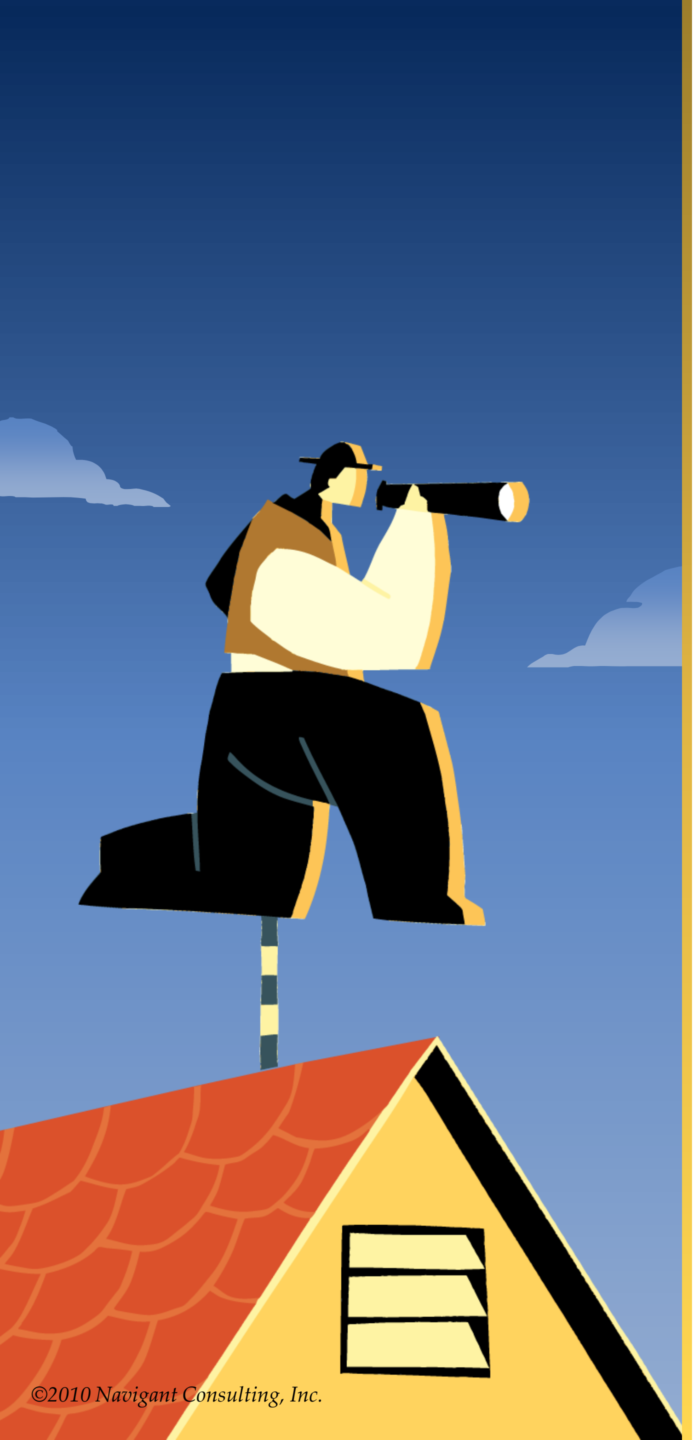

Independent Solar Assessment

Phase 1 – Penetration Levels and Costs

FINAL

Celebrating 25 Years

cleanenergy.org

Working towards a clean energy future

Southern Alliance for Clean Energy

November 5, 2010

NCI Reference: 142962

NAVIGANT

Disclaimer

Content of Report

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November 5, 2010

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SACE retained Navigant to investigate potential PV penetration levels in the Tennessee Valley Authority's territory.

Scope of Work

SACE has retained Navigant to investigate photovoltaic (PV) in the Tennessee Valley Authority's (TVA) territory. This portion of the work consisted of the following tasks:

1. Develop reasonable penetration levels of PV in TVA's territory, by market segment, through 2030.
2. Analyze and project current and future costs of PV
   - Both up-front and on-going in TVA's territory.
3. Calculate the total costs of each penetration scenario.

