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NET ENERGY ANALYSIS OF GEOPRESSURED GAS RESOURCES IN THE U.S. GULF COAST REGION

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Abstract—Geopressured gas is a vast but diffuse fuel resource in the U.S. Gulf Coast Region. The U.S. Department of Energy sponsored a test drilling program to evaluate the physical parameters of the resource base. Data from this evaluation program and other studies were incorporated into a model that compared the energy costs and yields of extracting geopressured gas. Results indicate that even the most promising geopressured prospects yield little net energy, even under optimistic assumptions concerning labor, government, and environmental energy costs. Conventional natural gas wells still yield substantially greater net fuel. Alternative technologies such as coal gasification also yield greater net fuel. We conclude that geopressured gas resources in the Gulf Coast do not represent a significant source of net energy for the nation based on current knowledge of reservoir parameters and extraction technology.

1. INTRODUCTION

Domestic proved reserves of liquid and gaseous hydrocarbons peaked in the early 1970s despite unprecedented levels of exploratory and development drilling since that time. Natural gas reserves peaked in 1967 at 293 trillion cubic feet (tcf) and consumption has exceeded new additions to reserves by an average annual rate of 10 tcf. Between 1973 and 1982, domestic wellhead gas prices increased by a factor of seven and total drilling by the petroleum industry increased 280%. Large increases in economic incentive and drilling effort, however, have not reversed the secular trend of declining gas discoveries per unit of drilling effort. The National Petroleum Council[1] has identified four types of unconventional gas resources whose exploitation in the future might supplement conventional domestic supplies: methane in tight sandstone formations, methane in Devonian shale formations, methane trapped in coal seams, and methane dissolved in geopressured aquifers.

Domestic geopressured gas resources occur almost exclusively in the northern Gulf Coast region of Texas and Louisiana (Fig. 1). DOE sponsored a test drilling program at several of the more promising sites to gain more detailed information on the characteristics and magnitude of geopressured gas resources. The purpose of this analysis is to incorporate the results of the test drilling program into a model which evaluates the energy costs and gains of developing geopressured gas resources.

The potential economic availability of alternative fuel sources is most often evaluated in terms of how high the price of conventional sources must go before the alternative source becomes economically feasible to exploit. For instance, Kuuskraa *et al.*[2] estimated that if the price of natural gas were to rise to $\$3.00/10^3\,ft^3$, 200–220 tcf of gas could be recovered from unconventional sources, an amount slightly larger than total proven reserves of conventional natural gas in 1982. In 1982, conventionally produced gas from deep formations in the Tuscaloosa trend, Louisiana was selling for $\$8.00–9.00/10^3\,ft^3$, several times the trigger price estimated by Kuuskraa *et al.* and others, but alternative sources were still not economically feasible. Dollar-based analyses require predictions of future economic conditions like the rate of inflation, interest levels, and relative price levels. These are uncertain predictions at best, even under stable economic conditions. In the past, start-up and production costs for new energy technologies have risen at roughly the same rate as the price of existing fuels, negating many price threshold estimates.

An alternative is to evaluate fuel resources in terms of their potential to provide net fuel to

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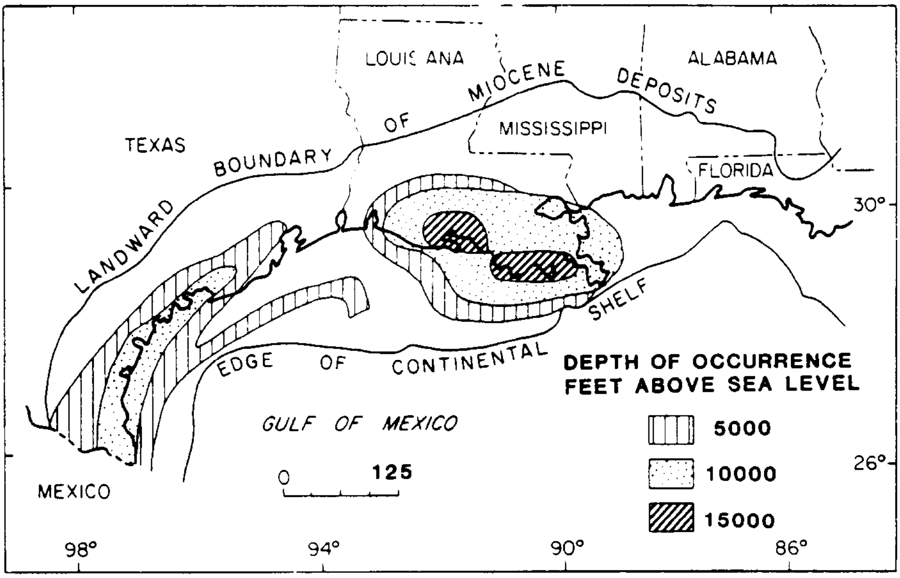

Fig. 1. The geopressured zone in the U.S. Gulf coast region.

the economy.[3,4,17,20,28] Energy return on investment (EROI) is the ratio of gross fuel extracted to the total energy required directly and indirectly from society (in fuel units of comparable quality) to locate, extract, and otherwise upgrade the fuel to a socially useful state. The EROI for fossil fuels is determined by two factors: its geological availability (mode of occurrence, depth of burial, etc.) and the state of extraction technology. The former factor exerts a strong influence over the form and direction of change in the latter factor. Energy analysis can evaluate the EROI of fuel resources based on a given extraction technology, and may provide insight into limitations on future technical improvements.

2. THE GEOPRESSURED/GEOTHERMAL RESOURCE BASE

The term geopressured reservoir or aquifer refers to fluids trapped in sedimentary strata (usually sandstone or shale) under pressures greater than the normal vertical pressure gradient of 0.465 psi/ft. The most intensively analyzed area for the development of geopressured/geothermal energy has been the northern Gulf of Mexico basin where, for the past 50×10^6 years, the rivers of the Gulf Coast have deposited interwoven layers of sand, clay and shale that eventually formed the reservoirs for today's geopressured zones. Concurrent with the increasing compaction of the sedimentary strata were pressure increases which forced the seawater out from between the pore spaces of the sand and clay particles. Normal fluid pressure exists where pore fluids are free to drain in response to increasing pressure and burial, conditions which allow for the dissipation of pressure.[5] In some instances, however, post-depositional activities such as salt tectonics and growth faults have effectively prevented fluid expulsion and allowed a build-up of pressure. Within the massive sandstone facies, pockets of geopressured fluid were formed at depths ranging from 6000 to 22,000 ft. These pockets also tended to trap the natural heat flow from the strata below, resulting in large temperature increases.

With these physical characteristics, geopressured reservoirs have the potential to yield three forms of energy: thermal, mechanical, and the methane dissolved in the geopressured fluids. Collectively, the three types of energy resources are termed geopressured/geothermal (GP/GT) energies. Current information indicates that reservoir temperatures are too low to warrant the generation of electricity directly, so research and development has focused on the methane portion of the resource base.

