3. Wyoming

Lands in the possession of the state of Wyoming may be leased for mining purposes by the State Board of Land Commissioners. There are some lands to which title is held not by the State Board of Land Commissioners but by the Wyoming Farm Loan Board. These lands came into state possession during the Great Depression as a result of foreclosures. Some were resold, but in compliance with the state law, mineral rights were reserved. Depending on ownership, the land (or mineral estate) is leased by the Land Commissioners or the Farm Loan Board, and the regulations make reference to both Boards, but in practice leasing is administered in both cases by the Land Commissioners and action by the Wyoming Farm Board is pro forma.

State law provides that any patent of state lands be with a reservation to the state of rights to minerals, whether known at the time or not, along with rights of access for mining or prospecting purposes, so that access to minerals in state lands must be by lease.

The Board has "wide discretion," expressly given in the regulations, to lease to such parties and upon such terms as "shall, in the judgment of the Boards, insure to the greatest benefit to the State."

To qualify as an applicant for a lease, one must be 21 years of age, a U.S. citizen (or have declared the intention to become one), or an association or corporation permitted by law and charter to engage in mining activities. There is no competitive bidding; applicants get priority on vacant land for which they submit lease applications until a decision is reached on their application. If a lease that is not producing comes up for renewal, there is a competition (in which the leaseholder may participate) but it is done on a lottery basis and there is no bonus involved.

Coal. Rents are set at a yearly minimum of $1 an acre, and minimum is what is charged in practice. After discovery of coal in commercial quantity (called "commercial discovery"), rents can be credited against royalties.

Royalties are set by a statutory minimum of 5¢ a ton of the mine run. In practice, however, the Board has adopted a percentage royalty of 7 percent of the value of the mine run, but in no case less than 25¢ a ton.

Acreage restrictions are as follows: A lease must generally be of contiguous or cornering lands, but variances may be granted by the Board if necessary, provided the lands fall within a 6 sq mi area (or six surveyed sections, which amounts to the same thing) in the Board's discretion. Only one class of lands (state lands, school, farm loan lands, or individual institutional lands) may be included in any one lease, and each lease may include no more than 1280 acres (2 square miles). The number of leases any single party may hold is within the discretion of the Board to decide "in the interest of fair trade, proper competition, and prevention of monopoly."

Duration of leases is to be up to 10 years, with a preference right of renewal for additional 10-year periods if the mine is in production. If it is not in production, as stated above, the lease is made available to the leaseholder and other applicants on a lottery basis.

Although the provision of the statute requiring bonds was removed in 1965, bonds may still be, and are still, required by regulation. At present, the bond requirement is a compliance bond of $5000 per lease, or $25,000 statewide. There is also an environmental bond in an amount equal to 100 percent of the potential damage development may do to the land.

Only one producing state coal lease is presently in effect in Wyoming, although there are a million acres leased for prospecting (there is no essential difference between the two prospecting and producing leases for there is no prospecting permit system comparable to the bifurcated federal system. A lease is a lease, and if it produces, it is a producing lease, with royalty and renewal preference rights).

Assignment of lease interests is permitted with the approval of the Board. Overriding royalties (the royalty paid the sublessor by the sublessee), however, are limited to 5 percent over that in the primary lease.

Relinquishment of leases, or parts of them, is permitted. Modification of lease terms while the lease is in force is by agreement between the Board and the lessee. A lease may be cancelled for noncompliance or nonpayment, but there is a right of recourse to the courts.

Oil Shale. At present there is no oil shale leasing in Wyoming, state or federal. The Wyoming Mining Rules and Regulations booklet states on the cover "except oil and gas and oil shale." There has not been any state oil shale leasing in Wyoming for a long time, if ever. The state's primary holds are the school sections, and it seemed unlikely that anyone would be interested in oil shale development of 640-acre plots. The Board of Land Commissioners thought the market for state oil shale lands would be among holders of federal oil shale leases, to tack adjacent lands onto their federal leaseholds. There was excitement about this prospect when the two federal oil shale tracts were offered in 1973. However, the federal oil shale leases in Wyoming did not sell. So everyone drew back to consider what to do next. There are now rules being drafted for oil shale leasing on Wyoming state lands, but they will not be ready until midsummer, 1975, at the earliest. Until then there is no oil shale leasing to be done on Wyoming state lands.

4. West Virginia

Mr. George Wise, the Land Agent with the West Virginia State Land Corporation, states that there is no body of leasing regulation. The Land Corporation uses as a reference the statute itself, Chapter 20 of the Laws of West Virginia. He states that there has been no coal land leased since 1967.

According to Mr. Wise, all applications for coal leasing must go first to the Director of the Department of Natural Resources, who then refers the application to the appropriate Division Chief, if the land comes under his jurisdiction. No mining is permitted in state parks, which means that strip mining is not to be permitted and deep mining is allowed only if the shaft is begun outside the state park boundary and then tunneled underneath. Applications concerning other lands under the jurisdiction of the Department of Natural Resources go to the appropriate Division Chiefs: forests, parks and recreation, and hunting and fishing areas. The State Auditor's Office handles land that has come to the state through escheat or default of taxes. The Highway Department handles lands they control. The Public Land Corporation has title to all land not assigned elsewhere, including specifically land in the beds of navigable streams.

West Virginia state lands are not sold, but may only be leased. And it is provided by statute that all leases must have the written approval of the Governor of West Virginia. In theory, bids are submitted to the Director of Natural Resources (or other responsible officer), who may reject them all or take the highest bid from a responsible bidder subject to the Governor's approval. Unlike the federal system in which all the terms are set in advance by the lessor and the bidder is only for bonuses, in West Virginia the system preserves more of the private law character, and lease bids are considered in their entirety. Thus, one bid may have a higher rent but a lower royalty than another, and this calls for judgment on the part of the Director (or other responsible officer). It is to be expected that when (and if) West Virginia state coal leasing resumes there will be a new set of guidelines on acceptable rents, royalties, and other terms and procedures.

G. Vetoed Strip Mine Act

The Surface Mining Control & Reclamation Act of 1974 contained a fairly comprehensive regulatory system covering surface mining and the surface effects of underground mining of coal. The bill would have had a marked impact on the coal situation had it gone into law, but it was vetoed by President Ford. This year a similar bill has been vetoed, and attempts in the House to override the veto failed. The major provisions of the vetoed bills will be described.

The basic premises were that, climate and terrain and local conditions being what they are, the best way to administer a program governing and limiting the effects of strip mining and mandating and supervising reclamation would be to have it done by the states. Accordingly, the framework that was established provided the states with primary administrative responsibility. The regulatory agencies created by the state were to demonstrate to the satisfaction of the Secretary of the Interior that they were capable of establishing and enforcing programs containing criteria no less stringent than those put forth in the Act. If they did so, then their programs would govern, and they could indeed be more severe than the federal program. If the states were unable to satisfy the Secretary that they could set up programs capable of this enforcement, or if, having set them up, the Secretary determined that the state programs were not properly enforcing the minimum criteria of the Act, he could establish a federal program in the area to preempt state enforcement, and keep it in force until such time as a satisfactory state program was put forth. The Secretary was also to enforce these requirements in federal leasing programs, or on federal lands generally, except Indian lands, which were considered separately. Among the principal elements of the program were stiff and explicit requirements for protection of the environment during the mining, and similarly stiff and explicit requirements for reclamation. The benchmark for restoration was to be the uses the land was capable of supporting before <u>any</u> mining was done on it, whether that mining was done by the present or proposed operator or by someone else 30 years before. It is to be noted that the present BLM regulations in 43 CFR Part 23 (Surface Exploration, Mining and Reclamation of Lands) and USGS regulations in 30 CFR Part 211 and 231 (Operating Regulations) have been or are being revised by the Department to reflect the wording and intention of the vetoed strip mine bills.

The first major reform would have been the removal of supervision and enforcement of surface mining and reclamation procedures from the BLM and the USGS and the placing of them in a new office in the Department of the Interior, to be called the Office of Surface Mining Reclamation and Enforcement. By law, no federal authority, program, or function having as its purpose the promotion of the development of any mineral resource shall be transferred to this office. The idea was to protect the new office from any conflicts of interest.

