US Electric Utilities & IPPs

How Cheap Can Solar Get? NREL's Take on Trends

Equities

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Solar costs to continue to decline across a variety of trends

We held our latest conference call with NREL (National Renewable Energy Labs) to discuss their views on Solar system cost trends. The main takeaway was their expectations for price improvements to continue via lower financing costs, supply chain costs, engineering specifications around the site; importantly, some shift of focus also back towards module efficiency. According to NREL, global ASP by 2016 is projected to be in the ~$0.55-$0.65/W range compared to ~$0.64/w in 2014; overall, we reiterate our assessment that falling costs and improving efficiencies will continue to underpin incremental solar growth, enabling at least a partial offset to tax subsidies falling away. Margin compression and balance of system (BOS) savings appear to be equally meaningful source of savings, with BOS worth up to ~$0.16/W via just two structural improvements (pre-assembly and lower-weight build codes).

LCOE of loans ~19%-29% lower than PPA approach – better to buy than rent

Compared to a traditional PPA structure, NREL believes using solar loans can help lower the cost of energy by ~19-29%; highlighting relatively low levels of risk associated with a PV project which gives the lease model significant opportunities for both cost savings without too much exposure to risk. That said, further innovations in the PPA structure vs traditional structures can make the ownership model more competitive too. We see an ongoing race between the loan vs. lease model as well as govt. subsidized ownership schemes in CA and HE among other states. Can and will consumers shift towards ownership? Some may – and the further question is how lease co's can benefit, such as via SCTY via the MyPower scheme.

Improvements in module efficiency haven't yet peaked either

According to NREL, improvements in efficiency in the past 8 yrs have been ~1-1/2 to 2%, as the industry focused on getting other costs down and was potentially under-investing in efficiency type R&D. However, now there may be a refocus towards efficiency improvements. According to NREL, the majority of modules used today are multicrystalline silicon using full square wafer (with has 60 wafers inside) providing ~250 - 260 watts, which means around 15% efficiency. Monocrystalline silicon can be a little better at about 16% efficiency. However, according to NREL, for monocrystalline silicon there are also other brands out there that can give much higher module efficiencies in the 20% range; and these may eventually be employed more frequently to increase the industry average.

What will the ITC impact be? Utility scale may contract; DG can remain robust

Speakers on the call agreed with the broader consensus that utility scale deployment will be impacted if ITC is reduced/removed. However, NREL believes that any contraction should not impact cost reduction via scale/learning, because this is a global market and a lot of that learning can be imported from more mature markets. On the DG side, opportunities will exist despite ITC removal, where there are parts of the US that are competitive even without the tax credi. Separately, for implications on US installers, NREL highlighted that if the ITC is reduced to 10%, then it is potentially more beneficial for solar companies to forego the ITC and get cheaper capital through lower cost financing through investors/banks. For DG, better financing and even better insulation practices can further improve penetration prospects.

PPA prices decline owing to developer competition: Will the trend continue?

NREL pointed out that PPA prices have continued to decline due to intense competition among solar developers, with some projects having signed PPA's for ~$0.05/kWh. However, going into 2016, expectation is for prices to not go down much below the 4.5-5 cents at the low end. Rather than prices breaking those lower levels, the trend to watch out for is PPA prices reaching those levels in several other markets.

Saving costs through "wind code reductions": better structural design should lead to BOS savings

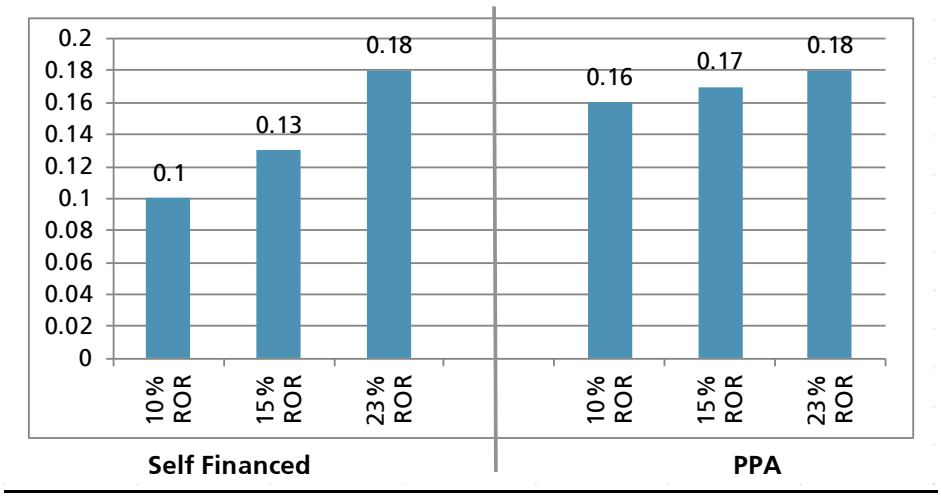
NREL pointed out that historically the industry has used ASCE 7 (the American Society of Civil Engineering code) to design most buildings and structures; and even for solar PV structures. However, a typical solar structure is now much shorter in height and lighter; so the historical wind code may in fact be too conservative for a PV design. Several manufacturers are now running newer wind color tests to estimate more realistic wind code assumptions for a ground mounted system.

Eventually lighter foundation requirements for lighter loads, and lower associated materials and labour requirements for a relatively simpler structure should lead to further BOS savings. Already, by end of 2013, BOS prices for a fixed axis ground mount utility-scale project, BOS was $1.8/W vs ~$4.36/W in end of 2009. For residential scale, of course BOS is higher - $3.29 end 2013, but even that has declined significantly from $6.91/W at 2009 end.

Commercial solar systems: self-financed vs PPA

NREL highlighted a study for commercial systems where they looked at the LCOE of a commercial system installed at Ikea (which self-financed and owns it ~35MW+ PV) and Staples (which leases its ~14MW PV via PPAs). NREL estimates that self-financed option results in a 30% lower LCOE than that when the sytem is PPA financed (in practice the discount rate should be different based on the installers risk perception; but the above estimate assumes similar risk perception – however, if assuming a 10% discount rate for a PPA and a 23% discount rate for self - purchase, then the LCOE would be 14% lower using the PPA). The chart below summarizes NREL's LCOE analysis:

Figure 1: Commercial system: self-financed vs PPA LCOE ($/kWh)



Source: NREL

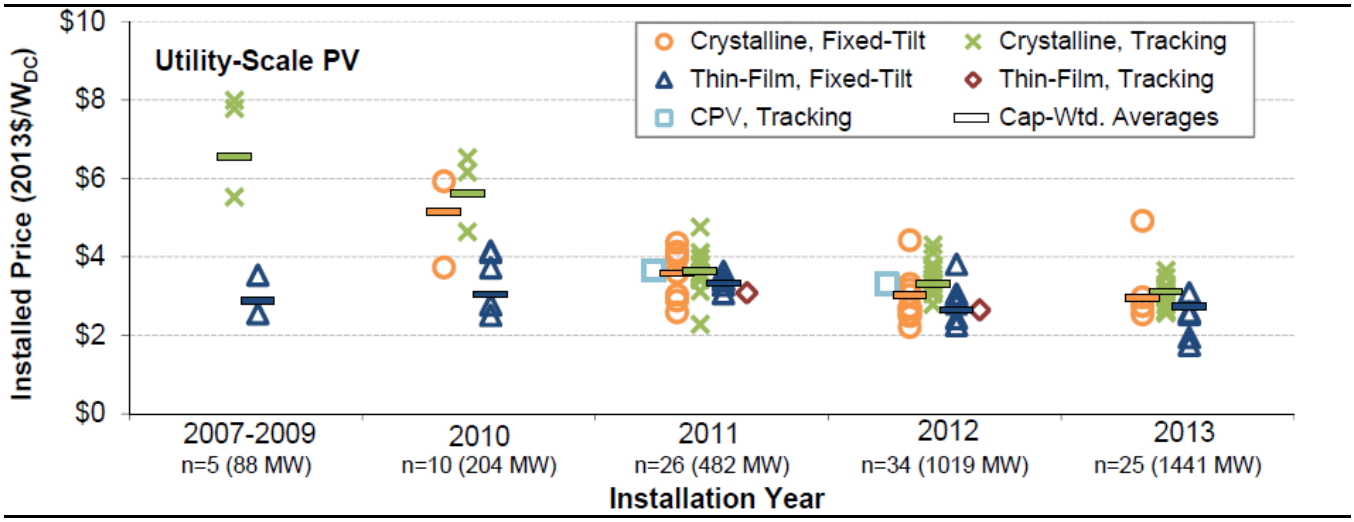
Utility scale PV projects: reported prices have been declining but perhaps not as much as costs

In the chart below we show we see a general trend that prices have been declining over time, but the rate of decline has considerable slowed down for projects that were installed between 2012 and 2013. Another trend we highlight is that the spread of reported installed price has decreased over the years as well; the price

distribution to the extent it still exists is largely owing to variation in system size, other project specific market and policy conditions, and contracting date. As of 2013, utility scale PV systems were in the ~$2.60/W-$3.20/W range.

