

Polygeneration of Hydrogen from Biomass Using Electrochemical Reforming (ECR)

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Abstract

This paper describes a new approach to distributed polygeneration systems using waste heat from power generation, and/or other renewable sources such as geothermal or solar heat, to drive an electrochemical reformer system that converts methanol efficiently into separate streams of hydrogen and carbon dioxide. Methanol, which can be economically made from the biogas produced by an anaerobic digester, fed with organic waste or biomass, becomes an intermediate between these renewable, domestic energy sources and hydrogen. With the carbon already captured prior to combustion, the hydrogen will be supplied directly to internal combustion engines, turbines and fuel cells for distributed polygeneration of electricity, heat and cooling. This ECR technology represents a step-change that improves energy efficiency and is scalable from 100 watt to 2MW modules. The solid output of the digester can also be combusted to produce additional saleable energy, gasified to produce liquid fuels through the Fischer-Tropsch process, or used as fertilizer. Waste heat from various processes used in the polygeneration process will be recovered by the anaerobic digester and/or the ECR. The ECR can be thought of as an electrochemically active heat sink that will dramatically reduce or eliminate the need for external water for cooling thermal plants. Finally the liquid effluent can also be used as an organic fertilizer, thereby creating a zero-waste biorefinery.

The anaerobic digesters and methanol synthesis systems used in these biorefineries are commercially available and well-proven worldwide. The only new technology proposed for these systems is the hydrogen generator. This new approach to hydrogen generation, called electrochemical reforming (ECR), is based on a novel liquid phase reforming process originally patented by the late Dr. Patrick Grimes[1,2] and developed at Gibbs Energy. Liquid phase ECR provides unique advantages over conventional steam reforming. This is because liquid phase reforming opens up novel electrochemical pathways that are not accessible in conventional gas phase steam methane reforming (SMR). Potential advantages include; i) higher efficiency than steam methane reforming, ii) lower reforming temperatures that can utilize available waste heat (<400°C), iii) simplified product clean-up, iv) reduced gas compression requirements.

Keywords

hydrogen, reforming, electrochemical reforming, aqueous-phase reforming, biorefinery, biomass, polygeneration

Introduction

Electrochemical reforming was first demonstrated by Dr. Patrick Grimes at Allis-Chalmers in the early 1960s as part of their work on a fuel cell tractor [3,4] and in support of the US Department of the Army program evaluating various approaches to the field synthesis of fuels. This program was called Energy Depot [5]. Throughout his subsequent career, Dr. Grimes continued exploring new conversion processes but always with a focus on the input fuel sources and their limiting chemical potential [6]. In 2003, Gibbs Energy was started with the intention of creating additional intellectual property and proving the thermodynamics and economics of this approach to improving the efficiency of processes [7]. Since the initial development program was funded by ConocoPhillip, the transportation market was the primary focus. Hydrogen was chosen as a target fuel since, in the long-term, it holds the promise of being a transportation fuel, but it is already the second most expensive input to the oil industry. As Table 1 shows below, current transport fuels have a hydrogen-carbon (H/C) ratio of about 2.18:1. Crude oil only has about a 2.07:1 ratio and the balance has to come from an external hydrogen source, generally a steam methane reformer (SMR). Today, the average consumption of hydrogen for this purpose is about 32,640,000 kg (~12.8 billion scf or 362,503,540 Nm³) per day [8]. This equals 756,966 barrels of oil equivalent ((BOE) 1 BOE = 6.185 GJ), or about the output of four average size refineries. Considering that biomass has an H/C ratio of only about 0.4:1, making up this massive hydrogen deficit poses a significant barrier its use as a cost-effective source of logistically compatible liquid fuels.

Energy Source	formula	C	H	O	water	H/C ratio	phase (STP)	btu/kg	MJ/kg
Hydrogen	H ₂		100.0%				gas	134,510	143.45
Methane	CH ₄	74.9%	25.1%			4	gas	49,500	52.79
LNG	CH ₄	74.9%	25.1%			4	liquid	52,326	55.80
BioGas	C _{1.1} H _{2.5} O	41.6%	7.9%	50.4%		2.27	gas	11,797	12.58
Diesel	C ₁₂ H ₂₆	84.6%	15.4%			2.18	liquid	43,379	46.26
Crude Oil	C _{7.1} H _{14.7}	85.2%	14.8%			2.07	liquid	43,167	46.04
Wood	C ₅ H ₂ O ₃	52.2%	2.6%	41.7%		0.40	solid	17,600	18.77
Coal (hard)	C _{18.8} H _{18.7} O	67.0%	6.6%	4.8%	12.0%	0.90	solid	22,791	24.31
Coal (soft)	C ₂₀ H _{5.3} O	55.0%	2.0%	4.0%	25.0%	0.66	solid	22,669	24.18

Table 1: H/C Ratios and Energy Content of Various Fuels

As the quality of available oil resources declines, and the fuel quality standards continue to increase, the demand for hydrogen is only going up from the current 2.8-5.6 Nm³ per barrel to as much as 15-28, a point some refineries processing heavy oils are already at. With this incremental growth in mind, Gibbs focused on a modular design that could be readily integrated into refinery growth plans. Work was done on the demonstration of a thermally driven system, using 200C waste heat, which is readily available in any refinery, as the driving force. Methanol was the first fuel tested and a complete system, with an electrochemical reformer, integrated carbon-capture and electrolyte regeneration was built and operated for several years [9]. In parallel with the lab work, extensive economic modelling was done to determine the market potential for the proposed ECR system. After two years of integrated system operation, updated models were done reflecting revised costs based on the performance data. Somewhat shockingly, we discovered that the technology was far more scaleable and cost-effective, than originally thought, and the projected costs and efficiencies opened up the possibility of methanol as an alternative method of moving natural gas to distant markets as well as the possibility using the ECR as a pre-combustion carbon capture system that would actually **increase** the efficiency of the power plant in which it was installed.

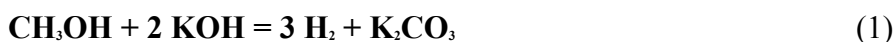
Finally, ways were sought to see how this technology could be used to recycle some of the carbon which nature has already recaptured as biomass. This led to the development of the business plan and system configurations that will be described in this paper.