The states would have had 18 months from enactment to submit a program if they wish to assume exclusive jurisdiction to regulate surface mining and reclamation in their states (this does not include activity on federal leaseholds). The Secretary would have had 6 months to review the program and approve or disapprove it. If he disapproved it, the state would have had 60 days to resubmit, and the Secretary 60 days more to redecide. If a state did not submit a program within the 18 months, or resubmit a disapproved one in the required time, or if the Secretary determined that a state program in operation did not meet the requirements of being able to enforce, at a minimum, the standards for operation and reclamation specified in the Act, he would then put a federal program in operation in that state. There would have been, of course, complicated hearing requirements. A state that did not apply or qualify in time could try for approval at any time; conversely, a state program deemed not to be working could be superseded in whole or in part at any time by a federal program. The idea was to have state programs for those states that want exclusive jurisdiction and can demonstrate that their programs would be sufficient in fact, not just on paper, to ensure that surface mining (and the surface and hydrological effects of underground mining) would be regulated and kept at least within the standards provided in the Act. States would have been quite free, in their own programs, to require a higher standard of performance from operators, but if it appeared that a lower standard would in practice be required, the federal program would have substituted to ensure this minimum compliance. And the "minimum" would not have been easy, either; the criteria in the federal program were rather stiff. A state program would have to incorporate, at a minimum, the environmental protection criteria discussed below, would have to provide sanctions, including bond forfeiture, suspension and revocation of permits, and civil and criminal penalties no less stringent than the federal program, would have to demonstrate the existence of sufficient personnel with sufficient expertise to enforce the requirements of the Act, would have to include a permit system that met the requirements of the Act, a procedure for designating areas unsuitable for any surface mining at all, and coordination procedures to prevent federal/state duplication. If it worked, the system would ensure that the provisions of the Strip Mine Act applied everywhere without the necessity of direct federal supervision or enforcement if the states would do it (or more) themselves.

Approval of a state program would require the approval of the Administrator of EPA as to air and water pollution regulation, and the input of EPA, Agriculture, and other federal agencies, a public hearing, and a finding by the Secretary that the state had the legal authority and personnel to enforce its program. (There was a provision suspending introduction of a federal program if implementation of the state program was held up by an injunction, such suspension not to exceed one year.)

Permits granted by a state program later superseded by a federal program are valid, but reviewable by the new authority, and vice versa.

Since it was in the contemplation of the Act that the same standards, at minimum, would be enforced by a state program or a federal program, the Act used the words "regulatory authority" to refer either to the federal Office of Surface Mining Reclamation and Enforcement or to an approved state authority, depending on the circumstances. This is helpful word usage, and for the sake of clarity it will be used here.

The so-called Environmental Protection Performance Standards stated:

1. Recovery of the coal is to be maximized so as to prevent the necessity of remining.

2. The land is to be restored to a condition at least fully capable of supporting the uses which it was capable of supporting before any mining was done, or "higher and better" uses if it is consistent with a local land-use plan, etc. The important thing is that an operator could be held responsible for returning land, which was mined before he arrived, to the condition it was in before anyone mined it. In other words, he could be required to leave the land better than he found it.

3. The approximate original contour of the land must be restored. This means backfilling, compacting where necessary because of volumetric expansion of spoil and mine waste, eliminating all highwalls (to prevent isolation of the land above the highwall), getting rid (in specifically approved ways) of spoil piles; depressions (unless needed for water

for revegetation), etc. Mountaintop mining is permitted under certain circumstances. Grading is required until the original contour is restored. If there is too much overburden and spoil, a contour so arranged to prevent slides, erosion, etc., must be created. Drainage of and covering of all acid-forming or toxic substances. A lot of complex technical requirements were given, but the crux was that the original contour must be restored unless there were too much overburden, in which case a contour would have to be created, which did not exceed the angle of repose.

4. Surface areas including spoil piles must be stabilized to control air and water pollution or erosion.

5. Topsoil must be segregated when removed so it (or a superior stratum if one is discovered) may be put on the top when the reclamation begins, and the topsoil or best available subsoil must be stored to preserve it, and it must be put back on the top of the restored contour. If the topsoil has to be segregated for so long that it would deteriorate, it may be necessary to plant vegetation on it to preserve it. It must be kept free of acid or other soil contaminants. The topsoil must be restored when mining is finished.

6. Offsite areas must be protected from slide or damage, and no spoil or waste may be put there.

7. Permanent impoundments of water may be created if called for in the reclamation plan (see below) subject to a number of severe requirements on size, dam construction, quality and level of impounded water, etc. Quality of water of surrounding users may not be impaired.

8. Auger holes must be filled with impervious and noncombustible substances.

9. The hydrologic balance must be preserved by avoiding acid or other toxic mine drainage, preventing contribution of suspending solids into stream flow or runoff above the level as measured before <u>any</u> mining in the area, removing siltation structures from drainways after revegetation, restoring aquifer capacity, protecting alluvial valley floors (if any), and so on.

10. Waste must be disposed of in compacted layers, etc.

11. Surface coal mining within 500 feet of active or abandoned underground mines is not allowed, subject to variances.

12. Groundwater must be protected from acid or other toxic leachates.

13. Conditions lending themselves to sustained combustion must be avoided.

14. The use of explosives is subject to restrictions.

15. Placement of access roads is subject to environmental restrictions (erosion, siltation, damage to wildlife habitat, water pollution, damage to private property, etc.).

16. Drainage channels or stream beds must not be blocked.

17. Regraded areas must be revegetated, using native species if possible, and the operator is responsible for seeing to it that the revegetation takes hold. His responsibility would have lasted 5 years after the last year of augmented seeding, fertilization, irrigation or whatever, or 10 years if the annual precipitation averages less than 26 inches. If the post-reclamation use is intensive agriculture, his period of responsibility would start with the initial planting.

18. Reclamation must be done in an "environmentally sound manner" and as contemporaneously as possible with the mining activity.

19. No debris on the downslope, etc.

This list gives a general idea of the breadth of the requirements; these requirements were stated in a much more complex manner in the bill itself. Certain variances are allowed, subject to restrictions and safeguards, and keyed to the post-mining land use plan. Thus the program was very comprehensive, with enforcement measures built in.

The Act required that, from date of enactment, anyone opening a new or previously abandoned mine must have a permit if the mine is within a state with an existing state program. There were initial regulatory procedures. Beginning with the date of enactment, any mining on a permit granted on or before enactment would have to meet some of the standards of the bill, those relating to restoration to condition capable of supporting before any mining, those relating to restoration to original contour, to segregation of topsoil, to hydrological balance, to water retention facilities, to revegetation, and to deep slopes. Work on permits issued before the date of enactment would have to meet these standards within 135 days. By the time 20 months had elapsed operators must have a permit from the state agency if they contemplate future work under the state program.

Federal or approved state programs would have to provide for random inspections, unannounced, to be held at least every three months. Later the inspection requirements are escalated to every month. It might be pointed out that the Environmental Impact Assessment Project study of the Proposed Coal Leasing Program EIS has noted that there are not enough agents available in the department now to cover even the minor inspection duties currently that would have been required. Although the bill contemplated establishment of a new office, there was doubt that even the new office would be able to obtain sufficiently trained manpower to do the inspection the bill would require. More important, it is equally or more doubtful that the states would have been able to obtain enough inspectors, and if they cannot demonstrate that they would have sufficiently trained people to carry out the requirements of the program they could not have gotten a state program approved, and a federal program would have to have been instituted.

Permit applications would have to have been accompanied by extensive documentation, a lot of it highly technical and expensive. Furthermore, the application fee for a permit under the new system "shall be based. . . upon the actual or anticipated cost of reviewing, administering, and enforcing such permit. . .," which is also likely to have been very expensive.

The strip mine bill also included an ambitious program of restoring abandoned strip mine sites not related to present operations: the scars of Appalachia, and so forth. This was to be paid for in large measure by fees from operators. The reclamation fee was, in the 1974 Act, set at 35¢ a ton for surface mining and 25¢ a ton for underground mining. It is interesting that, first, present operators would have been required to pay to reclaim land the destruction of which they had nothing to do with, and second, that the reclamation standards would have required restoration of the land to its use potential before <u>any</u> mining was done. Thus, in at least these two ways, present operators would have been required to pay for the sins of their predecessors. It is an interesting public policy to require coal operators to clean up a mess they themselves did not create.

An applicant for a mining operation permit under the Act would have had to present a reclamation plan, setting forth past and projected future land use, the capacity of the land to support a variety of alternative land uses, a detailed description of how the reclamation would be accomplished, intricate technical data of many sorts, results of test borings, a timetable, and a host of other information. One of the objections that the coal industry had to the Strip Mine bill was the immense amount of paperwork it would have imposed on them; at almost every step detailed reports and proposals would have been submitted. These would be expensive and would have added substantially to the cost of operating a coal mine.