The following slides present a summary of the work conducted by Navigant.

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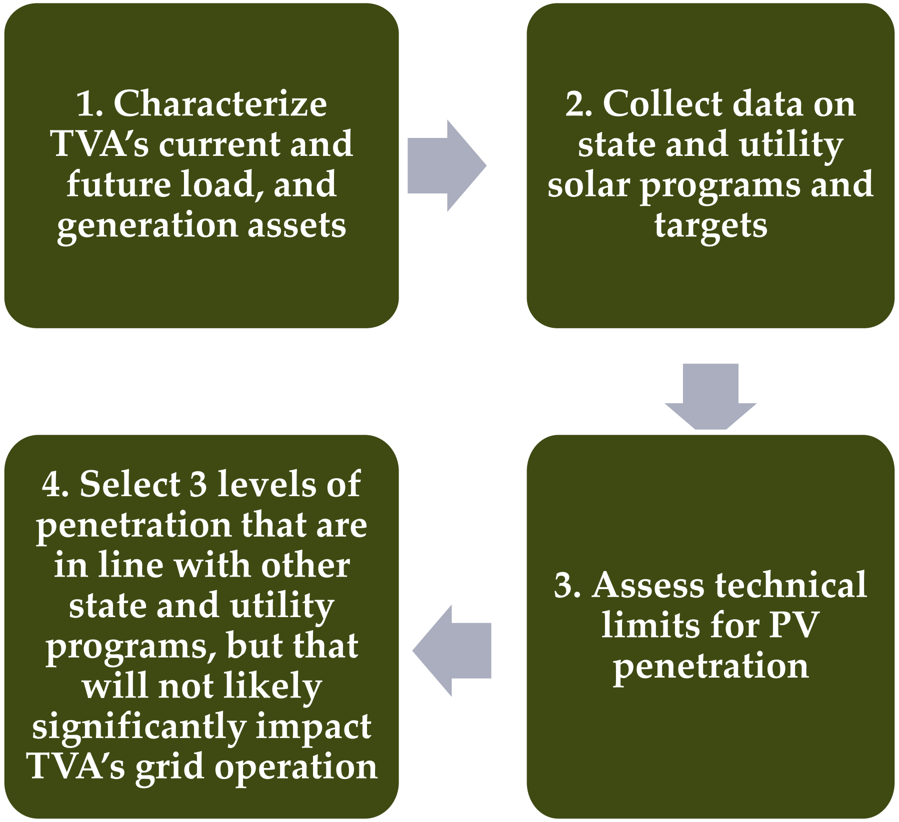
NAVIGANT ENERGY

Navigant used data from public sources to select 3 levels of PV penetration in TVA's territory.

Methodology

- Select three levels of PV penetration for further study.
- To date, no solar integration studies have been done for TVA or the eastern interconnect.
  - The National Renewable Energy Laboratory (NREL) has done an initial study for the western interconnect[1], but the study is not applicable to TVA given regional differences in generators available, weather, and load.
- As a result, Navigant undertook the process shown on the right.



1. Characterize TVA's current and future load, and generation assets

2. Collect data on state and utility solar programs and targets

3. Assess technical limits for PV penetration

4. Select 3 levels of penetration that are in line with other state and utility programs, but that will not likely significantly impact TVA's grid operation

Source:

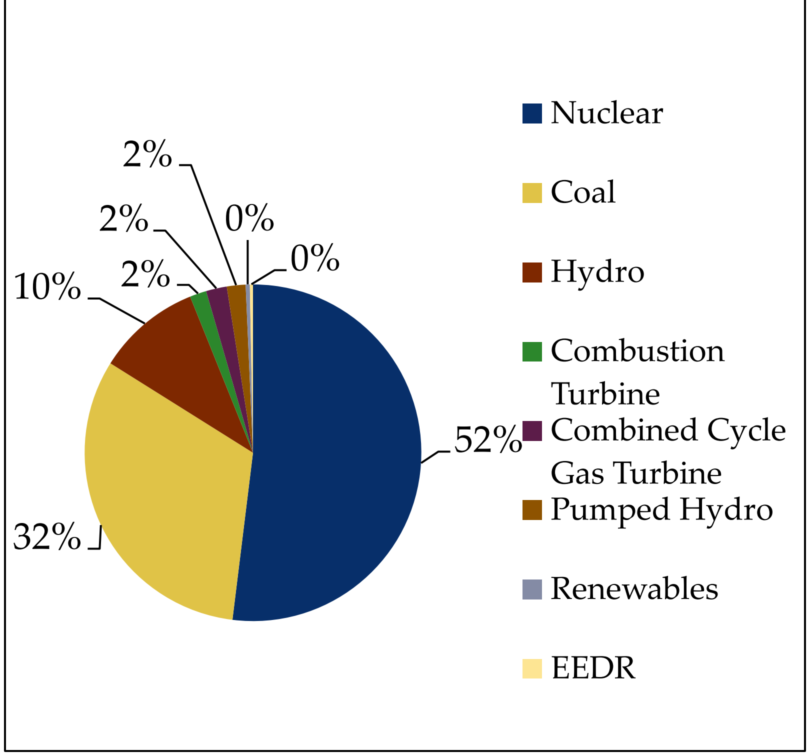
1. Available at http://www.nrel.gov/wind/systemsintegration/wwsis.html.

TVA serves 56 customers and 155 power distributors directly. These customers provide electricity to ~9 million people. [1]

TVA Overview

	2008	2009
Peak Load[2]	31,750 MW	30,500 MW
Annual Load[2,3]	180,500 GWh	194,300 GWh
Expected Load Growth to 2030[2]	1.1% average annual increase	
Expected Peak Demand Growth to 2030[2]	1.4% average annual increase	

TVA Generation Mix[4]