The drilling of over 300,000 oil and gas wells in the greater Gulf coast region has provided a comprehensive data base on the geologic and geophysical setting of the region, allowing estimates of the magnitude of the GP/GT resource base to be made (Table 1). The estimates

Table 1. Estimates of total in place and gross recoverable methane energy in the U.S. Gulf coast region. All estimates are in 10^{12} Btu. Modified from Johnson *et al.*[12]

Reference	Gross Methane Energy in place	Gross Recoverable Methane
32	60,000 - 105,000	2,400 - 52,000
33	5,735	256
34	---	2,000
37	---	150
38	13	13
39	3,000	125
40	---	222
41	100,000 1,146	
42	12,000 - 30,000	---
45	0.1 - 2,650	0.0001 - 1,000
46	23,927	768
47	111,500	---
49	3,000 - 40,000	500 - 2,000
50	---	150 - 2,000
51	---	45

exhibit a rather large range due to uncertainty of specific resource characteristics like porosity, permeability, salinity, temperature, and reservoir volume and continuity. None of these estimates consider the energetics of trying to exploit this dilute and remote (relative to conventional natural gas) energy source.

3. THE GEOPRESSURED GAS EXTRACTION SYSTEM

A typical single well system designed to extract geopressured gas has the following components: (i) A source well drilled into the geopressured zone, which ranges from about 6000 to 22,000 ft. The technique is similar to conventional oil and gas drilling except that a geopressured well requires larger diameter tubing (5.5 in. vs 3.5 in. for a conventional well). (ii) 2–3 reinjection wells drilled to shallower permeable formations (5000–6000 ft) are required to dispose of the spent brine after the methane has been removed. Alternately, the fluids could be piped to the Gulf of Mexico, but this option suffers from legal and environmental problems. Also, this disposal option would be limited to those sites that are offshore or very near the coast. Disposal into shallow aquifers is the conventional method of fluid disposal currently used on the Gulf Coast. For these reasons, the Gulf of Mexico disposal option was not considered in this analysis. (iii) Separation and disposal plant facilities consist of a series of collection pipes leading from the source well to separators which extract the methane from the brine, and disposal piping leading back to the reinjection wells. A more detailed breakdown of the specifications of these facilities is available in DOW Chemical.[6]

4. THE MODEL

(a) *Energy inputs*

Energy costs for the extraction of the methane portion of GP/GT resources fall into two main categories: (i) project energy costs (the direct and indirect fossil, hydro and nuclear energy expended by society) and (ii) environmental energy costs (the direct and indirect damage to society's natural energy resources). Project energy costs include site preparation, drilling, separation and disposal plant facilities, power costs for reinjection, and operation and maintenance costs. The first three of these are incurred during the start up period of the project, assumed to be one year in this analysis, during which no methane is extracted. Operation and maintenance and power costs begin in the second year of the project when extraction actually starts, and continue over the life of the project.

Potential environmental costs include loss of wetland supported activities (fisheries production and recreation) due to land subsidence, air and water pollution, and contamination of drinking water sources with brine. Environmental energy costs are much more difficult to quantify than project energy costs, but their effects may continue years after fuel extraction has ceased. It is important to assess environmental costs to the degree of precision possible.

The largest single component of project energy costs is the actual drilling of the source well and 2–3 reinjection wells. Dollar costs for the drilling of a geopressured well were calculated from a model developed by Wrighton[7] who found that drilling costs for conventional natural gas wells in coastal Louisiana are strongly influenced by the depth of the well and the year that the well is drilled. The cost vs depth and time relationship has an exponential form. The empirical relation for natural gas wells drilled in coastal Louisiana from 1975 to 1979 is

$$Y = K(e^{ax} - 1)e^{rt} \tag{1}$$

where Y = average cost of the well (in dollars), K = base drilling cost (in dollars), a = statistical parameter describing the curvature of the function, x = depth of the well in ft, t = time in years (1975 = 1, 1976 = 2, etc.), and r = annual rate of increase in well cost. This model correlates well with observed costs for natural gas wells in southern Louisiana ($r^2 = 0.98$). Dollar costs calculated with this model were increased by 25% to obtain a dollar cost for a geopressured well, due mainly to the larger tubing required for a geopressured well. The National Petroleum Council,[1] Quitzau,[8] and Abdulrahman[9] also used the 25% surcharge. Disposal wells were assumed to require smaller tubing and were not cost adjusted.

The conversion of dollar to energy costs was performed in two ways (Table 2). Under

Table 2. Breakdown of dollar and energy costs for drilling, site preparation, plant facilities, and operation and maintenance costs for a single geopressured well system in southern Louisiana. Totals may not add due to rounding.

Item	% of total cost☐	SIC Code■	Energy intensity factor• (BTU/1972$) A	B	Constant dollar cost△ (10^3 1972$)	Total energy cost (10^6 BTU) A	B
DRILLING:✱							
Tangibles:							
conductor	0.3	3701	218,072	218,072	7.00	1,526	1,526
surface casing	1.3	3701	218,072	218,072	30.35	6,618	6,618
intermediate "	7.7	3701	218,072	218,072	79.74	39,196	39,196
production "	12.8	3701	218,072	218,072	298.78	65,156	65,156
liner "	1.6	3701	218,072	218,072	37.35	8,144	8,144
tubing	5.1	3701	218,072	218,072	119.05	26,059	26,059
x-mas tree	3.9	4208	64,454	102,230	91.04	5,868	9,307
Subtotal	32.7				763.30	152,567	156,006
Intangibles:							
site prep.	5.2	6503	39,945	106,629	121.38	4,849	12,943
rig—140 days @ $7200/day	26.2	4503	52,932	95,367	611.39	32,389	58,306
mud	10.4	3619	65,954	152,260	242.76	16,010	36,963
logging & perforating	6.5	7301	22,551	72,104	151.72	3,421	10,940
bits	1.3	4503	52,932	95,367	30.34	1,605	2,893
rental equip.	1.3	5000	53,120	108,500▲	30.34	1,611	3,291
fuel & water	3.2	6803	47,190/1	,898,796	74.70	72,605	80,656
trucking	1.5	6503	39,945	106,629	35.01	1,398	3,733
coring	0.6	7301	22,551	72,104	14.00	315	1,009
geologic & engineering	3.9	7301	22,551	72,104	91.04	2,053	6,564
well supplies	0.7	4503	52,932	95,367	16.37	866	1,561
completion services	2.6	7301	22,551	72,104	60.69	1,368	4,376
cementing	3.9	3601	378,716	378,716	91.04	34,478	34,478
Subtotal	67.3				1570.80	172,968	257,713
TOTAL DRILLING	100.0				2,334.2	325,535	413,719
SITE PREPARATION:✱							
site preparation							
surveying		7303	9252	72,104	6.9	64	497
grading		1105	76,665	97,375	10.4	800	973
fencing		4205	135,500	135,500	17.4	2,307	2307
roads		1104	121,535	121,535	172.2	20,928	20,928
water services		6803	47,190	95,565	5.3	250	506
electric power							
power service		6801	47,190	95,565	7.6	357	726
flood lights		5501	46,392	95,565	3.8	175	363
shops, offices		1103	64,111	97,375	56.8	3,3639	5,531
contingency		1103	64,111	97,375	41.6	2,669	4,050
TOTAL SITE PREP:					321.7	31,193	35,939
SEPARATION PLANT:○							
1st stage separator		4006	90,783	114,670	86.9	7,892	9,964
2nd stage sep.		4006	90,783	114,670			