A performance bond would have to have been posted, which is sufficient to pay for the cost of putting into effect the approved reclamation plan if done by a third party. This includes recontouring, compacting, construction of water retention facilities, revegetation, etc., a very complicated and expensive business. Not only would this have been paid by the operator, but he would also have to post a bond of 100 percent of the cost. Surety premiums can be substantial, especially since the responsibility for revegetation extends 5 or 10 years after everything else is over and the bond can be increased during the term of the permit if necessary. Cumulatively, there appeared to be merit to the industry complaint that this bill would drive up their costs spectacularly.

There were also coal exploration permits, which would have required less elaborate information but which would have required an application fee similar to that described above for operating permits and the written consent of the surface owner.

Another important provision of the bills related to areas unsuitable for surface mining. The federal program provided, and the state programs to be approved would have to have provided, for procedures to declare certain areas unsuitable for any surface mining and therefore to prohibit surface mining at all on the area. On petition by any interested party, which can include agencies of government, areas could be declared unsuitable if the regulatory agency determined that reclamation pursuant to the requirements of the Act was not "feasible." Moreover, if the mining operations themselves would be incompatible with existing land use plans or programs, if they would affect "fragile or historic lands" in which the operations could result in damage to historic, cultural, scientific, or aesthetic values, if the operations could affect renewable resource lands and could result in substantial damage to water supply or food or fiber products or aquifers, or if the lands are "natural hazard lands" (floods, "unstable geology," etc.). In federal lands, the Secretary was directed to survey the federal lands and withdraw from leasing any such unsuitable lands. A public hearing was required. Withdrawn also were coal areas in the National Parks, National Forests, National Wildlife Refuges, National Trails, National Wilderness Areas, National Wild and Scenic Rivers, and National Recreation Areas. Withdrawn also were publicly owned parks or places included in the National Register of Historical Places, if an adverse impact was anticipated, unless the regulatory agency and the agency having authority over the park or place agreed, near roads (subject to permission to move the road), etc. In these areas surface mining permits would simply not be issued at all.

Another provision of interest: although the principal focus of the bills were on surface mining, there was also provision for protection against the harmful surface effects of underground mining. Permits would have to be issued for these effects, too, and would include provision for measures to prevent subsidence, maximize stability, maintain the surface value of the lands, make proper provision for disposal of mine waste of all sorts, keep leachate from the ground and surface waters, revegetate regraded areas, protect the hydrological balance, seal portals, and do various other things, which would be expensive and time-consuming.

Penalties could have been severe. There was a sort of graduated schedule, beginning with show-cause orders, proceeding through cease and desist orders and permit revocation, finally arriving at civil penalties for violations of the Acts, the state or federal program or their regulations, or the lease terms incorporating these restrictions, up to $5000 for each violation, each day being considered a separate violation. These civil penalties might be sought in any violation, but matters of past history, good faith attempts at abatement, seriousness of violation and consequencies, size of business (capability of absorbing the penalty), and negligence could all be taken into account. Hearings and appeals were provided. Willful or knowing violations could lead to criminal penalties, up to a $10,000 fine or a year in prison, or both. For approval, state programs had to include penalty provisions at least as stringent as these. False statements on any application, report, or other document involved in the program could also draw a $10,000 fine and/or a year in prison. There was nothing in the federal mining law up to this point that provided any of these sorts of penalties.

Protection of surface-owner interests: these provisions were defeated in the Senate markup of the latest bill. These would have required the written consent of the surface-owner for any mining of federal coal beneath his land that involved other than underground operations. In addition to this, the developer was required to pay the full money value of the surface-holder's interest as fixed by three appraisers, one appointed by the Secretary, one by the surface-owner, and one by the other two appraisers. The amount began with the fair market value of the surface estate, and then added to loss of income to the surface-holder during the mining operations, the cost of livestock, crops, water and so on, the cost of any other damage that might be done, and an additional amount related to the length of tenure of the surface-owner (uprooting long-established holdings, etc.), not to exceed the amount of the four additions listed or $100 an acre, whichever was less. This amount, if paid in installments, might be adjusted according to increases in the consumer price index. And it appears that the surface-owner would have gotten to keep his title to the surface estate.

To quality for this protection a surface-owner would have had to hold title, legal or equitable, to the surface estate, have a principal residence on the land or personally farm or ranch it or derive a significant portion of his income from such farming or ranching, and he would have had to have met these conditions for three years, provided, however, that if three years had not elapsed the Secretary could hold up putting the land into a leasing tract until the three-year period had been satisfied. This applied only to split-fee lands where the mineral estate is owned by the United States. Consent was not required under this section if the coal was not federal coal. There was also a provision that anyone who offered anything of value to a surface-owner to induce him to consent, or any surface-owner who accepts anything of value for his consent, was liable to a civil penalty of 1-1/2 times the value of the item of value. Consequently, no private deals were permitted. Federal lessees of surface interests (e.g., for grazing) were entitled to protection in the form of a consent requirement and the requirement of a bond against damage to the surface estate.

There were a number of other provisions to the bills of which the most interesting include:

1. Provision, in the case of checkerboards or other closely related federal and nonfederal lands, for cooperation between the state and federal authorities to avoid duplication. Since either one could delegate authority to the other, operators would have only one authority and set of rules and forms to deal with, instead of two.

2. Extensive provisions for hearings, public participation and public standing to sue in many of the stages of the program.

3. Special exemptions and provision for other arrangements for certain bituminous coal mines located west of the 100° meridian, and for anthracite mines, principally in Pennsylvania.

4. Exemption from the Act of people who took coal from their own land for their own use, and commercial operations limited to two acres or less.

5. Exemption of Indian lands from this program, pending a study. The idea of the study was to see if it can be arranged to have the Indian tribes act as states, running their own programs subject to federal preemption in the same fashion as state programs are.

It should be noted that these programs covered only coal, pending a study of extending the program, or devising a different program, for other minerals presumably including oil shale.

H. Existing Environmental Regulations

Three bodies of regulations deal with the environmental impact of coal exploration and mining: 43 CFR Part 23, which details the procedures of the BLM prior to issuance of a lease or permit, 30 CFR Part 211 ff., which details the responsibilities of the USGS for enforcement of the restrictions included in a lease or permit by the operation of 43 CFR Part 23, and 25 CFR Part 177, which covers Indian lands.

The Department of the Interior overhauled the first two of these sets of regulations with the intention of including in them as much as possible of the language of the 1974 Strip Mine bill. The title of 43 CFR Part 23 is "Surface Exploration, Mining and Reclamation of Lands." The principal provisions of the current regulations include the following:

1. No one may explore, test or prospect for Leasing Act minerals in such a way as to disturb the surface of the earth without a permit.

2. In connection with an application for a permit, the District Manager of the BLM must make or cause to be made a technical examination of the effects of the proposed exploration or surface mining on a variety of environmental elements, including:

    - Recreational, scenic, historical and ecological values.
    - Control of erosion, flooding and water pollution.
    - Isolation of toxic materials.
    - Prevention of air pollution.
    - Reclamation prospects, by revegetation, replacement of soil, or other means.

- Prevention of slides.
- Protection of fish and wildlife, and their habitats.
- Prevention of hazards to public health and safety.

3. Based on this technical examination, the BLM District Manager formulates general requirements for environmental protection that must be included in the lease or permit. Participation of other agencies, if they have the primary responsibility for the land, is provided for.

4. The District Manager may limit or prohibit operations on land where "previous experience under similar conditions has shown that operations cannot feasibly be conducted by any known methods or measures" to avoid:

   - Dangerous rock- or landslides.
   - Substantial deposition of silt or sediment into streams, lakes, or reservoirs.
   - Lowering of water quality below levels established by the state water pollution control agency, or by the Secretary.
   - Lowering of the quality of waters that exceed minimum standards, absent a certification that it will not preclude assigned uses of the water and that such lowering is "necessary to economic and social development."
   - Destruction of "key" wildlife habitat.
   - Destruction of "important" scenic, historic, natural, or cultural features.

   Water quality objections bring into force a requirement of consultation with the Federal Water Pollution Control Administration and a finding by them that the proposed activity will not violate the Federal Water Pollution Control Act.

