British Columbia Solar Market Update 2015

- Final Report -

Prepared for:

BC Hydro | **Fortis BC**

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1. Introduction

Compass Renewable Energy Consulting Inc. has prepared this solar market update to BC Hydro and Fortis BC Inc. to provide a current overview of solar technology and price and performance expectations in British Columbia.

Compass has been involved in supporting Ontario developers and owners of solar assets since 2011, and its principals have been involved in the solar industry for over 25 years. Compass has also undertaken US and global market support to clients assessing conditions in other jurisdictions to guide investment decisions.

Most market pricing information comes from Ontario and US experience, however the prevalence of solar developers operating globally means that the experience and commodity costs of solar components is transferable to most Canadian jurisdictions.

Two types of cost data are used in this report. First, reported data is recorded as of the date it was obtained and second, modeled or bottom-up data is derived from price quotes or bids. There is far more data available from the U.S., and most research reports are provided in USD. Some Ontario-specific experience and costing in CDN has been considered in drawing conclusions and considerations for British Columbia.

2. Technology Trends for Solar Electrical Energy

a. Evolution of Solar Technology

Since 2009, market prices for solar photovoltaic (PV) panels or modules have dropped five-fold, with system prices dropping three-fold. PV systems are being built on scales of a few kW to hundreds of MWs. Solar power makes up 5.3% of German electrical consumption, 7% of Italian consumption, and over 3% in five other European countries in 2013. Total installed capacity has risen from 23 GW in 2009 to 135 GW at the end of 2013. Annual installed capacity has jumped from 7 GW to 37 GW in the same time.

Crystalline silicon (c-Si) modules have a ~90% share of the total solar PV market. Thin-film modules comprise 10% of the market, and concentrating PV less than 1%.[1] Thin-film

[1] International Energy Agency, *Technology Roadmap – Solar Photovoltaic Energy 2014 Edition* http://www.iea.org/publications/freepublications/publication/TechnologyRoadmapSolarPhotovoltaicEnergy_2014edition.pdf

and non-crystalline technologies (CdTe, CIGS, a-Si etc.) had been expected to gain market share, but instead their share has shrunk by 5% since 2009.

Compared to photovoltaic solar technologies, Concentrating Solar (thermal) Power (CSP) uses the sun to heat a working fluid whose heat is then generally used to drive a steam turbine. As such, it provides all necessary ancillary services and has an ability to store thermal energy – thus reducing the potential for intermittence. CSP deployment has been much slower than expected since 2009.[2] The focus of this report will be on solar PV. As will be seen, it is more appropriate than CSP for deployment in British Columbia.

b. Current Solar Technology Options

Solar PV systems use semiconductors to generate direct current electricity. Solar cells – typically silicon – are sliced from larger wafers or ingots, arranged into modules surrounded by glass on the front and a frame surrounding the module and giving it structural support. Systems include inverters and balance of system components, which consist of transformers, wiring, racking and other structural components used for mounting, and potentially also tracking components and monitoring devices. Thin-film technologies use materials other than silicon and are typically not made of cells but rather are photovoltaic material deposited onto a larger module-sized area. Thin-film modules are often less efficient than crystalline silicon modules – 15% efficiency for CdTe thin film versus 19-21% for the best c-Si modules, both in 2013.[3]

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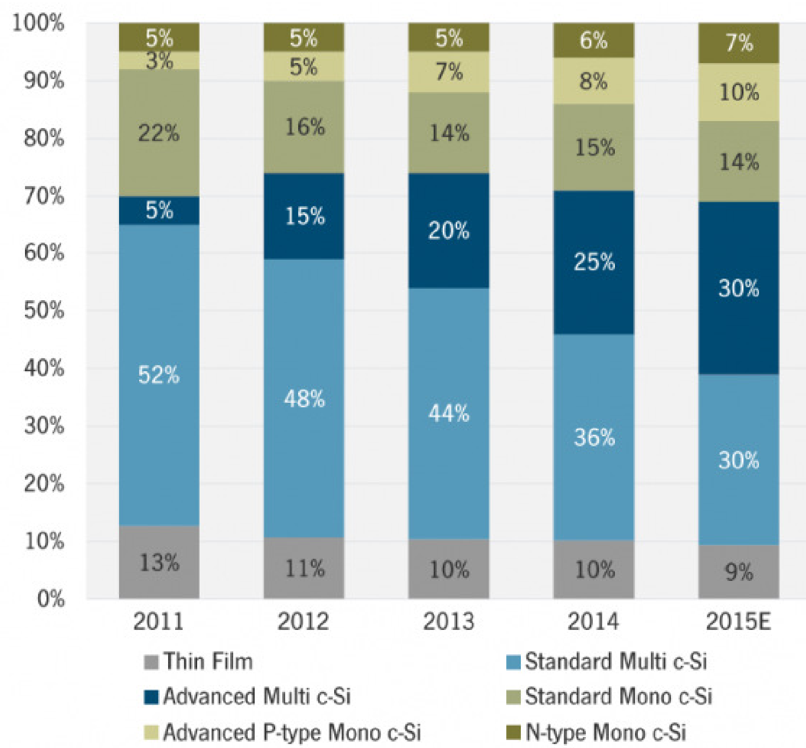
[2] International Energy Agency, *Technology Roadmap – Solar Thermal Electricity 2014 Edition* http://www.iea.org/publications/freepublications/publication/technologyroadmapsolarthermalelectricity_2014edition.pdf

[3] International Energy Agency, *Technology Roadmap – Solar Photovoltaic Energy 2014 Edition* http://www.iea.org/publications/freepublications/publication/TechnologyRoadmapSolarPhotovoltaicEnergy_2014edition.pdf

The market share of thin-film and standard c-Si cell technologies has been and is expected to continue to drop, as more advanced and efficient c-Si technologies are adopted (see

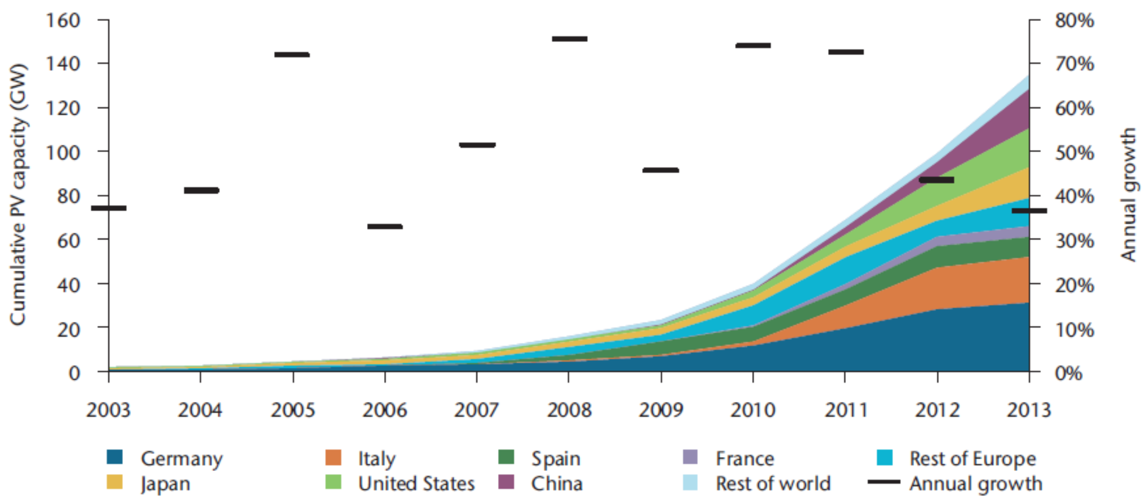
Figure *1* below).

Figure 1 – Global PV Market Share by Cell Technology 2011 - 2015 (GTM Research)



The annual growth rate of global cumulative solar PV installed capacity has grown by 49% on average since 2003 (
Figure 2).[4]

Figure 2 - Global Cumulative Installed Capacity and Growth Rate of Solar PV (IEA)



Solar thermal systems with storage provide firm, dispatchable energy that can be better matched to late-afternoon and evening demand peaks, for example. Considering that PV generation is most productive in the middle of the day, it can be said that PV and CSP with storage are complementary technologies from a grid perspective. CSP plants or alternative storage technologies will become more valuable as PV market share increases.[5]

The main CSP technologies are Linear Fresnel Reflector (LFR), towers or Central Receivers, Parabolic Dish (PD) and Parabolic Trough (PT).

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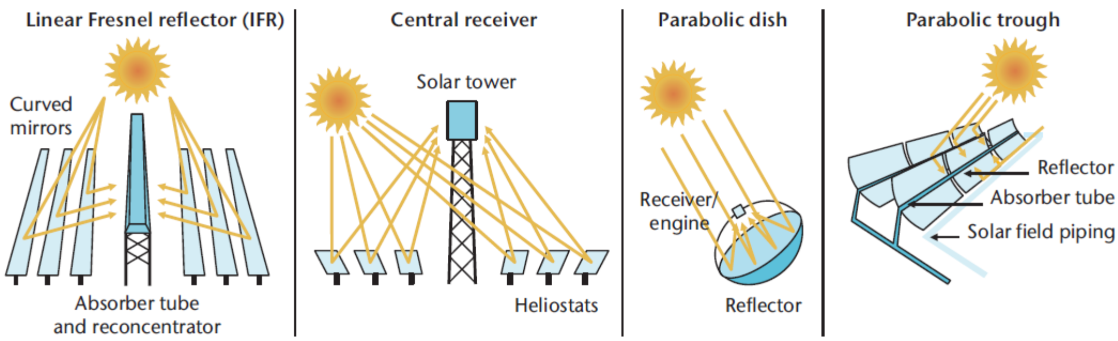
[4] International Energy Agency, *Technology Roadmap – Solar Photovoltaic Energy 2014 Edition* http://www.iea.org/publications/freepublications/publication/TechnologyRoadmapSolarPhotovoltaicEnergy_2014edition.pdf

[5] International Energy Agency, *Technology Roadmap – Solar Thermal Electricity 2014 Edition* http://www.iea.org/publications/freepublications/publication/technologyroadmapsolarthermalelectricity_2014edition.pdf

Figure 3 illustrates the operation and setup of these technologies.

