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April 24, 2000 ORIGINAL

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RECORDS AND REPORTING

VIA HAND DELIVERY

Blanca Bayo, Director
Records and Reporting
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, Florida 32399-0850

RE: Docket No. 000289-EU
Petition for Determination of Need for Electric Power Plant in St. Lucie County by Panda Midway Power Partners, L.P.

Dear Ms. Bayo:

Attached please find the original and 15 copies each of the Direct Testimony of Dale M. Nesbitt, Robert L. Davis, Francis Gaffney, Paul A. Arsuaga, Daniel E. White, Steven W. Crain and Jeffrey L. Meling to be filed in the above-cited docket. Also attached is a copy of each of the above witnesses' direct testimony to be stamped and returned to us for our files.

Thank you for your attention to this matter.

Very truly yours,

Suzanne Brownless

Suzanne Brownless
Attorney for Panda Midway Power Partners, L.P.

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cc: Steven W. Crain, P.E.
Jeff Schroeter, P.E.
Bill Lamb, Esq.

DN 05044-00 thru 05050-00

ORIGINAL

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In RE: Petition for Determination of Need for an Electrical Power Plant in St. Lucie County by Panda Midway Power Partners, L. P.	)	DOCKET NO. 000289-EU

DIRECT TESTIMONY

OF

DALE M. NESBITT, Ph. D.

ON BEHALF OF

PANDA MIDWAY POWER PARTNERS, L. P.

April 24, 2000

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

**IN RE: PETITION FOR DETERMINATION OF NEED
FOR AN ELECTRICAL POWER PLANT IN ST. LUCIE COUNTY
BY PANDA MIDWAY POWER PARTNERS, L.P.
FPSC DOCKET NO. 000289-EU**

DIRECT TESTIMONY OF DALE M. NESBITT, PH.D.

Q: Please state your name and business address.

A: My name is Dale M. Nesbitt and my business address is Altos Management Partners Inc., 27121 Adonna Ct., Los Altos Hills, CA 94022.

Q: By whom are you employed and in what positions?

A: I am presently Chief Executive Officer and President of Altos Management Partners Inc. Altos Management Partners Inc. is a management consulting firm. I am also a Director, President, and Chief Executive Officer of MarketPoint Inc. MarketPoint Inc. is a software development and support firm. I am a Director and Vice President of Reticle Inc. Reticle is an R&D company that is developing ultra high surface area carbon suitable for water deionization, water cleanup, and electroplating in the industrial mining business.

Q: Please describe your duties with Altos Management Partners and MarketPoint Inc.

A: I helped found Altos Management Partners Inc. in 1995 and became Chief Executive Officer and President of Altos Management Partners in January 1998. I am responsible for business development, leadership, technology and technique development, substantive analysis and consultation with clients, communication, strategic direction, project supervision, staff development, and other fiduciary and management roles at Altos. I founded MarketPoint Inc. in 1996 and assumed the position of President and Chief Executive Officer at that time. I am responsible for business development, leadership, software development, technology development, training, documentation, communication, staff development, project supervision, funding, and other fiduciary and management roles at MarketPoint.

PROFESSIONAL QUALIFICATIONS AND EXPERIENCE

Q: Please summarize your educational background and experience and any honors you have received.

A: I earned a B.S. degree in Engineering Science from the University of Nevada, Reno with high honors in 1969. I earned an M.S. degree in Mechanical Engineering from Stanford University in 1970, another M.S. degree in Engineering-Economic Systems (EES) from Stanford University in 1972, and a Ph.D. degree in Engineering-Economic Systems from Stanford University in 1975. My doctoral dissertation was defended with honors in the department of Engineering-Economic Systems at Stanford. I am a member of Phi Kappa Phi (national honorary society) and Sigma Tau (national honorary engineering society).

Q: Please summarize your employment history and work experience.

A: I joined Xerox Corporation at their Palo Alto Research Center in 1972 as an analyst in the management systems group. In 1974, I left Xerox to join Stanford Research Institute (SRI) initially as a Decision Analyst in its Decision Analysis Group. When I left SRI in 1977, I had become Manager, Decision Analysis--Energy. In 1977, I co-founded Decision Focus Incorporated (DFI), a private management-consulting firm that practiced in the oil, gas, electricity, telecommunications, air transportation, leisure services, environment, and high technology industries. As a director, officer, principal, and co-founder of the firm, I was able to work in multiple DFI business areas. DFI grew to have $20 million in annual sales with 150 employees, at which time in 1995 I elected to liquidate my interest in the firm, in part to pursue an opportunity offered to me by PanEnergy (later acquired by Duke Energy Corporation). The opportunity PanEnergy offered me was to take up to three years to build a definitive market-based, continent-wide model of the North American electricity industry so that they could achieve informational and competitive advantage in their emerging merchant electricity business.

During the time I was developing PanEnergy's electric market model, I co-founded and later joined Altos Management Partners originally as a Senior Consultant and now as Chief Executive Officer and President. Since founding Altos, I have helped promote, develop, and conduct Altos' oil, gas, and electricity modeling and management consulting practice. Altos' services now include short and long run models of North American gas markets, North American electricity markets, world and North American oil markets, a World Gas Trade program, a Western European gas program, a Southern Cone of South America Gas Model, a Southeast Australia Gas Model, an Electric Asset Operational Model, an asset valuation model, and a risk management and probabilistic analysis model. My resume is attached as Exhibit (DMN-1) and a brochure describing Altos' consulting practice and history is attached as Exhibit (DMN-2).

I recently founded MarketPoint Inc., which develops, licenses, and supports economic modeling software trade named MarketPoint™ as an internet product as well as a support service to Altos' management consulting practice. I also recently founded a chemical and mineral technology company, Reticle Inc., that is developing ultra high surface area carbon electrode material.

During my time in the consulting business (which has been continuous since 1974), I have served many of the multinational oil companies, most of the North American and some foreign natural gas pipelines, and a number of electric companies. Clients for whom I have worked during that period include:

- Agip
- Alberta Department of Energy
- Amerada Hess
- Amoco
- Argonne National Laboratory
- Atlantic Richfield Company
- Baytrust/Unilon
- BC Gas

- BHP Petroleum
- British Gas
- British Petroleum/Sohio
- California Energy Commission
- Calpine
- Canadian Energy Research Institute
- Chase Manhattan Bank
- Chevron
- Coastal/Colorado Interstate Gas
- Cogentrix
- Conoco
- Consolidated Edison Corporation
- Duke Energy
- El Paso Natural Gas
- Electric Power Research Institute
- Enron
- Enterprise Oil
- Exxon/Esso
- Fina
- Gas Research Institute
- Gulf Oil Corporation
- Husky Oil

- Illinois Department of Energy and Natural Resources
- Lasmo
- Lawrence Berkeley Laboratory
- Lawrence Livermore National Laboratory
- Los Alamos National Laboratory
- Maxus Energy
- National Energy Board of Canada
- National Petroleum Council
- New Mexico State Energy Office
- New York Gas Group (NYGAS)
- New York State Energy Office
- Northwest Energy Resources Company (NERCO)
- Nova Corporation
- Oak Ridge National Laboratory
- Office of Management and Budget
- Oryx Energy Corporation
- Panhandle Eastern Pipeline Company
- Pennsylvania Power and Light Company
- Petro-Canada
- PG&E Corporation, Pacific Gas and Electric Company,
- PG&E Generating, and PG&E Gas Transmission
- Phillips Petroleum

- Pipeline Power Partners
- Republic of Argentina
- Republic of Mexico
- Republic of Portugal
- Republic of South Korea
- Santa Fe Minerals Corporation
- Shell
- Sonat
- Southern California Edison Company
- Southern California Gas Company
- Stanford University
- Tenneco
- Tennessee Valley Authority
- Texaco
- Texas Utilities
- TransCanada Pipeline
- Yukon Pacific Corporation

Q: Have you previously testified before regulatory authorities or courts outside Florida?

A: Yes. I have provided testimony to various state and national regulatory bodies. I have testified before the

Economic Regulatory Administration of the United States government in support of the TransAlaska Gas Pipeline System in behalf of applicant Yukon Pacific Corporation. I provided testimony before the National Energy Board of Canada in support of the McKenzie Delta Pipeline (in behalf of applicants Gulf, Exxon, and Shell) and in a different proceeding, I provided testimony in behalf of TransCanada's application for eastward expansion. I testified before the Federal Energy Regulatory Commission in support of Pacific Gas Transmission Company's roll-in pricing application for its Alberta-to-California expansion project. I provided testimony before the British Columbia Utilities Commission (BCUC) in behalf of BC Gas' application for the Southern Crossing pipeline project. I provided testimony before the California Public Utilities Commission in support of Pacific Gas and Electric's application for rate relief and roll-in pricing for its gas lines 400 and 401. I have provided testimony before the California Energy Commission on a number of issues ranging from Southern California Edison's application for a firm transportation agreement with Pacific Gas Transmission (PGT) to offering information and counsel regarding appropriate discount rates and rates of return to ascribe to private companies who endeavor to enter California.

Q:Have you previously testified before regulatory bodies or courts in Florida?

A: Yes, I have testified before two different bodies on two different occasions, both during the past year. The first such testimony was before the Florida Public Service Commission (PSC) in the determination of need proceeding for the New Smyrna Beach Power Project, and the second was as an expert witness in the Site Certification Hearing for the New Smyrna Beach Project.

Q: On whose behalf are you testifying in this proceeding?

A: I am testifying in behalf of Panda Midway Power Partners, L. P. (Panda Midway), applicant for the Panda Midway power project in the Florida Regional Reliability Council (FRCC).

SUMMARY AND PURPOSE OF TESTIMONY

Q: What is the purpose of your testimony in this proceeding?

A: I have been asked by Panda Midway to provide my professional opinions with respect to a number of questions relating to the Panda Midway Project, including the following:

- Merchant power plants and the role of the merchant power sector in the U.S. electricity industry;

- Whether the Midway project is needed to provide electric system reliability in Florida and whether the Project is needed to provide economic, cost-effective power in the Peninsular Florida wholesale power market;

- Whether the Project is cost-effective; and

- Whether the Project will provide economic, environmental, or other benefits by its entry into the Peninsular Florida wholesale power market.

Q: Please summarize your testimony.

A: Merchant power plants provide a number of valuable functions in the electricity industry, including, but not limited to: true cost minimization, price depression or suppression, enhanced geographic diversity and dispersion of generation, improved environmental impacts, correct and proper price or cost benchmarking, enhanced fuel efficiency in the power generation sector, reduced market concentration and market power concerns, reduced risk to electric ratepayers, increased reliability of the system as a whole, and promoting the unbundling of generation from transmission and distribution. The entry of merchant power plants into power markets generally, and into the Peninsular Florida market specifically, will provide significant benefits to customers and the general public.

The Peninsular Florida wholesale power market needs a significant amount of additional new generating resources using the natural gas-fired combined cycle generation technology that the Panda Midway Project will utilize. My estimates indicate that the Peninsular Florida market needs and would benefit substantially from the entry of approximately 5,400 MW of new gas-fired combined cycle capacity, immediately or "overnight" if possible, in addition to all proposed additions reflected in the Peninsular Florida retail-serving utilities' current Ten Year Site Plans and in addition to the Panda Midway and Panda Leesburg Projects and the New Smyrna Beach Power Project being developed by an affiliate of Duke Energy.

The Midway Project's entry into the Peninsular Florida wholesale power market will provide substantial economic benefits to Peninsular Florida electric ratepayers by reducing the wholesale cost of electric power and thus the retail rates of Peninsular Florida's retail-serving utilities. My estimates indicate that the Project's entry will provide economic value in the form of price depression effects over the Project's first ten years of operation following its entry in 2003. Additionally, the Project will provide enhanced electric system reliability.

The Midway Project is demonstratively cost-effective both to Panda and to the ratepayers of Peninsular Florida. Accordingly, the Project is also economically viable under any reasonably foreseeable scenarios.

The Midway Project will provide significant additional benefits to Florida, including reducing environmental pollution from electricity generation, enhancing fuel efficiency in electricity production, reducing economic risk to Florida electric ratepayers, stimulating the addition of new gas transmission pipeline capacity into the Peninsula, and stimulating economic growth.

Q: What are the key questions addressed by your testimony?

A. My testimony addresses several questions related to the Panda Midway Project, including the following:

- Is there a need for 1000 MW of electric generation capacity and associated energy production in the proposed site of the Midway Project? The answer is yes, and the need is immediate.

- Will the Midway Project increase system reliability? The answer is yes. One more power plant serving the same level of demand in the FRCC region necessarily means higher reliability. The fact that its primary fuel comes from a separate, parallel, strictly independent natural gas pipeline and supply source further augments reliability.

- Is the proposed Midway Project the most cost-effective option to provide this capacity and energy? The answer is yes; the natural gas combined cycle electric generation technology of the Project is the most cost-effective option for capacity and energy in the local submarket, all Florida submarkets to which it is connected directly or indirectly, and to the Peninsular

Florida market as a whole. The Midway Project's technology is better than gas simple cycle, coal, oil, and other power plant technologies.

- Will the Midway Project be economically viable? The answer is yes. It will be profitable for its owners, impose zero risk on Florida ratepayers because it is a merchant plant, and reduce wholesale and retail prices in the Florida market by virtue of its entry.

- Will energy from the Midway Project be sold out of state? The answer is no, neither directly nor by displacement.

- Will the entry of the Midway Project drive Florida power prices down, or will it leave Florida power prices largely unchanged? In particular, will the entry of the Midway Project depress the price in the region contiguous to the plants and thereby reduce the price of electricity throughout the FRCC? The answer is yes. It will drive prices down substantially throughout the entirety of Peninsular Florida in 2003, and by similar amounts in following years. (The specific magnitude of price depression attributable to the Midway project is described in Exhibit DMN-3 to this testimony. To emphasize, the entry of the Midway Project will drive down power prices throughout Peninsular Florida relative to what they would otherwise be; there is a direct price depressive effect that accrues to all ratepayers in Florida.

- What, if any, effects will the Midway Project have on overall fuel efficiency and fuel use for electricity generation in Peninsular Florida? The entry of the Midway Project will reduce total fuel use for electricity generation in Florida, significantly improve the overall efficiency of electricity generation in Florida, and displace higher cost MWh that would otherwise be consumed in Florida by lower cost MWh that are generated by the Project.

- Will the Midway Project provide any direct environmental benefits? The answer is yes because Florida will require less hydrocarbon fuel--gas and/or oil--to generate the same number of MWh of energy and because the Project will be equipped with Selective Catalytic Reduction (SCR) to further reduce emission levels.

- Will the Midway Project cause old, inefficient power plants in Peninsular Florida to be shut down? Not necessarily. Old, inefficient plants will be kept in reserve and will be spinning during the peak winter and summer days. New plants such as the Midway Project will run in base load applications, but old plants will be operated as reserves during summer and winter peak days.

- Will the Midway Project reduce economic risk to Florida electric ratepayers? Yes, the Project will reduce ratepayer risk because Panda Midway Power Partners L.P. is bearing 100 percent of the capital cost risk of entry and 100 percent of the price and marketability risk. No ratepayer or wholesale market participant is being forced--or can be forced--to purchase power from the Project or to pay for the capital or operating costs of the Project.

- Will the Midway Project reduce market concentration among incumbent generators and thereby reduce prospects for exercise of market power? The answer is yes. The Project will dilute market power that the incumbent utilities would otherwise be able to exploit.

- Will the Midway Project catalyze the entry of new natural gas pipeline capacity into the state? The answer is yes, and the new pipeline into the state will increase natural gas supplies and decrease gas prices relative to what they would otherwise be.

Q: Are you sponsoring any exhibits to your testimony?

A: Yes. I am sponsoring a report that outlines the need for and benefits of the Panda Midway and Leesburg Projects, both individually and jointly. That report is incorporated herein by reference and is an intrinsic part of this testimony. It is entitled "Need for the Panda Leesburg and Midway Generation Projects in the FRCC" That report contains a number of appendixes, which it references from within. That report is attached to this testimony as Exhibit (DMN-3) and is subject to the same oath and representations as is this testimony.

Q: Does that conclude your testimony?

A: Yes, it does.

Dr. Dale M. Nesbitt
Summary Biography

Dr. Nesbitt began his career at Xerox Palo Alto Research Center (PARC) as an analyst in the Management Systems Department. (He was employee number 70 at PARC.) Dr. Nesbitt moved to Stanford Research Institute (SRI) in 1974, where he worked on the seminal energy models the SRI-Gulf Model and the SRI World Energy Model and became the Manager of the Decision Analysis--Energy group. In 1977, Dr. Nesbitt cofounded the management consulting company Decision Focus Incorporated (DFI), where he remained as a principal until 1995. In 1995, Dr. Nesbitt and a few senior colleagues founded Altos Management Partners so that they could reinitiate their personal practices assisting senior management in the energy and other industries. Dr. Nesbitt is well known in the energy industry for his market analysis products including the North American Regional Gas (NARG) model, the World Gas Trade model, the World Oil Model, the Western European Gas Model, and most recently the North American Regional Electricity Model. The market modeling methods developed by Dr. Nesbitt have been used for most of the North American energy companies in the oil, gas, and electricity business as well as a number of the key world players in Europe, Asia, the Middle East, South America, Australia, and Canada.

Dr. Nesbitt's consulting companies have spanned a broad range of industries and activities. He and his companies have worked outside as well as inside the energy industry. Outside the energy industry, Dr. Nesbitt's consulting companies have done seminal work in high technology (product pricing, new product introduction), airlines (fleet allocation, scheduling, and seat pricing for United, Continental, SAS, British Air, KLM), rental car companies (car pricing for Hertz), telecommunications (product line pricing for Pacific Bell, GTE, Bell Atlantic, NYNEX), trucking companies (Yellow), shipping (SeaLand-CSX), and environmental remediation. Inside the energy industry, Dr. Nesbitt has worked on every major pipeline that has entered the scene since 1980, valued the upstream business in every producing basin in North America, supported trading among many of the regions and hubs in North America, computed the value of Duke for the Duke-PanEnergy merger, developed power plants in various locations, valued upstream and pipeline assets in Asia, Australia, the Middle East, Europe, and South America, calculated forward prices and price differentials in and between every North American electric generation region, supported the California generation plant auction for two prospective bidders, and recently valued each and every power plant in North America to support acquisition for one of the big players. Dr. Nesbitt is just completing development of a new market prognostication system named MarketPoint that promises to reduce the cost, increase the accuracy, augment the profits, and reduce the risks of people who value their assets and trade their products using it.

ALTOS

DR. DALE M. NESBITT, President and CEO

Dr. Nesbitt holds a B.S. degree in Engineering Systems from the Univerity of Nevada—Reno, an M.S. degree in Mechanical Engineering at Stanford University, and and M.S. and a Ph. D. degree in Engineering-Economic Systems from Stanford Univerity.

ALTOS
DR. DALE M. NESBITT, President and CEO

FPSC Docket No. 000289-EU
Panda Midway: Nesbitt
Exhibit (DMN-2)
Page 1 of 19

DR. DALE M. NESBITT

HISTORY OF WORK ASSIGNMENTS AND PUBLICATIONS

Current as of March 2000

ALTOS
MANAGEMENT PARTNERS INC

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Los Altos Hills, CA 94022
(650) 949-3541 Business
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(650) 948-3396 FAX
dale.nesbitt@altosmgmt.com

ALTOS

DR. DALE M. NESBITT, President and CEO

SPECIALIZED PROFESSIONAL COMPETENCE

Guidance to corporate governance and senior management regarding investment, business development, marketing, cost management, risk management, and pricing decisions; competitive strategy; business process design; yield management and product line pricing; systems automation; modeling of energy and other commodity markets; risk management; management education.

MAJOR CONSULTING PROJECTS AT ALTOS MANAGEMENT PARTNERS INC. (1995-present)

Panda International	Support of two greenfield power plants in Florida.
Calpine	Support of greenfield power plants in Florida.
Cogentrix	Support of greenfield power plants in Florida.
El Paso Energy	Expansion and use of short term North American Regional Gas (NARG) model to predict forward prices, basis differentials, and values of storage and other arbitrage activities.
Atlanta Gas Light Company	Support of capacity plan following complete deregulation, unbundling, and auction of service to marketers and aggregators.
Reliant Energy	Support of European gas and electricity activities related to Reliant's purchase of Dutch electric company Una.
DOE/EIA	Analysis of nuclear plant reliability and prospective decommissioning.
New Mexico Oil and Gas Association	Invited speaker at annual conference.
BHP Petroleum	Construction and operation of Australian natural gas model.
Eureka County, Nevada	Support of Coastal Power Development Ruby pipeline and 500 MW combined cycle power development project at Newmont and Barrick gold mining properties.
Calpine	Supported project finance "Deal of the Year" Magic Valley credit

	revolver. Award banquet in New York at Waldorf Astoria on March 7, 2000 acknowledged Calpine Magic Valley as part of the "Deal of the Year."
Calpine	Economic model of the Colorado market.
PG&E Generating	PG&E Generating (formerly US Generating). Lead economic witness in the Okeechobee testimony before the Florida Public Service Commission.
Calpine	Economic model of the Nevada market to distinguish attractive from unattractive development sites
Calpine	Economic model of the Southern California market to distinguish attractive from unattractive development sites
Credit Suisse First Boston and ScotiaBank	Independent market analysis in support of the Calpine Magic Valley plant
Calpine	Developed the Calpine Magic Valley plant and presented it to the banking consortium (led by Credit Suisse First Boston and ScotiaBank)
Duke Energy	Duke. Lead economic witness in the Duke New Smyrna Beach testimony before the Florida Public Service Commission.
Texas Utilities	Texas Utilities. Valued all the California generation assets and recommended which ones to bid and how much to bid. Valued every generation plant in North America.
Duke Energy	Duke International. Built a model of the Ecuadorian electric and gas system and recommended an asset acquisition strategy.
Sonat	Sonat. Short term gas model to support trading. Electric model to evaluate generation projects in SERC, FPCC, MAPP, California, and elsewhere.
Coastal	Colorado Interstate Gas. Short term gas model
Southern California Edison	SCE. Developed a gas strategy for the post divestiture company.

PG&E	PG&E. Detailed electricity model of the United States and Texas ERCOT.
Pacific Gas Transmission	PGT. Valuation of Texas gas pipeline acquisitions.
BC Gas Company	BC Gas. Presented testimony to advocate the BC Gas Southern Crossing Project.
Duke Energy	Duke. Provided forward price projections to support critical power projects including St. Francis, Bridgeport, New Smyrna Beach, California (Moss Landing, Morro Bay, Oakland), Cajun.
Duke Energy	Duke. Calculated the intrinsic economic value of Duke Power for PanEnergy senior management to quantify economic value of the merger.
NationsBank	NationsBank. Seminar for 60 principal derivative customers.
MidCon	MidCon. Valuation of NGPL Amarillo and Eastern lines while Occidental was "shopping it around." MidCon wanted to know what was the right price, and they knew that they got higher than that.
El Paso/Tennessee	El Paso/Tennessee Gas Pipeline. Immediately following the El Paso acquisition, quantify the economic value of each of their key assets (lines 100, 200, 300, 500, 800, K-N, Broad Run, Midwestern Gas Pipeline). Tennessee wanted to know the value of their assets and whether to rehabilitate/upgrade with electric compression.
BHP Petroleum	BHP Petroleum. Southeast Australian gas model construction and transfer to MarketPoint.
	Turgen. Prospective development of integrated electricity-desalination units in the Middle East.
Pan Energy	PanEnergy Corporation. Comprehensive market model of North American electricity business in emerging deregulated environment to

	support asset acquisition, divestiture, merger/acquisition, marketing, and hedging decisions.
Amoco	Amoco. Analysis of market and profitability of North American natural gas business.
BHP Petroleum	BHP Petroleum Ltd. Constructed and used model of Australian natural gas supply, transportation, distribution, and demand to support exploration and development strategy.
Pacific Gas Transmission	Pacific Gas Transmission. Provided advice regarding potential acquisition.
PG&E	Pacific Gas and Electric Company. Supported testimony before California Public Utilities Commission regarding prudence of PGT/PG&E Expansion pipeline decision.
EPRI	Electric Power Research Institute. Whitepaper on the role of natural gas in the soon-to-be-deregulated electric industry.

MAJOR CONSULTING PROJECTS AT DECISION FOCUS (1977-1995)

Wisconsin Power and Light	Wisconsin Power and Light Company. Consultations regarding what emerging deregulation would mean to WP&L assets, strategy, and pricing.
Shell Oil	Shell Canada Ltd. Helped design a marketing strategy and implementation.
PanCanadian	PanCanadian Petroleum Ltd. Product line management for direct gas sales using Yield Management.
Pacific Gas Transmission	Pacific Gas Transmission. Provided testimony to advocate roll-in pricing of PGT Expansion project facilities before FERC. PGT was able to prevail through settlement in that litigation
Mobil Oil	Mobil Oil Corporation. World gas investment and marketing strategy.

Amoco	Amoco. European and Russian gas investment and marketing strategy.
Nova Corporation of Alberta	Nova Corporation. Customer and marketing support to 20 largest customers.
Williams	Williams Energy. Development of cogeneration project in Southwestern United States.
PG&E	Pacific Gas and Electric Company. New Method for managing transmission and distribution maintenance and rehabilitation assets.
Atlantic Richfield	Atlantic Richfield Company. Asian investment, operation, and marketing strategy.
	Canadian Enerdata. Characterization of commodity, index, and derivative trading in the Canadian gas business.
EPRI	Electric Power Research Institute. Support of member fuel purchasing working group.
Secretary of Energy of Mexico	Secretariat de Energia, Minas, y Industrias Patrimonios (SEMIP), Republic of Mexico. Supported SEMIP and PEMEX policy related to near term purchases of gas from the United States and long term purchases and/or sales between the United States and Mexico.
PG&E	Pacific Gas and Electric Company. Development of quantitative decision system to guide gas transmission and distribution system rehabilitation, replacement, and maintenance decisions.
Federal Highway Administration	Federal Highway Administration. Development of Bayesian statistical pavement performance methods, software, and training.
BHP Petroleum	BHP Petroleum. Built a gas market model of the Southern Cone of South America to support strategy for Latin American production, pipeline, and generation investments.
Potash Corporation of Saskatchewan	Potash Corporation of Saskatchewan. Strategy for controlling economic and environmental of salt and brine disposal.
Prince Edward	Prince Edward Island Department of Transportation. Application of

Island Department of Transportation	software and methods to predict pavement performance using Bayesian methods.
	City of Saskatoon Department of Public Works. Training session on advanced methods for asset management and performance prediction.
Atlantaic Richfield Company	Atlantic Richfield Company. Marketing strategy.
National Petroleum Council	National Petroleum Council. Assisted the Imports and Alaska, Unconventional Gas, and Conventional supply groups in quantifying prices and market implications of alternative resource supply scenarios.
Amoco	Amoco. Developed a world gas strategy and a Western European gas strategy.
Agip	Agip. Western European gas strategy
Chevron	Chevron. Development of a world gas strategy. We provided special assistance Chevron's African oil and gas strategy and Western European gas strategy.
Final Oil and Chemical	Fina. World gas strategy. Western European gas strategy.
Enron	Enron. World gas strategy. Western European gas strategy.
Phillips Petroleum	Phillips. World gas strategy Western European gas strategy.
Texaco	Texaco. World gas strategy. Western European gas strategy.
California Energy Commission	California Energy Commission. World and imported gas market analysis

Exxon	Exxon. World gas strategy.
Shell Oil Company	Shell. World gas strategy.
Amerada Hess	Amerada Hess. Western European gas strategy.
Baytrust/Unilon	Baytrust/Unilon. Western European gas strategy.
British Petroleum	BP. Western European gas strategy Confidential consulting related to European gas business.
British Gas	British Gas. Western European gas strategy.
Conoco	Conoco. Western European gas strategy.
Enterprise Oil	Enterprise Oil. Western European gas strategy.
Lasmo	Lasmo. Western European gas strategy.
Oryx Energy	Oryx. Western European gas strategy.
Santa Fe Minerals	Sante Fe. Western European gas strategy.
Nuclear Electric Company	Nuclear Electric. Western European gas strategy.
THE WORLD BANK	World Bank. Development of petroleum resources in Bangladesh.
Pacific Gas Transmission	Pacific Gas Transmission Company. Market and regulatory analysis of PGT expansion project.
Maxus Energy	MAXUS. Strategic price analysis.
Roads and Transportation Association of Canada	Roads and Transportation Association of Canada. Implementation and application of Bayesian statistical technique to predict pavement performance. In collaboration with the Roads and Transportation Association of Canada, we have conducted statistical analysis in: • Ontario • Saskatchewan • Newfoundland

Final Oil and Chemical	FINA. Strategic analysis.
TransCanada Pipelines	Transcanada Pipelines. Recommendations regarding California and other United States markets.
National Petroleum Council	National Petroleum Council. Support of Imports and Alaska group and Unconventional Gas group.
Pacific Gas Transmission	Pacific Gas Transmission Company. Recommendations regarding Pacific Gas Transmission expansion project for Board and senior management.
Enron	Enron. Strategic price analysis.
City of Saskatoon	City of Saskatoon. Three-day seminar in public infrastructure finance and management.
Los Angeles Department of Water and Power	Los Angeles Department of Water and Power. Analyzed various bypass options and made recommendation.
Southern California Edison	Southern California Edison. Strategic analysis of which prospective new pipeline corridor (if any) Southern California Edison should commit to. Public testimony before the California Public Utilities Commission made reference to the study and conclusions.
Southern California Gas	Southern California Gas Company. Delivery and support of GEMS software and NARG model.
TransCanada Pipeline	TransCanada PipeLines Company. Confidential.
Pacific Gas Transmission	Pacific Gas Transmission Company. Confidential.
Westcoast Energy	Westcoast Energy. Prepared submission to California Energy Commission and California Public Utilities Commission advocating the prospective attractiveness of British Columbia gas in California.

Gulf Canada Ltd.	Gulf—Canada. Prepared submissions to the National Energy Board to secure a certificate for export to the United States of MacKenzie Delta gas. Partly as a result of our work, Gulf¾Canada won its export certificate in late 1989.
Exxon	Esso Resources (Exxon). Prepared submissions to the National Energy Board to secure a certificate for export to the United States of MacKenzie Delta gas. Partly as a result of our work, Esso won its export certificate in late 1989.
Shell Oil	Shell—Canada. Prepared submissions to the National Energy Board to secure a certificate for export to the United States of MacKenzie Delta gas. Partly as a result of our work, Shell—Canada won its export certificate in late 1989.
Shell Oil	Shell USA. Confidential.
Roads and Transportation of Canada	Roads and Transportation of Canada (RTAC). Canadian Long Term Pavement Performance Program.
El Paso Natural Gas	El Paso Natural Gas. Prepared submission for the California Energy Commission and the California Public Utilities Commission advocating El Paso's position regarding the need for new interstate pipeline capacity into California.
Alberta Department of Energy	Alberta Department of Energy. Delivery and support of GEMS software and NARG model.
Canadian Energy Research Institute	Canadian Energy Research Institute. Support of Continental Gas Study No. 2.
National Energy Board of Canada	National Energy Board of Canada. Delivery and support of GEMS software and NARG model.
Energy Information Administration	Energy Information Administration (EIA). Forecasts of natural gas imports from Canada to the United States and calibration to the published results of the National Energy Board of Canada. I also made recommendations regarding longer term forecasting and national energy

strategy modeling system.

Atlantic Richfield Company	Atlantic Richfield Company. Renegotiate gas contracts in the face of falling prices.
Lawrence Berkeley Laboratory	Lawrence Berkeley Laboratory. Delivery and support of GEMS software and NARG model.
Lawrence Livermore Laboratory	Lawrence Livermore National Laboratory. Delivery and support of GEMS software and NARG model.
State Electricity Commission of Victoria	State Electricity Commission of Victoria (Australia). Demand-side planning for the electric generation, transmission, and distribution company in the state of Victoria, Australia. Integrated end use model of the state of Victoria to support demand-side management and supply issues.
Yukon Pacific Corporation	Yukon Pacific Corporation (Trans Alaska Gas Pipeline). Provided definitive written testimony regarding the economic impact of North Slope gas delivered to the Lower 48 United States through overland pipeline. Defended written testimony before the Economic Regulatory Administration.
California Energy Commission	California Energy Commission Gas-Related Assignments. Developed CEC North American Regional Gas (NARG) Supply-Demand Model and attendant data base. Trained CEC staff in ongoing independent use of NARG model. Developed definitive CEC report on California pipeline expansion. Developed slideshows and documentation in use by CEC to meet its gas forecasting and decision making needs. California Energy Commission Oil-Related Assignments. Contributed to development of short run model of world oil price to complement long run model. Contributed to review of California petroleum models. Contributed to development of model of California petroleum economy.
American Gas Association	American Gas Association. Instructor at cogeneration facility valuation seminar sponsored by the AGA for its members.
Canadian Western	Canadian Western. Developed techniques for assembling cogent probabilistic interviews of ten internationally known experts in gas spot and contract pricing. Conducted interviews of spot versus firm prices.

Synthesized interviews into cogent probability distributions over spot and contract prices.

Los Angeles Department of Water and Power

Los Angeles Department of Water and Power (LADWP). Assisted LADWP formulate a natural gas bypass strategy that would involve LADWP investment in interconnections with new pipelines that might penetrate California.

Southern California Edison

Southern California Edison (SCE) Company. Helped SCE analyze and understand how they should procure gas. Should they commit to new pipelines? Should they throw their support behind any particular pipeline? Should they confine their support to current pipelines? Should they commit to system gas on any pipeline? Helped SCE understand interfuel competition and multiregion competition and its prospective impact on their business.

Petro Canada

Petro-Canada. Generated price-volume business environment and attendant business plans.

Gulf Canada Ltd.

Gulf (Canada). Prepared testimony to the National Energy Board on the economic impacts of the MacKenzie Delta gas pipeline.

Esso Canada Ltd.

Esso (Canada). Prepared testimony to the National Energy Board on the economic impacts of the MacKenzie Delta gas pipeline.

Shell Canada Ltd.

Shell. Prepared testimony to the National Energy Board on the economic impacts of the MacKenzie Delta gas pipeline.

National Energy Board of Canada

National Energy Board of Canada. Developed September 1988 biennial forecast (published as an official document of the NEB). Analyzed impact of alternative assumptions regarding the United States resource base. Analyzed MacKenzie Delta pipeline.

Saskatchewan Department of Highways

Saskatchewan Highways. Value of obtaining better traffic information using new (and expensive) weigh in motion equipment. Is the information of sufficient value in shaping design and maintenance decisions to justify the high cost of expensive weigh-in-motion equipment? The answer was no. Development of sophisticated new pavement management tools and techniques and delivery of seminar to Saskatchewan Highways.

Canadian Energy Research Institute	Canadian Energy Research Institute. Provided model for Continental (North American) Natural Gas study.
Department of Energy	Department of Energy/Energy Information Administration. Development of cases coordinated with the National Energy Board of Canada to support EIA forecasting objectives.
LSI Logic	LSI Logic Corporation. New product introduction decision. Integrated Device Technology Inc. (semiconductor manufacturer). Pricing of semiconductor products.
Pacific Bell	Pacific Bell. Integrated planning of pricing, revenue, and demand for their telecommunications product line.
Bell Atlantic	Bell Atlantic. Redesigned strategic decision making process for network side of the business
GTE	GTE Services Corporation and General Telephone of Florida. Project supervisor. Customization of Product Management and Pricing for Telcos (PROMPT) capability to GTE/Florida service territory. Application to bypass, competition, pricing and amended calling area decisions.
Gas Research Institute	Gas Research Institute (GRI): Structured and implemented a quantitative procedure to manage GRI's R&D programs given GRI's R&D budget and other limitations. Determined the price and quantity implications of GRI's anticipated technology achievements. Structured and implemented multiattribute consumer choice model to support end-use R&D decision-making. Developed a supply strategy for GRI. Developed detailed models of the U.S. natural gas supply system. Developed demand models of the residential, commercial industrial, electric sectors
Standare Oil of Indiana	Standard Oil Company of Indiana (Amoco)/Natural Gas Supply Association, prepared comments for testimony on FERC Order 436.
Panhandle Eastern	Panhandle Eastern Pipe Line Corporation. Confidential

California Energy Commission	California Energy Commission. Implemented and supported a comprehensive model of the North American Natural Gas system including the United States, Canada, and Mexico so that the California Energy Commission can understand how California affects and is affected by the entire North American System.
LSI Logic	LSI Logic Corporation. Confidential.
Roads and Transportation Association of Canada	Roads and Transportation Association of Canada (RTAC). Built a model to characterize the effect of vehicle weights and dimensions regulations on truck transportation in Canada.
Elizabethtown Gas	Elizabethtown Gas Corporation. Gas purchasing strategy.
Pacific Lighting	Pacific Lighting Corporation. Expert testimony.
San Diego Gas and Electric	San Diego Gas and Electric Corporation. Gas purchasing strategy.
Consolidated Edison	Consolidated Edison. Gas purchasing strategy.
National Academy of Science	National Academy of Science. Invited presentation before a National Academy committee to discuss how R&D decisions are actually made in the private sector, how R&D decisions should be made, and what analytical tools are required to support such decision.
Saskatchewan Department of Highways	Saskatchewan Department of Highways. Invited presentation on how to build and computerize an analytical system to manage preventive maintenance, repair, rehabilitation, and reconstruction options in the Saskatchewan highway system.
Department of Energy/Fossil Energy Division	U.S. Department of Energy/Fossil Energy Division. Developed a textbook on utility and nonregulated industry finance. Developed a textbook relating project finance and corporate financial statements. Determined the appropriate national R&D strategy toward unconventional oil (e.g., tertiary oil recovery, tar sands). Developed a quantitative framework for determining effective R&D strategies for liquid and gaseous fuels.

Developed a critical review and synthesis of depletable resource exploration, development, and production models.

Energy Information Administration — Energy Information Administration (EIA). Design and development of their longer range forecasting model.

Standard of Ohio — The Standard Oil Company of Ohio (Sohio). Delivered the capability to represent the effect of interfuel competition on a broad range of Sohio business areas.

Illinois Department of Energy and Natural Resources — Illinois Department of Energy and Natural Resources. Delivered a capability to analyze energy supply, demand, and regulation within the state of Illinois and determine its implications for state regulators.

Peoples Republic of China — People's Republic of China. Member of natural gas industry delegation in 1982 to the People's Republic of China.

U.S. Department of Energy — U. S. Department of Energy, Office of Oil Policy. Developed a world oil model for use in price-quantity forecasting and policy analysis.

Tennessee Valley Authority — Tennessee Valley Authority (TVA). Developed an advanced production costing/optimal capacity expansion planning model.

Atlantic Richfield — Atlantic Richfield Corporation (Arco). Analyzed alternative business area investments.

Anaconda Company — Anaconda Company. Analyzed new property development decision for the Tonopah molybdenum project.

Argonne National Laboratory — Argonne National Laboratory (ANL). Delivered energy-economy models to developing countries including South Korea, Portugal, and Argentina. Designed a new modeling capability for use by developing countries.

Oak Ridge National Laboratory — Oak Ridge National Laboratory/DOE Fossil Energy. Formally related the methods underlying the Generalized Equilibrium Model to accepted economic theory. Developed a sophisticated quantitative framework for R&D portfolio management. Developed liquid and gaseous fuel supply models to support R&D decision-making.

Stanford University	Stanford University Energy Modeling Forum. Participant, Oil and Gas Modeling Forum, North American Natural Gas Modeling Forum, and North American Electric Modeling Forum.
ERDA Office of Fossil Energy	Office of Fossil Energy, ERDA. Managed an analysis of the effect of price controls on R&D strategies under the Market Oriented Program Planning Study (MOPPS).
American Gas Association	American Gas Association. Analysis of the consumer impacts of investments in high-cost sources near centers of demand.
National Research Council	National Research Council, Committee on Nuclear and Alternative Energy Systems. Energy modeling support.
Lawrence Livermore Laboratory	Lawrence Livermore Laboratory. Analyzed national benefits of energy technology R&D at Livermore.
Solar Energy Division, ERDA	Solar Energy Division, ERDA. Computed the magnitude of subsidy required to attain "target" solar energy penetrations.
Various Oil Companies	Various Oil Companies. Computation of price-quantity forecasts and strategic analyses using the SRI-Gulf Energy Model.
Council on Environmental Quality	Council on Environmental Quality. Study of western U.S. coal, oil shale, and synthetic fuels.
Velsocol Chemical	Velsicol Chemical Corporation. EPA Chlordane Suspension Hearings. Prepared legal testimony and questions to refute government economic analysis of chlordane suspension.
Stockholm Energy Board	Stockholm Energy Board. Analysis of proposed site for nuclear steam/electric plant within a district heating system.

MAJOR CONSULTING PROJECTS AT STANFORD RESEARCH INSTITUTE (1974-1977)

- National Science Foundation. Comparative analysis of methodologies for large-scale energy modeling.

- Office of Commercialization, ERDA. Analyzed the national economic, environmental, social, and financial costs and benefits of government incentives for synthetic gas and shale oil plants.

- Office of Management and Budget Inter-Agency Task Force on Synthetic Fuels Commercialization. Cost/benefit analysis of program alternatives and projections of synthetic fuel supply and demand.

- Electric Power Research Institute. Developed price and quantity to support R&D decision-making.

- Multiclient World Energy Study. Projection of world energy supplies, demands, prices and trade flows through 2025.

- Fossil Energy Division, ERDA. Developed and applied a new methodology for planning R&D decisions for several key fossil-related technologies.

XEROX PALO ALTO RESEARCH CENTER (1972-1974)

- Analyzed the decision to introduce the first generation of xerographic laser computer printers.

MANAGEMENT AND TECHNICAL EDUCATION EXPERIENCE

- Marketing, market positioning, and sales training program, focusing on effective company-to-company sales.

- Training program in how to understand and quantify the realities of competitive commodity, product, and service markets.

- Executive decision analysis seminars for U.S. companies and government agencies.

- Technical decision analysis seminars for analysts in many U.S. companies and federal agencies.

- Technical presentations to audiences of professionals or students at Stanford University and various analysis organizations.

MANAGEMENT EXPERIENCE

- Chairman of the Board, MarketPoint Inc.
- Vice President and Director, Reticle Inc.
- Senior Consultant, President, CEO, and Cofounder of Altos Management Partners Inc. (1995-present)
- Senior Principal and Cofounder of Decision Focus Inc. (1977-1995)
- President of Decision Focus Inc. (1984-1986)
- Secretary-Treasurer of Decision Focus Inc. (1983-1984)
- Manager, Decision Analysis-Energy Department at Stanford Research Institute.

ACADEMIC BACKGROUND

- Ph.D., Engineering-Economic Systems, Stanford University (1975).
- M.S., Engineering-Economic Systems, Stanford University (1972).
- M.S., Mechanical Engineering, Stanford University (1970).
- B.S., Engineering Science, University of Nevada (1969).

SELECTED PUBLICATIONS

- *A Comparative Analysis of Methodologies for Large-Scale Energy Modeling,* (coauthor), National Science Foundation/SRI Report (1977).
- "General Equilibrium, Duality Theory, and the Translog: An Elementary Introduction and Synthesis" (coauthor), *Economic Applique,* Archives de l'Institute de Sciences Mathematique et Economiques Appliques (1979).
- "The Economic Cost of a National Nuclear Moratorium" (coauthor), *Energy Policy* (1977).

- "A Decision Analysis of the Appropriate R&D Strategy for Enhance Oil Recovery (EOR)," (coauthor), *Energy Systems and Policy*, Volume 7, Number 3 (1983).
- "The Economic Benefits of R&D on Gas Supply Technologies," (coauthor), *Gas Research Insights*, Gas Research Institute, 8600 West Bryn Mawr Avenue, Chicago, IL 60631 (1985).
- "The Economic Foundation of Generalized Equilibrium Modeling," *Operations Research*, Vol.32, No.6, November-December 1984.
- "A Model of the World Oil Market with an OPEC Cartel," (coauthor), *Energy*, 1985.
- "Design of a Liquid Fuels Supply Model for U.S. Policy Analysis," (coauthor), *Energy*, Volume 8, No.3, 1983.
- A Theory of Supply Cartels with Application to OPEC, DFI Working Paper (1984).
- "Integrated National Energy Planning--A Case Study of the Republic of Korea," (coauthor), *Energy Journal*, January 1985.
- *Recommendations for a Synthetic Fuels Commercialization Program: Cost/Benefit Analysis* (coauthor), U.S. Government Printing Office (1975).
- *An Analytic Method for Making Research and Development Decisions*, (coauthor), DFI Working Paper (1984).
- "Pricing and Product Management at Pacific Bell," *Public Utilities Fortnightly*, October 3, 1986.
- *Improving Profits in Potash Mining by Managing Risks*, (coauthor), Canadian Institute of Mining and Metallurgy, October 1986.
- *A Computationally Efficient System for Infrastructure Management with Application to Pavement Management*, (coauthor), presented at Second North American Conference on Managing Pavements, Toronto, Canada, November 1987.

FPSC Docket No. 000288-EU
FPSC Docket No. 000289-EU
Panda Leesburg: Nesbitt
Exhibit (DMN-3)

NEED FOR THE PANDA LEESBURG AND MIDWAY GENERATION PROJECTS IN THE FRCC

Prepared by
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April 21, 2000

Florida Public Utilities Commission Dockets 000288-EU and 000289-EU

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1 THE PANDA MIDWAY POWER PARTNERS (PANDA MIDWAY) PROJECT AND THE PANDA LEESBURG POWER PARTNERS (PANDA LEESBURG) PROJECTS

1.1 Summary of the Projects

The Panda Midway and Panda Leesburg projects (which we call the Projects) are each nominally 1000 MW plants to be built and operated as merchant plants on two different sites in Florida. The Panda Leesburg Project will be located in Lake County near the Central Florida Substation of Florida Power Corporation (FPC). The Panda Midway Project will be located in St. Lucie County near the Midway Substation of Florida Power and Light Company (FPL).

The Panda Leesburg Project is scheduled to come into commercial service in May 2003. The Panda Leesburg project will tap two power lines in the vicinity of FPC's Central Florida Substation, namely the Central Florida Substation to Camp Hill 230 KV line and the Central Florida Substation to Clermont East 230 KV line. Gas for the project will be taken from the GulfStream gas pipeline. The Panda Leesburg project is comprised of four GE Frame 7FA or equivalent units, four matched heat recovery steam generators, and two steam turbine generators.

The Panda Midway Project is scheduled to come into commercial service in May 2003. The project will be located at a terminus of GulfStream gas pipeline, which will provide the gas. The Project will be connected to the Peninsular Florida transmission grid at the Midway Substation of Florida Power and Light Company. No new transmission lines will be required for interconnection to the FPL Midway Substation, which is immediately contiguous to Panda Midway's site. The Panda Midway Project is comprised of four high technology gas combustion turbines, four matched heat recovery steam generators, and two steam turbine generators.

The Leesburg and Midway Projects will have an approximate heat rate of 6,900 Btu/KWh (net heat rate, higher heating value of gas) at 100 percent load at 60 degrees Fahrenheit and relative humidity of 70 percent. I understand that the Projects will be equipped with low-NO_X burners. For modeling and evaluation purposes, we have assumed a heat rate of 6,900 Btu/KWh for the Projects. Also, we have assumed for analysis purposes a fully commoditized variable operating and maintenance cost (excluding fuel) of $2.00/MWH. Such assumptions are consistent with my experience for similarly configured plants.

1.2 Background of the Analysis

While the work underlying this report was performed under contract with Panda Energy International, this report represents my best judgment and professional opinions. To wit, the forward price calculations are not drawn from proprietary or confidential data from Panda Energy

International or any of its affiliates nor are they drawn from analysis or data provided by Panda. My objective has been to apply and put forth my best professional analysis and judgment based on what I consider to be the best available technology, experience, and data, not to mirror Panda's analysis or projections. Panda has reviewed with me their basic plan for the Leesburg and Midway Project, but it has been my responsibility to quantify those assumptions and to extract the project details from the Panda filing submitted to the Florida PSC. The final responsibility for the assumptions related to the economic analysis of the Panda Leesburg and Midway Projects presented herein was my responsibility. All work upon which this report is based was performed by me or under my direct supervision.

2 BACKGROUND RELATED TO MERCHANT POWER PLANTS

2.1 Definition of Merchant Power Plants

It is important to carefully restate what merchant power plants such as Panda Leesburg and Panda Midway are. I agree with the Florida PSC's stated definition of a merchant power plant as "a power plant with no rate base and no captive retail customers." To expand, a merchant power plant is an electric generation plant that has no mechanism by which it can force any customer, aggregator, marketer, utility, or any other individual or organization to either purchase its power output or to pay capital, operating, maintenance, fuel, or any other cost associated with that plant. What distinguishes a merchant plant from a non-merchant plant is that the merchant plant has absolutely no "cost passthrough" capability; it cannot force its costs on anyone.

Similarly, the Merchant Power Scoreboard defines "merchant" power generation capacity to be "capacity that has been either acquired or developed without long-term offtake commitments." The plant investors and operators shoulder the full risk of cost recovery as well as the expectation of adequate returns. Every customer of a merchant power plant is a voluntary customer, a customer that signs whatever power purchase contracts it wishes with the merchant power plant entirely of its own volition (or does not sign any contract at all but rather chooses to make spot purchases). Once a customer signs a contract, of course the contract is valid and enforceable. However, with a merchant plant, there is no certainty from the perspective of the plant owner of having signed power contracts prior to commissioning. The key word in merchant plant generation is "voluntary;" there is no authority that has the ability to force merchant plant costs to be paid by any third party.

Typically, a merchant power plant is situated within the boundaries of the service territory of a specific investor-owned utility, municipal, or electrical cooperative. (For example, the Panda Leesburg Project is located within the Florida Power Corporation retail service area, and the Panda Midway Project is located with Florida Power and Light retail service area. By analogy to other merchants around the country, the St. Francis plant in Missouri is located within Associated Electric Cooperative Inc.'s service area. The Magic Valley project will be located within the service area of Magic Valley Electric Cooperative in South Texas. The FPL Energy Bellingham, Massachusetts project is located within the Massachusetts Electric service area. The Calpine Sutter Plant is located within the PG&E service area.)

Frequently, a merchant power plant is owned by an entity other than the local utility, municipal, or cooperative in whose service area it is situated, but sometimes it is owned in direct partnership with the local incumbent utility. A power plant that is owned by a strictly external party is a pure merchant facility because it has no cost passthrough rights in the local service area and therefore must secure all its revenues through capacity plus energy sales based on various power purchase agreements (PPAs) within that service area. It is debatable whether a power plant that is jointly owned by an incumbent utility and an external party is or is not a merchant plant because there is always the possibility that the local incumbent utility will prefer its own plant and will therefore secure some degree of cost passthrough from its local regulators. The Leesburg and Midway plants are both pure merchant plants.

2.2 Functions of Merchant Power Plants

Merchant power plants provide a number of functions in the United States energy supply and distribution system, including but not necessarily limited to the following:

- **True cost minimization.** As I discuss elsewhere in this report, merchant plants have stronger incentives to pursue true cost minimization than do incumbents. The lower a merchant plant's costs, the more money its owners make (within prudent limits of operation, of course). Merchant plants have direct incentives to drive down generation cost because they capture as margin the difference between market price of capacity plus energy (over which they have no direct control) and their cost (over which they do have direct control). They have incentive to embrace new, best available technology in pursuit of true cost minimization. (This argument is not to be taken to the absurd. By low cost, I mean lowest, prudent, responsible operation at lowest possible prudent cost.)

- **Increased system reliability.** Reliability is somewhat of a "public good" in the immediate vicinity of a plant in a competitive market. (Reliability is a "public good" in a competitive market—it accrues to everyone whether they pay for it or not.) The Leesburg and Midway plants' very existence bolsters reliability in the vicinity of those plants. I will discuss later in Section 6 of this report precisely why the Leesburg and Midway plants directly and unequivocally increase system reliability within the FRCC. People who argue that uncontracted merchant units do not increase system reliability are wrong. Merchants physically deliver valuable electrical energy to the market hub most contiguous to their busbar, and they necessarily render supply more reliable at that busbar. Reliability accrues as a public good at that busbar by the very entry of that plant, even though its individual unit availability might not be 100 percent.

  The empirical evidence for such assertions are everywhere around us. Is gold delivery reliable because of the flourishing spot and forward exchange markets? Yes, reliability is an attendant benefit, enhanced reliability of supply. What about natural gas? Again the answer is yes. I submit the answer is yes for everything traded on exchanges in highly competitive public settings—wheat, crude oil, soybeans, copper, yen, etc. It is preposterous to argue that the reliability within the FRCC is not enhanced by the entry of another plant like Leesburg and Midway. Reliability is enhanced by the entry of every plant whether it is a merchant or utility owned plant and whether or not it is committed by contract. Reliability is in a very important sense a "public good" that accrues from participatory markets.

- **Geographic diversity and dispersion of generation.** Merchant plants sometimes occur in smaller capacity increments, and they are usually distributed throughout a given region rather than concentrated at a few central station generation areas. Diversity of siting cuts down on the need for new or additional transmission lines and large central station units and contributes to system redundancy and reliability. (As an illustrative example, one hundred sources each comprising 1/100 of a load are intrinsically more reliable than one single source comprising 100 percent of that load. The probability of a shortage (loss-of-load probability) is lower in the former case than in the latter. Leesburg and Midway both contribute directly to geographic diversity.

- **Improvement in the environment.** New, highly efficient, gas-fired technology is far less polluting than older generation technology simply because new technology with the much improved heat rate that it has moves only approximately half the fuel through the combustion unit than does older generation technology. There are therefore one half the waste molecules to dispose of, per each KWh of power generated. Furthermore, new technology burns methane (CH_4), commonly referred to as natural gas, and therefore produces as byproducts only carbon dioxide, water, and limited NO_X and CO emissions.

- **Price depression/suppression through merchant entry.** As I discuss elsewhere in this report, merchant plants have incentives to operate more efficiently and at higher levels than incumbent utilities' plants. (Incumbent utilities have incentives to run all their plants a little rather than to run their best plants all the time and their worst plants not at all.) Because merchants operate more aggressively than other plants, they induce the maximum possible price depression in they system in which they operate.

- **Correct and proper benchmarking.** Merchant power plants can be used to benchmark the cost structure of the incumbent utility. Merchant power plants have incentive to "chase price" and capture margins whenever they exist. By gaining price-chasing operating experience, merchant plant operators promise to explore and perfect new utility operating practice and thereby to catalyze changes in how utilities run plants. In the past, protected by cost recovery, utilities tended to run their plants conservatively. They did not pursue margin maximization or cost minimization but rather pursued steady state operation and maximal preservation of equipment. In the vernacular, utilities were managed by engineers rather than businessmen, economists, or finance people. That is changing for the better, and merchant plants such as Panda Leesburg and Midway are important catalysts.

- **Reducing the number of MWH generated by old, inefficient, high-cost, and high-polluting plants.** One of the functions of merchant plant entry is to promote economic Darwinism, i.e., survival of the fittest, by which I mean decreasing the production levels from old, inefficient, high-cost plants that should not be running as much because they are too costly. This is a positive, not a negative force. Old, high-cost, and high-polluting plants need to be scaled back precisely because they are old, high polluting, and high cost. Merchant entry accelerates this result.

- **Unbundling generation from transmission and distribution.** The entry of merchant plant facilitates the efficient operation of the generation sector through promoting decoupling and eventually unbundling of the generation business from the transmission and distribution business.

- **Rendering wholesale electricity prices transparent.** Entry of a significant number of merchant plants operating in the state renders the transfer price at the busbar and at the point of wholesale transaction much more transparent and much more tradable. Price transparency fosters efficient decision-making by producers and consumers, incumbents as well as merchants. ("Price transparency" occurs when there are a number of identifiable economic players who can and will quote prices for the basic commodity, thereby establishing a truly open market in which buyers and sellers can make effective decisions based on accurate and consistent price knowledge.)

  Traders and marketers can trade capacity and energy from merchant plants, but they are not necessarily allowed to trade capacity and energy from regulated plants. They can "mark to market" (evaluate price and value against current and projected market conditions) capacity and energy from merchant plants but not necessarily from other plants. The more merchant plants there are, the more incentives there are for a flourishing electricity trading business in a given region. The entry of trading businesses into the Florida Regional Coordination Council (FRCC) region will be a huge positive (as long as they are not incumbents' trading businesses), for such entry will render prices transparent not only in the present but also into the future. The FRCC region would benefit from the entry of a substantial generation presence in the state, for it would quickly highlight uneconomic activity and lead to cost minimization and aggressive price competition. The best markets are those that are actively and aggressively traded by a myriad of trading companies such as Enron Capital and Trade, Duke Energy Trading and Marketing, PG&E Energy Trading, TXU Trading, Southern Energy Services, El Paso Energy Trading, and the like. The more active and aggressive the trading, the more transparent the prices and the less likely higher cost generation will be imposed on anyone. Active trading will lower wholesale prices, thereby lowering prices in general and promoting economic development.

- **Merchant plants are a virtual "free lunch" for ratepayers.** Merchants enter with absolutely no risk to ratepayers. This is so because merchant plants recover their full cost only from opportunistic power sales in the wholesale market at market-based prices. Ratepayers have no obligation to buy from the merchant, yet the entry of each additional merchant drives local power prices lower than they would otherwise be. Entry by regulated incumbent utilities is more expensive because the incumbents lack the same incentive as merchants to control and minimize costs. By "free lunch," I am not limiting the concept to reduced electricity prices only. I am specifically including the enhancement and acceleration of a robust competitive wholesale market that seeks out the lowest possible cost and price and maximizes efficiency. By "free lunch," I am also referring to the public good nature of enhanced reliability as well as the fact that price depressions proliferate throughout the entire FRCC system and beyond and provide tremendous leverage.

- **Ameliorate market concentration concerns.** Entry of merchants is a "free lunch" for regulators and consumer advocates who are concerned about the existence as well as the execution of monopoly power, market power, and/or barriers to entry erected by the incumbent utility. Entry of merchant plants is a good way to discipline the incumbent utility to which a monopoly was granted without having to attack monopolization directly. Alleging and attacking market power is a difficult task, one that can be easily avoided by simply promoting and fostering a significant merchant power plant sector in the state. It is well known in the economics literature that the best way to ease market concentration concerns is to encourage and foster the entry of a competitive fringe, which is precisely what the entry of Panda Leesburg and Panda Midway will do. This is an important point. Entry of a merchant fringe eliminates the need for vigilance in policing market power, and this is very beneficial for the FRCC.

2.3 Wholesale Competition is Working in Other States

Wholesale competition has emerged in various venues throughout North America, buoyed in significant measure by marketing and trading companies such as Duke, Enron, El Paso, PG&E Energy Trading, Amoco, Southern, AEP, and others. It is also buoyed by plant auctions (which convert formerly utility-owned plants into merchant plants), and greenfield merchant plant entrants. Wholesale competition springs up whenever it is possible for purchasing utilities and power marketers to enter into contracts with wholesale suppliers. Wholesale competition also springs up in venues where there are power exchanges such as the California Power Exchange ("PX"), ISO New England, the Pennsylvania-New Jersey-Maryland ("PJM") Interconnection, or the Automated Power Exchange (APX). The reason wholesale competition springs up is that both buyers (retail-serving utilities) and sellers (merchant utilities and power marketers) want price transparency, and they generally achieve it by relying on trading companies to help them promote and sell their capacity and energy.

As I understand from the publicly available literature on merchant plant development and from Altos' experience in the area, the merchant plant segment of the United States was, as of December 21, 1999, of approximately the following size

- Currently Operational Merchant Capacity: 19,660 MW
- Merchant Plants Currently Under Construction: 16,204 MW
- Merchant Plants Currently Under Development: 8,494 -8,644 MW
- Merchant Plant Plans Currently reported: 77,258-79,018
- Disaggregation (sale of formerly utility-owned plants to merchant owners): 63,865 MW

2.3.1 Operational Merchant Plants

It is my understanding, based in part on the Merchant Plant Scoreboard (www.mwbb.com), assembled by Stephen H. Watts of McGuire, Woods, Battle, and Boothe, LLP), that merchant plants were operational as of December 21, 1999 at the following locations and sizes. (I am not attempting to be absolutely exhaustive with this list.)

- Antioch, California (680 MW)
- Archibald, Pennsylvania (70 MW)
- Beaver Falls, New York (79 MW)
- Bloomfield, New Mexico (74 MW)
- Bolling, Texas (78 MW)
- Bridgeport, Connecticut (520 MW new, total site 655 MW)
- Cassville, Wisconsin (53 MW, may be repowered to 300 MW)
- Channelview, Texas (590 MW)
- Cool Water, California (628 MW)
- DePere, Wisconsin (255 MW)
- East Dundee, Illinois (250 MW)
- El Segundo, California (1,020 MW)
- Ellwood, California (48 MW)
- Elwood, Illinois (600 MW)
- Etiwanda, California (1,030 MW)
- Florida, Massachusetts (10 MW)
- Ft. Martin, West Virginia (276 MW)
- Highgrove, California (154 MW)
- Huntington Beach, California (563 MW)

- Ingleside, Texas (440 MW)
- Long Beach, California (2,083 MW)
- Long Beach, California (530 MW)
- Long Beach, California (80 MW)
- Malden, Missouri (250 MW)
- Mandalay, California (570 MW)
- Milford, Massachusetts (150 MW)
- Mission, Texas (500 MW)
- Morro Bay, California (1,002 MW plus 530 MW of new combined cycle capacity planned)
- Moss Landing, California (1,478 MW plus 1060 MW of new combined cycle capacity planned)
- Oakland, California (165 MW)
- Pasadena, Texas (240 MW)
- Pepperell, Massachusetts (38 MW)
- Phillips Sweeny, Texas (330 MW)
- Potrero, California (360 MW)
- Providence, Rhode Island (495 MW)
- Redondo Beach, California (1,310 MW)
- Rifle, Colorado (80 MW)
- Rowe, Massachusetts (598 MW) pumped storage hydro plant
- San Bernardino, California (126 MW)
- Solvay, New York (79 MW)
- Somerset, Massachusetts 1,586 MW)
- Vernon, California (32 MW)
- West Enfield and Jonesboro, Maine (49 MW)
- Westbrook, Maine (39 MW)
- Wharton, Texas (78 MW)
- Wichita Falls, Texas (80 MW)

2.3.2 Merchant Plants Currently Under Construction

The following merchant power plant Projects are reported as being under construction as of December 21, 1999 (I am not trying to be absolutely exhaustive with this list):

- Agawam, Massachusetts (274 MW)
- Batesville, Mississippi (800 MW)
- Bellingham, Massachusetts, (550 MW)
- Blackstone, Massachusetts (550 MW)
- Boulder City, Nevada (480 MW)
- Bridgeport, Connecticut (180 MW)

- Brownsville, Tennessee (600 MW)
- Caledonia, Mississippi (475 MW)
- Casco Bay, Maine (520 MW)
- Charlton, Massachusetts (360 MW)
- Chouteau, Oklahoma (530 MW)
- Dighton, Massachusetts (169 MW)
- Edinburgh, Texas (700 MW)
- Gregory, Texas (300-400 MW)
- Grimes County, Texas (830 MW)
- Jackson, Georgia (400 MW)
- Jay, Maine (150 MW)
- Klamath Falls, Oregon (240 MW)
- Midlothian, Texas (1,100 MW)
- Milford, Connecticut (544 MW)
- Orange, Texas (100 MW)
- Rumford, Maine (265 MW)
- South Lebanon, Pennsylvania (700MW)
- St. Francis, Missouri (250 MW plus 250 MW additional contemplated)
- Sutter, California (480 MW)
- Tiverton, Rhode Island (265 MW)

2.3.3 Merchant Sites Under Development

The following merchant power plants are listed as having been under development as of December 21, 1999 (I am not trying to be absolutely exhaustive with this list):

- Accomac County, Virginia (300 MW).
- Alexandria, New Hampshire (15 MW)
- Bellingham, Massachusetts (550 MW)
- Burney, California (500 MW)
- Columbus, Georgia (680 MW)
- Cordova, Illinois (537 MW)
- Cumberland (180 MW)
- Dearborn, Michigan (550 MW)
- Edinburgh, Texas (1,000 MW)
- Edinburgh, Texas (500 MW)
- Elk Hills, California (500 MW)
- Fellows, California (300 MW)
- Hazleton, Pennsylvania (250 MW repowering)
- Henderson, Texas (830 MW)

- Joliet, Illinois 668 MW)
- Killingly, Connecticut (802 MW)
- McKittrick, California (1,048 MW)
- Pittsburg, California (550 MW)
- Pittsburg, California (880 MW)
- St. Landry, Louisiana (848 MW)
- Umatilla County, Oregon (550 MW)
- Vermillion, Indiana (640 MW)
- Victorville, California (680-830 MW)
- Westbrook, Maine (540 MW)

2.3.4 Reported Plants that are Serious Candidates for Construction and Operation

I am aware of the following plant sites as having been reported as serious candidates to become merchant plants (I am not trying to be absolutely exhaustive with this list):

- Antioch, California (530 MW)
- Ashland/Chester, Maine (56 MW)
- Astoria, New York (1,000 MW)
- Athens, New York (1,080 MW)
- Baytown, Texas (800 MW)
- Bear Creek, Montana (2,000 MW)
- Bellingham, Massachusetts (1,035 MW)
- Bellingham, Massachusetts (700 MW)
- Blackfoot, Montana (160 MW)
- Blackstone, Massachusetts (550 MW)
- Blythe, California (400 MW)
- Boston Edison, Massachusetts (2,800 MW)
- Brayton, Massachusetts 475 MW0
- Broad River energy center, South Carolina (450 MW)
- Brockton, Massachusetts (272 MW)
- Brooklyn, New York (520 MW)
- Buckner, Kentucky (550 MW)
- Bucksport, Maine (174 MW)
- Burney, California (550 MW)
- California City, California (1,000 MW)
- Calvert City, Kentucky (200 MW)
- Canton, New York (50 MW)
- Carlin, Nevada (500 MW)
- Casa Grande Desert Basin, Arizona (500 MW)

- Cassville, Wisconsin (550 MW)
- Chalmette, Louisiana (11 MW)
- Chehalis, Washington (460 MW)
- Christiana, Wisconsin (525 MW)
- Coastal Power Project, Nevada (500 MW)
- Cocoa, Florida (850 MW)
- Colorado Springs, Colorado (480 MW)
- Columbus, Indiana (500 MW)
- Columbus, Ohio (220 MW)
- Corpus Christi, Texas (500 MW)
- Covert, Michigan (1,000 MW)
- Crow Tribe, Montana (260 MW)
- Dallas, Texas (510 MW)
- Dartmouth, Massachusetts (170 MW)
- Delaware County, Pennsylvania (550 MW)
- Deming, New Mexico (250 MW)
- Denver, Colorado (150 MW)
- DePere, Wisconsin (500 MW)
- DeSoto, Indiana (640 MW)
- Dona Ana County, New Mexico (400 MW)
- Dracut, Massachusetts (750 MW)
- East Dundee, Island Lake, Illinois (550 MW)
- El Dorado, Arizona (1,800 MW)
- Ennis, Texas (350 MW)
- Eureka County, Nevada (550 MW)
- Everett, Massachusetts (315 MW)
- Everett, Washington (248 MW)
- Falmount, Maine (550 MW)
- Fellows, California (500 MW)
- Franklin, Georgia (1,100 MW)
- Fulton, Mississippi (260 MW)
- Gillette, Wyoming (80 MW)
- Glenville, New York (870 MW)
- Gorham, Maine (600 MW)
- Hanover, Pennsylvania (1,000 MW)
- Haverstraw, New York (550 MW)
- Haverstraw, New York (750 MW)
- Hermiston, Oregon (460 MW)
- Houston, Texas (155 MW)
- Jack County, Texas (510 MW)
- Jackson County, Georgia (400 MW)

- Jenks, Oklahoma (800 MW)
- Johnston, Rhode Island (550 MW)
- Kendall County, Illinois (1,100 MW)
- Kendall County, Illinois (668 MW)
- Kingman, Arizona (520-650 MW)
- Kissimmee, Florida (409 MW)
- Lake Charles, Louisiana (155 MW)
- Las Cruces, New Mexico (200 MW)
- Las Vegas, Nevada (14.5 MW)
- Lee County, Alabama (530 MW)
- Leesburg, Florida (1,000 MW)
- Libertyville, Illinois (300 MW)
- Linden, New Jersey (1,100 MW)
- Livingston, California (260 MW)
- Londonderry, New Hampshire (700 MW)
- Long Beach, California (1000 MW)
- Lordsburg, New Mexico (120 MW)
- Lost Pines, Texas (510 MW)
- Lowndes County, Mississippi (800 MW)
- Malden, Missouri (250 MW)
- Marcus Hook, Pennsylvania (725 MW)
- Marion, Texas (740 MW)
- Martin County, Minnesota (362 MW)
- Martins Creek, Pennsylvania (500-600 MW)
- Meriden-Berlin, Connecticut (520 MW)
- Middletown, Ohio (230 MW)
- Midway, Florida (1000 MW)
- Milford, Connecticut (544 MW)
- Mobile, Alabama (220 MW)
- Mojave County, Arizona (550 MW)
- Monroe, Georgia (160-300 MW)
- Morro Bay, California (530 MW)
- Moss Landing, California (1,060 MW)
- Neenah, Wisconsin (300-525 MW)
- New Albany, Mississippi (390 MW)
- New Smyrna Beach, Florida (500 MW)
- Newark, California (500 MW)
- Newington, New Hampshire (170-700 MW)
- Newington, New Hampshire (525 MW)
- Nichols, New York (520 MW)
- North Smithfield, Rhode Island (250-750 MW)

- Odessa, Texas (1,000 MW)
- Okeechobee, Florida (550 MW)
- Ontelaunee, Pennsylvania (545 MW)
- Otay Mesa, California (1,050 MW)
- Paris, Texas (1,000 MW)
- Pastoria, California (960 MW)
- Phoenix, Arizona (120 MW)
- Phoenix, Arizona (500 MW)
- Phoenix, Arizona (530 MW)
- Pike/Knox, Indiana (500 MW)
- Pioneer Energy Project, Kentucky (400 MW)
- Pleasant Valley, Minnesota (445 MW)
- Potrero, California (520 MW)
- Ramapo, New York (1,100 MW)
- Rathdrum, Idaho (270 MW)
- Rowan County, North Carolina (1,100 MW)
- Roxana, Illinois (634 MW)
- Rutland/Bennington Counties, Vermont (1225 MW)
- San Jose, California (600 MW)
- Sandwich, Massachusetts (525 MW)
- Sandwich, Massachusetts (665 MW)
- Santa Teresa, New Mexico (400 MW)
- Sayerville, New Jersey (800 MW)
- Scriba, New York (750 MW)
- Seguin, Texas (750 MW)
- Shadyside, Ohio (280 MW)
- Skygen Plant, Louisiana (240 MW + 400 MW)
- Smithfield, New Hampshire (350 MW)
- Smiths, Alabama (100 MW)
- Somers, Illinois (1,048 MW)
- Somerset, Massachusetts (475 MW)
- South City, California (550 MW)
- Southington, Connecticut (720 MW)
- Sumas, Washington (240 MW)
- Sumas, Washington (710 MW)
- Thomaston, Georgia (680 MW)
- Three Rivers, Texas (750 MW)
- Trenton, Ohio (640 MW)
- Vernon, California (550-850 MW)
- Wallingford, Connecticut (550 MW)
- West Deptford, New Jersey (800 MW)

- Westbrook, Maine (300 MW)
- Westfield, Massachusetts (272 MW)
- Whiting, Indiana (550 MW)
- Wichita falls, Texas (1,000 MW)
- Williamson, West Virginia
- Woodstock, Illinois (500 MW)
- Worthington, Indiana (400 MW)
- Wright, Wyoming (200-250 MW)
- Wright, Wyoming (240 MW)
- Wyandotte, Michigan (480 MW)
- Wyman, Maine (1000 MW)
- Yarmouth, Maine (550 MW)

2.3.5 Divestitures or Disaggregations of Former Utilities Resulting in Merchantization of Capacity

I am aware of the following disaggregations of former utilities that either already have or are likely to result in the creation of merchant capacity (I am not trying to be absolutely exhaustive or completely current with this list):

- Commonwealth Edison sold 2 coal-fired plants (1,108 MW Kincaid and 590 MW State Line).

- New England Electric System (NEES) sold 4,000 MW (fossil and hydro) including Brayton Point, Salem Harbor, Manchester Street, Bear Swamp Pumped Storage, 14 other hydroelectric stations on the Connecticut and Deerfield Rivers, and 23 multi-year PPAs totaling almost 1,100 MW.

- Pacific Gas & Electric Company sold 7,363 MW (8 plants, representing 98% of fossil capacity) including Morro Bay, Moss Landing, Oakland, Pittsburg, Contra Costa, Potrero, and generating capacity in the Geysers.

- Southern California Edison sold 10,000 MW (all fossil plants).

- Central Maine Power sold 2,150 MW including 550 MW of contracts with non-utility generators ("NUGs").

- Commonwealth Energy System sold 1,675 MW including. 675 MW of NUG contracts.

- Eastern Utilities Associates sold 1,065 MW including 165 MW of nuclear capacity and 522 MW of PPAs.

- Boston Edison sold 2,000 MW (all fossil) and sold its Pilgrim nuclear station (655 MW) to Entergy.

- New York State Electric and Gas (NYSEG) has proposed to auction 2,346 MW of coal-fired generation.

- Niagara Mohawk has proposed to auction 4,600 MW (fossil, nuclear, and hydroelectric).

- GPU has auctioned 5,300 MW fossil and hydro capacity plus the Oyster Creek and Three Mile Island nuclear plants.

- Consolidated Edison/orange & Rockland utility merger. O&R divested 980 MW and Con. Ed. is divesting 2/3rds of its5,500 MW in New York city and southern New York. Con. Ed. Has announced acquisition of Northeast Utilities, and plans to divest the nuclear capacity of Northeast.

- San Diego Gas and Electric wants to sell 2,375 MW (2000 MW fossil, 200 MW of QF contracts, and 175 MW of other power contracts)

- Duquesne Light plans to auction 3,035 MW of coal and nuclear capacity in ECAR

- Montana Power sold 1,543 MW of fossil, hydro capacities and related PPAs.

- Western Massachusetts Electric auctioned 541 Mw of thermal, hydro plants and contracts.

- Tucson Electric plans to sell the entire 1,992 MW of generating capacity it owns, co-owns, and leases in Arizona and New Mexico.

- Illinois Power sold the 950 MW Clinton nuclear generation station to PECO/BE.

- Centralia's owners are auctioning a 1,340 MW coal-fired plant and adjoining mine at Centralia, Washington.

- The Orlando Utilities Commission has sold its Indian River units to an affiliate of Reliant Energy (approximately 600 MW).

- Central Hudson is auctioning 972 MW of fossil fired capacity.

I believe there could be significant disaggregation impending within ERCOT as well, although as I understand it, nothing definitive has been announced. I do not believe disaggregation has been seriously proposed for Florida yet, but it might well occur in the future.

2.4 Projects I Have Personally Worked On

Some of the projects I worked on include St. Francis, Missouri; various Calpine projects including Magic Valley, Texas; Casco Bay, Maine; Bridgeport, Connecticut; New Smyrna Beach, Florida; Okeechobee Generating Company, Florida; Eureka County, Nevada; Cajun, Louisiana; all the disaggregated California plants; Canal, Massachusetts; and all the Central Maine Power plants.

