BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Joint Petition for Determination of Need for an Electrical Power Plant in Volusia County by the Utilities Commission, City of New Smyrna Beach, Florida, and Duke Energy New Smyrna Beach Power Company Ltd., L.L.P.	DOCKET NO. 981042-EM FILED: SEPT. 28, 1998

DIRECT TESTIMONY

OF

DALE M. NESBITT, Ph.D.

ON BEHALF OF

THE UTILITIES COMMISSION, CITY OF NEW SMYRNA BEACH, FLORIDA

AND

DUKE ENERGY NEW SMYRNA BEACH POWER COMPANY LTD., L.L.P.

DOCUMENT NUMBER-DATE
10702 SEP 28 98
FPSC-RECORDS/REPORTING

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Joint Petition for Determination of Need for an Electrical Power Plant in Volusia County by the Utilities Commission, City of New Smyrna Beach, Florida, and Duke Energy New Smyrna Beach Power Company Ltd., L.L.P.	DOCKET NO. 981042-EM FILED: SEPT. 28, 1998

DIRECT TESTIMONY

OF

DALE M. NESBITT, Ph.D.

ON BEHALF OF

THE UTILITIES COMMISSION, CITY OF NEW SMYRNA BEACH, FLORIDA

AND

DUKE ENERGY NEW SMYRNA BEACH POWER COMPANY LTD., L.L.P.

IN RE: JOINT PETITION FOR DETERMINATION OF NEED BY THE UTILITIES COMMISSION, CITY OF NEW SMYRNA BEACH, FLORIDA AND DUKE ENERGY NEW SMYRNA BEACH POWER COMPANY, FPSC DOCKET NO. 981042-EM

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., 1250 Aviation Avenue, Suite 200C, San Jose, CA 95110.

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

A: I am presently Chief Executive Officer and President of Altos Management Partners Inc. 1250 Aviation Avenue, Suite 200C, San Jose, CA 95110. Altos Management Partners Inc. is a Management Consulting firm. I am also a Director, President and Chief Executive Officer of MarketPoint Inc., 27121 Adonna Ct., Los Altos Hills, CA 94022. MarketPoint Inc. is a software development and support firm. I am also a Director and Vice President of Reticle Inc., 27121 Adonna Ct., Los Altos Hills, CA 94022. Reticle is a chemical and mineral technology company.

Q: Please describe your duties with Altos Management Partners.

A: I helped found Altos Management Partners Inc. in 1995 and assumed the position of Chief Executive Officer and President of Altos Management Partners in January 1998. I am responsible for business development, leadership, technology and technique development, communication, strategic direction, project supervision, staff development, and other fiduciary and management roles at Altos. My duties include working on client projects in addition to the foregoing roles. 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, training, documentation, communication, staff development, project supervision, and other fiduciary and management roles at MarketPoint. In 1998, I founded Reticle Inc. and presently serve as a director and Vice President. My duties include marketing and business development.

PROFESSIONAL QUALIFICATIONS AND EXPERIENCE

Q: Please summarize your educational background and experience.

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 from Stanford University in 1972, and a Ph.D. degree in Engineering-Economic Systems from Stanford University in 1975. My doctoral dissertation was accepted with honors from Stanford. I am a member of Phi Kappa Phi (national honorary society) and Sigma Tau (national honorary engineering society).

DIRECT TESTIMONY OF DR. DALE M. NESBITT

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) as a Decision Analyst in its Decision Analysis Group. When I left SRI in 1977, I was Manager, Decision Analysis—Energy. In 1977, I co-founded Decision Focus Incorporated (DFI), a private management consulting firm practicing in the oil, gas, electricity, telecommunications, air transportation, leisure services, environment, and high technology industries. I later helped found and later joined Altos Management Partners, originally as a Senior Consultant and now as Chief Executive Officer, and President, where I have helped consolidate Altos' oil, gas, and electricity modeling and management consulting practice. Altos' services now include short and long run models of North American gas (NARG), North American electricity, 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. I recently founded MarketPoint Inc., which develops, sells, and supports economic modeling software, and Reticle, Inc., a chemical and mineral technology company. During my time in the consulting business, which has been continuous since 1974, I have served most of the multinational oil companies based in North America, most of the North American natural gas pipelines, and a number of North American electric companies.

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

A: Yes. I have provided testimony to a number of different state and national regulatory bodies. For example, I have testified before the Economic Regulatory Administration of the United States government in support of the TransAlaska Gas Pipeline System. I provided testimony before the National Energy Board of Canada in support of the McKenzie Delta pipeline (in behalf of Gulf, Exxon, and Shell) and in a different proceeding 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 ("PGT") roll-in application. 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 regarding 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 on PGT to offering information regarding appropriate discount rates and rates of return to ascribe to private companies who endeavor to enter California.

PURPOSE AND SUMMARY OF TESTIMONY

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

A: I am testifying on behalf of the Utilities Commission of New Smyrna Beach, Florida ("UCNSB"), and Duke Energy New Smyrna Beach Power Company Ltd., L.L.P. ("Duke New Smyrna"), the joint applicants for the Commission's determination of need for the New Smyrna Beach Power Project (or "the Project").

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

A: My testimony addresses several questions related to the New Smyrna Beach Power Project, including the following:

1. Is there a need for 500 MW of electric generation capacity and associated energy production in the Peninsular Florida market? The answer is yes, and the need is immediate.
2. Is the proposed New Smyrna Beach Power Project the most cost-effective option to provide this capacity and energy? The answer is yes; the natural gas combined cycle technology of the New Smyrna Beach Power Project is the most cost-effective option for capacity and energy in the Peninsular Florida market. It is better than gas simple cycle, coal, oil, or other technologies.

3. Will the Duke New Smyrna Beach project be economically viable? The answer is yes. It will impose zero risk on Florida ratepayers because it is a merchant plant, reduce prices in the Florida market by virtue of its entry, and make money for its owners.
4. Will energy from the Duke New Smyrna Beach project be sold out of state? The answer is no, but even if it were, it would be strictly excess with regard to the Florida market.
5. What benefits, if any, will the Duke New Smyrna Beach project provide to Florida ratepayers? It will increase energy supply, decreasing Peninsular Florida energy prices relative to where they would otherwise be as a result. It will impose zero risk on Florida ratepayers. Florida ratepayers will not be obliged to buy energy or capacity from the project unless it is cheaper than all competing alternatives. It will reduce environmental emissions relative to what otherwise would occur because it is based on a low heat rate gas combined cycle configuration.

Q: Are you sponsoring any exhibits to your testimony?

A. Yes. I am sponsoring the following exhibits to my testimony.

DMN-1. Altos North American Regional Electric Model (graphic).

DMN-2. Altos North American Regional Gas Model ("NARG Model) (graphic).

DMN-3. 1998 Florida Load Duration Curve.

DMN-4. 1998 SERC/Southern Load Duration Curve.

DMN-5. Florida Capacity per NERC

DMN-6. Southern Capacity per NERC.

DMN-7. New Smyrna Beach Power Project, Projected Operations and Fuel Savings.

DMN-8. Florida - 1998 Baseload (40%).

DMN-9. Florida Dispatch - 1998 High Load Factor Intermediate (25%).

DMN-10. Florida Dispatch - 1998 Low Load Factor Intermediate (15%).

DMN-11. Florida Dispatch - 1998 High Load Factor Peak (15%).

DMN-12. Florida Dispatch - 1998 SuperPeak (5%).

DMN-13. Comparative Electricity Production Costs, SERC & FRCC, 1995-1998.

DMN-14. Benefits of Duke New Smyrna Beach Power Project (graphic).

DMN-15. <u>Achieving Competitive Advantage Through Quantitative Electric Asset Valuation Using the Altos North American Regional Electricity Model</u>.

DMN-16. <u>Overview of the North American Regional Gas (NARG) Model</u>.

I am also sponsoring Table 10 and Part I of Table 15 contained in the Exhibits submitted on August 19, 1998.

METHODOLOGY

Q. How have you addressed the foregoing questions regarding the New Smyrna Beach Power Project?

A: I have developed the information necessary to answer the foregoing questions by combining my company's (Altos's) North American Regional Electricity Model ("the Altos Model" or "the Altos Electric Model") illustrated in Exhibit ____ (DMN-1) and described more fully in Exhibit ____ (DMN-15), the associated Altos data base for that model, the North American Regional Gas (NARG) Model illustrated in Exhibit ____ (DMN-2) and described more fully in Exhibit ____ (DMN-16), and Altos's experience in the gas and electricity businesses.

Q: Please provide a brief history and methodology of the Altos North American Regional Electricity Model.

A: The Altos North American Regional Electricity Model is a 32-region integrated model of the North American electricity system that includes generation, transmission, consumption, fuels, and fuel competition. The Altos Electric Model includes all of the generation regions, all of the existing and prospective transmission interconnections, and all of the demand regions of North America. Generally speaking, the Altos Model includes all of the reliability coordinating regions in the U.S., Canada, and Mexico, plus numerous subregions. For example, the model treats the Southern Electric Reliability Council region ("SERC") as four separate sub-regions: the Southern Company system, TVA, VCR (Virginia and the Carolinas), and Entergy, which was formerly designated as the southeastern component of the Southwestern Power Pool.

The Altos Electricity Model includes transmission system integration and interconnection, consideration of multiple fuels and energy products, existing capacity and its cost structure, future changes in the cost structure of existing plants, retirements and decommissioning, new generation plant entry, inbound and outbound transmission capabilities, transmission entry, and demands and load shapes that vary over time within each region. In evaluating future capacity energy needs, the Altos Model considers the following generating technologies: gas/oil combustion turbine, gas combined cycle, oil combined cycle, pulverized coal, coal gasification combined cycle, nuclear, gas/oil steam, and waste-to-energy.

The North American Regional Gas Model (the "NARG Model") includes all gas supply basins, all existing and prospective interconnecting pipelines, and all of the gas demand regions of North American. In the NARG Model, each category of resource in each supply region is characterized by a detailed supply sub-model, each pipeline is characterized by a detailed transportation sub-model, and each demand region is characterized by a detailed demand sub-model. The NARG Model estimates, over time, the set of regional prices that simultaneously clear the markets in every wellhead, wholesale, and other market in North America.

Exhibits ____ (DMN-15) and ____ (DMN-16) to my testimony summarize the history and methodology of the Altos North American Regional Electricity Model and the NARG Model.

Q: Who uses the Altos North American Regional Electricity Model and the NARG Model?

A: Many of the major producers and pipelines and a number of the electric companies in North America have used my NARG and North American Electricity Models. I am allowed to disclose nothing other than the names of those users, the list of which includes Amoco, Arco, Associated Electric Cooperative, Inc., BC Gas, BHP Petroleum (Broken Hills), BP, British Gas Corporation, California Energy Commission, Canadian Energy Research Institute, Chase Manhattan Bank, CIA, Coastal/Colorado Interstate Gas, Conoco/DuPont, DOE/EIA, Duke Energy/Panhandle Eastern, El Paso, Enron, Exxon, LLL, LBL, Argonne, Oak Ridge, Los Alamos, MidCon/Occidental Petroleum, Mobil, National Energy Board of Canada, Nova Corporation, Oklahoma Gas and Electric, PanCanadian, Pennsylvania Power and Light, Petro-Canada, PG&E/PGT, Shell, So Cal Edison (SCE Corp.), Sonat, Texas Utilities Corporation, TransCanada Pipeline Corporation, TVA, and the Williams Companies. I can disclose what the foregoing users might have chosen to put into the public domain.

Q: Has the model been independently validated by a third party?

A: Yes. The Energy Information Administration ("EIA") of the United States government decided in 1980-1 to independently validate the GEMS model (GEMS 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. 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 GEMS 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 is the only model in existence that has been independently validated to such a degree.

Q: Before leading us through your detailed results, could you summarize the cost structure and performance you have assumed for the New Smyrna Beach Power Project?

A: I have assumed that the heat rate of the New Smyrna Beach Power Project will be 6,832 Btu per KWh at full load. Because the Altos Electric Model projects substantial run times for the New Smyrna Beach Power Project, I have not considered partial load heat rate performance of the facility (i.e., heat rate curves). I have assumed that the fully commoditized, variable, all-in, forward operating and maintenance cost of the New Smyrna Beach Power Project will be $2.30/MWH. This is consistent with what at least one vendor is offering in new combined cycle equipment it proposes to build. I understand from Duke New Smyrna that the projected in-service cost of the 500 MW New Smyrna Beach Project, including the transmission interconnection to the Smyrna Substation of the UCNSB, is approximately $160 million. This cost estimate includes permitting costs but does not include the costs of downstream transmission upgrades.

Q: Have you used Duke New Smyrna or UCNSB proprietary or confidential assumptions, data, or analysis in preparing your testimony?

A: Not to my knowledge. My testimony is based on my own work and assumptions and that of my Altos colleagues, particularly

Michael C. Blaha, with whom I have collaborated in preparing this testimony. While the work underlying this testimony was done under sponsorship by Duke New Smyrna, the work represents my and Altos's best judgment. To wit, the forward price calculations and their implications for the project are drawn from Altos's models, data, analyses, and personnel. They are not drawn from proprietary or confidential data from Duke New Smyrna, the UCNSB, or any of their affiliates, nor are they drawn from analysis or data provided by Duke New Smyrna or the UCNSB. My objective has been to apply and put forth my and Altos' best professional analysis and judgment based on our best available technology, experience, and data, not to mirror Duke New Smyrna's or the UCNSB's analyses or projections.

NEED FOR THE NEW SMYRNA BEACH POWER PROJECT

Q: Is there a need for 500 MW of new electric generation capacity and associated energy production in the Peninsular Florida market?

A: Yes, there is a need for more than 500 MW of new electric generation capacity and associated energy production in the Peninsular Florida market, the need is immediate, and the need is growing over time. The Altos North American Regional Electricity Model projects economically viable and profitable new additions of up to 6,000 MW of new gas-fired combined cycle ("CC") power plants in Peninsular Florida, which I use synonymously with the Florida Reliability Coordinating Council ("FRCC") region, and several tens of thousands of MW of new gas CC entry elsewhere throughout North America. Our predicted substantial quantity of new installed capacity in Peninsular Florida--6,000 MW--is approximately twice the quantity of new capacity that FRCC itself reported to NERC in FRCC's 1997 OE411 Annual Report. This is a strong statement in favor of the viability, need, and strong positive contribution of new gas CC capacity entry into the Florida market of the type Duke New Smyrna is proposing. In summary, there is a need for more than the 500 MW proposed by Duke New Smyrna.

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 some criterion such as reserve margin or loss-of-load-probability. (I should add, however, that even this simplistic comparison would underscore the need for projects such as the New Smyrna Beach Power Project). A simplistic "add up the installed capacity and compare against peak demand" notion of "need" such as the forgoing 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 eliminate old, uneconomic capacity, obviate the requirement to preserve and/or run it, and reduce the intrinsic cost to generate electricity in Florida. A critically important element of the need for new capacity is the need to retire old, uneconomic, and usually pollution-intensive capacity. (By analogy, the "need" for a new car is a need to retire your old 1972 Chevy Vega you would otherwise have to maintain and drive, thereby avoiding the much higher operating and maintenance cost and downtime of the Vega.)

The Altos Electric Model predicts that there are few places in North American where the need for new gas CC generation is more acute and more immediate than in Peninsular Florida. Florida is growing, and Florida electricity is expensive. New capacity such as the New Smyrna Beach Power Project is needed to meet inevitable growth in the state, ameliorate the current and future market price, and provide economic benefits via reduced market prices to the state of Florida.

Q: What is the historical and projected future load situation in Florida?

A: Altos has assembled hourly reported data for every hour in the past five years (including 1997) for every reporting entity in Florida (and elsewhere in the United States). This data has allowed us to assemble average daily load shapes, maximum daily load shapes, monthly load duration curves, and annual load duration curves for the Peninsular Florida market. Exhibit ___ (DMN-3) depicts the load situation in

Peninsular Florida inferred from reported hourly loads during every hour of the past five years. Exhibit ____ (DMN-3) indicates within each monthly time interval the average daily load shape for days in that month, the maximum daily load shape, and the minimum daily load shape. (The daily curves are the up-down-up-down curves shown for each month in the figure.) The hourly loads are ordered by hour in the month from highest load hour in the month down to lowest load hour in the month. This process of ordering from highest to lowest produces the monthly load duration curves, which are the downward sloping curves in the exhibit beginning at the start of each indicated month and ending at the end of that month. The exhibit also indicates the annual load duration curve beginning at the upper left and dropping to the lower right of the entire diagram. The annual load duration curve is the ordered set of annual loads from highest to lowest in descending order. These are the fundamental historical demand data that characterizes the Peninsular Florida market in aggregate. (Altos has undertaken this task for every one of the 32 regions of North America that are represented in the Altos Model so that we can understand the hourly, weekly, monthly, and annual demand profiles over the past five years and can reliably extrapolate it to the future.)

As seen in the monthly load duration curves in Exhibit ____ (DMN-3), peak demand in the FRCC/Florida market occurs in the summer, just as it does throughout most of the southern United States. However, unlike the rest of the southeastern United States, particularly SERC/Southern, the demand in Peninsular Florida during the winter months is more volatile. Interestingly, the observed winter peak is almost as high as the observed summer peak; however, the load variability during the winter is higher than the variability during the summer. The SERC/Southern region has been served by large gas pipelines over the years (e.g., Sonat, Transcontinental), and gas has penetrated the winter heating market there. A larger proportion of Florida customers rely on resistance heat during cold winter days, owing in part to the historical paucity of natural gas in Florida, rendering winter electricity demand volatility higher in Florida. The higher winter price volatility in Florida has consequences for the price differentials between the SERC/Southern region and Peninsular Florida during the winter and for the propensity to move power from Southern to Peninsular Florida during the winter.

As seen in the monthly load duration curves in Exhibit ____ (DMN-3), Florida is a dual peaking market. The peak-to-base ratio during the summer is calculated to be approximately 2.5:1, larger than the corresponding ratio in SERC/Southern and elsewhere in SERC. Obviously, Florida experiences strong peaks in the summer. However, the winter peak-to-base ratio in Peninsular Florida is nearly 3:1, presaging higher volatility of demand in the winter than in the summer. A plant such as the New Smyrna Beach Power Project built in Florida can take advantage of two peaks, but a plant built in SERC/Southern or other southern United States locations often can take advantage of only one.

The ability of Florida generators to capture two peak markets presents an interesting advantage for building new capacity in Florida as Duke New Smyrna and the UCNSB are proposing. It also raises the possibility, however, that during the winter, inbound transmission from SERC/Southern (which might be somewhat slack during the winter) will make up the Florida winter peak deficit. The Altos Model tells which is the better winter alternative -- new generation from the New Smyrna Beach Power Project versus more inbound transmission from Southern. (The Altos Model shows that indigenous combined cycle generation in Florida such as the New Smyrna Beach Power Project is better.) Referring back to Exhibit ____ (DMN-3), it is unlikely that there will be summer energy or capacity available to be imported into Peninsular Florida from points north. During the summer, the New Smyrna Beach Power Project will pay substantial benefits to Florida ratepayers by simply directly producing into the Florida market. The exhibit further suggests that prices will be firm for a substantial portion of the summer and winter, but not necessarily during spring and fall, months. The Altos Model will verify that fact as well, but the spring and fall prices will not fall low enough to knock the Project out of the mix very frequently. The model confirms that the Project will evolve rather quickly to become a baseload plant.

It is also important to consider and understand the role of the SERC/Southern region in these analyses of the Project. Exhibit ____ (DMN-4) illustrates the comparable load information for SERC/Southern as was presented for Peninsular Florida in Exhibit ____ (DMN-3). The magnitude of the winter peak in the SERC/Southern region is smaller, in relative terms, than the winter peak in Florida. This means that there will be excess energy exportability from Southern to Florida at all times except the summer peak. Furthermore, it is possible that the value of surplus exportability from Southern to Florida during the winter will be attractive in Florida (which should have substantially higher prices than Southern in the winter.) This is not a trivial insight, and it is explicitly accounted for in the Altos Model. The Model calculate the fair market value of energy in Southern during every month of the year and consider its prospective competitiveness against energy from other sources in Florida during every month of the year. This is critical to proper valuation of the New Smyrna Beach Power Project.

I should point out that I have subdivided each of the 12 monthly load duration curves in Exhibits ____ (DMN-3) and ____ (DMN-4) into five discrete blocks for every region in the Altos Electric Model. The five blocks, which range successively from base load to peak, are designated as follows.

1. Baseload (P1) – 40 percent of the hours in the month, i.e., those 40 percent of the hours with the lowest average load. This category represents the 0^{th} to the 40^{th} percentile of load.

2. High Load Factor Intermediate (P2) – those 25 percent of the hours in the month with the next higher average load. This category represents the 40^{th}. percentile to the 65^{th} percentile of load.

3. Low Load Factor Intermediate (P3) – those 15 percent of the hours in the month with the next higher average load. This category represents the 65^{th} percentile to the 80^{th} percentile of load.

4. High Load Factor Peak (P4) – those 15 percent of the hours in the month with the next higher average load. This category represents the 80^{th} percentile to the 95^{th} percentile of load.

5. Low Load Factor Peak or Superpeak (P5) – those 5 percent of the hours in the month with the highest average load. This category represents the 95^{th} percentile to the 100^{th} percentile of the load.

The Altos North American Regional Electricity Model will calculate market clearing prices for each of these categories of load for each month of the year, thereby dividing annual load into 60 time increments.

Q: What is the installed capacity in Peninsular Florida and Southern as compared with the foregoing daily, monthly, and annual load information?

A: The capacity situation in the Florida market according to NERC is summarized in Exhibit ____ (DMN-5), and the capacity situation in the Southern market according to NERC is summarized in Exhibit ____ (DMN-6). If we compare installed capacity in Peninsular Florida against the load duration curves in Exhibit ____ (DMN-3) that describe the present situation, Florida is short of baseload capacity, having a total of only 13,000 MW of existing base load capacity (coal, nuclear, and hydro). It is apparent from the curves in Exhibit ____ (DMN-3) that Florida is short of on-peak capacity as well. In fact, there is not enough installed indigenous base load capacity (13,000 MW) to meet hourly demand during most of the hours of the year. The "bottoms" of the monthly load duration curves in Exhibit ____ (DMN-3) are chronically above the 13,000 MW level, meaning that Peninsular Florida is and will remain for the foreseeable future chronically underserved in baseload energy. New power plants such as the New Smyrna Beach Power Project are critical if Florida is to relieve itself from the shortage of baseload capacity that presently faces the state. The model results will show that the New Smyrna Beach Power Project will initially run as an intermediate load plant but after a very few years will operate in baseload and will make up part of the difference between presently installed capacity and the bottoms of the monthly load duration curve. In short, Peninsular Florida is in a base load deficit condition, one that has traditionally been supplemented by baseload transmission imports from Southern.

Note further in Exhibit ____ (DMN-5) that Peninsular Florida is anticipating adding combined cycle units (approximately 3,000 MW by 2006) and buying more power from out-of-state providers. It is instructive to note in the Southern projection in Exhibit ____ (DMN-6), which is the Southern analog of Exhibit ____ (DMN-5), that those very out-of-state buyers are not planning to add capacity to sell it Florida. In fact, they are projecting reduced, not increased, electric sales to Florida. There is an intrinsic mismatch here. The Project will fill part of this mismatch and shelter Florida electric customers from higher prices. The Altos Electric Model tells us how this mismatch will be resolved both in terms of price and energy flows.

Returning to Exhibit ____ (DMN-5), almost all the indicated 23,000 MW of existing Florida oil-and-gas-fired steam-turbines, combustion-turbines and combined-cycle units have heat rates in excess of that of the proposed New Smyrna Beach Power Project (projected at 6,832 Btu/KWh). This means that the Project will be inframarginal relative to virtually all of the existing oil and gas power plants in Florida and will operate in preference to them. The majority of existing

Florida units are old and are not state-of-the-art. The presently existing Florida peaking units will continue to be run when inbound transmission is constrained or when Southern's coal facilities are fully dispatched and diverted elsewhere (to an increasing degree staying right at home in Southern to meet their growing indigenous peak demand). Introducing inframarginal sources of the type Duke New Smyrna and the UCNSB are proposing will pay immediate and substantial benefits not only to the owners of the new inframarginal Florida plants but also to the market as a whole through price softening, particularly during time of peak.

