8 percent of the total energy production. Table 2 provides a summary of electric energy production by fuel for both 1993 actual and a projection for 2003.

TABLE 1

U.S. ELECTRIC GENERATING CAPACITY VS LOAD (SUMMER)

	ACTUAL 1993		PROJECTED 2003		INCREASE-1993 vs. 2003		
	MW	% TOTAL	MW	% TOTAL	MW	% TOTAL	% INCREASE
GENERATING CAPACITY							
Nuclear	98,964	14.3	103,065	13.3	4,101	5.0	4.1
Hydro	63,897	9.2	68,579	8.8	4,682	5.7	7.3
Pumped Storage	17,375	2.5	18,957	2.4	1,582	1.9	9.1
Coal-Steam	290,106	41.8	296,632	38.2	6,526	8.0	2.2
Oil/Gas-Steam	139,375	20.1	137,798	17.8	(1,577)	(1.9)	(1.1)
Oil/Gas-Peaking	46,034	6.6	75,210	9.7	29,176	35.6	63.4
Oil/Gas-Combined Cycle	8,224	1.2	26,853	3.5	18,629	22.7	226.5
Other	2,275	0.3	6,224	0.8	3,949	4.8	173.6
Non-Utility	28,000	4.0	42,924	5.5	14,924	18.2	53.3
TOTALS	694,250	100.0	776,242	100.0	81,992	100.0	11.8
LOAD	580,753		677,798		97,045		16.7
CAPACITY MARGIN							
MW	113,497		98,444		(15,053)		
% of Load	19.5		14.5				(5.0)

Source: North American Electric Reliability Council, 1994-2003 Electric Supply & Demand Data Base

TABLE 2

U.S. ELECTRIC ENERGY SOURCES

	ACTUAL 1993		PROJECTED 2003		INCREASE - 1993 vs. 2003		
	1000 MWH	% TOTAL	1000 MWH	% TOTAL	1000 MWH	% TOTAL	% INCREASE
GENERATING CAPACITY							
Nuclear	611,068	20.1	689,685	19.3	78,617	14.6	12.9
Hydro	262,033	8.6	259,837	7.3	(2,196)	(0.4)	(0.8)
Coal-Steam	1,632,936	53.8	1,843,844	51.6	210,908	39.3	12.9
Oil/Gas-Steam	310,132	10.2	332,544	9.3	22,412	4.2	7.2
Oil/Gas-Peaking	6,037	0.2	30,734	0.9	24,697	4.6	409.1
Oil/Gas-Combined Cycle	22,640	0.7	113,643	3.2	91,003	16.9	402.0
Other	11,085	0.4	26,839	0.8	15,754	2.9	142.1
Non-Utility	181,473	6.0	277,252	7.8	95,779	17.8	52.8
TOTALS	3,037,404	100.0	3,574,378	100.0	536,974	100.0	17.7

Source: North American Electric Reliability Council, 1994-2003 Electric Supply & Demand Data Base

The generating resources and loads of the U.S. electric utilities are interconnected by a large network of transmission and distribution facilities. The contiguous 48 states are split into two systems - one consisting of the eastern two-thirds of the U.S. (Eastern Interconnection) with the balance consisting of the western one third (Western Interconnection). All utilities in these respective regions operate in synchronism with each other. The eastern and western systems are interconnected only through low capacity direct current links.

Transmission & Distribution Systems

Transmission voltages include 345 kV, 500 kV, and 765 kV in the extra high voltage class and 34.5 kV, 46 kV, 69 kV, 115 kV, 138 kV, 161 kV, and 230 kV in lower transmission voltages. Distribution voltages range from 2.4 kV to 34.5 kV. There is also a small amount of direct current transmission facilities in the 300 - 500 kV$\pm$ range. Table 3 is a tabulation of high voltage transmission line circuit miles for 1992 actual and an estimate for 2003 by voltage.

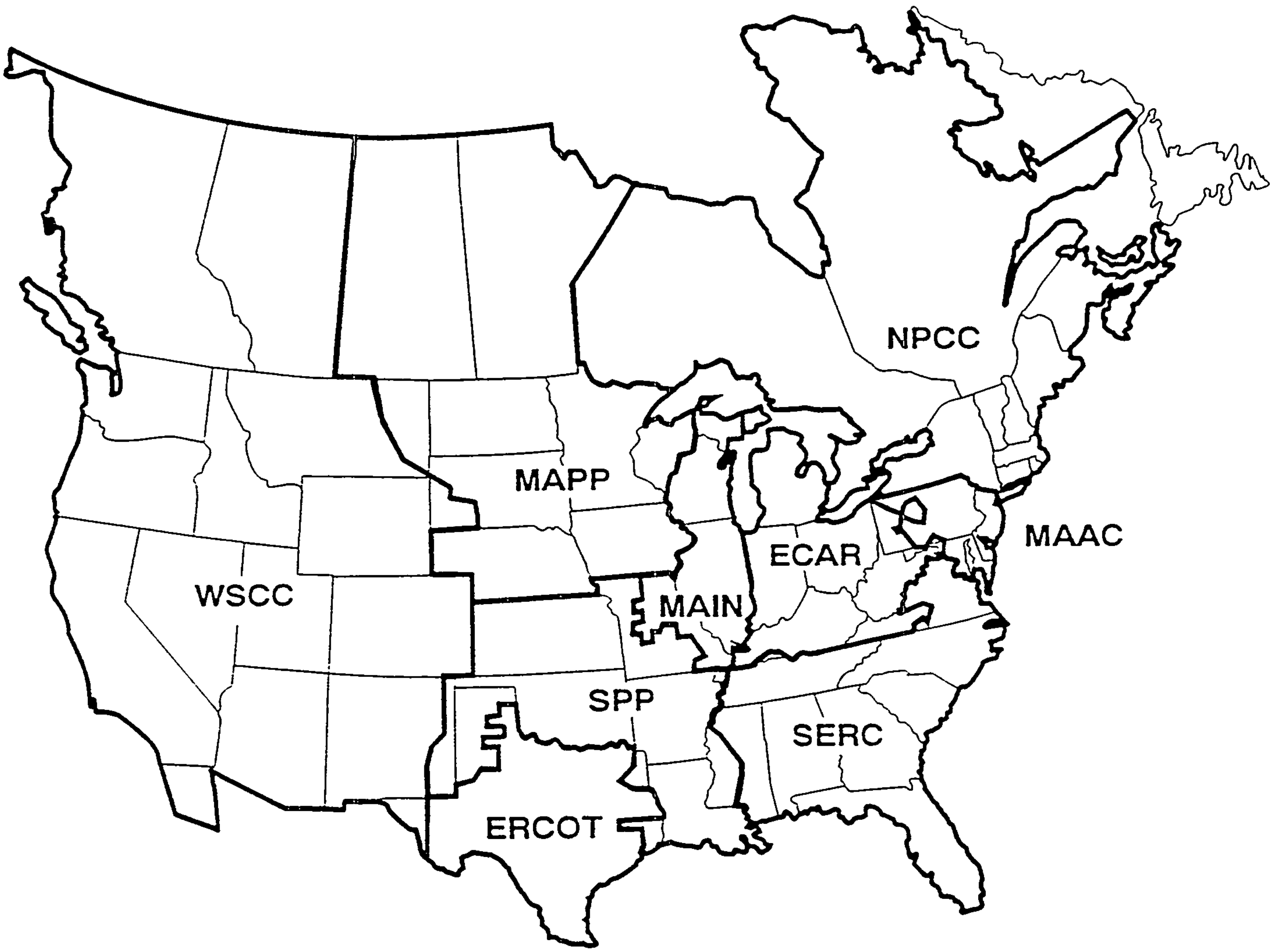
Transmission line construction is almost all overhead. Underground is used only in highly congested urban areas or for water crossings. A large number of distribution lines are underground in both urban and rural areas although the vast majority are overhead.

Overhead transmission line support structures include steel towers, steel poles, and wood poles. Concrete poles are used only occasionally. Most overhead distribution is constructed using wood poles. Overhead conductors are aluminum with some combination of steel or aluminum alloy core. Overhead ground or shield wires are usually made of high strength galvanized steel.

Reliability

Reliability of service is very important. The North American Electric Reliability Council (NERC) and nine regional reliability councils provide guidelines, policies, and oversight to electric utilities to assure electric supply reliability. Generation reserve levels are based on loss-of-load and other sophisticated analyses with actual installed reserves in the range of 15-20 percent of load. Operating and spinning reserves are in the six percent and three percent ranges, respectively. Bulk transmission networks are planned to meet first and second contingencies, with the desired level of reliability proportional to the critically of the circuit or load served. Figure 1 outlines the areas encompassed by NERC and the regional councils.

FIGURE 1
REGIONAL RELIABILITY COUNCIL BOUNDARIES



ECAR
East Central Area Reliability Coordination Agreement

ERCOT
Electric Reliability Council of Texas

MAAC
Mid-Atlantic Area Council

MAIN
Mid-America Interconnected Network

MAPP
Mid-Continent Area Power Pool

NPCC
Northeast Power Coordinating Council

SERC
Southeastern Electric Reliability Council

SPP
Southwest Power Pool

WSCC
Western Systems Coordinating Council

Affiliate

ASCC
Alaska Systems Coordinating Council

(Source: Reliability Assessment 1994-2003 Report by North American Electric Reliability Council)

U.S. TRANSMISSION LINES, 230 KV & ABOVE (CIRCUIT MILES)

	EXISTING 1992	EXISTING & PLANNED 2003	INCREASE 1992 vs. 2003
AC VOLTAGE (KV)			
230	71,640	76,544	4,904
345	48,768	51,502	2,734
500	23,760	28,340	4,580
765	2,426	2,541	115
TOTALS	146,594	158,927	12,333
DC VOLTAGE (± KV)			
250-300	465	465	-0-
400	436	436	-0-
450	192	192	-0-
500	1,333	1,333	-0-
SUBTOTALS	2,426	2,426	-0-
TOTAL, AC & DC	149,020	161,353	12,333

Source: North American Electirc Reliability Council, 1994-2003 Electric Supply & Demand Data Base

Safety & Design Standards

Safety is also important and facilities are designed to meet or exceed the requirements of the National Electrical Safety Code, the National Electric Code, Occupational Safety & Health Act, and other local and individual company requirements. Equipment and construction standards include those of the Institute of Electrical and Electronics Engineers (IEEE), American National Standards Institute (ANSI), National Electrical Manufacturers Association (NEMA), and the American Standards for Testing and Materials (ASTM). Equipment is purchased from U.S., European, and Asian manufacturers.

Engineering and construction are performed by combinations of utility company personnel, consultants, and contractors. Many utilities perform most of their work with their own forces; others do little or none.

Operations

Operation of the many interconnected utilities as a coordinated entity on a real time basis is critical to insure that generation and load are always matched, that there are sufficient spinning and operating reserves to meet load swings and unplanned generating unit outages, that voltage is within tolerances, that no lines are overloaded, and that frequency (60 Hz) is being maintained. This task is performed by the numerous energy and transmission control centers operated by the larger utilities. These centers monitor and control the transmission and generation facilities to assure that each individual utility is meeting its responsibilities and facilitate purchases and sales with neighboring utilities on a real-time basis.

The same centers usually are also in control of switching of transmission circuits and service restoration during maintenance and emergencies. Neighboring centers are in constant communication with each other and coordinate activities to maximize reliability and efficiency. In theory, any utility may purchase or sell power and energy to any other within their respective interconnection (Eastern or Western).

Control centers utilize combinations of electric utility owned and telephone company owned microwave, telephone, VHF and UHF radio, powerline carrier, and fiber optic networks to carry out their tasks. Their swift and efficient operation is highly dependent on the extensive use of computers.

Government Regulation

Federal, state and local government agencies play a large role in the ability of electric utilities to perform their tasks in a timely, efficient, safe, and profitable manner. Rates for power transactions are reviewed and approved by the Federal Energy Regulatory Commission (FERC), including wholesale rates, rates for transactions between utilities and transmission wheeling rates. Rates charged to retail consumers are typically reviewed and approved by state Public Utility Commissions (PSC) or Boards. In many cases, a state PSC must also approve the construction of major facilities (transmission lines and power plants) before the constructing utility may exercise the power of eminent domain and/or collect revenue for the new facility. Other approvals from federal, state, and local government agencies are required for new facilities to assure that environmental concerns and local land use plans are compatible with the new facilities. This may include transmission line routing and siting for substations and generating stations.

The telephone and natural gas industries in the U.S. are, for the most part, deregulated and these utilities now provide a wide range of "unbundled" services. The electric utility industry is, to some extent, following in the same tracks. For example, the trend now is for generation and transmission services to be provided as separate, unbundled services. Recent federal regulations mandate that transmission line owners provide access to their systems to others for the purpose of allowing them to wheel power across the owner's system, perhaps even to one of the owner's former wholesale customers.

While wholesale wheeling is now mandatory, retail wheeling, with a few exceptions, is not. Non-utility entities (independent power producers or IPPs) may compete for wholesale power sales on an equal footing with traditional electric utilities. The result is that rates charged by an electric utility are moving towards market based levels in lieu of the traditional cost based rates guaranteed in the past.

Another result of this new competition is that neighboring utilities which have had a long tradition of cooperating with each other now find themselves in intense competition for wholesale customers. It is feared that such competition may tend to reduce cooperation among utilities and cause reliability to suffer. Deregulation and the impact that it will have on transmission planning and reliability is one of the major concerns in the industry today.

<u>Barriers to New Construction</u>

Another major problem is the difficulty in receiving approval for the construction of new facilities, especially the routing of new high voltage transmission lines. Environmental issues, such as electromagnetic fields (EMF), are of major concern.

EMF

The electric utility industry is grappling with the issue of EMF and health concerns. Scientists continue to offer more studies and opinions but are able to do little to confirm or assuage the fears of the general populace and media coverage in the U.S. ranges from skepticism to sensationalism. U.S. legislators are faced with demands by the public to regulate exposure but have no sound risk or exposure limit data available on which to establish guidelines. Broad measures to eliminate human exposure to EMF created by 60 Hz electric supply systems would be economically irresponsible based on the current state of knowledge while ignoring the studies that purport a connection between exposure and health effects would be insensitive and counter to the mission of contributing to the qualify of life. Prudent avoidance is the position that most U.S. utilities choose although critics scorn the notion that mitigation activity should be linked with cost. This dilemma has now moved a step further to enter the legal arena.

Utilities across the U.S. are being challenged with lawsuits and labor compensation cases based on exposure to EMF. Government agencies are questioning the routes and designs of transmission and distribution facilities and the public is ever more active to influence day to day utility operations. Many U.S. utilities are responding to public concern by offering information and field measurements to those interested.

One major research effort is a federal EMF program called RAPID (Research and Public Information Dissemination), where $65 million dollars will be spent over roughly a five year period for research and public education with 50 percent being funded by the electric utility industry. The Electric Power Research Institute is also very active in EMF related research and many individual companies also elect to contribute to research efforts at local universities.

Power Quality

Power quality issues are becoming increasingly important as new technology based customer owned electronic and computer devices demand "purer" voltage waveforms and more stable voltages. Paradoxically, modern industrial devices can also be a source of troublesome harmonics.

Efficient Use of Existing Facilities

Due to the increased pressure to cut costs and to avoid construction of new high voltage transmission lines, there is considerable activity and interest in projects which will maximize the use of existing facilities and rights-of-way, such as:

1. Upgrading of existing lines to operate at a higher temperature by increasing ground clearances.

2. Reconductoring of existing lines.

3. Utilizing existing rights-of-ways to rebuild existing transmission lines at a higher voltage.

4. Utilizing existing rights-of-ways to build multiple circuit lines at the same or higher voltage.

5. Operating at optimum power factor to reduce line loading.

6. Use of dispersed generation to minimize peak loading and/or to provide additional reliability.

7. Use of reactive devices to control line flow and/or increase load carrying capacity.

<u>**Transmission & Distribution Research**</u>

U.S. electric utilities are very active in research and development to find better and more efficient materials and methods to solve the many problems outlined above. One of the most significant efforts, in addition to that carried out by the U.S. Department of Energy, is by the Electric Power Research Institute (EPRI). Approximately 728 utilities, both large and small, are members of this organization. Members suggest and approve the projects carried out and provide funding through their membership dues which funds an annual budget which is currently approximately $518 million dollars. Current research in the transmission and distribution area includes:

A. Transmission

1. Budget for 1994 is $11,100,000.

2. Total number of projects is 38.

3. Emphasis is on planning, design, and analysis products for upgrading systems, and investigation of underground cable and overhead systems to reduce cost and increase reliability.

B. Distribution

1. Budget for 1994 is $11,000,000.

2. Total number of projects is 40.

3. Emphasis is on reliability in fault finding and detecting devices, new planning tools, underground technology, and utility communication architecture (UCA) designed to facilitate communications throughout all utility operations.

C. Power Systems Operations

1. Budget for 1994 is $17,400,000.

2. Total number of projects is 44.

3. Emphasis is on reliability maintenance techniques for substations, technology to increase power transfers and control power flows, and software and techniques to aid system planners and system control operators.

D. Power Quality and Information Technology

1. Budget for 1994 is $6,300,000.

2. Total number of projects is 19.

3. Emphasis is on a new generation of motor drive systems, power quality software and techniques, and customer interfaces.

Conclusion

I hope this brief description of the U.S. electric utility industry has been interesting and informative. No doubt many characteristics, concerns, and research efforts mirror those of the electric utility industry in South Korea. It is hoped that through workshops such as this that electric utilities, manufacturers and consultants may learn from each other for the mutual benefit of all.

PRESENT STATUS AND FORCAST OF T & D FACILITES

OCT. 24, 1994

In-Suk Ko
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1. INTRODUCTION

The electricity business in Korea was first started by Seoul Electric Company on January 26, 1898 at the end of the Chosun Dynasty Period. It went through a variety of adversities and hardships such as unexperienced management techniques after the liberation from Japanese rule in 1945, the abrupt cut-off of electricity by North Korea on May 14, 1948, and the catastrophe of Korean War.

On July 1, 1961, three electric power companies(Korea electric, Seoul Electric, and South Korea Electirc Co.) were merged into one and was renamed as Korea Electric Company, Ltd.(KECO). KECO concentrated on implementing various projects to develop electric power resources in coping with the rapidly increasing electricity demand which out paced annual economic growth due to the rapid development of industry. On January 1, 1982, KECP was converted to a public corporation. This company has grown steadily and become the present KEPCO (Korea Electric Power Corporation), a public enterprise. This enterprise now possesses solid basis of managerial performance and improved financial structure.

In order to support the high growth rate in electricity demand, which is mainly due to steady growth of the national economy, future efforts will concentrate on improving the efficiency of electrical supply and enhancing consumer services as well as modernize electric facilities. My presentation will briefly cover the transition of T&D systems and the major directions to which they will be modernized.

2. TRANSMISSION AND SUBSTATION SYSTEM

In the 1960's, most of KEPCO's transmission system consisted of 66kV facilities with a few 154kV trunk lines. Since the beginning of the 1970s, loop-type transmission systems of 154kV have been constructed. In 1976, a new era of power transmission was opened when a 345kV transmission type was introduced in Korea. Nationwide loop-type network was formed in 1988 and 345kV loop system surrounding the metropolitan area was completed in 1992 to upgrade the transmission capability and stability of bulk power supply. By the end of 1993, total length of transmission lines reached 21,195 circuit-km, and underground transmission lines of 154kV reached 572 circuit-km.

Underground cables are being expanded steadily and the first underground transmission lines of 345kV in KEPCO power system will be in service in 1996.

Substation facilities consist of 67,670 MVA.

GIS substations have also been built since 1980. These substations were built in order to protect the environment, as well as to solve the problem in obtaining sites in metropolitan areas. In the future all substations will be constructed by full GIS type.

The power system of Cheju island located approximately 100km south of mainland is being operated seperately. It suffers from higher generation cost, relatively weak stability and rapidly increasing power demand.

KEPCO, therefore, has decided to build a HVDC link between Cheju island and mainland in order to overcome the above difficulties. The rated voltage and capacity is DC 180kV and 300MW. This system will be service in 1996.

According to the ever-increasing power demand and the power development plan, transmission system should be expanded.

Since the land cost is rising up, the effective utilization of land is greatly year after year. It results in difficulty for the acquisition of right-of-ways. The limit of the right-of-ways urges KEPCO to consider upgrade of system voltage.

It has been expected to encounter difficulties such as increase of fault level and continuous current level of equipments in case the current 345kV system has been expanded without system voltage upgrading.

The first 765kV T/L construction will be completed by the end of 1990's.

It will connect coal-fired power plants in the west coast and the south-west outskirts of Seoul area. The other 765kV line is planned to connect a huge nuclear power plant in the east-coast and east ourskirts of Seoul. The 765kV transmission system is expected to solve the problem of the regional imbalance of the supply and demand.

Futher expansion of the 765kV system after 2006 will depand on the site planning of power plants.

3. FOR DISTRIBUTION SYSTEM

In the distribution facilities, the total number of supporting structures was 182,000EA in 1961, but it was increased 4,680,000EA in 1993. And total length of distribution lines was increased remarkably from 36,968km to 713,934km, and the number of pole transformer from 52,967EA to 781,700EA.

For the underground distribution lines, beginning with the line between Hyojadong and Kwanghwamun in 1973, the lines was accomplished 3,083 km in Seoul (38.4 percent of the total distribution lines) was covered and 7,520 km was covered throughout the country (6.0 percent) as of the end of 1993.

Distribution voltage and system changed from 3.3kV 3-phase 3-wire in the beginning of the 1950's to 6.6kV 3-phase 3-wire in 1961.
Electric demand was increased continuously in 1960's, therefore KEPCO adopted 22.9kV-y and 11.4kV-y 3-phase 4-wire multi-grounded system to cope with the shortage of electric capacity in the distribution line. And 22.9kV-y system is applied tentatively in Moon-san, Ko-sung, Yang-ku area in 1965-66. Voltage Upgrading from 3.3kV and 6.6kV to 22.9kV-y is finished in 1986 in every Korean region except Seoul downtown and Cheju island.

We are upgrading Seoul downtown since 1988, Cheju island since 1991. Also voltage upgrading from 11.4kV-y system to 22.9kV-y system was accomplished in 1989.

For the secondary system, 110V and 220V are coexistent since conversion projects are still underway. However, the production of most home appliances having a 110V rating has been discontinued.

Starting in 1989, the secondary voltage conversion will be escalated to be on a large scale than now and its completion is expcted to be by the late 1990s.

Since 1980's, KEPCO introduced multi-divide multi-tie conception to distribution line to minimize the fault time and area when fault occured.

In the future, the improvement of distribution technique and the distribution facilities harmoning with environment will be more demanded, because of the high increase of electric demand, the change of social envirement and the desire of electric quality, etc.

Therefore we will propel some modified system, such as Distribution Automation System, Large Capacity Distribution System, Spot Network System, to cope with the above mentioned demand, and will optimize distribution planning and maintenance by CADPAD.

4. CONCLUSIONS

Before the end of the 1970s, because of our marvelous economic growth and industrial development we had made our best efforts to develop more power sources. But from the 1980s, KEPCO has invested for T&D facility of high quality and improved system reliabiliy.

The main considerations for T&D expansion are positive investment to improve facilites of the electric company, improvement of the quality of electrical equipment during manufacturing, and bettering the field construction of power facilities.

In order to achieve the ultimate goal of supplying high quality electricity, we will try to improve cooperation between our domestic industries, and reserch institutes, and increase the exchange of international technology.

INTELLIGENT DEVICES SIMPLIFY REMOTE

SCADA INSTALLATIONS IN SUBSTATIONS

Presented at the US/Korea Electric Power Technologies Seminar

October 24, 1994

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I.

Introduction

Utilities are increasingly relying on Supervisory Control and Data Acquisition (SCADA) Systems for the effective and economical management of electric transmission and distribution systems. Now, advances in equipment and design technologies have created opportunities for an increased level of monitoring and control at electric power substations. In the past, prohibitive factors, including complicated equipment and wiring retrofits, protocol compatibility, and hardware installation and maintenance costs have impeded electric utilities in their attempt at broad based application of SCADA systems in electric substations, particularly at distribution voltage levels.

These advances in equipment technologies have provided utilities with the opportunity to install and operate SCADA systems at lower cost, while providing flexibility for system expansion over longer periods. The development of intelligent microprocessor controlled devices and integrated communications has facilitated the use of a distributed design approach to installing SCADA monitoring and control in substations. This approach offers greater hardware flexibility and reduced installation costs while increasing reliability, making the addition of monitoring and control to electric substations increasingly practical.

This paper will examine current trends in the application of intelligent microprocessor controlled and electronic devices, in stand alone and distributed applications, and the simplification of techniques for installing SCADA systems in substations. It will also consider the potential advantages to be realized in cost and reliability, and examine the necessary changes in design and operation philosophies required to effectively implement the new technology.

II.

Background

The Function of SCADA Systems

Supervisory control and data acquisition (SCADA) systems play a vital role in the effective management and control of electric power generation, transmission, and distribution systems. By enabling system operations and engineering personnel to acquire information about the electric power network, and to take controlling actions based on this information, power system reliability and availability are greatly enhanced. The advantages of a comprehensive and broad based SCADA substation system are many, and include: Equipment malfunction monitoring for malfunctions which would otherwise go undetected, minimization of maintenance and repair costs, and the reduction of outage times. Redundancy in manpower and equipment can also be eliminated by automating remote substations and centralizing operations. Finally ,power system reliability can subsequently be increased without over design.

Electric Utilities have not overlooked the importance of SCADA Systems. According to a recent study conducted by CSR Inc., Roseville, California, "U.S. electric utilities plan to pour $710-million into new and upgraded energy management and supervisory control and data acquisition (EMS/SCADA) between 1992 and 1994".[1]

SCADA in Electric Transmission and Distribution Substations

The electric power network consists of generation, transmission, substation, and distribution facilities. The transmission and distribution substations, which contain the primary and secondary voltage transformation, switching, and protective equipment, are critical points of monitoring and control in the network. Information obtained at the power substation are critical inputs in the state representation of the electric network. SCADA systems provide a wide variety of information, and perform several functions in electric power substations, such as data monitoring, data acquisition, and supervisory control.

Engineering and operations personnel determine which values at the substation require monitoring by the SCADA system. The points to be monitored are chosen to provide the information necessary to determine the operating condition of the network and to make control decisions. Certain points in the substation may also be monitored which initiate automatic control action when particular values or conditions are met. The various types of data points to be monitored include analog data such as watts, vars, volts, amps, frequency, and status data of two and three state devices such as circuit breakers, switches, and tap-changers, time accumulated data such as watt-hours, and alarm data. The SCADA system will process and report alarm information with respect to set point limits imposed by operational and safety considerations.

Substation Data Acquisition and Capture

The remote monitoring and control system is located at the field sites where the desired network information is available. For the typical transmission and distribution voltage levels of 13.2 kV through 500 kV, this location is often the transmission and distribution substation facilities. Acquisition and capture of the appropriate network data is performed by the SCADA system at the substation and communicated to system operators. This can be accomplished by automatically scanning monitoring devices or having the devices "report by exception" any change of state or activity related to any alarm or abnormal condition. A data scan can also be initiated manually by a System Operator at the Control Center. As part of the data acquisition process, the SCADA system will monitor for telemetry failure or data corruption.

III

Considerations in the Design and Implementation of Substation SCADA

General Considerations

While the importance of broad based substation monitoring and control has been recognized, an increasingly competitive and cost conscious market makes instituting an area wide control and monitoring system, which encompasses manifold transmission and distribution level substations difficult. Because an effective and reliable method of controlling electric transmission and distribution will be essential to remaining competitive, is for this very same reason that the need for such a system is essential. Implementation of such a program, however, has been limited by the following economic and technological factors.

Economic and Technological Considerations

Traditional SCADA system installations, meaning non-intelligent monitoring devices such as transducers and dry-contacts hard-wired to a centrally located Remote Terminal Unit (RTU), can incur costs which are becoming increasingly difficult to justify on a benefit to cost basis. The ratio of tangible benefits to be gained over the service life of the system to initial costs is growing smaller. Furthermore, changes in equipment technology can raise the specter of equipment non-compatibility and/or obsolescence. Thus, the capital investment requirements for system installation and startup help determine whether or not substation control and monitoring is provided. System installation costs can normally include the following items.

Hardware and Equipment

Costs for equipment and hardware required for a traditional SCADA system installation, including dedicated RTUs, field I/O and termination panels, transducers, auxiliary relays, control switch relays, latching switch relays, test plugs, terminal blocks, and cable can often be significant. System purchasers must often balance the decision to hold initial costs lower by purchasing equipment with limited features, anticipating that additional functionality will not be required, or purchasing equipment with extended features in anticipation that the additional functionality will eventually be required.

Design and Engineering

Substantial design and engineering costs can be incurred in complex substation control and monitoring retrofit projects. Engineering requirements may include interface with existing systems, evaluation of point requirements, materials specifications, design drawings, and calculations. As the number of control and monitoring points increases, the engineering and design required for connection to additional equipment increases.

Construction and Start-Up

Traditional "hard-wire" methods for installing SCADA equipment increases the level of effort and durations required for construction personnel. If significant cabling to outdoor equipment is anticipated, extensive trenching and duct-work may be involved. Panel space requirements must be determined for transducer, relay, and control-switch installations Also, circuit disconnect and tagging procedures, particularly in CT and PT secondary circuits, may be both complicated and time consuming, consequently increasing schedule durations and costs.

Maintenance and Testing

A traditional substation SCADA installation does not easily adapt to changes in the system which it monitors. Changes in system parameters or requirements can often result in the need for additional hardware or wiring, increasing the long-term life cost of the system. For example, it may be determined that a substation with ampere and single phase-neutral kilovolt inputs on the feeders may also require watt, var, phase-angle and frequency inputs. This will require the addition of several new transducers and all associated cable and wiring for each feeder. Testing and troubleshooting hard-wired systems may also present a substantial cost over the life of the system.

IV

Traditional SCADA Analog, Control and Status Methods and Limitations

Monitoring of System Analog Values for SCADA

Analog signal monitoring is a vital component of any SCADA System. Values such as watts, vars, volts, amps, and frequency provide system operators with critical information regarding the state of the transmission and/or distribution system being monitored. With this information, system operators can make decisions and take appropriate action to correct or pre-empt situations that could lead to system instability or failure. The equipment and devices at the station site that transform the system values to signals suitable for interpretation by the SCADA system hardware and software are key elements in analog signal monitoring.

The various methods of transforming system level analog signals have traditionally been composed of circuits involving the use of primary current and potential transformers, auxiliary current and potential transformers, analog transducers, RTU input devices, and associated protective, isolating, and testing devices. A typical circuit provides volt, amp, watt and var values for input to a SCADA RTU via PT and CT input leads wired to volt, ampere, watt and var transducers, each with associated testing devices. Outputs from the transducers are hard-wired to the RTUs.

In this circuit, line current values are transformed by a primary current transformer set from kilo-ampere levels to values of typically one to five amperes. The secondary current for metering and SCADA is usually provided by the metering core of the C.T. column, and is typically available in the control, relay, or switchgear panel for the line. Secondary current values are then fed to the shorting test switches and subsequently to the current element inputs of the ampere, watt, and var transducers. Similarly, line voltage levels are transformed by a primary voltage transformer, from kilo-volt levels to values of typically 69 to 115 volts. This secondary voltage is typically available in the control, relay, or switchgear panel for the line. Secondary voltage values are fused, fed to the test switches and subsequently to the potential element inputs of the watt, var, and volt transducers. The transducers convert the secondary ampere and voltage levels to milliampere output signals. Depending on RTU system hardware, these signals can be fed directly to the RTU, or through a termination and interface unit, where scaling resistors may be used to calibrate the full scale values for subsequent input to the RTU.

While monitoring analog values in this way has proven to be technically adequate, it presents several practical problems, particularly in installations where a large number of analog values are required to be monitored.

Problems Associated with Analog Monitoring by Transducers

Many existing transmission and distribution substations today are now being considered for retrofitting to include SCADA monitoring and control capability. Because this capability was not envisioned when the installations were originally constructed, there is usually a problem with inadequate panel space required to mount all of the equipment and devices for SCADA monitoring. To provide analog points for line amps, volts, watts, and vars requires panel space for four transducers, test switches, and a fuse block. In older installations or small switchgear compartments, this panel space may not be available.

Wiring and cabling involved with monitoring analog values with transducers may be extensive, particularly if the transducers must be located separately from the relay and control panel where the current and potential secondaries are readily available. CT and PT circuits must be disconnected, opened, and reconnected to allow for the connection of current and voltage leads to the appropriate transducers. Shielded cable is required for the instrumentation level signals from the transducers to the RTU inputs. In distribution level substations or stations with a large number of feeders, large quantities of multi-conductor cable may be necessary, often requiring additional costs for cable support systems such as raceway and cable tray. If the cabling is between outdoor switchgear lineups and a central control house, additional costs associated with trenching and ductwork may be incurred.

