Jefferies Research

October 2007

Clean Technology Primer

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Solar Energy Primer

Investment Summary

We believe that the continued development of solar incentive programs will drive excellent long-term demand growth in the solar industry although we are cautious that near-term production increases could temporarily outstrip demand.

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Event

This report is designed to introduce investors to the solar industry with a focus on how we expect the vital incentive programs to shape the market in the near and long term. In our view, the solar industry is poised for excellent long-term growth although we could see some temporary over-supply issues in the near term.

Key Points

- In the US market, our top picks are SunTech, a leading Chinese solar cell and module producer, and Energy Conversion Devices, which we believe will increasingly be seen as a turnaround story near term, although we believe that the company must make significant improvements to the cost structure of its solar business to remain competitive long term. In Europe, we currently do not have any Buy-rated stocks due to concerns over the evolution of solar incentives in Spain.

- Incentives should prove to be durable and expansive. Given the high cost premium for solar over traditional forms of generation, the solar industry relies upon government-sponsored incentives to provide an economic return to solar investors. These programs have spread and we see excellent medium-term growth prospects in the US, Italy, France, and Greece (amongst others) as well as the traditional German and Japanese markets.

- Spain is at a crossroads. The current program and proposed next generation incentive plan are attractive but capped. We believe Spain will ultimately be a major ongoing source of demand for solar modules, although there is current uncertainty as the next generation incentive plan is now being developed.

- Very early stages of the growth story. Even in Germany, the most advanced solar market, solar generation represents less than 1% of total electricity consumption. We anticipate that incentive programs will allow demand to continue and would push prices downwards towards the industry Holy Grail of parity with grid pricing.

- Alternative technologies have potential to offer low-cost solutions as well as interesting products that could fill niches where crystalline-based solutions are not applicable. While we continue to believe that silicon-based crystalline technology will remain the dominant actor, we believe that alternative (a.k.a. "thin film") solutions could offer interesting growth opportunities.

Solar – A Secular Growth Story, but Invest Selectively

Today, grid connected solar is not cost-competitive with traditional energy generation and must rely on federal and state governments to create attractive incentive programs to reward end-user investors. Since 2004 when the German government passed the Renewable Energy Act, incentive programs in various guises have spread across the world and driven increasing levels of demand for solar products. Investors must believe that these incentive programs will be sustained in order to commit the capital for new installations. Without them, either demand for solar modules could slow or module prices could fall considerably.

While we believe the foundation has been laid for excellent incentive-priced demand from a wide range of markets (e.g., Germany, Spain, US, Italy, Japan, and others), demand in 2008, while expected to be strong, may not be sufficient to meet our expectations of a near doubling of module production. The reasons for this are varied. In Germany, demand is highly price sensitive and a further than anticipated fall in module prices will increase returns to purchasers of solar systems and thus drive rising demand. However, Spanish demand looks set to be limited by the proposed introduction of a hard cap for ground mounted solar projects. Japan is a traditional market but growth has been relatively modest over recent years while the emerging Italian, French, South Korean, and Greek markets are unlikely to show significant demand next year as non-financial barriers must be surmounted.

In our view, investors are best set to focus on solar companies that boast of a low cost base or a differentiated product offering. In the US market, our top picks are SunTech (STP, $45 Price Target, Buy), a leading Chinese solar cell and module producer and Energy Conversion Devices (ENER, $33 Price Target, Buy), which we believe will increasingly be seen as a turnaround story near term, although we believe that the company must make significant improvements to the cost structure of its solar business to remain competitive long term. In Europe, we currently do not have any Buy-rated stocks due to concerns over the evolution of solar incentives in Spain. We shall cover these issues in greater detail in the body of the report.

The silicon bottleneck appears to be loosening although we believe that a two-tier market could emerge with the top-tier dominated by companies with reliable, high-quality supplies of feedstock from established silicon producers. The second tier would be composed of companies tied to less reliable sources of feedstock such as semi-conductor scrap and emerging silicon producers. Companies looking to the latter to source feedstock could face delivery delays and/or quality issues as these new silicon producers work out the kinks in their new production facilities.

We continue to believe that the solar industry will remain a high-growth industry and that over-supply issues will likely be a temporary phenomenon in 2008. While we remain optimistic over a longer-term view, near-term issues and current sector valuations drive our current broadly cautious industry view.

Table 1: Global Solar Sector Coverage

		Current	Price			Current P/E (Jefferies Estimates)			P/E at Price Target		
Company	Analyst	Price	Target	Upside	Rating	2007E	2008E	2009E	2007E	2008E	2009E
SolarWorld	McNamara	42.9	33	-24%	Hold	50.6	30.7	24.7	38.5	23.3	18.8
Solon	McNamara	72.8	36	-50%	Underperform	43.7	27.8	20.7	21.8	13.9	10.3
ErSol	McNamara	71.9	55	-23%	Hold	73.3	15.3	10.0	56.2	11.7	7.6
REC	McNamara	246.0	209	-15%	Hold	70.7	57.7	27.7	60.2	49.1	23.6
Q-Cells	McNamara	78.2	64	-19%	Hold	56.3	38.0	25.4	45.8	30.9	20.6
PV Crystalox	McNamara	115	160	39%	Hold	20.2	16.4	11.0	28.1	22.8	15.3
Evergreen Solar	Clegg	9.2	10	9%	Hold	N/A	N/A	18.8	N/A	N/A	20.4
Energy Conversion Devices	Clegg	26.2	33	26%	Buy	N/A	-137.9	46.8	N/A	-173.7	58.9
SunTech	Clegg	38.8	45	13%	Buy	34.3	21.8	17.0	38.9	24.7	19.3
SunPower	Clegg	88.6	90	2%	Hold	74.5	44.3	26.5	75.6	45.0	26.9
Emcore	Lau	10.4	11	6%	Buy	-0.87	-0.01	N/A	N/A	N/A	N/A
					Weighted Average	*58.7*	*38.8*	*24.9*	*49.9*	*31.8*	*21.7*
					Weighted Average ex-Rec	*48.1*	*22.7*	*23.1*	*40.7*	*17.1*	*20.2*
											As of 9 Oct 2007

Source: Jefferies' Estimates

For your reference, we have also provided Table 2 illustrating the market cap and valuations of selected solar sector companies. While not all solar companies are included, this list comprises the largest and most liquid solar investments currently available.

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Table 2: Selected Solar Valuations

Company	Analyst	Symbol	Current Price	Market Cap (€m)	Price Target	Rating	P/E 07E	P/E 08E	P/E 09	12/31/06 to Current
SolarWorld	Michael McNamara	SWV (Ger)	42.9	4,794	33	Hold	50.6	30.7	24.7	80%
REC	Michael McNamara	REC (Nor)	246	14,970	209	Hold	70.7	57.7	27.7	116%
Q-Cells	Michael McNamara	QCE (Ger)	78.2	5,818	64	Hold	56.3	38.0	25.4	130%
ErSol	Michael McNamara	ES6 (Ger)	71.9	775	55	Hold	73.3	15.3	10.0	56%
Solon	Michael McNamara	SOO1 (Ger)	72.8	747	36	Underperform	43.7	27.8	20.7	210%
PV Crystalox	Michael McNamara	PVCS (UK)	115	711	160	Hold	20.2	16.4	11.0	IPO
Renesola	Not Covered	SOLA (UK)	293	435	NA	NC	21.8	13.3	9.2	-31%
Conergy	Not Covered	CGY (Ger)	57.8	2,312	NA	NC	34.8	18.4	13.5	20%
Solaria	Not Covered	SLR (Sp)	16.4	1,659	NA	NC	44.3	26.9	15.6	IPO
Aleo Solar	Not Covered	AS1 (Ger)	15.2	198	NA	NC	36.6	24.9	12.6	124%
CentroSolar	Not Covered	C3O (GR)	9.4	125	NA	NC	34.8	16.2	10.6	3%
Trina Solar	Not Covered	TSL (US)	53.4	826	NA	NC	40.1	15.3	9.9	182%
LDK Solar	Not Covered	LDK (US)	37.5	2,846	NA	NC	31.0	19.1	7.6	IPO
China Sunergy	Not Covered	CSUN (US)	10.1	292	12.5	NC	17.4	N/A	N/A	IPO
JA Solar	Not Covered	JASO (US)	41.0	1,378	NA	NC	37.2	26.3	15.1	IPO
SolarFun Power	Not Covered	SOLF (US)	12.7	446	NA	NC	N/A	N/A	N/A	IPO
Evergreen Solar	Paul Clegg	ESLR (US)	9.2	416	10	Hold	N/A	N/M	18.8	22%
Energy Conv. Devices	Paul Clegg	ENER (US)	26.2	724	33	Buy	N/A	-137.9	46.8	-23%
SunPower	Paul Clegg	SPWR (US)	88.6	3,941	90	Hold	75.1	56.8	31.5	138%
SunTech	Paul Clegg	STP (US)	38.8	4,098	44	Buy	38.4	24.3	18.7	14%
Emcore	John Lau	EMKR (US)	10.4	374	10	Buy	-12.0	N/A	N/A	88%
MEMC	Not Covered	WFR (US)	64.0	10,384	80	NC	19.6	15.7	13.6	63%
First Solar	Not Covered	FSLR (US)	137.3	7,252	NA	NC	211.2	96.0	49.2	360%
					Weighted Average		*68.8*	*40.9*	*25.1*	*117%*
					Ex - First Solar		*49.2*	*33.4*	*21.9*	*85%*
										As of 9 Oct 2007

Note: estimates for NC companies are consensus.
Source: Jefferies' Estimates

What to Expect in Solar – Executive Summary

The next 12 months will be a critical time for the solar industry. With the long-awaited increased silicon capacity finally coming on line in 2008 to partially ameliorate the supply crunch, the focus this year will be on the demand side of the ledger. The key issues will be the evolution of solar incentive programs and what medium and long-term impact they will have on demand. Our prediction is that solar incentives will not only prove to be durable in existing markets but will expand to open new markets for solar systems. While this is likely to generate positive returns for solar shares over the year, we would expect potentially significant volatility as the debate over incentives begins in earnest in several key markets.

We will discuss our views on ***global incentives*** in further detail in the *Solar Incentive Programs* section but for now we summarize a few key markets:

- *Germany* is scheduled to review its renewable energy act in 2007 with the new incentive program scheduled for implementation in 2008. We expect that the highly popular pro-solar programs will be continued albeit with a potential reduction in incentive levels designed to reduce prices for solar systems. While we do expect a positive result, we caution that the political debate inherent in the process could generate volatility, particularly in the second half of 2007.
- *Spain* will likely reach its proposed 371 MW solar capacity cap by late 2007. We would expect discussions on a "Phase 2" plan to be advanced during 2007, which could be a catalyst to solar shares. We expect Spain to be a key source of long-term demand although we have not yet seen the legislative framework to support demand growth beyond 2008. We would expect the "Phase 2" debate to begin in earnest in the latter part of the year.
- *The US* incentive programs are continuing to proliferate, and we believe the change in control of Congress is likely to accelerate this movement. We expect these programs to continue to drive significant increases in installations, with the biggest constraint to growth being the available supply of solar modules. But importantly, corporations are increasing their usage of Clean Technologies even before the incentive programs are consummated. Earlier this year, Wal-Mart announced that it had sent out Requests for Proposals (RFPs) to a number of solar suppliers for solar modules. The announced plan calls for the elimination of 20% of its stores greenhouse emissions within seven years. The company indicated that its long-term goal is to generate 100% of its energy requirements from renewable sources. The Wal-Mart plans are beneficial not only in terms of incremental demand (potentially 4+ GW) but as a sign that Corporate America is beginning to seek emission free and independent sources of power.

Non-financial barriers are a less well-known but equally important factor. The appearance of an attractive solar incentive program is a required first step but additional measures may be necessary to ensure that interested parties can successfully purchase and install solar systems. These barriers can vary market to market, but there are some common themes. We will address this in further detail later in the report.

We continue to believe that ***access to silicon*** will continue to be a key differentiator amongst solar companies. With new silicon capacity not yet on line and inventory stocks drying up, the scramble to secure feedstock will continue. Companies with a business model based on spot market purchases for their supply will continue to face punishing costs and the risk of production shortfalls will continue. Please refer to the *Silicon Supply Update* for more details. Once again, we prefer companies with secured supply of silicon sourced from well-established silicon producers or those not dependent on silicon for their growth.

We do not foresee a shift in the solar technology paradigm in 2007. While various thin film technologies are ramping up production, crystalline cells should remain the dominant solar system solution with a 90%+ market share in the medium term. However, we expect certain thin film technologies to find potentially lucrative niches such as flat roof or façade integrated applications.

Update on Spain

At the time of writing, Spain was approaching a crossroads in its path towards the hoped-for widespread adoption of solar power. We believe that Spain will continue to support investment in solar power although we remain concerned that any delays in the establishment of “next generation” solar incentives could lead to disruptions in this increasingly important market.

Background

First, we offer a brief introduction to the Spanish solar incentives that were signed into law under Ley Decreto 661/2007 in June 2007. This law offers extremely attractive feed-in tariffs for both rooftop and ground mounted systems with €0.42/kWh for 25 years available to the latter. The passage of this law has led to a massive surge of investors looking to install solar capacity with virtually 100% of this demand focused on large scale ground mounted units. The law also includes a cap/target of 371 MW of installed capacity that can qualify for the Ley Decreto 661/2007 tariffs. The law implicitly recognizes that the 371MW is a “soft” cap and that the final installed capacity could turn out to be a bit higher. Under the law, once the government calculates that qualified installed capacity has reached 85% of the target (315 MW), a trigger point is reached. At this point, the government “raises the red flag” which leads to a series of events:

- All solar projects that have not received full planning and grid connection permission cannot qualify for the tariffs available under Ley Decreto 661/2007. This does not signify that project permissioning must stop but rather than any permissions handed out after the red flag goes up will qualify for the *next* generation of solar incentives.
- Fully permissioned solar projects are given 12 months from the date of the red flag to complete construction. If the project is completed in time, it will be grandfathered under Ley Decreto 661/2007 and receive the current attractive feed in tariffs.
- The government is expected to produce its initial proposal for the next generation of solar incentives for consultation at or near the time the red flag is raised.

The attractive returns have yielded much more demand for solar projects than the government anticipated. When we first raised this issue in late July 2007, we estimated that the pipeline of fully permissioned projects was approximately 1000 MW (including more than 600MW in Castillo-Lo Mancha alone) which, if all were to be completed on time, would result in a Ley Decreto 661/2007-qualified installed capacity of roughly 1300 MW rather than the 371 MW target. This discrepancy is the result of a structural flaw in the incentive program. While targets are established, and financed, by the federal government, the grid connection and planning permissions are handed out by the local utilities and regional authorities.

Once the government realized the scale of the pipeline that, by law, could qualify for Ley Decreto 661/2007, it began to take actions designed to shrink that pipeline. First the government attempted to cut the 12-month grace period in half but had to reverse course within 48 hours and the 12-month period remained intact. Following this setback, the government then turned up the pressure on the banks to stop financing solar projects. This is important as the law requires solar investors to make an *aval*, or escrow payment, which can run to several million euros for a 10MW project, not to mention the cost of the project itself. The government has been putting pressure on the banks not to finance these payments in order to reduce the project pipeline. It is our understanding that this is proving to be successful and that the 1000 MW pipeline will likely translate into roughly 300 MW of completed projects following the red flag or 600-700 MW in total.

The reason for this action is simple … cost. Given that retail electricity tariffs in Spain are capped, the federal government must reimburse the utilities when the cost of wholesale electricity rises. This has occurred in Spain

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where rising demand and falling hydro-electric production (due to low water levels) has forced Spain to turn to more high cost gas and fuel oil generated electricity. The need to top up the utilities cost the federal government several billion euros in 2005 and 2006. One solution is to raise retail electricity rates, which this government has done, but this is never popular and the government is facing a general election in March 2008. The 371 MW target would result in annual payments to solar investors of €200-250m while a 1300 MW installed capacity could result in annual payments of €700-900m.

The red flag has been raised

The Spanish government announced that installed capacity in Spain had reached 335 MW and officially raised the red flag on 30 September 2007. Initially, we would prefer to examine the near term impact this action will have on the Spanish market. As we know, the government estimates that Spain has 335 MW of installed capacity. We estimate that an additional 150 MW are currently under construction and that an additional 150 MW of new projects will begin construction by year end. Assuming the new projects and those under construction are completed, this will result in approximately 635 MW of solar projects that qualify for the feed in tariff outlined in Ley Decreto 661/2007.

We recognize that the gross portfolio of consented projects in Spain is far higher than the 150 MW of new projects to begin construction by the end of the year. We believe the gross portfolio of consented projects has increased to roughly 1500 MW although no concrete figures are available. However, the government's efforts to limit the number of realized projects appear to have been successful.

Proposed next generation solar incentive scheme published

The Spanish government published a draft proposal for the next generation of solar incentive tariffs. Under the terms of the draft proposal, new solar incentive law would incorporate the following key items:

- A cumulative cap (i.e., includes the projected 635 MW of Ley Decreto 661/2007 qualified projects) of 1000 MW for ground mounted systems
- Feed in tariff for ground mounted systems connected to the grid after 29 September 2008 would fall to €0.31 / kWh (from €0.42 / kWh under Ley Decreto 661/2007)
- Rooftop installations would be granted a separate cap of 200 MW and the feed in tariff would remain stable at €0.44 /kWh

In our view, this draft, in its current state, is negative for the solar industry. The proposed 1000 MW cap is a hard cap so any installation above that 1000 MW figure would not qualify for the €0.31 /kWh feed in tariff but would instead receive pool pricing (approx €0.05 / kWh). Given the high cost of a solar installation, investors require the guaranteed feed in tariff else the project is immediately unprofitable.

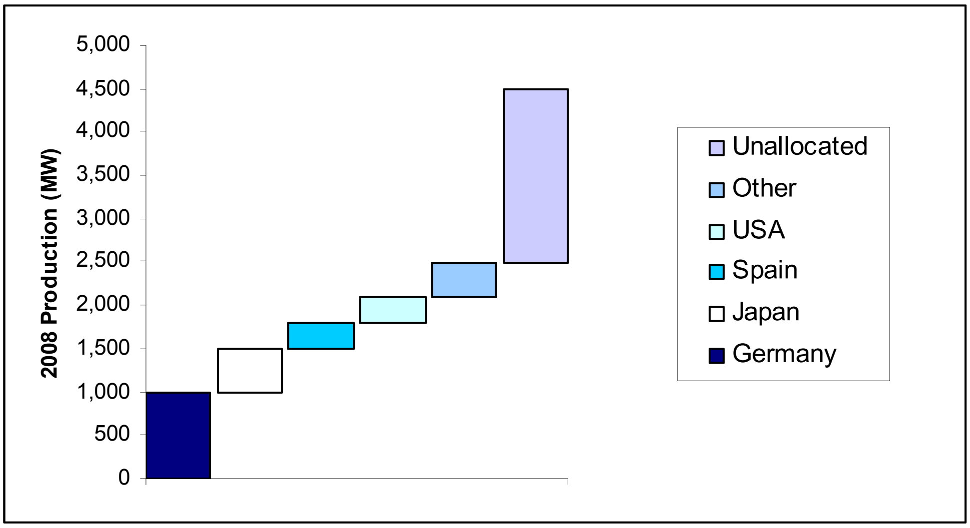
The hard-cap issue now comes to play. Investors will be very cautious about committing resources to solar projects if they lack certainty they can receive the feed in tariff guarantee. Additionally, information on solar installed capacity and status of project construction is patchy and backwards looking. The high penalties for over-shooting the cap and lack of information on current status will likely lead to many potential projects being shelved. In this light, we anticipate that demand will remain constrained next year. Our forecast assumes that Spanish developers install only 300 MW in addition to the 635 MW qualified for Ley Decreto 661/2007.

We must note that at this stage, these proposals are merely a first draft and that the solar industry and the government will be in negotiations. We have based our forecasts on the current proposal.

2008 Supply / Demand

We have built a rough estimate of demand from key markets and compared it to our projected 2008E module supply estimate. The demand estimate assumes that prices around the globe fall in line with local incentive programs (i.e., -5% in Germany). As the table shows, current demand estimates are insufficient to meet the expected surge in supply. However, we note that the industry traditionally shows a high degree of price elasticity and that lower prices would likely trigger higher levels of demand, particularly in mature, uncapped markets such as Germany and Japan.

Chart 1: Silicon Supply and Solar Production Forecasts



Source: Jefferies International

The "other" markets item includes future growth markets such as Italy, France, Greece, and South Korea. While we believe these markets are poised to grow significantly, we do not believe that they will have a significant impact on 2008E demand as non-financial barriers will likely slow deployment.

Global Solar Incentive Programs

Given that solar is not yet cost competitive versus traditional generation in virtually all markets, government sponsored incentives are required to promote solar investment. While forecasting the arrival and efficiency of incentives is tricky, we would suggest that investors focus on a few key markets, which should serve as catalysts to share price performance. Key issues to focus on will be the renewal of the EEG in Germany; creation of a post-2008 framework in Spain; and new state/federal incentive plans in the USA.

Germany. The EEG is scheduled to be reviewed by the end of 2007 with an updated incentive plan scheduled to go into effect in 2008. We do not anticipate that the incentive plans will be eliminated as they have proven very popular and many jobs have been created in the solar industry as a result of the high demand for solar systems. However, we do not expect to see the plan remain unchanged as there is some concern that system prices have not fallen as much as hoped and the high margins of many German wafer and cell producers may prove to be a tempting target to German politicians. Initial proposals from the Minister of the Environment indicate that the rate of digression for rooftop systems will be 5% in 2008 before rising to 7% in 2009-10 and 8% in 2011. Should this proposal pass into law, we would consider this a positive for the solar industry.

Spain. Please see the *Update on Spain* section of this report.

France. The French government has begun to aggressively promote renewable energy after years of reliance on nuclear power. Along with the aggressive wind targets, the French government is offering attractive incentives to solar investors. A rooftop system may earn a feed-in tariff of €0.30/KWh, while the investor can receive a tax credit for 50% of the system cost up to a maximum of €8,000 per household. While the feed-in tariff is low, the combination of the tariff and the tax credit could allow a solar investor in southern France to earn an IRR of up to 13.4% which compares to 14.2% in Spain and 6.5% in Germany (assumes 1300 sun hours in France, 1800 in Spain, & 1000 in Germany and a €5/Wp system price). However, many non-financial barriers, with EdF intransigence being the chief obstacle, must be overcome.

Other Europe. We believe that Italy and Greece are two potentially strong sources of demand growth. Both countries have passed highly attractive solar incentive programs via excellent feed-in tariffs. However, non-financial barriers must be overcome in both markets before growth can really take off.

USA. In the US, we see three types of legislation having the potential to raise investor expectations on the speed of solar adoption. First, legislation that extends or enhances existing tax incentives for solar and other renewables could speed solar adoption. Second, we believe that a new national renewable portfolio standard (RPS) is within the realm of political reality in the US near-term and introduction of an RPS bill is being considered. Third, CO2 legislation would increase the cost of electricity generated from coal and natural gas, making solar relatively more attractive, albeit still uneconomical near-term without subsidies.

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In August 2007, the House of Representatives passed (H.R. 2776), the "Renewable Energy and Energy Conservation Tax Act of 2007", which contained several pro-renewable provisions, including an eight-year extension (through 2016) of the 30% solar ITC for businesses (Investment Tax Credit), elimination of the $2,000 residential solar ITC cap (but no extension), an ITC offset against AMT (Alternative Minimum Tax) and removal of a utility exclusion on the solar ITC, among other provisions.

While we expect national subsidies to be extended and somewhat expanded in the US, it is unclear that ongoing legislative efforts to do so will be successful near-term. Currently, compromise is being sought for the Senate to pass a similar version of H.R. 2776, after several pro-renewables provisions were eliminated from a prior energy bill (H.R.6) that passed the Senate in June 2007, including several of the items passed in H.R. 2776. Yet, the issue of how to fund the House bill's pro-renewable provisions (eliminating certain favorable income tax treatments on oil and gas activities) remains contentious along partisan lines and a presidential veto remains a possibility, in our view.

Other World. The most important country for the solar market beside the aforementioned is China. The country is looking to solar as a way to bring energy to many of its rural areas. The government has mandated that the utilities generate 5% of their energy from renewable sources by 2010 and 10% by 2020. Assuming that solar accounts for only 25% of the renewable production, this would equate to over 6 GW of annual demand from China. Additionally, countries including Mexico, S. Korea, and Canada have all announced incentive programs within the last year. These regions are currently undersupplied due to the strong demand out of Europe and the US. We believe these areas represent additional pent-up demand that will allow for continued growth in the solar space should Europe slow.

Non-Financial Barriers

The emergence of financial incentives is, of course, critical to the success of solar. However, it is important to review some of the non-financial barriers to mass deployment of solar systems. While less well publicized, delays and bureaucratic hassles involved in installing solar systems can act as a fairly significant impediment. For example, a recent article in Photon International suggested that in France it can take up to 12 months to obtain approvals to install a PV system and sell electricity. While not necessarily as long, this type of delay is more the rule than the exception in many emerging solar markets. Some of the key non-financial barriers are:

- *Net Metering Rates.* This refers to the price at which excess electricity is sold to the grid and is not relevant in markets that have a feed-in tariff based incentive plan. Many grids prefer to purchase the excess power from a solar installation at wholesale (e.g., US $0.03–0.06/kWh) rather than the higher retail (US $0.10–0.20/kWh) while the owner of the installation naturally has a different view. Unattractive net metering rates can significantly reduce the financial incentive to install solar power, particularly in the residential market where the system may generate more power than the residential daytime load.
- *Net Metering Caps.* Regional grids may have limits on the amount of distributed generation and/or net metering that can be installed in a certain region. This situation occurred in parts of California and forced a halt to installations until the cap could be eliminated.
- *Planning Permission.* Many communities require planning permission in order to install solar panels on rooftops and can cause delays in installation.
- *Grid Connection.* Some regional/national grids have detailed specifications for generators seeking to dispatch to the grid. These specifications are often designed for central generation plant (200 MW +) and could place a heavy burden on homeowners.

While these problems may seem daunting, they can all be overcome although the process will certainly take some time. Additionally, many solar installers are seeking to provide much of the planning and permitting required as part of the sales package both to increase their potential revenue as well as incentivize sales.

Silicon Supply Update

The silicon bottleneck should reach its peak in 2007 as no significant production increases are scheduled and raw silicon inventories will likely have been used up. We anticipate that solar production, measured as MWp output, will increase by 10% driven by a higher estimated silicon production, reduction in silicon intensity (please see the following *Silicon Efficiency* section for more details), and a near doubling in thin film production offset by a drop in inventory drawdown. Given this tight supply, we continue to prefer companies with secured silicon supplies from proven producers of silicon.

We also believe that many companies may have difficulty reaching production estimates due to upstream supply difficulties. We note that ErSol was forced to reduce its 2007E production forecast from 70MW to 55MW due to the failure of several wafer suppliers to deliver. While we do not have visibility or predictions on which companies could face disruptions, we simply remind our clients that this issue is likely to rear its head over the course of the year.

Solar cell production rose approximately 40% in 2006. We believe there were several factors that led to this surprisingly strong performance:

- Improved silicon efficiency, principally due to reduction in wafer thickness, was greater than expected. During the course of the year, most wafer producers reduced average wafer thickness from 240–270 microns in early 2006 to 200–210 by the end of the year.
- Stocks of inventory likely proved to be greater than anticipated.
- Thin film production expanded greater than anticipated, led by companies such as First Solar and Unisolar.

Table 3: Silicon Supply and Solar Production Forecasts

	2004	2005	2006E	2007E	2008E	2009E	2010E
Hemlock Semiconductor Corp.	7,000	7,500	10,000	10,000	14,500	19,000	27,000
MEMC Electronic Materials	2,550	3,700	4,400	6,500	8,000	8,400	15,000
Mitsubishi Materials	2,200	2,800	2,800	2,800	3,200	3,360	3,528
Wacker-Chemie	5,200	5,200	6,500	7,500	9,000	13,500	21,500
Tokuyama	4,800	5,200	5,400	5,940	6,500	7,500	8,400
REC	5,300	5,300	5,500	5,500	8,125	13,000	19,000
DeGussa/SolarWorld				100	200	850	850
China			400	800	1,600	2,700	3,800
PV Crystalox						900	1,100
Elkem					1,250	5,000	10,000
DC Chemical					1,000	2,500	3,000
M Setek				600	3,600	5,200	10,000
LDK Solar						4,500	6,000
Other (including recycled)	1,300	2,000	2,100	2,250	2,800	3,840	5,132
Total Silicon	28,350	31,700	37,100	41,990	59,775	90,250	134,310
Less Semi demand	(19,500)	(20,000)	(21,000)	(23,100)	(25,410)	(27,951)	(30,746)
Silicon Deliveries to Solar *(m tons)*	8,850	11,700	16,100	18,890	34,365	62,299	103,564
+ Inventory *(m tons)*	4,876	5,390	2,790	0	0	0	0
= Solar Silicon *(m tons)*	13,726	17,090	18,890	18,890	34,365	62,299	103,564
g/Wp estimates	11.5	11.0	9.3	8.8	8.3	7.9	7.5
Crystalline Cell Production *(MW)*	1,194	1,554	2,042	2,150	4,116	7,855	13,746
Other Solar Production *(MW)*	63	82	174	348	522	825	1,400
Total Solar Production *(MW)*	**1,257**	**1,636**	**2,216**	**2,498**	**4,638**	**8,680**	**15,146**
Growth	*57%*	*30%*	*35%*	*13%*	*86%*	*87%*	*74%*

Source: Jefferies International Ltd.

We believe this industry-wide snapshot does not tell the whole story. In our view, it is vital not just to look at *how much* silicon production will increase but *who* is leading the expansion. Based on the figures presented in Table 3, global silicon production would rise by 24,475 tons from 2005 to 2008, representing a 77% increase. We note that over three-quarters of this increase is due to just four suppliers (Hemlock, Wacker, MEMC, & REC). Based on this, we would advise investors to prefer companies that secure their supplies from these well-established producers of silicon. Our top European pick, SolarWorld, has announced major contracts with both Wacker and Hemlock.

Another new development has been the rise of metallurgical grade silicon (m-Si) as a potentially significant source of supply to the solar industry from Norway-based Elkem. M-Si is a commodity that is currently used in the traditional Siemens reactor silicon production process. In this process, m-Si is gasified and is used as part of the trichlorosilane gas, which is injected into the deposition furnaces. Under the process developed by Elkem, the raw m-Si is not gasified but instead purified directly in to solar grade silicon. The benefit is the elimination of the gasification step which could result in an end product whose production cost is 30%–50% cheaper than silicon produced in the traditional Siemens-reactor process.

This m-Si purification process has been developed over several years by Elkem with several other potential suppliers such as Dow Corning also considering this approach. In the past, m-Si was usable in the solar industry only when mixed with traditional silicon, generally with a limit of a 10% blend. At this level, m-Si was unlikely to make a significant impact on the solar silicon industry. However, Q-Cells has secured approximately half of

Elkem's m-Si output beginning in late 2008 for use in its cell production. Q-Cells intends to employ a 50/50 blend initially and believes that it can produce solar cells using 100% m-Si in a relatively short time. Q-Cells believes that an m-Si based solar cell should have efficiency levels in line with current poly-crystalline cells (14%–15%); however, this has not yet been demonstrated on a commercial basis.

We believe Elkem's partnership with Q-Cells, the world's second largest producer of solar cells, is an excellent endorsement of Elkem's m-Si offering. Furthermore, we believe that BP Solar may have signed an offtake agreement for the remaining 50% of the Elkem production. If two of the top 10 producers of solar cells appear to believe in the Elkem m-Si product, who are we to argue?

Although m-Si offers lower production cost, it is an inferior product. At the moment, m-Si can only be used in 14%–15% efficiency poly-crystalline solar cells with no guarantee that it can achieve higher efficiency in a poly-crystalline form. The m-Si offering cannot currently be used to produce a mono-crystalline ingot nor is it usable in the semi-conductor industry.

The emergence of m-Si as a potentially credible source of feedstock to the industry could have several potential impacts on the industry:

- The arrival of a lower-cost alternative to traditional Siemens reactor-based silicon production could help usher silicon prices downward. However, m-Si production currently represents only 10% of forecast 2010E production, while Siemens reactor based technology represents 75%. Therefore, we do not see a significant impact on industry pricing from m-Si in this decade.
- We believe that m-Si will have relatively limited impact on established Siemens reactor-based silicon producers such as Wacker and Hemlock as they have the financial muscle and industry scale to absorb potential reductions in sales prices.
- We believe that the biggest impact of the emergence of Elkem's m-Si product will be on smaller, start-up Siemens reactor based producers. It is likely that many of these projects will not get off the drawing board as solar wafer and cell producers would not be inclined to pay higher prices when a suitable, lower-cost alternative is available.
- Finally, while Q-Cells has indicated that it believes it can use metallurgical grade silicon in larger quantities than previously, we would note that there is still significant manufacturing breakthroughs required to transfer the technology from the lab to the shop floor and there is no guarantee that it can be done.

Silicon Efficiency

Silicon efficiency is a vital issue in the solar industry. In today's climate of silicon shortages and global demand for solar exceeding supply of modules, reducing the silicon intensity of modules allows the industry to generate more output, and thus more sales, out of a fixed amount of silicon. In the longer term, lowering the silicon intensity is a key element in the battle to reduce the cost of solar systems. In our view, the solar industry has already plucked the low hanging fruit of silicon efficiency through the reduction of wafer thickness to the 200–240 micron range. However, this does not mean that we will see a lull in silicon efficiency evolution. We anticipate that silicon efficiency could improve another 5–10% in 2007 driven by rising percentage of thinner wafer production (much of 2006 wafer production was in the 240–270 micron range) and an increase in cell efficiency.

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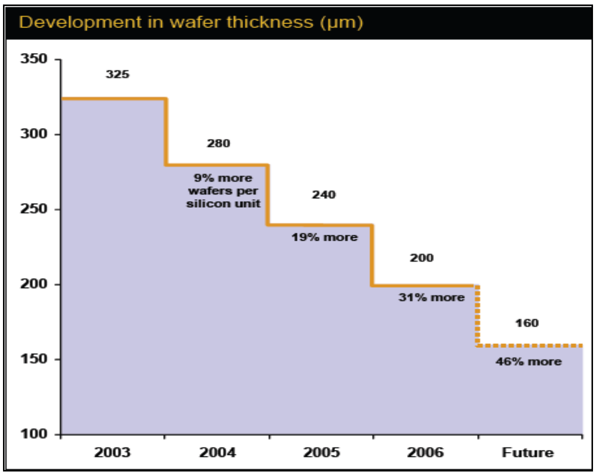
We use the phrase silicon efficiency to refer to the amount of silicon consumed per Wp of output. For example, if we indicate a silicon efficiency of 9 g/Wp this implies that the company requires 9 grams of silicon to produce 1 Wp of solar generation capacity. Therefore, if a company has feedstock of 500 metric tons of silicon, they would be able to produce 55.6 MWp of solar capacity. Crucially, there are two primary variables that impact the silicon efficiency:

Wafer Thickness. We do not expect significant deliveries of thinner wafers in 2007 as we suspect that the industry will adapt to a 200–240 micron standard while experimenting with thinner wafers. Despite this, we expect to see average delivered wafer thickness decline as much of 2006 production was in the 240–270 range while average delivered wafer thickness in 2007 should be closer to 200.

The logic behind the benefits of thinner wafers is fairly simple … if the wafer is thinner, then one can produce more wafers per kg of silicon. However, there are several issues that make this less straightforward. First, the wafer cutting procedure generates significant losses known as kerf losses (think of sawdust). When one has thinner wafers one must make more cuts and thus more kerf loss. While this can be partially offset by using a thinner wire in the cutting process, the net result is that the relationship between thinner wafers and wafer/kg output is not linear.

Chart 2: Wafer Thickness



Source: REC Capital Markets Day Presentation

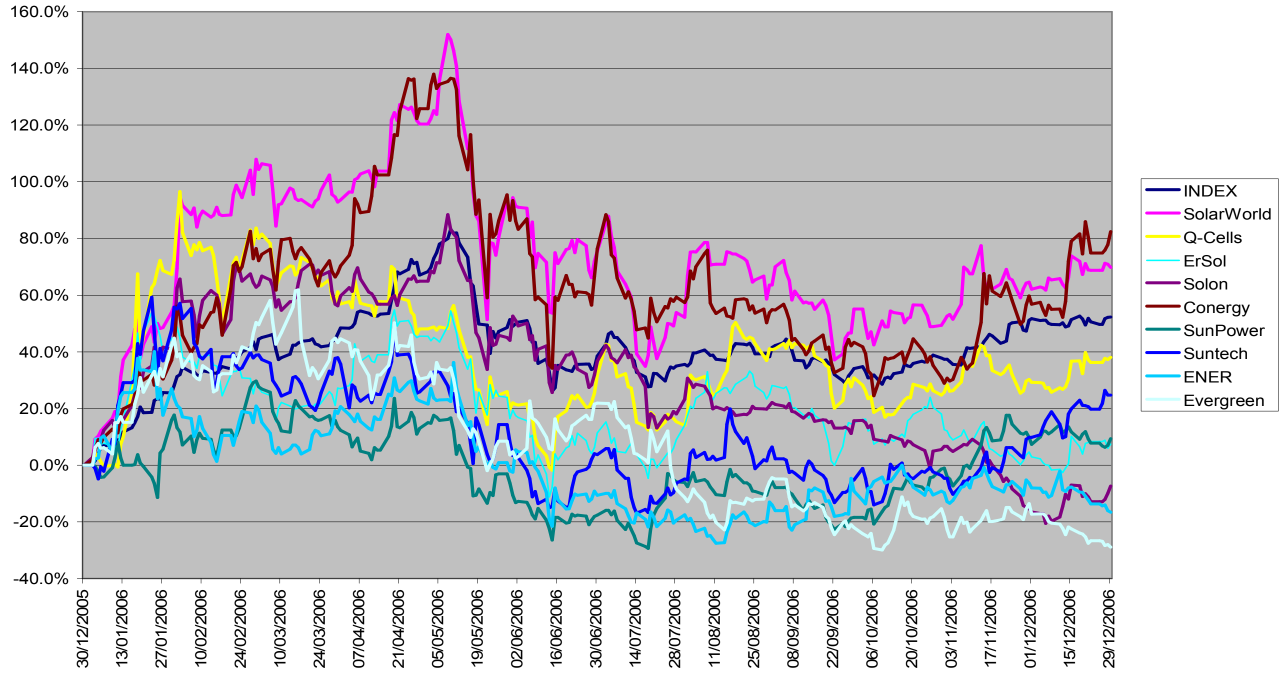
As Chart 2 shows, REC has reduced its wafer thickness by 38% from 325 microns in 2003 to 200 microns in 2006. However, this translates only to a 31% increase in the number of wafers per kg.

Cell Efficiency. We do not anticipate significant changes in average cell efficiency in 2007 as this is generally a gradual process. As a rule of thumb, each 100bp increase in cell efficiency results in a 7% reduction in the production cost/Wp. Cell efficiency has increased. This progress is steady but slow. Q-Cells reports that it has increased its average mass production poly-crystalline cell efficiency from 14.3% in 2002 to 14.8–15.6% by 3Q06. We do not anticipate a significant jump in industry cell efficiency in 2007; however, a 50-bp increase would be in line with incremental improvements.

2006 Review

Last year marked strong performance for both the solar sector and Jefferies Clean Technology research. Our top European pick SolarWorld was the second-best-performing share in the sector after being pipped at the post due to a late December rally for Conergy. Chart 3 below presents selected solar share performance for 2006. We note that REC, the largest listed solar company measured by market cap, is excluded as it did not list on the public market until May 2006.

Chart 3: Selected Solar Share Performance (2006)

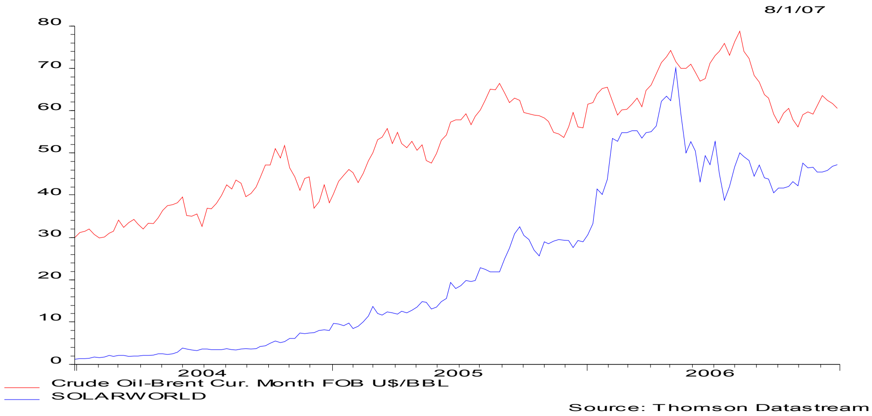


Source: Datastream

The previous year was a good one for solar shares with most leading solar companies generating positive returns. The year started well with a sector-wide rally triggered by a combination of President Bush's reference to renewable energy in the State of the Union Address and the passage of the California Solar Initiative. However, by May 2006 the rally had peaked and shares pulled back sharply as investors fretted over the impact of lower German feed-in tariffs on system prices. This retreat was exacerbated by the falling oil price. Once the correction had run its course, the sector has traded sideways with a fair degree of differentiation between shares. The main solar-specific issues surrounding the space over 2H06 were the outlook for German feed-in tariffs and evolution of the Spanish renewable energy legislation.

Chart 4 below illustrates the relationship between the oil price and solar shares (we use SolarWorld's share price as a proxy for the solar sector). While SolarWorld shares have clearly outperformed oil during the last three years, the results do show that there is a degree of correlation, in direction if not performance, between oil and solar. However, we would note that this correlation appears to have dissipated somewhat in 2007 as the profitable solar companies have been trading relative to their earnings. Solar companies without positive earnings tend to have a higher correlation with the price of oil.

Chart 4: Oil vs. Solar



Source: Thomson Datastream

Solar M&A

The last year was a fairly active one in the capital markets. Several IPOs, headlined by the REC listing in May 2006, were complemented by a range of acquisitions. As Table 4 below shows, most acquisitions were aimed at vertical integration with companies either moving upstream to secure feedstock or downstream to maximize sales potential. SolarWorld's opportunistic acquisition of Shell Solar stands out as the exception to the trend.

Table 4: Selected Solar Sector M&A 2006

Company	Target	Description	Comment
SolarWorld	Shell Solar	Leading crystalline cell manufacturer in USA	Shell was a motivated seller once MEMC broke its contract to supply silicon. SolarWorld was able to acquire production assets on the cheap but has also taken on Shell's bloated cost structure. SolarWorld expects the new operation to reach break even during 2007
ErSol	SRS	California based scrap silicon recycler	ErSol was attracted by SRS' 150 ton silicon inventory as well as future access to cheaper feedstock via the scrap silicon market
Solon	Blue Chip Energy	Austrian solar cell producer	Solon acquired 19% of BCE in order to help secure solar cell supply
SunPower	Powerlight	Largest US solar module installer	Allows the company to be fully integrated from wafer to installation. First major solar company to have this level of vertical integration although Conergy has announced plans that will result in a similar structure within 2-3 years.
SunTech	MSK	Leading Japanese solar module producer	Allows STP to penetrate the second largest solar market in the world (Japan). Cost to SunTech was low as MSK was operating at an estimated 30% utilization due to lack of solar cells.

Source: Jefferies International Ltd.

Table 5: Selected Solar Sector IPOs 2006

Company	Symbol	Market	Capital Raised	Description
REC	REC	Norway	€1.1bn	REC is the largest supplier of silicon as well as wafers to the solar industry and has a growing downstream cell and module business.
Aleo Solar	AS1	Germany	€95m	Aleo Solar is a German solar module producer
Renasola	Rena	UK (AIM)	£26m	Renasola is a Chinese silicon recycler that is integrating downstream to include ingot and wafer production
Solarfun Power	SOLF	USA	$150m	Chinese producer of solar cells and modules
Canadian Solar	CSIQ	USA	$115m	Canadian solar module producer with China based operations
First Solar	FSLR	USA	$400	Produces CdTe (thin film) solar modules
Trina Solar	TSL	USA	$90	Chinese solar system producer

Source: Jefferies International Ltd.

We would expect the 2006 trends to likely continue into 2007 with an attractive IPO pipeline. We would expect vertical integration to be an ongoing trend. Additionally, we believe that “silicon-rich” players may look to purchase idled downstream capacity from silicon poor wafer and cell makers.

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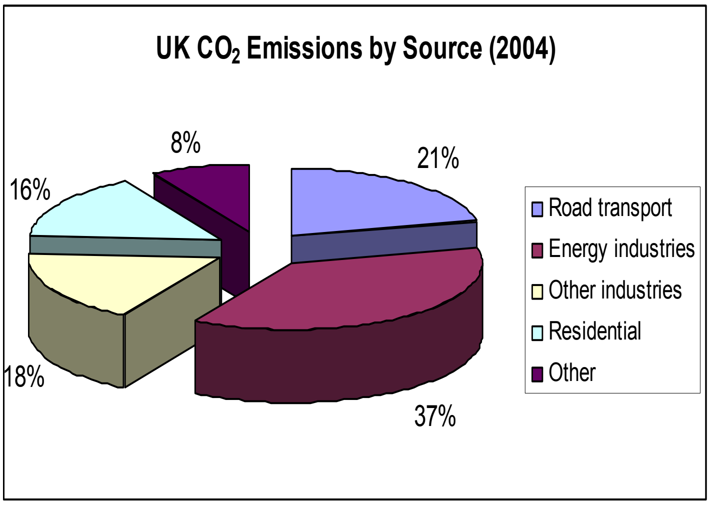
Solar Industry Primer – Summary

Higher oil and energy prices, coupled with increased environmental activism has led to increased global incentives for solar power. These incentives are increasingly making solar cost competitive and in many cases actually less expensive than retail electricity for the consumer, which has helped to drive the increase in global demand. While solar generation has grown at a ~30% CAGR over the past 10 years (albeit off a low base), it is only since 2004, with the passage of the Renewable Energy Law (EEG) in Germany, that the industry achieved sufficient scale and global penetration to attract mainstream customers. Previously, the industry consisted of early adopters, who chose solar for environmental purposes and not financial. The EEG provided a long-term financing program that has made solar installations a more attractive financial investment in addition to an environmentally friendly means of electricity generation. This coupled with new incentives in other regions of the world has allowed solar generation to grow into a mainstream industry. Please refer to the *Incentives* section for more details on global incentive programs.

We believe the spread of government-sponsored initiatives can be linked to three key issues:

Climate change. As illustrated in the chart on the right, the energy sector is the largest single source of carbon dioxide and thus a key target for emission reduction measures. Certainly, there are other means to reduce emissions via coal scrubbers, increased nuclear or wind power, but given that solar generation is emission free (post the initial refining of the silicon), we believe makes it attractive to lawmakers looking to demonstrate their pro-environment stance.

Chart 5: CO_2 Emissions



Source: DEFRA

Energy security. Much of the developed world relies on fossil fuel imports. In some cases, governments are concerned about the reliance on foreign supply, especially in the changing political landscape.

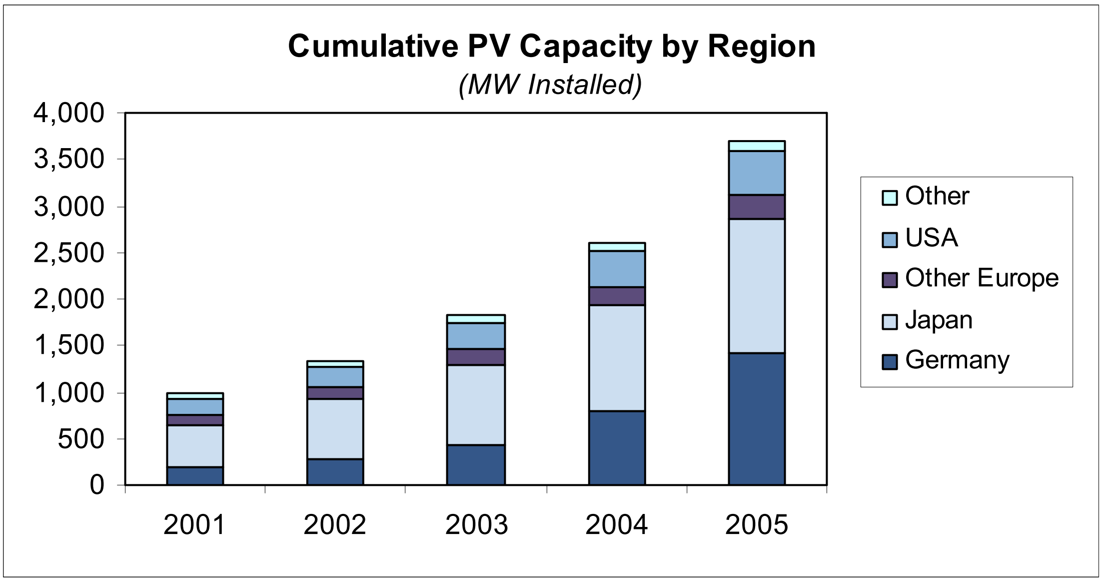
Energy prices. Rising demand for natural resources from the developing world, principally China and India, has led to higher prices for underlying raw materials (oil, natural gas, uranium) required to produce electricity. This, coupled with concerns over supply disruptions, has led to increasing energy prices. In the US, for example, electricity prices have increased an average of 4.5% a year for the last 10 years, but they are up 30% in some locations this year due to supply disruptions and high feedstock costs. Historically, the cost of solar has declined by 5% per year; therefore, should electricity prices continue to increase and solar prices decrease, the cost advantage that traditional forms of generation have over solar power also declines.

The ramp in demand for solar generation capacity has led to shortages of solar grade silicon (SGS), the key feedstock for crystalline solar cells, which currently represent more than 90% of all solar installations. While new technologies are being developed in labs, silicon based solar cells are likely to remain the main source for solar power, at least in the short term. Traditionally, the solar industry sourced low cost feedstock from the excess and off-spec production from silicon producers for the semiconductor industry. Previously, this “scrap” material was recycled or disposed of as waste. This worked well in a world where demand for SGS could be secured from the over-capacity in the silicon production industry. However, rising demand has eliminated most if not all of the slack capacity in the silicon industry. We will review the silicon supply situation in further detail later in this report.

Solar Market Growth

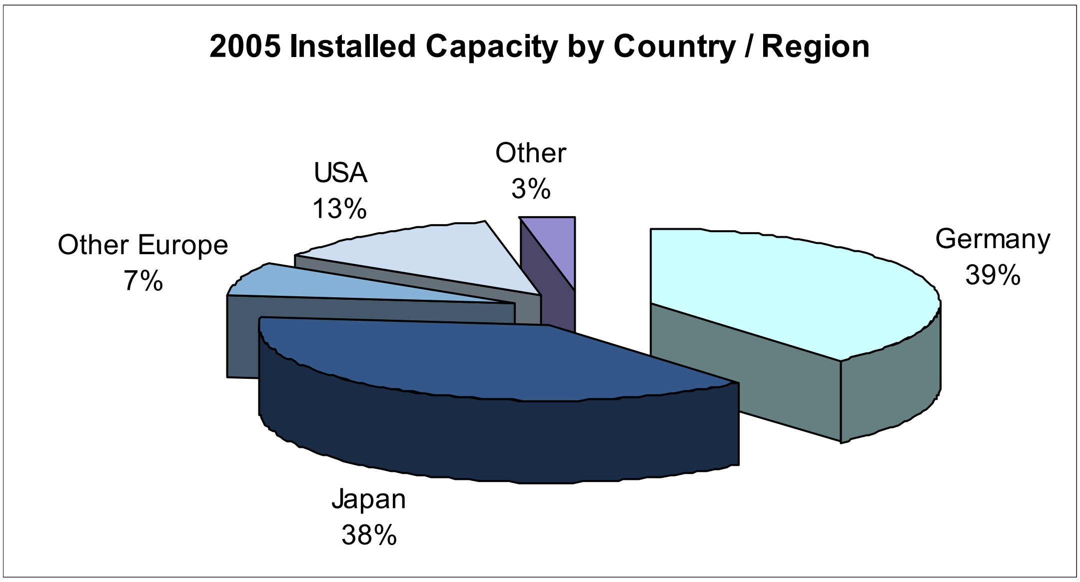
Installations to date have been focused on a few countries with Japan and Germany representing nearly three-quarters of total installed capacity as of YE2005. Germany has passed Japan in 2005 and now has the largest installed solar capacity base with approximately 1.4–1.6 GW as of YE2005. There is no single recognized figure for installed capacity as measurements vary from country to country. The data in Charts 6 and 7 are sourced from the International Energy Agency and does not include most emerging economies with China as a keynote omission.

