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U.S. Department of Energy, National Institute for Occupational Safety and Health, the National Institute of Environmental Health Sciences, and Oak Ridge National Laboratory.

September 1996. Questions and Answers. EMF in the Workplace. Provides information on EMF basics, research results and studies, workplace exposures, and exten-

sive EMF references. Single copies are available free from the EMF InfoLine, (800) 363-2383. Also available online at the EMF RAPID Home Page, www.niehs.nih.gov/emfrapid/home.htm

U.S. Department of Energy and the National Institute of Environmental Health Sciences. January 1995. Questions and Answers about EMF, Electric and Magnetic Fields Associated with the Use of [Residential] Electric Power, available in both English and Spanish. Single Copies are available free from the EMF InfoLine: (800) 363-2383. Multiple copies of the booklet can be purchased from the Superintendent of Documents, U.S. Government Printing Office, Washington, DC 20402. (202) 512-1800.

U.S. Environmental Protection Agency, Radiation Studies Division, Office of Radiation & Indoor Air, December 1992. EMF in Your Environment: Magnetic Field Measurement of Everyday Electrical Devices. Washington, DC 20460.

HOTLINES & INTERNET

[Contacts in California are listed in the insert on page 5.6.10]

EMF InfoLine (800) 363-2383. The EMF InfoLine is managed by the U.S. Environmental Protection Agency (EPA) and responds to public inquiries about 60-Hz EMFs and radio frequency radiation. It is jointly supported by the EPA and the EMF Research and Public Information Dissemination (RAPID) Program.

ENVIRO-HEALTH Hotline (800) 643-4794. The National Institute of Environmental Health Sciences operates a hotline to answer questions about various environmental health issues, including EMF.

EMFRAPID Home Page http://www.niehs.nih.gov/emfrapid/home.htm Provides information about the federal government's EMF research effort, including public information materials. The home page is maintained by the National Institute of Environmental Health Sciences and is funded by the EMF Research and Public Information Dissemination (EMF RAPID) Program.

ORGANIZATIONS & AGENCIES

California Department of Health (CDHS) Special Epidemiological Studies Program 2151 Berkeley Way, Annex 11, 5th Floor Berkeley, CA 94704 (510) 540-2669

California Energy Commission (CEC) Energy Facilities Siting and Environmental Protection Division 1516 9th Street Sacramento, CA 95814 (916) 654-3924

California Public Utilities Commission (CPUC) Energy Advisory Branch Commission Advisory & Compliance Division 505 Van Ness Avenue San Francisco, CA 94102 (415) 703-1567 Department of Engineering and Public Policy-Carnegie Mellon University 129 Baker Hall Pittsburgh, PA 15213 (412) 268-2670

National Institute of Environmental Health Sciences (NIEHS) P.O. Box 12233 Research Triangle Park North Carolina, 27709 (919) 541-3345 United States Environmental Protection Agency (EPA) Office of Radiation and Indoor Air Radiation Studies Division Washington, DC 20640 (800) EMF-2383 EMF Hotline

EPA Regional Office 74 Hawthorne Street San Francisco, CA 94105 (415) 744-1047 World Health Organization (WHO) 523 23rd Street, NW Washington, DC 20037 (202) 861-3222

RELATED ISSUES/CHAPTERS

- Energy Facility Planning (Chapter 3)
- Energy Facility Permitting (Chapter 4)



NOTES NOTES



TER 5.7: ENERGY FACILITY **CLOSURE/ABANDONMENT**

INTRODUCTION

Some improperly abandoned energy facilities can pose problems for communities and for the surrounding environment. Contaminated soil and water, leaking wells, unsafe and unsightly buildings and equipment are some of the possible problems associated with such facilities. Proper closure and abandonment of energy facilities will ensure the safety of the site and allow for future alternate uses:

Planning for the proper closure or abandonment of energy facilities presents many complexities. Abandonment generally entails one or more steps after operations are permanently terminated, such as removal of equipment, remediation of contaminated soils and water, and restoration. The timing and the efforts expended on these activities can be controversial.

It may also be difficult to know at the time of permitting what the conditions will be at facility closure time. In addition, the determination of what constitutes a public nuisance or a safety hazard can be controversial. In some cases the state and federal regulations may be vague. The type of facility and its location will usually affect whether potential abandonment issues exist.

There is greater potential for public nuisances and safety hazards for some types of energy facilities than for others. Potential abandonment issues for different facilities are addressed on the following page. Most local government experience

in California with abandonment issues is related to oil and gas facilities since they have existed for many years here, there have been numerous older sites improperly abandoned years ago, and they have presented serious public nuisance and safety hazards. Because of this experience, most of the ideas in this sub-chapter stem from issues and legal authority related to oil and gas development.

"The type of facility and its location will usually affect whether potential abandonment issues exist."

The ideas presented, therefore, are generalizations and do not mean that the problems associated with the abandonment or closure of oil and gas fields necessarily apply to all other types of energy facilities.

The location of an energy facility can be an important factor in determining whether it may become a public nuisance. For example, if the facility is located in an industrial zone planned for the long-term, it is less likely to be

considered a nuisance than if it is located by itself near an area frequented by people.

Energy facilities which may benefit from facility closure/abandonment planning and implementation include:

- Existing improperly abandoned facilities (such as oil fields and facilities abandoned long ago)
- Facilities currently in operation
- Facilities not yet permitted

For energy facilities that are in operation or not yet permitted, local governments may have the most control, but they also have options for dealing with existing improperly abandoned energy facilities.

However, local governments may be preempted by state or federal authority over certain energy facilities. For example, the Department of Conservation, Division of Oil, Gas and Geothermal Resources has authority over facilities in state designated oil development fields.

For energy facilities under their jurisdiction, local governments can set time limits for considering whether a facility is abandoned. Local governments can also state preferences even when they do not have facility jurisdiction. Some facilities temporarily halt operations due to resource or energy price fluctuations. It would be unreasonable to require a project

owner to remove equipment and reclaim a site if operations are expected to resume in a short while. While the project owner's future intent for the site should be considered, local governments may need to protect the community from nuisances and hazards from energy facilities that may never come back on line, and whose owner may walk away from them. To prevent that from happening, some local governments have required an abandonment plan, including financial security, as part of the permit process.

WHAT POTENTIAL IMPACTS ARE ASSOCIATED WITH ENERGY **FACILITY CLOSURE OR** ABANDONMENT?

The potential impacts associated with abandoned energy facilities are the potential contamination of air, water and soil at facilities that handled or stored hazardous materials. Facilities with wells, and with above ground and underground storage tanks, have the potential to contaminate the soil, groundwater, surface water and air if the equipment is not properly removed or plugged. The potential for such contamination exists during the operation of the facility as well, but if proper operating procedures are in place to prevent hazardous materials impacts, the impacts during closure should also be greatly reduced. (See Chapter 5.3 on Hazardous Materials Handling and Storage.)

Many energy facilities have equipment and buildings that constitute dangerous situations if not removed or isolated from the public. These facilities may also reduce the visual quality of an area and conflict with other potential future uses. If buildings or equipment are removed from the site, revegetation (perhaps using native plant species)

may be required in order to reduce erosion impacts. Proper abandonment procedures, as with proper construction procedures, will reduce impacts to a variety of on-site and off-site resources.

ARE THERE SPECIAL CONSIDERATIONS FOR DIFFERENT TYPES OF ENERGY **FACILITIES?**

- Energy facilities that extract, process, transport or store petroleum products have the potential to adversely impact soil, water, biological resources and air quality. Oil and gas wells, processing facilities, pipelines and storage tanks may leak during operation. If improperly removed, plugged or otherwise contained at closure, safety concerns will arise, and soil and water contamination can occur.
- Geothermal facilities share some of the potential contamination problems with oil and gas facilities. Geothermal water or steam often contains heavy metals and other hazardous materials. Wells, pipelines, and production facilities are potential sources of spills or leaks that could negatively affect the local environment. Extraction areas resulting from the operation of geothermal facilities can also have subsidence problems that may not become evident until after they have closed.
- Abandoned wind turbines pose some of the same problems as those in operation. If the blades are not dismantled and made inoperative, bird collisions and noise impacts may continue. The visual impacts and use of the often large tracts of land will continue.
- Large solar facilities can have several abandonment problems. If not dismantled, they can prevent

other uses including restoration of many hundreds of acres. Most large-scale solar facilities in California have natural gas backup systems which have abandonment issues including health and safety concerns. Solar thermal facilities currently use hundreds of thousands of gallons of heat transfer fluids that pose substantial cleanup costs should a spill occur.

- The closure of any solar photovoltaic (PV) facility will need to address the reuse, recycling or disposal of the PV panels which may contain hazardous materials.
- Waste-to-energy facilities can have hazardous materials leakage and hazardous ash contamination problems (leachate) both during and after operation. Site cleanup is often necessary.
- Abandoned hydroelectric facilities may result in silted over reservoirs and stagnant water. If not properly maintained or removed, a deteriorating dam may pose an especially dangerous flooding situation downstream.
- Oil and gas pipelines can either be removed or abandoned in place (cleaned and plugged). In areas where the presence of pipelines conflicts with other potential uses, such as recreational activities on beaches, removal will probably be the preferred abandonment procedure. In other areas where incompatibility is less of an issue, there may be fewer environmental impacts associated with proper abandonment in place.
- Electric transmission lines, when abandoned, may provide opportunities for communities to use the corridors for other purposes. There may be safety issues associated with the removal of the wires and

THE REGULATORY ENVIRONMENT RELATED TO ENERGY FACILITY CLOSURE

Federal

- Closure requirements and financial responsibility for Underground Storage Tanks (USTs)
- · Identification and listing of hazardous waste
- Well closure requirements and financial responsibility for hazardous waste injection wells

State

- Closure requirements for USTs that store hazardous materials
- Closure and post-closure plans and financial requirements for solid waste landfill
- Well abandonment standards for energy facilities with water wells on site
- Closure plan and financial responsibility for closure and liability for energy facilities permitted to store or treat hazardous waste on-site
- Operating requirements and financial responsibility for energy facilities that have oil, gas or geothermal wells

Local

- Facility closure plan requirements for energy facilities permitted by local fire departments to store hazardous materials on site
- Local ordinances related to facility closure

- Title 40, Gode di Federal Regulations. section: 280 T0 et seg
- section: 261.1 et seq.

 Fille 40: Code of Federal Regulations, sections: 144.60 et seq., 146.70

line 40. Code of federal Regulations

- Title 23, California Code of Regulations, section 2670 at seq
- Public Resources Code section 3500 et (seq).
- Water Code section 13750 et sequ
- Public Resources Code section 3200 et section 3200
- Uniform Life Code seanon 80, 101

poles, such as the proper handling and disposal of wooden poles treated with certain wood preservatives.

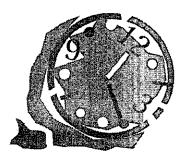
HOW CAN FACILITY CLOSURE/ ABANDONMENT PLANS BE USED?

A facility closure/abandonment plan provides information and time schedules for facility abandonment. However, not all abandonment plans need to contain the same level of detail.

Preliminary closure/ abandonment plan.

A preliminary closure/abandonment plan can be included with the initial permit application. It should include a description of the equipment and materials that will be utilized at the location and a rough estimate of the cost of abandonment and restoration or rehabilitation of the site. Its purpose is to alert the owners and the permitters of the facility to potential abandonment issues so. that they can be prepared for, and possibly minimized, during facility operation. It should also provide an idea of the eventual cost.

Energy facilities often operate for long periods of time. Requiring a detailed, final abandonment plan at the beginning may lock both parties into a program that is outdated by the time the facility is closed. Use of a preliminary closure plan with the original permit may be all that is needed to reduce potential abandonment impacts during operation.



Pinal closure/abandonment plan. A final closure/abandonment plan can be developed closer to the time of closure which will be able to take advantage of the most current technology and be tailored to the actual impacts of the facility rather than to the anticipated impacts at the time of the permit.

A final closure/abandonment plan is much more detailed and includes exact abandonment and restoration procedures that are intended to be carried out by the facility owner. A final plan can be prepared, and receive agency approval, at any time during the permitting or operating stages of a facility, but ideally should be in place before a facility is closed. A final evaluation can be done at the time of closure and revisions of the plan can be made.

WHAT ARE SOME SPECIAL CONSIDERATIONS OF A CLOSURE/ABANDONMENT PLAN?

Questions that need to be considered in an energy facility closure/ abandonment plan include:

- Will equipment or structural changes occur? That is, can the equipment be left as is, or should it be removed or otherwise made inaccessible?
- If fuels or hazardous material have been handled or stored on site, what will happen to them? Will they continue to be stored on site? What will be done with their containment vessels? Has any contamination resulted? How will contaminated soil and water be remediated?

SUGGESTED CONTENTS FOR A FINAL FACILITY CLOSURE/ABANDONMENT PLAN

- A project description including a discussion of future plans for the area occupied by the facility.
- A project schedule including the equipment and personnel needed to accomplish the project, removal plans for equipment with details of procedures, work sequences manpower requirements, water requirements, hazardous material disposal and safety.
- Remediation measures for soils and groundwater (the California Department of Toxic Substances Control may get involved with soil and groundwater contamination)

- Restoration methods for a returning the site to natural conditions and a discussion of topography, soil stabilization and aesthetic values
- Revegetation methods and protection measures for sensitive biological resources during abandonment
- A rezoning discussion of the appropriate zoning for the site based upon surrounding pand uses and future desired use by the land owner.
- A detailed discussion of the potential significant environmental impacts and proposed mitigation measures
- A discussion of financial responsibility and assurance

- Will it be necessary for any maintenance activities to continue? Will site security be required to prevent exposure to hazardous material or dangerous situations?
- Will impacts continue after closure or abandonment? If so, how can they be mitigated?

WHAT ARE THE PRINCIPAL PERMITTING ISSUES OF ENERGY FACILITY ABANDONMENT PLANNING?

The exact requirements for proper facility closure/abandonment will depend upon the type of materials that is/was present at the site, the type of equipment used, and any site specific conditions that would normally be identified in a California Environmental Quality Act (CEQA) analysis at the time of the original permit. For example, if sensitive biological resources have been identified at a facility, mitigation required during construction and operation may need to be addressed during abandonment as well. For energy facilities that were originally permitted before CEQA came into effect, abandonment conditions can be added to subsequent permits, provided the conditions are related to the activities for which the permit is sought. (The federal, state, and local regulatory environment is presented on page 5.7.3.)

One of the best ways to ensure a safe facility when it is closed is to require proper operating conditions when it is open. Proper operating conditions include hazardous materials management plans, accurate record-keeping, and security. In addition, local governments must be concerned with transfer of ownership, financial responsibilities, and the timing for developing and implementing closure plans.

Permit conditions that establish proper operating procedures will allow the operator of a facility to correct problems that are causing contamination and thus reduce the amount of cleanup at abandonment.

Accurate and thorough recordkeeping during construction and operation will make it easier to

"One of the best ways to ensure a safe facility when it is closed is to require proper operating conditions when it is open."

produce an abandonment plan by allowing for an early assessment of environmental issues prior to abandonment. A record of all the known materials that have been used on-site, the location of their storage and use, plus reports of spills or other accidents will aid in the development of the plan. If there are known cultural, biological, or other sensitive areas on-site, it will be easier to decide how to properly close the facility while protecting the resources.

Operations monitoring is also part of an early assessment of potential pre-closure conditions. Such monitoring should ensure that no improper activities occur during the productive life of an energy facility, thus making the abandonment procedure less difficult.

- Site security during the operation of the facility will ensure that no unknown materials are transported to the site, and thus unaccounted for in the records. If potentially dangerous equipment remains on-site after closure, site security may need to continue after abandonment. Hazardous material should not remain on-site after final closure. The closure plan should include timely removal.
- ☑ Transfer of ownership of an energy facility without complete knowledge of the potential closure issues may be a problem. It is important to ensure that new facility owners are subject to the existing permits and abandonment requirements, including timing of abandonment procedure and financial responsibilities.
- Establishing financial responsibility and assurance mechanisms has been used by some local governments to ensure that money will be available to return an energy facility site to an earlier condition, if appropriate, or some other, productive use. (See the table on the following pages.)
- Abandonment timing schedules should be set by local governments. Two schedules should identify when abandonment plans must be completed and when abandonment proceedings must be started. Setting a time limit for when final abandonment plans must be submitted to the local government is necessary so that the plans will be in place when a facility is ready to shut down. It will also give the local government a chance to comment on, and require alterations to, a plan prior to approval and implementation.

SUMMARY EVALUATION OF FINANCIAL ASSURANCE MECHANISMS

(Researched by Santa Barbara County for application to oil and gas facility abandonment and closure)

Financial Mechanism (Availability)	Accessibility	Cost	Effectiveness	Adaptability	
Trust Fund (public or private)	High to moderate for decommissioning	Moderate; about 1% of face value	High, if fully paid; moderate to low if buildup is allowed	High	
Enterprise Euro (puetre only)	Moderate particularly if understrictions on fund use are established	Low, unless funds must be placed in a trust fund	Low, if fund a stanctions only as a same an accounting mechanism: moderate to high if funds are placed in a trust fund.	Moderate to nigh	
Government Securities - • General Obligation Bonds (public only)	Low; laws limit bonding capacity and require voter approval	High to moderate; costs include interest payments, expense of issuing bonds, & expense of holding funds	High if bonds have been issued & use of funds is carefully restricted	Moderate to low; mainly a source of funds, not an assurance mechanism	
• Certificates of Participation (public only)	Low to moderate; avoids some obstacles of bonds; most available for facilities with a large & certain-revenue stream	High to moderate; more expensive than general obligation bonds	Fligh if certificates have been issued & use of funds is carefully restricted.	Moderate to low mainly a source of funds not an assurance mechanism	
• Revenue Bonds (public only)	Low; laws limit bonding capacity & require voter approval; most available for facilities with a large & certain revenue stream	High to moderate; more expensive than general obligation bonds	High if certificates have been issued & use of funds is carefully restricted	Moderate to low; mainly a source of funds, not an assurance mechanism	
l etter of Gredir (public or private)	High for large, financially strong entities, weak for others	Moderate I to 1-5% of face value per year	High		

Financial Mechanism (Availability)	Accessibility	Cost	Effectiveness	Adaptability
Security Bonds (public or private)	Low for decommissioning	Moderate to high; 0.35 to 5% of face value per year	High to moderate	High to moderate
Insurance (public or private)	Unavailable for decommissioning	i Flighto moderate	High to moderate	Very low. becouse decorardisticating, is a certain
				event, but unpredicible un dualeg
Risk Retention Group Coverage (public or private)	Not legal for decommissioning	Moderate to high; likely to be at least as expensive as insurance	Moderate to high, depending on group's financial strength	Not legally authorized
Cash	High for financially strong entitles	Low	High the	. Higja
Corporate Parent Guarantee (private only)	Low; available only to private firms that are subsidiaries with financially strong parents	Low; parent is not likely to charge a fee	Moderate; depends on financial means test that guarantor must pass	Moderate
Financial Means Test (public)	Low in short term because test has only recently been developed; available to financially sound agencies only	Low, agencies passing the test would not be required to pay a third party or to set aside funds	uncertain .	Moderate
Financial Means Test (private)	Moderate if existing test is used as model; available to large, financially sound firms only	Low; firms passing the test would not be required to pay a third party or to set aside funds	Depends on terms of test; does not reduce problem of delays in performance	Moderate

An idle facility must be considered abandoned at some point. Local government policies describing when particular types of facilities will be considered abandoned alert facility operators when something must be done, for example to reactivate the facility or to initiate abandonment procedures.

GENERAL PLAN IDEAS

The following are ideas which can be incorporated into general plan policy language providing they are consistent with goals adopted in the general plan. As is true for any adopted general plan language, if the city or county does not actually implement the language, any action taken by the local government to authorize a project would be subject to challenge based on the lack of implementation of the general plan.

- The city/county can develop a definition of abandoned energy facilities based on the time period during which the facility is not operating at a designated percentage of its potential capacity.
- The city/county can require developers of energy facilities to include a preliminary abandonment plan as part of the original permit for the facility. At least one year before a facility is scheduled to cease operations, the project owner can submit for approval a final abandonment plan that details exactly what will be done to restore the site to its original, preenergy facility condition.
- The city/county can require appropriate operating conditions at energy facilities, including a hazardous materials management plan (if hazardous materials are handled or stored on-site), accurate and thorough record-keeping, and site security. The city/county can

monitor the operations of energy facilities to ensure compliance with all permit conditions, including abandonment planning and implementation.

The city/county can require a status report for all existing energy facilities under its jurisdiction including operational, idle, previously but improperly abandoned facilities, and facilities previously not permitted by the city/county. The status report could assess the issues that may be of concern at abandonment, provide an estimate of the timing of facility closure and abandonment implementation, and estimate the cost of abandonment procedures. The status report could be updated every five years.

IMPLEMENTATION IDEAS

The following ideas can be used for the implementation of general plan policies. Any of the ideas used should, of course, be consistent with the entire general plan.

- Develop a definition of abandoned energy facilities for energy facilities expected to be in operation in the city/county. The local planning department, or other appropriate local government agency, should develop the definition.
- Develop guidelines for the requirements of abandonment plans. See the box on page 5.7.4 for items which can be included.
- Consider requiring an abandonment plan as a condition of a land use or conditional use permit.

- Consider requiring a financial security mechanism of the facility owner to ensure adequate funding for facility abandonment procedures.
- Consider requiring that equipment and construction materials be recycled or reused when feasible.
- Require a periodic status report of all energy facility abandonment plans within the city/county's jurisdiction. Provide a time schedule for when the report is due, and impose fines for late submittal. The fines will provide an incentive to complete the report in a timely manner, and can augment developer fees paid into an energy facility abandonment fund.

CASE STUDIES

Alameda County requires site restoration for wind farms that do not produce electricity for one year and which do not demonstrate to the Zoning Administrator that the equipment will again be operational.

Contact: Steve Richards, Alameda County Planning Department, 399 Elmhurst Street, Hayward, CA 94544, (510) 670-5400.

Glenn County has adopted a policy in its Energy Element to require the dismantling of wind turbine blades within six months of the time when the facility is no longer operational or not producing electricity. If not operated for two continuous years, the site is to be restored to its natural or previous state.

Contact: Glenn County Planning Department, 125 S. Murdock Street, Willows, CA 95988, (916) 934-6540.

Lassen County has an Energy Element policy that requires, as a condition of the use permit, reclamation of abandoned geothermal sites in accordance with an approved reclamation plan and the requirements of the Department of Conservation; Division of Oil, Gas and Geothermal Resources.

Contact: Lassen County Department of Community Development, 707 Nevada Street, Susanville, CA 96130, (916) 251-8269, FAX: (916) 251-8373.

The City of Palm Springs has adopted a zoning ordinance related to Wind Energy Conversion Systems (WECS). Regarding unsafe and inoperable WECS, the ordinance states that any commercial WECS that have not generated power for 12 consecutive months shall be declared a public nuisance which shall be abated by repair, rehabilitation, demolition or removal.

The proper abatement method shall be determined by the Director of Planning and Zoning. If the operator of the WECS can demonstrate that modernization, rebuilding or repairs are in progress or planned and the WECS will be returned to service as soon as possible, the WECS may not be

declared a nuisance. If the power production is halted due to lack of electricity purchase by a contracted utility, that period of non-purchase will be added to the 12 months.

The ordinance requires that when WECS are no longer operable, the site be restored to its condition prior to installation. A bond or other appropriate form of security may be required to cover the cost of removal and site restoration. *Contact:* Richard Patenaude, City of Palm Springs, Department of Planning and Building, P.O. Box 2743, Palm Springs, CA 92263-2743, (619) 323-8245, FAX: (619) 322-8360.

Santa Barbara County is developing a report "Abandonment of Oil and Gas Production Fields and Related Facilities." Proper abandonment is described in the report as the permanent termination of use and the series of steps that lead to the restoration of any oil and gas sites within the county's jurisdiction. The abandonment steps include the removal of all aboveground facilities, the remediation of contamination, the restoration and recontouring of the grounds, the revegetation of the land and, if applicable, the rezoning of the land to its highest and best use in order to protect the public health, safety and welfare, and promote sound land use planning in the county.

The draft report considers a policy to require periodic status reports of all oil and gas production facilities. The status reports will be used to help the county and operators to identify early possible abandonment problems. The reports will also estimate costs of the proper abandonment of a project so that

operators can provide adequate bonding and financial planning. *Contact:* Doug Anthony, Santa Barbara County, Planning and Development Department, Energy Division, 1226 Anacapa Street, Santa Barbara, CA 93101, (805) 568-2040.

INFORMATION RESOURCES

Additional local governments having policies and/or ordinances concerning the abandonment of oil and gas facilities, including wells and pipelines, can be used as a source of information regarding their experiences. These include: San Luis Obispo County, Ventura County, the City of Huntington Beach Fire Department, the City of Los Angeles Fire Department (Harbor Industrial and Commercial Well Unit), and the City of Torrance.

RELATED ISSUES/CHAPTERS

- Air Quality (Chapter 5.1)
- Biological Resources (Chapter 5.2)
- Hazardous Materials Handling and Storage (Chapter 5.3)
- Water Quality and Use (Chapter 5.4)



NOTES NOTES NOTES

DISTRIBUTED GENERATION

CHAPTER 6

ENERGY AWARE
PLANNING GUIDE: ENERGY FACILITIES



CHAPTER 6: DISTRIBUTED GENERATION

The California Energy Commission will provide a new chapter of this Guide in 1997 to address the topic of distributed generation in a more comprehensive manner than included herein. Distributed generation is one portion of a distributed energy 'system.' This system of distributed resources serves local areas only and may consist of small electric generation and storage devices as well as demand-side management techniques. The new chapter will focus on electric generation devices and any storage devices that may be used in conjunction with them. Such devices include small gas-fired generation and cogeneration systems, photovoltaics, fuel cells, small-scale wind turbine development, small-scale batteries and advanced storage technologies.

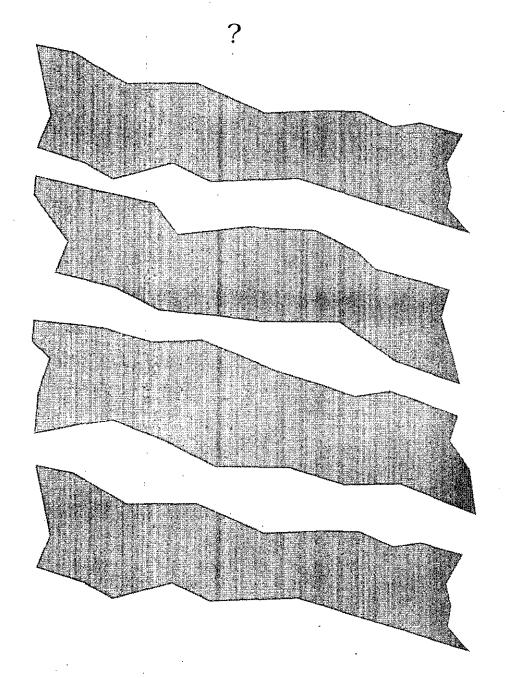
Local governments will want to be knowledgeable about distributed generation and related devices because, due to the devices' relatively small size, local governments will be involved in permitting them. The introduction of more distributed generation devices into communities will provide for greater opportunities, as well as greater necessity, for local governments and local utilities or other energy providers to work together in electrical service planning and permitting efforts. There can be benefits to the communities and to utilities with the use of these devices in specific situations. Such potential benefits, as well as potential permitting issues, will be addressed in the new chapter.

The new chapter will provide information, as current as possible, about new developing technologies and the potential uses of available or soon to be available devices. Rapid technological developments are being made in distributed generation devices. Costs will continue to decrease as markets increase both in this country and abroad. Distributed energy systems can provide possible solutions to the costs and environmental challenges of expanding and upgrading existing electrical systems to meet local increased loads or local electrical demand peaks. We believe that this new chapter will be timely and of particular interest to local governments as both permitters and potential customers. Smooth, efficient, and consistent permitting processes for these devices will benefit local governments, utilities, businesses or others using the devices, and California manufacturers seeking larger markets for the devices.

In this edition of the Guide, the reader can find some discussion of distributed resources in the following areas: page 2.6 and the footnote of page 2.9, page 3.1, Guest Author articles by Carl Weinberg and Donald Aitken at the end of Chapter 3, the glossary, and some of the technologies described in Appendix B.

NOTES NOTES NOTES

APPENDICES ?



ENERGY AWARE
PLANNING GUIDE ENERGY FACILITIES



APPENDIX A: Workshops Participant Lists

Focus Workshops December 1993 - February 1994.

Jay Abbott Manager-Resource Management International

Andy Abele Manager of Office of Technological Advances South Coast Air Quality Management District

Paul Ahern Associate Electrical Engineer City of Redding Electric Department

Eileen Allen Energy Facility Siting Planner California Energy Commission

Merle Anderson Planner Lassen County Planning Department

Thor Bailey Business Development Farm and Resource Management

Brett Bailey Geothermal Resource Technician San Bernardino Municipal Water Department

Larry Baird Policy Analyst California Energy Commission

Patricia Barnes Government Representative San Diego Gas & Electric Nick Bartsch Economic Development Coordinator California Energy Commission

John Benoit
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Department

Jonne L. Berning Manager of Technology Assessment Electric Power Research Institute

Carol Branan Manager Environmental Services Division Sacramento Planning & Development Department

Robert A. Briffett Resource Development Engineer LA Department of Water & Power

Peter Calarco Associate Planner Yuba County Planning & Building Department

Catherine Callahan Planner Santa Barbara County Resource Management Department

Jim Carlisle Senior Electrical Engineer Sacramento Regional Waste Water Treatment Plant

Bill Compton Executive Assistant Southern California Edison Company Judy Corbett
Executive Director
Local Government Commission

Betty Croly Consultant Alameda County Planning Department

John Deakin Director of Bureau of Energy Conservation San Francisco Public Utilities Commission

Steve Dee, AICP, REA Environmental Specialist Sacramento Municipal Utility District

Jeff Demos Consultant PCI USA

Lawrence Erkie Coordination Administrator Southern California Gas Company

Tony Eulo Project Manager Local Government Commission

Ellen Fitzgerald Senior Regional Planning Assistant Los Angeles County Department of Regional Planning

Sandy Fleischmann Planner Siting & Permit Assistance Unit California Energy Commission

Ranji George Program Supervisor South Coast Air Quality Management District Jim Harger

Special Projects Manager Southern California Gas Company

Peter Hill

Planning Manager Sacramento Area Council of Governments

Robert Hondeville

Energy Conservation Supervisor Turlock Irrigation District

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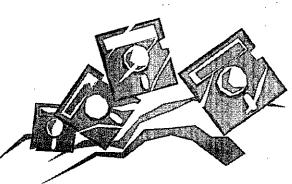
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NOTES NOTES NOTES



APPENDIX B: ENERGY FACILITY DESCRIPTIONS AND ISSUES

USING THIS APPENDIX

This appendix addresses the types of energy facilities that a local government may encounter either. in its planning processes or in permitting a specific project proposed by a developer. It is not intended to be a complete reference manual of every energy facility type, but it can assist local governments in acquiring some familiarity with energy facilities and their potential permitting issues which can improve the permitting process from the standpoint of local governments and of project developers.

