Deutsche Bank
Markets Research

Industry
Solar

Date
27 February 2015

North America
United States

Industrials
Clean Technology

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F.I.T.T. for investors

Crossing the Chasm

Solar Grid Parity in a Low Oil Price Era

Despite the recent drop in oil price, we expect solar electricity to become competitive with retail electricity in an increasing number of markets globally due to declining solar panel costs as well as improving financing and customer acquisition costs. Unsubsidized rooftop solar electricity costs between \$0.08-\$0.13/kWh, 30-40% below retail price of electricity in many markets globally. In markets heavily dependent on coal for electricity generation, the ratio of coal based wholesale electricity to solar electricity cost was 7:1 four years ago. This ratio is now less than 2:1 and could likely approach 1:1 over the next 12-18 months.

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Electricity Prices are Increasing, Despite Nat Gas Price Swings

Peak to trough, average monthly natural gas prices have decreased ~86% over the past 10 years. Yet, during this time period, average electricity prices have increased by ~20% in the US. The main driver for rising electricity bill is that T&D investments which represent 50% of bill have continued to ramp and have accelerated recently. In 2010, T&D capex levels of for US Utilities ~$27B were ~300% higher than 1981 levels. We expect electricity prices worldwide to double over the next 10-15 years making the case for solar grid parity even stronger.

Solar System Costs Could Continue to Decline

The economics of solar have improved significantly due to the reduction in solar panel costs, financing costs and balance of system costs. Overall solar system costs have declined at ~15% CAGR over the past 8 years and we expect another 40% cost reduction over the next 4-5 years. YieldCos have been a big driver in reducing the cost of capital and we expect emergence of international yieldcos to act as a significant catalyst in lowering the cost of solar power in emerging markets such as India.

How to Make Hay While the Sun Shines?

The solar sector has been generally under owned by institutional investors and we expect greater institutional ownership to drive positive momentum for the sector over the next 12-18 months. We expect a number of new business models focused on the downstream part of the value chain to emerge and expect innovative private companies to drive cost improvement/solar adoption. We believe companies involved in financing/downstream part of the value chain stand to generate the most significant shareholder value in the near term. Our top picks include SUNE, SCTY, SPWR, TSL, FSLR and VSLR.

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The New Dawn

We write this report because we think solar has now become an investable sector and over the next 5-10 years, we expect new business models to generate a significant amount of economic and shareholder value.

Looking back 8-10 years ago, the solar industry was in the primitive stages and mostly dependant on government subsidies. Most companies that came to the public market were manufacturing businesses earning above-average returns due to unsustainable government subsidies.

The global financial crisis which resulted in the demise of several solar companies was really a blessing in disguise. The financial crisis really acted as a catalyst that resulted in reduction of solar hardware costs. Emergence of innovative financing models by companies such as SolarCity and NRG really acted as the second catalyst for further reduction in solar financing costs.

As we look out over the next 5 years, we believe the industry is set to experience the final piece of cost reduction - customer acquisition costs for distributed generation are set to decline by more than half as customer awareness increases, soft costs come down and more supportive policies are announced.

While the outlook for small scale distributed solar generation looks promising, we remain equally optimistic over the prospects of commercial and utility scale solar markets. We believe utility scale solar demand is set to accelerate in both the US and emerging markets due to a combination of supportive policies and ongoing solar electricity cost reduction. We remain particularly optimistic over growth prospects in China, India, Middle East, South Africa and South America.

Several companies are working on improving the cost of energy storage and we expect significant progress on this front over the next 5 years. Solar plus storage is the next killer app that could significantly accelerate global solar penetration in our view. Solar is competitive in many markets globally today. But difficulty in accessing the grid and lack of net metering policies globally make the penetration of current technology relatively challenging despite attractive economics. We believe reduction in solar storage costs could act as a significant catalyst for global solar adoption, particularly in high electricity markets such as Europe.

While it is becoming increasingly clear that solar is now competitive with conventional electricity generation in many global markets, we believe there is still some policy uncertainty that could impact investor sentiment and overall supply/demand fundamentals. That said, we believe the dependence on subsidies has decreased significantly compared to a few years ago and demand drivers are also increasingly more diverse as well as sustainable. We expect solar sector's dependence on subsidies to gradually decrease over time, policy outlook to become more supportive and economics to take over politics over the next 3 years.

From a supply/demand stand point, we believe we are getting back to the pre-financial crisis era where "supply drove demand". Back then, most of the demand was created by financial investors that were chasing high returns in subsidized markets such as Italy, Germany, Spain and Czech Republic. Relatively attractive subsidies, easy access to financing and good project returns resulted in a strong rush in installations in many markets. We expect the emergence of yieldcos to result in a similar rush of capital chasing projects into the solar sector over the next few years. The only difference this time around is that 1) the amount of capital entering the solar sector could likely surpass the capital deployed prior to the financial crisis; 2) the purchasing power of this capital would be 2-3x greater than in the past as solar system costs have declined significantly and 3) the demand that would be created by this rush would be more diverse and sustainable (based on economics, not subsidies). More importantly, we believe majority of the module suppliers are now focused on deploying capital in downstream projects vs midstream/upstream manufacturing capacity. If the current demand momentum continues, we could potentially end up seeing some tightness across the value chain by end 2015 timeframe.

Yieldcos were the single biggest game changer for solar sector in 2014. Several successful yieldco IPOs raised capital from public equity markets in 2014 and lowered financing costs for developers. We expect successful IPOs of emerging market yieldcos to be an even more significant event for the solar sector in 2015. EM yieldcos have the potential to lower cost of capital for EM solar projects by 300-400 bps and reduce solar electricity costs by 3-4c/kWh, in our view. In markets such as India where solar electricity cost of ~12c/kWh is nearly competitive with coal at ~10c/kWh, EM yielcos could make solar even cheaper than coal and other forms of electricity generation. EM yieldcos come with a lot of risks - policy, currency, market risks to name a few. But if the equity markets are able to price some of the risks in valuation, the growth potential from these EM solar markets is enormous, in our view.

What happens beyond 2016 and what happens to yieldcos in a rising interest rate environment? These are some of the questions on the minds of investors. The ITC steps down from 30% to 10% in 2017 and the market (including us) is assuming this scenario plays out thereby impacting the growth of the US solar market. Having said that, we believe a number of other outcomes are possible. First, President Obama has proposed a permanent extension of the ITC and there is a small chance that this proposal goes through. Second, the industry association is lobbying hard to include a grandfathering clause in the ITC so that projects that start construction before end of 2016 can still get the ITC. Third, the industry is also proposing a gradual step down to 10% over multiple years and finally, we believe the inclusion of MLP status for renewables is also possible. All of these scenarios could turn out to be more favorable for the solar sector than the current scenario, in our view.

Finally, while interest rates could rise in the US, a globally coordinated rate increase is unlikely in our view. As long as the yieldcos are able to offset rising rates by finding incremental growth opportunities, we don't see a significant increase in yields. Moreover recent trading history of these vehicles suggest that investors view these stocks more like growth stocks as opposed to income stocks. Finally, a rising rate environment would likely mean a rising power price environment and as such we don't see any major impact on yieldco economics.

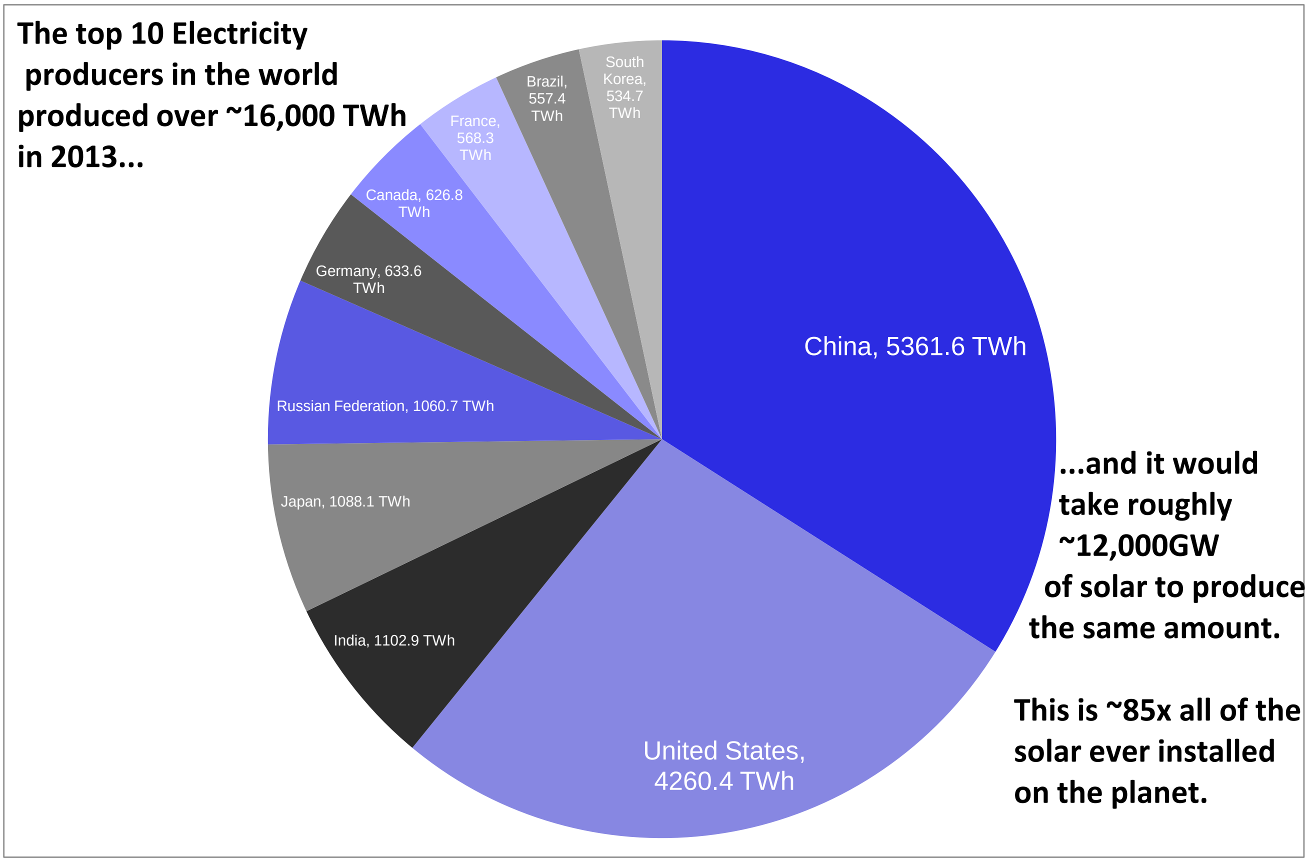
Solar Total Addressable Market is Massive

So how big could the solar market get? What is a reasonable medium term growth expectation? How about the near term growth outlook? Could our growth assumptions prove to be conservative? These are some of the commonly asked questions by investors. First, we believe if the entire global electricity generation were to be from solar, existing installed base (of solar) would need to be expanded by 120x. The top 10 electricity producing nations in the world generated over 16,000 TWh of electricity in 2013 and it would take roughly 12,000GW of solar to produce the same amount of electricity. Clearly, the total addressable market size is huge.

Despite the 30% CAGR over the past 20 years, the solar industry is still roughly 1% of the 6,000 GW or $2 trillion electricity market. Over the next 20 years, we expect the electricity market to double to $4 trillion and expect the solar industry to increase by a factor of 10. During this timeframe, the solar industry is expected to generate $5 trillion of cumulative revenue. By the year 2050, we expect global solar penetration rates to increase to 30%. We also see solar penetration rates increasing more rapidly in developing economies. India for example has recently announced targets to reach 100GW of solar capacity by 2022. Current installed generating capacity in India is ~280GW and the total installed generating capacity is estimated to reach 800GW by 2035. Assuming installed generating capacity reaches 400GW by 2022 timeframe, solar penetration would reach 25% of total capacity and nearly 60% of new installed capacity would be from solar sector. We believe the opportunity would be even bigger if companies start adding services to the solar PV offering and venture into adjacent markets such as wind and hydro.

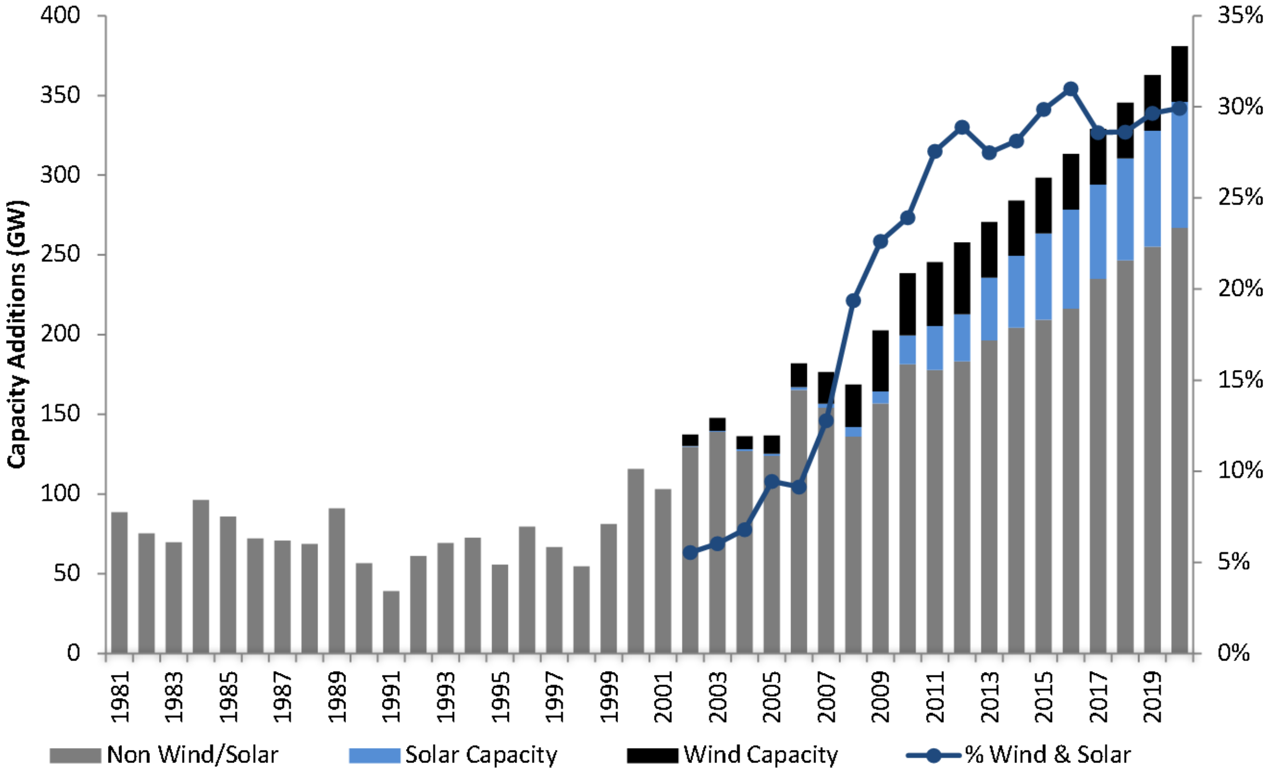
In the year 2000, solar was installed on roughly 100,000 homes and facilities. Over the last 15 years through 2015, solar has been installed on roughly 6 million homes and facilities. Nearly 200 GW of solar or roughly $900 billion of value was installed, but solar is still less than 1% of global electricity production. Over the next 20 years, we expect over 100 million new customers to deploy solar and roughly $4 trillion of value to be created during this timeframe. Over the next 20 years, we expect nearly 10% of global electricity production to come from solar. Bottom line: we believe the solar industry is going through fundamental change and the opportunity is bigger than it has ever been before.

Figure 1: The potential TAM for solar is huge.



Source:IEA, BP Statistical Review of World Energy:, 2014

Figure 2: Global Capacity Additions are Increasingly Wind and Solar



Source: EIA, GWEC, Deutsche Bank
Note: 5% growth rate in total capacity additions from 2012+. Wind Installs assumed flat at 5 year average of 39.5GW . Solar Installs are DB ests

What gives us confidence in our above assumptions of solar penetration rates? First, we believe electricity prices worldwide are set to double over the next 10-15 years. Second, we believe the cost of solar has decreased significantly over the past few years and this trend could continue for the foreseeable future. In the next two sections of the report, we go into these points in more detail.

Grid Parity is Here

Over 50% of Countries Under Review are Likely at Grid Parity Today

As we highlight in the next few sections of this report, roughly 30 countries are currently at grid parity out of our sample size of over 60 countries under review. In many of these markets, solar system costs vary from ~$1/W at the low end (for utility scale applications in India/China) to ~$2.90/W (for small resi installations in the US). In most cases however, the levelized cost of solar electricity is below the cost of retail/wholesale electricity in these markets today.

Figure 3: Countries With Regions of Grid Parity – Data

Country	Grid Parity	Insolation (kWh/m2/year)	Cost of Electricity Comp ($/kWh)	LCOE	Solar Premium/ Discount	IRR (20 Year System)	IRR (30 Year System)
Australia	Yes	1833	$0.49	$0.15	-$0.35	4781.22%	4781.22%
Belgium	Yes	867	$0.32	$0.24	-$0.08	4.34%	9.38%
Brazil	Yes	1667	$0.37	$0.18	-$0.19	44.53%	44.63%
Chile	Yes	1750	$0.25	$0.12	-$0.14	28.95%	29.40%
Denmark	Yes	813	$0.44	$0.35	-$0.09	15.62%	17.51%
France	Yes	1083	$0.21	$0.16	-$0.05	1.23%	7.58%
Germany	Yes	958	$0.33	$0.19	-$0.15	14.56%	16.55%
Guyana	Yes	1667	$0.28	$0.12	-$0.16	35.27%	35.49%
Hungary	Yes	1042	$0.26	$0.24	-$0.02	3.13%	8.67%
Ireland	Yes	750	$0.31	$0.27	-$0.04	-2.23%	5.90%
Israel	Yes	1917	$0.16	$0.14	-$0.02	8.34%	12.00%
Italy	Yes	1292	$0.31	$0.14	-$0.17	27.48%	27.97%
Japan	Yes	1167	$0.28	$0.14	-$0.14	17.71%	19.11%
Mexico	Yes	1792	$0.20	$0.13	-$0.08	12.45%	15.09%
Netherlands	Yes	917	$0.32	$0.27	-$0.05	6.25%	10.59%
New Zealand	Yes	1167	$0.20	$0.18	-$0.03	-1.43%	6.26%
Papua New Guinea	Yes	1417	$0.30	$0.17	-$0.13	25.63%	26.28%
Peru	Yes	1667	$0.13	$0.12	-$0.01	-	4.46%
Philippines	Yes	1583	$0.34	$0.10	-$0.24	52.81%	52.84%
Portugal	Yes	1458	$0.28	$0.25	-$0.02	22.19%	23.14%
Singapore	Yes	1500	$0.22	$0.16	-$0.06	12.05%	14.69%
Spain	Yes	1500	$0.24	$0.14	-$0.10	16.08%	17.88%
Solomon Islands	Yes	1417	$0.87	$0.14	-$0.73	-	-
Sweden	Yes	833	$0.30	$0.29	$0.00	0.17%	7.04%
Tonga	Yes	1583	$0.63	$0.13	-$0.50	-	-
Turkey	Yes	1500	$0.14	$0.14	-$0.01	-	4.52%
USA Virgin Islands	Yes	1667	$0.56	$0.20	-$0.37	-	-
Vanuatu	Yes	1417	$0.60	$0.19	-$0.41	567.63%	567.63%
China	Yes vs High Electricity Price	1333	$0.11	$0.11	$0.00	-	-
Hong Kong	Yes vs High Electricity Price	1333	$0.25	$0.15	-$0.09	11.64%	14.38%
India	Yes vs High Electricity Price	1604	$0.12	$0.10	-$0.02	-	-
Iran	Yes vs High Electricity Price	1583	$0.21	$0.16	-$0.05	11.52%	14.29%
Jamaica	Yes vs High Electricity Price	1750	$0.18	$0.14	-$0.04	10.52%	13.55%
Jordan	Yes vs High Electricity Price	1917	$0.35	$0.13	-$0.22	113.17%	113.17%
Pakistan	Yes vs High Electricity Price	1833	$0.16	$0.13	-$0.03	6.75%	10.92%
South Africa	Yes vs High Electricity Price	1833	$0.17	$0.13	-$0.04	3.82%	9.15%
Taiwan	Yes vs High Electricity Price	1583	$0.18	$0.15	-$0.03	5.73%	10.25%
United States	Yes vs High Electricity Price	1400	$0.07-0.39	$0.17	-$0.01	-	-
Uruguay	Yes vs High Electricity Price	1500	$0.25	$0.17	-$0.08	18.03%	19.51%
Total Count	39						

Note: Calculations do not account for any subsidies current or future. Electricity Prices are estimated for residential consumers.

Source: Deutsche Bank Estimates

In the US, for instance, we believe solar is currently competitive in more than 14 states without any additional state subsidies. Solar LCOE in these states ranges between 10-15c/kWh and compares to retail electricity price of 12-38c/kWh. By 2016, using our cost estimates, nearly 47 states would be at grid parity in the US, in our view. Similarly in Japan, solar LCOE of ~$0.14/kWh compares to retail electricity price of ~$0.26/kWh. In India, the ratio of coal based electricity to solar electricity was 7:1 roughly 4 years ago. That ratio is now less than 2:1 and likely approaching 1:1 this year. The reduction of financing costs through yieldcos could act as a significant catalyst for the Indian solar market in our view. Another market at grid parity is Chile, where the electricity prices are high and solar resources are abundant. Chile's electricity use per capita increased at a 33% CAGR between 2000 and 2010 and growth is expected to continue. According to Chile's Energy Minister, power prices are expected to increase by 30% in the next 7 years. Current unsubsidized solar LCOE of $0.12-0.18/kWh is well below the electricity price of ~$0.25/kWh.

Mexico is also emerging as an attractive growth market for solar, especially after the 2014 energy reforms that now allow private companies to build and operate power plants. In most regions, retail customers pay the DAC rate of ~22c/kWh once consumption increases above 150kWh compared to solar LCOE of ~$0.13/kWh. Moreover, electricity prices in Mexico are increaseing at 8-10% per annum due to strong demand growth and high prices for imported natural gas. We expect this trend to significantly impact grid parity economics in Mexico.

In Philippines, there is no national grid and peak power is often generated from diesel. The generation cost of coal electricity is $0.12/kWh. On top of that, T&D costs another $0.14/kWh resulting in total electricity cost of $0.26/kWh. Solar electricity on the other hand costs only $0.10/kWh in the Philippines.

Finally, Italy is another example of market at grid parity. According to an industry survey published in Sept '14, about 700MW of unsubsidized solar was connected to the grid in 2013. The government recently increased the net metering threshold from 200KW to 500KW and solar with net metering is currently 30-40% cheaper than electricity generated using fossil fuels. Solar LCOE of large project (where net metering is not available) is less than €100/MWh compared to retail electricity price of €130-150/MWh. Grid parity in Italy has been possible because of a significant reduction in system costs. Cost of ground based systems is €0.8/W whereas cost of ~200KW system is ~€1.15/W. With this kind of cost profile, increased consumer awareness and greater availability of institutional financing, we expect the unsubsidized solar market in Italy to experience significant growth over the next 3-5 years.

Figure 4: Overview of Key Countries – Key Metrics

Country	LCOE Today			Solar + Storage		Cost of Financing		Electricity		Market Size (GW Capacity)		Solar Market Size (GW)	
	Today	2017	2020	Today	Future (2020)	Today	Future (2017-2020)	Price Today	CAGR	2011A	10-Year CAGR	2015	Future (2020)
United States	$0.19	$0.13	$0.11	$0.33	$0.13	7%		$0.18	3.3% (10 Yr)	1053	2%	12.00	12.78
China	$0.11	$0.10	$0.09	$0.25	$0.11	7%		$0.11		1100	12%	13.00	18.09
Japan	$0.14	$0.13	$0.11	$0.28	$0.13	4%		$0.28		287	1%	9.00	4.76
India	$0.10	$0.08	$0.08	$0.24	$0.09	12%	10%	$0.12		238	7%	2.00	4.92
Germany	$0.19	$0.17	$0.15	$0.33	$0.17	5%		$0.33	5.6% (6 yr)	160	3%	2.04	2.45
UK	$0.23	$0.20	$0.18	$0.37	$0.20	5%		$0.21	9.2% (6 yr)	93	2%	2.25	2.19
Mexico	$0.13	$0.10	$0.09	$0.27	$0.11	9%	7%	$0.20		62	4%	0.25	3.00
Philippines	$0.10	$0.09	$0.08	$0.24	$0.10	7%		$0.34		16	2%	0.50	1.20
France	$0.16	$0.15	$0.13	$0.31	$0.15	5%		$0.21	4.7% (6 yr)	130	1%	0.92	2.29
Chile	$0.12	$0.10	$0.09	$0.26	$0.11	7%		$0.25		18	6%	1.00	1.20
South Africa	$0.13	$0.11	$0.09	$0.27	$0.11	10%	8%	$0.17		44	1%	0.80	1.00
Australia	$0.15	$0.13	$0.11	$0.29	$0.13	6%		$0.49		62	3%	0.85	1.26
Brazil	$0.18	$0.14	$0.12	$0.32	$0.14	14%	11%	$0.37		119	5%	0.04	0.85
Canada	$0.18	$0.16	$0.14	$0.32	$0.16	5%		$0.13	5.2% (8 yr)	139	2%	0.59	0.59
Thailand	$0.13	$0.13	$0.13	$0.27	$0.14	7%		$0.11		49	5%	0.60	0.90
Saudi Arabia	$0.11	$0.10	$0.09	$0.25	$0.11	7%		$0.07		51	7%	0.30	5.00
Italy	$0.14	$0.12	$0.11	$0.28	$0.13	5%		$0.31	3.1% (6 yr)	118	5%	0.40	0.44
UAE	$0.12	$0.10	$0.09	$0.26	$0.11	7%		$0.08		26	12%	0.10	0.30
Jordan	$0.13	$0.11	$0.10	$0.27	$0.12	7%		$0.35		3	7%	0.15	0.30

*LCOE based on 5% yoy system cost reduction
*US Est based on our cost curve through 2017 then 5% declines to 2020

*Highlighted = grid parity with storage vs electricity price today. We est storage costs at ~14 cents/kWh today and ~2 Cents in ~5 years

*Electricity prices are averages of retail price and are high end of range in some markets

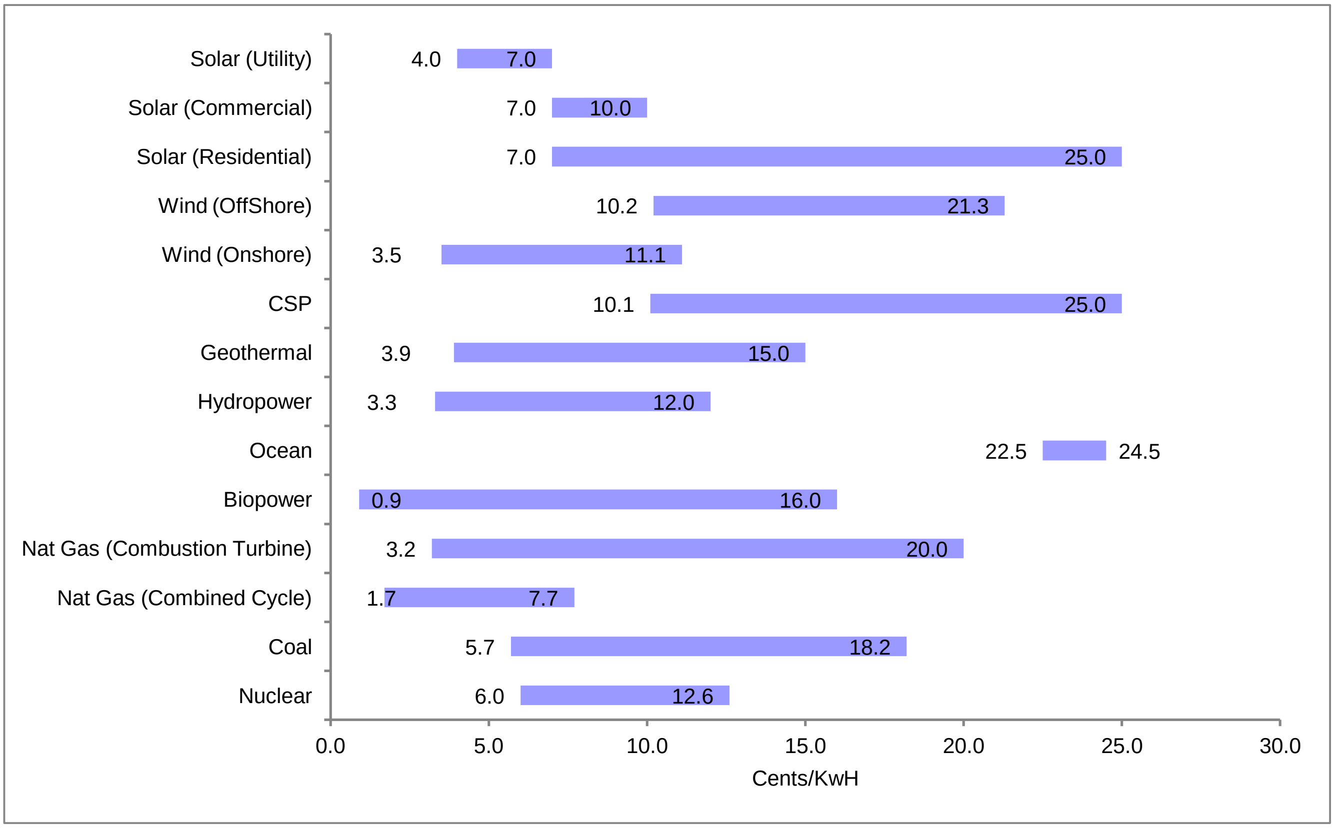
*Source: EIA

*Solar market size are DB ests

Source: Deutsche Bank, EIA

The figure below shows the cost of solar today versus other costs of electricity generation.

Figure 5: Solar Today Vs Other Forms of Utility Scale Electricity Generation (Cents/KwH)

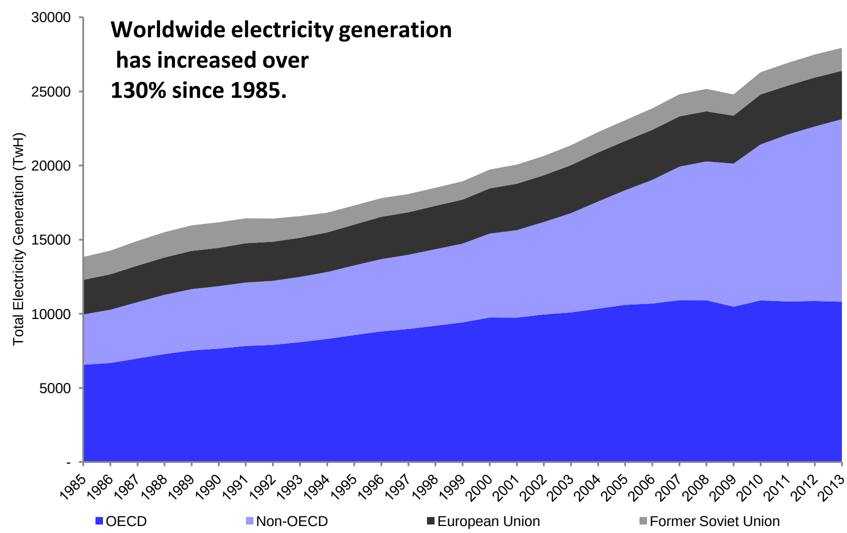


Source: Deutsche Bank, OpenEI Transparent Cost Database

Electricity: Capacity and Demand Increasing

Electricity Demand Growth Will Continue to Rise

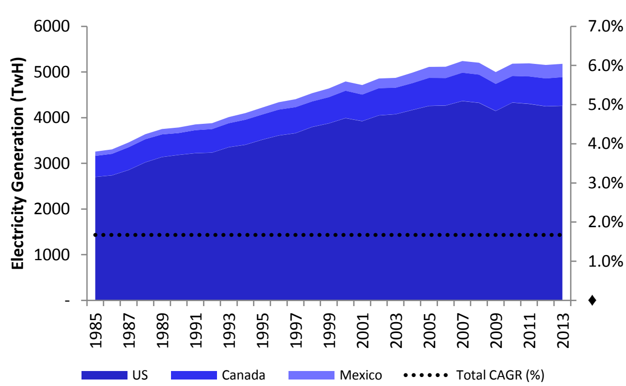
Figure 6: Electricity Use is Rising



Source: BP Statistical Review of World Energy 2014, Deutsche Bank

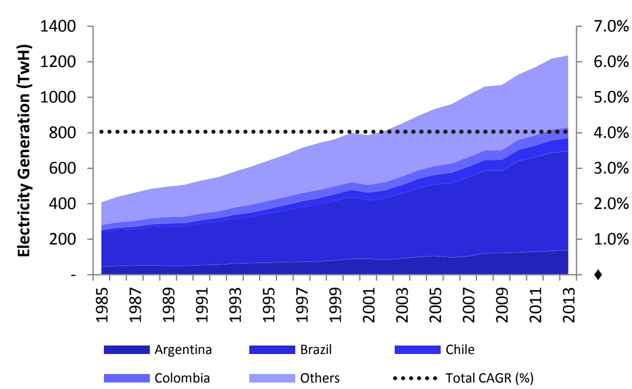
We continue to expect overall electricity demand to increase, despite energy efficiency measures. The Middle East and South/Central America in particular represent significant sources of growth in electricity demand with high quality solar resources. As these regions mature and costs come down further, the TAM will continue to expand.

Figure 7: TWh Used and CAGR (North America)



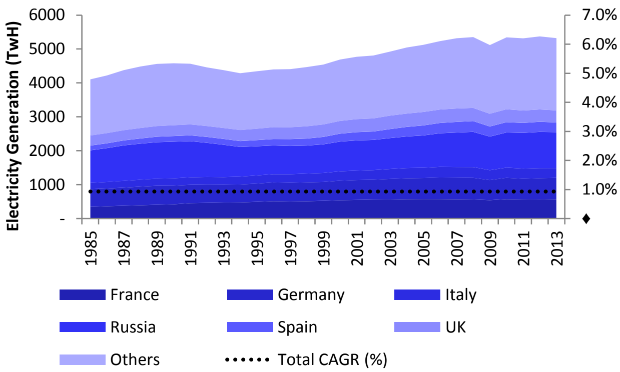
Source: BP Statistical Review of World Energy:, 2014, Deutsche Bank

Figure 8: TWh Used and CAGR (South/Central America)



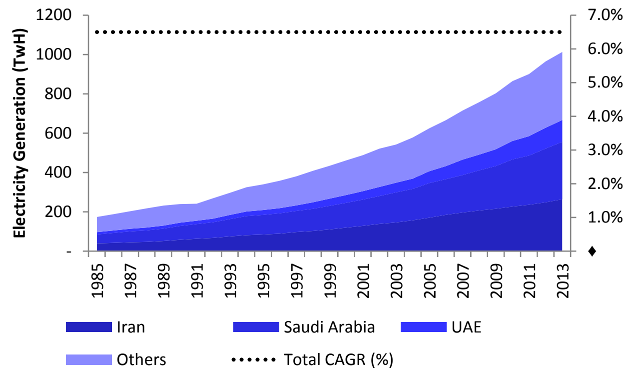
Source: BP Statistical Review of World Energy:, 2014, Deutsche Bank

Figure 9: TWh Used and CAGR (Europe/Eurasia)



Source: BP Statistical Review of World Energy:, 2014, Deutsche Bank

Figure 10: TWh Used and CAGR (Middle East)



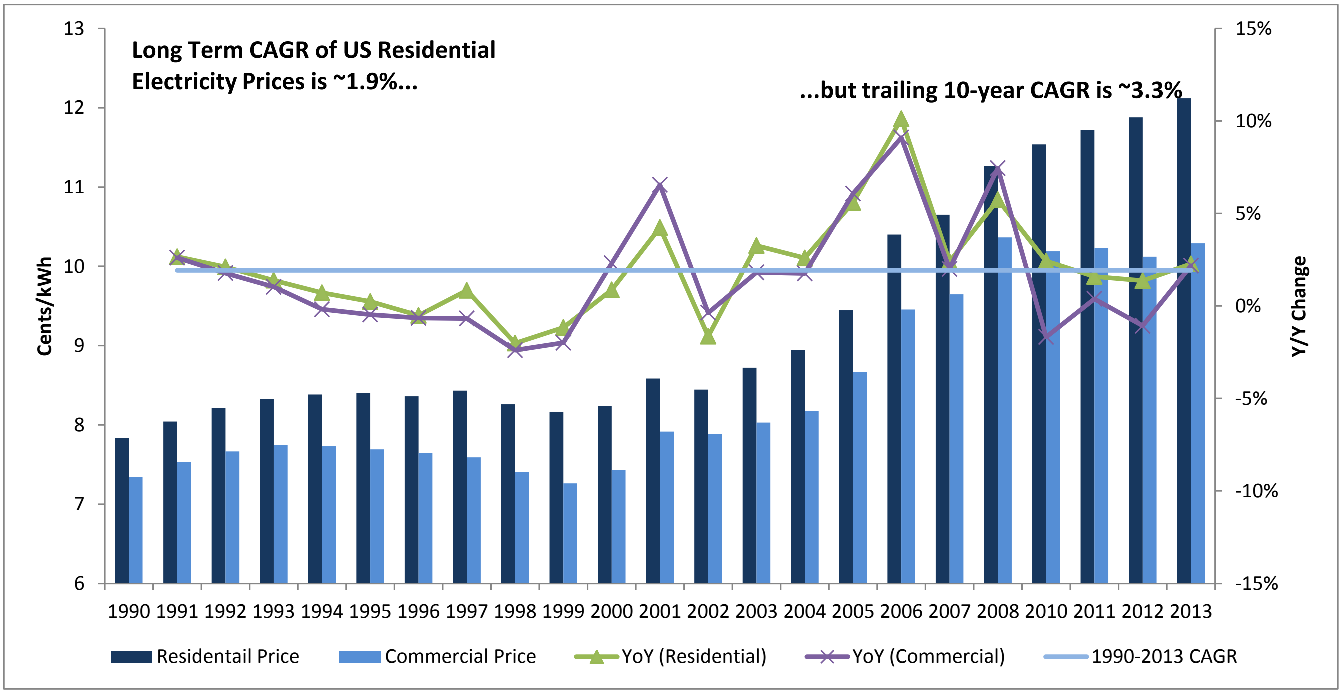
Source: BP Statistical Review of World Energy:, 2014, Deutsche Bank

Further, while policy incentives and regulatory framework will ultimately matter for any form of electricity generation, the real driver behind capacity additions generally is the need to replace old, inefficient generation and to meet incremental electricity needs. Even today, ~20% of the world's population does not have access to grid electricity. Due to declining costs and ability to deploy the technology without really developing the grid, we expect policy makers in developing countries to proactively promote solar.

Electricity Prices Will Continue to Rise

Our relatively bullish view on solar is based on the assumption that retail electricity prices will continue to rise over the next few years. As can be seen from the chart below, residential electricity prices in the US have consistently increased every year since 2002, and have only decreased (on a national blended basis) in 4 out of the last 24 years. We expect ongoing investment in transmission, distribution and utility scale generation to continue to fuel upward price momentum.

Figure 11: Electricity Prices Increase Consistently



Source: EIA, Deutsche Bank

Figure 12: Electricity Prices are Increasing (By State and Region)

cents/kWh Census Divisionand State	*LTM* Nov 2013-Oct 2014	2013	2012	*2012-2013* YoY
New England	17.67	16.23	15.74	3.1%
Connecticut	19.35	17.61	17.38	1.3%
Maine	15.13	14.41	14.72	-2.1%
Massachusetts	17.30	15.74	14.91	5.5%
New Hampshire	17.26	16.37	16.12	1.5%
Rhode Island	17.80	15.58	14.40	8.2%
Vermont	17.61	17.52	17.29	1.3%
Middle Atlantic	16.30	15.65	15.31	2.2%
New Jersey	15.71	15.64	15.77	-0.8%
New York	19.88	18.67	17.62	6.0%
Pennsylvania	13.33	12.82	12.83	-0.1%
East North Central	12.43	12.03	12.04	-0.1%
Illinois	11.19	10.39	11.48	-9.5%
Indiana	11.26	10.84	10.46	3.7%
Michigan	14.56	14.56	14.10	3.3%
Ohio	12.31	11.91	11.67	2.0%
Wisconsin	13.89	13.72	13.30	3.2%
West North Central	11.19	10.92	10.51	3.9%
Iowa	11.49	11.14	10.85	2.7%
Kansas	12.04	11.50	11.09	3.7%
Minnesota	12.16	11.91	11.37	4.7%
Missouri	10.63	10.47	9.97	5.0%
Nebraska	10.50	10.31	9.98	3.3%
North Dakota	9.65	9.35	9.22	1.4%
South Dakota	10.60	10.34	10.04	3.0%
South Atlantic	11.72	11.34	11.36	-0.1%
Delaware	13.41	13.13	13.64	-3.8%
District of Columbia	12.89	12.51	12.28	1.8%
Florida	11.87	11.39	11.55	-1.4%
Georgia	11.50	11.14	10.89	2.3%
Maryland	13.65	13.18	12.87	2.4%
North Carolina	11.21	10.91	10.85	0.5%
South Carolina	12.24	11.81	11.62	1.6%
Virginia	11.18	10.95	11.14	-1.8%
West Virginia	9.40	9.60	9.89	-2.9%

Source: EIA

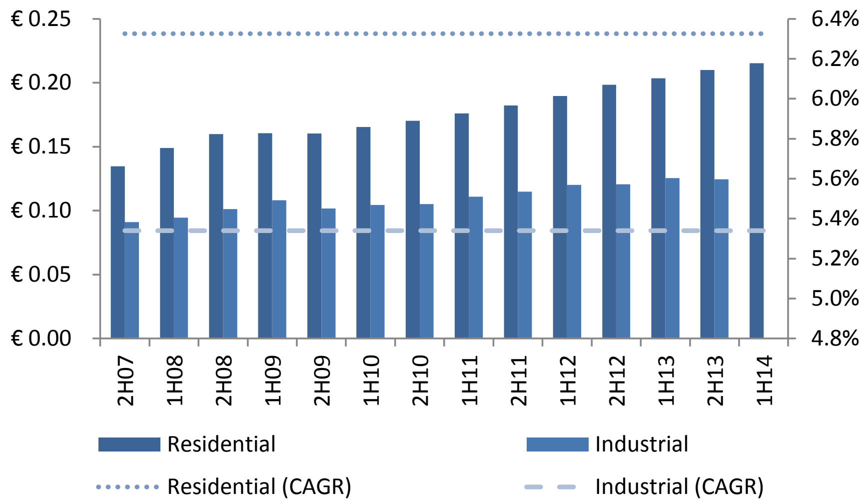
Figure 13: Electricity Prices are Increasing (By State and Region) Continued…

cents/kWh Census Divisionand State	2014	2013	2012	*2012-2013* YoY
East South Central	10.74	10.42	10.25	1.6%
Alabama	11.47	11.28	11.29	-0.1%
Kentucky	10.05	9.71	9.34	3.9%
Mississippi	11.34	10.75	10.23	5.0%
Tennessee	10.35	10.07	10.06	0.1%
West South Central	11.03	10.68	10.35	3.1%
Arkansas	9.54	9.49	9.27	2.4%
Louisiana	9.50	9.27	8.39	10.5%
Oklahoma	9.95	9.66	9.48	1.9%
Texas	11.74	11.32	11.08	2.2%
Mountain	11.61	11.22	10.83	3.6%
Arizona	11.82	11.56	11.10	4.2%
Colorado	12.16	11.81	11.33	4.2%
Idaho	9.76	9.27	8.49	9.2%
Montana	10.36	10.43	10.15	2.8%
Nevada	12.85	11.96	11.94	0.2%
New Mexico	12.15	11.59	11.31	2.5%
Utah	10.61	10.32	9.86	4.7%
Wyoming	10.56	10.24	9.93	3.2%
Pacific Contiguous	13.54	13.50	13.07	3.3%
California	16.06	16.15	15.48	4.3%
Oregon	10.43	9.95	9.88	0.7%
Washington	8.79	8.70	8.56	1.5%
Pacific Noncontiguous	29.51	28.52	28.84	-1.1%
Alaska	19.31	18.09	17.90	1.1%
Hawaii	37.70	36.94	37.29	-1.0%
U.S. Total	12.44	12.08	11.88	1.7%

Source: EIA

The same phenomenon is applicable in Europe as well. As can be seen from the chart below, residential and industrial electricity prices in Europe have increased at a CAGR of ~5% from 2H07 to 2H13 timeframe. Specifically, the average residential price in Europe has increased from €0.16/kWh in 2H07 to eur €0.22/kWh in 2H13 timeframe and industrial prices have increased from eur €0.10/kWh to eur €0.13/kWh.

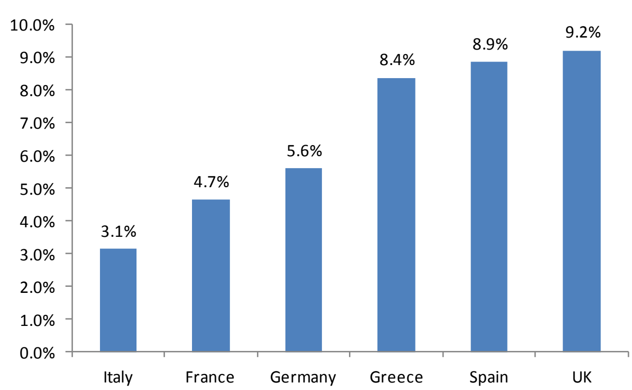
Figure 14: European Electricity Prices



Source: Eurostat, Deutsche Bank

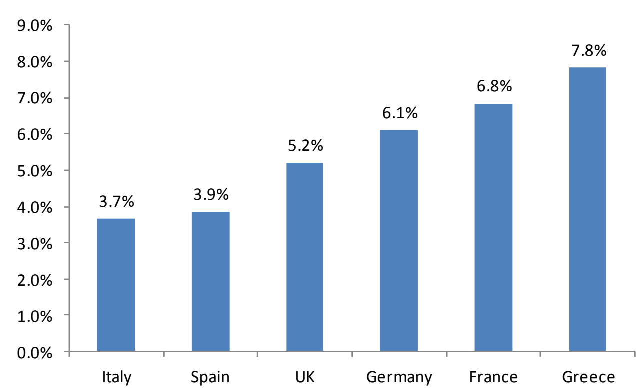
We also took a closer look at some of the key markets individually (Germany, Italy, France, Spain, UK, Greece) – and found that amongst them UK residential electricity prices increased the highest (CAGR of 9.2% over 1H08-1H14), followed by Spain (8.9%), Greece (8.4%), Germany (5.6%), France (4.7%) and Italy (3.1%). With respect to industrial electricity prices, Greece witnessed the most growth (CAGR of 7.8% over 2H07-2H13), followed by France (6.8%), Germany (6.1%), UK (5.2%), Spain (3.9%) and Italy (3.7%).

Figure 15: CAGR of Residential Electricity Prices



Source: Deutsche Bank, Eurostat
Note: Timeframe is 1H'08-1H'14

Figure 16: CAGR of Industrial Electricity Prices

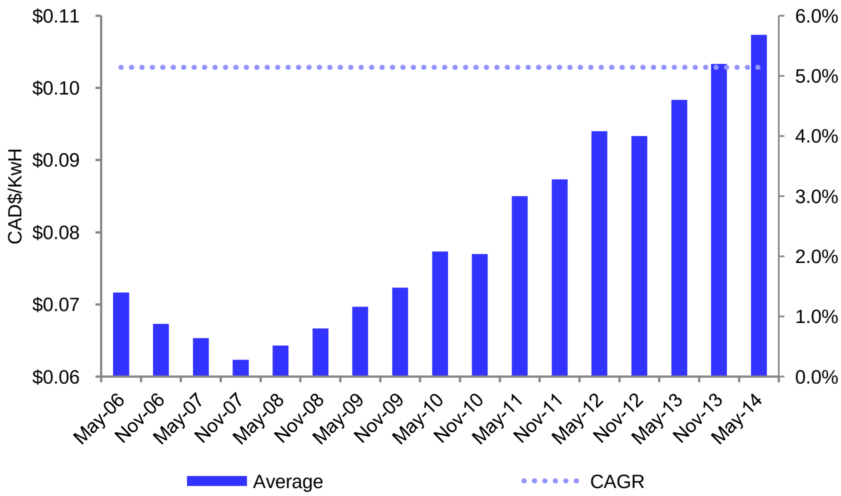


Source: Deutsche Bank, Eurostat
Note: Timeframe is 2H07-2H13

If electricity prices continue to increase at this pace, we believe many new markets in Europe are likely to achieve grid parity in the next few years.

We have identified another example of electricity price increases in Ontario, Canada. Average electricity prices have increased from C$0.07/kWh in May 2006 to C$0.11/kWh in May 2014 at a CAGR of ~5%.

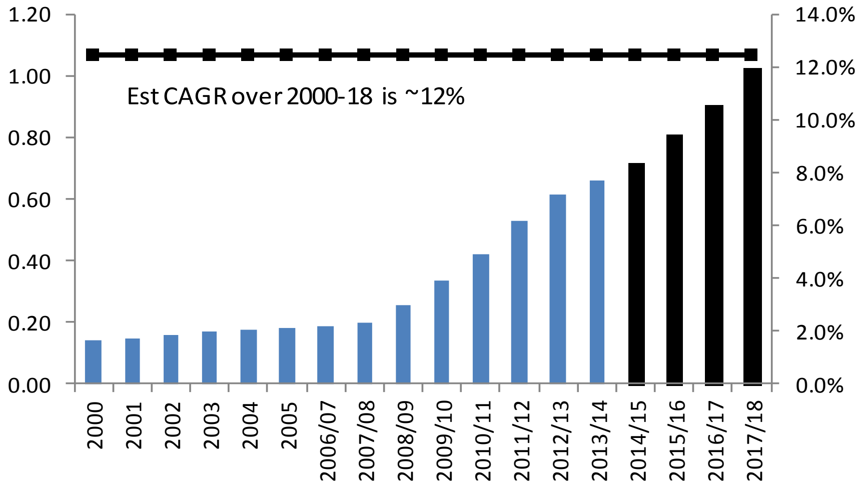
Figure 17: Ontario Electricity Prices



Source: Deutsche Bank, Ontario Energy Board

South Africa is another market that we believe has achieved residential grid parity for solar, but with rising grid prices, we expect grid parity over the next few years. We believe solar LCOE in the country is currently in the range of ~$0.13/kWh compared to avg. electricity price of ~$0.07-$0.17/kWh. We examined avg. electricity price trends since 2000, and found that prices have grown at a CAGR of ~13% through 2013/14 – from ~R0.14/kWh to ~R0.7/kWh. In Sep 2014, a committee of the country's energy regulator NERS recommended that Eskom (the state utility) under-recovered ~R7.8B of revenue in the previous tariff period, which could indicate that average tariffs could be set to increase by 12%+ through 2018 (NERSA had earlier granted 8% annual increase through 2018). If the recommendations are accepted, avg. electricity price in the country could go up to ~R1.02/kWh ($0.09/kWh). Given the expected rise in electricity prices, we expect solar to be increasingly competitive in the future.

Figure 18: South Africa Electricity Price (R/kWh)

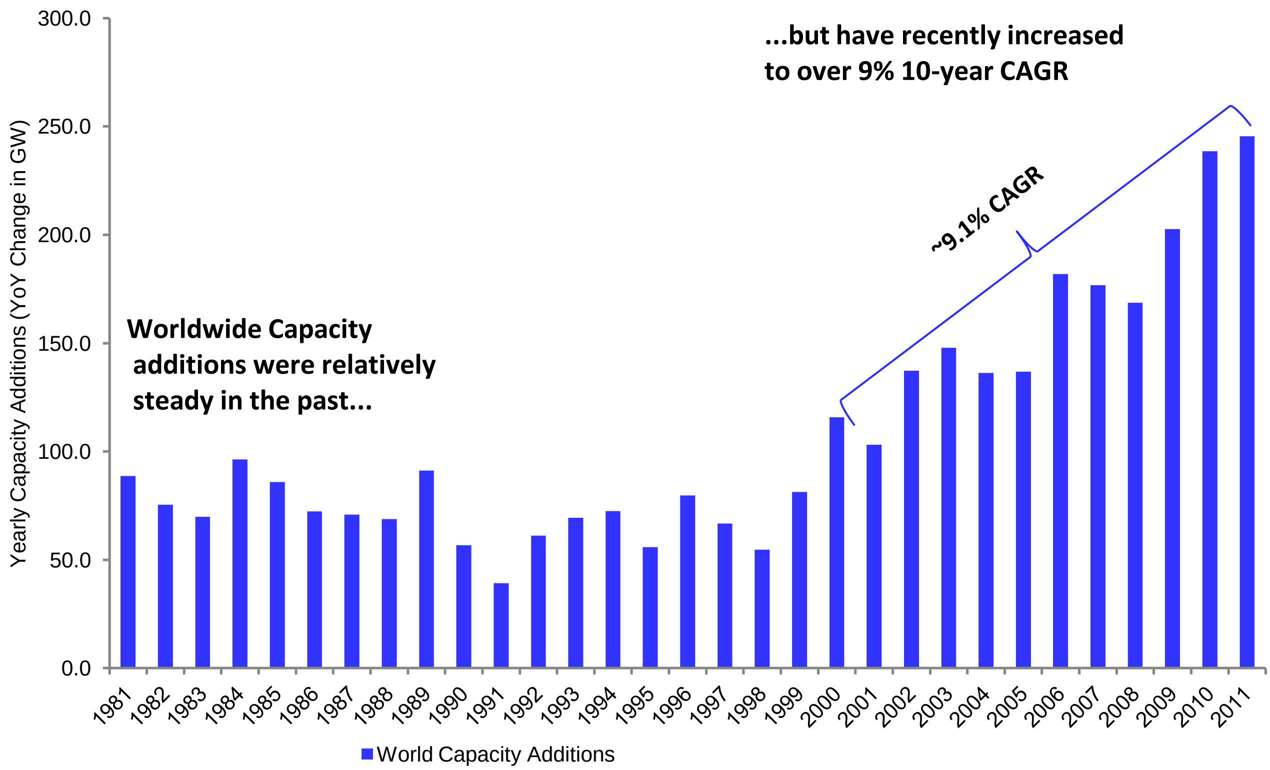


Source: Deutsche Bank

Emerging Markets Are Driving Capacity Needs

Why is the solar penetration story more interesting for emerging markets? First, global electricity capacity additions have been on a steady uptrend (achieving 9%+ CAGR over past 10 years), mainly due to growth of emerging markets. China alone has been adding ~75-100GW of capacity each year since 2005. While annual capacity additions will likely stabilize at some point, the recent data clearly indicates 200-300GW or more may be the new normal.

Figure 19: Worldwide Electricity Generating Capacity Additions



Source: IEA, Deutsche Bank

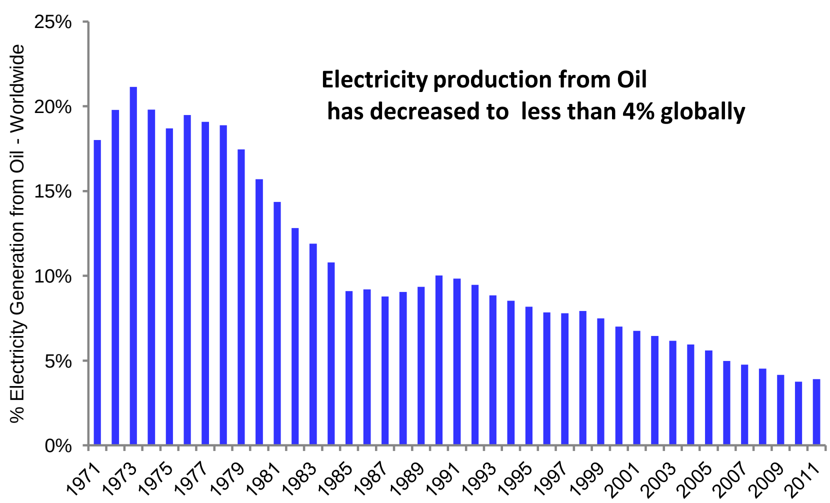
Solar Can Still Grow in Low Oil Price Era:

Worldwide Oil Use in Electricity Generation

Most Countries Generate Less than 5% of their Electricity From Oil

In aggregate, the world generates ~3.9% of electricity from oil. However, the US generates only 0.9% of electricity from oil and China generates even less – 0.17%.

Figure 20: Oil Use for Electricity Generation has Declined Substantially



Source: World Bank, 2011 Data

Furthermore, the majority of the countries which generate greater than 5% of their energy generation from oil are not expected to be notable solar markets. The only truly notable solar market where oil accounts for double digit (10%) percent of total generation is Japan. The Japanese solar market is largely influenced by constructive government policy and generates significant portions of total installs in non-utility scale solar (which is the only segment that would compete with oil fired generation).

Figure 21: Countries Generating >5% of Electricity from Oil

Count	Country	% Electricity from Oil	Greater than 500MW Market?	Count	Country	% Electricity from Oil	Greater than 500MW Market?
1	Malta	99%		29	Morocco	26%	
2	Eritrea	99%		30	Sudan	25%	
3	Benin	99%		31	Togo	24%	
4	Cyprus	96%		32	Indonesia	23%	
5	Lebanon	95%		33	Gabon	21%	
6	Jamaica	92%		34	Guatemala	19%	
7	Cambodia	90%		35	Singapore	18%	
8	Senegal	86%		36	Cameroon	18%	
9	Haiti	79%		37	Oman	18%	
10	Yemen, Rep.	78%		38	Mexico	16%	Yes - 2015
11	Jordan	73%		39	Nigeria	16%	
12	Nicaragua	66%		40	Egypt, Arab Rep.	16%	
13	Kuwait	62%		41	Argentina	15%	
14	Honduras	55%		42	Venezuela, RB	14%	
15	Sri Lanka	50%		43	Iraq	13%	
16	Dominican Republic	48%		44	Japan	10%	Yes - Current
17	Libya	44%		45	Greece	10%	
18	Cuba	43%		46	Chile	10%	
19	Panama	41%		47	Costa Rica	9%	
20	Syrian Arab Republic	40%		48	Malaysia	8%	
21	Pakistan	35%		49	Israel	7%	
22	El Salvador	34%		50	Croatia	7%	
23	Kenya	33%		51	Italy	7%	Previously
24	Ecuador	33%		52	Peru	6%	
25	Angola	29%		53	Algeria	5%	
26	Iran, Islamic Rep.	28%		54	Portugal	5%	
27	Uruguay	27%		55	Spain	5%	
28	Saudi Arabia	26%	Yes - 2016				
	World %	3.9%					

Source: Worldbank, 2011 Data

Cost of Oil Based Electricity Generation?

In order to examine our hypothesis that solar is not impacted by the price of oil, we ran an analysis to estimate the cost of electricity generated from oil.

Electricity Generation Cost From Oil as a Feedstock

While there are significant differences between all-in oil fired generation costs across the world, we believe that the actual cost of electricity from oil generation is significantly higher than electricity generated from solar in most instances.

According to the EIA, there are ~5.86MBTU in a barrel of oil, and a typical oil-fired electricity generating plant uses ~10,991 BTU to produce a single kilowatt hour of electricity. Therefore, at $50/barrel, the fuel cost alone to produce electricity is over 9 cents/kwh, and every $10 change affects the cost by ~2 cents/kwh.