5. Before disturbing the surface to explore, test, or prospect for Leasing Act minerals, an exploration plan must filed and approved by the USGS Mining Supervisor in consultation with the BLM District Manager. The exploration plan must include information on the land, proposed operating methods, and methods proposed to prevent fire,

erosion, pollution, damage to wildlife, public safety and natural resources both during and after exploration activities. There are provisions for negotiation if the plan is not initially acceptable.

6. Before beginning any mining operations under a federal permit or lease, a mining plan must be filed and approved by the USGS Mining Supervisor with the consultation of the BLM District Manager, as in an exploration plan. This proposed mining plan must include much information, including information about the land and

   - A statement of proposed operating methods, with information on proposed roads, trails, and structures.
   - An estimate of proposed water use and pollution.
   - A design for impoundment and treatment of runoff water, to prevent erosion, sedimentation, and pollution.
   - Description of methods to prevent fire, soil erosion, water pollution, damage to fish and wildlife, and dangers to public health and safety.
   - If revegetation is required, a detailed plan must be provided.
   - If regrading and backfilling is required, a detailed plan must be provided.

   There are provisions for negotiations and for approval of a partial plan, and similar administrative measures.

7. A performance bond is required sufficiently large to satisfy the reclamation requirement of the approved exploration or mining plan, but not less than $2000.

8. Elaborate reporting is required of the operator, detailing his progress in performing each of his obligations under the approved plan.

9. There is a provision headed "Notice of Noncompliance; Revocation," which provides for issuance of notices of noncompliance by the USGS or the BLM but does not mention revocation. As noted earlier, revocation of

a federal mining lease is not as easy as perhaps it should be.

10. There are appeals procedures.

25 CFR Part 177 governs Indian lands. It is very similar to 43 CFR Part 23, except:

1. In place of the BLM District Manager there is substituted the Superintendent of the BIA or his representative.

2. This will be superseded, since the Strip Mine bill does not apply to Indian lands, pending a study of the feasibility of having Indian tribes set up their own programs on a par with state programs.

3. There is provision for suspension and cancellation by the Mining Supervisor in case of noncompliance.

4. The Superintendent must consult with Indian landowners on actions he plans to take concerning technical examination, granting or denial of permits, exploration plans, noncompliance actions, etc.

30 CFR Part 211 provides Coal Mining Operating Regulations. It is principally concerned with the responsibilities of the USGS during the process of approval of exploration and mining plans and the supervision and enforcement of the statutes, regulations, and environmental protection restrictions incorporated into the terms of permits or leases. It applies to all federal leaseholds regardless of surface ownership, and to Indian lands. It provides, however, that (except with respect to §211.37, Surface Mining) in case of conflict with 43 CFR Part 23 and 25 CFR Part 177, discussed above, those regulations shall be considered superior to these.

The latest available text is that of a proposed revision, published in the Federal Register on January 30, 1975, but yet to be officially promulgated. This revision is part of the effort mentioned above to bring the existing federal regulations in line with the language of the

Strip Mine bill. Section 211.37 incorporates much of that language, and there are numerous other instances of strengthening of provisions in the existing Part 211.

There seems little point in detailed recitation of the provisions of this Part. Section 211.1(b), however, sums up the purpose of the provisions:

> "The purpose of the regulations in this part is to promote orderly and efficient prospecting, exploration, testing, development, mining, preparation and handling operations and production practices, without avoidable waste or loss of coal or other mineral deposits or damage to coal or other mineral-bearing formations; to encourage maximum recovery and use of coal resources; to promote operating practices which will avoid, minimize or correct damage to the environment--land, water and air--and avoid, minimize or correct hazards to public health and safety; to require effective reclamation of lands; and to obtain a proper record and accounting of all coal produced."

(The last purpose--that of a record--is there because the USGS has the responsibility for assessing and collecting royalties.)

The responsibilities of the USGS Mining Supervisor are enumerated. He is to inspect to prevent waste or damage, and regulate operations to conserve mineral resources. He is to require that operators obey the law and the regulations and conform to the requirements in their lease or permit, and in their approved exploration or mining plans. He is to require that work be performed in an environmentally sound manner, and that reclamation be done as contemporaneously as possible with the mining itself. He is to obtain and check production records and assess and collect rent and royalty money. He is to decide on applications for suspension of operations or termination of suspension (and on Indian lands transmit such applications to BIA officials). He is to determine whether operations that have ceased or that have been abandoned have conformed to reclamation and other requirements. He is to inspect and determine the adequacy of air and water pollution control methods, and require that they be sufficient to meet the requirements of the law, the lease or permit, and the operations plan. He is to determine the amount of reclamation bonds. He is to prescribe or approve methods of protection of water from leakage from wells and prospect holes drilled through coal. He is authorized to issue mining operations orders as necessary to assure compliance with the rules.

There is included in the next section a series of obligations of permittees and lessees, which obligations the USGS Mining Supervisor may also enforce, since they are made obligations by the regulations. Operators must conform with the laws, the regulations, the terms of leases and permits, the terms of approved plans, and the orders and instructions issued by the Mining Supervisor. They must take precautions to prevent waste and damage to mineral formations. They must "take such action as may be needed to avoid, minimize or control" soil erosion, air pollution, water pollution, alteration of water flow, damage to crops, vegetation or timber, injury to fish and wildlife and their habitat, unsafe conditions, damage to improvements, by whomever owned, and damage to recreational, scenic, historical, archaeological, and ecological values. All of which is purposefully vague; it is the responsibility of the Mining Supervisor to determine questions arising under these obligations, and his word is (subject to appeal procedures) the final one. He may issue mining operations orders to enforce any of these obligations as he sees fit ("Don't build the road here, build it there." "Install a mine drainage discharge monitoring device here, here and here," etc.).

There follow a number of highly complex and technical requirements dealing with reporting, maps and plans, requirements for the contents of proposed exploration and mining plans, surveillance wells and blowout control devices, etc. One thing of importance, which is not dealth with elsewhere, is a provision that production must be conducted in a manner to yield the maximum recovery of coal deposits consistent with environmental values, and that a lessee shall not "leave or abandon any coal which otherwise could be safely recovered by approved methods of mining when in the regular course of mining the time shall arrive for mining such coal." This is for the purpose of conserving natural resources, protecting the government's royalty interest, and preventing the environmental consequences attendant upon secondary or tertiary recovery attempts.

There is also provision in this part for such things as permission to mine narrow isolated strips of nonleased coal to prevent their loss, and other similar minor housekeeping matters.

Section 211 deals only with coal. Oil shale is included in the coverage of Part 231. However, there is no need to examine these provisions, which are very similar to those in Part 211, because the only federal oil shale leases that are likely to be let for some time have already been let, with elaborate environmental protection provisions of their own, and the study of the differences between USGS enforcement of coal leases and plans and oil shale leases and plans is not, at this point, very profitable.

It should be noted, however, that both parts of the regulations stipulate that if the orders of the Mining Supervisor are not obeyed, after due notice of noncompliance and so on, the Mining Supervisor may order suspension of operations. Appeals from Mining Supervisors' decisions go to the Director of the USGS (or, on Indian lands, to the Commissioner of the BIA), and from there to the Board of Land Appeals in the Office of Hearings and Appeals in the Office of the Secretary of the Interior.

I. State Reclamation Statutes and Regulations

It seems likely that in the light of federal action, state systems will be revised and/or will be superseded by the federal/state system outlined in the section on the Strip Mine bill. By and large, the state laws do not rise to the level that will be expected of them under the Strip Mine bill. Two things should be kept in mind, however. The first is that in Montana, contour mining is prohibited. The second thing to bear in mind is that in West Virginia the legislature has passed, for the third time in a row, a two-year moratorium on surface mining in counties in which there has been no surface mining in the past. If the Governor has not yet signed the bill, he is expected to.

J. Other Regulations

There are other agencies of government that have impact on coal mining. In addition to the Environmental Protection Agency (air and water pollution standards), there is also the Mining Enforcement and Safety Administration (Department of the Interior), which enforces the Federal Coal Mine Health and Safety Act of 1969. There is enforcement of nondiscrimination provisions of federal leases. These are tax issues. There are state mining safety laws, and requirements for licenses from state authorities to open and operate mines (which are primarily concerned with safety and competence of personnel). There are zoning and local land use regulations. The law on the subject is indeed a seamless web. This paper has endeavored to give the background of coal and oil shale leasing, and has attempted to shed some light on the principal environmental restrictions which affect rights under leases.