2.5 Altos Has Knowledge of the Merchant Plant Business

Altos is knowledgeable of the merchant plant business both because I have worked directly on merchant power projects and because I have analyzed the entire North American electricity and gas markets and their potential for merchant plant entry. I believe I know the conditions that stimulate merchant entry and where such merchant entry is likely to occur.

3 METHODOLOGY USED TO QUANTIFY THE NEED IN THE FRCC FOR PANDA LEESBURG AND PANDA MIDWAY

The methods I have selected to quantify and demonstrate the strong need in the FRCC for the Panda Leesburg and Panda Midway projects (and others like them) are based precisely on the recommended approach by one of the most notable economists in the field of public utility regulation, Dr. Alfred Kahn, who states on page 17 of his classic textbook on regulation entitled **The Economics of Regulation: Principles and Institutions**, MIT Press, Cambridge, 1988: "...the single most widely accepted rule for the governance of the regulated industries is regulate them in such a way as to produce the same results as would be produced by effective competition." Dr. Kahn himself holds out the competitive market paradigm as the paragon, the ultimate yardstick. Dr. Kahn would disagree with any arbitrary or self appointed repeal of the paradigm of the perfect competition yardstick in favor of some other unspecified form. Indeed, the yardstick of perfect competition, which is the very yardstick that is attracting Panda Midway and Panda Leesburg, should be fostered and encouraged by the Commission.

Dr. Kahn goes on to argue on page 65 of his classic text: "The central policy prescription of microeconomics is the equation of price and marginal cost." Again, perfect competition is held out as the regulatory ideal. Dr. Kahn continues: "As almost any student of elementary economics will recall, marginal cost is the cost of producing one more unit; it can equally be envisaged as the cost that would be saved by producing one less unit. Looked at the first way, it may be termed the incremental cost—the added cost of (a small amount of) incremental output. Observed in the second way, it is synonymous with avoidable cost—the cost that would be saved by (slightly) reducing output." People who would argue against merchant entry into a competitive wholesale power market are flying in the face of the words of Dr. Kahn. Any argument against unfettered merchant entrance would be directly inconsistent with what Dr. Kahn characterizes as what "almost any elementary student of elementary economics will recall," i.e., that perfect competition is indeed the ideal, both of regulation and of unregulated competitive markets. Perfect competition is known to "almost any elementary student of elementary economics" to maximize economic efficiency, as perfect competition is taught in every undergraduate microeconomics course in every university in the world. Perfect competition is de facto more efficient and creates a bigger pie than any other market structural form. This is not a question of opinion. It is a question of established mathematical and economic fact and cannot be repealed on the whim of politicians, regulators, incumbent monopolies, or others with naked self interest that would deny the entry of Panda Leesburg and Panda Midway and similar merchants. The very centerpiece of Dr. Kahn's arguments would imply the value of merchant entry, and it would imply that a model of competitive markets is the best way to represent and evaluate merchant entry into the FRCC market.

This section begins with an example that illustrates why the entry of Panda Leesburg and Panda Midway will suppress power prices throughout Florida relative to what they would otherwise be without those Projects and why such entry will pay massive benefits. These price reduction benefits are badly needed by the citizens and business throughout Florida because Florida has the highest wholesale power prices in the nation now (as reported by Public Utilities Fortnightly and put forth in my Duke New Smyrna Beach testimony), and Florida is facing high prices and continued shortage under the FRCC ten year forward plan (as our model results presented here will demonstrate). Thereafter, I will turn to the specific modeling system I have selected to implement the key concepts of market equilibrium, namely the Altos NARE and NARG models.

3.1 The Nature of Spatial Equilibrium and Why Supply Increases Cause Price Suppression Benefits Throughout the Entire System

Economic theory of competitive markets is clear that the entry of a new source of supply (e.g., a new merchant) decreases the price in every region of Florida because of its entry, including all inbound transmission entry points within Florida. There is no corner of Florida that will not benefit from the entry of Panda Leesburg and Panda Midway; price suppressions are ubiquitous. The entry of Panda Leesburg and Panda Midway also depress the price in contiguous regions such as Southern as well during those hours in which inbound transmission is unconstrained. People in Southern benefit from the price decreases they experience at the same time people in Florida benefit from the same price decreases. Price decreases benefit everyone in Florida, and they benefit everyone in contiguous states who experience them. Price depressions proliferate outward from their point of origin with a surprising lack of attenuation, as we will show with a simple example in this section.

Economic theory of competitive markets tells us that even though physical quantities (i.e., MWH) generated by a plant such as Panda Leesburg or Panda Midway might never leave a localized region where they are generated or the state as a whole in which they are generated, price depressions will occur throughout the state and in contiguous states that are directly connected to the FRCC. The fact that Leesburg and Midway power may not physically leave a given region or the state as a whole does not at all mean that people in contiguous regions of the FRCC or contiguous states do not benefit by the price suppressions that result from the Leesburg and Midway entry. It does not also mean that if people in contiguous regions or states benefit then people in Florida will not benefit. There is not a fixed amount of benefits to go around and that if someone in Georgia gets them then someone in Florida does not, or if someone in Miami benefits then someone in Jacksonville will not. Benefits borne by reduced price are not at all "zero sum" by nature. On the contrary, every ratepayer benefits from them. Price reductions are truly "manna from heaven" for consumers. Any assertion that if someone in Georgia or another region or state benefits then necessarily someone in Florida fails to benefit. That is patently false, as the forthcoming example will clearly show.

It is well known in the economics literature that in a spatially distributed system interconnected by transportation media such as the FRCC is, **reducing the price in one region causes prices to be reduced simultaneously in all regions.** There is no question about that. There is a definite free lunch where price depressions are concerned. I have put together in this section a simple, illustrative, "pencil and paper" example to demonstrate that indeed price depressions borne of new entry are strikingly large in magnitude, and they proliferate rather rapidly and with surprisingly little attenuation throughout the entire economic network in which they occur. In particular, the price reductions that will be induced locally within the regions of the FRCC contiguous to the Leesburg and Midway plants will proliferate quite unattenuated throughout the entire FRCC and by displacement throughout contiguous regions outside the FRCC as well. This simple example effectively illustrates the salient points and firmly rebuts any assertions that price reductions might be strictly localized in the vicinity of the Leesburg or Midway plants. This example is not a trifle; it is profound in its implications for the price suppression effects of the Leesburg and the Midway plants and any same or similar merchant.

3.1.1 Illustrative Example

Consider Figure DMN-1 in which there are two supply regions at the bottom of the diagram (denoted Regions 1 and 2), two demand regions at the top of the diagram (denoted Regions A and B), and an intervening transmission system interconnecting each supply region with each demand region. To keep the example simple, assume that the transmission is available in whatever quantity the market might want--there are no losses in transmission, and the costs of the transmission are as shown. To keep the example simple, I have assumed two individual, simple, straight line price-quantity supply curves, one in each of the two supply regions. I have assumed two individual, simple, straight line price-quantity demand curves, one in each of the two demand regions. This is conceptually quite a simple system, two supply regions each with a simple straight line supply curve, an interconnecting transmission system with unlimited availability and no losses at the indicated transmission costs, and two demand regions each with a simple straight line demand curve. In fact, this is one of the simplest examples one could render in a spatial market situation with spatially disparate supply separated from spatially disparate demand by an unconstrained transmission network. This is a simple analogy of the power situation in Florida's wholesale electric markets, and it embodies and in fact proves many salient points made elsewhere in this report.

What is the price-quantity solution for this simple spatially distributed example? What are the prices that simultaneously clear all the supply and demand markets and pay all the intervening transportation costs? (I should mention that these spatially distributed market equilibrium answers are exactly what the Altos model calculates.) The solution is depicted in Figure DMN-2, in which I have appended the prices and quantities flowing at the equilibrium prices. (I have used in Figure DMN-2 the notation quantity@price in the supply and demand regions to connote the "quantity flowing at the indicated price" and noted the quantities flowing through the various transmission links at equilibrium.) The market clearing prices in the two supply regions and the two demand regions are those shown in Figure DMN-2 and are summarized as follows:

$$q_1 = q_{1A} + q_{1B} = \frac{25}{11} = 2.273$$

$$q_2 = q_{2B} = \frac{29}{22} = 1.318$$

$$q_A = q_{1A} = \frac{41}{22} = 1.864$$

$$q_B = q_{1B} + q_{2B} = \frac{19}{11} = 1.727$$

$$p_1 = 1 + \frac{1}{2}q_1 = \$\frac{47}{22} = \$2.136$$

$$p_2 = 1 + 2q_2 = \$\frac{40}{11} = \$3.636$$

$$p_A = 5 - q_A = 5 - \frac{41}{22} = \$\frac{69}{22} = \$3.136$$

$$p_B = 5 - \frac{1}{2}q_B = 5 - \frac{1}{2}\frac{19}{11} = \$\frac{91}{22} = \$4.136$$

I should emphasize that the veracity of this example is very easy to prove. To verify that my calculations are correct in this scenario and the additional scenario I shall soon analyze, all one need do is verify that the indicated prices cause there to be zero excess supply and zero excess demand in regions 1, 2, A, and B and that the quantities balance everywhere throughout the transmission system. In particular, one need only substitute the prices into the equations to see that the sum of inbound supplies in each case is equal to the sum of outbound demands. I hasten to emphasize that the method by which I determined the solution is irrelevant; all that matters is that the sum of inflows equals the sum of outflows at each of the markets in the figure and that the prices and quantities in each of the supply and demand region lie precisely on the respective supply curves and demand curves in each region.

Now, let us do in the example precisely what the Leesburg and Midway plant will do in reality in Florida--shift the supply curve outward and to the right in one of the two supply regions. Let us move the supply curve in region 2 outward and to the right. Specifically, let us assume that there is a new supply source in region 2 that increases the supply curve there, all else equal. In particular, the new supply curve has the equation $p_2=1+3/2q_2$ rather than the old equation $p_2=1+2q_2$. Figure DMN-3 illustrates the situation in this new case with an increased source of supply in supply region 2.

What will happen to the market clearing price in supply region 2 with this new, more abundant supply equation? What will happen to price in demand region B? Region A? The answer, amazingly enough, is that **the price decreases by exactly the same degree in regions 1, 2, A, and B.** Figure DMN-4 presents the new market clearing prices and quantities, i.e., the new answer, and the following equations give the new answer and compare it to the old.

$$q_1 = q_{1A} + q_{1B} = \frac{36}{17} = 2.118 < 2.273$$

$$q_2 = q_{2B} = \frac{29}{17} = 1.706 > 1.318$$

$$q_A = q_{1A} = \frac{33}{17} = 1.941 > 1.864$$

$$q_B = q_{1B} + q_{2B} = \frac{32}{17} = 1.882 > 1.727$$

$$p_1 = 1 + \frac{1}{2}q_1 = \$\frac{35}{17} = \$2.059 < \$2.136 \quad \text{Price Suppression} = -\$0.077$$

$$p_2 = 1 + 2q_2 = \$\frac{121}{34} = \$3.559 < \$3.636 \quad \text{Price Suppression} = -\$0.077$$

$$p_A = 5 - q_A = 5 - \frac{33}{17} = \$\frac{52}{17} = \$3.059 < \$3.136 \quad \text{Price Suppression} = -\$0.077$$

$$p_B = 5 - \frac{1}{2}q_B = 5 - \frac{1}{2}\frac{32}{17} = \$\frac{16}{17} = \$4.059 < \$4.136 \quad \text{Price Suppression} = -\$0.077$$

Comparison of the market clearing prices in both of the supply regions and both of the demand regions in the old case (no new supply) with the new case (new supply in supply region 2) indicates that **the magnitude of price decrease from the base case to the new supply case is exactly the same in all four regions**—both supply regions and both demand regions. To emphasize, the price decreases by exactly the same magnitude in region A even though region 2 does not send any product at all to region A. Displacement alone is enough to cause the same price decrease in a demand region that is not even served. It is a fallacy disproved by this example that a direct connection from a supply source to a demand region is a necessary precursor to induce price depression. **The mere existence of displacement is sufficient to guarantee the exact same degree of price depression in a displacement market as in a direct market.** Economic theory as embodied in this example is sufficient to guarantee that. Notice that the displacement effect realized in supply region 1, which is two wheels removed from supply region 2 where the new supply was introduced, is exactly the same in magnitude as the price depression in the original region where the supply is increased. Regions upstream from demand regions where there is no effect save for first order, second order, and higher order displacement experience precisely the same degree of price reduction as the region in which the new source of supply occurs.

Lest there be confusion about the veracity of this example, the foregoing equations summarize the solution in the "high supply" case. **Notice that in all four regions in the example, the price drops by exactly the same magnitude even though the supply increase occurred in only one of the supply regions.** This is the salient finding—displacement markets experience precisely the same price suppressions as markets directly served by the entry of a new source of supply. There is no Balkanization of any region away from any other region as long as there is a fungible transmission system that interconnects them. This is why I get the results I do in the NARE model and why they are correct. This is why production simulation models are wrong—they do not get the spatial equilibrium problem right. They do not satisfy the criterion deeply embedded in this example and advocated by Dr. Kahn, namely that perfect competition with marginal cost pricing is the ideal criterion toward which regulators should strive.

It is entirely reasonable and possible and in fact entirely consistent with economic theory as embodied in this simple example that the supply regions where a new source is introduced experience a price reduction, the demand regions directly downstream from that supply region that receive positive quantities from that supply region experience exactly the same price reduction, demand regions that are not directly supplied by the supply region where a new source is introduced experience a price reduction of the exact same magnitude, and supply regions upstream from those displacement demand regions experience the exact same magnitude of price reduction as the original region itself. This simple example illustrates that price depressions emanating from the entry of a new supply source such as Leesburg or Midway proliferate outward unabated and undiminished in magnitude for a very long distance indeed. The Altos NARE model results are not only perfectly reasonable, they are in fact entirely expected both in a modeling sense and in a real world sense. Anything other than the Altos model results would be unexpected and unreasonable. Anything other than broadly proliferating price decreases throughout all of the FRCC brought about by the entry of Leesburg and Midway would be wrong.

The simple example indicates that the degree of price depression caused by a supply curve shift outward and to the right is the same everywhere. Why does the Altos NARE model not give precisely this result, i.e., the same price depression everywhere? Why in the context of this simple example has the Altos model predicted different degrees of price depression in different regions contiguous to and further away from the locations of the Leesburg and Midway plants? Keep in mind the assumption in the simple example that transmission was unconstrained in magnitude. The reason the Altos NARE model gives different degrees of price depression in different regions lies in the transportation restrictions and bottlenecks represented in the NARE transportation network and the transfer capabilities embedded therein. The foregoing simple example causes the magnitude of price depression to emanate outward unabated because there are no transmission bottlenecks and no barriers to entry for transmission anywhere in the example. When there are transmission bottlenecks, price suppressions can decrease in magnitude as one increases the number of wheels away from the source of increased supply, but the degree of attenuation is not necessarily severe. ~~That is, the attenuation may be quite small because there are so many~~ alternative routes from various sources of supply to various customers. Quite the contrary, the degree of attenuation is usually not particularly large because the electric transmission is usually not dramatically improperly sized or severely bottlenecked. (After all, the size of the transmission system is not an accident; it was designed that way.) Furthermore, the transmission system tends to operate at less than capacity during time of peak because transmission has lesser value at time of peak and because the mark to market value of losses at time of peak is largest. This means that transmission bottlenecks if they exist today are more likely to abate during time of peak than during time of off peak.

The point of this example is to illustrate how price depressions benefit Florida and non Florida customers alike even though the MWH are sold only locally in the vicinity of the Leesburg and Midway plants themselves in Florida. If customers in Georgia benefit from the fact that Florida prices are reduced on and off peak and drag Georgia prices down accordingly, that is perfectly OK. It is a benefit to Georgia that does not in any way whatsoever reduce the benefits in Florida one iota. It is patently wrong and naïve to assume that the price depressions that are caused by Leesburg and Midway must of necessity be strictly localized and must not accrue to anyone else. On the contrary, as we have shown, such price suppressions are significant and are ubiquitous throughout FRCC, and that is the reasonable rather than the unreasonable result. The fact that price depressions may be transmitted abated or unabated into all corners of the FRCC and into Georgia does not reduce their magnitude in Florida one iota. The illustrative example in this section is clear on that point.

Lest one doubt the veracity of the methodology or the result presented herein, please refer to the classic paper by Nobel Laureate Dr. Paul Samuelson "Spatial Equilibrium and Linear Programming" in the **American Economic Review** in 1956. The results herein are a standard result of what is called Samuelsonian spatial equilibrium, and it describes the behavior and evolution of spatially distributed markets such as the FRCC. The NARE model embodies the Samuelsonian spatial equilibrium approach as well. I will use the term Samuelsonian spatial equilibrium model and nodal pricing model synonymously in this report.

3.1.2 Price Reductions Apply to Every Unit of Production, Not Just Localized Production

There is one additional misconception that has befallen earlier merchant cases in Florida, one that needs to be dispelled here in order to fully legitimize the foregoing example and fully legitimize the NARE model as the proper and correct representation of FRCC power markets. What I will now show is that **the price reductions calculated apply to every unit of flowing product throughout the entire example, not just the flowing product in the immediate vicinity of the price increase**. (The analogy to FRCC electricity is clear—price decreases apply to every MWH in the state.) It is unequivocally wrong to isolate the price depression only to the increased production in the region where the supply increase occurs. It is wrong to assume that the price reduction applies only to the net increase in the market induced by the new supply source or to only a part of the entire collection of nodal markets. The price reductions calculated for the FRCC apply to every MWH of power flowing in the FRCC, not just a portion that might be designated "wholesale" or "uncontracted" or some other moniker.

There has been a prevalent notion, which is incorrect, that wholesale markets are isomorphic with uncontracted capacity or energy. This notion is misleading and misstates the impact of Leesburg and Midway on wholesale markets and wholesale markets in turn on customers. The idea that the regulatory fabric in FRCC will completely separate and Balkanize uncontracted energy and capacity markets from contracted energy and capacity markets is utterly at odds with experience in other states and other commodities. I know of no regulatory framework in place anywhere that is not specifically designed to pass through commodity cost reductions in upstream markets to downstream customers. The very idea that downstream customers do not benefit from fuel cost passthrough or purchased power cost passthrough is incorrect. On the contrary, Professor Kahn and most regulators understand that variable costs are designed to be invariably passed through directly to ratepayers and therefore that variable cost savings are generally, if not invariably, passed through directly to ratepayers. To reiterate, I know of no regulatory framework that does not pass reduced commodity acquisition costs (e.g., gas costs, electric power costs, water costs) directly through to customers. Quite the contrary, regulation is ubiquitously geared toward ensuring that granted monopolies purchase the cheapest commodity they can and flow the benefits of that cheapest commodity directly through to ratepayers without monopolizing or earning on it. Because of Averch-Johnson-Willisz effects, they do not always get the cheapest possible costs; however, they are obliged to flow whatever commodity costs they incur to ratepayers.

In past Florida PSC proceedings, certain incumbent utility advocates would have the Commission believe that utility customers should be permanently and completely Balkanized and separated from wholesale markets so that they cannot benefit from those markets at all. Would they have the Commission believe that there should be two tiers of customers in Florida, one large tier that is constrained to be a captive, unequivocal, uncontestable utility customer who is obliged to buy only from the utility and be intrinsically denied whatever benefits might be available from a competitive wholesale market? Would they have the Commission believe that utility customers are and should be denied wholesale market benefits no matter how much difference in price or cost might exist between the utilities to which they are captive and the wholesale markets? Would they require that one tier of the market pay for all the utilities' excess costs (stranded costs). Are the utilities decisions never to be "marked to market" in the wholesale markets that exist in the state? Balkanization and separation of utility customers from wholesale power market customers will never and should never happen.

Any assertion that captive utility customers should be forced by regulators to accept higher-than-market prices in regulated markets that coexist with transparent wholesale markets is simply wrong and unrealistic. The political and economic heat that arises from the availability of visible, transparent, lower cost commodity generally motivates regulatory bodies to move quickly and decisively toward the low price commodity source and to aid and abet the local utilities in their quest to do so. Furthermore, it is very easy indeed for a PSC to force least cost commodity purchase simply by disallowing recovery of excess costs from captive customers. I am confident that the review and oversight mechanisms are already in place to do so, and I am confident that the Florida PSC, just as all other PUCs do, can easily enforce least cost purchase.

The very assertion that captive utility customers will be forced to accept higher-than-market prices for upstream commodities in transparent markets is preposterous. Let me give a vignette from my own personal experience to illustrate. Several months after the passage of FERC Order 436 (which unbundled gas commodity from gas transmission service on the interstate pipeline system), my former consulting company received a call from Southern California Gas Company (the gas LDC in Southern California). I paraphrase the conversation: "We have a problem. The spot price of gas at Topock (the California-Arizona border where Southern California Gas was taking title to inbound gas from the interstate pipelines) has fallen $0.75/Mcf below our system gas acquisition price. (The system price was a fixed price that was part of a firm service contract with the upstream pipeline suppliers El Paso and Transwestern.) As you know, 100 percent of our gas at Topock is currently contracted system gas, and we have no escape clauses with the pipes for the firm gas we are buying. Unfortunately, that firm gas is now $0.75/Mcf higher than spot, and the California PUC and everybody else can clearly see that is true. The PUC is feeling the political heat, and they are telling us to immediately decontract 100 percent of our system gas, buy 100 percent of our gas on the spot market, enjoy the 30 percent or more price savings, and swing on the pipelines' system gas we were previously contracted for to meet our firm baseload needs. In effect, they want us to trade spot gas for system gas across the board and give California consumers the benefit of the lower spot price." The political heat quickly and decisively swung to low cost purchase.

Let me illustrate the absurdity of the argument that utility customers will not benefit from wholesale market price suppressions in one final way. Interveners in the past have asserted that there is and will continue to be a Balkanized, two part market in Florida where 95 percent of the customers are never allowed by the utilities or the Florida PSC to avail themselves of much cheaper wholesale power created by merchant entry (or any other source of lower cost wholesale power for that matter). To illustrate how ludicrous such an assertion is, consider the extreme end of the spectrum. Suppose wholesale power were absolutely free, zero cost, on the FRCC wholesale market. Would incumbent advocates have us believe that 95 percent of the Florida market and the Florida PSC would never figure out how to avail themselves of free electricity, i.e., that the regulators would allow FPL, FPC, and the others to force $33/MWH or so wholesale electricity on their customers when the wholesale market is free? That is patently ridiculous on its face and underestimates the intelligence and effectiveness of the Florida PSC. Periodic review and oversight of utility commodity purchase practice obviates imprudent purchasing and passthrough.

In summary, clearly the best and most descriptive representation of the FRCC is a fully fungible, competitive wholesale power market upon which the full range of FRCC customers will be able to rely. The institutions are in place to see that that occurs. The Samuelsonian model used by Altos for this evaluation is the proper way to characterize FRCC power markets and the benefits of Leesburg and Midway therein. I would assert that the simple example discussed previously and the more complex NARE model are precisely the correct model to simulate future gas and electricity markets in the FRCC. That is why I have used them.

3.2 Calculating the Need for Panda Leesburg and Panda Midway Using the Altos NARE Model

The simple example in Figure DMN-1 is not designed to analyze the FRCC market per se. However, I have used the same methodology extrapolated outward and upward to many competing supply regions, many competing transmission routes, many time points, and many competing demand regions. The North American Regional Electricity (NARE) and North American Regional Gas (NARG) models are based on the same concepts articulated in the context of Figure DMN-1.

3.2.1 Methodology of the NARE Model

To compute the need for Panda Midway and Panda Leesburg, I have built a detailed, regionally disaggregated market model of the Florida wholesale power market and contiguous regions, based on market conditions and prices at key power transfer point ("hubs" or "nodes"), and linked it with a detailed model of North America electric supply, transmission, and demand. The model of North America we started with is depicted in Figure DMN-5. (I will use the term NARE to refer to this model as well as the more FRCC-focused models described shortly. NARE is an acronym for North American Regional Electricity model.) The full NARE Model distinguishes approximately 35 regions of North America, representing native load within each region, inbound transmission to and outbound transmission from each region, generation within each region, and inbound fuels and fuel substitution within each region. The NARE Model represents fuel supply, indigenous generation, inbound transmission, indigenous demand, outbound transmission, and "mark to market" competition at the wholesale hub within each region and interlinks them all together in the form of a multiregional transmission grid. The NARE Model thereby represents market clearing prices in each region, basis differentials between regions, plant dispatch within each region, inbound and outbound transmission flows between and among regions, and the response of price and quantity at each location in the system in response to a change in any other part of the system. A more detailed discussion of the methodology and use of the NARE Model is provided in Appendix A attached hereto.

Within the NARE Model, Altos has disaggregated the FRCC region in order to distinguish the various important subregions as they are affected by generation, fuel availability, transmission rates and constraints, and regional demands. Figure DMN-6 indicates the logic used for such disaggregation. Thereafter, Altos has built a detailed representation of the FRCC region as indicated in Figure DMN-7 and used it to evaluate the impacts of the Leesburg and Midway Projects. Once Altos built the NARE Model and inserted the expanded representation of the FRCC region, that model was linked with the results of the NARG Model, which is pictured in Figure DMN-8 in order to obtain and use reasonable and consistent natural gas prices throughout North America and at all nodes represented within the FRCC region.

3.2.2 NARE Is a Nodal Pricing Model (As Is NARG)

Wholesale market clearing prices of electricity are and will be different at different geographic locations in Florida and throughout North America. There is a very important geographic dimension to electric power and natural gas prices, just as there is a distinct geographic component to every commodity for which transportation costs are significant. The reason prices are different at different geographic locations arises from the fact that different locations are separated by the transmission network and therefore on a regional basis may experience differing fuel prices as well as product prices. The nodal pricing model that Altos developed for FRCC and integrated into NARE takes account of locational differences within the FRCC and in fact throughout North America at the level of geographic detail shown in Figures DMN-5 through DMN-7 herein. (I should point out that the portions of the model that potentially impact the FRCC are the eastern portions of the model. ERCOT and the WSCC are significantly decoupled from the eastern grid. In making the Panda Leesburg and Midway evaluations, we have focused primarily on the eastern system.)

There are two important aspects of transmission that mandate the need for a nodal pricing approach: (1.) cost of transmission and (2.) availability of transmission (i.e., constraints or bottlenecks). Transmission cost alone causes prices to be different in different locations throughout the FRCC region (and in fact throughout North America as a whole). The foregoing simple example showed that. As a further example, if it is $5/MWH cheaper to generate power in a contiguous region but it only costs $1/MWH to transmit the power between regions and there is transmission capability to move as much power between the regions as the market might want, the markets in the two regions must equilibrate to prices that are precisely $1/MWH apart in price. In such a situation, the low-cost generators would gain additional profits from selling to the high-cost region, and high-cost region consumers would receive a direct economic benefit from having access to the contiguous low cost generators. In this simple example, transmission cost (assuming adequate capacity) would set the price differentials between the low cost region and the high cost region. Only a nodal pricing model that represents each of the regions as a distinct node and represents the internodal transmission costs could properly calculate the prices in each of the regions and the systematic price differentials between the regions. A traditional electric production simulation model would not properly capture the nodality of the FRCC and would therefore be wrong.

Transmission cost is not the only motivation for building a nodal pricing model to represent the benefits of characterizing the FRCC regional power market. Suppose the cost of transferring power between the regions were infinitesimal, but there was only a fixed, finite quantity of transmission capability available and it was only 50% of what the market would otherwise want, i.e., transmission was very low in cost but there is not enough capacity to transmit all the power the market would want to move. In such a situation, a "congestion price" would form across the interconnecting transmission link, and the price differential between the regions would be larger than the direct cost of transmission between the regions. The NARE model calculates the congestion price across links that are flowing at capacity and for which the market would want more flow.

The upshot is that transmission that interconnects regions must be represented in terms of both its cost and the capability. In our lexicon, transmission between regions must be represented using a supply curve for transmission services between the regions. If a transmission interconnection is fully saturated, there will be a congestion price differential between the regions. If the transmission interconnection is not congested, there will not be a congestion price differential between the regions--the price differential will be set by the direct cost of transmission. When one considers the complexity of the FRCC region transmission system (not to mention the complexity of the transmission system in the United States as a whole in which it is embedded), it is clear that a detailed nodal pricing model is needed to represent the proper prices and price differentials between all points in the system.

In evaluating the need for the Leesburg and Midway Projects, Altos' approach has been to build a detailed nodal model of the FRCC region that represents physical flow possibilities from every generator to the grid, between every two points on the grid, and from every point on the grid to load (offtake) at that point on the grid, taking account of the cost and capability constraints on the transmission system. Thereafter, in the case of Leesburg Project, we inserted a 1000 MW plant with the cost and operating characteristics of the Leesburg Project and assumed that all gas purchase and power sales transactions occur at the market clearing price of gas in the most contiguous node to the plant and the market clearing price of electricity at the closest node to the plant. That is, all electricity and gas transactions are assumed to occur at the market clearing price. By making this assumption, we are able to insert 1000 MW at the Leesburg Project site and calculate its effect nodally throughout the entire FRCC and contiguous systems, calculating the price reduction that it causes. By building a detailed nodal model of Florida, we are able to accurately assess not only the aggregate need in Florida for the Leesburg and Midway Projects but its specific regional distribution and how that regional need proliferates throughout the FRCC region. The nodal model we have developed tells us for example whether the Leesburg Project displaces power flows that would otherwise have to flow into certain regions Florida from other regions of the state or whether Leesburg is simply a net addition to south Florida generation and demand. It also tells us which MWH from which specific regional nodes will be displaced out of the Florida system at which points in time by the entry of the Project at its node. (The foregoing discussion in this paragraph used Leesburg as an example. Precisely the same statements are true for Midway.)

3.2.3 Panda Leesburg and Panda Midway (and NARE) Buy and Sell at Market Prices

Panda Leesburg and Panda Midway will and should buy and sell at market prices at their respective plant sites. Furthermore, such practice leads to the maximum possible benefits to the citizenry and business of Florida. In a previous proceeding (Okeechobee), the pejorative term "playing the spark spread" was ascribed to the behavior of merchant entrants, and it was held out to be a negative. In fact, "playing the spark spread" is precisely what Panda Leesburg and Panda

Midway can and should do because it creates the maximum possible benefits not only for themselves but also simultaneously for Florida ratepayers. Playing the spark spread is a positive, not a negative.

As merchants, Leesburg and Midway will mark their gas and power to market. That strategy continuously and effectively plays the spark spread. Previous interveners have implied incorrectly that this is a "bad" thing. On the contrary, it is not a "bad" thing, it is a "good" thing. It delivers the maximum possible economic efficiency benefits to the aggregate of Florida gas ratepayers plus power ratepayers. To see why playing the spark spread is not a "bad" thing, ask the following simple questions: Would the Commission want Leesburg and Midway or anyone else to burn up high priced $10/Mcf gas (during time of a gas shortage) when power price was only $30/MWH? Assuredly not -- the gas is worth more than the power. In such a situation, the gas would be worth far more to a Florida gas ratepayer than the power would be to a power ratepayer, and the Commission would want Leesburg and Midway and everyone else to deliver the gas in its original form to the needy gas ratepayer. In the converse situation, would the Commission want Leesburg and Midway or anyone else to burn up $2/Mcf gas (during time of gas abundance) when power price is $300/MWH? Most assuredly yes—the power is worth more than the gas. In such a situation, the power would be worth far more to a Florida electric ratepayer than the gas would be to a gas ratepayer, and the Commission would want Leesburg and Midway and everyone else to burn the gas and deliver the power to a needy electric ratepayer. Indictments of "playing the spark spread" fly in the face of the most basic, fundamental, elementary understanding of economic efficiency in multicommodity markets. Leesburg and Midway will, by marking its gas and electricity to market, be doing Florida a huge favor in terms of enhancing the overall efficiency of electricity plus natural gas from production to end use. Playing the spark spread is good, not bad, for Florida. Dr. Kahn's entreaty to price at marginal cost is not an electricity-only entreaty. It is a multicommodity entreaty. Arguments that "playing the spark spread" will be deleterious to the interests of Florida are dead wrong.

3.2.4 Specific Regionality of the NARE Model Used for This Evaluation

What was the specific regionality of the NARE Model used to quantify the price and quantity impacts in the FRCC market of the Leesburg and Midway Projects? The FRCC impacts were generated using a model with the regionality indicated in Figure DMN-7. In the figure, we have used the following regional designations to represent the various subregions of the FRCC:

- TAL: Tallahassee area
- OCA: Ocala area
- CRCF: Crystal River Central Florida area
- STP: St. Petersburg area
- TECO: Tampa Electric area
- LKW: Lake Wales area
- APO: Apopca area
- OUC: Orlando Utilities Commission area

- FPLW: Florida Power and Light West
- MIA: Miami area
- DEL: Deland area
- FPLE: Florida Power and Light East
- DUV: Duvall area
- PNT: Poinsett area
- MRT: Martin area
- GVL: Gainesville area
- LAK: Lakeland area
- JEA: Jacksonville area
- ANDY: Andytown area
- SOU: Southern Company service area

3.2.5 The NARE Model Explicitly "Competes Everything Against Everything Else"

The Altos NARE model explicitly and systematically compares every generation, transmission, fuel, and demand alternative against every other generation, transmission, fuel, and demand alternative individually and collectively and compares every alternative against every existing plant or other alternative as they affect the wholesale market in the FRCC. The NARE model contains every existing power plant in Florida and prospective new entry in Florida that might be assumed in a given scenario. The model then simulates competition among all existing and prospective plants that comprise that scenario. The Altos model pits every plant, existing or prospective, against every other plant. It therefore systematically and explicitly compares every plant, existing or prospective, against every other plant.

I emphasize that the supply stack or supply curve in competitive microeconomics pits every plant against every other plant explicitly and systematically. The result of such pitting of every plant against every other plant is that the marginal plant sets the market price to which each and every plant is then exposed. This cost of the marginal plant can be likened to a "limbo bar" under which every plant must pass if it is to be competitive and operational. Plants that cannot pass under the price "limbo bar" are out of the game and do not enter the market. The "limbo bar" is a very apt analogy--plants that get under it in a cost sense win and plants that cannot get under it in a cost sense lose out. The very existence of marginal cost pricing systematically and carefully does precisely what Dr. Kahn and various regulators and interveners assert needs to be done--it considers each and every alternative in the market and competes each and every alternative against each and every other alternative. It simulates the "war game" among all alternatives and rewards the winner with the market share, just as real world markets do.

The NARE-based needs analysis forthcoming in this report in will show that in fact the Leesburg and Midway Projects are the most beneficial alternatives for Florida customers; they easily get under the limbo bar, and they do so under a rather wide range of reasonable assumptions one might make about them and other plants and fuels. As an example, in the "with Leesburg" case to be discussed in the NARE model in a subsequent section, the market clearing price throughout

Florida would be the same after Leesburg and Midway's entry into the FRCC no matter what the specific cost of the Leesburg and Midway plant, just as Figure DMN-8 illustrates. In other words, it does not matter what the precise cost of the Leesburg and Midway plant is; entry of those plants will induce exactly the same price-depressing effect. This is an extremely elementary result from fundamental microeconomics, and it indicates the power of Leesburg and Midway being inframarginal entrants. The fact that Leesburg and Midway are inframarginal means that the Commission does not have to spend much effort reviewing the Leesburg or Midway cost estimates. Based as they are on new, state of the art technology, they are going to be inframarginal for many or all hours of the year, particularly the important, high price, peak hours.

Figure DMN-8 has another particularly important implication with regard to comparing everything against everything else. The plants arrayed one by one in ascending order of cost are explicitly and systematically competing against one another, and the market is explicitly and systematically taking account of such competition. The diagram in Figure DMN-8, which is the methodology embedded in the Altos model systematically compares everything against everything else.

What is the sensitivity of the benefits of Leesburg and Midway to alternative assumptions? To answer this question, consider Figure DMN-8. What could reasonably change the position of Leesburg and Midway in the supply stack so much that they would move off and to the right of the supply-demand crossing point? What could possibly change the fact that the entry of Leesburg and Midway displaces the original supply stack without Leesburg and Midway outward and to the right and that such displacement necessarily decreases the price of wholesale power in Florida? The answer is "Very little." Demand would have to be cut by more than half, an unlikely prospect. New capacity additions would have to be immediate and far larger than anything proposed to date, an unlikely prospect. Increasing or decreasing gas or other fuel prices raises the entire curve at once, and the relative heights of the lines changes very little. Changes in assumptions that "wiggle" the individual curves (the individual plants) have limited effect on the supply-demand balance and on the market price and therefore on the price depressive effects of Leesburg and Midway. Altos' answer is very robust indeed and not sensitive to reasonable changes in input assumptions. The benefits to Florida of the Leesburg and Midway project are very real and very certain, and they are not particularly sensitive to or contingent on anything. This is not surprising in a state with the highest wholesale power prices in the nation because of an inherent shortage of generation capability relative to demand and because incumbents have so successfully resisted merchant entry and as a direct result thereof exerted market power.

3.2.6 Overview of the Altos NARG Model

The NARG Model represents natural gas resource deposits by basin, resource production costs and volumes, interstate pipelines, "mark to market" competition at the various wholesale hubs, local distribution within demand regions to core and non-core market segments, competition with oil in the non-core market segments. The model calculates the market clearing price at every wellhead, wholesale market, and burnertip market in the United States and Canada and thereby calculates basis differentials, reserve additions, pipeline capacity additions, oil substitution, and the response of price and quantity at each location in the natural gas system in response to a change in any other part of the system. A more detailed overview of the Altos NARG Model is provided in Appendix B attached hereto. Figure DMN-9 depicts the NARG Model graphically.

3.3 Users of the NARE Model and/or the NARG Model

Many of the major natural gas producers and pipelines and a number of the electric companies in North America have used the NARG and NARE Models. Users of the NARE and NARG Models include Amoco, Arco, Associated Electric Cooperative Inc., BC Gas, BHP Petroleum (Broken Hills), BP, British Gas Corporation, the California Energy Commission, Calpine, Canadian Energy Research Institute, Chase Manhattan Bank, the CIA, Coastal/Colorado Interstate Gas, Cogentrix, Conoco/DuPont, DOE/EIA, Duke Energy/Panhandle Eastern, El Paso, Enron, Exxon, L.L.L., L.B.L., Argonne, Oak Ridge, Los Alamos, MidCon/Occidental Petroleum, Mobil, National Energy Board of Canada, Nova Corporation, Oklahoma Gas and Electric, PanCanadian, Panda, PG&E, Pennsylvania Power and Light, Petro-Canada, Pacific Gas & Electric, Pacific Gas Transmission, Shell, So Cal Edison (SCE Corp.), Sonat, Texas Utilities Corporation, TransCanada Pipeline Corporation, TVA, and the Williams Companies.

3.4 The Modeling Approach Has Been Independently Validated by a Third Party Under Sponsorship of the Federal Government

The Energy Information Administration ("EIA") of the United States government decided during the 1980-81 period to independently validate the GEMS model (GEMS, which stands for Generalized Equilibrium Modeling System, was the tradename of our model at that time.) EIA expended in excess of $1 million (in 1981 dollars) with Oak Ridge National Laboratories to validate our GEMS model. In particular, EIA endeavored to verify and validate the software, data, results, underlying economic theory, suitability and completeness of documentation, accuracy of forecasts, proper program implementation, sensitivity analysis, and other relevant attributes of the program. In effect, EIA subjected the GEMS model to a severe and comprehensive professional peer review in order to ensure that it was operating correctly and was appropriate for EIA's intended needs. (In EIA's judgment, Oak Ridge was an independent third party who could perform an objective, disinterested, credible, independent, third party validation.) As part of the validation, Oak Ridge made a number of suggestions (which were ultimately incorporated into our model and software), and they gave the GEMS approach and software a clean bill of health. To my knowledge, our GEMS model is the only model in existence that has been independently validated to such a degree. Details and voluminous documentation related to the independent third-party validation were available at the time of the validation from Oak Ridge. Oak Ridge has since licensed their own copy of GEMS and used it to support their own project work in support of the Fossil Energy Division of the Department of Energy. The MarketPoint approach is an evolutionary descendent of the GEMS model, and the methodological validation that pertains to GEMS pertains as well directly to MarketPoint.

The first versions of the NARE and NARG Models, which are essentially models and database components of larger models and modeling systems, were initially implemented within the GEMS model. They are now implemented within MarketPoint. The GEMS version of the NARE model was used to support the Duke New Smyrna Beach case before the Florida PSC. The MarketPoint version of the NARE model is currently being used to support the Okeechobee project before the Florida PSC.

4 OVERVIEW OF DATA AND ASSUMPTIONS USED IN THE NARE MODEL

What assumptions did we make regarding the existing Peninsular Florida generating fleet, transmission system, and load in this evaluation of the need for Leesburg and Midway? This section puts forth a summary of the data used for this analysis.

4.1 FRCC Supply Data As Used in NARE

This section summarizes how to read the supply side data contained in the Altos-proprietary spreadsheets used in NARE for the evaluation of Panda Leesburg and Panda Midway. I am presenting this to articulate the level of detail and comprehensiveness contained in the Altos generation unit data base.
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4.1.1 Generation Assumptions Used in NARE

Within the NARE model used for this evaluation, sources of supply are represented using what we term "electric generation nodes." These nodes represent categories or aggregates of electric generation characterized by prime mover (or generation technology, e.g., gas turbine, steam turbine), primary fuel (e.g., natural gas, coal), and secondary fuel (e.g., fuel oil 6, waste fuel). We use a rather self-explanatory mnemonic for characterizing the plant categories. For example, the generation category GT_NG_FO2 represents gas turbine generation technology burning natural gas as the primary fuel and fuel oil No. 2 as the secondary fuel. A generation category can contain one or more physical generating units or generating locations depending upon the level of aggregation assumed for a particular model.

The electric generation nodes that comprise the NARE model require four distinct data entities:

- **Capacity:** the capacity of the generation category expressed in megawatts (MW).
- **O&M:** the operating and maintenance cost of the generation capacity expressed in dollars per megawatt hour ($/MWH). Varies by load period.

- **Heat Rate:** the efficiency of the generation category in millions of Btu per kilowatt hour. (MMBtu/KWH). Varies by load period.

- **Availability:** the percent of time the generation category is available (%). Varies by time period and load period.

Every generation node contains the contribution from every plant in the FRCC with regard to each of the four foregoing categories. The generation categories and specific values for these data entities in the MarketPoint models for the FRCC are determined from the Altos proprietary FRCC supply stack contained in an Excel 2000 workbook. The workbook used for this evaluation is named FRCC_SupplyStack.xls. There are five worksheets in the workbook. The following subsections characterize those five worksheets so that the reader can understand the assumptions and content of those spreadsheets.

4.1.2 Worksheet Mappings

The worksheet entitled Mappings contains "mapping" tables that perform one of two functions:

- Relate values from raw data sources into categories used in MarketPoint models.

- Assign additional values to a row in the workbook based on mapped values.

There are five mapping tables in the aforementioned worksheet:

1. **RawGenCategory to MappedPrimeMover--**transforms the generation category based on the prime mover, primary fuel, and secondary fuel from the raw data sources (column RawGenCategory) to a prime mover category (column MappedPrimeMover). This table is contained in columns B, C in the worksheet. The MappedPrimeMovers will comprise common nodes in NARE.

2. **RawFuel to MappedFuel--**transforms the primary and secondary fuel (column RawFuel) from the raw data source to a fuel category (column MappedFuel). This table is contained in columns E, F in the worksheet. The MappedFuel will be associated with the various plant nodes in NARE.

3. **MappedGenCategory to O&M and Availability--**assigns generation category values for O&M and availability based on the MappedGenCategory of a plant/unit. This table is contained in columns H, I, J in the worksheet. The values for O&M and Availability are Altos proprietary values developed over the course of the last five years, and they are mapped into the appropriate nodes in the NARE model.

4. **County to Model Region**--assigns the multiregion descriptor to a row in worksheet PlantDatabase. This mapping assigns each plant in the FRCC (and elsewhere) to a specific NARE model region.

5. **City to County**--assigns a city to its corresponding county. This mapping is used for the rows in worksheet Existing that do not have a value in the county column.

4.1.3 New Plant Installations (Worksheet "FRCC_P_P")

Worksheet FRCC_P_P contains the FRCC planned and projected new plants beginning on January 1, 2000 forward in time according to the FRCC ten year plan. This worksheet was assembled manually and is intended to contain the most current projections of new builds in the FRCC and elsewhere.

4.1.4 Existing Plants as of December 31, 1998 (Worksheet "Existing")

Worksheet Existing contains the Altos proprietary FRCC (as of January 1, 1999) generating plant/unit database. This worksheet contains one row for each unit and/or plant that comprises the FRCC supply stack and was in place and operating on January 1, 1999.

The rows (records) in this worksheet represent the current state and culmination of Altos' ongoing effort over a five-year period beginning in 1995. In 1995, Altos set out to develop state of the art models and supporting data to support its practice in the electric industry. Altos has assembled this database from a wide variety of publicly available data sources (including, EIA, FERC 715, NERC ES&D, and others). The units and plants contained in this database are intended to span utility as well as non-utility generation. Depending upon the data source from which the row was gathered, each row in the database represents one generating unit or an entire generating location.

4.1.5 Worksheet "PlantDatabase"

Worksheet PlantDatabase contains a combination of records from worksheets Existing and FRCC_P_P. The rows contained in this worksheet are determined by the year for which a supply stack is desired. PlantDatabase contains the supply stack for a year 2002 scenario, thus it contains all records from worksheet Existing and those records from FRCC_P_P that come online through the year 2002.

4.1.6 Worksheet "ModelSupplyStack"

Worksheet ModelSupplyStack contains a pivot table that summarizes the records in worksheet PlantDatabase for use import into a MarketPoint model. Worksheets FRCC_P_P, Existing, and PlantDatabase contain 37 columns. A brief description of each column is given in the following table. Note that some columns may be empty for rows in the database since the raw data source providing the record did not contain that value.

Column Name	Column Description
Owner	Plant or unit owner
Station	Plant or unit location description
County	County where plant or unit is located
Unit No	Plant or unit number / description
Nameplate Capacity (MW)	Plant or unit nameplate capacity in MW
Summer Capability (MW)	Plant or unit summer capacity in MW
Winter Capability (MW)	Plant or unit winter capacity in MW
Prime Mover	Plant or unit generation technology
Primary Fuel	Plant or unit primary fuel
Secondary Fuel	Plant or unit secondary fuel
Online Yr	Year plant or unit began operation
Status	Plant or unit status (EIA definition)
Region	Plant or unit NERC region designation
Subregion	Plant or unit NERC sub-region designation
Cntrl	Control area to which plant or unit belongs
Area	MarketPoint™ model region designation
Zone	Control zone to which plant or unit belongs
Country	Country where plant or unit is located
State	State or Province where plant or unit is located
City	City where plant or unit is located
Water Source	Description of plant or unit water source
Ownership Type	Plant or unit ownership type (EIA definition)
HeatRate	Plant or unit Heat Rate (KWH / MMBTU)
P Fuel Transport	Mode of transportation for plant or unit primary fuel
S Fuel Transport	Mode of transportation for plant or unit secondary fuel
Online Mo	Month in Online Yr plant or unit began operation
Retire Yr	Year plant or unit is scheduled to be retired
Retire Mo	Month in Retire Yr plant or unit is scheduled to be retired
MappedPrimeMover	Prime Mover category corresponding to Prime Mover
MappedPrimaryFuel	Fuel category corresponding to Primary Fuel
MappedSecondaryFuel	Fuel category corresponding to Secondary Fuel
MappedGenCategory	Generation category formed from MappedPrimeMover, MappedPrimaryFuel, MappedSecondaryFuel
RawGenCategory	Generation category from Prime Mover, Primary Fuel

Column Name	Column Description
	Secondary Fuel
OM	Assigned O&M cost for plant or unit ($/MWH)
Avail	~~Assigned plant or unit availability (% of time) for plant or unit~~
12RegionAreaFromCounty	Assigned 12 Region Area based on county of the plant or unit
GenCategoryName	Name used within MarketPoint™ model for the plant or unit generation category

The Altos plant database together with these descriptors allows a user to fully and completely characterize all plants in the FRCC. The data in the referenced worksheets have been calibrated unit by unit and plant by plant against the Energy Information Administration and the FERC 715 plant data. It is our view that they are correct and current and properly reflect the present and future situation in the FRCC.

4.2 FRCC Demand and Load Data As Used in NARE

This section characterizes how electricity demand is represented in the NARE model. Electricity demand, which must be met in real time, occurs as depicted in the left hand diagram in Figure DMN-10. In particular, demand occurs at a different level for every hour of the day, month, and year. The vertical axis of the diagram represents MW of load, and the horizontal axis represents time measured in hours. The width of the diagram is one month, i.e., approximately 8760/12 = 730 hours depending on the particular month under consideration. Figure DMN-10 illustrates the fundamental definition of the load duration curve at the right—it is the sequence of hourly loads sorted from highest load hour to lowest load hour throughout the month. The vertical axis represents MW of demand. The horizontal axis represents hours of the month. The load duration curve is the fundamental medium through which a month is represented in our model.

Let us consider the load duration curve at the right in further detail. The area under the curve is the total energy delivered during the month. It is expressed in MWH, i.e., fundamental units of energy. If we were to gather historical demand data as in the leftmost curve, sort it to create the rightmost curve, and divide by the total MWH during the month, we would calculate what we term the normalized load duration curve. The normalized load duration curve delivers 1 MWH of energy, but it delivers that 1 MWH of energy according to the time pattern represented by the shape of the normalized load duration curve—a certain quantity of base, a certain quantity of intermediate, and a certain quantity of peak. More generally, if we subdivide the load duration curve into more categories than the simple base, intermediate, and peak (which we have done), we will be able to render a better approximation to the continuous curve.

Based on this view of the load duration curve, one can surely see why we need to obtain historical data. The historical data is represented by the curve on the left—the historically observed hourly consumption data. (As we discuss below, we have inferred our load forecasts from the FERC 714 reports.) In order to infer the shape of the load duration curve on the right, we need an accurate process for assembling the historical load data at the left and thereafter an accurate process of sorting it to create the load duration curve on the right. We will discuss this in more detail below.

Rather than working with the "continuous" load duration curve in Figure DMN-10, the model actually works with a discrete approximation to the load duration curve. Suppose we wished to create the best three-rectangle approximation to the continuous curve at the right of Figure DMN-10. (We actually use more than three blocks in the NARE model, but three blocks facilitate communicating the methods.) We would stack bricks under the load duration curve in a fashion analogous to Figure DMN-11. The three bricks would intersect the x-axis (the Hours axis) at three discrete points, and they would intersect the y-axis (the Consumption axis) at three different points as well. The three discrete points on the x-axis are often designated "base hours," "intermediate hours," and "peak hours." We would structure the three rectangle approximation so that the sum of the areas of the three rectangles is exactly equal to the area under the continuous load duration curve. This ensures that the total monthly energy demand given the continuous load duration curve is exactly equal to the total monthly energy demand given the discrete approximation. It is clear, we need not limit ourselves to a three-brick approximation. We could use two, five, or fifty bricks. We have chosen ten such bricks for each months for the present evaluation.

Figure DMN-12 depicts the discrete load duration curve in more detail. Each of the three rectangles corresponds to a particular number of hours in the month, as designated by where they intersect the x-axis. Each of the three rectangles corresponds to a particular quantity of energy during the month, as designated by their areas. And finally each of the three rectangles corresponds to a particular height on the vertical axis, i.e., a particular level of MW of generation. We have designated the number of hours in the peak load period to be the width of the first interval on the x-axis, namely $H_3(t)$. We have used the notation $H_3(t)$to indicate that the hours in the peak period can be defined differently for each month and therefore must be a function of the month we are modeling, i.e., $H_3(t)$ is time-dependent. The number of hours in the intermediate load period is designated by the notation $H_2(t)$, and the number of hours in the base load period is designated by the notation $H_1(t)$. Because there are approximately 730 hours in the month, we know that the following relationship must hold for every month

$$\mathbf{730 \cong H(t) = H_1(t) + H_2(t) + H_3(t)}$$

We have used time fractions designated $\mu_i(t)$ to represent the fraction of monthly hours that characterize the i-th time block. Using this designation, we write the foregoing equation in terms of the hourly fractions

$$\mathbf{730 = H(t) = H(t)[\mu_1(t) + \mu_2(t) + \mu_3(t)]}$$

Turning to the energy side of the equation, because we want the sum of the areas of the three rectangles to add up to the total energy demand during the month, which we designate D(t) to note that it is time-dependent, we must have the relationship

$$D(t) = E_1(t) + E_2(t) + E_3(t)$$

The first equation ensures that the hours add up and that none of the hours has been omitted, and the second ensures that the monthly energy demands in each of the blocks add up to the correct total monthly demand D(t). We should emphasize that what we usually have in building a model is a forward projection of the total monthly (or annual) demand D(t), which in the case of the FRCC and other regions is derived from FERC 714 documentation.

We have expressed the energy terms not as absolutes but rather as fractions of the total energy D(t). That is, we have defined constants $\alpha_i(t)$ such that

$$E_i(t) = D(t)\alpha_i(t)$$

The $\alpha_i(t)$ terms are called energy fractions, and they represent the fraction of total energy transacting in the given month that occurs during the i-th time interval. Knowing for each block as we do the total energy resident within the block and the total number of hours represented by the block, we can calculate the height of each block, which represents capacity that must be supplied during that load block.

$$C_i(t) = \frac{E_i(t)}{H_i(t)} = \frac{\alpha_i(t)D(t)}{H_i(t)}$$

That is, the consumption level $C_i(t)$ expressed in MW persists for $H_i(t)$ hours during the month. The distribution of this capacity $C_i(t)$ over the load periods weighted by the number of hours $H_i(t)$ in each load period fully characterizes the demand side of the NARE model. Using the foregoing notation and concepts, the fundamental inputs to the model are therefore very easy to calculate. They are

- The number of hours that comprise each month H(t).
- The number of hourly load blocks during the month and the fraction of hours represented by each hourly load block. In terms of the foregoing equations, the inputs are the $\mu_i(t)$ terms. These are inputs to the model and are specified in the table of overall model parameters.
- The total energy consumed during the month D(t). This information is assembled from the FRCC ten year plan or the ES&D forecast.
- The energy fractions over time [the $\alpha_i(t)$ terms]. These are inferred from the detailed hour by hour FERC 714 reported demand data.

Using these estimates, the load duration curve for each month that is input to the model is the following sequence of numbers

Number of Hours	Energy (MWH)	Capacity (MW)
$\mu_1(t)H(t)$ hours	$\alpha_1(t)D(t)$ MWH	$\frac{\mu_1(t)H(t)}{\alpha_1(t)D(t)}$ MW
...	...	...
$\mu_n(t)H(t)$ hours	$\alpha_n(t)D(t)$ MWH	$\frac{\mu_n(t)H(t)}{\alpha_n(t)D(t)}$ MW

To assemble demand, we utilized the FERC Form 714 reported hourly loads by virtually every reporting entity in the United States for a historical period of six years. By assembling hour by hour reported loads by every reporting entity, we were able to assemble a historical histogram of loads during the past six years. We then scaled this historical histogram of loads upward to the point at which the total energy under the histogram of loads matched the 1998 actual energy demand as reported by the NERC ES&D publication of the FRCC Ten Year Plan publication from July 1999. This allowed us to preserve the historical load shape but to match the 1998 reported net energy for load.

Figure DMN-13 illustrates graphically the monthly load duration curve we have derived for each forward period in the NARE Model for the FRCC for the year 2003. It is shown as a continuous curve in the diagram. It is important to point out that the NARE Model as used in this study is chronological in the sense of Figure DMN-14. In particular, each month in the NARE model is specifically distinguished and is in chronological order with regard to all the other months. Each year is chronological with regard to the other years. Within each month, loads are sorted and categorized into the ten highest-to-lowest load categories shown in the diagram. Furthermore, it is assumed that each increment of monthly load is coincident with the same increment of monthly load in each of the other regions of the model. While the model is capable of representing submonthly chronology and coincidence, we elected not to do so because we want our prices and our price decreases to be conservatively stated and because the extra detail does not in our view shed additional insight. In particular, detailed treatment of short term chronology would elevate prices at time of daily peak as compared with the nonchronological treatment we have chosen within the months of our model horizon. Chronological treatment would amplify prices and price decreases emanating from the entry of Leesburg and Midway and more strongly state the need than we have here.

The FERC Form 714 data that we have assembled provides monthly load duration curves for each month of the year. The first step in preparing demand projections for the identified subregions within Peninsular Florida is to select a number of discrete increments into which to disaggregate the continuous curve in Figure DMN-13. That is, if we wanted to use a "staircase " approximation to Figure DMN-13, how many stairs would we want to use in order to get a good enough approximation to the curve. If we elected to use ten stairs to approximate the curve, we would be able to draw the 10-stair discrete approximation shown in Figure DMN-15. (We have used 10 stairs per month to characterize the Florida market and in fact every market of North America in the NARE Model.) Notice that the curve in Figure DMN-15 distinguishes ten different, discrete demand levels because it has ten different, discrete horizontal blocks or plateaus. Beginning at the left, we see a series of declining plateaus until we reach the lowest horizontal plateau at the lower right. Each of these ten horizontal blocks or plateaus corresponds to a different level of demand, each of which is expressed in MW. But the discrete curve also demonstrates how many hours each of the ten discrete levels of demand occurs. For example, the highest and leftmost level of demand persists in the diagram for 1 percent of the hours in the month. Assuming that there are 730 hours in the month, this means that the highest level of demand indicated in the diagram exists for 7.3 hours in the month. The second to highest (and second to leftmost) level of demand exists for 3-1=2 percent of the hours in the month, i.e., 14.6 hours in the month. Continuing this logic across the diagram, we see that the diagram is in effect a monthly histogram for the occurrence of ten different levels of demand during the month.

The next step is to calculate the supply-demand equilibrium for each of these ten different levels of demand; this set of calculations yields a histogram of ten different, distinct market-clearing prices, each with a corresponding frequency of occurrence. Figure DMN-16 illustrates how this occurs. Ten demand points (each with a frequency of occurrence) are used in the NARE model. Ten supply-demand crossing points are calculated, giving ten market clearing prices on the vertical axis. These ten market-clearing prices occur with exactly the same frequency of occurrence as the ten demand blocks or plateaus that generated them. Therefore, the ten prices are in effect a histogram over prices during the month, a so-called price duration curve.

Figure DMN-17 shows direct output from the NARE Model for the APO region of Florida in which the Leesburg Project will be situated, and Figure DMN-18 shows the analogous curve for MER where the Midway Project will be situated, both diagrams representing the scenario "no Leesburg/no Midway" defined later in this report. (This scenario will be the base case against which we have measured the price depression and consumers surplus benefits that Leesburg and Midway induce jointly and individually.) These diagrams indicate the market clearing prices together with their frequencies of occurrence that persist at the busbars of the two Panda plants. In order to understand the market clearing prices depicted in that figure, remember that load has been disaggregated into ten monthly periods, which I will define more precisely in the following list:

- Average load during top 1 percent of hours (designated 1% in the diagram). This block or plateau of load takes the highest 1 percent of the hours of load during the month and calculates the average of those highest 1 percent of hourly loads. It represents the average or mean value of the highest 1 percent of hourly loads. We characterize it by the notation 1% because 1% of the time, the load equals or exceeds the indicated level. The price on the 1 % line is therefore the average price over the top 1 % of the hours in the given month.

- The average load for the next higher 2% of the hours, i.e., the hours between the 1% point and the 3% point. This block excludes the top 1% of hourly loads but includes the average of the next higher 2% of hourly loads. We designate this load category as the 3% point, indicating that for 3% of the time load is higher than this level. The price on the 3 % line is therefore the average price over the top 3 % of the hours minus the top 1 % of the hours in the given month.

The remainder of the load blocks similarly reflect the average load and the average price for the percentage of hours indicated. In effect, the percentage terms indicated in the legend represent the percent of time that the given or larger load persists. For example, the 3% curve represents the 97th percentile of load and therefore the 97th percentile of price. The load and price exceed the given level only 3% of the time. The 3% component of load is relatively "peaky;" load is higher than this level for only 3% of the hours of the month. Therefore, the percentages shown in the price diagram represent the percentage of time that on average the price is equal to or larger than the indicated curve.

After deriving historical monthly load duration curves, it is then necessary to project those monthly load duration curves forward in time for the next ten years. To do so, we assume a growth rate for peak energy growth and a growth rate for total energy growth. By so doing, we develop a projected forward monthly load duration curve for the next ten years. We have done so for by growing each individual region of the eastern grid at an assumed total energy growth rate. As described later in this report, the benefits of the Panda Projects are not particularly sensitive to reasonable changes in forward projections of load or demand. To wit, the benefits of the Panda Projects are not materially changed if we utilize lower or higher forward growth projections in the NARE Model across a reasonable range of uncertainty.

4.3 Transmission Assumptions Used in NARE

We have appealed to the FERC 715 reports to infer the peak transmission capabilities between the various busbars in the FRCC. In particular, we have inferred the sum total transfer capability between the collections of busbars from the FERC 715 reports that comprise our nineteen FRCC regions. We have specifically assumed that the maximum transfer capability between regions is the physical transfer capability inferred from the FERC 715s. We have assumed that both tariffs and losses are distance dependent in the FRCC, but we have adjusted the tariffs to approximate the vestiges of postage stamp ratemaking we believe will still be present in the year 2003 and beyond.

4.4 Fuel Price Assumptions Used in NARE

We have assembled a series of regional fuel price assumptions for use in NARE. It is presented in the attendant spreadsheet in Appendix C.

5 ISSUES RELATED TO THE NEED IN FLORIDA FOR PANDA LEESBURG AND PANDA MIDWAY

This section puts forth a number of issues that are important for the Commission to understand regarding why the Panda Leesburg and Panda Midway Projects are needed in Peninsular Florida. Some of these insights derive directly from our analytical work, and some derive from baseless criticisms and alternative viewpoints that have been put forth in other proceedings and venues and that we want to quell in advance. Some of the insights are extracted directly from relevant economic literature for presentation to the Commission in this case.

5.1 Merchants Do Not Threaten the Regulatory Fabric of a Region or State in Which They Enter

Merchants such as Panda Leesburg and Panda Midway do not threaten the regulatory fabric of the region into which they are introduced. On the contrary, they are a major benefit to regulators and ratepayers alike. They provide a benchmark on cost and performance that disciplines the regulated incumbents. They provide a competitive set of merchant plants to collectively reduce market power otherwise held and in the case of Florida wielded by incumbents to the detriment of ratepayers and businesses in the state. Merchant sponsors bring to regulators a mountain of objective information related to the markets and facilities they regulate, in effect doing a mountain of "homework" for regulatory bodies.

5.2 Merchants Require No Special Accommodations in Order to Enter and Succeed

Merchants would require no special accommodations in order to enter the FRCC wholesale market and bestow benefits on FRCC ratepayers. No special accommodations have been required in other states in which merchant plant entry has been proposed, regardless of the status of deregulation in those states, and none should be required in Florida. (All that is needed is the existence of a competitive wholesale market.) The incentives are clear for both the merchant entrant (enhanced profitability) and the ratepayers of Florida (price depression). We will discuss a few reasons why there need be no change in the existing Florida regulations required for Panda Leesburg and Panda Midway to enter and bestow benefits on Florida ratepayers and why therefore those plants are needed by citizens and businesses in Florida. It not an idle or baseless statement that merchants would enter without any special accommodations. There are a large number of impending applications in Florida in spite of the ponderous needs process that each potential aspiring entrant must complete before the Florida PSC. If there were fewer impediments to entry, it is certain that a larger number of these aspiring entrants would enter the state more quickly. To argue that aspiring merchants need any special accommodations or considerations is preposterous and is directly refuted by the long line of aspirants.

5.2.1 A State Would Not Need an ISO or Equivalent to Achieve Benefits from Merchant Entry

Would a state or a relevant market have to have an Independent System Operator (ISO) or equivalent to accommodate merchant plant transactions in the wholesale bulk power market? Not at all. Low-cost power is low-cost power independent of the regulatory and ownership structure of the transmission system. I am not aware of any regulatory framework that would deny the benefits of low-cost power to the region in which it is located. As outlined by Dr. Kahn and others, regulation is generally designed to pass through the direct acquisition cost of commodities and services at market rates, and as a result low-cost power in the FRCC would pay direct benefits. It is well to keep in mind that the function of an ISO is to secure and guarantee equal and open access to the electric transmission system for all players i.e., the system-generators, customers, marketers, aggregators, and so forth. Such a guarantee assists ratepayers in gaining benefits from low-cost entrants.

Obtaining benefits from an inframarginal plant (i.e., a power plant whose incremental production cost is less than the incremental cost of the highest-cost, or marginal, plant operating in a given hour) such as the Leesburg and Midway Projects is relatively simple. Generally, unless some unexpected system condition requires redispatch or unloading of certain transmission lines, all one has to do is "turn it on and leave it on." It will generate low cost MWH during virtually every hour of the year and will displace higher cost MWH's that would otherwise have to be used. To garner benefits from a plant such as Leesburg or Midway is a very simple problem for regulators—laissez faire is the best policy.

5.2.2 A State Would Not Need a State Power Exchange or Equivalent to Achieve Benefits from Merchant Entry

Would a state or reliability region have to have a power exchange (PX) or other buy-sell market mechanism to benefit from merchant plant entry? Not at all. In fact, a publicly mandated power exchange such as that in California is not necessarily needed for Florida to capture virtually all the benefits of merchant plant entry. The only thing needed is a competitive wholesale power market, and FRCC has that. If marketers and aggregators enter, so much the better, but even they are not needed. If a purely bilateral system of buys and sells were used, benefits would accrue to ratepayers as well.

5.2.3 Retail Deregulation/Retail Competition Are Irrelevant to the Benefits of Merchant Entrance

What, if any, relationship does wholesale competition have to the issues of deregulation, retail restructuring, or retail competition? Retail competition is quite different from wholesale competition. One can have a competitive, flourishing, active wholesale market with or without retail restructuring or retail competition. The Leesburg and Midway Projects can and should be evaluated independently of any retail restructuring or retail competition considerations. Leesburg and Midway are purely wholesale projects and should be evaluated accordingly. The sponsor is willing to build and operate them on the basis that they are wholesale projects. The modeling technology I have used to develop this report assumes a competitive wholesale market. It makes no assumptions one way or the other about retail competition. Furthermore, it conforms precisely to the approach advocated by Dr. Kahn—emulating perfect competition through equating price with marginal cost.

5.3 Objectives of Regulation Are to Emulate Competition and Marginal Cost Pricing, and Merchant Entry Fosters that Objective

To reiterate, Dr. Kahn tells us that the most efficient solution in an industry that is not a natural monopoly (which power generation is most definitely not) is the perfectly competitive solution, which in wholesale power markets (which are intrinsically competitive) is achieved by regulators backing away from any sort of intervention whatsoever and allowing entry and operation by independent, autonomous, atomistic, profit-seeking merchant entrants. That is precisely what Leesburg and Midway are--independent, autonomous, atomistic, profit-seeking merchant entrants. The Leesburg and Midway proposals for merchant entry are literally a classic textbook example of what the regulators should allow because it conforms exactly with the perfect competition paradigm. In my view, electric generation displays constant returns and ultimately decreasing returns to scale, and entry with virtually identical equipment by any atomistic producer is easy.

In order to argue against a perfect, competitive wholesale electricity market, one would have to argue that the factor markets or the customer markets in Florida are imperfect and in fact so highly distorted that the "second best" problem would point toward suspension of or intervention in an otherwise competitive wholesale electricity market. Assuredly upstream fuel markets are highly competitive and are far from imposing second best reconsiderations on power markets that would indicate a need for continued regulation of those markets. The demand side of the wholesale power market is likewise not so distorted as to obviate a competitive wholesale market. Regulatory rules bias in favor of least cost power purchase, and they need not impose second best reconsiderations on power markets that indicate the need for continued regulation. I think most people inside and outside Florida realize that the arguments that favor competitive wholesale power markets cannot be refuted or overturned based on second best distortionary arguments. Arguments that wholesale power markets require continued regulation have been thoroughly debunked around the United States and I believe in Florida. There is absolutely no need to regulate wholesale power markets from an economic or rate perspective. Quite the contrary, those markets are and should remain competitive. Panda Midway and Panda Leesburg are needed in those markets to alleviate the outrageously high prices and lack of reliability that will befall the FRCC under the currently pending ten year plan, which I believe evidences the exercise of market power by incumbents based on my modeling work.

5.4 Leesburg And Midway Projects Are the Most Cost Effective Alternatives

Are the proposed Leesburg and Midway Projects the most cost-effective alternatives available to provide additional power resources in peninsular Florida? Indeed they are. The fact that the Projects are the most cost-effective alternative is underscored by the fact that natural gas-fired combined cycle technology is currently the technology of choice for Florida utilities and in fact for many utilities throughout the United States. The Duke New Smyrna Beach merchant plant already approved by the Florida PSC is a natural gas combined cycle unit. The proposed Okeechobee plant is a combined cycle unit. Other plants such as the Florida Municipal Power Agency's proposed new plant, FPL's proposed repowering projects, Lakeland's planned "phased" combined cycle unit, and the City of Tallahassee's approved Purdom 8 unit, are all projected to use this same natural gas-fired combined cycle technology. This report has already discussed in detail that the analysis procedure we have used has competed all plants of all types against all other types for all loads.

5.5 Incumbent Utilities Cannot Build as Cheaply or Efficiently as Panda Leesburg or Panda Midway

Can incumbent utilities add new generating capacity as inexpensively and efficiently as merchant entrants such as Leesburg and Midway? I do not believe they can, not even the same plant configuration from the same plant manufacturer. I do not believe regulated incumbents protected by regulatory-assisted cost passthrough can or will add new capacity as inexpensively as merchants. Because they are protected by cost passthrough and because they earn on many of those costs, incumbent utilities are directly incentivized to build higher cost plants than they really have to and run them at higher cost than they really have to. (The incentive to maximize investment in a protected, regulated situation is termed the Averch-Johnson-Wellisz effect, and it is well-understood and accepted in the economic community.)

In interpreting my statement that the incumbents cannot build or operate as inexpensively as Panda Leesburg and Panda Midway, it is well to keep in mind that one should not appeal only to the narrowest sense of the Averch-Johnson-Wellisz effect. To do so is to systematically omit the important sense of the problem. As Averch, Johnson, and Wellisz have pointed out according to Dr. Kahn in the previously referenced classic monograph, the effect is not simply a padding or expansion of rate base but also a phenomenon of "paying too much for the same stuff others can get cheaper." (The discussion in Dr. Kahn's directly refutes assertions that there is no Averch-Johnson-Wellisz effect.) The aspect of the Averch-Johnson-Wellisz effect to which I am referring is the "$400 toilet seat" whereby the offerors of the toilet seat know that the utility customer is incentivized to pay more for it because he or she can earn on it at or above market rates or can pass the costs on to someone else. Knowing there is a more secure market downstream from the utility company to its customers and that utilities can figure out how to earn in that market at or above market rates, vendors can simply charge utilities more. Internal construction and operation groups within utilities can charge their parent companies more. This is not an indictment of utility companies per se, it is simply a recognition of the incentives they face and the fact that everyone knows it. In my experience, vendors know that a contract with a traditional cost of service utility can be a "meal ticket." A contract with a utility is not as penurious as a contract say with an unregulated company. The latter are always pinching the pennies because the funds to pay the contract come directly out of the company's bottom line; there is no passthrough to others possible to defray the cost. By contrast, regulated utilities can either capitalize what is provided and earn on it or pass it directly through to ratepayers as long as the company can advocate it to its PSC it can earn on it. Therein lies the Averch-Johnson-Wellisz effect, and it is quite clear that the incentives are present in Florida to cause it to occur.

In contrast to incentives facing incumbents, merchant entrants such as Panda have every incentive to reduce the cost of their new plants as much as possible. Every dime of cost reduction is a dime of profit in their pocket. They are incentivized quite antithetically to regulated incumbents. Merchant entrants make money by reducing costs while regulated incumbents make money by increasing costs. Given these incentives, I believe that incumbents will always build more expensive plants than merchant entrants because they will and should respond to the economic incentives they face. Because of Averch-Johnson effects, I would not agree with the argument that incumbents can add generating capacity just as inexpensively and efficiently as merchant entrants. I believe that merchants such as Leesburg and Midway will build substantially lower cost plants in FRCC than incumbents, and FRCC ratepayers will benefit proportionately more from merchants than they do from incumbents. I do not accept the argument that incumbents and merchants are substitutable. I believe incumbents are systematically and structurally higher in cost even though they can buy exactly the same equipment. That is why the Panda Leesburg and Midway plants are needed—to reduce the cost to FRCC ratepayers of the higher cost alternative for exactly the same commercial plants. They are also needed to discipline and benchmark the cost of the incumbents.

5.6 Parrying Three Specious Arguments that Presumably Favor Incumbents over Merchants

There have been arguments in the past that: (1.) the cost of capital for merchants is higher than for incumbents; (2.) regulators would stretch depreciation out in time for IOUs; and (3.) regulation would require straight line rather than accelerated depreciation. Every one of these three arguments is wrong, and each of these three arguments is irrelevant to the Panda Leesburg and Panda Midway decisions anyway. These are arguments that deserve to be put six feet under where they belong.

Let me address the second and third points first and the cost of capital issue thereafter. The second and third points have in my experience been soundly and roundly discredited by the experience of deregulation but evidently not in the minds of certain regulation advocates.

5.6.1 Stretching Depreciation Schedules in Time and Championing Straight Line Rather Than Accelerated Depreciation are a Failed Regulatory Policy of the Past

The idea put forth under item (2.) is a remnant of failed regulatory policies of the past. When I hear this hackneyed old argument that regulators can and should extend the depreciable life of regulated equipment, I always recall two important vignettes that directly refute such arguments. The first occurred when Judge Greene issued the Modified Final Judgment (MFJ) that broke up AT&T. When that occurred, I understood from Mike Ardley, Chief Statistician of Pacific Bell, when I worked in the telecommunications industry that the average remaining depreciable life of rotary phonesets then in place at that time was an astounding 13 years! There was 13 years of undepreciated embedded cost left in the average rotary phonesets then in place even though they were economically and technically obsolete and worth nothing in a fair market value sense. They were literally bookends. Yet AT&T was being pressed by regulators with the mindset to stretch the depreciation life of rotary phones out to 20 years and longer using precisely the logic espoused by certain regulatory advocates in the Okeechobee and probably other Florida PSC cases to subsidize near term rates at the expense of longer term rates.

In arguing for extended depreciation, people were and are invoking an incorrect "free lunch" argument. They are in effect arguing that extending the life is a free lunch to utility customers, leading to lower prices in the near term than would occur in a competitive market. That is wrong; mandates of excessively long depreciation schedule are no more than a blatant subsidy of ratepayers by shareholders and metastatic cancer to incumbents forced to carry long depreciation schedules on their books. Mandated longer-than-economic depreciation schedules devalues and daunts in-state investment. Who wants to invest in forty year, highly illiquid investments with regulators "clawing back benefits" by hammering on incumbents to depreciate over an even longer life? Who wants to face stranded cost risks implicit in forty year illiquid balance sheet entries with the knowledge that many other states have already deregulated and Florida might be next? Despite arguments to the contrary, extending depreciation lives is a certain ticket to hurting FPL, FPC, TECO, and their shareholders and discouraging investment in Florida. The market will punish them if regulators were to do that. The last companies on earth who want extended depreciation should be FPL, FPC, TECO, and the other incumbents.