You will find a brief overview of a large number of specific energy production, generation, transmission, distribution, and energy storage and management facility: types. (These categories of facilities were briefly defined in Chapter 1.) Facilities discussed include both those that are currently available commercially as well as those that are likely to become available within 12 years (although a few longer-term technologies, such as nuclear fusion and ocean wave energy conversion, are included due to local interest).

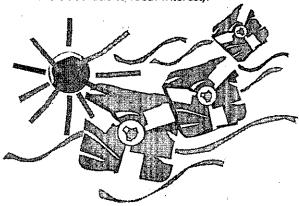
Appendix B contains the following:

- Table B-i is an index for locating the energy facility descriptions. For the purposes of this appendix, the facilities are organized into two broad categories:
 - 1) electric generation and storage and
 - 2) other energy facilities.
- · Table B-ii is a matrix of specific energy facility types and their major potential permitting issues and relative levels of significance. This can be used in conjunction with the issues described in Chapter 5. Please note that issues associated with transmission lines, such as EMF, are included only in the transmission line facility type. However, since transmission lines are connected to most types of generating facilities (power plants), issues related to electrical transmission facilities may accompany them also.

• Energy facility sections which contain facility descriptions, the major equipment configurations and applications, notation of commercial status, potential permitting issues, and references. Some of the sections are based on types of fuel and contain more than one specific facility type.

See Appendix F, "Power Plant Generating Efficiency", beginning on page F.7, for a comparison of typical efficiencies which may be achieved with various generation technologies.

For information on a generating or storage technology not listed in Table B-i, please refer to the Energy Commission's Energy Technology Status Report (ETSR) and/or contact the Energy Commission's Siting and Permit Assistance Program. The ETSR is a biennial staff report that provides technology evaluations for more than 230 electrical generation, storage and transmission, and end-use technologies. It serves as an important reference for use both internally at the Energy Commission and by other research and government institutions. In order to satisfy multiple levels of interest by readers, the most recent ETSR, published in 1992, is available in three forms, ranging from abbreviated to extremely detailed. (See the insert on the following page for more detailed information.)



HOW TO OBTAIN ETSR (Energy Technology Status Report) PUBLICATIONS

Energy Commission publication no. P500-92-007E is the 1992 ETSR Report Summary. It includes a technology evaluation matrix that provides an at-a-glance assessment of each technology's commercial status, major remaining research and development goals, and major deployment issues. Also included in this publication is a summary of the levelized cost of generation for each technology, expressed as a range of costs as a function of facility ownership.

Energy Commission publication no. P500-92-007 is the 1992 ETSR Final Report. It includes all of the information provided in the 1992 ETSR Report Summary plus one-page (front and back) "fact sheets" for each technology. These fact sheets include a description of the technology (often with a simplified schematic of the process), and more detailed information for each technology relative to the technology's commercial status, major research and development goals, and deployment issues. Also included is a list of references used in the development of the ETSR.

Energy Commission publication no. P500-92-007A V1 and P500-92-007A V2 are Volumes 1 and 2 of Appendix A of the 1992 ETSR. Appendix A contains the detailed electric generation technology evaluations, in the form of unabridged research work, which form the basis for all ETSR fact sheets and matrices. This appendix should be referred to when the most detail is needed.

To obtain a copy of these ETSR publications, contact the Energy Commission's Publications Office.

California Energy Commission Publications Office 1516 Ninth Street, MS-13 Sacramento, CA 95814 (916) 654-5200



TABLE B-I INDEX TO ENERGY FACILITY TYPES

ELECTRIC GENERATION AND STORAGE () 2 2 4 5 5 7 6 7 7 7 7 7 7 7 7 7 7 7 7 7 7 7 7	Seeton No
Anaerobic Digestion (biomass- or municipal waste-based)	B-1
Battery storage (utility-scale)	B-2
Biomass (see also Anaerobic Digestion) • direct combustion • thermal gasification	B-3
Coal	B-4
 conventional coal-fired boilers fluidized bed combustors integrated gasification combined cycle 	
Cogeneration (see Natural Gas and Oil, cogeneration)	-
Combined cycles (see Natural Gas and Oil, combined cycles)	
Compressed air energy storage (see Natural Gas and Oil, compressed air energy storage)	
Flywheel energy storage	B-5
Fuel cells	B-6
Garbage burners (see Municipal Solid Waste)	
Geothermal • liquid-dominated • flashed steam • binary • rotary separator • vapor-dominated	B-7
Hydroelectric conventional hydroelectric dam run-of-river pumped hydroelectric (storage) conventional modular	B-8
Magnetohydrodynamics	B-9
Municipal solid waste (see also Anaerobic Digestion) • direct combustion - mass burn • direct combustion - refuse-derived fuel • gasification - pyrolysis/thermal gasification • gasification - landfill gas recovery	B-10

ELECTRIC GENERATION AND STORAGE	u promogram de primogramica	Section No
Natural Gas and Oil advanced gas turbinesboilers		B-11
 cogeneration combined cycles compressed air energy stora repowering 	age	=
simple-cycle gas turbinessteam-injected gas turbines	•	
Nuclear		B-12
fissionfusion	•	
- tusion		
Ocean wave		B-13
Solid Waste (see Municipal Solid W	/aste)	, -
Solar photovoltaic		B-14
 distributed photovoltaic sys 	stems	
 utility-scale systems 	•	
Solar thermal	:	B-15
 concentrating systems 	•	
parabolic troughsparabolic dishes		
parabotic disites central receivers		
• salt ponds		
Waste-to-energy (see Anaerobic Di	gestion, Biomass, and Municipal S	Solid Waste)
Wave power (see Ocean Wave)		•
Wind		B-16
distributed wind systems utility-scale systems		
OTHER ENERGY FACILITIES		
Electrical transmission and distribu	ution systems	B-17
Energy production wells (oil, gas, a	and geothermal)	B-18
Ethanol and methanol production	facilities	B-19
Alternative fuel charging/fueling st	tations	B-20
Geothermal direct use		B-21
Petroleum and petroleum product	storage facilities	8-22
Pipelines (petroleum, petroleum p	roducts, and natural gas)	B-23
Refineries		B-24
Terminal facilities	•	R-25

TABLE B-II MATRIX OF ENE	RGY FAC	CILITY T	YPES VS	MAJOR F	ERMITTI	NG ISSUI	ES	
POWER PLANTS	Hazardous Materials Hand- ling and Storage	Air Quality	Water Use and Quality	Electromagnetic Fields	Biological Resources	Nuisance (Noise, Odors, andVisuat)	Energy Facility Abandon- ment/Closure	Land-intensive
ANAEROBIC DIGESTION (B-1)			*		4000			
BATTERY STORAGE (utility-scale) (B-2)								
BIOMASS (B-3)				******************************				
Direct Combustion		l Si se anter estar						
Thermal Gasification	isi kanan							
COAL (B-4)								
Conventional Coal-fired Boilers			ì					
Fluidized Bed Combustors								
Integrated Gasification Comb. Cycle		4			and the same			
FLYWHEEL ENERGY STORAGE (B-5)								
FUEL CELLS (B-6)		<u> </u>	<i>X/////</i>	<u> </u>	X/////	X//////	<i>X//////</i>	
GEOTHERMAL (B-7)								
Liquid-Dominated				-				
Flashed Steam								
Binary								e de la composition della comp
Rotary Separator (retrofit)								
Vapor-Dominated								
HYDROELECTRIC (B-8)								
Conventional Hydro						·		
Dam						<u>.</u>		**
Run-of-River								
Pumped Hydro (storage)							·	
Conventional		X/////						
Modular								
MAGNETOHYDRODYNAMICS (B-9)								
* Potential impact if no proper shielding	The same of the same same same same same same same sam	and an area of the second second	and teneral 12 color 16 sept.	mat	The second secon		A Commission of the Commission	
= no or insignificant issue	potentia	ally mod	lerate iss	sue	= po	tentially	significar	nt issue

TABLE B-ii MATRIX OF ENE	RGY FAC	ZILITY T	YPES VS	MAJOR I	ERMITTI	NG ISSU	ES	
POWER PLANTS (continued)	Hazardous Materials Hand- ling and Storage	Air Quality	Water Use and Quality	Electromagnetic Fields	Biological Resources	Nuisance (Noise, Odors, andVisual)	Energy Facility Abandon- ment/Closure	Land-intensive
MUNICIPAL SOLID WASTE (B-10)	<u> </u>		l				<u></u>	-
Mass Burn (direct combustion) Refuse-Derived Fuel (dir. combustion)		\$ ***						
Pyrolysis/Thermal Gasification	hand it has a set	Contract to the second	المسترية					
Landfill Gas Recovery								
NATURAL GAS AND OIL (B-11)								
Advanced Gas Turbines						9		
Boilers						Consideration and		
Cogeneration			ع لنسب					
Combined Cycles	404 Jan 100 100							
Compressed Air Energy Storage				<i>\\\\\</i>	******			
Simple-Cycle Gas Turbines							100	
Steam-Injected Gas Turbines								
NUCLEAR (B-12)	and alcoholysis and	¥77777		<i>V </i>				
Fission								
Fusion	77777						har see that the	
OCEAN WAVE (B-13)		<u> </u>	Simus 1 1 2 2	<u> </u>			. New .	
SOLAR PHOTOVOLTAIC (B-14)	Y////	X/////	VIIII	A	(/////	X/////	N/////	v
Distributed Photovoltaic Systems				***		<u> </u>	<u> </u>	
Utility-Scale Systems	<u> </u>	X/////	<i>X/////</i>	<u> </u>	8.544		-3-2-65-65-	
* Potential impact if no proper shielding.								
	i						_	
= no or insignificant issue	= poteni	tially mo	oderate i	ssue	= po	tentially	significan	nt issue

POWER PLANTS (continued)	Hazardous Materials Hand- ling and Storage	Air Quality	Water Use and Quality	Electromagnetic Fields	Biological Resources	Nulsance (Noise, Odors, andVisual)	Energy Facility Abandon- ment/Closure	Land-intensive
SOLAR THERMAL (B-15)		<u> </u>		·		J		
Concentrating Systems	<u> </u>		,					
Parabolic Troughs						_		
Parabolic Dishes (no gas assist)								J - 1. " J
Parabolic Dishes (gas assist)						9.0		
Central Receivers					114			(sam laransa)
Salt Ponds								
WIND (B-16)								w
Distributed Wind Systems								
Utility-Scale Systems								
OTHER ENERGY FACILITIES						20.		
Elec. Trans. & Distr. Systems (B-17)		<u> </u>			7°			
Energy Prod. Wells (oil, gas, geo) (B-18)								
Ethanol and Methanol Production (B-19)					**			
Alt. Fuel Charging/Fueling Stations (B-20))				-			
Electric Vehicle Charging		X////			\ ////	<u> </u>	<i>X/////</i>	
Liquified Petroleum Gas			X////			<u> </u>	<u> </u>	
Methanol and Ethanol			X////	X////	X/////	X////	X////	X///
Natural Gas		X////	X////	X////	X////		X////	
Geothermal Direct Use (B-21)		X////	X////	X////			X////	
Pet. & Pet. Product Storage Facilities(B-22	2)		100					
Pipelines (B-23)	4.44		114					
Refineries (B-24)							- ·	
							iii e	620(2)

= potentially moderate issue

= potentially significant issue

= no or insignificant issue

B-1. ANAEROBIC DIGESTION

Anaerobic digestion is one of three major waste-to-energy technologies (the others are Biomass and Municipal Solid Waste, discussed in Sections B-3 and B-10, respectively). Anaerobic digestion, also known as methane fermentation or biological gasification, uses microbiological methods to produce a gas from biomass fuels such as animal manure, or municipal waste fuels such as sewage sludge from sewage treatment facilities.

The anaerobic digestion of municipal solid waste mixed with sewage sludge or manure can also occur in what is called high-solids digestion. This process is currently undergoing research and development, and is close to commercialization.

The resulting gas, called biogas or digester gas, is a mixture primarily of methane and carbon dioxide. Note: the natural anaerobic digestion process that occurs in landfills is discussed separately in Section B-10, Municipal Solid Waste.

The most basic anaerobic digesters are covered lagoons where the natural microbial activity within the lagoon generates biogas that is then captured by the cover. An alternative digester design consists of mixing tanks with a mechanism for stirring in order to obtain even suspension of the sludge particles. The tanks can be either above ground or sunk into the ground part way. Temperature affects the rate of digestion and should be maintained in the range between 95°F and 105°F.

Other equipment typically includes holding tanks or lagoons, covers, piping, and other vessels for reactions, along with the power generation equipment. Another digester design involves pushing

the waste through a cylindrical reactor over a period of time. This design is called a plug flow digester and can be used with waste streams with a higher solids concentration. Mixing occurs as a result of the friction between the waste and the digester walls as it is pushed through. Solids concentrations can be on the order of 11 to 13% by volume. A typical fuel is municipal solid waste mixed with sewage sludge.

In order for an anaerobic digester to be economical, the cost of transporting the organic waste from its place of origin to the digester must be kept to a minimum. Thus, digesters are typically located at wastewater treatment facilities or large dairies. Systems are typically small and custom-designed for the particular quality and production rate of the waste.

Biomass-based fuels. Biomassbased fuels that are suitable for anaerobic digestion include highmoisture agricultural food processing wastes (such as tomato and grape pomace and cheese whey) and animal manures from dairies and feedlots. While manure may be available as a fuel source yearround, agricultural food processing residues may only be available during certain months.

In each of these cases, the fuel is free at the source. It must, however, be collected, processed and either used on-site or transported to an off-site location. Where unprocessed wastes cause odor and water pollution, such as in large dairies, anaerobic digestion reduces the odor and liquid waste disposal problems and produces a clean fuel suitable for electricity generation. Typically the biogas is combusted in an engine-generator, producing between 10 kW and 2 MW.

Sewage sludge as a fuel. — Anaerobic digestion is a mature technology used in municipal wastewater treatment. Anaerobic digestion has been used for many years primarily to stabilize the sewage sludge, and thus reduce pollution from it. Power production from the biogas produced has historically been seen as a secondary benefit.

After treatment in anaerobic digesters, the remaining sewage sludge is still high in water content, with only one percent to three percent solids. The treated sludge can be spread over large parcels of land without further processing, or it can be dried or otherwise processed to produce a cake-like product that consists of 15 percent to 30 percent solids. That material can then be transported fairly economically and is suitable for a number of final applications, including composting, land application, and combustion.

The Hyperion Energy Recovery System operated by the city of Los Angeles recovers the biogas created by the anaerobic digestion of waste-activated sludge and primary-treated sludge. The biogas is scrubbed for hydrogen sulfide removal and then used as a fuel in a combined-cycle cogeneration plant consisting of four gas turbines and one back pressure turbine, for a total of about 15 MW gross.

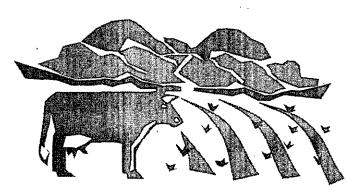
The remaining treated sludge then undergoes mechanical dewatering and evaporation processes to dry the sludge. The resulting sludge powder is then gasified under high temperature, and the gas produced is then combusted and additional electricity is produced in a steam turbine. See section B-10 (Municipal Solid Waste) for more on electricity generation via thermal gasification.

- Permitting Issues Some of the major issues associated with anaerobic digestion facilities include:
 - Ability to meet air quality requirements
 - Ability to ensure that health risks are kept to a minimum (since the pre-digested organic waste may contain diseasecausing organisms, especially in the case of sewage sludge or animal manures)
 - Possibility of odor nuisance if wastes are stored prior to digestion
 - Disposal or further processing of remaining (treated) highwater-content sludge (although the treated sludge is safer than the untreated sludge)
 - Possible impact to groundwater if leaching beds are used
 - Ability to handle accidental spills;
 - Changes in visual quality (although these may be minor if the digester system is located at the site where the wastes are received or produced)

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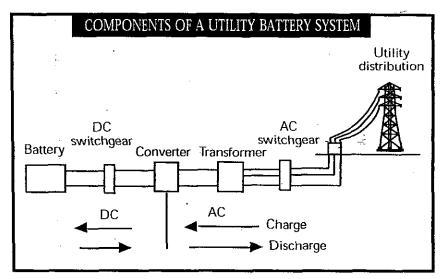


B-2. BATTERY STORAGE (UTILITY-SCALE)

Utility-scale batteries are modular energy storage devices that store electricity in chemical form for use at a later time. Such batteries are typically charged with relatively inexpensive, off-peak electricity and are then discharged during peak demand periods, releasing their stored energy as electricity (see figure). Using this "load leveling" process, utilities have an alternative to the traditional approach to meeting peak loads by adding more generation capacity. Batteries can be used for many other utility applications such as reliability and power quality, transmission and distribution equipment deferral, spinning reserve, and frequency regulation. A battery system provides the largest value. when it is used for more than one application at the same installation.

Unlike other storage technologies, such as conventional pumped hydroelectric which can range up to hundreds of MW in size, battery storage systems are much smaller and are appropriate for applications in small distribution areas as well as at the utility service area level. In addition, batteries can be located virtually anywhere, including urban areas, and can be controlled remotely. They can achieve full load in about five milliseconds.

There are three major types of utility-scale battery technologies that have been selected by the U.S. Department of Energy's (DOE) Utility Battery Storage Systems Program as the prime candidates for further analysis and development: lead-acid, sodium/sulfur, and



SOURCE: "Utility Battery Storage Systems Program Plan". FY 1994 - FY 1998; U.S. Department of Energy

zinc/bromine. 1 Of these, only the lead-acid battery is available commercially. Southern California Edison (SCE) has installed a 10 MW/40 MW-hr2 flooded lead-acid battery storage system at its Chino substation that has been in operation for more than seven years. It is the largest load-leveling utility battery system in the world. The Puerto Rico Electric Power Authority (PREPA) has a 20 MW flooded lead-acid battery in operation in San Juan which primarily provides spinning reserve capability and frequency control support to the island. Due to their satisfaction with the performance of the system, PREPA has decided to install a second battery storage system.

The U.S. DOE program is attempting to develop an improved valveregulated (sealed) lead-acid (VRLA) battery that will match or exceed the performance of the flooded lead-acid battery at a cost equal to or lower than the flooded lead-acid battery without sacrificing the inherent VRLA advantages (low maintenance, spill- and leak-proof, no hydrogen hazard during charging, and compact installation.)

A recycling industry is already in place for worn out cells (the automotive battery industry is based on lead-acid batteries.) The two other more advanced types of batteries being developed by the DOE program, the sodium/sulfur and the zinc/bromine, are still in the early stages of development and are not expected to be available commercially until the year 2000. These advanced batteries are expected to have potentially long lives (30 years versus five to 10 years for lead-acid batteries) and lower costs than lead-acid batteries. A recycling industry will need to be developed for these technologies. The recycling of sodium/sulfur batteries is environmentally benign. The recycling of zinc/bromine batteries is also relatively benign, but is slightly

¹ The names refer to the chemicals inside the battery cells.

² Utility-scale batteries are typically identified by their maximum power and energy capabilities. Thus, the SCE battery is capable of producing a maximum power output of 10 MW. It is able to sustain that power output for four hours (i.e., 10 MW for four hours equals a total energy discharge of 40 MW-hr.)

more complicated. However, neither type of battery involves the use of hazardous materials.

The batteries themselves do not emit any pollutants, although there could be emissions from the generating sources that are used to charge the batteries (e.g., if the generating sources are fossil fuelfired). Depending on the air emissions characteristics of the generating sources which charge the batteries off-peak versus the air emissions characteristics of an alternative fossil fuel-fired technology which may otherwise be required to meet the peak load, there could be a substantial net air quality benefit (in terms of amount of pollutants emitted as well as the timing of their release.)

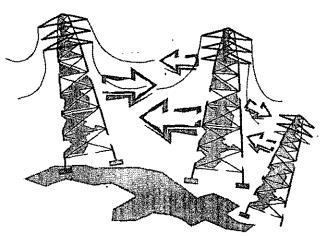
Permitting Issues. Only a small amount of land is required for battery systems (about 0.6 to 1.5 kWh of energy storage per square foot, or 26 to 65 MWh of energy storage per acre), which can probably be found at most typical substations. Spill containment and fire prevention equipment is reguired. The only water pollution occurs in the event of an acid spill-(flooded lead-acid batteries only.) If there is a spill, the acid must be neutralized, treated with absorbents, and the absorbents disposed of as hazardous wastes.

There are no air quality, noise, or odor impacts. Visual impacts are limited since batteries would typically be located at existing or planned substations. The battery would be considered to be hazardous waste and would need to be recycled or disposed of accordingly at the end of its life.

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- f) 1992 Energy Technology Status Report, Appendix A, Volume II: Detailed Electric Generation Technology Evaluations, California Energy Commission, Report no. P500-92-007A V2, December 1992. Section 16.3 (Utility Battery).
- g) TAGtm Technical Assessment Guide: Electricity Supply - 1993, Volume 1, Rev. 7, Electric Power Research Institute Report No. EPRI TR-102275-V1R7, June 1993.
- h) Telephone conversation with Abbas Akhil (Sandia National Laboratories), April 27, 1995.



B-3. BIOMASS

Biomass is one of three major waste-to-energy technologies (the others are Anaerobic Digestion and Municipal Solid Waste, discussed in Sections B-1 and B-10, respectively). Biomass power plants typically use biomass resources (e.g., residues from forestry and forest product mill operations, residues from agricultural field crops and food processing operations, and manure) as fuel in one of three processes: direct combustion systems that produce heat used to generate electricity via boiler/steam turbine subsystems; thermal gasification systems that create a "producer gas" which is combusted in boilers or engine-generator sets; and anaerobic digestion reactors which create a "biogas" that can then be combusted in boilers or engine-generator sets.

Anaerobic digesters, which can use biomass residues such as animal manure and high-moisture agricultural food processing wastes as well as municipal wastes such as sewage sludge, are discussed separately in Section B-1.

Forestry and forest product mill residues are generated from logging and mill processing operations, respectively. The amount of logging residue is directly related to the amount of timber harvested; hence, forestry-based biomass plants are highly dependent on the economics of the timber industry. Forestry and mill residues are generally available throughout the year. Large biomass facilities, however, typically stockpile three to six months or more of fuel, in order to minimize the impact of potential supply disruptions.

Agricultural crop residues include wastes generated from field crops such as straw as well as fruit and nut crops. Agricultural crop residues are generally available only during a two- to four-month harvesting season, typically between the months of May through December. As a result of this limited availability, biomass plants may use mixtures of agricultural and forestry residues with varying harvest seasons, or they may stockpile the fuel in order to maintain year-round operation.

Agricultural food processing residues include waste from processing berries, fruits, grains, nuts, and vegetables. Such residues are divided into low- and highmoisture content categories, since different energy recovery processes are used for each. Low-moisture content wastes, such as pits, shells, and nuts, are potentially suitable for the combustion and gasification technologies discussed below. High-moisture content wastes, such as tomato and grape pomace, are suitable for anaerobic digestion processes and are discussed separately in section B-1.

In 1992, 66 biomass direct combustion facilities were operating in California. These facilities had a total capacity of about 850 MW. This represents the largest biomass energy industry of any state in the U.S. The seven million bone dry tons (BDT) per year of biomass residue used by these facilities represents only about 15 percent of the total bio-mass resource potential of 47 million BDT identified in a collaborative study by the California Energy Commission and the U.S. Department of Energy's Western Regional Biomass Energy Program. Of the 47 million BDT potential, livestock manure is the most abundant resource, accounting for more than 25 percent of the total. Chaparral and field and seed crop residue together contribute over 30 percent of the total biomass resources potential. Less abundant are lumber mill waste, forest stash, and urban yard wastes. Fruit and nut crops, food processing waste, urban wood wastes, vegetable crops, energy crops, and nursery crops contribute the least amount of biomass.

As mentioned previously, only 15 percent of this total biomass potential is being used for energy production purposes (although another 16 percent is used for nonenergy commercial purposes such as conversion to fertilizer and plywood.) The biomass resources that are currently being used for energy production include lumber mill waste, livestock manure, urban wood waste, forest slash, food processing waste, fruit and nut crop residue, and field and seed crop residue.

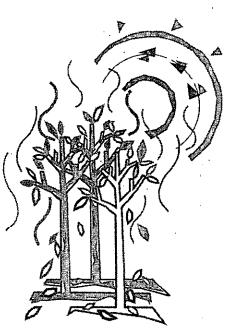
Wood waste is the primary fuel source in the biomass combustion industry. It accounted for about 73 percent of the total biomass fuel consumption in 1990. Of the 66 biomass direct combustion facilities, 61 use wood wastes either exclusively or in combination with other biomass resources.

At present, the outlook for both existing biomass plants as well as new plants is uncertain, due primarily to economic barriers. Many existing biomass plants are qualifying facilities (QFs) that have Interim Standard Offer 4 (ISO4) contracts that were first made available in 1983. The ISO4 contracts provide the option for some QFs to obtain fixed energy prices for up to ten years, after which energy prices

revert to the short-run avoided cost of the purchasing utility.

The short-run avoided cost, which is tied to natural gas prices, is far below the fixed, forecasted energy prices specified in the ISO4 contracts at the end of the fixedprice, ten-year period. As a result, QFs are experiencing substantial revenue reductions once they reach the "Year 11 Cliff.". See Chapter 2, section 2.1 for more on the topic of QF contracts.

In addition to the economic problems faced by many existing biomass plants, new facilities may not be cost-effective, especially in a more competitive environment. The capital costs for biomass facilities tend to be high compared to natural gas-fired combined cycle plants. In addition, the fuel cost for the industry's most popular fuel, wood waste, increased dramatically during the 1980s due to increased demands associated the rapid growth of the industry. At present, California biomass



energy producers are examining new ways to become more market competitive. Among the concepts being investigated are ways to reduce or eliminate biomass fuel costs (e.g., by accepting biomass "wastes" directly at the power plants), restructuring their debt load, and reconfiguring their electricity generation profiles (to optimize the generation of electricity during the utilities peak periods). In addition, biomass energy producers are investigating their capability to generate alternative high value products (such as ethanol) that could help diversify and increase their revenue streams.

BIOMASS DIRECT COMBUSTION

Direct combustion of biomass employs conventional steam boiler technology. There are four basic methods: pile burners; spreaderstokers which include fixed, dumping, and travelling grates; suspension and cyclonic burners; and fluidized bed combustors. In California, the most typical configurations used for biomass are spreader-stokers and fluidized bed combustion systems. However, the type of combustion system used depends on the properties of the fuel being combusted. For example, fluidized bed combustion systems are more commonly associated with facilities handling agricultural residues, while spreader-stokers are more typically used at facilities fueled primarily with forestry residues.

As mentioned earlier, there were 66 biomass direct combustion facilities operating in California in 1992. Most of these facilities are relatively small, generally averaging around 20 to 25 MW.

- Permitting Issues for Biomass Direct Combustion Facilities. Some of the major issues associated with biomass combustion facilities include:
 - · Reliability of the fuel source (both in terms of supply and price stability)
 - · Possible difficulty and space constraints associated with stockpiling the biomass fuel
 - · Ability to meet air quality requirements
 - · Disposal of ash
 - · Possible classification of the ash as a hazardous material
 - · Use of large amounts of water for cooling purposes (if wet cooling towers are used)
 - · Possible impacts on the longterm harvesting of agricultural and forestry residues if the lumber or agricultural practices upon which they depend are disrupted
 - Removal of forestry residues must be conducted in a manner to minimize impacts such as excessive soil disturbance by machinery, increased soil erosion, disturbance of wildlife habitat and migration routes, and interruption of forest nutrient recycling if too much residue is removed
 - Transportation and noise impacts from the transportation of the biomass from its point of creation to the centrally-located energy facility (generally not a factor with on-site facilities such as farms or food processing facilities, or small off-site facilities)

BIOMASS GASIFICATION

Biomass gasification involves reacting biomass residues in the presence of very limited quantities of air or oxygen. This thermochemical conversion process generates a producer gas containing hydrogen, methane, carbon monoxide, nitrogen, water, and carbon dioxide. This gas can then be burned directly in a boiler, or scrubbed for combustion in an engine-generator set to produce electricity.

Biomass gasification technology using air as the oxidant is commercially available for the generation of producer gas and its subsequent burning in a boiler. While the producer gas can also be used in engine-generator sets to produce electricity, it is necessary to clean (scrub) the gas of particulates, tars, and oils before it can be burned in an engine.

Currently, no commercially operating biomass gasification facilities of any type are in California. There may be, however, some limited development of biomass gasification facilities in California in the future, particularly if there are dramatic improvements in the technology and/or significant increases in electricity prices.

