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Florida Power
CORPORATION

James P. Fama
CORPORATE COUNSEL

October 29, 1990

Mr. Steve C. Tribble
Division of Records and Reporting
Florida Public Service Commission
101 East Gaines Street
Tallahassee, FL 32301

Re: Docket No. 900004-EG

Dear Mr. Tribble:

Enclosed for filing in the above-referenced docket is an original and fifteen (15) copies of Florida Power Corporation's Petition For Approval of Generation Plan.

Please acknowledge receipt and filing of the above by completing the form provided on the enclosed copy of this letter and returning same to this writer.

Very truly yours,

James P. Fama

James P. Fama

ACK ✓
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JPF/emh
Enclosures

DOCUMENT NUMBER-DATE
09763 OCT 30 1990
FPSC-RECORDS/REPORTING

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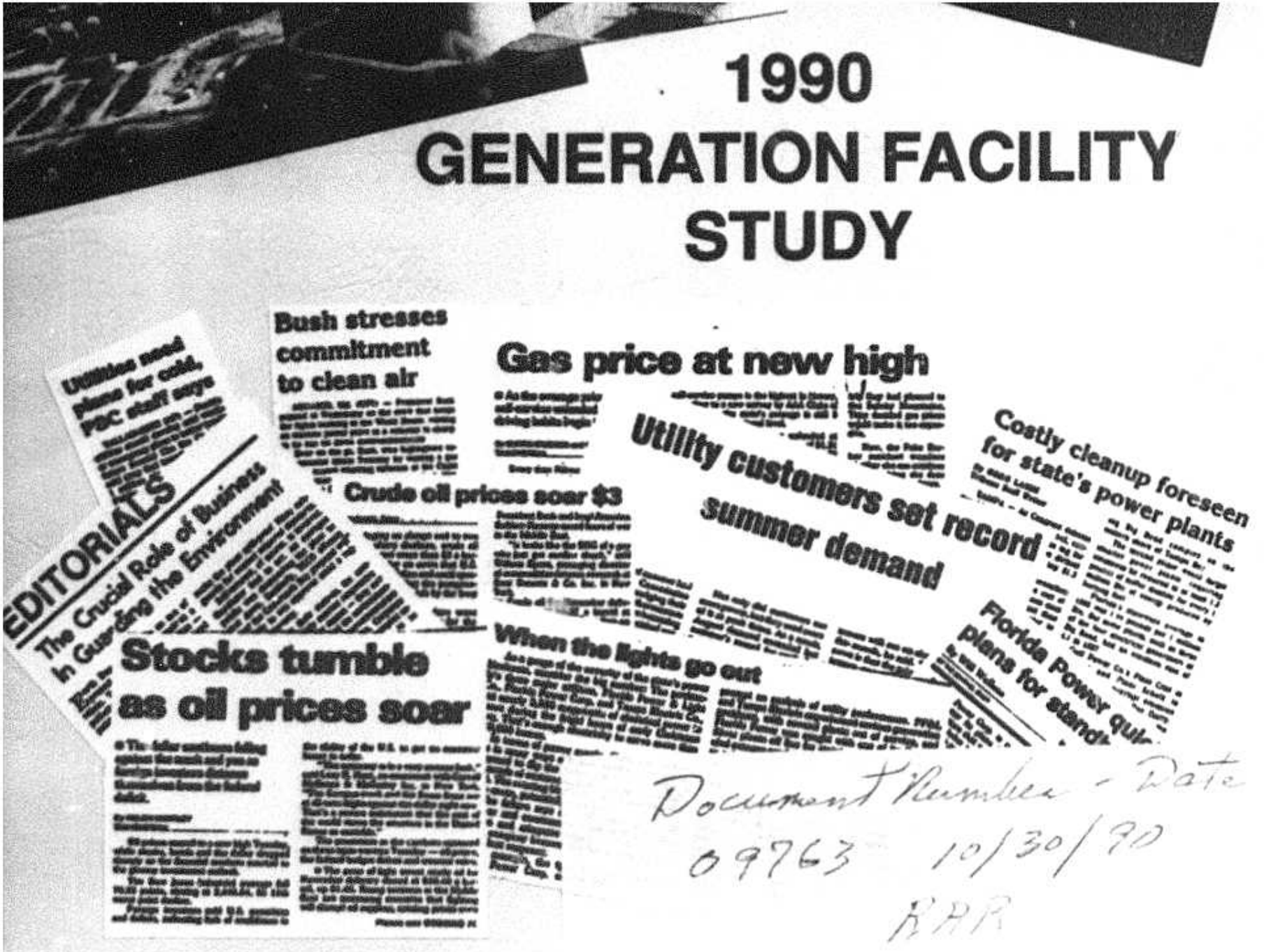
09762 OCT 30 1990
FPSC-RECORDS/REPORTING

1990
GENERATION FACILITY STUDY



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GENERATION PLANNING DEPARTMENT

ALTERNATIVE 9
COMBINED CYCLE - MUST RUN ON GAS

DESCRIPTION:

9 - 235 MW COMBINED CYCLES WITH A TOTAL INSTALLED CAPACITY OF 2115 MW.
GAS CONTRACT SECURED IN 1998.

SO2 EMISSION MODIFICATION:

ALL CC ON GAS AND ON MUST RUN STATUS BY 2001. CONVERT 1.1% TO 0.7%
SULFUR COAL AT CR 1 & 2.

SO2 EMISSION TONAGE:

2001:	134,918
2005:	122,578

AVAILABLE FUTURE EMISSION CONTROL MEASURES:

OPERATIONAL:

1. CONVERT BARTOW FROM 2.5% TO 1.0% SULFUR OIL (-8,000 TONS).
2. CONVERT TURNER & SUWANNEE FROM 2.5% TO 1.0% SULFUR OIL (-4,000 TONS).

CAPITAL INVESTMENT:

SCRUB CR 1, 2, 4 & 5.

GENERATION MIX BY FUEL TYPES IN 2005:

COAL	29.37%	OIL	10.84%	MILLER	4.76%
NUCLEAR	10.51%	DISTILLATE	1.21%	QF	14.40%
GAS	25.46%	PURCHASE	3.45%		

CAPACITY MIX BY FUEL TYPES IN 2005:

COAL	18.89%	OIL	16.27%	MILLER	3.36%
NUCLEAR	6.38%	DISTILLATE	20.48%	QF	10.12%
GAS	17.74%	PURCHASE	6.77%		

ACCUMULATED PW REVENUE REQUIREMENT (1990-2019): $21,004,749,000

RISK ANALYSIS:

THERE IS A 39% CHANCE THAT THIS ALTERNATIVE HAS A LOWER CUMULATIVE
PW REV REQ THAN ALTERNATIVE 5.

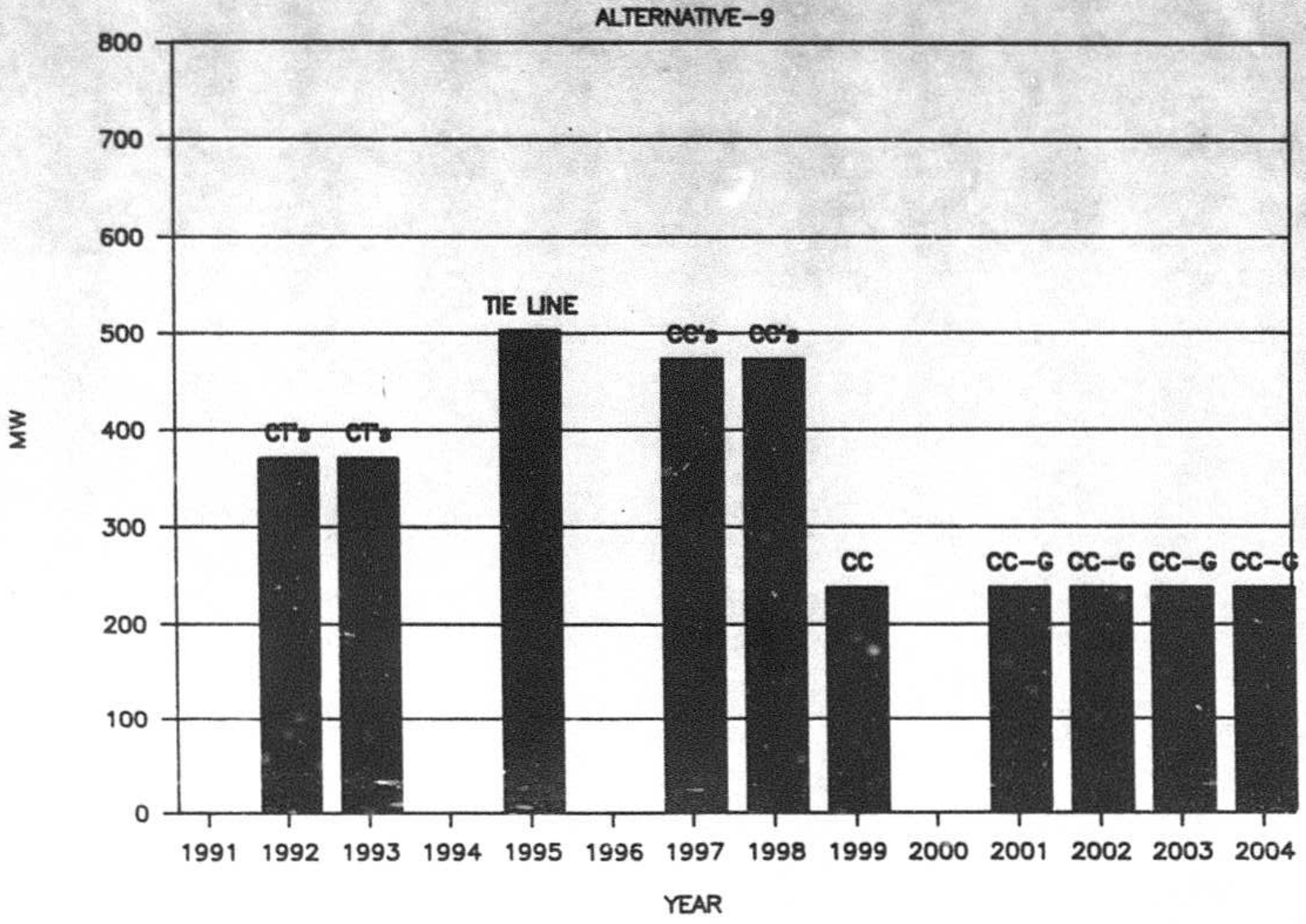
ADVANTAGES:

1. ATTRACTIVE ALTERNATIVE IN THE LOW FUEL SCENARIOS.
2. FUEL FLEXIBILITY PLUS OTHER OPTIONS FOR FUTURE EMISSION REDUCTIONS.
3. LESS CAPITAL COST.

DISADVANTAGES:

1. GAS DEPENDENCY.
2. FUEL PENALTY FOR MUST RUN STATUS.
3. CUM PW REV REQ IS $312 MILLION MORE THAN ALTERNATIVE 5.

1990 GENERATION FACILITY STUDY



ALTERNATIVE 10

COMBINED CYCLE AND COMBUSTION TURBINES (MUST SCRUB ALL COAL UNITS)

DESCRIPTION:

7 - 235 MW COMBINED CYCLE UNITS, 4 - 165 MW COMBUSTION TURBINES, TOTAL INSTALLED CAPACITY OF 2305 MW.

SO2 EMISSION MODIFICATION:

SCRUB CR 1, 2, 4 & 5 AT 90%, CONVERT CR 4 & 5 FROM 0.7% TO 1.1% SULFUR COAL.

SO2 EMISSION TONAGE:

2001:	101,043
2005:	110,744

AVAILABLE FUTURE EMISSION CONTROL MEASURES:

OPERATIONAL:

1. CONVERT BARTOW FROM 2.5% TO 1.0% SULFUR OIL (-17,000 TONS)
2. CONVERT TURNER & SUWANNEE FROM 2.5% TO 1.0% SULFUR OIL (-6,000 TONS)

CAPITAL INVESTMENT:

NONE.

GENERATION MIX BY FUEL TYPES IN 2005:

COAL	31.47%	OIL	19.92%	MILLER	6.06%
NUCLEAR	10.51%	DISTILLATE	13.46%	QF	14.40%
GAS	0.71%	PURCHASE	3.47%		

CAPACITY MIX BY FUEL TYPES IN 2005:

COAL	17.98%	OIL	16.13%	MILLER	3.30%
NUCLEAR	6.32%	DISTILLATE	39.49%	QF	10.03%
GAS	0.00%	PURCHASE	6.71%		

ACCUMULATED PW REVENUE REQUIREMENT (1990-2019): $21,448,495,000

RISK ANALYSIS:

THERE IS A 2.5% CHANCE THAT THIS ALTERNATIVE WILL HAVE A LOWER ACCUMULATED PW REVENUE REQUIREMENT THAN ALTERNATIVE 5.