Returning to my rotary phone vignette, when the MFJ was implemented, the then-remaining undepreciated embedded cost of those rotary phones was written off virtually immediately. Those phones and their 13 year remaining lives became instant stranded cost (as did a good bit of other phone company equipment). Recovery of those stranded costs was lost to the phone companies precisely because they were uneconomic and their remaining depreciation was uneconomic. I should mention that some ten yeas after the MFJ, there was an article in Investors Business Daily announcing that NYNEX and Ameritech had finally been told by their accountants to write off the undepreciated portion of historical embedded cost they had been carrying on their balance sheets since the MFJ. It was reasoned that longer-than-economic or lower-than-market values of depreciation should be marked to market, and the difference between mark to market depreciation and their actual depreciation should be sacrificed. (I perceive this philosophy has in recent years become incorporated in the FASB standards so that balance sheets do not become cluttered with embedded costs and other non-mark-to-market items whose intrinsic value is less than their historical embedded cost. I will discuss this further below.)

Using the extended depreciation logic proffered by certain regulation advocates, why not stretch power plants out to 150 years and water systems out to 175 years? It would be a super way to cut today's rates, and the present value of investment using simple models would still preserved. All utilities would have to do is wait 150-175 years to get their money back. Ain't that a great idea? Shouldn't our regulators force incumbent utility companies to maximize their stranded cost exposure? Shouldn't we do the same thing to power plants as we did to rotary phones when we put them on a 20 year depreciation schedule? Such a suggestion is poor public policy indeed, padding balance sheets of IOUs with uneconomic costs that are not justified on a mark to market basis. It is very poor policy indeed to be used as a way to subsidize entry by incumbents to the detriment of merchants. Florida needs merchants such as Leesburg and Midway to prevent that type of regulation from ever being seriously considered in Florida.

My understanding is that present day corporate accounting principles are now discouraging or outright preventing longer than economic depreciation schedules, as they absolutely should. Accounting principles should not and I believe do not allow depreciation schedules longer than economic life because they do not allow companies to carry undepreciated plant and equipment on their balance sheets at higher than their true economic value. In short, the strategy advocated by some that regulated utilities can and should stretch depreciable lives will I believe be precluded by auditors and external accountants. It is clear to me that in the 1990s, the Financial Accounting Standards Board (FASB) has been clamping down on companies who try to carry items on their balance sheets at other than fair market value or mark to market value (which they term "fair value" in the FASB summaries and which I term "mark to market value"). It appears extremely unlikely that companies such as FPL, FPC, TECO, and others will be allowed to carry long-lived undepreciated assets on their balance sheets and thereby be able to earn on and recover them in the distant future. (It would be necessary for them to carry such assets on their balance sheets in order to earn on and recover them.) To give a sense of the mindset of FASB, I have included summaries of a number of relatively new FASB rules in Appendix D. The writing on the wall is clear—FASB will increasingly disallow companies to stretch depreciation into the future. Rather, they will minimize depreciable lives so as to disencumber corporate balance sheets. That is precisely what merchants do naturally, and it will be a very positive force for the FRCC and for Florida ratepayers.

I should also point out one final fatal flaw in the argument that regulators should return to the failed policies of the past by imposing long depreciation schedules. Keep in mind, electric power plants, whether merchant or incumbent, must compete for capital in broad based capital markets. Those markets increasingly punish illiquidity because there are so many rapid, highly liquid opportunities to deploy that capital—internet and high technology companies and the like. (I seem to recall Alan Greenspan mentioned certain sectors such as high technology pulling capital from the rest of the economy in his speech to Congress last month.) Like it or not, FRCC investors must attract capital from United States aggregate capital markets, and extending depreciation schedules is a good way NOT to get it. It is a good way to cripple the incumbents and drive down their profits and creditworthiness.

All the indictments I have made of extended depreciation schedule pertain just as directly to the difference between straight line and accelerated depreciation. Straight line depreciation rather than accelerated depreciation is just a less extreme form of deferring depreciation to the future, and the market will punish it. Arguments that investments by incumbents should be favored because regulators can enforce extended depreciation schedules are vacuous and should be dismissed by the Commission.

5.6.2 Cost of Capital Is Irrelevant to the Panda Leesburg and Panda Midway Plants

With regard to cost of capital, that is not at all an issue here. Panda Leesburg and Panda Midway are bearing the entire capital cost and the cost of capital on the Leesburg and Midway projects. There is no feedback or feedthrough of capital cost of cost of capital to FRCC ratepayers. All arguments about cost of capital to merchants such as Leesburg and Midway are completely irrelevant. Such arguments are no more than a smokescreen by incumbents who are themselves passing cost of capital onto their ratepayers by force and who argue that cost of capital should therefore be a consideration. Panda Leesburg and Panda Midway are not passing any cost of capital on to anyone and therefore it is of no concern to the Commission.

5.6.3 The Commission Should Stay Away from the Failed Policies of the Past of Stretching Depreciation Schedules to Bar Merchant Entry

In conclusion, any argument that regulators can or should extend project depreciable life or impose straight line rather than accelerated depreciation decreases the liquidity of the investment and increases the balance sheet and stranded cost risk in the event of future deregulation. I believe the market will punish companies who attempt to do so, and such punishment will take the form of worse credit rating and worse share price appreciation. If this were to happen to regulated FRCC incumbents, ratepayers would pay for it directly. It is a good way to devalue your local utility companies such as FPL, FPC, and TECO, and I think it is very poor public policy as a way to keep merchants out. Quite the contrary, merchants are needed precisely to accelerate incumbents' depreciation schedules and work off their stranded cost risk before it actually happens.

5.7 Additional Benefits Provided by The Leesburg and Midway Projects

What economic benefits will the Leesburg and Midway Projects likely provide to the state of Florida and to Florida electricity customers? The analyses of the Florida and contiguous markets demonstrate that the Leesburg and Midway Projects will provide direct economic benefits in the form of lower-cost electricity to Florida utilities than would otherwise occur, reduced risk to Florida electric customers, reduced market power in electricity generation, enhanced fuel efficiency in electricity production in Florida, improved environmental quality in Florida, stimulated entry of new natural gas transmission pipeline capacity, and stimulated economic growth. By reducing electricity costs and prices, the Projects will also differentially favor lower-income persons and households.

The benefits of the Leesburg and Midway Projects are not sensitive to alternative reasonable projections of demand or demand growth in Florida. In fact, the Projects' benefits are rather insensitive to reasonable alternative projections of demand. Whether future demand is high or low, the Projects continue to "beat out"--i.e., operate in economic preference to--the same high cost plants at the margin of the FRCC region supply stack, shown in Figure DMN-19. The Leesburg and Midway Projects will provide greater benefits (cost savings, price suppression, environmental benefits) when demand is higher. However, the Projects will also provide similar benefits, though generally of slightly lesser magnitude, during lesser demand periods. In short, the Projects are always needed across the full reasonable range of forward demand projections. This is based on the price considerations and supply stack issues discussed above. Any allegation that somehow "there is not enough demand" to justify merchant entry is wrong. Merchant entry is justified to reduce the operating time of old, high-cost, high-polluting plants in Florida and to relegate them to service as lower load factor intermediate resources, peaking resources, and reserves. It is not really the demand that entices the Project's entry, it is the inefficient, high-cost plants in the current Peninsular Florida generation fleet that motivate entry by the Project and plants like it.

5.7.1 Electricity Price Depression or Suppression Effects Caused by the Entry of Panda Leesburg and Panda Midway

Displacement of generation from high-cost plants by low-cost plants causes an overall price reduction in Florida (relative to the price that would otherwise occur), and this price reduction causes a direct augmentation of Florida producers' plus consumers' surplus, i.e., a direct augmentation in Florida's "gross state product." Figure DMN-20 indicates why price reduction occurs as a result of the entry of the Leesburg and/or Midway Projects. Before proceeding with an explicit analysis of Figure DMN-20 and precisely how it quantifies the benefits to FRCC ratepayers from the entry of Leesburg and Midway, it is well to discuss why the geometry of the supply stacks in Figure DMN-20 is the correct geometry.

5.7.2 Extended Discussion of the Geometry of the FRCC Supply Stack and How Panda Leesburg and Panda Midway will Affect It

The leftward portion of the supply stack in Figure DMN-19 is the portion people normally term the "baseload" portion of the supply stack--the flat portion comprised by the low cost generators. The leftmost portion of the supply stack in Exhibit DMN-19 is rather flat. During the baseload hours, rightward displacement of the curve by 2000 MW does not raise the curve to any great degree. The height of the "with Panda Leesburg and/or Midway" curve and height of the "without Panda Leesburg and/or Midway" curve are roughly similar during time of base. Figure DMN-21 illustrates this phenomenon.

The situation during time of intermediate and peak is markedly different from the situation during time of base however. During time of intermediate and peak, the demand curve is passing through the supply stack somewhere between its middle to the right of the supply stack. The rightward shift (i.e., horizontal addition of 2000 MW associated with Leesburg and Midway) in the supply curve caused by the entry of 2000 MW of new capacity causes the "with Leesburg and/or Midway" supply stack to differ vertically from the "without Leesburg and/or Midway" supply stack at the middle to right range of the curve. The situation at the right of the supply stack, the situation that occurs at time of intermediate and peak precisely when prices are highest, is diametrically different from the picture at time of base.

Figure DMN-21 illustrates the situation with regard to how the entry of Panda Leesburg and Panda Midway alter the FRCC supply stack at time of baseload as well as peak. During such intermediate and peak hours, there is indeed a very large and pronounced erosion in market clearing price induced by the entry of the Panda Midway and Leesburg Projects, just as Figure DMN-21 illustrates. There is a very large price depression induced at time of peak—precisely when FRCC customers most need it—and a smaller price depression induced at time of base. In the vernacular, price suppression attributable to Leesburg and Midway are largest when the price is highest and when people need it most. Figure DMN-21 illustrates graphically the interpretation of the timing of the price suppressions that will be induced by the entry of Panda Midway and Panda Leesburg. Figure DMN-21 clearly puts to rest any assertion that Midway and Leesburg will not reduce market clearing price at any hour in any year. Leesburg and Midway will reduce the highest prices during the year by the greatest degree, precisely when such price reductions have the most value to FRCC ratepayers.

There is another aspect of the FRCC supply stack in Figure DMN-19 and how it is pushed rightward by the entry of Panda Leesburg and Panda Midway and why the situation is even more steep with more vertical displacement than might be apparent from Figure DMN-21. Consider that the Altos model does not use the aggregate supply stack from Figure DMN-19 but rather uses a set of regional substacks that sum in aggregate to the larger, aggregate FRCC supply stack. The supply stack in DMN-19 represents the entire FRCC as a single aggregate. The Altos NARE model, however, represents each subregion of the FRCC as a subaggregate. For example, FPLS contains only those generators that physically reside within the FPLS. FPLE contains only those generators that physically reside within the FPLE, and similarly for all the other regions. Clearly each of these subregional supply stacks is smaller and steeper than the aggregate supply stack in Figure DMN-19. As we subregionalize and disaggregate, the severe upward tilt of the subregional supply stacks becomes increasingly pronounced and the small granularity of the curves in all but the most baseloaded units becomes more pronounced. This means that the price suppression effect of Leesburg and Midway are very pronounced, just as the NARE model predicts.

5.7.2.1 The FRCC Now Operates and Will Continue to Operate On the Steepest Part of the Supply Stack at Time of Peak

I should also point out that the height of the maximum point in the FRCC supply stack in Exhibit DMN-10 is approximately $80, yet we have seen periods of time in the FRCC that have experienced prices of $150/MWH or higher. Clearly such prices are not being set by the marginal cost of production during "shortage" hours when prices rise to $150/MWH or higher. They are being set by such extreme situations as congestion prices on transmission links, default costs, outage costs, and the like. During those times, I would submit that the FRCC supply curve is extraordinarily steep, indeed almost vertical (as I believe it is in other locales as well). How else for example could an electric region such as MAIN have experienced $7,400/MWH power during the summer of 1998 or FRCC have experienced prices well above the marginal cost of the highest indigenous unit? They could not. In such situations, the FRCC would be darn glad indeed to have the Leesburg and Midway units in place. In the event of a shortage that drives prices above the $80/MWH range at the top of the FRCC supply stack, the presence of the Leesburg and Midway units can drive the price down from the astronomically high shortage price of $150/MWH or more to the marginal cost of the most costly plant in the FRCC. The price depression benefits of shortage mitigation can be colossal, and they derive from the intrinsic verticality of the FRCC supply stack. Again, this view of Leesburg and Midway as providing insurance against the shortage scenarios is valid, and it is a steep supply curve scenario.

5.7.2.2 Reserves and Ancillary Services Further Steepen the FRCC Supply Stack

There is another issue that serves to steepen the supply curves in the FRCC. There are a number of plants in the state that are not even resident within the supply stack at all because they are reserved for production of ancillary services (spinning reserves, operating reserves, second contingency reserves, regulation, and the like). Holding such plants in reserve, which could consume ten percent of the supply stack in Figure DMN-19, serves to further steepen the subregional supply stacks when considered for electrical energy production at the various nodal points around the FRCC. That is, ten percent of the plants in the supply stack in Exhibit DMN-19 might not even be present and resident.

5.7.2.3 Optionality Value Benefits of Leesburg and Midway Occur on the Steep Part of the Supply Stack

A final issue many people have apparently missed in evaluating the need for merchants such as Leesburg and Midway is what I term the "optionality value" or "hedge value" of capacity in Florida. One of the situations the FRCC wants to hedge against is the extreme cold weather situation, say for instance 20-25 degrees Fahrenheit from Pensacola to Miami occurring in the middle of January. Rest assured that such a situation would be characterized by a profoundly steep supply stack in the vicinity of the demand curve, which during that cold day lies far to the right and perhaps even off the FRCC supply stack to the right altogether. In that situation, theoretically, the supply curve is vertical, meaning that the Leesburg and Midway Projects would theoretically have an infinite value during that cold period. They would move the price down from infinity to the marginal cost of the last unit. That is a pretty hefty price decrement attributable to the Leesburg and Midway plants. While this example is a caricature, it certainly illustrates that the price depressive effects of Leesburg and Midway Projects can be astronomical during certain hours given the true nature of the supply stack in the FRCC

5.8 Panda Benefits from "First Mover Advantage," but Ratepayers Benefit Too

Are the Panda Leesburg and Midway Projects economically viable? In a competitive environment, a cost-effective facility is by definition economically viable. Indeed, the merchantization and commoditization of a market favors the low cost, inframarginal provider such as the Leesburg and Midway Projects. Altos has determined that the natural gas combined cycle technology is inframarginal in Florida, meaning that plants such as the Leesburg and Midway Projects could be economically viable and profitable and will displace production from a spectrum of old, high- cost, and more polluting incumbent utilities. The two Panda Projects are, without a doubt, economically and competitively viable.

The forthcoming NARE runs show definitively that Panda does not receive the entire benefit of entering the Florida market. Indeed, Florida ratepayers receive large benefits too—they get direct price reduction benefits from the entry of the Projects The fact that entry of the Projects causes prices to be lower than they would otherwise be without the Projects means unequivocally that the entry of the Projects will create more robust competition in the FRCC than there would be without the Projects. Because increased competition causes prices to be lower than they would otherwise be, the Panda Projects will not have the ability to monetize the entire benefit of their entry. FRCC ratepayers intrinsically and inherently receive benefits when entrance by merchant plants such as the Panda's occurs. By entering, the Projects will soften the FRCC prices that attracted them in the first place, and the Projects will make less money than would be indicated by present power prices. When the Projects enter, they depress price.

Some have argued in other proceedings and other venues that *"if additional new entrants are also restricted from free entry, the first entrants will reap the benefits of imperfect competition and achieve monopoly power in the form of higher margins, profits, and economic rents when they price the product and enter infra-marginally. These first in merchant plants would be better off if they can maintain their beneficial initial position and additional new supply is not added."* This is a preposterous argument, one that was dispensed with by the testimony in the Duke New Smyrna Beach case by a question from Commissioner Clarke, and one that can be easily thwarted and prevented by a Commission such as the Florida PSC who is in an important sense in the hotseat to get a lot of new capacity into Florida pronto. There is no evidence that the foregoing assertion has now or has ever been true. Quite the contrary. I live in the Silicon Valley of California. There is a term that has been coined in the Internet startup and venture capital businesses (and perhaps elsewhere) called "first mover advantage." The term means that the advantage goes to the fleet of foot. First mover advantage is thought to be a "good" thing in the sense that it strongly motivates early entry. Companies that enjoy first mover advantage are usually quickly confronted by second movers hot on their heels, who themselves are motivated by "second mover advantage." Second mover advantage is almost but not quite as strong as first mover advantage. Thereafter the third movers enter, then the fourth, then the fifth, and so on and so forth until the incentives to further entry are eliminated. Each successive entrant sees declining returns because each new entrant drives down the price of output and drives up the price of input factors of production, but each successive entry is nonetheless profitable and attracts participants. This is the story of competitive capitalism—good incentives attractive entry.

First mover advantage is recognized as a very strongly positive thing, not the deleteriously negative thing some have argued for in previous Florida PSC proceedings. I use an alternative term to characterize first mover advantage, namely Schumpeterian rents (after the economist Schumpeter). Schumpeter argued that first movers can and should obtain ephemeral scarcity rents, for that is what catalyzes them to move in the first place. I believe it to be a powerful example that first mover advantage has been firmly and eagerly institutionalized in the United States economy via the patent system, which offers ephemeral Schumpeterian rents to first movers as an inducement for those first movers to participate and innovate. The patent system bestows temporary Schumpeterian rents to first movers, but it is enough to encourage the innovation and entry we all want to catalyze new technology. The United States patent system recognizes that second movers, third movers, and so forth will enter and capture part of the benefits the first movers would otherwise capture. So it is with all competitive markets. If they are profitable, people enter and profits are reduced to long run marginal cost, all without any regulatory oversight, collectivism, political overhead, or other inefficiencies attendant with regulation. That is precisely the paradigm Florida should follow and precisely the reason there is a need for Leesburg and Midway.

My calculations show that Panda Leesburg and Midway stand to attain second or third mover advantage. The projects can expect to make more than the minimum return necessary to motivate a marginal entrant, but such returns will be short lived if there is sufficient additional entry from whatever source. I would characterize Leesburg and Midway's profits as Schumpeterian in nature, significant initially but ephemeral. Keep in mind, the bulk of the benefit that Leesburg and Midway earn occurs not solely because of the first mover advantage Leesburg and Midway gain because of their early entry into a market that is chronically short of capacity if the FRCC ten year plan is followed. In the case of Leesburg and Midway and other FRCC merchants, the first mover advantage is amplified because of the slower-than-efficient rate of entry contained in the FRCC ten year plan. Under the FRCC ten year plan, entry is so slow and sluggish relative to what is truly needed that prices remain higher in the NARE model than long run marginal cost for the horizon of the study. In such a market in which entry is restricted and sluggish, incumbents as well as new entrants lucky enough to enter the mix obtain scarcity rents but not necessarily monopoly rents. The best assurance that such rents will be truly Schumpeterian in nature (i.e., short in duration and ephemeral but nonetheless real) is to ensure that entry is not restricted into the FRCC, and the best way to do so is to approve and encourage merchants such as Leesburg and Midway.

5.9 The Panda Projects Are Financeable

I am confident the permitting and construction of the Projects will be financed by Panda equity and/or debt capital. The important point, however, is that the costs and risk of equity and debt capital will be borne entirely by the Projects and their investors and will not be borne by any FRCC ratepayers. That is, the cost of Panda's capital is not an issue here because the Project is being proposed as a merchant project. I should mention that Altos and I just completed what was heralded on March 7, 2000 in a celebration at the Waldorf Astoria Hotel in New York and simultaneously in London as the "Project Finance Deal of the Year," namely the Calpine Magic Valley revolver. I believe we have perspective on financing, and I believe that the Panda projects are eminently financeable.

5.10 Panda Leesburg and Panda Midway Do Not and Will Not Have Market Power

The idea that Panda Leesburg or Panda Midway might have market power is wrong. It may be possible in a one highly abstract, theoretical extreme, but it simply is not going to occur in the real world. The Commission can see why with a simple example. The FRCC consists of some 40 GW of generating capacity, and Leesburg and Midway at 2000 MW comprise 5 percent collectively of the FRCC market. Market power occurs when an individual market agent can drive prices upward by his or her unilateral control of quantity, most typically by a cutback or withholding of quantity from market. Market power is a "dp/dq effect." Simply put, a plant or a company has market power if it can change (usually restrict) its output dq and thereby unilaterally change the price dp in such as way as to make more money on the production it has not withheld from market than it foregoes on the production it has withheld. The company has to drive price up faster than the magnitude of production it foregoes in order to drive revenues up.

It is wrong to argue that Leesburg and Midway have any market power unless Leesburg and Midway are one of a very restricted number of merchant entrants ever (which simply is not going to happen). Suppose as an example Leesburg and Midway were to cut production from their joint maximum of 2000 MW down to 1000 MW during time of peak in that situation. As the FRCC market moves from 42,000 MW down to 41,000 MW GW to reflect the Leesburg and Midway cutback, there would have had to be a relatively large price depression resulting from that cutback during time of peak. There could not possibly be a large price depression unless the prices had been high in the 41,000 MW situation in the first place and much lower in the 42,000 MW situation. Otherwise, the postulated 50 percent production loss could not possibly have been compensated by the corresponding price increase resulting from the cutback. In summary, the only situation in which one could possibly argue that the marginal entrant (Panda) would have market power is if the peak price is very high in the 41,000 MW case and very low in the 42,000 MW case, i.e., the incremental 1,000 MW withheld from the market would have to have a major impact on peak price.

Suppose, however, there is just one additional merchant entrant above and beyond Panda, and its size is 500 MW. The total FRCC market is now 42,500 MW rather than the original 42,000 MW. In order for there to have been a large price elevation at time of peak in the monopoly (single entrant) case, the price given 42,000 MW would have had to be soft. Had it not been soft, there could have been insufficient elevation resulting from withholding the original 1000 MW of Panda capacity. If this were the case, assuredly the price at 42,500 MW would be even softer than at 42,000 MW. There would be dramatically reduced gains to withholding beginning from a base of 42,500 MW than there would be beginning from a base of 42,000 MW and dramatically reduced market power resident with either the first or second merchant at time of peak by the simple virtue of creating a second merchant entrant. This second merchant entrant in effect creates a merchant duopoly rather than a merchant monopoly. This phenomenon—allowing entry to dilute and eliminate market power—is well known in the economics literature. The Commission can verify my assertions by consulting the Nash Cournot references in the economics literature. The merchant fringe that is forming in the FRCC is small, atomistic, highly disparate, and ownership-diverse. Duke New Smyrna Beach, Leesburg and Midway, Okeechobee, Calpine, Reliant, and others of which I am aware will collectively ensure that there is no market power and that all new merchants are pure, traditional price takers even at time of peak.

Some have argued in previous venues that ad hoc introduction of merchant plants into Florida is a sub-optimal approach to mitigating market power by the present regulated utility incumbents. This is one of the most egregiously incorrect and misleading statements of fundamental microeconomics that could be made. The famed economists Nash, Cournot, Stackelberg, and others pioneered the analysis of a monopolistic supplier (or oligopolistic suppliers) in parallel with a competitive fringe vying to serve a market. Common undergraduate microeconomics texts show that the economically efficient solution is the one in which the monopolist (sometimes called the "Stackelberg leader" and other times called the large, concentrated Nash-Cournot player) engages in competitive, price taking behavior and furthermore that the larger the size of the competitive fringe, the closer to the efficient solution the market becomes. Period. Advanced undergraduate and graduate courses on monopoly behavior teach at a most fundamental level that the emergence of a competitive fringe with rapid and complete market entry leads directly and unequivocally to the elimination of market power and to the economically efficient solution. The Commission should foster entry of a disparate, competitive merchant fringe to ameliorate market power by the incumbents by approving proposals such as Panda Leesburg and Panda Midway and others.

Let me give a few references to back my assertion. Hal R. Varian, **Intermediate Microeconomics**, Fourth Edition, 1996, Norton, clearly states that pure competition is the efficient solution, and it occurs when unrestricted and complete entry is allowed into a Nash-Cournot monopoly-oligopoly situation such as exists in Florida. "If there are a large number of firms and each firm's influence on the market price is negligible then the Cournot equilibrium is effectively the same as pure competition." This directly refutes any market power assertion against merchant entry; entry of competitive merchant firms into a monopoly/oligopoly situation leads directly, unequivocally, and continuously to a competitive and efficient market solution. James W. Friedman in his classic monograph **Oligopoly and the Theory of Games**, North Holland, 1977, page 30, writes: "Intuition suggests that a Cournot oligopoly converges to a competitive market as the number of firms in the market increases without limit. Such convergence has two aspects; on the one hand, the Cournot equilibrium would be expected to converge to a competitive equilibrium (i.e., to the efficient point equilibrium), and, on the other, it would be expected that the total output in the industry would increase with the number of firms. The latter comes from a widely held belief that under oligopoly output is restricted as compared with what it would be under competition." James W. Friedman writes in a later text **Oligopoly Theory**, Cambridge Surveys of Economic Literature, Cambridge University Press, 1983, p. 39. "These examples suggest the following: (a) Cournot equilibrium is quasi-competitive. That is, total industry output rises and market price falls as the number of firms in the market increases. (b) As the number of firms goes to infinity, Cournot equilibrium converges to the competitive equilibrium. (c) The number of firms in the market rises to a finite upper bound if the firms have positive fixed cost. (d) The output of a given firm falls as the number of firms increase." We see the Altos model predicting each and every one of these phenomena as the merchant fringe grows in magnitude—incumbent output drops, price drops, the solution moves directly to an economically efficient solution, and Florida ratepayers benefit directly through price suppression.

Any argument that Panda Leesburg and/or Midway or any other merchant will have market power does not display even the most rudimentary knowledge of monopoly, oligopoly, and market power either in theory or as it exists in Florida. It is crystal clear that FPL and FPC individually and jointly have market power in generation because they individually and collectively enjoy market concentration. Like most other franchise utilities, they have been granted market power in Florida by design. To argue that they do not posses what they have been systematically granted is preposterous on its face. As players with market power, they are potentially Stackelberg leaders or large Nash-Cournot players either individually or collectively in the Florida market. Just as Stackelberg, Nash, Cournot, and their successors have proven, the unequivocally best, most economically efficient, and most optimal way to mitigate, forestall, and prevent the exercise of market power and eliminate it from consideration altogether is for a competitive merchant fringe to emerge and grow in Florida. From the perspective of economic efficiency, economic growth, low price, increased output and consequent increased reliability, and equity and fairness in FRCC, it is good public policy indeed to encourage and foster the emergence of a large and growing competitive merchant fringe. Such a fringe is known to maximize economic efficiency and wealth for Florida and eliminate the need for the Florida PSC to police the Florida generation business for prospective exercise of market power. It makes their job much easier and cheaper and leads to fewer mistakes and lower overhead and regulatory cost.

Lest the power of emergence of a competitive fringe be underestimated, consider the history of the world oil market since 1970. When the first oil crisis occurred in 1973, OPEC was supplying over 30 million barrels per day of a world demand in the range of 45 million barrels per day. OPEC owned and controlled 2/3 of the world oil market. Today, OPEC is supplying 26-28 million barrels per day of a world demand in the range of 60 million barrels per day. Market concentration has eased primarily because of the emergence of a competitive merchant fringe! Non-OPEC production has risen from its 1973 level of approximately 15 million barrels per day to today's level of approximately 30 million barrels per day. As reported in USA Today on approximately

Monday February 21, 2000, the price of gasoline we were paying in the 1970s expressed in today's present dollars-of-the-day terms would be $2.47/gal, far above what we are actually paying even at the local maximum of the past several months. Real, inflation adjusted oil prices have fallen dramatically with the emergence of a competitive fringe outside OPEC in spite of the fact that oil demand has grown markedly. The same phenomenon is in store for FRCC with the entry of merchants such as Leesburg and Midway. The emergence of a strong competitive merchant fringe will drive real prices down in the FRCC as compared to what they would otherwise be. Emergence of a competitive merchant fringe is the ideal way to do so. Approval of the Leesburg and Midway plant is the obvious best step toward that very desirable end.

I should point out the flip side of this argument as well. If Panda has market power by virtue of its entrance, the incumbents will most definitely have market power if Leesburg and Midway were to be denied entrance. This is definitely a situation the incumbents would not want the Commission to hear—the incumbents being so short of on peak capacity that they are able to withhold production during time of peak and thereby drive up prices at time of peak. Also, the Commission will not want to operate with the small level of reserves a situation like that would imply. The situation anti-merchants use to raise the specter of merchant market power is one that the Commission can erase by simply accelerating entry by merchants attracted to the FRCC. It is clear that the entry of merchants such as Panda Leesburg and Panda Midway is the best way to ameliorate and prevent the exercise of market power by incumbents.

5.10.1 Will Merchant Entrants "Collude" to Fix Prices and Production in Florida or Elsewhere?

Arguments that merchant entrants will collude is another ridiculous and specious argument, and it is untrue. In a previous Florida PSC proceeding, we saw a spurious argument that new merchants entering Florida will act as a collusive collective, withholding production at time of peak to drive up prices and garner monopoly rents. No one has ever offered an example of a group of electric power plant merchants who have ever colluded. (I should think their legal bills could get very high if they tried to collude, and they might end up in jail.) Assuredly, the Commission should not deny entry of plants like Leesburg and Midway based on the proposition that new entrants are intent on breaking the law as soon as they enter. Assuredly merchants, like everyone else, are innocent until proven guilty. Besides, first mover advantage is so strong that they need not break the law to succeed.

5.10.2 Arguments that Merchants Will Have Market Power Are Baseless

Florida would be well-advised to seek the establishment of a collection of merchant plants as a way to limit prospects for market power and price spikes by incumbents--a merchant industry just like ERCOT has. The Leesburg and Midway Projects (and the New Smyrna Beach Project recently approved by the Florida PSC) represent an effective start in building such a collection of merchant plants for Florida. Whether or not one believes that market power has been exercised by any individual or collective entity in Florida, the point is that the presence of a block of merchant generation capacity limits the existence and potential exercise of such market power and enables the reduction of whatever market power that is exercised by the incumbents. The existence of a collection of merchant plants is an effective check against market power and market concentration.

I should point out that a decrease in market power and market concentration usually manifests itself in terms of lower market prices (because of less restrictions on capacity and energy production) to Florida customers. Florida customers are the direct beneficiaries of whatever dilution of market power might occur as the result of the entry of the Projects. Entry of the Leesburg and Midway Projects directly reduces the potential exercise of market power by incumbents. The incumbent utilities in Florida have individually been granted a monopoly in their service territories, and they continue to strive bitterly to thwart all entrance. The entry of the Projects represents the entry of an entirely new, entirely independent, competitive, non-concentrated, profit-seeking source of capacity into the Florida wholesale market. It is well-established in the economics literature that entry of such a player to diminish prospective exercise of market power by the incumbents. The entry of the Leesburg and Midway Projects dilutes market concentration that is presently held by the incumbents. Moreover, it provides those benefits even without intervention by a regulatory or administrative body.

There is one more point to be made regarding market power. During the June 1998 price spike episode, the wholesale energy market exploded with spot prices reaching as high as $7,000/MWH in the MAIN (Mid America Interconnected Network) reliability region. Prospects for spot prices this astronomical during the peak period lie at the heart of the market power issue. Can some large Florida player withhold capacity and drive up price during peak and thereby garner monopoly rents? Can some player with multiple plants feign an "emergency shutdown" of one of them and, using the other plants, make more money than it could have earned by running all capacity? The prospect for the existence and exercise of market power appears to be at least as large in Florida as it could be in other jurisdictions, and it is more profitable to FPL, FPC, and TECO than to anyone else. A key factor making this possible is the absence of a significant amount of competitive merchant capacity to ensure against it. Entry of the Projects increases the size and importance of this competitive merchant capacity, which disciplines the monopoly/oligopoly incumbents and ensures against extraction of monopoly rents.

5.11 Establishment of an Unregulated Trading Affiliate by FPL Is a Danger Signal for Monitizing Rents and Avoiding the Letter and Spirit of Regulation

I should also point out that the establishment of an unregulated trading business creates for FPL the ability to capitalize on market power and monopoly rents. (I am told they have hired trading people.) By selling entitlements to its own unregulated affiliate at a regulated, cost-based price and then having the regulated affiliate turn around and resell them on a mark to market basis, FPL can avoid regulation altogether. In that event, by thwarting entry by Panda Leesburg and Panda Midway, the Florida PSC would be de facto subsidizing entry by FPL and allowing them to fully avoid regulation if they simply sell their entitlements to their own trading company at the regulated rate. The unregulated affiliate could thereafter turn around and resell them on a mark to market basis, garnering whatever rents Florida regulation might have wittingly or unwittingly granted them. Allowing Panda Leesburg and Midway into the Florida market will prevent that. Leesburg and Midway will not sell to FPL's trading company below a mark to market price and thereby subsidize them. Leesburg and Midway will not subsidize FPL's unregulated trading business. This is another element of need—to keep new additions out of the unilateral hands of the trading affiliates of Florida monopolists such as FPL.

5.12 The Panda Leesburg and Midway Projects Reduce Ratepayer Risk

Panda is bearing 100 percent of the capital cost risk of entry and 100 percent of the price and marketability risk. No ratepayer or wholesale market participant is being forced--or can be forced--to involuntarily "buy" reliability. Panda is subsidizing risk reduction to the Florida market because that is the cost it must bear to secure entry, i.e., that is the price Panda has to pay for the opportunity to seek profits with its new plants in that market.

5.13 Will the Panda Projects Keep Their Capacity Uncontracted in Order to Sell It at Very High Prices During Emergency Periods?

Let me be clear, choosing not to contract for one's capacity is not a market power issue. This is an issue of whether the Project hedges itself by signing long term capacity contracts or whether it decides to "go naked" without any capacity contract and sell energy into the spot market. In either case (contracting of capacity versus not contracting of capacity), let me be clear, the Leesburg and Midway Projects will have incentives to run at full capacity during time of peak. If their capacity is contracted, the people who own the contract will call on the plant and it will operate. If its capacity is not contracted, there will be absolutely no incentive to withhold generation during time of peak. Panda will have incentive to generate at maximum rates at time of peak.

The implication of this is clear. By allowing the Project into the Florida wholesale mix, Florida is guaranteeing that it will have more capacity in place that will operate at time of peak, and it will have the maximum possible price depressive effect during time of peak because Panda will have maximum incentives to monetize profits during that time. Panda will not have market power at time of peak; thus it will not be able to manipulate prices at time of peak. Panda will be a price taker at time of peak (and assuredly at time of off-peak).

Projects such as the Leesburg and Midway Projects offer an important additional element of insurance for FRCC customers. As I understand it, interruptible customers have so-called "buy-through" capability. Pursuant to some utilities' interruptible service tariffs, those utilities will go to the wholesale market to buy power for their interruptible customers when they would otherwise interrupt them. The retail utility then provides the power to its interruptible customers at cost plus an administrative charge, thus enabling the customers to avoid substantial costs and losses due to an actual loss of power. The presence of the Leesburg and Midway Projects will provide these utilities with an additional resource to enable them to maintain service to their valued interruptible customers while earning some additional revenue through the administrative charges and will provide these utilities' customers with the opportunity for additional protection from actual interruptions.

Uncommitted merchant capacity has had quite positive effects on power prices in other regions of the U.S. For example, the Electricity Reliability Council of Texas (ERCOT), which comprises the majority of generation within the state of Texas, has a peak demand of approximately 55,000 MW, and the majority of its indigenous generation is under the control of three investor-owned utilities just as in Florida. However, ERCOT also has roughly 7,550 MW of non-utility owned (NUG) generation. Of this 7,550 MW of NUG capacity, nearly 3,000 MW is industrial self-generation. Of the remaining 4,550 MW of NUG capacity, some 3,000 MW have historically been contracted to supply firm capacity and associated energy. The remaining 1,550 MW of NUGs supply merchant energy on an uncommitted basis. This as-available energy represents a price buffer in the ERCOT system, one that restrains whatever market power might otherwise exist. It is significant to note that the price explosions seen recently elsewhere in North America have not affected or even been seen in ERCOT. I believe that the existence of this 4,500 MW merchant plant buffer moderates within ERCOT the type of price spikes seen elsewhere. To understand why, ask whether a prudent merchant producer would ever in his wildest dreams pass up the opportunity to earn $7,000/MWH for output from its plant. The very act of entering the energy market and chasing such high price is the single most important force in defeating and reducing that price.

6 THE PANDA PLANTS STRICTLY INCREASE SYSTEM RELIABILITY IN THE FRCC, AND FRCC NEEDS INCREASED RELIABILITY

Do the Leesburg and Midway Projects increase the ability of the Peninsular Florida bulk power supply system to meet growing Florida load? They absolutely and unequivocally do. Growth in the demand for electricity (both peak generating capacity and electrical energy) is inevitable in Florida. When the Leesburg and Midway Projects enter the wholesale market, there will be incrementally more capacity "chasing" Florida demand than there would be without it. In other words, there will be more supply chasing the same demand. Because the Project will provide one more source of power than if it did not enter the Peninsular Florida wholesale power market, the Project will most definitely improve reserve margin and loss-of-load-probability. More supply available to serve the same demand necessarily means higher reserve margin and higher reliability.

There continues to be great confusion regarding the reliability increase that is brought about by the entry of merchants. In the past, some have argued that merchants do not augment system reliability because they are uncontracted or uncommitted. This is preposterous and dead wrong, and I have included this entire section to demonstrate why before we get to the economic model results for the Leesburg and Midway plants. Make no mistake, no matter what happens to the output of the Leesburg and Midway plants, each plant individually and both plants collectively increase the reliability of the FRCC system. Period.

This section contains a simplified but highly illustrative probabilistic analysis of reliability augmentation that occurs because of new plant entry. My arguments will be technical in nature in order to provide a rather sophisticated yet unequivocal analysis of the reliability problem so that cognizant technical people can inspect the viscera of the assumptions and procedures. My arguments in this section are centered on a simple yet very deep illustrative example. For simplicity of exposition, I have in the example assumed that all plants are the same size so that I do not have to carry the notational complexity of combinations of individualized plant sizes. This simplifying assumption in no way compromises the generality or the applicability of the ultimate conclusions. It is no way compromises the result that any addition of any plant at whatever level of availability that plant might have strictly increases system reliability in the FRCC. At the conclusion of the technical development, I get the to bottom line, a bottom line that refutes the preposterous lack-of-reliability assertions made in the past and I am confident to be made in the future by various incumbent utility advocates.

Using the inferential notation of probability theory, suppose that there exists a fleet of n plants. Consider the probability that exactly r of those plants are up and running and available to operate but that exactly n-r of those plants are down due to force or unforced outage. Denote that probability

$\{\mathbf{r,n}\}$ = probability that exactly r plants are running given that the overall fleet consists of n plants.

Let us assume that at least R plants must be up and available for running in order to serve the market demand in a given hour, i.e., to reliably serve load. The probability that there are R or more plants up and available for running in order to meet the demand for that hour is the probability that there are exactly R plants up, R+1 plants up, R+2 plants up, ... , or all n plants up, i.e.,

$$\{\#\ \mathbf{running} \geq \mathbf{R} | \mathbf{n\ plants\ in\ the\ fleet}\} = \sum_{r=R}^{n} \{\mathbf{r,n}\}$$

This is the correct formula for the probability that R or more plants will be running during the hour in question and therefore that there is no shortage during that hour. Let us now add one plant to the fleet mix with availability a, which we think of as the probability that the plant is up and available to run during the hour in question. We want to know what is the probability that R or more plants are running during the hour in question after the addition of the new plant to the fleet to create a fleet with n+1 plants in it. If we define the probability that there are exactly r of the expanded fleet of n+1 plants running, denoted {r,n+1}, we can use the probability expansion rule where the expansion is over whether the new plant is running or not to write

$$\{\mathbf{r,n+1}\} = \{\mathbf{r,n+1,Y}\} + \{\mathbf{r,n+1,N}\}$$

where Y designates that the event that the new plant is running and N designates the event that the new plant is not running. We then use conditional probability relationships to write

$$\{r,n+1\} = \{r,n+1|Y\}\{Y\} + \{r,n+1|N\}\{N\}$$

The first term {r,n+1/Y} is the probability that exactly r of the n+1 plants are running given that the new plant is running. This is just the probability that exactly r-1 of the original n plants are running, namely {r-1,n}. The second term {r,n+1/N} is the probability that exactly r of the fleet of n+1 plants is running given that the new plant is not running. It is therefore the probably that exactly r of the original plants are running {r,n} because the new plant is not. The probability that the new plant is running {Y} is a and the probability that it is not running {N} is (1-a). Making the requisite substitutions yields the expression.

$$\{r,n+1\} = \{r-1,n\}a + \{r,n\}(1-a)$$

The probability that at least R of the new fleet of n+1 plants is running given that the new plant has availability a is therefore the probability that R, R+1, R+2, …, or n+1 plants are running, namely

$$\{\#\ \text{running} \geq R|n+1\ \text{plants in the fleet}\} = \sum_{r=R}^{n+1}\{r,n+1\}$$

Substituting the expression for {r,n+1} into the expression yields the equation

$$\{\#\ \text{running} \geq R|n+1\ \text{plants in the fleet}\} = \sum_{r=R}^{n+1}\{\{r-1,n\}a + \{r,n\}(1-a)\}$$
$$= a\sum_{r=R}^{n+1}\{r-1,n\} + (1-a)\sum_{r=R}^{n+1}\{r,n\}$$
$$= a\{R-1,n\} + a\{R,n\} + \ldots + a\{n,n\}$$
$$+ (1-a)\{R,n\} + \ldots + (1-a)\{n,n\} + (1-a)\{n+1,n\}$$
$$= a\{R-1,n\} + \sum_{r=R}^{n}\{r,n\} + (1-a)\{n+1,n\}$$

The very last term is zero because it is impossible to run n+1 of n plants. Therefore, the sought after equation for the difference in reliability after the one new plant with reliability a is added is

$$\{\#\ \text{running} \geq R|n+1\ \text{plants in the fleet}\} = a\{R-1,n\} + \sum_{r=R}^{n}\{r,n\}$$
$$= a\{R-1,n\} + \{\#\ \text{running} \geq R|n\ \text{plants in the fleet}\}$$

If we look back at the equation for the probability that at least R or more of the original fleet of n plants are running, we can write the critically important formula

$$\{\#\ \text{running} \geq R | n+1 \text{ plants in the fleet}\} = a\{R-1,n\} + \{\#\ \text{running} \geq R | n \text{ plants in the fleet}\}$$

which can be rewritten in terms of the gain in system reliability when the fleet has n+1 plants rather than n plants, the newest plant having reliability a

$$\{\#\ \text{running} \geq R | n+1 \text{ plants in the fleet}\} - \{\#\ \text{running} \geq R | n \text{ plants in the fleet}\} = a\{R-1,n\}$$

This formula ends the technical development, which can be verified by cognizant probability people to be absolutely correct and valid.

The foregoing formula directly and thoroughly refutes arguments that the Leesburg and/or the Midway plant do not increase reliability. The difference in reliability before and after the Leesburg plant is strictly positive, and the difference in reliability before and after the Midway plant is strictly positive. Using Leesburg as an example, the Leesburg plant absolutely and unequivocally increases reliability in that it increases the probability that there are at least R plants running no matter what the incremental reliability of the Leesburg plant. There is no question the entry of Leesburg systematically and positively contributes to FRCC system reliability. There is a higher probability that more plants are running. The formula clearly and unequivocally implies the following:

1. **The reliability of the system goes up with the addition of any plant whose availability a is strictly greater than zero.** No matter what the incremental reliability of the newly entering plant, the reliability of the system always increases. Period. There is no refuting the fact that when one moves from a fleet of n plants to a fleet of n+1 plants with the additional plant having a reliability of a, as long as a is positive (i.e., nonzero) and not lockstep correlated with any other plant in the mix, the probability that at least R plants or more are running is strictly larger. The loss of load probability (which is often advocated as an appropriate and correct measure of reliability) is strictly decreasing. This is a standard, elementary result from reliability theory, and it generalizes to the more complex situation in the Florida market directly.

2. **The reason the reliability of the system goes up is that when the new plant is operating, the old system can get by with operating one fewer plant!** The old system does not have to be collectively as reliable as it did without the new entrant. The probability that the old system can sustain one less plant in available operating condition is higher. This is obvious. The reason that incremental reliability systematically improves with new entry such as Leesburg is that it allows the old system to be "one plant less reliable" than it would otherwise have to be, and the odds that the old system can sustain a state that is "one plant less reliable" are strictly higher.

3. **It is not necessary to have the reliability of the new plant be 100 percent in order to increase overall system reliability, and it is not even necessary to have the reliability of the new plant be "best in class" to increase overall system reliability.** All the incessant arguments that somehow Leesburg and Midway must be the "best in class" in terms of reliability in order to merit consideration for entry are absurd hogwash. No matter what the reliability of the new entrant, it systematically increases overall system reliability. Period. The increase in reliability of the system is proportional to the availability of the new plant and to the probability that the old system can run with one fewer plant. All else equal, we would want more reliable rather than less reliable plants to enter. However, even unreliable plants strictly increase overall system reliability. This is a fundamental result of reliability theory. The net entrant of even an unreliable component, because of redundancy, increases overall system reliability.

Lest the opposing advocates argue that the example here is too simplistic because it does not consider different plants sizes and the like, I will point out that the example generalizes to all such situations directly. The addition of a new plant increases system reliability no matter what its incremental availability is as long as that availability is positive. Contradictory testimony is profoundly misleading and highly in error. There is no "plant availability race" on in Florida, there is no "Kentucky Derby of plants based on availability factor," and there need not be any such race. Such a race would in fact be highly imprudent. There is no notion that only the "best in class" in an availability sense should have any preference. All incremental entrants in the 90 plus percent reliability range add so substantially to the overall reliability of the FRCC system that there is no need to discriminate. It is better to simply authorize yet another plant than it is to measure reliability differences between individual plants with a caliper. Measuring and comparing reliabilities with a fine tooth comb is a complete waste of the Commission's time and good will, time that is better spent ensuring the approval of a strong, flourishing competitive merchant fringe. Approving Leesburg and Midway is a great next step along that path that was properly initiated with Duke New Smyrna Beach.

I should point out that people who would argue against the reliability increase that occurs from merchant entry systematically (and probably conveniently) ignore another salient result of reliability theory. It is redundancy of supply, i.e., parallelism, that augments reliability. It is not the individual unit reliability that is the leading term. It is the addition of several new units to the system for which it highly unlikely that all of them will be down at once. That is the reason reliability increases so markedly when new merchant plants such as Leesburg and Midway are added. They provide an element of redundancy of supply in the existing FRCC system. (Suppose Alaska Flight 261 had a redundant jackscrew with reliability of only 50 percent. Overall system reliability would have been profoundly increased, and the jet would have been twice as reliable as it turned out in retrospect to be. As another example, why is it that parachutists wear a reserve chute? Redundancy!) In addition to reiterating the fact that Leesburg and Midway provide redundancy, I would reiterate that the Leesburg and Midway Projects have a systematically higher incentive for reliability than utility owned plants because Leesburg and Midway make zero money unless they are available, operating, and generating margin.

I should also point out that whether or not there might exist a contract for plant output is irrelevant to increased reliability. To illustrate, suppose in the extreme situation there were 100,000 MW of $3/MWH power that could delivered in the FRCC with probability 999,999/1,000,000 located smack dab in the center of the FRCC but that it was absolutely impossible to contract for any of it. Would that power be "unreliable" power because of the lack of a contract? Would people who oppose merchant entry ask the Commission to ignore that power altogether because an incumbent utility company declined to sign a contract for it so that they could sell their much higher embedded cost power to FRCC customers? Would they argue that the owner could ship the power out of state whenever he or she wanted and therefore the state should ignore it? I sincerely doubt it. Quite the contrary, that power would be considered firm, firm, firm, and the Commission and all FRCC customers would quickly and completely avail themselves of it. There would be no talk of unreliability because of lack of a contract. The Leesburg and Midway plants are simply less extreme cases of the same obvious conclusion—they strictly increase reliability in their contiguous busbars and throughout all of FRCC. Leesburg and Midway are reliable, they are far more incentivized to be operational during time of peak, and they systematically increase FRCC system reliability because they energize the FRCC busbar at time of peak. It is the incumbents' intransigence to sign a contract with a merchant and the ex post factor allegation merchants are uncontracted and therefore nonfirm that is the problem here. Incumbents are free to sign contracts with merchants, and it is my belief that merchants will be only too glad to oblige.

Some have stated that for years the Commission has consistently determined that noncommmitted capacity should not be treated as firm capacity. In my view, it is time for the Commission to change that practice if it indeed ever was a practice, for it daunts merchant entry, drives FRCC wholesale power cost higher than it otherwise has to be, hands the exercise of market power to the incumbents literally on a sliver platter, imposes regressive taxes in the form of high power prices on Florida people and businesses who can ill afford it, daunts industry from entering the state or charges them higher than market wholesale power costs, retards environmental benefits, drives investment and jobs that would otherwise occur in Florida out of state, and daunts or delays needed new gas pipeline capacity from entering the state quickly.

Some electric people call for a "reserve margin analysis" in order to quantify the true reliability impacts of the Panda plants. Have you ever considered how many jet aircraft Delta Air Lines might have in reserve on the tarmac waiting to relieve grounded jets with mechanical malfunctions? Is anyone calling for a reserves analysis of Delta jets? No. Have you ever considered how many Tcf of physical proved reserves BP Amoco might have "behind the pipe" in North America to back its long term, firm natural gas warranty contracts? Is anyone calling for a reserves analysis to see if they can make good on their warranties? No. Have you ever considered how Intel might use dual sourcing to create "vendors-in-reserve" to ensure its fabrication line inputs? Is anyone calling for a reserves analysis of Intel's fab capacity? No. Is there reserve refinery capacity in North America to ensure against the case of a heavy driving summer? In all cases, the answer is no. No one is calling for arbitrary, arcane, industry "insider," reserves analysis, and everyone is counting each and every unit of productive capacity in their calculations of industry capacity and possibly reserves. All capacity in place is and should be counted in reserves.

So should Leesburg and Midway when they are built in the FRCC be counted as part of the FRCC reserves.

Once the Commission recognizes that the entry of a new merchant such as Leesburg or Midway systematically adds positively to reliability in the state by creating more supply chasing the same demand, there is precious little to be gained from figuring out and debating exactly and precisely who benefits and to what degree from such reliability increase. There is precious little benefit in deciding exactly who should be the beneficiary of the reliability increase. Increased reliability is not largesse to be handed out by the Commission. The fact that there is a net positive increase should be enough for the Commission to rule that there is in fact a net positive reliability benefit to some or all of the electricity customers in Florida. Allocating that benefit among various classes of Florida and nonFlorida customers, transporters, and/or generators is a subject for a later proceeding (if at all) rather than a needs proceeding. Increased reliability, just like lower price, is manna from heaven that appears in the FRCC by the good graces of the entry of Leesburg and Midway. Leesburg and Midway take all the risks and pays all the costs, and the FRCC gains lower price and increased reliability. Why waste the time to apportion it with a caliper? I see no reason. The fact that it is large and it is there is enough to justify entry of the Leesburg and Midway project.

Contracts are not a necessary condition for reliability. I should point out that in the context of a robust, competitive, efficient wholesale market, no one has to specify what the "reliability criterion" is. Does anyone specify the reliability criterion for gold quoted in present and forward markets in the Wall Street Journal? No. The fact that there are myriad players in the market—producers, transporters, hoarders, consumers, speculators—ensures that prices quoted will be reliably transacted. I recall a speech by Dr. Roger Noll of Stanford University in which he noted that reliability of service in industries that have been deregulated and come to rely on market forces have become strikingly better than regulated industries when normalized to the level of output. An example I remember Dr. Noll quoting is that there are roughly the same number of airline mechanical failures as there used to be, but passenger loads are three times larger than they were at the time of deregulation. That corresponds by his thinking to a threefold increase in reliability, all with a dramatic reduction in real, inflation adjusted ticket prices. It is my view that nurturing and encouraging a flourishing wholesale market will give the most efficient, most proper reliability signals to the FRCC market. This strategy has worked in airlines, oil, natural gas, and probably other deregulated commodities. Electricity is no different. In short, the market can take care of reliability better than any individual, company, or regulatory body. It has always worked in other contexts. Entry of Leesburg and Midway will augment reliability through market mechanisms.

Does a merchant plant such as the Leesburg and Midway Projects have stronger incentives for on-peak operation than an incumbent utility? It is well to reiterate that a merchant plant makes zero money if it does not operate. It cannot monetize high prices if it does not produce MWH to sell at those higher prices. Unless a merchant plant operates, it loses money. What does this imply for the real world? First and foremost, a merchant plant has far greater incentives to be reliable and available during time of high prices than does a utility-owned unit. Utility-owned units are paid whether or not they are available and whether or not they generate, but merchant plants get paid only if they are available and operating. The entry of the Leesburg and Midway Projects, and other merchant plants like them, will increase availability and system reliability in Florida because of their markedly higher incentive to be available during times of high demand and thus higher prices and their inability to monetize high prices unless they operate. A merchant plant such as the Leesburg and Midway Projects cannot benefit from any market power aspect during periods of peak load, and it cannot make money during off-peak periods unless the price is higher than its cost of production and unless it actually produces.

Any argument that the entry of merchant units such as Leesburg or Midway will either strictly decrease or not affect at all (as opposed to strictly increasing) FRCC system reliability are preposterous on their face. Entry of compact, regionally dispersed plants such as the Leesburg and Midway Projects represents a much more distributed, much more diverse, much better incentivized set of plants, which promise to run more and run more reliably and in the nature of a public good increase the reliability of the FRCC system as a whole.

7 DENIAL OF PANDA LEESBURG AND PANDA MIDWAY WOULD BRING DISPROPORTIONATE HARM TO ECONOMICALLY DISADVANTAGED PEOPLE IN FLORIDA BY IMPROSING CONTINUED REGRESSIVE TAXES THROUGH HIGH UTILITY BILLS

There are very serious distributional issues or effects surrounding the Leesburg and Midway Projects. Electric bills are known to be "regressive." That means that poor people have to pay a higher fraction of their total income for electricity than rich people. This is not a trifle; poorer people in Florida are hurt to a disproportionately larger degree than richer people by the perpetuation of high prices and market power denial of entry of merchant plants and the moderating influence on price they cause. It would be unconscionable to deny the poorer segments of the Florida economy the price relief Leesburg and Midway would otherwise bestow on them. Because electric bills are regressive, reductions in electric bills benefit the poor to a greater degree than such reductions benefit the rich. Lower income ratepayers in FRCC receive disproportionately higher benefits than higher income ratepayers (in percentage terms) as a result of the price depression throughout FRCC that is caused by the Leesburg and Midway Projects. This is an important point. It is important to recognize that reductions in the market price of basic, essential commodities such as electricity have a disproportionately larger effect on lower income electric ratepayers than on higher income electric ratepayers. Merchant plant entry is one of the best friends lower income ratepayers can have--intrinsically lower cost entry that depresses price and therefore relieves the regressiveness of electric bills. Market power and restrictions against entry, precisely what the incumbents have and want to perpetuate, is the worst enemy of lower income people. Assuredly the Commission has a watchdog role to protect economically disadvantaged people in Florida. Economically disadvantaged ratepayers need projects such as Leesburg and Midway to free themselves from the shackles of incumbents with market power who proactively and aggressively restrict entry by opposing precisely such proposals as Panda's and Duke's and Okeechobee's before it.

This is not a trivial point at all. The FRCC has the highest priced wholesale market in the country. This means that poor people in the FRCC have the most regressive tax in the form of unnecessarily high utility bills in the country. This means that the FRCC more so than anywhere else in the country needs immediate entry of a large quantity of new, low cost generation and new, low cost gas pipeline capacity. There may well be no place in the country where new merchants like Leesburg and Midway should be approved and encouraged to enter more quickly than in Florida, bringing in GulfStream and/or Buccaneer right along with them.

8 PANDA AND LEESBURG STIMULATE ECONOMIC PRODUCTIVITY AND GROWTH IN FLORIDA

The Leesburg and Midway Projects' entry into the Florida wholesale power market will have a strong positive effect on Florida's economic productivity and growth. The displacement of high-cost generation from old, inefficient plants by low-cost generation from the Projects will directly augment Florida's "gross state product." Increased gross state product for Florida manifests itself in many attractive ways in the state including: attraction of investment into the state, increased employment, lower priced electricity, lower priced goods and services produced from electricity, increased disposable income to Florida ratepayers, and increased state income from sales, property, and income taxes, just to name a few. Commissioner Garcia stated several times during the Duke New Smyrna Beach hearing the importance of attracting investment and high quality operating jobs to Florida rather than having them go somewhere else. He is absolutely correct, and the Leesburg and Midway projects are perfect ways to get that to occur. That is another important dimension of need—the need for domestic as opposed to contiguous state construction and operation.

9 PANDA LEESBURG AND PANDA MIDWAY STIMULATE NEW GAS TRANSMISSION PIPELINE CAPACITY

Is there enough gas in Florida for the Leesburg and Midway Projects and more generally for Florida's growing needs? There will most assuredly be enough gas in Florida for the Projects once the Gulfstream gas pipeline project and/or the Buccaneer project is built. Indeed, it is my understanding that the Panda intends to commit to Gulfstream and thereby secure long-term firm transportation access to Gulf of Mexico offshore gas.

It is well to consider the ultimate size of the GulfStream project. As I understand it, when it is fully powered and fully compressed, the GulfStream pipeline will carry approximately 1.2 billion cubic feet per day into Peninsular Florida. To get an idea of the magnitude of a project that size, let us calculate how many MW of 6900 Btu/KWH heat rate combined cycle plants that single pipeline could fuel. Let us begin by calculating how much gas would be burned by 1 MW of capacity during a day:

$$1\text{MW} * 24\frac{\text{hr}}{\text{day}} * 6900\frac{\text{Btu}}{\text{KW}-\text{hr}} 1000\frac{\text{KW}}{\text{MW}}\frac{1\text{MMBtu}}{1{,}000{,}000\text{Btu}} = 165.6\frac{\text{MMbtu}}{\text{day}} = 154.6\frac{\text{Mcf}}{\text{day}}$$

Therefore, a 1.2 Bcf/day inbound gas pipeline, which is equivalent to 1,200,000Mcf/day of new inbound capacity, could support a total of

$$\frac{1{,}200{,}000\frac{\text{Mcf}}{\text{day}}}{165.6\frac{\text{Mcf}}{\text{day}}} = 7246\ \text{MW}$$

of new 6,900 heat rate gas combined cycle units in the FRCC. This would be a major boon to Florida and the FRCC, and it will be immediately catalyzed by the approval of Leesburg and Midway, who collectively will commit approximately 25 percent of the GulfStream ultimate capacity. This is a relatively small amount of the firm transportation on GulfStream and most assuredly will not cause any market power or other lack of competition issues on GulfStream.

I am confident that the Gulfstream pipeline owners view the Panda Leesburg and Midway Projects as a critically important "anchor tenants." Based on my experience in the natural gas area, I believe that the Leesburg and Midway Projects and projects like it are critical to Gulfstream's plans to expand. As such, the Projects (along with Okeechobee) can claim credit for all or part of the benefits that the Gulfstream pipeline will bring to Florida above and beyond its use in power generation. Make no mistake about it, without Leesburg, Midway, and Okeechobee, there will be no GulfStream. Furthermore, make no mistake about it, there are profound benefits to Florida from the entry of the Gulfstream natural gas pipeline. Florida has some of the highest natural gas prices on the continent. I would say that Florida is "short" of natural gas. By providing a solid anchor tenant, Panda is catalyzing the entry of a new natural gas pipeline, which will pay benefits to Florida citizens and industry far beyond electric generation interests.

I have seen firsthand in California the benefits of additional gas pipelines into a state. The discipline and competition induced by the entry of just one additional pipeline is quite large. California enjoys some of the lowest gas prices on the Continent, and that is the direct result of the entry of Kern River Pipeline from the Rockies and Pacific Gas Transmission Expansion from Alberta during the early 1990s. The two new entrants caused a great deal of competition to be imposed on the incumbents—El Paso and Transwestern—and their prices moderated substantially.

I should also emphasize that if there is even one Mcf of gas that comes through a new gas pipeline into Florida and is not consumed by a gas generation facility, then that Mcf of gas will necessarily pay direct economic benefits to Florida gas ratepayers. It is gas that comes to Florida that would otherwise never get there. In light of the fact that the Panda Projects will be down for maintenance at least some of the time and that the owners of GulfStream are going to be marketing to every prospective customer in Florida—generators and nongenerators alike—there is destined to be some excess natural gas deliverability into Florida that will pay benefits to gas ratepayers.

Furthermore, if that excess gas deliverability could be coupled with natural gas storage in Florida, that excess gas deliverability could be converted into time-of-peak gas use and increase the benefits severalfold.

It is well to keep in mind that the aggregate demand for gas plus electricity in Florida will be the same with or without the entry of a new gas pipeline such as GulfStream. (Much of the gas demand will be "latent" without the GulfStream pipeline and will go unsatisfied.) Entry of the Gulfstream pipeline does not change the market composition, but it does introduce a new element of supply into an otherwise fixed size market. Therefore, entry of that new natural gas pipeline necessarily decreases the price of gas, thereby paying direct benefits to gas ratepayers in Florida.

In assembling our natural gas price forecasts for Florida, I have taken into account the expansions of Buccaneer and GulfStream into Peninsular Florida. The manifestation of this assumption has been to assume constant natural gas prices across Florida from North to South and from East to West.

10 QUANTITATIVE RESULTS--THERE IS A STRONG ECONOMIC NEED FOR THE PANDA LEESBURG AND PANDA MIDWAY PROJECTS

Is there a need for 1000 MW of new electric generation capacity in or near the FPC Central Florida substation? Is there a need for 1000 MW of new electric generation capacity in or near the FPL Midway substation? Does that need extend to the Peninsular Florida market as a whole? The answer to all the foregoing questions is yes. Additional capacity, such as will be provided by the Leesburg and Midway Projects, is needed economically to provide low-cost power to the Peninsular Florida wholesale market and is also needed to provide additional system reliability in Peninsular Florida. It is also needed to shield FRCC ratepayers from the high prices that are imminent if the FRCC ten year plan truly guides future plant additions in the state. As we shall see, the magnitude of price decrease and economic welfare gain to FRCC ratepayers that results from one or both of the Panda units is substantial.

I should point out that this section presents a number of salient points from the NARE model runs. I have been selective in the particular aspects of the model results I have chosen to present here. The results are voluminous and comprehensive and span the entire eastern grid as well as the 19 region model of the FRCC indicated in Figures DMN-5 through DMN-7. I present here a small subset of the entire set of results from the model for the entire eastern grid, that subset being the most pertinent to the need for Panda Leesburg and Panda Midway. In particular, I have focused on what NARE calculates to be the benefits the 2000 MW of Panda Leesburg and Panda Midway capacity and why Florida needs those and other merchant and utility plants. Using NARE, I have also determined that the incumbent utilities' plans as embodied by the FRCC Ten Year Plan are quite inadequate for the citizens and business of Florida and this inadequacy is an important element of need.

10.1 Quantification Of The Consumers Surplus, Producers' Surplus, And Social Surplus Benefits Of Leesburg And Midway

Based on earlier discussions in Section 5, I can appeal to the specific supply curve and demand curve geometry in Figure DMN-20 secure in the knowledge that it is the right geometry. Figure DMN-20 assumes fixed, inelastic demand at every offtake point in Florida, as our NARE model has for the Leesburg and Midway valuation. When generation from any source displaces generation from another source in a commodity market setting, as the Leesburg and Midway Projects will do, the price of all electric energy in Florida unequivocally goes down. Do people in Florida "need" plants that create lower prices? Do Florida electricity consumers "need" lower prices? You bet they do. Florida ratepayers "need" the lower prices that entry of lower cost capacity and energy that plants like the Project can cause. The benefits of any price reduction in any commodity are an important economic reality. Higher prices (which will occur if the Leesburg and Midway Projects and other merchant projects like it are not allowed to enter and displace high cost generation that would otherwise have to be used) will saddle Florida ratepayers with higher prices and stunt economic growth in the state and hurt economically disadvantaged people through regressive utility bills.

The leftmost supply curve in the diagram shown in Figure DMN-20 represents the supply stack in Florida before the Leesburg and Midway Projects enter, and the rightmost supply curve represents the supply stack after the Projects enter. The rightmost curve is displaced to the right 2000 MW from the left curve, the 2000 MW representing the size of the Leesburg and Midway Projects. (The analysis works equally well if one considers each of the Panda plants individually.) The figure clearly indicates why the price decreases with the entry of the Projects collectively or either project individually. With the Projects, there will be more supply in the FRCC region chasing the same demand curve in FRCC, and the price of power in Florida will drop, particularly during time of peak when the state really needs it. Figure DMN-20 indicates that when an inframarginal unit such as the Leesburg and Midway Projects enters the wholesale market, wholesale energy prices in Florida will be directly reduced as a result of such entry. The circle at the right of the diagram indicates electricity prices falling because the additional capacity renders the supply curve more abundant and renders the price "softer" as a result. New entry by the Projects or any other similar merchant plant means that Florida electricity prices will drop.

The shaded and lettered areas in Figure DMN-20 indicate how to quantify and think about the economic (or technically, the "economic welfare") benefits of the Projects that accrue to ratepayers and citizens of Florida. The entry of the Projects shifts the original supply stack (i.e., the supply curve) for Peninsular Florida outward and to the right as discussed in Section 5. In particular, the entry of the Projects will move the supply curve from the leftmost supply curve in the figure to the rightmost supply curve in the figure. As this occurs, the market clearing price moves from the higher horizontal price line in the figure to the lower horizontal price line in the figure, and the quantity of electric energy consumed remains constant at the fixed, inelastic level. Price is depressed because of the increased capacity chasing a fixed demand.

Figure DMN-20 quantifies the economic benefit that the consumers in Florida receive as a result of the entry of the Project (the sum of areas A + B), which represents the saving in wholesale electricity bills that will be enjoyed by the customers that comprise the FRCC. The figure further quantifies the economic benefit that the producers in Florida receive because of the entry of the Projects (areas D - A), which represents the change in profit from serving customers at the lower price in the market containing the new Leesburg and Midway Projects (area A) plus the change in profit from serving customers with the lower cost plants than would otherwise have to be used. The total economic benefit is the algebraic sum of the consumers plus producers surplus calculations, which is the shaded area in the figure (B + D). The social surplus gain to Florida players from the entry of the Projects, the sum of areas B + D, is very simply and directly equal to the reduced total cost to serve the entirety of the FRCC ratepayer market because of the entry of the Panda Leesburg and Midway projects. Florida serves the customers at lower total cost because of the entry of Panda Leesburg, and the saving in total cost is the net economic welfare benefit.

Clearly Florida consumers will not go unrewarded because of the entry of the Panda Leesburg and Midway Projects. On the contrary, Florida consumers will be handsomely rewarded because of the price reductions those projects cause, particularly at time of peak. The critically important point is this—Florida customers receive a goodly fraction of the total benefits of merchant entry through cost competition and market arbitrage. Entry of a new, merchant plant such as the Leesburg and Midway Projects increases the amount of capacity chasing the same market that would have been there without the new entrant. More supply chasing the same market necessarily means lower market price for a merchant producer. Merchant producers do not have the luxury to impose their costs on downstream customers, and their entry therefore necessarily depresses market prices.

10.1.1 Quantification of the Consumer Surplus Benefits

Because I believe an important function of the Florida PSC is to advocate benefits to Florida customers—businesses and citizens alike—I have used consumers' surplus (areas A + B in Figure DMN-20) to quantify the benefits to Florida from the entry of Panda Leesburg and Midway and why Florida needs those two plants. The Altos NARE Model quantifies the specific price reductions that will be induced by such entry by defining the four runs of the NARE Model indicated in Figure DMN-22. The four runs enumerate all possible combinations with and without the two proposed Panda projects.

- Comparison of NL/NM with L/NM calculates the price depression benefits of Leesburg without Midway.
- Comparison of NL/M with L/M calculates the price depression benefits of Leesburg with Midway.

- Comparison of NL/NM with NL/M calculates the price depression benefits of Midway without Leesburg.

- Comparison of NL/M with L/M calculates the price depression benefits of Midway with Leesburg.

- Comparison of NL/NM with L/M calculate the price depression benefits of having both Midway and Leesburg in the FRCC mix.

The four NARE scenarios thus allow us to quantify the specific benefits of all possible combinations of the two Panda projects. They allow us to show that indeed both projects are needed in the FRCC mix and each project is needed individually. I should point out that the cases in Figure DMN-22 represent entire scenarios, i.e., entire time sequences of market clearing prices into the future in the FRCC and everywhere else in North America.

The results for the year 2003 for the four cases in terms of the average price of electricity throughout the FRCC in each of the four cases are shown in Figure DMN-23. (The prices are the annual MWH-weighted prices averaged across the entire FRCC.) The bottom row shows the price reduction that is specifically and systematically attributable to the entry of the Leesburg Project both in the presence and in the absence of the Midway Project. The rightmost column shows the price reduction that is specifically and systematically attributable to the entry of the Midway Project both in the presence and in the absence of the Leesburg Project. All prices in the diagram are averaged over all MWH delivered to customers by region throughout the FRCC. They are the consumers' surplus benefits—namely areas A + B in Figure DMN-20—divided by the total quantity of energy sold at wholesale in the FRCC market.

The price reduction impacts of the entry of the Panda Midway and/or Panda Leesburg plants are colossally large, yet they are entirely expected in light of the analysis and discussion earlier in Section 3 of this report. Keep in mind, price reductions in a single region of the FRCC proliferate outward rather unattenuated throughout all of the FRCC, just as our example in Section 3.1.1 clearly demonstrated is the right answer. To be specific, in the year 2003, a price reduction between $0.872/MWH (attributable to Midway if Leesburg is in the market) and $0.889/MWH (attributable to Midway if Leesburg in not in the market) for every MWH transacted in Florida is a rather colossal benefit, and it is directly attributable to the entry of a single 1000 MW plant, namely Midway. (Keep in mind, Panda Midway is twice as large as any of the previous applicants for needs certificates in Florida.) In the same year, the price reduction between $0.797/MWH (attributable to Leesburg if Midway is in the market) and $0.814/MWH (attributable to Leesburg if Midway is not in the market) for every MWH transacted in Florida is a rather colossal benefit, and it is directly attributable to the entry of a single 1000 MW plant, namely Leesburg. I should also emphasize that the price reduction of $1.686/MWH from the joint entry of both projects, i.e., the price difference between the NL/NM case and the L/M case is colossal as well. This is a profound result, one that must not be lost on the Florida PSC. Entry of the two Panda applicants—Leesburg and Midway—will induce a $1.686/MWH decrease in the price of ALL wholesale electrical energy in the FRCC in the year 2003. There is no more compelling case for need. FRCC ratepayers need the lower prices and economic benefits that the entry of Panda Leesburg and Midway will engender. To deny them that benefit is to impose economic losses on them.

This insight that the entry of both Panda Leesburg and Panda Midway results in a monumental $1.686/MWH price reduction throughout all of Florida is very compelling from another perspective as well. Candidly, **Florida is in serious trouble**. Incumbents have been barring entry and thereby exercising market power, and Florida is not scheduled to overcome it by the year 2003 under the construction schedule in the FRCC Ten Year Plan. Incumbents have been de facto thwarting entry of new gas pipelines such as GulfStream or Buccaneer. Our model results verify that Florida is in very serious electrical trouble at time of peak, and other regions in the eastern grid are in trouble also. SERC in particular has been growing rapidly, and new plant construction has simply not kept up. Increasingly, SERC power will be kept right at home at time of peak; it will not come to Florida. Rather rapidly into the future, Florida will not be able to count on Georgia and points northward for energy at time of peak. That means that Florida will be increasingly responsible for its own domestic time of peak needs, and there simply is not now nor will there be by 2003 under the FRCC Ten Year Plan sufficient on peak capacity to meet the FRCC need. FRCC is facing virtually certain continuing shortages at time of peak through the year 2003 even if Panda Leesburg and Panda Midway are built, and the situation will be markedly worse if those facilities are not approved and built in Florida immediately.

Would a traditional production simulation model show just how serious the problem in Florida is? I doubt it. It would be too simple and too seductive to merely assume in those models that the entire Georgia to Florida transmission link would flow at maximum capacity into Florida during time of peak. Such a model would erroneously assume that the inbound transmission line would be a "resource" committed to the FRCC market. (Those models place "resources" into a generation mix that competes for a noncontestable demand.) That assumption is not correct; there are no "committed" resources that transcend regional boundaries in a mark to market setting. All regions and all resources are fully contestable in a market context. Imports to Florida at time of peak promise to dry up because other regions in SERC need their own peak power. They will be increasingly loath to export it to Florida. The NARE analysis, which explicitly and systematically represents the entire eastern power grid in the United States and in integrated, arbitraging whole, shows that Florida is facing an impending peak shortage and time of peak import shortage. The Florida PSC must not count on importing peak energy and instead should quickly approve both Panda units to partially ameliorate your impending serious on peak capacity and energy shortage. To do otherwise is to condemn Florida ratepayers to chronic shortages and shortfalls during the peak periods for the foreseeable future.

It is very interesting to note that the incremental benefits of the Midway plant in terms of its ability to reduce price in Peninsular Florida are higher than the incremental benefits of the Leesburg plant. This is simply a manifestation of the fact that Midway has a slight locational advantage over Leesburg in terms of its ability to serve southern Florida markets, which are short of gas and generation capacity relative to need. Even though the benefit of the Midway plant is slightly larger than the benefit of the Leesburg plant, it is nonetheless true that both plants pay colossal benefits to Florida ratepayers. It is clearly true that both plants are needed, one slightly more than the other, but both are critically needed in the Peninsular Florida market.

The calculated price reductions pay millions of dollars per year in direct annual economic benefits to FRCC electric ratepayers. We have calculated the annual benefits in each of the next ten years by picking three representative future years—2003, 2007, and 2012—and extrapolating between them. Those results are presented in Figures DMN-24 and DMN-25 respectively. The present value of those benefits over a ten year period using a ten percent real discount rate is summarized in Figure DMN-26. The present value benefits themselves are also colossal from the individual and joint entry of Panda Leesburg and Panda Midway. Electric ratepayers in the FRCC receive direct economic benefits at the levels shown in Figure DMN-26 as a result of the authorization, construction, and operation of the Leesburg and Midway Projects on the announced schedule. These benefits will accrue directly to FRCC ratepayers in the form of electric bills that are lower than they would otherwise be. They will stimulate business and investment in the state, and they will stimulate state GDP. This is precisely the type of economic force that builds the Silicon Valleys of the world—low cost infrastructure and high value jobs. Restricted entry and application of market power (which has been the norm in Florida) sends those jobs and investments elsewhere and dooms Florida ratepayers to higher-than-needed prices and lower-than-needed reliability.

