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Intermittent electrical dispatch penalties for air quality improvement

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Intermittent Electrical Dispatch Penalties for Air Quality Improvement

by

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Abstract

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Like most large U.S. urban areas, the photochemical smog problem of the San Francisco Bay Area occurs as intermittent episodes. Current electric utility emissions regulations rely on mandated stack clean-up equipment which performs poorly on intermittent problems because emissions reductions are not concentrated during episodes. Electric utilities have some flexibility in the boilers they commit and dispatch during episodes, so a policy to encourage use of cleaner boilers could result in reduced emissions of the smog precursor gas NO_x. Such a policy deviates from the tradition of utility minimum cost operations, resulting in higher fuel costs. In this study, the dispatch of more polluting thermal generation within the confines of the Bay Area Air Quality Management District (BAAQMD) is penalized by the imposition of a variable NO_x tax. The effect is explored through a Lagrangian

relaxation unit commitment and dispatch simulation of an historic episode in September 1989, using a Monte Carlo sampling of outage states. Imposition of the tax results in modest NO_x reductions, achieved for a small increase in fuel bill. The cost per avoided ton of NO_x emitted during the episode is low compared to the costs of Selective Catalytic Reduction of NO_x. The taxed dispatch tends to use more units but at lower power. Additionally, the variance of expected emissions across the outage states of the system is reduced, reflecting the fact that the dispatch optimization takes full account of the tax. Since during any one future episode the system state is random, the lower variance implies that the existence of the tax lowers the risk that NO_x emissions will deviate from their expected value. Two power sector NO_x emissions patterns, with and without the tax, were fed into BAAQMD's version of the Urban Airshed Model, but the change in emissions resulted in an immeasurably small effect on peak ozone estimates for the September 1989 episode.

Catherine P. Koshland
Professor Catherine P. Koshland

Dedication

This dissertation is dedicated to Nyla Marnay who provided the financial and emotional support that made this work possible and who has suffered as much as I have.

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Glossary

'91 CAP	Bay Area '91 Clean Air Plan
AQ	air quality
BAAQMD	Bay Area Air Quality Management District
BAPS	Bay Area Power System
BARCT	Best Available Retrofit Control Technology as determined by the California Air Resources Board
CARB	California Air Resources Board
CBM	Carbon Bond Model
CF	capacity factor - the energy output of a generator over a period of time relative to the maximum possible production of the unit over the period - although the normal convention is to count losses due to forced outage as lost production, in this work CF's are usually calculated relative to the maximum production of the unit over the study period, given that production was impossible during periods of forced outage
CFM	common forecasting methodology - standardized data collection process used by the California Energy Commission
CPUC	California Public Utilities Commission - agency responsible for price regulation of electricity sold in CA by investor owned utilities, such as PG&E, but not municipal electric utilities, such as the City of Santa Clara

DSM	Demand Side Management
EEUCM	Economic and Environmental Unit Commitment Model: a production cost model developed by Prof. Terje Gjengedal at the Norwegian Technical University, Trondheim
EKMA	Empirical Kinetic Modeling Approach: a simple model of photochemical smog formation that estimates a peak ozone concentration based on emissions inventories of precursor gasses
ELDC	equivalent load duration curve
FDV	Federal Design Value - ozone concentration used to determine compliance or non-compliance with the Federal NAAQS for ozone, currently defined as the 4th highest daily peak O_3 concentration during a rolling 3 year period
LDC	load duration curve
LOLP	loss of load probability
NAAQS	National Ambient Air Quality Standards that have been established in Federal law for 7 pollutants: CO, SO_2, O_3, NO_2, NMHC, total suspended particulates, lead. The NAAQS for O_3 is 0.12 ppm mol fraction, averaged over a 1 hour period.
NMHC	Non-Methane Hydro Carbons - numerous pollutant species that play an important role in photochemistry - often referred to as Reactive Organic Gases (ROG) or volatile organic compounds (VOC's)
NO_x	common name for the combined total of the pollutants NO (nitric oxide) and NO_2 (nitrogen dioxide) - in calculations involving mass, NO_x is, by convention, assumed to be entirely NO_2

OTA	Office of Technology Assessment of the U.S. Congress
PAN	peryacytlnitrate: an eye and nose irritant component of photochemical smog
PURPA	1978 Public Utilities Regulatory Policies Act
QF	Qualifying Facility: an independent generator eligible to sell power to its local electric utility under the favorable terms of the PURPA
RECLAIM	Regional Clean Air Incentives Market: proposed SCAQMD program for emissions trading
SCAB	South Coast Air Basin
SCAQMD	South Coast Air Quality Management District
SCR	selective catalytic reduction - official California BARCT NO_x stack gas cleanup technology that employs injection of ammonia into the stack in the presence of a catalyst
SMUD	Sacramento Municipal Utility District - electric utility in the Sacramento area
SNCR	selective non catalytic reduction
UAM	Urban Airshed Model: the EPA approved photochemical smog modeling program used by BAAQMD and most other agencies
WAPA	Western Area Power Agency - supplier of electricity generated at Federally own stations to qualified buyers
WHO	World Health Organization

Preface

Overall, California's air quality problem is chronic, high ambient concentrations of photochemical oxidant smog on hot still days being the number one problem. Nonetheless, in certain areas of the State smog episodes are less frequent than in most large U.S. urban areas. Draconian and costly measures may well be necessary to combat the smog problem in California's worst areas, notably the South Coast Air Basin. The motivation for this work is simply that in areas only marginally out of compliance with air quality standards, such as the San Francisco Bay Area, alternative cheaper alternatives that come into force only during actual episodes could and should be pursued.

My background in electric utility planning tells me that power generation presents a prime candidate for one possible alternative intermittent regulatory regime that would focus emissions reductions during actual episodes, potentially, at a lower societal cost than traditional abatement strategies. This belief led me to attempt the work presented in this dissertation. I hope it paves the way towards recognition that the burden of currently planned smog abatement might prove unnecessarily high in marginal areas and that alternative intermittent policies should be sought to combat what is undeniably an intermittent problem. Perhaps by these means, more environmental clean up can ultimately be afforded by and for the citizens of the State.

Acknowledgements

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An enormous debt is also owed to Prof. Terje Gjengedal of the NTH in Trondheim, Norway. Prof. Gjengedal not only generously permitted me to use the EEUCM model, which he designed and built, but also patiently guided me through a much longer than anticipated period of model adaption and refinement. Ståle Johansen of EFI originally proposed this arrangement, which ultimately became so fruitful, and assisted during the entire EECUM adaption process.

Phil Martien of BAAQMD provided the mass of data that UAM consumes so voraciously, and also provided tireless advice and guidance on the District's meteorology and smog problem, and on use of UAM. My fellow Energy and Resources student, Bob Grace, who independently at the other end of the country managed to come up with a very similar thesis topic to mine has provided endless help and camaraderie during the pursuit of our respective degrees. G. Alan Comnes provided in-valuable advice on the CPUC perspective, and Mithra Moezzi of LBL struggled to keep me statistically legal.

Thanks also go to Tom Perardi, Jim Tomich, Toch Mangat, and Sunny Liston of BAAQMD, Don Lafrenz, and Scott Cauchois of the CPUC, Gary Bisonett, Claudia Grief, Ken Harlan, Mark Melgin, Frank Strehlitz, Dewey Seeto, and Bob Wagenor of PG&E, and Beth Swehr and Lucille Van Omering of CARB. Additionally, a large debt is owed to the many friends and colleagues, in particular Joseph H. Eto, Charlotte Standish, Todd Strauss, Shankar Subramanian, and Alva Svoboda, who have helped me through the academic and emotional trauma that is dissertation writing. And speaking of trauma, I must not forget W. Bart Davis of LBL, who recovered most of the volume you see before you following a catastrophic disk failure in December 1992.

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However, top billing must go to Dora, the dog who didn't eat my dissertation.

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19 August 1992

I. INTRODUCTION

A. Background

This work explores the relative costs of two alternative ozone abatement strategies for the power sector in the San Francisco Bay Area, where the goal of the abatement is improved local air quality as measured by actual physical NO_x emissions and human exposure to surface ozone. The two alternative strategies are: 1. *physical controls* as mandated by the current regulatory regime of pollution control equipment requirements; and 2. *intermittent dispatch penalties* on thermal generating resources. Virtually the entire analysis conducted here focuses on the second alternative, while the first serves as a benchmark alternative based on current regulatory goals.

Under current regulation, the imposition on generators of specific control equipment is implemented through a permitting system that requires emissions from large point sources be within fixed physical limits, under a specified test condition. The permit condition is usually set such that it will necessitate the installation of certain control equipment. In addition to the existence of the control equipment, other operating constraints, such as a daily or annual emission ceiling, are often imposed. An intermittent dispatch penalty regime, on the other hand, would impose no restrictions on generators during periods when the risk of smog formation is low, but encourage operation of generators in a less polluting manner under smog episode conditions. Since the standard operating rule for the power system is cost minimization, this alternative mode of operating the generation system will result in higher generation costs, and, almost certainly, higher fuel use.

The Bay Area experiences approximately 15 days/year when ozone concentrations exceed State of California ambient air quality standards, and a total of approximately 50 days when weather conditions favor smog formation and the District risks falling into noncompliance.[1] On these days, generators would be encouraged to curtail their NO_x emis - sions. The power sector is only a minor source of the other major smog precursor, hydrocarbons. The encouragement could be either in the form of command regulation or as penalties for operating not as desired by the District. An important subcase, however, would be a regime in which the utility is assessed a NO_x emissions tax. The mathematics of cost minimization under a tax regime is so straightforward and so similar to that of current fuel cost minimization that it can serve as a remarkably convenient vehicle for studying the effectiveness of a biased low-NO_x dispatch, and the NOx emissions tax approach is the only one considered in detail here.

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1 see figure E.3

Unlike most proposed emissions taxes, however, this tax would be nonuniform over time, depending on the amenability of ambient weather conditions to smog formation. The tax would stand at zero most of the time and peak during those hours of episode days when emissions are most detrimental, typically the few hours before an exceedence. The viability of such a scheme is not nearly as unlikely as it might seem because the nature of the utility industry has required the development of highly sophisticated methods for coping with operating restrictions that vary over time. Further, the basic problem is easiest to grasp in terms of a tax, whose influence on system operations can be readily estimated within the traditional framework of fuel cost minimization.

By conducting comparative runs, using a Lagrangian relaxation electric utility production cost model, the costs of imposing a penalized dispatch are found and a cost per avoided mass of NO_x calculated. This cost can be compared later to the cost of alternative physical control strategies, which has been researched in some detail already, and reported in California proceedings.[2,3] Additionally, an atmospheric chemistry model is used to estimate the ozone improvements that could

2 Bemis, *et al*, 1989

3 Randolph and Walters 1991

result from the reduced NO_x emissions achievable through an intermittently penalized dispatch.

As mentioned above, the issue of physical controls versus penalized dispatch is broached through a test case of the Bay Area Air Quality Management District (BAAQMD or District), and the point of view of the analysis is strictly that of the District. The generating resources and electricity demand within the District are isolated and used as a test system called the Bay Area Power System (BAPS). Because this regional approach conflicts with the traditions of utility modeling based on utility boundaries (geographical, jurisdictional, and rate class), the approach represents a major departure from established utility modeling practice and poses formidable data manipulation problems.

B. Hypothesis

1. statement

The hypothesis of this work consists of two parts, which must be tested in sequence.

1. At an estimable cost, the dispatch of electrical generating resources in the Bay Area can be pushed away from the cost minimizing point such that the emissions pattern of NO_x is more environmentally benign.
2. Adjusting the dispatch in this manner can be a more cost effective method of improving air quality in the Bay Area than the imposition of physical controls on NOx emissions from power generation.

2. contribution

The concept of environmental dispatch has a long, if sparse, history in the literature. Recently, together with a generally growing interest in intermittent emission control strategies, however, environmental dispatch has started to emerge as a serious policy proposal, especially for areas, such as the Bay Area, for which attainment of the NAAQS or State of California standards lies within reach. Inherent in suggestions that the dispatch of power generation should be constrained away from the normal minimum cost point in order to mitigate environmental stress tends to be the assumption that this kind of control strategy could prove more cost effective than direct controls. However, questions regarding the cost of dispatch constraints tend to be poorly addressed by a back-of-the-envelope approach because of the complexity of resource dispatch. This research derives an initial result using state - of-the-art dispatch techniques that can suggest whether the assumed cost saving potential really exists for a hypothetical case in which the resources of the Bay Area are dispatched to meet local demand case.

C. Method

1. data flow

Figure I.C.1: Data Flow in Idealized Analysis

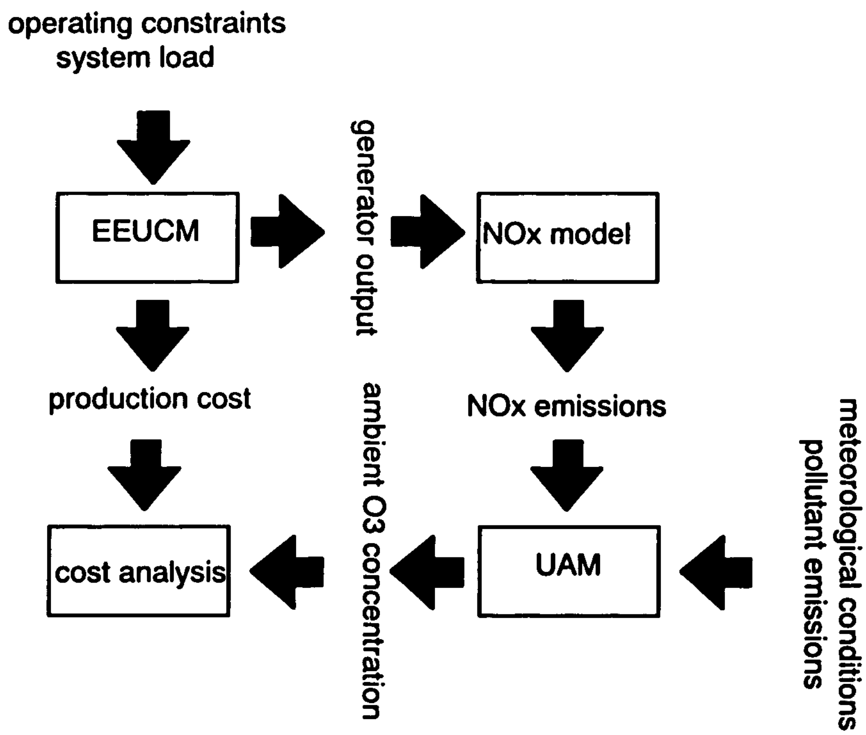

Figure I.C.1 shows the flow of data for a possible ideal analysis of this problem. A basic approach to the analysis would involve the running of two computer models in tandem, the Economic Environmental Unit Commitment Model (EEUCM) electric utility production cost model and the Urban Airshed Model (UAM) urban atmospheric chemistry model. The two have to be linked by the passage of a NO_x emission pattern over time from EEUCM to UAM. As the figure shows, the key inputs to production costing are twofold, approximating the supply and the demand on the system over the simulation period. System load data usually provide all the information needed for the demand side. The supply side definition consists of a complex data set containing all the operating information on the various resources available to the system operator during the simulation period. As the figure shows, there are two main outputs from the production cost simulation, both of which are key to the analysis. First, the model reports the cost of operating the system through the simulation period. This cost represents the minimum cost result, taking the NO_x tax into account, that the model was intended to find. Second, the model reports the manner in which all of the resources are used to achieve the minimum cost result. Note that the outputs from EEUCM are optimal in the sense that the effect of the NO_x tax on operating cost has been taken fully into account in the unit commitment and dispatch decisions. The separation of the process into a separate NO_x model is merely to stress that the output of a production cost model has to be reformatted and otherwise massaged before it can serve as an input to UAM.

The second output is essentially an expected operating schedule for each of the resources available to the operator during the simulation period. The result is a statistic because the availability of most resources is random leading to model outputs that are also random variables. These schedules form the basis for estimates of NO_x emissions flows over the simulation period, which are also reported by EEUCM. These flows are, in turn, fed into UAM, as point source emissions. The other inputs to UAM, primarily meteorological and topographical data plus emissions flows from other sectors, will be provided by BAAQMD.

The key output from UAM is the ambient concentrations of pollutants within each of the grid cells of the modeling domain. The BAAQMD domain covers a huge total area of 90 000 km^2 encompassing the District, a considerable land area beyond it, and some ocean.[4] The difference in production costs reported by the production cost model can be used, in principle, to estimate a cost of avoided ozone.

2. timing and geography

In practice, operating the two models in tandem, as shown in figure I.C.1, is not feasible given the limitations on data availability and computing resources. The biggest limitation derives from the nature of UAM, which is a highly data intensive model that consumes computer time.[5] UAM requires temperature, wind, and emissions data so detailed that BAAQMD has actually so far compiled complete data sets for only the first day of a single two-day episode. In fact, most of the Dis-

4 see figure G.1

5 Actual run time for a two-day simulation on a Sun 4/280 can exceed a week. That is, about 4 hours of cpu time are required to simulate one hour of actual experience. Even if the data were available, simulating all the 25-50 potential BAAQMD episode days would tie up a supercomputer for weeks.

trict's analysis to date is based on a repeat of this single day's data as a proxy for an isolated two-day episode, September 13 and 14, 1989, during which data was actually collected.[6,7] To assess the effect of various pollution abatement strategies on ozone episodes in the District, therefore, it must be assumed that several repeats of the days studied can well represent all the exceedances. All the UAM results reported in this study are based on the single September 1989 episode. In the case of the Bay Area, since most of the episodes occur during quite a well known smog season that lasts from the end of June until mid October, it does not seem like a particularly onerous assumption that all episodes are similar to the September 1989 one; however, there are some difficult questions regarding the weather conditions that are conducive to smog formation in the Bay Area. The 13 and 14 of September, 1989, episode occurred during a period of onshore winds, but other episodes occur when offshore winds pull pollutants from the Central Valley into the District. The potential benefits of pollution abatement within the District during an offshore-wind episode might be quite distinct from those observed in simulation of the September 1989 episode; therefore, any

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6 Data for a four-day episode in 1990 were collected as part of the San Joaquin Valley Air Quality Study and Atmospheric Utility Signatures, Predictions, and Experiments (SJVAQS/AUSPEX) project and will provide a more complete data set when it has been set up at the District.

7 Ranzieri and Thuiller 1991

conclusions drawn from the UAM modeling currently possible can only be tentative.

Not only is the existence of data at the level of detail required by UAM a problem, but even the manipulation of its huge data sets poses severe limitations. For example, the procedure for transferring estimates of NO_x emissions from the NO_x model in figure I.C.1 to UAM is not even a straight forward process. The outputs from the NO_x model have to be converted to the units and format required by UAM. Unfortunately, UAM uses a binary file that is written by a preprocessor of its own, and actual outputs from the NO_x model have to be embedded in the huge (~10 Mb) ASCII input file to the preprocessor, which contains details on all the Bay Area point sources during the test day. The power generation resources have to be identified and emissions from the corresponding stacks changed to reflect the changed dispatch. Smaller emission sources are described by the data in the area sources input file to UAM. In a more accurate simulation, this file may also have to be adjusted in some way to account for the smaller generating resources such as the qualifying facilities (QF's).[8]

Given the demands of UAM, the only feasible approach for the purposes of this analysis is to use it merely to assess the boundaries on

8 A qualifying facility is an alternative energy producer or cogenerator qualified to sell power to the local utility under the favorable terms of the 1978 Public Utilities Regulatory Policies Act (PURPA).

the effectiveness of a NO_x constrained dispatch, and use UAM to provide some general pointers about how the overall magnitude and pattern of air quality might be affected. This is achieved by running a limited number of cases representing various levels of lowered power generation within the District.

On the production costing side, because of the seasonal variation in fuel mix, ideally the analysis should be at least annual in scope. Specifically, one likely effect of a constrained dispatch would be the conservation of hydro generation for smog episodes; the cost of such a bias can reasonably be estimated only on an annual basis. On an even longer time scale, nuclear refueling and maintenance cycles could also be influenced by the need to ensure availability of this non-NO_x resource during episodes. In other words, estimating what reasonable reductions in the pollution pattern during an episode are feasible necessitates the analysis of at least the full year in which it occurs, probably a longer period.

Unfortunately, rescheduling of resources, such as hydro, would involve a complex separate analysis that is beyond the scope of this work. Additionally, the boundary problem also limits the possibility of conducting a thorough analysis. Since the District represents a small fraction of the total PG&E service territory, a tax biased dispatch of the entire PG&E system would produce only the rather uninteresting result that when taxes are enforced in the District, generation is moved outside of it. Such a result is uninteresting both because it is so obvious and because such a response is probably not permissible under the transport provisions of the California Clean Air Act.

Rather than undertake such a global analysis, the focus here is on the actual dispatch of thermal resources within the District. Thus, the problem addressed is the hypothetical one of how the generation resources within the District might be dispatched to meet the load within the District, and how these resources might be dispatched differently under a NO_x tax regime.

II. PRINCIPLES

A. Policy Problem

1. standards

As study of photochemical smog has progressed, concern over urban ozone concentrations has risen to the point where today, perhaps, it is considered the most serious pollutant of urban air in the U.S. Certainly, among the six EPA criteria pollutants, ozone has proven to be the most resistant to abatement efforts.[1] Most large U.S. urban areas violate the Federal National Ambient Air Quality Standard (NAAQS) for ozone, and the problem is equally severe in some other countries.[2] Mexico City has emerged in recent years as the world's ozone capital,

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1 Of the six criteria pollutants, the National Ambient Air Pollutant Index has fallen the least for ozone since 1979. The mean for the ozone index during 1984-88 was 93.4, where 1979=100 . The next smallest drop was recorded by NOx itself with 92.3. The other indices are: CO=77.1, SO_2=72.3, particulates=78.8, and lead=23.1. *(Statistical Abstract of the United States 1991)*

2 OTA 1989

having worse air quality today than Los Angeles has ever experienced.[3,4,5,6,7,8,9,10]

The number of U.S. non-attainment areas varies considerably from year to year depending on the weather, the business cycle, and the effectiveness of control strategies. The hot summer of 1988 caused a particularly serious smog year, leaving 101 U.S. metropolitan areas out of compliance and heightening debate over the possible restructuring of the Federal standard.[11,12] Conversely, only 63 areas were out of com-

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3 Romieu, Weitzenfeld, and Finkelman 1991

4 Legaretta 1990

5 Davalos and Herrera 1992

6 Legorreta *(sic)* and Flores 1991

7 Mumme 1991

8 Albarrán and Monge 1992

9 Beaton, *et al*, 1992

10 de Buen 1992

11 Fairley and Blanchard 1991

12 Chock 1991

pliance in 1987, and the average for the eight-year period, 1982-89, was 84 areas.[13,14]

The State of California has special authority under Federal law to establish its own standards, and has established an ozone standard both stricter and less flexible than the Federal standard, resulting in considerably more exceedences.[15]

The U.S. National Ambient Air Quality Standard for ozone is 0.12 ppm (240 $\mu g \cdot m^{-1}$) over a one hour averaging period, and the State of California standard is 0.09 ppm (180 $\mu g \cdot m^{-1}$), also over a one hour averaging period.[16] These are both the primary and secondary standards. Any single exceedence during any seven-year period implies *non-attainment* of the strict State standard. The California Clean Air Act of 1988 refers only to the State standard in that it reaffirms that attainment of the standard is necessary to protect public health. No changes are made to the standard itself, or its method of calculation. The State of California standard remains very strict and inflexible.

13 National Research Council 1991, page 32

14 *Areas* in this context are as defined by EPA for the purpose, and can be counties, Metropolitan Statistical Areas, or Consolidated Metropolitan Statistical Areas.

15 The State maximum permissible concentration is lower, 0.09 ppm versus 0.12 ppm, both over a one-hour averaging period, and no exceedences whatsoever are tolerated under the State standard, whereas the Federal standard is a rolling 3-year average.

16 For comparison, the World Health Organization guideline is 0.10 ppm (198 $\mu g \cdot m^{-1}$), the Canadian standard is 0.08 ppm (158 $\mu g \cdot m^{-1}$), and the Japanese standard is 0.06 ppm (120 $\mu g \cdot m^{-1}$).

The 1970 Amendments to the original Clean Air Act established the Federal NAAQS photochemical oxidant standard at 0.08 ppm. This standard was loosened to 0.12 ppm and redefined as an ozone only concentration in 1978, and has not been changed again.[17] The provisions of the 1990 Amendments change the approach to achieving the standard but not the standard itself. *Non-attainment* of the Federal standard requires exceedance of the 0.12 ppm concentration at one monitoring station, for an expected number of hours greater than one over a three-year period. In practice, the most widely reported concentration indicator is the Federal Design Value (FDV), defined as the fourth highest daily one-hour-averaged peak concentration over a rolling three-year period. The FDV presents a somewhat more stable indicator of changing air quality than a simple annual peak concentration, but is still a limited guide to exposures. The FDV for the Bay Area fell by 25% during the 1980's, which suggests some success in abatement efforts, although insufficient to achieve compliance.[18]

The 1990 amendments also classified the non-attainment areas into five categories, determined by the FDV; the categories are extreme (FDV>0.28), severe (0.18<FDV≤0.28), serious (0.16<FDV≤0.18), moderate

17 OTA 1989

18 At the end of 1992, the Bay Area had achieved compliance, based on the last three years of data. However, at the time of writing no change in the Federal designation seems imminent.

(0.138<FDV≤0.16), and marginal (0.121<FDV≤0.138). The Bay Area falls into the moderate category, having an FDV of 0.14. Only the Los Angeles-Long Beach area achieves the extreme classification.[19]

2. BAAQMD

Despite the generally good air quality in the Bay Area Air Quality Management District (BAAQMD or District) relative to the South Coast Air Quality Management District (SCAQMD), the Bay Area remains one of the air basins not in attainment with either the Federal or the State standard for ozone. The Bay Area's ambient ozone concentration typically exceeds the Federal ozone standard on about 2 or fewer days per year, and fails to meet the tighter State standard on about 15 days per year.[20]

Despite steady improvements in the District's ozone attainment over the last two decades, three factors will tend to tighten its rules over the coming decade. First, as in SCAQMD, most analysts expect growing populations to outstrip the benefits of current control measures. Second, provisions of the 1988 California Clean Air Act and the 1990 Amendments to the Federal Clean Air Act will increase the jurisdiction

19 The CMSA or Consolidated Metropolitan Statistical Area is Bureau of the Census definition of the L.A. urban area. Most of the data used in preparation for the Clean Air Act Amendments is reported by CMSA and/or county.

20 For example, in 1990, the Federal standard was exceeded on 2 days and the state standard on 14; in 1991, the equivalent exceedences numbered 2 and 23.

of State and Federal agencies within the District. And third, fears that relatively low ozone exposures may cause cumulative lung damage may strengthen resolve to limit ozone excursions, to lower exposures more generally defined, or to tighten existing standards.[21,22]

While ozone precursors are emitted by both mobile and point sources, the District's jurisdiction was historically, more or less, restricted to large point sources, including power generation. Federal and State agencies directly regulated mobile sources.[23] However, this established jurisdictional boundary blurred considerably after passage of the 1988 California Clean Air Act. This law requires districts to consider pollution reduction from mobile sources.[24] NO_x represents the major pollutant emission from oil or gas-fired power generation and the pressure to control NO_x emissions from the utility sector will certainly rise.

Direct exposure to ozone poses the prevalent air pollution problem in California, especially in the Bay Area, which is relatively free of other air quality problems. Ozone is harmful if breathed and is directly

21 CARB 1986

22 Bresnitz and Rest 1988

23 Strictly speaking, some local jurisdiction over mobile sources did exist, through designation of diamond lanes, bridge tolls, etc. However, only the State or Federal government could set emissions standards, and, also importantly, only the Federal government can set efficiency standards.

24 CCAA, section 40910

hazardous to plant life, so it is ozone in the mixed, lowest layer of the atmosphere that is of concern in this work. Further, the residence time of ozone in polluted urban air is short, no more than a few hours, so the problem of ozone exposure tends to be localized to cities and areas downwind of them. Concern about ozone depletion refers to concentrations of this gas in the stratosphere where it provides the only protection against incoming U.V. radiation of wavelength 0.18-0.34 μm.[25] Confusion over the importance of ozone is also compounded because it is a greenhouse gas, absorbing outgoing near I.R. radiation of wavelength 9.6 μm. Neither of these two environmental problems are addressed in this work, which is solely concerned with direct exposure to ozone at the surface.

3. representativeness

As mentioned above, by California standards, the Bay Area has reasonably good air quality. In fact, it typically experiences the second lowest number of exceedences among the 8 most populous California air basins.[26] Further, the record has improved steadily since the worst ever

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25 Approximately the bottom 11 km of the atmosphere form the troposphere and the next 40 km the stratosphere. Ozone concentrations in the stratosphere are highest at about 20 km where concentrations exceed those found at the surface.

26 The eight basins and number of 1987 State exceedence days are: Bay Area (46), North Central Coast (7), Sacramento Valley (51), San Diego (127), San Joaquin Valley (125), South Central Coast (123), South Coast (196), and Southeast Desert (150). (source: CARB 1989)

year of 1969. Improvement with respect to the State standard has been slower than with respect to the Federal standard, however.

The moderate air quality problem of the San Francisco Bay Area actually makes it a more interesting test case than the more frequently studied Los Angeles basin. Figure 2 shows a cumulative plot of the fraction of the U.S. population exposed to various levels of ozone exposure, as measured by the average annual number of days of exceedence of the Federal standard during 1987-89. While these data are inexact because of the discrepancies between area boundaries and the uneven exposures within areas, they do give an overall picture of the scope of the problem.

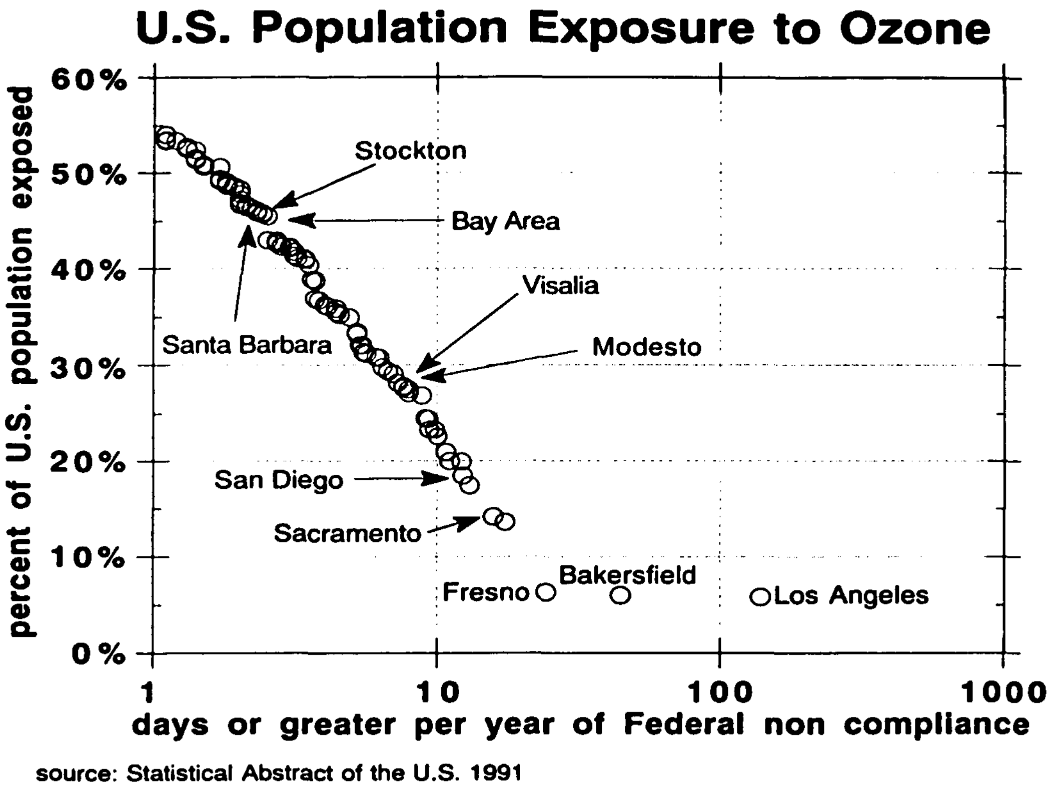

Figure II.1: Representativeness of the Bay Area - 1987-89

Note first that the total fraction of the U.S. population living in non - compliance areas totals a disturbing 54%. From this point, the exposed population fraction falls log linearly, such that only about 23% are exposed to 10 exceedence days or more. That is, while the total number of people exposed is huge, actually, over 30% of the U.S. population lives in areas that are only *marginally* out of compliance, that is, 10 days per year, or less. Further, fully 48% live in areas in noncompliance 18 days per year, or less. In keeping with these data, the Bay Area experienced an average 2.5 noncompliance days per year during the 1987-89 period.

This plot was actually constructed simply by cumulatively summing the populations of noncompliance areas. The points at which at the California areas are added to the total are shown on the figure. All large population centers in the State are out of compliance, as shown, and five of the worst seven areas are in California. The other two members of that group, which from the appearance of the figure are clearly large population centers, are New York with 17 days, and Chicago with 13 days. Los Angeles with 138 days, Bakersfield with 44 days, and Fresno with 24 days appear as clear outliers.

4. '91 CAP

The 1991 Bay Area Clean Air Plan ('91 CAP) was approved by CARB in late 1992. Historically, the District has taken a moderate hydrocarbon control strategy. That is, while the emphasis of its regulation has been the control of hydrocarbons, there certainly are NO_x regulations on the books. The '91 CAP stiffens NO_x rules and requires considerable new investment on the part of PG&E. The non-PG&E generation tends to be newer and already has tighter permit requirements, so the implied incremental investment is less. The evolving approach of the District reflects both the results of its UAM modeling and the changing climate on abatement strategies that was signaled by the release of the NRC report described in section II.B.4. More detail on the utility rules in the '91 CAP appear in figure G.3. Remember that the rules in the CAP are only proposed and the actual utility boiler rule will not be released until 1993.

5. intermittence

Clearly, the nature of the urban photochemical smog problem is intermittent, and, clearly, the Bay Area is rather typical of many U.S. non-attainment areas, experiencing about 2 exceedence days per year.[27] While there may be benefits to reducing ozone concentrations during non-episode times, the focus of policy since the first Federal Clean Air Act has been to reduce the number and duration of exceedences of air quality standards, both Federal and State. Given this historic focus on the peak of the smog problem, it is surprising that almost no regulations originating from the District, or other agencies, have any intermittent provisions. In the jargon of the utility industry, a problem that is dramatically peaking, that is, one occurring only a few hours per year, has been addressed as a strictly base load problem, that is, one that is evenly spread across all times.

It is, in fact, remarkable that among all the gamut of rules and regulations promulgated to abate the smog problem of U.S. cities, from catalytic converters on cars to the proposed SCR equipment on power

27 More details of the Bay Area smog problem is contained in section IV.B.

plant NO_x emissions, the author has unearthed only two precedents for intermittent policies. The first precedent concerns the use of oxygenated gasoline. Several jurisdictions have regulations requiring gasoline sold in the winter CO season have characteristics that result in lower CO emissions. CARB requires gasoline sold during winter months in non-compliance areas meet a mimimum oxygen content requirement.[28] The rule does not apply outside the winter months.

The second, and much more relevant, precedent concerns unloading of tankers in the Bay Area. A District's rule limits the unloading of tankers in the Bay during periods forecast as possible episodes by the District.[29] The rule clearly establishes a precedent for the type of intermittent tax postulated in this work. The precedent has two important elements: first, the refineries accepted this type of rule in preference to more onerous limits on tanker unloading; and second, the imposition of the rule depends on the accuracy of the District's smog episode forecasting. Given the provisions of the '91 CAP, the first element is important because the utility industry would be accepting the NO_x tax as an alternative to the CAP's costly SCR requirements.

Another way in which BAAQMD has shown interest in intermittent controls has been with calls for voluntary abatement when neces-

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28 BAAQMD Advisory, 28 October 1992

29 regulation 8, rule 44, Marine Vessel Loading Terminal, 4 January 1989

sary. One example of this approach is the *Don't Light Tonight* program, under which press announcements are made requesting residents to not use fireplaces or woodstoves during wintertime particulate or CO episodes. Also, during smog episodes, requests are made for residents to curtail driving and not paint, barbecue, or mow lawns.

While there are some examples of intermittent control policies, the limited level of interest in intermittent regulation is remarkable, given a problem that is so clearly intermittent in nature. Particularly, it should be emphasized that physical controls perform poorly with respect to this problem. While the cost of physical NO_x control, in terms of dollars per avoided kg may be low, it might be expensive in terms of dollars per avoided episode day kg. Or, to look at the problem the other way around, an intermittent control strategy that may be very costly in terms of dollars per avoided kg of emissions may still be cost effective in terms of dollars per avoided episode day kg. The smaller the number of hours of exceedence, the more powerful this effect can be, implying that as jurisdictions inch towards compliance, intermittent controls may look more and more attractive. This is particularly true of the power sector, which would be called upon to take emergency measures less frequently as compliance was approached.

6. SCAQMD

A notable feature of the BAAQMD '91 CAP is its references to South Coast AQMD rules. In the case of utility boilers, this tends to mean rules mimic those of SCAQMD, especially proposed rules 1134 and 1135.[30] This aspect of the '91 CAP raises two questions. The first one is familiar. Given the much more intermittent nature of the Bay Area's smog problem, does mimicking SCAQMD's approach make sense?

The second issue addresses a separate issue entirely. The fact is that since the release of SCAQMD's plan, the *1991 Air Quality Management Plan*, it has taken a quite different direction in its proposed NO_x regulation. SCAQMD has been studying a proposal called the Regional Clean Air Incentives Market (RECLAIM), which is basically a proposed NO_x and NMHC trading plan for the South Coast.[31,32] Under RECLAIM, NO_x would be traded as an area specific, but not time specific, commodity. It is unclear at this time whether a RECLAIM like program will ever go into effect, but as part of the work on the proposal, some legal work was done by SCAQMD that provides some general guidance into the legality of a possible NO_x tax. The SCAQMD counsel,

30 George, *et al*, 1991

31 SCAQMD 1992

32 NMHC refers to non-methane hydrocarbons, often also called in the literature volatile organic gases (VOC's), reactive organic gases (ROG's), or simply hydrocarbons.

Peter M. Greenwald, concluded that RECLAIM could be adopted under the authority of existing legislation. Greenwald, however, cites the following restrictions that existing law places on RECLAIM.[33,34]

[1.] The marketable permit program must be enforceable and the result in quantifiable, actual emissions reductions contributing to progress requirements as defined in federal and state law.

[2.] The program must require each new and modified major source to comply with "lowest achievable emission rate" ("LAER").

[3.] Federal new source offset requirements must, at a minimum, be met on an aggregate basis by all new and modified sources.

[4.] Federal and state requirements for existing sources to employ "reasonably available control technology" ("RACT") and "best available control technology" ("BARCT") must be met. It may be possible to demonstrate compliance with these requirements be aggregating emissions from some types of sources.

[5.] The program must require each source to comply with statutory provisions that mandate specific control technologies, and those which impose emissions limits designed to prevent localized health impacts.

33 Greenwald 1991

34 Peeters 1991 provides a more general discussion of the legal issues surrounding marketable pollution permits.

Applying these legal tests to a NO_x tax as described in this study leads to the following conclusions. Legal test 1. would quite naturally apply to any air quality initiative, including the NO_x tax. None of the remaining legal tests would be passed by the NO_x tax. These tests show how deeply command and control regulation is embedded and how effectively they preclude incentive based regulation.

7. electrification

The importance of the power sector in abatement strategies has been somewhat enhanced by increasing interest in electrification, especially in transportation. Electric motors emit virtually no pollutants at the point of operation; hence, replacing small emitting prime movers, which are area pollution sources, by electric motors dramatically reduces emissions at the point of end-use. Electric cars, like most electric motors, have high energy conversion efficiencies, so overall energy efficiency is not much reduced by the extra conversion step required to substitute electric vehicles for gasoline or diesel powered ones. This effect is both because conversion efficiencies in power generation can be high and because the overall efficiency of motor vehicles is low. Naturally, electrified public transportation can considerably improve overall energy efficiency.

Of course, electrification results in some small compensatory increase in utility stack emissions. However, because control of combustion is much more effective at the utility generator than in the field, and because a utility's diversified supply mix does not wholly depend on thermal generation; the compensatory emission is typically much smaller than the alternative area source emission. This is particularly true for hydrocarbons, which are rarely a problem in power generation, but it is also true for NO_x emissions.

Therefore, electrification plays a prominent role in the abatement strategy of both SCAQMD and BAAQMD, and is also addressed in the Federal Clean Air Act. Evaluation of abatement strategies should take the compensatory stack NO_x emissions into account; however, estimating it is non-trivial. The compensatory NO_x emission varies considerably seasonally and by time of day, as the supply mix, the marginal unit, and the power level of the marginal unit change.

B. Smog Problem

1. history

Urban air quality has posed a longstanding health concern, and scientific study of the effects of anthropogenic pollution dates from at least the 17th century.[35] Early concern focused on mortality during episodes of sulfurous or London smog. The worst ever London episode of 1952 resulted in 4 000 fatalities.[36] Concentrations of SO_2 during the episode reportedly reached 1.3 ppm, almost 10 times the current U.S. 24 h national ambient standard, and the total suspended particulate matter reached 4.5 $mg{\cdot}m^{-3}$, 30 times the PM10 standard.

The mixture of ozone (O_3), other oxidants, and many lesser pollutants that are collectively referred to here as *photochemical smog* was recognized only relatively recently as a pernicious threat to human health, vegetation,and materials.[37] Most of our understanding of the *smog* phenomenon comes from study of the infamous Los Angeles air quality problem, which began in the 1950's and continues. Although Los Angeles has by far the worst smog problem in the U.S., most major

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35 Finlayson-Pitts and Pitts, pp. 3-4

36 Finlayson-Pitts and Pitts, p. 5

37 The term *smog* will be used here, in keeping with common usage; however, please note that neither smoke nor fog are components of *photochemical smog*, which occurs on clear sunny days.

urban areas in warm climates experience occasional smog episodes, and some cities, such as Mexico City, are now worse than Los Angeles.

2. chemistry

Ozone is formed in polluted urban air through a complex series of chemical reactions involving many pollutants that are together often referred to as *ozone precursors*. These reactions also give rise to other minor but troublesome pollutants, notably peroxyacetyl nitrate (PAN), nitric acid (HNO_3), nitrous acid (HONO), and many organic compounds, some of which are carcinogens. Generally speaking, ozone is formed when oxides of nitrogen (NO_x) and reactive hydrocarbons (NMHC) are mixed together under the influence of incident ultra violet (UV) radiation in stagnant, warm air.[38,39] This process supplies essentially all known anthropogenic ozone. In any specific airshed, the relative importance of the two precursor groups, NO_x and NMHC's, in ozone formation and, consequently, the relative benefits of controlling either one or both of them are always a controversial topics. NO_x control poses a particularly tough regulatory dilemma because emissions can also have a short-run or local benefit called *NO_x quenching*, which

38 Nitric oxide (NO) and nitrogen dioxide (NO_2) are together referred to as NO_x.

39 The name Non-Methane Hydro-Carbons (NMHC's) derives from the practice of reporting hydro-carbon concentrations as two numbers, one for methane (CH_4), and one for all others. A large number of diverse species are covered by NMHC's and other names, such as reactive organic gases (ROG's) are common.

comes about because of the reaction of NO with O_3. One implication of this effect is that controlling both pollutants such that their ratio remains constant would have a better chance of reducing ozone formation.

Ambient ozone became a pollutant of concern in the Los Angeles basin during the 1950's. Haagen-Smit and others were able to reproduce the plant damage that had been observed in the basin by exposing laboratory samples to mixtures of olefins and ozone. These researchers quickly posed the hypothesis that the overall reaction forming the hazardous pollution was of the following form.

$$NMHC + NO_x + h\nu \rightarrow O_3 + \text{other pollutants} \quad \text{(a)}$$

where:	NMHC	= non-methane hydrocarbons
	NOx	= nitric oxide + nitrogen dioxide
	$h\nu$	= ultra-violet radiation
and	O_3 is ozone	

Thus, it has been known for some time that control of ambient ozone would depend on restricting emissions of either hydrocarbons or NOx, or both. However, working out the details of general reaction a, collecting the necessary emissions and other data needed to replicate actual atmospheric conditions, and building models to simulate smog formation and dissipation have proven mammoth ongoing research tasks.

Much of the chemical complication derives from the role of hydrocarbons in the overall reaction. The number of possible hydrocarbon reactants is huge and the number of possible reactions overwhelming. However, Seinfeld reports the following useful summary model, which provides valuable insights.[40]

basic reactions

$$NO_2 + h\nu \rightarrow NO + O \quad \text{(b)}$$

$$O + O_2 + M \rightarrow O_3 + M \quad \text{(c)}$$

$$O_3 + NO \rightarrow NO_2 + O_2 \quad \text{(d)}$$

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role of hydrocarbons

$$\Re H + OH\bullet \rightarrow \Re O_2\bullet + H_2O \quad \text{(e)}$$

$$\Re CHO + OH\bullet \rightarrow \Re C(O)O_2\bullet + H_2O \quad \text{(f)}$$

$$\Re CHO + h\nu \rightarrow \Re O_2\bullet + HO_2\bullet + CO \quad \text{(g)}$$

$$HO_2\bullet + NO \rightarrow NO_2 + OH\bullet \quad \text{(h)}$$

$$\Re O_2\bullet + NO \rightarrow NO_2 + \Re CHO + HO_2\bullet \quad \text{(i)}$$

$$\Re C(O)O_2\bullet + NO \rightarrow NO_2 + \Re O_2\bullet + CO_2 \quad \text{(j)}$$

$$OH\bullet + NO_2 \rightarrow HNO_3 \quad \text{(k)}$$

$$\Re C(O)O_2\bullet + NO_2 \rightarrow \Re C(O)O_2NO_2 \quad \text{(l)}$$

$$\Re C(O)O_2NO_2 \rightarrow \Re C(O)O_2\bullet + NO_2 \quad \text{(m)}$$

The first three reactions, b-d, show the basic ozone formation process. NO_2 photodissociates under the influence of UV radiation across quite a large band of the spectrum. The excited oxygen atom that

40 Seinfeld 1986, pp. 155-6

results quickly reacts with atmospheric oxygen to form ozone. The M in this reaction simply shows that another molecule must be present at the collision to maintain the energy balance. The most interesting equation is reaction d, which describes the NO_x quenching effect. Ozone can react with nitrous oxide to form nitrogen dioxide and oxygen. A similar reaction of NO with O_2 provides an alternative pathway of NO to NO_2, but this reaction is slow at ambient temperatures. The three basic reactions, b,c, and d, appear to be in balance, and build up of ozone would seem possible only as a result of disparities in the speeds of the three reactions. However, this is not true for two reasons: first, not only is the third reaction slow, but it is also improbable because the high concentrations of O_3 are found downwind of the high NO concentrations near pollutant sources; and second, the NO can become involved in many other reactions.

The lower section of the table, reactions e-m, shows, in the form of a simple model some of these other reactions. The • identifies the species as a radical, and the $\mathfrak{R}$ can be replaced by many radicals, including hydrocarbons of a wide range of complexities. As is immediately apparent, there are several pathways for NO to form NO_2, while N_O is nowhere returned as a product.

Without understanding equations e-m in detail, other useful insights can be gained from their basic form. The origin of the troublesome nitrogen that forms the combustion products is either the incoming fuel, that is nitrogen compounds in the fuel, or the combustion air, that is, molecular N_2. Looking at the equations above, clearly N_2 appears nowhere as a product. That is, the basic problem is that the process started by the combustion and continued in the troposphere afterwards does not return benign N_2; rather, the final products are various troublesome nitrogen products.[41] Notable among these products is nitric acid, HNO_3, which shows the acid precipitation link to smog. When the CH_3 radical fills the space in the penultimate reaction, the resulting product is the infamous peryacytlnitrate (PAN), which is a well known eye irritant found in photochemical smog.

3. consequences

Study of health effects of photochemical smog have focused on ozone. A powerful oxidant, ozone directly damages vegetation and quickly reacts with many substances such as rubber, although it is thought to be harmless to human skin. The risk of exposure to humans comes from eye and nose irritation, and most importantly, lung damage. When inhaled, ozone exacerbates numerous pulmonary ailments and can cause severe effects in sensitive individuals. Animal experi-

41 Notice that the SCR equation, which appears as equation c in section III.C, reverses the process and returns N_2 and water. The attraction of SCR should be immediately apparent from these equations.

ments have shown clear lung damage consequences from exposure to high ozone doses.[42] Damage has also been observed in the lungs of rats exposed to ozone concentrations in the 0.12 ppm range for as little as 6 weeks. Considerable variation in response among animal species, however, limits the extension of results to human populations. Effects on plant life and materials have been observed at much lower concentrations than necessary to cause observable effects in humans, but human health effects totally dominate discussion of the photochemical smog problem in California, so that will be the emphasis here.[43,44,45,46]

As with many types of exposure risks, the adverse effects of high concentrations of ozone over short periods are well established, whereas the low dosage cumulative effects remain uncertain.[47] The level of ozone exposure considered harmless, however, has consistently fallen since research into low level exposure began in the 1970's.[48] McDonnell reports clear evidence of reduced lung function in healthy adult men

42 Barry 1990

43 OTA 1989, p. 87

44 Adams 1990

45 Manning 1990

46 Hall 1989

47 Bresnitz and Rest 1988

48 OTA 1989, p. 40

exercising rigorously in 0.12ppm O_3 contaminated air.[49] The mean loss of lung capability was 3-5%, depending on the lung function test used. However, the range of response, 0-20%, shows that sensitivity to O_3 varies considerably, even across a homogeneous healthy population.

Similar tests at higher exposure levels showed that loss of lung function increased with exposure, although there was evidence that tolerance to the pollutant was setting in beyond 0.40 ppm, with lung function loss about three times as serious as observed at 0.12 ppm. If subjects are exposed to O_3 contaminated air over a series of days, there is also evidence of adaption, that is, of diminishing loss of lung function. However, this effect does not preclude the possibility of permanent lung damage from frequent exposure, and considerable efforts have been made to conduct sound epidemiologic studies in areas prone to photo-chemical smog, notably the South Coast Air Basin (SCAB).

Based on the belief that children are more susceptible than adults because they exercise more heavily out of doors, some studies have focused on them. Monitoring children in summer camps has shown that lung function is measurably lower on smoggier days, and that some effect can prolong over several days following an episode.[50]

Conducting large scale epidemiologic studies of the consequences

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49 McDonnell 1990

50 Dockery and Kriebel 1990

of low dose exposures is notoriously difficult.[51] Comparing urban populations with ones living in more pristine environments obviously creates enormous problems of control of confounding occupational, socio-economic, and ethnic factors. Within urban areas, controlling for relocation, commuting, etc., poses equally daunting problems. However, a long-term study of the respiratory capability of residents of several South Coast cities by UCLA researchers has been ongoing for more than a decade.[52,53] The study has been conducted on a huge scale, attempting to monitor samples taken from populations of 5-7000 residents of each city over several years, and to search for effects of different pollutants. Comparing residents of Lancaster, which experiences a high yearly average daily maximum total oxidant concentration of 0.07 pm but low SO_2, SO_4, and NO_2 concentrations, with residents of Long Beach with a comparable oxidant value of 0.04, but higher levels of the other pollutants, should isolate the effects of the oxidant exposure, and with residents of Glendora whose monitoring station reports the worst oxidant observations in SCAB.

Over time, the aim of lung function tests was to detect differences in the rate of declining lung function among residents of the cities. In

51 Bresnitz and Rest 1988

52 Rokaw, *et al*, 1980

53 Detels, *et al*, 1991

general, lung function peaks at about age 18, and declines thereafter. Detels, *et al*, suggest, on the basis of the various tests conducted, that oxidant exposure causes more damage to small airways than the other pollutants, which do more damage to the large airways, and that the effect of oxidants start at a younger age. Overall, however, lung damage is more severe in Long Beach than Lancaster, suggesting that direct control of the pollutants observed there is at least as important as ozone abatement.

In summary, evidence that short-term exposure to elevated ozone concentrations, for example, near the FDV, results in a temporary loss of lung function is strong, as is the evidence of permanent pulmonary damage in exposed laboratory animals. Further, certain sensitive populations suffer considerable duress as a result of exposures at this level. Evidence of permanent human lung damage is much less conclusive. The UCLA studies have shown differences in lung deterioration with age among residents of similar SCAB communities, but all of the communities are heavily polluted urban areas, and the effects of oxidants relative to other pollutants have not been clearly established.

4. abatement

The shape of the EKMA diagram described in section III.B.1 and fears that lowering NO_x emissions could result in elevated local peak ozone levels has historically led agencies towards NMHC emissions reduction as an ozone abatement strategy.[54] That situation has changed rapidly over the last few years, particularly since the publication of the National Research Council report *Rethinking the Ozone Problem in Urban and Regional Air Pollution*. The report points to several weaknesses of the EKMA approach, particularly that it is unable to address the variability of conditions that bring about episodes, the inability to model pollutant buildup over multi-day episodes, and its poor treatment of biogenic sources. Further, inventories have tended to underestimate NMHC emissions from both biogenic and anthropogenic sources, leading to misleading EKMA results. As a consequence, the Council recommends a major shifting of policy gears towards NO_x control.

> To substantially reduce ozone concentrations in many urban, suburban, and rural areas of the United States, the control of NO_x emissions will probably be necessary in addition to, or instead of, the control of VOCs.[55]

54 NO_x control has, however, been vigorously pursued in Japan. The Tokyo Electric Company, for example, has SCR installed on over 25% of its thermal capacity.

55 National Research Council 1991, page 13

C. Intermittence and Pollution Taxes

1. current regulation

a. introduction

The NOx regulations on power generation are usually defined in terms of a maximum stack gas pollutant mole fraction under a specified test condition, a typical value being 25 ppm for recently permitted combustion turbines.[56] The permitted emission ceiling is normally set after a *source test* , which includes measurement of the exhaust flow under a test condition, usually the full power output. The '91 CAP, however, proposes more NO_x control measures and defines the rules in various ways, including lbs/MBtu and lbs/MWh. The new rules are discussed in more detail in section II.A.4, while this section describes the general limitations of current regulations, and makes the case for an intermittent pollution tax on power generation as an economically efficient policy instrument to lower human ozone exposures.

From the standpoint of economic efficiency, existing District NO_x regulation has several deficiencies. The three major problems are: first and foremost, the failure to recognize intermittence, which is addressed at length in section II.C.3; second, the treatment of each source as an independent emissions problem instead of as part of an integrated

56 While a ppm mole fraction is not, strictly speaking a *concentration*, it is often referred to as such and will be here also.

interconnected system; and third, no incentive is provided to the utility to clean up beyond the specified permit level.

b. stack-by-stack regulation

The second major problem listed above is that current regulations specify acceptable emissions from a certain stack. This approach is misguided because electric power generation is an integrated system, and far from being independent of one another, the emissions from most stacks are interconnected in a complex contrived manner. Therefore, it is quite possible for a utility to shift generation from a more to a less polluting generator, thereby lowering total emissions. Existing regulation ignores these relationships, rather than trying to take advantage of them.

This interconnectedness has been addressed in some jurisdictions through the *bubble* concept. The emissions from all the stacks of a utility are treated as if they are all contained within one huge imaginary bubble, and only the sum of emissions within this bubble are constrained. This approach allows the utility considerably more flexibility in its choice of control strategy. Indeed, any one stack does not necessarily have to be controlled at all. If controlling emissions from a particular source is not cost effective for the utility relative to controlling one or more of its other sources, then a higher level of control of the other sources can compensate for the uncontrolled source. Because utilities have considerable flexibility in the scheduling of any one unit, approaching regulation of emissions from the utility sector as if all the stacks are independent incurs economic inefficiencies and has no compensating benefits. However, this is not to say that regulation must necessarily be centralized along the lines of the bubble concept. On the contrary, individual stack monitoring with an equal tax levied for emissions at each individual stack delivers even better incentives to utilities than the bubble approach because damage costs are, in fact, variable across stacks.

One consequence of stack-by-stack regulation merits special mention, grandfathering, which has long been recognized as a problem of U.S. environmental regulation generally.[57] Because permit conditions are usually established when a source first comes on line and are rarely changed afterwards, over time, the permitted emissions of various sources become uneven. Typically, older sources are permitted to emit more than newer ones because regulations get tighter over time. This results in two undesirable outcomes: first, older units will be favored in the dispatch over newer, cleaner ones because uncontrolled units will tend to have lower variable operating costs: and second, adoption of new cleaner generation is disfavored over life extension of older, dirtier

57 Palmer and Dowlatabadi, 1991

units, which are grandfathered into high emissions low operating cost permits. The grandfathering problem is particularly serious if a daily emissions ceiling on a new or planned cleaner unit becomes binding, so that generation there is limited in favor of older, dirtier units.

c. low cost clean-up

The third problem with current regulation listed above is that the utility is encouraged, through the imposition of fines, to maintain its emissions within the permitted concentrations but is given no incentive to exceed the specified levels of clean-up. Assuming that fines are sufficiently large as to provide a strong disincentive to exceed permitted emissions, then the utility's best strategy is to do nothing else about NO_x emissions, other than make sure the ceiling is not exceeded. This regulatory structure fails to provide the utility with any positive incentive to make cheap clean-up efforts that might lower overall emissions at low cost; rather, the utility must keep inside emissions guidelines at any cost.

A good example of the way this limits flexibility in practice concerns water injection in combustion turbines, a common method of NO_x control. Water injection into the turbine lowers its efficiency, so to limit this effect, the rate of flow is carefully controlled automatically by preprogrammed equipment. If the combustion turbine (CT) operator faces fixed permit condition, it will simply order the CT supplier to program the controller such that the condition is never quite broken. Since NO_x emissions increase with load, this usually means that the water flow increases with load. Given that the necessary equipment is in place and that the heat rate penalty while important is not huge, increasing the flow of water injection could offer a NO_x emission reducing opportunity at low marginal cost.[58] However, the nature of the permit structure precludes its use.

d. other limitations

There are, additionally, several lesser reasons why District regu - lation, as currently formulated, is misguided. Firstly, defining the permit condition in terms of a ppm stack gas mole fraction, while convenient from a monitoring stand point, is deceptive as a measure of the actual damage cost, which is the value that regulation should be seeking to lower. One of the elements in the imprecision of the ppm mole fraction is that it overlooks the importance of the stack gas flow rate. The same concentration at higher flow rates implies a greater mass of emissions. In other words, the utility is permitted to emit more under some operating states than under others. Similarly, since the concentration is defined under a fixed test condition, for example, at

58 **This is not to say that the total size of the emissions reduction potential is large, only that an incremental reduction may be available at low cost.**

15% excess O_2, the variations in emissions and damage that result from deviations from this condition are ignored. Emissions during start-ups are often explicitly excluded. The damage cost is much better represented as a mass flow of NOx emitted, that is, t/h t/d, or t/yr. In fact, permit conditions often specify a maximum mass flow in addition to the ppm stack gas mole fraction ceiling.

Secondly, excursions in the concentration often occur as a result of equipment malfunction and other deviations from steady state operations. It is fair to penalize the utility for these malfunctions only if the actual damage done is significant, and, clearly, if the total mass emitted is small, the excursion has done little harm. Conversely, regulations often exclude emissions during starts and other extreme non-steady state operations. Such exemptions fail to present the utility with the correct set of signals regarding start-ups and other operations. As discussed in more detail below and in Appendix B, the role of starts and other excursions from steady state conditions is a significant determinant of the overall pattern of emissions. Particularly, the utility should be presented with a penalty structure that results in the dispatcher making the correct choice between shut down and sustained minimum load operation.

Thirdly, neither constant stack gas pollutant concentrations nor fixed emissions ceilings recognize the seasonality of air quality problems. Even at a simpler level than attempting to recognize the importance of intermittence on a real-time basis, at least taking account of seasonality could increase efficiency. For example, in the Bay Area, CO emissions are rarely, if ever, a problem outside of the mid-winter months. Therefore, imposing any limit on CO during the summer and fall imposes a quite unnecessary constraint on utility operations. To see why this might be important, consider a unit that is a high CO but low NO_x emitter, relative to the other resources available. Clearly, this resource should be used in the summer over high NO_x emitting alternatives. However, the existence of the CO ceiling may limit its use in summer, when it could positively contribute to lowering total NO_x emissions. This effect is more important than it might seem because new combustion turbines, especially with steam or water injection, are low NO_x emitters, but high CO emitters, relative to steam units. From a public policy standpoint, District regulation should not discourage construction of such turbines for summertime peaking duty cycles simply because of the rare wintertime CO problem. More exotically, the possibility of seasonally adjusting the stoichiometry to alter the balance between emissions of the two pollutants should also not be excluded. This issue is discussed further in Appendix D.

2. pollution taxes

The goal of regulation should be to ensure that electricity is generated at the optimal level of pollution, meaning that the marginal damage cost for any level of generation equals the marginal control cost for that same level of generation. As economists enjoy pointing out, this optimal level of pollution is typically not zero.[59] On a per kWh basis, emissions should not necessarily be equal across all sources because the cost tradeoff can make a more polluting lower fuel cost resource more economical overall, as is explained in more detail below.

The notion that imposing a tax represents the most efficient way to redress the inefficiency caused by the existence of an externality dates far back in the economics literature, at least to Pigou, and such a tax is often called a *Pigovian tax*. According to Pigou, the tax should be designed such that the damage cost imposed by a polluter on others is exactly internalized, that is, so that the polluter faces the full societal cost rather than solely its own private cost. Pollution taxes represent one of two major categories of commonly proposed incentive-based abatement mechanisms, the other being marketable permits.[60]

Initiating a system of marketable NO_x emissions allowances, akin to the SO_2 allowances in the 1990 Amendments to the Federal Clean Air

59 for example, see Helfand 1992

60 Hahn and Stavins, 1991

Act, would be a complex undertaking for several reasons. First, for a commodity to be traded in a market, it must be clearly definable. While a simple description of an SO_2 allowance as the right to emit a ton of SO_2 during a calendar year is adequate, because the damage done by NO_x emissions is variable, no such simple definition is possible. This argument is expanded in the next section, II.C.3. Second, since the power sector is responsible for a small (relative to SO_2) share of NO_x emissions, a market for tradable NO_x emissions allowances would have to allow trading between sectors. Since, much of the emissions come from small area sources, such as vehicles, trading would involve large transactions costs and enforcement problems, or actually be impossible. It is for this reason that some analysts have argued that tradeable NO_x emissions allowances would be unworkable.

Given the problems inherent in implementation of a system of tradeable NO_x emissions allowances, imposition of a pollution tax appears to be the more workable alternative incentive-based policy instrument. There are two additional reasons why, for the purposes of this work, such a scheme is the assumed policy: first, a simple tax levied on NO_x emissions can be readily incorporated into standard dispatch mathematics, as shown in section II.D.3, and in Appendix B; and second, since the point of view of the analysis is that of the District, realism requires some respect of the limitations on its jurisdiction.

Specifically, the District has little jurisdiction over mobile sources, so postulating a system that involves inter-sectoral trading between point and mobile sources is unrealistic. On the other hand, the District does not exactly have the power to tax, although this power may derive from the county Boards of Supervisors by which it is formed. The CPUC, while unable to tax, as such, could order the utilities it regulates to dispatch as though such a tax existed. However, a considerable share of total generation is not under direct CPUC jurisdiction.

From a more strictly legal standpoint, the flexibility the District has to restructure its regulation is severely limited. See the discussion of SCAQMD's RECLAIM program in section II.A.6 for more detail.

The approach taken here of imposing an intermittent tax to reduce emissions in pursuit of the ambient standard is one that has a fine economics pedigree. Baumol and Oates refer to this general approach as *environmental charges and standards*.[61] They point out the difficulty in implementing a true Pigouvian tax, notably the problem of estimating the marginal damage cost at the equilibrium level of emissions, and suggest that environmental charges and standards may be more practical. But the attractiveness of this approach to economists is not solely its administrative simplicity, it also assures that the standard is reached at the least cost, even on quite loose assumptions on the behav-

61 Baumol and Oates 1975, page 137

ior of polluters.[62] Electric utility dispatch serves as a micro example of exactly the same principle. Since generators are in competition to supply customer load, taxing emissions tends to favor the generators that can lower emissions more cheaply, thus minimizing the total cost of reducing emissions. If the same NO_x tax were applied to all sectors of the economy as is applied to power generation, Baumol and Oates's minimum cost stadard achievement would result.

3. intermittence

The most important element in the regulatory instrument assumed here concerns the issue of intermittence. In the classic textbook exposition of the justification for pollution taxes, the argument is static, both in time and place.[63] The damage cost done by pollution is assumed to be a constant, which can be thought of as \$/kg externality. The estimated externality can be simply added to all units of production as a flat equivalent tax to restore production and consumption to socially optimal levels. Some economists have recognized the limitation of this view with regard to the urban smog problem, however, and have recognized the need to target emissions reductions.[64]

62 Baumol and Oates 1975, page 140

63 for example, see Pearce, Markandya, and Barbier 1989

64 Tietenberg 1985, page 162

The consequences of many forms of pollution can indeed reasonably be modeled in this way, CO_2 being a notable example. Since CO_2 causes no known direct harm to exposed plants or animals, when, where, and how it is emitted are quite unimportant. The critically important consequence of CO_2 emissions is that once free in the atmosphere, they potentially do catastrophic harm through the greenhouse effect. However, since this consequence comes only over time scales of decades or centuries, after all emissions from all sources are well mixed in the atmosphere, any kg of CO_2 emitted from any tailpipe, smoke stack, or forest fire can be treated as equally hazardous. At the other end of the spectrum, there are pollutants whose effects are localized and short-lived. Consider CO emissions, for example. Other than to the extent that they ultimately contribute to the CO_2 problem, CO emissions have no long-term, large-scale consequences and are considered hazardous for human and animal exposure only at high concentration. Once mixed in the atmosphere, CO quickly dissipates. In other words, the consequence is entirely local and transient. Clearly, the simple economic model only poorly represents this problem.

Consider now the damage cost function for NO_x emissions. It has some of the characteristics of both CO_2 and CO; some of its consequences are fixed and some vary by time and place. NO_x emissions are better modeled, therefore, by a function of the following form:

total damage cost = fixed damage cost + variable damage cost

This function could be interpreted as follows. First, NO_x does some harm on a regional or international scale through its role in acid deposition, which, within the context of utility operations at least, can be considered constant. Second, NO_x emissions incur local damage costs arising from smog that are highly variable, depending on where the stack is located and ambient emission when the emission occurs. Clearly, this second term is the focus of this work. Recognizing that the optimal tax will exactly equal the damage cost, the above function could be rewritten in symbols as an estimate of the optimal NO_x tax, as follows.

$$D(t,s) = d_f + d_v(t,s)$$

The total tax is $D(t,s)$, which has a fixed part, d_f and a variable part, $d_v(t,s)$. which varies by time, t, and by stack, s. All the terms carry units of \$/kg of NO_x emitted. Conveniently, the d_f would seem to be the natural purview of national and international organizations, while the $d_v(t,s)$, being localized, more naturally falls to local agencies. In other words, the total tax,$D(t,s)$, can be thought of as a Federal tax plus a District tax.

Consider the form of the local NO_x tax, $d_v(t,s)$, more closely. The polluter must be presented with a tax that will encourage it to change its production schedule such that its NO_x emissions pattern results in less variable damage. The value of $d_v(t,s)$ being determined, primarily, by weather conditions, should, in practice, be predicted about as well as the weather. See the next section, II.C.4 for discussion of the District's ability to accurately forecast episodes. For most of the time, the tax would be small, or zero, but it would increase steeply when the danger of a smog episode increased.

From the point of view of the utility dispatcher, given warning of a few days, scheduling would have to be adjusted to take the NO_x tax into account. Such a regulatory scheme is unfamiliar and raises several questions. First, uncertainty over the timing and duration of episodes imposes some cost on the utility beyond the actual total tax accrued. Luckily, in this area as in many others, the nature of the utility industry has brought forth a rich literature on the costliness of uncertainty, especially with regard to interruptible tariff structures. Second, legal questions obviously arise over the liability of the District for the accuracy of its forecasts. Third, revenues collected from the tax would be highly uncertain and budgeting on assumptions of such revenues would be a hazardous business. The tax scheme is best not thought of as a normal contribution to State or County coffers, but, rather, as a special assessment. To avoid budgetary chaos, perhaps, the revenues would have to be returned to electricity ratepayers through a balancing account or other mechanism.[65] If collections from the tax were treated as normal

65 For a description of how balancing accounts work in existing California ratemaking, see Marnay and Comnes, 1992.

revenues, the conflict over the need to keep the tax reflective of damage cost and to make the inflows more predictable would be irreconcilable. None of these important issues will be addressed in this work. Here, it is assumed that the tax has been correctly estimated and broadcast to the dispatcher ahead of each simulation period. The only cost of adjusting to the tax regime, therefore, is the cost of the tax itself plus any increase in production cost incurred as a result of the non-cost-minimizing dispatch.

In this work, the point of view is that of the District, and a pattern for d(t,s) will be assumed and the dispatch of the Bay Area power system simulated as if such a tax were in place. The actual form of d(t,s) is a two dimensional matrix, with a tax specified for every stack and every hour of the simulation period.

4. smog forecasting

If a NO_x tax were to be operated in practice, one of the obvious technical details that would be of great importance to utility dispatchers is the warning time the company would get before the imposition of the tax. Obviously, boiler starts are costly and having to revise commitment decisions to adapt to changing expectations of taxes is not costless. Any increase in operating costs resulting from these adjustments would add to the control cost of NO_x emissions avoided. While relatively little literature exists on the cost implications of unexpected increases in operating costs, there is a considerable literature that addresses the cost of customer outages.[66]

In the simulations conducted here, perfect foresight of tax levels is assumed. That is, the unit commitment logic was adjusted so that commitment is based on the tax and other costs. In an attempt to compensate for such an unrealistic assumption, a certain conservatism has pervaded other assumptions, such as the number of days of smog vulnerability.

In this section, the question of how well episodes can be predicted is addressed, albeit in a superficial manner. As mentioned frequently in this study, smog formation takes place only under certain weather conditions. Predicting a smog episode, therefore, can be thought of as predicting the weather, which puts the problem into clearer perspective. Note, however, that the vulnerability of the airshed to smog formation depends heavily on wind direction and speed, and these are harder meteorological variables to predict with accuracy than simply temperature and rainfall.

Figure II.C.1 shows some evidence of the District's ability to predict episodes. It shows how accurately the September 1989 episode day peaks were predicted one and two days in advance. While the results are

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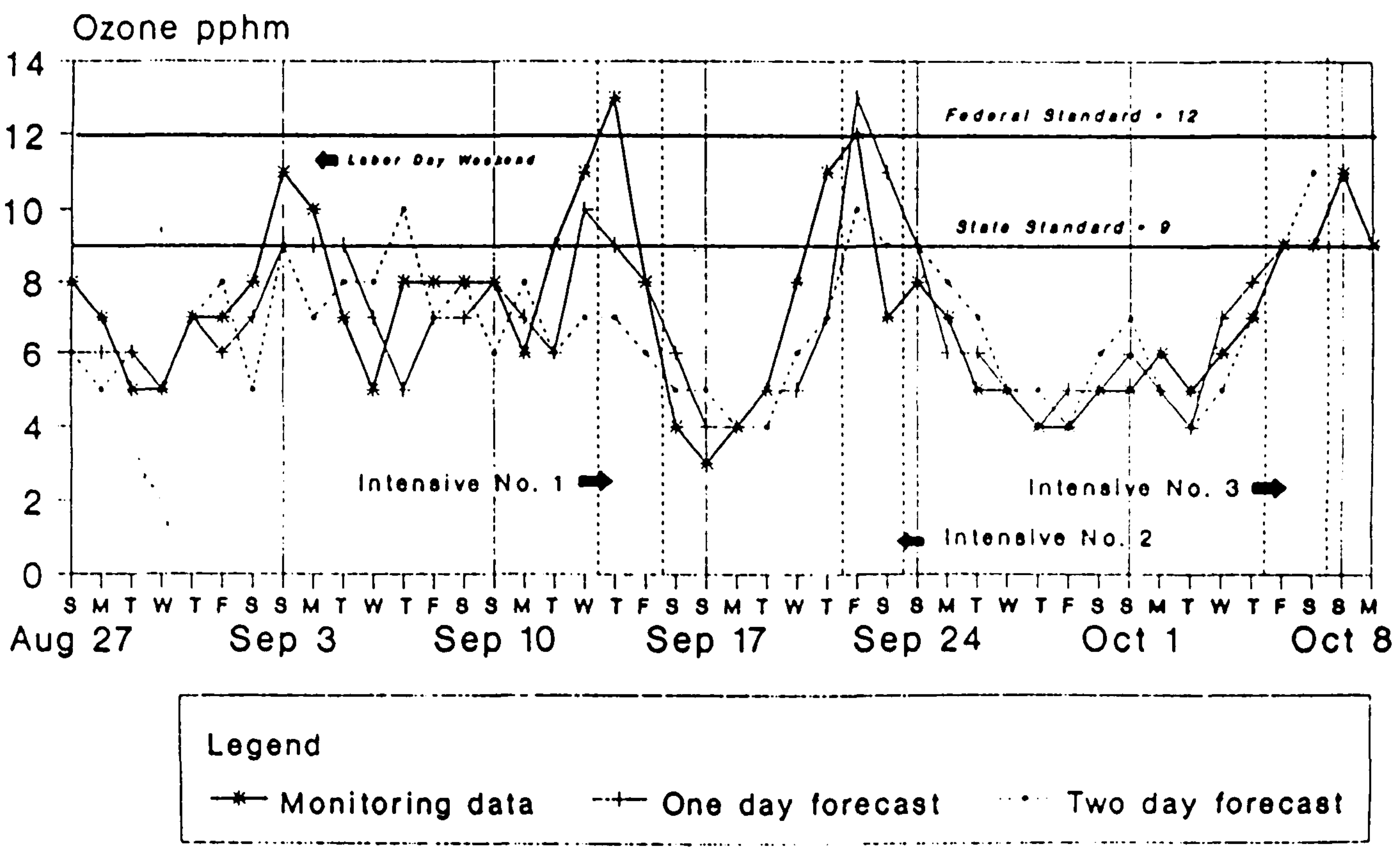
66 Strauss 1992

Figure II.C.1: BAAQMD Episode Forecast

1989 District High Ozone



source: BAAQMD

impressive, it is doubtful they would put the minds of dispatchers at rest, the main reason being that duty cycles are planned on a weekly basis. Changing the commitment, even with 2 days' notice, will incur some costs.

D. Power Sector

1. background

The role of the power sector in the urban photochemical smog problem is an ambiguous one, both in general and locally in the Bay Area. Power stations are a major cause of the smog precursor, NO_x , while, locally, the NO_x quenching effect may actually mean these emissions are beneficial. The electric utility industry accounts for a major share of total U.S. NO_x emissions, while the industry's share of urban airshed emissions locally in the Bay Area is small. While industry's share of Bay Area NO_x emissions is small, the District's compliance plan must rely heavily on power generation sources because its jurisdiction does not clearly cover the biggest source, transportation. The coincidence of peak power demands and weather conditions conducive to photochemical smog formation suggest the power sector should be a major focus of traditional abatement efforts, while the existence of sophisticated utility computer driven resource scheduling capability suggests that traditional regulation may not be the most effective approach.

2. coincidence

Nationwide, the power sector emits NO_x at roughly the same rate as all highway vehicles combined.[67] However, since NMHC emissions from the power sector are negligible, and since in California, where burning of fuel-NO_x producing heavy oil or coal in utility boilers is rare, the net impact of the power sector on air quality appears *prima facie* small.[68]

Determining the role of the power sector in any one air basin, such as the Bay Area, is far from straightforward. The District reports that the power sector emits less than 1% of all the criteria pollutants other than NO_x, and about 10 $kt \cdot yr^{-1}$, or 7% of all NO_x emissions, representing about 17% of all the NO_x under the jurisdiction of the District.[69] While these figures suggest that the District might be attracted to the sector for regulatory scrutiny, it appears that the sector is unlikely to make a significant contribution to improved air quality. However, there are several other reasons why this sector should be of special policy and research interest.

1. NO_x emissions from power generation are particularly harmful because they coincide with periods of photochemical smog forma-

67 Table 334 of the *Statistical Abstract* reports NOx emissions of 6.6 Mt for electric utilities and 6.8 Mt for all road vehicles in 1984. Further, the OTA forecasts growth in NOx emissions from utility boilers to the point that the power sector will emit as much NOx as all vehicles combined, on and off-road, by 2004 (OTA 1989).

68 The contribution of fuel-NO_x to emissions from pulverized coal combustion emissions can exceed thermal-NO_x by four to one.(Flagen and Seinfeld, p. 180)

69 BAAQMD 1989, p. 39

tion.[70] This unfortunate circumstance results from the coincidence of both processes with high ambient temperatures. Hot weather drives high electrical demand directly through air conditioning loads on the other. Ozone formation in the atmosphere, which is caused by UV radiation, also tends to occur on hot days.[71] In other words, power generation may be more damaging to local AQ than its small share of total emissions suggests because the sector's emissions occur at inopportune times. The negative consequences of bad emissions timing are further expanded by the tendency of utilities to resort to their oldest, least fuel-efficient, costliest, plants only at times of highest demand, and still further expanded because these older stations tend to be closer to densely populated areas where other sources of pollution are densest and total potential human exposure the greatest. In general, peaking resources need to be close to demand centers because transmission constraints will likely be binding when they are needed.

2. Large customers that adopt interruptible electricity rates often have backup generators that further contribute to emissions during times of high electrical demand.[72]
3. In general, electricity cannot be stored economically, which means power generation cannot be postponed; however, there is short-run flexibility in the choice and scheduling of resources.

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70 Gent and Lamont, 1971, p. 2562

71 Pagnotti 1990

72 Note that some interruptible tariffs place limits on the customer's use of back-up generators. For example, Southern California Edison's I-3 rate provision 12 permits the customer to use its backup equipment only during official utility interrupt.

4. The complexity of the dispatch problem in power generation has resulted in the development of sophisticated computer models to optimize resource scheduling.[73] In other words, the details of timing and geography that are so important in photochemical smog formation have long been studied by utilities because of their importance in the economics of power generation. As a result, the power sector is perhaps the only one for which the technology is in place to study the potential of industrial rescheduling for AQ improvement.
5. The substitution of electricity for other fuels, particularly in transportation, is often suggested as an air pollution control strategy and, indeed, electric vehicles play a central part of the ozone control strategy on the South Coast.[74] If this substitution results in more generation from local sources, the role of the power sector in emissions could be further increased.[75] Although most analysts assume battery recharging would be off-peak, determining the net effect on utility emissions and AQ is a highly complex problem that depends on generation resources used, rates of NO_x dissipation, recharging time, as well as the regulatory treatment of transportation electricity pricing. However, this is not to say there are not unequivocal AQ benefits from electric vehicles. Reductions

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73 Marnay and Strauss 1989

74 SCAQMD/SCAG 1989, p. 4-34

75 If one half of all the vehicles in the Bay Area were electric and all were powered by PG&E, total PG&E sales would be about 40% higher, assuming 2 million mixed commercial/private vehicles traveling 100 km/d at 4 km/kWh.

in carbon monoxide and hydrocarbon emissions are dramatic, only the effect of NO_x carries a caveat.[76,77]

6. The role of power generation in ozone formation is a key element in study of the heat islands problem and the local AQ consequences of global warming, as well as the potential benefits of electricity conservation. Since urban temperature increases simultaneously raise air conditioning demand and coincide with increased ozone formation, the emissions from power plants provide a positive feedback loop in the AQ degradation that results, while the effect would enhance the benefits of conservation.

3. environmental dispatch

Analysis of NO_x emissions from the power sector in the Bay Area is something of a contradictory problem. The above section outlined the bad news; namely, there are many good reasons to believe that power sector plays a more important role in photochemical smog formation than one might at first think. This section responds with the good news; namely, the power sector, by the very nature of its business and the technology it employs, has the potential to play a special role in smog abatement, if the regulatory environment is appropriately designed.

The full utility planning problem is described fully and the litera - ture on production cost modeling reviewed in section III.D.2. But the simple mathematics of dispatch and the way in which a NO_x tax can be

76 Wang, DeLuchi, and Sperling 1990

77 DeLuchi 1989

modeled within its framework is covered here. The concept of electrical *dispatch* is a simple yet much abused one. Temporarily, for the purposes of this section, the term will not be fully defined and will be used, somewhat inaccurately, to cover the general process by which utilities operate their power generation systems. The origin of the notion of dispatch lies in the basic engineering reality that electricity cannot be stored on scales useful to electric utilities; therefore, electric generators have to be centrally directed to produce, or dispatached, precisely as electricity demand requires. This basic engineering problem has received a massive amount of attention by researchers in many disciplines, resulting in the development of complex methods and technologies for the control of power systems.

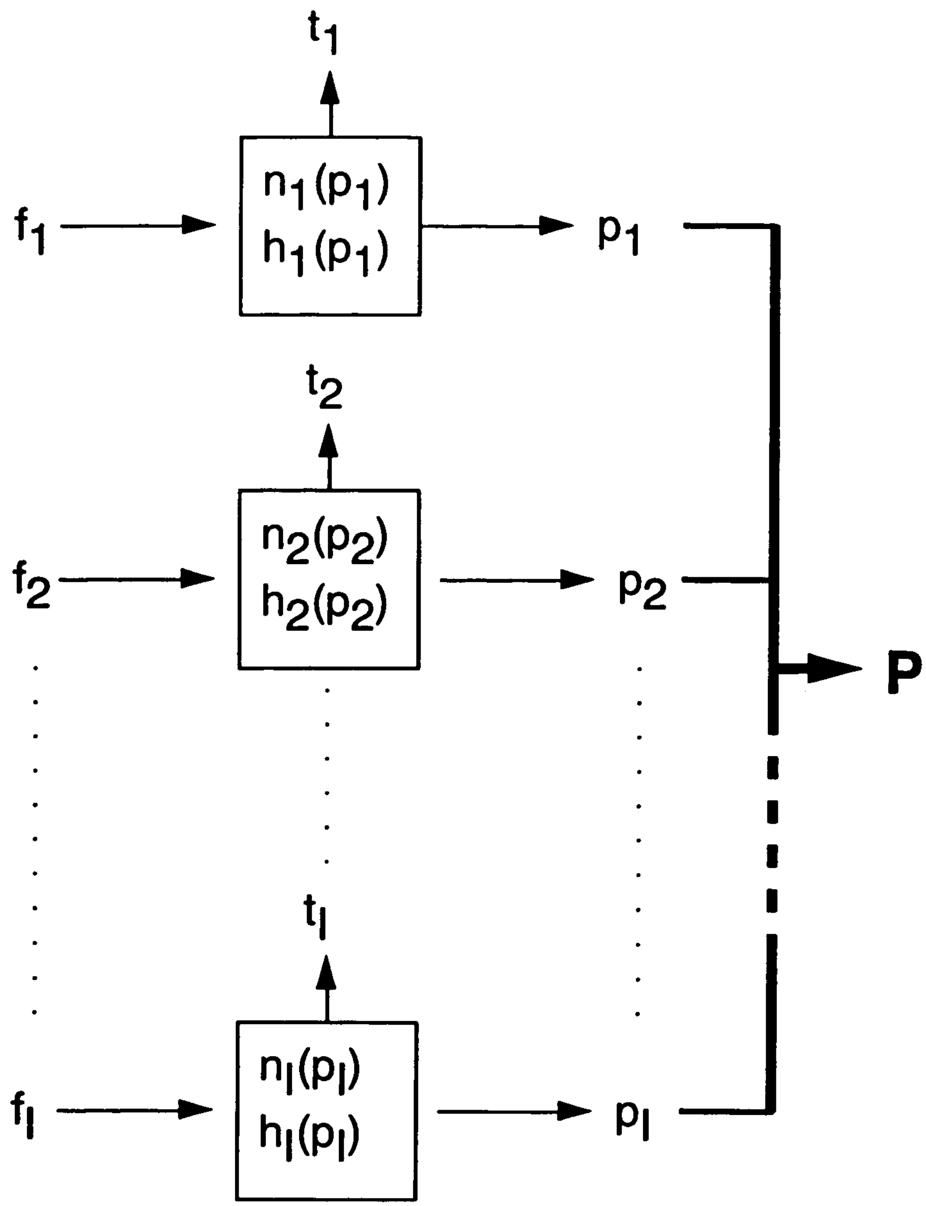
The model of system dispatch derives from the reality described above that electricity is non-storeable, and from an implicit assumption that the system must operate under central control. Even the most minor deviations from the optimum operating schedule cannot be tolerated for basic engineering reasons, resulting in this most authoritarian model. One individual, the *dispatcher*, establishes the operating schedule and issues appropriate instructions to *operators* responsible for each of the generators. This may not be a noticeably forward looking model for an industry that is undergoing steady decentralization, but this traditional model will be retained for the moment.

Although here the description of the system operations uses the traditional concept of the omnipotent dispatcher, it should be noted that actual real world operations at a large utility, such as PG&E, are now completely automated. Computers schedule resources and send out dispatch orders directly to generator control equipment along private communications media. As it happens, PG&E is a leader in the drive to totally integrate operations under the direction of central computers.[78]

The first principles of optimal dispatch can be demonstrated by some simple mathematics, and these prove sufficient to suggest a method for internalizing the external costs arising from NO_x emissions. Consider figure II.D.1, which shows the basic dispatch model for a thermal power generation system. The system contains I generators. Each converts a fuel costing, f_i, in units of money per energy, e.g. $/GJ, into an outflow of electric power, p_i, in power units, e.g. MW. Each unit has an energy conversion efficiency that varies across the operating range of the unit; this efficiency is described by the heat rate, or input-output (IO), function, $h_i(p_i)$. For any level of power output that unit i may be called upon to generate, the IO function gives the necessary energy inflow, e.g. GJ/h, and the product $h_i(p_i) \cdot f_i$ expresses this flow in monetary units, e.g. $/h. The full system demand to be met is **P** MW.

78 Hong, Imparato, Becker, and Malinowski 1992

Figure II.D.1: The Basic Dispatch Model



The basic problem is how to meet the load, **P**, at minimum cost, and can be described by the following optimization.

$$\min \mathbf{C} = \sum_i h_i(p_i)\cdot f_i$$

$$\text{s.t. } \sum_i p_i = \mathbf{P}$$

This problem can be converted to a Lagrangian and solved, as follows.

$$\mathcal{L} = \sum_i h_i(p_i)\cdot f_i + \lambda\left(\mathbf{P} - \sum_i p_i\right)$$

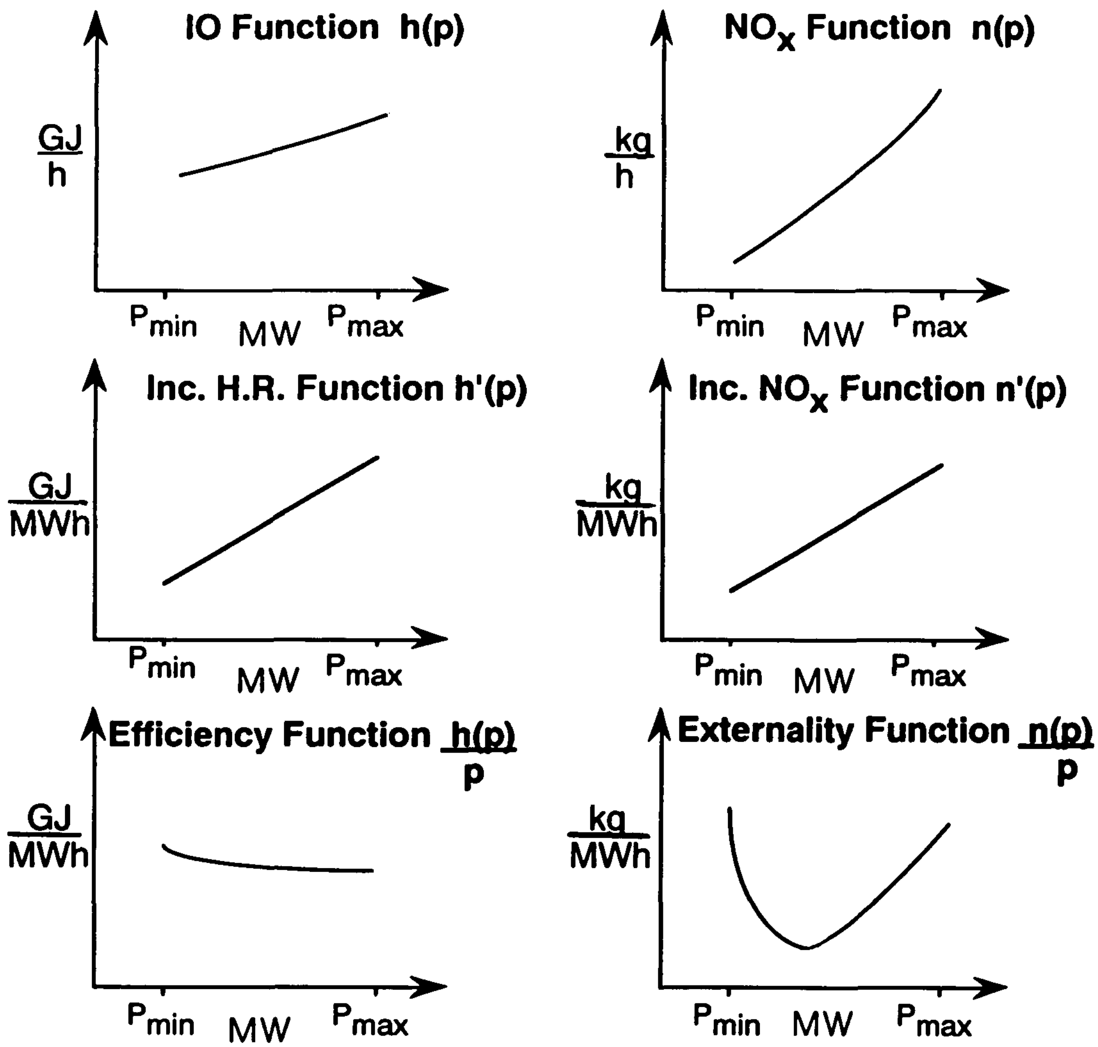
$$\frac{d\mathcal{L}}{dp_i} = h_i'(p_i)\cdot f_i - \lambda = \emptyset$$

$$h_i'(p_i)\cdot f_i = \lambda\,,\ \forall i$$

The derivative of the IO curve, $h'_i(p_i)$, usually called the incremental heat rate function, yields the increase in energy inflow, in GJ/h, needed to increase the outflow of electricity, in MW, by a minute amount. The product $h'_i(p_i)\cdot f_i$ shows the increment in terms of a monetary flow, and is, therefore, an instantaneous marginal cost. The result advises the dispatcher to issue operations orders such that all units on the system have equal marginal variable costs, in this case comprised of fuel cost only. In economic terms, this rule simply says that if power is being generated from any unit when a cheaper alternative is available, then the generating configuration is not optimal. This result follows the line of many basic results in economics, but it has such an impact on electrical engineering that the instantaneous system marginal cost is usually referred to as *system lambda*.

The instantaneous marginal cost results because all of the equations above are written in terms of flows, that is, in power units and flows of money. These units account for both the beauty and the limitation of this result. The beauty is found in its simplicity. For the hypothetical system operator, his/her job reduces to ramping up and down generators to meet demand according to the simplest of rules. The limitation of the result, from a practical standpoint, is that it really tells the operator nothing s/he did not already know. Intuition could lead to the same result. Further, the difficult problem turns out to be not the dispatch itself, but the unit commitment, that is, deciding when to start and stop units.

