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Current Legal and Institutional Issues in the Commercialization of Phosphoric Acid Fuel Cells

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TABLE OF ABBREVIATIONS AND ACRONYMS USED IN THIS REPORT

AQMD	Air Quality Management District
BAAQMD	Bay Area Air Quality Management District
BACT	best available control technology
Btu	British thermal unit(s)
CAA	Clean Air Act
CFR	Code of Federal Regulations
CGF	cogeneration facility (under PURPA Title II)
DOD	U.S. Department of Defense
DOE	U.S. Department of Energy
DWP	Department of Water and Power
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
ERA	Economic Regulatory Administration
EWLI	Earl Warren Legal Institute
Fed. Reg.	Federal Register
FERC	Federal Energy Regulatory Commission
FPC	Federal Power Commission
GRI	Gas Research Institute
GSA	U.S. General Services Administration
GWHR	gigawatt-hour(s)
h.	hour(s)
kg/y	kilogram(s) per year
KW	kilowatt(s)
KWH	kilowatt-hour(s)
LAER	lowest achievable emissions rate
m^3	cubic meter(s)
Mcf	thousand cubic feet
MFBI	Major fuel burning installation
MMBtu	million British thermal units
MMcf	million cubic feet
MW	megawatt(s)
MWH	megawatt-hour(s)

NAAQS	National Ambient Air Quality Standards (under CAA)
NASA	National Aeronautics and Space Administration
NCAQ	National Commission on Air Quality
NGPA	Natural Gas Policy Act of 1978
NOPR	Notice of Proposed Rulemaking
OPEC	Organization of Petroleum-Exporting Countries
P1 - P10	Natural Gas Curtailment Priorities under NGPA Title IV
PG & E	Pacific Gas and Electric Company
PIFUA	Powerplant and Industrial Fuel Use Act of 1978
PSD	Prevention of Significant Deterioration standards (under CAA)
PUC	Public Utilities Commission
PURPA	Public Utility Regulatory Policies Act of 1978
QF	qualifying facility (under PURPA Title II)
R & D	research and development
RACT	reasonably available control technology
ROI	return on investment
SCE	Southern California Edison Company
SDG & E	San Diego Gas and Electric
SIC	Standard Industrial Classification
SIP	State Implementation Plan (under CAA)
SPPF	small power production facility (under PURPA Title II)
TOD	time of day
TOU	time of use
tpy	ton(s) per year
WEPCO	Wisconsin Electric Power Company
WP & L	Wisconsin Power and Light Company

SUMMARY

The purpose of this project has been to identify and assess legal and institutional factors likely to affect the development and commercial diffusion of phosphoric acid fuel cells, and to help define issues for future research and action. The study has addressed matters relevant to both central and dispersed utility operations and to on-site applications. It has examined both perceived barriers and potential opportunities for fuel cell commercialization.

This report first discusses the general concept of commercialization as applied to emerging energy technologies. It briefly reviews the conditions which warrant participation by government, the range of activities government can pursue in support of overall energy policy objectives, and the importance of legal, regulatory and institutional analysis as input to the commercialization effort.

Against this background, the report next examines federal fuel use and pricing policies under the Powerplant and Industrial Fuel Use Act of 1978 and the Natural Gas Policy Act, viewed by some as potentially serious barriers to commercialization of first-generation fuel cells. The analysis suggests that in fact these regulatory schemes would not prohibit the use of natural gas or petroleum derivatives in most fuel cell applications, nor should they seriously deter fuel cell use except in certain commercial and industrial applications in regions where natural gas shortfalls are likely and alternate fuels are unavailable.

However, to conclude that existing regulatory schemes will not preclude most fuel cell applications is not to say that the technology will

be viewed as commercially desirable by all or any of those who might actually benefit from its use. To assess those prospects, the focus shifts to legal and institutional considerations which provide positive inducements or potential opportunities for fuel cell commercialization.

The cogeneration potential of fuel cells is generally viewed as a desirable characteristic for a wide range of applications. The analysis here reveals that the Public Utility Regulatory Policies Act of 1978 and its implementing regulations, requiring electric utilities to purchase power from qualifying cogenerators at the utility's "avoided cost," provide attractive opportunities to leverage the cogeneration value of fuel cells in certain settings. The discussion suggests that these findings have fundamental implications for demonstration and market assessment activities, as well as for the design and sizing of fuel cell systems.

The fuel cell's low-polluting characteristics are likewise viewed as an attractive feature which contributes to the versatility and siting flexibility of the technology. Analysis of the Clean Air Act and regulations discloses that this feature not only can permit electric generation or cogeneration where it might otherwise be prohibited, but can translate into tangible economic value. This is particularly true for larger fuel cell applications in certain identifiable air quality regions, where owner/operators may be able to realize substantial savings and/or income not available through the use of competing generation equipment or cogenerating equipment. These findings, too, have important implications for fuel cell market assessment activities.

Because of the nature and versatility of the technology, fuel cell commercialization necessarily involves a wide range of potential participants and institutional arrangements. The legal and regulatory barriers and opportunities examined here can affect each of these differently. The final chapter of this report reviews specific issues relevant to particular participant groups confronting the problem of commercialization, including those interested in promoting fuel cell technology and those interested in acquiring it.

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I. INTRODUCTION

This report presents the results of research performed by the Earl Warren Legal Institute under a grant from the National Aeronautics and Space Administration. The need for this type of research was presented to the Institute early in 1980 by senior personnel from NASA's Lewis Research Center responsible for managing the U.S. Department of Energy's Phosphoric Acid Fuel Cell Program. It was based on their recognition that as this developing technology approaches commercial feasibility, the issues confronting it will expand beyond the scientific and engineering challenges of the laboratory to include legal, institutional and behavioral considerations operating in the commercial marketplace, and that these considerations can profoundly influence future development directions insofar as they affect the viability and attractiveness of particular commercial applications.

NASA's program managers accordingly sought to supplement their own expertise in scientific and technical matters with comparable expertise in legal and institutional areas affecting emerging energy technologies. The Earl Warren Legal Institute had demonstrated such capabilities through similar work with the Department of Energy, state governments and the business community in the fields of geothermal and solar energy. It was therefore asked to undertake what was then conceived of essentially as the "issue definition" phase of a longer-term action program for fuel cells which NASA and DOE hoped to pursue.

The basic objectives of this research have been to identify legal and institutional issues affecting commercialization of phosphoric acid fuel cells; to assess the relative importance of these issues to ongoing development and commercialization efforts; and where appropriate, to suggest future activities which might address and resolve them. Guided by these basic objectives, the research program has been exploratory in nature, avoiding a rigid predefinition of issues in favor of a flexible approach shaped in part by actual research findings emerging in the course of the project.

This approach has, however, been informed by certain basic hypotheses suggested by our previous energy studies and by the technology under consideration. It is clear, for example, that institutional and behavioral considerations affect commercial acceptance of some energy supply technologies more than others. In general, these considerations tend to be more pervasive and more critical to success where the technology's potential applications extend beyond the energy industry to other sectors of society; where these applications vary widely; where fuel supply questions are involved; and especially where the technology invites or requires new types of commercial participants, new roles for old participants, or novel ways of doing business.

Applied to fuel cells, these general observations suggested that relevant issues for commercialization would arise across a very broad legal, institutional and behavioral spectrum, and would increase in number and importance as the analysis moved from centralized utility systems toward dispersed and on-site applications. The Institute's research generally has confirmed these hypotheses, and this report reflects a corresponding emphasis on issues arising in connection with the latter types of applications.

It also reflects some effort to adapt the original conception of this research to the reality of changed circumstances occurring since its inception. As noted above, the project was conceived early in 1980 as the first phase in a longer-term program of research and action. In that context, it could be most useful by identifying the widest possible range of legal and institutional issues relevant to commercialization efforts and defining an agenda and priorities for future research. However, the change in Administrations and in federal energy and budgetary priorities which occurred early in the project eliminated the prospect of a longer-term basic research program. Without such a program to pursue any research agenda defined at this stage, the broad identification of issues alone would be of limited use. It therefore seemed sensible to narrow the scope of our inquiry somewhat in order to address in greater depth certain areas which preliminary research suggested were most critical, an approach in which NASA concurred early in 1981. Accordingly, this report will concentrate most heavily on certain fuel use and pricing issues commonly perceived at the start of this project as potential barriers to fuel cell diffusion, and on some important incentives to fuel cell use under recent energy and environmental law and regulations. It will also suggest a variety of second-order issues requiring attention as commercialization efforts proceed (albeit with a reduced federal presence).

However, the objective of this report is not only to examine specific issues identified in the course of our research, but equally important, to provide a useful context for assessing their relevance to the efforts of NASA, DOE and the private sector to shepherd these advanced technologies from the laboratory to the marketplace. Toward that end, the following chapter examines the basic problem of "commercialization" and the relation of legal and institutional factors to the other elements which comprise it.

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II. THE COMMERCIALIZATION CONTEXT

A. In General

In common business usage, the term commercialization is sometimes used to describe the usual process through which many new products pass on their way from concept to market. This process typically begins with an idea and its associated research, passes through prototype development, commercial product design, market surveys and testing, establishment of production facilities and distribution networks, and ends with the commercial offering of a new product or service. Used in this business context, commercialization often refers to the activities which take place near the end of this sequence, although it may also refer to the entire process.

However, the term commercialization is also used to describe a separate set of activities designed to influence the usual concept-to-market path for a new product, and that is the meaning which we adopt here. Traditionally, although perhaps not necessarily, carried out by government, this kind of commercialization tries to assist some product or service into the marketplace. The objects of commercialization assistance are usually judged to possess some social or political advantages for society as a whole but, at least in the short run, to be only marginally attractive in the marketplace or to present tradeoffs unacceptable to key participants needed to get them there. Although the theoretical work on commercialization addresses a variety of new technologies and innovative processes or services, at least since the 1973-74 oil embargo the major federal programs in the field have focused on bringing new energy technologies into the commercial arena. Some of the basic conditions which can render such government efforts appropriate, and the types of activities available to government in pursuit of these efforts, are reviewed briefly below.

B. The Government Role in Commercialization

1. CONDITIONS FOR GOVERNMENT PARTICIPATION

To the extent that government is involved, energy commercialization is not an end in itself, but a means to achieving broader energy and public policy objectives. Clear formulation of those objectives is an essential prerequisite for government action in this sphere. On the broadest level, at least, that prerequisite has been present in the form of national energy and environmental legislation adopted by Congress in recent years. That legislation, discussed in the following chapters, establishes national priorities which include, among others, reduced dependence on foreign suppliers, allocation of premium fuels to their most essential uses, increased energy efficiency, greater reliance on coal and renewable alternatives, diversification and competition among domestic energy suppliers, and a cleaner environment.

The promise of a genuine contribution toward meeting some or all of these priorities is a threshold criterion for any technology considered a candidate for government commercialization. Beyond that, the presence of several related factors in combination suggests the appropriateness of government action. These include the need for heavy capital investment by prospective commercial participants, the need to compete in a highly regulated environment, and the need for certain participants to incur substantial risks if benefits to other participants and the public at large are to be realized.

The means available to government to raise and channel large amounts of capital, and the propriety of its doing so in pursuit of high national priorities, require little comment. The inescapable influence of government in a regulated environment — where to do nothing in reality is to prefer government policies already in force to others not yet endorsed — means that government "intervention" will occur either way, and the only real issue is whether it will occur by default or by deliberate policymaking which takes account of changing energy imperatives as they arise.

Apart from capital requirements and regulatory implications, the presence of some commercially unacceptable risk is a fundamental condition for government involvement in commercialization. Government commercialization programs were started largely because the private sector found the risk/reward balance of certain new energy technologies which promised public benefits either too uncertain or too heavily weighted toward risk. These programs have spawned a variety of activities, but most basically, have attempted to solve problems of excessive risk.

These risks may be absolute as they were in the case of nuclear power, where the predictable liabilities from a major accident were enormous. Even the best financed and most stable corporations and insurance companies could not allow themselves to be exposed to risks of that magnitude, and it was only after the Price-Anderson Act limited those liabilities that nuclear power could be fully developed. The huge capital investments required by some synfuels projects such as the Great Plains Coal Gasification Project reveal another side of this problem of absolute risk.

More commonly, however, the issue centers around distribution of risks both in time and among the interested parties. Virtually all commercialization programs propose to absorb or redistribute unacceptable short-term risks in return for projected long-term benefits. For laboratory-demonstrated technologies which appear promising, these short-term risks may arise in at least three closely related settings. First, there may be a stage, such as the move from prototype development to initial commercial production now facing fuel cells, at which the degree of risk and the capital commitment required are simultaneously at their highest. Second, at some stage in its development, a new technology may be only marginally competitive measured against rival technologies or against standards for ROI or market size which some of the important participants require for a new venture. Third, and perhaps most relevant to the research reported here, they may be excessive market uncertainties which are not sufficiently clarified by conventional market analysis.

Where these types of risks present obstacles to the development or diffusion of technologies promising real public benefits, government action designed to ensure or accelerate these benefits seems entirely appropriate. The following summarizes the range of actions traditionally relied on by the federal government for these purposes and, where appropriate, notes factors which could be relevant to their use in the fuel cell context.

2. FORMS OF GOVERNMENT PARTICIPATION

Direct Subsidies

The federal government has provided direct subsidies to energy-related technologies and new energy sources. These subsidies, like other less direct forms of support, serve fundamentally to affect the balance between competing technologies in the marketplace. They have not necessarily been <u>intended</u> to advance commercialization: aid to technologies with commercial applications has long been a spinoff of government research in other areas, including defense and space exploration. Thus nuclear power generation enjoyed the benefits of the most basic government-sponsored research into nuclear weaponry and of later work on nuclear reactors, and fuel cells have benefitted from publicly-supported research related to America's space program. Since the 1973-74 oil embargo, the federal government also has, or course, subsidized research into numerous energy sources and technologies with the express intent of aiding their commercial introduction.

Direct subsidy of new technologies has not been the main tool of commercialization policy. High costs, particularly for sustained support, and ideological preferences shared by both major political parties, have limited its use. Much federal commercialization policy has been based on the idea that government funding, if properly applied, can have an effect on new product development and marketing far beyond its actual percentage contribution to the total necessary expenditures. This has resulted in efforts to identify the points of leverage in each particular commercialization problem. Larger efforts have focused on providing tax incentives, loan guarantees, public markets for initial offerings of new products, and demonstration projects. Smaller scale programs dictated by this approach have prominently included identification of barriers and efforts to remove them, as discussed more fully in Part C, below.

Tax Incentives

Tax incentives are intended to change the financial balance in an investment decision to increase rewards or reduce risks. Some recent tax credits aimed at supplier investment in new energy technologies or sources actually have been intended not to confer special advantages on these technologies, but to accord them treatment equal to that given certain existing energy sources. Geothermal tax policy since 1978, for instance, has offered essentially equal treatment with oil and gas in covering certain investment and resource depletion risks, and in that sense can be viewed as removing barriers to geothermal competition created by previous tax policies. On the other hand, tax credits offered to prospective users of alternative technologies clearly favor the eligible technologies over conventional competitors not included, and represent efforts to assist the favored technologies into the marketplace by stimulating consumer demand.

Tax policy has not always proven to be a precise instrument in the service of commercialization. Tax credits passed to aid the development of a new industry do not necessarily affect all segments of it equally. They can shape an industry as well as promote it, and shape it in ways that do not necessarily reflect deliberate policy choices of the government. Tax credits, for instance, favor large companies with income against which to apply them over small, single product companies with little taxable income. Moreover, as political pressures result in the extension of tax incentives to all the competitors in a new field, relative advantage for any individual technology is lost. Such shotgun tax policies may favor investment or purchases in a particular field such as energy, but tend to dilute the effects of policy decisions to promote individual technologies.

Loan Guarantees and Development Banks

Another tool of commercialization has been aimed directly at risk reduction. Federal guarantees of loans from private lenders and direct federal loans to innovative projects have been tried separately and in combination to induce a flow of private capital into projects which would not normally meet conventional lending requirements. Loan guarantees, in particular, seem to offer a way to leverage the federal investment in promoting innovation. Development banks offering loans at less than full market rates have also been set up to pay for themselves in the long run.

Guarantees and development banks have too often failed in their purpose because government finds it extremely difficult to absorb risks. Pressure from past administrations and from congressional oversight have tended to make federal risk-absorbing institutions at least as conservative as the private sector they were meant to reassure or replace. The Geothermal Loan Guarantee Program, for instance, approved only four applications for guarantees during its first several years of existence. The standards it imposed on projects and the detailed and lengthy review it made of every aspect of proposals eliminated most of those intended to benefit from the program. The recently formed National Consumers Cooperative Bank, intended to support innovative cooperatives unable to find conventional financing, made its first large loans to three of the oldest and most stable cooperatives in the country.

Apart from the problem of government's own risk aversion, conventional loan guarantees probably are not the most effective option for stimulating fuel cell development for two reasons related to the · rticular nature of the commercialization problems confronting fuel cells. First, the uncertainties preventing the manufacture and commercial distribution of fuel cells are primarily related to assessment of markets. Prospective manufacturers and distributors are less concerned about the risks associated with one project, which might be guaranteed, than with long-term prospects for a broad and substantial market. Secondly, the major participants in fuel cell development are large corporations and utilities which have historically been uninterested in loan guarantees because their credit ratings do not allow them to default even on guaranteed loans.

Demonstration Projects

Support for demonstration projects probably has been the most widely used form of federal commercialization assistance. Various government agencies have supported demonstrations of innovative products and services, ranging from the Dial-A-Ride program for transporting the elderly and handicapped to light water nuclear reactors and other highly sophisticated products of technology, including advanced energy technologies in general and fuel cells in particular.

The work of others who have examined the demonstration concept in detail suggests several observations of relevance here.[1] One is the importance of avoiding premature demonstrations — i.e., those where perfor-

[1]Sumner Myers and E.E. Sweezy, *Why Innovations Falter and Fail: A Study of 200 Cases* (Denver Research Institute, University of Denver Report #R75-04, Denver, CO); *The Demonstration Project as a Procedure for Accelerating the Application of New Technology* (Charpie Task Force Report, U.S. DOE, Feb. 1978); Office of Technology Assessment, *The Role of Demonstrations in Federal R&D Policy* (U.S. Government Printing Office, Washington, DC 1978).

mance problems which technical personnel may consider routine are likely to exceed the expectations of the demonstration's nontechnical audience, thus discrediting the technology rather than advancing its cause. Another is the absolute necessity of defining the intended audience and determining precisely what is to be demonstrated — i.e., is the primary audience prospective manufacturers, suppliers, end users, investors, public agencies or someone else, and is the demonstration's central purpose to stimulate production, to create a market, to attract private or public capital, or some other objective? Finally, these studies confirm the importance of assessing the institutional environment into which the demonstrated technology is expected to fit, and particularly whether its adoption would continue or depart from basic traditions characteristic of that institutional setting.

Most of the questions raised by these studies have so far been addressed quite straightforwardly for the multi-megawatt fuel cell and its utility market. Here, an easily defined, technically sophisticated audience should be influenced by a properly conceived and executed demonstration. Both the manufacturers and the users have recognized the need to quantify fuel cells' special credits in order to determine their true value. Although Con Ed's federally-supported 4.8 MW demonstration in New York will not satisfy all the audience's questions, sales of pilot plants and perhaps some more aggressive demonstration program supported by the manufacturers could fill in the gaps. (This rather sanguine view of the value of demonstration to the commercialization of multi-megawatt fuel cells depends, of course, upon their performing as predicted.)

Demonstrating multi-kilowatt fuel cells presents a quite different set of problems largely because the potential audience is far broader and far more varied. To the extent that the performance to be demonstrated remains basically technical and economic and the audience continues to be largely the manufacturers and gas utilities, the demonstration remains subject to a relatively conventional set of arrangements and analyses. However, at some point in the commercialization process the demonstration may need to expand to include user attitudes and responses, and the audience may have to broaden to include potential end users themselves; these prospects present complex challenges for any demonstration project. If adoption and diffusion of fuel cells depends upon demonstrating their merits to an audience of energy users not now generating their own electricity, the demonstration faces one of the most difficult institutional environments. At this point, it remains an open question whether or not the 40 KW program currently planned can be structured to answer some of the regulatory, institutional and behavioral questions which may be crucial to widespread adoption of fuel cells by their ultimate users.

Government Markets and the "Big Buy"

Ironically, one of the government activities which has most successfully aided the commercial introduction of new products has done so inadvertently. The purchase by government agencies of the early production of UNIVAC and IBM computers, for instance, contributed vitally to the success of what was then a fledgling industry — but these purchases were motivated by government's need for information processing capabilities, not by a public policy decision to assist the struggling computer industry. Defense Department support for micro-chip development and subsequent purchases related to the design and manufacture of "smart" weaponry likewise were motivated by a shift in tactical planning and weapons requirements. In these and other cases, technological advances and lowered unit production costs which accelerated commercial introduction were unintended benefits.

Having observed this phenomenon, commercialization planners have tried to devise ways to use government purchases to assist new technologies into the marketplace. Programs such as the legislatively-mandated Federal Buildings Program have tried to guarantee that alternative energy sources would be used to satisfy some portion of federal energy needs. However, these conscious attempts to recreate accidental successes in commercialization have so far produced only limited results: a few solar-heated Veterans Administration hospitals have been built; some geothermal surveys have been performed at federal installations; part of the government motor pool has been required to use gasohol. These government purchases have been too small to significantly affect the development of the industries in question. They have, in fact, been much more on the order of demonstration programs in both scale and result than of government purchases, probably because the technologies involved have been marginal competitors in both the private and the government market.

The success stories of the computer and the micro-chip occurred where a need for information processing capabilities or national defense requirements created a real government market for the special characteristics of the new technology. Such a market can induce research which produces commercially successful applications of new technologies or can support investment in major production facilities which greatly accelerates their commercial introduction. The keys to this process are whether the innovation has characteristics that serve some substantial government requirement for additional capabilities and then whether the private sector can use those special characteristics. If both are true, then a commercialization situation exists which can properly and effectively be assisted by government purchases.

This approach to commercialization can work in cases where an innovation offering quantifiable benefits is passing through a transitional stage involving especially high risks, uncertainties or capital requirements in relation to the participants' capabilities. The predicted technical performance of fuel cells, the current stalemate in moving to commercial production, and DOD's expressed need for reliable, efficient, silent cogenerating equipment using domestically-produced fuels meet the criteria for effective commercialization through a federal "big buy."

C. Institutional and Legal Considerations

The importance of institutional factors has become part of the conventional wisdom in most studies of the adoption and diffusion of innovations. Under previous Administrations, work in this area has been the subject of continuing, if modest, direct support under the aegis of federal energy commercialization programs. This work has focused on identifying and ameliorating barriers to the introduction of promising technologies, and to a much lesser extent, on identifying institutional opportunities. It has proceeded in part from a recognition that some innovative energy industries were so embryonic that they had not yet defined the problems they were likely to encounter in dealing with institutional patterns and constraints developed over time without regard to today's energy imperatives, and that they were necessarily confronting one of the most heavily regulated environments in this country. Most commercialization planners by now have seen the possible impact on innovations of legal and regulatory decisions and institutional factors, and have recognized that real and perceived barriers to commercial acceptance do arise from these sources and from uncertainties about regulatory policies. The following discussion briefly examines the regulatory environment facing energy innovators and the resulting additional risks they confront in assessing markets for their technologies.

1. REGULATION AND EMERGING TECHNOLOGIES

Supply structures and consumption patterns surrounding energy are very deeply embedded in the larger structures of American society. Acquiring, producing, delivering and maintaining adequate supplies and pricing those supplies have profound domestic political consequences and momentous national security implications. The habits associated with energy consumption have shaped a way of life for this country's citizens and a way of operating in international politics, and significant changes affect huge segments of the populace and some of our largest and most powerful institutions.

Because of the enormous public interests involved, there is no more thoroughly regulated process in this country than the supply and consumption of energy. The regulatory framework encompasses the whole range of actual and potential participants from resource companies through equipment manufacturers, energy producers, transmitters, distributors, and end users. Myriad regulatory regimes provide complicated, multilevel avenues through which these different and often conflicting interests influence the process and are in turn affected by it. Regulation affects virtually every conceivable aspect of the process from environmental concerns to fuel uses and allocations, to financing and taxation, to rates and quality of service.

All of this should suggest that promising new energy technologies are a matter of supreme public interest, and that technological advances in the field — especially ones such as fuel cells which could fundamentally alter the practices of and relations among several major sectors of the structure — cannot possibly escape the effects of government policies already in place or future government actions. As the federal government reduces its participation, state, regional and local institutions which already play a significant role in energy regulation can be expected to assume a greater voice in directing the course of the adjustment in energy supply practices now clearly upon us.

Because of the critical importance of energy in an industrial society, pervasive regulation is likely to continue to be a fact of life for energy industries and for those dependent upon them. Thus despite current efforts to minimize the federal presence, energy innovations will continue to compete in a heavily regulated, highly structured, mature market. Ultimately, each must somehow find its place within a complex environment shaped by legislation, administrative policy, political pressures, and patterns of firmly fixed institutional and individual behavior. The need to address, to understand, and in some cases to alter these conditions to favor larger energy policy objectives provides part of the justification for commercialization activities.

2. MARKET UNCERTAINTIES AND INSTITUTIONAL FACTORS

The projected market justifying investment in a new energy technology may be a decade or more in the future. Long-range projections defining such markets have limited credibility in predicting both the timing and the ultimate magnitude of demand. Uncertainty over the application of existing regulatory policies and the direction of future policies adds to the "future noise" which obscures the analysis, and can present a serious disincentive to investment now by potential participants.

This is understandable, since the legal framework can dramatically alter the costs and benefits associated with new technologies, and can actually define what is possible. Federal legislation expressing national energy and environmental policy, state regulatory regimes, and local law allow certain activities and prohibit others; encourage participation by some entities and discourage it by others; and confer advantages on some institutional structures for energy supply while penalizing others. Those directly and substantially interested in the commercial success of a particular technology may be in a position to do the research needed to understand aspects of the existing legal framework which directly affect that technology. They may be able to analyze and assess the probabilities of changes occurring which would significantly alter the potential market for their product, and may even be in a position to help shape some of those changes. However, there are larger and less well understood legal and institutional issues which necessarily affect planning, and these tend to fall beyond the sphere in which most commercial enterprises are accustomed to dealing.

Essential services such as energy are customarily provided for users through an elaborate set of institutional, social and economic arrangements. Although some changes in production and supply patterns will have little impact on these arrangements, others can dramatically affect planning assumptions and development directions. For instance, shifts in the mix of large-scale generating capacity used by the major utilities still leave large corporate entities dealing with each other in familiar and conventional ways, while energy end users still turn on their switches, receive their customary supplies and accept their bills. Such shifts may cause problems for these large entities by exposing them, for example, to closer government scrutiny or to the intervention of anti-nuclear groups. Nevertheless, the fundamental system or production and distribution remains essentially untouched, and the basic issues facing commercial participants remain quite familiar.

In other cases far more dramatic effects can be expected. Legislation such as the Public Utility Regulatory Policies Act of 1978 (commonly known as PURPA, and discussed in detail in Chapter IV, *infra*) presents numerous specific issues requiring traditional legal analysis and business judgments by particular participants, but its overall purpose is to reshape the existing energy production and delivery system to accommodate a new group of possible entrants into the field. The prospect of such changes generates a novel and far-reaching set of questions about both institutional and individual behavior, where legislatively-created economic opportunities require tradeoffs between the costs of change and the comforts of inertia.

Although laws like PURPA generally result from pressure from groups and individuals with direct and substantial interests in institutional change for one set of reasons or another, the changes they induce provide opportunities for action by less committed energy users. These opportunities raise questions central to market assessment about the behavior of those people who, because of a new technology like the fuel cell, find themselves able to take advantage of a new law or regulation to enter an additional business or to provide themselves with a necessary product or service through an entirely new institutional structure.

In evaluating the likelihood that apartment developers or owners, for example, will consider on-site fuel cell services, cost and projected savings will be the threshold determinant, but other questions will arise. Will it solve or create problems that other energy options won't? How much trouble is it? Will it complicate relations with the tenants? Will the next owner value it? Will it entail doing business with unfamiliar and, perhaps, untrusted institutions? In assessing the tradeoffs that potential participants will make, the central issue may be the extent to which legal and institutional considerations allow fuel cell manufacturers or distributors to absorb the institutional costs while still producing savings for users and profits for themselves. In the final analysis, the answers to these questions will be balanced with technical and economic considerations in a complex equation. Framing that equation is a central task for market assessment planning, and fitting the results into a credible market analysis is properly the task of experts in the marketing field. However, defining the larger legal and institutional components which belong in the equation and examining their implications for other factors integral to a solution, is a task beyond the usual boundaries of commercial market analysis.

It is worth focusing on the uncertainties of market analysis because, in a sense, all other issues except technological performance are secondary. Put simply and obviously, the size and certainty of the market can go far toward justifying even the largest investment. In a survey of corporate managers of new product successes and failures, a Canadian study[2] found that the quality of market assessment activities and initial

[2]Robert G. Cooper, "Identifying Industrial New Product Success: Project NewProd," *Industrial Market Management*," 8:124-135.

marketing strategies form the most significant element in determining success or failure for new industrial products.

> Thus how well market-oriented activities are executed appears to be most critical in terms of determining the outcome of new industrial products. Overall, the five market-oriented activities ... have a mean correlation of 0.402, compared to 0.332 for the five technical-production activities and 0.340 for the two evaluation activities. (p. 131)

This survey goes beyond many other studies confirming the importance of market-related activities to eventual new product success, by examining the perceptions of managers as to how well they are served by such activities. In their views, two of the five market-related functions most important to success were the most poorly executed. These two, detailed market study/marketing research and test-marketing/trial selling, remain ahead for those working to bring fuel cells into the commercial market.

Mistrust of market projections, particularly long-range estimates in an area so volatile and so subject to regulatory intervention, is a critical barrier to the commercial introduction of fuel cells, both on-site and multi-megawatt. Research into, and analysis of, legal and institutional questions cannot remove that uncertainty, but it can narrow it substantially by identifying issues and providing a context for market research and testing. Such work thus becomes an extremely important precursor to shaping a credible assessment of potential fuel cell markets.

In approaching these questions, this report will focus first on perceived legal barriers of critical importance to all first-generation fuel cell applications, in the form of federal fuel use restrictions and natural gas pricing and curtailment policies. (Chapter III) The favorable resolution of these issues is in some sense the *sine qua non* for further commercialization efforts, since other issues would become moot if fuel restrictions were effectively to preclude fuel cell use. Since the analysis presented here indicates that that will not be the case, the report proceeds to an examination of the positive prospects for fuel cell commercialization, in the form of incentives and opportunities provided by the Public Utility Regulatory Policies Act and by current air quality regulatory regimes. (Chapter IV) Finally, the implications of the overall legal analysis for particular groups of participants in the commercialization process are explored, and recommendations for further action suggested, in Chapter V.

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III. PERCEIVED BARRIERS TO FUEL CELL USE: FEDERAL FUEL USE AND PRICING POLICIES

A. FEDERAL RESTRICTIONS ON PETROLEUM AND NATURAL GAS USAGE IN LARGE FACILITIES (PIFUA)

1. BACKGROUND

Following the oil embargo of 1973, the federal government undertook efforts to reduce the nation's reliance on costly and insecure foreign petroleum supplies, to conserve dwindling domestic oil and natural gas reserves, and to promote the development of abundant domestic coal resources.[3] In 1978, the U.S. Congress enacted the Powerplant and Industrial Fuel Use Act (PIFUA), which furthered these goals by restricting the use of petroleum and natural gas in "electric powerplants" and "major fuel burning installations" (MFBIs).

The following pages describe the workings of PIFUA's statutory provisions and the U.S. Economic Regulatory Administration's (ERA's) regulations implementing the Act, and explore the implications of their petroleum and natural gas use restrictions for the commercialization of fuel cells.[4]

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[3]Powerplant and Industrial Fuel Use Act of 1978 (PIFUA) §102(b).

[4]An EPRI-funded study has recorded utility industry concerns that federal fuel use restrictions such as PIFUA, and attendant uncertainties in the federal regulatory process, present significant impediments to the operation of fuel cells utilizing natural gas or naphtha or other petroleum products. (Energy Transition Corporation, *Commercializing the Utility Fuel Cell* (prepared for the Electric Power Research Institute, Contract No. TPS 79-760), January 1980.)

2. CURRENT RESTRICTIONS ON NATURAL GAS AND PETROLEUM USAGE

a. KEY TERMS

i. "Electric Powerplants" and "MFBIs"

Current regulations apply only to natural gas and petroleum usage in "electric powerplants" and "major fuel burning installations" ("MFBIs"), both of which are statutorily defined.[5] A fuel cell system must fall within one of these two definitions in order to be subject to the Act's fuel use restrictions. Two types of fuel cell systems will be tested against these definitions:

1. A fuel cell standing alone; and
2. A fuel cell used in conjunction with a waste heat recovery or supplemental-fired boiler.

A fuel cell system must satisfy *both* of the following two tests before it is regulated as an electric powerplant or MFBI:

Test One: Size of Facility

First, a single fuel cell unit must have a minimum fuel heat input rate of 1.056×10^{11} joules (100 million Btu (MMBtu)) per hour,[6] or a combination of such units (or of such units together with existing generating units) at the same site must each have a minimum input rate

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[5]See note 8, *infra*. Title IV of PIFUA (§§401-405) also authorizes ERA to prohibit, by rule or order, natural gas use in certain boilers producing steam for space heating and consuming at least 8.5×10^3 m^3 (300 Mcf) per day of natural gas. To date, ERA has not invoked this authority.

[6]10 CFR 500.2, 500.4; PIFUA §§103(a)(7)(A), (10)(A).

of 5.28×10^{10} joules (50 MMBtu) per hour and an aggregate rate of 2.64×10^{11} joules (250 MMBtu) per hour. Assuming a heat rate of 9.5×10^{6} joules (9,000 Btu) per KWH, to satisfy this test a fuel cell system would need to have an electric capacity exceeding 11 MW standing alone, or 5.5 MW if used in combination with other units with an aggregate capacity of more than 28 MW.[7] In short, the only fuel cell systems, if any, subject to PIFUA's provisions under current regulations are some multimegawatt systems.

Test Two: Type of Facility

Second, the fuel cell system must additionally consist of a "boiler," "gas turbine," "combined cycle unit" or "internal combustion engine" in order to come within existing statutory and regulatory definitions of electric powerplant or MFBI.[8] The definitions of these devices comport with normal industrial usage,[9] and it is doubtful that FERC or the courts could reasonably interpret them to cover fuel cells.

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[7]These would generally be limited to electric utility and certain large industrial fuel cell applications.

[8]"Electric powerplant" refers only to certain stationary generating units consisting of a boiler, gas turbine or combined cycle unit, which employ a generator to produce electric power for purposes of sale or exchange. (10 CFR 500.2; PIFUA §103(a)(7)(A))

"MFBI" is restricted to certain stationary units consisting of a boiler, gas turbine, combined cycle unit or internal combustion engine. (10 CFR 500.2; PIFUA §103(a)(10)(A))

[9]"Boiler" is "a closed vessel in which water is heated or vaporized to produce steam of one (1) percent or more quality." (10 CFR 500.2)

"Gas turbine" (or "combustion turbine") is "a unit that is a rotary engine driven by a gas under pressure that is created by the combustion of any fuel." (*Id.*)

"Combined cycle unit" is "a unit that consists of a combination of one or more combustion turbine units and one or more waste heat boilers with a substantial portion of the required energy input to the waste heat boiler provided by the exhaust gas from the combustion turbine unit(s)." (*Id.*)

"Internal combustion engine" is "a heat engine in which the combustion that generates the heat takes place inside the engine proper." (*Id.*)

Thus, since a fuel cell standing alone does not fit within any of the categories of "boiler," "gas turbine," "combined cycle unit," or "internal combustion engine," it cannot be considered an electric powerplant or MFBI subject to PIFUA's fuel use restrictions even if it exceeds the size threshold described above.

A boiler standing alone which produces thermal energy (e.g., process steam or heat) is an MFBI (hereafter, "boiler MFBI") if it meets the minimum fuel heat input rate criteria discussed above. A fuel cell cogeneration system which includes a supplemental-fired boiler to produce usable thermal energy, arguably might be considered a boiler MFBI.[10] On the other hand, a fuel cell cogeneration system with a waste heat recovery boiler (without supplementary firing) probably would not be considered a boiler MFBI, since the fuel cell standing alone would not be an MFBI and since the boiler itself would not require natural gas or petroleum as a fuel.[11]

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[10] It would not be an electric powerplant since the boiler does not employ a generator to produce electric power; instead, the boiler itself produces thermal energy.

ERA could, alternatively, apply the minimum fuel heat input rate criterion to the entire fuel cell system or to the boiler alone in order to determine whether MFBI regulations are triggered. As described in a later subsection, even if ERA decides that the fuel cell system or the boiler component of it constitutes an MFBI, a cogeneration exemption from PIFUA's fuel use restrictions should be readily obtainable in most instances.

[11] This interpretation is bolstered somewhat by an ERA pronouncement at the time it issued the current final rules for PIFUA in June 1980. Combined cycle units consist of one or more gas turbines and waste heat boilers, but the units are considered to be "nonboiler MFBIs" (as are gas turbines and internal combustion engines), which are subject to different PIFUA regulations than "boiler MFBIs." ERA had indicated in an interim rule prior to June 1980 that small amounts of supplementary firing would not cause a unit to lose its designation as a combined cycle unit. When pressed for a delineation of how much supplementary firing would be permissible, ERA proclaimed that it could not set an *a priori* maximum level,

ii. "Existing" and "New" Facilities

The PIFUA regulatory scheme distinguishes between "existing" and "new" facilities (powerplants or MFBIs). Generally, a facility's designation as "new," as opposed to "existing," hinges upon whether construction at the facility began after November 9, 1978.[12] A fuel cell cogeneration system whose components (fuel cell and boiler) are newly constructed will be considered a new boiler MFBI if it otherwise satisfies the MFBI criteria (subject to previously mentioned caveats).

ERA also deems "construction" of a new facility (a new combined cycle unit) to occur in the following two situations:[13]

- Addition of a waste heat recovery or supplemental-fired boiler to an existing combustion turbine unit;
- Addition of a combustion turbine as a heat source for an existing boiler.

By analogy, retrofitting a fuel cell to an existing boiler to create a cogeneration system may also constitute construction of a new facility: a new boiler MFBI.

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abrogated the interim rule and announced its intent to examine the issue on a case-by-case basis. (45 Fed. Reg. 38276, 38277 (June 6, 1980))

It would appear that a combined cycle unit is deemed to be a "nonboiler MFBI" because its waste heat boiler utilizes little or no natural gas and because its gas turbine component is a "nonboiler MFBI." By analogy, a fuel cell cogeneration system having a waste heat boiler without supplementary firing would not be an MFBI ("boiler" or "nonboiler") insofar as a fuel cell standing alone would not be an MFBI. By the same token, a fuel cell cogeneration system with a supplemental-fired boiler would be a "boiler MFBI."

[12] 10 CFR 500.2; PIFUA §§103(a)(8), (9), (11) and (12).

[13] 10 CFR 500.2; 45 Fed. Reg. 38276, 38277 (June 6, 1980).

b. **FUEL USE RESTRICTIONS FOR NEW MFBIs**

PIFUA calls for different use restrictions on natural gas and petroleum as "primary energy sources"[14] applying to the following four categories of facilities: "existing powerplants;" "new powerplants;" "existing MFBIs;" and "new MFBIs." The previous subsection indicated that at present most fuel cell systems will not be subject to PIFUA's restrictions, and that those systems which arguably might be subject to the Act would fall within the category of "new MFBIs."