Figure 3 - Primary Solar Thermal Technologies (IEA)



CSP generally requires good irradiation and often clear skies, compared to solar PV.[6]

Direct Normal Irradiance (DNI) is especially important to CSP facilities because thermal losses and parasitic consumption are nearly constant, regardless of the amount of sunshine received by the facility. Below a certain level of daily DNI, the net output of the plant is negligible. DNI is much more affected by clouds than the geographic distribution of irradiance.

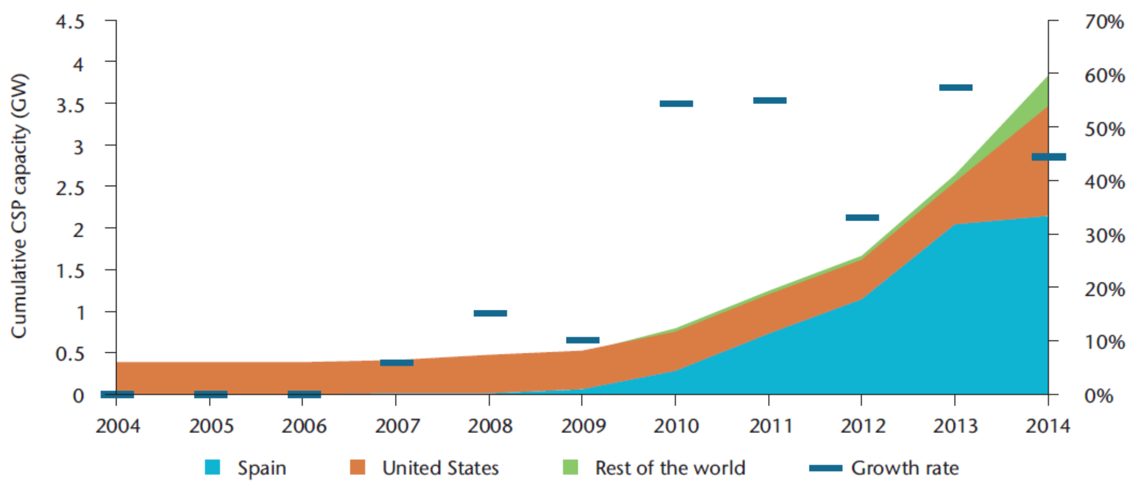
High DNI regions are hot and dry and usually have clear skies. These are usually within subtropical latitudes from 15° to 40° north or south. Higher elevations also usually have higher DNI. More equatorial latitudes are too cloudy, and higher latitudes often have cloudy conditions.[7]

[6] International Energy Agency, *Technology Roadmap – Solar Photovoltaic Energy 2014 Edition* http://www.iea.org/publications/freepublications/publication/TechnologyRoadmapSolarPhotovoltaicEnergy_2014edition.pdf

[7] International Energy Agency, *Technology Roadmap – Solar Photovoltaic Energy 2014 Edition* http://www.iea.org/publications/freepublications/publication/TechnologyRoadmapSolarPhotovoltaicEnergy_2014edition.pdf

Global cumulative installed capacity of CSP facilities, and its rate of growth, has been increasing in recent years (Figure 4)[8], however represents only approximately 3% of the installed capacity of solar technologies.

Figure 4 - Global Cumulative Installed Capacity and Growth Rate of CSP (IEA)



i. Solar: 100 kW to 1 MW

Solar PV installations in this size category are often distribution connected and often sited near or at the end-use electricity customer. Solar PV projects of this scale can be procured under British Columbia's Standing Offer Program.

Due to regulatory and permitting restrictions, solar PV projects of this size are often mounted on the roofs of buildings. A common solar application for this project size range is rooftop solar that is typically designed to reduce the site consumption of electricity by the end use customer. The common technology deployed is c-Si as the installed capacity on a rooftop is limited by usable rooftop space. Due to the higher conversion efficiency of c-Si versus thin film, c-Si is the preferred alternative to minimize the footprint of the solar facility on the rooftop.

[8] International Energy Agency, *Technology Roadmap – Solar Thermal Electricity 2014 Edition* http://www.iea.org/publications/freepublications/publication/technologyroadmapsolarthermalelectricity_2014edition.pdf

CSP is not suited to this size category due to the high fixed costs of the concentrator technologies and the need to off-set these relatively high costs over a larger project size.

ii. Solar: 1 MW to 5 MW

Solar PV projects of this size are not often designed to offset customer demand, and are at the small end of utility scale projects. They are more common in jurisdictions that have less available land area for solar farm installations.

Due to interconnection costs, projects in this size category are often distribution connected onto a feeder or directly into a distribution sub-station.

Depending on the project site, a solar PV project of this size would likely be limited to a single property, and a 5 MW project would require approximately 27.5 acres of land[9]. Projects of this size and cost typically require a long term PPA with a utility for financial support.

CSP is not suited to this size category due to the high fixed costs of the concentrator technologies and the need to off-set these relatively high costs over a larger project size.

iii. Solar: Over 5 MW

Solar PV installations in this size category are utility scale and can be sized as large as hundreds of MW given suitable available land area and grid connection capability. Utility scale commonly refers to projects in the 5-20 MW range, or greater.

Projects that are 10 MW or greater in this category are often directly connected onto a transmission circuit, depending on the requirements for generator connections in the jurisdiction.

Depending on the project size, a solar PV project of this size may be located on a single property or spanning multiple properties, and would require approximately 5.5 acres of land per MW[10]. Projects of this size and cost typically require a long term PPA with a utility for financial support.

[9] NREL Land Use Requirements for Solar Power Plants in the US, June 2013

[10] NREL Land Use Requirements for Solar Power Plants in the US, June 2013

CSP is most suited to this size category due to the high fixed costs of the concentrator technologies and the need to off-set these relatively high costs over a larger project size. The average size of solar thermal systems operational worldwide is ~60 MW, with parabolic trough the most common technology used. They are thus most common at this larger scale. There are currently approximately 60 solar thermal facilities in operation worldwide[11]

3. Solar Potential in British Columbia

a. Methodology

Two sources of solar irradiation projections were used in assessing and comparing the solar resource in different parts of British Columbia, NRCan (Cartes PV Maps) and PVWatts. NRCan's maps describe a solar system in kWh/kW/a featuring a fixed axis, tilt equal to the system's latitude, and azimuth of due South (180 degrees). System performance in Ontario correlates closely with projections from NRCan Carte. PVWatts does the same but can also analyze fixed, single and dual axis trackers. Compass found other sources of solar resource data, and these forecasts are available and will be validated by actual system performance from projects in British Columbia.

b. Technical and Financial Implications

Various fixed, dual-axis and single-axis tracking systems are available. Dual-axis trackers are most efficient from a kWh/kW perspective, but also are the most costly and require the most ongoing maintenance. Fixed systems also generally are less effective at more Northern latitudes.

Choosing the correct technology for a given project involves a trade-off between system efficiency (kWh/kW) and overall project economics and cost (LCOE, or $/kWh).

c. Environmental Characteristics and Development Timelines

British Columbia's Environmental Assessment (EA) Process measures the impact of major projects, and ensures that projects meet environmental, economic and social sustainability, heritage and health goals. The concerns of the public, First Nations,

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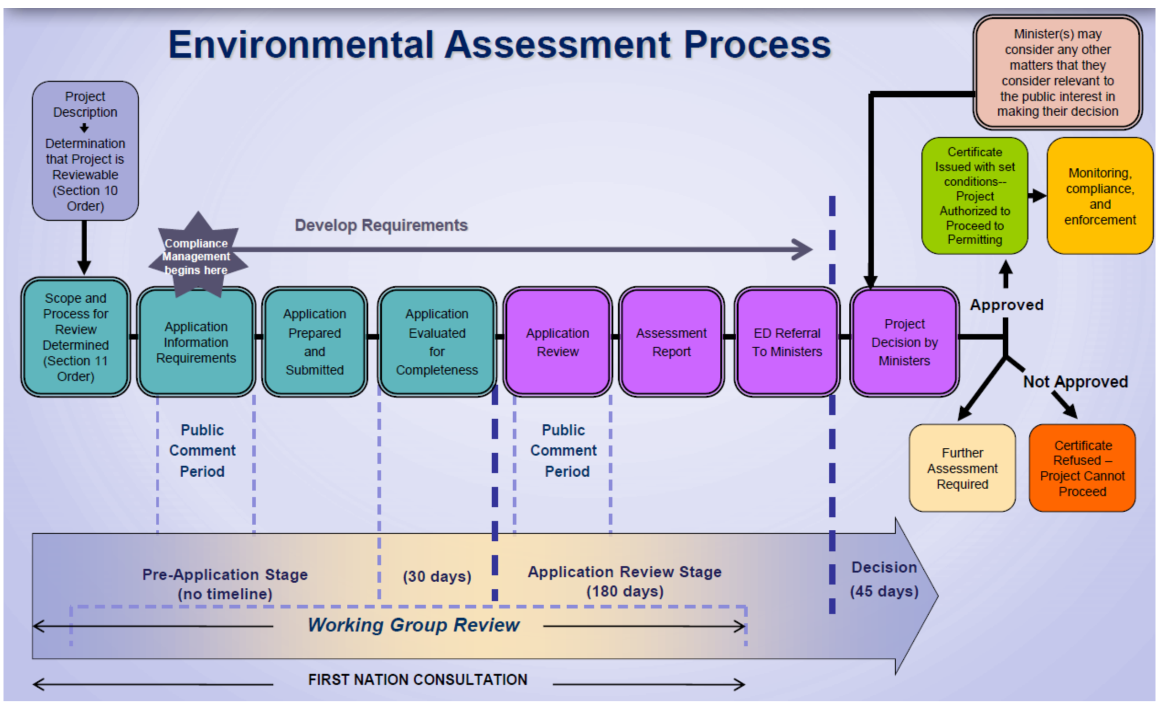
[11] Wikipedia, List of Solar Thermal Power Stations, accessed on February 27 2015, http://en.wikipedia.org/wiki/List_of_solar_thermal_power_stations

interested stakeholders and government agencies are considered. There is a 50 MW threshold for triggering BC's EA process. The Environmental Assessment Office manages this process under the Environmental Assessment Act. The process includes:

- Opportunities for the involvement of all interested parties;
- Consultations with First Nations;
- Technical studies to identify and examine potential significant adverse effects;
- Strategies to prevent, or reduce, adverse effects; and
- Development of comprehensive reports summarizing input and findings.