Figure II.D.2: Dispatch Functions



Returning to figure II.D.1, the simple model can be extended by observing that each of the generators, in addition to its power output, emits NO_x. As discussed in considerable detail in section III.C and appendix D, the formation of NO_x can be represented as a NO_x function very much like the IO curve. The properties of this curve are also described in section III.C. Since the goal here is to internalize the externality caused by those emissions, a reasonable approach is to treat the NO_x function exactly like the IO function but impose a cost of the dispatch for the output, NO_x, rather than the input, fuel. In figure II.D.1, each generator is presented as having a NO_x function, n_i. There is an outflow of NO_x from every generator, $n_i(p_i)$, and supposing a \$/kg tax, t_i, is levied on emissions from each generator, the optimization problem becomes.

$$\min \mathbf{C} = \sum_i \{h_i(p_i)\cdot f_i + n_i(p_i)\cdot t_i\}$$

$$\text{s.t.} \sum_i p_i = \mathbf{P}$$

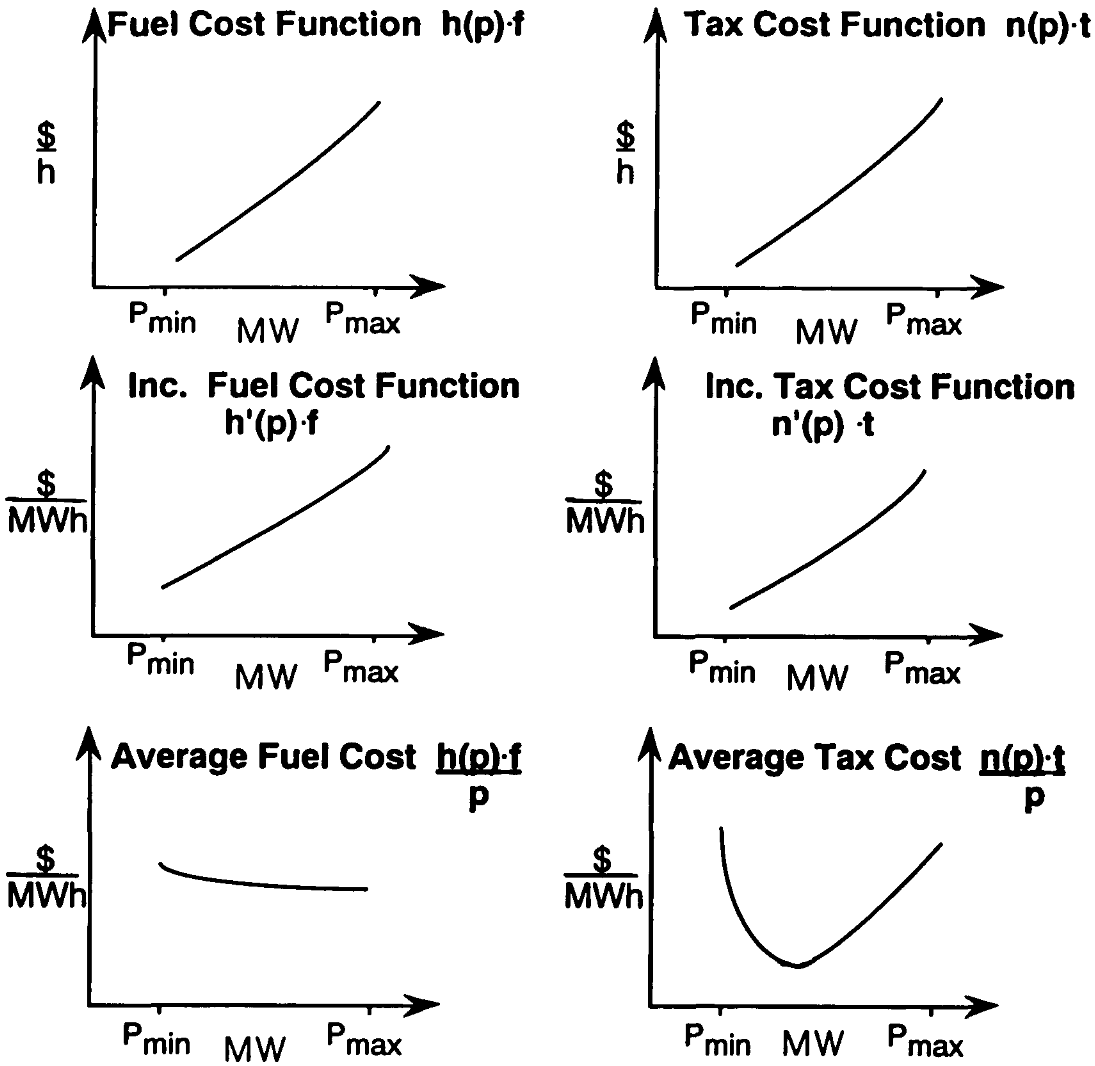
$$\mathcal{L} = \sum_i \{h_i(p_i)\cdot f_i + n_i(p_i)\cdot t_i\} + \lambda\left(\mathbf{P} - \sum_i p_i\right)$$

$$\frac{d\mathcal{L}}{dp_i} = h_i'(p_i)\cdot f_i + n_i'(p_i)\cdot t_i - \lambda = \emptyset$$

$$h_i'(p_i)\cdot f_i + n_i'(p_i)\cdot t_i = \lambda, \ \forall i$$

The outcome follows exactly as before, resulting in an alternative, almost as simple, operating rule for the dispatcher. As s/he monitors

Figure II.D.3: Cost Functions



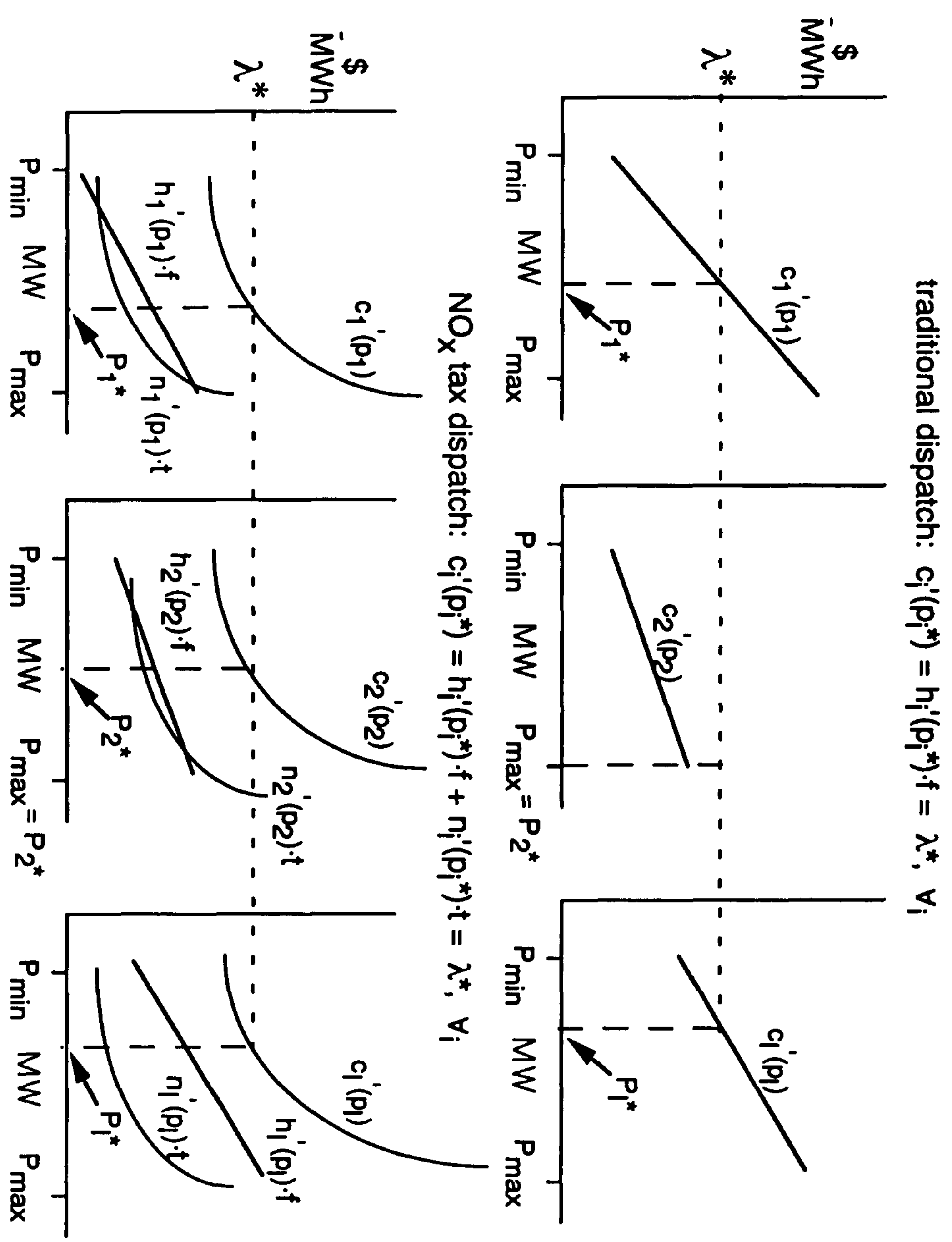
the continuous operation of his/her system, the money flow gauge that s/he is watching now reflects not just the fuel flow but also the NO_x flow.

Figures II.D.2 and II.D.3 explicitly lay out all the functions described, and show the parallelism between the treatment of NO_x emissions outflows and fuel inflows in this analysis. In figure II.D.2, the three left panels show the standard three curves used to describe the energy flows in a utility boiler and to optimize their operation. The I-O function is the basic heat rate curve which rates the MW power outflow from the generator to the GJ/h fuel inflow to the boiler. As mentioned many times in this study, this curve must be convex, or its derivative, the incremental heat rate function must be upward sloping. Finally, the energy conversion efficiency of the boiler and generator are presented in terms of averages, as the third panel shows. This curve is actually the inverse of the slope of a ray to the origin from the I-O function. Because of the convexity of the I-O curve, the efficiency function need not be monotonic, although in practice, they tend to have the shape shown, falling towards full load. The equivalent panels for the NO_x functions show that the NO_x outflows can be treated in exactly parallel fashion, assuming the same restrictions on the functions. The one interesting difference between the two is seen in the bottom panels, efficiency versus the externality. The emissions outflow from the boiler stack really does tend to have a shape as shown in the figure. The lowest average emission per MWh tends to occur in the mid power range and rises steeply in either direction. This feature is discussed in more detail in appendix D, but note now the importance of this feature. The best electricity bang for average fuel buck occurs out near or at full load, whereas the best electricity bang for average emissions buck occurs in the mid range. In other words, it should be possible to predict that one of the effects of taxing NO_x emissions will be a tendency to run units at lower power levels, and, since the power constraint must be respected, that more units will be needed as a consequence. Section IV.D in the results chapter confirms this expectation.

Figure II.D.3 merely confirms that all of the energy and NO_x physical flows can be converted to money flows by multiplying by the fuel cost and NO_x tax. Obviously, if the goal is to minimize cost rather than physical emissions or fuel consumption, then these are the functions that will be used.

Finally, figure II.D.4 shows in a simple graphical format what the equal system lambda rule means in traditional dispatch and a NO_x tax dispatch. In the upper panels, all system units are run at p_1^*, p_2^*, ... p_I^*, respectively. Note that units are run at the point of equal marginal fuel cost, unless an operating range constraint would be broken, as in the case of unit 2. The lower panel shows that the same demonstration works for the NO_x tax dispatch. The points on the summed incremental

Figure II.D.4: Dispatch Solutions



fuel cost and incremental NO_x tax curves are chosen in exactly the same manner. In this example, however, the shapes of the curves result in lower output from unit 2 and increases from units 1 and I. Once again, the argument is the same; the steep slope of the incremental NO_x tax curve results in a tendency to run more units at closer to their mid power range.

III. ANALYTIC TOOLS & METHODS

A. Background

Chapter II of this study has described the main principles involved in analysis of the problem at hand. However, this is not intended to be a purely theoretical analysis, and this chapter will describe some of the tools available to address the issue of a NO_x tax dispatch and its potential benefits to air quality in the District. The choice of tools reflects what models are reasonably accessible to an analyst properly equipped for the scientific analysis of policy, that is, with sophisticated computing capability both in terms of hardware and programming expertise, and a high level of technical knowledge about utility operations and smog modeling. The NO_x tax dispatch covered in chapter II represents the only substantive theoretical innovation.

Description of most of the necessary data manipulation appears in the various appendices. The tools covered here consist of the computer models used at each analysis step, which approximately coincide with the boxes of figure I.C.1. Section B discusses models of photo-chemical smog formation and transport, and, particularly, UAM, which is used in this analysis. Section C covers the issue of NOx formation in com - bustion and its control. Rather few analytic tools are available in this area. Computer models of combustion are highly complex and not a useful guide to actual utility boiler emissions. However, data on observed NO_x emissions from boilers are available and these can be used, and, further, can be incorporated into unit commitment and dispatch decisions, as described in section II.D.3. Appendix D describes in some detail the procedure by which the available NO_x emissions data are verified and converted to a form suitable for inclusion into the logic of EEUCM. The development, as part of this work, of such an approach precludes the need for a separate NO_x model, as suggested by figure I.C.1. However, conversion of the chosen expected values for hourly NO_x emissions to the input format required by UAM remains a tiresome task and is quite separate from the running of the two models, as described in section I.C.1.

Finally, this chapter contains a lengthy description of production cost modeling history and practice. The size of this section reflects the wide range of modeling options for production cost modeling as well as the interests of the author.

B. Smog Modeling

1. EKMA

Until recently, the empirical kinetic modeling approach (EKMA) model was the standard method used by many jurisdictions for ozone abatement strategizing, although it has not been extensively used by BAAQMD.[1] It is briefly discussed here for completeness and because its standard output, the isopleth EKMA diagram, provides a useful vehicle for considering the merits of NO_x versus NMHC control as ozone abatement policies. Figure III.B.1 shows an example of an EKMA diagram. The EKMA model initially used smog chamber like assumptions, the contours showing the peak ozone concentration that would result from various mixes of initial pollutants. The model was calibrated to actual smog chamber experiments. Later, however, EKMA was made more sophisticated with the addition of other pollutants during the process of the reactions, and variations in the pollutant mix to closer replicate specific airsheds.

Great emphasis has been placed in regulatory work on the rays to the origin, such as the ones shown in the figure. If the NMHC/NO_x ratio were 8/1, the fastest route to the next lowest isopleth is along the line, called the *ridge line*. Away from the ridge line, however, the

1 Most of the discussion of EKMA is taken from Finlayson-Pitts and Pitts 1986 sec. 10.B.3c.

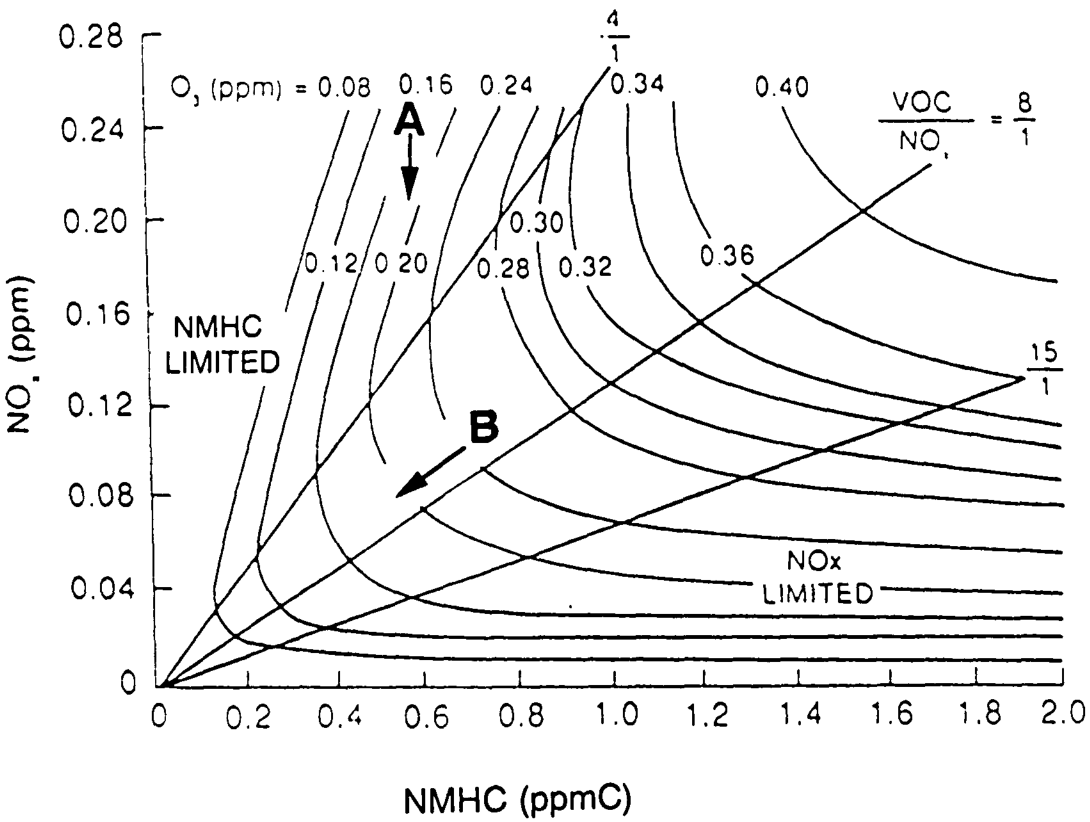


Figure III.B.1: Example of a EKMA Diagram

picture becomes more difficult. In the area marked *NOx limited*, the fastest route is through NO_x control only. But the most problematic area is the *NMHC limited* zone, which, unfortunately, is where conditions suggested that the Bay Area is located.

The source of the traditional regulatory emphasis of BAAQMD on NMHC control can be clearly seen by study of figure III.B.1. The District was thought to have a NMHC/NO_x ratio of approximately 3, and, given the peak ozone concentration of approximately 15, the District was thought to be at a point such as A. The main difficulty posed by the diagram should be immediately apparent. Because of the NO_x quenching effect, the isopleths bend back in the NMHC limited zone. From the standpoint of atmospheric chemistry, this makes perfect sense. At a certain point, if the air is very polluted, more NO_x is better than less because NO_x quenching will lower the peak ozone. From A, therefore, EKMA suggests that controlling NO_x alone will be counter productive because the District would move to a point along the path of the arrow, that is, to a point of higher peak ozone. In fact, the shortest distance to a lower isopleth would be through a NMHC control-only strategy, that is, to attempt to move directly westward in the diagram. This fact, together with the dangers of NO_x control, naturally lead to an emphasis on NMHC control.

There are some atmospheric chemistry reasons why such a simplistic view point is misguided, and these are discussed briefly in section II.B.4, but there are also some policy problems. In the case of the Bay Area, one of the key problems that has become apparent is transport. While it could well be true that peak ozone within the District could be lowered by increased NO_x emissions, that is, a move northwards from A, such a move would likely cause a deterioration of air quality in neighboring basins. The inclusion of the notion that basins must take account of transport in the California Clean Air Act has been the primarily force that has brought the District around to a NO_x control strategy.

The EKMA diagram would be instantly compared by anyone with an economics background to the families of indifference curves usually called the indifference map. The analogy does not hold up too well because, on the indifference map, the goal is to reach the highest contour possible given a budget line that permits various combinations of x and y, whereas, the goal in the EKMA diagram is to reach the lowest possible contour. In the indifference map, therefore, the solution is easily found at the tangency of the budget line and the highest possible contour.

Two lessons do emerge from the analogy. First, it becomes quite clear from economic theory what aspect of the shape of the curves causes the problem. In economics terms, the curves break the non-satiation assumption.[2] That is, more of all goods must be better than less, or normal solutions to the consumer problem do not exist. The same argument is true in an EKMA diagram. The problem arises because more NO_x can be better than less, which confounds our notions of rational abatement, which are based on the premise that less pollution is better than more. The second lesson is that thinking about the indifference map emphasizes what is missing from the EKMA diagram, namely a budget constraint. In fact, from the economists' point of view, the National Research Council's critique of EKMA misses its most glaring limitation. The correct short-run goal in EKMA should be to reach the next lowest contour at minimum control cost. The point on the target contour that policy should be leading towards could actually lie far away from the current point, if, for example, NO_x control is cheap relative to NMHC control. The optimal path towards the origin could be a twisty path indeed. This path could be found by finding the cheapest way downwards from a point such as A, although discontinuities are definitely possible, and the ratio of costs could change over as incremental control becomes more expensive. Of course, the problem still remains that the lowest cost path to the next lower contour may be increasing NO_x emissions, so this alternative has to be precluded.

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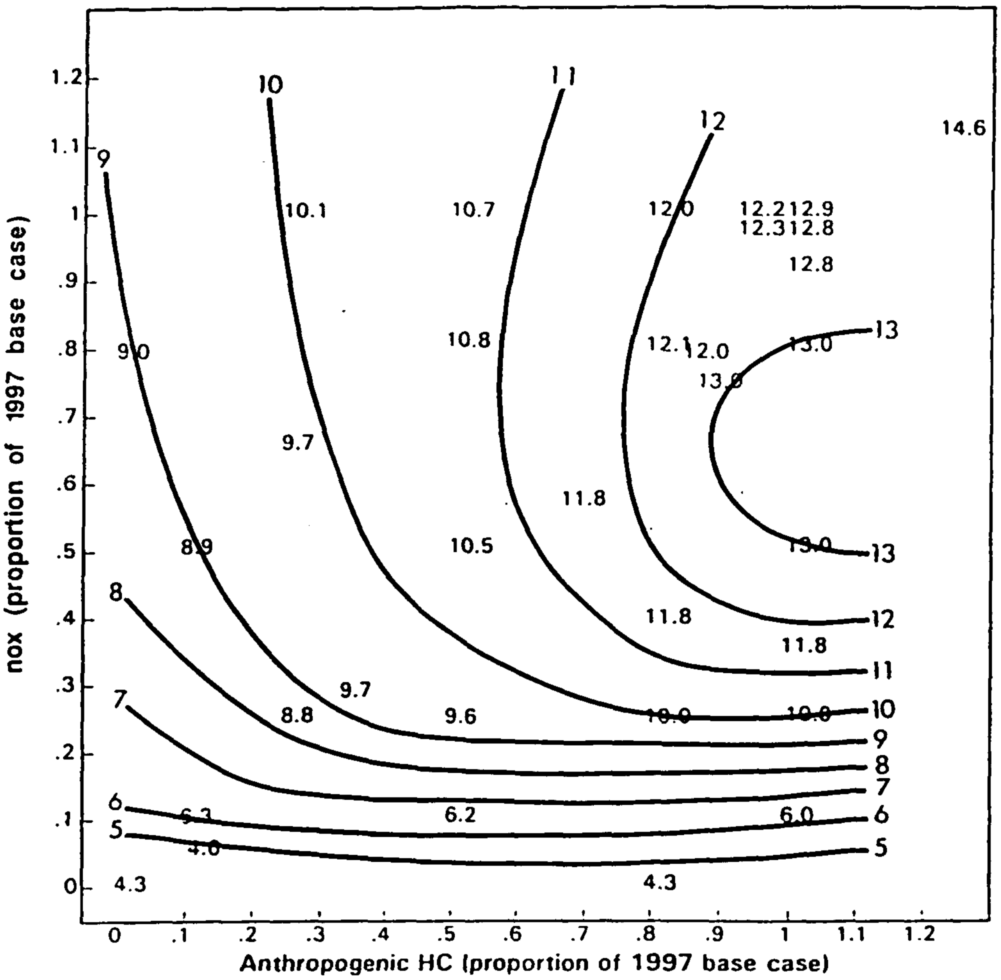
2 See, for example, Russell and Wilkinson, page 29.

Figure III.B.2: Isopleth Diagram for BAAQMD



Isopleths of peak ozone (pphm) from the UAM-CB4 model.

source: Umeda, et al, 1991

As mentioned above, the Bay Area was historically thought to be at a point similar to A, with a ratio of approximately 3/1. Recently, opinions have changed considerably. Evidence of shortcomings in NMHC inventories in other basins and results from UAM modeling led District researchers to conclude that NMHC emissions have been seriously underestimated and could actually be much closer to the ridge line, in the range of 5/1 to 8/1.[3] If this supposition is correct, then the policy problem becomes much clearer and, given reasonable relative costs of control for NO_x and NMHC, a policy involving control of both appears reasonable. Given the way in which figure III.B.1 is drawn, following a ray towards the origin would, therefore, be sensible if controlling an incremental kg of episode day NO_x cost approximately 5-8 times as much as controlling an incremental kg of episode day NMHC. If the ratio of control costs were higher than this ratio, then the correct path would stay above the ray, and if the ratio were lower, it would veer below the ray.[4]

Finally, consider figure III.B.2, taken from Umeda, *et al*, who are researchers at the District. They have taken the results from numerous

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3 Jiang, *et al*, 1991 page 11

4 If these ratios confuse you, think of it this way. A policy plan to move towards the origin along the 8/1 ray implies that 8 kg of NMHC can be controlled as readily as 1 kg of NO_x. If controlling NO_x is actually cheaper than this, which is most likely the case, then the best route to the next lower contour is to head for a point above the 8/1 ray.

UAM runs of the September 1989 episode and plotted them in a space similar to the EKMA diagram. Every number represents a model run and the implied location of the isopleths is shown. The 14.6 point in the north east corner represents a do nothing scenario with no abatement policies in place between 1989 and 1997. Results in the area of (1,1) show the outcome in 1997 if only current policies continue; that is, NO_x emissions will fall by approximately 15% and NMHC by 25%. Without additional policy initiatives, therefore, compliance will not be achieved in 1997. In this case, keeping the NMHC/NO_x fixed would imply following the diagonal to the origin. Although it is not precisely clear from the diagram, this could mean slightly higher peak ozone concentrations initially. Given the starting point, reductions in both pollutants during episodes would have to reduced by about 70% to reach compliance with the State standard of 0.09ppm.

2. UAM

a. Eulerian models

The Urban Airshed Model (UAM) developed by Systems Applications Inc. was released as a public domain model in 1980 and has been the recommended EPA model for urban atmospheric chemistry modeling since 1984.[5] BAAQMD, which previously used the LIRAC model, adopted UAM in 1987.

UAM is an Eulerian airshed model. This simply means that the model user attempts to establish, for every cell in a large geographical grid, a representation of the emissions, chemistry, meteorology, and sinks realistic enough to reproduce useful results over the simulation period, usually a few-day episode. The great advantage of Eulerian models derives from the detail of their results. Since they treat each cell individually, the results of controls on individual sources can, in theory, be identified. And the effects of alternative abatement strategies on sensitive local pollution hot spots can also be estimated. The great disadvantage of Eulerian airshed models is simply their complexity. The data requirements are huge, involving both surface and atmospheric values over a wide area. Collecting data requires expensive surface and atmospheric observation over a short intense period, and manipulating and maintaining the data sets requires further resources. Once the input data are available, solving the chemistry itself requires careful numerical analysis that has to be repeated numerous times, so the computing requirements are highly demanding. And finally, calibrating the models to historic experience requires considerable expertise, judgment, and time.

5 SAI 1990

b. CBM IV

In any model of atmospheric chemistry, it is not feasible to simulate all of the numerous chemical mechanisms involving hundreds of compounds that might be involved in tropospheric ozone formation. First, knowledge of some reaction's rate constants or products remains incomplete. And second, even if all the reactions were understood, the computational burden of solving the huge systems of equations involved would be overwhelming. Therefore, all models of atmospheric ozone formation explicity solve some well-known reactions involving important and well-known compounds, and then attempt to simplify the remaining reactions in some way. There are two general approaches to this simplification: a lumped approach and a carbon bond approach. In the first approach, compounds with similar reaction rates and products are identified and replaced by one representative species.

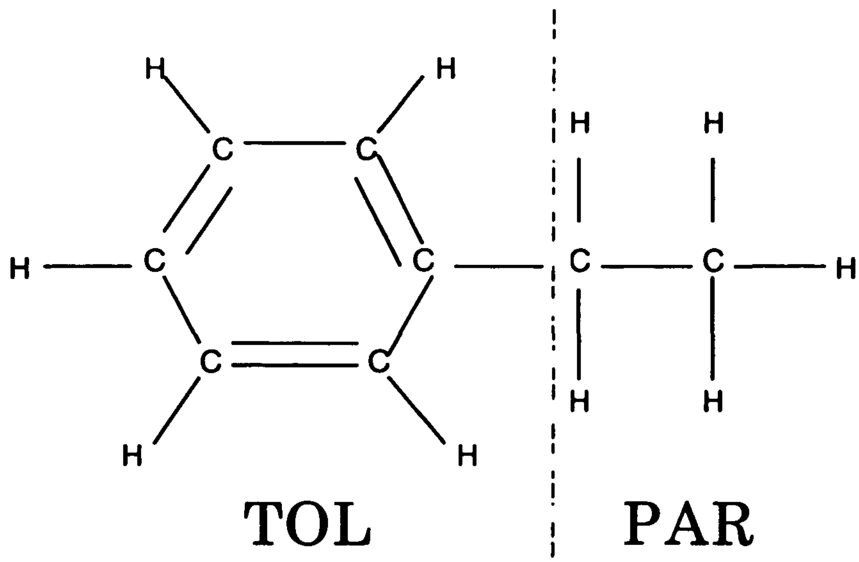
UAM employs the second approach, known as a carbon bond mechanism (CBM). In a CBM, as in the lumped approach, a few key species, such as formaldehyde (CH2=O), nitrogen dioxide (NO2), and ozone are explicitly considered. These species are either so important as to merit individual attention, or so unusual in their reaction rates or products as to be considered chemically unique. The remaining compounds, typically the complex hydro-carbons that make atmospheric chemistry so difficult, are represented in reactions by surrogates. Species are disaggregated on the basis of their carbon bond structure.

For example, consider ethylbenzene (C6H5–C2H5), which is an arene containing an aromatic benzene ring with an aliphatic side chain, as shown in figure III.B.3.[6]

Ethylbenzene can be represented by two fictitious surrogates, TOL and PAR, where TOL is seven-carbon-bond species whose chemistry is based on toluene (chemically methylbenzene or C_6H_5–CH_3), and PAR is a single carbon bond surrogate based on alkane (C_nH_{2n+2}) chemistry. On the left side of figure III.B.3, the benzene ring structure of eth - ylbenzene is identical to toluene. On the right side, the structure differs from toluene by an extra carbon atom, and three extra carbon bonds. Further, the structure to the right resembles the alkane pattern whose chemistry is well understood because of the importance and familiarity of the simple alkanes, methane, ethane, propane, etc.

6 Morrison and Boyd, p. 626

Figure III.B.3: Representation of Ethylbezene by TOL and PAR



Simplifications of the type described were used in the development of a CBM for UAM to produce a system of 204 chemical equations and rate constants in 87 species. These equations were further dramatically simplified by elimination of minor reactions, representation of groups of radicals by representative radicals, algebraic manipulation, and lumping. The ultimate result of this process was an 80-equation system in 33 species known as the Carbon Bond IV Mechanism (CBM-IV), which was extensively tested in the 1980's and compared to smog chamber results.[7]

The CBM-IV equations contain reaction time constants that vary over a wide range, so the whole system of equations cannot be efficiently solved with a precise numerical integration scheme; rather a combina-

7 Gery, Whitten, Killius, and Dodge 1989

tion of schemes is used.[8,9] Throughout the cells of UAM, CBM-IV is solved for every time step of the simulation. Therefore, for every day of a simulated Bay Area air pollution episode, the 80-equation system has to be solved about half a million times. The computing time of finding solutions varies considerably because it tends to take longer when concentrations of chemicals become lower and during transitions, such as at dawn or dusk.

c. dispersion

It is important to remember that the chemistry is only a part of the total problem. The actual pollutant concentration over time is delivered by the atmospheric dispersion equation. In addition to the chemistry, the equation must account for the transport and mixing of the reactants and products. This is done by an advection model and a turbulent diffusion model, into which the key inputs are wind and other atmospheric and topographical data. In the implementation used at BAAQMD, a prognostic wind model generates the initial wind data, which are then scaled to observed data at the surface. The prognostic model also generates temperatures in a similar manner. Most other inputs are derived from actual observations. The two other key terms in the

8 SAI 1990, p. 23

9 Seinfeld 1986, p. 607

atmospheric dispersion equation concern removal at the surface, which is approximated by experimental data, and the emissions flows themselves, which come from collected data.

d. other models

As a result of the demanding requirements of Eulerian airshed models, their use is restricted to intensive analysis of historic episodes and forecasting of the possible effects of future changes in conditions, such as population growth or the adoption of abatement strategies. A Lagrangian model serves as a second type of simulation model that can be used to assess the effects of individual sources.[10,11] Rather than trying to solve an entire grid of atmosphere, a Lagrangian model follows the progress of a column of air as it is moved by wind, and as it experiences different weather and new pollution inflows and outflows. While a Lagrangian model might be useful in determining the effects of constrained dispatch, none are available for the Bay Area.

To predict conditions over the near future, when resources do not permit the running of either class of chemistry models, districts typically use a third type of model usually referred to as a statistical or empirical model. A model of this type incorporates the pollution expe-

10 Finlayson-Pitts and Pitts, p. 620

11 Not to be confused with a Lagrangian Relaxation production cost model.

rience of past episodes in the form of simple predictive equations, using lagged variables. Given a set of observations on current conditions, such a model can predict with some accuracy the onset of a pollution episode. Apart from the importance of issuing public warnings of unhealthy conditions, being able to predict episodes well is necessary to muster data collection efforts for simulation models. The relevance of these models here is only that they could provide warning to a utility of an upcoming episode a few days in advance.

C. NOx Formation

1. NOx from power generation

For the purposes of analyzing ozone formation, the only pollutants from the power sector of interest are nitric oxide (NO) and nitrogen dioxide (NO_2), the two pollutants that together are known as NO_x. Several other oxides of nitrogen are found in exhaust fumes in lesser concentrations and are usually not monitored, but they can be important in ozone formation, despite their small total mass of emissions.[12] Although the overwhelmingly dominant NO_x species in exhaust fumes is NO, because NO itself is not considered a health hazard, and because it reacts in polluted air to form NO_2, analyses usually treat all NO_x as NO_2.[13,14] All NO_x mass data in this study treat all NO_x as NO_2.

NO is primarily formed in combustion by the Zeldovich mechanism.[15]

$$N_2 + O \rightarrow NO + N \qquad \text{(a)}$$

$$N + O_2 \rightarrow NO + O \qquad \text{(b)}$$

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12 Arjomand, Goodman, and Sawyer 1992

13 NO_2 fractions are highest in combustion turbine exhaust.

14 Currently stack monitoring in the Bay Area actually only considers NO, and estimates are made subsequently of the companion NO_2.

15 Flagen and Seinfeld, p. 168

The nitrogen comes from two sources, the fuel and the air. NO_x formed from the oxidation of organically bound nitrogen in the fuel is known as *fuel-NO_x* Since the fuel of interest here is natural gas, air represents by far the more important source. The pollution resulting from oxidization of nitrogen in the air is generally known as *thermal-NO_x*, and its formation peaks at the stoichiometric point, that is, where the equivalence ratio, ϕ, equals 1. Because the process is highly endothermic, formation of NO from atmospheric nitrogen is a slow and highly temperature sensitive process. In contrast to automobile engines, which are close to stoichiometric, combustion in utility boilers is lean with 3% excess oxygen ($\phi<1$). The existence of excess oxygen is important when NO_x control is considered by means of SCR, as explained below.

Because the dominant generation fuel in the Bay Area is natural gas, especially during smog season, fuel-NO_x does not normally merit important consideration. However, the dominance of thermal-NO_x carries two caveats. First, a significant share of generator capacity is not powered by gas. The leading examples are PG&E's combustion turbines, such as at the Oakland station, which burn diesel fuel. While such resources are few, and are rarely used, they cannot be ignored because of the above average probability that they will be used during an air pollution episode. Second, according to PG&E, the gas being burned in the Bay Area contains a small fraction of nitrogen.

Analysis of the Natural Gas Burned in PG&E Boilers[16]
(percentage by volume)

methane (CH_4)	92.50
ethane (C_2H_6)	4.70
propane (C_3H_8)	1.00
isobutane (C_4H_{10})	0.11
n-butane (C_4H_{10})	0.08
isopentane (C_5H_{12})	0.02
n-pentane (C_5H_{12})	0.02
hexanes (C_6 or >)	0.10
carbon diox. (CO_2)	0.47
nitrogen (N_2)	1.00

The role of the nitrogen in natural gas merits careful thought. While it certainly is nitrogen in the fuel, it is not *fuel nitrogen* because it is not bonded in the fuel. The role of this nitrogen, then, is more akin to atmospheric nitrogen and, in fact, has the effect of slightly raising the nitrogen mole fraction of the incoming air.

2. NO_x curves

As discussed in detail in section II.D.2 and in appendix D, for the NO_x tax dispatch to be modeled in the simple manner used here, NO_x curves must be upward sloping and convex. This requirement is adopted as an assumption in the modeling, and, in appendix D, the evidence available to support the assumption holding in practice is reviewed. Apart from the evidence provided by the data, however there

16 source: Bob Wagenor, PG&E, personal communication, 8 April 91

is a physical reason to believe that NO_x curves might have the assumed shape. As mentioned above, the formation of thermal NO is a highly temperature dependent process. More turbulent and complete combustion tends to result in more NO production, as does a longer residence time in the boiler. It is easy to speculate that higher temperatures will result as the boiler nears full load because the combustion will be more complete, and losses to the boiler walls will be smaller relative to the heat production. While residence time in the boiler may not necessarily increase, residence at high temperatures will as all the parts of the whole system reach higher temperatures.

3. NO_x control strategies

No attempt is made here to discuss the many possible NO_x control strategies in any detail. A huge literature exists on various attempts to limit NO_x formation in utility boilers and nothing new can be added here.[17,18] The goal here is to assess the potential of a NO_x tax dispatch, rather than any other control strategies. NO_x control strategies are of two basic types, combustion modification and exhaust gas clean-up. The logic that suggests the former approach is the temperature sensitivity of NO formation. Many methods can be used to lower combustion

17 Kokkinos and Hall, 1991

18 Kokkinos, *et al*, 1992

temperatures, reducing NO production. The second approach suggests finding a chemical process that can eliminate NO from the exhaust stream before it leaves the stack.

SCR is an exhaust gas clean-up approach, and since SCR has been used as a benchmark cost of control comparison for a NO_x tax dispatch, some discussion of how SCR works is in order. In section II.B.2, a simple chemical model of NO_x formation is presented. It is noted there that one way of looking at the NO_x problem is that molecular nitrogen enters the boiler in air, but is never returned in any of the reactions. That is, while much of the N_2 passes through the boiler unchanged by the combustion process, those molecules of N_2 that get involved in combustion seem irreversibly reformed. One possible agent that could return N_2 is ammonia, by the following reaction.

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O \qquad \text{(c)}$$

This is obviously a promising reaction because the products are innocuous and the reactants are readily obtainable. The two problems that arise are that oxygen must be made available in sufficient amounts, and that the reaction is highly temperature sensitive, being most effective in the 1200-1300 K range. The term *selective* refers to the need for oxygen, while the term *catalytic* obviously implies the need for one of several possible catalysts to be present.[19] These requirements are somewhat demanding. First, meeting the temperature requirement implies that the process will be less effective under certain boiler operating states than others. Second, oxygen must be provided. And third, the catalyst has to be provided and replaced as necessary. These requirements explain the basic cost structure of SCR. It is a capital intensive technology because a special chamber in the exhaust stack must be constructed, and this can be expensive if the original layout of the unit cannot easily accommodate the new equipment. However, there are variable costs involved in supply of amonia and the catalyst. SCR can be very effective under favorable circumstances, elimating over 80% of NO_x at full load. Evidence of the effectiveness of SCR at partial load is scant, despite considerable operating experience with SCR in Japan and Germany.[20]

Most other NO_x reduction technologies are less effective than SCR, but some may be desirable on other grounds. In this regard, one technology is of particular interest, selective non-catalytic reduction (SNCR). Although the chemistry of this process is identical, the engineering approach can be quite distinct. Rather than constructing a special reactor to house the catalyst, the ammonia is injected directly into the

19 Flagen and Seinfeld 1988, page 515

20 Kokkinos and Hall 1991

exhaust flow. A test by PG&E achieved 30 % NO_x reduction with limited equipment.[21] The attractiveness of this approach should be immediately apparent. Since the fixed capital investment is low, and the injection can be turned on and off, as needed, the avoided emissions can be readily concentrated during episodes, and can be achieved at low capacity factor units.

4. cost of SCR

As mentioned above, the official Best Available Retrofit Control Technology (BARCT) for utility boilers in California is selective catalytic reduction (SCR), and this technology will likely become mandated for most utility boilers in the District as the '91 CAP becomes slowly translated into actual District rules. Clearly, the designation of SCR as the best available technology defies economic reason because cost is simply not a factor in the choice. However, in the case of SCR, apart from its high overall cost, the structure of its cost poses a special problem. The nature of this problem is simply that SCR is capital intensive. In other words, it is a baseload technology whereas photochemical smog is a peaking problem. One of the major limitations of the BARCT requirement is that alternatives were *de facto* deemed unacceptable. This could represent a serious error of policy with regard to NO_x control

21 Himes, *et al*, 1992

Table III.C.1

Various Estimates of NOx Control Costs for Moss Landing 6*

Chris Marnay - 3 Dec 92 cap = 739 MW (1992 $)

av.NOx.red (kg/MWh)	CF (.%)	K cost ($/kW-yr)	fix. O&M ($/kW-yr)	var. O&M ($/MWh)	HR pen ($/MWh)	episode days1($/kg) 365	50	5
0.15	0.15	11.00	1.25	0.39	0.0045	65	473	4729
	0.45					23	170	1704
	0.75					15	110	1099
0.60	0.15					16	118	1182
	0.45					6	43	426
	0.75					4	27	275
2.00	0.15					5	35	355
	0.45					2	13	128
	0.75					1	8	82
0.45	*0.55*	*11.00*	*1.25*	*0.39*	*0.0045*	*7*	*48*	*476*

* based on data for Moss Landing 6
1 assumes average CF on all days

technology because a wide range of alternative control technologies is available. In the power sector, the minimum cost control strategy over time is actually a complex trajectory involving several technologies, including a low NO_x dispatch, with installation schedules that are reevaluated over time to reflect the progress thus far achieved towards meeting emissions reduction goals. Choice of the appropriate control technology for any one unit should take account of the duty cycle of the unit as well as its expected lifetime. The BARCT designation precludes consideration of all these factors.

Table III.C.1 demonstrates this problem. This table is a simple spreadsheet used for estimating the control cost of SCR. The data are loosely based on appropriate numbers for Moss Landing 6, which is one of the best SCR candidates among the BAPS units. Consider the last italicized line of the table first. This line uses reasonable assumptions for this unit, and 55% capacity factor (CF), and an average SCR NO_x reduction of 0.45g/MWh, or 90%. The next 4 columns of the table show the basic cost assumptions. These are based on PG&E's assumptions, which in turn came from an analysis conducted by PG&E's consultants. The annualized capital cost depends on an assumed fixed charge rate of 16%. The three right-hand columns show the control cost assuming three different lengths of smog season. The first column treats the whole year as evenly important, namely, the traditional assumption.

Table III.C.2

Range of Credible Effectiveness of SCR

power MW	tot.NOx kg/h	av.NOx kg/MWh	inc. kg/MWh	effect. %	SCR kg/MWh	red. kg/MWh
50	4	0.07	0.202	0	0.202	0.000
100	6	0.06	0.303	7	0.283	0.020
150	14	0.09	0.404	13	0.351	0.053
200	26	0.13	0.504	20	0.406	0.099
250	44	0.17	0.605	26	0.447	0.158
300	66	0.22	0.706	33	0.475	0.230
350	94	0.27	0.806	39	0.490	0.316
400	126	0.32	0.907	46	0.492	0.415
450	164	0.36	1.007	52	0.481	0.526
500	207	0.41	1.108	59	0.457	0.651
550	255	0.46	1.209	65	0.419	0.789
600	307	0.51	1.309	72	0.369	0.941
650	365	0.56	1.410	78	0.305	1.105
700	428	0.61	1.511	85	0.228	1.283
739	480	0.65	1.589	90	0.159	1.430

Under this assumption, plus the basic assumptions mentioned above, the cost of control that emerges is a reasonable 7 k$/t. This figure reflects the attractiveness of this unit for SCR, primarily because of its high CF. The next two columns show the cost of control if only 50 and 5, respectively, days are considered of high enough smog danger to warrant NO_x control. This shortening of the smog season, not surprisingly, drives up the control costs dramatically.

It has been argued elsewhere in this report, notably Appendix E, that a 50-day smog season assumption is reasonable for the District, suggesting that one of the best candidates for SCR, Moss Landing 6, can deliver NO_x emissions reductions for about 46$/kg. Hence, the number of approximately 50 $/kg control cost for SCR used in chapter IV as a basis of comparison between SCR and a NO_x tax dispatch. Note, however, two aspects of the 50-day assumption. First, it is somewhat conservative to begin with, given that the District experiences only 15-20 State non-compliance days per year. Second, assuming steady progress towards meeting the standard, which is clearly the District's aim, implies steadily escalating control costs. For the sake of argument, assume the District manages to reduce the number of days of exceedence danger from 50 today to 5, ten years hence. Now, the 50 $/kg control cost looks quite conservative, and a figure somewhere between 50$/kg and 500 $/kg becomes more plausible. Although this might sound simplistic, most analyses of control costs being done in the regulatory arena today will follow the procedure that results in the 7 \$/kg estimate and proceed no further.

Notice that in the calculations of the above paragraph no allowance was made for uncertainty in the data or assumptions. The remainder of the table shows the effect of varying just two of the critical assumptions, the CF of the unit, and the kg/MWh of NO_x avoided. The significance of the sensitivity on the CF assumption should be obvious. Since fixed costs are the overwhelming percentage of the total, 87 % in the case of the best guess italicized line, it is not surprising that lower CF's dramatically increase per kg costs. This demonstrates the baseload vs. peaking argument. Electric utility planning principles would naturally require the selection of higher variable lower fixed cost technologies for low CF duty cycles. However, the BARCT requirement confounds this principle. While SCR could eventually be proven to make economic sense for some high CF units, such as Moss Landing 6, it can never be the economic technology for all units.

The second sensitivity is on the data in the first column, the assumed kg/MWh of NO_x reduction. Table III.C.2 shows the derivation of possible kg/MWh of NO_x reduction assumptions. Applying the NO_x function developed for this study yields the NO_x emissions rates shown in column 2. Dividing column 2 by column 1 yields an average emissions rate for each level of power output. Since the NO_x function is convex, these averages increase. Since a common assumption is that SCR can reduce emissions by 90%, the 0.45 kg/MWh is approximately equivalent to an assumption that Moss Landing operates at 600MW at all times, which is reasonable.[22] The next column shows the incremental emissions rate at each power level.[23] These numbers show a much wider variation. To add a slight complication, assume that SCR is much less effective at low power than at full power. The next column shows a linearly interpolated effectiveness of SCR. The NO_x emissions reductions are again 90% at full power but fall to zero at minimum load. The next column shows the incremental emissions rate under SCR, and the final column contains the emissions reduction achieved. These numbers cover a more dramatic range, but it might be reasonable to choose a number from high up in the power range, where, presumably, the unit is operating when it produces the largest share of its total output. Nonetheless, the range of possible assumptions is large.

Returning to table III.C.1, the first three blocks of data show a sensitivity on the kg/MWh. Varying these assumptions results in the

22 If this is not clear, note in Table III.C.2 that the average NO_x emission of Moss Landing 6 is 0.51 kg/MWh if it operates at 600 MW. If emissions could be reduced by 90%, the average would be reduced to $0.9 \times 0.51 \approx 0.45$.

23 Referring to figure II.D.2, average emissions are the value of the externality function $n(p)/p$ at any power level, while the incremental emissions are the value of the incremental NO_x function $n'(p)$.

huge range of control cost estimates seen in the three right-hand columns.

D. Production Costing

1. peaking problem

The classic problem in electric utility economics and planning derives from the non-storability of electricity. While strictly speaking, electricity can be stored, in batteries for example, few economic storage technologies are known for utility sized needs. With no storage available, in general, the production and use of electricity has to be kept in precise balance, literally moment by moment. This harsh engineering reality makes utility operations and economics quite distinct from most production processes, for which production schedules can be optimized somewhat independently of expected product sales. Electric power generation economics, therefore, is more akin to that of service industries than manufacturing. Indeed, the problems that derive from non-storability, such as the need to plan for peak rather than average demand, are very similar to the issues facing service providers, such as airlines or restaurants. The peaking problem has traditionally dominated the electric utility economics literature, and to a lesser extent, the engineering literature. However, it can be deceptive to focus too heavily in planning on the need to meet peak load because other implications of choices can have bigger effects on costs. For example, the ability of a generating system to efficiently reduce generation to low levels during load troughs can be an important determinant of operating cost.

2. planning problem

The electric utility's basic problem is one of meeting customer demand through time at minimum cost, although customer demand in the case of electricity needs a little explanation. Electricity is an intermediate good, that is, useless in itself but valuable for the services it delivers. Customer demand, therefore, should be thought of in terms of the services delivered, rather than the actual metered energy consumption. As a result, utility investment intended to meet customer demand can take place on either side of the meter, and demand should not be viewed as exogenious to the problem, hence the popular term *demand side management* (DSM).

The goal of production cost modeling is to realistically simulate the utility's operation of its system through time, estimating expected costs as accurately as possible. However, because production costing normally takes place as part of a wider planning exercise, it is best viewed within that context. The overall utility planning problem can be summarized by seven steps.

1. *demand forecasting*

Most of production costing is, realistically or otherwise, based on the assumption of a known customer demand. Forecasting this load, incorporating the effects of DSM together with all the other many factors determining electricity demand, represents the first step in planning.

Utilities and regulators usually adopt a time horizon of 1 to 10 years, and it can be more distant in some cases.

2. *resource scheduling*

Many generating resources require complex advanced scheduling, and this problem is treated independently of the short-term sheduling of thermal generation. The two most important resources of this type are hydro and nuclear. In the case of hydro, the accumulation and decay of the resource in reservoirs must be planned on an annual, or longer, basis. The nuclear refueling and maintenance cycle for light water reactors also needs to be planned far ahead. Planning the maintenance schedule for other resources, notably the big thermal units, also falls within this step, although their maintenance schedules tend to be somewhat more flexible. The time horizon for these scheduling problems is usually 1 to 5 years, with a fixed cycle assumed beyond the horizon.

3. *fuel budgeting*

Anticipating supplies and prices of fuels is clearly of importance to utilities. The forecasting of fuel supplies and prices also usually takes place independently of actual production modeling, and typically has a time horizon of 1 month to 5 years.

4. *resource availability*

As mentioned above, electricity has to be generated exactly as demand for it arises. A key determinant of costs, therefore, is the availability of resources when called upon to generate. Making allowance in planning for the random failures of resources has been one of the areas of most intensive study. This is not a problem with a time horizon; rather, the horizon must necessarily be the same as the production simulation.

5. *unit commitment*

The unit commitment problem is, in essence, a start-stop or zero-one problem. The strange name derives from the fact that units usually cannot be started or stopped instantaneously, so once an operator has decided whether to have a unit running or not running, s/he is *committed* to that option for some time period. This issue represents a much more significant part of the whole planning process than *prima facie* observation might suggest. While simulating the up and down ramping of resources to follow load, *dispatch*, is relatively straight forward, deciding when to stop and start resources in anticipation of need and in keeping with the many operating constraints on generators is surprisingly complex. As a result, the time horizon for unit commitment rarely exceeds a week.

6. *dispatch*

Utility engineers use the term *dispatch* specifically to describe the process of up and down ramping of resources in real-time to follow load. Since a simple operational rule, discussed below, ensures minimum cost operation, dispatch can be readily simulated by fast algorithms. The time horizon of such simulation can range all the way from a day to a quarter century.

7. *capacity replacement*

The final step in the planning process concerns the retirement and replacement of existing units. While production costing would form a part of capacity replacement planning, other important analyses of financial prudence, technological progress, and political feasibility also play important roles. This problem has received the most attention in the environmental literature because technology choice has such an impact on the environmental externalities of power generation. The time horizons used are necessarily long because of the long lead times of power plant construction, and are usually from a decade to quarter century.

The important planning steps with respect to this work are 5. and 6., although keeping track of the big picture is always important. As mentioned above, the procedure of starting and stopping generators in anticipation of need is called *unit commitment* in the industry, and hence, the problem of deciding what resources to have ready for use is often referred to as the *unit commitment problem*. The actual ramping up and down of generators to follow fluctuations in load in real-time is called *dispatch*. However, in modeling circles in general, and particularly in the environmental dispatch literature, *dispatch* tends to encompass the whole process of deciding which resources to use, taking account of outages, that is step 4., as well as actually using them to meet load. Furthermore, these problems are often poorly distinguished from the retirement issue, step 7. This more general usage is adopted here only with respect to the environmental dispatch literature. At all other times, the terminology outlined in the 7 steps will be used.

3. history

The modern history of production cost modeling began in the 1940's when system planners first started to develop methods of incorporating the uncertainty of generating unit outages into estimates of cost, and subsequently, into planning decisions. First efforts were based on a graphical load duration curve (LDC) approach using the classic dispatch of units in fixed order to fill up the area under the LDC. That is, only step 5. was simulated, and even this one was only a rough approximation because units were dispatched discretly, violating the equal system lambda rule. Nonetheless, for long range planning purposes in an era of predictable demand growth, this approach, possibily calibrated to historic capacity factor experience, was adequate. By derating the capacity of units or adjusting the curve upward, the uncertainty that units could deliver their maximum energy could be accounted for in estimates of system operations; that is, step 4. above could be included.

The arrival of more computing power in the 1960's quickly led to attempts to simulate expected outages by random drawing, or Monte Carlo, methods. While these efforts were theoretically sound, the computational burden was too great for realistically sized systems. Suddenly, further pursuit of Monte Carlo approaches was derailed by the publication of Baleriaux's classic 1967 article.[24] Baleriaux proposed a convolution of the outage distributions of resources with the load duration curve to form an equivalent load duration curve (ELDC) that reflects both load and the uncertainty of outages.[25] The ELDC method was immediately tested and enthusiastically endorsed by Booth.[26]

The 1970's saw a period of feverish attention to the convolution prob - lem, leading to numerous proposals for carrying it out more efficiently

24 Baleriaux 1967

25 M.S. Gerber & Associates, 1987

26 Booth 1971

and accurately.[27,28,29] One proposal, namely, treating the ELDC as a distorted normal distribution that could be convolved with outage distributions by adding their respective cumulants, had a particularly important impact.[30,31,32] Cumulant solutions were so efficient that they permitted convolutions of hourly system loads in reasonable computer time, an approach that became immortalized by the POWRSYM model developed at the Tennessee Valley Authority, the forerunner of several current commercial models, such as P+.[33] Cumulant methods were also fast enough to permit the incorporation of production costing into expansion planning, as for example, in the Electric Generation Expansion Analysis System model (EGEAS), which uses a cumulant solution at every node to find the lowest cost path in a dynamic programming expansion optimization.[34]

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27 Wu and Gross 1977

28 Manhire and Jenkins 1981

29 Levy and Kahn 1982

30 Stremel, Jenkins, Babb, and Bayless 1980

31 Stremel 1981

32 Lin, Breipohl, and Lee 1989

33 P+ is a trademark of the P+ Corporation of San Jose, CA.

34 Caramanis, Schweppe, and Tabors 1982

The primary advantage of the Baleriaux-Booth method faded in the 1980's. The falling cost of computer time and a renewed interest in accurate hourly simulation have revived chronological modeling. Most importantly, the kind of planning issues and decisions now being made requires more detailed output and more careful respect of real-time operating constraints, especially for small systems. A chronological approach has inherent advantages, but serious drawbacks remain and the limits to computing time still require difficult compromises.

Also, in the late 1980's, modelers were looking at new approaches to production costing. An avenue of research that is now bearing fruit involves Lagrangian relaxation models. These models, while still mostly used in research, are now being commercialized.[35]

4. load duration curve models

An LDC approach dramatically simplifies production costing by compressing sequential hour-by-hour load data into a nonsequential probability distribution for load. The most notable feature of an LDC approach, however, is that steps 4. and 6. are solved directly by analytic means. Step 5, unit commitment, is overlooked, thereby implicitly ignoring the unit commitment constraints. The Baleriaux-Booth technique uses an ELDC representation. The probability distribution of

35 Grimes and Jabbour 1989

customer loads, the LDC, is convolved with the outage distributions of generating units as they are dispatched, forming the ELDC. This convolution procedure is commonly referred to as *probabilistic dispatch*. The dispatch itself follows a strict merit order. That is, the area under the LDC is filled up by expected energy output of resources, in strict order of increasing cost. A universally used refinement to the merit order is *block dispatch*. Block dispatch divided the output range of the unit into a small number, usually 4 or 5, blocks, which are then treated as individual resources in the dispatch, subject to the constraint that block n-1 of a unit must be dispatched before block n. In this way, the dispatch simulation becomes considerably more accurate because the engineering reality that the conversion efficiency varies across the output range, as discussed in appendix D, gets better reflected in the simulation.

Computationally fast techniques for the convolution allow the modeler to quickly evaluate different forecast scenarios. In addition, simplified unit commitment patterns provide fast outcomes for the dispatch of complex generation systems and can reduce the confusion caused by discontinuities in costs. Consequently, fast LDC models can be packaged in user friendly ways. The ELDC approach also has the benefit that loss of load probability (LOLP) estimates, an important input to planning for system reliability, emerge from the convolution process.

The initial reshuffling of data into an LDC, however, makes respecting some operational constraints troublesome, if not impossible. The implicit assumption in turning a chronological load pattern and an outage distribution into an ELDC is that each load point is an independent observation from the same probability distribution for load. Because loads during weekday afternoons are distributed differently from loads on Sunday mornings, partitioning the week into time periods produces better results. Nevertheless, within a subperiod, the LDC contains the assumption of independence of loads during consecutive hours. The ELDC approach further assumes that the dispatch during one hour is independent of the dispatch during any other hour. This crucial assumption may work for a system not severely limited by operating constraints, such as a strictly steam turbine system; however, difficult operating constraints like ramping limits, complicated energy storage mechanisms, load management, some non-dispatchable technologies, and time-differentiated purchase contracts all violate this fundamental assumption of chronological independence

5. chronological models

Chronological models that simulate the operation of the generation system hour-by-hour for a fixed length of time, generally one week, for one particular outage state of the system. Step 4., then, is critical in chronological models. An outage state is established, usually by means of a Monte Carlo draw. This outage state of the system indicates which generating units are available and which are on forced outage. The dispatch of a sample of system outage states is then simulated, hour-by-hour, usuing block dispatch and the mean of results reported.

In contrast to LDC models, both steps 5. and 6. are simulated. In further contrast, the simulation is not based on an analytic approach, but rather involves the application of a set of heuristic rules of thumb, derived from actual practice. The range of complexity of these rules is huge among models and individual users. However, knowing what the rules are and how they are applied makes the chronological approach closer to intuitive ideas of how to simulate dispatch and how real-time decisions are made. Keeping load data in their original order theoretically permits better use of the information they contain. For difficult modeling problems such as storage optimization, ramp constraints, and time-dependent contracts, hour-by-hour operational simulation under an hour-by-hour load shape makes algorithm logic more comprehensible. Unit commitment can also be more accurate and closer to actual experience. Also, as long as the chronology of information is maintained, models are upgradable. That is, consideration of additional local constraints is possible.

Finally, it should be noted that the two approaches are not mutually exclusive. All practical models based on the Baleriaux-Booth methodology modify the LDC by incorporating some chronological features. The extent to which this is reasonable and appropriate depends upon the complexity of the system being modeled and the accuracy requirements of the modeler.

6. hourly probabilistic dispatch

Instead of collapsing load data into an LDC, *hourly probabilistic dispatch* takes a hybrid approach. The chronology of the load is retained, but each hour is treated as a uniform distribution and a separate convolution is conducted for each hour. PROMOD III®, the most used commercial model, uses this method when calculating hourly marginal costs, although the original commitment from the aggregated LDC is used. The probabilistic, non-Monte Carlo mode of POWRSYM performs hour-by-hour commitment and dispatch but uses a convolution to solve each hourly marginal cost. The developers of the P+ model have further developed this approach and it is the default simulation method of that model. Probabilistic dispatch inherently assumes hour-by-hour independence.

7. Lagrangian relaxation models

All of production costing is optimization in the sense that a minimum cost solution is being sought subject to certain operating constraints, uncertainty of unit availability, and the need to meet customer demand. The LDC approach relies on the convolution to take account of the outages and relies on the merit order to guarantee cost minimization. The chronological approach relies on a complex set of rules to respect constraints on unit operation, but again relies on the merit order to find a minimum cost solution.

Given this framework, one might think that the actual optimization problem is not being efficiently solved by reliance on the adjusted merit order and block dispatch, and that perhaps the problem would be better solved by a mathematical formulation. Given a predetermined availability of units, couldn't their scheduling be optimized directly, without reliance on the merit order? Taking the optimization out of the production costing and solving it in an efficient manner is precisely what a Lagrangian relaxation approach, as used in EEUCM, attempts to do.

The equal system lambda rule for dispatch has been understood and applied for some time. However, as a guide to operations, this rule offers little additional guidance beyond what is already known from the merit order. In practice, the more difficult problem is the unit commitment problem, step 5, and dispatch can be efficiently managed simply on the basis of the merit order. It has been the focus of considerable research, therefore, to extend the optimization that leads to the equal lambda rule to include the unit commitment. The key complication that this adds to the problem is timing. Unlike the dispatch problem which involves a solution only in instanteous time, that is, in power units, the unit commitment problem involves decisions that depend on conditions and decisions within other time periods. Unfortunately, the inclusion of interperiod dependencies to the problem, together with the limitations on system operations lead to a complex set of constraints that result in a large, non-linear, mixed integer problem.[36,37] Most mixed integer problems cannot be solved directly. A series of solutions to a relaxation of the problem have to be found and then compared until the best possible one is found. Most of art in solving mixed integer problems comes in the manner in which feasible solutions are found such that the optimal one can be uncovered in the shortest time possible. The most common method is the branch and bound approach.[38]

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36 Ružić and Rajaković 1991

37 Zhuang 1990

38 Hillier and Lieberman 1990

A Lagrangian relaxation approach makes a mixed integer problem solvable by taking the troublesome constraints and putting them into the objective function.[39]

$$\min Z = \mathbf{ax}$$
$$\text{st: } \mathbf{Bx} \geq \mathbf{b}$$
$$\mathbf{Cx} \geq \mathbf{c}$$

Consider the problem above. All of the terms are conformable matrices, except for the value of the objective function, Z. The constraints to the problem have been partitioned such that the first set are the ones that make the problem hard to solve and remaining ones are easy. Since this problem cannot be solved as it stands, a Lagrangian relaxation approach places the troublesome constraints in the objective function.

$$\min Z = \mathbf{ax} + \lambda \cdot (\mathbf{b} - \mathbf{Bx})$$
$$\text{st: } \mathbf{Cx} \geq \mathbf{c}$$

By assumption, this problem is solvable, and since the vector λ is everywhere negative, the solution to this problem must be a lower bound on feasible solutions to the full problem. Adopting a Lagrangian relaxation approach leaves the modeler with three choices: 1. which constraints to relax; 2. how to find good values for λ; and 3. how to find feasible solutions to the relaxed problem such that the optimal solution to the full problem is found as quickly as possible. In production costing, the troublesome constraints are ones such as minimum uptime that involve several time

39 Fisher 1985

periods at once. Effective choices of multipliers have been marginal cost results from initial runs, and considerable debate surrounds the third question. This problem is mixed integer because the on-off decision for any one unit is a key decision variable, and one that has an important effect on costs. Such problems are notoriously difficult to solve in an efficient manner, and while the unit commitment problem was formulated in this way some time ago, the struggle to find efficient solution techniques is the subject of furious research.[40,41,42,43,44,45,46]

There is no one best approach, but a common approach involves solving the dual of the problem and using the multipliers found there as a starting point in an iterative solution of the primal problem. In a mixed integer problem, a positive duality gap is expected. Updating of the multipliers can be done by a subgradient method, or by an individual technique that treats violations of constraints unevenly.

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40 Aoki *et al* 1987

41 Bard 1988

42 Tong 1989a

43 Tong 1989b

44 Zhuang 1988

45 Ammons 1983

46 Ammons 1983

8. EEUCM

The EEUCM model has been built to employ a Lagrangian relaxation approach that incorporates all of the important operating restrictions, such as ramp rates, minimum up and down times, and spinning reserve requirements. Additionally, EEUCM has been constructed with environmental constraints directly employed to accommodate the simulation of control policies that involve emission limits over subperiods. Note, however, that EEUCM does not account for plant outages; it merely solves the unit commitment problem. The unit roster must be established by Monte Carlo sampling of the outage distributions in the standard manner.

IV. RESULTS

A. Project Summary

The incidence of the urban photochemical smog problem in most U.S. urban areas is quite localized and infrequent. The electric utility industry emits large amounts of NO_x, a key ozone precursor pollutant. Additionally, the unstoreable nature of electricity has required that the electric utility industry develop sophisticated methods and computer models for minimizing cost dynamically and coping with random system failures. This capability places the industry in the unique position of being able to respond to the need to control smog precursor emissions intermittently. The regulatory regime faced by electric utilities should create an environment in which this capability is used; that is, the unit commitment and dispatch decisions of a utility should take smog conditions into account.

The goal of this work is to explore the possible response of electric utilities to regulatory penalties on unit commitment and dispatch that would vary over time and place to reflect the variable favorability of local weather and topographic conditions to photochemical smog formation. A variable NO_x tax was quickly recognized as a particularly conceptual - ly attractive possible implementation of dispatch penalties. A variable NO_x tax can be readily incorporated into standard unit commitment and dispatch logic because its effect is so similar to traditional fuel cost minimization methods. Particularly, the shape of NO_x emissions functions is akin to input-output functions that relate energy inflows into boilers with power generated from an attached generator. This similarity makes the mathematics and implementation of a variable NO_x tax particularly straightforward. Capability to accommodate such a tax together with many other enhancements, including random generator failure, were added to the Economic Environmental Unit Commitment Model (EEUCM) electric utility production cost model.

To measure the effects of such a tax in practice, a fictitious utility based on power generation within the confines of the Bay Area Air Quality Management District (BAAQMD or District) jurisdiction was developed and simulated using EEUCM for a smog episode in September 1989. This system, BAPS, consists of most of the power generation within the District, which is dispatched to meet a load that approximates PG&E customer demand in the District.

The resources within this boundary consist of PG&E's steam plant, 16 sizeable QF's, and some smaller ones. The resources of the municipals were excluded from the analysis. Although it lies outside BAAQMD jurisdiction, PG&E's Moss Landing station was included because of its importance to the PG&E system, because it represents a major supply resource to the Bay Area, and because it forms a significant emissions point source that lies within the UAM modeling domain of the District. The data for all these resources appears in Appendix C. Electricity demand with the District was isolated by selecting a subset of PG&E's transmission planning area data sets. These data were carefully manipulated to create a within District load profile for 1989. The somewhat involved process by which this was done is described in Appendix A.

The fictitious BAPS was modeled using a Lagrangian relaxation unit commitment model EEUCM. This model was made available for use in this project by its developer, Prof. Terje Gjengedal at the Norwegian Institute of Technology, Trondheim. EEUCM is a research grade deterministic unit commitment and dispatch model that takes no account of random unit outages. Since expected results are more relevant to policy work, a system of Monte Carlo random outage draws was developed for use in this work and was implemented into EEUCM. The procedure for this considerable model enhancement is described in Appendix F. Typical runs of EEUCM involve 100 outage draws which incurs a computing burden that is costly but certainly not unreasonable.[1]

The NO_x tax was implemented directly into EEUCM. Some cursory research into the shape of NO_x emissions curves showed that emissions

1 Running EEUCM for BAPS for one week making 100 outage draws requires approximately one hour of cpu time on a Sun ELS workstation rated at 3.5 Mflops.

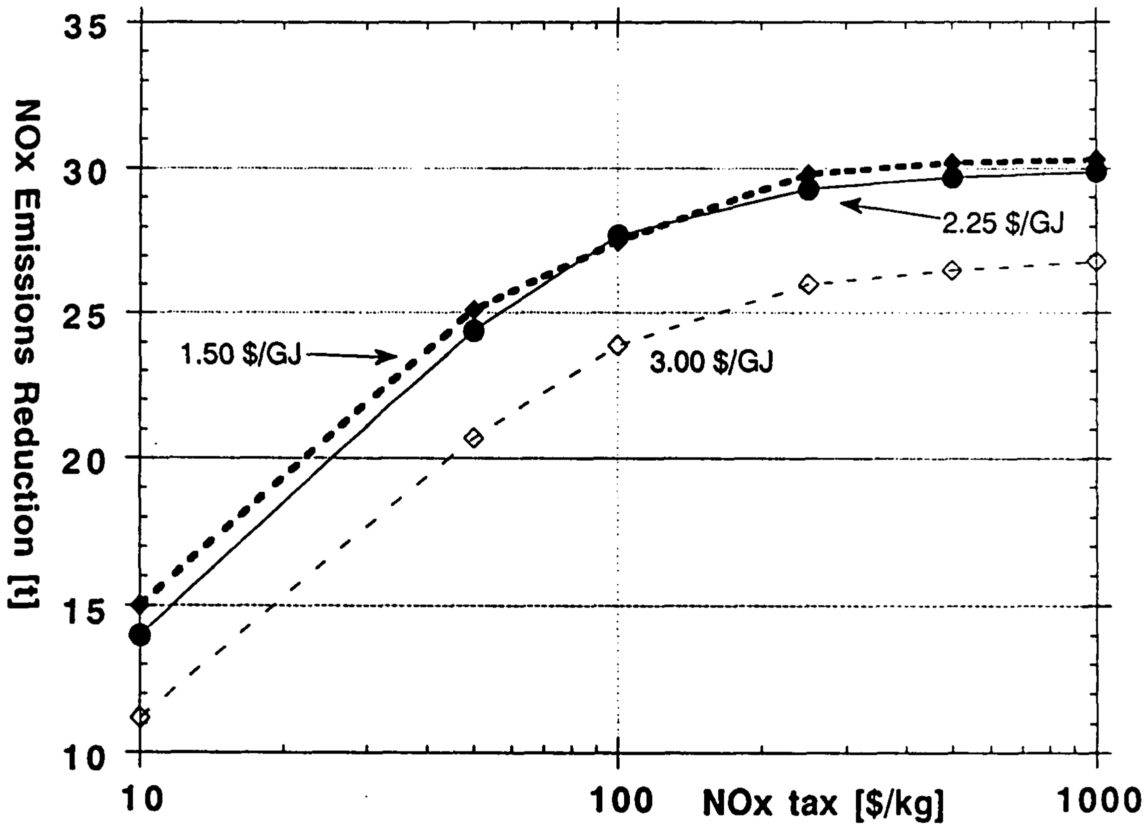
can be treated in a manner parallel to fuel costs and that the NO_x tax can be incorporated directly into the unit commitment and dispatch. The primary requirement for this approach to work is that the NO_x emissions curves be monotonically increasing and convex to the x-axis. The available evidence suggests that these conditions are met. A worked example of how such a NO_x dispatch works appears as Appendix B. The process by which the actual NO_x curves used in this analysis were developed is described in Appendix D. By incorporating the NO_x dispatch directly into EEUCM, the unit commitment and dispatch are totally reoptimized to reflect the effect of the tax on BAPS. Also, estimates of NO_x emissions are derived directly from the NO_x curves and are, therefore, much more realistic than back-of-the-envelope estimates that do not take account of changes in the unit commitment and dispatch brought about by the existence of the tax.

Historic air quality data from the Livermore monitoring station was used as the basis for estimating a suitable NO_x tax. The analysis of this historic data together with an explanation of how the tax was actually calculated appears in Appendix E. The tax changes through time to reflect the changing sensitivity of the local surface atmosphere to NO_x emissions. A marker tax rate was chosen and the tax defined at this point. For most of the analysis presented here that marker level was 0.1 ppm of ozone. Tax rates quoted as $/kg are the rates at this concentration. The rates are proportional to the ozone concentration with a fixed floor below which the tax cannot fall during an episode. The floor is typically set at one tenth of the marker tax rate.

B. Basic Results

Figure IV.B.1 shows some basic results for the episode week of 11 - 17 September, 1989. The x-axis shows the tax rate at the marker con - centration, and the y-axis the tons of NO_x emissions avoided for the week. The three curves represent three natural gas prices. The 2.25 $/GJ curve serves as the base case. Emissions reductions are quite dramatic at low tax rates, but the elasticity of emissions to the tax rate falls off sharply and over 90 % of the potential Emissions reduction is captured by a tax of 100 $/kg. The sensitivity using a lower fuel price of 1.50 $/kg produces similar results, but the higher fuel price results in lower emissions reductions across the board. The reason for this effect is that the higher fuel price case results in lower emissions, and there - fore, the potential of taxes to further reduce emissions is restricted. In fact, overall emissions are lower at every tax level under the higher gas price. This provides an interesting result, namely that higher gas prices encourage lower emissions. The reason for this effect, although it has not be investigated in detail, is probably that the higher gas price results in increased use of the cleaner resources.

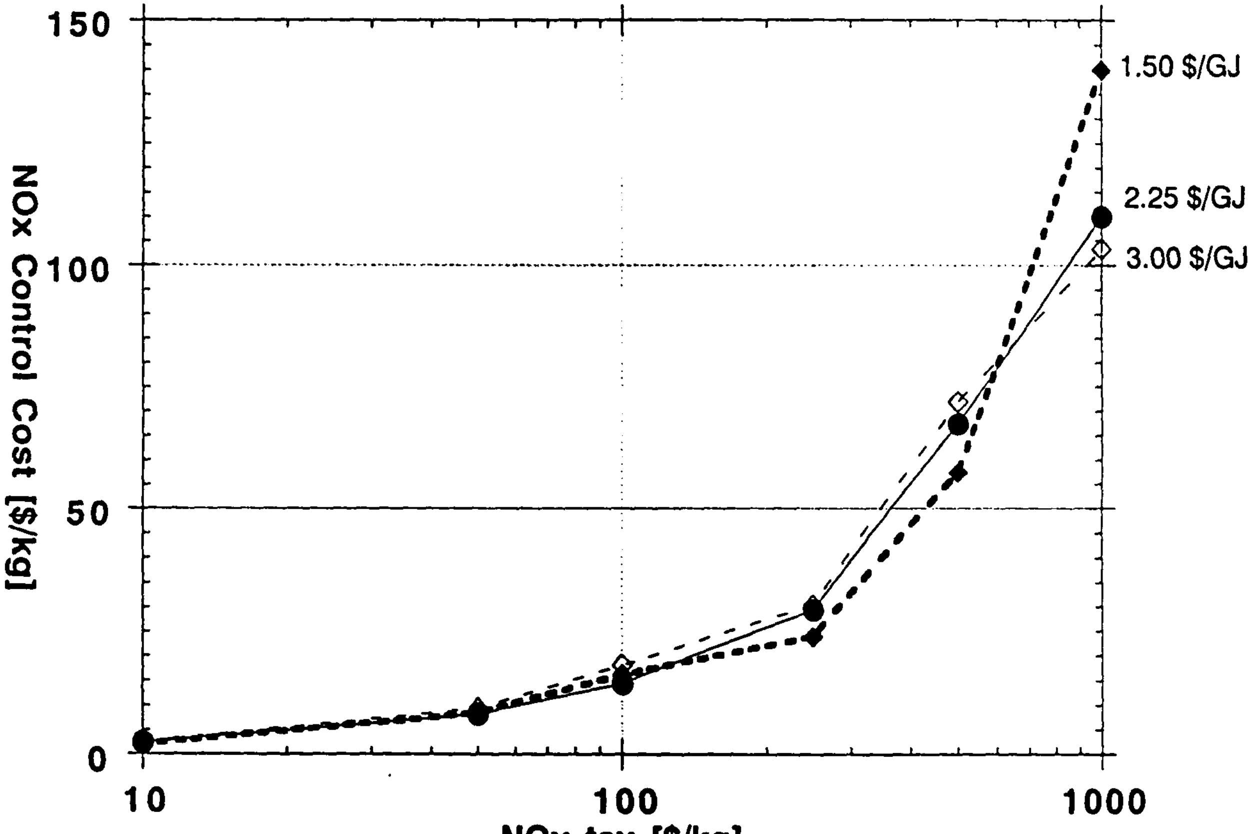
Sensitivity of NOx Emissions Reductions to Gas Price - 11-17 Sept. 1989



source: EEUCM simulation

Figure IV.B.1

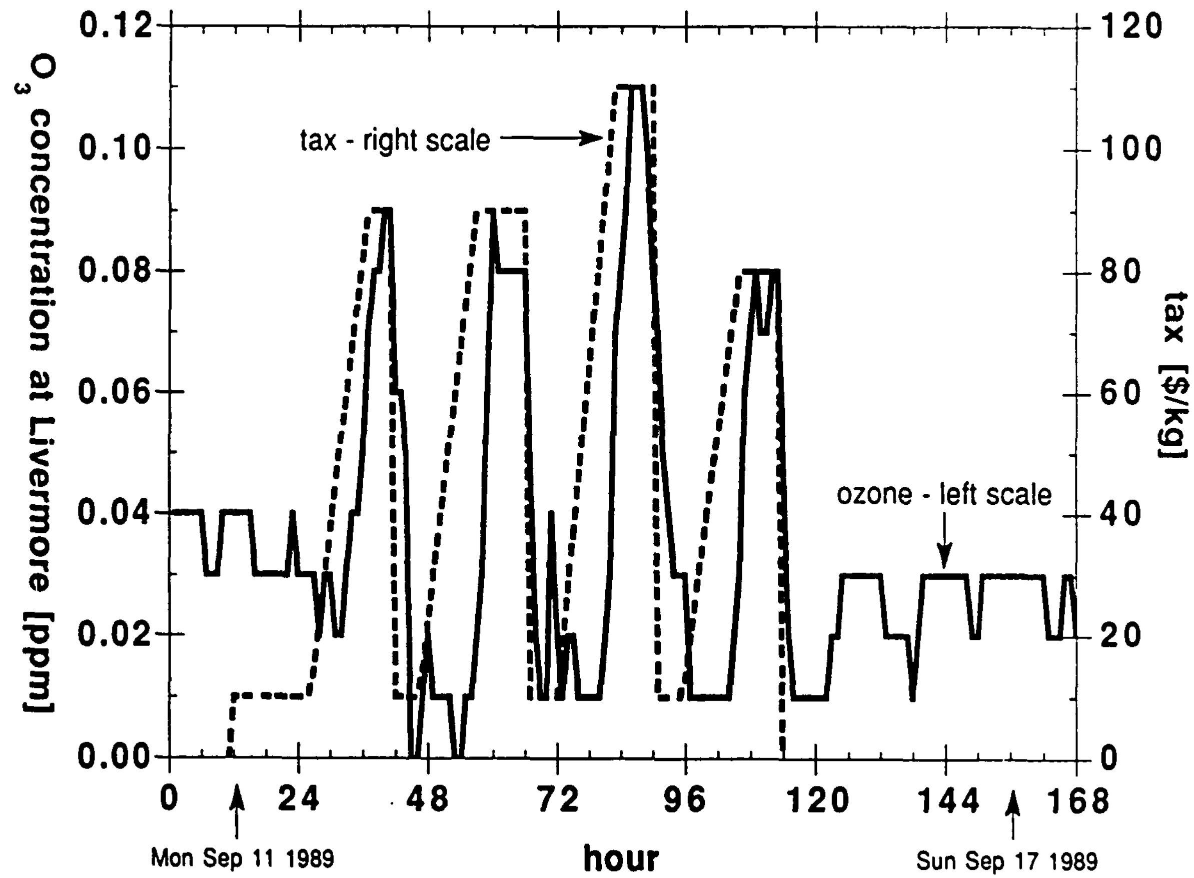
Sensitivity of NOx Emissions Reductions to Gas Price - 11-17 Sept. 1989



source: EEUCM simulation

Figure IV.B.2

Ozone Concentration at Livermore and NOx Tax
11-17 Sept. 89



source: CARB and tax program

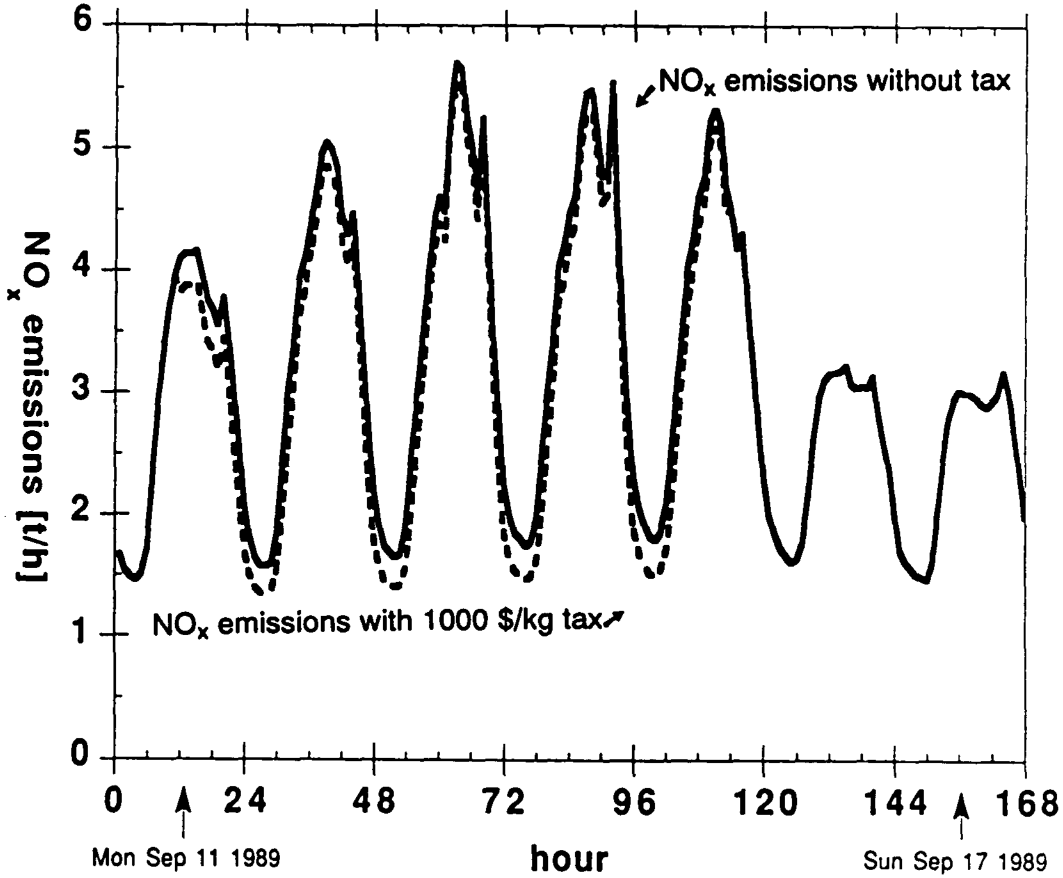
Figure IV.B.3

Figure IV.B.2 relates these emissions reductions to the increased fuel cost incurred. Again the three fuel price cases are shown. The y-axis now shows the NO_x control cost implied by the previous results. The notable feature of these results is that modest emissions reductions are achieved at low control cost, but control costs increase dramatically at higher tax levels. Selective Catalytic Reduction (SCR), the current California Best Available Retrofit Control Technology for steam boilers, can provide some perspective on the magnitude of these control costs. Assuming a 50-day smog season, the lowest realistic cost per episode day ton of NO_x controlled by SCR in the District is in the 50 \$/kg range. That is, all of the control below the 50\$/kg line could be interpreted as *prima facie* economic.[2] This preliminary evidence, then, suggests that a modest variable episode NO_x tax in the 100-500 \$/kg range may make good economic sense, although the impact of such a tax on total emissions and, therefore, air quality would not be dramatic by any means.

Consider now, figure IV.B.3, which shows the pattern of the NOx tax during this week. The figure shows both the hourly ozone concentration at Livermore, and the tax derived from it. As mentioned above, the tax comes on Monday, and remains in effect through the episode. The level of the tax precedes the ozone concentration by an assumed lag

2 Note, however, that in section II.C, choosing between SCR and the taxed dispatch does not result in the minimum control cost because other technologies may be economic for certain units.

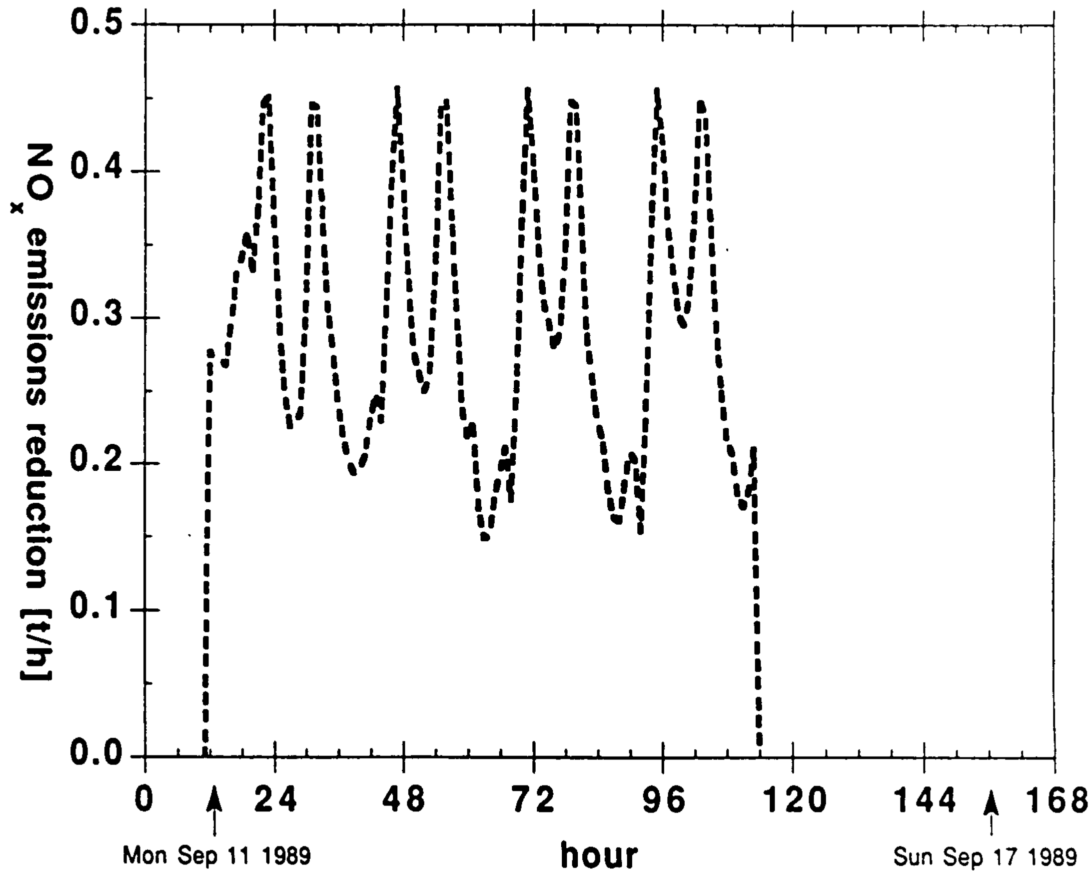
Total Hourly BAPS NO_x Emissions
11-17 Sept. 89



source: EEUCM simulation

Figure IV.B.4

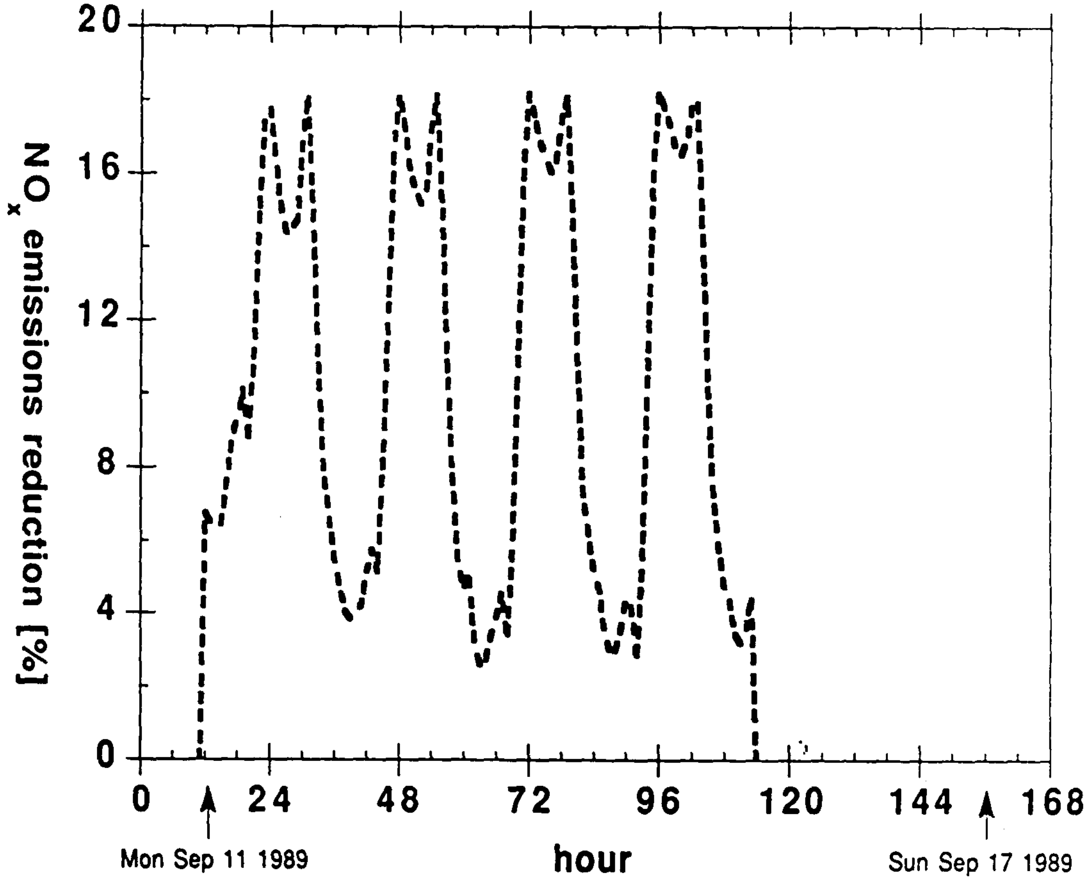
Total Hourly BAPS NO_x Emissions Reductions
11-17 Sept. 89



source: EEUCM simulation

Figure IV.B.5

Percent Hourly BAPS NO_x Emissions Reductions
11-17 Sept. 89

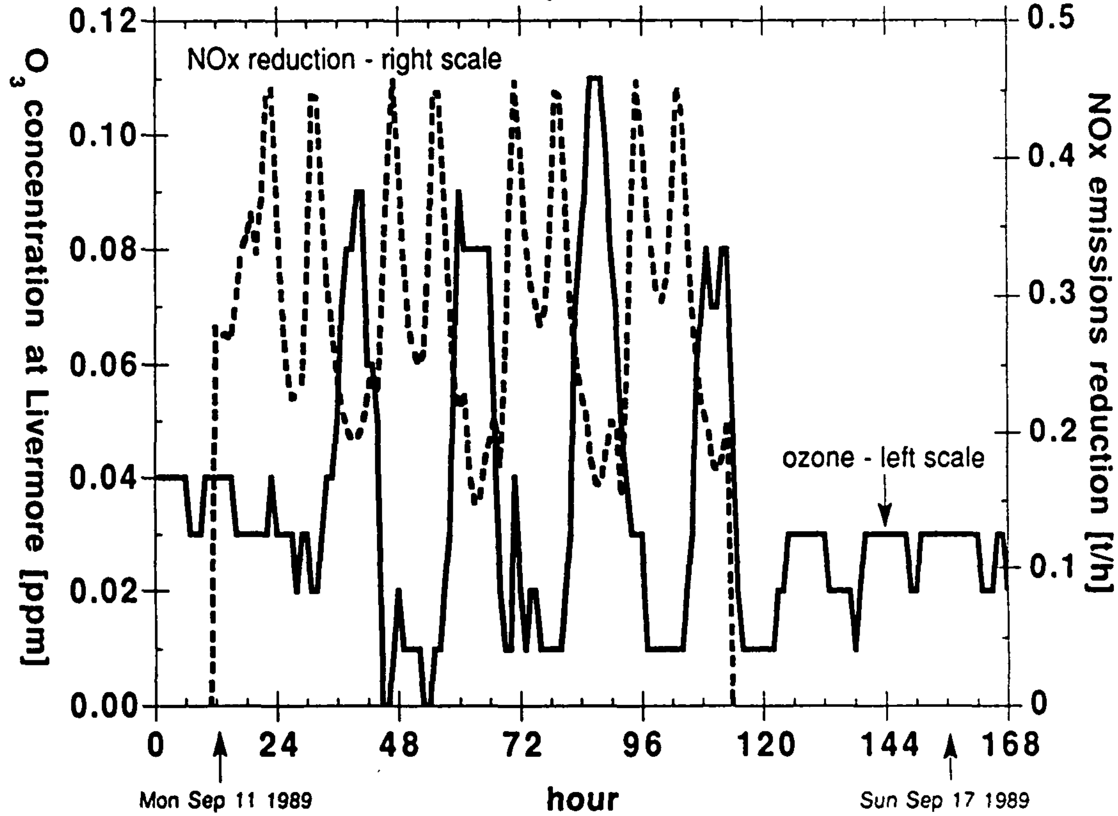


source: EEUCM simulation

Figure IV.B.6

Ozone Concentration at Livermore and NO_x Emission Reduction

11-17 Sept. 89



source: CARB and EEUCM simulation

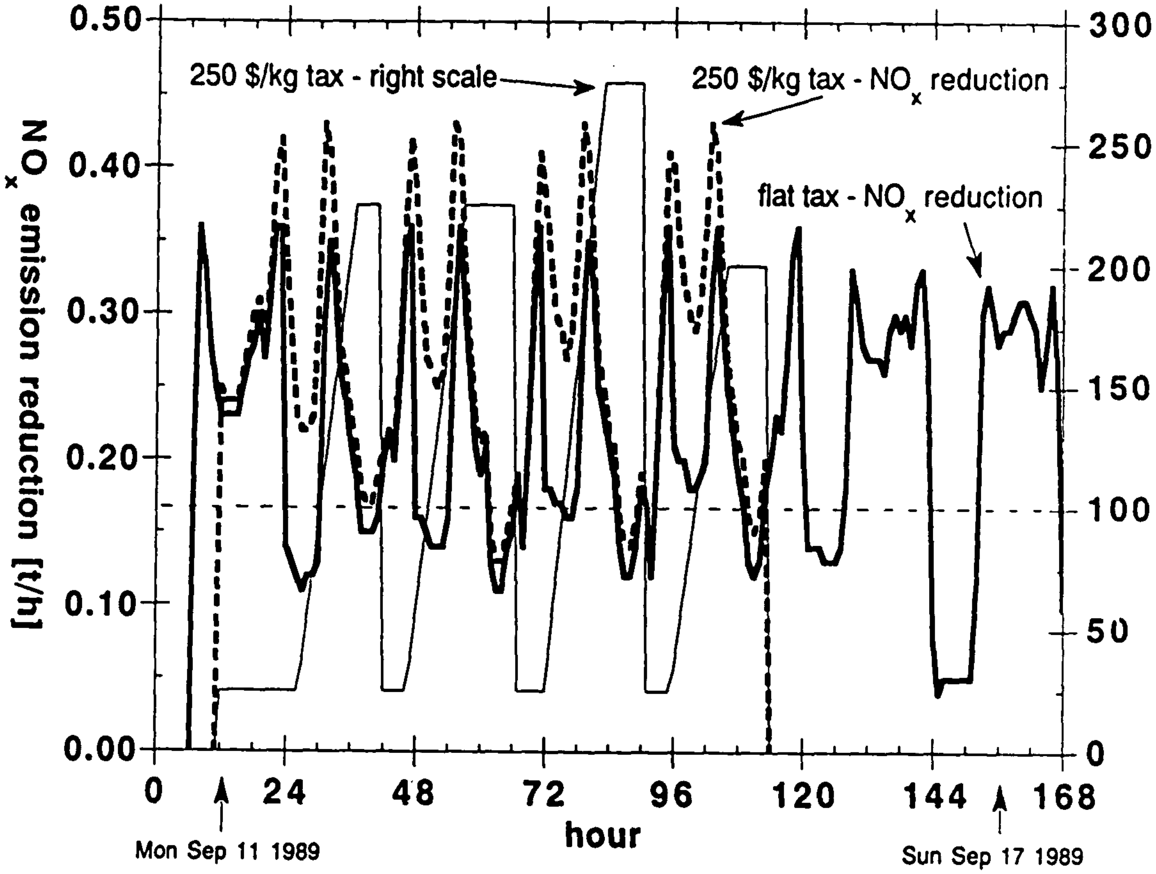
Figure IVB.7

of 3 h. Figure IV.B.4 shows the effect of the maximum tax, that is 1000 $/kg. The results are *prima facie* sensible. When the tax comes on, emissions fall and remain below the base case until it is turned off. Visually, it seems that the biggest impact of the tax occurs, surprisingly, when the level of the tax is lowest, that is, at night. The following two figures, IV.B.5 and IV.B.6, show these results in terms of mass of emissions avoided, and as a percentage of total emissions. The patterns are similar.