For new MFBIs consisting of a boiler (hereafter "new boiler MFBIs"), ERA prohibits the use of petroleum or natural gas as a primary energy source.[15] ERA may, but so far has not acted to prohibit such use in new MFBIs consisting of a gas (combustion) turbine, combined cycle unit, or internal combustion engine.[16]

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[14]"Primary energy source" generally means the fuel or fuels used by a powerplant or MFBI. (10 CFR 500.2; PIFUA §103(a)(15).

[15]10 CFR 503.3(a); PIFUA §202(a).

[16]10 CFR 503.3(b); PIFUA §202(b).

The analysis to this point suggests that only multi-megawatt fuel cell systems arguably classifiable as boiler MFBIs would be subject to PIFUA's restrictions. These would be cogeneration systems with supplemental-fired boilers (or possibly with waste heat recovery boilers without supplemental firing). Whether consisting of newly constructed fuel cell and boiler components or of a fuel cell retrofitted to an existing boiler, these would most likely be considered new facilities. Such systems therefore would be subject to PIFUA's fuel use restrictions for new boiler MFBIs, unless exempt under other provisions of the Act. The following subsection describes exemptions which would enable most such facilities to escape these restrictions.

c. EXEMPTIONS FROM FUEL USE RESTRICTIONS

PIFUA empowers ERA to issue both temporary (5-10 years duration) and permanent exemptions from its restrictions to operators of new boiler MFBIs. Grounds for such exemptions include, among others, the unavailability of a reasonably priced supply of coal or other alternate fuel; inadequate fuel transportation or storage facilities at the facility site; and inability to comply with applicable environmental requirements.[17]

Additionally, the operator of a new boiler MFBI can seek a permanent exemption as a "cogeneration facility" on one of two alternate grounds (discussed below) after satisfying all of the

[17] 10 CFR 503.20 through 503.44; PIFUA §§211-214.

following <u>three general criteria</u>:

1. The facility produces electric power and any other form of useful energy (such as steam, gas, or heat) that will be used for industrial, commercial or space heating purposes;
2. Electricity generated by the facility constitutes more than 10 and less than 90 percent of its useful energy output; and
3. The facility operator does not sell or exchange 50 percent or more of its net electric output.[18]

All fuel cell cogeneration systems should satisfy the first criterion, and all or most should also satisfy the second. Fuel cell cogenerators who plan to sell 50 percent or more of their electric output to an electric utility and/or other entities could run afoul of the third. (See Chapter IV, *infra*.) Fuel cell systems deemed new boiler MFBIs which violate any of the above criteria would be ineligible for a "cogeneration facility" exemption.

The operator of a fuel cell system which satisfies all three of these criteria may seek such an exemption on <u>either</u> of the following two grounds:[19]

1. The oil or gas consumed by the facility is less than would be consumed in its absence; <u>or</u>
2. The "public interest" would be served by granting an exemption "because of special circumstances such as technical innovation or maintaining industry in urban areas."

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[18] 10 CFR 505.27. We have found no time period specified in the regulations over which the percentages noted are to be calculated.

[19] *Id.*

Fuel cell cogeneration systems may have some difficulty in qualifying on the ground of oil and/or natural gas savings. The regulations require complicated calculations for demonstrating fuel savings. The oil and gas usage to be displaced by the cogeneration facility may come from one or more of the following types of facilities: existing or new facilities which are too small to be covered by PIFUA (i.e., those with fuel heat input rates less than 1.056×10^{11} joules (100 MMBtu) per hour); existing facilities subject to PIFUA which cannot burn an alternate fuel such as coal and which will be retired when an exemption is granted; new facilities which would be eligible for a PIFUA exemption; and powerplants whose electrical energy supplied to the grid will be displaced by the cogeneration facility, based on a 10-year forecast of utility loads and resources.[20] An industrial firm with no existing oil and/or gas-fueled facilities to retire, located in a utility service area with high projected electric demand growth, may be hard pressed to demonstrate net oil and gas savings from a multimegawatt fuel cell cogeneration system operating on natural gas or naphtha.[21]

Fuel cell cogeneration systems should, however, be able to qualify on "public interest" grounds, since they utilize an innovative electrochemical approach to electrical and thermal energy production to achieve unusually high efficiencies with only nominal air pollutant emissions, which in turn can promote industrial growth in urban areas

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[20] 10 CFR 505.27(c).

[21] Insofar as it is a product derived from crude oil, naphtha is a form of "petroleum" subject to PIFUA's fuel use restrictions. 10 CFR 500.2; PIFUA §103(a)(4).

with severe air quality problems that hamper the use of conventional energy technologies.[22]

To summarize, multimegawatt fuel cell facilities employing supplemental (and conceivably waste heat recovery) boilers for cogeneration arguably could be subject to PIFUA's fuel use prohibitions as new boiler MFBIs, but most should be able to obtain permanent exemption as "cogeneration facilities" on "public interest" grounds. Facilities which cannot qualify for this exemption (generally because of planned sales of 50 percent or more of their electric output) will need to obtain a permanent exemption on an alternative basis, such as inability to comply with applicable environmental requirements,[23] or face the PIFUA prohibitions on new boiler MFBIs using natural gas or petroleum (e.g., naphtha). The practical effects of these restrictions for large utility or industrial fuel cell systems may be to discourage cogeneration activities requiring the use of supplemental (or possibly waste heat recovery) boilers using natural gas or petroleum derivatives; to limit anticipated electricity sales to 50% of output to qualify for a cogeneration exemption; or, where on-site electrical demand would be significantly less than 50 percent of the system's electrical output, to down-size the system to achieve a high capacity factor.

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[22] See Appendix for a discussion of metropolitan "nonattainment" areas where fuel cells may have a marketable advantage over conventional energy technologies in the industrial sector.

[23] ERA has recently proposed the streamlining of the criteria for obtaining a permanent exemption based on inability to comply with applicable environmental requirements: the facility operator can file with ERA a certification stating that the facility is located in a "nonattainment area" or a "Class I attainment area" or that the facility would cause or contribute to violations of ambient air quality standards in a nonattainment or Class I area if it were forced to utilize coal or another alternate fuel. (46 Fed. Reg. 31216; July 12, 1981.) See Appendix for detailed discussion of air quality regulations affecting fuel cells.

3. PROPOSED MODIFICATIONS OF THE CURRENT SCHEME

In the 1981 session of Congress, House Republicans announced, but later canceled, plans to repeal PIFUA's fuel use prohibitions for new boiler MFBIs.[24] However, during its budgeting activities, the Congress did repeal §301(a)(1) of PIFUA which prohibited "existing powerplants" from using natural gas after 1990.[25]

The White House Cabinet Council on Natural Resources and Environment in its "Strategy Paper on Natural Gas Deregulation" (July 28, 1981) called for the repeal of PIFUA's natural gas use restrictions for existing and new MFBIs and electric powerplants. In the Council's words, "[t]his proposal could be part of a broader effort to seek repeal of [PI]FUA altogether."[26] The coal industry could oppose efforts to repeal PIFUA since the Act encourages the conversion of facilities to coal, but the Council opined that the industry might not do so if the Administration pushes for full decontrol of domestic gas prices by 1985.[27]

It seems likely that within the next few years the Administration will push for PIFUA's repeal, whether in a broad-brush or piecemeal fashion. Whether it will be able to attain this goal is not clear at this point.

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[24] *Energy Users Report*, July 9, 1981, p. 1060.

[25] *Id.*, August 20, 1981, p. 1321.

[26] *Id.*, August 27, 1981, pp. 1329, 1342.

[27] *Id.*, p. 1342.

4. IMPLICATIONS FOR FUEL CELL COMMERCIALIZATION

The previous discussion, summarized in Figure III-1, establishes several points regarding the application of PIFUA's fuel use prohibitions to fuel cell systems:

A fuel cell standing alone, irrespective of the magnitude of its generating capacity, is not subject to PIFUA.

Certain multimegawatt fuel cell cogeneration systems with supplemental-fired boilers (or possibly waste heat recovery boilers) which are classifiable as "new boiler MFBIs" may be subject to PIFUA's prohibitions on the use of natural gas or petroleum-derived fuels. However, these facilities generally should be able to obtain permanent exemptions as "cogeneration facilities" on "public interest" grounds. To qualify, fuel cell operators must restrict electrical energy sales to others (e.g., local electric utilities or industrial purchasers) to 50 percent or less of their facilities' electrical output: this restriction will tend to cause potential operators of fuel cell systems to down-size the planned capacity of their facilities. Some operators, however, can escape this restriction on electricity sales, if they can qualify for a permanent exemption from PIFUA's prohibitions on an alternative ground such as environmental restrictions on the use of coal or another non-oil or -gas fuel in their area.

The possible legislative or regulatory abrogation of PIFUA fuel use restrictions on "new MFBIs" prior to the initial commercialization phase for fuel cells would obviate the need for operators of fuel cell cogeneration systems utilizing natural gas, naphtha or other petroleum products to apply to ERA for permanent exemptions.

FIGURE III-1

PIFUA APPLICATION TO FUEL CELL SYSTEMS

Does system use natural gas or petroleum (e.g., naphtha)?

No → PIFUA does not apply.

Yes ↓

Does fuel heat input rate equal or exceed 1.056×10^{11} joules (100 MMBtu) per hour (11 MW) for a single unit, or 5.28×10 joules (50 MMBtu) per hour (5.5 MW) for each unit in combination aggregating 2.64×10 joules (250 MMBtu)?

No → PIFUA does not apply.

Yes ↓

Does system include attached boiler?

No → PIFUA does not apply.

Yes ↓

Is boiler supplemental-fired with natural gas or petroleum?

No → PIFUA does not apply.

Yes ↓

Does system qualify for permanent "cogeneration facility" exemption?

Yes → System is exempt if operator sells less than 50% of electrical output ("downsizing" effect).

No → Does system qualify for some other exemption (e.g., inability to comply with environmental requirements)?

- *Yes* → System is exempt.
- *No* → System may be subject to PIFUA's prohibitions on natural gas and petroleum use in "new boiler MFBIs."

B. FEDERAL NATURAL GAS PRICING AND CURTAILMENT POLICIES (NGPA TITLES I, II, AND IV)

1. DECONTROL AND INCREMENTAL PRICING (NGPA TITLES I AND II)

a. BACKGROUND

In 1978, the Congress enacted Title I of the Natural Gas Policy Act (NGPA) to reverse the decline in domestic production and reserves of natural gas. NGPA Title I substantially modified pre-existing price controls on domestic gas which were perceived to present economic disincentives for exploration and development (E&D) efforts. Gas producers would henceforth be able to obtain substantially higher prices for newly produced domestic gas as a reward for expanded E&D activities. As of 1985, the price of this "new gas" would be decontrolled and allowed to reach market clearing levels.

At the same time, Title II of NGPA was enacted to ensure that high-priority gas customers such as residential and commercial gas users would be at least partially shielded from the domestic gas price increases that would result inevitably from the implementation of the phased price decontrol schedule in Title I. Title II called for a surcharge to be imposed upon certain industrial gas users so that their gas supplies would be priced incrementally higher than those of high-priority gas users.

The following sections describe the workings of the current NGPA Title I and Title II programs, review proposed modifications to these programs, and suggest their implications for fuel cell commercialization.

b. DECONTROL OF DOMESTIC WELLHEAD PRICING OF NATURAL GAS (NGPA TITLE I)

i. Current Price Decontrol Schedule

Title I establishes a schedule for the phased decontrol of wellhead prices paid by gas pipeline operators to domestic producers for certain categories of natural gas.[28] Specifically, the act gradually deregulates the wellhead price of categories of domestic natural gas produced after 1977 ("new gas"). Starting with a base price of $1.75 per MMBtu in April 1977, the price of such categories of new gas is permitted to rise at a rate tied to the annual rate of inflation.[29] On January 1, 1985, these price controls are scheduled to be completely removed,[30] and new gas would be permitted to command whatever price the market would bear.

NGPA continues the pre-NGPA price controls on categories of natural gas produced prior to 1977 ("old gas"), but permits an annual upward adjustment linked to the general rate of inflation.[31] These price controls on old gas, unlike those on new gas, will continue indefinitely after 1985. These restrictions on old gas prices were designed by the Congress to prevent windfall profits to producers of old gas which would have resulted if gas produced prior to the NGPA's

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[28] NGPA §§101 *et seq.*; 18 CFR parts 270-272.

[29] NGPA §§102 and 103.

[30] *Id.*, §121. However, the President or the Congress has the authority to reimpose price controls in 1985. *Id.*, §122.

[31] *Id.*, §§104 and 105.

enactment could receive the higher price of new gas. Congress believed that gas producers should only be rewarded with higher prices for gas resulting from new, risky capital investments in exploration and development efforts.

ii. Proposals to Accelerate Decontrol

A key purpose of the NGPA approach to decontrol of new gas prices was to ensure that just prior to the lifting of price controls for such gas in 1985, its controlled price would approximate its decontrolled or free market price.[32] Since the passage of NGPA, however, the decontrol of domestic petroleum prices coupled with OPEC oil price increases has resulted in a situation whereby decontrol in 1985 would produce a sharp spike in new gas prices. Current estimates for the 1984 controlled and decontrolled prices (current 1984 dollars) of new gas are roughly \$3.50 per 1.056×10^9 joules (1 MMBtu) and \$7.00 per 1.056×10^9 joules, respectively.

The White House Cabinet Council on Natural Resources and Environment, chaired by Interior Secretary James Watt, is concerned that the occurrence of such a price spike for decontrolled new gas in 1985 could lead to the reimposition of price controls thereafter.[34] On July 28, 1981, the Council submitted, for internal review by the Administration, a strategy paper on natural gas deregulation proposing the complete decontrol of both new and old gas prices by 1985, with a phase-out

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[32] *Energy Users Report*, July 23, 1981, p. 1121.

[33] *Id.*, September 3, 1981, p. 1358.

[34] *Id.*, July 23, 1981, p. 1121.

of price controls during 1982-85 designed to avoid price spikes.[35]

The strategy paper proposes that old gas prices be increased relatively uniformly over a 36-month period until old gas attains a target price in 1985 pegged to 70 percent of the average U.S. refiner acquisition cost of crude oil, at which time price controls would be eliminated.[36] In short, the historically low, controlled price levels for old gas would be lifted to approach the market price of petroleum by 1985.

As to new gas, the Council suggests three options for the accelerated phase-out of price controls, permitting specified categories to immediately receive the target price tied to refiners' petroleum acquisition costs.[37] With each of the three options, full price decontrol of all new gas (post-1977) would occur in 1985. The strategy paper reports that, in 1982, average new gas prices (constant 1980 dollars) for three options would range from \$2.70 per 1.056×10^9 joules (1 MMBtu) (Option 3) to \$3.50 per 1.056×10^9 joules (Option 1), as compared with a fully decontrolled price of \$4.70 per 1.056×10^9 joules. By 1985, for all three options, the average price of new gas would exceed \$5.00 per 1.056×10^9 joules (constant 1980 dollars).[38]

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[35] *Id.*, August 27, 1981, pp. 1338-1343.

[36] *Id.*, pp. 1338-1339.

[37] Under Option 1, gas from all wells drilled after 1977 receives the target price in 1982. Under Option 2, only gas from certain classes of these wells receives the target price in 1982. Under Option 3, only gas from wells drilled after January 1982 receives the target price. (*Id.*, p. 1339)

[38] *Id.*, p. 1342.

While the final form of an Administration decontrol proposal and its prospects for success in the Congress are open questions,[39] at a minimum new gas prices will be deregulated by 1985 under the current NGPA scheme, and will dominate domestic gas pricing as supplies of old gas decline. In short, the average price of domestic natural gas will eventually reach parity with the market price of petroleum and will rise in response to OPEC pricing decisions and other events on the global petroleum market. While some of the implications of these developments seem clear enough on their face, their meaning for fuel cell commercialization can be better understood in the full context of NGPA's incremental pricing provisions and their possible repeal, discussed in the following sections.

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[39]The Cabinet Council recognizes that an Administration proposal for immediate price decontrol of all domestic natural gas could face insurmountable opposition within the Congress unless a windfall profits tax accompanied it. (*Id.*, July 23, 1981, p. 1121) As a result, the President may propose some form of phased price decontrol following one of the options outlined in the Council's strategy paper. (*Id.*, October 1, 1981, p. 1451) Sen. James McClure, Chairman of the Senate Energy Committee, has indicated that Congress probably would not enact any decontrol proposal until after the 1982 election year because of the potential political fallout of the decontrol issue. (*Id.*, September 24, 1981, p. 1432)

c. INCREMENTAL PRICING OF INDUSTRIAL NATURAL GAS (NGPA TITLE II)

i. Current Incremental Pricing Scheme

As noted earlier, NGPA Title II[40] was enacted partially to shield high-priority natural gas customers (e.g., residential and small commercial customers) from the price increases under the phased decontrol schedule, by passing through, via surcharge, a portion of the wellhead price increases to certain industrial facilities utilizing natural gas as a fuel to produce steam or electricity.

Industrial Gas Surcharge

The surcharge imposed by a gas distribution utility upon certain industrial customers is computed as follows. NGPA specifies an incremental pricing threshold (\$1.48 per 1.056×10^9 joules (1 MMBtu) as of March 1978, adjusted upward periodically for inflation).[41] A utility's acquisition costs for domestic new gas and for imported natural gas which exceed this threshold become a surcharge, which is passed through to operators of most "industrial boiler facilities."[42] However, the surcharge may not cause such a facility's natural gas costs to exceed a regional "alternative fuel cost" determined by FERC based on the regional price of high sulfur residual (No. 6) fuel oil.[43] The following list

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[40] NGPA §§201 *et seq.*

[41] NGPA §203(c).

[42] NGPA §§201(a)-(c), 203(a). See below for a discussion of types of facilities (including fuel cell systems) deemed to be "industrial boiler fuel facilities."

[43] NGPA §204(c), (3); 46 Fed. Reg. 38912 (July 30, 1981).

illustrates the current regional variability in "alternative fuel costs":[44]

STATE/REGION	ALTERNATIVE FUEL COST ($/1.056 X 10^9 joules)($/MMBtu) (October 1981)
Texas	2.99
Colorado	3.43
California	3.47
Illinois	3.70
New Jersey	3.82
New England	4.00

Industrial Boiler Fuel Facility

"Industrial boiler fuel facilities" subject to the surcharge are generally industrial plants, mills, refineries or other industrial complexes utilizing natural gas in boilers to generate steam and/or electricity.[45] The definition of "boiler fuel use" is, however, sufficiently open-ended so as to potentially include as well nonboiler

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[43]NGPA §204(c), (3); 46 Fed. Reg. 38912 (July 30, 1981).

[44]*Energy Users Report*, October 1, 1981, p. 1458.

[45]Relevant terms are defined as follows:

"Industrial boiler fuel facility": "any industrial facility, as defined by the Commission [FERC], which uses natural gas as a boiler fuel and which is not exempt under [NGPA] §206." (NGPA §201(c)(1))

"Boiler fuel use": "the use of any fuel for the generation of steam or electricity." (*Id.*, §201(c)(2))

"Industrial facility": "any facility engaged primarily in the extraction or processing of raw materials, or in the processing or changing of raw or unfinished materials into another form or product." (18 CFR 282.103(d)(1))

"Facility": "all buildings and equipment located at the same geographic site which are commonly considered to be part of one plant, mill, refinery or other industrial complex." (18 CFR 282.103(c))

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equipment located at industrial facilities, which utilizes natural gas to generate steam and/or electrical energy. A natural gas-fired fuel cell standing alone at an industrial site possibly could be considered an industrial boiler fuel facility under the terms of NGPA Title II. At a minimum, a cogeneration system located at an industrial site and consisting of a fuel cell and a (supplemental-fired or waste heat recovery) boiler would technically be considered an industrial boiler fuel facility, at least with respect to the boiler's use of natural gas (and perhaps with respect to the fuel cell's use of natural gas as well).

Exempted Facilities

Natural gas used for specified purposes and/or by specified end-users is expressly exempted from the incremental pricing provisions of NGPA Title II and therefore escapes the surcharge. Gas used by the following facilities is or can be exempted:[46]

- Electric utilities, for electricity generation
- "Small industrial boiler fuel facilities"
- "Qualifying cogeneration facilities"
- Schools, hospitals and similar institutions
- Agricultural uses lacking alternative fuels or feedstocks

Electric utilities can obtain exemptions for natural gas used for electricity generation, and therefore should have no trouble securing an exemption for a fuel cell standing alone which produces electricity

[46] 18 CFR 282.203; NGPA §206.

but no usable thermal output. If an electric utility-owned fuel cell system also produces usable thermal output, it is conceivable that this exemption would be limited to the portion of its natural gas input used to produce electricity, and would not extend to that used to produce thermal energy in a waste heat recovery or supplemental-fired boiler attached to the fuel cell — an issue which FERC has not yet had occasion to address.

"Small industrial boiler fuel facilities" are those with average daily natural gas usage of 8.5×10^3 cubic meters (300 Mcf) or less.[47] A fuel cell system otherwise deemed an industrial boiler fuel facility but which meets this criterion could obtain an exemption from the industrial gas surcharge. Assuming a heat input rate of 9.5×10^6 joules (9,000 Btu) per KWH, such a system could have a maximum operating capacity of up to 1.4 megawatts.[48]

Some industrial fuel cell applications are expected to have capacities exceeding 1.4 megawatts. However, many of these multimegawatt systems should be able to avoid the surcharge under Title II's exemption for "qualifying cogeneration facilities" meeting the criteria established by §201 of the Public Utility Regulatory Policies Act (PURPA) and its implementing regulations (discussed in section IV.B., *infra*).[49] Industrial fuel cell systems which cannot qualify for this exemption — either

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[47] 18 CFR 282.203(a)(1), (b)(2).

[48] $$1.4\ \mathrm{MW} = \left[\frac{8.5 \times 10^3\ \mathrm{m}^3}{\mathrm{day}}\right]\left[3.8 \times 10^{-1}\ \mathrm{joules}\right]\left[\frac{1.056 \times 10^9\ \mathrm{joules}}{2.83 \times 10\ \mathrm{m}^3}\right]\left[\frac{\mathrm{day}}{24\ \mathrm{h.}}\right]$$
$$\left(= \left[\frac{300\ \mathrm{Mcf}}{\mathrm{day}}\right]\left[\frac{\mathrm{KWH}}{9\ \mathrm{MBtu}}\right]\left[\frac{\mathrm{MMBtu}}{\mathrm{Mcf}}\right]\left[\frac{\mathrm{day}}{24\ \mathrm{h.}}\right]\right).$$

[49] NGPA §206(c); 18 CFR 282.202(e).

because they do not cogenerate or because their ratio of electrical and thermal outputs does not satisfy PURPA's criteria — would be subject to the gas surcharge. Fuel systems owned more than 50% by electric utilities are not "qualifying" facilities under PURPA rules, and could not obtain exemption on this ground.

Conclusion

Fuel cells may or may not be deemed to be "industrial boiler fuel facilities." Even if they are, most fuel cell systems probably will be eligible for a surcharge exemption under one of the exemption categories, including "small industrial boiler fuel facilities," "qualifying cogeneration facilities," or electric utility power generation systems. Only electric utility fuel cell cogeneration systems and certain industrial fuel cell noncogeneration and cogeneration systems larger than 1.4 megawatts seem likely to encounter some difficulties escaping a surcharge. If imposed, the surcharge would cause natural gas fuel costs for such systems to rise to a maximum level equivalent to the regional price of high-sulfur residual (No. 6) fuel oil.

ii. Proposed Repeal of Incremental Pricing

The incremental pricing program has not been effective in shielding high-priority natural gas customers from price increases due to phased decontrol. Currently, only 1500 industrial facilities nationwide, or 7 percent of the interstate gas market, are *not* exempt from the industrial gas surcharge.[50] Consequently, gas price increases (due

[50] *Energy Users Report*, July 30, 1981, pp. 1169, 1170.

to phased decontrol) which are in excess of allowable surcharges levied on nonexempt gas users are being passed through to exempt gas users, including high-priority gas customers such as residential and commercial users.

A rule proposed by FERC in 1980 which would have expanded to more than 50,000 the number of industrial facilities subject to incremental pricing was vetoed in the Congress.[51] This veto reflected Congressional discontent with the pricing program. Indeed, FERC's own current chairman, C.M. Butler III, recently declared that "incremental pricing is a failure" and called for complete deregulation of the domestic natural gas market.[52]

The White House Cabinet Council on Natural Resources and Environment included in its recent "Strategy Paper on Natural Gas Deregulation" a recommendation to the Administration to repeal outright the NGPA Title II incremental pricing program.[53] The U.S. Department of Energy has indicated that the Administration is in fact leaning toward endorsing this proposal.[54]

Questions remain as to whether and when the incremental pricing program will be substantially modified or totally repealed. Its

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[51] 45 Fed. Reg. 31622 (May 13, 1980); NGPA §202; *Energy Users Report*, May 22, 1980, p. 3.

[52] *Energy Users Report*, July 30, 1981, pp. 1173, 1174.

[53] *Id.*, August 27, 1981, pp. 1338-1339.

[54] *Id.*, p. 1329.

apparent failure as a price-shield suggests that the program's continuation would do little in any event to mitigate the severity of price increases borne by high-priority gas customers in the late 1980s and thereafter, even under the current domestic gas wellhead price decontrol program.

d. IMPLICATIONS FOR FUEL CELL COMMERCIALIZATION

The following two plausible alternative scenarios for domestic natural gas pricing in the late 1980s and thereafter, while substantially different in regulatory terms, appear to converge to the same ultimate result:

Scenario 1: Indefinite continuation of the current NGPA Title I and Title II programs (Status Quo Scenario)

Scenario 2: Decontrol of all domestic gas wellhead pricing as of 1985 and repeal of NGPA Title II (Decontrol Scenario)

In the "Status Quo Scenario," pricing of domestic new gas (post-1977) will be decontrolled in 1985, while price controls on old gas (pre-1977) will be maintained indefinitely. Domestic old gas supplies will, however, decline naturally, and new gas supplies priced at market clearing levels will elevate the average price of domestic gas to parity with world market prices for petroleum after 1985. The open question is not whether the current phased decontrol program will cause domestic gas prices to approach petroleum market price levels, but rather when this will occur. In any event, the current incremental pricing program will not shield high-priority gas customers such as residential and commercial gas users from these price increases.

In the "Decontrol Scenario," both domestic new gas and old gas prices are completely decontrolled in 1985 (following a gradual phase-out of controls during 1982-85), and the incremental pricing program is repealed. The only real difference between this scenario and the "Status Quo" one is the time period in which domestic gas prices reach parity with global oil prices. In the "Decontrol Scenario," parity will be attained in 1985, rather than at some indefinite time during the late 1980s or early 1990s.

The implications for fuel cell commercialization are clear cut. Assuming that fuel cells begin to reach the commercial market in the mid- to late 1980s, all potential fuel cell operators — be they residential, commercial, industrial or other — considering natural gas as a fuel will be facing natural gas prices which are equal to, or approaching in the near term, the decontrolled price of petroleum. Domestic gas prices in the late 1980s and thereafter will be inextricably linked with OPEC oil pricing decisions and other events in the global petroleum market. The resultant premium prices for natural gas (and petroleum products such as naphtha and distillate and residual fuel oils as well) can be expected to adversely affect the economics of fuel cell system operation.

Since these prices will also affect conventional generation and cogeneration technologies using natural gas or petroleum fuels, a central issue for fuel cell commercialization will continue to be the relative impact of these developments on fuel cells vis à vis competing fossil-fueled options. To the extent that the Administration's decision to reduce federal support for commercialization activities or other factors cause fuel cell schedules to slip beyond current target dates. comparisons already undertaken in this area are likely to be less and less useful, and will need to be reviewed and updated in any event as the current Administration's actions in this area begin to take more concrete shape and their consequences become clearer.

The economic consequences of decontrol under either scenario also underscore the need, already recognized by DOE, NASA/Lewis, fuel cell manufacturers and utility users groups, to develop capabilities for operation on fuels such as methane which can be derived from nonfossil sources. Although this study has not attempted to quantify the "special credits" theoretically available from fuel cells, it seems clear from our work that the absolute and relative values of particular "credits" (e.g., modularity, response times, or air quality benefits) will vary greatly among different types of users, so that in many cases the fuel cell will be competing largely on the basis of cost and energy efficiency alone. Where this is true, a nonfossil fuel capability may be a more powerful inducement to fuel cell use than any of the unique features characteristic of the technology.

2. NATURAL GAS CURTAILMENT (NGPA TITLE IV)

a. INTRODUCTION

In 1973, the Federal Power Commission (FPC) utilized its authority under the Natural Gas Act (15 U.S.C. §717 *et seq.*) to institute a natural gas curtailment priority scheme governing the allocation of natural gas supplies to customers of interstate pipelines during serious natural gas supply shortfalls (generally occurring in winter heating seasons). The FPC scheme ranked natural gas end users as high-priority or low-priority based on the importance of gas used to protect health, safety and other human needs; the operational difficulty of curtailing service to various customer classes; and the costs that different kinds of end users would experience in converting to an alternative fuel.[55]

The present natural gas curtailment scheme is similar to that originally promulgated by the FPC, although it is somewhat more elaborate and reflects a shifting of certain priority categories under the terms of NGPA Title IV. The following discussion first describes the classes of natural gas users within each gas curtailment priority category, starting with the highest priority (Priority One or P1) category, and relates each priority category to particular types of fuel cell applications. It then reviews proposed modifications in the current scheme as well as the Administration's position on the need for a priority scheme. Finally, it suggests the implications of the curtailment priority scheme for the marketability of fuel cells utilizing natural gas among different priority classes of natural gas users.

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[55] *Energy Users Report*, July 2, 1981, p. 1040. The Economic Regulatory Administration (ERA) within the U.S. Department of Energy has the current responsibility for reviewing and modifying the curtailment priority scheme according to the terms of Title IV of the Natural Gas Policy Act of 1978 (NGPA) (15 U.S.C. 3301 *et seq.*). The FPC's successor agency, the Federal Energy Regulatory Commission (FERC) presently administers and implements the curtailment policies promulgated by ERA.

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b. EXISTING CURTAILMENT PRIORITY SCHEME

The present natural gas curtailment priority scheme is summarized in Table III-1. During a natural gas supply shortfall the gas requirements of all customers in the P1 category are completely satisfied before those of P2 and lower priority categories, and so forth, through the lower priorities (P3, P4, etc.).

TABLE III-1

FERC NATURAL GAS CURTAILMENT PRIORITY SCHEME FOR DIRECT SALE, LOCAL DISTRIBUTION COMPANY AND INTERSTATE PIPELINE CUSTOMERS OF INTERSTATE PIPELINE SUPPLIERS

PRIORITY ONE (P1):

- Residences
- Small commercial establishments (including institutions and local/state federal government agencies): $< 1.42 \times 10^3$ m^3 (50 Mcf) per day (peak) and natural gas for purposes other than those involving manufacturing or electric power generation
- Schools
- Hospitals (including nursing and convalescent homes)
- Police; fire; sanitation and correctional facilities

PRIORITY TWO (P2):

- Essential agricultural use requirements (as determined by Secretary of Agriculture)

PRIORITY THREE (P3):

- Large commercial requirements ($\geq 1.42 \times 10^3$ m^3 (50 Mcf) per day (peak))
- Firm industrial requirements for plant protection, feedstock and process needs
- Pipeline customer storage injection requirements

PRIORITY FOUR (P4):

- All industrial requirements not specified in Priorities 3, 5, 6, 7, 8, 9 or 10

PRIORITY FIVE (P5):

- Firm industrial requirements for boiler fuel use at $< 8.5 \times 10^4$ m^3 (3,000 Mcf) per day, but $> 4.25 \times 10^4$ m^3 (1,500 Mcf) per day where alternate fuel capabilities can meet such requirements

PRIORITY SIX (P6):

- Firm industrial requirements for large volume ($\geq 8.5 \times 10^4$ m^3 (3,000 Mcf) per day boiler fuel use where alternate fuel capabilities can meet such requirements

PRIORITIES SEVEN - TEN (P7 - P10):

- Interruptible requirements of $> 8.5 \times 10^3$ m^3 (300 Mcf) per day, where alternate fuel capabilities can meet such requirements.

i. Priority One (P1)

The highest priority or P1 natural gas end users include residences, small commercial establishments, schools, hospitals, police and fire protection, and sanitation and correctional facilities.[56] For purposes of our analysis, the P1 users of central interest are residences, small commercial establishments, schools and hospitals.

Residences

The current scheme defines "residence" as "a dwelling using natural gas predominantly for residential purposes such as space heating, air conditioning, hot water heating, cooking, clothes drying, and other residential uses, and includes apartment buildings and other multi-unit buildings."[57] The definition of "residence" does not differentiate between natural gas utilized directly for "residential purposes" (e.g., by direct combustion of natural gas in a household appliance such as a gas stove or gas-fired furnace) and natural gas utilized indirectly for "residential purposes" by conversion into an intermediate energy form (e.g., by combustion of natural gas in a steam turbine-generator or gas turbine-generator to produce electricity for electric household appliances).[58]

Accordingly, reading the definition of "residence" by itself,

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[56] 10 CFR 281.203(a)(5); Natural Gas Policy Act of 1978 (NGPA) §401(f)(2).

[57] 10 CFR 281.203(a)(8); emphasis added).

[58] The old FPC definition of "residential" gas service applied only to "direct natural gas usage in a residential dwelling." 18 CFR 2.78(c)(1); emphasis added).

one may conclude that fuel cells operating on natural gas in an apartment building or other residence should be accorded P1 curtailment priority status, so long as they utilize the natural gas "predominantly for residential purposes" on the site. If granted P1 status, this type of residential fuel cell application would be insulated from most conceivable natural gas shortfalls.

As noted below, pre-NGPA regulations still in effect define utility service to natural gas customers "engaged primarily in . . . the generation of electric power" as low-priority "industrial" service (18 CFR 2.78(c)(3). According to FERC staff, this language does *not* refer to the output mix of a particular facility — i.e., "primarily" electric power rather than steam or other thermal output — but to the customer's "primary" business activity. Specifically, FERC interprets this provision to refer to the primary business activity of generating power for sale and distribution off-site.[59] Thus, this provision could result in reclassification of high-priority residential or apartment usage to low-priority industrial usage only where the latter criterion is met, independent of the facility's output mix.

Small Commercial Establishments

P1 status is also granted to "commercial establishments" (including institutions and local, state and federal agencies) with peak

[59] Personal communication from FERC staff member Mr. James Keily, October 1981. This interpretation is consistent with FERC's interpretation of similar language in PURPA §201 and 18 CFR §292.206.

daily gas requirements less than $1.4 \times 10^3\ m^3$ (50 Mcf).[60] However, these entities may *not* include in their P1 requirements natural gas utilized for manufacturing or electrical generation.[61] Consequently, these entities' fuel cell requirements are ineligible for P1 gas allocations and will be curtailed as P4 (or lower) end uses during a natural gas supply shortfall.[62]

Schools and Hospitals

Schools[63] and hospitals[64] are also designated as P1 natural gas users. Unlike "small commercial establishments," schools and hospitals are not explicitly precluded from utilizing P1 natural gas

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[60] 10 CFR 281.203(a)(9). As a point of reference, a 230-KW fuel cell system with a heat rate of 9.5×10^6 joules (9,000 Btu) per KWH would use $1.4 \times 10^3\ m^3$ (50 Mcf) per day of natural gas (1.056×10^9 joules/$2.83 \times 10\ m^3$)(or, 1 MMBtu/Mcf) operating at full capacity.

[61] "Commercial" service is service to natural gas customers "engaged primarily in the sale of goods or services including institutions and local, state, and federal government agencies for uses other than those involving manufacturing or electric power generation." (18 CFR 2.78(c)(2); emphasis added.)

[62] In fact, it is possible that a "small commercial establishment" using a fuel cell in addition to other gas-fired equipment could lose its P1 status entirely, if FERC were to interpret the $1.4 \times 10^3\ m^3$ (50 Mcf) per day ceiling as applying to its aggregate gas requirements (fuel cell plus non-fuel cell requirements).

[63] "'School' means a facility, the primary function of which is to deliver instruction to regularly enrolled students in attendance at such facility. Facilities used for both education and noneducational activities are not included under this definition unless the latter activities are merely incidental to the delivery of information." (10 CFR 281.203(a)(11)) FERC has ruled that dormitories, administration buildings and laboratories at a facility that satisfies the definition of "school" are also entitled to P1 priority status for gas requirements. (44 Fed. Reg. 61338, 61344 (October 25, 1979))

[64] "'Hospital' means a facility, the primary function of which is delivering medical care to patients who remain at the facility, including nursing and convalescent homes. Outpatient offices or doctors' offices are not included in this definition." (10 CFR 281.203(a)(10))

allocations for electrical power generation purposes, nor are they subject to an upper limit on the quantity of P1 natural gas available to them. It therefore appears that schools and hospitals can utilize P1 natural gas in their fuel cells to generate electricity and/or heat, both to serve their own needs and to sell to other entities irrespective of the latter's curtailment priority statuses, so long as their primary business activity does not become power generation for distribution and sale off-site (as discussed above in connection with residential usage).

ii. Priority Two (P2): Essential Agricultural Uses

"Essential agricultural uses" as determined by the U.S. Secretary of Agriculture are accorded the second highest or P2 natural gas curtailment status.[65] For these uses, the law does not restrict natural gas use for electric power generation as it does in connection with commercial establishments. Thus, fuel cells serving these uses should be entitled to P2 status, and could sell power to others subject to the limitations already noted for P1 users.

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[65] "The term 'essential agricultural use,' when used with respect to natural gas, means any use of natural gas —

(A) for agricultural production, natural fiber production, natural fiber processing, food processing, food quality maintenance, irrigation pumping, crop drying, or

(B) as a process fuel or feedstock in the production of fertilizer, agricultural chemicals, animal feed, or food,

which the Secretary of Agriculture determines is necessary for full food and fiber production." (NGPA §401(f)(1))

iii. Priority Three (P3): Large Commercial Users

The P3 natural gas uses of central interest to this study are "large commercial requirements." Included within this priority status are commercial firms, institutions, and public agencies, with peak daily gas requirements equaling or exceeding 8.5×10^4 m^3 (50 Mcf).[66] These entities may not include natural gas utilized for electrical generation within their P3 requirements.[67]

As a result, natural gas usage in fuel cells operated by entities otherwise deemed to be P3 customers would be curtailed as P4 (or lower) during a natural gas supply shortfall sufficient to trigger curtailment in their region.

iv. Priority Four (P4) - Priority Ten (P10): Industrial Users

The categories of P4 through P10 include most types of "firm" and "interruptible" "industrial" natural gas requirements.[68] These

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[66] Also included within P3 are: firm industrial requirements for plant protection, feedstock and process needs; pipeline customer storage injection requirements.

[67] See definition of "commercial" service at note 61 , *supra*.

[68] "Industrial" service is service to natural gas customers "engaged primarily in a process which creates or changes raw or unfinished materials into another form or product including the generation of electric power." (18 CFR 2.78(c)(3); emphasis added.)