Figure 22: Fuel Cost ONLY Per kWh generated from Oil

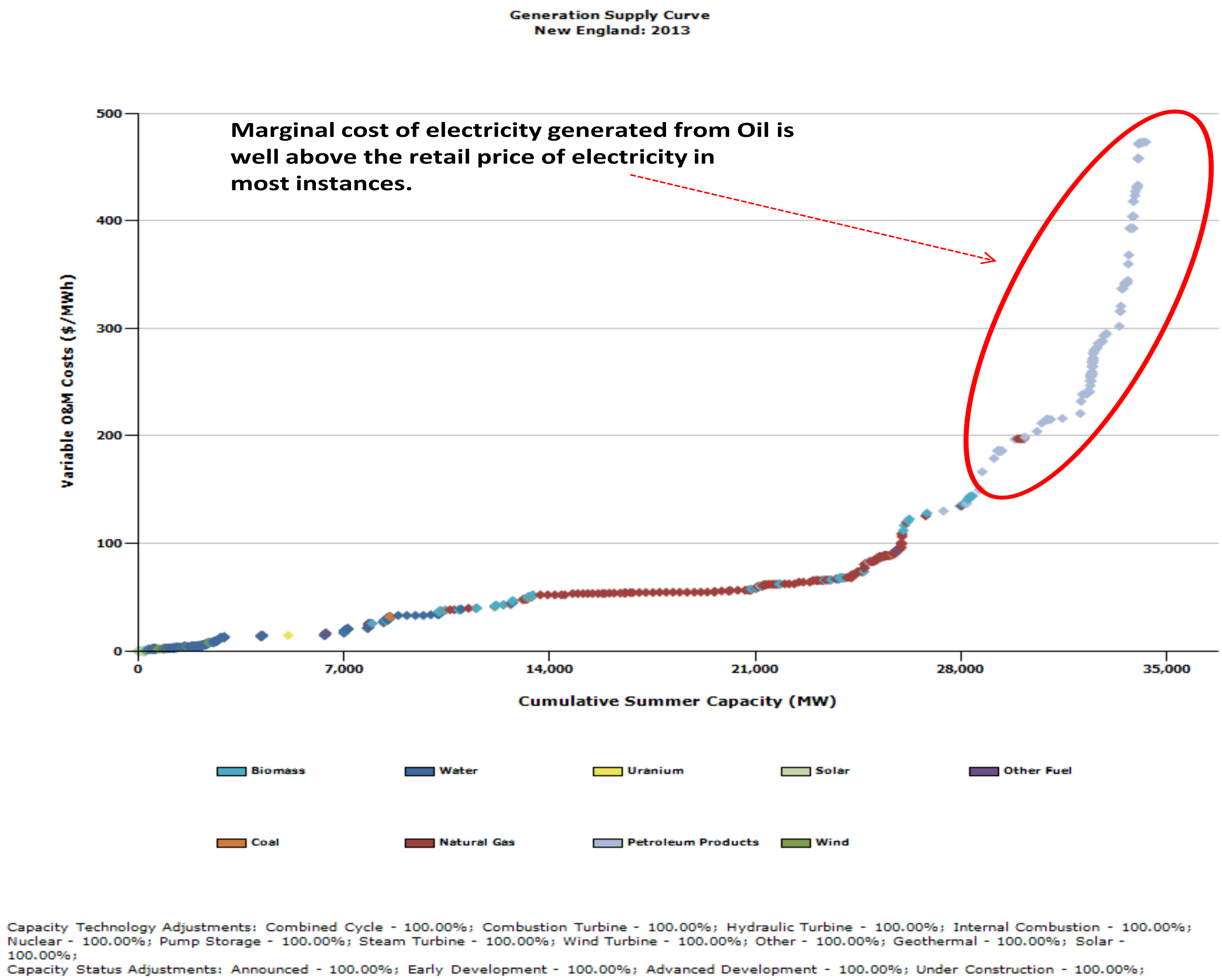
Cost/Barrel	Cost/kWh	Cost/Barrel	Cost/kWh
$30	$0.06	$80	$0.15
$40	$0.08	$90	$0.17
$50	$0.09	$100	$0.19
$60	$0.11	$110	$0.21
$70	$0.13	$120	$0.23

Source: EIA, Deutsche Bank

Actual Dispatch Curve in The US

Furthermore, even the above estimates drastically understate the actual incremental cost of electricity generated from oil. Shown below is the actual estimated supply curve in New England (in the United States) for capacity available during summer 2013.

Figure 23: Variable Cost of Electricity in New England



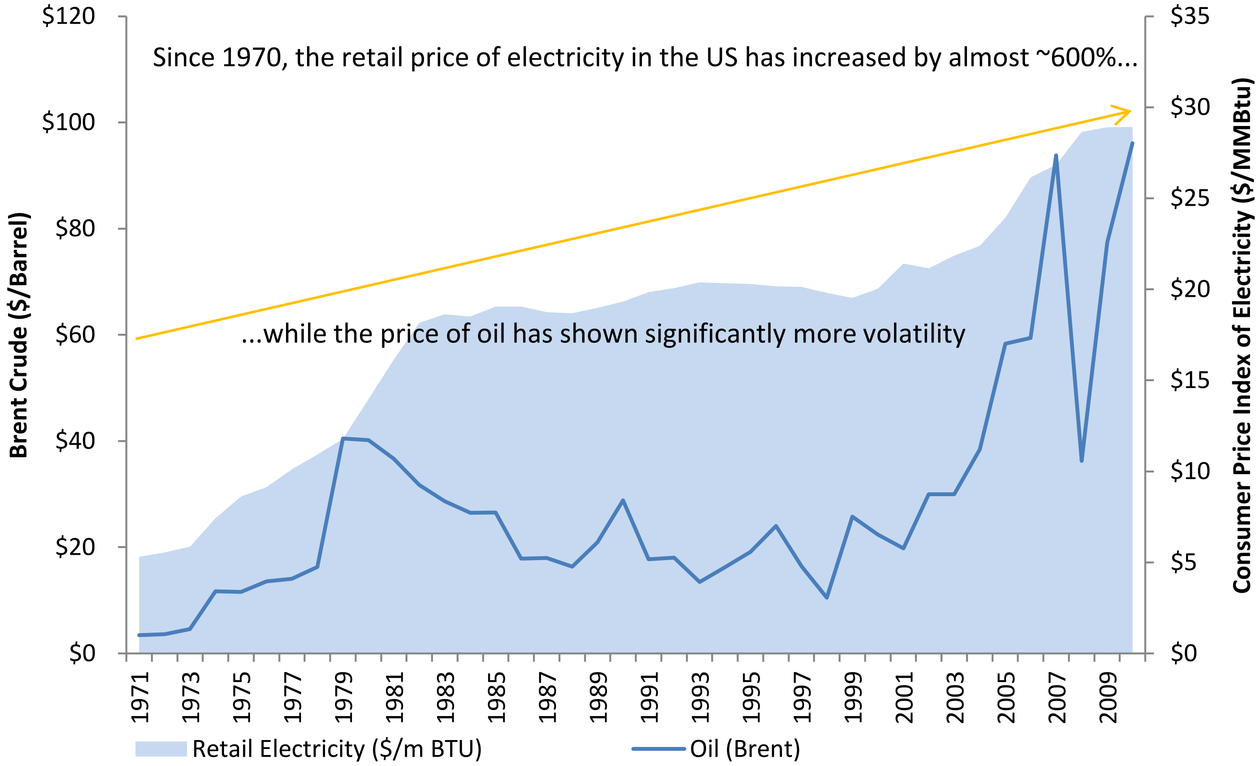
Source: SNL. Added text and emphasis from Deutsche Bank

This regional breakdown will generally hold true for most other regions as well, in our view. Each data point in the chart above is an estimate of the incremental cost of wholesale power. As shown above, oil fired generation cost typically ranges from ~10 cents per kWh to ~50 cents per kWh. With solar PPA's being signed at levels in the mid single digits (cents/kWh), the value proposition versus oil fired generation is compelling.

Long Term Relationship between Oil and Electricity

As shown below, the long term trend in the price of electricity is upwards, while the price of oil is much more volatile. If there were a fundamental basis for oil price changes affecting the price of electricity, the price of electricity should change much more.

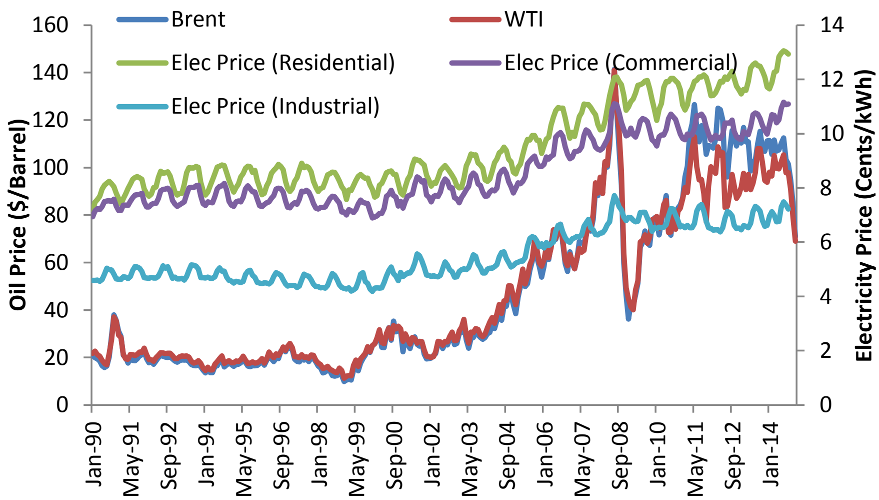
Figure 24: 40 Year Trend of Grid Sourced Electricity vs Oil Price



Source: EIA, Deutsche Bank

We view small scale, rooftop solar as one of the most attractive growth markets for solar installers, which also has clear a read-through for commercial and industrial segments (grid connected electricity prices for commercial and industrial customers is correlated with changes for residential customers).

Figure 25: Electricity Prices Across Consumer Segments Trend Together



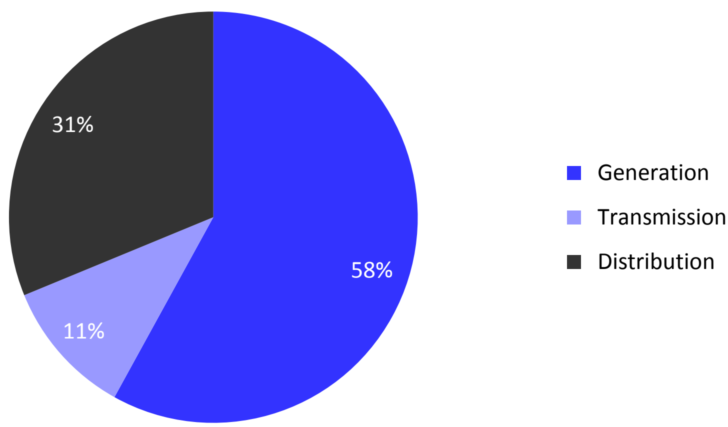
Source: EIA, Deutsche Bank

What Makes an Electricity Bill?

While much of the previous analysis has centered around generation costs from oil and all in electric costs, we note that over 40% of the average electric bill in the US can be attributed to transmission and distribution (T&D) costs. This is because the structure of most mature electric markets allow utilities to recoup costs for large upfront capital expenditures from transmission and distribution. This system has developed over the last century as the modern electric cost-recovery method.

Most investor owned regulated utilities are allowed to generate a regulated return over a multi-year timeframe. This system has facilitated grid build out across the US and other countries (although specific cost recovery mechanisms vary) as utilities are allowed to operate as a natural monopoly and are financially incentivized to build infrastructure (in the form of long term returns on upfront capital investment). Hence, the cost recovery for all necessary infrastructure – including but not limited to electric generation assets – necessitates the inclusion of T&D costs in the consumer's electric bill.

Figure 26: T&D Expense are a Significant Portion of Electric Bills



Source: EIA, Deutsche Bank

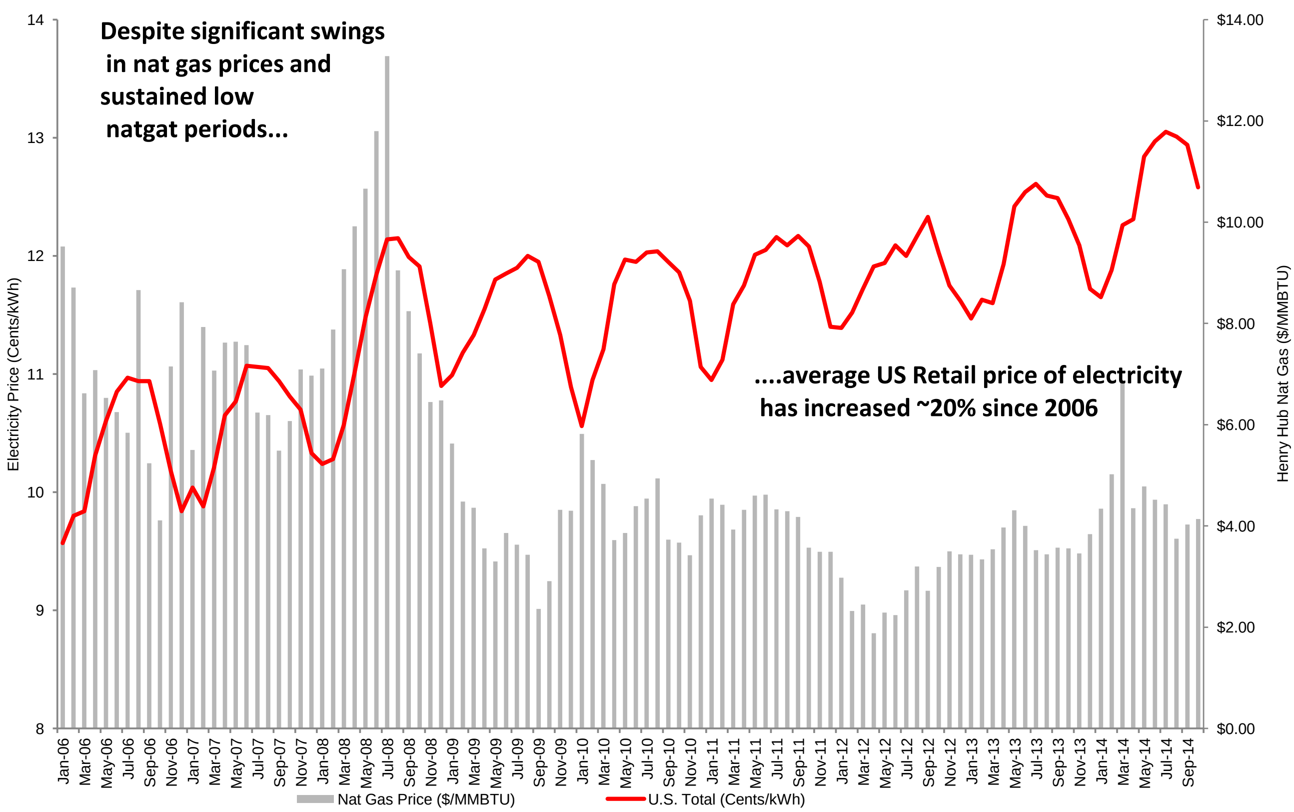
Therefore, even if feedstock for electricity generation were to decline substantially, transmission and distribution costs will continue to make up a large portion of an electric consumer's bill.

Forget Oil, Even Nat Gas Has Limited Impact on Retail Electricity Prices

Electricity Prices are Increasing, Despite Nat Gas Price Swings

As shown below, average US electricity prices are increasing (with average swings for seasonality) consistently over the last several years. In the first two years of the graph (2006-2008) Gas prices were generally above $6/MMBTU at the Henry Hub. Conversely, the most recent two years of data have yielded nat gas prices as low as sub-$2/MMBTU and generally below $4/MMBTU. Peak to trough, average monthly nat gas prices have decreased ~86% from $13.28/MMBTU (July 2008) to $1.88/MMBTU (April 2012). Yet, in this same time period between 2006 and 2015, average electricity prices increased ~20%.

Figure 27: Average US Retail Price of Electricity Continues to Increase



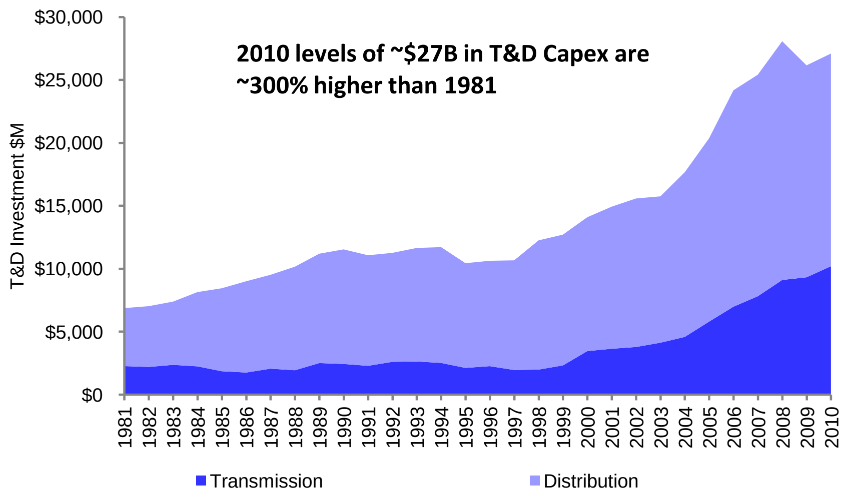
Source: EIA, Thomson Reuters

While there are regional variations on this theme and not every region or state has seen electricity price increases every year, the trend is clear and we believe natural gas prices are not the dominant factor in retail electricity prices.

T&D Capex is a Significant Driver of End-User Electricity Bills

In addition to compensating electricity providers for the electricity generation plants (through purchases of electricity), electricity bills are influenced by transmission and distribution spending. Over the last several decades, T&D levels have continued to ramp and accelerated recently. While rate of increase of incremental investment levels may slowdown, ongoing high investment levels will nonetheless increase the end-user electricity bills, as T&D components are generally a guaranteed cost recovery for utilities.

Figure 28: T&D Capex from US Utilities



Source: EIA

Electricity Prices Are Increasing

As shown in the following graphs the majority of states and regions have higher electricity prices.

Figure 29: Electricity Prices are Increasing (By Region)

Average Residential Electricity Prices 2013 vs 2012			
Region	**# States Increase**	**# States Decrease**	**% Increasing**
New England	5	1	83%
Middle Atlantic	1	2	33%
East North Central	4	1	80%
West North Central	7	0	100%
South Atlantic	5	4	56%
East South Central	3	1	75%
West South Central	4	0	100%
Mountain	8	0	100%
Pacific Contiguous	3	0	100%
Pacific Noncontiguous	1	1	50%
U.S. Total	**41**	**10**	**80%**

Average Residential Electricity Prices 2014 vs 2013			
Region	**# States Increase**	**# States Decrease**	**% Increasing**
New England	6	0	100%
Middle Atlantic	3	0	100%
East North Central	4	1	80%
West North Central	7	0	100%
South Atlantic	8	1	89%
East South Central	4	0	100%
West South Central	4	0	100%
Mountain	7	1	88%
Pacific Contiguous	2	1	67%
Pacific Noncontiguous	2	0	100%
U.S. Total	**47**	**4**	**92%**

Source: EIA

Figure 30: Electricity Prices are Increasing (By State and Region)

cents/kWh Census Divisionand State	*LTM* Nov 2013-Oct 2014	2013	2012	*2012-2013* YoY
New England	17.67	16.23	15.74	3.1%
Connecticut	19.35	17.61	17.38	1.3%
Maine	15.13	14.41	14.72	-2.1%
Massachusetts	17.30	15.74	14.91	5.5%
New Hampshire	17.26	16.37	16.12	1.5%
Rhode Island	17.80	15.58	14.40	8.2%
Vermont	17.61	17.52	17.29	1.3%
Middle Atlantic	16.30	15.65	15.31	2.2%
New Jersey	15.71	15.64	15.77	-0.8%
New York	19.88	18.67	17.62	6.0%
Pennsylvania	13.33	12.82	12.83	-0.1%
East North Central	12.43	12.03	12.04	-0.1%
Illinois	11.19	10.39	11.48	-9.5%
Indiana	11.26	10.84	10.46	3.7%
Michigan	14.56	14.56	14.10	3.3%
Ohio	12.31	11.91	11.67	2.0%
Wisconsin	13.89	13.72	13.30	3.2%
West North Central	11.19	10.92	10.51	3.9%
Iowa	11.49	11.14	10.85	2.7%
Kansas	12.04	11.50	11.09	3.7%
Minnesota	12.16	11.91	11.37	4.7%
Missouri	10.63	10.47	9.97	5.0%
Nebraska	10.50	10.31	9.98	3.3%
North Dakota	9.65	9.35	9.22	1.4%
South Dakota	10.60	10.34	10.04	3.0%
South Atlantic	11.72	11.34	11.36	-0.1%
Delaware	13.41	13.13	13.64	-3.8%
District of Columbia	12.89	12.51	12.28	1.8%
Florida	11.87	11.39	11.55	-1.4%
Georgia	11.50	11.14	10.89	2.3%
Maryland	13.65	13.18	12.87	2.4%
North Carolina	11.21	10.91	10.85	0.5%
South Carolina	12.24	11.81	11.62	1.6%
Virginia	11.18	10.95	11.14	-1.8%
West Virginia	9.40	9.60	9.89	-2.9%

Source: EIA

Figure 31: Electricity Prices are Increasing (By State and Region) Continued…

cents/kWh Census Divisionand State	2014	2013	2012	*2012-2013* YoY
East South Central	10.74	10.42	10.25	1.6%
Alabama	11.47	11.28	11.29	-0.1%
Kentucky	10.05	9.71	9.34	3.9%
Mississippi	11.34	10.75	10.23	5.0%
Tennessee	10.35	10.07	10.06	0.1%
West South Central	11.03	10.68	10.35	3.1%
Arkansas	9.54	9.49	9.27	2.4%
Louisiana	9.50	9.27	8.39	10.5%
Oklahoma	9.95	9.66	9.48	1.9%
Texas	11.74	11.32	11.08	2.2%
Mountain	11.61	11.22	10.83	3.6%
Arizona	11.82	11.56	11.10	4.2%
Colorado	12.16	11.81	11.33	4.2%
Idaho	9.76	9.27	8.49	9.2%
Montana	10.36	10.43	10.15	2.8%
Nevada	12.85	11.96	11.94	0.2%
New Mexico	12.15	11.59	11.31	2.5%
Utah	10.61	10.32	9.86	4.7%
Wyoming	10.56	10.24	9.93	3.2%
Pacific Contiguous	13.54	13.50	13.07	3.3%
California	16.06	16.15	15.48	4.3%
Oregon	10.43	9.95	9.88	0.7%
Washington	8.79	8.70	8.56	1.5%
Pacific Noncontiguous	29.51	28.52	28.84	-1.1%
Alaska	19.31	18.09	17.90	1.1%
Hawaii	37.70	36.94	37.29	-1.0%
U.S. Total	12.44	12.08	11.88	1.7%

Source: EIA

Solar "System" Costs Could Continue to Decline

Our constructive view on solar is largely dependent on the improving cost curve of the underlying technology. Overall solar system costs have declined at ~15% CAGR over the past 8 years and we expect 40% cost reduction over the next 4-5 years as a solar module costs continue to decline, panel efficiencies gradually improve, balance of system costs decline due to scale and competition, global financing costs decline due to development of new business models and customer acquisition costs decline as a result of increasing customer awareness and more seamless technology adoption enabled by storage solutions.

Where Are We Today: Our Take

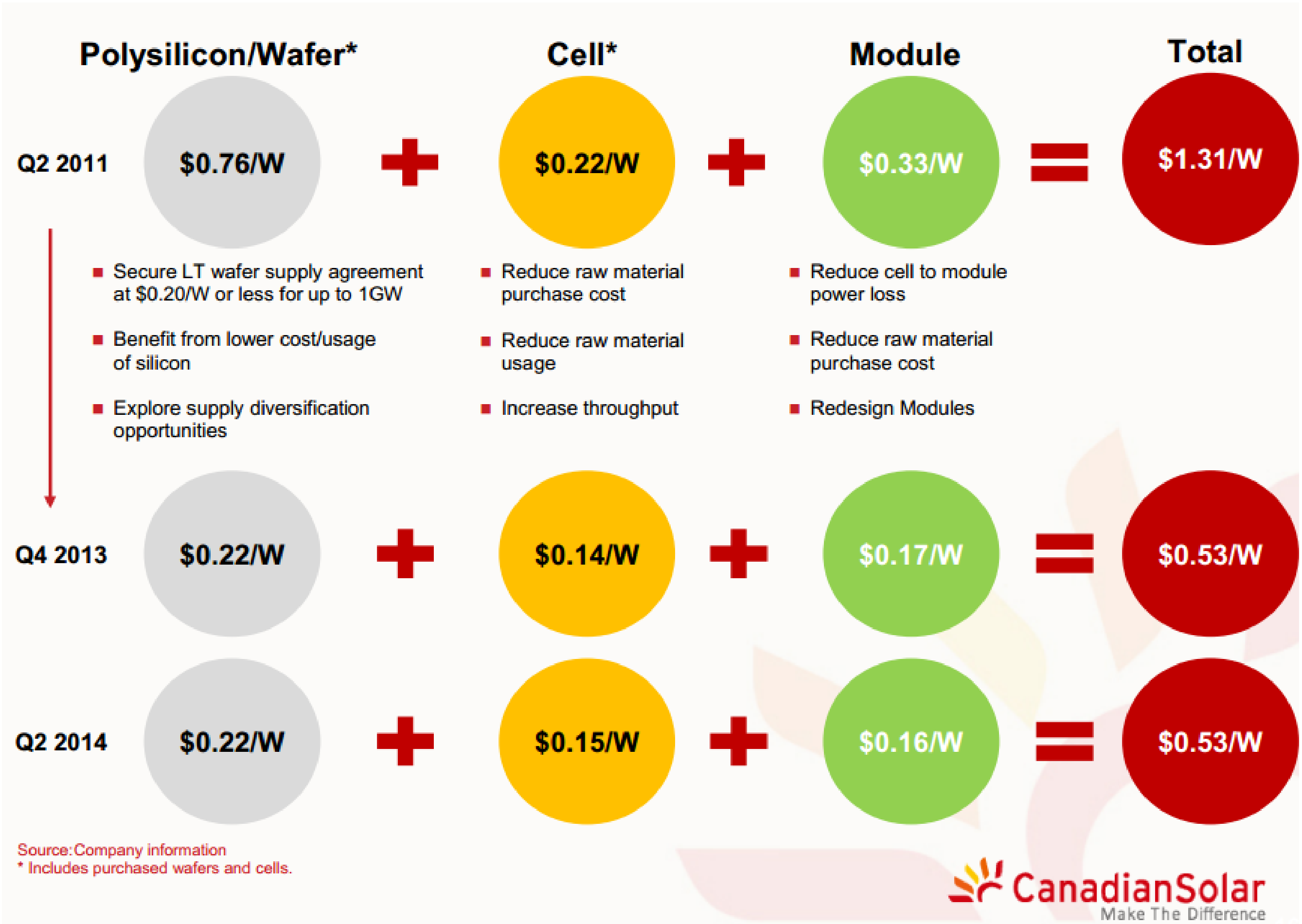
One of the most prevalent metrics for direct cost comparison is cost per watt, which we have estimated for various regions throughout the world.

While cost per watt is an appropriate measure to normalize cost comparisons, we note that economies of scale present in different segments/markets will skew cost per watt within regions. While some markets like the US and Japan will have a large portion of residential installations with less economies of scale, Utility scale or large DG markets like India and China will inherently achieve a lower cost per watt. Therefore, we have provided a starting point for analysis coupled with a scenario at different cost points in the previous section.

Module Cost of Production Today

As shown in the chart below, total module costs of leading Chinese solar companies have decreased from ~$1.31/W in 2011 to ~$0.53/W in 2014 primarily due to reduction in processing costs and polysilicon costs and improvement in conversion efficiencies.

Figure 32: Canadian Solar Cost Reduction History

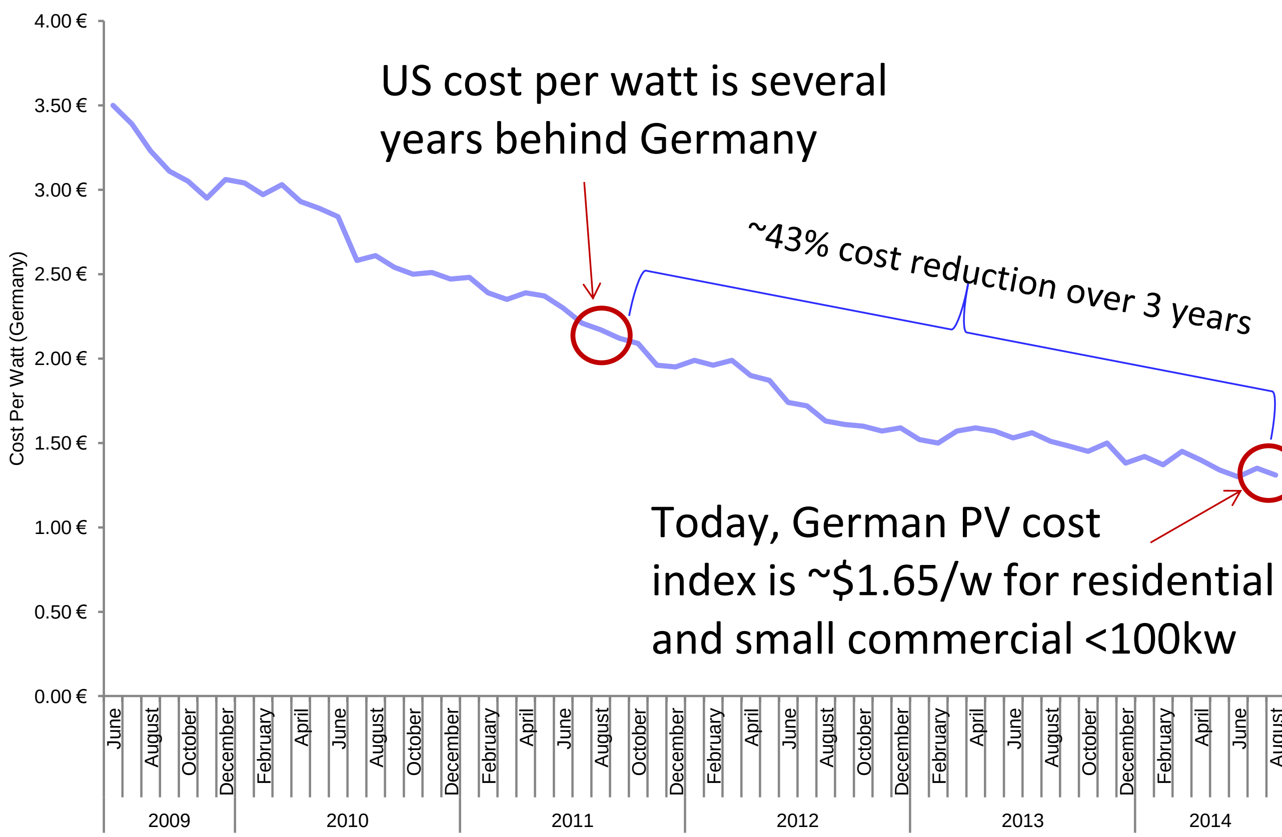


Source: Canadian Solar

We see total costs coming down 30-40% over the next several years

We think it is realistic to expect at least 30-40% reduction in cost per watt in key solar markets, while the greatest cost reductions are likely to come from the residential segments as scale and operating efficiencies improve. There is historical precedent for this in the oldest major solar market in the world – Germany. In fact, costs today are well below costs in the United States and other less mature markets.

Figure 33: German Cost Per Watt for Solar Arrays is Significantly Lower than other Markets



Source: Data sourced from www.photovoltaik-guide.de, Chart made by Deutsche Bank

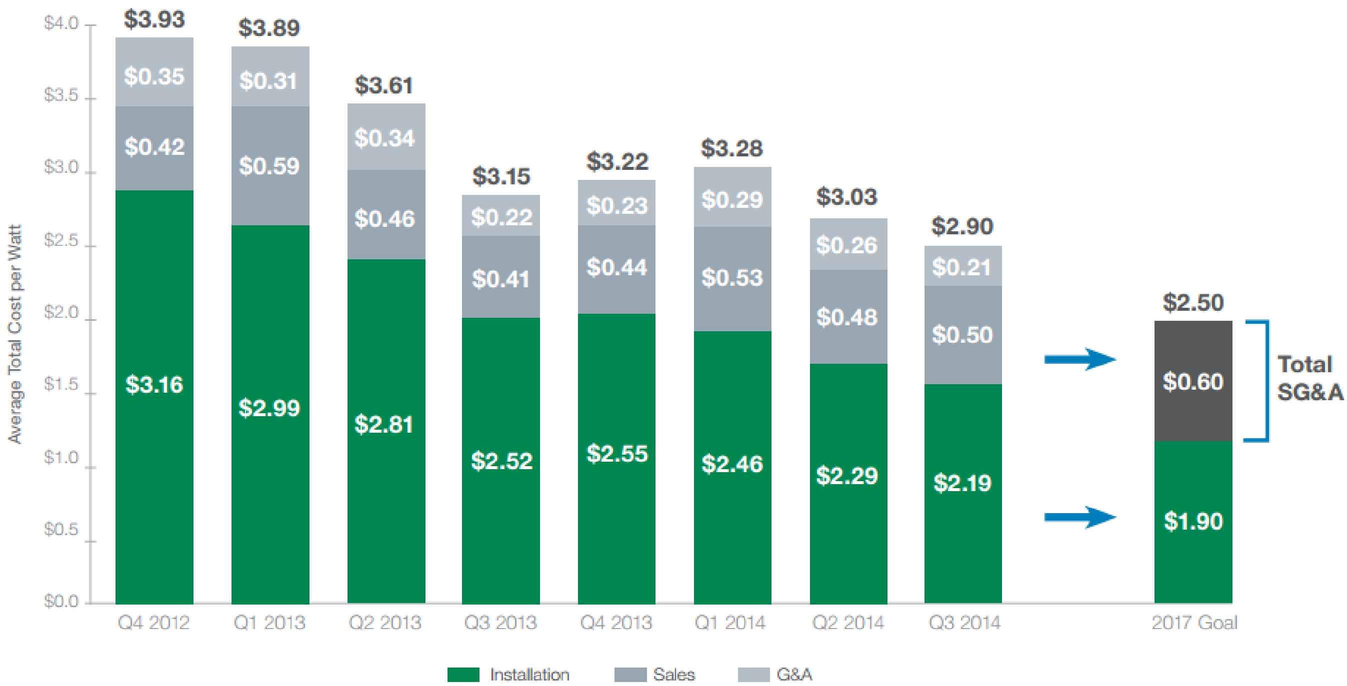
The exact drivers behind cost declines may vary between countries, but we believe the German example continues to prove that overall system costs have yet to reach a bottom even in comparatively mature markets.

Total Cost Reduction Will Be Multi-Faceted: Mostly Not From Polysilicon

While much of the cost reduction over the last 5-10 years has resulted from polysilicon price reductions, future cost reductions will necessarily come from non panel related balance of system costs. Polysilicon price reductions have accounted for significant portions of cost reductions, and were once the largest single cost component in panels, but this has changed drastically and rapidly over the last decade. In 2014, polysilicon represented no more than 10-11 cents per watt so even if costs are halved, the effect on the total system cost would be incremental – not revolutionary.

However, there are significant other cost drivers that we believe the industry will leverage to drive down LCOE over the next several years. We have outlined our estimates of current and future cost trajectory in the US below, which we expect to mirror other regions' cost roadmaps.

Figure 34: SolarCity 2017 Cost Targets



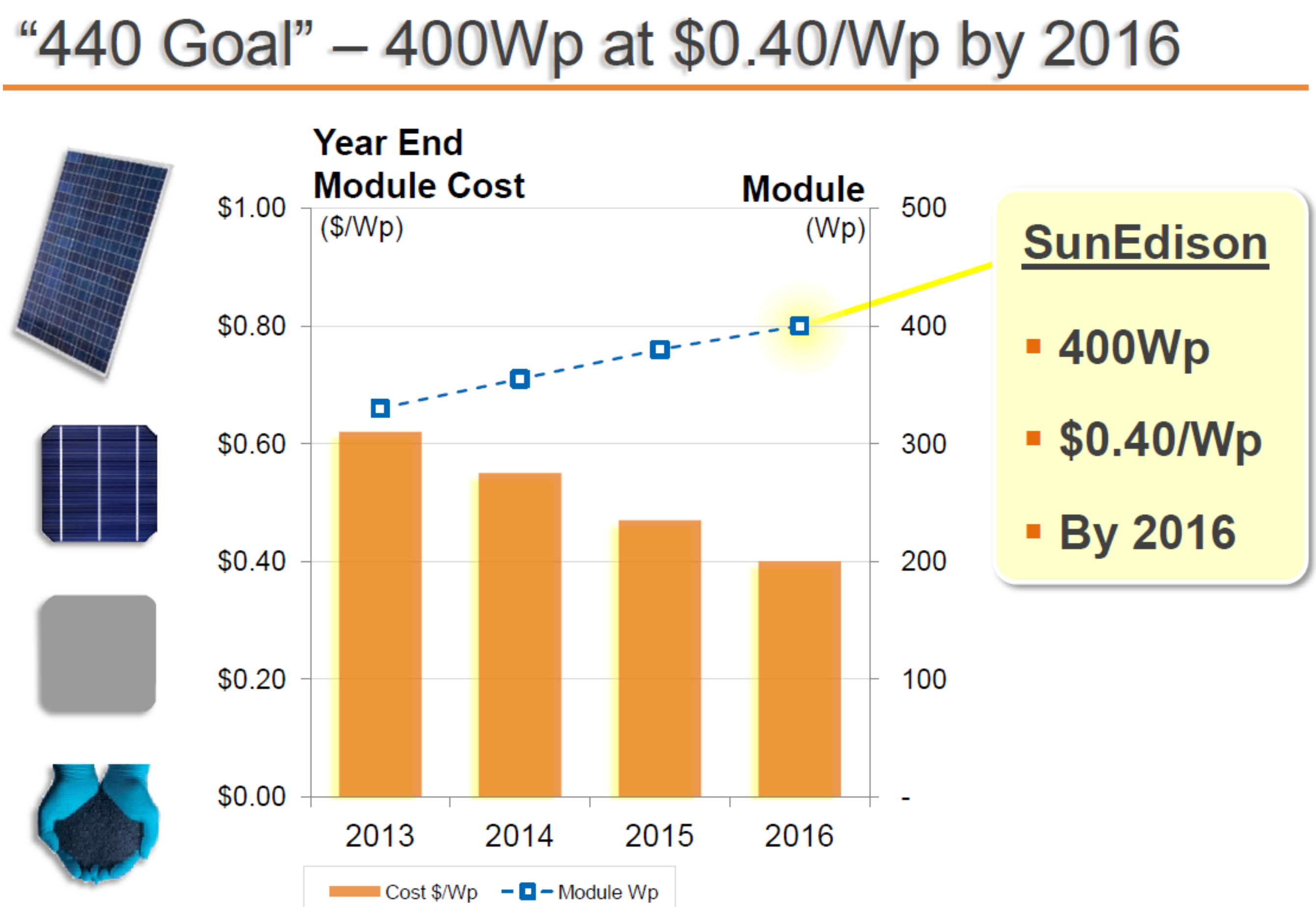
Source: SolarCity Investor Presentation

Panels: $0.75/W → $0.50/W

Panel prices in the US are already among the highest in the world today, so there would likely be price reductions simply through price arbitrage on a multi-year time horizon. However, we also believe there are fundamental reasons that panel prices worldwide are likely to trend lower over the next several years. While overhangs like trade cases or minimum price agreements could cloud the near term, we believe market inefficiencies will be worked out over the long term and the clearing price will reach $0.50 or lower within the next several years.

Companies like SunEdison have publically targeted $0.40/W panels by the end of 2016, and many Tier 1 Chinese manufacturers are achieving sub $0.50/W already in 2014. Given that most manufacturers are improving 1-2 cents per quarter, less than ten cents improvement (to reach $0.40) over the next 12 quarters is likely conservative. If panels are sold at a 10 cent gross margin for a total cost of $0.50/W, manufacturers would achieve 20% gross margin – well above recent historic averages. Furthermore, transportation costs and 'soft costs' which inefficiently raise the price of panels should gradually improve as governments work through trade issues

Figure 35: SUNE 40 cent 400 Watt Panel Goal



Source: Sunedison 2013 Capital Markets Day

Inverter: $0.25/W → $0.17/W

Inverter prices typically decline 10-15% per year, and we expect this trend to continue into the future. Large solar installers are already achieving ~$0.25/W or lower on large supply deals, and we expect additional savings will be found over the next several years. Component cost reduction, next generation improvements, and incremental production efficiencies will drive savings on the manufacturing side, while new entrants and ongoing price competition among incumbents will likely keep margins competitive and pass on much of the savings to installers.

Racking/Other Bos: $0.25/W→$0.16/W (Racking) and $0.30/W→$0.17/W (Other)

While racking is often overlooked as a source of cost reduction, we expect ongoing efficiency improvements, streamlining, and potential advances in materials to lead to incremental improvements. As standardization becomes more normalized in the industry, balance of system costs should decline.

Installation: $0.65/W → $0.45/W

Cost reduction on the installation side will come primarily from scale benefits, as we do not expect wage reductions. In fact, solar installation jobs are likely to increase substantially to keep pace with demand, but more experienced installers using better tools and techniques on larger systems are likely to more than offset any wage growth through efficiency gains.

Sales/Customer Acquisition Cost: $0.50/W → $0.20/W

We see substantial room for improvement over the longer term in cost per watt terms as solar gains mainstream acceptance is recognized as a cost competitive source of electricity, and companies develop new/improved methods to interact with customers.

Already, we are seeing domestic US firms develop automated online systems for customer sourcing, and these systems alone should allow substantial further automation as solar begins to 'sell itself'. Although adoption is still in the early stages in most markets, we think costs could reach the level in the next several years where homeowners begin to recognize inherent value of solar self generation. We believe this will have two effects: 1) customers who prefer to own their own systems and have the ability to do so could finance their solar installation through multiple types of solar loans which are already gaining in popularity and 2) customers who focus on the monthly electricity bill will continue to sign PPA's for solar priced below the retail electricity price curve.

Furthermore, the wild card for a third prong of the solar explosion lies in the regulatory environment. If utilities begin to offer competitive solar installations regardless of credit quality (under a third party ownership model), this would open the market to another vast source of potential customers.

We expect all of these factors to converge to drive substantial volume improvements over the next several years. Despite the potential for utility scale choppiness in yearly installs, residential and commercial installations have strong fundamental underpinnings which should continue to drive volume higher as costs reduce, LCOE is more competitive, and the customer base expands (which has a compounding effect as neighbors see each other installing solar).

Lastly, the power of all in cost should not be underestimated. A typical residential US-based system costs around ~$25-35K today, but we believe that comparable residential systems could easily dip into the $10-15K range over the next 5 years if market forces driving cost reduction are allowed to progress without substantial policy/exogenous shocks. If interest rates are reasonable and a homeowner takes out a loan, upfront capital investment would be as little as a few thousand dollars.

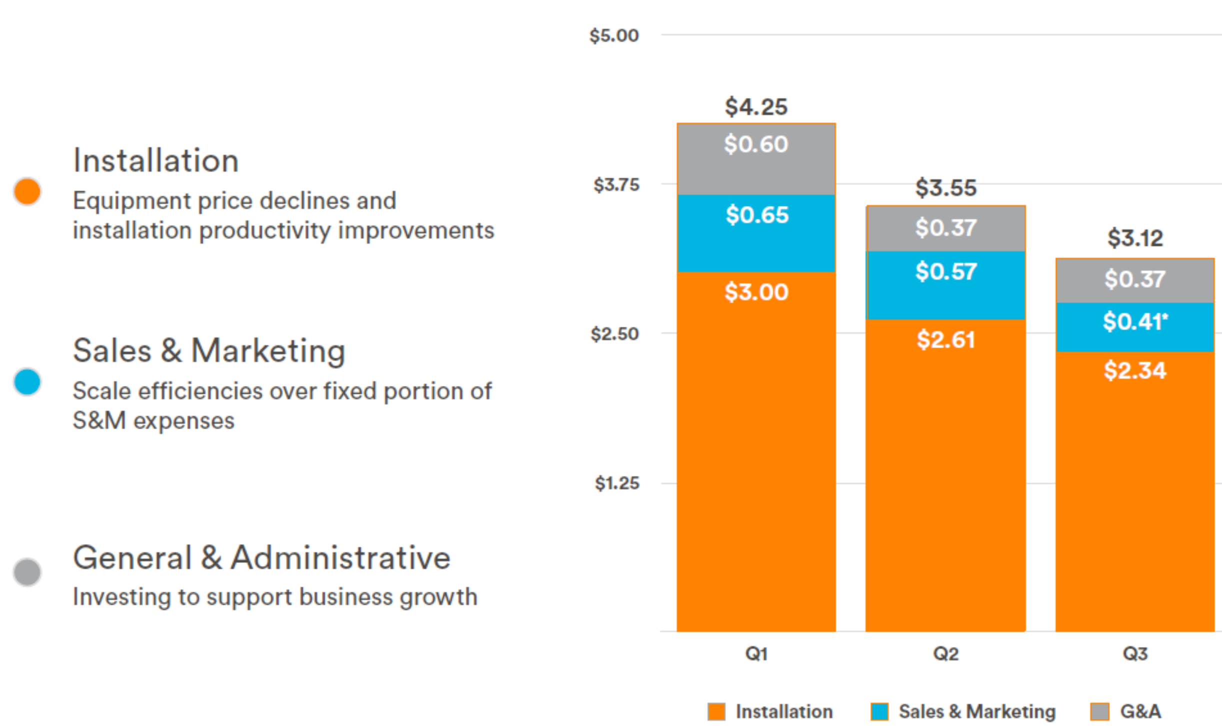
As shown below, total customer acquisition LCOE effect is in the 2-3 cent range (2.7 cents/kwh in our example). If costs come down substantially as we expect, this will have a self-reinforcing effect on solar deployments.

Figure 36: Customer Acquisition Cost LCOE Effect

Customer Acquisition ($/w)	Total Cost ($/w)*	LCOE	Difference
$0.50	$2.90	$0.173	
$0.30	$2.70	$0.163	$0.011
$0.20	$2.60	$0.157	$0.005
$0.00	$2.40	$0.147	$0.011
		Total Difference -->	$0.027
*Holding other costs constant			

Source: Deutsche Bank

Figure 37: Vivint Solar Cost Trend



*Note: The Q3 2014 sales and marketing cost per watt benefits from a change related to Vivint Solar's sales compensation policies. On a normalized basis sales and marketing cost per watt would have been $0.41.

Source: Vivint Solar

Other/Soft Costs: $0.20/w → $0.12/w

"Other" costs including soft costs of permitting, incentive collecting, etc account for at least 20 cents/w currently, although 'all in' soft costs from other parts of the cost stack would likely amount to a notably higher number.

We believe that policy rationalization, certainty, and regulatory streamlining could easily cut substantial costs across the solar value chain. Incentive expiration or marginalization (due to insignificant returns) as well as more efficiency and cooperation from utilities and governments should enable further cost improvements.

As shown below, soft costs likely account for $0.01-$0.02/kwh in LCOE, or ~10%+.

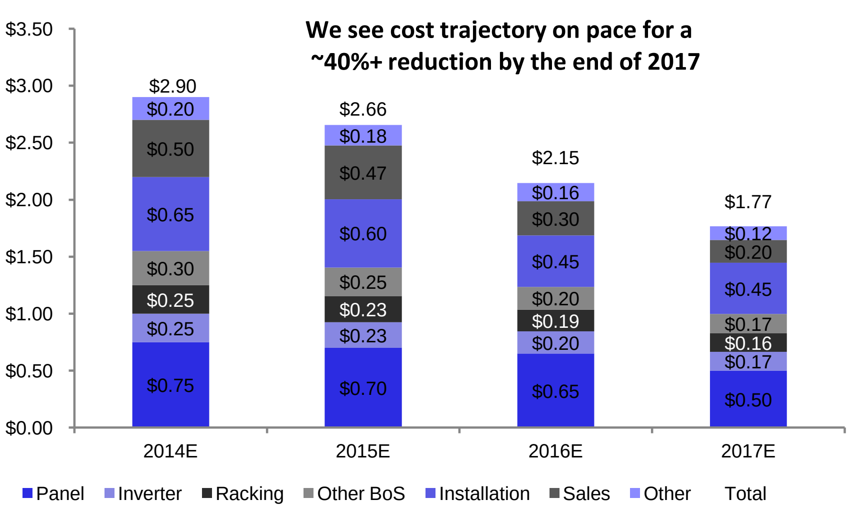
Figure 38: Cost Per Watt and Total Sun Hours Sensitivity Analysis

Total Sun Hours (Net of DC-AC Conversion)

Total System Cost ($/W)	1000	1100	1200	1300	1400	1500	1600	1700	1800	1900	2000
$1.00	$0.10	$0.09	$0.08	$0.08	$0.07	$0.07	$0.06	$0.06	$0.06	$0.05	$0.05
$1.20	$0.12	$0.10	$0.10	$0.09	$0.08	$0.08	$0.07	$0.07	$0.06	$0.06	$0.06
$1.40	$0.13	$0.12	$0.11	$0.10	$0.09	$0.09	$0.08	$0.08	$0.07	$0.07	$0.07
$1.60	$0.15	$0.13	$0.12	$0.11	$0.10	$0.10	$0.09	$0.09	$0.08	$0.08	$0.07
$1.80	$0.16	$0.15	$0.13	$0.12	$0.11	$0.11	$0.10	$0.09	$0.09	$0.08	$0.08
$2.00	$0.18	$0.16	$0.15	$0.13	$0.13	$0.12	$0.11	$0.10	$0.10	$0.09	$0.09
$2.20	$0.19	$0.17	$0.16	$0.15	$0.14	$0.13	$0.12	$0.11	$0.11	$0.10	$0.10
$2.40	$0.21	$0.19	$0.17	$0.16	$0.15	$0.14	$0.13	$0.12	$0.11	$0.11	$0.10
$2.60	$0.22	$0.20	$0.18	$0.17	$0.16	$0.15	$0.14	$0.13	$0.12	$0.12	$0.11
$2.80	$0.24	$0.21	$0.20	$0.18	$0.17	$0.16	$0.15	$0.14	$0.13	$0.12	$0.12
$3.00	$0.25	$0.23	$0.21	$0.19	$0.18	$0.17	$0.16	$0.15	$0.14	$0.13	$0.13
$3.20	$0.27	$0.24	$0.22	$0.20	$0.19	$0.18	$0.17	$0.16	$0.15	$0.14	$0.13

Source: Deutsche Bank

Figure 39: Cost Reduction Example: USA



Source: Deutsche Bank

YieldCos: Enabling The Transition To Grid Parity Growth

We believe the successful IPOs of some of the recent YieldCo offerings is a significant positive for the overall solar/renewables sector and a key catalyst enabling the sector's transition from subsidies to grid parity. We believe management teams can create greater long term shareholder value by spinning off projects into a new YieldCo vehicle versus selling projects.

What are some of the key positives of YieldCos for the solar sector? First, new YieldCo structure offers the company significantly lower cost of capital. Not only do YieldCos reduce the cost of equity from 10%+ to less than 5% but because in many cases, equity is trading at a lower cost than debt, YieldCos also offer the potential to change the capital structure which should enable further reduction in cost of capital. Second, YieldCos with scale and development capability have the option to grow into international solar markets or move into residential solar (where cost of capital is higher) and also potentially grow into wind/hydro/transmission segments. There is a significant amount of installed renewables/transmission that is capacity available for sale and a lot of that capacity could be acquired/dropped down into existing YieldCos.

Solar costs are set to decline further whereas electricity prices could rise in many markets globally. We expect the addressable market for YieldCos to only get bigger over time driving further interest from MLP/yield investors.

What are the benefits of YieldCos to the parent companies?

1) YieldCos enable investors to better value the company's ability to grow assets and assign a multiple on cashflows.

2) By creating a YieldCo, solar companies have the option to create an IDR structure and potentially benefit from growth of the YieldCo in the longer term. Solar companies were previously not able to benefit from this strategy by simply selling projects to a YieldCo.

3) More revenue streams can be dropped down into the YieldCos especially as assets continue to grow. One specific example is inclusion of O&M revenues from installed base of operating assets.

4) YieldCos expand the investor base and contribute to valuation multiple expansion. Several energy/MLP/utility investors are looking to invest in solar companies that have announced plans to form a YieldCo.

Within the US, we see increasing odds of renewables being treated as MLPs/REITs post 2016 timeframe. YieldCos with first mover advantage maybe able to grow significantly faster in that scenario, could potentially get acquired by MLPs that maybe looking for growth or see the value of their developed projects increase significantly.

That said, not all companies may be able to execute on the growth strategy. Only companies with strong development capability would get credit from investors in our view and would likely trade at better yields compared to YieldCos without strong development capability. We also like the equity of the "parent" vs YieldCo where YieldCos have an IDR structure (SUNE for example is likely to benefit from growth of TERP). Debt financing constraints, especially in international markets may also prevent several companies from achieving scale. Finally, cash generated by sale of projects to YieldCos in international markets could arguably be deployed for deployed for international project development without any tax implications whereas new YieldCos would likely have to pay taxes while repatriating cash to the US.

How Does a Yieldco – Parentco Create Value?

The Key is Cost of Capital Arbitrage

Assuming a typical YieldCo Vehicle is structured as a parent-subsidiary relationship, we believe a cost of capital arbitrage exists as long as the yield company's cost of capital is lower than the parent company's. This will likely remain the case given that one of the key aspects of a YieldCo is long term stable contracted cash flows with relatively low risk profiles.

Given high risk development profile, the parent equity generally trades at a lower multiple than YieldCo (say 8X EBITDA). Conversely, the YieldCo is assumed to contain long term highly contracted cash flows with strong (10-20%) growth prospects and generally trades at a higher multiple (say 12x EBITDA). In the event that parentco offers to sell 50MW of finished projects at 10x EBITDA to YieldCo, the parent company is able to sell a project above its own trading range and cost of project development, while the yield vehicle is buying assets below. Hence, both parent and yieldco receive a benefit from the transaction.

Storage: The Missing Link of Solar Adoption

Batteries delivered at an economically competitive price are the holy grail of solar penetration, and we believe the industry will begin deploying on a large scale within the next ~5 years or less. We expect battery deployment to occur primarily where there is a clear economic rationale. One of the clearest examples is commercial scale battery deployment, which is already occurring today in several countries. Commercial customers are often subject to demand based charges, which can account for as much as half of the electric bill in some months. We think companies with differentiated battery solutions coupled with intelligent software and predictive analytics that work with the grid to avoid these charges and smooth electric demand will pave the way for mass adoption. Additionally, we expect utilities worldwide to pursue batteries on a large scale as costs drop over the next several years and renewable/intermittent generation deployments increase. Residential customers without proper pricing mechanisms in place (for example, peak demand charges) are unlikely to pursue energy storage in the short term, although we believe solar leasing companies and other energy service companies could shift towards offering batteries as part of energy packages designed to integrate more intelligently with the grid and address utility concerns around distributed generation. We expect this trend to likely accelerate if positive incentive mechanisms are put in place, such as guaranteed interconnection timelines, effective utility-side deployment mechanisms, or tax/rebate incentives.

Cost for the large majority of available technologies is often economically prohibitive, although pumped hydro is an exception to the rule (however, we do not expect any notable increases in pumped hydro storage and it cannot be deployed in many instances).

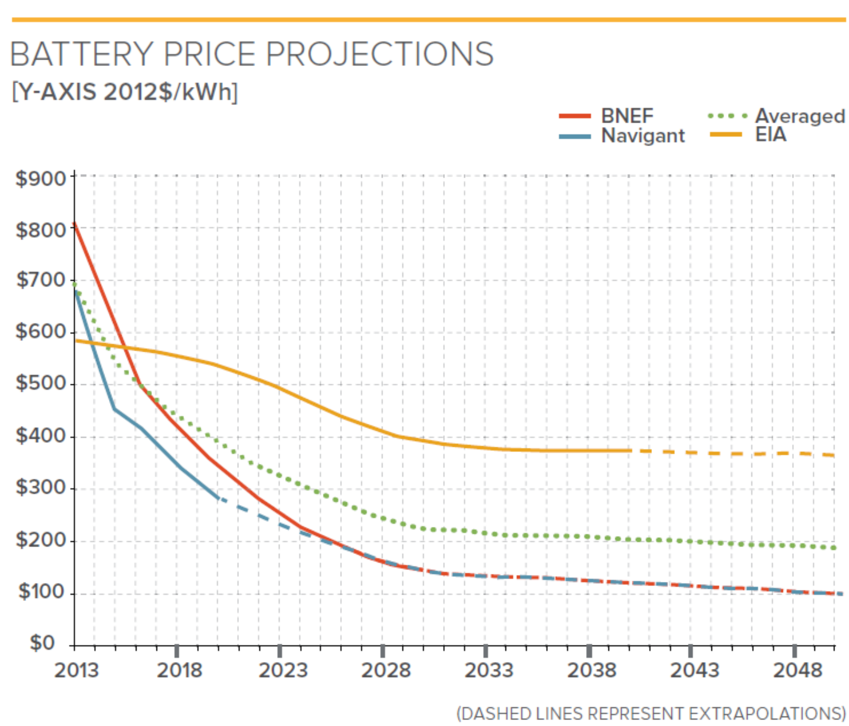
Summarized below is an overview of some of the key technologies that are being considered as potential longer term energy storage solutions. Based on our checks, many of these costs are already lower than published literature would suggest. Therefore, the costs below are likely conservative.

Figure 40: Overview of Storage Techniques

Technology	Maturity	Cost ($/kW)	Cost ($/kWh)	Efficiency	Cycle Limited	Response Time
Pumped Hydro	Mature	1,500-2,700	138 - 338	80-82%	No	Seconds to Minutes
Compressed Air (underground	Demo to Mature	960-1,250	60 - 150	60-70%	No	Seconds to Minutes
Compressed Air (Aboveground)	Demo to Deploy	1,950-2,150	390 - 430	60-70%	No	Seconds to Minutes
Flywheels	Demo to Mature	1,950-2,200	7,800 - 8,800	85-87%	>100,000	Instantaneous
Lead Acid Batteries	Demo to Mature	950-5,800	350 - 3,800	75-90%	2,200 - >100,000	Milliseconds
Lithium-Ion	Demo to Mature	1,085-4,100	900 - 6,200	87-94%	4,500 - >100,000	Milliseconds
Flow Batteries (Vanadium Redox)	Develop to Demo	3,000-3,700	620 - 830	65-75%	>10,000	Milliseconds
Flow Batteries (Zinc Bromide)	Demo to Deploy	1,450-2,420	290 - 1,350	60-65%	>10,000	Milliseconds
Sodium Sulfur	Demo to Deploy	3,100-4,000	445 - 555	75%	4500	Milliseconds
Power to Gas	Demo	1,370-2,740	NA	30-45%	No	10 Minutes
Capacitors	Develop to Demo			90-94%	No	Milliseconds
SMES	Develop to Demo			95%	No	Instantaneous

Source: State Utility Forecasting Group

Figure 41: Blended Battery Price Projections

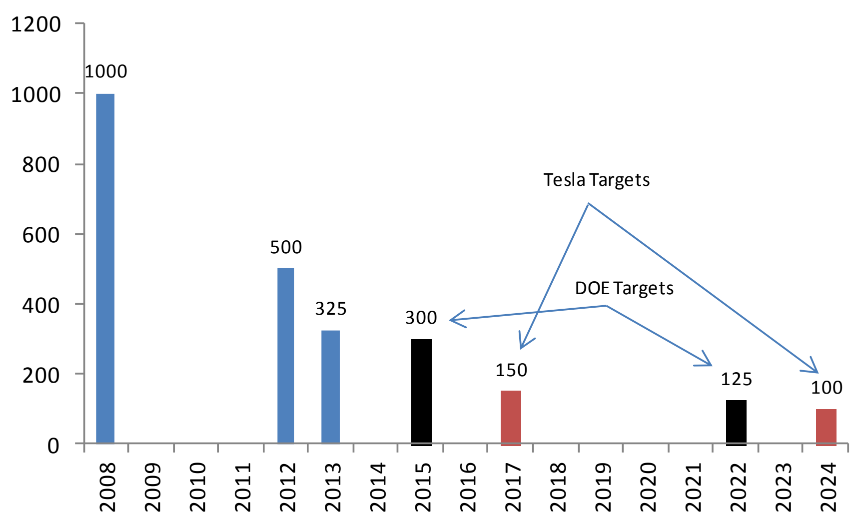


Source: Rocky Mountain Institute

The upfront cost for a typical Lead-acid battery may be as low as ~$200/kWh, while best in class lithium ion integrators are producing commercial/utility packages in the ~$500/kWh range exiting 2014, as compared to the upfront cost of ~$1000/kWh 12 months prior. We believe 20-30% yearly cost reduction is likely, which could bring conventional lithium ion batteries at commercial/utility scale to the point of mass adoption potential before 2020.