Table 2. (*Contd.*)

Item	% of total cost□	SIC Code■	Energy intensity factor• (BTU/1972$) A	B	Constant dollar cost△ (10^3 1972$)	Total energy cost (10^6 BTU) A	B
3rd stage sep.		4006	90,783	114,670			
disposal pumps		4901	50,714	104,470	123.2	6,248	12,870
collection pipe		4208	64,454	102,230	66.5	4,284	6,798
disposal pipe		4208	64,454	102,230	178.1	11,472	18,207
TOTAL PLANT:					464.9	30,831	47,841
OPERATION/MAINTENANCE:*							
Fixed cost:							
labor		1202	61,516	101,170	61.4	3,778	6,211
Transportation		6503	39,945	108,290	24.6	981	2,663
special tests		7301	22,551	72,104	30.7	692	2,213
laboratory		7301	22,551	72,104	15.4	346	1,110
supervision		1202	61,516	101,170	30.7	1,889	3,105
overhead (20%)		1202	61,516	101,170	33.8	2,078	3,419
TOTAL FIXED COSTS:					196.6	9,767	18,725
Variable costs:							
producing well repair		1202	61,516	101,170	0.614		
disposal well repair		1202	61,516	101,170	0.203		
pump main.		1202	61,516	101,170	0.307		
chemical		7301	22,551	101,170	0.184		
well treating		7301	22,551	72,140	0.184		
overhead(20%)		1202	61,516	101,170	0.289		
TOTAL VARIABLE COST:					1.780 1972	cents/bbl	

*Based on drilling a conventional natural gas well to 15,000 ft in south Louisiana. Option A includes direct fuel plus fuel in capital and equipment. Option B also includes estimate for energy costs of labor and government services

□Components of drilling costs from National Petroleum Council[1]

■Based on Standard Industrial Classification Manual, U.S. Bureau of Census.

•Energy intensity factors for option A from Hannon et al[10], under option B from Costanza.[11] Because Costanza used only an 87 sector breakdown of the economy, energy intensity factors for all components were not available under option B.

▲Dollar and energy costs for fuel and water services were assumed to be 50% fuel and 50% water services. The energy intensity for fuel sectors was calculated to be 1,898,796 BTU/$ under option A, and 2,300,000 BTU/$ under option B.

△Implicit Price Deflators were used to convert to constant 1972$.

✡From Carlson and Underhill.[58] Costs were scaled down for a single well system.

○From Johnson et al[12] and Abdulrahman.[9]

*From National Petroleum Council. Fixed costs represent annual charges. Variable costs are in 1972 cents per barrel.

option *A*, energy intensities calculated by Hannon *et al.*[10] were used. These energy intensities include only direct fuel use and indirect fuel embodied in other commodities and services. Under option *B*, energy intensities calculated by Costanza[11] were used. These include not only direct and indirect fuel use as in option *A*, but also an estimate of the energy costs of labor and government services. As the values in Table 2 indicate, adding labor and government services increased the energy intensity factors, especially for those tasks which are relatively labor intensive (e.g., the moving and construction of the drilling rig, and geologic and engineering services).

The total energy cost of a well divided by its total constant dollar cost produces an energy intensity factor (Btu/$) for the well as a whole. This figure represents the total energy required, directly and indirectly, to produce an average dollar worth of a natural gas well in southern Louisiana. Under option *A* (excluding labor and government services), the average energy intensity was 139,463 Btu/1972$. It was 177,242 Btu/1972$ under option *B*. The energy intensity factor can be applied to the dollar cost calculated for a particular prospect drilled to a certain depth in a given year to produce the total energy cost of a geopressured well.

Dollar and energy cost calculations for site preparation, separation and disposal plant costs, and operation and maintenance costs were calculated in a similar manner (Table 2). The

National Petroleum Council[1] estimated direct fuel costs for reinjection to be 1.5 ft^3 of natural gas (1530 Btu) per bbl of fluid reinjected.

(b) *Energy outputs*

Methane extraction was calculated using a model developed by Johnson *et al.*[12] and later modified by Abdulrahman.[9] For each prospect being analyzed, physical parameters such as depth and volume of reservoir, temperature, salinity, porosity, and permeability are read into the model which calculates brine production and methane content (in standard cubic feet (scf) per bbl) of the brine produced. In calculating the potential for methane extraction, the model used a stochastic Monte Carlo simulation technique to account for uncertainty of some of the reservoir parameters. The figures used in this analysis are the mean estimates from the Monte Carlo simulations.

Initial fluid production rates in the model were set at 40,000 bbl/day, the theoretical maximum rate thought possible based on current petroleum and reservoir engineering technology. The reservoir model allows the maximum producible brine flow rate, provided the wellhead pressure is abaove 500 psi, the pressure needed to deliver the gas to a distribution system.[9] As the reservoir is depleted, reservoir pressure begins to drop. The model cuts back fluid production when the pressure drops below the critical minimum threshold.

The potential for methane extraction was evaluated in 2 ways. First, 4 individual prospects considered to have the most attractive reservoir characteristics were analyzed. The extensive data gathering and analysis of potential geopressured sites throughout the Gulf Coast region as part of DOE's evaluation program indicated that these sites had the most favorable reservoir parameters. The prospects selected are in various stages of development as part of DOE's test drilling program. The prospects are the Pleasant Bayou well, located in Brazoria County, Texas which has been drilled and is now in advanced stages of production testing; LaFourche Crossing, located in LaFourche and Terrebonne Parishes in Louisiana; Gladys McCall in Cameron Parish, Louisiana, and Bayou Hebert in Vermilion Parish, Louisiana.

A base case scenario was also investigated to evaluate an average geopressured system. A set of best estimates of reservoir parameters for what a typical geopressured reservoir might have were obtained from Bassiouni *et al.*,[13] Dunlap and Dorfman,[14] Johnson *et al.*,[12] National Petroleum Council,[1] and Weise and Morton.[15] Reservoir parameters for the test sites and the base scenario are listed in Table 3. Comparison of the values between the test sites and the base case indicates that, in general, average reservoir conditions are estimated to be less conducive for brine production and methane formation relative to the test prospects, due primarily to smaller reservoir area.

One aspect of the four test sites should be emphasized. Despite the uncertainty that remains about their precise physical characteristics, enough is known to be able to distinguish them as the most favorable sites in the Gulf Coast region. The estimates of their potential to yield net methane energy should therefore be considered as an upper bound for geopressured gas extraction in the region, given the current state of extraction technology and geological knowledge. The average well drilled in the region will tend to have significantly less favorable reservoir parameters, and therefore provide less methane energy.