Referring to figure IV.B.5, emissions are clearly reduced most during the nighttime hours. In fact, the nighttime period contains two reductions peaks, one around midnight, and the other during the morning hours. Reductions in the afternoons are low, falling to a minimum that is only one third of the maximum. The most encouraging aspect of these results is the morning hour reductions. Given the lag in the atmospheric chemistry, reducing emissions during the morning hours should have a beneficial impact on afternoon ozone concentrations.

Figure IV.B.7 presents the ozone concentration data and the NO_x emissions reductions data together. The ozone data are the hourly observations at Livermore shown on the left scale, and the NO_x reductions data are the same as appear in figure IV.B.5. This plot shows that the peak emissions reductions achieved during the morning hours

NOx Emissions Reductions Under Flat $100 and $250 NOx Taxes - 11-17 Sept. 89



source: EEUCM simulation

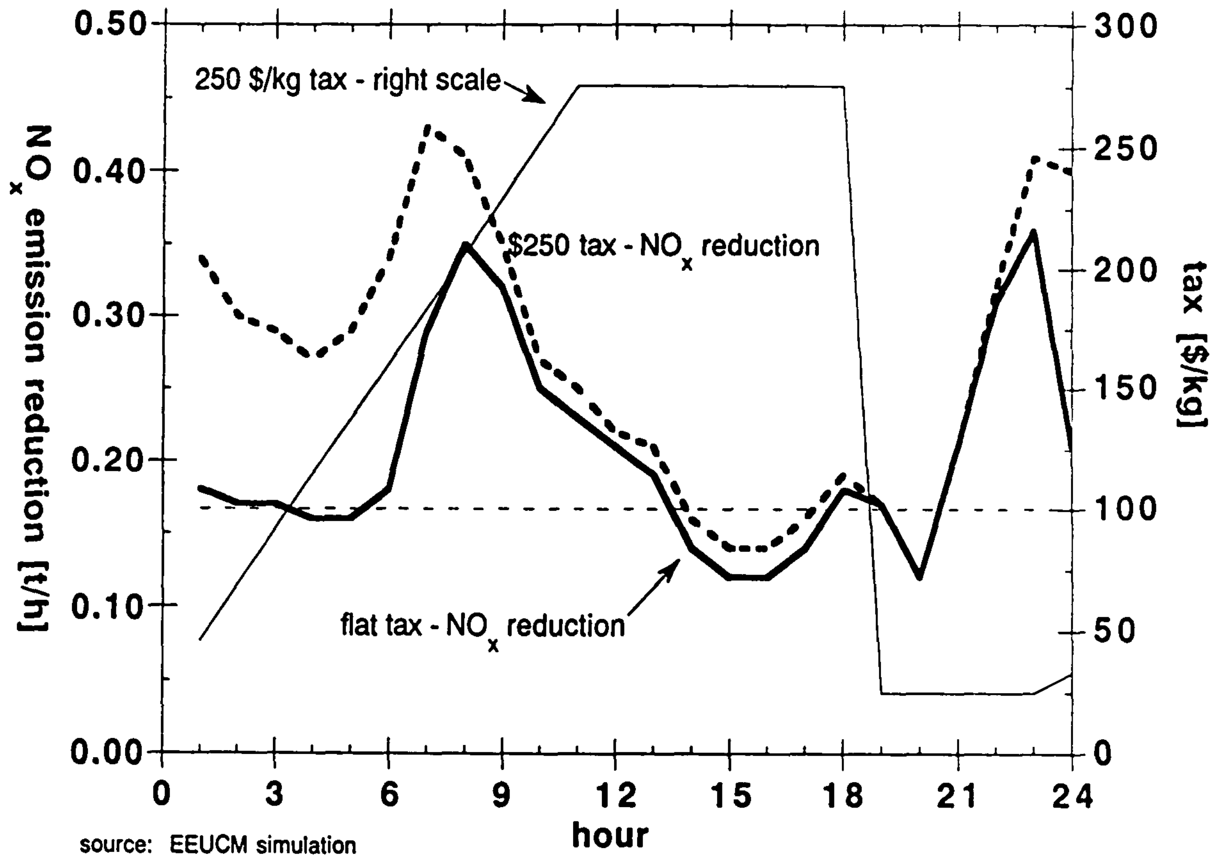
Figure IV.B.8

occur several hours in advance of the afternoon ozone peak. Remembering that the source of the tax imposed was the ozone concentration lagged by 3 hours, the dissimilarity in the patterns of the two plots is striking.[3]

The insensitivity of on-peak emissions to the tax suggests a sensitivity case in which the tax imposed does not vary over time. The results of such a sensitivity case are shown in figure IV.B.8. The two thin lines show two tax schemes. The first is of the same type described above, namely variable following the ozone concentration according to the procedure laid out in appendix E. This is the type of tax originally proposed. In this instance the tax rate at the marker concentration is 250 $/kg. The second tax is a simple 100 $/kg for all hours of the week. The two thicker curves show the relative NOx reductions of the two tax schemes. The dotted curve has the same pattern as described previously, although the emissions reductions are somewhat smaller than seen at the 1 000 $/kg level. Unlike the emissions reductions resulting from the variable tax, those resulting from the flat tax persist through the period. Further, as anticipated, the on-peak reductions are similar in both cases. The flat tax results in a similar twin-peaked nighttime NOx reduction pattern.

3 The derivation of the tax rate is explained in detail in appendix E, and actual tax rates appear as table E.2.

NOx Emissions Reductions Under Flat $100 and $250 NOx Taxes - Thurs. 14 Sept. 89



source: EEUCM simulation

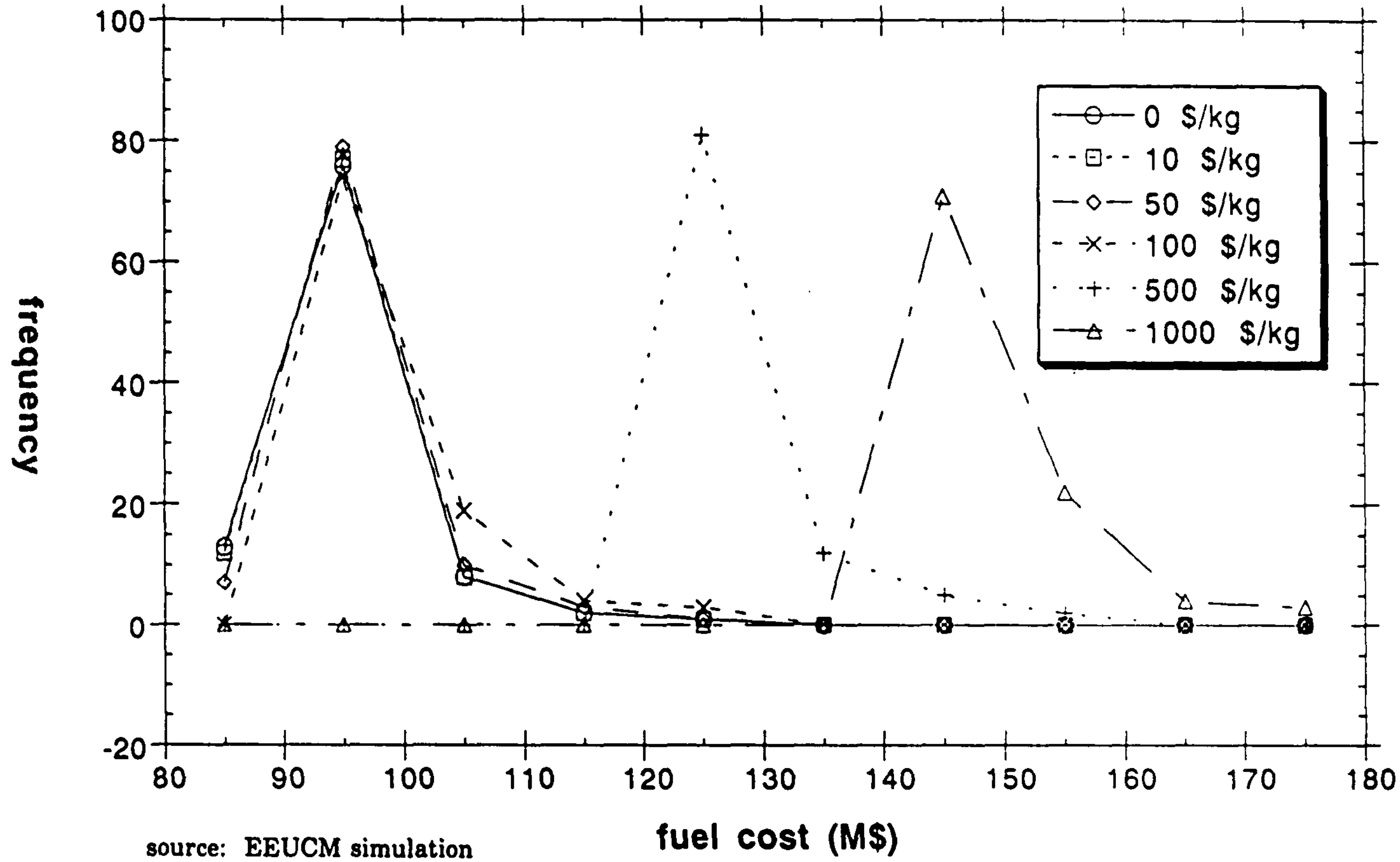
Figure IV.B.9

Figure IV.B.9 shows the thursday of the episode week in closer detail. All the curves are as before. The insensitivity of emissions reductions to the two taxes is quite clear in this graphic. The one surprising feature occurs in the very early morning hours. The variable tax rate falls below the 100 $/kg flat tax rate at 3:00 h, yet the emissions reductions of the higher tax not only remain above those of the flat tax, but the gap between them is actually larger to the left of 3:00 h than at any other time during the day. This seemingly anomalous result probably comes about because of unit commitment effects. Under the variable tax regime, different units tend to be run during the night. The cleaner ones would naturally be favored because of their benefits later in the day when the tax is in effect. This result shows the potential benefits of using a full-blown unit commitment and dispatch approach because it is exactly the sort of effect that would be lost by a simpler model.

C. Variance Results

Figures IV.C.1 and figure IV.C.2 demonstrate the most insightful results so far encountered in this work. One of the key justifications for using a Monte Carlo approach is that an entire distribution for the output results can be readily obtained. As mentioned above, EEUCM is not a probabilistic model, but rather it assumes all units to be perfectly reliable for the duration of the simulation. Considerable effort was

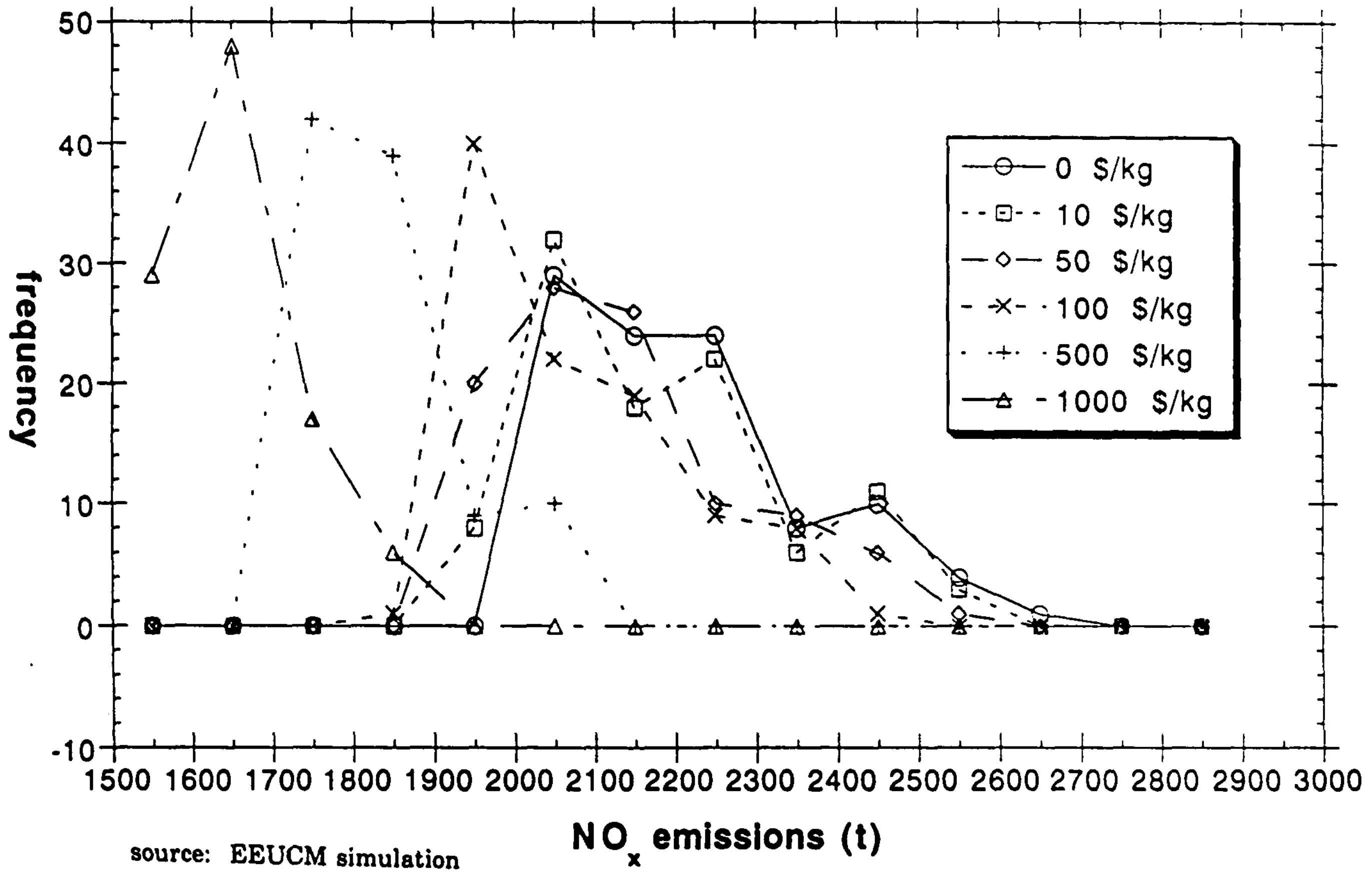
Histogram of Fuel Cost Distributions Sept. 89



source: EEUCM simulation

Figure IV.C.1

Histogram of NO_x Emissions Distributions Sept. 89



source: EEUCM simulation

Figure IV.C.2

expended during this project to implement a Monte Carlo random drawing scheme into EEUCM. The return on that effort is exactly the curves seen in the two figures.

Figure IV.C.1 shows the fuel cost results for a simulation run for all of September 1989. Some of the assumptions are different to those in the other cases reported above, so the results are not exactly comparable, but these curves are useful to demonstrate the key result. Each curve shows bined data from the 100 Monte Carlo iterations of these runs. As the tax rate is increased, the distributions move to the right. This increase in fuel cost is exactly the control cost for the NO_x emissions reductions achieved. The difference in total fuel cost divided by the NO_x emissions reductions achieved is precisely the control cost of the taxed dispatch. Now consider figure IV.C.2, which shows the equivalent curves for the total NO_x emissions during the simulation period. Re - member that all the outputs from a production cost modeling exercise are random variables. These curves show the distributions of these two random variables. NO_x emissions fall as the tax is increased, but, in stark contrast to the fuel cost distributions, these change shape signifi - cantly. Most importantly, the curves become much tighter, that is, the variance of the distributions falls, and quite dramatically. The 0 $/kg curve actually has a variance more than 5-fold that of the 1 000$/kg curve, although the difference in their means is only about 500t. How should this effect be interpreted?

Notice first that the shape of the NO_x curve tends towards that of the fuel cost curves when the tax increases. Intuitively, this makes sense. Since in the 0$/kg the tax has no effect on the unit commitment and dispatch, the NO_x emissions that result are merely accidental. The focus of the optimization is squarely on the fuel cost and nothing else. However, as the tax increases, the importance of the tax in unit commitment and dispatch decisions increases, and eventually rivals that of the fuel cost. It is not surprising then that at high tax levels the two curves start to look alike, because the two costs are being considered in the same manner.

This effect of a falling variance of emissions under increasing taxes has an important policy interpretation. Under current regulation, which requires that specified control equipment be installed on stacks no tax is charged. Emissions are lowered by requiring increasingly cleaner equipment be used. If such an approach were applied to BAPS, the result would be to move the entire NO_x emissions distribution to the left, but not to change its variance, just as the fuel cost moves to the right and yet does not change it shape. The policy interpretation of such a move is that even after the control equipment is in place, the risk that emissions will be different from their expected value remains similar.

Now consider the tax scheme presented in figure IV.C.2; when the tax is increased, the risk of emissions during an actual episode deviating from the expected value becomes significantly lower. To the policy-maker, this says that the existence of the tax has an added benefit beyond the actual emissions reductions it evokes themselves. The nature of that benefit is that the risk of things being worse than expected during an episode is reduced.

D. Capacity Factor Result

The description of NO_x curves in chapter II and appendix D compared the likely shapes of the two curves. An important difference between the two is that NO_x curves are more convex at power outputs close to full load. In other words, if there is a NO_x tax in place, the incremental tax cost will rise more steeply at high power output than the incremental fuel cost. Compared to results without a NO_x tax, therefore, the taxed dispatch should show a tendency to use units less near to full load. This, in turn, would suggest lower CF's on heavily used units and higher CF's on less used units, or a decrease in the variance of CF's.

Table IV.D.1 shows the unit CF's for the same run that is the basis of the UAM results reported in the next section. The first two columns show the names and nameplate capacities of the units. The third

Table IV.D.1

Comparison of Capacity Factors and Emissions for all BAPS Units

unit	cap.	ecap	eprod.nt	eprod.tx	cf.nt	cf.tx	change	eemis.nt	eemis.tx	change
	MW	MW	GWh	GWh	%	%	bef-aft	t	t	bef-aft
CONTRCS1	116	58	0.377	0.791	27	57	30	0.399	0.651	0.252
CONTRCS2	116	93	0.580	1.272	26	57	31	0.499	0.897	0.398
CONTRCS3	116	81	0.503	1.114	26	57	31	0.443	0.811	0.368
CONTRCS4	117	82	0.774	1.167	39	59	20	0.580	0.848	0.268
CONTRCS5	115	92	1.046	1.361	47	62	14	0.736	0.946	0.210
CONTRCS6	340	340	6.100	5.780	75	71	-4	4.877	4.527	-0.350
CONTRCS7	340	306	5.094	4.929	69	67	-2	4.219	3.978	-0.241
HNTRSPT1	56	50	0.010	0.013	1.0	1	0	0.017	0.023	0.006
HNTRSPT2	107	86	0.520	0.518	25	25	0	1.116	0.880	-0.236
HNTRSPT3	107	107	0.552	0.602	22	24	2	1.191	0.932	-0.259
HNTRSPT4	163	147	2.079	2.392	59	68	9	1.244	1.427	0.183
MOSLNDG1	116	35	0.299	0.411	36	49	13	0.474	0.566	0.092
MOSLNDG2	116	81	0.428	0.888	22	46	24	0.540	0.915	0.375
MOSLNDG3	117	47	0.096	0.399	9	36	27	0.276	0.506	0.230
MOSLNDG4	117	94	1.444	1.252	64	56	-9	1.310	0.994	-0.316
MOSLNDG5	117	94	1.106	1.034	49	46	-3	0.994	0.827	-0.167
MOSLNDG6	739	665	14.595	13.394	91	84	-8	10.152	8.778	-1.374
MOSLNDG7	739	665	14.551	12.615	91	79	-12	11.144	8.661	-2.483
OAKLAND1	64	58	0.029	0.036	2	3	1.0	0.051	0.064	0.013
OAKLAND2	64	64	0.029	0.036	2	2	0	0.051	0.064	0.013
OAKLAND3	64	64	0.029	0.036	2	2	0	0.051	0.064	0.013
PITSBRG1	163	147	2.344	2.157	67	61	-5	2.495	2.225	-0.270
PITSBRG2	163	147	2.351	2.214	67	63	-4	2.415	2.218	-0.197
PITSBRG3	163	163	2.493	2.308	64	59	-5	2.542	2.260	-0.282
PITSBRG4	163	147	2.383	2.176	68	62	-6	2.508	2.215	-0.293
PITSBRG5	325	292	5.508	5.218	79	74	-4	3.981	3.671	-0.310
PITSBRG6	325	260	6.098	6.082	98	98	0	3.183	3.174	-0.009
PITSBRG7	720	504	8.646	9.710	72	80	9	3.284	3.782	0.498

PORTBLE1	15	10	0.000	0.000	0	0	0	0.000	0.000	0.000
PORTBLE2	15	15	0.000	0.000	0	0	0	0.000	0.000	0.000
PORTBLE3	15	14	0.000	0.000	0	0	0	0.000	0.000	0.000
POTRERO3	207	207	3.827	3.318	77	67	-10	2.845	2.434	-0.411
POTRERO4	56	45	0.062	0.087	6	8	2	0.110	0.155	0.045
POTRERO5	56	56	0.062	0.087	5	7	2	0.110	0.155	0.045
POTRERO6	56	50	0.062	0.086	5	7	2	0.110	0.154	0.044
GILROYE1	130	117	1.555	2.136	55	76	21	0.311	0.427	0.116
FSTRWLR1	100	100	2.400	2.400	100	100	0	0.792	0.792	0.000
DOWCHEM1	70	70	1.678	1.679	100	100	0	0.554	0.554	0.000
GWFPOWR1	53	53	1.270	1.271	100	100	0	0.419	0.419	0.000
GWFPOWR2	35	35	0.838	0.839	100	100	0	0.276	0.277	0.001
CARDINL1	50	50	1.198	1.199	100	100	0	0.395	0.396	0.001
UNIONSF1	50	45	1.078	1.079	100	100	0	0.216	0.216	0.000
GAYLORD1	50	45	1.078	1.079	100	100	0	0.356	0.356	0.000
OLSHOSP1	36	36	0.862	0.863	100	100	0	0.284	0.285	0.001
CONTNER1	36	36	0.862	0.863	100	100	0	0.284	0.285	0.001
UNTCOGN1	30	30	0.718	0.719	100	100	0	0.237	0.237	0.000
UNIONRO1	27	24	0.581	0.582	100	100	0	0.192	0.192	0.000
OLSBERK1	26	26	0.624	0.624	100	100	0	0.206	0.206	0.000
ALTAMNT1	13	13	0.312	0.312	100	100	0	0.103	0.103	0.000
FAYETTE1	7	7	0.168	0.168	100	100	0	0.055	0.055	0.000
CATLYST1	6	6	0.144	0.144	100	100	0	0.047	0.047	0.000
OTHRBIO1	27	27	0.648	0.648	100	100	0	0.214	0.214	0.000
OTHRGAS1	11	11	0.264	0.264	100	100	0	0.087	0.087	0.000
IMPORT01	0.000	0	0.000	0.000	0	0		0.002	0.015	
UNSRVNGY	0.000	0	0.000	0.000	0	0		0.004	0.017	

column shows the expected available capacities for this run. Where the expected and nameplate capacities are identical, as in the case of CONTRCS6, it implies that this unit was available in every outage draw of the simulation. Where the expected capacity is lower than the nameplate capacity, the unit has been on outage during at least one of the draws. The next two columns show the energy output of each unit in a no tax case and in a 1 000$/kg case, the next two columns show the CF's. These are the CF's relative to the expected capacity, not the more usual CF's relative to nameplate capacity. Since these CF's show how much the unit ran relative to how much it was available, they are more useful indicators of the attractiveness of each unit to EEUCM.

At first glance, the results confirm expectations. Little used units such as CONTRCS1-3 and MOSLNDG1-3 have increased cf under the tax case, while the CF's of heavily used units, such as MOSLNDG6 & 7, fall. That is, EEUCM has attempted to run more resources nearer to the mid-range of power output, where average emissions are lowest. If this is not clear, reconsider figure II.D.4, which shows that the steep slope of the NO_x curve out near full load will tend to make the point of equal incremental cost occur in the mid-range of output. The cf increases for CONTRCS1-3 are particularly dramatic, rising from 26 and 27 % to 57%. The falls in CF's are smaller, but given the large size of the most energy efficient units, the reduction in energy output from them is significant.

The *bef-aft* column shows the difference in cf results. Since low CF's increase and high ones decrease, the variance of CF's would be expected to fall and, indeed, it does from 1474 to 1281.

There are two notable exceptions to the overall effect that units' CF's tend to bunch up in the tax case, PITSBRG6 & 7. However, the explanation of this outcome is straightforward. Remember that the effect under scrutiny in this section is only a secondary effect. Given units equal in other respects, in the tax case, they should tend towards more evenly distributed CF's. However, units are not at all equal in other effects, and, indeed, the first order effect is that clean units should be favored over more polluting ones. Not surprisingly, therefore, PITSBRG6 & 7 are among the least polluting of the steam units available, especially PITSBRG7, which has an average externality of only 0.338 kg/MWh in this simulation. By comparison, the other two large units MOSLNDG6 & 7 have externalities of 0.758 and 0.883kg/MWh respectively.

While the qualitative result described above makes intuitive sense, some of its implications are surprising. Consider the remaining three columns of table IV.D.1. They show the physical NO_x emissions from each unit and the differences between the with and without tax cases. The signs of the changes observed are as expected because they almost all follow the changes in the CF's, although they do necessarily need to do so because a unit may be committed and dispatched differently in each case. In general, the falls in emissions from the units that are cut back are proportionally similar to the fall in energy output, although somewhat larger, as would be expected. For example, MOSLNDG7 GWh output falls by 13% and the NO_x emissions fall by 22%. Conversely, the units that produce more electricity emit more NO_x, although proportionally less so. For example, while the generation of CONTRCS3 increases by 122%, the physical NO_x emissions increase by only 83%.

These results merely reconfirm that the NO_x tax dispatch is working correctly. EEUCM shifts generation to units that can provide it at a smaller emissions cost. However, the implication of the shift in generation is surprising. Under a NO_x tax dispatch, the emissions at dirtier units increases dramatically. Remarkably, three of the worst BAPS units, CONTRCS1-3, all increase their electrical output by over 100%, and the total NO_x emission of the three units increases by a staggering 76%. This result demonstrates how misguided a simple policy prescription might be. For example, in the absence of additional information, a reasonable sounding policy to encourage a low-NO_x dispatch might well include efforts to limit the use of units CONTRCS1-3, whose mean NO_x emissions are a high 0.918 kg/MWh in the no tax case, and encourage the use of the cleaner MOSLNDG6&7, whose emissions are 0.731 kg/MWh. Of course, EEUCM has shown us that the minimum cost policy is exactly the opposite.

Sobering as it is, there is no real mystery in this outcome. It merely shows that average emissions data are a poor guide to where the cheapest marginal reductions are to be found. Even though units like MOSLNDG6 & 7 are low emitters overall, when operating near to full power they are not, relative to units that may emit much more on average but are currently operating in the clean mid range of output.

One of the implications of the CF results is that capturing the potential benefits of a low NO_x dispatch would be extremely difficult under a command and control regime. Consider the attractiveness of a simple rule prohibiting the use of the most emitting units during episodes. Tempting as it may be to think that such a rule will result in lower emissions, this conclusion could to absolutely wrong, and a wiser policy might be to force greater use of the most emitting units.

E. UAM Results

The original intent of this work, as described in section I.C, was to directly inject the estimated stack NO_x outflows into the District's version of the UAM. This effort proved both demanding and disappointing. The point source input file to UAM is a huge file of approximately 10 Mb, and even though the District staff provided considerable assistance with running the model, changing such a file is not an insignificant task. An example of the input file together with more information about how it was manipulated appears in appendix H.

A key difficulty regarding the UAM point source input file is the nature of its format. Emissions of all pollutants at the hour together with specifications of stack dimensions occur in each block of data. There is not a one-to-one correspondence between the generators and stacks, and actually not between the generators and boilers. Table H.1 shows the assumptions that were made to identify a stack for the emissions calculated at the generator. This represents a large complication that was, in general, sidestepped in this work. However, since production costing optimizes the dispatch of generators, in practice the emissions may not fall into the neat correspondence implied by the NO_x functions used throughout this work. The convexity assumption, for example, may not hold.[4] However, NO_x functions have been used in this analysis in the same manner as they appear in CFM filings.

Another complication with the point source input files is that several occurrences of the same stack are possible. This capability of UAM was designed to permit multiple process emissions from the same stack, but it complicates identifying data in the file.

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4 The importance of this assumption is discussed in appendix D.

As a first test case, two UAM runs were made. The results appear in table IV.E.1 and figure IV.E.1. The stations are the monitoring stations within the modeling domain of the District. A full key to the names appears as table H.2. The hour column shows the hour that the highest ozone concentration was estimated by UAM. Since it is a two - day episode, the hour can exceed 24, if the highest observation occurs on the second day. The first four columns of data show the District's usual base case, known as baaqmd.788. The next two sets of data show two sensitivity cases. In the max.832 run, all the stacks within the District are changed to reflect emissions flows that might result if all of the units in the District were run at maximum power throughout the two - day episode. Note that Moss Landing was not changed from the as - sumptions embodied in the District's original point source input file. This simplification is merely to avoid having the work with the input file for outside the District, which would immediately double the work involved. In the min.831 case, all of the power plant emissions are eliminated completely from the input files. In other words, these two sensitivities represent polar cases. The maximum case is a worst case emissions scenario in which all units, whatever their norma duty cycle run at 100% CF. In the minimum case, all generators are shut down.

The results show modest changes in peak ozone. The only stations with concentration changes of > 0.004 ppm are Livermore, Oakland,

Table IV.E.1

Comparison of Peak Ozone Concentrations Under Various BAPS Emissions Levels

				Sept. 89 Episode				Chris Marnay		Nov-92		
			baaqmd.788				max.832				min.831	
station	hour	obs.	cell	ave.	hour	obs.	cell	ave.	hour	obs.	cell	ave.
BID	40	0.110	0.089	0.086	40	0.110	0.083	0.082	40	0.110	0.083	0.081
CON	41	0.100	0.085	0.083	41	0.100	0.084	0.082	41	0.100	0.086	0.084
FAI	38	0.100	0.094	0.090	38	0.100	0.093	0.088	38	0.100	0.094	0.090
FRE	15	0.110	0.094	0.095	15	0.110	0.093	0.093	15	0.110	0.097	0.097
GIL	41	0.130	0.104	0.099	41	0.130	0.103	0.099	41	0.130	0.103	0.099
HAY	19	0.110	0.085	0.084	19	0.110	0.085	0.082	19	0.110	0.087	0.085
LIV	40	0.110	0.109	0.111	40	0.110	0.108	0.109	40	0.110	0.111	0.116
LGA	15	0.090	0.103	0.107	15	0.090	0.101	0.105	15	0.090	0.103	0.107
MIN	42	0.140	0.129	0.123	42	0.140	0.128	0.123	42	0.140	0.129	0.124
MVW	16	0.070	0.095	0.096	16	0.070	0.094	0.094	16	0.070	0.097	0.097
NAP	40	0.080	0.083	0.082	40	0.080	0.083	0.082	40	0.080	0.083	0.082
OAK	38	0.040	0.048	0.054	38	0.040	0.047	0.053	38	0.040	0.051	0.058
PAT	41	0.120	0.118	0.117	41	0.120	0.116	0.115	41	0.120	0.121	0.121
PIT	41	0.100	0.092	0.086	41	0.100	0.088	0.080	41	0.100	0.090	0.083
RWC	40	0.050	0.088	0.088	40	0.050	0.087	0.087	40	0.050	0.091	0.091
RIC	40	0.060	0.058	0.062	40	0.060	0.057	0.060	40	0.060	0.058	0.062
ARK	38	0.040	0.054	0.054	38	0.040	0.054	0.054	38	0.040	0.055	0.056
SJO	39	0.090	0.090	0.095	39	0.090	0.088	0.093	39	0.090	0.090	0.095
SJA	16	0.110	0.104	0.103	16	0.110	0.102	0.101	16	0.110	0.104	0.103
SLE	18	0.040	0.068	0.070	18	0.040	0.067	0.069	18	0.040	0.068	0.074
SRA	16	0.080	0.063	0.064	16	0.080	0.062	0.064	16	0.080	0.061	0.064
SRO	40	0.060	0.075	0.074	40	0.060	0.075	0.073	40	0.060	0.075	0.073
SON	17	0.090	0.080	0.078	17	0.090	0.079	0.078	17	0.090	0.079	0.078
VAL	17	0.090	0.070	0.071	17	0.090	0.071	0.071	17	0.090	0.070	0.071
ALV	15	0.090	0.097	0.096	15	0.090	0.095	0.094	15	0.090	0.098	0.097
CAR	39	0.070	0.069	0.067	39	0.070	0.068	0.066	39	0.070	0.069	0.067
DVP	42	0.060	0.068	0.065	42	0.060	0.067	0.064	42	0.060	0.067	0.064
HOL	41	0.080	0.069	0.067	41	0.080	0.065	0.066	41	0.080	0.065	0.064
SAL	42	0.060	0.060	0.061	42	0.060	0.061	0.063	42	0.060	0.060	0.061
SRN	40	0.070	0.104	0.102	40	0.070	0.102	0.101	40	0.070	0.104	0.102
SCZ	40	0.060	0.066	0.066	40	0.060	0.065	0.066	40	0.060	0.066	0.066
VVL	39	0.100	0.092	0.094	39	0.100	0.091	0.093	39	0.100	0.091	0.093

PIN	42	0.080	0.079	0.077	42	0.080	0.086	0.080	42	0.080	0.078	0.077
REY	42	0.060	0.046	0.046	42	0.060	0.045	0.046	42	0.060	0.046	0.046
NHI	13	0.080	0.084	0.084	13	0.080	0.086	0.086	13	0.080	0.082	0.082
SAT	14	0.080	0.082	0.080	14	0.080	0.083	0.083	14	0.080	0.082	0.079
SAD	14	0.100	0.089	0.089	14	0.100	0.092	0.092	14	0.100	0.087	0.087
SAM	40	0.120	0.082	0.083	40	0.120	0.083	0.083	40	0.120	0.082	0.083
SAE	16	0.060	0.078	0.078	16	0.060	0.077	0.078	16	0.060	0.077	0.078
FOL	15	0.120	0.100	0.097	15	0.120	0.101	0.097	15	0.120	0.099	0.096
CIH	14	0.100	0.095	0.094	14	0.100	0.096	0.095	14	0.100	0.093	0.093
PLG	41	0.080	0.073	0.069	41	0.080	0.073	0.073	41	0.080	0.073	0.069
WLD	41	0.080	0.080	0.082	41	0.080	0.080	0.082	41	0.080	0.080	0.082
BRO	41	0.080	0.087	0.084	41	0.080	0.088	0.084	41	0.080	0.088	0.084
STM	39	0.090	0.094	0.092	39	0.090	0.094	0.091	39	0.090	0.094	0.091
STH	15	0.110	0.088	0.087	15	0.110	0.087	0.086	15	0.110	0.087	0.086
MOD	15	0.120	0.096	0.095	15	0.120	0.096	0.095	15	0.120	0.096	0.095
CRW	40	0.110	0.092	0.087	40	0.110	0.091	0.086	40	0.110	0.093	0.088
ROC	40	0.080	0.094	0.092	40	0.080	0.094	0.092	40	0.080	0.093	0.091

Paterson Pass, and Sacramento-Del Paso. The first three stations all register deteriorations in air quality, and they all lie roughly along a line running east from San Francisco to the eastern edge of the District, one of the worst areas of the District. The Sacramento station is the only one in the simulation that experiences an increase of > 0.004 ppm. Actually, these stations alone tell a large part of the overall story seen more clearly in figure IV.E.1. In this figure, stations that experience an increase in peak ozone of > 0.001 ppm as a result of reducing NO_x emissions are in square boxes, while stations with reductions of this magnitude are circled. Unmarked stations either are within ±0.001 ppm in each case, or there is no data.

The result is surprisingly clear cut, sites within the District, in general, do worse when emissions are reduced, while sites outside the District do better. In fact, almost all stations within the District experi - ence minor deteriorations in air quality when emissions are reduced. Surprisingly, given the concentration of steam generation around the Bay and in the Delta, the effect reaches all the way to the southern tip of the District, with even Gilroy registering a small deterioration.

Most stations outside of the District register small improvements in air quality, especially the ones in the Sacramento area. These results are somewhat disappointing in several ways. First, it appears that the NO_x quenching effect reaches all the way to the edge of the District,

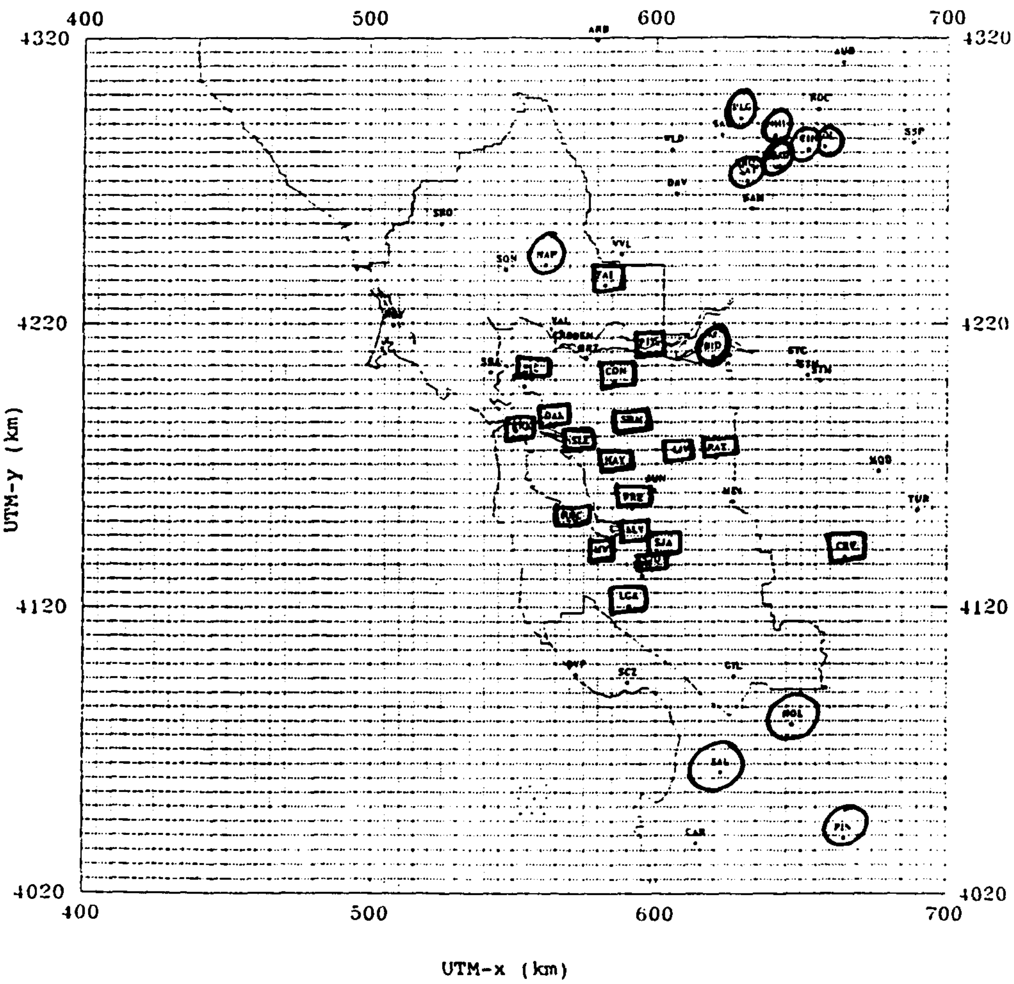
Table IV.E.2

Comparison of Peak Ozone Concentrations, Base and Policy Cases

	Sept. 89 Episode				Chris Marnay				Dec-92			
	baaqmd.788				base.833				policy.835			
station	hour	obs.	cell	ave.	hour	obs.	cell	ave.	hour	obs.	cell	ave.
BID	40	0.110	0.089	0.086	40	0.110	0.089	0.086	40	0.110	0.088	0.085
CON	41	0.100	0.085	0.083	41	0.100	0.085	0.083	41	0.100	0.085	0.083
FAI	38	0.100	0.094	0.090	38	0.100	0.094	0.089	38	0.100	0.094	0.089
FRE	15	0.110	0.094	0.095	15	0.110	0.096	0.097	15	0.110	0.096	0.097
GIL	41	0.130	0.104	0.099	41	0.130	0.103	0.099	41	0.130	0.103	0.099
HAY	19	0.110	0.085	0.084	19	0.110	0.087	0.085	19	0.110	0.087	0.085
LIV	40	0.110	0.109	0.111	40	0.110	0.110	0.115	40	0.110	0.110	0.115
LGA	15	0.090	0.103	0.107	15	0.090	0.103	0.107	15	0.090	0.103	0.107
MIN	42	0.140	0.129	0.123	42	0.140	0.129	0.123	42	0.140	0.129	0.123
MVW	16	0.070	0.095	0.096	16	0.070	0.096	0.097	16	0.070	0.096	0.097
NAP	40	0.080	0.083	0.082	40	0.080	0.083	0.082	40	0.080	0.083	0.082
OAK	38	0.040	0.048	0.054	38	0.040	0.050	0.057	38	0.040	0.050	0.057
PAT	41	0.120	0.118	0.117	41	0.120	0.120	0.121	41	0.120	0.120	0.120
PIT	41	0.100	0.092	0.086	41	0.100	0.092	0.084	41	0.100	0.092	0.084
RWC	40	0.050	0.088	0.088	40	0.050	0.090	0.090	40	0.050	0.091	0.090
RIC	40	0.060	0.058	0.062	40	0.060	0.058	0.062	40	0.060	0.058	0.062
ARK	38	0.040	0.054	0.054	38	0.040	0.055	0.056	38	0.040	0.055	0.056
SJO	39	0.090	0.090	0.095	39	0.090	0.089	0.095	39	0.090	0.089	0.095
SJA	16	0.110	0.104	0.103	16	0.110	0.104	0.103	16	0.110	0.104	0.103
SLE	18	0.040	0.068	0.070	18	0.040	0.068	0.073	18	0.040	0.068	0.073
SRA	16	0.080	0.063	0.064	16	0.080	0.061	0.064	16	0.080	0.061	0.064
SRO	40	0.060	0.075	0.074	40	0.060	0.075	0.073	40	0.060	0.075	0.073
SON	17	0.090	0.080	0.078	17	0.090	0.079	0.078	17	0.090	0.079	0.078
VAL	17	0.090	0.070	0.071	17	0.090	0.071	0.071	17	0.090	0.071	0.071
ALV	15	0.090	0.097	0.096	15	0.090	0.097	0.097	15	0.090	0.097	0.097
CAR	39	0.070	0.069	0.067	39	0.070	0.069	0.067	39	0.070	0.069	0.067
DVP	42	0.060	0.068	0.065	42	0.060	0.067	0.064	42	0.060	0.067	0.064
HOL	41	0.080	0.069	0.067	41	0.080	0.069	0.067	41	0.080	0.069	0.067
SAL	42	0.060	0.060	0.061	42	0.060	0.060	0.061	42	0.060	0.060	0.061

SRN	40	0.070	0.104	0.102	40	0.070	0.103	0.102	40	0.070	0.103	0.102
SCZ	40	0.060	0.066	0.066	40	0.060	0.066	0.066	40	0.060	0.066	0.066
VVL	39	0.100	0.092	0.094	39	0.100	0.091	0.093	39	0.100	0.091	0.093
PIN	42	0.080	0.079	0.077	42	0.080	0.078	0.077	42	0.080	0.078	0.077
REY	42	0.060	0.046	0.046	42	0.060	0.046	0.046	42	0.060	0.046	0.046
NHI	13	0.080	0.084	0.084	13	0.080	0.083	0.083	13	0.080	0.083	0.083
SAT	14	0.080	0.082	0.080	14	0.080	0.082	0.080	14	0.080	0.082	0.080
SAD	14	0.100	0.089	0.089	14	0.100	0.089	0.089	14	0.100	0.089	0.089
SAM	40	0.120	0.082	0.083	40	0.120	0.082	0.083	40	0.120	0.082	0.083
SAE	16	0.060	0.078	0.078	16	0.060	0.077	0.078	16	0.060	0.077	0.078
FOL	15	0.120	0.100	0.097	15	0.120	0.099	0.096	15	0.120	0.099	0.096
CIH	14	0.100	0.095	0.094	14	0.100	0.094	0.093	14	0.100	0.094	0.093
PLG	41	0.080	0.073	0.069	41	0.080	0.073	0.070	41	0.080	0.073	0.070
WLD	41	0.080	0.080	0.082	41	0.080	0.080	0.082	41	0.080	0.080	0.082
BRO	41	0.080	0.087	0.084	41	0.080	0.088	0.084	41	0.080	0.088	0.084
STM	39	0.090	0.094	0.092	39	0.090	0.094	0.091	39	0.090	0.094	0.091
STH	15	0.110	0.088	0.087	15	0.110	0.087	0.086	15	0.110	0.087	0.086
MOD	15	0.120	0.096	0.095	15	0.120	0.096	0.095	15	0.120	0.096	0.095
CRW	40	0.110	0.092	0.087	40	0.110	0.093	0.087	40	0.110	0.093	0.087
ROC	40	0.080	0.094	0.092	40	0.080	0.093	0.092	40	0.080	0.093	0.092

Figure IV.E.1: Effect of Reduced Power Sector NO_x Emissions on Peak Ozone at Monitoring Stations



source: UAM simulation

implying that NO_x emission reducing strategies will achieve no benefits to District residents, while, clearly, they will impose costs on them. Second, while there are apparent benefits in the Central Valley, espe - cially around Sacrament, since population densities are lower and the District's modeling domain does not cover the entire Valley, it is not possible to determine whether exposures are lower under the minimum case. Third, under the lower NO_x emissions case, conditions deteriorate at the District's Livermore area hot spot. In other words, the added pain is worst where it already hurts the most. A recently released study by the District on the effects of a non-utility boiler rule shows similar results.[5]

Finally, consider table IV.E.2. This table follows the format of table IV.E.1 and shows the results of attempting a more realistic comparison of cases. The baaqmd.788 case is the same as above, while the base.833 is one in which NO_x emissions from power plant stacks are replaced by the results of the EEUCM simulation of the episode days. The third case, policy.835, reports the results on the EEUCM with a tax in place. Disappointingly, the results barely differ. This outcome reconfirms the prior expectation that the current UAM modeling structure is too insensitive to enable translation of actual realistic policy cases into air quality effects. In other words, the results of the max.832 and min.831

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cases are about as useful as UAM results could be with respect to the problem at hand. They show the general direction of changes but numerically the results seem to show that net effects of any credible power sector policy, NO_x or other will be very small.

Ultimately, the goal of photochemical modeling should be to estimate the effects on human exposures of various policy scenarios. No attempt has been made here to convert the the predicted changes in ozone concentration into an exposure effect. There are two major reasons for the absence of such an analyis. First, the magnitude of effects is too disappointingly small to justify an exposure analysis. And second, and more important, the modeling domain of the District's version of the UAM is insufficiently large to capture the benefits of NO_x emissions reductions. Much of the improvements in smog might be expected to be deep in the south of the central valley. While population densities are lower in the areas that benefit from lower NO_x emissions, the area could be large, leading to a tradeoff the outcome of which is not easily guessed.

V. CONCLUSION

This project set out to determine whether biasing the dispatch away from the more polluting units in the Bay Area could result in reduced NO_x emissions during its intermittent episodes of poor air quality, and, if so, at what cost in terms of increased fuel burn.

The following hypotheses were set out in section I:

1. At an estimable cost, the dispatch of electrical generating resources in the Bay Area can be pushed away from the cost minimizing point such that the emissions pattern of NO_x is more environmentally benign.
2. Adjusting the dispatch in this manner can be a more cost effective method of improving air quality in the Bay Area than the imposition of physical controls on NO_x emissions from power generation.

Results regarding these two hypotheses are mixed. Regarding 1., it has been clearly shown that implementation of an intermittent NO_x emissions tax dispatch can be readily incorporated into traditional unit commitment and dispatch algorithms and production cost models. Applying the tax to the fictitious BAPS system using EEUCM success - fully shifts the dispatch away from the cost minimizing point, showing that an intermittent NO_x emissions tax is a particularly convenient biasing tool. Imposition of the tax lowers NO_x emissions modestly but at low increased fuel cost. However, using the UAM, it could not be shown that such a reduction is more environmentally benign, that is, that human ozone exposures are reduced. If large ozone reductions are simulated using UAM, peak ozone concentrations within the District are increased and those outside are decreased, resulting in no clear net improvement. Further, results from realistically sized emissions reductions result in no measurable ozone reductions.

Regarding hypothesis 2., the cost of modest NO_x emissions reductions are low compared to SCR, if the benefits are of the SCR are estimated over similar periods. However, in the test BAPS system, the NO_x emissions reductions were small, approximately 5% of the total during an episode week. The biased dispatch, therefore, can provide some initial low cost emissions reductions, but alone it is unlikely to provide adequate reductions to meet California Air Resource Board goals. A somewhat unanticipated benefit of the tax is that the variance of emissions is reduced. From a policy standpoint, this is an attractive feature of such a scheme because it implies expected emissions reductions will more likely be realized during future episodes.

Analysis of the 1989 air quality data from the Livermore monitoring station has shown that there are about 50 days/year in which the danger of an exceedence of the State of California ambient ozone standard is high enough to warrant influencing the dispatch. Analysis of data on the NO_x emission characteristics of PG&E and other units shows that emissions can be assumed to increase with load on the generator, and in a similar manner to the increase in fuel consumption. This has led to the development of a method for incorporating a biased dispatch into standard production costing algorithms.

Since there is a convenient parallelism between fuel costs and the imposition of a NO_x emissions tax, attention has focused on this convenient analysis approach to biased dispatch. Treatment of the tax in unit commitment and dispatch can then follow exactly the same procedures used to minimize fuel costs with the added complication that the tax must vary over time.

A Norwegian Lagrangian relaxation unit commitment and dispatch model, EEUCM, was used to test this approach. The NO_x emissions tax was incorporated directly into the model logic and the normally deterministic EEUCM was extended to permit Monte Carlo random outage draws. Data sets were built for the power generating system within the District, and it was run as an isolated system. While this is unrealistic relative to the way PG&E would actually run its system under a NO_x tax, it is a valuable exercise for studying in detail how operation of a thermal system would change under a tax regime. Simulations were run of the September 1989 episode that BAAQMD uses to test the effects of proposed rules.

The simulations show that the total potential NO_x emissions reduction possible during an episode is small, only about 4 % of total emissions. However, modest reductions in emissions can be achieved at low control costs compared to selective catalytic reduction (SCR), the currently mandated stack gas clean-up technology. Most of the benefits can be achieved with a tax that peaks at about 140 $\$_{1989}$/kg during the worst hours of the episode and varies during the other hours. At this tax rate, control costs average less than 20 $\$_{1989}$/kg, compared to over 50 $\$_{1989}$/kg for SCR.

In fact, the NO_x emissions reduction achieved is rather insensitive to the level of the tax, and a flat tax evokes a similar response in the dispatch. In other words, limitations on the flexibility of the system to respond to the tax appears to be a more powerful determinant of the magnitude of the response than the level of the tax.

The tax tends to change the dispatch in two ways. First, lower emitting units are favored over higher emitting ones. Second, because emissions increase with generator load, generation tends to be allocated more evenly across units, resulting in higher capacity factors on some units and lower ones on others. Since, many of the low capacity units are higher emitting ones, and *vice-versa*, these two effects work in opposite directions with some counter intuitive results. Notably, some units whose average emissions are high are used dramatically more when the tax is in place. This result suggests attempting to capture the potential benefits of a low NO_x dispatch using crude operating restrictions on units would be difficult in practice, and is unlikely to achieve the low cost NO_x reduction possible.

Finally, Monte Carlo results show that the variance of emissions falls as the tax is imposed and increased. This result has the important policy implication that when the tax is in place the risk of emissions exceeding their expected value as a result of the outage state of the system is lowered. That is, the existence of the tax provides an important benefit, even in the absence of actual NO_x emissions reductions.

In summary, results so far have shown that a biased dispatch is a viable policy to improve air quality, although the potential benefits are modest, and that unit commitment and dispatch simulation of a variable NO_x emissions tax is easily implemented.

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Chapter I. INTRODUCTION

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Chapter III. ANALYTIC TOOLS & METHODS

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Appendix A: Collecting Load Data for BAPS

1. introduction

This appendix describes the process by which a system hourly demand data set was estimated for the BAAQMD region. This power system, when isolated from the remainder of the PG&E planning area and the wider interconnected grid, serves as a test utility called the Bay Area Power System (BAPS). The full supply side data set of BAPS appears as appendix C.

A constant theme of this work has been the difficulty of reconciling the modeling and planning traditions of air quality researchers, who generally work with analysis boundaries that match the geographic boundaries of a region, with the traditions of utility analysts who usually draw their boundary around a utility territory, or family of territories. The difficulty of reconciling these two boundaries is nowhere more obvious than with regard to the problem of establishing a load data file that can reasonably represent the electrical consumption within the District's jurisdiction.

This clash of traditions has two levels, geographic and jurisdictional. The geographic level is self-explanatory; clearly, the boundaries of utility service territories in no way coincide with the political borders and topographic barriers that tend to define air basins and, subsequently, air quality modeling domains. With regard to the demand-side, this problem can be overcome, given sufficiently regionally disaggregated utility load data. Geography poses a bigger dilemma on the supply-side, because simulation of power generation, at least at the level typical of planning work, rarely pays more than cursory attention to the spatial distribution of generation. In fact, generally, the allocation of generation requirements to generating resources is usually done with no regard to geographic restrictions, such as transmission bottlenecks. When geographic considerations are considered, it is usually in an *ad hoc* fashion.

The second level of the problem, the jurisdictional one, presents the more difficult hurdle on the demand-side. The difficulty arises because several different types of regulatory jurisdiction co-exist within the outer geographic boundaries of a typical utility service territory. In the case of the Bay Area, by far the largest part, 85%, of total electricity consumption is recorded as sales by PG&E to ultimate customers under the jurisdiction of the CPUC. However, within the District, there are also municipal utilities, such as the City of Santa Clara; there are self-generators, such as the Shell refinery; there are direct sales from the Western Area Power Authority (WAPA) to customers, such as the Port of Oakland; there are deliveries to in District customers from their own out of District generation, such as the supply from the City of San Francisco's generation to the San Francisco Airport.

To paint a comprehensive picture of demand in the Bay Area, all of these complications would have to be resolved. However, for the purposes of this analysis, the problem can be dramatically simplified by an observation on the supply-side; namely, that PG&E and QF's that sell to PG&E operate almost all of the thermal generation in the District. That is, almost all thermal generation that is traded goes to serve PG&E customers. Thermal generation operated by self-generators that is not traded and thermal generation owned by municipal utilities are both limited and rarely used. Since treatment of non-thermal generation remains somewhat peripheral to the issue addressed here, a careful analysis of non-PG&E loads, while being interesting research, would be somewhat futile because virtually all of it is met with non-thermal generation outside the District. That is, in a comprehensive analysis, the non-PG&E loads would be carefully estimated and summed to PG&E's load, only for the matching non-PG&E generation to be subtracted again from the supply-side of the equation. Therefore, in this analysis, the estimation of customer demand focuses on PG&E customers. Non-PG&E non-QF generation, that is, thermal municipal generation and thermal self-generation, is excluded from the analysis. This approach represents a withdrawal from the regional approach but seems the best possible approximation, given the difficulties. Note that such an approximation would not be reasonable in other airsheds, where non-utility non-QF thermal generation is significant, SCAQMD being the obvious example.

The System that remains after these simplifications and approximations is called here the Bay Area Power System (BAPS). Given the crudity of the assumptions made and difficulty obtaining and massaging localized data, BAPS serves as a surprisingly useful test system. The use of actual Bay Area units rather than hypothetical ones adds a large measure of realism to the modeling and, more importantly, justifies the linkage of production costing to photochemical modeling.

2. TPA data

Requests were made to PG&E over an extended period for load data for the jurisdictional area of BAAQMD, as shown in figure G.1. For about a year, these requests were fruitless, but in PG&E's GRC filing for test year 1993, filed on 26 November 1992, PG&E introduced the concept of area specific marginal costing into ratemaking. PG&E argues in this showing that many of the important costs of meeting incremental load additions are transmission and distribution related, rather than generation related, and that these costs should be more accurately reflected in rates. PG&E proposes the estimation of localized costs based on its system of distribution planning areas (DPA's) and transmission planning areas (TPA's). From the starting point of the PG&E testimony, it became possible to identify a group of TPA's that roughly coincides with the BAAQMD territory, and, subsequently, to obtain the corresponding data from PG&E. These TPA's number 30 and are listed in table A.1. Three other TPA's that lie within the District, SFO3, SJO9, and SJO10, are not under CPUC jurisdiction and, therefore, PG&E has not developed load data for them. These three TPA's roughly coincide with demand from the City of San Francisco and the municipal utilities of Palo Alto and Santa Clara, respectively. These TPA's were totally excluded from this analysis. The City of Alameda municipal does not have its own TPA but is considered a part of ERB4. However, PG&E had already excluded the Alameda load from the data set supplied. That is, the *ERB4 TPA* used here is not consistent with the full PG&E TPA of the same name. Finally, the boundary of the District did not coincide well with the boundary of the VCV4 TPA, and so an assumption was made that one third of this TPA load lies within the District.

For the record, it should be summarized what steps would be necessary to expand the load shape into a true estimate of District demand. Hourly loads for the three municipals mentioned would have to be obtained and summed to the current shape. Estimates of City of San Francisco generation and imports would have to be developed and summed. And finally, other hourly inflows, most importantly WAPA direct sales to customers, would have to be estimated.

The supply mixes of the three Bay Area municipal utilities appear as table A.5. Clearly, thermal resources play a minor role in their supply mixes, and much of this thermal generation takes place outside the District, hence the decision to exclude them from the analysis. In fact, discussions with engineers at the municipals suggest that they view their thermal capacity, mostly in the form of recently installed combustion turbine capacity, as a means to cover non-firm purchases, which form a large share of their supply.

After considerable delay, PG&E did provide their data for the 30 listed TPA's in units of kW. Unfortunately, the data set was supplied in the inconvenient format shown in figure A.5, and was supplied without documentation. The 30 TPA's were compressed into two files, totaling approximately 10 Mb, with lines of 110 characters each, the end of the line often falling in the middle of an observation. Figures A.1 and A.2 show the programs that were written to read this awkward format and reduce the data set to a manageable size and format.

Some further cleaning was done on the TPA data before it could be used for production costing purposes. While correctly taking care of missing and inconsistent data problems is a tricky area, remembering that the goal was to use the data for general planning purposes, and that simulation would only use isolated weeks of the data, rule of thumb data cleaning was used. The following fixes were made to the data set.

1. Where an individual data point deviated more than 50% from the average of its neighbors, it was replaced by the mean of its neighbors. A common occurrence of this problem was in hour 2163 of most TPA's, which was the hour of change over to Pacific Daylight Time. Where 2 or 3 data points were missing, they were replaced by a linear interpolation of their neighbors.
2. Sequences of 168 hours or less of missing data, or data significantly different to adjoining weeks, were replaced by a weighted load estimate. Two sets of weights were derived. The first is the ratio of the hourly load to the mean of the three preceding hours' load, and the second is the ratio of the hourly load to the mean of three following hours. Those two weights were estimated using the average of the prior and subsequent week's loads during the corresponding hours. The missing data estimate was derived by summing the first weight times the prior three hours load average to the second weight times the subsequent three hours load average. The two weights varied in a linear fashion so the total weight favored the prior or subsequent loads depending on the proximity of each. That is, the first replacement datum is based solely on the data before it and the last missing datum is based solely on the data following it, and all points between are along a linear interpolation.
3. If a sequence of missing data extended beyond 168 hours, or if consecutive weeks contained missing data, then the missing data was simply replaced by the prior week's data.

The one significant occurrence of large sections of missing data was in the VCV10 TPA load file. The whole data set between hours 3088 and 5983 was reconstructed as a simple repeat of the prior weeks load, in keeping with rule 3. above. There were also other sections of missing data in this file. Figure A.2 shows the program written to make some of these fixes. This file represents the largest single source of questionable data, but, fortunately, the VCV10 TPA is the smallest TPA and contains a minuscule percentage of total District sales.

The resulting sales data obtained by massaging and summing the TPA data appear as table A.6. The TPA's range in size from fractions of a percent of the total sales to over 11%.

3. system load data

PG&E provided a system load data file that covered the same period as the TPA data. This file had many of the same problems, and an example of it is shown in figure A.6. Comparing this format shown in figure A.5 with that in A.6 shows that the two files are similar. However, the formats do differ slightly and the units are also different. As a result, a separate program, which is shown in figure A.4, was needed to read these data. The units of this data are a confusing tens of kW. The system data file also contained some spurious data points, and they are shown in table A.2. All the unbelievable data points were values too small relative to their neighbors. Luckily all are isolated data points and were identified as shown in the table A.2. The third column, *%mean*, shows how these points compared to the mean of their two neighboring points. Clearly, these points are all far too low to be credible, and they were simply replaced by the means shown in the fourth column.

This system load file represents the total of all TPA data, or all PG&E sales under the jurisdiction of the CPUC. A comparison of the peak and energy of this system file with the corresponding values from the PG&E planning area data are shown in figure A.8. All the TPA data are for the year 1990, and PG&E has compiled the data for that year only. Looking at 1990 in figure A.8 shows that both peak and energy in the TPA system file represent about 84% of the corresponding values in the 1990 planning area file. The difference between these two totals consists of many components, the largest of which are system losses and sales to SMUD. The annual TPA system fraction of the planning load of 84% actually hides considerable variation through the year in the relationship of TPA load to the planning area load. Table A.3 shows the 25 hours of 1990 in which the TPA share was lowest, and the 25 hours with the highest loads. Although the most extreme points are probably spurious data, the range of TPA fractions covers a surprising range of about 75 to 90%.

Also interesting in figure A.8 is the change in PG&E's sales since the mid 1980's. Until 1986, annual sales were stagnant. After 1986, on the other hand, sales growth resumed at about 3.5-4 %/yr. The pattern of change in the peaks is less obvious. Figure A.8 could be interpreted as suggesting that peaks followed the same pattern as energy but in a more volatile manner, or as suggesting that peaks have continued to grow throughout the decade.

Finally, a simple cross-check of the data against other data in the PG&E showing was made. The results of this check are shown as table A.4. The table shows sums across rate classes for energy and peak at three TPA's. These data are compared to the results obtained in this analysis by reading, massaging, and summing the TPA load data files. The errors in results are reasonable. Errors in peaks are higher than those in energy, and the largest errors are about 4%.

4. line losses

The next refinement that the data need is some account of line losses. PG&E could not supply any estimates of line losses by TPA or for the Bay Area as a whole. An estimate of losses, therefore, has to be made using the PG&E systemwide losses of 7.6 % and some simple assumptions. The two assumptions made are: 1. that losses within the District total the same percentage as the planning area losses, namely

7.6 %; and 2. that the losses increase with load but by less than the current square law would suggest.

These two assumptions lead to a simple method for adding losses to the District load. First, consider that the total load at the bus bar consists of two terms, sales to customers and losses. The losses are assumed to be a simple power function of the sales. That is,

system bus bar load =

customer demand + loss factor*(customer demand^power factor)

$$L_t = l_t + k \cdot l_t^p$$

Now the total planning area losses can be used to derive an estimate for k for any desired p < 2, as follows:

total losses = total losses

$$l \cdot \sum_t l_t = \sum_t k \cdot l_t^p$$

$$k = \frac{l \cdot \sum_t l_t}{\sum_t l_t^p}$$

The system loss factor for PG&E, l, is known to be 0.76, as mentioned above. The justification for keeping p<2 is that 2 is theoretical maximum, but because of the diversified nature of electricity demand not all loads along all wires are experiencing the same fraction level of peak load at any one time. That is, if all customer loads were perfectly coincident throughout the system, and the system were perfectly sized to meet these loads, p=2 would be a good assumption. However, in reality, loads are non-coincident, and hours of similar total system demand could result from quite different levels of stress on various system components. For the purposes of this work, p was set to 1.5, which results in a value for k of 0.001146, and the losses shown in figure A.9. Interestingly, percentage losses increase almost linearly with load across the range of interest, although in a slightly concave fashion. Using the k estimated as shown above ensures the total losses are 7.6% of sales.

The calculation of losses together with several other steps in the TPA data manipulation is implemented in a program called TPA-SUMMER, which is reproduced as figure A.10.

5. estimating load for 1989

One major obstacle remains before the estimated load data for the District can be used for production costing of the Bay Area power system. The input files to UAM used by the District are all based on an episode in September 1989, whereas all of PG&E's data was developed for 1990. Since, a reasonable approach for this analysis is to use 1989 as a test, the summed TPA data must be converted into a useable approximation of the 1989 data. Using the 1990 data and ignoring this detail is not a viable approach because the coincidence between high system loads and ozone forming weather would be lost.

The task of approximating 1989 loads was accomplished using a simple regression model, the SAS results for which are shown as table A.7. The fitted model estimates the 1989 load using 1990 load, the temperature at two of PG&E's weather monitoring stations, Potrero and Fresno, and other variables intended to capture the time-of-day, day-of-the-week, and seasonal effects. The weather data of Potrero and Fresno were chosen both because of their ready availability and because the climates of these two stations more or less bracket the range found in the PG&E service territory. Clearly, the range of climate within the District is quite significant and a bracket of this kind provides some hope of capturing the climatic dimension of the load data.

The first three coefficients α_1, α_2, and α_3 are on the intercept, the 1990 planning load, and the temperature at Potrero variables.

The next four coefficients, β_1-β_4, are on a temperature indicator variable, TEMPIND. The justification for the use of such a variable is demonstrated by figures A.11, and A.12. These figures show plots of the residuals from an early regression that did not include the TEMPIND variable, that is, treating the two sets of temperature data as a straight-forward continuous variable. Clearly, the residuals show a clear pattern, and a second order polynomial regression is shown, simply to demonstrate the relationship. In the absence of sophisticated software to rectify this problem through a data transformation, the data were segmented by the addition of a factor variable that takes a value of 0 if the temperature is < 10 C, 1 if the temperature is ≥ 10 but < 20, 2 if the temperature is ≥20 but < 30, and 3 otherwise. Using such variables requires the additional use of the product variable FRES*TEMPIND with its coefficients , γ_1-γ_4, to avoid bias. The reason that this refinement was used for only the Fresno data and not Potrero data is simply that, in early regressions, the Potrero variable was a much less potent explana - tory variable, and that, as figure A.12 demonstrates, the effect is less pronounced, largely because of the more equitable climate at that sta - tion.

All the remaining variables are straight forward factor variables relating to various aspects of time. The δ_1-δ_{12} coefficients are attached to a month-of-the-year indicator, the ε_1-ε_{24} to the hour of the day, and ζ_1-ζ_2 to a weekday-weekend indicator.

The fitted regression coefficients are implemented into a program, FINAL_LOAD, which appears as figure A.13. The program outputs the long sought after goal of this tedious analysis, a 1989 load shape for the PG&E segment of electrical demand in the District.

Figure A.14 shows the residuals derived from the SAS regression and the residuals obtained directly from the FINAL_LOAD program.

The perfect placement of the residuals along the diagonal shows that the regression equation has been correctly implemented in the program. Most of the residuals fall in the ±500 MW range, although the highest values are far above 1 000 MW. The extreme values almost certainly reflect data problems. Despite the high r^2 of 0.97 for the entire regression, residuals in the 500 MW range seem unacceptably high for an analysis such as this. However, in the absence of any clear opportunity for improving on the regression, these results are here accepted as adequate for the task at hand.

6. regression results

It is worthwhile analyzing the regression load data results more carefully, and especially, looking for any pattern in the relationship to the planning load data sets. Consider first figure A.15. This figure is a simple frequency plot of the estimated 1990 Bay Area load as a fraction of the planning load. The mean at 41.2 % shows that, according to this estimate, the Bay Area contributes less than half of the total PG&E demand. Before this entire analysis was undertaken, PG&E transmissions engineers had suggested that a reasonable assumed fraction would be 50 %. The analysis suggests that this is, indeed, a reasonable first order estimate, though nonetheless not close enough to the true value for production costing purposes.

The most notable feature of figure A.15 is its dramatic bimodal shape. Figure A.16 shows that this effect has also been successfully captured in the 1989 results. The slightly high mean of 41.7 for the 1989 data is somewhat worrisome, however. Inclusion of the 1989 planning load data as an explanatory variable has, at first impression, not resulted in a perfect estimate of the total energy, there remains an error of a half percent. However, this change in the Bay Area fraction could be explained by differences between 1989 and 1990 in the other variables, notably the temperature data. Perhaps the relative temperatures of Potrero and Fresno are sufficiently different between 1989 and 1990 to explain this result.

Observing this bimodal shape led to several tests that attempted to segment the data in a way that could satisfactorily explain this pattern. The segmentation that ultimately proved successful was somewhat surprising. It turns out that the left-hand hump of the bimodal distribution contains mostly early morning hours, while the right-hand hump contains the afternoon and evening hours. Figure A.17 shows this hourly effect in more detail. The plot shows the mean and standard deviation of each hourly distribution of fractions. The hourly effect is quite dramatic. The hours of 9:00 through 23:00 all lie above the mean, while the other hours all lie below it. The nighttime distributions also have lower standard deviations than the daytime and evening distributions.

The Bay Area represents a significantly higher share of total load during the afternoon and evening hours than during the nighttime hours. This is an interesting result because before this estimated load was available, reasonable hypotheses that would explain a Bay Area share both above and below the 50% guesstimated share were suggested, as were hypotheses about possible relative seasonal and diurnal variations in the share. Overall, the Bay Area load was not found to be more or less weather sensitive than the planning area as a whole, nor were there any noticeable seasonal effects; however, the diurnal effect described is clearly powerful. The economic effect of a larger concentration of industrial and commercial use in the Bay Area seems to outweigh any weather effect that one can speculate. For example, one would expect the non-Bay Area sector of the PG&E territory to be hotter, as a whole, than the Bay Area, with a resulting more weather sensitive load.

Finally, figure A.18 shows some representative full hourly distributions. Each histogram shows 365 bined observations, that is, at the stated hour of each day. Hours 3 and 6, the only nighttime representatives, again separate themselves from the other hours. First, the means are clearly lower, as figure A.17 has shown. Second, while all the distributions are biased to the right, with long left-hand tails, hours 3 and 6 are less biased.

7. supply-demand balance

Surprisingly, the total load derived as described and the total supply system as described in appendix C form a quite balanced test system. That is, if the resources described in appendix C are dispatched economically to meet the loads derived as described in this appendix, a reasonable match results. As described in more detail in appendix C, since a Monte Carlo approach was incorporated into EEUCM, some means of meeting energy shortfalls becomes essential. However, a configuration was found that reduced these shortfalls to very low levels. Despite the ability of BAPS resources to meet the BAPS load during the test period in September 1989, however, capacity factors on many units were much higher than occurs in practice. To make results a little more realistic, therefore, loads were deflated to bring the capacity factors down to more reasonable levels. A reduction in hourly loads by around 5% proved appropriate.

Table A1: PG&E TPA's Within BAAQMD

ID	*TPA*	*region*	*division*
1	EBR1	East Bay	Bay
2	EBR3	East Bay	Central
3	EBR4	East Bay	Mission
4	EBR5	East Bay	Mission
5	EBR6	East Bay	Mission
6	EBR7	East Bay	Diablo
7	EBR8	East Bay	Diablo
8	EBR9	East Bay	Diablo
9	EBR10	East Bay	Mission
10	NRB1	Redwood	North Bay
11	NRB2	Redwood	North Bay
12	NRB3	Redwood	North Bay
13	NRB4	Redwood	Vallejo-Napa
14	NRB5	Redwood	Vallejo-Napa
15	NRB6	Redwood	Santa Rosa
16	NRB10	Redwood	Vallejo-Napa
17	NRB13	Redwood	Santa Rosa
18	PEN1	Golden Gate	Peninsula
19	PEN2	Golden Gate	Peninsula
20	PEN3	Golden Gate	Peninsula
21	SFO1	Golden Gate	San Francisco
**	SFO3	Golden Gate	San Francisco
22	SJO2	Mission Trail	De Anza
23	SJO3	Mission Trail	De Anza
24	SJO4	Mission Trail	De Anza
25	SJO5	Mission Trail	De Anza & San Jose
26	SJO6	Mission Trail	De Anza & San Jose
27	SJO7	Mission Trail	San Jose
**	SJO9	Mission Trail	City of Palo Alto
**	SJO10	Mission Trail	City of Santa Clara
28	SKY1	Golden Gate	Skyline
29	VCV4*	Sacramento	Vaca-Valley
30	VCV10	Sacramento	Vaca-Valley-Travis AFB

* assumed to be one third in BAAQMD
** non-CPUC jurisdiction TPA's

Table A2: Replacement Values for TPA System File

hour	orig.value	%mean	replacement
6572	191230	16.8	1140130
6596	213310	18.3	1166385
6620	262050	21.5	1217805
6668	96910	9.0	1076870
6692	23270	2.3	1002985
6716	430	0.0	972060
6740	139150	12.5	1112605
6788	171580	15.0	1142465
6812	173080	15.0	1153420
6836	121930	11.0	1106970
6860	9380	0.9	993555
6908	146230	13.1	1119790
6932	176250	15.3	1153185
6956	159860	14.0	1140110
6980	148380	13.1	1136445
7004	83580	7.8	1069905
7052	9670	1.0	989035
7144	117321	10.5	1125491*
7145	103251	9.2	1114253*
7244	73800	6.9	1070070
7316	97630	9.0	1089965
7340	59280	5.6	1059805
7436	93300	8.6	1083020
7460	112910	10.3	1099235
7508	38070	3.6	1043580
7604	86980	8.1	1073620
7628	110310	10.1	1096935
7652	109930	10.0	1097330
7676	53360	5.1	1056205
7772	136060	12.1	1125105
7796	79330	7.4	1072105
7940	153610	13.4	1146780
7964	135260	11.9	1134195
7988	141360	12.4	1137620
8012	74180	6.9	1069860
8060	30950	3.0	1020805
8084	142810	12.5	1139480
8108	151610	13.2	1149095
8132	129960	11.6	1115655
8156	150150	13.2	1135760
8180	84610	7.9	1077780
8204	500	0.0	1006010
8228	22240	2.2	1017080
8252	176560	15.1	1165445
8276	166760	14.4	1156405
8300	140630	12.3	1139730
8324	165600	14.3	1158770
8348	130160	11.5	1129670
8372	63330	5.9	1065370
8396	68660	6.5	1063480
8420	186410	15.9	1169865
8468	211380	17.6	1200080
8516	215880	17.9	1208345
8540	144110	12.7	1138630
8564	102060	9.3	1097705
8588	20460	2.0	1028795
8636	134960	12.1	1113860
8660	148150	13.0	1135965
8684	92910	8.5	1090590
8708	43330	4.1	1044870

* - replaced by mean of two nearest values

Table A3: Hours of Lowest and Highest Ratios of TPA System to Planning Area Load for 1990

hour of year	hour of day	plan. load	tpa load	ratio
6435	3	9794	6983	0.712988
6436	4	9811	7004	0.713893
6434	2	9933	7121	0.716903
6437	5	10142	7326	0.722343
6433	1	10239	7406	0.723313
6432	24	11081	8216	0.741449
6532	4	8933	6748	0.755401
7395	3	8552	6465	0.755964
6533	5	8960	6781	0.756808
411	3	9287	7030	0.756972
6528	24	10318	7811	0.757027
6531	3	9125	6911	0.757370
412	4	9423	7139	0.757614
6552	24	9895	7500	0.757959
6530	2	9366	7111	0.759236
6534	6	9144	6947	0.759733
410	2	9358	7111	0.759885
6529	1	9596	7299	0.760629
6505	1	10158	7728	0.760780
6482	2	9265	7065	0.762547
6483	3	9124	6960	0.762823
6120	24	11131	8495	0.763184
6551	23	10781	8233	0.763658
1011	3	8383	6405	0.764046
6484	4	9158	6999	0.764250
. . .	. . .	. . .	. . .	. . .
6972	12	11968	10821	0.904161
4537	1	8328	7531	0.904299
6978	18	12315	11137	0.904344
6979	19	13081	11831	0.904442
7073	17	12487	11295	0.904541
6822	6	9388	8492	0.904559
6971	11	12072	10922	0.904738
6976	16	11983	10844	0.904949
6825	9	12183	11032	0.905524
6970	10	12069	10929	0.905543
6969	9	11696	10594	0.905780
7065	9	11818	10705	0.905822
6984	24	8757	7933	0.905904
6975	15	12188	11057	0.907204
6973	13	12126	11001	0.907224
6974	14	12279	11143	0.907484
6981	21	12003	10898	0.907940
6985	1	8627	7837	0.908427
6982	22	10869	9902	0.911031
6983	23	9732	8868	0.911221
6986	2	8480	7741	0.912854
7412	20	12363	11322	0.915797
7413	21	11570	10725	0.926966
7415	23	9608	8931	0.929538
7414	22	10563	10008	0.947458

Table A4:

Comparison of Peaks and Energies Estimated from TPA Files With the GRC Data Filed by PG&E

class	EBR 01 energy	EBR 01 load	EBR 07 energy	EBR 07 load	SJO 06 energy	SJO 06 load
AGRA			94 683	39	480 264	155
			49 856		264 869	3
AGRB	510 044	130	86 864	28	2 153 479	776
	496 999	52	33 528		1 476 127	12
E19S	21 604 185	5 214	57 233 042	24 264	248 616 518	92 171
	18 993 904	2 544	49 371 595		212 007 095	2 059
E19P	5 559 149	1 017	777 193	278	5 122 776	1 612
	5 292 237	574	545 282		4 494 505	34
E19T						
E20S	22 075 696	4 138	77 184 490	26 220	221 233 176	70 575
	20 288 042	2 172	44 589 302		190 880 947	1 526
E20P	597 659 544	101 549	56 285 838	15 067	160 660 318	54 383
	557 915 494	55 596	42 604 103		143 075 512	1 226
E20T	52 322 047	8 365	263 851 630	78 670	201 399 352	58 451
	61 582 180	7 235	269 604 105		191 809 396	1 334
MEDS	87 790 432	19 981	160 284 852	64 622	522 482 994	207 088
	82 492 770	10 210	133 267 762		451 576 737	4 620
MEDP	2 932 309	656			3 571 898	1 526
	2 759 863	336			3 663 857	39
MEDT						
RES	127 328 643	19 240	272 765 686	117 962	259 856 528	73 488
	140 563 814	15 243	264 664 435		284 968 089	1 399
SLP	31 030 132	8 230	76 180 870	36 670	147 083 598	74 373
	31 654 343	4 401	68 879 051		138 923 215	1 695
STL	842 903	23	1 408 477	119	4 038 448	112
	836 745	50	1 372 112		3 889 958	2
total	1 872 531 475	266 956	1 841 134 756	363 939	3 403 729 656	648 659
TPA sum	1 876 388 730	266 558	1 851 680 661	349 802	3 402 600 609	623 556
per.diff.	-0.206	0.149	-0.570	4.041	0.033	4.026

Table A5: Approximate Supply Mix of Bay Area Municipal Utilities

City of Alameda Energy	(GWh)	1991 %
NCPA geothermal	203	40.6
hydro	18	3.6
PG&E firm	50	10.0
NW contract	22	4.4
other NCPA non-thern	61	12.2
other NCPA thermal	14	2.8
WAPA	132	26.4
TOTAL ENERGY (GWh)	500	incl. losses
peak (MW) & CF (%)	90	0.63

source: City of Alameda

City of Palo Alto Energy		1991
WAPA	981	90.8
other	99	9.2
TOTAL ENERGY (GWh)	1080	incl. losses
peak (MW) & CF (%)	193	0.64

source: City of Palo Alto

City of Santa Clara Energy	(GWh)	1991 %
NCPA geothermal	500	21.2
hydro	80	3.4
cogen.(Robert Ave.)	40	1.7
Gianera	3	0.1
non-PG&E firm	95	4.0
PG&E firm	400	16.9
non-firm	15	0.6
PG&E Grizzly	40	1.7
WAPA	1164	49.3
other	25	1.1
TOTAL ENERGY (GWh)	2362	incl. losses
peak (MW) & CF (%)	400	0.67

source: City of Santa Clara

Table A.6: Sales and Fractions of Total by Bay Area Transmission Planning Area

TPA	Sales (GWh)	fraction
***	**********	********
EBR_01	1876.	0.049389
EBR_03	3479.	0.091576
EBR_04	818.	0.021536
EBR_05	1150.	0.030262
EBR_06	1889.	0.049710
EBR_07	1852.	0.048739
EBR_08	1299.	0.034193
EBR_09	337.	0.008867
EBR_10	1683.	0.044311
NRB_01	1161.	0.030563
NRB_02	86.	0.002268
NRB_03	591.	0.015568
NRB_04	433.	0.011404
NRB_05	959.	0.025241
NRB_06	921.	0.024254
NRB_10	168.	0.004409
NRB_13	208.	0.005473
PEN_01	1120.	0.029472
PEN_02	106.	0.002785
PEN_03	1061.	0.027916
SFO_01	4311.	0.113477
SJO_02	1224.	0.032213
SJO_03	2026.	0.053333
SJO_04	1189.	0.031306
SJO_05	1602.	0.042177
SJO_06	3403.	0.089562
SJO_07	462.	0.012171
SKY_01	1383.	0.036392
VCV_04	1169.	0.030778
VCV_10	23.	0.000612
totals =	37992.	0.999955

Table A.7: Results of SAS Regression

17:07 Wednesday, June 3, 1992

General Linear Models Procedure
Class Level Information

Class	Levels	Values
MOY	12	1 2 3 4 5 6 7 8 9 10 11 12
HOD	24	1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
DAYTYPE	2	0 1
TEMPIND	4	0 1 2 3

Number of observations in data set = 8760

General Linear Models Procedure

Dependent Variable: LOAD

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	44	9660359398	219553623	6609.61	0.0
Error	8715	289489240	33217		
Corrected Total	8759	9949848639			

R-Square	C.V.	Root MSE	LOAD Mean
0.970905	3.909358	182.2563	4662.05137

Source	DF	Type I SS	Mean Square	F Value	Pr > F
PL90	1	8299195803	8299195803	99999.99	0.0
TEMPIND	3	452213382	150737794	4537.92	0.0
FRES*TEMPIND	4	137284979	34321245	1033.23	0.0
POT	1	49967435	49967435	1504.26	0.0001
MOY	11	527813755	47983069	1444.52	0.0
HOD	23	169728090	7379482	222.16	0.0
DAYTYPE	1	24155954	24155954	727.21	0.0001

Source	DF	Type III SS	Mean Square	F Value	Pr > F
PL90	1	737193366.9	737193366.9	22193.02	0.0
TEMPIND	3	18164848.1	6054949.4	182.28	0.0001
FRES*TEMPIND	4	27154680.5	6788670.1	204.37	0.0001
POT	1	13438018.4	13438018.4	404.55	0.0001
MOY	11	116792805.2	10617527.7	319.64	0.0
HOD	23	193575366.4	8416320.3	253.37	0.0
DAYTYPE	1	24155954.0	24155954.0	727.21	0.0001

Parameter		Estimate	T for H0: Parameter=0	Pr > |T|	Std Error of Estimate
INTERCEPT		177.835026 B	6.01	0.0001	29.61035343
PL90		0.393145	148.97	0.0	0.00263903
POT		19.487647	20.11	0.0001	0.96888962
TEMPIND	0	-856.019091 B	-0.57	0.5662	1492.3065888
	1	1741.719019 B	21.25	0.0001	81.97956860
	2	411.435688 B	12.05	0.0001	34.13096376
	3	0.000000 B	.	.	.
FRES*TEMPIND	0	0.687279	0.02	0.9849	36.39528912
	1	-64.963116	-26.10	0.0001	2.48854909
	2	-20.195576	-13.80	0.0001	1.46308590
	3	1.396593	1.67	0.0956	0.83787090
MOY	1	2.524266 B	0.26	0.7966	9.79495512
	2	1.903314 B	0.19	0.8524	10.22805314
	3	7.576420 B	0.65	0.5172	11.69858969
	4	-132.952845 B	-9.74	0.0001	13.65420637
	5	-194.378504 B	-13.95	0.0001	13.93805056
	6	-419.657500 B	-26.66	0.0001	15.74280723
	7	-638.252624 B	-37.16	0.0001	17.17531042
	8	-545.441793 B	-32.79	0.0001	16.63616219

	9	-364.415686 B	-23.12	0.0001	15.76033491
	10	-96.011190 B	-6.81	0.0001	14.09147348
	11	-120.002606 B	-10.74	0.0001	11.17185800
	12	0.000000 B	.	.	.
HOD	1	-155.032937 B	-11.42	0.0001	13.57602863
	2	-247.177412 B	-18.06	0.0001	13.68331176
	3	-287.563014 B	-20.88	0.0001	13.77129125
	4	-327.099455 B	-23.70	0.0001	13.80387943
	5	-368.583745 B	-26.83	0.0001	13.73566956
	6	-409.393739 B	-30.00	0.0001	13.64452421
	7	-321.462725 B	-22.96	0.0001	13.99975584
	8	1.006138 B	0.07	0.9449	14.56714473
	9	154.859165 B	10.15	0.0001	15.25228648
	10	283.987035 B	17.95	0.0001	15.82291307
	11	359.163781 B	22.21	0.0001	16.17265357
	12	444.402888 B	27.41	0.0001	16.21064949
	13	394.051525 B	24.10	0.0001	16.35294293
	14	407.626640 B	24.87	0.0001	16.39260175
	15	398.624706 B	24.44	0.0001	16.31020007
	16	343.682934 B	21.29	0.0001	16.14470434
	17	241.400257 B	14.93	0.0001	16.16709710
	18	252.898521 B	15.44	0.0001	16.38371655
	19	324.129569 B	20.00	0.0001	16.20608987
	20	285.345878 B	17.94	0.0001	15.90164892
	21	303.387785 B	19.64	0.0001	15.45118473
	22	300.130490 B	20.65	0.0001	14.53416261
	23	182.026981 B	13.25	0.0001	13.74242966
	24	0.000000 B	.	.	.
DAYTYPE	0	-159.741582 B	-26.97	0.0001	5.92363651
	1	0.000000 B	.	.	.

NOTE: The X'X matrix has been found to be singular and a generalized inverse was used to solve the normal equations. Estimates followed by the letter 'B' are biased, and are not unique estimators of the parameters.