Chart 6: Installed Capacity Growth 2001–2005



Source: IEA –PVPS Trends in Photovoltaic Applications 1992–2005 (www.iea-pvps.org)

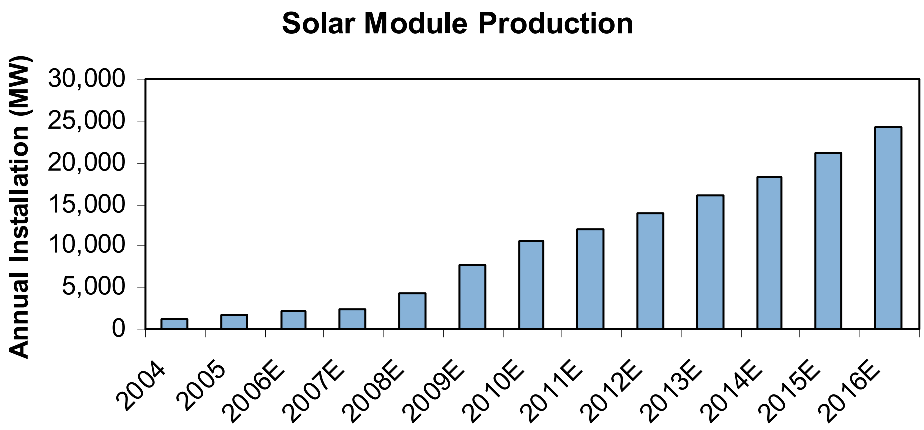
Chart 7: Global Installed Solar Capacity



Source: IEA –PVPS Trends in Photovoltaic Applications 1992–2005 (www.iea-pvps.org)

While growth in 2006 was somewhat muted because of limited silicon supplies, we anticipate that improvements in silicon efficiency and new silicon supplies coming on line starting in 2008 should allow the industry to accelerate its growth starting in 2008. We believe that demand is not the issue; supply of solar modules is the main limiting factor to industry growth in the near term. However, if the industry does not reduce the price to the end-customer in line with the reduction in the incentives, demand can be temporarily slowed. We project that annual solar production will increase from 2.2GW in 2006 to 10.5GW in 2010E, which represents ~45% CAGR, with most of the growth back end loaded because of the lack of new silicon supply until 2008. This forecast is based solely on announced silicon capacity expansion plans and could prove conservative if silicon manufacturers announce additional expansion plans for 2009–2010.

Chart 8: Solar Growth Forecast



Source: Photon International & Jefferies' Estimates

Cost Competitive

The goal of the solar industry is to become cost competitive with traditional forms of generation without incentives. Currently, incentives are required for solar to be cost competitive. Incentives are key to the solar industry as they serve as an accelerator for sales to allow producers to reach a scale not possible without government support. The chart below illustrates the long-term goals of the solar industry. The declining lines show projected production costs for solar generation capacity in various parts of the United States while the rising lines show projected retail prices for electricity. As Chart 9 shows, depending on location (solar insolation metrics), the combination of lower solar costs and higher electricity costs will make un-subsidized solar installments potentially more economical than purchasing from the grid. As Table 6 demonstrates, solar generation is a small part of the overall electricity market in the US. Solar generation accounted for only 0.018% of energy generation in 2005, and, even assuming a 31% growth rate, by 2010, solar generation would account for only 0.062% of total production. In fact, even continuing that growth rate until 2025 yields less than 3% of total electricity needs. Therefore, we do not believe that the growth in the solar industry should have any impact on the pricing of electricity for the foreseeable future. Also, while a recession or a drop in energy prices could negatively impact demand for solar, we believe the long-term trend for electricity pricing is higher due to growing global demand coupled with increased competition for raw material inputs. These industry dynamics are likely to continue to support financial investments in the solar industry over the longer term.

Table 6: Solar Only a Small Percentage of Total Energy Production

	2005	**2010**	**2015**	**2020**	**2025**
US Solar Industry Installed Base (MW)	530	2,045	7,888	30,433	117,409
million kwh @ 1200 hrs./yr.	636	2,454	9,466	36,520	140,891
US Energy Demand (million kwh)	3,621,000	3,978,318	4,370,895	5,276,090	5,796,731
	0.018%	**0.062%**	**0.217%**	**0.692%**	**2.431%**
Solar Growth	31%				
US Energy Volume Growth	1.9%				

Source: Energy Information Administration, Photon International and Jefferies Estimates

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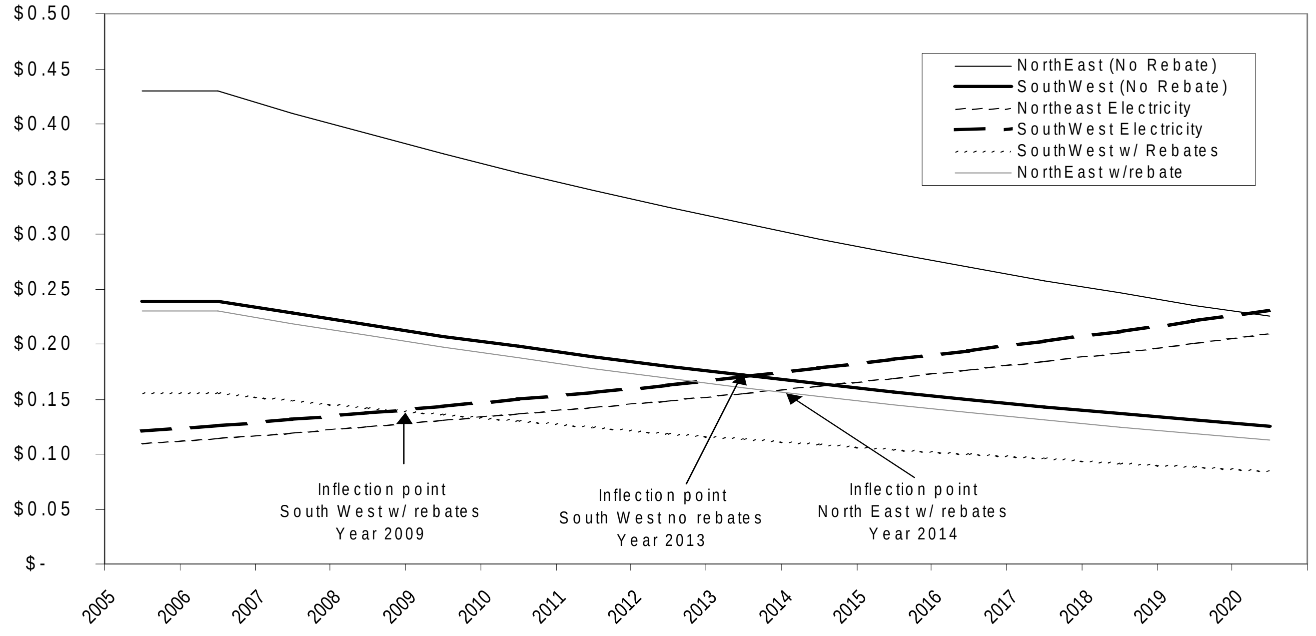
Based on current trends, in the southwest US, this could occur by 2013. Importantly, California's solar incentive program continues until 2016, past the point when solar is expected to be cost competitive with retail electricity without incentives. As well, California is key to the growth in the US because it is the largest solar state currently, but also it is typically on the leading edge of environmental issues that are often copied by other states. Already, Arizona and Pennsylvania have bills that are based on California's Solar Initiative.

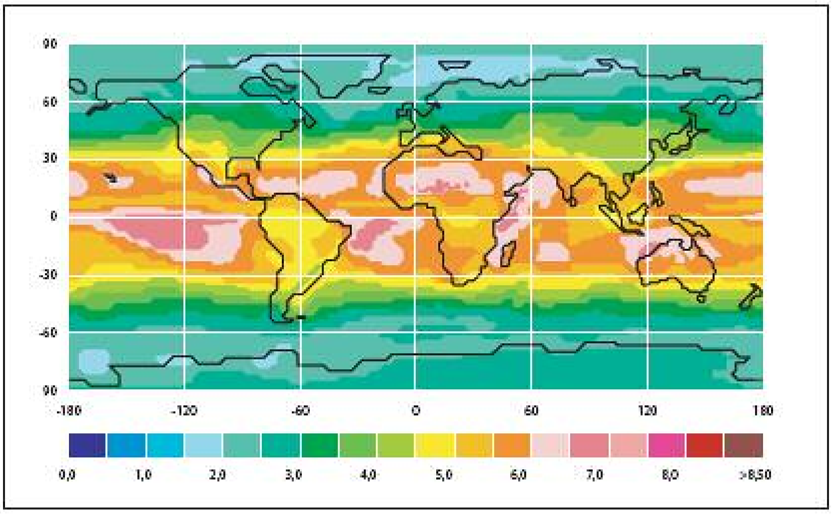
Chart 9: Solar vs. Traditional Production Cost



Source: Jefferies' Estimates

It is fairly self-explanatory that solar generation is a better proposition in sunnier climes. Higher solar radiation would translate to more sun hours, which would allow increased generation per installed unit and therefore reduce the installed cost of production. An interesting note is that solar installations are currently strongest in countries where the solar radiation characteristics are relatively poor (Germany and Japan). However, Spain has adopted a feed-in tariff plan based on the German model, which should lead to demand-pull moving southward from Bavaria to the Iberian Peninsula. A longer-term scenario could be increasing commercial scale installations in regions with very high solar radiation (North Africa & Central America) either for domestic use or for exports to energy-hungry but relatively sun-starved neighbors.

Figure 1: Solar Radiation



Source: NASA & REC Annual Report

Incentives

Solar generation capacity cannot, except in selected locations, compete on a cost-effective basis against traditional coal or natural gas fired energy generation. The up-front cost and relatively low utilization rates (solar power can only be generated when the sun is shining) for solar installations result in an installed production cost that is approximately 10x the cost of traditional generation although approximately 3–4x the more appropriate retail price of electricity. Given this situation, government initiatives are required to create incentives to invest in expensive and relatively inefficient solar generation capacity. A well-designed initiative will provide both the security of longevity to attract investors to the arena and will have incentives to reduce the up-front production cost of capacity. Broadly speaking, incentive schemes worldwide can be split into two camps, the feed-tariff model and the subsidy tax relief model. The reason for the difference in incentive programs is largely related to the tax systems in the individual countries.

Cost of Production Is Inappropriate Comparison. When comparing the viability of solar power costs, we think it is important to compare the cost of solar production with the retail cost of energy from the utility company and not the cost of generation for the utility. For example, a utility can produce electricity via coal for ~$0.03–0.05/kwh, versus $0.25–0.30/kwh for solar. However, coal production cannot be ramped up quickly to match demand, which requires the use of natural gas plants that cost $0.05–0.07/kwh. While still significantly below solar costs, the corporate or residential customer does not pay that amount either, but rather the market rate, which averages $0.10–0.15/kwh in the US. While that still leaves a gap between the cost of solar power and the retail price of grid electricity, the difference is made up through government incentive programs. Additionally, the calculation for solar power is based on the typical warranty life of 20 years. If the time frame is extended, as is likely to be the case in real world applications, then the production cost for solar becomes even more competitive. For example, by assuming a 30-year useful life instead of a 20-year useful life, the production cost would decline by $0.07/kwh. Therefore, a system calculated at $0.30/kwh would produce electricity for $0.23/kwh, which is nearly competitive with retail prices today.

Feed-In Tariff Model (Europe)

The feed-in model is best personified by the EEG introduced in Germany in 2004. Rather than focus on subsidizing the cost of the installation and / or reducing the electricity bill, it guarantees a high feed-in tariff to create an attractive financial investment. Under the feed-in tariff model, 100% of production is exported to the grid at a tariff guaranteed for 20 years (in the German case), while electricity consumed is imported from the grid. Thus, the solar panel is a financial investment rather than an environmentally friendly cost savings plan.

Table 7: German Feed-In Tariffs

Installation Type		2004 Tariff (€/kWh)	Annual Tariff Reduction
Rooftop Installments			
	<30 kWp	57.4	
	30-100 kWp	54.6	5%
	>100 kWp	54.0	
Façade Installments			
	<30 kWp	62.4	
	30-100 kWp	59.6	5%
	>100 kWp	59.0	
Open Air Sites		45.7	6.5%

Source: Jefferies' Estimates

To illustrate the investment potential of solar installation, we have constructed the following scenario. Back in 2004, a clever Bavarian farmer with a sun-drenched barn decided to install a 1 kWp unit at a cost of €5000. This barn has a south facing roof and thus the installation was able to enjoy 1,000 sun hours leading to 1000 kWh generation over the course of the year. As the farmer installed his panel in 2004, he was able to obtain the peak feed-in tariff available under the plan of €0.574 per kWh. As a result, at the end of the first year, the farmer had received payments from the local grid totaling €574. However, solar module performance degrades over time and 1000 kWh output is not likely to be repeated indefinitely. We assume module performance will degrade 15% over 20 years and the farmer's average annual payment will decline to approximately €490 by the end of the 20-year guarantee period. Based on these assumptions, a solar installation investment in 2005 generates an annual yield of 9.9–11.5% and an IRR of 8.8% although subsequent tariff reductions and flat installation prices have reduced this IRR to approximately 7% for investors who install in 2006, which still compares well to 10-year German government bonds yielding 3.3%.

The feed-in tariff may also be refined to provide incentives to reduce the cost of a solar installation. The EEG calls for the feed-in tariff to decline 5% every year. Thus investors who installed their solar panels in 2005 will receive a guaranteed tariff of €0.545/kWh while current investors will receive €0.518/kWh. If we assume that the installed price for 1 kWp has remained stable, the returns on the solar investment will decline and demand could be reduced.

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A key determinant to the success of a feed-in tariff model is determining who will pay the premium for solar power. Under the EEG, the cost of solar power is spread amongst households while industry and business are exempt. However, given that solar represents approximately 0.2% of total electricity generated in Germany, the impact is minimal. We have calculated that, at the current forecast growth rates and assuming that all other electricity prices are flat, higher priced solar power will lead to a 1% annual increase in home electricity bills over the next 10 years.

Subsidy/Tax Relief Model (US)

The subsidy/tax relief model is best demonstrated by the incentive programs in the United States. In contrast to the more common feed-in tariff model implemented by Germany, Spain, S. Korea and others, the tax relief/subsidy model provides tax relief and or subsidies on the initial cost of the system and not over time. Additionally, these tax incentives are a combination of federal, state, and even local incentives. In certain states, including California, NJ, and NY, cumulative incentives could subsidize two-thirds of the total costs of a new solar system. A breakdown of the incentives provided by the United States is discussed below.

Federal Incentives. The United States Congress passed President Bush's Energy Bill in late '05 and it became law in January 2006. Within the larger bill was specific tax credits for renewable energy and in particular, photovoltaic installations. For commercial applications, the federal government provided a 30% tax credit (no cap) for the installation of a solar system. Similarly, the energy bill allows for a 30% tax credit for residential photovoltaic systems as well, but there is a $2000 cap on the credit per year, which in most cases is not sufficient to meet the consumer's needs. A typical residential solar system in the US will cost $20,000–30,000, so the federal incentive for residential applications on its own is not enough to make solar cost competitive with retail without additional incentives. In total, this bill is much more attractive to commercial installations because of the lack of a cap on the incentive program. We believe this benefits those solar companies that specifically target the commercial market. Importantly, this is the first federal incentive program for US solar installations in over 10 years. While the current bill expires at the end of FY08, we believe that strong bi-partisan support coupled with high energy and oil costs are likely to result in an extension of the program and potentially an increase in the residential incentive cap. In fact, a couple of bills are currently in Congress that if passed would significantly increase incentives for the solar industry.

State Incentives. In total, over 40 US states have some sort of incentive program and have mandated net metering. The largest PV state California through the California Public Utilities Commission (CPUC) passed the California Solar Initiative (CSI). The CSI is a long-term incentive program that will provide $3.2 billion in rebates to both residential and commercial installations of solar systems. The goal is to install 3000 MW of solar modules by 2016, or roughly 2x the current global demand. The initial rebate is slated at $2.80 per watt, or roughly one-third of the total cost of an installed system. These incentives are on top of the federal incentives and cumulatively could reduce the cost for a system by two-thirds. Additionally, in certain locations, municipalities will also offer financial incentives or attractive financing to subsidize solar installations as well.

As Table 8 indicates, two states represent almost 90% of the installations in the US. California represents 70% of the solar installations, while New Jersey is 18%. We believe that as states pass new incentive programs, there is significant potential to drive industry growth. And with the passage of a longer-term federal incentive program, we think it is likely that additional states will follow California's lead.

Table 8: Solar Applications

Grid Tied Installations	2005	2006	'05–'06 Change	% of total
California	52015	70573	36%	70%
New Jersey	5526	17858	223%	18%
New York	1418	2709	91%	3%
Nevada	494	2619	430%	3%
Arizona	1549	2088	35%	2%
Massachusetts	640	1452	127%	1%
Colorado	179	933	421%	1%
Texas	593	714	20%	1%
Connecticut	174	541	211%	1%
Oregon	353	529	50%	1%
Others	699	1450	107%	1%
Total	63640	101466	59%	100%

Source: SEIA

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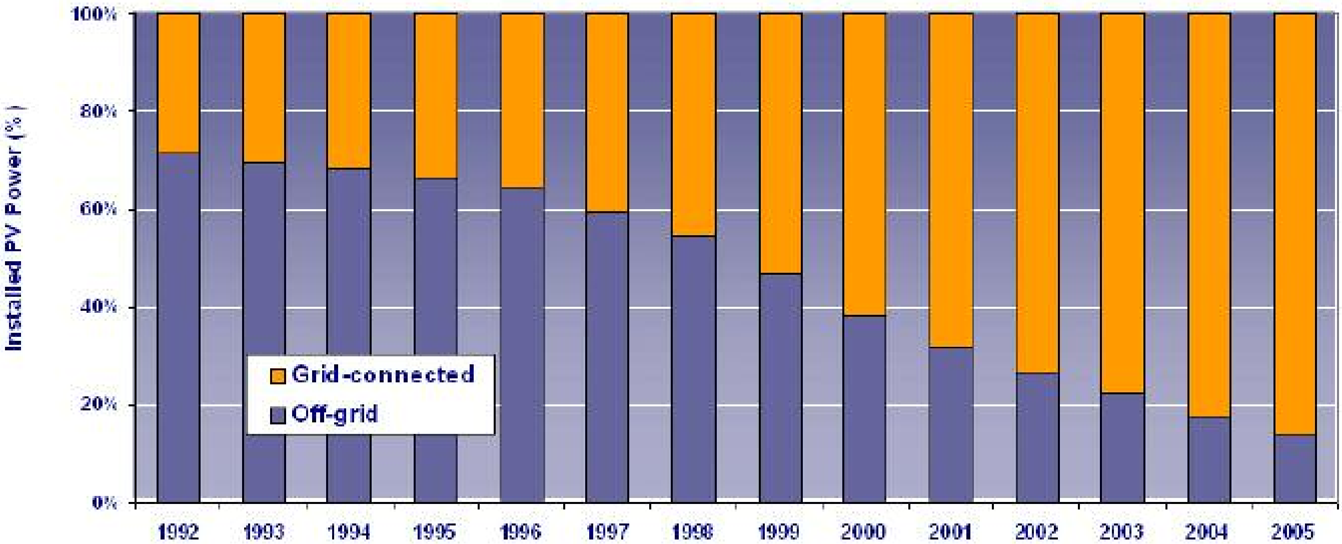
Net Metering. The US incentive programs are based on a process called net metering. This process requires the utility companies to buy electricity generated from solar systems at the retail price of electricity. This electricity is then fed back into the grid. In this arrangement, the customer that generates electricity would still buy his/her electricity from the grid; however, he would only pay for the difference between the amount of electricity produced and the amount of electricity consumed. In contrast to Europe, US installers only have an incentive to match their solar installations production with their actual use of electricity. If a solar system generates more power than is used by the customer, then the utility will still buy the excess power, but instead of paying the retail price of electricity to the solar generator, the utility is only required to pay its cost to produce the electricity. The cost to produce electricity for the utility may be only one-third of the retail price. Therefore, in most cases, we do not think it makes sense to build a solar system larger than the customer's demand for electricity.

Increasing Grid Connections for Solar. Incentive programs also have an impact on the application of solar power. The rise in incentive programs has not simply increased the volume of solar installations, it has also changed the nature of solar installations. In the past, solar was often used in off grid applications (rural electrification, telecom stations, vacation homes, etc.), while the arrival of grid feeding or grid supplementing incentive programs have increased the quantity of on grid applications for solar. This is highlighted in the chart on the following page.

Chart 10: Solar Applications



Source: IEA –PVPS Trends in Photovoltaic Applications 1992–2005 (www.iea-pvps.org)

Regional Developments

Over the coming years, we expect continued growth in solar based on new incentive programs for renewable sources in locations including Spain, Italy, Greece, S. Korea, China, California, and the United States, which will augment existing incentive programs in Germany and elsewhere. These subsidies effectively eliminate the cost differential between purchasing electricity off the grid and producing electricity via photovoltaic processes.

The United States – Potential Driver of Solar Growth

While the United States is the third largest solar country in the world, it has not approached its potential contribution to the solar industry. Currently, the country only gets 0.018% of total energy production from solar energy. And even if the industry were to grow over 30% a year for the next 20 years, it would still amount to only 2.4% of total energy production. Therefore, we believe the industry can grow at a rapid pace for many years without eliciting a competitive response from the traditional forms of energy generation (natural gas, coal, etc.). Importantly, new incentive programs that are currently in Congress could inspire even faster growth.

As Table 9 below indicates, the proposed bill would significantly increase the federal incentives in the US. This bill is commonly referred to as the "Robin Hood Bill" because it calls for the elimination of $14 billion in annual subsidies to the oil industry and redirecting those subsidies to renewable energy subsidies. The passage of this bill would be the largest single incentive program to date. As a comparison point, the California Solar Initiative calls for $3.2 billion in subsidies over an 11-year period whereas this bill would provide $14 billion per year. Even assuming that solar is only a third of the subsidies (likely more) that would amount to $4.7 billion annually. The key components of the new bill are the elimination of the cap on residential systems and the duration of the program.

We believe this will provide long-term visibility that will likely spur additional incentive programs from the individual states, which is necessary for the cost of solar electricity to be cost competitive with retail electricity. Importantly, following California's lead, several states are proposing new incentive programs.

Table 9: Securing America's Energy Independence Act

Securing America's Energy Independence Act (HR 550, Senate 590)
Extends Federal Tax Credits for PV installations through 2016
PV credit of $3.00/watt
Eliminates $2000 cap on residential systems
Not subject to Alternative Minimum Tax
Allows for accelerated depreciation of system costs
Retroactive to January 2007

Source: US Congress

US State Goals Indicative of Future Incentive Programs

As Table 10 indicates, 23 states have established aggressive goals for renewable energy production, with 17 of the states calling for a minimum of 10% of energy production from renewable sources. In order to meet these goals, the states will likely have to provide incentive programs for the adoption of solar, wind, geothermal, etc. These incentive programs are key to the growth of the solar industry in the US as the federal incentive program is not enough to bring the costs of solar down to grid parity without additional incentives from the states.

Table 10: US State Goals for Renewable Energy Production

State	Goal	Deadline
NY	24%	2013
NJ	22.5%	2021
CA	20%	2020
NV	20%	2015
HI	20%	2030
PA	18%	2020
WA	15%	2020
AZ	15%	2025
MT	15%	2015
RI	15%	2020
DC	11%	2022
CO	10%	2015
NM	10%	2011
MN	10%	2015
WI	10%	2015
ME	10%	2017
CT	10%	2010
DE	10%	2019
IL	8%	2013
MD	7.5%	2019
MA	4%	2009
VT	all new energy	2012
TX	5.9GW	2015
IA	0.1GW	

Source: DSIRE.ORG

Japan – Growth Post Incentives

Japan presently is one of the most mature PV nations, mainly because it was the first to introduce large incentives for PV systems. It currently has the second largest installed base of PV (Germany #1 in 2006). We believe Japan represents the future of the industry post incentive driven growth. The majority of installations in Japan are residential PV rooftop systems. Japan introduced rebates in 1994 to offset the high cost of solar at that time and due to the long-term nature of those incentives it was able to bring down the cost of PV by 72% in 10 years. At this point, the Japanese government has eliminated most of the incentives as the PV market has now reached maturity in this country. Given the high retail electricity prices in Japan because of high import costs for raw material inputs, solar energy has become cost competitive with its traditional fossil fuel counterparts, which is the reason for the cutback in solar incentives. Early forecasts for 2006 installations indicate growth of ~15%, which we believe is a positive indicator of the long-term viability of the industry post incentives.

Germany – Current Market Leader

The German PV market recently surpassed Japan as the largest solar market in the world based on installed MW of PV power in 2005. The main reason for this growth has been the favorable incentives for construction of PV systems that was enacted as law four years ago. Currently, under government-sponsored programs, utilities buy solar electricity on systems for €0.515/kwh and the utility sells the electricity back to the customer at €0.18/kwh. The law guarantees this tariff for 20 years, with 5% annual decreases in the buyback rate for attached systems and 6.5% decrease for free standing structures. For example, if an individual spends €5000 on a solar system and generates electricity for 1000 sun hours per year (German average), they would receive a net benefit of €540 euros per year. Over 20 years, this would equate to a risk-free rate of return of 7%, which is significantly higher than the yield on Eurobonds (~3.3%). The bottom line is that these incentives are likely to continue to result in strong demand growth in the German market.

Spain – Next Driver of Industry Growth

Due to recent government incentives similar to those in Germany, Spain has quickly surfaced as the fourth largest solar market. Spain, specifically its southern regions, has the highest solar insolation (sunlight capable of producing electricity through photovoltaic processes) levels in all of Europe leading it to be an ideal candidate for photovoltaic energy. Importantly, in 2004, Spain passed its own solar incentive program. The incentive program consists of a combination of national grants, soft loans for PV systems and tax deductions for loans. The main incentive, much like its German counterpart, is a pull-based incentive, which pays consumers above-market rates for on-grid PV generated electricity. The fixed feed-in premiums are €0.42/kWh for installations up to 100kW and €0.22/kWh thereafter. While somewhat lower the German model, the Spanish incentive program is more attractive because the feed-in tariffs are guaranteed for 25 years versus 20 in the German program. Additionally, Spain receives significantly more sun than Germany (1800 hrs./year versus 1000 hrs./yr.), which will yield 80% more electricity for the same sized system. Because of these benefits, we believe Spain is likely to pass Germany in PV installations over the next five years.

Table 11: Selected European Solar Feed-In Tariff Plans

Country	2007 Tariff*	Digression	Duration	Tax Credit	Other
Germany	€0.49 / kWh	5%	20 Years	No	EEG is up for review by YE2007
Spain	€0.44 / KWh	Inflation – 1%	25 years	No	Current regime is capped at 371 MW
France	€0.30 / kWh	N/A	20 Years	50% (max €8000)	Significant non-financial barriers slow market growth
Italy	€0.40 / kWh	2%	20 Years	No	See France
Greece	€0.45 / kWh	N/A	20 Years	20% (max €700)	Many potential investors are waiting to see if solar investments could qualify for EU funds.

* Small scale non-integrated systems

Source: Photon International, Jefferies International

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China – Long-term Growth Driver

While the global solar market is expanding rapidly without significant growth in China, recent announcements by the Chinese government could accelerate this growth further. In January 2006, the vice minister for China's economic planning board, Zhang Guobao, indicated that it was requiring power companies to generate 5% of their output from renewable sources by 2010 and 10% by 2020. During our visit to China in April 2007, the Chinese government increased this goal to 15% by 2020. The major sources of renewable energy are wind and solar (hydro is excluded from the directive). Assuming only 25% of the directive is generated from solar, it would equate to 2010 demand of 7.5 GW, or 4x the entire global market in 2006. However, we must note that while the government has made these proclamations, there has not been a centralized incentive program to date, which leads us to question the attainability of the 2010 goal.

Other

Greece has recently adapted a feed-in tariff mechanism. This could be a potentially huge market as Greece enjoys ample sunshine along with relatively high electricity prices on the isolated power systems of the Greek islands. France is also rumored to be considering adopting an attractive feed-in tariff. Given the solar radiation characteristics and high GDP per capita levels, with the right program, France could emerge as a potentially massive market.

Sustainability of Incentive Plans

Incentive plans serve two key roles. They are both a support mechanism for an industry that could not thrive without them and an accelerator of price declines that aim to make solar a truly cost-competitive form of generation. A key element of any incentive program is its predictability. Investors are looking for sustained long-term demand before they are willing to commit financial resources to production capacity. Lack of long-term commitment from state and federal governments in the United States, for example, have left it in a far weaker position than its wealth and climate might otherwise predict. We believe that the current crop of incentive plans looks to have a relatively secure future for the following reasons:

- **Job creation.** The EEG will come up for formal review at YE2007 in Germany. We feel there is only a minimal chance of significant alterations as the law has support across the political spectrum and the solar industry currently employs 30,000 people and rising in eastern Germany. These gains are being felt in varying degrees around the world.
- **Energy prices and security**. Many investors and consumers believe that high and rising energy prices are here to stay and that alternative energy is an excellent way of both solving the energy dilemma while also addressing the environment.
- **Environment.** Politicians of all stripes are beginning to join the scientific consensus that global warming is a reality and that actions must be taken to reduce man's impact on the climate. Or quite simply, politicians do not want to be viewed as anti-environment given the public support for environmental causes.

Pricing Forecasts

Most incentive programs are designed to encourage installed prices of solar power to decline over time. This can be done through annual reductions in the feed-in tariff or via planned reductions in capital subsidies based on time or accumulated installed volumes. For example, the German feed-in tariff for rooftop installation declines 5% annually and has fallen from €0.57 per kWh in 2004 to €0.518 in 2006. However, installed prices have remained stable, which has led to a contraction in the IRR of solar investment from 9% in 2004 to 6.5–7.0% in 2006 (based on 1000 sun hours and a stable €5,000/kWp installed cost). Should installed prices remain stable in 2007, the returns to solar investors would fall below 6%, and, although this remains more than 200bp higher than government bond returns, solar demand could suffer.

We believe price for solar modules and installed capacity will fall. The process would likely begin in Germany in 2007 and would spread globally, although the regional speed of decline would depend on the construction of individual federal or state incentive programs. We expect prices to fall 5% annually, driven by feed-in tariff reductions in Germany. However, given the fact that pricing did not decline in '06, the '07 pricing could fall at a faster rate to increase the rate of return to the end customer.

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We base our belief that prices will decline on the following:

- **German feed-in tariffs** are expected to decline again in 2007, and, with forecast IRR in optimal sites falling below 6% for the first time, demand could suffer. There has been much talk of a flattening of German demand in 2006 as the lower feed-in tariff has not been matched with lower prices leading to reduced returns. We believe that demand in Germany remains very strong, but that the rate of growth has slowed. Looking forward, newer markets such as Spain and Greece are likely to lead demand.
- **The EEG is scheduled for review** at the end of 2007. German politicians must decide if they wish to maintain, modify, or eliminate the highly successful solar feed-in tariffs. We believe that the solar industry will look to reduce its prices in Germany not only to maintain demand in the largest solar market but to show good faith to the legislators that, after a brief demand-driven period of stable price, the cost of solar will begin to fall.
- **Price parity** with traditional sources of energy remains as the "Holy Grail" of the industry. Until solar can compete with traditional sources of energy on a level playing field, the industry will be dependent upon incentive programs as the occasionally capricious politicians upon which the programs rely. It is interesting to note that in Japan, where high-energy costs have made solar generation cost competitive during daytime hours, demand has remained stable despite the virtual elimination of solar subsidies.

Another key discussion point is where price cuts will be felt. Governments and consumers are only interested in the cost of the installed capacity, not the price of wafers, cells, and modules. We assume that installed prices are to fall 5% per year and that silicon contract prices are unlikely to decline very much in the next few years. We would expect the installed capacity price cuts to be felt along the value chain from solar wafer producers right down to the installers. However, while we expect the magnitude of cuts to be shared, we expect the rate at which the cuts impact each segment to be different. In our estimation, wholesalers and installers at the bottom end of the food chain will initially feel price cuts but that the pain will fairly quickly be shared with upstream suppliers. However, as not all markets will see price declines at the same rate and time, some solar industry participants can offset price cuts in one market with increased sales in another.

While falling prices may at times give investors the vapors, we believe that this is a *positive* trend for the industry. Falling prices should allow solar to reduce the cost advantage of traditional energy and bring solar closer to reaching its "Holy Grail" cost parity. Furthermore, we believe that governments will be much more likely to support solar incentive programs if they can see progress in reducing costs. However, if we are pushing for falling prices, we must address …

Cost Reduction

To begin, we must first outline the scope and focus of falling prices. As previously indicated, we believe that prices for installed solar capacity will fall 5% a year and that the impact will be shared across the industry. Therefore, each segment of the industry must find ways to lower its costs or face margin erosion. There are several ways in which costs can be reduced. Below, we examine the major sources of cost cutting.

Economies of Scale

The solar industry has ample room to benefit from increasing economies of scale. It is important to note that, given the small size of the industry, individual companies have not yet had a chance to grow to optimum size. Case in point, the three largest listed European solar companies (SolarWorld, REC, & Q-Cells) had combined revenues of less that €1 billion in 2005. We believe the growth in the industry will lead to significant improvements through higher automation, more straight through processing, and improved production yields. This process is at its very early stages and we should see the benefits in the coming quarters and years as operating costs as a percentage of revenue should show stable to positive trends despite falling unit prices. We believe that the solar industry will likely experience similar economies of scale as the semiconductor industry. Over the last 30 years, for every doubling of production in the semiconductor industry, the per unit costs have declined by 28%. Similarly, Solarworld estimates that for every doubling of its production, per unit costs have declined by 20%. Therefore, we believe the solar industry will see similar benefits as other industries that ramped to efficient scale.

Silicon Efficiency

Crystalline silicon solar cells represent 90%+ of the total solar market and rely on silicon as the key feedstock. The surging demand for solar cells has led to a jump in silicon prices. Prior to the EEG, most solar companies could secure feedstock at $20/kg with little to no difficulty, while current silicon supply contracts are being priced above $100/kg for initial deliveries (please see *Silicon Supply Constraint to Industry Growth* section for further details). On a spot basis, the price for silicon has exceeded $200/kg. As a result of the surge in price, silicon wafers now represents up to 80% of the cost of a solar cell and has lead producers to look for producers to maximize their output from their silicon. There are two key areas to study:

- **Thinner Wafers**. Reducing wafer thickness can lead to a higher volume of wafer production from a static amount of silicon. However, a reduction in wafer thickness does not lead to a linear increase in wafer production unless kerf, or cutting in layman's terms, losses can be reduced as well. In the *Thinner Wafers* scenario shown in Table 12, we assume that wafer thickness is reduced 37% from 240 microns to 175 microns but the silicon cost per Wp (Watt peak) falls only 17% due to constant wire thickness.
- **Cell Efficiency**. Similarly, increased cell efficiency would allow each cell to generate more electricity and increase output potential from a static amount of silicon. In the Higher Cell Efficiency scenario shown in Table 12, we assume that cell efficiency improves 12% from 15% to 17% (17 / 15 = 1.12) and the Wp production per cell increases from 3.6 to 4.1. At this step, there is a linear impact between efficiency improvements and cost savings.

As Table 12 demonstrates, these two steps can produce a combined silicon cost savings of 29%. We point out that the assumptions we have used are not best-case scenarios. In fact, the best in class in the industry have already exceeded these levels. Wafer producers have already reached 200 micron wafers in standard production and 150 microns in lab conditions. Similarly, the best in class silicon based cell efficiency is over 21%, so we believe 17% cell efficiency for polycrystalline cells should be achievable on a mass scale within a couple years.

Table 12: Silicon Savings

Base Scenario							
1 Kg Silicon	=	29 Wafers *(@ 240 microns)*	x	29 Cells w/ 3.6Wp Output	*(@ 15% cell effiency)*		
1	=	29	x	3.6		=	104.4 Wp Production
€ 40						=	€ 0.39 Silicon cost/Wp
Thinner Wafers							
1 Kg of silicon	=	35 Wafers *(@ 175 microns)*	x	35 Cells w/ 3.6Wp Output	*(@ 15% cell effiency)*		
1	=	35	x	3.6		=	126 Wp Production
€ 40						=	€ 0.32 Silicon cost/Wp
					Cost Savings		***17%***
Higher Cell Efficiency							
1 Kg of silicon	=	29 Wafers *(@ 240 microns)*	x	29 Cells w/ 4.1 Wp Output	*(@ 17% cell efficiency)*		
1	=	29	x	4.1		=	118.9 Silicon cost/Wp
€ 40						=	€ 0.34 Silicon cost/Wp
					Cost Savings		***12%***
Thinner Wafers & Higher Cell Efficiency							
1 Kg of silicon	=	35 Wafers *(@ 175 microns)*	x	29 Cells w/ 4.1 Wp Output	*(@ 17% cell efficiency)*		
1	=	35	x	4.1		=	143.5 Silicon cost/Wp
€ 40						=	€ 0.28 Silicon cost/Wp
					Cost Savings		***27%***

Source: Jefferies International

Chart 11 below has been drawn from Renewable Energy Corp's (REC) presentation. It illustrates the potential for cost reduction potential available in the industry. REC has projected that unit (measured as solar modules) costs can be reduced by 50% by 2010. Given that we forecast unit prices to fall by only 20% in that period, this would indicate that there is scope for margin expansion despite falling prices. We use REC as an example as it represents a fully integrated silicon to module producer, which is likely representative of the industry in total.

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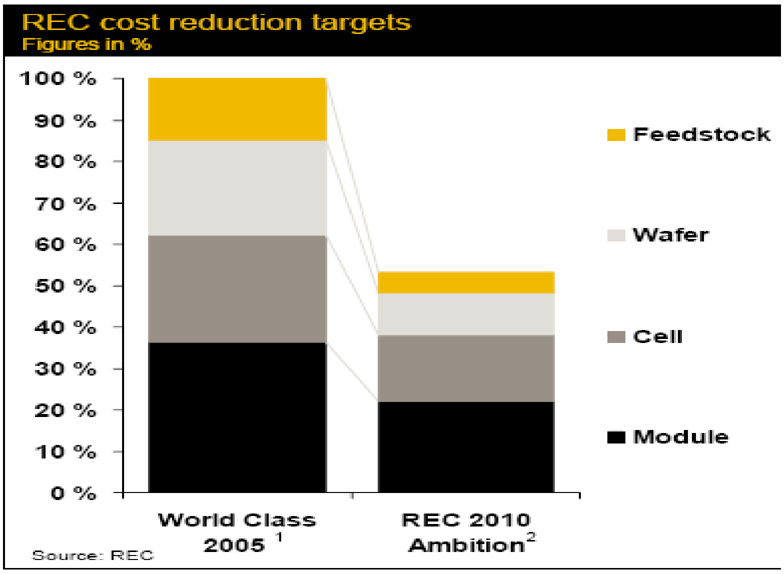
Chart 11: Cost Reduction Targets

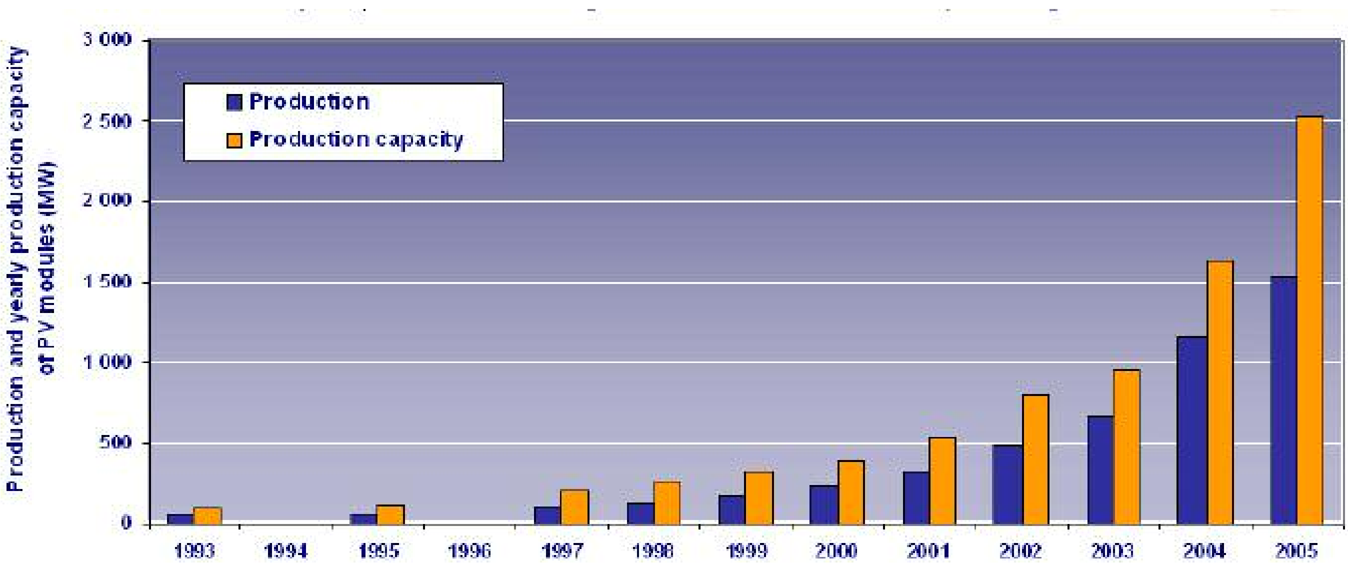


Source: REC Presentation

Silicon Supply Constraint to Industry Growth

The supply of silicon continues to be the largest impediment to growth. The production of wafers, cells and modules can ramp much more rapidly than the production of incremental silicon capacity. Utilization rates in the solar cell industry fell from 86% in 2004 to 70% in 2005 as silicon wafer supply was unable to keep up with cell capacity expansion. While a new wafer cutting plant or cell processing plant can be built and operational in less than a year, it takes two to three years to build a new greenfield silicon facility. Because of the lag between announcements and new production, we do not expect significant additions to new silicon supply until 2008. And even at that point, we do not expect the incremental capacity to fully offset the demand for silicon. Key points to understand regarding the silicon industry are described below.

Chart 12: Solar Cell Production & Capacity Trends 1993–2005



Source: IEA –PVPS Trends in Photovoltaic Applications 1992–2005 (www.iea-pvps.org)

Semiconductor Industry Takes Precedence. Silicon suppliers manufacture two grades of silicon, electronics grade silicon for the semiconductor industry and solar grade silicon (SGS) for the solar industry. The electronics grade silicon is higher purity (1 defect per trillion parts silicon represented by 1.0E-10), while SGS is 1/10,000th as pure at 1.0E-06. The silicon manufacturers would also rather supply the semiconductor industry because it provides roughly 500 basis points higher gross margins. Additionally, the semiconductor industry can afford to pay a higher price than the solar industry because silicon accounts for less than 1% of CGS in comparison to 20%+ for the solar industry. Therefore, at whatever silicon price, the semiconductor industry is likely to take precedence. According to our semiconductor analyst, Jefferies expects silicon demand to increase 10% annually through 2010 for the semiconductor industry. Historically, SGS was supplied to the solar industry from the waste of the semiconductor industry — silicon that did not meet the purity required for the semiconductor industry was sold to the solar industry at a reduced price. The rapid growth of the solar industry (30%+ CAGR over the last 10 years) has eliminated most of the excess capacity of the silicon manufacturers. For the first time, silicon manufacturers are expanding capacity to fill the needs of the solar industry.

Announced Silicon Expansion Plans Not Enough to Meet Demand through 2009. The announced silicon expansion plans by the industry are not likely enough to meet demand from solar manufacturers, which, in our opinion, is likely to result in tight markets past 2008 and additional silicon price inflation in both the spot and the contract price in the near term. Given new solar incentive programs in 10 countries, we do not think this silicon growth rate will be sufficient to meet demand for solar modules through 2009. However, with another large increase in 2010 supply, we believe the industry will likely be in a rough balance between supply and demand.

Silicon Pricing Likely to Remain High Post 2008. While the contract pricing for silicon has increased five-fold over the last three years from $20/kg to $100/kg+, we anticipate that contract prices could go even higher in the near term. Notwithstanding the strong growth in SGS in 2008–2009, the cumulative silicon growth rate from 2006–2009 is not likely enough to result in near-term price declines in the contract market as demand for solar is likely to exceed even this ramp in silicon production. Longer term, we anticipate continued additions to silicon supply that should allow for price declines from $100/kg to $50/kg, but this is not likely until at least 2010.

Inventory Surplus Yielded Higher ’06 Production. In 2006, the solar industry produced roughly 2200 MW of solar modules; however, the solar silicon produced in 2006 could only produce ~1700 MW. We estimate that the difference was due to stockpiled inventory of raw silicon that added roughly 300 MW worth of production in 2006 plus an additional 174 MW of thin film production. Prior to 2006, the silicon industry produced significantly more silicon than the solar industry could use, which led to a stockpiling of solar grade silicon. The expected solar grade silicon production is expected to yield 2081MW of crystalline silicon solar modules in ’07. Importantly, we do not think there is any stockpiled inventory remaining and as such we believe industry growth is likely to slow.

Non-Silicon Technologies Expected to Grow Faster. We expect solar technologies that are not based on crystalline silicon to grow faster than the industry from 2007–2010 as customer demand supports all technologies. We are modeling in 100% growth in 2006–2007, followed by 50% in 2008–2010. In the near term, these technologies should benefit from slower expansion in crystal solar panels and then revert to an industry growth rate as the silicon shortage abates. The main drivers in this space are thin film (amorphous silicon), Copper Indium Gallium Selenium (CIGS), Cadmium Tellurium (CdTe), and Gallium Arsenide. Our expected growth rates could be conservative if these companies can ramp up production more rapidly. Certainly, they should be able to sell all that they can make until at least 2010. The benefit to these technologies for the end customer is that they are typically priced at a 10–20% discount to the traditional solar modules.