"Firm" service is "service from schedules or contracts under which seller is expressly obligated to deliver specific volumes within a given time period and which anticipates no interruption, but which may permit unexpected interruption in case the supply to higher priority customers is threatened." (18 CFR 2.78(c)(4))

"Interruptible" service is "service from schedules or contracts categories include the lowest priority natural gas uses and are subject to fuel curtailment before P3 and higher priority users are affected during a natural gas shortfall. A review of Table III-1 indicates that a particular type of industrial natural gas requirement will rate a higher or lower priority status within the P4-P10 range depending upon the following factors:

Higher Priority	Lower Priority
Firm requirement	Interruptible requirement
Nonboiler fuel use	Boiler fuel use
Small gas requirement	Large gas requirement
No alternate fuel capability	Alternate fuel capability

As an illustration, electric utilities' multimegawatt steam electric generating facilities are among the lowest priority natural gas users because of their interruptible service, large boiler fuel requirements, and alternate fuel capabilities (e.g., No. 6 fuel oil).

Included within the P4-P10 range will be not only fuel cells operated by utilities and industrial users, but also those operated by certain entities that are generally treated as high priority gas customers, including small commercial establishments (P1) and large commercial customers (P3), but would be subject to reclassification to the extent of their gas use for electric power generation.

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under which seller is not expressly obligated to deliver specific volumes within a given time period, and which anticipates and permits interruption on short notice, or service under schedules or contracts which expressly or implicitly require installation of alternate fuel capability." (18 CFR 2.78(c)(5))

c. FUTURE MODIFICATIONS OF THE EXISTING SCHEME

i. ERA Alternatives

ERA has undertaken a review of alternative approaches for allocating natural gas supplies during severe supply shortfalls and is proposing a rule which continues the present curtailment priority scheme with only minor modifications.[69]

One option which ERA considered and rejected is a pro-rata curtailment scheme which would curtail all high and low priority gas users' supplies during a natural gas supply shortfall by an identical percentage reduction based upon the severity of the shortfall.[70]

ERA also has rejected a pricing or bidding approach for distributing gas supplies during a shortfall, in lieu of the current rationing approach.[71] It expressed the opinion that a pricing approach is infeasible at the interstate gas pipeline company level and would work, if at all, only at the end-user/distribution company level. ERA indicated that additional studies would be needed to determine the particular circumstances under which a pricing approach might make sense.

[69] *Energy Users Report*, July 2, 1981, pp. 1040-1043.

[70] *Id.*, p. 1041.

[71] *Id.*, p. 1042.

ii. Administration Position

The White House Cabinet Council on Natural Resources and Environment has recently drafted a document entitled "Strategy Paper on Natural Gas Deregulation," which is currently undergoing internal review by Administration officials.[72] The document proposes a number of legislative changes regarding natural gas pricing and use restrictions, but recommends that no legislative changes in curtailment policies be pursued. The cabinet council believes that "the need for a curtailment policy should decline over time as we approach full decontrol [of domestic natural gas wellhead prices]."[73] Their optimism appears to be founded upon the belief that natural gas price decontrol will improve domestic gas supplies to the point that regional gas supply shortfalls will cease to be a significant problem necessitating a curtailment policy.

In short, at the present time, it does not appear that either the Administration nor responsible federal agencies will substantially alter the current natural gas curtailment policy.

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[72] *Energy Users Report*, August 27, 1981, pp. 1338-1343.

[73] *Id.*, p. 1339.

d. IMPLICATIONS FOR FUEL CELL COMMERCIALIZATION

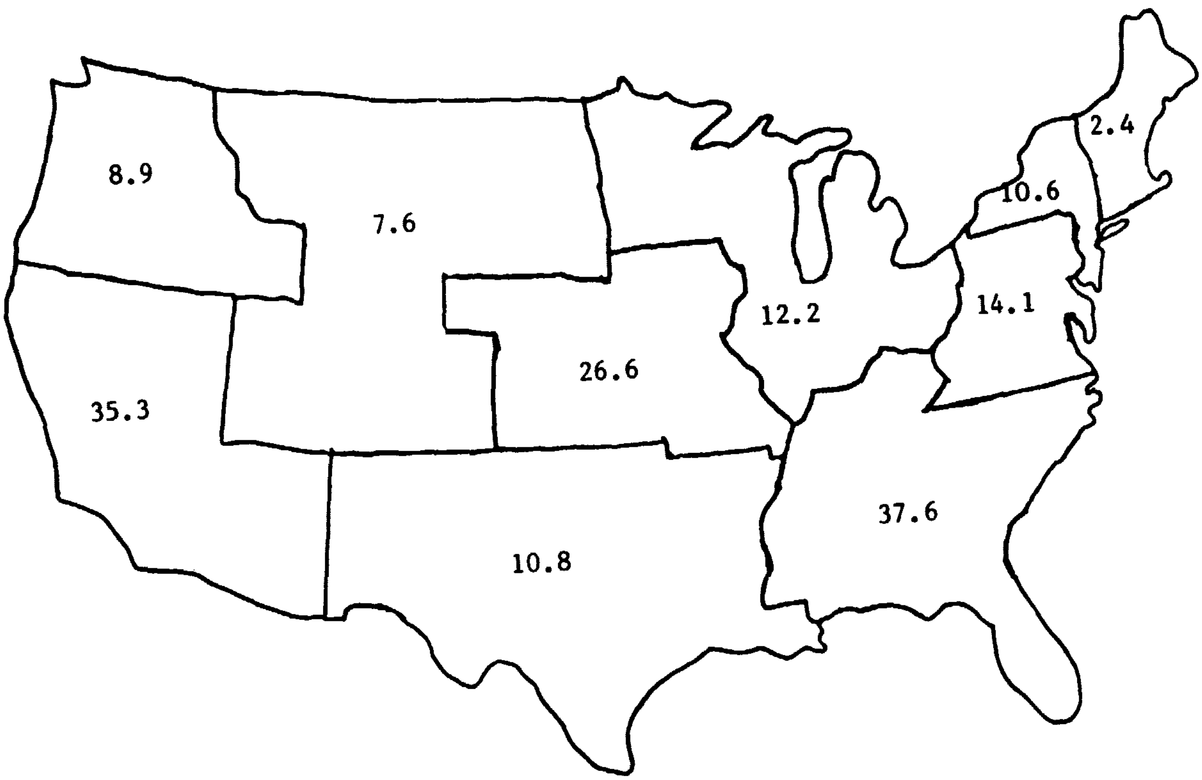
The possibility of natural gas curtailments can be expected to affect decisions by prospective fuel cell manufacturers, marketers and users, respectively, concerning technical specifications, marketing options and the viability of particular applications. Depending on the participants' assessments of the likelihood, breadth and severity of future curtailments, rational responses might range from total disinterest in natural gas-fired cells, to modest changes in specifications, market selection criteria or fuel supply arrangements.

Our analysis suggests that the effects of present curtailment policies will vary by region and by type of application. In regions of the country historically subject to natural gas shortfalls, certain classes of natural gas users accorded a low-priority status may experience curtailments which could preclude the use of fuel cells without fuel-switching capability and ready access to alternate fuels such as naphtha or propane.

Regional gas curtailments have occurred in the past during winter heating seasons. Figure III-2 shows the regional occurrence of such curtailments for the actual 1976-1977 heating season, expressed as a percentage of gas customers' requirements--that is, the gas supplies they would have been able to receive in the absence of curtailments. The figure is useful primarily to illustrate that curtailments are likely to vary substantially from one region of the country to another (largely as a function of the ability of regional pipeline companies to secure adequate supplies), and that in some regions, their effects will be large enough to exert real influence on user choices among available energy technologies.

FIGURE III-2

1976 - 1977 WINTER HEATING SEASON (NOVEMBER - MARCH)
CURTAILMENTS AS A PERCENTAGE OF NATURAL GAS
REQUIREMENTS BY DOE REGION



SOURCE: National Energy Information Center, U.S. Department of Energy *1977-1978 Heating Season: Projected Natural Gas Curtailments and Potential Needs for Additional Alternate Fuels* (DOE/EIA-0015), November 1977, Table 1, pp. 15-16.

For fuel cell manufacturers, this merely confirms recommendations already made by the electric utility Users' Group and others to concentrate on developing a multi-fuel capability, specifically incorporating methane or other non-natural gas capability.

For those interested in identifying early entry markets, the regional occurrence and variability of gas curtailments should be considered among the factors likely to influence user choices. In addition to monitoring the occurrence of future curtailments from this perspective, it would be useful to develop long-term regional supply and demand forecasts for natural gas, naphtha and other fuels feasible for fuel cell operation. If properly disaggregated by region and by class of potential fuel cell owner (e.g., residential, commercial and industrial) according to gas curtailment priority status (see Table III-2 , below), these forecasts should assist in the identification of types of potential fuel cell owners in certain regions who may face a substantial risk of natural gas curtailments and who may not have ready access to naphtha or other alternative fuels. These forecasts would also serve to allay the fears of potential fuel cell owners who are in no foreseeable danger of natural gas curtailments in areas where gas supply shortfalls are not expected.

Table III-2

NATURAL GAS CURTAILMENT PRIORITY SCHEME
BY
CLASS OF POTENTIAL FUEL CELL OWNER

Owner	Natural Gas Priority Status	
Residential Users (privately-owned apartment buildings; condominiums; cooperatives)	P1	High
Schools (public or private)	P1	High
Hospitals (public or private)	P1	High
Essential Agricultural Uses	P2	High
Commercial Users	P4	Low
Federal/State/Local Agencies	P4	Low
Industrial Users (including utilities)	P4	Low

It is perhaps worth noting that if the Administration's viewpoint is borne out by these forecasts, the federal curtailment policy, at least, will have little bearing upon fuel cell commercialization once potential fuel cell owners accept the premise of continued natural gas availability.

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IV. INCENTIVES AND OPPORTUNITIES FOR FUEL CELL USE: PURPA AND AIR QUALITY REGULATIONS

A. Introduction

The preceding discussion of fuel use regulation addresses what some have viewed as potentially critical legal barriers to commercialization of first-generation fuel cells. It suggests that, on closer scrutiny, existing regulatory schemes would not prohibit fuel cells using natural gas or petroleum derivatives in most applications, and probably would not seriously discourage their use except in certain commercial and industrial applications in regions where natural gas shortfalls are likely and alternate fuels are unavailable. Implementation of the Reagan Administration's announced intentions in this area would not alter these conclusions but would, if anything, strengthen them by removing some or all remaining legal barriers to natural gas use.

These conclusions can serve an important function in dispelling industry uncertainty and narrowing concerns over the implications of federal fuel use and pricing policies. That function is essential in the larger commercialization effort, since uncertainty and apprehension in themselves constitute very real barriers to proceeding. In this sense, these conclusions can be viewed as satisfying certain necessary but insufficient conditions for further interest in and progress toward commercial fuel cell use. They tell us that certain widely perceived legal barriers are less serious than some might have supposed, and will not <u>prevent</u> most fuel cell applications; it does not follow that fuel cells will necessarily be viewed as commercially desirable or acceptable. Thus the favorable resolution of fuel use issues simply permits one to proceed with the basic inquiry: Assuming that fuel cell performance and costs can meet some threshold level of commercial interest, what legal, institutional and behavioral considerations might affect further technology development and commercial viability, and how can these inform the commercialization effort?

To this point, our discussion of the potential impacts of national energy policy has focused on perceived barriers to fuel cell use. However, national policy as expressed through existing law and institutional arrangements also provides important incentives and opportunities for emerging energy technologies. For more familiar technologies such as solar, wind and geothermal, many of these inducements have been made explicit in law and regulations formulated with these technologies in mind and expressly intended to encourage their commercial development. For fuel cells, which have not yet captured this kind of public or legislative attention, currently available inducements arise from the interpretation or application of laws or structures designed to serve some societal interest not specifically related to fuel cell development or use.

The following sections discuss two such areas which could have important implications for fuel cell technical development and market identification. The first is Title II of the Public Utility Regulatory Policies Act of 1978, which provides important incentives for independent power production and cogeneration. The second is the Clean Air Act and related legislation, which attaches substantial economic value to technological advances which contribute to meeting national air quality standards.

B. Public Utility Regulatory Policies Act of 1978

The omnibus legislation collectively known as the National Energy Act of 1978, which included the Powerplant and Industrial Fuel Use Act and the Natural Gas Policy Act discussed above, also established the Public Utility Regulatory Policies Act, or "PURPA." Among the various pieces of legislation which expressed Carter Administration energy policy, and which so far appear to have survived the current Administration's scrutiny, Title II of PURPA has the most far-reaching implications for the future structure of the nation's electric supply industry, and possibly for development and marketing decisions affecting some types of fuel cells.

Title II's purpose is to foster competition in electric generation by encouraging independent producers to undertake small-scale generation using nonconventional fuels, and to increase fuel efficiency through cogeneration. Since not all independent power producers will be eligible for the benefits afforded by PURPA, the first inquiry is whether and under what conditions fuel cell facilities might qualify. For facilities which can qualify, the inquiry turns to the nature and scope of benefits available under PURPA and their possible relevance to fuel cell design and marketing decisions.

1. ELIGIBILITY FOR BENEFITS: QUALIFYING FACILITIES

Title II's benefits are available to two types of facilities: "small power production facilities" and "cogeneration facilities."[74] Section 201 of the statute defines a small power production facility ("SPPF") as one which produces up to 80 MW of electricity using biomass, waste, renewable resources or geothermal as its primary energy source. It defines a cogeneration facility ("CGF") as one which produces electricity *and* other useful energy (including steam or heat) for "industrial, commercial, heating, or cooling purposes," without regard to the size of the facility or the type of fuel used.[75] In order to be eligible for PURPA's benefits, an SPPF or CGF must be a qualifying facility ("QF") —that is, it must meet certain technical standards established by FERC regulations, and it must be owned by a person "not primarily engaged in the generation or sale of electric power" other than from SPPFs or CGFs.[76] FERC defines this to mean that the facility *must be owned not more than 50% by an electric utility or utilities, electric utility holding company or companies, their subsidiaries or combinations thereof.*[77]

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[74]PURPA §201 *et seq.*

[75]This definition, as amplified in the PURPA regulations (18 CFR §292.101 *et seq.*), differs in important respects from that used for determining exemptions from fuel use restrictions under PIFUA (*supra*, p. 22), but is incorporated as the standard for exemption from NGPA's incremental pricing scheme (*supra*, p. 35).

[76]PURPA 201.

[77]18 CFR §§292.101(b)(1), 292.204-.206. Hereafter, all references beginning "§292." are to sections appearing in Title 18 of the Code of Federal Regulations, which contains FERC regulations implementing PURPA.

How would these definitions apply in the fuel cell context? If a fuel cell facility were planned to utilize *only* the electric output and none of the cells' thermal potential, then it could not qualify as a cogeneration facility, but would have to qualify, if at all, as a small power producer. This means that it would have to satisfy the fuel use and size restrictions indicated above for SPPF. First-generation cells using natural gas or naphtha would not satisfy the fuel use restrictions, and therefore would not be eligible for SPPF status, whatever their size. Future fuel cell configurations utilizing methane or other fuels produced from biomass or waste could satisfy the fuel use restrictions, and would be SPPFs if their power production capacity were 80 MW or less. To attain "qualifying" status, they also would have to satisfy the ownership criteria described above and FERC technical requirements relating to the application of the "80 MW" limitation and the determination of the facility's "primary energy source."[78]

On the other hand, if a fuel cell facility were planned to utilize both the cells' *electric and thermal* output, then it would meet PURPA's definition of a cogeneration facility, regardless of the type of fuel used or the facility's size.[79] To attain "qualifying" status, such a facility would have to meet the usual ownership criteria as well as certain FERC

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[78]See §292.204.

[79]As noted earlier, PURPA requires that the facility's thermal output be used for "industrial, commercial, heating, or cooling purposes." Although partially redundant, the quoted language is clearly in the disjunctive, so that the "heating or cooling purposes" covered are not limited to commercial and industrial applications, but would include residential, institutional or other heating and cooling as well. See FERC comments on Final Rule in Docket No. RM79-54 (45 Fed. Reg. 17960, March 20, 1980).

technical standards for operation and efficiency which appear well within current fuel cell capabilities.[80]

In short, while early commercial fuel cells probably will not satisfy SPPF criteria, they can meet CGF criteria and become qualifying facilities when used in cogeneration applications. Consistent with Title II's intent to encourage such activities, there are virtually no procedural requirements for qualification: the regulations provide that a facility which meets the statutory definition of a SPPF or CGF and matches FERC's ownership and technical criteria *is* a qualifying facility ("QF").[81] This means that official intervention in the form of certification proceedings or other formal approval is not required[82] to confer QF status and hence, eligibility for PURPA's substantive benefits.

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[80] For topping-cycle facilities, which would include fuel cells, these standards require a minimum of only 5% useful thermal output during any calendar year period and, in relation to any oil or natural gas input, a minimum efficiency of 42.5% (based on the useful power output plus half the useful thermal output). See §§292.202(d) and 292.205(a).

[81] §292.207(a).

[82] Optional certification proceedings are available at the facility owner or operator's discretion. These might be invoked, for example, to allay uncertainty on the part of potential investors or prospective purchasing utilities (see text below). Short of exercising this option, QFs are required only to provide FERC with a simple notice specifying their location, nature, capacity and primary energy source, and the name and address of their owner or operator. See §292.207.

2. NATURE OF BENEFITS: UTILITY PURCHASES AND SALES; REGULATORY AND INCREMENTAL PRICING EXEMPTIONS

a. BACKGROUND

FERC's March 1980 rulemaking proceedings concisely summarize the circumstances leading to Title II's enactment and the nature of the benefits it provides for qualifying facilities:

> Prior to the enactment of PURPA, a cogenerator or small power producer seeking to establish interconnected operation with a utility faced three major obstacles. First, a utility was not generally willing to purchase the electric output or was not willing to pay an appropriate rate. Secondly, some utilities charged discriminatorily high rates for back-up service to cogenerators and small power producers. Thirdly, a cogenerator or small power producer which provided electricity to a utility's grid ran the risk of being considered an electric utility and thus being subjected to extensive State and Federal regulation.
>
> Sections 201 and 210 of PURPA are designed to remove these obstacles. Each electric utility is required under section 210 to offer to purchase available electric energy from cogeneration and small power production facilities which obtain qualifying status under section 201 of PURPA, and to provide back-up power and other services to such facilities on a non-discriminatory basis. For such purchases, electric utilities are required to pay rates which are just and reasonable to the ratepayers of the utility, which are in the public interest, and which do not discriminate against cogenerators and small power producers. Section 210(e) of PURPA provides that the Commission can exempt qualifying facilities from State regulation regarding utility

> rates and financial organization, [and] from Federal regulation under the Federal Power Act . . . and . . . the Public Utility Holding Company Act.[84]

Translation into practice of PURPA's broad mandate for power purchases and sales and regulatory exemptions has been primarily the responsibility of FERC, through federal rulemaking proceedings, and secondarily the responsibility of state public utility commissions and nonregulated (municipal and cooperative) utilities, through state rulemaking proceedings implementing FERC regulations and through administrative oversight of utility activities affecting QFs. FERC's rulemaking, now virtually completed, has resulted in comprehensive regulations defining the boundaries within which state regulatory commissions, utilities and QFs must operate. State implementation efforts are not as far along: some states have published final regulations and power purchase price schedules, but many have not, and few actual utility/QF transactions have so far occurred under PURPA. We have reviewed the proposed actions of about half the states, many of which remain in flux. The following discussion therefore focuses on the overall federal regulatory scheme, rather than attempting to

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[84] 45 Fed. Reg. 17959 (March 20, 1980; emphasis added). In addition to these basic purchase/sale and exemption provisions, other sections of Title II grant FERC explicit authority to order the physical connection of QFs with utility transmission facilities and related actions, and to require utilities to provide transmission services. (PURPA §§202-204) FERC has expressed the view that the authority and entitlement separately conferred by the interconnection sections is necessarily subsumed within that granted by §210; accordingly, these sections have not been addressed separately below. See NOPR in Docket No. RM79-55 (October 18, 1979); cf. 45 Fed. Reg. 33958 (May 21, 1980). However, see *American Electric Power Service Corp. v. FERC* (note 91, *infra*), decided January 22, 1982, as this report went to publication.

systematically catalogue state or local variations still in the process of evolving.

b. UTILITY POWER PURCHASES AND SALES

i. In General

The electric utility power purchase requirement is at the heart of PURPA. It virtually ensures that qualifying small power producers and cogenerators, including fuel cell owner/operators, will have a market for as much of their electric output as they might choose to sell. At the same time, it ensures that in most cases the prices paid for this output will be substantially higher than they might have been without PURPA.

To ensure a market for small power producers and cogenerators, PURPA and FERC rules require electric utilities to purchase *all* the electric output offered by QFs with which the utility is interconnected (except during system emergencies and unusual lightloading situations), and to interconnect with any QF where necessary to accomplish such purchases.[85]

To ensure prices substantially above those which independent power producers might otherwise have commanded from monopsony purchasers, PURPA directs that FERC shall provide for purchase rates based on the

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[85] §§292.303(a), (c) and 292.304(f). Any interconnection costs in excess of those which the utility otherwise would have incurred are to be reimbursed by the QF. See §§292.101(b), 292.306. [See, however, *American Electric Power Service Corp. v. FERC*, *infra*, n. 91, vacating FERC's blanket interconnection rule as of January 22, 1982.]

"incremental cost to the electric utility of alternative electric energy."[86] The quoted language in turn is defined to mean

> the cost to the electric utility of the electric energy which, but for the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source.[87]

This basic pricing standard is designed to allow QFs to benefit from the fact that a utility's incremental or marginal costs — and hence the prices payable to QF owner/operators — generally will represent its highest unit costs at a given point in time. Most electric utilities operate on the principle of "economic dispatch," which dictates that among various types of units comprising their generating mix, those with the highest operating costs (e.g., gas turbines for peaking) are brought into service last and taken out of service first as load shifts occur. This means that, at any given moment, a purchase from a QF can substitute for costs associated with the highest-cost units the utility would otherwise be operating. Similarly, in the long run, most electric utilities expect to meet projected demand growth by adding generating capacity or purchasing power at costs likely to be far higher than those associated with comparable capacity or purchase contracts already in place. To the extent that assured purchases of reliable power from QFs would defer or displace such capacity additions or purchases, they likewise would result in the avoidance of marginal costs and in payments to QFs substantially higher than the utility's average embedded system costs

[86] PURPA §210(b); emphasis added.

[87] PURPA §210(d): emphasis added.

which, without PURPA, would place a ceiling on prices paid for independently produced power.

The following discussion examines the implementation of this basic pricing principle by FERC and the state utility commissions, and suggests some of its implications for fuel cell commercialization. It is important to note at the outset that the rate provisions discussed here govern QF/utility transactions only where the QF so chooses: nothing in the Act or FERC regulations precludes negotiated agreements between the parties whose terms depart from what the regulations might otherwise require.[88] The intent is to allow QFs to retain flexibility in dealing with electric utilities, while greatly strengthening their bargaining position by providing clear legal rights and protections as a basis for negotiations.

ii. FERC Implementation of "Avoided Cost" Pricing

FERC regulations substitute the shorthand term "avoided costs" for PURPA's unwieldy "incremental cost" definition quoted above.[89] Thus, avoided costs are the costs which the purchasing utility would otherwise incur to generate equivalent power itself or to purchase it from some other generating source.

The legislation provides only that FERC shall not establish rates for purchases from QFs which exceed the purchasing utility's incremental

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[88] §292.301(b).

[89] §292.101(b)(6).

or avoided costs, suggesting that rates lower than avoided costs are permissible.[90] FERC regulations implementing this legislative directive do permit rates lower than avoided costs — but only for QFs whose construction commenced before PURPA's passage in November 1978. For all other QFs — including prospective fuel cell facilities — FERC rules require that rates be equal to the utility's avoided costs.[91] However, these rules do not entirely displace state law and, as FERC itself has explained, could effectively render avoided costs the *minimum* standard for rates for purchases from fuel cell and other qualifying facilities:

> This Commission has set the rate for purchases at a level which it believes appropriate to encourage cogeneration and small power production, as required by section 210 of PURPA. While the rules prescribed under section 210 of PURPA are subject to the statutory parameters, the States are free, under their own authority, to enact laws or regulations providing for rates which would result in even greater encouragement of these technologies. However, State laws or regulations which would provide rates lower than the federal standards would fail to provide the requisite encouragement of these technologies, and must yield to federal law.[92]

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[90] PURPA 210(b).

[91] 292.304(b). NOTE: On January 22, 1982, as final revisions of this report were completed for publication by NASA/LeRC, the U.S. Court of Appeals for the District of Columbia vacated FERC's "full avoided cost" rule and its blanket rule requiring interconnection, and ordered FERC to reconsider these issues. See *American Electric Power Service Corp., et al. vs. FERC*, U.S.Ct. App. (D.C.Cir.), No. 80-1789.

[92] 45 Fed. Reg. 12221 (February 25, 1980; emphasis added). Among some 25 states whose recent implementation efforts we have reviewed, only New Hampshire so far appears to have clearly provided for rates exceeding avoided costs, and then only with respect to purchases under the state's own Limited Electrical Energy Producers Act. This rate can be applied only to facilities of 5 MW or less (New Hampshire PUC, DE 79-208, Fifth Supplemental Order No. 14,280, June 18, 1980).

Simultaneous Purchase and Sale

An important feature of FERC's rules is that a new QF is entitled to be paid avoided cost rates for its entire output even where the utility is simultaneously selling electricity to the QF for use in its own operations.[93] This is true notwithstanding that the rules generally limit utility charges for electricity sales to QFs to the rates which would apply to comparable utility customers without their own generating capacity — i.e., rates based on conventional average costing principles.[94] As the Idaho Public Utility Commission commented in relation to this "simultaneous purchase and sale" feature of PURPA,

> [s]imply put, it means that a utility must purchase the entire output of a cogenerator or small power producer at the utility's own avoided costs and, at the same time, must supply the cogenerator or small power producer its entire electric requirement under non-discriminatory rate schedules. In short, the utility must buy at the margin and sell at retail.[95]

Stated from the opposite perspective, the QF may purchase all of its electric requirements at average-cost retail rates and sell all of its electric output at marginally-priced avoided cost rates. If a QF can receive higher prices for the electricity it sells than it must pay for the electricity it buys, it may be better off to buy all of its

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[93] §292.304(b)(4).

[94] See §292.305.

[95] Idaho Public Utility Commission Case No. P-300-12, Order No. 15746, p. 6 (June 13, 1980).

electric requirements from the utility and sell all of its electric output to the utility than to use any of that output for its own needs. This prospect could have important implications for cogeneration installations in general and for fuel cell systems in particular.

In general, it should provide greater flexibility for configuring cogeneration systems, since it means that the optimum system need not be solely a function of the relation of electric and thermal needs of the facility itself. Where the cogenerator's production cost for electricity is less than the purchasing utility's avoided cost, the cogenerator has an incentive to configure its system to maximize electric output for sales to the utility. So long as the thermal energy made available for industrial or commercial processes or used in heating or cooling is at least 5% of the facility's total energy output during any calendar year, and so long as it meets FERC's minimum efficiency standards, the facility can qualify as a CGF under PURPA however great its electrical output.[96]

The fuel cell's special characteristics may offer competitive advantages over other cogeneration technologies in this context. For most technologies, the option to "scale up" to increase electric output for sales to the utility is likely to be independently limited by factors such as manufacturing constraints, noise levels, air quality concerns and siting considerations. By contrast, the fue cell's

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[96]See §§292.205(a) and 292.202(h). As noted previously, the criteria for a "cogeneration facility" exemption from PIFUA's fuel use restrictions for new MFBIs are different from and more stringent than these requirements, and would limit the freedom of multi-megawatt fuel cell cogenerators using natural gas or petroleum fuels to maximize electric output for utility sales. (See *supra*, pp. 22 *et seq*.)

modularity, silent operation, negligible emissions and siting advantages offer great flexibility in scaling the size of a facility to achieve optimum returns under PURPA, and could make fuel cells quite attractive in comparison with other technologies for PURPA-inspired applications.

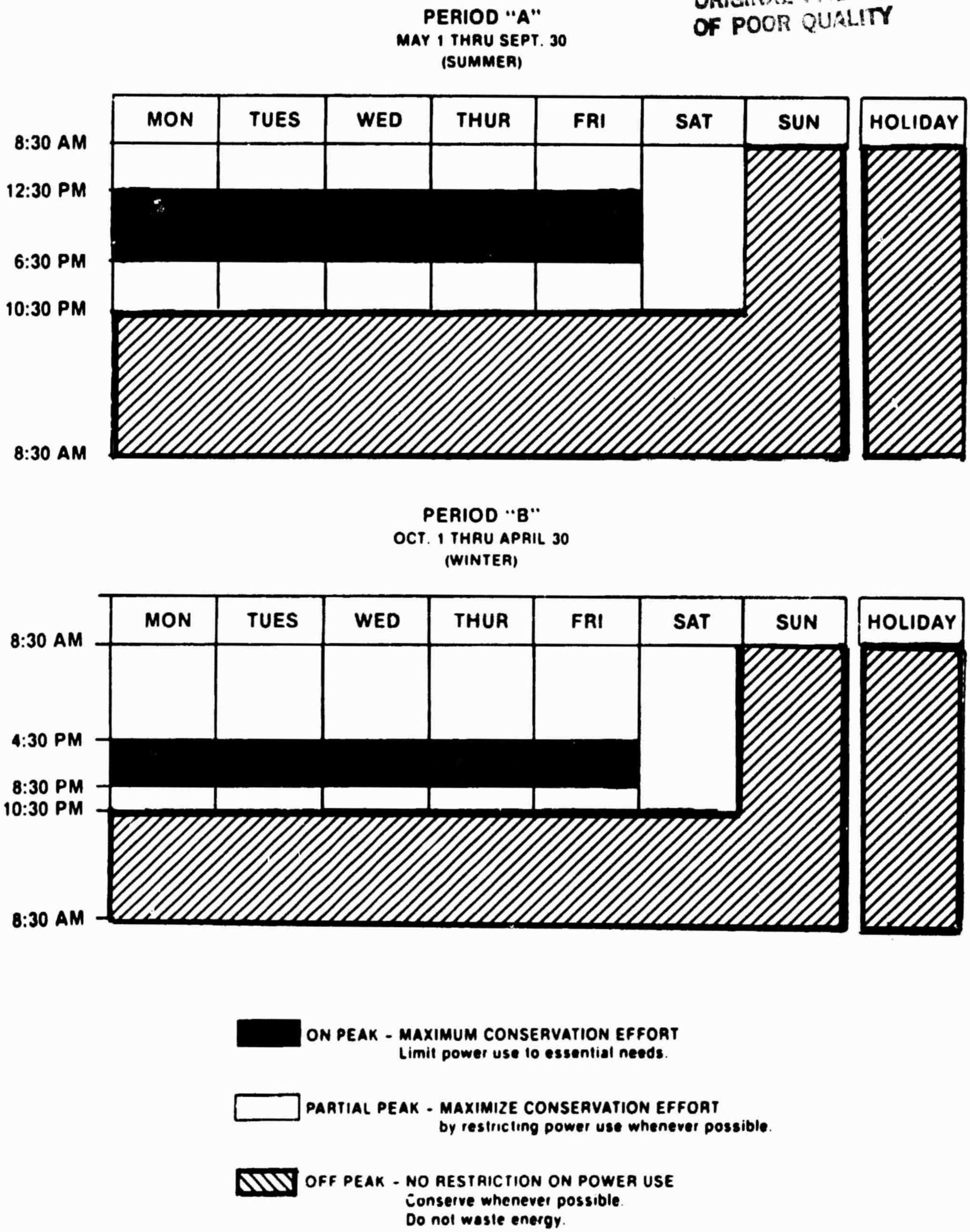
Opportunities to profit from FERC's simultaneous purchase and sale rule may be enhanced in areas where QFs are among the customer classes which an electric utility serves under time-of-day (TOD) rates. Unlike rates historically charged by utilities in this country, TOD rates vary according to the time that electricity is provided to the customer. This variation may occur either in demand charges (the amount charged for the maximum power in kilowatts consumed at any point in a given period), or in energy charges (the amount charged for the total energy in kilowatt-hours consumed during a given billing cycle), or in both.

TOD rate schedules typically contain two (peak and off-peak) or three (peak, shoulder and off-peak) periods. The length and timing of these periods and the ratio of peak to off-peak prices vary widely among different utilities. To illustrate, Figure IV-1 shows the timing and length of TOD rate periods used by California's largest utility, Pacific Gas and Electric Company, and Table IV-1 shows this information for other utilities as well as the relation among peak, shoulder and off-peak energy charges.

Because TOD rate schedules usually omit or drastically reduce the demand charge for off-peak and/or shoulder-peak periods, the effect of TOD service on QFs is to create a period during which electricity purchases by the QF from the utility can be made at very low rates. Except for QFs served by utilities with minimum demand charges, TOD rates permit

FIGURE IV-1

PG and E WEEKLY TIME OF USE ENERGY GUIDELINES



SOURCE: Pacific Gas and Electric Company, *Time of Use Rates for Very Large Customers, Third Annual Report* (March 31, 1980).

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TABLE IV-1

TOD RATE DIFFUSION AND ENERGY CHARGE RATIOS IN 1978*

A. Mandatory Rates

UTILITY	DATE EFFECTIVE	PEAK PERIOD	RATIO OF ENERGY CHARGES[1] (On-Peak:Off-Peak)
Pacific Gas & Electric (CA)	7/19/77	May-September 12:30p - 6:30p Weekdays October-April 4:30p - 8:30p Weekdays	May-Sept. 1.98:1.32:1 Oct.-April 1.98:1.32:1
San Diego Gas & Electric (CA)	4/12/78	May-September 10:00a - 5:00p Weekdays October-April 5:00p - 9:00p Weekdays	3.92:1.99:1
Southern California Edison	10/14/77	Nov. - April 5:00p - 10:00p Weekdays May - October 12:00n-6:00p Weekdays	1.27:1.14:1
Commonwealth Edison (IL)	11/23/77	9:00a - 10:00p Weekdays	See note 2.
Public Service Electric & Gas (NJ)	6/01/78	8:00a - 10:00p Weekdays	1.33:1.24:1
Long Island Lighting	8/01/77	June-September 10:00a - 10:00p except Sundays	1.85:1.53:1
Consumers Power (MI)	8/08/78	October-February 5:00p - 9:00p March-September 10:00a - 5:00p	1.15:1
Madison Gas & Electric (WI)	4/12/77	10:00a - 9:00p Weekdays	June-Sept. 2.53:1 Oct.-May 2:1
Wisconsin Electric Power	1/16/78	8:00a - 8:00p Weekdays	2:1
Wisconsin Power & Light	10/10/77	8:00a - 10:00p Monday-Saturday	2:1

* SOURCE: ICF Corporation, 1979, *Technical, Institutional and Economic Analysis of Alternative Electric Rate Designs and Related Regulatory Issues in Support of DOE utility Conservation Programs and Policy; Vol. I: Domestic Rate Survey.* HCP/B8681-01/1, U.S. DOE, Washington, D.C.

B. Voluntary Rates

UTILITY	DATE EFFECTIVE	PEAK PERIOD	RATIO OF ENERGY CHARGES[1] (On-Peak:Off-Peak)
Connecticut Light & Power and Hartford Electric Light[3]	11/28/77	9:00a - 8:00p EST	1.65:1
Delmarva Power & Light	3/01/78	10:00a - 10:00p Weekdays	1.27:1
Florida Power	9/18/75		
Tampa Electric	10/05/77		
Iowa Southern Utilities	6/78	8:00a - 8:00p	1.21:1
Northern States Power (MN)	1/24/78	9:00a - 9:00p Weekdays	1.[illegible]:1
Northern States Power (ND)	6/07/76	9:00a - 9:00p Weekdays	1.45:1
Northern States Power (SD)	7/01/76	9:00a - 9:00p Weekdays	1.45:1
Central Vermont Public Service	6/20/77	3 hours between 7:00a & 12:00n plus 4 hours between 4:00p & 10:00p daily	January-April 3.83:1 May-December 1:1
Green Mountain Power (VT)	7/01/77	8 hours per day	2.42:1
Massachusetts Electric	3/29/79	8:00a - 9:00p Weekdays	Nov.-June 14.38:1 July-October 16.54:1
		8:00a - 9:00p Weekdays	Nov.-June 6.02:1 July-October 6.92:1
Western Massachusetts Electric	9/01/78	8:00a - 8:00p Weekdays	2.73:1

NOTES

1 Three entries indicate on-peak: shoulder peak: off-peak. Ratios do not include fuel adjustment charges. In many cases, such charges are applied equally to all KWH and thus may reduce the ratio of on-peak to off-peak charges.

2 Under this tariff, a "Basic Energy Charge" is calculated from a declining block schedule. The total energy charge is then determined by adding .394 cents/on-peak KWH to the basic energy charge and by subtracting .40 cents/off-peak KWH from the basic charge. To determine the ratio of on-peak to off-peak charges, one must know the monthly level of usage.

3 Connecticut Power & Light and Hartford Electric Light are both part of Northeast Utilities. The ratio of energy charges shown is based on CL&P's tariffs. HEL's rates are similar.

a QF to avoid what is ordinarily a major component of electricity costs by using self-generated electricity during peak periods. By tailoring on-site electricity demand to occur during off-peak periods or by storing excess electricity for sale to utilities during peak periods, these QFs can take advantage of both the lower cost of utility-provided off-peak electricity and the higher avoided cost price paid for QF-provided on-peak electricity.

TOD rates are not available everywhere. They were first implemented in this country in 1977 for large commercial and industrial customers served by utilities in Wisconsin and California. Utilities in other states have been slow to adopt them. To accelerate their diffusion, PURPA Title I included TOD rates among ratemaking standards which state regulatory authorities and nonregulated utilities are required to consider. As a result, increasing numbers of states are either adopting TOD rates or studying their effectiveness more closely, and some utilities which have implemented them have extended them to commercial and industrial customers with lower monthly demands than the large customers served under earlier programs. Table IV-2 indicates the types and approximate numbers of customers currently served under TOD rates nationwide.

Although the future of Title I is somewhat clouded at this point, even prior to its passage utility commissions in several states had decided to adopt TOD rates as part of an effort to promote more efficient energy use. Thus, while Title I's repeal would remove the federal legal requirement for commissions to evaluate TOD rates, the institutional desire for methods to achieve greater energy efficiency and conserve premium fuels is likely to remain.

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TABLE IV-2

CATEGORY	NUMBER	GWHR[1]
Utilities covered by PURPA	328	2,571,000
Utilities offering TOD rates	56	1,121,000
Commercial/Industrial Customers served by utilities covered by PURPA	8,973,000	1,640,000
Commercial/Industrial Customers served by utilities offering TOD rates	2,700,000 (app.)	713,000
Commercial/Industrial Customers served by utilities offering TOD and eligible to be served under them	577,000	N/A
Commercial/Industrial as above, served under TOD rates	11,800	101,900
C/I served voluntarily	6,600	31,400
C/I served mandatorily	5,200	70,500
Residential customers served	70,775,000	779,300
Residential customers served by utilities with TOD rates of any kind	33,220,000	N/A
Residential customers served under TOD rates	99,600	946

[1]GWHR consumed or generated as appropriate.

NOTE: All figures are approximate. Utilities operating in more than one state are treated as separate utilities for each state, so the number of utilities is overstated.

N/A = Not Available

SOURCE: John Hoffman, U.S. Department of Energy (personal communication).