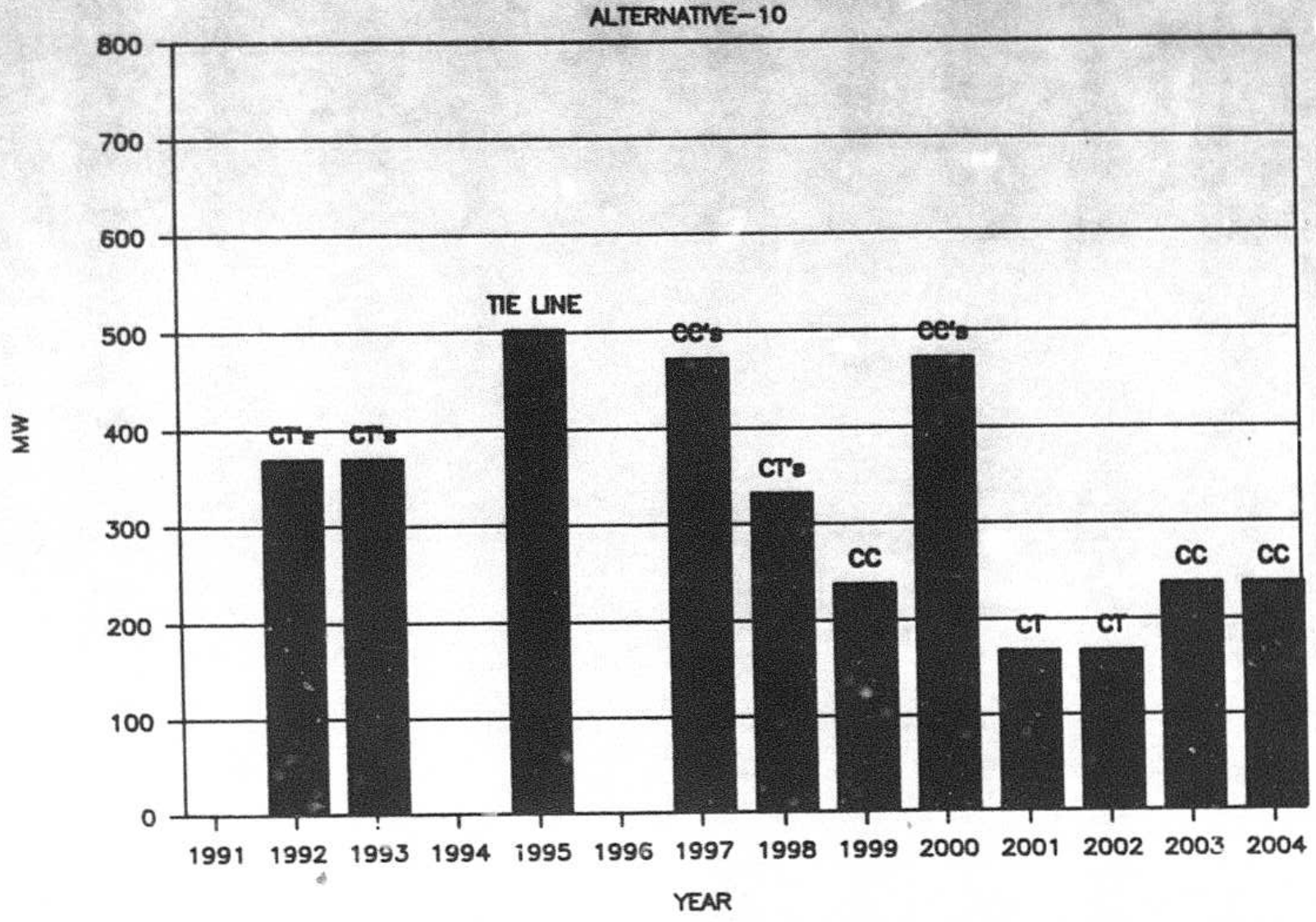
ADVANTAGES:

1. SO2 EMISSIONS ARE WELL BELOW EXPECTED LIMIT.
2. SMALL UNITS WITH SHORTER CONSTRUCTION LEAD TIME.

DISADVANTAGES:

1. DEPENDENT ON OIL AND DISTILLATE.
2. CUM PW REV REQ IS $756 MILLION MORE THAN ALTERNATIVE 5.
3. UNFAVORABLE IN HIGH FUEL AND HIGH DEMAND SCENARIOS.

1990 GENERATION FACILITY STUDY



ALTERNATIVE 10A
GASIFIED ORIMULSION

DESCRIPTION:

6 – 235 MW COMBINED CYCLE UNITS, 4 – 165 MW COMBUSTION TURBINES WITH A TOTAL INSTALLED CAPACITY OF 2070 MW. CONVERT BARTOW AND ANCLOTE TO ORIMULSION GAS IN 11/1995 AND 11/1997, RESPECTIVELY.

SO2 EMISSION MODIFICATION:

NONE.

SO2 EMISSION TONAGE:

2001:	124,174
2005:	131,605

AVAILABLE FUTURE EMISSION CONTROL MEASURES:

OPERATIONAL:

1. CONVERT CR 1,2 FROM 1.1% TO 0.7% SULFUR COAL(–20,000 TONS).
2. CONVERT TURNER & SUWANNEE FROM 2.5% TO 1.0% SULFUR OIL(–6,000 TONS).

CAPITAL INVESTMENT:

SCRUB CR 1, 2, 4 & 5.

GENERATION MIX BY FUEL TYPES IN 2005:

COAL	32.70%	OIL	2.73%	MILLER	5.42%
NUCLEAR	10.51%	DISTILLATE	11.29%	QF	14.40%
GAS	0.45%	PURCHASE	3.60%	ORIMULSION	18.30%

CAPACITY MIX BY FUEL TYPES IN 2005:

COAL	18.34%	OIL	4.06%	MILLER	3.90%
NUCLEAR	6.45%	DISTILLATE	38.28%	QF	10.23%
GAS	0.00%	PURCHASE	6.85%	ORIMULSION	12.40%

ACCUMULATED PW REVENUE REQUIREMENT (1990–2019): $20,595,470,000

RISK ANALYSIS:

THERE IS A 80% CHANCE THAT THIS ALTERNATIVE WILL HAVE A LOWER ACCUMULATED PW REVENUE REQUIREMENT THAN ALTERNATIVE 5.

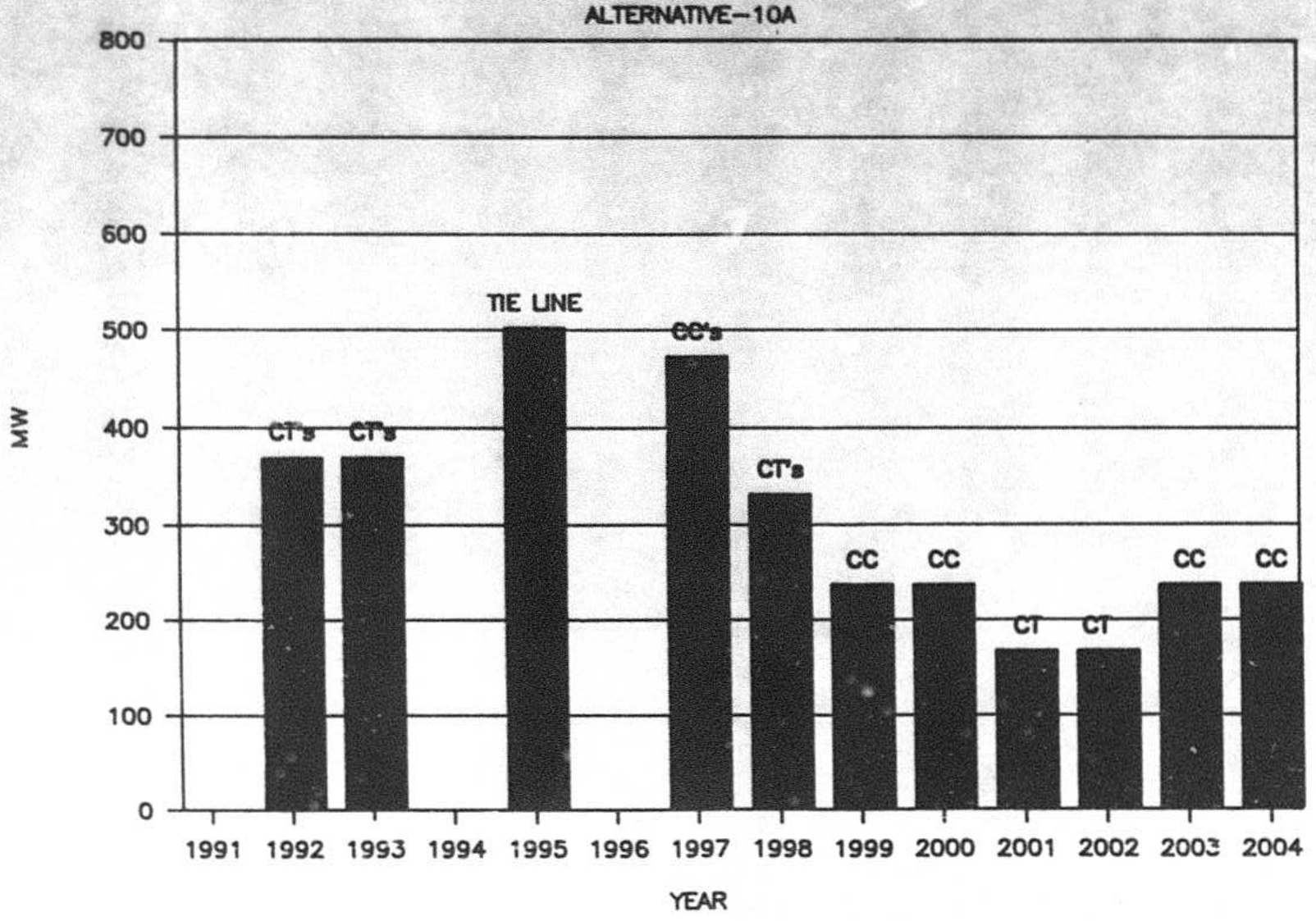
ADVANTAGES:

1. NO SCRUBBING OF EXISTING COAL UNITS.
2. SMALL UNITS WITH SHORTER CONSTRUCTION LEAD TIME.
3. LOW CAPITAL COST, COMBINED CYCLE EXPANSION PLAN.
4. CUM PW REV REQ IS $97 MILLION LESS THAN ALTERNATIVE 5.

DISADVANTAGES:

1. FUEL SUPPLY RISK (LIMITED FOREIGN SUPPLIER).
2. UNPROVEN TECHNOLOGY.
3. UNFAVORABLE IN HIGH FUEL AND HIGH DEMAND SCENARIOS.
4. ANCLOTE AND BARTOW MUST MAINTAIN A 70 % CAPACITY FACTOR.
5. 70 % OF REQUIRED SO2 REDUCTION DEPENDENT ON SUCCESS OF TECHNOLOGY.
6. ASSUMES ORIMULSION GAS PRICED AT HIGH SULFUR OIL PRICE.

1990 GENERATION FACILITY STUDY



ALTERNATIVE 11
ALL COAL UNITS

DESCRIPTION:

3 – 700 MW AND 1 – 200 MW COAL UNITS, WITH A TOTAL INSTALLED CAPACITY OF 2300 MW.

SO2 EMISSION MODIFICATION:

CONVERT 1.1% TO 0.7% SULFUR AT CR 1 & 2.

SO2 EMISSION TONAGE:

2001:	125,716
2005:	117,502

AVAILABLE FUTURE EMISSION CONTROL MEASURES:

OPERATIONAL:

1. CONVERT BARTOW FROM 2.5% TO 1.0% SULFUR OIL (–7,000 TONS).
2. CONVERT TURNER & SUWANEE FROM 2.5% TO 1.0% SULFUR OIL (–4,000 TONS).

CAPITAL INVESTMENT:

SCRUB 1, 2, 4 & 5.

GENERATION MIX BY FUEL TYPES IN 2005:

COAL	59.92%	OIL	7.47%	MILLER	2.91%
NUCLEAR	10.51%	DISTILLATE	1.00%	QF	14.40%
GAS	0.33%	PURCHASE	3.46%		

CAPACITY MIX BY FUEL TYPES IN 2005:

COAL	37.60%	OIL	16.02%	MILLER	3.30%
NUCLEAR	6.28%	DISTILLATE	20.17%	QF	9.96%
GAS	0.00%	PURCHASE	22.91%		

ACCUMULATED PW REVENUE REQUIREMENT (1990–2019): $20,973,487,000

RISK ANALYSIS:

THERE IS A 20% CHANCE THAT THIS ALTERNATIVE WILL HAVE A LOWER ACCUMULATED PW REVENUE REQUIREMENT THAN ALTERNATIVE 5.

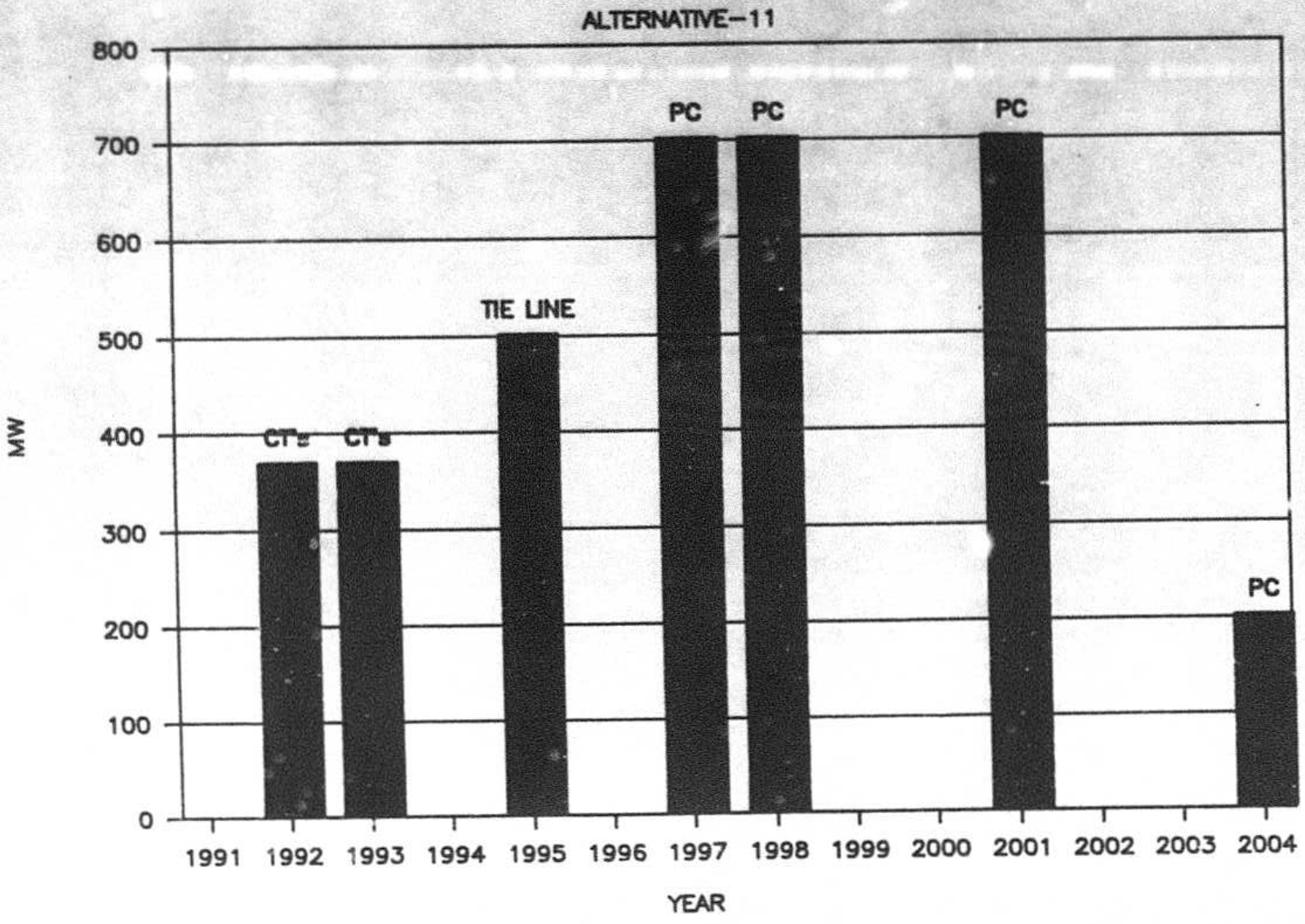
ADVANTAGES:

1. FUEL SUPPLY SECURITY.
2. FUEL FLEXIBILITY FOR FUTURE EMISSION REDUCTION.
3. SO2 EMISSIONS ARE WELL BELOW EXPECTED LIMIT.
4. ATTRACTIVE IN HIGH FUEL SCENARIOS.