Figure A1: Program to Read PG&E TPA Data

```
- - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - -
               PROGRAM TPA_READER
C this program is intended to read the TPA data in crazy format
C provided by PG&E and return it as something comprehensible
C this turns out to be a messy business

C the idea is to take advantage of the fact that the data, while
C chaotic, has a seven line cycle, i.e. line 8 has the same format
C as line 1, and line 9 the same as line 2, etc.
C thus, lines 1-7 are all read into arrays of appropriate length
C and then printed out in a sensible format

C note that everything is treated as text so the truncated data
C can be reconstructed
C character strings of length 10 are used to ensure no loaad data
C is lost in the shuffle

      CHARACTER*1  STRING01(10)
      CHARACTER*2  STRING02(10)
      CHARACTER*3  STRING03(10)
      CHARACTER*4  STRING04(10)
      CHARACTER*5  STRING05(10)
      CHARACTER*6  STRING06(100)
      CHARACTER*7  STRING07(10)
      CHARACTER*8  STRING08(10)
      CHARACTER*10 STRING10(100)

      OPEN(11,FILE='input')
      OPEN(21,FILE='output')

 1000 CONTINUE

C reading line 1
      READ(11,5010,END=2000) STRING06(1),STRING06(2),STRING10(1),
     1              STRING06(3),STRING06(4),STRING10(2),
     2              STRING06(5),STRING06(6),STRING10(3),
     3              STRING04(1)
 5010 FORMAT(1X,A6,8X,A6,2X,A10,3X,A6,8X,A6,2X,A10,
     1                        3X,A6,8X,A6,2X,A10,3X,A4)

C reading line 2
      READ(11,5011) STRING02(1),STRING06(7),STRING10(4),
     1              STRING06(8),STRING06(9),STRING10(5),
     2           STRING06(10),STRING06(11),STRING10(6),STRING06(12)
 5011 FORMAT(A2,8X,A6,2X,A10,3X,A6,8X,A6,2X,A10,
     1                        3X,A6,8X,A6,2X,A10,3X,A6)
```

```
C reading line 3
      READ(11,5012)
STRING06(13),STRING10(7),STRING06(14),STRING06(15),
     1               STRING10(8),STRING06(16),STRING06(17),STRING10(9),
     2               STRING06(18)
 5012 FORMAT(5X,A6,2X,A10,3X,A6,8X,A6,2X,A10,3X,A6,8X,A6,2X,A10,3X,A6)

C reading line 4
      READ(11,5013) STRING06(19),STRING10(10),
     1              STRING06(20),STRING06(21),STRING10(11),
     2              STRING06(22),STRING06(23),STRING10(12),
     3              STRING06(24),STRING05(1)
 5013 FORMAT(A6,2X,A10,3X,A6,8X,A6,2X,A10,3X,A6,8X,A6,2X,A10,
     1                          3X,A6,8X,A5)

C reading line 5
      READ(11,5014) STRING01(1),STRING10(13),
     1              STRING06(25),STRING06(26),STRING10(14),
     2              STRING06(27),STRING06(28),STRING10(15),
     2              STRING06(29),STRING06(30),STRING02(2)
 5014 FORMAT(A1,2X,A10,3X,A6,8X,A6,2X,A10,3X,A6,8X,A6,2X,A10,
     1                          3X,A6,8X,A6,2X,A2)

C reading line 6
      READ(11,5015)
STRING08(1),STRING06(31),STRING06(32),STRING10(16),
     1              STRING06(33),STRING06(34),STRING10(17),
     2              STRING06(35),STRING06(36),STRING07(1)
 5015
FORMAT(A8,3X,A6,8X,A6,2X,A10,3X,A6,8X,A6,2X,A10,3X,A6,8X,A6,2X,A7)

C reading line 8
      READ(11,5016)
STRING03(1),STRING06(37),STRING06(38),STRING10(18),
     1              STRING06(39),STRING06(40),STRING10(19),
     1              STRING06(41),STRING06(42),STRING10(20)
 5016 FORMAT(A3,3X,A6,8X,A6,2X,A10,3X,A6,8X,A6,2X,A10,
     1                          3X,A6,8X,A6,2X,A10,)

C now all that junk is written out in s straightforward
C three column format
      WRITE(21,6010) STRING06(1),STRING06(2),STRING10(1)
      WRITE(21,6010) STRING06(3),STRING06(4),STRING10(2)
      WRITE(21,6010) STRING06(5),STRING06(6),STRING10(3)
 6010 FORMAT(3A10)
      WRITE(21,6011) STRING04(1),STRING02(1),STRING06(7),STRING10(4)
 6011 FORMAT(4X,A4,A2,2A10)
      WRITE(21,6010) STRING06(8), STRING06(9), STRING10(5)
      WRITE(21,6010) STRING06(10),STRING06(11),STRING10(6)
      WRITE(21,6010) STRING06(12),STRING06(13),STRING10(7)
      WRITE(21,6010) STRING06(14),STRING06(15),STRING10(8)
```

```
      WRITE(21,6010) STRING06(16),STRING06(17),STRING10(9)
      WRITE(21,6010) STRING06(18),STRING06(19),STRING10(10)
      WRITE(21,6010) STRING06(20),STRING06(21),STRING10(11)
      WRITE(21,6010) STRING06(22),STRING06(23),STRING10(12)
      WRITE(21,6012) STRING06(24),STRING05(1), STRING01(1),
STRING10(13)
 6012 FORMAT(4X,A6,4X,A5,A1,A10)
      WRITE(21,6010) STRING06(25),STRING06(26),STRING10(14)
      WRITE(21,6010) STRING06(27),STRING06(28),STRING10(15)
      WRITE(21,6013) STRING06(29),STRING06(30),STRING02(2),STRING08(1)
 6013 FORMAT(4X,A6,4X,A6,A2,A8)
      WRITE(21,6010) STRING06(31),STRING06(32),STRING10(16)
      WRITE(21,6010) STRING06(33),STRING06(34),STRING10(17)
      WRITE(21,6014) STRING06(35),STRING06(36),STRING07(1),STRING03(1)
 6014 FORMAT(2A10,A7,A3)
      WRITE(21,6010) STRING06(37),STRING06(38),STRING10(18)
      WRITE(21,6010) STRING06(39),STRING06(40),STRING10(19)
      WRITE(21,6010) STRING06(41),STRING06(42),STRING10(20)

C now back to the top again
      GOTO 1000
 2000 CONTINUE

      CLOSE(11)
      CLOSE(21)

      END
C what a drag!!
```

Figure A2: Program to Read PG&E TPA Data

```
      PROGRAM FILLER

C This program is total kluge
C It reads data in the VCV10 file and "fixes" some of the problems
C A large section of data from hours 3808 to 5983 was missing and is
C replaced by the repeats of the last 168-hour period before 3808.
C A couple of other smaller holes are also filled.
C The changed lines are marked with a "*".

      INTEGER SAT
      REAL DATA(8760,10)
      CHARACTER*5 STRING
      CHARACTER*6 STAR(8760)

      DO 1005, I = 1, 8760
        STAR(I) = '      '
 1005 CONTINUE

      OPEN(11,FILE='VCV10')
      OPEN(21,FILE='new.VCV10')

      DO 1010, I = 1, 8760
        READ(11,5010) STRING,INT1,INT2,(DATA(I,J),J=3,4),STAR(I)
 5010   FORMAT(A5,5X,2I10,2F10.1,1X,A6)
        DATA(I,1) = REAL(INT1)
        DATA(I,2) = REAL(INT2)
 1010 CONTINUE

      DO 1015 I = 2955,3088
         DATA(I,3) =  (DATA(I+168,3) + DATA(I-168,3))/2.0
         STAR(I) = '    * '
 1015 CONTINUE

      DO 1016 J = 1,13
        SAT = 168
        IF (J.EQ.13) SAT = 159
        DO 1017 K = 1, SAT
          DATA(3807+((J-1)*168)+K,3) =  DATA(3808-169+K,3)
         STAR(3807+((J-1)*168)+K) = '    * '
 1017   CONTINUE
 1016 CONTINUE
```

```
      DO 1018 I = 7182, 7192
         DATA(I,3) =  (DATA(I+168,3) + DATA(I-168,3))/2.0
         STAR(I) = '    * '
1018  CONTINUE

      DO 1020, I = 1, 8760
        WRITE(21,5010) STRING,INT(DATA(I,1)),INT(DATA(I,2)),
     2    (DATA(I,J),J=3,4),STAR(I)
1020  CONTINUE

      CLOSE(11)
      CLOSE(12)

      END
```

Figure A3: Program to Reformat PG&E TPA Data

```
      PROGRAM FINAL_TABLE

C this program is the last in the chain that finally
C puts the TPA data in three nice tabular files with
C 10 TPA's in each

      CHARACTER*5 STRING
      INTEGER INT1,INT2, DATA(8760,31)
      REAL PERCH,RDATA

C the following are the infiles created by tpa_read

      OPEN(11,FILE='EBR_01')
      OPEN(12,FILE='EBR_03')
      OPEN(13,FILE='EBR_04')
      OPEN(14,FILE='EBR_05')
      OPEN(15,FILE='EBR_06')
      OPEN(16,FILE='EBR_07')
      OPEN(17,FILE='EBR_08')
      OPEN(18,FILE='EBR_09')
      OPEN(19,FILE='EBR_10')
      OPEN(20,FILE='NRB_01')
      OPEN(21,FILE='NRB_02')
      OPEN(22,FILE='NRB_03')
      OPEN(23,FILE='NRB_04')
      OPEN(24,FILE='NRB_05')
      OPEN(25,FILE='NRB_06')
      OPEN(26,FILE='NRB_10')
      OPEN(27,FILE='NRB_13')
      OPEN(28,FILE='PEN_01')
      OPEN(29,FILE='PEN_02')
      OPEN(30,FILE='PEN_03')
      OPEN(31,FILE='SFO_01')
      OPEN(32,FILE='SJO_02')
      OPEN(33,FILE='SJO_03')
      OPEN(34,FILE='SJO_04')
      OPEN(35,FILE='SJO_05')
      OPEN(36,FILE='SJO_06')
      OPEN(37,FILE='SJO_07')
      OPEN(38,FILE='SKY_01')
      OPEN(39,FILE='VCV_04')
      OPEN(40,FILE='VCV_10')
      OPEN(41,FILE='ERRORS')
C the reading of the data is a continuous loop
C with a simple sanity test on the data
```

```
          DO 1010 I = 1, 8760
            DO 1020 J = 11, 40
              READ(J,5010) STRING, INT1,INT2, RDATA
 5010         FORMAT(A5,5X,2I10,F10.1)
              DATA(I,J-10) = INT(RDATA+0.5)
              IF (PERCH.GT.100.0.AND.I.GT.1) THEN
                WRITE(41, *)'***ERROR*** = ',PERCH,'
     2                   INFILE = ',J,' HOUR = ',I
              ENDIF
              IF(INT1.NE.I) THEN
                PRINT *, 'INDEX MISMATCH'
                PRINT *, 'INFILE = ', J, ' HOUR = ', I
              ENDIF
 1020       CONTINUE
 1010     CONTINUE

          DO 1030 I = 11, 41
            CLOSE(I)
 1030     CONTINUE

C the data is written to the three output files
C according to the ID's in Table A1
C the total output files are now < 2 Mb
          OPEN(51,FILE='TPAs01-10')
          OPEN(52,FILE='TPAs11-20')
          OPEN(53,FILE='TPAs21-30')
          DO 1050 I = 1, 8760
            WRITE(51,5030) I,(DATA(I,J),J= 1,10)
            WRITE(52,5030) I,(DATA(I,J),J=11,20)
            WRITE(53,5030) I,(DATA(I,J),J=21,30)
 5030       FORMAT(I5,10I7)
 1050     CONTINUE

          DO 1060 I = 1,3
            CLOSE(50+J)
 1060     CONTINUE

          END
```

Figure A4: Program to Read PG&E Total TPA Data

```
      PROGRAM SYS_READ

C this program is intended to read the tota TPA data in crazy format
C given to me by PG&E and return it something comprehensible
C in the same manner that the tpa_read reorganizes the tpa data

      LOGICAL FIRST

      CHARACTER*1  STRING01
      CHARACTER*2  STRING02
      CHARACTER*3  STRING03
      CHARACTER*4  STRING04
      CHARACTER*5  STRING05
      CHARACTER*6  STRING06
      CHARACTER*7  STRING07
      CHARACTER*8  STRING08
      CHARACTER*9  STRING09
      CHARACTER*10 STRING10
      CHARACTER*11 STRING11(100)

      OPEN(11,FILE='input')
      OPEN(21,FILE='output')

      FIRST = .TRUE.

C a continuous loop starts here and runs until EOF found
C there is a 12 line cycle, 6 reads with two write formats
C for each - which is which is controled by the FIRST
C while the two formats are the same the data has to
C be reorganized differently

 1000 CONTINUE

C read lines 1 or 7

      READ(11,5010,END=2000) STRING10,(STRING11(J),J=1,8),STRING03
 5010 FORMAT(A10,1X,A11,1X,4(A11,1X,A11,1X,),A3)
      IF (FIRST) THEN
        WRITE(21,6010) STRING10, STRING11(1)
 6010   FORMAT(1X,A10,A11)
        DO 1010 I = 2,6,2
```

```
          WRITE(21,6020) STRING11(I), STRING11(I+1)
 6020   FORMAT(A11,A11)
 1010   CONTINUE
      ELSE
        WRITE(21,7010)STRING11(59),STRING01,STRING10
 7010   FORMAT(A11,A1,A10)
      DO 2010 I = 1,7,2
        WRITE(21,6020) STRING11(I),STRING11(I+1)
 2010 CONTINUE
      ENDIF

C read line 2 or 8

      READ(11,5020,END=2000)STRING08,(STRING11(J),J=11,18),STRING05
 5020 FORMAT(A8,1X,4(A11,1X,A11,1X,),A5)
      IF (FIRST) THEN
        WRITE(21,6030) STRING11(8),STRING03,STRING08
 6030   FORMAT(A11,A3,A8)
        DO 1020 I = 11, 18, 2
        WRITE(21,6020) STRING11(I),STRING11(I+1)
 1020   CONTINUE
      ELSE
        WRITE(21,7020) STRING03,STRING08,STRING11(11)
 7020   FORMAT(A3,A8,A11)
        DO 2020 I = 12,16,2
        WRITE(21,6020) STRING11(I),STRING11(I+1)
 2020   CONTINUE
      ENDIF

C read line 3 or 9

      READ(11,5030,END=2000)STRING06,(STRING11(J),J=21,28),STRING07
 5030 FORMAT(A6,1X,4(A11,1X,A11,1X,),A7)
      IF (FIRST) THEN
        WRITE(21,6040) STRING05,STRING06,STRING11(21)
 6040   FORMAT(A5,A6,A11)
        DO 1030 I = 22,26,2
          WRITE(21,6020) STRING11(I),STRING11(I+1)
 1030   CONTINUE
      ELSE
        WRITE(21,7030) STRING11(18),STRING05,STRING06
 7030   FORMAT(A11,A5,A6)
        DO 2030 I = 21,27,2
```

```
          WRITE(21,6020) STRING11(I),STRING11(I+1)
 2030     CONTINUE
       ENDIF

C read line 4 or 10

       READ(11,5040,END=2000)STRING04,(STRING11(J),J=31,38),STRING09
 5040  FORMAT(A4,1X,4(A11,1X,A11,1X,),A9)
       IF (FIRST) THEN
         WRITE(21,6050) STRING11(28),STRING07,STRING04
 6050    FORMAT(A11,A7,A4)
         DO 1040 I = 31,38,2
           WRITE(21,6020) STRING11(I),STRING11(I+1)
 1040    CONTINUE
       ELSE
         WRITE(21,7050) STRING07,STRING04,STRING11(31)
 7050    FORMAT(A7,A4,A11)
         DO 2040 I = 32,36,2
         WRITE(21,6020) STRING11(I),STRING11(I+1)
 2040    CONTINUE
       ENDIF

C read line 5 or 11

       READ(11,5050,END=2000)STRING02,(STRING11(J),J=41,49)
 5050  FORMAT(A2,1X,4(A11,1X,A11,1X,),A11)
       IF (FIRST) THEN
         WRITE(21,6060) STRING09,STRING02,STRING11(41)
 6060    FORMAT(A9,A2,A11)
         DO 1050 I = 42,48,2
           WRITE(21,6020) STRING11(I),STRING11(I+1)
 1050    CONTINUE
       ELSE
         WRITE(21,7060) STRING11(38),STRING09,STRING02
 7060    FORMAT(A11,A9,A2)
         DO 2050 I = 41,47,2
         WRITE(21,6020) STRING11(I),STRING11(I+1)
 2050    CONTINUE
       ENDIF

C read line 6 or 12

       READ(11,5060,END=2000)(STRING11(J),J=51,59),STRING01
```

```
 5060 FORMAT(1X,4(A11,1X,A11,1X,),A11,1X,A1)
      IF (FIRST) THEN
        DO 1060 I = 51,57,2
          WRITE(21,6020) STRING11(I),STRING11(I+1)
 1060   CONTINUE
      ELSE
        WRITE(21,6020)STRING11(49),STRING11(51)
        DO 2060 I = 52,58,2
          WRITE(21,6020) STRING11(I),STRING11(I+1)
 2060   CONTINUE
      ENDIF

c now the flag is reversed
      IF (FIRST) THEN
        FIRST = .FALSE.
      ELSE
        FIRST = .TRUE.
      ENDIF

      GOTO 1000
 2000 CONTINUE

      CLOSE(11)
      CLOSE(21)

      END
```

Figure A5: PGE.TPA.Data.1990

```
         1         2         3         4         5         6         7         8         9         1        11
12345678901234567890123456789012345678901234567890123456789012345678901234567890123456789012345678901234567890
---------+---------+---------+---------+---------+---------+---------+---------+---------+---------+---------+

" EBR1 " ,           1,       182017, " EBR1 " ,           2,       178296, " EBR1 " ,           3,       171713, " EBR
1 " ,           4,       169556, " EBR1 " ,           5,       170039, " EBR1 " ,           6,       172049, " EBR1 " ,
          7,       174692, " EBR1 " ,           8,       175972, " EBR1 " ,           9,       178550, " EBR1 " ,
    10,       185365, " EBR1 " ,          11,       193464, " EBR1 " ,          12,       201858, " EBR1 " ,          1
3,       201235, " EBR1 " ,          14,       199552, " EBR1 " ,          15,       196061, " EBR1 " ,          16,
  202033, " EBR1 " ,          17,       212321, " EBR1 " ,          18,       218511, " EBR1 " ,          19,       218
047, " EBR1 " ,          20,       216905, " EBR1 " ,          21,       212430, " EBR1 " ,          22,       205351,
" EBR1 " ,          23,       198775, " EBR1 " ,          24,       187746, " EBR1 " ,          25,       182008, " EBR
1 " ,          26,       180366, " EBR1 " ,          27,       178455, " EBR1 " ,          28,       178390, " EBR1 " ,
         29,       180133, " EBR1 " ,          30,       190786, " EBR1 " ,          31,       208031, " EBR1 " ,
    32,       225914, " EBR1 " ,          33,       232638, " EBR1 " ,          34,       236451, " EBR1 " ,          3
5,       236201, " EBR1 " ,          36,       237982, " EBR1 " ,          37,       235406, " EBR1 " ,          38,
  232821, " EBR1 " ,          39,       234101, " EBR1 " ,          40,       230042, " EBR1 " ,          41,       227
393, " EBR1 " ,          42,       239172, " EBR1 " ,          43,       239921, " EBR1 " ,          44,       236964,
" EBR1 " ,          45,       233471, " EBR1 " ,          46,       223691, " EBR1 " ,          47,       214440, " EBR
1 " ,          48,       197781, " EBR1 " ,          49,       191770, " EBR1 " ,          50,       189521, " EBR1 " ,
         51,       186598, " EBR1 " ,          52,       185967, " EBR1 " ,          53,       187796, " EBR1 " ,
    54,       194948, " EBR1 " ,          55,       210502, " EBR1 " ,          56,       230268, " EBR1 " ,          5
7,       233946, " EBR1 " ,          58,       239049, " EBR1 " ,          59,       234659, " EBR1 " ,          60,
  234678, " EBR1 " ,          61,       236141, " EBR1 " ,          62,       230779, " EBR1 " ,          63,       231
115, " EBR1 " ,          64,       226032, " EBR1 " ,          65,       221040, " EBR1 " ,          66,       234053,
" EBR1 " ,          67,       232843, " EBR1 " ,          68,       228369, " EBR1 " ,          69,       226029, " EBR
1 " ,          70,       219298, " EBR1 " ,          71,       207943, " EBR1 " ,          72,       194709, " EBR1 " ,
         73,       188331, " EBR1 " ,          74,       185017, " EBR1 " ,          75,       182764, " EBR1 " ,
    76,       183150, " EBR1 " ,          77,       184663, " EBR1 " ,          78,       192619, " EBR1 " ,          7
9,       212398, " EBR1 " ,          80,       228971, " EBR1 " ,          81,       236191, " EBR1 " ,          82,
  239173, " EBR1 " ,          83,       237233, " EBR1 " ,          84,       237991, " EBR1 " ,          85,       234
271, " EBR1 " ,          86,       234370, " EBR1 " ,          87,       229251, " EBR1 " ,          88,       229574,
" EBR1 " ,          89,       226601, " EBR1 " ,          90,       241154, " EBR1 " ,          91,       243137, " EBR
1 " ,          92,       237733, " EBR1 " ,          93,       233341, " EBR1 " ,          94,       221597, " EBR1 " ,
         95,       209438, " EBR1 " ,          96,       196678, " EBR1 " ,          97,       187824, " EBR1 " ,
    98,       184489, " EBR1 " ,          99,       183167, " EBR1 " ,         100,       183114, " EBR1 " ,          10
1,       186794, " EBR1 " ,         102,       194692, " EBR1 " ,         103,       210724, " EBR1 " ,         104,
  227945, " EBR1 " ,         105,       228911, " EBR1 " ,         106,       233298, " EBR1 " ,         107,       232
```

Figure A6: PGE.System.Load.1990

```
         1         2         3         4         5         6         7         8         9        10        11
123456789012345678901234567890123456789012345678901234567890123456789012345678901234567890123456789012345678901234
---------+---------+---------+---------+---------+---------+---------+---------+---------+---------+---------+----

         1,      697420,          2,      661440,          3,      638590,          4,      626480,          5,
  631030,          6,      654880,          7,      674300,          8,      715530,          9,      777150,
    10,      835650,         11,      877550,         12,      889640,         13,      898310,         14,      89
2390,         15,      888260,         16,      909560,         17,      976570,         18,     1041320,
19,     1010360,         20,      981930,         21,      914670,         22,      842330,         23,      744890
,        24,      684500,         25,      651620,         26,      638060,         27,      633280,         28,
   641560,         29,      677710,         30,      786880,         31,      946780,         32,     1022450,
     33,     1045580,         34,     1069260,         35,     1058390,         36,     1047990,         37,      1
027910,         38,     1014720,         39,      993220,         40,     1000480,         41,     1075890,
  42,     1195000,         43,     1164970,         44,     1122630,         45,     1057980,         46,      9782
20,         47,      878130,         48,      785640,         49,      714770,         50,      695110,         51
,      693250,         52,      702040,         53,      731660,         54,      846630,         55,     1019030,
        56,     1081430,         57,     1093650,         58,     1102810,         59,     1086770,         60,
 1055230,         61,     1040970,         62,     1028320,         63,     1008160,         64,      999230,
    65,     1071990,         66,     1201850,         67,     1175630,         68,     1134300,         69,      106
5480,         70,      984090,         71,      877330,         72,      782250,         73,      731170,
74,      712140,         75,      704400,         76,      721290,         77,      761250,         78,      874580
,        79,     1063180,         80,     1125110,         81,     1134980,         82,     1123630,         83,
   1107970,         84,     1079580,         85,     1066830,         86,     1055920,         87,     1041360,
      88,     1033160,         89,     1107310,         90,     1213740,         91,     1184690,         92,      1
134320,         93,     1068070,         94,      984920,         95,      867300,         96,      778690,
  97,      742040,         98,      720710,         99,      714950,        100,      722380,        101,      7633
50,        102,      865840,        103,     1041550,        104,     1101920,        105,     1121370,        106
,     1122030,        107,     1104310,        108,     1062220,        109,     1056030,        110,     1037440,
       111,     1017910,        112,     1006670,        113,     1059550,        114,     1162420,        115,
 1127640,        116,     1074660,        117,     1009460,        118,      957820,        119,      863840,
   120,      783910,        121,      728010,        122,      698800,        123,      685610,        124,      68
7120,        125,      702710,        126,      748410,        127,      794640,        128,      881300,        1
29,      958240,        130,      992400,        131,      995420,        132,      975120,        133,      948980
,       134,      910690,        135,      896940,        136,      900600,        137,      982740,        138,
   1073190,        139,     1027900,        140,      985360,        141,      932860,        142,      873690,
     143,      803000,        144,      740230,        145,      690070,        146,      668280,        147,
645390,        148,      647280,        149,      650030,        150,      676870,        151,      711770,
 152,      775900,        153,      861410,        154,      906030,        155,      929220,        156,      9312
60,        157,      926790,        158,      906610,        159,      897750,        160,      924770,        161
```

Figure A7: Program to Clean the TPA System File

```
      PROGRAM SYS_CLEAN

C this program checks the TPA system file for spurious data points
C and replaces them with a simple mean of the adjoining values
C note that all the spurious data is too small, there are not obs
C unrealistically large

      REAL DATA(8760,2),MEAN,TEMP

      DO 1000 I = 1, 8760
       DO 1000 J = 1,2
        DATA(I,J) = 0.0
 1000 CONTINUE

C all the data is read into an array called DATA
      OPEN(11,FILE='tpa_sys')
      DO 1010 I = 1, 8760
        READ(11,*) (DATA(I,J),J=1,2)
C       WRITE(6,*) (DATA(I,J),J=1,2)
 1010 CONTINUE
      CLOSE(11)

C all loads are compared to their neigbors and replaced
C by the mean of the neighbors if it is less than 50%
C of that mean
C since hours 7144 & 7145 are both missing, they are
C replace by a linear interpolation

      OPEN(21,FILE='tpa_sys.errors')
      MEAN = 0.0
      TEMP = 0.0
      DO 1020 I = 2, 8759
        IF(I.EQ.7144) THEN
          TEMP = DATA(I,2)
          MEAN = (DATA(I-1,2) + DATA(I+2,2)) / 2.0
          DATA(I,2) = DATA(I-1,2) + 0.333*(DATA(I+2,2)-DATA(I-1,2))
          WRITE(21,5010) INT(DATA(I,1)),INT(TEMP),
     2                (TEMP*100.0)/MEAN,INT(DATA(I,2)+0.5)
          GOTO 1020
        ENDIF
        IF(I.EQ.7145) THEN
          TEMP = DATA(I,2)
          MEAN = (DATA(I-2,2) + DATA(I+1,2)) / 2.0
          DATA(I,2) = TEMP
          DATA(I,2) = DATA(I-2,2) + 0.666*(DATA(I+1,2)-DATA(I-2,2))
          WRITE(21,5010) INT(DATA(I,1)),INT(TEMP),
     2                (TEMP*100.0)/MEAN,INT(DATA(I,2)+0.5)
```

```
         GOTO 1020
        ENDIF
        MEAN = (DATA(I-1,2) + DATA(I+1,2)) / 2.0
        IF (DATA(I,2)/MEAN.LT.0.5) THEN
        WRITE(21,5010) INT(DATA(I,1)),INT(DATA(I,2)),
     2               (DATA(I,2)*100.0)/MEAN,INT(MEAN+0.5)
 5010   FORMAT(I5,I10,F6.1,I10)
        DATA(I,2) = MEAN
        ENDIF
 1020 CONTINUE
      CLOSE(21)

C the fixed up data file is output in the same format
      OPEN(22,FILE='tpa_sys.fix')
      DO 1030 I = 1, 8760
       WRITE(22,5020) INT(DATA(I,1)),INT(DATA(I,2)+0.5)
 5020  FORMAT(2I11)
 1030 CONTINUE
      CLOSE(22)

      END
```

Figure A.8:

Peaks and Energies in PG&E Planning Data

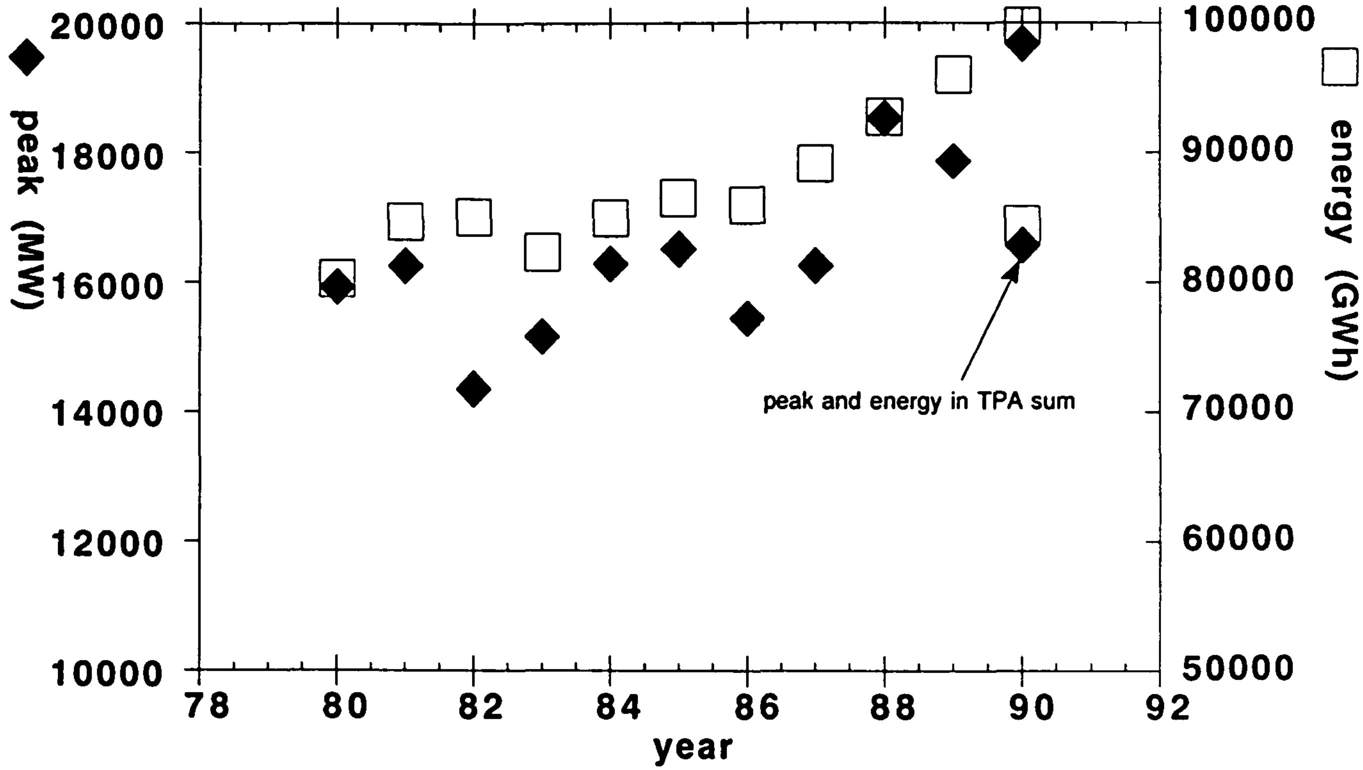


Figure A.9:
Estimated Percentage Losses for Bay Area Load

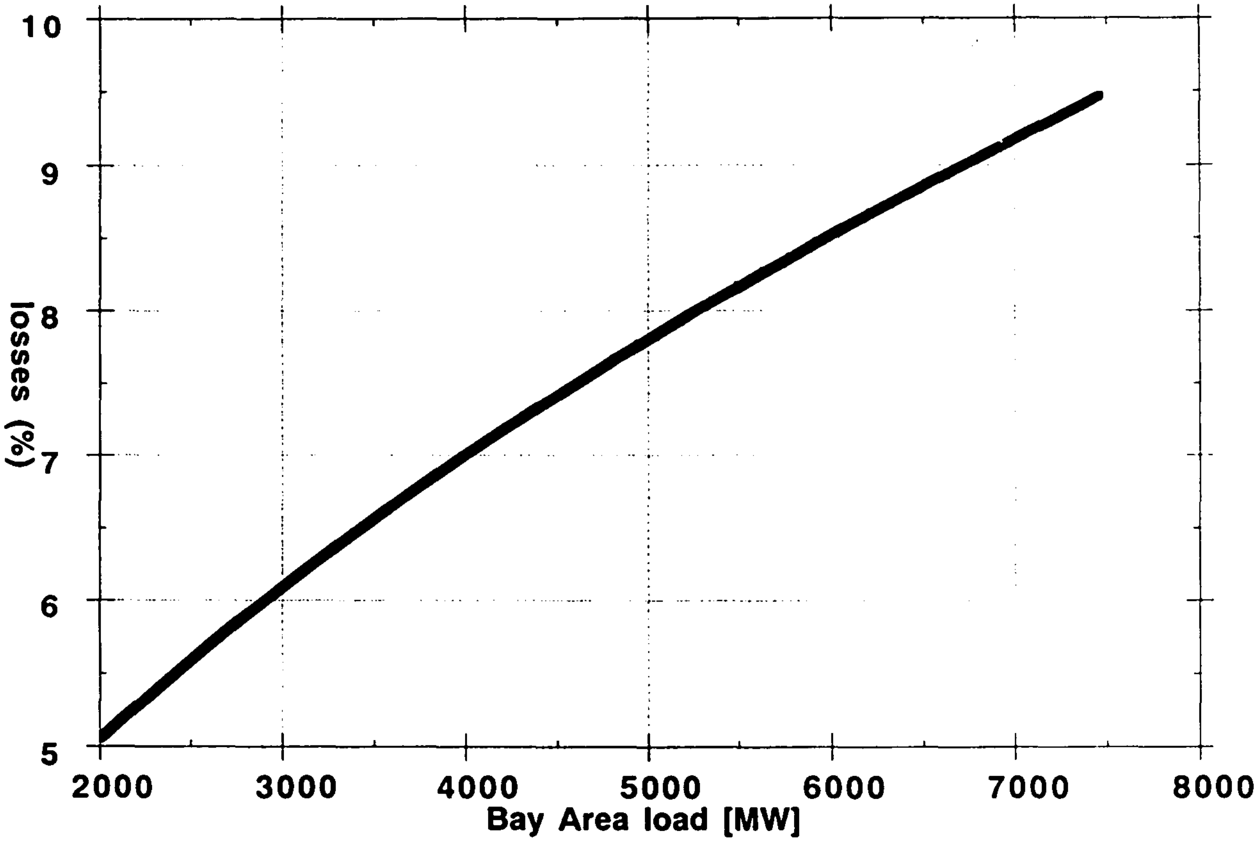


Figure A.10:

```
      PROGRAM TPASUMMER

C this program reads the data for all the TPA's and  sums them up to
form a
C total load (TPASUM) this is then compared to the PGE total TPA
system
C load and output - wholesale loads for sites in BAAQMD are added
and losses
C estimated - weather data for Fresno and Potrero is read and saved
C a grand file of dates, load and weather is output for regression

C the variables are as follows:
C BAQTOT(I)        = total of 30 TPA's in MW
C                         later the wholesale sales are added
C BAQTOTLOS(I)     = total BA load including losses for hour I
C BAQENRGY         = annual total of 30 TPA's in MWh
C BAQENRGYLOS      = annual total BA energy including losses
C BAQPEAKLOS       = annual BA peak including losses
C BAQPEAK          = annual BA peak  without losses
C CALENDAR          = 10 column calendar from subroutine TIMEKEEPER
C CHANGE            = logical to record changes in iteration loop
C DATA(I,J)        = TPA load data for hour I TPA J from TPA's files
C                     (this data is in kw,hence need for double
precision)
C ENERGIES(I)      = annual energy totals from each 30 TPA in MWh
C ENERGYTOT        = total annual 30 TPA energy
C HOUR              = temporary variable for the hour
C IPGEP90           = integer PG&E planning area load for 1990
C IWEATHFRES(7)    = temporary array of input weather data for Fresno
C IWEATHPOTR(7)    = temporary array of input weather data for Fresno
C IWHOLS(I)        = wholsesale loads in kW
C KONS              = magic constant from the losses calculation
C LOSSES            = annual total energy losses as a fraction of total
C                     generation - assumed to be 7.6% for PG&E
C PEAKS(I)         = peaks from each TPA
C PEAKHOUR         = hour of the peak of the sum of TPA's
C PEAKTOT          = sum of TPA peaks
C PGEP90            = PG&E planning area load for 1990
C PO                  = magic power assumption on non-coincidence
C POTRERO(I)       = hourly 1990 weather for Potrero, S.F.
C FRESNO(I)        = hourly 1990 weather for Fresno, S.F.
C TEMPEMP(2)       = temporary storage of temp and time
C TOPTEMPS(100,2)  = top 100 temperatures at Fresno
C TPASUM(I)        = hourly data from PG&E total TPA file, TPA_sys
C TPAS              = character string names for TPA's
C SUMLT             = sum of hourly loads same as BAQENRGY
C SUMLTPO          = sum of hourly loads to the power PO

      DOUBLE PRECISION DATA(8760,31),PEAKS(30),ENERGIES(30),HOUR
      DOUBLE PRECISION IWHOLS(8760),PEAKTOT,ENERGYTOT,TPASUM(8760)
      REAL BAQTOT(8760),BAQTOTLOS(8760),KONS,PO,LOSSES,SUMLT,SUMLTPO
      REAL BAQPEAK,BAQENRGY,BAQENRGYLOS,FRESNO(8760),POTRERO(8760)
```

```
      REAL  TOPTEMPS(500,2),TEMPTEMP(2),PGEP90(8760)
      CHARACTER*7  TPAS(30)
      INTEGER  CALENDAR(8760,10),PEAKHOUR,IWEATHFRES(7),IWEATHPOTR(7)
      INTEGER  IPGEP90(8760),IPGEPEAK,IPGENERGY
      LOGICAL CHANGE

      LOSSES = 0.076
      PO = 1.5
      YR = 90

      DO 100 J = 1, 30
         DO 101 I = 1, 8760
            BAQTOT(I)  = 0.0
            DATA(I,J)  = 0.0
            TPASUM(I)  = 0.0
            IWHOLS(I)  = 0.0
            PGEP90(I)  = 0.0
            IPGEP90(I) = 0
 101     CONTINUE
            ENERGIES(J) = 0.0
            PEAKS(J)    = 0.0
            TPAS(J)     = 'XXXXXXX'
 100  CONTINUE
            BAQPEAK   = 0.0
            HOUR      = 0.0
            IPGEPEAK  = 0
            IPGENERGY= 0
            KONS      = 0.0
            SUMLT     = 0.0
            SUMLTPO   = 0.0

C=================================================
C THIS BLOCK READS IN THE TPA AND WHOLESALE DATA
C=================================================

C reading the first TPA file
         OPEN  (11, FILE='../data/TPAs01-10')
         READ(11,5005)  (TPAS(J),J=1,10)
 5005 FORMAT(5X,10A7)
      DO 1010 I =1, 8760
           READ(11,*)  DATA(I,31),(DATA(I,J),J=1,10)
 1010 CONTINUE
      CLOSE(11)

C reading the second TPA file
         OPEN  (12, FILE='../data/TPAs11-20')
         READ(12,5005)  (TPAS(J),J=11,20)
      DO 1020 I =1, 8760
           READ(12,*)  HOUR,(DATA(I,J),J=11,20)
           IF(INT(HOUR).NE.INT(DATA(I,31)))
     2        PRINT *,'hour mismatch at hour ',I
 1020 CONTINUE
      CLOSE(12)
```

```
C reading the third TPA file
         OPEN  (13,  FILE='../data/TPAs21-30')
         READ(13,5005)  (TPAS(J),J=21,30)
       DO 1030 I =1,  8760
            READ(13,*)  HOUR,(DATA(I,J),J=21,30)
             IF(INT(HOUR).NE.INT(DATA(I,31)))
      2        PRINT *,'hour mismatch at hour ',I
 1030  CONTINUE
       CLOSE(13)

C reading the wholesale   file
         OPEN  (14,  FILE='../data/PGE_wholesale')
       DO 1035 I = 1,  8760
        READ(14,*)  HOUR,IWHOLS(I)
             IF(INT(HOUR).NE.INT(DATA(I,31)))
      2        PRINT *,'hour mismatch at hour ',I
 1035  CONTINUE
       CLOSE(14)

C reading the 1990 PGE planning area load file
         OPEN  (16,  FILE='../data/YR90')
         DO 1025 J = 1,  365
                READ(16,5007)  (IPGEP90(K),K=((J-1)*24)+1,((J-1)*24)+12)
                READ(16,5007)  (IPGEP90(K),K=((J-1)*24)+13,((J-1)*24)+24)
 5007       FORMAT(20X,12I5)
 1025    CONTINUE
       CLOSE(16)
       DO 1026 I = 1,  8760
          IF(IPGEP90(I).GT.IPGEPEAK)  IPGEPEAK  =  IPGEP90(I)
         IPGENERGY  =  IPGENERGY  +  IPGEP90(I)
 1026  CONTINUE

C==========================================================
C THIS BLOCK CALCULATES AND OUTPUTS THE TPA PEAKS AND ENERGIES
C AND THE TPA SYSTEM FILE IS READ
C==========================================================

C finding the peaks and energies for each TPA

       DO 1040 I = 1,  8760
         DO 1045 J =1,  30
              IF(DATA(I,J).GT.PEAKS(J))  PEAKS(J)  =  DATA(I,J)
             ENERGIES(J)  =  ENERGIES(J)  +  DATA(I,J)
 1045    CONTINUE
 1040  CONTINUE

C printing the peaks and energies
       PEAKTOT    = 0.0
       ENERGYTOT  = 0.0
         OPEN(21,FILE='TPA.Peaks.and.Energies')
        WRITE(21,5015)
 5015  FORMAT('      TPA  peak(MW)     energy(GWh)')
```

```
       DO 1050 I = 1, 30
            WRITE(21,5020)  TPAS(I),  PEAKS(I)/1000.,  ENERGIES(I)/1000000.
 5020     FORMAT(A7,2F10.3)
          PEAKTOT     = PEAKTOT + PEAKS(I)
           ENERGYTOT = ENERGYTOT + ENERGIES(I)
 1050  CONTINUE
            WRITE(21,5030)  PEAKTOT/1000.,  ENERGYTOT/1000000.
 5030     FORMAT('  TOTALS',2F10.0)
       CLOSE(21)

C reading the PG&E total TPA load file
          OPEN(22,FILE='../data/TPA_sys')
       DO 1060 I = 1, 8760
           READ(22,*) HOUR,TPASUM(I)
            IF(INT(HOUR).NE.INT(DATA(I,31)))
      2       PRINT *,'Hour mismatch at hour ',I
 1060  CONTINUE
       CLOSE(22)

C==============================================================
C IN THIS BLOCK THE TPA LOADS ARE SUMMED
C==============================================================

C this where the total BAAQMD load is estimated
C BAQTOT, is the sum of all of
C the 30 TPA's except that 28, VCV04, is only 1/3 in BAAQMD

          OPEN(22,FILE='BAQ.so.tot.TPA')
       DO 1070 I = 1, 8760
         DO 1075 J = 1, 28
             BAQTOT(I)  = BAQTOT(I)  + (DATA(I,J)/1000.)
 1075    CONTINUE
              BAQTOT(I)  = BAQTOT(I)  + ((DATA(I,28)*0.33)/1000.)
      2                          + (DATA(I,30)/1000.)
             BAQSHARE   = BAQTOT(I)  /  (TPASUM(I)*0.01)
             IF(BAQTOT(I).GT.BAQPEAK)  THEN
               BAQPEAK =   BAQTOT(I)
              PEAKHOUR = I
           ENDIF
            BAQENRGY       = BAQENRGY +   BAQTOT(I)
              WRITE(22,5040)     I,BAQTOT(I),TPASUM(I)*0.01,BAQSHARE
 5040               FORMAT(I5,2F10.0,F10.3)
              IF  (BAQSHARE.LT.0.25.OR.BAQSHARE.GT.0.75)  THEN
                  WRITE(6,*)  ' BAAQMD share < 25% or > 75% of TPA
total'
                     WRITE(6,5040)  I,BAQTOT(I),TPASUM(I)*0.01,BAQSHARE
           ENDIF
             SUMLTPO = SUMLTPO + BAQTOT(I)**PO
 1070  CONTINUE
           SUMLT    =   BAQENRGY
       CLOSE(22)

C==============================================================
```

```
C IN THIS BLOCK THE LOSSES ARE CALCULATED AND ADDED
C AND THE CALENDAR IS WRITTEN
C==========================================================

C this is where the wholesale and other supplementary loads are
added
C to PG&E's TPA load
C the hourly fractions are also output to be used in other load
calculations
C such as the estimate of the wholesale load

        OPEN(23,FILE='fractions')
       DO 1080 I = 1, 8760
           WRITE (23,5050) I, BAQTOT(I)/BAQPEAK
            BAQTOT(I) =  BAQTOT(I) + IWHOLS(I)/1000.0
 5050     FORMAT(I10,F10.6)
 1080  CONTINUE
       CLOSE(23)

C now the losses are estimated and added to the TPA load

        KONS = LOSSES * (SUMLT/SUMLTPO)
       DO 2010 I = 1, 8760
           BAQTOTLOS(I) = BAQTOT(I) + KONS*(BAQTOT(I)**1.5)
 2010  CONTINUE

C now run the calendar subroutine
        CALL TIMEKEEPER(CALENDAR)

C==========================================================
C IN THIS BLOCK READS THE WEATHER DATA
C==========================================================

C now read the temperature data for FRESNO and POTRERO
C since these files contain data for 89 and 90
C and are half hourly lots of data is skipped,
C hence the GOTO's
C the temps are printed out to the file temperature.check in F
C then converted to Celcius
       CHANGE = .FALSE.
       DO 2025 I = 1, 100
         TOPTEMPS(I,1) = 0.0
         TOPTEMPS(I,2) = 0.0
 2025  CONTINUE
          OPEN(14,FILE='../../weather/Fresno.89-90.PGE')
          OPEN(15,FILE='../../weather/Potrero.89-90.PGE')
         OPEN(25,FILE='temperature.check')
        OPEN(28,FILE='Celcius.data')
       WRITE(25,5055)
 5055  FORMAT(' hour Fres. Potr.')
       WRITE(28,*) 'hour Pot. Fres. ration'
       DO 2020 I = 1, 8760
 2030    CONTINUE
```

```
          READ(14,5060)(IWEATHFRES(J),J=1,7)
          READ(15,5060)(IWEATHPOTR(J),J=1,7)
 5060     FORMAT(I3,3I2,I3,I2,I5)
          IF(IWEATHFRES(1).NE.28)  PRINT *,  'Code mismatch at',I
          IF(IWEATHFRES(2).NE.90)  GOTO 2030
          IF(IWEATHFRES(6).GT.0)   GOTO 2030
          FRESNO(I)   = REAL(IWEATHFRES(7))
          POTRERO(I)  = REAL(IWEATHPOTR(7))
          IF(IWEATHFRES(2).NE.CALENDAR(I,9))  PRINT *,'year mismatch
at',I
          IF(IWEATHPOTR(2).NE.CALENDAR(I,9))  PRINT *,'year mismatch
at',I
          IF(IWEATHFRES(3).NE.CALENDAR(I,8))  PRINT *,'month mismatch
at',I
          IF(IWEATHPOTR(3).NE.CALENDAR(I,8))  PRINT *,'month mismatch
at',I
          IF(IWEATHFRES(4).NE.CALENDAR(I,7))  PRINT *,'date mismatch
at',I
          IF(IWEATHPOTR(4).NE.CALENDAR(I,7))  PRINT *,'date mismatch
at',I
        DO 2026 J = 1, 251
          IF(CHANGE) GOTO 2026
            IF  (FRESNO(I).GT.TOPTEMPS(J,2))  THEN
             TEMPTEMP(1)     = TOPTEMPS(J,1)
             TEMPTEMP(2)     = TOPTEMPS(J,2)
             TOPTEMPS(J,1) = REAL(I)
             TOPTEMPS(J,2) = FRESNO(I)
            DO 2027 K = 250,J+2,-1
                TOPTEMPS(K,1) = TOPTEMPS(K-1,1)
                TOPTEMPS(K,2) = TOPTEMPS(K-1,2)
 2027       CONTINUE
             TOPTEMPS(J+1,1) = TEMPTEMP(1)
             TOPTEMPS(J+1,2) = TEMPTEMP(2)
            CHANGE = .TRUE.
          ENDIF
 2026   CONTINUE
        CHANGE = .FALSE.
          WRITE(25,5065)  I,INT(FRESNO(I)+0.5),INT(POTRERO(I)+0.5)
 5065     FORMAT(3I5)
          FRESNO(I)   = (FRESNO(I)  - 32.0) * (5.0/9.0)
          POTRERO(I)  = (POTRERO(I) - 32.0) * (5.0/9.0)
          WRITE(28,5067)  I,CHAR(9),FRESNO(I),CHAR(9),POTRERO(I)
 5067     FORMAT(I5,A1,F6.1,A1,F6.1)
 2020   CONTINUE
      WRITE(25,*) '    '
        WRITE(25,*)  ' RANKED TEMPERATURE DATA FOR FRESNO'
      WRITE(25,*) ' rank   hour       T F         T C'
      DO 2040 I = 1, 250
          WRITE(25,5066)  I,INT(TOPTEMPS(I,1)),TOPTEMPS(I,2),
     2    (TOPTEMPS(I,2) - 32.0) * (5.0/9.0)
 5066 FORMAT(2I6,2F10.1)
 2040 CONTINUE
      CLOSE(14)
```

```
        CLOSE(15)
        CLOSE(25)
        CLOSE(28)

C===========================================================
C IN THIS BLOCK OUTPUTS THE LOADS AND SUMMARY DATA
C===========================================================

C now print the losses results
        BAQENRGYLOS   =   0.0
          OPEN(24,FILE='losses.results')
         WRITE(24,5075)
  5075  FORMAT(' hour  w/o_losses  w_losses       percent_loss')
        DO 3010 I = 1, 8760
             WRITE(24,5070)I,  BAQTOT(I),BAQTOTLOS(I),
       3                       (BAQTOTLOS(I)-BAQTOT(I))/(BAQTOT(I)/100.0)
   5070  FORMAT(I6,2F10.0,F10.3)
           BAQENRGYLOS   = BAQENRGYLOS +   BAQTOTLOS(I)
             IF(BAQTOTLOS(I).GT.BAQPEAKLOS)  BAQPEAKLOS  =  BAQTOTLOS(I)
  3010  CONTINUE
         WRITE(24,5080)  KONS
 5080 FORMAT('                               konstant  =  ',F10.6)
          WRITE(24,5081)  INT((BAQENRGYLOS/1000.0)+0.5)
  5081  FORMAT('total  BA  energy  including  losses  =  ',I10,'  GWh')
          WRITE(24,5082)  INT(BAQPEAKLOS+0.5)
  5082  FORMAT('  BA  annual  peak  including  losses  =  ',I10,'  MW')
           WRITE(24,5083)   (BAQENRGYLOS*100.0)/(BAQPEAKLOS*8760.)
  5083 FORMAT('               annual  capacity  factor  =  ',F10.1,'  %')
        CLOSE(24)

C===========================================================
C THIS BLOCK OUTPUTS THE FINAL DATA FILE FOR REGRESSION
C===========================================================

C now print the final output file for regression
C the Fresno data is translated to reflect results
C of earlier regression residuals
          OPEN(26,FILE='BA.load.1990')
         WRITE(26,*)  ' HOY HOD HOW DOY WOY DOW  WE DOM MOY  YR ',
      2                 '  FreT  PotT load  90PL  frac'
        DO 3020 I = 1, 8760
           WRITE(26,5090)
     2
(CALENDAR(I,J),J=1,6),CALENDAR(I,10),(CALENDAR(I,J),J=7,9),
         3       FRESNO(I),POTRERO(I),INT(BAQTOTLOS(I)+0.5),IPGEP90(I),
        4       BAQTOTLOS(I)/REAL(IPGEP90(I))
  5090      FORMAT(10I4,2F6.1,2I6,F6.3)
  3020  CONTINUE
        CLOSE(26)

C===========================================================
C THIS BLOCK OUTPUTS THE DATA FILE OF FRACTIONS
C===========================================================
```

```
      OPEN(27,FILE='comparative.fractions')
     DO 3030 I = 3,8760,3
      WRITE(27,6010)  I,CHAR(9),  BAQTOTLOS(I)/BAQPEAKLOS,CHAR(9),
     2    REAL(IPGEP90(I))/REAL(IPGEPEAK)
 6010  FORMAT(I6,1A,F8.6,1A,F8.6)
 3030  CONTINUE

      END

C
======================================================================
        SUBROUTINE  TIMEKEEPER(CALENDAR)
C this subroutine makes a
C this program makes a calendar and puts it into the matrix,
CALENDAR
C the cols of CALENDAR contain the following data
C       HOY = hour of the year 1 to 8760
C       HOD = hour of the day 1 to 24
C       HOW = hour of the week 1 to 168
C       DOY = day of the year 1 to 365
C       WOY = week of the year 1 to 53
C       DOW = day of the week 1 to 7, 1990 begins on a monday=1
C       DOM = day of the month 1 to 31
C       MOY = month of the year 1 to 12
C       YR  = 90 in this case
C       WE  = 0 if weekend, 1 otherwise

        INTEGER CALENDAR(8760,10)
         INTEGER  HOY,HOD,HOW,DOY,WOY,DOW,DOM,MOY,YR,WE

      HOY = 1
      HOD = 1
      HOW = 1
      DOY = 1
      WOY = 1
      DOW = 1
      DOM = 1
      MOY = 1
      YR = 90
      WE =  1

      DO 2010 I = 1, 8760

         CALENDAR(HOY,1)  = HOY
         CALENDAR(HOY,2)  = HOD
         CALENDAR(HOY,3)  = HOW
         CALENDAR(HOY,4)  = DOY
         CALENDAR(HOY,5)  = WOY
         CALENDAR(HOY,6)  = DOW
         CALENDAR(HOY,7)  = DOM
         CALENDAR(HOY,8)  = MOY
         CALENDAR(HOY,9)  = YR
```

```
          CALENDAR(HOY,10)  =  WE

         HOY  =  HOY  +  1
          IF(HOD.EQ.24)  THEN
           HOD  =  HOD  +  1
           DOW  =  DOW  +  1
           DOY  =  DOY  +  1
         ELSE
           HOD  =  HOD  +  1
         ENDIF
          IF(HOW.EQ.168)  THEN
           HOW  =  1
           WOY  =  WOY  +  1
         ELSE
           HOW  =  HOW  +  1
         ENDIF
          IF(HOD.EQ.25)  THEN
            IF(MOY.EQ.2)THEN
                IF(DOM.EQ.28)  THEN
                DOM  =  1
                MOY  =  MOY  +  1
                GOTO  2050
              ELSE
                DOM  =  DOM  +  1
              ENDIF
           ENDIF
               IF(MOY.EQ.1.OR.MOY.EQ.3.OR.MOY.EQ.5.OR.MOY.EQ.7.OR.
     2              MOY.EQ.8.OR.MOY.EQ.10.OR.MOY.EQ.12)  THEN
              IF(DOM.EQ.31)THEN
              DOM  =  1
              MOY  =  MOY  +  1
              GOTO  2050
            ELSE
              DOM  =  DOM  +  1
            ENDIF
           ENDIF
               IF(MOY.EQ.4.OR.MOY.EQ.6.OR.MOY.EQ.9.OR.MOY.EQ.11)  THEN
              IF(DOM.EQ.30)  THEN
              DOM  =  1
              MOY  =  MOY  +  1
              GOTO  2050
            ELSE
               DOM  =  DOM  +  1
            ENDIF
           ENDIF
         ENDIF
2050     CONTINUE
         IF(HOD.EQ.25)  HOD  =  1
          IF(DOW.EQ.6.OR.DOW.EQ.7)  THEN
           WE  =  0
        ELSE
           WE  =  1
        ENDIF
```

```
      IF(DOW.EQ.8)    DOW = 1
2010  CONTINUE
      RETURN

      END
```

Figure A.11
Regression Residuals and Temperature at Fresno

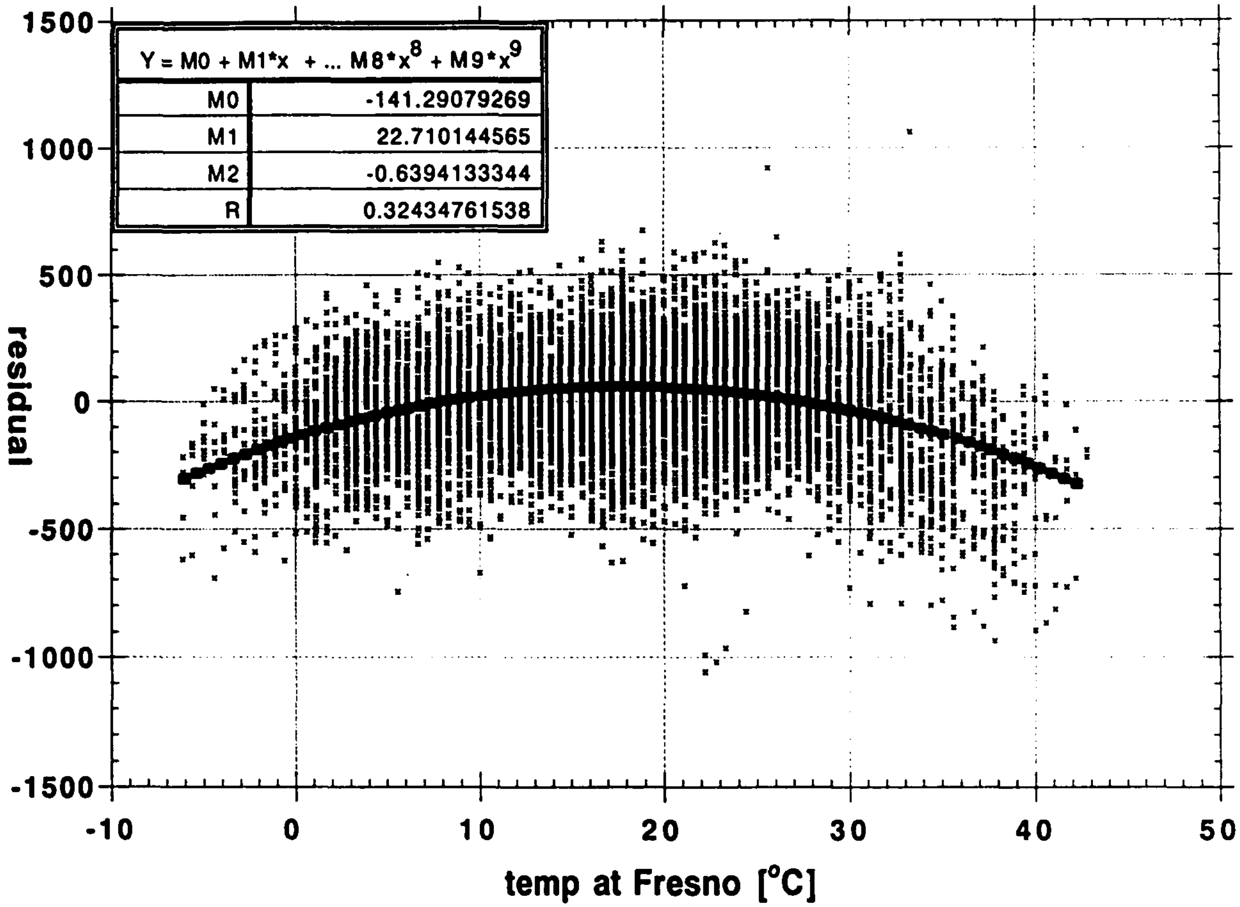


Figure A.12:
Regression Residuals and Temperature at Potrero

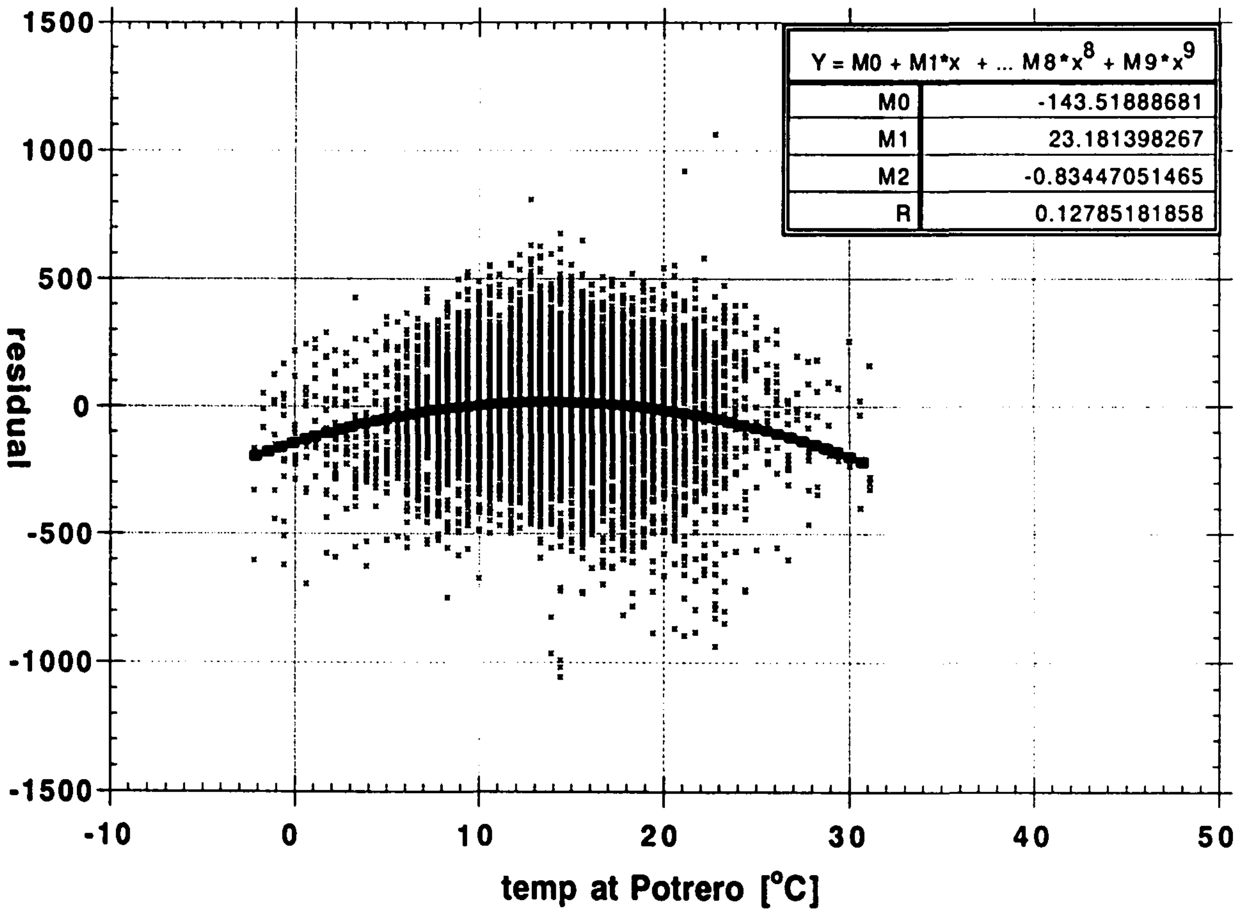


Figure A.13:

```
      PROGRAM FINAL_LOAD

C this program produces the 1989 load estimate based on
C the regression coefficients of the 1990 regression

      INTEGER CALENDAR(8760,10),IPGEP89(8760),NOBS
      INTEGER IWEATHFRES(7),IWEATHPOTR(7),TEMPIND(8760)

      REAL PGEP89(8760),FRESNO(8760),POTRERO(8760),BA89(8760)

      REAL HISTDAT(500,2),LOWER,UPPER,TEMP

      REAL ALPHA(3)
      REAL BETA(4)
      REAL GAMMA(4)
      REAL DELTA(12)
      REAL EPSILON(24)
      REAL ZETA(2)

      ALPHA(1)      =  177.835026
      ALPHA(2)      =    0.393145
      ALPHA(3)      =   19.487647

      BETA(1)       = -856.019091
      BETA(2)       = 1741.719019
      BETA(3)       =  411.435688
      BETA(4)       =    0.000000

      GAMMA(1)      =    0.687279
      GAMMA(2)      =  -64.963116
      GAMMA(3)      =  -20.195576
      GAMMA(4)      =    1.396593

      DELTA(1)      =    2.524266
      DELTA(2)      =    1.903314
      DELTA(3)      =    7.576420
      DELTA(4)      = -132.952845
      DELTA(5)      = -194.378504
      DELTA(6)      = -419.657500
      DELTA(7)      = -638.252624
      DELTA(8)      = -545.441793
      DELTA(9)      = -364.415686
      DELTA(10)     =  -96.011190
      DELTA(11)     = -120.002606
      DELTA(12)     =    0.000000

      EPSILON(1)    = -155.032937
      EPSILON(2)    = -247.177412
      EPSILON(3)    = -287.563014
      EPSILON(4)    = -327.099455
      EPSILON(5)    = -368.583745
      EPSILON(6)    = -409.393739
```

```
EPSILON(7)       =   -321.462725
EPSILON(8)       =      1.006138
EPSILON(9)       =    154.859165
EPSILON(10)      =    283.987035
EPSILON(11)      =    359.163781
EPSILON(12)      =    444.402888
EPSILON(13)      =    394.051525
EPSILON(14)      =    407.626640
EPSILON(15)      =    398.624706
EPSILON(16)      =    343.682934
EPSILON(17)      =    241.400257
EPSILON(18)      =    252.898521
EPSILON(19)      =    324.129569
EPSILON(20)      =    285.345878
EPSILON(21)      =    303.387785
EPSILON(22)      =    300.130490
EPSILON(23)      =    182.026981
EPSILON(24)      =      0.000000

ZETA(1)          =   -159.741582
ZETA(1)          =      0.000000

      CALL  TIMEKEEPER(CALENDAR)

C==============================================================
C THIS BLOCK READS THE PGE PLANNING LOAD DATA
C==============================================================
      PGEPEAK  = 0.0
      PGENERGY = 0.0
C reading the 1989 PGE planning area load file
      OPEN  (16,FILE='../data/YR89')
       DO 1010 J = 1,365
              READ(16,5010)(IPGEP89(K),K=((J-1)*24)+1,((J-1)*24)+12)
              READ(16,5010)(IPGEP89(K),K=((J-1)*24)+13,((J-1)*24)+24)
 5010        FORMAT(20X,12I5)
 1010    CONTINUE
      CLOSE(16)
      DO 1020 I = 1, 8760
         PGEP89(I)  = REAL(IPGEP89(I))
         IF(PGEP89(I).GT.PGEPEAK)  PGEPEAK  =  PGEP89(I)
        PGENERGY = PGENERGY + PGEP89(I)
 1020  CONTINUE

C==============================================================
C THIS BLOCK READS THE WEATHER DATA
C==============================================================

C now read the temperature data for FRESNO and POTRERO
C since these files contain data for 89 and 90,
C and data are half hourly, lots of data are skipped,
C hence the GOTO's - then temps are converted to Celcius

      CHANGE = .FALSE.
```

```
          OPEN(14,FILE='../../weather/Fresno.89-90.PGE')
          OPEN(15,FILE='../../weather/Potrero.89-90.PGE')
        DO 2020 I = 1, 8760
  2030     CONTINUE
             READ(14,5020)(IWEATHFRES(J),J=1,7)
             READ(15,5020)(IWEATHPOTR(J),J=1,7)
  5020      FORMAT(I3,3I2,I3,I2,I5)
            IF(IWEATHFRES(1).NE.28) PRINT *, 'Code mismatch at',I
            IF(IWEATHFRES(2).NE.89) GOTO 2030
            IF(IWEATHFRES(6).GT.0)  GOTO 2030
            FRESNO(I)   = REAL(IWEATHFRES(7))
            POTRERO(I)  = REAL(IWEATHPOTR(7))
             IF(IWEATHFRES(2).NE.CALENDAR(I,9)) PRINT *,'year mismatch
at',I
             IF(IWEATHPOTR(2).NE.CALENDAR(I,9)) PRINT *,'year mismatch
at',I
             IF(IWEATHFRES(3).NE.CALENDAR(I,8)) PRINT *,'month mismatch
at',I
             IF(IWEATHPOTR(3).NE.CALENDAR(I,8)) PRINT *,'month mismatch
at',I
             IF(IWEATHFRES(4).NE.CALENDAR(I,7)) PRINT *,'date mismatch
at',I
             IF(IWEATHPOTR(4).NE.CALENDAR(I,7)) PRINT *,'date mismatch
at',I
          FRESNO(I)  = (FRESNO(I)  - 32.0) * (5.0/9.0)
         IF(FRESNO(I).GT.39.9)                          TEMPIND(I) = 0
            IF(FRESNO(I).GT.29.9.AND.FRESNO(I).LE.39.9)  TEMPIND(I) = 1
            IF(FRESNO(I).GT.19.9.AND.FRESNO(I).LE.29.9)  TEMPIND(I) = 2
         IF(FRESNO(I).LE.19.9)                          TEMPIND(I) = 3
          POTRERO(I) = (POTRERO(I) - 32.0) * (5.0/9.0)
  2020 CONTINUE
  2040 CONTINUE
        CLOSE(14)
        CLOSE(15)

C
=====================================================================
=
C REGRESSION LINE USED HERE
C
=====================================================================
=

        DO 3010 I = 1, 8760
            BA89(I) = ALPHA(1) + ALPHA(2)*PGEP89(I) +
ALPHA(3)*POTRERO(I)  +
        2               BETA(TEMPIND(I)+1) + GAMMA(TEMPIND(I)+1)*FRESNO(I)
+
        3               DELTA(CALENDAR(I,8)) + EPSILON(CALENDAR(I,2)) +
        4             ZETA(CALENDAR(I,10)+1)
  3010 CONTINUE

C
```

```
C=================================================================
=
C PRINT A FILE FOR 89 JUST LIKE THE REGRESSION DATA SET
C
C=================================================================
=

         OPEN(21,FILE='BA.load.1989')
        WRITE(21,*) ' HOY HOD HOW DOY WOY DOW  WE DOM MOY  YR ',
     2                    '  FreT  PotT load  89PL  frac'
        DO 4020 I = 1, 8760
           WRITE(21,5030)
     2
(CALENDAR(I,J),J=1,6),CALENDAR(I,10),(CALENDAR(I,J),J=7,9),
     3        FRESNO(I),POTRERO(I),INT(BA89(I)+0.5),IPGEP89(I),
     4      BA89(I)/REAL(IPGEP89(I))
 5030      FORMAT(10I4,2F6.1,2I6,F6.3)
 4020   CONTINUE
        CLOSE(21)

C
C=================================================================
=
C PRINT A FILE OF THE HISTOGRAM DATA FOR 1989 FRACTIONS
C
C=================================================================
=

          OPEN(22,FILE='1989.histogram.data')

        HISTDAT(1,1) = 20.0
        DO 4025 I = 2, 100
           HISTDAT(I,1) =  HISTDAT(I-1,1) + 0.5
          HISTDAT(I,2) =  0.0
 4025   CONTINUE

        DO 4040 I = 1, 8760
           TEMP = BA89(I)/REAL(IPGEP89(I))
          DO 4050 J = 1, 100
             LOWER = (HISTDAT(J,1) - 0.25)/100.0
             UPPER = (HISTDAT(J,1) + 0.25)/100.0
              IF (TEMP.GE.LOWER.AND.TEMP.LT.UPPER) THEN
               HISTDAT(J,2) = HISTDAT(J,2) + 1.0
           ENDIF
 4050     CONTINUE
 4040   CONTINUE

       NOBS = 0
       DO 4060 I = 1, 100
            WRITE(22,5040) HISTDAT(I,1),CHAR(9),INT(HISTDAT(I,2))
          NOBS = NOBS + INT(HISTDAT(I,2))
 5040     FORMAT(F6.3,A1,I6)
 4060   CONTINUE
```

```
        CLOSE(22)

        END
C
=====================================================================

          SUBROUTINE  TIMEKEEPER(CALENDAR)

C this subrountine makes a calendar and puts it into the matrix,
CALENDAR
C the cols of CALENDAR contain the following data
C       HOY = hour of the year 1 to 8760
C       HOD = hour of the day 1 to 24
C       HOW = hour of the week 1 to 168
C       DOY = day of the year 1 to 365
C       WOY = week of the year 1 to 53
C       DOW = day of the week 1 to 7, 1990 begins on a monday=1
C       DOM = day of the month 1 to 31
C       MOY = month of the year 1 to 12
C       YR  = 89 in this case
C       WE  = 0 if weekend, 1 otherwise

          INTEGER CALENDAR(8760,10)
           INTEGER  HOY,HOD,HOW,DOY,WOY,DOW,DOM,MOY,YR,WE

        HOY = 1
        HOD = 1
        HOW = 1
        DOY = 1
        WOY = 1
        DOW = 7
        DOM = 1
        MOY = 1
        YR = 89
        WE =  0

        DO 2010 I = 1, 8760

           CALENDAR(HOY,1)    = HOY
           CALENDAR(HOY,2)    = HOD
           CALENDAR(HOY,3)    = HOW
           CALENDAR(HOY,4)    = DOY
           CALENDAR(HOY,5)    = WOY
           CALENDAR(HOY,6)    = DOW
           CALENDAR(HOY,7)    = DOM
           CALENDAR(HOY,8)    = MOY
           CALENDAR(HOY,9)    = YR
           CALENDAR(HOY,10)  = WE

          HOY = HOY + 1
           IF(HOD.EQ.24) THEN
            HOD = HOD + 1
```

```
          DOW = DOW + 1
          DOY = DOY + 1
       ELSE
          HOD = HOD + 1
       ENDIF
         IF(HOW.EQ.168)  THEN
          HOW = 1
          WOY = WOY + 1
       ELSE
          HOW = HOW + 1
       ENDIF
         IF(HOD.EQ.25)  THEN
            IF(MOY.EQ.2)THEN
                 IF(DOM.EQ.28)  THEN
                 DOM = 1
                 MOY = MOY + 1
                 GOTO 2050
               ELSE
                 DOM = DOM + 1
               ENDIF
          ENDIF
               IF(MOY.EQ.1.OR.MOY.EQ.3.OR.MOY.EQ.5.OR.MOY.EQ.7.OR.
     2              MOY.EQ.8.OR.MOY.EQ.10.OR.MOY.EQ.12)  THEN
              IF(DOM.EQ.31)THEN
              DOM = 1
              MOY = MOY + 1
              GOTO 2050
            ELSE
              DOM = DOM + 1
            ENDIF
          ENDIF
              IF(MOY.EQ.4.OR.MOY.EQ.6.OR.MOY.EQ.9.OR.MOY.EQ.11)  THEN
             IF(DOM.EQ.30)  THEN
              DOM = 1
              MOY = MOY + 1
              GOTO 2050
            ELSE
               DOM = DOM + 1
            ENDIF
          ENDIF
       ENDIF
2050   CONTINUE
       IF(HOD.EQ.25)  HOD = 1
        IF(DOW.EQ.6.OR.DOW.EQ.7)  THEN
          WE = 0
      ELSE
          WE = 1
      ENDIF
       IF(DOW.EQ.8)   DOW = 1
2010  CONTINUE
      RETURN

      END
```

Figure A.14:

Comparison of SAS and Predictive Equation Residuals

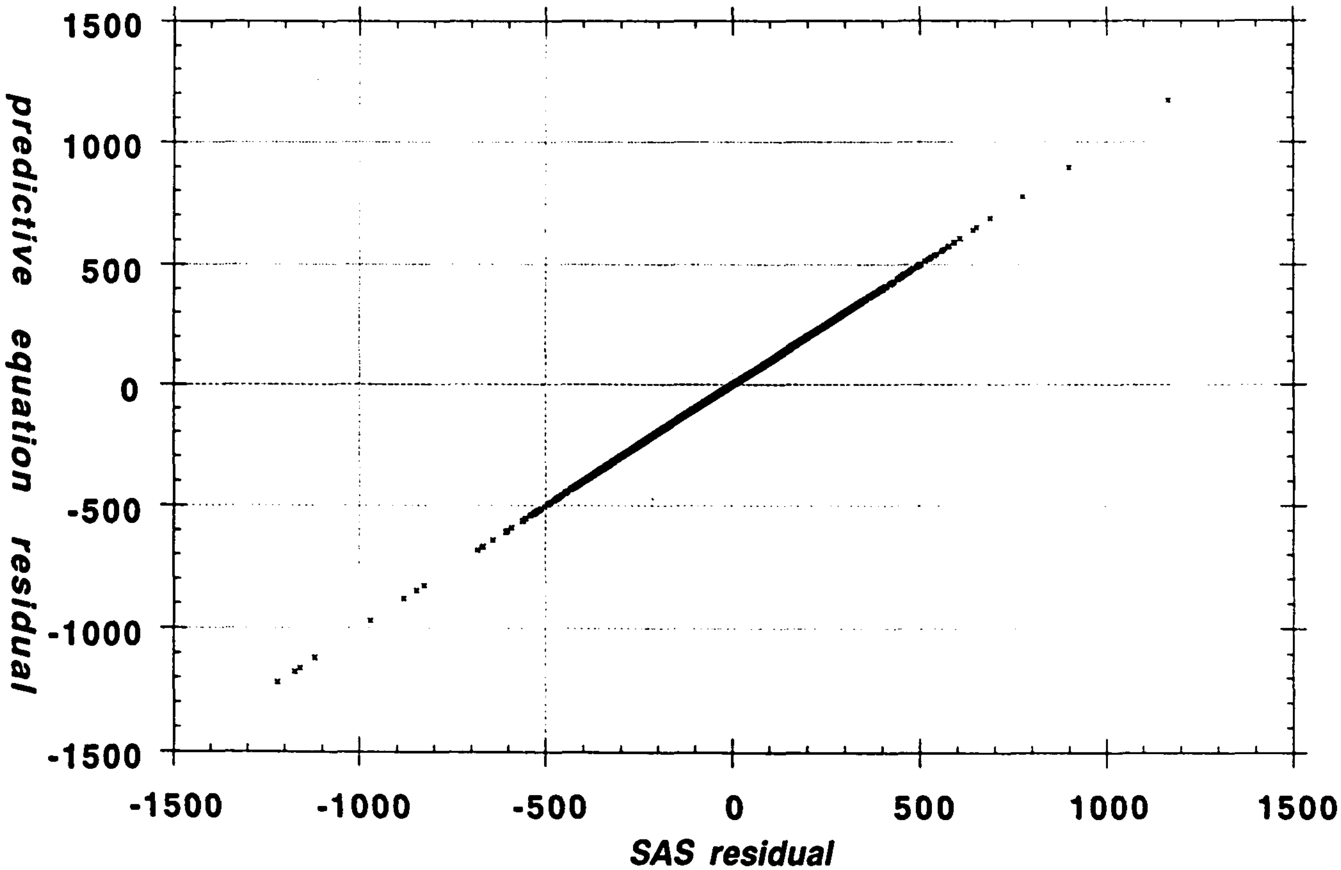


Figure A.15:

Frequency Histogram of Bay Area Load as a Fraction of the PG&E Planning Area Load 1990

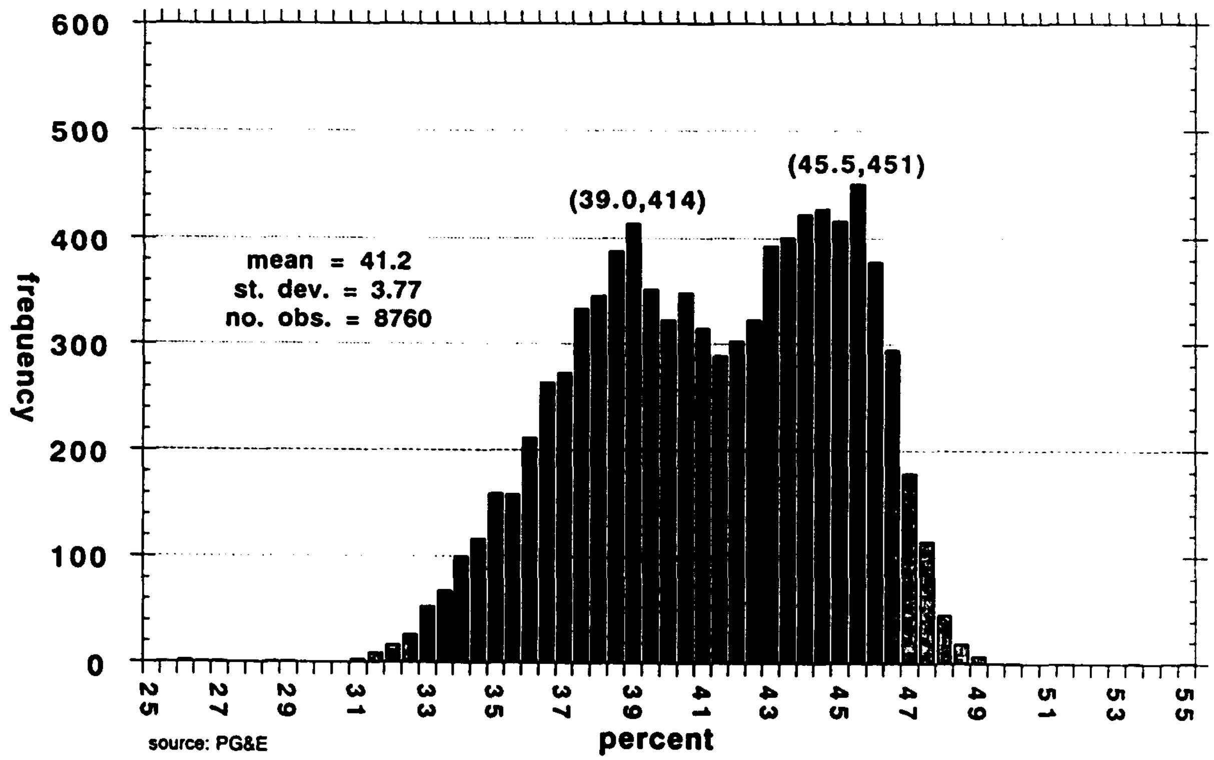


Figure A.16:

Frequency Histogram of Bay Area Load as a Fraction of the PG&E Planning Area Load 1989

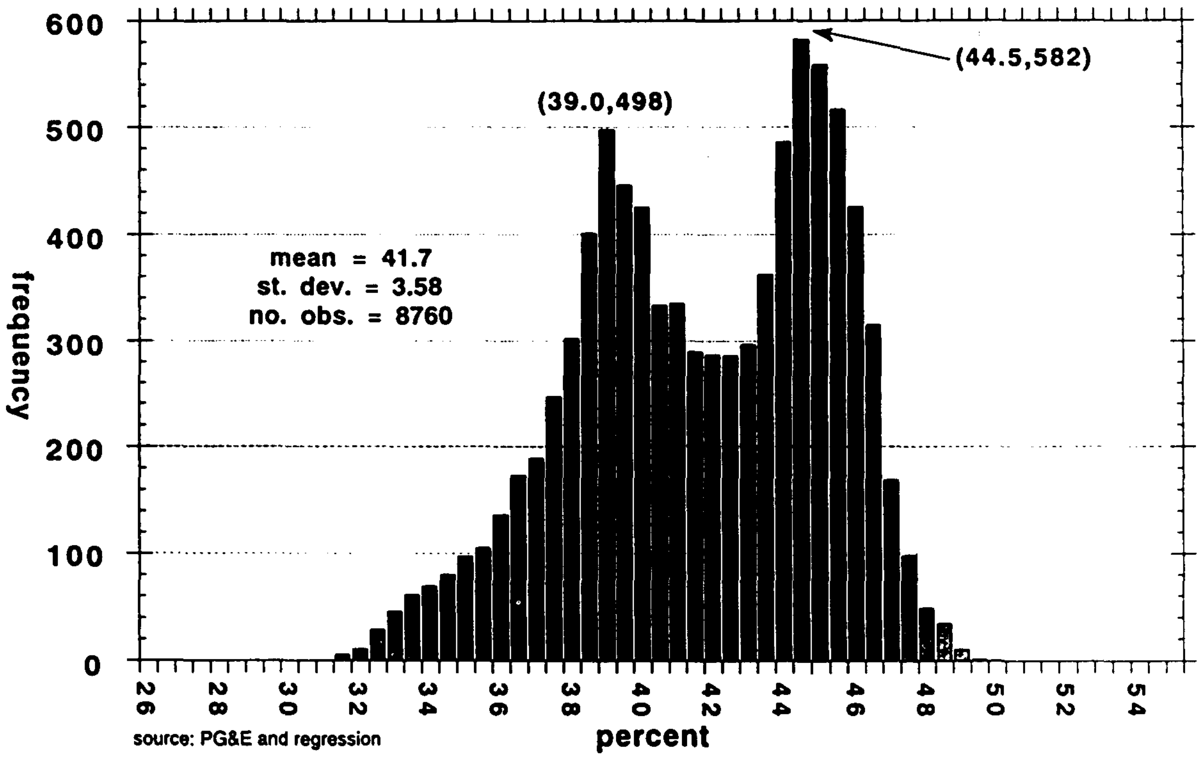


Figure A.17:
Bay Area share of PG&E Planning Load by Hour 1990 Showing Standard Deviations

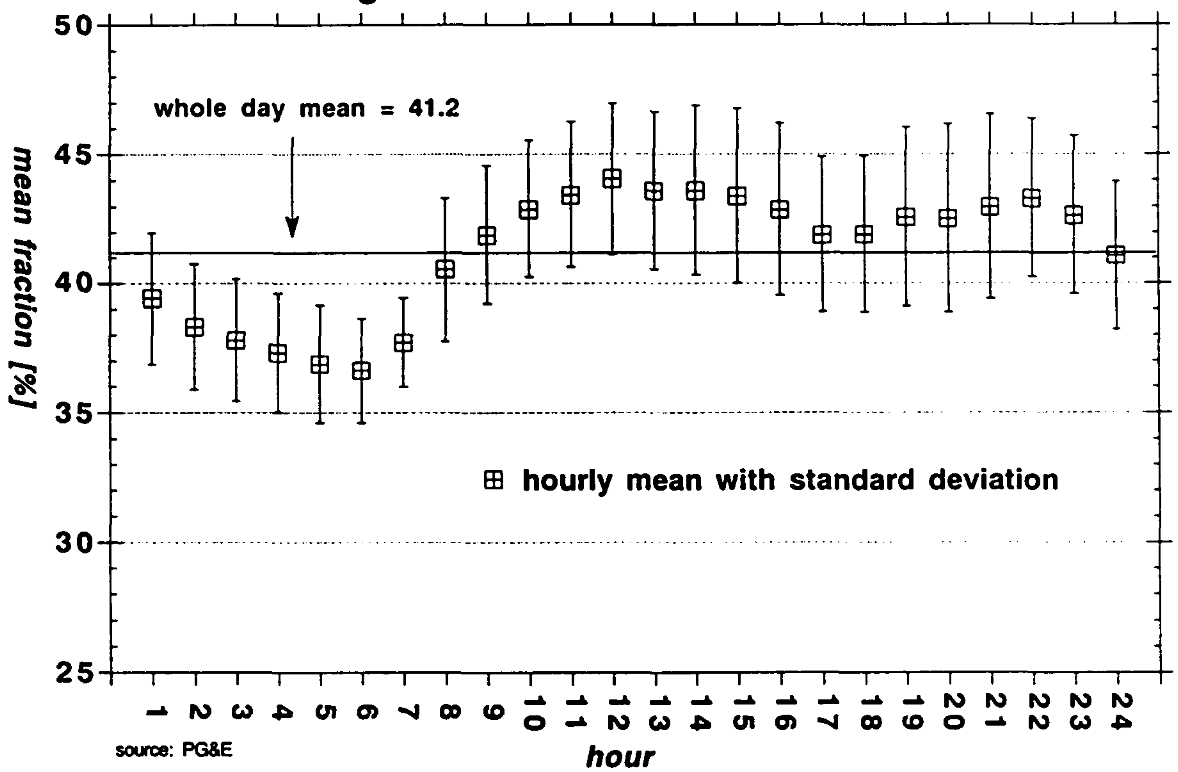
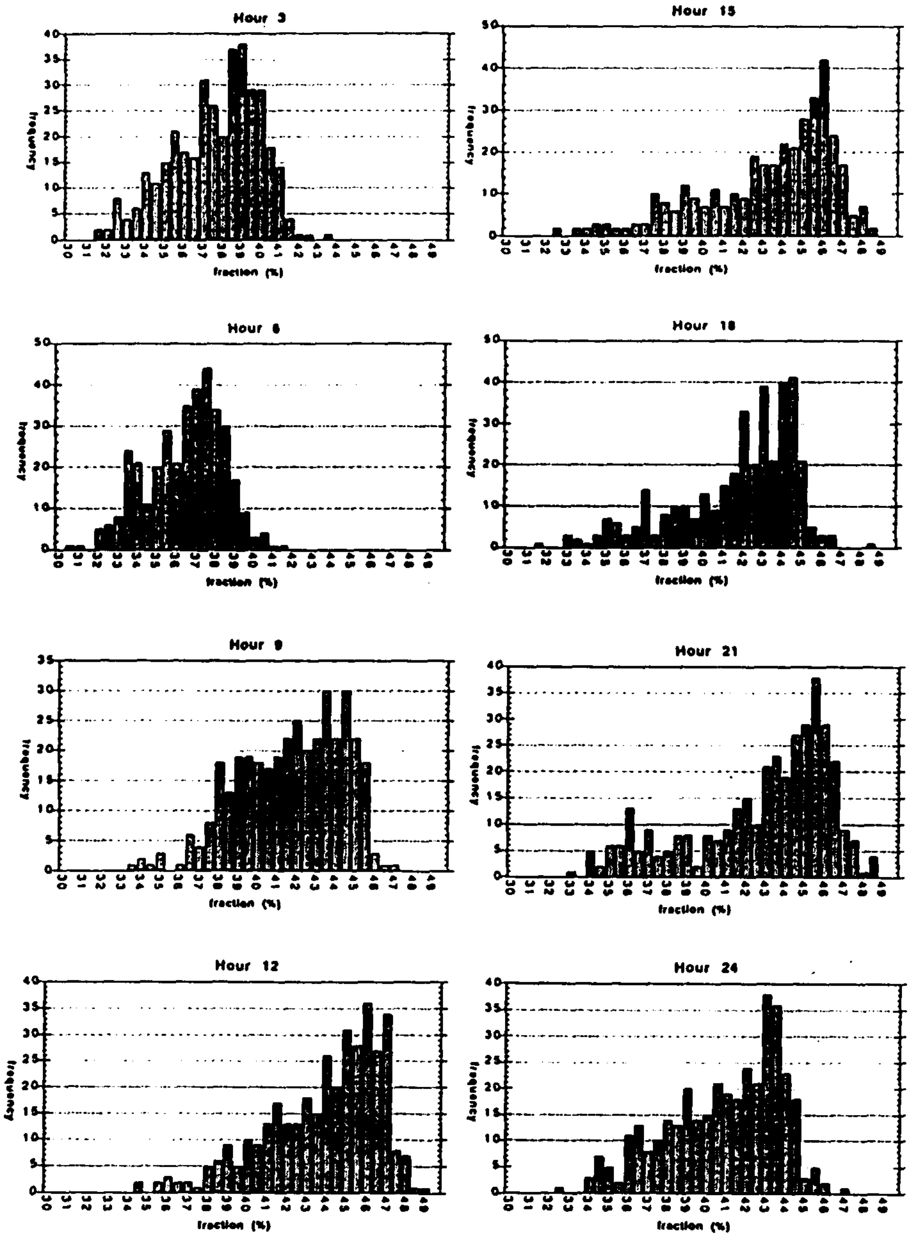


Figure A.18:
Bay Area Share of PG&E Planning Load
Some Hourly Distributions



Appendix B: Simple Example of NO_x Tax Dispatch

1. the model

In section II.D.3, the simple mathematics of dispatch under a NO_x tax regime is outlined. In this appendix, the basic equal lambda result is applied to a two-unit system, and a simple model of the system built.