The process can also be displayed as shown in Figure 5 below.

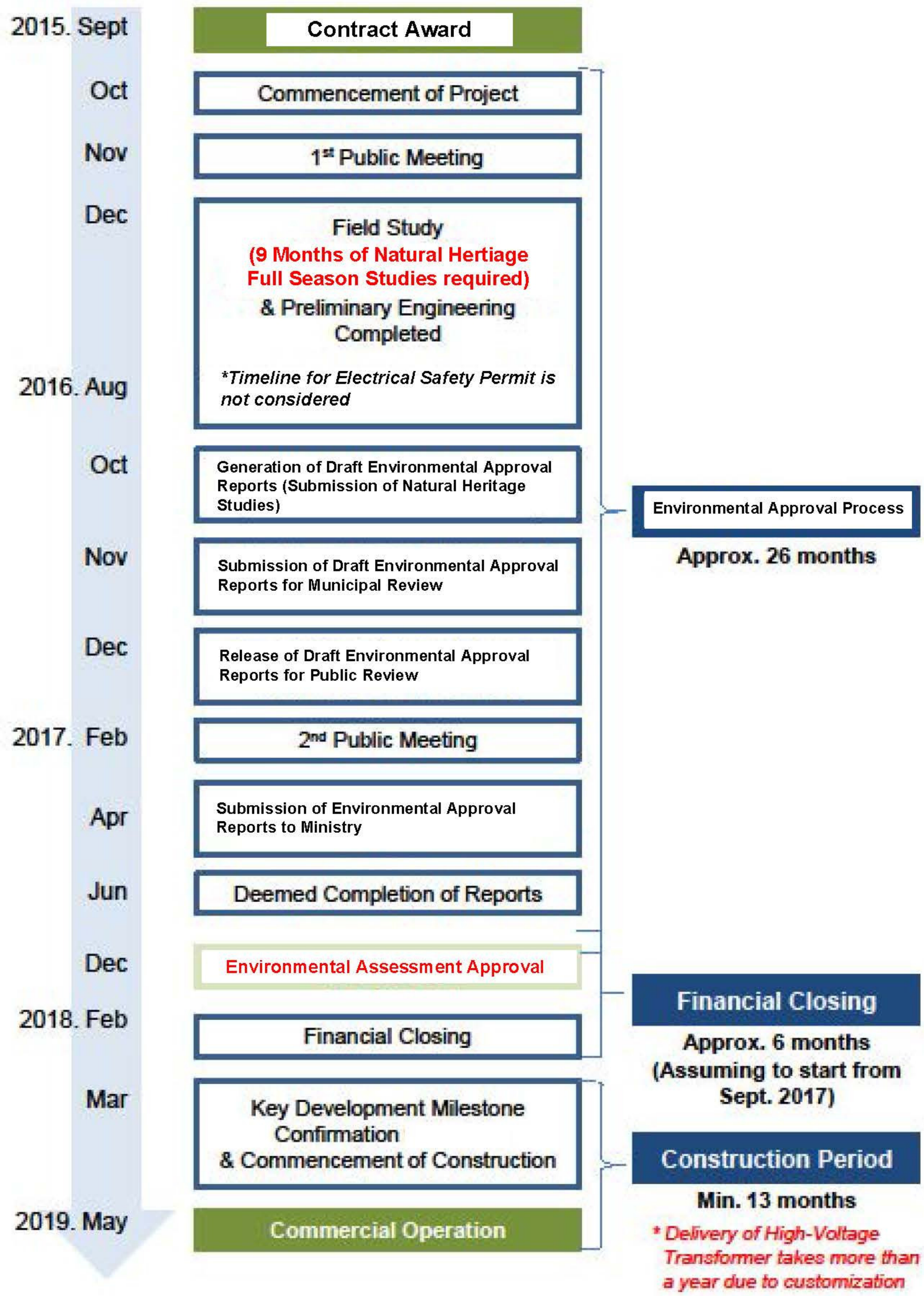
Figure 5 - Stages in Environmental Assessment Process (Province of BC)



CanSIA created a project development timeline (Figure 6) for consideration to the Ontario government that included a 26 month timeline for environmental approvals, within an overall 3 – 3.5 year project development timetable. This timeline is Ontario-specific, and environmental approval process requirements and local community consultations will affect this timeline.

Figure 6 - Development Timeline for Large-Scale Solar Project in Ontario (CanSIA)

Development Timeline for Large Scale Solar Project

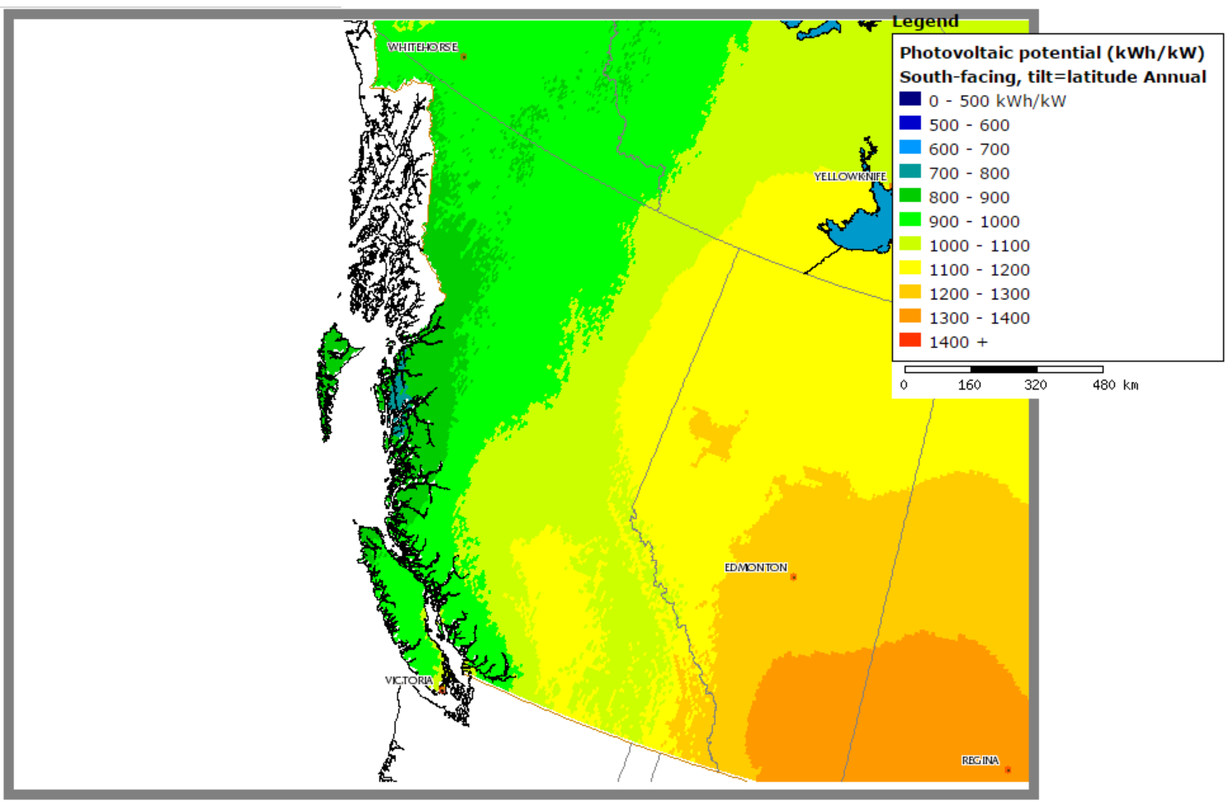


4. Potential Sites Across the IRP Regions

Solar irradiation maps are publically available using historical local weather station data. Experience in Ontario has shown close correlation with these projections.

Figure 7 below shows the NRCan Cartes PV Map used to find and generate the solar potential values for these sites.