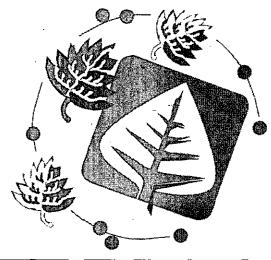
Permitting Issues for Biomass Gasification Facilities. In general, many of the issues already identified for biomass direct combustion facilities also apply. In addition, there may be wastewater streams produced that would require treatment.

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- e) 1992 Energy Technology Status Report, Appendix A, Volume I: Detailed Electric Generation Technology Evaluations, California Energy Commission, Report no. P500-92-007A V1 December 1992. Sections 1.3.2 (Biomass Fuels), 8.0 (Bio-massfired Plants), 8.1 (Biomass Direct Combustion), and 8.2 (Biomass Gasification).



B-4. COAL

Coal deposits form from plant materials by the action of heat, supplemented by pressure, over millions of years. The major elemental components of coal are carbon, hydrogen, and oxygen. Minor elements include sulfur, silicon, nitrogen, aluminum, iron, calcium, magnesium, potassium, sodium, and titanium.

Coal is by far the most abundant. fossil fuel in the U.S. At the beginning of 1985, the demonstrated reserve base, which is the amount considered to be technically and economically minable, was 478 billion tons (where one average ton of coal has the same heating value of 22,000 cubic feet of natural gas). Neither California nor its nearby states of Oregon, Nevada, Idaho, and Arizona have any significant coal reserves. While other states with large coal reserves pursued coal-fired technologies, California turned to its own indigenous resources, especially oil.

The delivered price of coal can be influenced more by transportation costs than by coal production costs, and thus the lack of significant in-state coal reserves has an impact on the economics of coalfired projects. In addition, coalfired plants emit more pollutants (on a pounds of pollutant per fuel heating value basis) than natural gas-fired plants. These factors, coupled with California's more stringent air pollution control requirements and the high cost of obtaining off-sets, have had a significant impact on the economics of in-state coal-fired projects.

As of 1992, 17 coal-fired plants with a total capacity of 553 MW were located in California. These plants are in Amador, Contra Costa, Kern, Los Angeles, San Bernardino, and San Joaquin counties. These plants represent 1.0 percent of the total capacity of California's power plants.

No utility-owned coal-fired power plants are operating in California (although California utilities own and operate coal-fired plants in other states.) Each of California's existing coal-fired plants is owned by a third-party power producer and is a qualifying cogeneration facility which produces useful thermal energy for an industrial process in addition to electricity production.

The three major types of coal conversion either commercially available or demonstrated on a commercial scale in California are: conventional pulverized coal-fired boilers, fluidized bed combustion boilers, and integrated coal gasification combined cycles. Another technology that can use coal, Magnetohydrodynamics, is discussed separately in Section B-9.

The U.S. Department of Energy's (DOE) Clean Coal Technology Demonstration Program is a \$6.9 billion cost-shared industry/ government technology development effort. The purpose of the program is to demonstrate a new generation of advanced coal-based technologies, with the most promising technologies being moved into the domestic and international marketplaces.

The 45 technologies being demonstrated in the DOE program seek to reduce the emissions of air pollutants and wastes, while achieving energy conversion efficiencies

equal to or greater than technologies currently available. Nineteen of the projects are aimed at emission control technologies that can be retrofitted to existing pulverized coal facilities, while six projects involve fluidized bed combustors and another six projects invotve integrated gasification combined cycles.

While no California utilities are participating in the program, nor are any of the 45 demonstrations taking place in California, it is possible that advancements from the Clean Coal Technology Program will result in the commercialization of coal technologies that can meet California's stringent air pollution control requirements while being cost-competitive with other fuel options.

CONVENTIONAL PULVERIZED COAL-FIRED BOILERS

Pulverized coal (PC) combustion boilers with steam turbine power generation are currently the principal electric power generation technology in the U.S., accounting for approximately 42 percent of the national generating capacity in 1991 (although there are only a handful of such plants in California.)

The major components of a PC plant typically include: coal handling equipment, steam generator equipment, turbine-generator, flue gas desulfurization equipment, electrostatic or mechanical particulate control, and bottom and fly ash handling equipment. Coal handling equipment includes the facilities needed to receive (typically by rail), store, control fugitive emissions from, convey, and pulverize the coal.

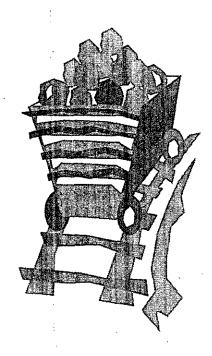
The pulverized coal is then combusted in a conventional boiler, where steam is generated to operate a steam turbine-generator to create electricity. Some of the resulting ash exits the bottom of the boiler in solid form as bottom ash, which is handled by bottom ash handling equipment.

The combustion products which exit the boiler, known as the flue gas, are then routed to an electrostatic or mechanical particulate collection system. The particulate matter collected, called fly ash, is then handled by fly ash handling equipment. Both the bottom and fly ash need to be disposed of as wastes or can be sold. A flue gas desulfurization system is required to remove sulfur oxides, which contribute to acid rain formation.

Conventional pulverized coal technology is losing ground to new coal use technologies such as fluidized bed combustion and integrated gasification combined cycles. Thus, it is unlikely that there will be any new pulverized coal plants proposed in California.

- Permitting Issues for Conventional Pulverized Coal-fired Boilers. Some of the major permitting issues associated with conventional pulverized coal-fired boilers include:
 - Ability to control fugitive emissions from, and prevent spontaneous ignition of, coal piles
 - · Ability to control the quantity of air pollutants in the combustion products, particularly nitrogen oxides, sulfur oxides, and particulate emissions
 - · Disposal of ash, and other wastes from flue gas desulfurization

- Possible classification of waste streams as hazardous materials. thereby restricting the number of allowable disposal sites and raising disposal costs
- Use of large amounts of water for dust control, coal washing, boiler makeup, wet cooling towers (if applicable), ash quenching, and desulfurization of the flue gas
- Biological impacts on the ocean or lake or river water due to thermal discharge (if oncethrough cooling is used)
- · Changes to visual quality due to power plant structures and coal unloading, handling, and storage facilities, as well as emissions from power plant stacks
- · Noise impacts from coal delivery, crushing, and handling facilities



- · Likely public opposition because of uncertainties over air quality, health and safety, and odor impacts from fugitive coal dust during handling and storage, and waste handling and storage
- · Possible poor public opinion due to concerns over acid rain and coal strip mining

FLUIDIZED BED COMBUSTION **BOILERS**

Fluidized bed combustion (FBC) reduces emissions of sulfur dioxide and nitrogen oxides compared to conventional pulverized coal plants. This is accomplished by controlling combustion parameters and by injecting a sorbent (such as crushed limestone) into the combustion chamber along with the coal. Crushed coal mixed with the crushed limestone is suspended on jets of air (or fluidized) in the combustion chamber. Sulfur released by the coal as it burns is captured by the limestone before it can escape from the boiler. The sulfur combines chemically with the limestone to form a new solid waste product, a mixture of calcium sulfite and calcium sulfate. Some of that solid waste is removed with the bottom ash. while the remaining solid waste is captured by the baghouse or other particulate collection systems.

The operating temperature of FBCs is about half that of conventional boilers, which helps minimize the formation of thermally-induced nitrogen oxides. As a result, less add-on equipment is typically needed to deal with nitrogen oxide emissions.

Some of the advantages of FBCs compared to conventional PC units include:

- The fluid-like motion of the solids in the combustion chamber promotes good mixing.
- The superior mixing permits combustion at substantially lower and more evenly distributed temperatures, thereby reducing the formation of nitrogen oxides.
- All types of coal or coal wastes can be used, including high-ash coals, because FBC can be designed for a wide variety of feedstock.
- The waste generated is a dry, benign solid that can be disposed of easily, or usefully employed (e.g., as material for road or building construction).

The two types of FBC include atmospheric fluidized-bed combustion (AFBC) and pressurized fluidized-bed combustion (PFBC). In AFBC plants, the combustion takes place at atmospheric pressure. Much of the equipment employed by conventional PC plants is used in AFBC plants, except for changes in the boiler configuration and the absence of post-combustion sulfur dioxide scrubbing equipment. AFBC technology is considered to be commercially available. The ACE Cogeneration Company has been operating a 100-MW AFBC plant in Trona (San Bernardino County) since 1990.

In PFBC plants, the combustion takes place at elevated pressures of about 16 times that of atmospheric. This results in the ability to produce electricity from a gas turbine cycle as well as a steam turbine cycle, which results in potentially higher energy conversion efficiencies, more compact plant size, and reduced capital costs compared with AFBCs.

However, PFBC technology is still in the demonstration phase, and has yet to demonstrate the favorable capital cost and long-term performance characteristics that are expected of commercial units.

- Permitting Issues for Fluidized Bed Combustion Boilers. Some of the major permitting issues associated with FBC boilers include:
 - Ability to control fugitive emissions from, and prevent spontaneous ignition of, coal piles
 - Ability to control both nitrogen oxide and carbon monoxide emissions
 - Disposal of significant amounts of alkaline solid waste (due to both the coal and limestone)
 - Possible classification of waste streams as hazardous materials, thereby restricting the number of allowable disposal sites and raising disposal costs
 - Use of large amounts of water for dust control, coal washing, boiler makeup, wet cooling towers (if applicable), and ash quenching
 - Biological impacts on the ocean or lake or river water due to thermal discharge (if oncethrough cooling is used)
 - Changes to visual quality due to power plant structures and coal unloading, handling, and storage facilities
 - Noise impacts from coal delivery, crushing, and handling facilities

- Likely public opposition because of uncertainties over air quality, health and safety, and odor impacts from fugitive coal dust during handling and storage, and waste handling and storage
- Possible poor public opinion due to concerns over acid rain and coal strip mining

INTEGRATED COAL GASIFICATION COMBINED CYCLES

Coal gasification consists of the integration of a coal gasification plant (which converts the coal into a clean fuel gas) and a gas-fired combined-cycle plant (which runs on the gasified coal). The basic components of an integrated gas-ification combined-cycle (IGCC) plant include: a coal preparation plant, a gasification unit, gas clean-up systems, and a combined-cycle plant.

The coal preparation plant sizes the coal and often mixes it with water to allow slurry injection into the gasifier. The coal is fed into either an air- or oxygen-blown gasifier. If the gasifier is oxygen-blown, an air separation plant is required to produce the oxygen. Water is introduced into the gasifier either in the slurry or via direct steam injection.

The resultant hot, raw, synthetic gas (syngas) is cleaned to remove tars, oils, acids, particulates, and sulfur. If the gas is cooled during the clean-up, steam is often raised for process use or power generation. The clean gas can then be burned in a conventional combined-cycle power plant consisting of one or more combustion turbine-generators, heat recovery steam generator(s), and a steam turbine-generator. The ash and

elemental sulfur are often suitable for sale. The tars and oils can be re-injected into the gasifier.

From 1984 to 1989, Southern California Edison (SCE) and the other Cool Water Program participants operated the first utility-scale demonstration IGCC power plant in the U.S. The Cool Water facility demonstrated the ability to achieve low emissions, and it produced a non-leachable ash that was stored at the site. Its continued operation after the end of the five-year demonstration period was denied by the Energy Commission due to its high operating costs and lack of need for the power by SCÉ.

Several years have elapsed between the end of the Cool Water demonstration and the current round of demonstration projects. The five "second-generation" IGCC projects now underway in the DOE's Clean Coal Technology Program will demonstrate a full range of variations in IGCC process: different gasifiers, different sizes, different coals, different cleanup systems, and different applications (including both "greenfield" and repowering). Three of these projects have either recently begun operation or will begin operation within a year.

The technology is not considered to be commercially available at this time, primarily because the economics of the technology have not been adequately demonstrated, nor has the performance of the second-generation IGCC projects been demonstrated. The technology has the potential to become commercial available about the year 2005.

- Permitting Issues for Integrated Coal Gasification Combined Cycles. Some of the major permitting issues associated with IGCC facilities include:
 - Ability to control fugitive emissions from, and prevent spontaneous ignition of, coal piles
 - Toxic streams produced in intermediate processes that could harm plant personnel in the event of uncontrolled leaks
 - · Possible classification of waste streams as hazardous materials, thereby restricting the number of allowable disposal sites and raising disposal costs
 - · Use of large amounts of water for dust control, coal washing, heat recovery steam generator makeup, wet cooling towers (if applicable), and ash quenching
 - · Biological impacts on the ocean or lake or river water due to thermal discharge (if oncethrough cooling is used)
 - · Changes to visual quality due to power plant structures and coal unloading, handling, and storage facilities
 - · Noise impacts from coal delivery, crushing, and handling facilities
 - · Likely public opposition because of uncertainties over air quality, health and safety, and odor impacts from fugitive coal dust during handling and storage, and waste handling and storage
 - · Possible poor public opinion due to concerns over acid rain and coal strip mining

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- e) Clean Coal Technology: The Investment Pays Off, U.S. Department of Energy Report No. DOE/FE-0291 (Revised), July 1995.

B-5. FLYWHEEL ENERGY STORAGE

Flywheel energy storage (FES) systems are also known as electromechanical batteries (note that electro-chemical batteries are discussed separately in Section B-2 (Battery Storage (Utility-scale)). Like electro-chemical batteries, they are modular energy storage devices that store electricity for use at a later time. Whereas electrochemical batteries convert electrical energy to chemical energy as a storage mechanism, flywheels convert the electrical energy to mechanical energy (kinetic energy stored in rotational motion).

Flywheels have typically been used as short-term energy storage devices for propulsion applications such as locomotive engines or large road vehicles. Advances in recent years of high strength/lightweight materials, high performance magnetic bearings, and power electronics technology have spurred a renewed interest by the transportation, utility, and manufacturing industries in FES technologies. Several companies are developing flywheels as load-leveling power devices for hybrid electric vehicles. In addition, American Flywheel Systems, Inc. is developing a flywheel as an energy storage system for pure electric vehicles.

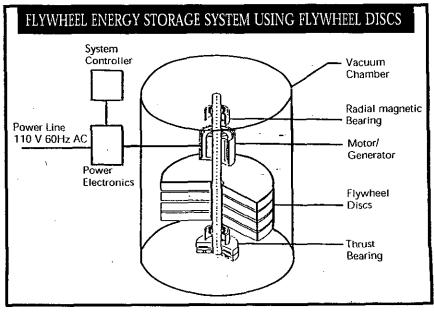
FES units can be used for utility dynamic energy storage (e.g., to improve frequency control, stability, and power quality), uninterruptible power supplies to protect electronic equipment and electrical machinery, and can be used to improve the utilization of intermittent energy sources such as wind and solar. They are especially well-suited for high-power applications with short-duration (minutes) discharge times that cycle frequently. While early studies of

flywheel energy storage considered designs with storage capacities up to 10 MWh and peak power outputs of 1 MW (i.e., they could provide 1 MW of power for 10 hours, or a lesser amount of output for longer than 10 hours), more recent studies are focusing primarity on much smaller units ranging from 1 kWh to 300 kWh, with maximum power outputs in the range of 10 kW to several hundred kW (i.e., they could provide 10 kW to several hundred kW for only a matter of seconds or minutes).

One arrangement for a flywheel energy system consists of the flywheel discs and hub, the variable frequency field motor/generator, the bearings and suspension equip-ment, the vacuum chamber/ con-tainment structure, and the power electronics and auxiliary systems (see figure entitled Flywheel Energy Storage System Using Flywheel Discs). Another arrangement, which is probably more typical of future designs that use composite materials for the flywheel, uses a rim (cylinder) design with the motor/generator inside the rim (see figure entitled Flywheel Energy Storage System Using 'Rim and Web' Configuration).

The flywheel (typically made of a high-strength, low-density graphite fiber composite material) is charged from a source using inexpensive off-peak electricity. That electricity runs the motor which turns the flywheel. A flywheel can be spun-up to full "charge" (i.e., its design rotational speed) in a matter of minutes. The magnetic bearings and vacuum chamber are required to minimize the friction losses which would result in self-discharge and a . tremendous heat load. The charged flywheel is then discharged when a load is applied, transmitting energy out of the system via the generator. The power electronics serve to regulate the frequency and voltage of the electrical output, since the rotational speed (frequency) of the flywheel changes as energy is discharged from the device.

FES systems are expected to have high "round-trip" energy storage efficiencies of about 85 to 95 percent (i.e., 85 percent to 95 percent of the electrical energy required to charge the flywheel can be retrieved when needed). They can be designed for a 20- to 30-year lifetime. The self-discharge time

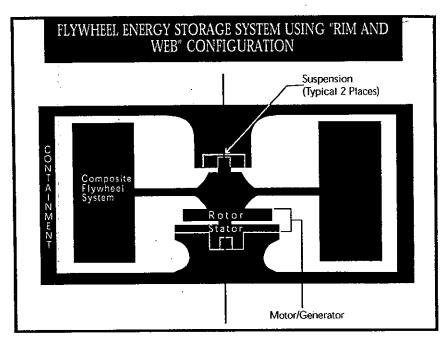


(the time required for the flywheel to slow to a stop when idling) could be potentially on the order of months.

Lawrence Livermore National Laboratory has entered into cooperative research and development agreements with Trinity Flywheel Batteries Inc. and Westing-house Electric Corporation to com-mercialize a flywheel designed to provide about 100 kW of power for up to 30 seconds. Trinity Flywheel will manufacture the flywheel batteries for use by Westinghouse's "Active Power Line Conditioner" system to smooth electric flows and ride through power outages. Trin-ity Flywheel is taking commercial orders for this design. The entire system is about 14 inches in diameter and 14 inches high.

Many small units could be used in paratlel for larger storage needs. Their modular nature and small size make them easy to ship and install in increments, thereby providing a close match between storage supply capacity and energy and capacity demands. Several flywheels operating in parallel could be used to defer distribution system upgrades by handling part of the load that might otherwise overload a substation transformer that is operating near its limit during daily load peaks.

In another development effort, Argonne National Laboratory is working with Commonwealth Edison Company (CECo) of Chicago on the development of a large-scale flywheel for utility loadfollowing and ramping applications. They are focusing on a flywheel design that could provide one MW of power for up to five hours. Their goal is to demonstrate smaller flywheels in the next few



years, leading to full-scale commercial demonstration and deployment of up to 2000 units by 1998. The one MW flywheel system would be approximately 10 feet in diameter.

The technology currently suffers from high capital costs. However, it is expected that capital costs will decrease as the economies associated with increasing production volume are realized. In addition to high capital costs, development work is focusing on the development of vacuum and magnetic bearing technologies in order to reduce friction losses and improve stability, as well as the development of flywheel materials and housing designs in order to improve safety.

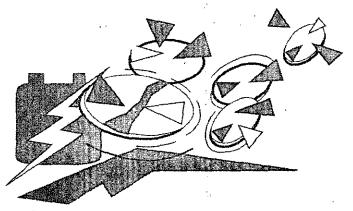
Flywheel systems could be sited either in underground or aboveground locations. Underground. siting has the advantage of minimizing the potential for damage from vehicular impacts. The flywheel could be housed in a thinwall steel casing in a reinforced concrete bunker with a highstrength lid. An effective aboveground design could incorporate a 'crash wall" liner that would contain the flywheel in the event of a major failure. Such a crash wall would also be adequate to protect the assembly from outside impacts.

Permitting Issues. Flywheels are relatively benign with respect to environmental impacts. There are no emissions or hazardous materials associated with the flywheel storage technology itself (although there could be emissions and hazardous material usage associated with the generating technologies which supply the electricity stored by the flywheel as kinetic energy.) Visual and land use impacts are limited since the systems are small and could easily be sited at existing or planned substations. Since the unit is operated in a vacuum, the noise transmitted to the environment will be minimal. As a result, FES systems can be sited in any industrial or utility setting.

The only significant safety issue is containment of the wheel structure in the unlikely event of mechanical failure during operation (the flywheels can operate at speeds of tens of thousands of revolutions per minute). It is anticipated, however, that the containment structure(s) can be adequately designed to support high-speed failure of the rotor.

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B-6. FUEL CELLS

A fuel cell, like a battery, transforms chemical energy into electrical energy directly, without a combustion process. It essentially consists of a cathode, an anode, and an electrolyte. Unlike a typical battery, a fuel cell requires a continuous supply of fuel and oxygen, but the fuel cell itself does not undergo material transformation. Hence, it never needs to be recharged.

Hydrogen-rich fuel gas (e.g., natural gas or methane) is supplied to the anode side, and oxygen (in the form of air) is supplied at the cathode side. The electrolyte material separating the anode and cathode provides a medium for the exchange of ions. The overall reaction combines hydrogen and oxygen to produce electricity, water, and heat. Since fuel cells produce direct current (dc) electricity, an inverter converts the power to alternating current (ac) before it can enter the utility system (see figure).

A fuel cell supplied with pure hydrogen and oxygen would emit no pollutants. When air is used to supply the oxygen, however, and when a fuel other than hydrogen is used (for example, natural gas, methanol, or gasified coal can be used in conjunction with a fuel reformer), there will be low levels of carbon dioxide emissions and there could be very low levels of hydrocarbons, carbon monoxide, and nitrogen oxides. Since fuel cells also produce water and heat as byproducts, they are well-suited for cogeneration applications.

Fuel cells have many benefits which make them particularly attractive in both utility-scale and distributed use systems. Their modular size makes it easy to

match the fuel cell plant capacity to the electric power needed (load). Their unique operating characteristics make them particularly attractive for load following (since they can operate at part load with a minimal loss of efficiency), distribution line voltage control, power quality control capability, and spinning reserve capability.

Fuel cells can easily be sited near electrical load centers in urban areas due to their minimal land use requirements, low emissions, minimal noise, modular nature, and ability to operate unmanned while being monitored remotely. The discharge water which is chemically created by the fuel cell is within sanitary sewer discharge standards and would meet local regulatory requirements. These attractive features make them easy to site at distribution substations, hotels, hospitals, jails, office buildings, and universities.

Several types of fuel cells are currently under development. These fuel cell types are categorized by electrolyte type. They include phosphoric acid, molten carbonate, solid oxide, alkaline, and proton exchange membrane.

Phosphoric acid fuel cells (PAFCs) are considered to be commercially available by the U.S. Department of Energy. More than 50 of International Fuel Cells/ON\$I Corporation's 200 kW PAFCs are in use. These units have achieved a total operational time of 439,000 hours with 95 percent availability. They have achieved a chemical-toelectrical conversion efficiency of 40 percent (lower heating value), and they generate about 700,000 Btu/hr of heat (which is enough to meet the thermal needs in many commercial and residential buildings). The overall cogeneration efficiency (electrical plus thermal)

is 85 percent (lower heating value). Emissions are so low that the South Coast Air Quality Management District has waived air pollution permitting.

The company's newest model, the PC-25C, is expected to have comparable performance bût will be one-third smaller and lighter than its predecessors. The PC-25C (fuel cell only) can fit in a space 10 feet wide by 18 feet long by 10 feet high.

Molten carbonate and solid oxide fuel cells are less far along in the development process. Unlike PAFCs (which operate at about 200°C), these two types operate at very high temperatures (approximately 650°C and 1,000°C respectively). This allows the potential for internal reforming of hydrocarbon fuels (thereby eliminating the need for an external fuel reformer) and also results in high-quality (high temperature) by-product heat being made available for a wider range of cogeneration applications.

The Santa Clara Demonstration Project is the world's first demonstration of a utility-scale molten carbonate fuel cell power plant. The 2 MW facility began operation in April 1996 and will undergo a demonstration period that lasts through 1998. The goals of that project are to demonstrate the low heat rate (high efficiency), acceptable reliability, operability, and maintainability. Energy Research Corporation plans to commercially introduce its Direct Fuel Cell power plants for dispersed generation and other power stations by the late 1990s, based on the results of the Santa Clara Demonstration Project.

M-C Power Corporation has developed its 250-kW molten carbonate fuel cell in conjunction with the U.S. DOE, the Gas Research Institute, and electric and gas utilities which include Southern California Edison, Southern California Gas, and San Diego Gas & Electric. The company is testing one fuel cell at UNOCAL's Fred L. Hartley Research Center in Brea. California. A second 250-kW power plant is located at the U.S. Naval Air Station Mirimar in San Diego. The M-C Power Corporation team plans to develop a 1-MW market-entry fuel cell system, with commercial availability targeted for 1999.

Other utilities are pursuing molten carbonate fuel cells that use gas mixtures produced from landfills or from the type of biomass decomposition occurring in anaerobic compositors.

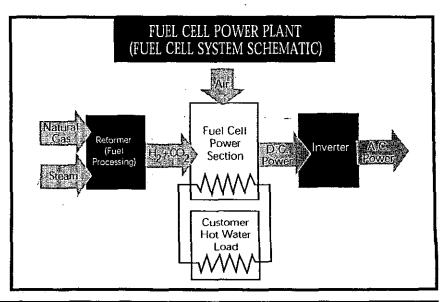
Alkaline and proton exchange membrane (PEM) fuel cells are currently being developed for transportation, space, and military applications. Several companies are aggressively developing PEM systems for a variety of applications. Potential utility applications for PEM fuel cells are primarily distributed generation uses, for remote areas, as well as for peak power supplies in urban and suburban locales. Systems over 50 kW are most likely to be used initially with transit buses. Once the market for larger systems develops, stationary applications should be cost effective for peaking and distributed generation applications. Fuel reforming and processing must develop in parallel with PEM development in order for PEM systems to be used widely.

In order for fuel cells to become fully commercialized, there are several remaining barriers that need to be overcome. These include high capital cost, improved efficiency, and demonstration of long-term reliability and performance.

Permitting Issues. There are no significant permitting issues associated with commercially-available phosphoric acid fuel cells.

- a) Resource: An Encyclopedia of Energy Utility Terms, Pacific Gas and Electric Company, 2nd edition, 1992, pp. 221-222.
- b) 1994 Energy Development Report: Volume I, Committee Draft, 12/9/94, Chapter 2, p. 4.
- c) "Fuel Celts Turn Up The Heat", Mechanical Engineering, December 1994, pp. 62-65.
- d) "Market Entry of 200-kW Phosphoric Acid Fuel Cell Power Plants", Electric Power Research Institute Technical Brief #RP3061, November 1994.

- e) Distributed Utility Valuation Project Monograph, Electric Power Research Institute Report No. TR-102807, PG&E Report No. 005-93.12, July 1993, pp. 95-102.
- f) Sacramento Municipal Utility District Advanced and Renewable Technologies Development Program -1994 Annual Update, Sacramento Municipal Utility District, 1994.
- g) 1992 Energy Technology Status Report-Final Report, California Energy Commission, Report no. P500-92-007, December 1992. Fact Sheet 15.1 (Fuel Cells-Phosphoric Acid Utility-Scale Applications), 15.2 (Fuel Cells - Molten Carbonate), 15.3 (Fuel Cells-Solid Oxide), 15.4 (Fuel Cells-Alkaline), and 15.5 (Fuel Cells-Proton Exchange Membrane).
- h) 1992 Energy Technology Status Report, Appendix A, Volume II: Detailed Electric Generation Technology Evaluations, California Energy Commission, Report no. P500-92-007A V2, December 1992. Sections 15.0 (Fuel Cells).



- i) Maier, Lonn and Ira Saletan, 1993. Draft Initial Study and Negative Declaration for the SMUD Headquarters Complex Fuel Cell Project (ONSI PC-25 Phosphoric Acid Fuel Cell). Sacramento Municipal Utility District.
- j) Maier, Lonn, 1992. Draft Negative Declaration and Initial Study for the SMUD Kaiser Medical Center-South Fuel Cell (ONSI PC-25 Phosphoric Acid Fuel Cell). Sacramento Municipal Utility District.
- k) Blaisure, Diana, 1992. Negative Declaration for the Hyatt Regency Hotel Fuel Cell (ONSI PC-25 Phosphoric Acid Fuel Cell). City of Irvine Department of Community Development; Irvine, California.
- I) Kinoshita, K. et al., Fuel Cells: A Handbook. U.S. Department of Energy, Office of Fossil Energy; Morgantown, West Virginia.
- m) ONSI Corporation, 1990. PC-25 On-Site Fuel Cell Power Plant Application Planning Guide. South Windsor, Connecticut.

- n) Appelby, A.J., and F.R. Foulkes, Fuel Cell Handbook, Van Nostrand Reinhold Publishers, New York, NY, 1988.
- o) "Fuel Cells Make Gains in Power Generation Market", Cogeneration and Competitive Power Journal, Winter 1995, Volume II, No. 1.
- p) "Current Status of Two Molten Carbonate Fuel Cell Installations", Cogeneration and Competitive Power Journal, Winter 1995, Volume II, No. 1.

B-7 GEOTHERMAL

Geothermal energy is the naturallyoccurring heat from the interior of the earth. Thermal energy within the earth approaches the surface in many different geologic formations: volcanic eruptions, geysers, fumaroles, mud pots, fault zones, and thermal springs. California has the largest geothermal energy potential of any state in the nation. At present, only a small part of California's available geothermal reserves are. being used.

As of 1995, there were 6,798 MW of geothermal generating capacity installed worldwide. Of this, 2,817 MW are installed in the U.S., Philippines, Mexico, Italy, Japan, and New Zealand. Predictions call for worldwide generating capacity to reach 9,960 MW in 2000.

Geothermal resources can be classified as hydrothermal, hot dry rock, geopressured, and magma. Hydrothermal resources contain hot water (i.e., are liquid-dominated), steam (i.e., are vapor-dominated), or a two-phase mixture of water and steam. Hot dry rock resources do not have fluids that can transport the energy away from the high-temperature subsurface rock, and therefore requiré

water from a surface source to be injected into the hot rock region in order to serve as a heat transfer medium. Geopressured geothermal systems (not found in California) are essentially liquid-dominated resources that also contain significant levels of natural gas and hydraulic energy. In a magma system, heat is derived directly from a shallow molten magma body.