Table 3. Reservoir parameter estimates for the four test sites and the base case scenario. Test site parameters from Abdulrahman.[9]

	Bayou Hebert	Gladys McCall	Lafourche Crossing	Pleasant Bayou	Base Scenario
Area (acres)	31881	6028	19679	15978	5120
Temperature (F)	234	298	253	306	250
Pressure (psia)	10800	13982	13017	11168	13000
Salinity (ppm)	135000	100000	45000	140000	96000
Thickness (ft)	200	350	180	140	250
Permeability (md)	20	71	121	115	30
Porosity (%)	22.5	15.5	25	20	20
Volume (cu. mi.)	1.89	0.62	1.12	0.52	0.30
Depth (ft)	13500	15500	15225	14674	16000
Compressibility	.000008	.000008	.000008	.000008	.000008

5. RESULTS

Under option *A* (excluding labor, government, and environmental energy costs), all 4 test sites recovered the large energy costs incurred during the drilling and preparation year of the project by the end of the first year of production (Fig. 2, a–e). Net energy yield from 2 of the prospects, Pleasant Bayou and Gladys McCall, fell to zero 12 years after production began, giving them only a 10 yr lifetime as net producers of energy. Only LaFourche Crossing and Bayou Hebert remained net producers of energy for the entire 20 years. Net energy yield declined over time for all the prospects, and rather precipitously in the case of Pleasant Bayou and Gladys McCall. The rapid decline in gas production is a direct result of the decline in brine production after the first few years due to the relatively small volumes of these two reservoirs and also to the cutbacks in flow rates necessary to maintain the critical wellhead pressure. Total

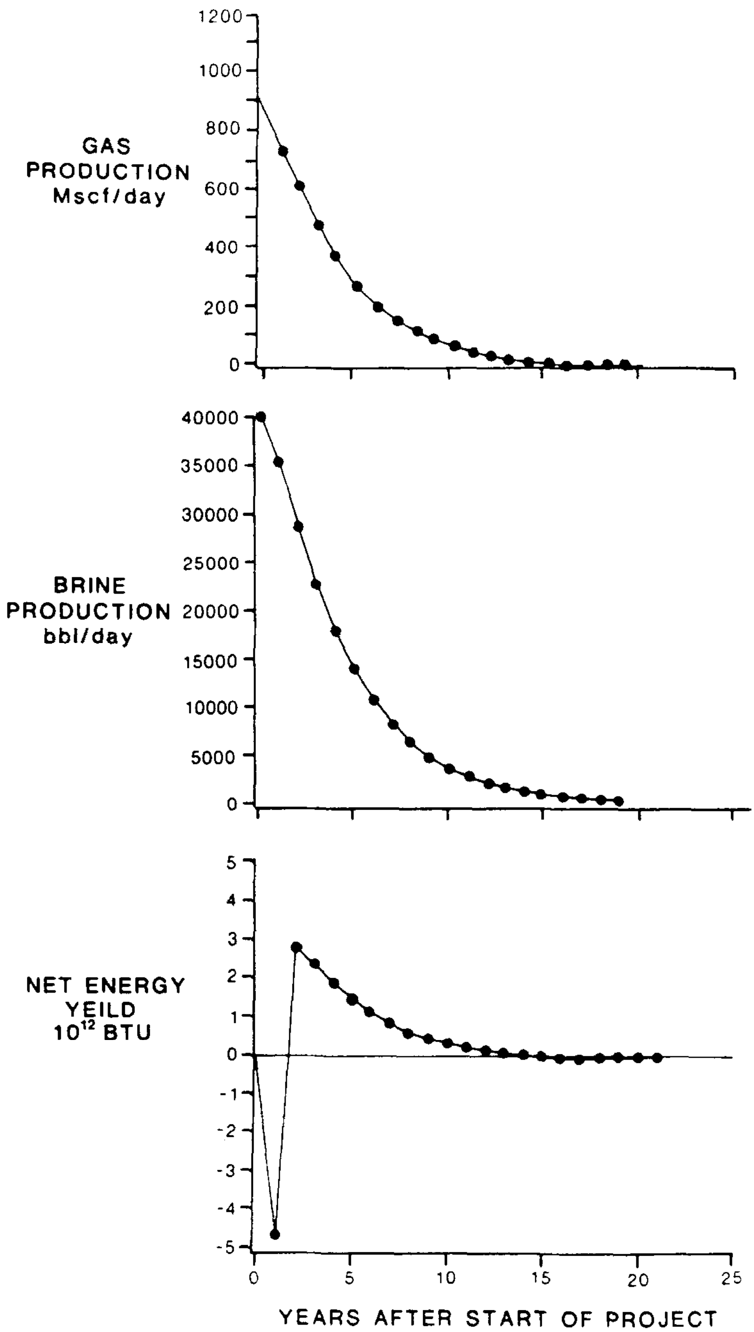

Fig. 2(a).

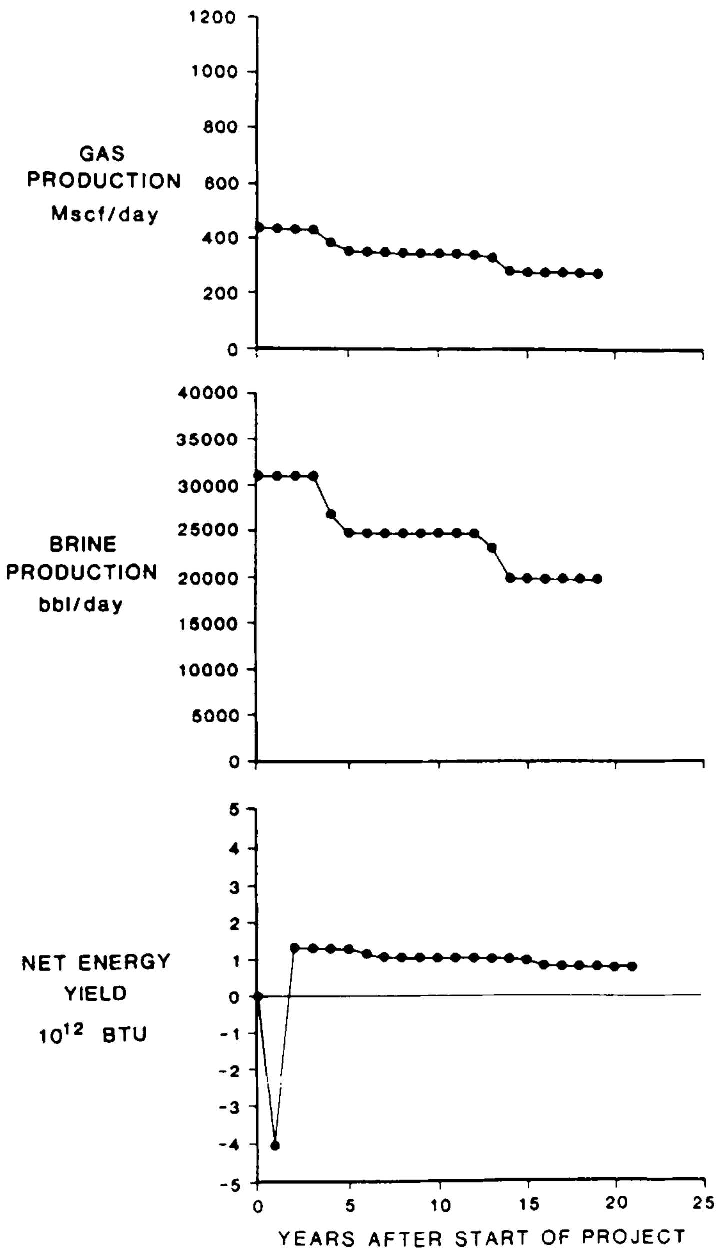

Fig. 2(b).