The capacity factors of the Panda Leesburg and Panda Midway plants will be quite high. Figure DMN-27 displays the plant capacity factors in the four scenarios in each of the three forward representative years as calculated by the NARE model. We interpret the capacity factors of the plants to be the fractions of time the plants can run without incurring operating margin losses, i.e., capturing zero or near zero margins as well as positive margins. The figure clearly indicates that the two plants are traditional base load plants and will enjoy a large number of run hours over their lives.

10.1.2 Is It Really Fair to Attribute the Calculated Price Decreases Specifically to the Panda Leesburg and Midway Projects?

Wouldn't some other identical plant if it entered in precisely the same place at precisely the same time have precisely the same price depressive effect as either of the Projects? It is both correct and appropriate to attribute the price decrease we have calculated to the entry of the Leesburg and Midway Projects. If a plant were to be built on essentially the same site the instant before one or both of the Projects, it could claim credit that we have here attributed to the Projects. However, in the event that plant were built in the local area an instant before one of the Projects, say Leesburg, Leesburg would as a result be displaced only one "click" to the right in the supply stack in Figure DMN-19. There would still be monumental benefits from the entry of the Projects even if some other plant were to be built ahead of it in the queue in precisely the same location. Admittedly, the incremental benefits of the Projects would be slightly smaller, but they would nevertheless still be astronomical.

10.1.3 Regional Distribution of Price Savings Attributable to Leesburg and Midway

The Leesburg Project individually depresses prices in all regions relative to what those prices would otherwise be. So does the Midway Project, and so does the pair of Projects. While for the Leesburg project, one might argue that the largest price depression throughout the FRCC would necessarily reside in the APO region where the plant will be built, this is not necessarily true. The exact degree of price depression is strongly a function of the overall FRCC transmission and generation system configuration. It is interesting to note, however, that the degree of price depression attributable to the entry of the Leesburg Project is rather similar across all the regions of the FRCC. Even the least affected region, which is most geographically removed from the Project, nonetheless sees a substantial price depression as a result of the entry of the Leesburg project with or without Midway and the entry of the Midway project with or without Leesburg. This is precisely what we expect in light of the example in Section 3.1.1.

I have prepared a set of tables that indicate the regional price depressions that result from Leesburg and Midway in all regions of the FRCC market. These regional price depressions, depicted in Figures DMN-28 through DMN-32 indicate the rather substantial degree of price depressions caused by Leesburg and Midway and assuredly underscore the need for those projects in the FRCC. The tables are rather striking in their implications for the strong degree of need in the FRCC for both of the proposed Panda plants, particularly the Midway plant. They are also rather striking that electric ratepayers distributed throughout the FRCC all benefit to a substantial degree from what are in reality quite localized investments. For example, the Midway project injects energy to the FRCC grid at Martin, but its price-suppressive effects are enjoyed everywhere throughout the FRCC. In fact, they are enjoyed within the contiguous geographic region (Southern) as well. Just as I showed in Section 3.1.1, price reductions travel far from the point at which those price reductions.

The magnitude of price depressions we have calculated should not be misinterpreted. In a previous Florida PSC proceeding, one of the adversaries made the preposterous calculation of dividing the FRCC-wide electric bill saving (the consumers' surplus bestowed upon Florida by the entry of Panda Leesburg and Panda Midway) by the annual output of the Leesburg plus Midway units. In effect, he wanted to divide the total consumers surplus gain to Florida by the number of MWH output by the Leesburg and Midway plants and thereafter argue that the number expressed in dollars per MWH is very high as compared with the market price. This is an absolutely meaningless, intellectually inane calculation. The simple example in Section 3.1.1 in this report shows quite clearly that colossal leverage a supply cost reduction can induce—the dollars of consumers' surplus benefits per MWH of product that caused them can be astronomically higher than the market price of the MWH that are actually sold by the newly entering, lower cost source. Nothing is surprising, counterintuitive, nor wrong about this conclusion. Section 3.1.1 is clear on this point. The leverage in terms of FRCC and contiguous region benefits arising from the entry of Midway and Leesburg is staggering, and it is staggering because of the paucity of capacity resident within Florida under the FRCC Ten Year Plan. By analogy, the leverage in Section 3.1.1 of the seemingly insignificant

10.1.4 Temporal Distribution of Price Savings Attributable to Leesburg and Midway

What is the distribution over time (i.e., load periods) of the price depressions in FRCC caused by the Leesburg and Midway Projects? Figures DMN-33 through DMN-36 detail for the year 2003 the average price across all the regions of the FRCC by month for the four cases enumerated in Figure DMN-19. Using the relationships among the cases in Figure DMN-22, we can calculate the load tranches by month during which the price depressions actually occur. Figures DMN-37 through DMN-41 calculate the price depressions by month by load tranche during which the Leesburg and Midway Projects depress the prices throughout the FRCC.

Notice in the referenced figures that the Leesburg and Midway Projects reduce prices in FRCC during most time periods of the year because, as illustrated in the FRCC supply stack, the Projects are low-cost inframarginal suppliers of electricity within FRCC during most time tranches of the year. The fact that the Projects lie to the left of most of the capacity in the FRCC and to the left of all but the lowest demand points ensures that they will depress prices in FRCC relative to what they would otherwise be.

Notice further that the primary benefits of the Panda and Leesburg plants occur in the summer at time of seasonal and within-monthly peak, precisely the time when new capacity is needed most in Florida. That is, the period of maximal depressive impact by Leesburg and Midway on FRCC price is precisely the period when prices are highest and FRCC ratepayers are being hurt most by the lack of capacity and energy. Merchants such as Panda Leesburg and Midway are truly manna from heaven in the sense that they have their maximal downward suppressive effect at precisely the time they are most needed. They do relatively less when relatively less is needed and relatively more when relatively more is needed.

There are two reasons for the strong summer need for the Panda Leesburg and Panda Martin plants, one obvious reason and one perhaps not so obvious reason. The obvious reason is that summer demand is high in the FRCC and therefore the economic and market value of every plant is elevated in the summer as compared with the shoulder or winter months. The not so obvious reason is that peak power is increasingly scarce throughout SERC and the FRCC, meaning SERC will be reluctant to export peak energy to the FRCC. Peak power is a scarce commodity throughout SERC, which is rapidly growing, and people who have it are increasingly reluctant to part with it. This is reflected in the fact that the price during time of peak grows to a very high level in SERC and well as FRCC, and this elevates the FRCC price of peak power to a very high level as a result of competitive market forces. Furthermore, it accelerates the premium on peak power generated right at home in the FRCC commands because one does not want to pay the mark-to-market value of transmission losses at time-of-peak prices.

10.1.5 Enhanced Fuel Efficiency in Power Generation

Do the Leesburg and Midway Projects reduce or increase overall fuel consumption in Florida? The Projects are highly efficient (estimated 6,900 Btu/KWh heat rate, which could actually be better if technology improves between now and the time the plants are installed) as compared with presently existing FRCC generation. This means that the plants have a thermal efficiency (energy content of electricity divided by energy content of natural gas) of approximately 50 percent. The better among the old plants in Florida have heat rates of approximately 10,000 Btu/KWh (efficiency 34.13 percent), and the older, more inefficient plants in Florida have heat rates on the order of 13,000 Btu/KWh, which corresponds to a thermal efficiency of 26.25 percent. Even using the conservative heat rate estimate offered for the Projects, the Projects' efficiencies are 1.5-2 times better than the efficiency of the production they will be displacing from the Florida mix. Let us calculate what 2000 MW of "old" 10,000 Btu/KWh heat rate plants would consume in Florida if they were not displaced by the Panda Leesburg and Midway units. They would consume

$$2000\text{MW} * 24\frac{\text{hr}}{\text{day}} * 365\frac{\text{days}}{\text{yr}} * 10000\frac{\text{Btu}}{\text{KW}-\text{hr}} 1000\frac{\text{KW}}{\text{MW}} \frac{1\text{MMBtu}}{1{,}000{,}000\text{Btu}} = 175.2\frac{\text{TBtu}}{\text{yr}}$$

of natural gas if they ran during every hour of the year. Each 2000 MW, 6,800 Btu/KWh heat rate plant entering the market would consume

$$2000\text{MW} * 24\frac{\text{hr}}{\text{day}} * 365\frac{\text{days}}{\text{yr}} * 6900\frac{\text{Btu}}{\text{KW}-\text{hr}} 1000\frac{\text{KW}}{\text{MW}} \frac{1\text{MMBtu}}{1{,}000{,}000\text{Btu}} = 120.9\frac{\text{TBtu}}{\text{yr}}$$

of gas. Because the new plants consume 120.9 Trillion Btu of gas per year and the old plants that are displaced consume 175.2 Trillion Btu of gas per year, the new plants displace up to 54.3 Trillion Btu per year or 148.8 MMcfd out of the inbound gas pipeline system (assuming one for one gas displacement from old inefficient 10,000 heat rate units into new, efficient 6,900 heat rate units). Assuming a capacity factor of approximately 95 percent on the new units, the actual amount of energy saving is 51.6 Trillion Btu per year of gas or gas equivalent. Recognizing that part of the displacement of the Projects will not be gas that would otherwise have to be used but rather would be fuel oil or distillate, the former of which has a higher pollutant content than gas, there are even more environmental benefits than would be indicated by a strict gas-for-gas displacement assumption. In particular, there will be a gas-for-oil displacement during some of the hours of the year, and such displacement has an extra element of environmental benefit. The NARE model is able to make this calculation explicitly not only for Florida but also for the entire eastern grid.

The reduction of the number of Btus of fuel consumed per MWH leads to direct economic benefits realized through having to buy and burn less fuel (lower fuel volume and total cost per MWH) and through having to build a lesser magnitude of new inbound natural gas pipe. Indeed, it is fair to argue that the Panda Midway and Leesburg units can displace approximately 148.8 MMcfd of gas pipeline capacity out of the Florida market that would otherwise have to be used. That is, entry of the two Panda projects will "free up" 150 MMcfd of existing gas pipeline space for alternative year round use. This alone will put substantial downward pressure on FRCC gas price, a benefit for which we have taken zero credit in this analysis. An attendant benefit is that Florida will not need to have as much natural gas pipeline capacity as it would have otherwise needed because of the entry of the Projects (and other merchants). Each successive merchant project that enters the Florida market thereafter will produce a roughly equal (but slightly smaller) reduction in fuel consumption than its immediate successor. The reason the reduction gets successively smaller is because each successive entrant will run slightly fewer than 8,760 hours during the year.

Does displacement of generation away from high-cost generators in favor of low-cost generators like the Leesburg and Midway Projects mean shutdowns of incumbent plants? Not necessarily. Displacement by the Leesburg and Midway Projects of the marginal MWH does not necessarily mean that the marginal plant that produces that marginal MWH will shut down. There is often a misconception in the context of the supply stack in Figure DMN-19 that addition of inframarginal units such as the Projects at the left of the supply stack necessarily means that some other specific, nameplate plant will shut down. That is, there may be a misconception that a new entry represents a one-for-one, zero sum game whereby the new entrant (e.g., one or both of the Panda Projects) completely replaces an old plant. This misconception is just that, and needs to be clarified and put to rest. Keep in mind, every hour of the year has a different level of demand, and therefore every hour of the year is characterized by the demand curve cutting through the supply stack in Figure DMN-19 at a different location. If the Projects enter, there are fewer hours of run time (but not necessarily zero run time) for each other existing plant. Because there is a distribution of demands and therefore hourly prices over the year, there is a frequency distribution of which plants are at the margin during each hour of the year. Therefore, the reduction in operating hours is spread across the various plants in Florida and is not concentrated on a single plant.

The correct way to think about this is as follows: If 2000 MW of new capacity such as the Panda Projects enter at the left hand side of the supply stack, the existing plants lying to the right in the supply stack in the Florida system experience reduced loads (but not necessarily zero loads). The older plants' load factors drop as the Projects displace operations during the hours they run, but their load factors do not drop all the way to zero. Figure DMN-42 illustrates this phenomenon conceptually by representing that the demand curve "walks all around" on the supply stack, rendering a different Florida plant marginal at each point in time. The supply stack itself also changes as plants go on planned maintenance outages or experience unplanned outages. The entry of the Leesburg and Midway Projects means that the demand curve affects each plant differently, differentially favoring the lower cost, leftward plants in the supply stack. The entry of the Projects reduces loads to a differentially higher degree the higher the plants lie in the cost merit order but does not necessarily eliminate loads for the high-cost plants altogether. In summary, the Projects will not necessarily cause a shut down of any particular Florida plant, but they will reduce load factors for a spectrum of higher-cost, more polluting, Florida plants.

It is not correct or appropriate to argue that the entry of the Leesburg and Midway Projects (or any other new plant) will necessarily make obsolete and shut down any one of the pre-existing plants. It is correct, however, to state that the entry of the Projects will displace hours of operation from some or all of the existing higher cost plants, reducing loads on the more expensive plants but not affecting loads on the less expensive plants at all.

If entry of the Leesburg and Midway Projects does not shut down old plants, what will happen instead? For the foreseeable future, Florida is and will be in a situation of low reserve margins in both summer and winter. (We have not included spinning or standby reserves in our analysis. That would make the price depressions arising from the entry of Leesburg and Midway even larger and the portending shortages that will occur even more extreme. Our decision not to include spinning or standby reserves renders our results conservative with regard to the need for Leesburg and Midway.) There is no question, Florida needs additional available generating capacity. The prices in the vicinity of the Leesburg and Midway plant in Figure DMN-17 and DMN-18 are very high, substantially higher than they need to be or should be. When a new plant such as Leesburg or Midway enters the wholesale market, an old plant will be relegated to reserve status during the coldest winter peak months and the hottest summer peak months. Reserves during the prospective winter and summer peaks have value even if a particular old plant that is providing those reserves is not selling a single MWH of energy. Old plants will be "hot" during the winter peak and "hot" during the summer peak. The old plants may also be activated when newer plants go on maintenance outages. In summary, the Projects may shift one or more old plants into spinning or standby reserve status or cause several plants to be ramped back.

10.2 Economic Need for the Low-Cost, Reasonably Priced Power Provided by Leesburg and Midway

Is there a need for the Leesburg and Midway Projects to provide low-cost, reasonably priced, and cost-effective power in Peninsular Florida? Yes, there is an immediate need for the 2000 MW those projects represent and in fact more. There is a need for more than 2000 MW of new electric generation capacity and associated energy production in the local markets contiguous to the Panda Projects (APO for Leesburg and MRT for Midway) and in the Peninsular Florida market in general. The need is immediate, and will continue to grow over time.

To construct our NARE model scenarios, rather than calculating the amount of new capacity that would economically be added to the FRCC in each future year, we used the capacity addition schedule postulated by the **1999 Regional Load & Resource Plan**, July 1999, prepared by the Florida Reliability Coordinating Council. As can easily be seen from the results we generated using this projected capacity addition schedule, the prices of wholesale power in the FRCC are and remain unnecessarily high at time of peak throughout the model horizon. These prices would fully pay for new natural gas combined cycle and combustion turbine capacity over an economically reasonable and feasible time horizon. They will clearly pay for both Leesburg and Midway and other new entrants thereafter. Figure DMN-17 showed the market equilibrium prices in APO contiguous to the Leesburg plant, and Figure DMN-18 shows the market equilibrium prices in MRT contiguous to the Midway plant as calculated by the NARE model. Those prices are still too high, even with the emergence of the Leesburg and Midway plants. This is not a trifle; market prices in Florida will still be too high even after the entry of both Leesburg and Midway capacity.

10.3 NARE Shows that the Capacity Addition Schedule in the FRCC Ten Year Plan is Too Low--This Is the Quintessential Definition of Need

Forward prices in Florida are destined to be high under the retarded and restricted entry schedule of the FRCC ten year plan, higher than most or all other areas of the United States. The FRCC ten year plan substantially underbuilds capacity and evidences the exercise of market power by the incumbents in the FRCC. The NARE model keeps showing high market clearing prices under the FRCC ten year plan, which implies that the plan is deficient in the amount of new capacity to be built. In particular, the reported $32/MWH price predicted by the Altos model in the year 2003 is the direct and logical consequence of the much-too-low capacity addition schedule implicit in the FRCC Ten Year Plan. The FRCC needs substantially more capacity, and there is room for both utility and nonutility capacity to be added. There is no implicit or explicit zero sum game going on in the FRCC between utilities and merchants. There is no need to restrict entry to utilities only or nonutilities only. Let the markets and the merchant plant process decide, but the Commission need not restrict or decelerate anything. The market needs the capacity that can be built by both.

The consequences of the FRCC ten year plan are precisely what some people fear—protracted very high prices in Florida accompanied by disruptions, shortages, and periods of astronomically high prices. This is precisely the world that entry in general and entry of projects such as Leesburg and Midway in particular will preclude and prevent. I would reply to those who might argue Altos' wholesale prices are too high: "The high prices you note are precisely the result of the FRCC incumbents restricting entry by merchants into their markets and perhaps restricting their own rate of entry below the competitively justified level so that they can garner monopoly rents from the rest of their own capacity that they choose to provide to the market. They will harm business and citizens in Florida, daunt entry of new business in Florida, create environmental pollution associated with old plants in Florida that is entirely unnecessary, and impose low reliability on Florida that need not be imposed. That will be the consequence of denying Panda Leesburg and Midway and relying instead on the much-too-low FRCC ten year plan."

Lest some would compare ubiquitous "system lambdas" taken from electric dispatch models against NARE model prices, it is well to emphasize that the NARE model prices contain BOTH the fair market value of energy (the system lambda component) as well as the fair market value capacity fully arbitraged in the energy market and fully bundled with the energy component. Just as oil contains a single aggregate representation of capacity, reserves, and production, so do the NARE prices contain a single aggregate value for capacity plus energy. For that reason, the analysis that people might perform comparing system lambdas with Altos prices is an "apples and oranges" comparison and has no valid meaning as a result. Altos' projected FRCC prices include bundled energy plus capacity, and system lambda is purely energy with perhaps some variable consumables.

I will, however, comment on the assertions made in the OGC proceeding before the Commission that the all in cost of a combined cycle in FRCC should be $28/MWH or so. We and our model agree with that as an approximate estimate of all in cost of a combined cycle plant based on new technology with gas priced at approximately $2.50/Mcf. The reason the forward price in the NARE model has not fallen to the $28 level, which I might interpret as long run marginal cost, is that **the capacity construction schedule in the FRCC ten year plan is just too slow and too small.** There are not enough builds in that plan to drive prices down to the level of long run marginal costs. The difference between $28/MWH and the approximately $32/MWH calculated by the NARE model is scarcity rent borne of too little FRCC construction, whether it arises from exercise of market power by the incumbents or merely slowness or restrictions in entry. The prices in the APO and MRT regions of the FRCC as represented in Figures DMN-17 and DMN-18, which are quite consistent with the prices throughout the FRCC as a whole, are substantially above long run marginal cost. The Florida PSC should quickly authorize plants such as Panda Leesburg and Panda Midway if it is to drop the market clearing price from its presently too-high-level down to long run marginal cost where it belongs.

10.4 Addition of Panda Leesburg and Panda Midway Do Not Preclude or Thwart New Entry by Incumbents

Our NARE analysis suggests that Florida is in trouble, particularly under the FRCC ten year plan. Florida is facing some of the higher prices in the nation under the ten year plan presently in place, and because that ten year plan is insufficient in terms of new capacity additions, I would foresee shortages that do not diminish over time. There is assuredly both need and room for merchants such as Panda Leesburg and Midway and incumbents alike. Incumbents' plants can be pursued completely independently of Leesburg and Midway and other merchants; both are needed. Merchants have absolutely no effect whatsoever on incumbent utility alternatives. The Commission should approve Leesburg and Midway and any of those other non incumbent owned alternatives it wishes. What troubles me, and what I would vehemently disagree with, is that merchant plants are not in the incumbents' lists of future possibilities, but nonmerchants are assuredly in my list and I would conjecture in Panda's list of future possibilities. I see no evidence of Panda wanting to thwart or prevent entry of utility owned plants by incumbents. Panda is not in my view looking to preclude any other entry of to gain unique, impenetrable competitive advantage. Panda does not strive to deny or restrict entry to incumbents. There is a very troubling asymmetry here, one with which I disagree.

It is clear from our NARE model analysis that the projected capacity addition schedule by the FRCC is too low. Wholesale market prices delivered to merchant entrants such as Panda will encourage more capacity addition than the FRCC ten year plan document would call for. In my view, the FRCC report should be viewed as insufficient in terms of the amount of capacity addition it advocates. The Panda Leesburg and Midway proposals are manna from heaven in the sense that they are badly needed and they will assuage difficulties that will assuredly occur if the FRCC ten year plan is followed. They will in addition assuage market power difficulties that will occur if market concentration is further exacerbated by placing a larger market share in the hands of the monopoly incumbents.

10.5 The FRCC Needs Overnight Construction of at Least 5,400 MW Followed by the FRCC Ten Year Plan Build Schedule

Altos' long-term analyses of the FRCC region indicates an economic need for the immediate ("overnight" if possible) addition of 5,400 MW of new natural gas-fired combined cycle capacity into the FRCC market (and the additional gas pipeline infrastructure that would be needed to support it). This 5,400 MW is needed in addition to all of the capacity additions shown in the current ten-year site plans of the FRCC retail-serving utilities, as well as in addition to the capacity of both the Leesburg and Midway Projects, the Okeechobee Generating Project, and the New Smyrna Beach Power Project being developed by an affiliate of Duke Energy.

This insight should not be particularly surprising in light of the colossal magnitude of price depressions induced by the Panda Leesburg and Panda Midway projects evidenced in Figures DMN-23 through DMN-25. The reason the price depressions attributable to Leesburg and Midway are as large as they are in the figures is that the capacity situation is so dire. It is not surprising that 5400 MW of new capacity could be profitably and immediately absorbed into the FRCC mix right away and that the incumbents have been effectively blocking it. I do not consider it coincidental that the magnitude of immediate new applications and impending applications for merchant entry total up to 5000 MW or perhaps more. Rather, I consider that magnitude of prospective applications as entirely consistent with the realistic views of a merchant industry poised to enter Florida, solve your looming reliability problems, and drive down your prices to long run marginal cost.

I should emphasize that I have not approached the question of "need" simplistically by measuring peak Florida demand (expressed in GW), adding up available installed capacity (expressed in GW), and comparing the two using a criterion such as reserve margin or loss-of-load probability. (I should add, however, that even this simplistic comparison would underscore the need for merchant projects such as Leesburg and Midway). A simplistic "add up the installed capacity and compare against peak demand" notion of "need" such as the foregoing misses the fundamental reality that some of the old installed capacity in Florida is higher in cost than what new capacity could be installed for. Installing new capacity will displace production from old, uneconomic capacity and reduce the intrinsic cost to generate electricity in Florida. A critically important element of the need for new capacity is the need to reduce the output of old, uneconomic, and more polluting capacity. That is precisely the calculation made within the NARE model.

Just "counting up" installed MW of supply to see if it equals or exceeds demand is simplistic because it imposes higher-than-necessary costs on Florida ratepayers and obscures the true issue of need. The need for the Leesburg and Midway Projects is in fact a need to reduce the output of old, inefficient, high cost, and more polluting plants in Florida that would otherwise have to be run if entry of the Projects were denied or delayed. Our NARE model predicts that there are few places in North America where the need for new natural gas combined cycle generation is more acute and more immediate than in Florida. Florida's economy is growing, and Florida's electricity is expensive. New capacity such as that provided by the Project is needed to meet the inevitable growth in the state, reduce current and future market prices, provide economic benefits via reduced power prices to all consumers in the state, promote efficient economic development, and reduce environmental pollution.

10.6 Leesburg and Midway Directly Improve Environmental Quality in Florida

The Leesburg and Midway Projects, like other natural gas combined cycle projects, provide environmental benefits in the form of reduced environmental emissions that would otherwise occur if older, less efficient, more polluting coal-fired plants, steam turbines, or combustion turbines in the Peninsular Florida generating fleet were operated instead. The technology embedded in the Project, with its lower fuel consumption and mass flow per MWH of production, typically pollutes less per unit of output than production from the plant it displaces, yielding a net pollution reduction.

The Leesburg and Midway Projects will be a state-of-the-art, high-efficiency generating unit with low air emissions. While environmental economists and others may argue about the costs caused by air pollution, it is not seriously argued that pollution is cost-free. Thus, to the extent that the Projects produce power with less pollutant emissions than the energy they displace, the Projects reduce the external costs imposed on society in general (everyone who breathes and maintains property) due to electricity generation. The fact that it may be difficult to quantify such external costs in dollar terms does not diminish their real effects.

There are two important dimensions related to the environmental benefits that the Leesburg and Midway Projects will bestow on the FRCC. The first dimension results from the pollution control equipment that will be installed on the plant, and the second dimension results from the intrinsically lower fuel consumption per MWH of power produced by the plant. With regard to the issue of pollution control equipment to be installed directly in the plant, I understand that the Projects will be equipped with Selective Catalytic Reduction (SCR) and low NOx burners, which means that the Projects will not rely simply on reduced fuel throughput to provide environmental benefits. On the contrary the Projects include specific equipment that render them substantially cleaner than a typical plant. This means that power that was previously being produced by a steam turbine unit at low efficiency without state-of-the-art environmental control equipment will, after the Project enters the Florida market, be produced by an efficient gas combined cycle plant with more and better environmental control equipment.

With regard to the second issue--lower fuel consumption per MWH as compared to the plants whose MWH the Projects will displace--the air pollution from a power plant depends in significant measure on how much fuel one has to burn and put through the plant to generate one MWH of electricity. If one has to put twice as much fuel with twice as much total pollutant content through a plant, one would expect twice as much pollutant emission because twice as many molecules would enter and exit the plant. By contrast, if one has to put half as much fuel through the plant as one would have had to put through the plant(s) whose production it displaces (as is the case with the Projects), one would only be emitting half as much material, i.e., half as many molecules into the atmosphere of Florida. The shift from old, low-efficiency, high-fuel consumption plants (not to mention highly polluting plants) to new, high- efficiency, low-fuel consumption plants with state-of-the-art pollution control equipment engenders an immediate savings in environmental pollutant emissions. In general, and in the specific case of the Project, efficient low-heat-rate technologies and plant configurations will reduce environmental emissions relative to what would otherwise occur because these plants will reduce the amount of fuel consumed for electricity production in Florida.

To get an idea of the pollution savings, return to the gas savings the Projects can be expected to engender in the FRCC market. Recall that the entry of 2000 MW of inframarginal capacity is destined to reduce gas or gas-equivalent consumption by 54.3 trillion Btu per year. That is 54.3 trillion Btu per year of fuel that would otherwise be burned in the FRCC that now does not have to be burned at all. With regard to the environment, that is manna from heaven, representing as it does fuel that does not have to be burned and therefore molecules of combustion products that do not have to be injected into the air or disposed of in the ground.

10.7 Leesburg and Midway Displace Generation from Old, Inefficient, High Cost Plants That Would Otherwise Have to Be Run

Each MWH of energy generated by the Leesburg and Midway Projects displaces one MWH of generation that would otherwise have to be provided by an older, higher cost plant. Such displacement is provided by operating new, lower cost, cleaner plants (namely the Leesburg and Midway Projects) instead of an old, higher cost, less efficient, more polluting plant presently resident within Florida that would otherwise have to operate. Most definitely, the entry of the Project involves direct, MWH-for-MWH displacement of generation from old, inefficient plants in Florida.

The position of the Projects in Figure DMN-19 clearly indicates that when the Projects enter the market, a combination of other plants further to the right in the supply stack will run for fewer hours to offset the increase in generation wrought by the Project. In particular, this includes all the gas steam turbines, the FO6 plants (steam plants that burn No. 6 fuel oil), and the FO2 plants (steam and other plants that burn No. 2 fuel oil) in Florida that reside in the supply stack to the right of the Projects. The Projects will run in preference to each and every one of these other plants.

I should emphasize that the Projects do not necessarily cause plants to be retired that would otherwise run if the Projects were not built. On the contrary, no particular plant will go out of business when the Projects enter the wholesale market. Rather, the older plants will move toward becoming suppliers of ancillary services and lower load factor intermediate and peaking service.

10.8 The Leesburg And Midway Projects Are Not Designed to Sell Power Into Another State—They Are Designed to Sell Power at Their Own Busbar

The question of whether Leesburg and/or Midway will sell power into another state is a specious question. Using Leesburg as an example (Midway is the same), Leesburg power will be sold at the busbar of the Leesburg plant. That is where the valuable economic commodity is delivered to the market and where the money for that commodity changes hands—at the busbar of the Leesburg plant. All changes in Florida or contiguous state power deliveries that occur because of the entry of Leesburg at its busbar are displacement-driven changes. They are not direct shipments of electrical energy from Leesburg to a customer location in another state.

No power from either of the Panda Projects will be sold out of Florida to Georgia or to another state. To understand why Florida power will not be sold out of state into Georgia in the event of the Projects' entry into the wholesale market, it is critical to understand the situation during time of peak load and during periods of base load demand. During times of base load demand, the marginal plant in Georgia is a coal plant, and the marginal plant in Florida is a gas plant. This means that the price of power in Florida is destined to be systematically higher than the price of power in Georgia during times of base load demand. There is absolutely no prospect during times of base load demand, given the price relationship it engenders that anyone would ship power "against the flow" from a higher price region (Florida) to a lower price region (Georgia). Who would ship power from a high value region to a low value region and pay money to do so? The answer is no one. Any assertion that Florida power will be shipped to Georgia during periods of base load demand is clearly not justified by the economic fundamentals. No rational individual would pump water downhill, and no one would ship power from a high price area to a low price area.

There will be at most a small amount of energy sold out of the state of Florida under the capacity addition schedule in the FRCC Ten Year Plan. The entire amount of new capacity would exclusively serve the Florida market, displacing production from old, high-cost, polluting plants that would otherwise have to generate in the Florida market. The total amount of capacity serving the Florida market would be painfully small, and that capacity would stay right at home in Florida except for certain superpeak periods. There is no prospect that any new plants would serve any load in Georgia, and there is even less prospect that any of the old plants whose production is displaced out of the Florida mix would generate energy that would be sold northward out of Florida into Georgia.

Turning to times of peak load, the marginal plant in Georgia (or in upstream regions) is a gas plant, and the marginal plant in Florida is a gas or oil plant. During peak periods, both Georgia and Florida generate power by burning natural gas at virtually the same marginal cost, and that marginal cost is high. The price of power during time of peak is high, the fair market value of losses during time of peak is high, and therefore the cost of transporting peak power is high. There is therefore declining economic incentive to transmit on-peak power during the summer. Peak power usually costs roughly the same everywhere, and it is not valuable to transmit commodities from one region to another where the commodity has the same price, and when one has to pay very high transmission costs because of losses in order to export power. Increasingly over time, there is diminishing incentive to move power in either direction across the Georgia-Florida border during time of peak. However, over the long term, the peak shortage may well become more severe more rapidly in Georgia than in Florida, and peak power would be expected to flow northward under that circumstance.

I should also note that peak demands are strongly coincident between Georgia and Florida. This is certainly true during the summer. When it is hot in Florida, it is generally hot in Georgia. This may be slightly less true during the winter. Cold fronts generally move southward, causing the peak demand to occur slightly earlier in Georgia than in Florida. This means that peak demands in Georgia and Florida tend to be coincident. This in turn means that there is decreasing incentive to important Georgia power into Florida during time of peak.

Let us be clear; the economic success of the Project does not depend on the Project selling or displacing any power outside Peninsular Florida. It is clear from our NARE analysis that the new Leesburg and Midway plants entering Florida will make more money generating and selling their generation right at home in Florida. They would make less money generating in Florida and selling in Georgia; that would be a less profitable option both because of the cost of transmission and they would lose because the fair market price in Georgia promises to be lower than the fair market price in Florida most of the time. There exists a lot of coal capacity in Georgia and points northward and westward, and that coal capacity is lower in cost than production from the old, high-cost, polluting plants displaced from Florida. These old Florida plants (displaced through the introduction of the Leesburg and Midway Projects and thus available to generate for the Georgia market) are simply not competitive against the Georgia capacity mix. Indeed, any plants whose production is displaced in Florida by the entry of either the small amount of the Project's capacity or even by the 5,400 MW of new capacity that can be absorbed into the Florida market will not be competitive in either Georgia or Florida.

Any argument that even after entry of the Leesburg and Midway Projects, FPL, FPC, or TECO would continue to use their old plants to generate just as they always have but instead send power north to Georgia implies that they will need Florida ratepayers to subsidize the difference between their generation cost and the (lower) price of power they could obtain in Georgia less the transmission cost from Florida to Georgia. The PSC can disallow the cost repercussions of any such uneconomic dispatch and thereby prevent uneconomic dispatch and/or subsidized power sales designed to keep incumbent Florida power plants operating. The idea that old plants will or should run as much after entry of the Projects as they did before the Projects entered the Peninsular Florida fleet is incorrect and will not be sustained by the market or in my view by the Florida PSC.

10.9 Florida's Dependence on Energy Imports From Georgia Will Continue to Decline

Florida promises to become less dependent on imports from Georgia than they have been in the past. Imports from the north into Florida are destined to decline in the future. Not only will there be little or no export of power northward from Florida to Georgia, there will be a reduction of on-peak power imports from Georgia to Florida in the future. Florida will become more self-sufficient. To wit, Southern will evolve from net exporter to net importer from its neighbors other than Florida. Why would Southern export less energy to Florida as the future unfolds? The answer needs to be considered during times of base load and thereafter during periods of peak load.

During off-peak periods, Southern's low cost coal units will be increasingly dedicated to local Southern Company markets as Southern's load grows. Rapid load growth in Southern coupled with the fact that no one in the Southern territory is planning to build any new coal plants means that capacity and energy will become more scarce in the Southern Company region than they have been in the past. This leaves less capacity and energy to be exported to Florida or elsewhere.

During peak periods, both Georgia and Florida generate power by burning natural gas at virtually the same marginal cost. There is therefore declining economic incentive to transmit on-peak power during the summer. Peak power usually costs about the same everywhere, and it is not valuable to transmit commodities from one region to another where the commodity has the same price, and when one has to pay transmission costs in order to export power. Increasingly over time, there is diminishing incentive to move power in either direction across the Georgia-Florida border. Amplifying the negative incentive to transmit on peak power is the observation that at the high peak prices, the fair market value of losses is very high indeed.

11 CONCLUSION

The Leesburg and Midway Generation Projects depress prices in the FRCC, thereby paying large direct benefits to FRCC ratepayers. The ratepayers bear absolutely no risk or cost whatsoever nor will they ever be mandated to accept power from the Projects. Furthermore, the Projects will create a net improvement in the environment and create an "anchor" for an important new gas pipeline that brings low cost gas to southern Florida where it is needed and where it pays benefits independent of the Projects. Furthermore, the Leesburg and Midway Projects will reduce market power of the incumbent generators in the state, market power that is already deleteriously impacting Florida ratepayers, businesses, and citizens. Finally, the Leesburg and Midway Projects will be profitable to Panda and will be built with all prudent speed if allowed.

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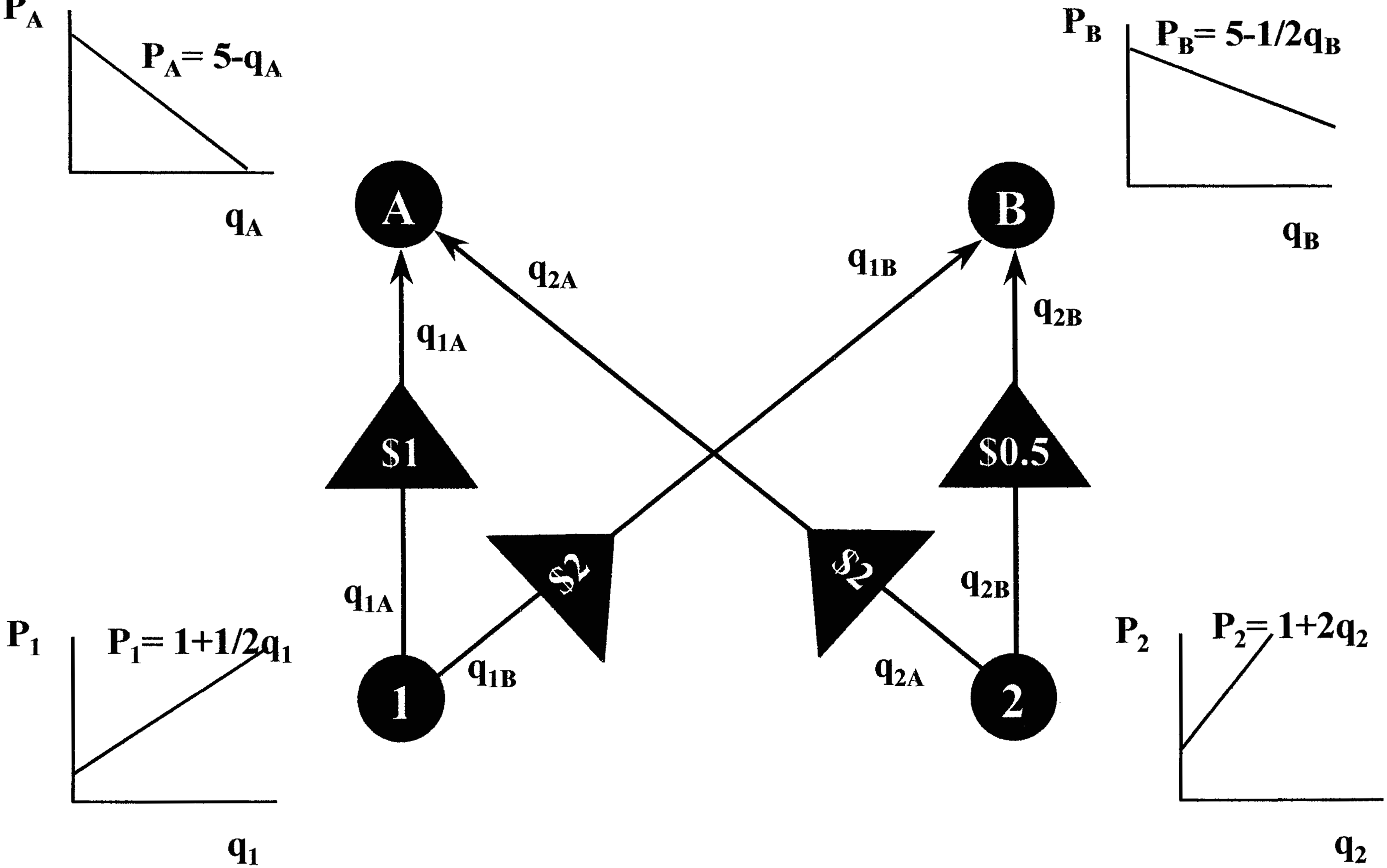

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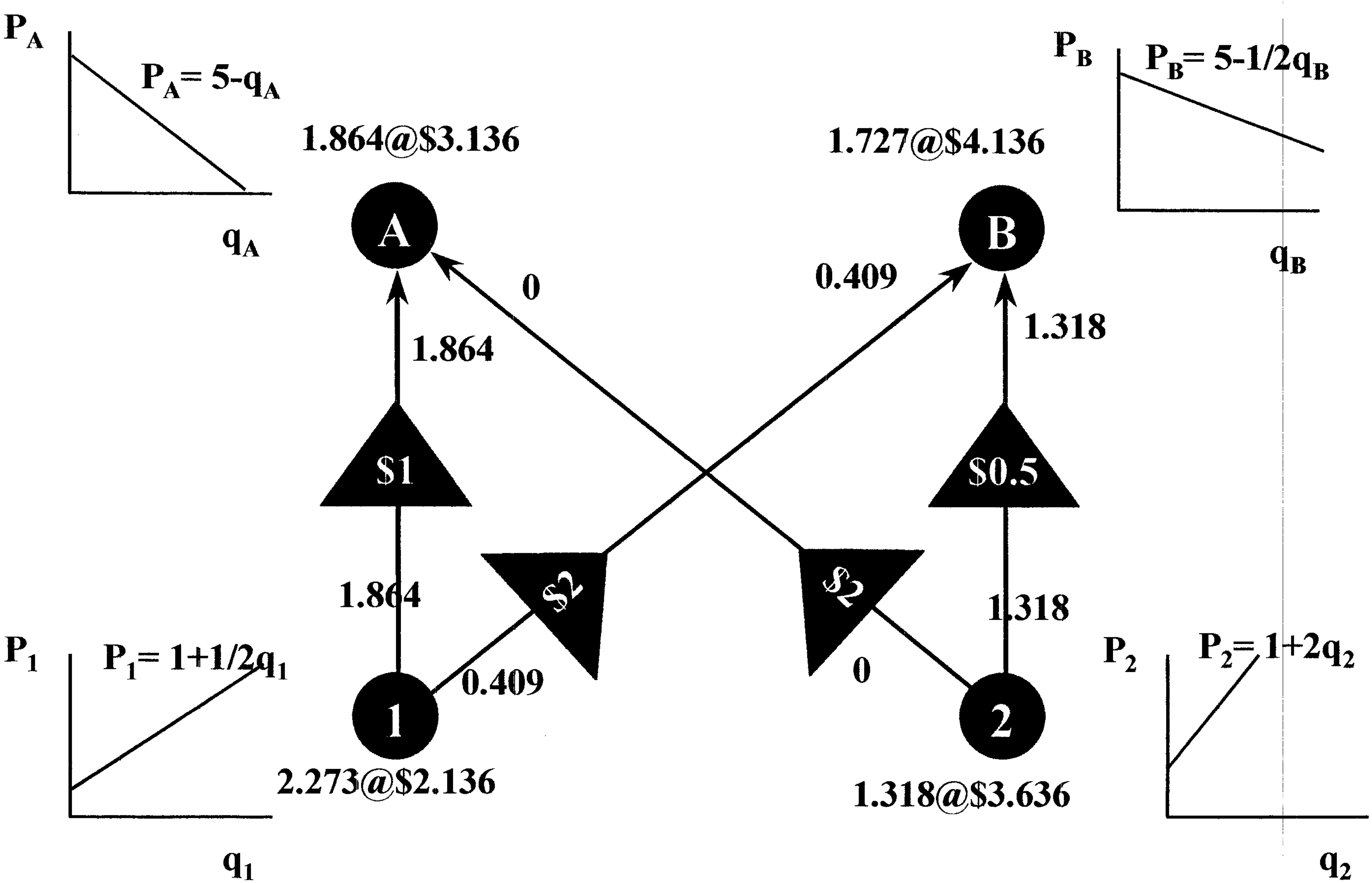

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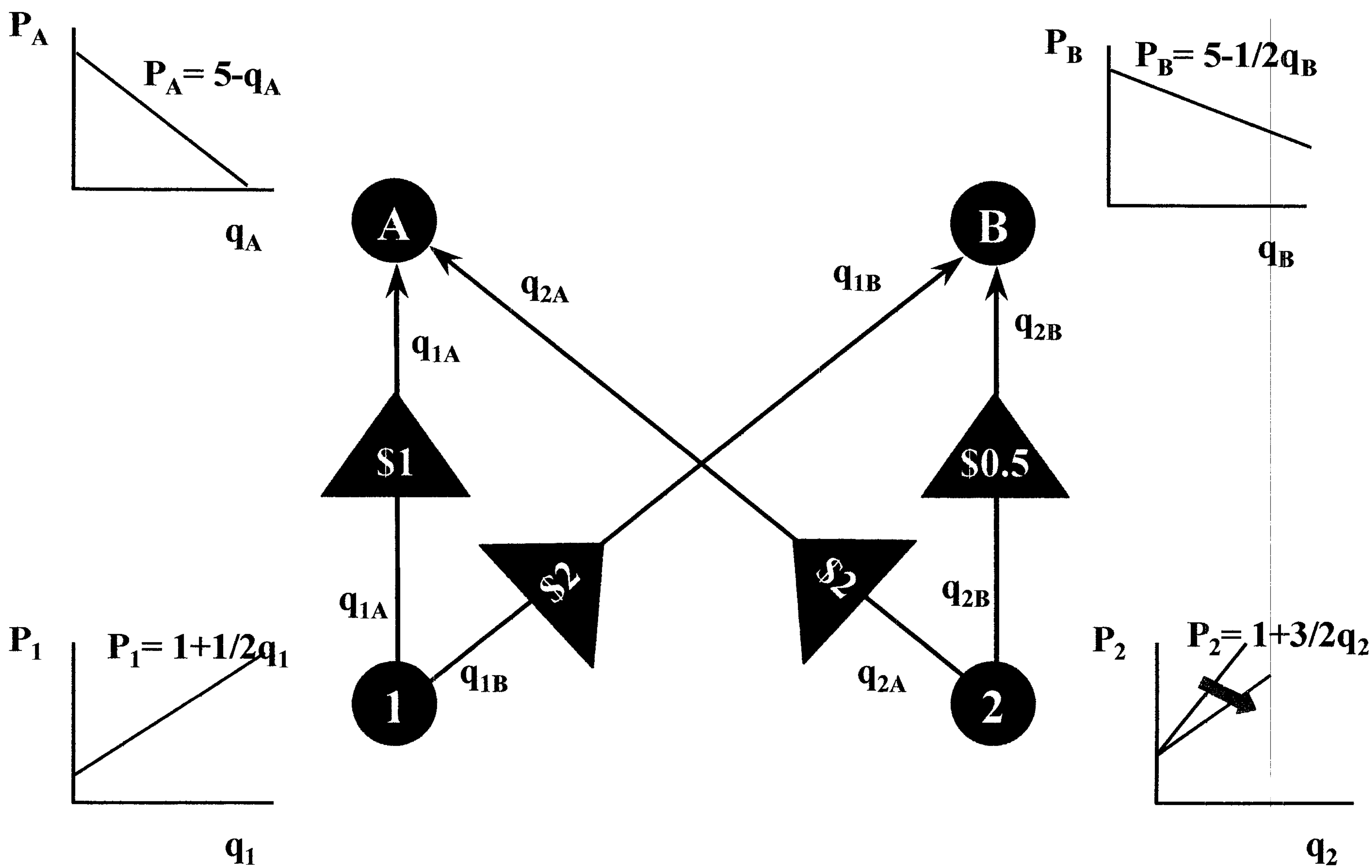

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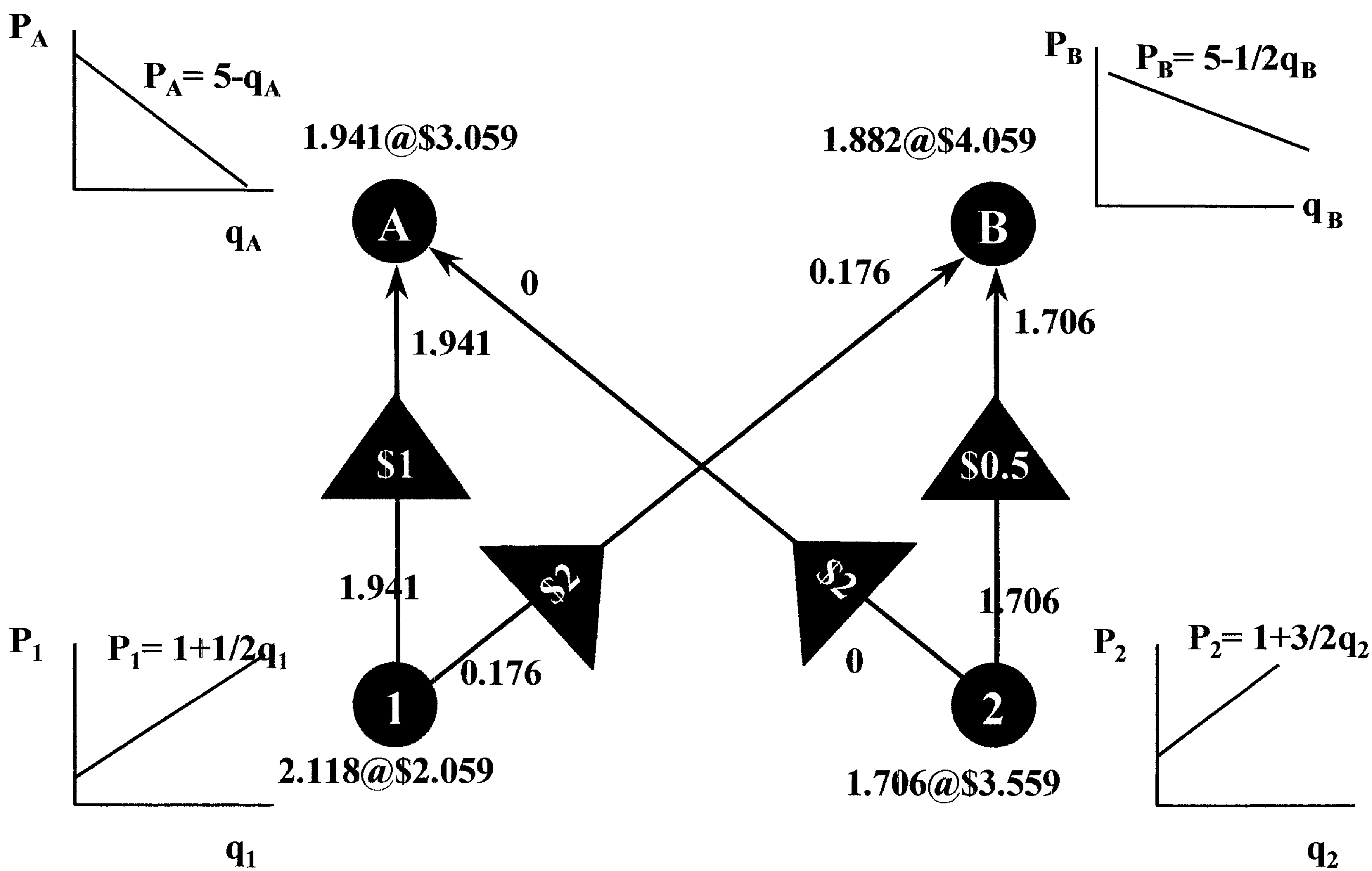

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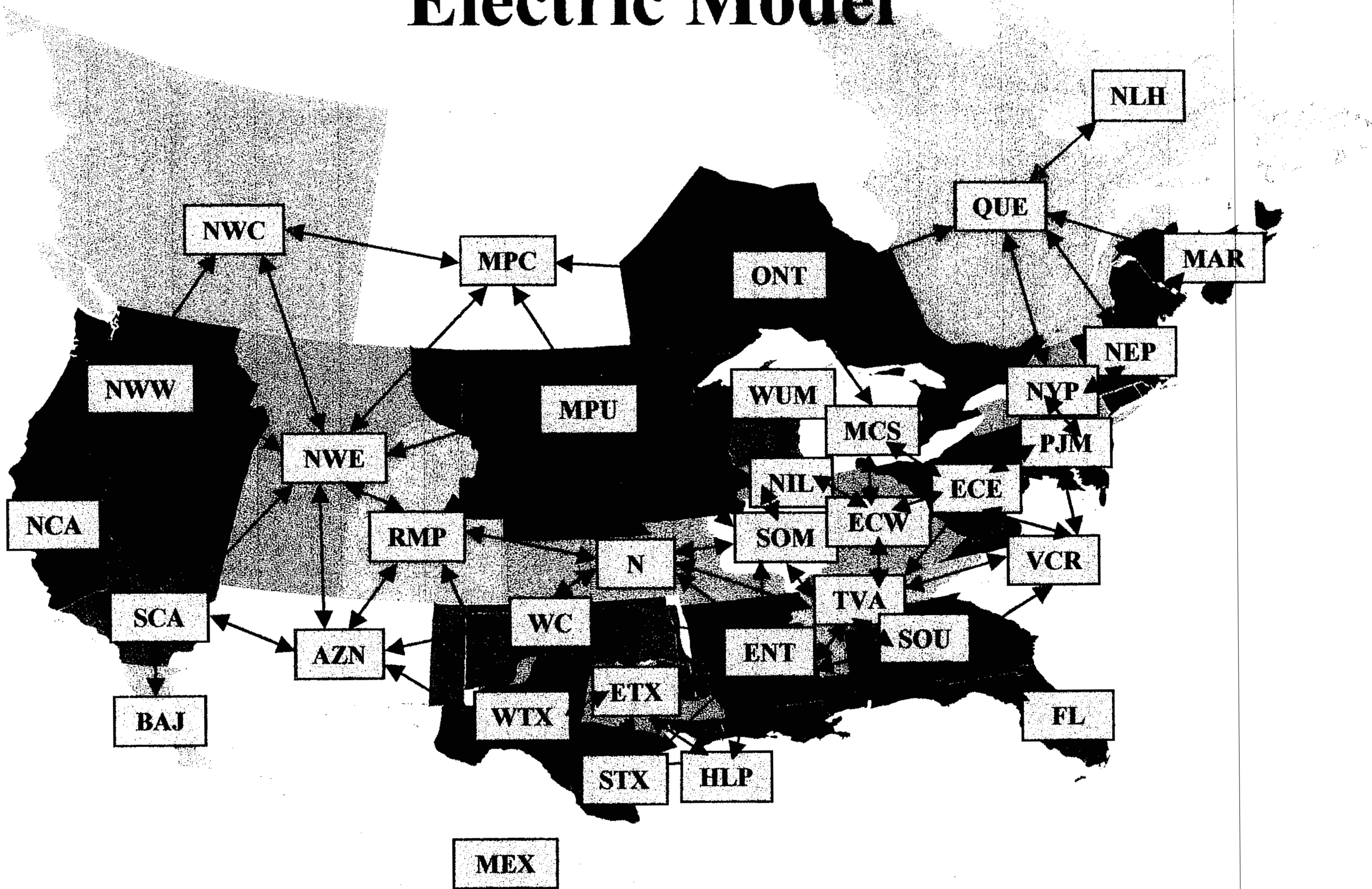

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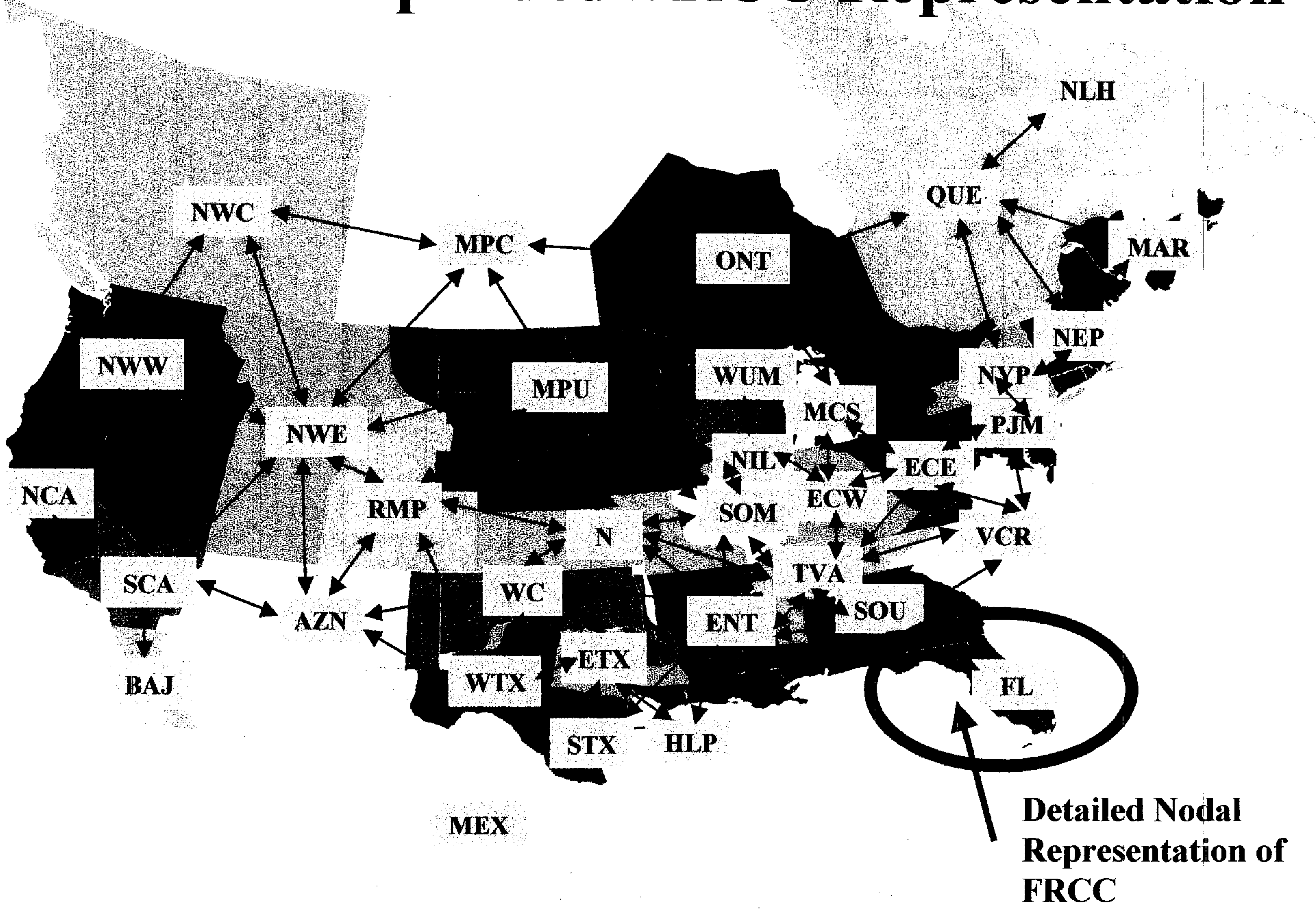

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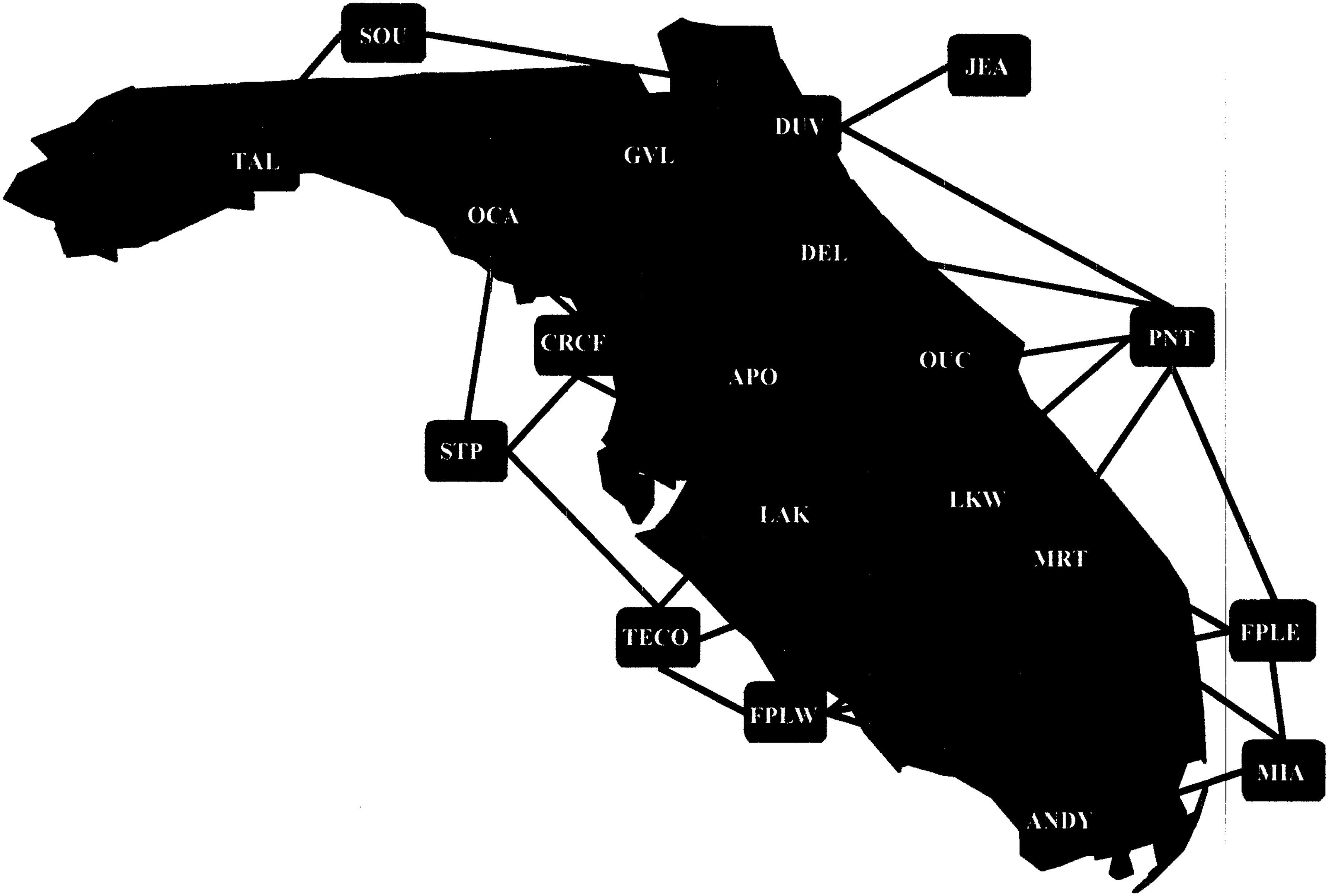

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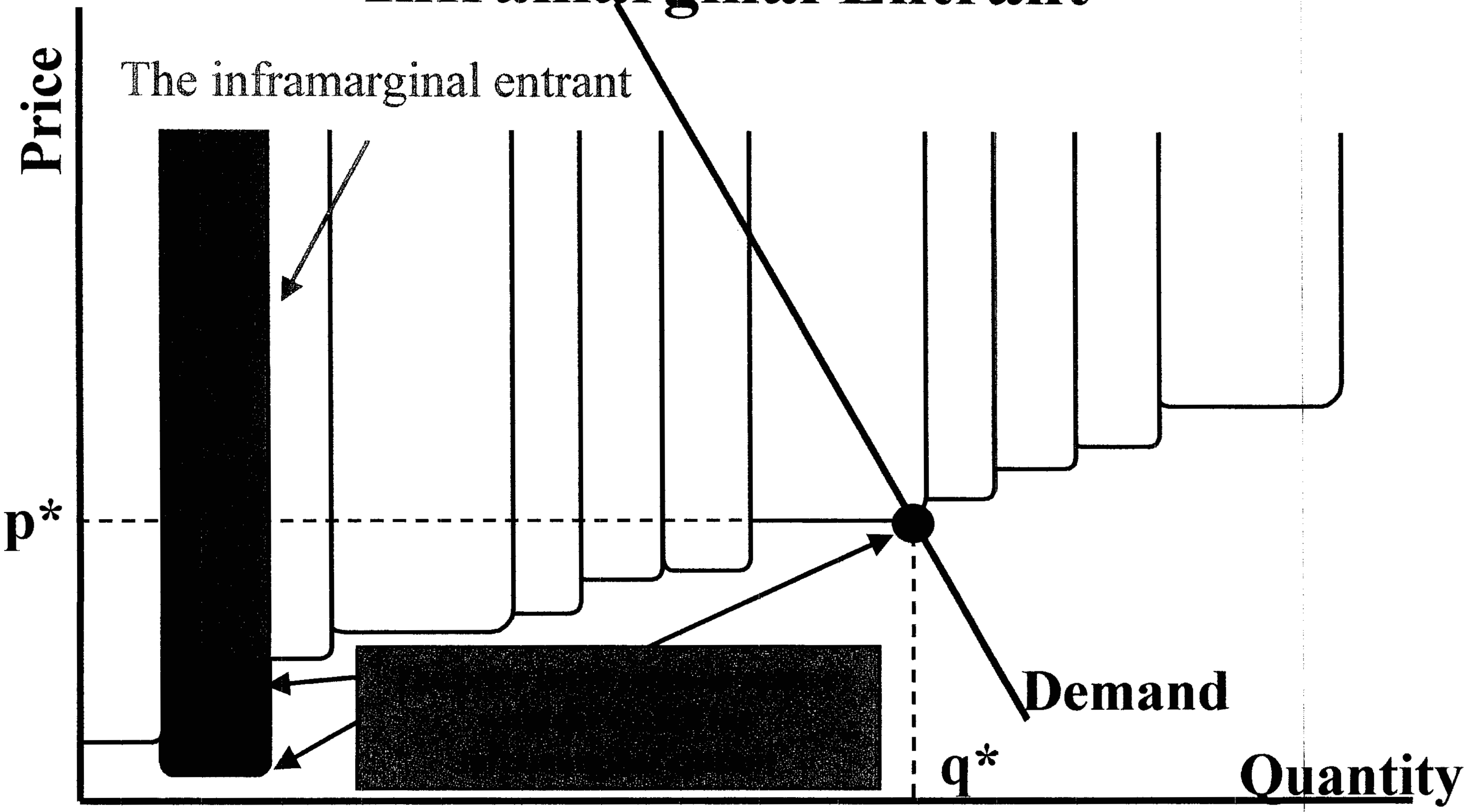

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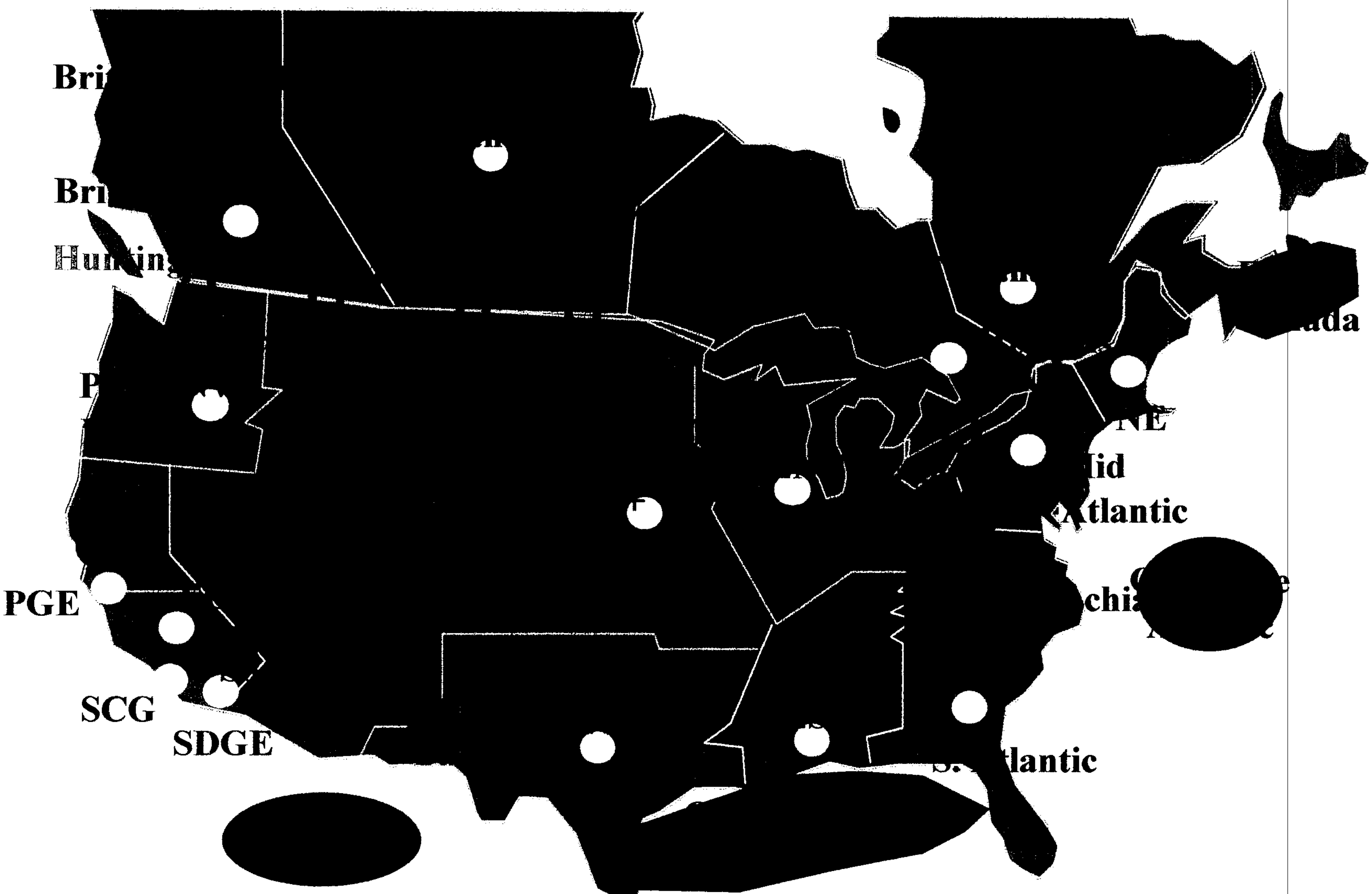

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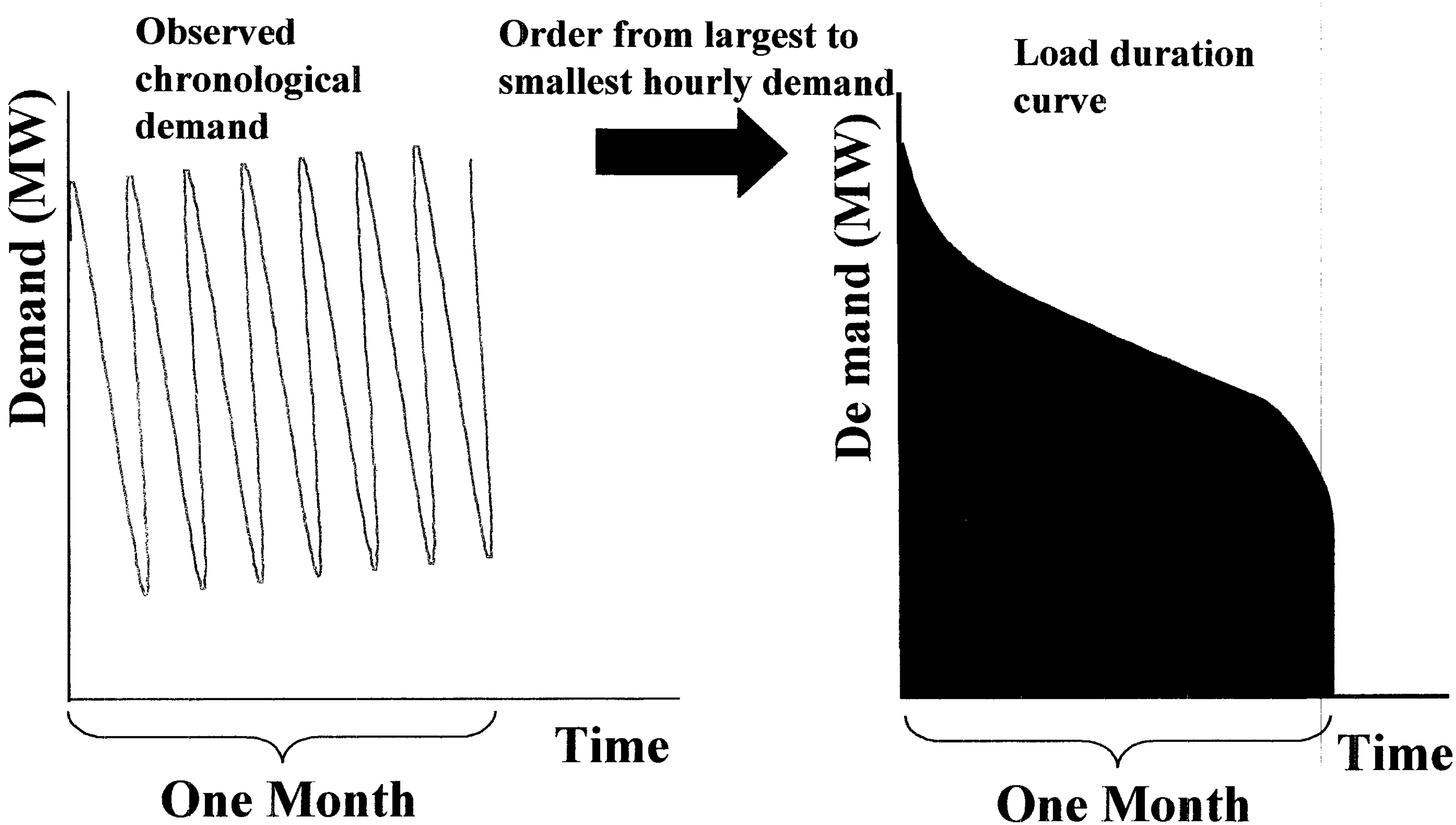

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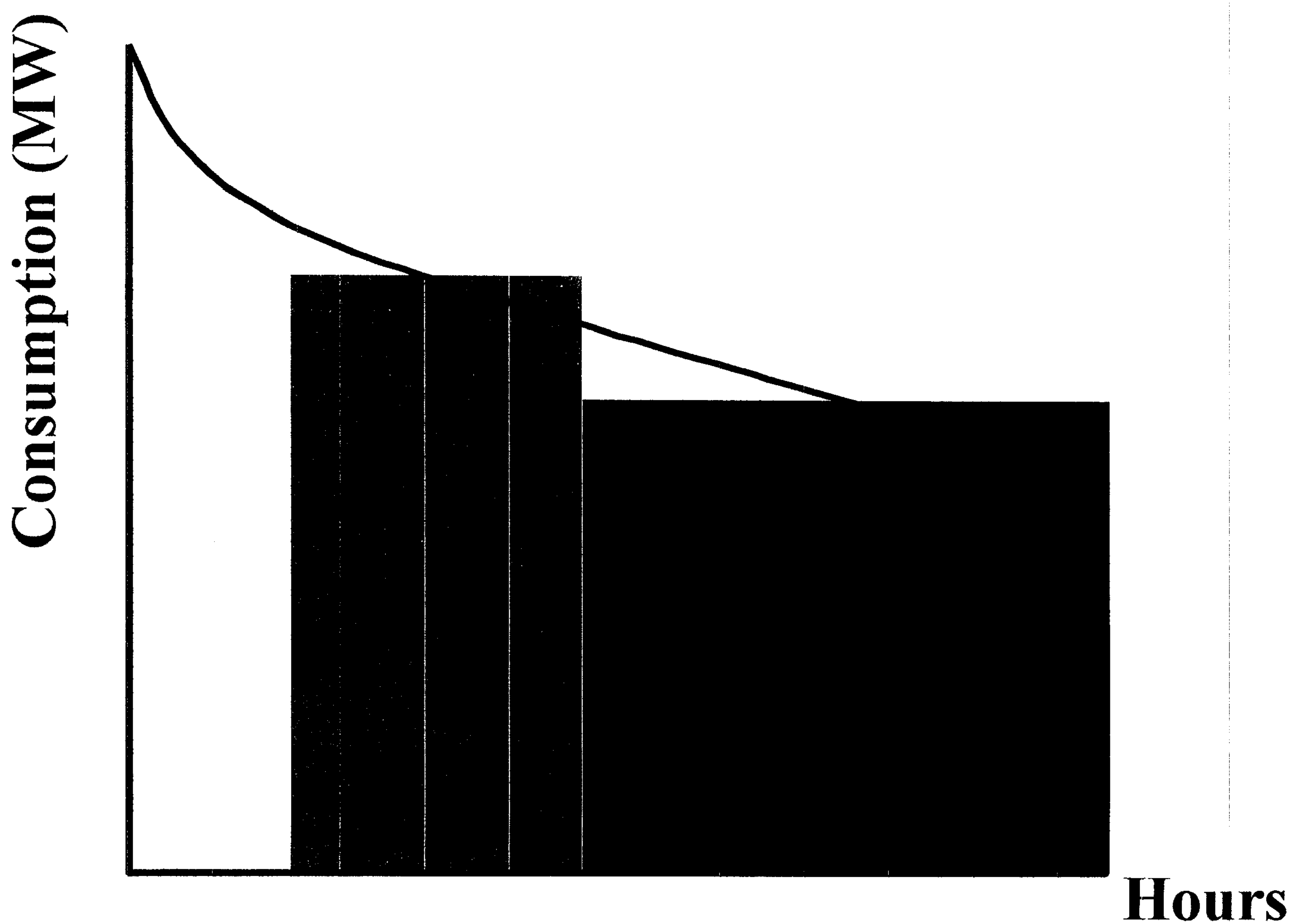