While California's hot dry rock and magma development potential is enormous compared to the current and potential future hydrothermal resource development, those two resource types are currently in early stages of development. Promising areas for future development of hot dry rock resources include Glass Mountain and Mono-Long Valley Known Geothermal Resource Areas (KGRAs), and the Geysers-Clear Lake region. Potential magma resource sites in California include the Mono-Long Valley and Coso Hot Springs KGRAs.

Hydrothermal resources are the most abundant source of presently usable geothermal energy. Geothermal power plants using hydrothermal resources are operational in Imperial, Inyo, Lake, Lassen, Mono, and Sonoma Counties.

In a hydrothermal system, water in sub-surface aquifers is heated by geothermal energy. The elevated temperature of the water creates a convection system which transfers the heat energy to the surface. In rare instances, the heat is great enough to vaporize the water, creating a steam reservoir (a vapordominated resource). The only vapor-dominated resource in the U.S. is found in California at the Geysers KGRA in Lake and

Sonoma counties, where reservoirs contain dry superheated steam with average temperatures of about 390°F.

In most hydrothermal systems, however, the reservoir is liquiddominated. Unlike the Geysers steam-resource, liquid-dominated systems of varying temperature are quite abundant and are found throughout California. A power plant for a high-temperature liquiddominated resource above 350°F typically uses a flash steam cycle. A rotary separator turbine can be used in conjunction with flashed steam technologies for additional power output. A binary cycle is the best choice for power generation for liquid-dominated moderate-temperature resources between about 220°F and 350 °F.

Low-temperature resources (below 220 °F) are not suitable for power generation, but can be used in direct heating applications (see Section B-21 entitled Geothermal Direct Use.)

VAPOR-DOMINATED **RESOURCES**

Electricity generation using vapordominated resources at the Geysers KGRA is a standard geothermal technology using conventional steam turbine-generators. The power plants there use dry steam produced from numerous production wells, and the steam from several wells is piped to the steam turbine-generator through extensive collection systems (see Section B-18 entitled Energy Production Wells (oil, gas, and geothermal) for more information on geothermal wells.)

Worldwide, dry steam power plants account for approximately 3,000 MW. Most of this development, 2,098 MW, is constructed at The Geysers. The generating capacity of the facilities in The Geysers range from 12 to 138 MW. The newer units have a typical capacity of 55 and 110 MW, although there are three 20 to 30 MW facilities.

After exiting the steam turbinegenerator, the steam is condensed with cooling water and pumped to evaporative cooling towers. About 70 percent to 75 percent of the geothermal steam exits the cooling towers as water vapor, while the remaining 25 percent to 30 percent is injected back into the ground via injection wells.

The geothermal steam contains high concentrations of chemicals and compounds in solid, liquid, and gaseous form. Non-condensable gases (primarily carbon dioxide, along with lesser amounts of hydrogen sulfide (H₂S), sulfur dioxide (SO₂), ammonia (NH₂), methane (CH₄), nitrogen, and others) can range from 0.1 to 5 percent of the steam. These gases must be treated before being discharged to the atmosphere via the cooling towers. Other emissions can include mercury, radon, arsenic, boron, and trace metals. Mitigation measures are employed so that emissions meet air and water quality standards.

Geothermal resources are considered to be renewable only if the rate of geothermal steam or liquid extraction does not exceed the rate at which the resource is renewed by the earth's heat. When the rate of energy extraction to generate electric power exceeds the natural recharge rate, energy production from the reservoir declines.

Although a nearly inexhaustible supply of heat occurs, the supply of water to transfer the heat is limited in the Geysers. The installed capacity at the Geysers was 2098 MW gross; the current generating capacity is around 1285 MW due to the de-cline in steam production. As a result, no new installed capacity is anticipated at the Geysers. The decline of steam to the existing geothermal power plants can usually be delayed by adding more production wells and reworking existing wells.

Some of the major issues associated with the existing Geysers power plants include:

- Long-term availability (and variability of quality) of the resource
- Air pollution from the gases and metals contained in the steam
- Substantial volumes of waste are generated during all phases of geothermal development (well drilling, power plant construction and operation), with the most toxic wastes being generated from operation of air pollution abatement systems
- Potential for unintentional contamination of ground and surface water due to accidental release of geothermal fluid containing arsenic, sulfur, heavy metals, salt, etc.
- Destruction and disturbance of habitat and cultural and paleontologic resources due to steam pipelines, generation facilities, well pads, and access roads
- Changes in visual quality from undisturbed and rural to industrial

- Increase in ambient noisé levels as well as the occurrence of major noise-producing events such as the discharge of steam when power plants shut down
- Possible localized subsidence (sinking of the land) around production wells and uplifting around injection wells

LIQUID-DOMINATED RESOURCES — FLASHED STEAM

The geothermal brine is brought to the surface and piped to a separation tank, where the pressure is reduced, causing the fluid to flash into steam. The steam is then passed through a turbine to generate power. The steam exiting the turbine is condensed in much the same manner as with dry steam plants. Less of the resource, however, is lost during evaporative cooling since less than half of the geothermal water that is produced actually flashes to steam. The remaining water that does not flash into steam is then injected back into the reservoir.

Flashed steam technology is used at six power plants operating in the Imperial Valley, with a combined capacity of 310 MW. There are also 272 MW of power plants operating in the Coso Geothermal Field, east of Bakersfield. The remaining potential for electricity generation is estimated to be 3,800 MW.

Permitting Issues for Flashed Steam Technology. All of the issues already mentioned for vapor-dominated resources also apply to flashed steam technologies. In addition, Imperial County has a policy requiring 100 percent injection of the fluids withdrawn from a geothermal reservoir (although they have permitted most

power plants with an injection requirement of 80 percent or more.) Such a policy reduces the potential for adverse impacts caused by subsidence, but also has the effect of requiring makeup water for flashed steam plants that use evaporative cooling systems.

LIQUID-DOMINATED RESOURCE — ROTARY SEPARATOR

The rotary separator turbine is a relatively new device that converts two-phase (geothermal liquid and vapor) flow energy into shaft power. In addition to shaft power, the turbine performs separation of the vapor from the liquid, and pressurizes the separated liquid. The turbine can be used in conjunction with traditional flashed steam technology in new applications, or can be retrofit to existing flashed steam power plants.

With conventional flashed steam plants, no power is generated when two-phase flow is flashed into steam and the remaining liquid is separated from the steam (and in fact, power is required to pressurize the remaining liquid brine and pump it back into an injection well). The rotary separator turbine can substitute for the gas-liquid separation tank. By taking advantage of the two-phase flow energy, it produces power while accomplishing the separation process, and eliminates the need for pumps to re-inject the brine. The net result is that the power output of a . combined rotary separator-flashed steam system can be approximately ten to thirty percent higher than a conventional flashed steam system using the same geothermal resource.

A wellhead power plant with a Biphase rotary separator turbine (Model 30 RSB) is being constructed at Cerro Prieto, Mexico. This model is sized for application as a topping turbine for use at most geothermal projects that have medium to high pressure resources. The first unit will increase the electricity production due to given well flow by more than 40%.

Permitting Issues for Rotary Separator Technology. For applications where the rotary separator turbines are retrofitted to existing power plants, there are no significant permitting issues associated with the rotary separator turbines.

LIQUID-DOMINATED RESOURCES - BINARY

Binary cycle technology incorporates two distinct closed fluid loops to generate electricity. The first loop passes the hot geothermal brine from the reservoir to a heat exchanger, where the heat vaporizes an organic fluid contained in the second loop. The second loop contains an organic fluid with a low boiling point, such as freon, isobutane, pentane, or other hydrocarbon. The vaporized hydrocarbon is piped to a turbine-generator, condensed, and returned to the heat exchanger in order to be vaporized again. The geothermal brine is injected back into the reservoir after giving up some of its heat in the heat exchanger.

Since the geothermal brine operates in a closed loop, no gases or other pollutants contained in the geothermal fluid are released to the atmosphere. The binary working fluid can be condensed using either air cooling or evaporative cooling (wet cooling towers).

Binary technology is used at five plants operating in the Imperial Valley, with a combined capacity of 96 MW. In Mono County, there are three plants operating with a combined capacity of 35 MW. Lassen County has two binary plants under 2 MW plus a 35 MW geothermal/biomass hybrid plant in operation.

- Permitting Issues for Binary Technology. Some major issues are associated with geothermal binary power plants:
 - Long-term availability (and variability of quality) of the resource
 - Air pollution associated with leaks in the working fluid loop and from wet cooling towers if agricultural wastewater is used for cooling water
 - Use of large amounts of cooling water (if wet cooling towers are used)
 - Destruction and disturbance of habitat and cultural and paleontologic resources due to generation facilities, well pads, and access roads
 - Changes in visual quality from undisturbed and rural to industrial

- a) Resource: An Encyclopedia of Energy Utility Terms, Pacific Gas and Electric Company, 2nd edition, 1992, pp. 231-232.
- b) "Getting the Most Out of Geothermal Power", *Mechanical Engineering*, September 1994, pp. 76-80.
- c) Committee Draft Energy Development Report, Volume II, December 9, 1994, p.6.

- d) Draft Geothermal Element to the Siskiyou County General Plan, February 1984, pp. 120-135.
- e) 1992 Energy Technology Status Report - Final Report, California Energy Commission, Report no. P500-92-007, December 1992. Fact Sheet 6.1 (Vapordominated Resources), 6.2.1 (Liquid-dominated Resources -Flashed Steam), 6.2.2 (Liquid-dominated Resources - Binary Cycle), 6.2.3.1 (Biphase Topping Cycle), and 6.2.3.2 (Biphase Bottoming Cycle).
- f) 1992 Energy Technology Status Report, Appendix A, Volume I: Detailed Electric Generation Technology Evaluations, California Energy Commission, Report no. P500-92-007A V1, December 1992. Sections 1.3.1 (Fuel Cycles Geothermal), 6.0 (Geothermal), 6.1 (Vapordominated Resources), 6.2.1 (Flashed Steam), 6.2.2 (Binary Cycle), and 6.2.3 (Biphase)

B-8. HYDROELECTRIC

Hydroelectric power, a renewable resource, is generated by hydraulic turbines which rotate due to the force of moving water as it flows from a higher to a lower elevation. The water can be flowing in natural streams and rivers or contained in man-made facilities such as reservoirs, pipelines, and canals. There are two main categories of hydroelectric power generation; conventional methods, which produce electricity via water flow in one direction (and are therefore dependent on seasonal runoff), and pumped storage methods, which are both producers and consumers of electricity as the water used to generate electricity can be recycled by pumping it back uphill.

Two types of conventional hydroelectric facilities are dams and runof-river. Dams raise the water level of a stream or river to an elevation: necessary to create a sufficient elevation difference (water pressure, or head). Dams can be constructed of earth, concrete, steel, or a combination of such materials. Dams may create secondary benefits such as flood control, recreation opportunities, and water storage. Run-of-river, or water diversion, facilities typically divert water from its natural channel to

run it through a turbine, and then usually return the water to the channel downstream of the turbine.

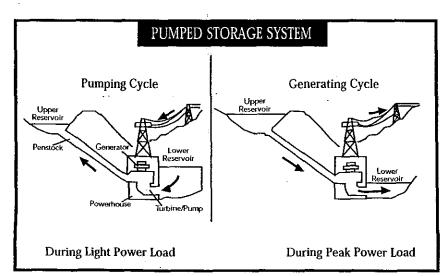
Such conventional methods offer the potential for low-cost baseload electricity, but their output is dependent on the time of year as well as annual precipitation. In contrast, pumped storage methods are typically used to provide power during peak demand periods on very short notice and are not dependent solely on runoff.

In a pumped storage facility, water is pumped during off-peak demand periods from a reservoir at a lower elevation for storage in a reservoir at a higher elevation. Electricity is: then generated during peak demand periods by releasing the pumped water from the higher reservoir and allowing it to flow downhill through the hydraulic turbine(s) connected to generators (see figure).

During the off-peak pumping cycle, the pumped storage facility is a consumer of electricity: in fact, the amount of electricity required to pump the water uphill is greater than the amount of electricity that is generated when the water is released during peak demand periods. However, pumped storage facilities are economical because they consume low-cost offpeak electricity, but generate highvalue on-peak electricity.

Pumped storage methods include both typical on-stream conventional and modular off-stream technologies. The major differences between modular pumped storage (MPS) and conventional pumped storage is that MPS systems are much smaller, use closed water systems that are artificially created instead of natural waterways or watersheds, and sites are selected with predetermined elevation differences so that modular pre-engineered equipment can be used. With the exception of evaporative losses, reservoirs are charged only once, either with groundwater or even municipal wastewater.

- Permitting Issues. Some of the issues associated with conventional hydroelectric power generation and typical on-stream pumped hydroelectric storage facilities include:
 - Water resources impacts (hydroelectric facilities may change stream flows, reservoir surface area, the amount of groundwater recharge, and water temperature, turbidity [the amount of sediment in the water] and oxygen content)
 - Biological impacts such as the possible displacement of terrestrial habitat with a new lake environment, alteration of fish migration patterns, and other impacts on aquatic life due to changes in water quality and quantity
 - · Possible damage to, or inundation of, archaeological, cultural or historic sites (primarily if a reservoir is created)



- · Changes in visual quality
- Possible loss of scenic or wilderness resources
- Increase in potential for landslides and erosion
- Recreational resources may be gained

Because MPS systems are not dependent on natural waterways and watersheds, they can be sited in areas that avoid many of the issues described above. In fact, desirable sites are not near rivers, lakes, streams, and other sensitive environmental areas in order to avoid the regulatory complexity and time associated with conventional pumped hydroelectric storage facilities.

- a) Resource: An Encyclopedia of Energy Utility Terms, Pacific Gas and Electric Company, 2nd edition, 1992, pp. 171, 238-239, 341-342, and 363-364.
- b) Small But Powerful A Review Guide to Small Alternative Energy Projects for California's Local Decisionmakers, Association of Bay Area Governments, September 1987, pp. 14, 36-41.
- c) Glenn County Energy Element of the General Plan, June 1993, pp. 119-127.

- d) 1992 Energy Technology Status Report - Final Report, California Energy Commission, Report no. P500-92-007, December 1992. Fact Sheet 7.1 (Conventional Hydroelectric), 16.1.1 (Conventional Pumped Hydroelectric), and 16.1.2 (Modular Pumped Hydroelectric).
- e) 1992 Energy Technology Status Report, Appendix A, Volume II: Detailed Electric Generation Technology Evaluations, California Energy Commission, Report no. P500-92-007A V2, December 1992. Sections 16.1.1 (Pumped Storage Hydroelectric) and 16.1.2 (Modular Pumped Storage).

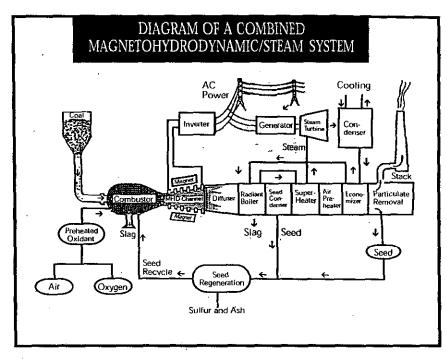


B-9. MAGNETOHYDRO-DYNAMICS

Magnetohydrodynamics (MHD) is the process of generating electricity by passing a conductive fluid or plasma through a magnetic field. Even though the MHD process has been recognized since Faraday discovered the properties of magnetism and electricity in 1832, the technologies that make MHD cost-effective are just now starting to become available. There is still much work to be done before a commercial MHD system is in operation.

The MHD generator consists of a channel surrounded by a large, powerful magnet through which hot gases (at about 5000 degrees F) from a fossil fuel combustor flow (see figure). The combustion product gases are seeded with a highly conductive salt, such as potassium carbonate. Also, the combustion air is preheated or enriched with oxygen in order to raise the temperature (and therefore the conductivity) of the gas or plasma. At near sonic speed, these hot gases are forced through the channel to produce a direct current (DC) electrical potential across the many pairs of electrodes. Power conditioning equipment then normalizes the outputs of the electrode pairs, and the inverter converts the DC electricity to alternating current (AC) in order to be compatible with the power grid.

After passing through the magnets, there is a considerable amount of heat remaining in the plasma which can be recovered in a heat recovery steam boiler and steam turbine-generator for additional electricity production. In fact, the high temperature of the combustion products leaving the MHD generator is compatible with the



design conditions of many existing steam power plants. Thus, one likely application for MHD is to retrofit an existing coal-fired steam power plant. First-generation MHD power plants may have thermal efficiencies of 40 percent to 50 percent, while mature plant efficiencies may be as high as 60 percent. Mature MHD plants could offer the highest energy conversion efficiency of any advanced coal technology.

The potassium-based seed which was injected into the combustor reacts with sulfur in the fuel, and the products are then removed from the system in the form of potassium sulfate. The potassium sulfate is then regenerated in a process which recovers the original potassium-based seed and separates out the sulfur and ash.

Magnetohydrodynamics can use coal or other combustible fuels. The primary fuel of interest in the U.S. for MHD is coal because MHD can potentially provide important efficiency and pollution

control benefits needed for coal technologies (See section B-4 for a discussion of other commercially available and advanced coal technologies.) One company, however, has investigated the possibility of a California MHD project using petroleum coke (the residual material left when crude oil is refined into finished products) as a fuel.

MHD is currently constrained by several technical and economic issues. Among these are: material strength and durability; development of efficient high-pressure combustors, superconducting magnet technology, and electrodes that can withstand the harsh environment of a MHD channel; development of economical inverters and power conditioning equipment; demonstration of adequate downstream heat and seed recovery; and most importantly, integration of these components into a unified generating system.

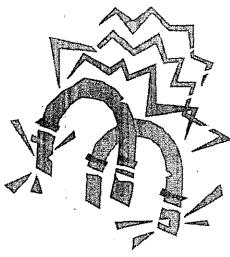
Thus, MHD technology is considered to be in the early stages of development. The U.S. Department of Energy's MHD Proof-of-Concept program was investigating three key subsystems at three different sites:

- 1) The topping cycle portion of . the MHD/steam combined-cycle power plant (which includes the coal combustor, MHD channel which converts the ionized gas flow into direct current, and the DC-to-AC inverter and other power conditioning equipment)
- 2) The bottoming cycle portion (which includes the radiant boiler, various steam and air heaters, and pollution control equipment)
- 3) The seed regeneration process (being tested in California)

That DOE program, however, lost its funding at the end of 1993. Substantial funding will be required to continue development; at present there is no U.S. organization withh sufficient funding and interest to continue such development. Therefore, the date for commercialization of MHD is unknown.

- Permitting Issues. Some of the major permitting issues associated with magnetohydrodynamics technology include:
 - Ability to control fugitive emissions from, and prevent spontaneous ignition of, coal piles (no additional impact if the MHD project is a retrofit to an existing plant)

- · Ability to control the quantity of air pollutants in the combustion products, particularly particulate emissions (Note, however, that as a retrofit technology, MHD has the potential to reduce emissions levels compared to the existing facility.)
- · Disposal of ash, sludge, and other wastes
- · Possible classification of waste streams as hazardous materials. thereby restricting the number of allowable disposal sites and raising disposal costs
- · Use of large amounts of water for dust control, coal washing, boiler makeup, wet cooling towers (if applicable), and ash quenching
- · Changes to visual quality due to power plant structures and coal unloading, handling, and storage facilities (not an issue for the retrofit of existing plants)



- Noise impacts from coal delivery, crushing, and handling facilities (no additional impact if the MHD project is a retrofit to an existing plant)
- Likely public opposition because of uncertainties over air quality, health and safety, and odor impacts from fugitive coal dust during handling and storage, and waste handling and storage
- Possible poor public opinion due to concerns over acid rain and coal strip mining

- a) Kessler, Robert, "Economic, Environmental, and Engineering Aspects of Magnetohydrodynamic Power Generation", Energy and the Environment in the 21st Century: Proceedings of the Conference held at the Massachusetts Institute of Technology, Cambridge, Massachusetts, March 26-28, 1990. Massachusetts Institute of Technology Press, 1991.
- b) Rosa, Richard J., Magnetohydrodynamic Energy Conversion, Hemisphere Publishing Corporation, 1987.
- c) MacRae, K. Morgan, New Coal Technology and Electric Power Development, Canadian Energy Research Institute, 1991.
- d) 1992 Energy Technology Status Report, Appendix A, Volume I: Detailed Electric Generation Technology Evaluations, California Energy Commission, Report no. P500-92-007A V1, December 1992. Section 3.6 (Magnetohydrodynamics).

B-10. MUNICIPAL SOLID WASTE

Municipal solid waste (MSW) is one of three major waste-to-energy technologies (the others are Anaerobic Digestion and Biomass, discussed in Sections B-1 and B-3, respectively). MSW can be directly combusted in waste-to-energy facilities as a fuel with minimal processing, known as mass burn; it can undergo moderate to extensive processing before being directly combusted as refuse-derived fuel; or it can be gasified using pyrolysis or thermal gasification techniques.

Each of these technologies presents the opportunity for both electricity production as well as an alternative to landfilling or composting the MSW. In contrast with many other energy technologies that require fuel to be purchased, MSW facilities are paid by the fuel suppliers to take the fuel (known as a "tipping fee"). The tipping fee is comparable to the fee charged to dispose of garbage at a landfill. Another MSW-to-electricity technology, landfill gas recovery, permits electricity production from existing landfills via the natural degradation of MSW by anaerobic fermentation (digestion) into landfill gas. Anaerobic digestion can also be used on municipal sewage sludge; it is discussed separately in Section B-1.

MASS BURN

Mass burn technology, the most common MSW-to-electricity technology, involves the combustion of unprocessed or minimally processed refuse. The major components of a mass burn facility include:

- a) Refuse receiving, handling, and storage systems
- b) The combustion and steam generation system (a boiler)

- c) A flue gas cleaning system
- d) The power generation equipment (steam turbine and generator)
- e) A condenser cooling water system
- f) A residue hauling and storage system

Incoming trucks deposit the refuse into pits, where cranes then mix the refuse and remove any bulky or large non-combustible items (such as large appliances). The refuse storage area is maintained under pressure less than atmospheric in order to prevent odors from escaping. The cranes move the refuse to the combustor charging hopper to feed the boiler.

Heat from the combustion process is used to turn water into steam, with the steam then routed to a steam turbine-generator for power generation. The steam is then condensed via traditional methods (such as wet cooling towers or once-through cooling) and routed back to the boiler. Residues produced include bottom ash (which falls to the bottom of the combustion chamber), fly ash (which exits the combustion chamber with the flue gas [hot combustion products]), and residue (including fly ash) from the flue gas cleaning system.

The combined ash and air pollution control residue typically ranges from 20 percent to 25 percent by weight of the incoming refuse processed. This ash residue may or may not be considered a hazardous material, depending on the makeup of the municipal waste.

It may be possible to avoid the production of hazardous ash by preventing the sources which create hazardous waste from entering the system. It is also possible to treat the ash. Both of these methods avoid the costs of disposal at a limited number of landfills classified as able to handle hazardous. materials. Non-hazardous ash can be mixed with soils for use as landfill cover, or can be sold (or given away) for such beneficial uses as pavement aggregate.

California has three MSW mass burn facilities in operation with a combined capacity of about 70 MW (gross rating). While the gross resource potential of MSW in California is estimated to be as high as 2,000 MW, only one new MSW-toelectricity facility is planned within California, with an estimated startup date of 1997. At present, the tipping fees in California are generally insufficient to make MSW-toelectricity facilities cost-competitive with other forms of electric generation.

- Permitting Issues for Mass Burn Facilities. Some of the major issues associated with mass burn facilities include:
 - Ability to meet air quality requirements
 - · Possible classification of the ash as a hazardous material
 - · Disposal of ash and other byproducts.
 - Possible conflict with adjacent land uses
 - · Disturbances to biological resources
 - Use of large amounts of water for cooling purposes (if wet cooling towers are used)

- Changes to visual quality due to power plant structures and traffic patterns
- Transportation impacts from numerous truck trips from the refuse source to the mass burn facility (note that collection and transportation would already be occurring, so the mass burn facility would only cause a change in traffic patterns)
- · Likely public opposition because of uncertainties over health, safety, odor, and traffic impacts (since it is most economical for the facility to be located near urban centers where the waste is generated)
- · Possible conflicts between using MSW for electricity generation and programs/goals for waste reduction techniques and recycling
- Possible hazardous materials leakage that may necessitate site cleanup after facility closure

REFUSE-DERIVED FUEL

Refuse-derived fuel (RDF) typically consists of pelletized or fluff MSW that is the by-product of a resource recovery operation. Processing removes ferrous materials, glass, grit, and other materials that are not combustible. The remaining material is then sold as RDF. Both the RDF processing facility and the RDF combustion facility are located near each other, if not on the same site.

The RDF can then be used in one of several configurations:

1) Dedicated RDF boilers designed with traveling grate spreader-stokers

- 2) Co-firing of RDF with coal or oil in a multi-fuel boiler
- 3) Dedicated RDF fluidized-bed boiler

There are currently no commercial RDF facilities in operation in California.

Permitting Issues for Refuse-Derived Fuel Combustion Facilities. The permitting issues discussed above for mass burn facilities also apply to RDF combustion facilities.

PYROLYSIS/THERMAL **GASIFICATION**

Pyrolysis and thermal gasification are related technologies. Pyrolysis is the thermal decomposition of organic material at elevated temperatures in the absence of gases such as air or oxygen. The process, which requires heat, produces a mixture of combustible gases (primarily methane, complex hydrocarbons, hydrogen, and carbon monoxide), liquids, and solid residues.

Thermal gasification of MSW is different from pyrolysis in that the thermal decomposition takes place in the presence of a limited amount of oxygen or air. The producer gas which is generated can then be used in either boilers or cleaned up and used in combustion turbine/ generators. The primary area of research for this technology is the scrubbing of the producer gas of tars and particulates at high temperatures in order to protect combustion equipment downstream of the gasifier and still maintain high thermal efficiency.

Both of these technologies are in the development stage with a limited number of units in operation. The Hyperion Energy Recovery System operated by the City of Los Angeles had a system designed to fire dried sewage sludge in a staged fluidized bed combustor. The resulting gas was then combusted in stages, and the heat was used to turn water into steam, driving a 10 MW steam turbinegenerator.

Permitting Issues for Pyrolysis/ Thermal Gasification Facilities. Most of the permitting issues discussed above for mass burn facilities also apply to pyrolysis and thermal gasification facilities. It is not economical to transport the gas produced by such facilities over long distances, so the power generation equipment must be sited with the gasification facilities. As with most refuse-to-energy facilities, it is typically only economical to site gasification facilities near urban centers.

Air emissions may be easier to control than with mass burn technology because the gas produced by the pyrolysis or thermal gasification facility can be scrubbed to remove contaminants prior to combustion. However, scrubbing the producer gas at high temperature is currently under research and the technology has yet to be demonstrated on a large scale. In addition, the pyrolysis and gasifier streams may contain organic compounds of concern that are difficult to remove.

LANDFILL GAS RECOVERY

Landfill gas (LFG) is generated by the natural degradation of MSW by anaerobic (without oxygen) microorganisms. Once the gas is produced, the gas can be collected by a collection system, which typically consists of a series of wells drilled into the landfill and connected by a plastic piping system.

The gas entering the gas collection system is saturated with water, and that water must be removed prior to further processing. The typical dry composition of the low-Btu gas is 57 percent methane (natural gas), 42 percent carbon dioxide, 0.5 percent nitrogen, 0.2 percent hydrogen, and 0.2 percent oxygen. In addition, a significant number of other compounds are found in trace quantities. These include alkanes, aromatics, chlorocarbons, oxygenated compounds, other hydrocarbons and sulfur dioxide.

After de-watering, the LFG can be further processed into a medium-, Btu gas (suitable for use in boilers for manufacturing processes, as well as for electricity generation via reciprocating engines or gas turbines (although it is relatively inefficient)). The most important part of the scrubbing process is the removal of sulfur dioxide from the gas since it results in corrosion within the combustion equipment.

Further processing into a high-Btu gas requires the removal of carbon dioxide as well as all remaining trace components. The resulting pipeline-quality gas is of high enough quality to be blended with existing natural gas systems; however, since the passage of legislation in 1988 which makes a seller of LFG to a gas utility liable for impacts of toxics in the gas, no LFG has been sold to a gas corporation.

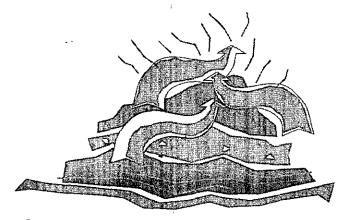
The gas is also suitable for electricity generation applications such as gas turbines and fuel cells. For example, Southern California Edison and Los Angeles Department of Water and Power operate a 40 kW phosphoric acid fuel cell using processed landfill gas at a hotel/convention center complex in the City of Industry.

The 25 landfill gas projects in California that provide electricity have a total of 178 MW of capacity, with the largest of these being the 50 MW facility at Puente Hills. There are, however, ten more plants in California that are temporarily shut down due to mechanical difficulties, low gas production (quantity and quality), or inability to secure contracts for electricity sales. Those plants have a combined capacity of about 38 MW.

Current research in the area of landfill gas recovery involves the recirculation of the leachate generated in the landfill by the anaerobic decomposition process. The recirculation of the leachate through the waste in a lined and covered landfill effectively accelerates and enhances the generation of methane gas. This form of landfill design and operation converts the landfill into a bioreactor. Yolo County is currently involved in this research at their Davis landfill.

- Permitting Issues for Landfill Gas Recovery. Since landfill gas recovery facilities are located at existing landfills, there are generally fewer permitting issues associated with them compared to other MSW-to-energy facilities. Some of the issues associated with LFG treatment and power generation equipment include:
 - Ability to meet air quality requirements
 - Handling and disposal of the condensate from the dewatering process

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- t) California Power Plant Maps, California Energy Commission Publication No. P700-92-003, July 1992.
- g) "Managing a Special Waste: Sewage Sludge", Solid Waste & Power, December 1992, pp. 50-58.
- h) Smith, D.L. and R.T. Haug, "The Hyperion Energy Recovery System: Innovative Technology for Municipal Sludge Management and Power Generation", Proceedings of the American Power Conference, 1987, Volume 49, pp. 750-755.
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- j) 1992 Energy Technology Status Report, Appendix A, Volume I: Detailed Electric Generation Technology Evaluations, California Energy Commission, Report no. P500-92-007A V1, December 1992. Sections 9.1.1 (MSW Mass Burn), 9.1.2 (MSW Refuse-derived Fuel); 9.2 (MSW Gasification), and 9.3 (MSW Landfill Gas Recovery).