System Control and Status Points for SCADA

The SCADA system can provide supervisory control of the substation transformation, switching, and protective equipment. This can include trip and close control of breakers and switches, set-point control of tap changers and voltage regulators, load shedding, restoration control, capacitor and reactor control, and lock-out and protection control. The operating status of every piece of electrical equipment in the substation can be monitored, as well as the operating status of substation support systems such as battery systems, relay systems, fire protection and security.

According to Newton-Evans Research, Ellicot City, Md. a study of 235 companies revealed that "Breaker control, extended sequence of events, and capacitor control were the most widely implemented among a host of SCADA applications".[2] The supervisory control portion of the SCADA system will itself be a monitored point in order to determine if initiated control actions were successful.

Circuit breaker control has traditionally been achieved through the use of interposing relays and control-switch relays (CSRs). A determination of breaker trip action is made by the system operator, and transmitted via the telemetry network from the Master Station to the RTU. The RTU receives, decodes, and checks the signal, and proceeds to take appropriate action to trip the circuit breaker. This is usually accomplished by providing an output from the RTU to energize an auxiliary relay. When closed, the contacts of the auxiliary relay energize the device which will directly initiate the tripping action. This device can be another relay, or an electrically operated control-switch relay (CSR). An electrically operated CSR is a manually operated control switch, with the added capability of having the switch mechanism or handle operated by energizing a relay integral to the switch. The CSR then passes tripping voltage, typically from the station battery, to the trip coils of the circuit breaker. Electrical control of devices such as tap changers or voltage regulators can be accomplished in a similar fashion, through the use of latching-switch relays (LSRs).

The operating status of electrical equipment and support systems can represent a significant portion of the SCADA system. Monitored status points can include circuit breaker trip/close status, disconnect switch open/close status, transformer tap-changer levels, relay operation status, and general station alarms. Monitoring of electrical equipment status is usually accomplished through the use of auxiliary contacts. Equipment contacts which represent the operating state of electrical equipment are wired directly to the RTU status inputs. A closed contact will pass field voltage to the status input of the RTU, representing that the contact is in an "on" or "high" state. The definition of the contact on and off states are programmed into the RTU. If a sufficient number of contacts are unavailable on the equipment itself, then auxiliary relays are used in a "contact-multiplying" function.

Problems Associated with Traditional SCADA Control and Status Methods

Many of the same problems associated with analog monitoring by transducers occur in control and status monitoring applications. Panel space may be unavailable for numerous auxiliary relays needed to provide status contacts to the RTU, particularly in older substation installations. The use of auxiliary relays lessens system reliability, as additional possible failure points are introduced into the system.

Extensive wiring and field cable may be required if the number of status points to be monitored is significant, increasing costs for equipment and construction.

The use of hard-wired auxiliary relays in complex monitoring schemes does not greatly facilitate testing or troubleshooting and may require additional equipment such as test blocks or plugs. In addition, the level of effort required for design and engineering for the status and control system increases in magnitude with the complexity of the field wiring and number of devices to be installed.

V.

Applications of Intelligent Devices to SCADA

Analog Monitoring Solutions with Intelligent Interface Equipment

Greater flexibility can be achieved over traditional transducers through the use of printed circuit transducing devices in conjunction with an intelligent analog interface device. Current Transformer Interface (CTI) or Potential Transformer Interface (PTI) printed circuit devices, such as those manufactured by Nitech, Inc. mount directly on the rear of common test block devices, such as General Electric PK Test Blocks, and provide transformation of secondary current and voltage levels, on the level of 5 amperes or 115 volts, to instrumentation signal levels, typically 4 to 20 milli-amperes. The CTI test switch current circuit leads pass through a hole in the circuit board and reconnects to the test switch block. The current lead then becomes the primary of the CTI transformer, and the screw terminals of the CTI become the secondary. These instrumentation signals are wired to a Remote Terminal Interface (RTI), which is programmed to calculate all required analog quantities, and transmit the data in serial format to the RTU via an RS-232 port.

By providing the capability to simply mount the CTI's and PTI's on the rear of test switch devices, savings in panel space and wiring requirements can be achieved over the use of individual transducers. Whereas only current and voltage signals are required by the Remote Terminal Interface, and analog quantities are transmitted to the RTU via an RS-232 port, cable requirements are reduced. Additionally, the Remote Terminal Interface can be mounted directly in the RTU cabinet, further reducing cable requirements.

Because the Remote Terminal Interface can be programmed to provide all of the required analog input quantities, the need for individual transducers is eliminated, resulting in substantial equipment cost savings, especially when a significant number of analog points are to be monitored. Interface boards and scaling resistors can be eliminated because calculations set-point and full scale values are programmed directly into the Remote Terminal interface. The commercially available Remote Terminal Interface Unit is completely programmable, and can also provide added functionality by monitoring all calculated data points over a user defined averaging interval, and time stamping the results for memory storage and retrieval.[3]

While the Remote Terminal Interface reduces the costs for equipment and wiring over traditional analog transducer installations, cable and terminations are still required between the CTI's and PTI's, and the centrally located Remote Terminal Interface. An approach which removes the monitoring device from a centralized location, and distributes the intelligent analog calculating and monitoring capabilities to the location of the actual points to be monitored, would reduce cable and wiring requirements even further, while increasing reliability and availability. Microprocessor-based, digital meters, such as those manufactured by Bitronics, Power Measurement Limited, or Sanagamo, placed in the relay and control panels provide the advantages of a local analog processing capacity with multiple analog measurements. These meters are coupled with an integral output communications capability which allows integration of several meters on a data bus, connected to an RTU, computer, or other SCADA interface host. Typical of this class of meter is the Power Measurement Ltd. 3710 ACM, which does not require intermediate transducers on phase voltage and current inputs. Additionally, no PT's are required for systems up to 347/600 volts, with resultant savings costs in wiring and equipment.[4] A single digital meter will replace the functions performed by multiple meters, transducers, and auxiliary relays. Digital meters are often supplied with enhanced functional capabilities, including variable setpoint control, analog value "logging", trending analysis, waveform capture, and harmonic analysis.

Placing the meter in the relay and control panel eliminates the need for current or potential secondary input cables and simplifies wiring. Because communication with the RTU is via an optically isolated port, often configured for EIA standard RS-232C or RS-485, points may be added or removed as required by simple changes to the meter programming, rather than by the installation of additional hardware and wiring. Reliability is increased by distributing possible points of failure rather than consolidating them in a centralized location. Also, testing and maintenance is greatly facilitated through the internal diagnostics which are provided with the microprocessor-based digital meters. When monitored values are out of tolerance the diagnostics can assist maintenance personnel in identifying the source of trouble, including communications failure, processor trouble, or A/D converter failure.

Control and Status Solutions with Intelligent Devices

The intention of integrating intelligent devices into the SCADA control and status system is reduce the overlapping levels of complexity associated with hard-wired electromechanical devices, reduce equipment and installation costs, maintain or improve reliability, and facilitate operation and maintenance. With the aging base of installed substations, modernizing and upgrading existing systems has become imperative. Many existing electromechanical protection systems have become increasingly complex and difficult to maintain. As part of upgrading these systems the protection systems can be upgraded with new digital relays, which will replace several electromagnetic relays and provide communications and SCADA capability. Due to the low burdens of the inputs, the existing CT's and PT's are usually adequate. Also, with the reduced panel space and simpler wiring required, the retrofit can be performed much less expensively than with traditional hard-wired relays.

For substation units being upgraded or retrofitted for new protection schemes, microprocessor-based digital protective relays commercially available from such vendors as Schweitzer, Basler, GEC, and ABB, provide communications and input/output capabilities well suited for incorporation into an integrated SCADA status and control monitoring system. For circuit breaker control applications, microprocessor relays provided with direct trip input and outputs can be wired to receive the tripping signal outputs from the RTU and provide a tripping signal to the circuit breaker trip-coils. This eliminates the need for replacing existing control switches with control-switch relays, or adding additional auxiliary tripping relays. In addition, programmable "masking" logic available in the relays provides interlocking, permissive, and logic such as synchronism for the SCADA trip and close functions, previously provided by hard wiring multiple relays.[5]

By distributing local memory and processing capabilities to the digital relays located at the point of data acquisition, the processing burden on the SCADA RTU and Master station can be reduced. Equipment status and operating information can be stored locally, and passed to the RTU during subsequent scan periods, or, when logical conditions are met, "reported by exception". Data can also be stored, and reported later in Sequence-of-Events (SER) format with time stamping, when requested by the SCADA host. This eliminates the need for speciality equipment, and allows open access to the SER data. In addition, micro-processor based digital relays are equipped with integral analog monitoring and metering capabilities, allowing the relay itself to be used for analog data acquisition. Transfer of the metering data to the SCADA RTU can be accomplished by either direct peer to peer communications with the RTU via RS-232C, or through the use of an interface adapter, which converts the metering serial data information to an analog output, such as a 4-20 milli-ampere signal.

Engineering and design of the SCADA scheme is considerably simplified by this approach. Integration of the supervisory trip and close control outputs into the existing protection schemes can now be accomplished by programming in the digital relay, rather than inserting the supervisory contact into complex hard-wired relay logic. Testing is facilitated by the self-diagnostics capabilities of the relay, and simplified wiring. Equipment costs are reduced, due to the multi-functionality of the relay, which replaces several electromechanical relays, auxiliary relays, transducers and meters.

Functional Integration and Distribution of the SCADA System Design

Processor based logic controllers acting as RTUs provide an effective means for integration of the intelligent monitoring and control devices, meters and relays into a comprehensive data acquisition and monitoring system. Manufacturers of Programmable Logic Controllers for use as RTUs provide several features that recommend them for use in SCADA Systems.

Multi-Protocol Ability

Protocol Converters allow the logic controller to support most common SCADA protocols in use today. This allows flexibility in choice of hardware to match the desired application, rather than choosing hardware to match the required Master Station protocol, and reduces software engineering costs.

Local Processing Capability

The logic controllers maintain local data analysis and processing capability which reduces the burden of data processing on the SCADA Master Station. This reduces the need for possible expansion of the SCADA host.

Functional Expandability

Micro-processor based logic controllers can be expanded to include relaying and protective functions in addition to SCADA and data acquisition functions, including breaker trip and re-closing, load shedding, tap-changing, line sectionalizing, bus restoration, and Sequence of Events reporting. These functions can be added with minimal addition of new hardware by utilizing existing I/O and making appropriate changes in the processor software.

Communications Capabilities

Processor based logic controllers can be equipped with the capability of direct communications with intelligent relays and meters, via EIA standard RS-232C or RS-485 ports, and protocol converters or bridges. In the case of the microprocessor relays and meters, these devices incorporate the functions of several electromechanical devices, and a single communications drop links them with the programmable logic controller RTU, thereby eliminating extensive hard wiring of analog, control and status points.

In addition, logic controllers can be distributed strategically throughout the substation to perform SCADA RTU data acquisition and protection functions at the actual location of the equipment being monitored and controlled. Data is shared along a peer to peer network with other local RTU's on the system, and with a master RTU which links to the SCADA host Master Station. This further reduces wiring requirements, and increases reliability in the system by reducing the probability that a single equipment failure will bring the entire SCADA system down.

Because detailed wiring to multiple relays, transducers and specialty devices is significantly reduced by the integration of intelligent devices and processor based logic controllers on a communications link, a "black-box" design approach is greatly facilitated. Modular design of system components can be logically added, removed, or modified with a minimum of field wiring or construction effort. Testing is simplified because it can be performed in a "blocking" fashion, logically isolating intelligent relays, meters and logic controllers to identify failed points on the system. Testing is also greatly facilitated by the use of logic controller's self diagnostics and off-line testing capacity.

"Report by Exception" SCADA

Logic controller manufacturers such as Modicon provide the capability to dramatically decrease communication line costs by utilizing "Report by Exception" SCADA methods. For example, utilizing a Nova-Tech 984-141 RTU and Modicon PLC Bridge Mux as a SCADA "Sub-Master", report by exception SCADA can be efficiently achieved. The 984-141 RTU monitors the substation points. Upon a report by exception condition, the RTU and it's associated modem will dial up the Modicon Sub-Master Bridge Mux, and write the changes to it's data base. Utilizing the PBX phone system with it's switching increases the chances of successfully dialing in. The Modicon Sub-Master Bridge Mux then performs the required protocol conversion to the SCADA host protocol, and appears as a regular RTU to the SCADA Master host.[6]

Report by exception does not require the SCADA Master host to continuously poll the RTU for data points. The RTU notifies the SCADA Master host when the monitored points have changed, by dialing up the SCADA host and transmitting the information. The logic which controls under what circumstances the RTU reports by exception is user configurable. Report by exception SCADA eliminates the need for a continuous communications link with it's associated costs, making SCADA in remote substations feasible where lack of communications or high communications costs were previously prohibitive factors.

VI.

Summary

The application of intelligent devices such as microprocessor based meters, relays, and logic controllers in a distributed configuration, directly addresses several factors which may have previously prohibited the installation of SCADA systems in substations.

Equipment costs are reduced due to the multi-functionality of the intelligent devices, which replaces the functions performed by several hard-wired relays and transducers. The modular expandability of logic controllers allows lower first cost in equipment purchases. It also provides the option of future expansion on an as-needed basis, which helps control incremental system costs.

Design and Engineering costs are reduced due to the fact the intelligent equipment incorporates the functions of several hard-wired relays and meters in one package, where design changes programmed in software rather than by the addition or removal of equipment and wiring. A "black-box" modular design approach can be performed in the design of the SCADA system.

Construction and start-up costs are reduced due to the decreased number of devices to be installed, the decreased panel space required for the equipment, the simplified wiring requirements, and reduced requirements for cable and support systems such as trenching and ductwork.

Testing and maintenance costs are also reduced due to the utilization of intelligent devices for SCADA. Micro-processor devices incorporate self-diagnostic functions which facilitate the test and checkout of equipment, and allow preventative maintenance. The modular design resulting from the simplified equipment connections allows easier isolation and testing of faulted components, and the communications capabilities provide the opportunity for "off-line" testing. Maintenance costs are decreased over the long term, due to the extended functions which may be added to the devices at little or no incremental cost. Simplified troubleshooting, and reduced communications costs are also benefits.

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FISHER PIERCE PRODUCTS FOR IMPROVING DISTRIBUTION SYSTEM RELIABILITY

Fisher Pierce Products

"FISHER PIERCE PRODUCTS FOR IMPROVING DISTRIBUTION SYSTEM RELIABILITY"

ABSTRACT

The challenges facing the electric power utility today in the 1990s has changed significantly from those of even 10 years ago. The proliferation of automation and the personnel computer have heightened the requirements and demands put on the electric distribution system. Today's customers, fighting to compete in a world market, demand quality, uninterrupted power service. Privatization and the concept of unregulated competition require utilities to streamline to minimize system support costs and optimize power delivery efficiency. Fisher Pierce, serving the electric utility industry for over 50 years, offers a line of products to assist utilities in meeting these challenges.

The Fisher Pierce Family of products provide tools for the electric utility to exceed customer service demands. A full line of fault indicating devices are offered to expedite system power restoration both locally and in conjunction with SCADA systems. Fisher Pierce is the largest supplier of roadway lighting controls, manufacturing on a 6 million dollar automated line assuring the highest quality in the world. The distribution system capacitor control line offers intelligent local or radio linked switching control to maintain system voltage and Var levels for quality and cost efficient power delivery under varying customer loads. Additional products, designed to authenticate revenue metering calibration and verify on sight metering service wiring, help optimize the profitability of the utility assuring continuous system service improvements for their customers.

A Microprocessor-Based Digital Feeder Monitor with High-Impedance Fault Detection

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Introduction

The high impedance fault detection technology developed at Texas A&M University after more than a decade of research, funded in large part by the Electric Power Research Institute, has been incorporated into a comprehensive monitoring device for overhead distribution feeders. This digital feeder monitor (DFM) uses a high waveform sampling rate for the ac current and voltage inputs in conjunction with a high-performance reduced instruction set (RISC) microprocessor to obtain the frequency response required for arcing fault detection and power quality measurements. Expert system techniques are employed to assure security while maintaining dependability. The DFM is intended to be applied at a distribution substation to monitor one feeder. The DFM is packaged in a non-drawout case which fits the panel cutout for a GE IAC overcurrent relay to facilitate retrofits at the majority of sites where electromechanical overcurrent relays already exist.

High Impedance Faults

To understand the performance of the DFM, it is necessary to define the high impedance faults targeted by this device. A high impedance fault is characterized by having an impedance sufficiently high such that it is not detected by conventional phase or ground overcurrent protection. A downed conductor fault occurs when the conductor is no longer intact on pole top insulators, but instead is broken and in contact with earth or a grounded object. An arcing fault is any high impedance fault which exhibits arcing.

Combinations of these types are possible. An example is an arcing, high impedance, downed conductor fault. The intent of the DFM is to detect high impedance faults which arc, and to differentiate those which are downed conductors from those which are not. Electrical signatures are used to identify the presence of arcing. If the arcing begins with a loss of load or with an overcurrent disturbance (as might occur when a conductor falls across another phase or neutral wire and then falls to ground), the DFM assumes that a conductor is down. If neither of these conditions initiates the arcing, the DFM assumes that the conductor is still intact. In the interest of system security,

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the DFM considers loss of load or an overcurrent disturbance to indicate a downed conductor if and only if one of these starts the arcing, and not if one these occurs after the initiation of arcing. The reason for this is that, following a recloser operation, power system load levels will often change sufficiently such that the DFM cannot distinguish between a recloser operation and a loss of load due to a broken conductor.

Algorithms Associated with High Impedance Fault Detection

An algorithm is simply a set of rules for solving a problem. For a microprocessor-based device, an algorithm is implemented by the software code run by the microprocessor. In the DFM, the detection of a downed conductor or arcing condition is accomplished through the execution of the following algorithms:

Energy Algorithm
Randomness Algorithm
Expert Arc Detector Algorithm
Load Event Detector Algorithm
Load Analysis Algorithm
Load Extraction Algorithm
Arc Burst Pattern Analysis Algorithm
Spectral Analysis Algorithm
Arcing Suspected Identifier Algorithm

Energy Algorithm

Arcing causes bursts of energy to register throughout the frequency spectrum, and they are readily detected at non-fundamental and non-harmonic frequencies. This characteristic of arcing faults is represented in Figure 1. The Energy Algorithm monitors a specific set of non-fundamental frequency component energies of phase and neutral current. After establishing an average value for a given component energy, the algorithm indicates arcing if it detects a sudden, sustained increase in the value of that component. The DFM runs the Energy Algorithm on each of the following parameters for each phase current and for the neutral: (1) even harmonics, (2) odd harmonics, and (3) non-harmonics. On a 60-Hz system, the non-harmonic component consists of a sum of the 30, 90, 150, ..., 750-Hz components, while on a 50-Hz system, it consists of a sum of the 25, 75, 125, ..., 625-Hz components. If the Energy Algorithm detects a sudden, sustained increase in one of these component energies, it reports this to the Expert Arc Detector Algorithm, resets itself, and continues to monitor for another sudden increase.

Randomness Algorithm

The Randomness Algorithm identifies another characteristic of these faults, that of having energy magnitudes which vary considerably from one half-cycle to the next, as shown in Figure 2. The Randomness Algorithm monitors the same set of component energies as the Energy Algorithm. However, rather than checking for a sudden, sustained increase in the value of the monitored component energy, it looks for a sudden increase in a component

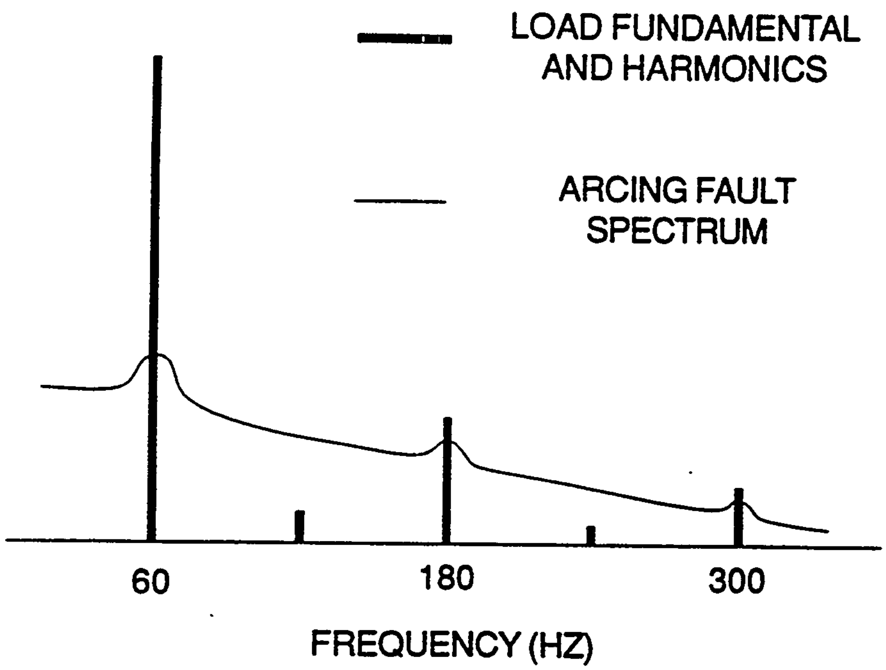


Figure 1

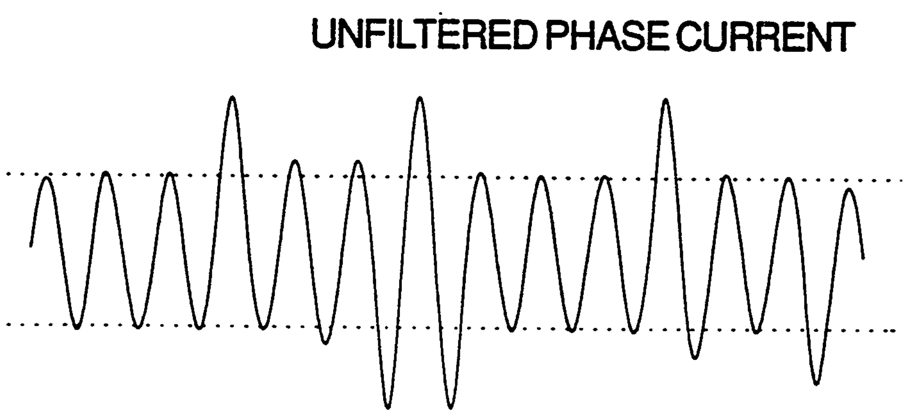


Figure 2

followed by highly erratic behavior. This type of highly random behavior is indicative of many arcing faults. Just as with the Energy Algorithm, if the Randomness Algorithm detects a suspicious event in one of its monitored components, it reports this to the Expert Arc Detector Algorithm, resets itself, and continues to monitor for another suspicious event.

Expert Arc Detector Algorithm

The purpose of the Expert Arc Detector Algorithm is to assimilate the outputs of the basic arc detection algorithms into one "belief-in-arcing" confidence level per phase. Note that there are actually 24 independent basic arc detection algorithms, since both the Energy Algorithm and the Randomness Algorithm are run for the even harmonics, odd harmonics, and non-harmonics for each phase current and for the neutral. The assimilation performed by the Expert Arc Detector Algorithm, then, is accomplished by counting the number of belief-in-arcing indications determined by any one of the twenty-four algorithms over a short period of time. Also taken into account is the number of <u>different</u> basic algorithms that indicate a belief in arcing. Various weights are assigned to each of the parameters to reflect the significance of the information in each parameter. These weights were derived from the analysis of hours of data from over 300 staged faults and other events.

The Expert Arc Detector Algorithm's belief-in-arcing confidence level for each phase increases as the number of basic algorithms that indicate a belief in arcing increases. It also increases with increasing numbers of indications from any one basic algorithm. These confidence level increases occur because multiple, consecutive indications and multiple, independent indications are more characteristic of the presence of arcing than a single algorithm giving a single indication.

Load Event Detector Algorithm

The Load Event Detector Algorithm examines, on a per-phase basis, one reading of RMS values per two-cycle interval for each phase current and the neutral. It then sets flags for each phase current and for the neutral based on the following events: (1) an overcurrent condition, (2) a precipitous loss of load, (3) a high rate-of-change, (4) a significant three-phase event, and (5) a breaker open condition. These flags are examined by the Load Analysis Algorithm. Their states contribute to that algorithm's differentiation between arcing downed conductors and arcing intact conductors, and inhibit the Expert Arc Detector Algorithm from indicating the need for an arcing alarm for a limited time following an overcurrent or breaker open condition.

Load Analysis Algorithm

The purpose of the Load Analysis Algorithm is to differentiate between arcing downed conductors and arcing intact conductors by looking for a precipitous loss of load and/or an overcurrent disturbance at the beginning of an arcing episode. A typical downed conductor pattern recognized by the algorithm is shown in Figure 3. The presence of arcing on the system is determined

Load/Event Analysis

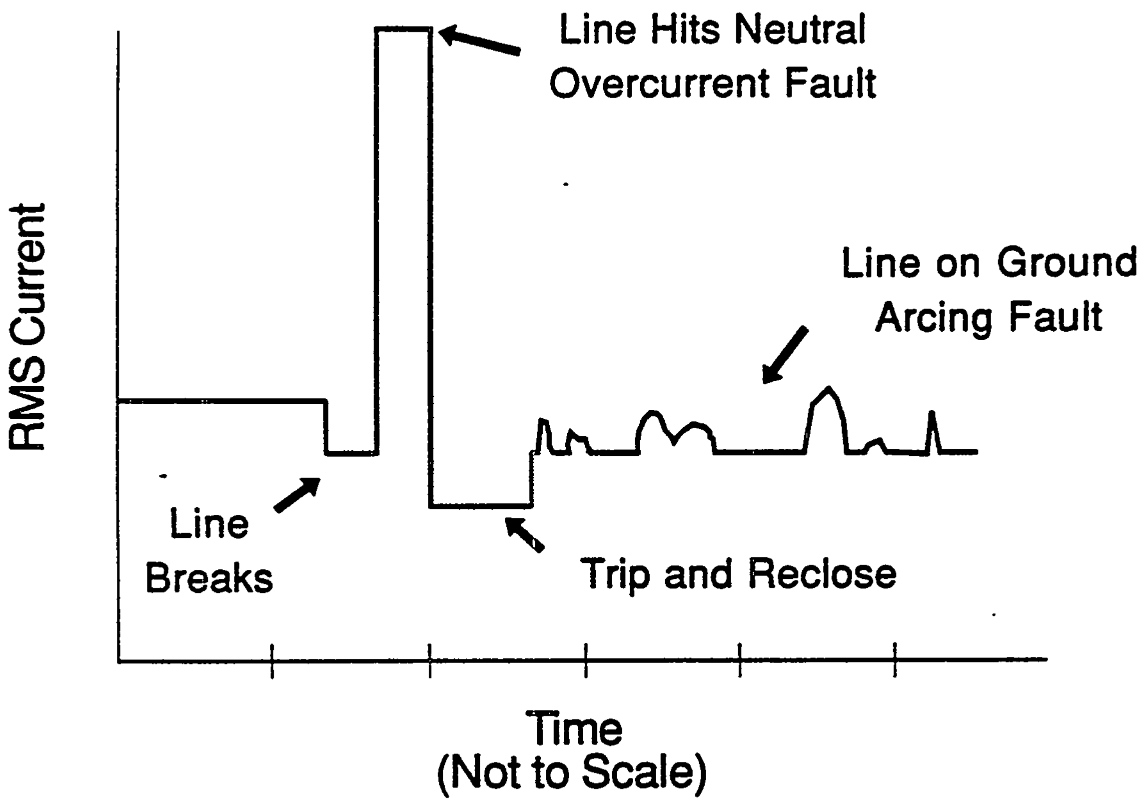


Figure 3

based on the output of the Expert Arc Detector Algorithm. If the DFM finds persistent arcing on the power system, the Load Analysis Algorithm then considers the type of incident that initiated the arcing and classifies the arcing conductor as either downed or intact. Another function of the algorithm is to provide coordination between the DFM and the power system's conventional overcurrent protection by observing a timeout from the beginning of the arcing before giving an indication of arcing.

If the Load Analysis Algorithm determines that a downed conductor or arcing exists, it attempts to determine the phase on which the high impedance fault condition exists. It does this in a hierarchical manner. First, if a significant loss of load triggered the Load Analysis Algorithm, and if there was a significant loss on only one phase, that phase is identified. If there was not a single phase loss of load, and if an overcurrent condition on only one phase triggered the algorithm, that phase is identified. If both of these tests fail to identify the phase, the phase with a significantly higher confidence level (e.g. higher than the other two phases by at least 25%) is identified. Finally, if none of these tests provides phase identification, the result of the Arc Burst Pattern Analysis Algorithm is checked. If that test fails, the phase is not identified.

Load Extraction Algorithm

The Load Extraction Algorithm attempts to find a quiescent period during an arcing fault so that it can determine the background load level of the neutral current. If it is successful in doing so, it then removes the load component from the total measured neutral current, resulting in a signal which consists only of the fault component of the neutral current. This information is then provided as input to the Arc Burst Pattern Analysis Algorithm.

Arc Burst Pattern Analysis Algorithm

The Arc Burst Pattern Analysis Algorithm attempts to provide faulted phase identification information based on a correlation between the fault component of the measured neutral current and the phase voltages. The fault component is received from the Load Extraction Algorithm. The result of the analysis is checked by the Load Analysis Algorithm if its other phase identification methods prove unsuccessful.

Spectral Analysis Algorithm

The Spectral Analysis Algorithm analyzes the non-harmonic components of the neutral current on the power system and correlates the shape of the non-harmonic components of the spectrum to an ideal 1/f arcing spectrum. A high correlation provides confirmation of the DFM's belief in arcing on the power system.

Arcing Suspected Identifier Algorithm

The purpose of the Arcing Event Trend Identifier Algorithm is to detect multiple, sporadic arcing events. If taken individually, such events are not sufficient to warrant an arcing alarm. When taken cumulatively, however, these events do warrant an alarm to system operators so that the cause of the arcing can be investigated.

Figure 4 illustrates the interaction of these various algorithms to produce three separate outputs associated with high impedance fault detection. The "arcing" output occurs relatively fast when persistent arcing is present or relatively slow (fraction of an hour to one or two hours) when arcing is intermittent. The "downed conductor" output occurs only when a precipitous loss of load or an overcurrent condition indicating a fault occurs prior to the detection of arcing. "Phase identification" (phase A, phase B, or phase C) is determined when either the arcing or downed conductor output occurs.

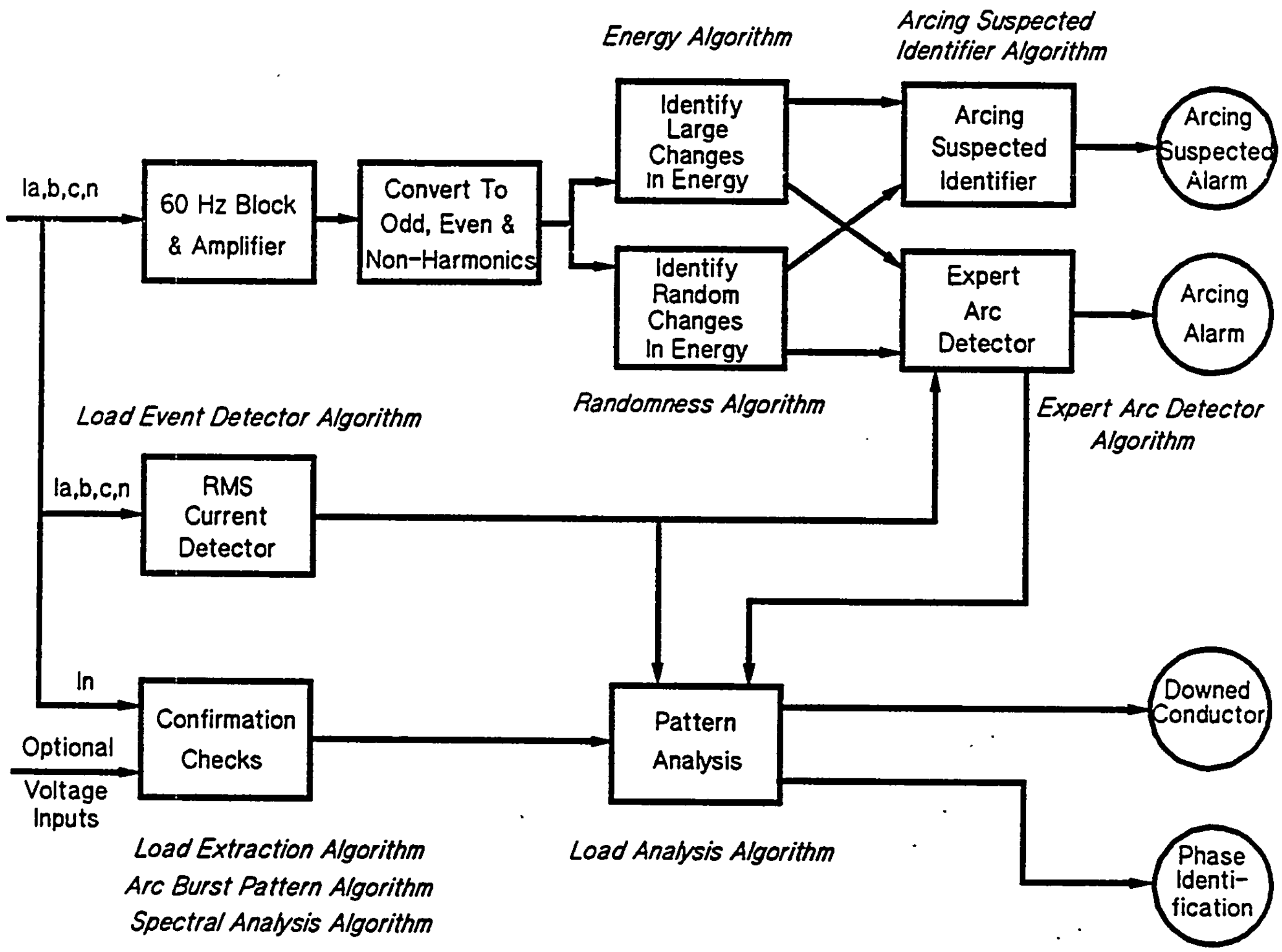
Control Strategies for High Impedance Fault Detection

Users of the DFM expect its high impedance fault detection to be secure and dependable. Most users will consider service continuity important, and will use the DFM to improve the ability to de-energize a feeder where a downed conductor poses a threat to life and property.