However, we highlight here that these are *reported* prices, which aren't necessarily reflective of the underlying cost reductions that are happening in the industry.

Figure 2: Reported prices for utility scale PV projects: a declining trend which has flattened a bit 2012+

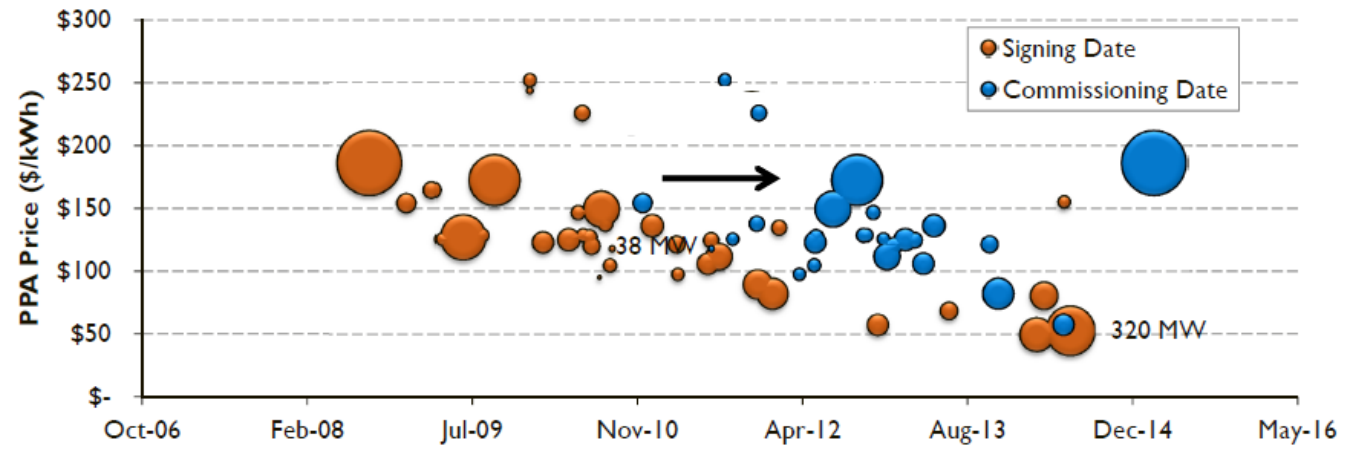


Source: Lawrence Berkeley National Lab, NREL

One of the reason reported prices don't reflect actual cost reductions is because the difference between the PPA price at signing date vs commissioning date can be significant. In the chart below, again from NREL's presentation made on the conference call, we can see that for projects where data was analysed, there was on an average about three years of lag between the date of PPA signing and of commissioning. Thus *reported prices* can actually be reflective of a PPA that was actually signed three years in the past.

The chart below also shows that PPA prices have also had a declining trend, driven by increasing competition amongst solar developers.

Figure 3: Solar PPA prices in the US per BNEF/NREL – declining trend still



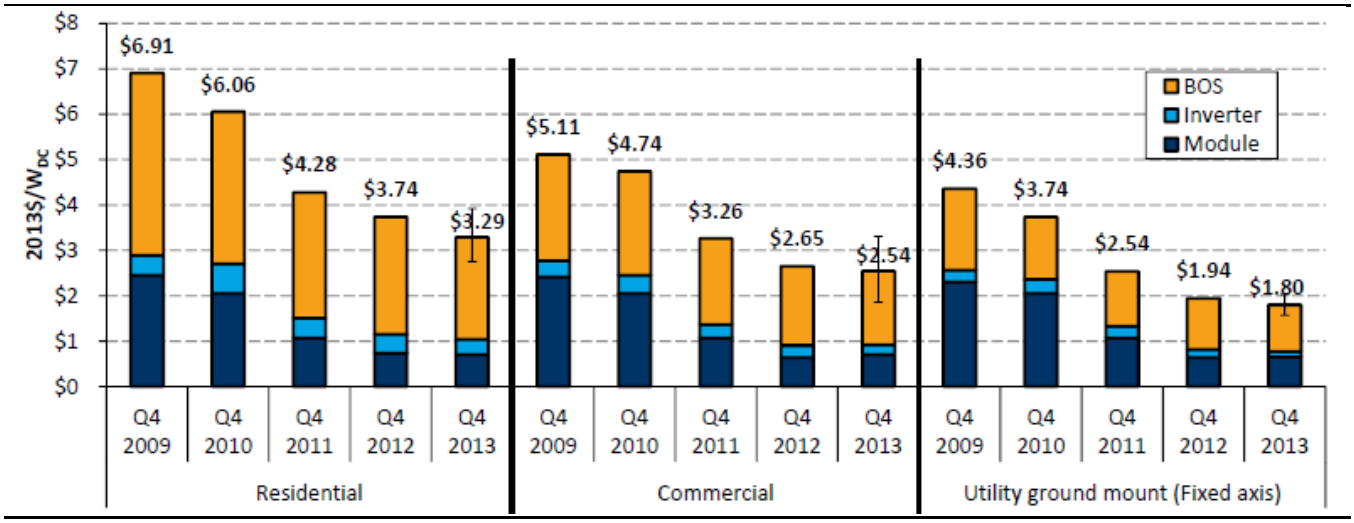
Source: BNEF, NREL; do not cite as is Preliminary data from NREL's presentation to UBS

System prices have historically fallen ~16-19% annually

Below we show NREL's estimate for PV system prices based on bottom up modelling. The trend shows falling prices (latest data point analysed is end of 2013). The data below shows cost over time independent of factors that could augment the underlying cost gains (i.e, external factors such as lack of competition should impact system prices, but will not impact system costs). This is the fair market value, rather than the cash purchase price. Reported costs by solar companies should essentially reflect the bottom-up cost based pricing below plus an operating margin for the installer. In the chart below system prices as modelled by NREL show a 16-19% per year decline.

According to NREL, the $3.29/W for the latest data point (4Q13) is consistent with what they have seen as reported prices from solar installers (the number is inclusive of what NREL believes are "sustainable margins".

Figure 4: NREL's cost base estimates for PV system prices (a historical trend)



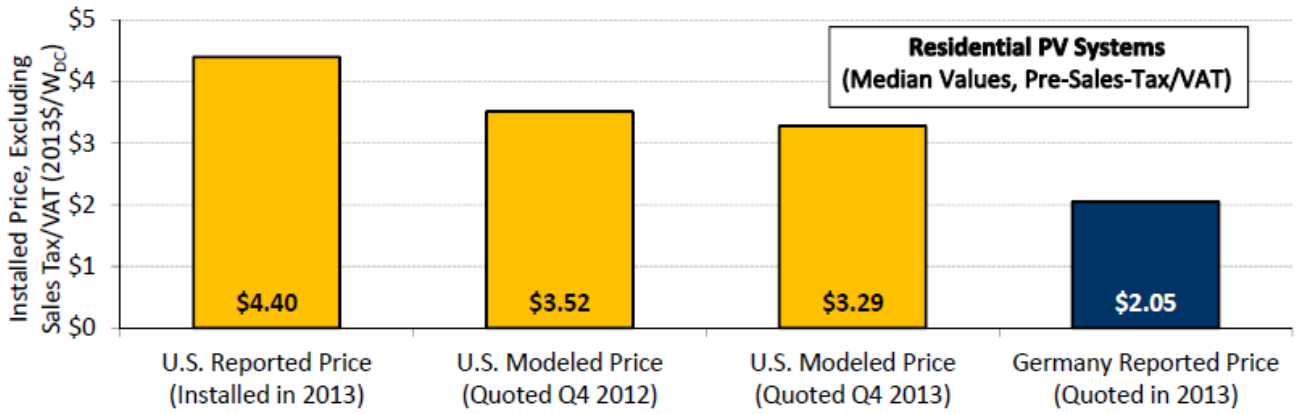
Source: NREL

Soft-costs (including installer margins) may represent near term cost-improvement potential

We use NREL's slide below to show an interesting trend – there is a significant difference in installed prices in the US vs several other major international PV markets – but particularly when compared to Germany (almost ~$2.4 differential on a pre-sales tax basis as of latest data analysed by NREL). We think irrespective of how steep further development in the US is (which would dictate urther economies of scale), the chart below highlights that there is another element of cost improvements that can be replicated by the learning-effect from more mature solar markets. NREL pointed out on the call that since costs of hardware are fairly similar across countries, the gap in total installed prices likely reflects differences in other soft/process-oriented costs (which also includes installer margins).