Technical Approach

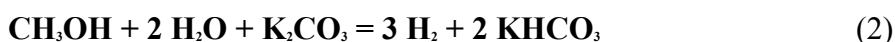
This new approach to hydrogen generation, called electrochemical reforming (ECR), is based a novel liquid phase reforming process originally patented by the late Dr. Patrick Grimes [1]. Liquid phase ECR provides unique advantages over conventional steam reforming. This is because liquid phase reforming opens up novel electrochemical pathways that are not accessible in conventional gas phase steam reforming. Potential advantages include:

1. Higher efficiency than steam methane reforming (SMR);
2. Lower reforming temperatures that can utilize available waste heat (<400°C);
3. Simplified product clean-up;
4. Reduced gas compression requirement.

Figure 1 below shows a generic flow chart with all of the elements necessary to create a liquid-phase ECR system. The simplest possible system using a redox reactor requires the following elements: one oxidizable reactant; one reducible reactant; electrically conductive catalyst material; one ionically conductive electrolyte; external energy addition; one desired product; and one by-product. Although the ECR can use a wide range of primary feedstocks, methanol was chosen first, because of its favorable thermodynamics as well as it being an economical, commercially available fuel. Initial experimental work for ECR hydrogen generation was preformed was conducted in KOH electrolyte. The overall ECR reforming reaction in hydroxide was:



Later work was performed in potassium carbonate electrolytes. The reaction in carbonates is:



In contrast, the overall reaction for steam reforming or liquid phase reforming at pH<7 is:

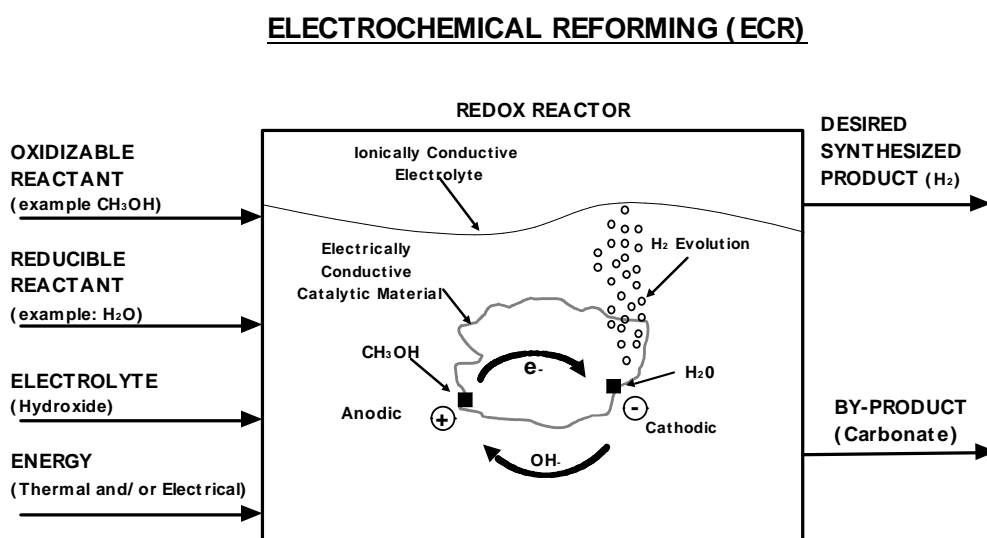


Figure 1: Grimes' ECR Process Flow

The ionically conductive material is liquid caustic electrolyte, such as an alkali hydroxide or

carbonate. Reforming a fuel, such as methanol in alkaline electrolytes increases the Free Energy driving force as compared to conventional gas phase or liquid phase reforming as shown in Figure 2. (Note; a negative free energy means that a reaction is thermodynamically favorable. A positive free energy is unfavorable.) Steam reforming of methanol is typically conducted at 250-350°C. Increasing reaction temperature increases the thermodynamic driving force and the rate of reaction. The thermodynamic driving force in KOH (at pH 14) or in K₂CO₃ (at pH 11) is much more favorable than steam reforming even at much higher temperatures. This shows that alkaline reforming will be active at much lower temperatures than steam reforming. This additional free energy advantage arises from the acid-base reaction between CO₂, a weak acid, and KOH or K₂CO₃, strong bases. Experimental data confirmed that the higher the pH, the greater the hydrogen generation rate and reaction selectivity. In hydroxide electrolytes, purities above 99% were achieved without any cleanup. Carbonate electrolytes dropped this figure to about 98.5%.

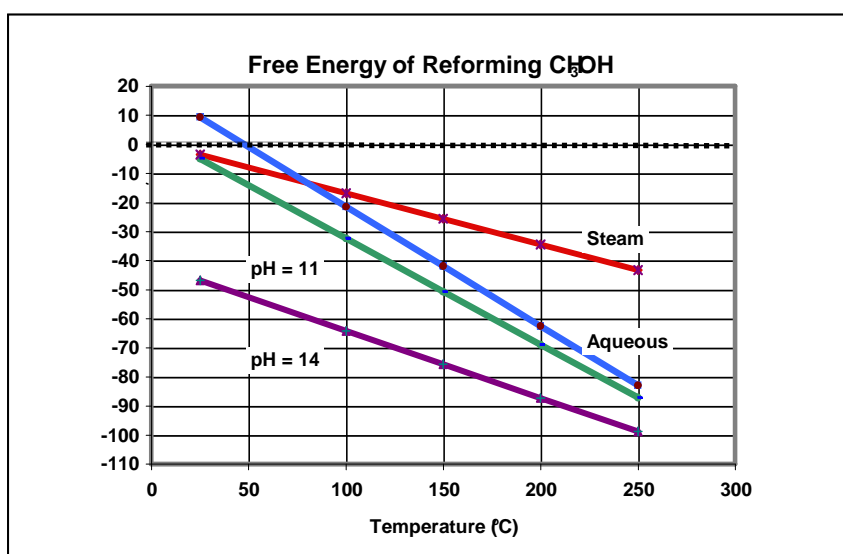


Figure 2: Comparison of Free Energy for Methanol Reforming in Various Media



Figure 3: Batch and Continuous Flow Test Stands

Figure 3 shows the test stands for the batch and continuous flow reactors where the ECR development work was done. Additional stands were used for the development of the electrolyte regeneration systems and half-cell reaction tests. Almost all of the data gathered was on methanol, since it was a readily available feedstock with a well understood cost. But, glucose and isopropyl were also tested to confirm the efficacy of the thermodynamic models and see if there was the possibility of direct utilization of biomass as a feedstock. The preliminary results of this work were promising, but the biomass-methanol-hydrogen pathway

2nd European Conference on Polygeneration – 30th March -1st April 2011 – Tarragona, Spain was chosen as the configuration with the least amount of technical risk to be followed for the initial stages of commercial exploitation.