COST-EFFECTIVENESS OF THE NEW SMYRNA BEACH POWER PROJECT

Q: Is the proposed power plant the most cost-effective alternative available to provide additional power supply resources in Peninsular Florida?

A: Yes. The Altos Electric Model confirms that gas-fired combined cycle technology, like that of the proposed Project, is the most cost-effective generation technology to add in Peninsular Florida. The fact that the Project is the most cost-effective alternative is underscored by the fact that gas CC technology is currently the technology of choice for Florida utilities and for many utilities throughout the United States. (The Altos Electric Model indicates that new entry of gas CC capacity will be one of the most important contributors to future energy flows as well as a key driver of future energy prices.) For example, the proposed Cane Island 3 plant of the Florida Municipal Power Agency and the Kissimmee Utilities Authority, 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 gas CC technology.

Q: Is the proposed power plant the most cost-effective alternative available for Duke New Smyrna in order to meet its obligations to the UCNSB and as a merchant power provider in Peninsular Florida?

A: Yes. The proposed Project is not only the most cost-effective alternative for the FRCC/Peninsular Florida market, it is also the most cost-effective alternative for Duke New Smyrna to meet its obligations to the UCNSB and as a merchant power provider in the Peninsular Florida market. This result follows directly from the above observations: if the best technology for the overall market is gas-fired CC capacity, then the best technology for an individual supplier, such as Duke New Smyrna, is that same technology. Again, this result is also confirmed by the observed fact that gas-fired CC capacity is the technology of choice for new capacity in Florida and across the U.S.

Q: What alternative generation technologies does the Altos North American Regional Electric Model consider in evaluating whether a proposed power plant is the most cost-effective alternative for a given situation?

A: The Altos Model considers gas-fired and oil-fired combustion turbines, gas-fired and oil-fired combined cycle units, gas-fueled steam generation units, oil-fueled steam generation units, pulverized coal units, integrated coal gasification combined cycle ("IGCC") units, nuclear units, and waste-to-energy technologies.

ECONOMIC VIABILITY OF THE NEW SMYRNA BEACH POWER PROJECT

Q: Please comment on the economic viability of the New Smyrna Beach Power Project.

A: In a competitive environment, a cost-effective facility is by definition economically viable. Indeed, merchantization and commoditization of a market favor the low cost provider. I have discussed and demonstrated that the gas CC technology is inframarginal in Florida, meaning that new plants such as the Project are economically viable and profitable The New Smyrna Beach Power Project is clearly economically and competitively viable.

Q: Are there any key market uncertainties that could depress Peninsular Florida/FRCC prices and spark spreads and hurt the Project's viability?

A: Not to my knowledge. The foregoing results certainly suggest that increasing transmission capability into Peninsular Florida from Southern and points north could put strong downward competitive pressure on Florida prices. I have run a case in which the inbound transmission capability from Southern is nearly doubled from its first contingency capability today of 3,600 MW up to 7,000 MW. This case depresses Florida prices and spark spreads a bit, but not enough to eliminate gas CC entry from Florida. The reason is that the coal units will be just as constrained in SERC and FRCC with or without new transmission capability into Florida. By opening up the market, new gas CC capacity moves more quickly and more completely to the margin in the whole region. New gas CC in Southern is actually less attractive to Florida than new gas CC in Florida. Almost doubling inbound transmission capability into Florida does not kill or daunt the need for new gas CC entry into Florida.

I have also run a completely unlimited and unconstrained inbound transmission case from every region into every other region shown in the model in Exhibit ____ (DMN-1). Our intention was to represent a case in which any incremental transmission project that experienced a high enough price differential across that project would be immediately and completely built. This unlimited transmission case, which incidentally carried a uniform $3/MWH inter-regional wheeling charge from every region to every contiguous region in

Exhibit ____ (DMN-1), did indeed daunt gas CC entry into Florida. In this case of unlimited low cost transmission, the gas CC business shifted en masse to Entergy (Louisiana) in order to be close to the cheapest natural gas on the continent. Because electric transmission is so cheap and so ubiquitous by assumption in this case, the cycling and peaking generation industry in the eastern and southern United States shifts quite quickly and dramatically into Louisiana and Texas, and a huge outbound electric transmission business is built to serve them. While this case might not represent the future configuration of the electric system, it clearly implies that the more transmission that becomes available into Florida, the more the gas CC industry shifts upstream to the lower gas price regions and away from the higher gas price regions. This makes good intuitive sense.

Over a broad range of alternative scenarios constructed in the past with the Altos Model, we have seen the Florida spark spreads remain quite robust, and we have seen the propensity for a substantial amount of gas CC entry into Florida. No reasonable sensitivity case changes the fact that Florida is short of capacity, baseload as well as peaking capacity. No reasonable sensitivity case changes the fact that Florida must either install needed capacity or purchase it over transmission lines from afar.

PROJECTED OPERATIONS OF THE NEW SMYRNA BEACH POWER PROJECT

Q: Please summarize the projected operations of the Project.

A: Exhibit ____ (DMN-7) summarizes the projected operations of the New Smyrna Beach Power Project for the period 2002 through 2012. This table shows that the Project is expected to operate at Capacity Factors ranging from approximately 83 percent in 2002, its first full year of operation, when its projected generation is 3,719,550 MWH, to approximately 94 percent in 2012, when it is expected to produce more than 4,200,000 MWH.

Q: Can you discuss the plant operation predictions from the model? More specifically, what plants will dispatch to what degree in what hours in what months?

A: Let me answer that question by proceeding through the Florida market in order: baseload (40% of the time), high load factor intermediate load (25% of the time), low load factor intermediate load (15% of the time), high load factor peak (15% of the time), and low load factor peak (superpeak, 5% of the time). I have assembled the Exhibits ____ (DMN-8) through ____ (DMN-12) from the Altos Electric Model run to depict plant dispatch in Florida for base (P1), high load factor intermediate (P2), low load factor intermediate (P3), high load factor peak (P4), and superpeak (P5).

Q: Does the Altos Electric Model indicate whether Duke New Smyrna is likely to sell any power outside Peninsular Florida?

A: Yes. My analyses indicate that very little, if any, power generated by the New Smyrna Beach Power Project will be sold outside Peninsular Florida, i.e., outside the FRCC region. In fact, my analyses indicate that, for a limited number of hours each year, the Project may actually decrease imports of coal-fired power from the SERC region. The economic success of the project does not depend on the project selling any power outside Peninsular Florida. Indeed, the project does not anticipate selling power outside Peninsular Florida.

Q: Are you aware of other evidence to support your conclusion that the output of the New Smyrna Beach Power Project will be sold entirely, or almost entirely, within Peninsular Florida?

A: Yes. The PowerDAT generation cost data published by Public Utilities Fortnightly shows that the raw generation costs of power generated within the FRCC is significantly, even dramatically, higher than the comparable raw generation cost of electricity produced in the SERC region. For example, Exhibit ____ (DMN-13) presents summary data for FRCC and SERC for 1997 and also for January through March 1998. (These are the most current and complete data available.) These data show that for 1997, and for the first quarter of 1998, the average generation cost (fuel plus variable operation and maintenance cost) in FRCC was **more than 50 percent greater than** the comparable average generation cost in the SERC region. For 1996, the difference was even greater. This demonstrates conclusively that the primary wholesale market for the output of the New Smyrna Beach Power Project is within Peninsular Florida.

BENEFITS PROVIDED BY THE NEW SMYRNA BEACH POWER PROJECT

Q: What benefits, if any, is the New Smyrna Beach Power Project likely to provide to Florida and its electric ratepayers?

A: The Project will increase energy supply, decreasing Florida energy prices relative to where they would otherwise be as a result. It will also limit or dampen market power, while imposing zero financial and operating risk on Florida ratepayers. Florida ratepayers will not be obliged to buy energy or capacity from the Project unless it is cheaper than all competing alternatives. It will reduce the quantity of fuel consumed for electricity generation, including both oil and gas that would otherwise be burned in much less efficient power plants, and will also reduce environmental emissions relative to what otherwise would occur because it is based on a low heat rate gas combined cycle configuration.

Q: Market power and market concentration among resident generators might become an issue in Florida. Would the entry of the New Smyrna Beach Power Project increase or decrease

market power and concentration relative to the level that would otherwise exist?

A: The Project's entry and presence would decrease whatever market power and market concentration would otherwise exist in Florida. I have not attempted for this analysis to quantify whether market power exists or is being exerted in Florida by any of the players individually or collectively. It is clear, however, that the entry of new facilities that are small in the overall scheme of the market and are owned by independent entities without any prospect of market power reduces whatever market concentration and market power might now or in the future exist in Florida. The entry and presence of the Project is at worst neutral and at best dilutive of market power and market concentration problems that might otherwise exist in Florida. The Commission should keep in mind that Peninsular Florida is dominated by three investor-owned utilities that individually and collectively own a significant proportion of the installed generating capacity in Peninsular Florida. With regard to market concentration, Florida Power & Light Company ("FPL") controls more than 40% of Peninsular Florida's generation capacity. Two-thirds of Peninsular Florida's generation capability resides collectively in the hands of FPL, Florida Power Corporation, and Tampa Electric Company.

Q: What, if any, effect would the presence of merchant capacity have on potential price spikes due to short-term capacity shortfalls?

A: During the summer of 1998, we have witnessed the explosion of the wholesale energy market with spot prices reaching as high as $7,000/MWH. Prospects for spot prices this astronomical during peak lie at the heart of the issue of the market power issue. Can some key Florida player withhold capacity and drive up price during peak and thereby garner monopoly rents? 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. To cite a contrasting example, ERCOT (which comprises the majority of Texas) has a peak demand of approximately 50,000 MW, and the majority of its indigenous generation is in the control of three investor-owned utilities just like Florida. However, ERCOT also has roughly 7,500 MW of generation capacity owned by cogenerators, industrial self-generators, and other entities not affiliated with retail-serving utilities. Of this 7,500 MW, nearly 3,000 MW is industrial self generation. Of the remaining 4,500 MW capacity, some 3,000 MW have historically been contracted to supply firm capacity and associated energy. The remaining 1,500 MW of capacity sells only as-available energy. This as-available energy represents a price buffer in the ERCOT system, one that restrains whatever market power might exist. It is significant to note that the price explosions seen recently elsewhere in North America have not affected ERCOT. There is an argument to be made that the existence of a 7,500 MW merchant capacity "buffer" moderates within ERCOT the type of price flyup seen elsewhere.

It would seem to me that Florida would be well advised to encourage a "merchant fringe" to limit prospects for market power and price flyup. The New Smyrna Beach Power Project represents an effective start building such a "merchant fringe" for Florida. I emphasize, I am not arguing that there is or is not any effective market power enjoyed or exercised by any individual or collective entity in Florida. I have not done the analysis. Rather, I am simply arguing that the existence of a "merchant fringe" of generation capacity ensures against the existence or exercise of such market power. The existence of a "merchant fringe" is an insurance policy against market power and market concentration.

I should point out that a decrease in market power and market concentration normally manifests itself in terms of lower market prices (because of less restrictions in capacity and energy production) to Florida customers. Florida electric customers are the direct beneficiaries of whatever dilution of market power might occur as the result of the entry of the New Smyrna Beach Power Project.

Q: What, if any, economic benefits is the New Smyrna Beach Project likely to provide to the State of Florida and to Florida electric customers?

A: The analysis herein of the Florida and contiguous markets demonstrates that the Project and gas CC projects like it will provide direct economic benefits in the form of lower-cost electricity to Florida utilities than would otherwise occur and more profits to low cost producers than would otherwise occur.

Exhibit ____ (DMN-14) indicates how to quantify and think about the economic welfare benefits of the Project. The entry of the New Smyrna Beach Power Project shifts the original supply curve for Florida outward and to the right. In particular, the entry of the Project 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 shifts from the leftmost vertical quantity line in the figure to the rightmost vertical quantity line. Price is depressed because of the increased capacity chasing a fixed demand, and quantity is stimulated because lower price attracts new customers and/or new uses. The shift from the upper left market clearing dot to the lower right market clearing dot in the exhibit makes both the price depression and the quantity stimulation clear.

The figure quantifies the economic benefit that the consumers in Florida get because of the entry of the Project (the sum of areas A + B + C), which represents the price reduction that is enjoyed by existing customers (A + B) plus new customers (C). The figure further quantifies the economic benefit that the producers in Florida get because of the entry of the Project (areas E + F – A), which represents the increased profit from serving old customers at the new lower cost (E) plus the increased profit from serving new customers at the new lower cost (F) minus the profits that were formerly realized (before the entry of the Project) by running old plants to serve old customers. It is well known that the total economic benefit is the algebraic sum of the consumers plus producers surplus calculations, which is the shaded area in the figure (B + C + E + F).

I have not quantified all the individual areas in the exhibit, but it would not be difficult to do so. If electricity demand in Florida were rather inelastic (i.e., steep demand curve), the benefits to Florida consumers would be equal to the volume of production from the Project in each hour of the year in which it is economic times the price depression the entry of the Project induces in the Florida market. It is clear from the exhibit that there must and will be a reduction in the price in the Florida market because of the entry of any inframarginal capacity such as the New Smyrna Beach Power Project. Florida consumers will not go empty handed because of the entry of the Project; some of the benefit of the entry will accrue to them through cost competition and market arbitrage. This is a critically important point. Entry of a new, merchant unit such as the New Smyrna Beach Power Project increases the quantity of capacity chasing the same market that would have been there with or without the new project. More supply chasing the same market necessarily means lower market price for a merchant producer. Merchant producers do not have the luxury of being able to impose their costs on downstream customers, and their entry therefore necessarily depresses market prices.

To summarize, as I mentioned previously, the existence of the New Smyrna Beach Power Project has the prospect of providing direct economic benefits in the form of a competitive check against market power and market concentration that a monopolistic or oligopolistic supplier might otherwise extract from its capacity and/or energy. The Project, like other gas CC projects, provides environmental benefits in the form of reduced environmental emissions that would otherwise occur if coal, steam turbines, or other baseload and/or peaking assets would have to be used instead.

Q: Will the Project result in primary fuel savings in Florida?

A: Yes. As shown in Exhibit ____ (DMN-7), the Project's operation is expected to result in significant savings in the consumption of primary fuel that would otherwise be burned to generate electricity. These savings are projected to be between 13 Trillion Btu and 15.5 Trillion Btu per year over the Project's first ten years of operation. If the Project displaces generation from heavy-oil-fired units, the gross oil savings can be expected to be on the order of 6 million to 7 million barrels of oil per year. Even if it only displaces gas burned in less efficient units, savings will be substantial.

Q: Please describe and discuss any other benefits that the Project will provide.

A: As discussed in the testimony of Mr. Meling, the New Smyrna Beach Project 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 New Smyrna Beach Power Project produces power with less pollution than the generation it displaces, the Project reduces 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.

CONCLUSION

Q: Please summarize the key conclusions of your testimony.

A: 1. There is an immediate and growing need for much more than the 500 MW of electric generation capacity proposed by Duke New Smyrna and the UCNSB and for the electric energy it will produce over its life.

2. The gas CC configuration proposed by Duke New Smyrna and the UCNSB is the most cost-effective option to provide the needed Florida capacity and energy. It is better than gas simple cycle, coal, oil, or other technologies.

3. The New Smyrna Beach Power Project is definitely economically viable. Its cost is lower than the marginal unit in Florida in an increasing number of hours, it will generate profits for its owners, it will depress wholesale electricity prices in Florida relative to what they would otherwise be, and it will be very clean and environmentally benign. As a merchant facility, it will impose zero cost risks on Florida ratepayers and electricity customers.

4. At most, an inconsequential amount of energy from the Project would ever be sold out of state. The Project requires no out of state sales to be profitable and economically viable.

5. The Project will provide a number of important benefits to Florida ratepayers. It will increase energy supply, decreasing Florida energy prices relative to where they would otherwise be as a result. It imposes zero risk on Florida

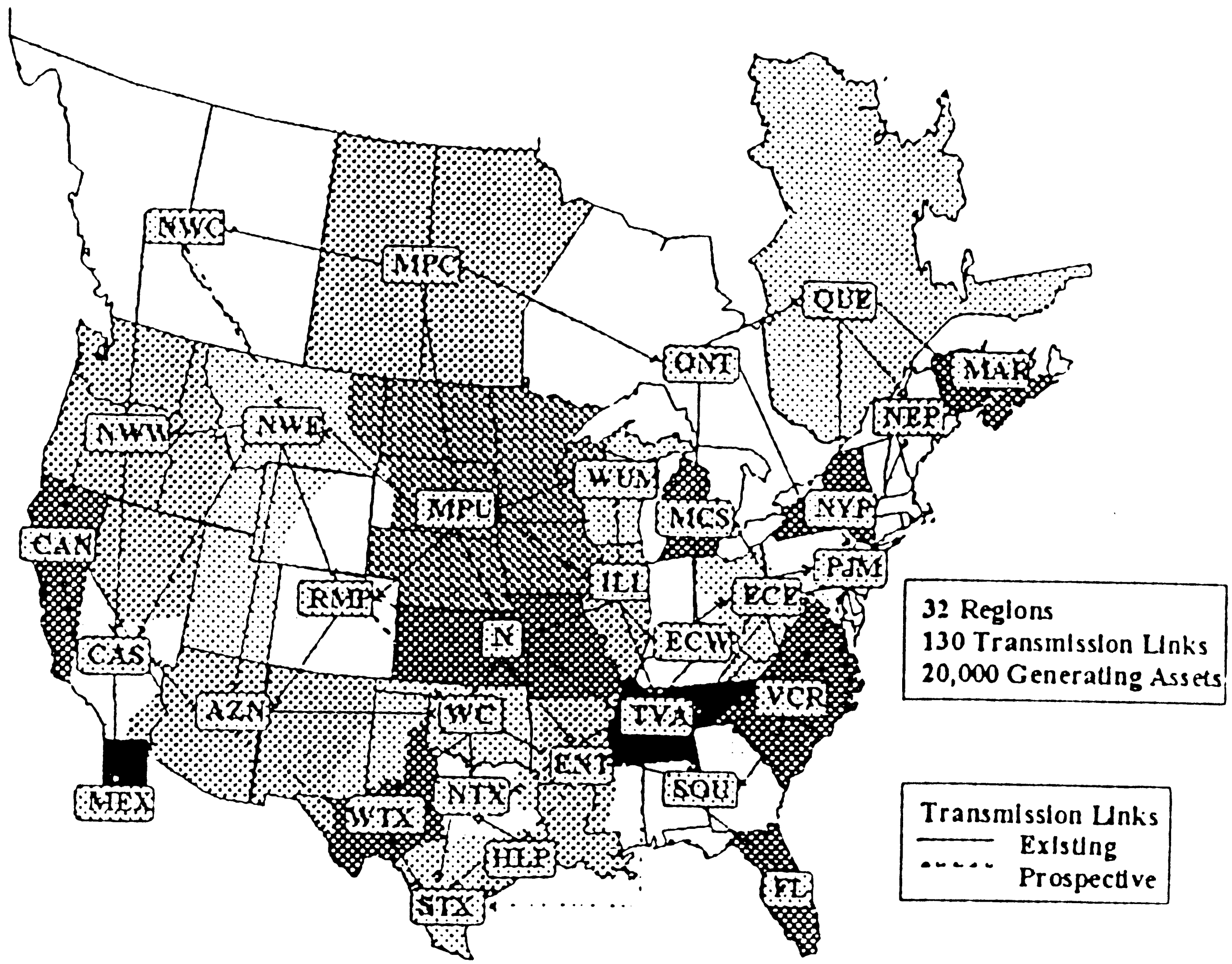
ratepayers. Florida ratepayers will not be obliged to buy energy or capacity from the project unless it is cheaper than all competing alternatives (which it is in initially 69 percent of the hours of the year rising to 92 percent of the hours of the year). It will reduce environmental emissions relative to what otherwise would occur because it is based on a low heat rate gas combined cycle configuration. Finally, it will ameliorate any market power or market concentration issues that might be present in Florida, reducing ratepayer prices as it does so.

Q: **Does this conclude your direct testimony?**

A: Yes. The foregoing testimony, together with the referenced Exhibits, concludes my testimony.

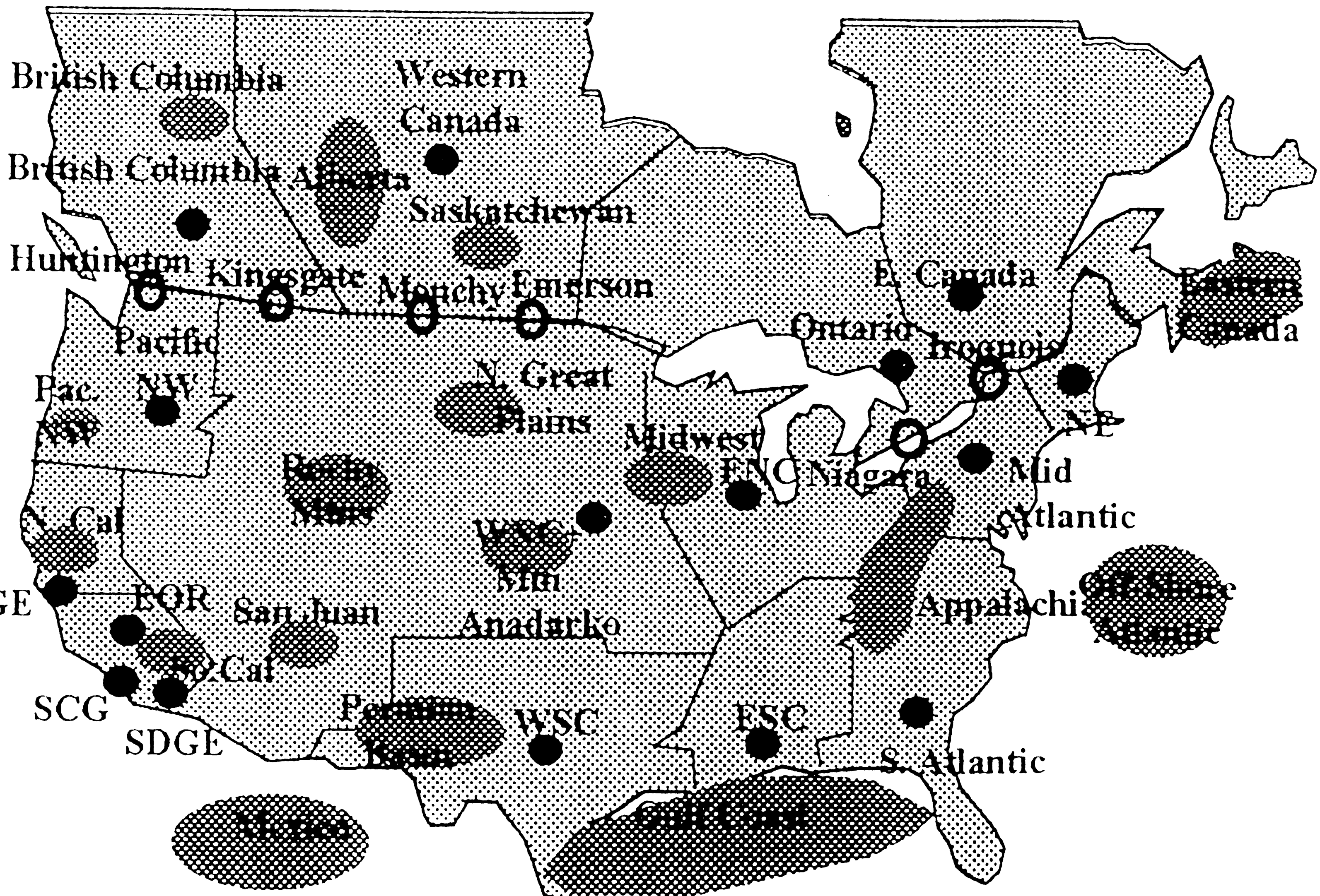
FPSC Docket No. 981042-EM
UCNSB/Duke New Smyrna
Witness: Nesbitt
Exhibit _____ (DMN-1)