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Production Primer

Upstream →			*Downstream*
Silicon	Wafers	Cells	Modules

Table 13: Solar Components

	Production Comments	Capital Intensity	Operating Margins
Silicon	Raw silicon with a purity of 90% is melted at around 1900°C and treated with siloxane gas, oxygen, and hydrochloric acid to raise purity to 99.9999%. Resulting product is chunks or granulated pure silicon. Approximately 1/3 the cost of production is energy usage.	Wacker Chemie is spending €200m to build a 3500 ton polysilicon (enough for about 350 MW at current efficiency levels) plant. Wacker estimates that a Greenfield site, with no existing generation capacity, would cost an additional 50%.	Wacker estimates that it earns 31% EBITDA margins for its poysilicon division.
Wafers	Raw silicon is melted in a crucible and then poured into a mould to form an ingot which is subsequently sectioned and sawed into a poly-crystalline wafer (see below for diagram). Mono-crystalline ingots are created using a seed crystal and drawing the ingot from the silicon melt before being squared off and sawed into wafers. Approximately 40% of silicon is lost in the sawing process	A rough estimate is €1 million for 1 MW of ingot production and wafer sawing capacity.	We estimate that EBIT margins in the consolidated ingot and wafer business is 35%.
Cell	Solar wafers are first acid washed to erase sawing damage and to create a “dimpled” surface to maximize absorption. The wafer then undergoes a series of chemical and thermal treatments to introduce an electrical field and reduce reflectivity before a metallic paste is screen printed on to the cell to provide electrical contacts. Current poly-crystalline cells have approximately 15% conversion efficiency (mono-crystalline cells are about 200 bp higher) and generate around 4 Wp per 156mmx156mm cell.	A complete cell production line can be installed for €0.4–0.6m per MW capacity.	Q-Cells, the leading independent producer of solar cells, posted 20.2% EBIT margins in 2005.
Module	Solar cells are connected in an aluminum frame and sandwiched between protective glass to shield the delicate cells. Note that module efficiency is lower (generally 100–200 bp) than the efficiency of the component cells as spacing between the cells is required to prevent a short. Sometimes, modules are mounted atop movable tracking systems that maximize sun exposure.	Basic solar module (not tracker) production capacity is not capital intensive. We estimate costs of €0.1–0.2m per MW of capacity. Securing supplies of cells is the most capital intensive demand on module producers.	Solon, the leading independent producer of solar modules, posted 7.3% EBIT margins in 2005.
Installation	Solar modules are often grouped into a solar panel which is placed on a mounting bracket (for rooftop installations) which are drilled to the roof of the structure. The panel is connected to an inverter costing approximately €500 per kWp capacity in order to be fed into the grid. Total cost of installation is approximately €1500 per kWp which includes inverter, materials, labor, and installer profits.	N/A	N/A

Source: Jefferies' Estimates

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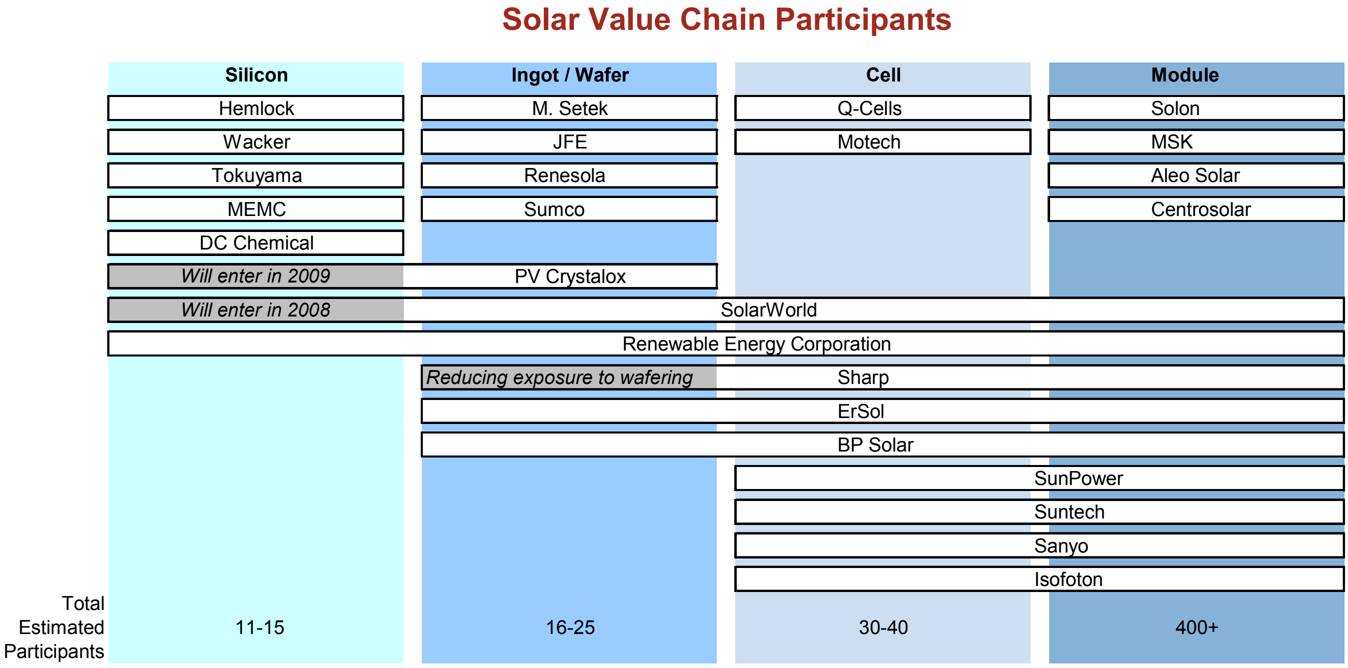
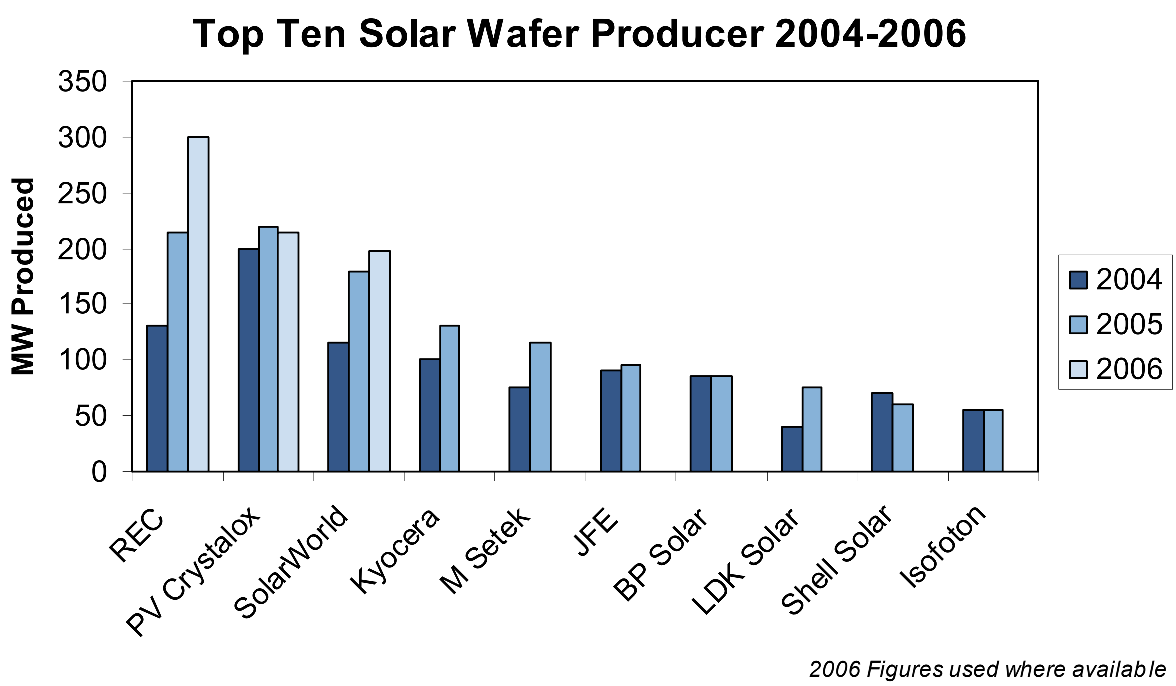
Chart 13: Solar Production Chain and Key Participants



Source: Q-Cells Analyst Presentation

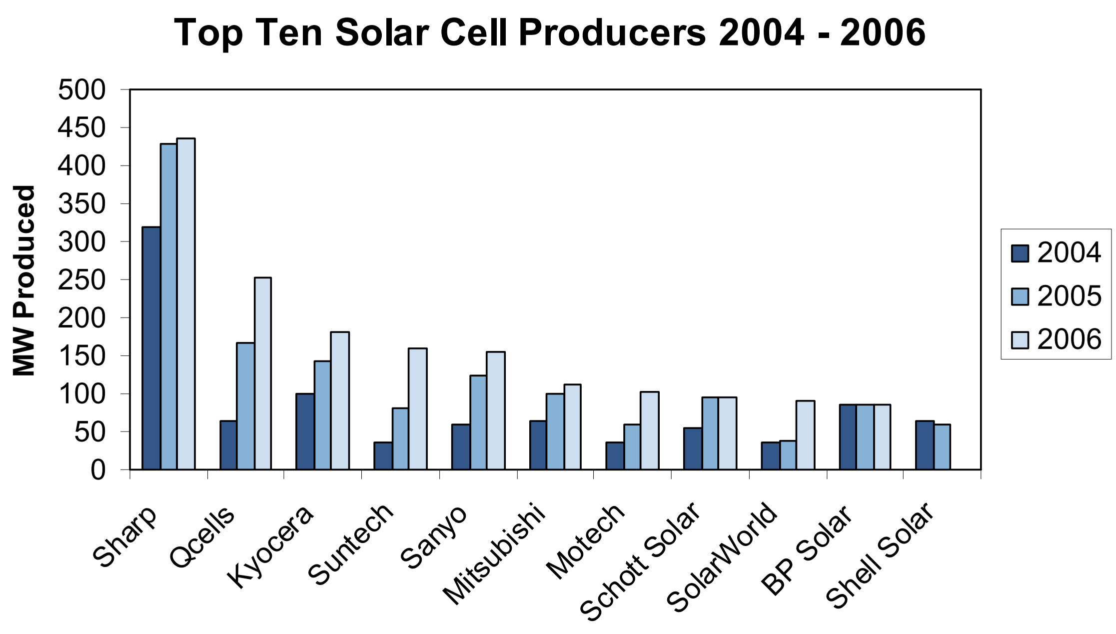
The charts below highlight the major wafer and cell producers and their output over the past three years. It is interesting to note the differing growth rates as some companies have been able to secure additional feedstock more successfully than others. However, these charts do not capture prices paid which is equally important.

Chart 14: Wafer Producers



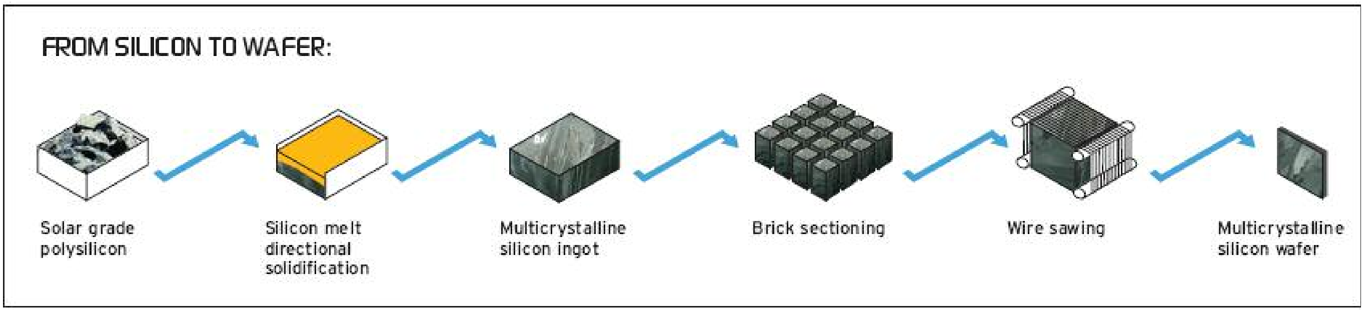
Source: Photon International

Chart 15: Cell Producers



Source: Photon International

Chart 16: Poly-silicon Wafer Production



Source: REC 2005 Annual Report

Silicon Suppliers Have Leverage Now … but Upstream Is Where the Value Is.

We believe that silicon manufacturers are likely to vertically integrate upstream to avoid becoming simply a commodity company. As Chart 16 indicates, the wafer and cell manufacturing process has the highest margins in the industry. And while silicon manufacturers are benefiting from the current shortage of silicon and increasing margins, we do not believe it is sustainable in the longer term. Currently, the silicon manufacturers have leverage over the downstream manufacturers and have been able to demand and receive large up front payments to secure silicon. However, at its most basic level, silicon is simply sand, the second most common element in the world. We believe that the silicon industry will revert back to a commodity business as expanding capacity eliminates the tightness in the industry. Already, companies like MEMC (WFR) and Renewable Energy Corporation have partnered up with wafer and cell manufacturers to vertically integrate, and we expect this trend to continue as the industry develops.

Chart 17: Value Capture in the Production Chain

	Volume	Revenue (€m)	EBIT Margin	Comments	Capital Intensity	Cost (m)
Silicon	1000 tons	€ 40.3	30-35%	Most costs are volume based so higher prices = higher margins	€0.08m / ton capacity	€ 80
Wafers	100 MW	€ 105.0	30-35%	Thinner wafers & saws can increase wafer/ton output	€0.6 - 0.7m / MW capacity	€ 65
Cell	100 MW	€ 200.0	20%	Higher cell efficiency can increase cell/wafer output	€0.4 - 0.5m / MW capacity	€ 45
Module	100 MW	€ 350.0	7%	Limited scope to benefit from upstream efficiency improvements	€0.1 - 0.2m / MW capacity	€ 15

Source: Jefferies' Estimates

Alternative Technologies

As Chart 18 demonstrates, traditional monocrystalline and polycrystalline solar cells account for 90% of total global production of solar cells. While we expect crystalline solar cells to remain the majority of solar sales, the silicon shortage is likely to provide an opportunity for competing technologies to benefit and potentially establish defendable positions because of their unique characteristics. The leading competing technologies are as follows.

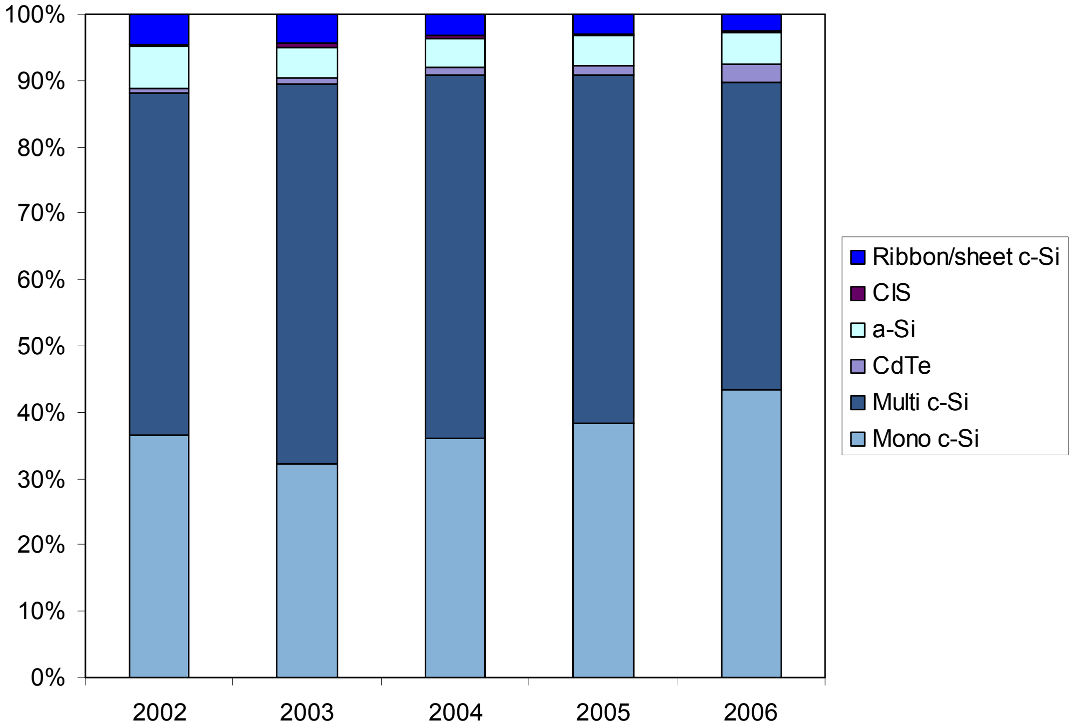
Thin Film. Thin film technologies currently represent only 4–5% of the entire solar market; however, we expect this segment to grow faster than the market, as the silicon shortage does not impact thin film manufacturers. Thin film solar modules can be manufactured from a variety of raw materials including: amorphous silicon (a-si), CIGS (Copper Indium Gallium Selenium), and Cadmium Tellurium (CdTe). In general, the benefits of thin film include: light weight, flexible, low cost manufacturing process, ability to deposit on multiple substrates, and no exposure to crystalline silicon. The negatives associated with thin film are lower conversion efficiencies (5–12%) and historically higher conversion efficiency degradation over time. Additionally, some technologies (CdTe and CIGS) use exotic raw materials that could significantly increase in price with production increases. The major players in this space include: Energy Conversion Devices (ENER), Daystar Technologies (DSTI), Kaneka, Fuji, First Solar (FSLR), and Spheral Solar Power. Additionally, traditional solar manufacturers including Q-Cells, Ersol, and Solarworld are investigating thin films as well. The bottom line is that these technologies have the potential to grow to 10%+ of the market by 2010.

String Ribbon. Given the shortage of silicon, manufacturers are exploring various techniques to reduce silicon usage. The string ribbon technology to produce wafers eliminates the need for cutting a wafer from an ingot. The benefit to this technique is that it eliminates kerf loss from the wire saw cutting the wafer. This kerf loss is typically 150–200 microns thick and produces a wafer that is 200–300 microns thick. Therefore, the string ribbon technology allows for 30–40% lower silicon usage versus cutting wafers from an ingot. The negative with this technique is that it produces lower efficiencies versus traditional polysilicon cells (15% vs. 16%). However, given the relatively new technology (<5 yrs.) versus more than 50 years for traditional crystalline cells, we believe the difference in efficiency will narrow over time. The main players in the technology are Evergreen Solar (ESLR) and Schott Solar.

Gallium Arsenide. Gallium Arsenide solar cells have better absorption capabilities than traditional crystal solar cells and because of that characteristic demonstrate significantly higher conversion efficiency (~30%). The negative associated with this technology is that it is significantly more expensive than traditional crystalline solar cells. Historically, these cells were used in space applications that did not have monetary constraints. In order to be used for terrestrial applications, the companies will have to significantly reduce costs. We think the most likely first terrestrial adoption is in combination with a solar concentrator or in a commercial mover that tracks the sun. The major producers of Gallium Arsenide solar cells are Emcore Photovoltaics (EMKR) and Spectrolab.

Organic Solar Cells. At an earlier stage of development are organic photovoltaic receptors. These organic receptors act as semiconductors similar to silicon based solar cells. The potential benefit for these cells is through a relatively simple manufacturing process in which organic cells can be printed onto a substrate, resulting in potentially lower costs. These organic cells have many of the same characteristics as the thin film cells today (lightweight, flexible). The disadvantage of organic solar cells are its relatively low efficiency of only 3–5%, less than half the efficiency of current thin film products. Additionally, no companies are currently at commercial levels of production. The following companies are working on developing this technology: BP Solar, Global Photonic Energy Corporation, Konarka Technologies, Luna Innovations, and Nanosys.

Chart 18: Solar Technologies



Source: Photon International

Risks

The principal risks are associated with the high investment cost for solar installations versus traditional forms of generation but there are others as well. We have identified and provided our insight on some of the key risks below:

- **Incentives.** As we previously mentioned, government support is vital to sustain current growth expectations and accelerate cost reductions to the point where solar can compete on a stand alone basis with traditional generation. We believe that a combination of energy security, energy prices, and increasing environmental awareness will all serve to ensure that government support grows rather than shrinks. However, this is the key risk to the solar sector at this point in time.
- **Silicon shortage.** This is a more company-specific risk. Lack of silicon can lead to significantly negative results. Less than three years ago, Shell Solar was a top five producer of crystalline cells, and in January 2006, it was sold to SolarWorld for virtually nothing … likely because they failed to secure silicon supply and elected to exit the crystalline cell business rather than face mounting operational losses.
- **Interest rates.** The genius of the feed-in tariff model is that it makes solar investment a financial rather than environmental decision. The downside to this is that if interest rates rise, the solar investment premium will decline and potentially reduce demand. We see this as a specific country-by-country risk but that global demand is so strong that a fall off in sales any one country, including Germany, would be more than compensated by new incentive programs that drive global demand.
- **Energy prices.** Fluctuations in energy prices can have a significant impact on solar shares. While natural gas actually has a more relevant impact on electricity prices, it is the oil price that often dictates short-term performance of solar shares. On a more fundamental basis, a sustained drop in energy prices would increase the time needed for solar to become cost competitive with traditional energy generation. However, we feel that high and rising energy prices will continue to contribute to the attractiveness of solar generation.

Conclusion

We believe that the solar sector represents an excellent long-term investment opportunity for investors, although we are aware that volatility will be high at times. The rising competition for fossil fuels, increased concerns over energy security, growing awareness of the impact of man on the climate, and the resulting spread in government incentive programs indicate to us that solar generation will be a growing and attractive arena for investors in the actual solar systems and also investors in the stocks of companies that manufacture the solar modules. We advise that investors be wary of chasing unsecured growth and focus their investments on companies whose long-term supplies of silicon provide high visibility for long-term production growth. Additionally, we would consider alternative technology investments that are not dependent on silicon for their growth.

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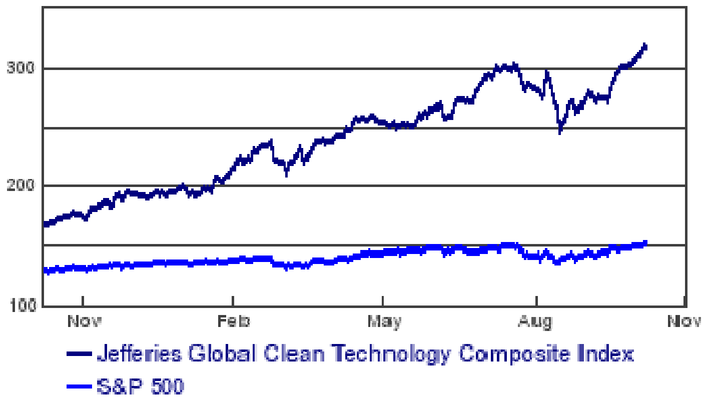
An Introduction to Jefferies Global Clean Technology Indices

Jefferies & Company, Inc. introduced a series of Global Clean Technology Indices which can be found through the following link (www.jefferies.com/indices). To qualify for the index, a company must generate 50% of its revenue from clean technologies with eligibility determined in conjunction with Jefferies equity research analysts. There are a total of four Global Clean Technology Indices:

- *Jefferies Global Clean Technology Composite Index* – includes solar, wind, fuel cells, microturbines, battery technology, biofuels, and other alternative solutions.
- *Jefferies Global Clean Technology Energy Generation Index* – a sub index that includes solar and wind.
- *Jefferies Global Clean Technology Energy Storage Index* – a sub index includes fuel cells, battery technology, & microturbines.
- *Jefferies Global Industrial Biotechnology Index* – An overlapping index which encompasses biofuels but also includes other industrial biotechnology companies.

Chart 19: Jefferies Composite Clean Technology Index Performance



Source: www.Jefferies.com/Indices

Clean Technology
Energy Storage - Battery Technology

Clean Technology

Advanced Battery Technology Primer

Investment Summary

We expect the advanced battery technology segments to grow faster than GDP due to strong growth in consumer electronics, wireless telecom, and hybrid vehicle growth. We would recommend investing in those companies that have exposure to these end markets.

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Event

This report is designed to assist investors in surveying the advanced battery technology landscape and reviewing individual technologies such as NiCd, NiMH, Li-ion, ultracapacitors, and alternative technologies.

Key Points

- **Rechargeable battery industry expected to grow faster than global GDP.** This will likely be driven by increased demand from developing economies coinciding with the proliferation of consumer devices such as cell phones, iPods, and PDAs.

- **Market share growth for high energy density products.** We expect that on the margin, higher energy density products will grow faster than low energy density products. In particular, we believe that lead-acid batteries and NiCd are likely to experience slower growth as customers switch to higher density. However, the relatively low cost of low energy density batteries will ensure the continued use of these battery types until competing technologies can offer energy densities at competitive prices.

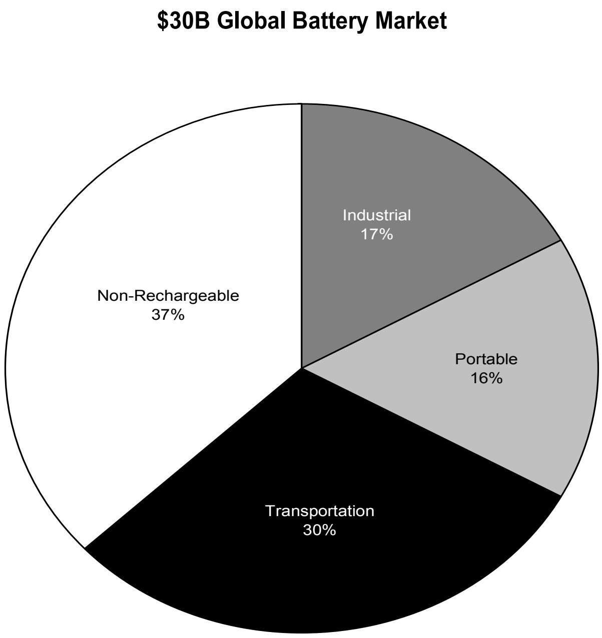
- **Hybrid vehicle growth to limit lead acid battery growth.** We expect that the growth of the hybrid industry over the coming years is likely to result in flat or even declining automotive lead acid battery sales. We believe that hybrid sales are likely to account for 5% of total US sales by 2011, and that the increase of hybrid sales with NiMH is likely to result in a similar decline for lead acid batteries. Ultimately, there is growing evidence that Li-ion will become the technology of choice for HEV manufacturers.

- **Ultracapacitors act as a supplement to batteries.** We believe that ultracapacitors are also likely to grow faster than the industry as these technologies are just now being designed into products. In our opinion, the fast charge/discharge capabilities for ultracapacitors make them likely candidates to be paired with storage capacity of batteries in HEV and wind applications

A Primer on Batteries

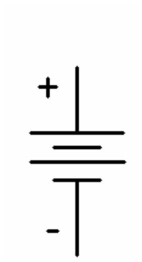
Given the trend towards increased power usage in electronic and transportation applications, we believe it is appropriate to provide greater detail on the various battery technologies and their growth prospects. This primer focuses on rechargeable batteries, which account for only 10% of unit volume, but importantly, 63% of industry revenues. The rechargeable market is segmented into three main areas, Transportation, Industrial, and Portable applications. We believe there are specific opportunities in both the transportation and portable segments to achieve GDP+ industry growth, while the industrial segment is likely to grow in line with GDP. But even more importantly, within each segment, we expect a shift in battery usage from lower density batteries to higher density, which is likely to result in faster than industry growth for those companies with advanced battery technologies.

Chart 1: Global Battery Market



Source: Laboratorie de Reactivite et de Chimie des Solides

Batteries – A Quick Overview

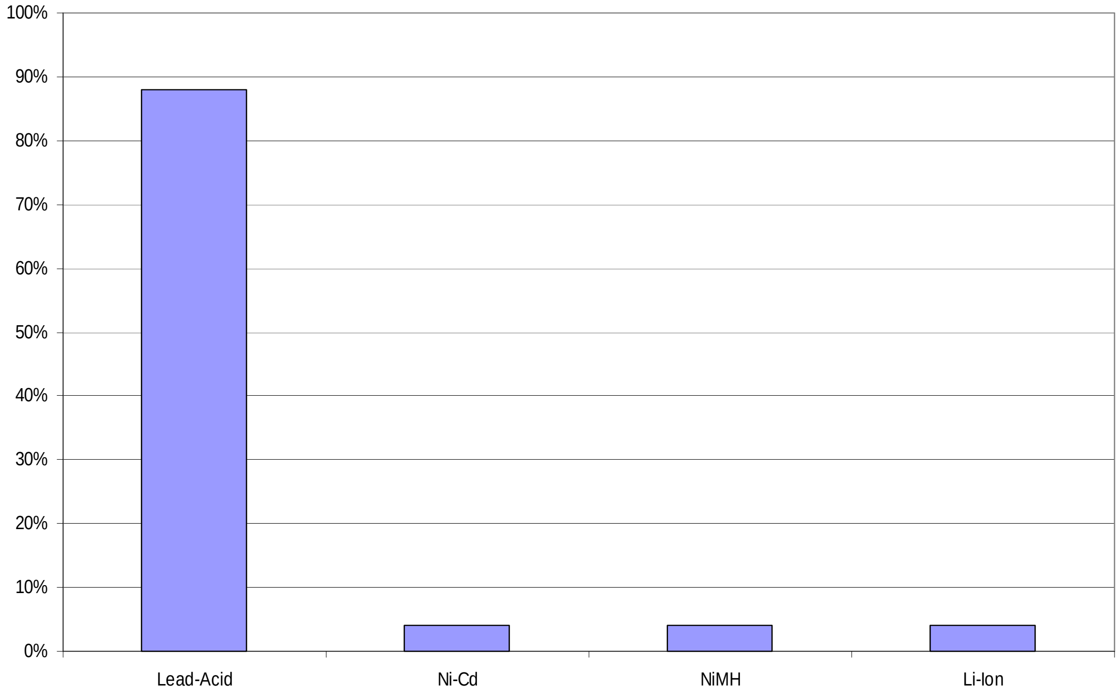


To start from the basics, a battery is a stand-alone power source that converts chemical energy into electrical energy through chemical reactions. A battery consists of a positive and negative electrode and an electrolyte. Energy is created when chemical reactions transfer energy from the electrodes to the electrolyte at their interface.

There are two key types of batteries — primary and secondary. Chemical reactions in primary batteries are irreversible, which makes them non-rechargeable. Primary batteries account for roughly 90% of total global battery unit volume, mainly small consumer disposable batteries. In secondary batteries, the chemical reaction can be reversed, which allows for recharging the battery, with the number of recharging cycles dependent on the battery's material. Secondary batteries account for roughly 10% of global battery production by volume.

A battery's characteristics depend, in large part, on their constituent materials. There are a wide range of battery systems made from varied metals, each with distinct attributes.

Chart 2: Rechargeable Batteries By Type

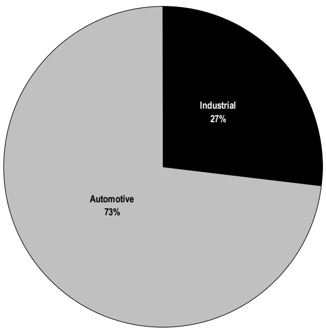


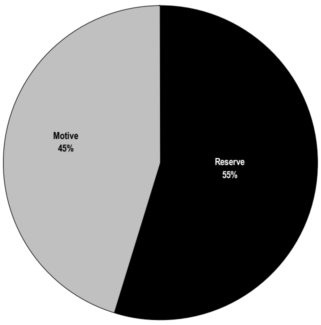
Source: Laboratorie de Reactivite et de Chimie des Solides

Lead Acid Is the Standard. As Chart 2 indicates, lead acid batteries account for almost 90% of the unit volume in rechargeable batteries. The lead-based battery technology was first discovered in 1859 and today's flooded batteries are not significantly different than those made 100 years ago. Lead acid batteries are widely used in automobiles, aircraft, boats, UPS applications, motive power (forklifts), telecom, and reserve power. The benefits of the lead acid technology are that it is proven, with over 100 years of commercial/residential use, and it is safe. Additionally, the lead-acid batteries are the cheapest battery technology available. The disadvantage of this battery type is that it has lower energy density in comparison to the newer advanced battery technologies and is significantly heavier.

Outlook: We expect lead acid batteries to continue to grow, but only in line with GDP, or even slightly below it. As Chart 3 indicates, the automotive market is the predominant end market, accounting for two-thirds to three-quarters of all lead-based battery requirements, with the remainder servicing the industrial market. The following companies are main suppliers to the auto market: Johnson Controls, Exide Technologies, Matsushita, and Japan Storage Battery. In the industrial market, Enersys (ENS, $18.19, Buy), Exide Technologies, East Penn, and C&D Technologies are the main players.

Chart 3: Lead-Acid Markets





Source: Laboratorie de Reactivite et de Chimie des Solides

Auto Markets to Benefit from China/India Growth, but Hybrids Are a Risk. The demand for automobile batteries is relatively stable in developed markets with roughly 80% of battery purchases coming from replacement batteries. Volume growth is driven by the 20% from new car sales and also from a growing installed base. Global manufacturers of lead acid batteries may benefit from higher growth in China and India as those countries continue to rapidly purchase/build new vehicles; however, given the low barriers to entry in the automotive market, we believe that local manufacturers are likely to benefit from this growth at the expense of the larger multinational battery suppliers. Additionally, increased hybrid sales could negatively impact lead acid battery sales. Hybrid vehicles typically use NiMH batteries instead of lead acid. Therefore, as hybrid vehicles grow, the resultant demand for lead acid batteries would shrink. We are forecasting ~5% of the auto market is hybrid vehicles by 2011, which would subsequently impact demand for lead acid batteries.

Industrial End Markets Expected to Grow Modestly. The industrial market is composed of the motive (forklift) market and the reserve power market. We believe the telecom market is likely to grow in excess of GDP as telecom carriers have started to ramp capex spending to meet the increasing demand for wireless and data services. In motive power, we expect the segment to move in line with GDP in the western nations, while at a faster rate in developing regions like China and India.

Industrial Markets Likely Safe From Alternative Technologies. Lead acid batteries are the low-cost battery solution to provide environmentally friendly (no emissions) power for forktrucks (motive power) and reserve power (i.e., telecom base stations). Because of the higher costs, advanced battery solutions like NiCd (2x more expensive), NiMH (3x more) and Li-Ion (5x+) are unlikely to be chosen as replacements for lead acid batteries in the industrial markets. For example, in motive power (forklifts), lead acid batteries provide a working solution; they can perform a full eight-hour shift and then recharge during the second shift. Replacement with the least expensive alternative (NiCd) would cost at least twice as much and the company would still need two batteries per forklift in order to recharge one while the other is operating. Additionally, forklifts require the heavy weight of lead to act as a counterweight for whatever the forklift is lifting. So a purchase of NiCd, or other advanced batteries, would also require the purchase of lead or other dense material to act as a counterweight. The bottom line is that the lead acid battery is the low-cost choice for forklift operations currently. Similarly in the reserve power market, the batteries are mainly used in telecom base stations and in uninterruptible power supplies (UPS). The negatives associated with the lead-acid battery are that it takes up 3-4x as much space as some of the advanced batteries and may need more maintenance (flooded batteries only). However, in our opinion, the lower cost and longer life cycle outweigh these negatives, in most situations. Of course, the exception to this rule is in remote areas where the cost of maintenance is significantly higher, it may make more sense to use advanced batteries that require less maintenance rather than the cheapest initial solution. In our opinion, except for remote locations and locations with severe space constraints, there is unlikely to be a significant shift away from lead acid batteries in reserve power.

Lead Price Inflation Key to Profitability. The price of lead is key to the profitability of both automotive and industrial lead-acid manufacturers. Lead costs alone can account for 20%-30% of cost of goods sold. Unfortunately, for the industry, increased demand from China and India has resulted in demand for lead exceeding supply and a subsequent tripling in the price of lead over the last three years. As expected, many lead acid battery manufacturers earnings declined or even lost money. In the automotive market, auto OEMs mandated price declines from suppliers of as much as 5% per year, while in the industrial market, companies were only able to realize 40%-50% of announced price increases. Given the recent increase in lead prices, we expect another round of battery price increases to offset the higher costs.

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Chart 4: Lead Price Chart ($/lb.)

Source: London Metals Exchange

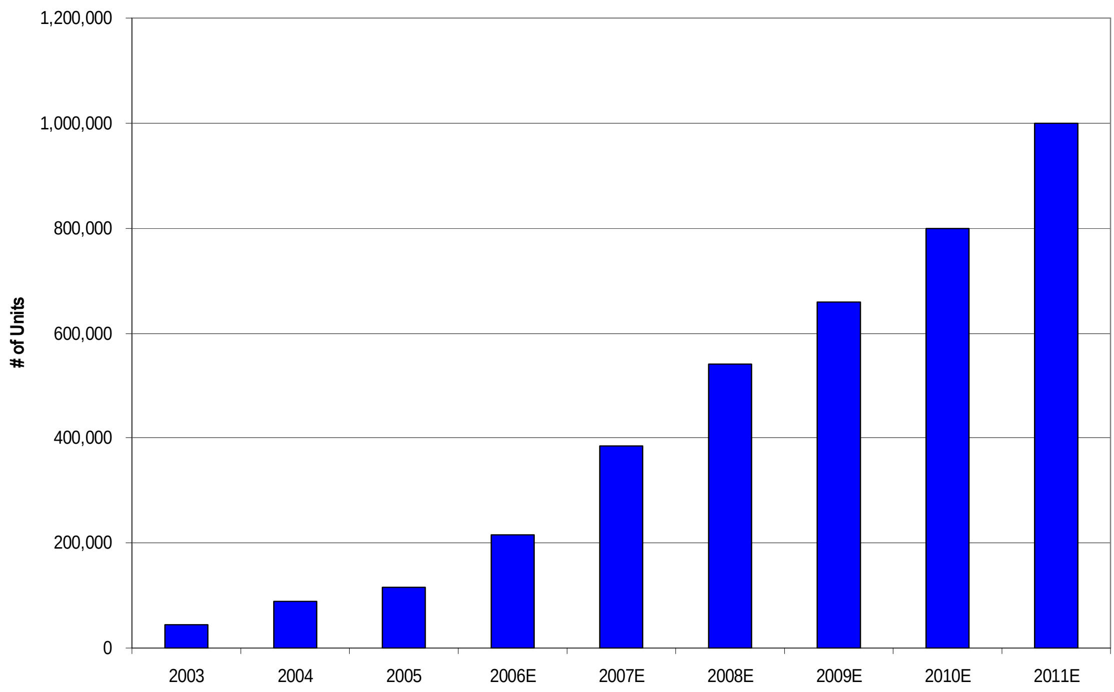
Nickel-Cadmium (NiCd). NiCd batteries make up a small niche of the battery market with only 4% of total units. NiCd batteries are largely used in industrial applications including industrial and telecom standby power, and in the aviation and rail markets for back-up power and starting systems. Additionally, NiCd batteries are used in consumer electronics and power tools. The batteries have better energy density than lead acid batteries and a longer cycle life. The major disadvantages with Ni-Cd are that it is environmentally unfriendly (Cadmium is a recognized carcinogen), is 1.5x to 2.0x the price of lead acid batteries, and potentially has thermal runaway issues (battery overcharge). Cadmium is also in relatively small supply and we believe if volumes were to ramp significantly, the price of Cadmium could rise similarly. Therefore, we remain cautious on this battery type as many of the applications NiCd currently serves can be served by NiMH batteries as well. And as the newer NiMH battery technology ramps up to larger scale and lower price, we would expect additional conversions to NiMH batteries. This trend is already occurring in power tool batteries and consumer electronics. The following companies are key manufacturers of NiCd batteries: Electro Energy, Saft (SAFT FP, €22.54, Buy), Hoppecke, and Panasonic.

Nickel-Metal-Hydride (NiMH) – NiMH batteries are used in the transportation (hybrid vehicles), telecom (stationary, backup power) and the consumer electronic markets. The advantages of this battery type are that it has higher energy density compared to lead acid and Ni-Cd batteries and is non-toxic. However, it has reduced cycle life compared to Ni-Cd. Importantly, battery planners can design recharging programs such that the battery never fully discharges, thereby extending the overall battery life by 3x+. For example, in hybrid vehicles, the engine will kick in when the battery charge has dropped to a prescribed level (~60% charge) and not allow the battery to fully discharge. By combining the NiMH battery with an advanced battery monitoring system, manufacturers have increased the expected battery life to more than 10 years.

Outlook. We believe that NiMH batteries are likely to grow in excess of the market growth rate as its key markets consumer electronics, hybrid vehicles, and telecom applications are all expected to grow faster than GDP. Additionally, we believe this battery type is likely to cannibalize sales from NiCd batteries because of its non-toxic componentry and similar prices with NiCd. The following companies manufacture NiMH batteries for the hybrid market: Cobasys (ENER, $25.80, Buy), Panasonic EV Batteries (Toyota), Sanyo, and SAFT. Importantly, ENER holds a number of patents for this battery technology and all of the companies mentioned above are licensees of ENER. Therefore, we view ENER as the best way to play the growth of the hybrid market. On the consumer battery side, Electro Energy, Maxell, Varta, Gold Peak Industries and Yuasa manufacture NiMH batteries. Again, many of these companies are licensees of ENER's NiMH technology.

Hybrid Vehicle Market to Drive NiMH Battery Growth. As Chart 5 demonstrates, we expect the US hybrid vehicle market to ramp significantly over the next five years to a total of 1 million vehicles by 2011. This expected annual growth of ~50% is quite achievable in our opinion, due to higher gasoline costs and concerns about the environment. Our forecasts amount to less than 5% of the total market, which could be conservative. The NiMH battery is the preferred technology for this application because of its relatively high energy density relative to lead-acid and NiCd batteries and its cheaper price relative to Lithium-Ion batteries. Quite simply, lead and NiCd batteries take up too much space in a car to be used in most hybrid applications. We expect NiMH batteries to continue to be the battery of choice for hybrids throughout this forecast period. While Lithium-Ion represents a potential replacement for NiMH batteries in this application, the technology needs to significantly reduce its cost (currently 2-3x more expensive) and solve the overcharging issue. We believe that automakers are not likely to put Li-Ion batteries in vehicles until this problem is solved because the public relations issues from a single explosion or fire would likely have serious negative implications for future sales.

Chart 5: US Hybrid Vehicle Growth



Source: *Automotive News*, Jefferies' Estimates

Lithium-ion and Lithium Metal – Lithium based batteries are the newest battery technology, first introduced by Sony in 1991. The initial application for these batteries was in consumer electronics as portable batteries for laptops and cell phones. Lithium based batteries now serve the consumer electronic industry, aircraft, and space applications and potentially, the hybrid vehicle market. These batteries have high energy density and low weight, but are more fragile and less stable than other technologies. In particular, thermal runaway is an issue that needs to be resolved for higher power applications (hybrid vehicles). Additionally, these batteries can cost as much as 3x NiMH batteries or 6x lead acid batteries. We believe that the industry will likely have to significantly reduce costs in order to effectively compete with NiMH batteries. In contrast to NiMH batteries, in which the technology is patented, many players are developing Lithium based batteries. Some of the players in this space are: China BAK Battery, Ener1, Japan Storage Battery, Matsushita, Panasonic EV Energy, Sanyo, SAFT, Hitachi, Sony, Ultralife Batteries, and Valence Technologies.

Lithium Metal has the highest energy density, but it is also the least stable and most prone to thermal runaway. Because of this trait, most manufacturers have switched to more stable compounds using lithium-ion using cobalt or manganese. These compounds are significantly more stable, but have significantly lower energy density, only slightly better than NiMH batteries. While thermal runaways are still relatively rare (1 in 200,000) for this technology, the potential damage from larger batteries in vehicles versus cell phones or laptops will likely result in slow adoption of this technology until it is proven safe. The recent recall by Sony and Dell of millions of Li-Ion laptop batteries only re-emphasizes the point.

Outlook. We expect the lithium based batteries to grow faster than the consumer markets and incrementally take share from Ni-Cd. However, we do not expect an expansion into the hybrid market over the next couple of years, as cost and safety issues are likely to prevent rapid adoption of this technology. Longer term, we do expect Li-Ion batteries in hybrid vehicles, but not likely until at least 2010 in commercial scale.

Ultracapacitors/Supercapacitors

Over the previous couple of years, the industry has grown 75%-100% annually, which we expect to continue at least through 2010 and likely for a significantly longer period of time. We believe the ultracapacitor provides solutions for engineers that were not possible even five years ago and we expect that customer acceptance of the product will continue to accelerate post 2010. We expect that as ultracapacitors become more widely known, additional applications will drive the growth longer term, which will increase the addressable market. As Table 1 demonstrates, ultracapacitors provide a better blend of power delivery and energy storage than either a pure capacitor or a battery. The benefits of ultracapacitors versus batteries are detailed in Chart 6, but in our opinion, the two most important characteristics are the fast charge/discharge cycle (half a second) versus eight hours for a lead acid battery and the nearly unlimited charge/discharge cycles (500K cycles versus <1000 for lead acid battery). The main disadvantages of ultracapacitors are that they cannot hold as much energy as a similarly sized battery and to a lesser extent, price. We believe that this indicates that both are likely to be used for specific applications. But in the case of ultracapacitors, the growth will be significantly higher because the base is low and they are creating new applications. The main competitors in this space are Maxwell Technologies, Montena, Ness Corporation, and Panasonic EV Energy.

Table 1: Ultracapacitor Characteristics

Ultracapacitor vs. Battery
100x more instantaneous power than batteries
lower weight vs. electrical energy stored
deeper discharge
lower wasted energy (less heat)
infinite charge/discharge cycles (extended Useful life)
better temp. variance (-40C to 65C)
environmentally friendly
Better Reliability - No Moving Parts or Chemical Reaction
U/C allow for smaller engines or batteries due to peak power requirements handled by U/C's
Long Shelf Life
Maintenance Free

Source: Jefferies & Company, Inc.

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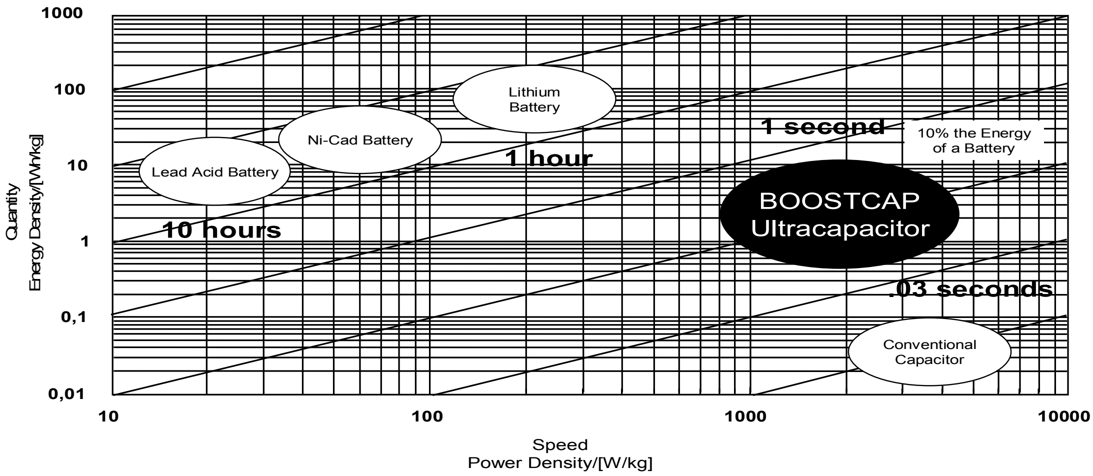
Chart 6: Ultracapacitor versus Battery Comparison



Source: Maxwell Technologies, Jefferies & Company, Inc.

Top-Down Analysis Implies a Potential $12B Market in 2010. Illustrated in Chart 7, the company and the industry have been able to reduce their costs to the end customer, which increases the potential addressable market significantly. In general, for every 50% reduction in cost to the end customer, the potential volume increases by a factor of 10. A simple example helps to demonstrate the point. A typical hybrid city bus costs around $300K today. To replace the batteries in a hybrid bus with ultracapacitors requires around 300 large cell (2700 farad) ultracapacitors. At $400 a piece in 1999, this equated to $120,000 for just the ultracapacitors alone, and thus ultracapacitors were not a viable option for the bus company. But today, at $25 each, the cost is only around $7,500 or 2.5% of the total bus cost. In a similar fashion, the cost of ultracapacitors is already low enough for the hybrid and luxury personal vehicle markets, but perhaps not quite cheap enough for mainstream autos. However, with another expected 50% reduction in expected end costs, we expect that ultracapacitors will likely become a valid alternative for automakers. Of course, given long-term design requirements of as much as seven years, it will likely take several years before ultracaps can achieve full market penetration. Importantly, while the auto industry is a significant long-term growth driver, industrial, telecom, and consumer electronics will likely drive growth in the near term.

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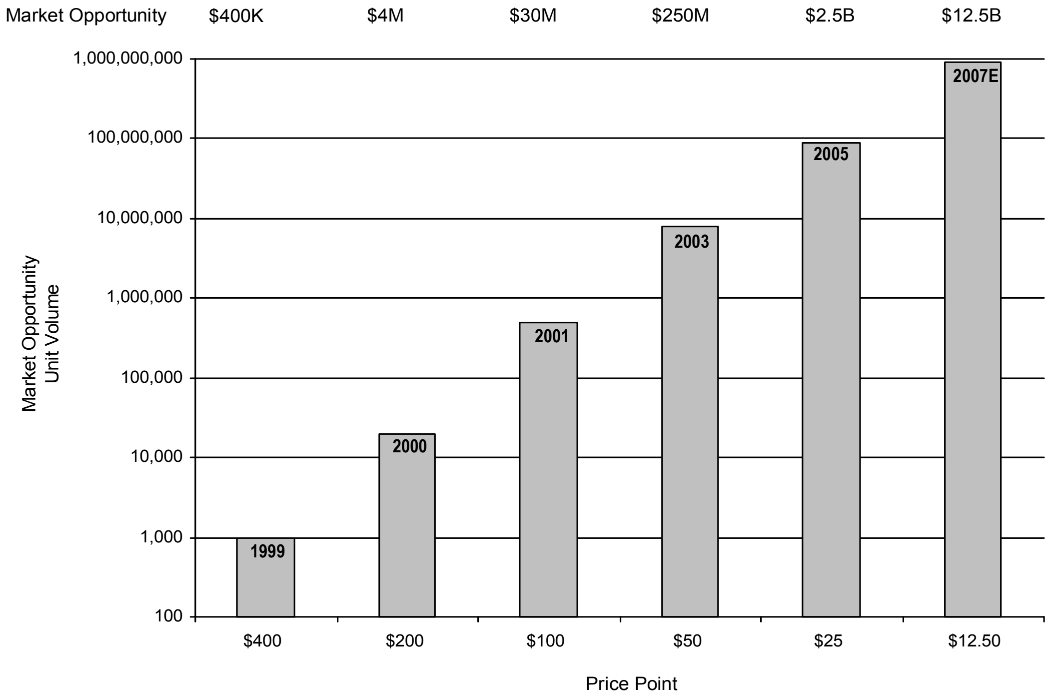
Chart 7: Top-Down Ultracapacitor Market Potential



Source: Maxwell Technologies, Jefferies & Company, Inc.

Other Technologies – A wide range of energy storage solutions are emerging to meet specific niche application requirements. These include alkaline based batteries, flywheels, lithium-polymer combination cells, nickel hydrogen, and zinc-air cells. Given the wide range of end user needs and specifications, the various emerging battery technologies have further fragmented and specialized the battery market, but in our opinion, are not likely to displace the above-mentioned technologies, except for customized applications. However, we believe the industry is shifting toward batteries with higher energy densities. As these technologies ramp production and reduce costs, we believe this shift could accelerate.

Conclusions

We expect overall demand for batteries to grow above global GDP as increasing globalization and rapid growth in undeveloped countries is likely to drive increased demand growth. We believe that the trend is toward those batteries with higher energy densities; however, the customer will not pay for higher energy density unless the application requires it. For example, telecom reserve power applications are likely to continue to be served by lead acid batteries because they are rarely used (only during power outages) and are the cheapest solution. In contrast, hybrid vehicles require greater energy density to power the drivetrain. Therefore, in that application, auto OEMs will pay a higher price for NiMH batteries, because of their requirement for space in a vehicle (i.e., the automaker cannot devote more than 5% of the vehicle volume to a battery pack). However, auto OEMs are unlikely to pay an even higher price for Li-Ion batteries, if NiMH batteries are sufficient. In total, we believe that NiMH, Li-Ion, and Ultracapacitors are likely to grow faster than the overall market, while lead-acid (automotive applications) and NiCd batteries are likely to grow slower than the overall market.

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Table 2: Battery Characteristics

	Lead Acid	Re-useable Alkaline	NiCd	NiMH	Li-ion	Li-ion Polymer
Gravimetric Energy Density (Wh/kg)	35-50	80	45-80	60-120	110-160	100-130
Cycle Life (# of cycles)	200-300	50	1500	300-500	500-1000	300-500
Self-discharge / Month	5%	0.3%	20%	30%	10%	10%
Shelf Life (months)	18	6	6	12	18	12
Operating Temperature (Celsius)	-20 to 60	0 to 65	-40 to 60	-20 to 60	-20 to 60	0 to 60
Battery Cost per Cycle	$0.10	$0.10 - $0.50	$0.04	$0.12	$0.14	$0.29
Key Commercial Uses	Industrial/ Automotive	Electronics	Electronics/ Industrial	Electronics/ Automotive	Electronics/ Specialist	Specialist/ Miltary
Date of Commercial Introduction	1970	1992	1950	1990	1991	1999
Toxicity	High	Medium	High	Low	Low	Low

Source: Battery University, Jefferies International Ltd.

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Clean Technology
Energy Storage - Fuel Cells

Clean Technology

Fuel Cell Technology Primer

Investment Summary

We believe that, although the potential benefits of various fuel cell applications are tremendous, the industry must face several significant challenges before most fuel cells can be commercially viable for mass application.

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Event

This report details the benefits and applications that the fuel cell industry could achieve, as well as the principal challenges facing the industry and a look at individual fuel cell technologies.

Key Points

- **Cost.** The cost of fuel cells is significantly higher than both traditional forms of generation and power storage. We believe that prices for most technologies must be reduced significantly before fuel cells can be rolled out on a commercial scale for either generation or storage applications.

- **Durability.** Fuel cells tend to be very fragile and unproven while the existing technology they often seek to displace is well known, battle tested, and quite durable. There is a wide range of durability issues that the industry faces across the entire spectrum of technologies and applications.

- **Infrastructure.** The most commonly known form of fuel cell is a hydrogen-powered PEM fuel cell, often used in transportation in lieu of an internal combustion engine. Unfortunately, hydrogen is not as ubiquitous as gasoline and faces significant infrastructure hurdles due to the incompatibility of much of the existing gas pipelines and hydrogen.

- **Environmental benefits.** While the previous points illustrate the challenges, it is time to recognize the potential benefits. Fuel cells generally have lower emissions and higher efficiency than the technologies they displace. This is true in virtually all applications.

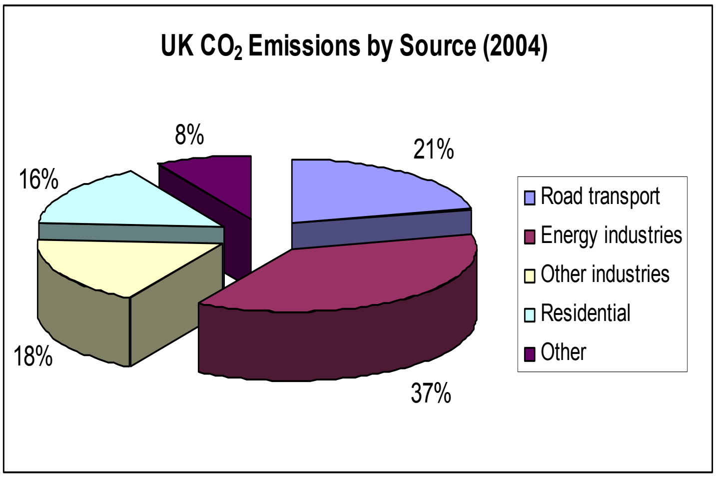
- **First adopters.** We believe that early adopters could be stationary generation and portable military/security users. While these are radically different applications, the specific technologies offer tremendous potential to improve on existing solutions.

Executive Summary

The basis for modern fuel cell technology emerged over 150 years ago when Welsh lawyer turned scientist William Robert Grove garnered international acclaim for his “Grove cell.” Fast forwarding to the late 20th century, fuel cells re-emerged in the public consciousness as a potential solution for both higher energy prices and environmentally damaging emissions. The idea of an electric car propelled by hydrogen powered fuel cells emitting nothing more than steam caught the public’s eye and attracted hundreds of millions of dollars in investment from both private investors and governments.