Thermodynamics

In all cases, extensive thermodynamic modelling was done on the reactions using both purchased and proprietary software. In cases where commercially available tables lacked necessary data, Gibbs generated it internally in the lab. The experimental data validated these models and the summary of the energy required to generate hydrogen from methane, methanol, carbon and water are shown in Table 2 below. The top yellow cell shows the energy required to make a mole of hydrogen using a conventional SMR, which accounts for 95% of the hydrogen produced and the lower yellow cell shows the energy required for water electrolysis, which produces the remaining 5%. A comparison of the two readily explains the difference in market share. Also, please note that these figures do not include the additional energy required for gas separation, where needed, and mechanical compression. Both of these requirements are dramatically reduced by the ECR.

	fuel	temp °C	ΔG kcal per mole fuel	ΔH kcal	ΔG kcal per mole H ₂	ΔH kcal	cell voltage	system efficiency	mechanical compression needed	gas separation needed	CC energy penalty	CC capital penalty
CENTRALIZED												
Steam Reforming	CH ₄	850	-38.77	40.40	-9.69	10.10	-	65%	yes	yes	30%	40%
DISTRIBUTED												
Steam Reforming ¹	CH ₄	800	-35.21	42.00	-8.80	10.50	-	65%	yes	yes	30%	60%
HT Reforming ¹	CH ₄	700	-27.86	45.17	-6.97	11.29	-	65%	yes	yes	30%	60%
Autothermal Reforming ¹	CH ₄	650	-24.07	46.74	-6.02	11.69	-	55%	yes	yes	30%	60%
Partial Oxidation ¹	CH ₄	600	-93.04	-11.36	-23.26	-2.84	-	50%	yes	yes	30%	60%
Electrochemical Reforming (t) ³	CH ₄	400	-1.89	29.95	-0.47	7.49	-	86%	no	no	-	-
Electrochemical Reforming (e)	CH ₄	25	17.77	34.80	4.44	8.70	0.09	78%	no	no	-	-
Steam Reforming ¹	CH ₃ OH	280	-18.03	25.95	-6.01	8.65	-	65%	yes	yes	30%	60%
Electrochemical Reforming (t) ³	CH ₃ OH	200	-17.71	2.87	-5.90	0.96	-	113%	no	no	-	-
Electrochemical Reforming (e)	CH ₃ OH	75	-11.77	6.20	-3.92	2.07	0.04	87%	no	no	-	-
Carbonate Solution												
Electrochemical Reforming	C	200	-19.68	-2.51	-9.84	-1.26	-	88%	no	no	-	-
Electrochemical Reforming	C	50	-13.51	1.38	-6.75	0.69	0.04	87%	no	no	-	-
Bicarbonate Solution												
Electrochemical Reforming	C	200	-5.62	8.51	-2.81	4.25	-	88%				
Electrochemical Reforming	C	50	-0.66	11.01	-0.33	5.51	0.04	87%				
Electrolysis ²	H ₂ O	75	54.76	67.94	54.76	67.94	1.95	65%	no	no	-	-
¹ system efficiency calculations include heat input, gas separation and compression costs												
² electrolysis system efficiency and CC energy penalty are based on the use of renewable electricity												

Table 2: Comparison of ECR, SMR & Electrolysis Energy & System Needs

Economics

From the outset, the goal of all of this work was to reduce the cost of hydrogen. Before work was begun, a preliminary model was developed to compare the potential cost of hydrogen from an ECR with an SMR as a function of the costs of natural gas and methanol. In order to confirm our assumption, in addition to extensive literature searches, both internal and external studies were done on these costs and projected trends. Also, quotes from vendors were obtained.

Two basic system configurations were modelled, one using bulk-phase reactors and another using a planar design more similar to other electrochemical systems. Although the bulk of the lab work was done in batch and continuous flow reactors, a planar configuration, similar to electrolysis, offers the best opportunity for scalability, both upward and down. The initial design target was for a 2,550 kg per day module (1,000,000 scf or 28,321 Nm³). This would fit in a standard 40' ISO shipping container. Later work showed that efficiency could be maintained all the way down to systems generating as little as 1 kg per day.

After the final capital and operating costs estimates were completed, and the thermal energy needs for the ECR operation were confirmed experimentally, the resulting cost projects opened up another potential market for the ECR, bulk energy transport. Since methanol synthesis can be done at much smaller scale than LNG, the ECR offers the possibility of making much of the world's "stranded" gas commercially recoverable. The summary of the energy efficiency is shown in Figure 4 below. (Please note that these figures do not include any increase in efficiency of an ECR system that was driven by waste heat.) Figure 5 shows the results of the cost and efficiency analysis described above.