Figure 7 - BC Solar Potential (NRCan Cartes PV Maps)



Fourteen sites were chosen within British Columbia for analysis of solar potential, listed below in Table 1 with their fixed-axis annual solar potential (azimuth of due South, tilt equal to latitude):

Table 1 - Sites for Solar Potential Analysis and BC Transmission Region

Transmission Region Number	Transmission Region Name	Analysis Site	Solar Potential (kWh/kW/a)
1	Vancouver Island	Victoria	1091
2	Lower Mainland	Vancouver	1009
2	Lower Mainland	Powell River	1019
3	North Coast	Vanderhoof	1039
4	Central Interior	Horsefly	1113
5	Peace Region	Fort St. John	1162
6	Revelstoke	Vernon	1131
7	Mica	Chase	1132
8	Selkirk	Osoyoos	1134
8	Selkirk	Kelowna	1133
8	Selkirk	Trail	1120
9	Kelly/Nicola	Kamloops	1160
10	East Kootenay	Elkford	1236
10	East Kootenay	Cranbrook	1227

Table 2 shows the relative solar potential of fixed, single and dual-axis trackers for some of the sites listed above. The percentage system loss used in PVWatts was varied so that the identical fixed-tilt scenario matched the results of NRCan, for better comparison of tracker technologies. Matching results required a 18% (i.e. Victoria) – 26% (i.e. Fort St. John) system loss for the various sites compared to the default 14% system loss in PVWatts – compensating for the otherwise more optimistic solar potential projections of PVWatts.

Table 2 – Solar Potential of Select Sites with Fixed, Single and Dual-Axis Trackers in PVWatts

Analysis Site	Solar Potential with Fixed System (kWh/kW/a)	Solar Potential with Single-Axis Tracker (kWh/kW/a)	Percent Increase from Fixed System with Single-Axis Tracker	Solar Potential with Dual-Axis Tracker (kWh/kW/a)	Percent Increase from Fixed System with Double-Axis Tracker
Vancouver	1010	1224	21.2%	1386	37.2%
Victoria	1092	1364	24.9%	1570	43.8%
Kamloops	1157	1429	23.5%	1640	41.7%
Fort St. John	1157	1421	22.8%	1658	43.3%

Table 3 - *Monthly Solar Potential of Select Sites with Fixed Systems in*shows the estimated monthly solar production for the same select four sites with a fixed system.

Table 3 - Monthly Solar Potential of Select Sites with Fixed Systems in NRCan Cartes (kW/kWh/a)

Month	**Vancouver**	**Victoria**	**Kamloops**	**Fort St. John**
January	41	43	49	59
February	53	57	68	80
March	86	95	111	122
April	99	108	118	128
May	108	118	124	122
June	110	118	122	121
July	123	130	133	121
August	121	128	131	117
September	112	123	119	99
October	75	88	93	84
November	43	47	52	58
December	37	39	40	50

The 14 analysis sites are shown in Figure 8 below. These sites were chosen to reflect a range of different geographies, population size, and solar potential, while at the same time ensuring a location in each transmission zone.

Figure 8 - Sites for Analysis of Solar Potential

Figure 9 below shows a map of BC Hydro's Transmission Planning Regions, with the 14 sites studied for solar potential marked in red.

Figure 9 – BC Hydro Transmission Planning Regions

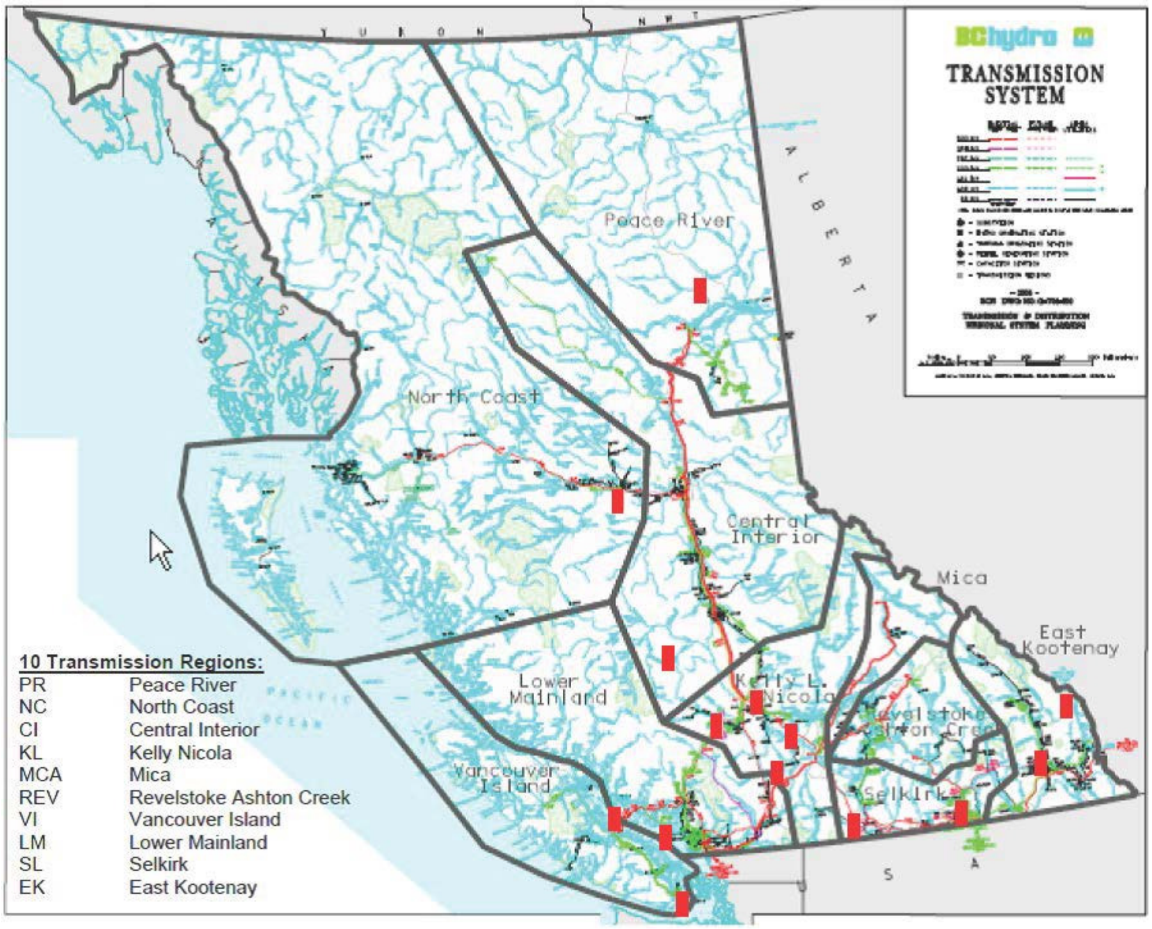
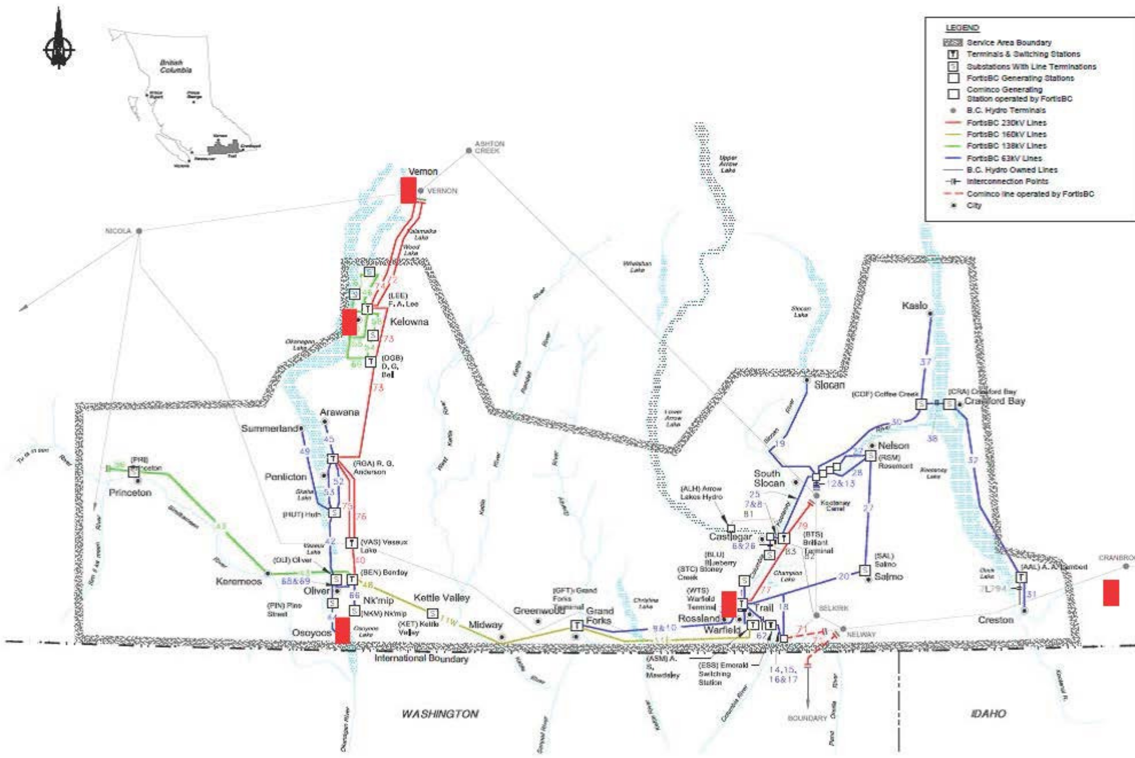


Figure 10 below shows the Fortis BC service area in more detail, with the 3 sites studied for solar potential within the service area marked in red.