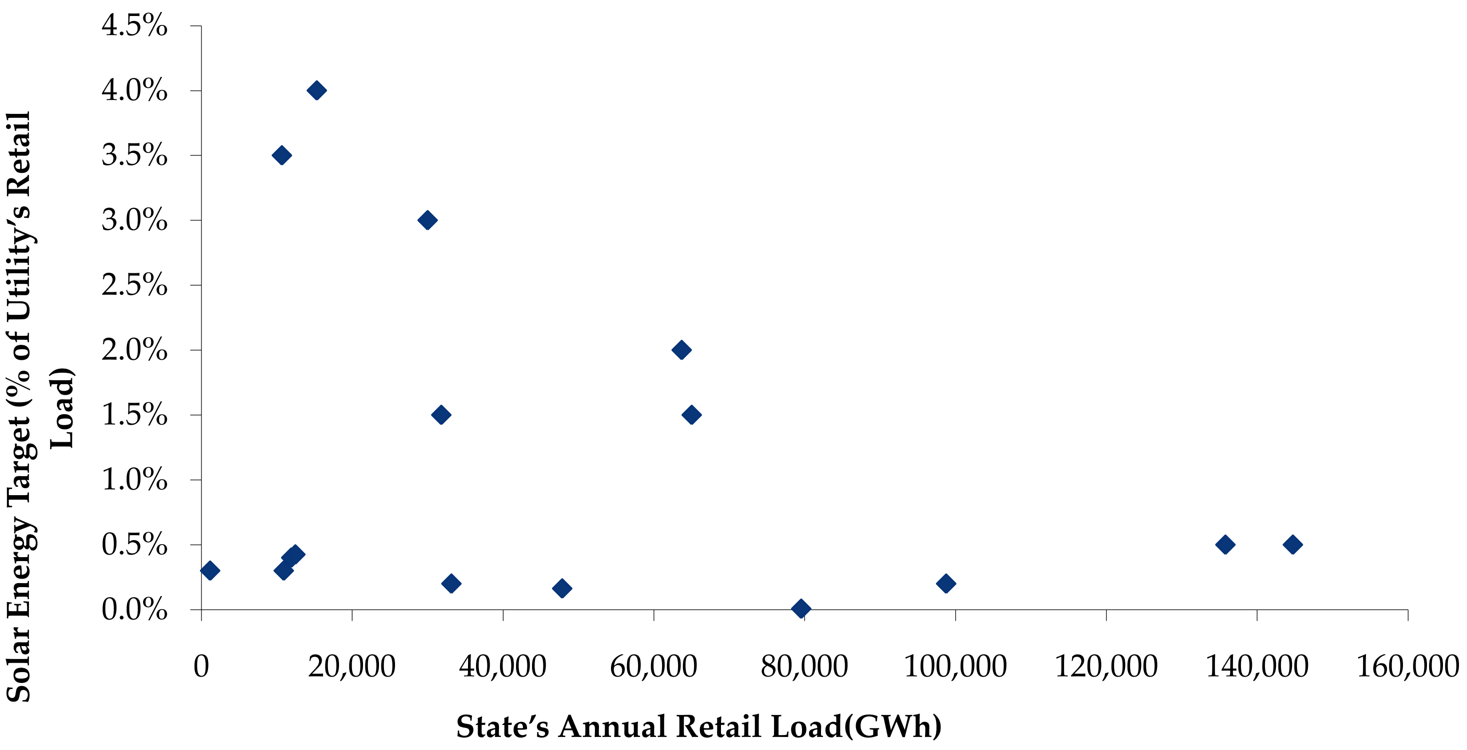


Sources:

1. http://www.tva.gov/foia/foia_guide.htm
2. http://www.tva.gov/irp/pdf/irp_complete.pdf, Used IRP Baseline
3. Southern Alliance for Clean Energy
4. U.S. Department of Energy's Energy Information Administration (EIA)

Many states have established solar specific targets as part of their Renewable Portfolio Standards (RPS). Targets range from 0.1% to 4%.

Mapping of State RPS Solar Set Aside Targets[1]

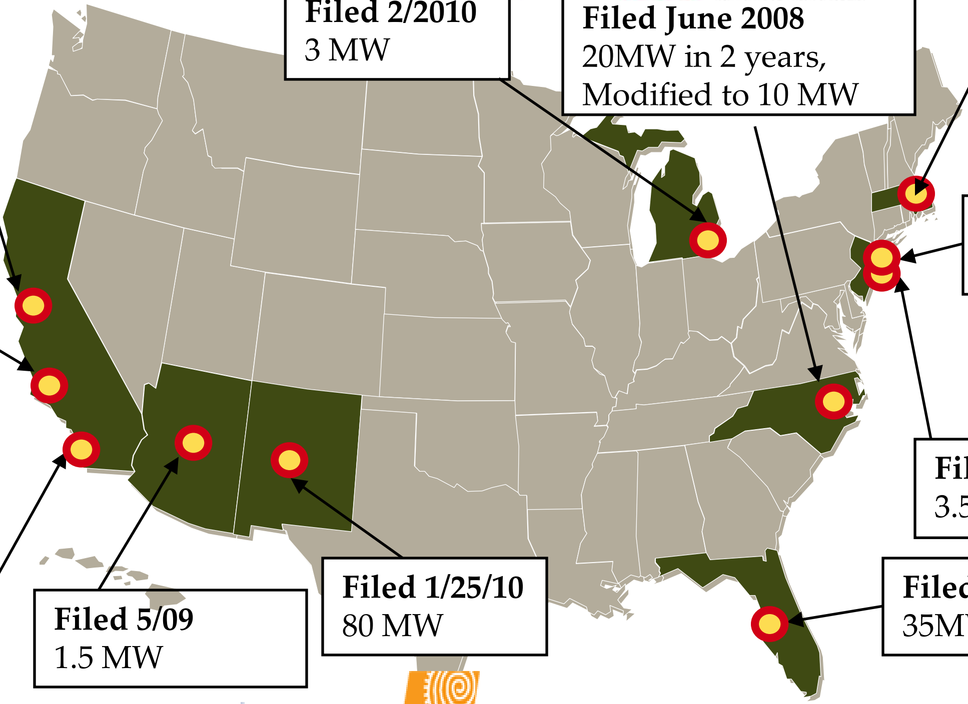


Notes:

1. Sources: EIA and www.dsireusa.org

In addition to state driven programs, many utilities are filing to own solar assets.