The DFM is designated a "monitor" rather than a protective relay to emphasize the fact that not all downed conductors can be detected by the DFM. For instance, a downed conductor on dry asphalt that does not produce arcing will not be detected by the DFM. It is difficult to derive a definitive, statistical performance of merit for DFM high impedance fault detection because of the wide variety of ground and circuit conditions which may be encountered. However, based upon documented field experience and assumptions of circuit environmental conditions, it can be expected that approximately 80% of all arcing, high impedance faults will be detected by the DFM, assuming the default sensitivities set at the factory.

Once detection occurs, the user must decide upon a course of action. A DFM contact closure associated with the downed conductor output of Figure 4 can be used to alarm or initiate a control action, the most apparent of which is tripping the feeder breaker. However, the user may consider whether tripping the feeder breaker and the resultant interruption of service is necessary where there is virtually no risk to person or property.

Downed conductor accidents have been and will be the subject of litigation. Given devices such as the DFM which can detect a high percentage of downed conductors, utilities, acting alone and influenced by regulating bodies, may feel compelled to install such devices to improve safety by selective clearing of suspected downed conductor faults. This approach will reduce the overall risk to person or property although the risk will not be entirely eliminated because not all downed conductors can be detected. On the other hand, a utility that chooses not to install such a device or not to trip if one is installed may be at a disadvantage in a court room situation. This is all very speculative, but it points out the advantage in using a new product which offers substantial improvements but is not perfect.



High Impedance Fault Detection Block Diagram

Figure 4

There are other service continuity and safety considerations that will influence how the DFM is used. In partially arid regions where a downed conductor can easily start a wild fire, the user may elect to always trip the feeder breaker. In a dense suburban area, the safety risk of a downed conductor may be substantially less than if one or more traffic lights at busy intersections are disabled as a result of the DFM tripping the feeder breaker. In a sparsely populated rural area with few feeders and laterals, where threat of wild fire from a downed conductor is low, service continuity may dictate that the DFM alarm only.

The ability or inability to communicate with a given distribution substation will also affect how the DFM is used. If information that an alarm contact has closed cannot be detected at a remote location, where appropriate action can be taken, then the remaining option is to allow the DFM to trip when a downed conductor is detected. For those distribution substations which are part of a SCADA system, a DFM alarm contact may be wired directly to the RTU at the substation.

If a SCADA RTU is not present, then the DFM's RS232 serial ports can provide remote communications. A DB-25 connector (PL-1) located on the rear of the case permits the user to communicate with the DFM from a local or remote computer or to connect the DFM to the host computer of a G-NET substation information and control system. A DB-9 connector located on the front panel of the DFM permits the user to communicate with the DFM from a local or remote computer, but it cannot be used to connect the DFM to the host computer of a G-NET system.

When communication via a serial port is desired, a local PC may be connected via the proper null-modem cable or a remote PC may be connected via interposing modems. Unique PC software, DFM-LINK, is required to communicate with the DFM. DFM-LINK allows the user to call in and inquire if an alarm condition exists. The G-NET system, which would typically be used at a substation to gather and sort information from multiple intelligent electronic devices (IEDs), will automatically call a remote PC to indicate that an alarm exists.

Other Monitoring Functions

In addition to high impedance fault detection, the following functions are available in the DFM:

Breaker Health Monitoring
Overcurrent Disturbance Monitoring
Power Quality Monitoring
Present Value Monitoring

Breaker Health Monitoring

The DFM calculates and stores the cumulative It or I^2t value (depending on a setting) of each of the three phase currents in order to monitor breaker health. These cumulative values, along with a count of breaker trips, are accessible either through the local man-machine interface (MMI) or via a serial port.

If the DFM is connected to a breaker that has had prior use, the DFM accepts initial cumulative values for each phase and an initial value for the total number of trips. This initialization is accomplished through a serial port. The breaker health values can also be reset through a serial port upon completion of breaker maintenance. If the DFM is configured to allow local MMI resets, a breaker health reset can also be accomplished through the local MMI.

Overcurrent Disturbance Monitoring

The DFM monitors for an overcurrent condition on the feeder by establishing overcurrent thresholds for the phases and for the neutral and then checking for a single two-cycle RMS current that exceeds those thresholds. Oscillography and fault data are captured if it is determined that an overcurrent condition exists. In addition, the DFM's local MMI responds with a blinking overcurrent message on the top display line and appropriate LEDs being lit.

Power Quality Monitoring

The DFM's power quality monitoring function provides information for assessing the duration and severity of periods of poor power quality. The DFM checks the power quality by calculating the total harmonic distortion (THD) on each of the three phase currents and voltages over one-minute intervals. The THD is then used to define the effect of harmonics on the power system currents and voltages. It represents the ratio of the root-mean-square of the harmonic content to the root-mean-square value of the fundamental quantity, expressed as a percent of the fundamental. Calculation of THD values requires the accumulation of the real and imaginary components of the 2nd through 13th harmonic frequencies. This accumulation is performed on the phase currents for each two-cycle sample interval. The three voltage inputs are sequentially analyzed, also using a two-cycle data window.

The THD values stored in the DFM are updated once per minute for each phase current and voltage. These values can be viewed on the local MMI or retrieved through a serial port. A command may also be used to retrieve all the real and imaginary components of the thirteen multiples of the fundamental frequency for the last two-cycle interval.

The power quality data maintained in the DFM includes minimum, maximum, and average values for THD, and the minimum 2-second RMS average for each phase voltage. This data is reported for a time interval configurable to 15, 30, or 60 minutes, with 2, 4, or 8 days of storage provided, respectively, depending on the time interval selected. An extended memory option is available that provides 35, 70, or 140 days of entries, respectively, again depending on the time interval. (The selected interval and storage capability apply to all the demand data in the DFM.)

Present Value Monitoring

The DFM provides typical panel meter functions by monitoring the present values of the three-phase distribution feeder and displays these on a 2-line by 20-character alphanumeric display located on the front panel. Present value data consists of the individual currents, voltages, watts, VARs, and power factors, as well as the individual total harmonic distortions (THDs) for each of the three phase currents and voltages in models that include power quality monitoring. Three-phase values are calculated for the watts, VARs, VA, and power factors. Each present value is updated once per second.

Additional Features

The following features are included in the DFM. The list of features is followed by detailed descriptions of each.

Breaker Control
Configurable Contact Converters
Configurable Outputs
Configurable Time Interval Demand Reporting
Daily Maximum Demand Reporting
Peak Value Reporting
Event Reporting
Fault Reporting
Harmonic Spectral Analysis
Instantaneous and RMS Oscillography
Local Man-Machine Interface (MMI)
Multiple Groups of High Impedance Settings
Password Protection
Power-On Self-Tests
Run-Time Self-Tests
Serial Communications
Time Synchronization

Breaker Control

Two of the DFM's output contacts are designated as control contacts and are configurable for tripping a breaker. If one or both of these are configured as such, the breaker can be tripped by closing one or both of those contacts. A 'close breaker' command will close a dedicated output contact. It is also possible to trip and close the breaker via external contacts wired to the DFM's contact converters by configuring one to 'open breaker' and another to 'close breaker'.

Configurable Contact Converters

All three of the DFM's contact converters are configurable. The user can select from eight possible assignments, but each contact converter (CC) may be given one and only one assignment, and no two CCs can be given the same assignment.

Configurable Outputs

To provide greater flexibility in utilization of the output contacts, four of the output contacts are designated as configurable. Two of these are designated as control contacts; the other two, as alarm contacts.

Configurable Time Interval Demand Reporting

Demand profiles are maintained in the DFM for the currents, watts, VARs, 3-phase VA, and power factors, as well as for the minimum, maximum, and average total harmonic distortions (THDs) and minimum 2-second average RMS voltages in models that include power quality monitoring. The demand profiles are averages that are calculated based on an interval of time known as the demand period, which is configurable to either 15, 30, or 60 minutes.

Daily Maximum Demand Reporting

In addition to the demand profiles, a 35-day history of daily maximums (or minimums, depending on the data) is also maintained. Included in this history are the maximum current per phase and neutral, the maximum three-phase watts, VARs, and VA, and the minimum three-phase power factor. For DFM models that provide power quality monitoring, the maximum THD per current and voltage phase and the minimum 2-second RMS voltage per phase are also included. Each of the entries in the 35-day log is based on a daily demand period average which represents the maximum (or minimum, if applicable) for each day. Each entry is time stamped independently to the nearest second. The 35-day log of daily maximums can be accessed through a serial port.

Peak Value Reporting

Peak values are maintained in the DFM which represent maximum values (or minimum, depending on the data) since the data storage memory was last cleared. Peak entries include the maximum phase and neutral currents, the maximum three-phase watts, VARs, and VA, and the minimum three-phase power factor. Peak THDs for each phase current and voltage, as well as the minimum 2-second average RMS voltages per phase are also included in models that provide power quality monitoring.

Event Reporting

A log of events is maintained in the DFM that contains the last 150 events. Events are time stamped to the nearest half-millisecond. Examples of events logged include alarms, contact operations, logins and logouts, oscillography captures, remote operations, and resets. Event data can be accessed through a serial port.

Fault Reporting

When either a high impedance fault or an overcurrent disturbance is detected, pertinent information (unit ID, date and time, operating time, pre-fault currents, fault currents and voltages, fault type, operation type, selected events) is stored in the DFM. Complete data for the most recent faults is maintained, up to a maximum number of faults. This maximum is configurable to either 1, 2, 4, or 8. The fault data can be accessed through a serial port, or an abbreviated summary containing only the fault types, operation types, and dates and times can be viewed on the DFM's local MMI.

Harmonic Spectral Analysis

Harmonic spectral analysis is performed in DFM models that provide power quality monitoring. Harmonic data is maintained by accumulating the real and imaginary components of the 2nd through 13th harmonic frequencies for phase currents and voltages. The last two-cycle interval of these components can be retrieved through a serial port for analysis.

Local Man-Machine Interface (MMI)

A local MMI, consisting of four pushbuttons, six LEDs, and a 2-line by 20-character alphanumeric display, provides the user easy access for monitoring present values, peak demand data, contact converter and output contact assignments, contact converter states, and disturbance data, as well as DFM status and alarm information. In addition, via the local MMI, the user may view the current date and time, view the DFM model and EPROM version numbers, zero the peak demands and breaker health values, initiate a self-test of the MMI, or initiate the automatic scrolling of present values on the bottom line of the display.

Multiple Groups of High Impedance Settings

Two separate groups of high impedance settings may be stored in the DFM's nonvolatile memory, with only one group active at a given time. The currently active group is determined by a setting. This setting can dictate that the normal settings are active, that the alternate settings are active, or that the active group is determined by the state of a contact converter. If tied to the state of a CC, the alternate settings are active if a CC configured for 'alternate settings' is closed; otherwise, the normal settings are active.

Instantaneous and RMS Oscillography

Two sets of oscillography data are stored in memory each time the DFM detects either a high impedance fault or an overcurrent fault, or when an external contact triggers oscillography. The first set of data consists of the instantaneous voltage and current values for up to 200 cycles of data. The memory for this data can be configured for the most recent one 200-cycle, two

100-cycle, four 50-cycle, or eight 25-cycle events. The second set of data consists of the two-cycle RMS values for the voltage and current for 5400 samples (3 minutes). The configuration of this data is tied directly to the instantaneous oscillography configuration, with the one, two, four, and eight mapped to 5400-sample, 2700-sample, 1350-sample, and 675-sample events, respectively.

Password Protection

Three different passwords provide security when uploading and viewing stored data, when performing control actions, and when changing settings via a serial port. Each password has a default which is stored in memory as shipped from the factory. These defaults must be changed when the DFM is placed in operation. The three passwords may be viewed in their encrypted form on the local MMI. They may be changed through a serial port.

Power-On Self-Tests

The most comprehensive testing of the DFM is performed during a power-up. Since the DFM is not performing any monitoring activities at that time, tests that would be disruptive to run-time processing may be performed. The power-on self-tests attempt to verify the DFM's hardware components (EPROM, local RAM, interrupt controller, timer chip, serial ports, DMA channels, nonvolatile memory, analog and digital I/O circuitry, MMI hardware, etc.).

Run-Time Self-Tests

The DFM's run-time self-test diagnostics are executed on a regular basis during online operation. These self-tests are intended to diagnose possible real-time failures due to component aging, premature component failure, etc. Tests that are run verify DFM memory cell integrity and bus connections without disturbing ongoing algorithmic and communication processes.

Serial Communications

Two RS-232 serial ports are provided on the DFM, one on the front panel and one on the rear panel.

Time Synchronization

The DFM includes a clock that can run freely from the internal oscillator or be synchronized from an external signal. Three different external time synchronization signals are possible. If available, an unmodulated IRIG-B signal connected to the IRIG-B BNC connector on the DFM's back panel is used to synchronize the clock. If the DFM is connected to the host computer of a G-NET substation information and control system, then the DFM receives a time synchronization pulse via pin 25 of PL-1 on the DFM's back panel. A time reference can also be supplied to the DFM from a PC connected via a serial port.

Strategies for Assessment and Test

The DFM is one of many new digital devices for protection and monitoring made available to the utility industry over the last ten years. While digital technology has been accepted by many utilities, each new device is generally evaluated on its own merits. To facilitate the acceptance of such new devices GE has initiated the concept of an Advisory Committee of Experts (ACE). The DFM ACE Team consists of approximately thirty participating utility members and fifteen associate members. The ACE Team acts as an ongoing forum for both application issues and collective performance assessment.

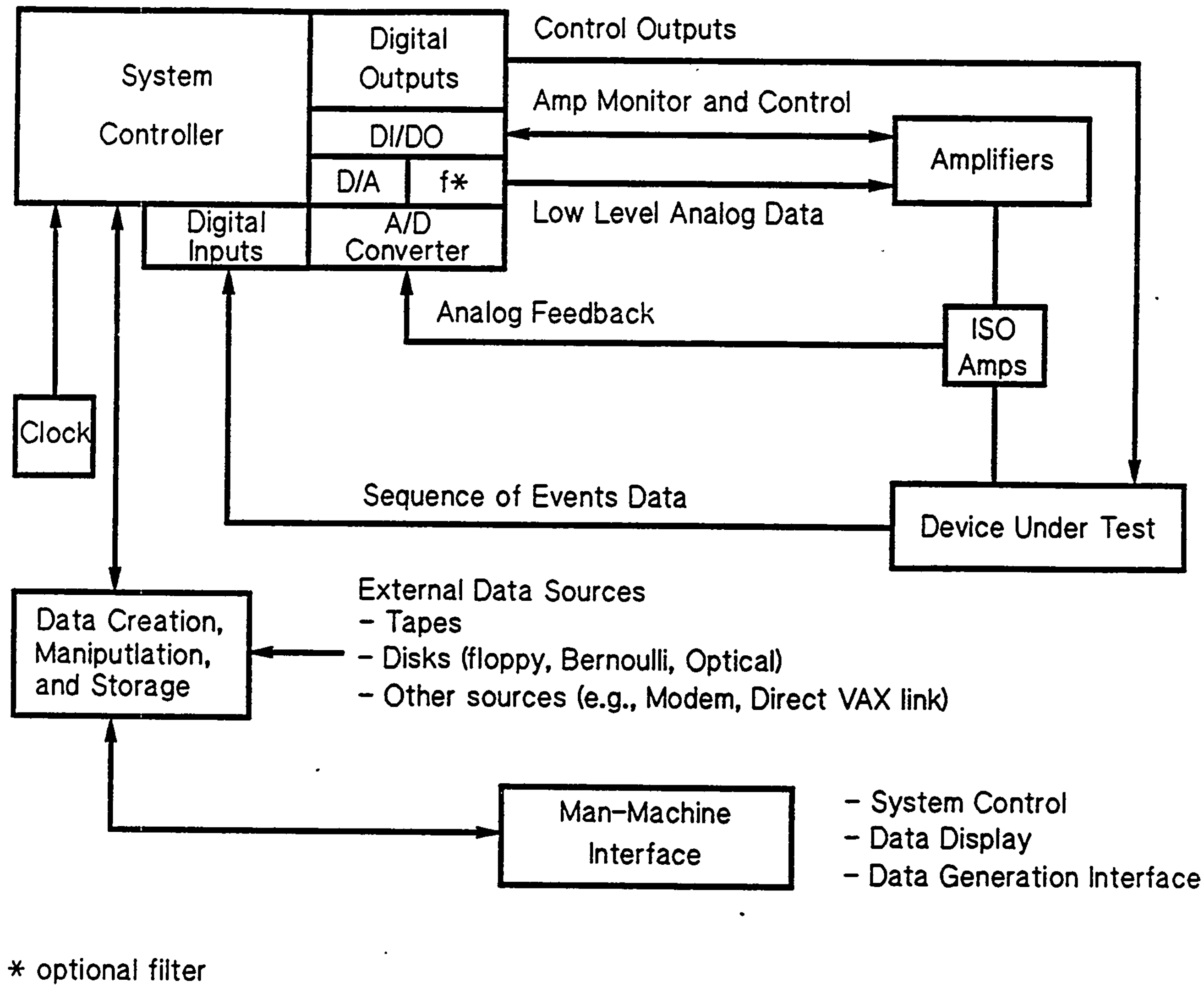
Many of the DFM's algorithms analyze higher order harmonic and non-harmonic frequencies which are beyond the capabilities of most analog simulators typically used for testing protective relay performance. However, the newer digitally-generated simulators, which use the output from EMTP studies or actual DFR recordings as inputs to linear amplifiers the outputs of which are applied to the device under test, are quite capable of the required frequency response. Figure 5 shows a simplified block diagram of the digital model power system (DMPS) located in GE's Malvern Technology Center.

An extensive digital data base of actual power system high impedance faults, as well as non-fault operating transients has already been accumulated. Much of this data was recorded at Texas A&M University's Downed Conductor Test Facility. This data base is currently being expanded by recording staged events on actual utility feeders located on the power systems of various ACE Team members.

At the present time, pre-production DFM units are being tested on the GE DMPS and are being installed on actual feeders by ACE Team members to gain actual in-service experience. A primary goal of the ACE Team concept is that this shared experience accumulated over a relatively short period of time be accepted by the industry in place of the more traditional two to three years of in-service experience (on some other power system) required before a new device is accepted. The sharing of field experience in various environments can provide a much higher confidence level than would be possible with individual utility experience.

Both the DMPS testing and field installation exposure are intended to show that the high impedance fault detection is secure and dependable. The other goals are to prove out the monitoring functions and to show that, as designed, the DFM can survive in the harsh environments encountered at distribution substations.

An ongoing task for GE and the ACE Team members is to determine the best way to field test the continuing viability of the high impedance fault detection after the DFM has been placed in service. The need for periodic testing of digital protective relays has been discussed extensively over the last ten years. While digital devices generally provide extensive self-test



Digital Model Power System Simplified Block Diagram

Figure 5

capability, self-testing cannot generally detect a failure in all components. For instance, most digital devices including the DFM use small magnetic CTs and VTs packaged inside the device's case to condition the current and voltage inputs for use by the analog-to-digital converter circuitry. These magnetic CTs and VTs may fail and not be detected by the device's self-test feature. Routine periodic testing is advisable. The question with a digital device is how extensive should this periodic testing be. Many utilities continue to perform periodic tests on digital protective relays in a manner identical to that used for electromechanical and static analog relays. This means that the functioning of the various measurement functions are checked by applying 60 Hz values of test current and voltage required to operate that function at its pickup setting. If a similar tact is taken with the DFM's high impedance fault detection function, then the application of 60 Hz quantities is not adequate. More sophisticated field test equipment will have to be used to obtain the required higher harmonic and non-harmonic frequencies. Whether periodic field testing of the DFM using only injected 60 Hz currents and voltages will be acceptable has not yet been determined.

Conclusions

The lingering problem of not being able to reliably detect high impedance faults and downed conductors has yielded to more than a decade of research and the availability of high performance microprocessors. The accumulated observations of Texas A&M researchers have been distilled into multiple algorithms to permit the detection of a large percentage of high impedance faults with excellent security. Even with these substantial improvements, a few unsafe conditions will never provide measurable parameters, and they will evade detection. The DFM which embodies this technology has been designed to fit the panel cutout of IAC relays to facilitate retrofits where one of the two or three existing phase overcurrent relays is to be replaced with the DFM. Close cooperation between the users and manufacturer in the assessment and application of the DFM is intended to benefit all parties including the general public.

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WORLD-WIDE DISTRIBUTION AUTOMATION SYSTEMS

By:
Terrence M. Devaney
ECC, Inc.

WHAT IS DISTRIBUTION AUTOMATION?

EVERYONE SEEMS TO HAVE THEIR OWN DEFINITION OF D.A.

UTILITIES DEFINITION OF THEIR DISTRIBUTION SYSTEMS VARY WIDELY

MANY DEFINE 34KV AND BELOW AS THEIR DISTRIBUTION SYSTEM

THERE ARE SOME THAT DEFINE THEIR DISTRIBUTION SYSTEM AS 69KV AND BELOW

DISTRIBUTION AUTOMATION

STATUS OF UTILITY AUTOMATION

- GENERATION
  - 50% CAPITALIZATION
  - MATURE TECHNOLOGY
- TRANSMISSION
  - 10% CAPITALIZATION
  - MATURING TECHNOLOGY
- DISTRIBUTION
  - 40% CAPITALIZATION
  - LITTLE OR NO AUTOMATION

IT IS BEST TO DEFINE D.A. FUNCTIONALLY

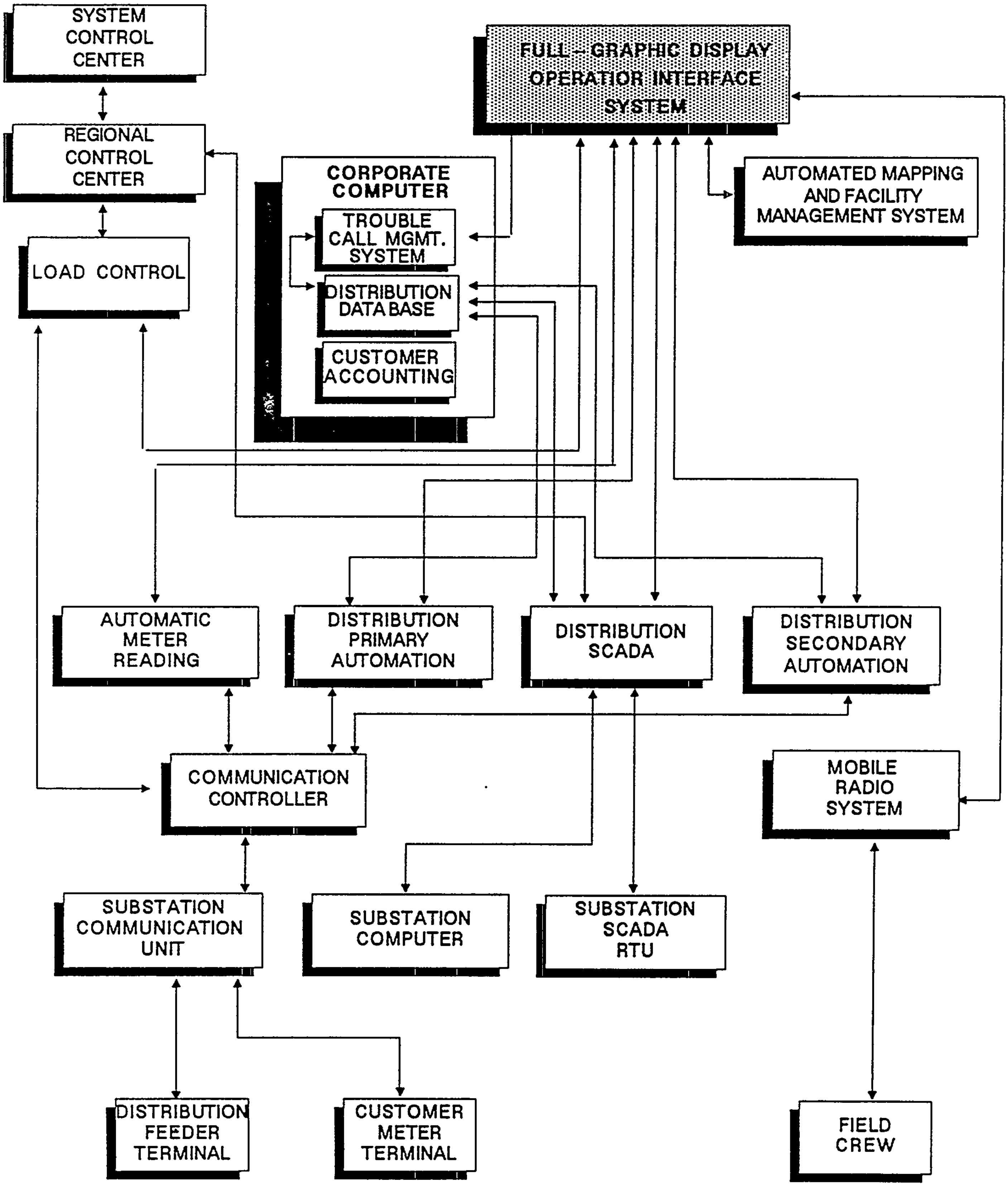
"D.A. IS THE REAL-TIME REMOTE MONITORING AND CONTROL OF EQUIPMENT ON THE DISTRIBUTION PRIMARY AND SECONDARY SYSTEMS"

THIS DEFINITION IS ONE THAT IS ACCEPTABLE AS A STARTING POINT TO DEFINE FUNCTIONS TO ACCOMPLISH THE ABOVE

GENERAL CATEGORIES OF D.A. FUNCTIONS

1. SUBSTATION FUNCTIONS
2. FEEDER FUNCTIONS
3. CUSTOMER FUNCTIONS

DISTRIBUTION MANAGEMENT SYSTEM



DISTRIBUTION AUTOMATION

SUBSTATION FUNCTIONS

- TRANSFORMER CONTROL
  - LOAD BALANCING
  - LOAD LOSSES
  - CIRCULATING CURRENTS
  - OVERLOADS
- PROTECTION
  - TRANSFORMER ISOLATION
  - AUTOMATIC RECLOSING
  - BUS FAULT ISOLATION
  - INSTANTANEOUS/TIME OVERCURRENT
  - UNDERFREQUENCY

DISTRIBUTION AUTOMATION

FEEDER (MEDIUM VOLTAGE) FUNCTIONS

- SECTIONALIZATION AND RECONFIGURATION
  - FAULT LOCATION
  - FAULT ISOLATION
  - SERVICE RESTORATION
  - FEEDER SWITCHING

- INTEGRATION VOLT/VAR CONTROL ALONG FEEDERS
  - FEEDER REACTIVE POWER CONTROL
  - FEEDER VOLTAGE CONTROL
  - BUS VOLTAGE CONTROL
  - HARMONICS CONTROL

DISTRIBUTION AUTOMATION

CUSTOMER (LOW VOLTAGE) FUNCTIONS

- LOAD MANAGEMENT
  - LOAD CONTROL
  - REMOTE SERVICE CONNECT/DISCONNECT
  - TIME-OF-USE SIGNALS

- REMOTE METERING
  - REMOTE METER READING
  - PEAK DEMAND METERING
  - REMOTE PROGRAMMING OF METER
  - LOAD SURVEY
  - TAMPER DETECTION

DISTRIBUTION AUTOMATION

POTENTIAL BENEFITS CATEGORIES

1. INVESTMENT SAVINGS
2. OPERATIONAL SAVINGS
3. MANPOWER SAVINGS
4. CUSTOMER SAVINGS

DISTRIBUTION AUTOMATION

POTENTIAL BENEFITS BY CATEGORY

1. INVESTMENT SAVINGS

- DEFERRED NEW SUBSTATIONS
- DEFERRED UPGRADING OF TRANSFORMERS
- DEFERRED RECONDUCTORING
- RELEASED TRANSMISSION CAPACITY
- DEFERRED NEW GENERATION

DISTRIBUTION AUTOMATION

POTENTIAL BENEFITS BY CATEGORY (CONT.)

2. OPERATIONAL SAVINGS

- REDUCED GENERATION FUEL USAGE
- IMPROVED VOLTAGE REGULATION
- REDUCED METERING COSTS
- REDUCED CONNECT/DISCONNECT COSTS
- REDUCED TAMPERING
- IMPROVED PRODUCTIVITY
- IMPROVED PLANNING FROM TIMELY DATA

DISTRIBUTION AUTOMATION

POTENTIAL BENEFITS BY CATEGORY (CONT.)

3. LABOR SAVINGS

- REDUCED MANPOWER
  - FOR SECTIONALIZING AND RESTORATION
  - FOR METERING AND MONITORING

- REDUCED MANHOURS
  - FOR SERVICE AND MAINTENANCE
  - FOR PLANNING AND ENGINEERING

DISTRIBUTION AUTOMATION

POTENTIAL BENEFITS BY CATEGORY (CONT.)

4. CUSTOMER SAVINGS

- FEWER COMPLAINTS
  - NO VOLTAGE SAGS
  - FEWER OUTAGES
  - SHORTER OUTAGES

- IMPROVED RELIABILITY
  - INDUSTRIAL FACTORIES AND PLANTS
  - COMMERCIAL BUILDINGS AND COMPLEXES
  - RESIDENTIAL HOMES AND APARTMENTS

DISTRIBUTION AUTOMATION

AUTOMATION COSTS

- INSTALLATION LABOR AND MATERIALS
- CONTROL EQUIPMENT
- COMMUNICATION HARDWARE/FIRMWARE
- MAINTENANCE OF HARDWARE/SOFTWARE
- COMPUTER HARDWARE/SOFTWARE
- TRAINING/RETRAINING
- MODELING AND ANALYSIS

DISTRIBUTION AUTOMATION

PLANNING QUESTIONS:

- WHICH FUNCTIONS ARE DESIRED?
- WHICH CUSTOMER CLASSES ARE BENEFICIAL?
- WHICH AREAS SHOULD BE AUTOMATED?
- WHAT DISTRIBUTION PENETRATION IS APPROPRIATE?

DISTRIBUTION AUTOMATION

ENGINEERING QUESTIONS:

- WHAT COMMUNICATION MEDIUM/SYSTEM IS OPTIMUM?
- WHAT ADDITIONAL CONTROL EQUIPMENT IS NECESSARY?
- WHAT ARE HARDWARE/SOFTWARE COSTS?
- WHAT IS IMPLEMENTATION SCHEDULE?

DISTRIBUTION AUTOMATION

OPERATIONAL QUESTIONS:

- WHAT IS THE COMMUNICATION ARCHITECTURE?
- HOW ARE FUNCTIONS INTEGRATED/COORDINATED?
- WHAT COMPUTER DATA BASES ARE NEEDED?
- WHAT INTERFACE PROTOCOLS/STANDARDS ARE NEEDED?