B-11. NATURAL GAS AND OIL

Natural gas- and oil-fired facilities account for a significant portion of California's power plants, both in terms of the number of power plants and total capacity. In 1992, 592 of the 1,341 power plants in California that are 10 kW or larger were natural gas- or oil-fired; those 592 power plants have a combined capacity of 29,875 MW (which represents about 55% of California's installed generating capacity.

While many of the facilities are dual-fuel facilities that can burn either natural gas or oil, natural gas is used primarily due to its cleaner-burning characteristics. Natural gas is one of the cleanest: commercial fuels. Unlike other fossil fuels (i.e., coal and oil), natural gas combustion produce less nitrogen oxides and carbon dioxide, and does not produce ash residue. Oil is typically used as a backup fuel for emergencies only since many facilities cannot meet air district emissions requirements when burning oil.

Energy Commission predictions of natural gas supply and price show that supplies for at least the next 20 years are adequate to meet existing and likely additional electricity generation needs, and the price is likely to remain refatively low and stable. Because of its availability (see Section B-23 entitled Pipelines (petroleum, petroleum products, and natural gas)) and price characteristics, and its ability to be used in a variety of configurations (discussed below) to meet a variety of utility and others' needs, natural gas-fired technologies are increasingly being considered for future resource additions by both utilities and non-utility generators.

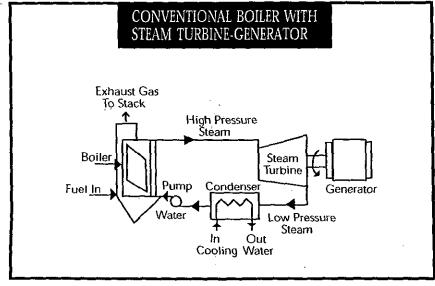
Natural gas is typically used in thermal power plant arrangements, which convert the thermal energy in the natural gas to electricity via combustion. The methods discussed here include both steam turbine-generator and combustion turbine-generator arrangements, as well as variations and combinations of the two. Fuel cells, which can also be fueled by natural gas, are discussed separately in Section B-6 entitled Fuel Cells.

CONVENTIONAL NATURAL **GAS-FIRED THERMAL POWER** PLANTS (BOILERS)

Conventional natural gas-fired thermal power plants, or boilers, are steam turbine-based power plants which burn the natural gas to heat a steam boiler. Steam created in the boiler then drives a steam turbine that spins the rotor of a generator. After passing through the turbine, the steam is condensed into water, and that water is then pumped back to the boiler where it is again turned to steam for power generation purposes (see figure entitled Conventional Boiler with Steam Turbine-Generator).

Such configurations are known as closed cycle arrangements because the working fluid (the water/steam) undergoes changes as it passes various points in the cycle but is not depleted. At coastal sites, water from the ocean may be used as cooling water. At inland sites, cooling towers are usually reguired. Such cooling towers typically require large amounts of cooling water that is not recoverable but is discharged (evaporated and lost through drift) from the cooling tower(s). (Air-cooled condensers are available, but they are a more costly option.)

Natural gas-fired boiler plants are a mature technology. They are typically large, on the order of several hundred to over a thousand MW. They are not very efficient compared to the other alternatives discussed below (see Appendix F "Power Plant Generating Efficiency" for more on the efficiency of various gas-fired configurations.) As a result, it is unlikely that future natural gas-fired boilers will be built. The most efficient natural gas-fired boilers are used for baseload duty, while older, less



efficient boilers may be used in intermediate or peaking duty applications.

Many of California's natural gasfired boilers are approaching the end of their useful life of 30 to 40 years and are unable to meet increasingly stringent emissions limits without retrofitting. Such aging, inefficient, relatively highpolluting power plants could be ideal candidates for repowering (discussed below.)

- Permitting Issues for Boilers. Some of the major issues associated with natural gas-fired boilers include:
 - Ability to meet air quality requirements
 - Use of hazardous materials associated with water treatment and air emissions reduction (e.g., ammonia and catalyst use for NOx reduction methods such as selective catalytic reduction [SCR])
 - Use of large amounts of water for cooling purposes (if wet cooling towers are used)

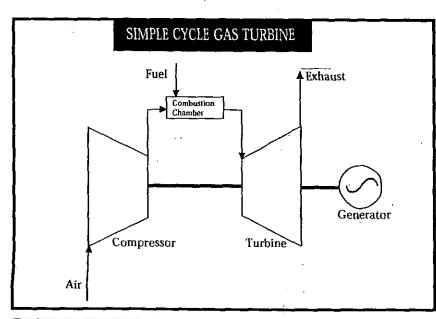
- Biological impacts on the ocean or lake or river water due to thermal discharge (if applicable)
- Changes in visual quality due to the power plant structures, including cooling towers (at inland sites) and tall stacks to vent exhaust emissions, plumes of water vapor (from cooling towers)
- Disturbances to biological resources

SIMPLE-CYCLE GAS TURBINES

Simple-cycle gas turbines, or combustion turbines, burn natural gas and compressed air in a combustion chamber to create hot combustion gases that drive a turbine-generator (see figure entitled Simple Cycle Gas Turbine below). Note that simple-cycle gas turbines do not require large quantities of water, since the working fluid is air (although large quantities of water or steam may be consumed in the combustion chamber if needed to control NOx emissions.) Gas turbines are open cycle arrangements, since the gas turbine exhaust is not recovered but is discharged directly into the atmosphere (although the heat from the exhaust can be captured and used for other purposes, as discussed below in some of the more complex cycles.)

Simple-cycle gas turbines are available in a wide range of sizes, ranging from several hundred kW to over a hundred MW. They are well-suited for peaking duty (less than 1,000 hours of operation per year) because of their quick-start capability and their ability to be operated from a remote location. Their small "footprint", short installation time, low capital cost, and modular nature make them ideal for adding capacity quickly and in appropriate increments. While not highly efficient in stand-alone, simple-cycle arrangements, they form the building blocks for some of the most efficient and flexible power plant configurations.

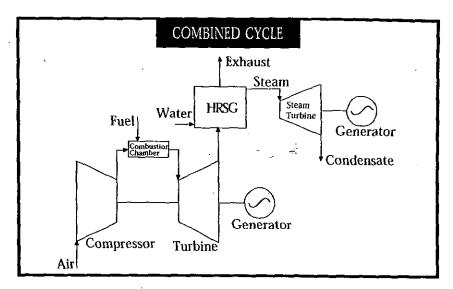
- Permitting Issues for Simplecycle Gas Turbines. Some of the major issues associated with simple-cycle gas turbines include:
 - The ability to meet air quality requirements
 - Use of hazardous materials associated with air emissions reduction (e.g., ammonia and catalyst use for NOx reduction methods such as SCR)



STEAM-INJECTED GAS TURBINES

Steam-injected gas turbines (STIGs), or steam-recuperated gas turbines, use a heat recovery steam generator (HRSG) to capture the heat from the gas turbine's exhaust to turn water into steam. That steam is then injected back into the gas turbine (see figure entitled Steam-injected Gas Turbine (STIG) below). The steam injection serves three purposes: it lowers NOx emissions, boosts power output, and raises efficiency compared to a simple-cycle gas turbine. STIG cycles are appropriate for baseload or intermediate duty. They are also attractive in cogeneration applications (discussed below), since they can be designed to generate enough steam both for process needs as well as for injection into the gas turbine. They are typically found in sizes below 60 MW.

- Permitting Issues for STIGs.
 Some of the major issues associated with STIGs include:
 - Ability to meet air quality requirements

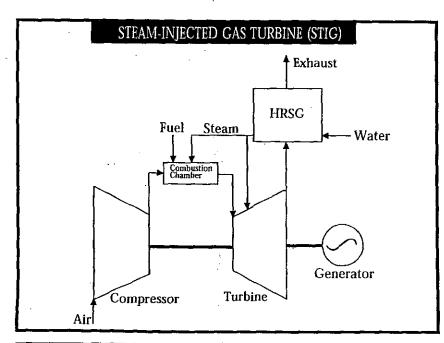


- Use of hazardous materials associated with water treatment and air emissions reduction (e.g., ammonia and catalyst use for NOx reduction methods such as selective catalytic reduction [SCR])
- Use of significant amounts of high-quality water for injection into the gas turbine for NOx control and power augmentation

COMBINED CYCLES

Combined cycles use both gas turbines and steam turbines. Natural gas or oil is first used to generate electricity in one or more gas turbine-generators (this is the topping-cycle portion of the plant.) The high-temperature exhaust is channeled to one or more HRSGs to produce steam, and the resulting steam is then used to drive a steam turbine-generator (the bottomingcycle portion of the plant) (see figure entitled Combined Cycle). In a typical state-of-the-art combined cycle arrangement, the gas turbine(s) provide about two-thirds of the total electrical output, while the steam turbine provides the remaining one-third.

Combined cycles are efficient, since the additional electric generation by the steam turbine-generator occurs without any additional fuel (beyond that required to fuel the gas turbine-generators.) Although combined cycles require a source of cooling water for the steam turbine portion of the plant, they require much less water than a boiler-steam turbine configuration with the same output as the entire combined cycle (since only one-



third of the cycle requires cooling water.) Combined cycles are appropriate for baseload and intermediate duty. They are found in sizes ranging from less than 10 MW to several hundred MW.

Permitting Issues for Combined Cycles. The issues for combined cycles are similar to those for simple-cycle gas turbines and boilers (since combined cycles consist of both gas turbines as the topping cycle and a closed-loop steam bottoming cycle). However, the magnitude of the impacts is less than that for boilers since combined cycles have a smaller "footprint", use significantly less water, and gas turbines are cleaner-burning than boilers of comparable size.

COGENERATION

Cogeneration is the sequential production of electricity and of thermal energy for some industrial process such as petroleum refining, food processing, ice making, or space heating and cooling needs. Electricity produced in excess of that facility's needs can be made available for sale. Cogeneration systems typically use considerably less fuel to deliver the same amounts of electricity and useful thermal energy than separate energy systems.

When energy input to the system is first applied to a useful thermal energy process, and then the waste heat from that process is used to generate electricity, the system is called a bottoming-cycle cogeneration facility. Such generating facilities are usually small, and not as economically competitive as topping-cycle cogeneration facilities, where energy is used first to produce electricity, and the waste heat is then applied to some industrial process.

Topping cycle gas turbine-based cogeneration power plants typically produce useful thermal energy in one of the following configurations:

- 1) A simple-cycle gas turbine paired with a HRSG
- A STIG paired with a HRSG
- A combined-cycle gas turbine/HRSG/steam turbine arrangement in which useful thermal energy in the form of steam is taken either from the HRSG or from a steam turbine extraction point

Cogeneration systems range in size from several kW to several hundred MW. Small-scale cogeneration systems can be designed to meet both the electricity and process energy requirements of facilities such as hospitals, hotels, jails, manufacturing facilities, large office complexes, and large institutions such as universities.

- Permitting Issues for Cogeneration. When cogeneration facilities are located at existing industrial sites, the potential visual and biological impacts are likely to be minimal. Other issues are dependent on the cycle configuration, but will likely include:
 - The ability to meet air quality requirements
 - · Use of hazardous materials associated with water treatment and air emissions reduction (e.g., ammonia and catalyst used for NOx reduction methods such as selective catalytic reduction [SCR])
 - Use of significant amounts of high-quality water for injection into the gas turbine for NOx control and power augmentation

(if based on a STIG) or for cooling of the steam bottoming cycle (if a combined cycle)

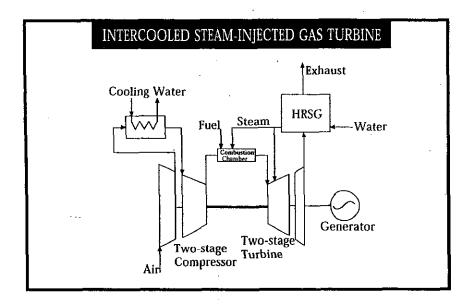
REPOWERING

Repowering refers to the conversion of an existing conventional oil- or natural gas-fired steam boiler plant into a combined cycle power plant. This is often done by retiring in place (or removing completely) the existing boiler and replacing it with one or more gas turbines and HRSGs. The exhaust heat from the gas turbine(s) is used to generate steam in the HRSG(s), and that steam is then used to generate power in the existing steam turbine-generator. The output of the site is typically tripled, due to the addition of the gas turbine(s).

Since the existing aging boiler is likely to be inefficient and relatively high-polluting, there will likely be a net air quality benefit due to repowering even though the repowered output is three times as large. The new configuration may produce more emissions on an annual basis, however, since it will likely operate more that its predecessor due to its very high efficiency.

Repowered combined cycle power plants typically have slightly lower efficiencies than their new combined cycle counterparts. A drop in efficiency of two or three percentage points (compared to the same gas furbine(s) paired with an optimized steam turbine) is typical.

The lower efficiency for repowered projects is due to the fact that the new gas turbine(s) are paired with an existing steam turbine. It may not be possible to provide an exact match between the gas turbine's exhaust heat and the steam turbine's requirements since gas turbines are available only in



discrete sizes. Also, a new steam turbine is likely to be more efficient than an existing steam turbine which could be as much as 30 or 40 years old (although steam turbine refurbishment at the time of repowering could improve the overall efficiency). Repowered combined cycles are appropriate for baseload and intermediate duty.

Permitting Issues for Repowered Facilities. Since repowering with gas turbines and HRSGs occurs at existing sites, the potential visual and biological issues are likely to be minimal. Assuming the boiler being retired had been operating up to the time of the repowering, the net change in air emissions, water use, and hazardous materials may be negative. The repowered plant, however, may be used more often than the old boiler, and thus on an annual basis may require more air offsets, water, and hazardous materials. See the previously discussed issue for combined cycles.

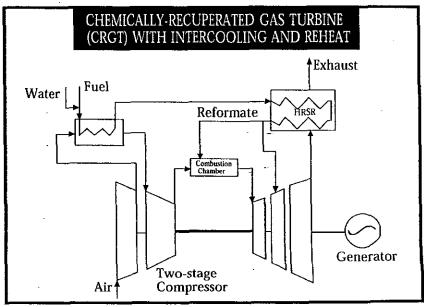
ADVANCED GAS TURBINES

Advanced gas turbines include such advancements as:

• The intercooled aeroderivative (ICAD) gas turbine cycles being investigated as part of the Electric Power Research Institute/PG&E Collaborative Advanced Gas Turbine (CAGT) program, whose participants include nearly all of Calif-ornia's public and private electric utilities. The aeroderiv-ative (aircraft-

derived) gas tur-bine has a multistage compressor/turbine design that can accommodate the diversion of compressed air from the low pressure compressor discharge to a heat exchanger (where the air is cooled) and its return to the high pressure compressor inlet. Intercooling the partially compressed air reduces the power requirement to the high pressure compressor, which means that more power is avail-able for sale. The figure entitled Intercooled Steam-Injected Gas Turbine shows the intercooling concept applied to a STIG.

· The chemically recuperated gas turbine (CRGT), which uses the gas turbine's exhaust heat in . a heat recovery steam reformer (HRSR). The exhaust heat provides the thermal energy necessary to accomplish partial steam reformation of natural gas in the reformer. The effluent produced by the reformer is a hydrogenrich, low-Btu fuel gas that fires the gas turbine. The reformed fuel gas (reformate) offers the possibility of ultra-low levels of NOx and carbon monoxide. The figure below entitled Chemically-



Recuperated Gas Turbine (CRGT) with Intercooling and Reheat shows the CRGT concept with intercooling and reheat.

Permitting Issues for Advanced Gas Turbines. The major issues associated with advanced gas turbines are dependent on the equipment configuration. ICADs and CRGTs would have issues similar to those of commercially-available simple-cycle gas turbines. CRGTs also require the use of water for the steam-methane reformer. Should the CRGT be able to demonstrate the ultra-low NOx levels predicted, there may be no need for the ammonia and catalyst associated with SCR, depending on air quality. regulations.

COMPRESSED AIR ENERGY STORAGE

Compressed air energy storage (CAES) uses a gas turbine and an airtight underground reservoir (such as a mined salt dome or a depleted natural gas reservoir.) Air is compressed using off-peak electricity and stored in the underground reservoir. During peak load periods, the stored air is discharged, heated by natural gas combustion, and fed into the turbine/expander (see figure entitled Compressed Air Energy Storage below). CAES technology

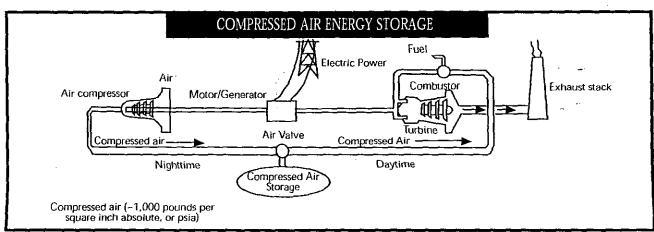
is in the demonstration phase of development. The first such facility in the United States is a 110 MW facility being demonstrated by the Alabama Electric Cooperative since 1991.

Permitting Issues for CAES
The major issues associated with
CAES facilities include those
associated with simple-cycle gas
turbines plus structural and geological issues associated with the
underground storage reservoir.

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- bines), 2.4.2 (Intercooled Steam Recuperated Gas Turbines), 2.4.3 (Chemically Recuperated Gas Turbines), 2.4.4 (Humid Air Turbine Cycle), 2.4.5 (Inter-cooled Reheat Combined Cycle), 10.1.1 (Cogeneration Heat Recovery), 10.1.2 (Cogeneration Combined Cycles), and \$\overline{1}6.2\$ (Compressed Air Energy Storage).
- d) Fuels Report, California Energy Commission Publication No. P300-93-019, February 1994.
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Source: Resource: "An Encyclopedia of Energy Utility Terms", Second Edition. Pacific Gas and Electric Company.

B-12. NUCLEAR

Nuclear technology includes two types: fission and fusion. Nuclear generating technologies based on fission are commercially available, whereas fusion is still in the early stages of research and development, and is at present only a theoretical possibility for controlled power generation. Nuclear fission is the process of splitting the nuclei of atoms, which releases stored energy (in the form of heat) from within those atoms. Nuclear fusion is the process of joining, rather than splitting, such atomic particles with similar releases of energy.

FISSION

Of the several types of fission reactors, the most common type in the United States is light water reactors (so called because regular (light) water is used to cool the reactor core) based on pressurized water reactor (PWR) and boiling water reactor (BWR) technology. PWRs and BWRs use uranium-235, a naturally-occurring radioactive isotope of uranium, as the fuel. As the nucleus of a uranium-235 atom is hit by a neutron, it splits into two smaller atoms of other elements, and releases heat and extra neutrons. Those neutrons hit more atoms of the original uranium-235, creating a fission chain reaction that releases more heat and neutrons.

In a PWR, the power plant's primary circulating system passes water through the reactor core, where the water is heated by the fission process. That water (under high temperature and pressure) is passed through a steam generator, where it releases its heat to the secondary circulating system. Water in the secondary circulating system is allowed to boil, and the resulting steam is used to drive a steam turbine-generator.

In a BWR, there is no need for a steam generator and a secondary circulating system, as the water in the primary circulating system is allowed to boil before exiting the reactor and is then routed directly to a steam turbine-generator.

Two operating nuclear power plants in California are at Diablo Canyon and San Onofre. Pacific Gas and Electric Co. owns the Diablo Canyon Nuclear Power Plant, which consists of two units. Unit 1 is a 1073 MW PWR which began commercial operation in May 1985, while Unit 2 is a 1087 MW PWR which began commercial operation in March 1986. Southern California Edison Co. and San Diego Gas and Electric Co. own the two operating units at the San Onofre Nuclear Generating Station. Unit 2 is a 1070 MW PWR that began commercial operation in August 1983, while Unit 3 is a 1080 MW PWR that began commercial operation in April 1984.

California also has three commercial nuclear power plants that are no longer in operation. These include the 63 MW BWR at the Humboldt Bay Nuclear Power Plant in Eureka (in operation from August 1963 to July 1976); the 913 MW PWR at the Rancho Seco Nuclear Power Plant owned by the Sacramento Municipal Utility District (in operation from April 1975 to June 1989); and the 436 MW San Onofre Unit 1 PWR (in operation from January 1968 to November 1992.)

None of these facilities has been decommissioned (which involves dismantling the reactor and transporting all radioactive materials to a site for disposal.) However, the

U.S. Nuclear Regulatory Commission (NRC) staff recently approved the decommissioning plan for the Rancho Seco Nuclear Power Plant. The dismantling process will occur in stages, with "final teardown" scheduled to begin in 2008.

Spent fuel-can either be reprocessed to recover usable uranium and plutonium, or it can be managed as a waste for long-term ultimate disposal. Since fuel reprocessing is not commercially available in the U.S., spent fuel is typically being held in temporary on-site storage at reactor sites until a permanent long-term waste disposal option becomes available. Such a long-term storage facility must exist before California law will permit construction of new nuclear power plant facilities.

There are several advanced reactor power plant designs being developed for near-term and mid-term deployment in the U.S. and overseas. These include both advanced light water reactor (ALWR) and advanced modular reactor designs. The ALWR program is focusing on both evolutionary and passive designs, using both BWR and PWR technologies. Each design configuration is seeking certification by the U.S. NRC as a pre-approved U.S. standard design under the U.S. Department of Energy's ALWR Design Certification Program.

The evolutionary ALWRs are advancements of today's light water reactor designs and use conventional safety system concepts. There are two evolutionary ALWR designs that are expected to be ready for commercial operation by the year 2000; the 1356 MW Advanced Boiling Water Reactor (ABWR) and the 1350 MW Advanced Pressurized Water Reactor (System 80+). Two ABWR units are being built in Japan. As of July 1996, the first unit is ready to begin commercial operation. The second unit is scheduled to begin operation in 1997. In June 1996, Tawain ordered two ABWR units. The System 80+ PWR received its ginal design approval from the NRC in July 1994.

The passive ALWR designs are greatly simplified and employ primary passive means for accident prevention and mitigation. There are two passive ALWR designs that have been considered: 600 MW Advanced Pressurized Water Reactor (AP600) and the 600 MW Simplified Boiling Water Reactor (SBWR). The AP600 Advanced PWR is expected to receive its final design approval from the NRC in September 1996. It could be ready for commercial operation by the year 2003. The future of the SBWR is uncertain at this time.

The Advanced Modular Reactor Program is focusing on the development of small (165 MW to 217 MW) reactors that can be grouped together as modules of a larger power station. The two advanced modular reactor designs, which are also seeking design certification, are the 1500 MW Advanced Liquid Metal Reactor (ALMR) and the 700 MW Advanced High Temperature Gas Cooled Reactor (MHTGR). These designs are expected to be ready for commercial operation by the year 2010.

- Permitting Issues for Fission Power Plants. Some of the issues associated with commercial nuclear power plants include:
 - Need for a long-term highlevel waste disposal facility and a decommissioning plan
 - Use of large amounts of water for cooling purposes (if wet cooling towers are used)

- Biological impacts on the ocean due to thermal discharge (if seawater cooling is used)
- · Designing for seismic safety
- Public safety concerns regarding catastrophic events
- Transportation issues associated with the development of an emergency evacuation plan
- Changes in visual quality due to the power plant structures, including the reactor vessel containment structure, and cooling towers (if applicable)
- Potentially significant amounts of land
- Potentially significant public opposition

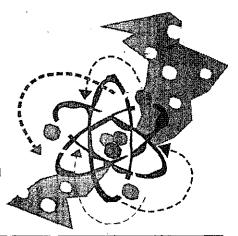
FUSION

A fusion reaction occurs when nuclei of light elements, specifically hydrogen and its isotopes (deuterium, or "heavy water", and tritium), are forced together at extremely high temperatures and densities until they fuse into nuclei of heavier elements and release enormous amounts of energy. If fusion is to yield net energy, the fuel must be heated in the form of plasma (a highly ionized gas) to a very high temperature and the plasma must then be held together for a sufficiently long time such that the number of fusion reactions occurring releases more energy than was required to heat the fuel.

The Princeton Plasma Physics Laboratory's Tokamak Fusion Test Reactor (TFTR) recently demonstrated fusion of deuterium-tritium plasma at 510 million C. That experiment produced heating equal to one-third of that needed for the fusion reaction to become selfsustaining. Thus, there is still—significant research that must be accomplished before fusion achieves a net energy output, and then even more development work to develop commercial power plant applications. It is estimated that commercial availability of fusion is at least 20 years away.

To generate commercial energy, the neutron energy would be converted to heat in a surrounding blanket of coolant, probably containing solid lithium compounds, with the heat converted to electricity in a conventional steam generator cycle. Although the fusion reaction does not produce radioactive fission products, the high energy neutrons do irradiate the surrounding reactor vessel and associated components. The irradiated material poses radioactive disposal problems similar to those for the irradiated reactor vessels of fission reactors. Thus, many of the permitting issues that apply to fission reactors would also apply to fusion reactors.

The term "cold fusion", as reported in the popular press in recent years, refers to the process of fusing hydrogen nuclei at room temperature. It was allegedly demonstrated in a simple laboratory apparatus in 1989 by Fleischman and Pons. Several experiments have been conducted to try to replicate their



work, with limited success. The phenomenon of cold fusion cannot be reproduced on demand and cannot be explained by conventional nuclear physics. Therefore, its commercial potential as an electric generating technology is uncertain.

- a) "World List of Nuclear Power Plants", *Nuclear News*, March 1994, Vol. 37, No. 3, pp. 43-62.
- b) Resource: An Encyclopedia of Energy Utility Terms, Pacific Gas and Electric Company, 2nd edition, 1992, pp. 318-321.
- c) Glenn County Energy Element of the General Plan, June 1993, p. 143.

- d) Evaluation of Power Facilities: A Reviewer's Handbook, prepared by the Berkshire County Regional Planning Commission, April 1974, pp. 56-57.
- e) "TFTR Set Another Record for Fusion Power", *Nuclear News*, December 1994, Vol. 37, No. 15.
- f) 1992 Energy Technology Status Report Final Report, California Energy Commission, Report no. P500-92-007, December 1992. Fact Sheet 1.1.4.1 (Nuclear Fission Full Fuel Cycle), 1.1.4.2 (Nuclear Fission Waste Disposal), 1.1.4.3 (Nuclear Fission Decommissioning), 1.2.3 (Fuel Cycles Nuclear Fusion), 4.1 (Nuclear Fission Pressurized Water Reactor), 5.1 (Nuclear Fusion High Temperature), and 5.2 (Cold Fusion).
- g) 1992 Energy Technology Status Report, Appendix A, Volume I: Detailed Electric Generation Technology Evaluations, California Energy Commission, Report no. P500-92-007A V1, December 1992. Sections 5.1 (High Temperature Fusion) and 5.2 (Cofd Fusion).
- h) "NRC Staff OKs Rancho Seco Plant", Sacramento Bee, March 22, 1995.
- i) TAGtm Technical Assessment Guide: Electricity Supply - 1993, Volume 1, Rev. 7, Electric Power Research Institute Report No. EPRI TR-102275-VIR7, June 1993.
- j) "A New Generation of Nuclear Reactors", *Mechanical Engineering*, April 1995, pp. 70-75.

B-13. OCEAN WAVE

Generating technologies for deriving electrical power from the ocean include tidal power, wave power, ocean thermal energy conversion, ocean currents, ocean winds, and salinity gradients. Of these, the three most well-developed technologies are tidal power, wave power and ocean thermal energy conversion. Tidal power requires large tidal differences which, in the U.S., occur only in Maine and Alaska. Ocean thermal energy conversion is limited to tropical regions, such as Hawaii, and to a portion of the Atlantic coast. Wave energy has a more general application, with potential along the California coast. The western coastline has the highest wave potential in the U.S.; in California, the greatest potential is along the northern coast.

Wave energy conversion takes advantage of the ocean waves caused primarily by interaction of winds with the ocean surface. Wave energy is an irregular and oscillating low-frequency energy source that must be converted to a 60-Hz frequency before it can be added to the electric utility grid.

Although many wave energy devices have been invented, only a small proportion have been tested and evaluated. Furthermore, only a few have been tested at sea, in ocean waves, rather than in artificial wave tanks.

There are currently more than 12 generic types of wave energy systems. Some systems extract energy from surface waves. Others extract energy from pressure fluctuations below the water surface or from the full wave. Some systems are fixed in position and let waves pass by them, while others follow the waves and move with them.

Some systems concentrate and focus waves, which increases their height and their potential for conversion to electrical energy.

A wave energy converter may be placed in the ocean in various possible situations and locations. It may be floating or submerged completely in the sea offshore or it may be located on the shore or on the sea bed in relatively shallow water. A converter on the sea bed may be completely submerged, it may extend above the sea surface, or it may be a converter system placed on an offshore platform. Apart from wave-powered navigation buoys, however, most of the prototypes have been placed at or near the shore.

The visual impact of a wave energy conversion facility depends on the type of device as well as its distance from shore. In general, a floating buoy system or an offshore platform placed many kilometers from land is not likely to have much visual impact (nor will a submerged system). Onshore facilities and offshore platforms in shallow water could, however, change the visual landscape from one of natural scenery to industrial.

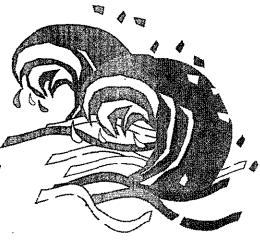
The incidence of wave power at deep ocean sites is three to eight times the wave power at adjacent coastal sites. The cost, however, of electricity transmission from deep ocean sites is prohibitively high. Wave power densities in California's coastal waters are sufficient to produce between seven and 17 MW per mile of coastline.