Tesla Motors, in partnership with Panasonic, is constructing the 'Gigafactory' in Nevada which aims to achieve these economies of scale and better. Tesla estimates that Gigafactory could drive down the cost of its own Li-ion batteries by more than 30% in its first year of production (the factory is scheduled to open in 2017) – which could reduce costs to the ~$150/kWh range. Separately, the US Department of energy has targeted battery cost levels of $300/kWh by 2015 and $125/kWh by 2022. Under this scenario, we believe the value proposition for behind the meter solar + battery is significantly more compelling.

Figure 42: Historical Battery Prices; DOE/Tesla Targets ($/kWh)



Source: Deutsche Bank, DOE, Tesla

Effect on LCOE

While current battery costs are relatively high, cost roadmaps that we have outlined show significant cost reduction over the next ~5 years. In turn, batteries paired with solar may become significantly more economical in the future on an LCOE basis.

Figure 43: Illustrative Solar + Battery LCOE

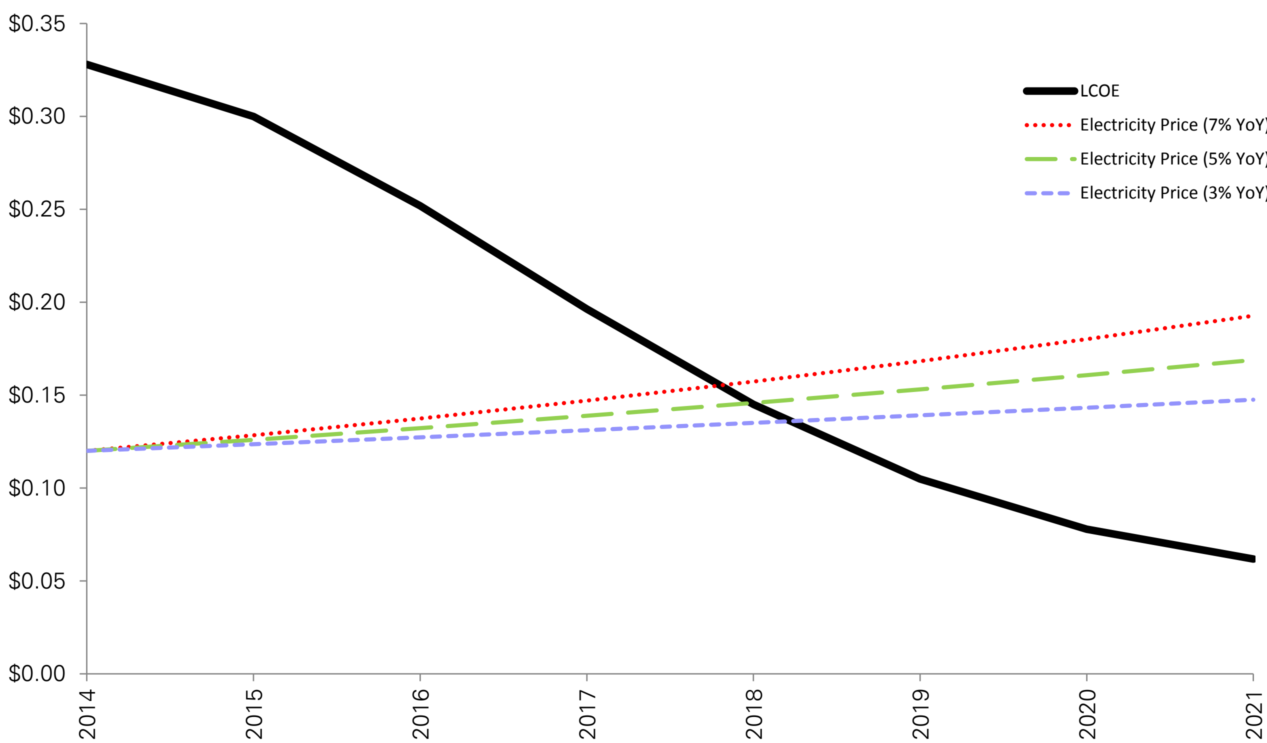
Today		Future	
Cost per KwH	$1,500	Cost per KwH	$150
Battery Size (kwh)	10	Battery Size (kwh)	10
Total Battery Cost	$15,000	Total Battery Cost	$1,500
System Size (w)	6400	System Size (w)	6400
Battery Cost/W	$2.34	Cost/W	$0.23
System Cost/W	$2.90		
Total System Cost	$5.24	Total With Future Battery*	$3.13
LCOE in the US (no battery)	$0.17		
With Battery	$0.31	LCOE With Future Battery*	$0.19
LCOE Improvement	**$0.12**	*assumes static system cost	

*15% yearly battery cost/w declines from today scenario, 5% in future scenario. 10-year replacement.

Source: Deutsche Bank

Using conservative assumptions and no incentives, our model indicates that the incremental cost of storage will decrease from ~14c/kWh today to ~2c/kWh within the next five years. When overall system cost decreases are considered, we believe solar + batteries will be a clear financial choice in mature solar markets in the future.

Figure 44: Illustrative example of System with Batteries at Grid Parity Assuming 10% total system cost reduction YoY



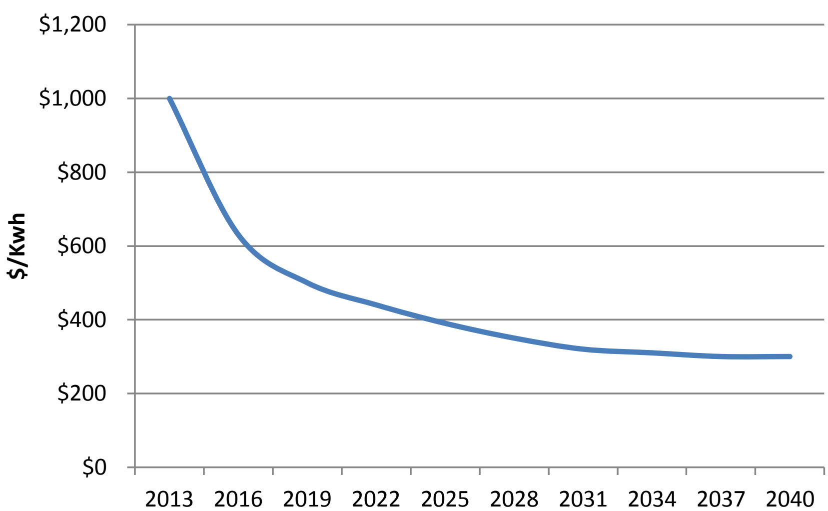
Source: Deutsche Bank

Overview of Mainstream (Electrochemical) Technologies

1. Lead-acid: Lead-acid batteries are the world's most commonly used batteries given lower cost, maturity of technology, and ease of availability. While lead acid batteries have been utilized in the past for grid storage, average life of 6-15 years does not match with solar panel life spans. Furthermore, lead-acid batteries have recharge/discharge characteristics which are less preferable for grid deployment (lifespan is shortened if the battery is not fully discharged).

2. Lithium-ion (Li-ion): Lithium ion batteries are considerably more widespread since the proliferation of cell phones, as they are well suited to mobile applications. Currently, they are primarily used for small portable applications given ease of ongoing recharge, higher energy storage potential, and longer lifespan. However, current cost structure is prohibitively high for large scale deployment for home storage, but scale manufacturing is likely to help bring down costs substantially over the medium term. Companies like Solarcity (via Tesla) plan to use lithium ion batteries as storage systems for home solar.

Figure 45: EIA Rough Cost Projections



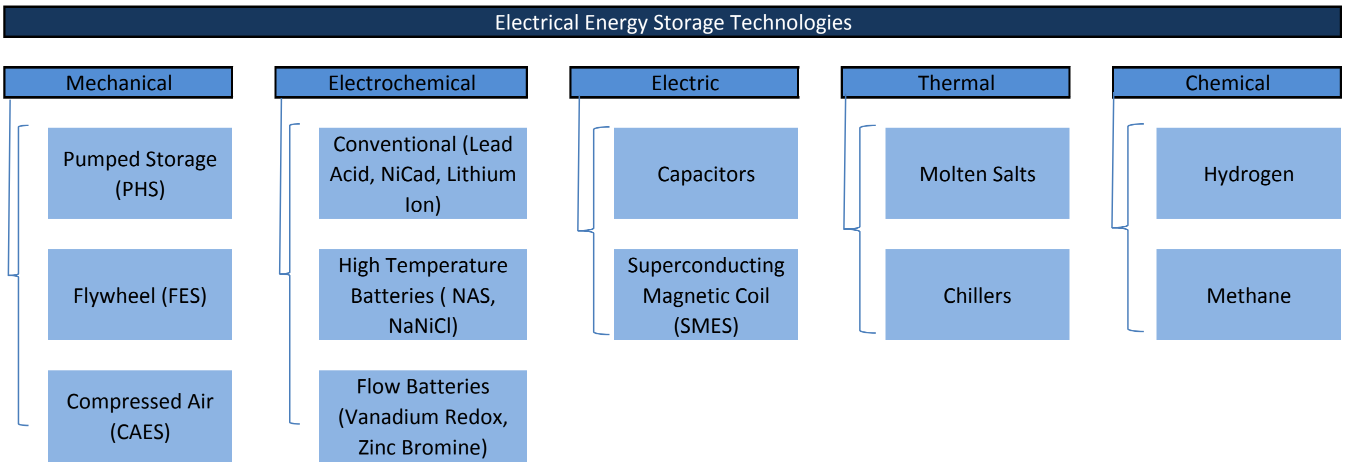
Source: EIA

3. Flow battery: Flow batteries as a commercial technology are relatively new but theoretically well suited to large scale utility storage. A flow battery typically consists of two tanks of liquids (electrolytes) which are pumped past a membrane held between two electrodes to store and generate electricity. This is in contrast with a Li-ion battery, where the energy-storing materials and electrolyte are enclosed in a cell. Key advantages of flow batteries include, ease of scaling, reliability, and long life. Flow batteries are used in various forms including Iron-Chromium flow batteries, Vanadium Redox flow batteries and Zinc-Bromine flow batteries. Recently, EnerVault dedicated its first commercial flow battery-based energy storage system in California. The project was funded in part by over $4.7M from US DOE and $476,000 from the California Energy Commission (CEC), and meant to demonstrate the feasibility of iron-chromium flow batteries as reliable utility-scale storage resources. We do not expect flow batteries to make a significant impact on grid storage in the next several years, but see potential for long term adoption as the technology and scale application matures.

Other Technologies

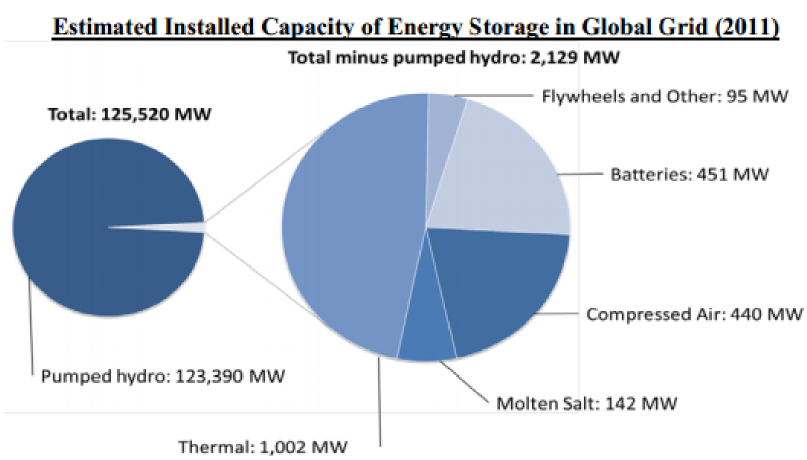
While electrochemical batteries are the most familiar examples of storage, a wide range of options exist with varying degrees of success. They typically fall into 5 buckets outlined below.

Figure 46: Storage Technologies



Source: Deutsche Bank, State Utility Forecasting Group

Figure 47: Est Global Energy Storage



Source: StrateGen Consulting 2011.

Note: Estimates include thermal energy storage for cooling only. Figures are current as of April 2010.

Source: StrateGen Consulting 2011

The US alone is estimated to have ~22K+ MW of pumped hydro power, versus 50-100MW of lithium ion battery storage. Most importantly for the future of energy storage, pumped hydro causes significant environmental impacts which most countries are shying away from. Conventional batteries are considerably easier to package, distribute, and scale over the long term. However, current costs need to come down.

Although lithium ion and other electrochemical based batteries are the most commonly discussed, we see a wide range of potential new technologies available to fill the need for on grid storage. For example, Southern California

Edison (SCE) recently procured ~26MW of storage based on commercial scale ice cooling from Ice Energy. This is an innovative use of well established technologies (in this case, freezing water). We have listed several of the companies to have commercial success with SCE below.

- **Ice Energy Holdings (25.6MW win from SCE)**: Rather than the typical chemical based batteries that many would think of, Ice Energy is focused on thermal ice based energy storage to reduce air conditioning energy peak energy use. By freezing liquid at night, retrofitting existing commercial AC systems and integrating with the grid, Ice Bear units are able to smooth peak demand by circulating the already-cooled liquid through the system to cool the air which is then used in the building HVAC system. Ice Energy is able to manufacture 10MW+ per month, and has over 24 million hours of fleet operation across 40+ utilities.
- **Advanced Microgrid Solutions (50MW win from SCE)**: Previously unknown before the SCE project win, the company plans to focus on stackable large scale commercially deployed, utility-facing battery systems for use in dense urban or Class A office regions. Similar to other winners, AMS will charge their batteries at night then deploy during a 2-4 hour peak demand interval as the utility needs to dispatch this demand-side management tool. AMS is assuming that lithium ion costs (or others – the company is technology agnostic) will continue to fall over the next several years and is pricing contract bidding appropriately, which likely helped it win. Furthermore, the appeal for the utilities is clear (they control everything about the system) while the appeal for commercial customers is also compelling (spend less on peak charges).
- **Stem (85MW win from SCE)**: This battery integrator company is primarily focused on commercial scale or larger installations which are able to shave peak charges in markets where commercial users may be subject to rapidly shifting electricity rates. In addition to integrating battery packages, Stem uses intelligent software analytics to predict grid charges and counteract them proactively. The company is backed by investors like Angeleno Group, Constellation Energy, GE Ventures, Iberdrola, and Jagen Pty. Stem focuses primarily on energy management and may pair its batteries with solar (such as a partnership with Kyocera in California, New York, and Hawaii) but the key focus for the company is on targeted software for demand management. This can generate immediate returns for commercial companies that are able to offset peak charges, and Stem is reported to have financed its own systems (similar to solar leasing companies) through utility payment savings. While improving battery technology is an important driver of driving systems at grid parity, Stem's business model appears to show that intelligent grid management will be just as important.
- **AES (100MW win from SCE)**: AES is a medium sized publically traded IPP/energy company with ~36GW in operation, several GW under construction, 10 million + customers, and a diverse range of energy sources. As an established energy company that is developing storage solutions, it is not surprising that they were able to bid successfully. The company's 100MW, 20 year PPA with SCE will provide a 100MW battery-based storage solution which can flex to 200MW as needed (400MWh).

Several storage start-ups have recently raised funding in order to commercialize technology and ramp up manufacturing. For instance, EOS energy storage is raising $25M in order to scale up manufacturing of hybrid Zinc cathode, aqueous electrolyte based battery. Once fully ramped, the battery would have 75% round trip efficiency, 30 year lifetime, $160/kWh cost. Zinc is much cheaper than lithium but the problem with Zinc is electrode corrosion and build-up. EOS solves this problem by a proprietary coating that creates a permanently conductive and non-corrosive surface.

Another start-up, Aquion Energy has raised more than $150M in equity and debt in order to deploy more than 1MW of sodium-ion batteries at $300/kWh price point.

Flow batteries from Imergy, UniEnergy, Cell-cube American Vandium and ViZn Energy are all targeting low price points.

Besides these start-ups, larger companies such as Panasonic, Mitsubishi, LG Chem, Samsung, Saft and A123 owner NEC are also targeting grid storage. AES Energy storage calls li-ion as the chemistry of choice for the next decade.

Figure 48: Emerging Battery Companies

		Current		Future	
Company Name	Technology Type	Cost ($/kwh)	Cost ($/Kw)	Cost ($/kwh)	Cost ($/Kw)
Aquion Energy	Sodium-Ion	$500		$250	
Eos Energy Storage	Zinc Air			$160	
Primus Power	Flow (Zinc Halogen with zinc plating and de-plating)	$500			
EnerVault	Flow (Iron Chromium)			$250	
Imergy Power (Deeya Energy)	Flow (Vanadium Based)	$500		$300	
Prudent Energy	Flow				
Redflow (Australia)	Flow (Zinc-Bromide)	$875		$525	
Cellstrom	Flow				
Gildemeister (EU)	Flow (Vanadium Based)	$1,000			
ZBB	Flow (Zinc-Bromide)	$3,175*	$1,2700*		
EnStorage (Israel)	Flow	$738		$307	
Premium Power	Flow				
Ice Energy	Thermal (water)				
Alevo	Lithium-iron-phosphate	$100			
Advanced Microgrid Solutions					
AES Energy Storage	Lithium-ion		$1,000		
Stem					
Ambri	Liquid Metal Battery			$500	
ELIIY Power	Lithium-iron-phosphate				
Sonnenbatterie	Lithium-iron-phosphate	$2,100-$2,888*			
Bloom energy					
Intelligent Energy					
Coda Energy					
Green Charge Networks					
Combined Energies					
Eonix					
Hollingsworth & Vose					
Bettergy					
Lionano					
Raymond Corp					
Graphenix Development					

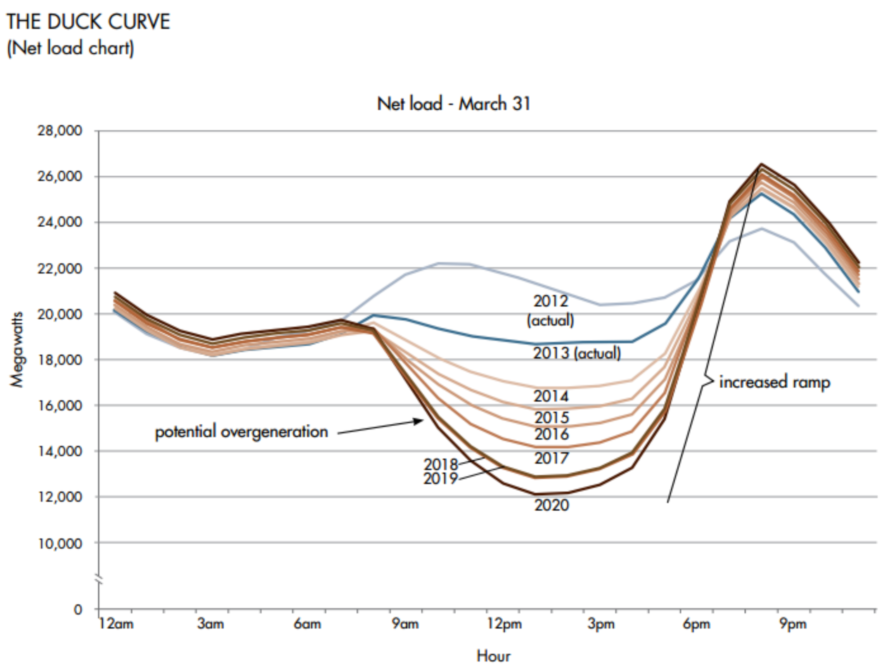
** cost of entire PV+Battery system*

Source: Deutsche Bank, GTM, Energystorage.org

Why Develop Battery Technology

The primary reasons for the necessity of energy storage additions include: 1) growth in renewables implies intermittent spikes or troughs in power generation and voltage, which could lead to grid instability at higher penetration rates (~10-15%+ grid capacity or generation). This was notably illustrated by the California Independent System Operator (CAISO) in late 2013 as it modeled issues in achieving 33% renewable energy by 2020. The implication is that a 100%+ increase in capacity needs in the span of 1-2 hours as renewable penetration grows will create significant challenges for grid stability under current norms. Behind the meter batteries would smooth the peak demand during the evening, while utility scale batteries could provide the rapid response time and fluctuation response necessary to support large scale variable generation.

Figure 49: Increasing Levels of Renewables = Difficulties for ISO's



Source: CAISO

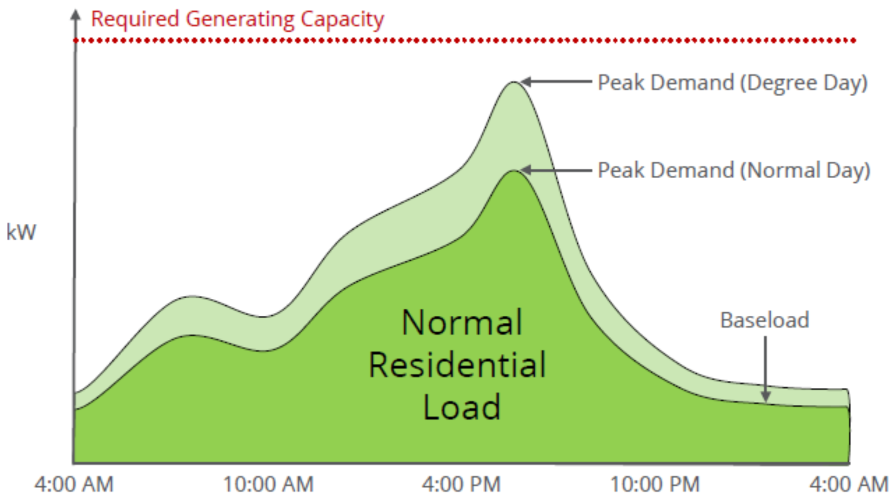
Other reasons include: 2) increased shift towards distributed generation; which is prompting some utilities to fight net metering, interconnection, or other solar incentives 3) increase in electricity prices; which makes systems with grid storage more economical 4) outages caused by natural disasters like hurricane Sandy (stand-alone microgrids that could fuel emergency infrastructure or individual communities). 5) Electrification of underserved areas of the world can be implemented effectively through micro-grids.

Benefits include – 1) providing backup power to homes, businesses or utilities; 2) cutting peak-demand charges; 3) providing firm peak capacity to the grid; 4) providing frequency regulation and improving relationship between distributed generation producer and utility with smart grid implementation.

Benefits: Residential + Utility

The current model for utilities necessitates planning for extreme scenarios. Specifically, all utilities must build enough capacity to handle extreme demand levels – for instance, consumers coming home on a hot day and all turning on their air conditioners, TV's, lights, etc on around the same time. This leads to a load curve as shown below:

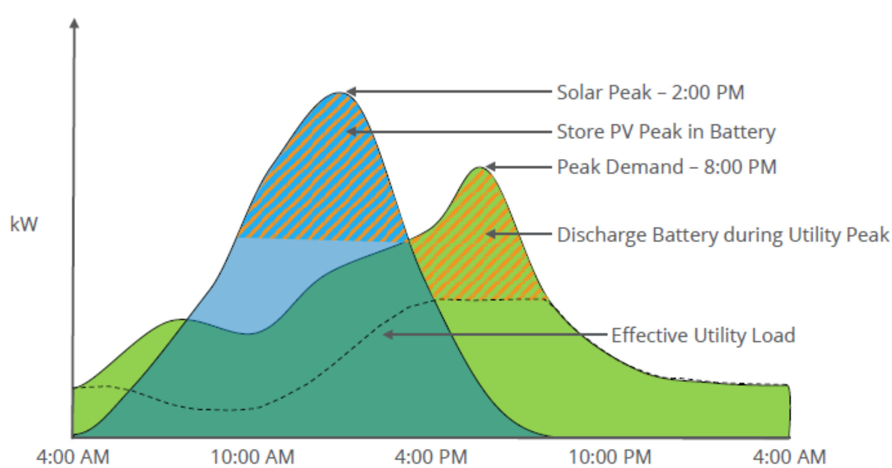
Figure 50: Load Curve (Summer)



Source: Sunpower 2014 Analyst Day

Given the spike in power demand during the early evening, residential adoption of batteries at scale could contribute meaningfully to peak demand shaving as batteries deploy during the evening to offset decreasing direct generation from sunlight.

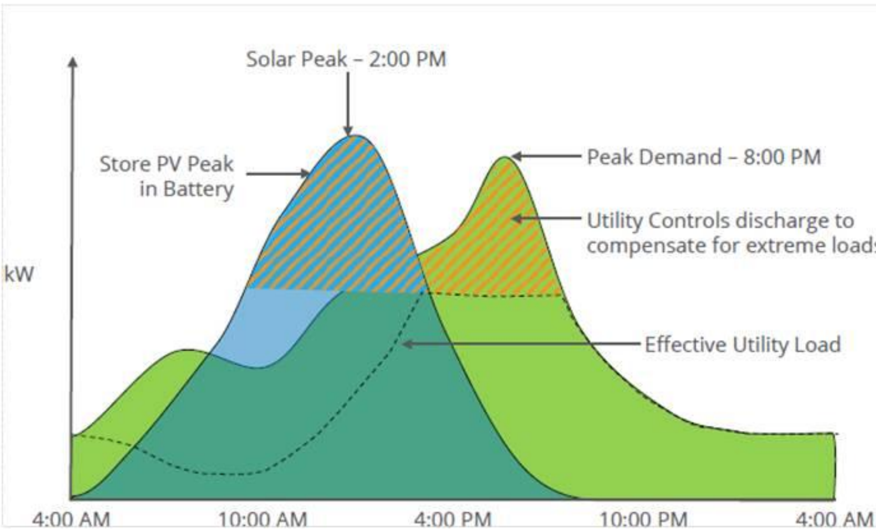
Figure 51: Theoretical load curve reduction with Storage



Source: Sunpower 2014 Analyst Day

The example above, while useful, understates the potential benefits from large scale adoption of solar + batteries with smart meters. Over the next decade, we see a substantial opportunity for utilities to utilize smart grids through residential battery aggregation. If utilities are incentivized to make the necessary changes, they could begin to aggregate neighborhoods of solar + batteries to behave as a single source of load reduction. Batteries could be dispatched as needed to reduce peak demand across the system. In a high grid-penetration scenario, this could reasonably lower the necessary capacity from conventional generation sources. In turn, we think it is reasonable to hypothesize that lowered capacity needs from lowered peak demand would simultaneously lower the need for large up front capital investment in peaker plants. Two likely scenarios for this scale deployment include 1) Third party leasing companies and individuals install solar + smart meters to work with the utilities or 2) the regulatory framework shifts and utilities begin including residential solar in their rate base. Both of these scenarios would likely significantly improve reliability, enable microgrids to function as needed, and improve grid resiliency during emergency situations.

Figure 52: Utilities Could Dispatch Batteries on Demand in the Future

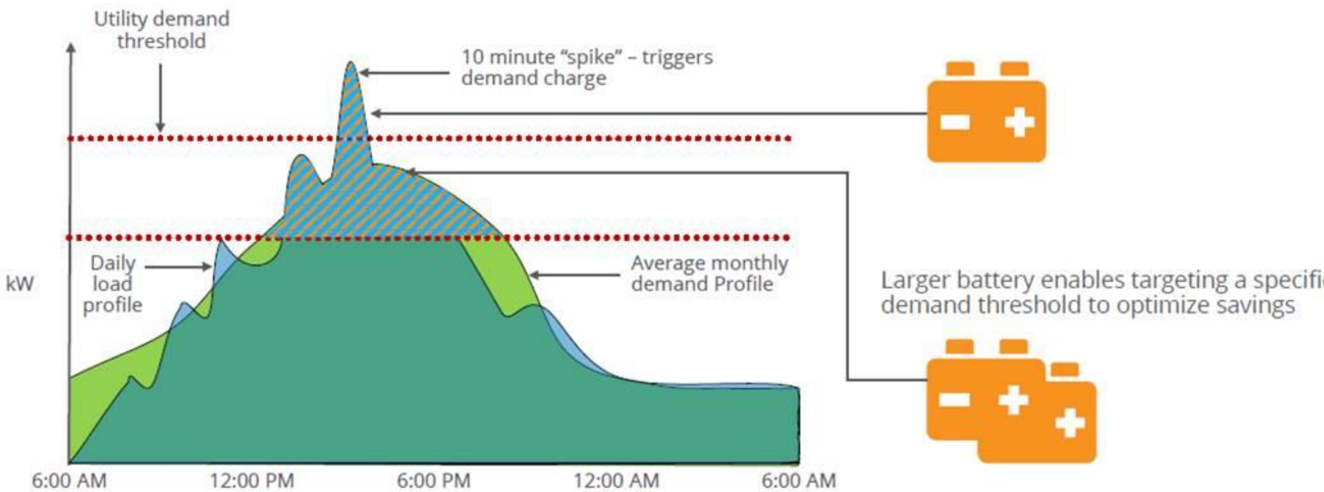


Source: Sunpower Analyst Day - 2014

Benefits: Commercial Customers Avoid Peak Charges

In addition to the potential uses on the residential side, commercial customers could significantly reduce their electric bill under time of use pricing or other pricing scenarios where demand charges make up a significant portion of the bill. During peak usage scenarios, batteries could be deployed immediately to shave the demand profile below the utility threshold.

Figure 53: Commercial Users Could Smooth Their Usage Profile



Source: Sunpower Analyst Day

Current Policy Incentives

1. Germany: Germany launched an energy storage subsidy in 2013 (effective since May 2013), under which, KfW Bankengruppe and the Federal Ministry for the Environment are supporting the increased use of energy storage in conjunction with solar PV systems linked to the electricity grid. The program aims to encourage further technical development of storage battery systems for solar PV installations. The program provides low-interest loans and repayment subsidies for new solar PV installations which incorporate a fixed battery storage system, and for the retrofit of such systems to solar PV installations commissioned after 31 Dec 2012. The subsidy amounts to a maximum of 30% of the investment cost for the energy storage system. In May 2014, BSW Solar reported that more than 4,000 new solar plus battery systems have been installed in the country. BSW Solar also noted that ~EUR66M in low-interest loans were distributed by the development bank and ~EUR10M was given out in grants.

2. Japan: In Mar 2014, Japan launched a subsidy program to support the installation of Li-ion battery-based stationary storage systems, offering to pay individuals and entities up to two-thirds of their purchase price. Japan's Ministry of Economy, Trade and Industry (METI) announced that a budget of JPY10B (~$98M) had been earmarked for the program. Subsidy payouts are capped at JPY1M ($10k) for individuals and at JPY100M for businesses, available for the installation of battery systems of 1kWh capacity or more.

3. US: ***California*** **-** California's AB 2514 energy storage procurement program requires California Public Utilities Commission (CPUC) to consider creating an energy storage procurement mandate for utilities. CPUC has approved a mandate that will require the state's big three investor-owned utilities to add 1.3GW of energy storage to their grids by the end of 2020 (SCE – 580MW, PG&E – 580MW, SDG&E – 165MW). Additionally, the state's Self-Generation Incentive Program (SGIP) provides financial incentives for the installation of clean and efficient distributed generation technologies. ***New York*** **-** New York Battery and Energy Storage Technology (NY-BEST) consortium was created in

2010 with a $25M grant from New York State Energy Research and Development Authority (NYSERDA) to position New York State as a global leader in energy storage technology. In Jan 2014, Consolidated Edison and NYSERDA announced that they intend to reduce peak energy demands during the summer. The announcement proposed a reduction of the load by 100MW, partly through the use of energy storage systems. Under the program, grants for thermal storage units increased from $600/kW to $2,600/kW, and grants for battery storage increased from $600/kW to $2,100/kW. The funding is capped at 50% of the project's costs. ***Washington*** - Washington State enacted two laws related to energy storage – 1) the first enables qualifying utilities to credit energy storage output of renewable sourced energy at 2.5 times the normal value; and 2) the second requires electric utilities to include energy storage in all integrated resource plans.

4. Canada: Under Ontario's long term energy plan (LTEP), the government intends to address regulatory barriers that limit the ability of energy storage technologies to compete in Ontario's electricity market. By the end of 2014, the government will include storage technologies in its procurement process - starting with 50MW. LTEP states that the new procurement process for renewable energy projects larger than 500kW will also provide an opportunity to consider proposals that integrate energy storage with renewable energy generation.

How To Make Hay While the Sun Shines?

What does it take to win in the solar sector?

Scale: Cost competitive and scalable technology solutions stand to gain share over the next growth phase of the solar sector. Most companies have been focused on scaling midstream parts of the value chain. We believe successful companies would be able to cost effectively scale the entire value chain (including downstream).

Capital: Access to low cost capital would be a significant competitive advantage for companies, especially as growth will come from new markets with no established financing solutions.

Technology: Not only companies with high efficiency would do well, we expect companies providing integrated products with micro-inverter solutions to also have a competitive advantage. Increasing functionality in the form of embedded hardware and software would be the primary differentiator of successful midstream solar companies. Over time, the integration of storage and energy management would become the primary differentiator for solar companies.

Diversification: We expect companies with diversified geographic and segment exposure to be in a better position to deal with changing policy environment. While incentives will continue to diminish over time, government policies will continue to impact the sector in a positive or negative way. Some countries may provide easy access to the grid for solar projects while others may make the rules on how solar companies access the grid more difficult. As such, being overly dependent on one market despite the significant size of the industry is not a good strategy in our view.

Policy Focus will Remain Front and Center in Many Markets

Within the US, the extension of ITC (set to expire in 2016), extending the MLP status to renewables, net metering 2.0 in California, grid integration in Hawaii and grid access charges in several states would be some of the policy items impacting solar supply chain. Additionally, trade case development in China, US and other global markets would be an important theme to watch in 2015. Adverse trade policies certainly pose the risk of slowing down growth in important solar markets, especially in light of the recent gas price weakness. That said, we believe a positive resolution of these trade disputes is likely and would set the stage for stronger growth in 2016.

Picking Winners/Losers

The solar sector has been generally under owned by institutional investors and expect greater institutional ownership to drive near term positive momentum for the sector. We expect a number of new business models focused on the downstream part of the value chain to emerge and expect innovative private companies to drive cost improvement/solar adoption. Both of these set of companies stand to generate significant shareholder value, in our view. We believe companies involved in financing/downstream part of the value chain stand to generate the most significant shareholder value in the near term. We expect these companies to be in a unique position to take advantage of the financing arbitrage offered by inefficient private markets and publicly trade "yield" vehicles. Solar is achieving grid parity in a number of new markets globally and we expect companies involved in project development/financing to benefit the most from the significant volume growth over the next few years. As storage costs start to improve we expect companies with cost competitive storage solutions to create the most shareholder value.

Long Term Risk: Evolving Utility Business Models

Based on ongoing disputes in Arizona, California, and Colorado, we see the beginnings of what could indicate a long term shift in how utilities and their regulatory commissions interact with solar. In 2015, we expect several key decisions from utility regulators to continue shaping this debate.

Certain utilities are currently arguing that owners of solar installations are not paying enough to support the grid, because transmission and distribution charges are generally based on metered electricity use. When a solar installation connects to the grid, it generates a portion of the owners electricity use and effectively acts as a reduction in grid demand. In most cases, this leads to a proportional decrease in the dollar charge for grid-sourced electricity (which includes a proportional charge for T&D cost recovery).

Solar companies, individual users, and freedom-of-choice advocates believe this representation does not accurately account for the positive external contributions that solar installations provide. Theoretically, large scale distributed generation adoption should lower peak electricity demand, reduce strain on the grid, provide emissions-free electricity with no fuel cost, and lower the amount of necessary future investment in the grid on all fronts. In a scenario where 'smart grids' allow distributed solar resources to be dispatched as requested by the grid operator, the benefits from DG installations should increase.

These debates are ongoing and unlikely to be finalized in the short term. On one hand, Arizona has already implemented a 'grid access' charge of $0.70/kw (~$4-5 dollars per month for a typical residential system), which was still considerably lower than the ~$20/month grid charge requested by the utility. On the other hand, key states like California and New York continue to provide a constructive regulatory environment that favors solar.

Long term, we believe the business models for solar and utility companies will necessarily shift as grid penetration rates increase (currently no more than 1-2% in even the high penetration states). Grid access charges could increase, utilities may start to compete more directly with solar installers, and cost recovery mechanisms generally will go through a rigorous analysis in most major solar markets.

Arizona is generally considered one of the most contentious regions for debate in the US, yet solar leasing companies like SCTY have continued to ramp their installation rates despite this.

Key Solar Markets – Multi GW

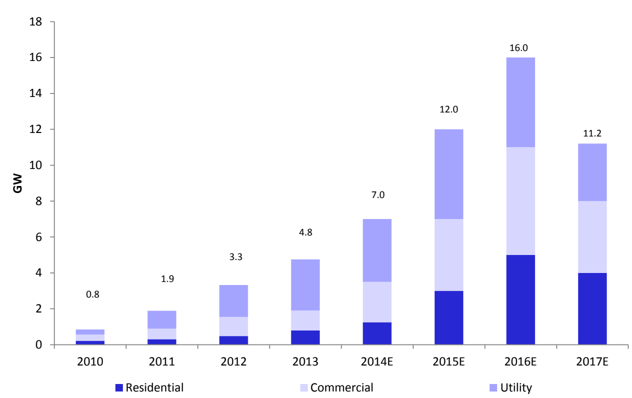
USA

Five Reasons Why Growth in the U.S Solar Market Could Exceed Expectations

1) Grid parity in 14+ states currently

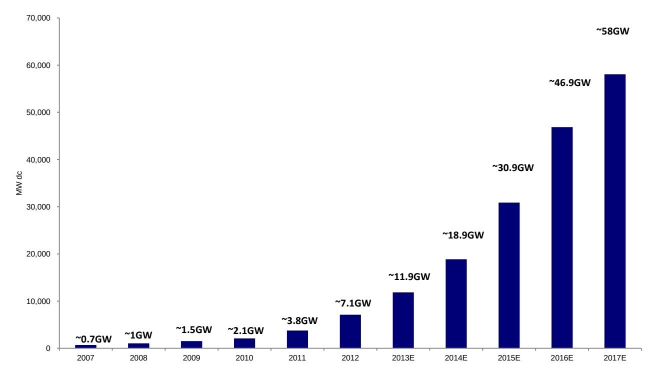
We believe solar is currently competitive in more than 14 states in the U.S without additional state subsidies. Solar LCOE in these states ranges from 10-15 c/kWh and compares to retail electricity price of 12-38 c/kWh in these markets. These grid parity states currently have a cumulative installed capacity of ~10GW as of 2013. However, considering the improved economics of solar in these markets along with other growth enablers such as solar leasing, availability of low cost financing, we expect installed capacity in the US to triple from 2014 exit levels of 18-19GW to approach 60GW through 2017.

Figure 54: US Total PV Installations



Source: Deutsche Bank, SEIA

Figure 55: Total PV Capacity



Source: Deutsche Bank

2) Potential for further cost reductions and solar growth in additional states over the next 12-18 months

Assuming solar system prices decline from $2.90/W currently to sub $2.50/W over the next 12-18 months, solar LCOE in existing grid parity states could decrease further to 9-14 c/kWh driving further acceleration in solar shipments in these markets. At these system price levels, solar has the potential to reach grid parity in 12 additional states as LCOE approaches 11-14 c/kWh in these states.

Figure 56: States Currently at Grid Parity

Grid Parity at $2.90 ($2.03 w/ ITC)	LCOE ($/KWh)	Average Cost of Electricity ($/KWh)
Hawaii	0.11	0.38
New York	0.14	0.20
California	0.11	0.16
Connecticut	0.14	0.19
Rhode Island	0.14	0.18
Nevada	0.10	0.13
Massachusetts	0.14	0.17
New Hampshire	0.14	0.17
Vermont	0.15	0.18
New Mexico	0.10	0.12
Arizona	0.10	0.12
New Jersey	0.14	0.16
Colorado	0.11	0.12
Maryland	0.13	0.14

Source: Deutsche Bank, EIA

Figure 57: Additional States Poised to Reach Grid Parity

Grid Parity at $2.50 ($1.75 w/ ITC)	LCOE ($/KWh)	Average Cost of Electricity ($/KWh)
Michigan	$0.13	$0.15
Delaware	$0.12	$0.13
Kansas	$0.11	$0.12
South Carolina	$0.11	$0.12
Wisconsin	$0.13	$0.14
Pennsylvania	$0.12	$0.13
District of Columbia	$0.12	$0.13
Florida	$0.11	$0.12
Maine	$0.14	$0.15
Georgia	$0.11	$0.12
Utah	$0.10	$0.11
Texas	$0.12	$0.12
North Carolina	$0.11	$0.11
Mississippi	$0.11	$0.11

Source: Deutsche Bank, EIA

3) Lower financing costs could provide additional growth kicker

We believe the broader acceptance of yieldco type structures could lower solar financing costs by ~200-300 bps in addition to providing significant amount of liquidity within the solar sector. Every 100 bps reduction in financing costs results in 1 c/kWh reduction of LCOE, in our view. We believe solar LCOE could potentially decrease from 9-15 c/kWh to 7-13 c/kWh as a result of wider acceptance of yieldco type structures. Wider availability of financing options could provide project developers some cushion in a rising interest rate environment.

Figure 58: Shift in LCOE for 100bps Reduction

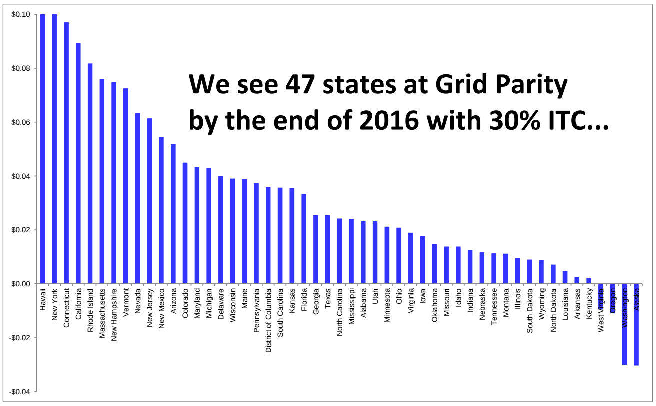
Cost of Debt/Discount Rate	Average LCOE ($2.03 w/ITC)	Reduction per 100bps
7%	$0.14	
6%	$0.13	$0.0093
5%	$0.12	$0.0091
4%	$0.11	$0.0089
3%	$0.10	$0.0086
2%	$0.09	$0.0082

Source: Deutsche Bank
Note: Average of all 50 states and DC for current net system LCOE (with ITC)

4) ITC expiration could act as another catalyst

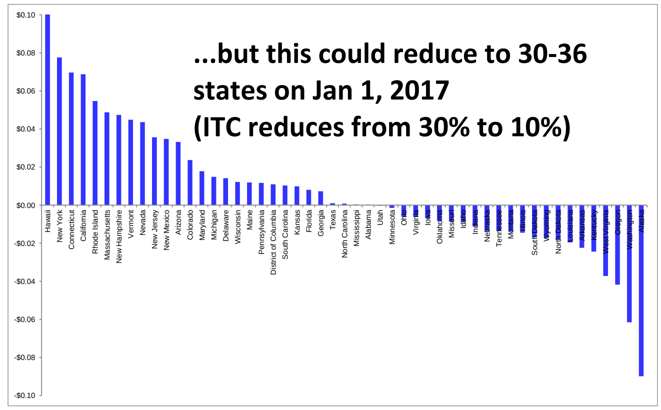
Current forms of federal investment tax credits are set to expire in 2016. Without any ITC, solar LCOE increases from 10-16 c/kWh to 15-21c/kWh and only 1 state (Hawaii) screening at grid parity states vs ~10 states currently. In a 2017+ 10% ITC environment, solar would be at grid parity in ~36 states (vs ~47 states with 30% ITC), assuming system prices and financing costs decline although the economics for solar would not be as attractive. Consequently, we expect to see a big rush of new installations ahead of the 2016 ITC expiration.

Figure 59: 2016 Grid Parity With ~30% ITC



Source: Deutsche Bank, EIA
Note: Both Graphs above show LCOE minus average electricity price in States

Figure 60: Grid Parity When ITC Steps Down to 10%



Source: Deutsche Bank, EIA

5) Leasing model is already much more mainstream with room to grow

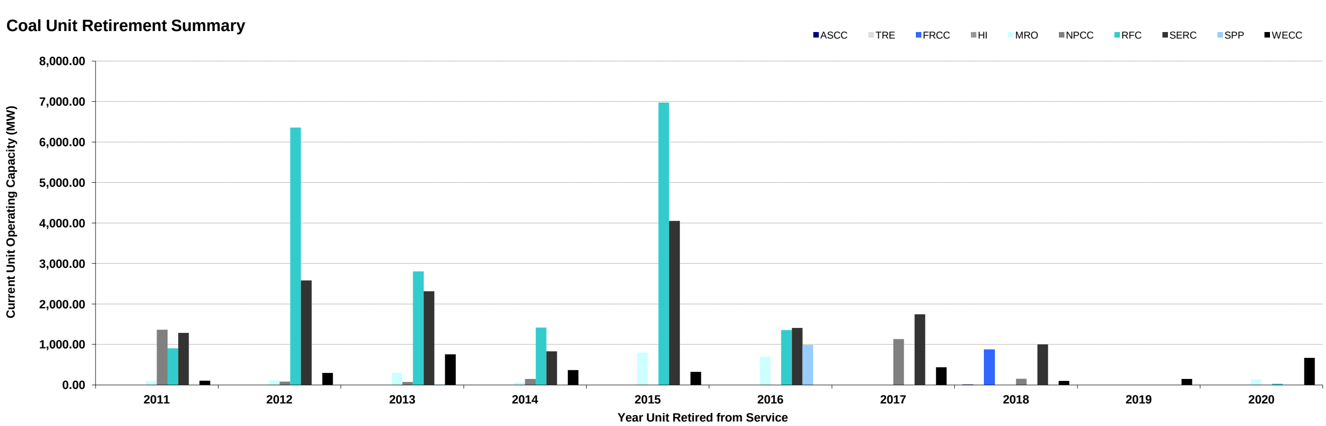
We believe the availability of residential leasing option would also act as a significant growth catalyst for the sector considering the fact that solar leasing companies are highly profitable and have strong incentive to maximize the number of leasing customers ahead of ITC expiration in 2016. While solar leasing is already attractive, we expect lease prices to decline further over the next 18 months and growth to accelerate. We have already seen evidence of this as top markets like California benefit from flat pricing models (well below the cost of electricity).

Overview

The US market has over 17.5GW of installed solar capacity and nearly 5GW of solar capacity was added in 2013. While the historic data shows a focus on utility scale installations, distributed generation (both residential and commercial) continues to make notable progress. We estimate that ~800MW of residential systems were installed in 2013 and expect this number to reach 5GW as solar securitization increases and more states continue to reach grid parity. We believe regions within 10+ states are at grid parity already, while more states will follow suit as cost per watt continues to decline fueled by BoS cost reductions, making solar more competitive with rising electricity rates over the long term.

Despite near term overhang from trade cases, we believe medium and long term market fundamentals remain intact and continue to see a notable ramp in installations in the 2015/2016 timeframe. While the distributed generation market will likely continue to expand rapidly, we see increasing signs of utility scale strength as coal plant retirements and EPA rules drive increasing installations ahead of 2017. Beyond 2016, we see the EPA's Clean Power Plan as an important multi-year driver for the utility scale market. The recently finalized Mercury and Air Toxics Standards Rule is generally expected to result in the retirement of an extensive number of coal plants over the next 1-2 years. We expect that this will provide a boost to potential utility scale solar, particularly when considered in the context of the upcoming carbon emissions rule. Through 2018 there are already ~25GW of plants scheduled for retirement, but this could prove to be conservative.

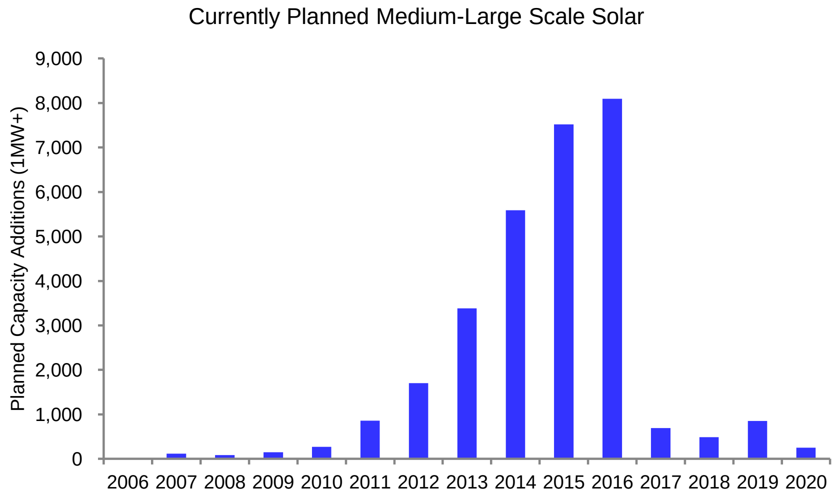
Figure 61: Coal Unit Retirement Summary (by NERC Region)



Source: SNL

The vast majority of these plants are scheduled to come from RFC and SERC regions, which constitute the majority of the east coast. Particularly in southern states, we see potential for utility scale solar to help coal plant replacement. One of the most commonly discussed US incentives is the 30% investment tax credit, which is expected to drive levels of solar investment through the end of 2016. Currently planned medium to large scale investment is shown below, and drops off steeply in 2017.

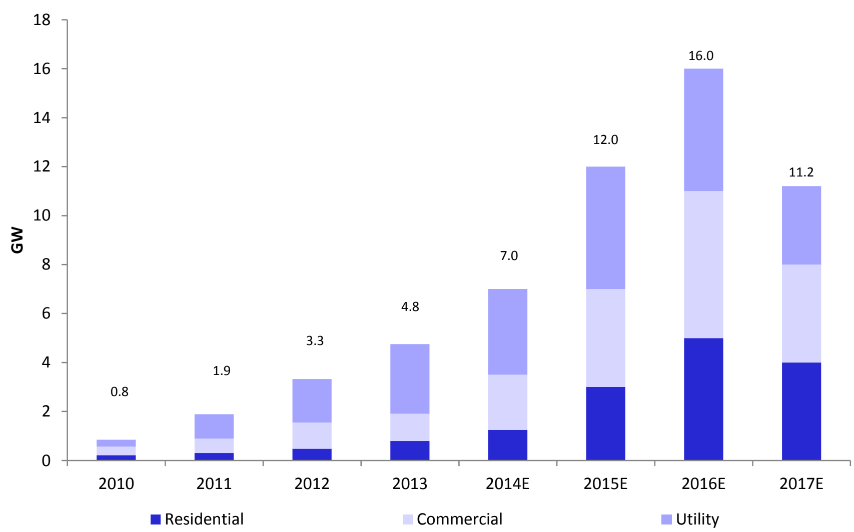
Figure 62: 1MW+ Capacity Additions



Source: SNL, As of 9.9.14

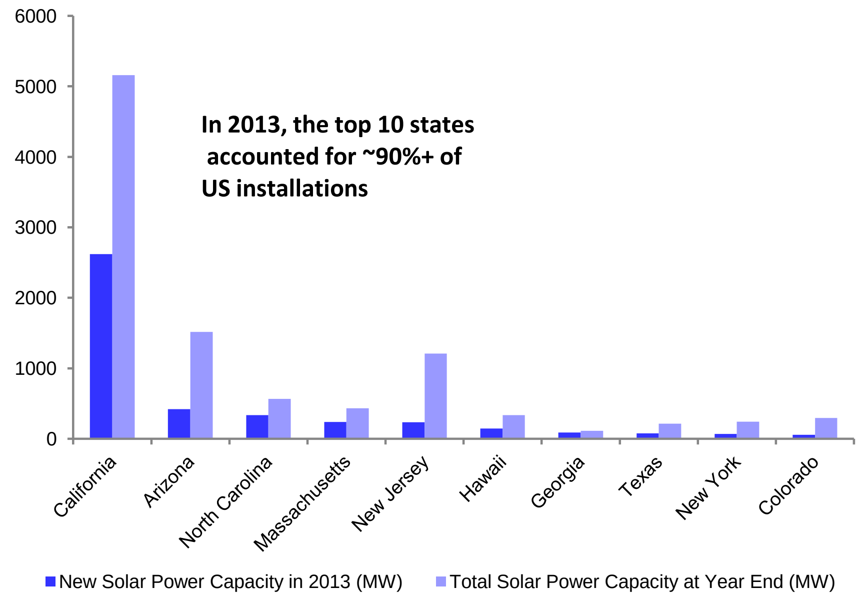
The breakdown of our US installation outlook is shown below. The drop from 2016 to 2017 will likely be driven by a drop in the large scale utility market, given the drop in the investment tax credit.

Figure 63: US Solar Installations Outlook



Source: Deutsche Bank, SEIA

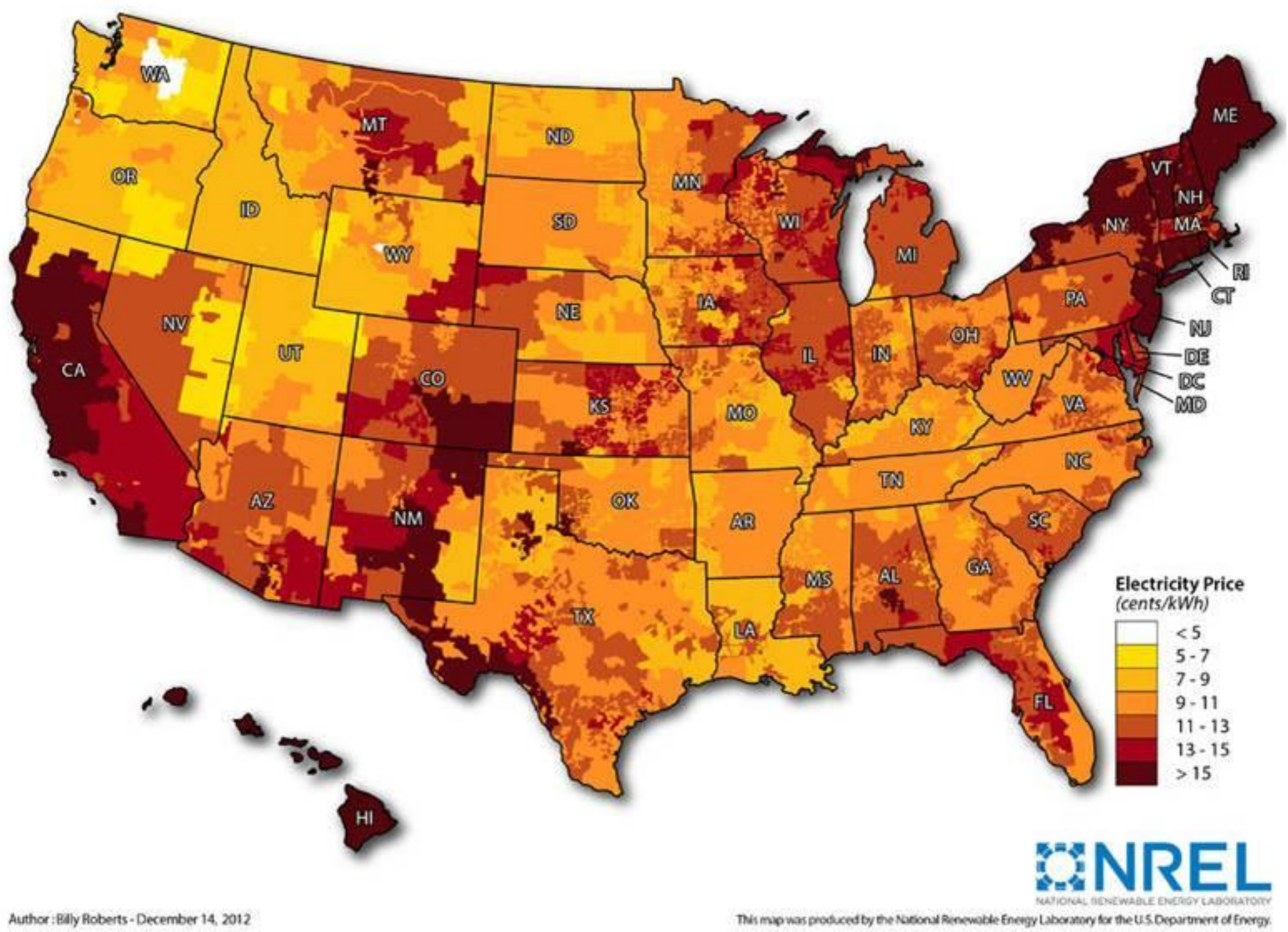
Figure 64: Total State Capacity/Installs



Source: Deutsche Bank, SEIA

State Economics

Figure 65: Dispersion of Electricity Prices in the US



Source: National Renewable Energy Laboratory

As shown above, the electricity price within any given state is often highly variable (we estimate many states are +/- 3 cents from the mean), while the vast number of rate structures can provide for further complications (fixed or variable pricing, time of use, demand response, volume pricing, etc). We have compiled the average state electric prices on a monthly basis and used the LTM average for our model.