The equal lambda dispatch rule together with the need to meet customer load, or the power balance constraint, lead to an optimal dispatch rule for a two-unit system as follows:

$$f_1 \cdot h'_1(p_1) + t_1 \cdot n'_1(p_1) = \lambda = f_1 \cdot h'_2(p_2) + t_2 \cdot n'_2(p_2)$$

$$p_1 + p_2 = L$$

In this formulation, as before, $h_i(p_i)$ is the I-O function, $n_i(p_i)$ the NO_x function, f_i the fuel price, t_i the NO_x tax, but unlike before, L is the customer load not P. The goal here is to build a model based only these simple optimal dispatch rules and some assumed I-O and NO_x functions. As always, this model is entirely in power units, that is, L represents instantaneous demand. Despite its simplicity, this model provides some useful demonstration of intuitive results.

The model consists of 2 thermal units with the following second - order polynomial I-O and NO_x functions.[1]

---

1 Note the distinction between upper case i, I, and lower case el, l, which are annoyingly similar in this typeface.

$$h_1(p_1) = k_{10} + k_{11} \cdot p_1 + k_{12} \cdot p_1^2$$
$$h_2(p_2) = k_{20} + k_{21} \cdot p_2 + k_{22} \cdot p_2^2$$

$$n_1(p_1) = l_{10} + l_{11} \cdot p_1 + l_{12} \cdot p_1^2$$
$$n_2(p_2) = l_{20} + l_{21} \cdot p_2 + l_{22} \cdot p_2^2$$

These I-O and NO_x functions lead to the following incremental functions.

$$h_1'(p_1) = k_{11} + 2 \cdot k_{12} \cdot p_1$$
$$h_2'(p_2) = k_{21} + 2 \cdot k_{22} \cdot p_2$$

$$n_1'(p_1) = l_{11} + 2 \cdot l_{12} \cdot p_1$$
$$n_2'(p_2) = l_{21} + 2 \cdot l_{22} \cdot p_2$$

Applying the optimal dispatch rule, yields.

$$\lambda = f_1 \cdot [k_{11} + 2 \cdot k_{12} \cdot p_1] + t_2 \cdot [l_{11} + 2 \cdot l_{12} \cdot p_1]$$
$$\lambda = f_2 \cdot [k_{21} + 2 \cdot k_{22} \cdot p_2] + t_2 \cdot [l_{21} + 2 \cdot l_{22} \cdot p_2]$$

These equations can be manipulated into expressions 1. and 2. for the optimal power contributions of units 1 and 2, p_1* and p_2*.

$$p_1^* = \frac{\lambda - f_1 \cdot k_{11} - t_1 \cdot l_{11}}{2 \cdot (f_1 \cdot k_{12} + t_1 \cdot l_{12})} \qquad 1.$$

$$p_2^* = \frac{\lambda - f_2 \cdot k_{21} - t_2 \cdot l_{21}}{2 \cdot (f_2 \cdot k_{22} + t_2 \cdot l_{22})} \qquad 2.$$

Substituting these expressions into the power balance equation provides an equation for the system marginal variable operating cost, λ*.

$$\lambda^* = \frac{\begin{array}{l} f_1 \cdot f_2 \cdot \left(k_{11} \cdot k_{22} + k_{12} \cdot k_{21} + 2 \cdot L \cdot k_{12} \cdot k_{22}\right) \\ \quad + f_1 \cdot t_2 \cdot \left(k_{11} \cdot l_{22} + k_{12} \cdot l_{21} + 2 \cdot L \cdot k_{12} \cdot l_{22}\right) \\ \quad\quad + f_2 \cdot t_1 \cdot \left(k_{22} \cdot l_{11} + k_{21} \cdot l_{11} + 2 \cdot L \cdot k_{22} \cdot l_{12}\right) \\ \quad\quad\quad + t_1 \cdot t_2 \cdot \left(l_{11} \cdot l_{22} + l_{12} \cdot l_{21} + 2 \cdot L \cdot l_{12} \cdot l_{22}\right) \end{array}}{f_1 \cdot k_{12} + f_2 \cdot k_{22} + t_1 \cdot l_{12} + t_2 \cdot l_{22}} \qquad 3.$$

Obviously, the two units have hard maximum and minimum constraints, which cannot be violated. Therefore, the following con - straints are included in the model.

$$p_{1,min} \le p1 \le p_{1,max}$$
$$p_{2,min} \le p2 \le p_{2,max}$$

The three solution conditions and the power constraints are im - plemented in a simple program called Two Unit Model (TUM), which appears as figure B.9. TUM repeats the solution technique for each hour of a 24-hour period.

2. the test system

TUM was run for a simple test case. The test system has two gas - fired units loosely based on Bay Area conditions. Initially, unit 1 is both more efficient and emits less NO_x than unit 2. However, unit 2 has a second NO_x function, representing possible emissions after addition of SCR equipment to the unit. The coefficients are as follows:

Unit 1

k_{10}:	650	k_{11}:	7.5	k_{12}:	0.0015	
l_{10}:	30	l_{11}:	0.1	l_{12}:	0.0006	
f_1:	2.25	$p_{1,min}$:	100	p_{max}:	750	

Unit 2

k_{20}:	1000	k_{21}:	7.5	k_{22}:	0.004	
l_{20}:	160	l_{21}:	-0.75	l_{22}:	0.005	no SCR
l_{20}:	100	l_{21}:	-0.35	l_{22}:	0.006	with SCR
f_2:	2.0	$p_{2,min}$:	300	$p_{2,max}$:	750	

Figures B.1 and B.3 show these I-O and NO_x functions. Unit 1 clearly has a better heat rate and lower emissions than unit 2 without SCR. The additions of SCR dramatically lowers emissions from 2 and makes it cleaner than unit 1, but the addition of SCR does not affect the heat rate.

Figures B.3 and B.4 show the results of running TUM for this utility. The load to be met peaks at 1250MW, and there is a total of 22000MWh of energy during the 24-hour period. The full results from this run appears as figure B.5. As the figure shows, the cleaner unit 1 provides 60% of the energy, but, being much cleaner, only 33% of the NO_x emissions. The diurnal load curve and the daily NO_x curve appear as figures B.3 and B.4. Unit 2 operates at its minimum load condition for 9 hours, and only reaches a peak output of 500MW.

3. an incremental SCR example

Often, the effectiveness of imposing an NO_x tax is questioned on the grounds that new generating capacity tends to be both cheaper and to operate and has lower NO_x emissions. Therefore, adding a NO_x tax will not change dispatch significantly, and, consequently, only trivial NO_x emissions reductions can be achieved. The test utility can be used to explore this claim.

Figure B.6 shows a summary of a series of runs. Runs 201-206 show the effect of incrementally increasing the NO_x tax, as shown the two columns headed *\$/kg*. In this case, the tax on either generator is the same. The maximum effect of the tax is achieved at a tax rate of only 5 *\$/kg*. Up to this point, increasing the tax disfavors use of unit 2, and its share of the total energy falls, although only from 40.1% to 37.3%. This unimpressive result is reflected in the NO_x emissions, which fall 5.5%.

The second series of runs, 211-219, use the SCR NO_x function for unit 2. This change dramatically reduces NO_x emissions in the zero tax case. Emissions are 61 % below the equivalent zero tax case without SCR. However, when the NO_x tax is imposed, the system is far more responsive. The 5 \$/kg case already has 15.2% lower emissions and the model is sensitive to taxes up to 500\$/kg, by which point, emissions have fallen by 24 %. The final columns of the figure show the \$/kg fuel cost of controlling the emissions and the incremental value across each step. While it would be unwise to assign too much real world significance to these numbers, the cost of control is low compared to other control technologies. For example, at the 5 \$/kg tax rate, the fuel cost per avoided kg of NO_x is a surprisingly low 20 ¢/kg.

Before installation of SCR on unit 2, the unresponsiveness of this system supports the assertion that a NO_x tax would not be effective at reducing emissions. However, the SCR case additionally shows that if high emitting units are cleaned up, favoring them in the dispatch can become an effective method for reducing emissions. In fact, across the whole range of the SCR cases, total fuel costs change by about only 2.5 %. Given the high cost of SCR and its poor performance in terms of dollars per episode day kg of NO_x removed, these results suggest that a combination strategy involving some less expensive control technology combined with a tax could be a cheaper overall control strategy.

Figure B.1
I-O Functions for Units 1 and 2

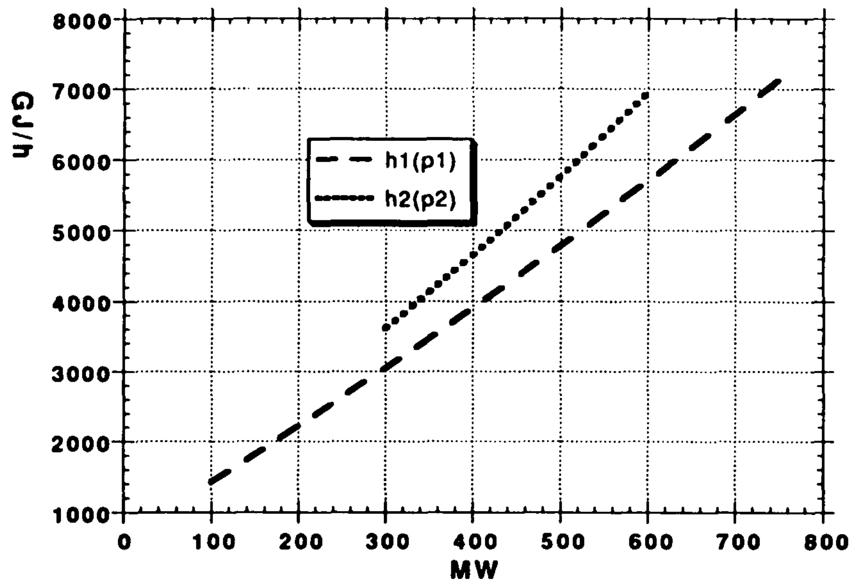


Figure B.2
NO_x Functions for Units 1 and 2

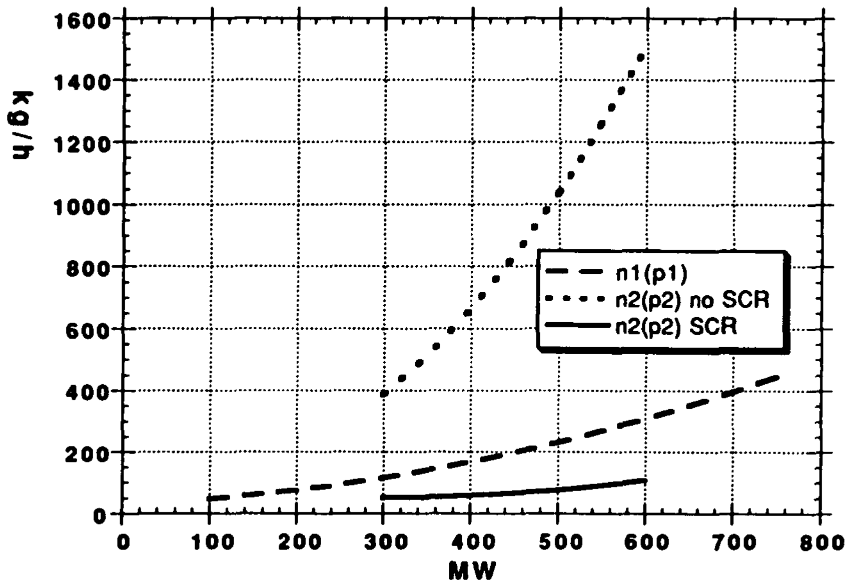


Figure B.3
Hourly MW Output of Units 1 and 2

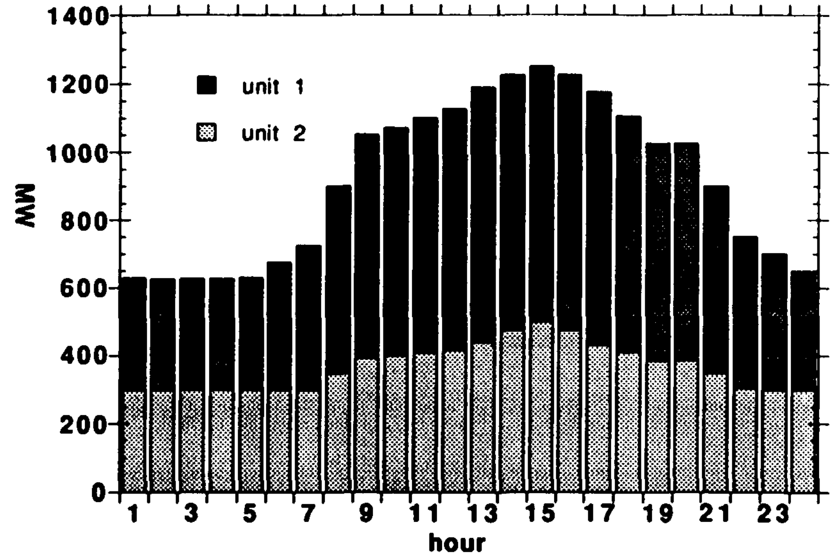


Figure B.4
Hourly NOx Emissions of Units 1 and 2

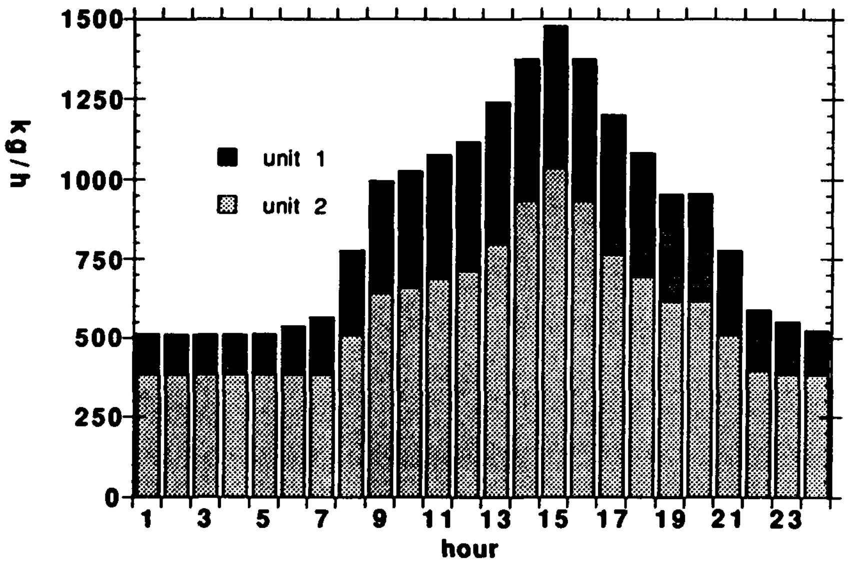


Figure B.5

BASE_CASE-201_21Sep92_19:45

hr.	load	lamsys	lamfuel	lamNOx	fuel.burn	fuel.cost	NOx.emis	tax.cost	f+tcost	av.fuel	v.f.cost
			System Results								
	MW	$/MWh	$/MWh	$/MWh	GJ	$	kg	$	$	GJ/MWh	$/MWh
1	630	19.10	19	0	6898	14619	513	0	14619	10.95	23.20
2	625	19.07	19	0	6856	14523	511	0	14523	10.97	23.24
3	625	19.07	19	0	6856	14523	511	0	14523	10.97	23.24
4	625	19.07	19	0	6856	14523	511	0	14523	10.97	23.24
5	630	19.10	19	0	6898	14619	513	0	14619	10.95	23.20
6	675	19.41	19	0	7283	15485	537	0	15485	10.79	22.94
7	725	19.74	20	0	7718	16464	566	0	16464	10.65	22.71
8	900	20.59	999	999	9343	19995	775	0	19995	10.38	22.22
9	1050	21.30	999	999	10791	23137	994	0	23137	10.28	22.04
10	1070	21.40	999	999	10988	23564	1026	0	23564	10.27	22.02
11	1100	21.54	999	999	11285	24208	1075	0	24208	10.26	22.01
12	1125	21.66	999	999	11534	24748	1116	0	24748	10.25	22.00
13	1190	22.04	22	0	12193	26166	1241	0	26166	10.25	21.99
14	1225	22.60	23	0	12584	26947	1374	0	26947	10.27	22.00
15	1250	23.00	23	0	12869	27517	1478	0	27517	10.30	22.01
16	1225	22.60	23	0	12584	26947	1374	0	26947	10.27	22.00
17	1175	21.90	999	999	12036	25837	1202	0	25837	10.24	21.99
18	1105	21.56	999	999	11335	24316	1083	0	24316	10.26	22.01
19	1025	21.18	999	999	10547	22606	956	0	22606	10.29	22.05
20	1025	21.18	999	999	10547	22606	956	0	22606	10.29	22.05
21	900	20.59	999	999	9343	19995	775	0	19995	10.38	22.22
22	750	19.88	999	999	7944	16959	590	0	16959	10.59	22.61
23	700	19.57	20	0	7500	15973	551	0	15973	10.71	22.82
24	650	19.24	19	0	7069	15002	524	0	15002	10.88	23.08

system sales(MWh)=	22000
system emissions(kg)=	20751
system fuel cost($)=	491278
system tax revenues($)=	0
system production cost($)=	491278
average production cost($/MWh)=	22.33

av.NOx kg/MWh	av.tax $/MWh	average sys.cost $/MWh
0.82	0.00	23.20
0.82	0.00	23.24
0.82	0.00	23.24
0.82	0.00	23.24
0.82	0.00	23.20
0.80	0.00	22.94
0.78	0.00	22.71
0.86	0.00	22.22
0.95	0.00	22.04
0.96	0.00	22.02
0.98	0.00	22.01
0.99	0.00	22.00
1.04	0.00	21.99
1.12	0.00	22.00
1.18	0.00	22.01
1.12	0.00	22.00
1.02	0.00	21.99
0.98	0.00	22.01
0.93	0.00	22.05
0.93	0.00	22.05
0.86	0.00	22.22
0.79	0.00	22.61
0.79	0.00	22.82
0.81	0.00	23.08

		Results for Unit 1									
k0:=	650	k1:=	7.50	k2:=	0.00	fuelcost=	2.25	$/GJ			
l0:=	30	l1:=	0.10	l2:=	0.00	NOxtax=	0.00	$/kg			
hr.	load	output	fuel	fuelcost	NOx	NOxcost	incfuel	incflcst	incNOx	incNOxcst	unit1
	MW	MW	GJ	$	kg	$	GJ/MWh	$/MWh	kg/MWh	$/MWh	$/MWh
1	630	330	3288	7399	128.30	0.00	8.49	19.10	0.50	0.00	19.10
2	625	325	3246	7303	125.90	0.00	8.48	19.07	0.49	0.00	19.07
3	625	325	3246	7303	125.90	0.00	8.48	19.07	0.49	0.00	19.07
4	625	325	3246	7303	125.90	0.00	8.48	19.07	0.49	0.00	19.07
5	630	330	3288	7399	128.30	0.00	8.49	19.10	0.50	0.00	19.10
6	675	375	3673	8265	151.90	0.00	8.63	19.41	0.55	0.00	19.41
7	725	425	4108	9244	180.90	0.00	8.78	19.74	0.61	0.00	19.74
8	900	551	5234	11776	266.90	0.00	9.15	20.59	0.76	0.00	20.59
9	1050	656	6216	13986	353.80	0.00	9.47	21.30	0.89	0.00	21.30
10	1070	670	6349	14286	366.40	0.00	9.51	21.40	0.90	0.00	21.40
11	1100	691	6551	14739	385.80	0.00	9.57	21.54	0.93	0.00	21.54
12	1125	709	6720	15119	402.30	0.00	9.63	21.66	0.95	0.00	21.66
13	1190	750	7119	16017	442.50	0.00	9.75	21.94	1.00	0.00	21.94
14	1225	750	7119	16017	442.50	0.00	9.75	21.94	1.00	0.00	21.94
15	1250	750	7119	16017	442.50	0.00	9.75	21.94	1.00	0.00	21.94
16	1225	750	7119	16017	442.50	0.00	9.75	21.94	1.00	0.00	21.94
17	1175	744	7060	15885	436.50	0.00	9.73	21.90	0.99	0.00	21.90
18	1105	695	6584	14815	389.10	0.00	9.58	21.56	0.93	0.00	21.56
19	1025	638	6050	13612	338.40	0.00	9.42	21.19	0.87	0.00	21.19
20	1025	638	6050	13612	338.40	0.00	9.42	21.19	0.87	0.00	21.19
21	900	551	5234	11776	266.90	0.00	9.15	20.59	0.76	0.00	20.59
22	750	445	4285	9641	193.30	0.00	8.84	19.88	0.63	0.00	19.88
23	700	400	3890	8753	166.00	0.00	8.70	19.58	0.58	0.00	19.58
24	650	350	3459	7782	138.50	0.00	8.55	19.24	0.52	0.00	19.24
output (MWh) =			13172								
NOx emissions (kg)			6780								
fuel cost ($) =			284068								
tax payment ($) =			0								
total cost ($) =			284068								

Results for Unit 2

k0:=	1000	k1:=	7.50	k2:=	0.00	fuelcost=	2.00	$/GJ			
l0:=	160	l1:=	-0.75	l2:=	0.01	NOxtax=	0.00	$/kg			
hr.	load	output	fuel	fuelcost	NOx	NOxcost	incfuel	incflcst	incNOx	ncNOxcst	unit1
	MW	MW	GJ	$	kg	$	GJ/MWh	$/MWh	kg/MWh	$/MWh	$/MWh
1	630	300	3610	7220	385.00	0.00	9.90	19.80	2.25	0.00	19.80
2	625	300	3610	7220	385.00	0.00	9.90	19.80	2.25	0.00	19.80
3	625	300	3610	7220	385.00	0.00	9.90	19.80	2.25	0.00	19.80
4	625	300	3610	7220	385.00	0.00	9.90	19.80	2.25	0.00	19.80
5	630	300	3610	7220	385.00	0.00	9.90	19.80	2.25	0.00	19.80
6	675	300	3610	7220	385.00	0.00	9.90	19.80	2.25	0.00	19.80
7	725	300	3610	7220	385.00	0.00	9.90	19.80	2.25	0.00	19.80
8	900	349	4109	8219	508.50	0.00	10.30	20.59	2.75	0.00	20.59
9	1050	394	4575	9151	640.50	0.00	10.65	21.30	3.19	0.00	21.30
10	1070	400	4639	9278	659.60	0.00	10.70	21.40	3.25	0.00	21.40
11	1100	409	4734	9469	689.00	0.00	10.77	21.54	3.34	0.00	21.54
12	1125	416	4814	9629	714.00	0.00	10.83	21.66	3.41	0.00	21.66
13	1190	440	5074	10149	798.00	0.00	11.02	22.04	3.65	0.00	22.04
14	1225	475	5465	10930	931.90	0.00	11.30	22.60	4.00	0.00	22.60
15	1250	500	5750	11500	1035.00	0.00	11.50	23.00	4.25	0.00	23.00
16	1225	475	5465	10930	931.90	0.00	11.30	22.60	4.00	0.00	22.60
17	1175	431	4976	9952	765.70	0.00	10.95	21.90	3.56	0.00	21.90
18	1105	410	4750	9501	693.90	0.00	10.78	21.56	3.35	0.00	21.56
19	1025	387	4497	8993	617.20	0.00	10.59	21.19	3.12	0.00	21.19
20	1025	387	4497	8993	617.20	0.00	10.59	21.19	3.12	0.00	21.19
21	900	349	4109	8219	508.50	0.00	10.30	20.59	2.75	0.00	20.59
22	750	305	3659	7318	396.20	0.00	9.94	19.88	2.30	0.00	19.88
23	700	300	3610	7220	385.00	0.00	9.90	19.80	2.25	0.00	19.80
24	650	300	3610	7220	385.00	0.00	9.90	19.80	2.25	0.00	19.80
output (MWh) =			8827								
NOx emissions (kg)			13972								
fuel cost ($) =			207210								
tax payment ($) =			0								
total cost ($) =			207210								

Figure B.6

Run Summary

run #	$/kg	$/kg	$/GJ	$/GJ	% MWh 1	% MWh 2	% NOx 1	% NOx 2	NOx kg	tax $	fuel $	$/MWh tax
	first unit 2 NOx function											
201	0.00	0.00	2.25	2.00	59.873	40.123	32.67	67.33	20751	0	491278	0.00
202	0.10	0.10	2.25	2.00	60.314	39.682	33.42	66.58	20537	2054	491288	0.09
203	0.50	0.50	2.25	2.00	61.550	38.445	35.57	64.43	19993	9997	491441	0.45
204	1.0	1.0	2.25	2.00	62.305	37.691	36.85	63.15	19714	19714	491634	0.90
205	5.0	5.0	2.25	2.00	62.659	37.341	37.45	62.56	19604	98023	491771	4.46
206	10	10	2.25	2.00	62.659	37.341	37.45	62.56	19604	196047	491771	8.91
	second unit 2 NOx function											
211	0.00	0.00	2.25	2.25	59.873	40.123	83.70	16.31	8100	0	491278	0.00
212	0.10	0.10	2.25	2.25	59.709	40.286	83.59	16.41	8073	807	491279	0.04
213	0.50	0.50	2.25	2.25	58.977	41.018	83.10	16.91	7955	3978	491314	0.18
214	1.0	1.0	2.25	2.25	58.023	41.973	82.44	17.58	7811	7812	491423	0.36
215	5.0	5.0	2.25	2.25	50.359	49.636	75.80	24.22	6867	34337	494002	1.56
216	10	10	2.25	2.25	45.536	54.459	70.44	29.58	6437	64373	496999	2.93
217	100	100	2.25	2.25	39.159	60.836	63.75	36.27	6157	615768	502669	27.99
218	500	500	2.25	2.25	38.418	61.577	63.04	36.98	6152	3076366	503514	139.83
219	1000	1000	2.25	2.25	38.318	61.677	62.92	37.08	6152	6152554	503633	279.66

$/MWh fuel	$/MWh	$/kg	nc. $/kg
22.33	22.33		
22.33	22.42	0.05	0.05
22.34	22.79	0.22	0.28
22.35	23.24	0.34	0.69
22.35	26.81	0.43	1.25
22.35	31.26	0.43	
22.33	22.33		
22.33	22.37	0.00	0.04
22.33	22.51	0.00	0.30
22.34	22.69	0.01	0.76
22.45	24.02	0.20	2.73
22.59	25.52	0.40	6.97
22.85	50.84	0.78	20.25
22.89	162.72	0.84	169.00
22.89	302.55	0.85	

Figure B.7
Hourly MW Output of Units 1 and 2

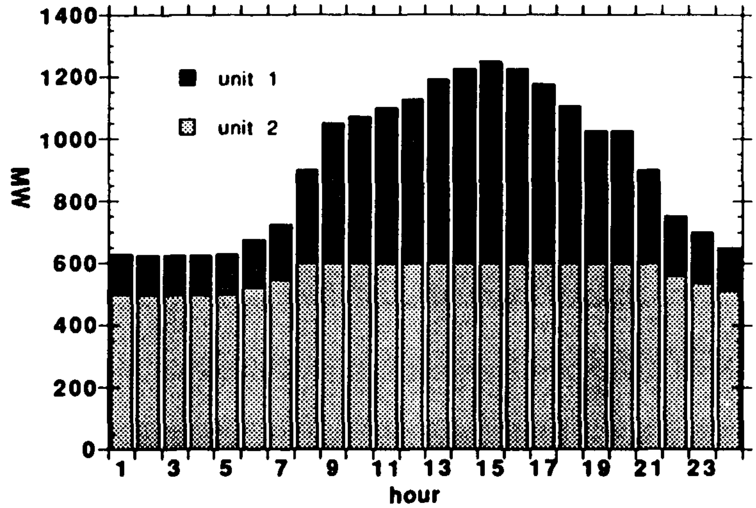


Figure B.8
Responsiveness of Emissions to a NOx Tax

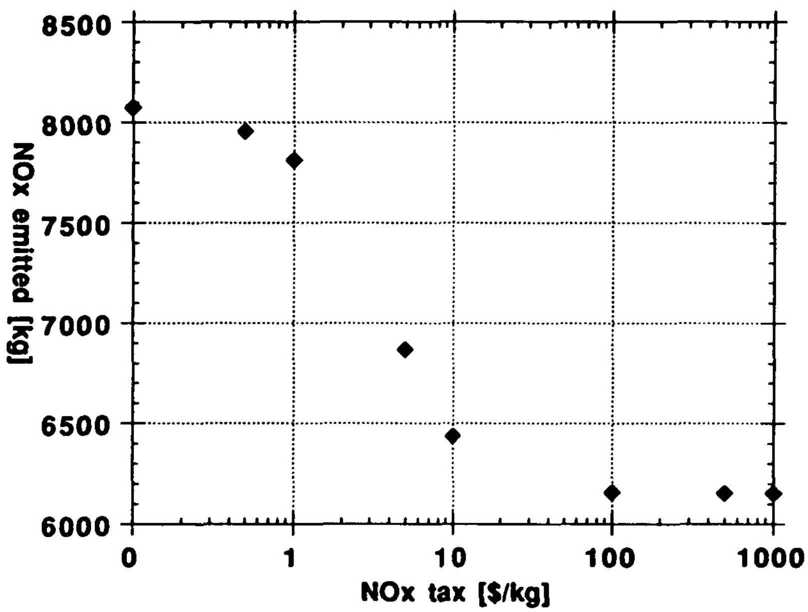


Figure B.9

```
      PROGRAM TUM
C this program solves a simple 2-unit system over a 24-hour period
C and carries out a fuel cost + NOx tax dispatch
C the only constraints are min and max load

      REAL K(2,0:3),L(2,0:3),F(2),T(2),LOAD(24),PMIN(2),PMAX(2),SALES
      REAL P(2,24),LAMSYS(24),LAMFUL(24),LAMNOX(24)
      CHARACTER*30 TITLE

      CALL INITIALIZER(K,L,F,T,LOAD,PMIN(2),PMAX(2),P,
     2                      LAMSYS,LAMFUL,LAMNOX,SALES)

      CALL READER(TITLE,K,L,F,T,LOAD,PMIN,PMAX)

      DO 1010 I = 1,24
        CALL SOLVER(K,L,F,T,LOAD(I),PMIN,PMAX,
     2   P(1,I),P(2,I),LAMSYS(I),LAMFUL(I),LAMNOX(I))
 1010 CONTINUE

        CALL WRITER(TITLE,K,L,F,T,LOAD,PMIN,PMAX,
     2        P,LAMSYS,LAMFUL,LAMNOX,SALES)

      END

C=======================================================================
C this is where the final calculations and the output is done
      SUBROUTINE WRITER(TITLE,K,L,F,T,LOAD,PMIN,PMAX,
     2        P,LAMSYS,LAMFUL,LAMNOX,SALES)

      REAL K(2,0:3),L(2,0:3),F(2),T(2),LOAD(24),PMIN(2),PMAX(2)
      REAL P(2,24),LAMSYS(24),LAMFUL(24),LAMNOX(24),SALES
      CHARACTER*30 TITLE

      REAL FUL(2,24),NOX(2,24)
      REAL FULCOST(2,24),NOXCOST(2,24),TOTFULCOST,TOTNOXCOST
      REAL INCFUL(2,24),INCFULCOST(2,24),INCNOX(2,24),INCNOXCOST(2,24)
      REAL AVEFUL(24),AVEFULCOST(24),AVENOX(24),AVENOXCOST(24)
      REAL AVESYS(24),TOTFUL(2),TOTNOX(2)
      REAL HTOTFUL(24),HTOTNOX(24),HTOTFULCOST(24),HTOTNOXCOST(24)
      REAL HTOTSYSCOST(24)
      REAL OUTPUT,FCOST,NCOST,TOTNOXSYS

C these are all the total results
        HTOTFUL(I)     =  FUL(1,I) + FUL(2,I)
        HTOTFULCOST(I) =  FULCOST(1,I) + FULCOST(2,I)
        HTOTNOX(I)     =  NOX(1,I) + NOX(2,I)
        HTOTNOXCOST(I) =  NOXCOST(1,I) + NOXCOST(2,I)
        HTOTSYSCOST(I) =  FULCOST(1,I) + FULCOST(2,I)

      DO 1001 J = 1, 2
        DO 1000 I = 1, 24
```

```
          FUL(J,I)          = 0.0
          NOX(J,I)          = 0.0
          INCFUL(J,I)       = 0.0
          INCFULCOST(J,I) = 0.0
          INCNOX(J,I)       = 0.0
          INCNOXCOST(I,I) = 0.0
1000    CONTINUE
      TOTFUL(J)     = 0.0
      TOTNOX(J)     = 0.0
1001 CONTINUE
      DO 1002 I = 1,24
        AVEFUL(I)         = 0.0
        AVEFULCOST(I)     = 0.0
        AVENOX(I)         = 0.0
        AVENOXCOST(I)     = 0.0
        HTOTFUL(I)        = 0.0
        HTOTFULCOST(I)    = 0.0
        HTOTNOX(I)        = 0.0
        HTOTNOXCOST(I)    = 0.0
        HTOTSYSCOST(I)    = 0.0
        SALES             = SALES + LOAD(I)
1002 CONTINUE

      DO 1010 I = 1,24
        DO 1015 J = 1,2
          FUL(J,I)          = K(J,0) + K(J,1)*P(J,I) + K(J,2)*P(J,I)**2
          TOTFUL(J)         = TOTFUL(J) + FUL(J,I)
          FULCOST(J,I)      = F(J)*FUL(J,I)
          INCFUL(J,I)       = K(J,1) + 2*K(J,2)*P(J,I)
          INCFULCOST(J,I)= F(J)*INCFUL(J,I)

          NOX(J,I)          = L(J,0) + L(J,1)*P(J,I) + L(J,2)*P(J,I)**2
          TOTNOX(J)         = TOTNOX(J) + NOX(J,I)
          NOXCOST(J,I)      = T(J)*NOX(J,I)
          INCNOX(J,I)       = L(J,1) + 2*L(J,2)*P(J,I)
          INCNOXCOST(J,I)= T(J)*INCNOX(J,I)
1015    CONTINUE
        HTOTFUL(I)      =  FUL(1,I) + FUL(2,I)
        AVEFUL(I)       =  HTOTFUL(I)/LOAD(I)
        HTOTFULCOST(I) =  FULCOST(1,I) + FULCOST(2,I)
        AVEFULCOST(I)  =  HTOTFULCOST(I)/LOAD(I)
        HTOTNOX(I)      =  NOX(1,I) + NOX(2,I)
        AVENOX(I)       =  HTOTNOX(I)/LOAD(I)
        HTOTNOXCOST(I) =  NOXCOST(1,I) + NOXCOST(2,I)
        AVENOXCOST(I)  =  HTOTNOXCOST(I)/LOAD(I)
        AVESYS(I)       =  AVEFULCOST(I)   +   AVENOXCOST(I)
        HTOTSYSCOST(I) =  FULCOST(1,I) + FULCOST(2,I)
     2                          + NOXCOST(1,I) + NOXCOST(2,I)
1010 CONTINUE

      TOTNOXSYS       = 0.0
      TOTFULCOST      = 0.0
      TOTNOXCOST      = 0.0
```

```
      DO 1020 J = 1,2
        TOTNOXSYS       = TOTNOXSYS +  TOTNOX(J)
        TOTFULCOST      = TOTFULCOST + TOTFUL(J)*F(J)
        TOTNOXCOST      = TOTNOXCOST + TOTNOX(J)*T(J)
1020 CONTINUE

      OPEN(21,FILE='tum.out')
        WRITE(21,5010) TITLE
5010 FORMAT(A30)

      WRITE(21,*) ' '
      WRITE(21,*) CHAR(9),CHAR(9),CHAR(9),'System_Results '
        WRITE(21,5015) CHAR(9),CHAR(9),CHAR(9),CHAR(9),CHAR(9),CHAR(9),
     2                 CHAR(9),CHAR(9),CHAR(9),CHAR(9),CHAR(9),CHAR(9),
     3                 CHAR(9),CHAR(9)
5015   FORMAT('hr.',A1,'load',A1,'lamsys',A1,'lamfuel',A1,'lamNOx',A1,
     2        'fuel.burn',A1,'fuel.cost',A1,'NOx.emis',A1,'tax.cost',
     3        A1,'f+tcost',A1,'av.fuel',A1,'av.f.cost',A1,'av.NOx',A1,
     4        'av.tax',A1,'av.sys.cost')
        WRITE(21,5016) CHAR(9),CHAR(9),CHAR(9),CHAR(9),CHAR(9),CHAR(9),
     2                 CHAR(9),CHAR(9),CHAR(9),CHAR(9),CHAR(9),CHAR(9),
     3                 CHAR(9),CHAR(9)
5016   FORMAT('    ',A1,'MW',A1,'$/MWh',A1,'$/MWh',A1,'$/MWh',A1,
     2        'GJ',A1,'$',A1,'kg',A1,'$',A1,'$',A1,'GJ/MWh',A1,
     3        '$/MWh',A1,'kg/MWh',A1,'$/MWh',A1,'$/MWh')
      DO 1025 I = 1,24
          WRITE(21,5017)I,CHAR(9),INT(LOAD(I)+0.5),CHAR(9),
     2      LAMSYS(I),CHAR(9),LAMFUL(I),CHAR(9),LAMNOX(I),CHAR(9),
     3      INT(HTOTFUL(I)+0.5),CHAR(9),INT(HTOTFULCOST(I)+0.5),CHAR(9),
     4      HTOTNOX(I),CHAR(9),INT(HTOTNOXCOST(I)+0.5),CHAR(9),
     5      INT(HTOTSYSCOST(I)+0.5),CHAR(9),AVEFUL(I),CHAR(9),
     6      AVEFULCOST(I),CHAR(9),AVENOX(I),CHAR(9),AVENOXCOST(I),
     7      CHAR(9),AVESYS(I),CHAR(9)
5017     FORMAT(2(I5,A1),3(F8.2,A1),2(I6,A1),F6.1,A1,
     2                  2(I6,A1),2(F8.2,A1),F8.3,A1,2(F8.2,A1))
1025 CONTINUE
      WRITE(21,*) 'system_sales (MWh) =',CHAR(9),CHAR(9),CHAR(9),
     2            CHAR(9),CHAR(9),INT(SALES)
      WRITE(21,*) 'system_emissions (kg)=',CHAR(9),CHAR(9),CHAR(9),
     2            CHAR(9),CHAR(9),INT(TOTNOXSYS)
      WRITE(21,*) 'system_fuel_cost ($)=',CHAR(9),CHAR(9),CHAR(9),
     2            CHAR(9),CHAR(9),INT(TOTFULCOST+0.5)
      WRITE(21,*) 'system_tax_revenues ($)=',CHAR(9),CHAR(9),CHAR(9),
     2            CHAR(9),CHAR(9),INT(TOTNOXCOST+0.5)
      WRITE(21,*) 'system_production_cost ($)=',CHAR(9),CHAR(9),CHAR(9),
     2            CHAR(9),CHAR(9),INT(TOTFULCOST+TOTNOXCOST+0.5)
      WRITE(21,*) 'average_production_cost ($/MWh) =',CHAR(9),CHAR(9),
     2            CHAR(9),CHAR(9),CHAR(9),(TOTFULCOST+TOTNOXCOST)/SALES

      DO 1030 J = 1,2
        WRITE(21,*) ' '
        WRITE(21,*)    CHAR(9),CHAR(9),'Results_for_Unit_',J
        WRITE(21,5020) CHAR(9),K(J,0),CHAR(9),CHAR(9),K(J,1),CHAR(9),
```

```
     2                  CHAR(9),K(J,2),CHAR(9),CHAR(9),F(J),CHAR(9)
 5020   FORMAT('k0: =',A1,F8.1,A1,'k1: =',A1,F8.3,A1,'k2: =',A1,F10.6,
     2        A1,'fuel cost =',A1,F6.2,A1,' $/GJ')
        WRITE(21,5030) CHAR(9),L(J,0),CHAR(9),CHAR(9),L(J,1),CHAR(9),
     2                  CHAR(9),L(J,2),CHAR(9),CHAR(9),T(J),CHAR(9)
 5030   FORMAT('l0: =',A1,F8.1,A1,'l1: =',A1,F8.3,A1,'l2: =',A1,F10.6,
     2        A1,'NOx tax =',A1,F6.2,A1,' $/kg')

        WRITE(21,5040) CHAR(9),CHAR(9),CHAR(9),CHAR(9),CHAR(9),CHAR(9),
     2                 CHAR(9),CHAR(9),CHAR(9),CHAR(9),CHAR(9)
 5040   FORMAT('hr.',A1,'load',A1,'output',A1,'fuel',A1,
     2         'fuelcost',A1,'NOx',A1,'NOxcost',A1,'incfuel',
     3         A1,'incflcst',A1,'incNOx',A1,'incNOxcst',A1,'unit1')
        WRITE(21,5041) CHAR(9),CHAR(9),CHAR(9),CHAR(9),CHAR(9),CHAR(9),
     2                 CHAR(9),CHAR(9),CHAR(9),CHAR(9),CHAR(9)
 5041   FORMAT(' ',A1,'MW',A1,'MW',A1,'GJ',A1,'$',A1,'kg',A1,'$',A1,
     2        'GJ/MWh',A1,'$/MWh',A1,'kg/MWh',A1,'$/MWh',A1,'$/MWh')

        OUTPUT = 0.0
        FCOST  = 0.0
        NCOST  = 0.0
        DO 1040 I = 1,24
          WRITE(21,5050)I,CHAR(9),INT(LOAD(I)+0.5),
     2        CHAR(9),INT(P(J,I)+0.5),CHAR(9),
     3        INT(FUL(J,I)+0.5),CHAR(9),INT(FULCOST(J,I)+0.5),CHAR(9),
     4        NOX(J,I),CHAR(9),INT(NOXCOST(J,I)+0.5),CHAR(9),
     5        INCFUL(J,I),CHAR(9),INCFULCOST(J,I),CHAR(9),
     6        INCNOX(J,I),CHAR(9),INCNOXCOST(J,I),CHAR(9),
     7        INCFULCOST(J,I)+INCNOXCOST(J,I)
 5050     FORMAT(I3,A1,I4,A1,3(I6,A1),F6.1,A1,I6,A1,5(F8.3,A1))
          OUTPUT  = OUTPUT + P(J,I)
          FCOST   = FCOST   + FULCOST(J,I)
          NCOST   = NCOST   + NOXCOST(J,I)
 1040   CONTINUE
      WRITE(21,*) 'output (MWh)=',CHAR(9),CHAR(9),CHAR(9),INT(OUTPUT)
      WRITE(21,*) 'NOx_emissions (kg) =',CHAR(9),CHAR(9),CHAR(9),
     2                  INT(TOTNOX(J)+0.5)
      WRITE(21,*) 'fuel_cost ($)= ',CHAR(9),CHAR(9),CHAR(9),
     2                  INT(FCOST+0.5)
      WRITE(21,*) 'tax_payment ($)=',CHAR(9),CHAR(9),CHAR(9),
     2                  INT(NCOST+0.5)
      WRITE(21,*) 'total_cost ($)=',CHAR(9),CHAR(9),CHAR(9),
     2                  INT(FCOST+NCOST+0.5)
 1030 CONTINUE

      CLOSE(21)

      RETURN
      END
C=================================================================
C this is the basic solution subroutine
C all it does is calculate the three basic solution equations
C and then take care of min and max load constraints
```

```
      SUBROUTINE SOLVER(K,L,F,T,LOAD,PMIN,PMAX,
     2          P1,P2,LAMSYS,LAMFUL,LAMNOX)

        REAL K(2,0:3),L(2,0:3),F(2),T(2),LOAD,PMIN(2),PMAX(2)
        REAL P1,P2,LAMSYS,LAMFUL,LAMNOX

C this is the lambda star equation

       LAMSYS =
     2  (F(1)*F(2)*(K(1,1)*K(2,2)+K(1,2)*K(2,1)+2.0*LOAD*K(1,2)*K(2,2))
     3 + F(1)*T(2)*(K(1,1)*L(2,2)+K(1,2)*L(2,1)+2.0*LOAD*K(1,2)*L(2,2))
     4 + F(2)*T(1)*(K(2,2)*L(1,1)+K(2,1)*L(1,2)+2.0*LOAD*K(2,2)*L(1,2))
     5 + T(1)*T(2)*(L(1,1)*L(2,2)+L(1,2)*L(2,1)+2.0*LOAD*L(1,2)*L(2,2)))
     6 / (F(1)*K(1,2)+F(2)*K(2,2)+T(1)*L(1,2)+T(2)*L(2,2))

C these are the two p star equations
      P1 = (LAMSYS - F(1)*K(1,1) - T(1)*L(1,1))
     2         /(2.0*(F(1)*K(1,2) + T(1)*L(1,2)))

      P2 = (LAMSYS - F(2)*K(2,1) - T(2)*L(2,1))
     2         /(2.0*(F(2)*K(2,2) + T(2)*L(2,2)))

C now the min/max constraints are taken care off
      LAMFUL  = 999.0
      LAMNOX  = 999.0
      IF(P1.GT.PMAX(1))THEN
        P1 = PMAX(1)
        P2 = LOAD - P1
        LAMFUL = F(2)*(K(2,1) + 2.0*K(2,2)*P2)
        LAMNOX = T(2)*(L(2,1) + 2.0*L(2,2)*P2)
        LAMSYS = LAMFUL + LAMNOX
      ELSEIF(P2.GT.PMAX(2))THEN
        P2 = PMAX(2)
        P1 = LOAD - P2
        LAMFUL = F(1)*(K(1,1) + 2.0*K(1,2)*P1)
        LAMNOX = T(1)*(L(1,1) + 2.0*L(1,2)*P1)
        LAMSYS = LAMFUL + LAMNOX
      ENDIF

      IF(P1.LT.PMIN(1))THEN
        P1 = PMIN(1)
        P2 = LOAD - P1
        LAMFUL  = F(2)*(K(2,1) + 2.0*K(2,2)*P2)
        LAMNOX  = T(2)*(L(2,1) + 2.0*L(2,2)*P2)
        LAMSYS  = LAMFUL + LAMNOX
      ELSEIF(P2.LT.PMIN(2))THEN
        P2 = PMIN(2)
        P1 = LOAD - P2
        LAMFUL  = F(1)*(K(1,1) + 2.0*K(1,2)*P1)
        LAMNOX  = T(1)*(L(1,1) + 2.0*L(1,2)*P1)
        LAMSYS = LAMFUL + LAMNOX
      ENDIF
```

```
      IF(P1+P2.GT.LOAD*1.01.OR.P1+P2.LT.LOAD*0.99) THEN
        PRINT *, 'ERROR  in SOLVER '
      ENDIF

      RETURN
      END
C======================================================================
C this subroutine read the input file
      SUBROUTINE READER(TITLE,K,L,F,T,LOAD,PMIN,PMAX)

        REAL K(2,0:3),L(2,0:3),F(2),T(2),LOAD(24),PMIN(2),PMAX(2)
        CHARACTER*1 S
        CHARACTER*30 TITLE

        OPEN(11,FILE='tum.in')
          READ(11,5010) TITLE
 5010     FORMAT(A30)
          READ(11,*) S
          READ(11,*) (PMIN(J),J=1,2)
          READ(11,*) (PMAX(J),J=1,2)
          READ(11,*) (K(1,J),J=0,2)
          READ(11,*) (K(2,J),J=0,2)
          READ(11,*) (L(1,J),J=0,2)
          READ(11,*) (L(2,J),J=0,2)
          READ(11,*) (F(J),J=1,2)
          READ(11,*) (T(J),J=1,2)
          READ(11,*) S
          DO 1010 I = 1, 24
            READ(11,*) LOAD(I)
 1010     CONTINUE
        CLOSE(11)

        OPEN(21,FILE='echo.input')
          WRITE(21,*) (K(1,J),J=0,2)
          WRITE(21,*) (K(2,J),J=0,2)
          WRITE(21,*) (L(1,J),J=0,2)
          WRITE(21,*) (L(2,J),J=0,2)
          WRITE(21,*) (F(J),J=1,2)
          WRITE(21,*) (T(J),J=1,2)
          WRITE(21,*) (LOAD(J),J=1,12)
          WRITE(21,*) (LOAD(J),J=13,24)
        CLOSE(21)

      RETURN
      END
C======================================================================
C this subroutine initializes the variables
      SUBROUTINE INITIALIZER(K,L,F,T,LOAD,PMIN,PMAX,
     2                         P,LAMSYS,LAMFUL,LAMNOX,SALES)

      REAL K(2,3),L(2,3),F(2),T(2),LOAD(24),PMIN(2),PMAX(2)
      REAL P(2,24),LAMSYS(24),LAMFUL(24),LAMNOX(24),SALES
```

```
      DO 1010 I = 1,2
        DO 1020 J = 1,3
          K(I,J)  = 0.0
          L(I,J)  = 0.0
1020    CONTINUE
        F(I)      = 0.0
        T(I)      = 0.0
        PMIN(I)   = 0.0
        PMAX(I)   = 0.0
1010  CONTINUE
      DO 1030 I = 1,24
        DO 1040 J = 1,2
          P(J,I)       = 0.0
1040    CONTINUE
        LAMSYS(I)      = 0.0
        LOAD(I)        = 0.0
        LAMFUL(I)      = 0.0
        LAMNOX(I)      = 0.0
1030  CONTINUE
      SALES = 0.0

      RETURN
      END
C=====================================================================
```

Appendix C: Bay Area Power System

1. introduction

Table C.1 contains the operating details of the units in the Bay Area Power System (BAPS). Most of the data on the PG&E stations come from the standard sources, the CEC CFM filings and past CPUC testimony. Data are intended to reflect 1989 conditions. As noted elsewhere in this report, while it is not within the confines of the District, Moss Landing is included in most of the analysis. Data on 16 non-PG&E generators were entered explicity and the other large (>1MW) within the District were included in two general resources, OTHERBIO1 and OTHERG - AS1. The NOx curves are the ones whose development is described in Appendix D.

2. BAPS

The BAPS test system, as explained in more detail in appendix A, does not totally encompass all electricity demand and generation within the District. The initial intent was to isolate such a system but this proved too complex a task for this project. On the demand side, the sales of the municipals are excluded, as are the imports by WAPA to final customers, self-generation and some other minor sources. On the supply side, Moss Landing, which is not within the District but within its UAM modeling domain, is included. The roughly 100 MW of municipal thermal generation in the District is not included.[1] The 7146MW system that results consists primarily (89%) of PG&E owned generation, the remainder being QF's. Given the small capacity of gas turbines owned by PG&E and the absolute dominance of natural gas fuel, it is not surprising that BAPS is fully 83% steam thermal generation.

From the point of view of NO_x dispatch, BAPS is a challenging system. The homogeneity of BAPS limits the potential of NO_x dispatch to reduce overall emissions. That is,flexibility to move generation from more polluting to less polluting units is limited. Clearly, a system that had a more diversified fuel mix would pose more opportunities for lowering emissions. On the plus side, BAPS provides a good opportunity to study the details of the dispatch in some detail. The pure dispatch effects should be clearly identifiable.

3. data sources

Following is a list of the major data sources for the information that appears in table C.1.

1. capacity and minimum load data for all PG&E units are taken from PG&E's PROMOD III® file from the March 1988 ECAC filing

1 Municipal thermal generation in the District consists of 4 25MW gas turbines, Alameda 1 & 2 and Gianeri 1 & 2, and a 6MW cogeneration project.

2. the I-O curve coefficients are taken from the same filing and regression described in appendix D
3. NO_x curve coefficients are taken from PG&E'S CEC CFM R-3A filing, 1 June 1991, and regression described in appendix D
3. basic QF data come from the PG&E's *Cogeneration and Small Power Production Quarterly Report* , second quarter, 1991
4. QF emissions based on an assumed 42 ppm permit condition, except for Gilroy Energy, which assumes 25 ppm
5. start-up emissions are assumed to be 33% of minimum load

Table C.1

Bay Area Power System v. 3.2.3
28-Sep-92

resource	Contra Costa 1	Contra Costa 2	Contra Costa 3
name	CONTRCS1	CONTRCS2	CONTRCS3
boiler name	CCB1&2	CCB3&6	CCB4&5
technology	steam	steam	steam
resource ID	11	12	13
operator	PG&E	PG&E	PG&E
county	Contra Costa	Contra Costa	Contra Costa
BAAQMD	Y	Y	Y
capacity [MW]	116	116	116
min. load [MW]	10	10	10
heat k0	1.254184E+02	1.272820E+02	1.256465E+02
rate k1	1.109464E+01	1.151407E+01	1.058740E+01
[GJ/h] k2	9.618715E-03	6.381152E-03	1.477305E-02
NOx l0	1.066105E+01	1.055426E+01	1.071995E+01
[kg/h] l1	1.740192E-01	2.019326E-01	1.553799E-01
l2	3.130855E-03	2.905147E-03	3.303725E-03
fuel	gas	gas	gas
fuel price [$/GJ]	2.25	2.25	2.25
time to cold [h]	7	7	7
cold start time [h]	7	7	7
cold start cost [$]	2227	2227	2227
start up m0	1	1	1
cost [$] m1	317.940	317.940	317.940
start up n0	1	1	1
NOx [kg] n1	4.196	4.245	4.159
ramp rate [MW/h]	240	240	240
min. up time [h]	1	1	1
stop cost [$]	1	1	1
stop emission [kg]	1	1	1
min. down time [h]	4	4	4
EFOR	0.210000	0.169000	0.222000

Bay Area Power System v. 3.2.3
28-Sep-92

resource	Contra Costa 1	Contra Costa 2	Contra Costa 3
IHR min. [MJ/kWh]	11.29	11.64	10.88
IHR 50% [MJ/kWh]	12.21	12.25	12.30
IHR 75% [MJ/kWh]	12.77	12.62	13.16
IHR 100% [MJ/kWh]	13.33	12.99	14.01
IFC min. [¢/kWh]	2.540	2.619	2.449
IFC 50% [¢/kWh]	2.747	2.757	2.768
IFC 75% [¢/kWh]	2.873	2.840	2.961
IFC 100% [¢/kWh]	2.998	2.924	3.153
INOx min. [g/kWh]	0.237	0.260	0.221
INOx 50% [g/kWh]	0.537	0.539	0.539
INOx 75% [g/kWh]	0.719	0.707	0.730
INOx 100% [g/kWh]	0.900	0.876	0.922
AFC min. [¢/kWh]	5.340	5.469	5.242
AFC 50% [¢/kWh]	3.108	3.168	3.062
AFC 75% [¢/kWh]	3.009	3.045	2.996
AFC 100% [¢/kWh]	2.991	3.004	3.011
ANOx min. [g/kWh]	1.271	1.286	1.260
ANOx 50% [g/kWh]	0.539	0.552	0.532
ANOx 75% [g/kWh]	0.569	0.576	0.566
ANOx 100% [g/kWh]	0.629	0.630	0.631

Bay Area Power System v. 3.2.3
28-Sep-92

resource	Contra Costa 4	Contra Costa 5	Contra Costa 6
name	CONTRCS4	CONTRCS5	CONTRCS6
boiler name	CCB7	CCB8	CCB9
technology	steam	steam	steam
resource ID	14	15	16
operator	PG&E	PG&E	PG&E
county	Contra Costa	Contra Costa	Contra Costa
BAAQMD	Y	Y	Y
capacity [MW]	117	115	340
min. load [MW]	10	10	46
heat k0	9.783147E+01	1.049282E+02	2.372579E+02
rate k1	1.024742E+01	1.015332E+01	9.537133E+00
[GJ/h] k2	9.445342E-03	8.344718E-03	1.426415E-03
NOx l0	8.281071E+00	8.457162E+00	2.991612E+01
[kg/h] l1	2.079196E-01	2.100938E-01	2.077203E-01
l2	3.322621E-03	3.237392E-03	1.528455E-03
fuel	gas	gas	gas
fuel price [$/GJ]	2.25	2.25	2.25
time to cold [h]	7	7	8
cold start time [h]	7	7	8
cold start cost [$]	1574	1574	4304
start up m0	1	1	1
cost [$] m1	224.685	224.685	537.826
start up n0	1	1	1
NOx [kg] n1	3.529	3.591	14.093
ramp rate [MW/h]	240	240	300
min. up time [h]	1	1	1
stop cost [$]	1	1	1
stop emission [kg]	1	1	1
min. down time [h]	4	4	5
EFOR	0.273000	0.237000	0.066000

Bay Area Power System v. 3.2.3

28-Sep-92

resource	Contra Costa 4	Contra Costa 5	Contra Costa 6
IHR min. [MJ/kWh]	10.44	10.32	9.67
IHR 50% [MJ/kWh]	11.35	11.11	10.02
IHR 75% [MJ/kWh]	11.91	11.59	10.26
IHR 100% [MJ/kWh]	12.46	12.07	10.51
IFC min. [¢/kWh]	2.348	2.322	2.175
IFC 50% [¢/kWh]	2.554	2.500	2.255
IFC 75% [¢/kWh]	2.679	2.608	2.310
IFC 100% [¢/kWh]	2.803	2.716	2.364
INOx min. [g/kWh]	0.274	0.275	0.348
INOx 50% [g/kWh]	0.597	0.582	0.727
INOx 75% [g/kWh]	0.791	0.769	0.987
INOx 100% [g/kWh]	0.985	0.955	1.247
AFC min. [¢/kWh]	4.528	4.664	3.321
AFC 50% [¢/kWh]	2.806	2.803	2.514
AFC 75% [¢/kWh]	2.743	2.720	2.437
AFC 100% [¢/kWh]	2.742	2.706	2.412
ANOx min. [g/kWh]	1.069	1.088	0.928
ANOx 50% [g/kWh]	0.544	0.543	0.644
ANOx 75% [g/kWh]	0.594	0.587	0.715
ANOx 100% [g/kWh]	0.667	0.656	0.815

Bay Area Power System v. 3.2.3
28-Sep-92

resource	Contra Costa 7	Hunters Point 1	Hunters Point 2
name	CONTRCS7	HNTRSPT1	HNTRSPT2
boiler name	CCB10		HPB3&4
technology	steam	GT	steam
resource ID	17	21	22
operator	PG&E	PG&E	PG&E
county	Contra Costa	San Francisco	San Francisco
BAAQMD	Y	Y	Y
capacity [MW]	340	56	107
min. load [MW]	46	55	10
heat k0	1.808711E+02	0.000000E+00	1.543959E+02
rate k1	1.011017E+01	1.373610E+01	1.043144E+01
[GJ/h] k2	3.843175E-04	0.000000E+00	2.182914E-02
NOx l0	2.568821E+01	0.000000E+00	2.782601E+01
[kg/h] l1	2.491279E-01	1.780000E+00	-4.399410E-01
l2	1.458537E-03	0.000000E+00	2.270169E-02
fuel	gas	distillate	gas
fuel price [$/GJ]	2.25	3.60	2.25
time to cold [h]	8	1	7
cold start time [h]	8	1	7
cold start cost [$]	4304	1	2227
start up m0	1	1	1
cost [$] m1	537.826	0.000	317.940
start up n0	1	1	1
NOx [kg] n1	13.277	0.000	8.480
ramp rate [MW/h]	300	100	240
min. up time [h]	1	1	1
stop cost [$]	1	1	1
stop emission [kg]	1	1	1
min. down time [h]	5	1	4
EFOR	0.058000	0.097000	0.115000

Bay Area Power System v. 3.2.3
28-Sep-92

resource	Contra Costa 7	Hunters Point 1	Hunters Point 2
IHR min. [MJ/kWh]	10.15	13.74	10.87
IHR 50% [MJ/kWh]	10.24	13.74	12.77
IHR 75% [MJ/kWh]	10.31	13.74	13.94
IHR 100% [MJ/kWh]	10.37	13.74	15.10
IFC min. [¢/kWh]	2.283	4.945	2.445
IFC 50% [¢/kWh]	2.304	4.945	2.873
IFC 75% [¢/kWh]	2.319	4.945	3.135
IFC 100% [¢/kWh]	2.334	4.945	3.398
INOx min. [g/kWh]	0.383	1.780	0.014
INOx 50% [g/kWh]	0.745	1.780	1.989
INOx 75% [g/kWh]	0.993	1.780	3.204
INOx 100% [g/kWh]	1.241	1.780	4.418
AFC min. [¢/kWh]	3.163	4.945	5.870
AFC 50% [¢/kWh]	2.529	4.945	3.259
AFC 75% [¢/kWh]	2.456	4.945	3.174
AFC 100% [¢/kWh]	2.424	4.945	3.197
ANOx min. [g/kWh]	0.875	1.780	2.570
ANOx 50% [g/kWh]	0.648	1.780	1.295
ANOx 75% [g/kWh]	0.722	1.780	1.729
ANOx 100% [g/kWh]	0.821	1.780	2.249

Bay Area Power System v. 3.2.3
28-Sep-92

resource	Hunters Point 3	Hunters Point 4	Moss Landing 1
name	HNTRSPT3	HNTRSPT4	MOSLNDG1
boiler name	HPB5&6	HPB7	MLB2&3
technology	steam	steam	steam
resource ID	23	24	31
operator	PG&E	PG&E	PG&E
county	San Francisco	San Francisco	Monterey
BAAQMD	Y	Y	N
capacity [MW]	107	163	116
min. load [MW]	10	31	10
heat k0	1.442820E+02	9.815517E+01	1.990331E+02
rate k1	1.192097E+01	1.079022E+01	7.914292E+00
[GJ/h] k2	9.406338E-03	5.243649E-04	5.024468E-02
NOx l0	2.627595E+01	8.056942E+00	1.327834E+01
[kg/h] l1	-2.665119E-01	2.882964E-01	9.837593E-02
l2	2.126635E-02	1.563827E-03	6.399866E-03
fuel	gas	gas	gas
fuel price [$/GJ]	2.25	2.25	2.25
time to cold [h]	7	6	7
cold start time [h]	7	6	7
cold start cost [$]	2227	2077	2227
start up m0	1	1	1
cost [$] m1	317.940	346.005	317.940
start up n0	1	1	1
NOx [kg] n1	8.493	6.104	4.918
ramp rate [MW/h]	240	180	240
min. up time [h]	1	1	1
stop cost [$]	1	1	1
stop emission [kg]	1	1	1
min. down time [h]	4	4	4
EFOR	0.125000	0.105000	0.606000

Bay Area Power System v. 3.2.3
28-Sep-92

resource	Hunters Point 3	Hunters Point 4	Moss Landing 1
IHR min. [MJ/kWh]	12.11	10.82	8.92
IHR 50% [MJ/kWh]	12.93	10.88	13.74
IHR 75% [MJ/kWh]	13.43	10.92	16.66
IHR 100% [MJ/kWh]	13.93	10.96	19.57
IFC min. [¢/kWh]	2.725	2.435	2.007
IFC 50% [¢/kWh]	2.909	2.447	3.092
IFC 75% [¢/kWh]	3.022	2.457	3.748
IFC 100% [¢/kWh]	3.135	2.466	4.403
INOx min. [g/kWh]	0.159	0.385	0.226
INOx 50% [g/kWh]	2.009	0.543	0.841
INOx 75% [g/kWh]	3.147	0.671	1.212
INOx 100% [g/kWh]	4.284	0.798	1.583
AFC min. [¢/kWh]	5.950	3.144	6.372
AFC 50% [¢/kWh]	3.402	2.708	3.209
AFC 75% [¢/kWh]	3.257	2.623	3.279
AFC 100% [¢/kWh]	3.212	2.583	3.478
ANOx min. [g/kWh]	2.574	0.597	1.490
ANOx 50% [g/kWh]	1.362	0.515	0.699
ANOx 75% [g/kWh]	1.768	0.545	0.808
ANOx 100% [g/kWh]	2.255	0.593	0.955

Bay Area Power System v. 3.2.3
28-Sep-92

resource	Moss Landing 2	Moss Landing 3	Moss Landing 4
name	MOSLNDG2	MOSLNDG3	MOSLNDG4
boiler name	MLB1&4	MLB5&6	MLB7
technology	steam	steam	steam
resource ID	32	33	34
operator	PG&E	PG&E	PG&E
county	Monterey	Monterey	Monterey
BAAQMD	N	N	N
capacity [MW]	116	117	117
min. load [MW]	10	10	7
heat k0	2.338511E+02	1.235108E+02	1.437815E+02
rate k1	9.885289E+00	2.219693E+01	8.856534E+00
[GJ/h] k2	2.666548E-02	1.803257E-02	1.360894E-02
NOx l0	1.431540E+01	1.002837E+01	8.299016E+00
[kg/h] l1	2.493764E-01	3.180006E-01	-1.268277E-01
l2	4.704734E-03	4.603799E-03	9.686688E-03
fuel	gas	gas	gas
fuel price [$/GJ]	2.25	2.25	2.25
time to cold [h]	7	7	7
cold start time [h]	7	7	7
cold start cost [$]	2227	2227	1574
start up m0	1	1	1
cost [$] m1	317.940	317.940	224.685
start up n0	1	1	1
NOx [kg] n1	5.702	4.511	2.602
ramp rate [MW/h]	240	240	240
min. up time [h]	1	1	1
stop cost [$]	1	1	1
stop emission [kg]	1	1	1
min. down time [h]	4	4	4
EFOR	0.442000	0.382000	0.197000

Bay Area Power System v. 3.2.3
28-Sep-92

resource	Moss Landing 2	Moss Landing 3	Moss Landing 4
IHR min. [MJ/kWh]	10.42	22.56	9.05
IHR 50% [MJ/kWh]	12.98	24.31	10.45
IHR 75% [MJ/kWh]	14.53	25.36	11.24
IHR 100% [MJ/kWh]	16.07	26.42	12.04
IFC min. [¢/kWh]	2.344	5.075	2.036
IFC 50% [¢/kWh]	2.920	5.469	2.351
IFC 75% [¢/kWh]	3.268	5.706	2.530
IFC 100% [¢/kWh]	3.616	5.944	2.709
INOx min. [g/kWh]	0.343	0.410	0.009
INOx 50% [g/kWh]	0.795	0.857	1.007
INOx 75% [g/kWh]	1.068	1.126	1.573
INOx 100% [g/kWh]	1.341	1.395	2.140
AFC min. [¢/kWh]	7.546	7.814	6.636
AFC 50% [¢/kWh]	3.479	5.707	2.725
AFC 75% [¢/kWh]	3.351	5.667	2.630
AFC 100% [¢/kWh]	3.374	5.707	2.627
ANOx min. [g/kWh]	1.728	1.367	1.127
ANOx 50% [g/kWh]	0.769	0.759	0.582
ANOx 75% [g/kWh]	0.823	0.836	0.818
ANOx 100% [g/kWh]	0.919	0.942	1.077

Bay Area Power System v. 3.2.3
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resource	Moss Landing 5	Moss Landing 6	Moss Landing 7
name	MOSLNDG5	MOSLNDG6	MOSLNDG7
boiler name	MLB8	MLB6-1	MLB7-1
technology	steam	steam	steam
resource ID	35	36	37
operator	PG&E	PG&E	PG&E
county	Monterey	Monterey	Monterey
BAAQMD	N	N	N
capacity [MW]	117	739	739
min. load [MW]	7	50	50
heat k0	1.296082E+02	6.491714E+02	6.491714E+02
rate k1	9.589114E+00	8.008987E+00	8.008987E+00
[GJ/h] k2	1.174390E-02	1.534524E-03	1.534523E-03
NOx l0	8.299016E+00	6.148135E+00	1.642026E+01
[kg/h] l1	-1.268277E-01	-1.010000E-01	-5.979020E-03
l2	9.686688E-03	1.006239E-03	1.080059E-03
fuel	gas	gas	gas
fuel price [$/GJ]	2.25	2.25	2.25
time to cold [h]	7	18	18
cold start time [h]	7	18	18
cold start cost [$]	1574	63795	63795
start up m0	1	1	1
cost [$] m1	224.685	3544.085	3544.085
start up n0	1	1	1
NOx [kg] n1	2.602	1.193	6.211
ramp rate [MW/h]	240	600	600
min. up time [h]	1	1	1
stop cost [$]	1	1	1
stop emission [kg]	1	1	1
min. down time [h]	4	10	10
EFOR	0.194000	0.186000	0.175000

Bay Area Power System v. 3.2.3
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resource	Moss Landing 5	Moss Landing 6	Moss Landing 7
IHR min. [MJ/kWh]	9.75	8.16	8.16
IHR 50% [MJ/kWh]	10.96	9.14	9.14
IHR 75% [MJ/kWh]	11.65	9.71	9.71
IHR 100% [MJ/kWh]	12.34	10.28	10.28
IFC min. [¢/kWh]	2.195	1.837	1.837
IFC 50% [¢/kWh]	2.467	2.057	2.057
IFC 75% [¢/kWh]	2.621	2.185	2.185
IFC 100% [¢/kWh]	2.776	2.312	2.312
INOx min. [g/kWh]	0.009	0.000	0.102
INOx 50% [g/kWh]	1.007	0.643	0.792
INOx 75% [g/kWh]	1.573	1.014	1.191
INOx 100% [g/kWh]	2.140	1.386	1.590
AFC min. [¢/kWh]	6.342	4.741	4.741
AFC 50% [¢/kWh]	2.811	2.325	2.325
AFC 75% [¢/kWh]	2.722	2.257	2.257
AFC 100% [¢/kWh]	2.716	2.255	2.255
ANOx min. [g/kWh]	1.127	0.072	0.376
ANOx 50% [g/kWh]	0.582	0.287	0.438
ANOx 75% [g/kWh]	0.818	0.468	0.622
ANOx 100% [g/kWh]	1.077	0.651	0.814

Bay Area Power System v. 3.2.3
28-Sep-92

resource	Oakland 1	Oakland 2	Oakland 3
name	OAKLAND1	OAKLAND2	OAKLAND3
boiler name			
technology	GT	GT	GT
resource ID	41	42	43
operator	PG&E	PG&E	PG&E
county	Alameda	Alameda	Alameda
BAAQMD	Y	Y	Y
capacity [MW]	64	64	64
min. load [MW]	63	63	63
heat k0	0.000000E+00	0.000000E+00	0.000000E+00
rate k1	1.371500E+01	1.371500E+01	1.371500E+01
[GJ/h] k2	0.000000E+00	0.000000E+00	0.000000E+00
NOx l0	0.000000E+00	0.000000E+00	0.000000E+00
[kg/h] l1	1.780000E+00	1.780000E+00	1.780000E+00
l2	0.000000E+00	0.000000E+00	0.000000E+00
fuel	distillate	distillate	distillate
fuel price [$/GJ]	3.60	3.60	3.60
time to cold [h]	1	1	1
cold start time [h]	1	1	1
cold start cost [$]	1	1	1
start up m0	1	1	1
cost [$] m1	0.000	0.000	0.000
start up n0	1	1	1
NOx [kg] n1	0.000	0.000	0.000
ramp rate [MW/h]	100	100	100
min. up time [h]	1	1	1
stop cost [$]	1	1	1
stop emission [kg]	1	1	1
min. down time [h]	1	1	1
EFOR	0.138000	0.124000	0.123000

Bay Area Power System v. 3.2.3

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resource	Oakland 1	Oakland 2	Oakland 3
IHR min. [MJ/kWh]	13.72	13.72	13.72
IHR 50% [MJ/kWh]	13.72	13.72	13.72
IHR 75% [MJ/kWh]	13.72	13.72	13.72
IHR 100% [MJ/kWh]	13.72	13.72	13.72
IFC min. [¢/kWh]	4.937	4.937	4.937
IFC 50% [¢/kWh]	4.937	4.937	4.937
IFC 75% [¢/kWh]	4.937	4.937	4.937
IFC 100% [¢/kWh]	4.937	4.937	4.937
INOx min. [g/kWh]	1.780	1.780	1.780
INOx 50% [g/kWh]	1.780	1.780	1.780
INOx 75% [g/kWh]	1.780	1.780	1.780
INOx 100% [g/kWh]	1.780	1.780	1.780
AFC min. [¢/kWh]	4.937	4.937	4.937
AFC 50% [¢/kWh]	4.937	4.937	4.937
AFC 75% [¢/kWh]	4.937	4.937	4.937
AFC 100% [¢/kWh]	4.937	4.937	4.937
ANOx min. [g/kWh]	1.780	1.780	1.780
ANOx 50% [g/kWh]	1.780	1.780	1.780
ANOx 75% [g/kWh]	1.780	1.780	1.780
ANOx 100% [g/kWh]	1.780	1.780	1.780

Bay Area Power System v. 3.2.3

28-Sep-92

resource	Pittsburg 1	Pittsburg 2	Pittsburg 3
name	PITSBRG1	PITSBRG2	PITSBRG3
boiler name	PTB1	PTB2	PTB3
technology	steam	steam	steam
resource ID	51	52	53
operator	PG&E	PG&E	PG&E
county	Contra Costa	Contra Costa	Contra Costa
BAAQMD	Y	Y	Y
capacity [MW]	163	163	163
min. load [MW]	31	31	31
heat k0	1.857058E+02	2.433852E+02	1.801279E+02
rate k1	8.924874E+00	7.666023E+00	8.894634E+00
[GJ/h] k2	8.412467E-03	1.558105E-02	9.371497E-03
NOx l0	4.336284E+01	4.757349E+01	4.266162E+01
[kg/h] l1	-1.648692E-01	-2.797610E-01	-1.674042E-01
l2	5.996064E-03	6.741227E-03	6.099259E-03
fuel	gas	gas	gas
fuel price [$/GJ]	2.25	2.25	2.25
time to cold [h]	16	6	16
cold start time [h]	16	6	16
cold start cost [$]	2077	2077	2077
start up m0	1	1	1
cost [$] m1	129.752	346.005	129.752
start up n0	1	1	1
NOx [kg] n1	14.525	14.975	14.300
ramp rate [MW/h]	180	180	180
min. up time [h]	1	1	1
stop cost [$]	1	1	1
stop emission [kg]	1	1	1
min. down time [h]	4	4	4
EFOR	0.087000	0.107000	0.086000

Bay Area Power System v. 3.2.3
28-Sep-92

resource	Pittsburg 1	Pittsburg 2	Pittsburg 3
IHR min. [MJ/kWh]	9.45	8.63	9.48
IHR 50% [MJ/kWh]	10.30	10.21	10.42
IHR 75% [MJ/kWh]	10.98	11.48	11.19
IHR 100% [MJ/kWh]	11.67	12.75	11.95
IFC min. [¢/kWh]	2.125	1.942	2.132
IFC 50% [¢/kWh]	2.317	2.296	2.345
IFC 75% [¢/kWh]	2.471	2.582	2.517
IFC 100% [¢/kWh]	2.625	2.868	2.689
INOx min. [g/kWh]	0.207	0.138	0.211
INOx 50% [g/kWh]	0.812	0.819	0.827
INOx 75% [g/kWh]	1.301	1.368	1.324
INOx 100% [g/kWh]	1.790	1.918	1.821
AFC min. [¢/kWh]	3.415	3.600	3.374
AFC 50% [¢/kWh]	2.675	2.682	2.670
AFC 75% [¢/kWh]	2.581	2.601	2.591
AFC 100% [¢/kWh]	2.573	2.632	2.594
ANOx min. [g/kWh]	1.420	1.464	1.398
ANOx 50% [g/kWh]	0.856	0.853	0.853
ANOx 75% [g/kWh]	0.923	0.934	0.927
ANOx 100% [g/kWh]	1.079	1.111	1.089

Bay Area Power System v. 3.2.3
28-Sep-92

resource	Pittsburg 4	Pittsburg 5	Pittsburg 6
name	PITSBRG4	PITSBRG5	PITSBRG6
boiler name	PTB4	PTB5	PTB6
technology	steam	steam	steam
resource ID	54	55	56
operator	PG&E	PG&E	PG&E
county	Contra Costa	Contra Costa	Contra Costa
BAAQMD	Y	Y	Y
capacity [MW]	163	325	325
min. load [MW]	31	46	46
heat k0	1.774657E+02	3.023789E+02	2.471965E+02
rate k1	8.926976E+00	8.634839E+00	8.685576E+00
[GJ/h] k2	8.348328E-03	3.693023E-03	1.358149E-03
NOx l0	4.221280E+01	1.612959E+01	1.085135E+01
[kg/h] l1	-1.516033E-01	1.672147E-01	3.836326E-01
l2	5.919600E-03	1.722545E-03	2.996383E-04
fuel	gas	gas	gas
fuel price [$/GJ]	2.25	2.25	2.25
time to cold [h]	6	12	10
cold start time [h]	6	12	10
cold start cost [$]	2077	4304	4304
start up m0	1	1	1
cost [$] m1	346.005	358.551	430.261
start up n0	1	1	1
NOx [kg] n1	14.257	9.064	9.614
ramp rate [MW/h]	180	300	300
min. up time [h]	1	1	1
stop cost [$]	1	1	1
stop emission [kg]	1	1	1
min. down time [h]	4	5	5
EFOR	0.132000	0.135000	0.255000

Bay Area Power System v. 3.2.3

28-Sep-92

resource	Pittsburg 4	Pittsburg 5	Pittsburg 6
IHR min. [MJ/kWh]	9.44	8.97	8.81
IHR 50% [MJ/kWh]	10.29	9.84	9.13
IHR 75% [MJ/kWh]	10.97	10.44	9.35
IHR 100% [MJ/kWh]	11.65	11.04	9.57
IFC min. [¢/kWh]	2.125	2.019	1.982
IFC 50% [¢/kWh]	2.315	2.213	2.054
IFC 75% [¢/kWh]	2.468	2.348	2.103
IFC 100% [¢/kWh]	2.621	2.483	2.153
INOx min. [g/kWh]	0.215	0.326	0.411
INOx 50% [g/kWh]	0.813	0.727	0.481
INOx 75% [g/kWh]	1.296	1.007	0.530
INOx 100% [g/kWh]	1.778	1.287	0.578
AFC min. [¢/kWh]	3.355	3.460	3.177
AFC 50% [¢/kWh]	2.652	2.497	2.346
AFC 75% [¢/kWh]	2.565	2.424	2.257
AFC 100% [¢/kWh]	2.560	2.422	2.225
ANOx min. [g/kWh]	1.394	0.597	0.633
ANOx 50% [g/kWh]	0.849	0.546	0.499
ANOx 75% [g/kWh]	0.917	0.653	0.501
ANOx 100% [g/kWh]	1.072	0.777	0.514

Bay Area Power System v. 3.2.3
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resource	Pittsburg 7	Portable 1	Portable 2
name	PITSBRG7	PORTBLE1	PORTBLE2
boiler name	PTB7		
technology	steam	GT	GT
resource ID	57	61	62
operator	PG&E	PG&E	PG&E
county	Contra Costa		
BAAQMD	Y	Y	Y
capacity [MW]	720	15	15
min. load [MW]	120	14	14
heat k0	9.703435E+02	0.000000E+00	0.000000E+00
rate k1	7.649096E+00	1.529750E+01	1.529750E+01
[GJ/h] k2	3.004041E-03	0.000000E+00	0.000000E+00
NOx l0	2.823125E+01	0.000000E+00	0.000000E+00
[kg/h] l1	1.584831E-01	4.213000E+00	4.213000E+00
l2	2.556222E-04	0.000000E+00	0.000000E+00
fuel	gas	distillate	distillate
fuel price [$/GJ]	2.25	3.60	3.60
time to cold [h]	18	1	1
cold start time [h]	18	1	1
cold start cost [$]	63795	1	1
start up m0	1	1	1
cost [$] m1	3544.085	0.000	0.000
start up n0	1	1	1
NOx [kg] n1	16.807	0.000	0.000
ramp rate [MW/h]	300	100	100
min. up time [h]	1	1	1
stop cost [$]	1	1	1
stop emission [kg]	1	1	1
min. down time [h]	10	1	1
EFOR	0.206000	0.257000	0.034000

Bay Area Power System v. 3.2.3
28-Sep-92

resource	Pittsburg 7	Portable 1	Portable 2
IHR min. [MJ/kWh]	8.37	15.30	15.30
IHR 50% [MJ/kWh]	9.81	15.30	15.30
IHR 75% [MJ/kWh]	10.89	15.30	15.30
IHR 100% [MJ/kWh]	11.97	15.30	15.30
IFC min. [¢/kWh]	1.883	5.507	5.507
IFC 50% [¢/kWh]	2.208	5.507	5.507
IFC 75% [¢/kWh]	2.451	5.507	5.507
IFC 100% [¢/kWh]	2.694	5.507	5.507
INOx min. [g/kWh]	0.220	4.213	4.213
INOx 50% [g/kWh]	0.343	4.213	4.213
INOx 75% [g/kWh]	0.435	4.213	4.213
INOx 100% [g/kWh]	0.527	4.213	4.213
AFC min. [¢/kWh]	3.622	5.507	5.507
AFC 50% [¢/kWh]	2.571	5.507	5.507
AFC 75% [¢/kWh]	2.490	5.507	5.507
AFC 100% [¢/kWh]	2.511	5.507	5.507
ANOx min. [g/kWh]	0.424	4.213	4.213
ANOx 50% [g/kWh]	0.329	4.213	4.213
ANOx 75% [g/kWh]	0.349	4.213	4.213
ANOx 100% [g/kWh]	0.382	4.213	4.213

Bay Area Power System v. 3.2.3

28-Sep-92

resource	Portable 3	Potrero 3	Potrero 4	Potrero 5
name	PORTBLE3	POTRERO3	POTRERO4	POTRERO5
boiler name		PRB3-1		
technology	GT	steam	GT	GT
resource ID	62	71	72	73
operator	PG&E	PG&E	PG&E	PG&E
county		San Francisco	San Francisco	San Francisco
BAAQMD	Y	Y	Y	Y
capacity [MW]	15	207	56	56
min. load [MW]	14	47	55	55
heat k0	0.000000E+00	1.566756E+02	0.000000E+00	0.000000E+00
rate k1	1.529750E+01	9.045085E+00	1.348290E+01	1.348290E+01
[GJ/h] k2	0.000000E+00	4.329305E-03	0.000000E+00	0.000000E+00
NOx l0	0.000000E+00	-2.163522E+01	0.000000E+00	0.000000E+00
[kg/h] l1	4.213000E+00	1.115824E+00	1.780000E+00	1.780000E+00
l2	0.000000E+00	-1.295695E-03	0.000000E+00	0.000000E+00
fuel	distillate	gas	distillate	distillate
fuel price [$/GJ]	3.60	2.25	3.60	3.60
time to cold [h]	1	6	1	1
cold start time [h]	1	6	1	1
cold start cost [$]	1	4451	1	1
start up m0	1	1	1	1
cost [$] m1	0.000	741.630	0.000	0.000
start up n0	1	1	1	1
NOx [kg] n1	0.000	9.222	0.000	0.000
ramp rate [MW/h]	100	180	100	100
min. up time [h]	1	1	1	1
stop cost [$]	1	1	1	1
stop emission [kg]	1	1	1	1
min. down time [h]	1	3	1	1
EFOR	0.090000	0.047000	0.044000	0.032000

Bay Area Power System v. 3.2.3

28-Sep-92

resource	Portable 3	Potrero 3	Potrero 4	Potrero 5
IHR min. [MJ/kWh]	15.30	9.45	13.48	13.48
IHR 50% [MJ/kWh]	15.30	9.94	13.48	13.48
IHR 75% [MJ/kWh]	15.30	10.39	13.48	13.48
IHR 100% [MJ/kWh]	15.30	10.84	13.48	13.48
IFC min. [¢/kWh]	5.507	2.127	4.854	4.854
IFC 50% [¢/kWh]	5.507	2.237	4.854	4.854
IFC 75% [¢/kWh]	5.507	2.338	4.854	4.854
IFC 100% [¢/kWh]	5.507	2.438	4.854	4.854
INOx min. [g/kWh]	4.213	0.994	1.780	1.780
INOx 50% [g/kWh]	4.213	0.848	1.780	1.780
INOx 75% [g/kWh]	4.213	0.714	1.780	1.780
INOx 100% [g/kWh]	4.213	0.579	1.780	1.780
AFC min. [¢/kWh]	5.507	2.831	4.854	4.854
AFC 50% [¢/kWh]	5.507	2.477	4.854	4.854
AFC 75% [¢/kWh]	5.507	2.413	4.854	4.854
AFC 100% [¢/kWh]	5.507	2.407	4.854	4.854
ANOx min. [g/kWh]	4.213	0.595	1.780	1.780
ANOx 50% [g/kWh]	4.213	0.773	1.780	1.780
ANOx 75% [g/kWh]	4.213	0.775	1.780	1.780
ANOx 100% [g/kWh]	4.213	0.743	1.780	1.780

Bay Area Power System v. 3.2.3
28-Sep-92

resource	Potrero 6	Gilroy Energy	Foster Wheeler	Dow Chemical
name	POTRERO6	GILROYE1	FSTRWLR1	DOWCHEM1
boiler name				
technology	GT	GT	GT	GT
resource ID	74	101	102	103
operator	PG&E	Gilroy Energy	Foster Wheeler	Dow Chemical
county	San Francisco	Santa Clara	Contra Costa	Contra Costa
BAAQMD	Y	Y	Y	Y
capacity [MW]	56	130	100	70
min. load [MW]	55	60	99	69
heat k0	0.000000E+00	0.000000E+00	0.000000E+00	0.000000E+00
rate k1	1.348290E+01	1.000000E+01	1.000000E+01	1.000000E+01
[GJ/h] k2	0.000000E+00	0.000000E+00	0.000000E+00	0.000000E+00
NOx l0	0.000000E+00	0.000000E+00	0.000000E+00	0.000000E+00
[kg/h] l1	1.780000E+00	2.000000E-01	3.300000E-01	3.300000E-01
l2	0.000000E+00	0.000000E+00	0.000000E+00	0.000000E+00
fuel	distillate	purchase	purchase	purchase
fuel price [$/GJ]	3.60	2.79	5.50	5.50
time to cold [h]	1	1	1	1
cold start time [h]	1	1	1	1
cold start cost [$]	1	1	1	1
start up m0	1	1	1	1
cost [$] m1	0.000	0.000	0.000	0.000
start up n0	1	1	1	1
NOx [kg] n1	0.000	0.000	0.000	0.000
ramp rate [MW/h]	100	200	100	100
min. up time [h]	1	1	1	1
stop cost [$]	1	1	1	1
stop emission [kg]	1	1	1	1
min. down time [h]	1	1	1	1
EFOR	0.121000	0.050000	0.050000	0.050000

Bay Area Power System v. 3.2.3
28-Sep-92

resource	Potrero 6	Gilroy Energy	Foster Wheeler	Dow Chemical
IHR min. [MJ/kWh]	13.48	10.00	10.00	10.00
IHR 50% [MJ/kWh]	13.48	10.00	10.00	10.00
IHR 75% [MJ/kWh]	13.48	10.00	10.00	10.00
IHR 100% [MJ/kWh]	13.48	10.00	10.00	10.00
IFC min. [¢/kWh]	4.854	2.794	5.498	5.498
IFC 50% [¢/kWh]	4.854	2.794	5.498	5.498
IFC 75% [¢/kWh]	4.854	2.794	5.498	5.498
IFC 100% [¢/kWh]	4.854	2.794	5.498	5.498
INOx min. [g/kWh]	1.780	0.200	0.330	0.330
INOx 50% [g/kWh]	1.780	0.200	0.330	0.330
INOx 75% [g/kWh]	1.780	0.200	0.330	0.330
INOx 100% [g/kWh]	1.780	0.200	0.330	0.330
AFC min. [¢/kWh]	4.854	2.794	5.498	5.498
AFC 50% [¢/kWh]	4.854	2.794	5.498	5.498
AFC 75% [¢/kWh]	4.854	2.794	5.498	5.498
AFC 100% [¢/kWh]	4.854	2.794	5.498	5.498
ANOx min. [g/kWh]	1.780	0.200	0.330	0.330
ANOx 50% [g/kWh]	1.780	0.200	0.330	0.330
ANOx 75% [g/kWh]	1.780	0.200	0.330	0.330
ANOx 100% [g/kWh]	1.780	0.200	0.330	0.330

Bay Area Power System v. 3.2.3
28-Sep-92

resource	GWF Power	GWF Power	Cardinal Cogen.	Union S.F.
name	GWFPOWR1	GWFPOWR2	CARDINL1	UNIONSF1
boiler name				
technology	FB	FB	GT	GT
resource ID	104	105	106	107
operator	GWF Power	GWF Power	Cardinal Cogen.	Union S.F.
county	Contra Costa	Contra Costa	Santa Clara	Contra Costa
BAAQMD	Y	Y	Y	Y
capacity [MW]	53	35	50	50
min. load [MW]	52	34	49	49
heat k0	0.000000E+00	0.000000E+00	0.000000E+00	0.000000E+00
rate k1	1.000000E+01	1.000000E+01	1.000000E+01	1.000000E+01
[GJ/h] k2	0.000000E+00	0.000000E+00	0.000000E+00	0.000000E+00
NOx l0	0.000000E+00	0.000000E+00	0.000000E+00	0.000000E+00
[kg/h] l1	3.300000E-01	3.300000E-01	3.300000E-01	2.000000E-01
l2	0.000000E+00	0.000000E+00	0.000000E+00	0.000000E+00
fuel	purchase	purchase	purchase	purchase
fuel price [$/GJ]	5.50	5.50	5.50	5.50
time to cold [h]	1	1	1	1
cold start time [h]	1	1	1	1
cold start cost [$]	1	1	1	1
start up m0	1	1	1	1
cost [$] m1	0.000	0.000	0.000	0.000
start up n0	1	1	1	1
NOx [kg] n1	0.000	0.000	0.000	0.000
ramp rate [MW/h]	100	100	100	100
min. up time [h]	1	1	1	1
stop cost [$]	1	1	1	1
stop emission [kg]	1	1	1	1
min. down time [h]	1	1	1	1
EFOR	0.050000	0.050000	0.050000	0.050000

Bay Area Power System v. 3.2.3
28-Sep-92

resource	GWF Power	GWF Power	Cardinal Cogen.	Union S.F.
IHR min. [MJ/kWh]	10.00	10.00	10.00	10.00
IHR 50% [MJ/kWh]	10.00	10.00	10.00	10.00
IHR 75% [MJ/kWh]	10.00	10.00	10.00	10.00
IHR 100% [MJ/kWh]	10.00	10.00	10.00	10.00
IFC min. [¢/kWh]	5.498	5.498	5.498	5.498
IFC 50% [¢/kWh]	5.498	5.498	5.498	5.498
IFC 75% [¢/kWh]	5.498	5.498	5.498	5.498
IFC 100% [¢/kWh]	5.498	5.498	5.498	5.498
INOx min. [g/kWh]	0.330	0.330	0.330	0.200
INOx 50% [g/kWh]	0.330	0.330	0.330	0.200
INOx 75% [g/kWh]	0.330	0.330	0.330	0.200
INOx 100% [g/kWh]	0.330	0.330	0.330	0.200
AFC min. [¢/kWh]	5.498	5.498	5.498	5.498
AFC 50% [¢/kWh]	5.498	5.498	5.498	5.498
AFC 75% [¢/kWh]	5.498	5.498	5.498	5.498
AFC 100% [¢/kWh]	5.498	5.498	5.498	5.498
ANOx min. [g/kWh]	0.330	0.330	0.330	0.200
ANOx 50% [g/kWh]	0.330	0.330	0.330	0.200
ANOx 75% [g/kWh]	0.330	0.330	0.330	0.200
ANOx 100% [g/kWh]	0.330	0.330	0.330	0.200

Bay Area Power System v. 3.2.3
17-Jan-93

resource	Gaylord	O.L.S. Hospital	Container Corp.	United Cogen.
name	GAYLORD1	OLSHOSP1	CONTNER1	UNTCOGN1
boiler name				
technology	GT	GT	GT	GT
resource ID	108	109	110	111
operator	Gaylord	O.L.S. Hospital	Container Corp.	United Cogen.
county	Contra Costa	Santa Clara	Santa Clara	San Mateo
BAAQMD	Y	Y	Y	Y
capacity [MW]	50	36	36	30
min. load [MW]	49	35	35	29
heat k0	0.000000E+00	0.000000E+00	0.000000E+00	0.000000E+00
rate k1	1.000000E+01	1.000000E+01	1.000000E+01	1.000000E+01
[GJ/h] k2	0.000000E+00	0.000000E+00	0.000000E+00	0.000000E+00
NOx l0	0.000000E+00	0.000000E+00	0.000000E+00	0.000000E+00
[kg/h] l1	3.300000E-01	3.300000E-01	3.300000E-01	3.300000E-01
l2	0.000000E+00	0.000000E+00	0.000000E+00	0.000000E+00
fuel	purchase	purchase	purchase	purchase
fuel price [$/GJ]	5.50	5.50	5.50	5.50
time to cold [h]	1	1	1	1
cold start time [h]	1	1	1	1
cold start cost [$]	1	1	1	1
start up m0	1	1	1	1
cost [$] m1	0.000	0.000	0.000	0.000
start up n0	1	1	1	1
NOx [kg] n1	0.000	0.000	0.000	0.000
ramp rate [MW/h]	100	100	100	100
min. up time [h]	1	1	1	1
stop cost [$]	1	1	1	1
stop emission [kg]	1	1	1	1
min. down time [h]	1	1	1	1
EFOR	0.050000	0.050000	0.050000	0.050000

Bay Area Power System v. 3.2.3

17-Jan-93

resource	Gaylord	O.L.S. Hospital	Container Corp.	United Cogen.
IHR min. [MJ/kWh]	10.00	10.00	10.00	10.00
IHR 50% [MJ/kWh]	10.00	10.00	10.00	10.00
IHR 75% [MJ/kWh]	10.00	10.00	10.00	10.00
IHR 100% [MJ/kWh]	10.00	10.00	10.00	10.00
IFC min. [¢/kWh]	5.498	5.498	5.498	5.498
IFC 50% [¢/kWh]	5.498	5.498	5.498	5.498
IFC 75% [¢/kWh]	5.498	5.498	5.498	5.498
IFC 100% [¢/kWh]	5.498	5.498	5.498	5.498
INOx min. [g/kWh]	0.330	0.330	0.330	0.330
INOx 50% [g/kWh]	0.330	0.330	0.330	0.330
INOx 75% [g/kWh]	0.330	0.330	0.330	0.330
INOx 100% [g/kWh]	0.330	0.330	0.330	0.330
AFC min. [¢/kWh]	5.498	5.498	5.498	5.498
AFC 50% [¢/kWh]	5.498	5.498	5.498	5.498
AFC 75% [¢/kWh]	5.498	5.498	5.498	5.498
AFC 100% [¢/kWh]	5.498	5.498	5.498	5.498
ANOx min. [g/kWh]	0.330	0.330	0.330	0.330
ANOx 50% [g/kWh]	0.330	0.330	0.330	0.330
ANOx 75% [g/kWh]	0.330	0.330	0.330	0.330
ANOx 100% [g/kWh]	0.330	0.330	0.330	0.330

Bay Area Power System v. 3.2.3

17-Jan-93

resource	Union Rodeo	O.L.S. Berkeley	Altamont LF	Fayette Kalina
name	UNIONRO1	OLSBERK1	ALTAMNT1	FAYETTE1
boiler name				
technology	GT	GT	GT	GT
resource ID	112	113	114	115
operator	Union Rodeo	O.L.S. Berkeley	Altamont LF	Fayette Kalina
county	Contra Costa	Alameda	Alameda	Alameda
BAAQMD	Y	Y	Y	Y
capacity [MW]	27	26	13	7
min. load [MW]	26	25	12	6
heat k0	0.000000E+00	0.000000E+00	0.000000E+00	0.000000E+00
rate k1	1.000000E+01	1.000000E+01	1.000000E+01	1.000000E+01
[GJ/h] k2	0.000000E+00	0.000000E+00	0.000000E+00	0.000000E+00
NOx l0	0.000000E+00	0.000000E+00	0.000000E+00	0.000000E+00
[kg/h] l1	3.300000E-01	3.300000E-01	2.000000E-01	3.300000E-01
l2	0.000000E+00	0.000000E+00	0.000000E+00	0.000000E+00
fuel	purchase	purchase	purchase	purchase
fuel price [$/GJ]	5.50	5.50	5.50	5.50
time to cold [h]	1	1	1	1
cold start time [h]	1	1	1	1
cold start cost [$]	1	1	1	1
start up m0	1	1	1	1
cost [$] m1	0.000	0.000	0.000	0.000
start up n0	1	1	1	1
NOx [kg] n1	0.000	0.000	0.000	0.000
ramp rate [MW/h]	100	100	100	100
min. up time [h]	1	1	1	1
stop cost [$]	1	1	1	1
stop emission [kg]	1	1	1	1
min. down time [h]	1	1	1	1
EFOR	0.050000	0.050000	0.050000	0.050000

Bay Area Power System v. 3.2.3
17-Jan-93

resource	Union Rodeo	O.L.S. Berkeley	Altamont LF	Fayette Kalina
IHR min. [MJ/kWh]	10.00	10.00	10.00	10.00
IHR 50% [MJ/kWh]	10.00	10.00	10.00	10.00
IHR 75% [MJ/kWh]	10.00	10.00	10.00	10.00
IHR 100% [MJ/kWh]	10.00	10.00	10.00	10.00
IFC min. [¢/kWh]	5.498	5.498	5.498	5.498
IFC 50% [¢/kWh]	5.498	5.498	5.498	5.498
IFC 75% [¢/kWh]	5.498	5.498	5.498	5.498
IFC 100% [¢/kWh]	5.498	5.498	5.498	5.498
INOx min. [g/kWh]	0.330	0.330	0.200	0.330
INOx 50% [g/kWh]	0.330	0.330	0.200	0.330
INOx 75% [g/kWh]	0.330	0.330	0.200	0.330
INOx 100% [g/kWh]	0.330	0.330	0.200	0.330
AFC min. [¢/kWh]	5.498	5.498	5.498	5.498
AFC 50% [¢/kWh]	5.498	5.498	5.498	5.498
AFC 75% [¢/kWh]	5.498	5.498	5.498	5.498
AFC 100% [¢/kWh]	5.498	5.498	5.498	5.498
ANOx min. [g/kWh]	0.330	0.330	0.200	0.330
ANOx 50% [g/kWh]	0.330	0.330	0.200	0.330
ANOx 75% [g/kWh]	0.330	0.330	0.200	0.330
ANOx 100% [g/kWh]	0.330	0.330	0.200	0.330

Bay Area Power System v. 3.2.3
17-Jan-93

resource	Catalyst IPT	Other Bio	Other Gas
name	CATLYST1	OTHRBIO1	OTHRGAS1
boiler name			
technology	GT	mixed	mixed
resource ID	116	117	118
operator	Catalyst IPT	many	many
county	Santa Clara	many	many
BAAQMD	Y	Y	Y
capacity [MW]	6	28	11
min. load [MW]	5	27	10
heat k0	0.000000E+00	0.000000E+00	0.000000E+00
rate k1	1.000000E+01	1.000000E+01	1.000000E+01
[GJ/h] k2	0.000000E+00	0.000000E+00	0.000000E+00
NOx l0	0.000000E+00	0.000000E+00	0.000000E+00
[kg/h] l1	3.300000E-01	3.300000E-01	3.300000E-01
l2	0.000000E+00	0.000000E+00	0.000000E+00
fuel	purchase	purchase	purchase
fuel price [$/GJ]	5.50	5.50	5.50
time to cold [h]	1	1	1
cold start time [h]	1	1	1
cold start cost [$]	1	1	1
start up m0	1	1	1
cost [$] m1	0.000	0.000	0.000
start up n0	1	1	1
NOx [kg] n1	0.000	0.000	0.000
ramp rate [MW/h]	100	100	100
min. up time [h]	1	1	1
stop cost [$]	1	1	1
stop emission [kg]	1	1	1
min. down time [h]	1	1	1
EFOR	0.050000	0.050000	0.050000

Bay Area Power System v. 3.2.3

17-Jan-93

resource	Catalyst IPT	Other Bio	Other Gas
IHR min. [MJ/kWh]	10.00	10.00	10.00
IHR 50% [MJ/kWh]	10.00	10.00	10.00
IHR 75% [MJ/kWh]	10.00	10.00	10.00
IHR 100% [MJ/kWh]	10.00	10.00	10.00
IFC min. [¢/kWh]	5.498	5.498	5.498
IFC 50% [¢/kWh]	5.498	5.498	5.498
IFC 75% [¢/kWh]	5.498	5.498	5.498
IFC 100% [¢/kWh]	5.498	5.498	5.498
INOx min. [g/kWh]	0.330	0.330	0.330
INOx 50% [g/kWh]	0.330	0.330	0.330
INOx 75% [g/kWh]	0.330	0.330	0.330
INOx 100% [g/kWh]	0.330	0.330	0.330
AFC min. [¢/kWh]	5.498	5.498	5.498
AFC 50% [¢/kWh]	5.498	5.498	5.498
AFC 75% [¢/kWh]	5.498	5.498	5.498
AFC 100% [¢/kWh]	5.498	5.498	5.498
ANOx min. [g/kWh]	0.330	0.330	0.330
ANOx 50% [g/kWh]	0.330	0.330	0.330
ANOx 75% [g/kWh]	0.330	0.330	0.330
ANOx 100% [g/kWh]	0.330	0.330	0.330

Appendix D: I-O and NOx Curves

1. introduction

As discussed in the main text, there is some uncertainty in the literature about the nature of NO_x emissions curves. For the approach taken here to be valid, as explained in section II.D, the curves must have the same form as I-O curves. In general historic practice, it has been assumed that NO_x emissions curves are of the right form to permit their use in dispatch logic in the same manner as I-O curves, but no definitive treatment of the issue exists in the literature.