Installed costs for residential PV systems in the US ~$4.4/watt vs ~$2.05 reported price in Germany – suggesting some near term potential for improvements in the US. (NREL uses latest data as in 4Q13)

Figure 5: Installed Prices for Residential PV: Scope for improvement in the US



Source: NREL

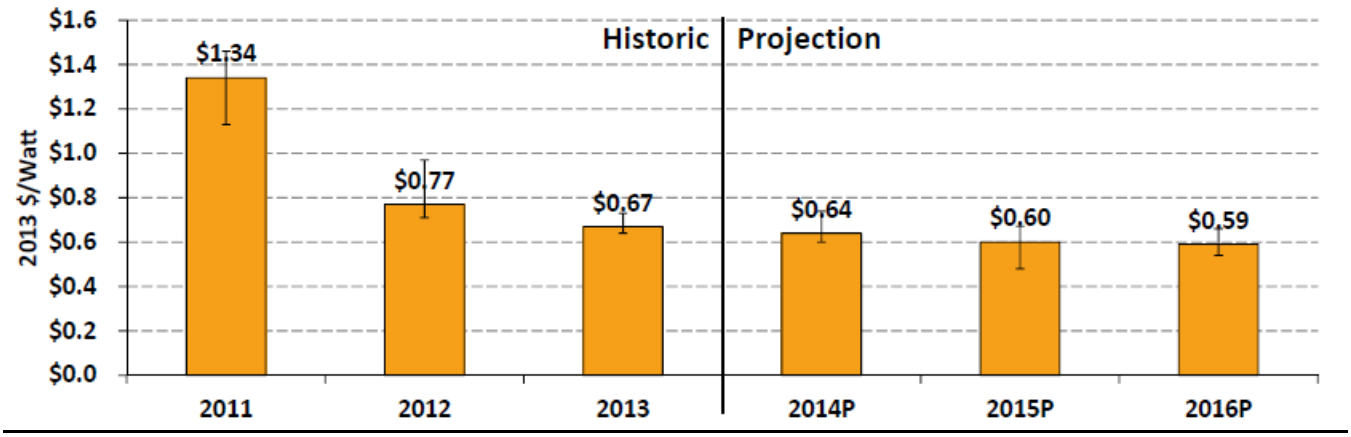
A look at global cost estimates

According to NREL, the consensus amongst analysts is that pricing should continue to decline across all PV markets, over the long run – with the low end of analyst targets very close to the SunShot target of $1/W installed over the long run (over the course of the next decade); whereas the higher end of those targets over the same period are ~ $1.00-$1.50/W above SunShot targets. Interestingly, price projections for 2020 right now, are almost half of what 2020 projections were 5-10 years ago.

In the chart below NREL uses the median (and max/min range) for various companies and analysts' estimates for average global selling price (ASP) for modules. Prices aren't forecasted to decline significantly over the 2014-16 periods, but are below the $0.60 mark by 2016. ASP for modules will be significantly higher than those below due to the impact of tariffs on Chinese and Taiwanese solar products.

Even if prices go down only slightly in coming years, this does not take into account gains from higher efficiency – so overall price of the system may decrease more that decline in modules, driven by improvements in efficiency.

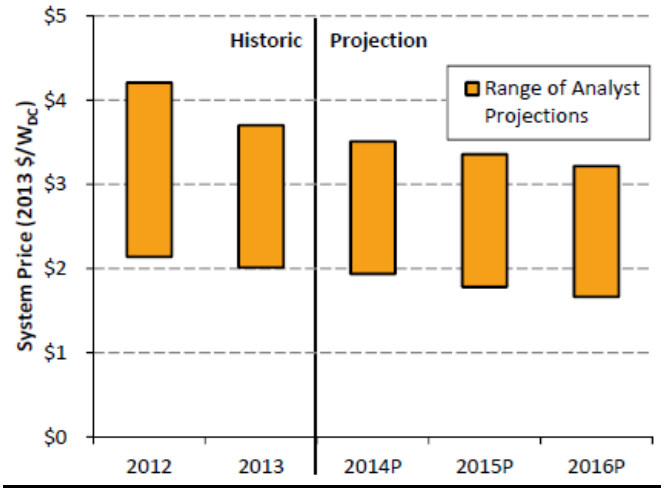
Figure 6: Global module ASP (US significantly higher due to tariffs)



Source: NREL's estimates using ASP for First Solar, Trina Solar, Yingli , and global - weighted average from the various analysts

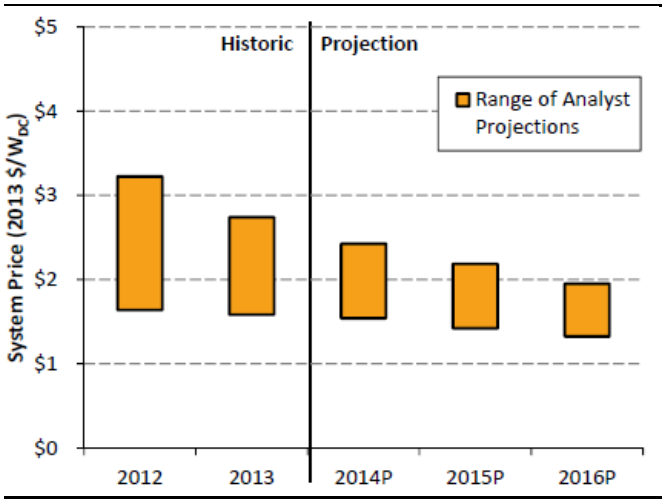
Again, for global prices NREL estimates that distributed solar will be in the $1.50/W-$3.00/W range by 2016; while utility scale solar systems will be in the $1.30-$1.95/W range by 2016 (based on an average from various reported sources).