Utility Programs for Distributed PV: Examples of Filings for Rate Basing



Pacific Gas and Electric Company

Filed February 2009
500MW in 5 years[3]

Southern California Edison
An Edison International Company

Filed March 2008
250MW in 5 years,
Modified to 500 MW[3]

SDGE
A Sempra Energy Utility

Filed July 2008
77MW in 4 years[1]

APS

Filed 5/09
1.5 MW

PNM

Filed 1/25/10
80 MW

DTE Energy

Filed 2/2010
3 MW

Duke Energy

Filed June 2008
20MW in 2 years,
Modified to 10 MW

nationalgrid

Proposed 4Q 2008
5MW

PSEG

Filed February 2009
120MW in 5 years

atlantic city electric
Pepco Holdings Inc

Filed November 2007
3.5MW in 5 years[2]

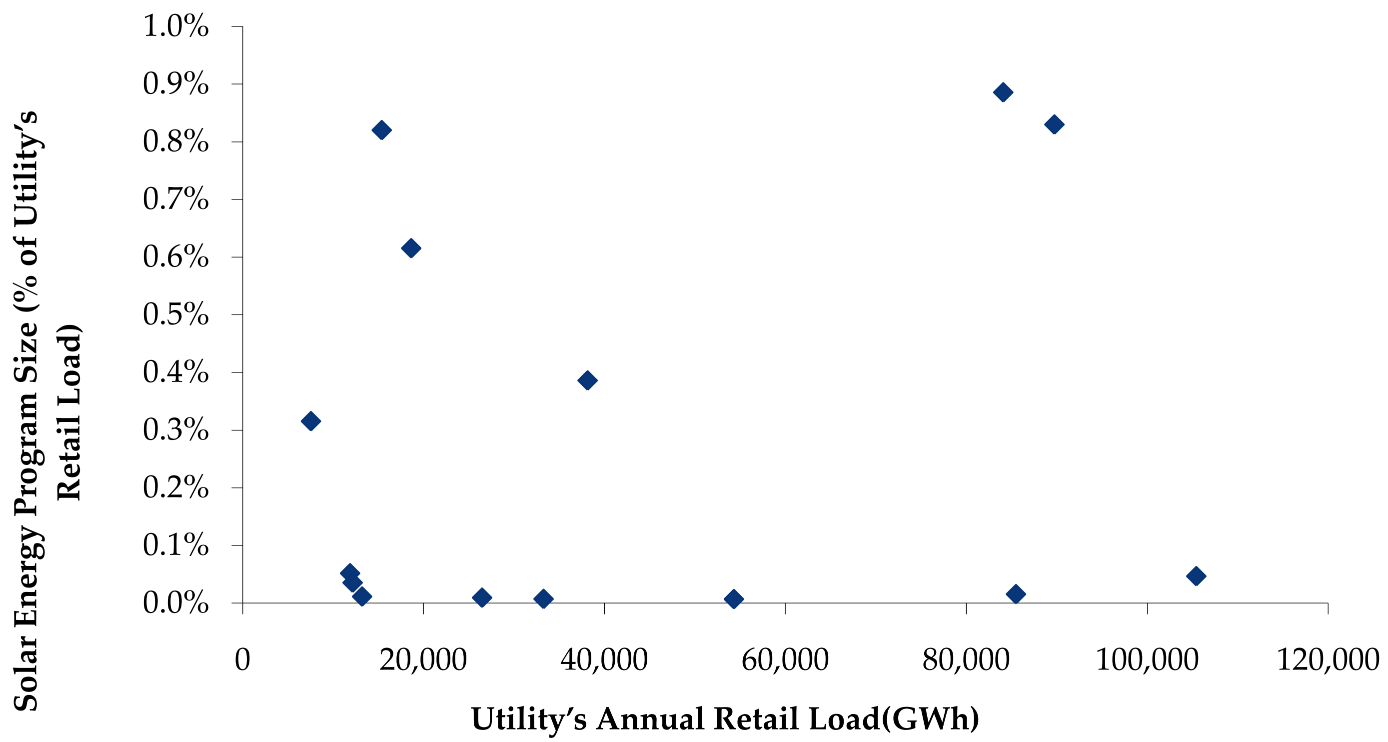
FPL

Filed 5/08
35MW Program

1. SDG&E: 55MW owned by utility
2. ACE: 0.5MW will be utility owned and located on utility facilities.
3. PG&E and SCE 50% ownership

Utility solar ownership programs will amount to between 0.05% and 1% of their retail load.

Mapping of Utility Solar Ownership Programs[1]



Notes:

1. Sources: EIA, NREL's System Advisory Model available at https://www.nrel.gov/analysis/sam/

The amount of roofspace and land available for PV development provides one upper bound on the penetration of PV in TVA's territory.

Roof-Mounted PV

- Not every square foot of rooftop is suitable for PV because of shading, orientation (e.g. north facing slope), and structural adequacy.
- In 2008, Navigant published a study for NREL investigating the actual amount of roofspace available for PV[1] on a state-by-state basis.
- Using the results of this study, Navigant estimates the technical potential (defined as the physical ability to install PV, independent of economics) at between 12 and 18 GW for residential and commercial rooftop in TVA's territory.

Ground-Mounted PV

- For ground-mounted PV, Navigant only considers certain land use types as viable for PV development:
  - Open, un-forested land not in a park, nature reserve, wetlands, etc.
  - Agricultural land not being used
  - Barren land (e.g. reclaimed mining lands)