2. evidence of convexity

A modest effort was made here to verify that NO_x emissions do behave in a manner that would justify their representation as convex, monotonically increasing curves. Unfortunately, the evidence available on the nature of emissions is spotty and informal. Furthermore, CFM reporting requirements do not require utilities to report fitted curves, and in informal communications, PG&E tends to use higher order polynomials. Consider figure D.1, which is reproduced from a paper on NO_x emissions control on this unit, Alamitos 6, a gas unit on the Edison system. The curves presented are convincingly of the correct general shape, although the spread of data around a fitted curve is quite large. In the upper panel, the obvious cluster of points that appears to lie on a separate higher curve across low load levels is most likely caused by a quirk of the operating procedure for this unit. Such points are common, for example, if different combinations of burners are used under various circumstances.

In some similar curves provided by the Los Angeles Department of Water and Power, a similar pattern appears. Unfortunately, these curves are not of a sufficiently high quality to be reproduced here. In total, while not definitive, the evidence available supports the critical assumption of convex, monotonically increasing NO_x emissions curves. There remains, however, the question of how the convexity of the NO_x emissions might be changed by the implementation of NO_x control equipment, such as SCR. Scant information exists in the literature regarding the shape of the NO_x emissions curve after installation of control equipment. What data exists seem to suggest that the NO_x reduction is proportionally more effective at full load, while in analysis of the effects of controls, an even proportional reduction is usually assumed.

Consider one other aspect of the upper panel in figure D.1. As has been mentioned in the main text, one of the interesting differences between I-O and NO_x emissions curves is that NO_x curves cover a far wider domain. This is easiest to see in this figure by considering the average emissions that would result in the unit were run continuously at one of the power levels along the curve. That is, consider the externality curve, as shown in figure II.D.2. This curve would reach its lowest point in the range of 250 MW, which the graph shows would result in emissions of about 50 lbs/h. That is, about 5 MWh could be generated for each lb of NO_x emitted. Now, consider an operating level way out near maximum power. A brief look at the axes will show immediately that this ratio nears one-to-one, or only 1 MWh could be generated for each lb of NO_x emitted. This cursory look shows that the domain in the externality curve of figure II.D.2 is much broader than that of the efficiency curve, which never covers a domain wherein the highest and lowest values differ by more than a factor of 2.

As mentioned in the main text, the implication of this feature of NO_x emissions is quite significant. It suggests that the imposition of a NO_x tax will tend to favor the operation of units at lower power levels. This result can be predicted because, as the cost to the utility of the NO_x tax becomes significant, the extra fuel expense incurred by operating units at less than maximum efficiency, usually close to full power, will be outweighed by the lower NO_x tax bill that can be enjoyed by partial power operations. That is, the marginal rate of substitution between fuel and NO_x will favor the burning of more fuel. This observation quickly leads to a second prediction, namely that the effectiveness of a

NO_x tax will decay as the system nears maximum power because the flexibility to operate units at partial power becomes more limited.

3. fitting of I-O and NO_x curves

The two curves that must be summed in the dispatch logic to implement a NOx tax dispatch are the incremental heat rate and incremental NOx cost curves, which are simply the first derivatives of the fuel cost and NOx cost functions, as shown in figure II.D.4. This section explains how these curves were actually developed for EEUCM.

The I-O curve is straightforward in that EEUCM uses a format that is common in the industry, namely, fitted second order polynomials of the following form, where P is the power output of the generator:

$$\text{energy in}\left[\frac{GJ}{h}\right] = k_0 + k_1 \cdot P[MW] + k_2 \cdot P^2[MW]^2$$

However, there are two complications. First, PG&E's data are available in two forms, as block heat rates in the CFM filing and production cost input files used in CPUC proceedings, or as fitted exponentials. The fitted exponentials are reported to the CPUC as coefficients A-D to the following function, where P is the power level:

$$\text{energy in}\left[\frac{kBtu}{h}\right] = A + B \cdot P[MW] + C \cdot e^{D \cdot P[MW]}$$

Second, the data are in American units and EEUCM assumes SI units. Both of these problems were solved by the simple, if tedious, expedient of generating data from the I-O function above using the coefficients reported by PG&E in its 1987 ECAC, and then converting the data to SI units to which a polynomial can be fitted. These calculations were carried out for each BAPS unit on a spreadsheet. An example of such a spreadsheet appears as figure D.2. The first page of the spreadsheet shows the basic PG&E coefficients and some values for the exponential function. The second page shows these data in SI units, together with the fitted polynomial coefficients, and the third page shows details of the regression.

Note that one of the limitations of optimization approaches like Lagrangian relaxation is that the convexity requirement complicates the treatment of the typical phenomenon found in utility boilers so that the fuel cost is considerably higher while the unit is operating at or near minimum load, which often called the minimum load burden. With block dispatch, as used in ELFIN and PROMOD III®, the first block can be given a high heat rate to compensate for the high cost of minimum load operations. Notice that on the first page of the spreadsheet, the average heat rate, av. HR, falls off sharply as power increases from the minimum load point. As long as the incremental heat rate between blocks increases, a block simulation should proceed correctly. However, when a continuous function is required, as in Lagrangian relaxation, a monotonically increasing curve must be fitted to the data. This makes incorporating high minimum block heat rate more difficult. However, the curves fitted to PG&E's data resulted in reasonable fits.

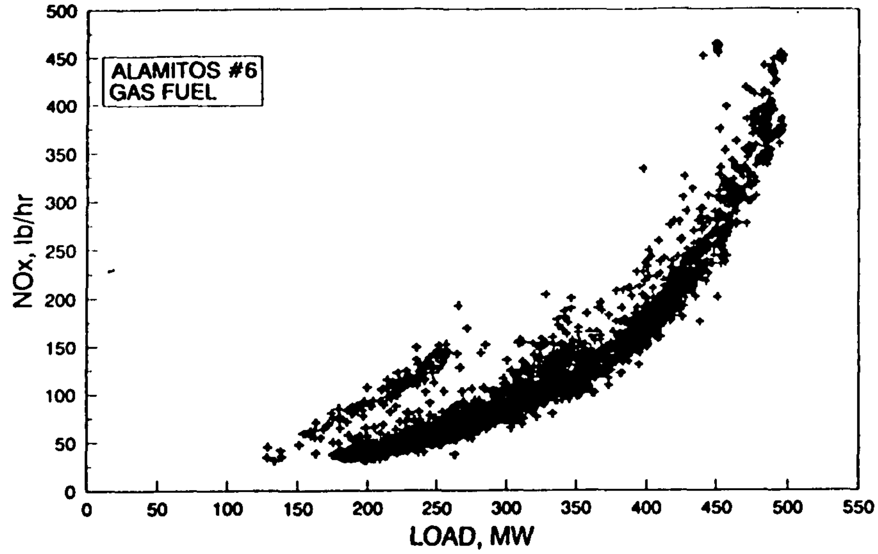
NOx curve data come primarily from the CFM filing required of PG&E in June 1991. CFM data are block data of the type used in most LDC production cost models. As mentioned above, there is no filing requirement for fitted curves, or for insuring that the data obey the convexity or monotonicity assumptions, so one might expect some problems fitting the well-behaved curves desired to these data, even in the absence of the minimum load burden problem.

Curves were fit to the NOx data in the same way that the polynomial fits were made to the heat rate data. Figure D.3 shows one of the spreadsheets used for this procedure. The spreadsheet in this case is a single page because the block data provides only a few points for curve fitting. The appearance of the heat rate curve coefficients, A-D, may be confusing. The reason for the appearance of heat rate information on the NOx spreadsheet is that the CFM data are reported in inconvenient lbs/MBtu, so conversion to a mass flow requires information about the fuel flow at any generation level.

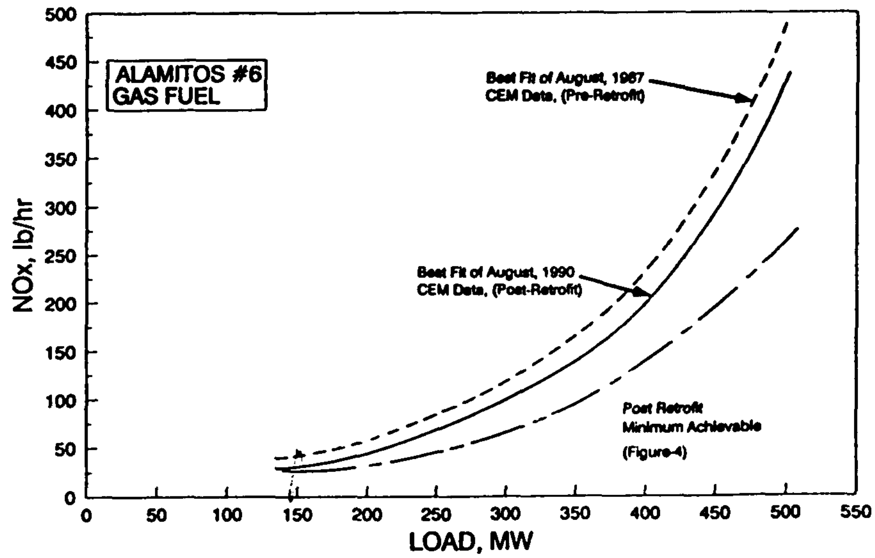
This simple curve fitting approach worked satisfactorily for most units. However, Moss Landing units 4,5, and 6 provided some minor difficulties, and one, Pittsburg 7, caused major difficulty. Figures D.4.1 - 2 show the three troublesome Moss Landing units. In each figure the PG&E curve is a simple interpolation of the block data points. Unfortu - nately, a simple fit to these data results, in each case, in a non-monotonic curve. The curve fits shown were derived by visually adjusting the data until a monotonic fit was possible. Clearly, the most troublesome unit is Moss Landing 7. The fitted curve represents the data poorly, especially in the 500-650 MW range. Given the favorable results with other units and the absence of further information, howev - er, the only reasonable approach is to accept this inaccuracy. Figures D.5 and D.6 show the much more serious problems of Pittsburg 7. Figure D.5 shows that a good possible fit to the data could be achieved using a third order polynomial; however, this would clearly not satisfy the monotonicity requirement. Figure D.6 shows that a simple second order polynomial fit results in a very unsatisfactory representation of the data. Notably, predicted emissions are too high at full load, yet too low at the 576 MW point. Since these data are unlike most other NOx data seen, the most likely explanation for the difficulty of this unit is spurious data.

Finally, figure D.7 shows an example of the results of the exercise described in this section. The second order polynomial fits of both the I - O and NOx curves are shown for Pittsburg 5.

Figure D.1



CEM Data for the Month of August, 1990



Comparison of Pre and Post Retrofit "Best Fit" Curve of CEM Data and Post Retrofit Minimum Achievable NOx Emission

source: de Volo, N. Bayard, L. Larsen, L. Radak, R. Aichner, and A. Kokkinos. "NOx Reduction and Operational Performance of Two Full-Scale Utility Gas/Oil Burner Retrofit Installations." Paper in Kokkinos, Angelos and R. Hall eds. *Proceedings: 1991 Joint Symposium on Stationary Combustion NOx Control*, vol. 2. Washington DC, 25-28 March 1991, GS-7447, Electric Power Research Institute, Palo Alto, CA.

CONVERSION OF BTU HEAT RATES TO EEUCM FORMAT

Chris Marnay   5 Nov 91   15:12
Pittsburg 5   PITSBRG5

*PG&E parameters   cap (MW) = 325.00
A= 67077.00
B= 7497.00
C= 219947.00
D= 0.004050

minimum block info

ouput (MW)	Btu/kWh	HHV eff.
46	14264	0.239

American Units & Exponential HR Curve

% cap	MW	inc. HR (Btu/kWh)	inc. HHV eff.	kBtu in	av. HR	av. HHV ef:
0.14	46.00	8570	0.398	656144	14264	0.239
0.25	81.25	8735	0.391	981861	12084	0.282
0.30	97.50	8819	0.387	1124480	11533	0.296
0.35	113.75	8909	0.383	1268513	11152	0.306
0.40	130.00	9005	0.379	1414056	10877	0.314
0.45	146.25	9108	0.375	1561214	10675	0.320
0.50	162.50	9217	0.370	1710094	10524	0.324
0.55	178.75	9334	0.366	1860815	10410	0.328
0.60	195.00	9459	0.361	2013501	10326	0.330
0.65	211.25	9593	0.356	2168287	10264	0.332
0.70	227.50	9735	0.350	2325315	10221	0.334
0.75	243.75	9888	0.345	2484737	10194	0.335
0.80	260.00	10050	0.339	2646717	10180	0.335
0.85	276.25	10224	0.334	2811429	10177	0.335
0.90	292.50	10409	0.328	2979058	10185	0.335
0.95	308.75	10608	0.322	3149802	10202	0.334
1.00	325.00	10819	0.315	3323875	10227	0.334

* source: 1987 ECAC 87-04-005/035

Figure D.2

Conversion to SI Units and Heat Rate Regression

GJ in	P	P^2	regression parameters	predicted GJ in	pred. av. eff.	pred. in eff.
692	46.0	2116.00		707	0.234	0.401
1036	81.3	6601.56	k0= 3.023789E+02	1028	0.284	0.390
1186	97.5	9506.25	k1= 8.634839E+00	1179	0.298	0.385
1338	113.8	12939.06	k2= 3.693023E-03	1332	0.307	0.380
1492	130.0	16900.00		1487	0.315	0.375
1647	146.3	21389.06		1644	0.320	0.371
1804	162.5	26406.25		1803	0.324	0.366
1963	178.8	31951.56		1964	0.328	0.362
2124	195.0	38025.00		2127	0.330	0.357
2288	211.3	44626.56		2291	0.332	0.353
2453	227.5	51756.25		2458	0.333	0.349
2622	243.8	59414.06		2627	0.334	0.345
2792	260.0	67600.00		2797	0.335	0.341
2966	276.3	76314.06		2970	0.335	0.337
3143	292.5	85556.25		3144	0.335	0.333
3323	308.8	95326.56		3320	0.335	0.330
3507	325.0	105625.00		3499	0.334	0.326

REGRESSION

Dependent Variable:

Variable	Mean	Parameter Estimate	Standard Error	T for H0: parameter=0
Intercept		302.38	8.37	36.15
Variable 1	193.88	8.63	0.10	89.74
Variable 2	44238.44	0.00	0.00	14.93

Source	DF	Sum of Squares	Mean Square	F-Value
Model	2.00	11408146.74	5704073.37	139059.69
Error	14.00	574.26	41.02	
Total	16.00	11408721.00		

Dependent Mean	2139.90
Root Mean Square Error	6.40
Coefficient of Variation	0.30
R-Square	1.00
Adjusted R-Square	1.00
Adjusted R-Square	1.00

Figure D.3

CONVERSION OF NOx EMISSION RATES TO EEUCM FORMAT

Chris Marnay 27-Feb-92 14:53

Pittsburg 5 unit = **PITSBRG5**

heat rate curve params.

A= 6.707700E+04
B= 7.497000E+03
C= 2.199470E+05
D= 4.050000E-03

max. cap (MW) = 325

minimum block info

ouput MW	Btu/kWh	HHV eff.
46	14264	0.239

% cap	gas lbNOx /MBtu	oil lbNOx /MBtu
min	0.08	0.39
25	0.10	0.35
50	0.12	0.30
80	0.14	0.30
100	0.17	0.33

heat rate info.				**gas NOx emissions**				**oil NOx emissions**			
% cap	cap. MW	E in MBtu/h	AHR Btu/kWh	st/h	kg/h	g/kWh	mol/s	st/h	kg/h	g/kWh	mol/s
0.14	46	656	14264	0.026	24	0.518	0.144	0.128	116	2.523	0.701
0.25	81	982	12084	0.049	45	0.548	0.269	0.172	156	1.918	0.941
0.50	163	1710	10524	0.103	93	0.573	0.562	0.257	233	1.432	1.405
0.80	260	2647	10180	0.185	168	0.646	1.015	0.397	360	1.385	2.174
1.00	325	3324	10227	0.283	256	0.789	1.547	0.548	498	1.531	3.004

gas emissions regression

est. NOx curve params.	kg/h	P	P^2	predicted kg/h
l0 = 1.612959E+01	23.8	46	2116	27.5
l1 = 1.672147E-01	44.5	81	6602	41.1
l2 = 1.722545E-03	93.1	163	26406	88.8
	168.1	260	67600	176.0
	256.3	325	105625	252.4

Fit of NOx Curve to PG&E Data
Moss Landing 4

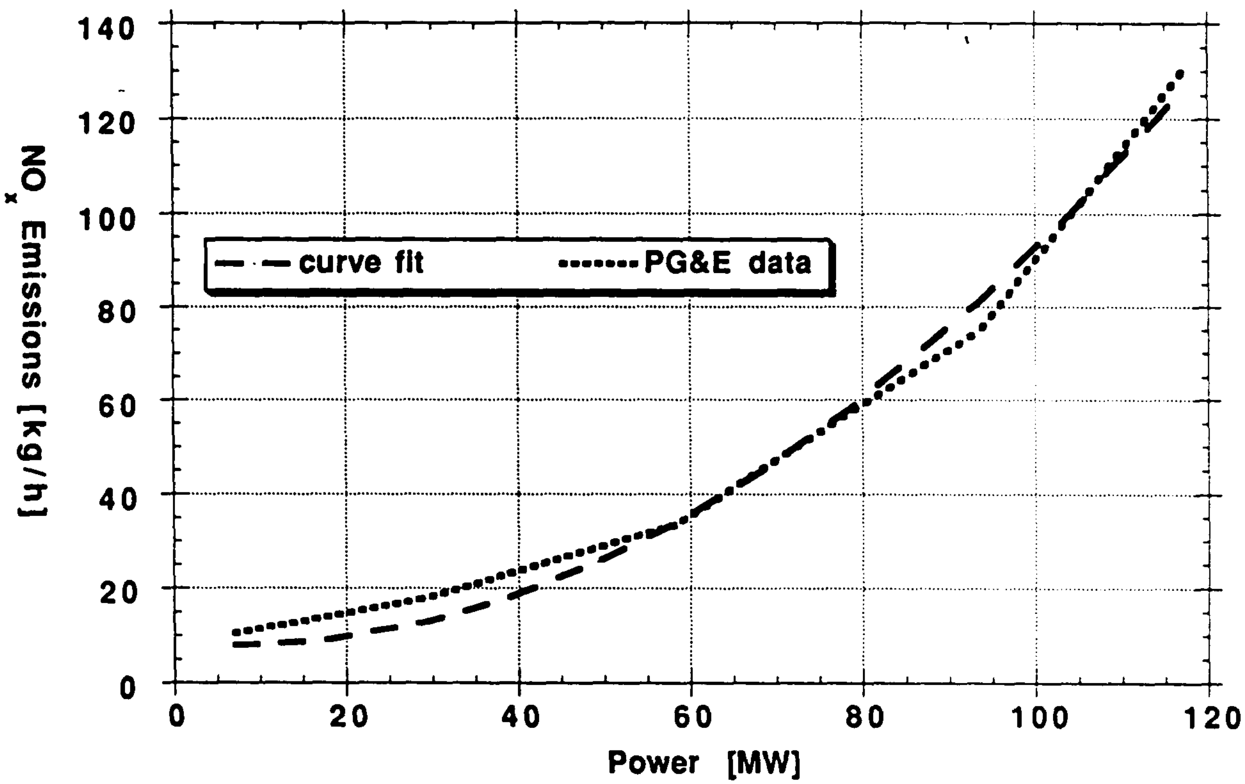


Figure D.4.1

Fit of NOx Curve to PG&E Data
Moss Landing 6

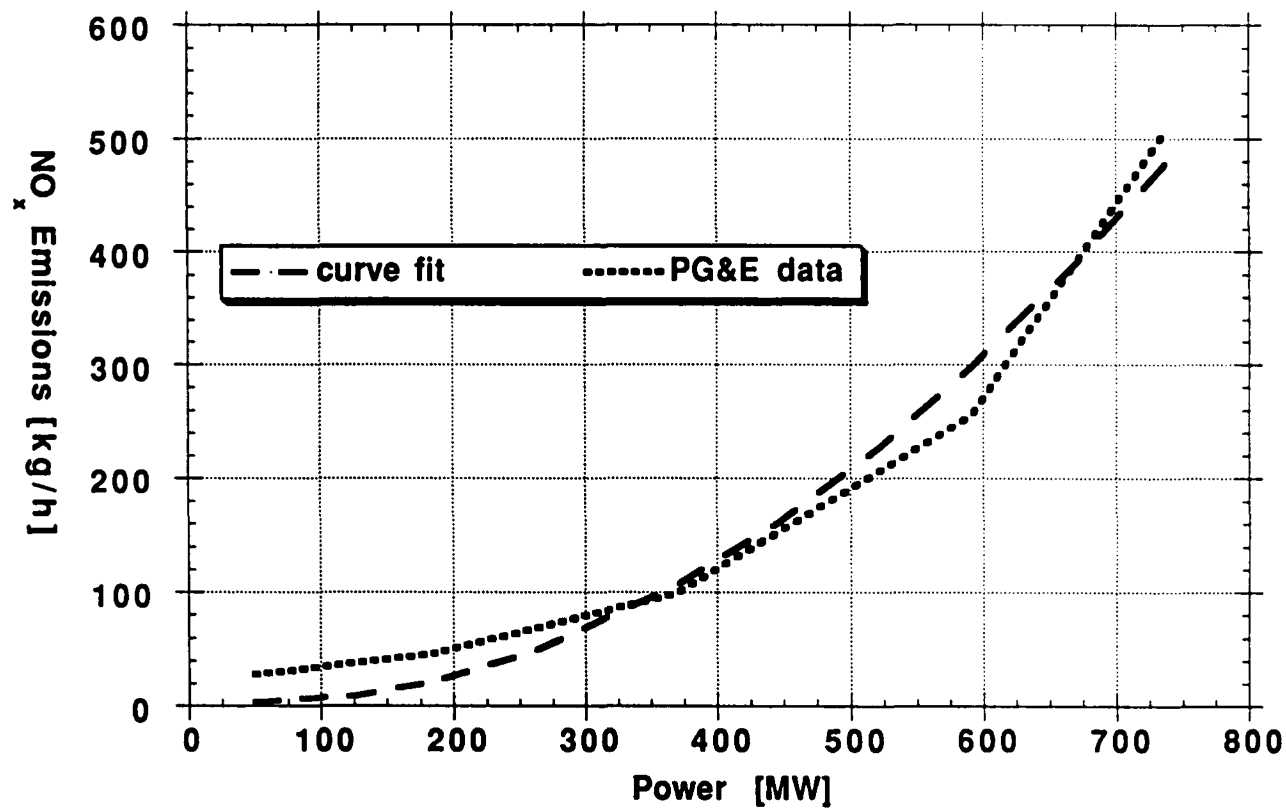


Figure D.4.2

Fit of NOx Curve to PG&E Data
Moss Landing 7

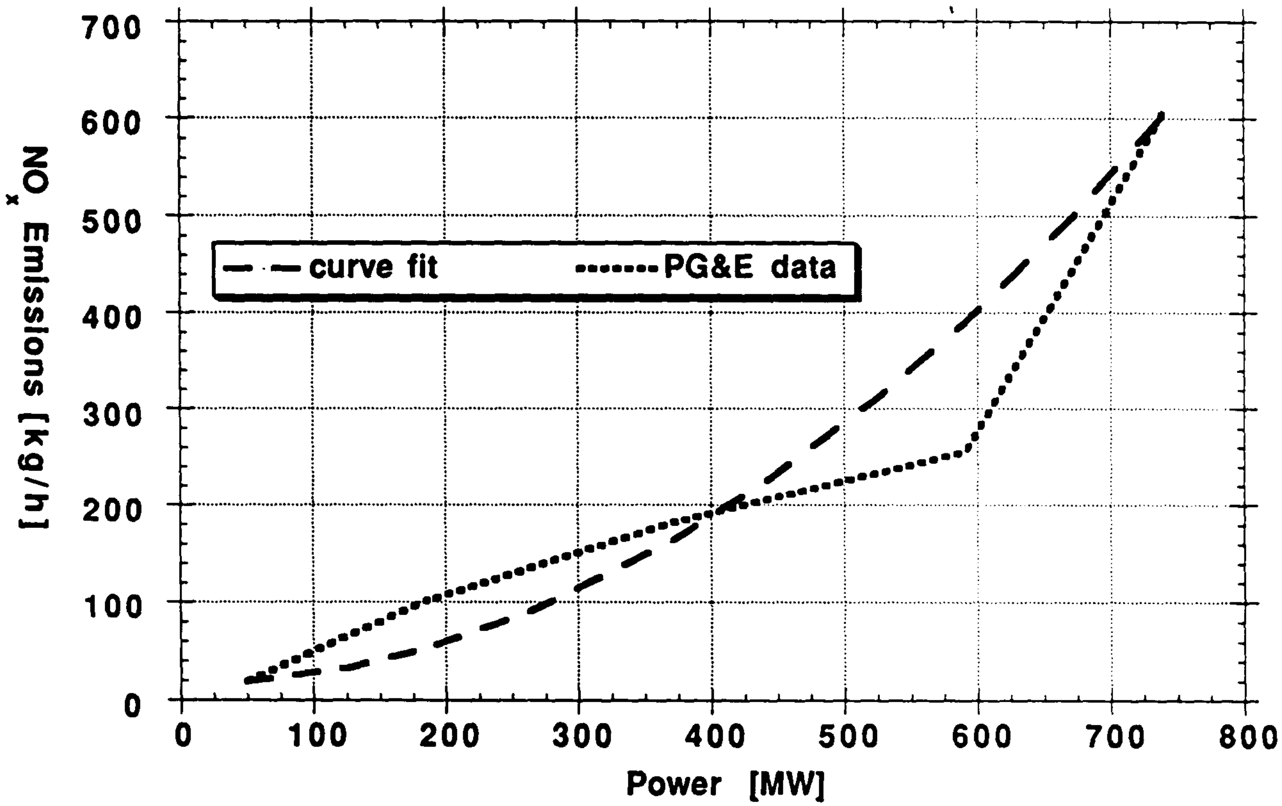


Figure D.4.3

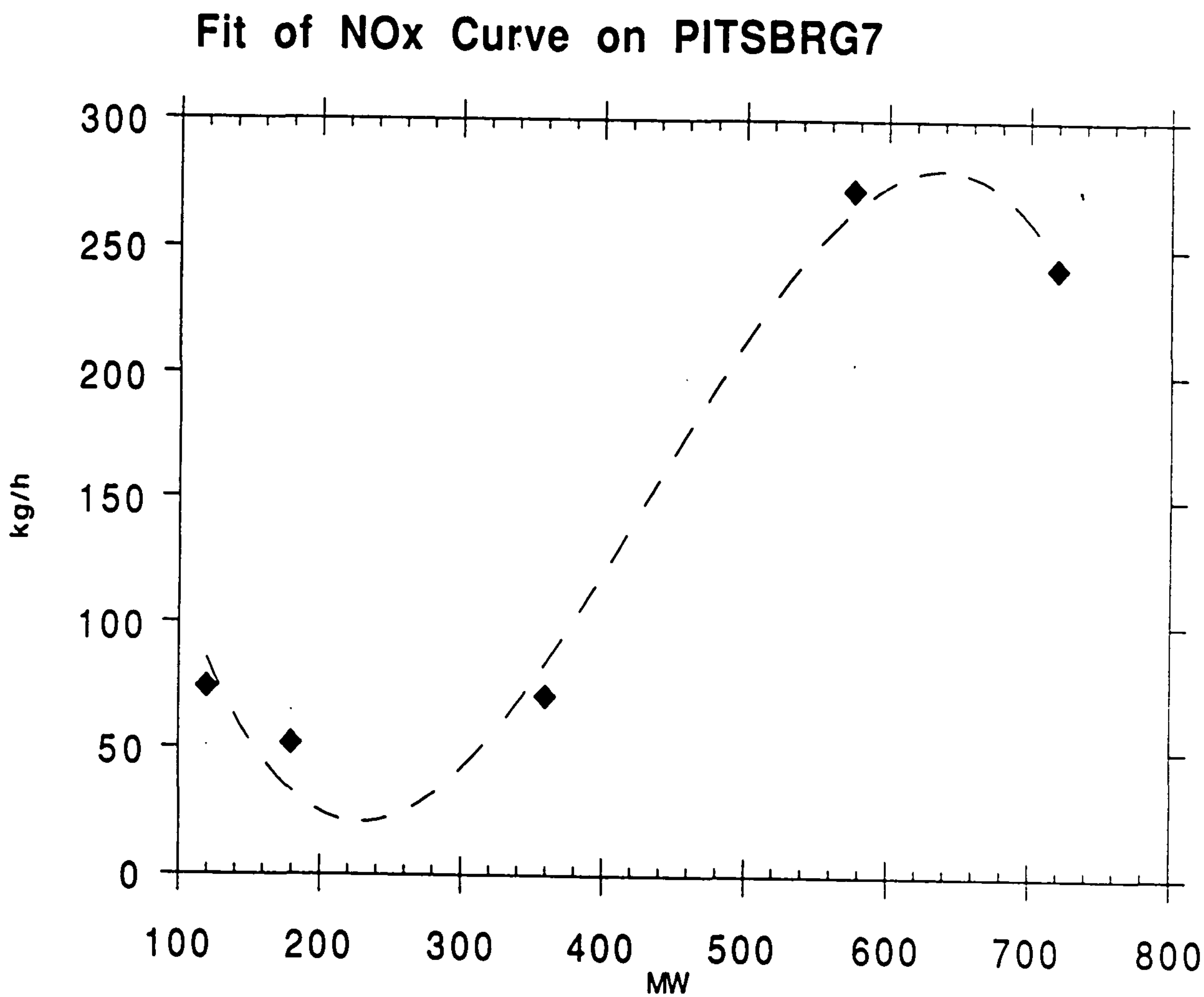
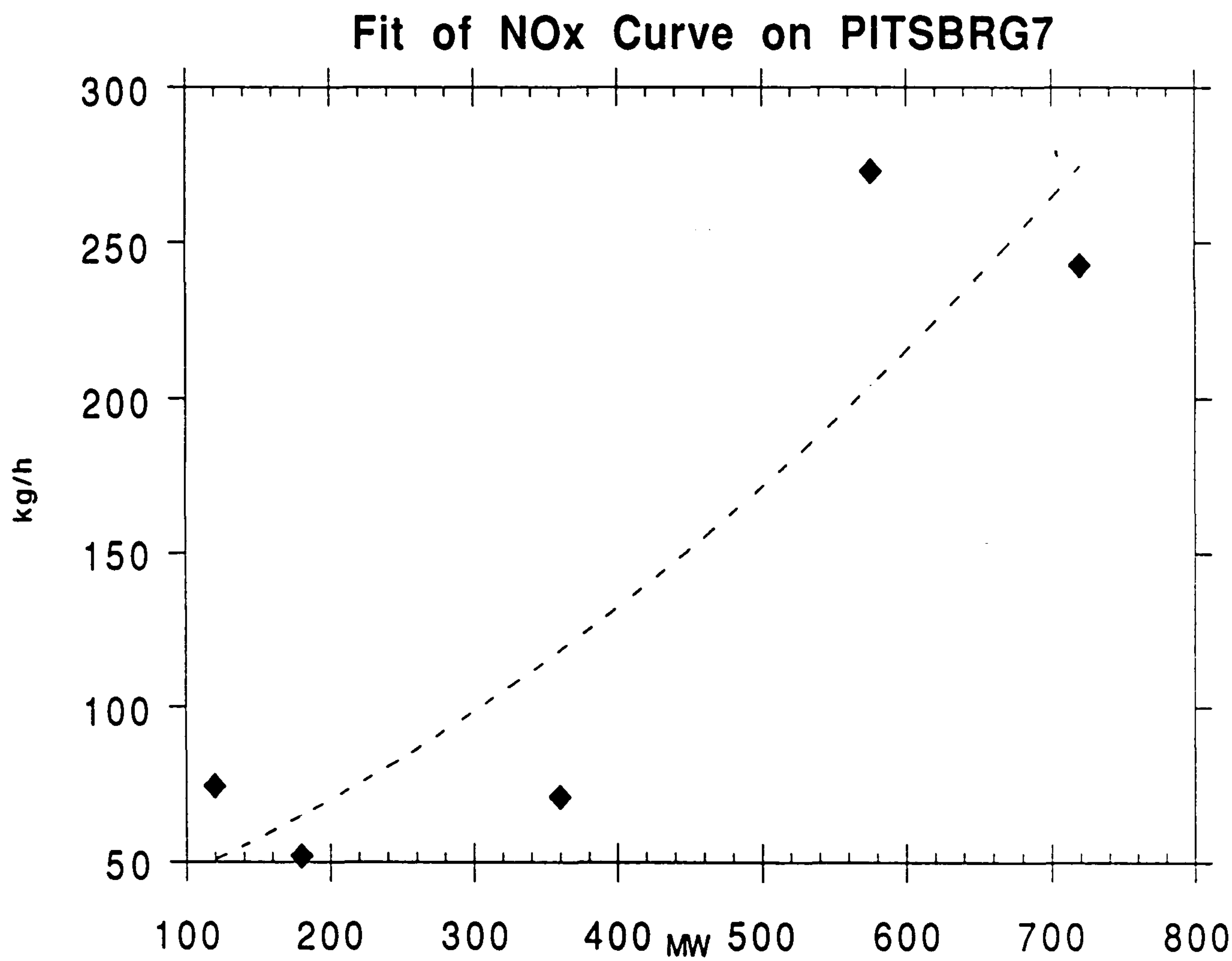

Fit of NOx Curve on PITSBRG7
kg/h
300
250
200
150
100
50
0
100
200
300
400
500
600
700
800
MW

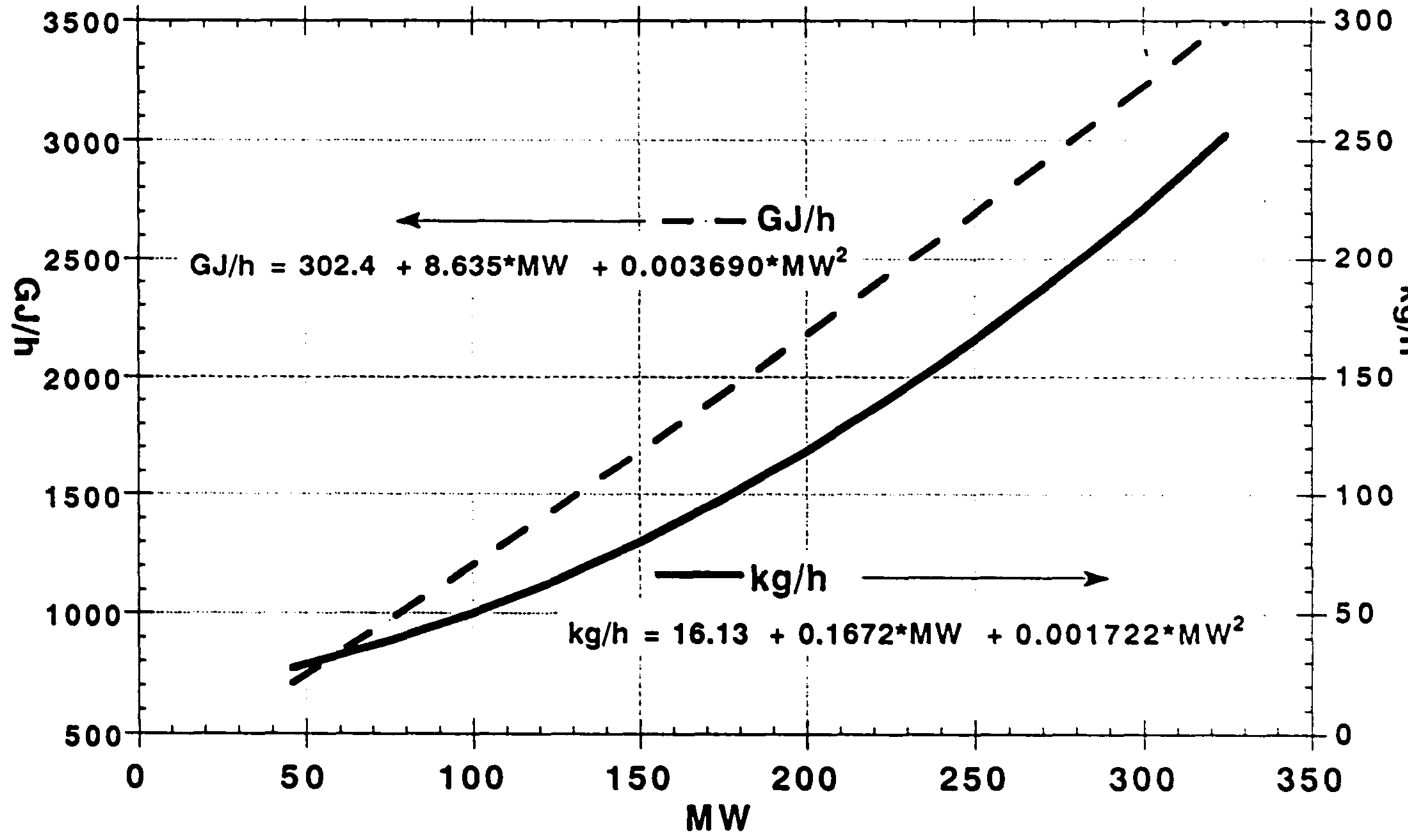
Figure D.5



Fit of NOx Curve on PITSBRG7
300
250
200
150
100
50
kg/h
100
200
300
400
MW
500
600
700
800

Figure D.6

Example of the IO and NOx Curve Inputs to EEUCM
Pittsburgh 5



source: PG&E

Figure D.7

Appendix E: NO_x Tax

1. introduction

One of the goals of this work is to estimate the likely response in BAPS operations to the implementation of a NO_x tax. Intuitively, the tax should reflect the damage done by the emissions. That is, the variable external cost should be internalized. It is clearly beyond the scope of this work to derive a full-blown damage function for NO_x emissions, yet it was a key goal to test responsiveness of the test system to reasonable tax rates, and to impose a tax that changes over time to reflect the time - dependency of the ozone damage function.

2. historic episode

The tax was implemented in a simple manner. Historic ozone concentrations at Livermore for 1989 were used as the basis for the tax. Analysis of the historic emissions data for the Bay Area focuses on the episode of mid September, 1989. The District models this episode using UAM, and results for it form the basis of policymaking. Figure E.8 shows the O_3 concentration results from a UAM run of the episode at 16:00, the peak hour. UAM achieved reasonable agreement with histor - ic data for the episode. As can be clearly seen from the figure, poor air quality around the District is quite localized. Two areas appear as hot spots, the area to the south and south-east of San Jose, and the Livermore vicinity. UAM predicts both of these areas to be in violation of the State standard at this hour. Even at this extreme time, O_3 concentrations were reasonable on the peninsula and in the East Bay, and were actually low along the coast. As mentioned above, such local variations make the assessment of human exposure quite complex.

Turning now to actual historic data rather than simulation results, figure E.4 shows a summary of 1989 data for the pollution monitoring Livermore station. The actual data are hourly O_3 concentrations reported by the station. These data have been collapsed into a set of points that show for each step in O_3 concentration the number of hours that the recorded concentration was at this level or higher and displayed in semi-log space.[1] Two points in figure E.4 are of particular interest, the Federal and State standards. Reading across from 12, the number of hours recorded with this concentration or higher is 4. Likewise, the number of hours that the State standard was exceeded at Livermore during 1989 was 59. The highest concentration of the year, recorded just once, was 14. The concentration of 0 was always exceeded, so that point appears at 8760 hours. As is clear from the graph, these data are close to linear in this semi-log space, and a fitted curve is shown. Whether this pattern holds true for other sites is, as yet, unknown, but the curve provides a convenient way of summarizing an unwieldy amount of data.

1 missing data points were filled in with the prior hour's concentration

Figure E.4 restates the lesson that, although exceedences are an important concern for health and productivity, the total hours of exceedence of standards is quite small. During 1989, Livermore was in violation of the State standard less than 1 % of the time.

To look at these data in terms of days of violation, consider figure E.3. It shows for any daily peak O_3 concentration at Livermore, x-axis, the number of days that this peak level was exceeded. Obviously, the y intercept is at 365 days. The question to be addressed here is on how many days should the tax be imposed. The daily peak O_3 concentration provides one way of answering that question. Clearly, the tax should be charged if the peak exceeds the 0.09 ppm State of California standard, and there must be some maximum acceptable peak concentration such that on days when the concentration fails to exceed this level there is no tax. The steepness of the curve in figure E.3 at daily peaks less than 0.06 is problematic. The number of days will be quite sensitive to the maximum acceptable peak concentration chosen. In any event, a maximum acceptable peak between 0.05 and 0.08 seems reasonable, and, in this work, 0.07 was used. At this level, there are 49 days that trigger the tax.

Figure E.5 shows the O_3 concentration at Livermore during the entire month of September 1989, and also the historic electrical load on the PG&E system. The O_3 concentration curve shows the diurnal cycle of O_3 formation and dissipation. On most evenings O_3 disappeared completely from the air, yet the afternoon peaks exceeded the State standard during 3 of the four weeks. The Federal standard was never exceeded during the month. The weekends of this month fell on the 2nd & 3rd, the 9th & 10th, the 16th & 17th, the 23rd & 24th, and the 30th & 31st. Except for the last week of the month, in which lower overall concentra - tions were experienced, the weekends had better air quality than the weekdays. The PG&E electrical load clearly follows a similar pattern during the episode. Notice the left-hand scale of the electrical load, showing that peak to off-peak ratio is far lower than that of the O_3 concentrations. Nonetheless, the similarity is striking, reinforcing the assertion that since both tend to occur at hot times, if other conditions favor photo-chemical smog formation, electrical load and O_3 concentra - tion will track each other. Even if emissions from the power sector were proportional to load, this would be a cause for concern. However, as argued above, the tendency of utilities to resort to their most polluting resources at times of high load intensifies the concern.

Figure E.6 shows the BAAQMD modeling episode in more detail. The data for the 14th show clearly that this was the worst day of the episode, and also the day of highest electrical load during the week. Also, the maximum reported concentration of 0.11 ppm, that is, in violation of the State but not the Federal standard, validates the UAM results shown in figure E.8. Also, as a reminder that the ozone problem is localized geographically, as well as over time, compare figure E.7, which shows the much lower reported concentrations for the same period at the San Francisco station.

3. NO_x tax implementation

A simple algorithm was developed to convert these concentrations into a tax rate in terms of $/kg of NO_x emitted. The algorithm can be outlined as follows:

1. the tax comes into effect 12 hours before the peak ozone concentration
2. the tax is proportional to the ozone concentration
3 the tax never falls below a floor level during an episode

Figure E.1 shows the program that implements this tax scheme, and figure E.2 shows an example of its output. The input data are the CARB pollutant observations for Livermore. These data were originally read from a raw tape provided by CARB, and missing data and other problems were fixed. CARB reports ozone concentrations as integers pphm, hence the boxy shape of the tax results. The dates in 1989 on which the tax is triggered are shown, as are the hourly tax rates in $/kg. During the September, 1989, episode, the tax is turned on monday and follows its variable pattern through friday afternoon.

Figure E.1

```
C this program generates a tax input file for EEUCM
C if the daily peak ozone concentration exceeds the
C maximum acceptable level,  MXACO, then
C it sets a tax proportional to the ozone concentations
C input in the ozone.for.tax file, lagged by LAG hours
C a minimum tax, MNTAX, is imposed during multi-day episodes
C the tax extends to some bound hour ahead of days when
C the tax is imposed
C the MXTAX level is set at a certain concentration,  STD,
C typically 0.1 ppm - that is, the tax rate exceeds this
C level if the concentration exceeds the STD
C   Chris Marnay - Sun Nov  8 08:27:06 PST 1992

      PROGRAM TAX

C variables:

C CALENDAR(8760,10)     = patented 1989 calendar
C DATA(8760,5)     = basic data array
C DAY(7)       = the days of the week
C DONE                  = logical true if week.data needed
C EPISODAY(365)    = single E or T to signify episode or tax day
C EPISODB      = largest gap between exceed. in an episode
C EPISODE      = logical for if its an episode or not
C HDM                   = cross check of input hour-day-month data
C ILOWER           = counter on array
C LAG              = lag time between ozone formation and emission
C LAST             = counter
C MONTH(12)        = months of the year
C MNTAX            = min. tax during an episode
C MXACO            = max. ozone before tax levied
C MXTAX            = tax levied if concentration is at the STD
C NED              = number of episode days
C NTD              = number of tax days
C PKOZ             = peak ozone for the day
C STAR(8760)       = an 8760 array with a * at each daily ozone peak
C TWINPK                  = logical true if exceedence hours follow
peak
C STD              = the standard ozone concentration
C BOUND            = furthest extent of tax due to episode

      CHARACTER*1 STAR(8760),EPISODAY(365),STRING1
```

```
      CHARACTER*3 DAY(7),MONTH(12)
      INTEGER BOUND,ILOWER,LAG,LAST,NED,NTD,CALENDAR(8760,10)
      INTEGER EPISODB
      LOGICAL DONE,EPISODE,TWINPK
      REAL DATA(8760,5),HDM(8760,4),MXACO,MXTAX,MNTAX,PKOZ,STD

C these are the key parameters to be set by the user in file
tax.params

      OPEN(12,FILE='tax.params')
      OPEN(13,FILE='tax.input_image')

        READ(12,*) STRING1
        READ(12,*) MXTAX
        WRITE(13,*) MXTAX
        READ(12,*) MNTAX
        WRITE(13,*) MNTAX
        READ(12,*) MXACO
        WRITE(13,*) MXACO
        READ(12,*) STD
        WRITE(13,*) STD
        READ(12,*) LAG
        WRITE(13,*) LAG
        READ(12,*) BOUND
        WRITE(13,*) BOUND
        READ(12,*) EPISODB
        WRITE(13,*) EPISODB

      CLOSE(12)
      CLOSE(13)

C now the ARB ozone input is read and the peaks found

      OPEN(11,FILE='ozone.for.tax')
      OPEN(21,FILE='peak_hours')

      DO 1000 I = 1, 8760
        STAR(I) = ' '
        DO 1000 J = 1, 5
          DATA(I,J) = 0.0
 1000 CONTINUE
      DO 1001 I = 1,365
        EPISODAY(I) = ' '
```

```
 1001 CONTINUE

C read in the data from ozone.for.tax file and
C fill up all the array cells where concentration is above
C the max. acceptable level with the minimum tax
C note the input units are pphm, hence the division by 100

      DO 1010 I = 1, 8760
        READ(11,5050) DATA(I,1),(HDM(I,J),J=1,4),DATA(I,3)
        DATA(I,3) = DATA(I,3)/100.0
 5050   FORMAT(6F6.0)
        IF(DATA(I,3).GT.MXACO) THEN
          DO 1015 K = 0, BOUND
            DATA(I-K,4) =  MNTAX
 1015     CONTINUE
        ENDIF
 1010 CONTINUE

C find the peak ozone concentration for each day

      DO 1020 I = 1, 365
        PKOZ = 0.0
        PKHR = 0.0
        LAST = 0
        DO 1030 J = 1,24
          IF(DATA(((I-1)*24)+J,3).GT.PKOZ) THEN
            STAR(((I-1)*24)+J) = '*'
            STAR(LAST) = ' '
            LAST = ((I-1)*24)+J
            PKOZ = DATA(((I-1)*24)+J,3)
            PKHR = DATA(((I-1)*24)+J,1)
          ENDIF
 1030   CONTINUE
C       WRITE(21,5020) I,INT(PKHR),PKOZ
C5020   FORMAT(2I6,F6.2)

C if the daily peak ozone  doesn't reach the max. acceptable level
C there is no tax

        IF(PKOZ.LE.MXACO) THEN
          GOTO 1020

C now start filling out the rest of the tax
```

```
C first, the episode and tax days are identified

        ELSE
          DO 1035 K = 1, EPISODB/24
            IF(I.GT.1.AND.EPISODAY(I-K).NE.' ') THEN
              DO 1036 L = 1,K
                EPISODAY(I)   = 'E'
                EPISODAY(I-L) = 'E'
 1036         CONTINUE
            ELSE
              EPISODAY(I)   = 'T'
            ENDIF
 1035     CONTINUE

C if the daily peak exceeds any pre-existing tax at the lagged hour
C update it to the peak tax

          IF (((PKOZ/STD)*MXTAX).GT.DATA(INT(PKHR)-LAG,4)) THEN
              DATA(INT(PKHR)-LAG,4) = (PKOZ/STD)*MXTAX

C now go as far back as BOUND and linearly interpolate the tax
C as long as it exceeds any pre-existing tax, or make the tax the
min.
C also look ahead and as long as the ozone concentration exceeds the
C std. at some time in the look ahead period, charge the MAXTAX

              DO 1040 K = 1, BOUND

IF(((REAL(BOUND)-REAL(K))/REAL(BOUND))*(PKOZ/STD)*MXTAX
     2                .GT.MNTAX) THEN
                   DATA(INT(PKHR)-LAG-K,4) =
                                               2
((REAL(BOUND)-REAL(K))/REAL(BOUND))*(PKOZ/STD)*MXTAX
                ELSE
                   DATA(INT(PKHR)-LAG-K,4) = MINTAX
                ENDIF
 1040         CONTINUE

C now go forwards from the peak hour to the bound and if the
C concentration anywhere still exceeds the max. acceptable level
C then the max. tax is charged throughout
C if there is a continued exceedence it's called a TWINPK
```

```
              TWINPK = .FALSE.
              DO 1041 K = BOUND, -LAG, -1
                IF(DATA(INT(PKHR)+K,3).GT.MXACO) THEN
                  TWINPK = .TRUE.
                ENDIF
                IF(TWINPK) THEN
                  DATA(INT(PKHR)+K,4) = (PKOZ/STD)*MXTAX
                ENDIF
 1041         CONTINUE

          ENDIF
C
C         IF(INT(HDM(I,1)).NE.CALENDAR(I,2)) PRINT *, 'HOD mismatch
at',I
C         IF(INT(HDM(I,2)).NE.CALENDAR(I,7)) PRINT *, 'DOM mismatch
at',I
C         IF(INT(HDM(I,3)).NE.CALENDAR(I,8)) PRINT *, 'MOY mismatch
at',I

C now determine whether this is an episode or an isolated exceedence
day
C if it's an episode bridge between days at the min. tax

          EPISODE = .FALSE.
          DO 1060 K = 12, EPISODB
             IF(DATA(INT(PKHR)-K,3).GT.MXACO) THEN
               EPISODE = .TRUE.
             ENDIF
 1060     CONTINUE
          IF(EPISODE) THEN
            DO 1070 K = 1, EPISODB
              IF(DATA(INT(PKHR)-K,4).LT.MNTAX
    2             .AND.MNTAX.GT.DATA(INT(PKHR)-K,4))
    3                DATA(INT(PKHR)-K,4) = MNTAX
 1070       CONTINUE
          ENDIF
        ENDIF

 1020 CONTINUE

      CLOSE(11)
      CLOSE(21)
```

```
C ==================================================================
===
C PRINT A FILE FOR 89 SUITABLE AS EEUCM INPUT
C ==================================================================
===

      CALL TIMEKEEPER(CALENDAR)

C first do a cross-check on the data

      DO 4025 I = 1, 8760
        IF(I.NE.CALENDAR(I,1))
     2     PRINT *, 'HOY mismatch at',I
        IF(INT(HDM(I,1)).NE.CALENDAR(I,2))
     2     PRINT *, 'HOD mismatch at',I
        IF(INT(HDM(I,2)).NE.CALENDAR(I,7))
     2     PRINT *, 'DOM mismatch at',I
        IF(INT(HDM(I,3)).NE.CALENDAR(I,8))
     2     PRINT *, 'MOY mismatch at',I
 4025 CONTINUE

C now set up the data

      DATA DAY   /'Mon','Tue','Wed','Thu','Fri','Sat','Sun'/
      DATA MONTH /'Jan','Feb','Mar','Apr','May','Jun',
     2            'Jul','Aug','Sep','Oct','Nov','Dec'/

      ILOWER = 1
      OPEN(22,FILE='input_tax')
      OPEN(25,FILE='ozone')
 4030 CONTINUE
      IF(ILOWER.GE.8760) GOTO 4040

        WRITE(22,5035)
     2    DAY(CALENDAR(ILOWER,6)),CALENDAR(ILOWER,7),
     3    MONTH(CALENDAR(ILOWER,8)),CALENDAR(ILOWER,9),
     4    EPISODAY(CALENDAR(ILOWER,4)),
     4    (DATA(J,4),J = ILOWER, ILOWER+11)
 5035 FORMAT(A3,X,I2,X,A3,X,I2,2X,A1,12F7.2)
        WRITE(22,5036)(DATA(J,4),J=ILOWER+12,ILOWER+23)
 5036 FORMAT(16X,12F7.2)

        WRITE(25,5045)
```

```
    2     DAY(CALENDAR(ILOWER,6)),CALENDAR(ILOWER,7),
    3     MONTH(CALENDAR(ILOWER,8)),CALENDAR(ILOWER,9),
    4     EPISODAY(CALENDAR(ILOWER,4)),
    4     (DATA(J,3),J = ILOWER, ILOWER+11)
5045 FORMAT(A3,X,I2,X,A3,X,I2,2X,A1,12F7.2)
       WRITE(25,5046)(DATA(J,3),J=ILOWER+12,ILOWER+23)
5046 FORMAT(16X,12F7.2)

     ILOWER = ILOWER + 24
     GOTO 4030
4040 CONTINUE

     NTD = 0
     NED = 0
     DO 4050 I = 1, 365
       IF (EPISODAY(I).EQ.'E')THEN
          NTD = NTD + 1
          NED = NED + 1
       ELSEIF (EPISODAY(I).EQ.'T') THEN
          NTD = NTD + 1
       ENDIF
4050 CONTINUE
     WRITE(22,*) '  '
     WRITE(22,*) '  '
     WRITE(22,*) '    total tax days =',NTD
     WRITE(22,*) 'total episode days =',NED

     CLOSE(22)
     CLOSE(25)

     DONE = .TRUE.
     DO 4027 I = 1, 8760
       IF(CALENDAR(I,8).EQ.9.AND.CALENDAR(I,7).EQ.11) THEN
         IF(DONE)THEN
           OPEN(24,FILE='week.data')
             WRITE(24,5091) CHAR(9),CHAR(9),CHAR(9),CHAR(9),CHAR(9)
5091         FORMAT('HOW',A1,'HOD',A1,'DOM',A1,'MOY',A1,'O3 CONC',
    2               A1,'TAX')
           DO 4026 J = 0, 167
             WRITE(24,5090) J+1,CHAR(9),CALENDAR(I+J,2),CHAR(9),
    2            CALENDAR(I+J,7),CHAR(9),CALENDAR(I+J,8),CHAR(9),
    3            DATA(I+J,3),CHAR(9),DATA(I+J,4)
5090         FORMAT(4(I5,A1),F6.3,A1,F10.2)
```

```
                DONE = .FALSE.
 4026         CONTINUE
              CLOSE(24)
            ENDIF
          ENDIF
 4027 CONTINUE

      END

C ==================================================================
      SUBROUTINE TIMEKEEPER(CALENDAR)

C this subrountine makes a calendar and puts it into the matrix,
CALENDAR
C the cols of CALENDAR contain the following data
C     HOY = hour of the year 1 to 8760
C     HOD = hour of the day 1 to 24
C     HOW = hour of the week 1 to 168
C     DOY = day of the year 1 to 365
C     WOY = week of the year 1 to 53
C     DOW = day of the week 1 to 7, 1990 begins on a monday=1
C     DOM = day of the month 1 to 31
C     MOY = month of the year 1 to 12
C     YR  = 89 in this case
C     WE  = 0 if weekend, 1 otherwise

      INTEGER CALENDAR(8760,10)
      INTEGER HOY,HOD,HOW,DOY,WOY,DOW,DOM,MOY,YR,WE

      HOY = 1
      HOD = 1
      HOW = 1
      DOY = 1
      WOY = 1
      DOW = 7
      DOM = 1
      MOY = 1
      YR = 89
      WE =  0

      DO 2010 I = 1, 8760

        CALENDAR(HOY,1)  = HOY
```

```
      CALENDAR(HOY,2)  = HOD
      CALENDAR(HOY,3)  = HOW
      CALENDAR(HOY,4)  = DOY
      CALENDAR(HOY,5)  = WOY
      CALENDAR(HOY,6)  = DOW
      CALENDAR(HOY,7)  = DOM
      CALENDAR(HOY,8)  = MOY
      CALENDAR(HOY,9)  = YR
      CALENDAR(HOY,10) = WE

      HOY = HOY + 1
      IF(HOD.EQ.24) THEN
        HOD = HOD + 1
        DOW = DOW + 1
        DOY = DOY + 1
      ELSE
        HOD = HOD + 1
      ENDIF
      IF(HOW.EQ.168) THEN
        HOW = 1
        WOY = WOY + 1
      ELSE
        HOW = HOW + 1
      ENDIF
      IF(HOD.EQ.25) THEN
        IF(MOY.EQ.2)THEN
            IF(DOM.EQ.28) THEN
              DOM = 1
              MOY = MOY + 1
              GOTO 2050
            ELSE
              DOM = DOM + 1
            ENDIF
        ENDIF
        IF(MOY.EQ.1.OR.MOY.EQ.3.OR.MOY.EQ.5.OR.MOY.EQ.7.OR.
     2       MOY.EQ.8.OR.MOY.EQ.10.OR.MOY.EQ.12) THEN
          IF(DOM.EQ.31)THEN
            DOM = 1
            MOY = MOY + 1
            GOTO 2050
          ELSE
            DOM = DOM + 1
          ENDIF
```

```
          ENDIF
          IF(MOY.EQ.4.OR.MOY.EQ.6.OR.MOY.EQ.9.OR.MOY.EQ.11) THEN
            IF(DOM.EQ.30) THEN
              DOM = 1
              MOY = MOY + 1
              GOTO 2050
            ELSE
               DOM = DOM + 1
            ENDIF
          ENDIF
        ENDIF
 2050   CONTINUE
       IF(HOD.EQ.25) HOD = 1
       IF(DOW.EQ.6.OR.DOW.EQ.7) THEN
           WE = 0
       ELSE
           WE = 1
       ENDIF
       IF(DOW.EQ.8)  DOW = 1
 2010 CONTINUE
      RETURN

      END

C=================================================================
```

tax.example

THE DAYS OF 1989 WITH A NON-ZERO NOx EMISSIONS TAX

Max. tax = 100 $/kg, Min. Tax = 10 $/kg, Max. accept. ozone = 0.07 ppm, Standard = 0.1 ppm
lag time = 3 h, tax limit = 12 h, exceedence gap = 48 h

Sun 9 Apr 89	T	0.00	0.00	0.00	0.00	16.67	25.00	33.33	41.67	50.00	58.33	66.67	75.00
		83.33	91.67	100.00	100.00	100.00	100.00	0.00	0.00	0.00	0.00	0.00	0.00
Sat 6 May 89	T	0.00	15.00	22.50	30.00	37.50	45.00	52.50	60.00	67.50	75.00	82.50	90.00
		90.00	90.00	90.00	90.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tue 16 May 89	T	13.33	20.00	26.67	33.33	40.00	46.67	53.33	60.00	66.67	73.33	80.00	80.00
		80.00	80.00	80.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Thu 1 Jun 89	T	0.00	0.00	15.00	22.50	30.00	37.50	45.00	52.50	60.00	67.50	75.00	82.50
		90.00	90.00	90.00	90.00	90.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Sat 17 Jun 89	T	13.33	20.00	26.67	33.33	40.00	46.67	53.33	60.00	66.67	73.33	80.00	80.00
		80.00	80.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
Thu 22 Jun 89	E	10.00	18.33	27.50	36.67	45.83	55.00	64.17	73.33	82.50	91.67	100.83	110.00
		110.00	110.00	110.00	110.00	110.00	110.00	110.00	10.00	10.00	10.00	10.00	15.00
Fri 23 Jun 89	T	22.50	30.00	37.50	45.00	52.50	60.00	67.50	75.00	82.50	90.00	90.00	90.00
		90.00	90.00	90.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		0.00	0.00	0.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
Wed 5 Jul 89	E	10.00	13.33	20.00	26.67	33.33	40.00	46.67	53.33	60.00	66.67	73.33	80.00
		80.00	80.00	80.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
Thu 6 Jul 89	E	10.00	10.83	21.67	32.50	43.33	54.17	65.00	75.83	86.67	97.50	108.33	119.17
		130.00	130.00	130.00	130.00	130.00	130.00	10.00	10.00	10.00	10.00	10.00	15.00
Fri 7 Jul 89	E	22.50	30.00	37.50	45.00	52.50	60.00	67.50	75.00	82.50	90.00	90.00	90.00
		90.00	90.00	90.00	90.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
Sat 8 Jul 89	E	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
		10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
Sun 9 Jul 89	E	10.00	13.33	20.00	26.67	33.33	40.00	46.67	53.33	60.00	66.67	73.33	80.00
		80.00	80.00	80.00	80.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
Mon 10 Jul 89	E	13.33	20.00	26.67	33.33	40.00	46.67	53.33	60.00	66.67	73.33	80.00	80.00
		80.00	80.00	80.00	80.00	80.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Figure E.2

		0.00	0.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
Fri 21 Jul 89	E	10.00	10.00	15.00	22.50	30.00	37.50	45.00	52.50	60.00	67.50	75.00	82.50
		90.00	82.50	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
Sat 22 Jul 89	E	10.00	16.67	25.00	33.33	41.67	50.00	58.33	66.67	75.00	83.33	91.67	100.00
		91.67	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
Sun 23 Jul 89	E	13.33	20.00	26.67	33.33	40.00	46.67	53.33	60.00	66.67	73.33	80.00	10.00
		10.00	10.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Thu 27 Jul 89	T	15.00	22.50	30.00	37.50	45.00	52.50	60.00	67.50	75.00	82.50	90.00	82.50
		10.00	10.00	10.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Thu 3 Aug 89	E	0.00	0.00	0.00	15.00	22.50	30.00	37.50	45.00	52.50	60.00	67.50	75.00
		82.50	90.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
Fri 4 Aug 89	E	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
		10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
Sat 5 Aug 89	E	15.00	22.50	30.00	37.50	45.00	52.50	60.00	67.50	75.00	82.50	90.00	82.50
		75.00	10.00	10.00	10.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		0.00	0.00	0.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
Sun 13 Aug 89	E	10.00	10.00	18.33	27.50	36.67	45.83	55.00	64.17	73.33	82.50	91.67	100.83
		110.00	100.83	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
Mon 14 Aug 89	E	10.00	11.67	23.33	35.00	46.67	58.33	70.00	81.67	93.33	105.00	116.67	128.33
		140.00	128.33	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	13.33	20.00
Tue 15 Aug 89	E	26.67	33.33	40.00	46.67	53.33	60.00	66.67	73.33	80.00	73.33	66.67	60.00
		53.33	10.00	10.00	10.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fri 25 Aug 89	E	0.00	13.33	20.00	26.67	33.33	40.00	46.67	53.33	60.00	66.67	73.33	80.00
		10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
Sat 26 Aug 89	E	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
		10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
Sun 27 Aug 89	E	10.00	13.33	20.00	26.67	33.33	40.00	46.67	53.33	60.00	66.67	73.33	80.00
		10.00	10.00	10.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Thu 31 Aug 89	E	0.00	0.00	15.00	22.50	30.00	37.50	45.00	52.50	60.00	67.50	75.00	82.50
		90.00	82.50	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
Fri 1 Sep 89	E	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
		10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
Sat 2 Sep 89	E	10.00	13.33	20.00	26.67	33.33	40.00	46.67	53.33	60.00	66.67	73.33	80.00

		73.33	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
Sun 3 Sep 89	E	16.67	25.00	33.33	41.67	50.00	58.33	66.67	75.00	83.33	91.67	100.00	91.67
		83.33	75.00	66.67	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	16.67
Mon 4 Sep 89	E	25.00	33.33	41.67	50.00	58.33	66.67	75.00	83.33	91.67	100.00	91.67	83.33
		75.00	10.00	10.00	10.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
Tue 12 Sep 89	E	10.00	10.00	15.00	22.50	30.00	37.50	45.00	52.50	60.00	67.50	75.00	82.50
		90.00	82.50	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	15.00	22.50
Wed 13 Sep 89	E	30.00	37.50	45.00	52.50	60.00	67.50	75.00	82.50	90.00	82.50	75.00	67.50
		60.00	52.50	45.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
Thu 14 Sep 89	E	18.33	27.50	36.67	45.83	55.00	64.17	73.33	82.50	91.67	100.83	110.00	100.83
		91.67	82.50	73.33	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	13.33
Fri 15 Sep 89	E	20.00	26.67	33.33	40.00	46.67	53.33	60.00	66.67	73.33	80.00	10.00	10.00
		60.00	53.33	10.00	10.00	10.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
Wed 20 Sep 89	E	10.00	10.00	10.00	13.33	20.00	26.67	33.33	40.00	46.67	53.33	60.00	66.67
		73.33	80.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	15.00
Thu 21 Sep 89	E	22.50	30.00	37.50	45.00	52.50	60.00	67.50	75.00	82.50	90.00	82.50	75.00
		67.50	60.00	52.50	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
Fri 22 Sep 89	E	10.00	10.00	10.00	15.00	22.50	30.00	37.50	45.00	52.50	60.00	67.50	75.00
		82.50	90.00	82.50	10.00	10.00	10.00	0.00	0.00	0.00	0.00	0.00	0.00
Fri 6 Oct 89	E	13.33	20.00	26.67	33.33	40.00	46.67	53.33	60.00	66.67	73.33	80.00	73.33
		10.00	10.00	10.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Sat 7 Oct 89	E	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		0.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
Sun 8 Oct 89	E	10.00	10.00	10.00	13.33	20.00	26.67	33.33	40.00	46.67	53.33	60.00	66.67
		73.33	80.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
Mon 9 Oct 89	E	13.33	20.00	26.67	33.33	40.00	46.67	53.33	60.00	66.67	73.33	80.00	73.33
		66.67	60.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
Tue 10 Oct 89	E	10.00	15.00	22.50	30.00	37.50	45.00	52.50	60.00	67.50	75.00	82.50	90.00
		82.50	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
Wed 11 Oct 89	E	10.00	10.00	13.33	20.00	26.67	33.33	40.00	46.67	53.33	60.00	66.67	73.33
		80.00	10.00	10.00	10.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
Tue 17 Oct 89	E	10.00	10.00	13.33	20.00	26.67	33.33	40.00	46.67	53.33	60.00	66.67	73.33

		80.00	73.33	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	15.00
Wed 18 Oct 89	E	22.50	30.00	37.50	45.00	52.50	60.00	67.50	75.00	82.50	90.00	82.50	75.00
		67.50	60.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
Thu 19 Oct 89	E	10.00	15.00	22.50	30.00	37.50	45.00	52.50	60.00	67.50	75.00	82.50	90.00
		82.50	10.00	10.00	10.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Sat 11 Nov 89	T	20.00	26.67	33.33	40.00	46.67	53.33	60.00	66.67	73.33	80.00	73.33	66.67
		10.00	10.00	10.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Sat 18 Nov 89	T	0.00	13.33	20.00	26.67	33.33	40.00	46.67	53.33	60.00	66.67	73.33	80.00
		10.00	10.00	10.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

total tax days = 49
total episode days = 40

Number of Episode Days Vs. Min. Acceptable O_3

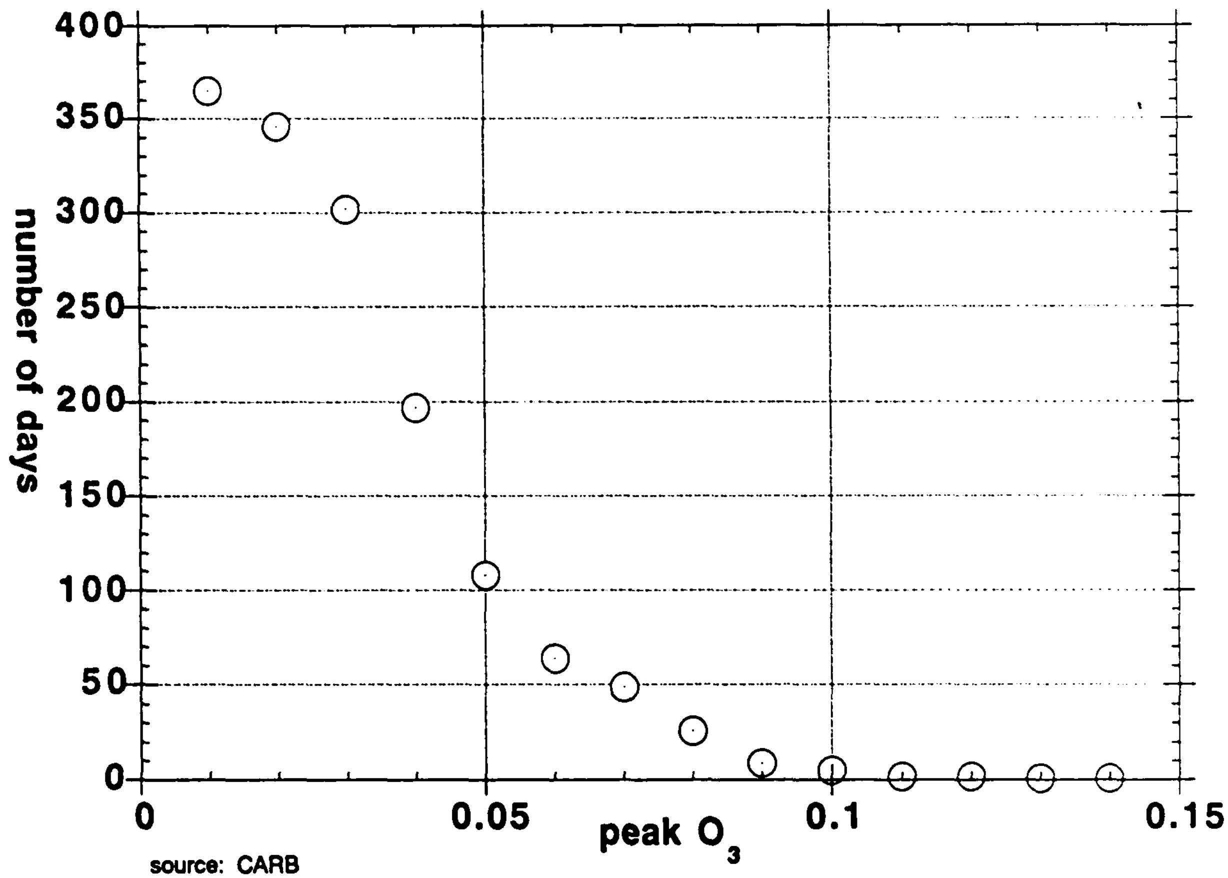


Figure E.3

Concentration Duration Curve for Livermore 1989

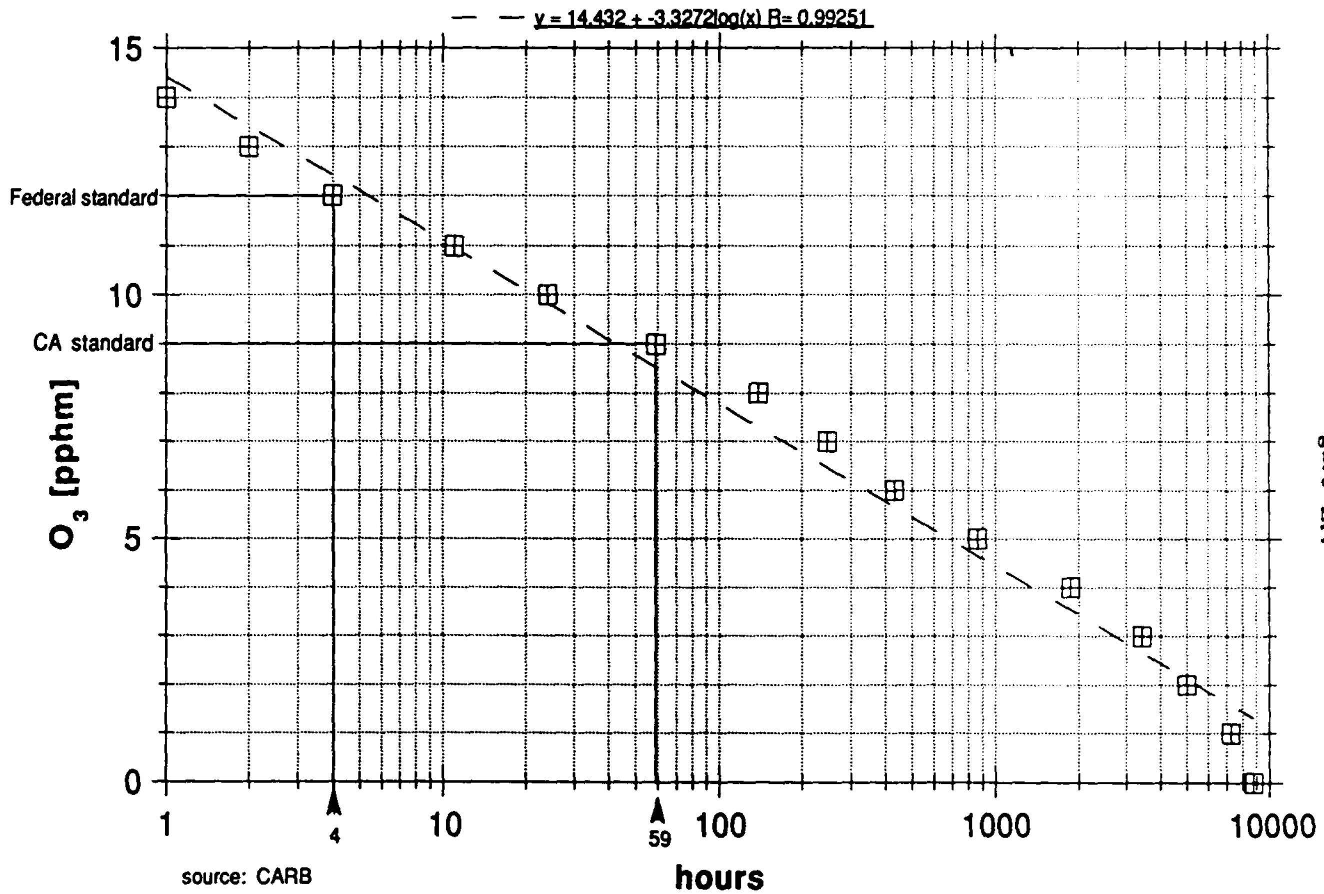
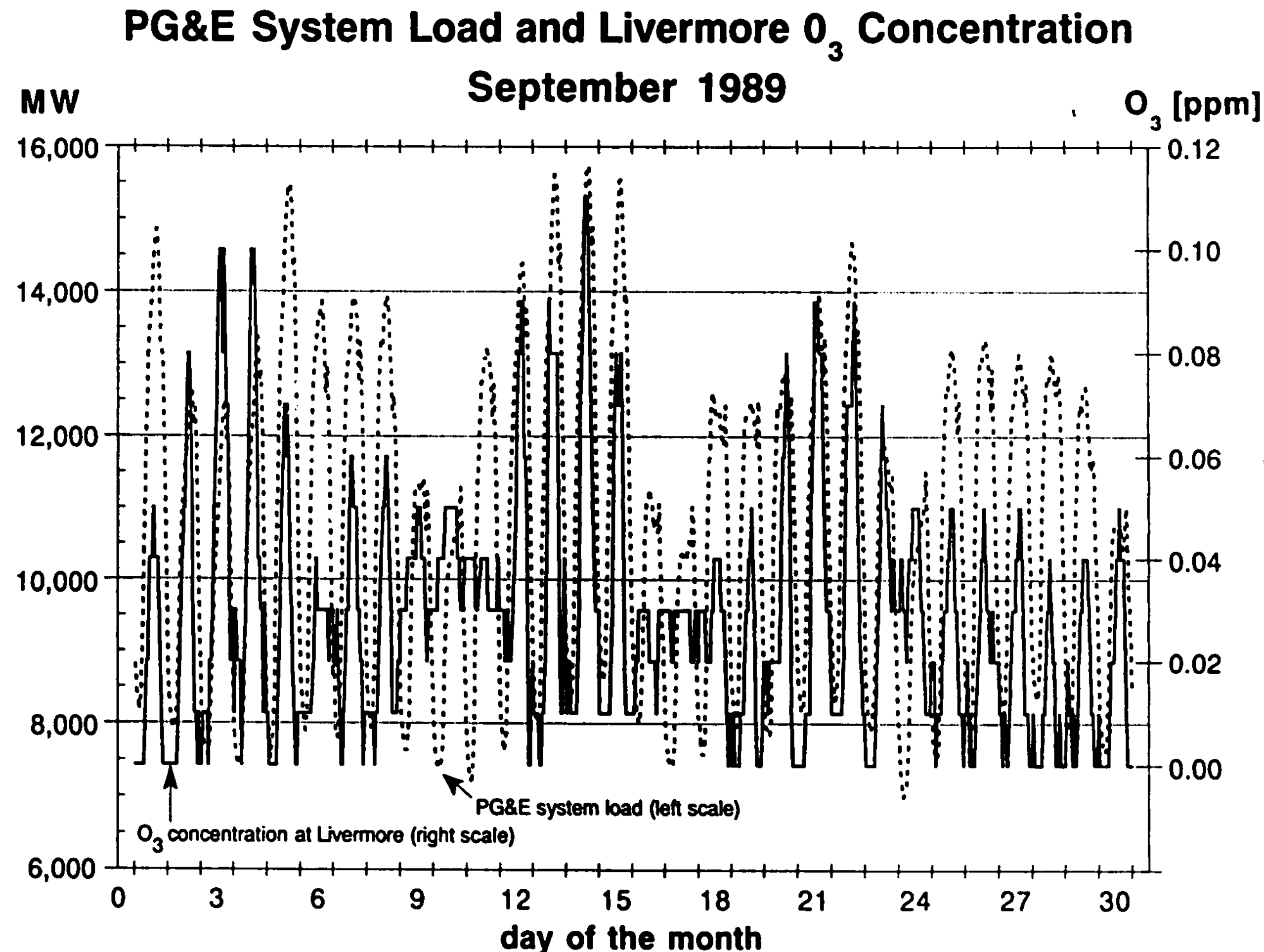


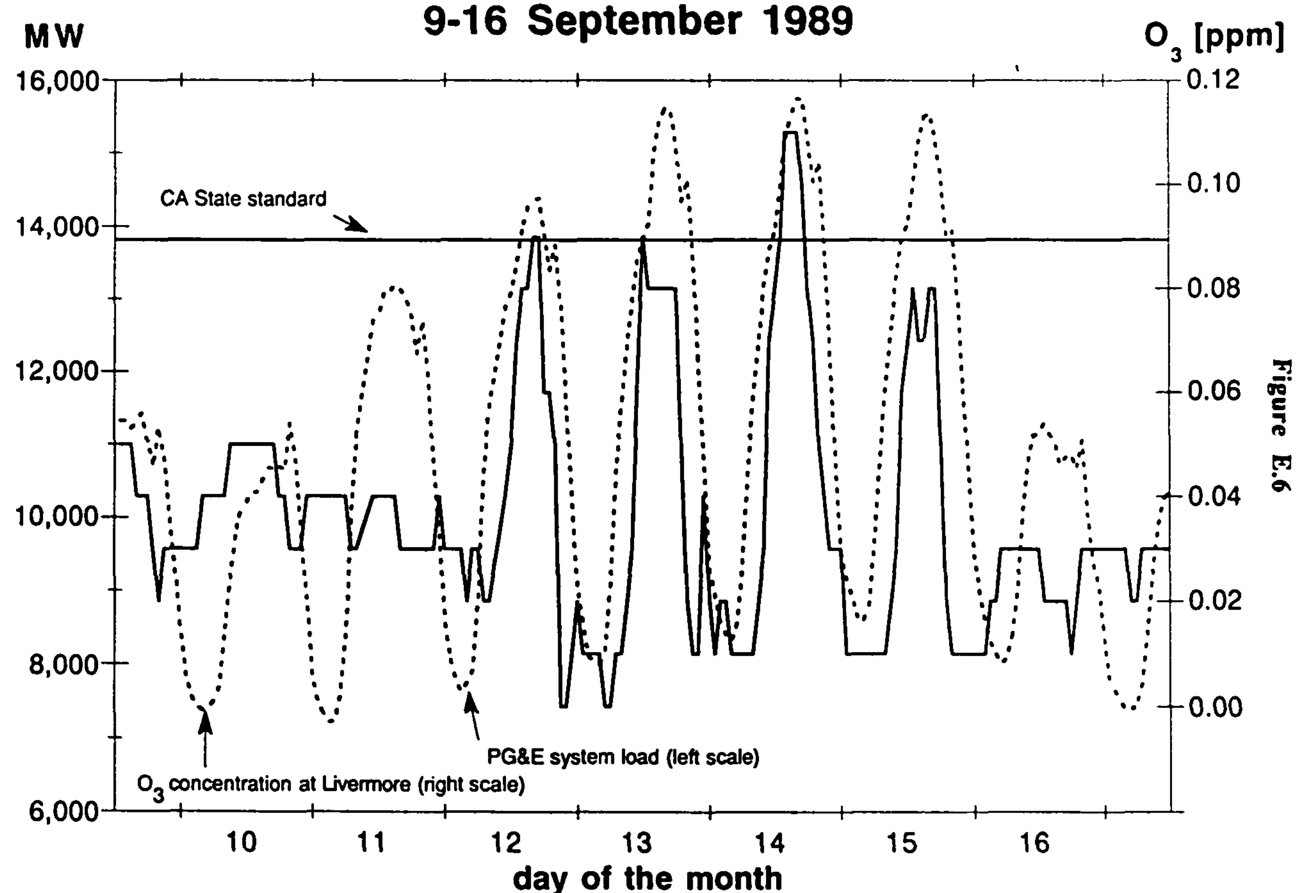
Figure E.4



source: CARB and PG&E

Figure E.5

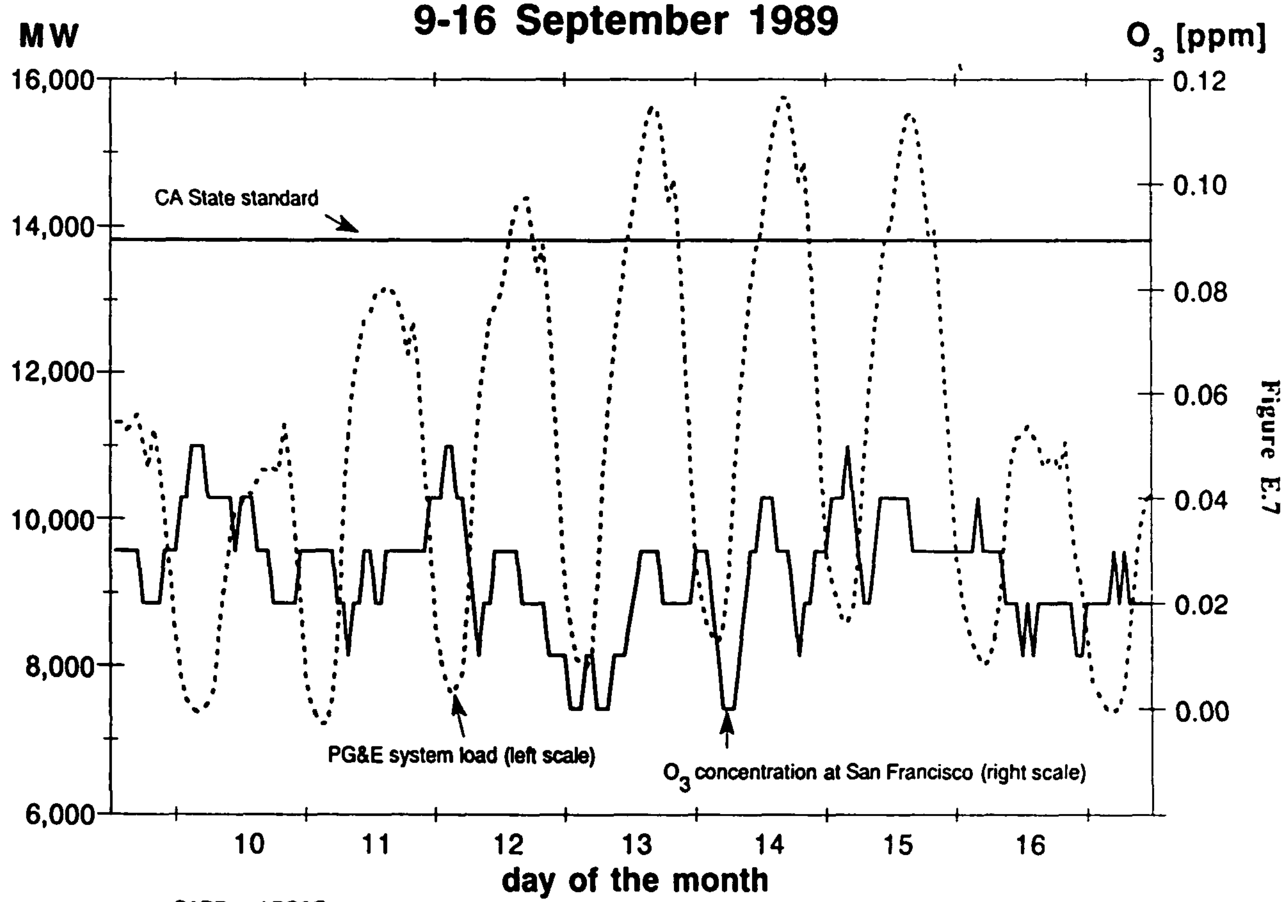
PG&E System Load and Livermore 0_3 Concentration
9-16 September 1989



source: CARB and PG&E

Figure E.6

PG&E System Load and San Francisco O_3 Concentration
9-16 September 1989

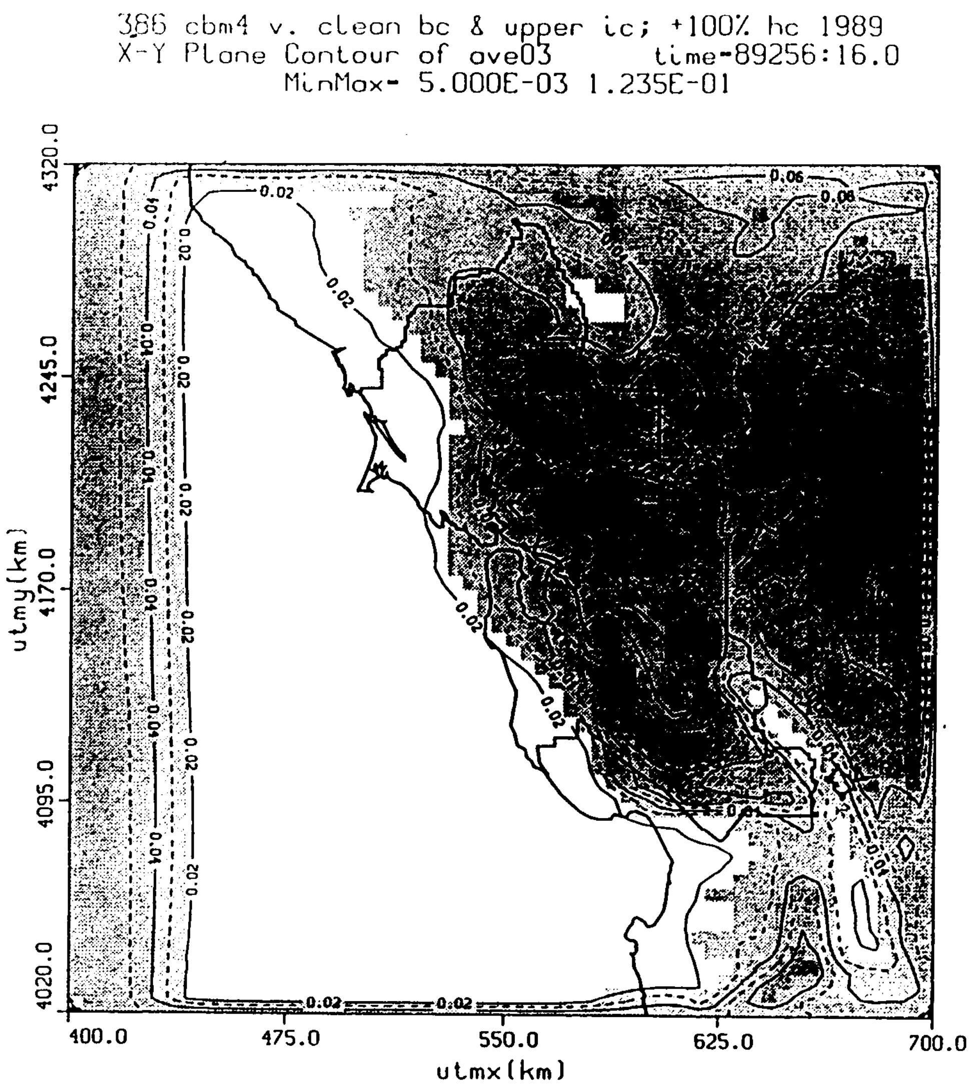


source: CARB and PG&E

Figure E.7

Figure E.8

Example of UAM Results



source: BAAQMD

Appendix F: Monte Carlo

EEUCM is a deterministic unit commitment and dispatch model. That is, in the EEUCM approach, all resources are assumed to be perfectly reliable and are available for the duration of the simulation as specified in the input file. In longer range production cost modeling, some account has to be taken of the fact that generators are not perfectly reliable. Rather, the set of available generators is random and the outputs from production cost models are, consequently, also random. For the purposes of this work, it was necessary to introduce randomness into EEUCM in some fashion. This was achieved by major modifications to EEUCM that permitted the running of multiple simulations using Monte Carlo draws on the availability of resources. Only a simple up-down draw was made for each unreliable resource in each simulation; that is, no partial outage states were considered, and the outage duration was equal to the period of the simulation. Most of the results presented here are based on runs of 100 Monte Carlo draws.