Figure 66: Most Expensive Electricity (Residential)

Rank	State	Last 12 Month Average Electricity Price Residential ($/kWh)	Commercial ($/kWh)	Industrial ($/kWh)
1	Hawaii	0.38	$0.35	$0.31
2	New York	0.20	$0.16	$0.06
3	Connecticut	0.19	$0.15	$0.13
4	Alaska	0.19	$0.17	$0.16
5	Rhode Island	0.18	$0.15	$0.13
6	Vermont	0.18	$0.15	$0.10
7	Massachusetts	0.17	$0.15	$0.13
8	New Hampshire	0.17	$0.14	$0.12
9	California	0.16	$0.15	$0.12
10	New Jersey	0.16	$0.13	$0.12
11	Maine	0.15	$0.13	$0.09
12	Michigan	0.15	$0.11	$0.08
13	Wisconsin	0.14	$0.11	$0.08
14	Maryland	0.14	$0.11	$0.09
15	Delaware	0.13	$0.11	$0.09
16	Pennsylvania	0.13	$0.10	$0.07
17	District of Columbi	0.13	$0.12	$0.08
18	Nevada	0.13	$0.10	$0.07
19	Ohio	0.12	$0.10	$0.07
20	South Carolina	0.12	$0.10	$0.06
21	Colorado	0.12	$0.10	$0.07
22	Minnesota	0.12	$0.10	$0.07
23	New Mexico	0.12	$0.10	$0.07
24	Kansas	0.12	$0.10	$0.07
25	Florida	0.12	$0.10	$0.08

Source: Deutsche Bank, EIA

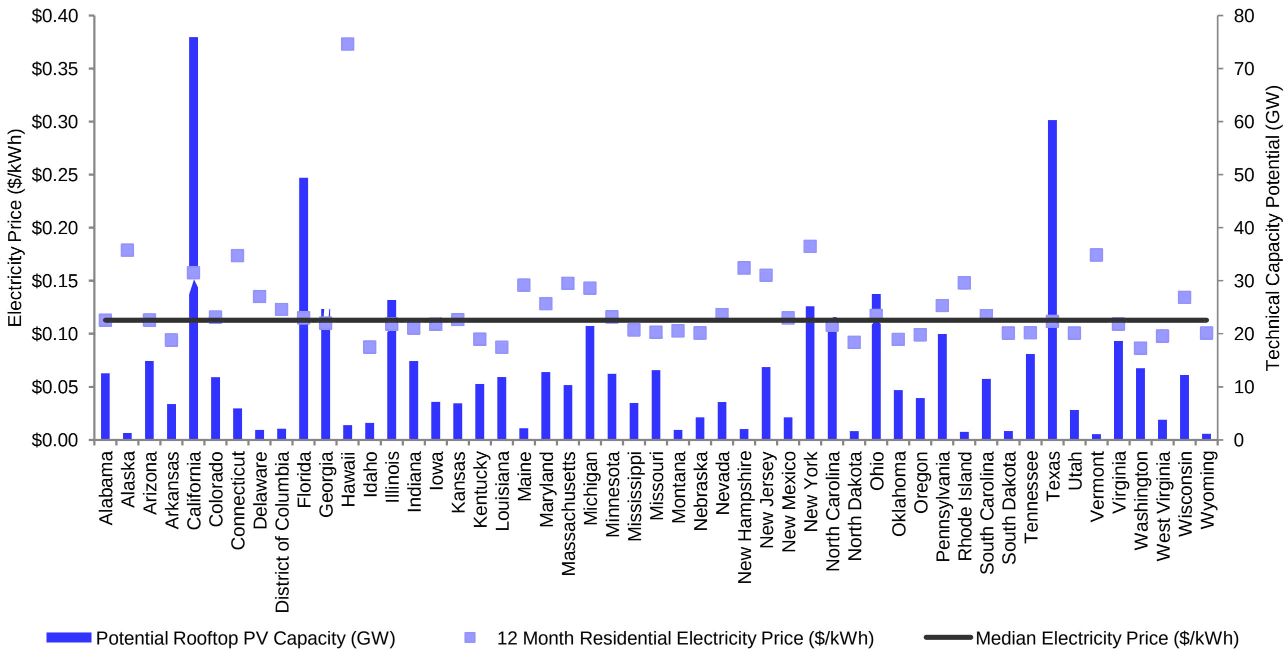
Figure 67: Least Expensive Electricity (Residential)

Rank	State	Last 12 Month Average Electricity Price Residential ($/kWh)	Commercial ($/kWh)	Industrial ($/kWh)
26	Arizona	0.12	$0.10	$0.07
27	Texas	0.12	$0.08	$0.06
28	Georgia	0.12	$0.10	$0.06
29	Iowa	0.11	$0.09	$0.06
30	Alabama	0.11	$0.11	$0.06
31	Mississippi	0.11	$0.11	$0.07
32	Indiana	0.11	$0.10	$0.07
33	North Carolina	0.11	$0.09	$0.06
34	Illinois	0.11	$0.09	$0.06
35	Virginia	0.11	$0.08	$0.07
36	Missouri	0.11	$0.09	$0.06
37	Utah	0.11	$0.09	$0.06
38	South Dakota	0.11	$0.09	$0.07
39	Wyoming	0.11	$0.09	$0.07
40	Nebraska	0.10	$0.09	$0.07
41	Oregon	0.10	$0.09	$0.06
42	Montana	0.10	$0.10	$0.05
43	Tennessee	0.10	$0.10	$0.07
44	Kentucky	0.10	$0.09	$0.06
45	Oklahoma	0.10	$0.08	$0.06
46	Idaho	0.10	$0.08	$0.06
47	North Dakota	0.10	$0.09	$0.08
48	Arkansas	0.10	$0.08	$0.06
49	Louisiana	0.09	$0.09	$0.06
50	West Virginia	0.09	$0.08	$0.06
51	Washington	0.09	$0.08	$0.04

Source: Deutsche Bank, EIA

In the absence of outside incentives, utility electricity prices are the main form of competition a residential/commercial solar project must face. We believe the top 10-15 states provide the most compelling possibilities for unaided cost parity, particularly as fossil fuel based generation has been in relative oversupply and this environment begins to shift. In a 2012 paper (U.S. Renewable Energy Technical Potentials: A GIS-Based Analysis) the US National Renewable Energy Laboratory (NREL) conducted a study on the technical potential for various renewable energy technologies. Using data from the EIA, McGraw-Hill, and Denholm and Margolis, NREL concluded that ~664GW of potential capacity could be realized by the rooftop market alone, versus <1% penetration currently.

Figure 68: Technical Rooftop Capacity Vs Electricity Price



Source: Deutsche Bank, NREL, EIA, McGraw Hill, Denholm and Margolis,

From their analysis, we see that ~51% (343GW) of the technical potential lies in states with electricity prices above the median electricity price ($0.1128/kWh) while, ~19% of the potential (~128GW) lies in states with residential electricity prices already above $0.15/kwh – primarily California (~76GW), New York (~25GW), New Jersey(13.7GW) and Connecticut(5.9GW).

Grid Parity Increasing

We believe that the US is at grid parity various regions where high electricity prices and the declining cost of solar has made investments increasingly attractive. By default our model takes into account the gross lifetime cost of the system and the lifetime electricity production, but we have assumed ITC inclusion (effectively 30% less system cost) in our LCOE analysis.

Below, we show the states which we believe have likely reached grid parity, depending on the region, electricity price, and type of consumption. Hawaii and California are consistently shown towards the top of the list due to high insolation (a measure of the sun's radiation) and high electricity prices, but different pricing schemes for types of electricity within state markets causes divergences thereafter.

Figure 69: States At or Near Grid Parity

Rank	Residential	Commercial	Industrial
1	Hawaii	Hawaii	Hawaii
2	New York	California	California
3	California	New York	Rhode Island
4	Connecticut	Connecticut	Connecticut
5	Rhode Island	Rhode Island	Massachusetts
6	Nevada	Massachusetts	New Jersey
7	Massachusetts	New Hampshire	New Hampshire
8	New Hampshire	New Mexico	Nevada
9	New Mexico	Vermont	Arizona
10	Vermont	Arizona	New Mexico
11	Arizona	Nevada	Colorado
12	New Jersey	New Jersey	Maryland
13	Colorado	District of Columbia	Florida
14	Maryland	Colorado	Vermont

Source: Deutsche Bank, EIA

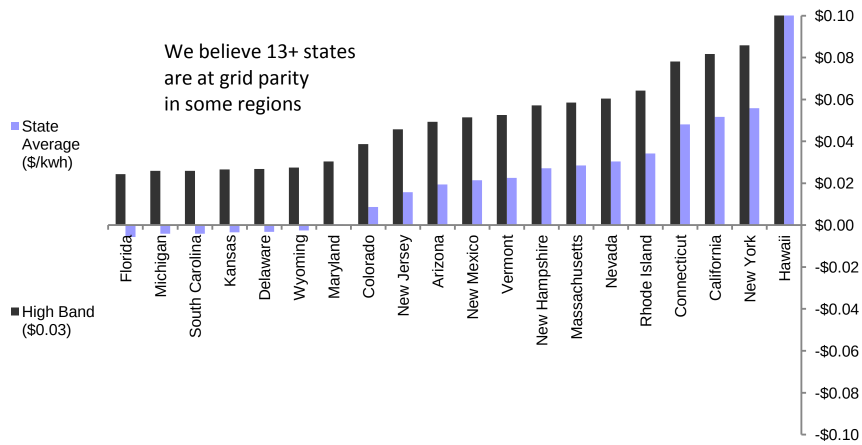
While Hawaii is an outlier due to drastically higher electricity prices, The next 10+ states closest to grid parity reinforce our view that high electricity prices provide the most compelling argument in favor of PV self generation. There is often a direct correlation between population centers and high electricity prices (more resources required to generate/transmit electricity equates to a higher rate base) which implies upside bias to our estimates as customer awareness increases and the financial viability of solar passes further into mainstream decision making.

Furthermore, we have conducted a similar analysis for Commercial and Industrial sectors and with the ITC. While we assumed \$2.03/w (\$2.90/w ex ITC) for residential, we have used \$1.61/w (\$2.30/w ex ITC) and \$1.44/w (\$2.05/w ex ITC) for commercial and industrial systems (given economies of scale). Our analysis shows that despite lower electricity prices to compete with compared to residential prices, the commercial market appears particularly attractive and should continue to be a solid growth driver for the US market. The residential market retains the most markets at grid parity in the current ITC environment.

Based on our analysis we believe 13+ States in the US are at grid parity in certain regions (depending on the local electricity price). Our base case model uses the 12 month rolling average electricity price for each state. However, given notable volatility in electricity prices within states, we have also tested our assumptions compared to a high band (+$0.03) above average. Our analysis shows that 20-40% of US States appear to be at or near to grid parity. Industrial electricity prices are the most difficult to compete with (as they are lowest) but are likely biased to the upside if our analysis considered other incentives in the LCOE calculation.

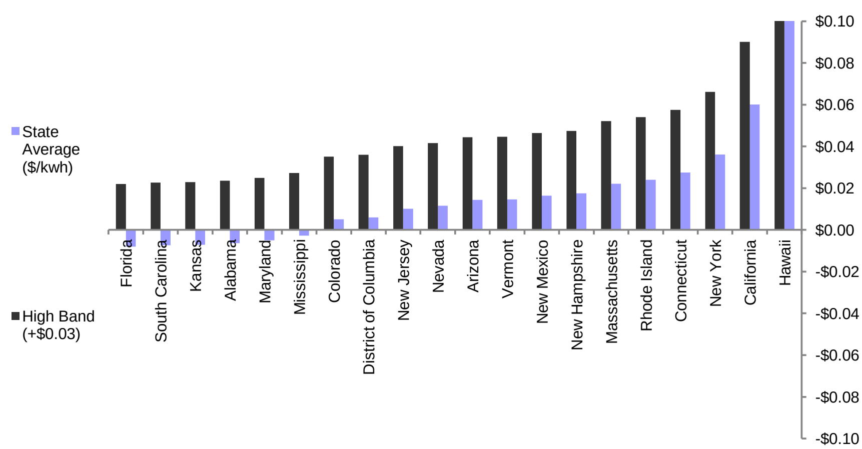
Key States – Distance from Grid Parity

Figure 70: Residential Parity @ $2.03 Net Cost (w/ ITC. $2.90/w Gross)



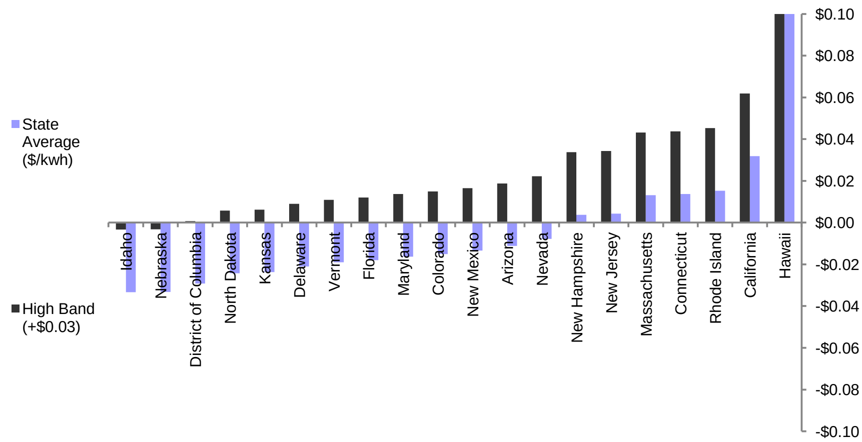
Source: Deutsche Bank, EIA
Note: These three successive graphs show LCOE minus electricity price (average and +3 cents)

Figure 71: Commercial Parity @ $1.61/w Net Cost (w/ITC. $2.30/w Gross)



Source: Deutsche Bank, EIA

Figure 72: Industrial Parity @ $1.44/w Net Cost (w/ ITC. $2.05/w Gross)



Source: Deutsche Bank, EIA

Inputs/Methodology

For our analysis we have considered systems using a traditional string inverter (replaced after 10 years). We assume a 1% production decrease every year, an 80% DC to AC efficiency conversion, and 365 days of electricity production. A yearly power price escalator (3%) is used to account for general price inflation or rising fuel costs.

Electricity production from the sample solar array was estimated using a point average insolation level from NREL's Solar Prospector (we have used levels for each State's most populous city) multiplied by the system size. We use the total system cost, the yearly operation & maintenance, inverter replacement costs, and debt payments to arrive at total cost for a year. We apply a discount rate equal to the total financing cost in order to arrive at a discounted total costs and production. LCOE is calculated as gross total lifetime costs divided by total lifetime electricity production (both are discounted at the cost of debt). Our model spans a 20 and 30 year lifespan.

Methodology

Furthermore, we have modeled out the cash flows of each system to arrive at unlevered IRR's ranging from 0 to 47%. Our model assumes that the electricity is either self used (representing an avoided cost) or sold back into the grid at the prevailing electricity price. The Solar Energy Industries Association (SEIA) reports that 43 of the 50 states + DC currently have some form of net metering in place. Despite some recent challenges to policies, we believe that net metering policies are likely to stay in place for the foreseeable future. The table below represents an unlevered system.

Figure 73: LCOE and IRR in USA's Most Populous Cities (100% equity, including ITC)

State	Insolation (kWh/m2/year)	Cost of Electricity	LCOE ($2.03 w/ ITC)	IRR (20 Year System)	IRR (30 Year System)
Hawaii	1816	$0.38	$0.11	41.12%	41.17%
California	1843	$0.16	$0.11	11.71%	13.13%
New York	1405	$0.20	$0.14	10.61%	12.17%
Connecticut	1381	$0.19	$0.14	9.80%	11.48%
Nevada	2047	$0.13	$0.10	9.52%	11.24%
Rhode Island	1396	$0.18	$0.14	8.53%	10.42%
New Mexico	2008	$0.12	$0.10	8.22%	10.15%
Massachusetts	1390	$0.17	$0.14	7.98%	9.95%
Arizona	2032	$0.12	$0.10	7.96%	9.94%
New Hampshire	1381	$0.17	$0.14	7.83%	9.83%
Vermont	1308	$0.18	$0.15	7.28%	9.37%
New Jersey	1420	$0.16	$0.14	6.77%	8.96%
Colorado	1779	$0.12	$0.11	6.28%	8.56%
Maryland	1475	$0.14	$0.13	5.20%	7.69%
Delaware	1463	$0.13	$0.14	4.81%	7.38%
Michigan	1341	$0.15	$0.15	4.75%	7.33%
Kansas	1621	$0.12	$0.12	4.74%	7.33%
South Carolina	1588	$0.12	$0.12	4.68%	7.27%
Wisconsin	1381	$0.14	$0.14	4.48%	7.12%
Florida	1615	$0.12	$0.12	4.47%	7.11%
Pennsylvania	1436	$0.13	$0.14	4.46%	7.10%
District of Columbia	1481	$0.13	$0.13	4.42%	7.07%
Maine	1229	$0.15	$0.16	4.04%	6.77%
Georgia	1548	$0.12	$0.13	3.43%	6.29%
Utah	1676	$0.11	$0.12	3.41%	6.28%
Wyoming	1682	$0.11	$0.11	3.40%	6.27%
Texas	1509	$0.12	$0.13	3.35%	6.23%
North Carolina	1579	$0.11	$0.13	3.34%	6.22%
Mississippi	1554	$0.11	$0.13	3.28%	6.18%
Alabama	1521	$0.11	$0.13	3.14%	6.07%
Minnesota	1387	$0.12	$0.14	2.66%	5.70%
Virginia	1500	$0.11	$0.13	2.58%	5.64%
Ohio	1363	$0.12	$0.15	2.58%	5.64%
Iowa	1436	$0.11	$0.14	2.35%	5.46%
Oklahoma	1646	$0.10	$0.12	2.25%	5.39%
Idaho	1667	$0.10	$0.12	2.16%	5.32%
Missouri	1512	$0.11	$0.13	1.99%	5.19%
Indiana	1399	$0.11	$0.14	1.72%	4.99%
Nebraska	1500	$0.10	$0.13	1.71%	4.98%
Tennessee	1518	$0.10	$0.13	1.68%	4.96%
Montana	1515	$0.10	$0.13	1.66%	4.95%
South Dakota	1445	$0.11	$0.14	1.33%	4.70%
Illinois	1369	$0.11	$0.14	1.33%	4.70%
North Dakota	1570	$0.10	$0.13	1.19%	4.59%
Louisiana	1557	$0.09	$0.13	0.86%	4.35%
Arkansas	1515	$0.10	$0.13	0.55%	4.13%
Kentucky	1430	$0.10	$0.14	0.47%	4.07%
West Virginia	1369	$0.09	$0.14	-1.03%	3.01%
Oregon	1229	$0.10	$0.16	-1.07%	2.98%
Alaska	636	$0.19	$0.31	-1.66%	2.57%
Washington	1211	$0.09	$0.16	-3.62%	1.29%

Source: Deutsche Bank, NREL, EIA
Note: Includes 30% ITC for all states

SREC Markets

State renewable energy certificates (SRECs) have helped to push New Jersey into one of the top solar markets in the country, and several other states have followed suit. While California does not currently utilize SREC markets the same way that other states do, we believe these market based instruments can be an effective means to increase ROI and enhance solar adoption rates.

Overview – Active Markets

New Jersey, Maryland, Delaware, Massachusetts, Ohio, Pennsylvania, North Carolina and Washington DC all employ active SREC markets currently. Indiana, Kentucky, West Virginia, and North Carolina also have marginal SREC markets because they have territory located within the PJM Regional Transmission Organization, which allows them to trade into active SREC markets like Ohio and Pennsylvania. Furthermore, California allows tradable renewable energy credits (TRECs) which are considerably different from SRECs and less likely to directly benefit distributed generation.

What is an SREC?

SREC's have been implemented to provide a partially market based incentive for solar capacity additions, particularly for distributed generation. 1 SREC is created for every 1 MWh of electricity generated from a solar installation. Using a Newark, NJ example, a 5kw system would generate ~6-8 SREC's per year. At current average wholesale prices, a residential system could generate incremental yearly income of ~$1,000-$1,500 per year.

SREC markets are primarily based on supply and demand, although the demand is essentially state mandated. The specifics vary across states, but there is generally a target renewable portfolio standard (RPS) with a specific carve out for solar generation over the next 10+ years as either a percentage of total electricity use or total GWh generated from solar. For example, the requirements for NJ are shown below, which have changed from absolute generation targets to % generation targets as shown.

Figure 74: New Jersey RPS Solar Mandate

Energy Year	Old Solar Carve-Out	New Solar Carve Out		Energy Year	OldSolar Carve-Out	New Solar Carve Out
EY 2011	306 GWh	306 GWh		EY 2020	2,164 GWh	3.38%
EY 2012	442 GWh	442 GWh		EY 2021	2,518 GWh	3.47%
EY 2013	596 GWh	596 GWh		EY 2022	2,928 GWh	3.56%
EY 2014	772 GWh	2.05%		EY 2023	3,433 GWh	3.65%
EY 2015	965 GWh	2.45%		EY 2024	3,989 GWh	3.74%
EY 2016	1,150 GWh	2.75%		EY 2025	4,610 GWh	3.83%
EY 2017	1,357 GWh	3.00%		EY 2026+	5,316 GWh	3.92%
EY 2018	1,591 GWh	3.20%		EY 2027	5,316 GWh	4.01%
EY 2019	1,858 GWh	3.29%		EY 2028 +	5,316 GWh	4.10%

*Note: Energy Year Begins June 1st of the prior calendar year in NJ

Source: NJ State Legislature Bills, DSIRE
Note: "Old Solar Carve Out" refers to A.B. 3520, while "New Solar Carve Out" refers to S.B. 1925

Eligibility and SACP

SREC's are generally designed to increase distributed generation market penetration and focus specifically on smaller system sizes more suited to residential or commercial scale. In some states, residential systems (<10-20kw) can use estimated generation for SREC credits but this is starting to change.

Solar Alternative Compliance Payments (SACPs) are effectively a price ceiling for SREC's, as they are the price a utility would pay if it cannot purchase SRECs for a lower price. The existence of this mechanism encourages market development but we believe it is unlikely that longer-term prices will rise above a certain discount to these levels, given the attractive economics from SRECs and relatively high prices for SACPs (~$300-400).

SRECs in Perspective

One of the most obvious benefits of an SREC is a notable reduction in the payback time for a solar system. Given that 1 SREC is created for 1MWh, each $100 in SREC prices is effectively equal to 10 cents per kwh. The average US retail electricity price is only 12 cents per kwh, so we can see that the economics improve with a functioning SREC market which is not dramatically in oversupply. This has happened before which can cause a precipitous decline in SREC prices and hurt the economics of legacy projects. However, state legislatures which choose to implement RPS with a solar carve out may be more likely than others to revise as needed.

SRECs in our Model

States with high insolation levels showed the greatest improvement in IRRs because they produced the most SRECs.

Figure 75: Theoretical $100 SREC Project IRR

				No SREC		$100 SREC	
State	Insolation (kWh/m2/year)	Cost of Electricity	LCOE ($2.03 w/ ITC)	IRR (20 Year System)	IRR (30 Year System)	IRR (20 Year System)	IRR (30 Year System)
Alabama	1521	$0.11	$0.13	2.80%	5.88%	7.55%	9.53%
Alaska	636	$0.19	$0.32	-2.31%	2.33%	-0.69%	3.41%
Arizona	2032	$0.12	$0.10	7.78%	9.82%	15.67%	16.53%
Arkansas	1515	$0.10	$0.13	0.06%	3.91%	4.54%	7.15%
California	1843	$0.16	$0.11	11.58%	13.02%	19.47%	20.05%
Colorado	1779	$0.12	$0.11	6.08%	8.44%	12.39%	13.61%
Connecticut	1381	$0.19	$0.15	9.64%	11.37%	14.83%	15.81%
Delaware	1463	$0.13	$0.14	4.55%	7.23%	9.29%	10.98%
District of Columbi	1481	$0.13	$0.14	4.14%	6.91%	8.90%	10.65%
Florida	1615	$0.12	$0.12	4.20%	6.95%	9.50%	11.14%
Georgia	1548	$0.12	$0.13	3.10%	6.12%	8.00%	9.89%
Hawaii	1816	$0.38	$0.11	41.08%	41.14%	59.59%	59.60%
Idaho	1667	$0.10	$0.12	1.77%	5.12%	6.97%	9.05%
Illinois	1369	$0.11	$0.15	0.89%	4.49%	4.91%	7.44%
Indiana	1399	$0.11	$0.14	1.30%	4.78%	5.46%	7.87%
Iowa	1436	$0.11	$0.14	1.97%	5.27%	6.32%	8.54%
Kansas	1621	$0.12	$0.12	4.48%	7.17%	9.85%	11.43%
Kentucky	1430	$0.10	$0.14	-0.03%	3.84%	4.14%	6.85%
Louisiana	1557	$0.09	$0.13	0.39%	4.13%	5.05%	7.53%
Maine	1229	$0.15	$0.16	3.74%	6.60%	7.51%	9.52%
Maryland	1475	$0.14	$0.14	4.95%	7.54%	9.80%	11.40%
Massachusetts	1390	$0.17	$0.14	7.80%	9.84%	12.72%	13.93%
Michigan	1341	$0.15	$0.15	4.49%	7.18%	8.76%	10.54%
Minnesota	1387	$0.12	$0.14	2.29%	5.51%	6.50%	8.69%
Mississippi	1554	$0.11	$0.13	2.94%	5.99%	7.84%	9.76%
Missouri	1512	$0.11	$0.13	1.59%	4.99%	6.18%	8.43%
Montana	1515	$0.10	$0.13	1.24%	4.74%	5.82%	8.14%
Nebraska	1500	$0.10	$0.13	1.29%	4.78%	5.82%	8.14%
Nevada	2047	$0.13	$0.10	9.36%	11.13%	17.74%	18.43%
New Hampshire	1381	$0.17	$0.15	7.65%	9.71%	12.51%	13.75%
New Jersey	1420	$0.16	$0.14	6.58%	8.84%	11.43%	12.81%
New Mexico	2008	$0.12	$0.10	8.04%	10.04%	15.87%	16.71%
New York	1405	$0.20	$0.14	10.46%	12.06%	15.90%	16.78%
North Carolina	1579	$0.11	$0.13	3.01%	6.04%	8.01%	9.90%
North Dakota	1570	$0.10	$0.13	0.73%	4.38%	5.47%	7.86%
Ohio	1363	$0.12	$0.15	2.21%	5.45%	6.32%	8.55%
Oklahoma	1646	$0.10	$0.12	1.87%	5.20%	7.00%	9.07%
Oregon	1229	$0.10	$0.16	-1.67%	2.74%	1.74%	5.09%
Pennsylvania	1436	$0.13	$0.14	4.18%	6.94%	8.77%	10.54%
Rhode Island	1396	$0.18	$0.14	8.36%	10.30%	13.40%	14.53%
South Carolina	1588	$0.12	$0.13	4.41%	7.12%	9.63%	11.25%
South Dakota	1445	$0.11	$0.14	0.89%	4.49%	5.19%	7.65%
Tennessee	1518	$0.10	$0.13	1.26%	4.76%	5.85%	8.16%
Texas	1509	$0.12	$0.13	3.02%	6.05%	7.75%	9.69%
Utah	1676	$0.11	$0.12	3.08%	6.10%	8.48%	10.28%
Vermont	1308	$0.18	$0.15	7.09%	9.25%	11.56%	12.93%
Virginia	1500	$0.11	$0.13	2.21%	5.45%	6.83%	8.94%
Washington	1211	$0.09	$0.17	-4.47%	1.02%	-1.16%	3.13%
West Virginia	1369	$0.09	$0.15	-1.63%	2.77%	2.25%	5.45%
Wisconsin	1381	$0.14	$0.15	4.21%	6.96%	8.59%	10.39%
Wyoming	1682	$0.11	$0.11	3.07%	6.09%	8.49%	10.28%

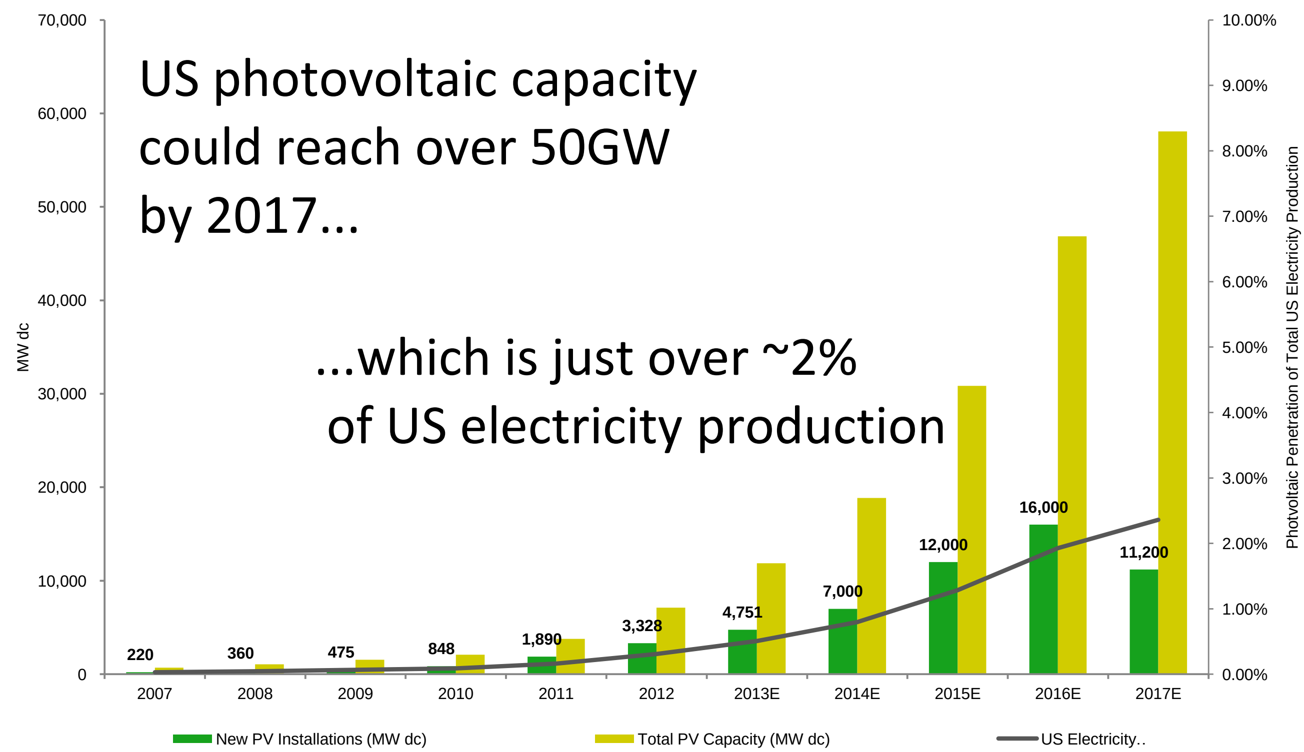
Source: Deutsche Bank, NREL

2016, 2017 and Beyond: Our Outlook

Our global outlook for solar shipments includes notable growth for the US market over the next several years, and we believe this will be increasingly driven by distributed generation, particularly as the ITC nears its step down to 10%. The economics are already compelling in 20-30% of US states and we expect this to improve as soft costs come down (lowering BoS) and potential customer awareness begins to ramp.

We believe 2015 will be a key inflection point for solar power in the United States. While 2013 and 2014 already showed impressive growth, 2015 and 2016 could see YoY increases of 30-70%, bringing total installs to 12GW and 16GW respectively. This implies nearly 50GW of nationwide photovoltaic capacity, of which 20-30GW will come from distributed generation. By 2017, even the drop in utility installations will be mitigated by the strength in distributed generation.

Figure 76: US Outlook



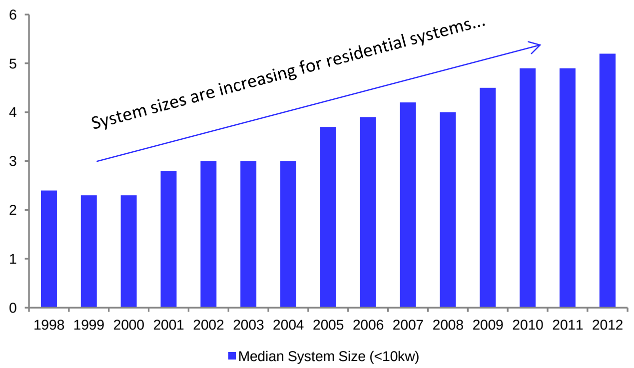
Source: Deutsche Bank, EIA. SEIA

To put this in perspective, Germany has ~36+GW of installed capacity today in a country with a population about ¼ as large as the US and a physical size smaller than the State of California. While the German PV and electricity markets have many differences, we believe this comparison can help put things in perspective.

Balance of Systems Can Lower Total Cost Significantly

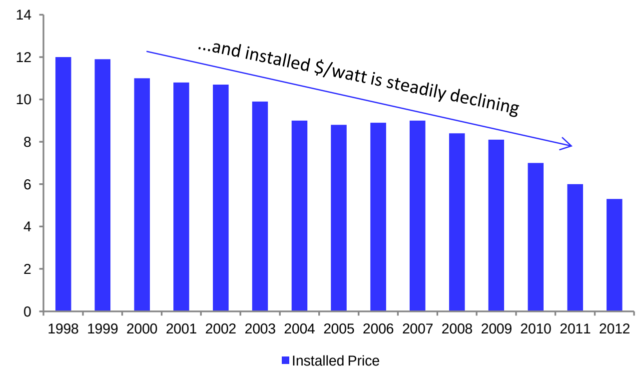
While the costs of small (<20kw) distributed generation systems generally range in the $2.50-4.00 cost today, we have seen dramatic reductions in system costs over the last decade and expect this to continue in the United States. We believe we can see 10-15% annual reductions in system cost/watt over the next several years, which should drive pure LCOE down to the 8-14 c/kwh range for potential grid parity states. Historically, we have seen this play out, although we note that much of the reduction going forward will come from non-panel costs.

Figure 77: Residential System Sizes are Increasing



Source: NREL – "Tracking the Sun VI"

Figure 78: System Costs are Decreasing

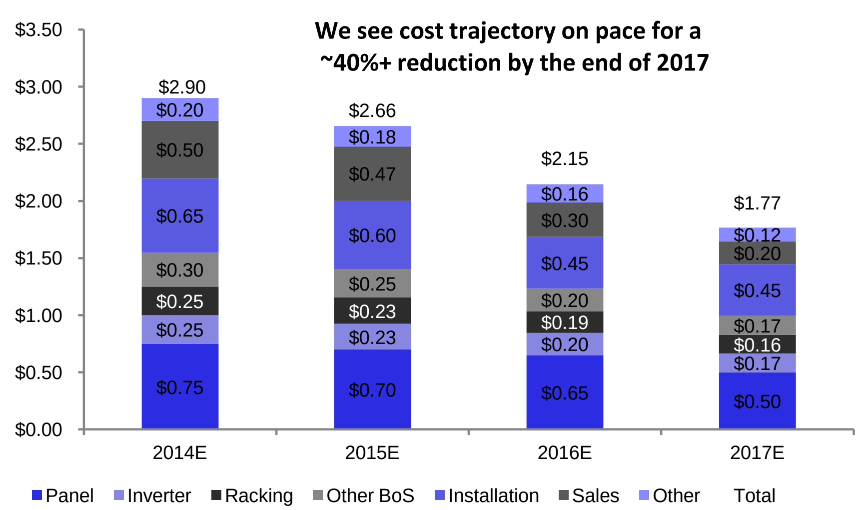


Source: NREL – "Tracking the Sun VI"

Cost Reduction Set for ~40% by 2017

As outlined in previous sections, we see ample room for cost reduction between now and the end of 2017, driven primarily by balance of system costs. Panel prices are likely to come down as trade cases are mitigated or reduced, but customer acquisition costs, installation, inverter, racking, and all other miscellaneous costs will likely continue to trend down on a cost per watt basis.

Figure 79: Estimated Cost



Source: Deutsche Bank

2016 Scenario: 47 States at Grid Parity

Utilizing our 2016 estimates outlined below, we believe ~47 states (including Washington DC) will be at grid parity exiting 2016 when the 30% ITC is factored in. Therefore, we expect a significant rush particularly in the residential segment, as large installers rush to complete as many installations as possible while the economics are best.

Figure 80: 2016 Assumptions

Assumptions	Value
Gross System Cost	$2.15
Net System Cost (Net 30% ITC)	$1.51
Inverter Cost	$0.16
ITC	30%
Cost of Debt/Discount Rate	7%
Equity	100%
Annual Electricity Price Increase	3%
SRECs	None

Source: Deutsche Bank

Figure 81: 2016 Scenario

State	Insolation (kWh/m2/year)	LCOE ($/KWh)	Average Cost of Electricity ($/KWh)	Solar Vs Avoided Cost	IRR (20 Year System)	IRR (30 Year System)
Hawaii	1816	$0.08	$0.40	-$0.32	77.60%	77.60%
New York	1405	$0.11	$0.21	-$0.10	18.21%	18.96%
Connecticut	1381	$0.11	$0.21	-$0.10	17.05%	17.89%
California	1843	$0.08	$0.17	-$0.09	19.83%	20.46%
Rhode Island	1396	$0.11	$0.19	-$0.08	15.28%	16.28%
Massachusetts	1390	$0.11	$0.18	-$0.07	14.51%	15.60%
New Hampshire	1381	$0.11	$0.18	-$0.07	14.31%	15.42%
Vermont	1308	$0.09	$0.19	-$0.07	13.56%	14.75%
Nevada	2047	$0.07	$0.14	-$0.06	16.66%	17.53%
New Jersey	1420	$0.11	$0.17	-$0.06	12.88%	14.15%
New Mexico	2008	$0.07	$0.13	-$0.05	14.84%	15.89%
Arizona	2032	$0.07	$0.13	-$0.05	14.49%	15.58%
Colorado	1779	$0.08	$0.13	-$0.04	12.24%	13.59%
Maryland	1475	$0.10	$0.14	-$0.04	10.82%	12.36%
Michigan	1341	$0.11	$0.15	-$0.04	10.24%	11.87%
Delaware	1463	$0.10	$0.14	-$0.04	10.32%	11.93%
Wisconsin	1381	$0.11	$0.15	-$0.04	9.90%	11.58%
Maine	1229	$0.12	$0.16	-$0.04	9.34%	11.10%
Pennsylvania	1436	$0.10	$0.14	-$0.04	9.87%	11.55%
District of Columbia	1481	$0.10	$0.14	-$0.03	9.82%	11.51%
South Carolina	1588	$0.09	$0.13	-$0.03	10.15%	11.79%
Kansas	1621	$0.09	$0.13	-$0.03	10.23%	11.86%
Florida	1615	$0.09	$0.13	-$0.03	9.89%	11.57%
Georgia	1548	$0.10	$0.12	-$0.02	8.58%	10.46%
Texas	1509	$0.10	$0.12	-$0.02	8.48%	10.38%
North Carolina	1579	$0.09	$0.12	-$0.02	8.47%	10.37%
Mississippi	1554	$0.10	$0.12	-$0.02	8.39%	10.31%
Utah	1676	$0.10	$0.11	-$0.02	8.55%	10.44%
Alabama	1521	$0.10	$0.12	-$0.02	8.22%	10.17%
Minnesota	1387	$0.11	$0.13	-$0.02	7.64%	9.69%
Ohio	1363	$0.11	$0.13	-$0.02	7.55%	9.61%
Virginia	1500	$0.11	$0.12	-$0.02	7.55%	9.61%
Iowa	1436	$0.10	$0.12	-$0.02	7.27%	9.38%
Oklahoma	1646	$0.09	$0.11	-$0.01	7.16%	9.29%
Idaho	1667	$0.09	$0.10	-$0.01	7.04%	9.20%
Missouri	1512	$0.10	$0.11	-$0.01	6.84%	9.03%
Indiana	1399	$0.11	$0.12	-$0.01	6.52%	8.77%
Nebraska	1500	$0.10	$0.11	-$0.01	6.52%	8.77%
Tennessee	1518	$0.10	$0.11	-$0.01	6.48%	8.74%
Montana	1515	$0.10	$0.11	-$0.01	6.46%	8.72%
Illinois	1369	$0.11	$0.12	-$0.01	6.07%	8.41%
Wyoming	1682	$0.11	$0.11	-$0.01	8.54%	10.43%
South Dakota	1445	$0.10	$0.11	-$0.01	6.08%	8.41%
North Dakota	1570	$0.10	$0.10	-$0.01	5.90%	8.27%
Louisiana	1557	$0.10	$0.10	$0.00	5.53%	7.97%
Arkansas	1515	$0.10	$0.10	$0.00	5.18%	7.69%
Kentucky	1430	$0.10	$0.11	$0.00	5.08%	7.61%
West Virginia	1369	$0.12	$0.10	$0.01	3.42%	6.31%
Oregon	1229	$0.12	$0.11	$0.01	3.38%	6.28%
Washington	1211	$0.10	$0.09	$0.03	0.68%	4.26%
Alaska	636	$0.24	$0.20	$0.03	2.74%	5.79%

Source: Deutsche Bank

2017+: 41 States at Grid Parity

We have applied the assumptions below to our model and found 41 states + DC (~80%) will be at grid parity, while only Washington and Alaska are more than 3 cents per kwh away. Therefore, we believe Solar can achieve cost competitiveness in most states even with a step down in the ITC. While there must be several more years of cost reductions, efficiency gains, and marketplace acceptance (which leads to lower overall costs) we see solar becoming increasingly mainstream as it passes cost competitiveness with traditional forms of generation. While we will likely see some utilities fight at every step of the way (because it threatens their business model), we expect system economics will ultimately win in the longer run and yearly installations will continue the general upward trajectory (although a 2016 rush is likely). Already we are hearing of the challenges that drastically increased solar penetration will have for the electricity grid, and we expect these discussions to become increasingly necessary as solar continues its path.

Figure 82: 2017 Assumptions

Assumptions	Value
System Cost	$1.77
Inverter Cost	$0.12
ITC	10%
Cost of Debt/Discount Rate	7%
Equity	100%
Annual Electricity Price Increase	3%
SRECs	None

Source: Deutsche Bank

Figure 83: 2017 Scenario.

State	Insolation (kWh/m2/year)	LCOE ($/KWh)	Average Cost of Electricity ($/KWh)	Solar Vs Avoided Cost	IRR (20 Year System)	IRR (30 Year System)
Hawaii	1816	$0.09	$0.41	-$0.32	73.57%	73.57%
New York	1405	$0.12	$0.22	-$0.10	17.69%	18.46%
Connecticut	1381	$0.12	$0.21	-$0.09	16.57%	17.44%
California	1843	$0.09	$0.18	-$0.08	19.25%	19.91%
Rhode Island	1396	$0.12	$0.19	-$0.07	14.86%	15.90%
Massachusetts	1390	$0.12	$0.19	-$0.07	14.12%	15.24%
New Hampshire	1381	$0.12	$0.19	-$0.06	13.93%	15.06%
Vermont	1308	$0.13	$0.19	-$0.06	13.21%	14.42%
Nevada	2047	$0.08	$0.14	-$0.06	16.19%	17.10%
New Jersey	1420	$0.12	$0.17	-$0.05	12.55%	13.84%
New Mexico	2008	$0.09	$0.13	-$0.05	14.44%	15.52%
Arizona	2032	$0.08	$0.13	-$0.04	14.10%	15.21%
Colorado	1779	$0.10	$0.13	-$0.04	11.93%	13.30%
Maryland	1475	$0.12	$0.15	-$0.03	10.55%	12.11%
Michigan	1341	$0.13	$0.16	-$0.03	10.00%	11.64%
Delaware	1463	$0.12	$0.15	-$0.03	10.07%	11.70%
Wisconsin	1381	$0.12	$0.15	-$0.03	9.67%	11.35%
Pennsylvania	1436	$0.12	$0.15	-$0.03	9.64%	11.33%
Kansas	1621	$0.11	$0.13	-$0.03	9.99%	11.63%
Maine	1229	$0.14	$0.17	-$0.03	9.13%	10.89%
South Carolina	1588	$0.11	$0.13	-$0.03	9.91%	11.56%
District of Columbia	1481	$0.12	$0.14	-$0.03	9.59%	11.29%
Florida	1615	$0.11	$0.13	-$0.02	9.66%	11.35%
Georgia	1548	$0.11	$0.13	-$0.02	8.39%	10.27%
Texas	1509	$0.11	$0.13	-$0.01	8.30%	10.20%
North Carolina	1579	$0.11	$0.12	-$0.01	8.29%	10.19%
Utah	1676	$0.10	$0.12	-$0.01	8.37%	10.25%
Mississippi	1554	$0.11	$0.12	-$0.01	8.21%	10.12%
Alabama	1521	$0.11	$0.13	-$0.01	8.05%	9.99%
Wyoming	1682	$0.10	$0.12	-$0.01	8.35%	10.24%
Minnesota	1387	$0.12	$0.13	-$0.01	7.49%	9.52%
Ohio	1363	$0.13	$0.13	-$0.01	7.40%	9.45%
Virginia	1500	$0.11	$0.12	-$0.01	7.40%	9.45%
Iowa	1436	$0.12	$0.13	-$0.01	7.13%	9.23%
Oklahoma	1646	$0.10	$0.11	$0.00	7.02%	9.13%
Idaho	1667	$0.10	$0.11	$0.00	6.91%	9.05%
Missouri	1512	$0.11	$0.12	$0.00	6.72%	8.89%
Indiana	1399	$0.12	$0.12	$0.00	6.41%	8.63%
Nebraska	1500	$0.11	$0.11	$0.00	6.40%	8.63%
Tennessee	1518	$0.11	$0.11	$0.00	6.37%	8.60%
Montana	1515	$0.11	$0.11	$0.00	6.35%	8.58%
South Dakota	1445	$0.12	$0.12	$0.00	5.98%	8.28%
Illinois	1369	$0.13	$0.12	$0.00	5.98%	8.28%
North Dakota	1570	$0.11	$0.11	$0.00	5.81%	8.15%
Louisiana	1557	$0.11	$0.10	$0.01	5.45%	7.85%
Arkansas	1515	$0.11	$0.10	$0.01	5.12%	7.58%
Kentucky	1430	$0.12	$0.11	$0.01	5.02%	7.51%
West Virginia	1369	$0.13	$0.10	$0.02	3.45%	6.26%
Oregon	1229	$0.14	$0.11	$0.03	3.40%	6.22%
Washington	1211	$0.14	$0.10	$0.05	0.91%	4.30%
Alaska	636	$0.27	$0.21	$0.06	2.80%	5.76%

Source: Deutsche Bank. See table on previous page for key assumptions

Figure 84: Country Snapshot

United States	2014	2017
Yearly Sun Hours (Net 20% Conversion Loss)	1,458	1,458
System Cost ($/W)	$2.90	$1.77
Discount Rate	7%	7%
Unsubsidized LCOE ($/kWh)	$0.19	$0.13
LCOE With 30% ITC (2014 est)	$0.14	
Electricity Price - High Residential ($/kWh)	$0.18	$0.21
Electricity Price - Low Residential($/kWh)	$0.08	$0.10

Electricity Market Size (GW)	~1040 GW
2014 Est Solar Installs (MW)	7,000
2015 Est Solar Installs (MW)	12,000
2016 Est Solar Installs (MW)	16,000
Cumulative Solar Installs at end of 2016	47,086

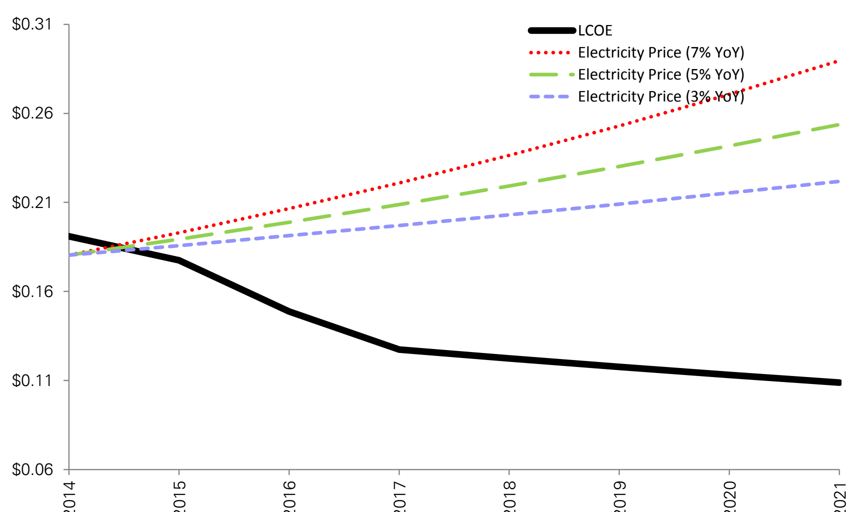
Policy Climate	ITC step-down from 30% to 10% in 2017 is challenging, but potential MLP status and continued success of Yieldco's improve investment climate and lower cost of capital. State incentives helped previously but are less important today as most goals have been met.

Other Remarks

*LCOE for US is DB est of Residential LCOE

Source: Deutsche Bank

Figure 85: USA LCOE Scenario Analysis

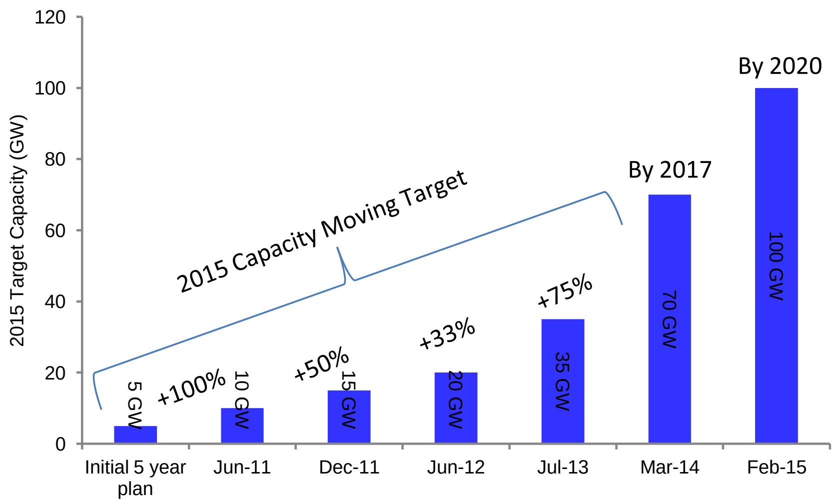


Source: Deutsche Bank

China

We believe China will continue to be one of the most important markets in the world over the next several years. 2014 was marked by continued investor uncertainty or skepticism around installation mix and targets, but we believe actual installations will continue at double digit GW levels on a yearly basis. A document released in September 2014 outlines specific policy support mechanisms for distributed generation that should help the country achieve ambitious solar installs goals.

Figure 86: Chinese Solar Targets are a Rapidly Moving Target…



Source: Deutsche Bank, NEA

While we expect the Chinese govt to continue fine tuning policy which could create a certain level of near term uncertainty, we believe long term Chinese policy fundamentals and support remains in place given the country's continued growing need for electricity demand, pollution concerns and vast domestic manufacturing industry. Furthermore, the release of the next 5 year plan in 2015-2016 timeframe could likely facilitate another increase in Solar targets, as could the implementation of the planned carbon trading scheme in 2016.

National Policy Initiatives Continue to Fuel Robust Growth

Figure 87: Utility Scale FiT

Previous Fit - Utility Scale	
All Regions	¥1.00
New FiT - Utility Scale	
Zone 1 - Western	¥0.90
Zone 2 - Northern	¥0.95
Zone 3 - All Others	¥1.00

Source: Deutsche Bank, Chinese Govt

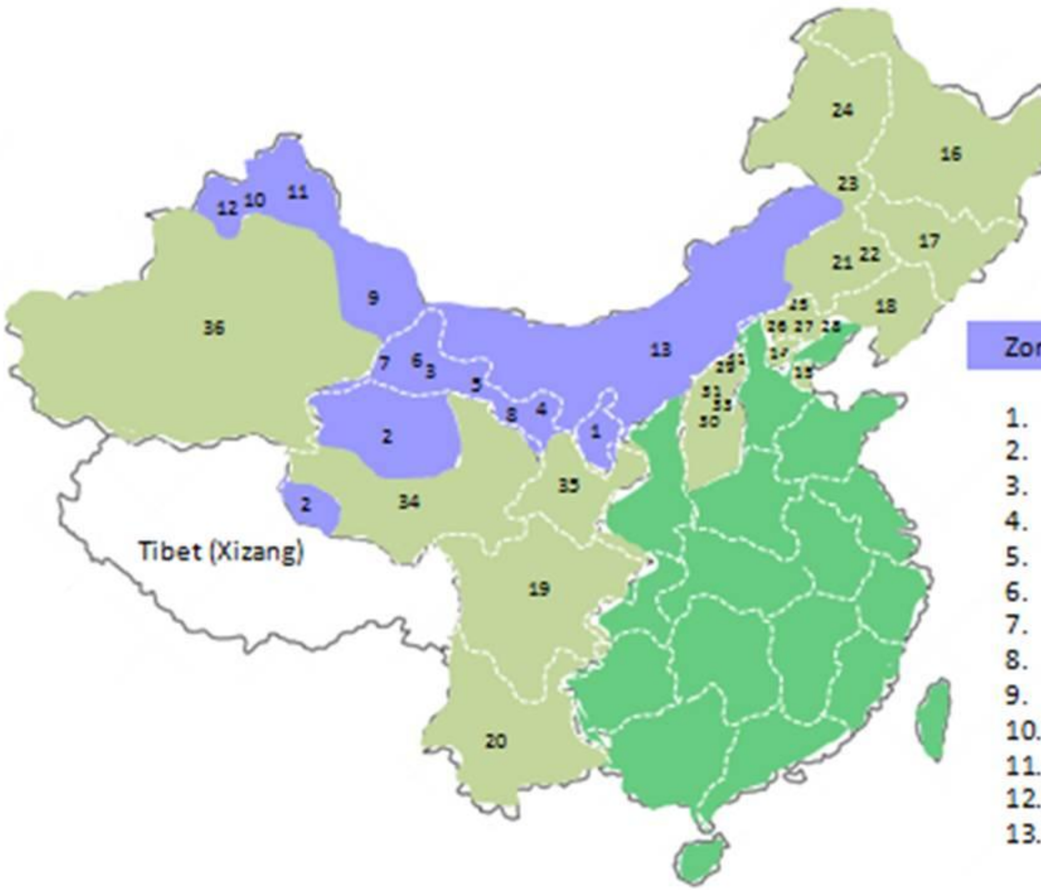
Small Scale Subsidies in Place and Increasing

In addition to utility scale feed in tariffs, China offers a more robust FiT for distributed generation under 20MW (Previously 6MW, clarified in late 2014). Distributed generation users are awarded a ¥0.42/kwh FiT, which is on top of the reduction in electricity use inherent in having a distributed system. Residential electricity prices generally range between ¥0.60 and ¥0.80/kWh, while commercial prices are in the higher ¥0.90-¥1.20/kWh range. We expect the commercial segment to ramp over the next several years as the recently announced DG policies take hold. Since commercial users are often large electricity consumers, it is reasonable to assume that all the electricity production will be consumed, which minimizes grid connection issues and will likely be supported by local policies as well.

Figure 88: Map of the National Utility FiT Structure

Zone – 2 (CNY0.95/kWh)

14. Beijing
15. Tianjin
16. Heilongjiang
17. Jilin
18. Liaoning
19. Sichuan
20. Yunnan
21. Chifeng
22. Tongliao
23. Xing'anmeng
24. Hulunbeier
25. Hebei Chengde
26. Zhangjiakou
27. Tangshan
28. Qinhuangdao
29. Datong
30. Shanxi
31. Xinzhou
32. Shanxi Yulin
33. Yan'an
34. Qinghai (not covered by Zone I)
35. Gansu (not covered by Zone I)
36. Xinjiang (not covered by Zone I)



Zone – 1 (CNY0.90/kWh)

1. Ningxia
2. Qinghai Haixi
3. Gansu Jiayuguan
4. Wuwei
5. Zhangye
6. Jiuquan
7. Dunhuang
8. Jinchang
9. Xinjiang Hami
10. Tacheng
11. Altay
12. Karamay
13. Inner Mongolia region excluding Chifeng, Tongliao, Xing'anmeng and Hulunbeier

Zone – 3 (CNY1.00/kWh)

Source: Map by Deutsche Bank. from Official Announcements
Note: Tibet (Xizang) will have a separate policy announced

Provincial/Local Incentives Provide Additional Growth Catalyst

In addition to central government incentives, we expect a number of provinces to provide additional local incentives as well, further improving project IRRs and fueling growth in respective regions. For example, the Hebei province provides RMB 30c/kWh for the first 3 years on top of the national RMB 1.0/kWh FiT. For projects starting in 2014/15, the 3 year provincial incentive has decreased to RMB 20c/kWh and RMB 15c/kWh respectively. Similarly, the Jiangsu province provides a 50c/kWh incentive on top of the national incentive for 5 years whereas the city of ShaoXin provides an additional RMB 1.0/kWh for 3 years for all commercial rooftop applications. Checks indicate that several additional provinces are considering similar local incentive programs.

Figure 89: Example Projects

Example (Utility Scale)	Gross Fit (¥/kwh)	LCOE (¥/kwh)	IRR - Utility Scale	
			W/ National FiT	W/ Provincial FiT
Hebei	¥0.95	¥0.62	11.2%	13.6%
Jiangsu	¥1.00	¥0.68	10.5%	16.2%
Example (Provincial DG)	**Effective Gross FiT (¥/kwh)**	**LCOE (¥/kwh)**	**IRR - Distributed Generation**	
Hebei DG (W/ Provincial)	¥1.50	¥0.69	17.4%	
Jiangsu DG (W/ Provincial)	¥1.70	¥0.75	17.0%	
Example (City DG)	**Effective Gross FiT (¥/kwh)**	**LCOE (¥/kwh)**	**IRR - Distributed Generation**	
			Utility Scale (For Comparison)	Distributed Generation
Shaoxing City, Zhejiang (Rooftop)	¥2.02	¥0.82	7.8%	15.3%

Source: Deutsche Bank.
Note: Gross FiT's are our estimate of DG FiT + cost of electricity.

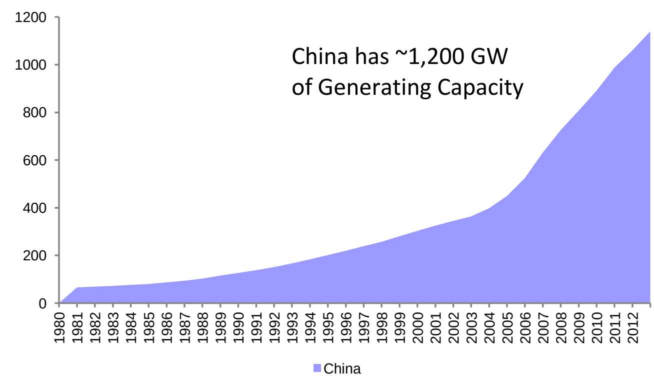
Actual Installs likely to Stay in Double Digit GW's

While the national government has created near term confusion for the market, we believe actual installs will show at most a slight hiccup year over year, and continue to see strong policy support for the domestic solar manufacturers/installers driving 10-12+GW over the medium term with visibility through 2017. Considering China's history of consistently increasing installation targets, we believe the most recently announced 70GW target by 2017 is easily achievable with additional potential upside from the next 5-year plan. As shown below, steady installs at ~13GW per year allow the country to achieve this target. This assumes essentially no growth from 2013 install levels, which we believe could prove conservative.

China Electricity Market Overview

In 1973, China accounted for 17 TWh of electricity generation (2.8% of worldwide production) versus ~4,200+ TWh (~20%) in 2010, according to the IEA. Growth in capacity has been similarly robust, accelerating rapidly in recent years. The Government has outlined plans to reach ~1400 GW of capacity in its 12 th 5 year plan, which implies 200-300 GW of additional capacity growth by 2015. However, the majority (70%+) of the electricity is generated by coal, which has helped contribute to recent reports of worsening air quality and environmental/health concerns.

Figure 90: Generation Capacity

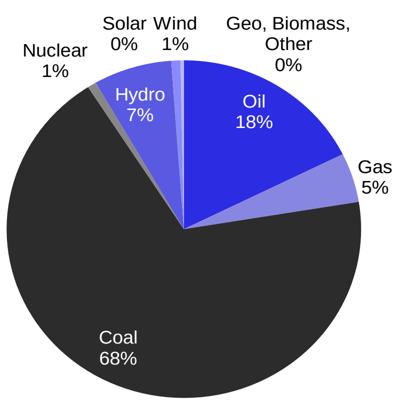


Source: Deutsche Bank

Resources aren't in population centers

In China, the majority of the coal (60%+) and hydropower (80%+) are located in the north and west respectively, while the majority of the population and manufacturing centers are not. As shown below, the primary energy use in China is firmly coal based.