ALTOS NORTH AMERICAN ELECTRICITY MODEL

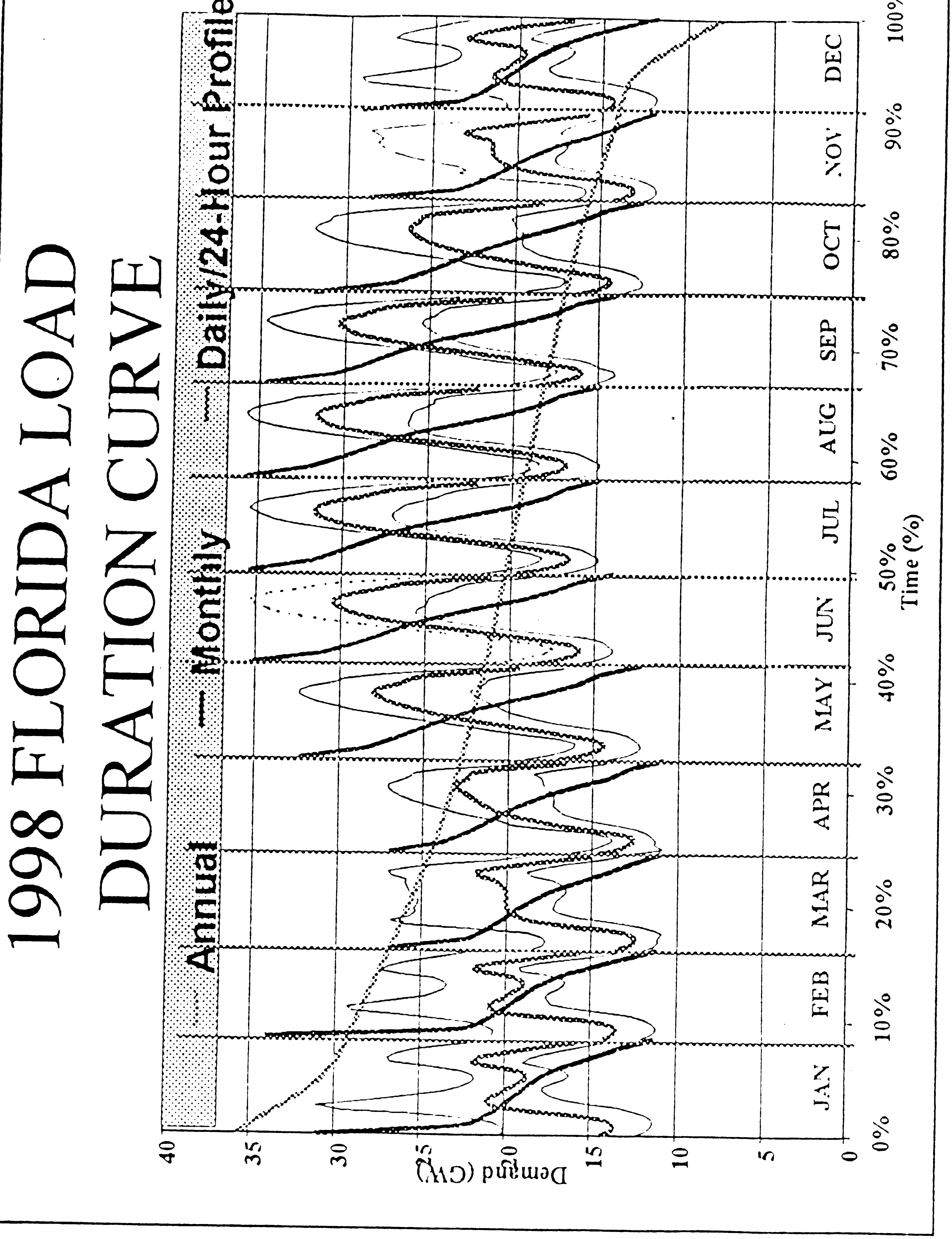


FPSC Docket No. 981042-EM
UCNSB/Duke New Smyrna
Witness: Nesbitt
Exhibit _____ (DMN-2)

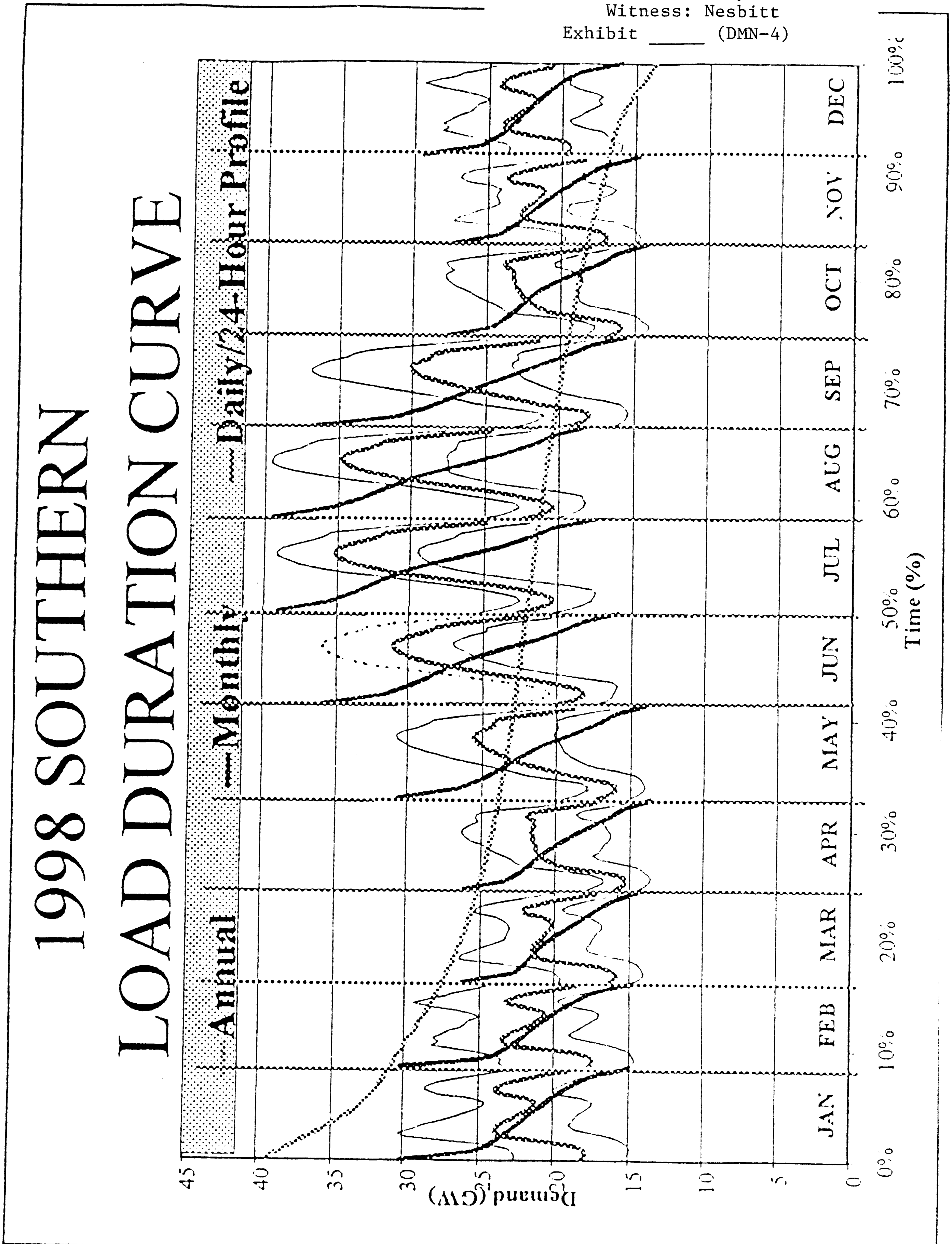
NORTH AMERICAN REGIONAL GAS MODEL (NARG)



FPSC Docket No. 981042-EM
UCNSB/Duke New Smyrna
Witness: Nesbitt
Exhibit _____ (DMN-3)



FPSC Docket No. 981042-EM
UCNSB/Duke New Smyrna
Witness: Nesbitt
Exhibit _____ (DMN-4)



FLORIDA
CAPACITY PER NERC

	Demand and Capability (MW)		Disposition and Sources (GWH)		Capacity Factors	
	1998	2006	1998	2006	1998	2006
Peak	35,643	41,388	183,281	219,688	58.7%	60.6%
Sales	528	-	-	-	0.0%	N/A
	36,171	41,388	183,281	219,688	57.8%	60.6%
Nuclear	3,876	3,876	29,946	30,094	88.2%	88.6%
Hydro	47	47	25	25	6.1%	6.1%
Coal	9,036	9,036	64,303	67,091	81.2%	84.8%
ST-Oil&Gas	13,761	13,715	33,949	26,130	28.2%	21.7%
CT-Oil&Gas	5,741	5,797	1,919	2,722	3.8%	5.4%
CC-Oil&Gas	2,828	5,711	20,137	43,455	81.3%	86.9%
Other	-	157	1,897	12,692	N/A	922.8%
IPP	2,173	2,173	15,614	14,339	82.0%	75.3%
Subtotal	37,462	40,512	167,790	196,548	51.1%	55.4%
Purchases	2,289	2,405	15,491	23,140	77.3%	109.8%
Total	39,751	42,917	183,281	219,688	52.6%	58.4%
Reserves	3,580	1,529				
Reserve Margin	9.9%	3.7%				

FPSC Docket No. 981042-EM
UCNSB/Duke New Smyrna
Witness: Nesbitt
Exhibit ______ (DMN-6)

SOUTHERN CAPACITY PER NERC

	Demand and Capability (MW)		Disposition and Sources (GWH)		Capacity Factors	
	1998	2006	1998	2006	1998	2006
Peak	39,423	47,647	199,723	229,510	57.8%	55.0%
Sales	1,598	1,521	10,811	12,311	77.2%	92.4%
	41,021	49,168	210,534	241,821	58.6%	56.1%
Nuclear	5,722	5,748	43,951	44,550	87.7%	88.5%
Hydro	4,434	4,434	7,599	7,562	19.6%	19.5%
Coal	24,970	24,970	145,946	152,019	66.7%	69.5%
ST-Oil&Gas	1,292	1,233	1,412	1,311	12.5%	12.1%
CT-Oil&Gas	3,475	4,034	4,657	6,318	15.3%	17.9%
CC-Oil&Gas	257	257	305	6,575	13.5%	292.1%
Other	-	-	728	829	N/A	N/A
IPP	1,419	7,826	785	18,022	6.3%	26.3%
Subtotal	41,569	48,502	205,383	237,186	56.4%	55.8%
Purchases	1,873	1,028	5,151	4,635	31.4%	51.5%
Total	43,442	49,530	210,534	241,821	55.3%	55.7%
Reserves	2,421	362				
Reserve Margin	5.9%	0.7%				

TABLE 10

NEW SMYRNA BEACH POWER PROJECT
PROJECTED OPERATIONS AND FUEL SAVINGS

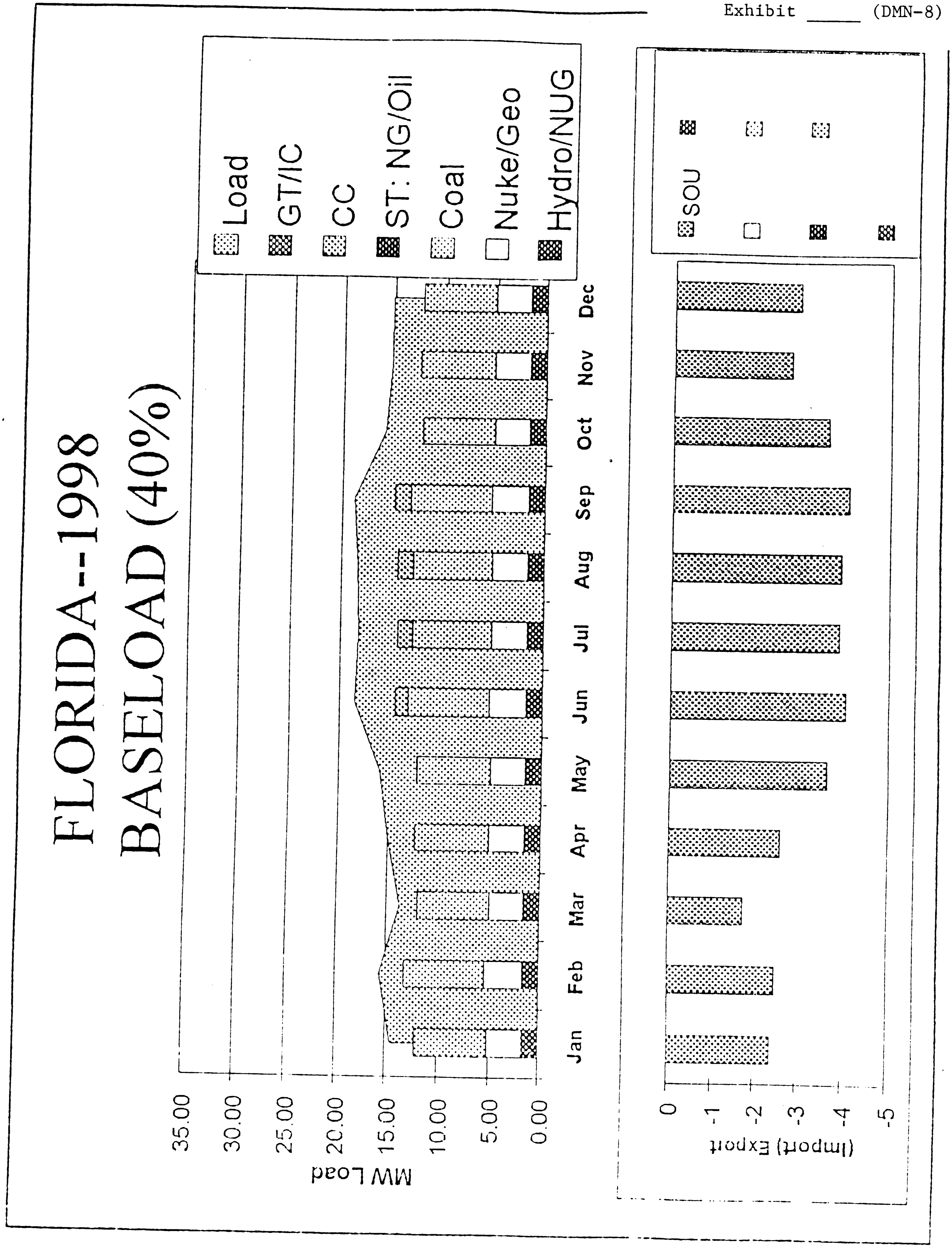
YEAR	GENERATION (MWH)	CAPACITY FACTOR %	PRIMARY ENERGY SAVED (MMBtu)	SAVINGS @ 100% NO. 6 OIL DISPLACED (BARRELS)	SAVINGS @ 100% NATURAL GAS DISPLACED (MCF)
2002	3,719,550.72	82.61	13,647,032	5,992,568	13,647,032
2003	3,768,894.72	83.70	13,828,075	6,072,066	13,828,075
2004	3,818,238.72	84.57	14,009,118	6,151,564	14,009,118
2005	3,862,154.88	85.54	14,170,246	6,222,318	14,170,246
2006	3,906,071.04	86.75	14,331,375	6,293,071	14,331,375
2007	3,952,454.40	87.78	14,501,555	6,367,799	14,501,555
2008	3,998,837.76	88.57	14,671,736	6,442,528	14,671,736
2009	4,046,701.44	89.63	14,847,348	6,519,641	14,847,348
2010	4,094,565.12	90.94	15,022,959	6,596,754	15,022,959
2011	4,164,140.16	92.48	15,278,230	6,708,846	15,278,230
2012	4,233,715.20	93.77	15,533,501	6,820,939	15,533,501
TOTALS			159,841,174	70,188,094	159,841,174

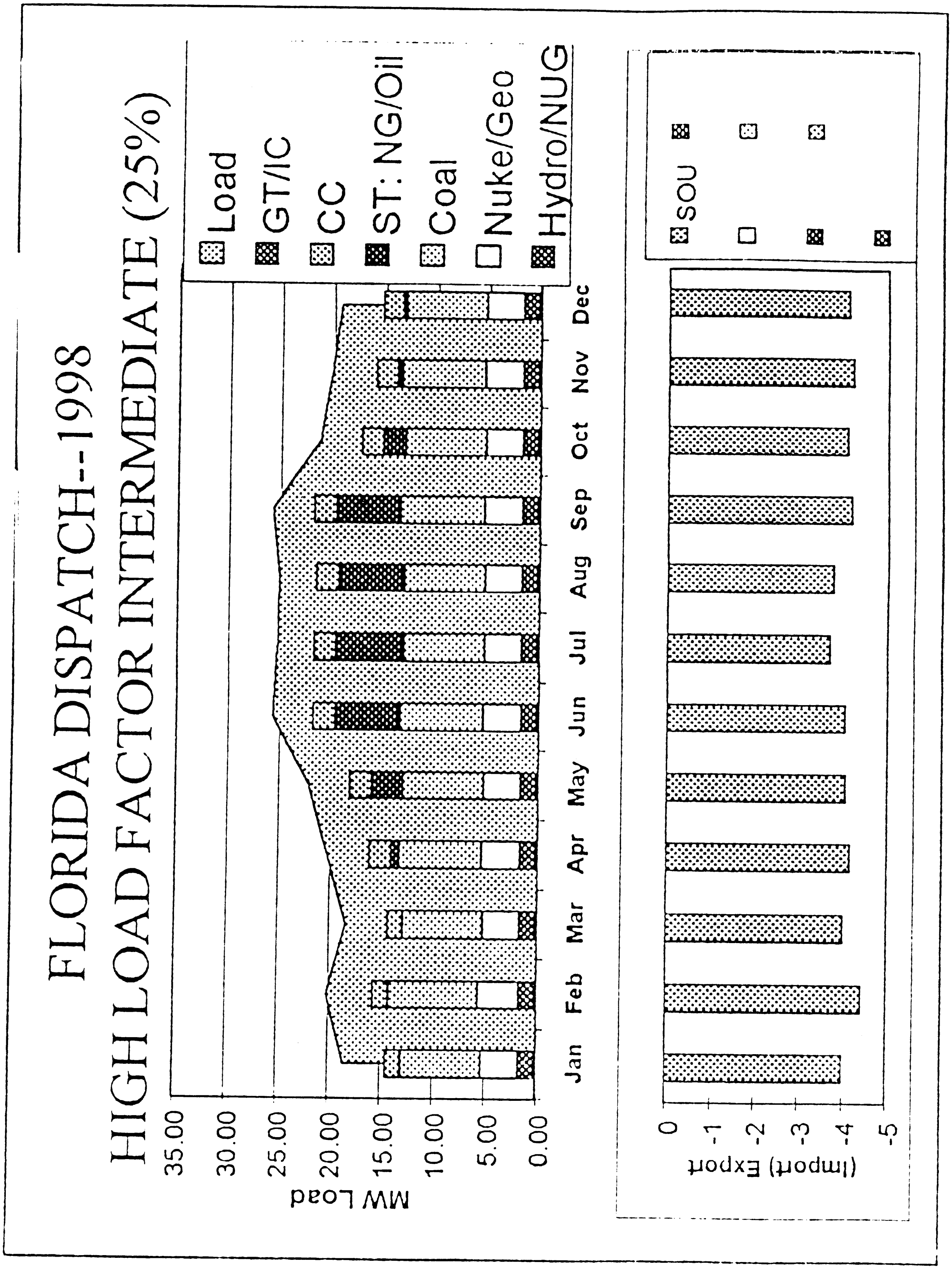
NOTES: (1) Primary energy saved estimated as the difference between Btu required to generate MWH in Column (2) in gas/oil steam generators with an average heat rate of 10,501 Btu/kWh and the Btu required to generate the same MWH at the NSB Project's heat rate of 6,832 Btu/kWh.

(2) Oil savings reflects total oil displaced assuming that all of the Project's output displaces oil-fired steam generation.

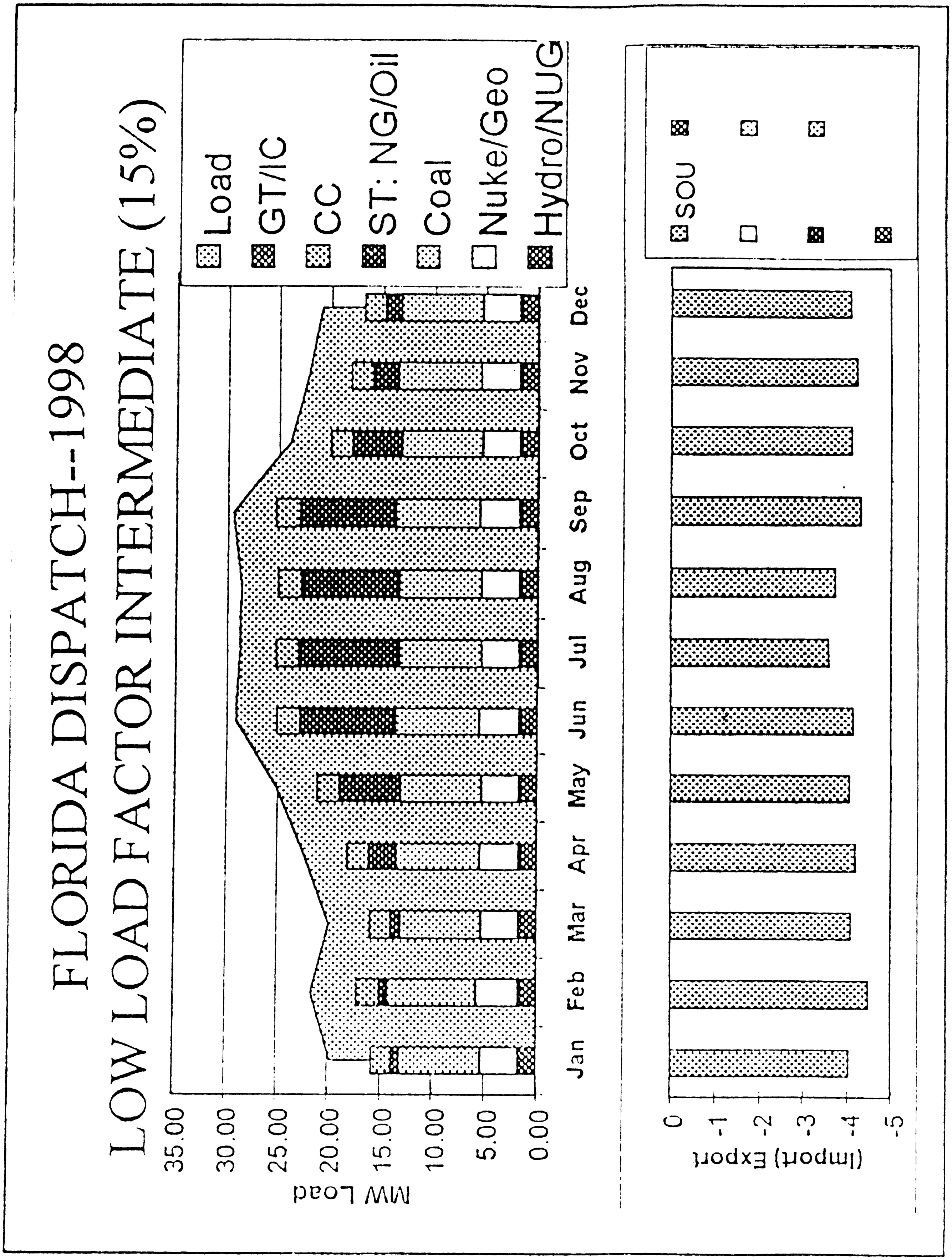
(3) Gas savings reflects net gas reduction to generate MWH in Column (2).