Figure 10 - Fortis BC Service Area

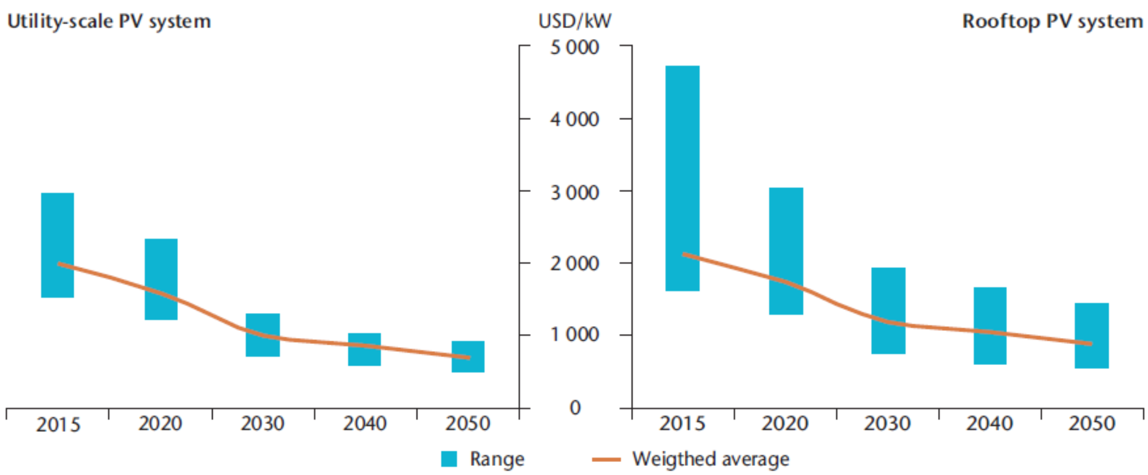


5. Current and Future Cost of Solar System Components

a. Fixed and Tracking PV

Various technologies and processes under development will further lower the cost of solar PV in the near term. The current path for conventional solar technologies is improving and continuously reducing in cost. Other new disruptive solar technologies are unlikely to play a major role in the near term, due to the time lag from innovation to commercialization. In the long term, the IEA predicts PV systems will be half the cost of today by 2040 (Figure 11). Utility scale is commonly used to describe systems from 5-20 MW and larger.

Figure 11 - Utility Scale and Rooftop PV System Cost Projections (IEA)

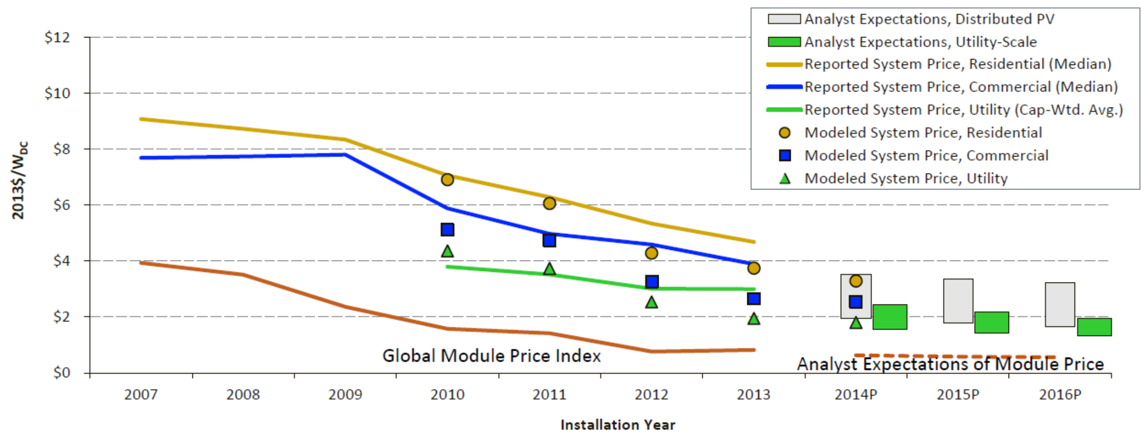


Cost declines have continued in spite of more stabilized module prices; system cost dropped 10-15% in California in the first half of 2013 with stable module prices. Cells and modules are an international commodity and vary much less than installed system costs. This difference can be attributed to soft costs like customer acquisition, permitting, inspection and interconnection, installation labour and utilization efficiency, and financing.[12] U.S. system costs are expected to continue to drop into the near future (see Figure 12 below).[13]

[12] International Energy Agency, *Technology Roadmap – Solar Photovoltaic Energy 2014 Edition* http://www.iea.org/publications/freepublications/publication/TechnologyRoadmapSolarPhotovoltaicEnergy_2014edition.pdf

[13] U.S. Department of Energy, *Photovoltaic System Pricing Trends 2014 Edition* http://www.nrel.gov/docs/fy14osti/62558.pdf

Figure 12 - U.S. PV System Prices over Time (Sunshot, USD)

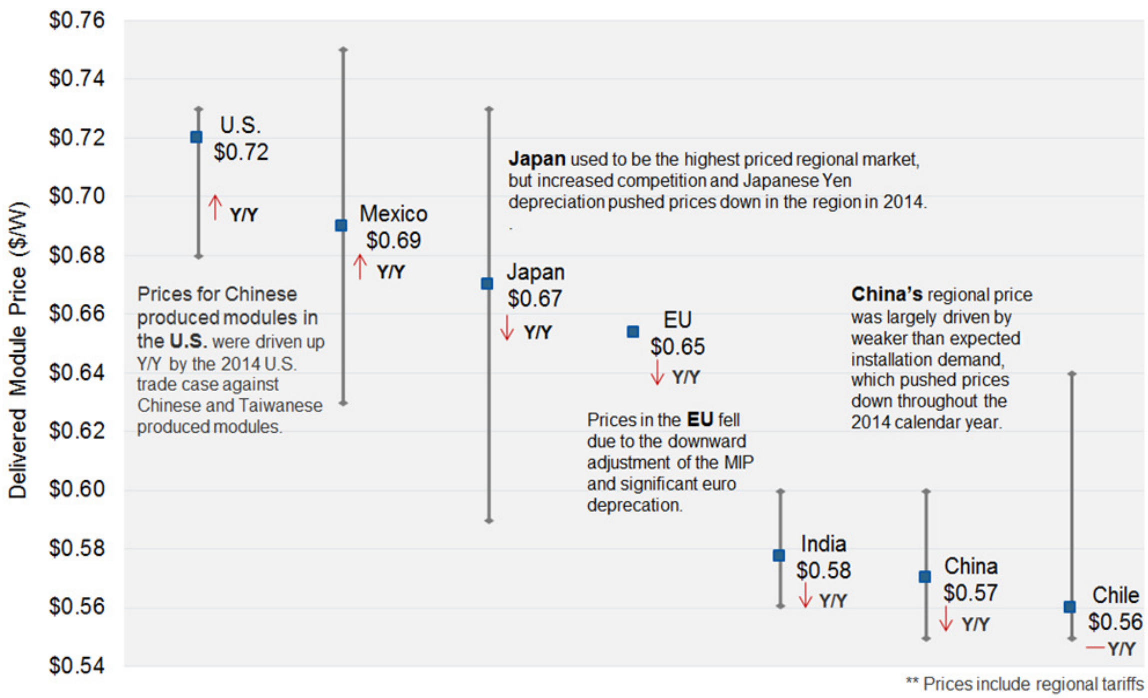


Both the system cost and difference in relative production has narrowed between fixed and single-axis solar PV systems recently.[14]

[14] International Energy Agency, *Technology Roadmap – Solar Photovoltaic Energy 2014 Edition* http://www.iea.org/publications/freepublications/publication/TechnologyRoadmapSolarPhotovoltaicEnergy_2014edition.pdf

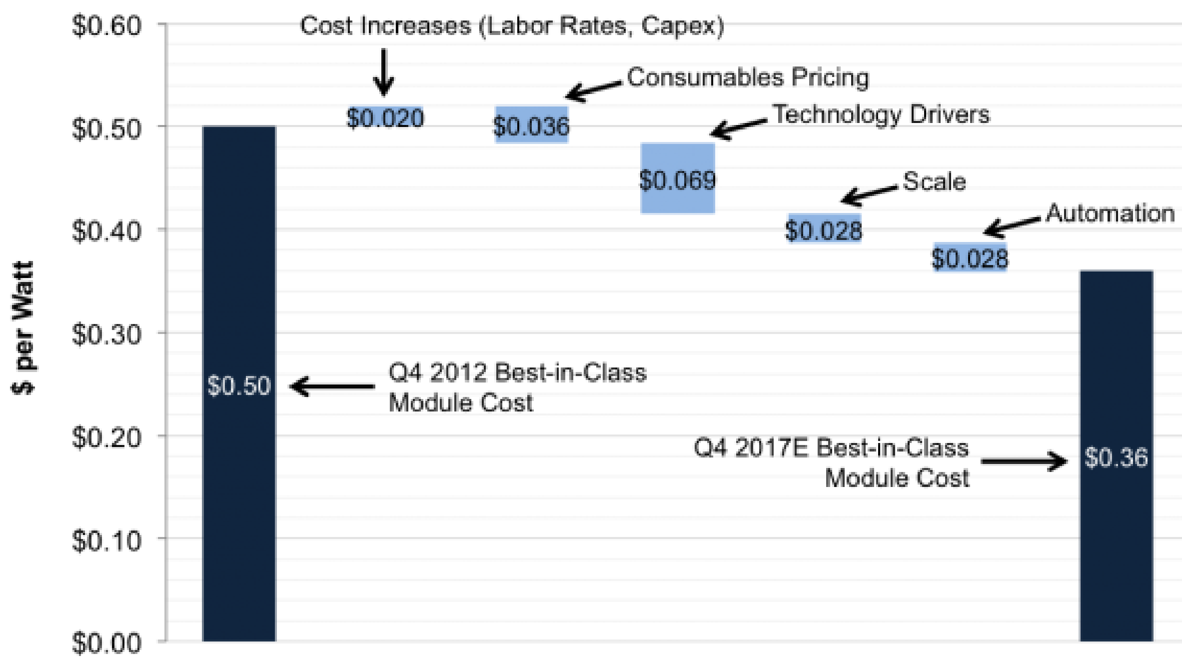
There is a large degree of variability in the regional pricing of modules. For a Tier 1 Chinese c-Si module, prices range from $0.72 in the U.S. to $0.65 in the EU to $0.56 in Chile (see Figure 13 below). Although modules exhibit commodity pricing in general, regional and country-specific duties, tariffs, taxes and equipment standards can contribute to price deviations.