DISADVANTAGES:

1. CAPITAL INTENSIVE.
2. LONG LEAD TIME FOR CONSTRUCTION MEANS EARLY COMMITMENT.
3. CUM PW REV REQ IS ABOUT $281 MILLION MORE THAN ALTERNATIVE 5.

1990 GENERATION FACILITY STUDY



ALTERNATIVE 12
IGCC AND COMBUSTION TURBINES

DESCRIPTION:

2-580 MW IGCC, 2-310 MW IGCC, 2-165 MW COMBUSTION TURBINES, WITH A TOTAL INSTALLED CAPACITY OF 2110 MW.

SO2 EMISSION MODIFICATION:

CONVERT CR 1 & 2 FROM 1.1% TO 0.7% SULFUR COAL.

SO2 EMISSION TONAGE:

2001:	125,716
2005:	117,502

AVAILABLE FUTURE EMISSION CONTROL MEASURES:

OPEATIONAL:

1.CONVERT BARTOW FROM 2.5% TO 1.0% SULFUR OIL (-7,000 TONS).

2.CONVERT TURNER & SUWANNEE FROM 2.5% TO 1.0% SULFUR OIL (-4,000 TONS).

CAPITAL INVESTMENT:

SCRUB CR 1, 2, 4 & 5.

GENERATION MIX BY FUEL TYPES IN 2005:

COAL	54.98%	OIL	10.45%	MILLER	3.67%
NUCLEAR	10.51%	DISTILLATE	2.00%	QF	14.40%
GAS	0.51%	PURCHASE	3.48%		

CAPACITY MIX BY FUEL TYPES IN 2005:

COAL	33.84%	OIL	16.27%	MILLER	3.36%
NUCLEAR	6.38%	DISTILLATE	23.26%	QF	10.12%
GAS	0.00%	PURCHASE	6.77%		

ACCUMULATED PW REVENUE REQUIREMENT (1990-2019): $21,447,515,000

RISK ANALYSIS:

THERE IS A 0.8% CHANCE THAT THIS ALTERNATIVE WILL HAVE A LOWER ACCUMULATED PW REVENUE REQUIREMENT THAN ALTERNATIVE 5.

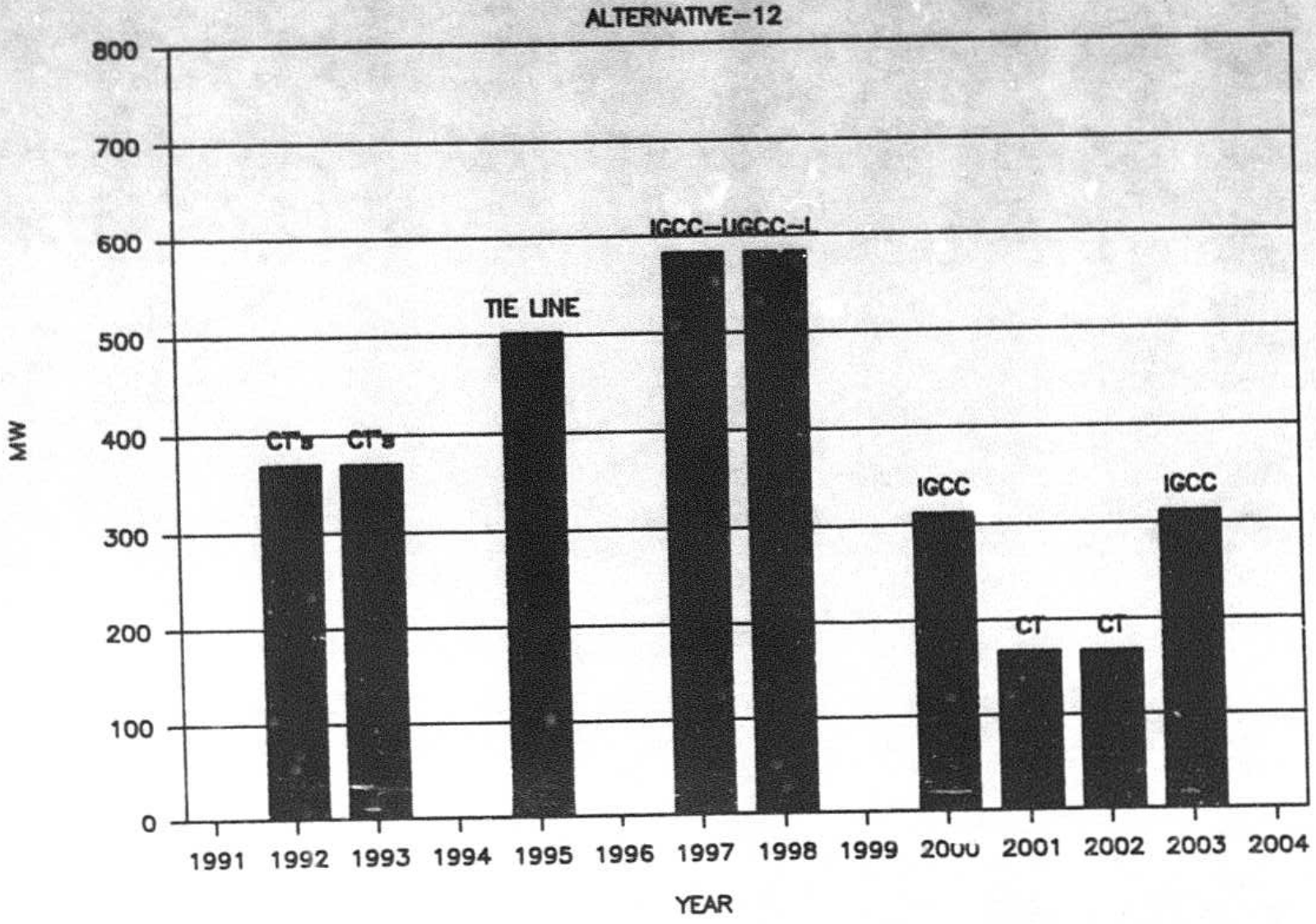
ADVANTAGES:

1. SCRUBBING OF EXISTING COAL UNITS NOT REQUIRED.
2. CLEANEST TECHNOLOGY (99% FOR SO2).
3. IGCC UNITS CAN BURN VERY HIGH SULFUR COAL (5%).
4. SO2 EMISSIONS ARE WELL BELOW EXPECTED LIMIT.

DISADVANTAGES:

1. UNPROVEN TECHNOLOGY (IGCC).
2. VERY HIGH CAPITAL COSTS.
3. CUM PW REV REQ IS $755 MILLION MORE THAN ALTERNATIVE 5.

1990 GENERATION FACILITY STUDY



APPENDIX B

FLORIDA POWER CORPORATION
Conservation Programs For the 90's

The following programs have been approved by the Florida Public Service Commission. It is expected that Florida Power will receive final permission to implement the programs about November 1, 1990.

HOME INSPECTION AUDIT

A certified Florida Power energy audit representative examines the home structure and energy using equipment. On a written checklist, the auditor indicates areas needing conservation actions. The customer receives information on the cost of any repairs or equipment recommended, how much the energy savings would be, and how long it would take to "pay back" the investment in energy cost saving. This information is based on averages for Florida homes. In addition, the auditor takes the opportunity to explain other Florida Power programs designed to promote energy efficiency. The audit covers the building structure, insulation, caulking and weatherstripping, heating and air conditioning systems, water heating, and other energy using appliances. There is no charge for the Home Inspection Audit.

HOME ENERGY CHECKUP

The Florida Power representative takes specific measurements of the home structure, insulation, and other items affecting energy use. A special computer analysis is done, and a written report is given to the home owner covering the cost and energy savings of recommended measures and practices for that residence. The analysis covers the building structure, insulation, caulking and weatherstripping, heating and air conditioning systems, water heating, and other energy using appliances. There is a $15 charge for the Checkup Audit.

HOME ENERGY FIXUP PROGRAM

Florida Power assists the customer in doing minor weatherization energy improvements to the home. If recommended on an audit and agreed to by the customer, Florida Power arranges for a contractor to do necessary weatherstripping, caulking, water heater insulation, and installing low-flow devices in showers. Florida Power pays half the cost of this work up to $75. Total costs for a Fixup seldom exceed $100 to $150.

RESIDENTIAL LOAD MANAGEMENT

Load Management is a voluntary program that allows Florida Power to turn off selected energy-using equipment (electric central heating and/or air conditioning, water heaters, and pool pumps) for short periods of time during peak electrical usage. If agreed to by the customer, radio controlled switches are installed on this equipment. The customer has a choice of time schedules to be cycled and receives a credit on the monthly electric bill depending on the schedule selected.

RESIDENTIAL LOAN TEST PROGRAM

Low interest loans are available to make major energy efficiency improvements to homes. The Florida Public Service Commission currently funds this program and sets standards for eligibility. A Florida Power energy audit is required.

RESIDENTIAL DUCT WORK PRESSURE TEST & REPAIR

If recommended on an audit, a pressure/evacuation test is done on the home's central duct work system. This identifies any air leaks that could cause energy loss by infiltration or exfiltration. The customer then has the option to have those leaks repaired. Florida Power pays half the cost of the test and the repair up to $125. Plugging these energy leaks will save significantly in home heating and cooling costs.

RESIDENTIAL INSULATION PROGRAM

Florida Power will assist the customer in upgrading ceiling/attic insulation to reduce energy losses for heating and air conditioning the home. If an energy audit shows that insulation in the home is presently less than R-II (an index of insulation value), Florida Power will pay up to $75 to have the insulation level improved to R-19. The customer obtains competitive bids from contractors approved by Florida Power.

HIGH EFFICIENCY RESIDENTIAL AIR CONDITIONING PROMOTION

Florida Power will conduct an incentive program for air conditioning equipment dealers to sell high efficiency central air conditioning, heat pumps, and heat recovery or heat-pump water heating equipment. Encouraging the sale of this equipment will assist the homeowner in reducing energy use and cost. The incentive program will award

points to the dealers which can be redeemed for merchandise gifts. Minimum efficiency ratings to qualify for the program will be specified by Florida Power Corp.

RESIDENTIAL AIR CONDITIONING TUNEUP

If the need for an air conditioning tuneup is indicated during an energy audit, Florida Power will give the customer a certificate worth $5 toward a tuneup of a central air conditioner or heat pump. Contractors will be approved by Florida Power to do this work. Maintaining equipment in good working condition will help to reduce energy use and costs.

TRADE ALLY PROGRAM

Florida Power representatives will be in close touch with all elements in the residential and commercial building field. Seminars will be sponsored on the Florida Energy Efficiency Building Code, how to build an energy efficient home, and energy-saving equipment. The duct work in model homes will be pressure tested for air leakage and repaired at no charge to the builder. Builders will be required to incorporate any changes indicated by the pressure test in the balance of homes built in that development.

LOAD MANAGEMENT THERMAL STORAGE

This is a pilot program in certain areas of Florida Power's service area. A heating storage system (large storage tank and control equipment) will be installed in selected test homes. The water in the tank will be heated during off-peak times. The "stored energy" will be used for home heating during times of peak electrical usage. Equipment in the home will be controlled through Florida Power's regular Load Management system.

BUSINESS ENERGY INSPECTION

The Business Energy Inspection is an audit of C/I facilities lighting, building envelope, water heating system, heating, ventilating, air conditioning and other energy-using systems. A written checklist is given to the customer indicating areas that need conservation action. In addition to suggestions that the customer may implement himself, the auditor explains other Florida Power programs that would assist the customer to incorporate energy-efficient actions or equipment. There is no charge for the Energy Inspection.

BUSINESS ENERGY ANALYSIS

The Analysis is an in-depth audit of the commercial/industrial customer's facility. The computer-assisted audit identifies the sources of energy consumption and makes written recommendations on how to improve energy efficiency. A certified Florida Power audit representative or engineer spends as much time in the customer's facility as needed to complete a thorough energy study. Information gathered is analyzed using an energy audit computer program. Specific recommendations are made for conservation actions with information on cost, energy savings, and payback time for each alternate recommendation. The Auditor will also explain Florida Power programs for financial assistance in making energy improvements. A charge is made for the Analysis audit in relation to the average monthly energy use of the facility. If recommendations are implemented, the implementation cost will be refunded to the customer up to the audit cost less $35.

COMMERCIAL/INDUSTRIAL DUCT WORK PRESSURE TEST & REPAIR

If recommended on an audit, a pressure/evacuation test is done on the central duct work system. This identifies any air leaks that could cause energy loss by infiltration or exfiltration. The customer then has the option to have those leaks repaired. Florida Power will pay up to $125 of the cost of the test and repair procedure. Plugging these energy leaks will save significantly in heating and cooling costs.

COMMERCIAL/INDUSTRIAL INDOOR LIGHTING PROGRAM

Florida Power will assist in the cost of retrofitting indoor lighting to high-efficiency types if found necessary on an audit. Incentives will be offered for replacing with high-efficiency fluorescent and incandescent lamp types, electronic ballasts, and silver film reflectors. In many commercial establishments, lighting is the primary energy user, and savings through efficiency improvements can be substantial.

COMMERCIAL/INDUSTRIAL HVAC TUNEUP

If the need for an air conditioning equipment tuneup is identified during an energy audit, Florida Power will give the customer a certificate worth $5 toward this service. Central Air Conditioners and Heat Pumps of 60,000 Btu or less are eligible. Contractors will be approved by Florida Power to do this work. Maintenance of equipment in good working order will help reduce energy use and cost.

COMMERCIAL/INDUSTRIAL ENERGY FIXUP

The C/I Fixup program provides minor weatherization measures as identified in an audit at a pre-determined price with assistance from Florida Power. Authorized measures include caulking, weatherstripping, door sweeps and thresholds, window film, water heater insulation, faucet aerators, lamp replacement (24 or less), and HVAC filter replacement. Florida Power will pay half of the cost of these services (up to $100) if handled by an approved contractor.

COMMERCIAL/INDUSTRIAL HVAC PROMOTION

Florida Power will conduct an incentive program for air conditioning dealers to sell high-efficiency central air conditioning, heat pumps, and heat recovery or heat pump water heating equipment. Encouraging this equipment will assist the customer to reduce energy use and cost. Eligible equipment is limited to 60,000 Btu or less. The incentive program will award points to the dealers which can be redeemed for merchandise gifts. Efficiency ratings to qualify for this program will be specified by Florida Power.

COMMERCIAL/INDUSTRIAL MOTOR EFFICIENCY PROGRAM

This program will offer an incentive to customers to replace inefficient motors with high efficiency types. In order to be eligible, the customer must have a Florida Power energy audit. FPC will specify efficiency ratings of the old and new equipment that will qualify for the rebate.

HEAT PIPE DEVELOPMENT

Florida Power is conducting a pilot program to analyze the energy savings resulting from installation of heat-pipe equipment on air conditioners to control humidity and reduce energy use. Eligible customers and rebate amounts will be determined during the project design phase and will be dependent on the customer's system configurations.