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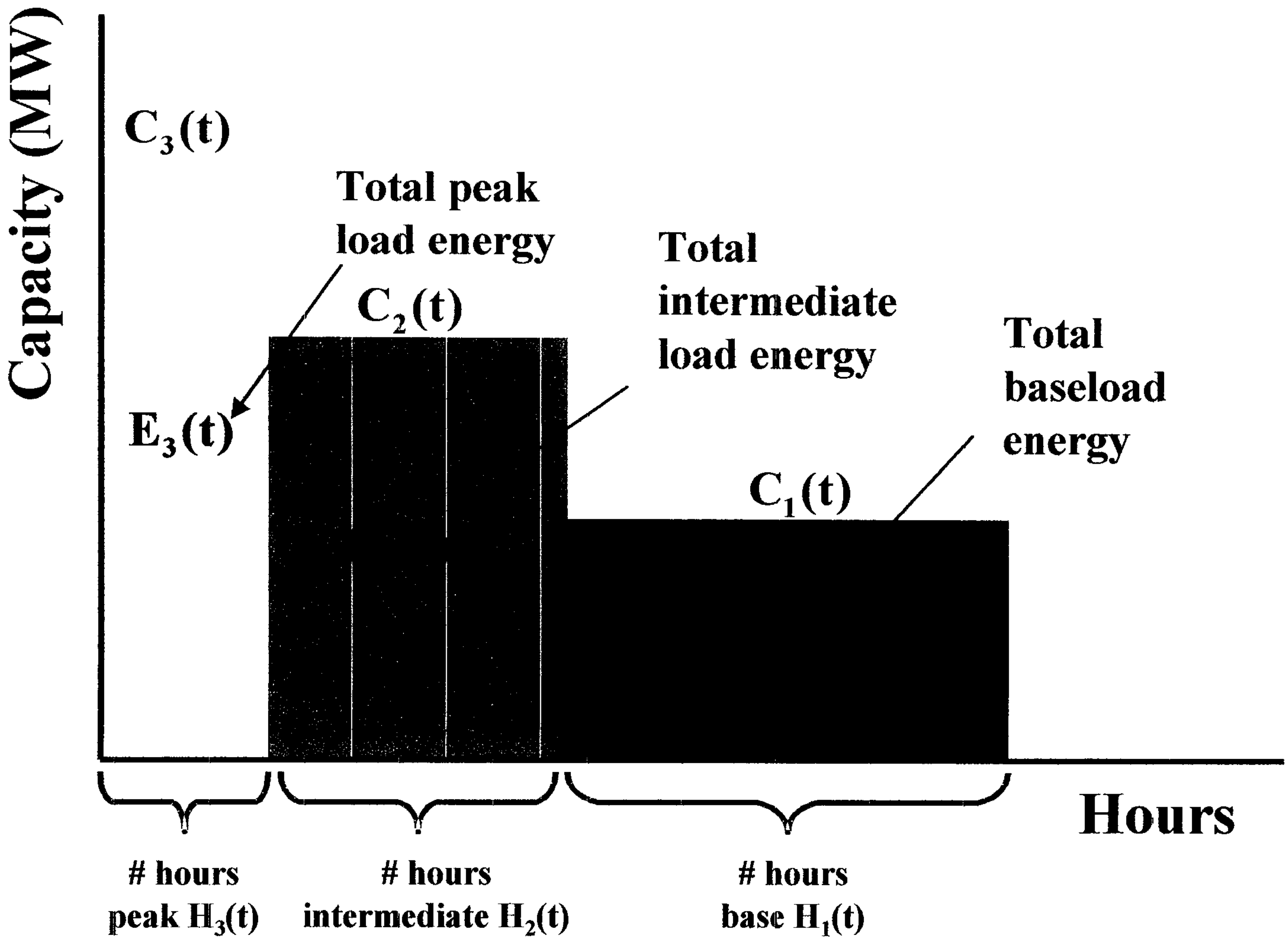

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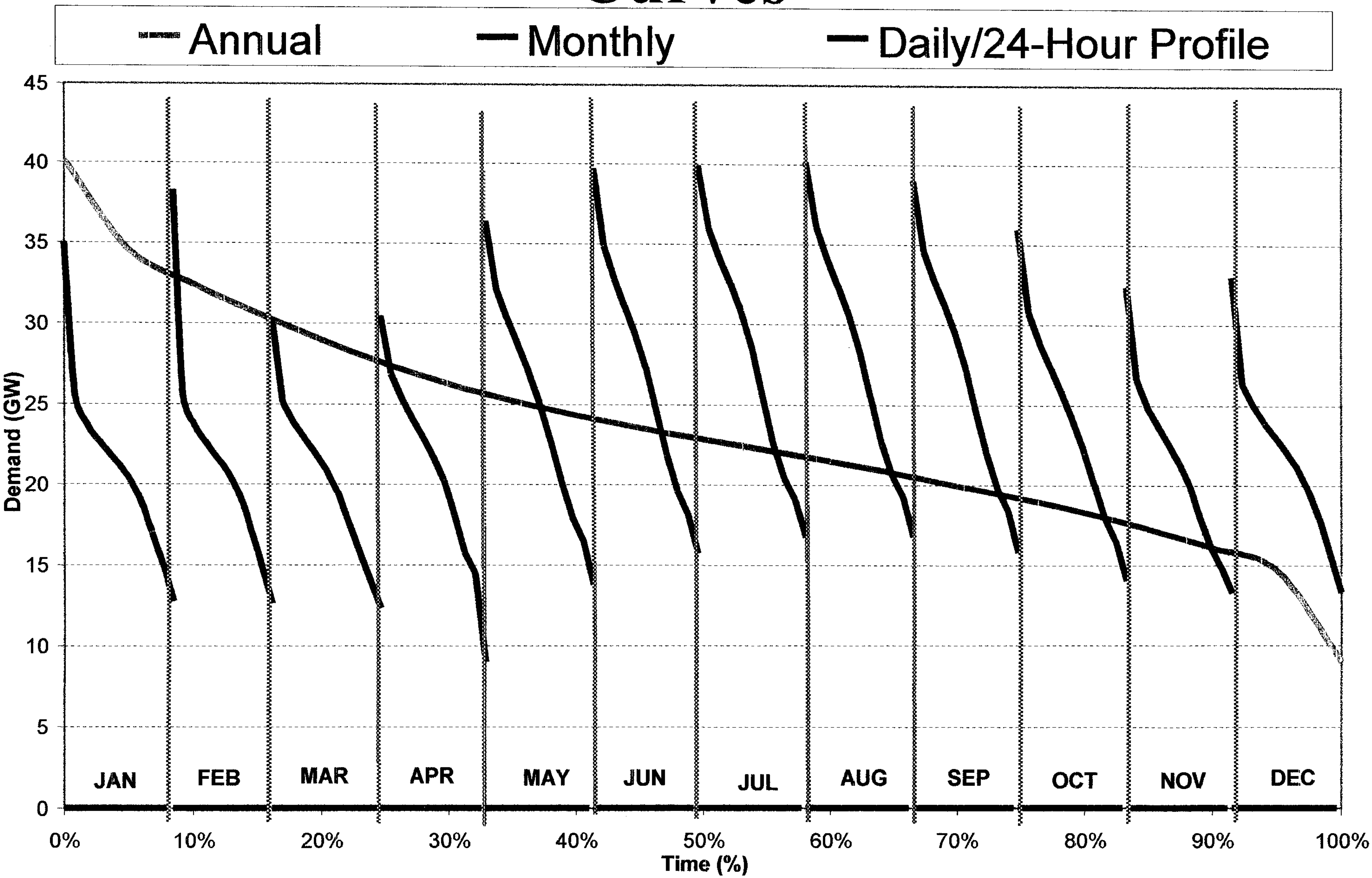

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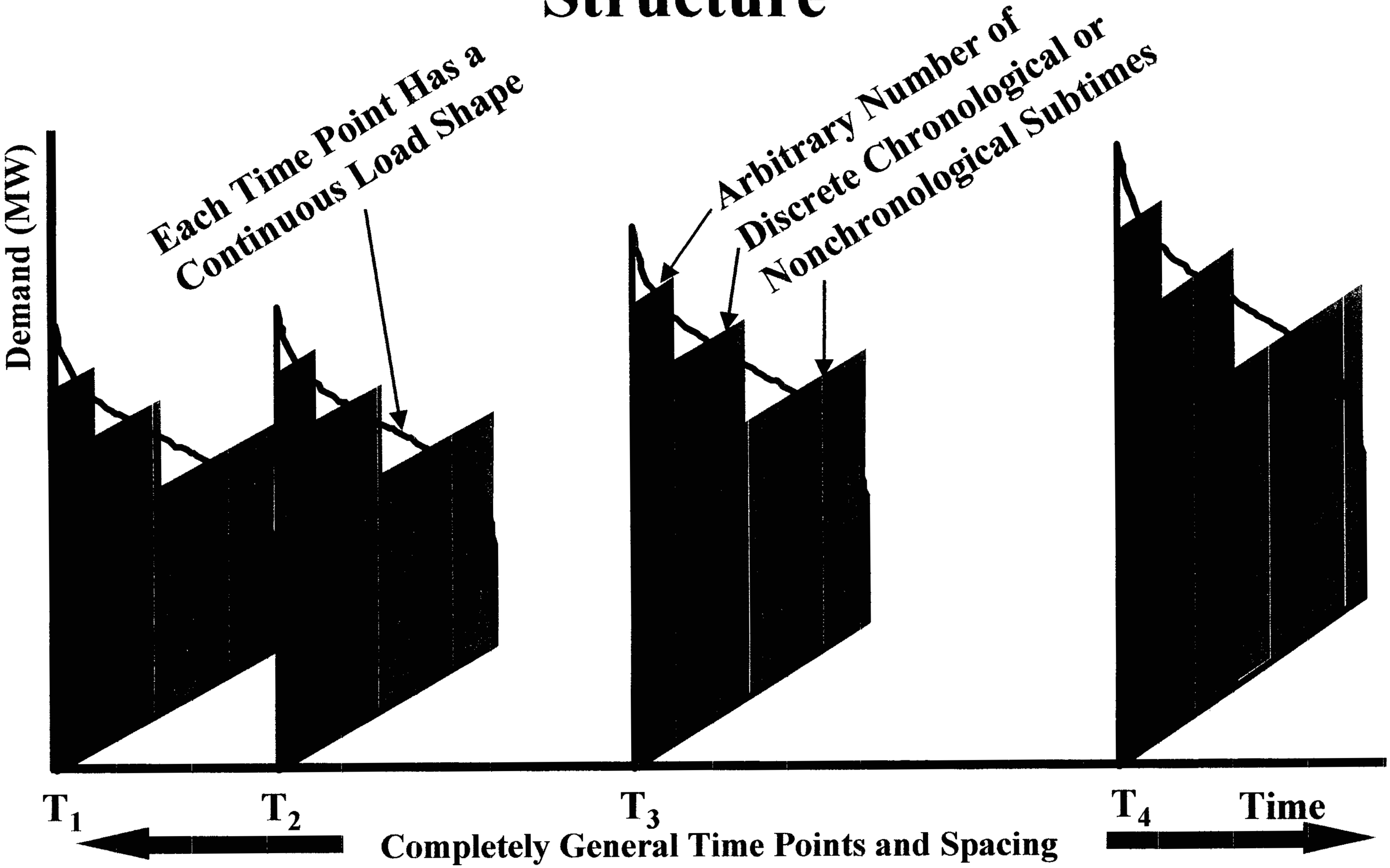

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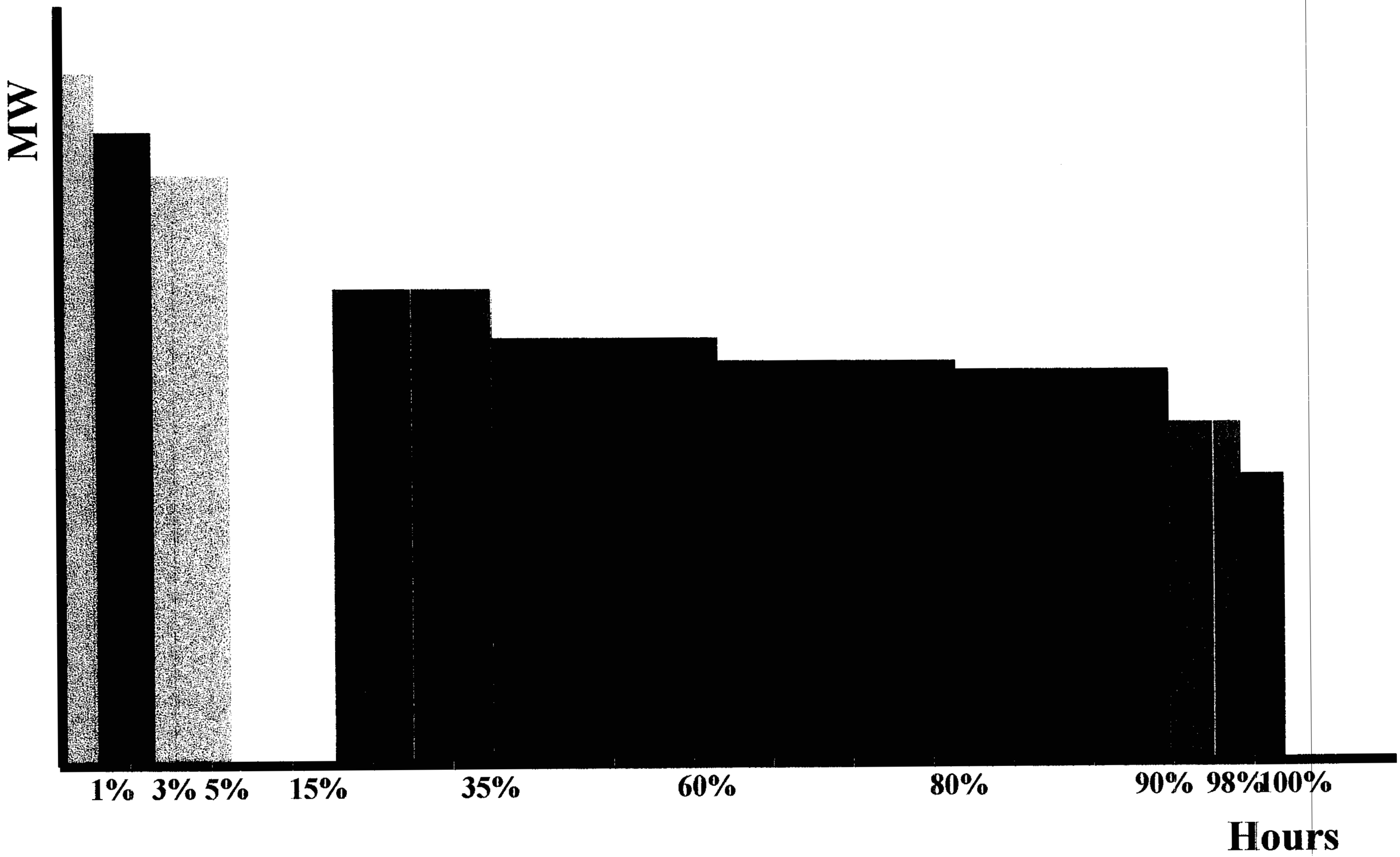

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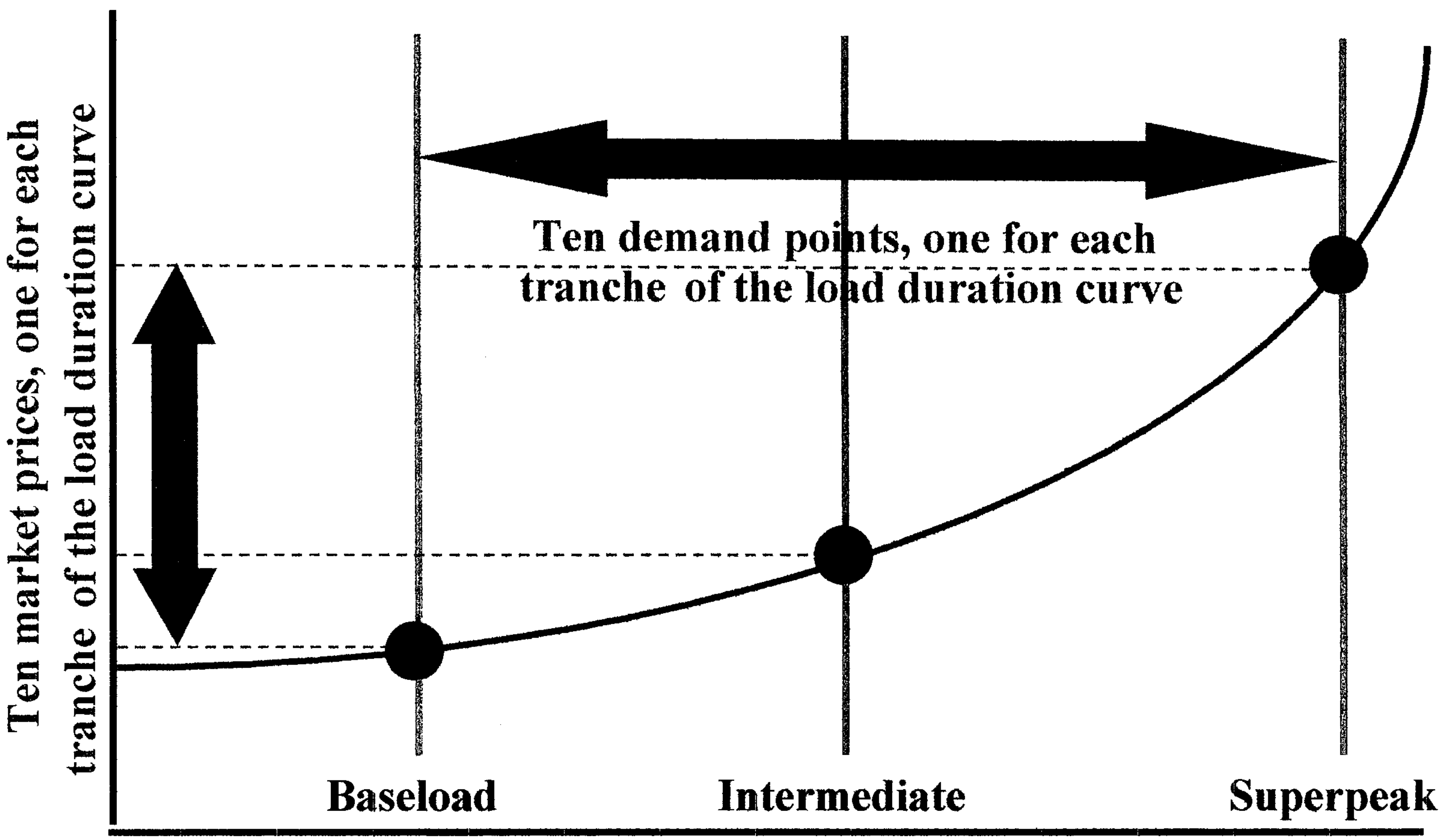

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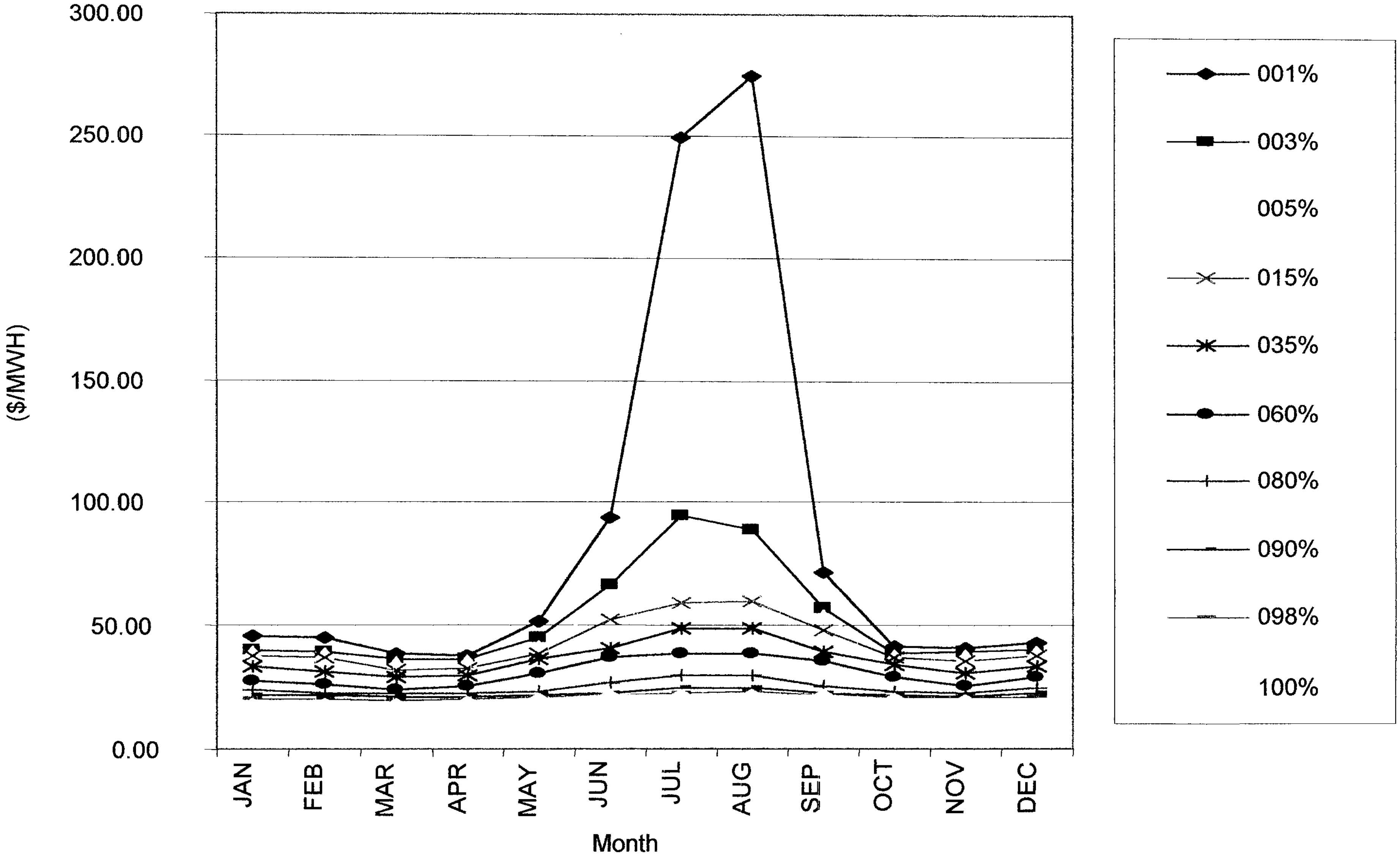

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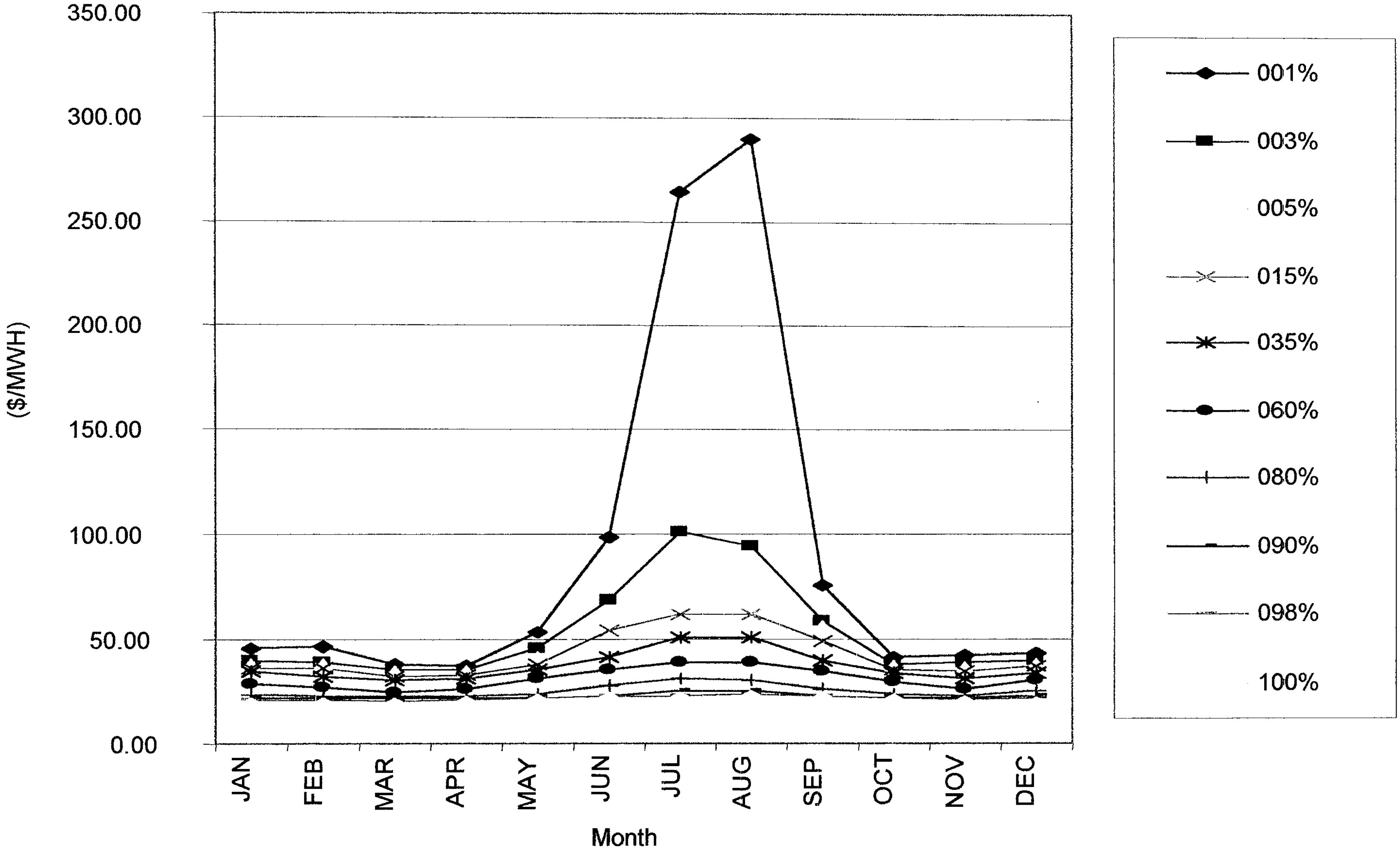

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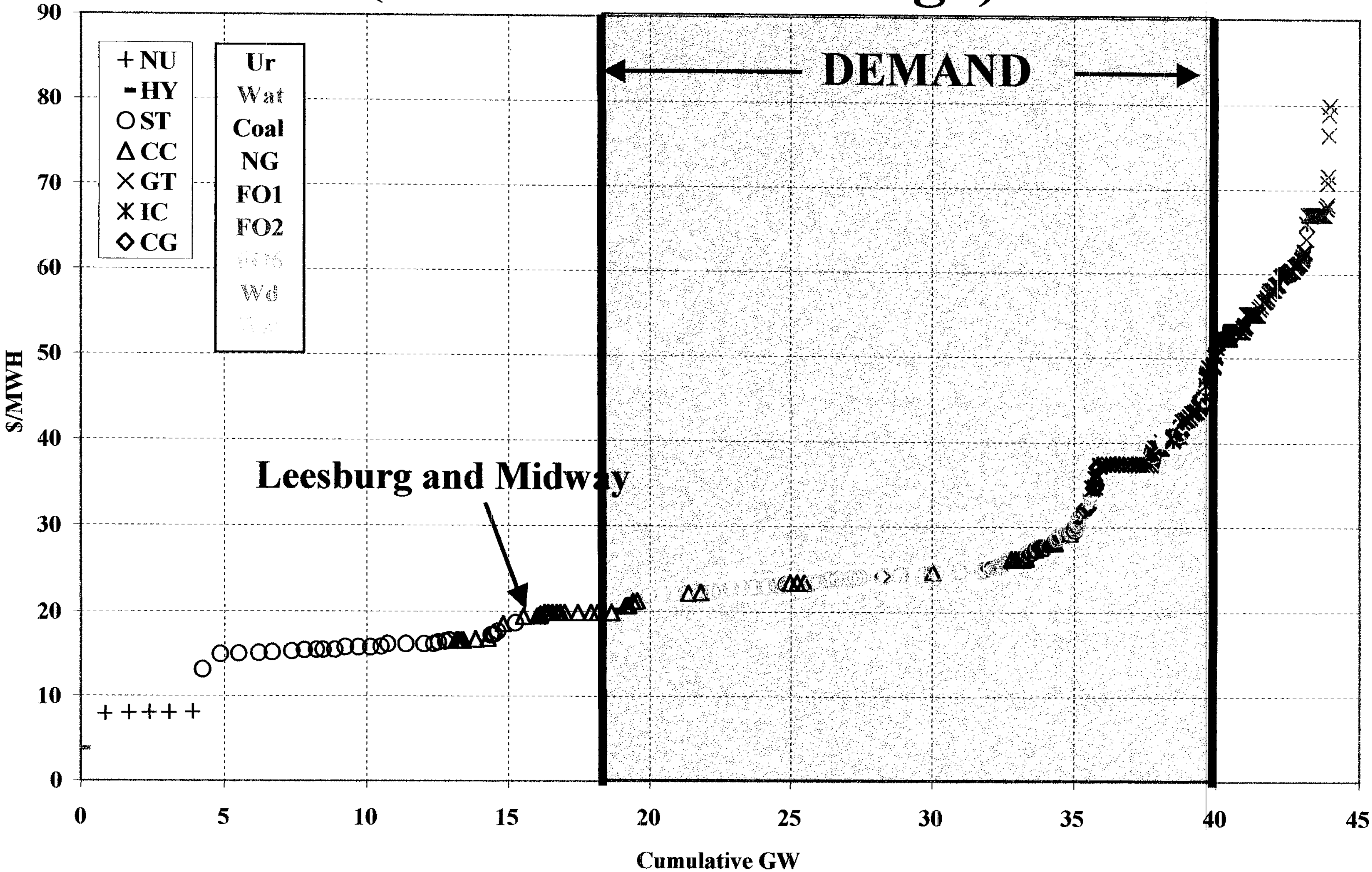

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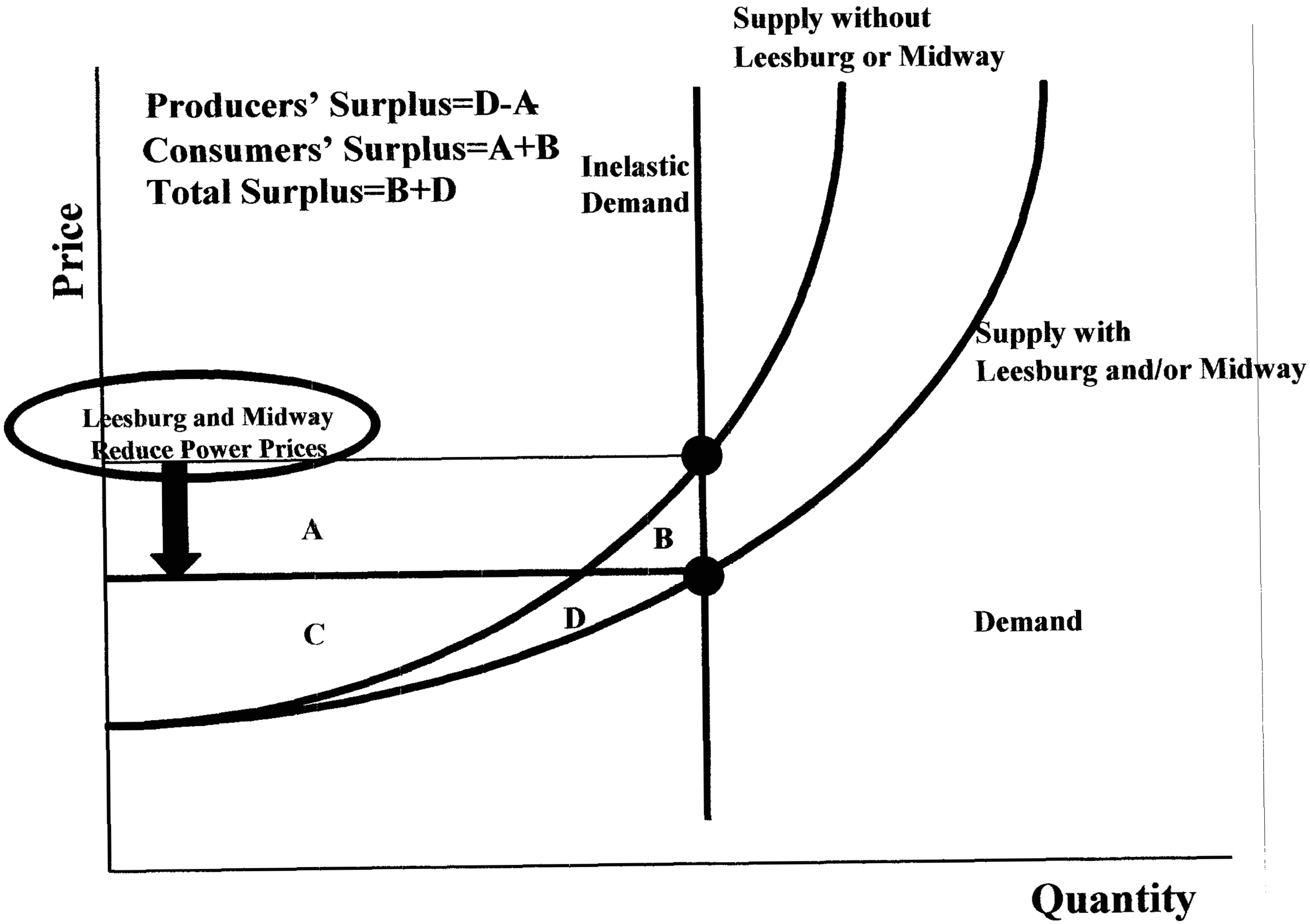

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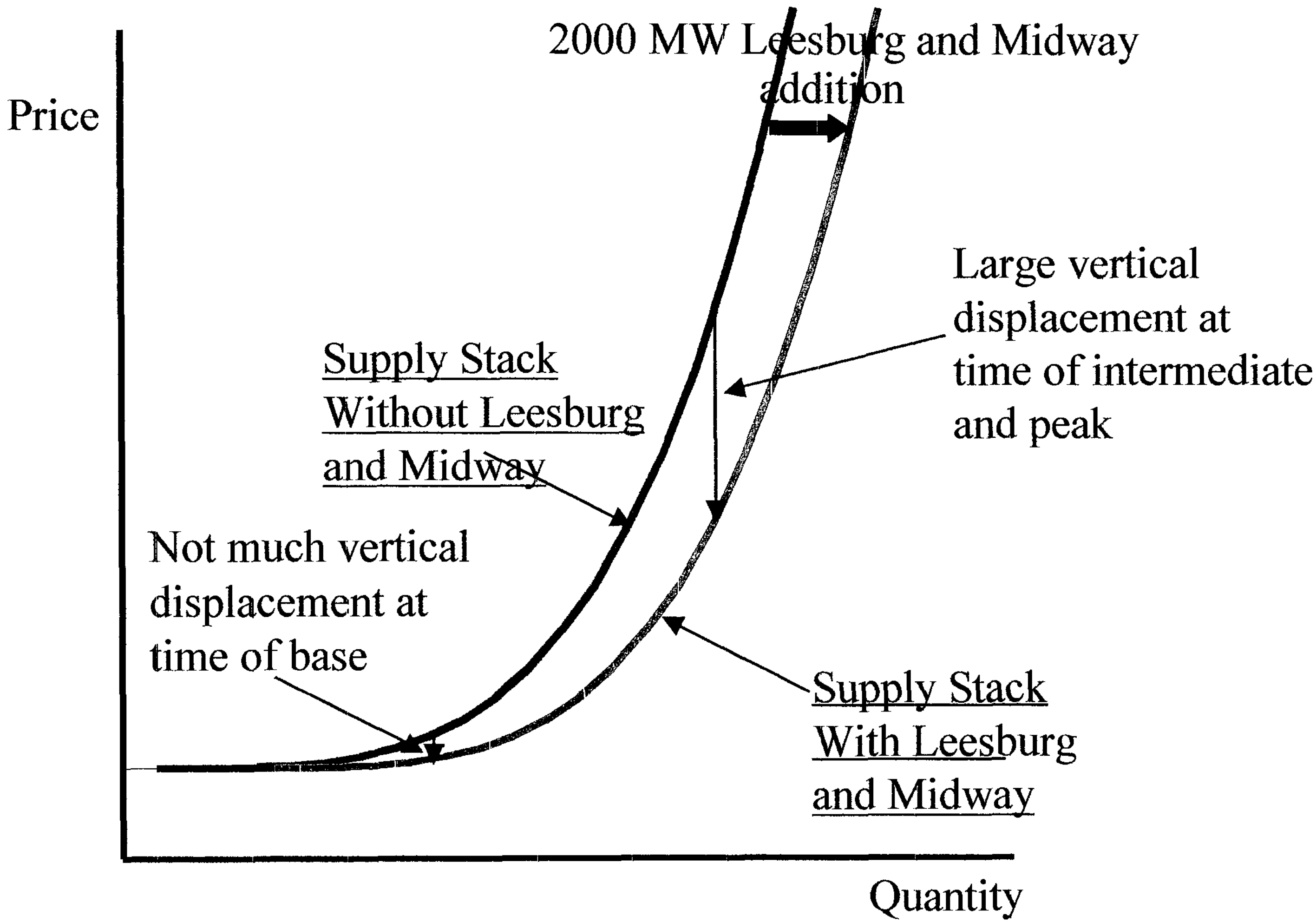


Figure DMN-22: The Four Panda NARE Cases

[redacted]

Case “NL/NM”	Case “NL/M”
Case “L/NM”	Case “L/M”

Figure DMN-23: The Four Wholesale Prices in FRCC in 2003 ($/MWH)

FRCC Avg. Price			Midway Price Reduction
	$34.18	$33.29	$0.89
	$33.36	$32.49	$0.87

Figure DMN-24: The Four Wholesale Prices in FRCC in 2007 ($/MWH)

FRCC Avg. Price	[redacted]		Midway Price Reduction
[redacted]	$36.60	$35.51	$1.09
	$35.53	$34.54	$0.99
[redacted]			

Figure DMN-25: The Four Wholesale Prices in FRCC in 2012

FRCC Avg. Price	[redacted]		Midway Price Reduction
[redacted]	$36.48	$35.34	$1.14
	$35.35	$34.42	$0.94
[redacted]			

Figure DMN-26: Discounted Annualized Values of Consumers' Surplus Benefits (billions of dollars)

2003 Discounted

FRCC Consumer Surplus	[redacted]		Midway Price Reduction
[redacted]	7.030	6.847	0.183
	6.862	6.683	0.179
	[redacted]		

2007 Discounted

FRCC Consumer Surplus	[redacted]		Midway Price Reduction
[redacted]	5.736	5.565	0.171
	5.569	5.414	0.155
	[redacted]		

2012 Discounted

FRCC Consumer Surplus	[redacted]		Midway Price Reduction
[redacted]	3.920	3.798	0.122
	3.799	3.698	0.101
	[redacted]		

Figure DMN-27: Plant Capacity Factors

2003

	Leesburg Only	Midway Only	Leesburg AND Midway
Leesburg CF	80%	N/A	80%
Midway CF	N/A	88%	88%

2007

	Leesburg Only	Midway Only	Leesburg AND Midway
Leesburg CF	90%	N/A	90%
Midway CF	N/A	90%	90%

2012

	Leesburg Only	Midway Only	Leesburg AND Midway
Leesburg CF	94%	N/A	94%
Midway CF	N/A	94%	94%

Figure DMN-28: Leesburg-Induced Price Depressions Without Midway

Leesburg without Midway			
	2003	2007	2012
ANDY	$0.62	$0.91	$0.97
APO	$1.80	$1.94	$2.04
CRCF	$1.11	$1.32	$1.40
DEL	$1.09	$1.25	$1.31
DUV	$0.50	$0.70	$0.74
FPLE	$0.60	$0.89	$0.94
FPLW	$0.83	$1.14	$1.22
GVL	$0.59	$0.81	$0.84
JEA	$0.47	$0.63	$0.64
LAK	$0.97	$1.23	$1.29
LKW	$0.96	$1.36	$1.43
MIA	$0.65	$0.97	$1.02
MRT	$0.58	$0.85	$0.89
OCA	$1.03	$1.29	$1.37
OUC	$1.20	$1.40	$1.47
PNT	$0.58	$0.82	$0.87
STP	$1.05	$1.31	$1.39
TAL	$0.46	$0.58	$0.60
TECO	$0.90	$1.17	$1.24
FRCC	**$0.81**	**$1.07**	**$1.13**

Figure DMN-29: Leesburg-Induced Price Depressions With Midway

Leesburg with Midway			
	2003	2007	2012
ANDY	$0.60	$0.79	$0.74
APO	$1.75	$1.85	$1.84
CRCF	$1.06	$1.24	$1.22
DEL	$1.05	$1.19	$1.14
DUV	$0.49	$0.60	$0.52
FPLE	$0.58	$0.75	$0.71
FPLW	$0.83	$1.06	$1.04
GVL	$0.58	$0.72	$0.64
JEA	$0.45	$0.52	$0.46
LAK	$0.94	$1.16	$1.13
LKW	$0.96	$1.29	$1.27
MIA	$0.64	$0.83	$0.78
MRT	$0.57	$0.72	$0.67
OCA	$1.00	$1.21	$1.18
OUC	$1.20	$1.33	$1.31
PNT	$0.59	$0.71	$0.64
STP	$1.01	$1.23	$1.20
TAL	$0.46	$0.45	$0.42
TECO	$0.87	$1.09	$1.06
FRCC	**$0.80**	**$0.97**	**$0.93**

Figure DMN-30: Midway-Induced Price Depressions Without Leesburg

Midway without Leesburg			
	2003	2007	2012
ANDY	$1.36	$1.55	$1.62
APO	$0.61	$0.82	$0.85
CRCF	$0.60	$0.78	$0.81
DEL	$0.59	$0.78	$0.80
DUV	$0.57	$0.84	$0.88
FPLE	$1.45	$1.66	$1.73
FPLW	$0.81	$0.99	$1.04
GVL	$0.55	$0.82	$0.88
JEA	$0.52	$0.75	$0.74
LAK	$0.58	$0.73	$0.76
LKW	$0.64	$0.78	$0.82
MIA	$1.44	$1.64	$1.72
MRT	$1.42	$1.61	$1.68
OCA	$0.59	$0.81	$0.84
OUC	$0.57	$0.77	$0.80
PNT	$0.80	$1.11	$1.15
STP	$0.64	$0.84	$0.88
TAL	$0.40	$0.53	$0.54
TECO	$0.67	$0.85	$0.89
FRCC	**$0.89**	**$1.09**	**$1.14**

Figure DMN-31: Midway-Induced Price Depressions With Leesburg

Midway with Leesburg			
	2003	2007	2012
ANDY	$1.34	$1.42	$1.39
APO	$0.56	$0.73	$0.66
CRCF	$0.54	$0.70	$0.63
DEL	$0.55	$0.71	$0.64
DUV	$0.56	$0.74	$0.66
FPLE	$1.43	$1.53	$1.50
FPLW	$0.81	$0.91	$0.86
GVL	$0.55	$0.74	$0.67
JEA	$0.51	$0.64	$0.56
LAK	$0.54	$0.66	$0.60
LKW	$0.64	$0.72	$0.66
MIA	$1.43	$1.50	$1.48
MRT	$1.41	$1.48	$1.46
OCA	$0.56	$0.73	$0.65
OUC	$0.57	$0.70	$0.64
PNT	$0.81	$1.00	$0.92
STP	$0.60	$0.76	$0.69
TAL	$0.39	$0.40	$0.37
TECO	$0.64	$0.77	$0.71
FRCC	**$0.87**	**$0.99**	**$0.94**

Figure DMN-32: FRCC Price Depressions with Both Leesburg and Midway

	Overall		
	2003	2007	2012
ANDY	$1.96	$2.33	$2.36
APO	$2.36	$2.67	$2.69
CRCF	$1.66	$2.02	$2.03
DEL	$1.64	$1.97	$1.94
DUV	$1.06	$1.44	$1.41
FPLE	$2.03	$2.41	$2.43
FPLW	$1.63	$2.05	$2.08
GVL	$1.14	$1.54	$1.51
JEA	$0.98	$1.27	$1.20
LAK	$1.51	$1.89	$1.89
LKW	$1.60	$2.07	$2.09
MIA	$2.08	$2.47	$2.50
MRT	$1.99	$2.33	$2.35
OCA	$1.59	$2.02	$2.03
OUC	$1.77	$2.10	$2.11
PNT	$1.39	$1.82	$1.79
STP	$1.65	$2.07	$2.07
TAL	$0.86	$0.98	$0.97
TECO	$1.54	$1.94	$1.94
FRCC	**$1.69**	**$2.06**	**$2.06**

Figure DMN-33: Average Price by Month in 2003 Across All FRCC Regions—NL/NM Case

BASE	01_001%	02_003%	03_005%	04_015%	05_035%	06_060%	07_080%	08_090%	09_098%	10_100%
JAN	$46.11	$40.38	$39.39	$37.68	$34.21	$28.38	$23.75	$22.05	$20.87	$19.20
FEB	$45.94	$39.91	$38.66	$36.75	$31.84	$26.45	$22.91	$21.79	$20.54	$19.01
MAR	$38.34	$36.34	$34.78	$32.24	$29.84	$24.28	$22.45	$21.32	$20.15	$19.20
APR	$37.70	$36.03	$35.15	$32.72	$30.54	$25.79	$22.38	$21.30	$20.69	$19.63
MAY	$52.47	$45.19	$41.55	$38.41	$36.15	$30.81	$23.29	$22.09	$21.59	$20.94
JUN	$96.06	$67.15	$59.22	$53.08	$41.34	$36.40	$27.07	$22.81	$22.20	$21.66
JUL	$244.45	$98.02	$72.84	$60.46	$50.14	$39.01	$30.51	$24.67	$22.79	$22.10
AUG	$249.31	$91.80	$72.25	$60.92	$49.92	$38.88	$30.31	$24.90	$23.09	$22.19
SEP	$73.54	$57.77	$54.52	$48.25	$39.62	$35.11	$25.66	$22.77	$22.26	$21.82
OCT	$41.75	$38.45	$37.58	$36.45	$33.84	$29.40	$23.00	$21.97	$21.46	$20.79
NOV	$41.70	$39.03	$37.33	$35.19	$31.12	$25.95	$22.64	$21.60	$21.00	$19.98
DEC	$43.79	$40.45	$39.37	$37.91	$33.91	$29.56	$24.75	$22.49	$21.33	$19.25

Figure DMN-34: Average Price by Month in 2003 Across All FRCC Regions—L/NM Case

LEESBURG	01_001%	02_003%	03_005%	04_015%	05_035%	06_060%	07_080%	08_090%	09_098%	10_100%
JAN	$43.63	$39.93	$39.03	$37.08	$33.16	$27.11	$23.67	$22.04	$20.88	$19.20
FEB	$43.60	$39.45	$38.30	$36.08	$31.10	$25.82	$22.92	$21.79	$20.58	$19.01
MAR	$37.98	$35.78	$33.55	$31.45	$28.58	$24.11	$22.45	$21.32	$20.15	$19.20
APR	$37.33	$35.56	$34.31	$31.90	$29.68	$25.16	$22.38	$21.27	$20.68	$19.63
MAY	$50.85	$43.47	$40.43	$37.99	$35.68	$30.12	$23.20	$22.09	$21.59	$20.94
JUN	$83.95	$64.67	$56.33	$50.74	$40.70	$35.86	$26.12	$22.77	$22.20	$21.66
JUL	$239.61	$89.70	$71.10	$58.48	$48.63	$38.59	$29.05	$24.38	$22.78	$22.10
AUG	$243.61	$83.79	$70.44	$58.45	$48.38	$38.44	$28.79	$24.57	$23.03	$22.19
SEP	$71.18	$56.07	$53.15	$46.14	$39.11	$34.17	$25.11	$22.74	$22.26	$21.82
OCT	$40.19	$38.03	$37.21	$35.99	$32.74	$28.28	$22.93	$22.00	$21.47	$20.79
NOV	$40.95	$38.57	$36.94	$34.03	$30.36	$25.19	$22.62	$21.61	$21.00	$19.97
DEC	$42.29	$40.00	$39.00	$37.39	$33.00	$28.13	$24.45	$22.50	$21.33	$19.25

Figure DMN-35: Average Price by Month in 2003 Across All FRCC Regions—NL/M Case

MIDWAY	01_001%	02_003%	03_005%	04_015%	05_035%	06_060%	07_080%	08_090%	09_098%	10_100%
JAN	$43.13	$39.65	$38.85	$37.26	$33.58	$27.10	$23.59	$22.04	$20.88	$19.20
FEB	$43.13	$39.13	$38.15	$36.38	$31.25	$25.52	$22.86	$21.79	$20.54	$19.01
MAR	$37.83	$35.92	$34.09	$31.62	$28.65	$23.99	$22.43	$21.32	$20.15	$19.20
APR	$37.26	$35.65	$34.73	$32.20	$29.62	$24.71	$22.34	$21.27	$20.67	$19.63
MAY	$50.73	$43.49	$40.18	$37.92	$35.78	$30.11	$23.13	$22.07	$21.59	$20.94
JUN	$84.61	$63.74	$56.43	$50.62	$40.42	$35.97	$26.11	$22.71	$22.17	$21.66
JUL	$240.39	$88.14	$69.83	$58.33	$47.66	$38.14	$29.32	$24.13	$22.67	$22.08
AUG	$245.41	$83.45	$69.82	$58.59	$47.54	$38.06	$28.79	$24.30	$22.95	$22.17
SEP	$70.84	$56.32	$53.20	$46.05	$38.71	$34.67	$24.68	$22.66	$22.23	$21.82
OCT	$40.06	$37.90	$37.15	$36.04	$33.15	$28.34	$22.86	$21.96	$21.46	$20.79
NOV	$40.70	$38.33	$36.93	$34.57	$30.33	$24.76	$22.57	$21.61	$21.00	$19.97
DEC	$41.91	$39.65	$38.88	$37.43	$33.35	$28.39	$24.31	$22.49	$21.32	$19.25

Figure DMN-36: Average Price by Month in 2003 Across All FRCC Regions—L/M Case

BOTH	01_001%	02_003%	03_005%	04_015%	05_035%	06_060%	07_080%	08_090%	09_098%	10_100%
JAN	$41.87	$39.28	$38.47	$36.66	$32.47	$26.31	$23.54	$22.04	$20.88	$19.20
FEB	$41.51	$38.75	$37.75	$35.65	$30.07	$25.07	$22.85	$21.79	$20.54	$19.01
MAR	$37.48	$35.38	$32.92	$30.85	$26.83	$23.84	$22.43	$21.32	$20.15	$19.20
APR	$36.89	$35.15	$33.64	$31.42	$28.50	$24.32	$22.34	$21.27	$20.67	$19.63
MAY	$48.86	$41.75	$39.57	$37.56	$35.30	$29.09	$23.06	$22.07	$21.59	$20.94
JUN	$78.46	$59.65	$53.89	$48.83	$39.92	$35.42	$25.51	$22.68	$22.17	$21.66
JUL	$235.06	$80.07	$67.65	$56.56	$46.11	$37.78	$27.56	$23.90	$22.64	$22.08
AUG	$240.57	$77.42	$67.45	$56.44	$45.96	$37.70	$27.40	$24.08	$22.89	$22.17
SEP	$68.45	$54.49	$51.42	$42.69	$38.28	$33.47	$24.37	$22.63	$22.23	$21.82
OCT	$39.46	$37.52	$36.76	$35.59	$32.14	$27.15	$22.81	$21.96	$21.47	$20.79
NOV	$40.20	$37.98	$36.51	$33.45	$29.17	$24.43	$22.57	$21.60	$21.01	$19.97
DEC	$41.13	$39.27	$38.47	$36.92	$32.38	$27.14	$24.14	$22.49	$21.33	$19.25

Figure DMN-37: Year 2003 Leesburg-Induced Price Depressions Without Midway

2003	Leesburg without Midway									
	01_001%	02_003%	03_005%	04_015%	05_035%	06_060%	07_080%	08_090%	09_098%	10_100%
JAN	-$2.49	-$0.45	-$0.36	-$0.60	-$1.05	-$1.27	-$0.08	$0.00	$0.00	$0.00
FEB	-$2.33	-$0.45	-$0.35	-$0.67	-$0.75	-$0.63	$0.01	$0.01	$0.03	$0.00
MAR	-$0.36	-$0.56	-$1.23	-$0.79	-$1.26	-$0.17	$0.00	$0.01	$0.00	$0.00
APR	-$0.37	-$0.47	-$0.83	-$0.82	-$0.86	-$0.63	$0.00	-$0.03	-$0.01	$0.00
MAY	-$1.62	-$1.72	-$1.12	-$0.41	-$0.47	-$0.69	-$0.08	$0.00	$0.00	$0.00
JUN	-$12.11	-$2.49	-$2.89	-$2.34	-$0.64	-$0.54	-$0.95	-$0.04	$0.00	$0.00
JUL	-$4.84	-$8.31	-$1.74	-$1.98	-$1.51	-$0.42	-$1.46	-$0.29	-$0.01	$0.00
AUG	-$5.70	-$8.01	-$1.81	-$2.47	-$1.54	-$0.45	-$1.53	-$0.32	-$0.06	$0.00
SEP	-$2.36	-$1.70	-$1.36	-$2.12	-$0.50	-$0.95	-$0.56	-$0.03	$0.00	$0.00
OCT	-$1.56	-$0.42	-$0.38	-$0.46	-$1.10	-$1.12	-$0.07	$0.03	$0.00	$0.00
NOV	-$0.75	-$0.46	-$0.39	-$1.16	-$0.75	-$0.76	-$0.01	$0.00	$0.00	$0.00
DEC	-$1.50	-$0.45	-$0.37	-$0.52	-$0.91	-$1.43	-$0.30	$0.01	$0.00	$0.00

Figure DMN-38: Year 2003 Leesburg-Induced Price Depressions With Midway

2003	Leesburg with Midway									
	01_001%	02_003%	03_005%	04_015%	05_035%	06_060%	07_080%	08_090%	09_098%	10_100%
JAN	-$1.26	-$0.37	-$0.38	-$0.60	-$1.11	-$0.78	-$0.06	$0.00	$0.01	$0.00
FEB	-$1.62	-$0.38	-$0.40	-$0.73	-$1.18	-$0.46	-$0.01	$0.00	$0.00	$0.00
MAR	-$0.35	-$0.54	-$1.17	-$0.77	-$1.82	-$0.15	$0.01	$0.00	$0.00	$0.00
APR	-$0.38	-$0.50	-$1.09	-$0.78	-$1.12	-$0.38	$0.00	$0.00	$0.00	$0.00
MAY	-$1.87	-$1.74	-$0.62	-$0.36	-$0.47	-$1.01	-$0.07	$0.00	$0.01	-$0.01
JUN	-$6.15	-$4.09	-$2.54	-$1.79	-$0.50	-$0.54	-$0.60	-$0.03	$0.00	$0.00
JUL	-$5.33	-$8.08	-$2.17	-$1.77	-$1.55	-$0.36	-$1.76	-$0.23	-$0.03	$0.00
AUG	-$4.84	-$6.03	-$2.37	-$2.15	-$1.59	-$0.36	-$1.39	-$0.22	-$0.05	$0.00
SEP	-$2.39	-$1.83	-$1.77	-$3.36	-$0.44	-$1.20	-$0.31	-$0.03	$0.00	$0.00
OCT	-$0.60	-$0.38	-$0.39	-$0.45	-$1.01	-$1.18	-$0.05	$0.00	$0.00	$0.00
NOV	-$0.50	-$0.35	-$0.42	-$1.12	-$1.16	-$0.32	$0.00	-$0.01	$0.00	$0.00
DEC	-$0.78	-$0.38	-$0.41	-$0.51	-$0.97	-$1.25	-$0.18	$0.00	$0.01	$0.00

Figure DMN-39: Year 2003 Midway-Induced Price Depressions Without Leesburg

2003	Midway without Leesburg									
	01_001%	02_003%	03_005%	04_015%	05_035%	06_060%	07_080%	08_090%	09_098%	10_100%
JAN	-$2.98	-$0.73	-$0.54	-$0.42	-$0.63	-$1.28	-$0.15	$0.00	$0.00	$0.00
FEB	-$2.81	-$0.77	-$0.50	-$0.37	-$0.59	-$0.92	-$0.05	$0.00	-$0.01	$0.00
MAR	-$0.52	-$0.41	-$0.69	-$0.62	-$1.19	-$0.29	-$0.02	$0.00	$0.00	$0.00
APR	-$0.43	-$0.38	-$0.42	-$0.53	-$0.92	-$1.08	-$0.04	-$0.03	-$0.01	$0.00
MAY	-$1.74	-$1.71	-$1.37	-$0.48	-$0.38	-$0.71	-$0.16	-$0.01	$0.00	$0.01
JUN	-$11.45	-$3.42	-$2.80	-$2.46	-$0.91	-$0.43	-$0.96	-$0.10	-$0.03	$0.00
JUL	-$4.06	-$9.87	-$3.01	-$2.13	-$2.48	-$0.87	-$1.19	-$0.54	-$0.12	-$0.02
AUG	-$3.90	-$8.35	-$2.43	-$2.33	-$2.37	-$0.82	-$1.53	-$0.60	-$0.15	-$0.02
SEP	-$2.70	-$1.45	-$1.32	-$2.20	-$0.90	-$0.45	-$0.99	-$0.11	-$0.03	$0.00
OCT	-$1.68	-$0.55	-$0.43	-$0.41	-$0.69	-$1.06	-$0.14	-$0.01	$0.00	$0.00
NOV	-$1.00	-$0.70	-$0.40	-$0.62	-$0.79	-$1.19	-$0.07	$0.01	$0.00	$0.00
DEC	-$1.88	-$0.80	-$0.49	-$0.48	-$0.55	-$1.18	-$0.44	$0.00	-$0.01	$0.00

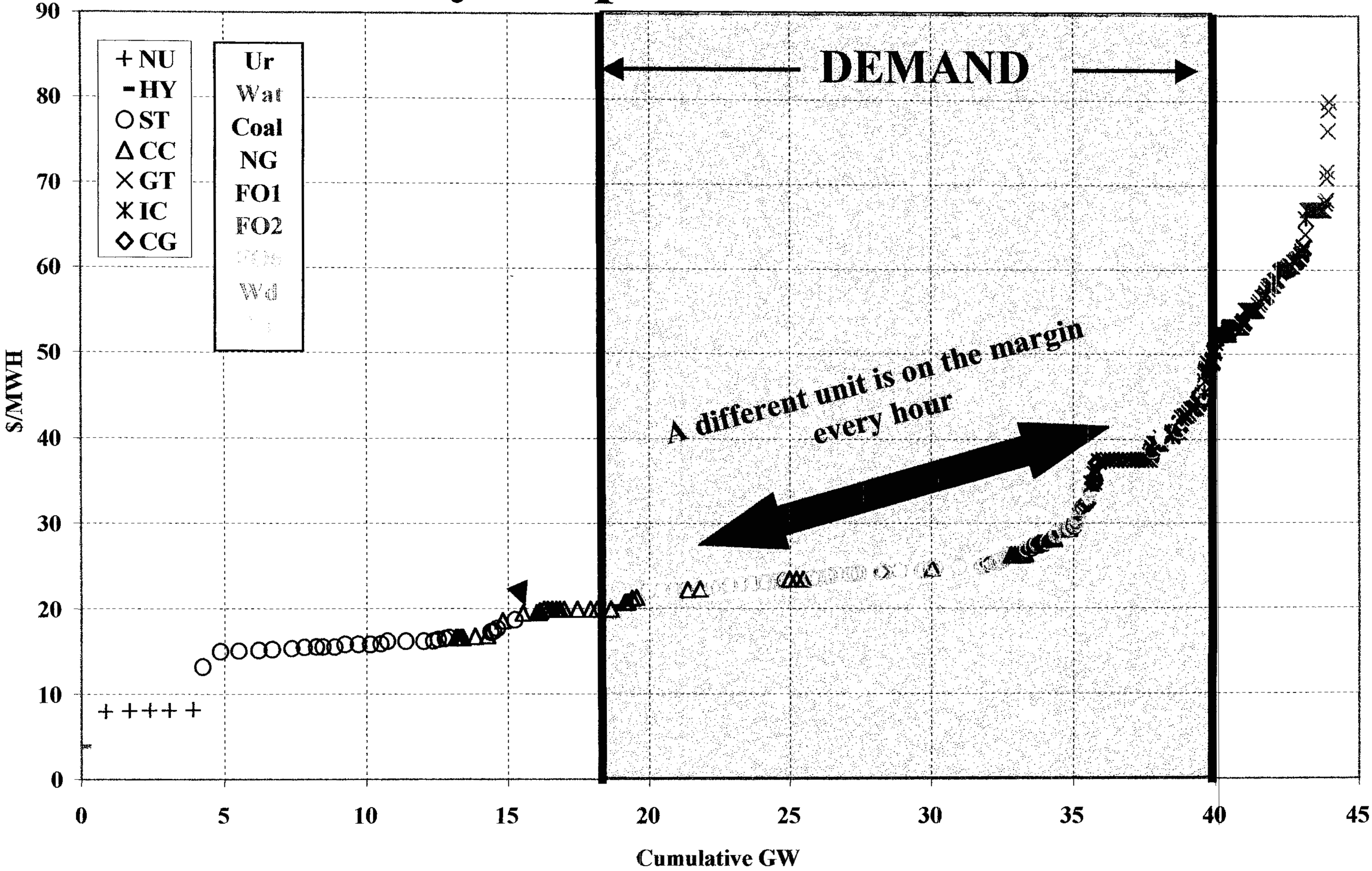
Figure DMN-40: Year 2003 Midway-Induced Price Depressions With Leesburg

2003	Midway with Leesburg									
	01_001%	02_003%	03_005%	04_015%	05_035%	06_060%	07_080%	08_090%	09_098%	10_100%
JAN	-$1.75	-$0.65	-$0.55	-$0.42	-$0.69	-$0.80	-$0.13	$0.00	$0.01	$0.00
FEB	-$2.09	-$0.70	-$0.56	-$0.43	-$1.02	-$0.75	-$0.07	-$0.01	-$0.04	$0.00
MAR	-$0.50	-$0.40	-$0.63	-$0.60	-$1.75	-$0.26	-$0.02	$0.00	$0.00	$0.00
APR	-$0.44	-$0.41	-$0.67	-$0.48	-$1.19	-$0.83	-$0.04	$0.01	$0.00	$0.00
MAY	-$1.99	-$1.73	-$0.86	-$0.43	-$0.38	-$1.03	-$0.15	-$0.01	$0.01	$0.00
JUN	-$5.49	-$5.02	-$2.44	-$1.90	-$0.77	-$0.44	-$0.61	-$0.09	-$0.03	$0.00
JUL	-$4.55	-$9.64	-$3.44	-$1.92	-$2.51	-$0.81	-$1.49	-$0.48	-$0.14	-$0.02
AUG	-$3.04	-$6.38	-$3.00	-$2.01	-$2.42	-$0.73	-$1.39	-$0.49	-$0.14	-$0.02
SEP	-$2.74	-$1.57	-$1.73	-$3.44	-$0.83	-$0.70	-$0.74	-$0.11	-$0.03	$0.00
OCT	-$0.72	-$0.51	-$0.44	-$0.40	-$0.59	-$1.13	-$0.12	-$0.04	$0.00	$0.00
NOV	-$0.75	-$0.59	-$0.44	-$0.59	-$1.20	-$0.75	-$0.05	$0.00	$0.01	$0.00
DEC	-$1.16	-$0.73	-$0.53	-$0.47	-$0.62	-$0.99	-$0.31	-$0.01	$0.00	$0.00

Figure DMN-41: Year 2003 Price Depressions Induced by Entry of Both Leesburg and Midway

2003	Overall									
	01_001%	02_003%	03_005%	04_015%	05_035%	06_060%	07_080%	08_090%	09_098%	10_100%
JAN	-$4.24	-$1.10	-$0.92	-$1.02	-$1.74	-$2.07	-$0.21	$0.00	$0.01	$0.00
FEB	-$4.42	-$1.15	-$0.91	-$1.10	-$1.77	-$1.38	-$0.06	$0.00	-$0.01	$0.00
MAR	-$0.87	-$0.95	-$1.86	-$1.39	-$3.01	-$0.44	-$0.01	$0.00	$0.00	$0.00
APR	-$0.81	-$0.88	-$1.51	-$1.31	-$2.04	-$1.46	-$0.04	-$0.02	-$0.01	$0.00
MAY	-$3.61	-$3.45	-$1.98	-$0.85	-$0.85	-$1.72	-$0.23	-$0.01	$0.01	$0.00
JUN	-$17.61	-$7.50	-$5.34	-$4.25	-$1.42	-$0.97	-$1.56	-$0.13	-$0.03	$0.00
JUL	-$9.39	-$17.95	-$5.19	-$3.91	-$4.02	-$1.23	-$2.95	-$0.77	-$0.15	-$0.02
AUG	-$8.74	-$14.38	-$4.80	-$4.48	-$3.96	-$1.18	-$2.91	-$0.82	-$0.20	-$0.02
SEP	-$5.10	-$3.27	-$3.10	-$5.56	-$1.34	-$1.65	-$1.30	-$0.14	-$0.03	$0.00
OCT	-$2.29	-$0.93	-$0.82	-$0.86	-$1.70	-$2.24	-$0.19	-$0.01	$0.00	$0.00
NOV	-$1.49	-$1.05	-$0.83	-$1.75	-$1.95	-$1.51	-$0.06	$0.00	$0.00	$0.00
DEC	-$2.66	-$1.18	-$0.90	-$0.99	-$1.53	-$2.42	-$0.61	$0.00	-$0.01	$0.00

Exhibit DMN-42: The Marginal Plant Is Actually a Spectrum of Plants



12 APPENDIX A: DESCRIPTION OF THE NORTH AMERICAN REGIONAL ELECTRICITY (NARE) MODEL

METHODOLOGY AND USE OF THE ALTOS NORTH AMERICAN REGIONAL ELECTRIC (NARE) MODEL

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APPENDIX A

CONTENTS

LIST OF FIGURES

1 INTRODUCTION AND OVERVIEW

Electricity is not the first commodity to be deregulated. It is not even the first commodity to be deregulated by mandatory unbundling of transmission services away from generation (commodity) services. Electricity is at least the third commodity to be deregulated through mandated unbundling. Telecommunications and natural gas before it were subjected to the same type of forced unbundling between transmission service and commodity. Exactly what market changes "unbundling" type of deregulation implies for the future is not as arcane or unpredictable as many would argue. Quite the contrary, disaggregation through forced unbundling subjects electricity markets to precisely the same type of competitive, market, and financial forces to which virtually all other commodities have been subjected for a long time, and it renders the textbook model of economic supply-demand balancing empirically correct and predictive. In building an electricity market model, we have combined solid fundamental economic principles together with lessons of learned from recently completed deregulations to help us guide our model design decisions so that we can support asset and marketing and trading businesses in electric power.

Before describing our North American electric model, there are a few realities of the electric power market as it will unfold in the future that need to be articulated. First and foremost, electric power plants are destined to become entrepreneurial, merchant elements, not regulated items. Regulators will no longer guarantee forced passthrough of fixed costs. It will be necessary to trade and arbitrage all their inputs and all their outputs in order to truly maximize value from those plants. This single change in the regulatory environment subjects electric generation assets to the vagaries of the market and therefore to unprecedented price uncertainty.

Second, it will be necessary to carefully and scrupulously manage both the forward cost to market of generating plants as well as the capacity expansion and retirement decisions related to those plants. Plant costs can no longer go unmanaged; they must be scrupulously and carefully understood, measured, and managed. After all, it will be the difference between sales and cost that will dictate profits, not just "cost plus" as in the old days.

Third, generation owners need accurate and credible forward electricity and fuel price curves in order to manage their asset and trading businesses, more credible and more accurate than their competitors. Portfolio generation companies are in an "arms race" against their large competitors, the company with the best forecast winning out over the worse companies. There is no escape from the need for accurate and credible price anticipation.

Fourth, price risks may or may not need to be managed. Large, diversified portfolio generators might well be able to shoulder regionally diversified market price risk. They may not want to "give away the upside in order to avoid the downside" as required by most risk management instruments. On the other hand, small to medium sized companies will most definitely want to hedge their generation assets using liquid, traded instruments to do so. In either case, risk management is no better than one's perception of the future MEAN or average price. Forecasting the future MEAN is critical to success.

In building the model described herein, we are helping our clients attack the foregoing needs head on. We help our clients manage price expectations better and more accurately than their competitors and act correctly and decisively based on those better price expectations. No matter what one might hear from efficient market or trading gurus, **it is the company with the best price forecast that will win.** Electricity markets will never be sufficiently efficient or complete to allow complete, perfect, frictionless hedging or idealized price discovery. With the paucity of storage and inventorying, electricity will always be volatile and somewhat unpredictable. More so than most other commodities, electricity begs for model-based forward price estimation to complement the imperfect information that will be revealed by markets.

In the discussion to follow, we will put forth the basic structure of our market model and supporting analytical techniques, which we have constructed to assist our clients and their selected partners to develop effective and maximally profitable asset acquisition, marketing, and trading activities. We should emphasize that our modeling system guides decisions related to both physical assets and trading instruments. After all, trading instruments (options, swaps, structured deals, etc.) are fundamentally no different from physical assets. Like physical assets, trading instruments make money based on price differences in the market. In the discussion to follow, we will use the word "asset" to describe physical plants, projects, existing capacity, or financial instruments that are the subject of arbitrage and trading. This document outlines the design of our North American multiregional electricity model and its supporting data base.

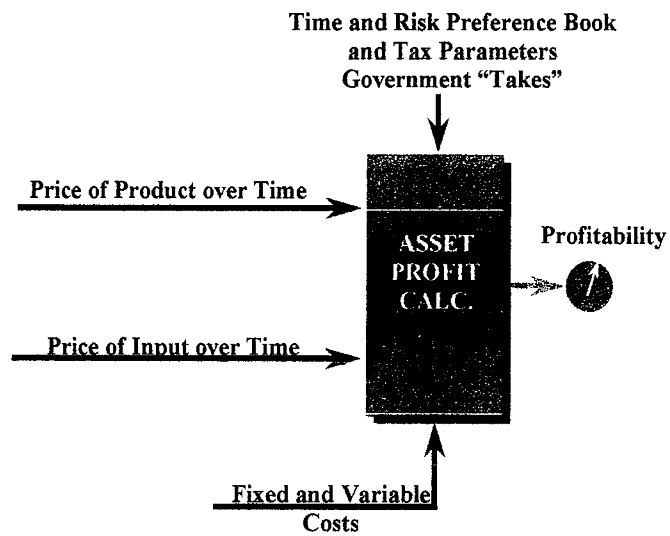
We should mention that the method of valuation presented here focuses primarily on what we term the intrinsic, deterministic value of the asset. The discussion here is based on the notion of valuing the asset based on a cogent and correct but deterministic set of forward prices. In a companion paper, we have developed a method to extend the intrinsic valuation procedure described here to calculate the full probabilistic value of an asset or a portfolio of assets, i.e., the full option value of the asset plus the deterministic, intrinsic value. The companion paper is based on the idea of using the deterministic value presented here as the MEAN of the forward probability distribution over forward price and augmenting it with a sophisticated Markov model of forward price volatility, mean regression, and serial correlation.

2 MEASURING ASSET PROFITABILITY

2.1 One Individual Asset

Evaluation of asset profitability typically begins with a discounted cash flow (DCF) or similar method configured as shown in Figure 1. Into the asset profitability calculator shown in the figure we put the fixed and variable costs of the asset (bottom); the corporate book and tax parameters (top); the corporate time and risk parameters (usually a hurdle rate) designated at the top; the "government takes" or other government royalty, lease bidding, production sharing, or other levies at the top; and projections of the price of the products[1] and the price of the inputs (left). The asset profitability calculator then creates one or more measures of corporate profitability, indicated by the "meter" at the right. Sometimes asset profitability calculators contain detail on asset operations, and other times they are simple, passive DCF calculations implemented on a spreadsheet.

Figure 1: Evaluation of Asset Profitability



Invariably, when evaluating an asset, the profitability calculator is run through a series of sensitivity ("What if?") cases. Costs are varied, prices are varied, book and tax parameters are varied, corporate measures of time and risk are varied, and the calculator is put through its paces. Not surprisingly, what people find as a result of such sensitivity analysis is this:

[1] In electric power applications, the problem is more complicated than this simple characterization. The price of the product varies continuously, and the plant must be turned on and off or ramped upward or downward to capture revenues or avoid losses. The revenues captured when the plant is on are related to the market price. The discussions in this paper assume that the plant is turned on and off so as to best capture margins.

- the **DIFFERENCE** between the price of the product and the price of the input is the most important variable affecting asset profitability. Every asset is in effect playing a "basis differential game," being "long" on product and "short" on input. This is fundamental; assets are always long with regard to their product and short with regard to their inputs. Assets are the quintessential "swaps."

- this **PRICE DIFFERENCE** is the least understood of all the inputs, and companies have precious little reliable information upon which to base their estimate of this price difference.

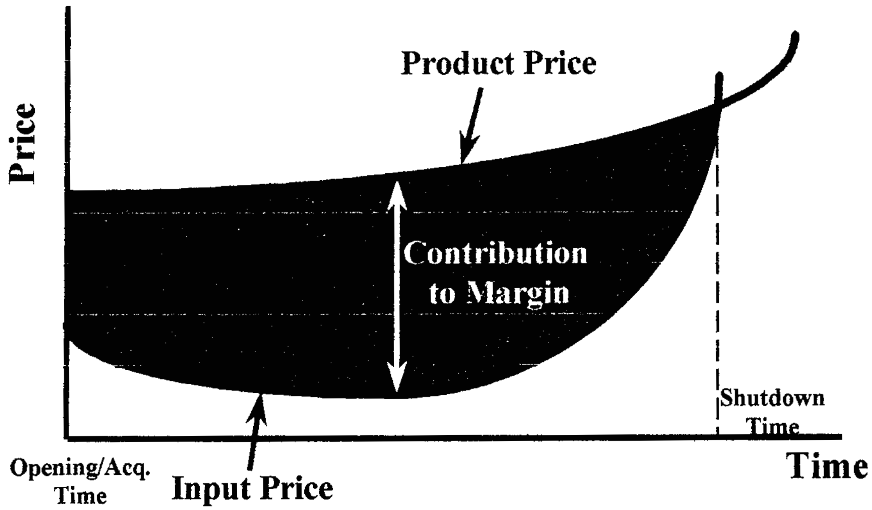
We emphasize the pivotal importance of the price differential across the asset, which we draw conceptually as in Figure 2. Suppose we knew the product price forward into the future beginning at the time at which we initiate possession of the asset (indicated as the product price curve in the figure) and we knew the prices forward into the future of the input factors (indicated as the forward cost curve in the figure). Using that information, we could easily subtract the forward cost from the product price to calculate the contribution to margin from the asset at each point in its future life. This contribution to margin is the contribution to corporate profitability attributable to the asset in each forward year of its life. If we know the contribution to margin in each forward year of the asset's life, we in effect know the shaded area in the figure, and we can calculate the discounted present value of that shaded area as of the time we take possession of the asset. By so doing, we are in effect calculating the discounted present value of the shaded area in the figure, and we interpret this as the present value of the future yield to the company that is specifically attributable to the asset. It is the contribution today to corporate wealth that is attributable to the future yield on the asset.