Figure 7: Global average system price projections: distributed systems



Source: Average as compiled by NREL from various sources

Figure 8: Global average system price projections: utility-scale systems

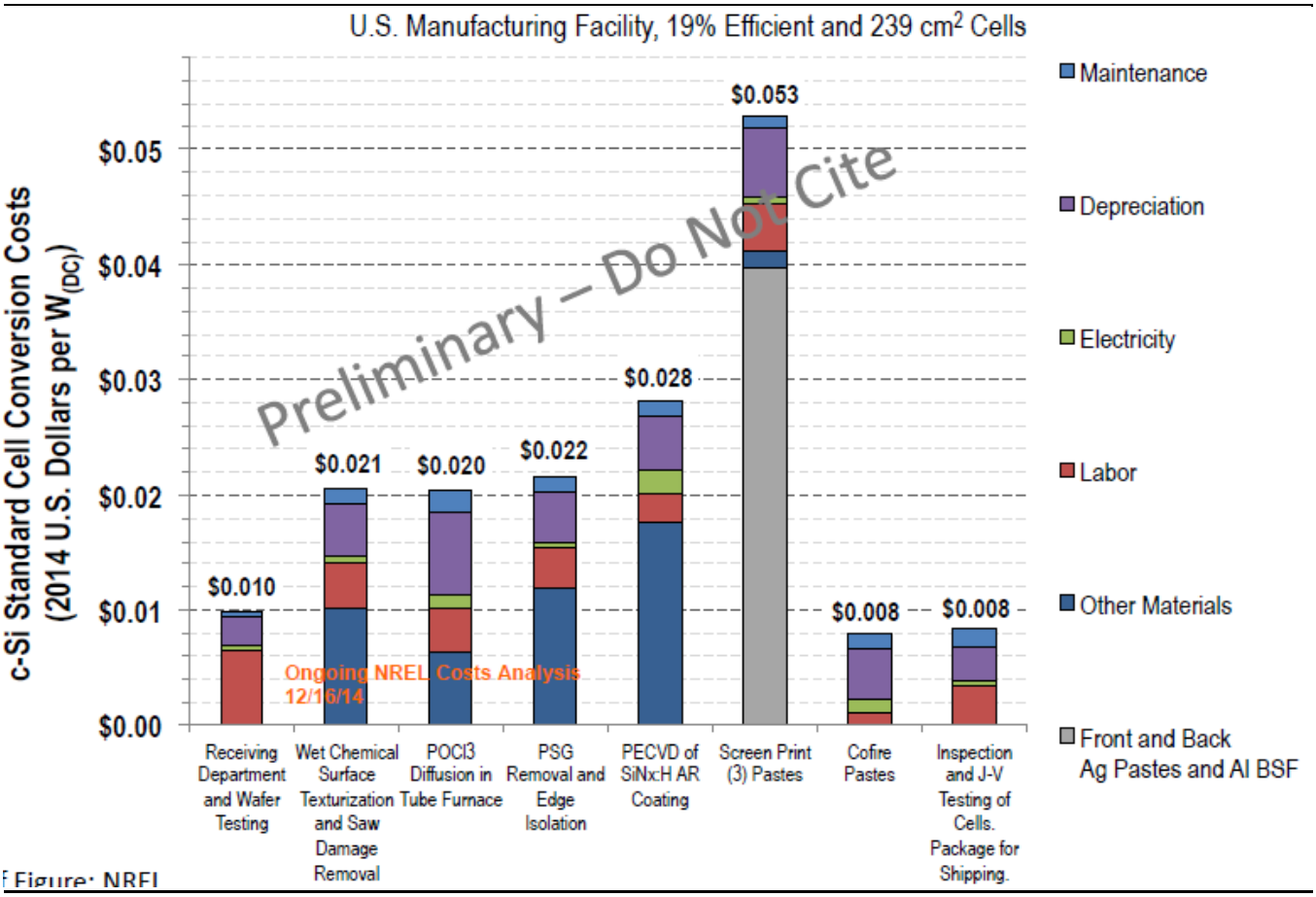


Source: Average as compiled by NREL from various sources

Looking under the hood: process costs

NREL's cost estimates are based on a bottoms-up approach for various processes that add to the cost of the final product. The chart below shows some of these key process required while processing a standard c-Si solar cell; including estimates for material, depreciation expense etc.

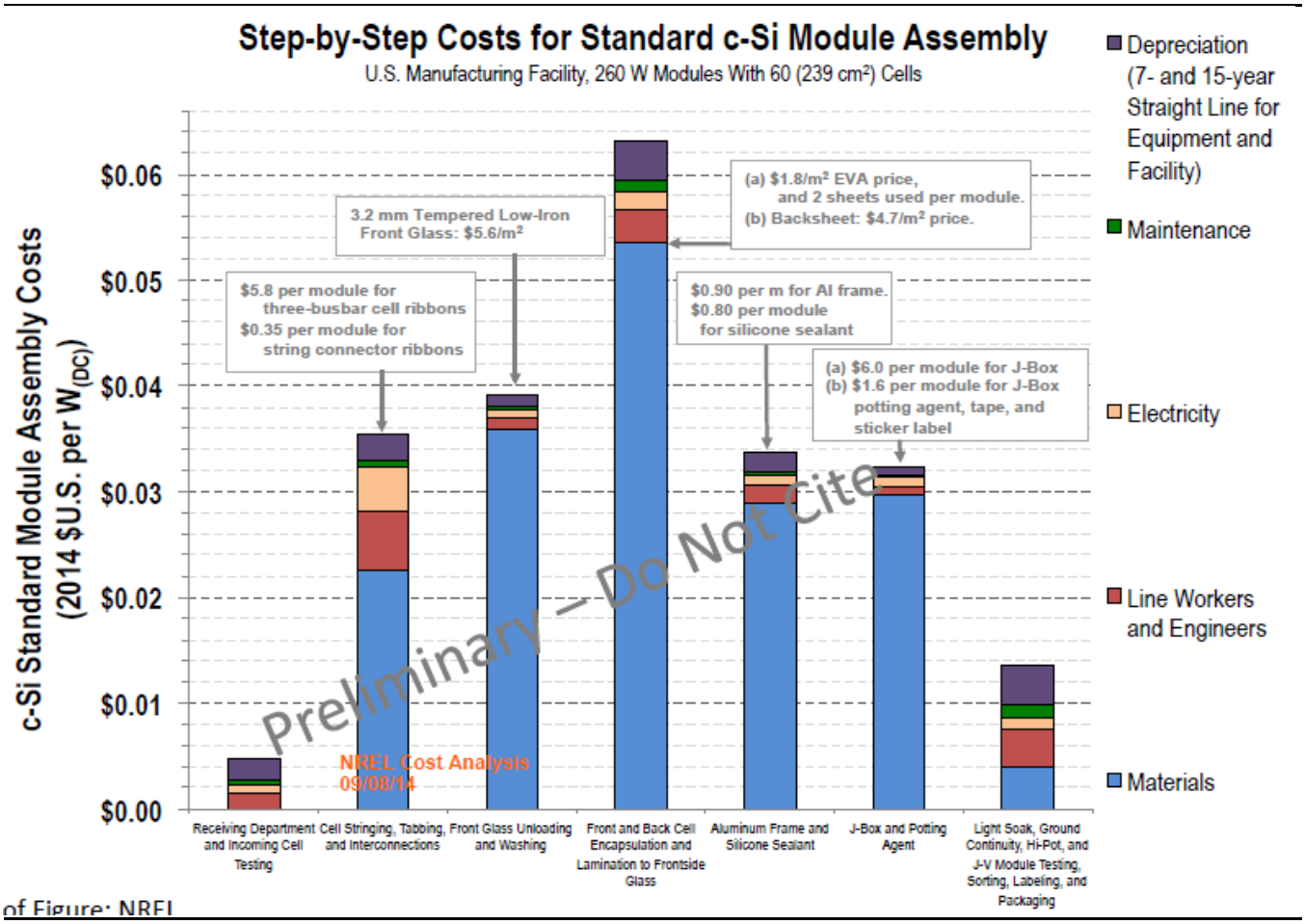
Figure 9: Step by step costs for a Standard Mono c-Si Solar cell processing



Source: NREL ; preliminary figures provided by NREL for our UBS presentation.

The chart below shows the step by step costs for module assembly. Materials constitute the main cost element at this stage. The costs below are module assembly costs, without including the cost of the cells.