A workable fuel cell solution has many attractive benefits. Looking just at the transport sector, enthusiasts dream of replacing gasoline fired engines with quieter and cleaner electric engines. The switch from fossil fuels to hydrogen powered fuel cells could virtually eliminate local emissions from the transport sector with even greater savings potential for stationary power. As the chart on the right shows, road transport represented 21% of carbon emissions in the UK in 2004 with over double that amount from electricity usage. We believe that other industrialized countries have similar emission levels. Any significant reduction in emissions from using fuel cells in vehicles, buildings and industry could have a significant impact on the build-up of greenhouse gases and reduce concerns over global warming. Another benefit would be the potential reduction in dependence on oil. Energy security is an increasingly important issue for governments around the world. To this end, many governments have set aside significant sums for development of fuel cells.

Chart 1: Carbon Emission Profile



Source: DEFRA

However, despite all of the obvious attractions of fuel cell potential, the idea of a fuel cell or hydrogen economy has not yet been turned into reality. Although fuel cells have been selling into niche markets on a commercial basis for some time, mass market applications have yet to take off. Given that we believe the benefits of a hydrogen or fuel cell economy are relatively clear and straightforward, we have chosen to focus on some of the challenges the fuel cell industry faces in commercializing the product. However, first we offer a quick overview of fuel cell technology and types of fuel cells.

Fuel Cell Technology Primer

While we do not intend to offer a scientific dissertation on the inner workings of a fuel cell, a quick summary of fuel cell technology basics may be in order. While different types of fuel cells have different operating characteristics, in general a fuel cell operates in the following manner.

Hydrogen (H2) molecules enter the fuel cell at the anode where a chemical reaction strips them of their electrons. The ionized (carrying a positive electrical charge) hydrogen atoms pass through the electrolyte membrane. The negatively charged electrons pass through a wire outside the fuel cell to create electrical current. The electrons and protons mix with air on the cathode to complete the reaction and create water as an exhaust. See below.

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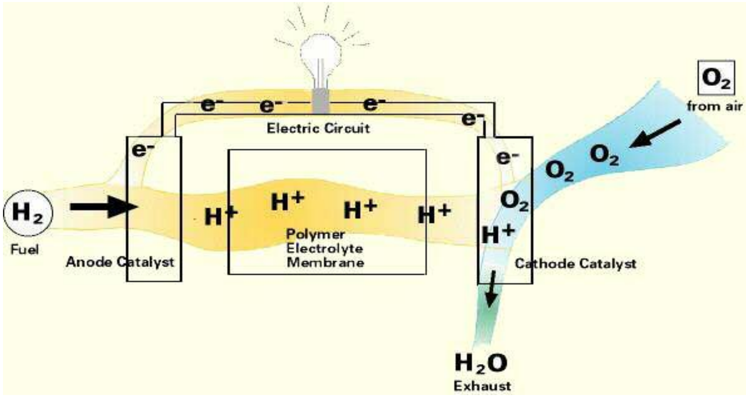
Figure 1: Fuel Cell Diagram (for PEM type fuel cell)



Source: Fuel Cells 2000

Fuel Cell Applications

As we mentioned in the Executive Summary, hydrogen powered PEM fuel cells remain a compelling and probably the most well known application for fuel cells. However, there is a vast range of applications that can be met with a variety of fuel cells types (we will review the various fuel cell technologies in the following section). While we cannot say if fuel cells will ever be deployed in the following applications, we present an abbreviated sample of possibilities:

- **Car engine replacement.** The application that immediately springs to mind when investors and the general public think of fuel cells. A hydrogen-fuelled electric engine could eliminate harmful tailpipe emissions and reduce dependence on imported oil. However, there are significant cost, durability, and fuelling issues that must be addressed.
- **On-board electronics.** Nearly 20% of US truck fleet fuel consumption is used when trucks are idled but electric power must be maintained. For example, refrigerated trucks must keep their engine running lest the refrigeration unit loses power and the perishables are lost. A fuel cell stack attached to a natural gas or propane tank could meet this demand and reduce idling losses. However, cost and durability have been key barriers here.
- **Military/Security.** The modern soldier carriers far more electronics than his predecessors and the resulting increase in power needs has led to heavier and heavier rucksacks as the soldiers are forced to carry extra batteries. Fuel cells could replace batteries in certain applications although cost and performance remain key concerns.
- **Stand-alone generation.** Diesel generators are the solution of choice for many stand-alone applications (telecom relay stations, construction sites, USP, etc.). A low-cost fuel cell stack could dislodge the inefficient diesel generator. Again, cost and durability are key issues.
- **Residential heat and power.** As certain types of fuel cells generate both heat and electricity using natural gas as a fuel, it is potentially possible to provide heat and power to the home using a fuel cell stack. Cost, durability, and performance have been key barriers.
- **Laptop battery augmentation / replacement**. A lightweight and easily rechargeable fuel cell could allow a laptop to run for days rather than hours without seeing an electrical outlet. However, cost and competition from alternative solutions remain key concerns.

Types of Fuel Cells

The term "fuel cell" has often been associated with low-temperature hydrogen powered cells commonly known as PEM (Proton Exchange Membrane) fuel cells. However, fuel cells come in many different forms and can use a range of fuels and have widely differing thermal and performance characteristics.

Table 1: Fuel Cell Types

Type	Comments
PEM	Require a polymer electrolyte membrane and metallic catalysts. PEM fuel cells require ultra-pure hydrogen as an input with this "fuel" needing to be created / synthesized elsewhere. Given their thermal characteristics (operating typically at 0-100°C), PEM fuel cells are the preferred solution for fuel cell powered vehicles.
Direct Methanol	Direct methanol fuel cells are similar to PEM fuel cells except that they convert liquid methanol, rather than hydrogen gas, into electricity. This technology is being actively developed by many leading Japanese corporations as a replacement for high capacity batteries for laptops and other relatively demanding portable devices.
Solid Oxide	Solid oxide fuel cells use hard ceramic electrolytes and operate typically at very high temperatures (800-1000°) and with superior efficiency than lower temperature PEM cells. Ceramic based solid oxide fuel cells do not require pure hydrogen and can operate with hydrocarbons (e.g., natural gas) as a fuel. Given their operating characteristics, solid oxide fuel cells are generally associated with fixed combined heat and power (CHP) generation projects.
Molten Carbonate	Molten carbonate fuel cells share many similar characteristics with solid oxide fuel cells with the major exception that they are based on molten carbonate salts and have significantly more complex system design limiting their use to very large scale plant (1>MW).
Alkali	The fuel cell of choice for early NASA projects. Alkali based fuel cells do not require membranes but still require catalysts and operate at 150-200°C. Pure hydrogen is also a requirement for alkali.

Source: Jefferies International Ltd.

Each type of fuel cell faces its own unique set of challenges. In the following sections, we have attempted to highlight the primary issues that fuel cell developers confront.

Cost

Exorbitant cost has been the principal issue for the fuel cell industry. According to the U.S. Department of Energy (DoE), fuel cells currently cost approximately $3000 per kW output, although many industry experts feel that this cost is too low by anywhere from 30%-70%. The DoE believes that fuel cells cannot compete with traditional forms of generation unless the cost per kW output is $1000. The most significant costs of a fuel cell have been:

- **Materials**. Industry standard polymers for PEM fuel cells currently costs approximately $500/m2 while specialty ceramic powders used in solid oxide fuel cells can be very expensive as well.
- **Fuel.** While hydrogen is plentiful it is always locked up in the form of water, hydrocarbons, etc. Pure hydrogen is not found anywhere on earth, forcing many fuel cell types to rely on synthesizing hydrogen at great financial cost and environmental damage.
- **Catalyst.** Low-temperature fuel cells require precious metal catalysts to ensure a successful electrochemical reaction. Currently, the industry standard is platinum, which has increased 26% in the last year to almost $1100/ounce. While other catalysts are under development, platinum continues to be the main catalyst.
- **Assembly.** Fuel cells require very high levels of engineering to produce a successful product. While economies of scale will undoubtedly reduce production costs, there are a number of economic issues that must be addressed before mass production becomes a reality.

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Fuel cell developers are constantly seeking to address these issues and efforts are under way at various companies to reduce the cost of fuel cells. Furthermore, certain types of fuel cells are exempt from some of the cost issues mentioned above. For example, some higher temperature and alcohol fuel cells do not require pure hydrogen, which obviates the need for expensive fuel costs. Also, high temperature fuel cells do not require catalysts. The disadvantage to high temperature fuel cells is that they are significantly larger and not suitable for transportation applications.

Durability

There is no point in commercializing a fuel cell if its effective productive life is too short. Fuel cells must be able to survive and function at high levels of efficiency in real world conditions. As is the case with the cost issue, the durability issue differs based on fuel cell types.

- **PEM** fuel cells have two primary durability concerns. First, the membrane must be precisely hydrated in order to operate and failures in hydration can reduce operational life. If it gets too wet the chemical reaction slows while if it dries out it can crack. Second, catalysts in a fuel cell can also be poisoned by impurities in the hydrogen fuel leading to decaying performance, or prohibitively expensive purification equipment.
- **Solid Oxide** fuel cells can suffer from thermal cycle-ability issues. In other words, they cannot typically be turned on and off. Given the high operating temperatures, the ceramic will expand and contract as the temperature rises and falls leading to failure of the fuel cell. Additionally, solid oxide fuel cells are significantly heavier than PEM fuel cells.

While many investors may believe that durability and cost are the same issue, we believe that they should be addressed separately. While durability undoubtedly impacts costs, we believe the practical effect of the durability issue is equally important. Just imagine a fuel cell powered car that needs a new engine every 6-12 months. Even if cost is not an issue, this is not an attractive consumer application.

Fuel Demands

Fuel cells and hydrogen have long been inextricably linked in investors' minds, with some justification. However, not all fuel cell types require pure hydrogen. This is important because sourcing hydrogen for fuel cells, or for any other reason, creates several major challenges.

- **Pure** hydrogen does not exist on earth and thus must be manufactured. The most common and by far the most economic method is to reform natural gas in order to remove carbon, methane and other molecules to be left with pure hydrogen. However, this is hardly ideal as a fossil fuel will remain as the feedstock for the hydrogen economy, reforming releases harmful emissions and much of the original energy content in the fuel is lost in the process. The other more expensive method is electrolysis by which water is broken down to the molecular level to create H_2 and 0_2. However, as an electrolyzer is essentially a fuel cell in reverse, the cost and durability issues previously mentioned persist.
- **Electricity** is also needed in large quantities to power an electrolyzer. The vision of renewable energy powering an electrolyzer to produce hydrogen out of water to be used to power an emission free economy is very appealing in principle. However, we suffer from a shortage of renewable energy generation and it makes little sense to divert the limited supply of renewable energy towards the hydrogen economy as the diverted renewable energy will have to be replaced with dirtier fossil fuel generation. In addition, due to the high cost of renewable power, "clean" hydrogen produced via this route is inherently expensive.
- **Transporting** hydrogen cannot be accomplished using existing hydrocarbon distribution infrastructure as differences in properties between pure hydrogen and these fuels can lead to leakage as well as damage to the pipelines themselves, tanker trucks require major modification and gasoline tanks are useless.
- **Storing** hydrogen gas is problematic for a couple of key reasons. Hydrogen's very low energy density means that much more gas (approximately 3X by volume when compared to natural gas and approximately 100X compared to gasoline) is needed to provide the same energy output. Therefore, storing enough hydrogen either requires large, extremely high pressure tanks, cryogenic liquefied H2 or storage in solid metal — each of these solutions being inherently problematic. This leads us to the second main issue … reactivity. Pure hydrogen is more reactive in the presence of oxygen than natural gas; this means it burns more easily and is inherently more dangerous.

Hydrogen Fuel

Hydrogen does have one key benefit; it does not have to be utilized as an input for a fuel cell to be effective. With a minimum of modifications, hydrogen can be used in most internal combustion engines in lieu of gasoline. Pure hydrogen has lower harmful carbon emissions when burned in an internal combustion engine. However, in order for hydrogen to be used as a gasoline substitute you need … hydrogen. In addition to all of the cost, durability and storage issues we mentioned previously, hydrogen refueling opportunities would have to be either ubiquitous for mass use or at a central location for fleet use. Additionally, the low energy density of hydrogen gas reduces travel radius while storing a highly pressurized, reactive gas in a moving car could prove dangerous in the case of an accident. However, if these critical issues can be overcome, the potential for hydrogen to displace gasoline could provide a significant opportunity.

Conclusion

Taken as a whole, the fuel cell industry still faces a long road of technical development and cost reduction before the product is likely to achieve mainstream acceptance. Given the volatility in the space and previous hype that surrounds the stocks, we would recommend a cautious approach to investing in the sector. However, within this broad category, we believe that individual technologies and applications could offer significant potential in terms of improving energy efficiency, emissions reductions, or both. The key will be to recognize the potential benefits of the specific fuel cell application, the challenges that must be overcome, and the potential size of the target market and estimated speed of adoption of the new technology.

Fuel Cell Companies

The universe of companies involved in fuel cell research and development is quite diverse. It ranges from small private companies with no commercial products to large capitalization, publicly traded companies developing commercial products. The main companies in the space include the following:

- Ballard Power Systems (NASDAQ: BLDP, NC)
- Ceres Power (AIM: CWR, Buy)
- Distributed Energy (NASDAQ: PLUG, NC)
- Energy Conversion Devices (NASDAQ: ENER, Buy)
- FuelCell Energy (NASDAQ: FCEL, NC)
- Hydrogenics Corporation (NASDAQ: HYGS, NC)
- International Fuel Cells, a United Technologies Company (NYSE: UTX, Buy, MC - $79B)
- ITM Power (AIM: ITM, NC)
- Mechanical Technology (NASDAQ: MKTY, NC)
- Millenium Cell (NASDAQ: MCEL, NC)
- Plug Power (NASDAQ: PLUG, NC)
- Angstrom Power (Private)
- Jadoo (Private)
- Nuvera Fuel Cells (Private)
- Protonex (Private)
- Ultracell (Private)

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Clean Technology
Industrial Biotech

Clean Technology

Biofuels: Growing Pains

Investment Summary

Biofuels continue to attract investor interest, as new technologies and potential applications as chemical feedstocks improve the demand outlook and create new opportunities. Short-term issues that could impact stocks, such as feedstock costs or oil and natural gas prices, need to be balanced against longer-term fundamentals, especially government mandates.

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This report provides a broad overview of ethanol and other biofuels, both the pitfalls and potential opportunities. We highlight several key factors that are likely to drive the biofuels industry over the next 3-5 years. We also provide detailed models of production economics to benchmark the industry.

Key Points

- **Two approaches to the industry.** For the near-term, we believe the sector will trade off news flow, particularly oil & gas prices (positive if rising), feedstocks (negative if rising), and regulatory news. For longer-term investors, we believe the underlying fundamentals--competitive advantage, supply/demand of feedstocks and related costs, as well as cost structures--should drive success or failure.
- **Time to consolidate:** With ethanol prices down 30% since May, crush margins at the lowest point since mid-2005, and borrowing costs rising, U.S. ethanol capacity expansions are being delayed or canceled. We expect a wave of consolidation while the industry waits for the distribution infrastructure to catch up.
- **Keys to winners:** Economies of scale on existing facilities; geographic diversity; ability to hedge appropriately; cost advantages in sourcing, production, and transportation. Enabling technologies should also do well, particularly seed and enzyme companies.
- **What to watch out for in regard to potential losers:** Older facilities, longer term paybacks for plants not coming on until the end of the decade, and technology or cost risks in the interim.
- **For longer-term investors:** The next wave of investor interest will likely be for companies that can decouple biofuels from agriculture and sidestep "food vs. fuel" risk. Tailored energy crops, cellulosic ethanol production using non-food crops, or integrated biorefinery models could receive premium valuations, and have a better chance at long-term success.
- **Key risks:** Low barriers to entry: roughly 86 new facilities or capacity expansions are targeted to come on line if they obtain financing, lifting U.S. ethanol capacity to almost 14bn gal/year by 2010, or roughly 2.5x 2006 domestic demand. Unless government mandates sharply increase, ethanol pricing (and margins) could remain under pressure. Rising capital costs are another issue, as is volatility in feedstock costs. Over the next 2-3 years, a wider range of investment themes will likely gain traction, including biocrude, biobutanol, biodiesel, cellulosic ethanol, biochemicals, and bioplastics.

Overview

Ethanol entering the consolidation phase. In 2005-1H06, ethanol shares were still in the "scarcity" phase, when first movers in ethanol fetched a premium due to the prospect of large near-term windfalls as well as the relative scarcity of investment vehicles to play the favorable newsflow. As more ethanol producers raised capital, the sector moved into a phase based on differentiating relative cost positions. Sector valuations compressed, reaching $1.30-$2.00/gal of 2009E capacity by early 2007, well below the $3-plus/gal attained in 2006. Nonetheless, the industry persisted with new projects, spurred on by the prospect of a possible favorable government mandate ("36bn gpy by 2022"). The industry now has 6.4bn gpy of installed capacity (vs. a current government mandate of 5.4bn gpy for 2008), and new projects on track to lift capacity to almost 14bn gpy by 2010. Importantly, even the new proposed renewable fuel mandate before the Senate would only hit this target in 2014—and the proposed legislation calls for a 2015 peak in the ethanol mandate of 15bn gpy (10% of the gasoline supply) with the rest coming from "second generation" fuels such as cellulosic ethanol, biodiesel or biobutanol. In effect, the proposed legislation would at best lag the projected supply additions by roughly four years, and the industry needs a sharp increase in the mandate to bring supply/demand back into balance. Meanwhile, ethanol prices have come under pressure due to distribution bottlenecks which have led to blenders capturing most of the $0.51/gal government subsidy for ethanol use. The combination of uninspiring longer-term mandates and near-term margin pressure, when coupled with unfavorable credit markets, is leading to project delays and cancellations. Sector valuations have compressed to less than $1/gal of 2009E capacity and set the stage for the industry's third phase: consolidation. VeraSun, for example, recently acquired ASAlliances Biofuels for $725m ($2.20/gal), making it the likely No. 3 player (1bn gpy of capacity by 2009) after Poet (1.5bn gpy) and ADM (1.6bn gpy). With relatively few large-scale plants available, however, consolidators could be hard-pressed to acquire facilities below replacement cost ($1.50-$2/gal).

Table 1: Ethanol Valuation Comparisons: An NPV of Capacity Approach

					Ent. Value/	$1/gal NPV		$1.50/gal NPV	
Company	**Ticker**	**Price**	**Rating**	**2009E Capacity**	**2009E capacity**	**Ent. Val.**	**% upside**	**Ent. Val.**	**% upside**
Aventine*	AVR	$10.33	NC	425	$0.77	$425	23%	$638	74%
BioFuel Energy	BIOF	$4.62	NC	345	$0.31	$345	156%	$518	269%
Pacific Ethanol**	PEIX	$9.46	NC	320	$1.36	$320	-31%	$480	12%
US BioEnergy	USBE	$7.44	NC	700	$0.87	$700	19%	$1,050	93%
Verasun	VSE	$12.24	NC	1,000	$1.03	$1,000	-3%	$1,500	53%
Average					*$0.87*				

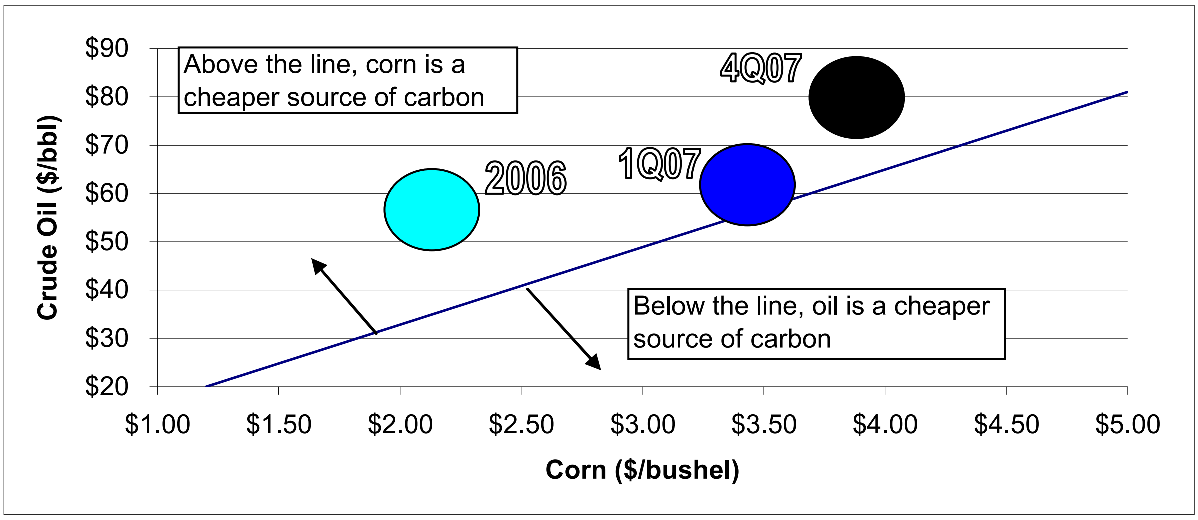
Source: Jefferies & Company, Inc. estimates, Bloomberg * Targets 750m gal/year by 2010. ** Targets 220m gal/year by mid-2008, 420m gal/year by end of 2010.

Winners and losers. Production economics, in our view, are probably the most significant guide to producers' viability and profits, which in turn drive shareholder value. While the entire industry is exposed to the issues related to near-term volatility in key feedstock costs (corn, natural gas) and the price of ethanol and gasoline, and longer-term risks from the capacity build, investors will likely differentiate both on near-term advantages due to successful hedging or feedstock sourcing (i.e., using EPS momentum as a proxy) as well as sustainable differences in cost structure. For example, larger facilities (economies of scale), flexible plant design (to be ready to switch to other feedstocks), lower distribution costs (e.g., located on one of the coasts and selling locally), or more flexible business models (e.g., investments in storage capacity and marketing services by Aventine and The Andersons) should be able to mitigate the impact of higher corn prices (we estimate a 2008 average of $3.50/bushel, with a bias to the upside) on margins, and consequently receive a more attractive relative valuation in 2007-2008. The ramp up in industry volumes should also bode well for suppliers of enabling technology and products (e.g., seeds and enzymes). On the other hand, smaller, older plants, particularly those located in regions where significant capacity additions are under way, companies without sophisticated hedging practices, and companies with stressed balance sheets are the most likely losers over the next few quarters. Companies with no plants in the ground and business plans predicated on plants starting up in 2009-2010 will likely be at risk as well.

Alternatives take the lead in 2008-2010. Over the next few years, investor interest will likely shift away from corn-based ethanol in favor of a wider range of biofuels, including biodiesel, biobutanol, biocrude and cellulosic ethanol. Cellulosic ethanol, while currently significantly more expensive to produce than corn-based ethanol, offers the promise of decoupling the ethanol industry from the "food vs. fuel" debate while reducing the risk to margins from rising corn prices. Biodiesel, in contrast, already offers a way to arbitrage a wide range of feedstocks, from palm oil to waste grease, against the cost of making diesel from gasoline. Importantly, biodiesel from at least some waste feedstocks is already competitive against conventional diesel even before the current tax incentives are taken into account. Biodiesel has two other significant advantages: it can be used in the existing petrochemical infrastructure, whereas ethanol needs to be blended downstream (effectively requiring the construction of a parallel distribution network), and projected capacity additions for the most part involve feedstock-flexible technology, reducing vulnerability to shortages in a particular feedstock. Finally, from a regional perspective, biofuels should be particularly positive for areas with ample water supplies and favorable soil quality, particularly Brazil, Argentina, Indonesia, and Africa.

Oil volatility key for investors. Assuming $3.50/bu corn, we estimate that ethanol is competitive with crude oil above $40/bbl, although co-products and process economics could reduce the breakeven point to as low as $30/bbl. Cellulosic ethanol, in contrast, only appears competitive with oil above $60/bbl. Excluding tax subsidies, we estimate biodiesel from waste products should be able to be profitable above $35/bbl crude oil, whereas biodiesel from higher-end vegetable oils should be profitable at $65/bbl crude. For biodiesel, the tax subsidies represent $13-$24/bbl crude equivalent depending on the feedstock being subsidized. We note, however, that the feedstock landscape is shifting rapidly as crop prices move higher in response to higher biofuel demand. Even when considered solely as sources of carbon, corn and crude oil's respective appeal can shift quickly due to price volatility.

Chart 1: Change in the Feedstock Landscape: Cost of Carbon in Corn vs. in Crude Oil



Source: Cargill, Industrial Biotechnology

A wider range of investor options. By the end of the decade, investors will need to assess the relative appeal of a wider range of investment plays on industrial biotechnology, broadly construed, and its applications. Besides biodiesel and corn-based ethanol, these include cellulosic ethanol, biobutanol, biocrude, biochemicals, and bioplastics. As more industrial biotechnology companies come public and move toward profitability, we expect ethanol shares to trade more on longer-term fundamental competitive positions. On a regional basis, we believe that Brazilian sugarcane-based biorefineries that integrate sugar-based and cellulosic ethanol, and possibly biodiesel and biochemicals, will likely dominate the lower end of the industry cost curve.

Key Context for Generalists

Biofuels such as ethanol, biodiesel, and eventually biobutanol are liquid fuels for transportation made from biomass. In effect, biofuels provide a way to convert into a useful form the chemical energy stored in algae, animal fats, or crops such as corn, wheat, beets, vegetable oils (soy, palm, rapeseed), wood, or straw. Biodiesel can be used as a direct substitute for fossil diesel, either as a blend or on its own, while ethanol is used both as an oxygenate (helping gasoline burn more efficiently) and, particularly in Brazil, as a substitute for gasoline. Whereas Brazil has been able to leverage low-cost agricultural feedstocks and relatively low energy use/capita to make a significant shift in favor of using ethanol as a fuel, the industry has been slower to expand in the US due to lower gasoline prices and the use of other fuel additives (most notably MTBE, which displaced roughly 2bn gal/year of ethanol demand until it was phased out in 1H06). Ethanol has more high-profile support in the Americas. It is derived from sugar, which in turn can be generated from corn (in the US), sugarcane (in Brazil), wine (Sweden), wheat, beets, or even cellulosic waste products such as stems and stalks (an R&D priority). Globally, biofuel production amounted to roughly 10bn gal in 2005. Industry projections suggest production could exceed 87bn gal by 2020.

Table 2: Global Biofuel Production by Region (bn gal/year), 2005 and 2020

(bn gal*)	2005	%	2020	%	CAGR
North America	4	39%	30	34%	15%
Europe & Eurasia	1.1	11%	20	23%	23%
Asia-Pacific	1.7	17%	30	34%	23%
South & Central America	4	34%	7	8%	5%
Total	10.3		87		16%

Source: DuPont *NB: 1 gallon = 3.785 liters

To get there, however, the industry expects persistently high energy costs as well as significant government support in the form of mandates, as well as advances in industrial biotechnology. Some of the targeted advances include new, tailored crops with higher starch content (enhancing yield by 3%-5%), advances in enzyme technology to better process cellulose, process improvements to improve thermal efficiency (reducing ethanol costs by as much as $0.20/gal), and, importantly, using co-products from ethanol production to manufacture biodiesel. Other targeted advances are intended to reduce the degree of direct competition between biofuel and traditional crop applications, particularly by shifting away from corn in favor of non-food crops. Clearly, changes in the energy cost outlook, regulatory support, or the pace of technical progress could alter industry forecasts. The industry also needs to put to rest the debate over energy efficiency.

- At 4bn gallons, ethanol contributed only 2% of the US gasoline supply in 2005, less than 1% of railroad shipments, but constituted 12% of total corn demand. By 2007, we expect ethanol to represent more than 25% of corn demand, sustaining a further increase in the level of corn prices. While there is some debate as to whether China can remain a net exporter of corn given its own biofuels ambitions, we expect other corn producers, particularly Argentina, to export more to the US in response to the higher US corn prices.

- With 85%-95% of US ethanol sold under 6- to 12-month fixed price contracts or tied to the price of gasoline, the volatility in ethanol spot prices does not directly translate into industry cash flows. As such, the industry has more flexibility to hedge its input costs against visible output prices.

- Ethanol yields are rising. Plants under construction are expected to average 2.8 gal/bushel of corn, up from 2.5 gal/bushel in the 1990s and 2.4 gal/bushel in the 1980s. Improved fermentation processes and higher-starch corn varieties could lift ethanol yields to north of 3.0 gal/bushel by early next decade.

- Long before any theoretical limits are reached, supply constraints are moving ethanol feedstock costs towards equilibrium by driving corn prices and acreage higher, much as Brazilian ethanol demand has contributed to a sharp rise in sugar prices (now triple the levels that prevailed only a few years ago).

- Cellulosic ethanol appears to be uneconomical at current gasoline prices, but significant advances need to be made before it will be competitive with corn ethanol and gasoline on a sustainable basis.

- By 2010-2012, fuels derived from other cellulosic feedstocks (e.g., switchgrass) could become cost-competitive with corn-based ethanol. Better enzymes, genetically modified crops, and better plant designs should make biodiesel and cellulosic feedstocks more viable, providing a substitute for corn-based ethanol. Importantly, newer ethanol plants are more likely to be designed to be convertible to cellulosic processes in anticipation of these feedstocks becoming competitive.

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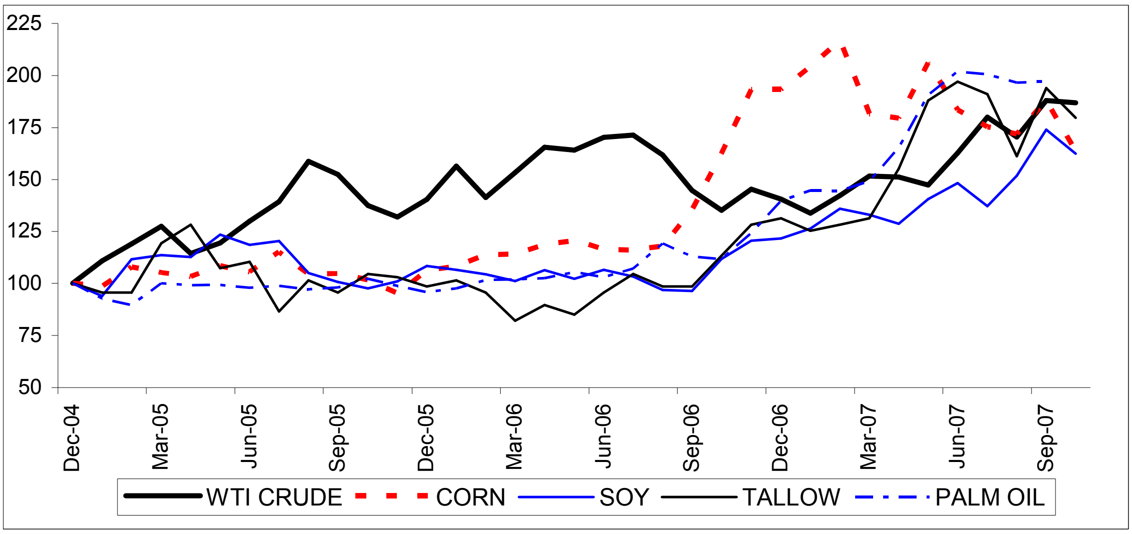
- Biodiesel should consume approximately 2.3bn lbs (10%) of soybean oil in 2007, up 110% YoY. Waste feedstocks, such as inedible tallow and yellow grease, have better economics, but supply is limited. Indeed, even if the industry can convert all the available grease, soybean oil, and tallow into biodiesel, it would only be large enough to displace 5% of current diesel demand (vs. 0.1% last year). Any push to further adopt biodiesel will hinge on the availability of feedstock imports (e.g., palm oil), which should entail structurally higher feedstock prices than domestic waste products. We estimate that using palm oil rather than waste products adds $1.20/gal.

- Regardless of the feedstock, we remain skeptical that the 85% ethanol fuels will be introduced quickly. While roughly six million flex-fuel vehicles in the US can burn E-85 fuel, the real bottleneck is deploying the necessary infrastructure at gas stations, which usually entails more risk for small operators. Also, in our view the jury is still out as to whether the infrastructure costs for rolling out E-85 will prove prohibitive given rival alternative power technologies (electric, hydrogen). If the US simply shifted to 10% ethanol content in its fuel supply, however, annual demand could eventually exceed 15bn gal, roughly 3-5bn more than the likely capacity from the corn crop. To achieve such a high target, we expect most of the volume will need to be supplied from cellulosic feedstocks. As such, we do not expect a significant roll-out of E-85 vehicles until the technology for cellulosic-based ethanol is proven to be viable at a commercial scale. Moreover, we believe that liquid fuel/electric cars such as GM's Volt represent a more compelling trend, given the opportunity to leverage the existing electrical grid without the infrastructure issues that bedevil E-85.

- We expect a structural increase in corn prices. As the chart below shows, inflation in feedstock prices has accelerated in recent years in response to the increase in energy costs and the consequent increase in demand for biofuels. Corn prices, at $3.50/bu, are still near recent highs, and we expect average prices this year to be $3.50/bu or higher. In recent years barley, wheat and rapeseed have more than doubled, partly due to biofuels demand, and we expect palm oil and soy prices to move higher in 2007-2008. Within three to five years demand for cellulosic ethanol will likely start to have an impact on wood prices as well.

Chart 2: Oil and Biofuel Feedstock Prices, Indexed YE04=100. The global investment in biofuels was one factor contributing to a rise in the requisite feedstocks.



Source: Renewable Fuels Association

Table 3: Industrial Biotechnology Universe

	Symbol	Rating	Close (US$)	Market Cap. (US$m)
BioFuels				
Ethanol				
Aventine	AVR	NC	$10.33	$433
Cosan	CSAN3.BZ	NC	$15.74	$2,972
CropEnergies	B1FHFF	NC	$7.20	$754
Green Plains Renewable Energy	GPRE	NC	$10.20	$61
MGP Ingredients	MGPI	NC	$10.14	$172
Pacific Ethanol	PEIX	NC	$9.46	$384
VeraSun	VSE	NC	$12.24	$958
Renova Energy	RVA.L	NC	$1.17	$38
US BioEnergy	USBE	NC	$7.44	$506
Cellulosic Ethanol				
Verenium	**VRNM**	**Hold**	**$5.55**	**$348**
Biodiesel				
Better Biodiesel	BBDS	NC	$1.05	$32
China Biodiesel	CBI.L	NC	$0.58	$59
Nova Biosource Fuels	NBF	NC	$2.57	$283
China Clean Energy	CCGY.OB	NC	$1.76	$38
D1 Oils	DOOIF	NC	$3.90	$250
Verbio	VBK.GR	NC	$5.21	$328
Diversified				
Abengoa	ABGOF	NC	$39.25	$3,530
ADM	ADM	NC	$33.53	$21,602
Actelios	ACT.IM	NC	$10.56	$715
Boralex	BLX.CN	NC	$17.29	$647
Environmental Power	EPG	NC	$5.19	$81
The Andersons	ANDE	NC	$47.79	$851
Enablers: Enzymes, Catalysts & Processes				
O2Diesel	OTD	NC	$0.41	$35
SunOpta	STKL	NC	$15.19	$959
Novozymes	NVZMF	NC	$122.50	$7,963
Sigma-Aldrich	SIAL	NC	$50.16	$6,549
Biobased Materials				
Cereplast	CERP	NC	$0.68	$175
Global Bio-Chem	0809.HK	NC	$0.40	$914
Enablers: Crops, Seeds & Starch				
DuPont	DD	NC	$49.48	$45,547
Monsanto	**MON**	**Buy**	**$89.52**	**$48,830**
Syngenta	SYT	NC	$44.95	$22,646
Tate & Lyle	TATYY	NC	$35.15	$4,229

Source: Factset

Key Investment Themes: Focus on Production Costs, Disruptive Technologies

Whereas ethanol production using corn or sugarcane uses basic yeast-based fermentation processes, we believe the rapid progress in biology is likely to deliver step-changes in technology over the next decade. The benefits of industrial biotechnology for agriculture are the most developed, and we believe opportunities in energy storage, bioconversion of heavy-carbon feedstocks, materials production, and carbon sequestration are only starting to be addressed. Currently, these opportunities are being blended together, which will likely lead to inefficiencies in the value chain. For investors interested in near-term developments, we would recommend a focus on companies that can help optimize key parts of the value chain, particularly feedstocks, conversion yields, and the ease of dropping alternate biofuels into the existing distribution infrastructure. In the long run, however, we expect differentiation in feedstocks to be accompanied by differentiation in co-products and plant design. This should create a premium for either platform companies that have the skill set to help other companies integrate plant design with metabolic engineering of the fermentation microbes, or companies that do a better job running integrated production facilities to improve co-product economics. Enablers that help these companies create their own value chains, rather than piggy-backing on the existing agricultural or petrochemical value chains, should be attractive longer-term plays as well.

With this in mind, key investment themes include the following:

- **Biodiesel vs. ethanol.** On a broad-brush basis, we favor biodiesel over ethanol. Biodiesel lacks the supply-chain issues that bedevil ethanol, biodiesel production processes typically have more flexible feedstocks, and biodiesel demand represents a much smaller portion of demand for those feedstocks. In either case, however, we expect to see new entrants compete with more innovative and thermally efficient plant designs over the next few years. Plant designs that generate less waste, with a higher yield, should be able to provide a sustainable cost advantage and higher returns on capital. This process of plant optimization, however, is a recipe for pushing existing capacity towards the higher end of the cost curve, and as the industry matures we expect ethanol shares to trade below replacement costs to reflect this ongoing cycle of innovation. This implies significant risk for consolidators given the current premiums being paid for ethanol capacity.

- **Alternatives to yeast and corn for ethanol production.** To date, ethanol production has focused on using yeast to ferment corn or sugarcane. Genetically modifying yeast is improving ethanol yields (on a gal/bushel basis), and modified enzyme cocktails have further improved ethanol economics. To make cellulosic ethanol economical, however, research is moving away from yeast towards genetically modifying bacteria such as *e. coli* to generate some of the enzymes organically, with some additional cellulases added as part of the conversion process. Others are starting instead from bacteria which produce their own cellulose. We are also seeing more investment in gasification processes that use inorganic catalysts rather than enzymes to improve reaction efficiency. Besides the range of production processes, ethanol producers need to ensure that the feedstock is environmentally sustainable: that is, it does not damage soil quality or the water table to the point of becoming unprofitable. Non-sustainable processes, in our view, will likely run into increasing regulatory obstacles in the coming years as consumers and governments become more sophisticated in their evaluation of environmental impacts.

- **Biochemicals vs. biofuels.** Similarly, we believe that biochemicals and biomaterials are better positioned to deliver returns across the cycle than biofuels. Again, in biofuels we see several plausible technologies likely to compete for investor attention by 2009-2010, and we expect new entrants with better plant design, co-product integration, and fermentation processes to increase the level of competition in each product line. In biochemicals and biomaterials, we see a better opportunity to establish a competitive advantage in IP that will enhance the scarcity value of the product. Moreover, by selling products that compete on value rather than a cost-plus commodity model, producers of specialty biomaterials should maintain some degree of insulation from volatile feedstocks. Finally, we believe we are very early in the cycle of government incentives for biomaterials, whereas government incentives for biofuels are already well established—and well anticipated by share prices.

- **Strong IP.** In particular, we would focus on companies with unique IP in the industrial biotechnology triangle of genetically modifying feedstock crops, discovering and modifying microbes to optimize the fermentation process, and developing enzymes to facilitate the process. Given the rapid pace of development of industrial biotechnology, these areas should have more sustainable barriers to entry than companies that rely on competitive advantages based on plant engineering, logistics, or prowess at hedging financial or commodity risk. Even so, companies that specialize in gene discovery, enzyme optimization, plant design and construction, or product distribution still face significant risk of commoditization, particularly as larger sums of capital are allocated to industrial biotechnology R&D (e.g., BP's $50m/year funding of Energy Biosciences Institute).

- **Integration vs. platform companies**. On a similar broad-brush basis, we expect the market to favor companies that integrate scientific platforms, design capabilities, production, and channels to market over platform companies. Integrating facility design, channel to end market, and genetic modification of feedstocks and fermentation processes will emerge as a key driver of higher returns on capital, in our view, because many of the essential business choices are "chicken and egg" questions. Which crop to grow, how best to grow it or hedge the supply from a third party, how to ensure the crop is environmentally sustainable, how to process it, what to turn it into, how to process the co-products, where to locate the plant, whether to optimize the process or retain flexibility, how best to get the products to market—the answers to each of these questions has an impact on the others, and on the long-term viability of the facility, and in many cases they are being evaluated without reliable precedents. At the current stage, an integrated approach should provide synergies in terms of tailoring fermentation microbes to the production process, and vice versa, as well as being able to accelerate the optimization of biomaterials to suit consumer requirements. As the industry matures, companies can spin-out non-core but capital-intensive processes, much as the refineries have outsourced their hydrogen supply in exchange for higher reliability of supply. In the meantime, as early stage companies are typically capital constrained, we expect a wide range of business models to evolve to bring down the aggregate cost of capital for the new technology.

- **Keep an eye on the majors**. The oil majors are increasingly involved in biofuels, both as transportation fuels and, at least anecdotally, as feedstocks for chemicals. ConocoPhillips and Tyson, for example, have announced an alliance to produce and market diesel fuel made from pork, poultry, and beef fat with an estimated $150-$175M facility in the US producing 175m gpy of biodiesel by 2009. ConocoPhillips also produces diesel from soybean oil at a plant in Ireland, and developed its fat-based diesel in Ireland as well. Most recently, it announced an alliance with ADM to develop biocrude, a more flexible intermediary, out of crops, wood and waste products. Chevron, meanwhile, is investing in a 100M gpy soybean-based biodiesel plant in Galveston, Texas, as well as in cellulosic ethanol. Outside the US, BP is investing in biobutanol (with DuPont), ethanol, and biodiesel (albeit with some controversy about the specifications) as well as a $500M BioSciences Institute with the University of California Berkeley, the University of Illinois, Urbana-Champaign, and the Lawrence Berkeley National Laboratory. PetroChina, meanwhile, has drawn attention with its plans to produce 667M gpy of non-grain ethanol by 2010 and 60M gpy of biodiesel. On the infrastructure side, while the US debate continues about the feasibility of ethanol infrastructure, Petrobras is building in Brazil a $235M dedicated ethanol pipeline that will run approximately 800 miles from the Goias state to a San Paulo refinery and then to the port of Sao Sebastiao. Competition from the oil majors, for both end markets and subsidies, could prove disruptive on a regional basis, particularly for producers that have older, smaller facilities that might face adverse transportation costs.

Another related investment theme would be opportunities to alleviate key bottlenecks in the supply chain, indirectly exploiting opportunities created by government mandates:

- **Distribution**. Ethanol is primarily distributed by truck, rail, or barge. Ethanol is hydrophilic, which can complicate using a pipeline. This property also provides an incentive for dedicated transport fleets (less time spent cleaning containers), which should provide an opportunity for transportation companies to improve their utilization rates. According to media reports, approximately 35%-40% of the new orders for railcars are for cars that can ship ethanol. Given the tight operating conditions in the railcar industry, however, we expect many of these new cars to be delivered in 2H07-2008. This implies that ethanol producers that have some degree of control over their distribution infrastructure will be best positioned over the next couple of years, while the rest could face significant cost inflation. At the same time, while rail capacity is a critical issue for ethanol producers, it is, in our view, immaterial for the railroads, as ethanol shipments represent only about 1% of total railcar loadings.

- **Storage.** As noted above, ethanol tends to separate from gasoline over time. As a result, it cannot be shipped in pipelines, and needs to be blended at distribution terminals rather than at the refinery. This implies the need for a significant increase in storage capacity over the next couple of years to accommodate the doubling in ethanol capacity expected by 2010. Companies that have significant storage capacity already on hand, such as The Andersons, will likely receive a premium for these assets regardless of the long-term economics of ethanol versus substitute biofuels.

- **Engines**. Most cars in the US cannot run on fuel that is more than 10% ethanol. Only about six million vehicles in the US can run on E85, fuel that is 85% ethanol. The retrofit, however, is relatively inexpensive, with industry observers estimating it at about $100/car (mostly for fuel lines, fuel tanks, and sensors). Companies that supply these components should see solid demand trends over the next three to four years, at least.

- **Feedstocks**. Even with its current fairly limited volumes, ethanol demand already represents roughly 20% of US corn demand. Multiple industry observers, including DuPont, have estimated that by the time US ethanol demand exceeds 5bn gallons, the industry will be nearing the limit of how much corn it can use without having an exaggerated impact on corn prices. Furthermore, the DoE has estimated that the US faces a longer-term constraint on the amount of corn that can be switched from food to ethanol, limiting ethanol volumes at roughly 12bn gal—a level the industry could reach as early as 2009. The next step will likely be a shift towards using waste cellulose, such as corn and wheat stalks or other vegetable matter. In the long run, we expect the industry to move towards dedicated energy crops, where the ethanol production can be integrated with chemical production much as in a traditional refinery. (For more details on the long-term potential, please see our April 24, 2006, primer, "Industrial Biotechnology".) This should reduce the direct pressure on corn prices and further differentiate biorefinery economics from the petrochemical value chain.

Table 4: Potential Trajectory for Ethanol Industry

	2005	Interim	Long-Term
Feedstock	Starch	Waste cellulose	Cellulosic energy crops (3x yield per acre)
US Volume (bn gallons)	4	20	30-200
% fossil fuel displaced	2%	10%	15%-100%
CO2 reduction	1.80%	9%	14%-90%
Process	Starch fermentation, limited cellulose processing.	Enzymatic hydrolysis, Cellulases, Single Sugar metabolisms, multiple microbes, energy crops, more residue processing	Designer cellulosic energy crops, integrated processing, single microbe capable of hydrolyzing cellulose and producing ethanol, carbon sequestration through plant partitioning
Deployment	Large, central processing	Large, central processing	Distributed or centralized
Energy yield	14%		37%-plus
Est. $/gal gasoline equivalent	$3.78	$1.62 Current mfg. costs 50% > starch	$0.91

Source: DOE

Table 5: Theoretical Yield of Alternate Feedstocks (ethanol gal/ton of feedstock)

Corn Grain	124.4
Corn Stover	113.0
Rice Straw	109.9
Cotton Gin Trash	56.8
Forest Thinnings	81.5
Hardwood Sawdust	100.8
Bagasse	111.5
Mixed Paper	116.2

Source: DOE

- **Land** could also emerge as an important bottleneck for the industry, implying upside potential for companies with real estate holdings close to new production facilities. To put this in perspective, the US has a total surface area of roughly 1.9bn acres (in the 48 contiguous states), but only about 400 million acres of cropland. Switchgrass is grown on only about 30 million acres of land covered by the Conservation Resource Program. Already the increased demand for biofuels has translated into higher prices for crop land. According to media reports, in 2006 the average price of farm land rose 15% in the US, 27% in Argentina, and 10% in Australia. In Idaho, crop land prices rose 35%.

According to an NRDC study conducted in 2004, more than 1.7bn acres would need to be shifted to biofuels if current technology were to displace US gasoline consumption (base case 289bn gal in 2050, up from 137bn gal in 2004). The NRDC believes this could be reduced to a more manageable requirement, below 50 million acres, if several (admittedly ambitious) innovations are delivered, including the following:

- Raise fuel efficiency to 50 mpg and implement new mass transit initiatives which could reduce gasoline demand by almost 40%.
- Improve crop yields as well as the conversion efficiency for converting cellulose to ethanol.
- Produce biodiesel from the waste products.
- Convert soybean production for animal feed to switchgrass and collect corn stover for conversion to fuel.

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Table 6: Land Needed to Meet Energy Needs in 2050 With Biofuels

Production and efficiency	Gasoline demand (bn of gals of gas equiv)	Switchgrass Yield (dry tons/acre/year)	Conversion Efficiency (gals gas equiv/ ton)	Land (m acres)
Status Quo In 2050	289	5	33	1753
Smart Growth & Efficiency	108	5	33	657
Increase Conversion Efficiency	108	5	69	313
Biofuels Coproduction	108	5	77	282
Increased Switchgrass Yield	108	12	77	114
Animal Feed From Switchgrass (73m acres, 50%-100% converted)				41-77
Corn Stover (323m tons, 75% collected)				21-88
Conservation Reserve Switchgrass (30m acres, 33%-50% converted)				6-48

Source: NRDC

How Much Is Capacity Worth?

As a rapidly emerging industry with volatile supply/demand dynamics, biofuels have experienced wide swings in valuations. Short-term traders frequently tie ethanol share performance to near-term trends in the price of ethanol, with gasoline prices, corn prices, and natural gas prices having a more limited impact on share volatility. The simplest fundamental approach, perhaps, is to draw an analogy to refineries, and place a comparable 5x-6x EBITDA on normalized estimates (e.g., once projected plants come onstream in 2009E or 2010E).

The nature of the biofuels market and the capital intensity of the industry have also led to widespread use of asset-based valuation models. In these models, the different biofuel producers are put on a common valuation basis by looking at the ratio of their enterprise value to their installed or expected capacity.

Capital costs for new ethanol capacity have risen to roughly $2-$2.25/gal, up from $1.50/gal in 2003-2004. Some of the increase has been driven by design changes, but the lion's share reflects higher metal prices and higher labor costs as the plant builders such as Lurgi and Fagen are running full out and have significantly extended their construction times for new plants, such that any new contracts are likely achievable only in 2009-2010.

- In the near term, while the industry cost curve remains relatively flat, we expect ethanol companies to trade above their replacement cost, or else become candidates for consolidation.

- In the long run, however, we expect improvements in plant design to lead to newer plants being consistently at the low end of the cost curve. As a result, equities for companies with older facilities will likely end up trading below their replacement value on an asset basis. In other mature capital-intensive industries such as offshore drillers and chemicals, discounts of 10%-15% to replacement asset values are typical and 30%-40% plausible at cyclical troughs.

A more nuanced approach, in our view, is to value ethanol capacity based on models of process economics. We give examples of such models in the next few pages. These models can be used in a couple of different ways. First and foremost, they can be used to assess what the long-term value of biofuel production might be under various market conditions. For ethanol, such an analysis would go beyond simply looking at the "crush spread," or the spread between ethanol prices and the requisite corn input costs, and takes into account catalyst costs, recovery of capital, natural gas prices, and other cost inputs.

Perhaps more importantly, the models provide a way to assess the "full cycle" value of biofuel capacity. Our key assumption is that, over time, the prices of oil-based and bio-based fuels will settle into an equilibrium such that biofuel producers generate long-term rates of return comparable with other commodity industries, or slightly below their cost of capital (i.e., 10% EBIT margins, 6%-7% after-tax ROIC). Simply put, in an industry where the marginal producers price their product at the cash cost of production, we expect producers to recover their capital costs, but not their initial fixed costs. Higher returns would provide an incentive to add additional capacity, putting upward pressure on input costs (e.g., corn in the case of ethanol, or rapeseed in the case of European biodiesel).

Such a valuation approach lends itself to a "base plus" analysis. After establishing a benchmark full-cycle valuation, one can then analyze the returns implied in current market prices to see whether likely favorable or unfavorable factors are adequately discounted. For example, one can infer the amount of "windfall" profits the producers are expected to generate before new competitor capacity brings returns down to full-cycle levels. Alternately, one can

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set equilibrium pricing based on the highest cost of production (e.g., cellulosic ethanol), and then explore the implications for fair value for the other producers.

In the following pages, we sketch equilibrium levels for each production method, assuming the industry aims for a 7% return on capital or 10% pre-tax margins. Such an equilibrium analysis supports $1.19/gal as a long-term fair value, in contrast to current market valuations of roughly $0.87/gal on 2009E targeted capacity.

Separately, in the near term, cash margins are below likely equilibrium levels, which should slow the capacity build out in the industry. We note, however, that the market already appears to be forecasting margin expansion, partly through consolidation but also, presumably, some relief from feedstock costs in 2008-2009 (a less likely proposition, in our view).