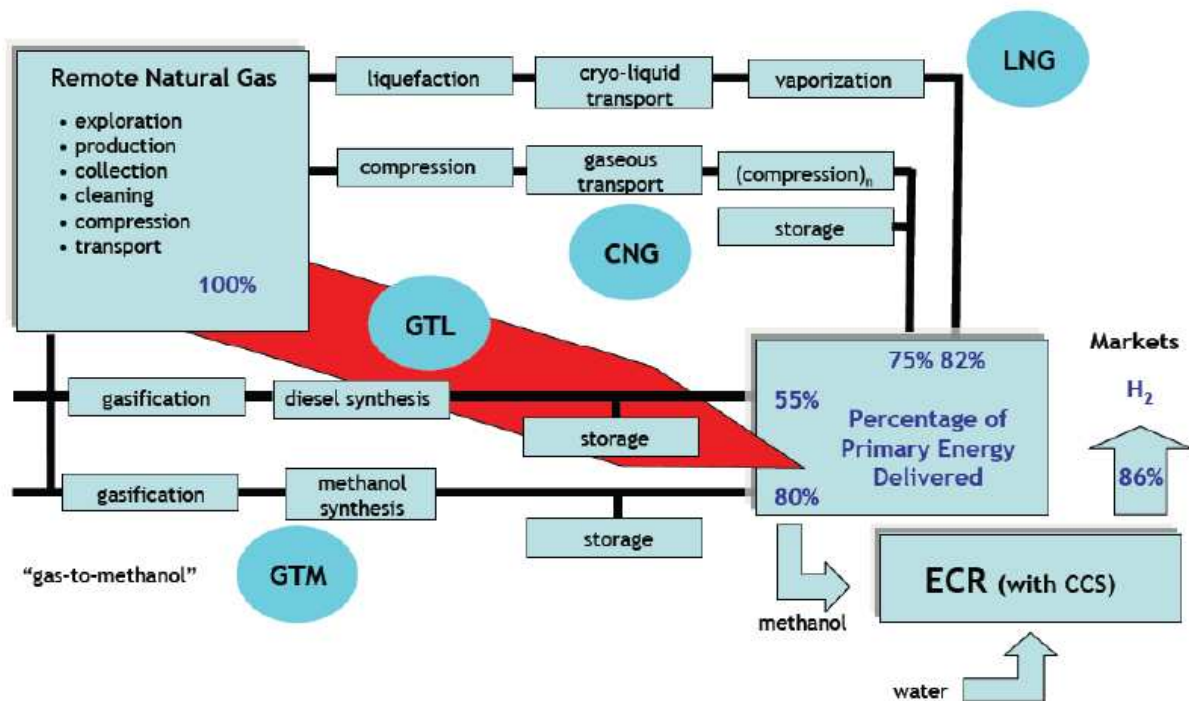


Figure 4: "Gas-to-Methanol versus Conventional Gas Transportation Technologies

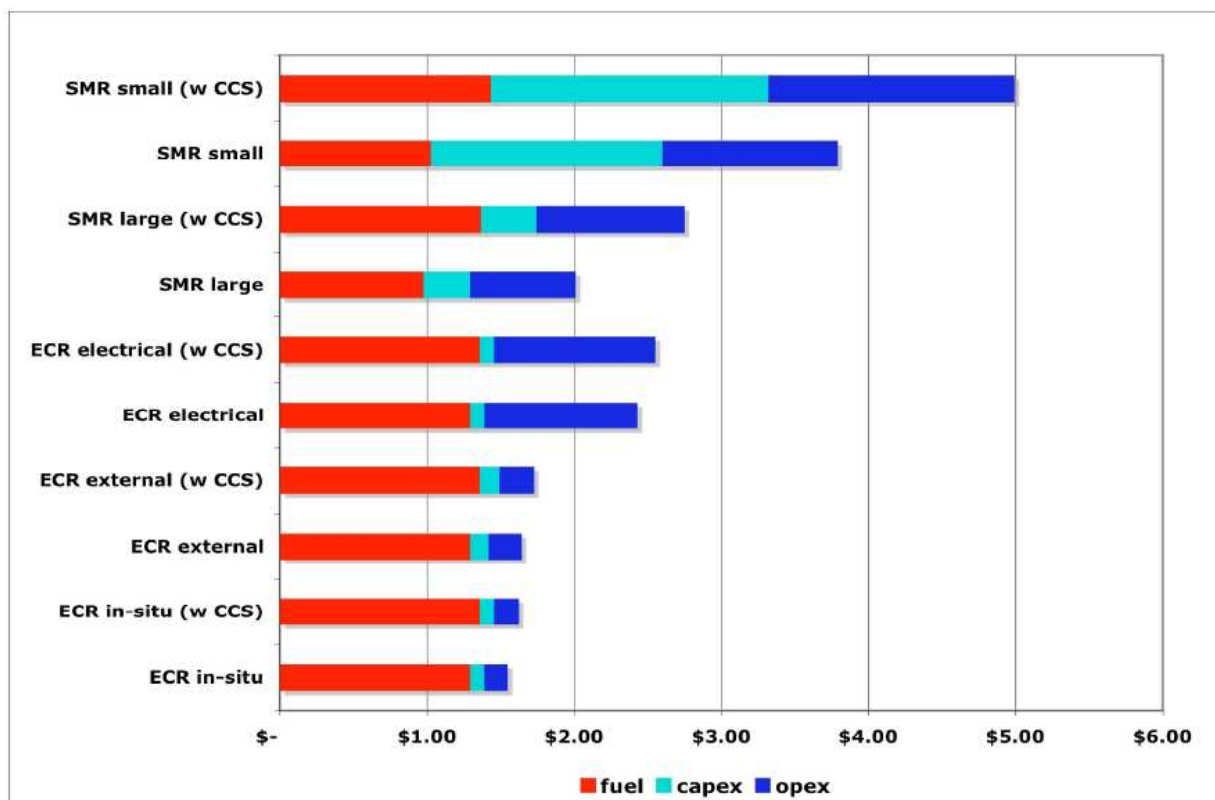


Figure 5: ECR versus SMR Hydrogen Cost Comparison

Figure 5 looks at a worst-case scenario where methanol costs \$1.00 per gallon. In discussions with potential vendors, methanol from Trinidadian gas could be landed on the US Gulf Coast for \$0.35/gallon and two US vendors quote \$0.50 per gallon for "wood alcohol". These prices, along with the carbon capture integral to the ECR process can have a major impact on the costs and markets of both hydrogen and power. (see Tables 3 & 4 below)