Figure 13 - Regional Price Variation for a Chinese Tier 1 Module in Q4 2014 (GTM Research, USD)



It is expected that the production cost for first-tier Chinese c-Si module manufacturers will drop from $0.50/W at the end of 2012 to $0.36/W at the end of 2017 (Figure 14).[15]

Figure 14 - Expected Chinese c-Si Module Cost and Key Drivers (GTM Research, USD)



Solar PV modules are also projected to become more efficient through the adoption of new high-efficiency c-Si cells, which now have a lower LCOE or $/kWh compared to simpler c-Si or thin film technologies (see Figure 14).[16]

i. Solar Costs: 100 kW to 1 MW

The U.S. DOE Sunshot Initiative, looking at work by NREL and LBNL, estimates that systems quoted in Q4 2013 and installed in 2014 in the U.S. were likely to have been done at $3.29/W for residential (~5 kW) and $2.54/W for commercial (~200 kW). By comparison, estimated (partially reported) prices for systems installed in 2013 were $4.69/W for residential and small commercial (<= 10 kW) and $3.89/W for large

[15] Greentech Media, *8 Solar Trends to Follow in 2015*, accessed on February 27 2015, http://www.greentechmedia.com/articles/read/The-Most-Important-Trends-in-Solar-in-8-Charts

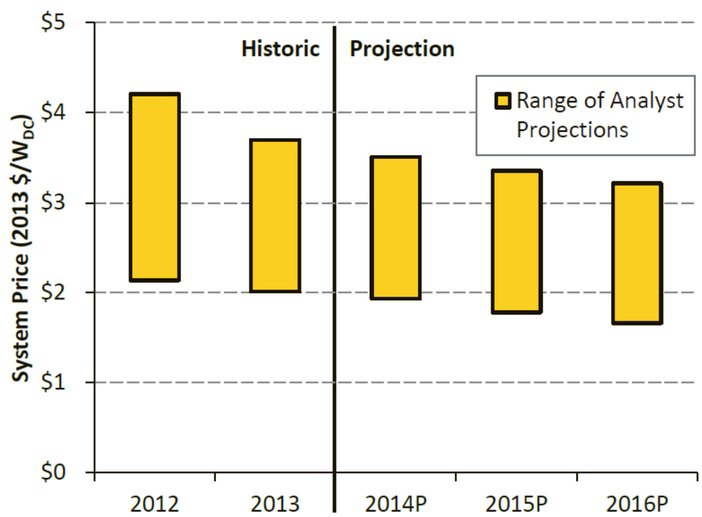
[16] Greentech Media, *Solar PV Module Costs to Fall to 36 Cents per Watt by 2017*, accessed on February 27 2015, http://www.greentechmedia.com/articles/read/solar-pv-module-costs-to-fall-to-36-cents-per-watt

commercial (>100 kW).[17] The Sunshot study also found that price reductions for residential and small commercial systems are increasing, averaging 6-7% per year from 1998-2013, but 12-15% from 2012-2013.

Commercial PV systems vary more significantly than utility scale systems – they can be more than twice as expensive in the U.S. as in Germany, for example.[18]

Analysts' projections for the global average near term price of distributed scale systems describe a price of $1.50 - $3.00 by 2016 (Figure 15).

Figure 15 - Recent Analyst Estimates (2012-2013) and Projections (2014-2016) of Global Average Distributed System Price (Sunshot based on Various Sources, USD)



[17] U.S. Department of Energy, *Photovoltaic System Pricing Trends 2014 Edition* http://www.nrel.gov/docs/fy14osti/62558.pdf

[18] International Energy Agency, *Technology Roadmap – Solar Photovoltaic Energy 2014 Edition* http://www.iea.org/publications/freepublications/publication/TechnologyRoadmapSolarPhotovoltaicEnergy_2014edition.pdf

ii. Solar Costs: 1 MW to 5 MW and Solar Costs: Over 5 MW

In 2013, over 3GW of utility-scale solar was installed in Canada and in the U.S. This represented 43% of all new capacity additions in Ontario (337 MW) and 30% of that in the US (2847 MW). Ontario ranked second in North America behind California for new utility-scale solar.[19]

A confluence of the decreasing capital costs and low cost of capital makes utility-scale solar competitive with day-time retail electricity prices in many markets today.[20]

Large central PV systems cost less than $1.50/W in 2013 in the U.S. , according to the IEA.[21] The U.S. Sunshot Initiative, using reported pricing in part, estimated that utility scale (equal to or greater than 5 MW) cost $3.00/W on a capacity weighted average in 2013. This discrepancy can likely be explained by a difference in the scale of systems examined, perhaps due to many smaller systems in the Sunshot data. Sunshot also projected an installed cost in 2014 (quoted Q4 2013) for utility scale systems (equal to or greater than 185 MW) of $1.80/W – 5% lower than the previous year.[22]

The costs of c-Si and thin film PV systems, both tracking and fixed, have been falling as well as converging over the past 7 years. The prices shown below in Figure 16 are reported U.S. utility scale installed prices, and so lag behind other cost estimates by how far in the past the contracting was.[23] The lag between contract award and construction helps explain the difference between reported costs and modeled costs.

[19] CanSIA, *A Confluence of Low Capital Costs and Cost of Capital for Utility-Scale Solar: Implications for Developers, Lenders and Political and Regulatory Decision-Makers*, presented January 30 2015 at the 6th Annual Canadian Power Finance Conference.

[20] CanSIA, *A Confluence of Low Capital Costs and Cost of Capital for Utility-Scale Solar: Implications for Developers, Lenders and Political and Regulatory Decision-Makers*, presented January 30 2015 at the 6th Annual Canadian Power Finance Conference.

[21] International Energy Agency, *Technology Roadmap – Solar Photovoltaic Energy 2014 Edition* http://www.iea.org/publications/freepublications/publication/TechnologyRoadmapSolarPhotovoltaicEnergy_2014edition.pdf

[22] U.S. Department of Energy, *Photovoltaic System Pricing Trends 2014 Edition* http://www.nrel.gov/docs/fy14osti/62558.pdf

[23] U.S. Department of Energy, *Photovoltaic System Pricing Trends 2014 Edition* http://www.nrel.gov/docs/fy14osti/62558.pdf

The capacity weighted average prices at utility scale for systems completed in 2013 in the U.S. were reported as:

- $2.97/W for c-Si with fixed tilt
- $3.12/W for c-Si with tracking
- $2.72/W for thin film with fixed tilt

Figure 16 - Reported Price of U.S. Utility-scale PV Projects over Time (Sunshot, USD)

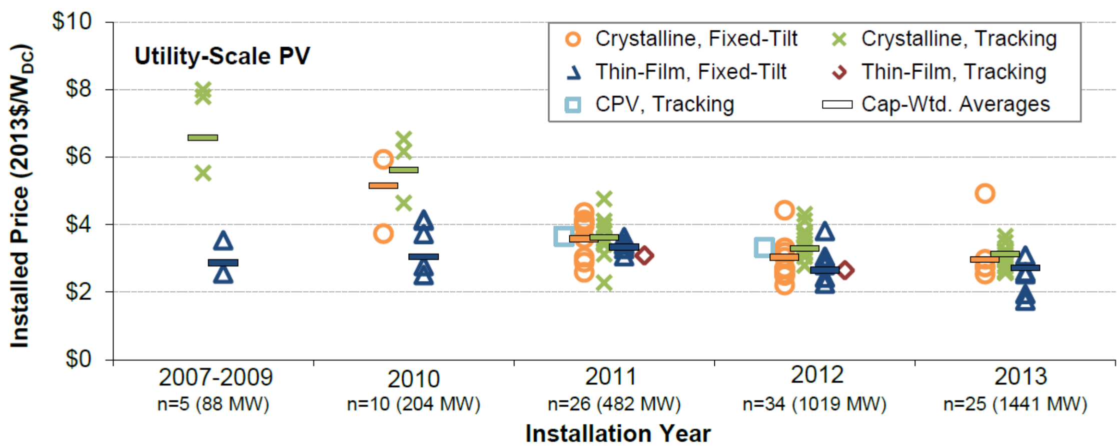
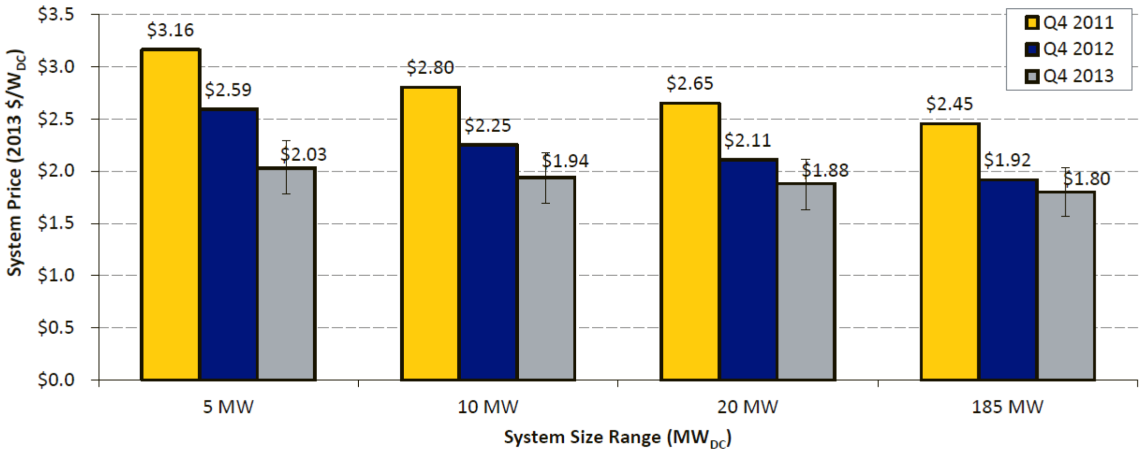


Figure 17 shows that most of the recent gains in reduced cost from economies of scale in utility scale systems (~70%) were found between 5 and 20 MW; as project size grew beyond 20 MW, there was a diminishing return to scale in reductions.[24] Prices were found to fall between 14-27% as systems grew from 5 to 185 MW, depending on the year analyzed. Thus in a jurisdiction like British Columbia, there would be no real driver for projects greater than 5-10 MW.