Table 7: Ethanol Valuation Comparisons: An NPV of Capacity Approach

Company	Ticker	Price	Rating	2009E Capacity	Ent. Value/ 2009E capacity	$1/gal NPV Ent. Val.	$1/gal NPV % upside	$1.50/gal NPV Ent. Val.	$1.50/gal NPV % upside
Aventine*	AVR	$10.33	NC	425	$0.77	$425	23%	$638	74%
BioFuel Energy	BIOF	$4.62	NC	345	$0.31	$345	156%	$518	269%
Pacific Ethanol**	PEIX	$9.46	NC	320	$1.36	$320	-31%	$480	12%
US BioEnergy	USBE	$7.44	NC	700	$0.87	$700	19%	$1,050	93%
Verasun	VSE	$12.24	NC	1,000	$1.03	$1,000	-3%	$1,500	53%
Average					*$0.87*				

Source: Jefferies & Company, Inc. estimates, Bloomberg * Targets 750m gal/year by 2010. ** Targets 220m gal/year by mid-2008, 420m gal/year by end of 2010.

Importantly, the equilibrium NPVs sketched out on the following pages are estimates of theoretical fair value for “typical current capacity”, excluding hedging. Capacity to be built for production in 2009, for example, would need to be discounted appropriately to reflect the fluid state of the industry (e.g., 15%-20% discount rate). Moreover, for actual facilities, the NPV would necessarily change due to that facility’s process economics, feedstock sourcing costs, co-products, logistical advantages or disadvantages, and operating rates, among other factors. Finally, these models exclude any estimate for SG&A or corporate overhead, which would pertain to equity valuations.

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Chart 3: US Dry Distiller Grain, Dry Mill Ethanol Plant Economics: $200M Plant Cost Reduces NPV by $0.19

1) Capital

Capital intensity ($/gal)	1.4
Plant Cost ($m)	$140.00
Capacity (m gal)	100
Capacity (m t)	0.30
Working Capital ($m)	20
Total Invested Capital ($m)	$160.00
Capital/Gallon ($)	$1.60
Capital/t ($)	$538

2) Variable Cash Costs

Corn	
Acres (m)	0.30
Bushels (m)	34.29
Ethanol yield (gal/bushel)	2.8
Price ($/bushel)	$3.42
Total cost of corn ($m)	*$117.26*
Cost of corn ($/gal)	*$1.22*
Processing	
Heat efficiency (BTU/gal)	35,000
Heat (in MMBTU)	3.36
Price of Natural Gas ($/MMBTU)	$7.05
Electricity (kWh)	110.40
Electricity ($/kWh)	$0.031
Total energy cost	*$27.11*
Total energy ($/gal)	*$0.29*
Other variable costs ($/gal)	
Waste Management	$0.006
Water	$0.007
Enzymes	$0.048
Yeast	$0.004
Chemicals	$0.023
Denaturant	$0.095
Maintenance	$0.030
Labor	$0.030
Administrative	$0.033
Other	$0.004
Total other variable costs ($/gal)	*$0.28*
Net cash costs of production ($/gal)	$1.78
Net cash costs ($m)	$171.34
Co-products	
Distiller's Dry Grains (lb/gal)	6.25
Total volume (m lb)	600
Price ($/t)	$101.40
Co-product value ($m)	*$27.60*
Co-product value ($/gal)	*$0.29*
Shipping ($/gal)	$0.08
Net cash cost (incl. Shipping, co-products)	$1.58
Capital recovery ($/gal)	$0.07
Total cost ($/gal)	***$1.65***

3) Sales

Operating rate (%)	96%
Volume (m gal)	96
Price of ethanol ($/gal)	$1.60
Gasoline equivalent ($/gal)	$2.16
W/ $0.51 refiners subsidy	$1.47
Revenue ($m)	$154

4) Key Assumptions

Industry margins settle at 10%.
Capital intensity ranges from 1x-1.8x.
Reserves, financing could reach $0.40/gal.
A bushel of corn yields 2.8 gallons of ethanol.
25% of corn is sold as distiller's dry grains.
35% less energy density than gasoline.
This model excludes SG&A, corporate costs.

5) Margin Analysis

Profit ($/gal)	($0.05)
Operating Margin (%)	-3.0%
Cash Margin (%)	-11.6%
Breakeven Gasoline ($/gal)	$2.13
W/ $0.51 refiners subsidy	$1.44
Crude Breakeven ($/bbl)	$39.94
Tax rate	*35%*
ROIC	-2%
Target EBIT margin	10%
Implied ethanol price ($/gal)	$1.83
Equivalent gasoline ($/gal)	$2.47
W/ $0.51 refiners subsidy	$1.96
Equivalent crude ($/bbl)	$54.36

6) Sensitivity Analysis **Current NPV: $ (0.31)**

Pre-tax profits ($/gal)

Corn ($/bu)	Price of ethanol ($/gal): $1.10	$1.35	$1.60	$1.85	$2.10
$2.92	(0.37)	(0.12)	0.13	0.38	0.63
$3.17	(0.46)	(0.21)	0.04	0.29	0.54
$3.42	(0.55)	(0.30)	***(0.05)***	0.20	0.45
$3.67	(0.64)	(0.39)	(0.14)	0.11	0.36
$3.92	(0.73)	(0.48)	(0.23)	0.02	0.27

ROIC

Corn ($/bu)	Price of ethanol ($/gal): $1.10	$1.35	$1.60	$1.85	$2.10
$2.92	-14%	-5%	5%	15%	25%
$3.17	-18%	-8%	2%	11%	21%
$3.42	-21%	-12%	***-2%***	8%	18%
$3.67	-25%	-15%	-5%	4%	14%
$3.92	-28%	-19%	-9%	1%	11%

Fair value (after-tax NPV $/gal) 10% discount rate 10% margin

Corn ($/bu)	Long-run Ethanol Price ($/gal): $1.33	$1.58	$1.83	$2.08	$2.33
$2.92	(0.90)	0.73	2.35	3.98	5.60
$3.17	(1.48)	0.15	1.77	3.40	5.02
$3.42	(2.06)	(0.44)	***1.19***	2.81	4.44
$3.67	(2.64)	(1.02)	0.61	2.23	3.86
$3.92	(3.22)	(1.60)	0.03	1.65	3.28

Additional value ($/gal) created by near-term windfalls

Windfall ($/gal)	# of years windfall persists: 1	2	3	4	5
$0.50	0.45	0.87	1.24	1.58	1.90
$0.75	0.68	1.30	1.87	2.38	2.84
$1.00	0.91	1.74	***2.49***	3.17	3.79
$1.25	1.14	2.17	3.11	3.96	4.74
$1.50	1.36	2.60	3.73	4.75	5.69

Source: Jefferies & Company, Inc. estimates

Chart 4: US Wet Mill Ethanol Plant Economics: Capital Intensive, but Higher NPV

1) Capital

Capital intensity ($/gal)	2.3
Plant Cost ($m)	$230.00
Capacity (m gal)	100
Capacity (m t)	0.30
Working Capital ($m)	20
Total Invested Capital ($m)	$250.00
Capital/Gallon ($)	$2.50
Capital/t ($)	$840

2) Variable Cash Costs

Corn	
Acres (m)	0.32
Bushels (m)	36.23
Ethanol yield (gal/bushel)	2.65
Price ($/bushel)	$3.42
Total cost of corn ($m)	*$123.89*
Cost of corn ($/gal)	*$1.29*
Processing	
Heat efficiency (BTU/gal)	35,000
Heat (in MMBTU)	3.36
Price of Natural Gas ($/MMBTU)	$7.05
Electricity (kWh)	110.40
Electricity ($/kWh)	$0.031
Total energy cost	*$27.11*
Total energy ($/gal)	*$0.29*
Other variable costs ($/gal)	
Waste Management	$0.006
Water	$0.007
Enzymes	$0.048
Yeast	$0.004
Chemicals	$0.023
Denaturant	$0.142
Maintenance	$0.030
Labor	$0.030
Administrative	$0.033
Other	$0.004
Total other variable costs ($/gal)	*$0.33*
Net cash costs of production ($/gal)	$1.90
Net cash costs ($m)	$182.55
Co-products	
Brewer's yeast ('000 t)	23
Corn gluten ('000 t)	173
Corn gluten meal ('000 t)	39
Corn germ ('000 t)	66
CCDS ('000 t)	64
Carbon dioxide ('000 t)	194
Co-product value ($m)	*$61.95*
Co-product value ($/gal)	*$0.65*
Shipping ($/gal)	$0.08
Net cash cost (incl. Shipping, co-products)	$1.34
Capital recovery ($/gal)	$0.12
Total cost ($/gal)	***$1.45***

3) Sales

Operating rate (%)	96%
Volume (m gal)	96
Price of ethanol ($/gal)	$1.60
Gasoline equivalent ($/gal)	$2.16
W/ $0.51 refiners subsidy	$1.47
Revenue ($m)	$154

4) Key Assumptions

Industry margins settle at 10%.
Capital intensity ranges from 1x-1.8x.
Reserves, financing could reach $0.40/gal.
A bushel of corn yields 2.65 gallons of ethanol.
Range of co-products subsidize 50% of corn
35% less energy density than gasoline.
This model excludes SG&A, corporate costs.

5) Margin Analysis

Profit ($/gal)	$0.15
Operating Margin (%)	9.3%
Cash Margin (%)	-18.8%
Breakeven Gasoline ($/gal)	$1.80
W/ $0.51 refiners subsidy	$1.12
Crude Breakeven ($/bbl)	$30.92
Tax rate	*35%*
ROIC	4%
Target EBIT margin	10%
Implied ethanol price ($/gal)	$1.61
Equivalent gasoline ($/gal)	$2.18
W/ $0.51 refiners subsidy	$1.67
Equivalent crude ($/bbl)	$46.21

6) Sensitivity Analysis — **Current NPV: $ 0.97**

Profits ($/gal)

Corn ($/bu)	Price of ethanol ($/gal) $1.10	$1.35	$1.60	$1.85	$2.10
$2.92	(0.16)	0.09	0.34	0.59	0.84
$3.17	(0.26)	(0.01)	0.24	0.49	0.74
$3.42	(0.35)	(0.10)	***0.15***	0.40	0.65
$3.67	(0.45)	(0.20)	0.05	0.30	0.55
$3.92	(0.54)	(0.29)	(0.04)	0.21	0.46

ROIC

Corn ($/bu)	Price of ethanol ($/gal) $1.10	$1.35	$1.60	$1.85	$2.10
$2.92	-4%	2%	8%	15%	21%
$3.17	-6%	0%	6%	12%	19%
$3.42	-9%	-3%	***4%***	10%	16%
$3.67	-11%	-5%	1%	8%	14%
$3.92	-13%	-7%	-1%	5%	11%

Fair value (after-tax NPV $/gal) — 10% discount rate — 10% margin

Corn ($/bu)	Long-run Ethanol Price ($/gal) $1.11	$1.36	$1.61	$1.86	$2.11
$2.92	(0.98)	0.65	2.27	3.90	5.52
$3.17	(1.59)	0.04	1.66	3.29	4.91
$3.42	(2.20)	(0.58)	***1.05***	2.67	4.30
$3.67	(2.82)	(1.19)	0.43	2.06	3.68
$3.92	(3.43)	(1.80)	(0.18)	1.45	3.07

Additional value ($/gal) created by near-term windfalls

Windfall ($/gal)	# of years windfall persists 1	2	3	4	5
$0.50	0.45	0.87	1.24	1.58	1.90
$0.75	0.68	1.30	1.87	2.38	2.84
$1.00	0.91	1.74	***2.49***	3.17	3.79
$1.25	1.14	2.17	3.11	3.96	4.74
$1.50	1.36	2.60	3.73	4.75	5.69

Source: Jefferies & Company, Inc. estimates

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Chart 5: US Cellulosic Ethanol Plant Economics (switchgrass)

1) Capital

Capital intensity ($/gal)	3
Plant Cost ($m)	$300.00
Capacity (m gal)	100
Capacity (m t)	0.30
Working Capital ($m)	20
Total Invested Capital ($m)	$320.00
Capital/Gallon ($)	$3.20
Capital/t ($)	$1,075.06

2) Variable Cash Costs

Switchgrass	
Acres (m)	0.29
Feedstock volume (t)	1.46
Ethanol yield (gal/t)	65
Price ($/ton)	$55.00
Total cost of switchgrass ($m)	*$80.38*
Cost of switchgrass ($/gal)	*$0.85*
Processing	
Heat efficiency (BTU/gal)	54,000
Heat (in MMBTU)	5.13
Price of Natural Gas ($/MMBTU)	$7.05
Electricity (kWh)	85.77
Electricity ($/kWh)	$0.031
Total energy cost	*$38.83*
Total energy ($/gal)	*$0.41*
Other variable costs ($/gal)	
Waste Management	$0.006
Water	$0.003
Enzymes	$0.200
Yeast	$0.004
Chemicals	$0.050
Denaturant	$0.142
Maintenance	$0.040
Labor	$0.050
Administrative	$0.040
Other	$0.140
Total other variable costs ($/gal)	*$0.68*
Net cash costs of production ($/gal)	$1.93
Net cash costs ($m)	$183.34
Co-products	
Distiller's Dry Grains (lb/gal)	0
Total volume (m lb)	0
Price ($/t)	$45.00
Co-product value ($m)	*$0.00*
Co-product value ($/gal)	*$0.00*
Shipping ($/gal)	$0.10
Net cash cost (incl. Shipping, co-products)	$2.03
Capital recovery ($/gal)	$0.15
Total cost ($/gal)	***$2.18***

3) Sales

Operating rate (%)	95%
Volume (m gal)	95
Price of ethanol ($/gal)	$1.60
Gasoline equivalent ($/gal)	$2.16
W/ $0.51 refiners subsidy	$1.47
Revenue ($m)	$152

4) Key Assumptions

Industry margins settle at 10%.
Capital intensity 3x, down to 1.5x-2x by 2020.
Yield reached 95 gal/ton by 2020.
No coproducts.
35% less energy density than gasoline.
This model excludes SG&A, corporate costs.

5) Margin Analysis

Profit ($/gal)	($0.58)
Operating Margin (%)	-36.2%
Cash Margin (%)	-20.6%
Breakeven Gasoline ($/gal)	$2.74
W/ $0.51 refiners subsidy	$2.05
Crude Breakeven ($/bbl)	$56.88
Tax rate	*35%*
ROIC	-11%
Target EBIT margin	10%
Implied ethanol price ($/gal)	$2.42
Equivalent gasoline ($/gal)	$3.27
W/ $0.51 refiners subsidy	$2.76
Equivalent crude ($/bbl)	$76.50

6) Sensitivity Analysis **Current NPV: $ (3.77)**

Profits ($/gal)

Feedstock ($/t)	Price of ethanol ($/gal): $1.10	$1.35	$1.60	$1.85	$2.10
$45.00	(0.93)	(0.68)	(0.43)	(0.18)	0.07
$50.00	(1.00)	(0.75)	(0.50)	(0.25)	(0.00)
$55.00	(1.08)	(0.83)	***(0.58)***	(0.33)	(0.08)
$60.00	(1.16)	(0.91)	(0.66)	(0.41)	(0.16)
$65.00	(1.23)	(0.98)	(0.73)	(0.48)	(0.23)

ROIC

Feedstock ($/t)	Price of ethanol ($/gal): $1.10	$1.35	$1.60	$1.85	$2.10
$45.00	-18%	-13%	-8%	-3%	1%
$50.00	-19%	-15%	-10%	-5%	0%
$55.00	-21%	-16%	***-11%***	-6%	-2%
$60.00	-22%	-17%	-13%	-8%	-3%
$65.00	-24%	-19%	-14%	-9%	-5%

Fair value (after-tax NPV $/gal) *10% discount rate* *10% margin*

Feedstock ($/t)	Long-run Ethanol Price ($/gal): $1.92	$2.17	$2.42	$2.67	$2.92
$45.00	(0.68)	0.95	2.57	4.20	5.82
$50.00	(1.18)	0.45	2.07	3.70	5.32
$55.00	(1.68)	(0.05)	***1.57***	3.20	4.82
$60.00	(2.18)	(0.55)	1.07	2.70	4.32
$65.00	(2.68)	(1.05)	0.57	2.20	3.82

Additional value ($/gal) created by near-term windfalls

Windfall ($/gal)	# of years windfall persists: 1	2	3	4	5
$0.50	0.45	0.87	1.24	1.58	1.90
$0.75	0.68	1.30	1.87	2.38	2.84
$1.00	0.91	1.74	***2.49***	3.17	3.79
$1.25	1.14	2.17	3.11	3.96	4.74
$1.50	1.36	2.60	3.73	4.75	5.69

Source: Jefferies & Company, Inc. estimates, NREL

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Chart 6: Brazil Sugar Cane Ethanol Plant Economics: Arbitrage of Ethanol vs. Sugar

1) Capital

Capital intensity ($/gal)	1.4
Plant Cost ($m)	$140.00
Capacity (m gal)	100
Capacity (m t)	0.30
Working Capital ($m)	20
Total Invested Capital ($m)	$160.00
Capital/Gallon ($)	$1.60
Capital/t ($)	$537.53

2)Variable Cash Costs

Arbitrage vs. Sugar Production	
Sugar (m lb)	1,282.50
Sugar needed for 1 gallon ethanol	13.5
Price ($/lb)	$0.10
Total cost of sugar ($m)	*$125.56*
Cost of sugar ($/gal)	*$1.32*
Other variable costs ($/gal)	
Total other variable costs ($/gal)	*$0.00*
Net cash costs of production ($/gal)	$1.32
Net cash costs ($m)	$125.56
Shipping ($/gal)	$0.25
Net cash cost (incl. Shipping, co-products)	$1.57
U.S. Tariff on imports	$0.54
Capital recovery ($/gal)	$0.07
Total cost ($/gal)	***$2.18***

3) Sales

Operating rate (%)	95%
Volume (m gal)	95
Price of ethanol ($/gal)	$1.60
Gasoline equivalent ($/gal)	$2.16
W/ $0.51 refiners subsidy	$1.47
Revenue ($m)	$152

4) Key Assumptions

Key issue is arbitrage with refined sugar.
13.5 lb of sugar = 1 gal of ethanol (15 in practice)
Capital intensity ranges from 1x-1.8x.
Shipping costs a $0.10-$0.20/gal headwind.
$0.54/gal headwind from import duties.
This model excludes SG&A, corporate costs.

5) Margin Analysis

Profit ($/gal)	($0.58)
Operating Margin (%)	-36.4%
Cash Margin (%)	17.4%
Breakeven Gasoline ($/gal)	$2.12
W/ $0.51 refiners subsidy	$1.43
Crude Breakeven ($/bbl)	$39.73
Tax rate	*35%*
ROIC	-22%
Target EBIT margin	10%
Implied ethanol price ($/gal)	$2.42
Equivalent gasoline ($/gal)	$3.27
W/ $0.51 refiners subsidy	$2.76
Equivalent crude ($/bbl)	$76.58

6) Sensitivity Analysis **Current NPV: $ (3.78)**

Profits ($/gal)

Sugar ($/lb)	Price of ethanol ($/gal): $1.10	$1.35	$1.60	$1.85	$2.10
$0.06	(0.54)	(0.29)	(0.04)	0.21	0.46
$0.08	(0.81)	(0.56)	(0.31)	(0.06)	0.19
$0.10	(1.08)	(0.83)	***(0.58)***	(0.33)	(0.08)
$0.12	(1.35)	(1.10)	(0.85)	(0.60)	(0.35)
$0.14	(1.62)	(1.37)	(1.12)	(0.87)	(0.62)

ROIC

Sugar ($/lb)	Price of ethanol ($/gal): $1.10	$1.35	$1.60	$1.85	$2.10
$0.06	-21%	-11%	-2%	8%	18%
$0.08	-31%	-22%	-12%	-2%	7%
$0.10	-42%	-32%	***-22%***	-13%	-3%
$0.12	-52%	-43%	-33%	-23%	-14%
$0.14	-63%	-53%	-43%	-34%	-24%

Fair value (after-tax NPV $/gal) *10% discount rate* *10% margin*

Sugar ($/lb)	Long-run Ethanol Price ($/gal): $1.92	$2.17	$2.42	$2.67	$2.92
$0.06	1.84	3.46	5.09	6.71	8.34
$0.08	0.08	1.71	3.33	4.96	6.58
$0.10	(1.67)	(0.05)	***1.58***	3.20	4.83
$0.12	(3.43)	(1.80)	(0.18)	1.45	3.07
$0.14	(5.18)	(3.56)	(1.93)	(0.31)	1.32

Additional value ($/gal) created by near-term windfalls

Windfall ($/gal)	# of years windfall persists: 1	2	3	4	5
$0.50	0.45	0.87	1.24	1.58	1.90
$0.75	0.68	1.30	1.87	2.38	2.84
$1.00	0.91	1.74	***2.49***	3.17	3.79
$1.25	1.14	2.17	3.11	3.96	4.74
$1.50	1.36	2.60	3.73	4.75	5.69

Source: Jefferies & Company, Inc. estimates, NREL

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Chart 7: Brazil Sugar Cane Ethanol Plant Economics: Estimate of Underlying Cash Costs

1) Capital

Capital intensity ($/gal)	1.4
Plant Cost ($m)	$140.00
Capacity (m gal)	100
Capacity (m t)	0.30
Working Capital ($m)	20
Total Invested Capital ($m)	$160.00
Capital/Gallon ($)	$1.60
Capital/t ($)	$537.53

2)Variable Cash Costs

Arbitrage vs. Sugar Production	
Sugarcane (t)	5
Sugarcane needed for 1 gallon ethanol	0.051
Price ($/t)	$18.00
Total cost of sugar ($m)	*$87.21*
Cost of sugar ($/gal)	*$0.92*
Other variable costs ($/gal)	
Chemicals	$0.003
Denaturant	$0.142
Maintenance	$0.016
Labor	$0.012
Administrative	$0.010
Other	$0.030
Total other variable costs ($/gal)	*$0.21*
Net cash costs of production ($/gal)	$1.13
Net cash costs ($m)	$107.45
Co-products	
Bagasse	$0.000
Other	$0.001
Co-product value ($/gal)	*$0.001*
Shipping ($/gal)	$0.25
Net cash cost (incl. Shipping, co-products)	$1.38
U.S. Tariff on imports	$0.54
Capital recovery ($/gal)	$0.07
Total cost ($/gal)	***$1.99***
	$1.13

3) Sales

Operating rate (%)	95%
Volume (m gal)	95
Price of ethanol ($/gal)	$1.60
Gasoline equivalent ($/gal)	$2.16
W/ $0.51 refiners subsidy	$1.47
Revenue ($m)	$152

4) Key Assumptions

$18/t derived from Cosan prospectus
19.5 gal/ton of sugarcane
Capital intensity ranges from 1x-1.8x.
Shipping costs a $0.20-$0.30/gal headwind.
$0.54/gal headwind from import duties.
This model excludes SG&A, corporate costs.

5) Margin Analysis

Profit ($/gal)	($0.39)
Operating Margin (%)	-24.4%
Cash Margin (%)	29.3%
Breakeven Gasoline ($/gal)	$1.86
W/ $0.51 refiners subsidy	$1.17
Crude Breakeven ($/bbl)	$32.55
Tax rate	*35%*
ROIC	-15%
Target EBIT margin	10%
Implied ethanol price ($/gal)	$2.21
Equivalent gasoline ($/gal)	$2.98
W/ $0.51 refiners subsidy	$2.47
Equivalent crude ($/bbl)	$68.60

6) Sensitivity Analysis **Current NPV:** **$ (2.53)**

Profits ($/gal)

Sugarcane ($/t)	Price of ethanol ($/gal) $1.10	$1.35	$1.60	$1.85	$2.10
$16.00	(0.79)	(0.54)	(0.29)	(0.04)	0.21
$17.00	(0.84)	(0.59)	(0.34)	(0.09)	0.16
$18.00	(0.89)	(0.64)	***($0.39)***	(0.14)	0.11
$19.00	(0.94)	(0.69)	(0.44)	(0.19)	0.06
$20.00	(0.99)	(0.74)	(0.49)	(0.24)	0.01

ROIC

Sugarcane ($/t)	Price of ethanol ($/gal) $1.10	$1.35	$1.60	$1.85	$2.10
$16.00	-30%	-21%	-11%	-1%	8%
$17.00	-32%	-23%	-13%	-3%	6%
$18.00	-34%	-25%	***-15%***	-5%	4%
$19.00	-36%	-27%	-17%	-7%	2%
$20.00	-38%	-29%	-19%	-9%	0%

Fair value (after-tax NPV $/gal) *10% discount rate* *10% margin*

Sugarcane ($/t)	Long-run Ethanol Price ($/gal) $1.71	$1.96	$2.21	$2.46	$2.71
$16.00	(1.15)	0.48	2.10	3.73	5.35
$17.00	(1.48)	0.14	1.77	3.39	5.02
$18.00	(1.81)	(0.19)	***1.44***	3.06	4.69
$19.00	(2.14)	(0.52)	1.11	2.73	4.36
$20.00	(2.48)	(0.85)	0.77	2.40	4.02

Additional value ($/gal) created by near-term windfalls

Windfall ($/gal)	# of years windfall persists 1	2	3	4	5
$0.50	0.45	0.87	1.24	1.58	1.90
$0.75	0.68	1.30	1.87	2.38	2.84
$1.00	0.91	1.74	***2.49***	3.17	3.79
$1.25	1.14	2.17	3.11	3.96	4.74
$1.50	1.36	2.60	3.73	4.75	5.69

Source: Jefferies & Company, Inc. estimates, NREL

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Government Initiatives Drive Global Landscape for Biofuels

Governments around the world have introduced initiatives to encourage the adoption of biofuels as a renewable alternative to fossil fuels and nuclear energy. Regulatory changes remain the dominant driver for the sector going forward.

In the United States, federal subsidies at various levels have been in place since 1978, supplemented by state subsidies. Currently refineries receive a $0.51/gal subsidy for blending ethanol as a fuel additive, while biodiesel receives a $1/gal subsidy if made from virgin oil and $0.50/gal if made from recycled oil such as cooking grease. The US also maintains a $0.54/gal tariff on ethanol imports in order to restrict competitive pressure from Brazil, though at current sugar and shipping costs Brazil's ability to import into the US appears fairly limited. In 2006, the phase-out of MTBE (a fuel additive made from petrol and alcohol), effectively increased ethanol demand by roughly 2bn gal/year. At the same time, the federal government has mandated renewable fuel consumption of 4bn gal in 2006, rising to 7.5bn gal in 2012, with new proposals that would raise this further. Multiple states have their own initiatives. Minnesota, for example, has implemented an E10 requirement and targets mandating E20 by 2013. Washington state has an E2 mandate in place effective the end of 2008. Missouri has mandated that all gasoline except for aviation fuel and premium gasoline in the state contain at least 10% ethanol by January 1, 2008. To put these initiatives in perspective, Missouri's mandate alone is expected to represent aggregate new demand for 300M gal/year of ethanol. Finally, the automotive industry appears to be more actively lobbying for incentives to help sell the 900,000 flex-fuel vehicles they plan to build in the US in 2007 (out of a total fleet of more than 230M vehicles). All in, industry observers estimate ethanol receives direct and indirect subsidies of $1.05-$1.40/gal, or 45%-60% of the current market price.

Brazil, the world's largest producer of ethanol, has also made the most effort to use ethanol as a substitute for fossil fuels. In response to the 1973-1974 oil shock, Brazil launched the Proalcool program, which initially provided incentives for producers and tax rebates for consumers. Currently ethanol use is not subsidized, and hydrated ethanol is competitive in the domestic market at 60%-70% of the price of E10 gasoline. Since 2003, Brazil has displaced approximately 40% of its oil consumption with ethanol, and flex-fuel cars now represent roughly 75% of annual new vehicle sales (vs. 4% in 2003). Brazil has an advantage due to lower per capita energy consumption and lower labor costs, but this shift has also been due to government discipline. The government mandates a 20%-25% blend of ethanol with gasoline, sets lower excise taxes on ethanol storage, and protects the domestic producers with a 20% duty on imports. Brazil has also introduced a biodiesel mandate: 2% by 2007 (800M liters), 5% by 2013 (2bn liters), and 20% by 2020 (12bn liters). Brazil produced 5.4bn gallons of ethanol in 2006, with 0.9bn exported, and production is expected to exceed 7.9bn gal/year by 2013 (1.5bn gal/year exported). Domestic demand is supported by the rapid adoption of flex-cars. Unlike the US, many of Brazil's plants can easily switch between producing sugar and ethanol, so the export supply of ethanol is currently driven at the margin by the economics of producing sugar. As such, Brazil needs a wide enough window between corn and sugar prices to overcome significant shipping costs (estimated at north of $0.15/gal) as well as a $0.54/gal import tariff imposed by the US. Brazil has 389 plants in operation and is expected to build more than 100 over the next couple of years.

Table 8: European Production of Biofuels (in tonnes)

	Ethanol			Biodiesel		
Country	**2002**	**2003**	**2004**	**2002**	**2003**	**2004**
Czech Rep.	5			69	70	60
Denmark				10	41	70
Germany			20	450	715	1,035
Spain	177	160	194		6	13
France	91	82	102	366	357	348
Italy				210	273	320
Lithuania						5
Austria				25	32	57
Poland	66	60	36			
Slovak Rep.						15
Sweden	50	52	52	1	1	1
UK				3	9	9
EU25	**388**	**425**	**491**	**1,134**	**1,504**	**1,933**

Source: EurObservER 2005

In Europe, the focus has been on biodiesel, which represents nearly 80% of the biofuel market. Germany, France, and Italy have taken the lead. With more than 15,000 biodiesel filling stations, Germany alone accounts for more than half of global biodiesel production and consumption. With transportation contributing an estimated 21% of EU greenhouse emissions, and increased concerns over volatile oil prices, the European Commission has set targets for renewable fuels of 2% of all transport fuels in 2005 (less than 1.4% in 2005), rising to 5.75% by 2010. This compares with an estimated 0.6% in 2003. Germany exempts biofuels and biomass-based heating oils from duties until 2009. France exempts 1.2M tpy of biofuels from excise taxes and has a progressive tax rate tied to the amount of biofuel blended into a transport fuel. Spain has adopted the EU's 5.75% target by 2010, and has also set a target of 2.2M tpy of biofuels (in tons equivalent to petrol) by 2010, versus 0.2M tpy in 2004. Sweden fully exempts biofuels from excise duties and targets 3% of total transport fuels. In 2005, European ethanol production amounted to roughly 1M tonnes, with capacity on track to triple by 2007. Biodiesel capacity is expected to exceed 4M tonnes by the end of 2006.

In Asia, Malaysia is planting more than 600,000 ha of palm oil plantations to support displacing 5% of diesel consumption with palm oil-based biodiesel in 2007. Longer term, Malaysia has set a target of providing 10% of global biofuel supply via palm oil. India has introduced a 5% blend mandate for several states, Thailand has provided tax incentives to support 10% blends, and Australia has set tax incentives through 2015 (with a step down in support after 2011). Japan targets using 500M liters of biofuels by 2010. Finally, China is investing more than $500M/year in agricultural biotech, with an eye to sponsor domestic companies such as Weiming and Biocentury that will develop and market inexpensive genetically modified crops. China has targeted a 10% blend of biofuels by 2020, which implies demand for 23M tpy of biofuel. The five largest Chinese ethanol producers have total capacity north of 1.5M tpy, 80% based on grains, 10% from sugar, 6% from paper pulp waste, and the rest from ethylene. China's planned biodiesel and ethanol capacity additions imply 11M tpy of installed capacity by 2010. Importantly, China has emphasized shifting new biofuels capacity away from feedstocks that humans consume as well, in sharp contrast to the US policy of ignoring the "food vs. fuel" conflict.

Ethanol: Key Considerations

Ethanol is an alcohol that can serve as a fuel as well as a substitute for the oxygenate MTBE. It has emerged as one of the highest-profile alternative energy plays due to favorable economics, particularly in 1H06, and high-profile political support. Ethanol is derived from sugar, which in turn can be generated from corn (in the US), sugarcane (in Brazil), wine (Sweden), wheat, beets, or even cellulosic waste products such as stems and stalks. Ethanol was first used in the US in the 1820s, and was an automotive fuel by the start of the 20th century. While the US government has subsidized ethanol production since the 1970s, the recent combination of high gasoline prices, the US phase-out of MTBE (2bn gal of incremental demand, or 50% of 2005 production), and process improvements made ethanol production economical, whereas a sharp increase in government support has made the significant capital investments required more palatable.

Rapid growth driven by mandates

Ethanol production in the US has grown rapidly, more than doubling since the late 1990s due to the federal and state mandates discussed above. As a result, the US production capacity in 2005 matched that of Brazil. At least 76 new projects and 10 plant expansions have been announced, amounting to almost 6.4bn gal/year. Given current capacity of 6.3bn gal/year, the proposed capacity expansions, if completed, would bring total installed capacity to almost 14bn gal/year. While federal mandates (currently targeting 7.5bn gal by 2012) are likely to rise once the 2007 Energy Bill is passed, to date none of the proposed increases exceeds the projected capacity additions. Unless the mandates are moved significantly higher, the base case for the industry could be a steady erosion in operating rates into the end of the decade. Moreover, once ethanol production exceeds the mandated usage requirements, we expect ethanol to shift to competing with gasoline on an energy content basis—i.e., at a 35% discount to gasoline prices rather than at a premium.

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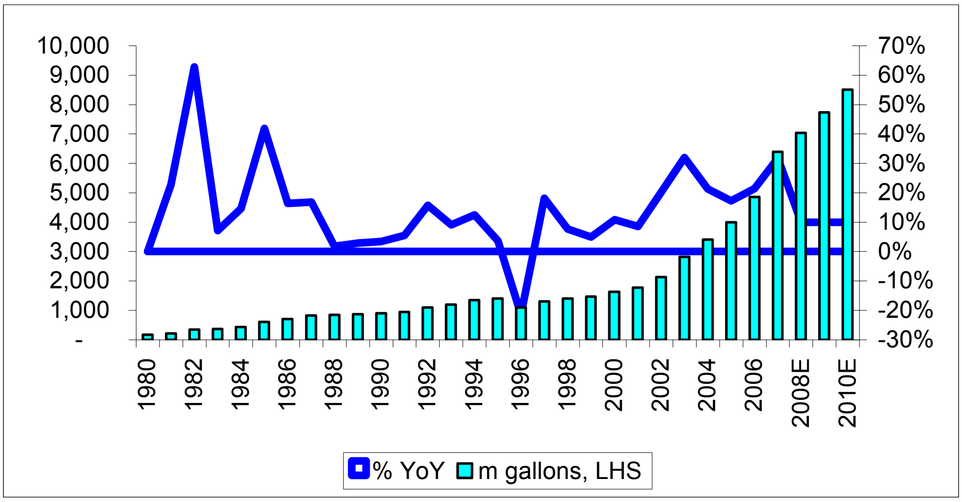
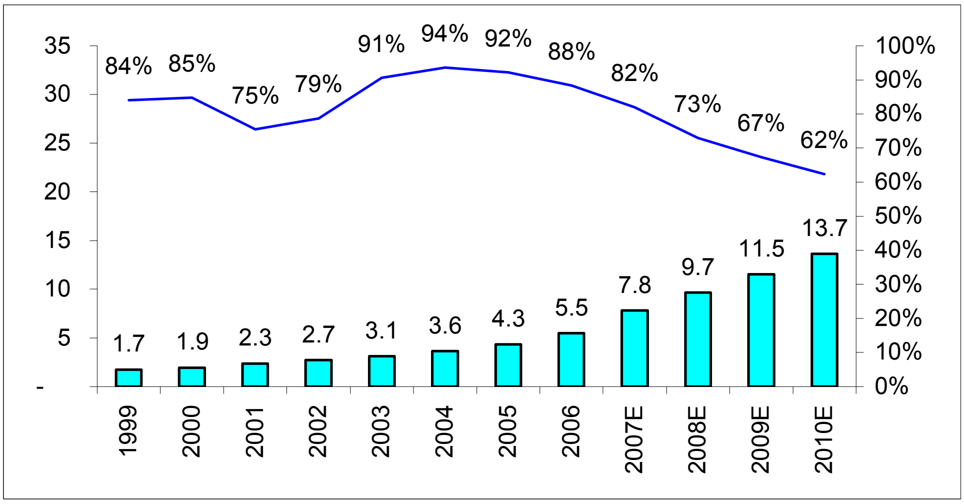
Chart 8: US Ethanol Production (m gal and % YoY, 1980–2005): 14% CAGR, 25% Since 2000



Source: Renewable Fuels Association

Chart 9: US Ethanol Year-end Capacity (bn gpy, LHS) and % Utilization Rate (RHS): New mandate needed



Source: Renewable Fuels Association

Due to this rapid expansion of capacity, the US is already the largest producer of ethanol in the world. The US market share rose 400 bps to 39.1% in 2006, and we expect US share of global capacity to continue to increase over the next few years, given the doubling in capacity expected by the end of the decade. Persistent high corn prices, particularly if not offset by higher gasoline (and consequently ethanol) prices, could lead to project cancellations or delays, particularly of the smaller facilities that will likely end up at the high end of the cost curve.

Table 9: 2006 World Ethanol Capacity (m gal): US Expands Its Market Share to More than 39%

Country	Production	% of total	Country	Production	% of total
USA	5,277	39.1%	Italy	43	0.3%
Brazil	4,491	33.3%	Australia	39	0.3%
China	1,017	7.5%	Sweden	30	0.2%
India	502	3.7%	Japan	30	0.2%
France	251	1.9%	Pakistan	24	0.2%
Germany	202	1.5%	Philippines	22	0.2%
Russia	172	1.3%	Guatemala	21	0.2%
Canada	153	1.1%	South Korea	16	0.1%
Spain	123	0.9%	Mexico	13	0.1%
South Africa	102	0.8%	Cuba	12	0.1%
Thailand	93	0.7%	Ecuador	12	0.1%
UK	74	0.5%	Nicaragua	8	0.1%
Ukraine	71	0.5%	Zimbabwe	7	0.0%
Poland	66	0.5%	Swaziland	5	0.0%
Saudi Arabia	53	0.4%	Kenya	5	0.0%
Argentina	45	0.3%	Mauritius	2	0.0%
Indonesia	45	0.3%	Others	463	3.4%
			Total	13,489	

Source: Renewable Fuels Association

Table 10: 2005 World Ethanol Capacity (M gal): US and Brazil Represent 70% of Global Supply. China Has Emerged as the No. 3 Player in Ethanol.

Country	Production	% of total	Country	Production	% of total
USA	4,264	35.1%	Australia	33	0.3%
Brazil	4,227	34.8%	Saudi Arabia	32	0.3%
China	1,004	8.3%	Japan	30	0.2%
India	449	3.7%	Sweden	29	0.2%
France	240	2.0%	Pakistan	24	0.2%
Russia	198	1.6%	Philippines	22	0.2%
Germany	114	0.9%	South Korea	17	0.1%
South Africa	103	0.8%	Guatemala	17	0.1%
Spain	93	0.8%	Ecuador	14	0.1%
UK	92	0.8%	Cuba	12	0.1%
Thailand	79	0.7%	Mexico	12	0.1%
Ukraine	65	0.5%	Nicaragua	7	0.1%
Canada	61	0.5%	Zimbabwe	5	0.0%
Poland	58	0.5%	Kenya	4	0.0%
Indonesia	45	0.4%	Mauritius	3	0.0%
Argentina	44	0.4%	Swaziland	3	0.0%
Italy	40	0.3%	Others	710	5.8%
			Total	12,150	

Source: Renewable Fuels Association

The surge in US capacity is ironic, as US ethanol had higher production costs even before the recent run in corn prices. The following two tables present estimates from the USDA and OECD, which echo anecdotal estimates.

Table 11: Estimated Costs of Different Biofuel Processes, 2004

Product	Feedstock		Energy		Processing		Co-Product Credits		Net cost	
	$/t	$/gal	$/t	$/gal	$/t	$/gal	$/t	$/gal	$/t	$/gal
EU Biodiesel (Vegetable Oil)	608	1.82	53	0.16	86	0.26	62	0.19	685	2.05
EU Ethanol (Wheat)	448	1.34	73	0.22	431	1.29	228	0.68	725	2.17
EU Ethanol (Sugar Beet)	381	1.14	73	0.22	358	1.07	105	0.31	707	2.12
US Ethanol (Corn)	245	0.73	80	0.24	130	0.39	90	0.27	365	1.09
Brazil Ethanol (Sugar Cane)	163	0.49	0	0.00	114	0.34	0	0.00	276	0.83
Gasoline (cash cost)										**0.40-0.60**

Source: OECD

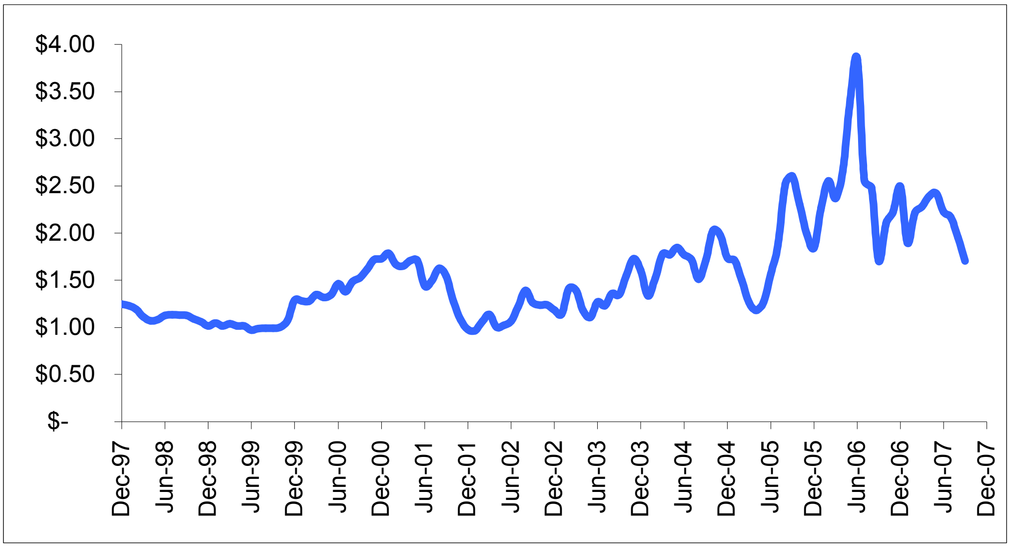
Table 12: Estimated Costs of Different Ethanol Feedstocks, 2003-2005 ($/gal)

Feedstock	US Corn Wet Milling	US Corn Dry Milling	US Sugar Cane	US Sugar Beets	US Molasses	US Raw Sugar	Brazil Sugar Cane	EU Sugar Beets
Conversion factor (gal/t)	98.21	98.21	19.5	24.8	69.4	135.4	19.5	24.8
Cost structure ($/gal)								
Feedstock (net of co-products)	0.40	0.53	1.48	1.58	0.91	3.12	0.30	0.97
Processing	0.63	0.52	0.92	0.77	0.36	0.36	0.51	1.92
Total cash cost	1.03	1.05	2.40	2.35	1.27	3.48	0.81	2.89
Depreciation (40 m gpy facility)	0.12	0.12	0.16	0.16	0.10	0.10	0.16	0.16
Total cost	1.15	1.17	2.56	2.51	1.37	3.58	0.97	3.05

Source: USDA

Pricing

Chart 10: US Ethanol Prices ($/gal), 1998-2006



Source: Bloomberg

US ethanol prices have been volatile over the past three years, with upwards price pressure through early 2006 driven by both rising gasoline prices (a function of higher crude oil prices) and, in the first half of 2006, the phase-out of MTBE. Markets with infrastructure bottlenecks saw the sharpest rise, with spot prices in New York exceeding $5/gal in June even as prices in Iowa remained below $4/gal. New capacity coming onstream and falling oil prices led to a sharp retracement (more than 50%) in ethanol prices to less than $2/gal. Higher oil prices helped ethanol prices recover to the $2.40-$2.50/gal range earlier this year, but the steady accumulation of new supply, coupled with distribution bottlenecks, has undercut pricing power. As a result, ethanol prices in the spot market have fallen

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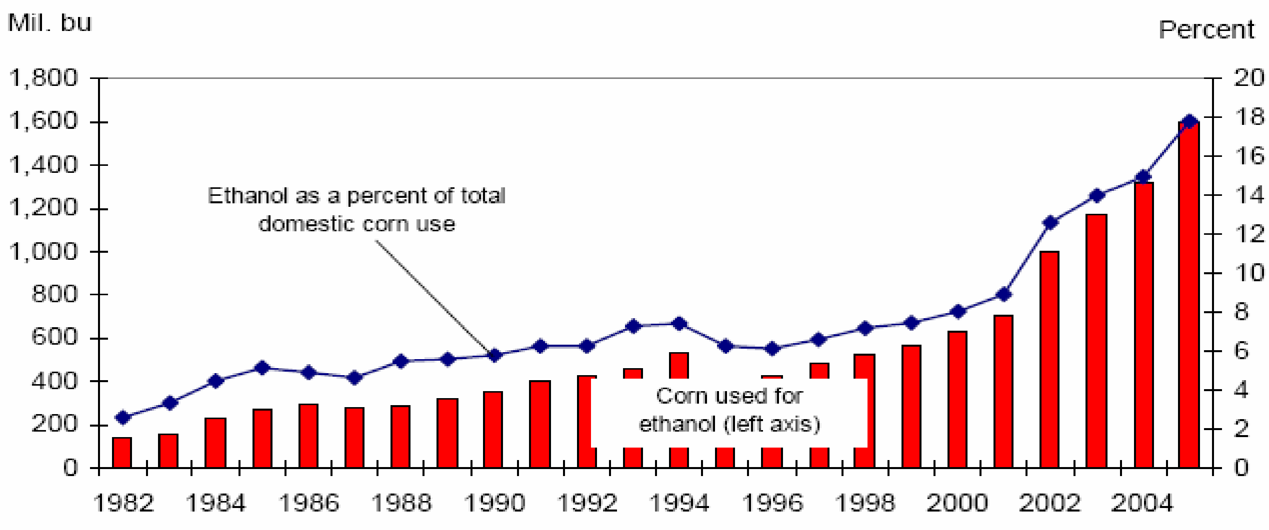
to roughly $1.70/gal. Importantly, 85%-95% of US ethanol production is sold under six- to 12-month fixed price contracts or tied to the price of gasoline.

Increased ethanol production leads to margin squeeze

Chart 11: Ethanol Demand (in m bushels and as % of total corn crop), 1982-2005



Source: USDA

At 4bn gallons, ethanol contributed only 2% of the US gasoline supply in 2005, less than 1% of railroad shipments, but constituted 12% of total corn demand. The phase-out of MTBE as a fuel additive added approximately 2bn gallons of incremental ethanol demand, requiring another 8% of the US corn crop. As a result, the USDA expects ethanol distillers to use more than 3.1bn bushels of the 2007 crop (25%-plus). By 2016, the USDA expects ethanol demand to account for 4.3bn bushels, or almost a third of the total corn crop even assuming at least a 15% increase in corn production. To some extent, this is offset by the use of distillers grain, an ethanol by-product, for feed and other uses.

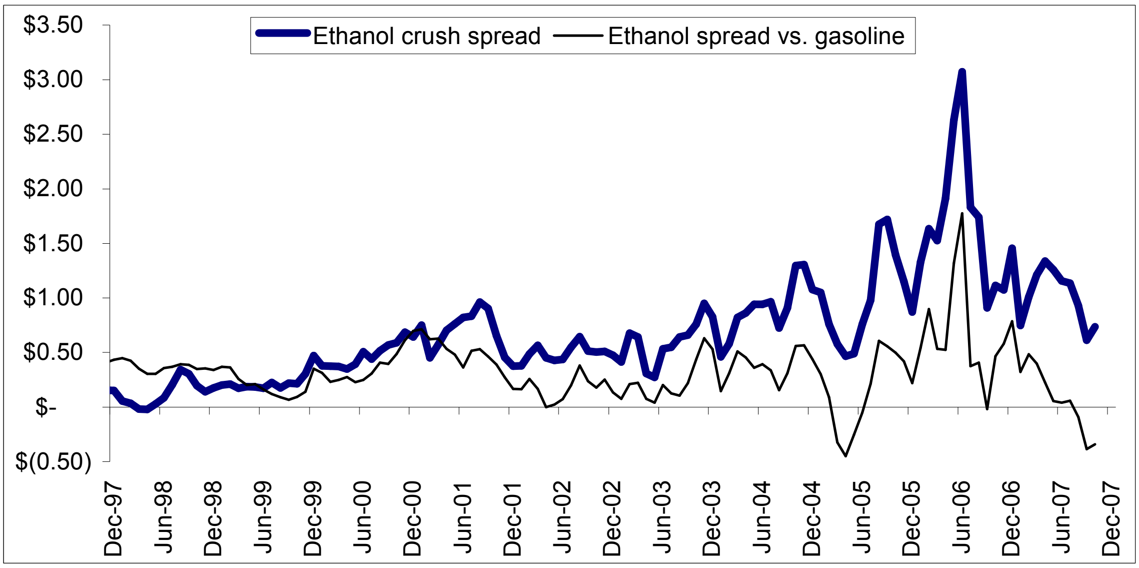
The rising demand for corn from ethanol producers is driving a step-change in corn prices, with corn futures north of $4.20/bu, up from a long-term range of $2.00-$2.50/bu. We estimate that every $0.05/bu increase in corn prices has a 60 bps impact on cash margins for a generic ethanol plant, although changes in feedstock costs will vary according to the specifics of each plant design and hedging policy. Overall, we expect crush spreads (the price of ethanol less energy and net corn costs) to contract in 2007, leading to a second YoY decline in industry profitability. Of more concern, corn prices look poised to rise further in 2008-2009, which will likely also lead to price inflation in derivatives (e.g., corn syrup) as well as substitute crops (e.g., soy, wheat). The DoE has estimates that, longer term, the industry will need to switch to cellulosic feedstocks by the time production exceeds 12bn gal/year: a thesis that could be tested as early as 2009 if all the proposed new corn ethanol plants are completed. We expect this to precipitate a shift in global corn trade flows, particularly to the benefit of Argentina and Brazil.