Figure 91: Primary Energy Consumption



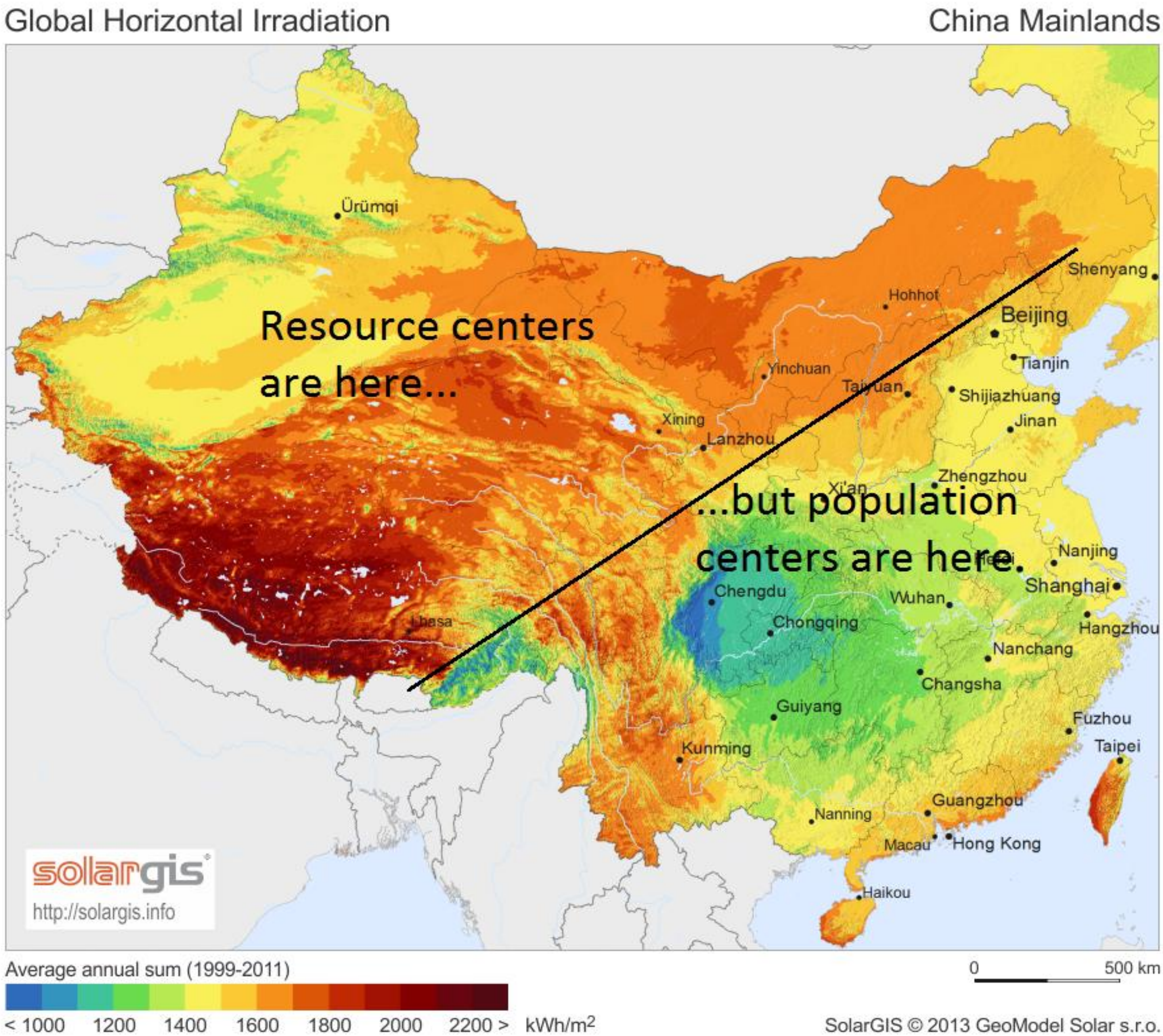
Source: BP Statistical Review of World Energy 2013

We expect policy will continue to attempt to change this makeup into the future, which will be constructive for Solar.

Transmission Corridors

In order to transmit electricity to the eastern population centers, China outlined the West-East Electricity Transfer project in the Tenth Five-Year Plan, which was designed to create three massive transmission corridors. These will not be complete until 2020 but are integral to moving power from the West and North regions to the population centers along the eastern coast and other manufacturing areas. As shown below, the most attractive solar resources are located far away from the population centers. The majority (~80%) of coal and hydropower are also located in this region.

Figure 92: China Solar Resource Map



Source: SolarGIS © 2013 GeoModel Solar s.r.o.; Modified by Deutsche Bank

Much of the state focus is centered around a shift in generating mix. China would like to reduce its reliance on coal as a percent of total generation mix, which requires a massive investment in transmission infrastructure. There are multiple ultra high voltage (UHV) lines being built currently, which will facilitate this shift.

Wholesale Prices

Below are examples of desulphurized prices of wholesale electricity in various regions in China as of 2011-2012. Central and East China have higher prices, which indicate more attractive economics for distributed generation in these regions.

Figure 93: Desulphurized Coal Price – 2012

North China	¥ / kwh
Beijing	¥0.400
Tianjin	¥0.412
Hebei North	¥0.424
Hebei South	¥0.430
Shanxi	¥0.374
Shandong	¥0.445
Inner Mongolia Self-Use	¥0.311
Inner Mongolia to Beijing Grid	¥0.374

East China	¥ / kwh
Shanghai	¥0.477
Jiangsu	¥0.455
Zheijiang	¥0.482
Anhui	¥0.446
Fujian	¥0.445

Central China	¥ / kwh
Hubei	¥0.478
Hunan	¥0.501
Jiangxi	¥0.485
Henan	¥0.419
Sichuan	¥0.449
Chongqing	¥0.444

South China	¥ / kwh
Guangdong	¥0.521
Guangxi	¥0.477
Yunnan	¥0.353
Guizhou internal use	¥0.373
Guizhou To Guangdong	¥0.383
Hainan	¥0.490

Source: EPA, NDRC, Shanghai Price Bureau, Suzhou Municipal Price Burea, Xinhuanet

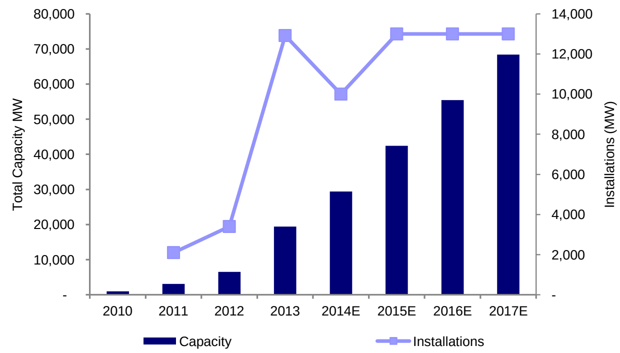
Figure 94: Country Snapshot

China	2014	2017
Yearly Sun Hours (Net 20% Conversion Loss)	1,333	1,333
System Cost ($/W)	$1.30	$1.11
Discount Rate	7%	7%
LCOE ($/kWh)	$0.11	$0.10
Electricity Price - High Residential ($/kWh)	$0.11	$0.13
Electricity Price - Low Residential($/kWh)	$0.08	$0.09
Electricity Market Size (GW)	~1250GW	
2014 Est Solar Installs (MW)	10,000	
2015 Est Solar Installs (MW)	13,000	
2016 Est Solar Installs (MW)	13,000	
Cumulative Solar Installs at end of 2016	55,745	
Policy Climate	Long term policy fundamentals and support remains in place given the country's continued electricity demand increases, pollution concerns, and vast domestic industry needs 2014 Target: 13GW 2017 Target: 70GW 2020 Target: 100GW	
Other Remarks	The release of the next 5 year plan in 2015-2016 timeframe could likely facilitate another increase in Solar targets	

*Electricity price is est of resi price, but majority of installs likely to be larger scale. Assumes 5% system price reduction YoY

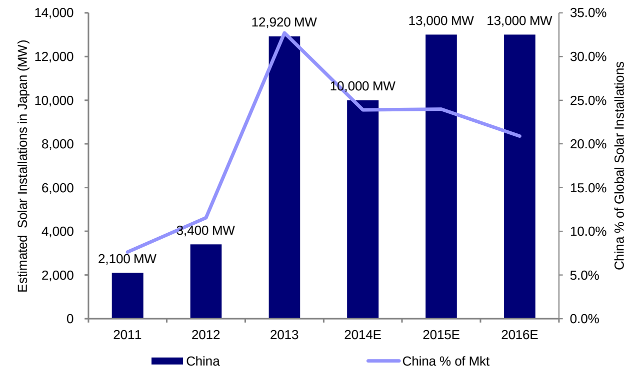
Source: Deutsche Bank

Figure 95: ~70GW by 2017



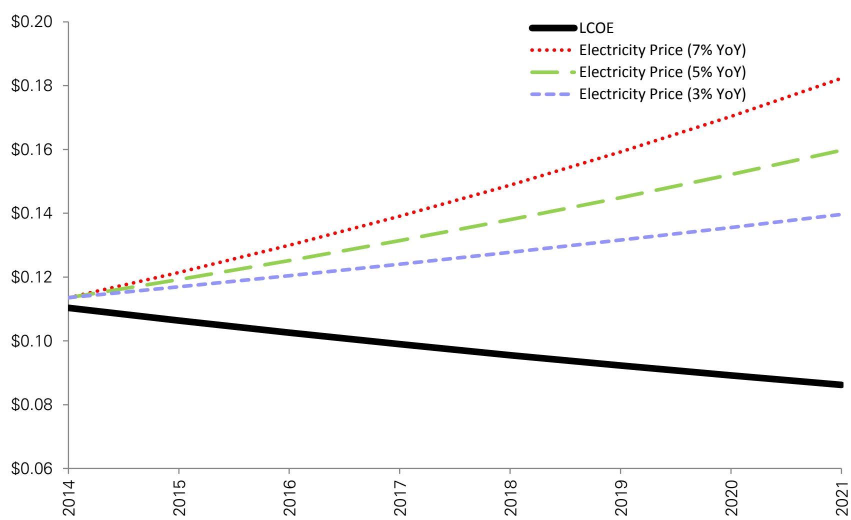
Source: Deutsche Bank, NEA

Figure 96: China Installations



Source: Deutsche Bank, NEA

Figure 97: China LCOE Scenario Analysis

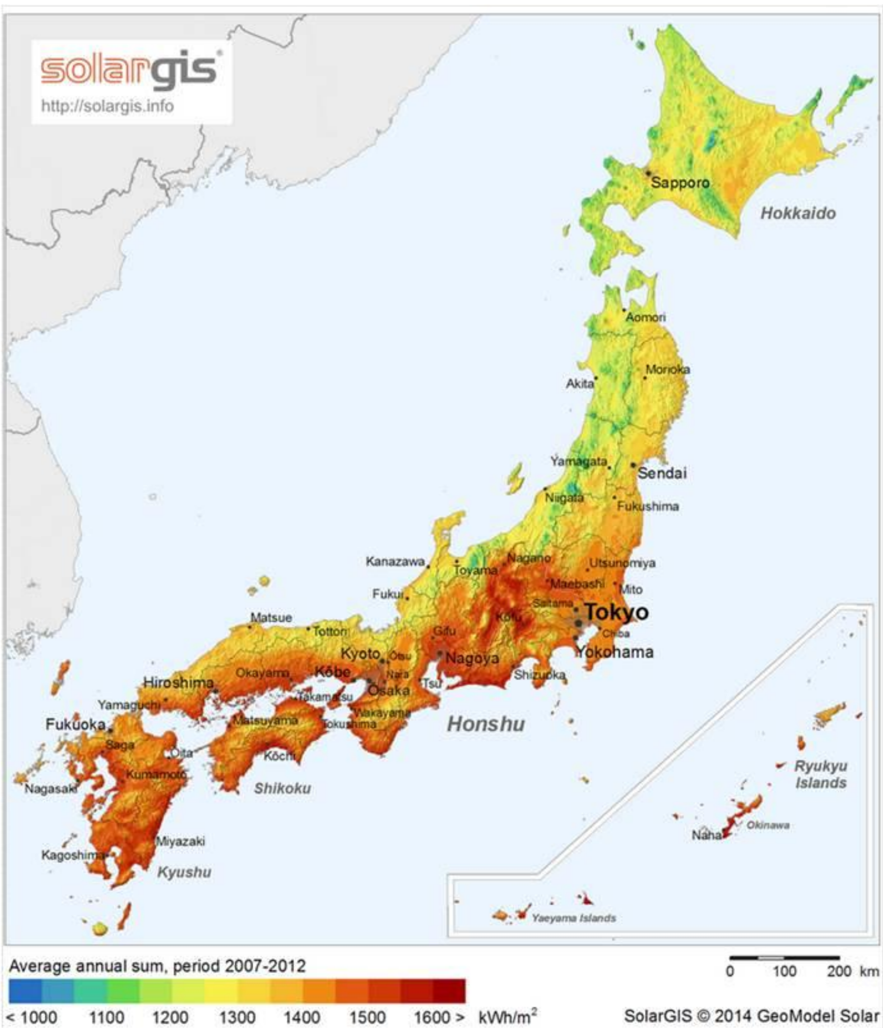


Source: Deutsche Bank

Japan

Japan is well positioned to continue the build out of solar installations for the foreseeable future, although we expect land and grid concerns could moderate growth rate over the medium term. The Fukushima nuclear disaster coupled with the country's relatively high solar resources have helped incentivize the government to enact favorable policies which have helped drive a significant increase in installations during the last several years.

Figure 98: Japan Solar Resources (Horizontal Radiance)

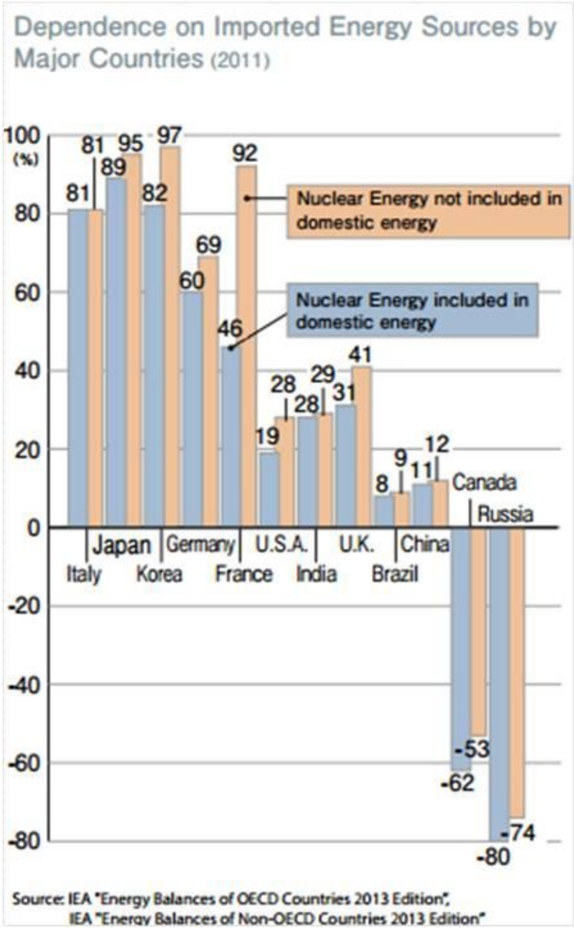


Source: SolarGIS © 2014 GeoModel Solar

Domestic Energy is Scarce

Relative lack of domestic energy sources provides further long term support for Solar installations in Japan. Japan is a high-technology, well developed country with high electricity needs and minimal ability to produce this with domestic resources. We believe this significantly enhances solar's popularity with domestic policy makers.

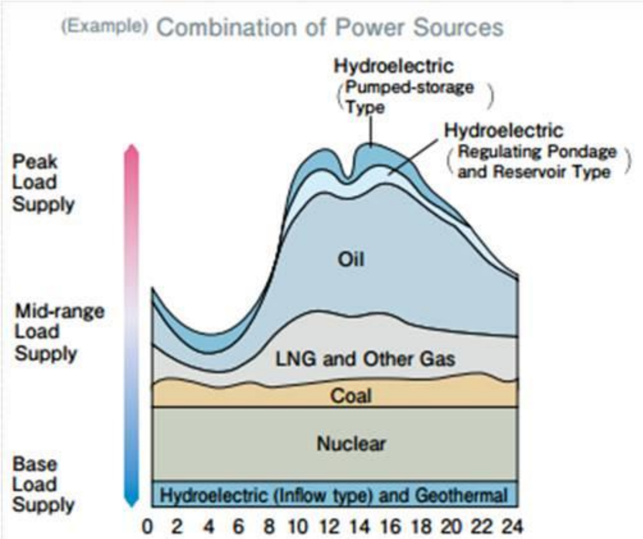
Figure 99: Japan Imports the Majority of Fuel



Source: IEA, Federation of Electric Power Companies Japan

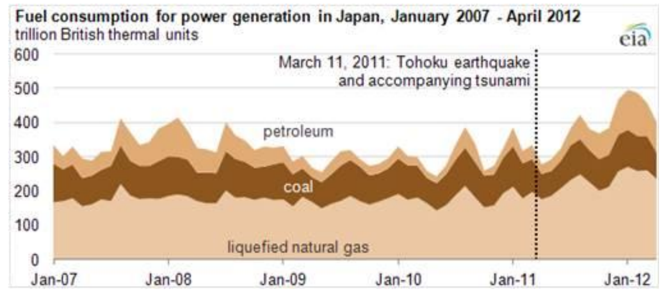
Given the dependence on energy imports, high oil use will be problematic for a closed island electric system like Japan. Even if oil prices were consistently relatively low, petroleum based generation is typically the highest cost form of generation, reserved only for peak generation needs – during times when solar can generate the most power.

Figure 100: Example of Hourly Electricity Generation Fuels



Source: Federation of Electric Power Companies Japan

Figure 101: Oil Use is Increasing

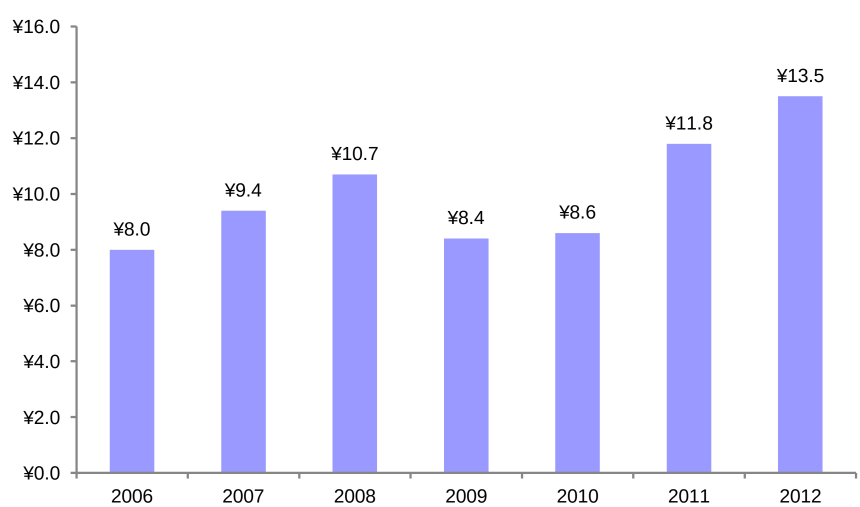


Source: EIA

Oil represents ~47% of total energy consumption in Japan, and the amount used in electricity generation has been increasing substantially in recent years as the country has shut down nuclear generation.

Furthermore, the average cost for utilities to produce one unit of electricity has increased, which will likely lead to increasing electricity costs over time for consumers.

Figure 102: Electricity Price (Yen/Kwh) – Average of Utilities

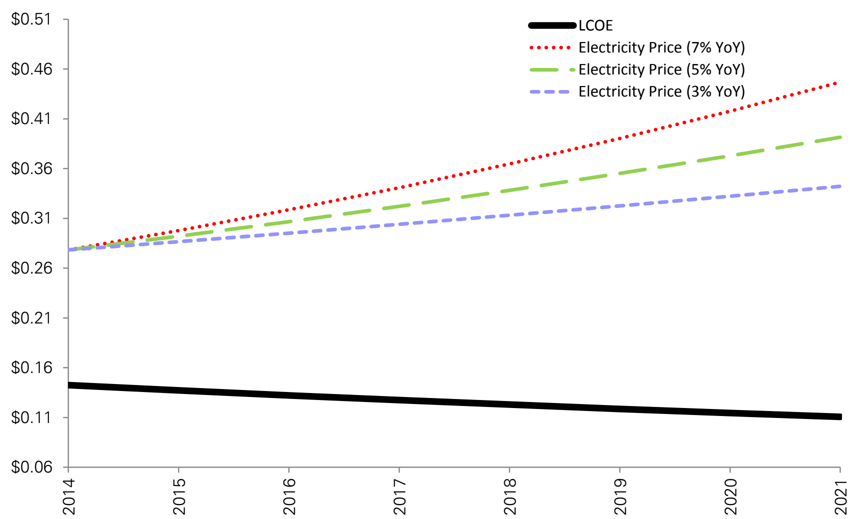


Source :Utility Data, Institute of Energy Economics Japan

Retail Grid Parity, But Challenges

Today, Japan has one of the highest retail costs of electricity in the world - ~$0.26/kWh on average and there are few fundamental drivers that could bring this cost down. Based on our analysis, Japan has reached grid parity with an estimated solar LCOE of ~$0.14/kWh compared to existing electricity prices of $0.23-$0.28/kWh.

Figure 103: Japan LCOE Scenario Analysis

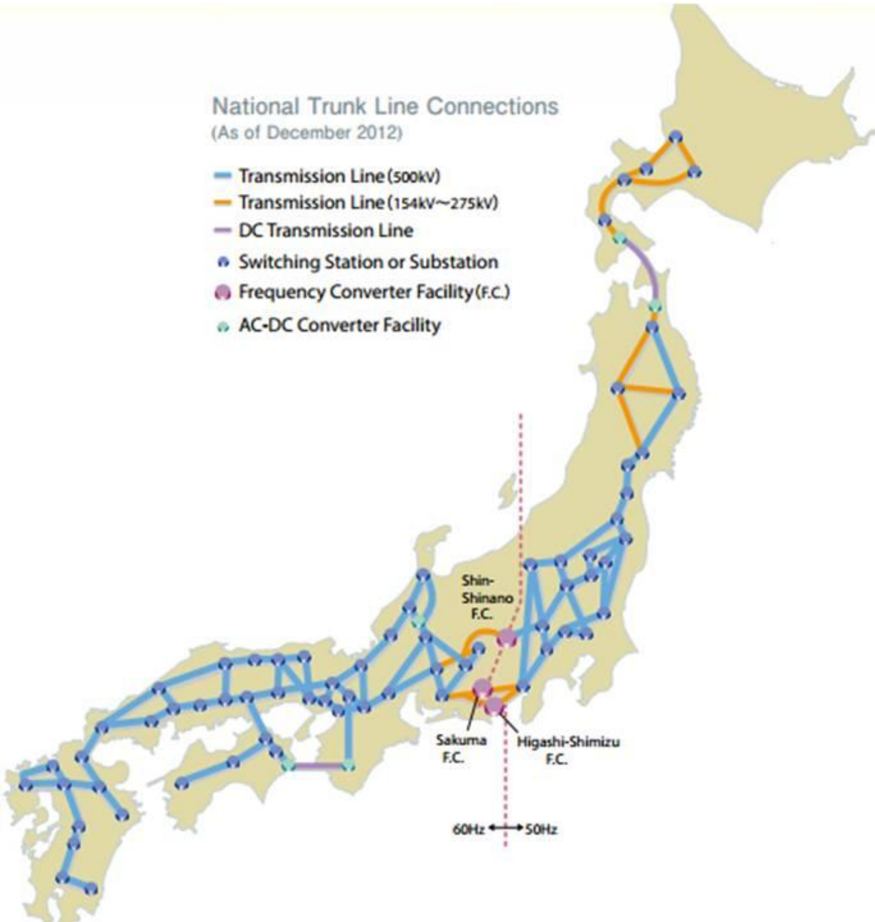


Source: Deutsche Bank

While rooftop/retail electricity is likely at grid parity already, we believe the next 5+ years could yield solar installations at costs below other forms of generation for wholesale electricity generation, given high input costs in the country.

However, Japanese grids face significant challenges integrating solar and shifting dynamics of regionally different east/west grids (which use different electricity frequencies due to historic differences).

Figure 104: Japanese Grid Layout



Source: Federation of Electric Power Companies Japan

We expect that one of the primary challenges as solar penetration increases in Japan will lie in grid integration and incentivizing utilities to build out the grid as needed to handle renewables.

Lucrative FiT Rates Provide Constructive Near-term Outlook

We are constructive on the near-term (1-2 years) solar demand outlook in Japan, given the high feed-in-tariffs offered by the govt. Japan has been offering one of the most lucrative solar FiT schemes in the world since July 2012. For FY 2014, the FiT rate (net of consumption tax) is JPY32/kWh for commercial customers and JPY37/kWh for residential customers.

However, FiT rates are unlikely to remain elevated for the long term, despite Japanese dedication to Solar deployments. We expect the FiT's will continue to decrease each April until they are phased out completely. However, grid parity should be present for most electricity segments and regions at that point, so installs could stabilize and land availability could be the more pressing issue for large scale installs.

However, Grid-connection Issues Could Slowdown Installations in the Medium Term

Although the near term outlook for solar demand remains robust, in our view, the installations could witness a slow-down in the medium-term (3-4 years), as focus shifts to other renewable and some nuclear plants resume operations. In Sep 2014, five of the country's leading utilities began restricting access to their grids citing rapid expansion of solar installations. Japan has approved ~72GW of renewable projects since the inception of the FiT program, of which solar accounted for ~96%. However, most solar projects have witnessed significant delays in grid-connection (only *~15%* of approved projects have been connected, as of Mar 2014). In the coming years, more emphasis might be given to other renewable like wind to offset bottlenecks associated with installing solar, in our view. However, we believe the above mentioned concerns are not likely to affect the country's DG market as rooftop is likely at grid parity.

Current Policies

Japan offers one of the most lucrative solar feed-in-tariff schemes in the world – JPY32/kWh for commercial customers (contract term of 20 years) and JPY37/kWh for residential customers (contract term of 10 years). Commercial customers are defined as systems >10kW in capacity, while residential customers are those with <10kW systems.

Additionally, Japan's Ministry of the Environment (MoE) plans to offer policy support to ground-mount solar projects (greater than 350kW in size) being built on dormant landfill sites. According to a study commissioned by the ministry in early 2014, landfill sites in Japan can accommodate ~7.4GW of extra solar capacity. This support is expected to last 3 years and will see MoE carry out feasibility studies on landfill sites and offer subsidies to local governments/ private companies, in order to encourage solar installations on landfill sites that have reached full capacity.

Although the high FiT rates have resulted in a surge in solar installations (~7GW in the year ending Mar'14), several projects have been witnessed significant delays in breaking ground. As of 2014 year-end ~70GW of solar projects were approved under the FiT scheme, but a good portion (20-30%) may not be built and only ~9.6GW of them were operational as of April 2014. However, Japan's Ministry of Economy, Trade and Industry (METI) is trying to expedite FiT approved solar projects and has put in place a 6-month deadline for approved projects to secure land and equipment.

Outlook

Given the 6-month deadline and continued lucrative FiT rates, our estimates assume that Japan sees continued strength in installations.

Figure 105: Country Snapshot

Japan

	2014	2017
Yearly Sun Hours (Net 20% Conversion Loss)	1,167	1,167
System Cost ($/W)	$2.00	$1.71
Discount Rate	4%	4%
LCOE ($/kWh)	$0.14	$0.13
Electricity Price - Average Residential ($/kWh)	$0.28	$0.32

Electricity Market Size (GW)	~290GW
2014 Est Solar Installs (MW)	8,000
2015 Est Solar Installs (MW)	9,000
2016 Est Solar Installs (MW)	9,180
Cumulative Solar Installs at end of 2016	38,840

Policy Climate	One of the most lucrative solar feed-in-tariff schemes in the world - For FY 2014 JPY32/kWh ($0.30/kWh) for commercial customers and JPY37/kWh ($0.35/kWh) for residential customers.
Other Remarks	Typical YoY FiT cuts are ~10%

*Electricity price is est of resi price, but majority of installs likely to be larger scale. Assumes 5% system price reduction YoY

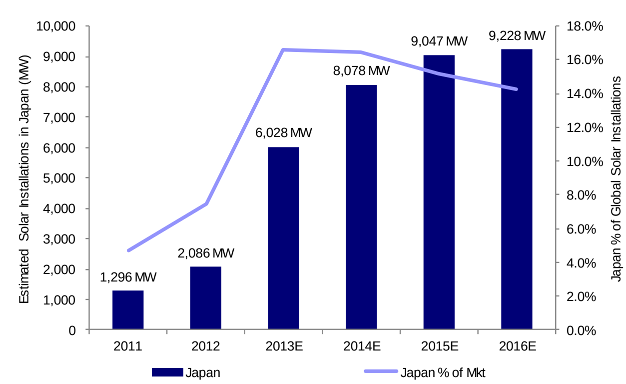
Source: Deutsche Bank

Figure 106: Japan Solar Incentives

Customer Type	System Size		FiT (JPY/kWh) (including tax)	FiT (~$/kWh) (including tax)	Term
Commercial	>10kW	Current (as of Apr'14)	32.0	0.30	
		Prior (as of Apr'13)	37.8	0.35	20 Years
		Prior (as of Jul'12)	42.0	0.39	
Residential	<10kW	Current (as of Apr'14)	37.0	0.35	
		Prior (as of Apr'13)	38.0	0.35	10 Years
		Prior (as of Jul'12)	42.0	0.39	

Source: Deutsche Bank, METI

Figure 107: Japan Solar Installations



Source: Deutsche Bank

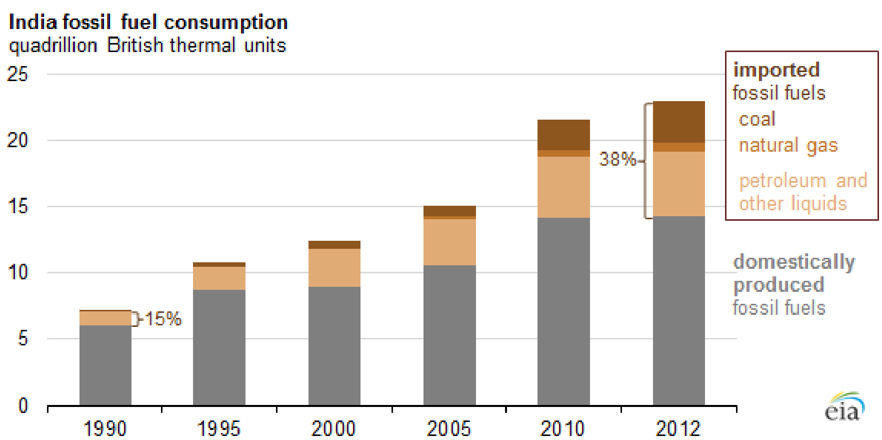
India

India has long been considered one of the highest-potential solar markets but development has been slow due in part to thin profit margins, uncertain regulatory environment and lack of high level focus on solar. Recently this has started to shift, but we expect policy implementation and installation uptick to be gradual. Most recently, the government has targeted ~100GW of solar by 2022.

High Dependence on Imports to Drive Growth in Renewable Capacity

India's dependence on imported fossil fuels has increased significantly over the last several decades – from ~15% in 1990 to ~38% in 2012. However, members of the Indian government have stated aims to become energy self-sufficient by 2030.

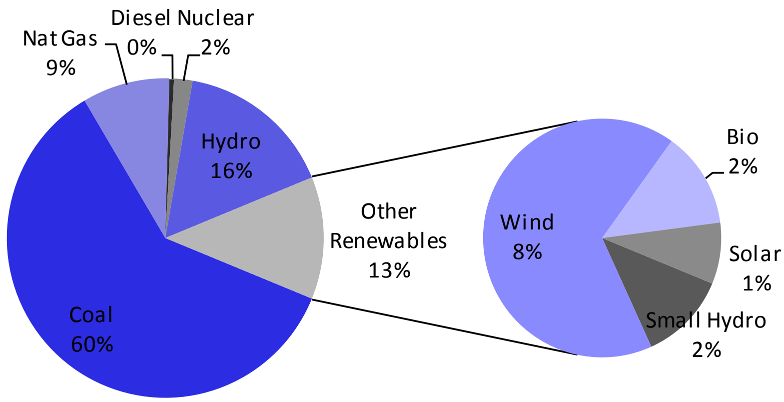
Figure 108: Dependence on Imported Fossil Fuels



Source: Deutsche Bank, US EIA

India's total installed power generating capacity stood at ~255GW as of Oct'14 – of which renewable energy accounted for just 13% (solar was 1%).

Figure 109: Installed Capacity (As of Oct 2014)



Source: Deutsche Bank, India's Central Electricity Authority

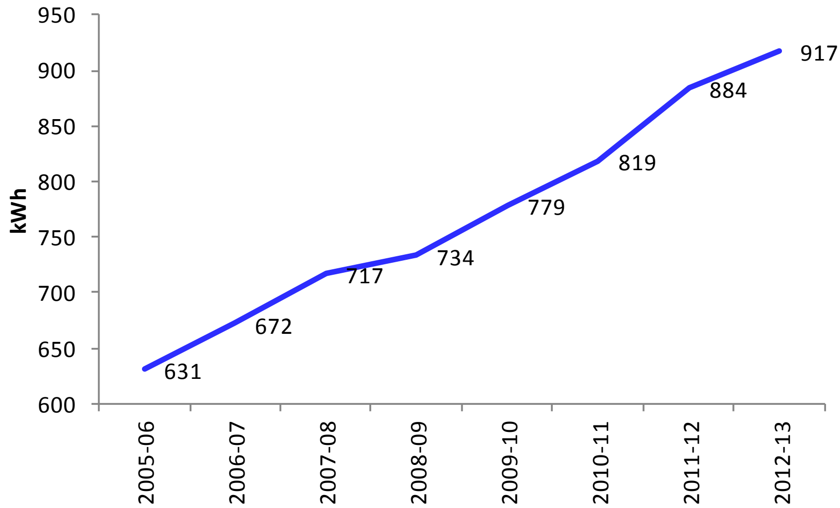
According to India's Central Electricity Authority (CEA), the anticipated power requirement during 2014-15 is likely to be more than 1,000 TWh, while the available supply is likely to be ~995 TWh, creating a deficit of ~5%.

Figure 110: Anticipated Power Surplus/Deficit (2014-2015)

Region	Requirement (TWh)	Availibility (TWh)	Surplus/Deficit
Northern	329	319	-3.1%
Western	288	289	0.3%
Southern	298	260	-12.7%
Eastern	119	115	-3.4%
North Eastern	15	12	-17.4%
All India	**1049**	**995**	**-5.1%**

Source: Deutsche Bank, India's Central Electricity Authority

Figure 111: Per-capita Consumption of Electricity (kWh)



Source: Deutsche Bank, India's Central Electricity Authority

Moreover, the country has an overall electrification rate of ~75%, which implies ~300-400M Indians are not connected to the grid. According to IEA, India would require another ~680GW of capacity additions during 2014-35. Under its 12th 5-year plan (2012-17), the country is targeting additions of 120GW of power capacity, of which >40GW was brought online in 2014. We believe solar and other renewables are well positioned to compose a notable share of this new capacity. India's power minister recently noted that the country needs to invest $250B in the energy sector over the next 5 years, of which the govt is targeting ~$100B of investment in renewables.

Underutilized Fossil Fuel Capacity Makes Renewables Attractive

India has suffered from serious power deficits, particularly when the fossil fuel-based capacity remains under-utilized due to fuel shortages and T&D losses. According to US EIA, utilization rates in fossil fuel-based power plants in India have fallen steadily since 2007 (from a peak of ~79%) to ~70% in 2013. We believe disruptions in steady domestic fuel supplies could make renewable capacity more attractive.

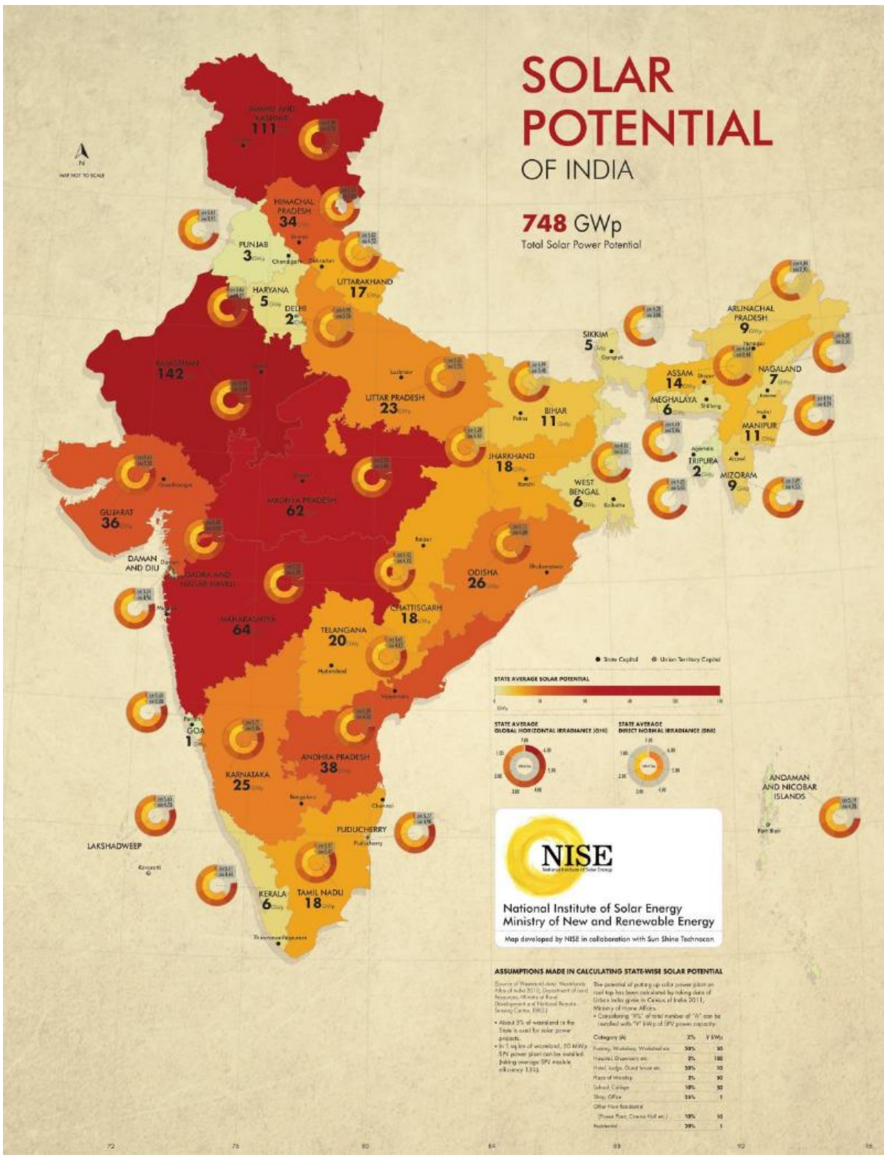
Solar Comes to Forefront, as New Govt Targets 100GW in 10 Years

The new Indian govt, which took office in May'14, has taken several steps to accelerate deployment of renewables, particularly solar, in the country. The new energy minister recently announced that the country's solar target will be increased to 100GW by 2022 – notably more than the previous target of 20GW. Given current installed capacity of ~3GW, the target implies an annual run rate of ~12GW for the next 8 years, although actual installs will likely ramp differently. Although the 100GW target looks quite ambitious, we believe it is achievable if the following issues are addressed timely and appropriately – 1) easing land acquisition requirements; 2) lowering cost of financing; 3) making long-term stable policies that can attract consistent investments. Although the govt has not yet announced a final framework/plan on how it wishes to achieve this target, it has announced plans to build 25 large solar parks that will house 20GW of capacity by 2020. MNRE has already identified 12 of the 25 sites where it will establish solar parks with capacities of between 500MW-1GW.

Total Solar Power Potential of the Country Estimated at ~750GW

According to a report by India's National Institute of Solar Energy in India, the country's total solar potential is estimated at ~750GW. The estimate is based on the assumption that only 3% of the total wasteland in a state is used for solar power projects. The current installed solar capacity is just 0.4% of this.

Figure 112: Total Solar Potential in India



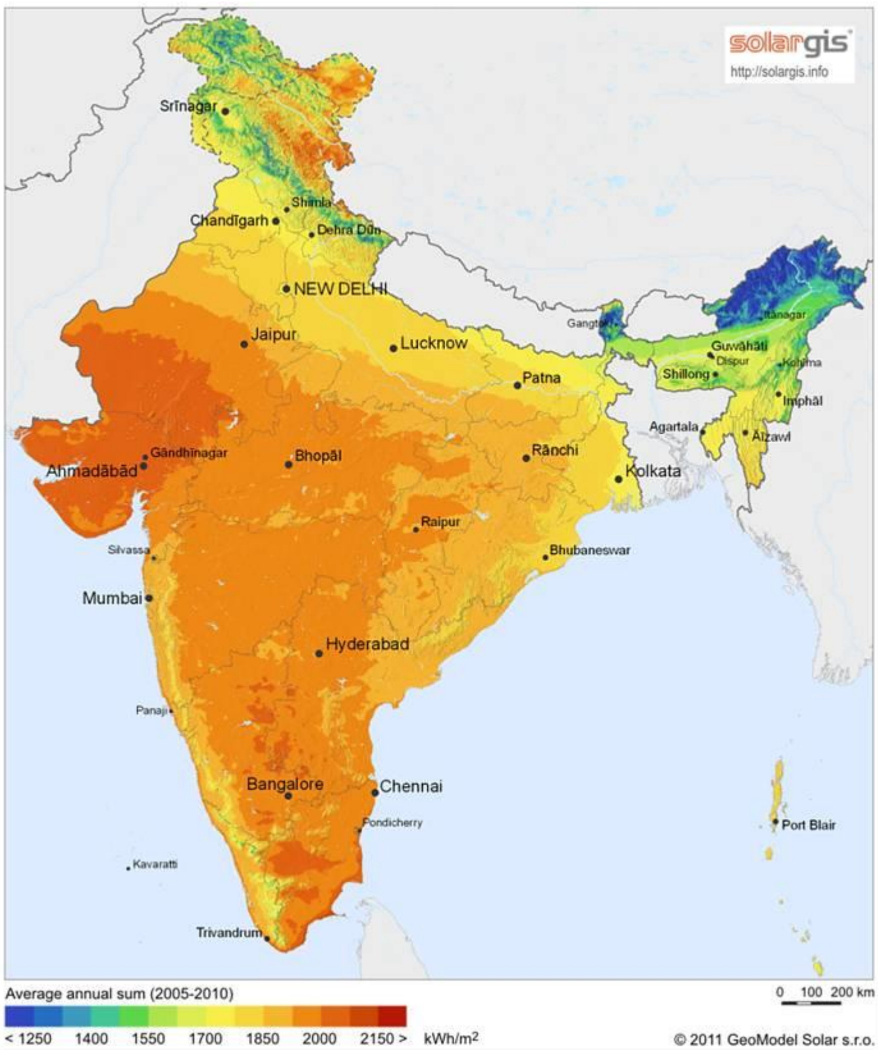
Source: Deutsche Bank, MNRE

The Gap Between Solar and Coal is Narrowing

Industry estimates indicate that the cost/kWh gap between power generated using coal and solar has reduced significantly over the last few years. Today, the cost of solar electricity in some regions is at or below parity with traditional power generated using imported coal, and is expected to achieve parity with power from domestic coal in 2020 time-frame. Indian solar LCOE of ~$0.10/kWh compared to electricity prices of ~$0.08-0.12/kWh.

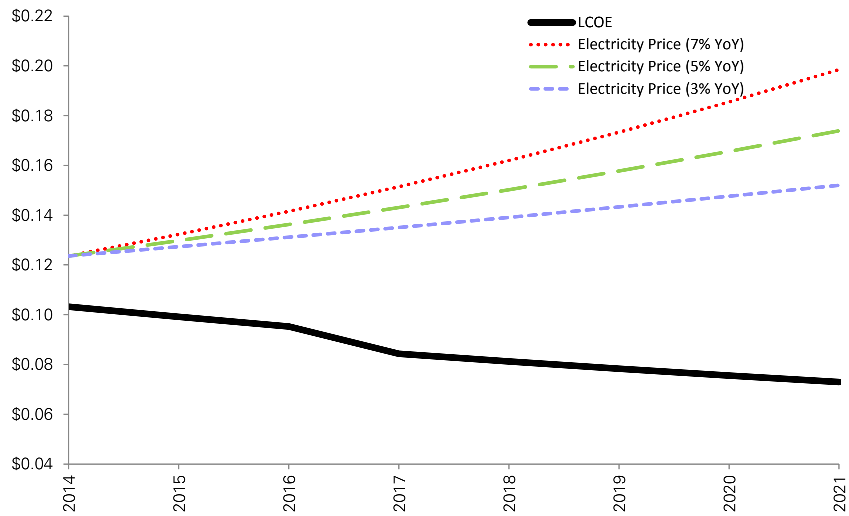
According to India's Central Electricity Regulatory Commission (CERC), the cost of domestic and imported coal is expected to increase annually by 6.7% and 13% respectively. Considering India's large coal fired plant fleet, solar additions will help control fuel costs.

Figure 113: India Solar Resources (Horizontal Radiance)



Source: SolarGIS © 2014 GeoModel Solar

Figure 114: India LCOE Scenario Analysis



Source: Deutsche Bank

Current Policies (Federal Level)

The new government in India (elected May'14) has stated plans to increase focus on renewables, particularly solar, to help deal with the country's power deficit. Recently, cooperation with the US govt has increased and India chose not to implement anti-dumping duties on imported modules, which should help pricing in the country (and by extension, installation economics). The government announced several key measures to promote the industry in its budget for FY14/15, including –; 1) Proposal to begin Ultra Mega Solar Power Projects in the states of Rajasthan, Gujarat, Tamil Nadu, and Laddakh in J&K. The plan sets aside INR 5B (~$84M) for this purpose; 2) Funding for agricultural pumps (~100k target) (INR 4B (~$66M)); 3) INR 1B (~$17M) for the development of 1 MW Solar Parks on the banks of canals; 4) Accelerating implementation of the Green Energy Corridor Project, which is designed to increase transmission and distribution infrastructure for renewable energy; and 5) Potential domestic manufacturing incentives.

Initially, India targeted 20GW of grid-connected solar capacity by 2022 under its Jawaharlal Nehru National Solar Mission (NSM) that was launched in 2010. However, the energy minister recently signaled intentions to raise the target to 100GW by 2022.

Under the initial NSM framework (20GW), deployment was set to occur in 3 phases: 1GW in Phase 1 (2012-13), 9GW in Phase 2 (2013-17)and 10GW in Phase 3 (2017-22). Phase 2 was further divided into 2 batches. Under batch 1, Solar Energy Corporation of India (SECI) invited bids in Oct 2013 in two categories - 375MW under DCR (Domestic Content Requirement) and 375MW under open category. PPAs with the successful bidders/ developers were signed in Mar 2014. For batch 2, the Ministry of New and Renewable Energy (MNRE) has proposed ~15GW in three tranches (this compares to original plan of 9GW under Phase 2 of NSM) - (i) Tranche - 1 3GW (2014-15 to 2016-17); (ii) Tranche - 2: 5GW (2015-16 to 2017-18); (iii) Tranche - 3: 7GW (2016-17 to 2018-19)

Renewable Targets: Recently, India's power minister suggested that a rule may be implemented where the addition of new coal plants would require the simultaneous investment in renewable capacity equal to ~5% of the traditional capacity. For example, a 4GW coal plant would have to also create ~200MW of renewable capacity.

Ultra Mega Solar Projects: The Indian government is planning to create incentives, (low-cost loans and grants) to set up 25 new solar power parks across the country to host close to 20GW of capacity by 2020. Each park will host large plants ranging between 500MW - 1GW that will feed power into the grid. Government programs will keep the price of land within the parks low to contain project costs, and the goal is to produce power at INR5.5/kWh ($0.09/kWh). India's Ministry of New and Renewable Energy (MNRE) released a draft policy for this program, under which – 1) states would supply the land and set up the infrastructure for the solar parks; 2) states will be obliged to buy at least 20% of the electricity from the projects; 3) MNRE would provide grants up to INR2M/MW ($33k/MW) or 30% of costs for setting up the parks, as well as grants of INR2.5M ($41k) per park for related expenses. MNRE has budgeted more than INR40B (~$655M) to develop these projects. The power minister recently announced that 12 states have been identified for ~22GW of PV capacity as part of this project (see details below).

Figure 115: Proposed Solar Parks/ Potential for Key States

State	Capacity of Proposed Plant (GW)
J&K	7.5
Rajasthan	3.7
Andhra Pradesh	2.5
Telangana	1.0
Gujarat	0.8
Others	6.6
Total	**22.0**

State	Estimated Potential (GW)
Rajasthan	142
J&K	111
Madhya Pradesh	60
Gujarat	36
Others	401
Total	**750**

Source: Deutsche Bank, MNRE

Examples of State Level Policies

Several Indian state governments have declared their state-level solar policies. We've outlined a few examples below:

Rajasthan: Rajasthan is targeting ~25GW over the next 7-8 years, through State or Private Enterprises or through Public Private Partnerships. In Oct 2014, SunEdison signed an MoU with the govt. of the state for 5GW of solar power plants.

Andhra Pradesh: In August 2014, media reports (PV-Magazine) suggested that the state government may unveil plans to target ~5GW solar power capacity by 2019. Following this in mid-Sep 2014, NTPC Ltd. signed an agreement with the state government to develop 1GW solar power projects in the state.

Tamil Nadu: In 2012, Tamil Nadu implemented a 3GW target by 2015. Of the 3GW target, 350MW was reserved for rooftop. In addition, the Tamil Nadu Energy Development Agency (TEDA) announced plans to set up solar rooftop projects at about 300 government buildings across the states that requested tender offers. However, the state has made little progress towards the 3GW goal and had an installed capacity of only ~109MW as of late 2014. To increase the pace of installations, Tamil Nadu's electricity regulator ordered the state's distribution utility to pay a tariff of INR7.01/kWh ($0.11/kWh) for power from solar PV plants and INR11.03/kWh ($0.18/kWh) to plants using solar-thermal technology (or less depending on treatment of depreciation benefits).

Karnataka: The state government has announced a 2GW target by 2022, which would be in addition to solar capacity coming from private project developers. Under the policy, the government would auction 1.6GW capacity for utility-scale projects, while ~400MW would be added in the form of rooftop grid-connected projects. The government also plans to implement a net metering policy to complement this program and provide financial incentives to households and commercials buildings.

Punjab: The Indian government recently announced plans to set up a 2GW solar power plant in the state of Punjab. Additionally, the state government is planning to set up 100 MW of rooftop solar power projects on all government buildings, and to install 10,000 solar-powered irrigation pumps.

Uttar Pradesh: The state government has targeted 500MW of PV capacity by 2017.

Outlook

Cumulatively, India has installed ~2.8GW of solar power capacity (as of 30 Sep, 2014), most of which (~2GW) was installed in the last two years. While India has been slower to expand than some expected, we see long term potential in the country and favorable regulatory shifts help to accelerate growth in the sector. Recent announcements from private companies like SunEdison coupled with talk of further cooperation with the US government and local policy announcements support our view that India is beginning to ramp installations and could become one of the top markets in the world.

Figure 116: Country Snapshot

India

	2014	2017
Yearly Sun Hours (Net 20% Conversion Loss)	1,604	1,604
System Cost ($/W)	$1.10	$0.94
Discount Rate	12%	12%
LCOE ($/kWh)	$0.10	$0.08
Electricity Price - Average Residential ($/kWh)	$0.12	$0.14

Electricity Market Size (GW)	~200GW
2014 Est Solar Installs (MW)	1,000
2015 Est Solar Installs (MW)	2,000
2016 Est Solar Installs (MW)	3,000
Cumulative Solar Installs at end of 2016	8,505

Policy Climate	Improving, though initial progress has been slow. Signals from the Government recently indicate this is shifting and we expect a constructive policy environment in the future.
Other Remarks	

*Electricity price is est of resi price, but majority of installs likely to be larger scale. Assumes 5% system price reduction YoY

Source: Deutsche Bank

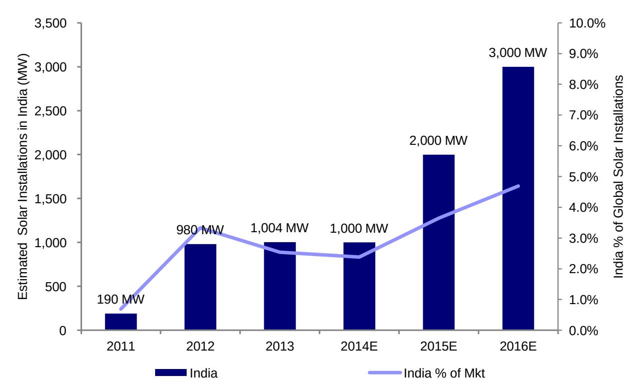
Figure 117: Initial India Solar Targets

National Solar Mission	
Period	**Target**
2012-13	1GW
2013-17	9GW
2017-22	10GW
State-level Targets	
Rajasthan	25GW in 7-8 years
Andhra Pradesh	5GW by2019*
Tamil Nadu	3GW by 2015
Karnataka	2GW by 2022
Punjab	2GW solar plant announced
Uttar Pradesh	500MW by 2017

** likely, not yet offcially announced*

Source: Deutsche Bank, MNRE

Figure 118: India Solar Installations



Source: Deutsche Bank, MNRE

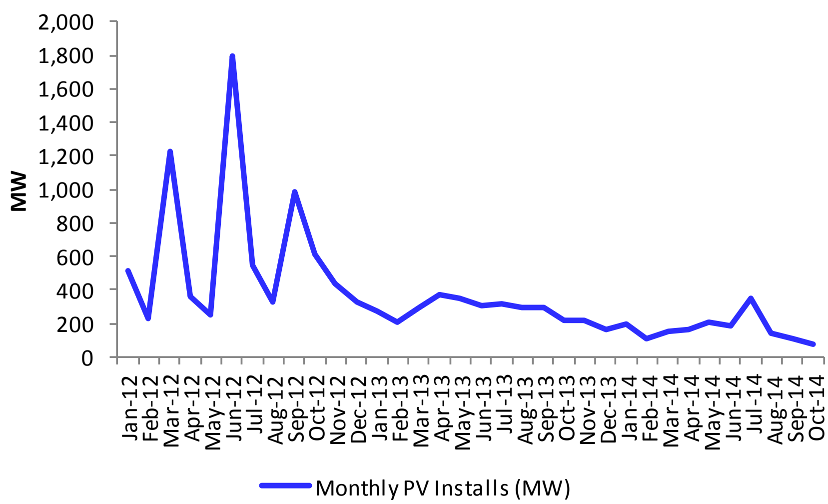
Germany

Although Germany was once the largest market in the world, recent shifts indicate economics of systems are significantly reduced from the past when high feed in tariffs dominated the national policy. We expect the majority of installations to come from the small scale rooftop segment going forward, given the country's high electricity price.

EEG Reforms Dramatically Slowdown Installations

The reform of Germany's renewable energy law (EEG), which came into effect in Aug 2014, includes charges for self-consumed PV systems (owners of >10kW PV systems will have to pay up to 30% of the EEG levy by the end of 2015, 35% by the end of 2016, eventually capped at 40% in 2017). This, coupled with a steady decline in FiT rates has slowed down installations in the country significantly.

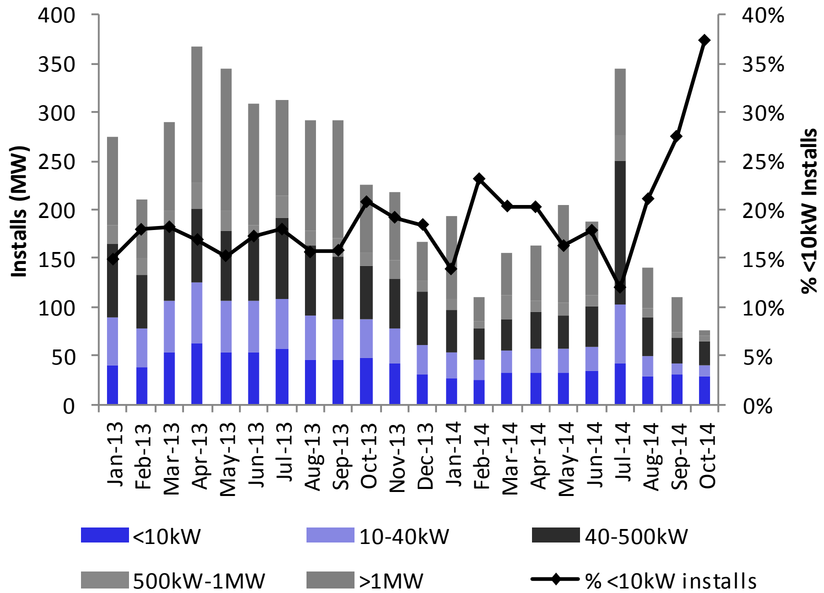
Figure 119: Monthly Installations (MW)



Source: Deutsche Bank, bundesnetzagentur

Going forward, we expect small-scale installations to increase their share in the total installation mix. Personal systems under 10KW can still self-consume without an additional charge.

Figure 120: Small Installs are Dominating Mix

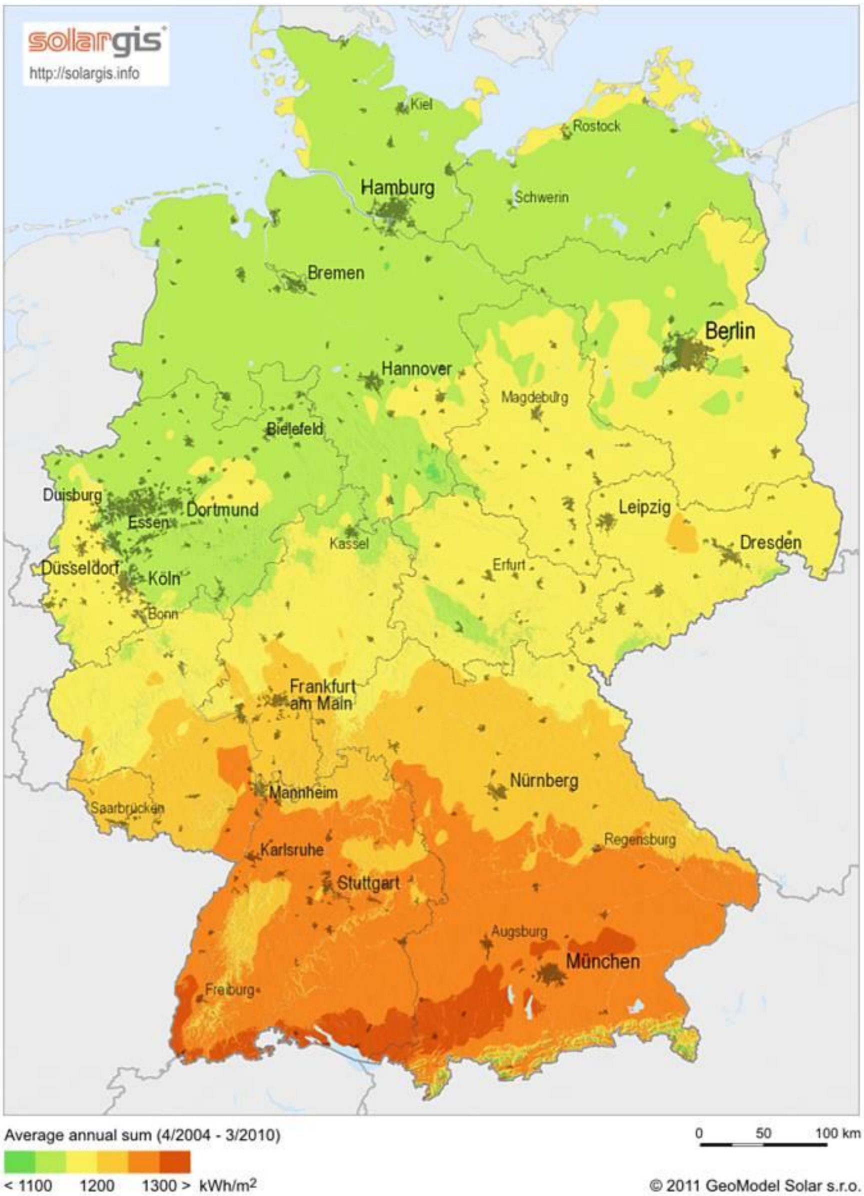


Source: German Federal Ministry for Economic Affairs and Energy

Solar At Grid Parity in Germany

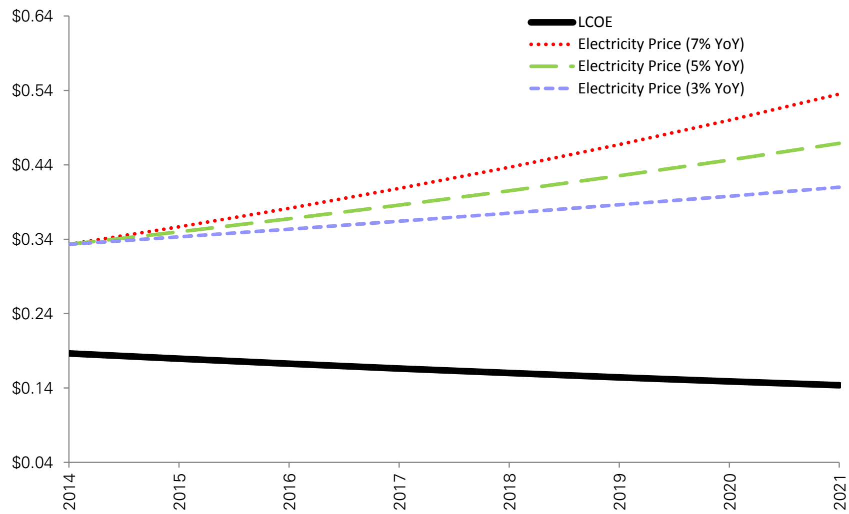
Based on our analysis, Germany is likely at grid parity with an estimated solar LCOE of ~$0.19/kWh compared to existing electricity prices in the high twentys to low thirty cents per kwh.