DISTRIBUTION AUTOMATION TRENDS

NORTH AMERICA

- Centralized Control
- More Integration of Systems
- More Two-Way Communications

EUROPE

- Control at Substations
- More One-Way Communications
  - Ripple
  - Distribution Line Carrier

JAPAN

- More Like Europe

DISTRIBUTION AUTOMATION MANAGEMENT

DATA BASES

- DISTRIBUTION SUBSTATION SCADA
- AUTOMATED MAPPING AND FACILITY MANAGEMENT
- FEEDER FAULT DETECTION AND SECTIONALIZATION
- CAPACITOR SWITCHING AND REGULATOR CONTROL
- TROUBLE CALL MANAGEMENT
- FIELD CREW SCHEDULING/DISPATCHING
- REMOTE METER READING
- LOAD SURVEY
- LOAD MANAGEMENT
- SERVICE CONNECT/DISCONNECT
- CUSTOMER BILLING

DISTRIBUTION AUTOMATION

IMPROVED DISTRIBUTION SYSTEM OPERATION

(THE MARVEL OF REAL-TIME DATA)

- OBTAIN FASTER DATA DURING EMERGENCY CONDITIONS
  - STORM CONDITIONS
  - MULTIPLE FAULTS

- PROVIDE BETTER DATABASE
  - BETTER PLANNING
  - IMPROVED ENGINEERING
  - BETTER INFORMED MANAGEMENT

- DETECT EQUIPMENT MALFUNCTION
  - FAILED COMMUNICATION/CONTROL EQUIPMENT
  - FAILED CAPACITOR SWITCHES
  - OPEN FUSES

STEPS TO IMPLEMENT DISTRIBUTION AUTOMATION

1. Cost/Benefit Study
2. Master Plan
3. Selection of System(s)
4. Pilot Test(s)
5. System Installation
6. System Maintenance
7. Upgrade and Replacement
8. Master Plan Review

DISTRIBUTION AUTOMATION

IMPROVED DISTRIBUTION SYSTEM OPERATION (CONT.)
(THE MARVEL OF REAL-TIME DATA)

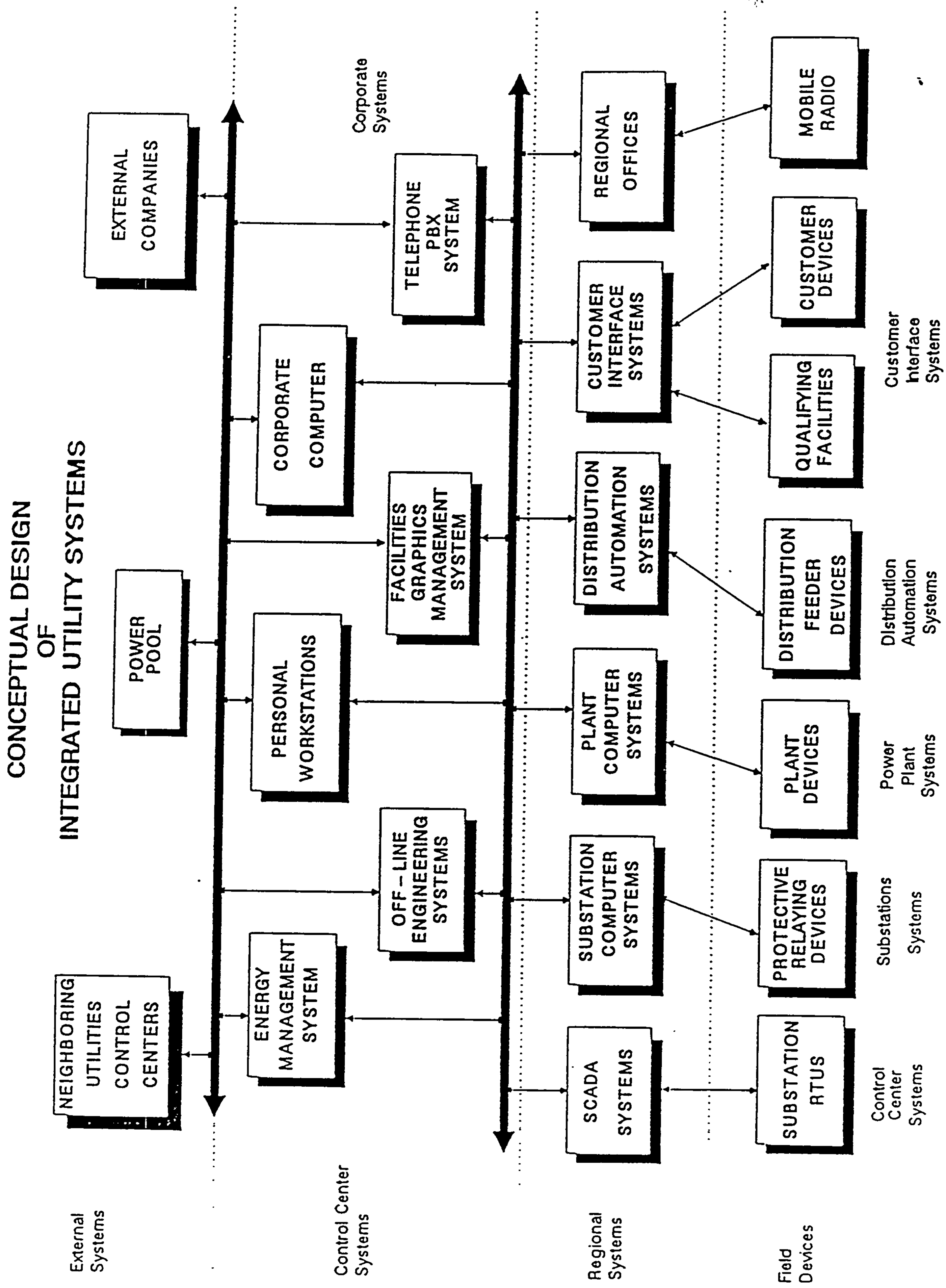
- IMPROVE PROTECTION ROUTINES
  - REMOTELY CHANGE EQUIPMENT SETTINGS
  - ADAPTIVE RELAY SETTINGS
  - BETTER COLD LOAD PICKUP

- PERFORM FASTER SECTIONALIZATION
  - REDUCED OUTAGE TIMES
  - FEWER CUSTOMERS OUT

- PERFORM ROUTINE FEEDER RECONFIGURATION
  - IMPROVED LOAD BALANCE
  - IMPROVED SYSTEM PERFORMANCE

MAJOR QUESTIONS FOR DISTRIBUTION AUTOMATION

HOW DO I JUSTIFY IT?!


CONCEPTUAL DESIGN
OF
INTEGRATED UTILITY SYSTEMS
External Systems
Control Center Systems
Corporate Systems
Regional Systems
Field Devices
NEIGHBORING UTILITIES CONTROL CENTERS
POWER POOL
EXTERNAL COMPANIES
ENERGY MANAGEMENT SYSTEM
OFF-LINE ENGINEERING SYSTEMS
PERSONAL WORKSTATIONS
FACILITIES GRAPHICS MANAGEMENT SYSTEM
CORPORATE COMPUTER
TELEPHONE PBX SYSTEM
SCADA SYSTEMS
SUBSTATION COMPUTER SYSTEMS
PLANT COMPUTER SYSTEMS
DISTRIBUTION AUTOMATION SYSTEMS
CUSTOMER INTERFACE SYSTEMS
REGIONAL OFFICES
SUBSTATION RTUS
PROTECTIVE RELAYING DEVICES
PLANT DEVICES
DISTRIBUTION FEEDER DEVICES
QUALIFYING FACILITIES
CUSTOMER DEVICES
MOBILE RADIO
Control Center Systems
Substations Systems
Power Plant Systems
Distribution Automation Systems
Customer Interface Systems

DISTRIBUTION AUTOMATION

COMPUTER MODELING OF SYSTEM

- COMPUTE COST/BENEFIT RATIOS
  - USE UTILITY COSTS
  - USE INDUSTRY AVERAGE COSTS
- PERFORM SENSITIVITY ANALYSIS
  - VARY INPUT PARAMETERS
  - VARY ECONOMIC (PRESENT VALUE) DATA
  - PERFORM YEAR-BY-YEAR ANALYSIS

DISTRIBUTION AUTOMATION

COMPUTER MODELING OF SYSTEM (CONT.)

- EVALUATE D.A. FOR CUSTOMER CLASSES
  - INDUSTRIAL
  - COMMERCIAL
  - RESIDENTIAL
- EVALUATE D.A. FOR DIFFERENT CONSTRUCTIONS
  - OVERHEAD
  - UNDERGROUND
- COMPARE BENEFITS
  - HARD SAVINGS
  - SOFT SAVINGS

DISTRIBUTION MANAGEMENT SYSTEMS

(EXAMPLES OF CONTEMPORARY SYSTEMS)

- ELECTRICAS REUNIDAS DE ZARAGOZA (SPAIN)
- PHILADELPHIA ELECTRIC COMPANY (PECO)

ELECTRICAS REUNIDAS DE ZARAGOZA (SPAIN)
REGIONAL TRANSMISSION & DISTRIBUTION UTILITY

SYSTEM CONFIGURATION:

- 4 REGIONAL DISTRIBUTION MANAGEMENT SYSTEMS
- 1 ENERGY MANAGEMENT SYSTEM (SUPPLIED BY EMPROS)

SYSTEM WILL BE INTEGRATED WITH AM/FM (AUTOMATED MAPPING/FACILITIES MANAGEMENT) SYSTEM

D.A. FUNCTIONS:

SUBSTATION MONITORING AND CONTROL

- MAN-MACHINE INTERFACE (MMI) USING FULL GRAPHICS AND AM/FM INFORMATION
- DISTURBANCE DATA COLLECTION
- HISTORICAL LOGS AND REPORTS

ELECTRICAS REUNIDAS DE ZARAGOZA (SPAIN)
REGIONAL TRANSMISSION & DISTRIBUTION UTILITY (CONT.)

- DISPATCHERS POWER FLOW
- DISPATCHER TRAINING SIMULATOR (TRANSMISSION SYSTEM)
- OPTIMAL POWER FLOW
- SHORT CIRCUIT ANALYSIS

LOAD CONTROL OF WATER HEATERS AND/OR AIR CONDITIONERS

INTEGRATION WITH AM/FM SYSTEM

- SCADA/AM/FM COMMUNICATION NETWORK CONFIGURATION
- SCADA/AM/FM COMMUNICATION PROTOCOL
- SCADA/AM/FM DATA BASE INTERFACE PROTOCOLS AND ACCESS PROCEDURES
- SCADA/AM/FM MAN-MACHINE INTERFACE CAPABILITIES - TRANSLATION AND X-WINDOWS
- SCADA/AM/FM DATA EXCHANGE REQUIREMENTS

ELECTRICAS REUNIDAS DE ZARAGOZA (SPAIN)
REGIONAL TRANSMISSION & DISTRIBUTION UTILITY (CONT.)

- SYSTEM CONFIGURATION MANAGEMENT
- MAN-MACHINE INTERFACE (MMI) (INTEGRATION WITH AM/FM MAPPING DATA)
- DATA BASE GENERATION AND MAINTENANCE
- DISPLAY GENERATION AND MAINTENANCE (DISPLAY SOURCE FROM AM/FM)
- PROGRAMMING SUPPORT
- SYSTEM BACKUP AND FAILURE MANAGEMENT
- AUTHORIZATION AND RESPONSIBILITY MANAGEMENT OF MULTIPLE AND/OR HIERARCHICAL SYSTEMS

FEEDER MONITORING AND CONTROL

- MONITOR FEEDER EQUIPMENT STATUS
- CONTROL FEEDER SECTIONALIZERS AND SWITCHES

FEEDER OUTAGE HANDLING AND RESTORATION SUPPORT

- FAULT LOCATION
- FAULT ISOLATION
- SERVICE RESTORATION
- COLD LOAD PICKUP
- LOAD SHEDDING

ELECTRICAS REUNIDAS DE ZARAGOZA (SPAIN)
REGIONAL TRANSMISSION & DISTRIBUTION UTILITY (CONT.)

DISTRIBUTION SYSTEM MANAGEMENT

- FEEDER LOAD ANALYSIS AND RECONFIGURATION
- SUBSTATION TRANSFORMER OVERLOAD/LOSS REDUCTION
- PROTECTION COORDINATION
- EQUIPMENT CAPACITY RATING
- TRANSFORMER LOAD MANAGEMENT

TROUBLE CALL ANALYSIS FUNCTION

- FEEDER OUTAGE IDENTIFICATION FROM CUSTOMER CALLS, CIS, AND AM/FM MAP DATA BASES
- ANALYSIS OF OUTAGE LOCATION ON FEEDER
- MMI DISPLAY OF AFFECTED FEEDER

DISTRIBUTION SYSTEM OPERATION MODELING

- DISTRIBUTION SYSTEM SUBSTATION AND FEEDER MODEL
- LOAD MODELING

ELECTRICAS REUNIDAS DE ZARAGOZA (SPAIN)
REGIONAL TRANSMISSION & DISTRIBUTION UTILITY (CONT.)

- STATE ESTIMATION FOR BAD DATA ANALYSIS AND MEASURING POINT WEIGHTS
- LOAD FORECAST
- POWER FLOW CALCULATION
- FAULT CURRENT CALCULATIONS
- STATISTICAL ANALYSIS OF DISTRIBUTION SYSTEM
- OFF-LINE ENGINEERING STUDIES OF DISTRIBUTION CONFIGURATION
- OPTIMIZATION OF DISTRIBUTION SYSTEM OPERATIONS
- DISPATCHER TRAINING SIMULATOR (DISTRIBUTION SYSTEM)

ELECTRICAS REUNIDAS DE ZARAGOZA (SPAIN)
REGIONAL TRANSMISSION & DISTRIBUTION UTILITY (CONT.)

POWER SCHEDULING AND GENERATION MANAGEMENT

- LOAD FORECAST
- INTERCHANGE SCHEDULING
- OPTIMAL POWER FLOW
- AUTOMATIC GENERATION CONTROL
- ENERGY ACCOUNTING

TRANSMISSION SYSTEM FUNCTIONS

- NETWORK TOPOLOGY
- STATE ESTIMATATION
- BUS LOAD FORECAST
- EXTERNAL MODEL
- CONTINGENCY ANALYSIS

ELECTRICAS REUNIDAS DE ZARAGOZA (SPAIN)
REGIONAL TRANSMISSION & DISTRIBUTION UTILITY (CONT.)

WORK ORDER MANAGEMENT (PRIMARILY AM/FM FUNCTIONS)

DISPATCHER TRAINING SIMULATOR

PHILADELPHIA ELECTRIC COMPANY
GENERATION, TRANSMISSION & DISTRIBUTION UTILITY

SYSTEM CONFIGURATION:

- 7 REGIONAL DISTRIBUTION MANAGEMENT SYSTEMS
- LINKED TO ENERGY MANAGEMENT SYSTEM (SUPPLIED BY ABB SYSTEM CONTROLS)

SYSTEMS ARE INTEGRATED WITH EACH OTHER.

ALL D.A. FUNCTIONS UNDERWENT COST/BENEFIT ANALYSIS

SUBSTATION SCADA:

- MONITORING EQUIPMENT STATUS
- MONITORING STATUS OF DISTRIBUTION SYSTEM
- SUPERVISORY CONTROL
- MONITORING OF THREE-PHASE AMPS
- MONITORING OF WATTS AND VARS
- DATA COMPILATION OF SUBSTATION DATA

PHILADELPHIA ELECTRIC COMPANY

GENERATION, TRANSMISSION & DISTRIBUTION UTILITY (CONT.)

CIRCUIT SCADA:

- FAULT ISOLATION & SERVICE RESTORATION
- REMOTE CIRCUIT SWITCHING
- VAR CONTROL AND POWER FACTOR CORRECTION
- MONITORING OF CIRCUIT DATA

CUSTOMER SERVICES:

- AUTOMATIC METER READING
- AUTOMATIC LOAD SURVEY
- AUTOMATIC CONNECT/DISCONNECT

DISPATCHER TRAINING SIMULATOR

GE Power Systems

U.S./KOREA ELECTRIC POWER TECHNOLOGIES
SEMINAR MISSION
SEOUL, KOREA
OCTOBER 24-28, 1994

AMORPHOUS METAL DISTRIBUTION TRANSFORMERS
THE ENERGY-EFFICIENT ALTERNATIVE

PRESENTED BY

THOMAS F. GARRITY
GENERAL MANAGER
POWER SYSTEMS ENGINEERING DEPARTMENT
GE POWER SYSTEMS
SCHENECTADY, NEW YORK, U.S.A.

AT THE WORKSHOP ON

TRANSMISSION & DISTRIBUTION LINE TECHNOLOGY

AMORPHOUS METAL DISTRIBUTION TRANSFORMERS THE ENERGY-EFFICIENT ALTERNATIVE

ABSTRACT

Amorphous metal distribution transformers have been commercially available for the past 13 years. During that time, they have realized the promise of exceptionally high core efficiency as compared to silicon steel transformer cores.

Utility planners today must consider all options available to meet the requirements of load growth. While additional generation capacity will be added, many demand-side initiatives are being undertaken as complementary programs to generation expansion. The efficiency improvement provided by amorphous metal distribution transformers deserves to be among the demand-side options.

The key to understanding the positive impact of amorphous metal transformer efficiency is to consider the aggregate contribution those transformers can make towards demand reduction. It is estimated that distribution transformer core losses comprise at least 1% of the utility's peak demand. Because core losses are continuous, any significant reduction in their magnitude is of great significance to the planner.

This paper describes the system-wide economic contributions amorphous metal distribution transformers can make to a utility and suggests evaluation techniques that can be used. As a conservation tool, the amorphous metal transformer contributes to reduced power plant emissions. Calibration of those emissions reductions is also discussed in the paper.

AMORPHOUS METAL DISTRIBUTION TRANSFORMERS THE ENERGY-EFFICIENT ALTERNATIVE

INTRODUCTION

Since their discovery in the 1970's, amorphous metals have promised improved system efficiency through the reduction of distribution transformer core loss, which is the leading contributor to distribution system losses [1]. Studies of distribution systems in the United States indicate that approximately 60% of distribution system losses are attributed to distribution transformers, with core losses accounting for 70% of the transformer energy loss. A typical, 25 kVA single-phase transformer made with a modern, silicon-steel core will have about 60 watts of core loss, while the same unit with an amorphous core will have 20 watts of core loss. Amorphous metal can reduce core losses by 60% – 70% over new silicon-steel, and by an even greater amount over older, existing silicon-steel cores.

This paper describes the properties of amorphous metal that are addressed in transformer core design, and the evaluation of the economic benefits to utility systems if strategies regarding the use of amorphous metal transformers for efficiency improvements, conservation, or demand-side management are implemented. It also discusses the environmental concerns over power plant emissions, and establishes the contribution amorphous transformers can make to reduced emissions.

Amorphous Technology

Amorphous metals are made by the rapid cooling of liquid metals which causes the metals' atoms to be locked in a random, liquid-like arrangement similar to glass, as opposed to the crystalline molecular structure of metal. That characteristic, coupled with the material's thinness, contribute to the significant reduction in hysteresis, and eddy current losses from what is available from conventional silicon steel. The material also requires design differences as compared to conventional transformer cores. The material's thinness, combined with its uneven surface results in a space factor (ratio of the space filled to the amount of space available) of about 80%, compared to 95% for silicon-steel. This requires a larger amorphous core, coil, and transformer tank for a given core cross-section. A larger core is also required because amorphous metal saturates at 1.58 Tesla, compared to 2.0 Tesla for silicon-steel, resulting in a required design flux density of 1.35 Tesla. The increased mass, however, does provide the benefit of a lower temperature rise, thus contributing to the transformer's long-term reliability. Amorphous metal cores also need to be annealed with a magnetic field to achieve lowest possible core loss and excitation levels. Despite these design differences, the efficiency improvement that amorphous metal provides has resulted in a commercially available product that has enjoyed growing, widespread acceptance as a reliable, stable, energy-efficient technology over the past thirteen years.

The Current Situation

In the world there are approximately 500,000 amorphous core transformers installed on distribution systems. About 400,000 – 450,000 are installed in the United States and there are an estimated 50,000 amorphous transformers in use in Japan. There is also an emerging usage of amorphous transformers in the People's Republic of China. In the U.S., approximately 10% of yearly sales of distribution transformers to utilities contain amorphous metal cores. The production capability has grown to produce over 100,000 units each year. Amorphous transformers are now available in all standard sizes and voltage classes in both single-phase from 10 kVA to 167 kVA, and three-phase from 75 kVA to 2,500 kVA.

Table 1 provides a comparison of typical core losses for in-service transformers, high-efficiency silicon steel transformers, and amorphous.

Looking ahead to the next ten years, current resource forecasts indicate that 663 GW of presently uncommitted capacity additions will be required throughout the world by 2003. Although it is expected that new generation equipment will be ordered to meet this need, there is awareness that conservation programs can provide a reasonable complement to generation expansion plans.

Integrated Resource Planning

One of the most significant considerations that has recently impacted efficiency evaluation is the utility use of the integrated resource plan (IRP). The IRP elevates efficiency to the same level of importance as other means of providing capacity such as new capacity additions, cogeneration, and demand side management.

Table 1

Amorphous vs. Silicon Transformer
Core Loss Comparison (Watts) 60 Hz.

	Rating (kVA)	In-Service Silicon (Avg.)	Hi-Efficiency Silicon (Typical)	Amorphous
Single-Phase	50	210	105	32
	75	260	130	39
	100	320	160	54
Three-Phase	150	540	270	107
	500	1400	710	260
	1000	2400	1200	420
	1500	3600	1800	555
	2000	4000	2000	750
	2500	4800	2400	850

Integrated Resource Planning is a way of analyzing the growth and operation of utilities that considers a wide variety of both supply (generation, cogeneration, and renewable) and efficiency/conservation (transmission, distribution, and customer demand) options. Through this process the optimal means of providing electric service to the public can be determined.

The analytical tools and methods of integrated resource planning allow utilities to project and assess the effects of a utility's future actions, such as retiring old generating plants, constructing new base-load and peak-load plants, using various mixes of fuels, realigning or upgrading distribution systems, encouraging conservation and efficiency, and offering incentives for actions that will moderate the daily and seasonal load shapes. The results of these analyses allow planners to select the mix of available options that will best suit the needs and interests of customers, and the power industry.

How does IRP differ from traditional planning? Traditional planning assumes a certain load or demand, and generation plans are developed to supply this load. IRP, in addition to evaluating various supply options, takes into account programs that can reduce load through system efficiencies, demand side management, or customer conservation measures, thereby focusing attention on the demand side of this system. The IRP process allows for consistent methods of analysis for all resource options, load supply or load reduction, and helps to ensure that all options are assessed in a comparable and consistent manner. It also attempts to assess the relative impacts of alternative decisions on the environment.

We note that Korea Electric Power Corporation (KEPCo), has stated plans [2] to replace electrical air conditioning systems with cold water storage and gas refrigeration systems, as well as to encourage the use of energy-efficient appliances. We believe that KEPCo could also benefit by considering transformer efficiency improvement as a demand-side initiative.

The efficiency improvement provided by amorphous core distribution transformers provides a means through which system efficiency can be improved with a resultant savings in production cost and the possibility of generation plant expansion deferral. In order to assess amorphous' potential in the integrated resource planning process a strategic evaluation of distribution transformer core loss must be made.

Traditionally, transformer efficiency has either not been evaluated, or has been specified as a limit that cannot be exceeded. Transformer efficiency can also be evaluated economically as part of the owning cost of the transformer. These economic evaluations should reflect the current and future incremental (avoided) costs of generation production, as well as the avoided cost of generation, and transmission and distribution capacity. Such evaluations will provide for the costs of transformer core and load loss and will result in the selection of optimal efficiency designs by the utility.

The very low levels of core loss that amorphous transformers provide suggest that economic evaluations of losses will demonstrate the attractiveness of this new core material, but it also allows amorphous transformers to be evaluated as a demand side management program.

The Korea Electric Power Corporation's 1994 annual report [2] stated transmission and distribution system losses of 5.6% of a total generation output of 144,437 GWh. If 60% of these losses are assumed to occur in the distribution system, with 60% of distribution losses occurring in distribution transformers, then transformers accounted for 2912 GWh of system loss. With the transformer core accounting for 70% of the transformer losses, it is estimated that distribution transformer cores contribute 233 MW to the KEPCo peak demand. Independent evaluations of various utilities suggest that approximately 1% of a utility's peak demand is consumed by conventional distribution transformers' core loss. KEPCo's published peak demand of 22,112 MW reinforces these assumptions on losses in distribution transformer cores and suggests that approximately 175 MW of existing capacity would be available if each distribution transformer on the KEPCo system were amorphous.

While it is unrealistic to think of transformer core loss capacity as being suddenly available, the integrated resource planning process can evaluate the benefits that can be derived from a program to replace existing transformers with amorphous transformers overtime.

On the aggregate, the capacity released by the use of amorphous transformers instead of the existing silicon-steel transformers is free to the generation dispatcher and is continuously available 8760 hours per year, with no associated forced outage rate. Thus, it is very desirable from a production cost savings viewpoint.

To demonstrate the economic merit of these evaluations, a smaller utility in the U.S. was studied to determine the benefit of amorphous transformers on its existing system. The system was modeled using the annual peak load and installed capability, including purchases. Figure 1 shows the 1989 peak load of 5800 MW, growing at a rate of 3% per year. The available generation each year, including committed additions is indicated by the capability. A 12% reserve margin is expected to be maintained, which establishes that additional capability is required. The total

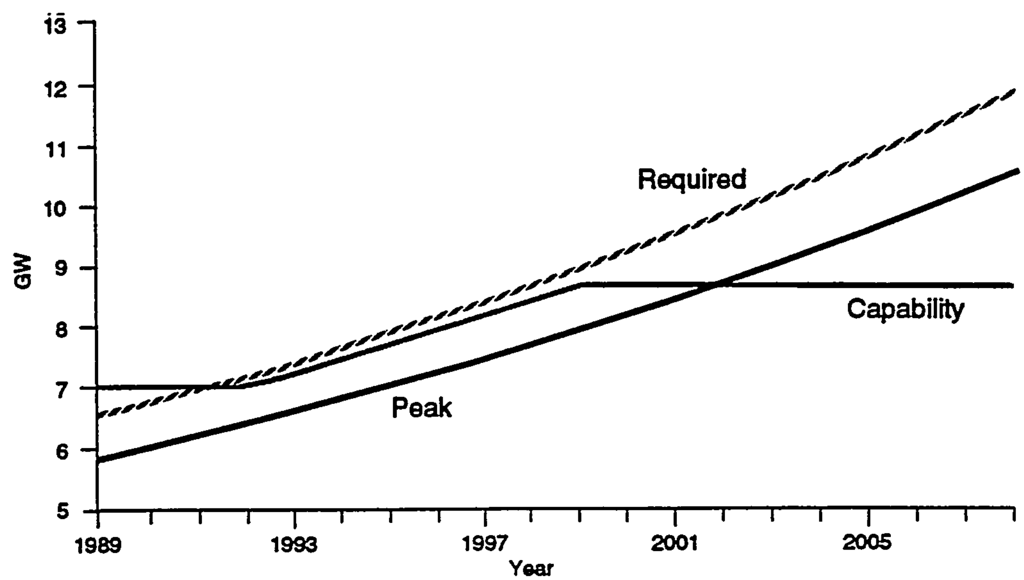


Figure 1. Utility Peak Demand and Capability.

generation capability of 6755 MW and the current production costs for each type of fuel are as indicated in Table 2.

Table 2

Generation Type	M W	$/kWh
Nuclear	690	.0108
Coal	2275	.0212
Oil/Gas Steam	1960	.0413
Gas Turbine	1700	.0558
Purchases	130	.0286

The annual fuel prices of oil and gas used in the production cost simulation are projected to grow at a rate of about 6% while coal is projected at a rate of 4%.

A production cost simulation was used to establish the net benefit of the capacity released from the transformer cores if they were all amorphous. Available data for this utility indicate approximately 300,000 existing distribution transformers with expected core losses of 180 watts each. These losses can almost all be released if the cores were amorphous, as shown in Table 3.

Table 3

Transformer	Core Loss	Total MW	Released MW
Existing	180	54	0
Amorphous	26	8	46

For the planning process, the existing transformer cores could also be replaced with higher-efficiency silicon iron transformers which would release 27 MW of core loss from the existing. Thus, amorphous represents an additional 19 MW of released capacity.

For this case, it was assumed that the benefits could be obtained over 15 years, and alternatively over 30 years. This requires consideration of the cost to change the existing transformers, and a price differential between amorphous and silicon-steel. The results of the production cost simulation is shown on Figure 2, with net benefits (current year equivalent capital value) and benefit/cost ratios as indicated. The higher benefit/cost ratio for the 30 year program results from the program's cost being spread over a longer period of time, but other considerations could justify the 15 year program.

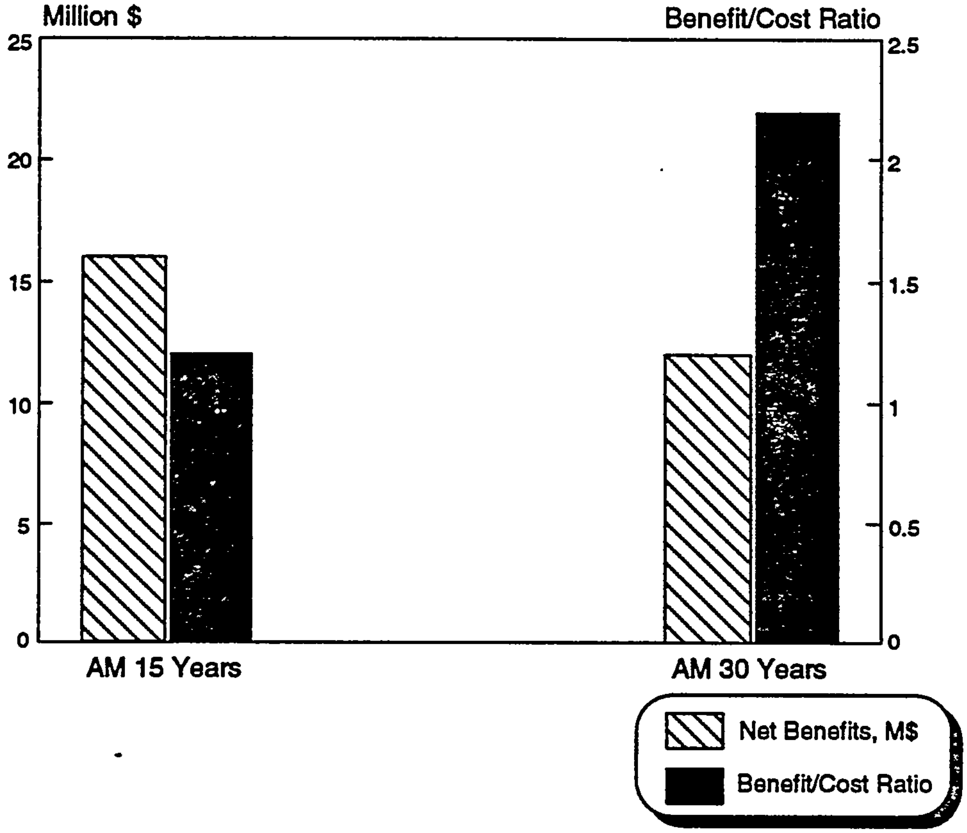


Figure 2. Net Capital Benefits and Benefit/Cost Ratios.

It is our understanding that KEPCo currently implements a transformer maintenance program in which transformers that have been in-service for approximately 10 years, are removed from service, refurbished, and reinstalled on the system. This program suggests an opportunity to evaluate the potential for releasing the core losses of those existing transformers through amorphous transformer replacements. The economic comparison would consider the price and cost of losses of the amorphous transformer, relative to the refurbishment cost, the cost of losses, and the cost of the eventual replacement of the older transformer if it is reinstalled. The removal and installation costs for the existing transformer would not be a factor since a transformer is removed from service and a replacement installed in either case. We believe that such an evaluation would yield favorable economic results in favor of the amorphous transformer. It could also be expected that the amophous transformer designs could negate the 10 year refurbishment policy, thus bringing additional economic benefit.

Distribution transformers are installed to serve new loads as well as to replace transformers that are removed from service because of failure, overload, or other reasons. Although the previous example demonstrated the economics of replacing existing core losses with high-efficiency amorphous cores, another strategy might evaluate the change in total distribution transformer core loss, if the annual purchase of transformers were amorphous instead of silicon-steel with no accelerated change-out plans. A large utility that purchases approximately 25,000 distribution transformers per year was studied to evaluate the change in total transformer core loss that occurs over time if the annual installations were amorphous instead of silicon-steel. Approximately 12,000 transformers serve new load, and 13,000 are replacements. Figure 3 demonstrates that the commitment to amorphous transformers begins to lower total system loss, and that in 25 years, there will be a 61 MW improvement for amorphous over silicon-steel.