In any case, the existence of TOD rates introduces another variable into the decision calculus of prospective nonelectric utility fuel cell users. Instead of facing a single cost for purchased electricity, such users are faced with a number of costs which must be balanced against avoided cost receipts which may also be time-differentiated. Ultimately, TOD rates may improve the profitability of fuel cells, and may lead to changes in optimal fuel cell configurations so as to increase the availability of peak electricity.

Determining Rates for Purchase

In order to decide whether particular prospective fuel cell facilities or other cogeneration or small power production systems present attractive business opportunities under PURPA, potential investors need to be able to determine or at least to estimate rates for purchases based on the costs which the participating electric utility will avoid by reason of such purchases from the proposed facility. PURPA and FERC regulations recognize this need and provide for it in several ways.

To begin with, FERC has made clear that a purchasing utility's avoided costs may include the costs of "electric _energy_ or _capacity_ or _both_."[97]

> _Energy costs_ are the variable costs associated with the production of electric energy (kilowatt-hours). They represent the cost of fuel, and some operating and maintenance expenses. _Capacity costs_ are the costs associated with providing the capability to deliver energy; they consist primarily of the capital costs of facilities.
>
> If, by purchasing electric energy from a qualifying facility, a utility can reduce its energy costs or can avoid purchasing energy from another utility, the rate for a purchase from a qualifying facility is to be based on those _energy costs_ which the utility can thereby avoid. If a qualifying facility offers energy of sufficient reliability and with sufficient legally enforceable guarantees of deliverability to permit the purchasing electric utility to avoid the need to

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[97] §292.101(b)(6); emphasis added.

construct a generating unit, to build a smaller, less expensive plant, or to reduce firm power purchases from another utility, then the rates for such a purchase will be based on the avoided capacity and energy costs.[98]

The regulations provide that each QF shall have the option to provide energy "as available" (i.e., nonfirm energy provided when the QF chooses) or "pursuant to a legally enforceable obligation" (i.e., firm energy or capacity provided when the purchasing utility requires it). For nonfirm energy, the rates for purchases are to be based on the utility's avoided costs calculated at the time of delivery. For firm energy or capacity, rates are to be based, at the QF's option, either on avoided costs calculated at the time of delivery *or* on avoided costs calculated at the time the obligation is incurred.[99] Although this option (where available) necessarily will be based on estimates and forecasts, it will result in a contract price fixed at the outset and therefore useful in providing the rate-of-return certainty needed by many potential investors. As one state utility commission wrote in a related context:

> The qualifying facility may provide power either under a cost-estimate option (with predetermined numbers that vary only periodically to reflect long-term escalations in O & M expenses) or under a valuation-at-time-of-delivery option (with prices tracking fluctuations in energy costs and varying

[98] 45 Fed. Reg. 12216 (February 25, 1980; emphasis added).

[99] §292.304(d); see also §292.304(b)(5).

C-2

upon [short] notice to the qualifying facility). Cautious investors may prefer the former option. High rollers will choose the latter. . . .[100]

Whether rates are to be based on avoided costs estimated in advance or calculated at the time of delivery, there must be some mechanism for identifying these costs. The electric utilities themselves should be best situated to determine their own actual and projected costs. Accordingly, FERC regulations require them to make available to state regulatory commissions and to the public detailed data from which their avoided energy and capacity costs can be derived. Such data, which is subject to utility commission review, must include among other things the utility's own estimates of avoided energy costs during peak and off-peak periods, its plans for capacity additions, and their estimated costs.[101] This data in itself does not represent the utility's rate for purchases from QFs, but is intended to provide a starting point for arriving at such a rate.

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[100] Idaho Public Utility Commission Case No. P-200-12, Proposed Order, p. 16 (July 1980). For anyone contemplating capital-intensive fuel cell facilities, it is worth noting that FERC has expressly sanctioned certain contractual arrangements which might assist QF financing:

> A facility which enters into a long term contract to provide energy or capacity to a utility may wish to receive a greater percentage of the total purchase price during the beginning of the obligation. For example, a level payment schedule from the utility to the qualifying facility may be used to match more closely the schedule of debt service of the facility. So long as the total payment over the duration of the contract term does not exceed the estimated avoided costs, nothing in these rules would prohibit a State regulatory authority or non-regulated electric utility from approving such an arrangement. (45 Fed. Reg. 12224; February 25, 1980)

[101] §292.302.

For QFs with a design capacity of 100 KW or less — which could include many potential commercial and residential fuel cell systems — state regulatory authorities and nonregulated utilities must put into effect standard rates for purchases; for QFs with a capacity over 100 KW they may, but need not, do so.[102] These standard rates will not necessarily reflect the supply characteristics of a particular QF, but are intended to minimize the transaction costs of negotiating individualized rates for small facilities (and in some states, for larger facilities as well[103]). In any case they must reflect the purchasing utility's avoided costs, including, where practicable, the individual and aggregate value of energy and capacity provided to the utility by dispersed small systems.[104] In other words, even where any single QF's contribution by itself would not permit the utility to defer or avoid capacity additions, if the aggregate contribution of QFs on the system would, then the standard purchase rates should include pro-rata shares of the utility's avoided capacity costs.[105] Technologies such as fuel

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[102] §292.304(c)(1) and (2).

[103] For example, among some 25 states whose implementation efforts were r viewed, Connecticut, Idaho, New Hampshire, North Carolina, South Caroli a and Vermont have ordered their utilities to make standard rates availa le to qualifying facilities larger than 100 KW. Although the California PUC has not yet adopted final rules under PURPA, qualifying facilities of any size are eligible for standard rates published pursuant to an earlier CPUC decision. The same would be true under rules proposed by the New York PUC staff, but not yet adopted by that Commission.

[104] §292.304(c)(3)(i) and (e)(vi).

[105] Absent empirical performance data, few state commissions have been able to come to grips with this regulatory directive. Among the few that have tried, Texas has directed its utilities to "evaluate" and report every two years on the usefulness of energy and capacity, including aggregate capacity, from interconnected intermittent facilities. (Texas PUC, Substantive Rule 052.02.05.058, August 20, 1981) Idaho requires its utilities to include a minimum "capacity deferral" value of 2 to 3 mills in their rates for non-firm energy. (Idaho PUC, Case No. P-200-12, Order

cells which are expected to offer reliable, predictable energy supplies or meet specified criteria (noted below) for energy availability may be able to derive additional benefit from a provision of the rules permitting standard purchase rates to differ based on the supply characteristics of different technologies.[106]

Additional Rate Factors and Leveraging Opportunities

For QFs for which standard purchase rates are unavailable (or appear unattractive), rates for purchases will be determined in negotiations with the purchasing utility, buttressed on the QF's side by PURPA's basic requirements and FERC's regulations interpreting them. In this connection, the regulations specify a variety of factors in addition to the electric utility's data to be considered in determining avoided costs in individual cases.

Some of these factors are related to technical characteristics of the particular QF, and could have implications for fuel cell design decisions. For example, the regulations attach value to the availability of energy or capacity from QFs during peak periods and system emergencies, measured by such factors as the QF's dispatchability, reliability and ability to separate its load from its generation.[107] How much "added value" might result from these characteristics can be expected to vary

No. 15746, August 8, 1980) California's Commission staff has recommended interim capacity payments to QFs providing nonfirm energy, computed at 50% of the avoided capacity cost which would be available to such a facility under a long-term contract. (California PUC, Order Instituting Rulemaking No. 2, January 20, 1981) And Colorado's Commission staff has proposed a "reliability adjustment" based upon the characteristics of particular classes of QF in the aggregate. (Colorado PUC Decision No. R81-801, Case No. 5970, May 6, 1981).

[106] §292.304(c)(3)(ii).

[107] See §292.304(e)(2).

according to the size of a QF or the aggregate contribution of a class of QFs and their purchasing utility's needs. It is too early in PURPA's history to predict how these values might work out in practice, but if they turn out to be significant as experience under the Act accumulates, then they may warrant recognition and attention in future fuel cell design specifications.

Other factors to be considered in arriving at avoided costs are related more directly to the purchasing utility's situation, and could have important bearing on fuel cell marketing decisions. For example, the regulations specify that the <u>relationship</u> between available QF energy and capacity, on the one hand, and the utility's ability to avoid costs, on the other, should be taken into account.[108] Among other things, this can mean that where a purchasing utility has excess capacity and/or has no plans to add capacity, the availability of QF capacity will not enable it to avoid capacity costs, and will not result in capacity-related payments to the QF.[109] Although payments representing avoided <u>energy</u>

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[108] See §292.304(e)(3).

[109] Utility commissions in Vermont, New Hampshire and Connecticut have accepted the arguments of some or all of their utilities that existing excess capacity renders it unnecessary for these utilities to include any capacity payments in their current price offerings to QFs. (See Vermont PSB General Order No. 65, June 18, 1981, and Recommendations and Comments of the Department of Public Service on Proposed General Order No. 65, April 4, 1981; New Hampshire PUC, DE 79-208, Fifth Supplemental Order 14,280, June 18, 1980; Connecticut PUC Docket No. 800601, "Application of the United Illuminating Company to Increase Its Rates," Supplemental Decision II, August 20, 1981) Other Commissions or their staffs, including, for example, those of California and South Carolina, have rejected such arguments in favor of the view that a QF's present contribution to a utility's ability to avoid capacity costs in later years should be reflected in capacity payments along the way, or that certain capacity costs are actually avoided even while excess capacity situations prevail, and that some capacity value accordingly must be part of the utilities' current price offers. (See South Carolina PSC, Docket No. 80-125-E-Order No. 81-214, March 20, 1981, and California PUC, Order Instituting Rulemaking No. 2, January 20, 1981)

costs will still be appropriate, a QF capable of offering firm, reliable power will forego the "added value" for capacity which would be available if it were dealing with a differently situated purchasing utility.

Again, this value will vary according to the situation, and its significance will become clearer as PURPA unfolds in practice. For now, the point to emerge from these provisions is that the purchasing utility's demand situation and planning framework can affect the capacity value available to qualifying fuel cell facilities. Thus, the same facility may be able to command more attractive returns from utilities with high projected capacity growth than from those with excess capacity or stagnant demand: this prospect can and should be factored into fuel cell marketing strategies.

This point, illustrated here in relation to capacity value, can be expanded to PURPA's power purchase scheme in general, and probably offers the most useful way of thinking about PURPA's relevance to fuel cell commercialization. Because of their potential flexibility in terms of fuel use, size and energy output, and because of special characteristics such as silent unattended operation and low pollutant emissions, fuel cells can be suitable for an unusually wide variety of applications. More than for less versatile technologies, their economic value to prospective owners, operators and other beneficiaries will depend on the particular circumstances in which they are used. The circumstances determining this "value-in-use" include not only internal technical and engineering considerations related to the users' process needs, load factors and the like, but also possible "external" values created by PURPA. PURPA thus affords the opportunity to leverage the value of fuel cells -- perhaps by incorporating design features which capitalize on PURPA's structure; perhaps by placing fuel cells in the service areas of electric utilities with especially high avoided costs in relation to fuel cell production costs; perhaps by targeting new markets for which PURPA makes cogeneration an option; most likely by some combination of these.

Simply to illustrate the magnitude and range of values which could be involved for fuel cell owners in a position to take advantage of PURPA, the following section utilizes actual recent avoided cost data to calculate sample values for sales to a local utility of fuel cell or other cogenerated energy and capacity. It also offers a simplified look at the sensitivity of a fuel cell owner's potential payoff to the size of the transaction and to the utility's avoided energy and capacity costs.

iii. Illustrative Payoffs for Fuel Cell Avoided Cost Sales

Cogenerator Sales to Utilities with High Avoided Costs

Most state public utility commissions throughout the country remain in relatively early stages of their efforts to implement federal PURPA requirements, and most commissions and their utilities have so far developed avoided cost data only for the current year or two. However, the California Public Utilities Commission and its regulated investor-owned electric utilities (Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas and Electric Company (SDG&E)) have developed projections of each utility's avoided energy and capacity costs through the mid-1980s, which will be somewhat more useful for illustrative purposes.

The California utility energy and capacity cost data for the years 1981 and 1984, presented in Tables IV-3 and IV-4 below, are instructive for two reasons. First, the data demonstrate the current magnitude of avoided costs for utilities such as PG&E, SCE and SDG&E, whose generating resources depend heavily on facilities requiring costly petroleum fuel. Second, the data illustrate the potential spiraling (in nominal terms) of these avoided costs over time. Unless they can substantially reduce their reliance upon oil-fired facilities, these and similarly situated utilities will almost certainly continue to experience increasing avoided costs throughout the coming decade. As they do, cogenerators located in their service areas nationwide should encounter greater economic incentives to sell electrical energy and capacity to their local electric utilities in the late 1980s and early 1990s, a time frame which comports with the commercialization schedule for fuel cells.

In order to underscore several trends, Table IV-3 presents several variants for the California utilities' 1981 and 1984 energy price offers, stated in cents-per-kilowatt-hour (¢/KWH). The price data for utility energy purchases during April 1981 includes both a flat rate (non-time-of-day or "non-TOD") and a range of time-of-day ("TOD") rates for off-peak and on-peak energy purchases. Not surprisingly, on-peak sales by cogenerators command the highest prices. The projected 1984 annual average non-TOD energy price data illustrate the potential escalation in avoided energy costs for the three utilities during 1981-1984. The projected 1984 summer on-peak price data demonstrate the seasonal variability in future avoided energy costs for a summer-peaking electric utility heavily dependent upon oil-fired facilities.

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TABLE IV-3

CALIFORNIA INVESTOR-OWNED UTILITY CURRENT AND PROJECTED AVOIDED ENERGY COST SCHEDULES

UTILITY	ENERGY PRICE OFFERS (¢/KWH)				
	April 1981			1984*	
	Non-TOD	TOD (off-/on-peak)		Non-TOD (annual average)	Summer On-Peak
PG&E	6.0	5.6	6.6	7.4	8.0
SCE	6.0	5.8	6.6	9.2	10.6
SDG&E	6.[illegible]	6.2	8.3	11.2	15.1

*Based upon California utility projections.
Source: California PUC, *Summary of Utility Rates for Purchases from Cogenerators and Small Power Producers, March 1, 1981.*

In order to receive a capacity premium in addition to an energy payment for sales to a local utility, a cogenerator must provide a specified amount of capacity on a firm basis; its value will increase as the length of the supply contract increases. The current 1981 and projected 1984 capacity price offers in Table IV-4, stated in dollars-per-kilowatt-year ($/KW-yr), are listed for contract periods of five, ten and twenty years.

TABLE IV-4

CALIFORNIA INVESTOR-OWNED UTILITY CURRENT AND PROJECTED AVOIDED CAPACITY COST SCHEDULES

UTILITY	CAPACITY PRICE OFFERS ($/KW-YR)					
	Utility/Cogenerator Contract Duration					
	5 yr.		10 yr.		20 yr.	
	1981	1984*	1981	1984*	1981	1984*
PG&E	60	69	66	76	77	89
SCE	39	82	64	102	93	133
SDG&E	--	30	22	53	43	78

*Based upon California utility projections.

Source: California PUC, *Summary of Utility Rates for Purchases from Cogenerators and Small Power Producers, March 1, 1981.*

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In order to illustrate the potential payoff to cogenerators of selling to utilities with currently high avoided costs, the data in these tables have been used to compute representative examples of the annual income which individual cogenerators could expect from sales of firm capacity and associated energy to the three California utilities in 1981 and 1984. The computations are based upon the alternative assumptions that the utility purchases firm capacity in the amounts of 10 KW, 100 KW and 1 MW — figures which might be thought of as representing one-fourth of the total output of fuel cell cogenerations systems with nameplate capacities of 40 KW, 400 KW and 4 MW, respectively.

The results of these calculations are set forth in Table IV-5.

TABLE IV-5

EXAMPLES OF COGENERATOR/UTILITY TRANSACTIONS
FOR UTILITIES WITH CURRENT AND PROJECTED HIGH AVOIDED COSTS

Utility: Size of Firm Capacity (and Associated Energy) Purchase		Cogenerator's Annual Income ($1,000's) a. Energy*		b. Capacity**		c. Total (a. + b.)	
		1981	1984	1981	1984	1981	1984
PG&E:	10 KW	5	7	< 1	< 1	6	7
	100 KW	53	65	7	8	60	73
	1 MW	526	648	66	76	592	724
SCE:	10 KW	5	8	< 1	1	6	9
	100 KW	53	81	6	10	59	91
	1 MW	526	806	64	102	590	908
SDG&E:	10 KW	6	10	< 1	< 1	6	10
	100 KW	59	98	2	5	61	103
	1 MW	587	981	22	53	609	1,034

Assumptions: *Utility's energy acquisition costs are computed from its April 1981 non-TOD rate and from its 1984 (annual average) non-TOD rate.

**Utility purchases firm capacity and associated energy for 10-year contractual term.

Source: Tables IV-3 and IV-4.

For example, a cogenerator who contracts to sell 10 KW of firm capacity and associated energy for a 10-year period commencing in 1984 to one of the three California utilities can expect to receive annually $7,000 to $10,000. Corresponding values for sales of 100 KW and 1 MW are $73,000 to $103,000 per year, respectively.[110] If avoided cost trends currently projected by the California utilities continue beyond 1984, comparable figures could be significantly higher in subsequent years when fuel cells are expected to be commercially available.

Cogenerator Sensitivity to Avoided Cost Rates

The avoided cost calculations above demonstrate the "high side of potential profitability for fuel cell power sales to local utilities in certain parts of the country, based upon currently available utility data. However, utilities in other parts of the country less reliant on petroleum fuels or facing slower demand growth currently have significantly lower avoided energy and/or capacity costs. Moreover, each utility's avoided costs will be continually in flux through the 1990s, based on changes in the utility's resource plans and operations driven by changing costs of labor, materials, fuels, capital and other external and internal economic and financial considerations. Thus it seems useful to consider a more generalized approach to computing potential payoffs from cogenerator/ utility transactions which can at least suggest the effects on cogenerators of variations in avoided costs.

For illustrative purposes, we analyzed a cogenerator's annual income from utility purchases of firm capacity and associated energy in the amounts of 10 KW, 100 KW and 1 MW, utilizing a range of combined energy/ capacity avoided cost rates (stated in ¢/KWH). We chose 1¢/KWH as the low end of the range to reflect the possibility (probably unrealistic in view of secular inflationary trends in the nation's economy) that some utilities

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[110] Columns a. and b. of Table IV-5 reveal that the sale by a cogenerator of firm capacity (in addition to energy) to an electric utility may add 5%-15% to the cogenerator's annual gross income from PURPA sales.

may succeed in achieving only <u>nominal</u> energy and capacity avoided costs by the late 1980s. We selected 15¢/KWH as the high end of the cost range, to cover the contingency that at least some utilities (for example, SDG&E, which is currently projecting this value as its avoided energy cost for on-peak electrical energy in the summer of 1984 (see Table IV-3)) may be unsuccessful in their attempts to turn around anticipated avoided cost increases by the conclusion of this decade. The results of this analysis are shown in Table IV-6.

TABLE IV-6

COGENERATOR'S ANNUAL INCOME ($1000s) FROM UTILITY FIRM CAPACITY (AND ASSOCIATED ENERGY) PURCHASES AT DIFFERENT AVOIDED COST RATES

Size of Utility Purchases	1¢/KWH	3¢/KWH	5¢/KWH	7¢/KWH	10¢/KWH	15¢/KWH
10 KW	0.9	2.6	4.4	6.1	8.8	13.1
100 KW	8.8	26.3	43.8	61.3	87.6	131.4
1 MW	87.6	262.8	438.0	613.2	876.0	1314.0

Using the figures from Table IV-6, Figure IV-2 generalizes the relationship of a cogenerator's annual income from sales to the utility of firm capacity and associated energy, on the one hand, and the utility's combined avoided energy/capacity rate, on the other. Thus, for example, a cogenerator's annual income from the sale of 500 KW of firm capacity and associated energy at utility avoided cost rates of 1¢/KWH and 15¢/KWH would yield roughly $50,000 and $650,000 of annual income, respectively. Although these are gross figures presented in their simplest form, they do reveal substantial differences in the income which a fuel cell or other cogeneration facility can expect depending upon the situation of the purchasing utility. Even accounting for the probability that fuel cell power production costs may vary with some of the same factors as the local utility's costs, these figures confirm that careful analysis of utility markets may identify leveraging opportunities which can make essentially the same manufactured fuel cell far more valuable in some settings than in others.

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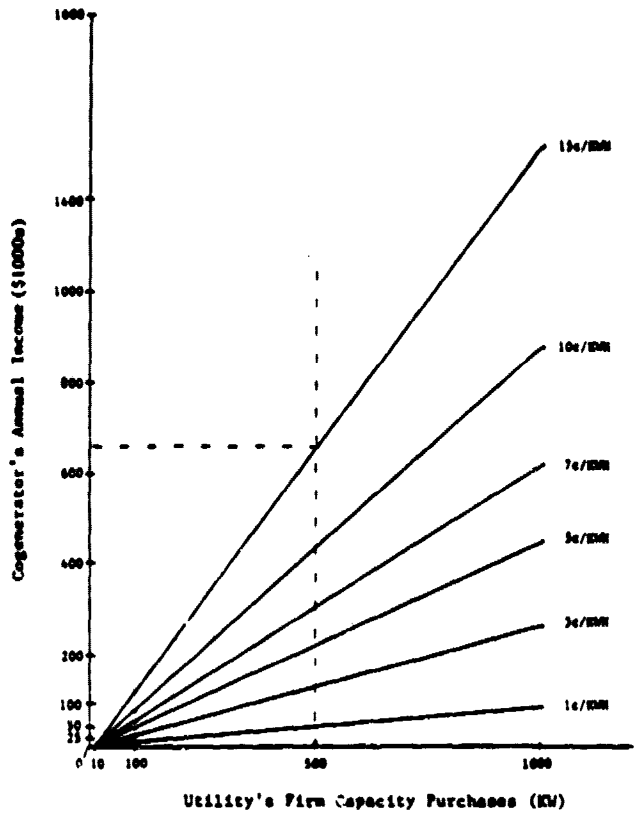
FIGURE IV-2

SENSITIVITY OF COGENERATOR'S ANNUAL INCOME
TO UTILITY' AVOIDED COST RATE
FOR FIRM CAPACITY (AND ASSOCIATED ENERGY) PURCHASES



Although the range of avoided cost values used in these calculations was chosen for illustrative purposes, it is not unrealistic in relation to avoided cost figures appearing in actual utility price offers published to date under PURPA. Tables IV-7 and IV-8 present published energy and capacity prices recently offered by utilities to qualifying facilities in a number o states representing various regions of the country. As noted earlier, at this writing many states still have neither adopted final rules implementing PURPA 210, nor required the publication of firm avoided cost offers, and many utilities accordingly have not made comparable figures available. These tables nevertheless represent a fair sampling of actual prices available at this writing to small power producers and cogenerators under PURPA.

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TABLE IV-7

Summary of Energy Price Offers (¢/KWH)

(Hourly and seasonal peak and off-peak time periods vary by utility within each state.)

State	Peak	Off-Peak	Non-TOD
ALABAMA (rate update not specified)			
ALABAMA POWER COMPANY			
- June through October	2.61	1.88	1.88
- November through May	2.20	1.77	1.77
[Rates available to QFs 100 KW or less]			
CALIFORNIA[1] (updated quarterly)			
SOUTHERN CALIFORNIA EDISON			
- August through October 1981 rate	7.7	6.9	[Available from SCE & PG&E]
PACIFIC GAS AND ELECTRIC			
- August & September 1981 rate	8.07	6.69	
- October 1981 rate	7.75	6.54	
SAN DIEGO GAS AND ELECTRIC			
- August & September 1981 rate	10.16	7.77	8.42
- October 1981 rate	10.55	7.88	8.42
[TOD rates available to all QFs; non-TOD rates available to QFs 100 KW or less]			
IDAHO[2]			
WASHINGTON WATER POWER			
- Rates revised as appropriate	-	-	2.7
UTAH POWER AND LIGHT			
- Rates revised as appropriate	-	-	2.4
IDAHO POWER COMPANY			
- Rates updated annually	-	-	2.67
[Rates available to QFs 10,000 KW or less that provide energy on an as-available basis.]			
NEW HAMPSHIRE[3]			
Statewide rate	-	-	7.7
[Rate available to all QFs]			
NEW MEXICO[4]			
PUBLIC SERVICE COMPANY OF NEW MEXICO			
- Primary Voltage Level			
June through August	3.522	1.620	2.107
September through May	3.584	2.680	2.461
Secondary Voltage Level			
June through August	3.868	1.860	2.299
September through May	3.872	2.961	2.648
[Rates available to QFs 100 KW or less]			

TABLE IV-7 (CONT.)

STATE	PEAK	OFF-PEAK	NON-TOD
NEW YORK[4] (recommended rate update not specified)			
CONSOLIDATED EDISON (proposed rate)			
- Primary Voltage Level			
Summer	9.98	2.5	-
Winter	4.1	2.2	-
- Secondary Voltage Level			
Summer	11.15	2.8	-
Winter	4.6	2.4	-
[Rates available to all QFs]			
NORTH CAROLINA			
CAROLINA POWER AND LIGHT			
- Annual rate (updated every 2 years)	2.80	2.07	-
DUKE POWER COMPANY			
- Annual rate (updated every 2 years	2.12	1.60	-
VIRGINIA ELECTRIC AND POWER COMPANY			
- Annual rate (updated annually)	5.203	3.132	-
NANTAHALA POWER AN[illegible] IGHT			
- Annual rate	-	-	2.253
[Rates available to all QFs]			
VERMONT (rates in effect till June 1982)			
Option 1 (statewide rate)	-	-	7.8
Option 2 (statewide rate)	9.0	6.6	-
[Rates available to all QFs]			
WISCONSIN (proposed rates)			
WISCONSIN PUBLIC SERVICE CORPORATION (propose to revise each December)			
- Nonfirm Energy	1.85	1.32	-
- Firm Energy	1.85	1.32	-
WISCONSIN ELECTRIC POWER COMPANY (revision date not specified)			
- Nonfirm Energy	2.90	1.45	-
- Firm Energy			
July through October	3.65	1.45	-
November through June	3.45	1.45	-
[Rates available to all QFs]			

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ENERGY PRICES

CONNECTICUT	PEAK	OFF-PEAK
(Utility-proposed rates expressed as % of average fossil fuel cost per fossil fuel KWH)		
CONNECTICUT LIGHT AND POWER COMPANY (proposed)		
- Nonfirm rate, available to all QFs	114%	89%
- Firm rate, available to QFs 100 KW or less	117%	92%
HARTFORD ELECTRIC LIGHT COMPANY (proposed)		
- Nonfirm rate, available to all QFs	114%	89%
- Firm rate, available to QFs 100 KW or less	117%	92%
UNITED ILLUMINATING COMPANY		
- Nonfirm rate, available to QFs 1000 or less	109%	95%
- Firm rate, available to QFs 1,000 KW or less	117%	103%

NOTES

1. The California Public Utilities Commission has not yet issued final rules implementing PURPA. These rates were published under Commission Decision No. 91109 (December 19, 1979) and subsequent resolutions requiring regulated utilities to publish price offers and contract terms equivalent to their full avoided costs for purchases of electricity from qualifying cogenerators and small power producers.

2. Price offers listed are annual averages. These include a payment toward capacity deferred by nonfirm energy (3 mills for Washington Water Power and Idaho Power; 2 mills for Utah Power and Light). Refer to Table IV-6 for the energy component paid to firm suppliers.

3. Minimum rate for QFs activated between June 1980 and initial generation of next scheduled baseload plant (Seabrook I) around 1983.

4. Primary voltage represents high voltage side of transformer. Secondary voltage represents low voltage or load-supplying side. Rates adjusted by transformer and line loss factors (the lower the voltage, the greater the energy losses).

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TABLE IV-8

SUMMARY OF STATES' CAPACITY PRICE OFFERS (¢/KWH)

Initial Operation Date:	1981	1983	1981	1983	1981	1983
Contract Term:	10 yr.		15 yr.		20 yr.	
***CALIFORNIA**[1]						
PACIFIC GAS AND ELECTRIC	.75	.83	.82	.90	.88	.97
SOUTHERN CALIFORNIA EDISON	.73	.99	.90	1.18	1.06	1.35
SAN DIEGO GAS AND ELECTRIC	.25	.47	.39	.62	.49	.73
***IDAHO**[2]						
UTAH POWER AND LIGHT	1.28	1.52	1.52	1.84	1.77	2.15
IDAHO POWER COMPANY	1.63	1.97	1.91	2.31	2.19	2.65
WASHINGTON WATER POWER	1.39	1.68	1.64	1.99	1.91	2.31

*These rates have been changed from KW/yr figures to the ¢/KWH figures shown here.

NORTH CAROLINA

	FIXED LONG-TERM RATES		
	5 yr.	10 yr.	15 yr. (or longer)
CAROLINA POWER AND LIGHT[3]			
- Peak Summer (July - October)	1.49	1.49	2.39
- Peak Nonsummer (November - June)	1.29	1.29	2.08
DUKE POWER COMPANY[3]			
- Peak Months (July - October, January - April)	1.11	1.11	1.17
- Nonpeak Months (All other months)	0.66	0.66	0.69

VIRGINIA ELECTRIC AND POWER COMPANY

- Peak KWH: 0.803 if contract is for 5 years
  1.253 if contract is for more than 5 years

NANTAHALA POWER AND LIGHT COMPANY

- Specifies only an annual rate of 2.690¢/peak KWH

CONNECTICUT

- No capacity payment offered because excess capacity present.

NEW HAMPSHIRE[4]

- Statewide rate: .5¢/KWH (except where excess capacity present)

VERMONT

- No capacity payment offered because excess capacity present.

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Notes

1. The California Public Utilities Commission has not yet issued final rules implementing PURPA. These rates were published under Commission Decision No. 91109 (December 19, 1979) and subsequent resolutions requiring regulated utilities to publish price offers and contract terms equivalent to their full avoided costs for purchases of electricity from qualifying cogenerators and small power producers.

   Purchase price for firm energy includes capacity component and energy component (see Table IV-5). Contracted-for capacity credits fixed over contract term. Rates updated approximately every two years in utilities' rate cases to apply to QFs which begin operation or recontract during that period. Separate capacity price offers for QFs smaller than 100 KW. QFs may select from several capacity payment options.

2. Capacity price offers shown are superseded by any higher offers current at date of QF's initial operation. Purchase price ofr firm energy to include both capacity component shown here and energy component. Cost figures for this energy component vary from 1.2 to 1.6c/KWH depending on the utility.

3. Capacity credits for long-term contracts fixed at initial level for contract term. Rates updated every two years to apply to QFs which begin production or recontract during that period. Duke and CP&L also offer annual capacity rates equal to 5-year contract price offers. Capacity credits for annual contracts fixed at initial level for contract term. Rates updated every five years to apply to QFs which begin production or recontract during that period.

4. Minimum rate for QFs presently operating and those activated between June 1980 and initial generation of next scheduled baseload plant (Seabrook 1) around 1983.

Sources for Tables IV-7 and IV-8

ALABAMA: Alabama Power Company - Rate PAE, March 1981.

CALIFORNIA: (CPUC) "Summary of Utility Rates for Purchases from Cogenerators and Small Power Producers," March 1, 1979, File No. 303; San Diego Gas and Electric: Appendix A, "Energy and Capacity Purchase Price Schedules," effective August 1 through October 31, 1981; Pacific Gas and Electric: "Power Sales Agreement," February 2, 1980 and Appendix B, August 1, 1981; Southern California Edison: "Interim Proposed Policy for Cogeneration and Small Power Production," August 1981.

CONNECTICUT: Northeast Utilities, Nonfirm Power Purchase Rate 980 and Firm Power Purchase Rate 981 for Connecticut Light and Power Co. and Hartford Electric Light Company, January 21, 1981; United Illuminating Self-Generator Rates, September 1, 1981.

IDAHO: Idaho PUC, Case No. P-300-12-Order No. 15746, August 1980; Idaho Power Co. "Power Sales Agreement for Cogeneration and Small Power Production," Appendix A, Tables 1 and 2, January 17, 1981; Washington Water Power Co., "Power Sales Agreement for Cogeneration and Small Power Production," December 31, 1981; Utah Power and Light Co., "Power Purchase Agreement," Appendix B, Table 1, February 28, 1981.

NEW HAMPSHIRE: New Hampshire PUC, DE 79-308-Fifth Supplemental Order 14,280, June 18, 1980.

NEW MEXICO: Public Service Co. of New Mexico: Schedule No. 12, "Cogeneration and Small Power Production - 100 KW or Less," May 27, 1981.

NEW YORK: New York SPC: Case No. 27574, "Consolidated Edison Co. of New York, On-Site Generation," Staff-Proposed Buyback Rate, Exhibit 75.

NORTH CAROLINA: North Carolina UC, Docket E-100, Sub 41 and Appendix A, September 21, 1981.

VERMONT: Vermont PSB, General Order No. 65, June 18, 1981 and "Recommendations and Comments of the Department of Public Service on Proposed Order No. 65," April 7, 1981.

WISCONSIN: Wisconsin Public Service Corp., Nonfirm (No. PG-2) and Firm (No. PG-3) Power Purchase Tariffs, April 4, 1980; Wisconsin Electric Power Co., Firm Surplus Energy Purchase Tariff (No. FP 1-1.2) and Nonfirm Surplus Energy Purchase Tariff (No. NFP 1-1.1).

Several points appearing in these tables are worth highlighting. Table IV-7 confirms that energy price offers differ dramatically among different utilities in different states and regions (largely as a function of utility reliance on petroleum fuels over coal, nuclear, hydroelectric or other lower-cost fuels). The table on its face suggests that fuel cell values related to income potential from PURPA power sales will differ accordingly. The table also notes that utility energy price offers are continually updated, making QF investment planning difficult in the absence of carefully negotiated long-term contracts that may have to sacrifice price to certainty of return. Finally, the table suggests that substantial premiums may be available to technologies such as fuel cells which are capable of providing reliable energy at peak periods.

Table IV-8 again shows substantial variation in avoided capacity costs among utilities, with similar implications for fuel cell marketing. It also establishes that capacity payments will typically be a relatively small portion of total avoided cost payments to QFs (although not necessarily of their net income from sales to the utility). And the table serves as a reminder that in some states, existing excess capacity will altogether preclude capacity payments from some utilities.

c. EXEMPTIONS FROM REGULATION AND INCREMENTAL PRICING

i. Exemptions from Certain Federal and State Utility Regulation

In keeping with PURPA's overall intent to encourage cogeneration and small power production, §210(e) of the statute directs FERC to prescribe rules exempting qualifying small power producers of up to 30 MW capacity (or 80 MW in the case of geothermal or biomass-fueled facilities) and all qualifying cogenerators from the major burdens of federal and state utility regulation. The rationale for these exemptions appears from the Conference Report accompanying the 1978 legislation:

> The conferees wish to make clear that cogeneration is to be encouraged under this section and therefore the examination of the level of rates which should apply to the purchase by the utility of the cogenerator's or small power producer's power should not be burdened by the same examination as are utility rate applications. . . . The establishment of utility type regulation over them would act as a significant disincentive to firms interested in cogeneration and small power production.[111]

In accordance with Congressional intent, FERC has adopted regulations providing liberal exemptions for QFs. In relevant part, §292.601

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[111] Conference Report No. 95-1750 (to accompany H.R. 4018), October 10, 1978; p. 98.

exempts qualifying SPPFs of up to 30 MW and all qualifying CGFs from almost all provisions of the Federal Power Act (the basic federal utility regulatory legislation), including those reflecting traditional rate regulation and securities regulation ordinarily attendant on public utility status. Section 292.602 exempts the same facilities and small power producers of up to 80 MW using biomass as a primary energy source from the federal Public Utility Holding Company Act and from state laws and regulations respecting electric utility rates and financial and organizational matters.

Although PURPA §210(e) is not explicit on the point, FERC interprets its exemption authority as to state regulation to extend only to regulation of wholesale sales, and not to retail sales over which FERC itself has no jurisdiction.[112] Retail sales of electricity and, in some states, of steam and/or hot water, are subject to regulation by state utility commissions.[113] Thus, although a qualifying fuel cell facility would be exempt from most federal and state regulation as to any sales of electricity for resale which it might make to an electric utility under the avoided cost scheme described earlier, exemption for retail sales of electricity or heat to nonutility purchasers

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[112] Personal communication from FERC staff member Mr. Michael Kessler, March 20, 1981; cf. PURPA §210(a), expressly limiting FERC's authority to prescribe rules governing QF power sales for purposes other than resale.

[113] FERC has taken the position that it has no authority to exempt cogenerators from state regulation as steam utilities. See FERC Staff Discussion, 44 Fed. Reg. 38865, note 5 (July 3, 1979).

would be a matter of state law.[114] As the Congressional Conference Report indicated, and as one of the authors of this report has explained in detail in the geothermal context,[115] the prospect of regulation can be a serious disincentive to undertaking the risks associated with a new energy technology, and at the least is likely to discourage distribution activities which might otherwise contribute to efficiency and economy. For these reasons, further fuel cell commercialization efforts should include a careful examination of relevant state law in this area;[116] the formulation of policies to ensure that the fuel cell's potential will be fully utilized through distribution systems where appropriate; and a vigorous program of action with individual state legislatures and utility commissions in a position to respond to such policies.

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[114] For detailed discussion of the jurisdiction of Western state utility commissions over steam or hot water in the geothermal context, see John T. Nimmons, *Overview of State Public Utility Regulation Impact on Geothermal Direct Heat Applications* and *State-By-State Analysis of Public Utility Laws Affecting Geothermal Direct Heat Applications* (Earl Warren Legal Institute Energy Studies Project, April and June 1979).

[115] See Nimmons, *Utility Policy and Geothermal Heating: Toward Rational Regulation* (Earl Warren Legal Institute Energy Studies Project, December 1980).

[116] An excellent start in the context of integrated community energy systems in general is *Community Energy Systems and the Law of Public Utilities*, a multi-volume, state-by-state study by Ross, Hardies , O'Keefe, Babcock & Parsons, One IBM Plaza, Suite 3100, Chicago, IL.

ii. Exemptions from Incremental Pricing

In addition to federal and state utility regulatory exemptions, FERC rules provide exemptions from the current scheme of incremental pricing for natural gas used in qualifying cogeneration facilities. For present purposes, the relevant provision is §292.205(c)(1), which establishes the exemption for any topping cycle cogeneration facility which qualifies under the minimum operating and efficiency standards and ownership criteria discussed previously. For a discussion of the meaning and implications of incremental pricing for fuel cells in general, see section III.B., above.

C. Air Quality Regulatory Regimes Promoting Fuel Cell Commercialization

1. INTRODUCTION

In the familiar litany of benefits or "special credits" accruing from fuel cells, their extremely low levels of pollutant emissions are virtually always cited. Fuel cell proponents would universally agree that this is an attractive characteristic and contributes to the versatility and siting flexibility of the technology. What is not widely understood is that the fuel cell's non-polluting characteristics not only can permit electric generation and cogeneration where it might otherwise be prohibited, but can translate into very real and very tangible economic value under conditions defined by existing federal and state air quality regulations. Where such conditions obtain, these regulations can provide the opportunity for potential fuel cell owners or operators to realize substantial savings and/or income which would not accrue from the use of competing generation or cogeneration equipment.

These possibilities arise under the regulatory regime established pursuant to the Clean Air Act of 1963 and related legislation. This regulatory scheme is extremely intricate and complex. Because of its potential importance to fuel cell commercialization, it is described in detail in the Appendix to this report. The following discussion summarizes its basic features and their relevance to the commercialization effort, and provides references to the more detailed treatment contained in the Appendix.