Table 13: Summary of Pricing for Ethanol, Oil and Biofuel Feedstocks, 1998-2007

		CAGR		% change (2001-2007)	
Commodity	**Current**	**1998-2007**	**2003-2007**	**From Peak**	**From Trough**
Ethanol ($/gal)	$1.72	3.2%	8.7%	-41%	136%
WTI ($/bbl)	$81.22	14.9%	24.4%	-1%	318%
Corn ($/bushel)	$3.23	-4.1%	9.8%	-25%	74%
Palm Oil ($/t)	$773	4.1%	20.0%	-2%	301%
Soy ($/bushel)	$8.86	-0.1%	13.8%	-14%	111%
Tallow ($/lb)	$0.301	5.9%	22.3%	-9%	244%

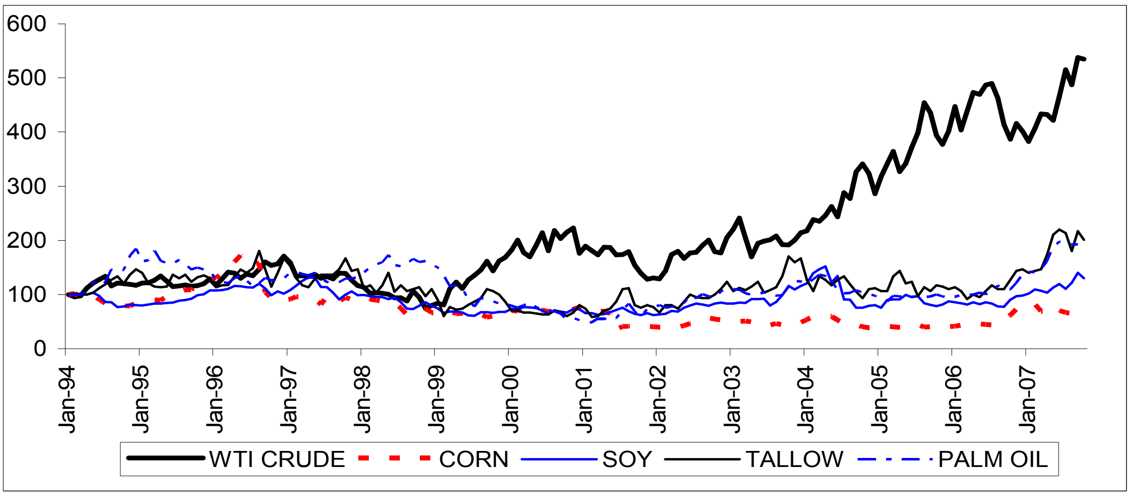
Source: Bloomberg

Chart 12: Ethanol Spread vs. Gasoline, and Ethanol Crush Spread, 1990-2005: Crush spreads back to mid-2005 levels



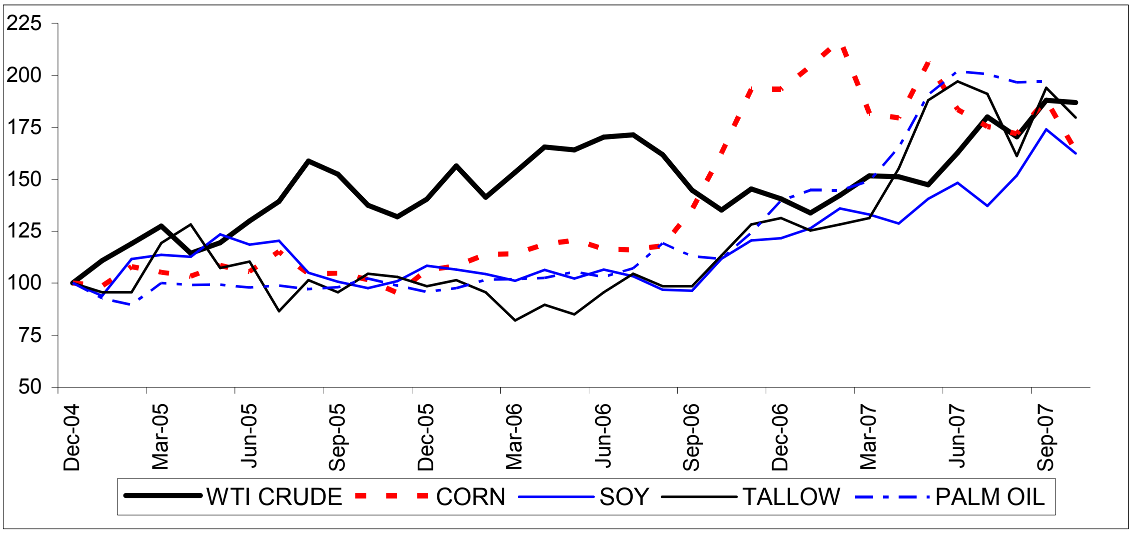
Source: USDA, Bloomberg

Chart 13: Oil and Biofuel Feedstock Prices, Indexed 1994=100. The surge in biofuel investment is motivated in large part by the perceived relative stability of agricultural feedstocks compared with the volatility in oil.



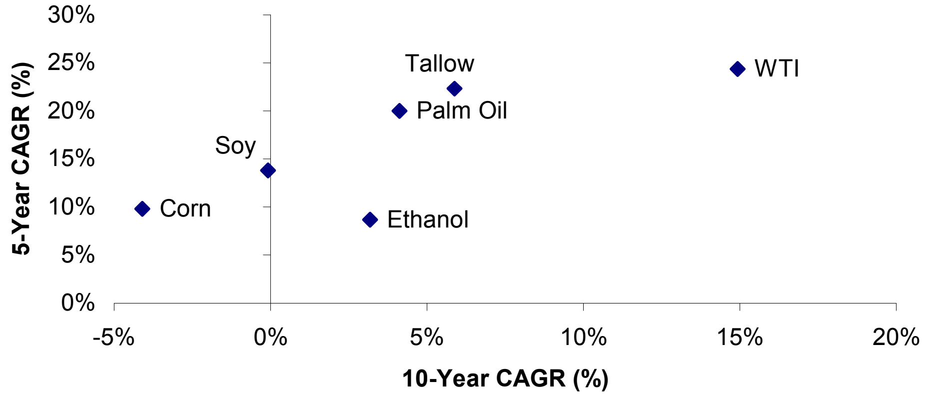
Source: Renewable Fuels Association

Chart 14: Oil and Biofuel Feedstock Prices, Indexed YE04=100. The global investment in biofuels was one factor contributing to a rise in the requisite feedstocks.



Source: Renewable Fuels Association

Chart 15: Oil and Biofuel Feedstock Momentum, 1998-2007



Source: Bloomberg

Transportation

Ethanol is primarily distributed by truck, rail, or barge. Ethanol is hydrophilic, which can complicate using a pipeline because ethanol tends to separate from gasoline over time. As a result, it cannot be shipped in pipelines, and needs to be blended at distribution terminals rather than at the refinery. This implies the need for a significant increase in storage capacity over the next couple of years to accommodate the capacity additions that have already been announced. Ethanol's miscibility issues also provide an incentive for dedicated transport fleets (less time spent cleaning containers), which should provide an opportunity for transportation companies to improve their utilization rates. According to media reports, approximately 35%-40% of the new orders for railcars are for cars that can ship ethanol. Given the tight operating conditions in the railcar industry, however, we expect many of these new cars to be delivered in 2H07-2008. While rail capacity is a critical issue for ethanol producers, it is, in our view, immaterial for the railroads, as ethanol shipments represent only about 1% of total railcar loadings.

With this in mind, transportation costs are a significant factor for ethanol producers. Industry sources estimate that in the US typical ethanol shipping costs run around $0.08/gal, vs. $0.02-$0.04/gal for tanker gasoline. Brazilian ethanol imported into the US faces higher shipping costs (estimated at $0.20-$0.25/gal), as well as a $0.54/gal import duty (to offset the $0.51/gal refiner's subsidy), and, importantly, competition from consumer sugar demand. Many Brazilian ethanol plants are flexible and can switch from producing ethanol to producing refined sugar (13-15 lb of sugar/gallon of ethanol), so the limiting constraint is the arbitrage between ethanol export economics and refined sugar economics.

Yields, process & location essential to cost position

In the US, roughly three quarters of ethanol production is based on a process called “dry milling”. In this process, corn is ground into flour, then mixed with water and enzymes to make dextrose, which is fermented into alcohol. In a nutshell, this process transforms corn into roughly equal parts ethanol, carbon dioxide, and distiller dry grains, which are fed to cattle. As a result, the key levers that affect process economics are feedstock costs, the ratios between the outputs, and logistics.

As a rough rule of thumb, feedstock costs typically represent 65% or more of the total cost of production. Arbitraging corn costs from suppliers is essential. The wave of new ethanol capacity coming onstream will likely reduce the flow of corn between states within the US, leading to regional price differentials in the cost of corn. Further contributing to opportunities for regional arbitrages will be disparities in natural gas costs (as much as 8% of the cost of producing ethanol), as well as the option of substituting coal for natural gas as the direct energy source for drying and steam production. As such, plants will likely see a fair amount of volatility in their position on the competitive cost curve depending on temporary shifts in regional supply/demand balances, as well as the relative value of co-products (particularly dried distiller grains). For example, locating a plant near a cattle farm so that the co-product distiller grains do not need to be dried can save as much as $0.04-$0.10/gal for a US ethanol producer.

Some ethanol producers use an alternative process called “wet milling.” In this process, chemical solutions and mechanical processes (i.e., grinding) separate out corn oil, fiber, starch, and other components, much as a refinery separates different co-products from oil. Key co-products are gluten (a less attractive substitute for dry distillers grains) and yeast (of unreliable value). Dry mills require about half as much capital as wet mills, or $1.50-$2.00/gal of capacity, but wet mills can produce a broader range of co-products, including animal feed and corn syrup. In either case, we expect plant debottlenecking to contribute 1%-2% annual capacity creep.

Another way to improve ethanol economics is to genetically modify the feedstocks or the enzymes to enhance yields. This also has the benefit of reducing the incremental demand for nitrogen fertilizer, water, and real estate—essential to avoiding adverse consumer sentiment on pollution and deforestation. DuPont and Monsanto (MON, $89.52, Buy) are working on corn with higher starch content (a 2%-4% higher fermentation yield). Novozymes and Danisco have introduced enzymes they claim can decrease the capital intensity for some crops by 15%-20%. The jury is still out, however, to what extent ethanol producers will need to share with farmers the value created by modified crops.

Cellulosic ethanol: Flexible feedstocks and government incentives

Given mounting concerns that basing biofuel production on conventional food crops will lead to food prices rising in an arbitrage with oil on BTU content, governments and producers are allocating more resources to research into ways to convert other vegetable matter into biofuels. In essence, producers are also looking at ways to convert the carbohydrates in the cellulosic matter into sugars that can be fermented into ethanol. This means companies can process waste products such as corn stover, switchgrass, sawdust, and forest thinnings, as well as algae (from wastewater treatment plants).

Helping move this from theory to practice, the US DOE announced on February 28, 2007, an initiative to invest up to $385M into six biorefinery projects in 2007-2010. Industry investments in these projects will lift the total investment to more than $1.2bn. This program is expected to be supplemented by a loan-guarantee program for cellulosic ethanol, which we expect will broaden the field of competitors.

Table 14: Summary of DOE Funding for Cellulosic Biorefineries

Project	Location	Capacity (m gpy)	Feedstock	Funding	Participants
Abengoa	Missouri	11.4	700 tpd corn stover, wheat straw, milo stubble, switchgrass	Up to $76M	Abengoa, Antares, Taylor Engineering
ALICO	Florida	13.9	770 tpd yard, wood and vegetative waste	Up to $33M	Bioengineering Resources, Washington Group, GeoSyntec, BG Katz and Emmaus Foundation
BlueFire Ethanol	Southern California	19	700 tpd green waste and wood waste from landfills	Up to $40M	Waste Management, JGC, MECS, NAES and PetroDiamond
Broin	Iowa	125	25% of production (31m gpy) will be cellulosic ethanol, using 842tpd of corn fiber, cobs, and stalks	Up to $80M	DuPont, Novozymes, NREL
Iogen	Idaho	18	700 tpd of what straw, barley straw, corn stover, switchgrass, and rice straw	Up to $80M	Iogen, Goldman Sachs, Shell
Range Fuels	Georgia	40	1,200 tpd of wood residues and wood energy crops	Up to $76M	Merrick, PRAJ, Western Research Institute, Georgia Forestry Commission, Yeomans Wood & Timber, BioConversion Technology, Khosla Ventures, Gillis Ag & Timber, CH2MHill

Source: DOE

Table 15: Composition of Grains vs. Cellulosics (% of total, +/- 5%)

	Corn Grain	Corn Stover	Switchgrass	Poplar
Starch	72%	0%	0%	0%
Cellulose/Hemicellulose	11%	69%	60%	72%
Lignin	0%	16%	10%	21%
Other Sugars	1%	4%	6%	3%
Protein	9%	2%	5%	0%
Oil/Extractives	5%	2%	13%	3%
Ash	2%	7%	6%	1%

Source: NREL

Ethanol from cellulosic feedstocks is expected to eventually cost \$0.60-\$0.75/gal to produce, or \$0.80-\$1.00/gal per equivalent gallon of gasoline. This compares with current production economics north of \$2/gal.

Of particular interest, in our view, is the DuPont/NREL/Novozymes/Poet project, which aims to produce ethanol from both corn starch and from the corn stover—trying to improve plant economics by using more of the crop as a fuel feedstock. As a rough rule of thumb, carbon is just under 45% of the dry weight of corn, and only about a third of that is in the leaves (vs. 25% in leaves, 25% in stems, 10% in cobs, and 7% in roots). Part of the appeal of cellulosic ethanol, then, is the opportunity to access a greater portion of the carbon content in the crop, rather than wasting it. Complicating this, however, is the consideration that crop residues also serve to help fix carbon in topsoil. As a result, farmers have raised the concern that using corn stover for cellulosic ethanol will end up “strip mining the topsoil,” leading to unsustainable longer-term process economics.

Shifting feedstocks could reduce the environmental impact. Switchgrass, for example, requires roughly 25% of the fungicide, 10% the insecticides, and half the fertilizer of corn, wheat, or soybean crops. Using switchgrass can also reduce the amount of nitrogen run-off by as much as 90% (vs. corn) or 50% (vs. soybeans). The NRDC, meanwhile, has further estimated that switchgrass can reduce soil erosion by north of 95%. Another appeal of using cellulosic feedstocks, in our view, is the opportunity to leverage the existing infrastructure of the North American paper industry.

Table 16: Steps in Biomass Conversion

Thermochemical treatment of raw biomass	Render complex polymers (cellulose, hemicellulose, lignin) more accessible to enzymatic breakdown
Enzyme applications (cellulases and hemicellulases)	Break down (hydrolyze) plant cell-wall constituents (polysaccharides) into simple sugars
Fermentation	Bacteria and yeast convert sugars to ethanol

Source: DOE

Other factors that should -+drive cellulosic ethanol economics include the cost of procuring biomass (collecting and storing the material), pre-treating the biomass (part of the overall cost of the process, also affecting capital intensity), optimizing plant designs (to reduce labor costs and capital intensity), opportunities to modify yeast (as a substitute for new enzymes), and government subsidies (rising globally as governments seek to hasten the diversification of energy sources). Improving yields (gal/acre) is critical, in our view, as higher yields should translate into economies of scale by reducing logistics costs for biomass harvesting.

Table 17: Theoretical Yield of Alternate Feedstocks (ethanol gal/ton of feedstock)

Corn Grain	124.4
Corn Stover	113.0
Rice Straw	109.9
Cotton Gin Trash	56.8
Forest Thinnings	81.5
Hardwood Sawdust	100.8
Bagasse	111.
Mixed Paper	116.2

Source: DOE

Consolidation and rationalization likely over the next two to three years

With the oil majors showing more interest in biofuels, coupled with the prospect of possible excess capacity in the ethanol industry by 2008-2009 and persistently high corn prices, we expect a wave of consolidation involving producers in the middle of the cost curve. Smaller producers at the high end of the cost curve will likely be displaced by the end of the decade.

E85: Unlikely

Most cars in the US cannot run on fuel that is more than 10% ethanol without a retrofit. Only about six million vehicles in the US can run on E85, fuel that is 85% ethanol. The retrofit, however, is relatively inexpensive, with industry observers estimating it at about $100/car (mostly for fuel lines, fuel tanks, and sensors). Similarly, drivers who want to use E85 need fuel pumps. Currently only 1,200 service stations, or 0.6% of the US infrastructure, can serve E85. GM estimates that converting 20%-30% of US service stations would serve 90% of US drivers.

Biodiesel: A Quick Snapshot

Biodiesel is an ester of fatty acids, derived from animal fats, waste oils and fats, fatty acids from waste treatment facilities, and vegetable oils such as rapeseed and soybean. Biodiesel is produced via transesterification, a relatively simple refining process that converts roughly 98% of vegetable oil to biodiesel. Methanol and catalysts convert fat or oil into glycerin and methyl esters (the biodiesel). The glycerin is sold to producers of soap, cosmetics or, at higher purity levels, pharmaceuticals. An alternative process would use ethanol rather than methanol; this has not been commercialized on a significant scale. Net-net, the National Biodiesel Board estimates that the standard process transforms feedstock (typically soy oil in the US, 87% of inputs), catalysts (1%), and alcohol (typically methanol, 12%) into biodiesel (methyl ester, 86%), glycerine (9%), alcohol (4%), and fertilizer (1%). Biodiesel can be mixed with regular diesel at any proportion: it has slightly less energy content (8% lower), but higher fuel density and a higher cetane number. When mixed with fossil diesel, it is referred to by the percentage of biodiesel in the blend. For example, B5 has 5% biodiesel, B10 10%, and so forth.

Table 18: Comparison of Transesterification Processes

Input	Methanol	Ethanol
Property	Methyl Ester	Ethyl Ester
Conversion factor (oil to biodiesel)	97.50%	94.30%
Total glycerin (%)	0.86%	1.40%
Viscosity	-	7.2% higher
% power vs. diesel	< 2.5%	< 4%

Source: BMVEL

Industry participants advance four arguments in favor of faster adoption of biodiesel: 1) regional benefits for agricultural producers, 2) reduced dependence on volatile fossil fuel feedstocks, 3) improved fuel performance, and 4) environmental benefits as biodiesel does not contain sulfur or aromatics and in its pure form is biodegradable (esp. attractive for marine applications). In terms of fuel performance, biodiesel provides a higher cetane rating, lubricity, and oxygen content. B2 and B5 are generally considered indistinguishable from fossil diesel from a functional standpoint, whereas B20 and above is more likely to encounter flow problems in colder temperatures unless additives are blended in.

Global biodiesel capacity is expected to reach 18M tpy by 2009, up from roughly 8M tpy currently. To date, Europe has taken the lead, with more than 6M tpy (1.9bn gal/year) of installed capacity in 2005, 85% of that derived from rapeseed, and another 4M tpy expected to be added by 2008. Brazil aims to implement B5 by 2012. Malaysia also has a high profile, as it is planting over 600,000 ha of palm oil plantations, with a target of switching to B5 by 2007 and, eventually, providing at least 10% of global biofuels production. In the US, the National Biodiesel Board estimates total installed capacity now amounts to 864M gal/year (vs. 2006 consumption of 250M gal). Announced capacity additions are enough to lift the industry to 2.6bn gal/year by 2008. The pace of capacity additions in the US has been accelerating, moreover: the industry had roughly 80M gallons in 2005, 25M in 2004, 2M in 2003, and only 0.5M in 1999. To put these figures in context, were biodiesel to reach 2% of total US diesel consumption, US demand would be approximately 1bn gal/year. Plant sizes have also increased sharply, with new world-scale plants on the order of 250,000 tpy, or 25x the standard size only a few years ago. The US has introduced tax credits of $1/gal for virgin oils and $0.50/gal for other products to help make the use of more expensive edible oil feedstocks competitive; in contrast, Germany and France have been scaling back subsidies.

Table 19: Comparison of Sources of Vegetable Oil

Plant	Source	Oil Content (%)	Months of harvesting	Yield (t/ha)
Palm	Pulp	26	12	3.0-6.0
Sunflower	Seed	38-48	3	0.5-1.5
Rapeseed	Seed	40-48	3	0.5-0.9
Castor	Seed	43-45	3	0.5-1.0
Peanuts	Seed	40-50	3	0.6-0.8
Soybeans	Seed	17	3	0.2-0.6

Source: BMVEL

As mentioned above, one appeal of biodiesel is feedstock flexibility. Producers can use fats, waste oils, or vegetable oils, which are all triglycerides that can be esterified into methyl or ethyl groups. Vegetable oils are extracted by pressing or distilling soybeans, cotton, sunflower seeds, rapeseed, corn, palm seeds, coconuts, and other oil-rich fruits. Acceptable fats, on the other hand, include tallow, pork fat, chicken fat, yellow grease, and cooking oil. Naturally, which feedstock will be favored depends on local economics, particularly the availability of storage infrastructure and the cost of logistics (production centers are often removed from consumer centers). In the US, soybeans account for more than 90% of biodiesel production. Overall, we expect producers with a flexible approach and access to large, well established global markets such as palm oil to face less feedstock price volatility over time than producers tied to a single crop. Waste feedstocks, such as inedible tallow and yellow grease, often have better economics, but supply is limited. Indeed, even if the US biodiesel industry can convert all the available grease, soybean oil, and tallow into biodiesel, it would only be large enough to displace 5% of current diesel demand (vs. 0.1% last year). Moreover, regional shifts in meat production (perhaps prompted by higher grain prices?) could have an impact on the availability of related waste products.

Chart 16 sketches typical US biodiesel costs. Production economics will vary depending on feedstock costs, logistics, and tax incentives. Anecdotally, our estimates compare with roughly $2.50-$3.00/gal for Brazilian production (jatropha or sunflower), or $1.60-$1.75/gal for Chinese (palm oil, vs. $2.25-$2.50/gal for rapeseed).

Chart 16: US Biodiesel Economics (factoring in tax subsidy, palm oil feedstock)

1) Capital

Capital intensity ($/gal)	1
Plant Cost ($m)	$50.00
Capacity (m gal)	50
Capacity (m t)	0.15
Working Capital ($m)	20
Total Invested Capital ($m)	$70.00
Capital/Gallon ($)	$1.40
Capital/t ($)	$470.34

2) Variable Cash Costs

Soybean	
Volume (t)	172,367
Feedstock volume (m lb)	380
Feedstock yield (lb/gal of biodiesel)	8
Price ($/lb)	$0.35
Total cost of feedstock ($m)	*$133.00*
Cost of feedstock ($/gal)	*$2.80*
Processing	
Heat efficiency (BTU/gal)	0
Heat (in MMBTU)	7.75
Price of Methanol ($/gal)	$1.70
Electricity (kWh)	42.88
Electricity ($/kWh)	$0.031
Total energy cost	*$14.50*
Total energy ($/gal)	*$0.15*
Other variable costs ($/gal)	
Waste Management	$0.006
Water	$0.003
Enzymes	$0.020
Yeast	$0.004
Chemicals	$0.023
Denaturant	$0.035
Maintenance	$0.040
Labor	$0.050
Administrative	$0.033
Catalyst	$0.020
Other	$0.004
Total other variable costs ($/gal)	*$0.24*
Net cash costs of production ($/gal)	$3.19
Net cash costs ($m)	$151.49
Co-products	
Glycerin (lb/gal)	0.5
Total volume (m lb)	23.75
Price ($/lb)	$0.04
Co-product value ($m)	*$0.95*
Co-product value ($/gal)	*$0.02*
Shipping ($/gal)	$0.10
Net cash cost (incl. Shipping, co-products)	$3.27
Capital recovery ($/gal)	$0.05
Total cost ($/gal)	***$3.32***

3) Sales

Operating rate (%)	95%
Volume (m gal)	47.5
Price of diesel ($/gal)	$3.05
Government credit	$1.00
Effective price	$4.05
Revenue ($m)	$192

4) Key Assumptions.

Capital intensity $1/gal
Conversion yield 8 lb/gal
Shipping costs $0.10/gal
No other chemical co-products.

5) Margin Analysis

Profit ($/gal)	$0.73
Operating Margin (%)	24.0%
Cash Margin (%)	-4.6%
Breakeven Diesel ($/gal)	$3.27
Government subsidy	$0
Crude Breakeven ($/bbl)	$84.10
Tax rate	*35%*
ROIC	43%
Target profit margin	10%
Target biodiesel price ($/gal)	$3.69
Government subsidy	$0
Effective price ($/gal)	$3.69
Crude equivalent ($/bbl)	$94.87

6) Sensitivity Analysis **Current NPV: $ 4.75**

$/gal Profit

Feedstock ($/lb)	Price of diesel ($/gal): $2.95	$3.00	$3.05	$3.10	$3.15
$0.31	0.95	1.00	1.05	1.10	1.15
$0.33	0.79	0.84	0.89	0.94	0.99
$0.35	0.63	0.68	**0.73**	0.78	0.83
$0.37	0.47	0.52	0.57	0.62	0.67
$0.39	0.31	0.36	0.41	0.46	0.51

ROIC

Methanol ($/gal)	Price of diesel ($/gal): $2.95	$3.00	$3.05	$3.10	$3.15
$1.60	0.65	0.70	0.75	0.80	0.85
$1.65	0.64	0.69	0.74	0.79	0.84
$1.70	0.63	0.68	0.73	0.78	0.83
$1.75	0.62	0.67	0.72	0.77	0.82
$1.80	0.61	0.66	0.71	0.76	0.81

After-tax NPV ($/gal) *10% discount rate* *10% margin*

Feedstock ($/lb)	Avg. Diesel Price ($/gal): $2.95	$3.00	$3.69	$3.10	$3.15
$0.31	6.18	6.51	4.48	7.16	7.48
$0.33	5.14	5.47	3.44	6.12	6.44
$0.35	4.10	4.43	***2.40***	5.08	5.40
$0.37	3.06	3.39	1.36	4.04	4.36
$0.39	2.02	2.35	0.32	3.00	3.32

Impact on NPV of sustained period of outsized margins

Excess Margin ($/gal)	# of years: 1	2	3	4	5
$0.25	0.23	0.43	0.62	0.79	0.95
$0.50	0.45	0.87	1.24	1.58	1.90
$0.75	0.68	1.30	1.87	2.38	2.84
$1.00	0.91	1.74	2.49	3.17	3.79
$1.25	1.14	2.17	3.11	3.96	4.74

Source: Jefferies & Company, Inc. estimates

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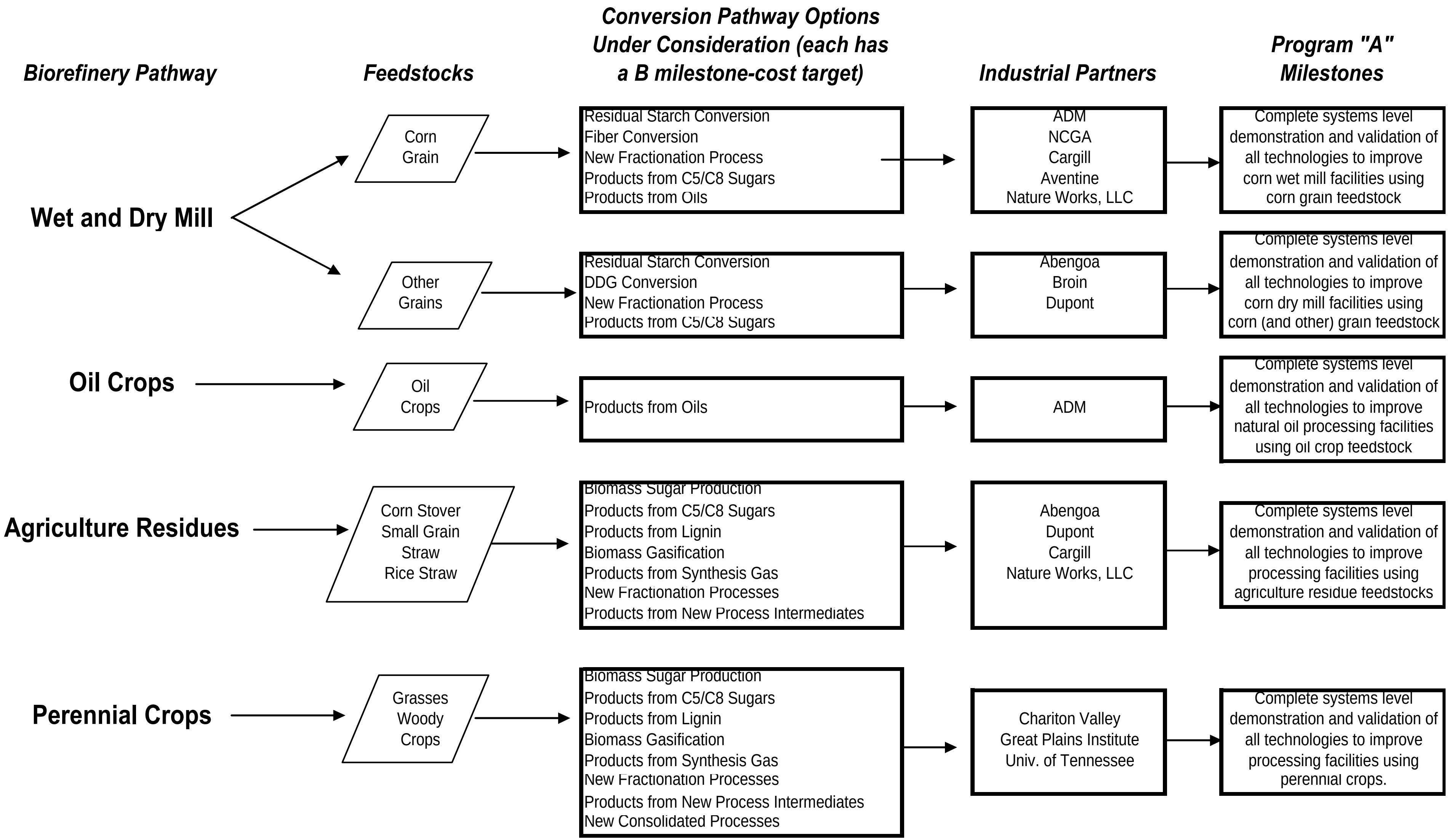
Chart 17: Agricultural Biorefinery Pathways, Including DoE Partners



Source: DoE

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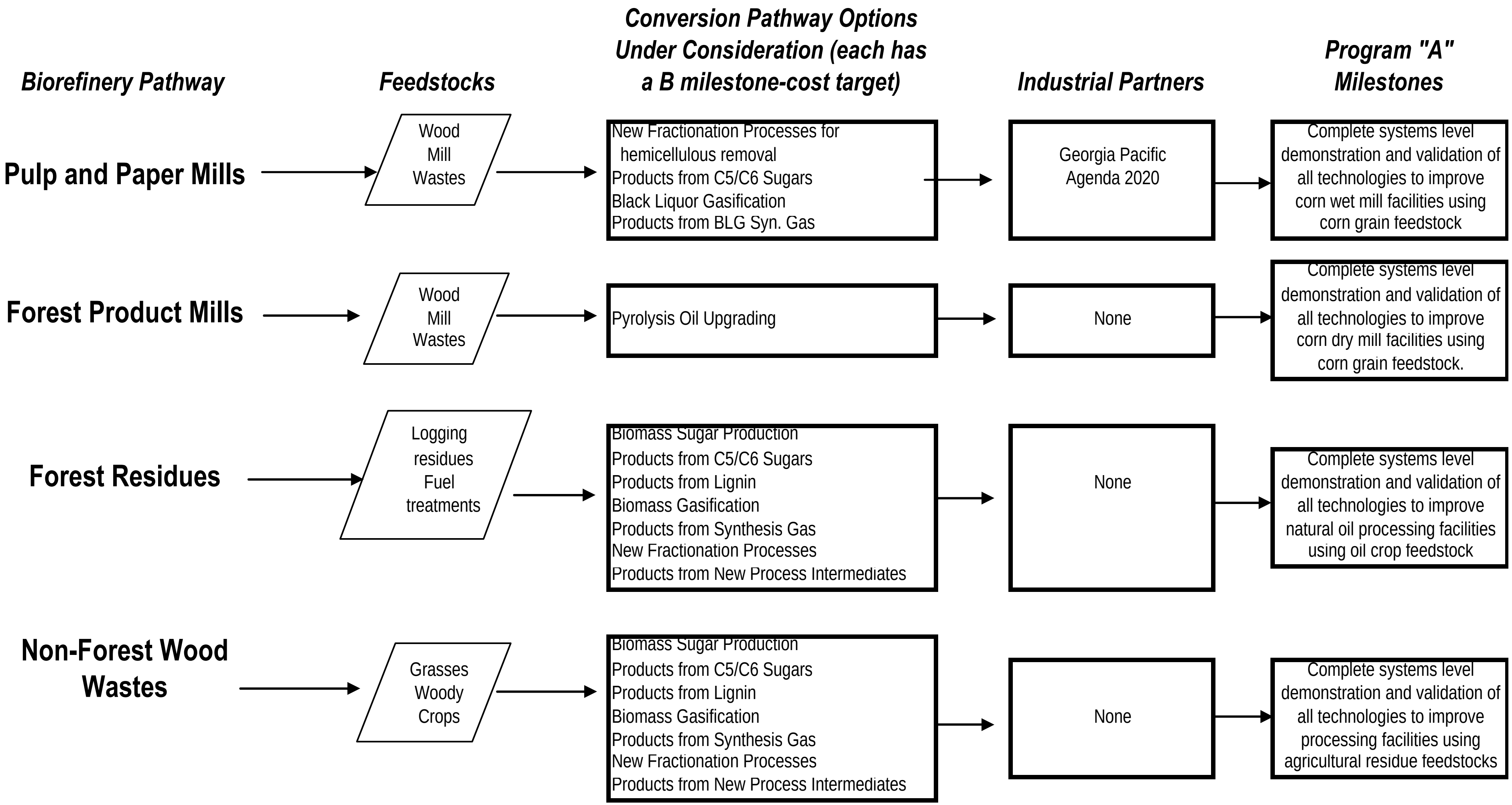
Chart 18: Forest Biorefinery Pathways, Including DoE Partners



Source: DoE

Clean Technology
Industrial Biotech

Clean Technology

Biodegradable Plastics: Key Questions

Investment Summary

Biodegradable plastics are emerging as an attractive niche product that downstream processors can use to address feedstock pressures while improving both their brands and the scarcity value of their operations. Metabolix (MBLX, $22.54, Buy) provides a pure-play on this investment theme.

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Event

This report provides a survey of the emerging biodegradable plastics industry, including key players, growth drivers, challenges, and likely investment themes.

Key Points

Bio-based materials in the spotlight. With oil back above $80 and significant capital investments announced by ADM, BASF, Cargill, DuPont, and Teijin Chemicals, bio-based alternatives to petrochemicals are attracting more interest. Over time, we expect the investment landscape to be framed by four themes:

- **Cost and brand considerations drive adoption:** Consumer demand, opportunities to reduce energy and waste handling costs, and regulatory drivers should drive 15%-plus annual growth in the 100,000-120,000 tpy market for biodegradable plastics (vs. 189,000 tpy of capacity based on renewable raw materials).
- **Range of manufacturing techniques:** In classic fermentation, to optimize yields companies modify organisms so they are more tolerant to their monomer by-products (make the yeast a happy alcoholic, as it were). In the "foie gras" method, companies modify metabolic feedback loops so organisms store excess energy as polymers. The former, in our view, is better suited for producing bio-based chemicals, the latter for bio-based polymers (due to lower capital costs).
- **Bio-based chemicals could compete for feedstocks.** Enzymes and cellulose-based products have been the highest-profile bio-based chemicals. We expect the industrial biotechnology industry to explore additional alternatives to petrochemicals that are more renewable (good for branding), biodegradable (reducing waste costs), and economical (particularly given stubbornly high oil prices). Most of these will increase demand for row crops as feedstocks. For example, CMAI has estimated 1m tpy of ethylene (1% of global demand) could require 520m gal of ethanol (2% of the U.S. 2006 corn harvest and 0.5% of arable land using 2006 yields). Sugarcane, switchgrass, palm oil, soybeans, and waste cellulose could offer better economics in some contexts.
- **New processes.** The most intriguing opportunities, in our view, will come when companies find ways to compress chemical manufacturing steps into a single biological pathway. We believe metabolic engineering will be essential if producers of bio-based chemicals are to drive down processing costs, and reduce capital intensity. With the field attracting new entrants rapidly, integrated R&D and production platforms could prove essential to maintaining a competitive advantage.

Overview

Nature does not eat plastic, yet. Microbes that have had thousands of years to learn to eat cellulose, lignin, and even oil, are about as comfortable eating plastic as vegetarians are eating rock. While certain fungi appear able to digest phenolic resins, PCBs, and even polystyrene, the most reasonable case for most of the roughly 1bn tons of plastic produced since 1950 globally is that it will still be around in several centuries' time. While large units of plastic, if discarded rather than recycled, might be expected to settle as sediment, eventually creating impromptu landfills, smaller units, such as those used in body scrubs and hand cleaners, are small enough to float on the ocean currents for thousands of years. Even "green" plastics that are intended to photodegrade or, by blending petrochemicals with starch-based polymers, biodegrade, will still leave behind small fragments of polymer. Moreover, these fragments appear to attract and absorb other wastes, such as PCBs and DDTs, sharply increasing their concentration in seawater.

Until regulators or waste treatment facilities tie the waste products back to consumers or producers as a cost, these considerations are largely immaterial. For companies that can produce polymers that biodegrade in natural environments, "natural plastics" as it were, and for investors, what matters is that there are applications for biodegradable plastics that can deliver economic value in the near term. Being able to leave erosion control stakes in the ground, for example, saves the cost of hiring staff to pick them up again. For other applications, such as the recently commercialized Target gift cards, the economics are driven by consumer sentiment, as certain consumers prefer to think that garbage will not be their most permanent legacy.

While the biodegradable plastic industry is still in its infancy, in our view, polymer producers and processors already recognize the importance of securing a diverse range of feedstocks. While much of this report is focused on biodegradable plastics rather than bio-based ones, the latter opportunity is likely to eventually emerge as the larger product category (albeit also more hotly contested) as traditional petrochemical producers look for ways to alleviate their risk profile in terms of dependence on oil and natural gas as feedstocks.

1. How large is the market?

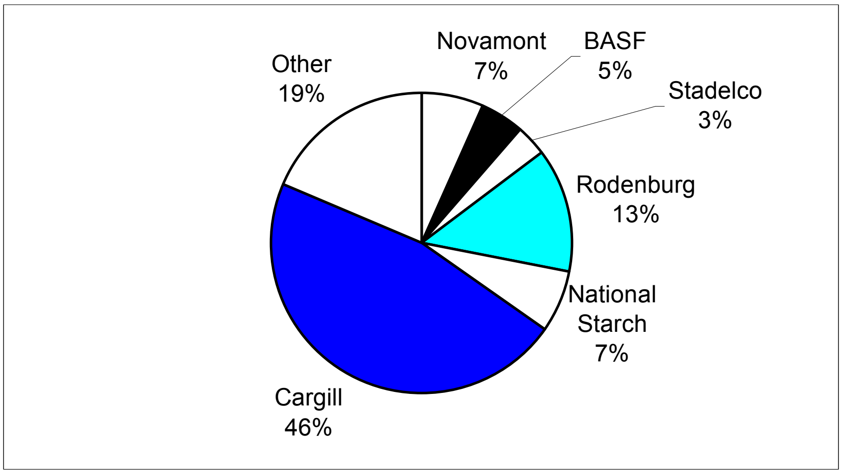
Supply/demand: We estimate global demand for biodegradable plastics at roughly 110,000-120,000 tpy (roughly 65% in Europe, 22% in North America, 10%-12% in Japan), and demand should grow 10%-15% through the end of the decade. The size of the market is obscured by inconsistencies in the available data (e.g., bio-based vs. degradable plastics), but we estimate bio-based (but not biodegradable) commodity chemicals could represent a market 2-4x as large as the market for biodegradable plastics. Installed capacity for biodegradable plastics reached approximately 300,000 tpy in 2006, with announced capital additions enough to add another 80% to global capacity by 2008. In the 1990s, the dominant technology was starch-based.

Key players: While data is sketchy, industry observers estimate there are roughly 60 producers of biopolymers, not all of which are biodegradable. Earlier this decade, PLA emerged as the dominant biodegradable plastic technology due to NatureWorks' $300m 140,000tpy PLA facility (using 0.5% of the U.S. corn crop), initially funded through a JV between Cargill and Dow Chemical. While Dow Chemical exited the JV in 2005, Cargill invested more than $750m in Natureworks, including basic R&D. In October 2007, Cargill sold 50% of Natureworks to Teijin, with an eye to further expanding capacity. Other key players include Metabolix (50,000 tpy PHA plant under a JV with ADM coming onstream in 2008), Novamont (35,000 tpy of a starch-blend called Mater-Bi, with another 15,000 tpy planned), BASF (14,000 tpy using a starch-PLA blend called EcoFlex), and Plantic (8,000 tpy of corn-based plastic).

New entrants: Biobased and biodegradable plastics are attracting a wide range of new entrants. The most notable include Dow Chemical (350,000 tpy of bio-based polyethylene by 2011), Braskem (200,000 tpy of bio-based polyethylene by 2010), Bio-On (10,000 tpy of PLA by 2009), Livan (50,000 tpy of corn-based packaging materials by 2009), and Tianan Biologic (10,000 tpy of PHBV by 2009 and 60,000 tpy by 2011).

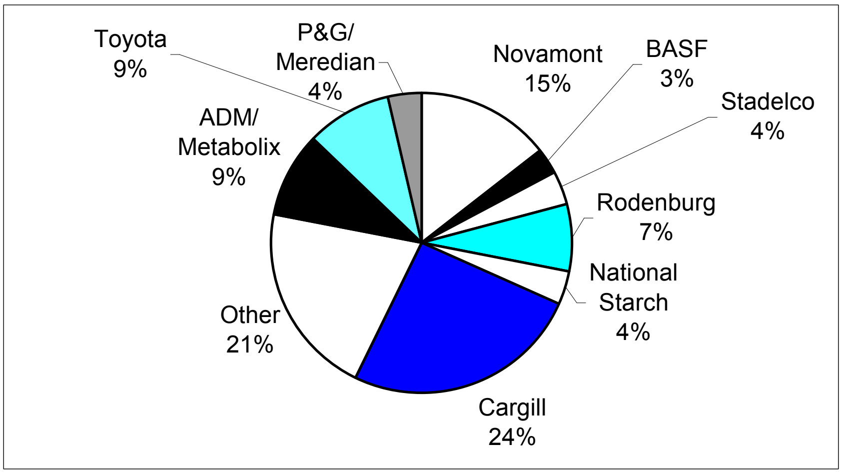
Potential demand: Industry observers have estimated the addressable market opportunity at 4.5m tpy, or 8x 2008E capacity, though market penetration is hindered by the need for tailored product formulations, processor partnerships, and end-consumer education. For example, Europe's COPA and COGEPA have estimated the addressable market at 2m tpy: 450,000 tpy for catering products; 400,000 tpy vegetable packaging; 400,000 tpy foil packaging; 240,000 tpy for 100% biodegradable diapers; 200,000 tpy tire components; 130,000 tpy biodegradable mulch foils; 100,000 tpy organic waste bags; and 80,000 tpy biodegradable foils for diapers.

Chart 1: Biodegradable Market Share (% of capacity), 2006 (300,000 tpy)



Source: Jefferies & Company, Inc. estimates, company data

Chart 2: Biodegradable Market Share (% of capacity), 2008E (550,000 tpy)



Source: Jefferies & Company, Inc. estimates, company data

2. How are bio-based plastics made?

Polyolefins such as HDPE, LDPE, PP, and PS are not biodegradable because of the strong carbon-carbon bonds that form the spine of the polymer. PET is also not biodegradable, because its phenyl ring blocks degradation by water molecules (i.e., hydrolysis). Together, these plastics represent roughly 90% of all plastics. Specialty polymers such as copolyesters, polyamides, and polyethers have weaker heteroatoms (non-carbon atoms) in the spine of the polymer, making them easier to break. Poly (vinyl alcohol) can be degraded by water due to the alternation of hydroxyl groups on the carbon atoms. Bio-based plastics, in contrast, are typically made through one of the following strategies:

- Extracted and used without modification. Starch is the most common example, being competitive with polyethylene on price. The main limitation is the need for blends to reduce sensitivity to water. Synthetic blends of polyethylene and starch are only partially biodegradable (the microbes eat the starch, but leave polyethylene flakes behind). Stiffeners (limestone, cellulose from recycled paper) can also be added to increase toughness. Metabolix's innovation is to discover how to make PHA polymers and co-polymers directly in plants, which should be price-competitive with commodity plastics while providing a far broader range of performance characteristics than starch.

- Broken down to sugars (monomers). Converted to new monomers, and then turned into polymers via chemical methods. This is the method used to make PLA, which degrades by hydrolysis.

- Broken down to sugars (monomers). Converted to polymers via fermentation. This is the approach Metabolix is taking in its JV with ADM. Microorganisms accumulate the PHA, which can eventually constitute as much as 80%-90% of dry weight. The PHA is then removed with a solvent. P&G and Kaneka have a JV focused on some grades of PHAs, but commercialization appears to have been delayed due to a mismatch in their interests (consumer products vs. durable goods).

- Small molecules (oils) are extracted, then cross-linked using chemical methods to make thermosets. Examples would include the soy-oil based composites for John Deere tractors that are sold by Ashland (ASH, $66.32, Hold). This is, in our view, the preferred approach for producing bio-based durable thermosets.

Table 1: Classes of Biodegradable Plastics

	Natural/Synthetic	Renewable?	Manufacturer
Aromatic Polyesters			
Aliphatic-aromatic copolyesters	Synthetic	No	BASF, Eastman
Modified PET & derivatives	Synthetic	No	DuPont
Aliphatic Polyesters			
Polybutylene Succinate	Synthetic	No	Showa Denka, SK Chemicals
Polycaprolactone	Synthetic	No	Dow, Solvay, Daicel
PHA	Natural	Yes	Metabolix, Kaneka/PG
PLA	Synthetic	Yes	Cargill, Hycail, Mitsui, Toyota
Others			
Polyvinyl Alcohol	Synthetic	No	Various
Starch-based Polymers	Natural	Yes	Novamont, Rodenburg, Plantic, Biop
Cellulose Acetate	Natural	Yes	Innovia Films, FKuR

Source: Environment Australia, European Bioplastics

3. Why Metabolic Engineering? Fermentation vs. the Foie Gras Method.

Microbial physiology, and the ensuing production of desirable value-added metabolites, can be stretched way beyond 'wild type' parameters through the selective use of genetic engineering and culture conditions (referred to as metabolic engineering).

Microbial fermentation techniques have a recognized place in the production of low-volume, high-value products (like drugs), but moving to lower value, higher volume chemicals requires moves to maximize efficiency and minimize costs and waste by-products. Microbial processes are composed of a number of research, development, scale-up, and commercial elements; however, they need to be viewed as an integrated whole in order to optimize yield, productivity, and competitive cost comparisons. In particular, the choice between fermenting monomers and polymers is critical in evaluating the capital costs of different bio-based chemical production methods.

A fermentation vat is a complex world: aqueous mixtures of cells jostle with soluble extra-cellular products, intracellular products, converted substrate, and media components. The actual growth conditions and downstream separation techniques depend highly on the location (extra-/intra-cellular), size, charge, and solubility of target products; for commodity chemicals the focus is on finding the cheapest route. However, regardless of the product the highest purity in the final 'broth' is the most desirable—for chemicals, fermentation represents a large percentage of the total production costs (and where 'integrated' development can play a most valuable part).

Most bio-based plastics use chemical biological processes, usually fermentation, to create the monomer (picture small beads of plastic), and traditional chemical processes to make the polymer (stitch the beads together into a sheet or film). The plants provide the feedstocks, whether as starch (storing carbohydrates in corn, potatoes, wheat, etc.), protein (e.g., in soybeans), cellulose (the cell walls in wood, cotton, corn, wheat, etc.), or lipids (e.g., in vegetable oils). A clear illustration of this approach is Braskem's "green plastic", where sugarcane ethanol is transformed into ethane, and then converted via traditional petrochemical processes into polyethylene.

In the fermentation approach, the limiting factor is the biological organism's ability to tolerate the alcohol it produces. Eventually, the organism kills itself. An alternative approach is what we characterize as the "foie gras" method: modifying metabolic pathways so that organisms make the desired polymer inside, like beads of fat. More technically, many microbes have the facility to produce polyhydroxyalkanoates (PHAs), which are accumulated as intracellular carbon and energy storage materials. In this approach, the technical challenge is to dismantle the feedback loops so the organism does not realize it is gaining weight. The appeal is that one can eliminate process steps and make polymers directly, rather than making monomers to be processed later on. This should significantly reduce both waste products and capital requirements: picture compressing an ethylene cracker and polyethylene plant inside a blade of grass.

4. Is biobased the same as biodegradable?

Using renewable resources does not guarantee the product is biodegradable. Many biorenewable plastics are not biodegradable, are only partially biodegradable, or only biodegrade in specific environments. Moreover, some of these biodegrade in part due to hydrolytic breakdown, effectively melting like the Wicked Witch of the West. This means that these polymers require further modification or additives to operate in the presence of liquids or high humidity. Other synthetic degradable plastics are actually photodegradable: they break down after several days' exposure to sunlight into smaller, non-degradable, flakes that then form a permanent part of the ecosystem. Similarly, some polymers are only "bioerodable," as they break into smaller flakes on exposure to heat or UV radiation, but are not necessarily digestible by microbes.

Table 2: PHA Rate of Biodegradation vs. Peers (in micrograms/sq. mm)

	PHA	**PCL**	**Cello-phane**	**PHA**	**PCL**	**Cello-phane**	**PHA**	**PCL**	**Cello-phane**
Days	Marine water			Marine sediment			Soil	Soil	Soil
14	27	7.5	11	11	1	11	18	2	8
28	24	27	11	17	2	11	28	12	10
42	Gone	27	11	31	3	11	48	12	11
56	-	27	-	32	3.5	-	77	12	12
70	-	27	-	-	8	-	-	-	-

Source: Company information

PHAs, in contrast, can be broken down enzymatically by microbes in soil, water, and even in anaerobic environments. They are relatively stable with respect to water, and also have good UV stability (comparable to polyolefins, styrenics, and aromatic polyesters). In effect, the biodegradation begins when microbes on the surface of the PHA use enzymes to break down the polymer into smaller units (hydroxyacids) that are then used as sources of energy (carbon). The waste products are either carbon dioxide and water (in aerobic environments) or carbon dioxide and methane (in anaerobic environments). Various studies have suggested that PHAs degrade 2x-5x faster than polycaprolactone or other synthetic aliphatic polyesters, depending on the environment. Importantly, PLA, the closest rival for PHAs, does not biodegrade readily below 60 degrees Celsius.

Table 3: Commercially Available Biodegradable and Compostable Polymers*

Material	Type	Supplier/ Distributor	Products	Degradation Products	Extent of Degradation	Standard Met
Biomax™	aliphatic copoly-esters, modified PET	Dupont/ www.allcompost.com	Coating and film for food packaging, sandwich bags, utensils, fibers.	Carbon dioxide, water, biomass.	2 to 4 months in compost depending upon temperature	ASTM D6400
Biopol™	PHB/V polybuty-rate and valeric acid	Metabolix Inc/ Biocorp	Consumer disposables, Containers, trash bags, packaging	Carbon dioxide, water.	20 days in sludge, to 1 month in compost	ASTM D6400, EN13432
Eastar Bio™	Biodegrad-able copolyester	Eastman Chemical Company/ Farnell Packaging Biodegradable Products	Trash bags, film, liners	Carbon dioxide, water, biomass.	2 to 4 months in compost depending upon temperature	ASTM D6400, EN13432
Ecoflex™	Aliphatic-aromatic Polyester	BASF/ www.allcompost.com	Compost bags, trash bags, carrier bags, fruit and vegetable bags.	Carbon dioxide, water, biomass.	2 to 6 months in compost depending upon temperature	ASTM D6400, EN13432
Mater-Bi™	60% starch and 40% polyvinyl alcohol	Novamont/ BioBag Corporation	Trash bags, lawn and garden bags	Carbon dioxide, water, biomass.	3 to 6 months in compost depending upon temperature	ASTM D6400, EN13432, BPI
Nature-Works™	Polylactic acid (PLA)	Cargill Teijin/ Biodegradable Food Service, Eco-Products, Inc.	Clear cups, clamshells, salad bowls	Carbon dioxide, water	1 to 3 months in compost depending upon temperature	ASTM D6400, EN13432
Plantic™	Starch-PVOH	Plantic Technologies of Australia/ same	Rigid containers, trays	Carbon dioxide, water.	1 to 2 months in compost depending upon temperature	EN 13432

Source: California IWMB

Compostable plastics can help reduce the environmental burden of plastic. For example, in 2003, plastics represented ~10% (by weight) of materials in California's waste stream. Table 3 indicates the results of published research in California. The ASTM D6400 standard differentiates between biodegradable and degradable plastics (the European standard is EN 13432). The BPI certificate demonstrates that the material meets the requirement of ASTM D6400 and will biodegrade during municipal/commercial composting.