As of 1995, 685 kW of grid connected wave generating capacity is operating worldwide. This capacity comes from eight demonstration plants ranging in size from 350 kW to 20 kW. None of these plants are located in California, although

economic feasibility studies have been performed for a 30 MW wave converter to be located at Half Moon Bay. Additional smaller projects have been discussed at Fort Bragg, San Francisco and Avila Beach. There are currently no firm plans to deploy any of these projects.

Wave energy conversion is not commercially available in the U.S. The technology is in the early stages of development and is not expected to be available within the near future due to limited research and lack of federal funding. Research and development efforts are being sponsored by government agencies in Europe and Scandinavia.

Many research and development goals remain to be accomplished, including cost reduction, efficiency and reliability improvements, identification of suitable sites in California, interconnection with the utility grid, better understanding of the impacts of the technology on marine life and the shoreline. Also essential is a demonstration of the ability of the equipment to survive the salinity and pressure environments of the ocean as well as weather effects over the life of the facility.



- Permitting Issues. Some of the issues that may be associated with permitting an ocean wave energy conversion facility include:
 - Disturbance or destruction of marine life (including changes in the distribution and types of marine life near the shore)
 - Possible threat to navigation from collisions due to the low profile of the wave energy devices above the water, making them undetectable either by direct sighting or by radar. Also possible is the interference of mooring and anchorage lines with commercial and sportfishing.
 - Degradation of scenic ocean front views from wave energy devices located near or on the shore, and from onshore overhead electric transmission lines

- a) Ocean Energy Recovery: The State of the Art, American Society of Civil Engineers, 1992.
- b) Natgerman, George, Wave Power, in Encyclopedia of Energy Technology and the Environment, John Wiley & Sons, 1995.
- c) Ocean Energy Technology Information Module, Advanced Energy Systems, Pacific Gas & Electric Company, Department of Research and Development, Report 007.6-91.4, September 30, 1991.
- d) Shaw Ronald, Wave Energy: A Design Challenge, Ellis Horwood Limited, England, 1982.

- e) 1992 Energy Technology Status Report — Final Report, California Energy Commission, Report no. P500-92-007, December 1992. Fact Sheet 14.2 (Ocean Energy Conversion -Wave Energy Conversion).
- f) 1992 Energy Technology Status Report, Appendix A, Volume II: Detailed Electric Generation Technology Evaluations, California Energy Commission, Report no. P500-92-007A V2, December 1992. Sections 14.0 (Ocean Energy) and 14.2 (Wave Energy).

B-14. SOLAR PHOTOVOLTAIC

Photovoltaic (PV) cells (also called solar cells) convert the sun's electromagnetic energy (not its heat) directly into electrical power. (Note: solar thermal technologies, which use the sunlight's heat, are discussed separately in section B-PV cells are non-mechanical semiconductor devices, typically made of silicon, that produce direct current (dc) electricity.

Groups of cells mounted on a plate and connected electrically make up a PV module. Connected modules attached to a frame form a PV array, and arrays connected and electrically matched constitute a PV system. Inverters are used to convert the dc electricity into alternating current (ac) for compatibility with transmission and distribution systems. Since clouds, rain, fog and darkness can reduce or prevent electrical output, future PV systems may include storage capacity, although storage methods are currently not cost-effective.

PVs have many benefits including negligible air and water quality impacts, quiet operation and minimal need for maintenance due to the lack of moving parts. The modular design of PV systems makes them attractive for both utility-scale systems as well as distributed use systems. New materials, manufacturing processes, and designs are being demonstrated, showing promise for bringing down costs and improving solar conversion efficiencies.

Of the three major categories of PV collector modules (flat-plate crystalline silicon, flat-plate thin film, and concentrators), concentrating systems which track the sun have the highest current and future predicted conversion efficiencies. Today's generations of PV have the

following typical annual average conversion efficiencies: 11-13 percent for flat-plate crystalline silicon modules, 4 percent to 6 percent for flat-plate thin film modules, and 14-17 percent for concentrator modules. Near-term efficiency goals (late 1990s) are: 15 percent for commercial flat-plate crystalline silicon modules, 10 percent for commercial flat-plate thin film modules, and 20 percent for commercial concentrator modules.

Utility-scale PV power can help meet peak energy demand in areas where there are significant air conditioning loads, since solar insolation levels are often at their highest during peak demand periods. Central station PV plants for utility bulk power applications are not generally cost-effective, due mainly to their high capital cost and need for improved conversion efficiencies. In certain applications, however, the benefits could outweigh the costs. With today's technology, a 10 MW PV plant would require approximately 100 acres of land.

The largest operating PV system in the world is the Sacramento Municipal Utility District's grid-connected 2 MW PV1/PV2 power plant. PV1 and PV2 are rated at 1 MW each and were put on line in August 1984 and March 1986. respectively.

Distributed PV systems include remote or stand-alone applications and grid-connected "distributed utility" applications. Remote PV systems can be cost-effective in applications where they compete with the high cost of utility power line extensions (for example, at remote facilities such as emergency call boxes along freeways and parkways, and vacation cabins, or where power lines must be under-

grounded or pass over difficult terrain.)

Grid-connected distributed utility applications can be cost-effective in certain applications where they can defer the need for costly transmission and distribution upgrades. An example of this is the 500 kW PV at PG&E's Kerman distribution substation, where the output of the PV has allowed PG&E to defer upgrading the distribution transformer that was exceeding its operating limits.

Other potential locations and uses for PVs include; residential or commercial building rooftops, in existing parking lot unused air space, and building-integrated systems, where PVs may be integrated as skylights, window, wall or roof components, shade devices and other building components. The primary issue associated with such applications is solar access, since the PV arrays must be free of shading by trees or buildings.

The Photovoltaics for Utility Scale Applications (PVUSA) Project is a national public-private partnership that is assessing and demonstrating the viability of utility-scale PV systems. PVUSA participants include the U.S. Department of Energy, the California Energy Commission, the Electric Power Research Institute, the Sacramento Municipal Utility District Pacific Gas and Electric Company, and 10 utilities and other energy-related agencies.

PVUSA offers utilities hands-on experience needed to evaluate and utilize maturing PV technology; provides manufacturers with a test bed for their products; and encourages technology improvement and cost reductions in PV modules and balance-of-system components. The project also establishes the

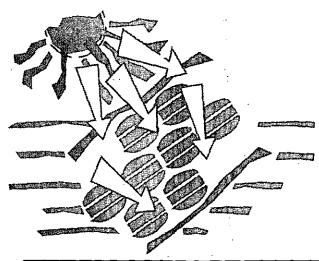
communication channels between utilities, government laboratories and the PV industry that will be needed for successful development and commercialization of utility PV systems.

PVUSA consists of two types of demonstrations: emerging module technologies (EMTs, which are unproven but promising state-of-the-art PV technologies in 20-kW (nominal) arrays); and utility-scale (US) systems, which represent more mature PV technologies in 200-to-500-kW (nominal) turnkey systems. PVUSA's primary test site in Davis, California, is the location of eight EMT arrays and three US systems.

- Permitting Issues. Some of the issues associated with utility-scale PV systems include:
 - Use of large tracts of land that are incompatible with other land uses (approximately ten acres per MW output)
 - · Changes in visual quality
 - · Disturbances to wildlife habitat

- a) Resource: An Encyclopedia of Energy Utility Terms, Pacific Gas and Electric Company, 2nd edition, 1992, pp. 421-423.
- b) Small But Powerful A Review Guide to Small Alternative Energy Projects for California's Local Decisionmakers, Association of Bay Area Governments, September 1987, pp. 11, 31-35.
- c) New World Record For Commercial-scale Solar Electricity, Electric Power Research Institute News Release, November 4, 1994.
- d) Distributed Utility Valuation Project Monograph, Electric Power Research Institute Report No. TR-102807, PG&E Report No. 005-93.12, July 1993, pp. 95-102.

- e) 1992 Energy Technology Status Report - Final Report, California Energy Commission, Report no. P500-92-007, December 1992. Fact Sheet 13.1 (Photovoltaics - utility scale applications) and 28.1 (On-site electricity production - distributed photovoltaic systems).
- f) 1992 Energy Technology Status Report, Appendix A, Volume II: Detailed Electric Generation Technology Evaluations, California Energy Commission, Report no. P500-92-007A V2, December 1992. Sections 13.0 (Photovoltaics) and 13.1 (Utility Scale Photovoltaic Applications).
- g) Sacramento Municipal Utility District Advanced and Renewable Technologies Development Program - 1994 Update, Sacramento Municipal Utility District, 1994.
- h) 1995 PVUSA Progress Report, prepared by the PVUSA Project Team, PG&E R&D Report no. 96-30910000.1.



B-15. SÕLAR THERMAL

Solar thermal systems use the sun's heat to create electricity and include both solar thermal electric concentrating systems and saltgradient solar ponds (also known as salt ponds). Solar thermal electric technologies are typically found in utility-scale size ranges. (Note: solar photovoltaic systems, which convert the sun's radiation directly into electrical power and are typically found in much smaller size ranges, are discussed separately in section B-14.)

SOLAR THERMAL ELECTRIC CONCENTRATING SYSTEMS

Concentrating systems use mirrored surfaces to concentrate solar energy typically to:

- a) Heat a transfer fluid which conveys the heat to the working fluid of a heat engine
- b) Directly heat the working fluid of a heat engine

The heat transfer fluid is either a high temperature oil-based fluid or a higher temperature molten salt, which is a mix of nitrate salts similar to nitrate fertilizers. The working fluid, which expands under heat to drive the heat engine, is steam for steam turbine-generators, and hydrogen or helium for another type of engine called the Stirling.

Most of California's existing solar thermal power plants are located in desert areas. A survey conducted on behalf of the Energy Commission of parcels of marginal or fallow agricultural land larger than 1500 acres located in areas of high solar insolation found that 80 percent of the siting possibilities are outside of the desert. In such

areas the biological, cultural, and paleontologic resources impacts may be minimal or non-existent.

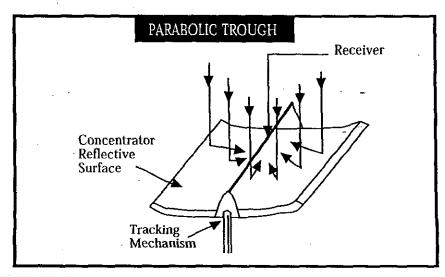
In addition, solar thermal power plants placed on land formerly used for agriculture may serve to mitigate water problems, since solar thermal power plants which use steam as the working fluid use only about 17 percent of the water needed by agriculture. Some of the major issues associated with solar thermal facilities are highly dependent on the site chosen and whether or not the land has been previously disturbed.

Three primary categories of solar thermal concentrating systems are: parabolic troughs, parabolic dishes, and central receivers.

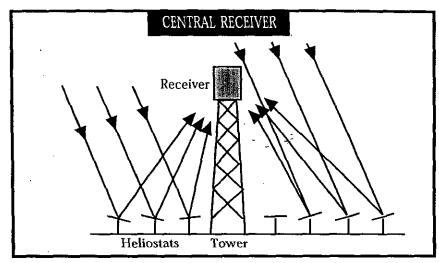
Parabolic Trough. Parabolic trough systems use a concave-shaped trough collector with a highly reflective surface to focus solar energy on a heat collecting pipe (receiver) located at the line of focus of the trough. In the Luz Solar Electric Generating Station design, the heat transfer fluid (a synthetic oil) circulates through the tube receivers, and the hot oil is then routed to a heat exchanger, where steam is formed for driving the turbine-generator.

The parabolic trough design is the only solar thermal technology that is currently economically feasible and is considered to be commercially available is some cases. The most recent design is 80 MW in size and is natural gas-assisted, using natural gas to create steam for electricity production during periods of low solar insolation or during the night.

- Permitting Issues for Parabolic Troughs. Some of the issues associated with parabolic troughs may include:
 - Use of large tracts of land (approximately four to five acres per MW output); the use is incompatible with other land uses
 - Disturbances or destruction of wildlife habitat, especially to rare and/or endangered species' habitat (in the desert)
 - Disturbance or destruction of cultural and paleontologic resources (if on previously undisturbed land).
 - Water requirements for the steam cycle and cooling towers; water supply as a concern, particularly on undisturbed land in the desert;



- Changes in visual quality
- Public health and safety issues associated with the storage, handling, and disposal of oil-based heat transfer fluids, including the potential for accidental releases
- Air emissions associated with operation of a natural gas-fired backup system (if applicable)
- Parabolic dish. Parabolic dish. systems collect and concentrate solar energy via a large, sun-tracking dish. At the dish's focal point, the thermal energy is transferred to a working fluid for subsequent conversion into electrical energy by a heat engine mounted on the dish. Structural limitations result in dish sizes that produce from 25 to 50 kW per dish. Parabolic dish technology is not commercially available, as there are several research and development goals which must be met, including demonstration of improved efficiency, component reliability, and lower cost for the Stirling engine.
- Permitting Issues for Parabolic Dishes. Parabolic dish systems, like parabolic trough systems, may involve the use of natural gas firing of the Stirling engine for periods of low solar insolation. Some of the issues associated with parabolic



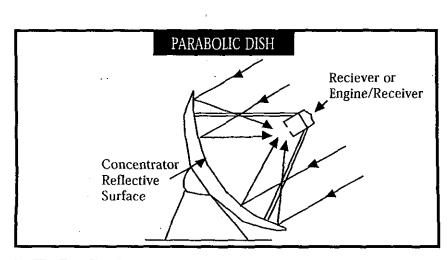
dishes are similar to the issues associated with parabolic troughs, except that neither water nor heat transfer fluid are used. Parabolic dishes have stightly higher land use requirements (approximately six to nine acres per MW output) than parabolic troughs. Parabolic dish systems share with photovotaic systems the characteristics of modularity and stand-alone/unsupervised operation. Thus, they may be used in small numbers, in market niche applications, and in remote areas.

Central Receivers. Central receivers use a field of computer-guided heliostats (mirrors) to focus sunlight onto a tower-mounted receiver. The circulating heat

transfer fluid is typically a molten salt which is transported from the top of the tower to a ground level storage tank. The hot molten salt can be stored in the tank for use later (such as during cloudy periods or at night), and is eventually routed to a heat exchanger where its heat is used to turn water into steam for driving a steam turbinegenerator. The thermal storage capability of this central receiver design eliminates the need for a natural gas-fired backup system.

Solar Two, a 10-MW central receiver project developed by the U.S. Department of Energy and several utilities, was dedicated on June 5, 1996 in Barstow, California. It is the successor to Solar One, the world's first-utility-scale central receiver system, which operated from 1982 to 1988 at the same site. Solar Two uses 1,926 heliostats to reflect the sun's energy to the receiver at the top of a 300-foot tower. Solar Two can continue producing electricity for up to three hours after sundown.

Permitting Issues for Central Receivers. Some of the issues associated with central receivers include:



- · Use of large tracts of land (approximately nine to 10 acres per MW output); the use is incompatible with other land uses
- Disturbances or destruction of wildlife habitat, especially to rare and/or endangered species' habitat (in the desert)
- Disturbance or destruction of cultural and paleontologic resources (if on previously undisturbed land)
- · Water requirements for the steam cycle and cooling towers; water supply as a concern on undisturbed land in the desert
- Changes in visual quality

SALT PONDS

Salt ponds are bodies of water with greater salinity at the bottom than at the surface. The bottom storage layer retains its heat because its high salt concentration increases the density gradient enough to suppress the natural tendency for heated water to rise to the surface. As a result, the temperature in the bottom layer can be maintained at about 180 degrees F. Heat from the bottom layer is used to heat a working fluid, which drives a heat engine or turbine-generator.

Salt pond technology is not commercially available in the U.S. because of insufficient technical maturity and high capital cost. The technology requires the existence of a shallow, salty body of water, or of land with economic access to sait.

- Permitting Issues for Salt Ponds. Some of the issues associated with salt ponds include:
 - Use of large amounts of land/ water surface (approximately 10 to 50 acres per MW output)
 - · Disturbance of large areas of surface vegetation and biological resources
 - Possibility of waterfowl becoming encrusted with salt in briny waters where evaporation ponds are used
 - · Potential for contamination of groundwater due to the highly concentrated brine solution and a hydrocarbon working fluid in a binary cycle turbine
 - Changes in visual quality

- a) Resource: An Encyclopedia of Energy Utility Terms, Pacific Gas and Electric Company, 2nd edition, 1992, pp. 421-423.
- b) Small But Powerful -- A Review Guide to Small-Alternative Energy Projects for California's Local Decisionmakers, Association of Bay Area Governments. September 1987, pp. 12, 13, 31-35.
- c) 1992 Energy Technology Status Report - Final Report, California Energy Commission, Report no: P500-92-007, December 1992. Fact Sheet 12.1.1 (Central Receivers), 12.1.2 (Parabolic Dishes), 12.1.3 (Parabolic Troughs), and 12.2 (Salt Ponds).
- d) 1992 Energy Technology Status Report, Appendix A, Volume II: Detailed Electric Generation Technology Evaluations, California Energy Commission, Report no. P500-92-007A V2, December 1992. Section 12.0 (Solar Thermal Electric).
- e) Technical Potential of Alternative Technologies — Final Report, prepared for the California Energy Commission by Regional Economic Research, December 2, 1991.
- f) "Generator is a Beacon to Supporters," The Arizona Repub-
- g) "A Hot Recipe For Power," Sacramento Municipal Utility District Customer Connections, June 1996.

B-16. WIND

Wind power plants are turbines which use the energy in the motion of the wind to make mechanical energy, which is then converted to electrical energy.

The components of a utility-scale "windfarm" include wind turbines, an underground power transmission system, control and maintenance facilities, and a substation that connects the farm with the utility power grid. Utility-scale wind turbines are classified by size as follows: small (less than 50 kW); intermediate (50 to 500 kW); and large (above 500 kW). Small and intermediate turbines make up the bulk of the installed turbine base, although research and development continues to focus on the large and intermediate categories.

Utility-scale windfarms are generally located in areas with average annual wind speeds of at least 13 miles per hour. Wind power is more available during certain seasons because climatic conditions affect wind speed. In California, wind speeds are highest in the hot summer months, and approxi-. mately three-fourths of all annual wind power output is produced during the spring and summer.

Another application of wind is in distributed use systems, which provide on-site power in either stand-alone or grid-connected configurations. Most such systems range in size from one to 25 kW. Distributed wind systems are applicable to industry, water districts, rural residences, agricultural use, and a wide variety of isolated power uses located in good wind resource areas.

Wind power for utility-scale applications is considered to be commercially available under most conditions. The technology is considered to be mature, and there are several system suppliers.

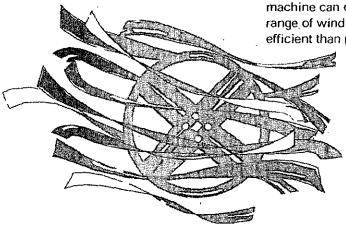
Wind power for distributed applications is considered to be commercially available under limited conditions. Distributed wind systems can be a cost-effective option in remote locations where a utility connection would not be economically feasible.

While the power produced by many of California's existing wind turbines is non-competitive with other forms of electricity generation, some of the newest wind turbine designs may be able to match or beat the power prices from many coal and nuclear plants. One design has blades that are 100 feet in diameter, approximately twice as long as many installed turbines. The 400 kW machine can operate in a wider range of wind speeds and is more efficient than previous models.

While the power is currently more expensive than that produced by natural gas-fired plants, the price of wind power is not affected by fuel price increases or supply disruptions. In addition, there is currently an attractive federal tax credit for wind generation.

Other advantages of wind power include the following:

- It forestalls or replaces the need to build potentially more polluting con-ventional power plants
- It produces virtually no pollution of air, water, or soil
- It is renewable (non-depletable). There is enough wind in the U.S. to power the entire country
- · Because of its modular nature, it is easy to add capacity as needed
- Installing wind turbines is relatively quick
- Permitting Issues. Some of the potential issues associated with windfarm development include:
 - Use of large tracts of land (the average windfarm requires 17 acres of land to produce one MW of electricity. However, simultaneous land uses such as agriculture and cattle grazing occur often)
 - Erosion in desert areas
 - Changes in visual quality (since windfarms tend to be located at or just below ridge lines)
 - · Disturbances to wildlife habitats



- Avian mortality due to collisions with wind turbines and associated wires (research is ongoing to reduce bird deaths)
- Noise (wind turbines generate both audible and low frequency [deep base vibration] sound waves)
- Grass or brush fires caused by shorts in the electrical cables in the unlikely event that they become stretched or twisted when the turbines turn to catch the wind

- a) Resource: An Encyclopedia of Energy Utility Terms, Pacific Gas and Electric Company, 2nd edition, 1992, pp. 490-492.
- b) Small But Powerful A Review Guide to Small Alternative Energy Projects for California's Local Decisionmakers, Association of Bay Area Governments, September 1987, pp. 18-23.
- c) "Power Firm Races Into the Wind," San Francisco Chronicle, August 29, 1994.
- d) Gipe, Paul, Wind Power for Home & Business: Renewable Energy for the 1990s and Beyond, Chelsea Green Publishing Company, 1993.

- e) 1992 Energy Technology Status Report — Final Report, California Energy Commission, Report no. P500-92-007, December 1992. Fact Sheet 11.1 (Wind-Utility Scale Applications) and 28.3 (On-site Electricity Production — Distributed Wind Systems).
- f) 1992 Energy Technology Status Report, Appendix A, Volume II: Detailed Electric Generation Technology Evaluations, California Energy Commission, Report no. P500-92-007A V2, December 1992. Section 11.1 (Utility Scale Wind Systems).

B-17. ELECTRICAL TRANSMISSION AND DISTRIBUTION SYSTEMS

The traditional electrical power delivery system is typically described as starting at a generating station. Power is produced at the generating station and is transported through the generating station switchyard to the transmission system. The transmission system transports the power in large quantities over long distances to local distribution centers, called substations. From substations, power travels via distribution systems to local power consumers (see Figure).

Transmission system facilities include high-capacity transmission lines that are typically supported on metal towers. The voltage on

these lines generally ranges from 161 to 500 kilovolts (kV). The power lines require long, narrow, continuous land corridors.

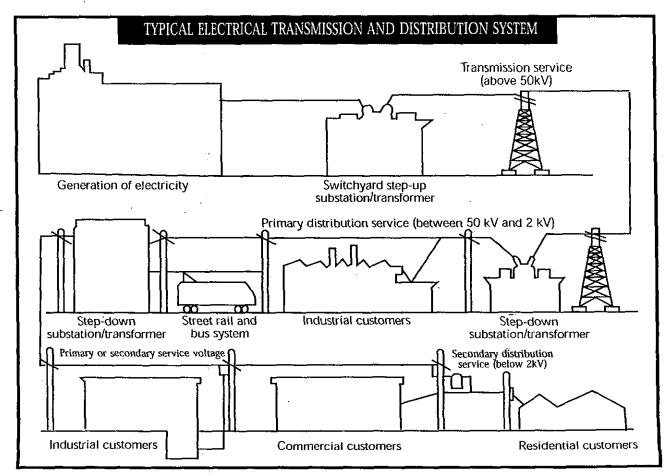
The transmission system also requires parcels of land for facilities such as transmission system substations. At transmission substations, the incoming transmission voltage is reduced to levels of 50 to 161 kV. This voltage level is called sub-transmission. The outgoing sub-transmission system is similar in appearance to the transmission system.

The transmission system carries large amounts of power from the generating station's switchyard to the transmission substation, while the sub-transmission lines branch out from the transmission substation, carrying less power along

each line but in several directions. The ending points of the subtransmission system are either large industrial or commercial consumers, or distribution substations which further reduce the voltage.

From distribution substations, which require parcels of land, the power is then carried over low-voltage distribution lines requiring long, continuous land easements. These lines, which are typically wires supported by wooden poles or underground cables, deliver power to small consumers such as homes and offices.

Permitting Issues. Some of the issues that may be associated with permitting transmission and subtransmission lines and transmission substations include:



SOURCE: "Resource: An Encyclopedia of Energy Utility Terms", Second Edition. Pacific Gas and Electric Company.

- Use of long continuous corridors of land (lines only, not substations). Sim-ultaneous land uses, such as agriculture and cattle grazing, can occur if suchuses do not conflict with the operation and maintenance of the transmission lines
- · Changes in visual quality
- Disturbances to and destruction of vegetation and wildlife habitat during construction
- Avian collisions with transmission lines and electrocution from transmission lines and transformers
- Potential health effects from electric and magnetic fields

The issues associated with lower-voltage distribution lines and substations are similar. Distribution lines and substations, unlike many high-voltage transmission lines and substations, are typically located closer to population centers. While the biological impacts may be lesser because distribution lines tend to be located on developed land, the visual impact and public nuisance issues may be more significant.

Some of the issues that may be associated with permitting underground distribution lines include:

- Use of long right-of-way corridors
- Disturbances to and destruction of vegetation and wildlife habitat during construction
- Potential health effects from electric and magnetic fields (although the magnetic field strength is typically reduced compared to overhead lines)

- a) Resource: An Encyclopedia of Energy Utility Terms, Pacific Gas and Electric Company, 2nd edition, 1992, pp. 169-170, 186-187, and 441.
- b) Draft Lassen County Energy Element, prepared for the Lassen County Board of Supervisors by Michael Clayton & Associates, March 10, 1993, pp. 98-102.
- c) Evaluation of Power Facilities: A Reviewer's Handbook, prepared by the Berkshire County Regional Planning Commission, April 1974.



B-18. ENERGY PRODUCTION WELLS (OIL, NATURAL GAS, AND GEOTHERMAL)

Energy production wells include the wells and other facilities needed to extract and produce subsurface oil, natural gas, and geothermal resources. The locations of these resource types varies across the state (see box entitled California Counties with Oil, Gas, or Geothermal Production, as well as the map with oil, gas, and geothermal resource areas contained in Chapter 3).

The general processes involved in identifying and developing oil, natural gas, and geothermal fields are similar. First, a particular area that has the potential for recoverable resources is identified. This identification process can involve seismic testing and other forms of geologic analysis. Second, the area

is explored by drilling test wells (also called prospect or exploratory wells) in order to determine the existence and/or the extent of the reserves. Assuming favorable results from the second step, the field is developed and operated, which involves drilling development wells (and injection wells where applicable), and installing the necessary pipelines, tanks, and processing facilities (where applicable) to extract and produce usable crude oil, natural gas, or geothermal resources. Finally, the field and the individual wells must be properly abandoned (e.g., when the resource is depleted or it is no longer economical to operate the well.)

As discussed in Appendix C, the California Department of Conservation, Division of Oil, Gas, and Geothermal Resources supervises the drilling, operation, maintenance, and abandonment of oil,

gas, and geothermal wells. Their role is to prevent waste and damage to oil and gas deposits; prevent damage to property and natural resources; protect freshwater resources from contamination due to oil or gas operations; and ameliorate land subsidence over or adjacent to oil or gas pools when this land surface is subject to inundation from the sea.

OIL AND NATURAL GAS WELLS

Crude petroleum is generally found in porous layers of sedimentary rocks located as much as several miles below the earth's surface. Natural gas usually co-exists in nature with petroleum, and the two are often produced from the same well simultaneously (see box entitled *The Origin and Accumulation of Petroleum.*) Natural gas produced from a reservoir that contains petroleum is termed associ-

CALIFORNIA COUNTIES WITH OIL, GAS, OR GEOTHERMAL PRODUCTION							
Oil and Gas Production	Gas Production Only	Electrical Generation from Geothermal Energy	Commercial Low-Temperature Geothermal Use				
Alameda Contra Costa Fresno Kern Kings Los Angeles Monterey Orange San Benito San Bernardino San Luis Obispo San Mateo Santa Barbara Santa Clara Tulare	Butte Colusa Glenn Humboldt Madera Merced Sacramento San Joaquin Solano Stanislaus Sutter Tehama Yolo	Imperial Inyo Lake Lassen Mono Sonoma	Alpine Colusa Contra Costa Imperial Inyo Kern Lassen Modoc Monterey Mono Napa Plumas Riverside San Bernardino				

Source: 1994 Annual Report of the State Oil & Gas Supervisor, California Department of Conservation, Division of Oil, Gas, & Geothermal Resources Report No. PRO6, 1995, p. 62.

ated gas if it exists as free gas in a gas cap above the petroleum layer, or dissolved gas if it is in solution with the petroleum.

Natural gas can be formed from sources other than those from which oil is derived, such as peat deposits or coal fields. Gas produced from a reservoir that does not contain crude oil (i.e., from a gas well) is referred to as nonassociated gas because it is not directly associated with oil underground.

In addition to the oil and natural gas deposits found beneath the land, California also has several offshore oil and gas wells. These include wells in state tidelands (defined as the area under state control from the shore to three miles offshore) as well as federal outer continental shelf (OCS) waters (defined as from three miles offshore to 200 miles offshore).

At the end of 1994, California had 214 active oil fields (which includes nine active federal OCS fields). These fields had 39,696 producing wells on them at that time (which includes 397 federal OCS producing wells). The total oil produced from these wells in 1994 was 344.5 million barrels. Onshore production accounted for 77 percent of California's production in 1994, while state offshore production accounted for 6 percent and federal offshore accounted for 17 percent. In addition to petroleum, these wells also produced 197.8 billion cubic feet of associated natural gas.

California also had 87 active dry gas fields (which includes one active federal OCS field) at the end of 1994. These fields had 1,058 producing wells on them at that time (which includes 17 federal OCS producing wells). The total natural gas produced from these wells in 1994 was 311.4 billion cubic feet.