The discounted present value of the future margin generated by the asset is the contribution to corporate wealth today represented by the asset. If we already own the asset, it represents the intrinsic value of the asset to the corporation. If we are considering acquiring the asset, it is the benchmark against which we must compare the cost to acquire the asset. If the cost to acquire the asset exceeds the net present future value of the asset, one does not want to acquire the asset. If the cost to acquire the asset is lower than the net present future value of the asset, one will want to consider acquiring it. (Whether we actually acquire it depends on our capital budgeting process, which compares all potential business ventures whose acquisition costs are lower than the present value of future returns and picks the best.) Once we know the discounted present value of the shaded area in Figure 2, the decision to acquire the asset is simple—just compare the acquisition cost against the future yield.

Two critically important insights emerge from Figure 2. First, **one cannot escape the need to project forward prices for the products of and the inputs to each and every asset it owns, each and every asset it considers owning, and each and every**

asset it considers selling. There is no escape from the need to predict forward prices more accurately and more correctly than one's competitors. The company that makes the better forward price projections wins (statistically speaking) because it has more accurate knowledge of the values of its assets. The company that makes the poorer forward price projections loses (statistically speaking) because other people identify and take the best opportunities first.

Figure 2: Price Differential Across the Asset Is the Most Important Determinant of Value



Second, **not only is the problem of projecting forward prices critically important to the asset business, so is the problem of projecting forward asset operating costs**. To wit, the bottom curve in Figure 2 is just as important as the top curve in understanding asset profitability. It is the DIFFERENCE between the curves that matters. It is incumbent upon us to understand and anticipate forward cost to market of each and every asset it owns. It is critically important to understand, measure, and project the cost structure of our evolving asset business. We will return to this theme shortly, articulating how we have approached the cost side of the problem. Before doing so, we will continue discussing the revenue side, i.e., the market side.

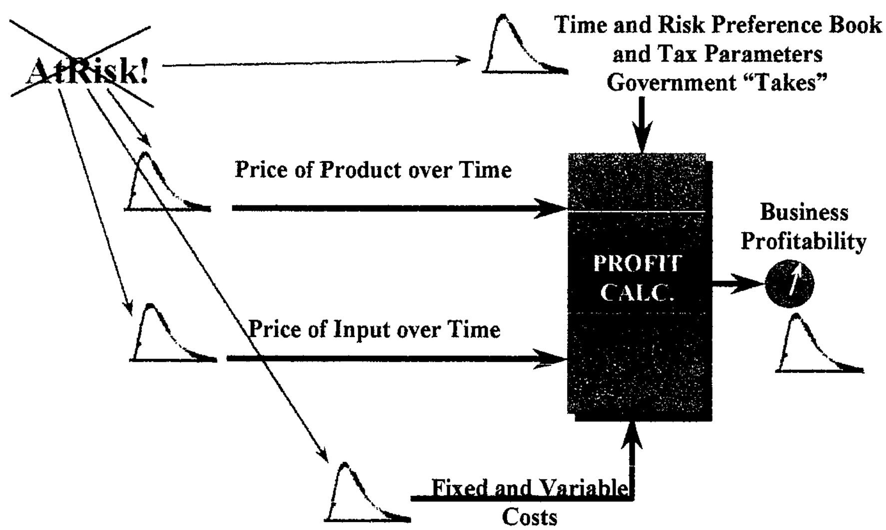
2.2 Individual Asset Risk

In light of the central importance of the price difference across the asset, companies sometimes reason: "We don't really know what the price difference will be, so let's just put in probability distributions for the critical forward variables. Let's put in probability distributions over plant costs. Let's put in probability distributions over book and tax parameters. Let's put in probability distributions over prices or price differences.

This will allow us to calculate a probability distribution over asset profitability. We can use this probability distribution to assess the risk-return nature of the asset. This will give us the right answer."

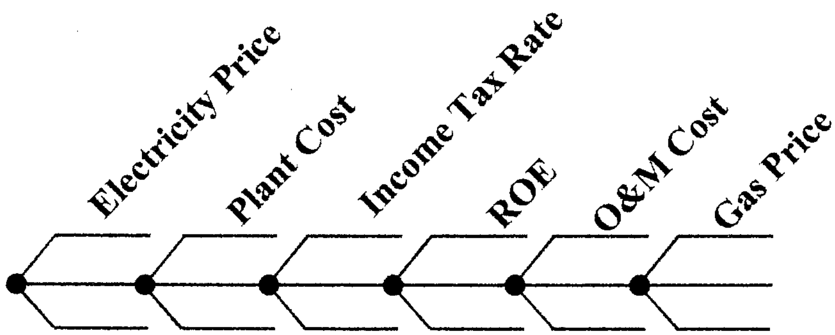
Such a probability approach, often implemented as a "Monte Carlo" simulation, decision tree, influence diagram, or At Risk! Excel add-in, is illustrated in Figure 3. Notice in the figure that probability distributions are placed onto all the input arrows to the profitability calculator. The probability calculator then calculates the probability distribution over profitability from the independent probability distributions over each of the inputs. This procedure is literally fraught with conceptual and practical difficulties, but many managers feel mighty comfortable because they are taking account of uncertainty. Yet the process is usually badly flawed.

Figure 3: You Could Put Probabilities Into Your Profit Calculator...



How do people typically implement such a calculation, and why do they get into trouble? They begin by estimating independent probability distributions over each of the individual inputs to the profitability calculator. They then enumerate all possible combinations of settings for all the input variables using probability trees as shown in Figure 4, calculate the probability of each combination of variables, and thereafter run the profitability calculator once for each combination. In this way, they obtain what they interpret as a probability distribution over asset profitability (which we call a profit lottery) as shown in Figure 5. The probability distribution over profitability in Figure 5 depicts the expected profitability of the asset (shown to be slightly positive in the figure), the standard deviation (shown to be rather wide in the figure), the "skewness" of the probability distribution (in the figure, the distribution is stacked toward the left hand or low profitability side, and in fact higher order properties. Parenthetically, in our experience, Figure 5 is typical of individual assets: a high probability of low or negative profits but a "long positive tail," representing the remote possibility of a "home run."

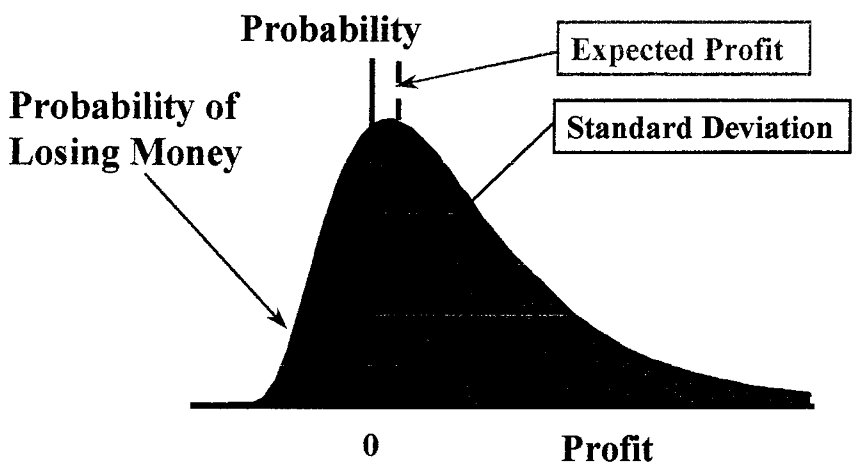
Figure 4: And Then Run Out a Series of Probability-Weighted Scenarios...



3^6 combinations (=3^6 calculations) 3^6 probabilities

While the approach of estimating probability distributions over asset profitability parameters seems intuitively appealing and correct, it misses the boat in the most important dimension. It does not take into account whether the asset under consideration is correlated or uncorrelated with the rest of one's business or with the rest of the market. It does not consider whether the asset is in point of fact simply one more small addition to the selfsame large lottery the business is already playing, i.e., whether the asset is tightly correlated with the rest of one's business and therefore offers limited diversification benefits. Conversely, it does not consider whether the asset brings new and independent elements of uncertainty to one's asset portfolio and therefore offers systematic diversification advantages. It does not consider whether the asset is anticorrelated with the rest of one's portfolio and therefore offers valuable hedging and risk mitigation possibilities. It simply ignores altogether how the asset fits into one's overall asset portfolio and whether it renders the portfolio better or worse. To illustrate with a simple example, the profitability of a new oil well anywhere in the world is directly and positively correlated with the profitability of every other oil well everywhere else in the world. A new oil well does not diversify risk; it is simply adds to an already large oil price lottery. World oil price strongly ties oil wells' profitabilities together. Is this true of electric generation assets, which can occur in highly Balkanized markets separated by high transmission costs, or is electric generation an intrinsically coupled and correlated business that has the same risks as the oil business? Prospective and current generation owners surely need to understand this.

Figure 5: ...Ending With a Probability Distribution Over Project Profitability



The difficult part of managing one's business portfolio is to ensure that the assets in the portfolio are mutually complementary and that their returns are not completely correlated, i.e., that asset profitabilities are not completely contingent on the exact same set of events. We need to be sure that each of the assets in one's portfolio is at least partially independent of the other assets. One needs to be sure that with each new asset we are not simply buying a bigger and bigger piece of the same old lottery unless we are absolutely convinced that each incremental piece offers increasingly attractive returns to compensate for the increasing portfolio risk. (Unfortunately, in the real world, each additional asset tends to offer decreasingly attractive expected returns rather than increasingly attractive prospects. Diminishing marginal returns is an immutable rule of business and economic life.) If one does not manage the correlation characteristics of his asset portfolio, the volatility of his share price will be increased, the price of his stock will not appreciate as rapidly, dividends will not accrue as rapidly, his credit rating will not be as high and his cost of capital will suffer, and his stock's "beta" will be higher than it should be.

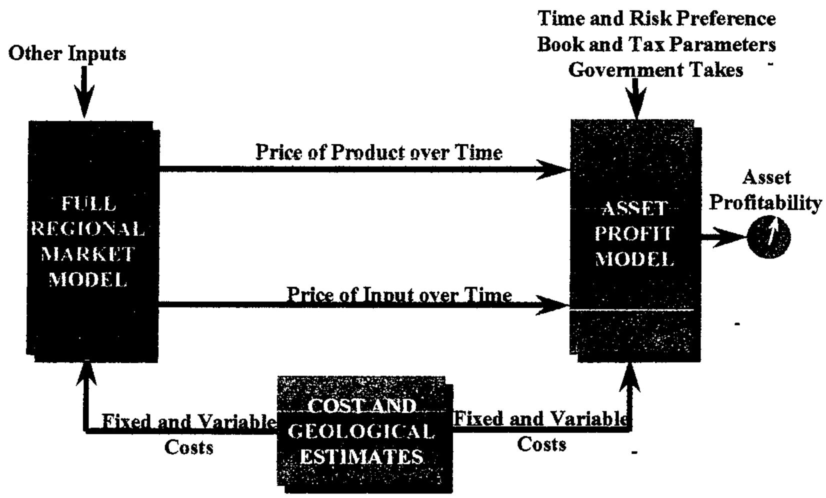
Our approach systematically and structurally takes account of the important correlating as well as uncorrelating forces across your portfolio. While our technique, like many others, is able to evaluate the average profitability of each individual asset, it is able to quantify the correlating and uncorrelating forces and thereby give a true representation of the risk-return nature of your asset portfolio. It does not deceive you into thinking that the value of your portfolio is merely the sum of the average returns of each business activity that comprises it. It recognizes the reality that with assets "2 + 2 is not necessarily equal to 4." Indeed, with our correct correlation mathematics, "2 + 2 equals 5 for sufficiently large values of 2 and 2 + 2 equals 3.5 for sufficiently small values of 2!" Portfolio mathematics is critical to the success of any company who owns any assets at all, paper or physical assets.

2.3 A Market-Based Approach To Asset Valuation

How do we approach the problem of valuing individual assets and portfolios of business assets? The answer is illustrated in Figure 6, a critically important extension of the simple asset calculation in Figure 1. In Figure 6, we make the identical asset profitability calculation as in Figure 1. However, we generate consistent projections of prices of products and inputs using a **full multi-regional market model** as shown at the left. Inputs to the full multi-regional market model are indicated at the bottom of the diagram. They include the full forward cost to market estimates including all variable and fixed costs for all existing and prospective plants and assets in the market, including not only the particular asset being analyzed (indicated at the right) but also all assets that compete with or complement the particular asset being analyzed. By assembling a market-wide asset data base and delivering it to a full multi-regional market model, we ensure that the price calculations indicated in Figure 2 take proper and consistent account of one single collection of technology cost and performance estimates. That is, the price calculations are fundamentally determined by a common and correct set of estimates of all plants in the market, including their forward costs to market (i.e., variable costs and nonsunk fixed costs), all plants that might prospectively enter the market including their full capital and operating costs over their lifetimes, and all plants that might be driven from the market by stronger competitors. By including all capacity currently in place and all capacity that might prospectively enter or exit the market, the price calculation in the full multi-regional market model is able to account for all correlations between plants, technologies, processes, and fuels. The multi-regional market model does not go awry by failing to account for common technologies and processes employed in similar ways everywhere in the market. It does not miss the "zero sum" nature of competitive markets in which similar assets positioned in geographically disparate locations must compete for common markets, winner take all. It does not therefore miss the fact that the electricity market is structurally interconnected and intertwined. It protects our customers from making egregious valuation mistakes and overpaying for assets.

By introducing a structural representation of the market, we are able not only to forecast forward prices on a structural basis but also to systematically correlate the various prices in our markets: electricity versus gas prices, electricity versus coal prices, coal versus gas prices, regional price differences at the wellhead and the busbar, etc. We are also able to calculate the structural relationships between prices at different locations and prices at different points in time. By so doing, the vagaries and naiveté's otherwise involved in direct subjective estimation of prices and price correlations are eliminated. The interrelationships among the assets in our portfolio are properly calculated, and the risk-return nature of our portfolio is properly quantified. Most importantly, we are able to systematically understand and predict the **PRICE DIFFERENTIALS** between products and inputs that dictate the profitability of our assets.

Figure 6: Melding Full Regional Market Model with Profitability Calculator

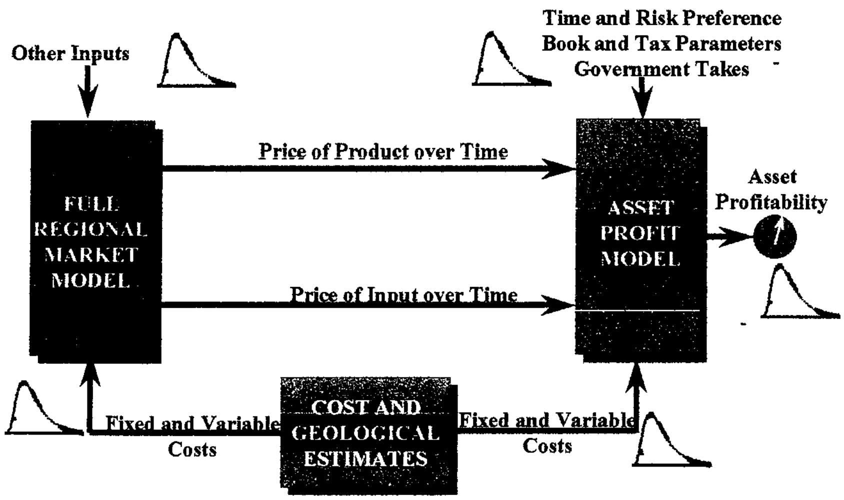


Why are such structural correlations important? The reason, quite succinctly, is that the profitability of an electric power plant is a function of the "spark spread" across that plant, defined in the vernacular as the price differential between electricity and the fuel (e.g., natural gas). Would-be asset owners need to know not only what the spark spread will be but also what variables will affect it. Will higher gas prices widen or narrow the spark spread, or will electricity price rise right along with gas price? If the latter is true, the profitability of the asset is insensitive to gas price. If the profitability is sensitive to gas price, a gas price hedge strategy might ameliorate asset ownership risk. However, if the profitability is insensitive to gas price (i.e., electricity price moves right along with gas price), a gas price hedge strategy would be futile. Rather than being the hedge you thought it was, it is pure speculation. Needlessly adding speculation when you thought you were adding hedging devalues one's company and debilitates financial performance.

2.4 Market-Based Approach To Asset Portfolio Risk

To add the dimension of uncertainty to our market-based approach is straightforward. In order to evaluate the true riskiness of each asset in our portfolio, all we need to do is postulate probability distributions over the critical inputs to Figure 7 rather than to Figure 1: (1.) Technology cost and performance estimates, (2.) Inputs to the market model, and (3.) Corporate book and tax parameters. The procedure surrounding Figures A-4 and A-5 can be directly extended to the larger and more comprehensive market modeling context, as Figure 7 summarizes. After inputting such information into Figure 7, our system can calculate a probability distribution over the true profitability of the asset, taking full and explicit account of the correlations between the asset, the rest of one's portfolio, and the market as a whole. Such an approach does not miss the critical correlations between plant and technology cost and performance estimates, market prices, and asset profitability. It gets the inter-asset correlations right and ensures that one is properly measuring the variance as well as the expected return in his overall portfolio. It shelters the asset owner from mistakenly and imprudently buying a hedging instrument he or she does not need and thereby worsening rather than improving risk.

Figure 7: We Do Risk-Return Valuation in a Full Market Context



3 STRUCTURE OF THE FULL REGIONAL MARKET MODEL TO PROJECT PRICES AND PRICE DIFFERENCES

Having identified the need to understand prices and price differentials in order to guide our asset strategy, we are faced with the prospect of building a model to assist us in doing so. As we approach the problem of building such a model, we must recognize a few fundamental facts. First, the price differential across an asset is determined by the market. It is not determined by the cost of the individual asset being analyzed. In the coming deregulated electricity world, the price differential will no longer be determined by rate base formulas through which fixed as well as variable costs can be imposed by companies downstream on electric customers with regulatory complicity. It will not be determined by system lambdas, which reflect the fact that fixed costs were imposed on customers completely apart from energy sales. To be valid, our market model must represent the market at large, not just the individual asset being valued. It must include all assets presently in place combined with all assets that might be built combined with all assets to be retired, and it must consider how those assets jointly and mutually dictate future prices and profits. In the real world, prices are formed from the AGGREGATE of all assets in place, not any individual asset. The premium is on proper representation of the aggregate collection of assets, not on any individual asset.

Second, the price differential across any asset depends on fuel price, heat rate curve (from which we calculate fuel cost), variable cost, operating and maintenance cost, wheeling cost and radius, new equipment installations, future cost evolution, demand variation, and a plethora of economic and cost considerations. Clearly the box in Figures A-6 and A-7 entitled "Cost and Performance Estimates" must be addressed comprehensively. Later sections in this document outline the difficult problem of assembling the necessary cost and performance estimates for every existing plant in the system and every prospective future plant in the system as we have approached it.

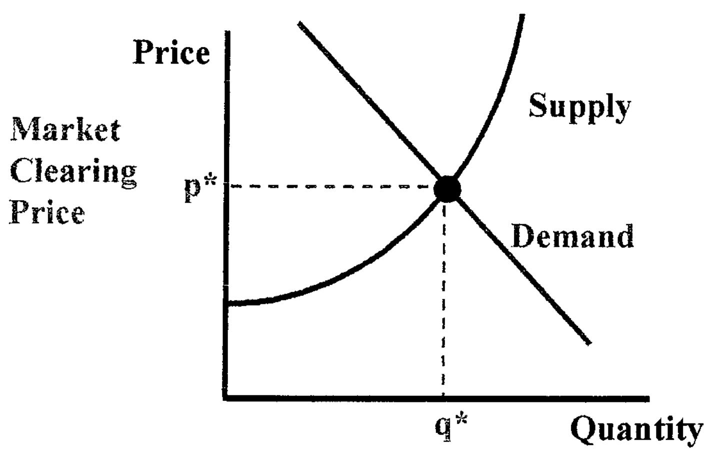
Third, and extremely important, future prices and price differentials cannot be discerned from market observations. For commodities such as electricity, there are simply no spot or futures markets to observe and therefore no market observations to be made. Energy markets are so distorted by fixed cost passthroughs external to those markets that energy prices do not represent the intrinsic cost structure of the industry nor the intrinsic value of the commodity. Even after some semblance of spot and forward markets emerge, they are likely to be so lightly traded (so "thin") that they will provide only the most rudimentary price information but will not support sale or purchase of commodity. What good is observation of a price that will not sustain sale or purchase? It is at best a gross indicator of general market trends, an academic nicety.

Clearly what we need to support our marketing, trading, and asset acquisition and divestiture decisions is a forward projection of electricity, gas, coal, and oil prices that truly represents what those commodities will sell for over the life of the asset. We do not want an academic or hypothetical projection or incomplete market observation, we want a projection of what the actual, real, concrete, palpable market will sustain. Because we cannot look to securities and commodities that trade in broad exchange markets for guidance, what technique should we use? The answer is that we should use "high technology," i.e., state-of-the-art, quantitative economic science, to help us represent what is likely to happen as the future electricity market opens for competition. Economic science, which is becoming and will continue to become increasingly pertinent, is from our perspective represented in Figure 8.

If we want to understand and predict present and forward electricity prices, we must quantify the supply curve for electricity, the demand curve for electricity, and (not shown) the transmission grid that interconnects supply with demand. We must extend and extrapolate the simple supply-demand curve pair in the diagram to consider every region of North America and every future time point in sufficient detail so that the consequent projections of prices are sensible and complete. This is the challenge that faces us and that we have met in building our model. The remainder of this document will briefly describe the process by which we quantified and integrated the electricity supply situation, the transmission situation, and the demand situation and thereby built our Multiregion North American Electric model. We reiterate that our overriding purpose is to provide accurate and credible projections of future electricity and fuel prices with which to conduct the evaluations summarized above.

Figure 8: After Deregulation Here Is How the World Will Work

The fundamental economics of supply and demand

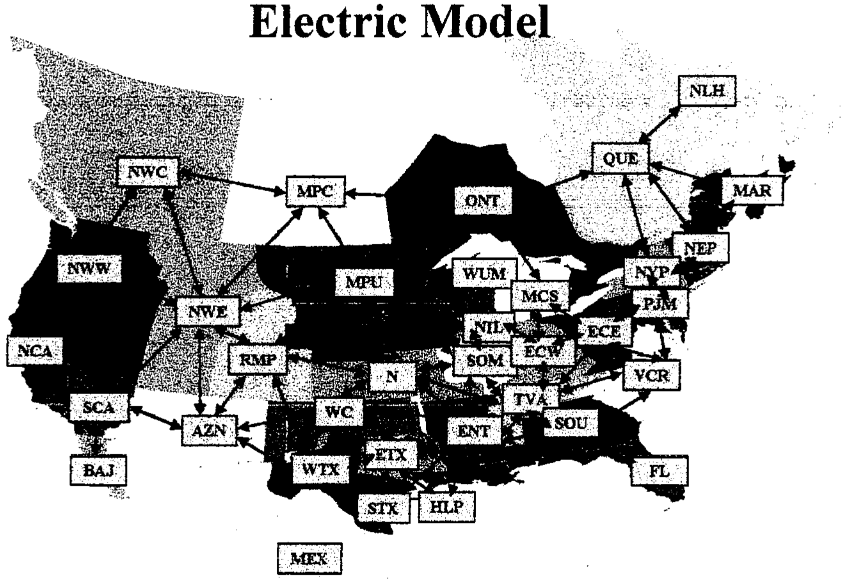


3.1 Representation of Electricity Supply

3.1.1 Regionalization

The first step in constructing our model was to regionalize the generation, transmission, and demand regions of the North American electric and fuel markets. Figure 9 provides a schematic representation of the regionalization used. In building our model, we wanted to retain sufficient regional detail so that we could properly represent the capital stocks of generation capacity and fuel supply in each region as distinct from every other region. However, we did not want the model to become so large and unwieldy that it became unrunnable. The regionalization in Figure 9, based in significant measure on the NERC regions and subregions, provided an effective compromise between the objectives of extensive regional detail at one end of the spectrum and workability and usability at the other.

Figure 9: Altos North American Electric Model



Within each of the subregional ovals in Figure 9 resides a comprehensive model of indigenous generation, inbound transmission, native load, and outbound transmission. The regional network submodel, common for all 30 regions, is depicted in Figure 10. Notice how it enumerates the full range of regional generation options at the lower left, the full range of incoming transmission options at the lower right, the native load (including load shape) at the upper left, and the outbound transmission at the upper right. Our approach is fundamentally tied to network diagrams of the form in Figure 10, just as our North American Regional Gas (NARG) model is tied to analogous regional network diagrams for gas supply, transportation, and demand markets.

3.1.2 MarketPoint Allows Subregionalization

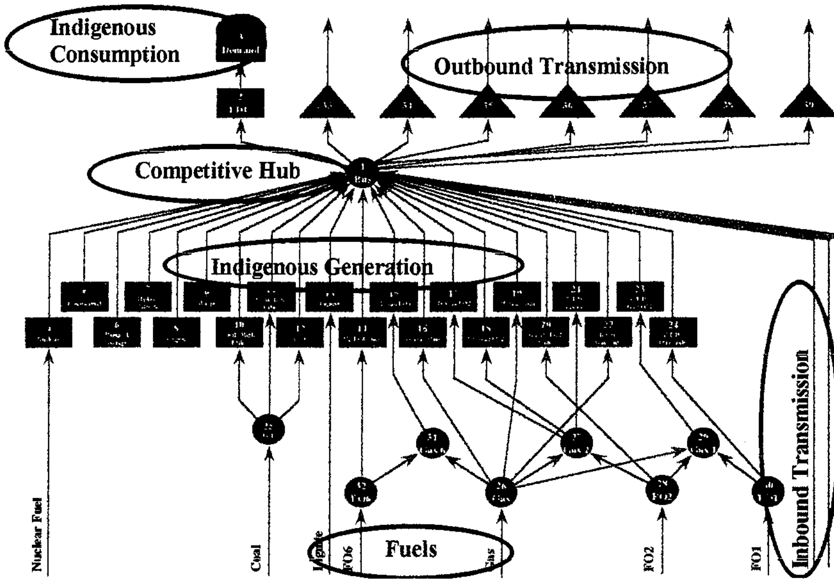
In the real world, individual assets are located in specific, highly localized regions of the United States, and the fuel, generation, inbound transmission, outbound transmission, and demand infrastructure in the immediate regions surrounding the plant fundamentally affect the value of the asset. It is necessary, therefore, to disaggregate the regions near the asset in more detail than the regions further from the asset. To illustrate how MarketPoint allows you to do that, consider a hypothetical asset that might be built in southern Texas, i.e., Southern ERCOT. For such a plant, we would need to further disaggregate the ERCOT portion of the Altos North American model as indicated schematically in Figure 11. To wit, we cannot simply use the original highly aggregated representation of ERCOT; we must represent ERCOT in a high degree of nodal detail so that we can understand the interplay between generation and transmission within ERCOT and the interplay between ERCOT and the rest of the United States and the continent. MarketPoint allows us to disaggregate ERCOT into the detailed "nodal" substructure shown in Figure 12. As indicated in the figure, the expanded MarketPoint model is a nodal pricing model of ERCOT, and it is embedded in and interconnected to the entire North American electric grid. It calculates market clearing prices and energy flows at every node within the ERCOT system and every node within the North American system, all on an interconnected basis.

The red elements in the figure represent regions or "nodes" in ERCOT. As indicated in the figure, the specific nodes used to represent ERCOT for purposes of this discussion of a prospective South Texas plant include

- VALL (Rio Grande Valley)
- CBEN (Central Power and Light South)
- CPS (San Antonio)
- AEN (Austin)
- LCRA (Lower Colorado River Authority)
- HLP (Houston)
- STEC (South Texas Electric Coop)
- JWT (Jewett)
- TU (Texas Utilities-Dallas)
- TU/E (Cooperatives east of Dallas)
- TU/W (Texas Utilities-West)
- WTX (West Texas)
- BRYN (Bryan/College Station)
- TNMP (Texas New Mexico Power Pool)

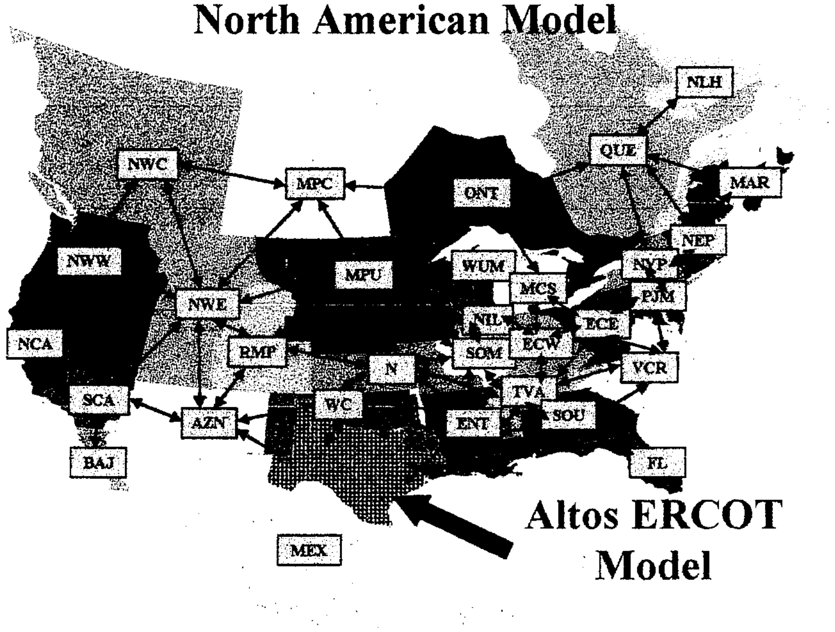
These nodes are conceived of as locations at which there are aggregates of generation, aggregates of load, aggregates of inbound transmission, and/or aggregates of outbound transmission. These nodes themselves can therefore be thought of as regional market entities that compete against each other as well as complement each other within the ERCOT system. We think of generators in each of the red nodes as competing for load not only it the node in which their generator is physically located but also in contiguous nodes in which their generator might have a competitive advantage over incumbents in that node. In MarketPoint, just as in the real world, there is "rivalry" among the nodes in ERCOT to meet the demands resident within each node. It is this internodal rivalry that dictates which generators will run, which will not, which segments of the transmission system will be used, which will not, and where after all such rivalry plays out prices in ERCOT will ultimately be driven. It is this rivalry that dictates what ERCOT prices will be into the future.

Figure 10: Sophisticated Network Representation of Regional Options



The yellow ovals in the nodal diagram in Figure 12 are also very important. They represent transmission capabilities in expressed in terms of MW of capacity that interconnect the ERCOT nodes. Specifically, they represent first contingency transmission capabilities along the transmission corridors between the nodes or regions. First contingency transmission capability is used to represent transmission capacity between the nodes because nodal prices are determined by total, aggregate flowing quantities, not contracted quantities, uncontracted quantities, portions of total quantities, or some other subset of total energy. After all, it is total energy into and out of each node that sets the market clearing price at that node. The numbers inside the yellow ovals in Figure 12 depict the transmission capability assumptions upon which our model is based, i.e., the first contingency transfer capabilities.

Figure 11: Embed Detailed ERCOT Model within North American Model



MarketPoint systematically and internally balances inbound and outbound transmission against indigenous generation at every individual market node that comprises ERCOT (and in fact North America as a whole). Every individual nodal market within ERCOT is assumed by MarketPoint to be served by the most competitive mix of plants plus inbound transmission lines possible, given that every other nodal market is being served by its own most competitive possible mix of plants plus inbound transmission lines.

3.1.3 Temporal Assumptions

MarketPoint contains a very general internal representation of time and temporality. This allows MarketPoint models to be built and modified very easily compared to the alternative. Indeed, dealing with model temporality is generally the hardest part of modeling. To be specific, MarketPoint allows

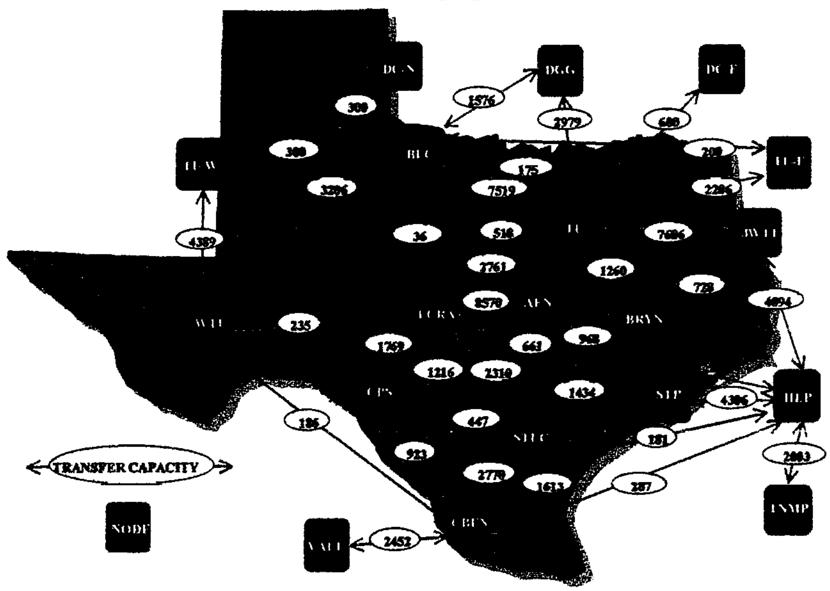
- **Whatever number of time points you want.** There is no limit on the number of time points. You can have hourly, daily, weekly, monthly, annual, or multiannual time points.

- **Whatever interval between the time points you want.** As an example of what you can do, you can begin the model horizon with 12 monthly time points followed by six annual time points followed by six biennial time points.

- **Whatever number of sub-time points within each time point you want.** There is no limit on the number of increments you can use to represent a load duration curve or discretize a period-wise chronological load at each time point within the model.

Figure 13 illustrates the temporality that is supported by the MarketPoint modeling system.

Figure 12: Detailed Nodal Representation of ERCOT

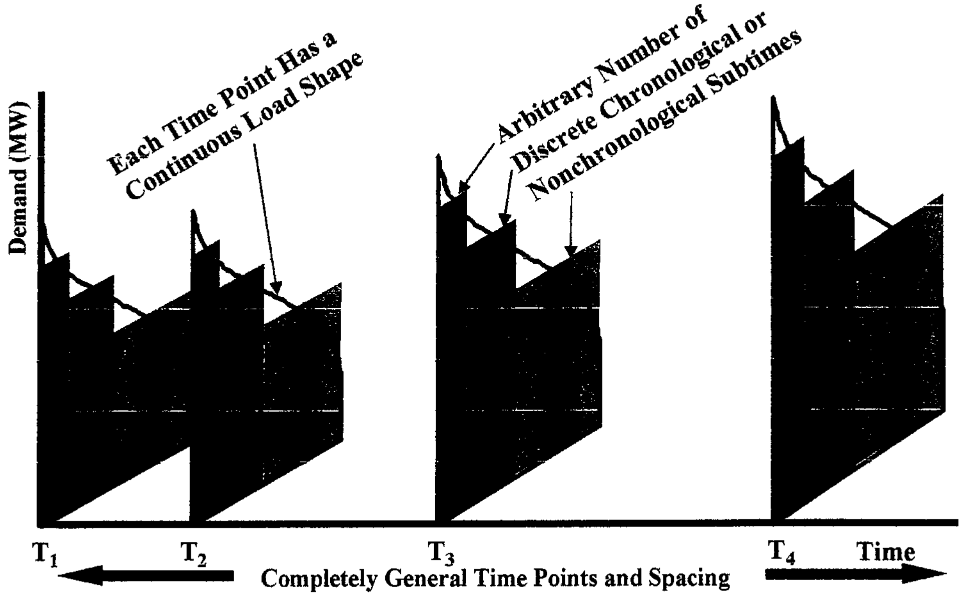


3.1.4 Incorporating Forward Cost to Market for Existing Generation Units in a Region

Having regionalized the North American market as in Figures A-9 through A-12, the next task is to specify the nature of the existing generation mix region-by-region. In the lexicon of the network diagram in Figure 10, we need to "populate the generation nodes" with generation plant data. This has been accomplished according to the logic illustrated in Figure 14. To generate the necessary data, we have estimated the capacity and the forward cost to market for every one of the generation units in a given region—utility-owned units and independently owned units alike. Thereafter, we line up the units in that region in ascending order of forward cost as shown in Figure 14. For each unit in the stack, the width of the supply curve for that unit represents the capacity to produce electricity, and the height of the supply curve represents the forward cost of doing so with that unit. The lower right envelope of this stack (i.e., the lower right boundary of the curve) represents the electricity supply curve available from the aggregate of all the existing generation units in the region. It is the sought-after supply curve based on the capital stocks that exist today.

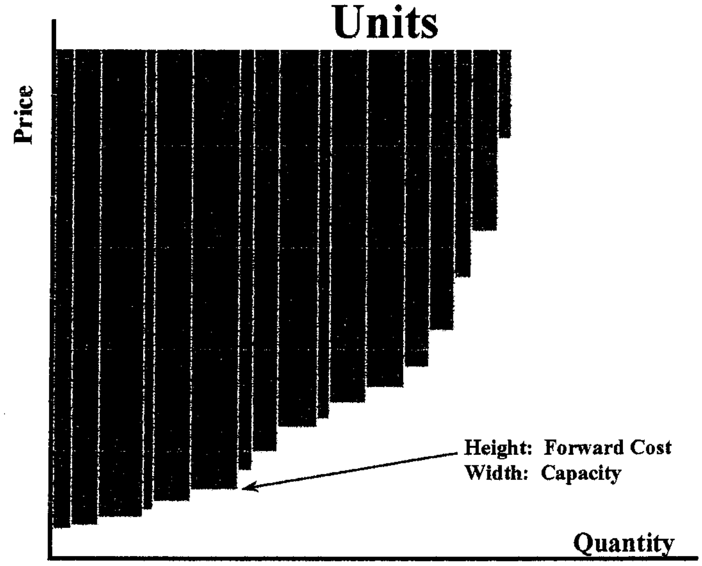
What types of judgments and adjustments have been necessary to craft the supply stack in Figure 14? The answer lies in a brief description of how one must think about forward cost to market for each of the existing generation plants. Figure 15 summarizes what we have included and not included in each element of the generation supply stack in Figure 14. Beginning at the bottom, notice that we have included as part of the forward cost all fuel-related costs (bottom) and all variable costs (e.g., consumables). Variable cost is assumed to include costs that will be incurred if the plant operates but will NOT be incurred if the plant does not operate. Variable costs are those that need not be borne if the plant does not operate. They are avoidable. The second from the bottom element of the diagram is understood to include all nonfuel costs that can and will be foregone and avoided if the plant is not run.

Figure 13: MarketPoint Allows Completely General Time Period Structure



Turning to the most difficult element of the forward cost stack, designated fixed operating and maintenance cost in Figure 15, it is clear that a portion of the fixed O&M cost must be included in forward cost because it can be avoided if the plant does not run. For example, the basic, minimum, prudent maintenance cost necessary to keep the plant in service can be avoided by shutting down the plant. In a competitive market, such cost will have to be repatriated through energy sales; otherwise, plant owners will be obliged to permanently shut down the plant because it loses money with every KWh of operation. In the figure, therefore, a portion of the nonvariable O&M cost must be included in the forward cost of the plant and therefore included in the height of the supply curve.

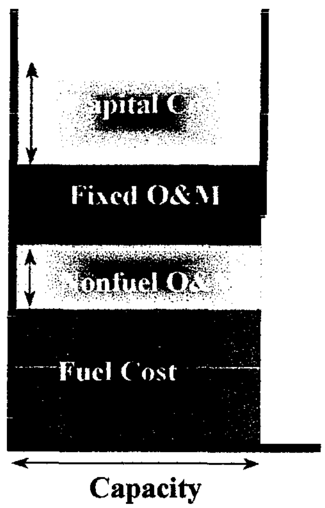
Figure 14: We Have Assembled the Generation Supply Stack for Pre-existing Units



It is also true that because fixed O&M costs are presently being repatriated largely through fixed cost passthrough as part of the regulatory compact, completely apart from energy sales, they have been arguably been substantially higher than would be sustained in a competitive market. (Such argument is similar to but not identical with the Averch-Johnson effect, which argues that if utility companies are paid to make risk free investments, they will over invest relative to an economically efficient level.) The portion by which fixed O&M costs are too high and will not be repatriated through energy sales in the forthcoming competitive electricity market must be excluded from forward cost to market. They must appear above the horizontal line in Figure 15 and they must be viewed as sunk costs (if they are incurred at all). The question of fixed O&M costs is a difficult problem, one that has consumed a great deal of debate and analysis related to this model. We are convinced ours is the correct approach, but analysis and revision must continue.

There is another interpretation of forward cost to market, which is equivalent to the foregoing, that merits extended discussion. Using the analogy of a jet aircraft that is owned by an airline company, we see in Figure 16 that its cost structure is comprised of four fundamental elements: variable operating cost, cycling cost, preservation cost, and all sunk costs. Variable costs include fuel, consumables, crew, etc. Cycling costs include incremental costs necessary to provide the specific time schedule of services demanded by their market. Preservation cost represents the lowest prudent cost required to maintain the aircraft in serviceable form so that it can carry passengers and generate revenue. It can be regarded as mileage- or flight hour-dependent maintenance costs and other such fixed maintenance items. Finally, there are a number of sunk and/or allocated costs that can be attributed to ownership of the airplane (e.g., depreciation, gate leases, airport fees). These sunk costs are truly sunk and are independent of the operation or the airplane.

Figure 15: For Each Producing Unit, We Estimate Forward Cost To Market



- **FORWARD COST EXCLUDES**
  - **Capital cost**
  - **Some Fixed O&M (Preservation)**
- **FORWARD COST INCLUDES**
  - **Some Fixed O&M (Cycle)**
  - **Nonfuel variable O&M**
  - **Fuel cost**
- **WIDTH OF SUPPLY CURVE IS CAPACITY**

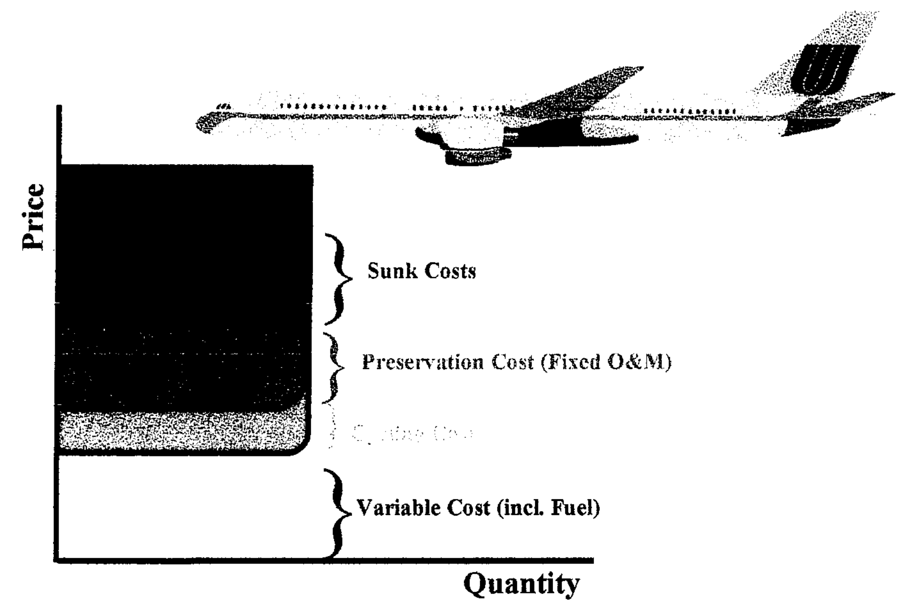
In assembling a forward cost curve for an airplane, we would argue that it should be composed of the variable cost plus the cycling cost plus the preservation cost. These three categories of cost, and only these three categories, can be considered avoidable if the airline company were to sell their plane to Air Ghana, Air Nigeria, etc. or simply decommission it. To wit, variable cost, cycling cost, and preservation cost are avoidable by simply divesting the asset. If the market fails to repatriate such cost through ticket sales, the airline company can and will choose not to incur those costs. The decision not to incur any of these three categories of cost—variable cost, cycling cost, or preservation cost—is tantamount to a decision to divest the airplane. Whether or not to operate the airplane is a function of the SUM of all three of these forward costs to market. It is critically important to realize that the market must repatriate ALL forward costs—variable cost, cycling cost, and preservation cost—or the asset will be retired and removed from the North American asset mix. Precisely the same is true for power plants, semiconductor plants, steel mills, and all other capital assets. If the market (or some government agency that provides an equivalent subsidy) fails to repatriate variable cost, cycling cost, and preservation cost, electric plants will be decommissioned and abandoned.

The curve in Figure 16 must be recast in terms of variable cost, cycling cost, and preservation cost. Figure 17 illustrates. Clearly, the forward cost to market for any electric plant must, in the absence of full cost passthrough via regulatory formula, include each of these three categories. The forward cost estimates we apply in our model have taken great effort to embed the view implicit in Figure 17. Given this view, it is absolutely clear that forward prices will NOT be equivalent to "system lambdas." System lambdas reflect only fuel costs and nonfuel pure variable operating cost. They systematically exclude those elements of cost so important to the forthcoming merchant world—cycling and other service costs and preservation costs. Any model that purports to equate forward price with forward system lambda is both incorrect and misleading. We should also note in passing that the cycling and preservation costs of much of the older capacity resident within the North American generation plant inventory is quite high. There is large difference between pure variable cost and total forward cost to market for these older plants. This large difference imperils the competitiveness of these older plants and attracts entry, a phenomenon our model is uniquely able to model. This is a critically important point. Old plants must compete against all other plants in the generation inventory, and those old plants must carry the heavy disadvantage of high nonvariable O&M cost. When those plants are transformed from their present highly protected state of fully regulated plants with full cost passthrough to merchant plants that face market prices for both fuel and power, their high O&M costs will become increasingly daunting.

Turning to the last cost category, all embedded capital costs and capital recovery factors must be viewed as sunk costs and will not be repatriated or repatriatable through energy sales. Gone with the demise of fixed cost passthrough is the notion of "return on and return of rate base." Gone is the notion of guaranteed repatriation of embedded capital outside energy sales. Gone in the forthcoming merchant era is the notion of fixed cost passthrough downstream to unwitting customers who are forced to accept it. In the coming merchant world, there are no customers who can be forced to do anything! Just like other industries ranging from gold, oil, semiconductors, or agriculture, yesterday's capital costs and cash flows deriving therefrom are sunk and unaffected by future plant operation. Those costs must not be included in forward cost to market estimates necessary to run a market model. While we want to consider the possibility of embedded costs (i.e, stranded costs) being repatriated in transmission or distribution tariffs within the electric power system, we also will want to consider the possibility that they will either be recovered totally outside the energy system or not recovered at all by electric utility shareholders.

The most difficult aspect of measuring forward cost to market has proven to be estimating what magnitude of formerly fixed operating and maintenance costs should be included as a forward cost and how much it contributes to the height of the supply curves? What portion of historical preservation costs will actually be borne by and repatriated to generation owners in the competitive market? We have made such estimates for each of the units in each of the 30 regions of North America and incorporated them into our estimates of the heights of the supply curves. This is not a job for the fainthearted—estimating forward in time what cost it will REALLY require in a fully competitive market to preserve capacity for intermittent use.

Figure 16: Cost Structure for an Airplane

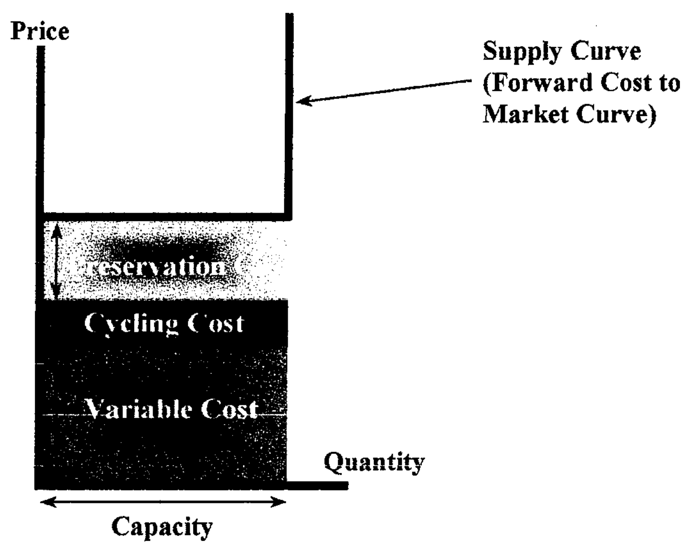


We have implemented our plant data management system within a proprietary software system known as MarketPoint. One of the outputs of that system is the region-by-region supply stacks discussed in detail in this section. Figure 18 puts forth the supply stack calculated for the WSCC:California-Southern Nevada generation region.

3.1.5 Scope and Origin of the Generation and Transmission Data Base

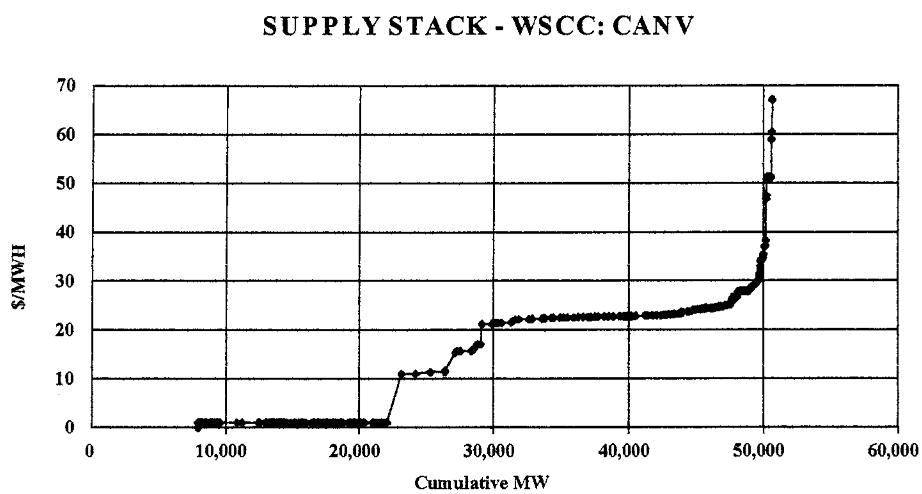
As indicated in Figure 19, we have downloaded some 24,000 generating plants that comprise North America including capacities and forward costs from publicly and privately available sources. Before arraying them as shown in the figure, it has been necessary to undertake a rather extensive reconciliation and comparison process. We should caution that such downloading has not been conducted as a simplistic, thoughtless, mechanical process. It is much more difficult than that; analysis and "thinking" are required. There is much anomalous cost and capacity information embedded in commercially and publicly available sources (e.g., RDI, ES&D) that has to be ferreted out and adjusted. It has been necessary for us to render judgments and adjustments to many of the plant capacity and forward cost estimates in order to create supply curves that are credible and reasonable. It has also been necessary to adjust them to consider the coal, gas, oil, and nuclear fuel cost projections into the future we want to use. We should emphasize that we have downloaded not only utility-owned, muni-owned, and coop-owned units but also privately and independently owned generation units. In the merchant market of the future, there is fundamentally no difference or distinction between utility-owned and non-utility-owned units. We have access to proprietary data bases that enumerate all independently owned as well as utility-owned generation units in North America.

Figure 17: Recategorization of Plane Forward Costs



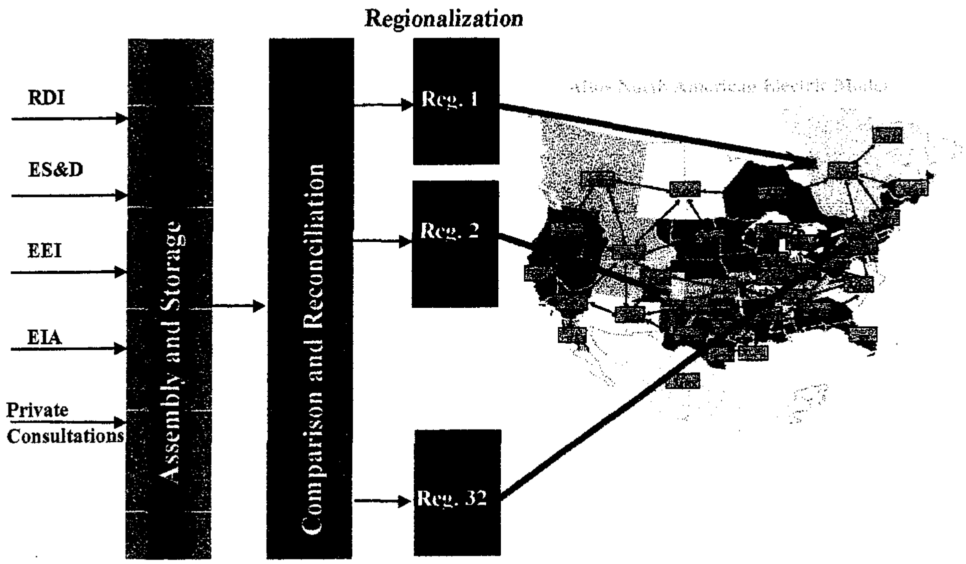
We should point out that we have gone to great effort to include each and every MW of capacity that exists in each of our regions including investor owned utilities, munis, cooperatives, and independently owned generation whether it has been reported or not. Because it is the aggregate of supply--reported plus unreported supply—that in aggregate combines to satisfy demand, we have taken great effort to include all the independent as well as reported generators in every region. We have frequently seen other consultants and modelers report lower capacities than we do and consequently report and advocate lower reserve margins than we do. Why would they lack such access, and why should Altos have it? It is because most consultants and others simply take the generation unit and load data as reported by the NERC Electric Supply and Demand report and pass it on in the form of reserve margin and other calculations. They put it in models, they put it into supply stacks, calculate reserves, etc. Keep in mind, the NERC reports simply bundle and pass along information that is reported by individual reporting utilities. The problem with data based on NERC is that it systematically excludes many of the so-called "phantom units" because such independently owned units often have no capacity contracts with utilities and therefore utilities do not have to report them to NERC or to anyone else. Because utilities report only capacity they have under contract, there is a systematic low bias in utility reports and the consequent NERC reports; their reported capacity is systematically low. To reiterate, utilities rightly consider only that capacity that is under contract and therefore is routinely a part of their business.

Figure 18: California Supply Stack



Are the "phantom plants" to which we have alluded at all visible? Is there a systematic way to observe where they are and how big they might be? The answer is yes, but one must be very sophisticated about utility data, and her or she must be a sophisticated software engineer to gain access to them. Utilities are required to report to FERC on a substation by substation basis inbound and outbound sources of energy by source, loads and generation, loss rates, reactance, voltages on transmission systems, and the like. (This is required as part of their FERC 715 transmission reporting.) Embedded in the voluminous FERC 715 information (which is a compilation of the detailed substation by substation transmission and energy reporting) is production by source from each and every generation station in the United States by name whether or not that particular generation station might be under contract to a utility and therefore whether or not it might be included in NERC reporting. To wit, the requisite plant by plant information is resident within the FERC 715s; they collectively contain more complete and accurate information as to precisely what capacity exists in each region whether or not that capacity is under contract to any resident utility, muni, or coop. In other words, the FERC 715s are the place where the fundamental substation by substation buy and sell information is recorded, nowhere else.

Figure 19: We Have Automated All the Data Input



Altos has downloaded every FERC 715 for every substation in the United States and accumulated the energy inflows and outflows at every location by source to infer how much capacity truly exists at each substation within the United States. This is a very ambitious software engineering process, one that requires knowledge of how to download the FERC 715 data in automated form, how to read it with a computer program, how thereafter to process and sort it to infer what capacity truly exists at what substation, and finally how to aggregate it into the type of supply stack information in Figure 15.

Because utilities do not themselves report uncontracted capacity, consulting companies that lack Altos' software capability sometimes access other plant data sources such as the Energy Information Administration Inventory of Power Plants and assume that they are accurate because all power plants in the country are required to report to the EIA and therefore are contained therein. However, Altos has found this to be an inaccurate source as well. It too is problematic because it includes not only phantom generation but also industrial self generation. There is no offset for internal industrial consumption that must be matched with industrial self generation; EIA merely reports gross generation capacity. Furthermore, there is a significant reporting time lag in the

EIA information. It is an annual report, and it is typically 1-2 years behind (as many EIA documents are). Also, it is purely historical; EIA does not project capacity additions. There is an obvious bias toward overreporting large plants-utility, phantom, plus self generation-but overreporting small plants. The EIA documentation is not therefore as satisfactory as the 715 method.

Does any of this matter? It clearly does. Having reviewed the FERC 715 data on a substation by substation basis, we observe time and again that at time of peak, utilities are not always running their own indigenous peaking units. They are buying as available energy from another local source at time of peak! This is not at all unusual; it occurs frequently. Resident utilities are choosing to use these phantom generators at time of peak and not therefore to fire up their own peaking capacity. Without the FERC 715 information, one could not verify this or measure this at all. This practice of using as available energy as a peaking source means that the local utility is using phantom capacity rather than its own capacity to meet peak reserve requirements. Obviously, the reserve requirement under such practice is higher than what is being reported by utilities to NERC. Furthermore, the very fact that as available energy is available at time of peak means that it is above and beyond the consumption levels at the plant sites where the as available generation occurs. It is clearly "excess" with regard to self use. Recognizing that these as available energy sales some from excess capacity with regard to industrial self use, the FERC 715s are giving us exactly what we want—capacity and energy that are available to the electric grid.

The MarketPoint input data system has been configured as shown in Figure 19. The system contains plant data for every utility-owned and independently owned generation unit in North America as shown on the left. It compares and reconciles all the publicly and privately available data source and develops a single, consistent, reasonable set of generation data. The electric data base is an important part of the MarketPoint product and is provided to our customers along with the model.

3.1.6 Cost Reduction and Performance Improvements for Existing Units in a Given Region

As we have observed in every industry that has deregulated, "the good get better and the bad become moribund." There is tremendous incentive immediately following deregulation for existing plants to reduce their forward cost to market over time. Darwinian natural selection (survival of the fittest) virtually guarantees that it will occur. Such cost reductions obviously include reducing fixed O&M, both the market repatriatable portion and the nonrepatriatable portion. As a directly relevant example, consider that airlines (and maintenance contractors) have reduced prudent and mandatory maintenance costs for their 747s as far as they prudently can, and those reduced costs have been repatriated through airline ticket revenues. Airlines have also reduced or eliminated altogether excess or imprudent fixed O&M they may have been charging before deregulation. In short, they have learned to repatriate that portion of maintenance cost that is required by them and their competitors to remain airworthy, and they have eliminated redundant or unnecessary costs. Competitive forces compel them to be constantly vigilant in seeking out and eliminating fixed O&M costs that can be prudently eliminated.

Figure 20 represents the inexorable downward pressure against forward cost to market experienced by the presently existing generation capital stocks, i.e., it represents how cost reduction affects the entire supply stack from Figure 14. The stack of supply curves represented in blue represents presently existing capacity and forward cost embedded in presently existing vintages of plant and equipment. The downward-shifted stack represents the downward migration in forward cost to market for each individual vintage of plant currently in place and collectively for the entire set of vintages. Keep in mind, this downward shift occurs as plant owners simultaneously and/or individually reduce the three important elements of costs—variable cost, cycling cost, and preservation cost. We have carefully considered and represented this downward evolution in our model.

Based on empirical observation of every industry that has been deregulated, it is absolutely unacceptable to hold the cost structure for the existing capital stock of plants constant and static at today's level. We have rendered difficult judgments regarding the most likely future evolution of forward cost structure of the existing mix of plants in place, and we have embedded that judgment in our model. We believe that plants that do not reduce costs are likely to exit the market and only plants that reduce costs will remain in the mix. We characterize this inexorable cost reduction as shown in Figure 21. In effect, we have placed existing vintages of plant on a "learning curve" through the future to reflect our judgment as to what is possible and/or likely.

3.1.7 Retirements of Existing Units in a Given Region

Alas, notwithstanding the inexorable pressure for cost reduction, many existing plants simply cannot hope to survive. Competition is quintessentially Darwinian, the weak, the old, and the sick do not survive. Some economists have dubbed capitalism a system of "graceful obsolescence." Plants retire because they age, and their operating and maintenance costs escalate to noncompetitively high levels. It is well to consider that the average age of electric generation capital stocks is over 20 years in North America, older than at any time in the past. Cost escalation in the older plants resident within that mix is inevitable. Cost escalation in plants currently in cold shutdown is inevitable, and it is likely that few or none of those plants will ever reenter the market.

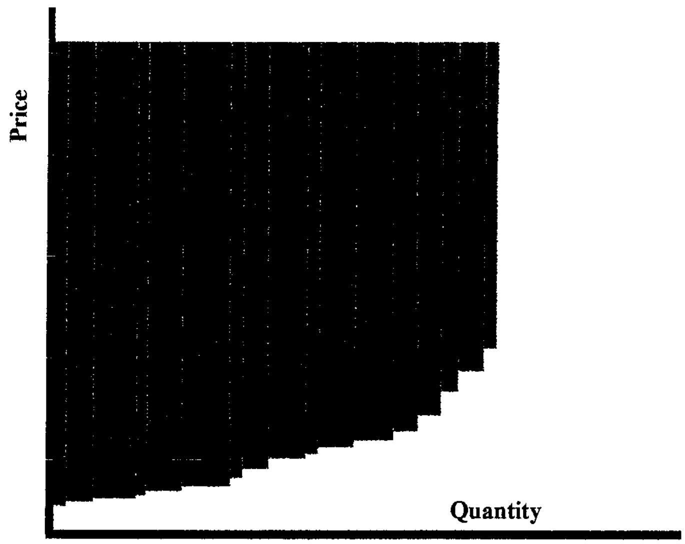
What does aging mean? How is it manifest in terms of forward cost to market for a given plant? The answer is obvious when one considers his or her personal automobile. When the car is new, its forward cost to market (fuel cost plus maintenance cost) is low and flat, remaining so until the car hits a certain age. After a certain age, the sum of fuel cost plus maintenance cost begins inexorably to appreciate. Maintenance becomes more frequent and more costly. Whereas maintenance used to mean an oil change, it now means a transmission overhaul or a valve job. Whereas outages used to mean running out of gas, outages now mean two weeks in the shop while the user commits to a rental car. We can plot the phenomenon of plant aging conceptually as in Figure 22. The top right portion of the supply curve (the old, high cost plants in place today), can be expected to shift over time to the left as companies abandon those old plants in favor of new plants or imports via transmission from contiguous areas. We have given a great deal of attention in our electricity model to the problem of quantifying which plants are likely to escalate in forward cost to market the most quickly and thereby be the most quickly "out of the money." On a region-by-region basis, we have made an assessment of the rate of escalation of forward cost to market escalation due to aging and an estimate therefore of how far the leftward shift in Figure 22 might indeed be.

As a parenthetical note, it is well to consider that the most underestimated and underpredicted phenomenon in other industries that have experienced deregulation was the rate and extent of shutdown and retirement of capital stocks rendered economically obsolete and noncompetitive by deregulation. In particular, commodity prices fell, and formerly cost-competitive production facilities or processes were instantly rendered noncompetitive and driven out of the market. Without a regulatory safety net to repatriate the higher-than-market costs of these plants, they were quickly retired and written off. (Recall how quickly rotary phones left the scene, how quickly Alaskan and Canadian frontier gas were abandoned, and how quickly synfuels projects were terminated.) Our model strives not to understate plant retirements that might occur under future deregulation of electricity. Instead, we have estimated the rate and extent of plant aging so that we can predict which vintages and types of plants on a region by region basis are likely to exit the generation mix as shown in Figure 22.

3.1.8 Ingress and Egress of Transmission to and from Each Generation Region

As if cost evolution in existing plants were not a difficult enough problem, deregulation opens the Pandora's box of "competition from afar" via long distance electric transmission. While in the halcyon days of rate of return regulation, utility companies could generate exclusively for their own accounts, staving off transmission and generation entrants into their service territories through franchise control, they now face the prospect of transmission entering their service regions and competing with their generation assets. That is the "bad news." There is, however, offsetting "good news." Generation companies can compete with plants in contiguous service territories by exploiting outward bound transmission, thereby augmenting the markets they can serve. The logistics of inbound and outbound transmission add a degree of competition and a degree of analytical complexity to the electric power industry that has not been present historically. The historical types of models used in the industry, particularly production simulation dispatch models, were and are unequipped to represent the inbound and outbound transmission issues that will begin to affect the industry in the future. Production simulation models should go the way of the dinosaur, a relic of an industry environment that is long since gone.

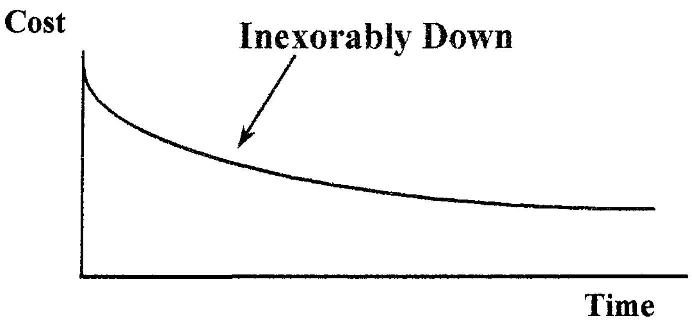
Figure 20: Competitive Pressure Reduces Forward Cost of All Units



How do we represent the emerging open access transmission system and its implications for electric power? The answer is apparent from the structure of the map in Figure 9 and the subregional network diagram in Figure 10 or Figure 12. We have represented existing and prospective transmission linkages among all the contiguous regions and subregions in the diagram, we have represented all the indigenous generation alternatives within each region and subregion, and we have represented electricity demand within each region and subregion. To wit, we have used "brute-force enumeration" to characterize all the existing and prospective generation, inbound transmission, outbound transmission, and native consumption options within each region and between each pair of contiguous regions. Focusing on transmission, within each of the regions and subregions in Figure 9 and Figure 10, we have represented generation, transmission, and consumption as shown in Figure 23.

Figure 21: Competition Pushes Costs Down

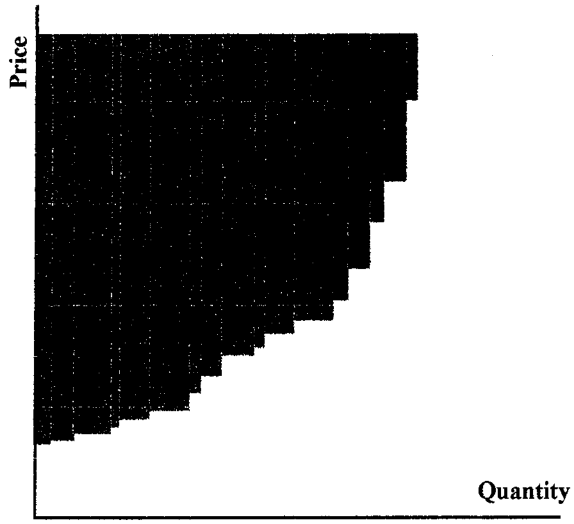
Cost reduction never fails in a competitive economy



The title of Figure 23 is significant, the "conventional wisdom" of the electric transmission business. The "conventional wisdom" suggests that generators in a particular region will generate power and wheel it to their own customers (which we term intra-regional wheeling), ship it to customers in contiguous regions, and receive it from generators in contiguous regions. It is usually further conjectured that such transactions will all occur at a single tariff, a "postage stamp tariff." A postage stamp tariff or rate is a single, common rate for point to point transmission service, but the rate is independent of the entry point and the exit point. Postage stamp rates charge a shipper to "get on and get off the train" but do not levy a distance-dependent charge. Postage stamp rates have the property that wheeling costs are the same, absolutely identical, for all entry and exit points on the transmission system. Wheeling power a distance of 300 yards costs the same as wheeling it 350 miles. While we want to admit into our model the possibility of postage stamp transmission rates for both intra-region and inter-region wheeling, we also want to admit the possibility of market-sensitive rates, distance dependent rates, and zone rates in electric transmission, just as we have seen evolve in the gas and telecommunications businesses. There is no earthly region why rates should equilibrate to a single postage stamp rate. On the contrary, postage stamp rates hurt certain transmission linkages, and the owners of those linkages can be expected to reset their tariffs as a competitive measure. We have retained the ability to consider the widest possible range of transmission rates and infer what particular set or sets of rates are likely to be market-sustainable.

Motivated by our ambitious goals for modeling electric transmission, we have proceeded as follows. We have implemented the structure in Figure 23 for each of the 30 regions and subregions in Figure 9, but we have connected them together as shown in Figure 24.

Figure 22: Competitive Pressure Retires Old Plants



The reason for the interconnection indicated in Figure 24 is that we want to allow the possibility that the transmission tariff from the left region to the right region is DIFFERENT from the transmission tariff from the right region to the left region. We also want to allow the possibility that the intra-regional wheeling tariff in the left region is DIFFERENT from either of the two inter-regional tariffs, and that all are DIFFERENT from the intra-regional tariff on the right. This is not to say that we dismiss the possibility that they might all be the same. On the contrary, the structure we have built allows us to set them all equal to represent prospective postage stamp wheeling. However, it is to say that we want to preserve the possibility of setting them all to be different and thereby to represent scenarios whereby owners of transmission strive to price at market rates and strive to extract whatever rents they can whenever they can extract them. We also strive to represent the possibility that transmission might enter on an unregulated, unguaranteed, greenfield way at some time in the future. (The example of privatized highways argues that merchant entrepreneurs might build transmission if there is sufficient rent earning possibility they can glean from such entry.)

There is one other critically important aspect of our transmission submodel that merits discussion here. Referring to the inter-region and intra-region wheeling links, they have a fixed maximum capacity today. We have made a great deal of effort to estimate and input today's transmission system maximum capacities in the model. We have attempted to represent maximum inter- and intra-regional capacities so that we can identify near term bottlenecks caused by transmission capacity limitations. In addition, however, just as with generation, it is possible to reinforce existing transmission infrastructure to increase inter-regional and intra-regional transmission capacity. It is also possible to implement greenfield transmission capacity, adding lines that are either parallel to existing lines or lines along fundamentally new routes. Our model considers existing transmission capacity, the cost and capacity of augmenting existing capacity, and the cost and capacity of building new, greenfield transmission capacity. Just as with other commodities, prospective new electric transmission competes against old, and the combination of prospective new and old transmission compete against indigenous generation.

Figure 22: Competitive Pressure Retires Old Plants

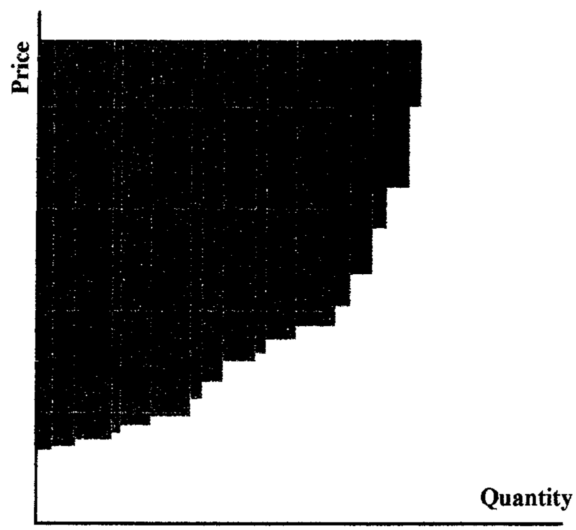
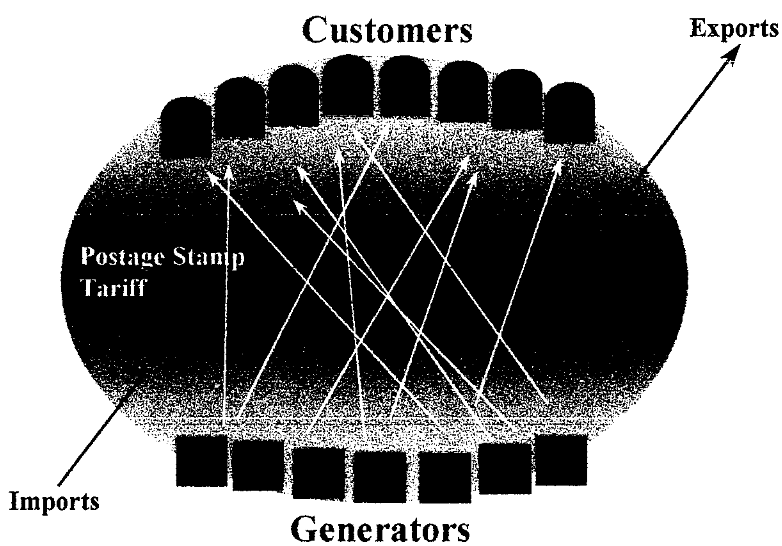


Figure 25 represents economically what the combination of cost improvements in existing plants combined with incoming transmission can do to the original supply curve that characterizes only the existing capital stocks (black in the figure). Intuitively, there is a large increment of energy supply from incoming transmission that can materialize at or near a given price. This increment of incoming transmission energy competes "one-up" against the existing generation mix within the region. Furthermore, the existence of this transmission increment, because it drives the lower right boundary of the supply curve downward and to the right, has the prospect to dramatically depress market clearing prices of electricity in the region. In effect, it creates additional supply to chase a fixed level of demand. When additional supply chases a fixed level of demand, prices cannot help but fall (relative to what they would otherwise be). Indeed, incoming transmission depresses prices in the region into which it enters. Always.

Figure 23: Transmission Conventional Wisdom

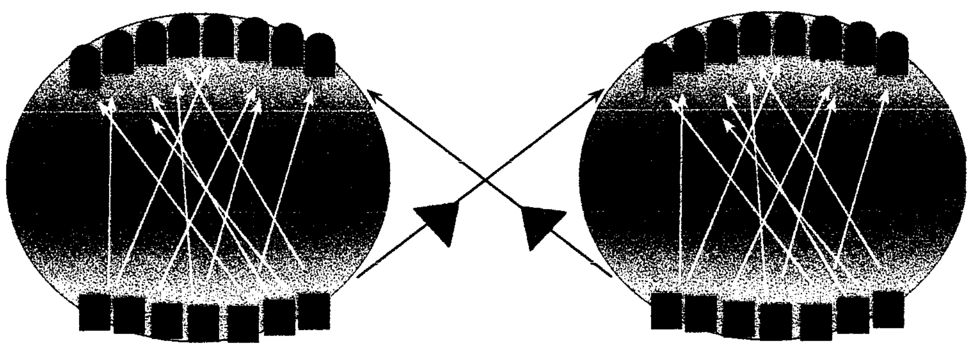


By implementing the transmission increment as shown in Figure 25, we are able in the power model to represent the true effects of inter- and intra-regional wheeling. We will not naively miss the prospective effects of incoming transmission buoyed by generators in contiguous regions who are striving to increase profits. We will not inadvertently miss "competition from afar," directed as it will assuredly be to high margin business. We will not inadvertently overvalue indigenous assets in any given region because we fail to consider the possibility of aggressive incoming transmission into the region.