The random number generator used was a common one used in Monte Carlo studies. The implementation of the random number generator is shown in figure F.2. A short test was conducted of the generator with disappointing results, which appear in figure F.1. In Monte Carlo production cost modeling, the status of a unit is determined by whether its random draw is greater than the availability of the unit, or equivalently, less than its forced outage rate. That is, the frequency distribution should be as close to uniform as possible. Each line of the table shows for the points shown, 0.7,0.8,0.9,0.95, and 0.99, the fraction of the distribution of random draws below the point. That is, a perfect result would have each number in each column converging to its heading as the number of draws becomes large. Each row in the table represents the frequency distribution after a series of 1 000000 draws had been made, each series starting from a different seed. The program that conducts this test appears as figure F.3.

The results show that the random number generator is clearly biased, although the bias appears only in the third place of decimals. This random number generator is accurate enough for exploratory work of this kind, but should not be used where greater accuracy is required.

Figure F.1:Random Number Generator Test

Chris Marnay 2-June-92

run	# draws	0.70	0.80	0.90	0.95	0.99
1	1000000	0.699662	0.801067	0.903520	0.951141	0.991271
2	1000000	0.699721	0.801103	0.903591	0.951191	0.991285
3	1000000	0.699704	0.801094	0.903595	0.951184	0.991283
4	1000000	0.699669	0.801029	0.903552	0.951170	0.991271
5	1000000	0.699659	0.801061	0.903538	0.951155	0.991268
6	1000000	0.699675	0.801072	0.903570	0.951177	0.991282
7	1000000	0.699658	0.801074	0.903524	0.951144	0.991270
8	1000000	0.699669	0.801063	0.903584	0.951171	0.991290
9	1000000	0.699696	0.801092	0.903575	0.951175	0.991283
10	1000000	0.699691	0.801068	0.903560	0.951180	0.991279
11	1000000	0.699681	0.801041	0.903557	0.951168	0.991273
12	1000000	0.699750	0.801141	0.903595	0.951184	0.991287
13	1000000	0.699676	0.801077	0.903585	0.951167	0.991290
14	1000000	0.699704	0.801094	0.903548	0.951155	0.991276
15	1000000	0.699721	0.801136	0.903609	0.951189	0.991281
16	1000000	0.699650	0.801050	0.903578	0.951165	0.991287
17	1000000	0.699695	0.801098	0.903553	0.951158	0.991275
18	1000000	0.699662	0.801069	0.903559	0.951178	0.991284
19	1000000	0.699684	0.801046	0.903541	0.951165	0.991278
20	1000000	0.685652	0.796412	0.880247	0.955079	0.994007
21	1000000	0.699667	0.801064	0.903566	0.951179	0.991283
22	1000000	0.699706	0.801072	0.903571	0.951180	0.991279
23	1000000	0.699675	0.801074	0.903579	0.951187	0.991288
24	1000000	0.699657	0.801062	0.903512	0.951140	0.991266
25	1000000	0.699740	0.801147	0.903604	0.951193	0.991289
26	1000000	0.699694	0.801122	0.903573	0.951166	0.991281
27	1000000	0.699702	0.801103	0.903583	0.951174	0.991289
28	1000000	0.699715	0.801119	0.903591	0.951169	0.991287
29	1000000	0.699686	0.801051	0.903552	0.951152	0.991274
30	1000000	0.699654	0.801069	0.903519	0.951144	0.991268
31	1000000	0.699673	0.801069	0.903585	0.951182	0.991285
32	1000000	0.699698	0.801090	0.903581	0.951186	0.991279
33	1000000	0.699687	0.801034	0.903563	0.951183	0.991279
34	1000000	0.699707	0.801100	0.903584	0.951166	0.991278
35	1000000	0.699682	0.801081	0.903543	0.951161	0.991269
36	1000000	0.699708	0.801098	0.903591	0.951167	0.991284
37	1000000	0.699689	0.801072	0.903555	0.951173	0.991284
38	1000000	0.699677	0.801054	0.903570	0.951183	0.991278
39	1000000	0.699709	0.801112	0.903588	0.951168	0.991289
40	1000000	0.699684	0.801047	0.903553	0.951162	0.991276
41	1000000	0.699664	0.801073	0.903563	0.951172	0.991275
42	1000000	0.699703	0.801074	0.903586	0.951167	0.991277
43	1000000	0.699697	0.801096	0.903550	0.951161	0.991269
44	1000000	0.699694	0.801100	0.903579	0.951185	0.991291
45	1000000	0.699657	0.801039	0.903535	0.951156	0.991278
46	1000000	0.699667	0.801039	0.903541	0.951168	0.991276
47	1000000	0.699712	0.801096	0.903595	0.951183	0.991286
48	1000000	0.699702	0.801083	0.903579	0.951169	0.991277
49	1000000	0.699686	0.801089	0.903589	0.951169	0.991281

50	1000000	0.699681	0.801054	0.903562	0.951181	0.991280
51	1000000	0.699677	0.801045	0.903553	0.951160	0.991275
52	1000000	0.699710	0.801118	0.903582	0.951166	0.991284
53	1000000	0.699732	0.801142	0.903584	0.951175	0.991277
54	1000000	0.699695	0.801099	0.903587	0.951171	0.991291
55	1000000	0.699665	0.801050	0.903567	0.951152	0.991288
56	1000000	0.699704	0.801094	0.903597	0.951192	0.991284
57	1000000	0.699683	0.801086	0.903530	0.951147	0.991270
58	1000000	0.699678	0.801076	0.903538	0.951155	0.991269
59	1000000	0.699702	0.801090	0.903604	0.951180	0.991290
60	1000000	0.699671	0.801057	0.903564	0.951179	0.991276
61	1000000	0.699707	0.801078	0.903562	0.951183	0.991281
62	1000000	0.699689	0.801086	0.903548	0.951162	0.991274
63	1000000	0.699665	0.801065	0.903542	0.951155	0.991269
64	1000000	0.699704	0.801069	0.903572	0.951173	0.991278
65	1000000	0.699658	0.801049	0.903566	0.951170	0.991291
66	1000000	0.699695	0.801090	0.903556	0.951166	0.991273
67	1000000	0.699672	0.801047	0.903562	0.951166	0.991276
68	1000000	0.699669	0.801047	0.903552	0.951170	0.991275
69	1000000	0.699656	0.801113	0.903572	0.951165	0.991278
70	1000000	0.699677	0.801088	0.903545	0.951163	0.991266
71	1000000	0.699695	0.801095	0.903595	0.951176	0.991286
72	1000000	0.699687	0.801066	0.903585	0.951181	0.991279
73	1000000	0.699702	0.801061	0.903566	0.951179	0.991277
74	1000000	0.699688	0.801059	0.903560	0.951170	0.991282
75	1000000	0.699696	0.801065	0.903569	0.951163	0.991275
76	1000000	0.699676	0.801076	0.903587	0.951169	0.991281
77	1000000	0.699696	0.801098	0.903591	0.951170	0.991287
78	1000000	0.699693	0.801084	0.903588	0.951172	0.991279
79	1000000	0.699721	0.801138	0.903593	0.951183	0.991284
80	1000000	0.699696	0.801073	0.903571	0.951175	0.991284
81	1000000	0.699696	0.801093	0.903558	0.951168	0.991273
82	1000000	0.699694	0.801085	0.903547	0.951159	0.991268
83	1000000	0.699688	0.801068	0.903578	0.951163	0.991276
84	1000000	0.699703	0.801073	0.903565	0.951171	0.991273
85	1000000	0.699655	0.801062	0.903512	0.951138	0.991267
86	1000000	0.699713	0.801115	0.903590	0.951179	0.991284
87	1000000	0.699688	0.801066	0.903572	0.951163	0.991276
88	1000000	0.699659	0.801037	0.903557	0.951159	0.991279
89	1000000	0.699688	0.801086	0.903540	0.951156	0.991266
90	1000000	0.699684	0.801058	0.903569	0.951157	0.991274
91	1000000	0.699665	0.801059	0.903555	0.951179	0.991279
92	1000000	0.699644	0.801043	0.903578	0.951174	0.991291
93	1000000	0.699717	0.801121	0.903590	0.951184	0.991287
94	1000000	0.699679	0.801059	0.903563	0.951168	0.991276
95	1000000	0.699682	0.801089	0.903550	0.951159	0.991273
96	1000000	0.699710	0.801132	0.903581	0.951190	0.991283
97	1000000	0.699679	0.801091	0.903556	0.951153	0.991270
98	1000000	0.699739	0.801143	0.903596	0.951192	0.991288
99	1000000	0.699668	0.801036	0.903557	0.951167	0.991273
100	1000000	0.699706	0.801111	0.903555	0.951160	0.991270
means ->		0.699548	0.801033	0.903334	0.951208	0.991306

Figure F.2

```
C=================================================================
C This subroutine uses a simple random number generator to produce
C N random draws in the 0-1 interval, given an initial seed, ISEED
C Histogram data of binned random numbers is outut to the file
C histogram.data
C         Chris Marnay  12 June 1992

      SUBROUTINE RANDOM(ISEED,N,RNUMS,NMCITS,MCI)

C variables:
C COUNT       = running total number of draws
C HISTDATA    = is the array of bin mid-points and # in bins
C IA,IB,IC    = parameters of random generator eq.
C ISEED    = seed for random generator eq
C LOWER       = lower bound of bin
C N           = number of random numbers requested
C NBINS         = number of bins for histogram
C NOBS        = total number of draws made
C STEP        = width of bin
C U           = 0 < random number < 1.0
C UPPER       = upper bound of bin

      INTEGER IA,IB,IC,ISEED,N,NOBS,NBINS,N,NMCITS,MCI
      REAL HISTDATA(100,2)
      DOUBLE PRECISION RNUMS(100),LOWER,UPPER,STEP

      IA = 743315861
      IB = 245094853
      IC = 31

      NBINS = 100

C set up the histogram data set
      IF(MCI.EQ.1) THEN
        NOBS = 0
        STEP = 1.0/REAL(NBINS)
        HISTDATA(1,1) = STEP/2.0
        DO 1010 I = 2, NBINS
          HISTDATA(I,1) = HISTDATA(I-1,1) + STEP
          HISTDATA(I,2) = 0.0
 1010   CONTINUE
```

```
      ENDIF

C-------------------------
C the draws are made in this loop
C that is broken when enough have been made
C actual draws are made here according method
C proposed by Morgan 1984

      DO 2010 K = 1, N
        ISEED = MOD(IA*ISEED + IB,2**IC)
        IF(ISEED.LT.0) ISEED = ISEED + 2147483647
        RNUMS(K) = ISEED * (1.0/(2.0**IC))
 2010 CONTINUE

C now the draw is added to the histogram data array
      LOWER = 0.0
      UPPER = 0.0
      DO 1020 I = 1, NBINS
          LOWER = (HISTDATA(I,1) - (STEP/2.0))
          UPPER = (HISTDATA(I,1) + (STEP/2.0))
        DO 1040 K = 1, N
          IF (RNUMS(K).GE.LOWER.AND.RNUMS(K).LT.UPPER) THEN
            HISTDATA(I,2) = HISTDATA(I,2) + 1.0
            NOBS = NOBS + 1
          ENDIF
 1040   CONTINUE
 1020 CONTINUE
C-------------------------
C data for a histogram of the distribution is output
C this distribution should be uniform

      IF(MCI.EQ.NMCITS) THEN
        OPEN(31,FILE='histogram.data')
        DO 1030 I = 1, NBINS
          WRITE(31,5040) HISTDATA(I,1),CHAR(9),INT(HISTDATA(I,2)),
     2    CHAR(9),HISTDATA(I,2)/REAL(NOBS)
 5040     FORMAT(F6.3,A1,I6,A1,F6.3)
 1030   CONTINUE
        WRITE(31,*) '# observations = ',NOBS
        CLOSE(31)
      ENDIF

      END
```

Figure F.3

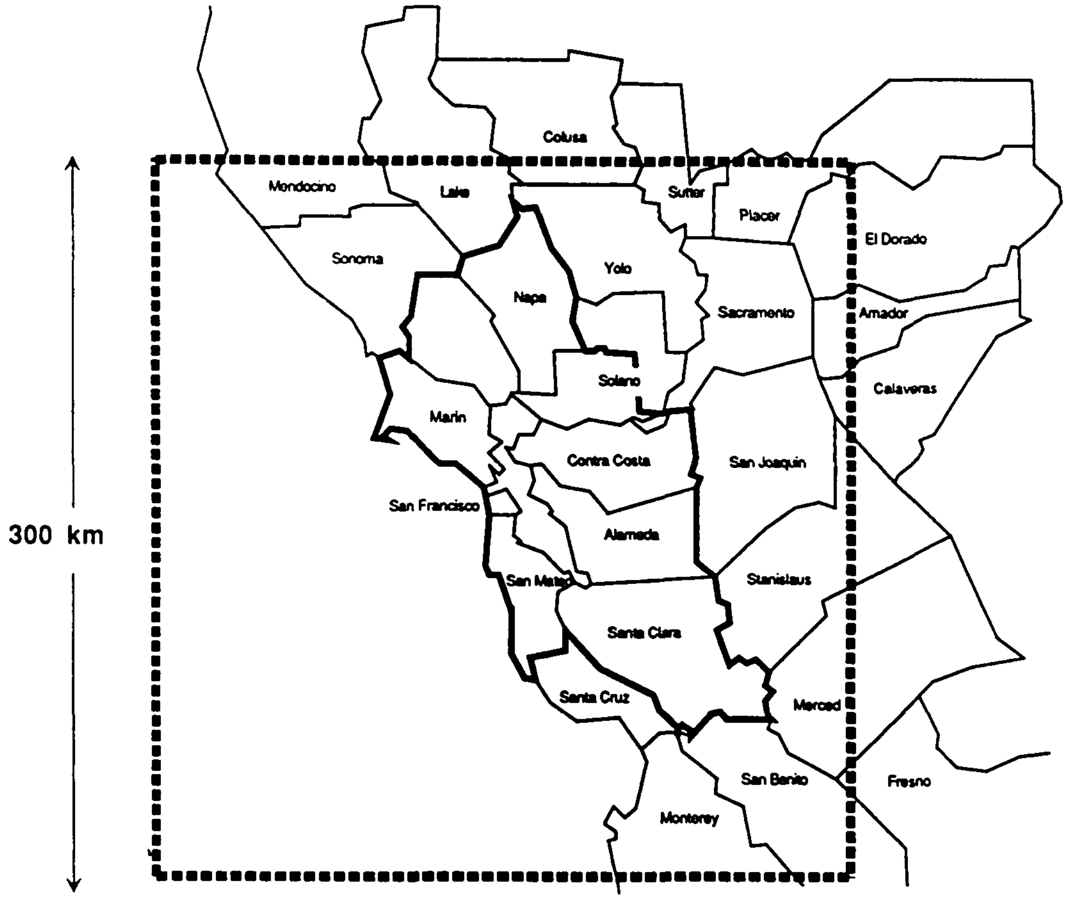
```
C=====================================================================
C This program tests the random number generator
C the fraction of draws below or equal to levels in TESTS(J)
C are output after n, then n*10, etc. up to 1e9 draws
C a different seed is used in each series
C  Chris Marnay - 12 May 1992

      PROGRAM RANDOMTEST

C variables:
C COUNT        = running total number of draws
C IA,IB,IC     = parameters of random generator eq.
C ISED          = seed for random generator eq
C N            = number of random numbers requested
C NOBS(J)      = total number of draws made at each test level
C STOP          = max number of draws
C TESTS(J)     = points where draws compared
C U            = 0 < random number < 1.0

      INTEGER COUNT,IA,IB,IC,ISED,NOBS(5),STOP,SEEDS(100)
      REAL    TESTS(5)
      DOUBLE PRECISION U

      STOP = 1000000

C these seeds are usually 10 digits
      DO 1010 I = 1,100
        SEEDS(I) =  2000000000 - (I-1)*(20000000)
 1010 CONTINUE

      TESTS(1) = 0.700
      TESTS(2) = 0.800
      TESTS(3) = 0.900
      TESTS(4) = 0.950
      TESTS(5) = 0.990

      IA = 743315861
      IB = 245094853
      IC = 31

C-------------------------
      DO 1050 I = 1, 100
```

```
C the draws are made in this continuous loop
C that is broken when enough have been made

        COUNT    = 1

        NOBS(1) = 0
        NOBS(2) = 0
        NOBS(3) = 0
        NOBS(4) = 0
        NOBS(5) = 0

        ISED     = SEEDS(I)

        OPEN(100 + I)
        WRITE(100 + I,*) 'seed = ', ISED
        WRITE(100 + I,*) 'number of draws  0.7  0.8',
     2       ' 0.9  0.95 0.99'

 100    CONTINUE

C actual draws are made here according method
C proposed by Morgan 1984
      ISED = MOD(IA*ISED + IB,2**IC)
      IF(ISED.LT.0) ISED = ISED + 2147483647
      U = ISED * (1.0/(2.0**31.0))
      ISED = INT(U * 2147483647.0)

C now the draw is added to the running total
      DO 1020 J = 1, 5
        IF (U.LE.TESTS(J)) THEN
          NOBS(J) = NOBS(J) + 1
        ENDIF
 1020 CONTINUE

C if  it's time to output results, do it
      IF (COUNT.LT.1000.AND.MOD(COUNT,100).EQ.0) THEN
         GOTO 1030
      ELSEIF (COUNT.LT.10000.AND.MOD(COUNT,1000).EQ.0) THEN
         GOTO 1030
      ELSEIF (COUNT.LT.100000.AND.MOD(COUNT,10000).EQ.0) THEN
         GOTO 1030
      ELSEIF (COUNT.LT.1000000.AND.MOD(COUNT,100000).EQ.0) THEN
         GOTO 1030
```

```
      ELSEIF (COUNT.LT.10000000.AND.MOD(COUNT,1000000).EQ.0) THEN
         GOTO 1030
      ELSEIF (COUNT.LT.100000000.AND.MOD(COUNT,10000000).EQ.0) THEN
         GOTO 1030
      ELSEIF (COUNT.LT.1000000000.AND.MOD(COUNT,100000000).EQ.0)
THEN
         GOTO 1030
      ELSE
         GOTO 150
      ENDIF
 1030 CONTINUE
      WRITE(100 + I,5010) COUNT, CHAR(9),REAL(NOBS(1))/REAL(COUNT),
     2                     CHAR(9),REAL(NOBS(2))/REAL(COUNT),
     3                     CHAR(9),REAL(NOBS(3))/REAL(COUNT),
     4                     CHAR(9),REAL(NOBS(4))/REAL(COUNT),
     5                     CHAR(9),REAL(NOBS(5))/REAL(COUNT)
 5010   FORMAT (I15,5(A1,F8.6))
 150  CONTINUE

C the loop continues until enough draws have been made
      IF (COUNT.GE.STOP) THEN
        GO TO 200
      ELSE
        COUNT = COUNT + 1
        GOTO 100
      ENDIF
 200  CONTINUE

      CLOSE(100 + I)
 1050 CONTINUE

      END

C-------------------------
```

Appendix G: General Data

Figure G.1



BAAQMD Jurisdiction and UAM Modeling Domain

Figure G.2

Days of Non Compliance and Population - 1987-89

rank	area	days /year	pop (000's)	% U.S. pop.	sum
1	Los Angeles-Anaheim-Riverside, CA	137.5	14532	5.843	5.84
2	Bakersfield, CA	44.2	543	0.218	6.06
3	Fresno, CA	24.3	667	0.268	6.33
4	New York-N. N.J-Long Island, NY-NJ-CT	17.4	18087	7.272	13.60
5	Sacramento, CA	15.8	1481	0.595	14.20
6	Chicago-Gary-Lake County, IL-IN-WI	13.0	8066	3.243	17.44
7	San Diego, CA	12.3	2498	1.004	18.44
8	Houston-Galveston-Brazoria, TX	12.2	3711	1.492	19.94
9	*Knox County, ME	11.1	*100*	0.040	19.98
10	Baltimore, MD	10.7	2382	0.958	20.93
11	Boston-Lawrence-Salem, MA-NH	10.0	4172	1.677	22.61
12	Milwaukee-Racine, WI	9.8	1607	0.646	23.26
13	Muskegon, MI	9.4	*100*	0.040	23.30
14	Atlanta, GA	9.3	2834	1.139	24.44
15	Sheboygan, WI	9.1	*100*	0.040	24.48
16	Philadelphia-Wilmington-Trenton, PA-NJ-MD	8.8	5899	2.372	26.85
17	El Paso, TX	7.9	592	0.238	27.09
18	Hartford-New Britain-Middleton, CT	7.9	1086	0.437	27.52
19	Modesto, CA	7.6	371	0.149	27.67
20	Visalia-Tulare-Porterville, CA	7.6	312	0.125	27.80
21	Greensboro-Winston Salem-High Point, NC	7.2	942	0.379	28.18
22	Parkersburg-Marietta. WV-OH	7.2	*100*	0.040	28.22
23	Pittsburgh-Beaver Valley, PA	7.0	2243	0.902	29.12
24	Springfield, MA	6.7	530	0.213	29.33
25	Providence-Pawtucket-Fall River, RI-MA	6.4	1142	0.459	29.79
26	St. Louis, MO-IL	6.2	2444	0.983	30.78
27	Portland, ME	6.1	*100*	0.040	30.82
28	Nashville, TN	5.6	985	0.396	31.21
29	Huntington-Ashland, WV-KY-OH	5.5	313	0.126	31.34
30	*Kewaunee, County, WI	5.5	*100*	0.040	31.38
31	Cincinatti-Hamilton, OH-KY-IN	5.4	1744	0.701	32.08
32	Portsmouth-Dover-Rochester, NH-ME	5.3	*100*	0.040	32.12
33	Cleveland-Akron-Lorain, OH	5.2	2760	1.110	33.23
34	Worcester, MA	5.2	437	0.176	33.40
35	Washington, DC-MD-VA	4.9	3924	1.578	34.98
36	Baton Rouge, LA	4.5	528	0.212	35.19
37	Grand Rapids, MI	4.4	688	0.277	35.47
38	Richmond-Petersberg, VA	4.4	866	0.348	35.82
39	Raleigh-Durham, NC	4.1	735	0.296	36.11
40	Atlantic City, NJ	4.0	319	0.128	36.24
41	Buffalo-Niagara Falls, NY	3.8	1189	0.478	36.72
42	Beaumont-Port Arthur, TX	3.7	361	0.145	36.87
43	Detroit-Ann Arbor, MI	3.7	4665	1.876	38.74
44	Owensboro, KY	3.7	*100*	0.040	38.78
45	*Sussex County, DE	3.6	*100*	0.040	38.82
46	Dallas-Fort Worth, TX	3.5	3885	1.562	40.38
47	Charlotte-Gastonia-Rock Hill, NC-SC	3.4	1162	0.467	40.85
48	*Jefferson County, NY	3.4	*100*	0.040	40.89

49	Reading, PA	3.4	337	0.135	41.03
50	*Edmonson County, KY	3.2	*100*	0.040	41.07
51	Allentown-Bethlehem, PA-NJ	3.1	687	0.276	41.34
52	Dayton-Springfield, OH	3.1	951	0.382	41.73
53	Birmingham, AL	3.0	908	0.365	42.09
54	Erie, PA	3.0	276	0.111	42.20
55	Scranton-Wilkes-Barre, PA	3.0	*100*	0.040	42.24
56	*Hancock County, ME	2.8	*100*	0.040	42.28
57	Albany-Schenectady-Troy, NY	2.7	874	0.351	42.63
58	Toledo, OH	2.7	614	0.247	42.88
59	Johnstown, PA	2.5	*100*	0.040	42.92
60	San Francisco-Oakland-San Jose, CA	2.5	6253	2.514	45.44
61	Greenville-Spartanburg, SC	2.4	641	0.258	45.69
62	*Lincoln County, ME	2.4	*100*	0.040	45.73
63	*Smyth County, VA	2.4	*100*	0.040	45.77
64	Charleston, WV	2.3	250	0.101	45.87
65	Stockton, CA	2.3	481	0.193	46.07
66	Harrisburg-Lebanon-Carlisle, PA	2.2	588	0.236	46.30
67	Santa Barbara-Santa Maria-Lompoc, CA	2.1	370	0.149	46.45
68	Youngstown-Warren, OH	2.1	493	0.198	46.65
69	Altoona, PA	2.0	*100*	0.040	46.69
70	Lake Charles, LA	2.0	*100*	0.040	46.73
71	Lexington-Fayette, KY	2.0	348	0.140	46.87
72	Memphis, TN-AR-MS	2.0	982	0.395	47.27
73	Norfolk-Virginia Beach-Newport News, VA	2.0	1396	0.561	47.83
74	Salt Lake City, UT	2.0	1072	0.431	48.26
75	Louisville, KY-IN	1.9	953	0.383	48.64
76	*Essex County, NY	1.8	*100*	0.040	48.68
77	Knoxville, TN	1.8	605	0.243	48.92
78	Montgomery,AL	1.8	293	0.118	49.04
79	Canton, OH	1.7	394	0.158	49.20
80	Johnson City-Kingsport-Briston, TN-VA	1.7	436	0.175	49.38
81	Miami-Fort Lauderdale, FL	1.7	3193	1.284	50.66
82	Lewiston-Auburn, ME	1.5	*100*	0.040	50.70
83	York, PA	1.5	418	0.168	50.87
84	Columbus, OH	1.4	1377	0.554	51.42
85	Fayetteville, NC	1.4	275	0.111	51.53
86	*Greenbrier County, WV	1.4	*100*	0.040	51.57
87	Manchester, NH	1.4	*100*	0.040	51.61
88	Tampa-St. Petersburg-Clearwater, FL	1.4	2068	0.831	52.44
89	Poughkeepsie, NY	1.3	259	0.104	52.55
90	Lancaster, PA	1.3	423	0.170	52.72
91	Kansas City, MO-KS	1.2	1566	0.630	53.35
92	South Bend-Mishawaka, IN	1.1	*100*	0.040	53.39
93	*Livingston County, KY	1.1	*100*	0.040	53.43
94	Evansville, IN-KY	1.1	279	0.112	53.54
95	Indianapolis, IN	1.1	1250	0.503	54.04
96	Waldo County, ME	1.1	*100*	0.040	54.08
	source: Statistical Abstract of the U.S. tables 36 & 363	total=	134512		54.1

Table G.3

New Power Generation Regulations BAAQMD 1991 Clean Air Plan

#	origin SCAQMD	requirement	$/t NOx	t/d ER	date	affects	technology	$/kW
D1	1110.2	NOx: 36 ppm (CO: 2000 ppm)	10250	6.0-7.7	1992	fixed IC engines ≥ 50 HP mobile IC engines ≥ 100 HP (10 kW or 20 kW back-up gen.)	NSCR/SCR	250-500
D2	1134	1-2.9 MW: 25 ppm 2.9-9.9 MW: 9 ppm 2.9-9.9 MW (no SCR): 15 ppm ≥ 10 MW: 9 ppm ≥ 10 MW (no SCR): 12 ppm	13250	5.9-6.3	1993	QF, munis, and PG&E CT's ≥ 1 MW	methanol/ SI/SCR	?-160 20 $/kW*y
D3	1135	SCR	15400	10.9-12.2	1993	PG&E	SNCR/SCR	129*

* based on PG&E estimate of 0.5 G$ total cost

Appendix H: UAM Inputs

This appendix describes the assumptions and tools used to convert the hourly NO_x emissions that emerge from the simulation by EEUCM into the inputs required by UAM. This is the activity in the *NO_x model* box of figure I.C.1. While this may sound like a trivial task, in fact, some key assumptions have to be made, and the data maniupulation itself is no small undertaking.

One of the key difficulties is that EEUCM, like all production cost models, assumes the problem is one of up and down ramping generators, as shown in figure II.D.1. Photo-chemical models, and pollution models in general, assume the problem is one of smoke stacks and tracing the effects of the pollutants that emerge from them. There would not be a gap between these two perspectives, if each generator were connected to a unique boiler and it, in turn, vented to a unique stack. While such a conveniently simple setup is not unknown, for example, the Pittsburg station is exactly of that form, this is the exception rather than the rule. At most stations, there are complications. The generator is fed by more than one boiler, more than one boiler vent to the same stack, or a boiler vents to several stacks. Based on the information available from PG&E on the actual configurations at its stations, and some crude assumptions, the correspondences show in table H.1 were developed and used. For example, emissions from unit 1

(CONTRCS1) were assigned equally to boilers 1 & 2, and assumed to go equally up stacks 1 & 2.

The EEUCM outputs of the form shown in appendix I are first converted by a simple spreadsheet program to the format shown in table H.4. These data are in the units of mol/s required by UAM. All prior work has been strictly in kg/h units. The data of table H.4 are read and injected into the UAM point source input file. An example of the UAM input appears as table H.3. As mentioned in chapter I, the actual input file is huge (~ 10 Mb), and not at all easy to work with. Each block of data has two lines, the first specifying the source, and the second giving the hourly emission of each of 13 pollutants. The first row contains data such as the ID number of the source, the county in which it is located, its UTM coordinates, the stack height in ft and diameter in m, the velocity of stack gas, and some summary data as a check to the detail in the second row. Row 2 shows the pollutant emissions in mol/s. The second and third columns show the NO_2 and NO, respectively. In this analysis, the emissions are treated entirely as NO.

A further complication of this input format is that several entries can exist for the same stack. The file was set up in this way to accommodate multiple industrial processes that might vent to the same stack. In utility work, however, this provides an added nuisance. In any case, this messy data injection is achieved by the equally messy program shown in figure H.2.

Table H.2 shows the monitoring stations in the modeling domain of the District. Figure H.2 shows the program that extracts the ozone peaks from the UAM output.

The method described in this appendix for converting EEUCM outputs to UAM inputs is crude and makeshift. Given the proven insensitivity of UAM to input adjustments of the order predicted by EEUCM, these assumptions are not significant. However, when a more careful analysis is done, some effort should be made to better relate the units to their corresponding boilers and stacks. If this exercise needed to be done routinely, a more user friendly conversion method would be needed.

Table H.1

Boiler-Unit-Stack Numbering Assumptions

Chris Marnay - 07 Nov 92 13:11

Contra Costra

boiler	*stack*	*unit*
1	1	1 = boiler 1 & 2
2	2	2 = boiler 3 & 6
3	3	3 = boiler 4 & 5
4	4	
5	5	
6	6	
7	7	4
8	8	5
9	9 - units 6 & 7 both on boiler 9 (450 ft high)	
10	there is no 10 stack at Contra Costa	

Hunters Point

boiler	*stack*	*unit*
	1 & 2 out of use	
3 & 4	3	2
5 & 6	4	3
	6 is out of use	
7	7	4
engine	*stack*	*unit*
1	5	1

Moss Landing

boiler	*stack*	*unit*
1		
2	boilers 1-6 stacks identical to Contra Costa 1-6	
6		
7	7	4
8	8	5
6-1	9	6
7-2	10	7

stacks 9-10 are 500 ft high and 245 ft^2 area

Oakland

engine	*stack*	*unit*
1	1	1
2	2	
3	3	2
4	4	
5	5	3
6	6	

Pittsburg

boiler	*stack*	*unit*
1	1	1
2	2	2
3	3	3
4	4	4
5	4	5 stacks 5&6 148 ft²
6	6	6
7	7	7 stack 7 314 ft²

Potrero

boiler	*stack*	*unit*
3-1	1	3

engine	*stack*	*unit*
1	2 same as Oakland	4
2	3	
3	4	5
4	5	
5	6	6
6	7	

Table H.2

Air Quality Monitoring Sites
Within UAM Modeling Domain

Code	ID	Sitename	Agency	Lat	Long	East	North	Ele(m)
1001	BEN	Benicia	BAAQMD	38.053	122.153	574.3	4211.8	12
1002	BID	Bethel Island	BAAQMD	38.015	121.639	619.5	4208.1	0
1003	CON	Concord	BAAQMD	37.939	122.025	585.7	4199.3	26
1004	CRO	Crockett	BAAQMD	38.055	122.233	567.3	4212.0	79
1005	FAI	Fairfield	BAAQMD	38.246	122.057	582.5	4233.3	4
1006	FRE	Fremont	BAAQMD	37.536	121.961	591.8	4154.6	16
1007	GIL	Gilroy	BAAQMD	37.000	121.574	626.9	4095.6	62
1008	HAY	Hayward	BAAQMD	37.654	122.031	585.5	4167.7	302
1009	LIV	Livermore	BAAQMD	37.685	121.765	608.9	4171.4	150
1010	LGA	Los Gatos	BAAQMD	37.227	121.979	590.6	4120.3	116
1011	MRZ	Martinez	BAAQMD	38.013	122.133	576.1	4207.4	9
1012	MIN	Mines Road	BAAQMD	37.552	121.571	626.2	4156.9	628
1013	MVW	Mountain View	BAAQMD	37.373	122.077	581.8	4136.5	43
1014	NAP	Napa	BAAQMD	38.311	122.295	561.6	4240.3	12
1015	OAK	Oakland	BAAQMD	37.798	122.267	564.5	4183.5	10
1016	PAT	Patterson Pass	BAAQMD	37.690	121.631	620.7	4172.1	524
1017	PIT	Pittsburg	BAAQMD	38.029	121.894	597.1	4209.4	2
1018	PTR	Point Richmond	BAAQMD	37.926	122.384	554.1	4197.6	2
1019	RWC	Redwood City	BAAQMD	37.483	122.203	570.5	4148.5	4
1020	RIC	Richmond	BAAQMD	37.950	122.356	556.6	4200.3	12
1021	ARK	San Francisco - Ark.	BAAQMD	37.766	122.398	553.0	4179.8	5
1022	ELL	San Francisco - Ellis	BAAQMD	37.784	122.421	551.0	4181.8	41
1023	SJO	San Jose - 4th	BAAQMD	37.340	121.888	598.5	4133.0	25
1024	SJA	San Jose - Piedmont	BAAQMD	37.392	121.842	602.5	4138.8	62
1025	SJB	San Jose - Burbank	BAAQMD	37.324	121.926	595.2	4131.1	36
1026	SLE	San Leandro	BAAQMD	37.718	122.162	573.9	4174.7	14
1027	SRA	San Rafael	BAAQMD	37.973	122.518	542.3	4202.7	3
1028	SRO	Santa Rosa	BAAQMD	38.444	122.709	525.4	4254.9	52
1029	SON	Sonoma	BAAQMD	38.298	122.456	547.6	4238.8	34
1030	VAL	Vallejo	BAAQMD	38.103	122.237	566.9	4217.3	6
1031	ALV	Alviso	BAAQMD	37.435	121.952	592.7	4143.4	1
1032	SUN	Sunol	BAAQMD	37.594	121.876	599.2	4161.1	140
2001	CAR	Carmel Valley	MBAPCD	36.476	121.733	613.5	4037.3	131
2002	DVP	Davenport	MBAPCD	37.012	122.188	572.3	4096.3	91
2003	HOL	Hollister	MBAPCD	36.844	121.361	647.0	4078.7	126
2005	SAL	Salinas	MBAPCD	36.697	121.633	622.2	4062.0	13
2006	SRN	San Ramon	PG&E	37.785	121.965	591.1	4182.2	146
2007	SCZ	Santa Cruz	MBAPCD	36.984	121.986	590.2	4093.4	28
2008	VVL	Vacaville	YSAPCD	38.342	121.990	588.2	4244.0	64
2009	PIN	Pinnacles NM	NPS	36.485	121.158	665.0	4039.1	102
2010	REY	Pt. Reyes NS	NPS	38.123	122.900	508.2	4219.2	31
2019	NHI	North Highlands	SCAPCD	38.713	121.380	640.9	4286.0	27
2020	SAT	Sac'to - T St.	ARB	38.568	121.492	631.4	4269.7	7

source: BAAQMD

Table H.2 (Cont'd)

Code	ID	Sitename	Agency	Lat	Long	East	North	Ele(m)
2022	SAD	Sac'to - Del Paso	SCAPCD	38.614	121.367	642.2	4275.0	25
2024	SAM	Sac'to - Meadowview	SCAPCD	38.481	121.473	633.2	4260.1	12
2025	SAC	Sac'to - El Camino	SCAPCD	38.611	121.381	641.0	4274.6	18
2026	SAE	Sac'to - Earhart	SCAPCD	38.717	121.592	622.4	4286.1	9
2027	FOL	Folsom	ARB	38.675	121.186	657.8	4282.1	57
2028	CIH	Citris Heights	ARB	38.667	121.250	652.3	4281.1	52
2031	PLG	Pleasant Grove	ARB	38.767	121.514	629.1	4291.8	50
2034	WLD	Woodland	YSAPCD	38.673	121.788	605.4	4281.0	20
2035	DAV	Davis	ARB	38.533	121.775	606.8	4265.5	16
2036	BRO	Broderick	YSAPCD	38.592	121.508	629.9	4272.4	6
2057	STM	Stockton - Mariposa	ARB	37.932	121.220	656.4	4199.6	13
2058	STC	Stockton - Claremont	ARB	37.995	121.308	648.6	4206.4	13
2059	STH	Stockton - Hazelton	ARB	37.951	121.269	652.1	4201.6	13
2060	TUR	Turlock	ARB	37.515	120.850	690.0	4154.0	30
2062	MOD	Modesto - 14th	ARB	37.642	120.994	677.0	4167.8	27
2063	CRW	Crows Landing	ARB	37.371	121.132	665.4	4137.5	130
2066	SSP	Ponderosa High	EDCAPCD	38.683	120.833	688.5	4283.6	462
2070	ROC	Rocklin	PCAPCD	38.792	121.208	655.6	4295.0	100
2072	AUB	Auburn	PCAPCD	38.938	121.104	664.3	4311.4	433
2076	ARB	Arbuckle	ARB	39.020	122.081	579.6	4319.2	43

Table H.3: Point Source Input File to UAM

```
CB4 SPECIATED POINT EMISSIONS FOR 1989.  Dec 22,1990.
HOUR 89256 0000 89256 0100
  10  4285  2      553.37  4199.03  150.0   2.41  625  41.5      .0 4478.6     .0
 0.000E+00 2.556E-02 4.856E-01 0.000E+00 0.000E+00 0.000E+00 0.000E+00 0.000E+00
 0.000E+00 0.000E+00 0.000E+00 0.000E+00 0.000E+00
  10  4340  2      553.37  4199.03  175.0    .92 1000    .1      .6     .0     .0
 0.000E+00 0.000E+00 0.000E+00 0.000E+00 1.231E-04 2.742E-06 0.000E+00 0.000E+00
 0.000E+00 3.612E-06 0.000E+00 0.000E+00 0.000E+00
  10  4341  2      553.37  4199.03  175.0    .92 1000    .1      .3     .0     .0
 0.000E+00 0.000E+00 0.000E+00 0.000E+00 6.299E-05 1.402E-06 0.000E+00 0.000E+00
 0.000E+00 1.848E-06 0.000E+00 0.000E+00 0.000E+00
  11  1426  2      577.89  4208.50  162.0   2.43  550  15.4      .0 4444.4     .0
 0.000E+00 2.536E-02 4.819E-01 0.000E+00 0.000E+00 0.000E+00 0.000E+00 0.000E+00
 0.000E+00 0.000E+00 0.000E+00 0.000E+00 0.000E+00
  11  1759  2      578.52  4208.50   75.0   1.68   60  34.1    10.8     .0     .0
 0.000E+00 0.000E+00 0.000E+00 0.000E+00 2.255E-03 5.021E-05 0.000E+00 0.000E+00
 0.000E+00 6.615E-05 0.000E+00 0.000E+00 0.000E+00
  13   806  2      582.19  4208.36  250.0   3.66  440  18.6     6.3 3101.5     .0
 0.000E+00 1.770E-02 3.363E-01 0.000E+00 1.308E-03 2.913E-05 0.000E+00 0.000E+00
 0.000E+00 3.838E-05 0.000E+00 0.000E+00 0.000E+00
  13   832  2      582.45  4208.54  223.0    .91  602  50.0    38.5  910.1  207.1
 3.882E-02 5.193E-03 9.867E-02 0.000E+00 8.039E-03 1.790E-04 0.000E+00 0.000E+00
 0.000E+00 2.358E-04 0.000E+00 0.000E+00 0.000E+00
  16   300  2      566.29  4210.34  207.0   1.37  100   1.8    81.0     .0     .0
 0.000E+00 0.000E+00 0.000E+00 0.000E+00 1.690E-02 3.764E-04 0.000E+00 0.000E+00
 0.000E+00 4.959E-04 0.000E+00 0.000E+00 0.000E+00
  16   306  2      566.29  4210.34  207.0   1.37  100   1.8     8.8     .0     .0
 0.000E+00 0.000E+00 0.000E+00 0.000E+00 1.844E-03 4.106E-05 0.000E+00 0.000E+00
 0.000E+00 5.410E-05 0.000E+00 0.000E+00 0.000E+00
```

```
  16   308  2     566.29  4210.34  207.0   1.37  100   1.8   20.8     .0     .0
 0.000E+00 0.000E+00 0.000E+00 0.000E+00 4.344E-03 9.673E-05 0.000E+00 0.000E+00
 0.000E+00 1.274E-04 0.000E+00 0.000E+00 0.000E+00
  15     5  8     575.78  4213.91  394.0   4.72  634  17.6     .0 4009.6     .0
 0.000E+00 2.288E-02 4.347E-01 0.000E+00 0.000E+00 0.000E+00 0.000E+00 0.000E+00
0.000E+00 0.000E+00 0.000E+00 0.000E+00 0.000E+00
  15     6  8     575.78  4213.91  394.0   4.72  634  17.6   31.1 1855.6     .0
```

Table H.4: Sample of Input Data to the PTSRCE_POLICY.F Program

Sept. 12, 1983 (mol/s)

CONTRCS 18

1	0.059	0.059	0.059	0.059	0.059	0.059	0.059	0.059	0.059	0.059	0.059	0.338
	0.338	0.338	0.338	0.338	0.338	0.338	0.338	0.338	0.338	0.261	0.180	0.126
2	0.059	0.059	0.059	0.059	0.059	0.059	0.059	0.059	0.059	0.059	0.059	0.338
	0.338	0.338	0.338	0.338	0.338	0.338	0.338	0.338	0.338	0.261	0.180	0.126
3	0.060	0.060	0.060	0.060	0.060	0.060	0.060	0.060	0.060	0.060	0.060	0.338
	0.338	0.338	0.338	0.338	0.338	0.338	0.338	0.338	0.338	0.275	0.186	0.127
4	0.060	0.060	0.060	0.060	0.060	0.060	0.060	0.060	0.060	0.060	0.060	0.338
	0.338	0.338	0.338	0.338	0.338	0.338	0.338	0.338	0.338	0.275	0.186	0.127
5	0.058	0.058	0.058	0.058	0.058	0.058	0.058	0.058	0.058	0.058	0.059	0.339
	0.339	0.339	0.339	0.339	0.339	0.339	0.339	0.339	0.328	0.248	0.174	0.125
6	0.058	0.058	0.058	0.058	0.058	0.058	0.058	0.058	0.058	0.058	0.059	0.339
	0.339	0.339	0.339	0.339	0.339	0.339	0.339	0.339	0.328	0.248	0.174	0.125
7	0.092	0.092	0.092	0.092	0.092	0.092	0.092	0.092	0.100	0.167	0.181	0.723
	0.723	0.723	0.723	0.723	0.723	0.723	0.723	0.723	0.664	0.491	0.333	0.228
8	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
9	0.768	0.768	0.768	0.768	0.768	0.768	1.298	2.778	4.904	5.148	5.148	3.969
	4.028	4.094	4.187	4.133	4.037	4.021	3.903	4.021	3.376	2.529	1.755	1.238
10	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Figure H.1

```
C This program reads the BAAQMD hourly ozone files and finds
C the peak hour in each column.  Then this data is written out
C in tab format for import into a spreadsheet.

C   Chris Marnay - Tue Nov 10 22:40:54 PST 1992

      PROGRAM DAILY_PEAK

C variables:
C     MONSTN     = name of the monitoring station
C     INNFILES   = names of the input files
C     DATA       = all the found peaks

      CHARACTER*3 MONSTN(100),STRING3
      CHARACTER*25 INNFILES(10)
      REAL DATA(100,100)

C first the names of the in files are set up

      INNFILES(1) = 'baaqmd.788                  '
      INNFILES(2) = 'max.832                     '
      INNFILES(3) = 'min.831                     '
      INNFILES(4) = 'base.833                    '
      INNFILES(5) = '                            '

C the out loop is across the file names
C the inner loop is across the stations in the input
C (usually about 50)

      DO 1020 I = 1, 4
        OPEN(10+I,FILE=INNFILES(I))
        READ(10+I,1005,END=1020) STRING3
 1005   FORMAT(A3)
        DO 1010 J = 1, 80
          CALL READER(10+I,MONSTN(J),DATA(J,I*10+1),DATA(J,I*10+2),
     2      DATA(J,I*10+3),DATA(J,I*10+4))
 1010   CONTINUE
        CLOSE(10+I)
 1020 CONTINUE
```

```
C this block outputs the data to the file station.summary
C with the input file names as headers

      OPEN(21,FILE='station.summary')
      WRITE(21,5020) CHAR(9),CHAR(9),CHAR(9),CHAR(9),INNFILES(1),
     2               CHAR(9),CHAR(9),CHAR(9),CHAR(9),INNFILES(2),
     2               CHAR(9),CHAR(9),CHAR(9),CHAR(9),INNFILES(3),
     2               CHAR(9),CHAR(9),CHAR(9),CHAR(9),INNFILES(4)
 5020 FORMAT('station',A1,'hour',3A1,A25,3(4A1,A25))
      DO 1040 J = 1, 100
        IF(INT(DATA(J,11)).NE.0) THEN
        IF(INT(DATA(J,11)).NE.INT(DATA(J,21))) PRINT *, 'hr mismatch'
        IF(INT(DATA(J,11)).NE.INT(DATA(J,31))) PRINT *, 'hr mismatch'
        IF(INT(DATA(J,11)).NE.INT(DATA(J,41))) PRINT *, 'hr mismatch'
        WRITE(21,5010) MONSTN(J),
     2           CHAR(9),INT(DATA(J,11)),CHAR(9),DATA(J,12),
     3           CHAR(9),DATA(J,13),CHAR(9),DATA(J,14),
     4           CHAR(9),INT(DATA(J,21)),CHAR(9),DATA(J,22),
     5           CHAR(9),DATA(J,23),CHAR(9),DATA(J,24),
     6           CHAR(9),INT(DATA(J,31)),CHAR(9),DATA(J,32),
     7           CHAR(9),DATA(J,33),CHAR(9),DATA(J,34),
     8           CHAR(9),INT(DATA(J,41)),CHAR(9),DATA(J,42),
     9           CHAR(9),DATA(J,43),CHAR(9),DATA(J,44)
 5010     FORMAT(A3,4(A1,I2,A1,2(F5.3,A1),F5.3))
        ENDIF
 1040 CONTINUE
      CLOSE(21)
      OPEN(22,FILE='max.min')
      WRITE(22,5041) CHAR(9),CHAR(9),INNFILES(2),CHAR(9),CHAR(9),
     2               INNFILES(3),CHAR(9)
 5041 FORMAT(A1,A1,A25,A1,A1,A25,A1)
      WRITE(22,5040) CHAR(9),CHAR(9),CHAR(9),CHAR(9),CHAR(9)
5040 FORMAT('station',A1,'obs.',A1,'cell',A1,'ave',A1,'cell',A1,'ave')
      DO 1050 J = 1, 100
        IF(INT(DATA(J,11)).NE.0) THEN
        WRITE(22,5030) MONSTN(J),CHAR(9),INT(DATA(J,11)),
     2     CHAR(9),DATA(J,12),CHAR(9),DATA(J,23), CHAR(9),DATA(J,24),
     3     CHAR(9),DATA(J,33),CHAR(9),DATA(J,34)
 5030     FORMAT(A3,A1,I2,A1,F4.2,4(A1,F8.6))
        ENDIF
 1050 CONTINUE
      CLOSE(22)
      END
```

```
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%

C this subroutine does the actual reading

      SUBROUTINE READER (K,MONSTN,DATA1,DATA2,DATA3,DATA4 )

C variables:
C      MONSTN    = monitoring station name
C      LASTMONSTN= last station name
C      TEMPMONSTN= temp. station name
C      DATAX_    = the data points returned to main
C                  (ie the found maxima)
C      TEMPDATA  = array of the input data

      CHARACTER*3  MONSTN,LASTMONSTN,TEMPMONSTN
      REAL TEMPDATA(4),DATA1,DATA2,DATA3,DATA4
      INTEGER K

      DO 1000 I = 1,4
        TEMPDATA(I) = 0.0
1000  CONTINUE
      DATA1  = 0.0
      DATA2  = 0.0
      DATA3  = 0.0
      DATA4  = 0.0

C reading is in a continuous loop broken by the endoffile
C or, more likely, a change in the station name
C note that the number of hours reported is not consistent
C across monitoring stations, hence the need for the test
C of station names and the break when it changes
C if the name has changed, the file is backspaced

 1010 CONTINUE
        READ(K,5010,END=1030) TEMPMONSTN,(TEMPDATA(J),J=1,4)
 5010   FORMAT(7X,A3,F5.0,F8.2,E13.5,E16.5)
        IF(TEMPMONSTN.NE.LASTMONSTN) GOTO 1030
        MONSTN = TEMPMONSTN
        IF(TEMPDATA(2).GE.DATA2) THEN
          DATA2 = TEMPDATA(2)
          DATA1 = TEMPDATA(1)
        ENDIF
        IF(TEMPDATA(3).GT.DATA3) DATA3 = TEMPDATA(3)
```

```
      IF(TEMPDATA(4).GT.DATA4) DATA4 = TEMPDATA(4)
      LASTMONSTN =  MONSTN
      GOTO 1010
1030 CONTINUE
    LASTMONSTN  =  TEMPMONSTN
    BACKSPACE(K)

    RETURN
    END
```

%%%

Figure H.2

```
C This program reads the pt89in_nwsff file and finds all the PG&E
C sources and replaces them with data from the hourly.data file.
C They are ouput to new files pt89in_policy and, with all PG&E NO
C and NO2 emissions changed to the Sep 12, 92 emissions predicted
C by EEUCM.
C A file of the PGE data before and after, pt89inandout_max_PGE,
C is also written.
C          Chris Marnay  - Wed Oct 28 18:41:55 PST 1992

       PROGRAM PTSRCE_POLICY

       REAL CONTRCS(0:10,25),HNTRSPT(0:7,25),MOSLAND(0:5,2)
       REAL OAKLAND(0:6,25),PITSBRG(0:7,25),POTRERO(0:1,25)
       CHARACTER*7 STRING7(6)

C READEMIS reads in the values from a file called hourly.data
       CALL READEMIS(CONTRCS,HNTRSPT,MOSLAND,OAKLAND,
     2    PITSBRG,POTRERO,STRING7)

C PLACER inserts these values into the UAM ptsrce file.
       CALL PLACER(CONTRCS,HNTRSPT,MOSLAND,OAKLAND,
     2    PITSBRG,POTRERO,STRING7)
       END

C===================================================================
C this subroutine reads the max.data file and retuns the data
C in an array for each station indexed by the stack ID used in
ptsrcein

       SUBROUTINE READEMIS(CONTRCS,HNTRSPT,MOSLAND,OAKLAND,
     2    PITSBRG,POTRERO,STRING7)

C the first (zero) row of C every arrary contains the !! station !!
ID
C all the other rows contain the !! stack !! ID and emissions in
mol/s

       REAL CONTRCS(0:10,25),HNTRSPT(0:7,25),MOSLAND(0:5,2)
       REAL OAKLAND(0:6,25),PITSBRG(0:7,25),POTRERO(0:1,25)
       CHARACTER*7 STRING7(6)

       OPEN(11,file='hourly.data')

C now read in the data, note the indexes on reads to match indexes
above

       READ(11,5010) STRING7(1),CONTRCS(0,2)
 5010  FORMAT(A7,F5.0)
       IF(STRING7(1).NE.'CONTRCS')
      2    PRINT *,'ERROR CONTRCS NE ',STRING7(1)
```

```
      DO 1010 I = 1, 10
        READ(11,5020) CONTRCS(I,25),(CONTRCS(I,J),J=1,12)
5020  FORMAT(F2.0,12F6.3)
        READ(11,5021) (CONTRCS(I,J),J=13,24)
5021  FORMAT(2X,12F6.3)
1010  CONTINUE

      READ(11,5010) STRING7(2),HNTRSPT(0,2)
      IF(STRING7(2).NE.'HNTRSPT')
     2    PRINT *,'ERROR HNTRSPT NE ',STRING7(2)
      DO 1090 I = 1, 7
        READ(11,5020) HNTRSPT(I,25),(HNTRSPT(I,J),J=1,12)
        READ(11,5021) (HNTRSPT(I,J),J=13,24)
1090  CONTINUE

      READ(11,5010) STRING7(4),MOSLAND(0,2)
      IF(STRING7(4).NE.'MOSLAND')
     2    PRINT *,'ERROR MOSLAND NE',STRING7(4)
      DO 1060 I = 1, 10
        READ(11,5020) MOSLAND(I,25),(MOSLAND(I,2),J=1,12)
        READ(11,5021) (MOSLAND(I,J),J=13,24)
1060  CONTINUE

      READ(11,5010) STRING7(5),OAKLAND(0,2)
      IF(STRING7(5).NE.'OAKLAND')
     2    PRINT *,'ERROR OAKLAND NE',STRING7(5)
      DO 1050 I = 1, 6
        READ(11,5020) OAKLAND(I,25),(OAKLAND(I,J),J=1,12)
        READ(11,5021) (OAKLAND(I,J),J=13,24)
1050  CONTINUE

      READ(11,5010) STRING7(3),PITSBRG(0,2)
      IF(STRING7(3).NE.'PITSBRG')
     2    PRINT *,'ERROR PITSBRG NE ',STRING7(3)
      DO 1030 I = 1, 7
        READ(11,5020) PITSBRG(I,25),(PITSBRG(I,J),J=1,12)
        READ(11,5021) (PITSBRG(I,J),J=13,24)
1030  CONTINUE

      READ(11,5010) STRING7(6),POTRERO(0,2)
      IF(STRING7(6).NE.'POTRERO')
     2    PRINT *,'ERROR POTRERO NE',STRING7(6)
      DO 1040 I = 1, 7
        READ(11,5020) POTRERO(I,25),(POTRERO(I,J),J=1,12)
        READ(11,5021) (POTRERO(I,J),J=13,24)
1040  CONTINUE

      CLOSE(11)

C that takes care of getting emissions data in
      RETURN
```

```
      END

C===========================================================
C this subroutine makes replaces the data in the _nwsff files
C with that found by the READEMIS subroutine

      SUBROUTINE PLACER(CONTRCS,HNTRSPT,MOSLAND,OAKLAND,
     2     PITSBRG,POTRERO,STRING7)

      CHARACTER*25  INNFILES(2),OUTFILES(2)
      CHARACTER*53  HEADER
      CHARACTER*132 LINE132
      CHARACTER*7   STRING7(6)

      REAL CONTRCS(0:10,25),HNTRSPT(0:7,25),MOSLAND(0:5,2)
      REAL OAKLAND(0:6,25),PITSBRG(0:7,25),POTRERO(0:1,25)
      REAL DATA(13),OLDATA(13)

C these ridiculous variables are to keep track of the passage
C of the hours in the data file.  Every stack is meticulously
C set just once and zeroed out on other occurences. Each variable
C contains the number of times the stack emission has been changed
C and this must be the same as the number of hours passed.
C Hey, if you can think of a better way, tell me about it.
C OK, OK, an array would have been better.

      INTEGER HOUR
      INTEGER LHCONTRCS01,LHCONTRCS02,LHCONTRCS03,LHCONTRCS04
      INTEGER LHCONTRCS05,LHCONTRCS06,LHCONTRCS07,LHCONTRCS08
      INTEGER LHCONTRCS09,LHCONTRCS10
      INTEGER LHHNTRSPT01,LHHNTRSPT02,LHHNTRSPT03
      INTEGER LHHNTRSPT03,LHHNTRSPT04,LHHNTRSPT05
      INTEGER LHHNTRSPT06,LHHNTRSPT07
      INTEGER LHMOSLAND01,LHMOSLAND02,LHMOSLAND03
      INTEGER LHMOSLAND04,LHMOSLAND05
      INTEGER LHOAKLAND01,LHOAKLAND02,LHOAKLAND03,LHOAKLAND04
      INTEGER LHOAKLAND05,LHOAKLAND06
      INTEGER LHPITSBRG01,LHPITSBRG02,LHPITSBRG03,LHPITSBRG04
      INTEGER LHPITSBRG05,LHPITSBRG06,LHPITSBRG07
      INTEGER LHPOTRERO01

C      print *, STRING7(1),CONTRCS(0,2)
C     do 10 i = 1, 10
C        print *, contrcs(i,1),contrcs(i,2)
C10   continue
C      print *, STRING7(2),HNTRSPT(0,2)
C     do 11 i = 1, 7
C        print *, HNTRSPT(i,1),HNTRSPT(i,2)
C11   continue
C      print *, STRING7(4),MOSLAND(0,2)
C     do 13 i = 1, 5
```

```
C         print *, MOSLAND(i,1),MOSLAND(i,2)
C13    continue
C       print *, STRING7(5),OAKLAND(0,2)
C      do 14 i = 1, 6
C         print *, OAKLAND(i,1),OAKLAND(i,2)
C14    continue
C       print *, STRING7(3),PITSBRG(0,2)
C      do 12 i = 1, 7
C         print *, PITSBRG(i,1),PITSBRG(i,2)
C12    continue
C       print *, STRING7(6),POTRERO(0,2)
C       print *, POTRERO(1,1),POTRERO(1,2)

       INNFILES(1)  ='pt89in_base                '
       INNFILES(2)  ='pt89out_nwsff              '
       OUTFILES(1)  ='pt89in_policy              '
       OUTFILES(2)  ='pt89out_policy             '

C All the changed lines are output to the following file
       OPEN(22,FILE='pt89policy_changes')

       LHCONTRCS01 = 0
       LHCONTRCS02 = 0
       LHCONTRCS03 = 0
       LHCONTRCS04 = 0
       LHCONTRCS05 = 0
       LHCONTRCS06 = 0
       LHCONTRCS07 = 0
       LHCONTRCS08 = 0
       LHCONTRCS09 = 0
       LHCONTRCS10 = 0
       LHHNTRSPT01 = 0
       LHHNTRSPT02 = 0
       LHHNTRSPT03 = 0
       LHHNTRSPT04 = 0
       LHHNTRSPT05 = 0
       LHHNTRSPT06 = 0
       LHHNTRSPT07 = 0
       LHMOSLAND01 = 0
       LHMOSLAND02 = 0
       LHMOSLAND03 = 0
       LHMOSLAND04 = 0
       LHMOSLAND05 = 0
       LHOAKLAND01 = 0
       LHOAKLAND02 = 0
       LHOAKLAND03 = 0
       LHOAKLAND04 = 0
       LHOAKLAND05 = 0
       LHOAKLAND06 = 0
       LHPITSBRG01 = 0
       LHPITSBRG02 = 0
```

```
      LHPITSBRG03 = 0
      LHPITSBRG04 = 0
      LHPITSBRG05 = 0
      LHPITSBRG06 = 0
      LHPITSBRG07 = 0
      LHPOTRERO01 = 0

       DO 1000 K = 1, 13
         OLDATA(K) = 0.0
         DATA(K)   = 0.0
 1000  CONTINUE

      DO 1020 I = 1, 2
        OPEN(11,FILE=INNFILES(I))
        OPEN(21,FILE=OUTFILES(I))

        HOUR = 0

C The first line is just header that read and written
C back to the output files.
        READ(11,5000)  HEADER
        WRITE(21,5000) HEADER
        IF(I.EQ.2) WRITE(22,*) '   '
        WRITE(22,*) ' lines with differences between file:',
     2   INNFILES(I),' and ',OUTFILES(I)
        WRITE(22,5000) HEADER
 5000   FORMAT(A53)

C The next line could be either a source specification line,
C END, or a new hour header.
 1010   READ(11,5010,END=1030) LINE132
 5010   FORMAT(A132)

C If it's a new hour, it's just written out and the next line read
C If it's the END line, it's written out and the reading is
C  terminated.
C Otherwise, it's assumed to be a source specification line.
C The hour is also taken from this line.

        IF(LINE132(1:4).EQ.'HOUR') THEN
          WRITE(21,5020) LINE132
          WRITE(22,*) '         '
          WRITE(22,5015)
 5015     FORMAT(132('#'))
          WRITE(22,5020) LINE132
 5020     FORMAT(A26)
          WRITE(22,*) '         '
          BACKSPACE(11)
          READ(11,5025) HOUR
 5025     FORMAT(22X,I2)
          GOTO 1010
```

```
        ELSEIF(LINE132(1:3).EQ.'END') THEN
          WRITE(21,5040) LINE132
          WRITE(22,5040) LINE132
 5040     FORMAT(A3)
          GOTO 1030
        ELSE
          WRITE(21,5030) LINE132
 5030     FORMAT(A80)
        ENDIF

C Now the data line is read and stored as OLDATA.
        READ(11,5050)  (DATA(J),J=1,13)
 5050   FORMAT(13E10.3,2X)
        DO 1015 K = 1, 13
          OLDATA(K) = DATA(K)
 1015   CONTINUE

C If the source is a PG&E source, the NO, and NO2, col. 2,
C are zeroed out and col. 3 replaced by the data in hourly.data.
C the PG&E stations are:
C      12 = Pittsburg
C      18 = Contra Costa (Antioch)
C      24 = Hunters Point
C      26 = Potrero
C     482 = Oakland
C      13 = Moss Landing (only station in "out" file)
C NOTE!! These codes are not unique, so the two files
C        have to be tested separately, hence the IF(I...
C
C believe me, it gets worse . . ..
C now we have to check the source number against all the stack ID's
C you're right, this crazy . . .

C might as well start with PITSBRG
        IF(I.EQ.1) THEN
          IF    (LINE132(1:11).EQ.'   12     1') THEN
            DATA(2)       = 0.0
            IF(LHPITSBRG01+1.EQ.HOUR) THEN
              DATA(3)      = PITSBRG(1,HOUR)
              LHPITSBRG01 = HOUR
            ELSE
              DATA(3)      = 0.0
            ENDIF
          ELSEIF(LINE132(1:11).EQ.'   12     2') THEN
            DATA(2)       = 0.0
            IF(LHPITSBRG02+1.EQ.HOUR) THEN
              DATA(3)      = PITSBRG(2,HOUR)
              LHPITSBRG02 = HOUR
            ELSE
              DATA(3)      = 0.0
            ENDIF
```

```
      ELSEIF(LINE132(1:11).EQ.'    12      3') THEN
        DATA(2)        = 0.0
        IF(LHPITSBRG03+1.EQ.HOUR) THEN
          DATA(3)      = PITSBRG(3,HOUR)
          LHPITSBRG03 = HOUR
        ELSE
          DATA(3)      = 0.0
        ENDIF
      ELSEIF(LINE132(1:11).EQ.'    12      4') THEN
        DATA(2)        = 0.0
        IF(LHPITSBRG04+1.EQ.HOUR) THEN
          DATA(3)      = PITSBRG(4,HOUR)
          LHPITSBRG04 = HOUR
        ELSE
          DATA(3)      = 0.0
        ENDIF
      ELSEIF(LINE132(1:11).EQ.'    12      5') THEN
        DATA(2)        = 0.0
        IF(LHPITSBRG05+1.EQ.HOUR) THEN
          DATA(3)      = PITSBRG(5,HOUR)
          LHPITSBRG05 = HOUR
        ELSE
          DATA(3)      = 0.0
        ENDIF
      ELSEIF(LINE132(1:11).EQ.'    12      6') THEN
        DATA(2)        = 0.0
        IF(LHPITSBRG06+1.EQ.HOUR) THEN
          DATA(3)      = PITSBRG(6,HOUR)
          LHPITSBRG06 = HOUR
        ELSE
          DATA(3)      = 0.0
        ENDIF
      ELSEIF(LINE132(1:11).EQ.'    12      7') THEN
        DATA(2)        = 0.0
        IF(LHPITSBRG07+1.EQ.HOUR) THEN
          DATA(3)      = PITSBRG(7,HOUR)
          LHPITSBRG07 = HOUR
        ELSE
          DATA(3)      = 0.0
        ENDIF

C how about CNTRCS next?

      ELSEIF(LINE132(1:11).EQ.'    18      1') THEN
        DATA(2)        = 0.0
        IF(LHCONTRCS01+1.EQ.HOUR) THEN
          DATA(3)      = CONTRCS(1,HOUR)
          LHCONTRCS01 = HOUR
        ELSE
          DATA(3)      = 0.0
        ENDIF
```

```
ELSEIF(LINE132(1:11).EQ.'    18       2') THEN
  DATA(2)         = 0.0
  IF(LHCONTRCS02+1.EQ.HOUR) THEN
    DATA(3)       = CONTRCS(2,HOUR)
    LHCONTRCS02 = HOUR
  ELSE
    DATA(3)       = 0.0
  ENDIF
ELSEIF(LINE132(1:11).EQ.'    18       3') THEN
  DATA(2)         = 0.0
  IF(LHCONTRCS03+1.EQ.HOUR) THEN
    DATA(3)       = CONTRCS(3,HOUR)
    LHCONTRCS03 = HOUR
  ELSE
    DATA(3)       = 0.0
  ENDIF
ELSEIF(LINE132(1:11).EQ.'    18       4') THEN
  DATA(2)         = 0.0
  IF(LHCONTRCS04+1.EQ.HOUR) THEN
    DATA(3)       = CONTRCS(4,HOUR)
    LHCONTRCS04 = HOUR
  ELSE
    DATA(3)       = 0.0
  ENDIF
ELSEIF(LINE132(1:11).EQ.'    18       5') THEN
  DATA(2)         = 0.0
  IF(LHCONTRCS05+1.EQ.HOUR) THEN
    DATA(3)       = CONTRCS(5,HOUR)
    LHCONTRCS05 = HOUR
  ELSE
    DATA(3)       = 0.0
  ENDIF
ELSEIF(LINE132(1:11).EQ.'    18       6') THEN
  DATA(2)         = 0.0
  IF(LHCONTRCS06+1.EQ.HOUR) THEN
    DATA(3)       = CONTRCS(6,HOUR)
    LHCONTRCS06 = HOUR
  ELSE
    DATA(3)       = 0.0
  ENDIF
ELSEIF(LINE132(1:11).EQ.'    18       7') THEN
  DATA(2)         = 0.0
  IF(LHCONTRCS07+1.EQ.HOUR) THEN
    DATA(3)       = CONTRCS(7,HOUR)
    LHCONTRCS07 = HOUR
  ELSE
    DATA(3)       = 0.0
  ENDIF
ELSEIF(LINE132(1:11).EQ.'    18       8') THEN
  DATA(2)         = 0.0
  IF(LHCONTRCS08+1.EQ.HOUR) THEN
```

```
        DATA(3)      = CONTRCS(8,HOUR)
        LHCONTRCS08  = HOUR
      ELSE
        DATA(3)      = 0.0
      ENDIF
    ELSEIF(LINE132(1:11).EQ.'   18      9') THEN
      DATA(2)        = 0.0
      IF(LHCONTRCS09+1.EQ.HOUR) THEN
        DATA(3)      = CONTRCS(9,HOUR)
        LHCONTRCS09  = HOUR
      ELSE
        DATA(3)      = 0.0
      ENDIF
    ELSEIF(LINE132(1:11).EQ.'   18     10') THEN
      DATA(2)        = 0.0
      IF(LHCONTRCS10+1.EQ.HOUR) THEN
        DATA(3)      = CONTRCS(10,HOUR)
        LHCONTRCS10  = HOUR
      ELSE
        DATA(3)      = 0.0
      ENDIF

C in the mood for some HNTRSPT?

    ELSEIF(LINE132(1:11).EQ.'   24      1') THEN
      DATA(2)        = 0.0
      IF(LHHNTRSPT01+1.EQ.HOUR) THEN
        DATA(3)      = HNTRSPT(1,HOUR)
        LHHNTRSPT01  = HOUR
      ELSE
        DATA(3)      = 0.0
      ENDIF
    ELSEIF(LINE132(1:11).EQ.'   24      2') THEN
      DATA(2)        = 0.0
      IF(LHHNTRSPT02+1.EQ.HOUR) THEN
        DATA(3)      = HNTRSPT(2,HOUR)
        LHHNTRSPT02  = HOUR
      ELSE
        DATA(3)      = 0.0
      ENDIF
    ELSEIF(LINE132(1:11).EQ.'   24      3') THEN
      DATA(2)        = 0.0
      IF(LHHNTRSPT03+1.EQ.HOUR) THEN
        DATA(3)      = HNTRSPT(3,HOUR)
        LHHNTRSPT03  = HOUR
      ELSE
        DATA(3)      = 0.0
      ENDIF
    ELSEIF(LINE132(1:11).EQ.'   24      4') THEN
      DATA(2)        = 0.0
      IF(LHHNTRSPT04+1.EQ.HOUR) THEN
```

```
          DATA(3)      = HNTRSPT(4,HOUR)
          LHHNTRSPT04 = HOUR
        ELSE
          DATA(3)      = 0.0
        ENDIF
      ELSEIF(LINE132(1:11).EQ.'   24      5') THEN
        DATA(2)        = 0.0
        IF(LHHNTRSPT05+1.EQ.HOUR) THEN
          DATA(3)      = HNTRSPT(5,HOUR)
          LHHNTRSPT05 = HOUR
        ELSE
          DATA(3)      = 0.0
        ENDIF
      ELSEIF(LINE132(1:11).EQ.'   24      6') THEN
        DATA(2)        = 0.0
        IF(LHHNTRSPT06+1.EQ.HOUR) THEN
          DATA(3)      = HNTRSPT(6,HOUR)
          LHHNTRSPT06 = HOUR
        ELSE
          DATA(3)      = 0.0
        ENDIF
      ELSEIF(LINE132(1:11).EQ.'   24      7') THEN
        DATA(2)        = 0.0
        IF(LHHNTRSPT07+1.EQ.HOUR) THEN
          DATA(3)      = HNTRSPT(7,HOUR)
          LHHNTRSPT07 = HOUR
        ELSE
          DATA(3)      = 0.0
        ENDIF

C POTRERO, perhaps ?

      ELSEIF(LINE132(1:11).EQ.'   26      1') THEN
        DATA(2)        = 0.0
        IF(LHPOTRERO01+1.EQ.HOUR) THEN
          DATA(3)      = POTRERO(1,HOUR)
          LHPOTRERO01 = HOUR
        ELSE
          DATA(3)      = 0.0
        ENDIF

C OAKLAND . . .

      ELSEIF(LINE132(1:11).EQ.'  482      1') THEN
        DATA(2)        = 0.0
        IF(LHOAKLAND01+1.EQ.HOUR) THEN
          DATA(3)      = OAKLAND(1,HOUR)
          LHOAKLAND01 = HOUR
        ELSE
          DATA(3)      = 0.0
        ENDIF
```

```
          ELSEIF(LINE132(1:11).EQ.'   482      2') THEN
            DATA(2)        = 0.0
            IF(LHOAKLAND02+1.EQ.HOUR) THEN
              DATA(3)      = OAKLAND(2,HOUR)
              LHOAKLAND02 = HOUR
            ELSE
              DATA(3)      = 0.0
            ENDIF
          ELSEIF(LINE132(1:11).EQ.'   482      3') THEN
            DATA(2)        = 0.0
            IF(LHOAKLAND03+1.EQ.HOUR) THEN
              DATA(3)      = OAKLAND(3,HOUR)
              LHOAKLAND03 = HOUR
            ELSE
              DATA(3)      = 0.0
            ENDIF
          ELSEIF(LINE132(1:11).EQ.'   482      4') THEN
            DATA(2)        = 0.0
            IF(LHOAKLAND04+1.EQ.HOUR) THEN
              DATA(3)      = OAKLAND(4,HOUR)
              LHOAKLAND04 = HOUR
            ELSE
              DATA(3)      = 0.0
            ENDIF
          ELSEIF(LINE132(1:11).EQ.'   482      5') THEN
            DATA(2)        = 0.0
            IF(LHOAKLAND05+1.EQ.HOUR) THEN
              DATA(3)      = OAKLAND(5,HOUR)
              LHOAKLAND05 = HOUR
            ELSE
              DATA(3)      = 0.0
            ENDIF
          ELSEIF(LINE132(1:11).EQ.'   482      6') THEN
            DATA(2)        = 0.0
            IF(LHOAKLAND06+1.EQ.HOUR) THEN
              DATA(3)      = OAKLAND(6,HOUR)
              LHOAKLAND06 = HOUR
            ELSE
              DATA(3)      = 0.0
            ENDIF
          ENDIF
C and in round 2, there's still MOSLAND to worry about
C MOSLAND still has to be fixed, need 10 stacks have 5
C
C       ELSEIF(I.EQ.2) THEN
C         IF  (LINE132(1:11).EQ.'   13      1') THEN
C           DATA(2)        = 0.0
C           IF(LHMOSLAND01+1.EQ.HOUR) THEN
C             DATA(3)      = MOSLAND(1,HOUR)
C             LHMOSLAND01 = HOUR
C           ELSE
```

```
C               DATA(3)      = 0.0
C             ENDIF
C           ELSEIF(LINE132(1:11).EQ.'    13      2') THEN
C             DATA(2)        = 0.0
C             IF(LHMOSLAND02+1.EQ.HOUR) THEN
C               DATA(3)      = MOSLAND(2,HOUR)
C               LHMOSLAND02 = HOUR
C             ELSE
C               DATA(3)      = 0.0
C             ENDIF
C           ELSEIF(LINE132(1:11).EQ.'    13      3') THEN
C             DATA(2)        = 0.0
C             IF(LHMOSLAND03+1.EQ.HOUR) THEN
C               DATA(3)      = MOSLAND(3,HOUR)
C               LHMOSLAND03 = HOUR
C             ELSE
C               DATA(3)      = 0.0
C             ENDIF
C           ELSEIF(LINE132(1:11).EQ.'    13      4') THEN
C             DATA(2)        = 0.0
C             IF(LHMOSLAND04+1.EQ.HOUR) THEN
C               DATA(3)      = MOSLAND(4,HOUR)
C               LHMOSLAND04 = HOUR
C             ELSE
C               DATA(3)      = 0.0
C             ENDIF
C           ELSEIF(LINE132(1:11).EQ.'    13      5') THEN
C             DATA(2)        = 0.0
C             IF(LHMOSLAND05+1.EQ.HOUR) THEN
C               DATA(3)      = MOSLAND(5,HOUR)
C               LHMOSLAND05 = HOUR
C             ELSE
C               DATA(3)      = 0.0
C             ENDIF
C           ENDIF
          ENDIF
C I've had it this . . . .

C This is the dramatic line, finally the data is ready for writing
          WRITE(21,5050)   (DATA(J),J=1,13)
C that was it, pretty wild, eh?

C now confirm the fixup by writing to the pt89max_changes_PGE file

            IF(INT(OLDATA(3)*100.0).NE.INT(DATA(3)*100.0))THEN
              WRITE(22,5030) LINE132
              WRITE(22,5050) (OLDATA(J),J=1,13)
              WRITE(22,5050) (DATA(J),J=1,13)
              WRITE(22,*) '=+=+=+=+'
            ENDIF
```

```
C Now, back to read the next line of the file.
        GOTO 1010

 1030  CONTINUE

C If the END has been found, the files are closed.
       CLOSE(11)
       CLOSE(21)

 1020  CONTINUE

       CLOSE(22)

       RETURN
       END
C===================================================================
```

Appendix I: EEUCM Inputs & Outputs

This appendix contains examples of the input and output to EE - UCM. As mentioned in the main text and in appendix F, EEUCM is a strictly research grade model, and considerable enhancements were necessary before the work of this study could be undertaken. These enhancements are varied. First, the unit commitment logic and dis - patch logic were changed to account for the NO_x tax as well as fuel costs. Second, the Monte Carlo capability described in appendix F was added. Third, the input and output files were greatly expanded to permit simulation of time periods of variable length, to input the tax and load data, and to keep track of random number seeds.

The appendix contains some samples of changes of the third type. Figure I.1 shows the basic data input to EEUCM. The data are unfor - matted and should exactly agree with that shown in appendix C. Table I.2 shows the simplest output file from EEUCM. Each row shows the total data from a Monte Carlo draw and subsequent simulation. Table I.3 shows the expected values for the major unit results. Table I.4 shows the first 24 hours of expected hourly results for the system, and table I.5 shows the results from the first iteration of this simulation. Tables I.6 and I.7 show the most difficult output files to set up. EEUCM had no unit by unit results initially. These output files were entirely designed and programmed for this study. Figure I.1 shows the major output subroutine to EEUCM, which was completely rewritten.