UCNSB/Duke New Smyrna
Witness: Nesbitt
Exhibit ______ (DMN-8)

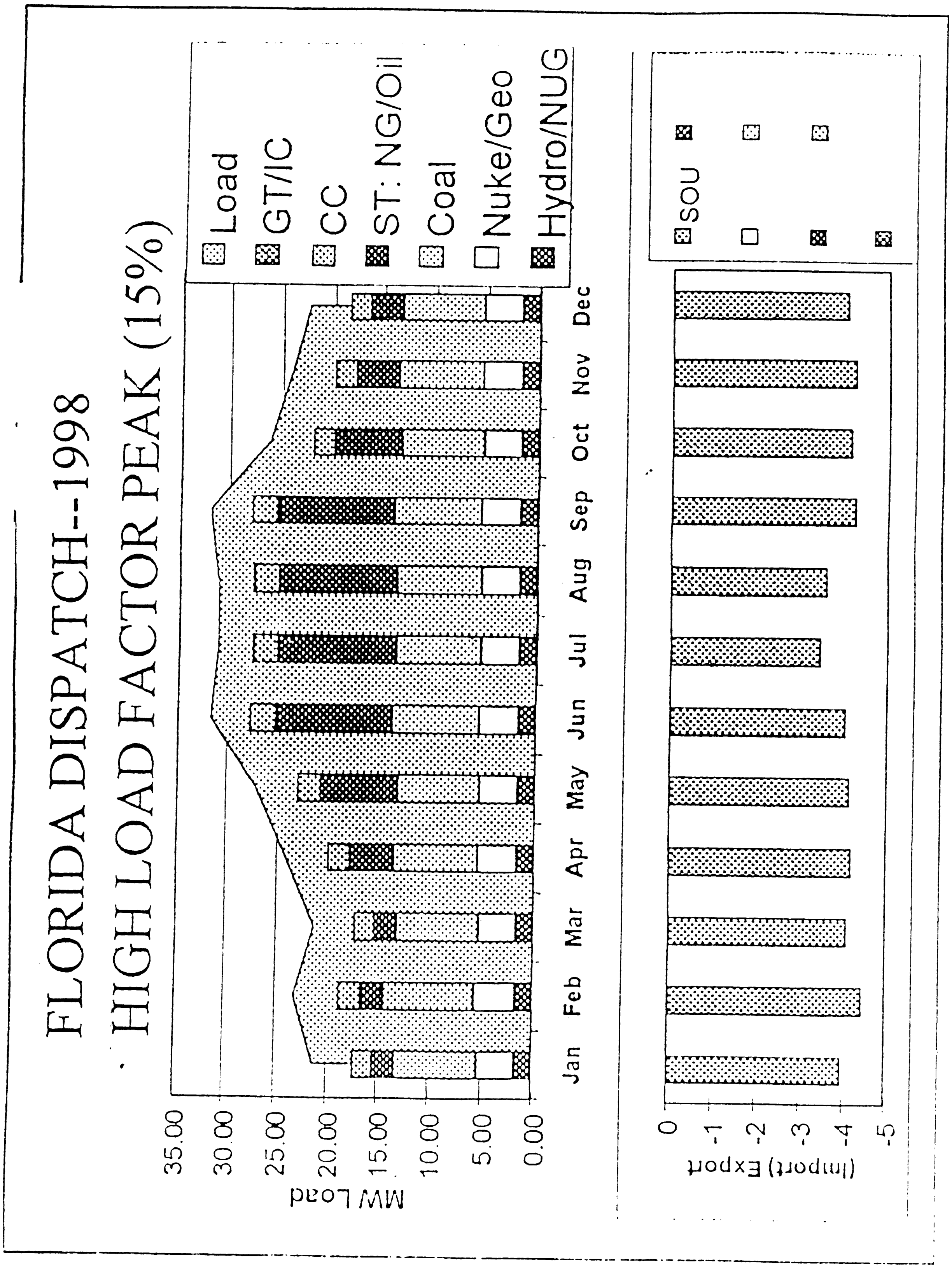



FLORIDA DISPATCH--1998
HIGH LOAD FACTOR INTERMEDIATE (25%)
MW Load
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Load
GT/IC
CC
ST: NG/Oil
Coal
Nuke/Geo
Hydro/NUG
(Import) Export
0
-1
-2
-3
-4
-5
SOU

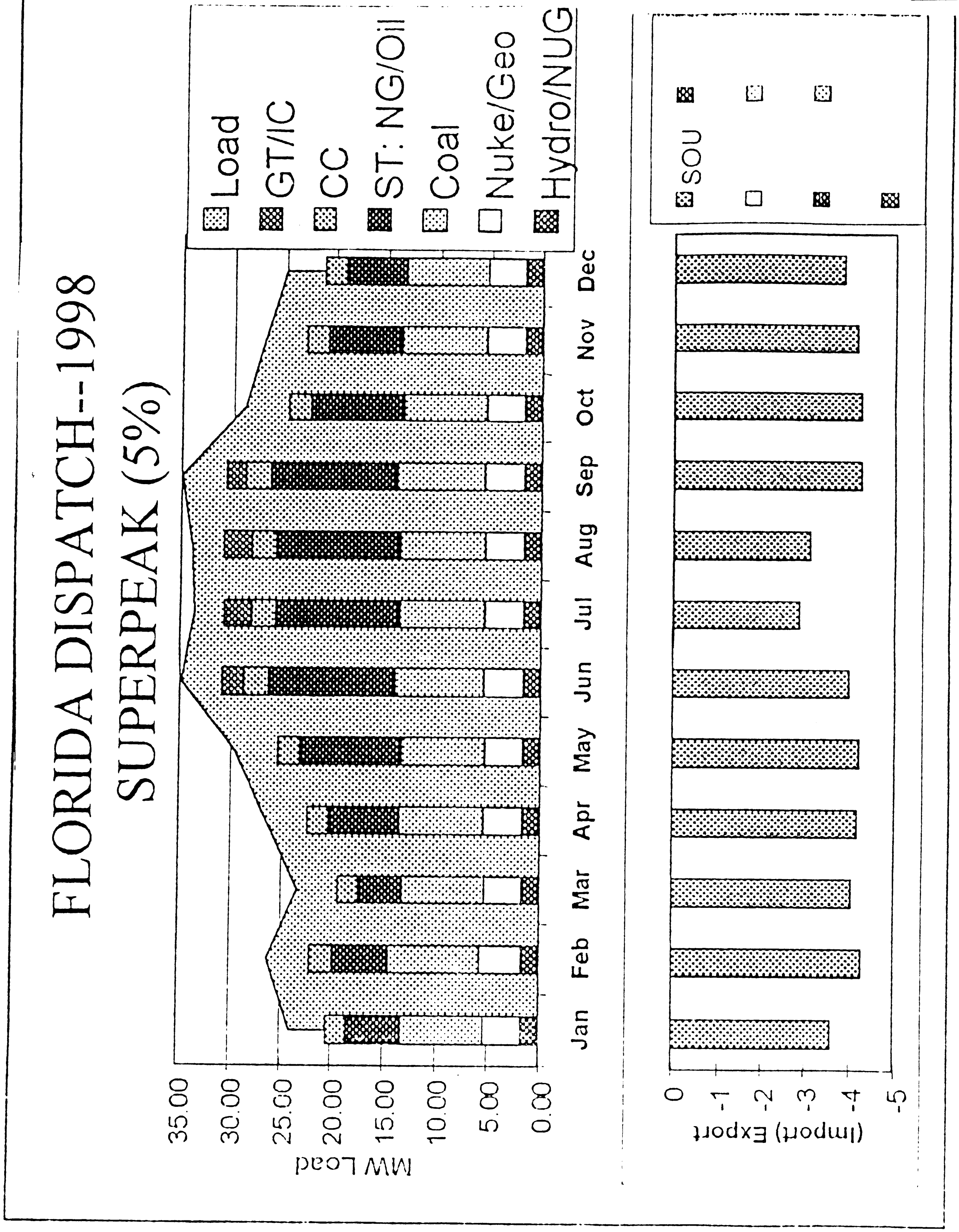
FPSC Docket No. 981042-EM
UCNSB/Duke New Smyrna
Witness: Nesbitt
Exhibit ____ (DMN-10)



FPSC Docket No. 981042-EM
UCNSB/Duke New Smyrna
Witness: Nesbitt
Exhibit ____ (DMN-11)



FPSC Docket No. 981042-EM
UCNSB/Duke New Smyrna
Witness: Nesbitt
Exhibit _____ (DMN-12)



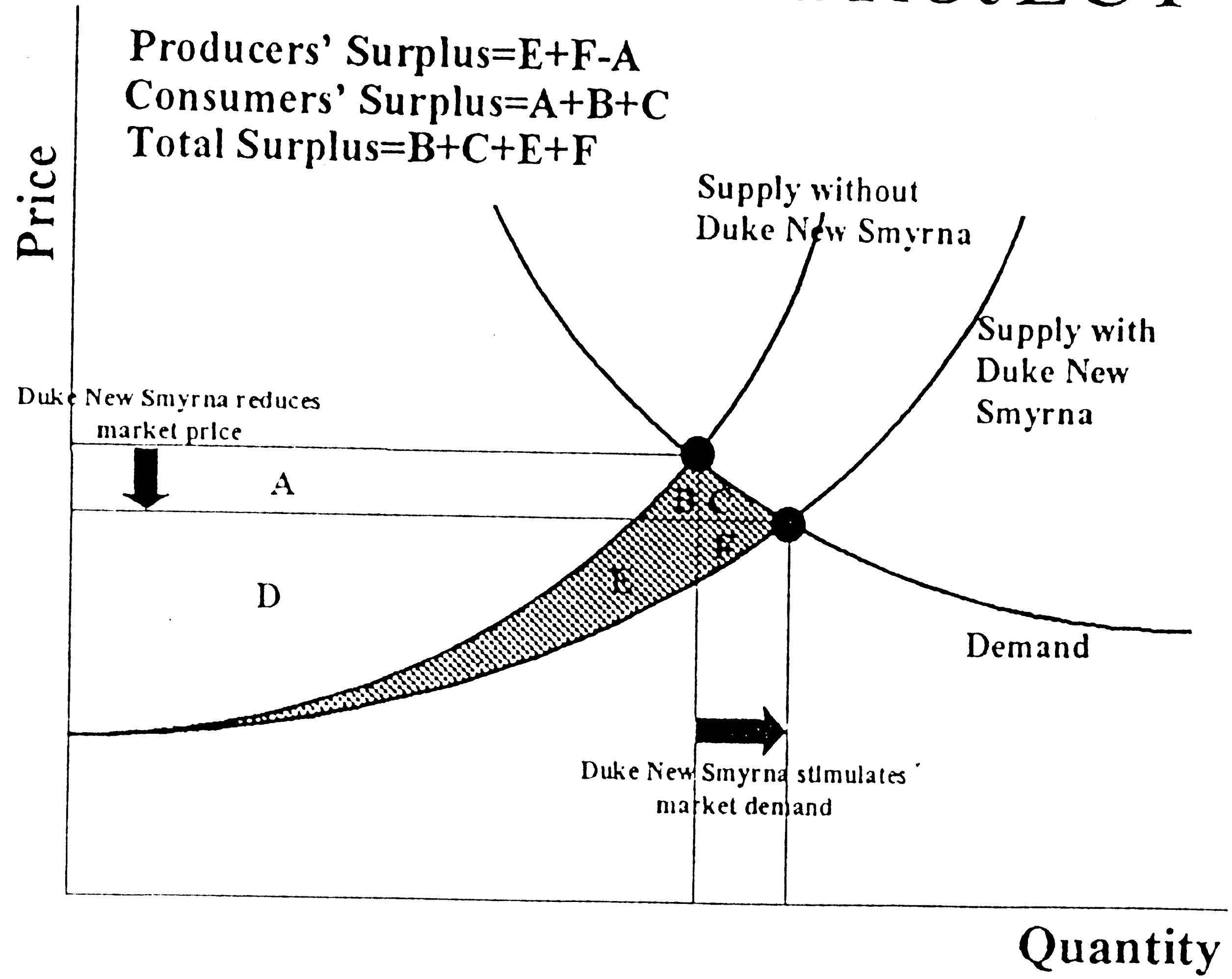
COMPARATIVE ELECTRICITY PRODUCTION COSTS, SERC & FRCC, 1995-1998

NERC REGION	JANUARY THROUGH DECEMBER			JANUARY THROUGH MARCH		
	1995	1996	1997	1996	1997	1998
SERC						
ELECTRIC GENERATION	555,505	584,329	604,058	145,303	145,980	152,272
PRODUCTION COSTS (¢/KWH)	1.76	1.71	1.68	1.66	1.66	1.58
RETAIL RATES (¢/KWH)	5.89	5.73	5.71	5.67	5.57	5.53
FRCC						
ELECTRIC GENERATION	145,464	142,421	144,669	32,611	31,081	32,633
PRODUCTION COSTS (¢/KWH)	2.41	2.69	2.54	2.71	2.60	2.39
RETAIL RATES (¢/KWH)	7.00	7.27	7.30	7.27	7.41	7.12

FPSC Docket No. 981042-EM
UCNSB/Duke New Smyrna
Witness: Nesbitt
Exhibit ____ (DMN-14)

BENEFITS OF DUKE NEW SMYRNA PROJECT

Producers' Surplus=E+F-A
Consumers' Surplus=A+B+C
Total Surplus=B+C+E+F



FPSC Docket No. 981042-EM
UCNSB/Duke New Smyrna
Witness: Nesbitt
Exhibit ____ (DMN-15

ACHIEVING COMPETITIVE ADVANTAGE THROUGH QUANTITATIVE ELECTRIC ASSET VALUATION

USING THE

ALTOS NORTH AMERICAN REGIONAL ELECTRICITY MODEL

Altos
Management Partners Inc.
San Jose Jet Center
1250 Aviation Drive, Suite 200C, San Jose, CA 95110
(408) 275-0799 FAX: (408) 275-0799

Contents

1. INTRODUCTION AND OVERVIEW 3

2. MEASURING INDIVIDUAL ASSET PROFITABILITY 4

3. MEASURING INDIVIDUAL ASSET RISK 7

4. A MARKET-BASED APPROACH TO ASSET VALUATION 10

5. MARKET-BASED APPROACH TO ASSET PORTFOLIO RISK 11

6. STRUCTURE OF THE FULL REGIONAL MARKET MODEL TO PROJECT PRICES AND PRICE DIFFERENCES 12

6.1. Representation of Electricity Supply 14
6.1.1. Regionalization 14
6.1.2. Incorporating Forward Cost to Market for Existing Generation Units in a Region 15
6.1.3. Cost Reduction and Performance Improvements for Existing Units in a Given Region 21
6.1.4. Retirements of Existing Units in a Given Region 23
6.1.5. Ingress and Egress of Transmission to and from Each Generation Region 24
6.1.6. Prospective Entry of New Generation Units into a Given Region 29
6.1.7. Summary of Supply Representation (Generation Plus Transmission) 31

6.2. Representation of Demand 32

7. SUMMARY OF MODEL STRUCTURE 37

Copyright 1998, Altos Management Partners Inc., All Rights Reserved

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 in fact the third such commodity. Telecommunications and natural gas before it were subjected to precisely the same type of forced unbundling between transmission service and commodity. We believe that what the "unbundling" type of deregulation implies for the future is not as arcane or unclear 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. In building an electricity market model, we combine 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, **<u>it is the company with the best</u>**

Copyright 1998, Altos Management Partners Inc., All Rights Reserved

price forecast that will win. Period. 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 includes what we term the intrinsic, deterministic value of the asset. The methodology here is based on the notion of valuing the asset based on a cogent and correct but deterministic set of forward prices. There is no attempt in this report to incorporate the effects of uncertainty, i.e., to augment the intrinsic, deterministic value of the plant with the so-called "option value" of the plant. 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 plus 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 INDIVIDUAL ASSET PROFITABILITY

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.

[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.

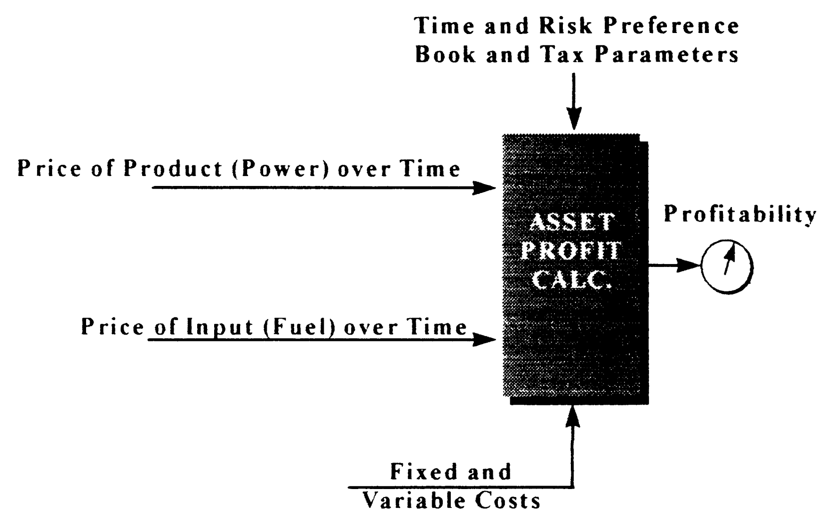
Copyright 1998, Altos Management Partners Inc., All Rights Reserved

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:

- 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.

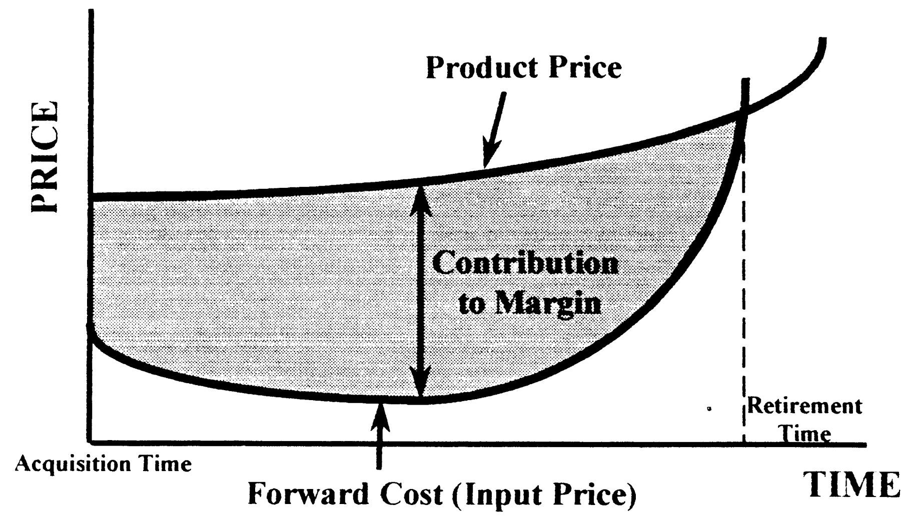
Figure 1: EVALUATION OF ASSET PROFITABILITY



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 gray 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.

Copyright 1998, Altos Management Partners Inc., All Rights Reserved

Figure 2: PRICE DIFFERENTIAL ACROSS AN ASSET IS THE MOST IMPORTANT DETERMINANT OF VALUE



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 gray 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.

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

Copyright 1998, Altos Management Partners Inc., All Rights Reserved

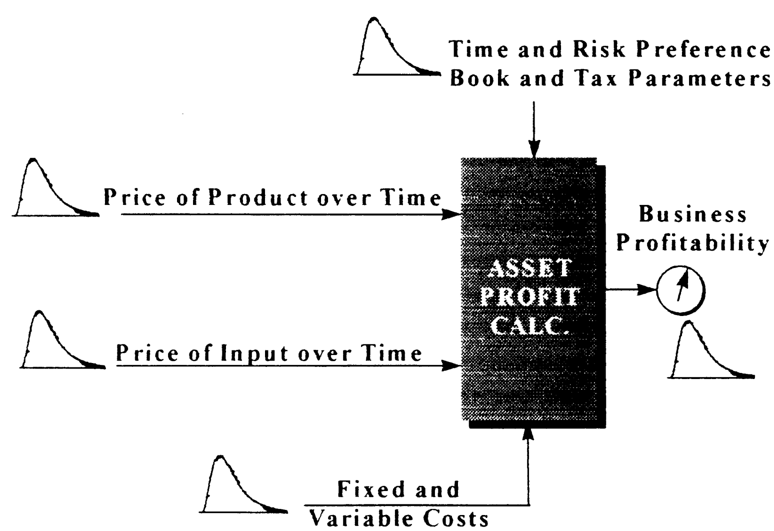
to this theme shortly, articulating how we have approached the cost side of the problem. Before doing so, we will continue discussing the revenue side, i.e., the market side.

3. MEASURING 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: WE COULD PUT PROBABILITIES INTO THE PROFIT CALCULATOR

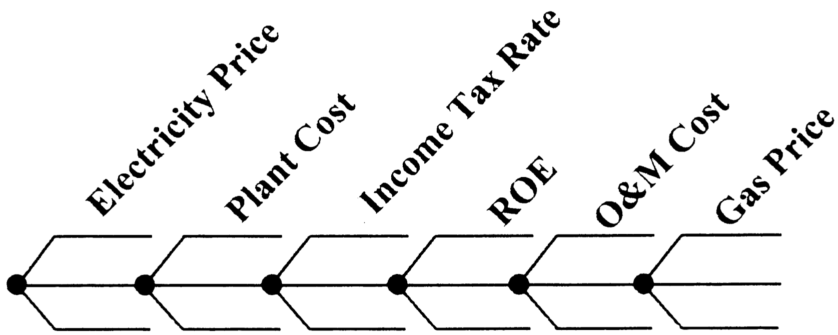


How do people typically implement such a calculation, and why do they get into trouble? They begin by estimating independent probability distributions over each of the individual inputs to the profitability calculator. They then enumerate all possible combinations of settings for all the input variables 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

Copyright 1998, Altos Management Partners Inc., All Rights Reserved

(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: RUN OUT A SERIES OF PROBABILITY-WEIGHTED SCENARIOS

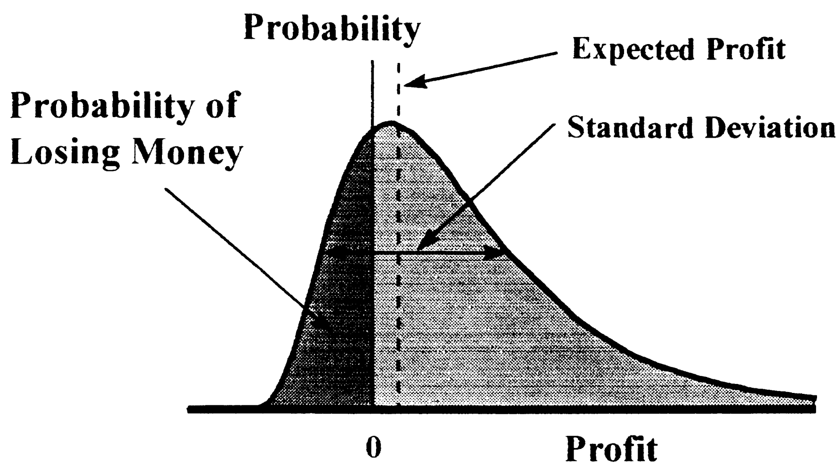


3^6 combinations (=3^6 calculations)
3^6 probabilities

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.

Copyright 1998, Altos Management Partners Inc., All Rights Reserved

Figure 5: A PROBABILITY DISTRIBUTION OVER 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.) <u>If we do not manage the correlation characteristics of our asset portfolio, the volatility of our share price will be increased, the price of our stock will not appreciate as rapidly, dividends will not accrue as rapidly, our credit rating will not be as high and our cost of capital will suffer, and our stock's "beta" will be higher than it should be.</u>

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.

Copyright 1998, Altos Management Partners Inc., All Rights Reserved

4. 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.