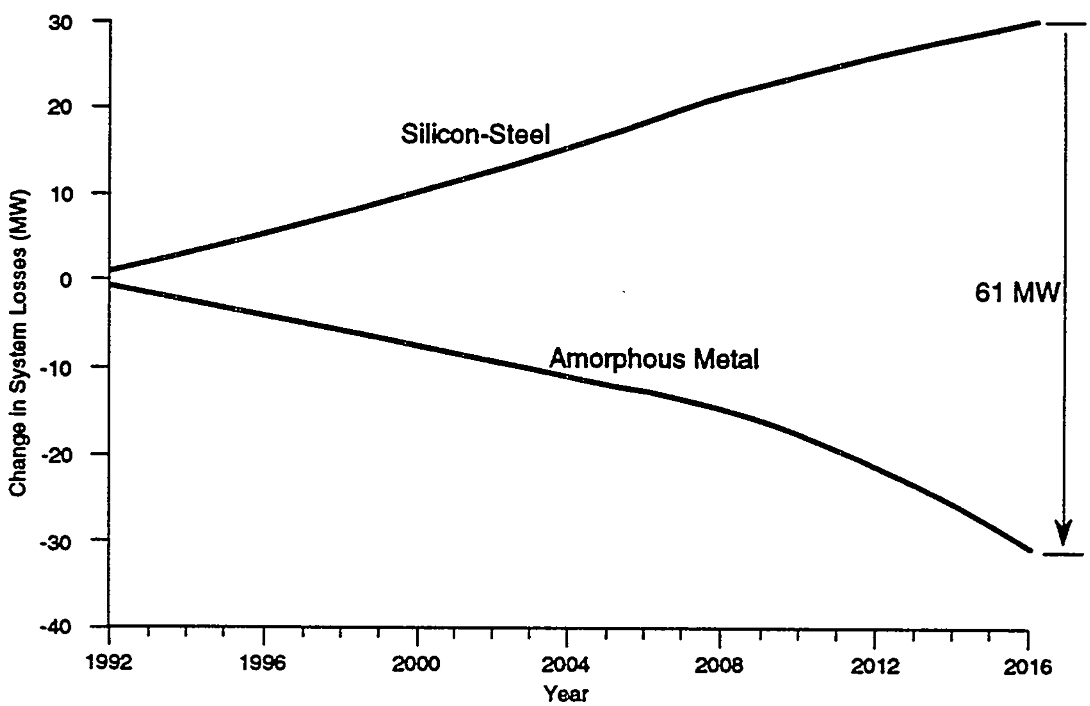


Figure 3. System Losses as a Function of Transformer Technologies

The Environment

Today, environmental concerns have grown in importance as utilities, government agencies and the public search for cost-effective methods to reduce power plant emissions. We understand that Korea's Air Quality Control Law includes continuous monitoring of air quality, authorization procedures for air pollutants emission facilities, and establishment of special emissions standards in special countermeasures areas [3]. Because amorphous transformers significantly reduce system losses, power plants will generate less energy, thereby reducing emissions.

As an example of the reduction in power plant emissions when amorphous transformers are applied, the power plant emissions data in Table 4 are used. The emissions values shown are assumed to be typical of existing generating plants. These data can vary depending upon power plant technology and the degree to which pollution control equipment has been applied.

Table 4

Typical Emissions Data for Existing Power Plants

kG/MBtu

	Coal-Fired Steam	Combustion Turbine
CO_2	77	45.4
SO_x	1.54	0.05
NO_x	0.41	0.23
Particulates	0.05	.009

For this example, it is assumed that the heat rate of coal-fired steam plants is 9,800 Btu/kWh, and the heat rate of existing combustion turbines is 13,000 Btu/kWh. It is also assumed that the average core loss differential between an amorphous transformer and its alternative is 150 watts, based on a composite of all transformer ratings, and that the utility has 500,000 distribution transformers on its system. The application of amorphous transformers results in an annual energy savings of:

$$500{,}000 * 150\text{W} * 8760 \text{ hours/year} * 10^{-3} = 657{,}000{,}000 \text{ kWh}$$

If it is assumed that the core loss savings results in reduced generation only at coal-fired steam plants, then the fuel consumption at the coal-fired steam plant is reduced:

$$657{,}000{,}000 \text{ kWh} * 9{,}800 \text{ Btu/kWh} * 10^{-6} = 6{,}438{,}600 \text{ MBtu}$$

If it is assumed that the core loss savings results in reduced generation only at combustion turbine plants, then a similar calculation shows that the fuel consumption at the combustion turbine plants is reduced by 8,541,000 MBtu.

Once the reduction in fuel consumption is known, the emissions reductions can be calculated by multiplying the fuel consumption reduction by the values shown in Table 4. Table 5 shows the emissions reduction for a case in which the core loss savings results only in reduced generation at coal-fired steam plants, and for a case in which the core loss savings results only in reduced generation at combustion turbine plants.

Table 5

Typical Annual Emissions Reduction

Metric Tons

	Reduced Generation Only at Coal-Fired Steam Plants	Reduced Generation Only at Distillate Oil Combustion Turbine Plants
CO_2	495,772	387,761
SO_x	9,915	427
NO_x	2,640	1,964
Particulates	322	77

The table shows that the application of amorphous transformers can result in significant amounts of pollution reductions. This is a tangible benefit to the utility and its customers, and it should be considered when evaluating the merits of amorphous transformers relative to alternatives.

CONCLUSIONS

Amorphous core distribution transformers are a commercial reality. The exceptionally low core losses available with this technology provide the impetus through which a strategic assessment of its positive contribution to conservation and demand-side management programs can be made. When contrasted with other programs, the amorphous transformer strategy has the advantages of: continuous availability of its benefits; no risk; positive environmental impact; and an incremental cost, as transformers must be purchased, regardless. Amorphous metal distribution transformers warrant consideration in any utility's planning process.

REFERENCES

[1] November 1983, "Improved Methods for Distribution Loss Evaluation", Electric Power Research Institute , Report EL3261, Volume 1.

[2] KEPCo '94 Korea Electric Power Corporation.

[3] "National and International Approaches to Air Pollution Control", Clean Air Around the World, Second Edition, International Union of Air Pollution Prevention Associations, pp. 245-264.

Amorphous Metal Distribution Transformers
The Energy-Efficient Alternative

T.F. Garrity, General Manager
Power Systems Engineering Department
GE Industrial and Power Systems

Amorphous Metal Distribution Transformers

Current Status

- 500,000 units in use
  - 450,000 in U.S.
  - 50,000 in Japan
  - Growing interest in People's Republic of China, other countries
- Worldwide projection – 663 GW uncommitted capacity requirement by 2003
- Efficiency improvement – a positive complement to capacity expansion

Amorphous vs. Silicon Transformer

Core Loss Comparison (Watts) 60 Hz

	Rating (kVA)	In-Service Silicon (Avg.)	Hi-Efficiency Silicon (Typical)	Amorphous
Single-Phase	50	210	105	32
	75	260	130	39
	100	320	160	54
Three-Phase	150	540	270	107
	500	1400	710	260
	1000	2400	1200	420
	1500	3600	1800	555
	2000	4000	2000	750
	2500	4800	2400	850

Amorphous Metal Distribution Transformers

– A Demand-Side Initiative –

- Distribution transformer core loss reduction
  - Continuous – 8760 hours/year
  - Stable – Loss reduction constant over time
  - Secure – No dependence on consumer
- Incremental cost – transformers must be purchased for new load, replacements

Korea Electric Power Corporation

Amorphous Potential

Total generation	144,437 GWh
Losses @ 5.6%	8089 GWh
Distribution losses @ 60%	4853 GWh
Distribution transformer losses @ 60%	2912 GWh
Distribution transformer losses @ 70%	2038 GWh

Korea Electric Power Corporation

Amorphous Potential

Distribution Transformer Core Loss $= \dfrac{2038 \text{ GWh}}{8760 \text{ Hours}}$

= 223 MW

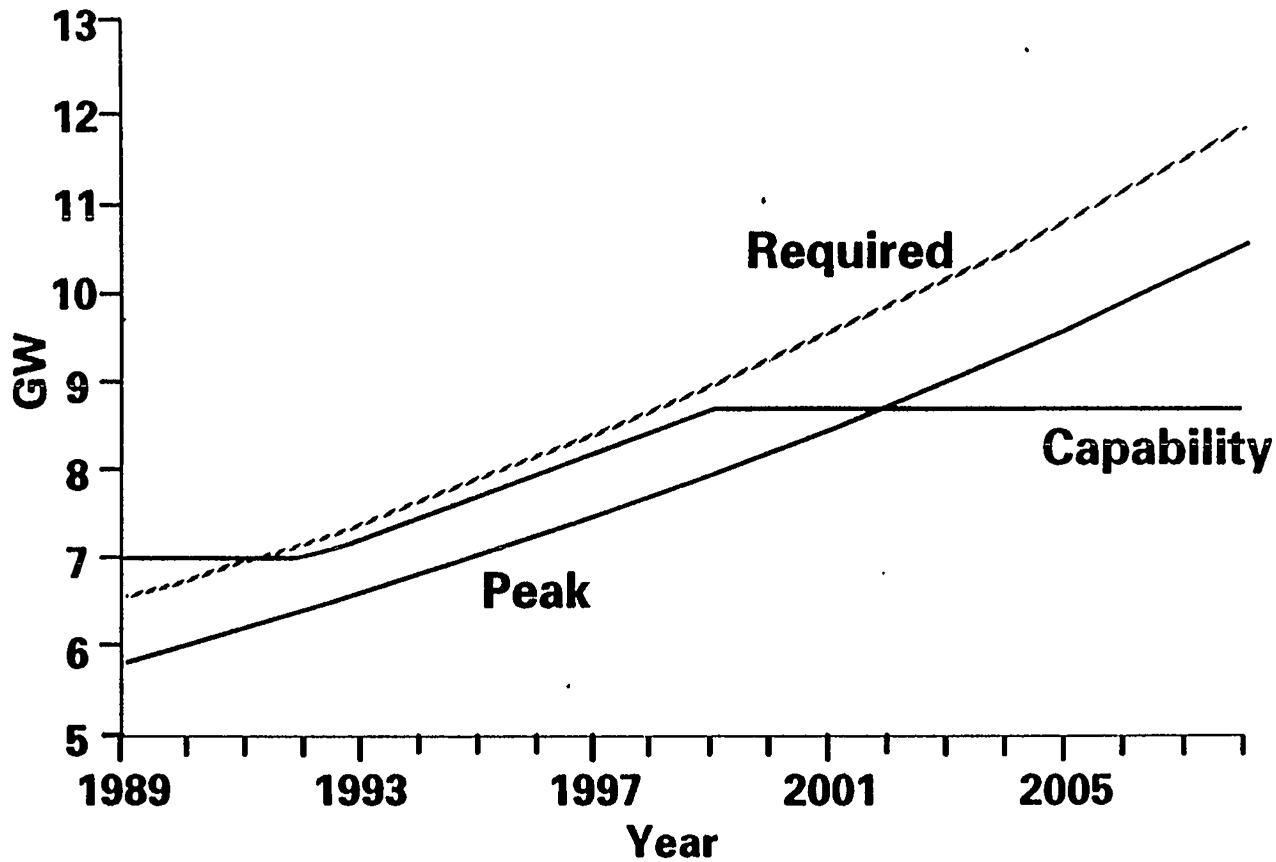
Alternatively....

Core loss ≈ 1% of peak demand

.01 x 22112 MW = 221 MW

Amorphous core capacity release potential: 175 MW

Utility Peak Demand and Capability



Generation Type	MW	$/kWh
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Transformer	Core Loss	Total MW	Released MW
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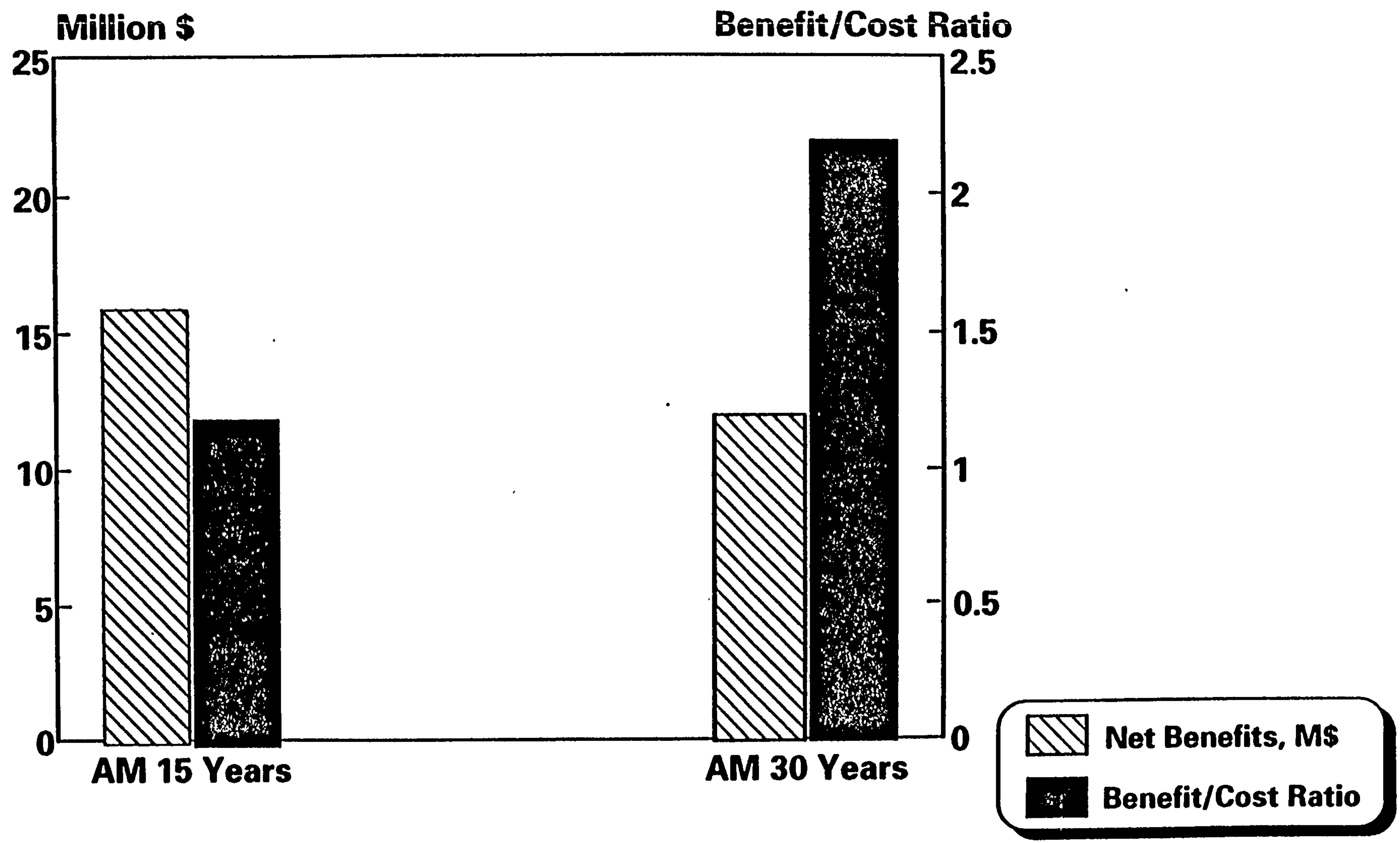
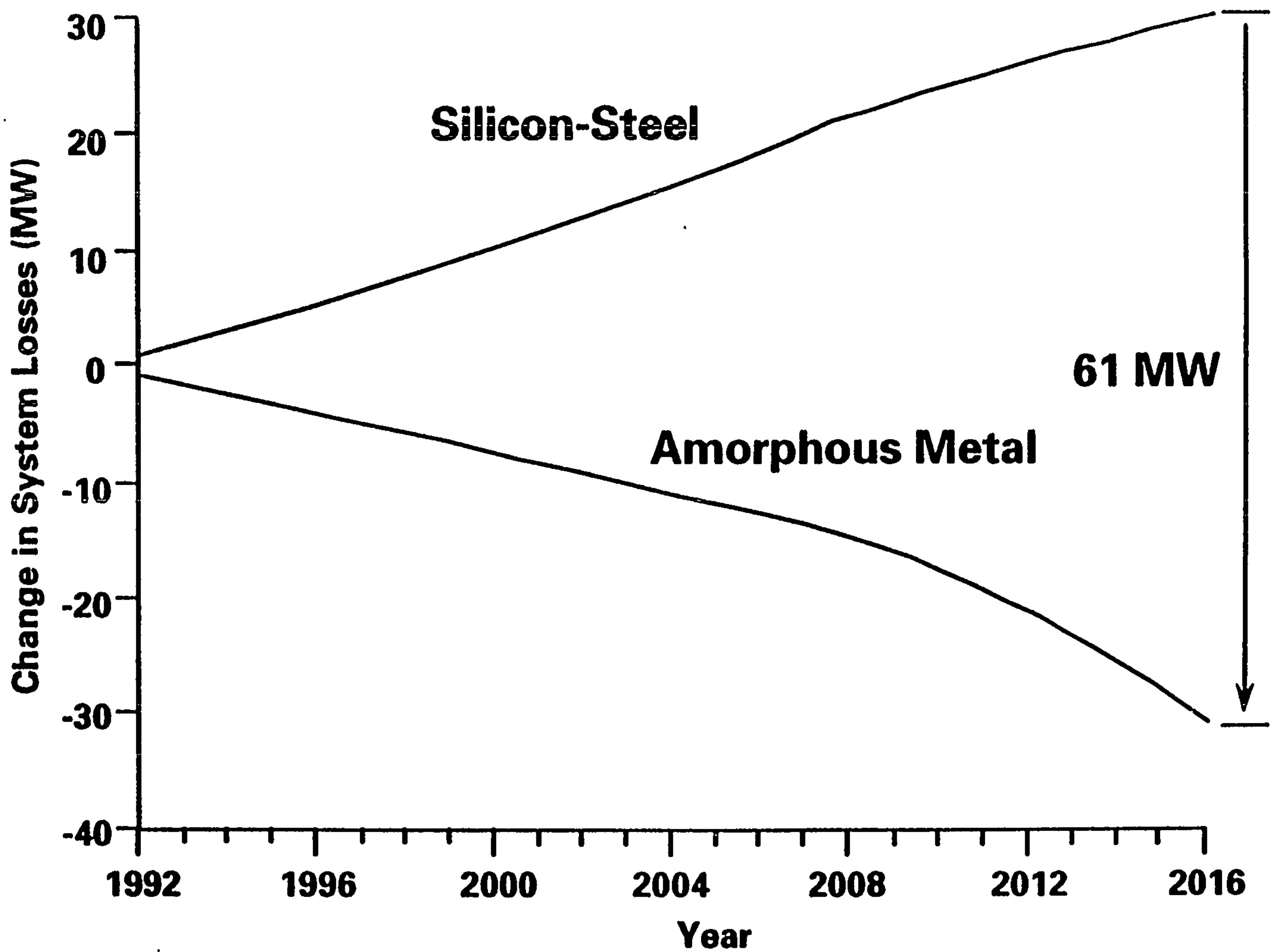
Net Capital Benefits and Benefits/Cost Ratio



System Losses as a Function of Transformer Technologies



Typical Emissions Data for Existing Power Plants

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NO_x	0.41	0.23
Particulates	0.05	.009

Emissions Reduction

Assume: 500,000 distribution transformers

Average loss reduction potential: 150 Watts

$500{,}000 \times 150\ W \times 8760\ hours/year \times 10^{-3}$

$= 657{,}000{,}000$ kWh saved annually

Heat Rates

Coal/steam – 9800 BTU/kWh
Combustion turbine – 13000 BTU/kWh

Fuel Saved

Coal/steam – 6,438,600 MBtu
Combustion turbine – 8,541,000 MBtu

Typical Annual Emissions Reduction

Metric Tons

	Reduced Generation Only at Coal-Fired Steam Plant	Reduced Generation Only at Distillate Oil Combustion Turbine Plant
CO_2	495,772	387,761
SO_x	9,915	427
NO_x	2,640	1,964
Particulates	322	77

Amorphous Metal Distribution Transformers

- 13 years of growing, reliable application
- No risk – core loss reduction is firm
- System benefits – continuously available
- Positive environmental impact

Amorphous Metal Distribution Transformers

- A strategic part of resource planning

DISTRIBUTED GENERATION SYSTEMS MODEL

C. Roger Barklund
EG&G Idaho

DISTRIBUTED GENERATION SYSTEMS MODEL

Slide 1

Good Morning. My name is Rodger Barklund, and I am going to describe and talk about the distributed generation systems model developed at the Idaho National Engineering Laboratory, and its application to a situation within the Idaho Power Company's service territory. The growing community of McCall Idaho is straining the electric power supply in the winter. Idaho Power Company is concerned with meeting the expected peak demand should the main supply into McCall be unavailable.

Slide 2

The Idaho National Engineering Laboratory, part of the Department of Energy system, is located on 2315 square kilometers in the eastern Idaho desert. It is the nation's foremost nuclear reactor research and testing facility. Since being established in 1949, there have been fifty-two reactors built here, thirteen of them are still operable. There are additional laboratory and office facilities located in Idaho Falls, sixty-five kilometers east. Although nuclear research and development is still a major part of the laboratory's mission, we also lead in developing hazardous and radioactive waste clean-up methods. Another project area is technology transfer. The laboratory develops and transfers new technologies to the private sector. My group, power systems, is involved in all aspects of this industry area. We are installing wind farms at remote sites, and are working on solar photovoltaic applications.

Slide 3

Here is an outline of the continental United States, highlighting Idaho. I include this slide so that everyone here will know where Idaho is located in the U.S.

Slide 4

Idaho is the nation's twelfth largest state in land area, but the forty-fourth in population. What this means is that the electric power demand is geographically diverse, with some areas having difficult access for power transmission and distribution.

This shows the location of the Idaho National Engineering Laboratory, and the cities of Idaho Falls, Boise and McCall.

The commercial electric utility industry has undergone significant changes in recent years. These changes are: shifting public attitudes toward energy conservation, growing opposition to siting of large generating facilities, rising transmission and distribution costs, slow (but continuing) growth in demand, and emerging non-utility generation. The utility industry is responding with a number of strategies to accommodate increasing demand. One strategy is distributed generation, in which relatively small generation and energy storage facilities are distributed around the utility's local service area close to the loads that they supply. This approach avoids some of the difficulties encountered by the utility industry in siting or upgrading electrical generation facilities and transmission lines.

System dynamics modeling is applied to a specific situation for which distributed generation appears to be a realistic solution. One situation, for example, is the reliability of the electric power supply at McCall, Idaho.

With the surrounding mountains, and winter cold and snow, the McCall area is similar to that of Chin Hae, Korea, a city I visited several years ago.

Power transmission into the McCall area is constrained by cost and environmental concerns about transmission line siting and maintenance, and population growth is expected to strain the capacity of the existing power supply. An alternative to new or upgraded transmission lines at McCall is distributed generation. This alternative may allow Idaho Power Company to defer or avoid investment in new transmission lines while increasing reliability of the local power supply, especially at times of high peak demand.

Systems analysis techniques are used to model the decisions required for the utility to screen the various available options of storage, generation, and transmission line development. The Idaho National Engineering Laboratory developed a loop diagram systems model of the "McCall problem," and created a computer model to facilitate solution. This model addresses siting issues, public and environmental impacts, economics and reliability, and projected growth of demand. The model is intended for use by utility planners in screening alternatives and suggesting areas for more detailed investigation.

Slide 5

I am going to talk about our objectives in developing the distributed generation model, the approach we used in developing the model, and more details about the "McCall problem", then I will describe the model.

Slide 6

With the wide variety of electric power generation options available, we wanted a model which we could use to screen the various distributed generation alternatives. We wanted to be able to vary the inputs and observe the effects in order to rank the alternatives by the various criteria. We wanted to assess the viability and limitations of distributed generation for use as a utility resource. Finally, because utilities are very capital intensive, and tend to avoid unproven technologies, we wanted to enhance the Idaho National Engineering Laboratory's understanding of the electric utility's concerns in implementing technological change.

Slide 7

In our approach, we wanted to take a systems look at the "McCall problem". We decided to expand the view to consider more of the total transmission system, while remaining focused on the power reliability in McCall. Local and external solutions were to be considered.

First, we had to identify "all" system components. The word all is in quotes because we realized that we probably would not identify every factor in the decision making process, and we could only include the major factors if we hoped to keep the model to a manageable size. Then we faced the task of determining the component interactions. How would intended land use affect land price? How seriously would environmental concerns affect public opinion? Would the greater reliability of power result in increased demand? Questions like these, and many others, had to be addressed to enable model development.

After defining the component interactions, we then had to determine how to quantify each component state and how each interaction would affect that state. As the decision factors come into the model, with their multiple inputs and differing effect on the other factors, the model simulates non-linear system behavior. There are multiple loops in the model, each with feedback from several stages. This dramatically increases the complexity of the model, but it more closely resembles the thought processes an analyst would go through in considering the same situation.

When all the potentially viable solutions are contained within the model, each in turn may be analyzed. Combinations of alternatives may also be considered. This then enables comparison of the alternatives on the basis of several criteria.

Slide 8

McCall, Idaho is an attractive city surrounded by mountains and national forests, and there are two lakes nearby. Year around outdoor activities abound. Because of these features, McCall has grown considerably in the last ten years. Idaho Power Company provides electric power to the area with one 138 kV 100 MW line and two 69 kV lines which have a combined 50 MW capacity, for a total capacity of 150 MW. With mild summers requiring little cooling, the annual peak demand occurs with the winter heating loads. The estimated peak for the 1994-95 winter is 68 MW. In considering the electric power reliability in the McCall area, Idaho Power is concerned about meeting the winter peak demand should the 100 MW line be unavailable.

Slide 9

The combined capacity of the two 69 kV lines is 50 MW. Voltage at McCall is the limiting factor. For example, with 1.0 p.u. voltage at Emmett and Weiser, the voltage at McCall with 50 MW transmission is 0.91 p.u. This is the Idaho Power company lower limit. The lines' thermal limit is reached at about 72 MW, which would result in a McCall voltage of about 0.65 p.u.

Slide 10

Some conventional transmission upgrades were considered as alternatives. The first was to build another 138 kV line in parallel with the existing one using the existing corridor. Cost for this is estimated at $7.8 M.

Slide 11

Upgrading the west side of the 69 kV loop line to 138 kV was proposed with a cost of $9.5 M.

Slide 12

Upgrading the east side of the 69 kV loop line to 138 kV was also proposed. This is estimated to cost $17 M.

Slide 13

Any of these options will more than adequately supply McCall with reliable electric power. However, the capacity is much greater than needed and could result in stranded investment if McCall's growth slows. Additionally, the paralleled 138 kV line would not increase the reliability of the supply into McCall since the majority of the line's outages are weather related. Parallel lines in the same corridor would be affected similarly.

Distributed generation is viewed as a viable option to meet McCall's power needs and allow deferral of expensive transmission line upgrade.

Slide 14

This is a loop diagram model of some resource. This shows some of the relationships among the decision factors such as resource availability, price, demand and other resource uses. Using diesel fuel as an example resource, let's assume that the supply and demand are in balance. Now, there is some new increase in resource demand. This increased demand reduces resource availability. This opposite effect on the downstream element is indicated by the letter "o". As resource availability decreases, the resource price increases. Increasing price will reduce both other resource uses and resource demand, as shown in this slide. The letter "B" indicates that this is a "balancing" loop. When the loop is perturbed, it will iterate until it is again in balance generating new resource price, demand and availability.

Slide 15

Here is the model with all the loop diagrams shown. This shows the complexity of the model.

Slide 16

Here, the model is shown in block form.

The upper left block of this slide describe the impacts of availability and reliability for resources and power generation capacity. The lower left block balances supply and demand by capacity expansion and demand management efforts. The upper right block shows the interactions of the various impacts of the system, such as environmental, public, regulatory impacts, etc. and the lower right focuses on the system economics. Each block interacts with all the other blocks.

The model itself is also dynamic in that some portions are included when analyzing one option, but excluded when considering another option. For example, the resource loop diagram shown earlier. When considering the diesel engine generator option, this loop was excluded because ten MW of diesel generation would only negligibly affect diesel fuel demand and price. But in the case of geothermal generation, there could be many competing uses for that resource, so this loop would then be included in the model.

Slide 17

We used a commercially available dynamic systems modelling software called "ithink" to run the distributed generation model. This enabled development of a very flexible screening model used to evaluate the relative performance of alternatives. The model includes: generation, storage, and transmission. Economics. And "soft" variables. I will talk about soft variables in a moment.

Slide 18

Here are the generation options considered. (read list) Biomass was considered a strong contender since there already exists a 5 MW woodwaste generating plant nearby. Fuel cell and gas turbine are not viable in this situation because there is no natural gas pipeline into the area.

Slide 19

The model includes these storage and transmission line options.

Slide 20

Now the economics of the alternatives. All alternatives were considered with the same economic basis in order to present each option's result on the same level.

Net present value was selected because currently Idaho power operates on a cost minimization basis, not necessarily on profit, although they are considering a change.

No cost escalation.

The model calculated profit, but this figure is negative in all alternatives even after capital debt is retired due to the limited number of hours of operation projected.

We did not consider any value in distributed generation enabling other more costly alternatives to be deferred.

Slide 21

This slide lists the soft variables. These factors sometimes strongly affect the outcome of the decision, but they are unmeasurable! It is important in the model to assign a common range for quantifying these soft variables, and we have chosen 0 to 1. The number itself is meaningless, its importance lies solely in its value relative to the other variables. The soft variables' value must be consistent with the others. For example, high environmental impacts is not consistent with high public and customer support.

Slide 22

This and the next few slides list the various inputs to the model. You can read these as well as I can so I'll just pause for a moment at each slide.

Slides 23-26

Slide 27

The model can generate graphs or tables of virtually any selected parameter. This slide shows some of the financial aspects of installing 10 MW of diesel engine generation at McCall. The information here is typical. At the left side are the scales used in this graph. This indicates that functions 1 and 2 use one scale from 6 million dollars to negative 2 million. Functions 3,4 and 5 use a different scale from 3 million dollars to negative 1 million. Debt decreases as payments are made, profit is negative until the debt is retired. This profit picture does not include the fuel and O&M costs associated with the diesels. This slide was from an early stage of the model, and this error has been corrected, but the slides have not been updated.

Slide 28

Some of the soft variables' response are shown in this slide. We assumed that public support would be moderate until the project completed, and would then decrease to no support, but no opposition either. Public effects would increase slightly as the increased power reliability offset the effects of have a generation facility located nearby. Overall acceptance, however, (and here is the exception to the soft variable range of 0 to 1) starts out positive and drops to moderately negative. This occurred because in this stage of the model, we had no mitigation of environmental impact.

Slide 29

During the model development, several questions have arisen. Are there other economic models just as useful, or perhaps moreso? Have we excluded or improperly modelled some system components or relationships? There's our blind spot. We are looking for those areas. What about lumping the soft variables? Is a soft variable that would have a significant impact on the model's outcome being hidden by lumping?

As the model gains sophistication, we hope to answer these and other questions.

Slide 30

As the model evolves, there are some areas deserving (and requiring) further work. Some of those areas are how the model handles energy storage and solar and wind alternatives. We are working on making it easier to perform a sensitivity analysis on the soft variables in order to confirm model accuracy. We also are working on enhancing the user interface, and how to include sufficiently accurate demand-side management into the model.

Slide 31

The distributed generation model is an excellent tool for comparing a utility's distributed generation alternatives in a given location.

System analysis and dynamic modelling is appropriate for screening these alternatives and determining those to be studied further.

Our goal is improve the robustness and versatility of the model to make it appropriate and useful in screening any utility distributed generation application.

Any questions?

The Idaho National Engineering Laboratory is a public resource with vast capabilities. The distributed generation model is only a small example of the Laboratory's work. If this model could be useful to you, or if you have another opportunity for us to assist you, please contact us.

Thank you very much!