- It was beyond the scope of this study to identify constraints on suitable locations for installation of ground-mounted PV, but high level reviews of land use patterns (from satellite photos) suggest that most of the available land in TVA's territory is forested or used for agriculture.
- There may be locations suitable for ground-mounted PV, but Navigant was not able to quantify the amount.

---

[1] Refer to the full report (J. Paidipati, L. Frantzis, H. Sawyer, A. Kurrasch *Rooftop Photovoltaic Market Penetration Scenarios* NREL/SR-581-42306 February 2008) for more detail on the methodology used.

The variability of PV output requires dispatchable resources to firm output.

Dispatchable Resources

- Given that PV is a non-dispatchable resource and output can vary during the course of a day, dispatchable resources are needed for back-up.
- However, the required back up capacity is typically not one to one[1] for variable resources such as wind and solar power, but a full solar integration study[2] is required to appropriately assess the amount needed for TVA to integrate solar.
- Given that a full integration study is outside the scope of this project, Navigant quantified the amount of dispatchable resources available in TVA's territory from the data on slide 8:
  - Combustion Turbines: 11,641 MW
  - Storage: 1,712 MW
  - Hydro: 5,074 MW (Note: Hydro is not always dispatchable, it depends on how a utility operates its resources)
  - In addition, TVA is exploring 580 MW of new pumped storage by 2029[3].

Notes:

1. For example, the *Eastern Wind Integration and Transmission Study* conducted by Enernex Corporation for the National Renewable Energy Laboratory (available at http://www.nrel.gov/wind/systemsintegration/ewits.html) showed that 1,247 MW of wind in TVA's territory only needed between 365 and 420 MW of spinning reserves.
2. An example study was conducted by Xcel Energy for Colorado for penetration levels <10% and is available at http://www.xcelenergy.com/SiteCollectionDocuments/docs/PSCo_SolarIntegration_020909.pdf
3. http://www.tva.gov/irp/pdf/irp_complete.pdf

Upper limits of penetration depend on where PV is interconnected.