Table I.1: EEUCM Input File

```
55,1            NO OF UNITS, NO.OF POLLUTANTS (=1 if NOx only)
CONTRCS1  01     NAME
3,0.0           UNIT-STATUS(1:M-R WITH FIXED GEN,2=M-R WITH FREE GEN,3=FREE UNIT
1,7,4,-100       MIN UPTIME,COLDSTART-TIME, MIN-DOWNTIME,TIME-STATUS AT T=0-
10.0,116.0,2.25          PMIN,PMAX,FUELPRICE ($/GJ)
1.254184e+2,1.109464e+1,9.618715e-3   k0,k1,k2 : HEAT-RATE coeffs.
1,303.803,1     m0,m1, stop cost ; hot start cost, cost time gradient,stop cost
1.066105e+1,1.740192e-1,3.130855e-3         10, 11, 12  : NOx curve coeffs.
1,4.196,1.0     n0,n1, stop emission : coeffs. for start up emissions
1.0,1.0              COEFFICIENTS FOR SCALING OF COSTS (MUST BE SET TO 1)
0.21
CONTRCS2  02     NAME
3,0.0           UNIT-STATUS(1:M-R WITH FIXED GEN,2=M-R WITH FREE GEN,3=FREE UNIT
1,7,4,-100       MIN UPTIME,COLDSTART-TIME, MIN-DOWNTIME,TIME-STATUS AT T=0-
10.0,116.0,2.25          PMIN,PMAX,FUELPRICE ($/GJ)
1.27282e+2,1.151407e+1,6.381152e-3   k0,k1,k2 : HEAT-RATE coeffs.
1,303.803,1     m0,m1, stop cost ; hot start cost, cost time gradient,stop cost
1.055426e+1,2.019326e-1,2.905147e-3         10, 11, 12  : NOx curve coeffs.
1,4.245,1.0     n0,n1, stop emission : coeffs. for start up emissions
1.0,1.0              COEFFICIENTS FOR SCALING OF COSTS (MUST BE SET TO 1)
0.169
CONTRCS3  03     NAME
3,0.0           UNIT-STATUS(1:M-R WITH FIXED GEN,2=M-R WITH FREE GEN,3=FREE UNIT
1,7,4,-100       MIN UPTIME,COLDSTART-TIME, MIN-DOWNTIME,TIME-STATUS AT T=0-
10.0,116.0,2.25          PMIN,PMAX,FUELPRICE ($/GJ)
1.256465e+2,1.05874e+1,1.477305e-2   k0,k1,k2 : HEAT-RATE coeffs.
1,303.803,1     m0,m1, stop cost ; hot start cost, cost time gradient,stop cost
1.071995e+1,1.553799e-1,3.303725e-3         10, 11, 12  : NOx curve coeffs.
1,4.159,1.0     n0,n1, stop emission : coeffs. for start up emissions
1.0,1.0              COEFFICIENTS FOR SCALING OF COSTS (MUST BE SET TO 1)
0.222
CONTRCS4  04     NAME
3,0.0           UNIT-STATUS(1:M-R WITH FIXED GEN,2=M-R WITH FREE GEN,3=FREE UNIT
1,7,4,-100       MIN UPTIME,COLDSTART-TIME, MIN-DOWNTIME,TIME-STATUS AT T=0-
7.0,117.0,2.25          PMIN,PMAX,FUELPRICE ($/GJ)
9.783147e+1,1.024742e+1,9.445342e-3   k0,k1,k2 : HEAT-RATE coeffs.
1,214.693,1     m0,m1, stop cost ; hot start cost, cost time gradient,stop cost
8.281071,2.079196e-1,3.322621e-3         10, 11, 12  : NOx curve coeffs.
1,3.529,1.0     n0,n1, stop emission : coeffs. for start up emissions
1.0,1.0              COEFFICIENTS FOR SCALING OF COSTS (MUST BE SET TO 1)
0.273
CONTRCS5  05     NAME
3,0.0           UNIT-STATUS(1:M-R WITH FIXED GEN,2=M-R WITH FREE GEN,3=FREE UNIT
1,7,4,-100       MIN UPTIME,COLDSTART-TIME, MIN-DOWNTIME,TIME-STATUS AT T=0-
7.0,115.0,2.25          PMIN,PMAX,FUELPRICE ($/GJ)
1.049282e+2,1.015332e+1,8.344718e-3   k0,k1,k2 : HEAT-RATE coeffs.
1,214.693,1     m0,m1, stop cost ; hot start cost, cost time gradient,stop cost
8.457162,2.100938e-1,3.237392e-3         10, 11, 12  : NOx curve coeffs.
1,3.591,1.0     n0,n1, stop emission : coeffs. for start up emissions
1.0,1.0              COEFFICIENTS FOR SCALING OF COSTS (MUST BE SET TO 1)
0.237
CONTRCS6  06     NAME
3,0.0           UNIT-STATUS(1:M-R WITH FIXED GEN,2=M-R WITH FREE GEN,3=FREE UNIT
1,8,5,-100       MIN UPTIME,COLDSTART-TIME, MIN-DOWNTIME,TIME-STATUS AT T=0-
```

```
46.0,340.0,2.25          PMIN,PMAX,FUELPRICE ($/GJ)
2.372579e+2,9.537133,1.426415e-3   k0,k1,k2 : HEAT-RATE coeffs.
1,513.917,1     m0,m1, stop cost ; hot start cost, cost time gradient,stop cost
2.991612e+1,2.077203e-1,1.528455e-3         10, 11, 12  : NOx curve coeffs.
1,14.093,1.0     n0,n1, stop emission : coeffs. for start up emissions
1.0,1.0             COEFFICIENTS FOR SCALING OF COSTS (MUST BE SET TO 1)
0.066
CONTRCS7  07     NAME
3,0.0          UNIT-STATUS(1:M-R WITH FIXED GEN,2=M-R WITH FREE GEN,3=FREE UNIT
1,8,5,-100       MIN UPTIME,COLDSTART-TIME, MIN-DOWNTIME,TIME-STATUS AT T=0-
46.0,340.0,2.25          PMIN,PMAX,FUELPRICE ($/GJ)
1.808711e+2,1.011017e+1,3.843175e-4   k0,k1,k2 : HEAT-RATE coeffs.
1,513.917,1     m0,m1, stop cost ; hot start cost, cost time gradient,stop cost
2.568821e+1,2.491279e-1,1.458537e-3         10, 11, 12  : NOx curve coeffs.
1,13.277,1.0     n0,n1, stop emission : coeffs. for start up emissions
1.0,1.0             COEFFICIENTS FOR SCALING OF COSTS (MUST BE SET TO 1)
0.058
HNTRSPT1  08     NAME
2,0.0          UNIT-STATUS(1:M-R WITH FIXED GEN,2=M-R WITH FREE GEN,3=FREE UNIT
0,0,0,-100       MIN UPTIME,COLDSTART-TIME, MIN-DOWNTIME,TIME-STATUS AT T=0-
0.0,56.0,3.6          PMIN,PMAX,FUELPRICE ($/GJ)
0.0,1.37361e+1,0.0   k0,k1,k2 : HEAT-RATE coeffs.
1,0.0,1      m0,m1, stop cost ; hot start cost, cost time gradient,stop cost
0.0,1.78,0.0         10, 11, 12  : NOx curve coeffs.
1,0.0,1.0     n0,n1, stop emission : coeffs. for start up emissions
1.0,1.0             COEFFICIENTS FOR SCALING OF COSTS (MUST BE SET TO 1)
0.097
HNTRSPT2  09     NAME
3,0.0          UNIT-STATUS(1:M-R WITH FIXED GEN,2=M-R WITH FREE GEN,3=FREE UNIT
1,7,4,-100       MIN UPTIME,COLDSTART-TIME, MIN-DOWNTIME,TIME-STATUS AT T=0-
10.0,107.0,2.25          PMIN,PMAX,FUELPRICE ($/GJ)
1.543959e+2,1.043144e+1,2.182914e-2   k0,k1,k2 : HEAT-RATE coeffs.
1,303.803,1     m0,m1, stop cost ; hot start cost, cost time gradient,stop cost
2.782601e+1,-4.39941e-1,2.270169e-2         10, 11, 12  : NOx curve coeffs.
1,8.48,1.0     n0,n1, stop emission : coeffs. for start up emissions
1.0,1.0             COEFFICIENTS FOR SCALING OF COSTS (MUST BE SET TO 1)
0.115
HNTRSPT3  10     NAME
3,0.0          UNIT-STATUS(1:M-R WITH FIXED GEN,2=M-R WITH FREE GEN,3=FREE UNIT
1,7,4,-100       MIN UPTIME,COLDSTART-TIME, MIN-DOWNTIME,TIME-STATUS AT T=0-
10.0,107.0,2.25          PMIN,PMAX,FUELPRICE ($/GJ)
1.44282e+2,1.192097e+1,9.406338e-3   k0,k1,k2 : HEAT-RATE coeffs.
1,303.803,1     m0,m1, stop cost ; hot start cost, cost time gradient,stop cost
2.627595e+1,-2.665119e-1,2.126635e-2       10, 11, 12  : NOx curve coeffs.
1,8.493,1.0     n0,n1, stop emission : coeffs. for start up emissions
1.0,1.0             COEFFICIENTS FOR SCALING OF COSTS (MUST BE SET TO 1)
0.125
HNTRSPT4  11     NAME
3,0.0          UNIT-STATUS(1:M-R WITH FIXED GEN,2=M-R WITH FREE GEN,3=FREE UNIT
1,6,4,-100       MIN UPTIME,COLDSTART-TIME, MIN-DOWNTIME,TIME-STATUS AT T=0-
31.0,163.0,2.25          PMIN,PMAX,FUELPRICE ($/GJ)
9.815517e+1,1.079022e+1,5.243649e-4   k0,k1,k2 : HEAT-RATE coeffs.
1,330.62,1     m0,m1, stop cost ; hot start cost, cost time gradient,stop cost
8.056942,2.882964e-1,1.563827e-3       10, 11, 12  : NOx curve coeffs.
1,6.104,1.0     n0,n1, stop emission : coeffs. for start up emissions
1.0,1.0             COEFFICIENTS FOR SCALING OF COSTS (MUST BE SET TO 1)
```

```
0.105000
MOSLNDG1  12    NAME
3,0.0          UNIT-STATUS(1:M-R WITH FIXED GEN,2=M-R WITH FREE GEN,3=FREE UNIT
1,7,4,-100       MIN UPTIME,COLDSTART-TIME, MIN-DOWNTIME,TIME-STATUS AT T=0-
10.0,116.0,2.25          PMIN,PMAX,FUELPRICE ($/GJ)
1.990331e+2,7.914292,5.024468e-2  k0,k1,k2 : HEAT-RATE coeffs.
1,303.803,1     m0,m1, stop cost ; hot start cost, cost time gradient,stop cost
1.327834e+1,9.837593e-2,6.399866e-3       10, 11, 12  : NOx curve coeffs.
1,4.918,1.0     n0,n1, stop emission : coeffs. for start up emissions
1.0,1.0              COEFFICIENTS FOR SCALING OF COSTS (MUST BE SET TO 1)
0.606000
MOSLNDG2  13    NAME
3,0.0          UNIT-STATUS(1:M-R WITH FIXED GEN,2=M-R WITH FREE GEN,3=FREE UNIT
1,7,4,-100       MIN UPTIME,COLDSTART-TIME, MIN-DOWNTIME,TIME-STATUS AT T=0-
10.0,116.0,2.25          PMIN,PMAX,FUELPRICE ($/GJ)
2.338511e+2,9.885289,2.666548e-2  k0,k1,k2 : HEAT-RATE coeffs.
1,303.803,1     m0,m1, stop cost ; hot start cost, cost time gradient,stop cost
1.43154e+1,2.493764e-1,4.704734e-3       10, 11, 12  : NOx curve coeffs.
1,5.702,1.0     n0,n1, stop emission : coeffs. for start up emissions
1.0,1.0              COEFFICIENTS FOR SCALING OF COSTS (MUST BE SET TO 1)
0.442000
MOSLNDG3  14    NAME
3,0.0          UNIT-STATUS(1:M-R WITH FIXED GEN,2=M-R WITH FREE GEN,3=FREE UNIT
1,7,4,-100       MIN UPTIME,COLDSTART-TIME, MIN-DOWNTIME,TIME-STATUS AT T=0-
10.0,117.0,2.25          PMIN,PMAX,FUELPRICE ($/GJ)
1.235108e+2,2.219693e+1,1.803257e-2  k0,k1,k2 : HEAT-RATE coeffs.
1,303.803,1     m0,m1, stop cost ; hot start cost, cost time gradient,stop cost
1.002837e+1,3.180006e-1,4.603799e-3       10, 11, 12  : NOx curve coeffs.
1,4.511,1.0     n0,n1, stop emission : coeffs. for start up emissions
1.0,1.0              COEFFICIENTS FOR SCALING OF COSTS (MUST BE SET TO 1)
0.382000
MOSLNDG4  15    NAME
3,0.0          UNIT-STATUS(1:M-R WITH FIXED GEN,2=M-R WITH FREE GEN,3=FREE UNIT
1,7,4,-100       MIN UPTIME,COLDSTART-TIME, MIN-DOWNTIME,TIME-STATUS AT T=0-
7.0,117.0,2.25          PMIN,PMAX,FUELPRICE ($/GJ)
1.437815e+2,8.856534,1.360894e-2  k0,k1,k2 : HEAT-RATE coeffs.
1,214.693,1     m0,m1, stop cost ; hot start cost, cost time gradient,stop cost
8.299016,-1.268277e-1,9.686688e-3       10, 11, 12  : NOx curve coeffs.
1,4.328,1.0     n0,n1, stop emission : coeffs. for start up emissions
1.0,1.0              COEFFICIENTS FOR SCALING OF COSTS (MUST BE SET TO 1)
0.197000
MOSLNDG5  16    NAME
3,0.0          UNIT-STATUS(1:M-R WITH FIXED GEN,2=M-R WITH FREE GEN,3=FREE UNIT
1,7,4,-100       MIN UPTIME,COLDSTART-TIME, MIN-DOWNTIME,TIME-STATUS AT T=0-
7.0,117.0,2.25          PMIN,PMAX,FUELPRICE ($/GJ)
1.296082e+2,9.589114,1.17439e-2  k0,k1,k2 : HEAT-RATE coeffs.
1,214.693,1     m0,m1, stop cost ; hot start cost, cost time gradient,stop cost
8.299016,-1.268277e-1,9.686688e-3  10, 11, 12  : NOx curve coeffs.
1,4.109,1.0     n0,n1, stop emission : coeffs. for start up emissions
1.0,1.0              COEFFICIENTS FOR SCALING OF COSTS (MUST BE SET TO 1)
0.194000
MOSLNDG6  17    NAME
3,0.0          UNIT-STATUS(1:M-R WITH FIXED GEN,2=M-R WITH FREE GEN,3=FREE UNIT
1,18,10,-100       MIN UPTIME,COLDSTART-TIME, MIN-DOWNTIME,TIME-STATUS AT T=0-
50.0,739.0,2.25          PMIN,PMAX,FUELPRICE ($/GJ)
6.491714e+2,8.008987,1.534523e-3  k0,k1,k2 : HEAT-RATE coeffs.
```

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1,3386.568,1     m0,m1, stop cost ; hot start cost, cost time gradient,stop cost
6.142026e+1,-1.01e-1,1.006239e-3       10, 11, 12  : NOx curve coeffs.
1,13.673,1.0     n0,n1, stop emission : coeffs. for start up emissions
1.0,1.0              COEFFICIENTS FOR SCALING OF COSTS (MUST BE SET TO 1)
0.186000
MOSLNDG7  18    NAME
3,0.0           UNIT-STATUS(1:M-R WITH FIXED GEN,2=M-R WITH FREE GEN,3=FREE UNIT
1,18,10,-100        MIN UPTIME,COLDSTART-TIME, MIN-DOWNTIME,TIME-STATUS AT T=0-
50.0,739.0,2.25          PMIN,PMAX,FUELPRICE ($/GJ)
6.491714e+2,8.008987,1.534523e-3  k0,k1,k2 : HEAT-RATE coeffs.
1,3386.568,1     m0,m1, stop cost ; hot start cost, cost time gradient,stop cost
1.642026e+1,-5.97902e-3,1.080059e-3       10, 11, 12  : NOx curve coeffs.
1,17.21,1.0     n0,n1, stop emission : coeffs. for start up emissions
1.0,1.0              COEFFICIENTS FOR SCALING OF COSTS (MUST BE SET TO 1)
0.175000
OAKLAND1  19    NAME
2,0.0           UNIT-STATUS(1:M-R WITH FIXED GEN,2=M-R WITH FREE GEN,3=FREE UNIT
0,0,0,-100        MIN UPTIME,COLDSTART-TIME, MIN-DOWNTIME,TIME-STATUS AT T=0-
0.0,64.0,3.6         PMIN,PMAX,FUELPRICE ($/GJ)
0.0,1.3715e+1,0.0  k0,k1,k2 : HEAT-RATE coeffs.
1,0.0,1         m0,m1, stop cost ; hot start cost, cost time gradient,stop cost
0.0,1.78,0.0         10, 11, 12  : NOx curve coeffs.
1,0.0,1.0     n0,n1, stop emission : coeffs. for start up emissions
1.0,1.0              COEFFICIENTS FOR SCALING OF COSTS (MUST BE SET TO 1)
0.138000
OAKLAND2  20    NAME
2,0.0           UNIT-STATUS(1:M-R WITH FIXED GEN,2=M-R WITH FREE GEN,3=FREE UNIT
0,0,0,-100        MIN UPTIME,COLDSTART-TIME, MIN-DOWNTIME,TIME-STATUS AT T=0-
0.0,64.0,3.6         PMIN,PMAX,FUELPRICE ($/GJ)
0.0,1.3715e+1,0.0  k0,k1,k2 : HEAT-RATE coeffs.
1,0.0,1         m0,m1, stop cost ; hot start cost, cost time gradient,stop cost
0.0,1.78,0.0         10, 11, 12  : NOx curve coeffs.
1,0.0,1.0     n0,n1, stop emission : coeffs. for start up emissions
1.0,1.0              COEFFICIENTS FOR SCALING OF COSTS (MUST BE SET TO 1)
0.124000
OAKLAND3  21    NAME
2,0.0           UNIT-STATUS(1:M-R WITH FIXED GEN,2=M-R WITH FREE GEN,3=FREE UNIT
0,0,0,-100        MIN UPTIME,COLDSTART-TIME, MIN-DOWNTIME,TIME-STATUS AT T=0-
0.0,64.0,3.6         PMIN,PMAX,FUELPRICE ($/GJ)
0.0,1.3715e+1,0.0  k0,k1,k2 : HEAT-RATE coeffs.
1,0.0,1         m0,m1, stop cost ; hot start cost, cost time gradient,stop cost
0.0,1.78,0.0         10, 11, 12  : NOx curve coeffs.
1,0.0,1.0     n0,n1, stop emission : coeffs. for start up emissions
1.0,1.0              COEFFICIENTS FOR SCALING OF COSTS (MUST BE SET TO 1)
0.123000
PITSBRG1  22    NAME
3,0.0           UNIT-STATUS(1:M-R WITH FIXED GEN,2=M-R WITH FREE GEN,3=FREE UNIT
1,16,4,-100        MIN UPTIME,COLDSTART-TIME, MIN-DOWNTIME,TIME-STATUS AT T=0-
31.0,163.0,2.25          PMIN,PMAX,FUELPRICE ($/GJ)
1.857058e+2,8.924874,8.412467e-3  k0,k1,k2 : HEAT-RATE coeffs.
1,123.982,1     m0,m1, stop cost ; hot start cost, cost time gradient,stop cost
4.336284e+1,-1.648692e-1,5.996064e-3       10, 11, 12  : NOx curve coeffs.
1,14.525,1.0     n0,n1, stop emission : coeffs. for start up emissions
1.0,1.0              COEFFICIENTS FOR SCALING OF COSTS (MUST BE SET TO 1)
0.087000
PITSBRG2  23    NAME
```

```
3,0.0            UNIT-STATUS(1:M-R WITH FIXED GEN,2=M-R WITH FREE GEN,3=FREE UNIT
1,6,4,-100        MIN UPTIME,COLDSTART-TIME, MIN-DOWNTIME,TIME-STATUS AT T=0-
31.0,163.0,2.25          PMIN,PMAX,FUELPRICE ($/GJ)
2.433852e+2,7.666023,1.558105e-2  k0,k1,k2 : HEAT-RATE coeffs.
1,330.620,1     m0,m1, stop cost ; hot start cost, cost time gradient,stop cost
4.757349e+1,-2.79761e-1,6.741227e-3       10, 11, 12  : NOx curve coeffs.
1,14.975,1.0     n0,n1, stop emission : coeffs. for start up emissions
1.0,1.0              COEFFICIENTS FOR SCALING OF COSTS (MUST BE SET TO 1)
0.107000
PITSBRG3  24     NAME
3,0.0            UNIT-STATUS(1:M-R WITH FIXED GEN,2=M-R WITH FREE GEN,3=FREE UNIT
1,16,4,-100        MIN UPTIME,COLDSTART-TIME, MIN-DOWNTIME,TIME-STATUS AT T=0-
31.0,163.0,2.25          PMIN,PMAX,FUELPRICE ($/GJ)
1.801279e+2,8.894634,9.371497e-3  k0,k1,k2 : HEAT-RATE coeffs.
1,123.982,1     m0,m1, stop cost ; hot start cost, cost time gradient,stop cost
4.266162e+1,-1.674042e-1,6.099259e-3       10, 11, 12  : NOx curve coeffs.
1,14.3,1.0     n0,n1, stop emission : coeffs. for start up emissions
1.0,1.0              COEFFICIENTS FOR SCALING OF COSTS (MUST BE SET TO 1)
0.086000
PITSBRG4  25     NAME
3,0.0            UNIT-STATUS(1:M-R WITH FIXED GEN,2=M-R WITH FREE GEN,3=FREE UNIT
1,6,4,-100        MIN UPTIME,COLDSTART-TIME, MIN-DOWNTIME,TIME-STATUS AT T=0-
31.0,163.0,2.25          PMIN,PMAX,FUELPRICE ($/GJ)
1.774657e+2,8.8926976,8.348328e-3  k0,k1,k2 : HEAT-RATE coeffs.
1,330.620,1     m0,m1, stop cost ; hot start cost, cost time gradient,stop cost
4.22128e+1,-1.516033e-1,5.9196e-3       10, 11, 12  : NOx curve coeffs.
1,14.257,1.0     n0,n1, stop emission : coeffs. for start up emissions
1.0,1.0              COEFFICIENTS FOR SCALING OF COSTS (MUST BE SET TO 1)
0.132000
PITSBRG5  26     NAME
3,0.0            UNIT-STATUS(1:M-R WITH FIXED GEN,2=M-R WITH FREE GEN,3=FREE UNIT
1,12,5,-100        MIN UPTIME,COLDSTART-TIME, MIN-DOWNTIME,TIME-STATUS AT T=0-
46.0,325.0,2.25          PMIN,PMAX,FUELPRICE ($/GJ)
3.023789e+2,8.634839,3.6930293e-3  k0,k1,k2 : HEAT-RATE coeffs.
1,342.611,1     m0,m1, stop cost ; hot start cost, cost time gradient,stop cost
1.612959e+1,1.672147e-1,1.722545e-3       10, 11, 12  : NOx curve coeffs.
1,9.064,1.0     n0,n1, stop emission : coeffs. for start up emissions
1.0,1.0              COEFFICIENTS FOR SCALING OF COSTS (MUST BE SET TO 1)
0.135000
PITSBRG6  27     NAME
3,0.0            UNIT-STATUS(1:M-R WITH FIXED GEN,2=M-R WITH FREE GEN,3=FREE UNIT
1,12,5,-100        MIN UPTIME,COLDSTART-TIME, MIN-DOWNTIME,TIME-STATUS AT T=0-
46.0,325.0,2.25          PMIN,PMAX,FUELPRICE ($/GJ)
2.471965e+2,8.685576,1.358149e-3  k0,k1,k2 : HEAT-RATE coeffs.
1,411.134,1     m0,m1, stop cost ; hot start cost, cost time gradient,stop cost
1.085135e+1,3.8365326e-1,2.996383e-4       10, 11, 12  : NOx curve coeffs.
1,9.614,1.0     n0,n1, stop emission : coeffs. for start up emissions
1.0,1.0              COEFFICIENTS FOR SCALING OF COSTS (MUST BE SET TO 1)
0.255000
PITSBRG7  28     NAME
3,0.0            UNIT-STATUS(1:M-R WITH FIXED GEN,2=M-R WITH FREE GEN,3=FREE UNIT
1,18,10,-100        MIN UPTIME,COLDSTART-TIME, MIN-DOWNTIME,TIME-STATUS AT T=0-
120.0,720.0,2.25          PMIN,PMAX,FUELPRICE ($/GJ)
9.703435e+2,7.649096,3.004041e-3  k0,k1,k2 : HEAT-RATE coeffs.
1,3386.568,1     m0,m1, stop cost ; hot start cost, cost time gradient,stop cost
2.823125e+1,1.584831e-1,2.556222e-4       10, 11, 12  : NOx curve coeffs.
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1,16.807,1.0      n0,n1, stop emission : coeffs. for start up emissions
1.0,1.0              COEFFICIENTS FOR SCALING OF COSTS (MUST BE SET TO 1)
0.206000
PORTBLE1  29      NAME
2,0.0            UNIT-STATUS(1:M-R WITH FIXED GEN,2=M-R WITH FREE GEN,3=FREE UNIT
0,0,0,-100         MIN UPTIME,COLDSTART-TIME, MIN-DOWNTIME,TIME-STATUS AT T=0-
0.0,15.0,3.6          PMIN,PMAX,FUELPRICE ($/GJ)
0.0,1.52975e+1,0.0   k0,k1,k2 : HEAT-RATE coeffs.
1,0.0,1          m0,m1, stop cost ; hot start cost, cost time gradient,stop cost
0.0,4.213,0.0          10, 11, 12  : NOx curve coeffs.
1,0.0,1.0      n0,n1, stop emission : coeffs. for start up emissions
1.0,1.0              COEFFICIENTS FOR SCALING OF COSTS (MUST BE SET TO 1)
0.257000
PORTBLE2  30      NAME
2,0.0            UNIT-STATUS(1:M-R WITH FIXED GEN,2=M-R WITH FREE GEN,3=FREE UNIT
0,0,0,-100         MIN UPTIME,COLDSTART-TIME, MIN-DOWNTIME,TIME-STATUS AT T=0-
0.0,15.0,3.6          PMIN,PMAX,FUELPRICE ($/GJ)
0.0,1.52975e+1,0.0   k0,k1,k2 : HEAT-RATE coeffs.
1,0.0,1          m0,m1, stop cost ; hot start cost, cost time gradient,stop cost
0.0,4.213,0.0          10, 11, 12  : NOx curve coeffs.
1,0.0,1.0      n0,n1, stop emission : coeffs. for start up emissions
1.0,1.0              COEFFICIENTS FOR SCALING OF COSTS (MUST BE SET TO 1)
0.034000
PORTBLE3  31      NAME
2,0.0            UNIT-STATUS(1:M-R WITH FIXED GEN,2=M-R WITH FREE GEN,3=FREE UNIT
0,0,0,-100         MIN UPTIME,COLDSTART-TIME, MIN-DOWNTIME,TIME-STATUS AT T=0-
0.0,15.0,3.6          PMIN,PMAX,FUELPRICE ($/GJ)
0.0,1.52975e+1,0.0   k0,k1,k2 : HEAT-RATE coeffs.
1,0.0,1          m0,m1, stop cost ; hot start cost, cost time gradient,stop cost
0.0,4.213,0.0          10, 11, 12  : NOx curve coeffs.
1,0.0,1.0      n0,n1, stop emission : coeffs. for start up emissions
1.0,1.0              COEFFICIENTS FOR SCALING OF COSTS (MUST BE SET TO 1)
0.090000
POTRERO3  32      NAME
3,0.0            UNIT-STATUS(1:M-R WITH FIXED GEN,2=M-R WITH FREE GEN,3=FREE UNIT
1,6,3,-100         MIN UPTIME,COLDSTART-TIME, MIN-DOWNTIME,TIME-STATUS AT T=0-
47.0,207.0,2.25          PMIN,PMAX,FUELPRICE ($/GJ)
1.567565e+2,9.045085,4.329305e-3   k0,k1,k2 : HEAT-RATE coeffs.
1,708.661,1      m0,m1, stop cost ; hot start cost, cost time gradient,stop cost
-2.163522e+1,1.115824,-1.295695e-3       10, 11, 12  : NOx curve coeffs.
1,9.222,1.0      n0,n1, stop emission : coeffs. for start up emissions
1.0,1.0              COEFFICIENTS FOR SCALING OF COSTS (MUST BE SET TO 1)
0.047000
POTRERO4  33      NAME
2,0.0            UNIT-STATUS(1:M-R WITH FIXED GEN,2=M-R WITH FREE GEN,3=FREE UNIT
0,0,0,-100         MIN UPTIME,COLDSTART-TIME, MIN-DOWNTIME,TIME-STATUS AT T=0-
0.0,56.0,3.6          PMIN,PMAX,FUELPRICE ($/GJ)
0.0,1.34829e+1,0.0   k0,k1,k2 : HEAT-RATE coeffs.
1,0.0,1          m0,m1, stop cost ; hot start cost, cost time gradient,stop cost
0.0,1.78,0.0          10, 11, 12  : NOx curve coeffs.
1,0.0,1.0      n0,n1, stop emission : coeffs. for start up emissions
1.0,1.0              COEFFICIENTS FOR SCALING OF COSTS (MUST BE SET TO 1)
0.044000
POTRERO5  34      NAME
2,0.0            UNIT-STATUS(1:M-R WITH FIXED GEN,2=M-R WITH FREE GEN,3=FREE UNIT
0,0,0,-100         MIN UPTIME,COLDSTART-TIME, MIN-DOWNTIME,TIME-STATUS AT T=0-
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0.0,56.0,3.6          PMIN,PMAX,FUELPRICE ($/GJ)
0.0,1.34829e+1,0.0    k0,k1,k2 : HEAT-RATE coeffs.
1,0.0,1          m0,m1, stop cost ; hot start cost, cost time gradient,stop cost
0.0,1.78,0.0          l0, l1, l2  : NOx curve coeffs.
1,0.0,1.0       n0,n1, stop emission : coeffs. for start up emissions
1.0,1.0               COEFFICIENTS FOR SCALING OF COSTS (MUST BE SET TO 1)
0.032000
POTRERO6  35       NAME
2,0.0            UNIT-STATUS(1:M-R WITH FIXED GEN,2=M-R WITH FREE GEN,3=FREE UNIT
0,0,0,-100         MIN UPTIME,COLDSTART-TIME, MIN-DOWNTIME,TIME-STATUS AT T=0-
0.0,56.0,3.6          PMIN,PMAX,FUELPRICE ($/GJ)
0.0,1.34829e+1,0.0    k0,k1,k2 : HEAT-RATE coeffs.
1,0.0,1          m0,m1, stop cost ; hot start cost, cost time gradient,stop cost
0.0,1.78,0.0          l0, l1, l2  : NOx curve coeffs.
1,0.0,1.0       n0,n1, stop emission : coeffs. for start up emissions
1.0,1.0               COEFFICIENTS FOR SCALING OF COSTS (MUST BE SET TO 1)
0.121000
GILROYE1  36       NAME
2,0.0              STATUS(1:M-R WITH FIXED GEN,2=M-R WITH FREE GEN,3=FREE UNIT
1,1,1,-100         MIN UPTIME,COLDSTART-TIME, MIN-DOWNTIME,TIME-STATUS AT T=0-
60.0,130.0,2.79  PMIN,PMAX,FUELPRICE ($/GJ)
0.0,10.0,0.0       k0,k1,k2 : HEAT-RATE coeffs.
1,0.0,1            m0,m1, stop cost ; hot start cost, cost time gradient,stop cost
0.0,0.2,0.0        l0, l1, l2  : NOx curve coeffs.
1,0.0,1.0          n0,n1, stop emission : coeffs. for start up emissions
1.0,1.0            COEFFICIENTS FOR SCALING OF COSTS (MUST BE SET TO 1)
0.050000
FSTRWLR1  37       NAME
2,99.9             STATUS(1:M-R WITH FIXED GEN,2=M-R WITH FREE GEN,3=FREE UNIT
1,1,1,-100         MIN UPTIME,COLDSTART-TIME, MIN-DOWNTIME,TIME-STATUS AT T=0-
99.99,100.0,2.79  PMIN,PMAX,FUELPRICE ($/GJ)
0.0,10.0,0.0       k0,k1,k2 : HEAT-RATE coeffs.
1,0.0,1            m0,m1, stop cost ; hot start cost, cost time gradient,stop cost
0.0,0.33,0.0        l0, l1, l2  : NOx curve coeffs.
1,0.0,1.0          n0,n1, stop emission : coeffs. for start up emissions
1.0,1.0            COEFFICIENTS FOR SCALING OF COSTS (MUST BE SET TO 1)
0.050000
DOWCHEM1  38       NAME
2,69.9              STATUS(1:M-R WITH FIXED GEN,2=M-R WITH FREE GEN,3=FREE UNIT
1,1,1,-100         MIN UPTIME,COLDSTART-TIME, MIN-DOWNTIME,TIME-STATUS AT T=0-
69.9,70.0,5.50   PMIN,PMAX,FUELPRICE ($/GJ)
0.0,10.0,0.0       k0,k1,k2 : HEAT-RATE coeffs.
1,0.0,1            m0,m1, stop cost ; hot start cost, cost time gradient,stop cost
0.0,0.33,0.0        l0, l1, l2  : NOx curve coeffs.
1,0.0,1.0          n0,n1, stop emission : coeffs. for start up emissions
1.0,1.0            COEFFICIENTS FOR SCALING OF COSTS (MUST BE SET TO 1)
0.050000
GWFPOWR1  39       NAME
2,52.9              STATUS(1:M-R WITH FIXED GEN,2=M-R WITH FREE GEN,3=FREE UNIT
1,1,1,-100         MIN UPTIME,COLDSTART-TIME, MIN-DOWNTIME,TIME-STATUS AT T=0-
52.9,53.0,5.50   PMIN,PMAX,FUELPRICE ($/GJ)
0.0,10.0,0.0       k0,k1,k2 : HEAT-RATE coeffs.
1,0.0,1            m0,m1, stop cost ; hot start cost, cost time gradient,stop cost
0.0,0.33,0.0        l0, l1, l2  : NOx curve coeffs.
1,0.0,1.0          n0,n1, stop emission : coeffs. for start up emissions
1.0,1.0            COEFFICIENTS FOR SCALING OF COSTS (MUST BE SET TO 1)
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0.050000
GWFPOWR2  40      NAME
2,34.9             STATUS(1:M-R WITH FIXED GEN,2=M-R WITH FREE GEN,3=FREE UNIT
1,1,1,-100        MIN UPTIME,COLDSTART-TIME, MIN-DOWNTIME,TIME-STATUS AT T=0-
34.9,35.0,5.50  PMIN,PMAX,FUELPRICE ($/GJ)
0.0,10.0,0.0      k0,k1,k2 : HEAT-RATE coeffs.
1,0.0,1           m0,m1, stop cost ; hot start cost, cost time gradient,stop cost
0.0,0.33,0.0       10, 11, 12  : NOx curve coeffs.
1,0.0,1.0         n0,n1, stop emission : coeffs. for start up emissions
1.0,1.0           COEFFICIENTS FOR SCALING OF COSTS (MUST BE SET TO 1)
0.050000
CARDINL1  41      NAME
2,49.9             STATUS(1:M-R WITH FIXED GEN,2=M-R WITH FREE GEN,3=FREE UNIT
1,1,1,-100        MIN UPTIME,COLDSTART-TIME, MIN-DOWNTIME,TIME-STATUS AT T=0-
49.9,50.0,5.50  PMIN,PMAX,FUELPRICE ($/GJ)
0.0,10.0,0.0      k0,k1,k2 : HEAT-RATE coeffs.
1,0.0,1           m0,m1, stop cost ; hot start cost, cost time gradient,stop cost
0.0,0.33,0.0       10, 11, 12  : NOx curve coeffs.
1,0.0,1.0         n0,n1, stop emission : coeffs. for start up emissions
1.0,1.0           COEFFICIENTS FOR SCALING OF COSTS (MUST BE SET TO 1)
0.050000
UNIONSF1  42      NAME
2,49.9            STATUS(1:M-R WITH FIXED GEN,2=M-R WITH FREE GEN,3=FREE UNIT
1,1,1,-100        MIN UPTIME,COLDSTART-TIME, MIN-DOWNTIME,TIME-STATUS AT T=0-
49.9,50.0,5.50  PMIN,PMAX,FUELPRICE ($/GJ)
0.0,10.0,0.0      k0,k1,k2 : HEAT-RATE coeffs.
1,0.0,1           m0,m1, stop cost ; hot start cost, cost time gradient,stop cost
0.0,0.2,0.0       10, 11, 12  : NOx curve coeffs.
1,0.0,1.0         n0,n1, stop emission : coeffs. for start up emissions
1.0,1.0           COEFFICIENTS FOR SCALING OF COSTS (MUST BE SET TO 1)
0.050000
GAYLORD1  43      NAME
2,49.9            STATUS(1:M-R WITH FIXED GEN,2=M-R WITH FREE GEN,3=FREE UNIT
1,1,1,-100        MIN UPTIME,COLDSTART-TIME, MIN-DOWNTIME,TIME-STATUS AT T=0-
49.9,50.0,5.50  PMIN,PMAX,FUELPRICE ($/GJ)
0.0,10.0,0.0      k0,k1,k2 : HEAT-RATE coeffs.
1,0.0,1           m0,m1, stop cost ; hot start cost, cost time gradient,stop cost
0.0,0.33,0.0       10, 11, 12  : NOx curve coeffs.
1,0.0,1.0         n0,n1, stop emission : coeffs. for start up emissions
1.0,1.0           COEFFICIENTS FOR SCALING OF COSTS (MUST BE SET TO 1)
0.050000
OLSHOSP1  44      NAME
2,35.9            STATUS(1:M-R WITH FIXED GEN,2=M-R WITH FREE GEN,3=FREE UNIT
1,1,1,-100        MIN UPTIME,COLDSTART-TIME, MIN-DOWNTIME,TIME-STATUS AT T=0-
35.9,36.0,5.50  PMIN,PMAX,FUELPRICE ($/GJ)
0.0,10.0,0.0      k0,k1,k2 : HEAT-RATE coeffs.
1,0.0,1           m0,m1, stop cost ; hot start cost, cost time gradient,stop cost
0.0,0.33,0.0       10, 11, 12  : NOx curve coeffs.
1,0.0,1.0         n0,n1, stop emission : coeffs. for start up emissions
1.0,1.0           COEFFICIENTS FOR SCALING OF COSTS (MUST BE SET TO 1)
0.050000
CONTNER1  45      NAME
2,35.9 STATUS(1:M-R WITH FIXED GEN,2=M-R WITH FREE GEN,3=FREE UNIT
1,1,1,-100        MIN UPTIME,COLDSTART-TIME, MIN-DOWNTIME,TIME-STATUS AT T=0-
35.9,36.0,5.50  PMIN,PMAX,FUELPRICE ($/GJ)
0.0,10.0,0.0      k0,k1,k2 : HEAT-RATE coeffs.
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1,0.0,1             m0,m1, stop cost ; hot start cost, cost time gradient,stop cost
0.0,0.33,0.0         l0, l1, l2  : NOx curve coeffs.
1,0.0,1.0           n0,n1, stop emission : coeffs. for start up emissions
1.0,1.0             COEFFICIENTS FOR SCALING OF COSTS (MUST BE SET TO 1)
0.050000
UNTCOGN1  46        NAME
2,29.9              STATUS(1:M-R WITH FIXED GEN,2=M-R WITH FREE GEN,3=FREE UNIT
1,1,1,-100          MIN UPTIME,COLDSTART-TIME, MIN-DOWNTIME,TIME-STATUS AT T=0-
29.9,30.0,5.50     PMIN,PMAX,FUELPRICE ($/GJ)
0.0,10.0,0.0        k0,k1,k2 : HEAT-RATE coeffs.
1,0.0,1             m0,m1, stop cost ; hot start cost, cost time gradient,stop cost
0.0,0.33,0.0         l0, l1, l2  : NOx curve coeffs.
1,0.0,1.0           n0,n1, stop emission : coeffs. for start up emissions
1.0,1.0             COEFFICIENTS FOR SCALING OF COSTS (MUST BE SET TO 1)
0.050000
UNIONRO1  47        NAME
2,26.9              STATUS(1:M-R WITH FIXED GEN,2=M-R WITH FREE GEN,3=FREE UNIT
1,1,1,-100          MIN UPTIME,COLDSTART-TIME, MIN-DOWNTIME,TIME-STATUS AT T=0-
26.9,27.0,5.50     PMIN,PMAX,FUELPRICE ($/GJ)
0.0,10.0,0.0        k0,k1,k2 : HEAT-RATE coeffs.
1,0.0,1             m0,m1, stop cost ; hot start cost, cost time gradient,stop cost
0.0,0.33,0.0         l0, l1, l2  : NOx curve coeffs.
1,0.0,1.0           n0,n1, stop emission : coeffs. for start up emissions
1.0,1.0             COEFFICIENTS FOR SCALING OF COSTS (MUST BE SET TO 1)
0.050000
OLSBERK1  48        NAME
2,25.9              STATUS(1:M-R WITH FIXED GEN,2=M-R WITH FREE GEN,3=FREE UNIT
1,1,1,-100          MIN UPTIME,COLDSTART-TIME, MIN-DOWNTIME,TIME-STATUS AT T=0-
25.99,26.0,5.50     PMIN,PMAX,FUELPRICE ($/GJ)
0.0,10.0,0.0        k0,k1,k2 : HEAT-RATE coeffs.
1,0.0,1             m0,m1, stop cost ; hot start cost, cost time gradient,stop cost
0.0,0.33,0.0         l0, l1, l2  : NOx curve coeffs.
1,0.0,1.0           n0,n1, stop emission : coeffs. for start up emissions
1.0,1.0             COEFFICIENTS FOR SCALING OF COSTS (MUST BE SET TO 1)
0.050000
ALTAMNT1  49        NAME
2,12.9              STATUS(1:M-R WITH FIXED GEN,2=M-R WITH FREE GEN,3=FREE UNIT
1,1,1,-100          MIN UPTIME,COLDSTART-TIME, MIN-DOWNTIME,TIME-STATUS AT T=0-
12.99,13.0,5.50     PMIN,PMAX,FUELPRICE ($/GJ)
0.0,10.0,0.0        k0,k1,k2 : HEAT-RATE coeffs.
1,0.0,1             m0,m1, stop cost ; hot start cost, cost time gradient,stop cost
0.0,0.33,0.0         l0, l1, l2  : NOx curve coeffs.
1,0.0,1.0           n0,n1, stop emission : coeffs. for start up emissions
1.0,1.0             COEFFICIENTS FOR SCALING OF COSTS (MUST BE SET TO 1)
0.050000
FAYETTE1  50        NAME
2,6.9              STATUS(1:M-R WITH FIXED GEN,2=M-R WITH FREE GEN,3=FREE UNIT
1,1,1,-100          MIN UPTIME,COLDSTART-TIME, MIN-DOWNTIME,TIME-STATUS AT T=0-
6.99,7.0,5.50     PMIN,PMAX,FUELPRICE ($/GJ)
0.0,10.0,0.0        k0,k1,k2 : HEAT-RATE coeffs.
1,0.0,1             m0,m1, stop cost ; hot start cost, cost time gradient,stop cost
0.0,0.33,0.0         l0, l1, l2  : NOx curve coeffs.
1,0.0,1.0           n0,n1, stop emission : coeffs. for start up emissions
1.0,1.0             COEFFICIENTS FOR SCALING OF COSTS (MUST BE SET TO 1)
0.050000
CATLYST1  51        NAME
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2,5.9               STATUS(1:M-R WITH FIXED GEN,2-M-R WITH FREE GEN,3 FREE UNIT
1,1,1,-100          MIN UPTIME,COLDSTART-TIME, MIN-DOWNTIME,TIME-STATUS AT T=0-
5.99,6.0,5.50        PMIN,PMAX,FUELPRICE ($/GJ)
0.0,10.0,0.0        k0,k1,k2 : HEAT-RATE coeffs.
1,0.0,1             m0,m1, stop cost ; hot start cost, cost time gradient,stop cost
0.0,0.33,0.0         10, 11, 12  : NOx curve coeffs.
1,0.0,1.0           n0,n1, stop emission : coeffs. for start up emissions
1.0,1.0             COEFFICIENTS FOR SCALING OF COSTS (MUST BE SET TO 1)
0.050000
OTHRBIO1  52        NAME
2,26.99             STATUS(1:M-R WITH FIXED GEN,2=M-R WITH FREE GEN,3=FREE UNIT
1,1,1,-100          MIN UPTIME,COLDSTART-TIME, MIN-DOWNTIME,TIME-STATUS AT T=0-
26.99,27.0,5.50     PMIN,PMAX,FUELPRICE ($/GJ)
0.0,10.0,0.0        k0,k1,k2 : HEAT-RATE coeffs.
1,0.0,1             m0,m1, stop cost ; hot start cost, cost time gradient,stop cost
0.0,0.33,0.0         10, 11, 12  : NOx curve coeffs.
1,0.0,1.0           n0,n1, stop emission : coeffs. for start up emissions
1.0,1.0             COEFFICIENTS FOR SCALING OF COSTS (MUST BE SET TO 1)
0.050000
OTHRGAS1  53        NAME
2,10.99             STATUS(1:M-R WITH FIXED GEN,2=M-R WITH FREE GEN,3=FREE UNIT
1,1,1,-100          MIN UPTIME,COLDSTART-TIME, MIN-DOWNTIME,TIME-STATUS AT T=0-
10.99,11.0,5.50     PMIN,PMAX,FUELPRICE ($/GJ)
0.0,10.0,0.0        k0,k1,k2 : HEAT-RATE coeffs.
1,0.0,1             m0,m1, stop cost ; hot start cost, cost time gradient,stop cost
0.0,0.33,0.0         10, 11, 12  : NOx curve coeffs.
1,0.0,1.0           n0,n1, stop emission : coeffs. for start up emissions
1.0,1.0             COEFFICIENTS FOR SCALING OF COSTS (MUST BE SET TO 1)
0.050000
IMPORT01  54       NAME
2,0.0               STATUS(1:M-R WITH FIXED GEN,2=M-R WITH FREE GEN,3=FREE UNIT
0,0,0,-100          MIN UPTIME,COLDSTART-TIME, MIN-DOWNTIME,TIME-STATUS AT T=0-
1.0,9999.0,10.0         PMIN,PMAX,FUELPRICE ($/GJ)
0.0,10.0,0.0        k0,k1,k2 : HEAT-RATE coeffs.
0.0,0.0,0.0         m0,m1, stop cost ; hot start cost, cost time gradient,stop cost
0.0,10.0,0.0         10, 11, 12  : NOx curve coeffs.
0.0,0.0,0.0.0           n0,n1, stop emission : coeffs. for start up emissions
1.0,1.0             COEFFICIENTS FOR SCALING OF COSTS (MUST BE SET TO 1)
0.000000
UNSRVNGY  55         UNSERVED ENERGY MUST BE THE LAST RESOURCE IN INPUT FILE
2,0.0                STATUS(1:M-R WITH FIXED GEN,2=M-R WITH FREE GEN,3=FREE UNIT
0,0,0,-100           MIN UPTIME,COLDSTART-TIME, MIN-DOWNTIME,TIME-STATUS AT T=0-
1.0,9999.0,15.0     PMIN,PMAX,FUELPRICE ($/GJ)
0.0,10.0,0.0         k0,k1,k2 : HEAT-RATE coeffs.
0.0,0.0,0.0         m0,m1, stop cost ; hot start cost, cost time gradient,stop cost
0.0,10.0,0.0         10, 11, 12  : NOx curve coeffs.
0.0,0.0,0.0.0           n0,n1, stop emission : coeffs. for start up emissions
1.0,1.0             COEFFICIENTS FOR SCALING OF COSTS (MUST BE SET TO 1)
0.000000
WEIGHTS
1.0,0.0,0.0         INDIVIDUAL WEIGHTING COEFFICIENTS
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Table I.2: Expected Value Results of Sytem Totals

run#: 0 EVs EXAMPLE Tax=0 - Episose 11-17Sep89
Tue Dec 15 12:03:52 PST 1992
Total Energy Demanded: 712.554 GWh

MCI	output	fuel	heat.rate	fcost	avfcst	NOx	av.emiss.	txcost	avtxcst	av.totc
	GWh	TJ	GJ/MWh	$e6	$/MWh	t	kg/MWh	$e6	$/MWh	$/MWh
1	712.6	7935.	11.136	20.929	29.37	464.9	0.652	1.772	2.49	31.86
2	712.6	7823.	10.979	20.672	29.01	430.9	0.605	1.626	2.28	31.29
3	712.6	8065.	11.319	21.408	30.04	524.4	0.736	2.097	2.94	32.99
4	712.6	7834.	10.994	20.425	28.66	436.8	0.613	1.649	2.31	30.98
5	712.5	7988.	11.211	21.080	29.58	498.0	0.699	1.931	2.71	32.29
6	712.6	7864.	11.036	20.765	29.14	437.9	0.615	1.654	2.32	31.46
7	712.5	7980.	11.199	20.882	29.31	504.8	0.708	1.987	2.79	32.10
8	712.6	7982.	11.202	21.142	29.67	511.9	0.718	2.005	2.81	32.48
9	712.6	7932.	11.132	20.956	29.41	466.8	0.655	1.801	2.53	31.94
10	712.5	8304.	11.654	22.455	31.51	582.2	0.817	2.374	3.33	34.85
	712.6	7971.	11.186	21.071	29.57	485.9	0.682	1.889	2.65	32.22

Table I.3: Expected Value Unit Results

run#: 0 unit EVs EXAMPLE Tax=0 - Episose 11-17Sep89
Tue Dec 15 12:03:52 PST 1992

unit	cap.	for	ecap	eprod	cf1	cf2	efuel	ecost	eemis	etaxr	etcost
	MW		MW	GWh	%	%	TJ	M$	t	M$	M$
CONTRCS1	116.	0.210	58.	3.815	39.2	19.6	67.	0.150	3.467	0.016	0.165
CONTRCS2	116.	0.169	93.	5.794	37.2	29.7	91.	0.205	4.373	0.020	0.226
CONTRCS3	116.	0.222	81.	5.118	37.5	26.3	81.	0.183	3.914	0.018	0.201
CONTRCS4	117.	0.273	82.	6.563	47.7	33.4	89.	0.200	4.656	0.021	0.222
CONTRCS5	115.	0.237	92.	8.297	53.7	42.9	108.	0.243	5.601	0.025	0.269
CONTRCS6	340.	0.066	340.	43.213	75.7	75.7	470.	1.058	33.559	0.129	1.187
CONTRCS7	340.	0.058	306.	36.151	70.3	63.3	400.	0.900	29.018	0.114	1.014
HNTRSPT1	56.	0.097	50.	0.318	3.8	3.4	4.	0.016	0.566	0.003	0.019
HNTRSPT2	107.	0.115	86.	4.159	28.9	23.1	75.	0.168	8.517	0.037	0.205
HNTRSPT3	107.	0.125	107.	4.735	26.3	26.3	84.	0.188	9.834	0.045	0.233
HNTRSPT4	163.	0.105	147.	15.355	62.3	56.1	183.	0.412	9.128	0.041	0.453
MOSLNDG1	116.	0.606	35.	2.368	40.5	12.1	60.	0.136	3.517	0.014	0.150
MOSLNDG2	116.	0.442	81.	4.199	30.8	21.5	88.	0.198	4.751	0.021	0.219
MOSLNDG3	117.	0.382	47.	1.228	15.6	6.2	49.	0.111	2.364	0.010	0.120
MOSLNDG4	117.	0.197	94.	9.491	60.4	48.3	119.	0.268	7.964	0.032	0.300
MOSLNDG5	117.	0.194	94.	7.679	48.8	39.1	102.	0.231	6.246	0.027	0.257
MOSLNDG6	739.	0.186	665.	98.304	88.0	79.2	997.	2.244	66.517	0.235	2.479
MOSLNDG7	739.	0.175	665.	94.819	84.9	76.4	963.	2.167	68.900	0.234	2.401
OAKLAND1	64.	0.138	58.	0.544	5.6	5.1	7.	0.027	0.968	0.006	0.032
OAKLAND2	64.	0.124	64.	0.664	6.2	6.2	9.	0.033	1.182	0.007	0.040
OAKLAND3	64.	0.123	64.	0.664	6.2	6.2	9.	0.033	1.182	0.007	0.040
PITSBRG1	163.	0.087	147.	15.789	64.1	57.7	188.	0.423	16.135	0.063	0.486
PITSBRG2	163.	0.107	147.	15.968	64.8	58.3	192.	0.433	16.147	0.063	0.496
PITSBRG3	163.	0.086	163.	16.875	61.6	61.6	199.	0.448	16.463	0.065	0.513
PITSBRG4	163.	0.132	147.	15.960	64.8	58.3	188.	0.423	16.118	0.062	0.485
PITSBRG5	325.	0.135	292.	37.561	76.4	68.8	413.	0.928	26.435	0.101	1.029
PITSBRG6	325.	0.255	260.	43.297	99.1	79.3	437.	0.982	22.620	0.082	1.064
PITSBRG7	720.	0.206	504.	66.817	78.9	55.2	795.	1.790	25.653	0.106	1.896
PORTBLE1	15.	0.257	10.	0.063	3.6	2.5	1.	0.003	0.266	0.002	0.005
PORTBLE2	15.	0.034	15.	0.078	3.1	3.1	1.	0.004	0.328	0.002	0.006
PORTBLE3	15.	0.090	14.	0.040	1.7	1.6	1.	0.002	0.167	0.001	0.003
POTRERO3	207.	0.047	207.	26.748	76.9	76.9	290.	0.652	19.805	0.076	0.728
POTRERO4	56.	0.044	45.	0.912	12.1	9.7	12.	0.044	1.623	0.009	0.054
POTRERO5	56.	0.032	56.	0.980	10.4	10.4	13.	0.048	1.744	0.010	0.058
POTRERO6	56.	0.121	50.	0.841	9.9	8.9	11.	0.041	1.498	0.009	0.049
GILROYE1	130.	0.050	117.	13.201	67.2	60.4	132.	0.368	2.640	0.011	0.380
FSTRWLR1	100.	0.050	100.	16.799	100.0	100.0	168.	0.469	5.544	0.020	0.489
DOWCHEM1	70.	0.050	70.	11.745	99.9	99.9	117.	0.646	3.876	0.014	0.660
GWFPOWR1	53.	0.050	53.	8.889	99.8	99.8	89.	0.489	2.933	0.011	0.499
GWFPOWR2	35.	0.050	35.	5.865	99.7	99.7	59.	0.323	1.936	0.007	0.330
CARDINL1	50.	0.050	50.	8.385	99.8	99.8	84.	0.461	2.767	0.010	0.471
UNIONSF1	50.	0.050	45.	7.546	99.8	89.8	75.	0.415	1.509	0.005	0.420
GAYLORD1	50.	0.050	45.	7.547	99.8	89.8	75.	0.415	2.490	0.009	0.424
OLSHOSP1	36.	0.050	36.	6.033	99.8	99.8	60.	0.332	1.991	0.007	0.339
CONTNER1	36.	0.050	36.	6.033	99.8	99.8	60.	0.332	1.991	0.007	0.339
UNTCOGN1	30.	0.050	30.	5.025	99.7	99.7	50.	0.276	1.658	0.006	0.282
UNIONRO1	27.	0.050	24.	4.069	99.7	89.7	41.	0.224	1.343	0.005	0.229
OLSBERK1	26.	0.050	26.	4.367	100.0	100.0	44.	0.240	1.441	0.005	0.245
ALTAMNT1	13.	0.050	13.	2.183	99.9	99.9	22.	0.120	0.720	0.003	0.123

Table I.4: Expected Value System Hourly Results

0 unit EVs EXAMPLE Tax=0 - Episose 11-17Sep89
Tue Dec 15 12:03:52 PST 1992

hour	load	output	lambda	fuel	fcost	tax	NOx	taxr	tcost
	MW	MW	$/MWh	TJ	M$	$/kg	t	M$	M$
1	2784.	2784.	21.85	31.935	0.090	0.000	1.652	0.000	0.090
2	2615.	2615.	21.58	30.302	0.086	0.000	1.525	0.000	0.086
3	2536.	2536.	21.45	29.548	0.084	0.000	1.468	0.000	0.084
4	2498.	2498.	21.39	29.178	0.083	0.000	1.441	0.000	0.083
5	2572.	2572.	21.51	29.884	0.085	0.000	1.494	0.000	0.085
6	2850.	2850.	21.95	32.574	0.091	0.000	1.701	0.000	0.091
7	3556.	3556.	22.93	39.614	0.107	0.000	2.304	0.000	0.107
8	4262.	4262.	24.13	46.964	0.123	0.000	2.930	0.000	0.123
9	4683.	4683.	25.42	51.570	0.134	0.000	3.292	0.000	0.134
10	4943.	4943.	28.34	54.587	0.141	0.000	3.549	0.000	0.141
11	5111.	5111.	29.36	56.583	0.146	0.000	3.723	0.000	0.146
12	5203.	5204.	31.55	57.709	0.148	0.000	3.823	0.000	0.148
13	5224.	5224.	31.68	57.955	0.149	0.000	3.846	0.000	0.149
14	5220.	5220.	31.65	57.910	0.149	0.000	3.842	0.000	0.149
15	5233.	5233.	31.73	58.063	0.149	0.000	3.856	0.000	0.149
16	5121.	5121.	29.48	56.710	0.146	0.000	3.735	0.000	0.146
17	4983.	4983.	28.53	55.056	0.142	0.000	3.588	0.000	0.142
18	4929.	4929.	28.28	54.420	0.140	0.000	3.536	0.000	0.140
19	4839.	4839.	26.49	53.373	0.138	0.000	3.455	0.000	0.138
20	4996.	4996.	28.60	55.214	0.142	0.000	3.601	0.000	0.142
21	4760.	4760.	25.86	52.456	0.136	0.000	3.371	0.000	0.136
22	4312.	4312.	24.27	47.508	0.125	0.000	2.973	0.000	0.125
23	3846.	3846.	23.31	42.592	0.114	0.000	2.560	0.000	0.114
24	3276.	3276.	22.55	36.782	0.100	0.000	2.052	0.000	0.100

Table I.5: Hourly Iteration Results

run 0 it 1 EXAMPLE Tax=0 - Episose 11-17Sep89
Tue Dec 15 12:03:52 PST 1992

hr.	load MW	tax $/kg	prod MW	lambda $/MWh	fuel TJ	cost M$	dump MWh	emis. t	taxr M$	tcotst M$
1	2784.	0.00	2784.	21.93	32.	0.090	0.	1.660	0.000	0.090
2	2615.	0.00	2615.	21.66	30.	0.086	0.	1.529	0.000	0.086
3	2536.	0.00	2536.	21.52	29.	0.084	0.	1.466	0.000	0.084
4	2498.	0.00	2498.	21.45	29.	0.084	1.	1.437	0.000	0.084
5	2572.	0.00	2572.	21.58	30.	0.085	0.	1.495	0.000	0.085
6	2850.	0.00	2849.	22.02	32.	0.091	-1.	1.710	0.000	0.091
7	3556.	0.00	3556.	22.94	40.	0.107	0.	2.324	0.000	0.107
8	4262.	0.00	4261.	23.90	47.	0.124	-1.	2.935	0.000	0.124
9	4683.	0.00	4683.	24.86	51.	0.134	0.	3.236	0.000	0.134
10	4943.	0.00	4944.	25.95	54.	0.140	1.	3.450	0.000	0.140
11	5111.	0.00	5112.	26.62	56.	0.145	1.	3.587	0.000	0.145
12	5203.	0.00	5204.	27.01	57.	0.147	1.	3.665	0.000	0.147
13	5224.	0.00	5224.	27.13	58.	0.148	0.	3.683	0.000	0.148
14	5220.	0.00	5220.	27.11	58.	0.148	0.	3.680	0.000	0.148
15	5233.	0.00	5233.	27.20	58.	0.148	1.	3.692	0.000	0.148
16	5121.	0.00	5121.	26.66	56.	0.145	0.	3.595	0.000	0.145
17	4983.	0.00	4982.	26.11	55.	0.141	-1.	3.484	0.000	0.141
18	4929.	0.00	4929.	25.89	54.	0.140	1.	3.437	0.000	0.140
19	4839.	0.00	4840.	25.54	53.	0.138	1.	3.361	0.000	0.138
20	4996.	0.00	4996.	26.17	55.	0.142	0.	3.496	0.000	0.142
21	4760.	0.00	4760.	25.20	52.	0.136	0.	3.297	0.000	0.136
22	4312.	0.00	4311.	24.06	47.	0.125	-1.	2.971	0.000	0.125
23	3846.	0.00	3846.	23.19	43.	0.114	0.	2.577	0.000	0.114
24	3276.	0.00	3276.	22.62	37.	0.101	0.	2.075	0.000	0.101

Table I.6: Hourly Unit Results

run 0 it 1 EXAMPLE Tax=0 - Episose 11-17Sep89 -Tue Dec 15 12:03:52 PST 1992

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UNITS 1 TO 10

HOUR	LOAD	LAMBDA	CONTRCS1	CONTRCS2	CONTRCS3	CONTRCS4	CONTRCS5	CONTRCS6	CONTRCS7	HNTRSPT1	HNTRSPT2	HNTRSPT3
	UNIT ID# ->		1	2	3	4	5	6	7	8	9	10
	MAX OUTPUT ->		116	116	0	117	115	340	340	56	107	107
	MIN OUTPUT ->		10	10	0	7	7	46	46	0	10	10
1	2784.	21.928	10.	10.	0.	7.	7.	73.	46.	0.	10.	10.
2	2615.	21.664	10.	10.	0.	7.	7.	46.	46.	0.	10.	10.
3	2536.	21.518	10.	10.	0.	7.	7.	46.	46.	0.	10.	10.
4	2498.	21.448	10.	10.	0.	7.	7.	46.	46.	0.	10.	10.
5	2572.	21.584	10.	10.	0.	7.	7.	46.	46.	0.	10.	10.
6	2850.	22.019	10.	10.	0.	7.	7.	87.	46.	0.	10.	10.
7	3556.	22.939	10.	10.	0.	7.	7.	231.	95.	0.	10.	10.
8	4262.	23.904	10.	10.	0.	20.	28.	340.	340.	0.	10.	10.
9	4683.	24.856	10.	10.	0.	42.	54.	340.	340.	0.	14.	10.
10	4943.	25.954	23.	10.	0.	68.	83.	340.	340.	0.	25.	10.
11	5111.	26.620	38.	25.	0.	84.	101.	340.	340.	0.	32.	10.
12	5203.	27.008	47.	38.	0.	93.	111.	340.	340.	0.	36.	10.
13	5224.	27.132	50.	43.	0.	96.	114.	340.	340.	0.	37.	10.
14	5220.	27.110	50.	42.	0.	95.	114.	340.	340.	0.	37.	10.
15	5233.	27.198	52.	45.	0.	97.	115.	340.	340.	0.	38.	10.
16	5121.	26.656	39.	26.	0.	85.	101.	340.	340.	0.	32.	10.
17	4983.	26.107	26.	10.	0.	72.	87.	340.	340.	0.	27.	10.
18	4929.	25.895	22.	10.	0.	67.	81.	340.	340.	0.	25.	10.
19	4839.	25.536	13.	10.	0.	58.	72.	340.	340.	0.	21.	10.
20	4996.	26.166	28.	10.	0.	73.	88.	340.	340.	0.	27.	10.
21	4760.	25.200	10.	10.	0.	50.	63.	340.	340.	0.	18.	10.
22	4312.	24.058	10.	10.	0.	24.	32.	340.	340.	0.	10.	10.
23	3846.	23.192	10.	10.	0.	7.	9.	270.	222.	0.	10.	10.
24	3276.	22.616	10.	10.	0.	7.	7.	180.	46.	0.	10.	10.

FAYETTE1	7.	0.050	7.	1.175	99.9	99.9	12.	0.065	0.388	0.001	0.066
CATLYST1	6.	0.050	6.	1.007	99.9	99.9	10.	0.055	0.332	0.001	0.057
OTHRBIO1	27.	0.050	27.	4.535	100.0	100.0	45.	0.249	1.496	0.005	0.255
OTHRGAS1	11.	0.050	11.	1.847	99.9	99.9	18.	0.102	0.609	0.002	0.104
IMPORT01	9999.	0.000	9999.	0.731	0.0	0.0	7.	0.073	7.310	0.040	0.113
UNSRVNGY	9999.	0.000	9999.	0.168	0.0	0.0	2.	0.025	1.680	0.006	0.031

Table I.7: Unit by Unit Hourly Results

run #: 0 it 1 EXAMPLE Tax=0 - Episose 11-17Sep89 -Tue Dec 15 12:03:52 PST 1992

CONTRCS1 fuel price = 2.25 $-GJ capacity: 116. MW

hour	sysMW	NOxt	output	ssem	genem	mc	tax	mt	mc+mt	lambda
1	2784.	0.	10.	17.8	228.303	25.40	0.00	0.00	25.40	21.93
2	2615.	0.	10.	0.0	228.303	25.40	0.00	0.00	25.40	21.66
3	2536.	0.	10.	0.0	228.303	25.40	0.00	0.00	25.40	21.52
4	2498.	0.	10.	0.0	228.303	25.40	0.00	0.00	25.40	21.45
5	2572.	0.	10.	0.0	228.303	25.40	0.00	0.00	25.40	21.58
6	2850.	0.	10.	0.0	228.303	25.40	0.00	0.00	25.40	22.02
7	3556.	0.	10.	0.0	228.303	25.40	0.00	0.00	25.40	22.94
8	4262.	0.	10.	0.0	228.303	25.40	0.00	0.00	25.40	23.90
9	4683.	0.	10.	0.0	228.303	25.40	0.00	0.00	25.40	24.86
10	4943.	0.	23.	0.0	540.103	25.95	0.00	0.00	25.95	25.95
11	5111.	0.	38.	0.0	1105.275	26.62	0.00	0.00	26.62	26.62
12	5203.	0.	47.	0.0	1536.869	27.01	0.00	0.00	27.01	27.01
13	5224.	0.	50.	0.0	1691.938	27.13	0.00	0.00	27.13	27.13
14	5220.	0.	50.	0.0	1663.978	27.11	0.00	0.00	27.11	27.11
15	5233.	0.	52.	0.0	1777.371	27.20	0.00	0.00	27.20	27.20
16	5121.	0.	39.	0.0	1142.691	26.66	0.00	0.00	26.66	26.66
17	4983.	0.	26.	0.0	651.416	26.11	0.00	0.00	26.11	26.11
18	4929.	0.	22.	0.0	500.636	25.89	0.00	0.00	25.89	25.89
19	4839.	0.	13.	0.0	293.550	25.54	0.00	0.00	25.54	25.54
20	4996.	0.	28.	0.0	696.789	26.17	0.00	0.00	26.17	26.17
21	4760.	0.	10.	0.0	228.303	25.40	0.00	0.00	25.40	25.20
22	4312.	0.	10.	0.0	228.303	25.40	0.00	0.00	25.40	24.06
23	3846.	0.	10.	0.0	228.303	25.40	0.00	0.00	25.40	23.19
24	3276.	0.	10.	0.0	228.303	25.40	0.00	0.00	25.40	22.62

Figure I.1: Output Subroutine to EEUCM

```
C This is the main output subroutine to EEUM.
C original program: Terje Gjengedal,
C expanded by Chris Marnay - Sat Dec 19 14:38:24 PST 1992
C==================================================
      SUBROUTINE UTSKRIV(IUT,NMIN,OPTPROD,OPTRES,INTRVL,N,
     *UTFILE,NAMN,NAMN2,MINEPS,IHOVED,ILOS,EMISNO,
     *LAGMAX,LAST,ROTKRAV,OPTLAMBDA,OPTMAX,PMIN,PMAX,HKOST,
     *B,EPS,FORKOST,ID,ITESTUT,UPEMISS,GENEMISS,TOTEMISS,
     *BPRIS,D0,D1,D2,DS0,DS1,DN0,TOTALMWH,LOAD,CAPS,FORS,
     *TAX,EG0,EG1,EG2,ES0,ES1,EN0,MCI,NMCITS,HEADER,DATESTAMP,
     *NRUN)

c_m <
C   SUBROUTINE FOR PRINTING SIMULATION RESULTS
c_m >
C   SUBRUTINE SOM SKRIV UT SIMULERINGSRESULTATA
C--------------------------------------------------

      INTEGER IUT,INTRVL,ITESTUT,N,IHOVED,ILOS,NRUN
      REAL NMIN,OPTPROD(1000,100),OPTRES(1000,100),BPRIS(100)
      REAL MINEPS,LAGMAX,LAST(1000),ROTKRAV(1000),OPTLAMBDA(1000)
      REAL OPTMAX(1000),PMIN(100),PMAX(100),HKOST,B,EPS,FORKOST
      CHARACTER NAMN(100)*8,NAMN2(100)*14,UTFILE*50
      INTEGER IFERD,IANTUT,IT,I

c_m Aug 25 10:12:32 PDT 1992 <

      INTEGER EMISNO
      INTEGER ID(100)

      CHARACTER TEMPHEAD(10)*8

      REAL GENEMISS(1000,100,3),UPEMISS(1000,100,3),
     2  TOTEMISS(1000,100,3)
      REAL SYSEMISS(1000),DELSPIN,KI
      REAL MC(1000,100),MT(1000,100)
      REAL BPRIS(100),D0(100),D1(100),D2(100)
      REAL DS0(100),DS1(100),DN0(100),TOTALMWH,LOAD(1000)
      REAL TAX(1000,100),EG0(100,3),EG1(100,3),EG2(100,3)
      REAL ES0(100,3),ES1(100,3),EN0(100,3)
      REAL CAPS(100,2),FORS(100)

      REAL TOTOPTPRODU(100),TOTOPTPRODT(1000),GTOTOPTPROD,ETOTOPTPROD
      REAL TOTOPTFUELU(100),TOTOPTFUELT(1000),GTOTOPTFUEL,ETOTOPTFUEL
      REAL TOTOPTCOSTU(100),TOTOPTCOSTT(1000),GTOTOPTCOST,ETOTOPTCOST
      REAL TOTOPTEMISU(100),TOTOPTEMIST(1000),GTOTOPTEMIS,ETOTOPTEMIS
      REAL TOTOPTTAXRU(100),TOTOPTTAXRT(1000),GTOTOPTTAXR,ETOTOPTTAXR
      REAL ETOTOPTPRODU(100),ETOTOPTFUELU(100),EPMAX(100)
      REAL ETOTOPTCOSTU(100),ETOTOPTEMISU(100),ETOTOPTTAXRU(100)
      REAL ETOTOPTPRODT(1000),ETOTOPTFUELT(1000),EOPTLAMBDA(1000)
      REAL ETOTOPTCOSTT(1000),ETOTOPTEMIST(1000),ETOTOPTTAXRT(1000)

      INTEGER MCI,NMCITS
      REAL MCF
```

```
      CHARACTER*1  STRINGI
      CHARACTER*35 HEADER
      CHARACTER*28 DATESTAMP

C     CHARACTER*4  LVL2NAME,LVL3NAME,LVL4NAME,LVL5NAME
C     CHARACTER*7  LVL1NAME
C     CHARACTER*13 FILENAME

C     LVL1NAME='out_100'
C     LVL2NAME='out_'
C     LVL3NAME='out_'
C     LVL4NAME='out_'
C     LVL5NAME='out_'

C     FILENAME ='XXXXXXXXXXXXX'

      KI  = 1000.0
      MCF = 1.0/REAL(NMCITS)

C     CAPS(N,N) = min and max output of all units
C     DELSPIN = deliberate spin. = spin. target - max. output
C     EMISNO = number of pollutants
C     EPMAX(N) = expected max. capacity by unit
C     ETOTOPTPRODT(INTRVL) expected total hourly output all units
C     ETOTOPTPRODU(N) expected total output by unit
C     ETOTOPTFUELT(INTRVL) expected total hourly fuel burn all units
C     ETOTOPTFUELU(N) expected total fuel burn by unit
C     ETOTOPTCOSTT(INTRVL) expected total hourly fuel cost all units
C     ETOTOPTCOSTU(N) expected total fuel cost by unit
C     ETOTOPTEMIST(INTRVL)expected total hourly NOx emiss all units
C     ETOTOPTEMISU(N) total NOx emissions by unit
C     ETOTOPTTAXRT(INTRVL) total hourly NOx tax revenue all units
C     ETOTOPTTAXRU(N) total NOx tax revenue by unit
C     FORS(N) = forced outage rates of all units
C     GENEMISS(1000,100,3)= generation emissions
C     GTOTOPTPROD = grand total production
C     GTOTOPTEMIS = grand total NOx emissions
C     GTOTOPTFUEL = grand total fuel burn
C     GTOTOPTCOST = grand total fuel cost
C     GTOTOPTTAXR = grand total tax revenue
C     ID = ID number of the unit
C     INTRVL = number of hours in simulation, had to change namve
C               from INTRVL because of complift with use of INTRVL to
C               change masks
C     IOUTNUM = index of the MCI output file names
C     LVLxNAME = filename for levelXoutput
C     SYSEMISS(1000) = total emissions from the system by hour!!in t!!
C     TEMPHEAD = temporary character string of column headings
C     TOTEMISS(1000,100,3)= total emissions
C     TOTOPTPRODT(INTRVL) total hourly output from all units
C     TOTOPTPRODU(N) total output by unit
C     TOTOPTFUELT(INTRVL) total hourly fuel burn from all units
C     TOTOPTFUELU(N) total fuel burn by unit
C     TOTOPTCOSTT(INTRVL) total hourly fuel cost from all units
C     TOTOPTCOSTU(N) total fuel cost by unit
C     TOTOPTEMIST(INTRVL) total hourly NOx emissions from all units
```

```
C     TOTOPTEMISU(N) total NOx emissions by unit
C     TOTOPTTAXRT(INTRVL) total hourly NOx tax revenue from all units
C     TOTOPTTAXRU(N) total NOx tax revenue by unit
C     MC(1000,100) = marginal cost by unit (Incre. HR * Fuel Cost)
C     MT(1000,100) = marginal tax by unit (Incre. emiss * tax)
C     UPEMISS(1000,100,3) = startup emissions

c_m >

      WRITE(IUT,*)' PRINTING RESULTS FOR MC ITERATION', MCI

C------------------------------
c_m <
C   OUTPUTING THE OPTPRODUCTION SCHEDULE FOR THE OPTIMAL
C                  PRIMAL SOLUTION?
c_m >
C    UTSKRIFT AV OPTPRODUKSJONER FOR BESTE PRIMALLOSNING
C
      IF(MINEPS.LE.EPS)THEN
        WRITE(IUT,6110)
      ELSE
        WRITE(IUT,6100)
      ENDIF

      WRITE(IUT,6120)MINEPS,IHOVED,ILOS
      WRITE(IUT,6130)NMIN,LAGMAX

C     WRITE(IUT,8764)HKOST,B,FORKOST

C----------------------------------------------------------------------
C    PRINTING LOAD, SPINNING RESERVE, AND LAMBDA
C----------------------------------------------------------------------
c_m < this block does the basic calculations for the output

        DELSPIN = 0.0
        GTOTOPTPROD = 0.0
        GTOTOPTFUEL = 0.0
        GTOTOPTCOST = 0.0
        GTOTOPTEMIS = 0.0
        GTOTOPTTAXR = 0.0
        IF(MCI.EQ.1) THEN
          ETOTOPTPROD = 0.0
          ETOTOPTFUEL = 0.0
          ETOTOPTCOST = 0.0
          ETOTOPTEMIS = 0.0
          ETOTOPTTAXR = 0.0
          DO 1425 J = 1,N
            EPMAX(J)         = 0.0
            ETOTOPTPRODU(J) = 0.0
            ETOTOPTFUELU(J) = 0.0
            ETOTOPTCOSTU(J) = 0.0
            ETOTOPTEMISU(J) = 0.0
            ETOTOPTTAXRU(J) = 0.0
 1425     CONTINUE
          DO 1426 IT = 1,INTRVL
            EOPTLAMBDA(IT)  = 0.0
```

```
          ETOTOPTPRODT(IT) = 0.0
          ETOTOPTFUELT(IT) = 0.0
          ETOTOPTCOSTT(IT) = 0.0
          ETOTOPTEMIST(IT) = 0.0
          ETOTOPTTAXRT(IT) = 0.0
 1426   CONTINUE
      ENDIF
C-----------------------------------------------

      DO 1420 IT = 1, INTRVL
        TOTOPTPRODT(IT) = 0.0
        TOTOPTFUELT(IT) = 0.0
        TOTOPTCOSTT(IT) = 0.0
        TOTOPTEMIST(IT) = 0.0
        TOTOPTTAXRT(IT) = 0.0
 1420 CONTINUE
      DO 1430 J = 1, N
        TOTOPTPRODU(J) = 0.0
        TOTOPTFUELU(J) = 0.0
        TOTOPTCOSTU(J) = 0.0
        TOTOPTEMISU(J) = 0.0
        TOTOPTTAXRU(J) = 0.0
 1430 CONTINUE
      DO 1479 IT=1,INTRVL
        DO 1450 J = 1, N
          TOTOPTPRODT(IT) = TOTOPTPRODT(IT) + OPTPROD(IT,J)
          TOTOPTFUELT(IT) = TOTOPTFUELT(IT) + D0(J)
     2       + D1(J)*OPTPROD(IT,J) + D2(J)*OPTPROD(IT,J)**2.0
          TOTOPTCOSTT(IT) = TOTOPTCOSTT(IT)  + BPRIS(J)*(D0(J)
     2       + D1(J)*OPTPROD(IT,J) + D2(J)*OPTPROD(IT,J)**2.0)
          TOTOPTEMIST(IT)=TOTOPTEMIST(IT) + EG0(J,1)
     2       +EG1(J,1)*OPTPROD(IT,J) + EG2(J,1)*OPTPROD(IT,J)**2.0
          TOTOPTTAXRT(IT) = TOTOPTTAXRT(IT)  + TAX(IT,J)*(EG0(J,1)
     2       + EG1(J,1)*OPTPROD(IT,J) + EG2(J,1)*OPTPROD(IT,J)**2.0)

          TOTOPTPRODU(J) = TOTOPTPRODU(J) + OPTPROD(IT,J)
          TOTOPTFUELU(J) = TOTOPTFUELU(J) + D0(J)
     2       + D1(J)*OPTPROD(IT,J) + D2(J)*OPTPROD(IT,J)**2.0
          TOTOPTCOSTU(J) = TOTOPTCOSTU(J)  + BPRIS(J)*(D0(J)
     2       + D1(J)*OPTPROD(IT,J) + D2(J)*OPTPROD(IT,J)**2.0)
          TOTOPTEMISU(J) = TOTOPTEMISU(J) + EG0(J,1)
     2       +EG1(J,1)*OPTPROD(IT,J) + EG2(J,1)*OPTPROD(IT,J)**2.0
          TOTOPTTAXRU(J) = TOTOPTTAXRU(J)  + TAX(IT,J)*(EG0(J,1)
     2       + EG1(J,1)*OPTPROD(IT,J) + EG2(J,1)*OPTPROD(IT,J)**2.0)

 1450   CONTINUE
        GTOTOPTPROD = GTOTOPTPROD + TOTOPTPRODT(IT)
        GTOTOPTFUEL = GTOTOPTFUEL + TOTOPTFUELT(IT)
        GTOTOPTCOST = GTOTOPTCOST + TOTOPTCOSTT(IT)
        GTOTOPTEMIS = GTOTOPTEMIS + TOTOPTEMIST(IT)
        GTOTOPTTAXR = GTOTOPTTAXR + TOTOPTTAXRT(IT)

        IF(ITESTUT.GE.2)THEN
          EOPTLAMBDA(IT)   = EOPTLAMBDA(IT)   + OPTLAMBDA(IT)*MCF
          ETOTOPTPRODT(IT) = ETOTOPTPRODT(IT) + TOTOPTPRODT(IT)*MCF
          ETOTOPTFUELT(IT) = ETOTOPTFUELT(IT) + TOTOPTFUELT(IT)*MCF
```

```
          ETOTOPTCOSTT(IT) = ETOTOPTCOSTT(IT) + TOTOPTCOSTT(IT)*MCF
          ETOTOPTEMIST(IT) = ETOTOPTEMIST(IT) + TOTOPTEMIST(IT)*MCF
          ETOTOPTTAXRT(IT) = ETOTOPTTAXRT(IT) + TOTOPTTAXRT(IT)*MCF
        ENDIF
 1479   CONTINUE

        ETOTOPTPROD = ETOTOPTPROD + GTOTOPTPROD*MCF
        ETOTOPTFUEL = ETOTOPTFUEL + GTOTOPTFUEL*MCF
        ETOTOPTCOST = ETOTOPTCOST + GTOTOPTCOST*MCF
        ETOTOPTEMIS = ETOTOPTEMIS + GTOTOPTEMIS*MCF
        ETOTOPTTAXR = ETOTOPTTAXR + GTOTOPTTAXR*MCF

C------------------------------------------------------------------
C this block-calulates the expected results for each unit

      DO 1460 J = 1, N
        EPMAX(J)         = EPMAX(J)         + PMAX(J)*MCF
        ETOTOPTPRODU(J)  = ETOTOPTPRODU(J)  + TOTOPTPRODU(J)*MCF
        ETOTOPTFUELU(J)  = ETOTOPTFUELU(J)  + TOTOPTFUELU(J)*MCF
        ETOTOPTCOSTU(J)  = ETOTOPTCOSTU(J)  + TOTOPTCOSTU(J)*MCF
        ETOTOPTEMISU(J)  = ETOTOPTEMISU(J)  + TOTOPTEMISU(J)*MCF
        ETOTOPTTAXRU(J)  = ETOTOPTTAXRU(J)  + TOTOPTTAXRU(J)*MCF
 1460 CONTINUE

C------------------------------------------------------------------
C this block makes the files for and outputs the level 1 stuff

      OPEN(100)
      IF(MCI.EQ.1) THEN
        WRITE(100,6035) NRUN,HEADER,DATESTAMP
 6035   FORMAT('run#:',I5,' EVs',X,A35,' ',A28)
        WRITE(100,6071) TOTALMWH/KI
 6071   FORMAT('Total Energy Demanded:',F10.3,' GWh')
        WRITE(100,6072)
 6072   FORMAT('MCI  output  fuel heat.rate fcost avfcst  NOx',
     2          '  av.emiss. txcost avtxcst  av.totc')
        WRITE(100,6073)
 6073   FORMAT('       GWh     TJ  GJ/MWh     $e6  $/MWh    t',
     2          '    kg/MWh    $e6    $/MWh    $/MWh')
        REWIND(100)
      ENDIF
      DO 1070 I = 1, MCI+3
        READ(100,6070) STRING1
 6070   FORMAT(A1)
        print *, string1
 1070 CONTINUE
      WRITE(100,6060)MCI,GTOTOPTPROD/KI,
     2     GTOTOPTFUEL/KI,GTOTOPTFUEL/GTOTOPTPROD,
     3     GTOTOPTCOST/KI**2.0,GTOTOPTCOST/GTOTOPTPROD,
     4     GTOTOPTEMIS/KI,GTOTOPTEMIS/GTOTOPTPROD,
     5     GTOTOPTTAXR/KI**2.0,GTOTOPTTAXR/GTOTOPTPROD,
     6     (GTOTOPTCOST+GTOTOPTTAXR)/GTOTOPTPROD
 6060   FORMAT(I3,F8.1,F8.0,F7.3,F9.3,F6.2,F7.1,F8.3,F7.3,2F8.2)
      IF(MCI.EQ.NMCITS) THEN
        WRITE(100,6080)
 6080   FORMAT(80('-'))
```

```
      WRITE(100,6090)    ETOTOPTPROD/KI,
     2      ETOTOPTFUEL/KI,ETOTOPTFUEL/ETOTOPTPROD,
     3      ETOTOPTCOST/KI**2.0,ETOTOPTCOST/ETOTOPTPROD,
     4      ETOTOPTEMIS/KI,ETOTOPTEMIS/ETOTOPTPROD,
     5      ETOTOPTTAXR/KI**2.0,ETOTOPTTAXR/ETOTOPTPROD,
     6      (ETOTOPTCOST+ETOTOPTTAXR)/ETOTOPTPROD
 6090 FORMAT('    ',F8.1,F8.0,F7.3,F9.3,F6.2,F7.1,F8.3,F7.3,2F8.2)
     ENDIF
     CLOSE(100)

C---------------------------------------------------------------------
C this block for level 2 output, that is, unit totals & hourly totals

      IF(ITESTUT.GE.2)THEN

C       IF(MCI.EQ.1) THEN
C         DO 4050 IOUTNUM = 0,NMCITS
C           IF(IOUTNUM.GT.0) THEN
C             REWIND(32)
C           ELSE
C             OPEN(32,FILE='filecounter')
C           ENDIF
C           WRITE(32,4010) LVL2NAME,200+IOUTNUM
C4010       FORMAT(A4,I3)
C           REWIND(32)
C           READ(32,4020) FILENAME
C4020       FORMAT(A7)

C reactivate these when you get more 200 level output
C           OPEN(200+IOUTNUM)
C           WRITE(200+IOUTNUM,4030) NRUN,IOUTNUM,HEADER,DATESTAMP
C4030   FORMAT(I5,' it:',I3,X,A35,'-',A28)
C           CLOSE(200+IOUTNUM)
C4050     CONTINUE
C         CLOSE(32)
C       ENDIF

        IF(MCI.EQ.NMCITS) THEN
          OPEN(200)
          WRITE(200,4030) NRUN,HEADER,DATESTAMP
 4030     FORMAT(I5,' unit EVs ',A35,'-',A28)
          WRITE(200,4031)
 4031     FORMAT(' unit    cap. for    ecap  eprod    cf1   cf2   ',
     2              'efuel  ecost  eemis  etaxr   etcost')
          WRITE(200,4032)
 4032     FORMAT('          MW          MW    GWh     %     % ',
     2              '   TJ      M$      t      M$       M$')
          DO 4060 J = 1, N
            WRITE(200,4070) NAMN(J),CAPS(J,2),FORS(J),EPMAX(J),
     2      ETOTOPTPRODU(J)/KI,
     3      (ETOTOPTPRODU(J)*100.0)/(EPMAX(J)*REAL(INTRVL)),
     4      (ETOTOPTPRODU(J)*100.0)/(CAPS(J,2)*REAL(INTRVL)),
     5      ETOTOPTFUELU(J)/KI,ETOTOPTCOSTU(J)/(KI**2.0),
     6      ETOTOPTEMISU(J)/KI,ETOTOPTTAXRU(J)/(KI**2.0),
     7      (ETOTOPTCOSTU(J)+ETOTOPTTAXRU(J))/(KI**2.0)
 4070       FORMAT(A8,F5.0,F6.3,F5.0,F8.3,2F6.1,F6.0,F7.3,F8.3,2F7.3)
```

```
 4060       CONTINUE
            CLOSE(200)

            OPEN(250)
            WRITE(250,4030) NRUN,HEADER,DATESTAMP
            WRITE(250,4090)
 4090       FORMAT('hour load outputlambda  fuel   fcost  tax',
     2        '    NOx       taxr       tcost')
            WRITE(250,4091)
 4091       FORMAT('       MW     MW    $/MWh     TJ      M$    $/kg',
     2             '      t        M$          M$')
            DO 4080 IT =1, INTRVL
              WRITE(250,4085) IT,LOAD(IT),
     2      -       ETOTOPTPRODT(IT),EOPTLAMBDA(IT),
     3              ETOTOPTFUELT(IT)/KI,ETOTOPTCOSTT(IT)/KI**2.0,
     4              TAX(IT,1),ETOTOPTEMIST(IT)/KI,ETOTOPTTAXRT(IT)/KI**2.0,
     5              (ETOTOPTTAXRT(IT)+ETOTOPTCOSTT(IT))/KI**2.0
 4085         FORMAT(I4,2F6.0,F6.2,F8.3,F6.3,F7.3,2F8.3,F12.3)
 4080       CONTINUE
            CLOSE(250)

          ENDIF
        ENDIF

C-------------------------------------------------------------------
C this block makes the files for and output the level 3 stuff

        IF(ITESTUT.GE.3)THEN

C         IF(MCI.EQ.1) THEN
C           OPEN(32,FILE='filecounter')
C           DO 1050 IOUTNUM = 1,NMCITS
C             IF(IOUTNUM.GT.1) THEN
C               REWIND(32)
C             ENDIF
C             WRITE(32,6010) LVL3NAME,300+IOUTNUM
C6010         FORMAT(A4,I3)
C             REWIND(32)
C             READ(32,6020) FILENAME
C6020         FORMAT(A7)
C             OPEN(300+IOUTNUM,FILE=FILENAME)
C             WRITE(300+IOUTNUM,6030) NRUN,IOUTNUM,HEADER,DATESTAMP
C6030         FORMAT(I5,' it:',I3,X,A35,'-',A28)
C             CLOSE(300+IOUTNUM)
C1050       CONTINUE
C           CLOSE(32)
C          ENDIF

         OPEN(300+MCI)
         WRITE(300+MCI,6030) NRUN,MCI,HEADER,DATESTAMP
 6030    FORMAT('run',I5,' it',I3,X,A35,'-',A28)
         WRITE(300+MCI,6040)
 6040    FORMAT(' hr. load  tax  prod  lambda fuel   cost dump',
     2          ' emis.  taxr  tcotst')
         WRITE(300+MCI,6045)
 6045    FORMAT('        MW  $/kg    MW    $/MWh    TJ    M$    MWh',
```

```
     2           '      t     M$        M$')
        DO 1040 IT = 1,INTRVL
          WRITE(300+MCI,6050)IT,LOAD(IT),TAX(IT,1),
     2      TOTOPTPRODT(IT),OPTLAMBDA(IT),
     3      TOTOPTFUELT(IT)/KI,TOTOPTCOSTT(IT)/KI**2.0,
     4      TOTOPTPRODT(IT)-LOAD(IT),
     5      TOTOPTEMIST(IT)/KI,TOTOPTTAXRT(IT)/KI**2.0,
     6      (TOTOPTCOSTT(IT)+TOTOPTTAXRT(IT))/KI**2.0
 6050       FORMAT(I5,F6.0,F6.2,F6.0,F7.2,F6.0,F6.3,F5.0,3F7.3,)
 1040   CONTINUE
        CLOSE(300+MCI)
      ENDIF
c_m >
C--------------------------------------------------------------------
C     output block for level 4 the unit hourly production only

      IF(ITESTUT.GE.4)THEN

C       IF(MCI.EQ.1) THEN
C         OPEN(32,FILE='filecounter')
C         DO 2050 IOUTNUM = 1,NMCITS
C           IF(IOUTNUM.GT.1) THEN
C             REWIND(32)
C           ENDIF
C           WRITE(32,7010) LVL4NAME,400+IOUTNUM
C7010       FORMAT(A4,I3)
C           REWIND(32)
C           READ(32,7020) FILENAME
C7020       FORMAT(A7)
C           OPEN(400+IOUTNUM,FILE=FILENAME)
C           WRITE(400+IOUTNUM,7030) NRUN,IOUTNUM,HEADER,DATESTAMP
C7030       FORMAT(I5,' it:',I3,X,A35,'-',A28)
C           CLOSE(400+IOUTNUM)
C2050     CONTINUE
C         CLOSE(32)
C       ENDIF

        ITEST4=1
        IFERD=0
c_m >
        TEMPHEAD(1) = '    HOUR'
        TEMPHEAD(2) = '    LOAD'
        TEMPHEAD(3) = '  LAMBDA'

C output loop starts here

        OPEN(400+MCI)
        WRITE(400+MCI,6030) NRUN,MCI,HEADER,DATESTAMP
 1500   CONTINUE
          WRITE(400+MCI,*) ' '
          WRITE(400+MCI,5010)
5010      FORMAT(80('+'))
c_m <
          IF((N-IFERD).GT.10)THEN
            ISTARTI=IFERD+1
            IANTUT=IFERD+10
```

```
          ELSE
           ISTARTI=IFERD+1
           IANTUT=N
          ENDIF
c_m >
          DO 1010 I = 1, 8
            IF(I.EQ.1) THEN
              WRITE(400+MCI,5015) ID(ISTARTI),ID(IANTUT),
     2          (NAMN(K)(I:I),K=ISTARTI,IANTUT)
 5015         FORMAT('UNITS',I4,' TO',I4,2X,10(3X,A1,2X))
            ELSE
              WRITE(400+MCI,5020) (TEMPHEAD(J)(I:I),J=1,3),
     2          (NAMN(K)(I:I),K=ISTARTI,IANTUT)
 5020       . FORMAT(2X,A1,4X,A1,6X,A1,3X,10(3X,A1,2X))
            ENDIF
 1010     CONTINUE
          WRITE(400+MCI,5030)
 5030     FORMAT('---- ----- -------',10(' -----'))

          WRITE(400+MCI,5040) (ID(K),K=ISTARTI,IANTUT)
 5040     FORMAT(7X,'UNIT ID# ->',10(2X,I4))
          WRITE(400+MCI,5050) (INT(PMAX(K)),K=ISTARTI,IANTUT)
 5050     FORMAT('     MAX OUTPUT ->',10I6)
          WRITE(400+MCI,5055) (INT(PMIN(K)),K=ISTARTI,IANTUT)
 5055     FORMAT('     MIN OUTPUT ->',10I6)
          WRITE(400+MCI,5030)

          DO 1514 IT=1,INTRVL
c_m <
            WRITE(400+MCI,6170)IT,LOAD(IT),OPTLAMBDA(IT),
     2        (OPTPROD(IT,I),I=ISTARTI,IANTUT)
c_m >
1514      CONTINUE

          IFERD=IFERD+IANTUT-ISTARTI+1
          IF(IFERD.GE.N) ITEST4=0
          IF(ITEST4.NE.0) GO TO 1500

          CLOSE(400+MCI)

      ENDIF

C output level 4 loop stops here
C================================================
C this block is the output level 5

      IF(ITESTUT.GE.5)THEN

C       IF(MCI.EQ.1) THEN
C         OPEN(32,FILE='filecounter')
C         DO 3050 IOUTNUM = 1,NMCITS
C           IF(IOUTNUM.GT.1) THEN
C             REWIND(32)
C           ENDIF
C           WRITE(32,7010) LVL5NAME,500+IOUTNUM
C8010       FORMAT(A4,I3)
```

```
C           REWIND(32)
C           READ(32,8020) FILENAME
C8020       FORMAT(A7)
C           OPEN(500+IOUTNUM,FILE=FILENAME)
C           WRITE(500+IOUTNUM,8030) NRUN,IOUTNUM,HEADER,DATESTAMP
C8030       FORMAT(I5,' it:',I3,X,A35,'-',A28)
C           CLOSE(500+IOUTNUM)
C3050     CONTINUE
C         CLOSE(32)
C        ENDIF

        OPEN(500+MCI)
        WRITE(500+MCI,6030) NRUN,MCI,HEADER,DATESTAMP
        DO 1020 J = 1,N
          WRITE(500+MCI,5060)
 5060     FORMAT(80('='))
          WRITE(500+MCI,5070) NAMN(J), BPRIS(J),PMAX(J)
 5070     FORMAT(A8,'  fuel price =',F6.2,' $-GJ','  capacity:',F5.0,
     2    ' MW')
          WRITE(500+MCI,5090)
 5090     FORMAT(' hour sysMW NOxt  output ssem  genem',
     2            '    mc      tax     mt      mc+mt    lambda')
          WRITE(500+MCI,5091)
 5091     FORMAT('----- ----- ----- ----- ----- ------- ',
     2            5(' -------'))

          DO 1030 IT = 1, INTRVL
C calculating marginal cost and marginal tax
            MC(IT,J) = 0.0
            MC(IT,J) = BPRIS(J)*(D1(J) + 2.0*D2(J)*OPTPROD(IT,J))
            MT(IT,J) = 0.0
            MT(IT,J) = TAX(IT,J)*(EG1(J,1) + 2.0*EG2(J,1)*OPTPROD(IT,J))
            WRITE(500+MCI,5080) IT,LOAD(IT),SYSEMISS(IT),
     2        OPTPROD(IT,J),UPEMISS(IT,J,1),GENEMISS(IT,J,1),
     3        MC(IT,J),TAX(IT,J),MT(IT,J), MC(IT,J)+MT(IT,J),
     4        OPTLAMBDA(IT)
 5080       FORMAT(I5,3F6.0,F6.1,F9.3,5F8.2)
 1030     CONTINUE
 1020   CONTINUE
        CLOSE(500+MCI)
      ENDIF

CCCCCCCCCCCCCCCCCCCCCCCCCCCCCCC
C
c_m <
C  RESULTS USED FOR GRAPHING
c_m >
C  UTSKRIFT AV RESULTATER TIL KURVETEGNING
C
C
C         OPEN(22,FILE='KURVEDATA:SYMB',STATUS='UNKNOWN')

C         WRITE(22,*)(LAST(IT),IT=1,INTRVL)
C         WRITE(22,*)(OPTLAMBDA(IT),IT=1,INTRVL)
C         WRITE(22,*)(OPTMAX(IT),IT=1,INTRVL)
C         WRITE(22,*)(ROTKRAV(IT),IT=1,INTRVL)
```

```
C        DO 1537 I=1,N
C        WRITE(22,*)(OPTPROD(IT,I),IT=1,INTRVL)
C        WRITE(22,*)(OPTRES(IT,I),IT=1,INTRVL)
1537     CONTINUE
C        CLOSE(22)

9998  CONTINUE


750   FORMAT('***    CPU-TID  :  ',F7.3,'   SEK.')
511   FORMAT(22I3)
501   FORMAT('  UNIT    NO .  :',I3)
6100  FORMAT('***   NO CONVERGENCY    ***')
6110  FORMAT('***     CONVERGENCY     ***')
6120  FORMAT('DUALITY  GAP ',2X,F10.3,' # OF ITS ',2X,I6,
     2 ' # OF SOLTNS ',2X,I6)

6130  FORMAT(' CRITERIA :',F15.0,'    LAGRANGECRITERIA :',F15.3)

6141  FORMAT('ENHET     MIN-POWER  (MW)     MAX-POWER  (MW)')
6142  FORMAT(I3,10X,F6.1,13X,F6.1)
6151  FORMAT(1X,'hour',5(4X,A14,4X))
6159  FORMAT(2X,'****     NO FEASIBLE SOLUTION IS FOUND    ***** ')
6160  FORMAT('***  OPTIMUM (BEST) GENERATION SCHEDULE    ***')
6162  FORMAT('*** START-STOP          I OPTIMAL LOSNING  ***')

C
C c_m <
C               WRITE(IUT,6170)IT,LAST(IT),OPTLAMBDA(IT),
C       2           (OPTPROD(IT,I),I=ISTARTI,IANTUT)
C c_m >
C
6170  FORMAT(I4,F6.0,F8.3,10(F6.0))
6171  FORMAT(2X,I3,2X,10(3X,I3,3X))
8765  FORMAT(2X,'GENERATION COST IN INTERV.',I4,'  IS  :',F9.2)
8764  FORMAT(2X,'TOTAL GEN COST:',F10.2,
     2' START-STOP COSTS :',F10.2' AS PERCENT :',F6.3)

      RETURN
      END
```