[24] U.S. Department of Energy, *Photovoltaic System Pricing Trends 2014 Edition* http://www.nrel.gov/docs/fy14osti/62558.pdf

Figure 17 - Bottom-up Modeled Overnight Capital Cost of U.S. Utility-scale PV Systems by Size, 2011-2013 (Sunshot, USD)



Analysts' projections for the global average near term price of utility scale systems describe a price of $1.30 - $1.95 by 2016 (Figure 18).

Figure 18 - Recent Analyst Estimates (2012-2013) and Projections (2014-2016) of Global Average Utility Scale System Price (Sunshot based on Various Sources, USD)

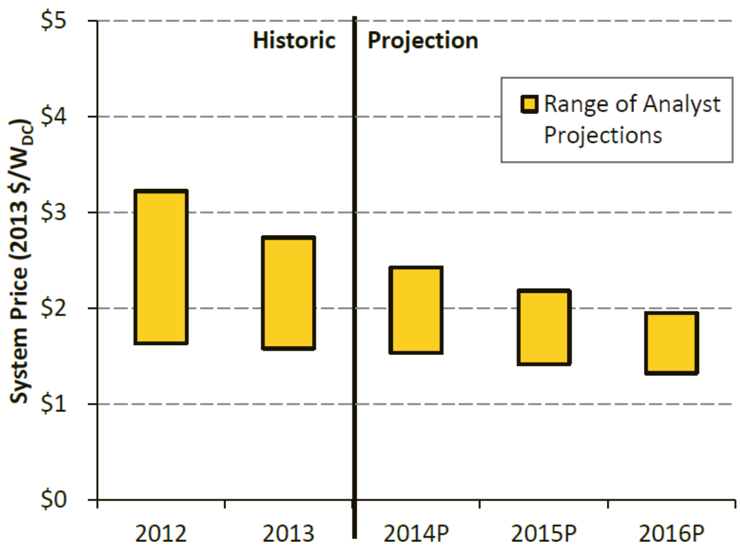


Figure 19 below illustrates the relative values of cost components within a single-axis tracking PV system at the utility scale.

Table 4 similarly shows the numeric values of these cost components. Soft costs (including direct labour; engineering; permitting, inspection and interconnection; and supply chain, overhead and margin) represent 34% of the total turnkey pricing in this example.

Figure 19 - Modeled Utility Turnkey Single-Axis Tracking PV System Pricing With Cost Breakdown (GTM Research, USD)

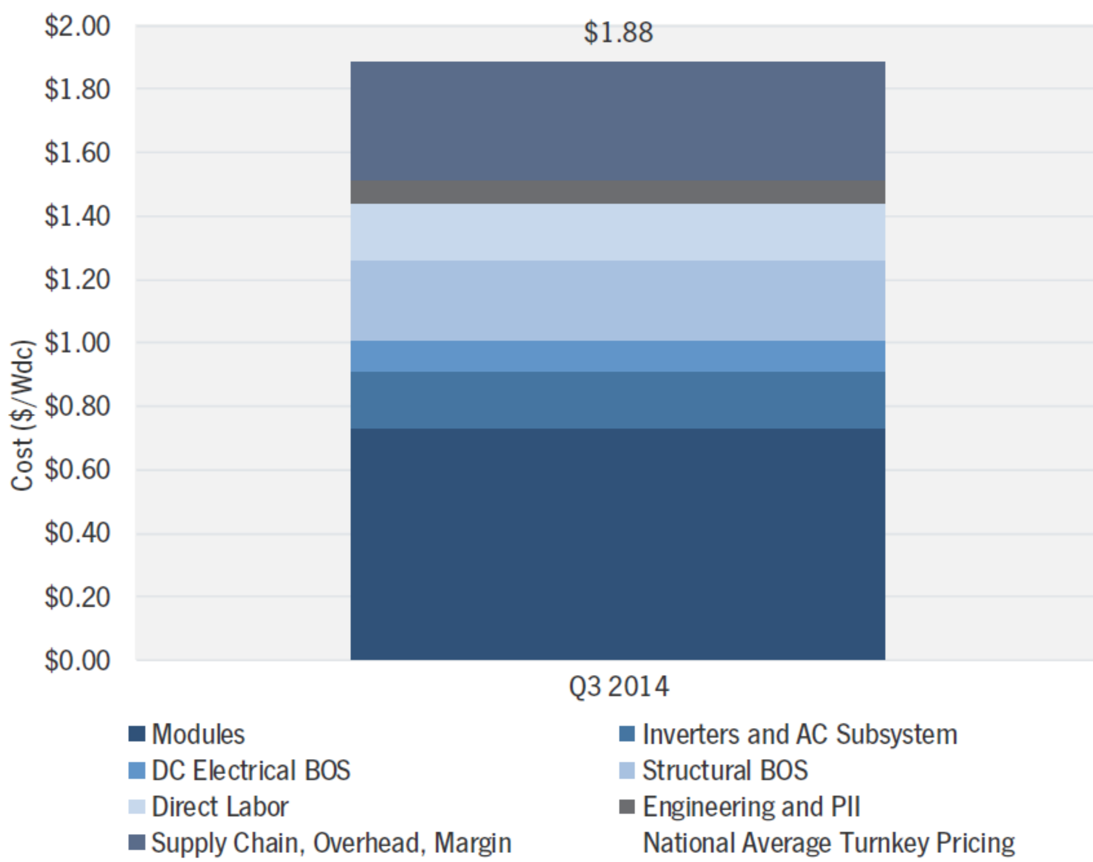


Table 4 - Cost Components of Modeled Utility Turnkey Single-Axis Tracking PV System Pricing (GTM Research)

Component	*Cost (2014 USD)*	*Percent of System Cost*
Modules	$0.73	38.8%
Inverters and AC Subsystem	$0.18	9.6%
DC Electrical Balance of System	$0.08	4.3%
Structural Balance of System	$0.25	13.3%
Direct Labor	$0.18	9.6%
Engineering and Permitting, Inspection and Interconnection	$0.07	3.7%
Supply Chain, Overhead, Margin	$0.39	20.7%

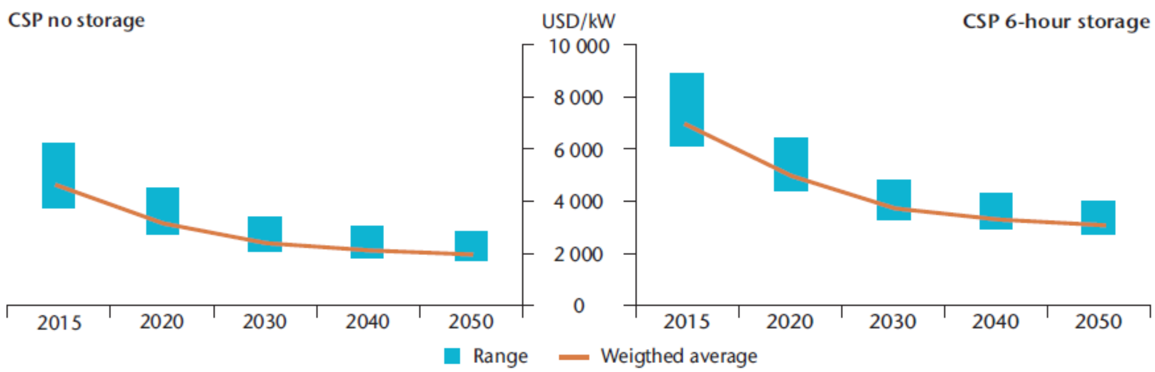
b. Solar Thermal

CSP system costs are expected to drop by half by 2030 (Figure 20).[25] This long term cost projection is somewhat difficult to compare to more near-term cost projections for solar PV, which show in the near term a much lower cost for solar PV. The combination of CSP and storage may be more competitive when its operational benefits are considered. The U.S. Department of Energy's Sunshot program predicts an even more aggressive reduction in CSP costs than the IEA ($60/MWh (USD) by 2020, as compared to $130/MWh projected by the IEA).[26]

[25] International Energy Agency, *Technology Roadmap – Solar Thermal Electricity 2014 Edition* http://www.iea.org/publications/freepublications/publication/technologyroadmapsolarthermalelectricity_2014edition.pdf

[26] International Energy Agency, *Technology Roadmap – Solar Thermal Electricity 2014 Edition* http://www.iea.org/publications/freepublications/publication/technologyroadmapsolarthermalelectricity_2014edition.pdf

Figure 20 - Solar Thermal Investment Cost Projections (IEA, 2013 real dollars)



It is anticipated that new materials, plant design, thermodynamic cycles will help to meet these projected cost reductions. Larger systems will allow for a reduction in the relative costs of turbines and balance of plant. The IEA anticipates a 10% learning rate – that is, unit costs will diminish by 10% for each doubling of cumulative capacity installed.