Distributed PV

- For PV installed as distributed generation, Navigant has found that penetrations, on a peak basis, of higher than 5% to 10% can impact grid operations.
- Above this level, impacts could include:
  - Adequate voltage regulation may be difficult due to changes in feeder load and power flow while PV is producing.
  - Changes in PV output can cause the power flow on distribution feeders to vary, and in some high generation/low load cases, the flow could reverse.

Central Station PV

- For PV installed on the transmission system, Navigant has found that penetrations, on a peak basis, of higher than 10% to 15% can impact grid operations.
- Above this level, impacts could include:
  - Changes to operation of base load resources if PV is high and load is low.
  - The variability of PV output due to cloud transients has been shown to create power fluctuations, and may be incompatible with the ramp rates of some central station generation.

Scenarios

- Given the uncertainty as to what level of penetration (as a % of system peak) will impact grid operation, Navigant examined three scenarios of penetration level (as a % of system peak) that impact grid operation:
  - **Lower End** – 5% for DG and 10% for Central Station
  - **Mid Range** – 7.5% for DG and 12.5% for Central Station
  - **Upper End** – 10% for DG and 15% for Central Station

Sources include: Distributed Photovoltaic Systems Design and Technology Requirements, C. Whitaker, J. Newmiller, M. Ropp, and B. Norris, February 2008; Navigant experience from similar studies; interconnection rules in other states outside TVA's territory, and U.S Department of Energy, *Solar Visions Study – Draft*, May, 2010 available at http://www1.eere.energy.gov/solar/vision_study.html

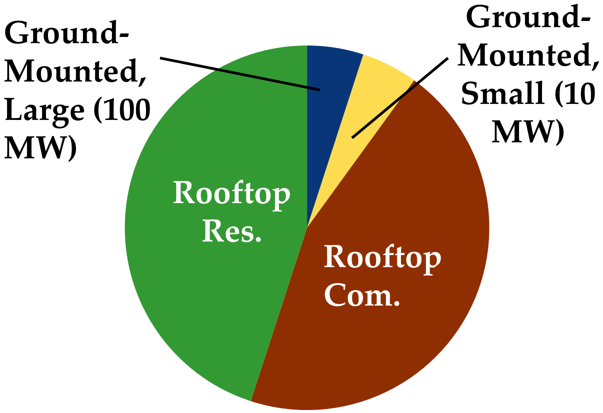
Given that system location will likely impact penetration levels, Navigant looked at different scenarios of system locations.

System Location

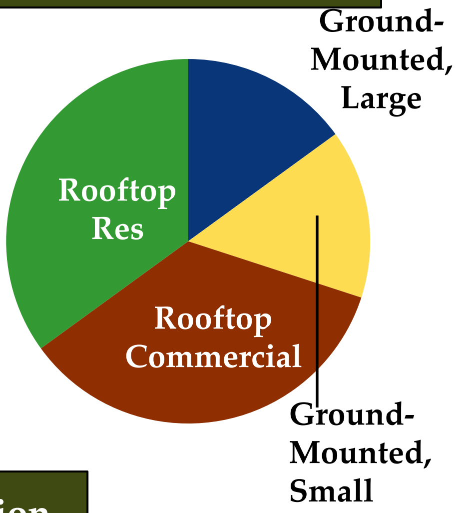
- As discussed on the proceeding slide, the point of PV interconnection would likely influence the level of penetration at which PV impacts grid operation.
- Given that an exact assessment of the technical potential of ground mounted (assumed to be primarily central station PV) has not been done for TVA's territory, Navigant analyzed 3 different levels of central station PV.

Scenarios Analyzed

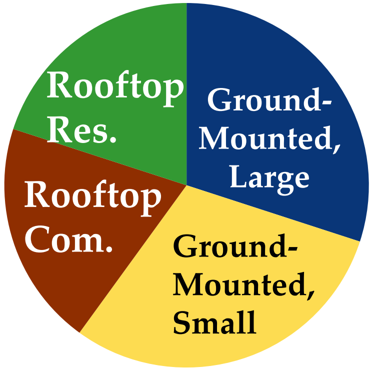
Minimal Central Station



1/3 Central Station



Majority Central Station



Chosen penetration levels result in between ~2.2 and 5.2 GW of PV installed by 2030.