8--FINANCING THE SYNTHETIC LIQUID FUELS INDUSTRY BY THE U.S. CAPITAL MARKETS

By Ronald L. Cooper, John W. Ryan, Barry L. Walton

A. Introduction

The future outlook for investment in the U.S. domestic energy industry must be considered within the framework of capital expenditure requirements for other sectors of the economy. Capital requirements for the aggregate economy in turn depend on the future growth of the GNP and the rate of inflation.

The discussion in this chapter begins by outlining the framework in which the capital expenditures requirements for the aggregate economy and the domestic energy industry are generated. First, the projections for the aggregate economy are based on the Ford Foundation Energy Policy Project (EPP), A Time to Choose: America's Energy Future,[1] as well as other sources.[2-7] Projections for the energy industry to 1985 rely heavily on the study carried out for the Ford Energy Policy Project by Hass, Mitchell, and Stone.[8] Projections for 1985-2000 are based on the extrapolation of past trends and the 1973-1985 relationships between capital expenditures and energy output. Second, the capital expenditures for the energy industry are discussed for two main scenarios: Historical growth (HG), and technical fix (TF). HG assumes that the growth of energy consumption continues in the future at rates close to historical rates, with little or no conservation. TF assumes a much greater amount of demand conservation which, in turn, significantly lowers the growth of energy consumption over the 1975-2000 period. Under HG, three subscenarios are considered: (1) accelerated development of domestic petroleum supplies (HG1); (2) accelerated nuclear development (HG2); (3) continued heavy reliance on imports of crude oil (HG3). The domestic capital requirements for the energy industry differ for each scenario. Third, the capital requirements of the petroleum industry with and without synthetic fuels are compared to the petroleum industry's sources and uses of funds.

B. Outlook for Total Business Fixed Investment and Other Related Macroeconomic Variables

Business fixed investment represents one use of total savings in the aggregate economy. Other competing uses of savings funds are financing increases in business inventories, residential construction, and federal, state, and local debt financing. Total savings comes from two main sources: business savings, and personal savings of households. Another source of savings, when funds flowing into the country exceed funds flowing out, is net foreign investment. The total sources and uses of savings and investment funds for 1973 are shown in Table 8-1. Projections of the total sources and uses of funds are made for 1975-2000, and funds statements for 1985 and 2000 are presented in Table 8-2 for illustration. Also shown are the cumulative totals for the sources and uses of funds over the 1975-2000 period. The projections are made in two stages. First, predictions of "desired" capital are made for the 25-year period for each sources and uses component. The methodology behind these projections, which covers each category in Table 8-2, is explained in Appendix A, Tables A-1 through A-5. Since the total sources of funds must balance the total uses, Table 8-2 includes both the "desired" and "realized" projections. For each year over the 1975-2000 period, the total use of funds exceeds the total supply of funds on a "desired" basis. The equality between the total sources and uses of

Table 8-1

SOURCES AND USES OF FUNDS--1973
(Billions of Current Dollars)

Sources of Funds		
Business savings	136.5	
Personal savings	74.4	
Net foreign investment	0.1	
Total sources	211.0	
Uses of Funds		
Business fixed investment	136.8	
Residential construction	57.2	
Inventory investment	15.4	
Federal deficits	5.6	
State and local government borrowing	-9.2	(surplus)
Credit agency borrowing	9.5	
Statistical discrepancy*	-4.3	
Total uses	211.0	
Savings Gap	0	

*The statistical discrepancy arises from the inability to measure the uses of funds with precision.

Source: Reference 6.

funds in each year is accomplished by interest rate adjustments in the capital markets. To eliminate the discrepancy between total investment and total saving, the total sources have been increased by half the amount of the gap, and the total uses have been similarly decreased. The total amounts within the sources and uses are allocated to each component on the basis of historical shares.

Table 8-2

PROJECTED SOURCES AND USES OF FUNDS
(Billions of Current Dollars)

	1985		2000		Cumulative 1975-2000	
	Desired	Realized	Desired	Realized	Desired	Realized
Sources of Funds						
Business savings	$378	$417	$1326	$1453	$14,639	$15,910
Personal savings	139	153	535	586	5,696	6,191
Net foreign investment	0	0	0	0	300	326
Total sources	$517	$570	$1861	$2039	$20,635	$22,427
Uses of Funds						
Business fixed investment	446	408	1623	1492	17,413	16,126
Residential construction	135	123	475	437	5,223	4,837
Inventory investment	27	25	96	88	1,053	975
Federal deficits	4	3	4	3	91	84
State and local government borrowing	3	2	5	5	103	95
Credit agency borrowing	10	9	15	14	335	310
Total uses	$625	$570	$2218	$2039	$24,218	$22,417
Savings Gap	108	0	357	0	3,538	0

Current dollar projections of business fixed investment are converted to constant 1973 dollar projections by dividing the current dollar figure by the projected implicit price deflator corresponding to business capital expenditures. The methodology for projecting the capital expenditures price deflator is explained in Appendix A, Table A-3.

C. Investment in the Energy Industry

Energy investment is projected in Table 8-3 for the five major energy groups--domestic petroleum, electric utilities, natural gas, coal, and nuclear--for 1975-2000 for the three options under the HG scenario. Energy investment projections are also developed for the TF scenario.*

In the reference case, synthetic fuels are excluded from energy investment over the 1975-2000 period. The EPP energy projections are adjusted to exclude synthetic fuels by shifting synthetic fuel entries to the imports category. Table 8-3 shows capital expenditure projections at 5-year intervals for 1975-2000 for the three options under HG. The average annual growth rates of capital expenditures in 1973 dollars for HG1, HG2, and HG3 are, respectively, 4.79, 4.72, and 4.53 percent. The corresponding average annual growth rate for total business fixed investment (Appendix A, Table A-3) over the same time span is 4.3 percent. Thus, because investment in the energy industry under HG is projected to grow at a faster rate than for the economy as a whole, the share of total investment devoted to the domestic energy industry must increase significantly for the projected domestic supply options to be met. Under HG, the increasing shares of energy investment reach a maximum

*In the Ford study,[1] a third main scenario is considered--zero energy growth (ZEG). However, insufficient information is provided in that study for SRI to develop energy investment projections for ZEG.

Table 8-3

PROJECTIONS* TO 2000 OF CAPITAL INVESTMENT IN U.S. DOMESTIC ENERGY INDUSTRY UNDER HISTORICAL GROWTH: BILLIONS OF 1973 DOLLARS
(Excluding Synthetic Liquid Fuels)

	1975	1980	1985	1990	1995	2000
HG1						
Domestic petroleum and natural gas production and refining	13	18	23	25	28	30
Electric utilities, including nuclear facilities	21	30	42	57	72	87
Natural gas distribution	5	5	5	5	6	6
Coal production (excluding coal for synthetic gas)	2	2	2	2	3	3
Nuclear fuel production	0	2	2	3	5	6
Total	41	57	74	92	114	132
HG2						
Domestic petroleum and natural gas production and refining	13	18	23	24	25	26
Electric utilities, including nuclear facilities	21	31	43	59	75	92
Natural gas distribution	5	5	5	5	6	6
Coal production, excluding coal for synthetic gas	2	2	2	2	2	3
Nuclear fuel production	0	2	2	4	6	8
Total	41	58	75	94	114	135
HG3						
Domestic petroleum and natural gas production and refining	13	14	16	18	20	22
Electric utilities, including nuclear facilities	21	30	42	57	72	87
Natural gas distribution	5	5	5	5	5	6
Coal production, excluding coal for synthetic gas	2	2	2	2	3	3
Nuclear fuel production	0	2	2	3	5	6
Total	41	53	67	85	105	124

*Appendix B describes the methodology underlying the projections.

in 1995 and somewhat decline between 1995 and 2000. For example, under option HG1, as shown in Table 8-4, the energy share of investment increases from about 29 percent in 1975 to 34 percent by 1995, and 32 percent in 2000.

Table 8-4 shows the increases in the energy share of total investment with the introduction of synthetic fuels for automotive transportation. The synthetic fuels investment projections are taken from Chapter 6.* It is observed from Table 8-4 that the required shares of investment in energy increase much more significantly with the introduction of synthetic fuels. For example, under option HG1, the share of energy in total investment increases from about 29 percent to a maximum of 36 percent in 1995, and then falls back to 35 percent in 2000.

Table 8-5 presents capital expenditures at 5-year intervals for 1975-2000 under the technical fix scenario (TF1). Because of the much greater amount of energy conservation in TF than HG, energy investment requires much lower shares of total business fixed investment.