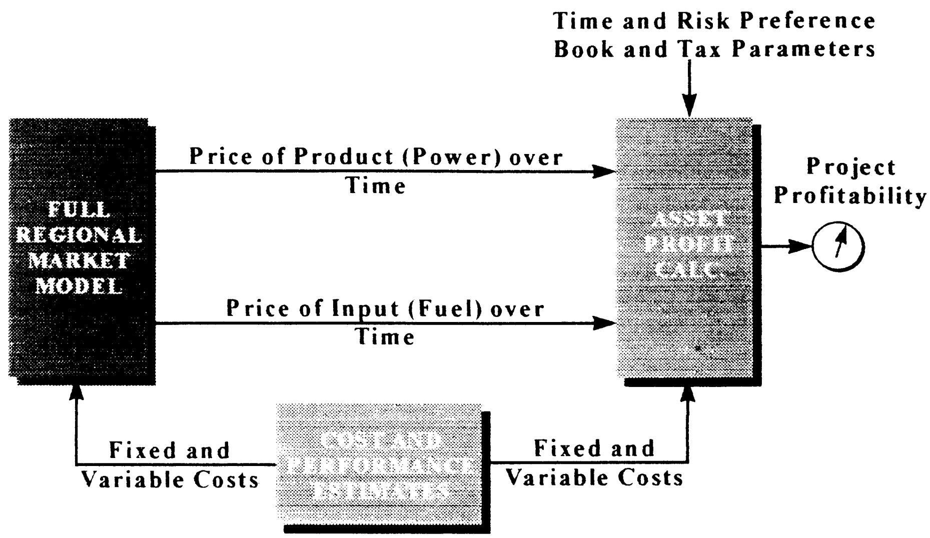
By introducing a structural representation of the market, we are able not only to forecast forward prices on a structural basis but also to systematically correlate the various prices in our markets: electricity versus gas prices, electricity versus coal prices, coal versus gas prices, regional price 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.

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

Copyright 1998, Altos Management Partners Inc., All Rights Reserved

speculation when you thought you were adding hedging devalues one's company and debilitates financial performance.

Figure 6: EVALUATION OF PROFITABILITY IN FULL REGIONAL MARKET CONTEXT

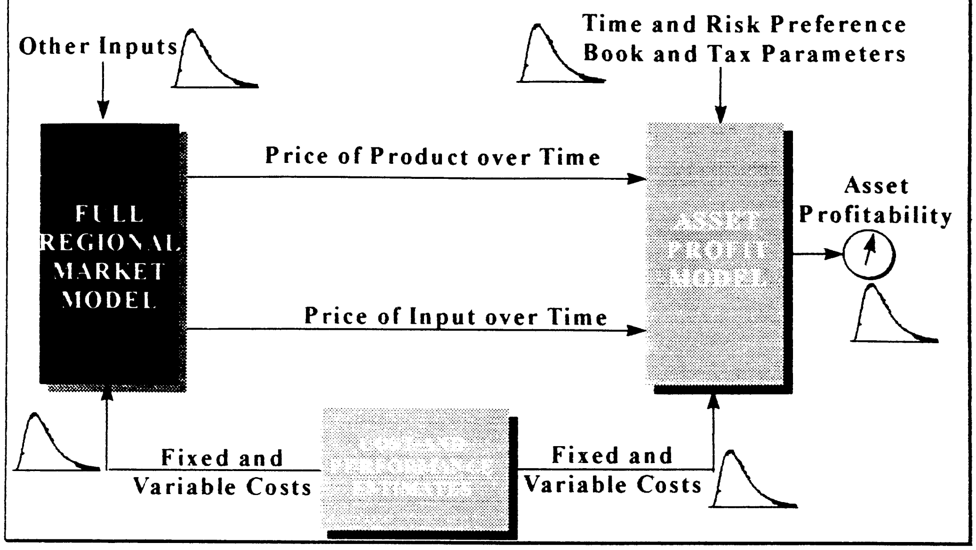


5. MARKET-BASED APPROACH TO ASSET PORTFOLIO RISK

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 4 and 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.

Copyright 1998, Altos Management Partners Inc., All Rights Reserved

Figure 7: PROBABILISTIC RISK-RETURN VALUATION IN A FULL MARKET CONTEXT



6. 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 "merchant electric world," the price differential will no longer be determined by rate base formulas through which fixed as well as variable costs can be imposed downstream on unwitting customers by companies 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 merchant 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.

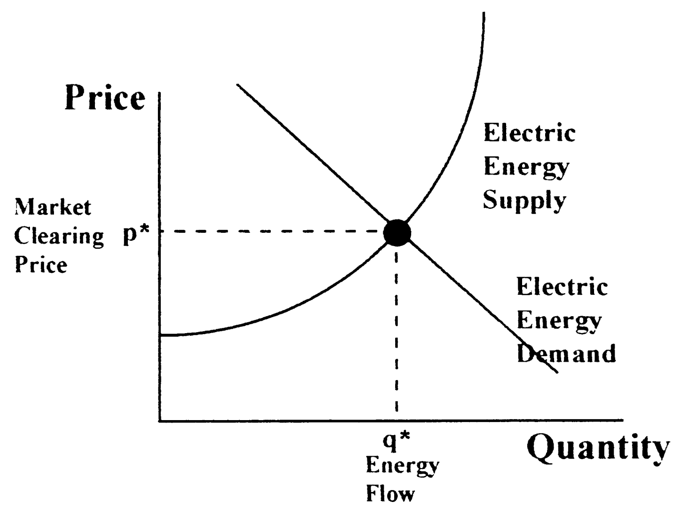
Second, the price differential across any asset depends on fuel price, heat rate curve (from which we calculate fuel cost), variable cost, operating and maintenance cost, wheeling cost and radius, new equipment installations, future cost evolution, demand variation, and a plethora of economic and cost considerations. Clearly the box in Figures 6 and 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.

Copyright 1998, Altos Management Partners Inc., All Rights Reserved

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. Markets are so distorted by fixed cost passthroughs outside energy markets that those 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.

Figure 8: AFTER DEREGULATION, HERE'S THE WAY THE WORLD WILL WORK



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.

Copyright 1998, Altos Management Partners Inc., All Rights Reserved

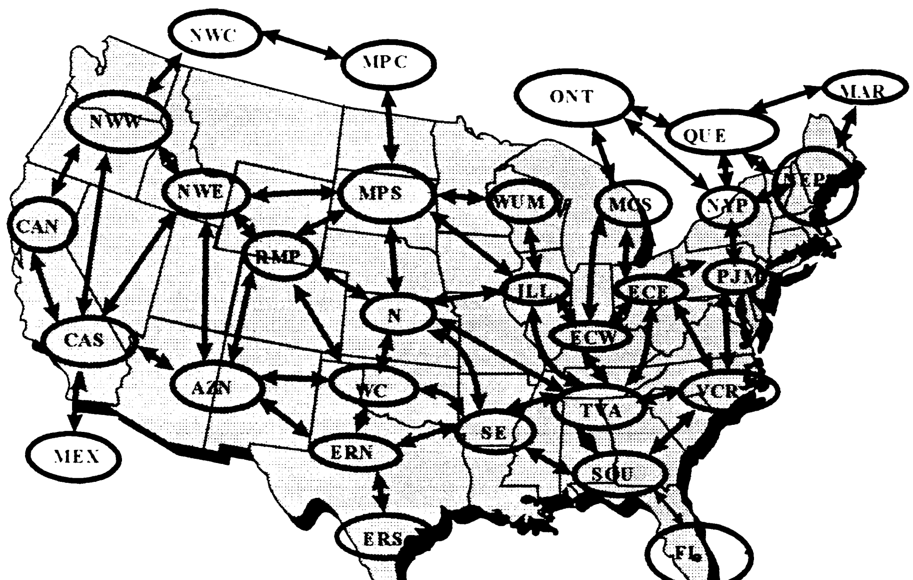
This document will briefly describe the process by which we quantified and integrated the electricity supply situation, the transmission situation, and the demand situation and thereby built our Multiregion North American Electric model. We reiterate that our overriding purpose is to provide accurate and credible projections of future electricity and fuel prices with which to conduct the evaluations summarized above.

6.1. Representation of Electricity Supply

6.1.1. 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: AN INTERCONNECTED MODEL OF THE UNITED STATES



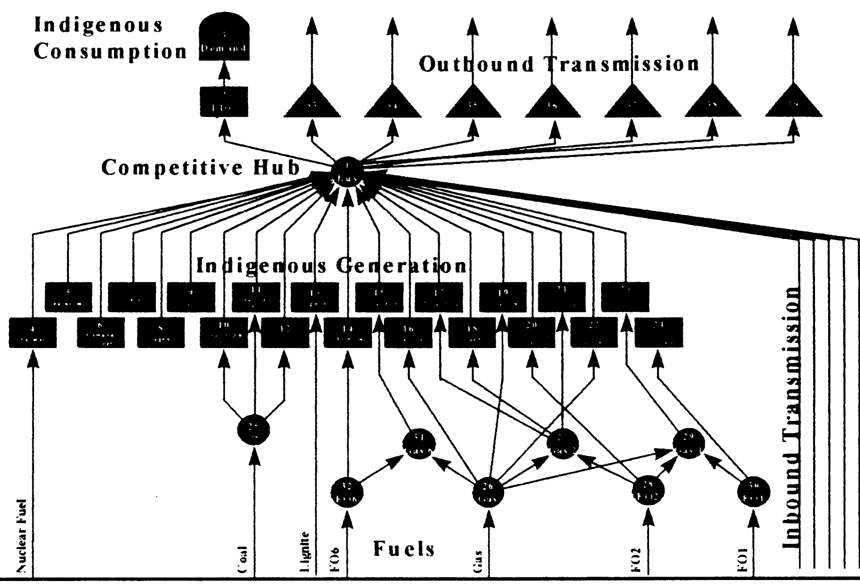
As currently configured, the regionalization of the model can be quickly and easily disaggregated. We can pass a "magnifying glass" over one of the foregoing regions, subdividing and subregionalizing it further than indicated in the diagram.

Within each of the subregional ovals in Figure 9 resides a comprehensive model of indigenous generation, inbound transmission, native load, and outbound transmission. The

Copyright 1998, Altos Management Partners Inc., All Rights Reserved

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.

Figure 10: REGIONAL GENERATION-TRANSMISSION-CONSUMPTION OPTIONS



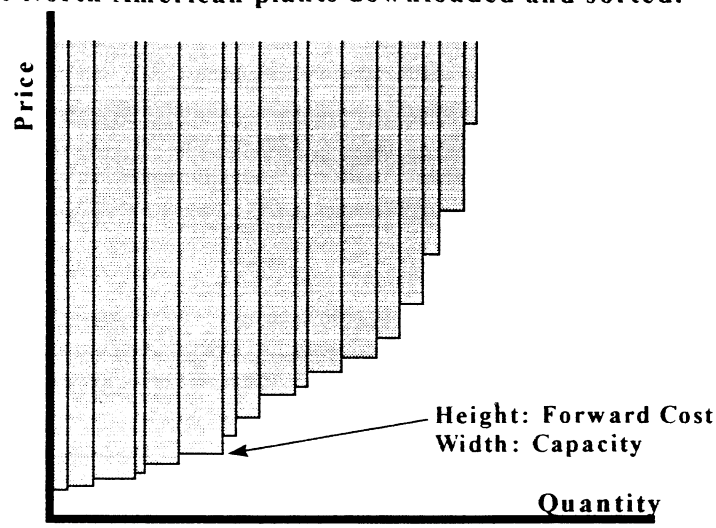
6.1.2. Incorporating Forward Cost to Market for Existing Generation Units in a Region

Having regionalized the North American market as in Figures 9 and 10, 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 11. 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 11. 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.

Copyright 1998, Altos Management Partners Inc., All Rights Reserved

Figure 11: LINE UP EXISTING GENERATORS IN ASCENDING ORDER OF FORWARD COST

- **16000 North American plants downloaded and sorted.**



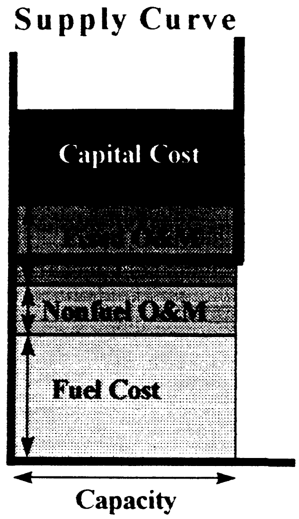
As indicated in the figure, we have downloaded some 16,000 generating plants that comprise North America including capacities and forward costs from publicly and privately available sources. Before arraying them as shown in the figure, it has been necessary to undertake a rather extensive reconciliation 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.

What types of judgments and adjustments have been necessary to craft the supply stack in Figure 11? 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 12 summarizes what we have included and not included in each element of the generation supply stack in Figure 11. 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

Copyright 1998, Altos Management Partners Inc., All Rights Reserved

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 12: QUANTIFICATION OF FORWARD COST TO MARKET



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

Turning to the most difficult element of the forward cost stack, designated fixed operating and maintenance cost in Figure 12, 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.

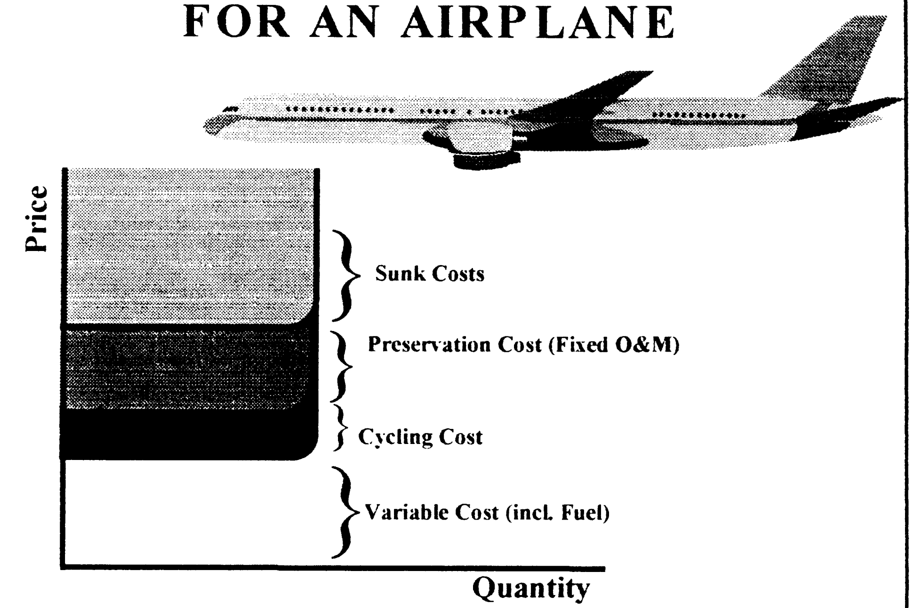
It is also true that because fixed O&M costs are presently being repatriated largely through fixed cost passthrough as part of the regulatory compact, completely apart from energy sales, they have been arguably been substantially higher than would be sustained in a competitive market. (Such argument 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 12 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

Copyright 1998, Altos Management Partners Inc., All Rights Reserved

airline company, we see in Figure 13 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 13: COST STRUCTURE FOR AN AIRPLANE

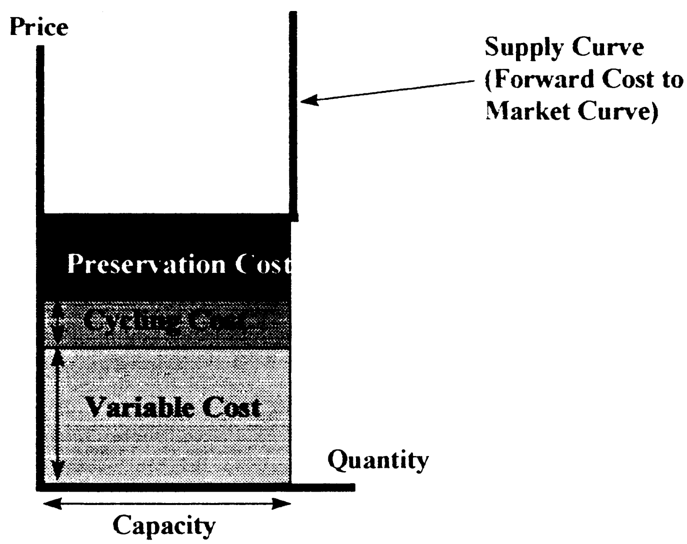


In assembling a forward cost curve for an airplane, we would argue that it should be composed of the variable cost plus the cycling cost plus the preservation cost. These three categories of cost, and only these three categories, can be considered avoidable if the airline company were to sell their plane 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.

Copyright 1998, Altos Management Partners Inc., All Rights Reserved

The curve in Figure 13 must be recast in terms of variable cost, cycling cost, and preservation cost. Figure 14 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 14. 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.

Figure 14:
RECATEGORIZATION OF PLANT FORWARD COSTS



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

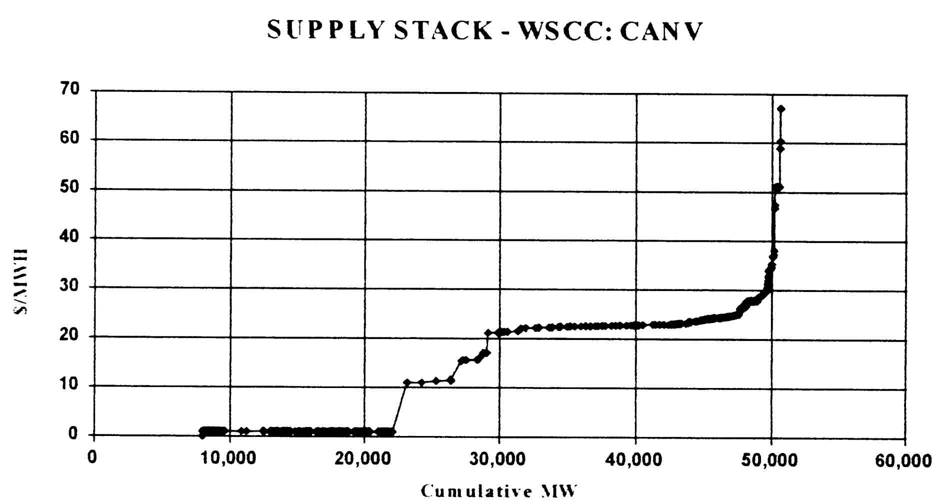
Copyright 1998, Altos Management Partners Inc., All Rights Reserved

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.

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 15 puts forth the supply stack calculated for the WSCC:California-Southern Nevada generation region.

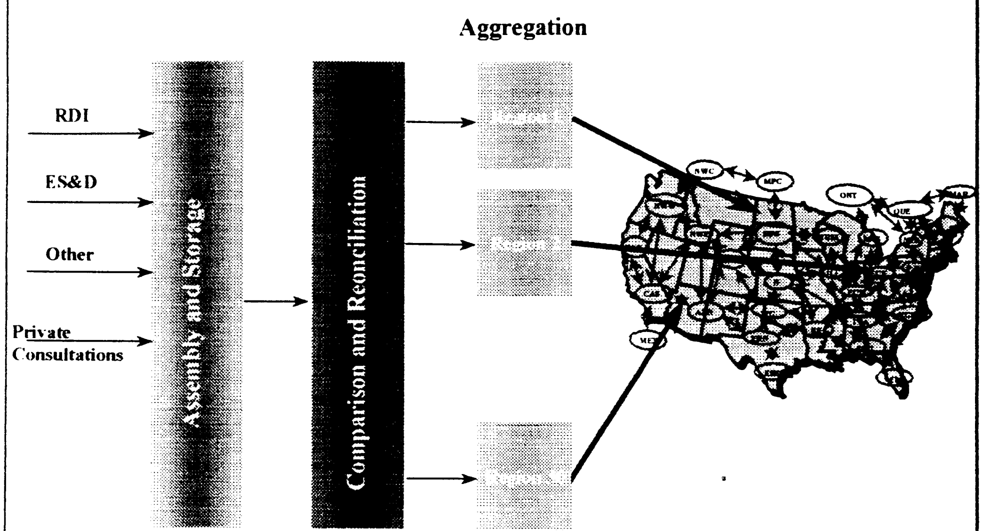
Figure 15: CALIFORNIA SUPPLY STACK



MarketPoint is configured as shown in Figure 16. 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.

Copyright 1998, Altos Management Partners Inc., All Rights Reserved

Figure 16: MARKETPOINT™ GENERATION DATA



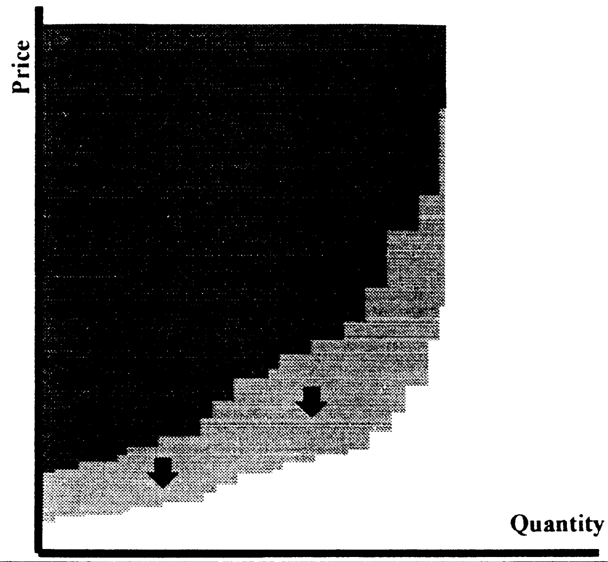
6.1.3. Cost Reduction and Performance Improvements for Existing Units in a Given Region

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 17 represents the inexorable downward pressure against forward cost to market experienced by the presently existing generation capital stocks. The stack of supply curves represented in black represents presently existing capacity and forward cost embedded in presently existing vintages of plant and equipment. The downward-shifted gray 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.

Copyright 1998, Altos Management Partners Inc., All Rights Reserved

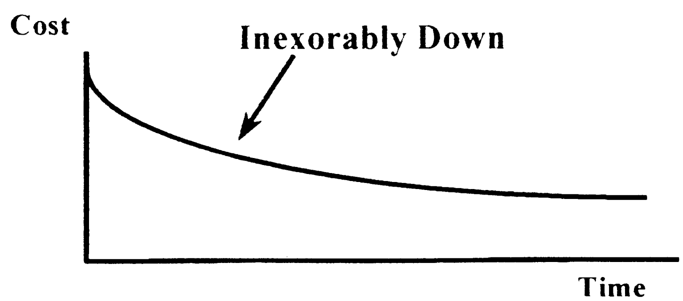
Figure 17: COMPETITIVE PRESSURE REDUCES FORWARD COST



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 18. 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.

Figure 18: COMPETITION PUSHES COSTS DOWN

Cost reduction never fails in a competitive economy.



Copyright 1998, Altos Management Partners Inc., All Rights Reserved

6.1.4. Retirements of Existing Units in a Given Region

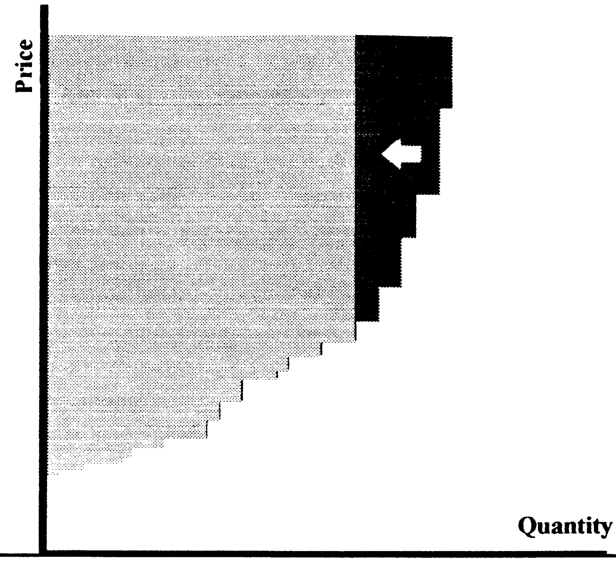
Alas, notwithstanding the inexorable pressure for cost reduction, many existing plants simply cannot hope to survive. Competition is quintessentially Darwinian, the weak, the old, and the sick do not survive. Some economists have dubbed capitalism a system of "graceful obsolescence." Plants retire because 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 19. The top right portion of the black 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 19 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 19.