Figure 121: Germany Solar Resources (Horizontal Radiance)



Source: SolarGIS © 2014 GeoModel Solar

Figure 122: Germany LCOE Scenario Analysis



Source: Deutsche Bank

Current Policies

Germany's Renewable Energy Act's (EEG) latest amendment took effect Aug 2014. Some of the key changes include –

- From 1 Aug, the proceeds for electricity from large-scale plants (>500kW) will consist of a market premium (details below) and an electricity price directly negotiated with the customer. For small systems (<500kW), feed-in tariffs will continue. For the month of Aug, the EEG 2014 has set a new support base for FiTs (details below). For Sep 2014, there will then be a fixed digression of 0.5%. Afterwards, the monthly digression will be determined each quarter.

Figure 123: FiT Rates (<500kW) in EUR c/kWh for Aug/Sep

	Rooftops			Non Residential
EEG 2012	**up to 10 KWp**	**up to 40 kWp**	**up to 500 kWp**	**up to 500 kWp**
from 01.07.2014	12.88	12.22	10.9	8.92
EEG 2014	**up to 10 KWp**	**up to 40 kWp**	**up to 500 kWp**	**up to 500 kWp**
from 01.08.2014	12.75	12.4	11.09	8.83
from 01.09.2014 (0.5% degression)	12.69	12.34	11.03	8.79

Source: Deutsche Bank, bundesnetzagentur

Figure 124: Market Premium (>500kW) in EUR c/kWh for Aug/Sep

	Rooftops				Non Residential
EEG 2012	**up to 10 KWp**	**up to 40 kWp**	**up to 1 MWp**	**up to 10 MWp**	**up to 10 MWp**
from 01.07.2014	12.88	12.22	10.9	8.92	8.92
EEG 2014	**up to 10 KWp**	**up to 40 kWp**	**up to 1 MWp**	**up to 10 MWp**	**up to 10 MWp**
from 01.08.2014	13.15	12.8	11.49	9.23	9.23
from 01.09.2014 (0.5% degression)	13.08	12.74	11.43	9.18	9.18

Source: Deutsche Bank, bundesnetzagentur

- **Calculation of monthly digression for FiT:** The regular monthly reduction of 0.5% will be increased or decreased depending on newly commissioned capacity in the preceding reference 12 months. Digression will increase if the installed capacity of PV installations exceeds the target corridor (2.4-2.6GW), and will decrease if it falls below the target corridor. The tables below shows the digression rates both under the previous EEG 2012 and the new EEG 2014.

Figure 125: Digression Calculation

EEG 2012		EEG 2014	
> 7,500 MW	2.8%	> 7,500 MW	2.8%
> 6,500 MW	2.5%	> 6,500 MW	2.5%
> 5,500 MW	2.2%	> 5,500 MW	2.2%
> 4,500 MW	1.8%	> 4,500 MW	1.8%
> 3,500 MW	1.4%	> 3,500 MW	1.4%
Target corridor: 2500 to 3500 MW	1.0%	> 2,600 MW	1.0%
< 2,500 MW	0.8%	Target corridor: 2,400 to 2,600 MW	0.5%
< 2,000 MW	0.5%	< 2,400 MW	0.3%
< 1,500 MW	0.0%	< 1,500 MW	0.0%
< 1,000 MW	-0.5% (increase)	< 1,000 MW	0.0% plus increase 1.5% once at beginning of quarter

Source: Deutsche Bank, bundesnetzagentur

- The maximum of 52GWp at which support for new PV systems will be stopped has remained unchanged.

- EEG Levy: Electricity consumers in Germany will be charged proportionally per kWh used for the costs of supporting renewable energy (currently ~6.24 euro c/kWh). For self-generated electricity from systems larger than 10kW commissioned after Aug 1, 2014, a reduced EEG levy of first 30% and later 40% will be charged. Small systems (<10kW) remain exempt.

Outlook

Given target installation corridor of 2.4-2.6GW and reduction in large scale project economics, we do not expect installs to shift significantly and will likely stay around the ~2GW range.

Figure 126: Country Snapshot

Germany

	2014	2017
Yearly Sun Hours (Net 20% Conversion Loss)	958	958
System Cost ($/W)	$2.00	$1.71
Discount Rate	5%	5%
LCOE ($/kWh)	$0.19	$0.17
Electricity Price - Average Residential ($/kWh)	$0.33	$0.39
Electricity Market Size (GW)	~180GW	
2014 Est Solar Installs (MW)	2,145	
2015 Est Solar Installs (MW)	2,038	
2016 Est Solar Installs (MW)	2,000	
Cumulative Solar Installs at end of 2016	41,457	

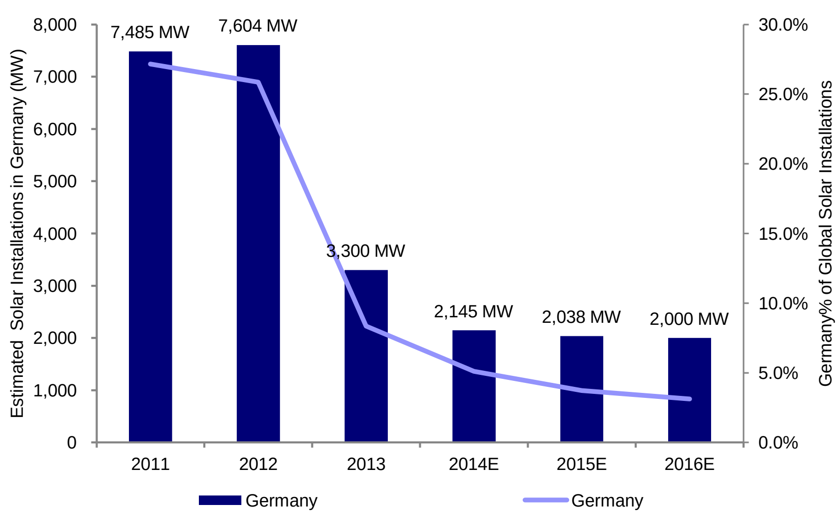
Policy Climate

Policy environment is less constructive than several years ago, but likely attractive enough to support small system installations on an ongoing basis.

Other Remarks

Source: Deutsche Bank

Figure 127: Germany Solar Installations



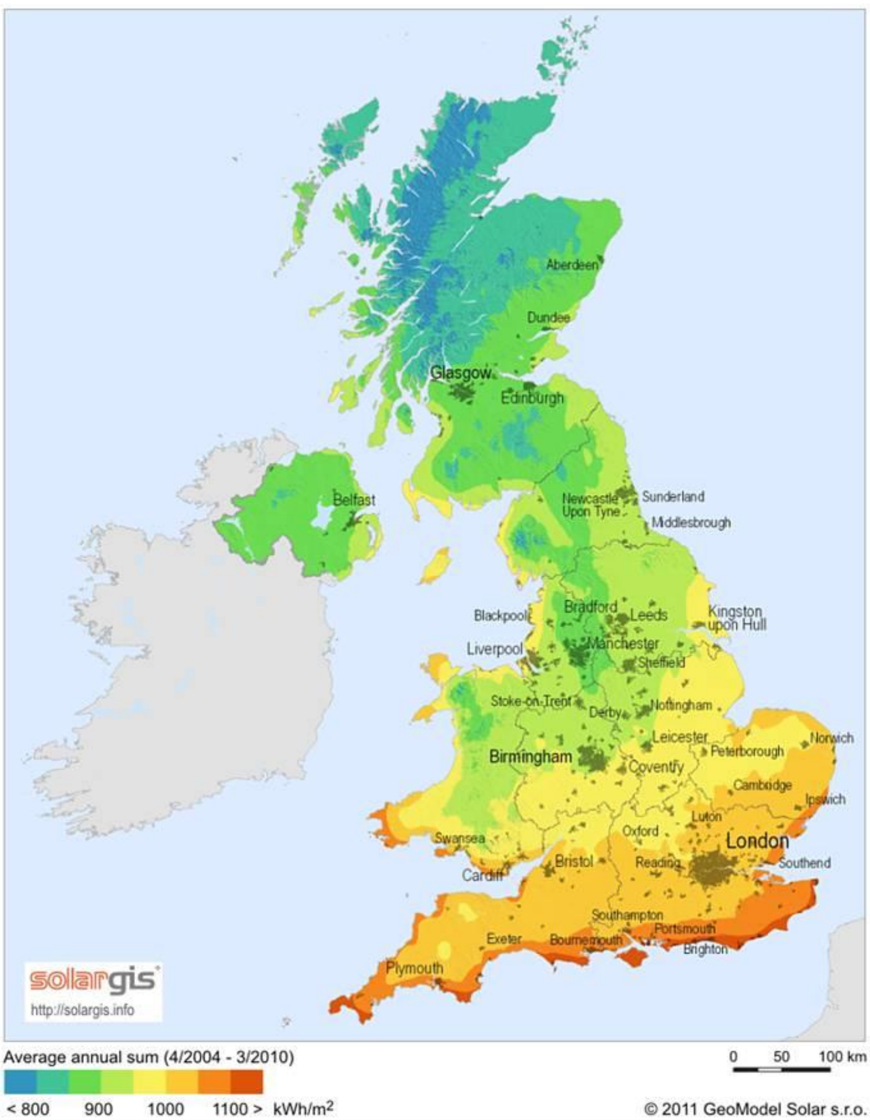
Source: Deutsche Bank, bundesnetzagentur

UK

Although the UK govt appears willing to support long term solar installation goals, shifts towards DG-only policies and relative lack of near-term grid parity lead us to believe that the UK market will likely be relevant on a global scale but decreasing on an absolute basis once the large scale incentives shift in early 2015.

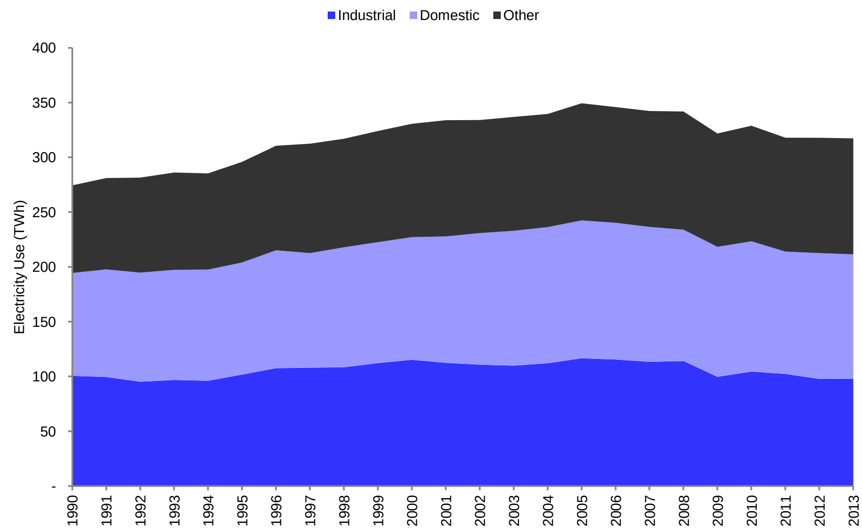
Furthermore, electricity use is relatively flat in recent memory. Therefore, the potential for incremental utility scale generation is not significant.

Figure 128: UK Solar Resources (Horizontal Radiance)



Source: SolarGIS © 2014 GeoModel Solar

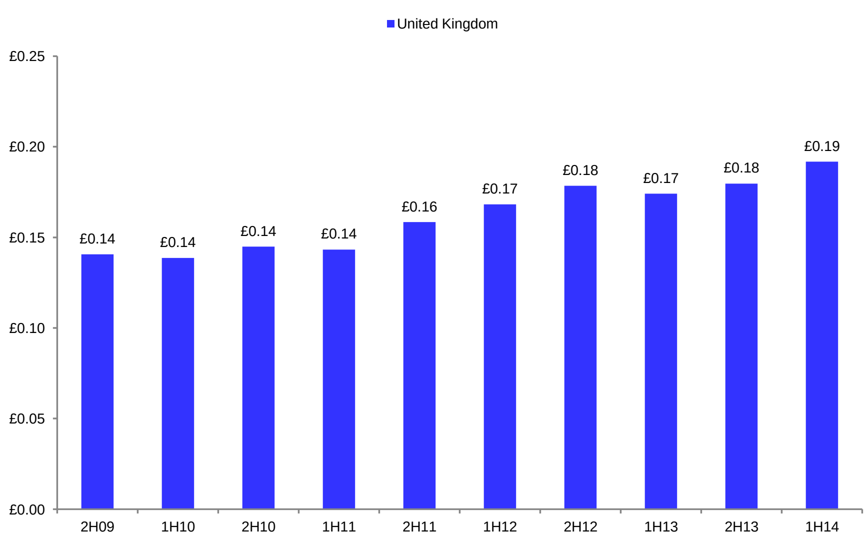
Figure 129: Electricity Use in the UK (TwH)



Source: UK Department of Energy & Climate Change

We see support for retail additions over the longer term, as the retail price of electricity continues to trend up over time.

Figure 130: Retail Price of Electricity (UK)

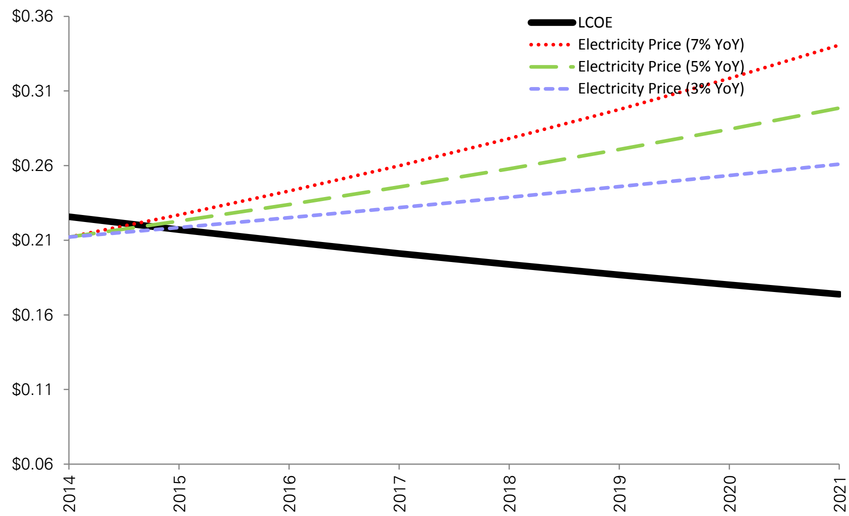


Source: Eurostat

Not Quite at Grid Parity, but Potential for Retail

Retail electricity prices of ~$0.21/kWh are still below unsubsidized solar cost in the low 20 cent/kWh range, but system cost reductions could change this dynamic over the next several years as the market develops.

Figure 131: UK LCOE Scenario Analysis



Source: Deutsche Bank

Withdrawal of Subsidy for Large-scale PV (>5MW) Poses Long-term Uncertainty

DECC's decision to withdraw Renewable Obligation subsidy scheme for solar PV plants larger than 5MW from Apr'15, is likely to affect the pace of solar installations going forward. Post RO withdrawal, large-scale PV plants will switch to CfD mechanism where they will directly compete with onshore wind projects. For the first round of CfD auction, the govt has budgeted GBP65M (~$102M) for established technologies that include solar and onshore wind. Of the GBP65M, GBP50M will be awarded to projects that begin operations in 2015/16, and GBP15M for projects that get operational from 2016/17 onwards.

Focus on Ground-mounted projects (<5MW)/ DG Could Stabilize Demand

Post Apr'15, we expect an increase in focus on ground-mounted PV projects that are less than 5MW, which would continue to benefit from RO support. This, coupled with growth in the residential/ commercial rooftop solar (~40% of current installed capacity), could potentially stabilize demand, in our view.

Current Policies

UK government's support mechanism for solar is broadly divided in two categories – support for large-scale installations (>5MW) and that for small-scale installations (<5MW). Renewables Obligation Certificate (ROC) has been the main support mechanism for large scale solar projects in UK, while smaller scale generation is supported through the FiT scheme.

In early 2014, UK's Department of Energy and Climate Change (DECC) noted that the large-scale solar PV installations grew faster than previously expected, and the aim of the government was to support the growth of rooftop and mid-scale sector. As a result, DECC proposed withdrawal of Renewable Obligation subsidy scheme for solar PV plants larger than 5MW from Apr'15. If proposed changes go ahead, >5MW plants would be forced to switch to the "Contracts for Difference" (CfD) mechanism, under which renewable energy generators are guaranteed a fixed price (called strike price) for the energy they produce. On the other hand, the government also recently announced that it plans to implement automatic approval for setting up rooftop solar PV projects of size up to 1MW (currently auto-approval is restricted to 50kw).

Outlook

As a result of the proposed expiration of RO support for large scale installations from Apr'15, we expect UK installations to ramp substantially in the short term, although post Apr'15 installs will likely scale down. Total installations reached ~1GW in 1H14, (cumulative capacity now surpasses 5GW). We expect another ~2GW of installations in 2H14 as developers ramp up , which could bring FY installs to ~3GW. In 2015, the annual new installation figure is likely to drop to 2-2.5GW, in our view, although this will likely be 1H weighted. Overall, the DECC aims to have 22GW of solar power installed by 2020

Figure 132: Country Snapshot

United Kingdom	2014	2017
Yearly Sun Hours (Net 20% Conversion Loss)	792	792
System Cost ($/W)	$2.00	$1.71
Financing Cost ($/W)	5%	5%
LCOE ($/kWh)	$0.23	$0.20
Electricity Price	$0.21	$0.25
Electricity Market Size (GW)	~90GW	
2014 Est Solar Installs (MW)	3,000	
2015 Est Solar Installs (MW)	2,250	
2016 Est Solar Installs (MW)	1,800	
Cumulative Solar Installs at end of 2016	10,291	
Policy Climate	Reduced support for large scale projects signals likelihood that total incremental installs may fall, but ongoing support for small scale is encouraging.	
Other Remarks		

*Electricity price is est of resi price, but majority of installs likely to be larger scale. Assumes 5% system price reduction YoY

Source: Deutsche Bank

Figure 133: UK Solar Incentives

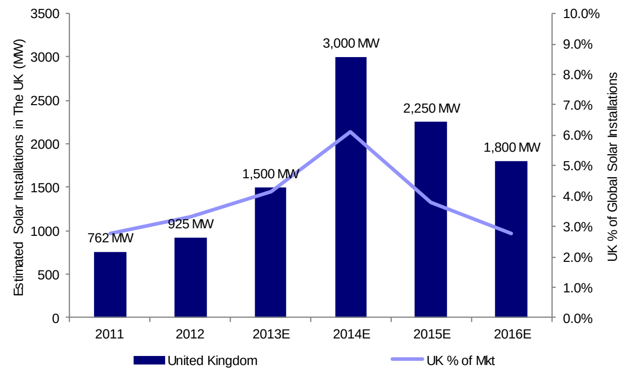
ROCs/MWh	2013/14	2014/15	2015/16	2016/17
Building-mounted solar PV	1.7	1.6	1.5	1.4
Ground-mounted solar PV	1.6	1.4	1.3	1.2

** ROC support for >5MW likely to end from Apr'14*

FiT Scheme Band	Tariff (Jul-Dec 2014) in p/kWh	Tariff (from 1 Jan 2015) in p/kWh	Tariff (from 1 Jan 2015) in $ cents/kWh
<=4kW	14.38	13.88	22.06
>4-10kW	13.03	12.57	19.99
>10-50kW	12.13	11.71	18.61
>50-100kW	10.34	10.34	16.44
>100-150kW	10.34	10.34	16.44
>150-250kW	9.89	9.89	15.73
>250kW-5MW	6.38	6.38	10.14
Stand alone	6.38	6.38	10.14
Export tariff	4.77	4.77	7.58

Source: Deutsche Bank, DECC

Figure 134: UK Solar Installations



Source: Deutsche Bank

Key Markets – The ~1GW Club

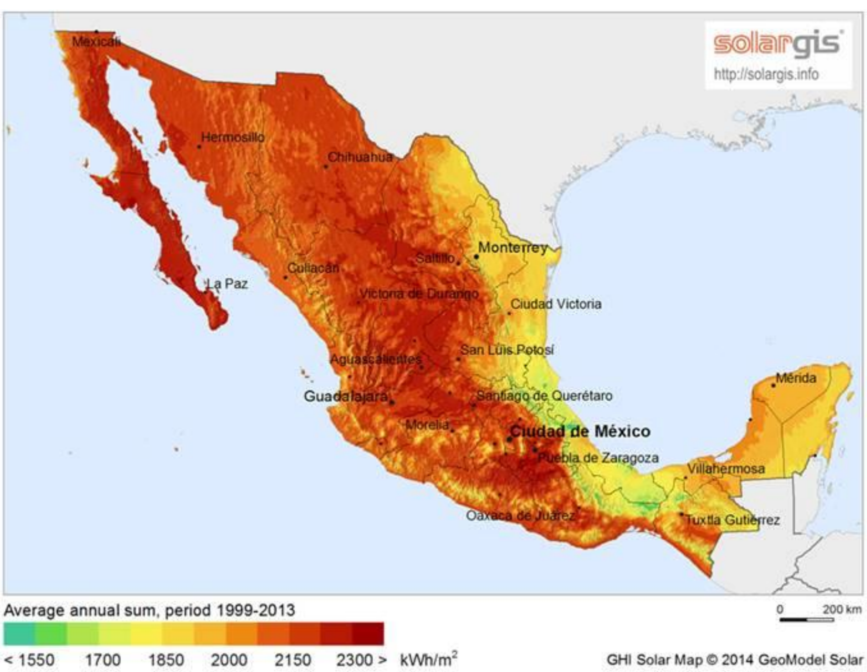
Mexico

Solid Fundamentals, Energy Reforms Make Mexico an Attractive Market

Mexico is an emerging attractive market for both utility scale and distributed generation. Virtual net metering was established in Mexico in 2007 and is administered by the CFE, Mexico's state owned utility. This effectively allows companies to buy power from solar plants anywhere else in the country. Therefore, users in high priced electricity regions can use power from solar plants in areas with low development costs. This is an important policy that should help drive solar investment in the country.

While CFE has owned and operated most power plants in the past, independent power producers (IPPs) are starting to gain traction in Mexico - often through renewables. Given high insolation levels (>4.5kWh/m^2/day in ~70% of the country) and high energy prices for commercial/industrial consumers, we believe key fundamentals in Mexico's renewable energy sector are already in place. Previously, Mexico has set the goal to generate 35% of its energy from renewable sources by 2024 (vs. ~14% currently).

Figure 135: Mexico Solar Resources (Horizontal Radiance)

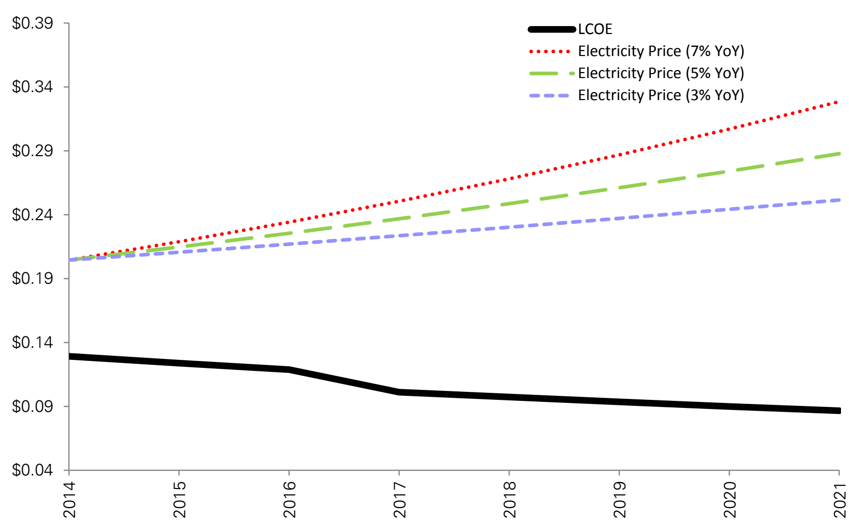


Source: SolarGIS © 2014 GeoModel Solar

Mexico’s energy reforms, which were signed into law in 2014, have also opened up the previously restricted electricity market, allowing private companies to build and operate power plants. In fact, the new law requires state utility company CFE to prioritize the purchase of electricity from renewable. Specific features of the law that could help drive renewable investment include 1) an independent role for grid operator CENACE; 2) requirements to procure renewable energy; 3) enables companies to directly sign electricity contracts with renewable energy generators; and 4) mandates the creation of a system of renewable energy certificates.

Retail electricity prices in Mexico are typically in the 6-9 cents/kWh range for systems that consume up to 150kWh of electricity. In most regions, retail customers pay the DAC rate of ~22c/kWh once consumption increases above 150kWh, which implies considerably higher prices for most commercial users. High prices for imported natural gas, limited hydro and coal resources, weak grid infrastructure and energy demand growth of ~4% per annum is driving electricity price growth of 8-10% per annum. Commercial businesses represent 65% of Mexico's total electricity sales and this represents the largest opportunity for solar developers, in our view. Given govt subsidization of electricity prices for residential customers, small scale residential installations are unlikely to proliferate.

Figure 136: Mexico LCOE Scenario Analysis



Source: Deutsche Bank

Outlook

With no more than 100-200MW of solar currently installed, Mexico represents a strong potential growth market. We see installations ramping notably in the future as developers work through initial kinks and expect Mexico to surpass 1GW of installations within the next several years.

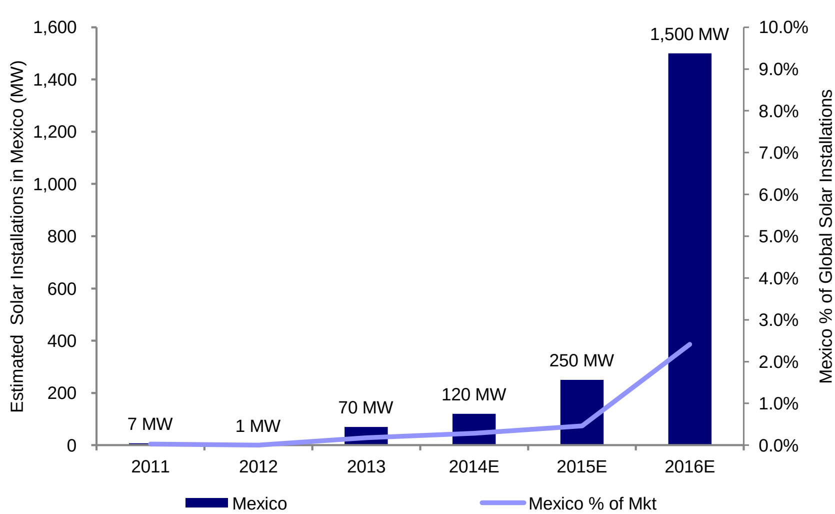
Figure 137: Country Snapshot

Mexico		
	2014	**2017**
Yearly Sun Hours (Net 20% Conversion Loss)	1,792	1,792
System Cost ($/W)	$2.00	$1.71
Discount Rate	9%	7%
LCOE ($/kWh)	$0.13	$0.10
Electricity Price - Average Residential ($/kWh)	$0.20	$0.24
Electricity Market Size (GW)	~65GW	
2014 Est Solar Installs (MW)	120	
2015 Est Solar Installs (MW)	250	
2016 Est Solar Installs (MW)	1,500	
Cumulative Solar Installs at end of 2016	1,948	
Policy Climate	Recent energy reforms and virtual net metering coupled with solid fundamentals provide an attractive investment environment for developers	
Other Remarks		

*Electricity price is est of resi price, but majority of installs likely to be larger scale. Assumes 5% system price reduction YoY

Source: Deutsche Bank

Figure 138: Mexico Solar Installations

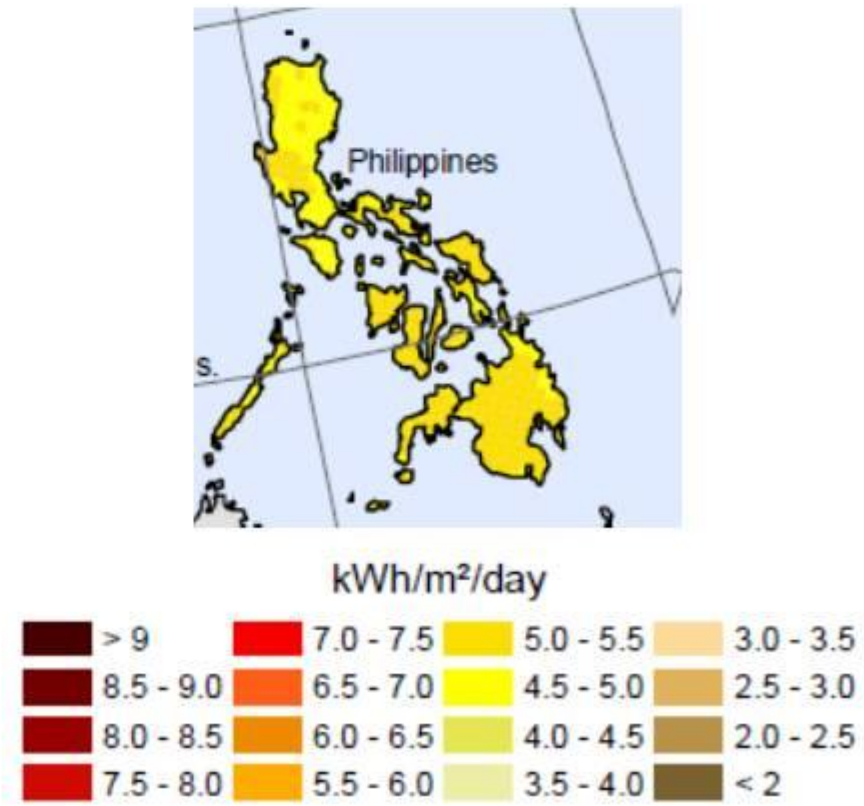


Source: Deutsche Bank ests

Philippines

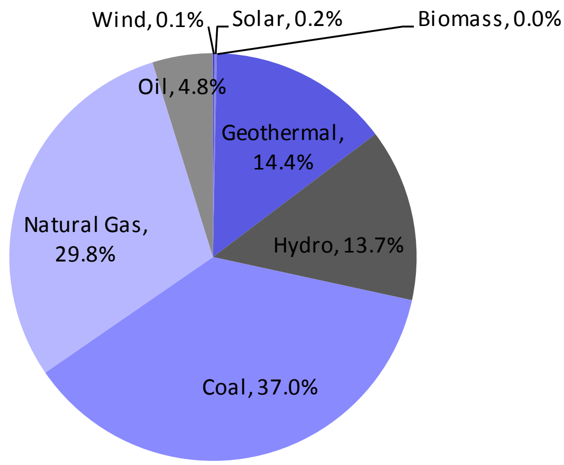
The Philippines is a notable attractive market for solar. The country is is experiencing rapid electricity demand growth coupled with substantial (~90%) energy import requirements. The Philippines also has relatively high solar insolation levels of ~1,600 kWh/kW/year and in an effort to address the growing energy needs, the country increased focus on renewables. Renewable sources currently account for ~30% overall energy mix and are targeted to represent 50% by 2030.

Figure 139: Philippines Solar Resources (Horizontal Radiance)



Source: NREL

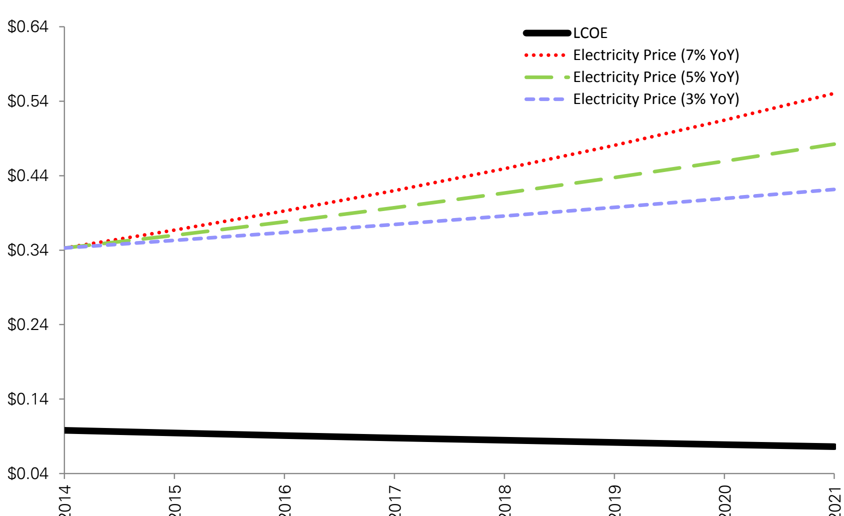
Figure 140: Power Generation Mix



Source: Philippines DOE

The Philippines has about 7,000 islands and no national grid (regional grids are in place). Therefore, the country requires various forms of localized generation and peak power is often generated from diesel. Furthermore, solar is likely already competitive with coal and diesel based electricity generation. The cost of electricity from a coal plant in the country can run up to P5.50/kWh ($0.12/kWh) plus P6.50/kWh (~$0.14/kWh) for distribution and transmission - P12.00/kWh (~$0.27/kWh) total. Our calculated LCOE value of ~$.010/kWh (and no T&D cost if self consumed) appears quite attractive by comparison.

Figure 141: Philippines LCOE Scenario Analysis



Source: Deutsche Bank

Net Metering in Place

The Philippine Renewable Energy Act of 2008 approved net metering in the country (effective July 2013) which allows residential and commercial consumers to install roof-top solar panels (not to exceed 100kW) and sell surplus energy to the grid to receive credits that lower their utility bills.

In addition, the country's Energy Regulatory Commission (ERC) in 2012 approved FiT rates for solar at P9.68/kWh (~$0.22/kWh) with a 6% annual digression that which results in rates of P8.55/kWh (~$0.20/kWh) for Aug 2014-July 2015. Recent indications are that the country-wide target of 50MW may be revised upwards to ~500MW

Outlook

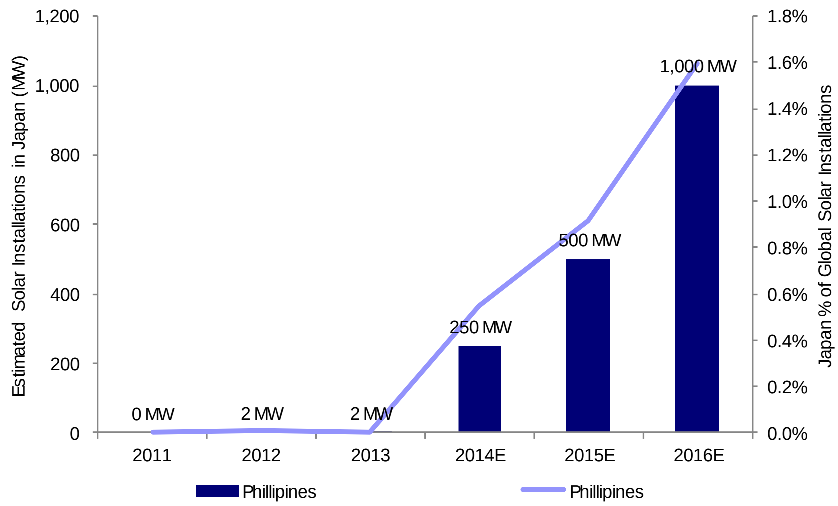
Although the Philippines installed electric capacity is only ~16GW, based on the historical runrate and government forecasts for incremental 10GW of electricity capacity growth through 2030, we estimate the Philippines solar market could become a multi GW market in the next several years. Nearly 50% of the incremental capacity growth is estimated to come from renewables and we expect solar to dominate the mix of renewables. As recent as Apr 2014, the DOE has approved applications for 52 solar projects with a combined capacity of 978MW, which includes 29 applications for 557MW of capacity from Nov 2012 to Apr 2014.

Figure 142: Country Snapshot

Philippines	2014	2017
Yearly Sun Hours (Net 20% Conversion Loss)	1,583	1,583
System Cost ($/W)	$1.40	$1.20
Discount Rate	7%	7%
LCOE ($/kWh)	$0.10	$0.09
Electricity Price - Average Residential ($/kWh)	$0.34	$0.40
Electricity Market Size (GW)	~16GW	
2014 Est Solar Installs (MW)	250	
2015 Est Solar Installs (MW)	500	
2016 Est Solar Installs (MW)	1,000	
Cumulative Solar Installs at end of 2016	1,754	
Policy Climate	Net metering and FiT's are helpful for small system economics	
Other Remarks		

Source: Deutsche Bank

Figure 143: Philippines Solar Installations



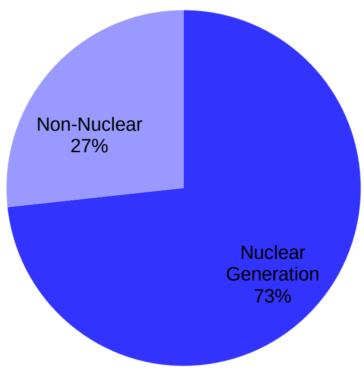
Source: Deutsche Bank, ERC

France

Proposed €10B Energy Law/ Clear Policy Climate to Spur Solar Growth

In a bid to reduce France's reliance on nuclear power from ~75% currently to 50% by 2025, the govt is indicating an increased focus on renewable deployments. Specifically, the environment minister signaled intentions to mobilize €10B in investment through tax credits and low-interest loans. While €5B will of the targeted investment will come from govt-owned lender Caisse des Depots et Consignations, the rest will come from non- state banks. Moreover, the govt is now targeting 32% of energy from renewables by 2030 (vs. 14% in 2012), and 75% cut in emissions by 2050.

Figure 144: Electricity Mix in France (TWh)

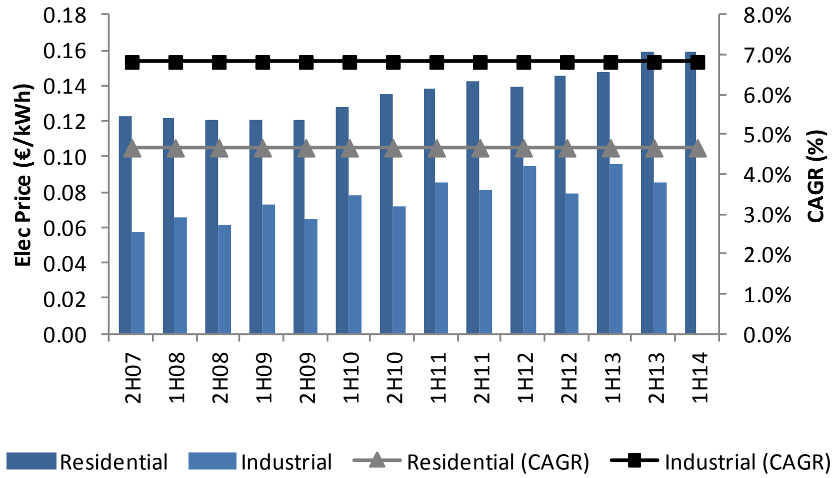


Source: OECD

France has ~5GW of solar installations and the rate of installs has slowed considerably since 2011 – current installs accounted for only ~1% of its electricity use in 1H14. However, we believe installations are likely to pick up going forward. While small-scale installations are able to receive relatively high FiT rates, large-scale installations typically use tenders (govt recently launched a new 400MW RfP for >200Kw solar PV projects).

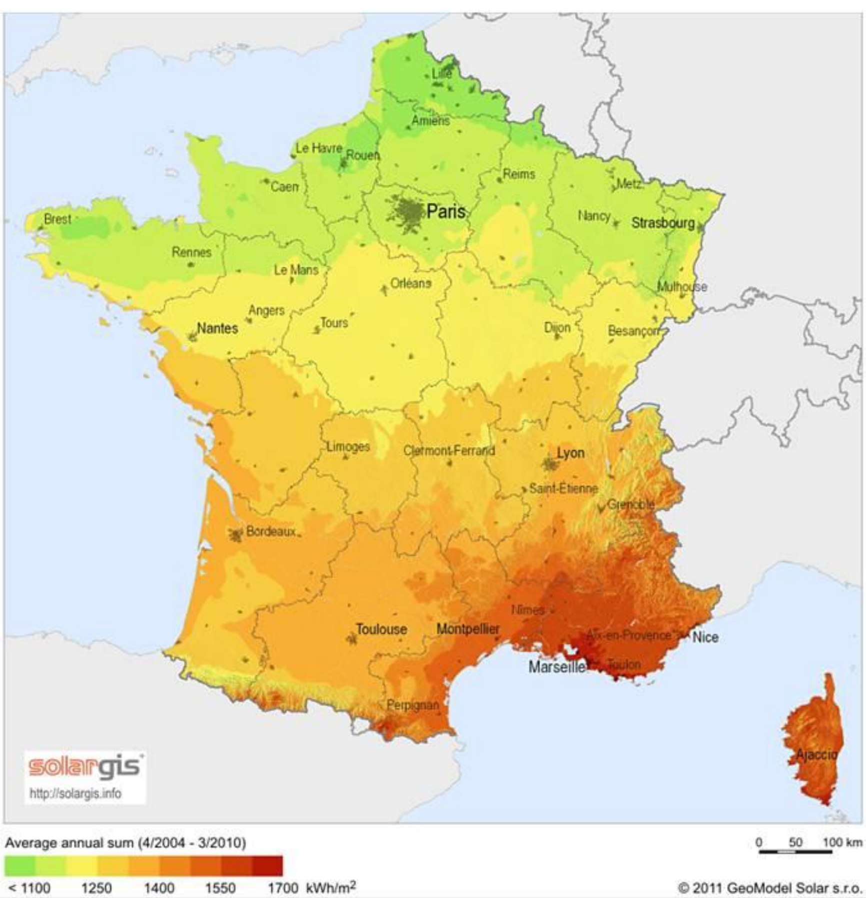
Furthermore, the country's electricity prices have consistently increased over the past 7-8 years (where data was available). Residential electricity prices in France increased at a ~5% CAGR over 1H08-1H14, while industrial electricity prices increased at a ~7% CAGR during 2H07-2H13.

Figure 145: Growth in Electricity Prices



Source: Deutsche Bank, Eurostat

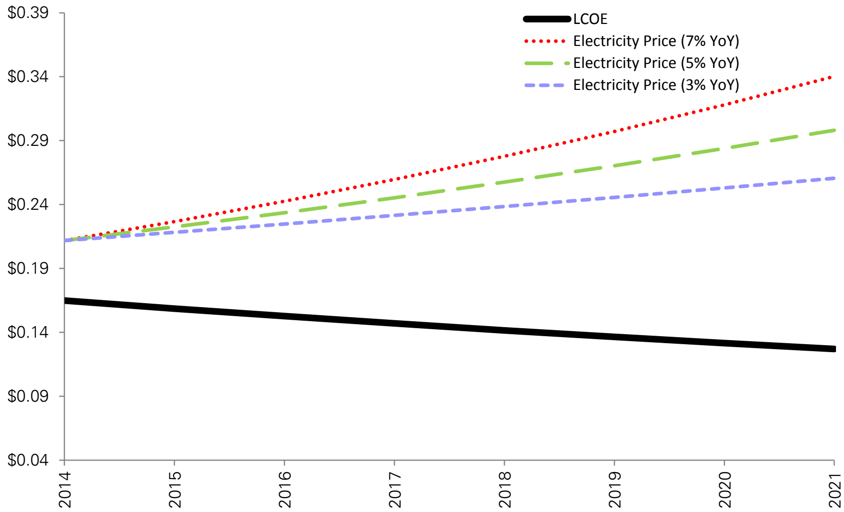
Figure 146: France Solar Resources (Horizontal Radiance)



Source: SolarGIS © 2014 GeoModel Solar

Furthermore, our analysis indicates parts of the country may be at grid parity today.

Figure 147: France LCOE Scenario Analysis



Source: Deutsche Bank

Current Policies

Under the France's policy framework, small PV systems (up to 100kW) benefit from higher FiT rates, but larger systems receive significantly lower rates. However, larger installations (>100kW) are also eligible to participate in the tender process, which will help drive installations. Specifically, all rooftop projects 100kW-250kW will use a "simplified" call-for-tender; while rooftop projects >250kW, and ground-mounted projects of any size can respond to a more conventional request-for-proposal (RFP). The move to switch to tenders for >100kW installations was initially designed to allow greater control over large scale installations.

There have been several attempts in recent years to provide policy support in the country. For example, in late 2014, France announced a new 400MW RFP for solar projects larger than 250kW. Prior to that in Apr 2013, the country announced plans to tender 120MW of 100-250kW rooftop PV installations by 2015 (tenders of 40MW per year). In Mar 2013, the country announced tender for 400MW of >250kW installations. In Jan 2013, France doubled its annual minimum installation rate, from 500MW in 2012 to 1GW in 2013, but that goal was not achieved. In 2014, France's Energy Regulatory Authority (CRE) announced new feed-in tariff rates for 1Q14 at EUR0.0736–0.2851 per kWh (see below).

Figure 148: France FiT (1Q14)

Installation Type	Capacity	Jan-Mar 2014 (EUR/kWh)	Jan-Mar 2014 (~$/kWh)
BIPV	0-9kW	0.2851	0.37
Simplified BIPV	0-36 kW	0.1454	0.19
	36-100 kW	0.1381	0.18
Without integration or outside above criteria or	0-12MW	0.0736	0.10

Source: Deutsche Bank, CRE

Outlook for 2014/15

Annual installations in France declined in 2012 and 2013 – likely due to the switch from FiT's to tenders. Installations have declined in the last several years (to 613MW in 2013), but the market showed signs of recovery in 2014, with installations of ~672MW in the first 3 quarters (192MW in 1Q14, 194MW in 2Q14 and ~286MW in 3Q14). Quarterly run rate of 200-300MW indicates that policy support mechanisms are beginning to help more, and the country could reach a yearly run rate above 1GW in the future. We do not expect the country to provide major surprises, but should remain a relatively sustainable market.

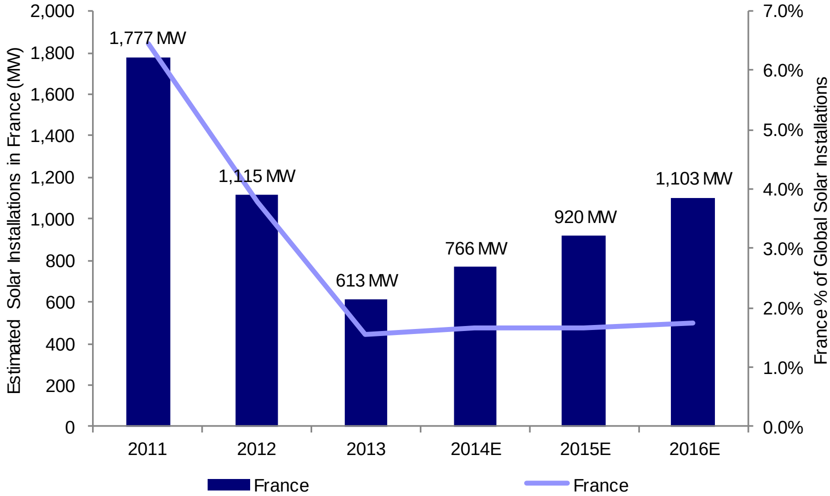
Figure 149: Country Snapshot

France	2014	2017
Yearly Sun Hours (Net 20% Conversion Loss)	1,083	1,083
System Cost ($/W)	$2.00	$1.71
Discount Rate	5%	5%
LCOE ($/kWh)	$0.16	$0.15
Electricity Price - Average Residential ($/kWh)	$0.21	$0.25
Electricity Market Size (GW)	~125GW	
2014 Est Solar Installs (MW)	766	
2015 Est Solar Installs (MW)	920	
2016 Est Solar Installs (MW)	1,103	
Cumulative Solar Installs at end of 2016	12,025	
Policy Climate	Generally improving policy climate should support yearly installs in the ~1GW range. We do not expect a major shift in installations.	
Other Remarks		

*Electricity price is est of resi price. Assumes 5% system price reduction YoY

Source: Deutsche Bank

Figure 150: France Solar Installations



Source: Deutsche Bank, EPIA

Chile

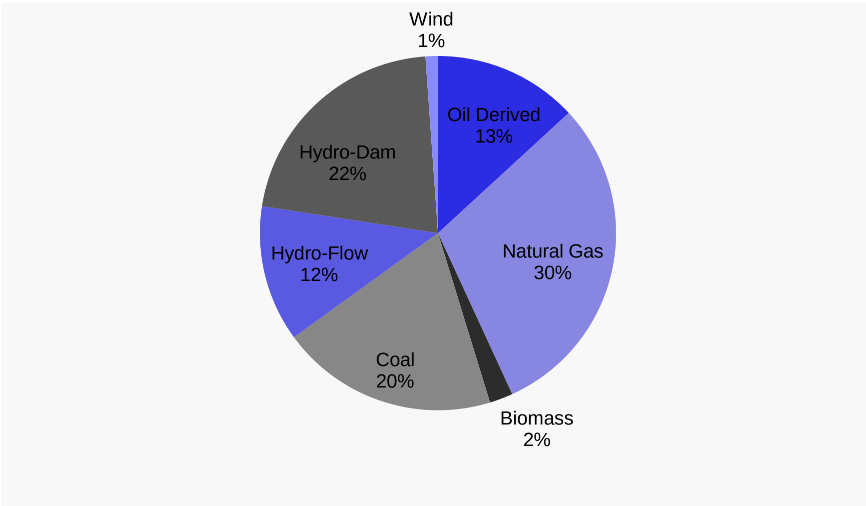
As home to one of the most attractive solar resources in the world, Chile was among the first self-sustaining solar markets where new projects are already being produced at or below grid parity. We expect installations to continue ramping as high electricity prices coupled with unique opportunities in the mining sector create a robust environment for most of the top solar companies in the world to continue building large scale commercial or utility projects. In addition, expected addition of the net metering policy for projects under 100KW should act as a catalyst for rooftop generation.

Figure 151: Chile Solar Resources

Source: SolarGIS © 2014 GeoModel Solar

The Chilean electricity market is characterized by high prices, near complete private ownership, and extensive industrial sector demand particularly from the mining sector. There is currently almost 20GW of installed capacity dominated by natural gas, hydro and coal generation.

Figure 152: Chile Generation Capacity



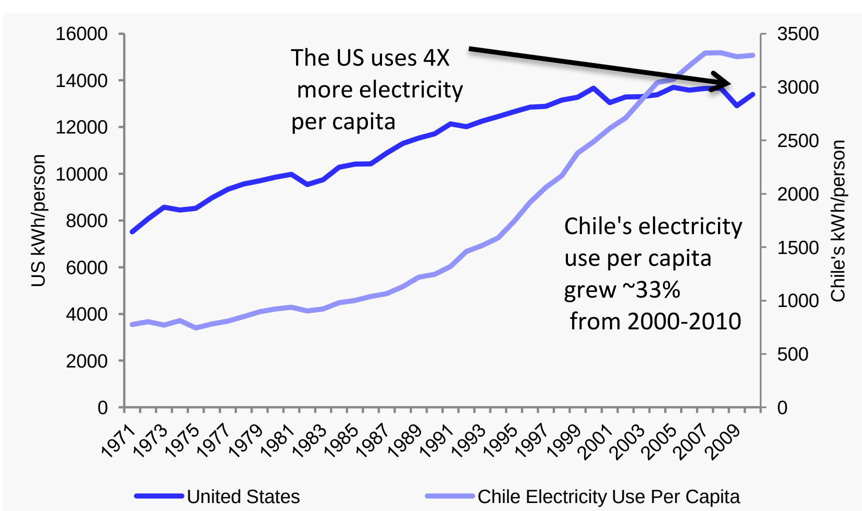
Source: Centro de Despacho Economico (CDEC)

However, there are notable differences between the north and south in terms of electricity generation within the country. While 33% of overall capacity is hydro based, the north section of the country has much less rainfall and consequently, almost no hydropower. We expect the majority of solar installations coming online over the next several years to be located in the SING (northern grid), which is much drier and, consequently, cannot support the level of hydro generation present in the SIC.

Electricity Use is Expanding Rapidly

Based on historic trends, it is evident that electricity demand is expanding rapidly in the country.

Figure 153: Electricity Use Per Capita – US vs Chile

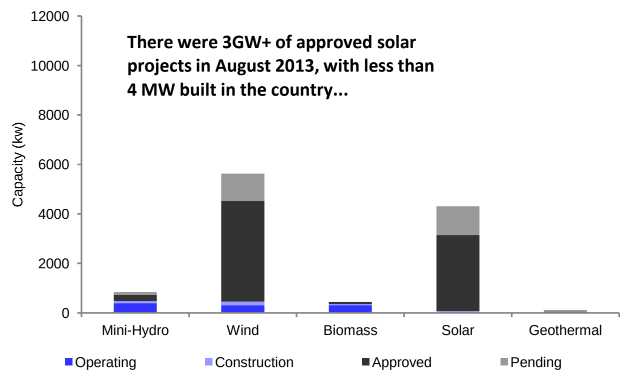


Source: World Bank, Deutsche Bank

Significant progress in the past year

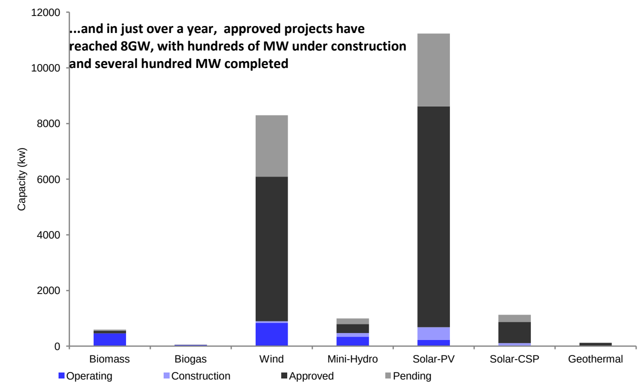
While the solar market was almost nonexistent before 2013, recent progress has been rapid and drastic. Total installations have increased from less than 4MW in mid 2013 to 222MW as of November 2014. More importantly, ~8GW of solar plants have been approved, with another 2.6GW under review. This is more than double the capacity approved/pending as recently as a year prior.

Figure 154: Past Projects Pipeline Was Robust…



Source: Centro de Energias Renovables

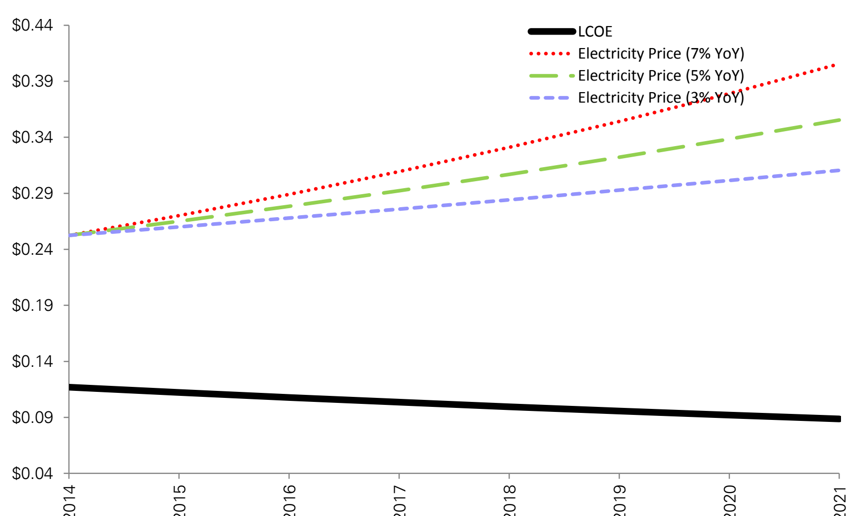
Figure 155: …And is Significantly Expanded



Source: Centro de Energias Renovables

In the longer term, high energy prices and near ideal environmental conditions will allow extensive solar development in a rapidly developing economy. The mining companies will play a key role in furthering the economic interests of the country and the energy needs in the north, which should help spur long term investment and construction. We favor strategies that begin partnerships with mining companies as a bridge to further development in the country. With overall system costs at ~$2-3/W, we expect to see development ramp quickly.

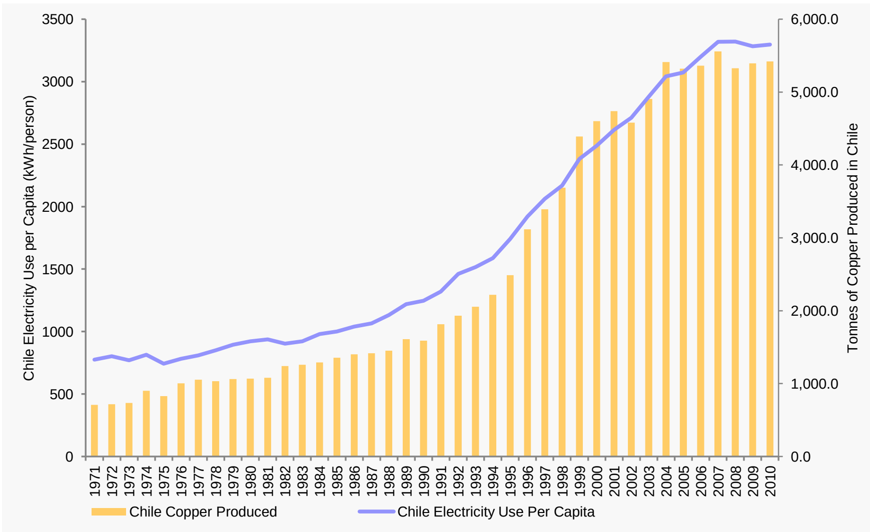
Figure 156: Chile LCOE Scenario Analysis



Source: Deutsche Bank

We believe Chile's notable ramp from almost no capacity to a likely yearly install rate in the 1GW+ range can be attributed in part the electric-intensive mining industry.

Figure 157: Mining Sector Activity Correlates to Electricity Use



Source: World Bank, Cochilco

While the pipeline of solar projects in Chile may face some regulatory and logistic hurdles, we expect strategic partnerships with mining companies to be a good source of growth for solar companies. Mining companies appear to be among first movers helping to bring projects to completion as they seek to shore up their long term electricity needs and improve their environmental image. Long term PPA's have been signed in the $100-120/MWh range which is competitive with gas (~$120s/MWh) and coal (~$80s/MWh), with no commodity risk.

The Risk is Transmission

Much like other countries experiencing rapid growth in renewables, the electric grid will need significant investment. Chile is uniquely challenging because the two major electric grids in the north and south of the country are not connected. Much of the generation potential for solar lies in the north, but a large portion of the energy use is in the south. While there are plans to change this and improve the grid, pace of installation growth could be constrained in the future if interconnection is not possible. However, mining company partnerships will help offset this.

Current Policies

Chile has updated its renewable-related policies several times in recent memory in recognition of the country's significant potential.

In Oct 2013, Chilean President signed into law a bill which mandates that utilities source 20% of their electricity from non-conventional renewable energy (NCRE) by 2025. Under the new law, the Ministry of Energy will hold annual bidding for utilities to purchase electricity from NCRE sources. Additionally, the president also signed a law making changes to the permitting process – with an aim to reduce estimated permitting time from 700 to 150 days.

In May 2014, the Chilean president published the Energy Agenda – which included a goal to ensure 45% of installed electrical generation capacity between 2014 and 2025 comes from renewable sources.

In Sep 2014, the government released CLP780M ($1.3M) to fund the early-stage development of 51 renewable energy projects totaling 740MW, of which there are 12 solar plants. Additionally, net-metering was launched in the country recently (to be effective from first week of Oct 2014). Under the program, owners of PV systems with a capacity of less than 100kW will be paid for surplus electricity, which will be sold to the country's national grid at a fixed tariff rate.

Outlook

Chile has a constructive overall environment for renewables, particularly solar, primarily because of high power prices (~$0.25/kWh) that make unconventional sources of energy cost-competitive. According to Chile's Energy Minister, power prices are likely to increase 30% in the next 7 years. Current unsubsidized solar LCOE of $0.12-0.18/kWh or lower in some cases can help drive significant investment in the country's power generation over the longer term.