1990 GENERATION FACILITY STUDY

AUGUST, 1990

Executive Summary

Introduction:

Florida Power Corporation has completed the 1990 Generation Facility Study. With approximately 740 MW (winter rating) of combustion turbine capacity in the immediate horizon and the first phase of a 500 kV tie line by December 1995, this study only forecasted the capacity options for the analysis time frame of 1997 to 2005. Based upon expectation of future load growth, fuel prices, technologies, capital costs and Clean Air regulation, the conclusions of this study provide capacity addition options that best suit Florida Power Corporation's needs.

Key Assumptions:

The key assumptions for this study were:

1. Demand and energy growth rate
2. Cogeneration
3. Energy Management
4. Relative price of coal, oil, and natural gas
5. General inflation rate
6. Capital cost of alternatives
7. Regulatory limits on sulfur dioxide (SO_2) emissions
8. Available technologies

The forecasts of demand and energy, fuel and capital cost were expanded to produce low and high values with associated likelihoods of occurring.

The following facilities were assumed to be in service by 1997:

1. All ECS units, except Avon Park 2, will return to service by November 1992.
2. 370 MW (winter rating) of combustion turbines in November 1992.
3. 370 MW (winter rating) of combustion turbines in November 1993.
4. The first phase of a 500 kV tie line constructed to Southern Company by December 1995.

The candidate capacity alternatives for analysis were:

- Standard pulverized coal with scrubbers
- Integrated coal gasification combined cycle
- Combined cycle
- Combustion turbine

Methodology:

A series of scenario alternatives were created to meet system capacity requirements using a wide range of technology combinations. The analysis of each alternative focused on the relative economics and risk associated with each alternative under uncertainty. Consideration of practical constraints such as licensing, site preparation, fuel security, construction schedules, company expertise and expected Clean Air regulation were also considered. A flow chart of the complete generation planning process for the Facility Study is illustrated in Figure 1 on the following page.

GENERATION PLANNING PROCESS

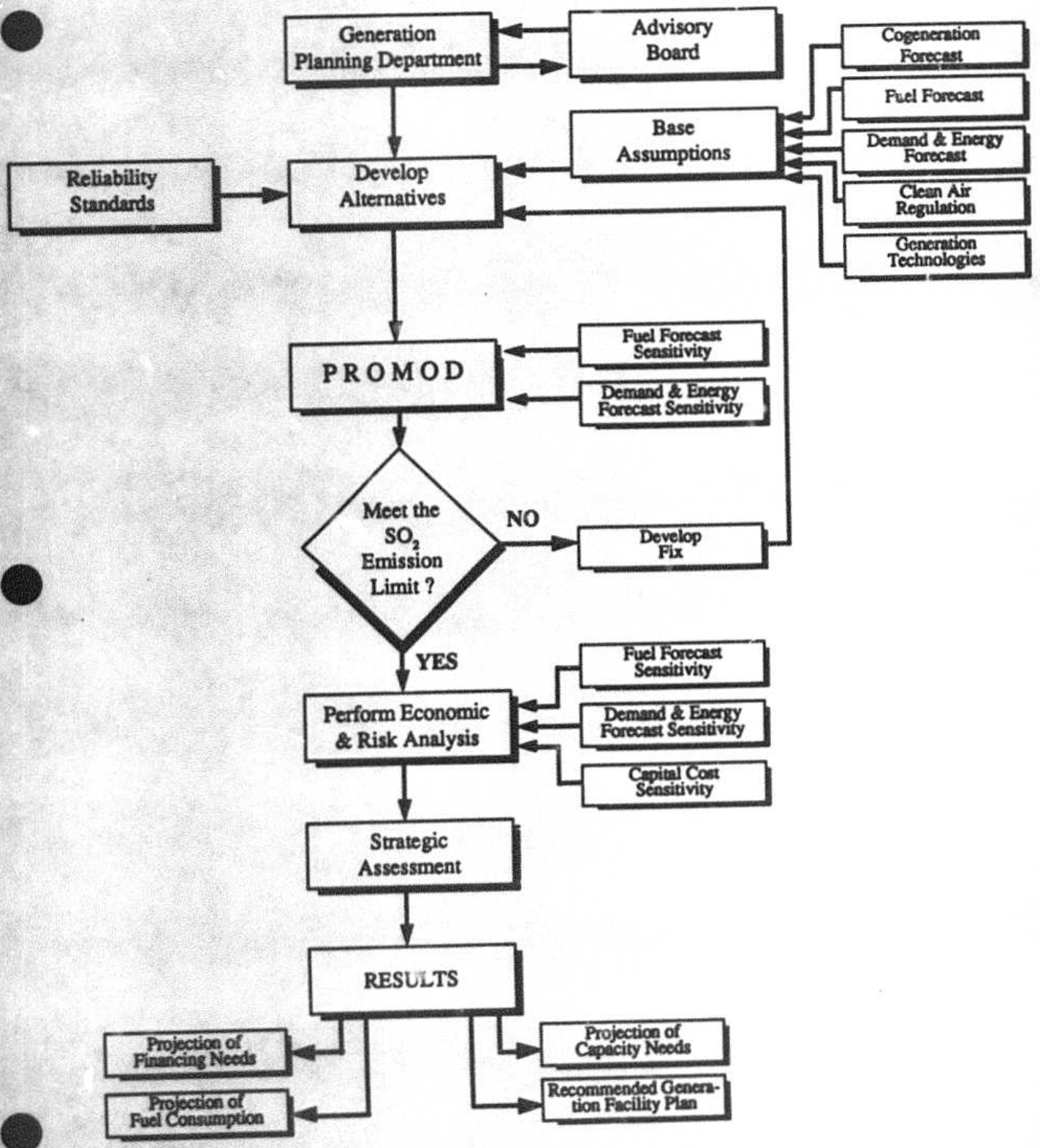


Figure 1

Results:

The following capacity additions are recommended as a result of the study:

- Install two advanced combustion turbines at 165 MW (winter rating) each in November 1997.

- Install a conventional 700 MW (winter rating) pulverized coal plant with at least 90-percent efficient scrubbers in November 1998.

- Install a conventional 700 MW (winter rating) pulverized coal plant with at least 90-percent efficient scrubbers in November 2000.

- Install one advanced, 165 MW (winter rating) combustion turbine in November 2002.

- Install one advanced, 165 MW (winter rating) combustion turbine in November 2004.

- Actively pursue the commercialization of IGCC technology and Orimulsion gasification for use in FPC's system.

These recommendations will best meet Florida Power Corporation's capacity requirements through the year 2005. The primary features of this plan are:

1. Fuel stability - Over 50-percent of the system energy will be produced by coal.

2. Florida Power Corporation Expertise - FPC has built and operated pulverized coal plants effectively. The company is experienced in purchasing and handling coal.

3. The pulverized coal plants with scrubbers will provide clean, low cost, base load capacity to displace older, higher emission units. This will allow compliance with the expected clean air standards without adding scrubbers to existing units.

4. The combustion turbine installation schedule can be modified to meet changes in system requirements. The short lead times for combustion turbines will allow capacity additions to match changes in the demand forecast.

5. Gasification technologies can be integrated into the Facility Plan. If this technology is successful, the system fuel cost will be lowered and system SO_2 emissions will be reduced. Should the gasification technology fail, the recommended plan can also minimize the penalties.

I. Assumptions and Forecast

The assumptions used in the study included the forecasts of demand and energy, cogeneration, fuel prices, sulfur emission limits of the Clean Air Regulation, financial and capital cost. For the assessment of future uncertainty, the assumptions for demand and energy, fuel prices, general inflation rate and capital cost forecasts were further expanded to include high and low values with associated probabilities of occurrence.

A. Demand and Energy

The medium demand and energy forecast used in the study was Florida Power Corporation's September 1989 Forecast.

The forecasts of cost-effective conservation and load management programs as well as the interruptible load are included in the demand and energy forecast. The new generation facilities are considered and added as part of future total resources required by Florida Power Corporation.

Conservation Programs:

Florida Power Corporation will implement a comprehensive series of new conservation programs through the study period in addition to others already in effect. In addition, existing programs will be extended to additional customers. These programs will include:

- Home Inspection Audit
- Home Energy Checkup

- o Home Energy Fixup Program
- o Business Energy Inspection
- o Business Energy Analysis

The net impact of these programs is projected to reduce the need for 650 MW of new generation through 2005. Additional conservation programs will be added as they are shown to be cost-effective. Appendix B provides a brief description of the conservation programs that were considered.

Load Management:

Florida Power Corporation operates the largest domestic load management system in the United States with more than 270,000 customers participating. The system is fully dispatchable from the Energy Control Center and is controlled using a VHF radio system. By planning to reach 50-percent penetration, this program is forecast to reduce the winter demand by 1272 MW in the year 2005.

Interruptible Load:

Florida Power Corporation offers interruptible service to commercial and industrial customers. This rate program is forecast to reduce the need for 402 MW of new generation through 2005.

The following table and Figure 2 show the forecast estimates of need for all additional resources by the year 2005.

Additional* Resource	MW	Percentage
Load Management	678	12.6
Conservation Programs	342	6.4
Cogeneration	1,003	18.7
Interruptible Load	144	2.7
Purchase	400	7.5
New Generation	2,796	52.1
		100%

* Base Year 1991

For the high and low forecasts, a set of energy forecasts created with the Monte Carlo technique for the years 1990 through 2010 was provided by the Load Forecasting Department. The uncertainties included in the technique used were population, price of electricity sold by FPC and the Gross National Product of the United States. The variable of

temperature was not considered. The energy at lower and higher 25-percent quartiles of each year were identified. Assuming the same load factors as the ones used in the September 1989 Forecast, the respective demands of each year were calculated.

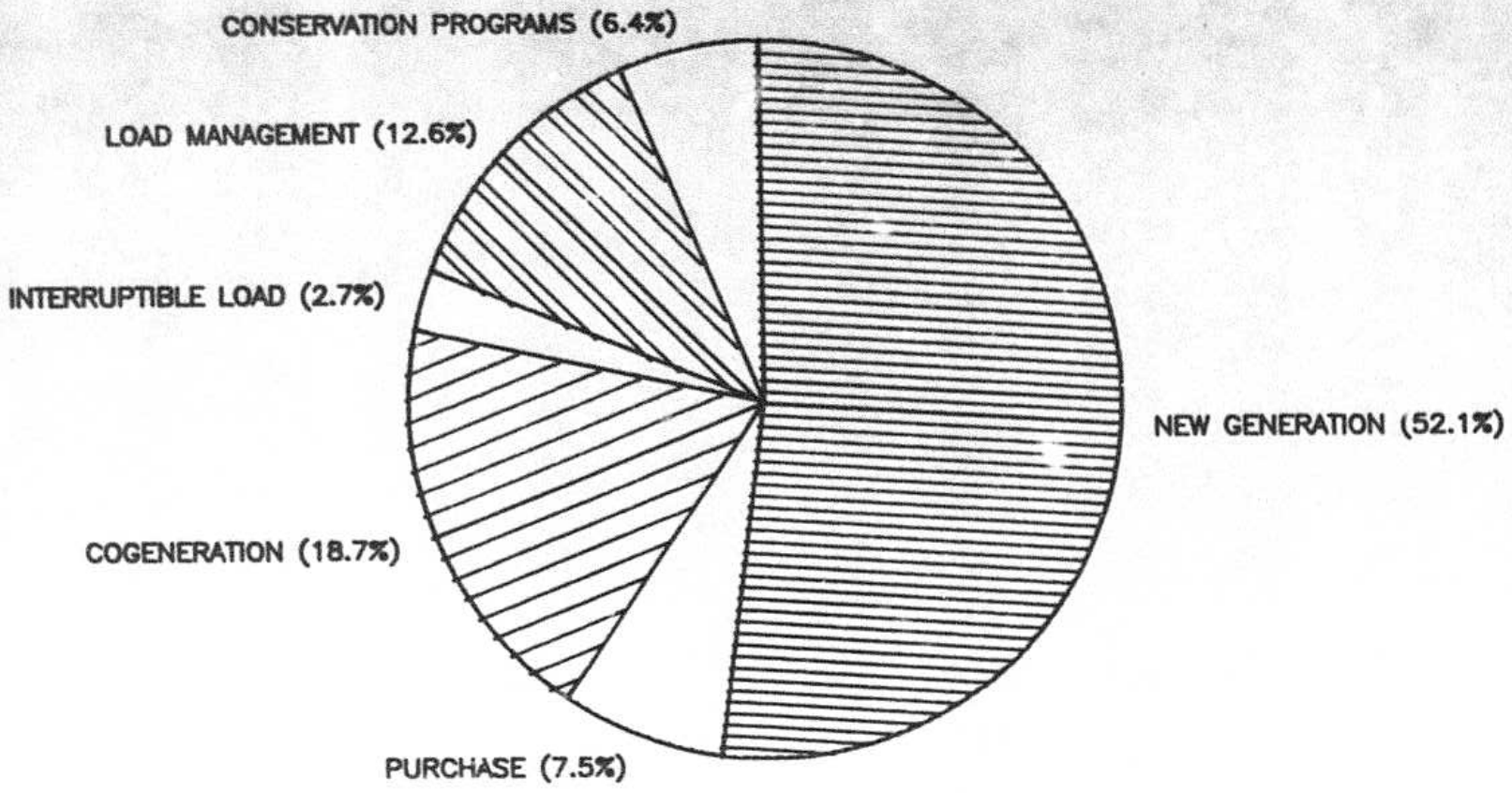
Figure 3 is the table for the winter peak demand forecast of high, medium and low. Figure 4 is the table for the energy forecast of high, medium and low. Figure 5 and Figure 6 show the winter peak demand comparison and energy from the high, medium and low forecasts, respectively.

B. Cogeneration

Florida Power Corporation's future generation requirement is heavily impacted by the amount of cogeneration it has projected. The Cogeneration Forecast used in the Facility Study was issued in March, 1990 by the Cogeneration Department. It includes the existing cogenerators, and also the cogenerators with signed contracts as well as projected future cogeneration. The net capacity shown in the forecast (RPT1) also reflected the probability of the cogenerator's availability. Based on the March forecast, the total capacity for the existing and the contracted cogenerators is about 325 MW in 1995. The projected total cogeneration capacity by the year 2009 is 1422 MW as shown in Figure 7.