Under both historical growth and technical fix scenarios, energy industry investment has to increase relative to total business fixed investment because of increased reliance on domestic energy sources. Past growth in energy demand has been met by larger imports while domestic production has declined.

Under all scenarios electric utility investment requires a major portion of the total energy industry investment--roughly 60 percent or more. Therefore, the funds and interest rates available to other industries are quite sensitive to events concerning electric utilities.

*It is assumed that the production of synthetic fuels for automotive transportation will replace an equivalent amount of crude oil imports, and it will not substitute for domestically produced oil. Table B-3 summarizes the annual synthetic fuels investment for the maximum credible implementation scenario.

Table 8-4

CAPITAL EXPENDITURES FOR ENERGY INDUSTRY COMPARED
TO TOTAL U.S. BUSINESS FIXED INVESTMENT
UNDER HISTORICAL GROWTH
(Percent)*

		1975	1980	1985	1990	1995	2000
Excluding synthetic fuels	HG1:	29	31	32	33	34	32
	HG2:	29	31	32	33	34	33
	HG3:	29	29	29	30	31	30
Including synthetic fuels†	HG1:	29	32	33	35	36	35
	HG2:	29	32	33	36	36	35
	HG3:	29	30	30	32	33	33

*Defined by dividing energy investment from Table 8-3 by "desired" business fixed investment for the appropriate year from Table A-3.
†Annual investment for synfuels from the maximum credible implementation scenario (Table 6-8, Chapter 6) was added to investment in Table 8-3.

Investment required for coal production is less than 5 percent of the electric utilities investment. Since electric utilities are a regulated industry, the government can (through a liberal treatment of rate requests) provide the utilities with an internal source of funds financed by the general public. Thus, while historical financial markets will play a role, the ultimate outcome to financing energy production will be dominated by politically dictated policies.

Table 8-5

CAPITAL INVESTMENT IN U.S. DOMESTIC ENERGY
INDUSTRY FOR TECHNICAL FIX SCENARIO
(EXCLUDING SYNTHETIC FUELS)
(Billions of 1973 Dollars)

	1975	1980	1985	1990	1995	2000
Domestic petroleum and natural gas production, refining, excluding gas pipelines	$13	$17	$21	$21	$22	$22
Electric utilities, including nuclear facilities	21	25	30	34	38	43
Natural gas pipelines	5	5	5	5	5	5
Coal production, excluding coal for synthetic natural gas	2	2	1	1	2	2
Nuclear fuel production	0	1	2	2	2	3
Total	$41	$50	$59	$63	$69	$74

ENERGY'S SHARE OF TOTAL INVESTMENT
(Percent)*

	1975	1980	1985	1990	1995	2000
Excluding synthetic fuels	29	28	25	23	20	18
Including synthetic fuels†	29	28	27	25	23	20

Note: Appendix B describes the methodology underlying the projections.

*Defined by dividing energy investment from the upper part of the table by business fixed investment for the appropriate year from Table A-3.
†Annual investment for the maximum credible scenario Table A-8 was added to energy investment.

D. Capital Availability in the Petroleum Industry

To assess the impact of synthetic fuels industry on capital markets, the sources and uses of funds within the petroleum industry were calculated for the HG1 scenario with and without synthetic fuels. The analysis was carried out to the year 2000, using the methodology of Hass, et al.;[8] the data and details of the financial relationships are presented in Appendix C. Briefly, the industry assets are used to project the internal sources of funds based on a rate of return after taxes and a depreciation rate. The uses of funds are annual investment and dividends. The annual investment data are shown in Table C-1. Assumptions made in the calculations are as follows:

1. The historical after-tax return applies to new investments as well as existing investments.*
2. Depreciation rates will approximate recent levels as a percent of assets.
3. External funds will be available to maintain historical debt-equity ratios.
4. Historical payout rates will be maintained.

The initial calculations were carried out using constant 1973 dollars for investment and cash flow calculations. The cash flow for the domestic petroleum industry are depicted in Figures 8-1 and 8-2 (see Table C-2 for basic data) for no synthetic liquid fuels and with synthetic liquid fuels. In both cases, after 1985 there are excess funds available, which are assumed to be paid out in dividends. Prior to 1985,

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*This assumes that federal energy policy concerning synthetic fuels will both establish conditions making synthetic fuels as profitable as conventional fuels and also mitigate business risks to the extent that a rate of return on investment higher than conventional fuels would not be justified.

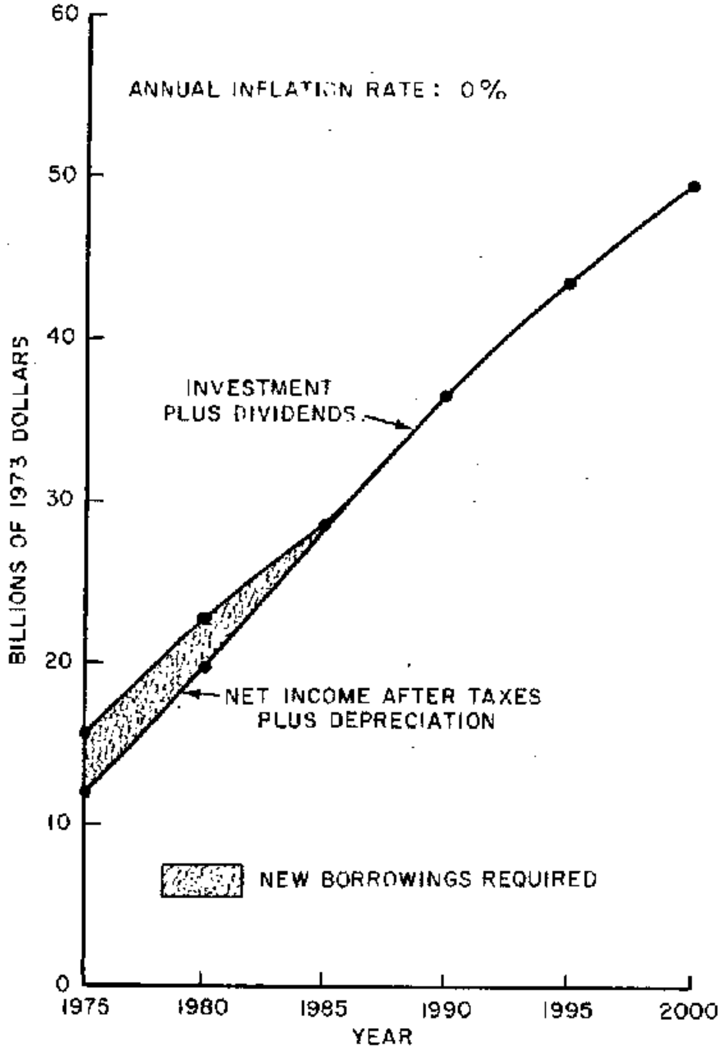

FIGURE B-1. PROJECTED CASH FLOW FOR DOMESTIC OIL AND GAS INDUSTRY — NO SYNTHETIC LIQUID FUELS — AT A ZERO RATE OF ANNUAL INFLATION