Distributed Generation Systems Model

Presented by:

C. R. Barklund

U.S./Korea Electric Power Technologies Seminar

Seoul, Republic of Korea
October 1994

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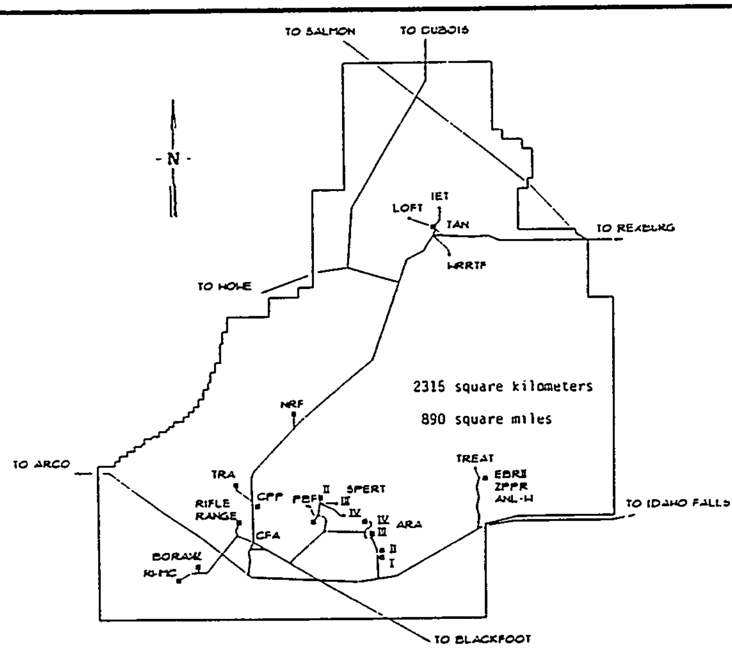

Idaho National Engineering Laboratory

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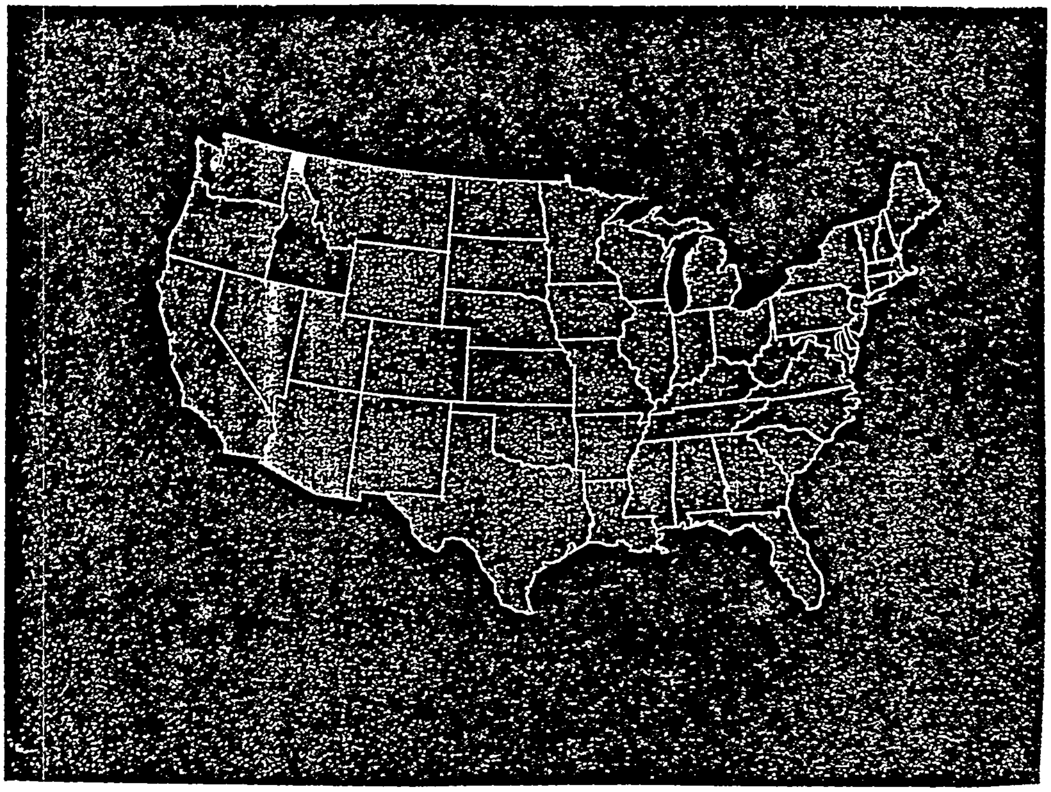

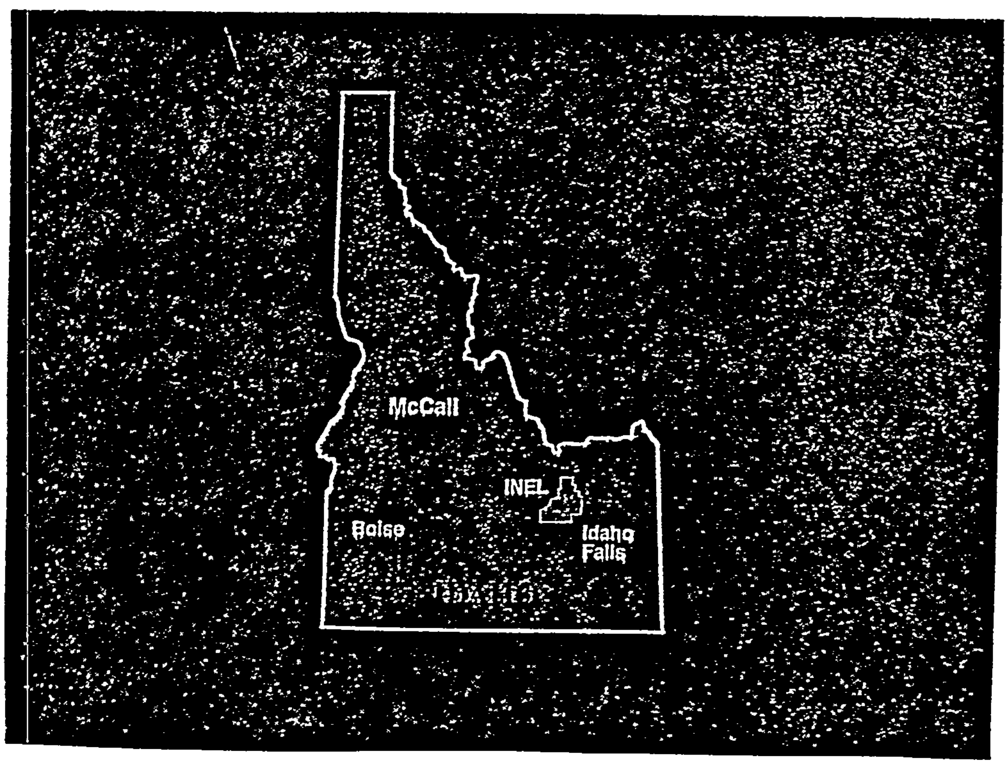
McCall
INEL
Boise
Idaho
Falls

Outline

Objectives

Approach

The McCall Problem

Description of the Model

Conclusion

INEL

Objectives

- Develop a screening model for Distributed Generation alternatives
- Better understanding of Distributed Generation as a utility resource
- Further INEL's understanding of utility concerns in implementing technological change

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Approach

- Systems Analysis
  - Identify "all" system components
  - Identify component interactions
- System Dynamics Modeling
  - Quantifies component states and interactions
  - Simulates behavior of nonlinear systems
    - Feedback
    - Complexity
  - Facilitates comparison of alternatives

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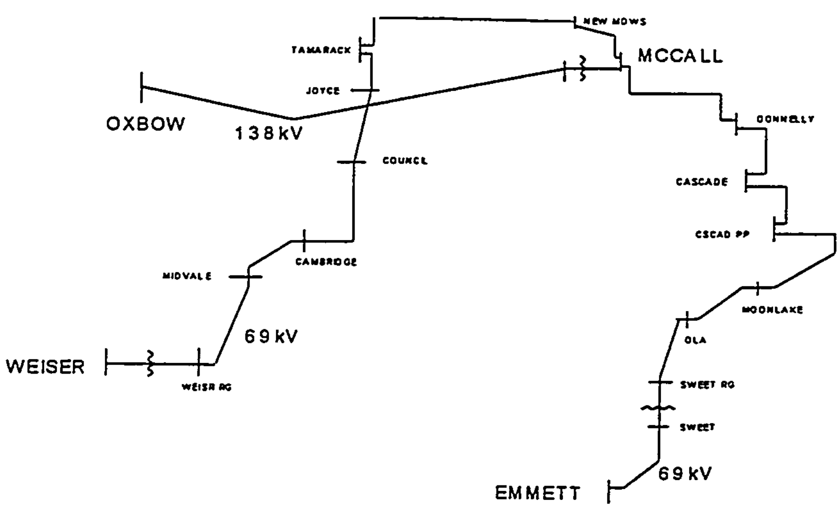
The McCall Problem



Estimated winter peak is 68 MW for 1994-95.

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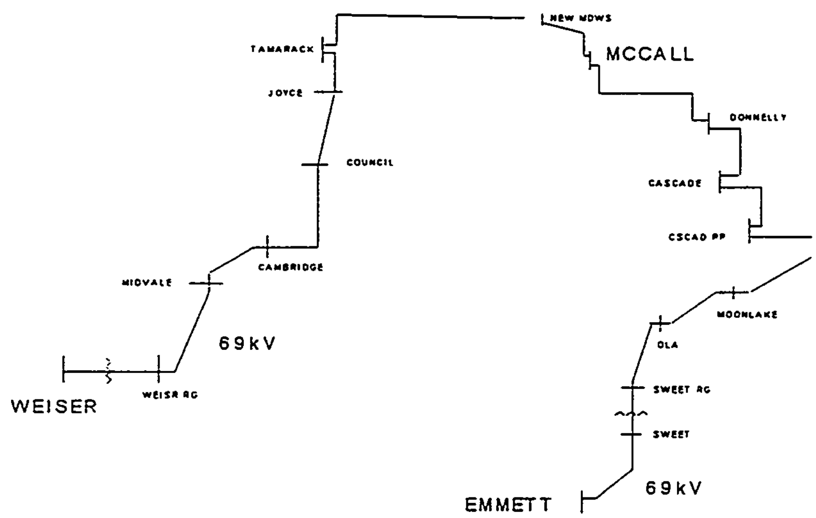

Capacity of 69kV loop is 50MW, limited by voltage. Considerable thermal margin remains.

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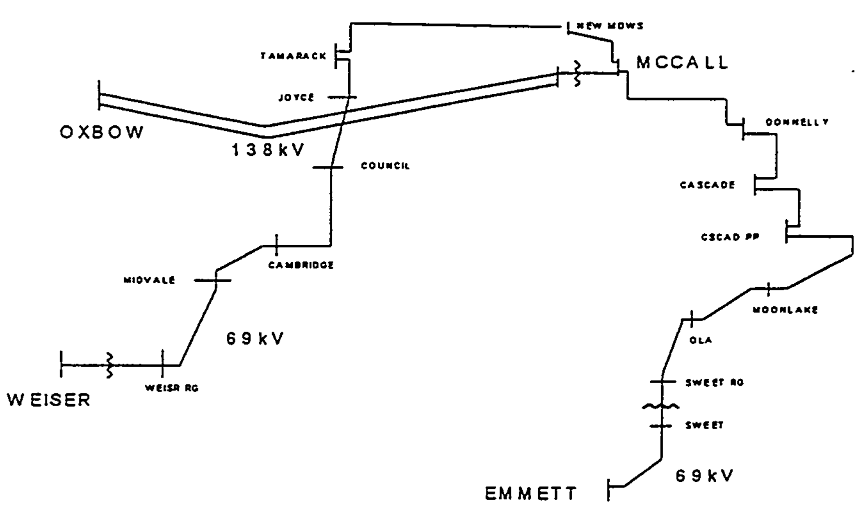

Cost to build 138kV line in parallel with existing line is estimated at $7.8M.

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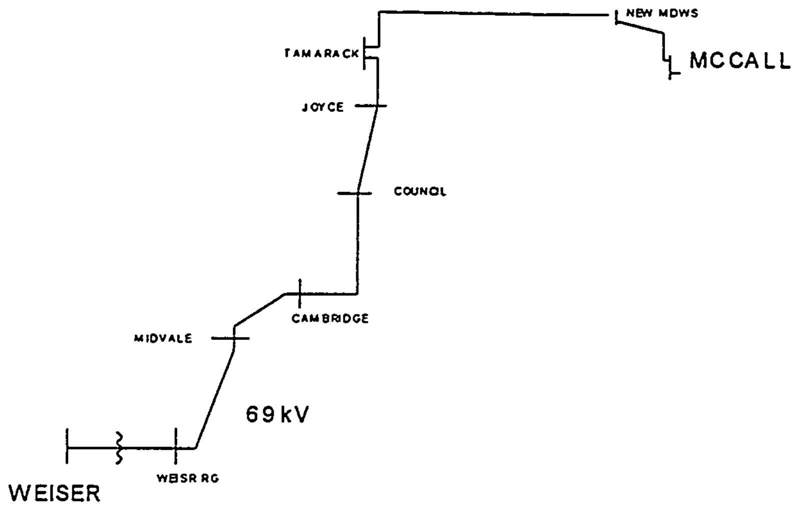

Cost to upgrade West-side (Weiser) line from 69kV to 138kV is $9.5M.

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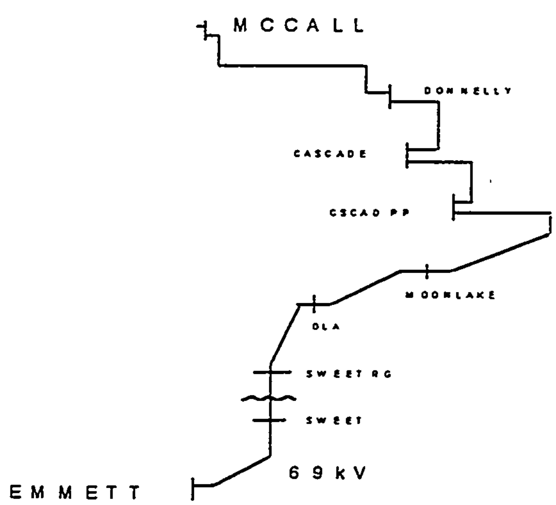

Cost to upgrade East-side (Emmett) line from 69kV to 138kV is estimated at $17M.

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McCall Options Summary

- All these options provide a much higher capacity than needed and could incur significant stranded investment should growth rates slow in McCall area.
- Distributed Generation is a possible viable option to either defer or eliminate the need for transmission upgrades.

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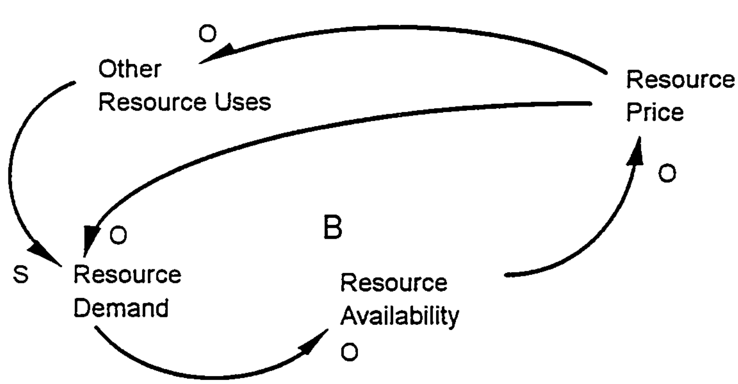
Loop Diagram Model



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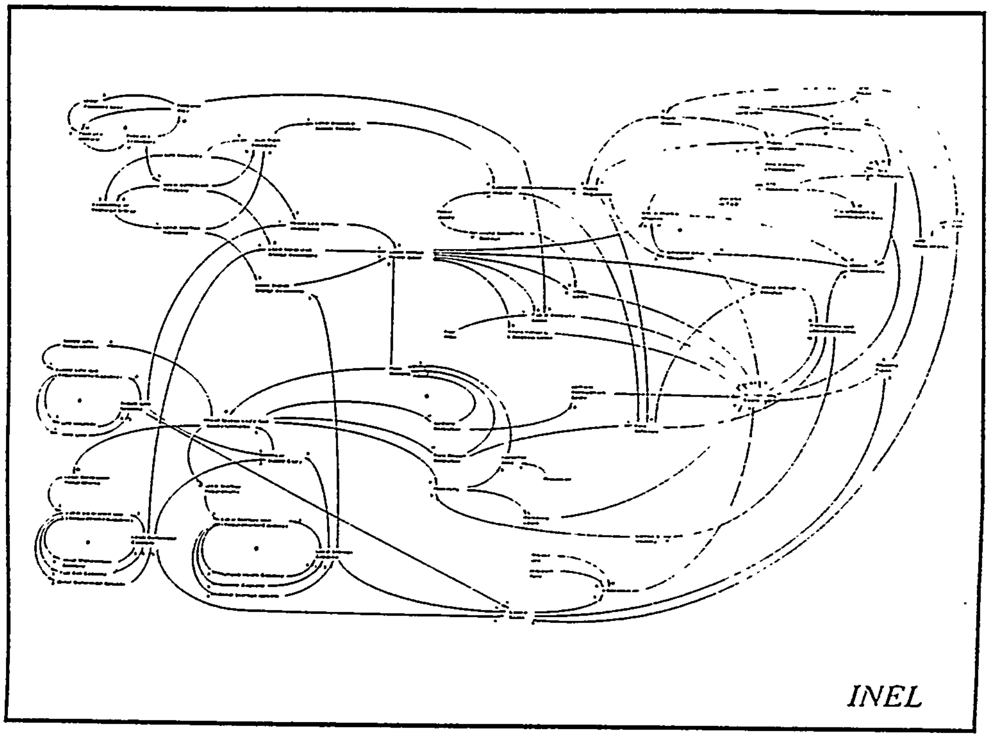
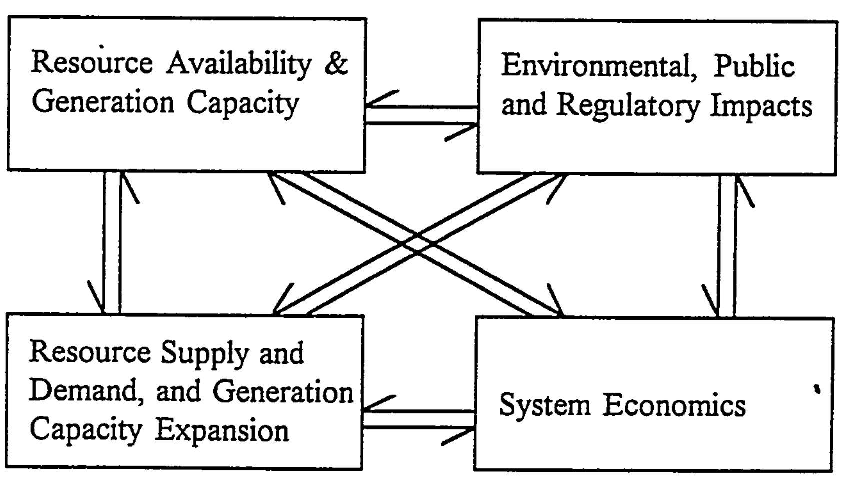


Model Block Diagram



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The ithink™ Model

- A screening model, to evaluate relative performance of alternatives
- Includes:
  - Generation, storage, transmission
  - Economics
  - "Soft" variables

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Generation Options

Biomass
Diesel
Fuel Cell
Gas Turbine
Geothermal
Hydropower
Solar Photovoltaic
Wind Turbine

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Storage Options

Batteries
Compressed Air
Flywheel
Pumped Storage
Thermal Storage

Transmission Line Options

Line Upgrade
New Line

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Model Economics

Present value

No escalation

Profit-based

No explicit valuation of
project deferral

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Soft Variables

Public Support
Customer Support
Public Rate Regulation
Environmental Impacts
Site Availability

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ithink™ Model Input - McCall

Property Tax Rates
Initial Price per kWh
Electricity Cost
Initial Gen Capacity
Initial Storage Capacity
Initial Transmission Line Capacity
Initial Peak Demand
Initial Population
Population Growth Fraction
McCall Load Factor
Minimum Demand
Oxbow Line Reliability
Land Base Price
Other Land Uses

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ithink™ Model Input - Project

Discount Rate
Marketing Costs
Demand Management Costs
Power Quality
Land Requirements
Site Accessibility
Site Suitability
Project Economic Life
Project Environmental Impacts
Annual Environmental Mitigation Costs

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ithink™ Model Input - Generation

Generation Delay
Cost and Capacity for:
- Biomass
- Diesel
- Fuel Cell
- Gas Turbine
- Geothermal
- Hydropower
- Solar Photovoltaic
- Wind Turbine

Fuel and Resource Price
Gen T&D Cost
Gen O&M Cost per kWh
Gen Waste Cost per kWh
Generator Reliability

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ithink™ Model Input - Storage

Storage Delay
System Cost and Capacity for:
- Batteries
- Compressed Air
- Flywheel
- Pumped Storage
- Thermal Storage

Storage T&D Costs
Storage O&M Cost per kWh
Storage System Reliability

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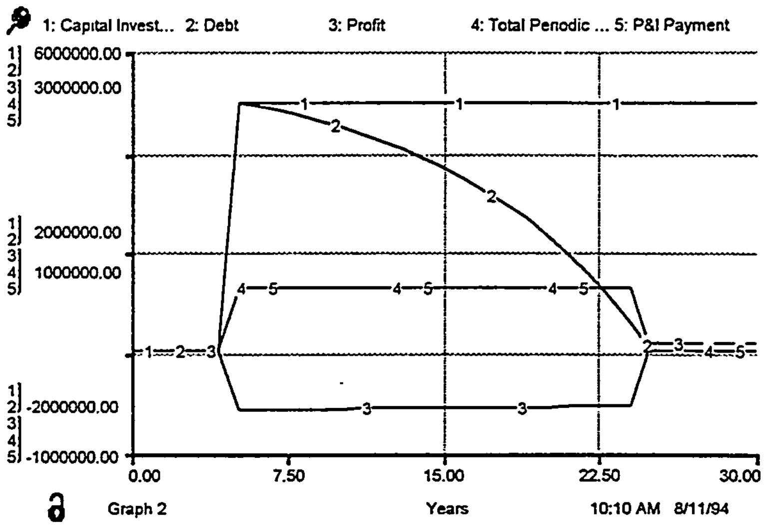
ithink™ Model Input - Transmission

Trans Line Delay
Line Upgrade Capacity
Line Upgrade Increment
Line Upgrade Unit Cost
New Line Capacity
New Line Increment
New Line Unit Cost
Line Reliability

INEL

Finances



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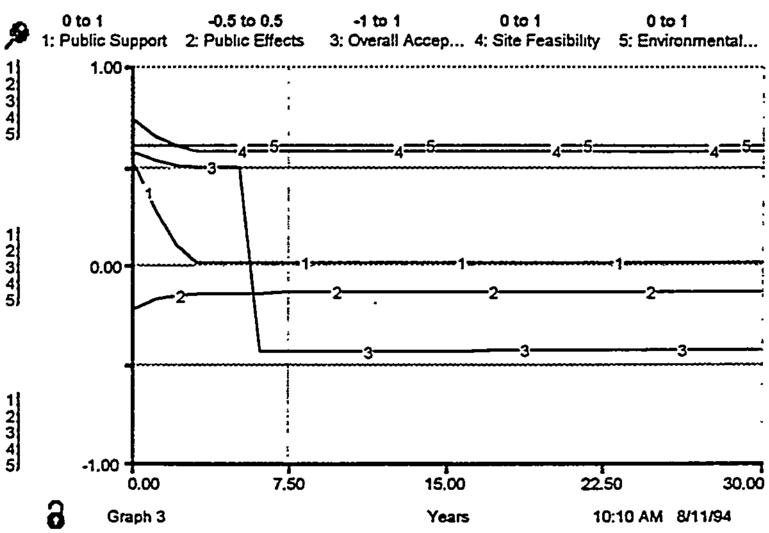
Figures of Merit



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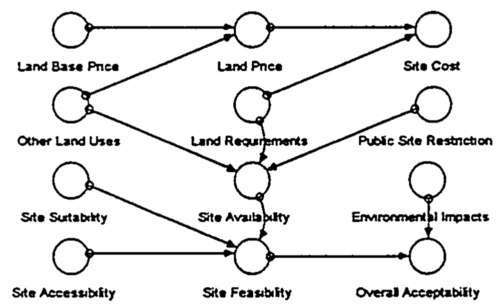
Questions

- What other economic models are useful?
- What system components or relationships have we left out or misrepresented?
- Does lumping of soft variables affect results?



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The ithink™ Model

- Areas for further work
  - Energy storage
  - Solar and wind alternatives
  - Enhanced user interface
  - Demand-side management

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Conclusion

The INEL Distributed Generation Model allows comparison of a utility's DG alternatives in a local area such as McCall.

The system analysis and modeling approach appears appropriate for screening alternatives.

Our goal is to make the model suitable for screening any utility DG problem or application.

INEL

CURRENT TRENDS IN THE APPLICATION OF NON - CERAMIC INSULATORS FOR TRANSMISSION & DISTRIBUTION LINES SUBJECT TO CONTAMINATION

U.S. / KOREA ELECTRIC POWER TECHNOLOGIES
SEMINAR MISSION
SEOUL, KOREA
OCTOBER 1994

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ASIA PACIFIC REGION
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FRANKLIN PARK, ILLINOIS

INDUSTRY OVERVIEW

Non - Ceramic Insulators (NCI) have been in application for more than 25 years. During this time, manufacturers have worked diligently to improve product designs and polymer materials. Today, the use of Non - Ceramic Polymer insulators is proliferating as Utilities become more confident in this advanced technology. The application advantages of NCI technology are more widely recognized and understood and credibility is growing in the long term service performance of these insulators. Current estimates place the NCI market share as high as 50% of the total U.S. transmission insulator market.

Indeed, Reliable Power Products is proud to advise that their insulators have been selected for the first 500 KV - DC transmission line in the USA to use 100% composite polymer insulators. With the combination of Los Angeles Department of Water and Power (Los Angeles to Las Vegas) and Salt River Project (Las Vegas to Phoenix), a total of almost 1,000 Kms. of transmission line will be insulated with Silicone Rubber Polymer Insulators. The total project will include almost 15,000 insulator strings.

User confidence is not confined to the USA market. The application of NCI's by International Utilities has also experienced significant growth. This may be evidenced by EHV installations in South America, Middle East, South Africa, Australia and South East Asia.

Why are NCI's becoming so popular? The answer lies in the many advantages that Utilities gain from their use:

* Installation costs are lower because of the reduction in weight offered by NCI's when compared to the more conventional ceramic insulator strings. A comparable suspension insulator weighs only 10% of its ceramic counterpart. Post insulators weigh about 40% of the porcelain equivalent. As a result, installation savings as high as US$400,000 (Won 340,000,000) have been reported by contractors on major EHV projects.

* NCI's are resistant to vandalism. Gunshot damage to the polymer weathersheds is of no consequence. Unlike ceramic insulators which can provide spectacular failures when damaged by gunfire, NCI's offer little of interest to vandals since bullets simply pass through the weathersheds with no visible signs of success. Only a direct hit on the fiber-reinforced plastic rod (FRP) can cause damage to the insulator. The insulator's narrow profile provides a difficult target ensuring maximum safety from these direct hits.

* The resilient polymer material dramatically reduces handling and transportation damage.

* Maintenance costs are minimized since silicone based polymers do not require periodic washing to ensure correct electrical performance.

* Initial purchase price of NCI's has dropped below that of ceramic materials as manufacturers realize the economies associated with volume production.

NCI PRODUCT OFFERINGS

NCI's are available in two types of polymer compounds. We can conveniently divide NCI's into two specific polymer families: Organic (EPR/EPDM etc) and Inorganic (Silicone based). The Organics are derived from crude oil and are characterized by their carbon backbone whereas Inorganics are derived from the element Silicon and exhibit a Silicon - Oxygen backbone.

Unlike ceramic insulators, where material performance is essentially the same from one manufacturer to another, NCI's will differ greatly in performance because of their inherent properties, i.e. Silicone versus Carbon based. Much research has been devoted to this subject by independent laboratories which include such esteemed facilities as Arizona State University, Ontario Hydro, Chalmers University, EPRI (USA), Hydro - Quebec and the Swedish Transmission Research Institute. Their work to date may be summarized in a few brief sentences:

a) Organic (carbon based) polymers do not exhibit long term "hydrophobicity" characteristics and tend to exhibit material changes more rapidly than silicones

b) Silicone based polymers exhibit long term "hydrophobicity" and the ability to encapsulate surface contamination thus rendering the contamination hydrophobic.

c) Silicone based compounds also provide superior resistance to degradation by Ultra Violet exposure.

The concept of hydrophobicity is critical to the performance of NCI's and will be discussed later in this paper.

The design and test protocols for NCI's are typically governed by two International Standards: ANSI C29.11 and IEC 1109.

CONTAMINATION FLASHOVER:

The process of contamination flashover is critical in any study of insulator performance. Indeed, it is this type of flashover which causes the most regular failure of the insulation system. Most Utilities recognize this problem and over - insulate the system well in excess of the BIL requirements.

The steps which lead to contamination flashover may be summarized thus:

- periods of dry weather cause contamination to be deposited on the insulator surface.
- the arrival of moisture in the form of fog, mist, light rain etc dissolves the contamination layer and forms a continuous conductive film across the insulator surface.
- leakage currents flow within this conductive layer causing localized heating which dries out the moisture film. This localized drying forms dry bands across which the full voltage is imprinted.
- surface electrical activity is induced across the dry bands and causes the surrounding air to become ionized.
- the ionization lowers the dielectric strength of the air and leads to complete insulation failure.

Many methods have been attempted by Utilities to prevent contamination flashover, namely:

- increased number of disks to increase leakage distance and, hence, reduce electrical stress
- resistive glaze insulators to encourage complete drying of the conductive moisture layer
- surface paints and greases

It should be noted that these solutions are either inefficient (over - insulation of the system or higher system losses) or short lived. A more appropriate solution can be found by re - visiting the causes for contamination flashover, in particular, the formation of a continuous moisture layer. If the material of the insulator were able to repel water and inhibit the formation of this layer then leakage currents will be minimized. Therein lies the basis of successful application of polymer insulators.

Silicone based polymers, in particular, exhibit the property of "Hydrophobicity" or the ability of the material to form water beads on its surface. As noted previously, research data shows that Silicone polymers inherently offer long term hydrophobic properties. In contrast, organic polymers have been shown to lose their hydrophobic properties in relatively short periods. Further, after electrical

NCI SELECTION CRITERIA

Lack of familiarity with NCI construction often leads the Power Engineer to believe that special hardware designs are required for the installation of NCI's. While it is true that the more complete selection of end fittings available on NCI's can be used to reduce the amount of hardware, NCI's can also be supplied with conventional socket and ball fittings compatible with ANSI and IEC specifications.
In addition, the tensile strength ratings of NCI's are quoted in accordance with normally accepted standards (120 KN, 160 KN, 210 KN, 300 KN, 400 KN etc.)

In the most simple terms, three items are required to permit the selection of NCI's: section length, tensile strength and leakage distance.

Section Length: In general, the section length of NCI's can be matched to the section length of ceramic disks. The Reliable Power Products design allows the section length to be varied in increments of 1" (25mm). Other manufacturers will have equal or less flexibility.
Thus NCI's can be used easily in the re-insulation of transmission lines without alteration of hardware or line sags.

Tensile Strength: As noted previously, NCI's are designed with the same tensile ratings as conventional ceramic insulators and may be selected as direct substitutes i.e. porcelain M&E rating of 120 KN can be replaced by an NCI of the same rating.

Leakage Distance: Leakage distance of NCI's is a critical application parameter and has been the subject of much research. Contamination flashover tests of naturally aged NCI's and new NCI's indicate that Organic materials (EPR, EPDM) do not provide the same long term performance of Inorganic materials (Silicone based). Indeed, it has been suggested that, while silicone based polymer NCI's may be selected with the same leakage distance as porcelain, Organic NCI's require at least 30% more leakage. In summary, one can adopt the following -

- Silicone based polymers: use the same leakage as porcelain

- Organic polymers: use 30% more leakage than porcelain.

For new applications, IEC - 815 leakage guidelines should be followed for silicone. Again, consideration should be given to increase EPR/EPDM leakage by 30% or one contamination category higher.

activity causes the polymer to lose hydrophobicity, silicone is able to recover fully with no measurable deterioration after a relaxation period of approximately 18 - 24 hours. Organic polymers cannot recover this property and will allow water to spread across the surface.

The chemical structure of Silicone Polymers includes molecular chains of various lengths. Research data shows that the very low molecular weight (LMW) chains are mobile within the material and tend to migrate to the surface. It is this concentration of LMW chains at the surface which cause differential surface tensions and the ability of the material to form water beads. More importantly, the LMW chains also have a tendency to migrate through and encapsulate any contamination layer that forms on the surface of the material, thereby making the contamination layer itself hydrophobic.

Therefore, it becomes clear that, regardless of contamination, Silicone Polymer insulators will exhibit strong hydrophobic properties which lead to superior electrical performance in the prevention of contamination flashover. Further, the minimal leakage currents have no deteriorating effect on the material and little or no erosion is evident on naturally or artificially aged silicone polymer insulators. Indeed, analysis of naturally aged silicone rubber has shown that there is no deterioration of the material and that aged material behaves in exactly the same manner as new material.