TOTAL ADDITIONAL RESOURCES

REQUIRED BY 2005



Note: Base year 1991

Figure 2

Demand Uncertainty For Low, Medium and High

Based on Load Forecast Department

Year	Low Demands Prob=25%	Sept 1989 Accel. L.M. Forecast Demands Prob=50%	High Demands Prob=25%
1990	6,349	6,466	6,573
1991	6,495	6,643	6,783
1992	6,728	6,837	7,109
1993	6,953	7,094	7,425
1994	7,143	7,319	7,727
1995	7,382	7,567	8,088
1996	7,581	7,764	8,406
1997	7,759	7,958	8,711
1998	7,932	8,184	9,020
1999	8,106	8,404	9,331
2000	8,269	8,616	9,627
2001	8,439	8,834	9,938
2002	8,599	9,046	10,234
2003	8,753	9,259	10,551
2004	8,906	9,472	10,843
2005	9,056	9,666	11,143
2006	9,193	9,875	11,456
2007	9,343	10,081	11,755
2008	9,498	10,288	12,080
2009	9,644	10,489	12,399
2010	9,767	10,694	12,682
Esc.	2.18%	2.55%	3.34%

Figure 3

Energy Uncertainty For Low, Medium and High

Based on Load Forecast Department

Year	Low Requirements Prob=25%	Sept 1989 Accel. L.M. Forecast Requirements Prob=50%	High Requirements Prob=25%	Load Factor
1990	27,935,028	28,478,201	28,924,204	50.23%
1991	28,762,450	29,522,752	30,037,733	50.55%
1992	29,871,114	30,539,970	31,559,502	50.68%
1993	30,984,350	31,886,258	33,088,332	50.87%
1994	32,059,503	33,215,043	34,684,264	51.24%
1995	33,278,088	34,689,061	36,462,251	51.46%
1996	34,282,456	35,914,807	38,011,947	51.62%
1997	35,208,539	37,105,097	39,529,517	51.80%
1998	36,086,165	38,258,364	41,039,898	51.94%
1999	36,974,378	39,382,053	42,560,213	52.07%
2000	37,802,761	40,462,957	44,009,361	52.19%
2001	38,641,963	41,544,724	45,506,986	52.27%
2002	39,441,256	42,606,323	46,941,804	52.36%
2003	40,198,710	43,654,791	48,461,013	52.43%
2004	40,932,824	44,681,190	49,833,569	52.46%
2005	41,733,699	45,722,769	51,350,552	52.61%
2006	42,424,772	46,765,206	52,866,824	52.68%
2007	43,169,317	47,793,484	54,314,486	52.74%
2008	43,920,483	48,802,605	55,856,757	52.79%
2009	44,641,369	49,804,191	57,397,557	52.84%
2010	45,254,275	50,826,333	58,756,900	52.89%
Esc.	2.44%	2.94%	3.61%	

Figure 4

1990 GENERATION FACILITY STUDY

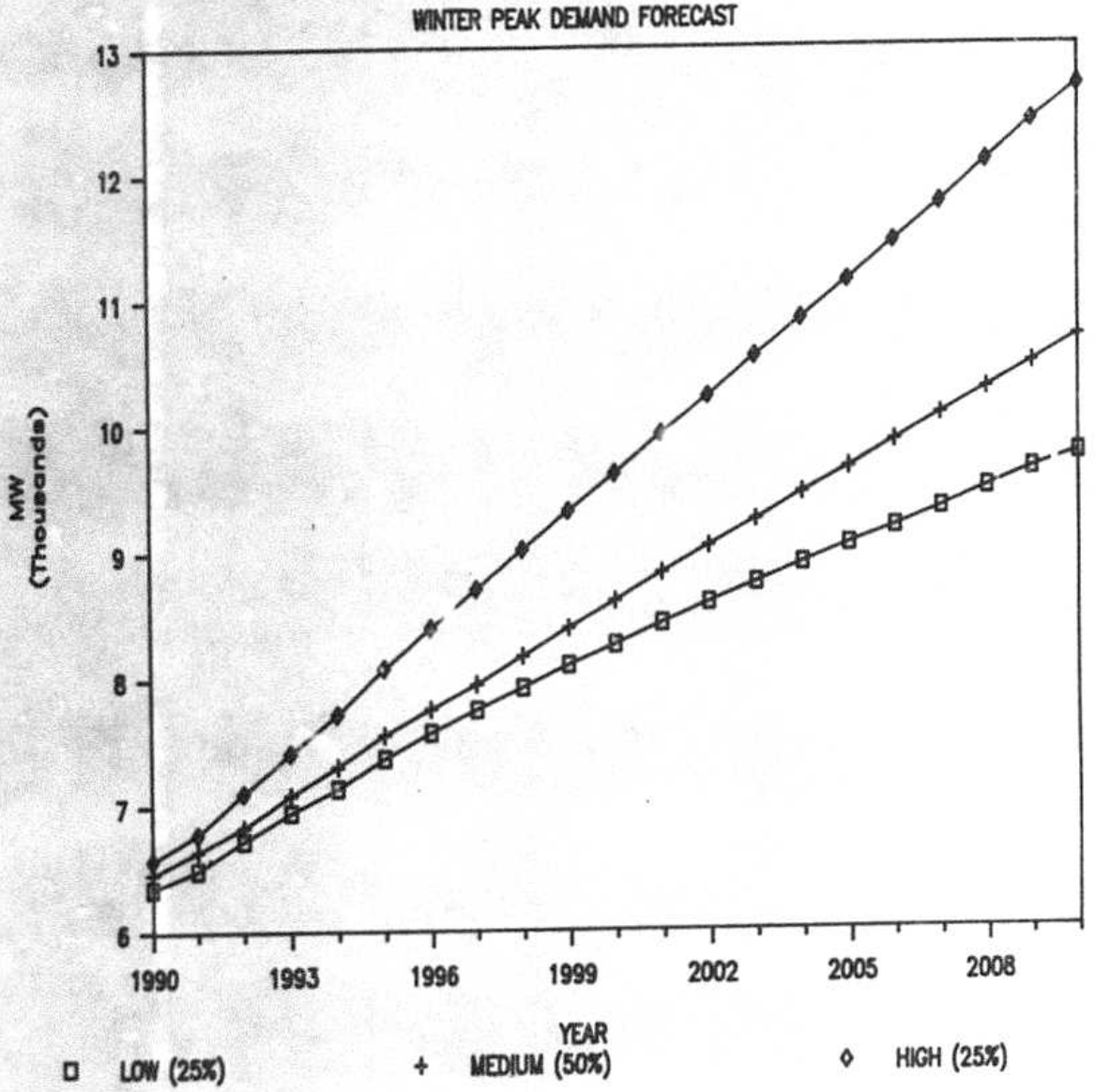


Figure 5

1990 GENERATION FACILITY STUDY

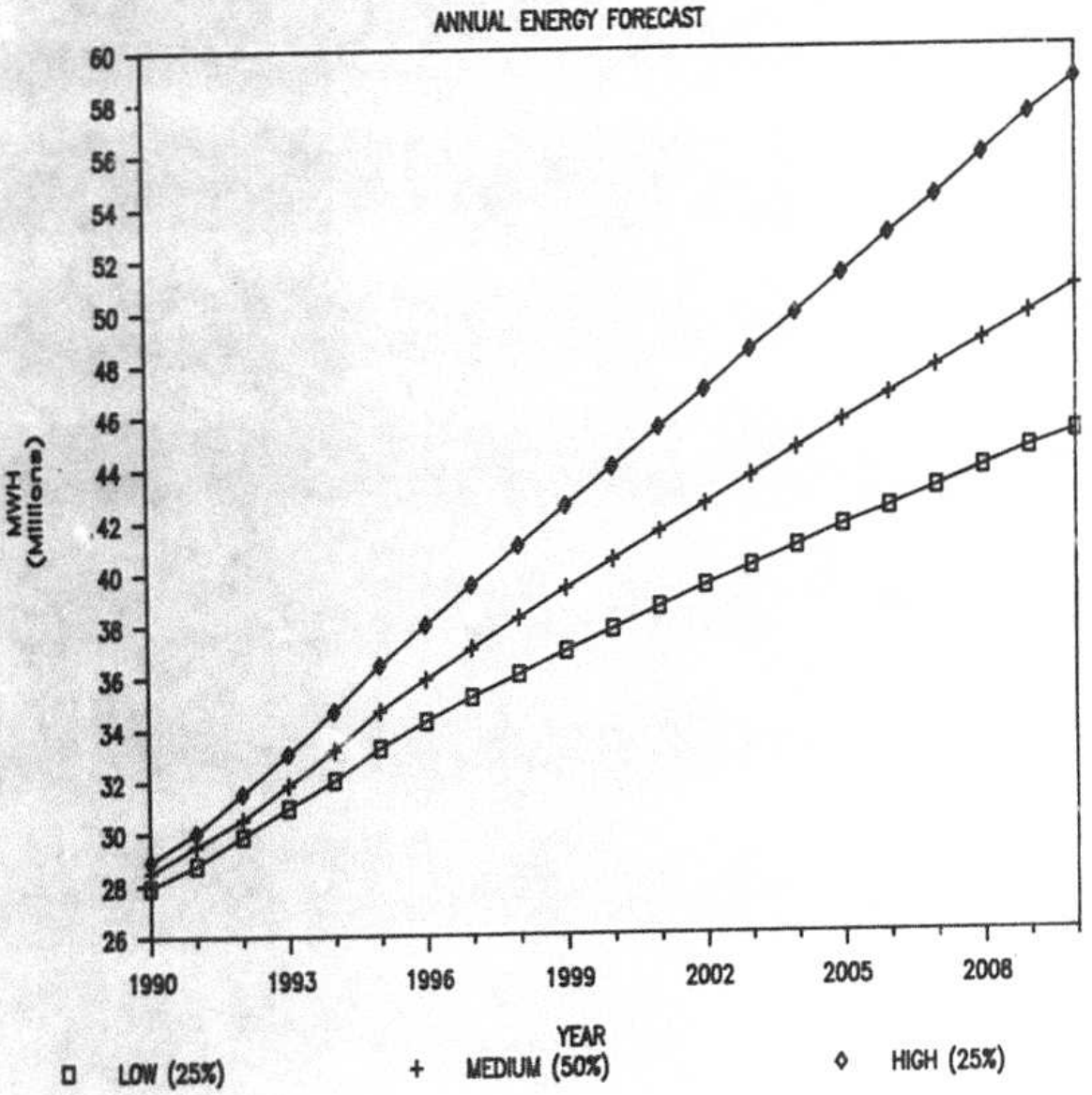


Figure 6

1990 GENERATION FACILITY STUDY

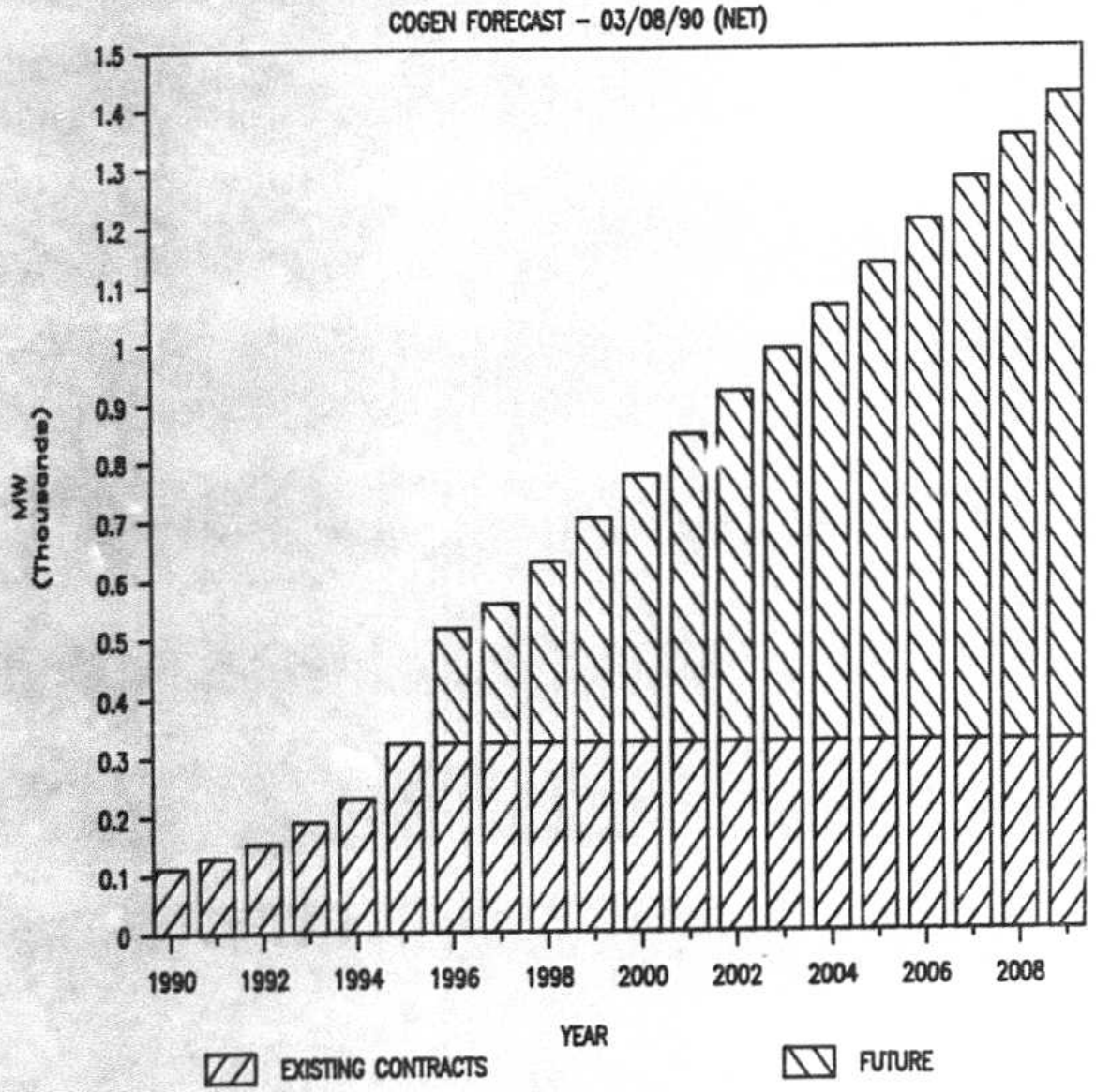


Figure 7

C. Fuel Price

The medium forecast of fuel prices was provided by the Fuel & Special Projects Department specifically for the 1990 Generation Facility Study. It reflects the impact of the Clean Air Regulation on the fuel prices. The cleaner fuels such as gas have a higher escalation rate than the dirty fuels such as high sulfur oil. Since the existing gas pipeline capacity already has been allocated completely, the gas in the forecast was assumed to be separately negotiated and transported through a new pipeline. There will be fixed charges for the new gas pipeline associated with the gas consumed and the price of gas in the forecast reflects the market price at that time. The forecast also shows the widening of differentials between oil and coal prices in 1994 which represent the general trend that forecasters predict.

The medium fuel forecast has coal prices closely following the general inflation rate. It begins to escalate at the average annual inflation rate of 5.1-percent in 1995. The oil and gas prices in the medium fuel forecast are more volatile, and escalate at a rate higher than the general inflation rate. The average general inflation rate is used after year 2001. Figure 8 demonstrates the relationship between various types of fuels for the base fuel forecast.