Figure 10: Calculated Step Costs for Standard Mono c-Si Module Assembly

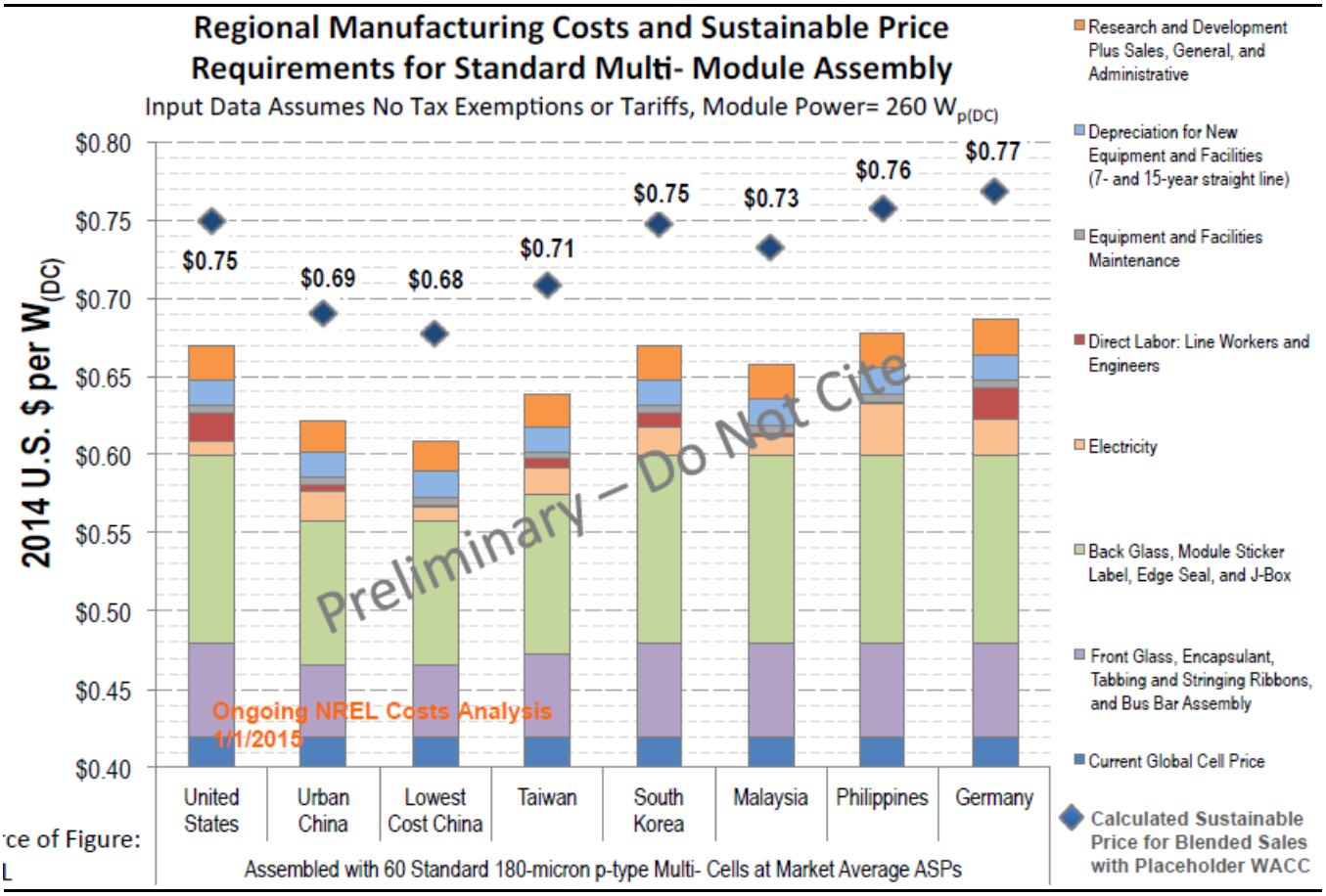


Source: NREL

How cheap is manufacturing the panels today really?

The chart below shows the cell costs incorporated into the total module costs. The chart below summarizes module manufacturing costs in different facilities around the globe; based on NREL's data base of manufacturing activities in the solar supply chain. The bar chart shows the bottom up results whereas the datapoints above the bars reflect NREL's calculation for a 'minimum sustainable price' – this basically represents an operational margin based upon a weighted average cost of capital.

Figure 11: Standard Multi - Module Assembly With a Representative 2014 Global Cell Price

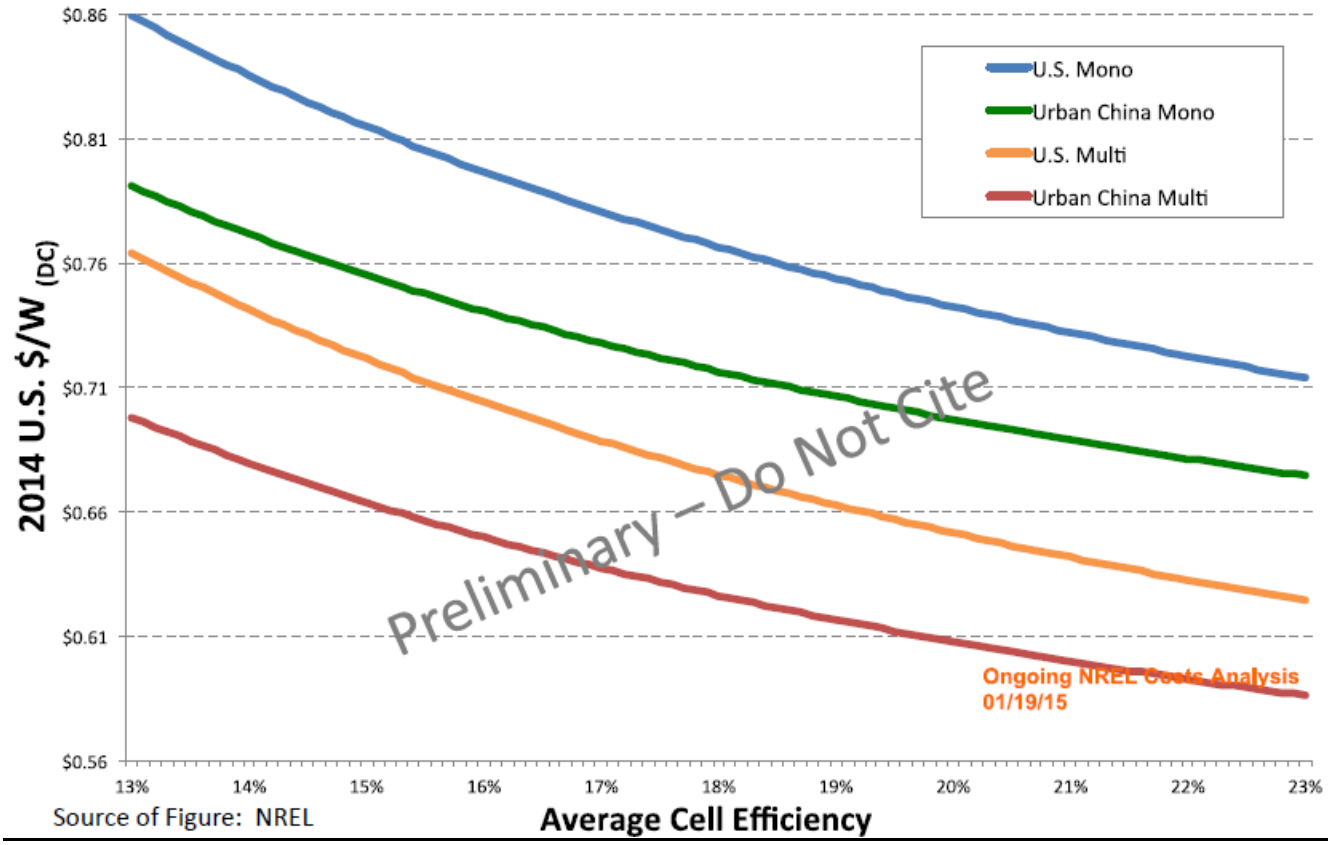


Source: NREL

Increasing efficiency will be an important factor in closing in on SunShot targets

According to NREL, improvements in efficiency in the past 8 yrs have been ~1-1/2 to 2%, as the industry focused on getting other costs down and was potentially under-investing in efficiency type R&D. However, now there may be a refocus towards efficiency improvements. The chart below is from an ongoing study at NREL, and the results may not yet be final. However, so as to understand the trend, the charts shows how increasing efficiency leads to lower costs. Improving efficiency can lead to not only lower module costs, but lower overall costs for the system.

Figure 12: Preliminary NREL analysis: Sensitivity of Standard 60 - Cell Module Costs to Cell Efficiency



Source: NREL

Conference Call on 2015 Solar Trends

Continuing to our solar series, we present below highlights from our call with *NREL (National Renewable Energy Labs) to discuss their views on Solar system cost trends. The text below has been edited for grammar and to aid ease of reading.*

We encourage you to reference the accompanying presentation, which has been partially reprinted above with permission. Please contact us or NREL for a copy of the full slide deck.

A replay of the call can be accessed using the replay dial in details below:

Replay Information (available until 2/18)

Toll Free: 800 633 8284

Toll: +1 402 977 9140

Passcode: 21759851

Julien Dumoulin Smith: Good afternoon and thank you for joining us on our latest call in our 'Solar Series'. We're joined today by David Feldman and his colleagues from the Strategic Energy Analysis Center over at the National Renewable Energy Lab (NREL) – which is part of the Department of Energy (DOE).

With that I'll turn it over to David - thank you very much for taking some time with us today, David.

David Feldman: Thank you Julien, really appreciate the opportunity. I have got a few people on the line with me here at NREL - Ran Fu, Mike Woodhouse, Kelsey Horowitz and Donald Chung. So anything I miss I'm sure they will be able to answer without a problem.

The Department of Energy funds a host of national labs to do a series of analysis focused on benchmarking costs, looking at historic and current pricing and cost as well as looking at trends within the industry and opportunities for cost reduction.