By the same token, however, we will not fail to properly represent the fact that outbound transmission can create heretofore-unavailable energy markets for existing plants in certain regions. Our model considers the fact that outbound transmission can be an attractive business alternative for existing and prospective new generators in certain regions. Outbound transmission means that plants need not necessarily be sited contiguous to markets. Plants can be sited many miles away more contiguous to attractive fuel supplies and the electricity transported on an increasingly competitive transmission system to new markets. The more transmission that leads away from an existing plant, the larger the prospective market that plant sees. Larger prospective market available to a given plant means a higher selling price for the output from that plant. The model strives to balance (in the economic sense) the price-stimulating influence of outbound electric transmission against the price-suppressing influence of inbound electric transmission. We believe we have the tools and the emerging data to do so, and we have carefully employed them in valuing a rather broad range of assets and business prospects thus far.

Figure 24: Interconnected Existing And Prospective Wheeling Links

All interregional tariffs and capacities estimated

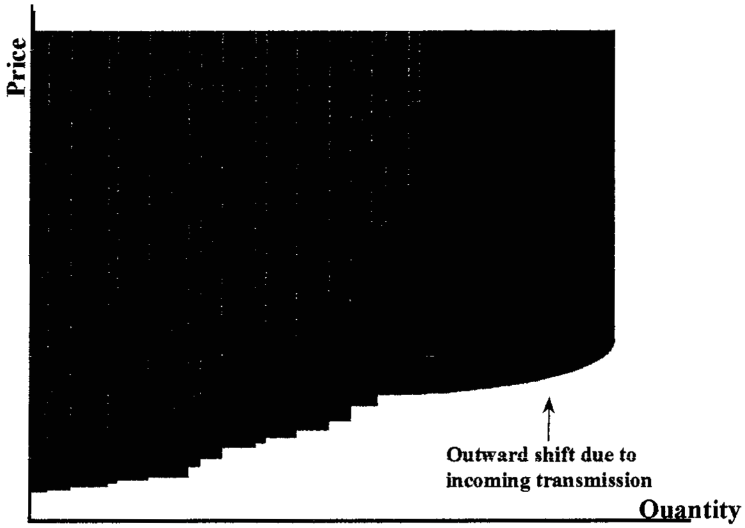


Before leaving the issue of transmission, we need to represent what transmission implies for contiguous regions. Figure 26 illustrates two regions, one a region (at the left) with excess generation capacity relative to demand and one (at the right) with tight capacity relative to demand. Notice that the region with excess capacity at the left evidences a lower market-clearing price than the tight region in the absence of interconnecting transmission. As illustrated in the figure, if the incremental cost of transmission is smaller than the price differential that would be sustained in the market between the two regions if they were isolated, transmission will enter. As it enters, the critical insights are those shown in the figure:

- Price in the region where the transmission originates will INCREASE. Outbound transmission stimulates market-clearing price because it provides more demand against a constant generation mix.

- Price in the region where the transmission terminates will DECREASE. Inbound transmission decreases market clearing price because it provides more supply against a constant customer mix.

Figure 25: Incoming Transmission Adds Supply And Reduces Cost



- If the cost of transmission happened to be higher than the price differential between regions in the absence of transmission, there would be absolutely no transmission between the regions. Transmission will have absolutely no effect on the price in either region or the flow between them.

- In the absence of transmission limitations, the price differential between the two regions will shrink to the point at which it equals the transmission cost between the regions. In other words, transmission capacity will enter up to the point at which the price differential between the regions is exactly equal to the marginal transmission cost between regions.

- If there exists an immutable upper bound on transmission, the price differential between the two regions will remain larger than the transmission cost between the regions. Transmission will depress the price differential, but it will not be sufficient in size to depress the price differential all the way to marginal transmission cost.

Transmission is difficult to model because one does not know priori which regions will have low prices during which periods and which regions will have high prices during which periods. The only way to accurately model transmission is through "brute force," systematically enumerating every existing and prospective transmission link complete with cost and capacity between every pair of regions in the model. This is precisely why dispatch-oriented production costing models have completely "fanned" on transmission. They have absolutely no hope of modeling transmission, for they require that one input an a priori estimate of what transmission assets are present in each region. It is not physically possible to have an asset from region A available in region A as a generation asset and simultaneously in region B as a vertically integrated generation-transmission asset, as dispatch models would force you to assume. Our approach is the only dynamic approach we know of that can represent the simultaneity of transmission implicit in Figure 9.

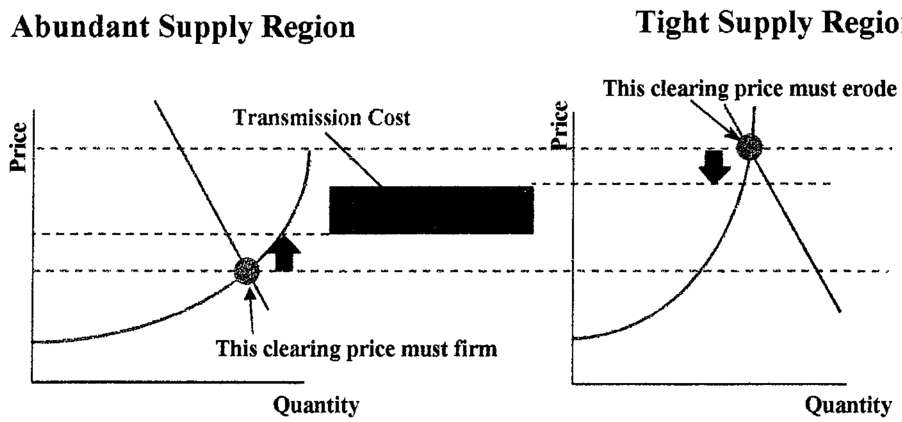
3.1.9 Prospective Entry of New Generation Units into a Given Region

As if the foregoing issues were not sufficiently daunting and difficult, it is true that if the price of electricity rises to the point at which that price is capable of repatriating the full capital cost plus the full operating cost of a new, greenfield facility plus a minimum market-level rate of return necessary to draw capital from financial markets into that new, greenfield facility, we must expect such new, greenfield facilities to be built and enter the market. In effect, the full capital and operating cost of a greenfield facility must "cap" the price of energy in each of the 30 generating and consumption regions. There is no way that long term prices should exceed the full cost of a greenfield facility for very long. Increasingly easy entry will guarantee that it will not.

Figure 27 represents the fact that new greenfield units can be expected to enter if the prices rises sufficiently to draw them into the market. Notice at the right hand side of the diagram that if the full fixed and variable cost of a greenfield unit plus a return to its owners will be repatriated by electricity prices, that greenfield unit will enter. Furthermore, there is no limit in each region on the entry of greenfield units. Gas combined cycle plants are literally commodities in their own right and can be added wholesale on a consistent and common basis. Recognizing the fact that entry is very easy and relatively quick, we must represent the fact that the supply curve becomes horizontal at an electricity price necessary to fully repatriate all fixed plus variable costs of a new greenfield unit. It is this flattening of ultimate electricity prices that inevitably obsoletes and shuts down old electric generation capacity. Old capacity is replace by the entry of new, whose full fixed plus variable cost undercuts the variable cost of the old, decrepit units.

We should note in Figure 27 the use of the terms marginal variable cost and marginal capital cost. What we are attempting to indicate in the figure is that the price of electricity is capped by the "marginal new unit," the unit that offers the best sum of fixed plus variable cost. What the precise configuration of this unit is given local fuel costs, altitude, temperature, and other characteristics varies from region to region. We have gone to great effort to estimate the capital cost, operating cost, and heat rate of each and every prospective new unit that could conceivably enter the market in each region. This information is part of the model database. New units enter if the price rises to the point where it crosses the flat portion of the supply curve at the extreme right of the figure. In MarketPoint, new equipment costs have been estimated from developers, equipment vendors, and cognizant electric power professionals by our staff and represents an important judgmental assumption to the model.

Figure 26: Transmission Dictates Prices and Differentials



Greenfield entry is important in the sense that the rate and magnitude of capital stock rollover and new equipment entry in other industries that have deregulated has been colossally underestimated. The telecommunications industry was rife with stories of overcapacity during Judge Greene's Modified Final Judgment to break up AT&T, yet North America experienced a literal explosion of capacity. The gas industry was rife with stories of excess reserves and a gas bubble during FERC Order 436, yet in spite of prices falling by almost ½ in real terms since then, North America still experiences massive drilling, reserve additions, abundance of supply, and low prices. We have given special attention to the question of greenfield entry because we do not want to repeat the mistakes of other deregulating industries. Furthermore, we want to identify specific greenfield entry opportunities for our clients.

3.1.10 Summary of Supply Representation (Generation Plus Transmission)

It is important to summarize the issues we have accounted for related to electric energy supply. Figure 28 does so. Notice in the figure, we have taken great effort to represent on a region by region basis the following five supply- and transmission-related phenomena:

- Cost and capacity of existing generation capacity
- Cost reduction that will evolve in existing generation capacity
- Imminent retirements in noncompetitive generation capacity
- Ingress and egress of transmission capacity to and from every North American region
- Entry of new, greenfield capacity based on the full fixed and variable forward cost to market.

The figure summarizes how MarketPoint represents each of these phenomena individually and collectively. We are unaware of any analytical framework save ours that systematically and formally represents each of these five supply phenomena, collectively or individually.

Figure 27: Never Underestimate New Entry

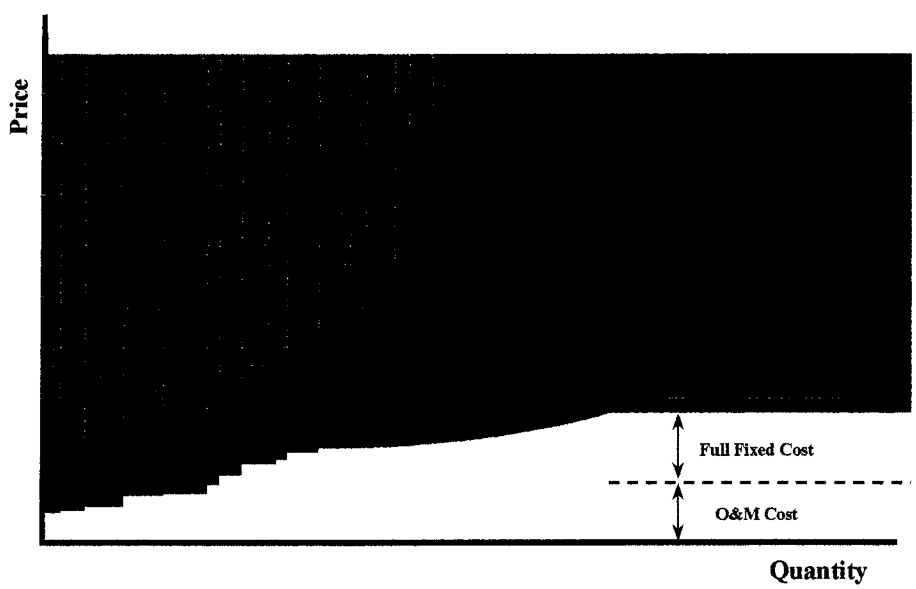
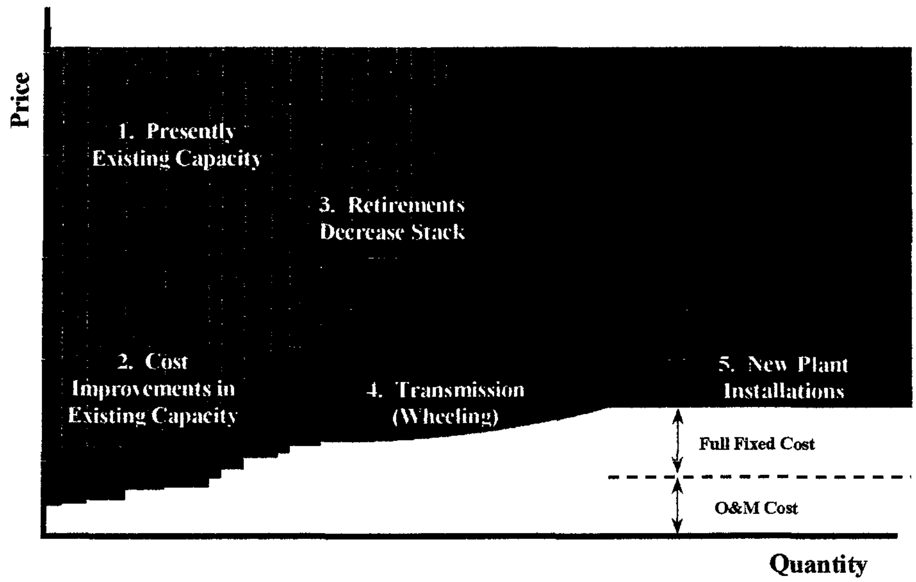


Figure 28: The Key Phenomena MarketPoint Represents

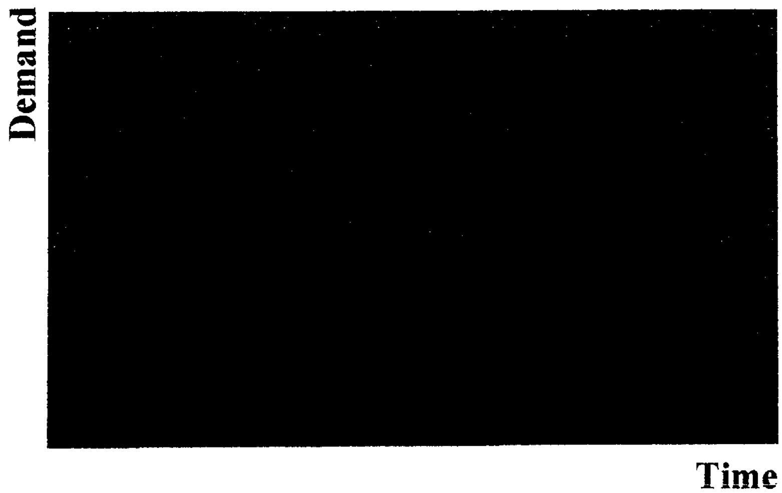


3.2 Representation of Demand

Having completed our generation and transmission overview in the previous section, we now turn to the question of incorporating electric energy demand into our model(s). Electricity demand varies by hour of day, day of week, week of year, and year. Furthermore, because electricity is not storable, it is the ultimate in "just in time" (JIT) manufacturing product. Literally 100 percent of all inventory must be embedded in standing capacity to produce, not in inventory that can be stored and resold upon demand. With today's technology, one cannot store electrons for later use. They flow and are used when they are generated. Generation units are like flashlights. When one turns on the switch, the flashlight produces light. When one turns off the switch, the flashlight immediately ceases to produce light. Like a flashlight beam, one cannot turn on the light during times when he does not need it and inventory it for when he does need it.

Projecting electric energy demand is akin to predicting demand for light from the flashlight. We need to project the hour by hour, day by day, week by week, and year by year demand for the beam of light, i.e., the aggregate stream of electric energy required by the customers in a given region. Figure 29 recognizes that the hourly demand for electric energy must be projected region by region throughout the 30 regions we use to comprise the North American electricity market.

Figure 29: We've Measured Demand Variation by Time of Day, Week, Season and Year



How can we determine what the hourly load variation is, and how can we project it 10 or more years into the future? To do so, we have accessed the hourly demand reports by every utility and other reporting entity in the country. We have accessed this voluminous information in automated form by hour by reporting entity over a complete three year historical period. It is our intention in so doing to be comprehensive, generating histories of demand by hour for every reporting entity in North America over the past three reporting years. By so doing, we are able in effect to develop a historical load duration curve for every hour of the year. This highly detailed information will allow us to build comprehensive models of demand at different levels of detail over different time horizons for our model.

What is the demand side methodology we have used? The raw, reported data alluded to above represents a historical demand schedule, which varies by time of day, week, season, and year. Figure 29 provides a conceptual illustration of the time-varying historical data we have assembled to populate our demand model within every subregion in North America and every node of every regionalized model such as the ERCOT model in Figure 12. The figure emphasizes that electricity demand is different for every historical hour reported in every region at every reporting point in North America. Indeed, there is a time-varying schedule of demand of the form in Figure 29 stretching over the past three years at every point in North America.

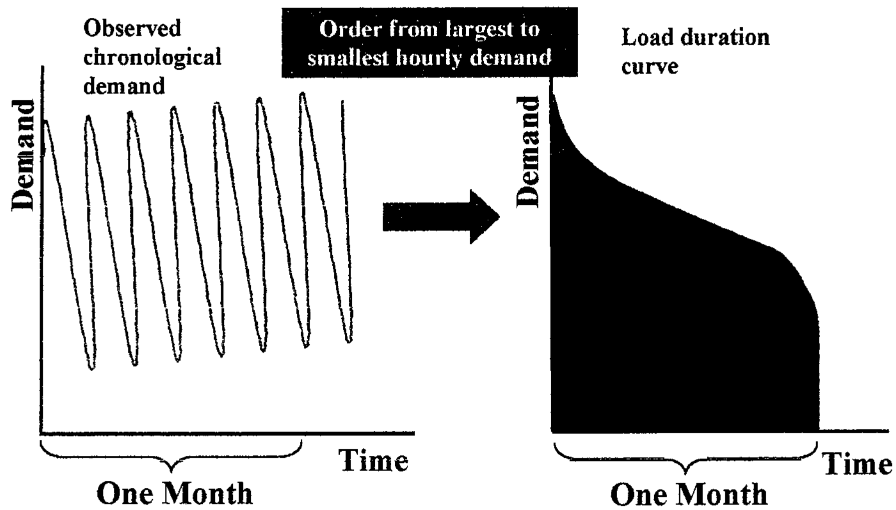
The next step is to aggregate the raw information hour-by-hour, region-by-region to create 30 regional aggregates of hour-by-hour electric energy consumption. To wit, we have taken the curves of the form in Figure 29 and aggregated them hour by hour according to the geographic subdivisions in Figure 9. After such aggregation, we can develop an overall curve of the form in Figure 29 for each of the 30 regions that comprise our model.

Once we have assembled this hour-by-hour load pattern over the three year historical period for the 30 regions of our model, we need to aggregate this data to the level required by the market model we wish to use. We can either maintain the hour-by-hour chronological form of the data, or we can use it to calculate daily, weekly, seasonal, and/or annual representations of load and load duration. Before discussing exactly how we have processed and aggregated the hourly demand data, it is worthwhile to define unequivocally what we mean by a load duration curve. To develop load duration curves, we begin with the hour by hour demand schedules for each of the 30 regions as depicted in Figure 29 and reorder them in sequence from highest demand to lowest demand in the given year. This demand reordering process can be used to create regional load duration curves as depicted in Figure 30. Such load duration curves represent total demand that occurs during a year, and they represent the total demand that occurs in every individual hour of the year. However, by reordering demands from highest hour to lowest hour, we lose the chronology of hourly demand by day, by week, and by season. All we would have is a highest-to-lowest snapshot of annual demand as distributed throughout the hours of the year. Whether this reordered series of demands is sufficient for a given need depends on whether we are studying hourly and daily load following. If not, the unordered representation of loads is sufficient. If so, we need to retain the chronology.

Using the WSCC, California and Southern Nevada as an example, Figure 29 illustrates three different analyses of the demand data we have undertaken. To begin, the figure depicts the average daily demand pattern for each of the twelve months of the year, which is termed "Monthly Average Hourly Demand" in the figure. The average daily load shapes are the solid curves that embody the characteristic double peak in the winter and the characteristic single peak in the summer. They are derived from three year average hour by hour demand by month as derived from the Altos demand data base. Such daily load shape information is used to simulate daily operation in our models. Referring again to Figure 31, we have crafted 12 monthly load duration curves and a single annual load duration curve. The 12 monthly load duration curves are used to populate our monthly models, and the annual load duration curve is to populate our longer run annual models. The comprehensiveness and hour-by-hour chronology of our demand side information is critical to developing demand side data of the type shown in Figure 31.

It is useful to review how we take the fundamental demand information in the form of Figure 31. We will use the monthly load duration curve as an example. The monthly load duration curves that come from the FERC 714 information we have assembled have the form in Figure 32, which are just the monthly load duration curves from Figure 31 for each month of the year. The first step is to select a number of discrete increments into which we want to disaggregate the continuous curve in Figure 32. That is, if we wanted to use a "stairstep" approximation to Figure 32, how many stairs would we want to use in order to get a good enough approximation to the curve. If we had elected to use ten stairs to approximate the curve, we would be able to draw the 10-stair discrete approximation to the continuous curve in Figure 32 as shown in Figure 33. The process of moving from the continuous curve in Figure 32 to the discrete approximation in Figure 33 can be done using extremely fancy, sophisticated, statistical fitting methods, or it can be done very approximately.

Figure 30: Create Monthly Load Duration Curve by Sorting



Notice that the curve in Figure 33 distinguishes ten different, discrete demand levels because it has ten different, discrete horizontal tranches. Beginning at the left, we see the highest tranche, and we see a series of declining tranches until we get to the lowest horizontal tranche at the lower right. Each of these ten horizontal tranches corresponds to ten different level of demand, each of which we express in MW. But the discrete curve also tells us how many hours each of the ten discrete levels of demand occurs. For example, the highest and leftmost level of demand persists in the diagram for 1 percent of the hours in the month. Assuming that there are 730 hours in the month, this means that the highest and leftmost level of demand persists in the diagram for 7.3 hours in the month. The second to highest and second to leftmost level of demand persists for 3-1=2 percent of the hours in the month, i.e., 14.6 hours in the months. Continuing this logic across the diagram, we see that it is in effect a histogram for the occurrence for ten different levels of demand. If we calculate the supply-demand equilibrium for each of these ten different levels of demand, our model will calculate a histogram or market clearing price. There will be ten different, distinct market clearing prices each with a corresponding frequency of occurrence. That is precisely what the MarketPoint model does in its simplest form. Figure 34 illustrates how this occurs. Ten demand points (each with a frequency of occurrence) go into the model. Ten supply-demand crossing points are calculated, giving ten market clearing prices on the vertical axis. These ten market clearing prices occur with exactly the same frequency of occurrence as the ten demand tranches that generated them. Therefore, the ten prices are in effect a histogram over prices during the month, a so called price duration curve.

Figure 31: California-Nevada Historical Pattern of Load

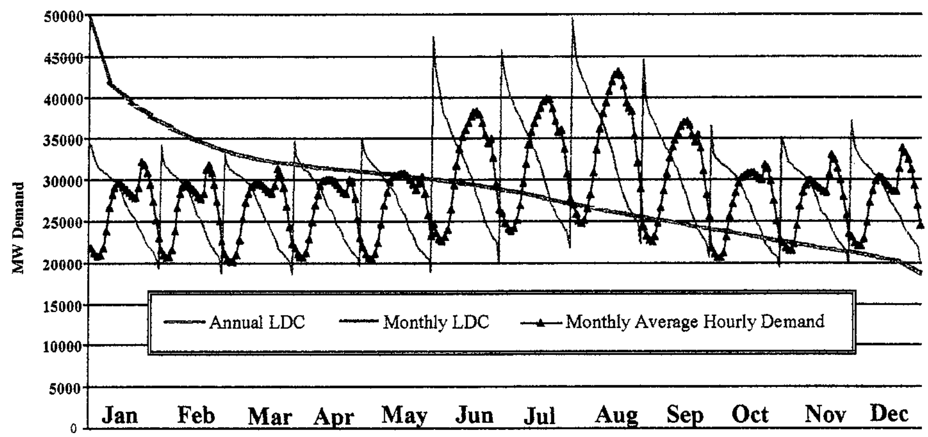
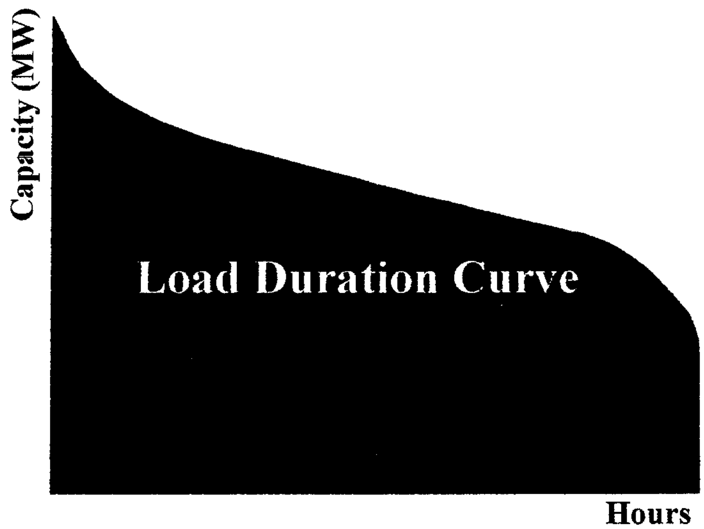


Figure 35 shows direct output from the model. In order to understand the market clearing prices depicted in that figure, consider that load has been disaggregated into ten monthly periods:

- Average load during top 1 percent of hours (designated 1%).
- The average load excluding the top 1 percent of the hours but including the top 3 percent of the hours (designated 3%).
- The average load excluding the top 3 percent of the hours but including the top 5 percent of the hours (designated 5%).
- The average load excluding the top 5 percent of the hours but including the top 15 percent of the hours (designated 15%).
- The average load excluding the top 15 percent of the hours but including the top 35 percent of the hours (designated 35%).
- The average load excluding the top 35 percent of the hours but including the top 60 percent of the hours (designated 60%).

- The average load excluding the top 60 percent of the hours but including the top 80 percent of the hours (designated 80%).
- The average load excluding the top 80 percent of the hours but including the top 90 percent of the hours (designated 90%).
- The average load excluding the top 90 percent of the hours but including the top 98 percent of the hours (designated 98%).
- The average load excluding the top 98 percent of the hours but including the top 100 percent of the hours (designated 100%).

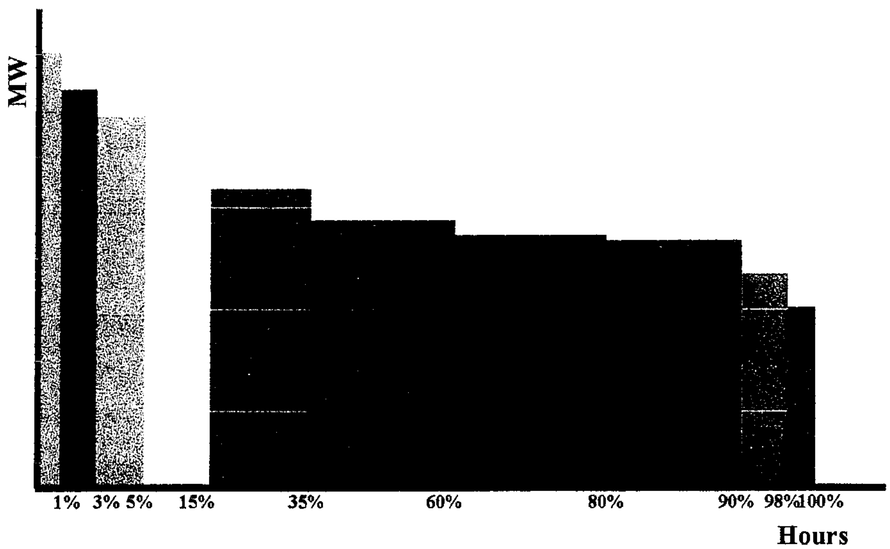
Figure 32: We Begin with a Continuous Load Duration Curve for Each Region in the Model



In effect, the percentage terms indicated in the legend represent the percent of time that the given or larger load persists. For example, the 3% curve represents the 97th fractile of load; the load exceeds this level only 3% of the time. This component of load is relatively peaky; load is higher than this level for only 3% of the hours of the month. Therefore, the percentages shown in the price diagram represent the percentage of time that the price is equal to or larger than the indicated curve.

Figure 35 represents just such a price duration curve that was calculated by the Altos model in support of the Duke New Smyrna Beach application in Florida. It is immediately apparent from the diagram that we used five demand tranches rather than ten because there are five price lines in the diagram. Nonetheless, we have calculated a price duration curve for every month of the year in Florida and plotted the estimated production cost of the Duke New Smyrna Beach unit. This is precisely what the model is designed for and is so good for.

Figure 33: Disaggregate Each Month into Ten Load Tranches



Our electric energy demand projection combined with a normalized load duration curve calibrated to historical load shapes constitutes a forward demand schedule in the electric model. In the lexicon of economic theory, this demand projection represents an "inelastic" projection of electric energy demand. We have the capability on a load category by load category basis to specify a price elasticity of demand so that the actual projected demand for electricity by the model is price sensitive. This capability is represented schematically in Figure 36. Notice in the figure that we specify price-sensitive demand curves for each of the discrete increments of load. There is a peak load demand curve complete with price sensitivity, an intermediate load demand curve complete with price sensitivity, and a base load demand curve complete with price sensitivity. We believe this price sensitivity to be potentially important as the true marginal cost of on peak power becomes increasingly exposed to electricity customers for the first time. In the past, customers have been insulated from the true marginal cost (i.e., the true price) of peak load power because of regulatory cross subsidies of peak load prices by base load prices and of residential customers (who cause the peak to a significant degree) by industrial customers. Our price sensitivity feature has not yet been fully studied or exploited, but it promises to be important to asset valuation and trading in some regions during some periods of time.

Figure 34: Discretized Load Duration Curve Gives Ten Market Clearing Prices

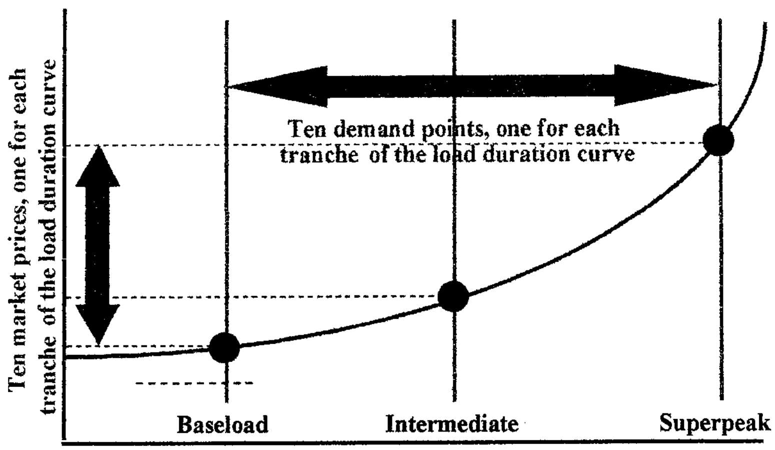
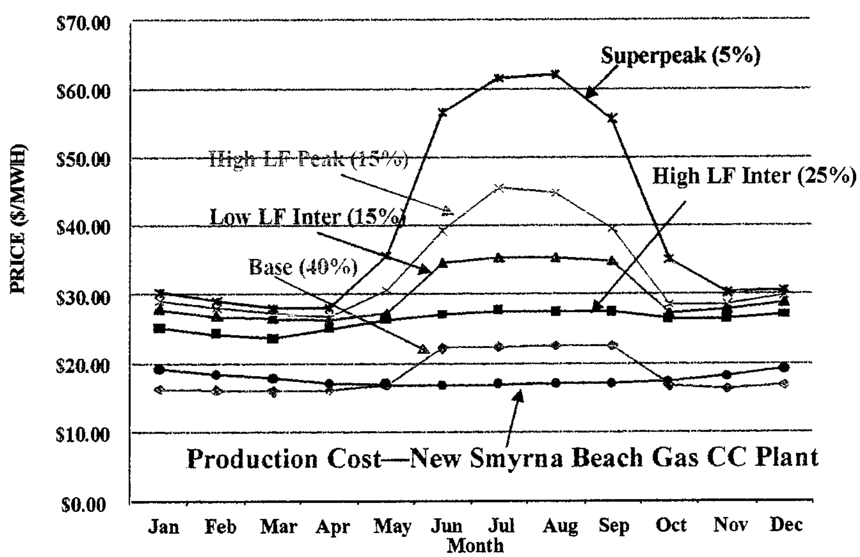


Figure 35: The Duke/Altos Model Predicts Forward Market Clearing Price in Florida

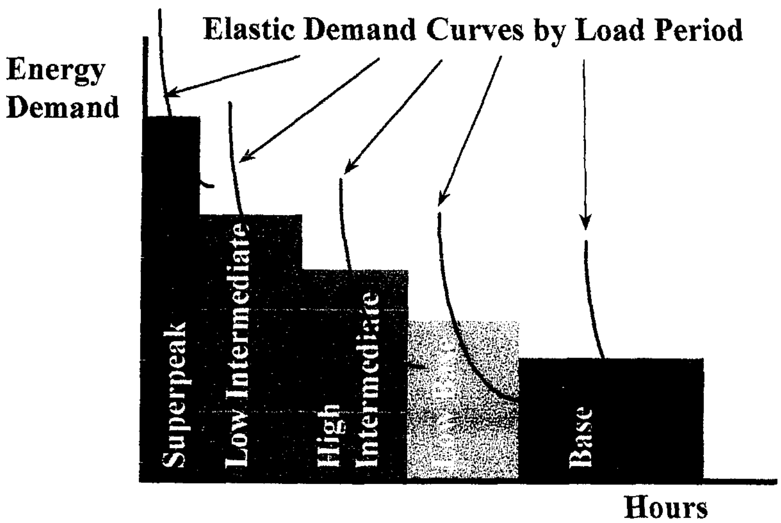


4 SUMMARY OF MODEL STRUCTURE

To summarize, the Altos North American Electric Power Model can be represented schematically as shown in Figure 28. The model contains a complete representation of supply including

- generation as it presently exists,
- cost reduction in present capital stocks,
- retirement of present and future capital stocks,
- existing and new increments of inbound transmission,
- existing and new increments of outbound transmission, and
- prospective entry of new plants and new technologies.

Figure 36: We Can Consider Price Elasticity in Each Load Period



The model contains a complete representation of inbound and outbound inter-regional transmission that can accommodate not only postage stamp transmission tariffs but also a rich and complete range of distance-based, zone-based, value-based, monopolistic, or other tariff structures. On the demand side, the model is capable of representing demand on a chronological basis, but the present implementation used to support long and short run decision is based on a discretized load duration curve approximation. Viewed as an integrated whole, the model represents changing supply and changing demand and finds the market clearing price and quantity. In our lexicon, the model finds the "magic crossing point" between supply and demand. The market clearing price represented by this magic crossing point varies throughout the year as shown in the figure.

5 CONCLUSION

Altos and our customers have developed increasing confidence in the results of the MarketPoint model, and more companies are becoming increasingly committed to using it to guide their asset valuation decisions and our marketing and trading decisions. We believe that the model can generate competitive advantage, allowing us to increase profits and reduce risks of our asset and trading businesses and to coordinate and marry them at the most fundamental level.

13 APPENDIX B: DESCRIPTION OF THE NORTH AMERICAN REGIONAL GAS (NARG) MODEL

MODELING OF DEPLETABLE RESOURCES, PIPELINES, AND DEMAND IN THE NORTH AMERICAN REGIONAL GAS (NARG) MODEL

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April 17, 2000

APPENDIX B

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1 OVERVIEW AND SUMMARY OF NARG

1.1 Overview of the North American Regional Gas (NARG) Model

The North American Regional Gas (NARG) model[1] is an economic model of the natural gas industry of North America that represents how regional interactions between supply, transportation, and demand determine price, quantity, and reserve additions. The objective of this report is to describe how the NARG model works and why it is the best representation of North American gas markets available anywhere. We provide enough detail to illustrate comprehensively how the model works, yet we omit the detailed mathematics. Readers desiring a more mathematical description are referred to Nesbitt, Haas, and Singh, The GRI North American Regional Gas Supply-Demand Model, Decision Focus Incorporated report to the Gas Research Institute, 1988, available from Altos to our licensed customers. The balance of this initial section discusses the time horizon and time period conventions resident within the model. Section 2 characterizes the resource model in depth. Section 3 describes the demand side of the model, and Section 4 outlines the pipeline transportation component of the model. Collectively, these sections provide enough methodological information to characterize rather completely how the NARG model works and why it represents North American gas markets in the best possible way.

1.2 The Need for a North American Gas Model

Producers own natural gas resources in various basins in North America. They must monetize those resources to generate profits and shareholder value, and their ability to do so depends on the forward market price in the region where they are located and the cost to produce them. Pipeline companies own gas transmission assets, and they must likewise monetize those assets to create profits and shareholder value. Their ability to do so depends on the forward market price at the downstream end of their pipe minus the forward market price at the upstream end of their pipe. Trading companies own "paper" assets that must be bought and sold in order to monetize them. Profitability depends on forward market prices from which paper assets derive value (hence the term "derivative." Consumers must shop prudently and accurately for the lowest cost gas available, and their ability to do so depends on the forward market price in the region in which they operate. Vince Lombardi once said: "Winning isn't everything, it's the only thing," Altos observes: "Price isn't everything; it's the only thing." **NARG is the premier forward price prognostication tool in the natural gas industry.**

[1] GEMS is a tradename owned by Decision Focus Incorporated.

NARG simulates how regional interactions between supply, transportation, and demand interact to determine market clearing price, flowing volume, storage injection and withdrawal, and reserve additions. The geographic scope of the NARG model is presaged in Figure 1. In its original long-run form, NARG represents a forward time span of thirty years or more. In its newer short run form, NARG represents month-by-month a forward time span of 36 months, taking account of market region and production region storage injection and withdrawal as well as supply, transportation, and demand. NARG has been in continuous existence since 1983 and has been used for every pipeline expansion decision and most of the resource basin profitability evaluations in North America since that time.

Figure 1: The North American Regional Gas (NARG) Model

NARG comes to our customers fully equipped with the best and most tested natural gas data available. Figure 2 illustrates the basic sources of data upon which our model relies. Altos has an agreement with the United States Geological Survey (USGS) whereby the USGS delivers to Altos its best and most current United States natural gas supply data. Derived from detailed probabilistic analysis of an astounding 575 plays that comprise the United States gas and oil resource base, the USGS data lies at the heart of Altos' reference case resource database. Altos also has an agreement with the premier energy organization in Canada, the National Energy Board, to provide the entirety of its Canadian gas supply, pipeline transportation, and demand data. Altos has the best and most current pipeline data in North America. Altos and our clients continually revise and update the transportation data including capacity (obtained by continual downloading of EIA data), tariffs, embedded cost, discounting behavior, dates of entry of prospective new pipelines, and costs of those new pipelines. To populate the demand side of NARG, we download EIA and GRI demand data by segment. All NARG data can be amended element by element to substitute client-proprietary considerations and to represent uncertainty.

Figure 2: Sources of NARG Data

	UNITED STATES	CANADA
SUPPLY	USGS	NEB
PIPELINE	Altos	NEB
DEMAND	GRI/EIA	NEB

1.3 Time Period Structure of the NARG Model

The NARG model and the MarketPoint software upon which it is based are neither short- or long-term in nature. The MarketPoint approach is fully the most general approach in existence with regard to its dynamic assumptions. In particular, MarketPoint assumes that the future price schedule is a continuous, nonlinear function. (It makes a similar continuous assumption for flowing gas volume, reserve additions, and capacity additions.) The MarketPoint user specifies the time interval over which he or she wishes to sample from the continuous price (or other function) by specifying the following three parameters:

- Number of Time Points, i.e., the number of samples from the continuous future nonlinear price curve the user wishes to consider.

- Time Interval Between Time Points, i.e., the inter-time point interval the user wishes to consider.

- Number of Intra-Year Time Points, i.e., the number of subannual time points within each year the user wishes to consider. For example, in the short run gas model, we specify 36 monthly time increments. Time variation of core and noncore demand across these monthly time increments allows us to take account of seasonal demand variation and storage injection/withdrawal to fulfill it. MarketPoint allows us to specify as many intra-year periods as we like, including months (January, February, March,...) or others.

Armed with these inputs, which are "data" to the model and are not hard-wired into the computer code, MarketPoint creates the specified number of time points separated by the specified time interval. The long term version of the NARG model specifies ten (10) time points separated by a five (5) year interval with a single intra-year time increment. This creates a 45-year future model horizon, sampling from the continuous nonlinear future price curve ten times, and considering only annual gas demand.

2 THE SUPPLY SIDE OF THE NARG MODEL

This section puts forth a rather complete description of the supply elements of the NARG model. We will discuss not only the rationale and details of the supply side calculation but also fully characterize the supply side data, where we get it, and why it is the best and most accurate descriptor of North American supply.

2.1 Regional Structure

The NARG model is a multiregional supply, transportation, and demand model. The reasoning underlying the supply regionalization is central to a full understanding of NARG. This section discusses how and why we have regionalized North America to take account of the resource deposition.

2.1.1 Regional Structure of the United States

It would not be useful to subdivide the supply regions in the NARG model according to political or demographic boundaries (e.g., states, provinces, census regions). Rather, it is more useful and appropriate to subdivide the supply regions according to existing and prospective natural gas producing potential, i.e., to subdivide on a geological basis. In making such subdivision, consideration must be given to the structure of the existing and prospective future pipeline system. In particular, supply regions must be associated with the upstream ends of existing pipelines and with the upstream ends of anticipated new pipelines. The supply regions in the NARG model were selected with several considerations in mind.

First, when it is necessary to distinguish differences among gas producing basins in terms of transportation costs to demand regions that compete for that gas, those basins have been associated with distinct supply regions. That is, transportation cost differentials dictate supply regionalization.

Second, for those sources that will require new pipeline or gathering capacity, regional supply distinctions have been made. If a particular resource producing basin relies on the addition of new pipeline or gathering capacity to become economically viable, that supply region is distinguished from other supply regions. Indeed, in such cases, the supply region and the outward-bound pipeline are inextricably linked, and we must model them in effect as a pair. Proper consideration of the relationship between pipeline segments and resource production regions was one of the primary considerations that has in recent months motivated the disaggregation of the Texas intrastate portion of the natural gas system and disaggregation of the Gulf Coast and Gulf-to-Northeast pipeline links. To wit, we needed to disaggregate the Gulf Coast gas-producing region in order to represent in more detail its configuration relative to the supply basins it exploits and the interim or final demand centers it serves.

Third, when it is necessary to distinguish resource endowment and cost differences among producing basins, those basins are distinguished by region. In general, there are substantial differences among resource producing regions with regard to extent, cost, and distribution of the natural gas resource base. Some would argue that such heterogeneity of the resource base motivates an extremely detailed representation of natural gas supply. Countering such argument is the observation that much supply side aggregation is dictated by the specific structure of the pipeline system. We have sought to balance the desire for more supply side regional and technological detail with the desire to realistically represent the transportation corridors for delivering gas to market. However, it has become clear over time that it is increasingly necessary to disaggregate the Louisiana and Texas region of the Gulf of Mexico, both onshore and offshore. The region is that recently unfolding resource deposition information related to the onshore and offshore Gulf resource indicates substantially higher potential located in specific locations. Our disaggregation of the Gulf of Mexico resource base was designed to capture those newly emerging realities.

Fourth, many supply or pipeline projects have direct effects only in localized regions of the United States or Canada, yet the indirect effects proliferate broadly throughout all supply and demand regions of all countries represented. In effect, prices carry economic signals from the single directly affected region to all other regions of the country along all the paths of the pipeline network. The representation of the pipeline network must contain sufficient detail to represent all important existing and prospective future paths. Noting that pipeline connections cause adjacent markets to communicate, we are motivated to incorporate a larger rather than a smaller number of pipelines and pipeline corridors into NARG.

Fifth, government policy can be region-specific. Excessive aggregation across regions would obviate the ability of the model to properly represent government policy. For example, there are significant tax, financial, and other differences among regions, necessitating regional distinctions in the model. A specific illustration is the argument that the Alliance pipeline might use liquid sales to subsidize gas transportation. In such a scenario, the transportation cost along Alliance would be smaller than "normal" gas pipeline economics might otherwise dictate. The NARG model can represent such phenomena related to Alliance as well as a wide range of policy and other similar phenomena.

With regard to the conventional and deep natural gas resource base, the Potential Gas Committee (PGC) regions and designations were adopted and incorporated into the model. There are several reasons for this regionalization. First, much of the resource data is reported in geological and geographic zones consistent with the PGT regions. The PGC, the United States Geological Survey (USGS), and similar resource base reporting organizations have given a great deal of much thought to the appropriate degree of regional disaggregation of the conventional resource base. We have sought to incorporate that thought by adopting their regions.

Unconventional gas (tight sands, methane from coal deposits, and Devonian shale), which are commonly called "continuous deposits," are associated in the model with conventional gas supply regions and are distributed among the conventional gas supply regions as dictated by their actual physical location. The unconventional gas resource base is distinguished in the same degree of regional detail as the conventional gas resource base, but the realities of where it occurs are properly represented. Using the same regional distinctions for unconventional as well as conventional gas is particularly convenient and we think proper because the unconventional gas resource must enjoy the same access to the transportation system as conventional. Furthermore, the unconventional resource base is further down the economic ladder than the conventional resource base, meaning that the pipeline infrastructure built to exploit the lower cost conventional resource base is likely to dictate the exploitation pattern of the higher cost unconventional resource base.

Synthetic sources (e.g., coal gasification) are regionalized according to coal producing regions of the United States. The major coal producing regions of the United States have been associated with the various PGC supply regions and have been placed into the corresponding aggregate NARG model gas supply regions. For example, the North Dakota coal region (where minemouth coal gasification might occur) is considered to lie within the Northern Great Plains supply region. Small, exotic sources such as methane from waste or biomass are positioned within the various demand regions, representing the fact that they use only the distribution system, not the transportation system.

2.1.2 Regional Structure of Canada

The regional structure of the Canadian gas system and the supporting resource data are distinguished as follows. The Western Canadian Sedimentary Basin has been disaggregated into the three provinces in which it resides, and the balance of the Canadian resource base has been distinguished regionally:

- British Columbia
- Alberta
- Saskatchewan
- Eastern Canada including Sable Island and Hibernia
- MacKenzie Delta
- Canadian Arctic (Beaufort Sea, Arctic Islands)

As with the United States, the particular regional disaggregation for Canada was chosen with several purposes in mind. First, we need to properly position the primary gas deposits in Canada. It is known that the vast majority of economic Canadian gas occurs within Alberta in the Western Canadian Sedimentary Basin. Yet, that there are significant gas deposits in British Columbia and Saskatchewan and that the latter deposits are positioned differently with regard to the Canadian transportation system.

Second, the Canadian resource base must be distinguished at a level of geographic detail necessary to support analysis of existing and prospective Canadian border import locations to the United States: Huntington/Sumas (Westcoast), Kingsgate (PGT), Monchy (Northern Border), Alliance, Emerson (Great Lakes), Niagara, and Iroquois. The level of border import and demand detail within the United States dictates the level of resource base disaggregation needed for Canada.

Third, it was necessary to distinguish key demand patterns in Canada, which in the past have influenced not only delivered gas prices in Canada but also export economics and government policy. In particular, much of Canadian gas demand occurs within Ontario, which is Canada's most populous and most politically influential province. However, Ontario demand must be served through long distance pipeline from Alberta either indirectly through the Great Lakes system or directly through TransCanada.. In recent years, Ontario has imported gas across the St. Claire lake from Detroit, thereby experiencing competition from the United States. Alberta and points intermediate (i.e., Saskatchewan) must therefore be distinguished.

Fourth, it is necessary to distinguish the more Northern, Arctic gas resource base in sufficient detail; otherwise, one cannot predict what is the most economical resource base exploitation pattern and what will be its impact on gas price throughout North America if any.

Finally, the eastern Canadian resource producing basin contiguous to the Sable Island has grown in importance. We have distinguished the Eastern Canadian, Sable Island resource base as well.

2.1.3 Geographic Representation of Gas Import Alternatives

Border import locations are positioned at various points along the United States-Canadian border and the United States-Mexico border. There are two prospective border import locations from Mexico represented in the model. LNG import locations are positioned along the east, Gulf, and west coasts at various existing and prospective future locations. The NARG model is embedded within a World Gas Trade Model that explicitly calculated the LNG import point prices based on world supply-transportation-demand considerations. This is necessary to ensure that the prospective and existing interconnections to the rest of the world are credible.

2.1.4 Overall Regional Structure

The NARG model, which is the North American portion of the World Gas trade model, distinguishes three geographic regions, the United States, Canada, and Mexico. Alaska is represented as part of the United States, but the colossal transportation system that would be needed to move Alaskan gas to the Lower 48 United States and its interconnection with Canada is represented. The NARG model contains the following regional detail

Supply

- United States
  - Anadarko/Arkoma Basins
  - Appalachian Basin
  - Gulf of Mexico Basins disaggregated by Texas and Louisiana onshore and offshore
  - Gulf-to-Northeast Pipeline Corridor Transportation Region
  - LNG Import Terminals
  - Mexico Border Import and Consumption Locations
  - Midwestern Basins
  - North Alaska
  - Northern California Supply Region
  - Northern Great Plains Basins
  - Offshore Atlantic Coast
  - Permian Basin
  - Rocky Mountain Basins

- San Juan/Raton Basins
- South Alaska
- Southern California Supply Region

■ Canada

- Alberta Supply Region
- British Columbia Supply Region
- Eastern Canada Supply Region
- Northern Canada Supply Region
- Saskatchewan Supply Region

Canadian Border Import Locations

Oil Supply Region

Demand

■ United States

- East North Central Demand Region
- East South Central Demand Region
- EOR Demand Region
- Middle Atlantic Demand Region
- New England Demand Region
- Pacific Gas and Electric Demand Region
- Pacific Northwest Demand and Supply Region
- San Diego Gas and Electric Demand Region
- South Atlantic Demand Region
- Southern California Gas Company Demand Region
- West North Central-Mountain Demand Region
- West South Central Demand Region

■ Canada

- British Columbia Demand Region
- Canadian Oil Region
- Eastern Canada Demand Region
- Ontario Demand Region
- Western Canada Demand Region

The regionalization of the NARG model is embedded in the network "tinkertoy" diagrams we provide to our NARG customers, an example of which is contained in Figure 3. In reviewing our network diagram representations of North America (which are available to NARG licensees), it will become immediately obvious just how the foregoing regions have been represented and what level of detail is contained within each region. It will represent the degree to which NARG represents individual, nameplate pipelines and the degree to which it represents pipeline corridors or bundles.

2.2 The Depletable Resource Supply Hexagons--How Do They Work?

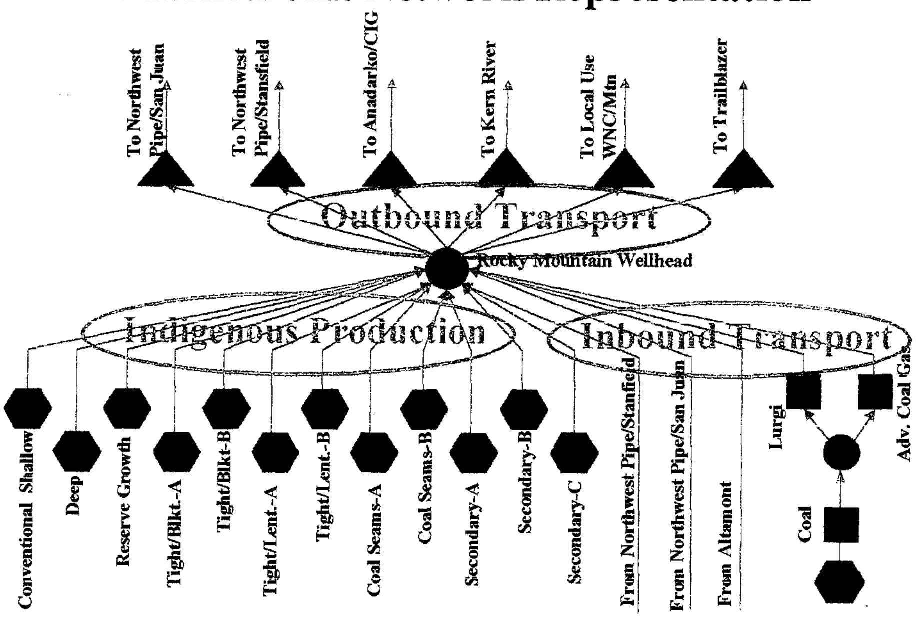
This section outlines how the supply nodes in the NARG network operate. Implicit in this discussion are a number of critical dimensions of the NARG technique:

- What is the economic logic and rationale that underlies NARG?
- What is the data necessary to support the supply nodes? How should it be interpreted? How should it be assembled?
- What are the characteristics of supply-demand equilibrium in an economic system containing depletable resource processes? How can the supply-demand-balancing concept be applied to markets with depletable resource processes within?
- What is the right way to represent depletable resource production? There are so many incorrect or naïve ways to represent depletable resource production. There is only one right way. What is it?
- What is the right way to represent equilibration between resource markets (e.g., gas) and financial markets? Financial markets provide such variables as the cost of capital, which is related to returns on equity in broad financial markets and interest rates on debt in broad markets. How do we represent the fact that at supply-demand equilibrium, there can be no possibility of arbitrage between financial markets and gas markets? In a modeling sense, how can we be sure that the forward price and cost of gas are properly related to discount rates that represent costs of capital?

This section answers those questions in summary form. We have prepared much more detailed documentation elsewhere and can make copies available to our NARG customers upon request.

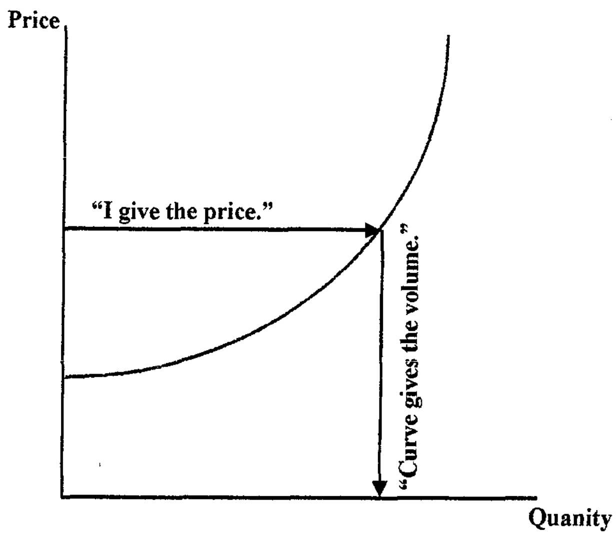
To begin this discussion, consider the simply notion of an economic supply curve. Figure 4 is a traditional static economic supply curve. It is static in the sense that it represents a single point in time, i.e., a "snapshot" in time. The simple static supply curve answers the following question: "If the market price were p, how much supply would the producer voluntarily and profitably deliver to the market?" Such a supply curve can be derived fundamentally by appealing to the notion of a price-taking, profit-maximizing producer doing the best he can given that everyone else in the economy is simultaneously doing the best they can. (We have interpreted the supply curve as a price-taking, profit-maximizing producer elsewhere in our NARG documentation. See Nesbitt, Haas, and Singh, The Gas Research Institute North American Regional Gas Supply-Demand Model, Decision Focus Incorporated report to the Gas Research Institute, 1988.) Keep squarely in mind, the notion of a supply curve is tantamount to the notion of a price-taking, profit-maximizing producer. In NARG, just as in the real world, producers are assumed to be striving to maximize profits. The notion of a price-taking producer is depicted in the simple static supply curve in Figure 4 by reading a price off the vertical axis and using the curve to find the corresponding quantity on the horizontal axis. The quantity on the horizontal axis has the property that it represents the very last Mcf in the market that can be produced profitably at the given price p. (The very last Mcf is termed the marginal Mcf.) All Mcf's less than the very last Mcf will be produced at a strictly positive profit; their cost will lie below that of the marginal Mcf. The very last Mcf can be produced at "breakeven," i.e., zero profit. Economists use the term "direct supply curve" for Figure 4 to indicate the fact that the market is specifying a price and the producers are deciding how much to produce at that price.

Figure 3: Rocky Mountain Wellhead Gas Market--MarketPoint Network Representation



NARG uses the inverse of the direct supply curve, which is depicted in Figure 5. In particular, NARG specifies a quantity on the horizontal axis and uses the supply curve to read the corresponding price off the vertical axis. As indicated in Figure 5, the inverse supply curve as it is termed by economists begins by specifying a quantity or volume to be delivered to the market on the horizontal axis and then uses the inverse supply curve to read the price off the vertical axis necessary to motivate producers to voluntarily and profitably produce and deliver that specified quantity to the market. The notion of an inverse supply curve in Figure 5 is quintessential to the NARG calculation procedure in a way that will be made clear shortly. To reiterate, NARG will be asking the question: "If the market wanted me to deliver the quantity q, how high a price would the market have to sustain in order to induce me to voluntarily and profitably deliver that quantity?" The inverse supply curve is exactly the same as the direct supply curve; they are precisely the same curve. With the inverse supply curve, one reads the price from the vertical axis at a prespecified quantity from the horizontal axis by following the arrows in Figure 4 rather than the reverse direction in Figure 5.

Figure 4: Direct Supply Curve



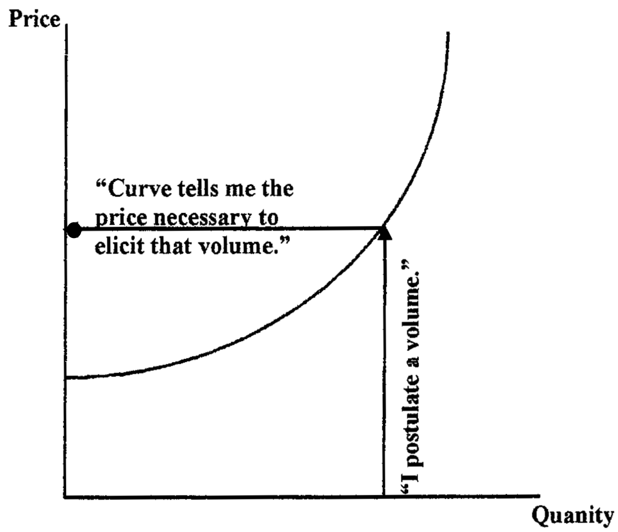
Using the notion of an inverse supply curve, how does NARG work? The answer is simple. NARG successively executes the following set of steps:

1. Guess the supply volume, i.e., guess a quantity on the horizontal axis of Figure 5.

2. Read the price necessary to elicit that supply volume from the inverse supply curve by following the upward and leftward arrow in Figure 5.

3. Pass the price thus determined to the demand curve, i.e., to the portion of the market that lies downstream from the supply processes.

Figure 5: Inverse Supply Function



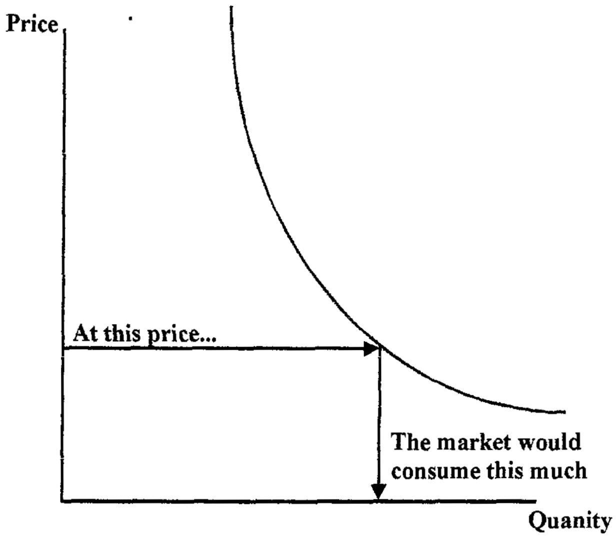
4. Determine the market demand that would occur at the price specified in step 3 by reading it from the demand curve. Figure 6, which represents the demand curve, illustrates how this is done.

5. Pass the demand quantity back to the supply curve.

6. If the demand passed back to the supply curve in step 5 is the same as the supply volume that was initially guessed in step 1, NARG is complete and can quit. If the demand from step 5 is different from the supply volume that was initially guessed in step 1, NARG replaces the guess in step 1 with the calculated volume from step 5 and repeats. NARG will have to execute this series of steps a number of times until the step 1 guess is the same as the step 5 guess. When the two successive guesses are equal, NARG has achieved supply-demand equilibrium. The NARG method is no more than a simple supply-demand cobweb method commonly seen in the economics literature and is illustrated in Figure 7.

NARG works as a supply-demand cobweb procedure that finds the "magic crossing point" between supply and demand. The inputs to the NARG model are the two curves in Figure 7, the supply curve and the demand curve. The outputs from the NARG model are the price and the quantity where the two curves cross each other. To emphasize, **inputs are curves, and outputs are magic crossing points.** The magic crossing points represent market clearing prices and quantities traded at those prices. What is needed to create and run NARG is the supply curve and the demand curve. The remainder of this section describes how we conceive and assemble the supply curves basin by basin for natural gas supply and region by region for natural gas demand.

Figure 6: Demand Evaluation



We should emphasize that representing primary resource production is not as simple as assembling a static, time-independent supply curve of the form in Figure 4 or Figure 5. Depletable resource supply is most definitely NOT a static issue; it is an intrinsically dynamic issue. Depletable resource supply must specifically account for such phenomena as

- Production dynamics for each well, including the maximum possible level of production and the degree of cost escalation beginning from the time production from each vintage of well is initiated until the time that well is exhausted. The full life cycle production profile and cost of each well are intrinsically dynamic and must be considered.

- Successively ongoing exploration and production across a given basin. Successive, cumulative exploration and production is what causes a resource to be depleted in a given basin. Capital and operating costs and dry hole probabilities change as depletion exhausts resource deposits in descending order of attractiveness across each producing basin, and we must represent the dynamics of that process.

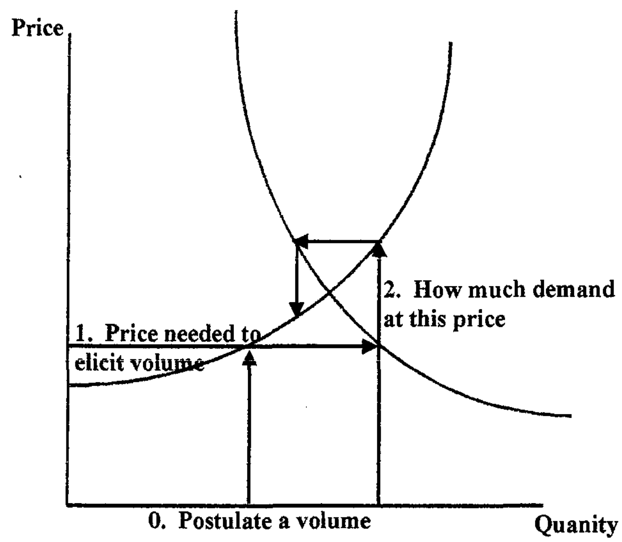
- Technological innovation, including 3D seismic, horizontal drilling, advanced drilling such as spiral drilling, etc. Such technological innovation has in the past decade stimulated aggregate volumes available in each basin and has depressed the cost of exploiting any given volume. Technological innovation has created an important dynamic force that we must carefully and explicitly represent.

- Retirements of existing capacity. As old wells are retired, the fundamentals of short run supply change. This too is an important dynamic issue that NARG represents.

- Addition of new reserves and subsequent production from those reserves. NARG focuses on the process by which a market draws in new reserves and new production from those new reserves over time. In economists' jargon, NARG gives a great deal of attention to "entry" and "exit" in the primary resource producing sector.

NARG represents each of these elements in ways we are about to describe.

Figure 7: NARG Uses an Iterative Supply-Demand Calculation



The analogy in Figure 7 of "start with a guess at quantity q; read the price p off the supply curve" will be preserved as we extend to a fully dynamic model. However, we have to carefully extend the notion so that it remains robust and correct. To do so, we have used the analogy "start with a guess at the production schedule q(t) forward through time; read the corresponding price schedule p(t) forward through time" off the supply curve. Rather than beginning with a scalar quantity q and reading off a scalar price p, we start with a time-vector q(t) and determine a time-vector p(t). To begin the NARG supply node calculation, therefore, we guess a gas production schedule q(t) forward through time. The forward gas production schedule q(t) extends forward throughout the entire time horizon of the model. Figure 8 illustrates what such a gas production schedule q(t) might look like.

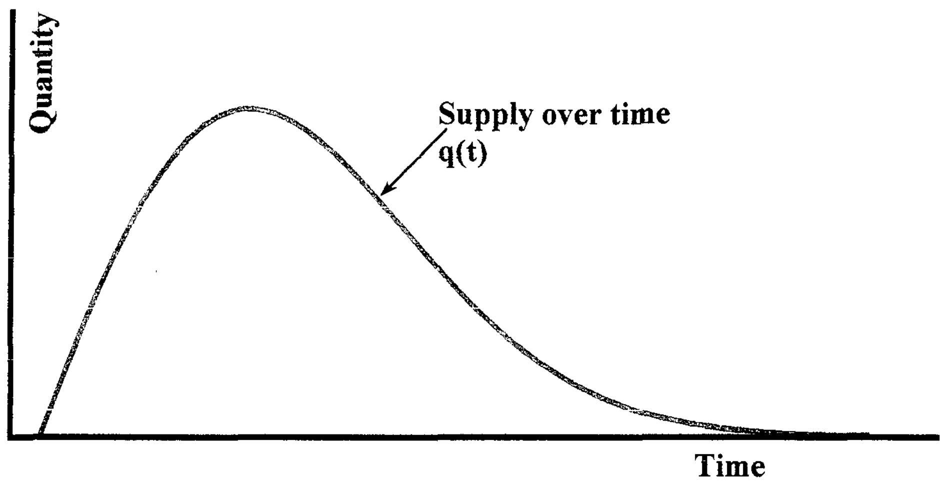
Beginning with the postulated schedule of gas production forward in time q(t) as indicated in Figure 8, we must first determine the schedule by which proved reserves must be added in order to sustain and meet the specified gas production schedule q(t). To wit, how much and when would reserves have to be added to meet the production schedule q(t) in Figure 7? The answer is found by first recognizing that each well, i.e., each vintage of well, experiences a geometrically declining level of production during its life. The production schedule from a well decays geometrically (exponentially) as shown in Figure 9. We use the convention that the area under what we call the "facility decline profile" (the exponential curve) is 1 Mcf. The facility decline profile therefore tells us what is the time pattern of future production that will derive from each Mcf of proved reserves today. For example, if there were 6.87 Tcf of proved reserves in place today, the production from that 6.87 Tcf of proved reserves will follow the shape of the facility decline curve in Figure 9 normalized to a total shaded area of 6.87 Tcf. Geometric (or other) facility decline curves are the fundamental building blocks of primary resource production, i.e., the fundamental relationship between proved reserves in the ground and flowing gas into the gathering and interstate pipeline system. The facility decline curve relates deliverability to proved reserves.

The facility decline curve is one of the fundamental data inputs to the NARG resource model. For each hexagonal tinkertoy in the model, i.e. for each increment of resource in each producing basin, we input a geometric decline rate for that tinkertoy. The reciprocal of the geometric decline rate is commonly known as the "reserves-to-production ratio." If we want a 10 year R/P ratio, we simply input a geometric decline rate of 0.1. This creates the following equation for the facility decline curve in Figure 6: $prod(t)=0.1*(1-0.1)^t$. Summation of this equation from 0 to infinity verifies that the area under the curve is indeed 1 Mcf. Annual production in the first year is 0.10 Mcf, production in the second year is 0.09 Mcf, production in the third year is 0.081 Mcf, and so forth.

As noted in Figure 9, the facilities decline curve is not restricted to be exponential in form. Indeed, one can specify any shape one wishes R/P ratios in the current version range from 5 years on the low side (for deep water Gulf of Mexico gas) to 15 years on the high side for coalbed methane and tight sands. In practice, relatively little is lost by assuming geometric facility decline. Notwithstanding the fact that some resource "techies" made a big deal out of nuances in facility decline curves, sensitivity analysis in NARG will quickly confirm that it is changes in the R/P ratio, not detailed nuances, are what matter.

Given the facility decline profile, how do we calculate the rate of proved reserve additions necessary to sustain the postulated quantity schedule q(t) in Figure 8? The answer is simple; we simply stack "exponential bricks" under the quantity schedule q(t). Figure 10 shows how. If we consider a given year t in the middle of the postulated forward production schedule q(t), we notice that reserves have to be proved before, during, and after time t. Before year t in the figure, there are five periods during which reserves have to be added to sustain the production schedule q(t) before year t. The quantity of reserves that have to be added in year t, indicated by the light gray exponential curve at the top, is that quantity necessary to make up the shortfall in production in year t and ensure that q(t) units are flowing to market.

Figure 8: Estimate of Forward Production Schedule



The process of "stacking in" exponential bricks to satisfy the postulated production schedule is rather simple mathematically and rather revealing graphically and economically. If we keep track of the CUMULATIVE quantity of reserves proved since the beginning of time, we will have a plot of the total shaded area in Figure 10 as it grows over time. The total shaded area begins at zero when the postulated production schedule q(t) is zero. The shaded area grows to be equal to the area under the first exponential brick at time t=1. It grows to be equal to the sum of the areas under the first two exponential bricks at time t=2. It grows to be equal to the sum of the areas under the first three exponential bricks at time t=3. By the time we reach period t in the figure, the cumulative additions to reserves is equal to the entire shaded area in the figure. Cumulative additions to proved reserves is simply the growing shaded area in Figure 10 over time. In a critically important sense, cumulative additions to proved reserves characterizes cumulative depletion and exhaustion of a given resource basin. Cumulative additions to proved reserves represents cumulative exploitation of the resource base in a given basin, i.e., cumulative extraction and exploitation of the resource base in that basin.

Figure 9: Production from Each Well Decreases Geometrically

NARG can use any shape; one need not assume only geometric decline.

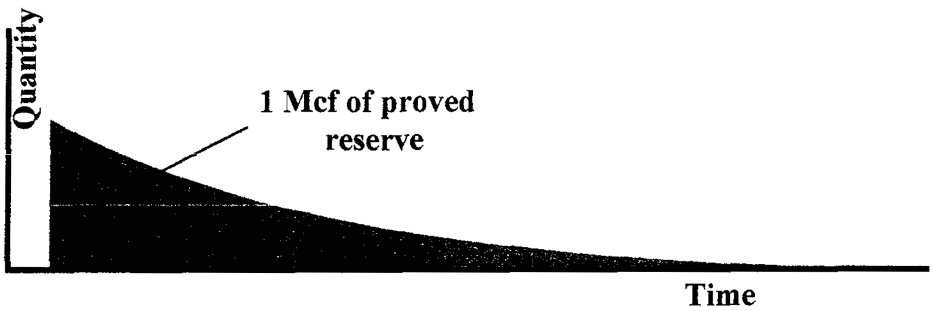
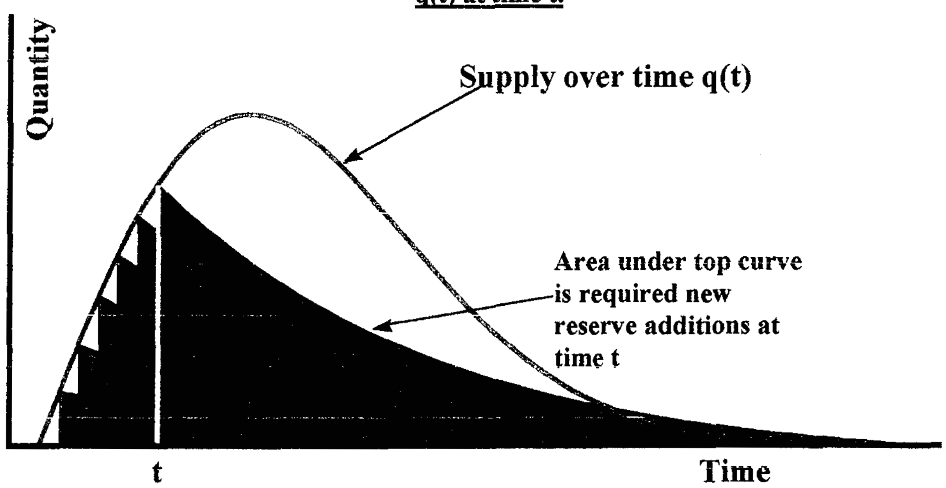


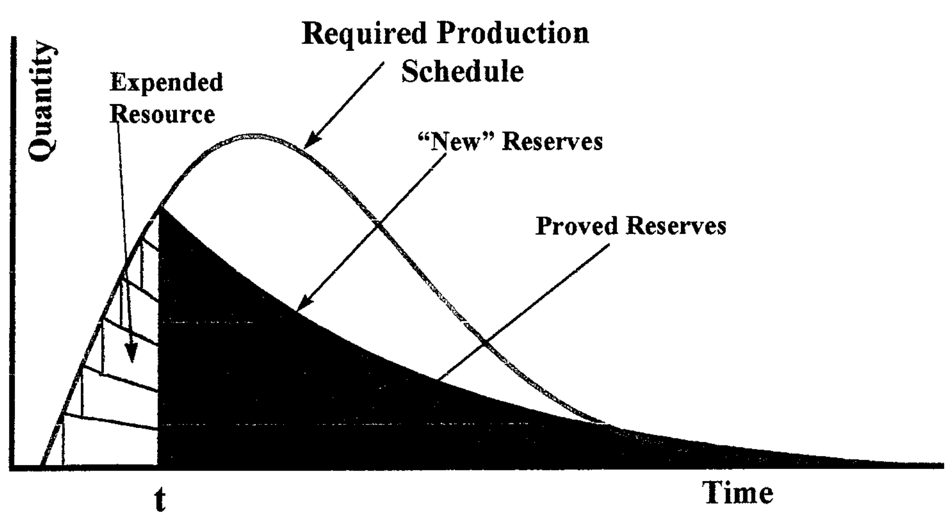
Figure 10: Meeting Demand Means Stacking in "Exponential Bricks"

Total shaded area is cumulative reserve adds necessary to supply q(t) at time t.



The concepts in Figure 10 contain some critically important elements and some critically important terminology. By reshading various portions of Figure 10, we can define and illustrate some critically important resource base concepts as indicated in Figure 11. At the left, we see in the yellow area that portion of previously proved reserves that have been delivered to market and burned as of time t. They are reserves that have been expended as of time t. They are gone forever and are not available for future consumption; they kept someone warm last winter. The green area in the middle of the figure represents proved reserves in place as of time t. The total green area represents reserves that are in existence as of time t and will be produced at time t or in some future time. They are "reserves" in the sense they are destined for market at some future time; they will not be withheld because their forward cost to market is low. They will not all come to market at once because they are constrained by their facility decline curve. The red area at the top represents the quantity of new reserves that must be provided as of time t. In order to sustain the given production schedule q(t) through and including time t, producers must add reserves equal in magnitude to the red area at the top at time t. Clearly, as indicated in the figure, reserves must be added well ahead of production. Our clients tell us that Figure 11 has greatly clarified what in the world people are talking about in the resource business. The figure makes clear what we mean by proved reserves; it is the middle green area. It is resource to be produced in the future but constrained by the remainder of the facility decline profiles for every vintage of well in place. It makes clear how much new reserves must be added in year t in order to sustain a given production schedule. To add fewer reserves is to fall short of the production schedule q(t).