5. Can biodegradable plastics compete with petrochemical plastics on cost, capital intensity?

While biodegradability is an attractive feature, the first hurdle is cost. Importantly, rising oil prices and advances in production processes have brought biodegradable plastics such as PHAs, PLAs, and PCL within sparring distance of oil-based commodity plastics. Table 4 provides a comparative overview of estimated production economics and projected cash returns at current levels. Besides presenting the capital costs for the plastic facilities, we also

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provide estimates for an "integrated capital cost," factoring in the capital required to produce the key feedstocks as well. To a certain extent, this is a fuzzy metric, as we do not attempt to calculate the all-in capital cost back to the refinery or oil well stages, but we believe this is roughly comparable to the capital cost of the ADM-Metabolix PHA facility, excluding the capital costs for corn cultivation, collection, and conversion into PHA feedstock.

Table 4: Comparative Economics of Metabolix PHA vs. Commodity Plastics

$/lb	Price	Cash Cost	Margin	Invested Capital	Integrated Capital Cost	Cash Return	Integrated based on
ABS	$1.02	$0.96	$0.06	$0.72	$1.09	6%	Acrylonitrile, Butadiene, Styrene, ABS
HDPE	$0.73	$0.55	$0.18	$0.41	$0.76	24%	Ethylene, PE
Ethylene				$0.37			
PP	$0.72	$0.58	$0.14	$0.32	$0.45	32%	Propylene, PP
PET	$0.75	$0.73	$0.02	$0.32	$0.82	2%	Ethylene Glycol, PTA, PET
PS	$0.89	$0.80	$0.09	$0.32	$0.94	10%	Ethylene, Benzene, Styrene, PS
Polycarbonate	$1.72	$1.23	$0.49	$1.40	$1.97	25%	Cumene, Acetone, Polycarbonate
PLA	$0.85	$0.70	$0.15	$0.97	$0.97	15%	
PHA	$2.00	$1.20	$0.80	$1.81	$1.81	44%	

Source: Jefferies & Company, Inc. estimates

6. Can biodegradable plastics compete on a life-cycle basis?

Table 5: Life-cycle Energy Requirements for PHA vs. Other Plastics

Megajoules/kg	Energy	Raw Materials	Total	Kg of oil/natural gas used to make 1 lb of plastic
Thermoplastic starch	25		25	
PVOH	-	-	57	
PLA	56	-	56	1.9
PHA (ferment)	11	47*	58	0.25
PET	38	39	77	2.26
PCL	-	-	77	
HDPE	31	49	80	2.2
PS (general purpose)			87	
Nylon	81	39	120	4.7

Source: Jefferies & Company, Inc. estimates, Environment Australia, Scientific American, European Science and Technical Observatory * Renewable (crop-based)

As companies increasingly look to reduce their overall environmental impact, we expect this to favor biobased plastics. For example, from a life-cycle perspective, we estimate Metabolix's manufacturing process uses roughly half the amount of energy inputs as a commodity plastic such as HDPE. Importantly, more than 80% of this is actually renewable inputs (i.e., the crop) rather than fossil fuels. As a result, making PHAs uses almost 90% less oil or natural gas as a commodity plastic. Similarly, we estimate PHAs generate less than half of the CO_2 emissions of producing a similar weight of PE or PET, or less than 1 kg/kg of plastic produced. Total GHG emissions can be reduced further by using corn stalks and windpower to power production facilities.

Table 6: Estimated Cost Stack for Producing PHA Plastic ($/lb)

Sweetener (3lb)	$0.48
Petrochemical Co-Feed	$0.09
Solvents	$0.09
Other Variable Costs	$0.02
Fixed Costs	$0.40
Total Cash Cost	$1.07
Depreciation ($/lb)	$0.13
Total Cost	$1.20

Source: Jefferies & Company, Inc. estimates

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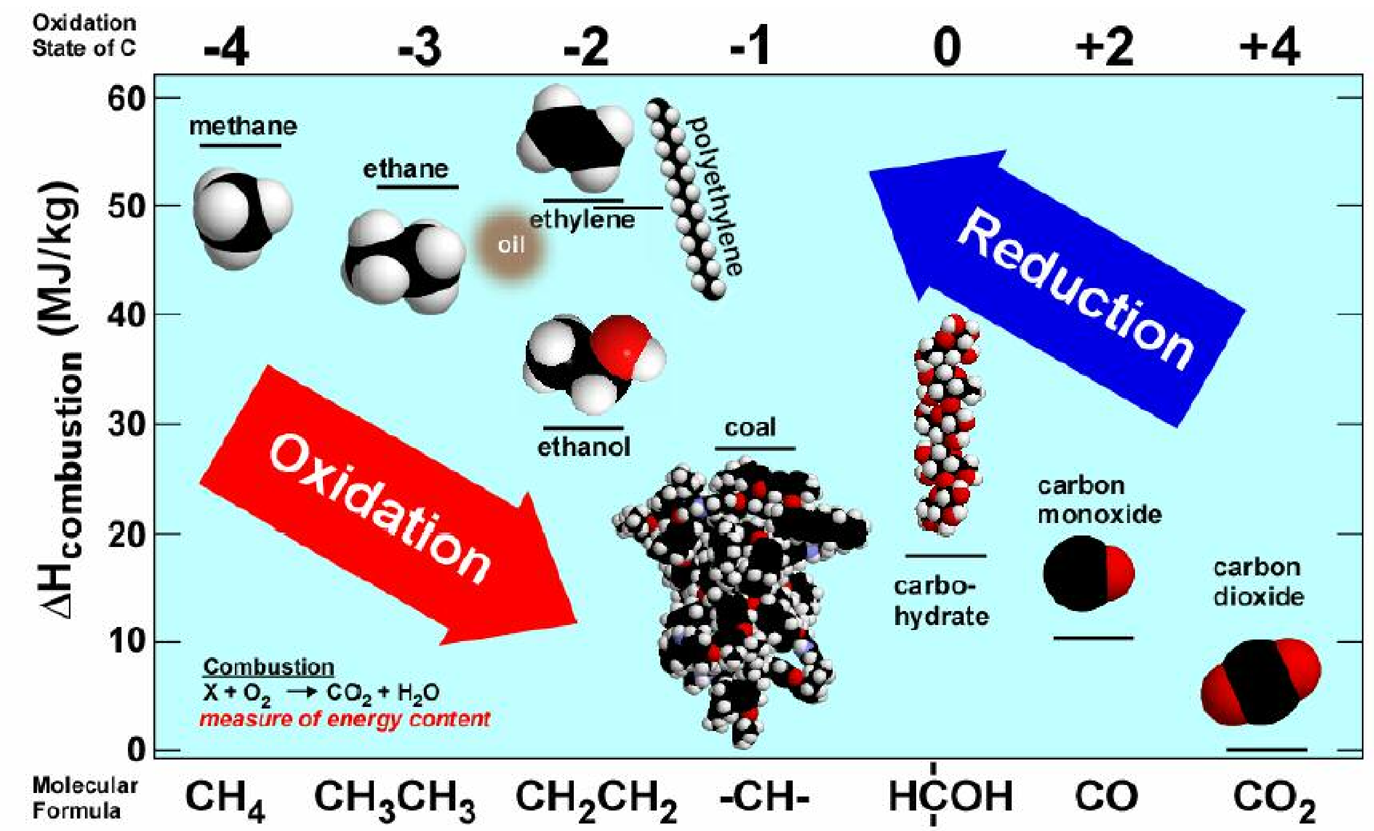
Another way to look at this is that, fundamentally, the opportunity to displace conventional plastics hinges on both the premium customers that are willing to pay for biodegradable properties and, more importantly on the arbitrage between biological feedstocks (sugar, corn) and petrochemical feedstocks (oil, natural gas) on process economics, as sources of carbon, and as producers of CO_2. Moreover, biodegradable plastics will have to compete with biobased plastics and other crop derivatives (such as fuel alcohol), so process economics should take into account substitution opportunities as well as the opportunity to displace petrochemicals. There are a few structural issues which frame this competitive landscape:

- **Arbitraging sources of carbon**. The chemical industry's transition from wood and coal to oil and natural gas in the 20th century was driven by the relative ease of turning ethane and methane into polyolefins. To use coal or carbohydrates, in contrast, one faces two challenges: the feedstock is lower energy; and the plant will typically have higher capital costs.

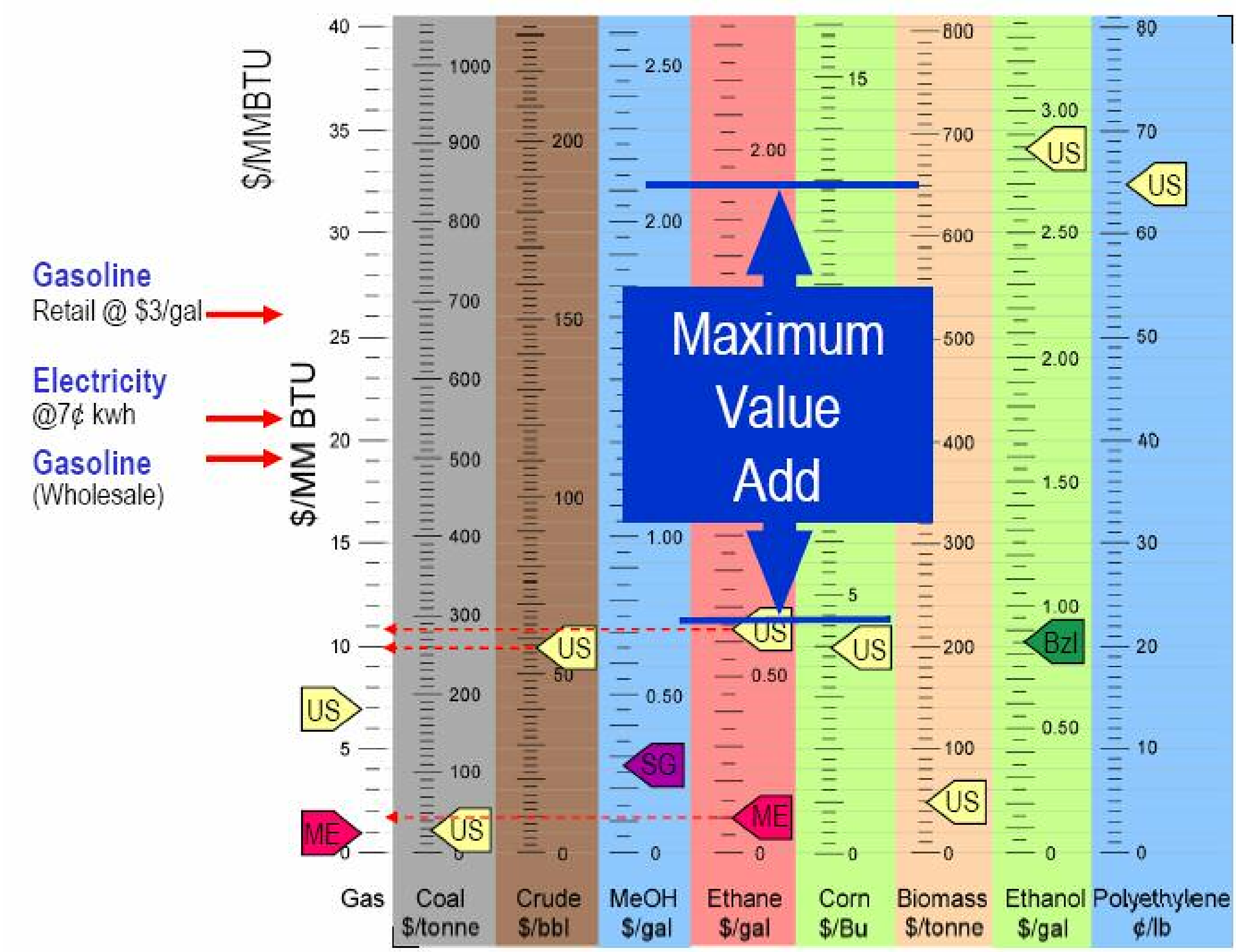
Chart 3: Alternative Feedstock Options: Switch to Coal or Starch Increases Energy Costs



Source: Dow Chemical

- **Arbitraging variable costs.** The following chart shows, as a theoretical assumption, the variable cost in terms of energy of making polyethylene from various feedstocks, including natural gas, coal, corn, and biomass. In practice, experienced plant operators such as Dow Chemical have been able to extract only about a quarter of the theoretical value gap between polyethylene and the feedstocks—and this is only in traditional polyolefins where it has had decades to perfect the chemical process. Importantly, Brazilian ethanol and biomass could prove to be long-term sources of chemical feedstocks, whereas corn-based ethanol is prohibitively expensive at current levels. This provides theoretical support for announcements by Dow and Braskem of projects to produce bio-based plastics from Brazilian sugarcane. The chart below also shows where the relative costs are for electricity and gasoline, which are easier to transport (and hence more attractive) than energy for chemical plants.

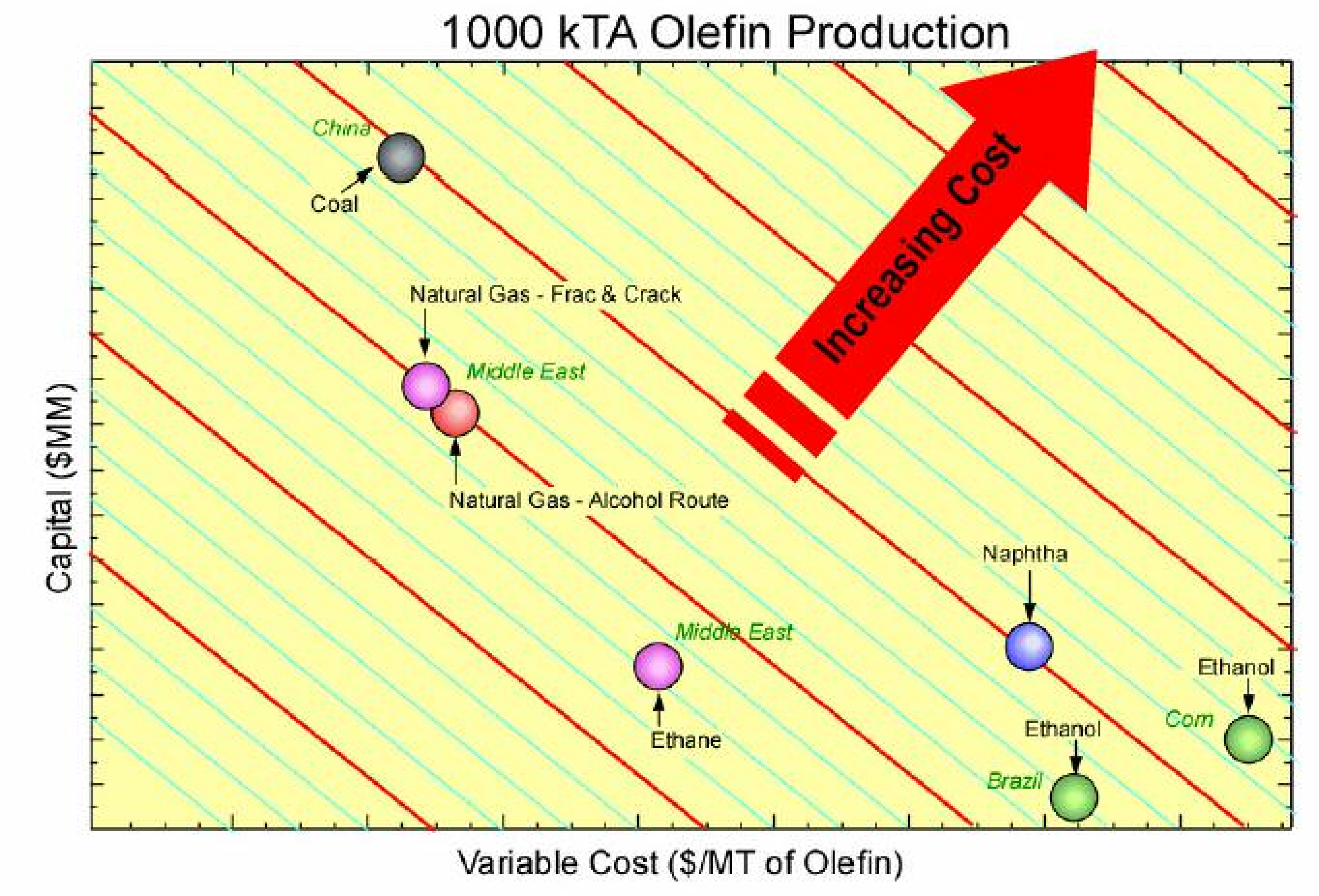
Chart 4: Arbitraging the Variable Cost of Energy



Source: Dow Chemical

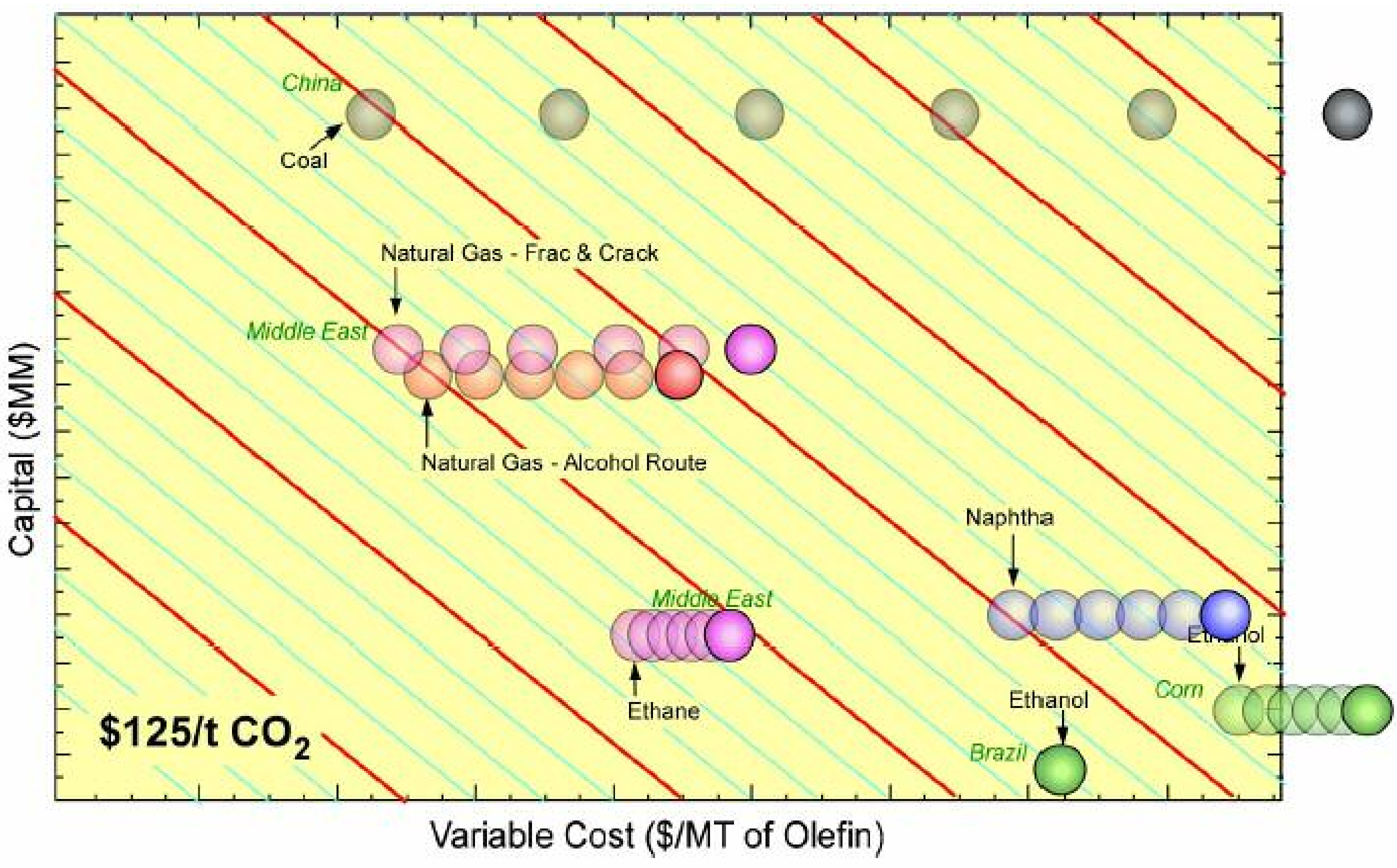
- **Arbitraging capital costs and CO_2 emissions**: While coal may be attractive from a variable cost standpoint, capital costs are high (as much as $2-$3bn), whereas ethanol plants are relatively capital light (as much as 80%-90% less). A related issue is the volatility in variable costs, with significantly more volatility in ethanol and naphtha. If CO_2 shifts from being an external cost to an economic cost, it will have a significant impact on the relative appeal of different feedstocks. Importantly, Dow noted that even for ethanol CO_2 costs could be an issue, as fermentation typically produces 1.6lb of CO_2 for each lb of ethanol produced. As a result, even if governments start charging for CO_2, Middle Eastern ethane and natural gas will probably remain the most attractive feedstock for most non-biodegradable/green-branded chemicals and polymers.

Chart 5: Relative Appeal of Different Feedstocks Based on Both Variable Cost and Capital



Source: Dow Chemical

Chart 6: Impact of CO_2 Costs on Relative Costs of Different Feedstocks



Source: Dow Chemical

7. What drives market adoption?

In our view, biodegradable plastics will be adopted fastest when they are competitive on cost and performance, contribute additional environmental benefits, reduce waste, and provide additional savings of labor or energy. The most attractive opportunities include the following:

- Coated paper for products such as food wrappers and disposable cups.
- Films for packaging such as shopping bags, fresh food wrapping, plastic wrap for catering, and even compost bags and food scrap bags for municipal waste processing.
- Agricultural mulch film. PHA film could be ploughed into the soil, rather than removed, and have the potential to enhance topsoil rather than hasten erosion.
- Consumer packaging materials, such as straws, six-pack rings, bottle caps.
- As filler in wood-composite materials (in excess of a 17bn lb market, currently 30%-50% plastic filler).

In many cases, the regulatory tide has already started to move in favor of degradable plastics. For the last decade, several U.S. states have required six-pack rings be photodegradable, and more recently federal procurement programs have identified several categories where biobased products are designated as preferred, including adhesives, insulating foam, and construction panels, biodegradable containers and films, carpets, glass cleaners, greases, and metalworking fluids. Unlike biofuels and other forms of alternative energy, however, bio-based and biodegradable plastics have not yet received a sustained over-arching government mandate to help create the market. With plastics representing 5% of fossil fuel consumption (the single largest source of demand after energy and transport), we believe government intervention is inevitable. Indeed, one of the longer-term impacts of the latest effort by the European Union to evaluate the toxicity of 30,000 chemicals (REACH) could be to increase the relative cost of conventional plastics, particularly those with high additives content and known persistent pollutant emissions (e.g., PVC). France could require the use of biodegradable plastics for packaging film by 2010 and other countries could follow suit.

In the meantime, as companies such as ADM and Cargill build larger facilities, and achieve economies of scale, the addressable market for bio-based and biodegradable plastics should continue to expand. Pull-through demand is also being created through initiatives by downstream corporations such as Wal-Mart to become more environmentally friendly. Wal-Mart, for example, plans to use roughly 114m PLA containers a year, displacing the equivalent of 800,000 barrels of oil. Similarly, Sainsbury has moved to cut by 50% the amount of plastic packaging used for vegetables and fruits, effectively switching 3,500 tpy of plastic demand to PLA plastic derived from non-GMO corn.

Table 7: Key Polymers Present Longer-term Environmental Risks

Polymer	Applications	Environmental issues
Polycarbonate	Baby bottles, sports water bottles	Can leach bisphenol A, which disrupts the endocrine system
Polystyrene	Single-use disposable cups and containers, meat trays, egg cartons, cutlery, foam for insulation and packaging	Toxic when burned. Contains styrene (affects the reproductive system), benzene, and butadiene
Polyvinyl Chloride	Building pipes and roofing, siding and flooring, window frames, also credit cards, shower curtains, beach balls, food containers	High chlorine and additive content (e.g. phthalates), other persistent organic pollutants

Source: Healthy Building Network's Guide To Plastic Lumber

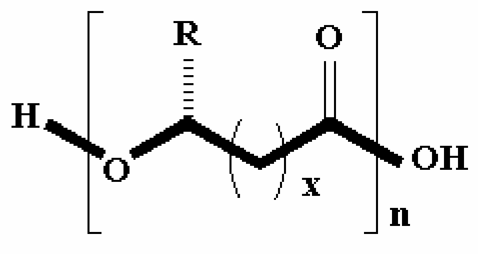
8. What objections do recyclers raise?

Metabolix will need to manage its brand carefully if PHA is to avoid the opposition PLA has encountered in recent quarters. Currently less than 10% of plastic waste is recycled, and margins remain thin. Recyclers have objected increasingly that PLA's recyclability is not fully demonstrated, and they resist having PET and PLA blended in the same products. Sorting the two requires infrared sorting equipment that is too expensive for smaller recycling operations, and recycled PET is already established as a viable commodity (worth $0.15-plus/lb). At the same time, PLA, having been marketed as biodegradable, breaks down quickly only under ideal (i.e., industrial) composting conditions, when microbes can digest the plastic in a 140 degree F environment for more than a week (there are only 113 in the U.S.)—and there is also some debate as to whether the lactic acid in PLA short-circuits the composting process. Also, there appears to be a growing recognition that, for the plastic that ends up in landfills (and plastics contribute 25% of landfill volume currently), biodegradability is a moot point, as that environment lacks the microbes, water, and oxygen needed to break down the plastic.

9. What are PHAs? A flexible class of natural plastics.

Much as humans store excess energy from their diets as fat, many microbes store excess carbon and energy as PHAs, or polyhydroxyalkanoates. Unlike most other bio-based or biodegradable polymers, these are literally "natural plastics": candy for (other) microbes, they biodegrade in environments where even most "biodegradable" plastics remain inert.

Chart 7: PHA Molecular Structure



Source: Company information * R = carbon chain up to C13, x = 1-3. Metabolix PHA is based on R=methyl, x=1. PLA is based on R=methyl, x=0, etc.

More technically, Metabolix PHA natural plastics are semicrystalline thermoplastics. The basic homopolymer is poly-(3-hydroxybutyric acid), or PHB. The underlying structure is similar to other plastics such as polylactic acid (PLA) and polycaprolactone (PCL). Metabolix can modify the plastic's hydrophobicity, tensile strength, transition temperatures, and level of crystallinity, effectively making molecules that deliver a wide range of properties, comparable to everything from rigid thermoplastics to thermoplastic elastomers, as well as forms useful in waxes, adhesives, binders, and solvents. In some cases, the properties are even competitive while eliminating the need for traditional additives such as plasticizers, for example simply by adjusting the relative mix of hydroxyvalerate (PHV) and hydroxybutyrate (PHB) in the PHBV co-polymer.

In general, PHAs are thermally stable under 180°C and demonstrate good resistance to hot liquids. Metabolix believes that PHAs could eventually provide a viable alternative, at least on a performance basis, for more than half of the plastics market, though we believe that for many applications the world does not need another source of plastic except for feedstock diversification. The company has already conducted proof-of-concept trials to show that PHAs can be processed using existing commercial processes. In practice, however, we expect Metabolix to compete first to displace conventional plastics in select niches within the roughly 20% of the market constituted by disposable products. Currently, for contrast, the entire global bio-based plastics market is less than 1% of the total global plastics market, with demand for bio-based plastics growing faster than 15% per year.

Table 8: PHA Water Barrier Properties vs. Other Plastics (in g/m2/day at 23 degrees C, 90% humidity, 50 micron film)

Metabolix PHAs	20-150
Annealed PLA	3,400
PCL	3,600
Ecoflex (BASF)	3,400-3,600
Bionolle (Showa Denka)	6,600
Cellulose Acetate	58,400
Polypropylene	3-5
PET	10-15
Nylon 6	15

Source: Company information

10. How hard is it to develop an integrated PHA fermentation process?

Natural organisms can produce PHAs via fermentation, but the process has tended to be cost-prohibitive due to low yields, slow growth rates, instability, and the difficulty of isolating the PHAs. The challenge is to fine-tune metabolic pathways, with several genetic changes integrated in the chromosome in a stable fashion, expressed in a coordinated fashion, and each one several times more productive than the naturally occurring variant. To develop an integrated large-scale fermentation process, for example, would take several steps:

<u>1. Organism selection</u>: Many microbes accumulate PHA (a range of polymers, from poly-3-hydroxybutyrate, PHB, through poly-3-hydroxyoctaoate). However, PHB is not a normal metabolite of *Escherichia coli* (*E.coli*), a selected production strain, but can be ‘forced’ into manufacturing PHA through metabolic engineering techniques (see next). What can be improved at this stage include basic microbial characteristics, including:

- substrate versatility,
- by-product formation (what, how much),
- health status (i.e., susceptibility to process snafus) and
- physiological make-up (maximal growth rate, aeration requirements, etc.)

<u>2. Metabolic and Cellular Engineering</u>: There are believed to be two principal biosynthetic pathways producing microbial PHA; including those with short chains, like PHB and others with longer side-chains (with more elastomeric properties). A combination of the two pathways probably provides the hydroxy-acid monomers—useful co-polymers of this type, defined by Metabolix as PHB-co-HX, include PHB-co-3-hydroxyhexanoate. The genes essential for this activity (understood to be currently up to nine) can be engineered into the production strain; gene ‘cassettes’ that could be used for this purpose have been identified in a range of bacterial species (notable examples are *Ralstonia eutropha* and *A.vinelandii*). The ultimate goals of this stage are to improve or add some (or all) of the following:

- existing properties of the microbe (bias carbon flux to PHA biosynthesis),
- introduce novel functions (includes ‘switching’ carbon flux to PHA, enhanced product recovery, broaden substrate and product ranges),
- fermentation under non-standard conditions (adapting process to scale-up constraints).

3. Fermentation process development: Much of the preparatory work (from academic and pre-competitive research) needs to be tuned to the commercial process, particularly in respect to microbe culture conditions and growth media optimization (this may require a significant move from a complex to a more defined medium). Looking downstream, to improve efficiency and cost factors, product recovery and purification are keys areas of focus; this can relate back into optimizing growth and media conditions, in terms of, for example, minimizing by-product formation or developing a high-cell density production method (for example, fed-batch vs. batch).

4. Downstream processing: The importance of this step — and particularly how it relates to cost in production of PHAs — must not be overlooked. The right technique at the right time; for example, Metabolix has optimized PHA recovery through incorporating a nuclease gene in the production strain (post cell lysis helps reduce broth viscosity to aid product recovery).

In terms of types of PHA, production can be tailored to specific demand. Either PHB homopolymer or co-polymers of PHB and an external organic acid feed (e.g., B-hydroxyvalerate, HV) can produce a range of thermoplastic polymers which can be processed with conventional techniques into bottles, moldings, fibers, and films.

11. What genetic modifications might be needed to optimize PHA production?

PHB/PHA biosynthesis in microbes is a complex and tightly regulated process. The modifications involved are delicate. For example, a brief summary of the process (in the model organism, *Azotobacter vinelandii*) is as follows:

1. 3-step synthesis: Condensation of acetyl-CoA to form acetoacetyl-CoA (step 1), which is reduced by an NADPH-reductase to produce beta-hydroxybutyryl-CoA (step 2); then polymerisation by PHB synthase to form PHB (step 3). This synthesis is under allosteric control of the step-1 enzyme (beta-ketothiolase).

2. Gene regulation: A PHB biosynthetic gene cluster, *phbB/phbA/phbC*, codes for the enzyme activities of a beta-ketothiolase (step 1), an acetoacetyl-CoA reductase (step 2), and PHB synthase (step 3), respectively. Expression of the genes is under transcriptional control by two overlapping promoters (themselves controlled by additional genetic elements, *phbR* and *rpoS*).

3. 'Global regulatory system': another control system to regulate biosynthesis (integrated with RpoS); kinase (GacS) and regulator (GacA) enzymes offer additional biosynthesis control through interplay with *rpoS*.

4. PHB synthesis under different growth conditions: in exponentially growing cells, 'balanced growth' conditions produce little PHB (beta-ketothiolase activity inhibited), with low transcription of *phbB/A/C* caused by lack of RpoS (which also affects PHB promoter activation) and low levels of *PhbR* (also dependent on RpoS). However, on entering a 'stationary' phase, increased transcription of *rpoS* and *phbR* stimulates transcription of *phbB/A/C*. In addition, the tricarboxylic acid cycle activity may slow during this phase, relieving an inhibition on beta-ketothiolase.

5. Adopting a fermentation strategy to favour PHB production: Another feature of metabolic engineering to help improve process yields is selective mutation-repression to optimize metabolite flux through the PHA pathway (e.g., alginate synthesis blockade). Further pathways to be modulated include the tricarboxylic acid cycle (TCA): for example, in *Azotobacter*, gene knockout of *pycA* can reduce oxaloacetate levels, reducing flux through the TCA cycle to citrate, helping optimize flux into PHA accumulation.

More refined modulation is aimed to 'force-feed' engineered microbes on chemical feedstock, aiming to harness more specialized biotransforming genes to incorporate different co-monomers that could lead to new products with new properties. Genes from a range of microbial and yeast sources are being investigated for specific product formats; these regulatory genes include:

- *gdhA* (glutamate dehydrogenase);
- *gadA/ gadB* (glutamate-succinic semi-aldehyde transaminase);
- *4hbD* (4-hydroxybutyrate dehydrogenase); and
- 4-hydroxybutyrate-CoA transferase gene.

12. Can PHAs stretch to medical applications?

PHA are biocompatible materials that could have important medical applications. For example, an MBLX spin-off, Tepha (private), has developed a medical grade P4HB (poly-4-hydroxybutyrate); the first product TephaFLEX Absorbable suture, was cleared earlier this year for US marketing. Another PHA polymer, TephELAST (absorbable elastomer), is under development for a range of medical devices in endovascular, cosmetic, and regenerative medicine applications.

Clean Technology
Energy Generation - Wind

Clean Technology

Wind Power Primer

Investment Summary

The wind energy sector has grown to become the most significant producer of zero emission power. We believe this sector holds tremendous growth potential as more and more governments adopt pro-wind policies.

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Event

This report is designed to provide investors with a background on the development and future of the wind power industry.

Key Points

- **European leadership.** As has been the case with solar, Germany has led the way with its innovative feed-in tariff regime. Europe represented more than 65% of installations from 1995-2006, and growth looks likely to remain strong as France and the United Kingdom remain relatively underdeveloped, particularly given the excellent wind conditions that exist in both countries.

- **North American potential.** Canada and the United States have been sleeping giants in the global wind sector. With high energy demand and tremendous wind energy potential, these two countries have the potential to install wind generation capacity on a previously unimaginable scale. The extension of the PTC in the USA to year-end 2008 was one of the most important events of 2006.

- **High scalability.** Amongst zero to low-emission sources of power (e.g., wind, solar, hydro), wind has the greatest potential to be rolled out in mass scale. For example, the solar industry installed approximately 1600 MW of capacity in 2005 compared to an estimated 11,352 MW for wind. In 2006, wind installations reached a record 15,016MW.

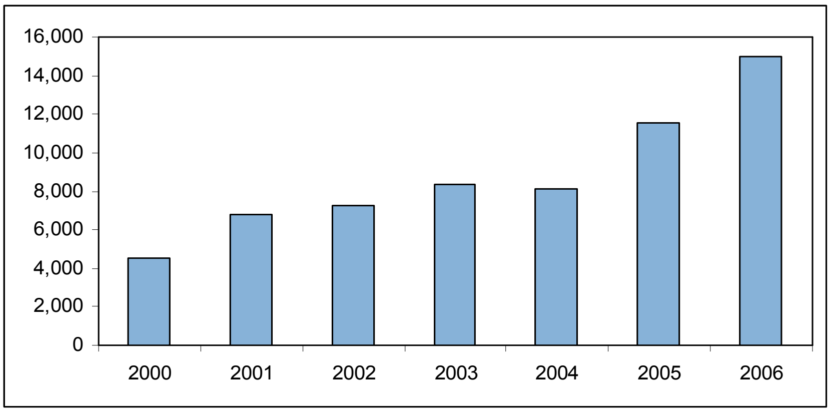
- **Lowest pricing.** Wind is also the most affordable source of zero-emission power. Improved turbine technology has dramatically reduced the cost of wind capacity and allowed the price premium versus traditional energy to drop dramatically. In fact, unsubsidized wind power is currently cost competitive with gas and coal in certain high capacity factor locations.

- **Limitations.** Wind turbines can be very intrusive as many of the largest are nearly 100m in height, leading to NIMBY (not in my backyard) concerns. Additionally, suitable wind sites are not ubiquitous and often not located near centres of demand.

Wind Market Development 2006 - Summary

The wind industry posted record installation growth for the second consecutive year as annual installations reached 15,016MW in 2006. The most significant drivers of this record-setting trend were the production tax credit (PTC) in the USA, the surprisingly strong growth in historically important markets such as Germany, and the emergence of China and India as significant investors in wind generation capacity. Governments in these and other national markets have continued to support pro-wind energy policies as rising concerns over climate change and energy security have catalyzed the desire to emphasize development of zero-emission and sustainable sources of domestic energy generation.

Chart 1: Global Annual Wind Installation 2000 - 2006 (MW)



Source: BTM Consult.

Governments around the world continued to push forward efforts to support renewable energy through a variety of incentives and targets. Some key developments were the Chinese government's target of 10% of electricity from renewable sources by 2015, the one-year extension of the PTC to year end 2008, and the European Union's target of 20% of electricity from renewable sources by 2020 agreed to in 1Q07. These events, both specific and non-specific to wind power, highlight that renewable energy is no longer the sole province of the environmental lobby but has moved into the mainstream.

The turbine shortage continued in 2007 and is likely to remain a limiting factor to industry growth through YE2008 with many producers suggesting that current order books are nearly filled until 2009. This led to an estimated 5% increase in the cost/MW of a turnkey wind farm (source: BTM Consult). However, capacity is rising in the industry as component producers have increased confidence in the sustainability of growth forecasts. BTM Consult has increased its production estimate by an average of 24% for the period 2007-11 to reflect the growing demand and supply. A key element in this increase is the expectation that the PTC will be extended through the end of the forecast period. Previous forecasts assumed the PTC would lapse at the end of 2007.

The trend towards larger-scale turbines and wind farms continued as utilities take an increasingly important role in the development of wind farms. This is a reflection not only of the recognition by some (but not all) utilities that wind is an increasingly common way of generating low-cost renewable energy as well as the desire for turbine manufacturers to direct scare turbines to well-financed customers at the expense of smaller, independent developers. This looks likely to continue as the increasing scale of wind developments is putting them beyond the scope of all but the largest independent wind farm developers.

BTM-Consult estimated that wind generated electricity reached 152 TWh in 2006. To put this in perspective, this represents 0.8% of the global electricity consumption estimates presented by the IEA and is approximately the annual electricity consumption of Sweden (population: 9 million). Additionally, total installed wind capacity has risen to 74.3 GW, which represents 1.7% of global installed capacity while the 15 GW of newly installed capacity in 2006 represented 12% of global installations in 2006. Clearly, while wind is increasingly seen as a viable mainstream option, it represents a tiny slice of total global generation capacity.

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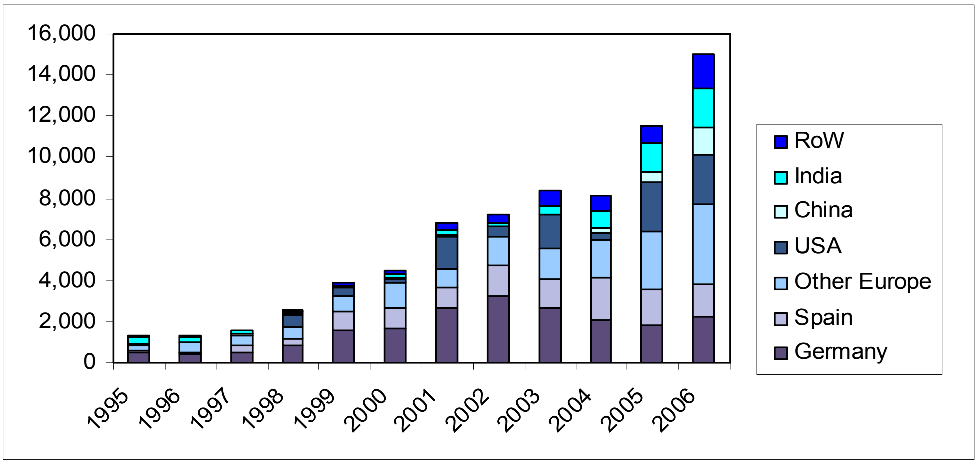
National Wind Industry Developments

The renewal of the PTC in the USA and the emergence of new markets, India and China in particular, have reduced the wind industry's reliance on Europe. From 2000-2004 European countries represented between 66%-87% of turbine installations, principally driven by the two wind colossi Germany and Spain. Demand is now much more widespread as many larger markets are increasingly adopting attractive wind incentives. During 2006, Europe represents 51% of total installations.

Chart 2: Annual Installation by Country (MW)



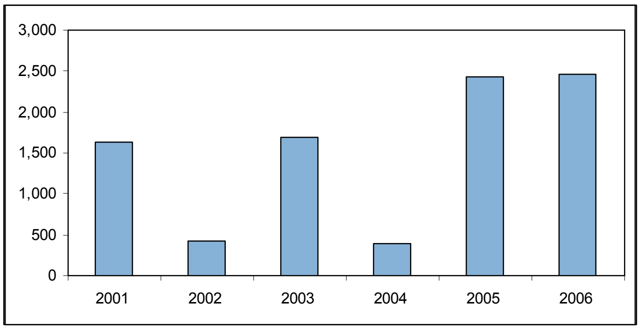
Source: BTM Consult.

USA

The most significant event of 2006 was the one-year extension of the PTC to the end of 2008. This extension does not solve the stop-start nature of wind installations in the USA although it does allow developers to continue to work with an 18- to 24-month time horizon. Additionally, the Democratic-party-controlled Congress is negotiating an energy bill which could see an extension of the PTC through until 2013 and could lead to sustained demand for turbines in the critical US market.

We believe that the flat YoY installation growth is a function of strong global demand for the limited number of turbines and that growth should continue in the coming years.

Chart 3: US Installations 2001-06 (MW)



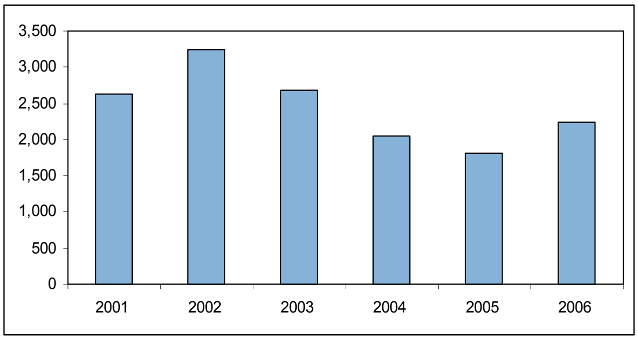
Source: BTM Consult.

Germany

Germany reversed three consecutive years of declines and posted a 23.5% increase in annual installation in 2006. Given that the incentive programs remained unchanged and that re-powering (replacing older turbines — usually located in excellent sites — with newer models) and offshore deployment has not yet begun in significant volume, this growth came as a bit of a surprise.

Germany is the first country to break the 20GW of installed wind capacity barrier, and wind power represented approximately 7% of total electricity consumption in 2006. BTM Consult expects that German installations will revert to their downward course in the next two to three years before rebounding driven by offshore development and re-powering.

Chart 4: German Installations 2001-06 (MW)



Source: BTM Consult.

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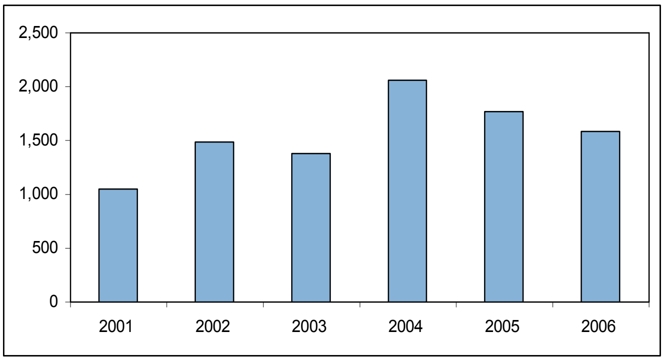
Spain

The Iberian giant (at least in terms of installed capacity) witnessed a second consecutive year of declining installed capacity. The principal culprits were uncertainty over the future of the existing wind incentive regime as well as lack of capacity in the transmission network, particularly to windy Galicia in the northwest corner of the country. Despite the slowing rate of installations, wind energy represented 8% of total and 32% of spot market electricity in 2006 according to *Windpower Monthly*.

Chart 5: Spanish Installations 2001-06 (MW)



Source: BTM Consult.

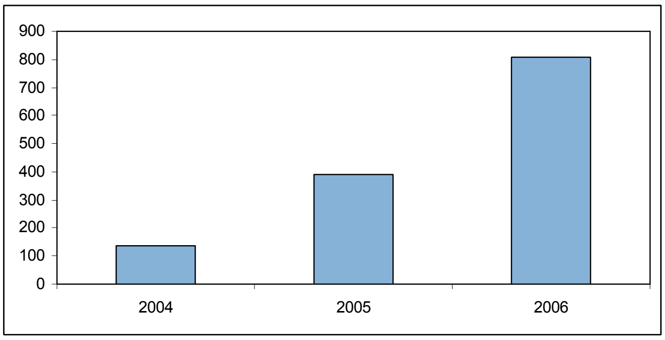
Spanish wind generators were dismayed when the new Energy Secretary Ignasio Nieto proposed a draft law that would potentially cut wind incentives in half and put a cap on wind prices. The catalyst for this proposal was the drought in Spain, which reduced hydro reserves and led to an increase in higher cost gas and oil-based generation, which raised the average cost of wholesale electricity. Under the most commonly used wind power incentive plan, wind power prices are calculated as a premium over wholesale prices, and this led to a significant increase in profitability to wind operators as they benefited from higher prices although the wind is still free. The situation was exacerbated by the fact that Spain caps retail electricity prices and the government is forced to pay the grid (Red Nacional) the difference between rising wholesale and fixed retail prices. This subsidy amounted to €3 billion in 2006, of which roughly 30% was directed to the wind energy sector.

Sr. Nieto had proposed a draft law which would place a floor and ceiling on wind energy prices regardless of the cost of traditional energy. The cap was initially fixed at €84.7/MWh and would have applied to all wind generators regardless of the regime in place when they installed their turbines. However, it now appears that the government, after facing fierce criticism from both the wind industry and the national electricity regulator (the Comision Nacional de la Energia or CNE), has changed its mind and will maintain the current regime through 2012. Should this prove to be the case, Spain is likely to remain a strong source of demand, and installed capacity could reach the government's YE2010 target of 20,000MW (currently 11,614 MW)

France

France emerged as a potentially significant source of new demand growth in 2006 when the French government reversed course and substantially improved the financial terms available to wind farm operators. Traditionally, the French government had argued that its heavy use (more than three-quarters of total generation) of emissions-free nuclear power excused it from the need to support renewable energy. However, the government changed its mind and has targeted 13,500 MW of wind power by 2010. While this target is unlikely to be reached, the doubling of installations in 2006 should give an indication that France and its excellent wind resources will be a force to be reckoned with. Additionally, state energy giant Areva (CEI FP, Hold, PT €700, Ian MacLeod) has attempted to move in to the wind sector via an offer for Repower (RPW GR, NC) although is currently caught in a bidding war with Suzlon.

Chart 6: French Installations 2004-06 (MW)



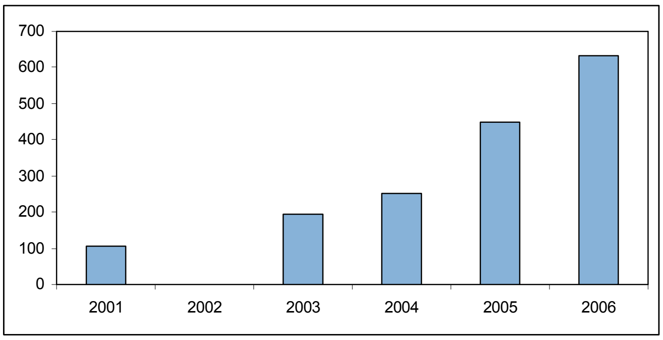
Source: BTM Consult.

United Kingdom

The UK posted record installations for the fourth time in the current millennium with 631 MW installed. In addition to the record installations, several large-scale projects were given planning permission, which has lifted the national consented portfolio to nearly 4600 MW. While the growth rate is impressive, the level of installation is low, particularly when one considers the excellent wind resources available in the British Isles, particularly in the north of Scotland.

There were some policy wobbles that have raised concerns over the medium-term outlook for the British wind industry. The Department of Trade and Industry is worried that the current Renewable Obligation (RO) scheme is proving to be too costly and not delivering sufficient investment. Several policy trial balloons have been raised with varying results.

Chart 7: UK Installations 2001-06 (MW)



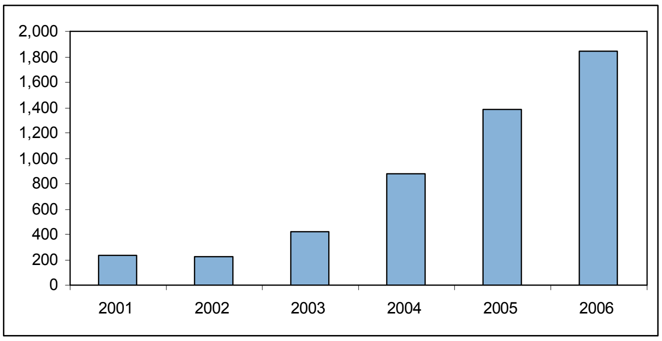
Source: BTM Consult.

While it is too early to comment on potential replacements for the RO scheme, if it is indeed replaced, as we know little of the alternatives. Another ongoing issue has been the lack of available transmission capacity, particularly to the windy parts of northern Scotland. The issue is not so much will capacity be increased, but when and who will pay for it.

India

India has emerged from virtually nowhere to become the third largest installer of wind capacity in 2006, trailing only the USA and Germany. Demand in India is driven not only by federal renewable energy quotas but also the strong demand for additional power stemming from the country's high growth rate and low electrification levels. India is an unusual market in one key aspect. Generally speaking, wind farms are developed to feed the grid. In India, roughly 70% of the wind capacity is owned by manufacturing firms looking to secure their own source of power. The future of wind power looks quite promising although lack of transmission capacity and failure to deliver sufficient incentives at the state level could limit the potential of the Indian market.

Chart 8: Indian Installations 2001-06 (MW)



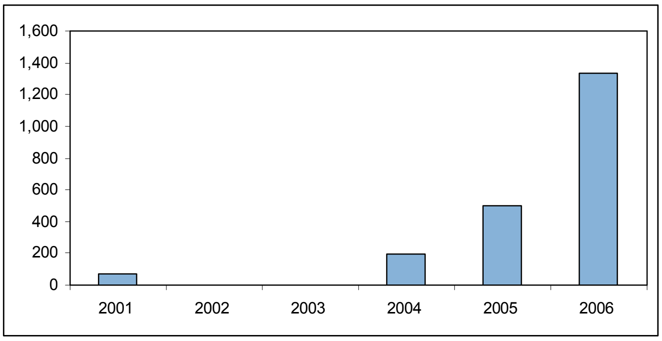
Source: BTM Consult.

China

China's emergence has been even more spectacular than India although installations have not yet reached the scale witnessed on the sub-continent. This growth has been driven by the central government's target of 10% of electricity from renewable resources by 2010 and 15% by 2020. Additionally, China has a voracious appetite for additional power so, much like India, market forces are very much at play along with regulatory incentives. We would expect that China will likely continue to be a significant source of demand.

China, like many emerging wind markets, has mandated a minimum local content requirement (70% in China) which has led to the emergence of several domestic turbine manufacturers lead by Goldwind although foreign producers still control the majority of market share.