Copyright 1998, Altos Management Partners Inc., All Rights Reserved

Figure 19: COMPETITIVE PRESSURE RETIRES OLD PLANTS



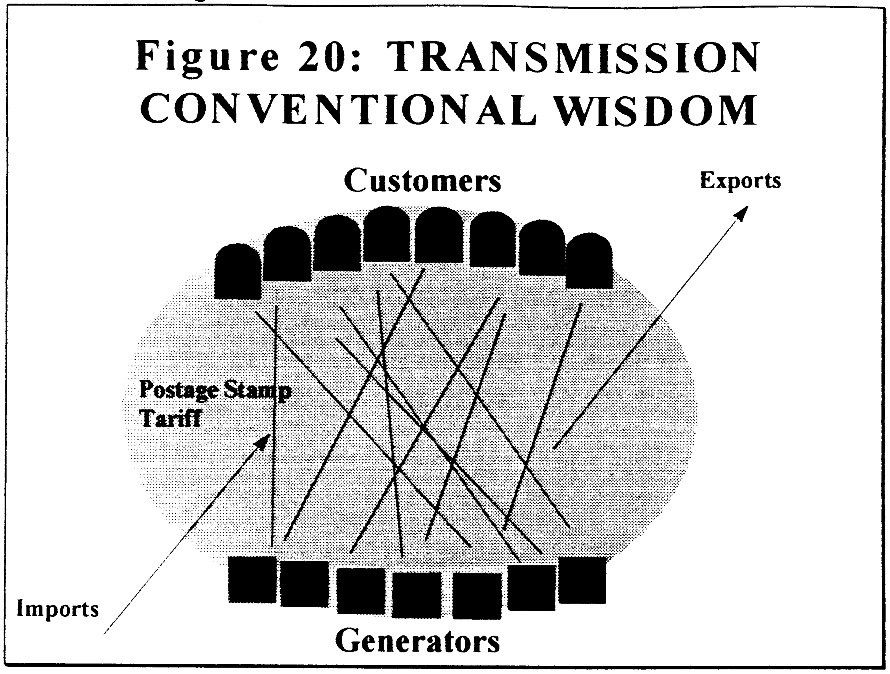
6.1.5. Ingress and Egress of Transmission to and from Each Generation Region

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 absolutely unequipped to represent the inbound and outbound transmission issues that will begin to affect the industry in the future. Production simulation models have gone the way of the dinosaur, representing an industry environment that is long since gone.

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. 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

Copyright 1998, Altos Management Partners Inc., All Rights Reserved

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 20.

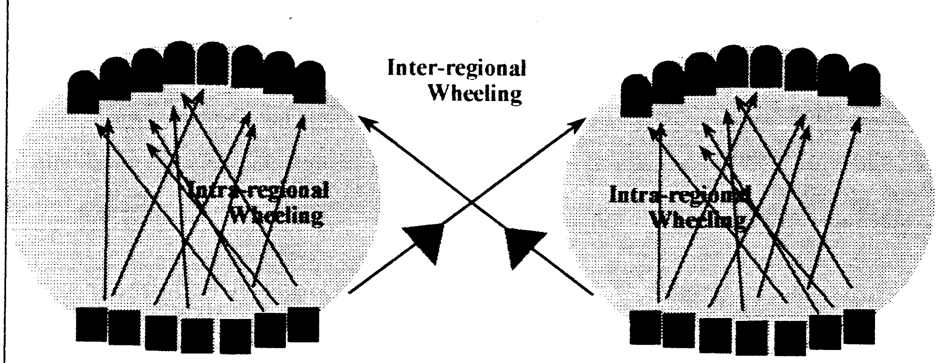


The title of Figure 20 is significant, the "conventional wisdom" of the electric transmission business. The "conventional wisdom" suggests that generators in a particular region will generate power and wheel it to their own customers (which we term intra-regional wheeling), ship it to customers in contiguous 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 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 20 for each of the 30 regions and subregions in Figure 9, but we have connected them together as shown in Figure 21.

Copyright 1998. Altos Management Partners Inc., All Rights Reserved

Figure 21: WE REPRESENT INTERCONNECTED WHEELING LINKS



The reason for the interconnection indicated in Figure 21 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.

Copyright 1998, Altos Management Partners Inc., All Rights Reserved

Figure 22: INCOMING TRANSMISSION ADDS SUPPLY AND REDUCES COST

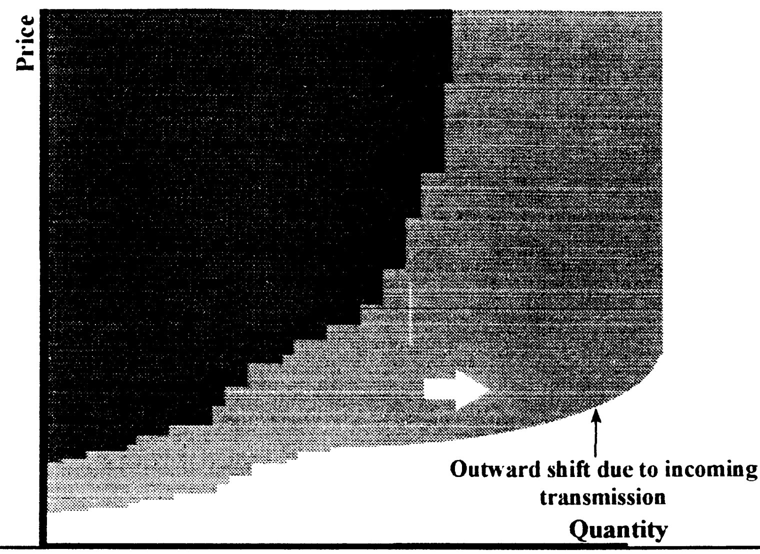


Figure 22 represents economically what the combination of cost improvements in existing plants combined with incoming transmission can do to the original supply curve that characterizes only the existing capital stocks (black in the figure). Intuitively, there is a large increment of energy supply from 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.

By implementing the transmission increment as shown in Figure 22, 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

Copyright 1998, Altos Management Partners Inc., All Rights Reserved

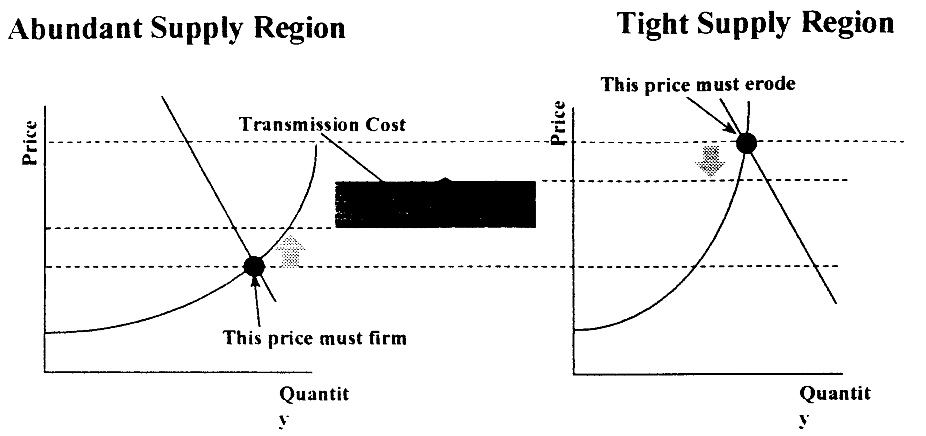
away from an existing plant, the larger the prospective market that plant sees. Larger prospective market available to a given plant means a higher selling price for the output from that plant. The model strives to balance (in the economic sense) the price-stimulating influence of outbound electric transmission 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.

Before leaving the issue of transmission, we need to represent what transmission implies for contiguous regions. Figure 23 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.
- 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.

Copyright 1998, Altos Management Partners Inc., All Rights Reserved

Figure 23: TRANSMISSION DICTATES PRICES AND DIFFERENTIALS



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.

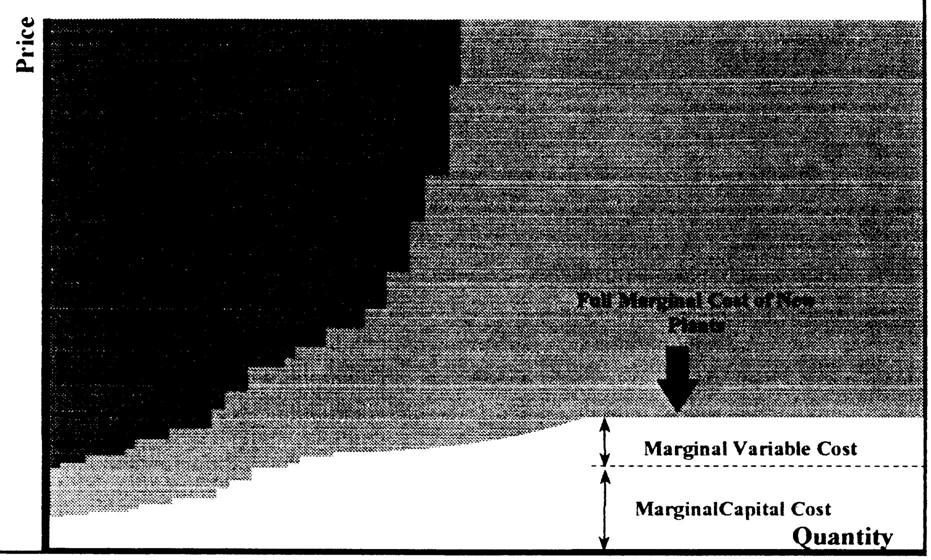
6.1.6. Prospective Entry of New Generation Units into a Given Region

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.

Copyright 1998, Altos Management Partners Inc., All Rights Reserved

Figure 24 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

Figure 24: NEW PLANTS ENTER AT FULL MARGINAL COST



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 24 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 the Altos model, 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.

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

Copyright 1998, Altos Management Partners Inc., All Rights Reserved

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.

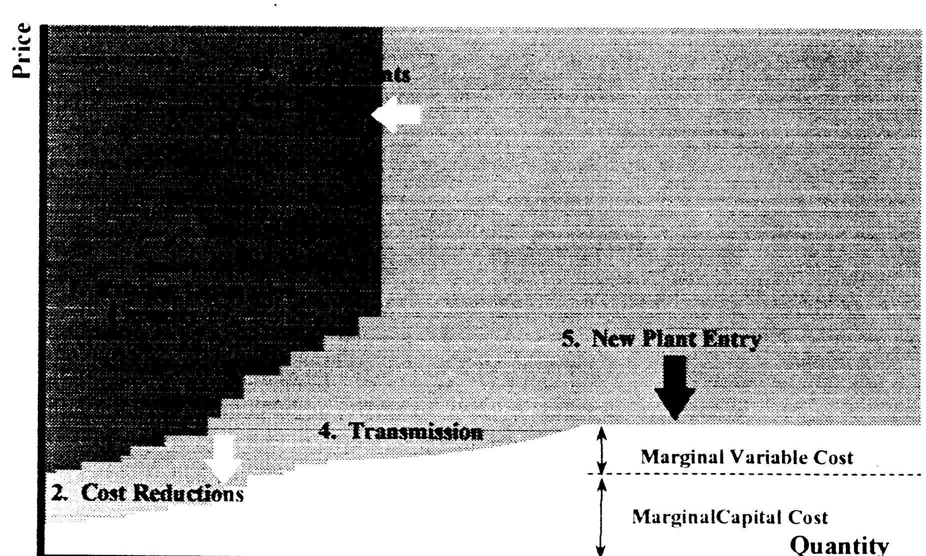
6.1.7. Summary of Supply Representation (Generation Plus Transmission)

It is important to summarize the issues we have accounted for related to electric energy supply. Figure 25 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 our endeavors to represent 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 25: FIVE KEY PHENOMENA



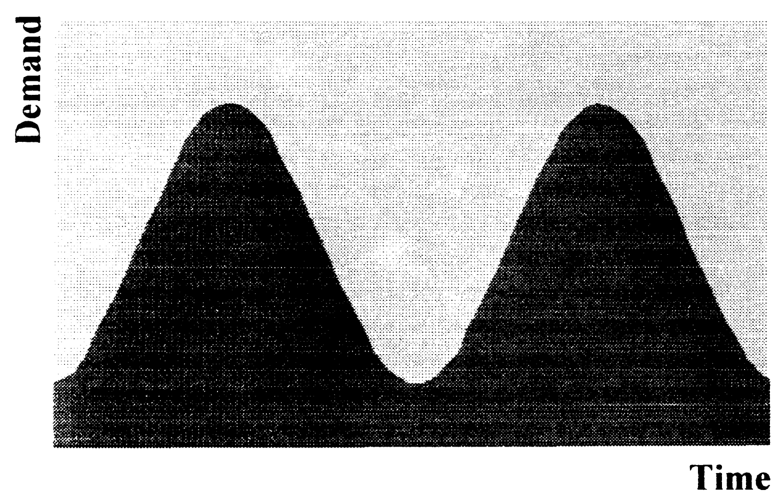
Copyright 1998, Altos Management Partners Inc., All Rights Reserved

6.2. 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 26 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 26: DEMAND VARIES 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.

Copyright 1998, Altos Management Partners Inc., All Rights Reserved

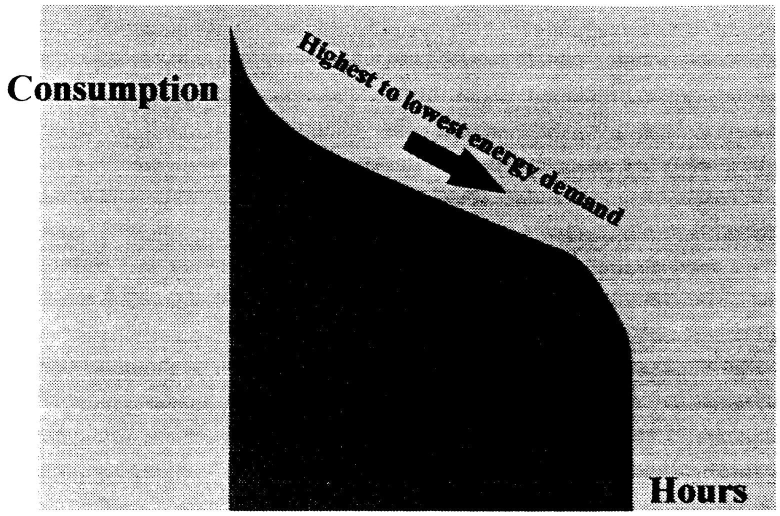
What is the demand side methodology we have used? The raw, reported data alluded to above represents a historical demand schedule, which varies by time of day, week, season, and year. Figure 26 provides a conceptual illustration of the time-varying historical data we have assembled to populate our demand model. 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 26 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 26 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 26 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 26 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 27. 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.

Copyright 1998, Altos Management Partners Inc., All Rights Reserved

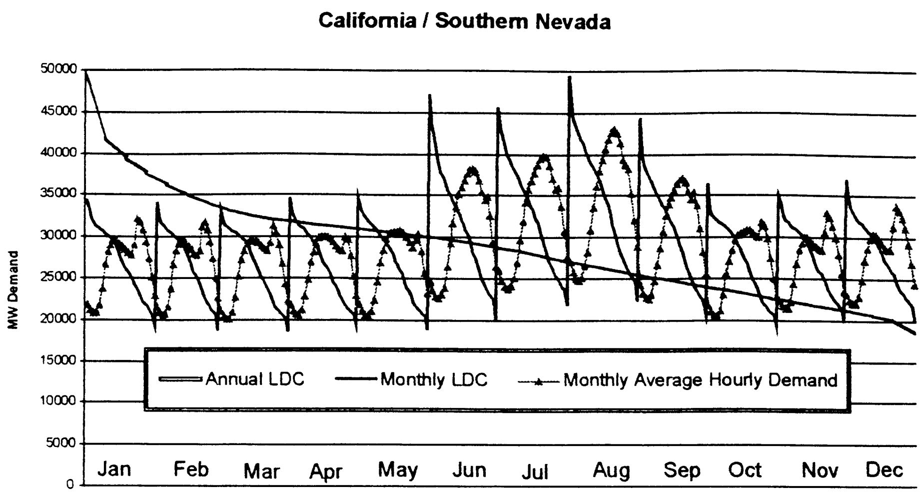
Figure 27: CALCULATION OF LOAD DURATION CURVE BY REGION



Using the WSCC, California and Southern Nevada as an example, Figure 28 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 28, 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 28.

Copyright 1998, Altos Management Partners Inc., All Rights Reserved

Figure 28: DEMAND INFORMATION SUITABLE FOR MODEL INPUT



Referring initially to the annual load duration curve, which serves as the basis for our annual, long term model, we must disaggregate the curve and place it into the model to characterize time-varying electricity demand. Having developed each load duration curve, we first discretize each curve into specific load periods. For our long term model, we have used three load periods, which we have designated base, intermediate, and peak. For our monthly model, we have used five load periods: base, high intermediate, low intermediate, high peak, superpeak In the longer term model, we have defined base load as that demand that persists 100% of the time, i.e., the bottom block in Figure 29. Intermediate load is that load that persists 50% of the time. It corresponds to the middle block in the diagram. Peak load demand persists 15% of the time in the current version of the Altos model, and it corresponds to the top block in the diagram.

Once we have created the regional load duration curves of the form in Figure 29, we then normalize them so that each curve represents the annual load variation for 1 GWh of total energy demand. That is, the area under the normalized load duration curve is 1.0; the sum of the areas of the three rectangles in Figure 29 is 1.0. Following such normalization, we are then able to multiply the normalized load duration curve by a long run electric energy projection such as that produced by NERC to obtain a ten or twenty year, load dependent, electric energy demand projection. This is precisely what we have done on a region by region basis throughout North America, multiplied the normalized load duration curves derived from historical data by projections of electric energy demand derived and extrapolated from FERC.

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 30. Notice in the figure that we specify price-sensitive demand curves for each of the discrete increments of load.

Copyright 1998, Altos Management Partners Inc., All Rights Reserved

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 29: DISCRETE APPROXIMATION TO LOAD DURATION CURVE

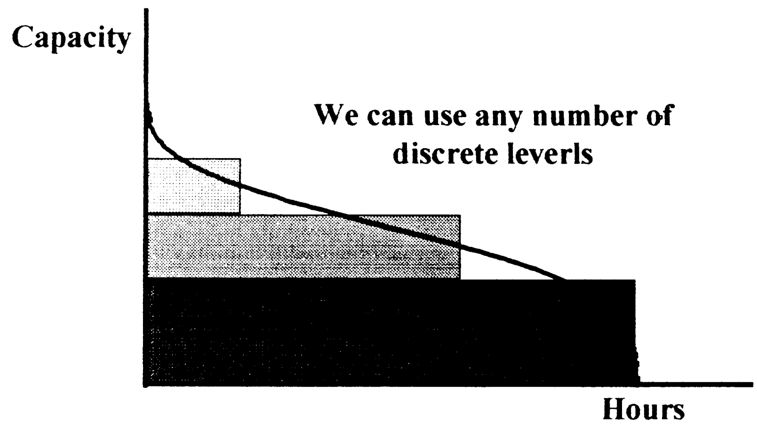
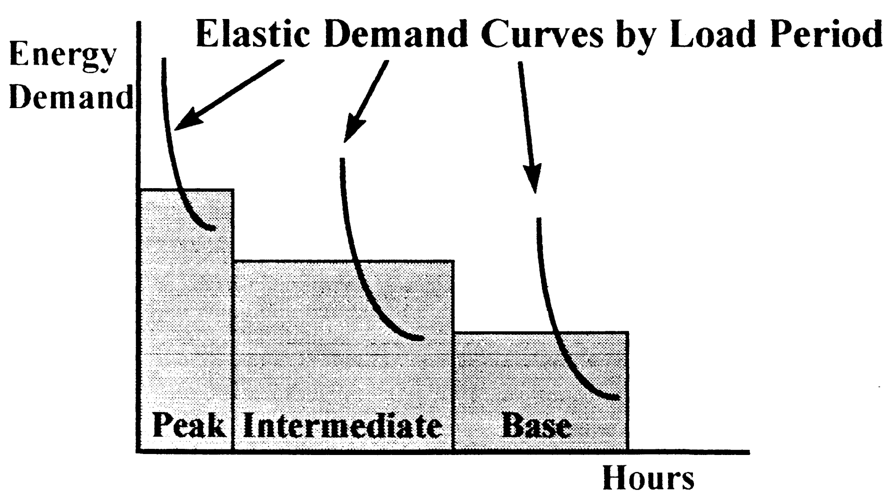


Figure 30: DISCRETIZE TO CALCULATE PRICE IN EACH LOAD PERIOD



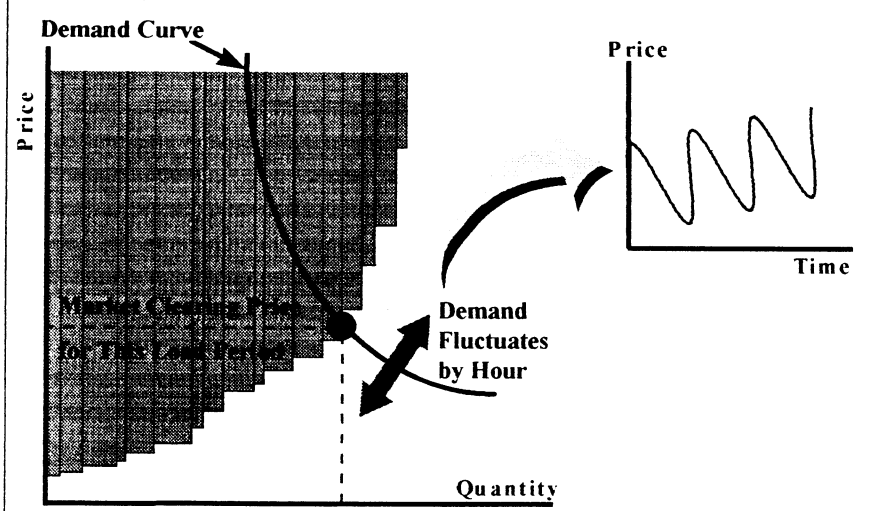
Copyright 1998, Altos Management Partners Inc., All Rights Reserved

7. SUMMARY OF MODEL STRUCTURE

To summarize, the Altos North American Electric Power Model can be represented schematically as shown in Figure 31. 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 31: A DYNAMIC INTERREGIONAL PRICING MODEL OF ELECTRICITY



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.

Copyright 1998, Altos Management Partners Inc., All Rights Reserved

We have developed increasing confidence in the general results of the 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.

Copyright 1998, Altos Management Partners Inc., All Rights Reserved

FPSC Docket No. 981042-EM
UCNSB/Duke New Smyrna
Witness: Nesbitt
Exhibit ____ (DMN-16)

OVERVIEW OF THE NORTH AMERICAN REGIONAL GAS (NARG) MODEL

by

Dale M. Nesbitt

August 1998

Altos
Management Partners Inc.
San Jose Jet Center
1250 Aviation Avenue - Suite 200C, San Jose, CA 95110
(408)275-0789 FAX: (408)275-0799

TABLE OF CONTENTS

1. OVERVIEW AND SUMMARY OF NARG 3
    1.1. General 3
    1.2. Time Period Structure Of The NARG Model 3
2. THE SUPPLY SIDE OF THE NARG MODEL 4
    2.1. Regional Structure 4
        2.1.1. Regional Structure Of The United States 4
        2.1.2. Regional Structure Of Canada 6
        2.1.3. Geographic Representation Of Gas Import Alternatives 7
        2.1.4. Overall Regional Structure 7
    2.2. The Depletable Resource Supply Hexagons--How Do They Work? 8
3. THE DEMAND SIDE OF THE NARG MODEL 26
    3.1. Regional Structure 26
    3.2. How Do We Represent Gas Demand? 27
    3.3. The "Answer" Given By The Model – Market Clearing Prices And Quantities Flowing At Those Prices 30
4. THE PIPELINE COMPONENT OF THE NARG MODEL 36

Proprietary and Confidential to Altos Management Partners Inc., Copyright 1998

1. OVERVIEW AND SUMMARY OF NARG

1.1. General

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 herein is to describe the NARG model works. We have provided enough detail to illustrate rather comprehensively how the model works, yet we have omitted 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. 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. Time Period Structure Of The NARG Model

The NARG model and the Generalized Equilibrium Modeling System (GEMS) approach upon which it is based are neither short- or long-term in nature. The GEMS approach is fully the most general approach in existence with regard to its dynamic assumptions. In particular, GEMS 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 GEMS 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. GEMS 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, GEMS 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,

[1] NARG and GEMS are tradenames owned by Decision Focus Incorporated.