	Power Plants						Hydrogen Plants		
	Gas Combined Cycle		Supercritical Pulverized Coal		IGCC		Hydrogen Plants		
	ECR hydrogen	natural gas	ECR hydrogen	coal	ECR hydrogen	coal	ECR	SMR	
Efficiency (LHV)									
w/o capture	61.2%	55.7%	43.2%	43.2%	41.7%	41.7%	86%	65%	
w/ capture	70.5%	48%	54.7%	33%	52.7%	35%	86%	60%	
Fuel (\$/kWh)									
w/o capture	\$ 0.0245	\$ 0.043	\$ 0.0348	\$ 0.022	\$ 0.0361	\$ 0.023	\$ 1.468	\$ 3.077	
w/ capture	\$ 0.0199	\$ 0.050	\$ 0.0282	\$ 0.029	\$ 0.0292	\$ 0.028	\$ 1.189	\$ 3.323	
MeOH (\$/gallon)	\$ 0.35		\$ 0.35		\$ 0.35		\$ 0.35		
CH4 (\$/MMBTU)		\$ 7.00						\$ 6.00	
Coal (\$/MMBTU)				\$ 2.84		\$ 2.84			
Capital Expense (\$/kW)									
w/o capture	\$ 852	\$ 568	\$ 1,286	\$ 1,286	\$ 875	\$ 1,326	\$ 474	\$ 661	
% increase	0%	76%	0%	63%	0%	37%		0	
increase	\$ 0	\$ 432	\$ 0	\$ 810	\$ 0	\$ 491	\$ 5	\$ 132	
w/ capture	\$ 852	\$ 1,000	\$ 1,286	\$ 2,096	\$ 875	\$ 1,817	\$ 474	\$ 793	
Non-Fuel (\$/kWh)									
w/o capture	\$ 0.020	\$ 0.016	\$ 0.035	\$ 0.035	\$ 0.023	\$ 0.035	\$ 0.489	\$ 1.026	
w/ capture	\$ 0.020	\$ 0.036	\$ 0.035	\$ 0.061	\$ 0.023	\$ 0.050	\$ 0.396	\$ 1.108	
Cost of Electricity (COE) (\$/kWh)									
w/o capture	\$ 0.045	\$ 0.059	\$ 0.070	\$ 0.057	\$ 0.059	\$ 0.058	\$ 1.96	\$ 4.10	
w/ capture	\$ 0.045	\$ 0.066	\$ 0.070	\$ 0.090	\$ 0.059	\$ 0.078	\$ 1.59	\$ 4.43	
Savings	48%		23%		24%		64%		
Emissions (kg CO2/kWh)									
w/o capture	-	0.367	-	0.762	-	0.773	-	43.28	
w/ capture	-	0.051	-	0.114	-	0.108	-	6.06	
Cost/tonne CO2 captured	\$ 0.00	\$ 73.82	\$ 0.00	\$ 42.97	\$ 0.00	\$ 24.89	\$ 0.00	\$ 8.82	

Table 3: Conventional Hydrogen & Power Generation versus ECR

Distributed Power Plants									
	Gas Turbine Simple Cycle		Microturbine		IC Engine		Diesel Engine		
	ECR hydrogen	natural gas	ECR hydrogen	natural gas	ECR hydrogen	natural gas	ECR hydrogen	natural gas	
Efficiency (LHV)	w/o capture	33.9%	30.8%	28.0%	28.0%	28.0%	28.0%	28.0%	28.0%
	w/ capture	33.5%	22%	27.7%	20%	27.7%	20%	27.7%	20%
Capture Energy Penalty		1%	40%	1%	40%	1%	40%	1%	40%
Fuel (\$/kWh)	w/o capture	\$ 0.0444	\$ 0.078	\$ 0.0537	\$ 0.017	\$ 0.0537	\$ 0.017	\$ 0.0537	\$ 0.017
	w/ capture	\$ 0.0448	\$ 0.109	\$ 0.0542	\$ 0.024	\$ 0.0542	\$ 0.024	\$ 0.0542	\$ 0.024
MeOH (\$/gallon)		\$ 0.35		\$ 0.35		\$ 0.35		\$ 0.35	
CH4 (\$/MMBTU)		\$ 7.00		\$ 7.00		\$ 7.00		\$ 7.00	
Capital Expense (\$/kW)	w/o capture	\$ 1,375	\$ 950	\$ 1,100	\$ 1,100	\$ 875	\$ 1,326	\$ 875	\$ 1,326
	w/ capture	\$ 1,375	\$ 1,900	\$ 1,100	\$ 2,200	\$ 875	\$ 2,652	\$ 875	\$ 2,652
Amortization (\$/kWh)	rate	7%	7%	7%	7%	7%	7%	7%	7%
	term	15	15	15	15	15	15	15	15
w/o capture	\$ 0.020	\$ 0.014	\$ 0.016	\$ 0.016	\$ 0.013	\$ 0.019	\$ 0.013	\$ 0.019	
	\$ 0.020	\$ 0.028	\$ 0.016	\$ 0.032	\$ 0.013	\$ 0.038	\$ 0.013	\$ 0.038	
O&M (\$/kWh)	w/o capture	\$ 0.030	\$ 0.024	\$ 0.026	\$ 0.026	\$ 0.023	\$ 0.029	\$ 0.023	\$ 0.029
	w/ capture	\$ 0.030	\$ 0.038	\$ 0.026	\$ 0.042	\$ 0.023	\$ 0.048	\$ 0.023	\$ 0.048
Cost of Electricity (COE) (\$/kWh)	w/o capture	\$ 0.094	\$ 0.115	\$ 0.096	\$ 0.059	\$ 0.089	\$ 0.066	\$ 0.089	\$ 0.066
	w/ capture	\$ 0.095	\$ 0.174	\$ 0.096	\$ 0.098	\$ 0.090	\$ 0.111	\$ 0.090	\$ 0.111
Savings		45%		2%		19%		19%	
Emissions (kg CO2/kWh)	w/o capture	-	0.367	-	0.762	-	0.773	-	0.773
	w/ capture	-	0.051	-	0.114	-	0.108	-	0.108
Cost/tonne CO2 captured	\$ 0.00	\$ 159.62	\$ 0.00	\$ 50.98	\$ 0.00	\$ 58.74	\$ 0.00	\$ 58.74	

Table 4: Conventional Distributed Generation versus ECR

The cost of methanol assumed for these analyses was \$0.35 per gallon and specially notice that Table 4 shows the ECR in markets that currently have no carbon capture options available.

Biomass-to-Hydrogen Applications

In order to break the lock between the price of natural gas and methanol, biomass sources can be used. However, as Table 1 shows, biomass is hydrogen poor but biogas is hydrogen rich. Therefore, Gibbs Energy developed a business plan that would field anaerobic digester based biorefineries that would sell a range of commercially valuable outputs. Figure 6 below shows the inputs and outputs of a typical dry digester based biorefinery system. Based on quotes from vendors, the methanol cost from biomass is projected to be about \$0.30/gallon.