1990 GENERATION FACILITY STUDY

FUEL FORECAST

BASE ESCALATION

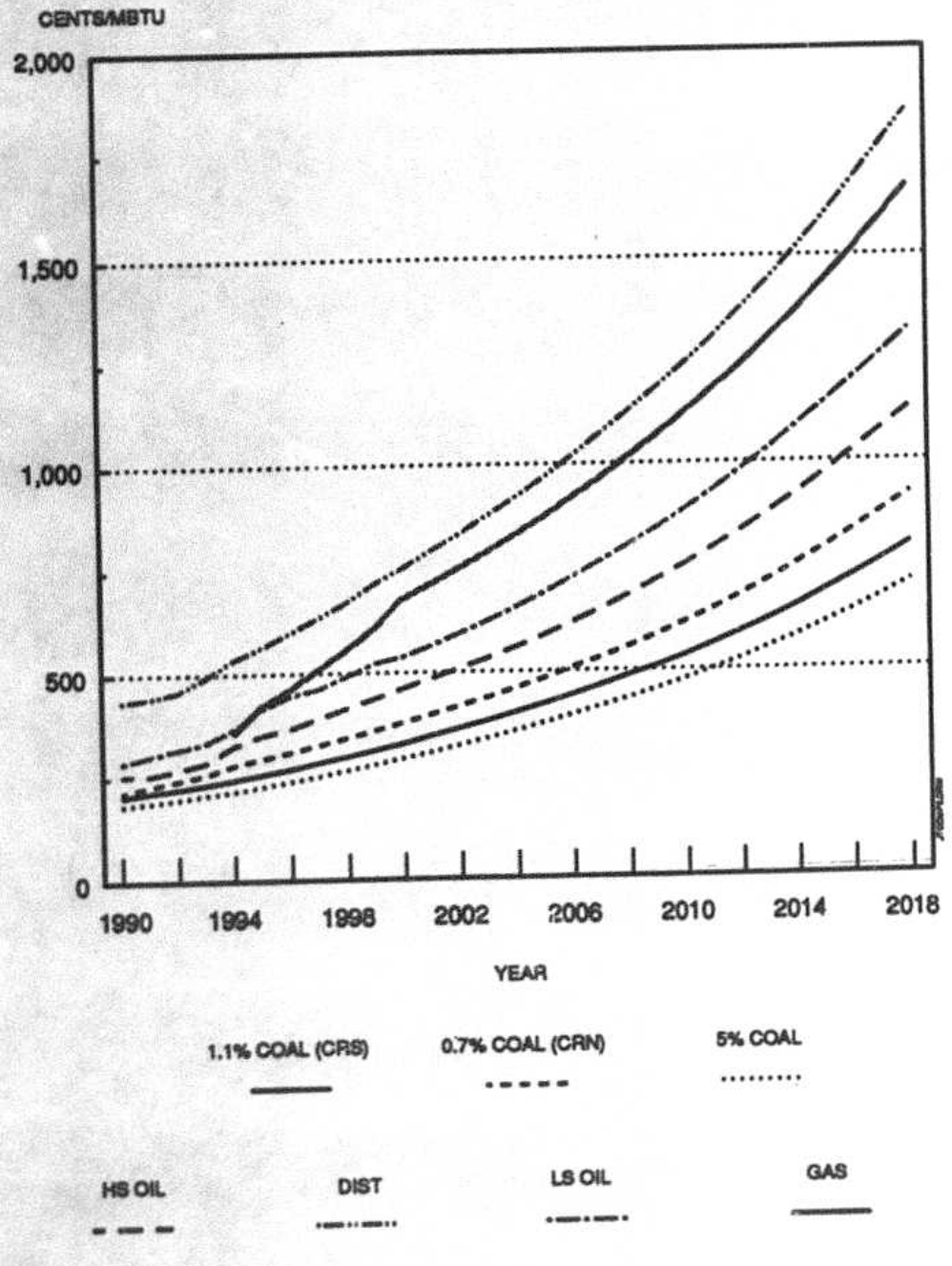


Figure 8

The high fuel forecast simulated the situations including the oil embargo, a greater demand for cleaner fuels and depressed economics. It escalated at an annual high inflation rate of 6.5-percent. It also included a bigger increase of differentials between oil and coal, and gas and coal in 1996 to reflect the unexpected situations.

The low fuel forecast has all fuel prices escalated below the average general inflation rate of 4.2-percent ior to 1995, and at the inflation rate of 4.2-percent beginning in 1995.

Figures 9, 10, and 11 show the medium, high and low fuel forecasts used in the facility study from 1990 through 2018, respectively.

FUEL COST PROJECTIONS FOR GENERATION FACILITY STUDY
MEDIUM FORECAST
(PER APRIL 6, 1990)

2.5 % RESID. OIL / HS COAL = 1.361 (1996)

DIST. / 2.5 % RESID. OIL = 1.646 "
1.0 % / 2.5 % RESID. OIL = 1.217 "
NEW GAS / 2.5 % RESID. OIL = 1.260 "

2.5 % RESID. OIL / HS COAL = 1.406 (2005)

DIST. / 2.5 % RESID. OIL = 1.636 "
1.0 % / 2.5 % RESID. OIL = 1.172 "
NEW GAS / 2.5 % RESID. OIL = 1.477 "

YEAR	H.S. COAL (C/MBTU)	ESCL (%)	L.S. COAL (C/MBTU)	ESCL (%)	(4 TO 5 %) H.S. COAL (C/MBTU)	ESCL (%)	2.5 % RESID OIL (C/MBTU)	ESCL (%)	DIST. OIL (C/MBTU)	ESCL (%)	1.0 % RESID OIL (C/MBTU)	ESCL (%)	NEW PIPELNE GAS (C/MBTU)	ESCL (%)	0.3 % RESID OIL (C/MBTU)	ESCL (%)	FLA GAS (C/MBTU)	GA GAS (C/MBTU)	GA GAS W/O TRANS (C/MBTU)
1990	204.14	66.0	214.26		182.61		254.00		434.48		285.70				355.90		300.00	280.00	251.03
1991	214.36	5.0	229.68	7.2	189.91	4.0	254.00	0.0	441.72	1.7	301.60	5.6			355.90	0.0	300.00	280.00	229.55
1992	223.16	4.1	243.00	5.8	199.40	5.0	269.80	6.2	456.21	3.3	317.50	5.3			372.90	4.8	300.00	285.00	253.00
1993	232.54	4.2	256.28	5.5	207.40	4.0	285.70	5.9	492.41	7.9	333.30	5.0			406.80	9.1	325.00	310.00	276.37
1994	242.84	4.4	279.34	9.0	215.70	4.0	325.40	13.9	535.86	8.8	365.10	9.5	355.00		457.60	12.5	385.00	385.00	349.65
1995	255.22	5.1	293.59	5.1	226.70	5.1	349.20	7.3	564.83	5.4	412.70	13.0	420.00	18.3	508.50	11.1	450.00	450.00	412.85
1996	268.24	5.1	308.56	5.1	238.26	5.1	365.10	4.6	601.03	6.4	444.40	7.7	460.00	9.5	542.40	6.7	490.00	490.00	450.96
1997	281.92	5.1	324.30	5.1	250.41	5.1	388.90	6.5	637.24	6.0	460.30	3.6	510.00	10.9	576.30	6.2	540.00	540.00	498.96
1998	296.30	5.1	340.83	5.1	263.18	5.1	412.70	6.1	673.45	5.7	492.10	6.9	560.00	9.8	610.20	5.9	590.00	590.00	546.87
1999	311.41	5.1	358.22	5.1	276.61	5.1	436.50	5.8	716.90	6.5	523.80	6.4	610.00	8.9	644.10	5.6	640.00	640.00	594.67
2000	327.29	5.1	376.49	5.1	290.71	5.1	460.30	5.5	753.10	5.0	539.70	3.0	680.00	11.5	711.90	10.5	710.00	710.00	662.36
2001	343.98	5.1	395.69	5.1	305.54	5.1	483.78	5.1	791.51	5.1	567.22	5.1	714.68	5.1	748.21	5.1	744.68	744.68	694.61
2002	361.53	5.1	415.87	5.1	321.12	5.1	508.45	5.1	831.88	5.1	596.15	5.1	751.13	5.1	786.37	5.1	781.13	781.13	728.51
2003	379.97	5.1	437.08	5.1	337.50	5.1	534.38	5.1	874.30	5.1	626.56	5.1	789.44	5.1	826.47	5.1	819.44	819.44	764.13
2004	399.34	5.1	459.37	5.1	354.71	5.1	561.63	5.1	918.89	5.1	658.51	5.1	829.70	5.1	868.62	5.1	859.70	859.70	801.57
2005	419.71	5.1	482.80	5.1	372.80	5.1	590.28	5.1	965.75	5.1	692.10	5.1	872.01	5.1	912.92	5.1	902.01	902.01	840.92
2006	441.12	5.1	507.42	5.1	391.82	5.1	620.38	5.1	1015.01	5.1	727.39	5.1	916.48	5.1	959.48	5.1	946.48	946.48	882.28
2007	463.61	5.1	533.30	5.1	411.80	5.1	652.02	5.1	1066.77	5.1	764.49	5.1	963.23	5.1	1008.41	5.1	993.23	993.23	925.74
2008	487.26	5.1	560.49	5.1	432.80	5.1	685.27	5.1	1121.18	5.1	803.48	5.1	1012.35	5.1	1059.84	5.1	1042.35	1042.35	971.43
2009	512.11	5.1	589.08	5.1	454.87	5.1	720.22	5.1	1178.36	5.1	844.46	5.1	1063.98	5.1	1113.89	5.1	1093.98	1093.98	1019.44
2010	538.22	5.1	619.12	5.1	478.07	5.1	756.95	5.1	1238.45	5.1	887.52	5.1	1118.24	5.1	1170.70	5.1	1148.24	1148.24	1069.90
2011	565.67	5.1	650.70	5.1	502.45	5.1	795.56	5.1	1301.61	5.1	932.79	5.1	1175.27	5.1	1230.41	5.1	1205.27	1205.27	1122.93
2012	594.52	5.1	683.88	5.1	528.08	5.1	836.13	5.1	1368.00	5.1	980.36	5.1	1235.21	5.1	1293.16	5.1	1265.21	1265.21	1178.67
2013	624.84	5.1	718.76	5.1	555.01	5.1	878.77	5.1	1437.77	5.1	1030.36	5.1	1298.21	5.1	1359.11	5.1	1328.21	1328.21	1237.26
2014	656.71	5.1	755.42	5.1	583.32	5.1	923.59	5.1	1511.09	5.1	1082.91	5.1	1364.42	5.1	1428.42	5.1	1394.42	1394.42	1298.83
2015	690.20	5.1	793.94	5.1	613.07	5.1	970.69	5.1	1588.16	5.1	1138.13	5.1	1434.00	5.1	1501.27	5.1	1464.00	1464.00	1363.54
2016	725.40	5.1	834.44	5.1	644.33	5.1	1020.20	5.1	1669.15	5.1	1196.18	5.1	1507.14	5.1	1577.84	5.1	1537.14	1537.14	1431.55
2017	762.40	5.1	876.99	5.1	677.19	5.1	1072.23	5.1	1754.28	5.1	1257.18	5.1	1584.00	5.1	1658.31	5.1	1614.00	1614.00	1503.03
2018	801.28	5.1	921.72	5.1	711.73	5.1	1126.91	5.1	1843.75	5.1	1321.30	5.1	1664.78	5.1	1742.88	5.1	1694.78	1694.78	1578.15

Figure 9

FUEL COST PROJECTIONS FOR GENERATION FACILITY STUDY
HIGH FORECAST
(PER APRIL 6, 1990)

2.5 % RESID. OIL / NS COAL = 2.505 (1996)

DIST. / 2.5 % RESID. OIL = 1.518 "
1.0 % / 2.5 % RESID. OIL = 1.122 "
NEW GAS / 2.5 % RESID. OIL = 1.473 "