Proprietary and Confidential to Altos Management Partners Inc., Copyright 1998

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

Proprietary and Confidential to Altos Management Partners Inc., Copyright 1998

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

Proprietary and Confidential to Altos Management Partners Inc., Copyright 1998

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
- 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.

Proprietary and Confidential to Altos Management Partners Inc., Copyright 1998

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

- North Alaska (1)
- South Alaska (2)
- San Juan/Raton Basins (3)
- Rocky Mountain Basins (4)
- Northern Great Plains Basins(5)
- Anadarko/Arkoma Basins (6)
- Permian Basin (7)
- Gulf of Mexico Basins (8)
- Midwestern Basins (9)
- Appalachian Basin (10)
- Offshore Atlantic Coast (11)
- LNG Import Terminals (12)
- Canadian Border Import Locations (13)
- Mexico Border Import and Consumption Locations (14)
- Pacific Northwest Demand and Supply Region (15)
- West North Central-Mountain Demand Region (16)
- West South Central Demand Region (17)
- East North Central Demand Region (18)
- South Atlantic Demand Region (19)
- East South Central Demand Region (20)
- Middle Atlantic Demand Region (21)
- Oil Region (22)

Proprietary and Confidential to Altos Management Partners Inc., Copyright 1998

- Southern California Supply Region (23)
- Northern California Supply Region (24)
- Pacific Gas and Electric Demand Region (25)
- Southern California Gas Company Demand Region (26)
- San Diego Gas and Electric Demand Region (27)
- EOR Demand Region (28)
- New England Demand Region (29)
- Gulf-to-Northeast Pipeline Corridor Transportation Region (30)
- Canada: British Columbia Supply Region (C1)
- Canada: Alberta Supply Region (C2)
- Canada: Saskatchewan Supply Region (C3)
- Canada: Northern Canada Supply Region (C4)
- Canada: Eastern Canada Supply Region (C5)
- Canada: Western Canada Demand Region (C6)
- Canada: Ontario Demand Region (C7)
- Canada: Canadian Oil Region (C8)
- Canada: Eastern Canada Demand Region (C9)
- Canada: British Columbia Demand Region (C10)

The indexes we have associated with each region correspond to the NARG model indexes used internally.

The regionalization of the NARG model is embedded in the network "tinkertoy" diagrams that will be provided under separate cover. In reviewing those diagrams, it will become immediately obvious just how the foregoing regions have been represented and what level of detail is contained within each region.

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

Proprietary and Confidential to Altos Management Partners Inc., Copyright 1998

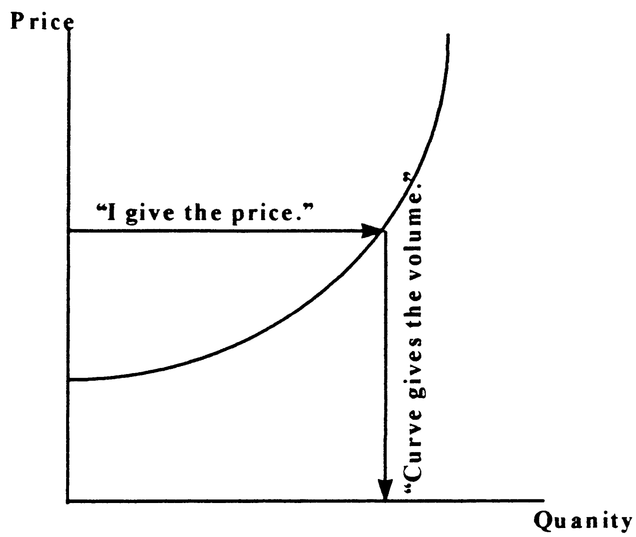
possibility of arbitrage between financial markets and gas markets? In a modeling sense, how can we be sure that the forward price and cost of gas are properly related to discount rates that represent costs of capital?

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 1 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, <u>The Gas Research Institute North American Regional Gas Supply-Demand Model</u>, 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 1 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 1 to indicate the fact that the market is specifying a price and the producers are deciding how much to produce at that price.

Proprietary and Confidential to Altos Management Partners Inc., Copyright 1998

Figure 1: Direct Supply Curve



NARG uses the inverse of the direct supply curve, which is depicted in Figure 2. 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 2, 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 2 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 2 rather than the reverse direction in Figure 1.

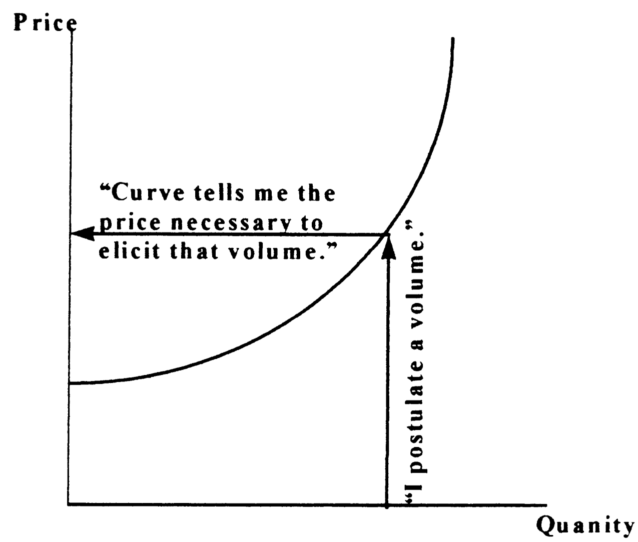
Using the notion of an inverse supply curve, how does NARG work? The answer is simple. NARG successively executes the following set of steps:

1. Guess the supply volume, i.e., guess a quantity on the horizontal axis of Figure 2.
2. Read the price necessary to elicit that supply volume from the inverse supply curve by following the upward and leftward arrow in Figure 2.
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.
4. Determine the market demand that would occur at the price specified in step 3 by reading it from the demand curve. Figure 3, which represents the demand curve, illustrates how this is done.
5. Pass the demand quantity back to the supply curve.

Proprietary and Confidential to Altos Management Partners Inc., Copyright 1998

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 4.

Figure 2: Inverse Supply Curve



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 4, 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.

Proprietary and Confidential to Altos Management Partners Inc., Copyright 1998

Figure 3: Demand Evaluation

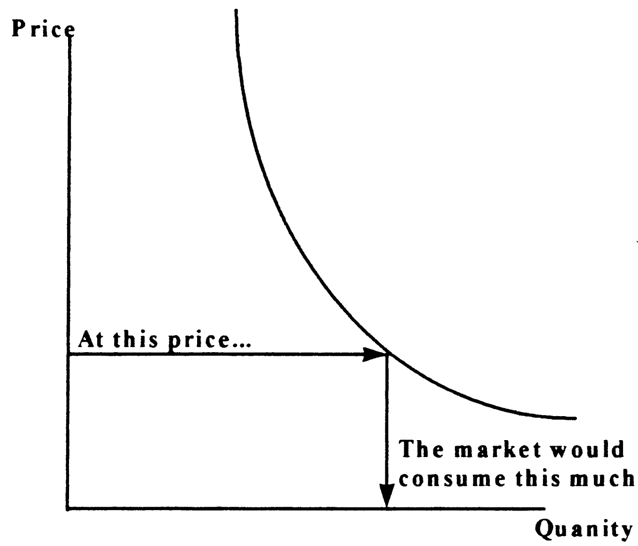
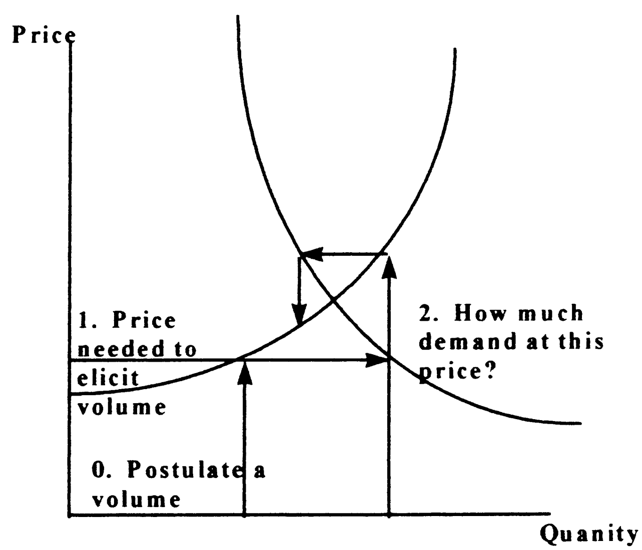


Figure 4: NARG's Iterative Supply-Demand Calculation



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 1 or Figure 2.

Proprietary and Confidential to Altos Management Partners Inc., Copyright 1998

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.

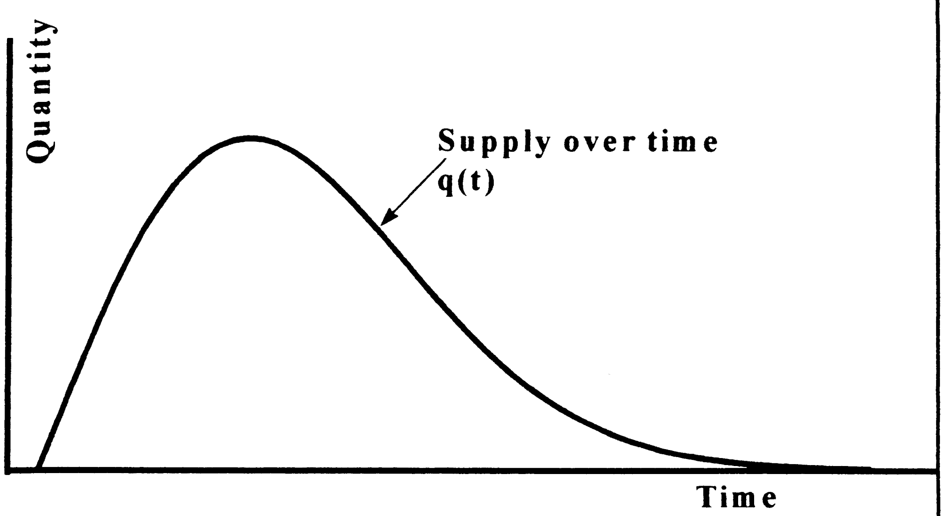
- Addition of new reserves and subsequent production from those reserves. NARG focuses on the process by which a market draws in new reserves and new production from those new reserves over time. In economists' jargon, NARG gives a great deal of attention to "entry" and "exit" in the primary resource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

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

The analogy in Figure 2 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 5 illustrates what such a gas production schedule q(t) might look like.

Proprietary and Confidential to Altos Management Partners Inc., Copyright 1998

Figure 5: Estimate of Forwarad Production Schedule



Beginning with the postulated schedule of gas production forward in time q(t) as indicated in Figure 5, 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 4? 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 6. 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 6 normalized to a total shaded gray area of 6.87 Tcf. Geometric 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.

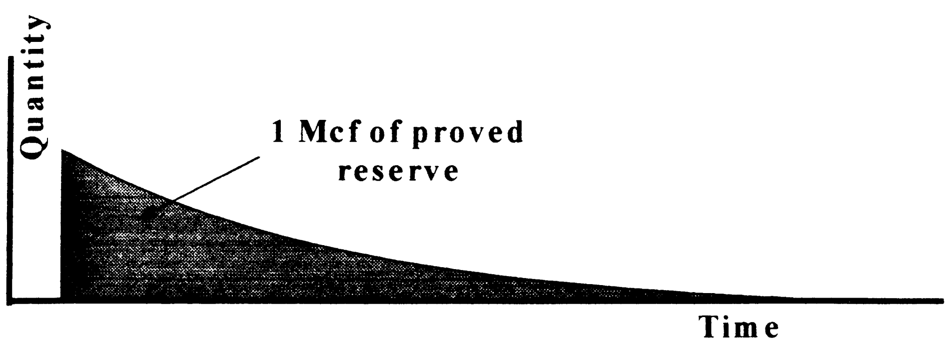
The facility decline curve is one of the fundamental data inputs to the NARG resource model. For each hexagonal tinkertoy in the model, i.e. for each increment of resource in each producing basin, we input a geometric decline rate for that tinkertoy. The reciprocal of the geometric decline rate is commonly 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.

Proprietary and Confidential to Altos Management Partners Inc., Copyright 1998

As noted in Figure 6, the facilities decline curve is not restricted to be exponential in form. Indeed, one can specify any shape one wishes. For the current version of NARG, however, we have assumed that every resource node in the model has a geometric decline profile. 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.

Figure 6: Production from a Well Declines Geometrically

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

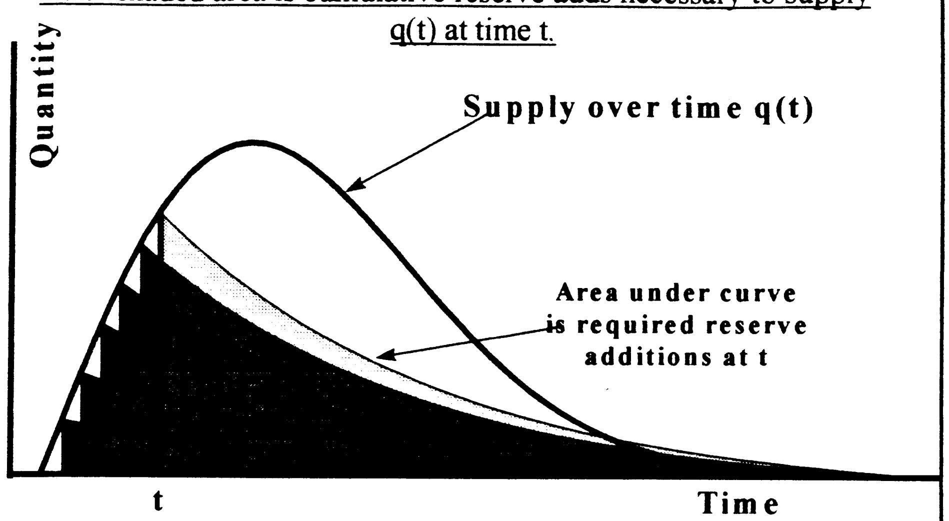


Given the facility decline profile, how do we calculate the rate of proved reserve additions necessary to sustain the postulated quantity schedule q(t) in Figure 5? The answer is simple; we simply stack "exponential bricks" under the quantity schedule q(t). Figure 7 shows how. If we consider a given 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.

Proprietary and Confidential to Altos Management Partners Inc., Copyright 1998

Figure 7: Meeting Demand Means Stacking in "Exponential Bricks"

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



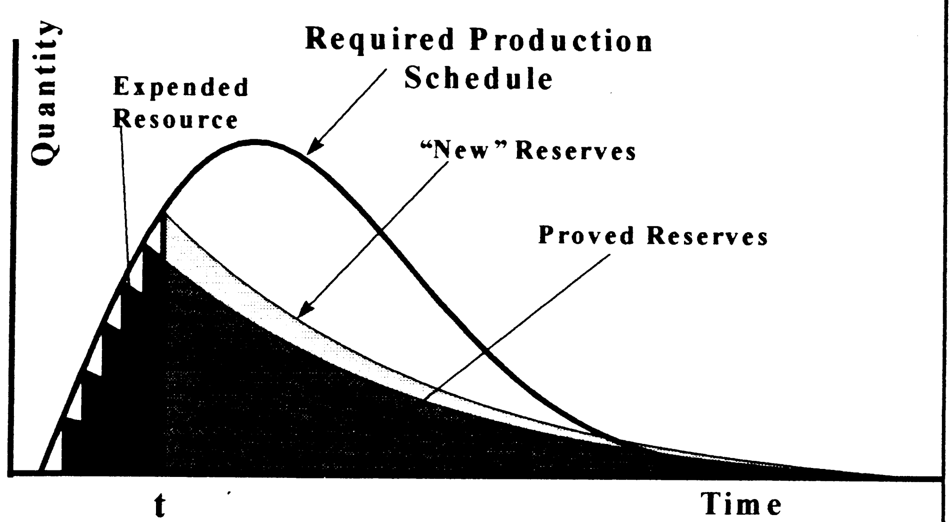
The process of "stacking in" exponential bricks to satisfy the postulated production schedule is rather simple mathematically and rather revealing graphically and economically. If we keep track of the CUMULATIVE quantity of reserves proved since the beginning of time, we will have a plot of the total shaded area in Figure 7 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 gray area in Figure 7 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.

The concepts in Figure 7 contain some critically important elements and some critically important terminology. By reshading various portions of Figure 7, we can define and illustrate some critically important resource base concepts. At the left, we see in the most darkly shaded 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 medium gray area in the middle of the figure represents proved reserves in place as of time t. The total medium gray 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 light gray area represents the quantity of new reserves that must be provided as of time t. In order to sustain the

Proprietary and Confidential to Altos Management Partners Inc., Copyright 1998

given production schedule q(t) through and including time t, producers must add reserves equal in magnitude to the light gray 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 8 has greatly clarified what in the heck people are talking about in the resource business. The figure makes clear what we mean by proved reserves; it is the middle gray shaded 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 8: Critical Resource Terminology

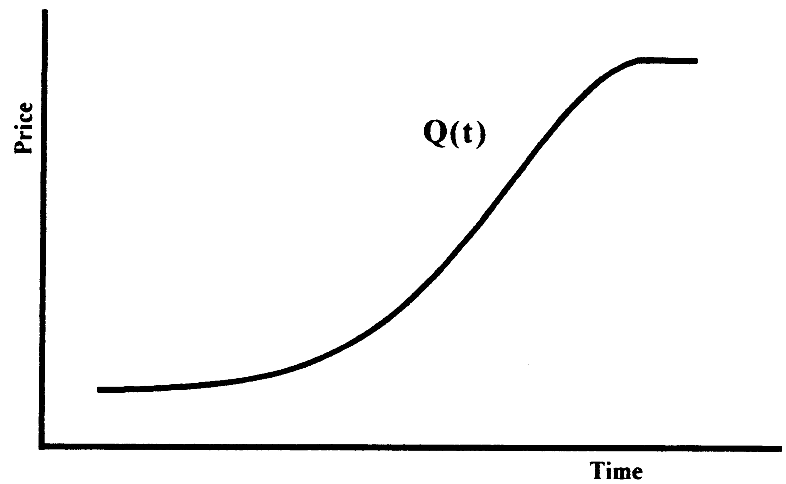


The critical datum from Figure 8 that must be specified to the model is first year proved reserves, i.e., the middle gray area in the figure as of the first model year. NARG requires that the user specify how much proved reserve exists in every producing basin region by region throughout North America. This middle gray 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 8, i.e., the growing total shaded area, over time, it will have the monotonically increasing shape shown in Figure 9. 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 9, denoted Q(t), is derived directly and unequivocally from the postulated schedule q(t) of future production.

Proprietary and Confidential to Altos Management Partners Inc., Copyright 1998

Figure 9: 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 9. 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 10. We term the curve in Figure 10 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 10 for several other reasons:

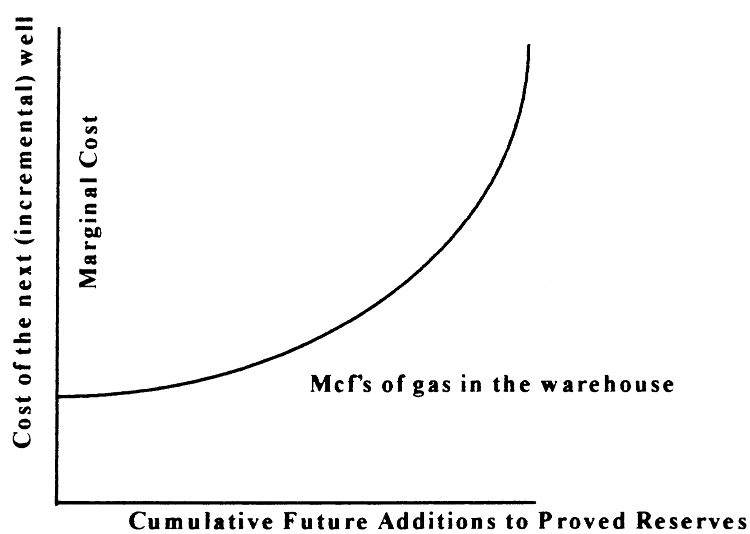
- It is unequivocal. There are no mistakes of interpretation. We know precisely what we mean. We must enumerate every Mcf of gas and attach a cost to every Mcf.

- 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 GRI/EEA Hydrocarbon model completely 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. Hydrocarbon model price projections have been a sad joke in the industry, an embarrassment, because they continue to confound the issue of total resource supply with the issue of the dynamics of extraction.

- It is not confounded by price. Price is explicitly entered as one variable, namely the variable on the vertical axis. The discussion of the shortcomings of the Hydrocarbon model pertain to this issue as well. That model confounds price and cost with they dynamics of production and intertwines it with the total volume available. As many of our customers have commented, the particular strength of this approach is that it allows one to put in the proper forward shape of the supply functions and thereby ensure that you do not miss the proper market price behavior.

Figure 10: Resource Marginal Cost Curve



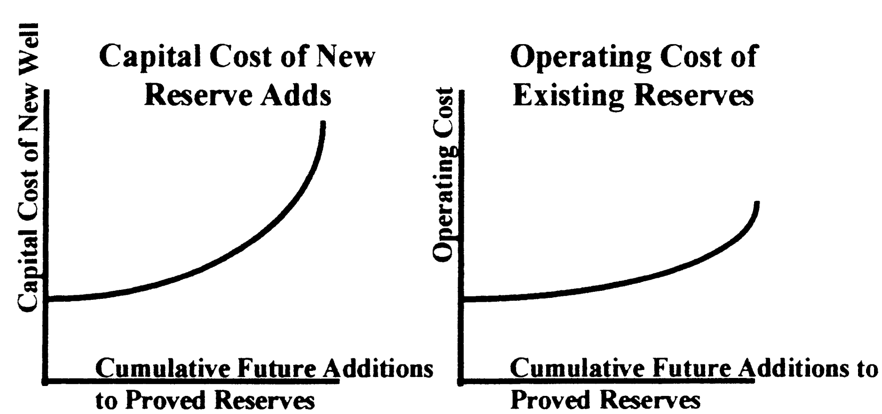
The resource marginal cost curve in Figure 10 is the fundamental input to NARG that characterizes the volume and cost of resource deposits in each of the basins of NARG. Because we recognize that resource production requires both fixed (capital) and variable cost, we have actually input to NARG a pair of curves similar in concept to the single aggregate curve in Figure 10. 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 11 illustrates. The fundamental resource inputs to NARG are the pair of curves in Figure 11. In particular, each hexagon in the NARG network requires precisely the pair of curves in Figure 11. When we deliver NARG, we deliver a complete and

Proprietary and Confidential to Altos Management Partners Inc., Copyright 1998

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.