net energy yield ranged from 0.7×10^{12} Btu in the case of Pleasant Bayou and Bayou Hebert to about 6.0×10^{12} Btu in the case of LaFourche Crossing.

EROI values for the test sites ranged from about 1.8:1 for Pleasant Bayou to about 5.4:1 for LaFourche Crossing under option *A* (Table 4). Due to the precipitous decline in their production of gas in the second 10 years, the net yield and EROI for Pleasant Bayou and Gladys McCall were greater after 10 years than after 20 years, because energy costs for operation and maintenance and reinjection exceeded methane production during the second ten years.

In the base scenario under option *A*, the initial drilling and preparation energy costs were not recovered until after the fourth year of fluid production (Fig. 2e). The net yield of methane energy fell to zero 16 years after fluid production began, giving an effective life of 12 years of net energy yield. The EROI values for the base scenario indicate that, given the uncertainty that

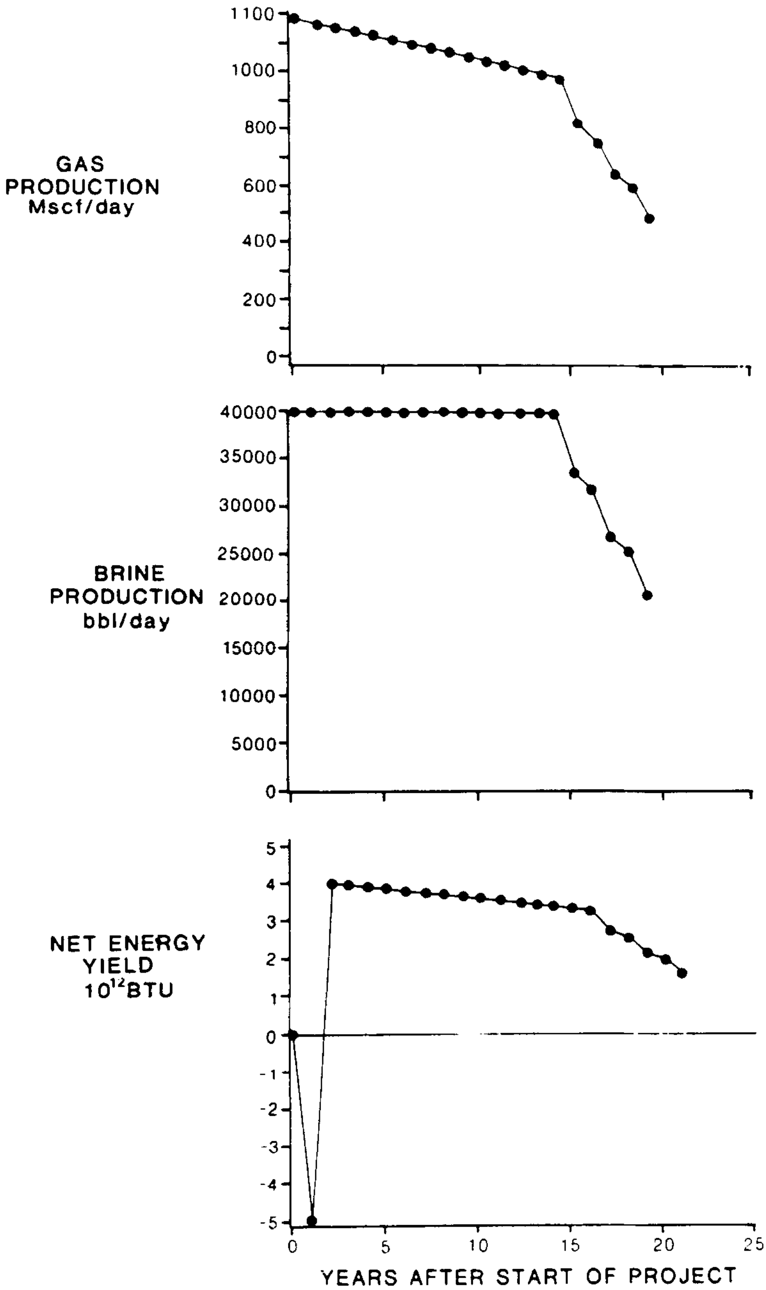

Fig. 2(c).

still remains about their exact reservoir parameters, reservoirs with parameters similar to the base scenario are borderline in terms of their potential to yield net energy.

Including the energy costs of labor and government services reduced the net energy yields and EROI ratios in all instances (Table 4). In the base scenario, the EROI ratio dropped below the energy break even point when the costs of labor and government services were included.

(a) *Environmental impacts*

The empirical evaluation of environmental services in a cost-benefit framework is a difficult but critical problem. Due to their common property nature and difficulty in quantification, environmental services have often been ignored in cost-benefit analysis despite the fact that all human economic activity is supported by a wide variety of natural resources (e.g., clean air and water, etc.).