SUMMARY :

NCI technology has advanced to a level where product maturity and stability are becoming trademarks of some manufacturers. This may be demonstrated by the longevity of a given polymer formulation i.e. no changes to the formulation over an extended period of time and confirmed performance in transmission applications. Product design enhancements prevent water ingress to the FRP rod and reduce electrical stress with corona rings applied at 230 KV and above.

This discussion has provided some insight into the proper selection and application of NCI's. It is not, however, a comprehensive guide and further information may be obtained from the various publications listed in the Appendix. It is also recommended that Utilities contact specific NCI manufacturers to evaluate their products and perform comparative studies that investigate the following key areas:

- Longevity of formulation (how often has the manufacturer changed formulations and why? How long has the present formulation been supplied in applications?)

- Successful application experience in the intended environment

- Long term material hydrophobicity

- Experience at the intended voltage levels

It is advisable to contact other Utilities for objective performance reports.

APPENDIX A

IEC 815 (1986), "Guide for the Selection of Insulators in Respect of Polluted Conditions," Table II Section 4.

IEEE - 987, "Guide for the Application of Composite Insulators." To be published in 1994.

R. Munteanu, "Silicone Rubber Insulators Reduce Life Cycle Costs," Transmission and Distribution International Magazine, First Quarter 1994.

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Steps to Contamination Flashover

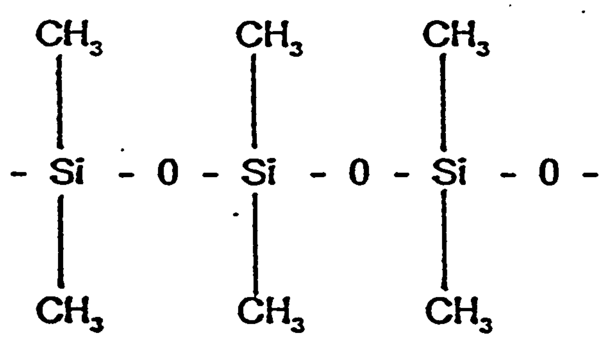
- Deposit of contaminants during dry weather
- Partial wetting of surface due to fog, dew, light rain
- Leakage current flow through electrolyte film
- Dry Band due to heating and uneven drying
- Surface arcing in air
- Air ionization and dielectric breakdown
- Insulator Flashover

Methods to prevent or reduce Contamination Flashover

- Increase Leakage Distance
  - Extra Disks
  - Special Disks (Anti-fog, Aerodinamic)
- Surface Treatments
  - Periodic washing
  - Semiconductive - Resistive Glaze (RG)
  - Silicone based greases
  - Paints (silicon, teflon)
- Alternate materials
  - Silicone Rubber Insulators: Compositz(tm)

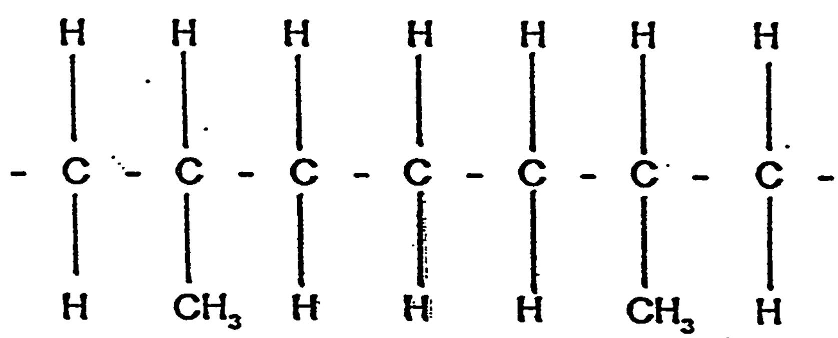
ORGANIC VS. INORGANIC POLYMERS

BACKBONE OF SILICONE POLYMER CHAIN (INORGANIC)



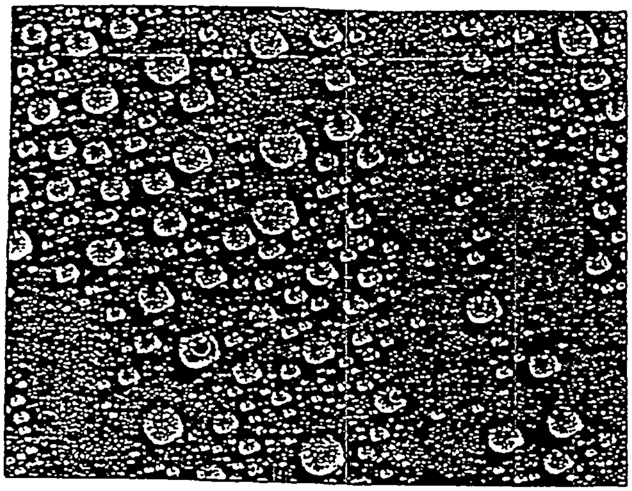
SILICON-OXYGEN BOND IS THE SAME BOND FOUND IN QUARTZ, SAND AND GLASS.

BACKBONE OF EPDM, EPM POLYMER CHAINS (ORGANIC)

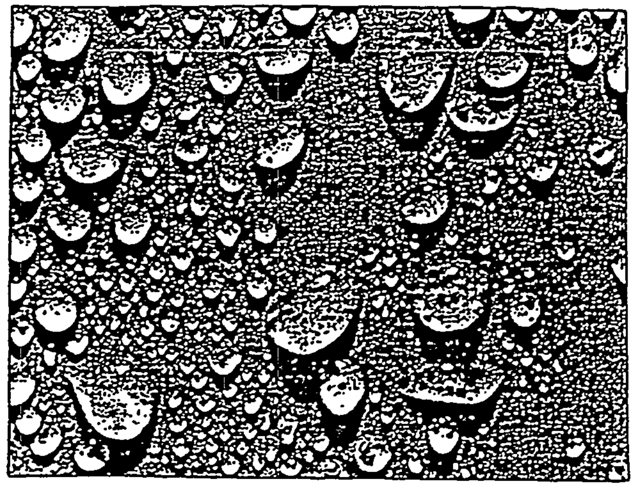


CARBON-CARBON BOND STRENGTH IS SIGNIFICANTLY LOWER THAN THE SILICONE-OXYGEN BOND - THE POLYMER BACKBONE IS SUSCEPTIBLE TO ATTACK BY ULTRAVIOLET RAYS, HEAT AND OXYGEN.

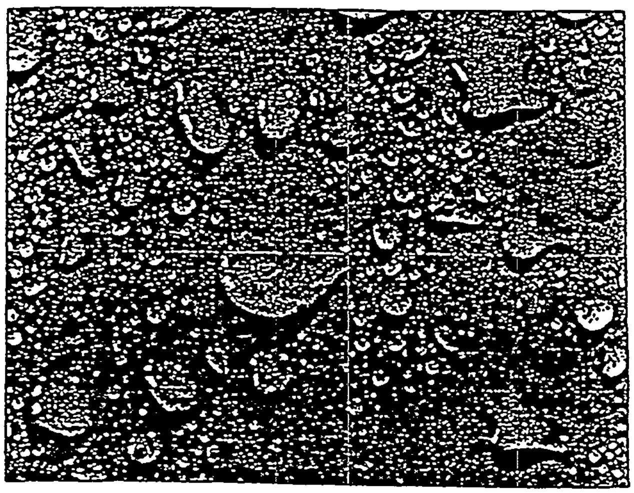
22



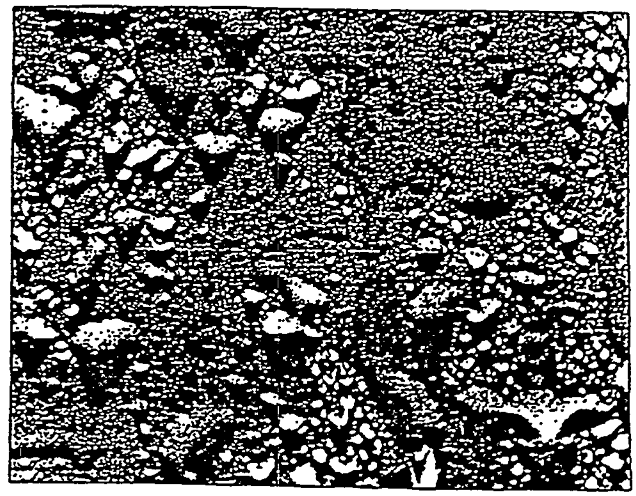
HC 1



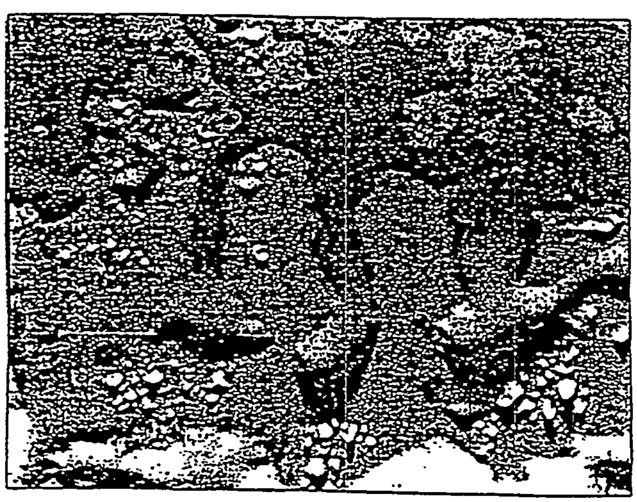
HC 2



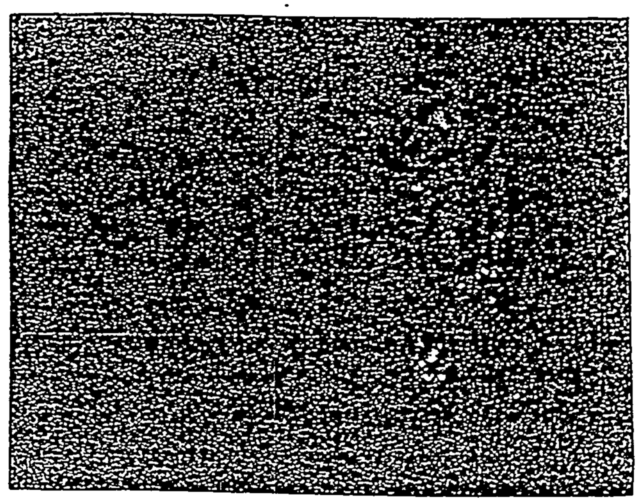
HC 3



HC 4



HC 5

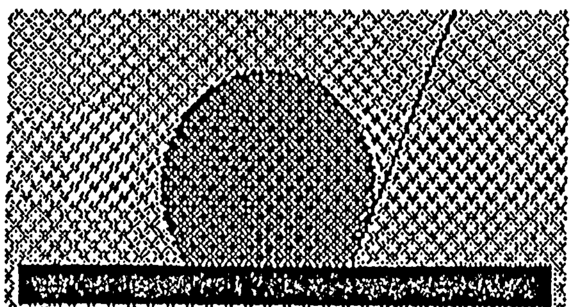


HC 6

Fig 3 *Typical examples of surfaces with HC from 1 to 6 (natural size).*

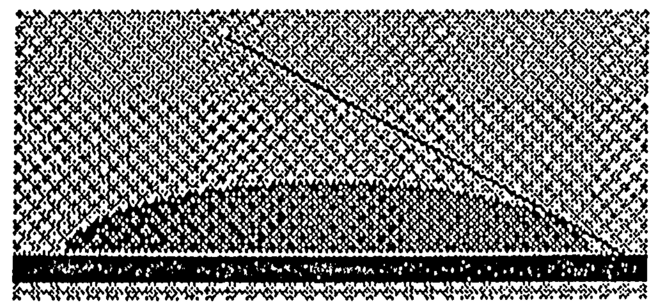
Polymer Insulators
Hydrophobicity: Water repelency

SILICONE
Hydrophobic

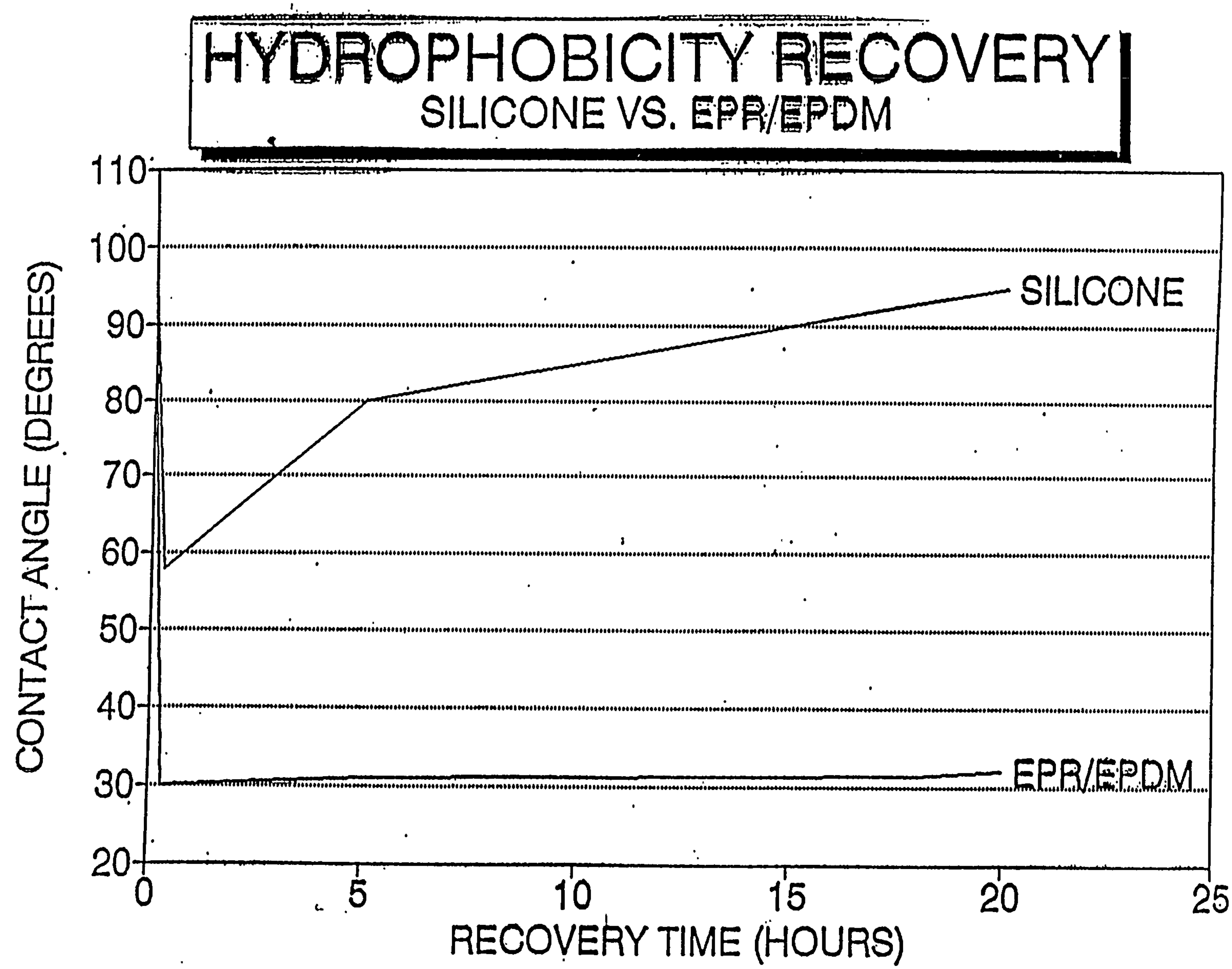


The surface repels water.
Water forms beads
Contact Angle >= 90 deg.

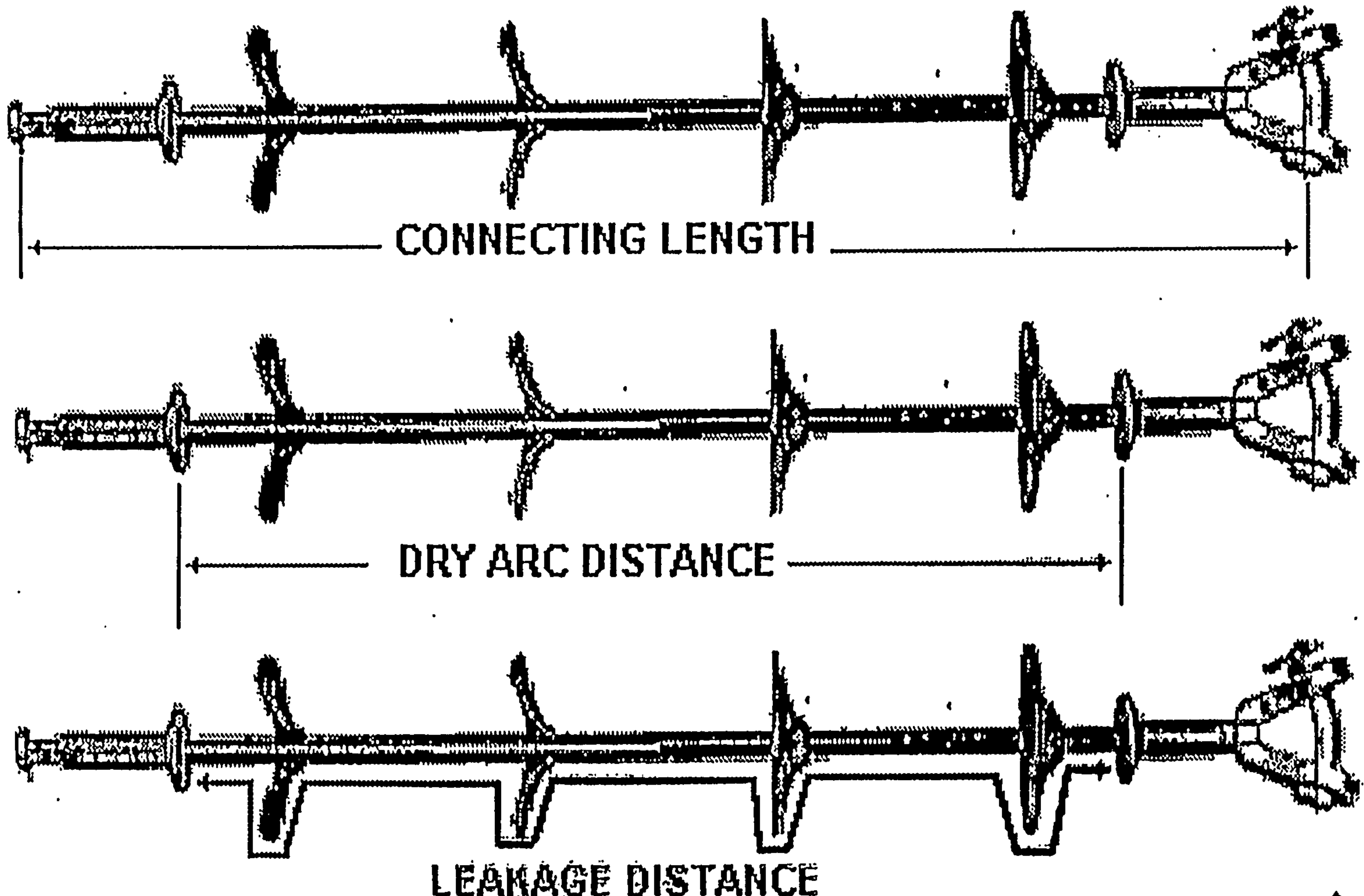
PORCELAIN
Hydrophillic



Surface doesn't repel water.
Water spreads and wets surface.
Contact angle < 90 degrees


HYDROPHOBICITY RECOVERY
SILICONE VS. EPR/EPDM
CONTACT ANGLE (DEGREES)
110
100
90
80
70
60
50
40
30
20
0
5
10
15
20
25
RECOVERY TIME (HOURS)
SILICONE
EPR/EPDM

Compositz(tm) Insulators - Characteristics



AlliedSignal
ADVANCED
MATERIALS

Energy Conservation
in
Electric Distribution

prepared by
Chong-Jin Lee
AlliedSignal Korea, Ltd.

October 24-28, 1994

Energy Conservation in Electric Distribution

INTRODUCTION

This paper discusses the potential for energy and power savings that exist in electric power delivery systems. These savings translate into significant financial and environmental benefits for electricity producers and consumers as well as for society in general. AlliedSignal's knowledge and perspectives on this topic are the result of discussions with hundreds of utility executives, government officials and other industry experts over the past decade in conjunction with marketing our Amorphous Metal technology for electric distribution transformers.

Amorphous metal is a technology developed by AlliedSignal that significantly reduces the energy lost in electric distribution transformers at an incremental cost of just a few cents per kilo-Watt-hour. The purpose of this paper is to discuss:

- Amorphous Metal Alloy Technology
- Energy Savings Opportunity
- The Industrial Barriers and Remedies
- Worldwide Demand
- A Low Risk Strategy

I wish this presentation will help KEPCO achieve their stated aims of ensuring sound development of the national economy and enhancement of public life through the economic and stable supply of electric power. AlliedSignal Korea Ltd. in conjunction with AlliedSignal Amorphous Metals in the U.S. are here to work with KEPCO, transformer manufacturers, industry, and government agencies to achieve greater efficiency in power distribution.

AMORPHOUS ALLOY TECHNOLOGY

Amorphous metals are metal alloys with a non-crystalline atomic structure. They are produced by cooling molten metal at a very high rate, on the order of one million degrees per second producing a thin strip with a random atomic structure. Figure 1 illustrates the production process using planar flow casting invented by AlliedSignal in the mid-1970s. This process was used to produce METGLAS® transformer core alloy in an Electric Power Research Institute (EPRI) sponsored program to demonstrate the technology and produce a low core loss alloy for transformer manufacturing studies.

Since the mid 1970s, AlliedSignal has spent hundreds of millions of dollars on the amorphous program, including significant efforts improving the quality of the alloy and reducing the production cost. We believe that the current amorphous metal transformer has reached the point where the benefits received from the new technology outweigh the increased costs compared to the conventional silicon steel core transformers.

The random atomic structure of amorphous alloys results in a unique set of physical properties. Of particular interest for transformer applications is the incredible ease of magnetization. This is illustrated in Figure 2, which compares the magnetization curves of regular grain oriented silicon steel and METGLAS transformer core alloy. The area within each of these "B-H loops" is proportional to the energy dissipated as heat with each magnetization cycle. These characteristics directly relate to the energy efficiencies shown in Figure 3. The cores of the 700,000 - 800,000 distribution transformers in service in Korea go through this cycle continuously at 60 Hz, 2 billion times per year.

The core loss savings available with METGLAS alloy are dramatically illustrated in Figure 4. These infrared thermographs compare a high efficiency silicon steel distribution transformer to the amorphous alloy core unit of the same rating. The temperature difference of approximately 30°C measured in this experiment illustrates the degree of savings that are possible. The core losses of the transformers containing METGLAS alloy are generally 65 to 70 percent lower than the silicon steel units. The winding loss at full load is approximately the same for units containing the two different types of core alloy.

Figure 5 shows an example of the extensive testing that has been done by one transformer manufacturer to demonstrate that distribution transformers containing METGLAS alloy meet or exceed the stringent test standards required by their customers. Reliability is, of course, a central concern with any equipment that is purchased by electric utilities. Extensive field evaluation programs of amorphous metal transformers utility systems in both the U.S. and Japan have been performed. Today the electric utility industry has over 12 years of experience with amorphous core transformers with no reported failures due to the core material.

ENERGY SAVINGS OPPORTUNITY

Distribution transformers with ultra-efficient amorphous metal cores offer energy savings opportunities for two market segments; the electric utility (KEPCO) and their commercial and industrial customers. Electric utilities deliver power to their customers over a complex system of electrical conductors, switches, voltage regulators, capacitors, transformers, and a variety of protection and measurement devices know as the transmission and distribution system. This system delivers and regulates the flow of electricity from generally remote generation locations to consumers. Figure 6 illustrates this in a simplified diagram. High voltage transmission begins at the generator step-up transformer. The voltage is then progressively lowered through several levels of substations as power is distributed over the service territory. Distribution transformers, located near the end user, perform the final voltage reduction. All of this equipment consumes energy. Distribution transformers account for over 25% of this energy loss.

The majority of distribution transformers are owned by the electric utility for service to residential customers and small businesses. Often, however, larger commercial and industrial customers own their own transformers and purchase power from the electric utility at high voltages. Thus energy savings and the resulting cost reduction are available to the electric utility, on the distribution system and to commercial and industrial customers that own their distribution transformers.

Distribution transformers do not represent the only energy savings opportunity on the transmission and distribution system. While energy loss in power delivery cannot be eliminated, numerous efficiency technologies are available to minimize waste. These technologies generally involve a greater initial investment and in most cases, improve both system efficiency and reliability. Our analysis indicates that T&D system loss could be reduced in the U.S. and Western Europe from over 9% to about 6% of generation by a combination of the advanced technologies.

Regions of the world with rapidly growing electric demand may be well positioned to exploit these efficiency technologies as they expand their T&D systems. The developed nations face the much more difficult proposition of retrofitting their massive and still functioning systems to enjoy the benefits of the most modern, lowest loss technology. For example, the U.S. Department of Energy is presently conducting an analysis of the energy savings potential and economic feasibility of replacing inefficient distribution transformers with modern, low loss units.

Korea has lower transmission and distribution losses, about 5.6% of generation, due to greater population density and the use of high efficient transmission technology, nevertheless, improvements are possible, as illustrated in Figure 7.

Electric generation data and estimates of growth rates and T&D system loss for several major countries and regions of the globe are shown Figure 8. Figure 9, which is based on these data illustrates that energy loss in T&D will more than double, reaching nearly 2 trillion kilo-watt-hours annually over the next twenty years if present levels of system loss continued. Most of the loss increase will occur in China, Eastern Asia and India, because of their rapid projected growth in generation. An alternate path, implementing technologies to achieve a 6% T&D system loss could save much of this extra waste, over 900 billion kilo-watt-hours per year. Manufacturers of energy efficient technologies, such as amorphous metal distribution transformers, may have significant market opportunities both within Korea and as exports.

Distribution transformers are remarkably efficient and durable machines. Their service life can exceed thirty years while their operating efficiency is generally above 95 percent. Despite their efficiency, distribution transformers in the aggregate consume a significant amount of energy because they are so numerous. Between 700,000 and 800,000 distribution transformers are in service today on KEPCO's electric distribution system. Furthermore, over 70,000 new units are purchased and installed annually to replace failed units and to service new growth.

A conservative estimate based on KEPCO's total annual generation output indicates that each year approximately 2 billion kilowatt hours of electric energy, over 1.4 percent of total KEPCO generation, is lost in the iron cores of distribution transformers. Over 70 percent of this energy loss is unnecessary and could be eliminated by renewal, over time, with ultra-efficient amorphous metal distribution transformers.

In making any decision on energy conservation investments, however, cost effectiveness is a key criterion to consider. Programs that cost effectively reduce energy waste can lower customer bills while providing environmental and economic benefits to society as a whole.

A widely used and relatively simple screening tool to judge conservation cost effectiveness is to calculate the Cost Of Saved Energy (COSE) for potential efficiency investments, as shown in Figure 10. The investment cost (C) is the incremental expense for greater efficiency, beyond that needed to meet minimum reliability and service requirements. The Capital Recovery Factor in the COSE equation is a standard formula that discounts the value of future savings so that projects of various durations can be easily compared.

The Cost of Saved Energy calculated by this formula for amorphous metal transformers is generally in the 1.5 to 5 cent per kilo-Watt-hour range. These correspond to simple payback periods in the 5 to 10 year range. This should prove financially attractive to both utilities and their customers.

BARRIERS AND REMEDIES

Given that amorphous metal distribution transformers and other transmission and distribution efficiency technologies can save significant electricity cost effectively, an obvious question is what can be done to accelerate their deployment. AlliedSignal has identified a number of institutional impediments, as listed in Figure 11, that act to constrain these cost effective and environmentally friendly investments. Some of these barriers clearly do not apply to KEPCO, as is evidenced by the relative efficiency of the Korean transmission system, but the barriers may be faced by Korean suppliers of efficiency equipment to other worldwide markets. In other instances, the barriers may, in fact, apply to KEPCO. Perhaps the methods discussed to overcome these impediments will be helpful in enabling pursuit of increased efficiency.

1) Lack of Capital

The higher technology equipment that can reduce T&D loss is generally more expensive to purchase. A perceived lack of capital to fund these extra expenditures can result in spite of the relatively small size of T&D budget lines compared to major generation expansion projects. This misperception can be avoided if all resource options are considered in an integrated planning process.

In other cases, a true lack of capital can exist despite the economic desirability and other benefits of T&D conservation investments. The best remedies for this impediment may reside with the institutions that finance electric power construction projects. In considering their risk in financing a generation construction project, they should perhaps evaluate the efficiency of the system that will deliver the newly generated power. Certainly, for a given level of power to be delivered to the customer, a plant connected to a 20% loss delivery system will be more costly and expensive than if a more efficient delivery system was in place. It may be prudent for lenders to encourage greater investment in T&D efficiency improvements. This is particularly true for multinational financial institutions that are also under increasing pressure to exercise better environmental stewardship.

2) Lack of Awareness and Inattention

In some cases, investments to reduce T&D loss are not made because decision makers are not aware of the technology opportunities, or view power delivery as a lower priority. This may occur when generation investment dwarfs T&D spending, for example during the U.S. generation spending boom illustrated in Figure 12. Between 1968 and 1982, generation construction expenditures grew three times faster than T&D, breaking the historical parity between these investment categories. In such a circumstance it is understandable, but perhaps unwise, for executives and regulators to spend less attention on T&D opportunities. The more strategic perspective and analytic discipline of Integrated Resource Planning can help avoid such inattention.

Decision makers may also ignore opportunities for T&D energy conservation if they apply the simplistic one dimensional model of Integrated Resource Planning shown in Figure 13. In this view the utility can meet its resource needs by producing more energy on its side of the meter, or by encouraging its customers to conserve to reduce demand. Of course as illustrated in Figure 14 customers can also produce electricity and producers can also conserve. In the United States, the potential of economical cogeneration was recognized in the 1978 PURPA Legislation. A decade later, over 60% of America's generation capacity additions came from cogeneration and independent power producers. More recently, in the 1992 Energy Policy Act and in President Clinton's October 1993 Climate Change Action Plan, the U.S. government recognized the significance of T&D conservation in Integrated Resource Planning. These legislative and executive actions demonstrate one role that governments can play to create awareness and overcome inattention.

3) Regulatory Barriers

Government regulation of electricity prices is universal, complex and necessary. However, in some cases, the system of price regulation imposes a financial penalty on the share holders of utilities that invest in economical energy conservation. This creates an obvious, and probably unintended, barrier to cost effective T&D efficiency investments.

One example of regulatory barrier in the U.S. results from the "Return on Rate Base" system. In this system the price of electricity is set to reimburse the utility's operating expenses and provide a percentage return on its capital assets (i.e., the "Rate Base"). Lower fuel expenses result as soon as an efficiency investment lowers T&D losses, but earning of the return may be delayed for several years until the investment is included in Rate Base at a formal rate proceeding. This delay shifts a greater portion of the conservation benefits to rate payers at the expense of utility shareholders. A delay of as short as two or three years can result in the utility never fully recovering its extra investment in efficiency.

The 1992 Energy Policy Act directs state regulatory commissions to examine such disincentives to cost effective T&D efficiency investments and to consider establishing rates that encourage economical power delivery conservation. A number of methods to combat the existing disincentives exist. Shared savings programs, establishing interest accruing balance accounts and providing a slightly higher rate of return for loss reduction investments are among the mechanisms that state regulators may adopt.

Another case of regulatory barriers occurs in the United Kingdom, where electric prices have been partially deregulated. Generation prices are established by competition, while transmission and distribution charges are set by separate controls on total revenue. The existing revenue control formula provides a revenue bonus for Distribution Companies that reduce system loss, but the amount of extra revenue is inadequate. For example, a £10 million investment to reduce distribution loss by 0.1% would save electric consumers £37 million over five years and £94 million over 30 years. However, the control formula provides less than £1 million of extra revenue to the Distribution Companies, so they are unlikely to undertake the investment. The U.K. Office of Electricity Regulation is presently conducting a broad review of the distribution controls, including the issue of providing a positive motivation for economical loss reduction

4) Government Support

Clearly, the electric utility and their customers are key to achieving the energy efficiency and environmental goals of the country, Government, however, can play a vital role in promoting and accelerating the move to efficiency. Figure 15 shows some of the actions the U.S. government has taken to encourage transmission and distribution efficiencies. For example, the U.S. government in response to the goals of the Framework Convention on Climate Change, initiated the Climate Change Action Plan. Under this plan, the U.S. Environmental Protection Agency (EPA) is launching the Energy Star Transformer program. This is a voluntary program to encourage electric utilities to become partners, by increasing the efficiency of their distribution system. This program is expected to save $280 million of electricity and reduce carbon emissions by eight hundred thousand metric tons annually by the year 2000.