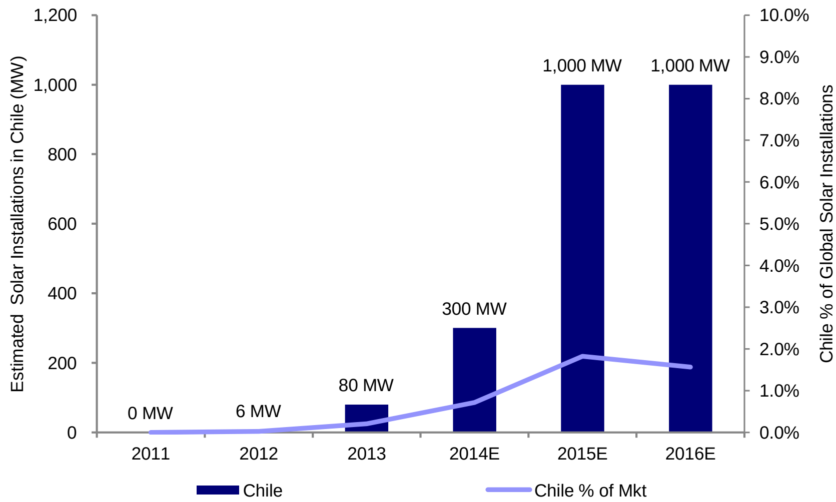
Figure 158: Country Snapshot

Chile	2014	2017
Yearly Sun Hours (Net 20% Conversion Loss)	1,750	1,750
System Cost ($/W)	$2.00	$1.71
Discount Rate	7%	7%
LCOE ($/kWh)	$0.12	$0.09
Electricity Price - Average Residential ($/kWh)	$0.25	$0.29
Electricity Market Size (GW)	~16GW	
2014 Est Solar Installs (MW)	300	
2015 Est Solar Installs (MW)	1,000	
2016 Est Solar Installs (MW)	1,000	
Cumulative Solar Installs at end of 2016	2,386	
Policy Climate	While generally supportive of renewables, Chile is regarded as one of the first truly sustainable non-subsidized markets in the world. Therefore, the policy environment is less important. However, recent changes to net metering show commitment to ongoing policy support.	
Other Remarks	Mining sector provides ample opportunities for growth, given high electricity use in remote regions with high solar potential	

*Electricity price is est of resi price. Assumes 5% system price reduction YoY

Source: Deutsche Bank

Figure 159: Chile Solar Installations



Source: Deutsche Bank

South Africa

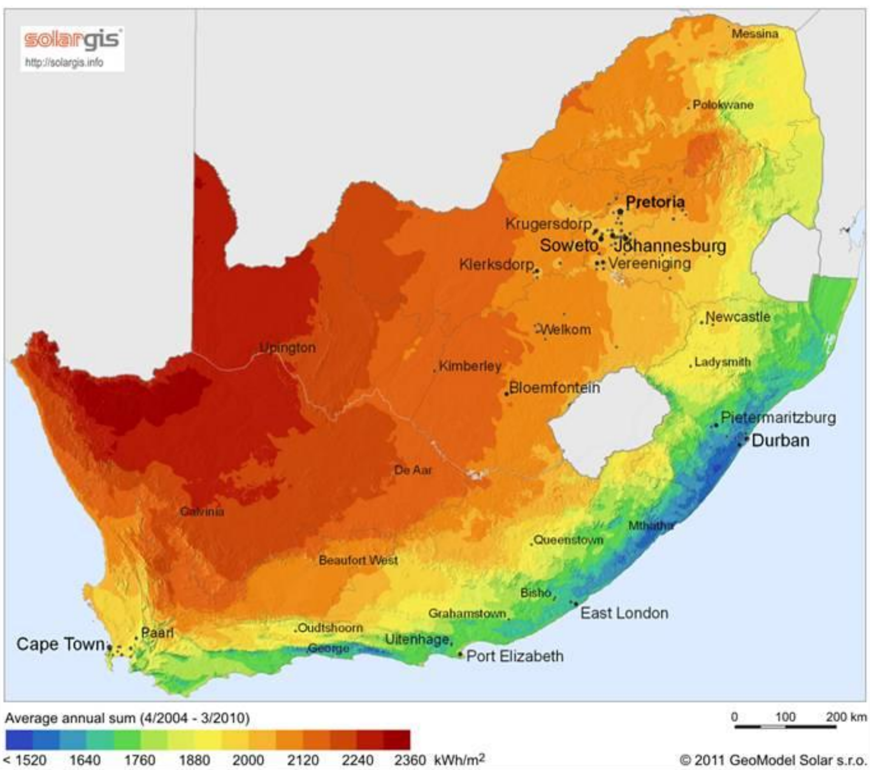
~8GW Target Likely to Be Achieved Well Before the Deadline

South Africa is emerging as an important market for solar installations. The country has set a target of achieving ~8.4GW of solar capacity by 2030 through its Renewable Energy Independent Power Producer Programme (REIPPP), which allows the state utility company, Eskom, to buy renewable energy from producers of renewable energy. Recent evidence suggests this could be surpassed well before 2030 timeframe as the tender process has been very successful and high domestic electricity prices help solar compete.

Grid Parity Likely

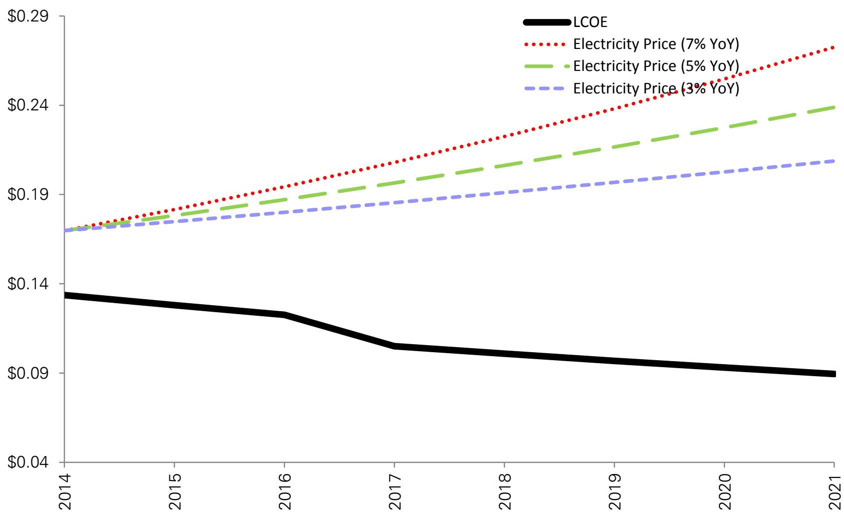
South Africa is likely at grid parity, in our view. High insolation particularly in the North West region coupled with high electricity prices makes this an attractive market.

Figure 160: South Africa Solar Resources (Horizontal Radiance)



Source: SolarGIS © 2014 GeoModel Solar

Figure 161: South Africa LCOE Scenario Analysis



Source: Deutsche Bank

Outlook

South Africa has over 500MW installed capacity after four utility-scale solar power projects were commissioned in May 2014. During the first auction for renewable energy projects, a total of 28 projects were awarded (19 solar PV - 630MW, and 2 CSP – 150MW). Following this, two more auctions compounded with the first to create a current utility-scale pipeline approaching 2GW. If the government continues to support developers in the region, we expect South Africa will remain a solid solar market going forward.

Figure 162: Country Snapshot

South Africa

	2014	2017
Yearly Sun Hours (Net 20% Conversion Loss)	1,833	1,833
System Cost ($/W)	$2.00	$1.71
Discount Rate	10%	8%
LCOE ($/kWh)	$0.13	$0.11
Electricity Price - High Residential ($/kWh)	$0.17	$0.20
Electricity Price - Low Residential($/kWh)	$0.08	$0.10

Electricity Market Size (GW)	~45GW
2014 Est Solar Installs (MW)	300
2015 Est Solar Installs (MW)	800
2016 Est Solar Installs (MW)	1,200
Cumulative Solar Installs at end of 2016	2,441

Policy Climate

The country has set a target of achieving ~8.4GW of solar capacity by 2030 through its Renewable Energy Independent Power Producer Programme (REIPPP),

Other Remarks

*Electricity price is est of resi price, but majority of installs likely to be larger scale. Assumes 5% system price reduction YoY

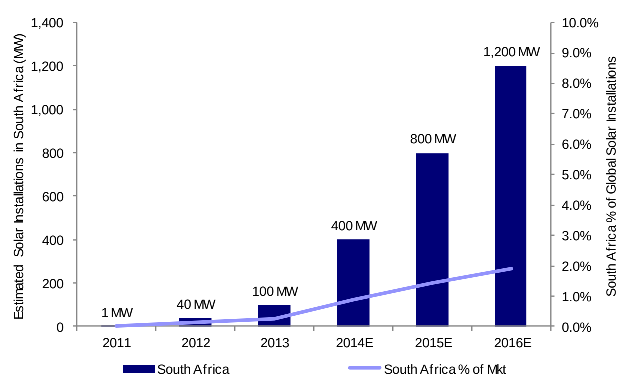
Source: Deutsche Bank

Figure 163: South Africa REIPPP Results

REIPPP	PV (MW)	CSP (MW)
Round 1	630	150
Round 2	460	50
Round 3	450	200
Total	**1540**	**400**

Source: Deutsche Bank, South Africa Government

Figure 164: South Africa Solar Installations

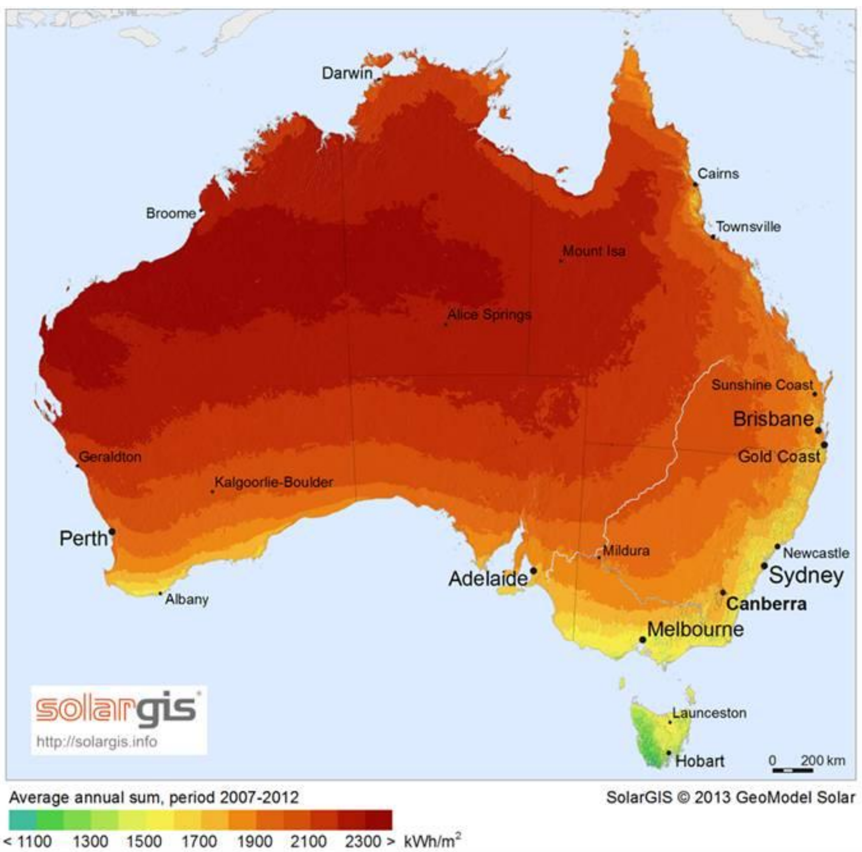


Source: Deutsche Bank

Australia

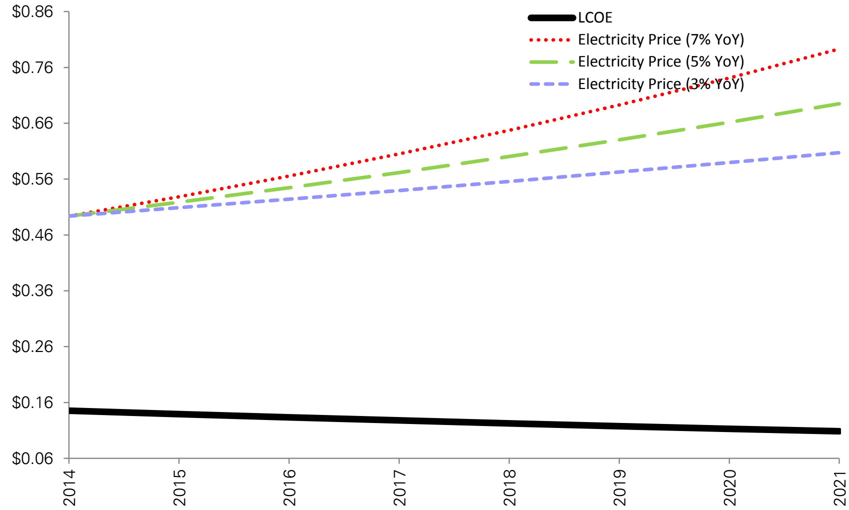
Despite high sunlight and electricity needs, policy support in Australia has been waning quickly. However, we believe grid parity for small systems is already in place in the country, which will support a relatively stable long term installations outlook. Electricity prices for residential customers reach well into the double digits, and a notable mining sector in the country provides future opportunities similar to the Chilean market.

Figure 165: Australia Solar Resources (Horizontal Radiance)



Source: SolarGIS © 2014 GeoModel Solar

Figure 166: Australia LCOE Scenario



Source: Deutsche Bank

Policy Uncertainty Over LRET Likely to Affect >100kW Installations

The Australian govt has proposed scaling-down the 2020 Large-scale Renewable Energy Target to ~26TWh from 41TWh, although recent indications suggest there may be a compromise somewhere in the mid 30'sTWH. Although the proposed change is pending final approval and implementation (due to a stiff resistance from the Opposition Labor party), it has created enough uncertainty that many large scale projects are stalled. We believe there are ~1GW worth solar projects in early stages of development that may not continue should the proposed change be implemented. Below is a list of some projects that are at risk.

Figure 167: Solar Projects At Risk Due To Proposed Scale-down of LRET

Company/ Organization	State	Project	Capacity (MW)	Comments
Neoen	NSW	-	115	115MW of large scale solar proposed
-	QLD	Kilcoy solar project	400	
Recurrent Energy	QLD	RE Oakey solar project	80	
Sunshine Coast Council	QLD	-	15	
Neoen	WA	Mungari solar project	50	
Neoen	WA	Chapman solar project	30	
-	WA	-	30	Perth region
-	WA	-	20	mid west region
-	WA	-	20	Two 10MW solar PV plants in mid west region

Source: Deutsche Bank, RenewEconomy: http://reneweconomy.com.au/2014/the-wind-and-solar-projects-that-would-disappear-along-with-ret-24255

However, Residential/Commercial Solar Installs Likely to Witness Steady Growth

Although there are risks to the progress of large-scale solar installations, we believe small-scale installs are likely to continue upward trajectory. In fact, most of solar installations in Australia are small-scale residential/commercial rooftop systems, which are unaffected by the proposed changes. According to Australian Bureau of Statistics, currently 14% of Australian households have rooftop PV – implying significant room for further growth, given grid parity in the country.

Current Policies (Federal Level)

The main solar incentive scheme in Australia at the federal level is the Renewable Energy Target (RET), which is divided into two segments - the Small-scale Renewable Energy Scheme (SRES) and the Large-scale Renewable Energy Target (LRET). SRES works by issuing Small-scale Technology Certificates (STCs) to eligible households, based on the expected output of the solar system over a 15-year period, (1MWh = 1 STC). STCs can be traded and sold, which provides an up-front cash stream for solar system owners. Meanwhile, LRET provide for Large-scale Generation Certificates (LGCs) that can be generated by commercial and utility-scale systems over 100kW. LGCs are produced on an ongoing basis after the system starts producing power, and therefore provide an ongoing revenue stream for their operators.

In 2010, the govt set RET at 20% of renewable by 2020. The govt also set a target for LRET at 41TWh, while SRET was just given a notional target of 4TWh.

The Australian government recently constituted an expert panel to review RETs. The panel has recommended two options for the LRET (currently set at 41,000 GWh of electricity from large-scale renewable energy by 2020) – 1) the scheme should be closed to new investment within a month of the change; or 2) the target should be set at 20% and subsequently be reset each year and new renewable energy power stations be given approval only if electricity demand increased. The panel recommended two options for SRES: – 1) it should be abolished immediately; or 2) it should be quickly phased-out by cutting the period of subsidies from 15 to 10 years immediately, reducing the period further by 1-year every year after 2016, and phasing out the program to new entrants in 2020 instead of 2030. Additionally, the Climate Change Authority reviewed the SRES program and recommended no changes, primarily because it is already set to begin phase out in 2017.

In Oct 2014, Industry Minister Ian Macfarlane announced that the govt. would seek to cut the 2020 RET for large-scale developers (LRET) to ~26TWh by 2020 (from 41TWh previously), which he said represents the “real 20%” (previous target of 41TWh is likely to represent ~27% of the energy mix). The changes would need support of the opposition in the Senate to become a law. Macfarlane noted that there will be no changes to household solar scheme, which means that the upfront subsidy in the form of certificates will still be available for systems under 10kW. However, there is uncertainty whether commercial-scale solar (10-100kW) will continue to receive certificates.

Current Policies (State Level)

Over the last couple of years, most states in Australia have either cut the FiTs paid for solar energy, or abolished them completely. The current FiT schemes prevalent in the major solar states are listed below.

Queensland (QLD): In 2014r, QLD closed its solar bonus program for new applicants. The program offered a government mandated solar FiT of A$0.44/kWh, which is paid to eligible customers (who applied before 10 July 2012 and consume <100MWh/year) for the surplus electricity generated from solar PV systems, which is exported to the Queensland electricity grid. New customers are required to negotiate directly with retailers over a price for the energy they produce.

New South Wales (NSW): The state of NSW has closed its solar bonus scheme to new applicants. However, NSW residents can choose to use a "Voluntary Solar Buyback". NSW's Independent Pricing and Regulatory Tribunal (IPART) announced the Solar Bonus Scheme benchmark buyback rate range of 4.9-9.3c/kWh for solar power fed into the electricity grid for 2014/15. The rate range is the benchmark for the unsubsidized FiTs that retailers may "voluntarily" offer PV customers who are not part of the Solar Bonus Scheme. Under the previous scheme, the state pays FiT of A$0.60 or A$0.20 per kWh (depending on the date of application) to those customers who connected systems by June 2012.

Victoria (VIC): Victoria offers incentives to solar customers in the form of FiT payments, which will be reviewed/ updated annually until 2016 by the Essential Services Commission (ESC). Currently, the FiT offers a minimum of A$0.08/kWh for 2014 for excess electricity fed back into the grid. The FiT is only available to solar systems with a capacity of <100kW. ESC has released a draft decision to adopt a minimum FiT rate of A$0.062/kWh to apply from 1 Jan 2015 (the rate was lowered from A$0.074/kWh as the Australian government decided to repeal the carbon price). Previously, the state offered Transitional and Standard FiT schemes (closed on 31 Dec 2012) with rates of A$0.25/kWh or 1:1 buy back.

South Australia (SA): Households and small businesses with solar PV systems in South Australia may receive a FiT for the electricity they export to the distribution network. All residential and small business PV customers can receive a retailer-paid feed-in tariff (R-FiT) from their electricity retailer. Some customers also receive a distributor-paid feed-in tariff (D-FiT) of either A$0.16 A$0.44 per /kWh from SA Power Networks. Residential and small business PV customers are entitled to receive a minimum R-FiT from 1 July 2014 until 31 Dec 2014. The minimum to be paid by retailers is A$0.06/kWh for electricity fed into SA Power Networks' distribution network.

Western Australia (WA): WA government stopped its FiT scheme for new applicants. Under the previous scheme, the state pays FiT of A$0.40 or A$0.20 per kWh (depending on the date of application) to those customers who connected systems by mid-2011. Synergy, Western Australia's largest energy retailer, offers a Renewable Energy Buyback Scheme. As of 2014, Synergy bought renewable energy from customer at ~A$0.089/kWh.

Outlook

According to the Australian PV Institute, cumulative PV installations in Australia reached ~4GW as of Nov'14, (~448MW installed during 1H14). Given policy uncertainty and relative negative sentiment, we expect more future installations to be focused on clear grid-parity segments such as residential. Longer term, we see potential for commercial/industrial customers. Furthermore, there is a notable pro-solar contingent in the country, which could shift policy direction in the future. However, short-medium term momentum appears to be against large scale projects.

Figure 168: Country Snapshot

Australia

	2014	2017
Yearly Sun Hours (Net 20% Conversion Loss)	1,833	1,833
System Cost ($/W)	$3.00	$2.85
Discount Rate	6%	6%
LCOE ($/kWh)	$0.15	$0.14
Electricity Price - High Residential ($/kWh)	$0.49	$0.57
Electricity Price - Low Residential($/kWh)	$0.23	$0.27

Electricity Market Size (GW)	~60GW
2014 Est Solar Installs (MW)	1,100
2015 Est Solar Installs (MW)	850
2016 Est Solar Installs (MW)	893
Cumulative Solar Installs at end of 2016	6,030

Policy Climate	Govt has signaled intentions to cut RET for large-scale developers to ~26TWh by 2020 (from 41TWh previously). Currently, the move has been rejected by the opposition.

Other Remarks

*Assumes 5% system price reduction YoY

Source: Deutsche Bank

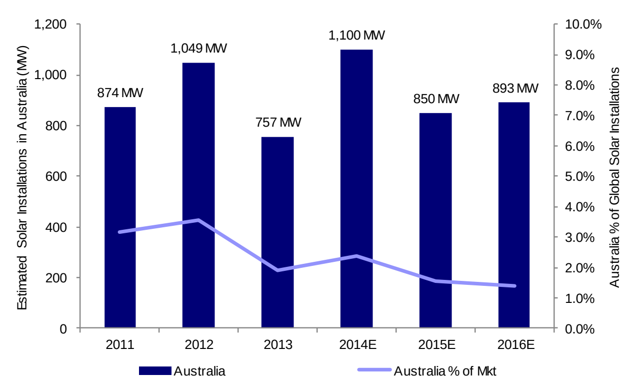
Figure 169: Australia Solar Incentives

Federal Incentives	Comments
SREC	For small-scale customers. STCs issued based on the expected output of the solar system over a 15-year period
LRET	LGCs can be generated by commercial and utility-scale systems over 100kW
**in August 2014, A govt sponsored "Report of the Expert Panel" recommended cuts to incentives*	

State Incentives	Comments
QLD	Solar Bonus Scheme closed for new applicants.
NSW	Solar Bonus Scheme closed for new applicants. Customers can use "Voluntary Solar Buyback", benchmark rate of 4.9-9.3c/kWh (~US$0.04-0.08/kWh) for 2014/15.
VIC	FiT payments of A$0.08/kWh (~US$0.07/kWh) for 2014 . Draft decision of A$0.062/kWh (~US$0.06/kWh) to apply from 1 Jan 2015
SA	retailer-paid feed-in tariff (R-FiT) of A$0.06/kWh (~US$0.05/kWh) from 1 July 2014 until 31 Dec 2014.
WA	Solar Bonus Scheme closed for new applicants. Synergy, Western Australia's largest energy retailer, offers a Renewable Energy Buyback Scheme.

Source: Deutsche Bank, State Govt Websites

Figure 170: Australia Solar Installations



Source: Deutsche Bank, Australian PV Institute (APVI) Solar Map, funded by the Australian Renewable Energy Agency, accessed frompv-map.apvi.org.au on Nov 3, 2014

Key Markets: ~500MW Club

Brazil

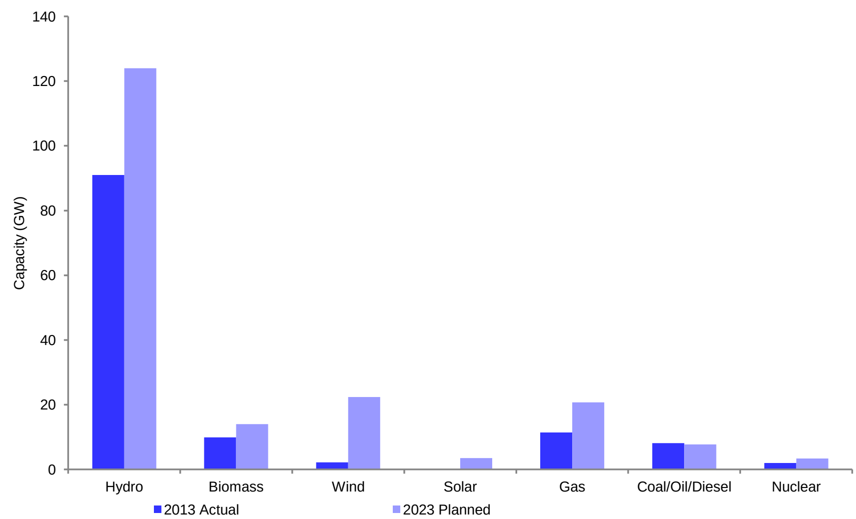
Brazil has the largest electricity capacity in South America with over ~125GW installed, primarily composed of hydro-power (~73%+) and expectations to increase to ~200GW in the next ten years (~7GW each year). Solar resources are robust in the country and we expect that the targets may shift to accommodate more resource diversity over the medium term.

Figure 171: Brazil Solar Resources

Source: SolarGIS © 2014 GeoModel Solar

The Ministry of Mines and Energy in Brazil updates its 10 year plan annually, and has outlined the targets as shown below.

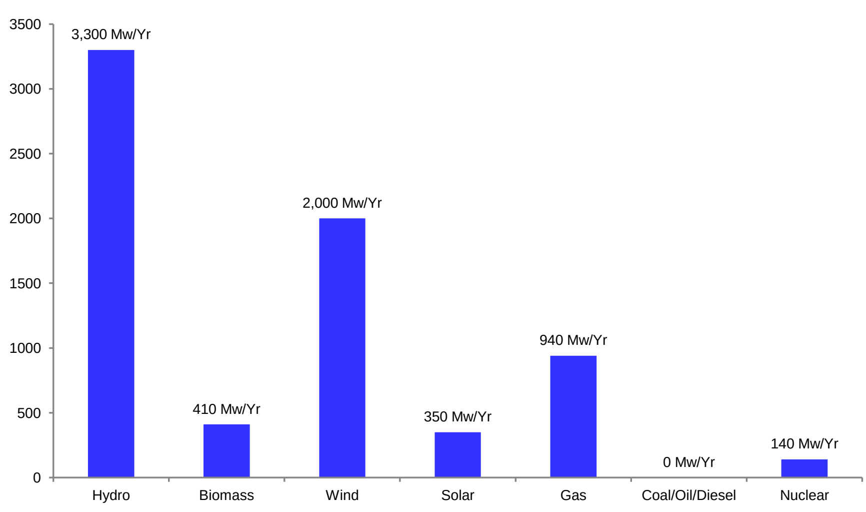
Figure 172: Generation Capacity



Source: Brazil Ministry of Mines and Energy

Electricity prices range from $0.07/kwh to $0.17/kwh and have risen in recent years despite government efforts to curb electricity price inflation. As seen in 2014, drought can have a significant effect on the country's ability to generate adequate electricity, and we expect the govt's targets for solar may shift towards more constructive outcomes for solar, despite current targets of ~350MW/Year.

Figure 173: Brazilian Govt 10-Year Yearly Targets



Source: Brazil Ministry of Mines and Energy

Current Policies/Events

Brazil has set a target to add 3.5GW of solar capacity by 2023. In Oct 2014, the country held an auction to negotiate energy to be produced exclusively by solar farms. The govt. granted contracts for the 31 solar parks with a combined capacity of over 1GW, which was notably above market expectations of ~500MW. The final price for solar power came at ~BRL220/MWh (~$89/MWh). The country's energy regulator Aneel had set a BRL262/MWh (~$106/MWh) ceiling price for solar power. Brazil's Solatio Energia and Renova Energia, along with Italy's Enel Green Power won contracts to deliver >70% of the solar capacity awarded in the auction.

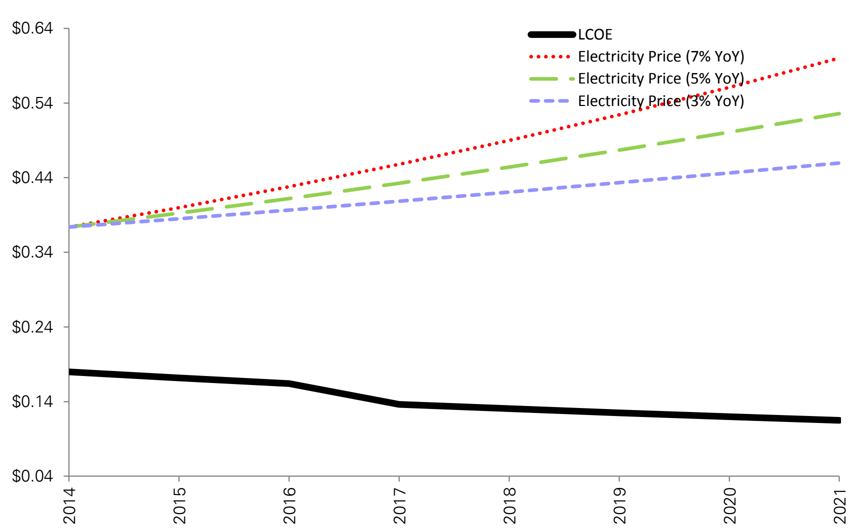
In Nov 2014, Renova Energia and SunEdison agreed to jointly build 1GW of PV plants in Brazil (over a period of 4-5 years).

Brazil's state-owned development bank BNDES has announced that it will offer loans to power companies to cover up to 65% of the cost of new solar projects in the country. BNDES also said that developers proposing solar projects at the auction will have the cost of borrowing lowered in proportion to the local content that they commit to use.

Outlook

We believe Brazil represents a notable potential solar market, and recent policy movements coupled with success in neighboring countries should help position the country for future growth. While current installed base of 100-200MW may be slow to begin significant growth, we expect growth rates to pick up substantially over the next several years.

Figure 174: Brazil LCOE Scenario Analysis



Source: Deutsche Bank

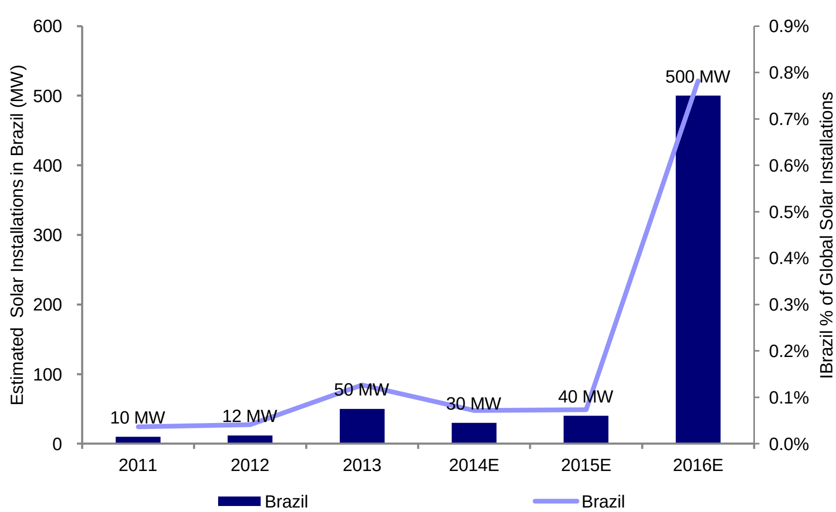
Figure 175: Country Snapshot

Brazil		
	2014	**2017**
Yearly Sun Hours (Net 20% Conversion Loss)	1,667	1,667
System Cost ($/W)	$2.00	$1.71
Discount Rate	14%	11%
LCOE ($/kWh)	$0.18	$0.14
Electricity Price - Average Residential ($/kWh)	$0.37	$0.43
Electricity Market Size (GW)	**~115GW**	
2014 Est Solar Installs (MW)	30	
2015 Est Solar Installs (MW)	40	
2016 Est Solar Installs (MW)	500	
Cumulative Solar Installs at end of 2016	642	
Policy Climate	Current 3.5GW target likely conservative. Government auctions signal increasing support	
Other Remarks		

*Electricity price is est of resi price, but majority of installs likely to be larger scale. Assumes 5% system price reduction YoY

Source: Deutsche Bank

Figure 176: Brazil Solar Installations



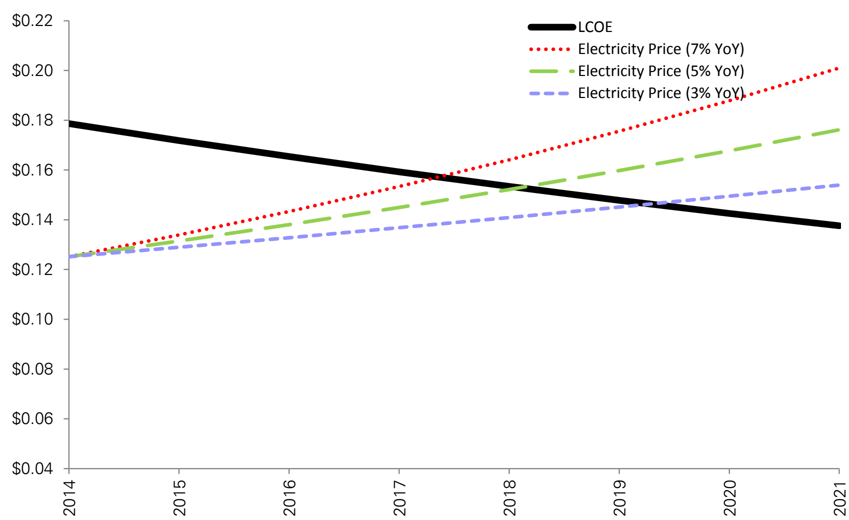
Source: Deutsche Bank

Canada

As we have seen in Germany and the UK, countries with modest solar resources can still be major solar hubs under friendly policy environments and falling installation costs. In 2010 the cost of solar electricity was ~$300-410 per MwH, while our current cost estimate of ~$200/MwH has already reached previous industry estimates of ~$146-200/MwH by 2025.

Residential electricity prices in Canada range between 8-16 cents/kwh, and we believe that prices could reach grid parity by the ~2017-18 timeframe using conservative assumptions. In higher electricity regions, we could see grid parity even sooner.

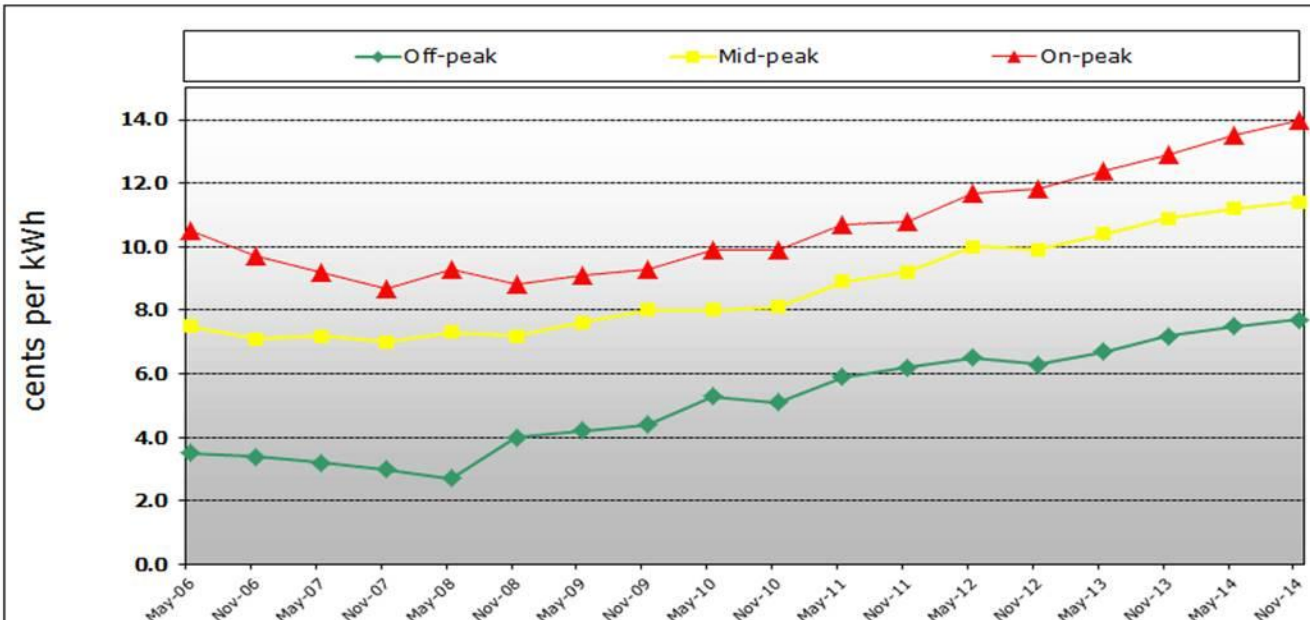
Figure 177: Canada LCOE Scenario Analysis



Source: Deutsche Bank

Over the past 8 years, the cost of electricity in Ontario has increased at an average ~6%+ CAGR, and we expect Canadian electricity prices will continue to increase over the longer term as demand increases

Figure 178: Ontario Electricity Prices Are Rising

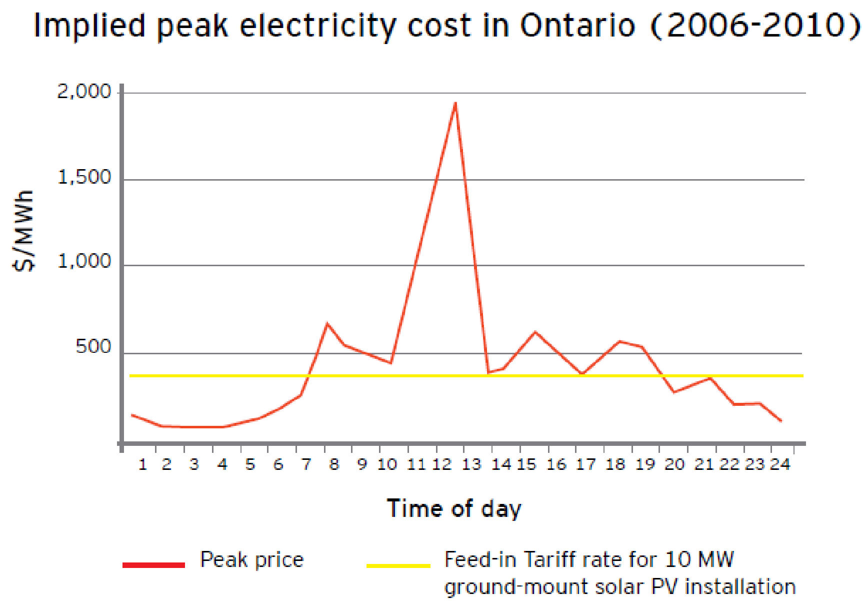


	May-06	Nov-06	May-07	Nov-07	May-08	Nov-08	May-09	Nov-09	May-10	Nov-10	May-11	Nov-11	May-12	Nov-12	May-13	Nov-13	May-14	Nov-14
Off-peak	3.5	3.4	3.2	3	2.7	4	4.2	4.4	5.3	5.1	5.9	6.2	6.5	6.3	6.7	7.2	7.5	7.7
Mid-peak	7.5	7.1	7.2	7.0	7.3	7.2	7.6	8	8	8.1	8.9	9.2	10	9.9	10.4	10.9	11.2	11.4
On-peak	10.5	9.7	9.2	8.7	9.3	8.8	9.1	9.3	9.9	9.9	10.7	10.8	11.7	11.8	12.4	12.9	13.5	14

Source: Ontario Energy Board

Furthermore, the electricity market in Canada is conducive to solar generation. During key hours of the day, peak pricing in parts of the country can reach several hundred dollars per MWH, which coincides with Solar's generation potential. Customers as well as utilities have incentives to increase their solar adoption in order to avoid peak pricing.

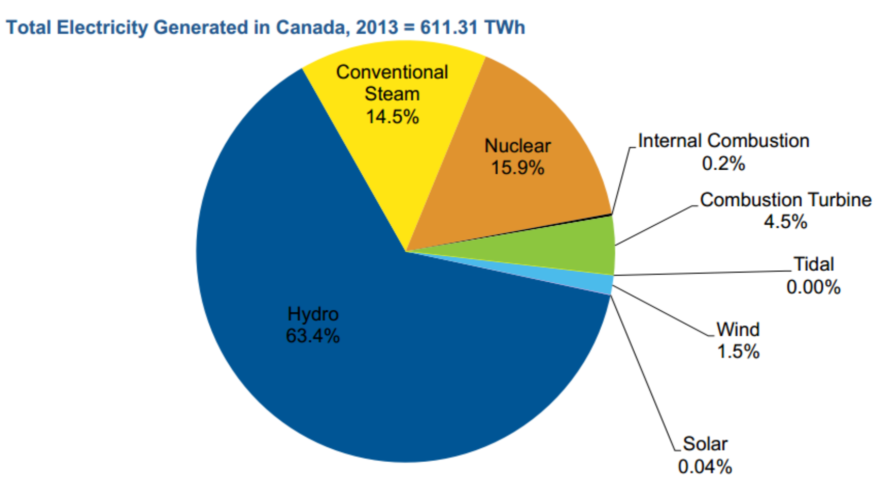
Figure 179: Peak Electricity Cost



Source: Earnst and Young Via the Canadian Solar Industries Association

Solar currently accounts for almost no generation in the country, and the ongoing dependence on hydro indicates that there are opportunities for solar to continue to gain share as utilities diversify and invest in peak load balancing.

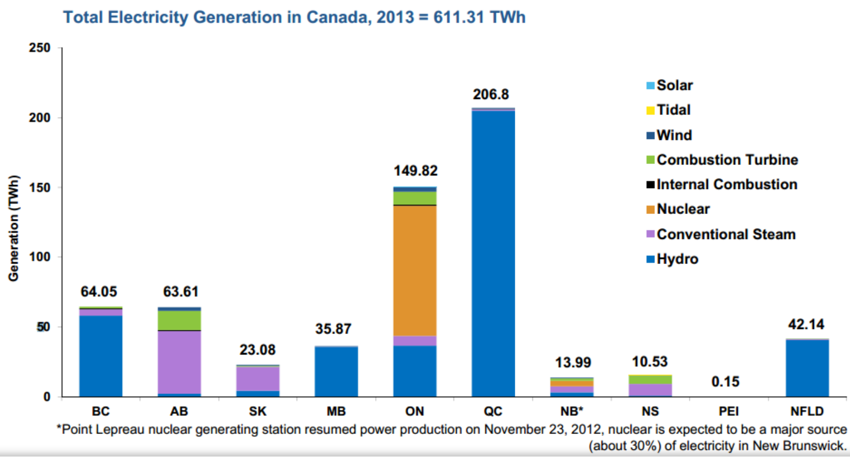
Figure 180: Electricity Source



Source: Statistics Canada

Ontario and Quebec produce over half of the available electricity in the country, and we see the greatest potential for solar adoption in these regions – particularly Ontario given the friendly policy environment.

Figure 181: Generation by Region in Canada



Source: Statistics Canada, Electric Power and Generation - Annual (CANSIM 127-0007), 2013. Retrieved 25 May 2014, Canadian Electricity Association

Since we are not currently at grid parity in Canada, we expect important solar-friendly policies such as the Ontario feed in tariff should help fuel further investment in the country. While FiT's have provided attractive project returns (high teens or better, in many cases) which have caused large Canadian companies like TransCanada to invest in the business, we expect a transition to net metering in the future would help avoid a boom-bust cycle as the economics continue to improve.

Current Policies

The Ontario Power Authority (OPA) administers FIT Program, which is open to projects with nameplate capacity between 10kW-500kW. For small projects (<10kW), OPA implemented a microFIT Program; while for those >500kW, OPA is developing a new procurement process called Large Renewable Procurement (LRP). The current FiT pricing by project size is shown in the table below.

Figure 182: Ontario FiT (effective Sep 30, 2014 for FIT and Jan 1, 2015 for microFIT)

	Project Size*	**FiT Price (CAD$ c/kwh)**	**FiT Price (~US$ c/kwh)**
Solar (PV) (Rooftop)	≤ 10 kW	38.4	34.1
	>10 ≤ 100 kW	34.3	30.5
	> 100 kW ≤ 500 kW	31.6	28.1
Solar (PV) (Non-Rooftop)	≤ 10 kW	28.9	25.7
	> 10 kW ≤ 500 kW	27.5	24.4

*Source: Deutsche Bank, OPA, * The FiT Program is available to Small FIT projects (generally ≤ 500kW*

Additionally, some projects are offered "price adders" to reflect higher development and operation/ maintenance costs. The "price adder" is an incremental increase in the price paid per kWh of electricity (paid in addition to the contracted FiT price). Price adders are available to projects that have a minimum15% participation level from municipalities, public sector entities, communities, or Aboriginal groups. These are not applicable for rooftop PV projects.

Figure 183: Ontario FiT Price Adders

	Equity Participation 15-50% Participation		>50% Participation	
	CAD$ c/kWh	~US$ c/kWh	CAD$ c/kWh	~US$ c/kWh
Maximum Aboriginal Price Adder	0.8	0.7	1.5	1.4
Maximum Community Price Adder	0.5	0.5	1.0	0.9
Maximum Municipal or Public Sector Entity Price Adder	0.5	0.5	1.0	0.9

*Source: Deutsche Bank, OPA, *not applicable for PV rooftop projects*

The Large Renewable Procurement (LRP) is a competitive process for procuring renewable energy projects >500 kW in capacity. The LRP is currently in the Request for Qualifications (RFQ) stage. Evaluation of specific large renewable projects will occur at the Request for Proposals (RFP) stage, wherein only qualified applicants who have met the requirements of the RFQ may submit proposals. After the RFP stage, OPA may award contracts for successful projects up to specified procurement targets for each renewable fuel (140MW for solar).

Outlook for 2014/15

As of 1Q14, OPA was managing 2.1GW of combined capacity from solar PV projects – of which ~1.2GW is in commercial operation and 998MW under development. All projects that are under development are scheduled to be in-service before the end of 2017. We expect annual installations in Canada to increase marginally over the next few years.

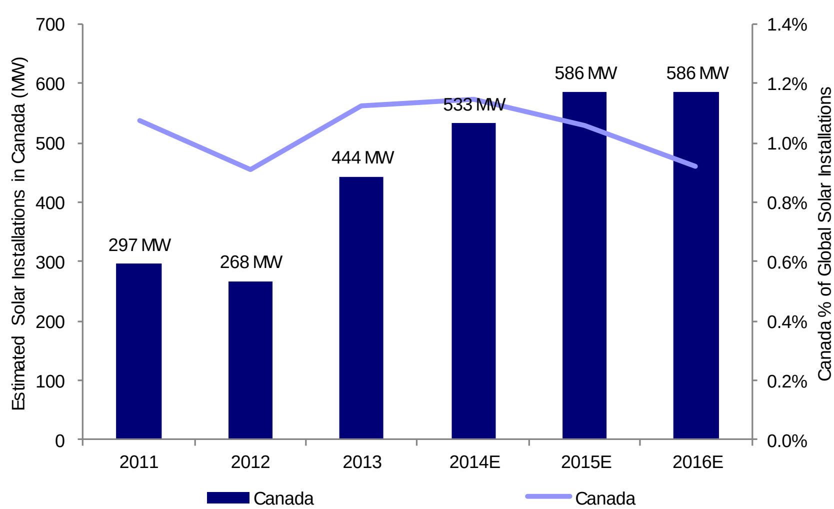
Figure 184: Country Snapshot

Canada		
	2014	**2017**
Yearly Sun Hours (Net 20% Conversion Loss)	1,000	1,000
System Cost ($/W)	$2.00	$1.71
Discount Rate	5%	5%
LCOE ($/kWh)	$0.18	$0.16
Electricity Price - Average Residential ($/kWh)	$0.13	$0.14
Electricity Market Size (GW)	~140GW	
2014 Est Solar Installs (MW)	533	
2015 Est Solar Installs (MW)	586	
2016 Est Solar Installs (MW)	586	
Cumulative Solar Installs at end of 2016	3,012	
Policy Climate	Ontario has a FIT Program for 10kW-500kW systems and a microFIT Program for <10kW systems. OPA is also developingnew procurement process called Large Renewable Procurement (LRP) for >500kW systems.	
Other Remarks		

*Electricity price is est of resi price, but majority of installs likely to be larger scale. Assumes 5% system price reduction YoY

Source: Deutsche Bank

Figure 185: Canada Solar Installations

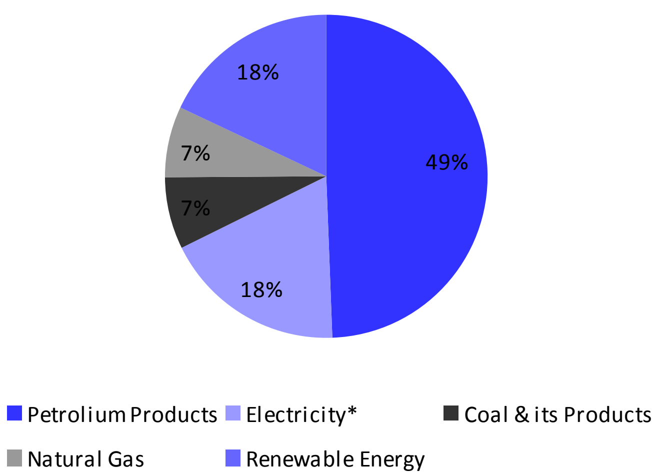


Source: Deutsche Bank, OPA

Thailand

Although the Thai government is not as stable as other countries we've profiled, it is still emerging as an attractive market for growth. The govt is attempting to cut reliance on energy imports (mostly oil and natural gas), which account for almost 50% of the country's primary energy supply. During Q1'14, renewable accounted for ~14% of the primary energy supply and ~18% of the final energy consumption.

Figure 186: Thailand – Final Energy Consumption – Q1'14



*Source: Deutsche Bank, DEDE, *Including off grid power generation*

Under its Alternative Energy Development Plan 2012-2021, the govt has set a 25% renewable target by 2021 (or ~14GW renewable capacity).

Figure 187: Renewable Deployment vs. Target

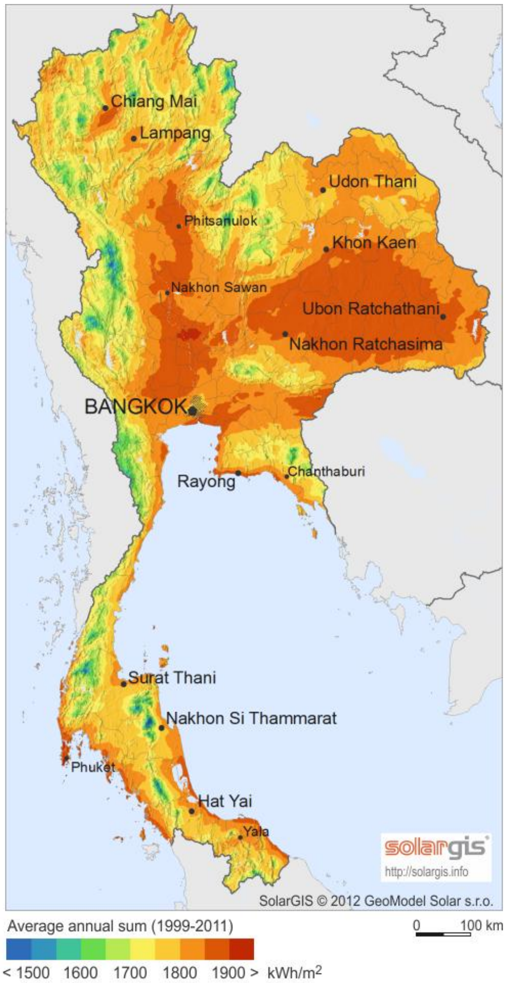
	As of Q1'14	2021 Target
Solar	961	3000
Wind	223	1800
Small Hydro Power	112	324
Biomass	2351	4800
Biogas	275	3600
MSW	47	400
New Energy	0	3

Source: Deutsche Bank, DEDE

Not Quite at Grid Parity

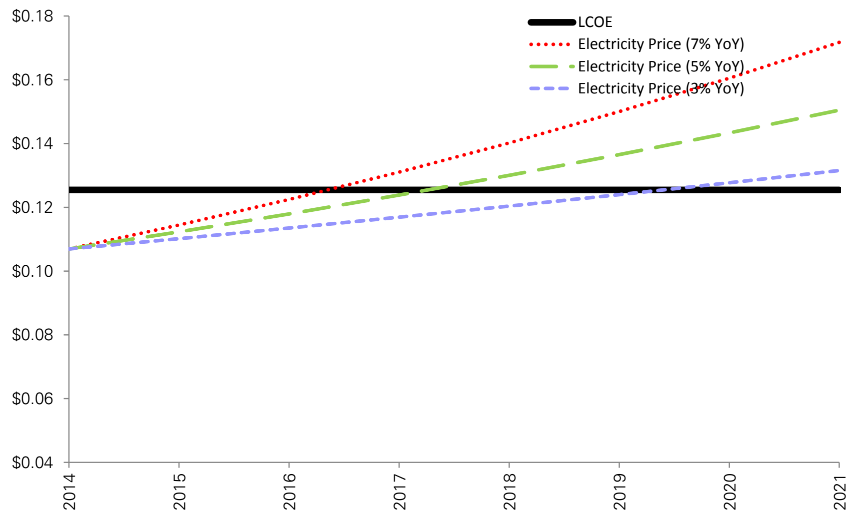
Although the country has generally good solar resources, low electricity prices make grid parity difficult. Our current est of ~$0.13/kwh will likely approach lower electricity prices within the next few years, however.

Figure 188: Thailand Solar Resources (Horizontal Radiance)



Source: SolarGIS © 2014 GeoModel Solar

Figure 189: Thailand LCOE Scenario Analysis



Source: Deutsche Bank

Current Policies and History

In July 2013, Thailand's government increased its target for solar installations to 3GW by 2021 (from 2GW previously). While the original 2GW target was to be achieved only from large scale solar (from a policy initiated in 2006), the incremental 1GW will be achieved by two new programs, mentioned below.

- **Solar Rooftop Program (200MW):** In 2013, the government announced that the rooftop program would have a quota/target of 200MW (see details in figure below) and all the systems were required to start commercial operations by 31 Dec 2013. These systems will be eligible for feed-in tariffs for a period of 25 years. Although the country was able to achieve the quota of commercial projects (100MW), it only achieved 30MW of residential rooftop installations at the time. Thai National Energy Policy Commission (NEPC) recently announced that 70MW of residential rooftop capacity will be opened up for applications receiving a FiT rate of 6.85 Baht/kWh for 25 years.

Figure 190: Rooftop FiT and Quota

Classification	Scale	Quota	FiT (baht/kWh)	FiT ($/kWh)
Residential	0-10kW	100MW	6.96	0.22
Small and Medium Commercial	>10-250kW	100MW	6.55	0.20
Medium and Large Commercial	>250kW-MW		6.16	0.19

** This is for systems that were required to start operations by Dec 2013*

Source: Deutsche Bank, DEDE

- **Community-based Ground-mounted Systems (800MW):** The second program announced by the government is designed to utilize a special feed-in tariff for community-based ground-mounted solar systems with a quota/target of 800MW, and a minimum project size of ~1MW. Projects were required to start commercial operations by 31 Dec 2014. It is expected that ~60 villages would need to cooperate to provide the equity share of 15M Thai Baht for one project, while the debt share (estimated at ~45M Thai Baht) shall come from two national banks –

the Bank for Agriculture and Agricultural Cooperatives (BAAC) and the Government Savings Bank (GSB). Feed-in tariffs (see details in figure below) will go directly to the group of villages that have invested in the installation.

Figure 191: Community-based Ground-mounted Systems FiT

Year	FiT (baht/kWh)	FiT ($/kWh)
1-3	9.75	0.30
4-10	6.50	0.20
11-25	4.50	0.14

Source: Deutsche Bank, DEDE

Outlook

The country has recently increased installation growth following the two programs announced in July 2013. Total installations of 269MW in 2H13 (driven by mostly the rooftop target of 200MW with a Dec 2013 deadline) preceded ~137MW 1Q14. Future installations of community based ground-mount systems will help drive adoption, but government instability could lead to measured progress going forward.

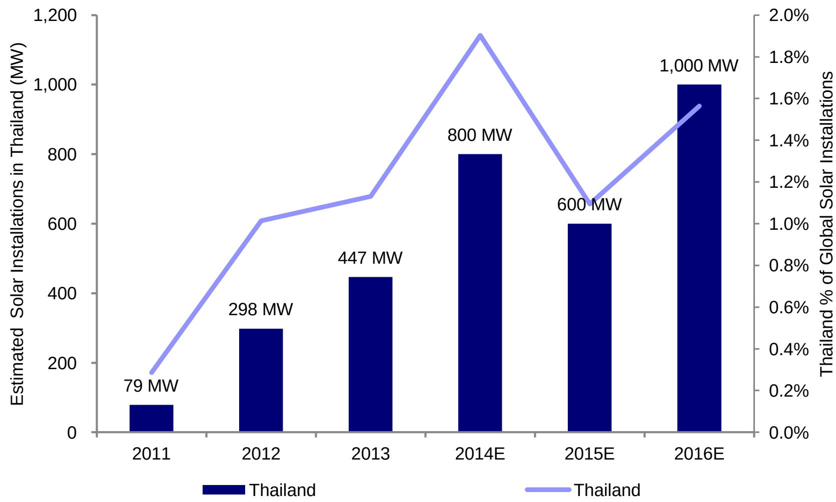
Figure 192: Country Snapshot

Thailand		
	2014	**2017**
Yearly Sun Hours (Net 20% Conversion Loss)	1,500	1,500
System Cost ($/W)	$2.00	$1.71
Discount Rate	7%	7%
LCOE ($/kWh)	$0.13	$0.13
Electricity Price - Average Residential ($/kWh)	$0.11	$0.12
Electricity Market Size (GW)	~35GW	
2014 Est Solar Installs (MW)	800	
2015 Est Solar Installs (MW)	600	
2016 Est Solar Installs (MW)	1,000	
Cumulative Solar Installs at end of 2016	3,224	
Policy Climate	Generally positive particularly through community based solar initiatives, but Govt instability could lead to uncertainty.	
Other Remarks		

*Electricity price is est of resi price, but majority of installs likely to be larger scale. Assumes 5% system price reduction YoY

Source: Deutsche Bank

Figure 193: Thailand Solar Installations

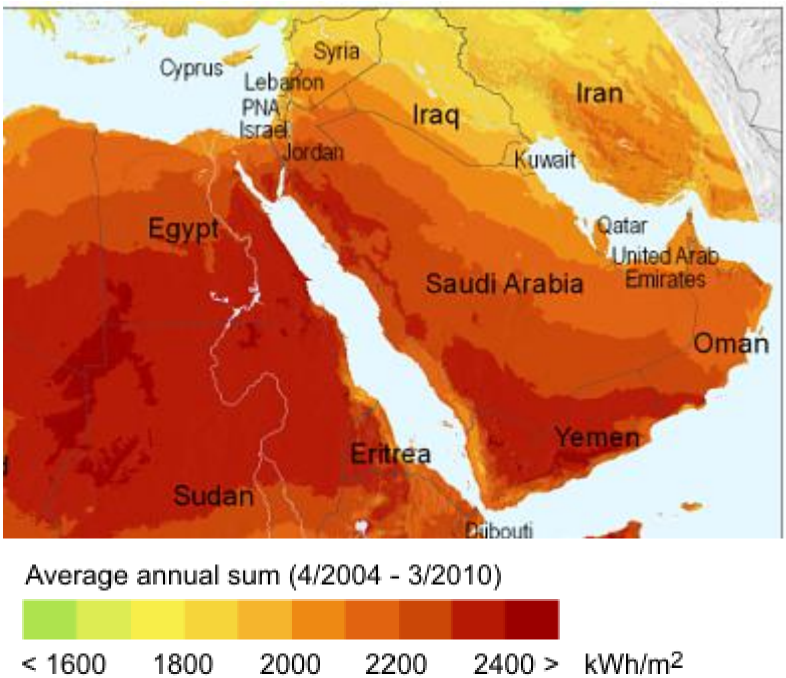


*Source: Deutsche Bank, DEDE, *2011 number is cumulative installations until 2011*

Saudi Arabia

Saudi Arabia has one of the highest insolation levels in the world and a substantial open desert area. However, government subsidization, rising domestic energy use, and population shifts/increases are making ongoing oil use for electricity increasingly difficult. For long term resource planning, we expect the Saudi Government to begin implementing national solar installation goals which could likely ramp in conjunction with other forms of renewable additions.