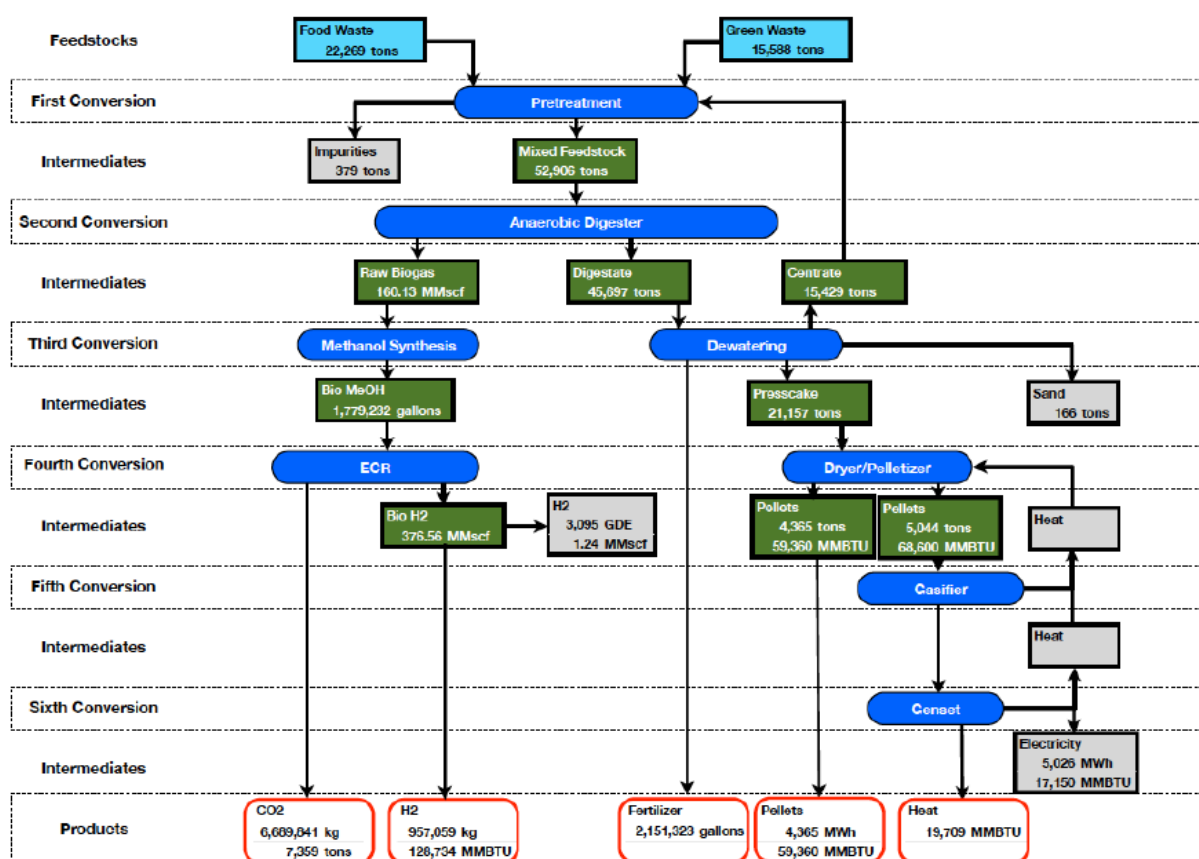


Figure 6: 37,857 short ton per annum ECR Biorefinery Flows

Process	Primary Feedstock	Cost \$	/Unit	H2 Cost \$/MMBTU	H2 Cost \$/kg
SMR	natural gas	\$6.00	/MMBTU	\$15.37	\$2.07
ECR	methanol	\$0.35	/gallon	\$5.72	\$0.77
ECR	natural gas	\$6.00	/MMBTU	\$12.93	\$1.74
ECR	biomass	\$20.00	/ton	\$5.28	\$0.71

Table 5: Cost of ECR Hydrogen from Biomass, Methanol & Natural Gas

Table 5 shows the cost of hydrogen from biomass, methanol and natural gas. The following examples show the effects of the availability of such low-cost hydrogen in several markets.