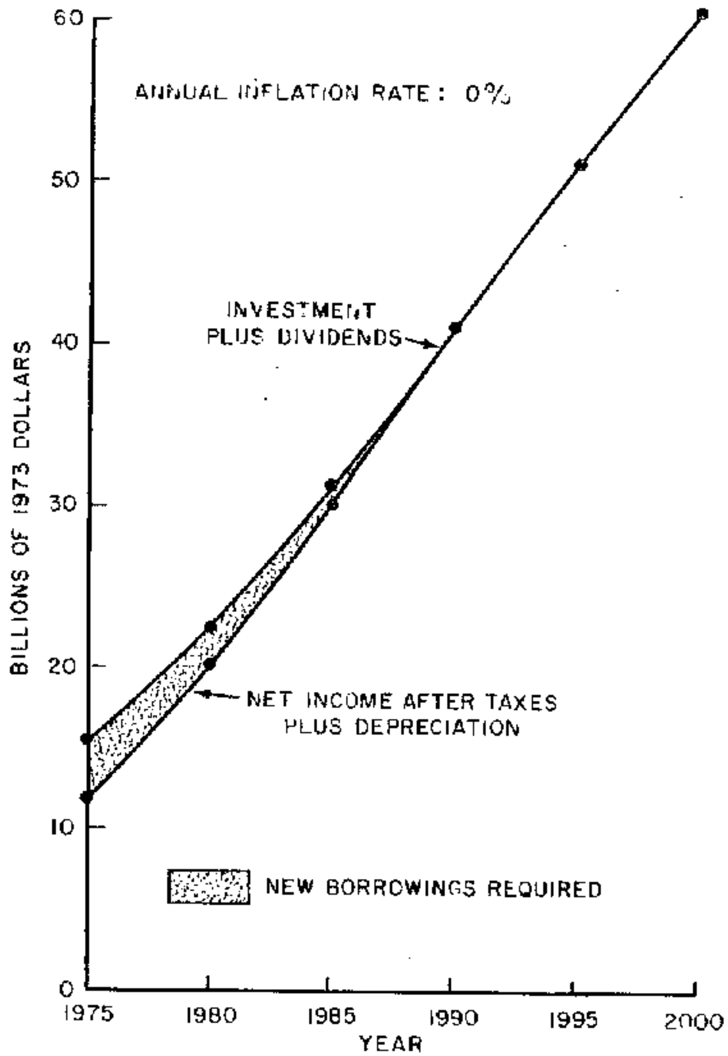

FIGURE B-2. PROJECTED CASH FLOW FOR DOMESTIC OIL AND GAS INDUSTRY — CONVENTIONAL ACTIVITIES PLUS SYNTHETIC LIQUID FUELS — AT A ZERO RATE OF ANNUAL INFLATION there is a shortage of internally generated funds shown by the shaded gap between the sources and uses levels in the figures.

This constant dollar analysis implies no large impact of synthetic fuels on capital markets since the petroleum industry generates more cash than it needs. This occurs in spite of the low productivity of assets employed. In 1973, total assets were $80 billion and output was 45×10^{15} Btu;* according to the balance sheet figures as projected in Appendix C, the productivity of assets diminishes as follows:

	Total Assets	Energy Output	Productivity
1985	$247 billion	63×10^{15} Btu	0.25×10^{6} Btu/$
2000	$417	82×10^{15} Btu	0.20×10^{6} Btu/$

This implies that the assumptions of a constant rate of return on assets is important, since lower productivity requires more assets which, under constant return, generate more net income as well as more depreciation funds. It is implicit in the rate of return assumption that the petroleum companies are able to maintain prices at a level high enough to generate a 10 percent return on total financing.

The analysis was extended to consider the future flow of funds under inflation at 5 and 8 percent per year. The results show that in an inflationary environment, borrowed funds are needed whether or not synthetic fuels are assumed. Figures 8-3 to 8-6 show the necessary borrowings in these cases. Under 8 percent inflation, the petroleum industry with synthetic fuels must borrow $58 billion in 2000; however, this

*A quadrillion (10^{15}) Btu is about 10^{18} J.

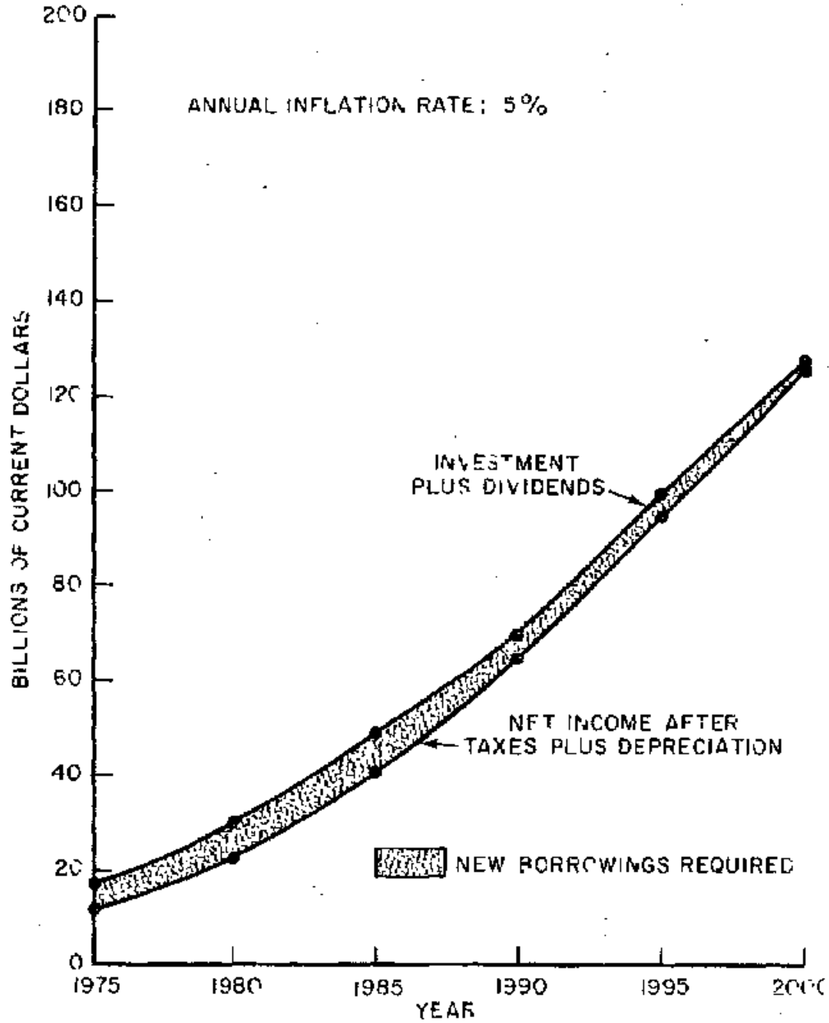

FIGURE 8-3. PROJECTED CASH FLOW FOR DOMESTIC OIL AND GAS INDUSTRY – NO SYNTHETIC LIQUID FUELS – AT A FIVE PERCENT ANNUAL RATE OF INFLATION

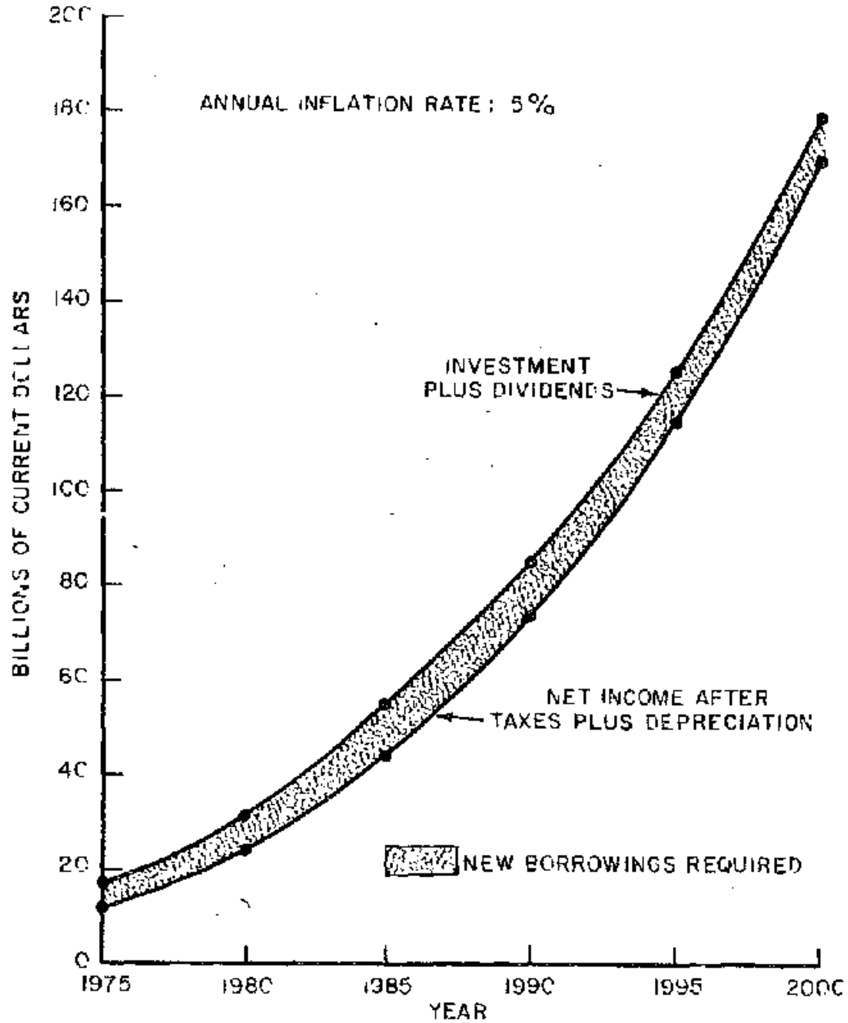

FIGURE 8-4. PROJECTED CASH FLOW FOR DOMESTIC OIL AND GAS INDUSTRY – CONVENTIONAL ACTIVITIES PLUS SYNTHETIC LIQUID FUELS – AT A FIVE PERCENT ANNUAL RATE OF INFLATION