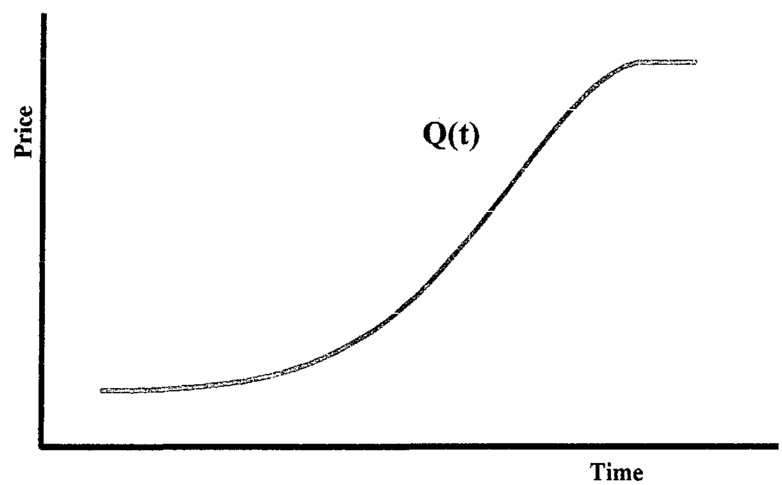
Figure 11: Critical Resource Terminology



A critical datum from Figure 10 that must be specified to the model is first year proved reserves, i.e., the middle area in the figure as of the first model year. NARG requires that the user specify how much proved reserve exists in every producing basin region by region throughout North America. This middle area is an important, user-specified input to the NARG model. NARG then adds new reserves during the forward horizon of the model according to the logic of the light gray area.

If we make a plot of cumulative reserve additions using the logic in Figure 11, i.e., the growing total shaded area, over time, it will have the monotonically increasing shape shown in Figure 12. Cumulative reserve additions will grow at a substantial rate initially or during some point in the production horizon of the basin and then will flatten out as little or no additional exploration and production occurs. Keep in mind, the curve for cumulative future reserve additions in Figure 12, denoted Q(t), is derived directly and unequivocally from the postulated schedule q(t) of future production.

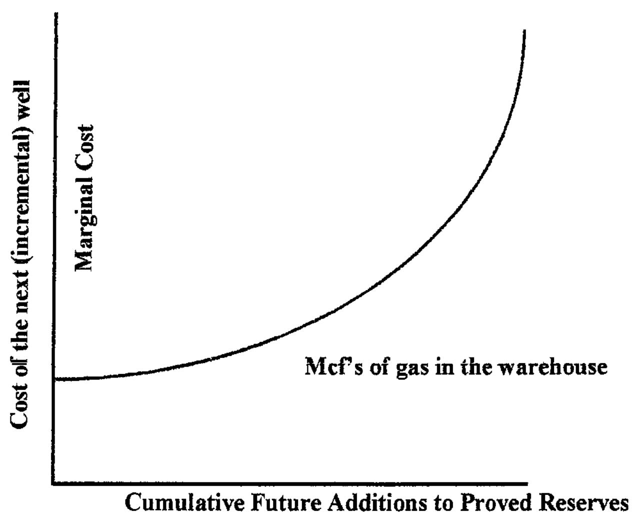
Figure 12: Cumulative Future Reserve Additions Over Time



Let us now turn to the question of how much the cost of each successive unit of reserves might change as the basin is exploited according to the cumulative reserve addition schedule in Figure 12. To do so, let us consider the resource producing basin as a "warehouse" that contains every Mcf of gas resident in the given somewhere on a shelf in that warehouse. Let us suppose further that the owner of the warehouse has lined up every Mcf of gas in his warehouse in ascending order of full fixed plus variable cost beginning at the door and extending inward further and further from the door as total costs go up. If we plot the cumulative volume of all gas in his warehouse against the cost of each successive Mcf of gas in his warehouse, we will obtain the curve in Figure 13.

We term the curve in Figure 13 the resource marginal cost curve. In our experience, the resource marginal cost curve so defined is the most fundamental and most correct characterization of the resource deposition in a basin. It contains an unequivocal representation of BOTH the cost and the volume of reserves that can be proved and produced in a basin. It is not limited to volume, and it is not limited to cost. It explicitly couples volume with cost. We are very enamored of the representation in Figure 13 for several other reasons:

Figure 13: Resource Marginal Cost Curve



- It is unequivocal. There are no mistakes of interpretation. We know precisely what we mean. We must enumerate every Mcf of gas and attach a cost to every Mcf.

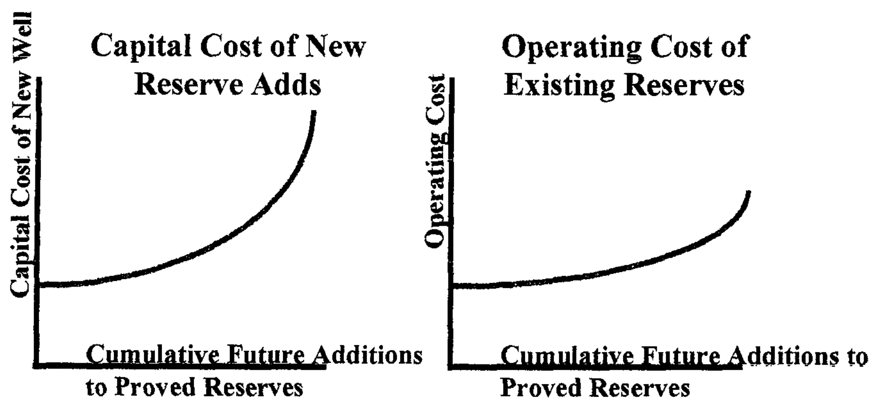
- The underlying definition of "technology" is unequivocal. If we want to impose technological learning, we must specifically extend the curve outward and to the right or downward in a way that simulates the application of the new technology. Alternatively, we must distort the curve outward and downward to simulate advancing technology.

It is not confounded by dynamics. Dynamics, i.e., how fast reserves might be proved, are superimposed ex post facto from the outside, not embedded arbitrarily in the supply curves as they are in other models. By separating the dynamics from the resource deposition, we are able to make accurate characterizations of the resource in place and thereafter accurate characterizations of the dynamics and technology of exploration and production. We see this as a major strength of NARG. By contrast, the EEA

Hydrocarbon model misses the boat because of its confounding of resource deposition with finding rate dynamics. By extrapolating historical finding rate trends, the model simply cannot escape from historical dynamic issues completely unrelated to the deposition of the resource itself. This is why the Hydrocarbon model has been so remiss at predicting forward production schedules and forward prices.

The resource marginal cost curve in Figure 13 is the fundamental input to NARG that characterizes the volume and cost of resource deposits in each of the basins of NARG. Because we recognize that resource production requires both fixed (capital) and variable cost, we have actually input to NARG a pair of curves similar in concept to the single aggregate curve in Figure 13. The leftmost curve represents that capital cost necessary to prove each successive Mcf of reserves, and the rightmost curve represents the variable cost necessary to produce from each successive Mcf of reserves. Figure 14 illustrates. The fundamental resource inputs to NARG are the pair of curves in Figure 14. In particular, each hexagon in the NARG network requires precisely the pair of curves in Figure 14. When we deliver NARG, we deliver a complete and fully documented set of such pairs of curves for every increment of gas, onshore and offshore, deep and shallow, conventional and unconventional, foreign and domestic, throughout North America.

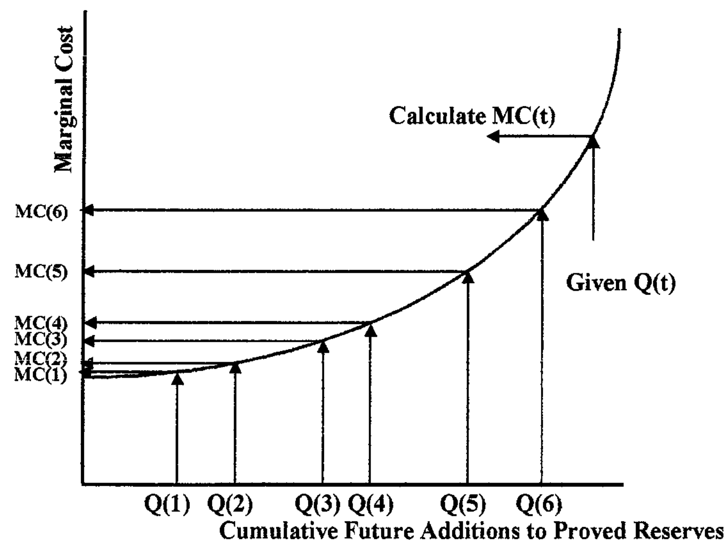
Figure 14: Fixed and Variable Cost of Resource Exploration



Even though the model contains the pair of supply curves in Figure 14, we will continue the discussion of how the resource model works by using the simplified curve in Figure 13. Given the schedule Q(t) of cumulative additions to proved reserves necessary to sustain the postulated schedule q(t) of production, which is depicted graphically in

Figure 12, suppose we plot it on the horizontal axis of Figure 13 and read the corresponding marginal cost MC(t) from the marginal cost curve as indicated in Figure 15. That is, for each level of cumulative reserve additions Q(t), we proceed upward from that point on the horizontal axis, then proceed leftward from that point at which that vertical curve intersects the supply curve to the vertical axis. By so doing for every point Q(t) in the forward horizon of the model, we are in effect using the marginal cost curve to determine the schedule of marginal cost over time, i.e., MC(t). The forward schedule of marginal cost MC(t) is interpreted as follows. "If the production schedule q(t) were followed, the full cost of the last well to be drilled in year t, i.e., the marginal well in year t, would be MC(t). The schedule MC(t) is truly a schedule of the marginal well and its cost over time. It represents the full cost of the last Mcf to be added in each year. It is the worst well that is competitive in each future year.

Figure 15: Calculating Marginal Cost Over Time

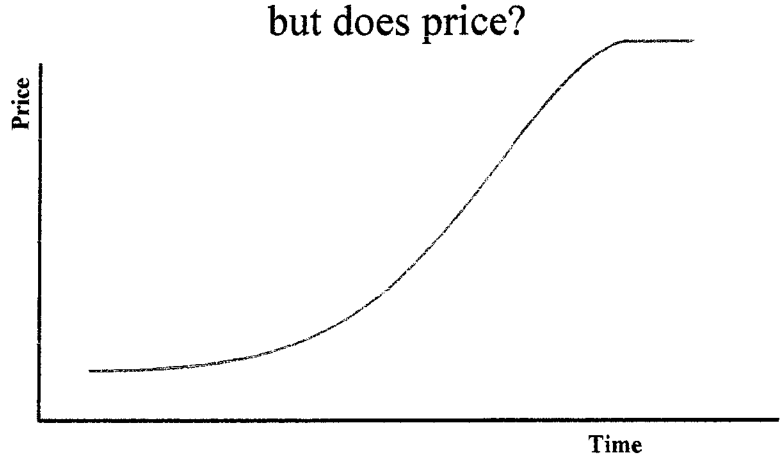


The time schedule of marginal cost MC(t) derived from the foregoing procedure has the form in Figure 16. If the supply curve is upward sloping, the marginal cost curve will likewise be upward sloping because the cumulative reserve addition schedule Q(t) is monotonically increasing. The only way the marginal cost curve can be downward sloping over time is if technological innovation and cost reduction reduces cost faster than depletion as represented by the supply curve in Figure 13 escalates cost. This has probably occurred during certain periods of the 1980s and 1990s; however, it is unlikely to persist forever. Inexorably, depletion will ultimately set in. The question, however, is when. The supply data embedded in the current version of the NARG model result in rather flat real supply curves for the next 30 years or more.

Once we have calculated the marginal cost schedule over time, are we done? Isn't price equal to marginal cost? The answer is an unequivocal NO! There is one critically important step left to go. Producers would not necessarily be willing to deliver wells to market at the postulated rate q(t) if the price they got was the schedule MC(t). To see why, consider the situation in Figure 17. A producer holding the marginal well at time t would receive the price p(t+1) if he waited until time t+1 to deliver his marginal well. His cost would remain constant at MC(t) if he delayed the marginal well to time t+1. Hence, the profit he would get by waiting would be p(t+1)-MC(t). However, he would not receive the money until time t+1. Its discounted present value as of time t would be {p(t+1)-MC(t)}/(1+r) where r is the producer's discount rate. As indicated in the figure, the profit margin received one year into the future but discounted one year back to the present would be a lower bound on the profit the producer would expect to get in the current year t. (The producer could get that much money by simply delaying the marginal well by one year, so the market would have to compensate him or he would not deliver the marginal well in year t and the production schedule q(t) would not be met.) Indeed, the price p(t) would have to be greater than or equal to p*(t) = MC(t) + {p(t+1)-MC(t)}/(1+r). The price necessary to elicit the production schedule q(t) in year t would be p*(t), not MC(t). It is this calculation of p*(t) that is made within NARG.

Figure 16: Cost of the Marginal Well (Marginal Cost) Over Time

Marginal cost rises with cumulative depletion but does price?



Why is this the correct model of resource pricing in a competitive market? The reason is simple. Under this simple equilibration between discounted present value of margins that can be captured over time, there is absolutely, unequivocally no incentive for arbitrage between the physical market for gas and the financial market as represented by the discount rate r. There is no incentive for people to convert their gas to money, secure in the knowledge that the money will escalate in value faster than the gas would have escalated had they left it in the ground. Likewise, there is no incentive to withhold gas from market, secure in the knowledge that gas prices will escalate fast enough so that you make more money on gas price appreciation than you would have made in the financial markets. There must be absolute, lockstep equilibration between gas markets and financial markets as represented by discount rates. Otherwise, the postulated forward price solution from the model will not be stable in the real world and cannot be advocated as a valid, reasonable, sustainable projection of forward gas price. The reasoning in Figure 17 assures that the "gas in the ground-money in the bank" tradeoff does not favor one over the other. All possible arbitrage between the two will have been completed so that there is stable, sustainable equilibration. This is absolutely critical to valid, reasonable forward price forecasting.

Figure 17: There Can Be No Arbitrage Possibility at Equilibrium

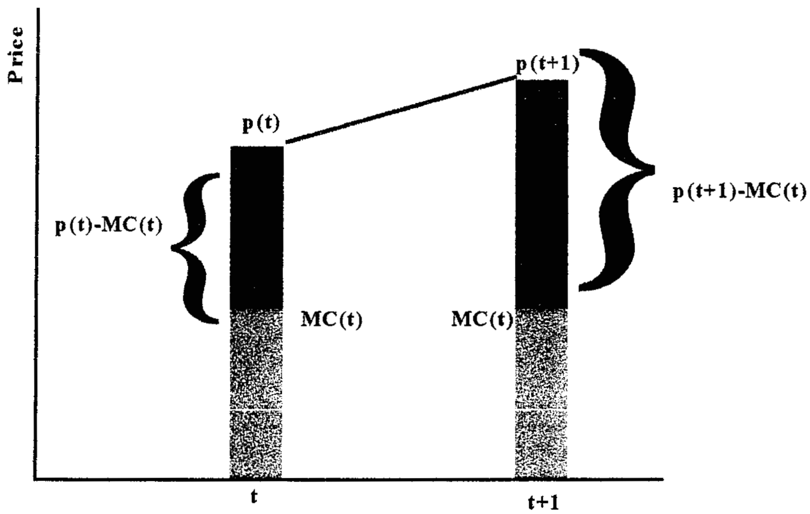
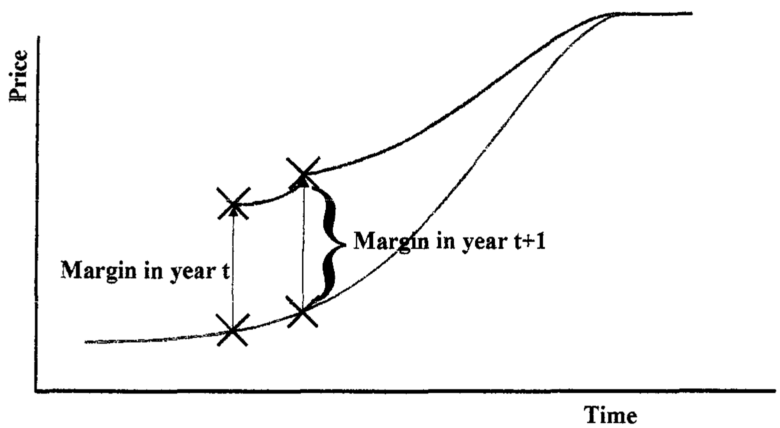


Figure 18 summarizes this notion that there must be complete equilibration between gas in the ground and money in the bank at equilibrium. The price schedule that is reported by the resource hexagon to the demand portions of the model must be the higher of the two curves, not the lower marginal cost schedule MC(t) in the diagram. The price reported to the demand portions of NARG must be such that no producer has any incentive to change his production schedule over time. If producers have incentive to change over time in the real world, assuredly, they WILL change. If they have incentive to change, assuredly the price that contains such incentives will not be sustainable in the market. Such a price cannot be a market-clearing price; it must not be reported to the demand side of the model for equilibration. This is a critically important feature of NARG not to be underemphasized. The price that is reported to the demand sectors from the supply models is such that no producer has any incentive to reschedule his production over time given that price schedule. It is a no-arbitrage price.

Figure 18: Price Must Not a Financial Arbitrage Over Time

Margin in year t at least as high as discounted margin from year t+1.

Gas in the ground must equilibrate with money in the bank.

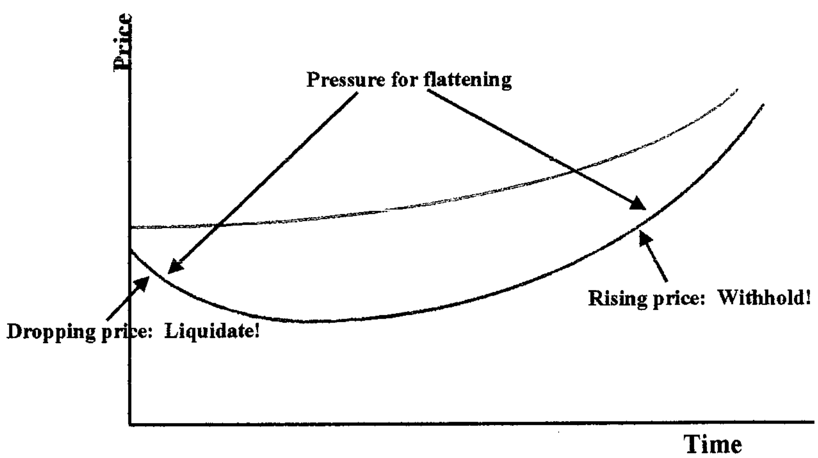


Why go to all this trouble to equilibrate gas markets with financial markets? The answer is that we want to eliminate hockey stick and other "stupid" forward price projections. Hockey stick price forecasts are indeed stupid; they cannot be sustained in a market. To see why, consider Figure 19. During periods of rapid price de-escalation at the front end of the hockey stock price forecast, gas is crashing in value. Producers would face very strong incentives to drill their prospects and liquidate their resource holdings before their value deteriorates dramatically. Incentives to liquidate one's gas in the very short run would create strong market force to drop near term price and therefore flatten out the downward trend at the front end of the hockey stick forecast. To wit, there is systematic force that flattens an otherwise declining price trend. The front end of the hockey stick experiences forces that tend to flatten it. Similarly, during the period of rapid price escalation at the back end of the hockey stick price forecast, gas is soaring in value because of gas price appreciation. Producers would face very strong incentives to hoard their resource until after its price had escalated to new heights and liquidate it only thereafter. As producers hoard their gas at the front end, there would be shortage conditions and near term prices would escalate, tending to flatten out the escalating portion of the hockey stick. Therefore, there are strong, systematic forces that tend to flatten out the price-escalating portion of the hockey stick forecast. Obviously, hockey stick price forecasts of the type we see from the Hydrocarbon or Brooks model are unequivocally wrong. They do not properly consider arbitrage between financial and physical markets. Such price forecasts cannot possibly serve as the basis for cogent strategy and pipeline analysis.

How might we summarize our resource module? We will do so from two perspectives. The first is the flow of logic beginning with a postulated production schedule forward in time q(t) and ending with a price schedule forward in time p(t). The second is to summarize the data that are needed to execute the resource process. The logical sequence of operations employed in the resource model is the following:

Figure 19: Hockey Stick Price Forecasts Are Wrong

The market arbitrages Hockey sticks.



STEP	VARIABLE CALCULATED	OPERATION REQUIRED
1	Guess q(t)	Make a guess at production schedule
2	Calculate Q(t)	Calculate cumulative reserve additions necessary to sustain production schedule q(t)
3	Calculate MC(t)	Read marginal cost off resource marginal cost curve
4	Calculate p(t)	Calculate price p(t) from marginal cost MC(t) to eliminate intertemporal arbitrage
5	Report p(t) to demand model	Deliver the price schedule p(t) to the demand portion of the model
6	Get demand d(t)	Read demand d(t) from demand curve given price p(t)

		from resource process
7	Compare d(t) and q(t)	Determine whether supply and demand quantities are the same. If so, quit. If not, substitute d(t) for q(t) and repeat

The data required to implement the resource model are the following:

1. Reserves to production ratio, allowing us to calculate the facility decline curve in Figure 9.

2. Initial year proved reserves, i.e., the middle shaded area in Figure 11. This represents the inventory that exists in the first model year, an inventory that will be produced to market during the model horizon.

3. The pair of resource supply curves in Figure 14, which characterizes aggregate resource deposition in each resource producing basin.

4. The discount rate used to make the "no intertemporal arbitrage" equation in Figure 17. This discount rate must represent the market-determined cost of capital that directs resource exploitation decisions in the energy business. It is NOT a hurdle rate; it is a market-observed and market-determined cost of capital that faces energy producers.

These four elements fully comprise the NARG resource base. Keep in mind, we need each of these four elements for every increment of resource for every producing region in North America. That is, there is a separate reserves to production ratio, initial year proved reserves, pair of resource supply curves, and discount rate specified for every hexagon in the NARG model. To reiterate, we deliver the data resource data assumed for the current version of NARG to our customers and licensees so that they review, evaluate, and customize it.

A final note on the resource process is related to the age-old question: What is the output of the resource model? Based on the discussion herein, the outputs of the resource model are simple

- The equilibrium price schedule p(t) forward in time over the model horizon.

- The equilibrium production schedule q(t) forward in time over the model horizon.

- The equilibrium schedule of reserve additions Q(t) forward in time over the model horizon.

In short, model outputs are price, production, and reserve additions over the forward horizon.

3 THE DEMAND SIDE OF THE NARG MODEL

Having completed our discussion of supply, this section turns to the question of representing natural gas demand on a regional basis throughout North America. This discussion begins with how we have regionalized the demand side and thereafter puts forth our demand modeling technology.

3.1 Regional Structure

The degree of regional disaggregation on the demand side of the NARG model is governed by the census regions of the United States. There is much historical precedent to disaggregating gas demand by census region, and there is much accepted data. Furthermore, climatic distinctions among census regions are usually deemed adequate to reflect different weather and usage patterns throughout the United States. Two of the standard census regions have been aggregated. We have aggregated the West North Central census region with the Mountain census region to create the single, aggregate West North Central-Mountain region. The Pacific region has been substantially disaggregated. In particular, we have broken California away from the Pacific Northwest. Within California, we have represented PG&E, SoCal Gas, San Diego Gas and Electric, and the EOR demand region. Within Canada, the model aggregates the thirteen provinces and territories into four aggregate demand regions. Western Canada contains all provinces to the west of and including Manitoba except for British Columbia, which is represented as a separate and distinct region. Eastern Canada includes all provinces east of the Ontario/Manitoba border excluding Ontario, which is represented as a separate and distinct region.

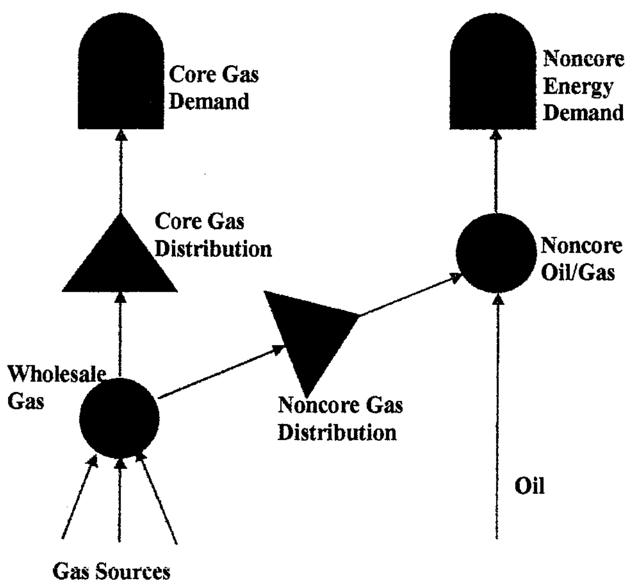
3.2 How Do We Represent Gas Demand?

Inside each of the fifteen demand regions, the NARG model is structured to take account of key demand-side phenomena including demand stimulation at lower prices, demand suppression at higher prices, and interfuel substitution between oil and gas. In order to represent such phenomena, it is necessary to recognize the segmented nature of gas demand. To properly characterize gas demand, it is important to distinguish at least two types of consumers in gas markets. The first, sometimes termed the "core market," is largely captive and exhibits relatively inelastic gas demand. The remainder, termed the "noncore market," is possessed of an immediate alternative such as fuel oil. As long as gas price remains below that of the alternative, noncore gas demand is relatively firm. If gas price rises to or above the price of the alternative, noncore gas demand will switch away from gas toward the alternative.

A simple network characterization of gas demand can be represented in network form as in Figure 20. In the figure, energy is assumed to flow along the links through the processes from bottom to top. The figure depicts two demand "tombstones," one for core demand and one for noncore demand. Each tombstone contains a demand curve, i.e., a price-quantity relationship that specifies the quantity of gas (or gas-equivalent) that will be consumed at every possible price. Notice in the diagram that noncore demand can be satisfied either by gas or by the substitute (assumed to be oil in the diagram). Core demand can be satisfied only by gas. Gas moves from wholesale at the lower left through a core distribution process to core customers, and it moves through a noncore distribution process to the burnertip point of competition at which it must compete against oil.

Economists characterize the simple core/noncore network representation of demand using a demand curve such as that in Figure 21. The figure delineates the size of the core and noncore markets and shows the assumed oil price. In the figure, gas demand is shown to be equal to core demand for gas prices above the oil price and to be equal to core plus noncore demand for gas prices at or below the oil price.

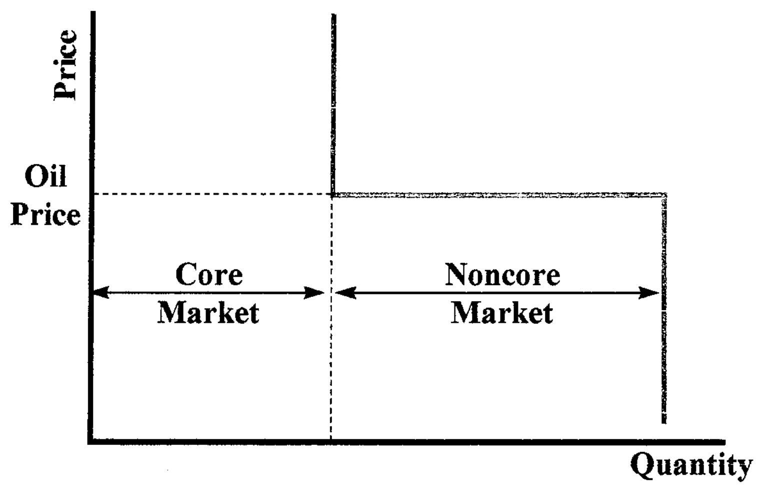
Figure 20: Network Representation of Gas Demand



In reality, core gas demand is somewhat elastic, and noncore gas demand is highly segmented, each segment facing a slightly different substitute price. Therefore, in reality, the demand graph in Figure 21 should be "rounded off" as shown in Figure 22. The demand curve in Figure 22, very characteristic of gas demand, has an inelastic portion at high gas prices, a very elastic "shoulder" for gas prices in the vicinity of oil price, and an inelastic portion at low gas prices. Results generated by the NARG model rely heavily on the distinctive pattern of gas demand in Figure 22.

It is interesting to note that the width of the shoulder in Figure 22 has diminished during the past two decades as the industrial sector of the United States has emigrated or shrunk. What used to be a relatively broad shoulder in our formerly industrialized economy has now become a much narrower shoulder in our service economy. Such narrowing has vital consequences for the relationship between the market clearing price of gas relative to the price of oil, implying a much weaker degree of coupling between the two than was true historically.

Figure 21: Segmented Representation of Gas Demand



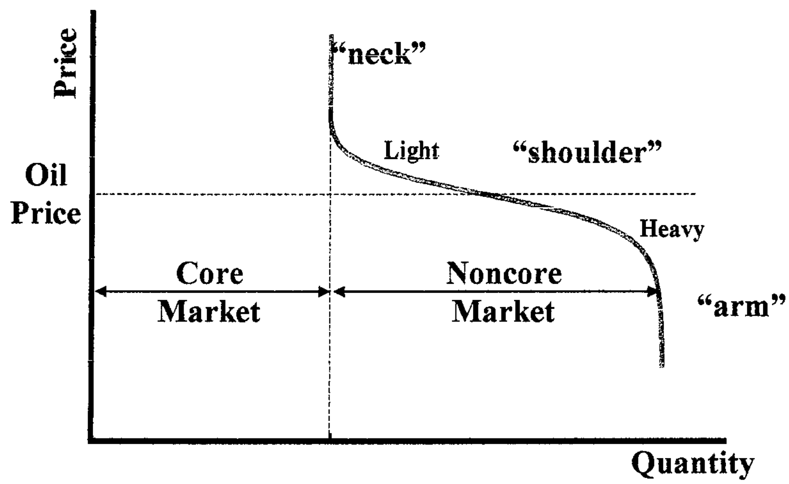
Every demand region in the model contains the network structure in Figure 20 and therefore the demand curve structure in Figure 22. Thus, every demand region in the model represents demand stimulation/repression at different prices as well as substitution at the exogenously given price of the substitute. The data needed for the demand side of the NARG model is the demand curve in Figure 22 itself. In order to construct the demand curve in Figure 22, we need its constituent elements, which are best seen by referring to the "caricature" of demand illustrated in Figures 20 and 21:

- a demand curve (price versus quantity versus time) for noncore use. We need to place a demand curve into the core demand tombstone. Most often, we simply use a projection forward in time of noncore demand and assume that overall noncore demand is inelastic at that level.

- a demand curve (price versus quantity versus time) for core use. We need to place a demand curve into the noncore demand tombstone. Most often, we simply us a projection forward in time of core demand and assume that core demand is inelastic at that level.

- an estimate of noncore distribution cost, which is needed in order to properly represent burnertip gas pr ices relative to oil prices.
- a projected time schedule of the price of oil against which gas must compete.
- an estimate of core distribution cost.
- lag parameters that simulate adjustments in capital stock necessary for gas/oil substitution.

Figure 22: Wholesale Gas Demand Curved is Rounded Off



In particular, we need a projection of core and noncore market size, the price of oil, and the core and noncore distribution costs. We deliver to our NARG customers comprehensive analysis of how these data are conceived and assembled for NARG.

The two demand curves within the demand tombstones for each demand region are inferred from GRI's Baseline forecast or another similar source. In particular, we have divided sectoral gas demand projections into a core (nonsubstitutable) and a noncore (substitutable) component. We should emphasize that undue attention on demand is probably not warranted. In light of the bullish and escalating projections of natural gas supply in the Gulf Coast and elsewhere, gas supply has increased in importance relative to gas demand. This is not to say that demand issues are unimportant. It is to say, however, that gas demand is less important than gas supply.

3.3 The "Answer" Given By The Model – Market Clearing Prices And Quantities Flowing At Those Prices

Equilibrium models such as the NARG Model plot gas supply and demand curves on the same graph and seek to find the intersection. The intersection specifies a market-clearing price at which the market will tend to operate. Indeed, there are economic forces that drive the market toward that price. The intersection also specifies a quantity that will be traded in the market at the market-clearing price. Using the characteristic pattern of demand in Figure 22, we can make some rather profound and far-reaching conclusions about the nature of the regional supply-demand equilibrium. In particular, we see that there are three possible supply-demand cases that can occur, each of which has distinctive and important properties:

Case 1: The gas supply curve intersects the demand curve above the shoulder, as shown in Figure 23. The market clearing price (denoted p*) of gas is seen to exceed the price of oil. Furthermore, in this ease,

- gas supplies will be "tight."
- noncore users will be driven to the substitute.
- a core user will be the marginal gas user.
- core users will be obliged to buy gas at a premium over oil.

Case 1 will occur if oil prices are low (that is, low shoulder in the demand curve), gas supplies are tight (that is, high gas supply curve), or gas demand is high.

Case 2: The gas supply curve intersects the demand curve along the shoulder as shown in Figure 24. Notice that

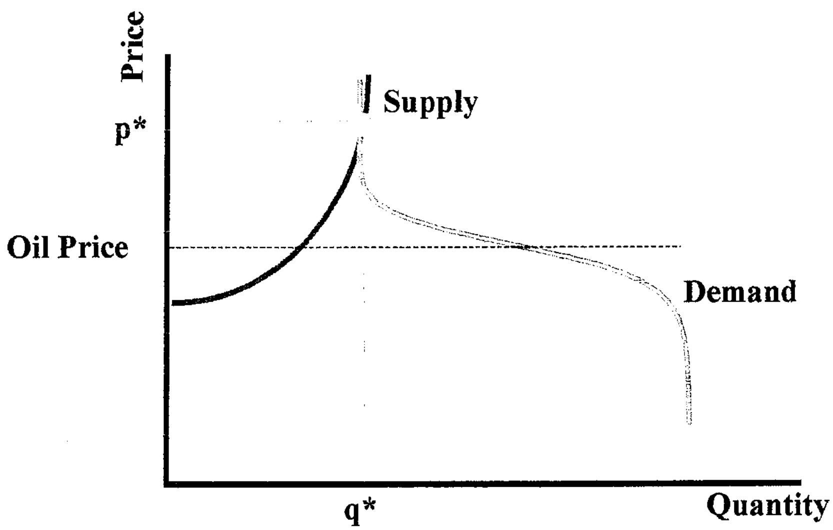
- the market clearing price of gas will be equal to the price of oil.
- some noncore customers will use gas, while some will utilize the substitute.

This is the case that so many people implicitly assume ALWAYS applies to gas. Many people lazily and incorrectly assume that oil and gas prices must equilibrate. As we have seen in Case 1, this is not necessarily true. It is quite coincidental when Case 2 rather than Case 1 occurs.

Case 3: The gas supply curve intersects the demand curve below the shoulder as shown in Figure 25. The market-clearing price of gas is seen to be below that of oil. In this case

- gas supplies will be "abundant."
- noncore users will be attracted to gas.
- a noncore customer will be the marginal source
- both core and noncore users will buy gas at a discount relative to oil.

Figure 23: Case 1--Gas Price Clears on "Neck;" Gas Price Above Oil Price

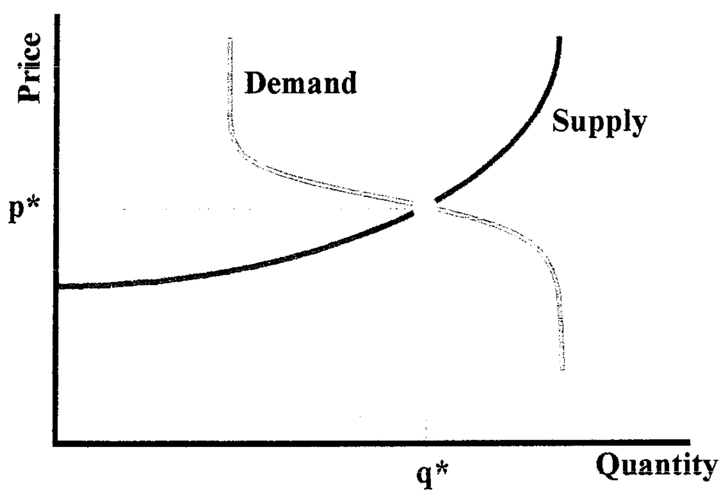


Case 3 will occur if oil prices are high (that is, high shoulder in the demand curve), gas supplies are abundant (that is, low gas supply curve), or gas demand is low.

A conspicuous observation in Figures 23 through 25 is that in general **THE MARKET CLEARING PRICE OF GAS WILL NOT BE EQUAL TO THE PRICE OF OIL**. Gas and oil prices will not be at parity. Indeed, only if the supply curve intersects the demand curve precisely through the shoulder, that is, on the flat portion of the demand curve as in Figure 24, will the price of gas be equal to the price of oil. As we have already argued, the shoulder has narrowed substantially over the past two decades, rendering it decreasingly likely that Case 2 will occur.

Different supply-demand scenarios will in general correspond to one of the three cases discussed earlier. For example, a base case scenario might correspond to Case 3 (gas supply intersects demand below the shoulder so that gas price is below oil price). However, a low resource base scenario, all else equal, would shift the supply curve upward and to the left so that in fact Case 1 rather than Case 3 pertains; gas supply would intersect above the shoulder.

Figure 24: Case 2—Market Clears on "Shoulder;" Gas and Oil Price Equal



Comparison of high versus low gas resource base scenarios (and in fact almost any pair of scenarios involving different supply curves and/or different demand curves) leads to a critical conclusion:

<u>The market clearing price of gas will be different between different demand, supply, and oil price scenarios.</u>

This finding has profound ramifications:

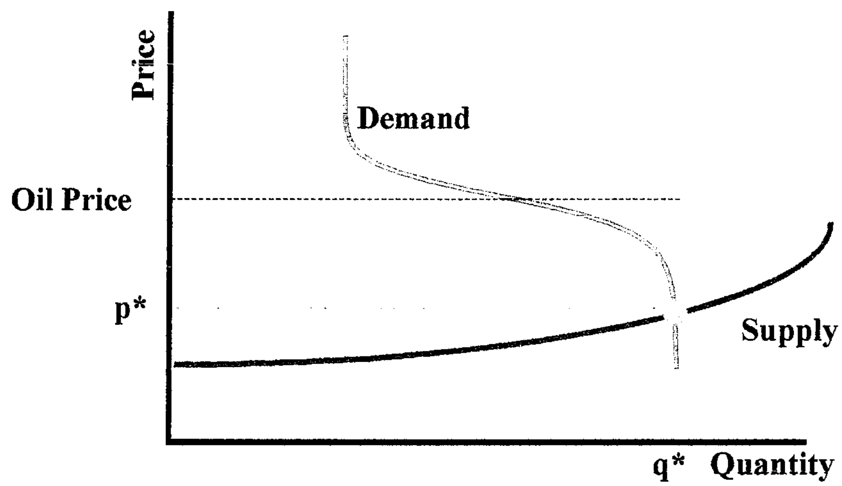
- In general, the customary assumption of oil/gas price parity at the burnertip is wrong. To assume such parity is to get the wrong answer both for burnertip market clearing price and quantity consumed.

- In general, the customary practice of equating gas wellhead prices to oil price "netbacks" from the burnertip through the pipeline system is wrong. To calculate oil price netbacks is to get the wrong answer both for wellhead market clearing price and quantity produced.

- Oil and gas prices are likely to move farther away from parity as the noncore market decreases relative to the core market. Conversely, the larger the noncore market, the nearer to parity oil and gas prices are likely to be.

We conjecture that the customary (and increasingly incorrect) procedure of netting back burnertip-equivalent oil prices to the wellhead originated in the days when the United States had a large industrial sector, that is, a large noncore market relative to the core market. Although not technically correct even in those days, oil price netbacks were serendipitous; there existed a broad noncore "shoulder" in the economy that virtually ensured that Case 2 would apply. However, now that the industrial sector has declined in size relative to the residential and commercial core sectors, Case 1 or Case 3 is much more likely to pertain today. Oil price netbacks are inevitably destined to be wrong today and in the future.

Figure 25: Case 3—Gas Market Clears on "Arm;" Gas Price Below Oil Price



The alternative to assuming oil/gas price parity at the burnertip and calculating netbacks to the wellhead is to enumerate all present and potential future supply regions using supply curves, all present and potential future demand regions using demand curves with noncore shoulders, and all present and potential future transportation links connecting supply regions to demand regions and thereafter to explicitly compute the prices and quantities at which all supply and demand curves simultaneously intersect. This is precisely what the NARG model does.

We should also point out that the Case 1-Case 2-Case 3 configurations change during the year as well. In the winter, we often see a Case 1 world in the Northeast and Midwest. Gas demand accelerates because of the cold weather, while gas supply stays constant because the pipeline supply system is fixed. In the summer, we see a Case 3 world persisting in the Gulf of Mexico. There are no heating demands, meaning aggregate demand is small and implying that the demand curve is pressed toward the left axis. During the course of the year, the demand curve oscillates from left to right, while the supply curve remains relatively fixed. As shown in Figure 26, this means that the market clearing price during the year moves upward and downward in a relatively predictable fashion. While the longer term version of the NARG model considers only average annual demand, the NARG model contains the logic to make the seasonal calculation illustrated in Figure 26.

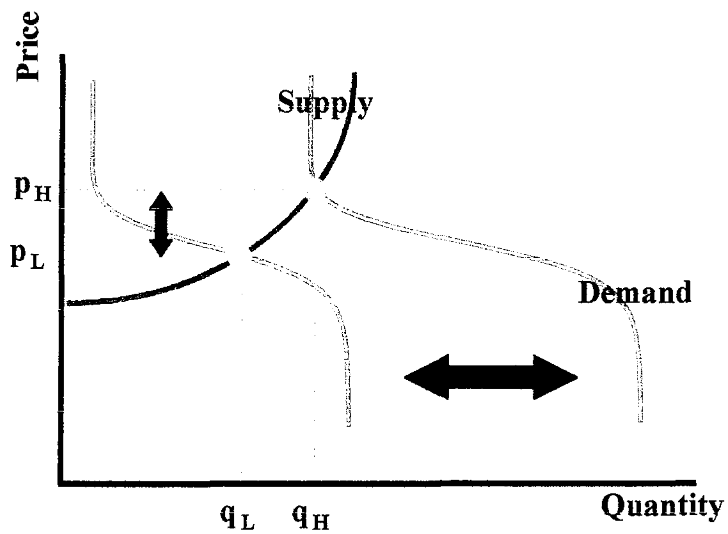
Finally, many have argued that the simple oil-for-gas substitutability model that led to the "neck-shoulder-arm" demand curve pattern in Figure 22 is oversimplified. In particular, gas does not substitute for oil at a single oil price. Rather there are many different types and qualities of liquid fuels (No. 1 fuel oil, No. 2 fuel oil, Low sulfur No. 6 fuel oil, High sulfur No. 6 fuel oil, etc.), and there are a number of different segments that consume either those fuels or consume gas (e.g., electric generation using steam turbines, electric generation using combustion turbines, industrial process head, industrial boilers). Each segment and each fuel represent a different regime of oil-for-gas substitution, and the model needs to represent some or all of these segments. Such demand side disaggregation is quite easy to accomplish in NARG by simply expanding the network diagram in Figure 20 to consider additional segments and additional substitution commodities. In doing so, one would develop a demand curve that looks not like a "neck-shoulder-arm" pattern in Figure 20 but rather has a series of substitution zones as shown in Figure 27. This subsegmented representation of demand might or might not be important in certain applications. If it is, it can be easily accommodated by expanding the segmented network representation in Figure 20 to create the demand curve in Figure 27.

4 THE PIPELINE COMPONENT OF THE NARG MODEL

Turning from the supply and demand elements of the NARG model, we note that the degree of pipeline detail must be consistent with the degree of supply and demand detail elsewhere in the model as discussed earlier in this section. In particular, while we could enumerate and distinguish every individual pipeline in the United States, we have instead sought commonalities among supply regions, pipelines, and demand regions that allow aggregation. In fact, rather than representing individual pipelines, we have instead represented pipeline corridors from our supply regions to our demand regions. Indeed, these corridors are quite explicitly defined by the characterization of our supply and demand regions and by the configuration of the United States and Canadian pipelines systems that exist today.

Embracing the notion of pipeline corridors, we begin by considering the network of existing pipelines. Each of the existing pipeline corridors begins in a given supply region, extends perhaps through intermediate supply and demand regions, and terminates in a demand region. The network of existing pipeline corridors interconnects all currently producing regions with all currently consuming regions. We have given a great deal of attention and effort to representing the existing pipeline system, including capacity and cost. To our NARG customers, we deliver the pipeline data for existing pipeline routes throughout North America used in the NARG model.

Figure 26: Gas Demand "Wiggles" During the Year, Taking Price With It

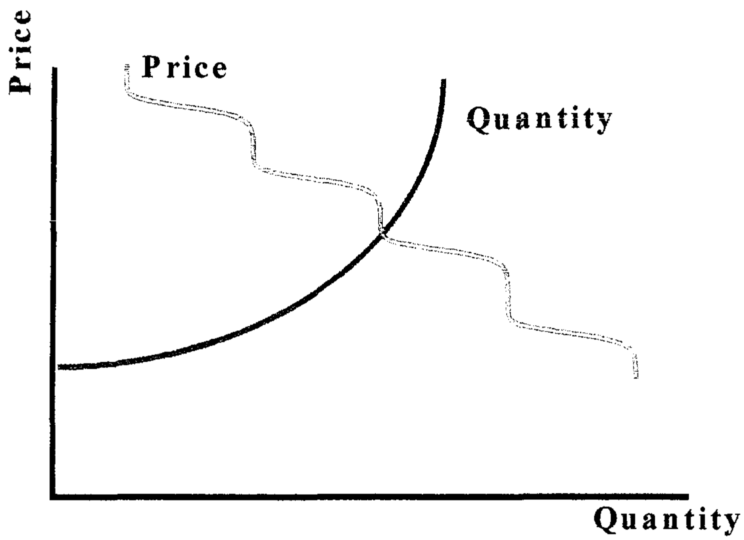


Because the NARG model predicts the evolution of the North American gas system over the next 40 years, we cannot stop with existing pipeline corridors. Rather, it is necessary to enumerate all prospective future pipelines that might be built in the next 40 years. These prospective future pipelines connect new producing regions (or subregions) with various demand regions, and they connect Canada and Mexico to the United States. NARG enumerates the pipelines that can be prospectively built within the time horizon of the model. We will discuss shortly how we have characterized prospective new pipelines and pipeline expansions.

The prospective new pipelines in NARG are just that--prospective. They will be built only if they become economic. They will be built only if supplies at the upstream end, marked up to account for the cost of the new pipelines, constitute the most competitive source at the downstream end. We will discuss nuances of capacity expansion below (e.g., looping or compression augmentation for existing capacity). In the model, looping is considered as an option for all existing capacity as well as for the existing links of the new corridors.

Because the linkage between Canada and the United States is potentially so important, we have distinguished in some detail the pipelines in Canada that directly or indirectly lead to the lower 48 United States. These Canadian pipelines, should they be built, provide a route for hundreds of Tcf into United States markets should those Tcf become economically competitive.

Figure 27: Demand Curve May Be Sub-Segmented



In reviewing the Canadian export situation in the NARG model, the prospective routes from North Alaska through Alberta and ultimately to the United States and from Northern Canada (MacKenzie and Beaufort Sea) through Alberta and ultimately to the United States must be represented. The former pipeline represents the upstream leg of the ANGTS system while the latter pipeline represents the pipeline that will have to be built in order to exploit Canadian Arctic gas (the Polar project and prospective expansions). Competition between these two pipelines will in part determine the competitive viability of the various Arctic supply regions and of the pipeline projects proposed to serve them.

Once we have enumerated all the existing pipelines and pipeline corridors, we must represent the cost and the capacity of those corridors. How do we think about the supply curve for pipeline service? The answer is rather clear. If we knew the maximum annual throughput for a pipe and we knew the forward cost to market borne by the owner of that pipe from its origin to its destination, we could make a plot of the supply curve for that pipe as in Figure 28. The height of the supply curve is the forward cost to market, i.e., the variable cost the owner of the pipeline would have to bear in order to provide service. The width of the supply curve is the capacity, i.e., the annual throughput, of the pipe. The width represents the physical size of the facility, and the height represents the forward cost to continue to provide service. In the most fundamental sense, the supply curve for transportation service in Figure 28 is the economic representation of the cost and capacity of the pipe in question. It is completely devoid of the regulatory baggage of the past. There is no embedded or historical cost in the curve; there is only forward cost to market. There is no guarantee that the owner of the pipeline facility can or will recover any embedded historical cost; there is only the forward cost the owner has to bear in order to continue to provide the transportation service.

For every existing pipeline corridor in the NARG model, we have created a supply curve for pipeline service of the form in Figure 28. The data necessary to characterize such pipeline service includes

- The forward cost to market, i.e., the height of the pipeline supply curve. We have used pipeline costs specified by our customers and contractors over the years to characterize the cost along each existing pipeline link.

- The capacity of the pipe, i.e., the width of the pipeline supply curve. We have used estimates of capacity, i.e., maximum annual throughout, specified by our customers and contractors over the years to characterize the annual capacity of each existing pipeline link in the model.

The pipeline database delivered to our NARG customers contains such estimates for every pipeline link the North America as estimated for use in NARG.

There are several generic types of pipeline capacity expansion that can be implemented:

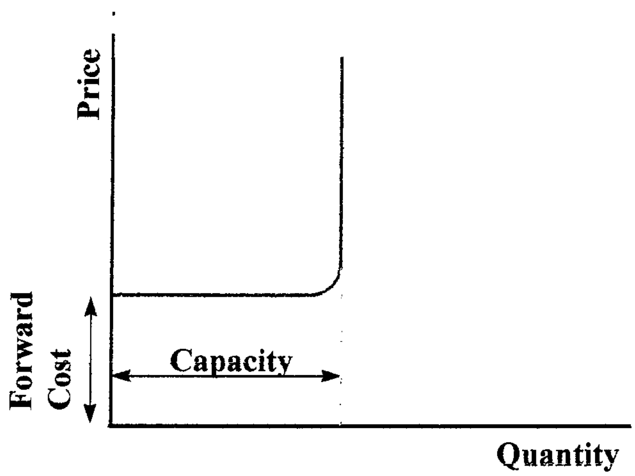
- expansion of capacity of a given pipeline by such actions as looping or increasing pressure.

- expansion of capacity along a given corridor by adding a new pipeline.

- addition of an entirely new, greenfield increment of pipe

We represent each of these types of capacity addition in the same fashion. We input an estimate of the full forward cost to market—capital cost plus operating cost—and graft it onto the right hand side of the existing capacity curve in Figure 28. Thus, the logic for adding new pipeline capacity within NARG is represented graphically as shown in Figure 29. Notice that once the market hits the full capital and operating cost of new capacity, such new capacity can enter without bound. The aggregate supply curve for existing plus new pipeline capacity in Figure 29 is estimated along every pipeline corridor, existing or prospective, in the NARG model. Therefore, in addition to the foregoing cost and capacity data for new pipes, we need an estimate of the full forward cost of expansion for new transportation capacity along that corridor.

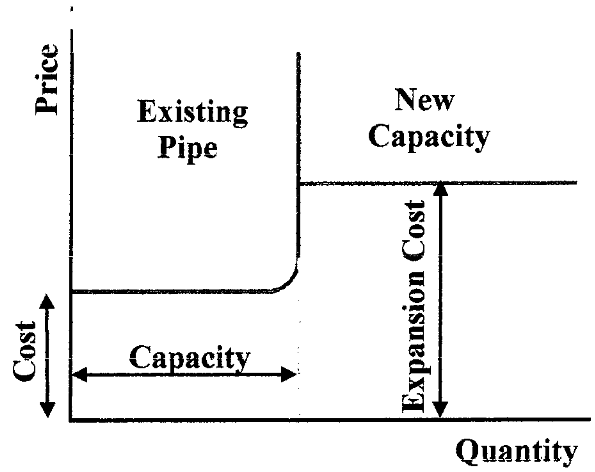
Figure 28: Supply Curve for Existing Pipeline Service



5 CONCLUDING REMARKS

NARG has become the industry-leading model of North American natural gas price and basis forecasting, asset valuation, pipeline addition, investment, abandonment, and long run marketing. It has outlasted most or all of its competition over the past 20 years. In the past year, we have been working assiduously to complement the long run annual structure of NARG with a short term (36 month) monthly model that can guide short term price and basis forecasting and can guide a broad range of trading and marketing decisions. The short run model, which has not yet been fully documented, will be ready for commercial use in the first quarter of 2000 and will be offered and licensed under the same terms as NARG.

Figure 29: Supply Curve for Pipeline Service



14 Appendix C: NARE Model Fuel Price Forecasts

FRCC Fuel Price Forecasts in the NARE model

FRCC Region	Fuel	Load Tranche	January	February	March	April	May	June	July	August	September	October	November	December
TALLAHASSEE	Nat. Gas.	1	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		2	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		3	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		4	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		5	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		6	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		7	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		8	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		9	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		10	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
	FO2	1	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		2	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		3	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		4	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		5	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		6	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		7	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		8	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		9	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		10	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
	FO6	1	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		2	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		3	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		4	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		5	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		6	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		7	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97

	8	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
	9	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
	10	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
WD	1	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00
	2	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00
	3	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00
	4	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00
	5	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00
	6	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00
	7	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00
	8	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00
	9	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00
	10	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00
WASTE	1	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
	2	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
	3	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
	4	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
	5	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
	6	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
	7	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
	8	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
	9	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
	10	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
Hyd	1	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80
	2	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80
	3	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80
	4	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80
	5	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80
	6	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80
	7	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80
	8	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80
	9	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80
	10	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80

DUVALL	Nat. Gas.	1	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		2	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		3	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		4	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		5	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		6	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		7	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		8	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		9	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		10	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
	FO2	1	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		2	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		3	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		4	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		5	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		6	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		7	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		8	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		9	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		10	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
	Coal	1	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		2	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		3	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		4	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		5	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		6	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		7	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		8	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		9	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		10	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
JEA	Nat. Gas.	1	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		2	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		3	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83

	4	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
	5	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
	6	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
	7	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
	8	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
	9	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
	10	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
FO2	1	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
	2	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
	3	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
	4	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
	5	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
	6	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
	7	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
	8	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
	9	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
	10	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
FO6	1	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
	2	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
	3	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
	4	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
	5	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
	6	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
	7	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
	8	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
	9	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
	10	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
WD	1	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00
	2	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00
	3	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00
	4	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00
	5	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00
	6	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00

	7	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00
	8	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00
	9	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00
	10	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00
WASTE	1	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
	2	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
	3	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
	4	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
	5	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
	6	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
	7	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
	8	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
	9	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
	10	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
Hyd	1	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80
	2	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80
	3	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80
	4	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80
	5	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80
	6	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80
	7	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80
	8	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80
	9	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80
	10	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80	$3.80
Coal	1	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
	2	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
	3	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
	4	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
	5	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
	6	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
	7	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
	8	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
	9	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43

		10	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
	SUN	1	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00
		2	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00
		3	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00
		4	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00
		5	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00
		6	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00
		7	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00
		8	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00
		9	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00
		10	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00
GAINESVILLE	Nat. Gas.	1	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		2	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		3	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		4	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		5	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		6	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		7	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		8	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		9	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		10	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
	FO2	1	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		2	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		3	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		4	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		5	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		6	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		7	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		8	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		9	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		10	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
	FO6	1	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		2	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97

		3	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		4	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		5	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		6	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		7	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		8	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		9	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		10	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
	Coal	1	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		2	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		3	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		4	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		5	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		6	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		7	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		8	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		9	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		10	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
OCALA	Nat. Gas.	1	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		2	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		3	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		4	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		5	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		6	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		7	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		8	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		9	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		10	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
CRYSTAL RIVER	Coal	1	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		2	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		3	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		4	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		5	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43

		6	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		7	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		8	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		9	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		10	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
	Uranium	1	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75
		2	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75
		3	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75
		4	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75
		5	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75
		6	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75
		7	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75
		8	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75
		9	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75
		10	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75
DELAND	Nat. Gas.	1	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		2	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		3	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		4	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		5	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		6	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		7	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		8	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		9	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		10	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
	FO2	1	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		2	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		3	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		4	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		5	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		6	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		7	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		8	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81

		9	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		10	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
	FO6	1	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		2	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		3	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		4	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		5	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		6	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		7	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		8	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		9	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		10	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
APOPCA	Nat. Gas.	1	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		2	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		3	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		4	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		5	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		6	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		7	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		8	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		9	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		10	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
	FO2	1	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		2	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		3	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		4	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		5	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		6	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		7	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		8	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		9	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		10	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
POINSETT	Nat. Gas.	1	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83

	2	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
	3	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
	4	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
	5	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
	6	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
	7	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
	8	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
	9	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
	10	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
FO2	1	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
	2	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
	3	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
	4	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
	5	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
	6	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
	7	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
	8	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
	9	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
	10	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
FO6	1	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
	2	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
	3	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
	4	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
	5	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
	6	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
	7	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
	8	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
	9	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
	10	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
WASTE	1	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
	2	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
	3	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
	4	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00

		5	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
		6	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
		7	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
		8	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
		9	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
		10	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
ORLANDO U. C.	Nat. Gas.	1	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		2	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		3	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		4	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		5	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		6	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		7	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		8	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		9	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		10	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
	FO2	1	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		2	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		3	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		4	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		5	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		6	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		7	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		8	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		9	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		10	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
	FO6	1	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		2	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		3	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		4	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		5	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		6	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		7	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97

		8	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		9	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		10	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
	Coal	1	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		2	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		3	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		4	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		5	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		6	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		7	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		8	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		9	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		10	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
ST. PETE	Nat. Gas.	1	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		2	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		3	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		4	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		5	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		6	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		7	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		8	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		9	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		10	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
	FO2	1	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		2	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		3	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		4	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		5	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		6	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		7	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		8	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		9	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		10	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81

	FO6	1	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		2	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		3	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		4	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		5	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		6	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		7	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		8	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		9	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		10	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
	WASTE	1	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
		2	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
		3	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
		4	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
		5	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
		6	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
		7	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
		8	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
		9	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
		10	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
	Coal	1	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		2	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		3	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		4	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		5	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		6	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		7	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		8	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		9	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		10	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
TECO	Nat. Gas.	1	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		2	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		3	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83

	4	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
	5	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
	6	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
	7	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
	8	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
	9	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
	10	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
FO2	1	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
	2	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
	3	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
	4	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
	5	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
	6	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
	7	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
	8	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
	9	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
	10	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
FO6	1	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
	2	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
	3	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
	4	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
	5	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
	6	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
	7	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
	8	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
	9	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
	10	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
WASTE	1	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
	2	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
	3	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
	4	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
	5	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
	6	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00

		7	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
		8	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
		9	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
		10	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
	Coal	1	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		2	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		3	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		4	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		5	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		6	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		7	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		8	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		9	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		10	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
LAKELAND	Nat. Gas.	1	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		2	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		3	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		4	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		5	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		6	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		7	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		8	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		9	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		10	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
	FO2	1	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		2	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		3	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		4	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		5	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		6	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		7	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		8	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		9	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81

		10	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
	FO6	1	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		2	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		3	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		4	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		5	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		6	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		7	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		8	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		9	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		10	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
	WD	1	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00
		2	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00
		3	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00
		4	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00
		5	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00
		6	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00
		7	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00
		8	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00
		9	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00
		10	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00
	Coal	1	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		2	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		3	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		4	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		5	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		6	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		7	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		8	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		9	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		10	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
LAKE WALES	Nat. Gas.	1	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		2	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83

		3	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		4	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		5	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		6	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		7	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		8	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		9	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		10	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
	FO2	1	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		2	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		3	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		4	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		5	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		6	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		7	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		8	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		9	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		10	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
	FO6	1	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		2	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		3	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		4	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		5	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		6	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		7	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		8	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		9	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		10	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
FPLW	Nat. Gas.	1	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		2	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		3	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		4	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		5	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83

	6	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
	7	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
	8	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
	9	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
	10	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
FO2	1	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
	2	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
	3	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
	4	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
	5	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
	6	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
	7	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
	8	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
	9	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
	10	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
FO6	1	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
	2	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
	3	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
	4	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
	5	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
	6	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
	7	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
	8	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
	9	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
	10	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
WASTE	1	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
	2	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
	3	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
	4	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
	5	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
	6	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
	7	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
	8	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00

		9	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
		10	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
MARTIN	Nat. Gas.	1	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		2	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		3	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		4	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		5	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		6	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		7	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		8	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		9	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		10	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
	FO2	1	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		2	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		3	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		4	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		5	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		6	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		7	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		8	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		9	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		10	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
	FO6	1	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		2	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		3	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		4	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		5	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		6	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		7	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		8	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		9	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		10	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
	Coal	1	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43

		2	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		3	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		4	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		5	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		6	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		7	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		8	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		9	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
		10	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43	$1.43
	Uranium	1	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75
		2	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75
		3	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75
		4	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75
		5	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75
		6	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75
		7	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75
		8	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75
		9	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75
		10	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75
FPLE	Nat. Gas.	1	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		2	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		3	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		4	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		5	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		6	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		7	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		8	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		9	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		10	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
	FO2	1	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		2	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		3	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		4	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81

	5	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
	6	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
	7	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
	8	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
	9	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
	10	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
FO6	1	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
	2	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
	3	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
	4	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
	5	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
	6	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
	7	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
	8	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
	9	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
	10	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
WD	1	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00
	2	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00
	3	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00
	4	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00
	5	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00
	6	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00
	7	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00
	8	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00
	9	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00
	10	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00
WASTE	1	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
	2	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
	3	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
	4	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
	5	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
	6	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
	7	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00

		8	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
		9	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
		10	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
ANDYTOWN	Nat. Gas.	1	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		2	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		3	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		4	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		5	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		6	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		7	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		8	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		9	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		10	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
	FO2	1	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		2	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		3	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		4	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		5	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		6	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		7	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		8	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		9	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		10	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
	FO6	1	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		2	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		3	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		4	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		5	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		6	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		7	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		8	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		9	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		10	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97

	Uranium	1	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75
		2	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75
		3	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75
		4	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75
		5	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75
		6	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75
		7	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75
		8	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75
		9	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75
		10	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75	$0.75
MIAMI	Nat. Gas.	1	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		2	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		3	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		4	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		5	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		6	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		7	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		8	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		9	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
		10	$2.83	$2.79	$2.77	$2.73	$2.73	$2.72	$2.72	$2.73	$2.72	$2.71	$2.76	$2.83
	FO2	1	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		2	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		3	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		4	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		5	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		6	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		7	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		8	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		9	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
		10	$3.81	$3.78	$3.77	$3.74	$3.74	$3.73	$3.74	$3.74	$3.73	$3.73	$3.76	$3.81
	FO6	1	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		2	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
		3	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97

	4	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
	5	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
	6	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
	7	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
	8	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
	9	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
	10	$2.97	$2.94	$2.93	$2.91	$2.92	$2.91	$2.91	$2.91	$2.91	$2.90	$2.93	$2.97
WASTE	1	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
	2	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
	3	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
	4	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
	5	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
	6	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
	7	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
	8	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
	9	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
	10	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00

15 APPENDIX D: SUMMARY OF REPRESENTATIVE AND DIRECTLY PERTINENT FASB STATEMENTS FROM FASB WEBSITE (RUTGERS/FASB)

This summary of FASB statements was taken from the Rutgers FASB website and reproduced here in different typeset. It is intended that this section reproduce information from the Rutgers RFASB website verbatim.

Summary of Statement No. 105
Disclosure of Information about Financial Instruments with Off-Balance-Sheet Risk and Financial Instruments with Concentrations of Credit Risk
(Issued 3/90)

Summary

This Statement establishes requirements for all entities to disclose information principally about financial instruments with off-balance-sheet risk of accounting loss. It is the product of the first phase on disclosure of information about financial instruments. This first phase focuses on information about the extent, nature, and terms of financial instruments with off-balance-sheet credit or market risk and about concentrations of credit risk for all financial instruments. Subsequent phases will consider disclosure of other information about financial instruments. The disclosure phases are interim steps in the Board's project on financial instruments and off-balance-sheet financing. Recognition and measurement issues are currently being considered in other phases of the project.

This Statement extends present disclosure practices of some entities for some financial instruments by requiring all entities to disclose the following information about financial instruments with off-balance-sheet risk of accounting loss:

- The face, contract, or notional principal amount
- The nature and terms of the instruments and a discussion of their credit and market risk, cash requirements, and related accounting policies
- The accounting loss the entity would incur if any party to the financial instrument failed completely to perform according to the terms of the contract and the collateral or other security, if any, for the amount due proved to be of no value to the entity
- The entity's policy for requiring collateral or other security on financial instruments it accepts and a description of collateral on instruments presently held.
- This Statement also requires disclosure of information about significant concentrations of credit risk from an individual counterparty or groups of counterparties for all financial instruments.

This Statement is effective for financial statements issued for fiscal years ending after June 15, 1990.

Summary of Statement No. 107
Disclosures about Fair Value of Financial Instruments
(Issued 12/91)

Summary

This Statement extends existing fair value disclosure practices for some instruments by requiring all entities to disclose the fair value of financial instruments, both assets and liabilities recognized and not recognized in the statement of financial position, for which it is practicable to estimate fair value. If estimating fair value is not practicable, this Statement requires disclosure of descriptive information pertinent to estimating the value of a financial instrument. Disclosures about fair value are not required for certain financial instruments listed in paragraph 8.

This Statement is effective for financial statements issued for fiscal years ending after December 15, 1992, except for entities with less than $150 million in total assets in the current statement of financial position. For those entities, the effective date is for fiscal years ending after December 15, 1995.

Summary of Statement No. 115
Accounting for Certain Investments in Debt and Equity Securities
(Issued 5/93)

Summary

This Statement addresses the accounting and reporting for investments in equity securities that have readily determinable fair values and for all investments in debt securities. Those investments are to be classified in three categories and accounted for as follows:

- Debt securities that the enterprise has the positive intent and ability to hold to maturity are classified as held-to-maturity securities and reported at amortized cost.
- Debt and equity securities that are bought and held principally for the purpose of selling them in the near term are classified as trading securities and reported at fair value, with unrealized gains and losses included in earnings.
- Debt and equity securities not classified as either held-to-maturity securities or trading securities are classified as available-for-sale securities and reported at fair value, with unrealized gains and losses excluded from earnings and reported in a separate component of shareholders' equity.

This Statement does not apply to unsecuritized loans. However, after mortgage loans are converted to mortgage-backed securities, they are subject to its provisions. This Statement supersedes FASB Statement No. 12, Accounting for Certain Marketable Securities, and related Interpretations and amends FASB Statement No. 65, Accounting for Certain Mortgage Banking Activities, to eliminate mortgage-backed securities from its scope.

This Statement is effective for fiscal years beginning after December 15, 1993. It is to be initially applied as of the beginning of an enterprise's fiscal year and cannot be applied retroactively to prior years' financial statements. However, an enterprise may elect to initially apply this Statement as of the end of an earlier fiscal year for which annual financial statements have not previously been issued.

Summary of Statement No. 119
Disclosure about Derivative Financial Instruments and Fair Value of Financial Instruments
(Issued 10/94)

Summary

This Statement requires disclosures about derivative financial instruments-futures, forward, swap, and option contracts, and other financial instruments with similar characteristics. It also amends existing requirements of FASB Statement No. 105, Disclosure of Information about Financial Instruments with Off-Balance-Sheet Risk and Financial Instruments with Concentrations of Credit Risk, and FASB Statement No. 107, Disclosures about Fair Value of Financial Instruments.

This Statement requires disclosures about amounts, nature, and terms of derivative financial instruments that are not subject to Statement 105 because they do not result in off-balance-sheet risk of accounting loss. It requires that a distinction be made between financial instruments held or issued for trading purpose (including dealing and other trading activities measured at fair value with gains and losses recognized in earnings) and financial instruments held or issued for purposes other than trading. It also amends Statements 105 and 107 to require that distinction in certain disclosures required by those Statements.

For entities that hold or issue derivative financial instruments for trading purposes, this Statement requires disclosure of average fair value and of net trading gains or losses. For entities that hold or issue derivative financial instruments for purposes other than trading, it requires disclosure about those purposes and about how the instruments are reported in financial statements. For entities that hold or issue derivative financial instruments and account for them as hedges of anticipated transactions, it requires disclosure about the anticipated transactions, the classes of derivative financial instruments used to hedge those transactions, the amounts of hedging gains and losses deferred, and the transactions or other events that result in recognition of the deferred gains or losses in earnings. This Statement also encourages, but does not require, quantitative information about market risks of derivative financial instruments, and also of other assets and liabilities, that is consistent with the way the entity manages or adjusts risks and that is useful for comparing the results of applying the entity's strategies to its objectives for holding or issuing the derivative financial instruments.

This Statement amends Statement 105 to require disaggregation of information about financial instruments with off-balance-sheet risk of accounting loss by class, business activity, risk, or other category that is consistent with the entity's management of those instruments. This Statement also amends Statement 107 to require that fair value information be presented without combining, aggregating, or netting the fair value of derivative financial instruments with the fair value of nonderivative financial instruments and be presented together with the related carrying amounts in the body of the financial statements, a single footnote, or a summary table in a form that makes it clear whether the amounts represent assets or liabilities.

This Statement is effective for financial statements issued for fiscal years ending after December 15, 1994, except for entities with less than $150 million in total assets. For those entities, this Statement is effective for financial statements issued for fiscal years ending after December 15, 1995.

Summary of Statement No. 121
Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of
(Issued 3/95)

Summary

This Statement establishes accounting standards for the impairment of long-lived assets, certain identifiable intangibles, and goodwill related to those assets to be held and used and for long-lived assets and certain identifiable intangibles to be disposed of.

This Statement requires that long-lived assets and certain identifiable intangibles to be held and used by an entity be reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. In performing the review for recoverability, the entity should estimate the future cash flows expected to result from the use of the asset and its eventual disposition. If the sum of the expected future cash flows (undiscounted and without interest charges) is less than the carrying amount of the asset, an impairment loss is recognized. Otherwise, an impairment loss is not recognized. Measurement of an impairment loss for long-lived assets and identifiable intangibles that an entity expects to hold and use should be based on the fair value of the asset.

This Statement requires that long-lived assets and certain identifiable intangibles to be disposed of be reported at the lower of carrying amount or fair value less cost to sell, except for assets that are covered by APB Opinion No. 30, Reporting the Results of Operations-Reporting the Effects of Disposal of a Segment of a Business, and Extraordinary, Unusual and Infrequently Occurring Events and Transactions. Assets that are covered by Opinion 30 will continue to be reported at the lower of carrying amount or net realizable value.

This Statement also requires that a rate-regulated enterprise recognize an impairment for the amount of costs excluded when a regulator excludes all or part of a cost from the enterprise's rate base.

This Statement is effective for financial statements for fiscal years beginning after December 15, 1995. Earlier application is encouraged. Restatement of previously issued financial statements is not permitted. Impairment losses resulting from the application of this Statement should be reported in the period in which the recognition criteria are first applied and met. The initial application of this Statement to assets that are being held for disposal at the date of adoption should be reported as the cumulative effect of a change in accounting principle.

Summary of Statement No. 133
Accounting for Derivative Instruments and Hedging Activities
(Issued 6/98)

Summary

This Statement establishes accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts, (collectively referred to as derivatives) and for hedging activities. It requires that an entity recognize all derivatives as either assets or liabilities in the statement of financial position and measure those instruments at fair value. If certain conditions are met, a derivative may be specifically designated as (a) a hedge of the exposure to changes in the fair value of a recognized asset or liability or an unrecognized firm commitment, (b) a hedge of the exposure to variable cash flows of a forecasted transaction, or (c) a hedge of the foreign currency exposure of a net investment in a foreign operation, an unrecognized firm commitment, an available-for-sale security, or a foreign-currency-denominated forecasted transaction.

The accounting for changes in the fair value of a derivative (that is, gains and losses) depends on the intended use of the derivative and the resulting designation.
For a derivative designated as hedging the exposure to changes in the fair value of a recognized asset or liability or a firm commitment (referred to as a fair value hedge), the gain or loss is recognized in earnings in the period of change together with the offsetting loss or gain on the hedged item attributable to the risk being hedged. The effect of that accounting is to reflect in earnings the extent to which the hedge is not effective in achieving offsetting changes in fair value.

For a derivative designated as hedging the exposure to variable cash flows of a forecasted transaction (referred to as a cash flow hedge), the effective portion of the derivative's gain or loss is initially reported as a component of other comprehensive income (outside earnings) and subsequently reclassified into earnings when the forecasted transaction affects earnings. The ineffective portion of the gain or loss is reported in earnings immediately.

For a derivative designated as hedging the foreign currency exposure of a net investment in a foreign operation, the gain or loss is reported in other comprehensive income (outside earnings) as part of the cumulative translation adjustment. The accounting for a fair value hedge described above applies to a derivative designated as a hedge of the foreign currency exposure of an unrecognized firm commitment or an available-for-sale security. Similarly, the accounting for a cash flow hedge described above applies to a derivative designated as a hedge of the foreign currency exposure of a foreign-currency-denominated forecasted transaction.

For a derivative not designated as a hedging instrument, the gain or loss is recognized in earnings in the period of change.

Under this Statement, an entity that elects to apply hedge accounting is required to establish at the inception of the hedge the method it will use for assessing the effectiveness of the hedging derivative and the measurement approach for determining the ineffective aspect of the hedge. Those methods must be consistent with the entity's approach to managing risk.

This Statement applies to all entities. A not-for-profit organization should recognize the change in fair value of all derivatives as a change in net assets in the period of change. In a fair value hedge, the changes in the fair value of the hedged item attributable to the risk being hedged also are recognized. However, because of the format of their statement of financial performance, not-for-profit organizations are not permitted special hedge accounting for derivatives used to hedge forecasted transactions. This Statement does not address how a not-for-profit organization should determine the components of an operating measure if one is presented.

This Statement precludes designating a nonderivative financial instrument as a hedge of an asset, liability, unrecognized firm commitment, or forecasted transaction except that a nonderivative instrument denominated in a foreign currency may be designated as a hedge of the foreign currency exposure of an unrecognized firm commitment denominated in a foreign currency or a net investment in a foreign operation.

This Statement amends FASB Statement No. 52, Foreign Currency Translation, to permit special accounting for a hedge of a foreign currency forecasted transaction with a derivative. It supersedes FASB Statements No. 80, Accounting for Futures Contracts, No. 105, Disclosure of Information about Financial Instruments with Off-Balance-Sheet Risk and Financial Instruments with Concentrations of Credit Risk, and No. 119, Disclosure about Derivative Financial Instruments and Fair Value of Financial Instruments. It amends FASB Statement No. 107, Disclosures about Fair Value of Financial Instruments, to include in Statement 107 the disclosure provisions about concentrations of credit risk from Statement 105. This Statement also nullifies or modifies the consensuses reached in a number of issues addressed by the Emerging Issues Task Force.

This Statement is effective for all fiscal quarters of fiscal years beginning after June 15, 1999. Initial application of this Statement should be as of the beginning of an entity's fiscal quarter; on that date, hedging relationships must be designated anew and documented pursuant to the provisions of this Statement. Earlier application of all of the provisions of this Statement is encouraged, but it is permitted only as of the beginning of any fiscal quarter that begins after issuance of this Statement. This Statement should not be applied retroactively to financial statements of prior periods.