Refining

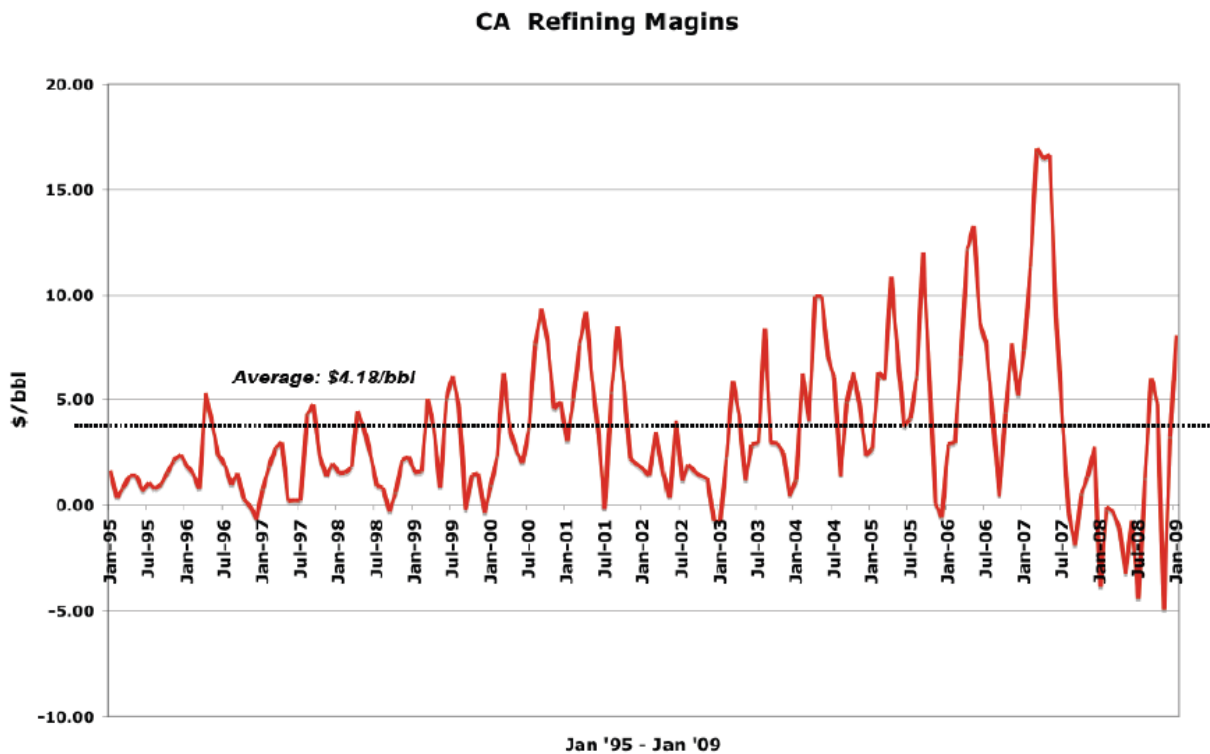


Figure 7: Refining Margins in California from 1995 to 2009

California Refinery Hydrogen (OGJ 2006 Refinery Survey)		Crude Capacity	SMR Cost	ECR Cost	Savings	New Margin	SMR CO ₂
Company	City	bpd	\$M/year	\$M/year	\$M/year	\$/bbl	tonnes/year
Big West Oil LLC	Bakersfield	65,000	\$ 57.19	\$ 19.73	\$ 37.46	\$ 1.58	455,341
Kern Oil Refining Co.	Bakersfield	25,000					-
San Joaquin Refining Co. Inc.	Bakersfield	24,300	\$ 13.48	\$ 4.65	\$ 8.83	\$ 1.00	107,320
Valero Energy Corp.	Benicia	139,500	\$ 253.22	\$ 87.37	\$ 165.85	\$ 3.26	2,016,074
BP PLC	Carson	247,000	\$ 202.19	\$ 69.76	\$ 132.43	\$ 1.47	1,609,793
ConocoPhillips	Carson and Wilmington	260,000	\$ 194.10	\$ 66.97	\$ 127.13	\$ 1.34	1,545,401
Chevron Corp.	El Segundo	161,000	\$ 267.66	\$ 92.35	\$ 175.31	\$ 2.98	2,131,059
Tosoro Corp.	Goldon Eagle	52,000	\$ 202.19	\$ 69.76	\$ 132.43	\$ 6.98	1,609,793
Paramount Petroleum Corp.	Long Beach	138,700					-
Shell Oil Products US	Martinez	157,600	\$ 195.06	\$ 67.30	\$ 127.76	\$ 2.22	1,553,067
Chevron Corp.	Richmond	225,000	\$ 298.47	\$ 102.98	\$ 195.49	\$ 2.38	2,376,360
ConocoPhillips	Rodeo and Santa Maria	120,000	\$ 171.19	\$ 59.07	\$ 112.12	\$ 2.56	1,362,958
ExxonMobil Refining Supply Co.	Torrance	149,500	\$ 306.17	\$ 105.64	\$ 200.53	\$ 3.67	2,437,686
Valero Energy Corp.	Wilmington	80,000	\$ 96.28	\$ 33.22	\$ 63.06	\$ 2.16	766,568
Sholl Oil Products US	Wilmington	100,000	\$ 211.82	\$ 73.08	\$ 138.73	\$ 3.80	1,686,449
Total		1,944,600	\$ 2,469.01	\$ 851.89	\$ 1,617.11	\$ 2.28	19,657,867

Table 6: California Refinery Model Economic Summary

Figure 7 shows that the average profit margin for refineries in California from 1995 until 2009 was \$4.18 per barrel. Table 6 shows the cost of hydrogen and the potential savings from ECR hydrogen using methanol made from biogas. This offers a potential increase in profit margins of \$2.28 per barrel or 54.5%. This calculation includes no monetary benefit from the reduction in emissions of almost 20 million short tons of CO₂ per year. All cost and performance figures were based on the 2,550 kg per day module mentioned above.

Distributed Generation

Another interesting market that Gibbs looked at was distributed generation using arrays of commercially available internal combustion engines that have been modified to operate on hydrogen. Performance figures were based on the data provided by Ford to the US Department of Energy and the first target market analyzed was multi-family housing with a minimum of 200 units per site. This size was chosen because there are technically-qualified staff on site and there are about 120,000 such sites in the US.