2. STATIONARY SOURCE REGULATION IN NONATTAINMENT AND ATTAINMENT AREAS

a. NONATTAINMENT AND ATTAINMENT AREAS

Pursuant to the Clean Air Act of 1963, as amended, the Environmental Protection Agency (EPA) has promulgated national standards for air quality. These standards, known technically as "national ambient air quality standards" or "NAAQS," establish allowable levels for each of various pollutants, including sulfur dioxide (SO_2), nitrogen dioxide (NO_2), carbon monoxide (CO), particulate matter (PM), and ozone (O_3).

Air quality control regions, and portions of such regions, which presently fail to meet these standards as to any of these pollutants are designated as "nonattainment areas" as to each such pollutant. Areas which do meet applicable standards are classified as "attainment areas." As to all of its nonattainment areas, each state must submit for EPA's approval a state implementation plan (SIP) to attain NAAQS by the end of 1982 or 1987, depending upon the pollutant. As to all areas presently classified as attainment areas, the SIP must set forth plans to maintain NAAQS.[117]

b. MAJOR EXISTING SOURCES

As to both nonattainment and attainment areas, SIPs contain emissions limitation schedules. These limitations apply to "major existing sources"--i.e., presently operating industrial facilities or

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[117] See Appendix A, section II.A.

other "stationary sources" which actually or potentially emit 9.072×10^4 kg per year (kg/y) (100 tons per year (tpy)) or more of a regulated pollutant.[118] Operators of regulated existing sources are required to control their source's emissions to bring them within these limitations.

To minimize compliance costs, the EPA has abandoned an earlier policy requiring strict compliance at each emissions point (stack, vent, port, etc.) within a facility, in favor of a policy permitting the operator to place an imaginary "bubble" over its facilities (or several operators to "bubble" their combined facilities) and reduce emissions below required levels at points with low control costs in lieu of equivalent reductions at points with high control costs: so long as the source's aggregate emissions satisfy the SIP limitations, the facility is in compliance.

c. MAJOR MODIFICATIONS AND MAJOR NEW SOURCES

Existing major sources undergoing "major modifications" (those resulting in net emissions increases of $2.268\text{-}9.072 \times 10^4$ kg/y (25-100 tpy) depending upon the pollutant), and "major new sources" (9.072×10^4 kg/y or more in nonattainment areas and 9.072×10^4 kg/y - 2.268×10^5 kg/y (100-250 tpy) or more, depending upon the type of source, in attainment areas) are subject to stricter pollution control technology requirements than existing sources.[119]

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[118] See *Id.*, section II.B. Generally, only large-scale industrial facilities generate 9.072×10^4 kg/y (100 tpy) or more of any pollutant.

[119] See *Id.*, section II.C.

In nonattainment areas, operators of these new or modified major sources generally must comply with a "nonattainment offset policy" or a "growth allowance policy."[120] Nonattainment offset policies require the source operator to obtain surplus emissions reductions from an existing source or sources in the area to "offset" (on at least a one-for-one basis) the incremental emissions of a particular pollutant from the new or modified source. State growth allowance policies reserve in the SIP an emissions allowance for each pollutant to permit the construction and operation of major new sources and major modifications. These allowances can then be allocated among operators of such sources to offset their incremental emissions.

In attainment areas, operators of new or modified major sources must ensure that federally prescribed maximum increases in pollutant concentrations ("PSD increments") are not exceeded. If the incremental emissions of these sources cause or contribute to the violation of a PSD increment, the operator must secure offsets from existing sources in the area sufficient to prevent or correct the violation.[121]

d. MINOR SOURCES

In areas with intractable air pollution problems, sources other than those defined as existing sources and major new and modified sources

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[120] See *Id.*, section III.B.1.a. for a list of states with nonattainment offset and/or growth allowance policies. Currently, 41 states have some form of nonattainment offset policy.

[121] See *Id.*, section II.C.3.b.

(i.e., "minor sources") may be subject to similar air pollution control requirements as their major source counterparts, including offsets.[122]

3. CREATION, TRADING AND BANKING OF OFFSETS

a. SOURCES AND USES OF OFFSETS

Only existing source operators can create surplus emissions reductions which can serve as offsets.[123] They can create these in various ways, including the addition of pollution control equipment; the modification, replacement or shutdown of equipment, processes or an entire plant or facility; or changes in process or product inputs.

Existing source operators can keep the offsets they have created for their own present or prospective needs. They can use these "internal offsets" for "bubble" applications in an existing source, or for "netting"[124] emissions increases and decreases at a major existing source to avoid offset and/or other requirements for a major modification at the source.

Alternatively, existing source operators can transfer their offsets by sale, exchange or donation to others for the latter's present or prospective use. These "external offsets" will be needed by new or modified major source operators who do not control sufficient internal

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[122] See *Id.*, section III.B.1.a.

[123] See *Id.*, section III.A.

[124] See *Id.*, section II.C.1.c.

offsets from other nearby sources, in order to satisfy regulatory requirements for nonattainment offsets (in nonattainment areas) or for PSD increment exceedance offsets (in attainment areas).

b. OFFSET TRANSACTIONS TO DATE

Nonattainment offset transactions so far have constituted the overwhelming majority of all types of offset transactions, due largely to a lag in development and implementation of regulations for other types of offsets.[125] Within this group of nonattainment offset transactions, internal offset transactions have outpaced external ones by a factor of twenty. Of the relatively few external offset transactions, only a small portion have involved the payment of money by the recipient of the offsets. California has approved the lion's share of all nonattainment offset transactions approved nationwide.

c. FORMAL OFFSET BANKING AND TRADING PROGRAMS

EPA is encouraging states and local air pollution control agencies to develop formal programs for banking and trading of offsets. Under these schemes, a state or local agency develops a central registry where emissions reductions credits are certified at the time they are created (for example, when a process is shut down or additional pollution control equipment is installed at an existing source). Certified credits are recorded as public information and stored for future use as offsets.[126]

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[125] See *Id.*, sections III.B.1. and 2.

[126] See *Id.*, section III.B.3.b. for identification of state and local agencies with formal banking systems in place or under consideration.

Firms seeking external offsets can contact the bank to determine potential offset availability.

To date, firms with potential emissions reductions generally have not realized the potential market value of external offset transactions, due to the paucity of such transactions and the inaccessibility of information on offset prices and availability.[127] With formal banking, market prices for offsets within areas should become more predictable as more external offset transactions occur and information on these transactions is widely disseminated.

Subject to EPA's review and approval of their SIPs, states and local air quality agencies are vested with broad discretion to determine the types and sizes of sources subject to offset requirements, as well as geographical, temporal and other limitations on offset transactions. Offset policies accordingly vary widely in their overall scope, their geographical coverage, and the nature of the restrictions they impose on offset transactions. For example, some state and local agencies have specified time limits for the retention of credits, to prevent hoarding by credit owners which can impede free trading in offsets. Others have reserved the right to confiscate a portion of banked credits in the event that stricter emissions requirements are needed to ensure successful air cleanup efforts. These restrictions, which vary significantly from agency to agency, may promote or impede offset banking and trading.[128]

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[127] See *Id.*, section III.C.1.d.

[128] See *Id.*, sections III.B.1.a. and 3.c.

4. OFFSETS AS AN IMPETUS FOR FUEL CELL COMMERCIALIZATION

a. FUEL CELLS AS SOURCES OF EMISSIONS REDUCTION CREDITS

The fuel cell's significantly lower emissions levels of regulated air pollutants can be a key selling point vis à vis conventional generation and cogeneration technologies.

Operators of existing sources can utilize fuel cells (preferably in a cogeneration mode for economic efficiency) to replace their existing polluting on-site energy-generating equipment--for example, diesel generators and oil-or gas-fired boilers--and thereby create emissions reduction credits. They can use these credits as internal offsets, sell them to others as external offsets, or bank them for future internal or external use.

Operators of new sources with external offset requirements could purchase fuel cell systems in lieu of conventional generating or cogenerating equipment to meet the on-site electrical and/or thermal energy requirements of such sources, in order to minimize the cost of external offsets required for on-site emissions. Alternatively, they could purchase fuel cell systems for one or more existing sources within the area of the new sources as offsets for the new sources' incremental emissions. The operator of an existing source would get a "free ride" by modernizing (and perhaps expanding) its energy generating capability at someone else's expense.

b. POTENTIALLY ATTRACTIVE FUEL CELL MARKETS

Assuming the continuation of the current regulatory regime, prime targets of opportunity for fuel cell marketing in terms of air quality leveraging possibilities should include operators of existing and new major sources — generally, utilities and large-scale industrial facilities[128] — in areas with significant demands for "bubble," "netting," nonattainment and/or PSD increment exceedance offsets. Except for unusually large facilities or those in poor air quality regions with particularly stringent regulations affecting even minor sources, commercial and residential operations are far less sensitive to air quality regulation, and on-site fuel cell installations in these situations can benefit correspondingly less from air quality leveraging under existing schemes.

Projections developed by the National Commission on Air Quality (NCAQ), empowered by the Congress to study existing and alternative air quality regulatory schemes, indicate that a significant number of nonattainment areas are expected to continue to have ozone and particulate matter violations of NAAQS after 1987, necessitating ozone precursor (hydrocarbons and nitrogen dioxide) and particulate matter offsets. Certain source types in attainment areas may also require offsets in this time frame.[129] "Bubble" applications in these nonattainment and attainment areas could continue to occur, insofar as existing sources are subjected to tightening of emissions limitations.

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[128] See section II.C.1.b. of Appendix A for a list of industrial facilities generally deemed to be major sources.

[129] See section III.C.1. for a discussion of specific nonattainment areas where offsets may be required in the late 1980s, as well as a description of source types in attainment areas for which offsets may be required.

Ongoing market research will be needed to identify particularly attractive areas and entities. Within this group of potentially attractive market areas, those areas which have active offset trading and banking programs with relatively few restrictions should be slated for early marketing activities.

c. REGULATORY PROPOSALS IMPEDING FUEL CELL COMMERCIALIZATION

NCAQ has proposed, and the Administration is evaluating, several options for substantially modifying the current provisions of the federal Clean Air Act which must be reauthorized for fiscal year 1982 and thereafter in the current session of the Congress.[130] It remains to be seen whether these options are formally proposed in legislation and, if so, whether they survive the ensuing political battle. Enactment of some of these modifications could remove the substantial impetus provided by the current regime to source operations to replace existing equipment with less polluting equipment, and to install equipment with low emissions levels in new sources. In that event, a key marketable advantage of fuel cells over conventional generation and cogeneration technologies would be effectively neutralized.

Ongoing monitoring of proposed or implemented changes in the air quality regulatory regime will be needed to assess whether the fuel cell's air quality benefits persist as a marketable feature of the technology throughout its initial commercialization phase in the mid-to-late 1980s.

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[130] See section III.C.2. of Appendix A for an expanded discussion of these proposals.

V. IMPLICATIONS FOR KEY PARTICIPANTS IN FUEL CELL COMMERCIALIZATION

A. INTRODUCTION

This chapter recapitulates and augments the discussions of Chapters II through IV. It is divided into four sections reflecting key groups of participants in the fuel cell commercialization process: fuel cell manufacturers, fuel cell distributors, fuel cell end users, and the federal government. Each section reviews specific issues of interest to the particular participant group confronting the problem of commercialization, including matters relevant to those interested in promoting the technology and to those interested in acquiring it.

The manufacturers' section posits that "state-of-the-art" fuel cell technology must compete against "off-the-shelf" technologies, and suggests marketing considerations which may help overcome behavioral resistance. The distributors' section considers issues relating to both gas and electric utility distributors, and to nonutility distributors. The end users' section includes gas and electric utility and nonutility end users. Finally, the section on the federal government's role suggests research and monitoring activities, technical information programs and legislative involvement which could facilitate commercialization efforts.

B. MANUFACTURERS

1. "OFF-THE-SHELF" AND "STATE-OF-THE-ART" TECHNOLOGIES

Fuel cell manufacturers face an obstacle common to promoters of new technologies: potential consumers generally prefer "off-the-shelf" technologies with easily ascertainable technical and economic performance characteristics to "state-of-the-art" technologies about which they know little or nothing. During its initial commercialization phase in the latter half of this decade, the fuel cell will be competing with conventional fossil fuel-fired generation and cogeneration technologies. Industrial, commercial, residential and other consumers will have ready access to information about the processes, performance characteristics, costs, payoffs and reliability of the conventional technologies. By contrast, the fuel cell will employ a novel electrochemical technique for electrical and thermal energy production, and it will have a limited track record in terms of technical and economic performance. Fuel cell manufacturers therefore must strive to overcome the behavioral resistance of potential fuel cell users to the technology due to its novelty and attendant uncertainties, and to communicate to them the salable features of fuel cells in comparison with conventional energy technologies, including low air and noise pollutant emissions, modularity, minimum site requirements and so on.[131] This effort can be greatly assisted by

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[131] These arguments about consumer resistance to fuel cell marketing efforts apply with less force to electric and gas utilities. The gas and electric utility industries have been actively interested in the development of commercially available fuel cell units since

factoring into any marketing efforts the findings and conclusions of the kind of legal analysis presented here.

2. MARKET RESEARCH

This report has identified several types of markets which might be targeted for initial fuel cell commercialization efforts.

a. PURPA

Section IV.B. of the report has described the economic benefits which Title II of PURPA affords to non-electric utility fuel cell operators who can qualify as cogenerators or small power producers under the Act. Generally, the higher an electric utility's "avoided costs" of producing or purchasing electricity are in relation to a fuel cell's production costs, the more attractive are sales of all or a portion of the fuel cell's output to the utility. A fuel cell operator may optimize the economic benefits of such sales by selling all of the fuel cell's output to the utility at the utility's avoided costs and purchasing on-site electrical requirements at the utility's average tariff rate; moreover, the operator may wish to oversize the fuel cell system relative to on-site electrical demand to maximize the payoff from such sales to the local utility.

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the inception of commercialization efforts. The levels of activity of utility research groups (GRI and EPRI) and of utility users groups reflect the commitment to fuel cell development by the two utility industries. Entities in the nonutility sectors to which substantial economic benefits might accrue from fuel cell use appear to be relatively unrepresented, and are appropriate candidates for increased involvement.

It would be in the interests of fuel cell manufacturers to sponsor, as part of their market research, ongoing studies of utility "avoided cost" trends nationwide. These studies should seek to identify specific electric utilities whose avoided energy and/or capacity costs are anticipated to be especially high in the latter half of the 1980s and thereafter. Section IV.B. of the report discusses characteristics of electric utilities which contribute to high avoided costs and offers some examples of utilities with currently high avoided costs. The service areas of such electric utilities could be targeted in the manufacturers' initial market penetration strategies, and particular classes of potential fuel cell users within those areas identified as attractive candidates to acquire fuel cells (by virtue of their ability to capitalize on PURPA sales to utilities).

b. CLEAN AIR ACT

Section IV.C. of the report has delineated economic benefits which fuel cell operators may derive from the low emissions characteristics of the fuel cell in comparison with the high emissions rates of conventional generating and cogenerating technologies.

Operators of "existing sources" can utilize fuel cells to replace their existing on-site generating equipment and thereby create "emissions reduction credits." They can use these credits for present "internal" offset requirements, sell them to others to satisfy the latter's "external" offset requirements, or "bank" the credits for future sale or internal use.

Operators of "new sources" subject to external offset requirements can purchase fuel cells in lieu of conventional generating or cogenerating equipment to meet on-site electrical and/or thermal energy requirements, in order to minimize the external offsets which they would otherwise need to acquire. Alternatively, they can purchase fuel cells for existing sources within the area as offsets for their own incremental emissions.

Prime targets of opportunity for manufacturers' initial fuel cell marketing efforts should, therefore, include operators of existing and new sources subject to offset regulations — generally utilities and large-scale industrial facilities — located in areas with significant offset demands.[132] The report indicates specific nonattainment areas which are expected to require hydrocarbon and nitrogen dioxide offsets and particulate matter offsets after 1987, and suggests certain types of sources in attainment areas which may require offsets in the same time frame.[133] Within this group of potentially attractive market areas, the most desirable will be those which have active and ongoing formal offset trading and banking programs with a minimum of "red tape," and in which external offset transactions command the highest prices (on a dollars-per-kg/y (dollars-per-tpy) basis).

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[132] A list of large-scale industrial facilities generally deemed to be "major sources" subject to offset regulations is presented in §II.C.1.b. of the Appendix. "Minor sources" in certain areas with intractable air pollution problems may also be subject to offset requirements. (*Id.*, §III.B.1.a.)

[133] See §III.C.1. of the Appendix for a detailed discussion.

3. FUEL CELL DESIGN SPECIFICATIONS

During the course of their product development activities, the manufacturers will optimize the design specifications of first-generation fuel cell units offered commercially to dovetail them to specific markets which market research indicates will afford opportunities for early market penetration. This section suggests factors to include in the design optimization process.

a. OPTIMAL MODULE SIZING

One factor which the manufacturers will consider in the design of fuel cells is the optimal sizing of commercially available modules. Different fuel cell sizes will undoubtedly be offered for different applications: the 40 kw and 5-11 MW commercial prototypes being studied by gas and electric utilities, respectively, underscore this point. As an example, this report suggests that operators of very large industrial facilities may derive a combination of significant economic benefits from operating fuel cell systems, including: the energy and economic efficiency of operating a fuel cell system in a cogeneration mode to meet on-site electrical and/or thermal energy demands; the PURPA economic benefits of electricity sales to electric utilities; and the economic benefits of internal and external offset transactions involving fuel cells. Accordingly, manufacturers may wish to consider marketing different sizes of fuel cell modules designed to meet the on-site (electrical and/or thermal) energy requirements of different sizes and types of industrial facilities, and/or their requirements for electricity sales to electric utilities. Sizing requirements will, of course, vary both within and across classes of industries and should be one element of market research examining the potential needs of large industrial facilities in different Standard Industrial Classification codes.

b. DISPATCHABILITY, RELIABILITY AND LOAD-SHEDDING CAPABILITY.

The report suggests that the PURPA requirements governing "qualifying facilities" (QFs) may have additional ramifications for fuel cell design decisions by the manufacturer. Insofar as the Act and its implementing regulations attach economic value (reflected in the rates that the QF can charge a utility) to physical characteristics of a QF such as its dispatchability by the electric utility, its reliability, and its ability to separate its load from its generation during a utility system emergency, manufacturers should give thought to optimizing fuel cell design for these types of physical characteristics so as to facilitate PURPA sales by fuel cell operators to electric utilities.

c. ALTERNATE FUEL CAPABILITIES.

Section III. B. of the report has described the impacts of current regulations implementing NGPA Titles I, II and IV which govern the pricing of domestically produced natural gas and the federal curtailment priority scheme used during regional natural gas shortfalls.

The analysis details how prices for domestic natural gas, by no later than the late 1980s or early 1990s, will attain rough parity with decontrolled prices for petroleum products (such as naphtha) set in large part by OPEC pricing decisions and other events in the global petroleum market. One implication of this for fuel cell commercialization is that, as the prices of natural gas and naphtha become more dear, the prices of alternative fuels such as biomass-derived gas which cannot presently compete with conventional fuels will become more competitive with these fuels for fuel cell operators.

The analysis also posits the open question of whether the eventual decontrol of domestic natural gas prices will materially improve the domestic gas supply picture. Certain regions of the country have experienced natural gas supply shortfalls which have necessitated gas curtailment practices designed to protect "high-priority" gas end-users (such as residences, schools and hospitals) by curtailing "low-priority" ones (particularly industrial facilities with alternate fuel capabilities and interruptible gas requirements). If natural gas pricing decontrol does not significantly improve the availability of natural gas in these regions, gas curtailments will continue to be a fact of life. In some regions, only certain industrial gas customers may be affected, and in others, high priority residential and other gas users may also be impacted.

Accordingly, several implications merit consideration: First, manufacturers' current efforts to expand alternate fuel capabilities to include not only natural gas, naphtha and other liquid petroleum products, but also fuels derived from other feedstocks such as biomass and coal should help to promote fuel cell acceptance in areas of the country historically susceptible to natural gas and naphtha supply shortfalls. Such efforts might be supplemented by periodic regional supply and demand forecasts (disaggregated by class of potential fuel cell owner such as residential, commercial, industrial, etc.) for natural gas, naphtha and other fuels feasible for fuel cell operation, in order to identify particular areas in which shortfalls of a specific fuel may be expected to occur, and which therefore may not be ideal starting points for initial fuel cell marketing efforts.

4. MARKETING AND DISTRIBUTING

At this stage of fuel cell development and demonstration, business planning for actual commercial marketing and distribution activities is obviously premature, and in any case is beyond the scope of this report. While the selection of entities and strategies for marketing and distribution is ordinarily the manufacturers' prerogative and may vary from firm to firm, a variety of entities appear to be logical candidates for involvement in one way or another. These would include the manufacturers themselves, independent firms operating as manufacturers' representatives, gas utilities, electric utilities, architect-engineering firms, and perhaps others. The participation of gas and electric utilities in these efforts seems most likely to raise legal and institutional issues requiring attention. Some of these are suggested in the following section.

C. DISTRIBUTORS

Distribution of fuel cells to end users might take a number of forms. The distributor might sell the fuel cell outright to the end user, it might lease it, or it might retain control of the fuel cell facility and sell the energy produced by it to the end user (fuel cell energy service). Some of the issues likely to arise in these settings are reviewed below.

1. UTILITY DISTRIBUTORS

a. GAS UTILITIES

Natural gas distribution utilities, GRI and their fuel cell users group have evidenced an interest in examining the possible benefits of distributing fuel cells. To date, they have not expressed a categorical preference for any one of the options of fuel cell sales, leases or energy services. Most likely, different gas utilities will prefer different distribution options based on their own economic, financial, and organizational considerations. Some will sell or lease fuel cells and sell natural gas to fuel them; others will own and operate fuel cells and sell the electrical (and possibly thermal) outputs.

One issue to be evaluated by each gas utility considering these roles is whether the activities contemplated will be regulated as public utility functions. Sales of electrical energy from fuel cells (energy service) other than by contract to selected users would be treated as a public utility activity in most states, whereas sales or leasing of fuel cells (probably through a subsidiary) may not be. Public utility laws and regulations vary substantially from state to state. Their impact can substantially affect the structuring of gas utility activities in this area, and should be the subject of careful research by GRI or individual gas utilities.

Assuming that utility status attaches to energy service arrangements, another question is whether a gas company providing such services would be compelled or permitted to establish a rate base for the costs of owning and operating fuel cells separate and apart from its general rate base for gas distribution activities. This question also requires careful examination of specific states' public utility statutes and regulations.

Perhaps the most important and far-reaching issue in this area is the possible conflict between gas and electric utility-provided energy services in areas covered by electric utility franchises. This will require analysis of court and commission interpretations governing the scope of such franchises, as well as examination of specific franchises in particular cases. Franchise gas utility restrictions might take the form of geographical limitations on service or explicit prohibitions on engaging in the generation of electrical energy for purposes of sale; electric utility franchises might or might not preclude the particular gas utility activities contemplated in a given situation. Resolution of these questions requires careful attention by GRI and/or individual gas utilities in the reasonably near future, so that any legislative or regulatory changes which might be needed could be initiated in a time frame consistent with gas utility plans for commercial participation.

b. ELECTRIC UTILITIES

To date, electric utilities have tended to focus on their own ownership of fuel cells at central station and substation locations to supply electricity to their transmission and distribution systems, rather than on the prospects for marketing and distributing fuel cells to others. Over time, however, some electric utilities may perceive potential economic and financial benefits in such activities similar to those perceived by some gas utilities.

These electric utilities will encounter the same kinds of public utility regulatory questions regarding fuel cell distribution subsidiaries and rate basing, and will need to undertake the same types of legal research. Franchising questions relating to the sale of electrical energy from dispersed fuel cells may need to be addressed, along with questions of the allowable scope of any distribution activities.

2. NONUTILITY DISTRIBUTORS

As noted above, fuel cell manufacturers may decide to rely on nonutility entities as distributors, including themselves, manufacturers' representatives, or architect-engineering firms.

These nonutility distributors could encounter institutional problems in the area of fuel cell energy services. A nonutility distributor who sells the electric output of a fuel cell may be regulated as a public utility with its rates subject to the approval of a public utility commission. As mentioned previously, public utility regulations vary among states, and the treatment of specific nonutility distributors in particular situations will be determinable only through the review of specific state laws and regulations governing public utilities.

D. End Users

This section discusses findings of the report relating to both utility and nonutility fuel cell end users.

1. GAS UTILITIES

In addition to questions of franchising and rate treatment discussed above, several other issues deserve attention in the specific context of gas utility ownership or energy service-related activities.

PURPA's limitations on electric utility ownership of "qualifying facilities" do not apply to gas utilities.[134] Thus, PURPA permits gas utilities which otherwise satisfy QF criteria to sell the electric output of fuel cells operated by them to local electric utilities at the latter's avoided costs, a potentially lucrative activity where the electric utility has high avoided costs. Gas utilities interested in this prospect would additionally need to examine whether the terms of their state or local franchises might preclude such electricity sales.

If it supplied thermal energy to others, a gas utility could, in some states, be subjected to public utility regulation of such activities and might be required to seek an amendment of its franchise in order to engage in them.

Gas utility-operated fuel cell units standing alone (without connection to a supplemental-fired boiler) would not be subject to PIFUA's use restrictions on natural gas.

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[134] See FERC Docket No. RM79-54, Order No. 70-B, 45 Fed. Reg. 52779 (August 8, 1980).

In areas subject to periodic gas shortfalls, curtailment priorities for on-site fuel cells owned and operated by gas utilities providing energy services should be determined, as in other cases, by the type of activity and purpose for which the gas is used, independent of fuel cell ownership.

2. ELECTRIC UTILITIES

To the extent that they follow the lead of gas utilities in examining the provision of fuel cell energy services to service area customers, electric utilities will face similar rate-basing, franchise and other public utility regulatory issues mentioned above for gas utilities, with the notable exception that PURPA limits their participation in QF ownership to 50%, and thus suggests somewhat different questions in this area (relating to structuring relationships with possible joint venture partners and insulating their QF activities from their other activities).

PIFUA has several implications for electric utilities operating fuel cells on natural gas or petroleum products (including naphtha). Fuel cell units operated by them without connection to a gas-fired supplemental-fired boiler will not be subject to PIFUA's restrictions on oil or natural gas usage. Certain multimegawatt fuel cell cogeneration systems (with attached boilers) owned by them may arguably be subject to PIFUA's prohibitions on oil or gas usage in "new boiler MFBIs," and they would therefore need to secure a permanent exemption from fuel use restrictions governing these types of facilities. Insofar as they have focused on central station applications for fuel cells, electric utilities have generally not been overly interested in recovering thermal energy from fuel cells for cogeneration purposes and would not be expected to design fuel cell cogeneration systems which include supplemental-fired boilers. They could, in any event, recover useful thermal energy from a fuel cell (in the event that they wish to cogenerate) without resort to a supplemental-fired boiler, by using a waste heat recovery boiler without supplemental firing; this latter type of fuel cell system would probably escape PIFUA's prohibitions.

Electric utilities will find the air quality benefits of fuel cells to be attractive for two reasons. In areas where they operate existing polluting, inefficient generation equipment, they can retire these existing sources and replace them with fuel cells: surplus emissions reduction credits created in these internal offset transactions can be sold or banked. In areas where they have no existing sources, their "new source" fuel cells would probably need to have capacities of at least 100 MW to emit the pollutant levels which would result in their classification as "major sources" subject to new source review. Even in areas where offsets are required for "minor new sources" as well as major ones, only nominal external offsets would be required for fuel cell systems, whereas significant offsets would be needed for conventional electrical generating equipment such as steam turbine, gas turbine and combined cycle units.

Other attributes of fuel cells such as minimum site requirements, load following capability, silent operation, and spinning reserves, among others, are well documented in EPRI literature.

Electric utilities operating fuel cells with natural gas in areas of the nation susceptible to periodic shortfalls of natural gas will be treated as low-priority gas customers during curtailment periods. These utilities should have an alternate fuel capability for their fuel cell units.

3. NONUTILITIES

a. GENERALLY

This subsection treats issues common to all or most classes of nonutility fuel cell users.

NGPA

All nonutility fuel cell users face the prospect, in the late 1980s or early 1990s, of prices for natural gas and naphtha and other light petroleum products which are in rough parity and which are tied to OPEC pricing decisions and other events in the global energy market. Consequently, these fuel cell fuels will become more costly, and alternate fuels such as biomass gas and synfuels which are not presently cost-competitive may become more so.

In areas of the country which have experienced natural gas shortfalls, fuel cell operators using natural gas may be subject to curtailment. Depending upon the severity of a shortfall, curtailments may extend only to "low-priority" gas users such as utility and industrial facilities or may include "high priority" gas users such as residential fuel cell users.

PIFUA

Federal oil and gas fuel use restrictions will not apply to nonutility-operated fuel cells standing alone, regardless of their size. Certain multimegawatt fuel cell cogeneration systems employing supplemental-fired boilers may be subject to PIFUA's prohibitions on oil and natural gas usage, but generally will be eligible for permanent exemptions as "cogeneration facilities," provided that less than 50% of their net electric output is sold or exchanged. Where no other ground for exemption (e.g., environmental or logistic requirements) is available, and oil or gas fuels are contemplated, this restriction may influence operators of these large fuel cell systems to down-size their units to a level consistent with on-site energy demands so as to operate them efficiently at a high capacity factor. This down-sizing effect contrasts with PURPA's oversizing effect described below. Although PIFUA's 50% ceiling on electric sales by facilities seeking cogeneration exemptions would limit possibilities for "scaling up" to maximize PURPA sales to electric utilities, it would affect only the largest nonutility installations.

PURPA

Most fuel cell cogeneration systems operated by nonutilities should satisfy PURPA's "qualifying facility" criteria. They will be able to sell all or a portion of their fuel cell's electrical output to an electric utility at the utility's "avoided costs" without being subjected to state public utility regulation. Fuel cell owners may wish to oversize their fuel cells so as to maximize the profitability of their electricity sales to a local utility, while purchasing back from the utility their on-site electrical requirements at the utility's average tariff rate.

Public Utility Regulation

In many states, nonutilities may be exposed to public utility regulation for sales of electrical energy or usable thermal energy to nonutilities such as co-located industrial facilities, commercial establishments or apartment buildings. In general, regulation will be triggered only by energy sales offered to the general public, but state definitions in this area vary widely.

Clean Air Act

As described in greater detail in the prior section on fuel cell manufacturers, operators of "existing sources" and "new sources" subject to offset regulations — at a minimum, large-scale industrial facilities and other sources deemed to be "major sources," and, in certain areas with poor air quality, "minor sources" as well — located in nonattainment and attainment areas will find the fuel cell effective to minimize the costs of offset requirements (in the case of both new and existing sources) and to maximize the economic benefits of emissions reduction credits for internal use, banking or sale (in the case of existing sources only).

The following subsections describe particular characteristics of specific categories of nonutility fuel cell end users which may make them attractive candidates and examine issues of special importance to them.

b. INDUSTRIAL END USERS

Generally, industrial firms which have one or more of the following attributes may find the economic benefits of fuel cell ownership attractive to them:

- they have significant on-site electrical and/or thermal energy demands;
- they currently generate (but do not cogenerate) all or a portion of their electrical and/or thermal energy requirements, or are sophisticated in the use of high technology equipment, and therefore have a technical orientation which might encourage generating their own energy;
- they purchase all or a substantial portion of their electrical needs from a local electric utility, but face the

prospect of severe energy cost escalation;

- they are in the business of undertaking risk-oriented ventures and may view acquisition of fuel cells for purposes of PURPA sales to electric utilities as an attractive investment;
- they are a "new" or "existing" source facing costly external or internal offset requirements, in view of plans to build new industrial facilities or modify existing ones, or because of tightening local pollution control requirements.

Since industrial firms tend to prefer investments with high rates of return and short payback periods, the payoffs of utilizing a fuel cell to cogenerate, engage in PURPA sales and/or benefit from emissions offset transactions will need to be substantial. Interested industrial entities may include not only firms engaged in heavy industrial production, but also owners or developers of industrial parks who see a profit in providing electrical and/or thermal energy services to park lessees.

As previously stated, industrial end users who utilize natural gas in their fuel cells will be subject to curtailment as "low priority" gas users in areas subject to gas curtailments and will need to secure arrangements for a backup fuel such as naphtha.

c. COMMERCIAL END USERS

Certain types of commercial end users may find fuel cells to be attractive.

Twenty-four hour foodstores, restaurants, hotels and motels will have round-the-clock electrical and thermal energy loads and may find the fuel cell's electrical and low-quality thermal output characteristics to be appealing.[135]

Operations of private commercial centers (for example, office parks and shopping malls) may find fuel cells to be useful for providing electrical and thermal energy services to their lessees.

Commercial entities' electricity generation activities will not be treated as "high priority" gas uses, and their fuel cell systems will be susceptible to curtailment in regions experiencing severe gas shortfalls.

d. RESIDENTIAL END USERS

Attractive residential fuel cell applications may include multifamily dwellings such as apartment buildings, condominiums, and cooperatives. From a behavioral viewpoint, very large multifamily dwellings probably will be the most attractive applications, since their owners or operators will be more likely to have the technical and entrepreneurial orientation to be attracted to the full range of fuel cell benefits (including PURPA sales to electric utilities) outlined for industrial firms, and many will already be in the business of providing space heating and domestic water heating services to residents. An illustrative example is Coop City in New York City, a high-rise residential building complex operated by a cooperative association, which is exploring the possibility of utilizing

[135] National chains of these types of commercial establishments may be particularly attractive candidate markets for fuel cell manufacturers and distributors, insofar as they provide centralized procurement points for potentially large fuel cell markets. These chains should be included in market research.

natural gas from a local landfill to operate cogeneration equipment which will serve the on-site electrical and thermal energy requirements of its 50,000 cooperative members.

Residential fuel cell owners generally will be classified as "high priority" gas customers and therefore generally insulated from gas curtailments.

e. SCHOOLS, HOSPITALS AND SIMILAR INSTITUTIONS

Schools, hospitals and similar institutions such as prisons may find fuel cells attractive for meeting on-site energy needs. Residential colleges and hospitals may have round-the-clock electrical and thermal loads (e.g., space and water heating) which can make full use of a fuel cell system's outputs. Hospitals, in particular, are accustomed to using high technology equipment. The administrators of these facilities would probably not view the payoff of PURPA electrical energy sales in the same light as more entrepreneurial entities; they would take a more conservative approach by focusing on on-site benefits as a deciding factor. Consequently, the economics of fuel cell ownership might not appear as attractive as in the case where PURPA sales are factored into the decisionmaking process.

Schools, hospitals and similar institutions are treated as "high-priority" gas users.

f. GOVERNMENT OFFICE BUILDINGS

Government office buildings would be able to utilize the electrical and thermal outputs of a fuel cell cogeneration system during daylight hours, but would need to sell electricity to a local utility during off-peak hours to maintain the system at a high capacity factor. Those public entities which have taken a public leadership role in promoting energy efficiency may view the fuel cell as a technology worthy of promotion.

The U.S. General Services Administration (GSA) which is the federal agency responsible for the operation of federal office buildings could play a significant role as central procurer for a large fuel cell market. GSA could publicly demonstrate the benefits of fuel cell operation (including air pollution emission reductions by displacing electricity from conventional fossil-fuel-fired power plants) and help to lower the unit costs of first-generation fuel cell units.

g. U.S. MILITARY FACILITIES

Military bases contain facilities similar to those found in civilian institutions such as residential colleges and hospitals, which contribute to round-the-clock electrical energy and thermal energy demands. These facilities include mess halls, dormitories, PXs and other facilities.

The U.S. Department of Defense (DOD), which has already shown strong interest in fuel cells for military installations, could play a major role as a central procurer for a very large potential fuel cell market. As is the case with GSA, DOD could contribute to the demonstration of first-generation commercial fuel cell units and to the lowering of their unit costs.

E. FEDERAL GOVERNMENT

The previous subsection noted potentially significant roles that federal agencies (GSA and DOE) can play in demonstrating the benefits of fuel cells and lowering their unit costs by large central procurements (as has occurred, deliberately or otherwise, with other new high technologies such as aviation, computers and telecommunication equipment). Insofar as net social benefits result from efficient utilization of fossil fuels and protection of air quality, these actions are readily justifiable in terms of the national interest.

As discussed earlier in Chapter II, federal agencies such as NASA and DOE could usefully perform a variety of other functions to further facilitate fuel cell commercialization. These agencies can, of course, continue direct support for technology research and development addressing issues such as multi-fuel capability and other performance characteristics to which PIFUA, NGPA, PURPA and Clean Air Act regulations attach particular value. They can also sponsor some of the nontechnological research and demonstration activities which we believe must be pursued, including ongoing monitoring of regulatory changes in PURPA[136] and the Clean Air Act, and regional trends in utility avoided costs and offset banking and trading.

Either agency could then serve a vital role as a central repository of information for manufacturers, distributors and prospective users of fuel cells (as well as for promoters of other state-of-the-art technologies in a position to benefit from the results of such work), and could sponsor

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[136] See note 91, *supra*, illustrating the potential for major alterations in regulatory requirements and the need for constant monitoring in this rapidly developing field.

technical symposia and workshops to disseminate this kind of information to interested participants, while providing an ongoing forum for the communication of private sector needs and perceptions to government agencies in a position to respond.

Finally, based on these kinds of activities, NASA, DOE and other interested federal agencies could actively initiate and sponsor legislation to reduce prevailing uncertainties, remove unnecessary legal, institutional and regulatory barriers. and provide incentives where necessary to assist fuel cells through the transition from the laboratory to the commercial arena.

VI. SUMMARY, CONCLUSIONS AND RECOMMENDATIONS

The purpose of this study has been to identify and assess legal and institutional factors likely to affect the development and commercial diffusion of phosphoric acid fuel cells, and to help define issues for future research and action. The study has addressed matters relevant to both central and dispersed utility operations and to on-site applications. It has examined both perceived barriers and potential opportunities for fuel cell commercialization. Key issues are discussed from the viewpoint of various participants in the fuel cell commercialization process: the fuel cell manufacturers, fuel cell distributors, fuel cell end users, and the federal government.

Major federal legislation analyzed for this study includes the Powerplant and Industrial Fuel Use Act of 1978 (PIFUA), the Natural Gas Policy Act (NGPA), the Public Utility Regulatory Policies Act of 1978 (PURPA), and the Clean Air Act.

In general, the study concludes that the potential barriers to fuel cell commercialization presented by PIFUA and NGPA are not as serious as some have supposed and should not seriously deter fuel cell use except in certain commercial and industrial applications in regions where natural gas shortfalls are likely and alternate fuel are unavailable. Perhaps even more importantly, the analysis of PURPA and the Clean Air Act reveals attractive opportunities for fuel cells in certain settings.

The specific findings of this study have fundamental implications for demonstration and market assessment activities as well as for the design and sizing of fuel cell systems, and can affect each of the participants in the commercialization process differently. More specific conclusions which emerged from this study are summarized below.

PIFUA was enacted by the U.S. Congress to restrict the use of petroleum and natural gas in "electric powerplants" and "major fuel burning installations," and accordingly has been perceived as a potential deterrent to the commercialization of fuel cells using these fuels or their derivatives. However, analysis of the Act reveals that most fuel cell applications will not be subject to PIFUA's restrictions at all, and those which arguably could be generally should be able to obtain exemptions from these restrictions. Specifically:

(a) A fuel cell standing alone should not be subject to the Act's fuel restrictions, irrespective of the magnitude of its generating capacity.