THE ORIGIN AND ACCUMULATION OF PETROLEUM

Per oleum and natural gas are derived from dead organic (plant and animal) material which was buried below ancient seas in a geologic process called sedimentation. The most widely accepted theory for the transformation of organic substances into crude penaleum is the combined effect of severe conditions of pressure and temperature over extremely long time periods. The move-ment of crude petroleum from the place of origin to the traps where accumulations are now found most likely occurred in an upward direction. The oil continually rose by water displacement மையாததில் ringration was halted by an impermeable barrier ... called cap rock. Natural gas, which is often dissolved under natural pressure in crude petroleum, sometimes rises above the oil when gas is present in large enough amounts. The natural pres sure from both the natural gas above the oil and the salt water below the oil is used beneficially in transporting oil to the surface when drilled a lorthis reason, both natural gas and salt water are commonly extracted together with oil from the well.

Source: D'Acierno, J. and A. Hermelee, Physical Aspects of the U.S. Oil and Gas Systems, Brookhaven National Laboratory Report No. BNL 51076, November 1979.

DEVELOPING OIL AND GAS FIELDS

Surface exploratory methods bring in equipment for a short time while the study is being conducted, and then the equipment is removed. Most exploratory methods do not have a permanent impact on the land, but they can create significant, short-term impacts.

In California, exploratory and development wells are typically drilled using the rotary method (see figure entitled Rotary Drilling Equipment). During the drilling operation, drilling mud (generally a mixture of clay and water chosen for its physical and chemical properties) is pumped down the drill pipe and out through the drill bit. The mud cools the drilling bit and, after jetting through the holes in the bit, picks up the rock cuttings and returns to the surface through the space between the drill pipe and the wall of the hole. Upon reaching the surface, the mud travels through a screen that removes the cuttings and then into a mud pit from which it is pumped and circulated back down the drill pipe to pick up more cuttings.

When a drill bit becomes dull, all drill pipe must be removed from the hole so the drill bit can be changed. As drill pipe is removed, it is stacked vertically against the derrick, usually in lengths of 60 or 90 feet, depending on the derrick size. When the old bit is brought to the surface and replaced, the pipe is screwed back together as it is run back into the well bore, often over two miles deep (the deepest producing well in California is over three miles deep.) The process of changing drill bits occurs many times as the well is drilled.

An alternative to the conventional rotary drilling method is coiled tube drilling. Coiled tube drilling involves the use of a continuous flexible steel tube instead of drillstring sections that can take days to replace a drillbit. The coiled tube drillstring does not have to be rotated since the drillbit is driven by a downhole motor. There are still some problems with the technology such as buckling of the drillstring and sometimes poor reliability of downhole motors in slimhole sizes. The tubing diameter can be up to almost three inches.

Coiled tube drilling is being used in Shell's McKittrick field, where 68 wells out of 115 planned steam injection wells (used with enhanced oil recovery methods, discussed later in this section) are being drilled using the technology with

two-inch tubing. Well depths are less than 1,000 feet, and the access there is difficult from the surface because of the numerous pipelines, which makes the use of coiled tube drilling technology a particular advantage since it works well in confined spaces. In the McKittrick field the technology is saving drilling and rig costs, although it is generally chosen by field developers more because of the need to advance the technology's status and because of its future potential to save money when the technology is mature.

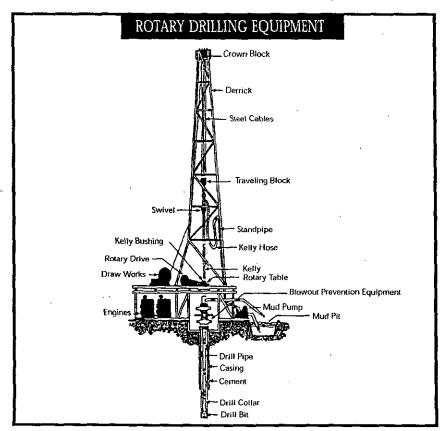
Most wells are drilled vertically (i.e., the well is directly over the oil or gas zone.) Wells, however, can also be directionally drilled, where the well is drilled at an angle (as much as 80 degrees from vertical in some cases). Directional drilling is used in urban areas, where it is

not possible (either physically or economically) to locate the well directly over the targeted oil or gas zone. It can also be used to reach off-shore oil from an on-shore location, or to reach several areas from a single stationary off-shore platform or island.

The California Department of Conservation, Division of Oil, Gas, and Geothermal Resources requires the installation of blowout prevention equipment on wells during drilling operations to prevent blow-outs (uncontrolled gushers). Installed early in the drilling process, all successive drilling occurs through the blowout prevention equipment. As a result, blowouts are a rare occurrence in California, and the few that have occurred were typically the result of human error.

Before penetrating oil or gas reservoirs, most wells pass through freshwater and saline aquifers. Large diameter metal pipe called casing is set with cement into the hole during drilling to protect these aquifers. For their mutual protection, aquifer and reservoir fluids must not be allowed to migrate outside the casing and infiltrate other strata. Such intermingling could destroy aquifer quality and impair well production.

If the oil or gas zone has sufficient pressure to be brought to the surface without pumping, a series of valves, attached to the permanent casing, can be installed above the well to regulate the rate of oil or gas flow. Most natural gas zones have sufficient pressure for such a weilhead arrangement. However, many oil wells require an artificial lift system to bring the oil to the surface (either immediately upon resource extraction or after the natural reservoir pressure declines after a period of extraction). The most common method is to use a



Source: California Oil, Gas, and Geothermal Resources: An Introduction, California Department of Conservation, Division of Oil and Gas, third edition, 1983, p.36.

rod pump at the bottom of tubing. The pumping unit has a motor and gears that move the beam and the attached rods up and down, operating the pump (see figure entitled Enhanced Oil Recovery Via Steam Injection).

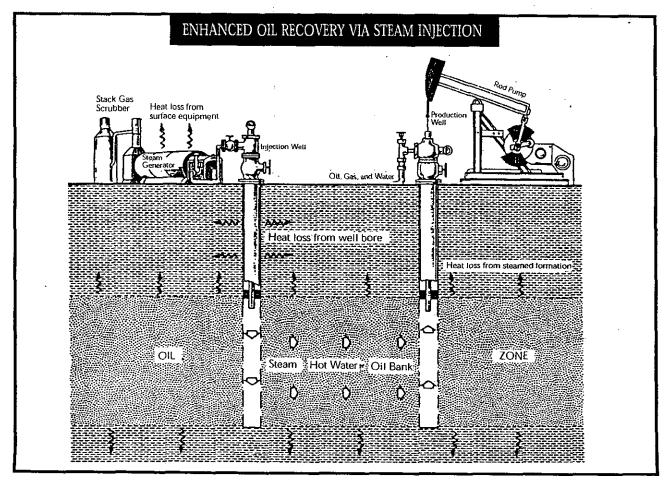
Only about five percent to 30 percent of the original oil-in-place can be produced from California fields using these conventional production methods. For additional production, enhanced oil recovery (EOR) methods are required. EOR methods either make the oil less viscous or they increase the sub-surface pressure in order to push the oil, or they do both. EOR methods include steam injection, natural gas injection, waterflooding, chemical injection, and others.

The most important EOR method used in California is steam injection, because of the state's abundance of heavy (viscous) crude oil. Heavy crude oil has the consistency of cold molasses. The heat from the steam lowers the viscosity (thickness) of the oil so that it will flow more easily.

The figure entitled Enhanced Oil Recovery Via Steam Injection shows a thermally enhanced oil recovery (TEOR) process using steam generators. Note that this arrangement requires a separate well, called an injection well, for the steam injection. It should also be noted that TEOR methods can also be accomplished very efficiently using cogeneration facilities. Waste heat from a thermal

power plant can be captured and used to raise steam for the TEOR process. See the Cogeneration portion of section B-11 "Natural Gas and Oil".

The oil and associated gas leave the well through a pipeline attached to a device called a separator, where the gas is separated from the oil and water, and the sediment and water are separated from the oil. The wastewater is then injected back into the ground via injection wells. The oil is stored in field storage (stock) tanks. Pipelines carry most of California's crude oil from the field storage tanks to refineries (see section B-23, "Pipelines (Petroleum, Petroleum Products, and Natural Gas) and section B-24 "Refineries"). Natural



Source: California Oil, Gas, and Geothermal Resources: An Introduction, California Department of Conservation, Division of Oil and Gas, third edition, 1983, p.50.

gas from the separation process is routed into a line leading to a gas plant where the "wet fractions" are removed. The wet fractions consist of natural gasoline, butane, propane, and other gases. Once the wet fractions are removed, the dry gas goes into the commercial natural gas pipelines (see section B-23 Pipelines (Petroleum, Petroleum) Products, and Natural Gas).

When non-associated gas is produced from gas wells, the proportion of liquid to gas is generally low enough to permit gathering pipelines to transport the gas either to a gas processing plant or directly to a utility company's collecting line without the use of a separator.

It can take about a month to drill and complete an on-shore oil well to a depth of 5,000 feet (completion includes casing the well and installing the necessary production and processing equipment.) Deeper wells and other situational factors such as directional drilling and the composition of the rock strata can result in drilling times of several months.

Once the useful life of production. and injection wells has expired, the wells must be properly abandoned by filling the wells with cement to seal access to the well and to protect the different layers beneath the well, especially fresh water aquifers. In addition, removal of all above-ground facilities and other restoration activities may be required (see section 5.7 "Energy Facility Closure/Abandonment).

Permitting Issues for Oil and Gas Wells. An Executive Order by former President Bush placed a moratorium on new leases in federal waters until the year 2000. Although there are currently almost 70 existing undeveloped leases infederal waters that could be devel-

oped, none are currently being pursued by the leaseholders. Thus, it is unlikely that there will be any exploratory or new development activities in the near future. The only activity expected is completion of platforms on existing leases and new wells to be drilled from existing platforms. Efforts are underway to assess the potential for future development in federal waters. A study being conducted jointly by the Minerals Management Service and the industry that will focus on developing offshore oil with minimal environmental impacts should be complete by mid-1997.

In addition, a recent (September 1994) law forbids future drilling in the three miles of water off the coast that are under state control, along the entire 840-mile California coastline.

As a result of these actions, the permitting issues described below refer only to onshore oil and gas wells.

Some of the major issues associated with onshore oil and gas wells include:

- · Possible soil erosion during exploration and drilling activity
- Ground subsidence during operation of the field may impact nearby infrastructure such as sewer, water, and gas mains
- Special disposal sites may be ... required for drilling mud
- · Possible surface and groundwater contamination from accidental spills during drilling
- · Possible contamination of fresh water aquifers from pumping extracted wastewater through injection wells

- · Ability of oil and gas field equipment to meet emissions requirements
- Possible incompatibility with adjacent land uses (if located in an urban area)
- Significant water use by TEOR processes
- · Biological resources impacts due to the degradation of air, water, noise, and soil quality around the field
- · Temporary and permanent changes in visual quality due to tall derricks, drilling equipment, rod pumps, processing facilities, and associated tanks and pipe-
- Short-term increases in noise during exploratory activity (such as the use of "thumper trucks" and possibly explosives) and around-the-clock drilling
- · Long-term increases in noise during well production
- Proper closure and abandonment of wells at the end of their productive life

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- a) California Oil, Gas and Geothermal Resources - An Introduction, California Department of Conservation, Division of Oil and Gas, third edition, 1983.
- b) 1994 Annual Report of the State Oil & Gas Supervisor, California Department of Conservation, Division of Oil, Gas, & Geothermal Resources Report No. PR06, 1995.
- c) D'Acierno, J. and A. Hermelee, *Physical Aspects of the U.S. Oil and Gas Systems*, Brookhaven National Laboratory Report No. BNL 51076, November 1979.
- d) March 30, 1995 telephone conversation with Kaleeq Siddiqui, Minerals Management Service, (805) 389-7724.
- e) "New Law Permanently Bans Drilling Off Coast", San Francisco Chronicle, September 29, 1994.
- f) Glenn County Energy Element of the General Plan, Final Draft, June 30, 1993.
- g) 1992 Energy Technology Status Report, Appendix A, Volume I: Detailed Electric Generation Technology Evaluations, California Energy Commission, Report no. P500-92-007A V1, December 1992. Sections 1.1.1.1 (Conventional Oil Extraction), 1.1.1.2 (Enhanced Oil Recovery), and 1.1.1.2.1 (Enhanced Oil Recovery -Thermal).

- h) Energy Infrastructure of the United States and Projected Siting Needs: Scoping Ideas, Identifying Issues and Options, Draft Report of the Department of Energy Working Group on Energy Facility Siting to the Secretary, December 1993.
- i) "High Hopes for Coiled Tube Drilling," *Petroleum Economist*, October 1994, pp. 16-17.

GEOTHERMAL WELLS

Geothermal energy is natural heat generated deep inside the earth. Such heat is generally not usable unless it is near the earth's surface and heats rocks and under-ground water. Hydrothermal resources are the most abundant source of presently usable geothermal energy (see section B-7 "Geothermal" for a discussion of other types of geothermal resources). In a hydrothermal system, water in subsurface aquifers is heated by geothermal energy. In rare instances, the heat is great enough to vaporize the water, creating a steam reservoir. In most hydrothermal systems, however, the reservoir is liquid-dominated and of lower temperature than vapor-dominated resources. Geothermal reservoirs vary greatly in depth, volume, temperature, fluid salinity, and non-condensible gas content. (See box entitled What Are Geothermal Resources?.)

After performing preliminary resource assessment work in an area, the next phase of development is actual drilling to confirm and produce the resource. This takes the form of test or exploratory wells initially, followed by fully-completed production and injection wells. Injection wells are used to inject spent geothermal fluids back into the producing aquifer. Such a practice provides an efficient and environmentally acceptable disposal method while also contributing to the resource's longterm productivity.

The total geothermal field development project consists of the geothermal production and injection wells, resource transportation lines, production equipment, roads, and other facilities which are necessary to supply geothermal energy to any particular heat utilization equipment for its productive life. The steam collected can then be used for power generation or direct use applications (see sections B-7 "Geothermal" and B-21 "Geothermal Direct Use," respectively.)

In geothermal power plant applications, steam from several geothermal production wells is delivered to the power plants through steamgathering pipelines. The wells can be a mile or more from the power plant. For low-temperature geothermal projects, only one or two

WHAT ARE GEOTHERMAL RESOURCES?

Geothermal resources are defined as ... the natural heat of the earth, the energy in whatever form below the surface of the earth present in resulting from, created by, or from which may be extracted natural heat, and all minerals in solution or other products in whatever form obtained from naturally heated fluids, brines, associated gases and steam excluding oil shydrocarbon gas or other hydrocarbon substances." (Fittle 114, California Code of Regulations, section 1920(a))

production wells may be required, with perhaps one injection well if the geothermal water quality is poor enough that subsurface disposal is necessary.

Drilling techniques for both production and injection wells are similar. Low-temperature wells can be drilled with standard water well drilling equipment and may take only a week or two to drill and complete. High-temperature wells are drilled with equipment similar to that used for oil and gas development, and may take several months to drill and complete.

Although much of the drilling technology for geothermal resources is adapted from the oil and gas industry, many geothermal reservoirs, particularly high-temperature systems, are generally composed of harder, more corrosive rock structures and fluids. Thus, the drilling and completion technology requirements are often more demanding. In areas where the rock formations do not cave in readily and formation pressures are not very high, it may be possible to use air as the circulating medium rather than mud. For example, \supset wells drilled at The Geysers geothermal field were supplied with air from large air compressors that was used to keep the bit cool and to remove the cuttings from the hole.

▶ Permitting Issues. In general, the number and severity of environmental impacts increases with increasing resource temperatures. Thus, the environmental impacts associated with the drilling of a single production well from a 100 degree F resource that will operate a residential heat pump are significantly different from the impacts associated with the drilling of

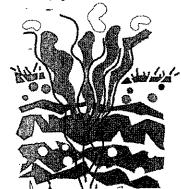
multiple production and injection wells from a 300 degree F resource that will be used for power production. (See sections B-7 "Geothermal" and B-21 "Geothermal Direct Use" for more on the permitting issues associated with these types of end uses.)

Depending on the geothermal resource, some of the major permitting issues associated with geothermal wells include:

- Land use incompatibility, including access to the site
- Possible soil erosion during exploration and drilling activity
- Potential for contamination of surface and ground water from production and injection wells
- Ability of geothermal field equipment to meet emissions requirements
- Possible air emissions of noncondensible gases such as hydrogen sulfide (which may be present in the geothermal fluid in lethal quantities)
- Special disposal sites may be required for drilling mud (if applicable) and residue from the hydrogen sulfide abatement process
- Temporary and permanent changes in visual quality due to tall derricks, drilling equipment, processing facilities, and associated tanks and pipelines
- Short-term increases in noise during exploratory activity and around-the-clock drilling
- Possible ground subsidence (localized sinking around production wells and uplifting around injection wells)

- Possible induced seismicity from the withdrawal and injection of geothermal fluids (note that many geothermal reservoirs are located in regions with a high frequency of naturallyoccurring seismic events)
- Biological resources impacts due to the degradation of air, water, noise, and soil quality around the field
- Proper closure and abandonment of wells at the end of their productive life

- a) California Oil, Gas and Geothermal Resources — An Introduction, California Department of Conservation, Division of Oil and Gas, third edition, 1983.
- b) Draft Geothermal Element to the Siskiyou County General Plan, February 1984, pp. 71-86, 121-135.
- c) Phair, Kenneth A., "Getting the Most out of Geothermal Power", Mechanical Engineering, September 1994.
- d) 1992 Energy Technology Status Report, Appendix A, Volume I: Detailed Electric Generation Technology Evaluations, California Energy Commission, Report no. P500-92-007A V1, December 1992. Section 1.3.1.1 (Hydrothermal).



B-19. ETHANOL AND METHANOL PRODUCTION **FACILITIES**

Ethanol (CH₃CH₂OH) and methanot (CH₃OH) are the most common alcohols used in motor fuel mixtures, and both are used in the United States. Both alcohols are also employed for a variety of nonfuel uses such as plastics, solvents and coatings. Ethanol is presently produced from the yeast-based fermentation of sugar and starches in agricultural crops such as sugarcane, corn and sorghum. Methanol is produced by the thermochemical reforming of natural gas, although it can also be made from petroleum and coal. At present there are no commercial methanol production facilities situated in California, and only three plants produce ethanol, primarily as a byproduct from food processing wastes.

Emerging technologies for producing both ethanol and methanol from cellulosic biomass (e.g., nonfood crops and agricultural waste, MSW and wood waste) may lead to the construction of alcohol production facilities in California, especially in view of the wide variety of biomass resources that exist here.

Biomass-to-ethanol production technology is based on the hydrotysis of cellulose and hemicellulose into simple sugars that can then be biologically fermented to produce ethanol. The ethanol is then purified by distillation and the residual water remaining after distillation is removed using molecular sieves. The remaining material from the biomass consists principally of lignin and can be used as boiler fuel for process heat or further utilized as a crude chemical feedstock.

Strong potential also exists to produce methanol from biomass using one of a variety of innovative thermochemical gasification technologies. Carbonaceous material such as chipped wood or crop waste is gasified at high temperatures to produce a synthesis gas which is then readily converted to methanol using widely available commercial process technology.

Permitting Issues. It is possible that facilities to produce methanol from natural gas using conventional synthesis technology may be sited in California, although none now exist in the state. The air quality concerns center on NOx from the gasifier or other process heat facilities and fugitive organic emissions from alcohol handling and storage tanks.

Wastewater discharge from fermentation-based ethanol production must be properly treated before discharge. Pollutants of concern can include high concentrations of brine and biochemical oxygen demand (BOD) from dissolved organic wastes. There are no extraordinary discharge treatment requirements as compared to other industrial processes such as food processing or publicly owned treatment works (POTWs).

In terms of land impacts, it is likely that ethanol production facilities will be relatively small in scale, as compared with a petroleum refinery, due to the modular nature of the production process and the dispersed nature of the feedstocks. In addition, since biomass feedstocks are typically bulky and have a low energy density, the plants will be located close to the sources of feedstock in order to keep transportation costs down. Regions with a strong agricultural or forest products.base may make good sites for these plants.

Conventional methanol production facilities will be sited near sources of low cost natural gas and are likely to be larger than biomass-tomethanol plants due to established economies of scale. These plants tend to be very clean compared to similar processing plants such as oil refineries. Biomass to methanol plants, however, will be located in much the same fashion as ethanol production facilities and will probably have a relatively small footprint. Although it is poisonous to humans and animal life, methanol is more biodegradeable and dissipates into the natural environment more rapidly than petroleum-based fuels.

- a) Fuels Report. California Energy Commission, February 1994, Publication No. P300-93-109.
- b) The Production of Fluid Fuels From Biomass. Katofsky, Ryan E., Princeton University, Center for Energy and Environmental Studies, New Jersey June 1993.
- c) Biofuels for Transportation: The Road from Research to the Marketplace. National Renewable Energy Laboratory, Golden, Colorado, February 1995.

B-20. ALTERNATIVÉ FUEL CHARGING/FUELING STATION

In the near future, local planners will see a new kind of energy facility to be integrated into community plans: vehicle energy stations that dispense alternative fuels and/or electricity for a new generation of low and no-emission autos and trucks. Alternate fuel vehicles (AFV) will need special fueling and/or charging facilities that are only now being conceptualized and planned at the state level. The following pages contain descriptions of:

- a) Electric Vehicle Charging Stations
- b) Liquified Petroleum Gas Fueling Stations
- c) Methanol and Ethanol Fueling Stations
- d) Natural Gas Fueling Stations.

The Energy Commission has prepared the Calfuels plan that outlines future needs for AFV commercialization. According to the Energy Commission, the timing and extent of commercialization for various AFVs is uncertain, with the exception of electric vehicles (EVs). The California Air Resources Board (CARB) will contract with original equipment manifacturers to produce aminimum number of EVs over three years, beginning in

1998. In 2003, CARB has a mandate that ten percent of all vehicles sold in California must be zero-emission vehicles.

Currently, the existing refueling net-work for AFVs is extremely limited. Customer service and training have been minimal, and work in the areas of technology standardization and code revisions is in the early stages. Key barriers that need to be eliminated, in part through local planning, were identified as follows in the Energy Commission Calfuels plan:

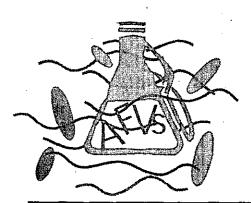
- All AFVs
 - a) Lack of training for vehicle technicians and emergency personnel
 - b) Need for increased public awareness about AFVs
- · Electric vehicles
 - a) Lack of standard charging connector
 - b) Need for the state to adopt national code revisions and to disseminate code information to local enforcement agencies

(Note: The State Building Standards Commission adopted the new codes in 1995. The codes take effect August 1996.)

- Methanol vehicles
 - a) Limited fuel supplies
 - b) Cost of production facilities
 - c) Limited fueling network

- Ethanol vehicles
 - a) High fuel prices
 - b) Limited fueling network
- Natural gas vehicles
 - a)_Limited fueling network
- b) Cost of natural gas compression and fueling systems.
- Need for the state to adopt national code revisions and to disseminate code information to local enforcement agencies
- Hydrogen vehicles
- a) Need for additional research, development, and demonstration
- b) Perception of high safety risks

Local governments can help reduce or eliminate many of these barriers by considering AFV fueling and/or charging needs when updating local transportation plans and landuse development standards. For technical assistance, interested community planners should contact their local natural gas and electric utilities, or the Energy Commission's Energy Technology Development Division.



B-20.a ELECTRIC VEHICLE CHARGING STATIONS

Electric vehicles (EVs) are an emerging technology with approximately 2900 EVs currently in use in California. The adoption of the Low Emission Vehicle and Clean Fuel Regulations by the California Air Resources Board has accelerated EV development in recent years. Beginning in 2003, the regulations require that ten percent of the new vehicles sold in California must be zero-emission vehicles.

EVs are expected to be charged predominantly at private home base locations, such as residential or company garages. Because EVs currently have limited driving ranges, the availability of public charging facilities for full or partial charges away from the home base - called "opportunity" charging will help build consumer confidence and increase use of, and the early market for, EVs. Likely locations for opportunity charging include parking facilities for shopping areas, the workplace, park and ride lots, and airports. Fleet or commercial users may also need access to public charging facilities away from their home base.

The EV Industry has developed three standard energy levels for charging EVs:

Level 1:

Charging that can be done from a standard, grounded 120 Volt, three-pronged outlet available in all homes.

Level 2:

Charging at a 240 Volt/40 Amp EV charging station functioning at 240 Volt/40 Amps with special consumer features to make it easy and convenient to plug in and charge EVs at home or at an EV charging station on a daily basis.

Level 3:

A high-powered charging technology currently under development that will provide a charge in five-10 minutes, making it analogous to filling the tank of an internal combustion engine at a local gasoline station.

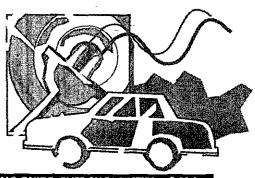
Of the three charging levels established, Level 2, a 240 Volt/40 Amp circuit is expected to be the consumers' preference at both private and public facilities. Operating at a rate up to five times faster than Level 1, Level 2 will meet the typical driver's daily needs in three-five hours of charging — at home, work, or special public charging facilities.

The EV Industry is developing two different kinds of systems to charge vehicles. One system, conductive charging, uses standard plug technology. The other, inductive charging, allows AC power to pass magnetically from the power source to the vehicle. The industry has nearly completed standardization of both charging interfaces.

California's five major utilities have extensive electricity generating capacity. Augmenting this capacity, each utility has access to, and routinely uses, power generated by other utilities to meet their customers' demands. Through the use of load management and on-line system capacity, California's utilities can meet the incremental demand for electricity needed to serve EVs without adding generation capacity. Some upgrades are expected on local distribution systems to meet EV demand.

Permitting Issues. The EV Industry is working to revise model electrical codes to adequately address the safety needs of EV charging sites without creating overly burdensome restrictions. Additional work is being focused on model building codes that will address issues related to both batteries and charging. To ensure that codes will be in place in California to time to prepare for the 1998 introduction of EVs, the state is initiating a revision to its building codes. The revised state code will be consistent with industry efforts to change the model codes.

Throughout this process, the state is supporting the transfer of information between local regulatory officials and industry to ensure that safety concerns are adequately addressed. Some cities such as Los Angeles, West Hollywood, and Sacramento are already moving forward to include EV charging facilities in their city plans. For instance, they are setting goals for providing EV charging ports at parking facilities and developing local building code requirements.



- a) Calfuels Plan: Developing an Infrastructure Plan for Alternative Fuel Vehicles, California Energy Commission, September 1994, Publication No. P500-94-002. The Calfuels Plan was prepared in compliance with AB 3052 (Chapter 762 of 1992 statutes, Public Resources Code Section 25326) to explore infrastructure barriers to the deployment of alternative transportation fuels in California.
- b) The ABCs of AFVs: A Guide to Alternative Fuel Vehicles, January 1995, California Energy Commission, Publication No. P180-95-001.
- c) Alternative Fuel Information,
 U.S. Department of Energy,
 Office of Energy Efficiency and
 Renewable Energy, 1994.
- d) NFPA 58, Standard for the Storage and Handling of Liquified Petroleum Gases, National Fire Protection Association, Quincy, MA.
- e) Industrial Fire Safety, "Addressing the Fire Hazards of Alternative Fuels for Public Transit Buses," Parts 1 and 2, (September/October and November/December 1993) by Ralph Kerwin.

- f) Fuel Facts: Liquified Petroleum Gas Motor Fuel (LPG)/ Propane, Western Liquid Gas Association, Fair Oaks, CA, May 1992.
- g) Natural Gas Fuels Magazine "Construction of NGV Facilities: A-Practical Guide to Working with the Fire Department," March 1994, by Ralph Kerwin, Gage-Babcock & Associates.

B-20.b LIQUIFIED PETROLEUM GAS FUELING STATIONS

Liquified petroleum gas (LPG) is one of the most popular alternative vehicle fuels in use today. LPG has been in widespread use as a motor fuel for several decades; some 330,000 vehicles in the United States employ this fuel. It is distributed at approximately 1400 public refueling stations in California, including many existing gas stations.

The on-road vehicles using it are virtually all conversions of existing original equipment manufacturer (OEM) vehicles, although OEMs are now producing selected models with an LPG option. Vehicle conversions are accomplished by making fuel intake changes and replacing or adding fuel tanks to the vehicle. Vehicle fueling is done by service station personnel rather than by the customer and takes a little longer than dispensing gasoline.

LPG is widely distributed in the United States and in California. It is often used for heating and cooking purposes in rural areas not served by natural gas lines, as well as for agricultural processing such as crop drying. It is commonly delivered to fueling stations and enduser storage tanks via tank trucks. Bulk transport occurs primarily in railroad cars and (in certain areas) by pipeline.

LPG is commonly a mixture of propane (C₃H₆) and higher hydrocarbons, principally butane (C_AH₉). It is a gas at room temperature and is stored under pressure as a liquid. It is non-toxic, and spilled LPG readily evaporates, hence it poses no threat of contaminating water or soil. Its vapors are denser than air and can collect in low-lying areas and pool along the ground; this can be hazardous in the event of a leak, since ignition sources distant from the leaking storage vessel can trigger a fire. LPG is obtained either as a condensible fraction of produced naturaligas (approximately 70 percent of supply) or as a byproduct from the refining of petroleum (approximately 30 percent).

Permitting Issues. No storage tank permits are required, since all storage is typically in pressurized above-ground tanks. Because of the above-ground storage, certain building set-back and secondary containment (berming) requirements must be met. Current fire codes (e.g., National Fire Protection Association (NFPA) 58) cover these stations.

REFERENCES

a) Calfuels Plan: Developing an Infrastructure Plan for Alternative Fuel Vehicles, California Energy Commission, September 1994, Publication No. P500-94-002. The Calfuels Plan was prepared in compliance with AB 3052 (Chapter 762 of 1992 statutes, Public Resources Code Section 25326) to explore infrastructure barriers to the deployment of alternative transportation fuels in California.