YEAR	N.S. COAL (C/MBTU)	ESCL (%)	L.S. COAL (C/MBTU)	ESCL (%)	(4 TO 5 %) N.S. COAL (C/MBTU)	ESCL (%)	2.5 % RESID OIL (C/MBTU)	ESCL (%)	DIST. OIL (C/MBTU)	ESCL (%)	1.0 % RESID OIL (C/MBTU)	ESCL (%)	NEW PIPELINE GAS (C/MBTU)	ESCL (%)	0.3 % RESID OIL (C/MBTU)	ESCL (%)	FLA GAS (C/MBTU)	ESCL (%)
1990	205.48	6.6	225.91	6.6	189.51		254.00		441.72		285.70				415.30		300.00	
1991	219.04	6.6	240.82	6.6	199.89	5.5	270.83	6.6	447.70	1.4	311.90	9.2			440.70	6.1	350.00	16.7
1992	233.50	6.6	256.71	6.6	212.55	6.3	288.70	6.6	478.14	6.8	332.48	6.6			470.30	6.7	400.00	14.3
1993	248.91	6.6	273.65	6.6	226.99	6.8	324.79	12.5	515.91	7.9	368.39	10.8			508.50	8.1	500.00	25.0
1994	265.34	6.6	291.71	6.6	241.82	6.5	369.94	13.9	561.30	8.8	413.33	12.2	525.00		550.80	8.3	555.00	11.0
1995	282.59	6.5	310.67	6.5	257.54	6.5	394.35	6.6	598.36	6.6	440.61	6.6	563.00	7.2	590.00	7.1	593.00	6.8
1996	300.96	6.5	330.86	6.5	274.28	6.5	753.80	91.1	1144.00	91.2	845.77	92.0	1110.00	97.2	1127.10	91.0	1140.00	92.2
1997	320.52	6.5	352.37	6.5	292.11	6.5	802.80	6.5	1218.36	6.5	900.75	6.5	1182.15	6.5	1200.36	6.5	1212.15	6.5
1998	341.35	6.5	375.28	6.5	311.09	6.5	854.98	6.5	1297.55	6.5	959.29	6.5	1258.99	6.5	1278.38	6.5	1288.99	6.5
1999	363.54	6.5	399.67	6.5	331.31	6.5	910.55	6.5	1381.89	6.5	1021.65	6.5	1340.82	6.5	1361.48	6.5	1370.82	6.5
2000	387.17	6.5	425.65	6.5	352.85	6.5	969.74	6.5	1471.72	6.5	1088.05	6.5	1427.98	6.5	1449.98	6.5	1457.98	6.5
2001	412.33	6.5	453.31	6.5	375.79	6.5	1032.77	6.5	1567.38	6.5	1158.78	6.5	1520.60	6.5	1544.22	6.5	1550.80	6.5
2002	439.14	6.5	482.78	6.5	400.21	6.5	1099.90	6.5	1669.26	6.5	1234.10	6.5	1619.65	6.5	1644.60	6.5	1649.65	6.5
2003	467.68	6.5	514.16	6.5	426.22	6.5	1171.40	6.5	1777.76	6.5	1314.32	6.5	1724.93	6.5	1751.50	6.5	1754.93	6.5
2004	498.08	6.5	547.58	6.5	453.93	6.5	1247.54	6.5	1893.32	6.5	1399.75	6.5	1837.05	6.5	1865.35	6.5	1867.05	6.5
2005	530.45	6.5	583.17	6.5	483.43	6.5	1328.63	6.5	2016.38	6.5	1490.73	6.5	1956.45	6.5	1986.59	6.5	1986.45	6.5
2006	564.93	6.5	621.08	6.5	514.86	6.5	1414.99	6.5	2147.45	6.5	1587.63	6.5	2083.62	6.5	2115.72	6.5	2113.62	6.5
2007	601.66	6.5	661.45	6.5	548.32	6.5	1506.96	6.5	2287.03	6.5	1690.82	6.5	2219.06	6.5	2253.24	6.5	2249.06	6.5
2008	640.76	6.5	704.44	6.5	583.96	6.5	1604.91	6.5	2435.69	6.5	1800.73	6.5	2363.30	6.5	2399.70	6.5	2393.30	6.5
2009	682.41	6.5	750.23	6.5	621.92	6.5	1709.23	6.5	2594.01	6.5	1917.77	6.5	2516.91	6.5	2555.69	6.5	2546.91	6.5
2010	726.77	6.5	799.00	6.5	662.35	6.5	1820.33	6.5	2762.62	6.5	2042.43	6.5	2680.51	6.5	2721.80	6.5	2710.51	6.5
2011	774.01	6.5	850.93	6.5	705.40	6.5	1938.65	6.5	2942.19	6.5	2175.19	6.5	2854.74	6.5	2898.72	6.5	2884.74	6.5
2012	824.32	6.5	906.24	6.5	751.25	6.5	2064.67	6.5	3133.43	6.5	2316.57	6.5	3040.30	6.5	3087.14	6.5	3070.30	6.5
2013	877.90	6.5	965.15	6.5	800.08	6.5	2198.87	6.5	3337.10	6.5	2467.15	6.5	3237.92	6.5	3287.80	6.5	3267.92	6.5
2014	934.96	6.5	1027.88	6.5	852.09	6.5	2341.80	6.5	3554.01	6.5	2627.52	6.5	3448.39	6.5	3501.51	6.5	3478.39	6.5
2015	995.74	6.5	1094.69	6.5	907.47	6.5	2494.01	6.5	3785.02	6.5	2798.30	6.5	3672.53	6.5	3729.11	6.5	3702.53	6.5
2016	1060.46	6.5	1165.85	6.5	966.46	6.5	2656.12	6.5	4031.05	6.5	2980.19	6.5	3911.25	6.5	3971.50	6.5	3941.25	6.5
2017	1129.39	6.5	1241.63	6.5	1029.28	6.5	2828.77	6.5	4293.07	6.5	3173.91	6.5	4165.48	6.5	4229.65	6.5	4195.48	6.5
2018	1202.80	6.5	1322.34	6.5	1096.18	6.5	3012.64	6.5	4572.12	6.5	3380.21	6.5	4436.23	6.5	4504.57	6.5	4466.23	6.5

Figure 10

FUEL COST PROJECTIONS FOR GENERATION FACILITY STUDY
LOW FORECAST
(PER APRIL 6, 1990)

2.5 % RESID. OIL / HS COAL = 1.036 (1996)

DIST. / 2.5 % RESID. OIL = 1.755 "
1.0 % / 2.5 % RESID. OIL = 1.077 "
NEW GAS / 2.5 % RESID. OIL = 0.977 "

YEAR	H.S. COAL (C/MBTU)	ESCL (%)	L.S. COAL (C/MBTU)	ESCL (%)	(4 TO 5 %) H.S. COAL (C/MBTU)	ESCL (%)	2.5 % RESID OIL (C/MBTU)	ESCL (%)	DIST. OIL (C/MBTU)	ESCL (%)	1.0 % RESID OIL (C/MBTU)	ESCL (%)	NEW PIPELINE GAS (C/MBTU)	ESCL (%)	0.3 % RESID OIL (C/MBTU)	ESCL (%)	FLA GAS (C/MBTU)	ESCL (%)
1990	199.12		211.07		173.91		206.35		362.07		222.22				238.10		231.35	
1991	206.89	3.9	219.30	3.9	180.69	3.9	214.40	3.9	376.19	3.9	230.89	3.9			300.80	4.4	239.40	3.5
1992	214.96	3.9	227.86	3.9	187.74	3.9	222.76	3.9	390.86	3.9	239.89	3.9			313.60	4.3	247.76	3.5
1993	223.34	3.9	236.74	3.9	195.06	3.9	231.45	3.9	406.11	3.9	249.25	3.9			326.30	4.0	256.45	3.5
1994	232.05	3.9	245.98	3.9	202.67	3.9	240.47	3.9	421.94	3.9	258.97	3.9	235.00		338.90	3.9	265.00	3.3
1995	241.80	4.2	256.31	4.2	211.18	4.2	250.57	4.2	439.66	4.2	269.85	4.2	244.87	4.2	353.13	4.2	274.87	4.2
1996	251.95	4.2	267.08	4.2	220.05	4.2	261.09	4.2	458.13	4.2	281.18	4.2	255.15	4.2	367.97	4.2	285.15	4.2
1997	262.53	4.2	278.29	4.2	229.29	4.2	272.06	4.2	477.37	4.2	292.99	4.2	265.87	4.2	383.42	4.2	295.87	4.2
1998	273.56	4.2	289.98	4.2	238.92	4.2	283.49	4.2	497.42	4.2	305.30	4.2	277.04	4.2	399.52	4.2	307.04	4.2
1999	285.05	4.2	302.16	4.2	248.96	4.2	295.39	4.2	518.31	4.2	318.12	4.2	288.67	4.2	416.30	4.2	318.67	4.2
2000	297.02	4.2	314.85	4.2	259.42	4.2	307.80	4.2	540.08	4.2	331.48	4.2	300.80	4.2	433.79	4.2	330.80	4.2
2001	309.50	4.2	328.08	4.2	270.31	4.2	320.73	4.2	562.76	4.2	345.40	4.2	313.43	4.2	452.01	4.2	343.43	4.2
2002	322.50	4.2	341.85	4.2	281.66	4.2	334.20	4.2	586.40	4.2	359.91	4.2	326.60	4.2	470.99	4.2	356.60	4.2
2003	336.04	4.2	356.21	4.2	293.49	4.2	348.23	4.2	611.03	4.2	375.02	4.2	340.31	4.2	490.77	4.2	370.31	4.2
2004	350.15	4.2	371.17	4.2	305.82	4.2	362.86	4.2	636.69	4.2	390.77	4.2	354.61	4.2	511.39	4.2	384.61	4.2
2005	364.86	4.2	386.76	4.2	318.67	4.2	378.10	4.2	663.43	4.2	407.19	4.2	369.50	4.2	532.86	4.2	399.50	4.2
2006	380.18	4.2	403.01	4.2	332.05	4.2	393.98	4.2	691.29	4.2	424.29	4.2	385.02	4.2	555.24	4.2	415.02	4.2
2007	396.15	4.2	419.93	4.2	345.99	4.2	410.53	4.2	720.33	4.2	442.11	4.2	401.19	4.2	578.56	4.2	431.19	4.2
2008	412.79	4.2	437.57	4.2	360.53	4.2	427.77	4.2	750.58	4.2	460.68	4.2	418.04	4.2	602.86	4.2	448.04	4.2
2009	430.13	4.2	455.95	4.2	375.67	4.2	445.73	4.2	782.11	4.2	480.03	4.2	435.60	4.2	628.18	4.2	465.60	4.2
2010	448.19	4.2	475.10	4.2	391.45	4.2	464.46	4.2	814.96	4.2	500.19	4.2	453.89	4.2	654.57	4.2	483.89	4.2
2011	467.02	4.2	495.05	4.2	407.89	4.2	483.96	4.2	849.18	4.2	521.20	4.2	472.95	4.2	682.06	4.2	502.95	4.2
2012	486.63	4.2	515.84	4.2	425.02	4.2	504.29	4.2	884.85	4.2	543.09	4.2	492.82	4.2	710.71	4.2	522.82	4.2
2013	507.07	4.2	537.51	4.2	442.87	4.2	525.47	4.2	922.01	4.2	565.90	4.2	513.52	4.2	740.56	4.2	543.52	4.2
2014	528.37	4.2	560.09	4.2	461.47	4.2	547.54	4.2	960.74	4.2	589.66	4.2	535.08	4.2	771.66	4.2	565.08	4.2
2015	550.56	4.2	583.61	4.2	480.85	4.2	570.54	4.2	1001.09	4.2	614.43	4.2	557.56	4.2	804.07	4.2	587.56	4.2
2016	573.68	4.2	608.12	4.2	501.05	4.2	594.50	4.2	1043.13	4.2	640.23	4.2	580.98	4.2	837.84	4.2	610.98	4.2
2017	597.78	4.2	633.66	4.2	522.09	4.2	619.47	4.2	1086.95	4.2	667.12	4.2	605.38	4.2	873.03	4.2	635.38	4.2
2018	622.88	4.2	660.28	4.2	544.02	4.2	645.49	4.2	1132.60	4.2	695.14	4.2	630.80	4.2	909.70	4.2	660.80	4.2

Figure 11

D. Financial

Average annual inflation rates for base, optimistic (low) and pessimistic (high) were developed by the Economic Research Department. The average annual inflation rate of 5.1-percent, 4.2-percent and 6.5-percent were assigned to medium, low and high scenarios, respectively. Since the inflation as measured by CPI, GNP deflator or PPI should not differ significantly over the long-term forecast period, it should be appropriate to use the general inflation rate for all cost escalation in the study including capital cost.

The discount rate used in the study was 9.96-percent, which is the corporate after tax cost of capital.

E. Capital Cost

The conceptual capital cost estimates for future generating capacity used in the study are based on the Conceptual Cost and Performance Data Book provided by the Generation Technology Department. The study assumed that all future CT's will be built on the existing generation plant sites. It further assumed that all future coal and combined cycles will be constructed at the proposed "coal capable site". Therefore, all the capital cost excluded the siting and other necessary associated costs. The base capital cost was assessed at the probability of occurrence of 50-percent. The high and low capital costs relative to the medium capital cost are shown in the following table:

Technology	Low Prob = 25%	Medium Prob = 50%	High Prob = 25%
CT	-15%	Base	+15%
CC	-15%	Base	+15%
PC	-10%	Base	+15%
IGCC	-15%	Base	+15%

These variations reflect market conditions and minor scope changes related to unit performance improvement and emission controls.

The comparison of capital cost for various technologies studied is shown in Figure 12.

COMPARISON OF CAPITAL FOR GENERATION TECHNOLOGIES

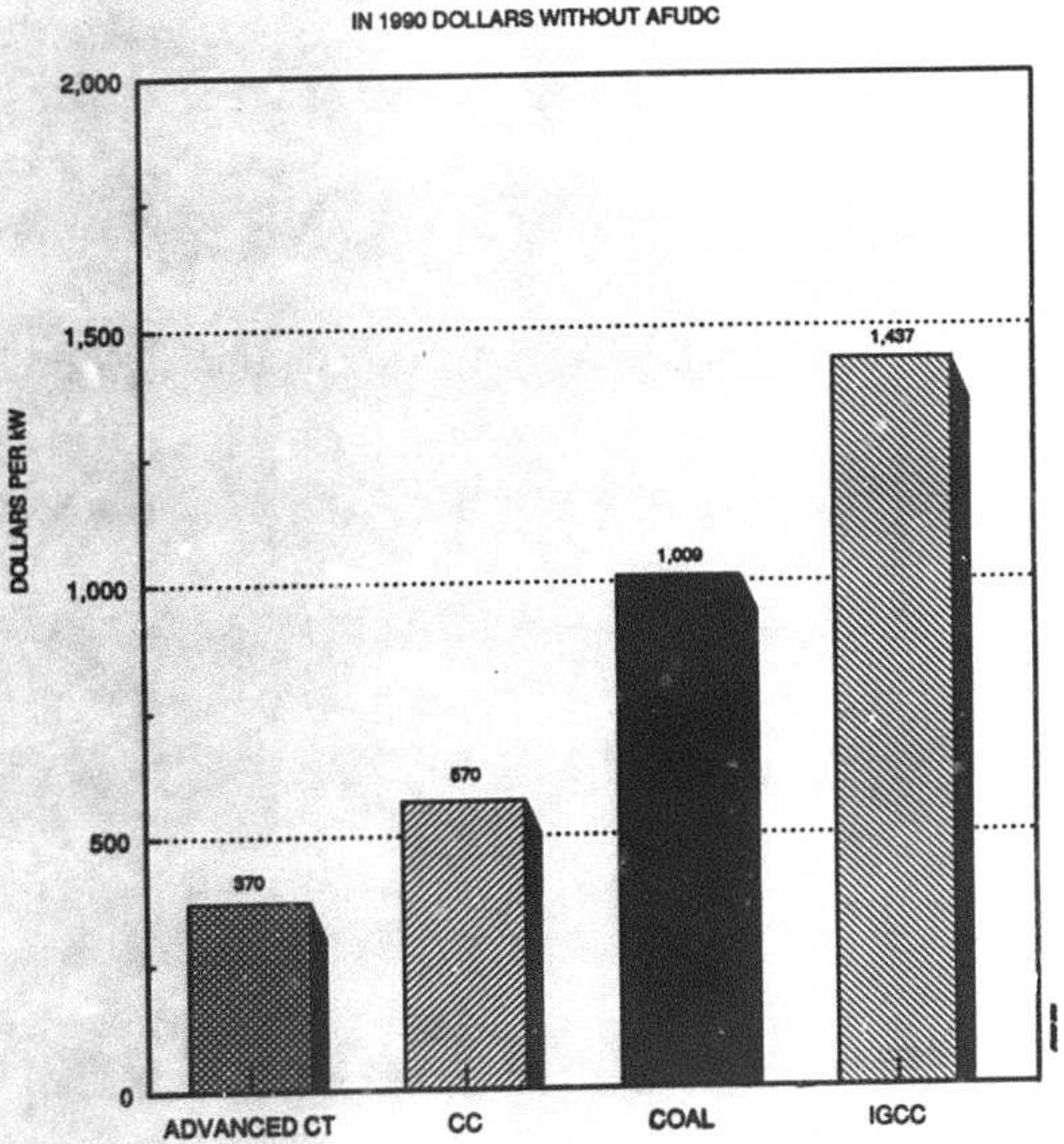


Figure 12

F. Clean Air Regulation

Different versions of the Clean Air Regulation have been passed by both the Senate and the House. The final regulation which is expected to reach the White House by October 1990 will be a somewhat compromised version of the regulations passed by the Senate and House. Since Acid Rain Legislation is a major part of the regulation, the limits of sulfur and the other particulate emissions are a serious concern of the country's utilities. In this study, the control of sulfur emission in the year 2001 is addressed. The emission control of other particulates such as NO_x, SO_x, etc. is not addressed in the study because they are still under investigation for their limit and effect.