Starting with our slides, I'll go to Slide 3 of the presentation. As you can see there's a few different ways you can think about price, different ways of measuring it. One is by looking at how it's being reported. The other is by trying to

benchmark it through cost modeling. Neither is right, both have their advantages.

But in either case we can see **cost declines occurring in the near past and an expectation that those will continue in the future.** And there are a few reasons that we think that is so.

If you look at Slide 4 - this is from analysis from the Lawrence Berkeley National Lab. They tracked down over 100 reported utility scale PV system prices. As you can see there's a wide range in reported pricing per year. There was over all a downward trend, but as you can see in 2012 and 2013 there wasn't really that much of a decline. Again these are reported prices - and **reported prices aren't necessarily reflective of the underlying cost reductions that are occurring within the industry.**

One reason we might not see cost reductions from reported price is because of what you see on Slide 5, which shows PPA pricing in the United States. This is from Bloomberg New Energy Finance, and is segmented into two ways. We look at the signing date of the PPA and the commissioning date. We can still see a PPA reduction in price over time but the difference between the signing date and the commissioning date for these projects can be quite sizeable ones.

In fact for these projects, where we have data, there was actually a three-year lag between the signing date and the commissioning date. So when you hear about prices within the market, there potentially is **a big difference between when a PPA price for when it's signed and what the market looks like when it actually gets commissioned.**

So when we look at pricing, the reported pricing could be reflective of a PPA that was signed three years ago; which had a different pricing environment.

Shifting to Slide 6 Lawrence Berkeley National Lab and other Universities took a look at trying to deconstruct PV pricing, particularly in the distributed space, to try and get a sense of what is the best metric in determining how to lower these prices.

And they came up with a lot of **factors which influence system pricing, such as installer density, consumer value of solar, household density, population demographics, and system size.** And they found actually a pretty good correlation between a lot of these factors – however, But they also found that even when they looked at all the factors they could still only explain somewhere between 33 and 38% of that; which suggest variation in price may be caused by unobservable characteristics, such as willingness for consumer to search for lower price.

Shifting to Slide 7, shows the bottom up, cost plus modeling of system-level pricing. And over the past five years we can see prices continue to fall.

And these cost-plus modeling conforms with a lot of what's being reported. For example **our residential benchmark of $3.29/Watt conforms pretty well with the reported Solar City residential cost plus a reasonable margin.**

It's important to note that what we're trying to do is look at cost over time independent of factors that could augment the underlying cost gain. So if for example, there's lack of competition or increased incentives that actually could impact the price of the system. But that shouldn't impact the cost.

So when we do our modeling we try and take some of those extraneous things out even though potentially they impact price. Looking into the future - and we can see this in Slide 8 - **we think that there is still tremendous amount of**

costs that could be taken out of the system and price reduction. No matter if you look at the reported pricing or the modelled pricing that we've benchmarked there's still a significant gap between what are the U.S. market and other markets such as Germany; which in 2013 had quoted a residential prices around $2.00 versus, reported numbers in the U.S. which are over twice that.

Beyond the country level factors which we may or may not be able to change, the U.S. has a lot of opportunities for cost reduction both in price and in terms of the cost of energy. One such place is through **better financing terms; either through more efficient or lower cost to capital**.

We did an analysis if you look at Slide 9 for opportunities for using solar loans to help lower the cost of energy; compared to traditional PPA structure (of course there are innovations happening in the PPA space as well). But we look at the traditional PPAs versus the new loans that are coming out onto the market here. **Cost of energy could be reduced by anywhere from 19 to 29%.** There are other risks and factors associated with owning a project versus leasing it but then it has to do with fluctuations and cash flow and potential exposure to risk.

But, given the what we feel is a **relatively low levels of risk associated with a PV project** we think that there's significant opportunities for both cost savings without too much exposure to risk.

In Slide 10 we also looked at that in the commercial space. We did an in-depth analysis case study with both IKEA and Staples. IKEA owns all their systems and they have over 35 megawatts of PV in the U.S. and I think over 90% of their stores. Staples also has a lot of solar. They lease all of it. So there's different ways that you can install on a commercial space. And they've learned a bunch of ways of reducing the cost through better leasing terms.

In the case for IKEA they feel like they have a chance to take a lot more of the benefits themselves by owning it and by thinking about this PV ownership on a longer term than other owners might think.

Now with that said, everyone has their own perspective of what the risk associated with a solar project are. So potentially the discount rate should be different when thinking about self-financing versus PPA.

Looking into the future and on Slide 11 we compiled a series of analysts' projections for module level pricing. Last year overall the industry generally expects that in the next few years pricing is going to be relatively flat. They'll go down a little bit. Now again this is reported price. As you can see the price isn't expected to go down too much. But this doesn't take into account potential gains through increased efficiency.

So even if something is only going down in price a little bit, the gains in efficiency might be able to lower the overall price of the system a lot greater than these reductions.

We shift to Slide 12; again this is analysts' projections on the system level. As we talked about earlier in the call there is a great degree of range in pricing out there in the market place. Most analysts still have a range in price in the future. And there's a difference of opinion of how low prices can go.

But there is still expected for the most part a continued reduction in price in the near term. We look at the long term on Slide 13. Analysts from varying places still think that PV has significant opportunity for price reductions; most analysts think that by the **2020 - 2030 range that PV prices will probably get close to these targets which**

would give PV cost-competitiveness with traditional sources of energy generation without any subsidies.

So with that I'm going to turn the mike over to Mike Woodhouse. And he's going to spend a little bit of time talking about module level re-manufacturing costs.

Mike Woodhouse: Thank you David and thank you Julien for the chance to talk today.

Looking at Slide 14 I'll just briefly say that here at NREL what we do in our bottoms-up module manufacturing costs - we first start with looking at the global supply chain for all the different components that go into the module. This data on Slide 14 is from our database that we've collected by looking at companies individually across the globe and mapping out the capacities of the different components across the globe as seen here.

And this is important because in the bottom you can see the countries listed. And in our cost modeling results we try and model the costs for those different locations across the globe.

Looking at Slide 15 you can see the breakdown for just the Asian activities in photovoltaic manufacturing. Costs are not uniform across a country, of course - for example in China, we believe there can be different manufacturing costs as you move across different provinces. Same goes for the United States or any country for that matter. Different provinces, different states have different manufacturing costs as well. This becomes important because our model results have two cases for China as we'll see in just a minute.

Looking at Slide 16 this is just an overview of the crystalline silicon supply chain. Again we look at all the parts, polysilicon ingots, wafers, cells and modules.

Slide 17 is from a paper that's been published, and for which Ran here in the room was the first author. It was published in the IAAA journal of photovoltaics. As you see here, in it, we put together our estimates of the supply curve of these different polysilicon companies with their publicly reported cash costs as the height of the bars. And the width of the bars is proportional to their market share.

So we looked at these companies individually, assessed the technologies that they're using and carry-out cost models around the different technologies. Slide 18 is a good overview of our bottoms-up methodology. We start with the process flow. So with the given technology the first question becomes what are the steps in that process. Here we see on Slide 18 the steps in making multicrystalline silicon wafers; which if you see those in modules they're the full square wafers that have typically a blueish color on the surface of them.

And on Slide 18 this is a representative process for how these wafers are made. What we do is knowing the process mapped out here we go through and collect equipment costs, material costs, etc. for each one of the steps in our model process flow.

Moving to Slide 19. This is a representative process for making the plain vanilla standard silicon cells. There are higher efficiency designs out there that typically cost more and have a higher module selling price.

But what we've got on this slide is just a representative process flow for how the standard cells are made; which typically yield **efficiencies between 17 and 20%** depending upon the company and the optimization of their manufacturing lines.

Slide 20 is an overview of the step-by-step costs. This is looking under the hood if you will of how we put together our manufacturing cost model results. Again you can see some estimate of materials and depreciation expense, maintenance, etc. for all the different steps in manufacturing.

On Slide 21 you see an overview of how the total module is put together for making crystalline silicon photovoltaics module. In this case you could tell by the shape of the wafers that these are monocrystalline silicon wafers. And in Slide 22 you can see the step-by-step costs that we've assembled for assembling modules. This is the module assembly cost only. This does not include the cost of the cells. The cell cost incorporated into the total module costs are shown on Slide 23.

So on Slide 23 this is our compilation of module manufacturing costs for different facilities across the globe; again going back to the starting point of our global database of manufacturing activities. These are our bottom-up results and above that the bars represent the total costs.