- b) The ABCs of AFVs: A Guide to Alternative Fuel Vehicles, January 1995, California Energy Commission, Publication No. P180-95-001.
- c) Alternative Fuel Information, U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, 1994.
- d) NFPA 58, Standard for the Storage and Handling of Liquified Petroleum Gases, National Fire Protection Association. Quincy, MA.
- e) Industrial Fire Safety, "Addressing the Fire Hazards of Alternative Fuels for Public Transit Buses," Parts 1 and 2, (September/October and November/ December 1993) by Ralph Kerwin.
- f) Fuel Facts: Liquified Petroleum Gas Motor Fuel (LPG)/ Propane, Western Liquid Gas Association, Fair Oaks, CA, May 1992.
- g) Natural Gas Fuels Magazine "Construction of NGV Facilities: A Practical Guide to Working with the Fire Department," March 1994, by Ralph Kerwin, Gage-Babcock & Associates.

B-20.c METHANOL AND ETHANOL FUELING STATIONS

An increasing number of methanolfueled cars are operating in California, and at least two of the automobile manufacturers — Ford Motor, Company and Chrysler — have indicated that they will be increasing production. These cars operate on both straight gasoline and fuel! methanol (or M85, an 85 percent blend of methanol and gasoline). As of 1995, about 12,500 of these fuel flexible vehicles (FFVs) are operating in the state. The number of ethanol cars operating in California is minor at present, although OEMs are producing volumes of these cars for use in the Midwestern U.S.

A methanol fueling facility looks and operates exactly the same as a conventional gasoline station, and the equipment used (including the dispensers, pumps, hoses and underground storage tanks) are the same, with a few minor changes. Major retailers in cooperation with the Energy Commission have established approximately 50 publicly accessible fueling stations in California. Additional stations are likely to be sited in both Northern and Southern California by independent fuel retailers in cooperation with. the local Air Quality Management: Districts.

The California Air Resources Board (CARB) has established regulations which require that fuel retailers operating over a certain volume of fuel sales in the state must make an alternative fuel available at their stations once the number of vehicles using that fuel exceeds certain thresholds.

The first level of the Clean Fuels "trigger" is 20,000 vehicles using any particular one of a number of designated clean alternative transportation fuels. This number of vehicles is determined as the sum of the alternative fueled vehicles that are either already registered with the state Department of Motor Vehicles (DMV) and/or officially projected by the car makers to be sold within a given year.

Once the first tier of 20,000 cars is reached, the fuel retailers must establish a total of 90 stations in the South Coast Air Basin region of Southern California. Subsequent increments in the number of vehicles trigger additional "make-available" requirements.

Requirements for the use of ethanol are virtually the same as for methanol. At present, the market for neat (100 percent alcohol) or nearneat ethanol fuel blends is not yet established in California.

Permitting Issues. The permitting issues for these fuel stations are the same as for any conventional petroleum fuel station. Underground storage tank permits, air emissions permits and other requirements must be met. Current fire codes (e.g., NFPA 30 and 37) cover these stations.

- a) Calfuels Plan: Developing an Infrastructure Plan for Alternative Fuel Vehicles, California Energy Commission, September 1994, Publication No. P500-94-002. The Calfuels Plan was prepared in compliance with AB 3052 (Chapter 762 of 1992 statutes, Public Resources Code section 25326) to explore infrastructure barriers to the deployment of alternative transportation fuels in California.
- b) The ABCs of AFVs: A Guide to Alternative Fuel Vehicles, January 1995, California Energy Commission, Publication No. P180-95-001.
- c) Alternative Fuel Information, U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, 1994.
- d) Methanol as a Motor Fuel: Review of the Issues Related to Air Quality, Demand, Supply; Cost, Consumer Acceptance and Safety, California Energy Commission, April 1989, Publication No. P500-89-002.
- e) NFPA 30 and 30A, Flammable and Combustible Liquids Code, National Fire Protection Association, Quincy, MA.
- f) NFPA 37 Automobile and Marine Service Station Code, National Fire Protection Association, Quincy, MA.

B-20.d NATURAL GAS VEHICLE FUELING STATIONS

Natural gas vehicles (NGVs) have gained a substantial share of the alternative-fuel vehicle market over the past three years. Original equipment manufacturers, such as Ford, Chrysler and General Motors, are producing vehicles designed to operate on natural gas (dedicated vehicles) or on a combination of natural gas and either-gasoline or diesel (bi-fuel vehicles). Currently, about 6,000 NGVs are operating in the state, relying on 120 public and private natural gas fueling stations.

Natural gas fueling facilities generally consist of one or more gas compressors, compressed gas storage tanks, and gas dispensing equipment. Natural gas can be dispensed by either "fast-fill" or "time-fill" systems at both public and private access stations. Fast-fill systems can fuel a vehicle in about the same time as a conventional liquid-fuel dispenser. Fuel is supplied to these systems through an underground pipeline and then compressed and stored in an aboveground tank until the gas is needed.

natural gas and dispense it directly into NGVs, eliminating the need for storage vessels. These systems require'six to eight hours to fuel an NGV and are commonly used by fleets with vehicles that return to a central location and park overnight. The number of vehicles that can be fueled from a time-fill station depends on the size of the compressor, the gas storage capacity of the vehicles, and the desired fill time. NGVs can also be fueled at residential sites with small compressor appliances. The appliance fills the vehicle with gas at a rate that is about the equivalent of one gallon of gasoline per hour.

Time-fill systems compress the

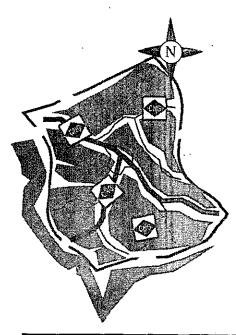
Two common alternatives to developing permanent fueling facilities are to distribute natural gas to fleets via mobile fueling trucks or tube trailers. Mobile fueling trucks fill directly from the pipeline using an on-board compressor dispensing the gas either directly into vehicles or into stationary storage vessels for subsequent time- or fast-fill into vehicles. Tube trailers are filled with compressed natural gas at a natural gas fueling station and then driven to other locations for dispensing fuel. Tube trailers can also fast-fill vehicles using a small compressor to increase gas pressure.

In general, natural gas supplies are abundant and pipelines for fuel transport and distribution are extensive and adequate. Even under conservative conditions, it is estimated that the recoverable gas resources in the lower 48 states are sufficient to serve the current demand for gas for-another 60 - 70 years.

Permitting Issues. The approval process for installing a natural gas fueling facility varies from city to city with interpretations of standards and codes sometimes inhibiting or delaying facility installation. Local code enforcers base their approval decisions on their local codes, which are modeled after state and national codes. Codes of interest for natural gas stations include fire, electrical, and plumbing codes. Chapter 4 of NFPA 52 serves as a key reference document for fueling station installations.

REFERENCE

a) Calfuels Plan: Developing an infrastructure Plan for Alternative Fuel Vehicles, California Energy Commission, September 1994, Publication No. P500-94-002.



B-21. GEOTHERMAL **DIRECT USE**

Geothermal resources can be used for industrial, agricultural, commercial, and residential direct-use applications such as water heating, space heating, and cooling as well as to generate electricity (see figure entitled The Approximate Temperature Required for Various Geothermal Uses). As discussed in Section B-7 (Geothermal), moderate- and high-temperature geothermal resources can be used for power generation, while lowtemperature resources are unsuitable for power generation. Both moderate- and low-temperature resources can be used for directuse applications. In addition, after high-temperature resources are used to produce electricity, the lower-temperature waste heat resulting from the electricity generation process can be cascaded for direct-use applications.

The overall potential for direct-use applications is believed to outnumber electrical-grade prospects by as much as ten to one. In California, 46 of 58 counties have lowertemperature resources which could support direct-use applications. The figure entitled California's Low- and Moderate-Temperature Geothermal Resource Areas shows the areas in California that have low- and moderate-temperature geothermal resources that are suitable for direct-use applications. High-temperature geothermal resources, which are located within the shaded areas of the figure, are shown separately on the Major Energy Resources map in Chapter 3, page 3.14.

Two of the most common geothermal direct-use applications are space heating and water heating. Space heating applications range

from full geothermal district heating systems (such as developed in the cities of San Bernardino and Susanville) to greenhouses and individual residences. Water heating is the simplest and, in many situations, the most cost-effective application of low- and moderatetemperature geothermal resources, and existing systems can often be converted for such use. Another application for low-to moderatetemperature resources is agricultural drying operations.

Since geothermal fluids typically contain impurities which can degrade the components of heating systems, heat exchangers are used to transfer the heat from the geothermal fluid to a secondary fluid (typically potable water or a refrigerant). The secondary fluid is then circulated through the heating system so that the internal system components are isolated from potentially damaging geothermal fluids.

Geothermal direct-use systems require production wells, and may necessitate injection wells. However, discharge of fluids to surface waterways occurs (such as in San Bernardino and Susanville) when the temperature and chemistry of the geothermal fluids meet standards which protect the environment. If injection is necessary, 100 percent of the fluids are returned into the subsurface, since such direct uses extract only heat from the geothermal resources. Issues relating to geothermal wells are discussed in Section B-18 [Energy Production Wells (oil, gas, and geothermal)].

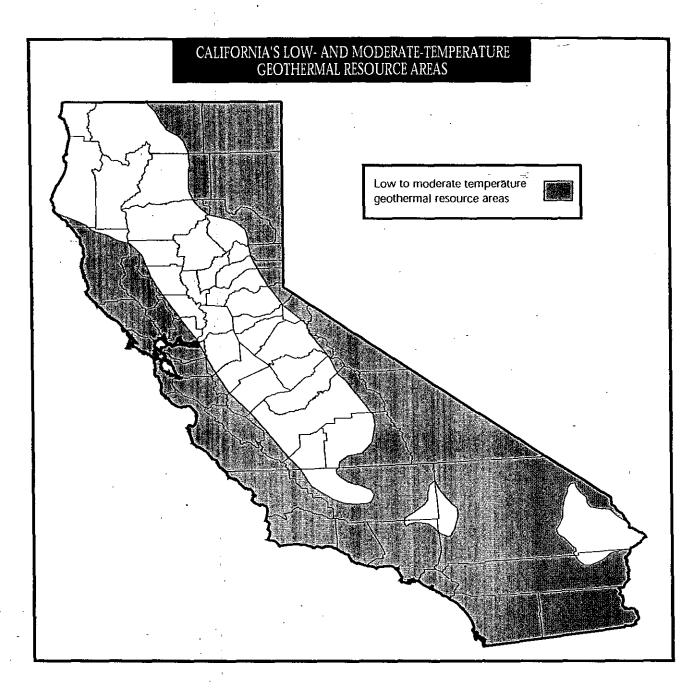
 Permitting Issues. in general, direct-use geothermal projects have fewer environmental impacts than high-temperature projects which produce electricity. They typically

use only the heat from the geothermal fluid, not the fluid itself, and therefore do not need to treat impurities in the geothermal fluid. If injection is necessary, heat remaining in the geothermal fluid that is not transferred to a secondary fluid for beneficial uses is injected back into the ground with the geothermal fluid, so there is no need for cooling facilities as with electricity production. If surface discharge of geothermal fluids to surface water channels is permitted, it does require a permit, typically valid for five years, and is renewable for like increments of time. Monitoring of discharges is always a permit condition.

Direct-use applications are generally smaller, and require fewer wells per development, shallower drilling depths, lower temperatures and flow rates, and fewer surfacedisturbing activities than for electricity production applications. As with geothermal electricity production, an issue that must be considered is the protection of ground water aquifers from contamination by geothermal waters, which is typically accomplished by casing the geothermal wells to separate geothermal fluids from the surrounding environment.

Whereas high-temperature geothermal resources for electricity production are typically located in undeveloped rural areas, low- and moderate-temperature resources are more widely distributed throughout the state. Because the desired end use must be located close to the geothermal resource in order to be practical and costeffective, direct-use applications are likely to be on or near land that is already being used for agricultural, industrial, commercial, or residential purposes.

THE APPROXIMATE TEMPERATURE REQUIRED FOR VARIOUS GEOTHERMAL USES °C ٠F 200 392 374 190 356 180 Evaporation of highly concentrated solutions Refrigeration by ammonia absorption Digestion in paper pulp, Kraft .338 170 Heavy water via hydrogen sulphide process Drying of diatomaceous earth 160 320 Drying of fish meal Temp. range of Drying of timber conventional fuel power production 302 150 Alumina via Bayers process 284 140 Drying farm products at high rates Canning of food 266 130 Evaporation in sugar refining Extraction of salts by evaporation and crystallization 248 120 Fresh water by distillation Most multiple effect evaporations, concentr. of saline sol. Refrigeration by medium temperatures 230 110 Drying and curing of light aggreg, cement slabs 212 100 Drying of organic materials, seaweeds, grass, vegetables, etc. Washing and drying of wool 194 90 Drying of stock fish intense de-icing operations 176 Space heating 80 Greenhouses by space heating 158 70 Regrigeration by low temperature 140 60 Animal husbandry Greenhouses by combined space and hotbed heating 122 50 Mushroom growing Balneological baths 104 40 Soil warming Swimming pools, biodegradation, fermentations 86 30 Warm water for year-around mining in cold climates De-icing 70 20 Hatching of fish; fish farming



- a) Draft Geothermal Element to the Siskiyou County General Plan, February 1984, pp. 120-135.
- b) Direct Utilization of Geothermal Energy: A Layman's Guide, Geothermal Resources Council Special Report No. 8, 1979.
- c) 1992 Energy Technology Status Report - Final Report, California Energy Commission, Report no. P500-92-007, December 1992. Fact Sheet 27.2 (Geothermal Direct Use).
- d) 1992 Energy Technology Status Report, Appendix A, Volume I: Detailed Electric Generation Technology Evaluations, California Energy Commission,
- Report no. P500-92-007A V1, December 1992. Section 1.3.1.1 (Hydrothermal).
- e) 1992 Energy Technology Status Report, Appendix B, Volume II: Detailed End-Use Technology Evaluations, California Energy Commission, Report no. P500-92-007B V2, December 1992. Section 27.2 (Geothermal Direct Use).

B-22. PETROLEUM AND PETROLEUM PRODUCT STORAGE FACILITIES

PETROLEUM

Petroleum storage facilities in California are located at refineries and tank farms. Refinery petroleum storage tanks typically contain about seven days of petroleum supply. Statewide, the volume of petroleum stocks at refineries are approximately 13 million barrels.

Tank farms are facilities which have the capacity to store 20,000 barrels or more of petroleum and which are not located at a refinery. By definition, tank farms do no contain lease storage, which is storage of petroleum from producing properties before first sale or shipment. Tank farms are owned or operated by firms other than refiners and must report information on shipments to the Energy Commission if they store more than 30,000 barrels of petroleum at any time during the current or preceding year.

It is unlikely that additional petroleum storage facilities will be constructed in the near future. While refinery working storage capacity for petroleum changes from one year to another, actual storage volumes are significantly lower than available capacity. At the end of 1993, crude oil inventories were approximately ten million barrels below storage capacity.

PETROLEUM PRODUCTS

Storage of petroleum products occurs at refineries and bulk terminals located throughout California. Bulk terminals are used for wholesale marketing of products and have storage capacities of 50,000 barrels of product or more.

Large end users, such as electric utilities, also maintain inventories of products, primarily residual fuel oil.

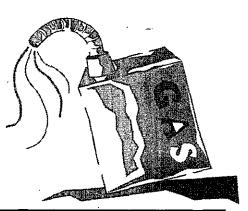
California refineries have between nine and 12 million barrels of gasoline stored at any given time. Wholesale marketers also have significant gasoline storage capacity at bulk terminals and maintain levels of gasoline inventories similar to those held by refiners. The petroleum industry also maintains several million barrels of distillate fuel, aviation fuel and residual fuel inventory.

Stored products are designated as being either primary or secondary. Refineries represent primary storage and terminals are secondary storage.

Permitting Issues for Petroleum and Petroleum Product Storage Facilities. The petroleum industry has invested in additional storage capacity and modified storage tanks in response to federal and state reformulated gasoline and diesel fuel requirements. Some refiners have added storage capacity to compensate for the increased types of fuels that are now being produced or are soon to be produced. Other refiners have modified existing tanks to be drained dry to prevent mixing of different gasolines produced by the refinery.

These changes were necessary since California supplies fuel to neighboring states that are not subject to California's more stringent specifications. Since these additions and modifications have been permitted, it is unlikely that additional modifications will be initiated.

- a) Petroleum Industry Information and Reporting Act Handbook, January 1994, California Energy Commission, Publication No. P300-92-007. This handbook contains all the forms required to be submitted by the petroleum industry and the Petroleum Industry Information and Reporting Act regulations which contain definitions for various types of storage.
- b) Quarterly Oil Report, Fourth Quarter 1993, April 1994, California Energy Commission, Publication No. P300-94-003. This report describes petroleum fuels market trends, price trends, refinery activity, petroleum production trends and petroleum company financial performance. It also contains aggregated petroleum statistics for California based on industry submittals to the Commission.
- c) Regional Petroleum Product Reserve Feasibility Study, December 1993, California Energy Commission, Consultant Report, Publication No. P300-93-019F. This report examined the feasibility of establishing a petroleum product reserve for use during energy emergencies. It contains information on petroleum product pipeline corridors and their vulnerability during an earthquake.



B-23. PIPELINES (PETROLEUM, PETROLEUM PRODUCTS, AND NATURAL GAS)

PETROLEUM PIPELINES

California's refineries receive approximately 40 percent of their petroleum supply from pipelines. These pipelines vary widely in type and size. Pipelines can be heated or unheated, proprietary or common carrier, and carry 20,000 to 300,000 barrels per day. Proprietary lines are those owned and operated by individual oil companies. Common carrier lines can be used by various interests that pay a fee for their use.

The pipelines in California transport petroleum in five broad directions and range in diameter from eight inches to thirty inches. Pipelines run from Bakersfield to Los Angeles, Bakersfield to San Francisco, Southern California to West Texas, Ventura to Los Angeles and from the Pacific Coast to Bakersfield.

The All American line is a 30-inch. common carrier pipeline and carries various blends of California petroleum and Alaska North Slope petroleum to West Texas. Four Corners lines are common carrier and transport Alaska North Slope and various blends of petroleum from Bakersfield to Los Angeles and to neighboring states. Mobilhas proprietary lines between Bakersfield and Los Angeles, Carpinteria and Ventura and San Ardo and Estero Bay. Unocal and Chevron own and operate pipelines from Bakersfield to San Francisco as well as several others. Texaco also owns a line from Bakersfield to San Francisco, but it is operated as a common carrier line. Shell owns a line between Ventura and Los Angeles.

In 1996, an additional petroleum pipeline is expected to be carrying petroleum from the Bakersfield area to Los Angeles refineries. The pipeline is designed to carry up to 110,000 barrels per day and will be owned by several interests including Chevron, Texaco, and Pacific Pipeline System, Inc. It will be an underground line as are others in the state.

- Permitting Issues for Petroleum Pipelines. Some of the issues that have been associated with the construction of new petroleum pipelines include:
 - · Use of long corridors of land
 - Disturbances to vegetation, cultural and paleontologic resources, and wildlife during construction
 - Safety of the line during earthquakes and the potential soil and water contamination from spills from line breakage and related health effects

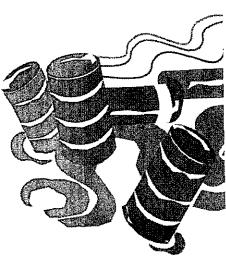
Even though these are concerns with constructing petroleum pipelines, government agencies have favored pipeline movement of petroleum when the alternative has been tanker transport. Agencies and environmental groups have endorsed pipeline movement because spills are less likely to occur from pipelines and easier to contain than tanker spills. The petroleum industry has favored marine tanker use because pipeline transport is the higher cost transportation method.

PETROLEUM PRODUCTS PIPELINES

California petroleum product pipelines are located primarily in northern and southern California with no pipeline linkage between these regions. Pipelines range in size from three inches to 22 inches in diameter and are connected to other product pipelines, refineries and product terminals. Pipelines run from Bakersfield to the San Francisco area and to Sacramento and Reno, Nevada. Pipelines from the Los Angeles area also transport product to Arizona and New Mexico. One line from Southern California also transports product to Las Vegas.

Product transporters reporting to the Energy Commission must own or operate a product pipeline transporting 20,000 barrels of petroleum products during any month. Pipeline shipments can reflect product entering the pipeline from refinery storage facilities or from other terminals or other pipelines. Most exports of product from California occur by pipeline.

Permitting Issues for Petroleum Products Pipelines. Same as petroleum pipelines.



NATURAL GAS PIPELINES

California has thousands of miles of transmission pipelines and nearly a hundred thousand miles of distribution pipelines in the ground. Most of the tranmission lines are owned and operated by. the state's three major local distribution companies (LDCs): Pacific Gas and Eletric Company (PG&E), Southern California Gas Company (SCG), and San Diego Gas and Electric Company (SDG&E). Other pipelines, within California state boundaries, owned and operated by interstate pipeline companies include Kern River Gas Transmission Company and Mojave Pipeline Company in the Mojave Desert and Kern County, and Tuscarora Gas Transmission Company in the northeast corner of the state.

California receives approximately 85 percent of its natural gas requirements form supply regions outside the state (Canada, the Southwest U.S., and the Rocky Mountains). The remaining portion comes from in-state producers. The interstate pipelines supplying natural gas to California and their respective capacities are shown below.

Gas pipelines are usually underground with above ground compressor stations which push gas into and through the pipelines. Typical residential customers might receive their gas through a small distribution line only one inch in diameter while the line in the the street serving a community might be two inches. Commercial and industrial customers often receive gas from four to 12 inch diaameter pipelines and the major transmission pipelines are three feet or more in diameter.

The local distribution utility system distributes gas at pressures and quantities appropriate to meet its individual customer needs from very low pressures sserving residential users to more than 60 punds per square inch(PSI) serving some commercial and small industrial users. Major transmission pieplines flow gas at pressues up to 800 psi.

Natural gas storage is also an important part of the natural gas pipeline system, as it allows LDCs and customers with storage access to place additional natural gas supplies in inventory with the intent of using that inventory for load balancing and meeting peak demand days. In general, gas is placed (injected) on storage during the summer and withdrawn during the winter when heating

rewuirements are high. Storage facilities in the state include those managed and operated by PG&E and SCG. One independent storage facility is presently operating in the state, while two others are currently considering developing additional facilities.

The construction of new and expanded interstate pipelines to the state combined with the implementation of open access transmission services has increased market competition since 1992. According to an analysis performed by Crossborder Services, increasing access to multiple supply regions has increased market competition and open access on natural gas pipelines, producing nearly \$3.0 billion in benefits to California consumers between 1992 and 1994. The Energy Commission expest these befenefits t0 continue to be realized in the near and longterm.

Permitting Issues for Natural Gas Pipelines

The issues are similar to those for petroleum and product pipelines, with the addition of noise or vibration potential from compressor stations. An interstate natural gas pipeline must get a license to construct from the FEderal Energy Regulatory Commission (FERC) while an intrastate pipeline must obtain a Certificate of Public Convenience and Necessity (CPNC) from the CPUC. After these authorizations, the largest concerns are usually environmental issues over rights of way and construction, which are taken up with local jurisdictions.

Pipeline Gas Supply Region Capacity (MMCF/D) HiPaso Natural Gas Southwest U.S. 3290Kern River Gas Transmission Rocky Mountains 1.775 Pacific Gas Transmission Western Canada 1065 Transwestern Pipeline Southwest U.S. 700 Total 6830

- a) Petroleum Industry Information Reporting Act submittals from the petroleum industry to the California Energy Commission.
- b) The Bakersfield Californian; March 11, 1994. Article entitled "Oil Expected to Flow from Kern to L.A. by 1996", Robert Price.
- c) Regional Petroleum Product Reserve Feasibility Study, December 1993, California Energy Commission, Consultant Report, Publication No. P300-93-019F. This report examined the feasibility of establishing a petroleum product reserve for use during energy emergencies. It contains information on petroleum product pipeline corridors and their vulnerability during an earthquake.
- d) Santa Fe Pacific Pipelines System Map.

- e) Santa Barbara County Crude Oil Transportation Analysis, Arthur D. Little, Inc., February 1990. This report describes California petroleum pipelines and provides maps of pipeline routes by region.
- f) Fuels Report, California Energy Commission, December, 1995, Publication No. P300-95-017. The Fuels Report describes emerging trends and long-range forecasts of the demand, supply and price of petroleum, petroleum products, natural gas, coal and synthetic and other fuels. It is the state's principal fuels policy document.
- g) The California Gas Report (CGR), prepared annually by the California gas and electric utilities is available from each utility directly. The CPUC, Energy Commission and others in the gas industry use this as a reference for historical information as well as forecasts. Each gas utility makes its own longrange plan for natural gas supply to meet anticipated demand. These are summarized in a single document.
- h) 1995 Naturál Gas Market Outlook, October 1995, California Energy Commission Publication No. P 300-95-0. This biennial report presents an independent analytical forecast for the supply availability, demand, and price of natural gas for California over the next twenty years. Analyses performed by the Energy Commission staff incorporate data from the CGR, numerous documents which independent gas marketers and utilities file with the Energy Commission, annual reports from the state Division of Oil, Gas, and Geothermal Resources, and a variety of other sources. This report presents assumptions, analyses and detailed information on the forecast price and supply of natural gas to meet projected consumer demand.

B-24. REFINERIES

California's refineries are located in the San Francisco Bay area, Los Angeles area and the Central Valley. Statewide, refiners rely on Alaska for 45 percent of their petroleum supply and California for about 50 percent. Foreign sources provide the balance. Each day approximately two million barrels of petroleum are processed into a variety of products with gasoline representing about half of the total product volume. (A list of refineries, their location and capacity is shown in the attached table.)

Refineries can be classified as topping, hydroskimming or complex. Topping refineries are the least sophisticated and contain only the atmospheric distillation tower and possibly a vacuum distillation tower. The topping refiner's ability to produce finished products depends on the quality of the petroleum being processed. A hydroskimming refinery has reforming and desulfurization process units in addition to basic topping units. This allows the refiner to increase the octane levels of motor gasoline and reduce the sulfur content of diesel fuel. Complex refineries are

the most sophisticated refinery type and have additional process units to "crack" the heavy gas oils and distillate oils into lighter, more valuable products.

Using a variety of processes including distillation, reforming, hydrocracking, catalytic cracking, coking, alkylation and blending, the refinery produces many different products. The four basic groups are motor gasolines, aviation fuel, distillate fuel and residual fuel. On a statewide average, about 12 percent of the product from California's refineries is aviation fuel, 13 percent is distillate fuel and 9 percent is residual fuel.

Complex refineries have the highest utilization rate at approximately 95 percent. Utilization rate is the ratio of barrels input to the refinery to the operating capacity of the refinery. Complex refineries are able to produce a greater proportion of light products, such as gasoline, and operate near capacity because of California's large demand for gasoline.

Permitting Issues. It is unlikely that new refineries will be built in California. In fact, in the last 10 years 10 California refineries have closed, resulting in a 20 percent reduction in refining capacity. Further refinery closures are expected for small refineries with capacities of less than 50,000 barrels per day. The cost of complying with environmental regulations and low product prices will continue to make it difficult to continue operating older, less efficient refineries.

To comply with federal and state regulations, California refiners have. invested approximately 5.8 billion dollars to upgrade their facilities to produce cleaner fuels, including reformulated gasoline and lowsulfur diesel fuel. These upgrades

have received permits since lowsulfur diesel fuel regulations went into effect in 1993. Requirements to produce federal reformulated gasoline took effect at the beginning of 1995 and more stringent state requirements for reformulated gasoline went into effect statewide on June 1, 1996.

- a) Petroleum Industry Information Reporting Act submittals from the petroleum industry to the California Energy Commission.
- b) Fuels Report, California Energy Commission, February, 1994, Publication No. P300-93-109. The Fuels Report describes emerging trends and long range forecasts of the demand, supply and price of petroleum, petroleum products, natural gas, coal and synthetic and other fuels. It is the state's principal fuels policy document.
- c) Quarterly Oil Report, Fourth Quarter 1993, April 1994, California Energy Commission, Publication No. P300-94-003. This report describes petroleum fuels market trends, price trends, refinery activity, oil production trends and petroleum company financial performance. It contains aggregated petroleum statistics for California based on industry submittals to the Commission including refinery utilization rates.
- d) 1994 Annual Report, Western States Petroleum Association.

CALIFORNIA REFINERY LOCATIONS AND CAPACITIES

CLASSIFICATION OF REFINERS BASED ON CRUDE OIL CAPACITY (BARRELS PER DAY)

LARGE REFINERS			INDEPENDENT AND SMALL REFINERS		
CÓMPANY	LOCATION	CAPACITY	COMPANY	LOCATION	CAPACITY
ARCO	Carson	237,000	Tosco	Martinez	160,000
Chevron	El Segundo	230,000	Ultramar	Wilmington	68,000
	Richmond	230,000	Santa Maria Refining Co.	Santa Maria	10,000
Exxon	Benicia	128,000	Kern	Bakersfield	21,400
Mobil	Torrance	130,000	Huntway	Benicia	8,600
Shell	Martinez	148,900	нинкмау	Wilmington	5,500
Texaco	Bakersfield	56,000	Lunday	South Gate	8,100
	Wilmington	64,000	Paramount	Paramount	46,500
Unocal*	Wilmington	105,600	San Joaquin	Bakersfield	24,300
	San Francisco	73,100	Sunland	Bakersfield	12,000
	Santa Maria	42,000	Ten By	Oxnard	4,000
		TOTAL : 1,444,600			ROTFAL 368,400

Note: Data on this table represents total crude oil capacity, not distillate production or diesel fuel capacity. Diesel production potential varies.

Source: "Table 38 Capacity of Operable Petroleum Refineries by State as of January 1, 1995," Energy Information Administration/Petroleum Supply Annual 1994, Volume 1, pages 84-86.

^{*}Unocal has 115,000 barrels per stream day (BPSD) of idle atmospheric distillation capacity acquired from its purchase of the Shell Wilmington refinery. At the present time Unocal is running the two facilities as a single unit.