In addition, the DOE has been authorized to establish efficiency standards for distribution transformers. Ideally, if a standard was implemented today based on the most efficient available technology, an annual savings of 3 million MWH per year and over 660 thousand metric tons of carbon per year could be achieved by the year 2000. Because distribution transformers have service lives of 30 or more years, these savings would be sustained, and grow, through the 21st Century. Further, the Department of Energy (DOE) has been directed to determine the economic feasibility and potential savings of retiring older, inefficient utility distribution transformers before the end of their normal service lives. We anticipate that a program directed at retiring, rather than refurbishing inefficient transformers will provide an additional 1.3% energy savings. The Korean government may wish to consider similar actions to expedite the move to a more efficient distribution system.

WORLDWIDE DEMAND

The demand for amorphous metal distribution transformers is increasing rapidly worldwide as the cost effective energy savings and environmental benefits are recognized. Amorphous metal transformers are already well established in both the United States and Japan. U.S. utilities have been experiencing the benefits of increased transformer efficiency for over 12 years. Last year, amorphous metal distribution transformers represented over 10% of the annual U.S. distribution transformer purchases with an increasing penetration trend.

In Japan, electric utilities are increasingly achieving savings through amorphous metal transformers. Demand for amorphous metal transformers has experienced robust annual growth in recent years, as all nine electric utilities purchase greater numbers of these ultra-efficient transformers. TEPCO, Japan's largest utility, in 1994 will meet 20 percent of their annual pole distribution transformer requirements with amorphous metal transformers. Japanese transformer manufacturers are well positioned to meet the increased demand with an installed annual production capacity of over 60,000 amorphous metal transformers.

Following closely behind the United States and Japan in the move to amorphous metal distribution transformers are India and Taiwan. India is currently developing prototypes for economic evaluation and expanding capacity for both domestic and potential export opportunities. In addition, the Indian government has provided funds to help offset the initial price premiums for amorphous transformers and to jump start a large scale amorphous metal distribution transformer program. In Taiwan, Taiwan Power Co. has adopted total owning cost loss evaluation methodology for the economic evaluation of distribution transformers. Further, they have released an international tender for 1000 amorphous metal transformers. Both India and Taiwan are in the process of developing commercial scale manufacturing capabilities.

Interest in amorphous metal transformers is increasing in China and Thailand and in both countries programs are underway to manufacture prototypes for economic feasibility studies. With growing demand for electric energy to service the further industrialization of these economies, amorphous metal distribution transformers offer significant opportunity to help these countries meet their energy needs cost effectively, while preserving the environment.

A LOW RISK STRATEGY

Amorphous metal distribution transformers represent a low risk energy conservation and environmental betterment opportunity for KEPCO, their customers and society as a whole. These ultra-efficient transformers have undergone extensive testing and field evaluation at hundreds of utilities worldwide, with successful results. KEPCO has had positive energy savings results with amorphous metal distribution transformers. AlliedSignal is positioned to support a Korean commitment to greater transformer efficiency.

AlliedSignal manufacturers METGLAS transformer core alloy in Conway, South Carolina. Plant capacity continues to expand to meet customer demands. In addition, we have amorphous metal core manufacturing facilities in India and New Jersey. As the markets for amorphous metal distribution transformers continue to increase, we are exploring additional locations for production in Asia. AlliedSignal Korea, Ltd. is here locally to meet the customer service needs of KEPCO and transformer manufacturers.

Certainly the move to ultra-efficient amorphous metal transformers is a low risk strategy. The energy savings are predictable and measurable. No actions are required on the part of the customer and there is no impact to customer service. Transformer manufacturers would have very limited initial capital investment, with amorphous metal core supply available. Only as experience and economic conditions and opportunities warrant, would Korean transformer manufacturers need to invest in the core manufacturing technology.

CONCLUSION

In summary, amorphous metal distribution transformers represent a significant cost effective, energy savings opportunity. It is based on a proven technology with over a decade of field experience. Electric utilities and their customers, throughout the world, are realizing the benefits from these ultra-efficient transformers. AlliedSignal is well positioned in Korea to provide technical and customer service support. A strategic decision for increased distribution transformer efficiency will help KEPCO and their customers maintain their worldwide competitive cost positions.

EPRI/Metglas Products
Pilot Plant Facility Schematic

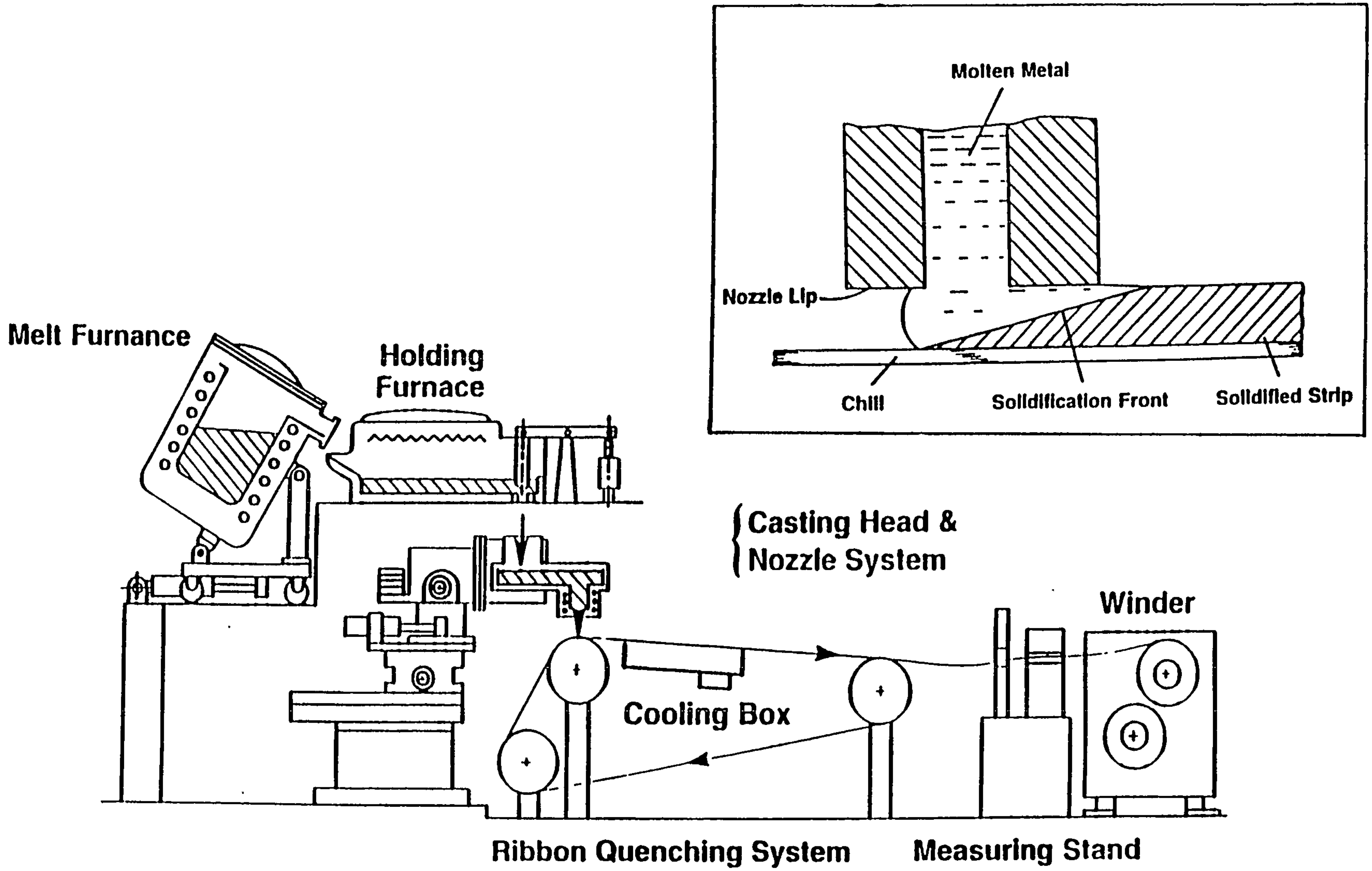


Figure 1

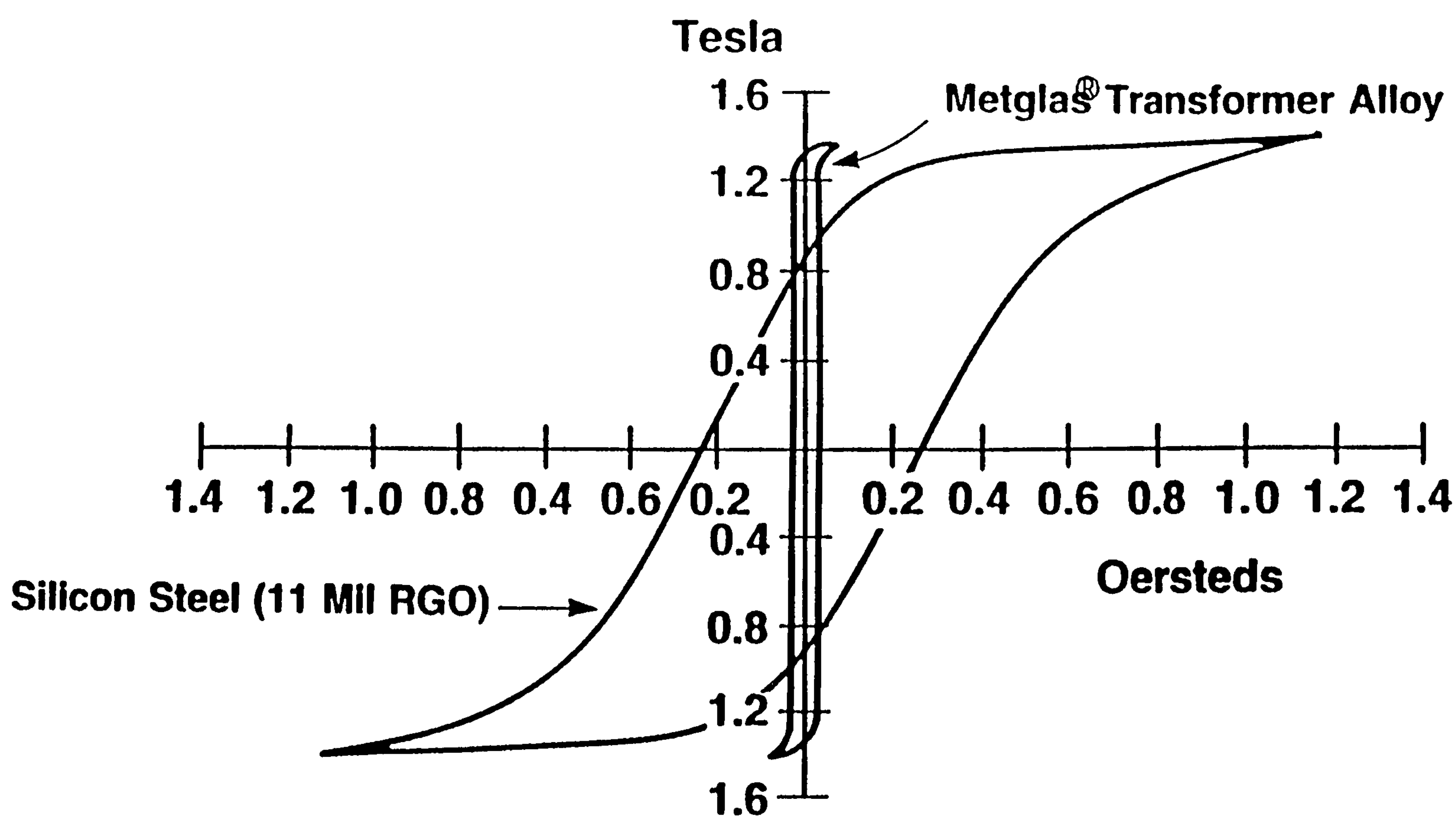
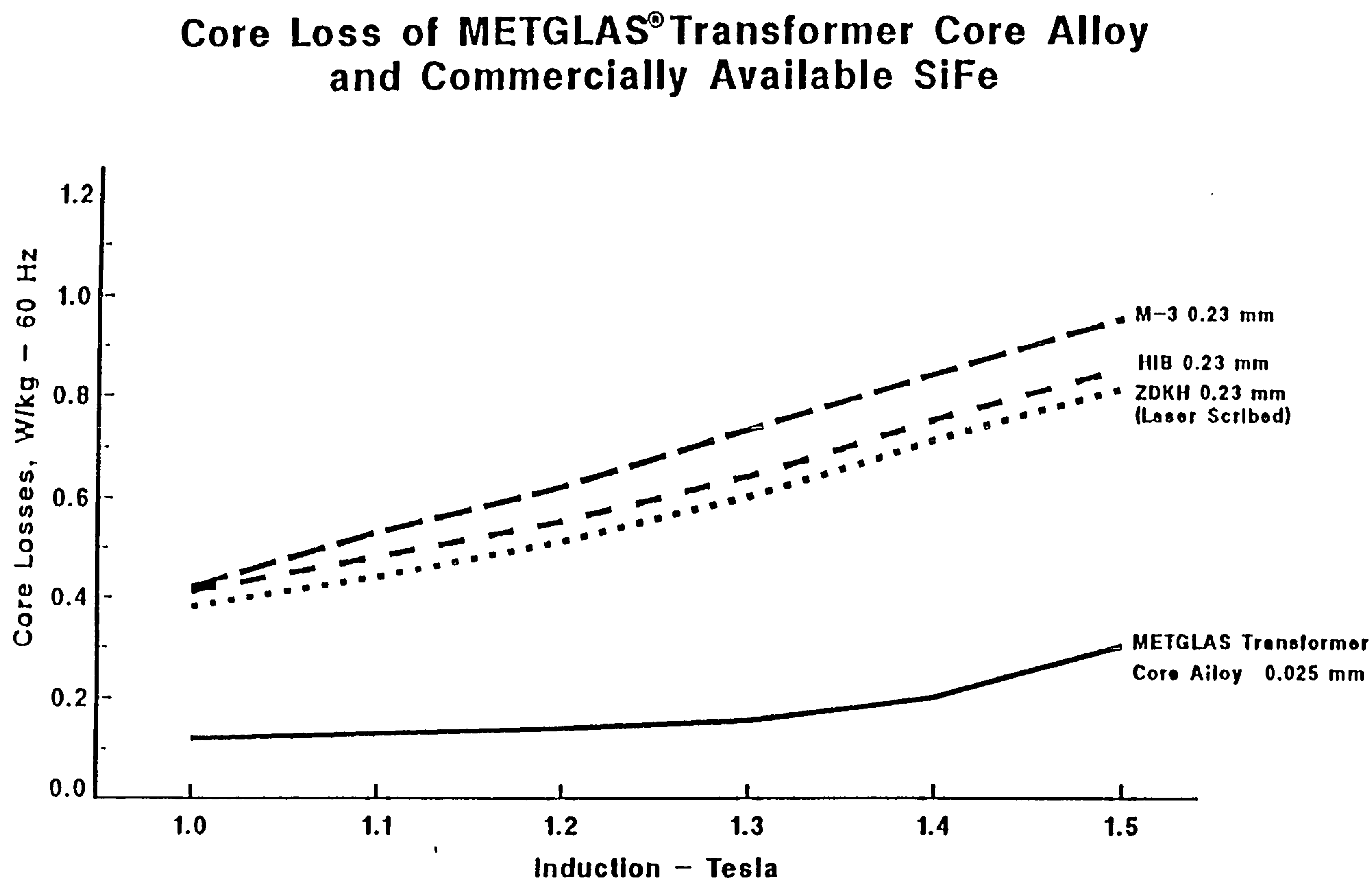
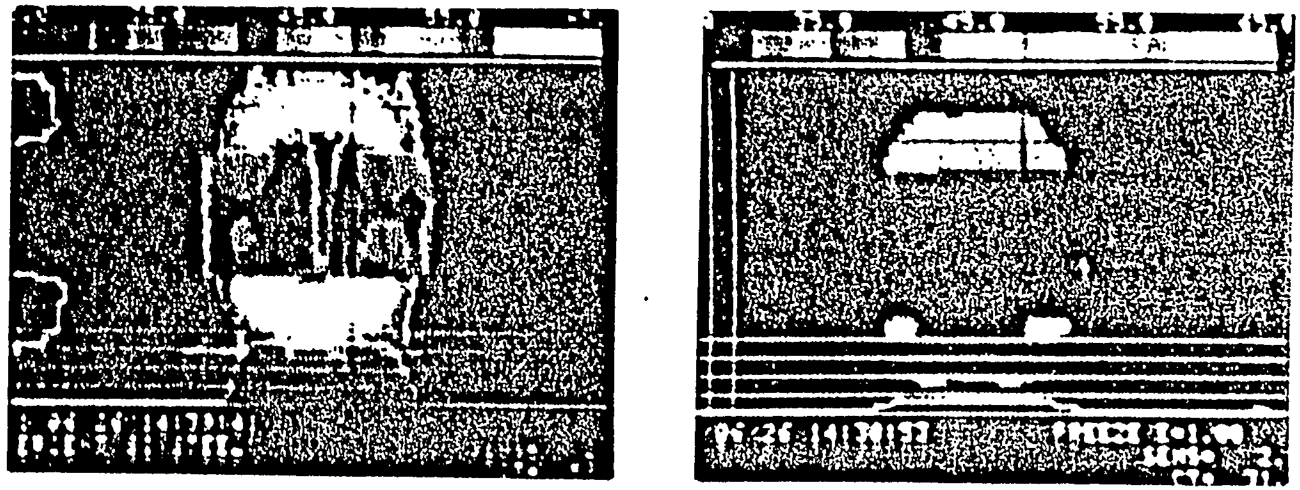

Tesla
1.6
1.2
0.8
0.4
0.4
0.8
1.2
1.6
Metglas® Transformer Alloy
1.4 1.2 1.0 0.8 0.4 0.6 0.2
0.2 0.4 0.6 0.8 1.0 1.2 1.4
Oersteds
Silicon Steel (11 Mil RGO)

Figure 2



Core Loss of METGLAS® Transformer Core Alloy and Commercially Available SiFe
M–3 0.23 mm
HIB 0.23 mm
ZDKH 0.23 mm (Laser Scribed)
METGLAS Transformer Core Alloy 0.025 mm
Core Losses, W/kg – 60 Hz
Induction – Tesla
0.0
0.2
0.4
0.6
0.8
1.0
1.2
1.0
1.1
1.2
1.3
1.4
1.5

Figure 3



Thermography of two identically loaded distribution transformers demonstrates the extraordinary potential for energy savings.

The traditional silicon steel core on the left wastes energy as heat. The ultra-efficient amorphous alloy core on the right loses much less energy.

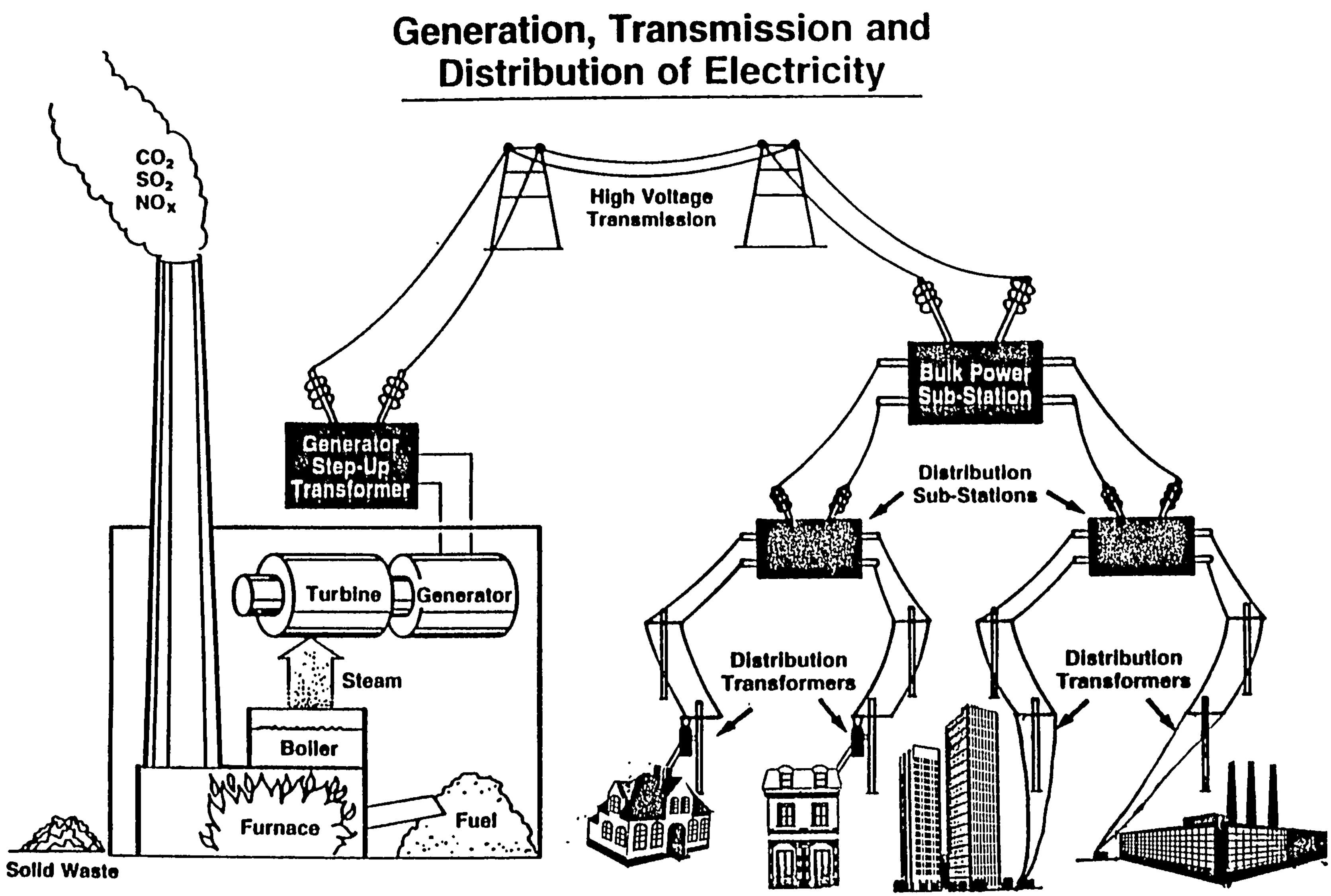
Figure 4

Transformer Performance Comparisons

Typical 25kVA Units

	Metglas Alloy	Silicon Iron
Core Loss (W)	15.4	57
Load Loss (W)	328	314
Exciting Current (%)	.14	.36
Impedance (%)	2.45	2.45
Audible Noise (db)	33	40
Temperature Rise (°C)	48	57
Short-Circuit Test (XN)	40	40
Inrush Current (XN) (Cal, 0.01/0.1 sec)	21/13	23/14
TIF @ 100/110% Exc. (IT/kVA)	2/10	5/25
Weight (lbs)	441	406

Figure 5



Consumers

Figure 6

Energy Efficiency Technologies Reduce T&D Loss

- Higher Voltage Distribution/Transformer Circuts
- Power Factor Correction
- Larger Size/Lower Resistance Conductors
- Efficiency-Driven Circut Configurations
- Low-Loss Distribution Transformers
- Early Retirement of High-Loss Equipment

Figure 7

Electric Generation, Projected Growth and T&D System Loss

	Electric Generation (Billion, kWh)	Estimated System Loss	Projected Annual Growth Rate
North America	3418	9.3%	2.1%
Europe	2573	9.5%	2.0%
Japan	758	8.8%	2.3%
China	647	11.0%	9.0%
East Asia & India	644	15.0%	10.0%

Figure 8

T & D Energy Loss

Growing Costs and Pollution

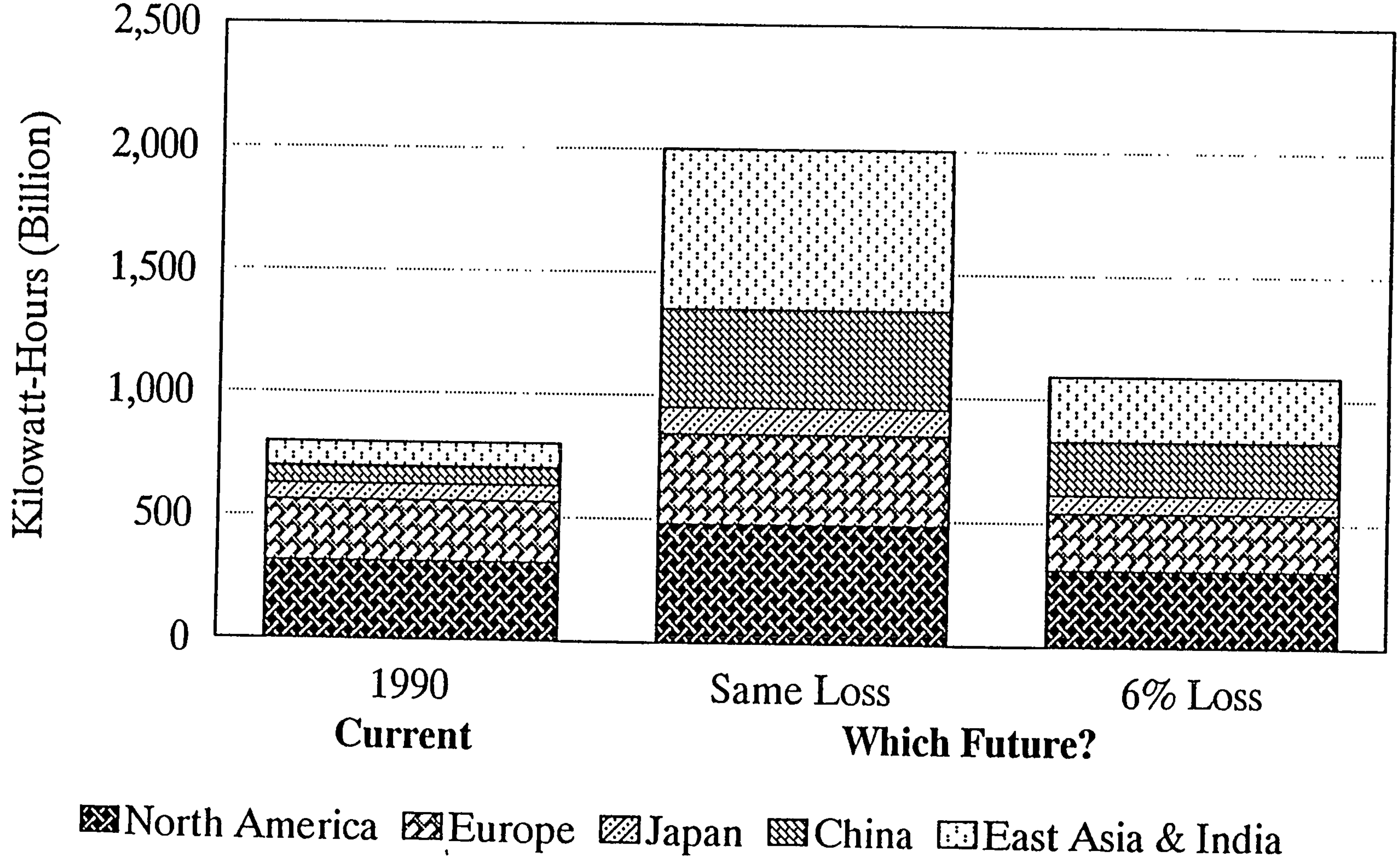


Figure 9

COST OF SAVED ENERGY

$$COSE = \frac{C}{E} x \frac{i\,x\,(1+i)^{n}}{(1+i)^{n}-1}$$

C = Conservation investment

E = Annual energy savings (kWH/Yr)

i = Real interest rate, used to discount future values

n = Expected duration of energy savings (Yr)

Figure 10

Barriers To Cost Effective, Energy Efficient Investments

- Lack of capital
- Lack of Awareness or inattention
- Regulatory barriers

Figure 11

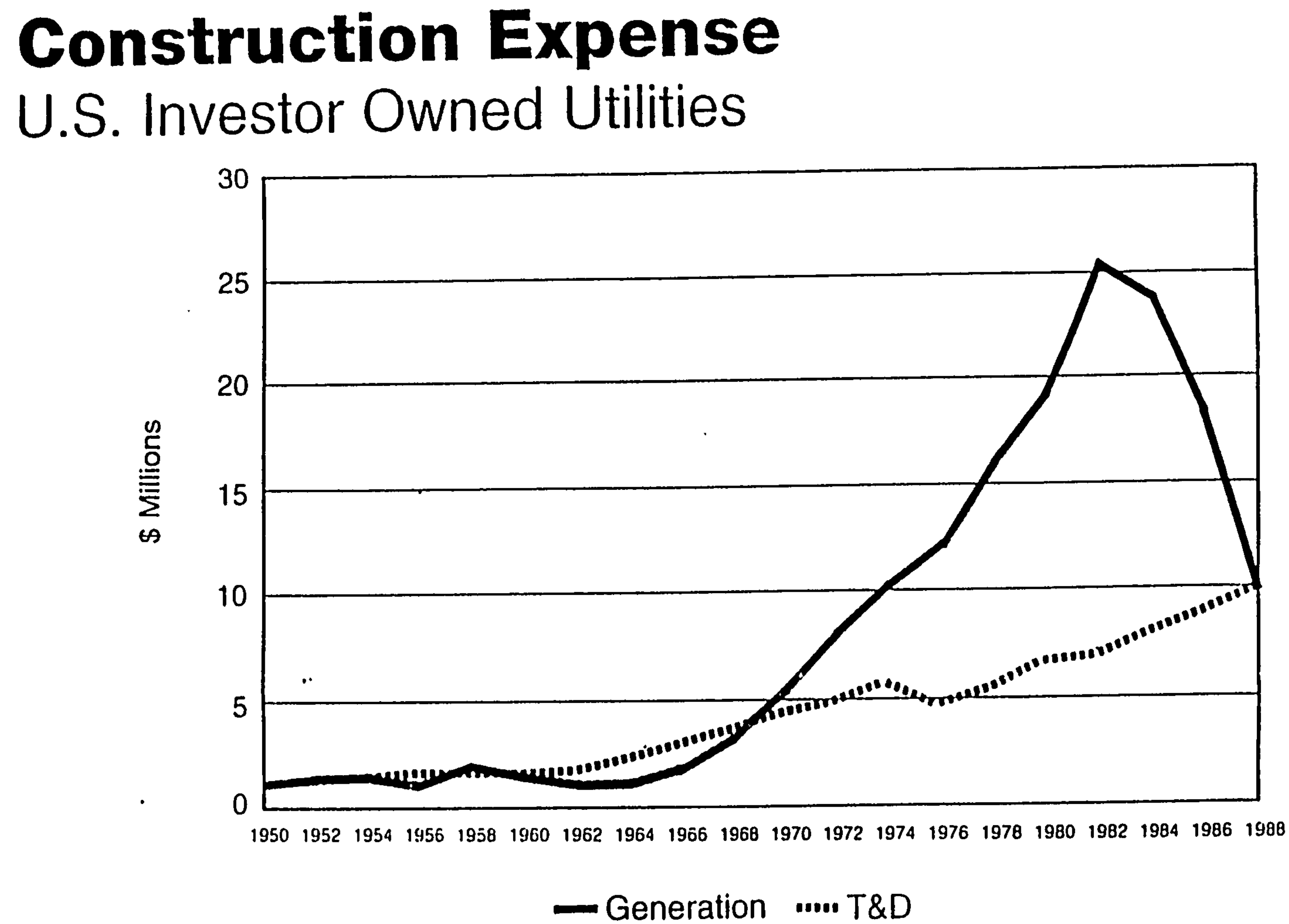

Construction Expense
U.S. Investor Owned Utilities
$ Millions
30
25
20
15
10
5
0
1950 1952 1954 1956 1958 1960 1962 1964 1966 1968 1970 1972 1974 1976 1978 1980 1982 1984 1986 1988
Generation
T&D

Figure 12

Meeting Energy Needs

Make
More
(CREATE)

Use
Less
(CONSERVE)

UTILITY | CUSTOMER

Supply vs. Demand

Figure 13

Meeting Energy Needs

	UTILITY	CUSTOMER
Make More (Create)	Generation	Cogeneration 1978 Public Utilities Regulatory Policy Act
Use Less (Conserve)	Transmission & Distribution 1992 Energy Policy Act	Demand-Side Management

Figure 14

US Policy Supports AMT Conservation

- 1992 Energy Policy Act
- EPA - Energy Star Transformer
- DOE - Transformer Efficiency Standards
- DOE - Accelerated Transformer Retirement Study

Figure 15

Workshop Participants

U.S.-KOREA ELECTRIC POWER GENERATION SEMINAR MISSION

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