(b) Certain multimegawatt fuel cell cogeneration systems with supplemental-fired boilers (or possibly waste heat recovery boilers) may be subject to PIFUA's prohibitions on the use of natural gas or petroleum-derived fuels. However, these facilities generally should be able to obtain permanent exemptions as "cogeneration facilities" on "public interest" grounds. To qualify, fuel cell operators must restrict electrical energy sales to others (e.g., local electric utilities or industrial purchasers) to 50 percent or less of their facilities' electrical output. Some operators, however, can escape even this restriction if they can qualify for a permanent exemption on an alternative ground such as environmental restrictions on the use of coal or other non-oil or -gas fuels in their area.

Like PIFUA, the NGPA has been perceived to establish significant disincentives for prospective fuel cell users. Here again, analysis reveals that these disincentives are less serious than frequently perceived, although some of the provisions of this Act can impact on fuel cell marketing strategy.

For the purpose of this study, Titles I, II, and IV of the Act were analyzed.

Title I establishes a schedule for the phased decontrol of wellhead prices paid by gas pipeline operators to domestic producers for certain categories of natural gas. Specifically, the Act gradually deregulates the wellhead price of categories of domestic natural gas produced after 1977 ("new gas"). Starting with a base price of $1.75 per MMBtu in April 1977, the price of such categories of new gas is permitted to rise at a rate tied to the annual rate of inflation. On January 1, 1985, these price controls are scheduled to be completely removed, and new gas would be permitted to command whatever price the market would bear. NGPA continues the pre-NGPA price controls on categories of natural gas produced prior to 1977 ("old gas"), but permits an annual upward adjustment linked to the general rate of inflation. These price controls on old gas, unlike those on new gas, will continue indefinitely after 1985.

NGPA Title II was enacted partially to shield high-priority natural gas users (e.g., residential and small commercial customers) from the effects of wellhead price increases permitted under Title I's phased decontrol schedule, by passing through a portion of these increases, via surcharge, to certain lower-priority industrial facilities utilizing natural gas as a fuel to produce steam or electricity. Industrial fuel cell facilities may or may not be subject to such surcharges in the first instance under NGPA's existing regulations, but even if they are, many should qualify for exemption as "small" facilities, qualifying cogeneration facilities, electric utility generation systems or other expressly exempted users; only certain systems exceeding 1.4 MW seem likely to encounter difficulty in escaping a surcharge.

Although both Titles I and II are considered candidates for repeal or modification, as discussed in the report, it appears that in any case natural gas prices will approach petroleum market price levels and that the incremental pricing provisions (if retained) will not shield high-priority gas customers from these price increases. Assuming that fuel cells begin to reach the commercial market in the mid- to late 1980s, all potential fuel cell operators — residential, commercial, industrial or other — considering natural gas as a fuel will be facing natural gas prices which equal or approach decontrolled petroleum prices. By the late 1980s, domestic gas prices will be inextricably linked with OPEC oil pricing decisions and other events in the global petroleum market. The resultant premium prices for natural gas (and petroleum products such as naphtha and distillate and residual fuel oils as well) can be expected to adversely affect the economics of fossil-fueled fuel cell systems in relation to nonfossil-fueled technologies.

These prospects underscore the need to develop capabilities for operation on fuels such as methane which can be derived from nonfossil sources: for some users, a nonfossil fuel capability may be a more powerful inducement to fuel cell use than any of the unique features characteristic of the technology. However, since decontrolled prices will also affect conventional generation and cogeneration technologies using natural gas, a central issue for fuel cell commercialization will continue to be the relative impact of these developments on fuel cells vis à vis competing fossil-fueled options.

In addition to decontrol and incremental pricing, NGPA Title IV establishes a curtailment priority scheme governing the allocation of natural gas supplies to interstate pipeline customers during serious natural gas shortages. Under this scheme, the highest priority (P1) natural gas customers include residences, small commercial establishments, schools, hospitals, police and fire protection, and sanitation and correctional facilities.

Second highest priority (P2) is accorded to essential agricultural uses. These are followed by large commercial users (P3) and industrial users, including electric utilities (P4-P10).

Title IV defines "residence" as "a dwelling using natural gas predominantly for residential purposes such as space heating, air conditioning, hot water heating, cooking, clothes drying, and other residential uses, and includes apartment buildings and other multi-unit buildings." The current definition does not differentiate between natural gas utilized directly (e.g., in a gas stove or gas-fired furnace) and natural gas utilized indirectly (e.g., in a steam or gas turbine to produce electricity); so long as it is used predominantly for "residential purposes" on the site, it will be accorded high priority status.

"Commercial" service is service to natural gas customers "engaged primarily in the sale of goods or services including institutions and local, state, and federal government agencies for uses other than manufacturing or electric power generation." (Emphasis added.) Although commercial customers generally are accorded either P1 or P3 status depending on the size of their peak gas requirements, gas used in fuel cells for electric generation would not be eligible for such priorities, and would be curtailed as P4 or lower during severe shortages. Unlike commercial establishments, Title IV does not preclude schools and hospitals or "essential agricultural uses" (as determined by the U.S. Secretary of Agriculture) from utilizing natural gas allocations for electrical generation purposes, nor does it impose ceilings on the quantity of high priority natural gas available to them.

If higher gas prices resulting from Title I's decontrol program in fact lead to reduced demand and/or increased domestic gas production, then shortages should be ameliorated and curtailments should be minimized or forestalled. Until then, however, the possibility of natural gas curtailments can be expected to affect decisions by prospective fuel cell manufacturers, marketers and users, respectively, concerning technical specifications, marketing options and the viability of particular applications. Depending on the participants' assessments of the likelihood, breadth and severity of future curtailments, rational responses might range from total disinterest in natural gas-fired cells, to modest changes in specifications, market selection criteria or fuel supply arrangements.

The effects of present curtailment policies will vary by geographical region as well as by type of application. In regions of the country historically subject to natural gas shortfalls, low-priority gas customers could experience curtailments which would preclude the use of fuel cells without fuel-switching capability and ready access to alternate fuels such as naphtha or propane. For those interested in identifying early entry markets, the regional occurrence and variability of gas curtailments should be considered among the factors likely to influence user choices.

In addition to monitoring the prospects for curtailments from this perspective, it would be useful to develop long-term regional supply and demand forecasts for natural gas, naphtha and other fuels feasible for fuel cell operation. If properly disaggregated by region and by class of potential fuel cell owner (e.g., residential, commercial and industrial) according to curtailment priority status, these forecasts should help identify types of potential fuel cell owners in certain regions who may face a substantial curtailment risk and who may not have ready access to naphtha or other alternative fuels. These forecasts could also serve to allay any concerns of potential fuel cell owners who are in no foreseeable danger of natural gas curtailments in areas where gas shortages are not expected.

The analysis of PIFUA and NGPA summarized here suggests that these regulatory schemes would not prohibit fuel cells using natural gas or petroleum derivatives in most applications, and probably would not seriously discourage their use except in certain commercial and industrial applications in regions where natural gas shortages are likely and alternate fuels are unavailable. These conclusions can serve an important function in dispelling industry uncertainty and narrowing concerns over the implications of federal fuel use and pricing policies. That function is essential in the larger commercialization effort, since uncertainty and apprehension in themselves constitute very real barriers to proceeding. In this sense, these conclusions satisfy certain necessary but insufficient conditions for further interest in and progress toward commercial fuel cell use. Beyond this, it remains to examine positive legal and regulatory inducements which can encourage prospective fuel cell users to invest in this new technology. Both PURPA and the Clean Air Act provide such inducements.

Title II of PURPA is intended to foster competition in electric generation by encouraging independent producers to undertake small-scale generation using nonconventional fuels, and to increase fuel efficiency through cogeneration. The arrangements mandated by PURPA have far-reaching implications for the future structure of the nation's electric supply industry, and possibly for development and marketing decisions affecting some types of fuel cells.

Title II's benefits, reviewed below, are available to two types of facilities: "small power production facilities" and "cogeneration facilities." A small power production facility is defined as one which produces up to 80 MW of electricity using biomass, waste, renewable resources or geothermal as its primary energy source. A cogeneration facility is one which produces electricity and other useful energy (including steam or heat) for "industrial, commercial, heating, or cooling purposes," without regard to the size of the facility or the type of fuel used. To qualify for PURPA benefits, facilities must meet certain technical standards and must be owned by a person or persons "not primarily engaged in the generation or sale of electric power," which means that the facilities must be owned not more than 50% by an electric utility or utilities, electric utility holding company or companies, their subsidiaries or combinations thereof. FERC rules permit gas utilities to own qualifying facilities eligible for Title II's benefits, including "avoided cost" sales to electric utilities.

If a fuel cell facility were planned to utilize only the electric output and none of the cells' thermal potential, then it could not qualify as a cogeneration facility, but would have to qualify, if at all, as a small power producer. This means that it would have to satisfy the fuel use and size restrictions indicated above. First-generation cells using natural gas or naphtha would not satisfy the fuel use restrictions, and therefore would not be eligible whatever their size. Future fuel cell configurations utilizing methane or other fuels produced from biomass or waste could satisfy the fuel use restrictions, and would qualify if their power production capacity were 80 MW or less and if PURPA's ownership criteria were met.

On the other hand, if a fuel cell facility were planned to utilize both the cells' electric and thermal output, then it would meet PURPA's definition of a cogeneration facility regardless of the type of fuel used or the facility's size, subject only to ownership criteria and certain technical standards which appear well within current fuel cell capabilities.

For qualifying fuel cell installations, PURPA virtually ensures a market for as much of their electric output as they might choose to sell. As interpreted by FERC, the Act also ensures that in many cases the prices paid for this output will be substantially higher than they might have been without PURPA.

To ensure a market for small power producers and cogenerators, PURPA and FERC rules generally require electric utilities to purchase all the electric output offered by qualifying facilities with which the utility is interconnected and (subject to the outcome of litigation now pending) to interconnect with any qualifying facility where necessary to accomplish such purchases. To ensure prices above those which independent power producers might otherwise have commanded from monopsony purchasers, FERC rules (also under challenge) require purchase rates equal to the purchasing utility's incremental or "avoided cost" of power, typically exceeding the utility's average embedded costs which might otherwise limit power purchase rates.

These rules provide that qualifying facilities are entitled to be paid avoided cost rates for their entire output even where they are simultaneously purchasing electricity from the utility at its lower average cost for use in their own operations. Under this scheme, which so far has withstood legal challenges, qualifying facilities may purchase all of their electricity requirements at average-cost retail rates and sell all of their electric output at marginally-priced avoided cost rates. Opportunities to profit from FERC's simultaneous purchase and sale rule may be enhanced in areas where qualifying facilities are among the customer classes which an electric utility serves under time-of-day rates. Design decisions which take into account technical characteristics valued under PURPA can further enhance fuel cell economics and marketability.

In addition to these power purchase requirements, FERC rules exempt qualifying small power producers of up to 30 MW capacity (80 MW for geothermal or biomass-fueled facilities) and all qualifying cogenerators from the major burdens of federal and state utility regulation governing wholesale power sales (though not from those governing retail sales of electricity or heat to nonutility purchasers, which typically will be regulated under existing state laws unless they involve limited distribution systems based on individually negotiated contracts).

Apart from PURPA's benefits, other legal and regulatory inducements for the deployment of fuel cell powerplants arise from their benign environmental characteristics. Specifically, the fuel cell's nonpolluting characteristics can translate into very real and very tangible economic value under conditions defined by the federal Clean Air Act and regulations and by state air quality regimes in furtherance of the federal scheme. Where such conditions obtain, these regulations can provide the opportunity for potential fuel cell owners or operators to realize substantial savings and/or income which would not accrue from the use of competing generation or cogeneration equipment.

Operators of existing polluting generating sources (for example, diesel generators and oil- or gas-fired boilers) can replace them with fuel cells and thereby create "emissions reduction credits." These credits, which have actual dollar values, can be applied as offsets to reduce pollution control or other costs otherwise associated with plant renovations or expansions; they can be sold to others for similar purposes; or they can be "banked" for future internal or external use. "New source" operators can acquire fuel cells to meet on-site needs and minimize external offset requirements and costs, or even to be used by other, existing sources in the area as offsets for the new source's incremental emissions.

Assuming the continuation of the current regulatory regime, prime targets of opportunity for fuel cell marketing in terms of air quality leveraging possibilities should include operators of existing and new major sources — generally, utilities and large-scale industrial facilities — in poor air quality areas with significant demands for "bubble," "netting," nonattainment and/or PSD increment exceedance offsets. Except for unusually large facilities or those in poor air quality regions with particularly stringent regulations affecting even minor sources, commercial and residential operations are far less sensitive to air quality regulation, and on-site fuel cell installations in these situations can benefit correspondingly less from air quality leveraging under existing schemes.

Ongoing market research will be needed to identify particularly attractive areas and entities. Within this group of potentially attractive market areas, those areas which have active offset trading and banking programs with relatively few restrictions should be slated for early marketing activities.

While this study has evaluated the impact of several major pieces of federal energy legislation on the commercialization of fuel cell powerplants, it has by no means been exhaustive. Other legal and institutional considerations, including those arising from state and local laws and regulations, should be reviewed for possible adverse or beneficial impacts on fuel cells. Much of the federal legislation reviewed here requires implementation and enforcement by state regulatory agencies. The nature of their actions will vary from state to state, and in some areas, these agencies remain in relatively early stages of rulemaking. Continuous and systematic monitoring of changes in controlling laws and regulations and in related developments, such as avoided cost trends for individual electric utilities nationwide, regional gas curtailment practices and air quality developments in different localities, is critical to all of the participants in fuel cell commercialization.

At the state and local level, one of the most important and far-reaching issues for future attention is the possible conflict between gas and electric utility-provided energy services in areas covered by electric utility franchises. This will require analysis of court and commission interpretations governing the scope of such franchises, as well as examination of specific franchises in particular cases. Since issues arising in this area may significantly affect the structure of the industry affected by commercialization efforts, they should receive early attention.

While this study has identified various factors potentially bearing on market assessment, such as natural gas curtailment policies and anticipated regional supply variations, electric utility avoided costs and air quality considerations, these factors will need to be quantified where possible to identify specific market segments which are particularly attractive for fuel cells. Toward this end, efforts should be undertaken to:

(a) Identify specific electric utilities whose avoided energy and/or capacity costs are anticipated to be especially high in the latter half of the 1980s and thereafter. Section IV.B. of the report discusses characteristics of electric utilities which contribute to high avoided costs and offers some examples of utilities with currently high avoided costs. The service areas of such electric utilities could be targeted in the manufacturers' initial market penetration strategies, and particular classes of potential fuel cell users within those areas identified as attractive candidates to acquire fuel cells (by virtue of their ability to capitalize on PURPA sales to utilities).

(b) Identify specific nonattainment areas which are expected to require hydrocarbon and nitrogen dioxide offsets and particulate matter offsets after 1987, and certain types of sources in attainment areas which may require offsets in the same time frame. Within this group of potentially attractive market areas, the most desirable will be those which have active and ongoing formal offset trading and banking programs with a minimum of "red tape," and in which external offset transactions command the highest prices.

(c) Identify regions of the country that have experienced natural gas shortages which have necessitated gas curtailment practices designed to protect high-priority gas end-users (such as residences, schools and hospitals) by curtailing low-priority ones.

APPENDIX A - FEDERAL AND STATE AIR QUALITY REGULATORY REGIMES PROMOTING FUEL CELL COMMERCIALIZATION

BY

KEVIN D. SHEEHY

I. INTRODUCTION

This appendix explains the workings of the federal and state air quality regulatory regimes impacting industrial facilities and other "stationary sources," and describes the manner in which these regimes may serve to foster the commercialization of fuel cells in the late 1980s and thereafter.

Section II of this appendix differentiates the federal air quality regulatory provisions governing "existing stationary sources" and governing "major new sources" and "major modifications" in "nonattainment" and "attainment" areas. It describes four methods whereby such source types may be required, either to avoid or comply with certain state or local air pollution control regulations, to "offset" their air pollutant emissions: "bubble," "netting," nonattainment, and PSD increment exceedance offsets.

Section III examines more closely the methods whereby offsets are created, traded and banked. It describes current offset trading and banking activities, as well as future trends in these activities based, alternatively, on t e current air quality regulatory regime and on proposed changes in the federal Clean Air Act.

Section IV relates future offset trading and banking trends to fuel cell commercialization efforts in the latter part of this decade and thereafter, and suggests several potentially attractive markets for fuel cells in this time frame which should be the subject of future market research.

II. FEDERAL AIR QUALITY REGULATORY PROVISIONS GOVERNING THE SITING, OPERATION AND EXPANSION OF STATIONARY SOURCES

A. Brief Overview of Stationary Source Regulation

Section II describes in broad terms those sections of the federal Clean Air Act and EPA's implementing regulations which exert a significant impact nationwide upon the siting, operation and expansion of air pollutant-emitting industrial facilities and other "stationary sources," and which, we believe, can provide a potentially significant impetus to fuel cell marketing efforts geared to both utility and nonutility entities.

This subsection presents a brief overview of relevant features of the federal regulatory scheme for stationary source emissions. Following subsections provide greater detail on specific portions of the scheme.

Exercising its authority conferred by the federal Clean Air Act,[1] EPA has promulgated national ambient air quality standards (NAAQS) for the following *criteria* pollutants: sulfur dioxide (SO_2), nitrogen dioxide (NO_2), carbon monoxide (CO), particulate matter (PM), and ozone (O_3).[2] The standards for each of these criteria pollutants have taken two forms: *primary* NAAQS to protect the "public health" and *secondary* NAAQS to

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[1]Clean Air Act (hereafter CAA) §109.

[2]EPA has also promulgated NAAQS for lead, but this criteria pollutant has no relevance to our analysis of fuel cells. Standards for "noncriteria" pollutants (e.g., asbestos, fluorides, and vinyl chloride) are also beyond the scope of this report.

protect the "public welfare"; PM and SO_2 are the only criteria pollutants for which EPA has developed secondary NAAQS that exceed the primary NAAQS.[3] Air quality control regions, and portions of such regions, which presently exceed primary or secondary NAAQS are denominated as *nonattainment areas*; those regions that comply with NAAQS are classified as *attainment areas*.[4] Depending upon the relative mix of pollutants within that region, a given region may have both a nonattainment status for one or more criteria pollutants, and an attainment status for the remaining criteria pollutants.

The Clean Air Act generally requires each state to develop, and submit to EPA for approval, a *state implementation plan* (SIP).[5] The SIP must be able to demonstrate attainment of the primary NAAQS for each of the criteria pollutants in all of its nonattainment areas by December 31, 1982; for the O_3 and CO primary NAAQS, a state which can demonstrate its inability to meet the 1982 attainment deadline in a particular nonattainment area, despite the implementation of all "reasonably available control measures" (RACM), is permitted to extend its attainment deadline to December 31, 1987.[6] The state's SIP must also demonstrate that secondary NAAQS will be attained "as expeditiously as practicable" in all nonattainment areas.[7] Finally, the

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[3] CAA section 109.

[4] *Id.* section 107(d). Hereafter, we will also use the term "attainment area" to refer to areas for which available information is insufficient to classify as "nonattainment." *Id.*

[5] *Id.* section 110.

[6] *Id.* section 172(a)(1), (2). A construction moratorium is placed upon major new facility construction in states whose SIPs are deemed by EPA to be inadequate to meet these statutory attainment deadlines. *Id.* section 110(a)(2)(I).

[7] *Id.* section 172(a)(1).

SIP must contain a program which ensures that NAAQS for each criteria pollutant are maintained in all attainment areas.[8]

A state's SIP must impose emissions limitations on "existing" and "new" stationary sources (and schedules for compliance with these limitations) which ensure the attainment and maintenance of NAAQS for each region.[9] The SIP must also include provisions requiring permits for the construction and operation of "new" and "modified" "major stationary sources" in nonattainment areas (hereafter, Clean Air Act Part D requirements, or "nonattainment" regulations)[10] and in attainment areas (hereafter, CAA Part C requirements, or Prevention of Significant Deterioration of Air Quality (PSD) regulations.[11] These terms and regulatory provisions are described more fully in the following subsections.

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[8] *Id.* sections 110(a)(2)(B), 161.

[9] *Id.* section 110(a)(2)(B).

[10] *Id.* sections 171 *et seq.* (Part D).

[11] *Id.* sections 160 *et seq.* (Part C)

B. Existing Stationary Sources

1. SIP EMISSIONS LIMITATIONS

As previously noted, "existing" stationary sources[12] in both nonattainment and attainment areas within a particular state are subject to specific emissions limitations (and concomitant schedules) within an EPA-approved SIP as part of the state's overall strategy to attain and maintain NAAQS on a statewide basis within the time frame of the Clean Air Act.

At this point, it is useful to illustrate the workings of an SIP in relation to an existing source within a particular nonattainment or attainment area. A *stationary source* is "any building, structure, facility, or installation which emits or may emit any air pollutant."[13] One example of an existing stationary source is an industrial facility with several production process units emitting the same type of pollutant; a state SIP might list different specific emissions limitations by pollutant (e.g., tons-per-year or pounds-per-hour of hydrocarbons) for each of the process units. As another example, the operator of a utility powerplant with several boiler stacks might be required to comply with a uniform emissions limit by pollutant (e.g., X pounds-per-hour of SO_2) at each of the stacks.

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[12]The differentiation between *existing* and *new* stationary sources hinges upon whether a source predates the publication date for relevant air quality implementing regulations promulgated by EPA. *Id.*, sections 111(a)(2), (b).

[13]*Id.*, section 111(a)(3)

At a minimum, an SIP must include a permit program regulating the construction, operation and modification of existing sources deemed to be *major sources*: that is, stationary sources which emit or have the potential to emit 100 tpy (9.072×10^4 kg/y) or more of a pollutant.[14] To the extent necessary to ensure that NAAQS are achieved and maintained, an SIP should also include a program for enforcing emissions limitations on existing sources which are *minor sources* — that is, those that emit less than 100 tpy. In other words, some air pollution control agencies will only need to enforce emissions limits on major sources, and others will need to do so for both major and minor sources.

2. RACT

Operators of existing sources in nonattainment areas are additionally required to implement *reasonably available control technology* (RACT) at these sources, as part of an overall SIP strategy to ensure "reasonable further progress" toward attainment by the statutory deadlines of the Clean Air Act.[15]

3. "BUBBLE" POLICY

In December 1979, EPA implemented a *bubble policy* to afford operators of existing sources in nonattainment and attainment areas a certain degree of flexibility in complying with the emissions limitations

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[14] *Id.*, sections 100(a)(2)(D), 302(j). See section II.C.1. of this Appendix for a detailed description and examples of "sources" and "major sources."

[15] *Id.*, section 172(b)(3).

contained in the state SIPs.[16] As previously noted, prior to this policy's inception, SIPs required the operator of an existing facility to comply with specified emissions reductions at each emissions point within the facility. Now, an operator can satisfy the aggregate required emissions reductions for a given pollutant at the facility by placing a "bubble" over the facility's emissions points (stacks, vents, ports, etc.), and optimizing the costs of pollution control: that is, by instituting additional emissions reductions <u>below</u> required levels at one or more emissions points with low pollution control costs, as a substitute (on a one-for-one basis) for required emissions reductions at one or more other points with high pollution control costs. For example, the operator of the previously mentioned industrial facility could undertake additional reductions of hydrocarbons at one or more of the other units. Similarly, the utility operator of the powerplant might be permitted to optimize the mix of low-sulfur coal and stack cleaning controls at each of its boilers to satisfy the plant's aggregate required emissions limitations for SO_2, in lieu of achieving uniform emissions limitations for SO_2 at each stack.

EPA is permitting <u>multiplant</u> emissions trades as well, as part of its "bubble" policy.[17] The operator or operators of two or more existing sources within an attainment or nonattainment area must be able to show that application of a bubble approach to the facilities collectively will be consistent with the attainment and maintenance of NAAQS in the area.

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[16] 44 Fed. Reg. 71780-71788 (December 11, 1979).

[17] 44 Fed. Reg. 71782, 71783, 71788 (December 11, 1979).

4. EXPANSIONS OF EXISTING FACILITIES

In addition to optimally deploying pollution controls at existing emissions points, the operator of an existing facility must also consider the incremental pollution control requirements of planned or potential facility expansions. Generally speaking, expansions of existing facilities are subject to the same types of SIP emissions limitations mentioned above. Special rules govern, however, facility expansions or modifications which are deemed by the Clean Air Act to be "major modifications." The applicability of these rules ("nonattainment" and PSD regulations) to "major modifications" (and to "major new sources" as well) is discussed in the following subsection.

C. MAJOR NEW SOURCES AND MAJOR MODIFICATIONS

1. COMMON TERMS OF NONATTAINMENT AND PSD REGULATIONS

As we have indicated, stationary sources deemed to be "major new sources" and "major modifications" are subject to nonattainment regulations and/or PSD regulations. In this subsection, we define and illustrate the terms "source," "major new source" and "major modification" as utilized in these two sets of regulations.

Until recently, the terms "source," "major new source," and "major modification" have had substantially different meanings in the nonattainment and PSD regulations. In March of 1981, the EPA, putting into effect the Reagan Administration's stated policy of relaxing federal regulatory regimes to stimulate economic development, proposed to alter the definitions of these terms in its nonattainment regulations, in order to bring them in line with their usage in the PSD regulations.[18] EPA staff has indicated that these proposed definitional changes will be approved by EPA in final form without substantial alteration during the next several months, and, for purposes of our analysis, we assume that the PSD and nonattainment usages of these terms will, in fact, be substantially similar (with certain exceptions enumerated below).

a. "SOURCE"

The current PSD and proposed nonattainment definition of *stationary source* is "any building, structure, facility, or installation which emits or may emit any air pollutant subject to regulation under the Act."[19] In turn, "building, structure, facility, or installation" means "all of the pollutant-emitting activities which belong to the same [two-digit Standard Industrial Classification (SIC) ("Major Group") code], are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control)." As an example, EPA would generally consider an entire industrial plant (rather than an individual piece of process equipment located within the plant)

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[18] 45 Fed. Reg. 52676 (August 7, 1980) (current PSD regulations); 46 Fed. Reg. 16280 (March 12, 1981) (proposed nonattainment regulation changes).

[19] 40 CFR 51.24(b)(5); 40 CFR 52.21(b)(5); 40 CFR 51.18(j)(1)(i); 40 CFR 52.24(f)(1); 40 CFR Part 51, Appendix S, section II.A.1.

[20] 40 CFR 51.24(b)(6); 40 CFR 52.21(b)(6); 40 CFR 51.18(j)(1)(ii); 40 CFR 52.24(f)(2); 40 CFR Part 51, Appendix S, section II.A.2.

to be a "source." The implications of this regulatory approach of aggregating pollutant-emitting units of a plant into one "source" will become clearer as we illustrate the workings of the nonattainment and PSD regulations in subsequent subsections. Each "source" is classified by a two-digit SIC code according to its primary activity (as determined by its principal product(s) produced or distributed, or by services rendered); consequently, support facilities (which standing alone could have different SIC codes) are lumped together with primary facilities as a single "source". As an example, the emissions of a boiler used to generate process steam for a pulp mill would be attributed to the mill; if the boiler serves both a pulp mill and a plywood plant, the boiler's total emissions are attributed to whichever of the two plants uses the bulk of the boiler's annual output.[21]

We would anticipate, therefore, that a fuel cell providing on-site electricity and/or heat to a residential, commercial, industrial or other facility would generally be regarded as a support activity and aggregated with the primary activities of the facility as a single stationary source having the facility's Major Group SIC code: for example, restaurants (Major Group 58); operators of residential, commercial or industrial buildings (Major Group 65); hotels and motels (Major Group 70). An open question remains whether an on-site fuel cell at an industrial plant or other facility would be considered a source, separate and apart from the facility, if the bulk of the fuel cell's electrical and/or heat output

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[21] 45 Fed. Reg. 52676, 52695 (August 7, 1980).

is sold to an electric utility or other utility. The implications of this possibility will be treated in the next section.

b. "MAJOR NEW SOURCE"

The PSD and nonattainment definitions of "major new source" differ somewhat, although they are based upon the same definition of "source."

For purposes of PSD regulation, a "new" source is generally considered to be a *major source* if it emits, or has the potential to emit, 2.268×10^5 kg/y (250 tpy) or more of any pollutant (criteria or noncriteria) subject to regulation under the Clean Air Act.[22] The PSD definition of "major source" is more inclusive for the following specific types of stationary sources which emit, or have the potential to emit, 9.072×10^4 kg/y (100 tpy) or more of any regulated pollutant:[23] fossil fuel-fired steam electric plants with heat inputs exceeding 250 million Btu per hour; coal-cleaning plants; Kraft pulp mills; Portland cement plants; primary zinc smelters; iron and steel mill plants; primary aluminum ore reduction plants; primary copper smelters; municipal incinerators with potential inputs greater than 250 tons of refuse per day; hydrofluoric, sulfuric, and nitric acid plants; petroleum refineries; lime plants; phosphate rock processing plants; coke oven batteries; sulfur recovery plants; carbon black plants (furnace process); primary lead smelters; fuel conversion plants; sintering plants;

[22] 40 CFR 51.24(b)(1)(i)(b); 40 CFR 52.21(b)(1)(i)(b).

[23] 40 CFR 51.24(b)(1)(i)(a); 40 CFR 52.21(b)(1)(i)(a).

secondary metal production plants; chemical process plants; fossil fuel boilers (or combinations thereof) totaling more than 2.64×10^{11} joules-(250 MMBtu-)per-hour input; petroleum storage and transfer units with a total storage capacity exceeding 4.77×10^{4} m^3 (300,000 barrels); taconite ore processing plants; glass fiber processing plants; and charcoal production plants.[24]

For purposes of nonattainment regulation, a "new" source is considered to be a *major source* if it emits, or has the potential to emit, 9.072×10^{4} kg/y (100 tpy) or more of any regulated pollutant.[25]

Potential to emit means the maximum capacity of a stationary source to emit a pollutant, taking into account air pollution control equipment; restrictions on hours of operation; restrictions on the type or amount of material combusted, sorted or processed; and other physical and operational limitations.[26] In other words, a new facility whose unabated pollutant emissions might exceed the appropriate kg/y (tpy) level (9.072×10^{4} kg/y (100 tpy) or 2.268×10^{5} kg/y (250 tpy)) will not be considered a "major source" for a given pollutant, if pollution control equipment and/or other physical or operational limitations bring its potential emissions below the appropriate kg/y (tpy) level. Normally, facilities capable of generating

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[24] We have listed these facilities to suggest them as prime targets of opportunity for future fuel cell marketing efforts directed to the industrial sector. These types of facilities will be major contributors to economic development in both nonattainment and attainment areas as they are constructed and expanded. Section IV will describe in greater detail targets of opportunity for fuel cell commercilization.

[25] 40 CFR 51.18(j)(1)(v); 40 CFR 52.24(f)(5); 40 CFR Part 51, Appendix S, section II.A.4.

[26] 40 CFR 51.24(b)(4); 40 CFR 52.21(b)(4); 40 CFR 51.18(j)(1)(iv); 40 CFR 52.24(f)(4); 40 CFR Part 51, Appendix S, section II.A.3.

at least 9.072×10^4 kg/y (100 tpy) of a pollutant, after the imposition of abatement measures, will fit within one of the categories previously listed for PSD regulation; that is, "major sources" are generally large-scale industrial facilities.

The following examples illustrate the meaning of the term "major new source" for nonattainment and PSD regulatory purposes. A firm plans to construct and operate a new facility with potential emissions of 1.81×10^5 kg/y (200 tpy) PM and 4.5×10^4 kg/y (50 tpy) SO_2. In an area designated nonattainment for PM, the facility is a major source of PM only if it falls within one of the previously enumerated categories of facilities (with emissions exceeding 9.072×10^4 kg/y (100 tpy) PM); otherwise, it does not exceed the 2.268×10^5 kg/y (250 tpy) minimum and is a minor source for PM. The facility is a minor source for SO_2 in both nonattainment and attainment areas for SO_2.

Column a. of Table A-1 contains emissions data for an experimental fuel cell (utilizing natural gas) emitting the criteria pollutants SO_2, PM, NO_2, and HC (hydrocarbons: a regulated precursor of ozone). From the high values of pollutant emissions in column a., we have calculated how large a commercial fuel cell (embodying the experimental cell's emissions performance characteristics) would need to be, in order to generate at least 9.072×10^4 kg/y (100 tpy) of each of these pollutants; the results of our calculations are listed in column b. of the table. A fuel cell system producing all (or a substantial portion) of a new source's emissions of NO_2 or HC would need to have a capacity on the order of 100 MW to be considered a "major new source" under the nonattainment regulations; to constitute a "major new source" under the PSD regulations, the comparable capacity threshold for each of these two pollutants would be 100 MW or

TABLE A-1

REQUIRED FUEL CELL SIZE TO PRODUCE 9.072 X 10 KG/Y (100 TPY) OF A CRITERIA POLLUTANT BASED ON CURRENT FUEL CELL EMISSIONS DATA

Pollutant	a. Emissions* (kg/MWh)	a´. Emissions* (lbs/MWh)	b. Fuel Cell Size† (MW)
SO_2	$0 - 1.36 \times 10^{-4}$	0 - 0.0003	8×10^{4}
PM	$0 - 1.36 \times 10^{-5}$	0 - 0.00003	8×10^{5}
NO_2	$6.3 \times 10^{-2} - 1.1 \times 10^{-1}$	0.139 - 0.236	10^{2}
HC	$1.4 \times 10^{-2} - 1.0 \times 10^{-1}$	0.031 - 0.225	10^{2}

[1] This emissions data is for an experimental fuel cell utilizing natural gas.

Source: Institute of Gas Technology, Handbook of Fuel Cell Performance (prepared for the U.S. Department of Energy, Contract No. EC-77-C-03-1545), May 1980, p. 4.

[2] These values represent the minimum fuel cell size needed to produce 100 tons per year of a particular criteria pollutant. The values are computed from the high values in the range of emissions listed for each pollutant in column a. It is assumed that the fuel cell is operating at a capacity factor of 100 percent.

250 MW, depending upon the type of new source of which the fuel cell would be deemed to be a part.[27] With respect to SO_2 or PM emissions, no conceivable fuel cell application would be sufficiently large, standing alone, to satisfy the nonattainment or PSD criteria for a major new source for either of these latter two pollutants. It bears repeating, however, that the aggregate emissions of a given pollutant by a fuel cell and other pollutant-emitting units may be considered collectively to be a major new source, even though the fuel cell's emissions are too low, by themselves, to satisfy the emissions threshold for a major new source.

c. "MAJOR MODIFICATION" AND "NETTING"

As we have previously indicated, expansions and other modifications to existing sources which amount to "major modifications" are subject to the same nonattainment and PSD regulatory regimes as are "major new sources." The explanation of a "major modification" is less straightforward than that of a "major source." In the following paragraphs, we will describe and illustrate the term "major modification" in a broad-brush fashion.

The term "major modification" applies only to certain modifications of major stationary sources. These may be major sources that currently exist, or they may be major new sources that will exist at the time a "major modification" is proposed to be constructed.[28] Generally, modifica-

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[27] Fuel cell applications of 100 MW or more would generally be of interest only to electric utilities considering multimegawatt central station electrical generation facilities.

[28] See II.C.1.b., *supra* for the definition of "major source" contained in the nonattainment and PSD regulations.

tions of minor (existing or new) stationary sources are not subject to nonattainment or PSD review.[29]

A *major modification* is "any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant [regulated by the Clean Air Act]."[30]

Net emissions increase is the sum of the increase in the source's emissions due to the proposed modification together with any "contemporaneous" increases and decreases in emissions from other pollutant-emitting activities at the source.[31] The federal nonattainment and PSD regulations deem emissions increases and decreases at the source to be "contemporaneous" with those from the modification if the increases and decreases occur within the time period commencing five years prior to construction of the modification and ending on the date that the emissions increase from the

[29] One exception under the federal regulations is the modification of a minor source, when the modification has emissions of a given pollutant equal to those of a major source; in this case, the modification is, in fact, treated as a "major new source" for regulatory purposes. Another exception is treated more fully in section II.C.3., *infra*: a source which is major for one pollutant may be subject to PSD review for minor emissions of other pollutants which exceed certain *de minimus* levels. Certain state and local agencies regulate, however, both major and minor sources. See sections II.B.1. and II.B.1.a.

[30] 40 CFR 51.24(b)(2); 40 CFR 52.21(b)(2); 40 CFR 51.18(j)(1)(vi); 40 CFR 52.24(f)(6); 40 CFR Part 51, Appendix S, section II.A.5.

[31] 40 CFR 51.24(b)(3); 40 CFR 52.21(b)(3); 40 CFR 51.18(j)(1)(vii); 40 CFR 52.24(f)(7), 40 CFR Part 51, Appendix S, section II.A.6.

modification occurs; however, EPA allows each state latitude in its SIP provisions for nonattainment and PSD regulations, to define "contemporaneous" as any "reasonable period" prior to the date of occurrence of an emissions increase from the modification.[32] The process of summing contemporaneous emissions increases and decreases is called "*netting*" and is analogous to the "bubble" approach for offsetting emissions from different pollutant-emitting activities within an existing stationary source which is not undergoing a major modifification.

To constitute a "major modification," the modification must result in a "net emissions increase" which is both positive and "*significant*." EPA has established a "*de minimus*" level of emissions for each criteria (and noncriteria) pollutant, which level must be equaled or exceeded, before the "net emissions increase" from a modification is considered to be "significant" for that particular pollutant. The *de minimus* levels for the five criteria pollutants are as follows:[33]

CO	9.072×10^4 kg/y	(100 tpy)
NOx	3.63×10^4 kg/y	(40 tpy)
SO_2	3.63×10^4 kg/y	(40 tpy)
PM	2.27×10^4 kg/y	(25 tpy)
O_3	3.63×10^4 kg/y	(40 tpy) (volatile organic compounds)

The following examples illustrate the workings of the definition of "major modification." The operator of an industrial plant producing 2.7×10^5 kg/y (300 tpy) SO_2 (i.e., a major source) plans to modify the facility in 1987:

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[32] *Id.*

[33] 40 CFR 51.24(b)(23); 40 CFR 52.21(b)(23); 40 CFR 51.18(j)(1)(xiii); 40 CFR 52.24(f)(13); 40 CFR Part 51, Appendix S, section II.A.11.