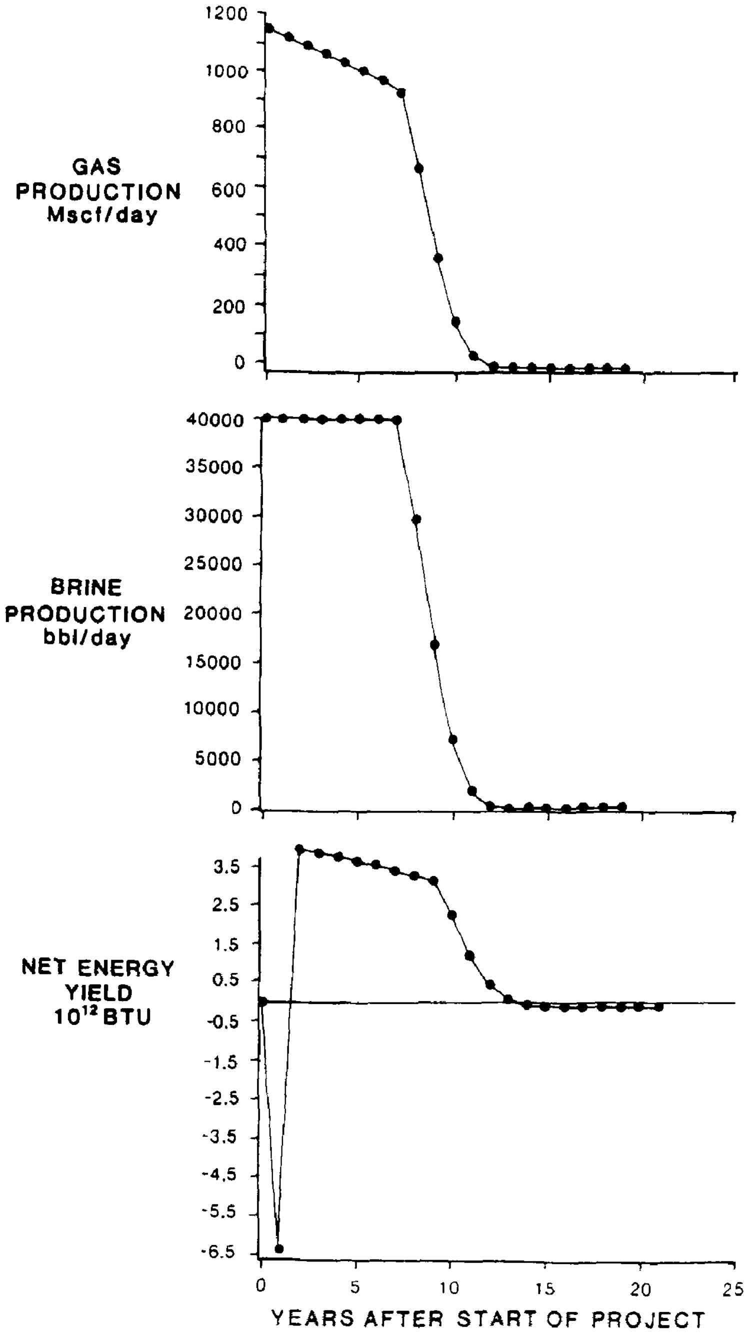

Fig. 2(d).

Economists generally favor willingness-to-pay schemes to evaluate environmental services.[16] Ecologists and many energy analysts generally favor an energy-based evaluation of natural resource contribution to economic activity. Recent research in this area has provided a framework and preliminary data for implementing this type of analysis.[17-21] Both energy analysis and willingness-to-pay approaches to evaluating environmental services require substantial refinement. They do, however, provide a basis from which preliminary investigations of natural resource contributions to human economic systems can be made.

Subsidence of the ground surface due to fluid extraction and its physical, biologic, and socioeconomic consequences is likely to be the most severe environmental impact associated with the development of geopressured resources.[22] The direct and most severe impacts from

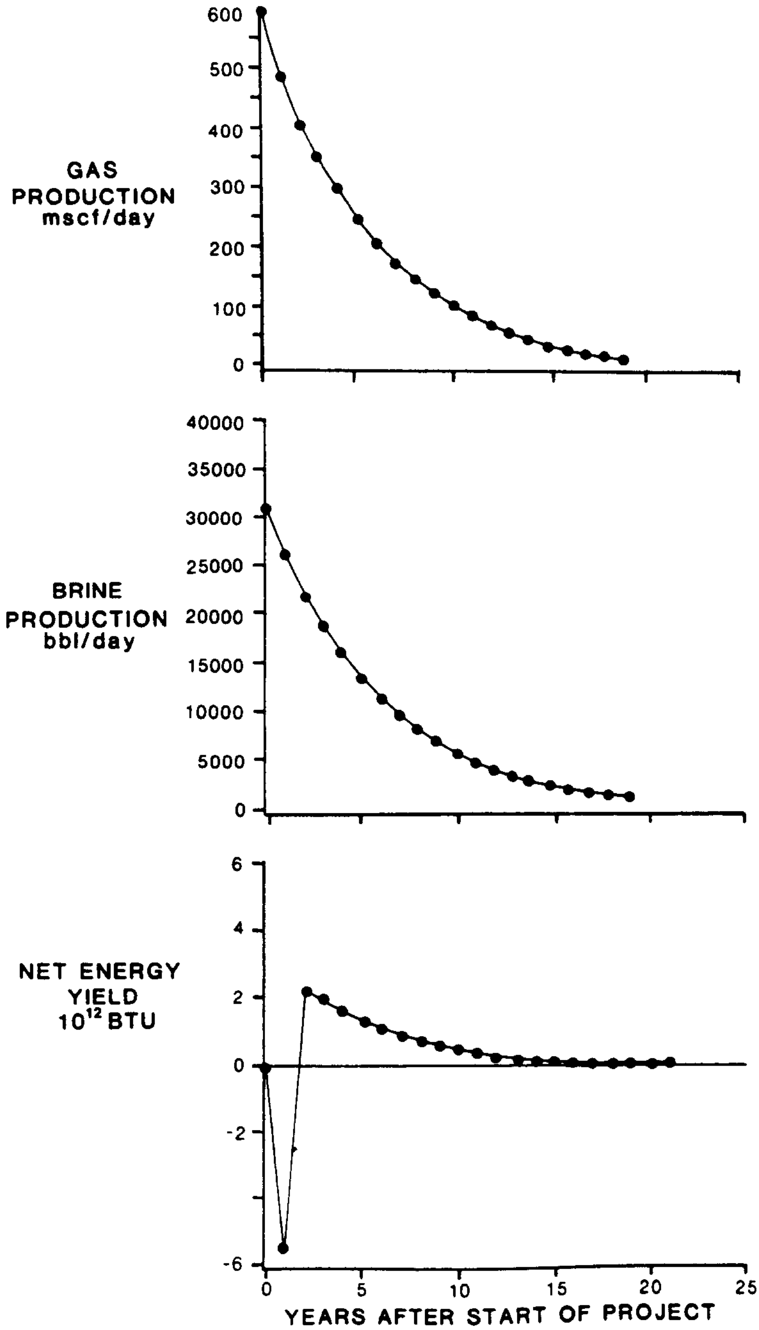

Fig. 2(e).

Fig. 2. Brine and methane extraction and net energy yield for (a) Pleasant Bayou Herbert, (c) LaFourche Crossing, (d) Gladys McCall, and (e) the base case scenario.

subsidence are likely to be on the physical and hydrologic regimes of the region, where the alteration of water flow patterns in existing marshes, bays, estuaries, rivers, and groundwater may occur. Depending on the particular location of a well, even small amounts of subsidence (several inches) could have serious impacts. Due to natural subsidence from compaction of coastal sediments and coastal downwarping combined with human-induced subsidence from canals and maintenance dredging, Louisiana is already losing to open water about 40 mi^2 of wetland per year.[23] Even slight amounts of subsidence in many coastal areas could therefore accelerate the rate of wetland loss. Conversely, the same amount of subsidence in an upland or slightly hilly region may not have any deleterious effects. The potential impact of subsidence

Table 4. Summary of fluid and methane extraction, energy costs and net energy return. Option A includes direct fuel plus fuel embodied in capital and equipment. Option B includes estimate of energy costs of labor and government services. All values in 10^{12} Btu unless otherwise noted. Totals may not add due to rounding.