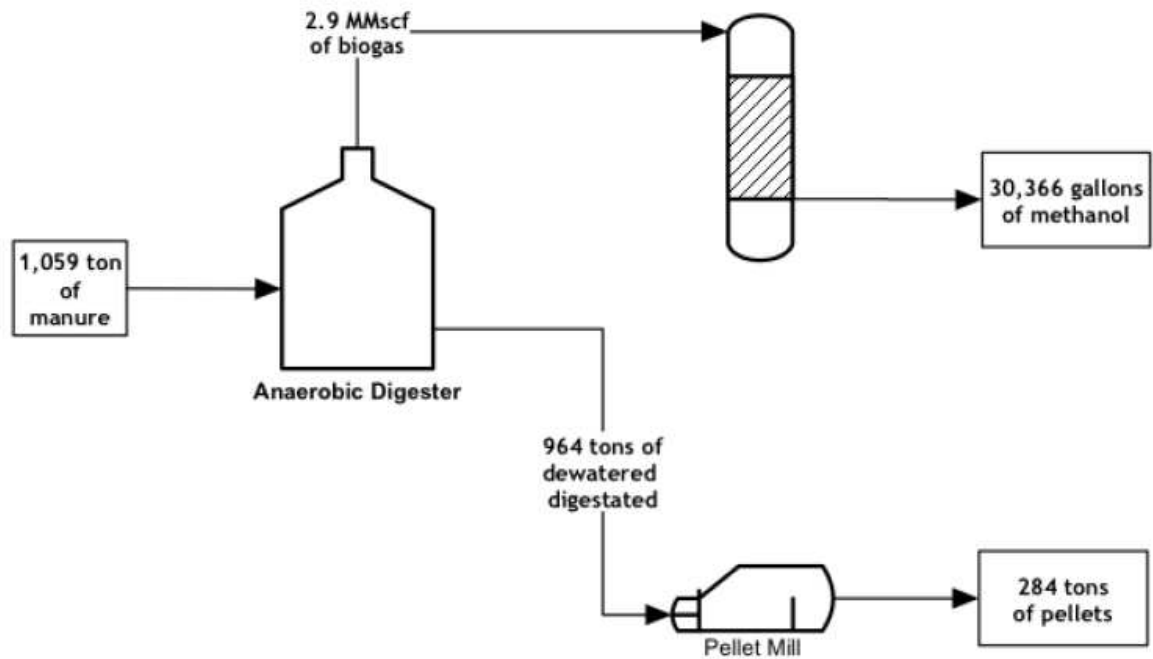


Figure 8: Daily Flows for a 100 ton/day Biomass-to-Methanol Facility

Figure 8 shows the daily flows for a biorefinery capable of producing 100 short tons of methanol per day. The hydrogen that could be made from this methanol would supply all of the energy for 4,425 average apartments while the pellets could power another 4,041. Figure 9 below shows the daily flows for 200 of the hydrogen fed apartments.

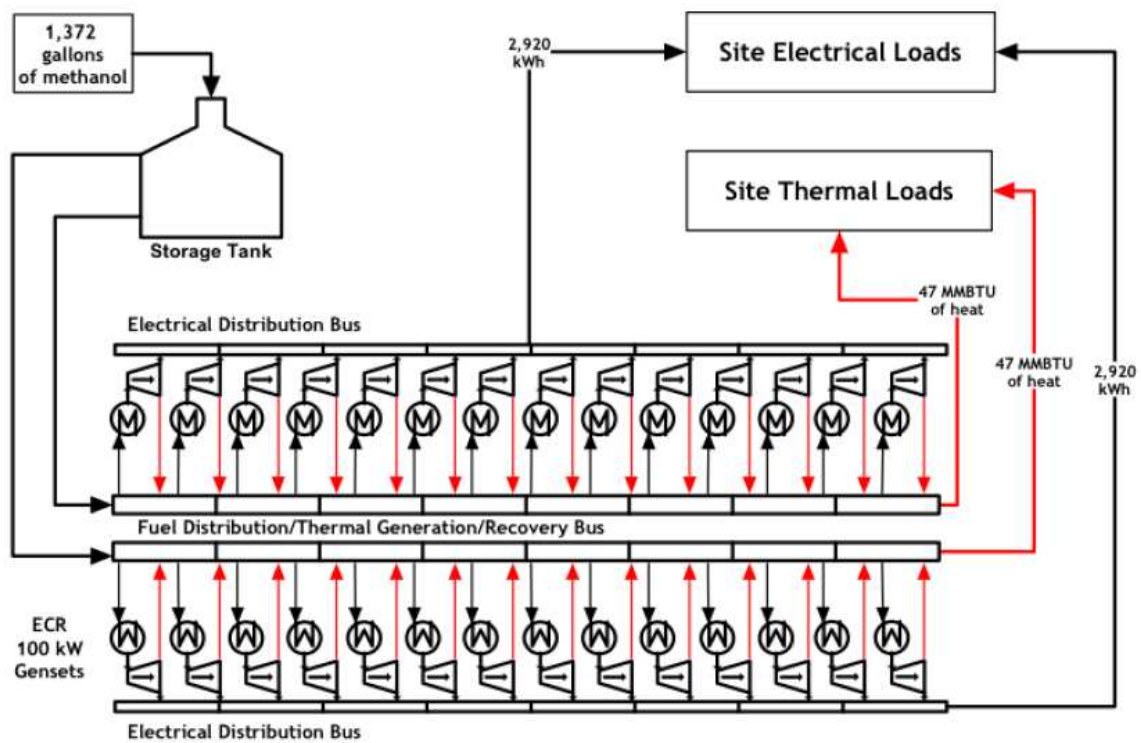


Figure 9: Daily Flows for a 200 Unit Apartment Complex

Value Summary				
Apartment Value	\$121	/ft2	Energy System	
Construction Cost	\$90	/ft2	capex	\$85,197,858
Apartment Size	1,000	ft2	increase	16%
total size	4,523,314	ft2	value increase	66%
total value	\$547,321,029			
Rent	\$14.52	/ft2/yr		
NOI	50%		increased:	
	\$32,839,262	/yr	NOI	\$21,741,097
Cap Rate	6.0%		Value	\$362,351,609
Value	\$547,321,029			
LTV	80%			
Mortgage Proceeds	\$437,856,823		Mortgage Proceeds	\$289,881,288
Yield	6%		Yield	26%

Table 7: Economic Value of Bio-Methanol Fed ECR Apartments

This table summarizes the business case for providing all of the energy requirements for 4.425 apartments with distributed, ECR hydrogen-fueled CHP systems. The publicly traded apartment companies in the US realize yields on capital of about 6% per annum (prior to the 2008 crash). The yield on capital for the distributed CHP systems, including the central biorefinery, is 26%. If the biorefinery and distributed CHP systems are financed with the apartments, they will only represent a 16% increase in capital costs while adding 66% to the value of the properties by increasing the Net Operating Income.

Conclusion

Based on the last eight years of lab work, studies, market research and modelling, We can see a wide range of uses for the ECR and its low cost hydrogen. The problems of hydrogen as a transport fuel are well known and have led us to ignore this as a near term market. Existing hydrogen markets are sufficient to justify the deployment of a system that offers half the cost while including integrated carbon capture with no energy penalty.

On other feedstocks, such as natural gas and coal, the pre-combustion capture, driven by power plant waste heat, actually will increase the efficiency of the target facility. This unique attribute remains to be proven on these new energy sources.

Therefore, Gibbs Energy will continue its work on the development of commercially competitive systems while identifying appropriate licensees and strategic partners.

Nomenclature

Example:

BOE	barrel of oil equivalent
CC	carbon capture
CHP	combined heat and power
ECR	Electrochemical Reforming
H/C	hydrogen to carbon ratio
IGCC	integrated-gasifier, combined-cycle
Nm ³	normal cubic meters
SMR	Steam Methane Reformer
scf	standard cubic foot
STP	Standard Temperature and Pressure
T:	Temperature [C]

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