Chart 9: Chinese Installation



Source: BTM Consult.

Developers

Another trend that has emerged over the past several years has been the increasing influence of large scale and/or utility wind developers. We believe this is a reflection of the increasing role of the utility scale wind farm as well as the rising importance of the US market where the PTC favors developers with existing tax bills. Further evidence of this trend can be seen in the increasing size of installed turbines as seen in the table below.

Turbine manufacturers also tend to favor the emergence of large, well-financed customers who can sign multi-year contracts covering hundreds of megawatts.

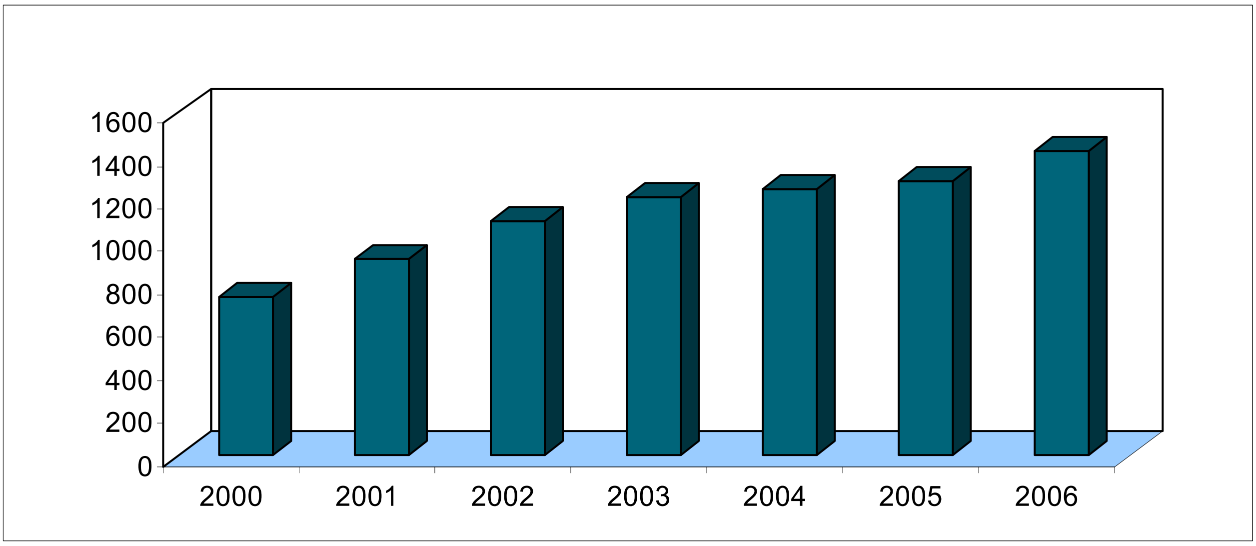
Independent wind farm developers and tax-driven private investors (very popular in Germany) are likely to decline in importance.

Chart 10: Leading Wind Developers

Developer		**MW Installed**
Iberdrola	Spain	4,434
Florida Power & Light	USA	4,300
Acciona Windpower	Spain	3,133
Babcock Brown	Australia	1,631
Scottish Power/PPM	UK	1,593
Endesa	Spain	1,500
Eurus Energy Holding	Japan	1,324
EDP	Portugal	1,010
Shell Renewable	Netherlands	849
Essent / Nuon	Netherlands	840
Total		**20,614**
As a % of total installed capacity		*27.7%*

Source: BTM Consult.

Chart 11: Average Installed Turbine Size (KWp)



Source: BTM Consult.

Supply Chain Developments

According to BTM Consult, a leading wind energy consultancy, several bottlenecks exist in the supply chain that could limit growth in the next couple of years. These limitations are present in several areas and could provide a hint to Clipper's (CWP LN, 649p, Hold) acquisition intentions. We highlight a couple of key component bottlenecks:

- *Large bearings.* Bearing issues has been estimated to cause 80%-85% of all interruptions of supply and/or performance issues. Heavy demand for bearings is caused both by new turbine construction and the need to retrofit and repair existing turbines that have suffered bearing failures. Many of these failures are linked to the upscaling of turbine size leading to disproportionate load increases on key bearings.
- *Gearboxes.* Currently, Winergy (Siemens) and Hansen (Suzlon) supply 60% of the global supply of wind turbine gearboxes. Gearbox producers have been unwilling to invest significant capital in additional capacity due to often volatile order flows and relatively low margins in the business. While capacity looks set to increase sharply, gearbox availability remains a potential limiting factor in 2007-8.
- *Blades.* The blade shortage is not universal. The majority of wind turbine blades are either manufactured in-house or by privately owned LM Glasfiber based in Denmark. There is no significant shortage of blades for smaller turbines, but limitations do exist for carbon fiber blades for multi-MW class (1.5MW+) turbines.

Growth Forecasts

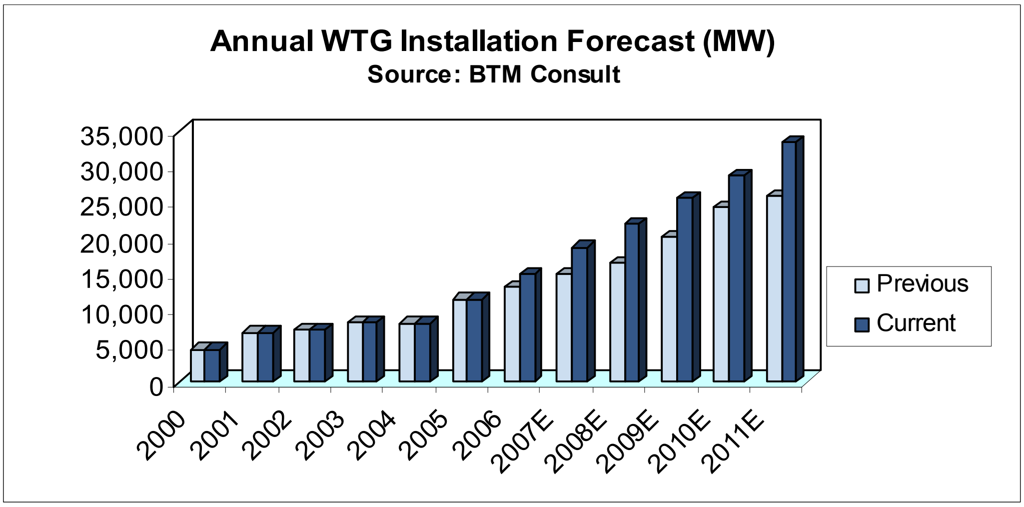
We believe that the future looks very bright for the wind industry. Its low cost and widespread availability make it an ideal solution to the need to reduce dependence on energy imports and lower harmful emissions from the energy generation industry. In addition, the rising cost of energy and the potential for carbon emission charges could narrow the gap between traditional fossil fuel generation and wind generation. Indeed, in certain areas wind can already compete with traditional electricity on a level playing field. However, in most locations, wind will require incentives in order to compete with traditional electricity. We believe these incentives, in whatever form they appear, will likely continue for the following reasons:

- *Competition for resources.* The increased prices for fossil fuels have been in part driven by increased competition from the developing economies as well as rising demand in the developed economies. While conservation could offset higher demand in the developed world, we do not expect demand from the emerging economies to slacken and thus prices for traditional fuels will face pressure.
- *Energy security.* Many western nations rely on imported fossil fuels. While wind power cannot reduce oil dependency, it can help reduce demand for the natural gas used in the growing number of gas fired generators. Unfortunately for Europe and the US, many fossil fuels are found in regions that are either unfriendly, unstable, or unreliable, which forces governments to seek home-grown renewable sources of energy.
- *Environmental concerns*. Awareness of man's impact on the environment appears to be on the rise, and global warming in particular is attracting plenty of media attention as of late. Wind has one of the lowest emissions of any alternative energy and can be deployed in massive scale.
- *Falling cost premium.* The sustained rise in traditional energy prices (4%-5% p.a. over the last 10 years in US and Europe) has reduced the premium paid for alternative energy and weakened the key argument against the deployment of alternative energy resources. Furthermore, if the environmental impact of fossil fuel pollution was added to the cost of traditional energy generation, the alternative energy premium would shrink significantly and even disappear in many places. However, booming demand for wind turbines has lifted prices some 20%-30% over recent years.

Global Forecasts

We have elected to utilize the growth forecasts prepared by BTM Consult, a wind energy consulting firm that is widely regarded as one of the leading experts on the wind energy market. It should be noted that these forecasts assume that the PTC in the US is extended through 2011.

Chart 12: Global Market Growth Forecasts



Source: BTM Consult.

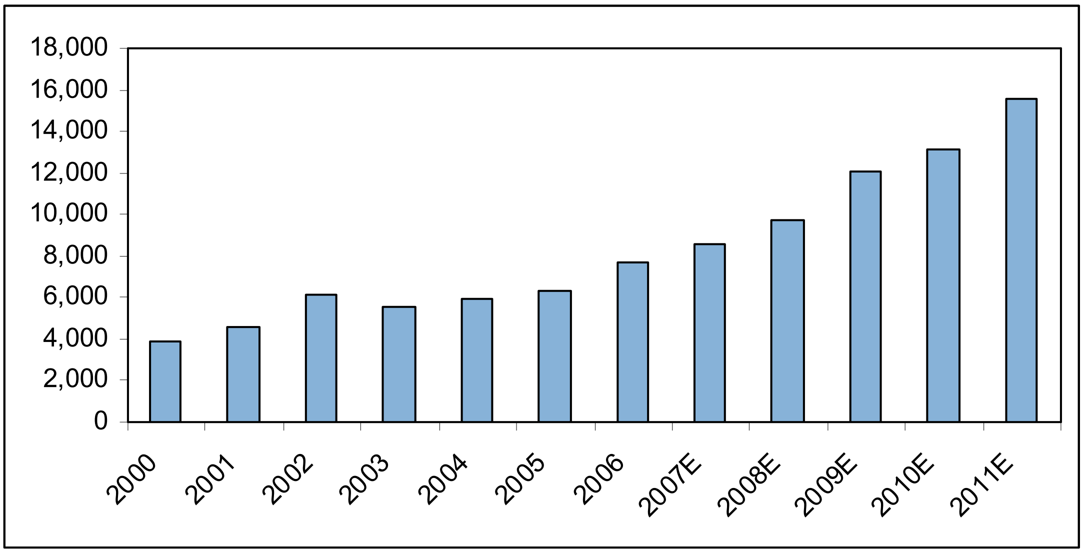
We note that BTM Consult has increased its annual installation forecast for the 2007-2011E period by an average of 24%. This increase has been driven by the assumption of the extension of the PTC in the US through the end of the forecast period as well as rising demand in the emerging markets of China and India. Driven by this increasingly stable source of demand, turbine manufacturers and their component suppliers are ramping up capacity to meet this demand.

Europe – relatively untapped?

While Europe represents 65% of global installed capacity, Germany and Spain alone account for two-thirds of that capacity, or 43% of total global capacity. Most countries have relatively minor investment in wind despite their often superior wind characteristics. Figure 1 illustrates the average wind speeds throughout Europe. In particular, we suggest that investors focus on the British Isles and northern France where some of the best wind conditions are located and, ideally, are near centres of demand. France has amended its incentive scheme to allow for a 10-year feed in tariff (previously 5 years) at €0.082 / kWh and set a target of 13,500MW of wind capacity by 2010 from a current 775MW at YE05. The British Isles have some of the best wind resources in Europe and, given its high population density, is likely to be a leading catalyst for development of offshore wind. The forecast below is based on several key assumptions:

- Germany will maintain its feed-in tariff structure and that both off-shore and repowering will not begin in earnest for several years.
- Spain will maintain an attractive tariff structure and will overcome most of its transmission bottleneck issues to reach its 20 GW target by 2010.
- France will continue to show impressive growth, although the 2010 installed capacity forecast of 7200 MW will fall short of the aggressive 13,500 MW government target.

Chart 13: European Installation Forecast 2007-2011 (MW)



Source: BTM Consult.

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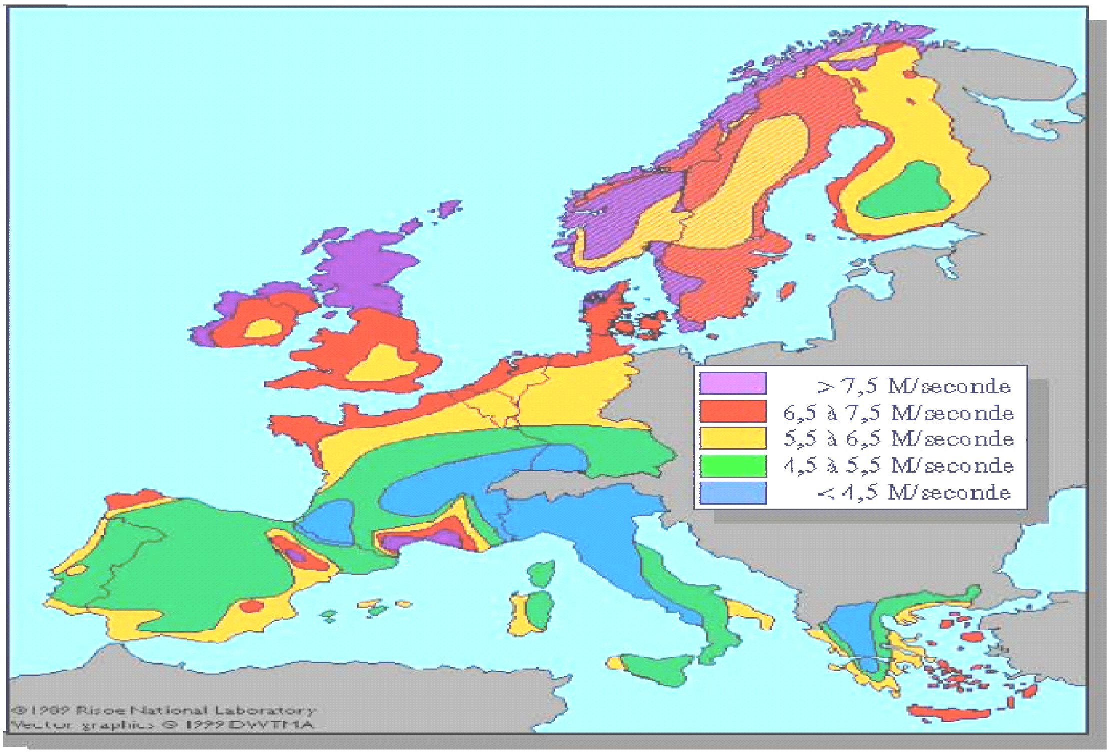
Figure 1: Average European Wind Speeds

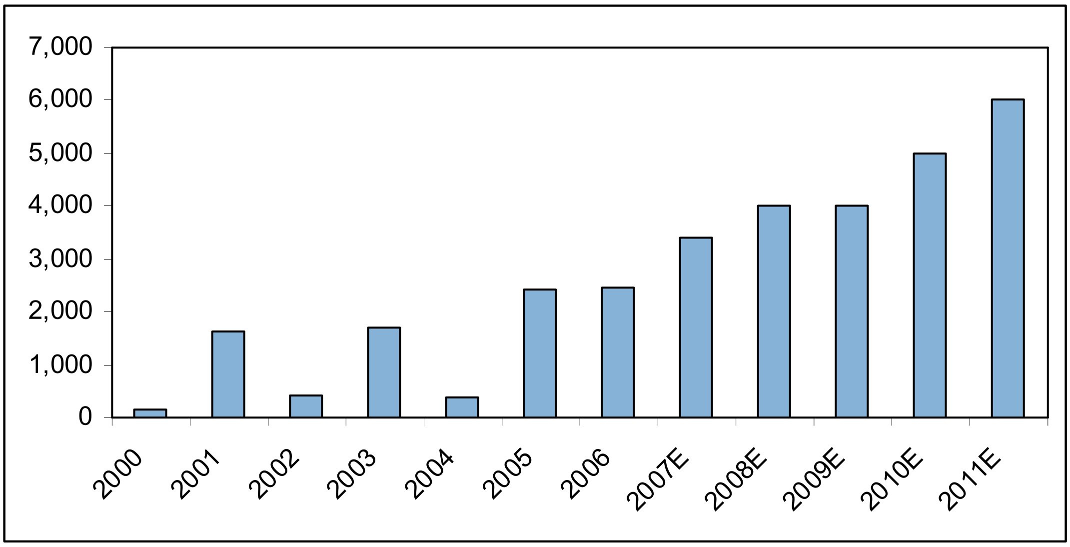


Source: Risø National Laboratory, Denmark

Potential in the Americas

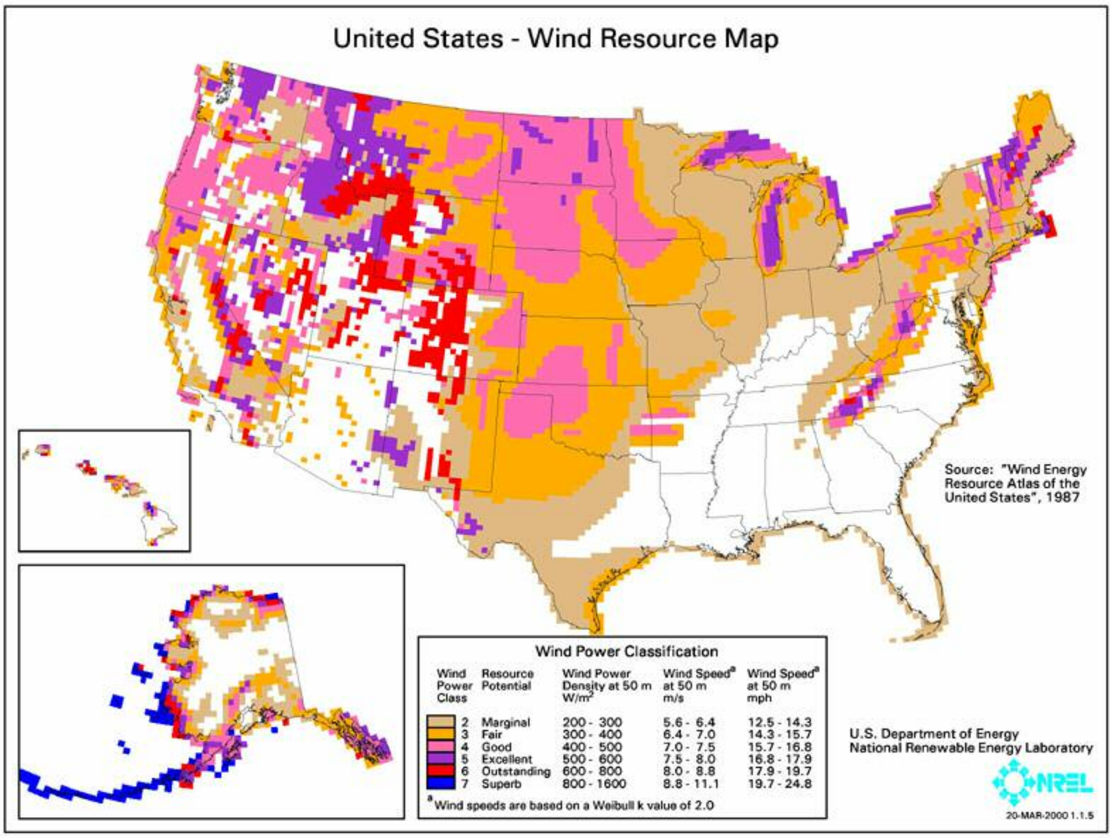
The American Midwest has been referred to as the "Saudi Arabia of Wind" and central Canada also possesses tremendous wind resources. The US market is particularly attractive as it not only has excellent wind resources but plenty of domestic demand and a well established grid. In addition, many potential wind farm sites are located in areas of low population density and, phrasing this politely, minimal chance of disruption to sites of outstanding natural beauty (this analyst is native to the Midwest and can attest to this personally). This untapped potential is being unlocked as developers rush to get projects completed and take advantage of the PTC, which is set to expire in 2008 although there are currently proposals in Congress to extend the PTC through to 2013. The growth forecast below assumes the PTC is maintained throughout the 2007-2011 period.

Chart 14: US Installation Forecast 2007-2011 (MW)



Source: BTM Consult.

Figure 2: U.S. Wind Resource

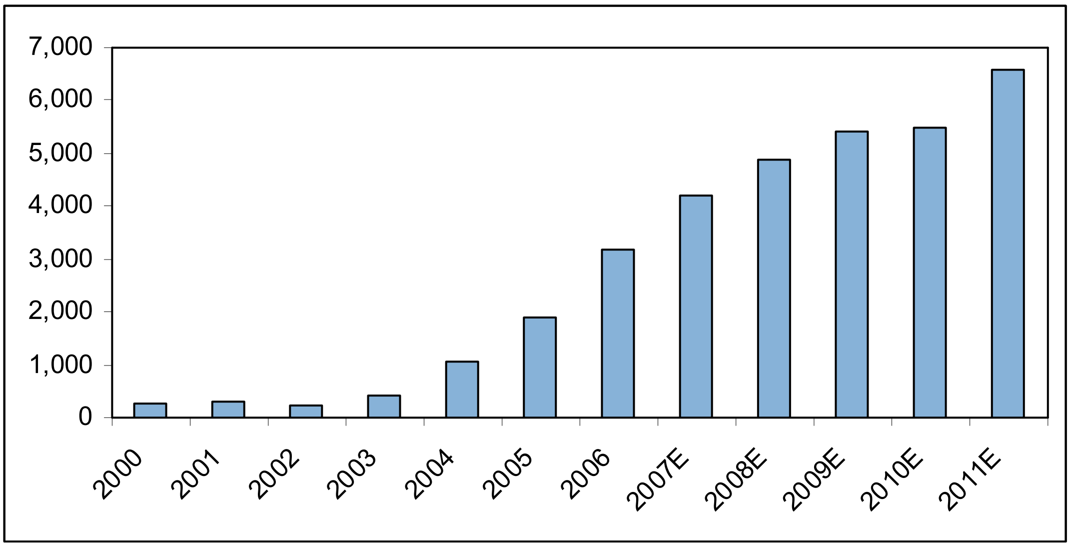


Source: Jefferies International Ltd.

New Markets Emerge

China and India are set to continue to increase in stature as annual installations in the two countries will double over the forecast period driven by renewable energy quotas and strong demand for new generation capacity (of any type) in both countries. China will quickly surpass India in annual installations and will increase its gap over the years as Indian installations level off at the 2400-2600MW range.

Chart 15: Chinese and Indian Combined Installation Forecast 2007-2011 (MW)



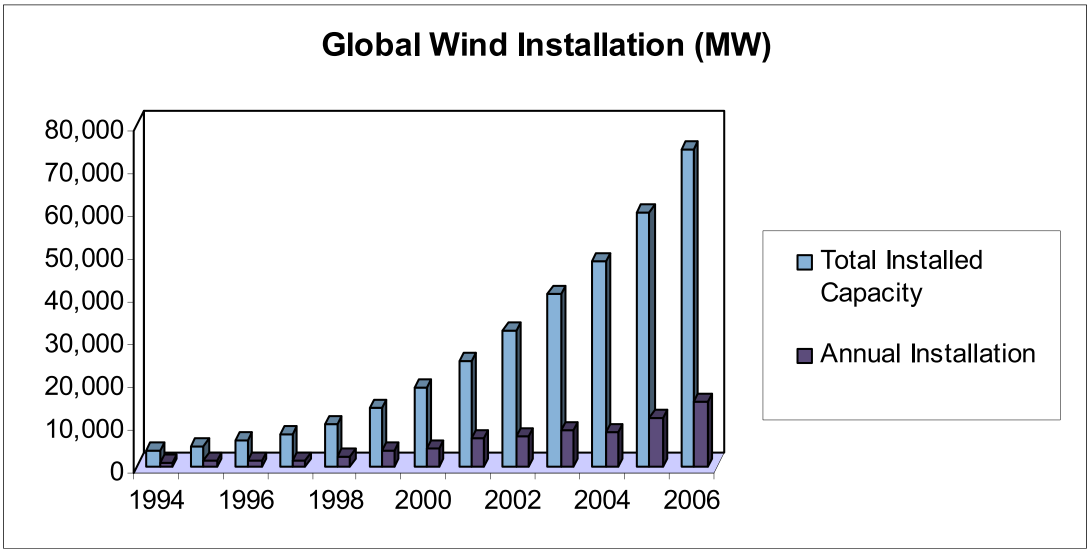
Source: BTM Consult.

Wind Market Background

The concept of harnessing the wind to provide energy has been around for centuries. Windmills first emerged in Persia in the seventh century and shortly thereafter appeared in both China and Europe. Early windmills clearly were not developed to reduce carbon emissions or offer peak shaving opportunities. Rather they were labor saving devices designed to grind grain into flour and free up human and/or animal labor for more productive pursuits. However, in more recent times, the potential to use wind power to generate electricity has been noted and exploited. Wind now represents the largest share of alternative energy generation and represents up to 7%-8% of electricity consumption in wind-intensive markets such as Germany and Spain.

The wind market emerged in the 1980s in both the US and Europe in response to the oil crisis of the 1970s, which led many countries to seek alternative sources of energy. However, it was not until the middle of the following decade that the modern wind industry began to emerge. As is shown in the table below, the global wind market has gone from strength to strength with cumulative installed capacity increasing by an average of 29% p.a., while annual installations have risen in nine out of the 10 years. Importantly, driven by strong global demand, both 2005 and 2006 were record years for installations.

Chart 16: Global Installations 1995-2006



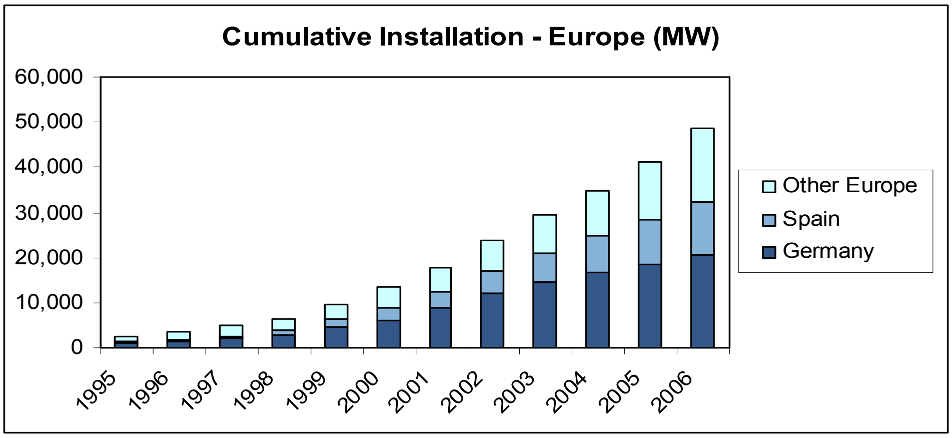
Source: BTM Consult.

Europe leads the way …

While the modern wind industry has its roots on both sides of the Atlantic, as for many other sources of alternative energy, it was Europe that quickly emerged as the global leader in wind powered generation. The chart below illustrates the huge lead Europe has established in the global wind market; it represented 70% of all wind installations in the 1995-2006 period.

The gap in installed capacity is not a result of a windier Continent. Indeed, the UK has some of the best wind potential in Europe while the American Midwest has been referred to as the "Saudi Arabia of Wind." The difference is the incentive programs that allow investors to earn an attractive return on wind projects. We will examine these incentive programs further in the *Incentives* section (next page).

Chart 17: European Wind Installations 1995-2006



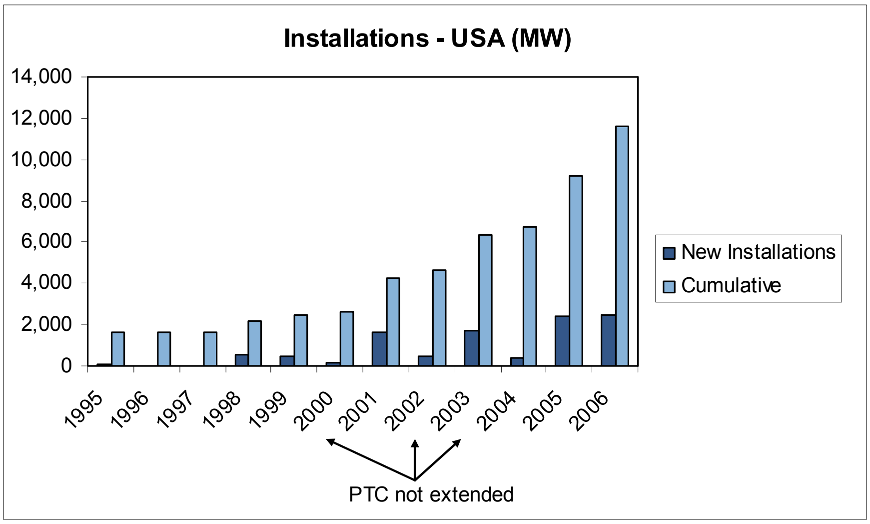
Source: BTM Consult.

… while the Americas are catching up

While the average growth rate of cumulative installed capacity is relatively strong, the lack of consistency has been a significant limiting factor. The volatile nature of annual installments is linked to the on-again off-again nature of the PTC. A reading of the chart below would indicate fairly clearly that the PTC has been granted in 1998-9, 2001, 2003, and 2005. However, the PTC has been extended through to YE2008 leading to record levels of installations in 2005 & 2006.

This lack of consistency has hurt the US market as many domestic WTG producers have been unwilling to invest in production and assembly facilities in the face of such uncertain demand. Currently, there is only one US company in the top 10 WTG producers.

Chart 18: U.S. Installations 1995-2006

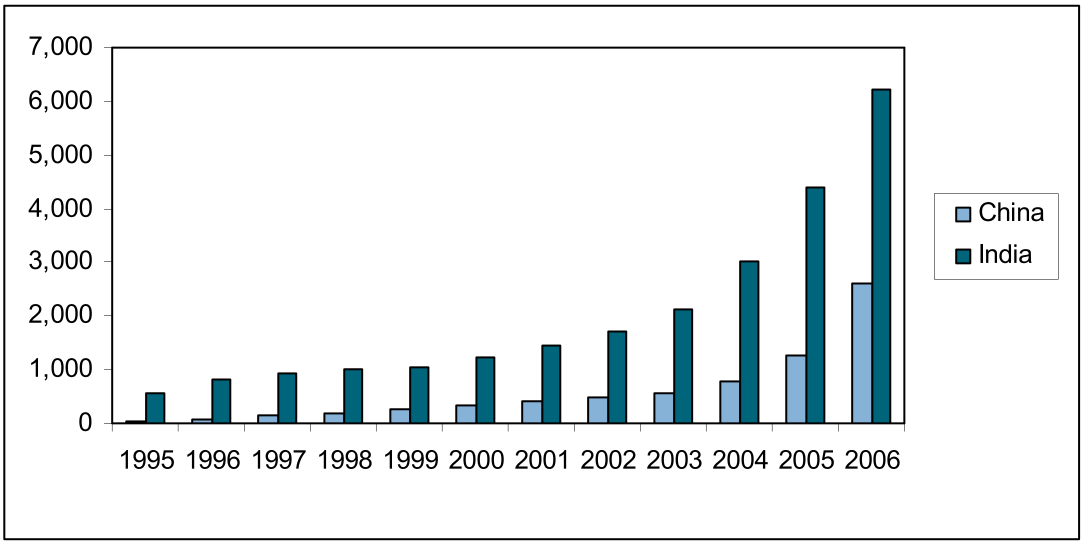


Source: BTM Consult.

Asia arrives

India and China have emerged as growing forces in the global wind market and currently represent 15.4% of installed global capacity by YE2006. While much of the developed world views wind as a clean source of energy, these countries suffer from power deficits and use wind both to reduce harmful emissions as well as to grow their installed base to meet rising demand.

Chart 19: Indian & Chinese Installations 1995-2006 (Cumulative MW)



Source: BTM Consult.

Incentive Programs

As previously mentioned, incentive programs rather than wind characteristics determine the growth of wind installations. WTG costs are higher than that of traditional fossil fuel burning plants, although this is compensated by the lack of fuel costs and, in some markets, benefits accrued to non-emitting sources of energy. However, like virtually all forms of alternative energy, wind power suffers from intermittency issues. In other words, the blades only turn when the wind is blowing and utilization ("capacity factor") is much lower than a traditional gas or coal burning plant. Thus a wind farm generally requires some form of incentive in order to generate an attractive financial return, *although rising energy prices mean that wind farms in advantageous locations can compete with fossil fuel fired wholesale electricity without any form of subsidy.*

Incentive programs vary from country to country and, within the US, from state to state. Given that the two largest wind markets in the world, Spain and Germany, both utilize a form of feed-in tariff guarantees, it would be logical to assume that this is the most effective catalyst for wind investment. We will discuss three primary forms of incentives:

- *Feed-in Tariffs*. Similar to the solar incentives, these tariffs guarantee that 100% of produced power will be purchased by the grid operator at a fixed or pre-agreed price. The structure of the tariff varies from country to country and can be set either as a fixed rate or as a premium over a pool price. Another key factor is the duration of the feed-in tariff agreement as the longer the wind farm operator can secure a guaranteed (and hopefully premium) price on the output, the better the return.
- *Renewable Portfolio Standards* (RPS). Federal or state governments can set hurdle rates for renewable generation as a percent of the total and levy fines for non-compliance. This has led to tradable Renewable Obligation Certificates (ROCs) in the United Kingdom, which allow producers of low-emission energy to receive a premium on their energy sales paid for by fossil fuel generators that have not met their renewable obligation.
- *Production Tax Credit* (PTC): The US. federal government will offer a $0.018 tax credit for every kWh of energy produced in the first 10 years of operation. This credit is due to expire in 2008.

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Table 1: Incentive Programs

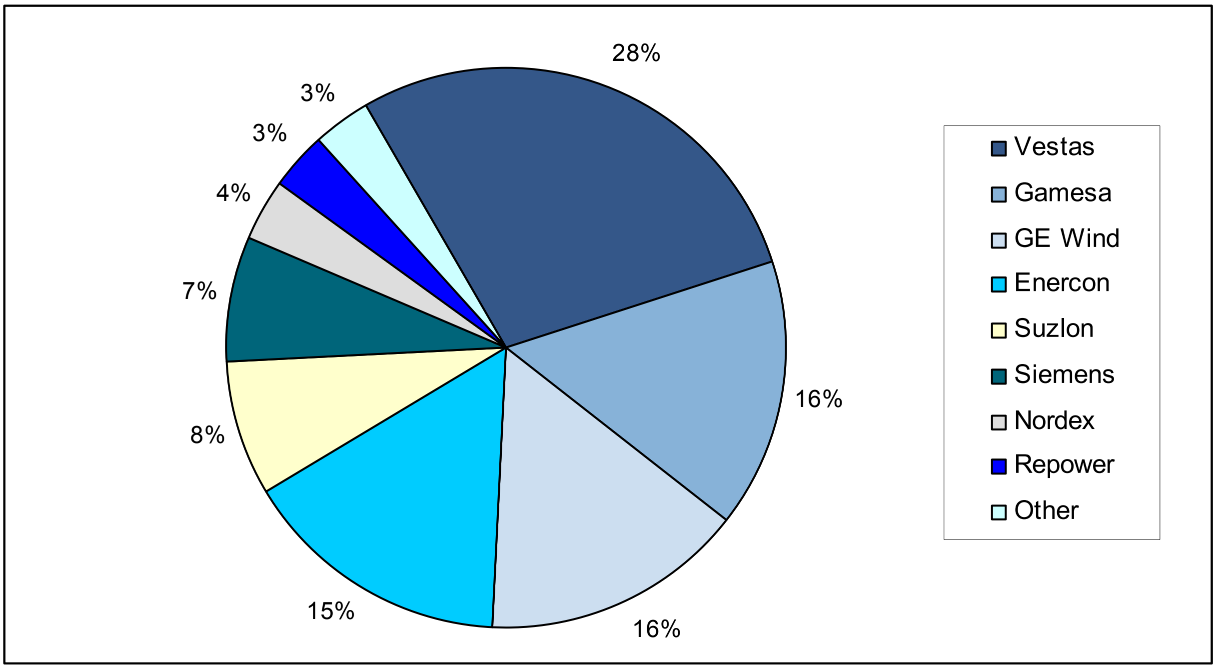
Country	Rate per kWh *Euro-cent*	Comments
Austria	**7.80**	For 13 years price per kWh EURct 7.8 on approved project. Price per kWh on new projects under consideration
Australia	**4.25**	The Renewable Energy Act in force since 2001 regulates the subsidies used to promote wind energy. Price at EURct 4.4 per kWh divided almost half & half between energy price and environmental bonus.
Belgium	**7.50**	The tariff consists of 5.0 EURct (fixed for 10 years) + 2.5 EURct (green certificate).
Czech Rep.	**8-10**	EURct 8.0-10.0 per kWh. There are two different payment schemes obtainable; one with a fixed price and another with a green subsidy component.
Denmark	**3.63**	Consists of price from NordPool spot market plus a 1.2 cent CO2 premium. Projects established by end 2002 (applying to the repowering scheme) are paid 8 cents for the first 12,000 full load hours. Under new repowering scheme payment is NordPool price plus 1.6 EURct per kWh. Special rates for offshore projects.
Estonia	**7.35-8**	There are 2 options: 1. To sell the electricity under 12-year contract on either market price of 2.6 EURct/kWh plus a premium of 5.4 EURct/kWh. 2. To sell the electricity under 12-year contract to Eesti Energia with a feed-in price of 7.35 EURct/kWh.
France	**8.36**	Rates for the initial 5 years, thereafter a reduction to 3.05 EURct per kWh in high-wind regimes over the following 10 years.
Germany	**8.8-9.1**	8.8 EURct per kWh onshore and 5.9 EURct per kWh offshore. Feed-in law as of July 2004. The rates will apply for the initial 5 years of operation and thereafter the overall feed-in rate will be adjusted to reference "energy values" for the respective location. Prices the initial 5 years at 8.36 EURct, thereafter 5.28 EURct per kWh. Poor wind site will prolong the higher rate. Offshore projects have for the initial 9 years 9.10 EURct, thereafter 6.19 EURct per kWh.
Greece	**6.61-8.17**	Rates differ by location. Mainland wind energy producers get 90% of the consumer price. Wind farms without grid access to mainland get 7.31 cents per kWh. A 40% grant of capital costs possible. Special rates available on the Greek Islands.
Ireland	**5.7-5.8**	Projects larger than 5MW get 5.7 EURct and smaller installations get 5.8 EURct. Tariffs on Ireland are index regulated. There is a 15-year contract period.
Italy	**18.50**	6 EURct per kWh electricity price. 12.5 EURct per kWh Green Certificate. Tariff for 2006 production was 14.94 EURct/kWh. REcnet plants now come under the new support scheme based on a compulsory RES quota and tradable green certificates granted to qualified RES plants over 12-year lifetime. Certificates relating to the 2006 production are trading at approx. 12.5 EURct/kWh, which adds to a wholesale price of electricity of about 6 EURct/Kwh.
Japan	**9.06**	Rates for projects realised in 2002 and 2003. Further subsidies up to 50% of the capital cost can be obtained for public companies and 33% for private companies.
Latvia	**2.50**	Tariff approx. 2.5 EURct as per pool price.
Lithuania	**6.30**	Tariff 6.3 EURct per kWh. Contract through year 2020.
Netherlands	**8.00-9.00**	Renewable energy producers receive this price due to strong consumer demand for green energy. RECS are imported from other European countries.
Norway	**5.00**	4.0 EURct per kWh Nordpool price plus 1.0 EURct as subsidy. It is considered that the investors will get a 15-year support. New feed-in price under consideration. Enova is the administrating body.
Poland	**9.00**	EURct 9.0 per kWh. The price consists of energy and a subsidy for a Green Certificate.
Portugal	**8.20**	First 2,000 full load hours get 8.2 cents. Thereafter 7 cents for the next 2,000 full load hours, thereafter a slight reduction in the payment rate. Regulation in force since late 2001.
Spain	**9.34**	EURct 9.34 per kWh variable. EURct 6.8929 per kWh as fixed. Rates are obtained adding a premium of 3.0635 EURct/kWh plus an incentive of 0.7659 EURct/kWh to the market price with a lump sum that averaged 9.34 EURct/kWh during 2006. Generators also have the option to get a full fixed price of 6.8929 EURct/kWh for their electricity. Spanish legal framework is currently under revision to reduce such high prices. New regulation expected within the first quarter of 2007.
Sweden	**7.60**	Onshore: 7.6 EURct, Offshore: 8.8 EURct. The compensation consists of the following main component: electricity payment per kWh 4.9.
UK	**7.4-7.89**	Quota system for all RES-E. Starting at 3% in 2003 up to 10.4% in 2010—there is a penalty for non-compliance at 3.51 £/kWh. Eligible RES-E are exempt from the Climate Change Levy certified by the Levy Exemption Certificates. These cannot be trade separated from the electricity. The levy tax is 0.43 £/kWh.
USA	**3.62**	PTC prolonged another 2 years until end of 2008. Renewable portfolio standards now in 18 states.

Source: BTM Consult ApS – March 2007

Wind Turbine Producer Market Shares

The WTG industry has witnessed a tremendous amount of consolidation through M&A activity over the past 10 years and has resulted in a market where the top five players control 86% of the market. Over time we have witnessed the emergence of GE Wind (a blend of Tacke GmbH, Zond Systems Corp. and Enron Wind) and Vestas. Vestas grew its market share substantially in 2004 with the acquisition of NEG Micron, which held a 10% market share in 2003.

Chart 20: WTG Market Shares - 2006



Source: BTM Consult

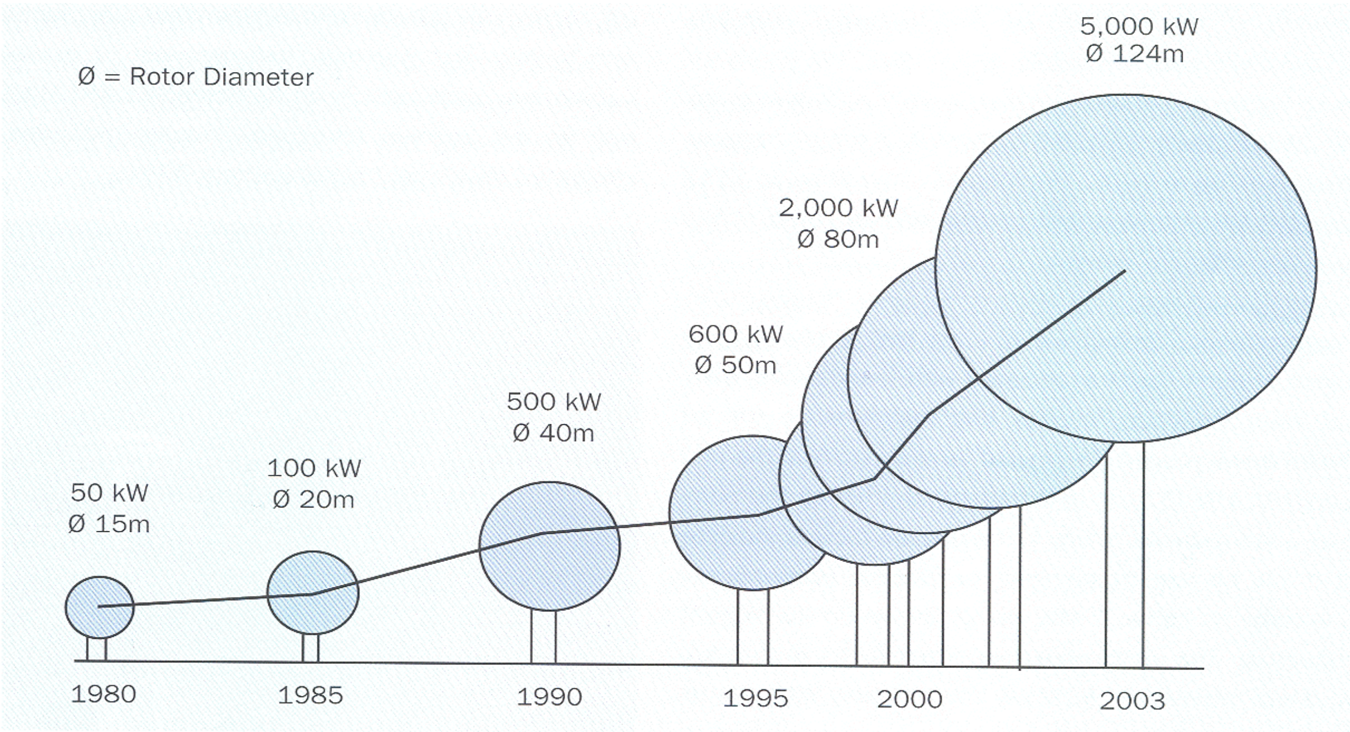
General Electric (GE, $41. 81, Hold) is the only US-based company amongst the top 5 (and top 10). This is a reflection Europe's traditional advantage in offering long-term incentives to the wind industry, which has led to growth in European production capacity. However, as the US market is considered to be poised for accelerating growth, many WTG producers are expanding capacity and opening production facilities in the United States.

Currently, market share is not an issue. The recent boom in demand for WTG, driven primarily by the return of the PTC in the US, has led to a significant backlog of orders at the turbine manufacturers. Many developers indicated a 12- to 24-month wait to receive their turbines and some prices have risen by as much as 20%. Additionally, payment terms are being shifted in favor of the turbine makers with higher down payments and final payments scheduled for delivery rather than installation or interconnection.

Wind Turbine Development

The wind turbine has changed quite a bit since the days that Don Quixote tried to run one through with a lance. These changes have continued in the modern area as producers strive to increase their efficiency and durability. The most obvious difference is size. As the figure below clearly illustrates, the WTG have increased dramatically in size and capacity over the past 25 years. This has allowed demand to shift from localized production, often driven by lack of grid access or environmental concerns, to large utility scale developments designed to feed the grid.

Figure 3: Wind Turbine Evolution



Source: BTM Consult.

Superficially, there are few significant differences between the design and performance of turbines produced by the major manufacturers. The most significant alternative solution is the gearless drive train offered by Enercon which allows higher reliability but at the cost of higher weight. Enercon also uses ultra-capacitors to drive blade pitch control which should, according to management, lower maintenance costs. In general, the product offering for the onshore market is fairly homogenous and producers have been focused on marginal reductions in operating costs through higher reliability and reducing COGS in an attempt to differentiate their products.

Reliability is a key component as component failure can lead to downtime, which can trigger financial penalties to WTG producers and/or high maintenance costs to wind farm operators. The need for sturdier machines is increased by the trend towards larger machines which, although they possess much better installed cost/MW output, do create increased stress loads on the equipment. As a rule of thumb, energy output increases as a square of the blade diameter while the load on the drive train increases as a cubed function of blade diameter. Furthermore, larger rotor diameter increases asymmetrical stress on the WTG as the force of the wind hitting the upturned blade is much higher than the force of the wind hitting the downward pointed blade(s).

WTG manufacturers have been addressing these issues in several areas.

- Blades can now be pitched (turned into the wind to reduce the exposed surface area) to reduce stress load on the tower and control blade speed.
- Blades are also now manufactured with carbon fibre which allows for lower rotor weights which reduces stress load on the gearbox and the tower. This can also help reduce cost.
- Variable speed systems allow turbines to operate at high efficiency over a wider range of wind speed as well as lower stress loads. This both dramatically increases the number of sites that can be exploited and it also reduces costs.

As a result of the increasing installation of utility scale wind farms, WTG manufacturers have also been asked to increase their grid compatibility to ensure a tighter integration with a grid principally designed to support traditional forms of generating capacity. This has forced producers to make certain that the wind developments ensure fault ride through capability (turbine does not trip from the grid during grid disruptions) and improved power control capability as the increasing weight of wind in the generation mix forces wind generators to perform certain grid stabilization operations normally carried out by traditional generators.

Although WTG has been around for quite some time now, barriers to entry remain relatively high. In the past 10 years the industry has consolidated around the top five players, and only Suzlon, which serves primarily the small-scale turbine market in India, has emerged as a credible international player although Goldwind in China may duplicate this success.

Offshore Wind

The offshore market offers great potential for growth as much of Europe's best wind resources are located on the coasts and Not in My Backyard (NIMBY) concerns are expected to be far less if the turbines are placed several miles off the coast and mostly out of sight. However, there are significant technical challenges related to the offshore market. The cost of installing an offshore turbine is estimated to be 50% higher than onshore and operating expenses are 100% higher. In order to make the economics work, offshore installations must receive privileged incentive programs or operate at potentially unrealistically high capacity factor.

Turbine manufacturers are currently working to develop truly massive scale (4-5 MW) turbines that would be too large for onshore application but which could deliver the economics for offshore work. However, as the turbines get larger, the stresses are greater.

As of YE2005, there were 679MW of operating offshore wind farms located primarily in the British Isles and off the coast of Denmark. Most of these operate in relatively shallow water where installation and operational costs are easier to control. We believe the challenge will be to develop deep water sites and that this market is unlikely to show significant growth for another three to four years.

Developing a Wind Farm

During our background research and channel checks, we spoke with several wind farm developers in the US and Europe in order to understand the mechanics and procedures involved in developing a wind farm. We believe it would be instructional if we summarize our findings and offer some insights we have gleaned. The following steps represent the progression from empty site to functioning wind farm:

1. *Secure the site.* Once a likely candidate site is located, the developer must first secure the rights to construct and operate a wind farm from the owner of the land. Generally speaking, the land owner is paid a (very) small percentage of sales to secure access.

2. *Test the site.* Wind speeds must be tested over a long period of time (12+ months is ideal) in order to ensure that there is sufficient wind to make a wind farm viable as well. Additionally, it can be beneficial to determine the time the wind blows as a site that blows at peak demand can usually obtain a better energy price than a site where the wind blows mostly at night.

3. *Project planning.* Assuming the wind test results are positive, the next step is to plan the project. Some key issues at this stage are ease of access to a grid interconnection and site access as these can have a significant impact on overall project cost. For example, your site may have excellent wind characteristics but if the road infrastructure is insufficient to support the heavy equipment necessary to build the site, you will face an additional cost.

4. *Secure planning permission*. This can often be the trickiest part as the developer has to seek permission from local authorities to construct the wind farm. Local authorities are often concerned about the potential protest from locals (NIMBY is a global phenomenon) concerned over the impact of wind turbines appearing near their homes. This issue is more significant in densely populated areas (England) and places of recognized natural beauty (Scotland).

5. *Secure a Power Purchase Agreement (PPA)*. Up to this point, the process is roughly similar regardless of location … that all changes now. As was illustrated in Table 1, there are a wide variety of incentive plans and an even wider variety of revenue arrangements. The PPA will be a function of the local incentive scheme plus the local tax regime. Interestingly, some developments in the US may not be seeking PPAs but may prefer to operate as a merchant generator selling into the open market. This is possible only when electricity prices and capacity factors are high and electricity can be produced below the cost of traditional sources.

6. *Finance the project*. Most wind farms are financed with non-recourse project financing with an equity ratio of 10%-20%. Interest rate levels clearly play a key role in determining the viability of a project. At this stage, companies may look to sell tax credit, emissions credit, or depreciation streams to offset the upfront cost.

7. *Secure the turbines*. Given the stop-start nature of incentives in the US, turbine component and assembly capacity expansion has been restrained. However, with rising energy prices globally and expectations that

the US will extend the PTC, order books at WTG producers are full and lead times are 12-24 months in many cases. A developer will often have to make a 5%-10% deposit on the cost of the turbine at this point.

8. *Construct the project*. Pretty straightforward although local infrastructure can slow construction. This is usually outsourced by the developers.

9. *Operate/sell the project*. There is a wide range of options here. Some operators simply construct the projects using their own or third-party turbines and sell them at pre-agreed prices on a turnkey basis while others choose to operate the projects for their own benefit. The key financial metric to look at here is cash flow IRR.

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