The points above the bars represent our calculation of minimum sustainable price; which is representative of an acceptable operating margin based upon a weighted average cost of capital that we calculate.

So in this plot you can see our estimates of minimal sustainable price *which do not necessarily reflect the market prices for modules*. But that again **I think we would argue that maybe some margins - especially at the module manufacturing end could be higher for the long-term sustainability of the module manufacturing industry.**

And on Slide 24, the last slide related to module manufacturing, some curves showing how the costs are

reduced as the cell efficiency goes up. This is an important point we feel because in order to reach the SunShot target one lever that can be pulled to reach that goal is to improve efficiencies of cells. **Improving cell efficiency helps not only module manufacturing costs but also systems costs**; which Ran, who here at NREL will talk about next.

Ran Fu: Thanks Mike. This is Ran, working for NREL on the System Cost Modeling Work and I try to identify the drivers behind the cost.

So on Slide 25 that's the cost breakdown for the whole model structure. So you can see all the different elements are considered in this model. And then if you go to the next slide, Slide 26, that's the results coming from this system-level cost modeling approach. Because we estimate that the different regional costs including the labor cost, the material cost and the weather condition because the wind speed and also the snow loading will affect the cost for building the PV system.

So for instance on this U.S. map a different color represents the different cost difference compared to the national medium volume. **California is a bit darker because California has higher labor rates compared to the national average. Or for instance New York, Florida, Connecticut are darker as well because they have higher labor rates and also the worse weather situation because they have more snow and the higher wind speed.**

And so if we take those install price, we can use them to calculate the LCOE. So first we calculate the dollar per watts measure and then right now we can estimate the dollar per kilowatt hour rate as well on this map.

The LCOE calculation considers a lot of additional assumptions including the incentives, the discount rates and also how you structured the financing. So the LCOE is largely

depends on those financial assumptions in addition to the install price on the previous map.

And then on the Slide 28 we can talk about what's the potential way that we are thinking about how to reduce the costs. So for instance this chart shows the cost reduction pathways excluding the module price. So that's just presumed the module price is zero. And then what's going to happen for this cost reduction pathways looks like.

So for instance we can **scale up the system sites because we can gain some economies of scale when you have a larger system size because some expense are fixed.** For instance the permeating cost, the administration costs. Those are the fixed costs.

And then you can always **increase the module efficiency because that means you will install fewer pieces of modules and use less labor to install the modules. So when you do both that's the limitation you can reach the 67 cents per watt for the module system.**

But however that's still above 50 cents per watts, the SunShot target. So that means probably people have to do **something else beyond increasing the module efficiency.**

And on the next slide, the Slide 29, the last one is to show what's the additional practice that people are using to reduce the system costs. So one is to **change the wind code** because historically people try to use the traditional design code to design the solar system. However compared to the traditional structure, a solar structure is shorter and it's lighter so it turns out the qualification that people are using is too conservative for a solar project.

And also people right now are trying to use the **preassembly method**. So people try to preassemble everything in the factory before shipping them to the field; people can use that to lower labor rates and to use some more temperature controlled practice – making it more efficient in terms of cost; and also in terms of the construction management.

So those are the two major cost reduction pathways that we have been observing during the conversation with developers and the installers.

Julien Dumoulin Smith: Excellent. Well guys that was fantastic. I very much appreciate it.

So for my first question – can you talk a little bit on how much further reduction are we talking about? How do you see the cost reductions taking place on an annualized basis - for the utility scale and also the residential?

David Feldman: Well I'll take a first stab and then have Ran correct me. So, I don't think there's one price. We already see systems going in for very low levels in certain areas, in the $1.50 a watt range or at least being quoted for these things.

So I think, even by doing nothing, there is going to be reduction that's going to occur from just these systems actually being installed. But there still exists higher priced environments.

And some of that's going to go away **through the industry just becoming more mature**. And some of that's going to go away potentially *through necessity* with the investment tax credit does either go away in the case of the 25D credit or just reduce the 10%.

So, there's a counter to that side; reductions are going to probably occur more with continued deployment. And if we're in a pricing environment that are not favorable to solar then there's going to be less deployment and so there's going to be less learning.

I think we divide the market into two categories - utilities scale or wholesale market and the DG market. **In the wholesale market most people think that by 2017 if the tax credits aren't extended, the market's going to contract significantly so opportunities for learning might not happen**. Although this is very much a global market so potentially there are opportunities to learn still overall in the global market and bring into the U.S.

From the **DG side I think most people think that there's still going to be opportunities where there are parts of the U.S. that are competitive even without the tax credit.** And there's still a lot of opportunity between where we are now and where we could be in terms of reducing financing costs and both better insulation practices and more favorable environments through better state and local laws.

But some of this is dependent on the value of the avoided cost; which is all tied in to the value of solar and how net metering occurs. And so that's largely dependent on things that haven't happened yet as the utilities try and, potentially change the way rates are structured.

Ran, if you have any thoughts , I'll turn it to you.

Ran Fu: Thanks David. I'll just add a few points. So for the engineering side or from the technology side the developers or installers - they try to find ways to reduce the cost in the field. Like one way is to use less conservative design methodologies to reduce the total amounts of the materials

and also the total amount of labor. And also try to use better logistics and preassembly method to reduce the construction costs.

So those are the part of the way that people have been using during the engineering prospect. And we have also noticed that there's a **trend for shifting the focus from the dollar per watts to the dollar per kilo-hour.** So when you have a tracker on your system your dollar per watts costs would be higher; however the return on the **dollar per kilowatt-hour is more favorable**. So by using the tracker people can actually lower the LCOE numbers so they are two defined metrics; but I think right now people put more and more attention on the dollar per kilowatt-hour. And the second case is for both DG and utility scale PV - people try to emphasize the retained price instead of the EPC cost.

For instance **using solar securitization so as to leverage the whole lifecycle of the PV system;** in some case for the size and they use the retail price so they repay more systems rather than just sell the system to the off-takers. I think those are the kind of financial innovations that will continue.

Julien Dumoulin Smith: Great. Well thank you guys. Perhaps just a follow up here in terms of what's the average efficiency today? And how much improvement in the efficiency panel are you seeing?

David Feldman: The **majority of modules are multicrystalline silicon using full square wafer**; it has 60 wafers, 60 cells inside of it - there you see about 250 - 260 watts which is around **15% efficiency**. And for **monocrystalline silicon** with the same simple manufacturing process that we outlined it's **about 16% efficiency.**

But for monocrystalline silicon there are also other brands out there such as SunPower that give much higher module **efficiencies in the 20% range.**

Mike Woodhouse: I might just add quickly I think the improvements in efficiency have been **in the past eight years or so - 1-1/2 to 2% absolute.** I think *the industry was focused on getting costs down, utilizing capacity and was potentially under-investing in efficiency type R&D*. I think we're getting to a point where costs have been squeezed down on a lot of the low-hanging fruit has been plucked. And we might start to see more of a focus on returning to higher efficiencies because that's the next way to bring down total module costs.

Julien Dumoulin Smith: Great. Excellent. How are you getting the $3.29/Watt estimate for Q4 '13 for residential costs on your slide? And also what do you think that number is today?

Ran Fu: I think this **$3.30 or $3.29 number is just the fair market value instead of the cash purchase price.** There are several different potential options that you can chose from: you can either just pick the cash or you can just use a lease. Or you can do the pre-lease so there are several different options. You can even do the zero down payment options and then pay the bill every month. In our estimates we're actually looking at the second case.

So we tried to estimate what's the break-even price if you generate the power each year and then you maintain the system whether using it or not. For instance replace the module, replace the inverter so you can actually calculate the break-even price when you do that discount cash flow calculation.

So that's why a lifetime cycle when you do the fair market value calculation compared to the overnight capital cost for

the cash purchase option. so this $3.30 is a similar way when First Solar presented this $3.30 per watts number from their financial statement.

So that's why we compare those two numbers and then try to find out if there's a discrepancy between our model number and the actual reported price. And actually it's pretty close after you consider a reasonable operating margin on top of the sales rate dollar per watts cost.

David Feldman: So just to add upon it - this is great summary by Ran and as Donald said our residential model expert is unfortunately not on the call but the **$3.29 is representative of what we feel are sustainable margins.**

And we feel like there are places out there that do not have potentially sustainable margins through a lot of factors - either lack of competition or other extraneous things that allow them to charge a higher price.