For CSP systems on the scale of hundreds of kWs to multi-MWs, too little data on current installations exist to accurately make cost projections into the future.[27]

As previously noted, Direct Normal Irradiance (DNI) is especially important to CSP facility performance because thermal losses and parasitic consumption are nearly constant. Areas with high levels of DNI are usually within latitudes from 15° to 40° north or south and thus are less likely to represent a significant opportunity for large scale deployment in British Columbia.

[27] International Energy Agency, *Technology Roadmap – Solar Thermal Electricity 2014 Edition* http://www.iea.org/publications/freepublications/publication/technologyroadmapsolarthermalelectricity_2014edition.pdf

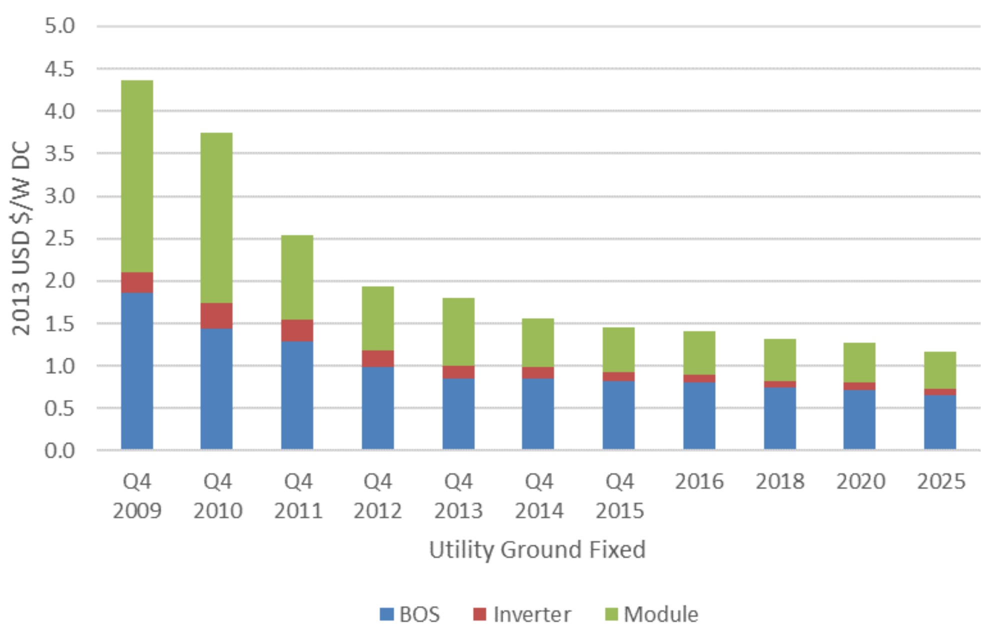
6. Conclusions and Considerations for British Columbia

a. Utility-Scale Pricing Forecast for British Columbia

Compass has analyzed a number of studies and amalgamated them into its own projection of system and component costs through the year 2025. This incorporates analyst's projections as collected by NREL, GTM Research and the IEA. Figure 21 below shows the historical and projected component and system costs in 2013 USD, and Figure 22 shows projected component and system costs using a $1 USD = $1.2 CDN conversion. These are nominal costs, unadjusted for inflation. Because this analysis is based on many studies looking at utility scale projects but without deeper specificity into the size or characteristics the projects analyzed, this analysis is best described as applying generally to utility scale solar PV projects 5 MW and over.

System prices have fallen between 16% – 19% per year since 2009, with half to two thirds of this drop related to module price reductions.[28]

Figure 21 - Historical and Projected Component and System Costs (Compass)



[28] U.S. Department of Energy, *Photovoltaic System Pricing Trends 2014 Edition* http://www.nrel.gov/docs/fy14osti/62558.pdf

Figure 22 - Projected System and Component Costs in $ CDN (Compass)

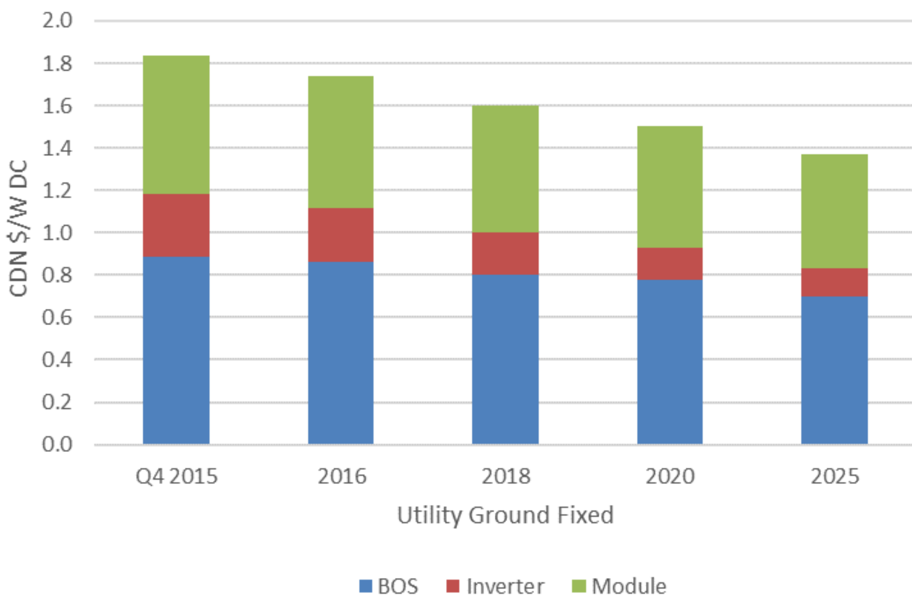


Table 5 - Breakdown of Projected System and Component Costs in $ CDN (Compass)

Component	*Cost (2015 CDN)*	*2015 Percent of System Cost*	*Cost (2025 CDN)*	*2025 Percent of System Cost*
Modules	$0.70	39.5%	$0.54	40.6%
Inverters and AC Subsystem	$0.16	9%	$0.09	6.8%
DC Electrical Balance of System	$0.10	5.7%	$0.08	6.0%
Structural Balance of System	$0.18	10.2%	$0.15	11.3%
Direct Labor	$0.15	8.4%	$0.11	8.3%
Engineering and Permitting, Inspection and Interconnection	$0.08	4.5%	$0.06	4.5%
Supply Chain, Overhead, Margin	$0.40	22.6%	$0.30	22.5%

The pricing and costing analysis also takes into consideration the current market conditions in Ontario, which provides a reasonable reference point for expected prices for project developers in British Columbia.

PV modules are available from a number of bankable Tier 1 Ontario manufacturers to supply the early Feed-in Tariff projects that carry with them obligations to source equipment locally. These modules are currently available to project developers for prices ranging from $0.65 - $0.75 CDN per watt DC. The recent decision of the Canadian Borders Services Agency to establish interim duties on imported Chinese modules in the range of 10% - 200% is not expected to have any immediate impact on these prices, as alternative sources for modules, and competitive prices continue to be available, in including from Canada. Ontario manufacturers are free to import PV cells from any country duty-free, and perform the robotic final assembly into modules, and can do so at globally competitive prices.

Inverters are similarly available from a variety of equipment suppliers and with increasing inverter sizes, unit cost for these products has decreased to a level of approximately $0.16 - $0.20 CDN today. Many of the inverters come from markets with lower labour costs and are available in Ontario for projects that no longer have local content obligations, with some manufacturers offering such equipment for projects for 2015/16 delivery at $0.10 - $0.12/W CDN.

BOS costs and other factors that influence final project costs include:

- Modules
- Inverters
- Balance of System (racking and mounting, electrical hardware, grid connection etc.)
- Labour, engineering and construction
- Shipping

The question of whether a cost component is a global commodity or locally priced or sourced informs the derivation of a Canadian or British Columbia system cost projection. Mounting systems are often locally made, but with materials that are often global commodities. Electrical equipment and hardware are global commodities and can be purchased locally or from abroad. Labour is locally sourced and contingent on local conditions and cost pressures. Some jurisdictions have local inverter or module manufacturing or assembly, but in British Columbia these would both be sourced from abroad.

Permitting, financing and soft costs are highly local in nature and can represent a sizable share of the overall cost. Policy and regulatory change and international financial trends can have a large effect over a multi-year cost projection, however global investor interest in operating PV assets have contributed to the reduction in end-user costs of solar PV. The availability of low-cost or subsidized debt can improve the economic viability of projects. Jurisdictions with this feature can see significant customer savings on a per unit basis.

Continued improvements in module efficiency and manufacturing scale represent the leading drivers of future cost reductions for many reasons. Balance of system material costs are unlikely to fall significantly in the future. Declines in inverter costs have a smaller percentage effect on the overall cost. Finally, increased module efficiency reduces the need for all other inputs on a $ per W basis, as the project requires less labour, hardware and other balance of system components.

Compass projects an average 2.5% annual system cost reduction of from Q4 2014 – 2025. This compares with the following other projects in similar periods:

- NREL projects 0.4 - 4.7% annual system cost decline 2014-2025
- Black and Veatch projects 0.8% annual system cost decline 2014-2025
- IEA projects 4.2% annual system cost decline 2015-2020
- GTM Research projects 5.6% annual module cost decline 2012-2017

Solar PV is a constantly advancing technology whose application at utility MW scale will continue to increasingly contribute to least cost power system planning decisions globally, particularly in markets with solar production profiles that match local consumption profiles.