1) by adding a new production unit which will emit 2.27×10^4 kg/y (25 tpy) SO_2; and 2) by increasing the hours of operation at the plant's existing production units, thereby further increasing the source's emissions of SO_2 by 1.8×10^4 kg/y (20 tpy). Without "contemporaneous" emissions decreases at the major source, the "net emissions increases" from the source's modifications in 1987 equal 4.1×10^4 kg/y (45 tpy) SO_2 and are "significant" (i.e., greater than 3.7×10^4 kg/y (40 tpy) SO_2); consequently, the modifications to the plant are "major," necessitating PSD review in an SO_2 attainment area or nonattainment review in an SO_2 attainment area or nonattainment review in an SO_2 nonattainment area. If, however, in 1986, the operator of the major source installs additional pollution control equipment at one or more of the plant's existing production units, thereby reducing the plant's overall SO_2 emissions by 2.72×10^4 kg/y (30 tpy) (to a level of 2.45×10^5 kg/y (270 tpy) SO_2), the "contemporaneous" plant emissions decrease of 2.72×10^4 kg/y (30 tpy) SO_2 in 1986 can be used to "offset" 2.72×10^4 kg/y (30 tpy) SO_2 of the planned 4.1×10^4 kg/y (45 tpy) SO_2 emissions increase in 1987 from the proposed plant modifications; the resulting "net emissions increase" of 1.36×10^4 kg/y (15 tpy) SO_2 would be less than the *de minimus* level of 3.7×10^4 kg/y (40 tpy) SO_2, and the proposed 1987 source modifications would not be subject to PSD or nonattainment review. A subsequent modification to the plant in 1988, which would contribute 2.72×10^4 kg/y (30 tpy) SO_2, would, however, be considered a "major modification"; the "netting of "contemporaneous" emissions increases and decreases of SO_2 at the plant [$(-2.72 \times 10^4$ kg/y$)(1986) + (4.1 \times 10^4$ kg/y$)(1987) + (2.72 \times 10^4$ kg/y$)(1988) = 4.1 \times 10^4$ kg/y SO_2][1] as of 1988 exceeds the SO_2 *de minimus* threshold of 40 tpy.

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[1][(-30 tpy)(1986) + (45 tpy)(1987) + (30 tpy)(1988) = 45 tpy SO_2].

triggered in either of the following circumstances: 1) when a new source is a major source of a pollutant for which the area (in which the source is to be located) is designated nonattainment; 2) when a modification of a source results in a "significant net emissions increase" of a pollutant for which the source is a major source and for which the area is designated nonattainment.[34] Once these provisions are triggered, the operator of a "major new source" or "major modification" must satisfy the following Clean Air Act nonattainment requirements in order to obtain a permit to construct and operate the new or modified major source:

a. LAER

The operator is required to install pollution control equipment that will result in the *lowest achievable emissions rate* (LAER) for each pollutant for which the source is a "major new source" or "major modification."[35] This emissions rate must be equal to or lower than the allowable emissions rate for the pollutant resulting from the application of *best available control technology* (BACT) to the "major new source" or "major modification."[36]

b. IN-STATE SOURCES UNDER COMMON CONTROL

The operator must additionally demonstrate that all existing major sources within the state which are owned or operated by such person (or by

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[34] 45 Fed. Reg. 52676, 52711 (August 7, 1980).

[35] CAA section 173(2).

[36] *Id.*, section 171(3).

any entity controlling, controlled by, or under common control with such person) are in compliance, or on a schedule for compliance, with all applicable air quality standards.[37]

c. <u>"NONATTAINMENT OFFSET" AND "GROWTH ALLOWANCE" POLICIES</u>

The "major new source" or "major modification" must not interfere with ongoing state efforts to attain and maintain NAAQS in the nonattainment area. State and local air quality control agencies can ensure the satisfaction of this condition through <u>one or both</u> of the following approaches permitted by the Clean Air Act: an emissions offset policy and a growth allowance policy.

Briefly, in a state with a *nonattainment offset policy*, the operator of a "major new source" or "major modification" must obtain surplus emissions reductions of a pollutant from one or more existing sources in the area to "offset" on at least a one-for-one basis (to ensure "reasonable further progress" toward attainment) the incremental emissions of the pollutant from the new or modified major source.[38] We will describe the workings of nonattainment offset policies in greater detail in Section III.

In a state with a *growth allowance policy*, the state has reserved in its SIP an emissions allowance for "major new sources" and "major modifications" in a nonattainment area.[38a] The state or local air quality

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[37] *Id.* section 173(3).

[38] *Id.* section 173(1)(A).

[38a] *Id.* section 173(1)(B).

control agency can allocate emissions from the allowance to these sources to "offset" their emissions until the allowance is completely allocated, after which time no new construction can occur without further emissions reductions (via offsets or emissions standards ratcheting) by existing sources in the nonattainment area.

3. PSD REGULATIONS

Part C of the Clean Air Act mandates that each state include, within its SIP, provisions to prevent the significant deterioration of ambient air quality in attainment areas ("clean" areas).[39] These PSD regulations are designed to ensure the continuation of economic development within a state's "clean" areas, through the construction and operation of "major new sources" and "major modifications," without permitting a "clean" area's air quality to deteriorate below the NAAQS (and thereby become a nonattainment area).

"Clean" areas fall within one of three area designations: *Class I* (generally national wilderness areas and parks); *Class II* (the current designation of all "clean" areas not deemed to be *Class I*); and *Class III* (areas desiring substantial economic development).[40] Each of the three area classifications differs in the amount of air quality deterioration (and therefore economic growth) that is deemed permissible. This allowable deterioration is specified by a maximum allowable increase in the ambient concentration of a pollutant (*PSD increment*) which may not be exceeded by new or modified major sources within an attainment area;[41] the "baseline

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[39] *Id.*, section 161.

[40] *Id.*, sections 162-164.

[41] *Id.*, section 163.

for determining air quality deterioration within a "clean" area is generally the ambient air quality at the time of the first PSD permit application in the area.[42] Class I areas have the smallest PSD increments, and Class III areas have the largest ones: PSD increments for Class I, II, and III areas represent 2%, 25% and 50%, respectively, of the applicable NAAQS.[43] Currently, PSD increments for the three area classifications have been established only for SO_2 and PM; EPA is studying the possible establishment of PSD increments for the other criteria pollutants as well, together with other regulatory alternatives.[44]

The PSD regulations are set in motion by the following situations:[45] 1) A "major source" of any pollutant locating in an area designated attainment for that pollutant or any other pollutant is subject to PSD review; once PSD review is triggered by the source, PSD review extends to each pollutant emitted in greater than *de minimus* amounts (see Section II.C.1.c., above) for which the area is designated attainment. As an example, a source which is major only for a nonattainment pollutant (i.e., "nonattainment" for the area in which the source is locating) will, nevertheless, be subject to PSD review for any attainment pollutant(s) emitted by the source in greater than *de minimus* amounts. 2) A modification to a "major source" of any pollutant which is located in an area designated attainment for

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[42] *Id.* section 169(4).

[43] National Commission on Air Quality, To Breathe Clean Air (hereafter *NCAQ*), March 1981, pp. 148-149.

[44] 46 Fed. Reg. 34044 (June 30, 1981); CAA section 166.

[45] 45 Fed. Reg. 52676, 52710-11 (August 7, 1980).

that pollutant or any other pollutant is subject to PSD review (as a "major modification") if the modification causes a "significant net emissions increase" of any pollutant for which the area is designated attainment. For example, the modification of a major source for a nonattainment (or attainment) pollutant will be subject to PSD review for any attainment pollutant(s) emitted by the modification in greater than *de minimus* amounts.

Once PSD review is triggered, the operator of a "major new source" or "major modification" must satisfy the following PSD requirements, in order to obtain a permit to construct and operate the new source or modification:

a. <u>BACT</u>

For "major new sources," "best available control technology" (BACT) is required for each pollutant emitted by the source in excess of *de minimus* amounts. For "major modifications," BACT is required only for modified or added units at the source which result in a "significant net emissions increase" for a pollutant emitted by the source.[46]

b. <u>INCREMENT EXCEEDANCE OFFSETS</u>

The PSD review process includes a determination of whether a "major new source" or "major modification" will cause or contribute to the violation of the PSD increment for an attainment area; if an area's

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[46] CAA sections 165(a)(4), 169(3); 40 CFR 51.24(k)(1), 52.21(k)(1); 45 Fed. Reg. 52676, 52722-23 (August 7, 1980).

PSD increment is currently exceeded, or will be exceeded as a result of the proposed construction, the air quality control agency may not issue a permit for the new or modified major source.[47]

In order to avoid a PSD increment exceedance, a state may require the operator of a new source to secure surplus emissions reductions from existing stationary sources ("offsets") within an attainment area. To correct an existing increment exceedance, the operator of a proposed major source or modification would need to secure sufficient offsets not only to offset the source's emissions of an attainment pollutant, but also to rectify the PSD increment exceedance for the pollutant (i.e., an offset/source emissions ratio in excess of 1:1). If a proposed major source or modification would result in a new violation of a clean area's PSD increment for a pollutant, the operator would only need to obtain sufficient offsets to avoid an increment exceedance (i.e., an offset/source emissions ratio less than 1:1).

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[47] CAA section 165(a)(3).

[48] 43 Fed. Reg. 26380, 26401 (June 19, 1978).

III. CREATION, TRADING AND BANKING OF "OFFSETS

A. Sources and Uses of Offsets

In Section II of this chapter, we reviewed the relevant provisions and terms of the Clean Air Act and EPA's implementing regulations which govern the siting, operation, and expansion of stationary sources. In Section III, we will discuss in greater detail the means whereby "offsets" are created by, traded among, and banked by operators of stationary sources. This section lays the groundwork for our discussion in Section IV of the potential incentives afforded by the "offset" market to fuel cell commercialization.

As used in this section, the term *offset* means any emissions reductions of a particular pollutant at one or more pollutant-emitting activities of an existing stationary source, which emissions reductions are over and above those emissions limitations for the pollutant specified for the existing source in the SIP.[49] The key point is that only existing sources can create offsets. As will be made clearer below, new sources (generally, major sources) must obtain offsets from existing sources.[50]

Depending upon the type of source, existing sources (especially

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[49] Here, we use the term "existing source" in a broad sense to include sources in existence in the future for which modifications are proposed.

[50] As we have noted in Section II.C.2.c., states can create quasi-offsets by establishing "growth allowances" for new or modified major sources in their SIPs and allocating the allowances to operators of these sources to offset their incremental emissions.

industrial plants) can create offsets through a variety of methods including: addition of pollution control equipment; modification, replacement or shutdown of equipment, processes, or an entire plant or facility: changes in hours of operation; changes in process inputs (including fuel type)or product outputs.

The operator of an existing source may utilize these surplus emissions reductions as *internal offsets* (that is, keep them for the operator's own present or prospective needs) or as *external offsets* (that is, transfer them by sale, exchange or donation to others for the latter's present or prospective use).[51] The circumstances under which offsets are required are described below. The process of "banking" offsets for future internal and/or external usage is detailed in the following subsection.

Intra-Source Offsets. Operators of existing sources require intra-source (internal) offsets in the following two situations which we have described more fully in Section II:

1. "Bubble" applications for existing sources in attainment or nonattainment areas to meet SIP emissions limitations. (Sec. II.B.3.)[52]
2. "Netting" to avoid nonattainment or PSD review of a proposed modification to a major source. (Sec. II.C.1.c.)

Inter-Source Offsets. Operators of "major new sources" and "major modifications" will need to secure inter-source offsets in the following

[51] 44 Fed. Reg. 3274, 3285 (January 16, 1979); 40 CFR Part 51, Appendix S, section V.A.

[52] Where a bubble includes two or more sources ("multiplant"), the offsets must originate from the sources within the bubble.

two situations:

1. Offsets to ensure "reasonable further progress" toward attainment in nonattainment areas. (Sec. II.C.2.c.)
2. Offsets to avoid or correct a PSD increment exceedance in an attainment area. (Sec. II.C.3)

These inter-source offsets may be internal (i.e., from sources under common ownership or control with new or modified major source) or external (i.e., obtained from another entity).

B. Current Offset Trading and Banking Activities

This subsection describes current nationwide offset trading and banking activities as background for a later discussion of possible future trends in offset transactions and their potential impact upon fuel cell commercialization.[53]

1. NONATTAINMENT OFFSET ACTIVITIES

a. STATE NONATTAINMENT OFFSET POLICIES

According to EPA, at the present time, virtually all of the states have incorporated some form of nonattainment offset provisions in their

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[53] We are indebted to Wes Vivian of the University of Michigan Institute for Public Policy Studies for much of the information on nationwide offset activities in this and the following subsections. The data are drawn from Mr. Vivian's recent seminal study (coauthored by William Hall) prepared for EPA, entitled: *An Examination of U.S. Market Trading in Air Pollution Offsets* (University of Michigan: Ann Arbor), March 1981 (hereafter, *Vivian*).

SIPs.[54] Subject to the Clean Air Act's requirements regarding attainment deadlines for criteria pollutants and EPA's review and approval of their SIPs, states and local air quality control agencies are vested with broad discretion to determine the types and sizes of sources subject to offset requirements, as well as geographical, temporal and other limitations upon offset transactions. Because of this latitude, state and local offset policies vary greatly in their relative complexity and stringency.

SIP definitions of "source," "major source," "major modifications" and other definitions in the nonattainment provisions must be <u>at least as stringent</u> as the definitions contained in the federal regulations.[55] As a result, compared with the federal nonattainment requirements of offsets for major new sources" (> 9.072×10^4 kg/y (100 tpy)) and for "major modifications" (> $2.27 \times 10^4 - 9.072 \times 10^4$ kg/y (25-100 tpy) "net emissions increase" depending upon the pollutant type), at least a handful of state and local air quality control agencies have very stringent regulations regarding the type of new sources requiring offsets, including:[56]

- Wisconsin: minor and major new sources of HC, SO_2, CO, or PM
- Ventura County AQMD, CA: new sources > 9.072×10 kg/y (1 tpy) of HC, NO_x, SO_2, or PM
- Puget Sound AQMD, WA: minor and major new sources of SO_2
- South Coast AQMD, CA: new sources > 6.8×10 kg/day (150 lb/day) HC, NO_x, SO_2 or PM

Other provisions of state or local nonattainment offset regulations

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[54]Office of Planning and Management, U.S. Environmental Protection Agency, *Emission Reduction Banking and Trading Status Report*, June 15, 1981, p. 1.

[55]40 CFR 51.18(j)(1); 45 Fed. Reg. 52676, 52743 (August 7, 1980).

[56]*Vivian*, Table 6A.1, p. 6-1.

C-3

may also be unique. As an example, the Bay Area AQMD (San Francisco Bay Area) in California regulates NO_x and HC as precursors of ozone (for which the Bay Area is nonattainment). The BAAQMD permits the use of inter-pollutant offsets: HC offsets may substitute for NO_x offsets when a new source would emit NO_x.[57]

State and local air quality control agencies also vary considerably in the quantitative requirements and geographical limitations imposed upon offset transactions. SIP provisions must be at least as stringent as federal regulations which generally permit O_3 (volatile organic compounds) or NO_x offsets from within a broad area of nonattainment, including the new or modified major source, but urge air quality modeling for SO_2, PM or CO offsets to demonstrate a "net air quality benefit" when the offset source and major source are not in close proximity.[58] In the following illustration, one sees the different approaches of New Jersey and the South Coast AQMD (California) in setting *offset ratios* — the ratio between required offsets and emissions of a major source or modification — as a function of pollutant type, and as a function of distance between the offset source and the major source or modification:[59]

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[57] *Id.*

[58] 40 CFR 51.18(j)(3)(f); 40 CFR Part 51, Appendix S, section IV.D.; 45 Fed. Reg. 52676, 52746 (August 7, 1980).

[59] *Vivian, loc. cit.*

	Pollutant	Offset Distance	Offset Ratio
New Jersey	HC, NO_x	0 - 100 mi.	>1 :1
	" "	100 - 250 "	>1.5:1
	" "	250 - 500 "	>2 :1
	SO_2, PM, CO	0 - 0.5 mi.	>1 :1
	" " "	0.5 - 1 "	>1.5:1
	" " "	1 - 2 "	>2 :1
South Coast AQMD, CA	HC, NO_x, SO_2, PM, CO	0 - 15 mi.	1.2:1
	HC, NO_x, SO_2, PM, CO	>15 mi.	determined by modeling

Finally, states vary in their reliance upon the offset strategy to improve air quality in nonattainment areas. In reviewing states' proposed SIP submittals to EPA covering nonattainment areas, *Vivian* catalogued the following data on nonattainment area clean-up strategies:[60]

1. Thirty states propose both an offset policy <u>and</u> a growth allowance strategy:
    a. Fourteen of these states anticipate a significant demand for offsets.
    b. The remaining sixteen states regard offsets only as a "last resort" strategy and expect growth allowance allocations to new sources to handle most of the demand.
2. Eleven states and the District of Columbia propose only an offset strategy.
3. The remaining states either propose only a growth allowance strategy or propose neither strategy.

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[60] *Id.* pp. 3-5 and 3-6.

Figure A-1 displays this information on state offset provisions. Section IV will discuss the implications of these state-to-state variations for fuel cell commercialization.

b. NATIONWIDE NONATTAINMENT OFFSET TRANSACTIONS

The EPA-funded Vivian study has been the only comprehensive effort to date to catalogue and analyze the types of offset transactions nationwide. The study listed, as of November 1980, at least 600 internal offset transactions approved by air quality officials, and 32 external offset transactions approved or submitted for review, for major new sources and modifications proposed for nonattainment areas.[61] California accounted for more than 500 (or roughly 80 percent) of the approved internal offset cases and five (or 15 percent) of the approved/pending external offset cases.[62] Figure A-2 depicts the nationwide distribution of nonattainment offset cases.

Vivian revealed that more than one-half of the 48 offsets transferred from one entity to another (in the 32 reported external offset transactions) were donated by the operator of the offset source (22) or were assigned at no cost by the state (3). The study was able to obtain offset price data for only eight cases in nonattainment areas within six states.[63] Figure A-3 aggregates this data on a statewide basis by pollutant. The figure is intended to suggest the state-to-state variability in external offset prices: for example, particulate matter offsets ranging from \$8.70 per 10^3 kg/y (\$8 per tpy)

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[61] *Id.* Table 7B.1, pp.7-1 ff.

[62] *Id.*

[63] *Id.* pp. 4-6, 7.

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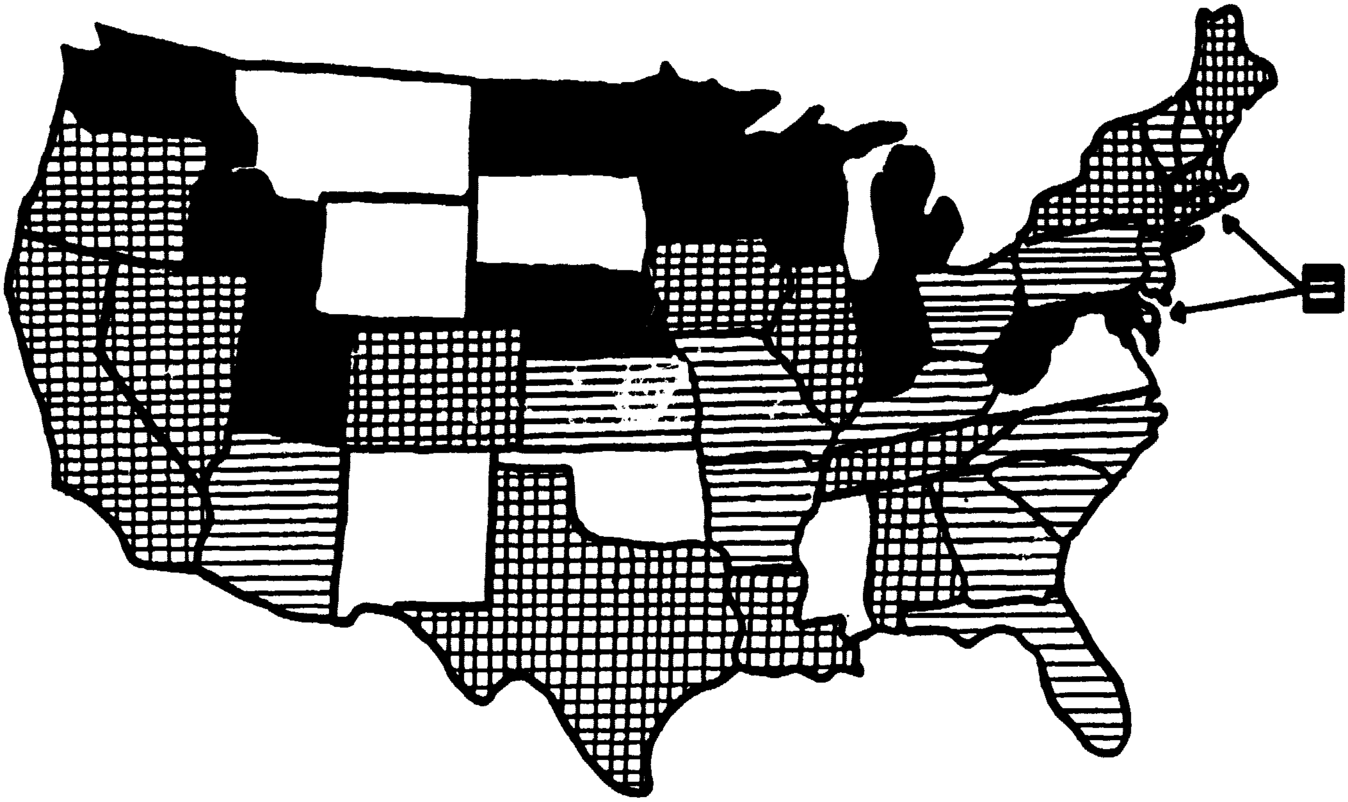
FIGURE A-1

STATE NONATTAINMENT OFFSET POLICIES



OFFSET POLICY ONLY

OFFSET POLICY AS PARALLEL STRATEGY WITH GROWTH ALLOWANCE POLICY

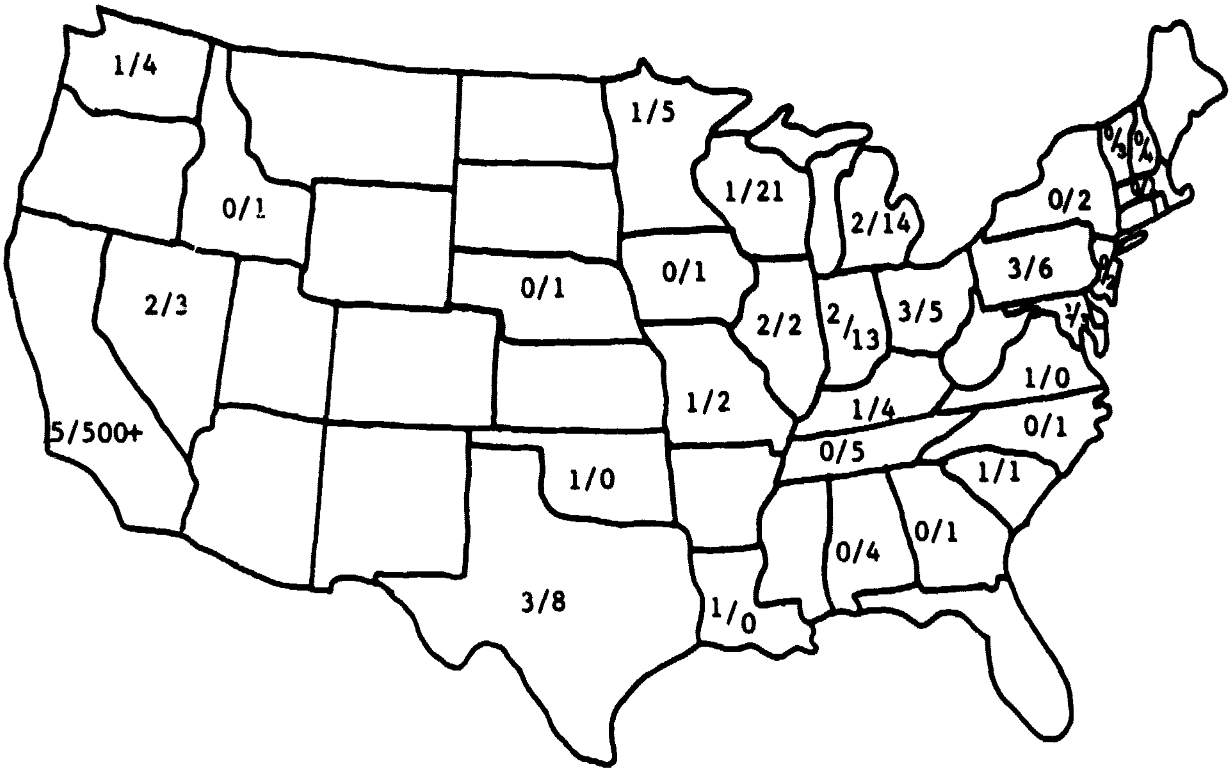
OFFSET POLICY AS "LAST RESORT" STRATEGY

NO OFFSET POLICY (INCLUDING ALASKA AND HAWAII)

SOURCE: VIVIAN, PP. 3-5, 6; 6-1 FF (TABLE 6A.1).

FIGURE A-2

EXTERNAL/INTERNAL NONATTAINMENT OFFSET CASES APPROVED OR PENDING AS OF NOVEMBER 1980



#/# = External Cases (approved or pending)/Internal Cases (approved or pending)

No Entry = No External Cases or Internal Cases approved or pending

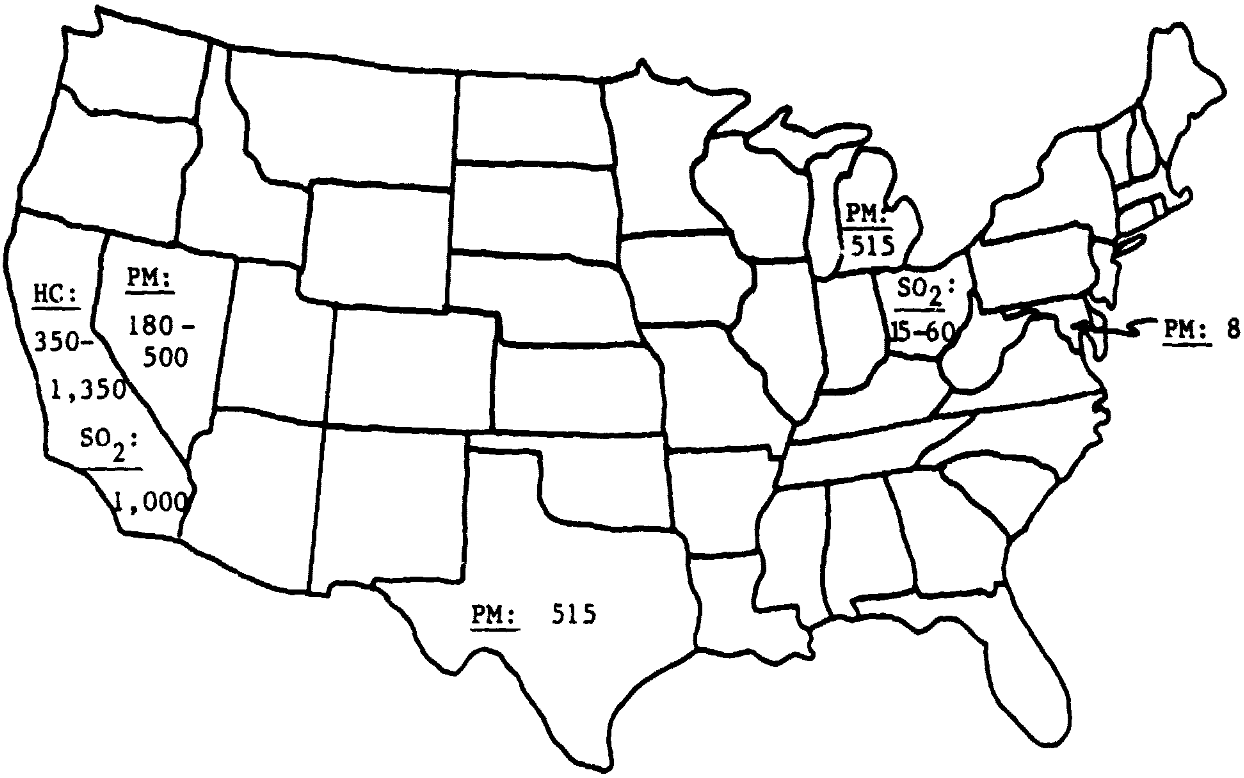
<u>STATES WITH GREATER THAN TEN CASES:</u>

California (> 500)	Indiana (15)
Wisconsin (22)	Texas (11)
Michigan (16)	

SOURCE: *Vivian*, Table 7B.1, pp. 7-1 ff.

FIGURE A-3

REPORTED PRICES FOR EXTERNAL OFFSETS
BY STATE AND POLLUTANT
($-PER-TPY)



SOURCE: *Vivian*, pp. 4-6, 7.

($8 per tpy) in Maryland to $566 per 10^3 kg/y ($515 per tpy) in Michigan and Texas. It should be noted that offset price differentials may occur as well between nonattainment regions within a state.

Summarizing the previously mentioned findings of the Vivian study, we see that:

1. Nationwide internal offset transactions have outpaced external ones by a factor of twenty.
2. Of the relatively few external offset transactions to date, only a small portion have involved the payment of money by the recipient of the offsets.
3. California has approved the lion's share of offset transactions nationwide.

2. OTHER OFFSET ACTIVITIES

To date, the level of activity for offset transactions other than nonattainment offsets has been low. For certain of these offsets, this has been due in large part to a lag in the development and implementation of regulations, as compared with the nonattainment offset policy which was first instituted by EPA in 1976.[64]

a. PSD INCREMENT EXCEEDANCE OFFSETS

Although the rules governing offsets for PSD increment exceedances were established in June 1978,[65] only a handful of states currently have

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[64] 41 Fed. Reg. 55524 (December 21, 1976).

[65] 43 Fed. Reg. 26380 (June 19, 1978).

attainment areas with PSD increments in danger of being exceeded (i.e., allocatable increment at less than 15 percent of maximum increment level): Louisiana (HC); Texas (HC); and North Dakota (SO_2).[66] The Vivian study was able to identify only one PSD offset transaction nationwide: offsets for SO_2 increment exceedance of a Class I area in North Dakota.[67]

b. "BUBBLE" OFFSETS

EPA formalized its bubble policy three years after its nonattainment offset policy.[68] The Vivian study indicated three states as having bubble provisions in their SIP submittals to EPA: New Jersey (HC); Alabama (HC, NO_x, SO_2, PM, CO); and Indiana (HC, NO_x, SO_2, PM, CO).[69] In January 1981, EPA streamlined its provisions for SO_2 and PM "bubbles" and extended them to include nonattainment areas (as well as attainment areas) in states whose SIPs had not been fully approved by EPA,[70] and this past April, EPA approved New Jersey's HC "bubble" provisions as a model for other states.[71]

This past February, EPA announced that seventy "bubbles" were being developed by firms, and that at least thirty had been formally submitted to state agencies for approval. Roughly half of these bubbles were for HC emissions, and the remainder were evenly divided between PM and SO_2. EPA

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[66] *Vivian*, Table 6A.1, pp. 6-15, 6-18.

[67] *Id.*, Table 7A.1 (Case ND01).

[68] 44 Fed. Reg. 71780 (December 11, 1979).

[69] *Vivian*, Table 6A.1, pp. 6-5, 6-9, and 6-12.

[70] U.S. Environmental Protection Agency, Press Release, "Detailed Statement on Bubble Policy Changes," January 16, 1981.

[71] Office of Planning and Management, U.S. Environmental Protection Agency, *Emission Reduction Banking and Trading Status Report*, June 15, 1981, p. 2.

had already approved one SO_2 bubble and was proposing to approve nine other bubbles.[72]

c. <u>"NETTING" OFFSETS</u>

The "netting" rules for major modifications subject to nonattainment or PSD regulation were only recently finalized.[73]

3. BANKING ACTIVITIES

a. <u>BANKING EXPLAINED</u>

As we noted in section IIIA, the operator of an existing source has several options regarding emissions reductions at the source in excess of SIP emissions limitations: immediate use of the surplus emission reductions as internal offsets; immediate transfer to another entity of the reductions as external offsets; or "banking" the reductions as credits for future usage as internal or external offsets.[74]

The "banking" process may be accomplished one of two ways: in *informal banking*, the operator of a source keeps internal records of emissions reductions credits, and presents the records to an air pollution control agency for certification when the credits are <u>needed</u> as offsets.

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[72] Office of Planning and Management, U.S. EPA, *The Bubble Policy Status Report*, February 1, 1981, p. 1.

[73] 45 Fed. Reg. 52676 (August 7, 1980).

[74] 44 Fed. Reg. 3274, 3285 (January 16, 1979); 40 CFR Part 51, Appendix S, section IV.C.5. The operator of a major new source or major modification in a nonattainment area may, likewise, bank any acquired external offsets which exceed the amounts of offsets required to ensure reasonable further progress in the nonattainment area. *Id.*

In *formal banking*, a state or local agency establishes a central registry where emissions reduction credits are certified at the time they are created (for example, when a process is shut down or additional pollution control equipment is installed at an existing source), recorded as public information, and stored for future use as offsets.

The formal banking system serves several purposes: The bank reduces the uncertainty of the owner of the credits that the credits are available to meet future internal offset requirements necessitated by future construction of major new sources or modifications. It also serves as a central repository of information on potential offset availability for firms seeking external offsets; over time, as more and more external offset transactions occur, facilitated by the bank, market prices for external offsets should become more predictable.

b. FORMAL SYSTEMS IN PLACE OR UNDER CONSIDERATION

In Table A-2, we list the three regional air quality agencies which currently have formal banking systems in operation, as well as the twelve states and nineteen local/regional agencies considering the institution of formal banking systems. Figure A-4 displays this information on a map; a quick glance at Figure A-2 reveals a fairly good correlation between states with significant offset case activities and states, localities or regions actively considering or instituting banking. Of the states, localities and regions interested in formal banking, the ones leading the pack in terms of finalizing their proposals for submittal to EPA are: Oregon; Maryland; Chicago, IL; Southeast Michigan Council of Governments, MI;

TABLE A-2

FORMAL BANKING SYSTEMS IN PLACE OR UNDER CONSIDERATION

I. ESTABLISHED BANKING SYSTEMS

Jefferson County (Louisville), KY

Puget Sound (Seattle), WA

San Francisco Bay Area, CA

II. STATES INTERESTED IN FORMAL BANKING

Alabama	New Jersey
Colorado	New York
Illinois	Oregon
Indiana	Texas
Maryland	Virginia
Minnesota	Washington

III. LOCALITIES AND REGIONS INTERESTED IN FORMAL BANKING

Boston, MA	Minneapolis, MN
Buffalo, NY	New Orleans, LA
Charleston, SC	New York, NY
Chicago, IL	Portland, OR
Cincinnati, OH	Richmond, VA
Dayton, OH	San Diego, CA
Detroit/ S.E. Michigan, MI	Shasta County, CA
Evansville, IN	South Coast (Los Angeles), CA
Grand Rapids, MI	Ventura County, CA
Madison, WI	

SOURCES: Controlled Trading Project, U.S. Environmental Protection Agency, map entitled "Many Cities, Regions, and States Have Expressed Interest in Banking," undated.

Office of Planning and Management, U.S. Environmental Protection Agency, Emissions Reduction Banking and Trading Status Report, June 15, 1981.

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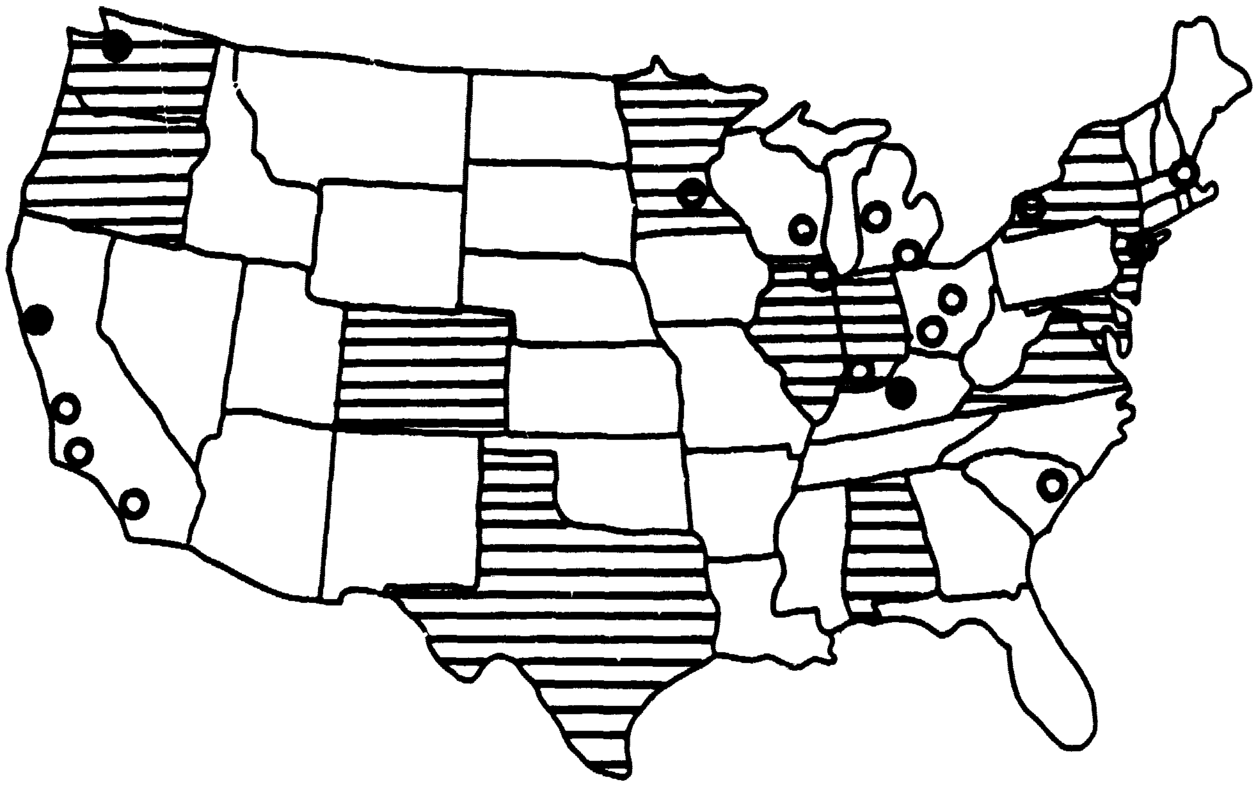
FIGURE A-4

FORMAL OFFSET BANKING SYSTEMS IN PLACE OR UNDER CONSIDERATION



● FORMAL BANKING SYSTEM IN PLACE

○ LOCALITY OR REGION CONSIDERING FORMAL BANKING

▤ STATE CONSIDERING FORMAL BANKING

SOURCE: TABLE A-2.

Ventura County, CA; and Shasta County, CA.[75]

As of June of this year, the three operational banking systems had performed the following activities:[76] Jefferson County, Kentucky, had logged twenty emissions reduction credit deposits, six credit withdrawals, and one external trade. The San Francisco Bay Area AQMD had recorded fifty deposits and was undertaking an outreach program to inform area industries about the benefits of banking. Puget Sound AQMD in Washington had approved substantial emissions reduction credit deposits for PM, HC, and CO emissions.

c. <u>RESTRICTIONS ON OFFSET BANKING AND TRADING</u>

Subject to the general proviso that the Clean Air Act pollution control requirements be satisfied, EPA permits each state the freedom "to govern ownership, use, sale, and commercial transactions in banked emissions offsets as it sees fit."[77] EPA exhorts each state to "provide a registry to identify the person, private entity, or governmental authority that has the right to use or allocate the banked emissions reductions, and to record any transfers of, or liens on, this right that the reviewing authority may allow."[78] Given this latitude, states and local agencies have taken different tacks in establishing ground rules for offset banking and trading.

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[75] Office of Planning and Management, U.S. Environmental Protection Agency, *Emission Reduction Banking and Trading Status Report*, June 15, 1981.

[76] *Id.*

[77] 44 Fed. Reg. 3274, 3280 (January 16, 1979).

[78] *Id.*, p. 3280.