This is also not indicative of potential price increases due to,favorable accounting practices that allow higher tax credit claim. I'd also point that there still is a range in price out there.

Julien Dumoulin Smith: Great. When you talk about the wind code reductions, what exactly is that?

Ran Fu: Historically people used the ASCE 7 - the American Society of Civil Engineering code - to design every single structure for each tunnel buildings. And people used to use the same code to design the solar PV system. But however because the solar structure is so different now shorter, lighter; many people realized that historical wind code is too conservative for the PV design.

So that's why there are a lot of activities going on to try to estimate what's the more realistic wind code for a ground mounting system like the commercial or a UTCR system. A lot of installers or the Original Equipment Manufacturers try to develop their own wind code by using the wind color test.

So the result from the wind color test is more realistic and that is more suitable for a solar PV because it is a customized wind code, rather than just using the generic wind code from the book.

Mike Woodhouse: Right. I might just clarify - when Ran says different code, it's not actually a different code but rather it's just plugging in more refined assumptions specific to solar structures. So there is nothing in the code, for example, about a solar mounting system.

And those factors as applied to solar structure are typically too conservative. And so by using wind tunnel testing, you can get a more appropriate assumption within the greater context; but still have the same structural code.

But the **end result is loads are lighter, foundation requirements will be less, material will be less etc. Any that labor can be reduced because it's a slightly simpler structure. So it's not a different code it's just different assumptions within the code that are more appropriate for solar-specific structures.**

Julien Dumoulin Smith: It appears in the bottom-up model in your slide, that the balance of system is the majority of cost. But according to what we are seeing in the market is that the modules 32 to 45%, inverter being 8-12 and Balance of System is the balance. It appears that the bottom-up slide contradicts this.

So can I ask how you came up with the Balance of System costs. They're basically saying the module is 40%, the inverter is 10% and the Balance of System is more but perhaps a little bit shifted in your discussion.

Ran Fu: So I think that's a way to unify the formats. Because actually for instance on the Slide 29 the BOS, the Balance of System is defined for racking foundation ACDC materials: only for those items and not including the labor, land, permitting, internal connection. So we're actually talking about two different BOS.

But on Slide 29 the BOS is more specific for those materials. So if you want to do the math check then we can maybe sum up the BOS from table on the Page 29 so that's 17 cents for BOS, 14 cents for installation and 11 cents for development and the sum for overhead and profit. So those will all match up.

I think the discrepancy just came from the different category, how we define the categories.

Julien Dumoulin Smith: But just to be clear - so the 67 cents you're showing here for like an at scale system - how does that relay back to the $1.80 that you show for a utility ground mount fixed access for 4Q '13.

Ran Fu: So the $1.80 is using the 185 megawatt, project size and was 15% for module efficiency. So for instance on Slide 28 there are four different arrows representing four different project size; but none of them represent a 185 megawatt project size. But the closest one is the 150 megawatt using the 15% module efficiency. That's about 29 cents excluding the module. So if we consider 70 cents for module then that will be roughly $1.70 for total system. So that's just different categories.

Mike Woodhouse: Yes to clarify 28 and 29 are roadmaps right. So, when we start at on the left on Slide 28 for example $1.14 that's kind of where we are today for a five megawatt system at a 15% module efficiency. And so what Ran was trying to show on this slide is well, what is the effect of scale module

efficiency or both. So 67 cents is not intended to be a benchmark of today or even the near future.

That's what could be possible if you could scale up to what's shown and have modules at a 25% efficiency; which by the way aren't real yet. So that 67 is one stop on the roadmap.

Julien Dumoulin Smith: Right. All right. So that's fair - a cool apples and oranges.

Two other basic questions coming through. First one, what do you estimate the dollar per megawatt hour impact is on PPA prices for losing the ITC. And this may be a little bit of a trick question because it's asking basically what is the cost offset as you see the production costs coming down through that period as well?

Maybe separated out, what's the ITC impact first and foremost? And then secondly how much cost reductions do you expect through that period to effectively offset it? Or to what extent can it offset it?

David Feldman: I'll just say that Mark Bolinger did a great report. It came out a few months ago. He's from Lawrence Berkeley National Lab, where he talks a bit about this. I mean just to get a sense of the question, without the tax credit potentially you could get a lower cost financing through cheaper investors plus banks, have a higher loan.

Potentially use cheaper capital through either yield cos or banks but obviously you're going to lose that very significant benefit. But the paper found - - I don't have it in front of me - - but basically, **the 30% is still a better option even with higher financing; but at 10% it's potentially more beneficial to use, to potentially forego the ITC and get the cheaper financing.**

So I guess the short answer is we don't have a calculation in front of us but it's going to be somewhat of a trade-off. And I would point to the other analysts who probably did the calculation when they made their assessment that there is an expectation that there will be a **drop off in utility scale deployment when the ITC is reduced**.

Julien Dumoulin Smith: Right. Absolutely. through 2016, where do you see PPA prices trending? So Georgia we saw $65/MWh recently, Texas so they saw it was $50/MWh. What kind of absolute dollar level PPA prices are you thinking about, broadly speaking and using those as reference points?

David Feldman: I think those numbers are going to **depend on the region. I don't predict that prices are going to get too much lower than those numbers that you quoted - so the 4-1/2 to 5 cents is the low end. But potentially those will open up in more markets.**

So it's not just about having those prices, it's about getting those prices in more markets. So you've seen places open up to solar like Utah and Idaho where it's such a cheap energy markets already; but now solar is a viable option. And so I think it's more about the expansion of opportunities in the U.S. rather than 4-1/2 cents going much lower.

Ran Fu: And just to add one point - there are so many different financial assumptions. For example that WACC, the Weighted Average of Cost of Capital on Slide 27 was using 10.9%. However if you try to leverage the benefits from the (unintelligible) then you can probably lower this cost. And then when you have a lower discount rate the LCOE calculation will be totally different. So that also depends on the different assumptions that you have.

Julien Dumoulin Smith: Right. Great. Why are the costs based on 60 cell panels versus 72 cell and what is the price-based on module size?

David Feldman: Roughly the same. Some costs are fixed. For example if you look at the back side of a module you'll see a junction box. And if you have more watts coming out of a module because it's larger than your $4 to $6 dollar junction box becomes lower cost in dollar per watt terms for example.

I think that the larger format modules have the savings more in the Balance of Systems installation. You guys can correct me if I'm wrong.

Mike Woodhouse: Maybe. I mean they're still roughly the same efficiency so overall area efficiency is kind of the same. You might save in labor because it's less handling.

David Feldman: But I think we typically look at **60 cell because it's still most of the market**. And so it's more common but yes, to Mike's point, the overall pricing per watt is probably the same and the cost is probably about the same per watt.

Julien Dumoulin Smith: Right. Perhaps to summarize the call here. If I could ask high-level, what are the major factors bringing down costs? And how much cost do you see going down, for Balance of System versus modules? I mean are we talking about modules going down a further 10 - 20 cents to the decade and then Balance of System another X percentage further? And from where do you have the greatest confidence in the cost reductions? Just as a summary.

David Feldman: I'll start it off and then let the others finish it. Percentages are tough because it depends when you're starting from. I think there's great opportunity with **lower financing costs** with new innovations that are happening in the market place. And particularly, if the tax credit doesn't get extended there'll be opportunities for significant reductions in financing costs and the squeeze in the markets.

And because solar is growing so much there's a lot more transparency and cost reduction through just the growth and maturation of the industry. So if we point to other markets out there in the world we're still from a pricing perspective towards the higher end.

Mike Woodhouse: Yes I would say there's some **supply chain costs**. Some fat in the supply chain that could be trimmed once there's bigger scale to achieve more learning. Some of the materials that go into making a module could come down in price. Although some of it's commoditized - the glass, the frame, that kind of thing. But in the manufacturing process to make the cells there's cost reduction opportunities certainly.

Ran Fu: For Balance of System or for a system level cost reduction I think those two ones that we just mentioned - revise the wind code and or pre-assembly etc. And also those are not imagination because people are using those two methods to reduce the costs. So those are the ongoing practice to help people to reduce their costs. And so I will say people are on the learning curve to adopt more and more from those two different practice to reduce the costs.

Julien Dumoulin Smith: Great. Excellent. Well it's five past the hour so I don't want to hold up people too long. But this is fantastic. Thank you to the whole team for taking the time.

END

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