Prospect	Avg. fluid prod. (bbl/day)	Avg. gas. prod. (mcf/day)	Total gas prod.	Total energy cost A	Total energy cost B	Net energy yield A	Net energy yield B	EROI (ratio) A	EROI (ratio) B
Bayou Hebert									
10 yrs.	27478	386	1.44	0.74	0.77	0.69	0.67	1.94	1.87
20 yrs.	24567	344	2.56	1.03	1.47	1.53	1.09	2.48	1.74
Pleasant Bayou									
10 yrs.	18631	388	1.44	0.73	1.00	0.71	0.44	1.97	1.44
20 yrs.	9832	206	1.54	0.84	1.20	0.70	0.34	1.83	1.28
Gladys McCall									
10 yrs.	36627	960	3.57	1.05	1.48	2.52	2.09	3.40	2.41
20 yrs.	18772	490	3.65	1.16	1.68	2.49	1.97	3.14	2.17
Lafourche Crossing									
10 yrs.	40000	1050	4.56	0.95	1.30	3.61	3.26	4.80	3.50
20 yrs.	36960	984	7.23	1.34	1.79	5.89	5.44	5.39	4.03
Base Case									
10 yrs.	15452	297	1.02	0.79	1.08	0.23	-0.06	1.29	0.94
20 yrs.	9468	181	1.19	0.91	1.30	0.28	-0.11	1.30	0.91

induced by the withdrawal of geopressured fluids must therefore be considered on a site specific basis.

Several analyses have provided preliminary estimates of the degree of subsidence that might be expected based on laboratory experiments[24] and analogies to other coastal regions where large amounts of liquid hydrocarbons and brine have been extracted for a long period of time.[25] Four prospects in Texas and Louisiana were evaluated in terms of their potential for subsidence, based on most likely reservoir parameters, and a more pessimistic worst case scenario.[24]

Estimates of total vertical subsidence made by EDAW, Inc.[24] ranged from 0.05 to 0.8 ft in the best case, to as much as 4 ft in the worst case scenario. The most likely estimate was 0.05 in./yr. This value falls within the range of 0.03 and 0.9 in./yr reported by Grimsrud *et al.*[25] for the area around Chocolate Bayou, Texas, where the withdrawal of liquid hydrocarbons and brine fluids has been on-going since the 1940s.

While acknowledging the preliminary nature of these values, the estimates for the total surface area affected by subsidence can be used to calculate the energy costs of subsidence for a prospect based on the following assumptions: (i) the prospect is located in a coastal wetland and (ii) any change in the elevation of the marsh due to subsidence will result in the marsh being inundated and converted to open water. These assumptions obviously exclude all upland sites and sites within the coastal zone that are in areas of active land building, but do serve as a useful starting point since a good share of the coastal wetlands in Louisiana are very sensitive to small changes in elevation.[26,27]

Based on these assumptions, the energy cost of subsidence can be estimated from

$$\text{energy cost} = (\text{area}) \times (\text{energy value/area}) \tag{2}$$

Estimates of the energy value of wetlands as solar energy collectors and their dollar values as producers of fish, wildlife, and recreation services have been attempted. These estimates are summarized in Table 5. Problems exist with all these estimates, and there is a high degree of imprecision inherent with any one technique. Using several independent methods, however, estimates of the energy value of wetlands converge on about 30×10^6 Btu/acre/yr, or about \$300/acre/yr.

Table 5. Estimates of embodied energy and economic value of a year's primary production in Louisiana Coastal wetlands.

Approach	Embodied energy value ✱ (10 BTU/acre/yr)	Dollar value □ (1972$/acre/yr)	Reference or note
ENERGY ANALYSIS:			
Biological production	39.3	(393)	■
WILLINGNESS-TO-PAY:			
Consumer Surplus	(9.5)	95	44
Gross Benefits	(14.8)	148	36
	(21.6)	216	54
	(33.4)	334	44
	(14.2)	142	44
Net Benefits	(14.5)	145	•
Replacement Value	(1575.6)	15756	36
	(191.6)	1916	▲
Total Range	9.5 - 1575.6	95 - 15756	
Reasonable Range	9.5 - 39.3	95 - 393	△
Most Reasonable Point Estimate	30	300	✲

✱Converted to BTU of fossil equivalent (FE). Numbers in parentheses converted from dollar value estimates using a conversion factor of 100000 BTU FE/1972$ calculated by Costanza.[11]

□Numbers in parentheses were converted from embodied energy estimates using the same conversion factor as used in above.

All others were reported in current dollars and were converted to 1972$.

■Based on the difference in gross primary production between wetlands (average of salt, brackish, and fresh marsh) and open water (average of saline, brackish, and fresh) of 786 × 10^6 BTU biomass/acre/yr. This was converted to fossil equivalents (FE) using a conversion factor of .05 FE/biomass equivalent[56] yielding 39.3 × 10^6 BTU FE/acre/yr.

•From Mumphrey et al's[44] gross benefits estimate of 334 1972$/acre/yr adjusted to exclude some of the value added due to factors other than the wetlands themselves. Based on dockside rather than retail value of fisheries.and trapping.

▲Based on costs to restore the marsh to its original condition. Figures are conservative since the cost estimates do not take into account special problems of Louisiana marsh. Revegetation values calculated in 1978 assumed 19,360 plant sites/acre, $0.19 planting cost per plant site plus $0.45 plant cost/plant site, or $0.64 total cost/plant site. Total costs estimated at $52,000/acre of marsh restored excluding site leveling. At a six percent discount rate this compounds to $1,916/acre/yr in constant 1972 dollars.

△All of the estimates listed in this table suffer from conceptual and/or empirical problems. Although the total range was over three orders of magnitude, the replacement value estimates should probably be excluded since they probably overestimate the true value by a large factor.

✲Most of the willingness-to-pay estimates are probably under estimates because they include only a portion of wetland services used in the economy. The biological productivity estimate is probably an overestimate because not all the energy captured by the wetland system is useful to the economy. The average of the willingness-to-pay approaches (excluding the replacement value estimate) was $180/acre/yr (18 × 10^6 BTU FE/acre/yr). This figure, averaged with the biological productivity estimate yields a point estimate of about 30 × 10^6 BTU FE/acre/yr ($300/acre/yr).