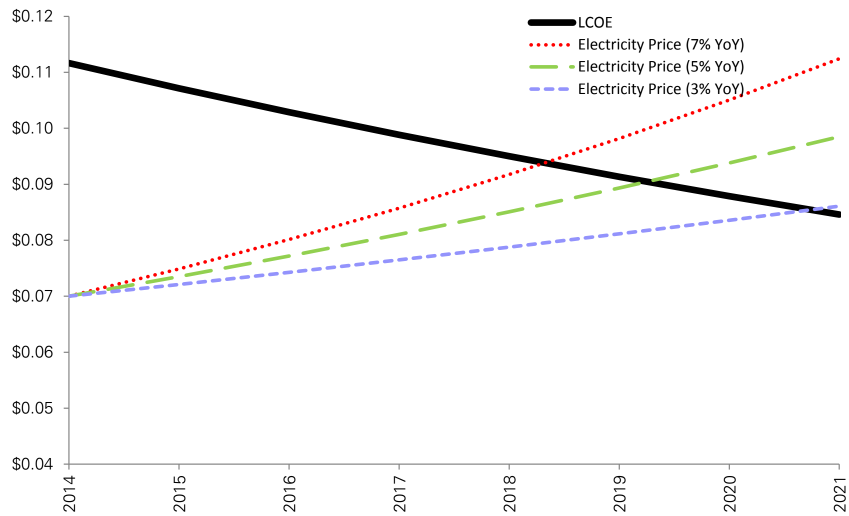
Figure 194: Middle East Solar Resources (Horizontal Radiance)



Source: SolarGIS © 2014 GeoModel Solar

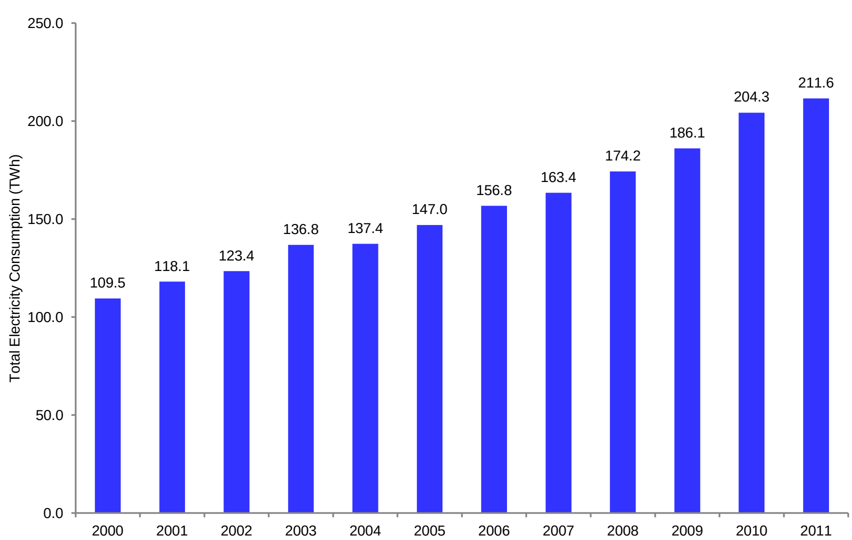
Retail price of electricity in Saudi Arabia ranges from roughly ~$0.01/kWh to ~$0.07/kWh due to ~70%+ government subsidization. While this makes purely economic competitiveness unlikely in the near term, we believe LCOE could reach as low as low to mid single digit cents per kwh.

Figure 195: Saudi Arabia LCOE Scenario Analysis



Source: Deutsche Bank

Figure 196: Saudi Arabia Electricity Consumption



Source: EIA

Ongoing increases in electricity consumption within the country are likely to support long term policy goals to move away from domestic oil consumption for electricity. Saudi Arabia currently has over 50GW of installed capacity with plans to more than double to ~120GW+ by 2032

Current Policies

The renewable program of the country is managed by the King Abdullah City for Atomic and Renewable Energy (K.A.CARE), which was established in April 2010. Under the program, the country is targeting 41GW of solar power by 2040 (initial targets of 16GW PV and 25GW CSP). In the near term, the country aims to add 6GW of solar installations by 2020. The most recent comments around 2040 are in opposition to previous targets of 2032.

In early 2014, Saudi Aramco announced that it plans to look into solar investments with a greater interest. Additionally, Chinese National Nuclear Corporation (CNNC) has also signed a partnership agreement with K.A.CARE to cooperate on the development of renewable and nuclear energy in the country.

Outlook

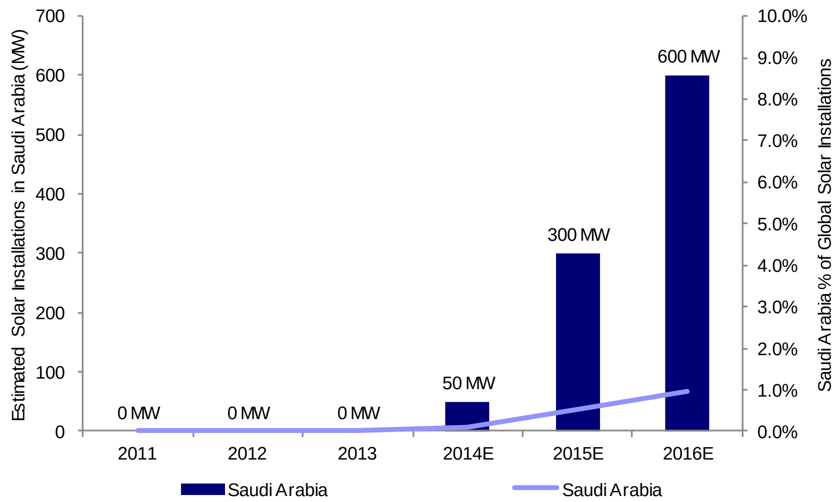
The Middle East Solar Industry Association (MESIA), has recently claimed that Saudi Arabia will launch 700-1000MW, which could mark the beginning of a larger scale deployment but timing is uncertain. Given the recent push out of targets, this may be more of a longer term target. Currently, the country has ~20MW of solar installed capacity but we may start to see the state owned companies explore additional options in the short to medium term.

Figure 197: Country Snapshot

Saudi Arabia		
	2014	**2017**
Yearly Sun Hours (Net 20% Conversion Loss)	1,833	1,833
System Cost ($/W)	$2.00	$1.71
Discount Rate	7%	7%
LCOE ($/kWh)	$0.11	$0.09
Electricity Price - Average Residential ($/kWh)	$0.07	$0.08
Electricity Market Size (GW)	~51GW	
2014 Est Solar Installs (MW)	50	
2015 Est Solar Installs (MW)	300	
2016 Est Solar Installs (MW)	600	
Cumulative Solar Installs at end of 2016	950	
Policy Climate	Targets have been pushed out from 2032 to 2040, but recent leadership transition could open up the country to further changes	
Other Remarks		

Source: Deutsche Bank

Figure 198: Saudi Arabia Solar Installations



Source: Deutsche Bank, MESIA

Key Markets: <500MW

Italy

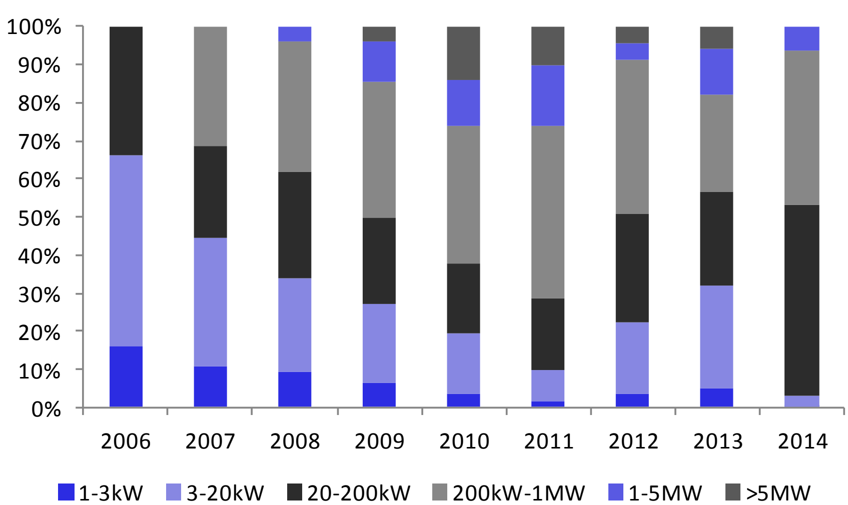
Retroactive FiT Cuts/ Tax on Self-consumed Solar Power Jeopardize Outlook

After discontinuing FiT for new solar installations (from July 2013), Italian parliament has now approved retroactive FiT cuts and new taxes for self-consumed solar electricity. We believe retroactive cuts are likely to deter new investments in the country, which could significantly slowdown the pace of new installations, particularly large-scale systems. Installations reached only ~1.2GW in 2013 (vs. ~3.6GW in 2012), and have slowed down further in 2014 – with only ~89MW installed under the subsidization program in the first seven months. Some of the more dire predictions suggest that there will be a large number of solar arrays put up for sale or foreclosed on due to the retroactive cuts.

However, Expansion of Net Metering Policy Likely to Drive DG Installs

In a positive move for the industry, the Italian parliament has approved expansion in the net metering policy, which raises the limit from 200kW/installation to 500kW to be eligible for net metering. From Jan- July 2014, 53% of the new installations were sub 200kW systems, which indicates net metering is helping. Future installs in the sub 500kW range should be more attractive.

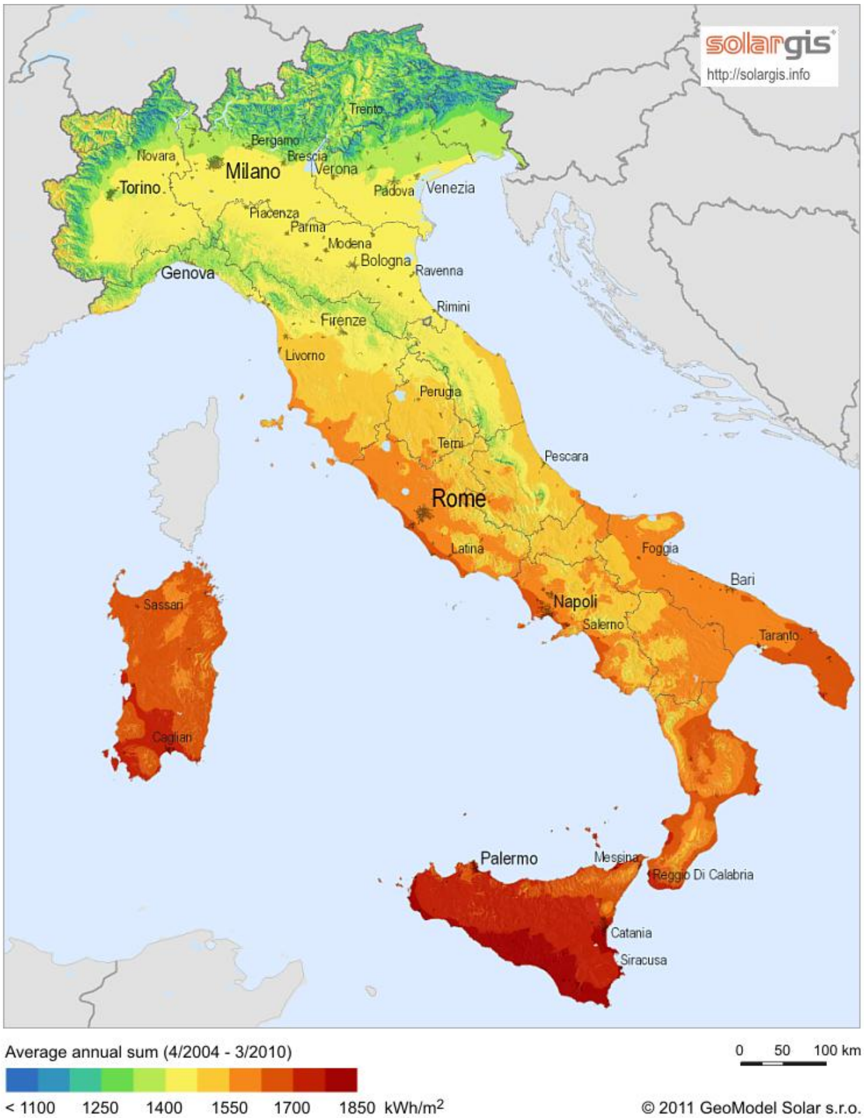
Figure 199:PV Installation Mix (Tracked Systems)



Source: Deutsche Bank, GSE, 2014 mix is from Jan-Jul, 2014

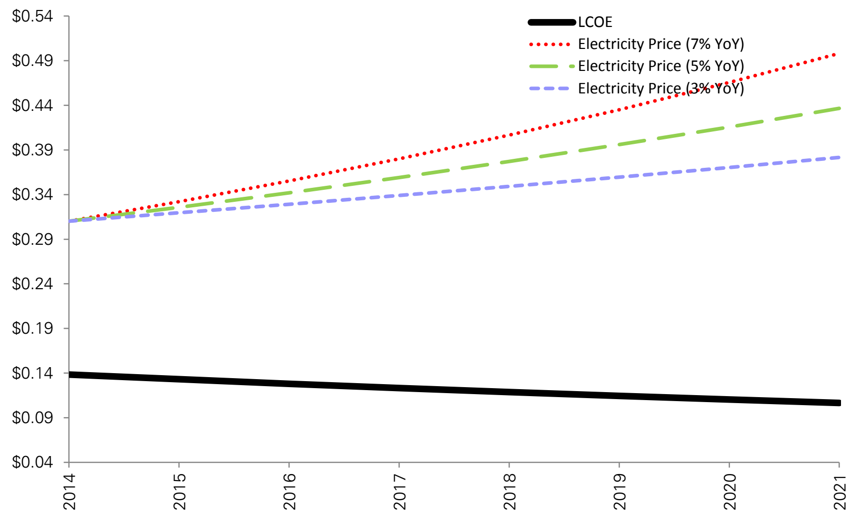
Due to high electricity prices and solid solar fundamentals, we expect Italy has already reached grid parity for non-utility scale systems.

Figure 200: Italy Solar Resources (Horizontal Radiance)



Source: SolarGIS © 2014 GeoModel Solar

Figure 201: Italy LCOE Scenario Analysis



Source: Deutsche Bank

Current Policies

In August 2014 the Italian Parliament approved a decree that retroactively cut FiTs for PV plants larger than 200kW. Otherwise, state company Gestore Servizi Energetici (GSE) pays a fixed rate to PV plant operators for 20 years, but recent retroactive cuts have targeted changes. Under the new law, existing solar power generators have three options – 1) voluntarily accept a flat reduction of 6-9% in the tariff, depending on the size of the system; 2) accept a bigger cut in FiT rates by 2019 and receive higher rates as compensation after that; and 3) extend their existing FiT contracts from 20 to 24 years and see the rate fall by 17-25%. The new law will also see GSE pay a fixed monthly payment of only 90% of the plant's estimated annual electricity production, the remaining 10% will be paid up in full in June of the following year. The parliament also decided to raise the upper limit for net metering in the country from 200kW to 500kW per installation. We believe this move will drive rooftop installations in the country.

Outlook

Negative policy shifts are a headwind for large scale installations, but we expect to see more DG installs given the shifts towards larger net metered systems.

Figure 202: Country Snapshot

Italy

	2014	2017
Yearly Sun Hours (Net 20% Conversion Loss)	1,292	1,292
System Cost ($/W)	$2.00	$1.71
Discount Rate	5%	5%
LCOE ($/kWh)	$0.14	$0.12
Electricity Price - Average Residential ($/kWh)	$0.31	$0.36

Electricity Market Size (GW)	~125GW
2014 Est Solar Installs (MW)	500
2015 Est Solar Installs (MW)	1,000
2016 Est Solar Installs (MW)	1,200
Cumulative Solar Installs at end of 2016	20,418

Policy Climate

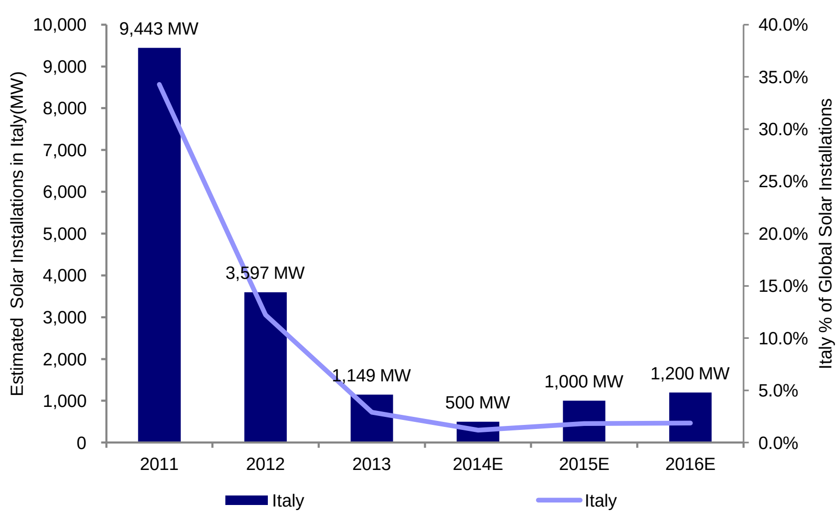
Although recent increases in the net metering limts are a positive, retroactive changes to the feed in tariff system could lead to prolonged market uncertainty.

Other Remarks

*Assumes 5% system price reduction YoY

Source: Deutsche Bank

Figure 203: Italy Solar Installations

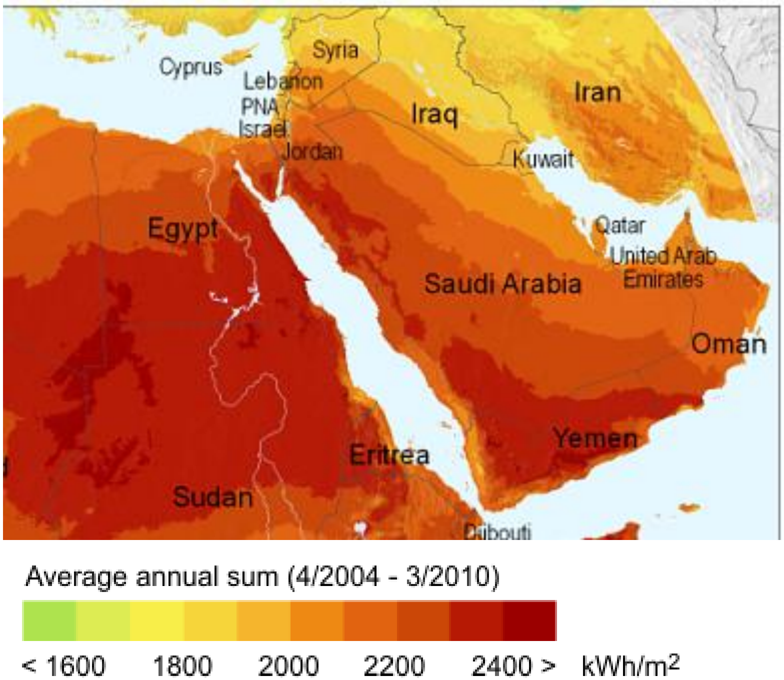


Source: Deutsche Bank, GSE

UAE

Electricity rates in the UAE are heavily subsidized (~55-90%) for domestic users and solar is therefore unlikely to be driven by electric rates in the area. The local governments have shown interest in expanding use of solar, so we may see increased policy support in the region.

Figure 204: UAE Solar Resources



Source: SolarGIS © 2014 GeoModel Solar

Current energy supply is dominated by natural gas due to the region's vast reserves, but both Dubai and Abu Dhabi are actively attempting to promote new industries and develop the region for the long term. High air conditioning needs and increasing industrial needs should drive long term support for solar, although the scale will be appropriate to the UAE's size, existing resources, and needs.

Current Policies

Dubai: The Dubai Integrated Energy Strategy 2030 (DIES), which was established in 2011, targets less dependence on natural gas through increased production of electricity from sources like clean coal, nuclear and solar. As part of this strategy, Dubai plans to supply 1% of its electricity from renewable sources by 2020 and 5% by 2030. As a result, Dubai will need ~200MW solar capacity by 2020 and 1GW by 2030, which will be installed in one solar park – the Sheikh Mohammed bin Rashid Al Maktoum Solar Park. The first 13MW will be completed by First Solar. Additionally, Dubai Electricity and Water Authority (DEWA) plans to establish a market for residential and commercial roof-top solar systems, which may be facilitated by a future FiT implementation, in our view.

Abu Dhabi: Abu Dhabi is targeting 7% of its energy from renewables by 2020. Abu Dhabi has also set up Masdar, a green-energy firm (also known as Abu Dhabi Future Energy Company) which is investing in a number of renewable energy projects in the UAE. In 2013, Masdar, in partnership with Total and Abengoa, launched the 100MW CSP plant Shams 1 in Abu Dhabi. Currently, Masdar is awaiting approval for its Noor 1 PV plant that has a capacity of 100MW. In the future, Masdar also plans Noor 2 that will have a capacity of 100-200MW. Moreover, energy regulators in Abu Dhabi have announced that they will submit a proposal to develop a 500MW solar rooftop scheme to the Executive Council in 2014.

Outlook

Currently, the UAE has ~20MW capacity installed, but we believe installs could begin to ramp as Dubai and Abu Dhabi move to diversify their electricity generation.

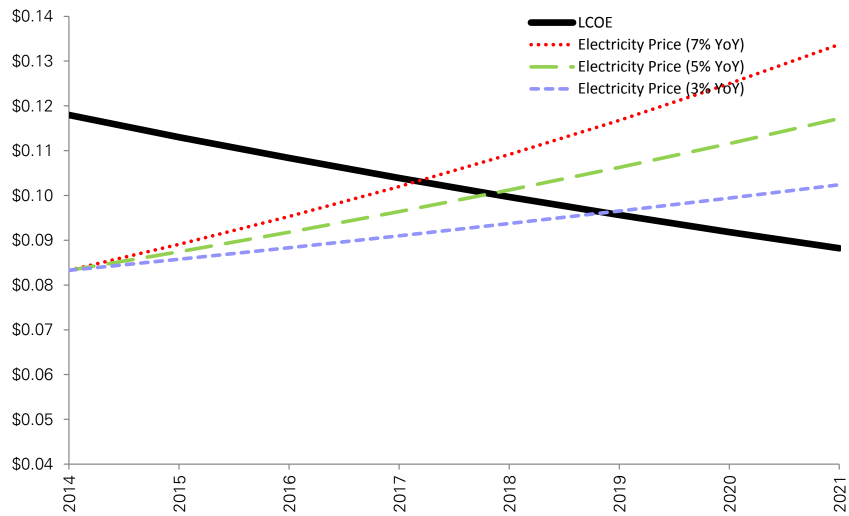
Figure 205: Country Snapshot

UAE	2014	2017
Yearly Sun Hours (Net 20% Conversion Loss)	2,083	2,083
System Cost ($/W)	$2.50	$2.14
Discount Rate	7%	7%
LCOE ($/kWh)	$0.12	$0.10
Electricity Price - Average Residential ($/kWh)	$0.08	$0.10
Electricity Market Size (GW)	~25GW	
2014 Est Solar Installs (MW)	50	
2015 Est Solar Installs (MW)	100	
2016 Est Solar Installs (MW)	150	
Cumulative Solar Installs at end of 2016	320	
Policy Climate	Dubai plans to supply 1% of its electricity from renewable sources by 2020 and 5% by 2030; while Abu Dhabi is targeting 7% of its energy from renewables by 2020	
Other Remarks		

*Electricity price is est of resi price, but majority of installs likely to be larger scale. Assumes 5% system price reduction YoY

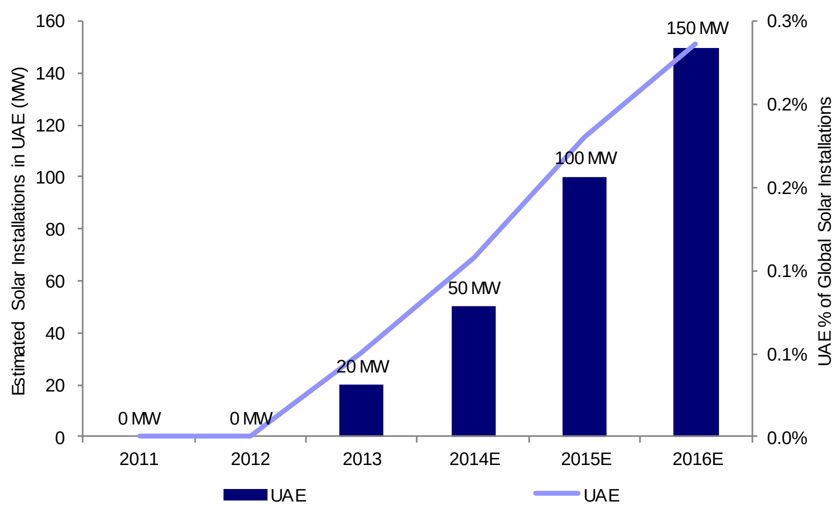
Source: Deutsche Bank

Figure 206: UAE LCOE Scenario Analysis



Source: Deutsche Bank

Figure 207: UAE Solar Installations

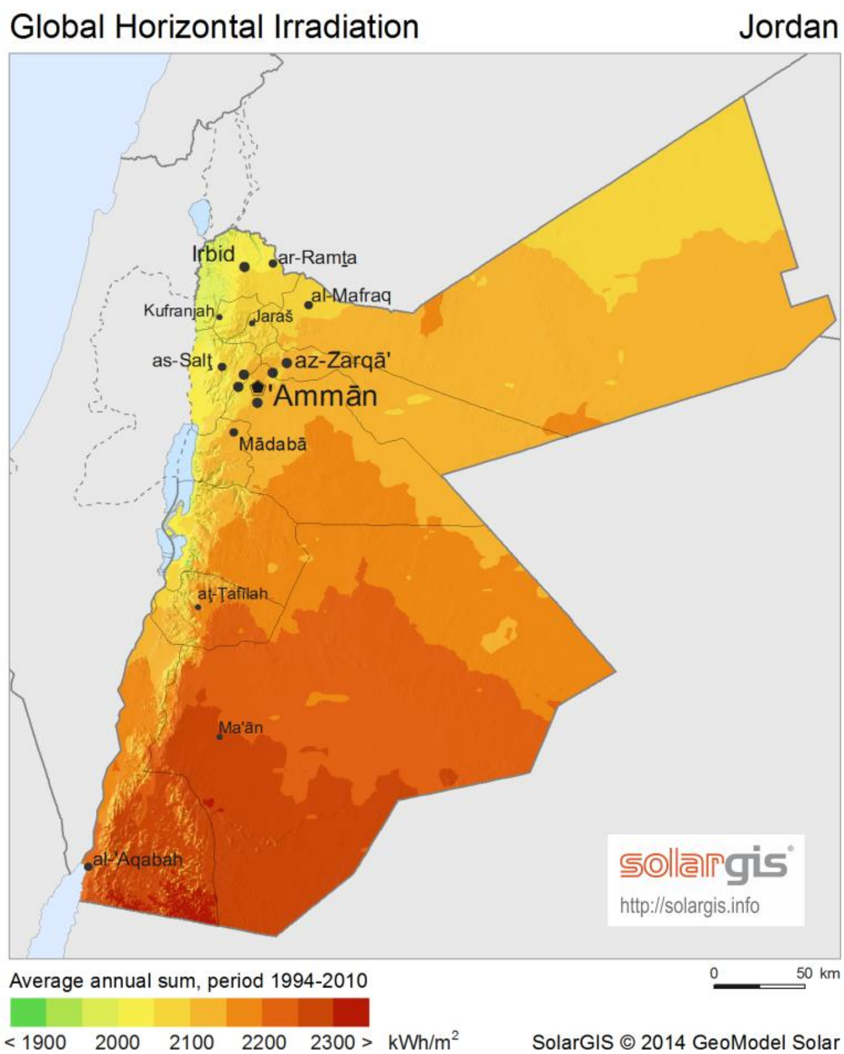


Source: Deutsche Bank

Jordan

We expect Jordan to be one of the first movers in solar adoption for the Middle East as tariffs for larger electricity users increases, the region's resources are recognized, and solar starts to gain more traction in the region. Jordan imports 90%+ of total energy, which account for 40%+ of the government budget. Therefore, we see strong financial and policy incentives for the Jordanian government to utilize domestic solar resources to hedge against long term need for energy imports.

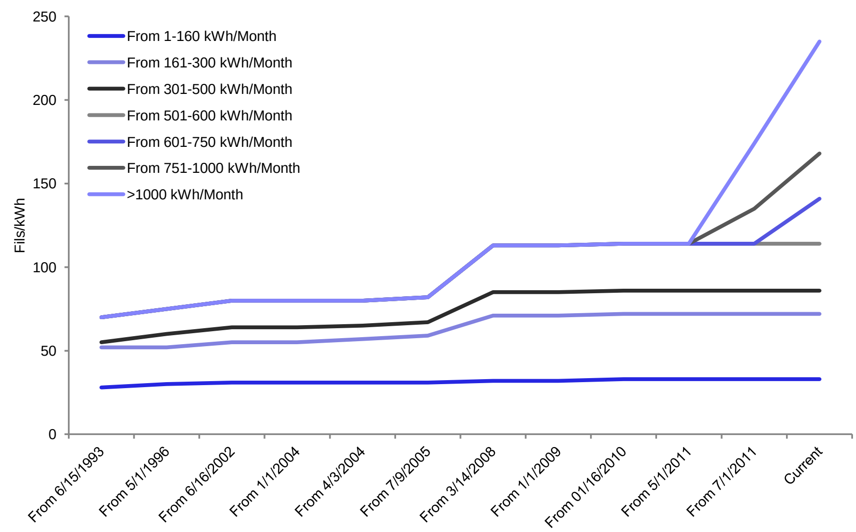
Figure 208: Jordan Solar Resources



Source: SolarGIS © 2014 GeoModel Solar

As shown below, electricity tariffs have been steadily increasing for domestic customers (most notably in the high-use category).

Figure 209: Historic Electric Tariff Increases (residential)



Source: NEPCO

Current Policies

Jordan imports a significant portion of domestic energy (~90%+ of total energy consumption is imported) and is targeting changes to its energy consumption. Under its new National Energy Strategy, the government is looking to increase the overall renewable energy share to 7% by 2015 and to 10% by 2020 (currently around ~2%). The government has also stated targets for ~600MW of solar installations by 2020.

Under the country's Renewable Energy & Energy Efficiency Law, the Ministry of Energy and Mineral Resources (MEMR) is required to issue tenders for renewable energy projects. Most importantly, the law ensures that companies can bypass the complicated bidding process prevalent previously and negotiate directly with the ministry. The law also sets up the Jordan Renewable Energy and Energy Efficiency Fund (JREEEF), which will be financed by various national and international institutions. Companies will be allowed to apply for the Fund's support when setting up renewable energy projects in the country.

Under round 1 of direct proposals, launched by MEMR May 2011, 12 PV projects with total capacity of 170MW were approved. Final agreements for round 1 are still being finalized. MEMR launched round 2 in Oct 2013, under which 47 PV project proposals qualified (24 of those qualified "conditionally"). In round 2, final approval is likely to be given to four ~50MW PV projects. In 2014, round 3 tenders were canceled while the deadline for round 2 was extended.

In Feb 2014, the government approved PPAs for 200MW of new solar plants in the country. The seven individual projects will each be awarded JOD0.12 /kWh (US$0.17/kWh). Additionally, First Solar has signed an agreement to provide EPC services for the ~53MW Shams Ma'an PV plant, which is scheduled for completion in 2016.

Outlook

Given the relatively successful direct rounds of bidding coupled with high electricity prices and several high profile developers entering the market, we expect Jordan could be one of the first notable solar markets in the Middle East. However, given the relatively small market size, absolute installs may not exceed a several hundred MW run rate in the short-medium term

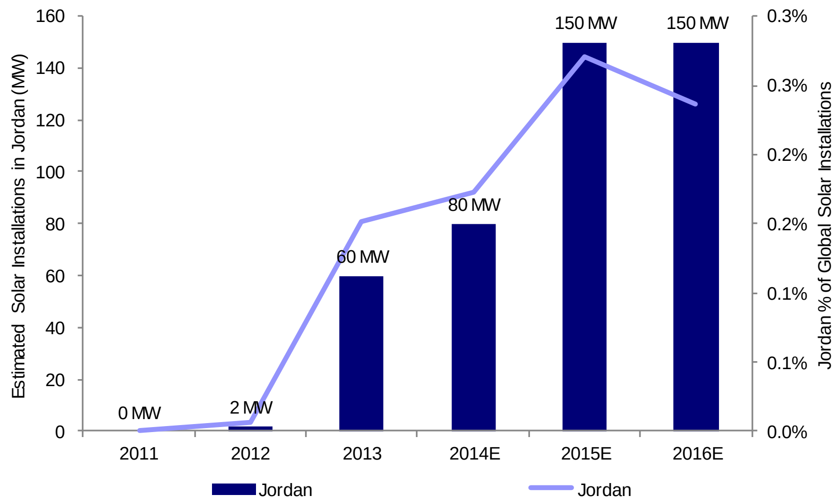
Figure 210: Country Snapshot

Jordan		
	2014	**2017**
Yearly Sun Hours (Net 20% Conversion Loss)	1,917	1,917
System Cost ($/W)	$2.50	$2.14
Discount Rate	7%	7%
LCOE ($/kWh)	$0.13	$0.11
Electricity Price - Average Residential ($/kWh)	$0.35	$0.41
Electricity Market Size (GW)	~3GW	
2014 Est Solar Installs (MW)	80	
2015 Est Solar Installs (MW)	150	
2016 Est Solar Installs (MW)	150	
Cumulative Solar Installs at end of 2016	765	
Policy Climate	Jordan imports ~96% of its domestic energy, and is targeting changes to its energy consumption. The country aims to increase the overall renewable energy share in the energy mix to 7% by 2015 and to 10% by 2020 (vs. ~2% currently). The govt aims to have 600MW of solar installations by 2020.	
Other Remarks		

*Electricity price is est of resi price, but majority of installs likely to be larger scale. Assumes 5% system price reduction YoY

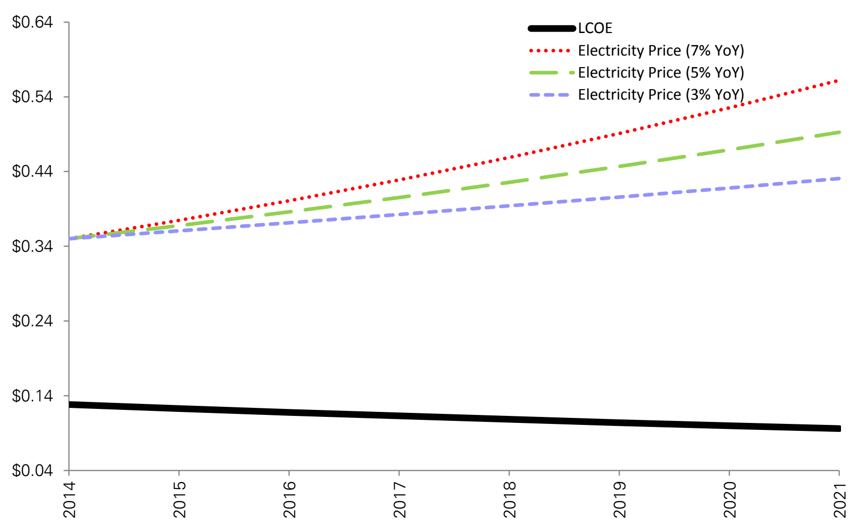
Source: Deutsche Bank

Figure 211: Jordan Solar Installations



Source: Deutsche Bank

Figure 212: Jordan LCOE Scenario Analysis



Source: Deutsche Bank

Demand Overview

We are introducing our estimates through 2020 and tweaking estimates for several other years. We are adjusting our 2016 and 2017 estimates from 62GW and 59GW to ~63.9GW and ~64.7GW respectively. Our 2018-2020 estimates are 72.7GW, 86.2GW, and 96.7GW.

Figure 213: Demand Overview

NEW PV INSTALLATIONS BREAKDOWN (MW)

MW	2011	2012	2013	2014E	2015E	2016E	2017E	2018E	2019E	2020E
Asia										
China	2,100	3,400	12,920	10,000	13,000	13,000	13,000	14,950	16,445	18,090
y/y (%)	*110%*	*62%*	*280%*	*-23%*	*30%*	*0%*	*0%*	*15%*	*10%*	*10%*
Japan	1,296	2,086	6,028	8,000	9,000	9,180	7,344	5,875	5,288	4,759
y/y (%)	*31%*	*70%*	*189%*	*33%*	*13%*	*2%*	*-20%*	*-20%*	*-10%*	*-10%*
India	190	980	1004	1,000	2,000	3,000	4,000	5,000	6,000	7,000
y/y (%)	*20%*	*416%*	*2%*	*0%*	*100%*	*50%*	*33%*	*25%*	*20%*	*17%*
Thailand	79	298	447	800	600	1,000	1,500	2,000	2,500	2,500
y/y (%)		*277%*	*50%*	*79%*	*-25%*	*67%*	*50%*	*33%*	*25%*	*0%*
Philippines	0	2	2	250	500	1,000	1,050	1,100	1,150	1,200
y/y (%)			*0%*	*12400%*	*100%*	*100%*	*5%*	*5%*	*5%*	*4%*
Rest of Asia		1,000	2500	3,250	3,750	3,800	4,500	4,700	4,900	5,000
y/y (%)			*150%*	*30%*	*15%*	*1%*	*18%*	*4%*	*4%*	*2%*
Asia Subtotal	*3,665*	*7,764*	*22,899*	*23,050*	*28,350*	*29,980*	*30,344*	*32,525*	*35,133*	*37,348*
% of World		*26%*	*58%*	*55%*	*52%*	*47%*	*47%*	*45%*	*41%*	*39%*
Americas	**2011**	**2012**	**2013**	**2014E**	**2015E**	**2016E**	**2017E**	**2018E**	**2019E**	**2020E**
US	1,600	3,313	4,751	7,000	12,000	16,000	11,200	12,880	14,812	17,034
y/y (%)	*82%*	*67%*	*43%*	*47%*	*71%*	*33%*	*-30%*	*15%*	*15%*	*15%*
Canada	297	268	444	533	586	586	586	586	586	586
y/y (%)	*100%*	*20%*	*-17%*	*20%*	*10%*	*0%*	*0%*	*0%*	*0%*	*0%*
Mexico	7	1	70	120	250	1,500	2,000	2,000	3,000	3,000
y/y (%)		*-86%*	*6900%*	*71%*	*108%*	*500%*	*33%*	*0%*	*50%*	*0%*
Chile	0	6	80	300	1,000	1,000	1,500	1,500	2,000	2,500
y/y (%)			*1233%*	*275%*	*233%*	*0%*	*50%*	*0%*	*33%*	*25%*
Brazil	10	12	50	30	40	500	600	700	800	850
y/y (%)		*20%*	*317%*	*-40%*	*33%*	*1150%*	*20%*	*17%*	*14%*	*6%*
Central America				300	400	500	700	1,000	1,500	2,000
y/y (%)					*33%*	*25%*	*40%*	*43%*	*50%*	*33%*
Rest of Americas		300	1000	1,225	1,860	2,100	2,900	3,000	3,100	3,200
y/y (%)			*233%*	*23%*	*52%*	*13%*	*38%*	*3%*	*3%*	*3%*
Americas Subtotal	*1,914*	*3,900*	*6,395*	*9,508*	*16,136*	*22,186*	*19,486*	*21,666*	*25,798*	*29,170*
% of World		*13%*	*16%*	*23%*	*29%*	*35%*	*30%*	*30%*	*30%*	*30%*

Source: Deutsche Bank

Figure 214: Demand Overview Continued

Europe	2011	2012	2013	2014E	2015E	2016E	2017E	2018E	2019E	2020E
United Kingdom	762	925	1500	3000	2250	1800	1890	1985	2084	2188
y/y (%)	*500%*	*-70%*	*62%*	*100%*	*-25%*	*-20%*	*5%*	*5%*	*5%*	*5%*
Germany	7,485	7,604	3,300	2,145	2,038	2,000	2,060	2,122	2,228	2,451
y/y (%)	*4%*	*2%*	*-57%*	*-35%*	*-5%*	*-2%*	*3%*	*3%*	*5%*	*10%*
Italy	9,443	3,597	1,149	500	1,000	1,200	1,500	2,000	2,500	3,000
y/y (%)	*307%*	*-62%*	*-68%*	*-56%*	*100%*	*20%*	*25%*	*33%*	*25%*	*20%*
Spain	400	332	118	100	100	150	160	180	200	250
y/y (%)		*-17%*	*-64%*	*-15%*	*0%*	*50%*	*7%*	*13%*	*11%*	*25%*
France	1,777	1,115	613	766	920	1,103	1,324	1,589	1,907	2,288
y/y (%)	*109%*	*-60%*	*-45%*	*25%*	*20%*	*20%*	*20%*	*20%*	*20%*	*20%*
Rest of Europe	2,007	3,072	2,497	997	1,227	1,509	1,856	2,282	2,807	3,453
y/y (%)	*205%*	*53%*	*-19%*	*-60%*	*23%*	*23%*	*23%*	*23%*	*23%*	*23%*
Europe Subtotal	*21874*	*16645*	*9177*	*7508*	*7534*	*7762*	*8790*	*10158*	*11726*	*13630*
% of World		*57%*	*23%*	*18%*	*14%*	*12%*	*14%*	*14%*	*14%*	*14%*
Middle East/Africa	**2011**	**2012**	**2013**	**2014E**	**2015E**	**2016E**	**2017E**	**2018E**	**2019E**	**2020E**
Saudi Arabia	0	0	0	50	300	600	1,500	2,500	4,000	5,000
y/y (%)				*#DIV/0!*	*500%*	*100%*	*150%*	*67%*	*60%*	*25%*
United Arab Emeriates	0	0	20	50	100	150	200	200	250	300
y/y (%)				*150%*	*100%*	*50%*	*33%*	*0%*	*25%*	*20%*
Jordan	0	2	60	80	150	150	170	200	250	300
y/y (%)			*2900%*	*33%*	*88%*	*0%*	*13%*	*18%*	*25%*	*20%*
South Africa	1	40	100	300	800	1,200	1,500	2,000	2,500	3,000
y/y (%)		*3900%*	*150%*	*200%*	*167%*	*50%*	*25%*	*33%*	*25%*	*20%*
Rest of Middle East/Africa		12	100	400	600	1,000	1,500	2,000	2,500	3,000
y/y (%)			*733%*	*300%*	*50%*	*67%*	*50%*	*33%*	*25%*	*20%*
Middle East/Africa Subtotal	*1*	*54*	*280*	*880*	*1,950*	*3,100*	*4,870*	*6,900*	*11,500*	*14,100*
% of World		*0%*	*1%*	*2%*	*4%*	*5%*	*8%*	*9%*	*13%*	*15%*
Australia	**874**	**1049**	**757**	**1100**	**850**	**893**	**1200**	**1500**	**2000**	**2500**
y/y (%)	*124%*	*20%*	*-28%*	*45%*	*-23%*	*5%*	*34%*	*25%*	*33%*	*25%*
Total	**27,557**	**29,412**	**39,508**	**42,046**	**54,820**	**63,921**	**64,690**	**72,749**	**86,156**	**96,748**
y/y (%)	***53%***	***7%***	***34%***	***6%***	***30%***	***17%***	***1%***	***12%***	***18%***	***12%***

Source: Deutsche Bank

Supply

Polysilicon supply has undergone drastic changes over the past several years as tier 2/3 suppliers have largely gone bankrupt, leaving only a handful of meaningful suppliers in the marketplace. Capacity adds continue to keep prices depressed, and we see enough incremental capacity coming online to maintain a balance over the next few years.

Figure 215: Capacity

Year End Capacity (MT)	2010	2011	2012	2013	2014	2015E	2016E	2017E
INCUMBENT POLY SUPPLIERS								
Hemlock Semiconductor	36,000	44,000	50,000	50,000	50,000	50,000	50,000	50,000
Tokuyama	8,200	8,200	9,200	15,400	29,200	29,200	20,000	20,000
Mitsubishi Materials	3,300	4,350	4,350	4,350	4,350	4,350	4,350	4,350
Sumitomo Titanium	1,400	3,600	3,900	3,900	3,900	3,900	3,900	3,900
Mitsubishi Polysilicon	1,500	2,000	2,200	2,200	2,200	2,200	2,200	2,200
REC	17,000	17,000	17,000	20,000	39,000	39,000	42,000	42,000
Wacker	30,500	42,000	52,000	52,000	59,000	85,000	90,000	90,000
SunEdison (incl. SMP JV)	7,800	9,200	4,200	4,200	4,200	17,700	17,700	42,700
Incumbents - Total	**105,700**	**130,350**	**142,850**	**152,050**	**191,850**	**231,350**	**230,150**	**255,150**
New Entrants NON - CHINA POLY SUPPLY								
OCI	27,000	42,000	42,000	42,000	42,000	52,000	52,000	52,000
M.SETEK	7,000	7,000	7,000	7,000	7,000	7,000	7,000	7,000
Nitol Group	3,500	3,500	3,500	5,000	5,000	11,000	11,000	11,000
Others (Russia, New entrants)	1,000	3,000	5,000	5,000	5,000	5,000	5,000	5,000
Non - CHINA Total	**38,500**	**55,500**	**57,500**	**59,000**	**59,000**	**75,000**	**75,000**	**75,000**
New Entrants CHINA POLY SUPPLY								
Asia Silicon	2,000	5,000	5,000	5,000	5,000	11,800	11,800	11,800
Daqo Group	3,300	4,300	5,000	6,150	12,150	12,150	12,150	25,000
Emei Semiconductor	350	350	350	350	350	350	350	350
Luoyang Semiconductor	3,300	3,300	3,300	3,300	3,300	3,300	3,300	3,300
LDK Solar	11,000	17,000	17,000	17,000	17,000	17,000	17,000	17,000
GCL	25,000	46,000	65,000	65,000	85,000	90,000	90,000	90,000
Wuxi Zhongcai	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Sichuan Xinguang	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500
TPSI (Taiwan Polysilicon)	0	3,000	8,000	8,000	8,000	8,000	8,000	8,000
TBEA (China)	0	1,200	10,000	12,000	15,000	15,000	15,000	15,000
Others (China)	5,000	12,000	15,000	35,000	25,000	25,000	25,000	25,000
China - Total	**52,450**	**94,650**	**131,150**	**154,300**	**173,300**	**185,100**	**185,100**	**197,950**
New Entrants - Total	**90,950**	**150,150**	**188,650**	**213,300**	**232,300**	**260,100**	**260,100**	**272,950**
Total (excl. Met Poly)	**196,650**	**280,500**	**331,500**	**365,350**	**424,150**	**491,450**	**490,250**	**528,100**

Source: Deutsche Bank, Company Reports

Figure 216: Supply

Annual Supply (MT)	2010	2011	2012	2013	2014	2015E	2016E	2017E
INCUMBENT POLY SUPPLIERS								
Hemlock Semiconductor	27,900	34,000	36,000	42,500	42,500	42,500	45,000	45,000
Tokuyama	7,300	8,200	4,500	5,000	10,035	16,060	16,974	15,000
Mitsubishi Materials	2,168	3,251	2,000	3,800	4,133	4,133	4,133	4,133
Sumitomo Titanium	1,190	2,125	3,188	3,315	3,315	3,315	3,315	3,315
Mitsubishi Polysilicon	1,275	1,488	1,785	1,870	1,870	1,870	1,870	1,870
REC	10,500	16,672	18,790	19,764	18,600	21,450	27,945	33,600
Wacker	30,500	35,500	38,000	49,000	48,840	57,600	70,000	72,000
SunEdison (incl. SMP JV)	6,102	5,950	5,360	4,200	3,990	7,665	12,390	21,140
Traditional Poly Suppliers - Total	**86,934**	**107,186**	**109,623**	**129,449**	**133,283**	**154,593**	**181,627**	**196,058**
Non-China Poly Supply								
OCI	18,000	35,000	40,000	25,935	37,800	44,650	49,400	49,400
M.SETEK	5,400	7,000	7,000	6,300	6,300	6,300	6,300	6,300
Nitol Group	760	3,500	3,500	2,125	2,500	3,200	4,400	4,400
Others (New entrants)	917	2,000	5,000	5,000	4,750	4,500	4,500	4,500
Non - China Total	**25,077**	**47,500**	**55,500**	**39,360**	**51,350**	**58,650**	**64,600**	**64,600**
China Poly Supply								
Asia Silicon	1,200	2,400	4,500	2,000	1,500	2,520	3,540	3,540
Daqo Group	3,650	4,300	3,568	4,805	6,150	9,720	9,720	13,003
Emei Semiconductor	329	350	350					
Luoyang Semiconductor	1,588	2,475	3,300					
LDK Solar	5,000	10,220	17,000	0	1,020	4,250	5,950	7,650
GCL	17,040	29,414	37,055	50,440	67,500	78,750	81,000	81,000
Wuxi Zhongcai	1,000	1,000	1,000					
Sichuan Xinguang	1,708	1,500	1,500					
TPSI (Taiwan Polysilicon)	0	1,500	1,500					
TBEA (China)	0	600	1,000	6,600	10,125	12,000	13,500	13,500
Others (China)	4,555	8,500	16,230	33,250	21,000	17,500	17,500	17,500
China - Total	**36,070**	**62,259**	**87,003**	**97,095**	**107,295**	**124,740**	**131,210**	**136,193**
Total (excl. Met Poly)	**148,081**	**216,945**	**252,126**	**265,904**	**291,928**	**337,983**	**377,437**	**396,850**

Source: Deutsche Bank, Company Reports

Supply

GCL Poly

GCL Poly aims to add a total of 25k MTpa FBR capacity by end-2015. It also plans to expand its existing Siemens facility by 10,000 MTpa in 2015, so that total poly capacity could increase from 65k MTpa by 3Q14 to 100k MTpa by end-2015. (source: GCL Poly: Inflection point – upgrading to Buy, Feb 11, 2015)

Wacker

Wacker has increased utilization levels recently. Wacker's Polysilicon's sales in 2Q14 increased ~34% Y/Y driven by a significant increase in volumes and better pricing. Wacker has voiced expectations that prices will remain strong driven by solid demand environment. The company is building a new poly plant in the US (20K MT capacity), which is scheduled to be commissioned in 2H15. The company's poly capacity was ~52K MT as of 2013-end. We expect debottlenecking activities and US plant to take poly capacity to 59K MT in 2014, 85K MT in 2015 and 90K MT in 2016. We expect utilization levels to be high in ~80% range over the next few years.

OCI Co.

OCI recently decided to restart a project which will supply ~20KMT (expected to come online in mid-2015), overall, bringing total poly capacity from ~42K MT to ~52K MT. We expect high utilization levels particularly as OCI is generally not subject to Chinese tariffs

Daqo

Daqo shipped 1.4K MT of poly in 2Q14 (up 3% Y/Y) and expects shipments in 3Q14 to be 1.45-1.50K MT. The company decreased production costs to ~$14/kg and expects further decreases by mid-2015 to ~$12/kg. Poly ASP in 2Q14 increased to $22/kg, and the company expects poly ASP to increase further in 4Q13 and beyond, driven by robust end-market demand. Company anticipates high utilization rates for poly production in 2014 – with poly volume expected to be close to the nameplate capacity of ~6K MT. In 2014, Daqo raised ~$55M through a follow-on public offering, which will be used for the expansion at the company's Xinjiang poly facility. Daqo expects construction to finish by the end of 2014 – taking the poly capacity to ~12K MT. Subsequently, the company plans to increase its poly capacity to 25K MT, which we believe could complete in 2017.

REC Silicon

REC produced ~4.4K MT (~3.7K MT of FBR, ~0.4K MT of Semi-grade, ~0.3K MT of Siemens Solar) and sold ~4.2K MT of poly in 2Q14. REC targets ~5K MT of poly production for 3Q14 (~4.3K MT of FBR) and ~18.6K MT for full year 2014 (~15.7K MT of FBR). The company benefitted from high poly ASP during the quarter (spot price for solar-grade poly up 4% Q/Q to ~$21/kg), driven by strong demand. As such, the company expects poly market to remain balanced during 2H14, and expects flat to modest increase in poly prices through 2H14. In 2014, REC entered into a JV with Shaanxi Non-Ferrous Tian Hong New Energy to build a poly plant with a nameplate capacity of 18K MT. REC's poly capacity currently stands at ~20K MT and the new JV will increase the capacity to ~39K MT by 2014-end. The company also plans to expand capacity at its Moses Lake facility by 3K MT, which would raise poly capacity to 42K MT in the second half of 2016.

Tokuyama

Tokuyama reported a decline in sales of solar-grade poly in June '14 quarter, despite a recovery in the overall global demand, due to a strategic shift. The company is constructing a new poly production facility in Malaysia, which will focus on producing solar-grade poly. The facility has a capacity of ~14K MT and is expected to start operations in Sep-Oct 2014. The company expects capacity utilization to be well over 50% at launch, and then gradually increase, with full production likely from mid-2015. Currently, the company has a poly capacity of ~15K MT (9K in MT in Japan and 9K MT in Malaysia). With the new Malaysian facility, the capacity should increase to ~29K MT by 2014 end.

Supply Demand: Could Be Tight

Although several poly producers are adding capacity in the next 1-2 years, we see supply/demand balance as barely balanced over the medium term, and well within the margin of error. We expect this balance to be maintained over the next several years and do not expect any drastic shifts in poly prices, although there may be gradual price declines as lower cost capacity comes online.

Figure 217: Supply Demand - Balanced

Supply/Demand	2011	2012	2013	2014E	2015E	2016E	2017E
New PV Installation (MW)	27,557	29,412	39,508	42,046	54,820	63,921	64,690
Inventory Requirement (MW)	2,756	2,941	1,975	2,102	2,741	3,196	3,234
Inventory % of Demand	*10%*	*10%*	*5%*	*5%*	*5%*	*5%*	*5%*
Total PV Module Shipments (MW)	**30,313**	**32,353**	**41,484**	**44,149**	**57,561**	**67,117**	**67,924**
Efficiency Loss	*5.0%*	*5.0%*	*4.0%*	*4.0%*	*4.0%*	*3.0%*	*3.0%*
Total PV Cell Shipments (MW)	**31,829**	**33,971**	**43,143**	**45,914**	**59,863**	**69,130**	**69,962**
Thin Film Supply (MW)	2,083	1,945	1,742	2,279	2,663	2,930	3,223
Polysilicon Consumed (ton/MW)	6.5	6.0	5.5	5.4	5.4	5.3	5.3
Total Solar Poly Reqd (MT)	**193,344**	**192,156**	**227,707**	**235,632**	**308,880**	**350,863**	**353,719**
Poly demand from Semis (MT)	**29,657**	**30,218**	**32,839**	**34,152**	**35,518**	**36,939**	**38,417**
Total poly demand (MT)	**223,001**	**222,374**	**260,545**	**269,784**	**344,398**	**387,802**	**392,136**
Poly supply (MT) - excluding scrap/U	**252,126**	**252,126**	**265,904**	**291,928**	**337,983**	**377,437**	**396,850**
Under Supply (Over Supply) (MT)	**(29,125)**	**(29,752)**	**(5,359)**	**(22,144)**	**6,416**	**10,365**	**(4,714)**
Under Supply (Over Supply) (MW)	**(4,481)**	**(4,959)**	**(974)**	**(4,101)**	**1,188**	**1,956**	**(889)**
% of demand	*-16%*	*-17%*	*-2%*	*-10%*	*2%*	*3%*	*-1%*

Source: Deutsche Bank

However, 2017 could see a short term oversupply as policy shifts in key markets such as the US and Japan cause demand to stagnate in the near term. We expect the upward demand trend to continue thereafter.

Appendix 1

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Additional information available upon request

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Company	Ticker	Recent price*	Disclosure
Vivint Solar	VSLR.N	8.07 (USD) 27 Feb 15	1,7,8

*Prices are current as of the end of the previous trading session unless otherwise indicated and are sourced from local exchanges via Reuters, Bloomberg and other vendors . Data is sourced from Deutsche Bank and subject companies.

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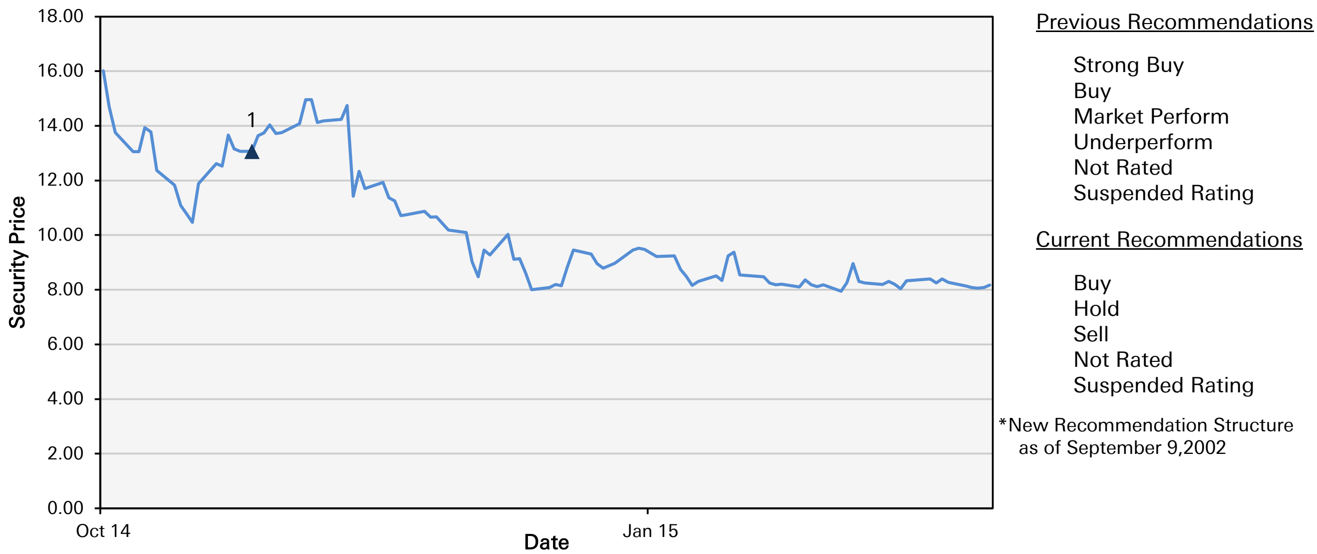
(as of 2/27/2015)



1.	10/26/2014:	Upgrade to Buy, Target Price Change USD20.00

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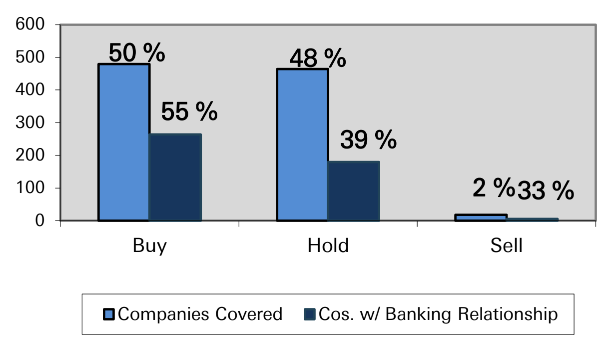

North American Universe

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