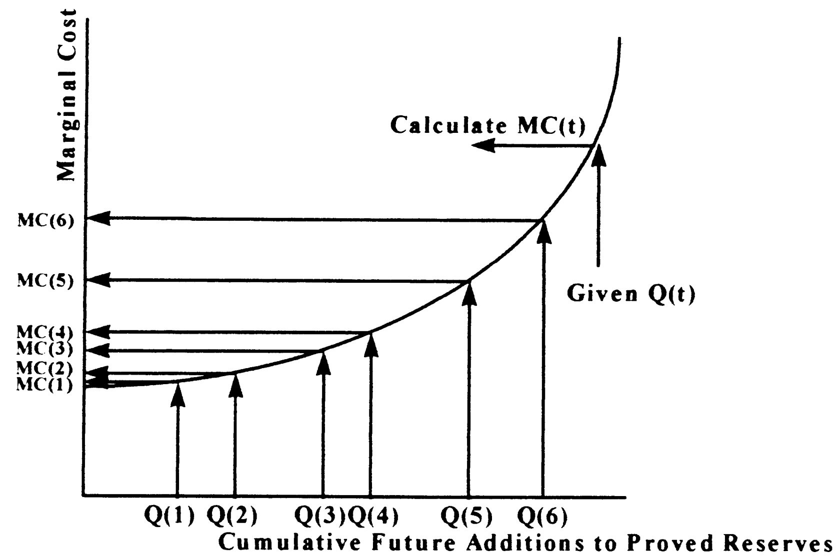
Even though the model contains the pair of supply curves in Figure 11, we will continue the discussion of how the resource model works by using the simplified curve in Figure 10. Given the schedule Q(t) of cumulative additions to proved reserves necessary to sustain the postulated schedule q(t) of production, which is depicted graphically in Figure 9, suppose we plot it on the horizontal axis of Figure 10 and read the corresponding marginal cost MC(t) from the marginal cost curve as indicated in Figure 12. 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 11: Fixed Cost and Variable Cost of Resource Exploitation



Proprietary and Confidential to Altos Management Partners Inc., Copyright 1998

Figure 12: Calculating Marginal Cost over Time

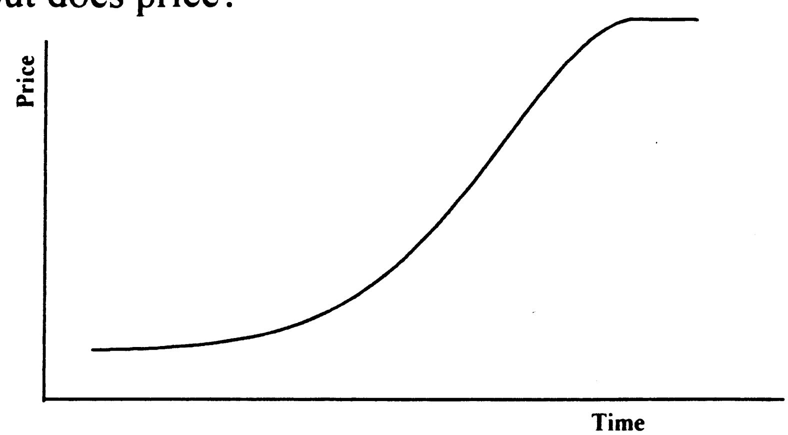


The time schedule of marginal cost MC(t) derived from the foregoing procedure has the form in Figure 13. If the supply curve is upward sloping, the marginal cost curve will likewise be upward sloping because the cumulative reserve addition schedule Q(t) is monotonically increasing. The only way the marginal 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 10 escalates cost. This has probably occurred during certain periods of the 1980s and 1990s; however, it is unlikely to persist forever. Inexorable 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.

Proprietary and Confidential to Altos Management Partners Inc., Copyright 1998

Figure 13: Cost of the Marginal Well (Marginal Cost) Over Time

- Marginal cost rises with cumulative depletion, but does price?



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 14. 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.

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

Proprietary and Confidential to Altos Management Partners Inc., Copyright 1998

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 14 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 14: There Can Be No Arbitrage Possibility at Equilibrium

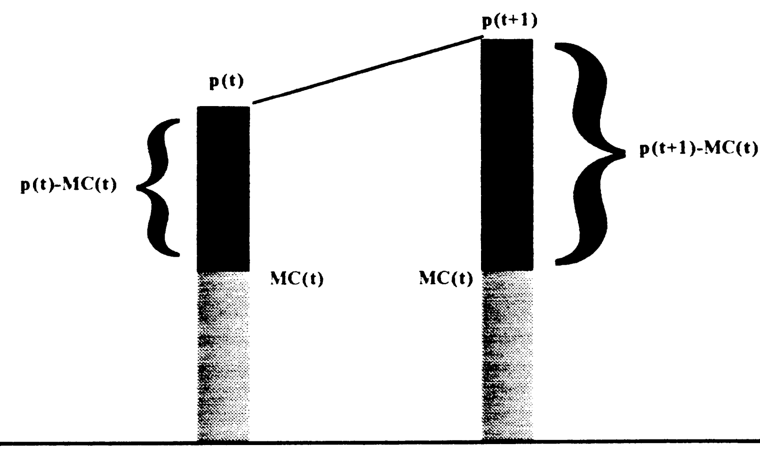


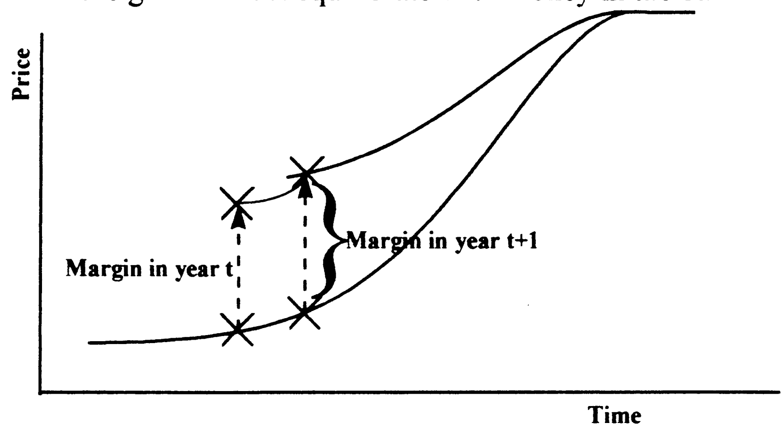
Figure 15 summarizes this notion that there must be complete equilibration between gas in the ground and money in the bank at equilibrium. The price schedule that is reported by the resource hexagon to the demand portions of the model must be the higher of the two curves, not the lower marginal cost 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, assuredly, they WILL change. If they have incentive to changes, assuredly the price that contains such incentives will not be sustainable in the market. It 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.

Proprietary and Confidential to Altos Management Partners Inc., Copyright 1998

Figure 15: Price Must Not Allow 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.

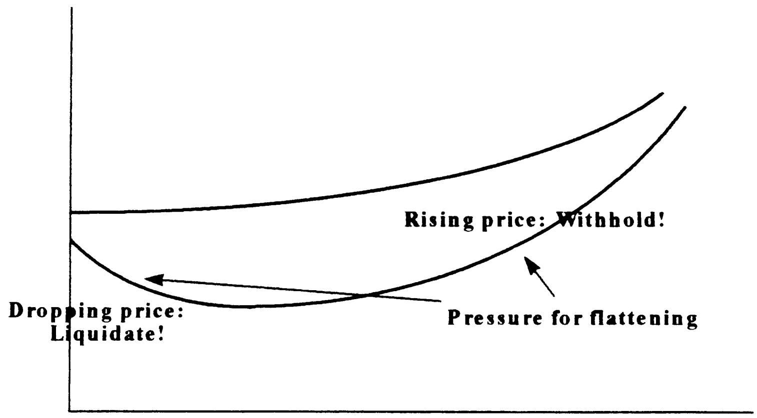


Why go to all this trouble to equilibrate gas markets with financial markets? The answer is that we want to eliminate hockey stick and other "stupid" forward price projections. Hockey stick price forecasts are indeed stupid; they cannot be sustained in a market. To see why, consider Figure 16. During 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 model as unequivocally wrong. They do not properly consider arbitrage between financial and physical markets. Such price forecasts cannot possible serve as the basis for cogent strategy and pipeline analysis.

Proprietary and Confidential to Altos Management Partners Inc., Copyright 1998

Figure 16: Hockey Stick Price Forecasts Are Wrong

- The market arbitrages Hockey Sticks.



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:

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 6.

Proprietary and Confidential to Altos Management Partners Inc., Copyright 1998

2. Initial year proved reserves, i.e., the middle gray shaded area in Figure 8. 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 11, which characterizes aggregate resource deposition in each resource producing basin.

4. The discount rate used to make the "no intertemporal arbitrage" equation in Figure 14. 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

Proprietary and Confidential to Altos Management Partners Inc., Copyright 1998

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 17. 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 18. 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.

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 18 should be "rounded off" as shown in Figure 19. The demand curve in Figure 19, 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 19.

Proprietary and Confidential to Altos Management Partners Inc., Copyright 1998

Figure 17: Network Representation of Gas Demand

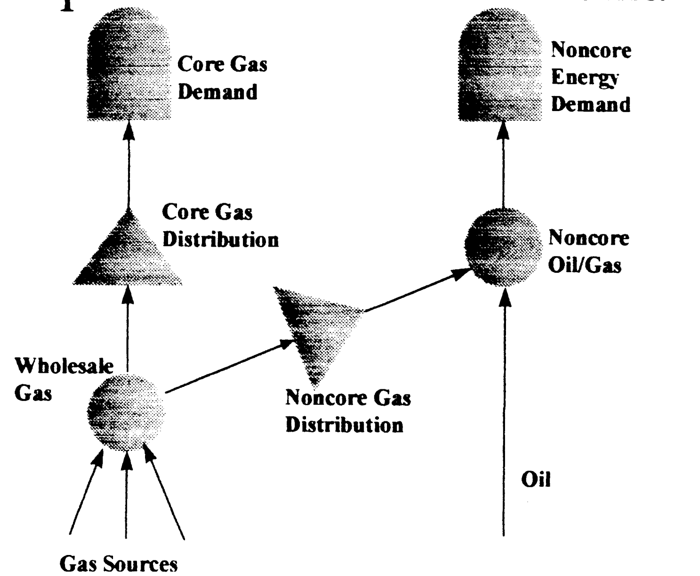
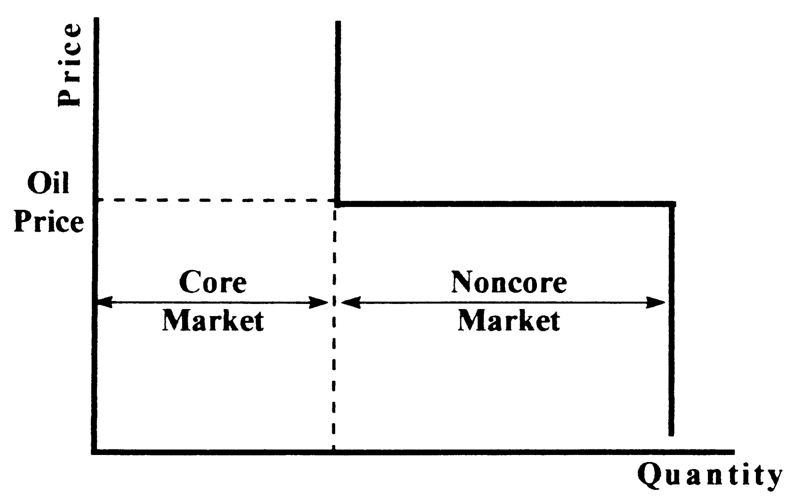
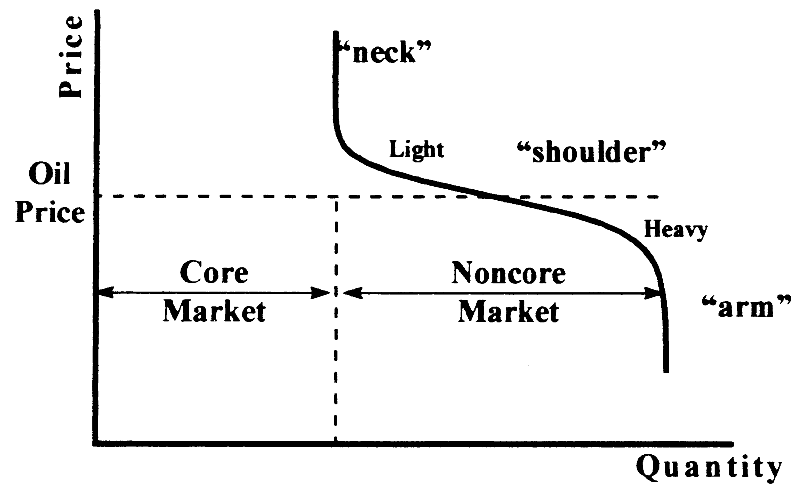


Figure 18: Segmented Representation of Gas Demand



Proprietary and Confidential to Altos Management Partners Inc., Copyright 1998

Figure 19. Wholesale Gas Demand Curve is Rounded Off



It is interesting to note that the width of the shoulder in Figure 19 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.

Every demand region in the model contains the network structure in Figure 17 and therefore the demand curve structure in Figure 19. 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 19 itself. In order to construct the demand curve in Figure 19, we need its constituent elements, which are best seen by referring to the "caricature" of demand illustrated in Figure 18:

- 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.

Proprietary and Confidential to Altos Management Partners Inc., Copyright 1998

- an estimate of core distribution cost.
- lag parameters that simulate adjustments in capital stock necessary for gas/oil substitution.

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 have been inferred from GRI's 1996 Baseline forecast. In particular, we have divided GRI's 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 19, 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:

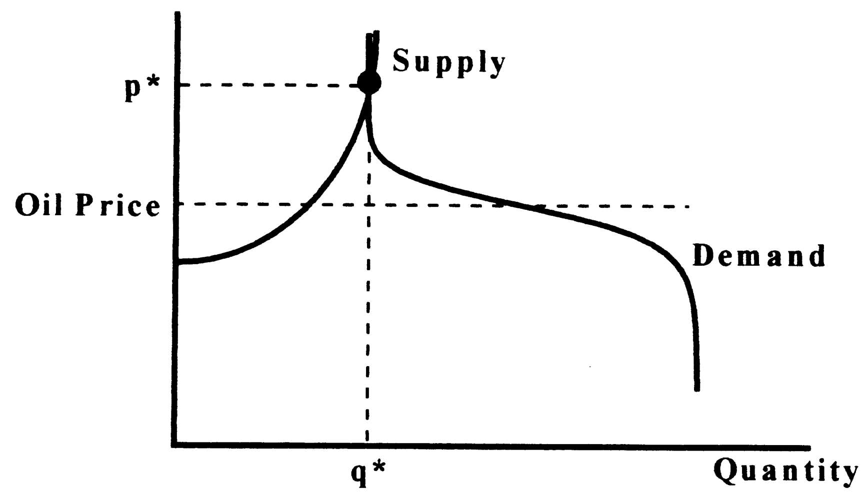
Case 1: The gas supply curve intersects the demand curve above the shoulder, as shown in Figure 20. The market clearing price (denoted p*) of gas is seen to exceed the price of oil. Furthermore, in this ease,

- 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.

Proprietary and Confidential to Altos Management Partners Inc., Copyright 1998

Figure 20: Case 1--Gas Price Clears on "Neck;" Gas Price Above Oil Price



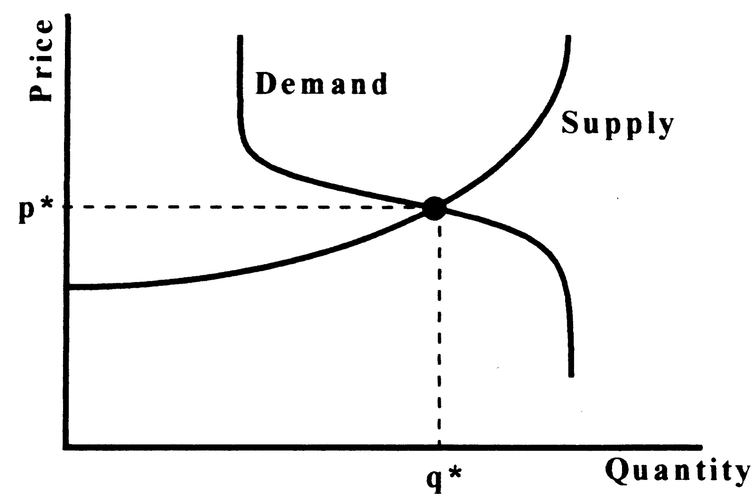
<u>Case 2: The gas supply curve intersects the demand curve along the shoulder as shown in Figure 21.</u> Notice that

- 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.

Proprietary and Confidential to Altos Management Partners Inc., Copyright 1998

Figure 21: Case 2--Market Clears on "Shoulder;"--
Gas and Oil Price Equal



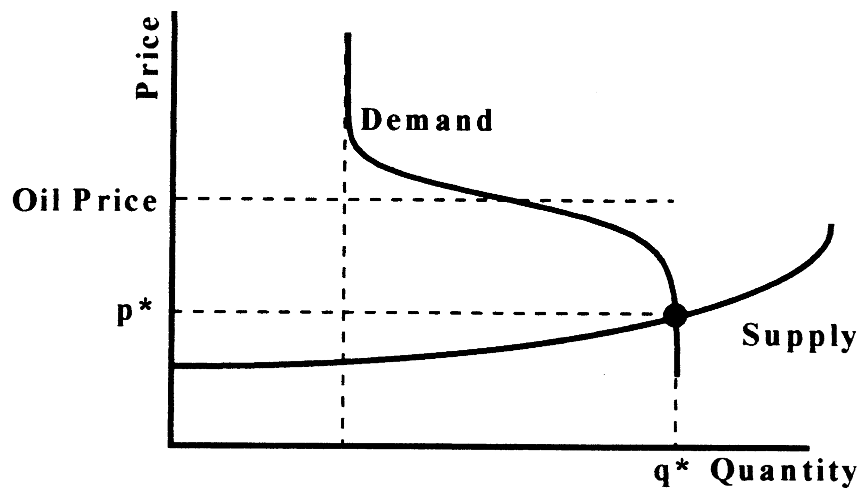
Case 3: The gas supply curve intersects the demand curve below the shoulder as shown in Figure 22. The market-clearing price of gas is seen to be below that of oil. In this case

- 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.

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.

Proprietary and Confidential to Altos Management Partners Inc., Copyright 1998

Figure 22: Case 3--Gas Market Clears on "Arm;" Gas Price below Oil Price



A conspicuous observation in Figures 20 through 22 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 20, 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.

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:

THE MARKET CLEARING PRICE OF GAS WILL BE DIFFERENT BETWEEN DIFFERENT DEMAND, SUPPLY, AND OIL PRICE SCENARIOS.

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"

Proprietary and Confidential to Altos Management Partners Inc., Copyright 1998

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.

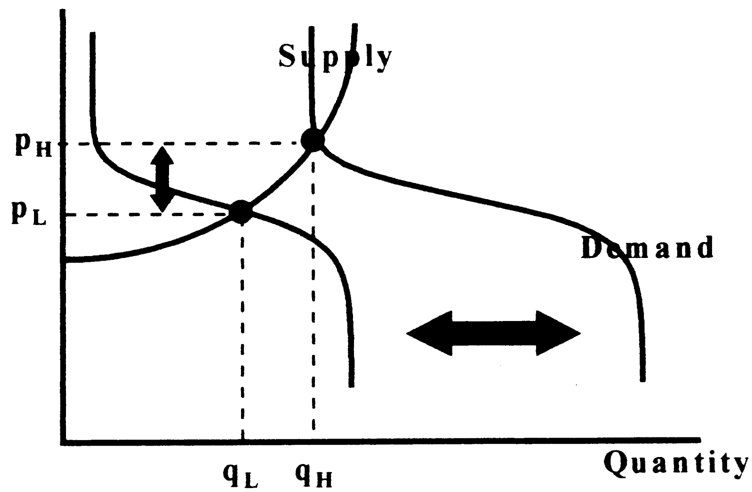
We conjecture that the customary (and increasingly incorrect) procedure of netting back burnertip-equivalent oil prices to the wellhead originated in the days when the United States had a large industrial sector, that is, a large noncore market relative to the core market. Although not technically correct 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.

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 23, 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 23.

Proprietary and Confidential to Altos Management Partners Inc., Copyright 1998

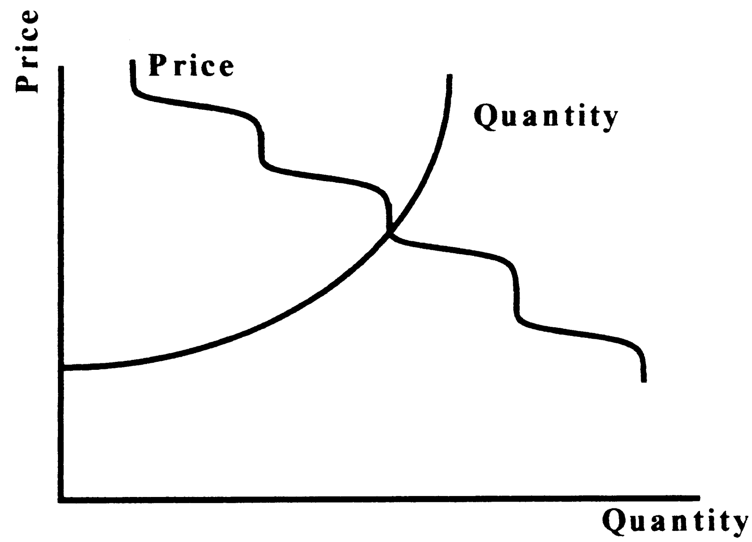
Figure 23: Gas Demand "Wiggles" During the Year, Taking Price with It



Finally, many have argued that the simple oil-for-gas substitutability model that led to the "neck-shoulder-arm" demand curve pattern in Figure 19 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 17 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 19 but rather has a series of substitution zones as shown in Figure 24. 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 17 to create the demand curve in Figure 24.

Proprietary and Confidential to Altos Management Partners Inc., Copyright 1998

Figure 24: Demand Curve May Be Sub-Segmented



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.

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.

Proprietary and Confidential to Altos Management Partners Inc., Copyright 1998

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.

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 25. 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 25 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 25. The data necessary to characterize such pipeline service includes

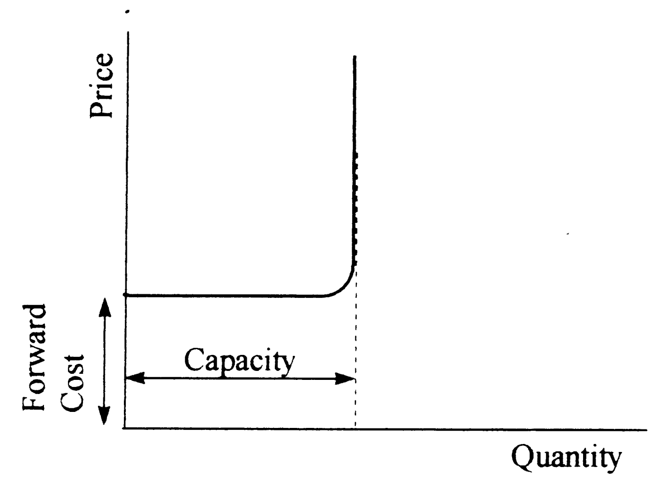
- The forward cost to market, i.e., the height of the pipeline supply curve. We have used pipeline costs specified by our customers and contractors over the years to characterize the cost along each existing pipeline link.

- 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.

Proprietary and Confidential to Altos Management Partners Inc., Copyright 1998

The pipeline database delivered to our NARG customers contains such estimates for every pipeline link the North America as estimated for use in NARG.

Figure 25: Supply Curve for Existing Pipeline Service



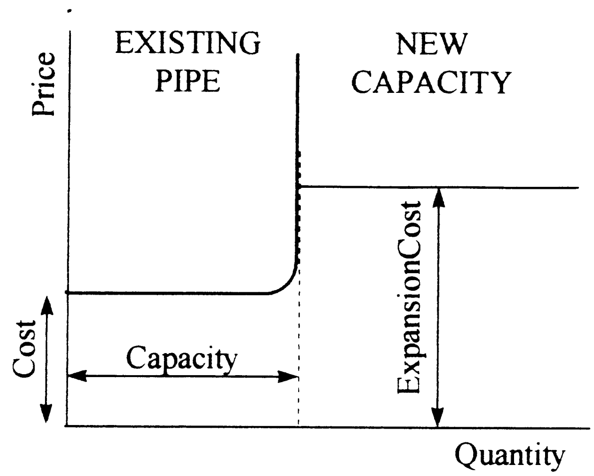
There are several generic types of pipeline capacity expansion that can be implemented:

- 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 25. Thus, the logic for adding new pipeline capacity within NARG is represented graphically as shown in Figure 26. 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 26 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.

Proprietary and Confidential to Altos Management Partners Inc., Copyright 1998

Figure 26: Supply Curve for 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 third quarter of 1997 and will be offered and licensed under the same terms as NARG.

Proprietary and Confidential to Altos Management Partners Inc., Copyright 1998