Table 6. Estimates of the energy cost of subsidence from geopressured fluid withdrawal from a single prospect area. Option *A* uses an energy intensity factor the 19881 fuel/real GNP ratio. Option *B* uses the average energy intensity (including labor and government services) across an 87 sector breakdown of the economy as calculated by Costanza.[11]

Area of Subsidence (mi^2)	Energy Cost (10^{12} BTU) A Discount rate 1%			B Discount rate 1%		
	1%	3%	10%	1%	3%	10%
0	0	0	0	0	0	0
5	1.8	1.1	0.3	2.2	1.7	0.5
20	5.8	4.3	1.3	8.3	7.0	2.1
100	26.3	21.5	6.5	39.4	35.3	10.6

Estimates of the energy cost due to subsidence based on the foregoing are shown in Table 6. If 20 mi^2 were affected, the upper bound in EDAW's[24] best case scenario, comparison of the values for energy costs in Table 6 with the net energy yields in Table 4 indicates that the net energy gains of all the prospects except for Lafourche Crossing would be negated. In the most pessimistic case of 100 mi^2, the net energy gains from all of the prospects would be negated several times over by the environmental energy costs of subsidence. Based on these calculations, the impact area would have to be in the range of 0–5 mi^2 for the most promising test sites to remain net energy producers.

The imprecise nature of these estimates should again be emphasized. Many geopressured sites are not in coastal wetland areas, and not all those in wetlands are in areas where surface subsidence of a few inches will result in inundation and land loss. The wetland value estimates are also very imprecise. This analysis does, however, suggest that the potential environmental effects of geopressured gas development in the coastal region cannot be dismissed casually. In the upper range of subsidence rates currently thought most likely, land loss due to subsidence can negate much of the net energy yield from all but the most promising of prospects analyzed in this report. Continued monitoring of the test sites is necessary in order to determine more precisely the extent of surface subsidence. Additional research on the energy and economic costs of wetland loss is also necessary to improve the quantification of these potentially significant costs.

6. SUMMARY AND CONCLUSIONS

Geopressured gas is a vast but diffuse resource in the Northern Gulf Coast region. A well drilled virtually anywhere in the coastal region is likely to encounter brine deposits with dissolved methane somewhere between 6000 and 20,000 ft. The energetic and economic viability of a geopressured well is more difficult to evaluate than a conventional gas well, because the latter often includes distinct dry holes which are clearly unprofitable. It is essential to identify those minimum reservoir conditions that will allow for gas formation sufficient to make its extraction economically and energetically feasible.

The diffuse nature of geopressured gas resources combined with the large investment of energy and other resources required to exploit it make geopressured gas a marginal source of net energy. For geopressured gas to be a significant source of net fuel for the nation, large numbers of reservoirs with physical characteristics similar to Lafourche Crossing (see Table 3) must exist. Current information suggests this is unlikely. The EROI for an average geopressured reservoir is likely to be in the range of the energy-breakeven point, depending on specific reservoir parameters, especially salinity and areal extent (Fig. 3.). Estimates of average reservoir conditions may change with additional research and development. Since the onset of DOE's test drilling program, however, the original estimates for likely salinities have consistently been revised upward,[14] while estimates of typical reservoir area have been consistently revised downward. Both trends have the effect of reducing the potential EROI for a project.

(a) *Comparison with other net energy analyses*

Carlson and Underhill[58] calculated EROI values of 14–18 for geopressured gas. Their results are overly optimistic for several reasons. First, their analysis was based on pre-test drilling reservoir parameter estimates cited by DOW[6] which subsequent test drilling has proven to be

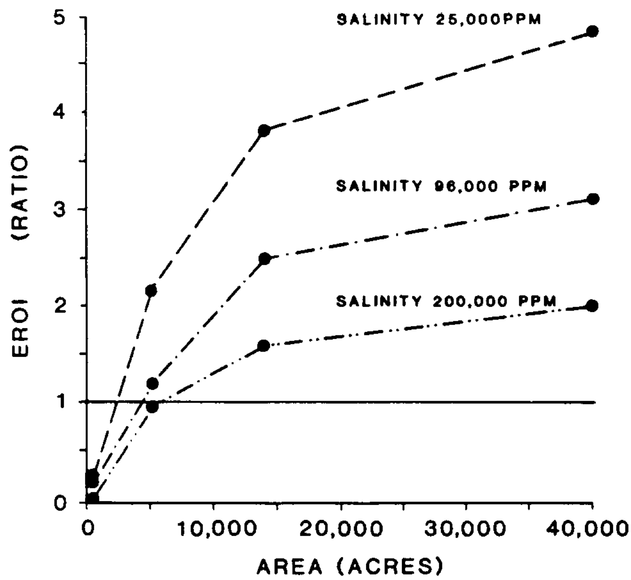

Fig. 3. Energy return on investment (EROI) for the base scenario as a function of salinity and reservoir area. Energy costs of labor, government, and environmental services excluded.

overly optimistic. DOW estimated the average methane content of geopressured brine to be 40 scf/bbl. The average methane content calculated in this analysis ranged between 20 and 27 scf/bbl. The lower methane content is due to higher salinities and lower reservoir temperatures than were estimated prior to the test drilling program. DOW also assumed a constant 40,000 bbl/day brine production. The model[12] used in our analysis accounts for the fact that production rates must be cut back periodically to maintain a critical minimum wellhead pressure. Average production rates calculated in our analysis ranged from 9500 to 37,000 bbl/day over a 20 yr period. It does not appear that many reservoirs exist that would be able to maintain a 40,000 bbl/day production rate.

Carlson and Underhill assumed drilling costs, the largest component of total energy cost, to be 50% drilling services and 50% tubing, etc. We incorporated more detailed cost breakdown of drilling given by National Petroleum Council[1] into the model developed by Wrighton[7] which accounts for the exponential increase with depth in drilling costs in southern Louisiana. Third, Carlson and Underhill included only direct fuel costs and fuel embodied in capital and equipment used. Our analysis also includes an estimate of the energy costs of labor, government and environmental services.

(b) *Comparison with other sources of natural gas*

Results of our analysis indicate that large scale investment in drilling projects designed solely to extract geopressured gas is not a desirable action at this time. Conventionally produced natural gas in the late 1970s had an EROI between 20 and 40, depending on what energy costs are included.[28,52] Synthetic gas from coal may give an 18:1 return on direct and indirect fuel costs.[53] Individual sites analyzed above produced between 0.7 and 5.5×10^9 scf of gas (net) over a 20 yr period. Conventional deep gas wells in Louisiana as of mid 1981 produced 17×10^9 scf/yr, or 34×10^9 scf over a 20 yr period.[29] Wrighton[30] cites median gross daily production rates of about 8.6×10^6 scf for 44 gas wells in the Tuscaloosa trend. The mean gross production rate for the 4 test sites we analyzed was about 500 mcf/day, and only 180 mcf/day for the base scenario.

There is an alternative option that could improve slightly the EROI ratios calculated here, although it would be limited in its applicability. It has been termed the piggy-back option, whereby a conventional gas well that has been drilled and determined to be a dry hole is converted to a geopressured well.[12] Quitzau[8] found that this option improved the net present value compared to a well drilled solely to produce geopressured gas. This option is limited, however, by the reduced brine production through the smaller (3.5 in.) tubing, and by the fact that conventional natural gas wells are not always on sites that are attractive geopressured gas sites as well.

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