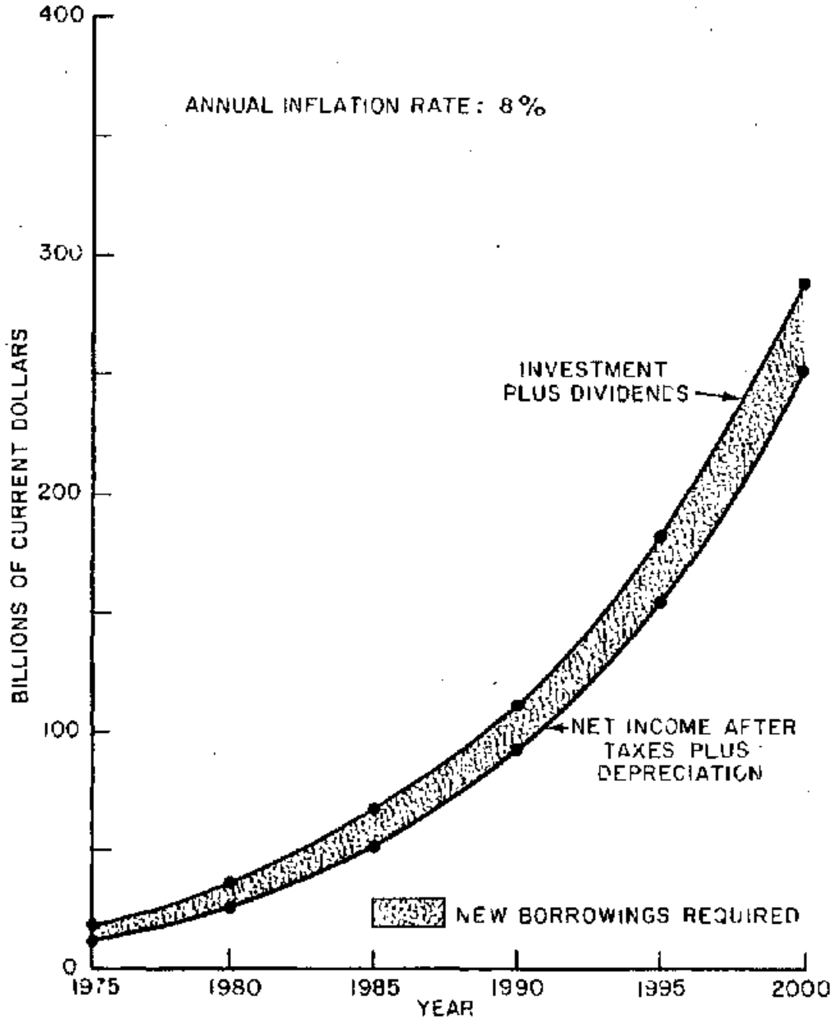

FIGURE B-5. PROJECTED CASH FLOW FOR DOMESTIC OIL AND GAS INDUSTRY–NO SYNTHETIC LIQUID FUELS–AT AN EIGHT PERCENT ANNUAL RATE OF INFLATION

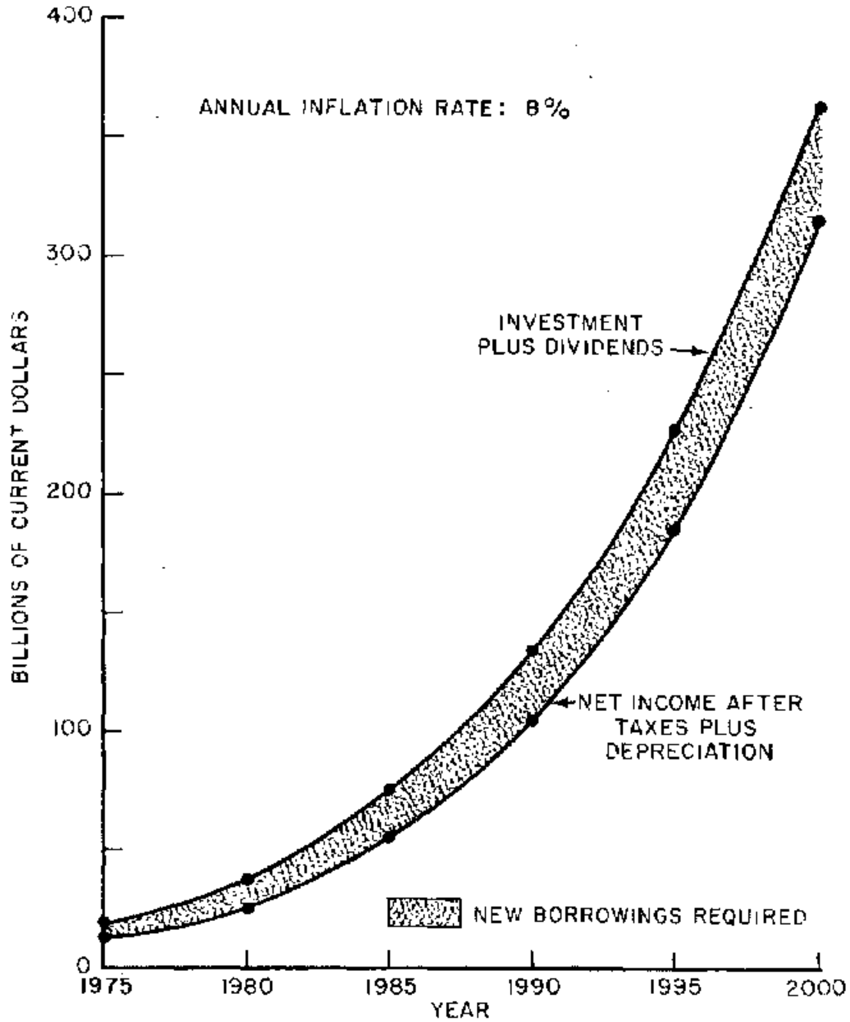

FIGURE 8-6. PROJECTED CASH FLOW FOR DOMESTIC OIL AND GAS INDUSTRY–CONVENTIONAL ACTIVITIES PLUS SYNTHETIC LIQUID FUELS–AT AN EIGHT PERCENT ANNUAL RATE OF INFLATION

is a small fraction of its total cach flow of $315 billion in 2000 and less than the dividend payout (see Table C-4).

The reason for the shortage of internal funds under inflation is that depreciation of fixed assets is based on historical rather than replacement cost. Consequently, cash flow from depreciation does not generate sufficient cash to replace existing assets and to add to assets as well.

E. Conclusions

The findings of this flow of funds analysis of the petroleum industry demonstrate the importance of inflation rates and governmental policy on industry cash flow. Fiscal policies that result in inflation prevent depreciation credits from providing enough cash flow to actually replace existing assets at the higher prices. As a result, industry must use a portion of its after-tax income to maintain existing asset levels. Funds for growth are thereby diminished and the need to attract funds from external sources is increased. In the petroleum industry, funds for growth have been hurt by recent changes in the tax laws affecting depletion allowances and foreign tax credits.

The results of this chapter project faster growth for petroleum industry investment than for total business fixed investment. In the early 1970s the petroleum industry accounted for 7.5 to 9 percent of total business fixed investment while our projections are that the percentage will double to 18 percent by 1995. There will be much competition from other sectors of the economy for capital that will work against realizing such growth.

Within the energy industry itself, for example, electric utilities will require vast amounts of new capital. Likewise, other basic industries need large amounts of capital for expansion, modernization and pollution control. Such needs will likely cause intense competition for newly formed capital.

However, the projections of this chapter show the petroleum industry able to provide internally for an increased fraction of its investment funds by the year 2000.* Our model (and assumptions) project that in an 8 percent inflation economy, new borrowings by the petroleum industry would fall from 31 percent down to 15 percent of cash flow by the year 2000.

*The projections of this chapter are based partly on the assumption that real GNP will grow at an average annual rate of 3.6 percent. This assumption may be valid only if energy prices remain relatively cheap. It was, unfortunately, beyond the scope of this effort to also attempt to model the dependency of GNP on energy prices.