Based on the Environmental and Licensing Department's interpretation of the regulation, the limit of sulfur emission in the Senate version is approximately 157,000 tons, and the limit of sulfur emission for the House version is approximately 142,000 tons for FPC. The final version of the regulation is expected to have the limit of sulfur emission falling somewhere between 157,000 and 142,000 tons. For the purpose of the study, the design limit for sulfur emission for FPC in the year 2001 is 130,000 tons.

The following assumptions were also made in the study:

- o No value is given to the excess emission credits.
- o Cogeneration and purchase power transactions come with their own emission credits.

II. Reliability Analysis

The supply-side and demand-side resources of an electric utility must be sufficient for the utility to reliably meet customer needs. These resources include the capacity of the generating units owned by the utility, capacity available to the utility from outside sources, and direct customer load control capability. The amount by which the capacity exceeds system firm peak demand is referred to as reserve capacity. Having adequate reserve capacity allows for the failure and maintenance of generating units and load control equipment. Adequate reserve capacity also protects against capacity short-falls in the event of higher than anticipated system peak loads.

If system reliability were the only concern, electric utilities would plan their system with a very large reserve capacity. However, the cost to maintain the reserves must be considered. Therefore, reliability and cost must be balanced. In long-range planning studies, some measure must be employed to determine the appropriate level of reserve capacity.

Probabilistic methods are employed by Florida Power Corporation as part of its evaluation of generation adequacy. The most commonly used probabilistic method is the loss of load probability (LOLP). This represents the expected number of days per year that the generation will be insufficient to serve the daily peak load. The LOLP was used in this study to determine whether installed capacity was adequate, as well as winter reserve margin criteria.

The LOLP method combines the probabilities of generation forced outages, scheduled maintenance, and generation capacities with the system load. A table of all the possible capacity combinations is made for all the generating units not on scheduled maintenance. This table gives the probability that the generating system will not be adequate to meet each possible load level. The loss of load probability is calculated by summing the probabilities of not meeting the peak load each day. Florida Power Corporation's system is designed to meet a 0.1 day per year LOLP by using its own generating capacity and dependence upon tie lines to the assistance area. The 0.1 day per year LOLP has been found to be an acceptable criterion on larger generating systems. The assistance area includes Peninsular Florida (excluding Florida Power Corporation).

A winter peak reserve margin was also used in assessing FPC's need for future capacity. Loss of load probability implies that a system is expected to experience a loss of capability to serve load. A criterion is established which recognizes an acceptable probability of load loss. FPC's most severe load situation occurs in the winter months during an intense short duration peak period. Internal FPC studies have theoretically shown that overall system LOLP is acceptable while not meeting the winter peak demand with native generation. From an operational standpoint, a positive winter peak margin should be maintained. A companion criterion of 10-percent winter reserve margin was also observed to meet this need.

Florida Power Corporation will continue to strengthen its interconnection capability with other utilities to improve the system reliability.

III. Technologies and Alternatives

A. Technologies

Only viable generation technologies are considered for the additions to Florida Power Corporation's future power supply system in the study. The generation technologies used are listed and described as follows:

Combustion Turbine - 165 MW (winter rating) with advanced technolog/ similar to GE Frame 7000F, use natural gas and distillate oil.

Combined Cycle - 235 MW (winter rating) with advanced technology similar to GE Frame 7000F, use natural gas and distillate oil.

Pulverized Coal - 700 MW (winter rating) with reference design similar to Crystal River Units 4 & 5 with scrubber, use Eastern bituminous coal. For study purposes, 1-percent sulfur coal similar to the coal consumed at Crystal River South is used.

IGCC - 310 MW and 580 MW (winter rating) with conventional technology similar to the Texaco Coolwater project, use 1-percent sulfur coal similar to the coal consumed at Crystal River South is used.

Currently, a proposal of fuel alternatives from Texaco is under study by the New Technology Department and the Generation Planning section of System Planning. The initial proposal is for Texaco to construct a gasifier at the Bartow site. It would use Orimulsion, a low grade crude

oil from Venezuela as fuel to produce the synthetic gas to sell to FPC. Since the price of Orimulsion is relatively inexpensive, it would be economical to consume the gas at the Bartow site and future combustion turbines or combined cycles. Therefore, this alternative is considered in the study.

The atmospheric fluidized bed technology is not considered in the study at this time because of its relatively high capital cost, similarity in benefit to a scrubbed coal unit, and size limitation (less than 150 MW).

B. Alternatives

The alternative selection process for this study begins in 1997. A group of twelve alternatives were selected by the Facility Study team in conjunction with its Advisory Board for the study. These twelve alternatives selected represent the well-thought, well-diversified, reasonable combinations of generation technologies that could best respond to various combinations of forecast outcomes during the study period. The timing and amount of the generating facilities were determined by the reliability model (TIGER) at the medium demand and energy forecast.

Each alternative also contains the proper measures required to meet the expected SO_2 emission limit. The measures only considered fuel switching and scrubbing the existing coal units. A complete description of the twelve alternatives is shown in Figure 13 on the following page.

ALTERNATIVES FOR 1990 GENERATION FACILITY STUDY

ALTERNATIVE	1997	1998	1999	2000	2001	2002	2003	2004	EMISSION FIX-UP	TOTAL ADDED CAPACITY
1	COAL	CC	CC	2-CC	CC		CC-G	CC-G	SCRUB CR4,5	2,345
2	2-CC	2-CC	CC	2-CC		CC-G	CC-G	CC-G	SCRUB CR4,5	2,350
3	2-CC	2-CC	2-IGCC	3-IGCC		IGCC-L			FUEL SWITCH	2,130
4	COAL	CT	CT	COAL	CT	CT	CT	CT	SCRUB CR4,5	2,390
5	2-CT	COAL		COAL		CT		CT	FUEL SWITCH	2,060
6	2-CC	2-CT	CC	2-CC	CT	CC-G	CC-G		SCRUB CR4,5	2,140
7	2-CC	2-CC	CC	2-CC	CC		CC	CC	SCRUB CR1,2,4,5	2,350
8	2-CC	2-CC-G	CC-G	2-CC-G		CC-G	CC-G	CC-G	SCRUB CR4,5	2,350
9	2-CC	2-CC	CC		CC-G	CC-G	CC-G	CC-G	MUST RUN GAS	2,115
10	2-CC	2-CT	CC	2-CC	CT	CT	CC	CC	SCRUB CR1,2,4,5	2,305
10A	2-CC	2-CT	CC	CC	CT	CT	CC	CC	ORIMULSION	2,070
11	COAL	COAL			COAL			COAL*	FUEL SWITCH	2,300
12	IGCC-L	IGCC-L		IGCC	CT	CT	IGCC		FUEL SWITCH	2,110

NOTE:

1. COAL: REF, SCRUBBED, 700MW COAL*: REF, SCRUBBED, 200MW
   CC: ADVANCED, DISTILLATE, 235 MW
   CC-G: ADVANCED, GAS, 235 MW
   CT: ADVANCED, DISTILLATE, 165 MW
   IGCC: 310 MW
   IGCC-L: LARGE IGCC, 580 MW
2. ALL CAPACITIES ARE BASED ON WINTER RATING.
3. WHEN CC-G IS INSTALLED, PREVIOUS CC WILL BE CONVERTED TO GAS.
4. ALL IN-SERVICE DATES ARE NOVEMBER 1.

Figure 13

10/3/90

IV. Sulfur Emissions

A. Clean Air Regulation

The Clean Air Regulation has been passed by both the United States House of Representatives and the Senate. A joint Senate and House Committee will work out a compromise bill for final passage in late 1990. The final bill will determine Florida Power Corporation's allocation of SO_2 emissions. It will have a significant impact on the planning and operation of the FPC system. FPC does not have any difficulty in meeting the Phase I provisions of the legislation. The Phase II provisions of the legislation has the intent of limiting the electric industry to 8.9 million tons of yearly SO_2 emissions.

While the final legislation has not been passed at the time of this facility study, a number of reasonable assumptions had to be made in order to proceed.

1. A total FPC SO_2 limit of 130,000 tons was selected as a design criterion. This is lower than the House bill limit of 142,000 tons to allow for possible changes in the final legislation. The 130,000 ton limit also provides for a margin of safety in the event of unforseen problems in complying with the SO_2 limits.

2. The House and Senate bills excluded existing combustion turbines from the system SO_2 limit calculation. The Florida Power Corporation SO_2 emission totals do not include the existing peakers

at Avon Park, Debary, Bartow, Bayboro, Higgins, Intercession City, Turner, Port St. Joe, Rio Pinar and Suwannee.

3. The SO_2 limits are system wide and there are no individual unit Phase II unit limitations.

4. The Phase II limitations will take effect in January 2001.

B. Emission Reduction Options

The following methods were considered as practical measures of SO_2 emission reductions:

1. Install emission control equipment (scrubbers) on existing or new units to reduce stack emissions. The scrubbers were assumed to be 90-percent effective.

2. Replace high sulfur fuels with lower sulfur fuels or fuels with no sulfur (natural gas).

3. Install new units that can burn high sulfur fuels with low SO_2 emissions such as Integrated Gas Combined Cycle (IGCC), fluidized bed or scrubbed pulverized coal plants.

4. Make power purchases to displace high emission generation. This could include purchases from cogenerators, independent power producers or other utilities.

5. Construct low emission generating units using low sulfur fuels, such as combined cycle units on natural gas or distillate fuel.

C. SO_2 Emissions on FPC System

These technologies were tested individually and in combination to find a facility plan that would meet all of the traditional requirements of a generation expansion plan as well as the new constraint of SO_2 system wide limits. Several important principles became apparent during the emission simulations.

1. The application of these technologies to reduce emissions does not always produce obvious results. Due to the economic dispatch of units, the emissions improvements on one unit can cause it to operate at a higher cost, and a less clean unit may then become more economical. The clean unit runs less, the less clean unit runs more and the emissions are not lowered as expected.

2. The total emissions are highly dependent upon the Demand and Energy Forecast. The load shape and total energy production can vary the annual SO_2 emissions significantly.

3. A high cost differential between low sulfur fuels and high sulfur fuels will cause an increase in emissions if both fuels are used on the system.

4. The addition of scrubbers on existing pulverized coal units lowers both the MW capacity of the plant and its availability. These detriments cause the need for additional capacity to maintain an equivalent system reliability. Furthermore, the capital cost impact of adding scrubbers to Crystal River 1 & 2 and 4 & 5 are $361/KW and $278/KW, respectively.

D. Other Available Emission Reduction Options

There are other emission reduction options available for FPC that are not considered in this study. For instance, extremely clean coal and oil fuels could be obtained and the environmental dispatching of units instead of dispatching units economically are viable options. Two of the selected alternatives included "must run" scenarios for units burning gas to lower system emissions, but this was not a true emissions dispatch. In general, the emissions dispatch can improve the system SO_2 emissions to provide short-term reductions, but is not sufficient to provide long-term compliance to the SO_2 limits.

Emission Formulas:

Distillate Oil:

$$\text{Sulfur (Tons)} = \frac{\text{Barrels} \times 305.25 \frac{\text{Lbs.}}{\text{Barrel}} \times 0.005}{2000 \frac{\text{Lbs.}}{\text{Ton}}}$$

High Sulfur Oil:

$$\text{Sulfur (Tons)} = \frac{\text{Barrels} \times 348.56 \frac{\text{Lbs.}}{\text{Barrel}} \times 0.025}{2000 \frac{\text{Lbs.}}{\text{Ton}}}$$

Low Sulfur Oil:

$$\text{Sulfur (Tons)} = \frac{\text{Barrels} \times 348.56 \frac{\text{Lbs.}}{\text{Barrel}} \times 0.01}{2000 \frac{\text{Lbs.}}{\text{Ton}}}$$

Low Sulfur Coal:

Sulfur (Tons) = Tons x 0.007

High Sulfur Coal:

Sulfur (Tons) = Tons x 0.011

Very High Sulfur:

Sulfur (Tons) = Tons x 0.05

SO_2 (Tons) = Sulfur (Tons) x 2

V. Decision Analysis

Decision analysis is the methodology employed in this study. Decision analysis tests proposed alternatives under the uncertainties which have the greatest influence on them. The resulting product is a determination of how well a particular decision performs under uncertainties.

The first step in a decision analysis is to determine the key forecasts. In this study the fuel forecast, demand & energy forecast and capital cost are identified as the ones which can greatly affect the decision. The uncertainty of the key input forecasts are represented by high, medium and low forecasts. Each forecast has its associated probability of occurrence (outcome). Figure 14 shows the outcomes of the key forecasts at high, medium and low scenarios. However, the forecasts of fuel and demand & energy are interrelated. Therefore, the uncertainties of fuel and demand & energy forecasts are always studied together. Then, alternatives for capacity addition which are best designed to respond to particular combinations of uncertainties are selected. The selected alternatives included in the study only provided new generating units through 2005. Needs beyond that time frame were not assessed at this time. With uncertainties of the fuel forecast, demand & energy forecast and capital cost, a total of twenty-seven (3 x 3 x 3 = 27) individual cases were developed to test each alternative. While demand & energy was known to be uncertain, the timing and amount of the generating facilities would not be allowed to be adjusted in the process. An assessment of expected outcomes as well as risk can be derived from the analysis. Relative comparisons of cumulative present worth revenue requirements between multiple alternatives can also be made.

Figure 15 shows the decision tree and how each alternative was tested.

UNCERTAINTY OF KEY ASSUMPTIONS

	OUTCOME		
	HIGH	MEDIUM	LOW
FUEL PRICES	20.00%	55.00%	25.00%
DEMAND & ENERGY (NORMAL WEATHER)	25.00%	50.00%	25.00%
CAPITAL COST OF TECHNOLOGIES	25.00%	50.00%	25.00%

Figure 14

The following program was submitted, but was not approved by the Florida Public Service Commission. The program will be resubmitted with additional information at a later date.

DEMAND REDUCTION CAPITAL OFFSET PROGRAM

This program will enable Florida Power to assist customers with major demand reduction projects that are not covered by other programs. At the time of an audit, the Florida Power representative will identify any special conservation measures eligible for consideration under this program, the customer will provide all information necessary, and a contract will be signed covering the project. The rebate amount will be based on the Public Service Commission's cost-effectiveness analysis, and will be limited to a maximum of $150 per kW reduced.