At a minimum, major existing sources in areas with offset trading and banking programs will be permitted to bank emissions reductions credits to meet present or future internal or external offset demands. State and local air pollution control agencies have, however, the discretion to permit or prohibit offset banking and trading by minor sources. EPA encourages states and localities to permit such offset banking and trading by minor sources (as a potentially inexpensive supply of offsets) in areas where major sources may be subjected to substantial incremental pollution control burdens; however, it notes the potential difficulties of establishing baseline emissions levels for minor sources, in order to approve potential emissions reduction credits, and of monitoring such reductions.[78a]

The Puget Sound AQMD in Washington permits the owners of formally banked emissions reduction credits an eight-year period (from the initial date of deposit) in which to utilize the credits for external or internal offset purposes.[79] During this eight-year period, banked credits will be discounted on a pro-rata basis only to the extent that EPA requires an emissions rollback within nonattainment areas to ensure reasonable further progress to attainment. At the conclusion of the eight-year period, the AQMD will confiscate unused banked credits and offer them for sale at a public auction with the proceeds being used to compensate the offset owner for the taking. This auction provision is designed to ensure that owners of banked credits do not tie up the offset market by hoarding credits indefinitely.

[78a] Office of Planning and Management, United States Environmental Protection Agency, Emission Reduction Manual, September 1980, p. 13.

[79] *Vivian*, Table 6A.1, p. 6-25.

The Bay Area AQMD in California utilizes a two-tier approach.[80] Operators of offset sources may utilize informal banking to keep track of source emissions increases and decreases used for internal offsets. Formal banking is required for banked credits used as external offsets. The AQMD affords owners of formally banked credits a three-year grace period following banking during which time no banked credits will be confiscated; following this period, pro-rata reductions of banked credits may occur, to meet ratcheted air quality requirements, and the AQMD reserves the right to impose a moritorium on all future credit banking, depending upon the relative success of efforts to ensure reasonable further progress to attainment. The grace period is designed to add some regulatory certainty to the banking and trading process.

The Jefferson County AQMD in (Louisville) Kentucky confiscates a portion of formally banked emissions reduction credits at the time of deposit.[81] These confiscated credits are reserved by the AQMD for future allocation to designees of its own choice. The AQMD reserves the right to undertake future additional confiscations if it encounters difficulties in meeting attainment deadlines.

The Southeastern Michigan Council of Governments has proposed a banking plan whereby, after an initial grace period, a portion of a holder's unused banked credits is periodically subject to confiscation for sale at public auction (with the auction proceeds providing compensation to the

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[80] *Id.* pp. 6-21, 6-22

[81] *Id.* p. 6-10.

holder for the confiscation).[82] Different confiscation timetables are applied to banked emissions reduction credits created in different manners:

Method of Creation of Banked Credit	Timetable for Confiscation and Public Auction of Banked Credits Following Deposit
Improved Control Technology	5 years: 50 percent 7 " : 50 "
Curtailments, Fuel Switches, Process Changes	3 " : 25 " 4 " : 25 " 6 " : 50 "
Shutdown of Plant if Company Has Other Manufacturing in Area	2 " : 25 " 3 " : 25 " 4 " : 50 "
Shutdown of Plant if Company Has No Other Manufacturing in Area	1 " : 100 "

One sees a strong policy in this proposed scheme disfavoring industries leaving an area and reaping an economic benefit (via offsets) from their plant shutdown.

Other states such as Massachusetts, Connecticut, Rhode Island and New York place no time limit on the bankability of emissions reduction credits.[83]

At least two states, Pennsylvania and Oregon, permit offset transactions only between the operator of an offset source and the actual user of the offset for a major new source or modification.[84] This type of

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[82] *Id.* p. 6-13.

[83] *Id.* pp. 6-3 to 6-5.

[84] *Id.* pp. 6-7, 6-24.

restriction precludes "free trade" in offsets, since it cuts out potential middlemen such as offset brokers from offset transactions and forces an entity acquiring offsets in excess of its current external offset requirements to bank them for its own future use, in lieu of trading them to a third party.

We see from these varying approaches the competing tensions that each state or local air pollution control agency must balance in developing a banking policy. It must face the contingency that its nonattainment strategy will fall behind schedule, necessitating additional emissions reductions from existing stationary sources, additional reductions in banked emissions reduction credits, and/or more stringent offset requirements. By the same token, it must be careful to avoid undue restrictions upon offset banking and trading, as well as regulatory uncertainties, which interfere with an efficient banking and trading system; otherwise, operators of existing sources facing stringent, changing or otherwise uncertain ground rules for banking and trading may decide to postpone emissions reductions until an internal or external offset demand arises, thereby frustrating a state's efforts to foster banking and early air cleanup. On the other hand, rules lacking time restrictions on the duration of banking may promote hoarding of potential offsets by firms.

C. FUTURE OFFSET TRADING AND BANKING TRENDS

1. STATUS QUO AIR QUALITY REGULATORY REGIME

In this section we examine future trends in offset demand, trading and banking for both nonattainment and attainment areas, with the operating assumption that the federal and state air quality regulatory regimes will remain substantially similar to the ones currently in place through the early 1990s. In the following section, we describe changes in these regulatory approaches proposed by the National Commission on Air Quality and by the Reagan Administration, and explore the implications of these proposals for future offset trading and banking activities.

a. NONATTAINMENT OFFSETS AND NETTING

The National Commission on Air Quality (NCAQ)[85] has developed projections on the ability of nonattainment areas nationwide to attain NAAQS by the Clean Air Act deadlines in 1982 and 1987.[86] Its studies indicate that certain regions of the country probably will not meet the federal deadlines for attainment. Figures A-5 through A-8 depict the results.

Figure A-5 contains the NCAQ projections for ozone nonattainment areas in 1982 and 1987.[87] NCAQ projects that at least the following regions

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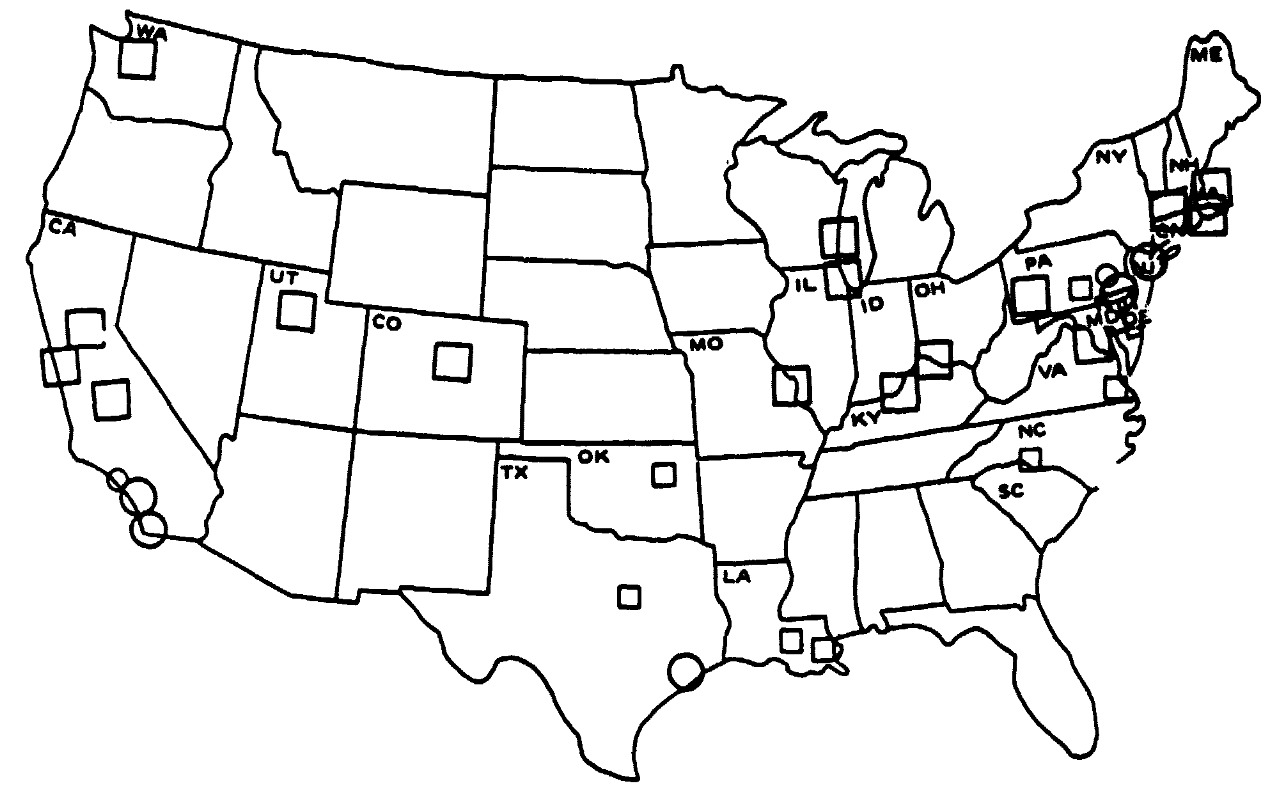
[85]In the 1977 amendments to the Clean Air Act, Congress established NCAQ to study, and report on, alternative air pollution control technologies and strategies and the efficacy of the current air quality regulatory regime. CAA section 323. In March 1981, NCAQ released its report to the Congress entitled *To Breath Clean Air* (hereafter *NCAQ*).

[86]See Section II.A., *supra*.

[87]*NCAQ*, pp. 18, 121-127.

FIGURE A-5
NCAQ NONATTAINMENT PROJECTIONS FOR OZONE



PROJECTED NONATTAINMENT, 1987

- ◯ Areas Over 500,000 1980 Urbanized Population
- ○ Areas Under 500,000 1980 Urbanized Population

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PROJECTED NONATTAINMENT, 1982

- □ Areas With 1987 Extension
- ▫ Areas With 1982 Deadlines

SOURCE: NCAQ, P. 122.

will still be nonattainment by 1987: the Philadelphia (PA)-Camden (NJ) area to the Northeastern New Jersey-New York City-Southwestern Connecticut area; the Houston (TX) area; and the Southern California coastal and inland areas. Assuming that these projections are correct, in these areas one would expect that nonattainment offsets for ozone precursors — NO_x and HC — will continue to be required after 1987, with perhaps greater required offset ratios than presently in effect, in order to compensate for slippage in the attainment schedule.

Figure A-6 depicts the NCAQ projections for PM nonattainment areas following the 1982 deadline.[88] NCAQ has not performed any PM projections for the late 1980s, and its report does not indicate how long the PM nonattainment problem will persist after 1982.

Figure A-7 contains NCAQ's 1982 projections for SO_2 nonattainment areas.[89] Areas with major SO_2 problems in this time frame include: four urban areas (Pittsburgh, Indianapolis, Gary, and Chicago); and areas near nonferrous smelters in the Southwest and Northwest. No SO_2 nonattainment projections have been done for the late 1980s.

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[88] *Id.* pp. 18, 124, 127-128.

[89] *Id.* pp. 18, 112-113, 126, 129.

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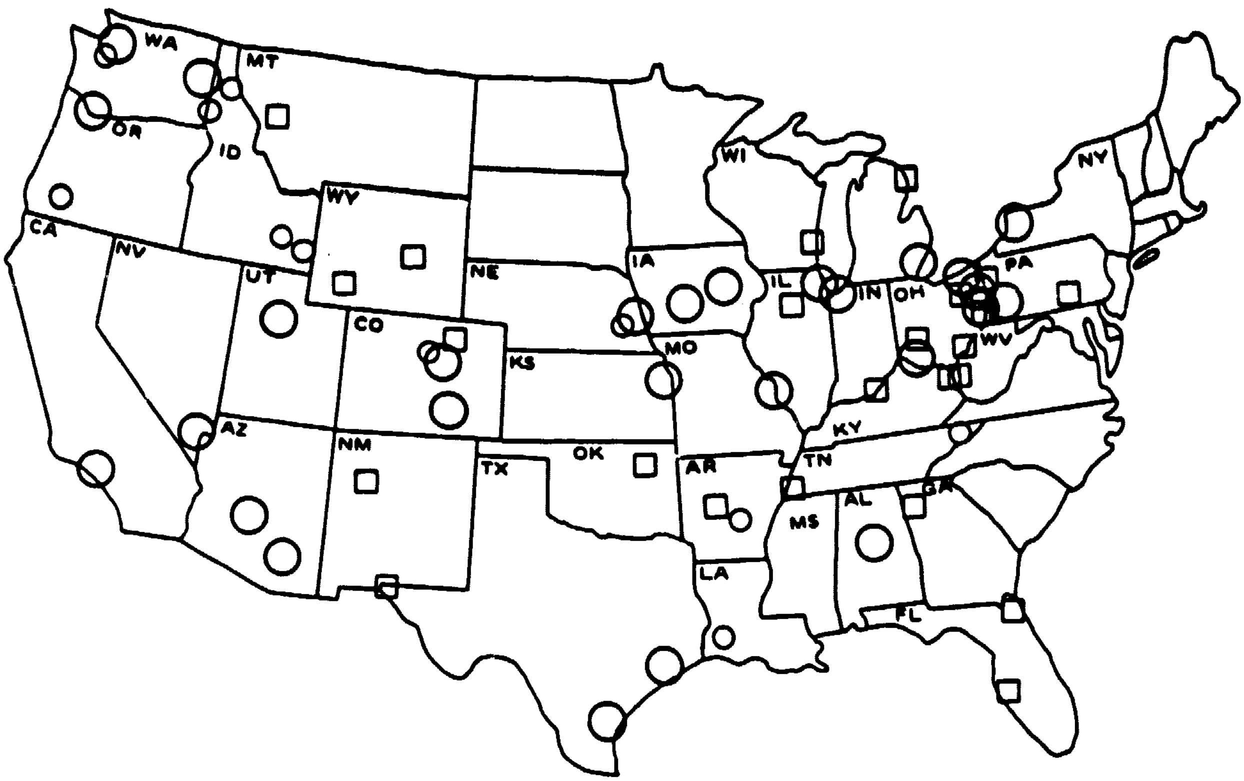
FIGURE A-6

NCAQ NONATTAINMENT PROJECTIONS FOR TOTAL SUSPENDED PARTICULATES PRIMARY STANDARD (1982 DEADLINE)



Major Metropolitan Areas (Certain Nonattainment)

Minor Areas (Certain Nonattainment)

Potential Nonattainment Areas

SOURCE: NCAQ, P. 124.

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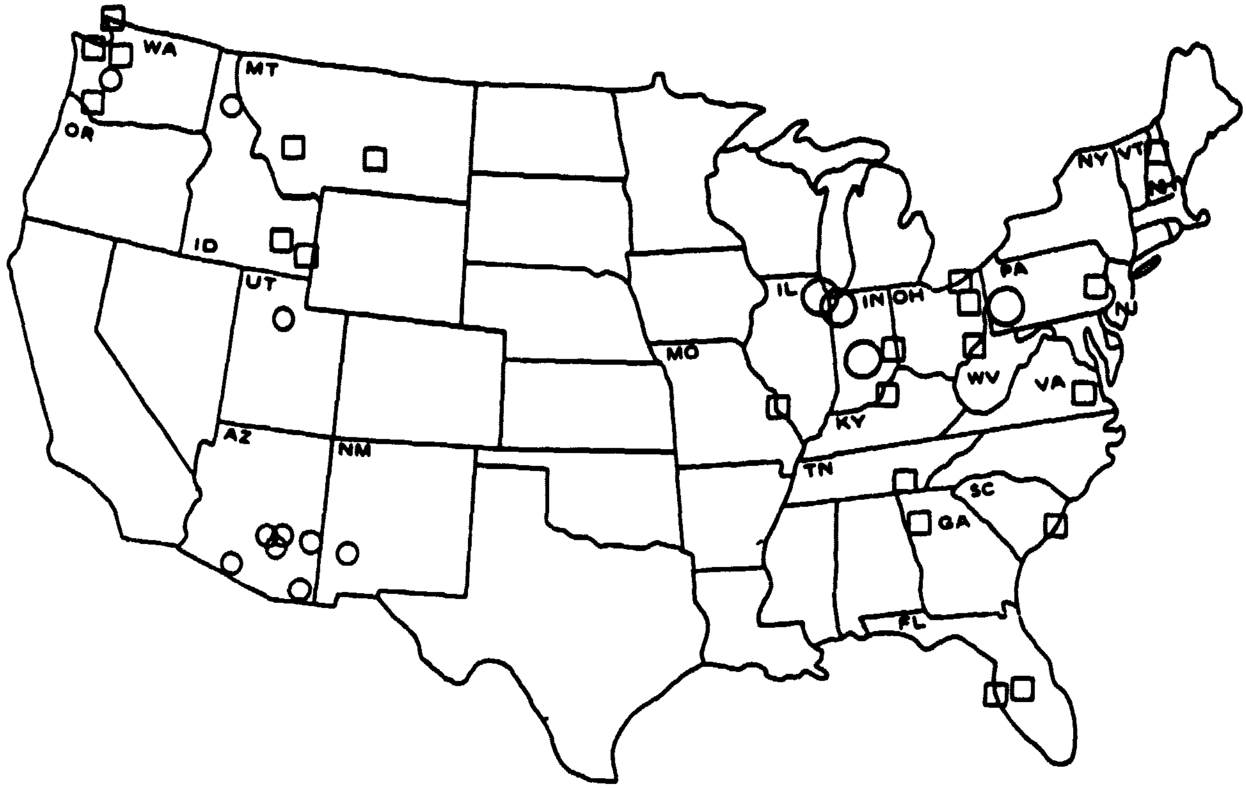
FIGURE A-7

NCAQ NONATTAINMENT PROJECTIONS, SULFUR DIOXIDE PRIMARY STANDARD (1982 DEADLINE)



○ Major Metropolitan Areas (Certain Nonattainment)

○ Nonferrous Smelter Areas (Certain Nonattainment)

□ Potential Nonattainment Areas

SOURCE: NCAQ, P. 126.

NCAQ projects that the NO_x standard will be attained in the early 1990s nationwide if stricter NO_x emissions standards are promulgated for light and heavy trucks in 1986 (as required by the Clean Air Act). On the other hand, if current automobile NO_x emissions standards are relaxed by a factor of two, Phoenix, Philadelphia and many other large cities would be in nonattainment in the 1990s.[90]

Figure A-8 portrays CO nonattainment areas in 1982 and 1987 as projected by NCAQ.[91] Problem areas in 1987, due in large part to mobile sources (automobiles and trucks), are Denver, Los Angeles, and Chicago.

Based upon its projections, NCAQ concludes that, after 1982, ozone and particulate matter are the only criteria pollutants whose NAAQS will be "exceeded in any significant number of areas where stationary sources are major contributors;" therefore, most of the offsets required for major new sources and major modifications in nonattainment areas will be for NO_x and HC as ozone precursor pollutants and for PM.[92]

NCAQ does not address the question of "netting" by modified sources in nonattainment areas, but we can safely assume that existing sources with

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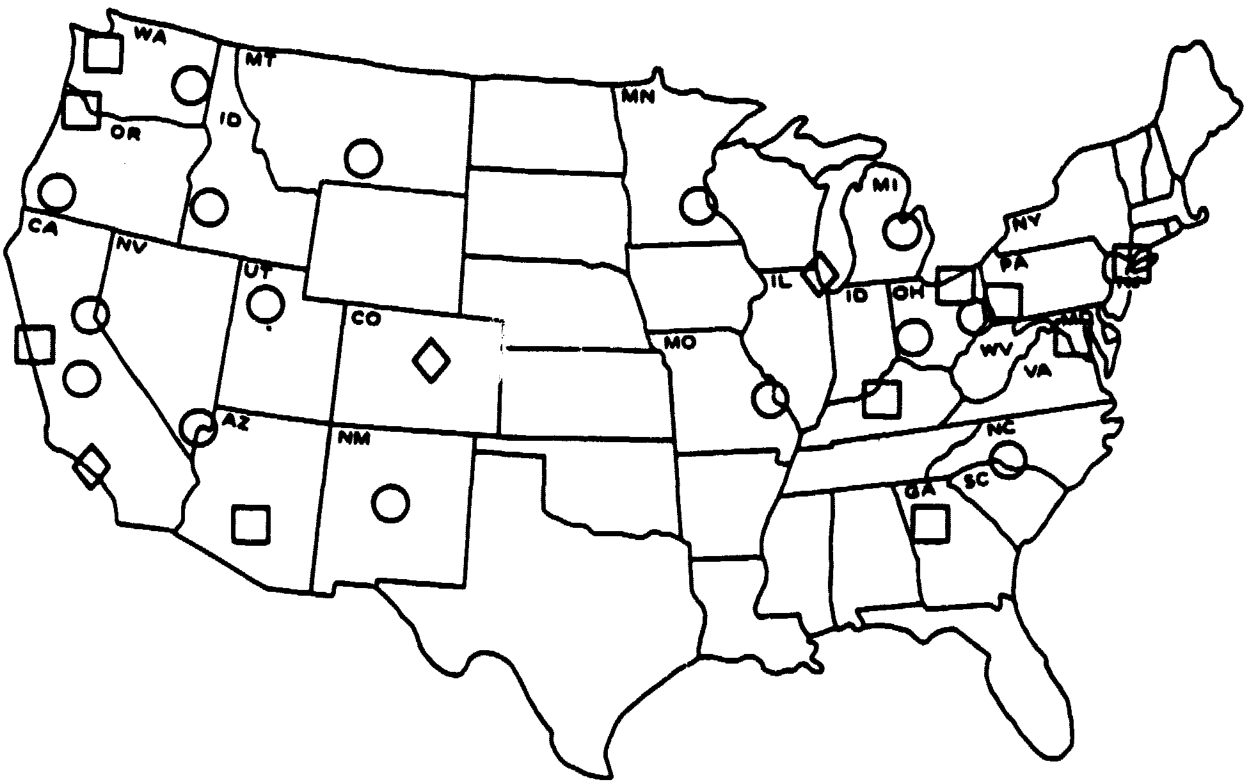
[90] *Id.* p. 129.

[91] *Id.* pp. 18, 125, 128.

[92] *Id.* p. 137.

FIGURE A-8

NCAQ NONATTAINMENT PROJECTIONS, CARBON MONOXIDE (ASSUMES NO RELAXATION OF CARBON MONOXIDE EMISSION STANDARDS)



◇ Will Not Attain by 1987

☐ Will Not Attain by 1982; Will Attain by 1987
(150% Over Standard With Over 500,000 1980 Urbanized Population)

○ Will Not Attain by 1982; Will Attain by 1987

SOURCE: NCAQ, P. 125.

available internal offsets will pursue "netting" so that a source modification does not trigger nonattainment regulations for a major modification.[93]

Those areas of the country that are currently designated nonattainment for which NCAQ projects attainment by 1987 will require measures by the states and local air quality control agencies to ensure the maintenance of NAAQS. While section 110(a)(1) of the Clean Air Act requires SIPs to include plans to maintain NAAQS once attainment occurs, NCAQ notes that only California and Idaho have developed maintenance strategies: for example, the Bay Area AQMD proposes increased offset ratios as one technique to ensure maintenance of standards. In NCAQ's words, the "focus of EPA is on ensuring that the NAAQS are met; maintenance is to be considered at a future time."[94] One would, however, expect that, in the absence of substantial regulatory changes, offset transactions will play an important role in fostering economic growth in these areas in the late 1980s and beyond.

b. PSD INCREMENT EXCEEDANCE OFFSETS AND NETTING

The degree to which offsets for PSD increment exceedances will take on growing importance is uncertain. As we noted earlier, only one such offset has been certified to date.[95] The Vivian study concludes that these offsets will become common, based on reported deterioration in increment levels in some areas.[96] NCAQ believes that industries seeking

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[93] See Section II.C.1.c., *supra*.

[94] *NCAQ*, p. 120.

[95] See section III.B.2.a., *supra*.

[96] *Vivian*, p. 3-3.

sites for major new sources in attainment areas will generally pursue a policy of "site avoidance" in areas where PSD increment exceedances may be expected to occur;[97] hilly terrains and proximity to Class I PSD areas are factors incorporated into "site avoidance" planning. NCAQ concludes that sources potentially encountering increment exceedance problems will be limited to certain major modifications of existing sources, oil shale facilities in Colorado and Utah, energy facilities in the Gulf Coast area near Houston, and other sources limited to a particular site.[98] One can surmise that the operators of the modified sources with adequate internal offsets will resort to "netting" to avoid PSD regulations governing major modifications.[99]

c. BUBBLE OFFSETS

As we previously indicated, EPA has recently streamlined and expanded the scope of its "bubble" regulations, and a substantial number of "bubble" applications are currently in the regulatory pipeline.[100] The Vivian study concluded that "bubble" offsets may comprise the lion's share of all offset transactions in the near term.[101] It is conceivable that, in those nonattainment areas nationwide experiencing attainment schedule delays well into the late 1980s, existing sources may be subject to tighter

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[97] *NCAQ*, pp. 25, 26, 168-69, 184-85.

[98] *Id.* 25-27, 52, 168-69, 184-85.

[99] See section II.C.1.c., *supra*.

[100] See section III.B.2.b., *supra*.

[101] *Vivian*, p. 2-2.

emissions limitations; therefore, greater numbers of operators of existing sources in these areas would be expected to pursue a "bubble" approach to contain their compliance costs. Similarly, existing sources in attainment areas experiencing PSD increment exceedance problems may also rely more extensively on the "bubble" technique.

d. OFFSET TRADING AND BANKING

Future volumes of offsets traded and banked in the previously described nonattainment and attainment areas with significant anticipated offset demands will hinge on a number of countervailing factors.

The volumes of offsets traded among operators of stationary sources within an area with high offset demands will depend in large part upon: (1) the physical availability of sufficient banked and/or potential emissions reductions from existing sources within the area to satisfy the area's ongoing aggregate demands for internal and external offsets; and (2) the willingness of operators of these existing sources to transfer offsets surplus to their own needs to other firms in the area.

The Vivian study concludes that industrial firms with existing sources have a supply of potential emissions reductions at these facilities which are well in excess of current production emissions levels;[102] however, the study does not attempt to assess the ability of available supplies of these potential emissions reductions credits to satisfy both internal and external offset demands within a particular nonattainment or attainment area. Generally only firms without adequate internal

[102] *Id.*

offsets which are constructing major new sources seek out external offsets. Firms with potential emissions reductions that could be sold as external offsets do not, however, realize the potential market value of external offset transactions due to the paucity of such transactions to date and the inaccessibility of information on offset prices and availability, and these firms are likely to do nothing in the way of undertaking such reductions until another firm approaches them with a lucrative offer to purchase offsets.[103]

NCAQ also concludes that firms undertaking facility modifications will generally have recourse to adequate internal offsets; therefore, operators of large facilities (major new sources) locating in areas where they have no current facilities operating will provide the principal demand for external offsets.[104] NCAQ notes that firms may prefer to hoard potential emissions reductions to meet future internal offset demands, in lieu of selling them to others, and operators of major new sources may need government assistance to obtain offsets.[105] Similarly, firms with bankable emissions reduction credits may resist banking, to avoid the possibility that a competitor will acquire their credits for its own facility expansions, or that a competitor will learn about a low-polluting production process.[106]

In a previous section, we delineated particular features in state

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[103] *Id.*

[104] *NCAQ*, pp. 136, 185.

[105] *Id.*, pp. 136-137.

[106] *Id.*, pp. 278-279.

and local air quality agencies' offset policies which may inhibit or promote trading and banking.[107]

Clearly, it is too early in the game to proclaim federal, state and local offset trading and banking programs as long-term unqualified successes or failures. Assuming the current regulatory regime continues substantially unchanged, the efficacy, longevity and nationwide diffusion of these programs will hinge upon whether more and more state and local agencies undertake formal banking and trading programs to attain and maintain air quality standards in nonattainment and attainment areas, whether agencies with existing banking and trading programs remove potential impediments to banking and trading in their regulatory provisions, and whether firms with potential on-site emissions reductions will be able and willing to satisfy internal and external offset demands.

2. MODIFIED AIR QUALITY REGULATORY REGIME

In this section we consider the ramifications of several proposed changes in the existing air quality regulatory regime on future offset demand, trading and banking.

a. NCAQ PROPOSALS

In addition to evaluating the efficacy of current offset trading and banking activities, NCAQ has evaluated alternative approaches to attaining and maintaining NAAQS in nonattainment and attainment areas.

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[107] See section III.B.3.c., *supra*.

One option endorsed by NCAQ is the use of emission fees, in lieu of direct regulation, as a method to induce firms to reduce pollution at their facilities.[108] Under this approach, fees could be set at a level which would make the addition of emission controls at a source more economical than payment of the fee. The fee could be used for subsidizing pollution controls, for financing air pollution control agencies, or for general revenue purposes. Potential problems of the emission fee approach include setting an appropriate fee level and ensuring the adequacy and accuracy of monitoring data for source emissions as a basis for assessing the fee.

Based on its studies, NCAQ recommended to the U.S. Congress that states and the federal government should consider economic incentive measures such as emission fees "as a substitute for, or as a supplement to, direct regulation.[109] More specifically, NCAQ recommended that states should consider these economic incentive measures as an alternative to RACT[110] for existing sources in nonattainment areas.[111] The fee approach, if applied to existing sources as a substitute for RACT, could undercut the market for external nonattainment offset transactions between operators of existing sources and operators of major new sources; the inducement of paying a fee might be more attractive to the operator of an existing source than the "headache" of retrofitting and maintaining adequate

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[108] *NCAQ*, pp. 48, 279-280.

[109] *Id.*, p. 65.

[110] See section II.B.2., *supra*.

[111] *NCAQ*, p. 59.

pollution control equipment, not only to satisfy RACT requirements, but also to create additional emissions reductions to provide an external offset for another firm. In lieu of a market approach, the state or local control agency would allocate "offsets" (by using the fees to clean up sources) in a manner analogous to the growth allowance approach.[112]

NCAQ also recommended that the federal emission offset policy be revised to permit a state to require operators of new sources in nonattainment areas to pay a fee in lieu of securing offsets from operators of existing sources.[113] The state would utilize the fee to reduce other sources' emissions of pollutants emitted by the new sources. EPA would set the fees by pollutant on a nationwide basis based upon new source emission control costs. While it appears to offer operators of new sources a means of circumventing the previously mentioned problem of obtaining adequate external offsets, this proposal would effectively displace the market for external offset transactions in nonattainment areas implementing the fee approach, assuming that most operators of modified and unmodified existing sources can satisfy their own offset requirements internally, and that operators of major new sources would be the primary (or sole) market for external offsets.

b. ADMINISTRATION PROPOSALS

The 1977 amendments to the Clean Air Act authorized appropriations for carrying out the act's provisions through fiscal year 1981;[114]

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[112]See section II.C.2.c., *supra*.

[113]*NCAQ*, p. 60.

[114]CAA, section 327.

consequently, this year Congress is considering reauthorization of the act for the fiscal year 1982 and subsequent years. The Reagan Administration has not formally proposed legislative changes, but press accounts reveal that the Administration is actively considering substantial modifications of the act's provisions proposed in a draft policy paper prepared by the White House Cabinet Council on Natural Resources and Environment under the direction of Interior Secretary James Watt.[115]

The council's draft paper includes the following significant proposed changes in the Clean Air Act:[116]

In nonattainment areas, new sources would not be required to obtain emissions offsets or to install pollution control equipment to satisfy LAER requirements.[117] States which fail to submit SIPs would not be subject to federal sanctions,[118] and EPA would not be permitted to devise SIPs for such states; in short, the federal air quality regulatory regime would be founded upon "state voluntarism." In nonattainment areas which could not attain NAAQS by 1987, a state would only be required to impose RACT[119] on all sources not in compliance, and EPA would be empowered to extend the compliance date for such sources beyond 1987.

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115 *The Energy Daily* Vol. 9, No. 120, June 23, 1981, pp. 1-2, 6.

116 *Id.*

117 See section II.C.2.a., *supra*.

118 See fn. 6, *supra*.

119 See section II.B.2., *supra*. RACT is less stringent than BACT or LAER.

With respect to PSD regulations, the council proposes that Class II and III areas be eliminated and that Class I areas be preserved. As a result, with the exception of Class I areas, attainment area increments[120] would be abolished, and air quality in these areas would be permitted to deteriorate to NAAQS levels.

The implications of these proposals for offset banking and trading are clear: if enacted into law, they would effectively end external offset transactions involving nonattainment offsets or PSD increment exceedance offsets for major new sources and major modifications. At the present time, it is uncertain whether the Administration will propose formally these sweeping legislative changes and whether Congress will modify substantially the Clean Air Act in the course of its pending reauthorization debate.

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[120] See section II.C.3.b., *supra*.

IV. OFFSETS AS AN IMPETUS FOR FUEL CELL COMMERCIALIZATION

In this section, we identify potential market opportunities for fuel cells in the late 1980s and thereafter, based upon the offset trading and banking trends described in section III. In this time frame, a key selling point for fuel cells vis a vis conventional generation and cogeneration technologies can be the degree to which emissions levels of regulated air pollutants for fuel cell systems are significantly lower than those for the latter technologies.[121] By virtue of this air quality benefit, the fuel cell can be utilized as a tool for creating emissions reduction credits for use as internal or external offsets. This marketing advantage may, however, be neutralized if the current regulatory scheme of offset requirements is abrogated.

A. Fuel Cells as Sources of Emissions Reduction Credits

Operators of existing sources can utilize fuel cells (preferably in a cogeneration mode for economic efficiency) to replace their existing, polluting on-site energy-generating equipment — for example, diesel generators and oil- or gas-fired boilers — and thereby create emissions reduction credits. They may derive an economic benefit from utilizing these credits as internal offsets, selling them to others as external offsets, or banking them for future internal or

[121] See Table A-1 in Section II.C.1.b. (Appendix), *supra*, for the requisite sizes of an experimental fuel cell system to generate 100 tpy of SO_2, PM, NO_x and HC, respectively.

external use.[122] To the extent that its potential supply of emissions reduction credits is otherwise inadequate to meet its present internal offset demand, or its prospective internal demand as necessitated by future planned source modifications or future tightening of state/local air pollution control requirements, the operator of an existing source may perceive the fuel cell as an attractive replacement for polluting equipment. In a nonattainment or attainment area where the external offset demand is high and external offsets are scarce and/or costly, the operator of an existing source may view the fuel cell as a profitable method to produce emissions reduction credits for sale as external offsets. Open questions remain as to the prospective ability of operators of existing sources to satisfy internal and/or external offset demands within particular nonattainment or attainment areas, and as to their prospective willingness to do so.[123]

Conversely, operators of new sources with external offset requirements in nonattainment or attainment areas could purchase fuel cell systems for one or more existing sources within their area to replace the latter's existing polluting generating equipment as an offset for the former's incremental pollutant emissions. The operator of the existing source would, in effect, get a "free ride" by being able to modernize (and perhaps expand) its on-site energy-generating capability at someone else's expense.[124]

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[122] See, generally, section III.A., *supra*. The operator of an existing source can derive an added economic benefit from <u>oversizing</u> the fuel cell system in order to sell surplus electrical energy and/or capacity to a local electric utility at the latter's "avoided costs" pursuant to PURPA section 210 (see section IV.B. of this report).

[123] See section III.C.1.d., *supra*.

[124] The operator of the new/modified source would probably be able to bank for its own future use surplus external offsets resulting from this offset transaction. See fn. 74, *supra*.

B. Potentially Attractive Fuel Cell Markets

Major sources — both existing and new — in nonattainment and attainment areas with significant anticipated offset demands should be designated as prime targets of opportunity for fuel cell marketing efforts. Assuming the current air quality regulatory regime continues in its present form well into the 1990s, these sources will be subject to a variety of possible offset requirements: "bubble," "netting," nonattainment or PSD increment exceedance offsets.[125] These major sources will generally be large-scale industrial facilities.[126]

Potentially attractive fuel cell market areas would include: nonattainment areas where O_3 and PM violations of NAAQS are expected to continue through the late 1980s, necessitating NO_x, HC, and/or PM nonattainment offsets for major new sources and major modifications, and perhaps "bubble" offsets for major existing sources as well;[127] and attainment areas with significant air quality degradation problems, necessitating PSD increment exceedance offsets for major new sources and major modifications, and perhaps "bubble" offsets for major existing sources as well.[128] Within this group of potentially attractive market areas, those

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[125]See, generally, sections II.B., II.C., and III.C., *supra*.

[126]See section II.C.1.b., *supra*, for a list of industrial source types which can be expected to emit at least 100 tpy of a regulated pollutant and therefore be considered as major sources.

[127]See sections III.C.1.a. and c., *supra*, for specific nonattainment areas where these offsets may be required within this time frame.

[128]See sections III.C.1.b. and c., *supra*, for descriptions of sources in attainment areas for which these offsets may be required.

areas which have active and ongoing formal offset trading and banking programs with only a modicum of restrictions should be slated for the first round of marketing activities.[129]

In certain nonattainment and attainment areas nationwide, existing and new minor sources may also be subject to offset requirements, and existing minor sources may be permitted to bank emissions reduction credits and sell them as external offsets.[130] In these areas, the potential air quality and economic benefits of fuel cells relative to conventional energy technologies may be marketed to operators of minor sources as well as to operators of major sources. It should be noted, however, that the smaller the size of a fuel cell system (and the equipment that it replaces) is, the smaller the resulting emission reduction credits; below a certain size, these credits may have only nominal market value, for example, to a major source shopping for external offsets in areas where the major source has the option of acquiring sufficient credits, to meet its external offset needs, from a few large sources, in lieu of from many minor sources. In short, the size of the potential emissions reduction credits and their market value as external offsets may have a direct and substantial bearing upon the economic attractiveness of a fuel cell system: to the operator of an existing minor source who contemplates purchasing a fuel cell, and to the potential purchasers of the resulting emissions reduction credits within the area; to the operator of a major or minor new source or modification who contemplates purchasing fuel cells for one or more minor sources as an offset to its own incremental emissions.

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[129] See sections III.B.3.b. and c., *supra*, for examples of current and proposed banking programs and of banking and trading restrictions.

[130] See sections II.B., III.B.1.a., and III.B.3.c., *supra*, for examples of specific areas.

C. REGULATORY PROPOSALS IMPEDING FUEL CELL COMMERCIALIZATION

Up to this point, our observations in section IV on potential markets for fuel cells have been founded upon continuation, well into the 1990s, of the current air quality regulatory regime, including offsets requirements. In section III.C.2., we examined the impacts of several proposed modifications of this regime upon future offset trading and banking trends. NCAQ has suggested that states should have the option of substituting emissions fees or other economic incentives for an emissions offset approach.[131] A draft proposal currently under internal review by the Administration would effectively abrogate current regulations governing nonattainment offsets, postpone deadlines for compliance with NAAQS, and dilute pollution control technology requirements, among other things.[132] It remains to be seen whether these options are formally proposed in legislation during the current session or subsequent sessions of the Congress, and whether such legislation survives the ensuing political battle.

Enactment of one or more of these proposals could effectively remove the substantial impetus provided by the current regulatory regime to source operators to replace their existing generating equipment with less polluting equipment in existing sources and to install generating equipment with low emissions levels in new sources. As a result, a key marketing advantage of fuel cells over conventional generation and

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[131] See section III.C.2., *supra*.

[132] *Id*.

cogeneration technologies — low emissions levels — could be effectively neutralized.

Ongoing monitoring of future offset trading and banking trends and of potential or actual air quality regulatory changes until the commercialization date of fuel cells will be required, in order to properly assess whether the fuel cell's air quality benefits will persist as a marketable feature of the technology throughout its initial commercialization phase.