Selected Penetration Level[1,2]

- Given that two uncertainties exist in Navigant's analysis – upper limit on PV penetration that could impact grid operation and location of PV interconnection – Navigant analyzed nine different combinations of maximum penetration and system location:

Total Installations by 2030 (MW_{pDC})	Interconnection Point		
Maximum Penetration Level	Minimal Central Station	1/3 Central Station	Majority Central Station
Lower End	2,200	2,600	3,200
Mid Range	3,200	3,600	4,200
Upper End	4,200	4,600	5,200

- Navigant's rationale to support these assumptions is as follows:
  - The precedent exists – from state programs – for potential PV penetration up to 4% on an energy basis. This analysis stays below that amount with 3% penetration in the highest case.
  - The precedent also exists from utilities that currently have short term (e.g. in the next 5 years) plans to procure up to 1% solar. Given that announced plans are only in the short term, many utilities might have higher PV Penetration levels by 2030.
  - The corresponding capacities do not exceed the technical potential for rooftop PV in TVA's territory shown on slide 12.
- The cost of these penetration levels will be analyzed in the final section of this study.

Notes:

1. This assumes a 1.4%/Year peak demand growth in load taken from TVA's Baseline Forecast in its IRP.
2. This analysis assumes a DC to AC de-rate of ~85%. The actual penetration is based upon the AC ratings of the system, which will be ~15% lower than what is shown here.

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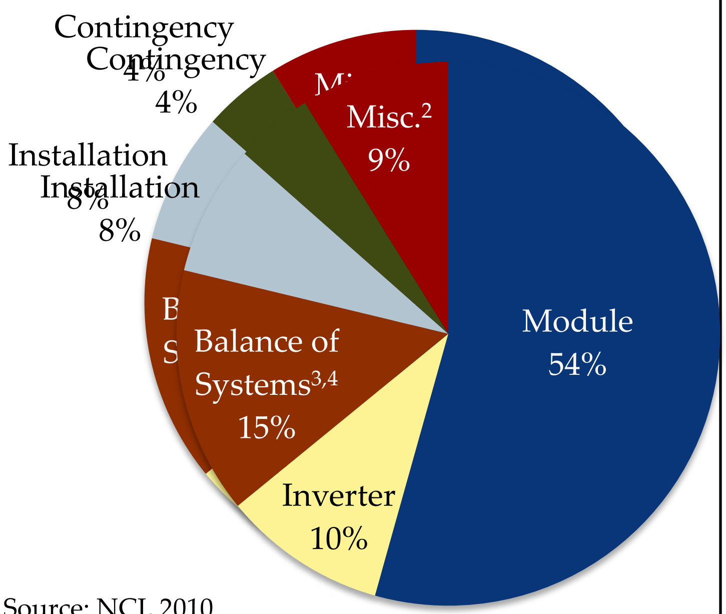
System Cost Overview

- This section reviews Navigant's calculations and analysis on current and future installed costs for PV in TVA's territory.
- The analysis is based upon Navigant's internal cost models that account for regional variations in system costs, publicly available data on system costs in TVA's territory, and interviews with installers active in TVA's territory.
- The projections to 2030 represent Navigant's best estimate for how system costs will change over time.
  - Organizations, such as the U.S. Department of Energy, have set installed cost goals that are lower than Navigant's assessments.
  - These goals assume several technological breakthroughs or significant business changes that have not occurred yet, so Navigant assumed it would be premature to take them into account.
- The following slides review Navigant's analysis for ground mounted and roof mounted PV systems.
  - Note that every PV system is different and variations in design can impact cost.
  - The estimates here are for typical systems.
  - Some actual systems might be higher or lower than the estimates shown here.

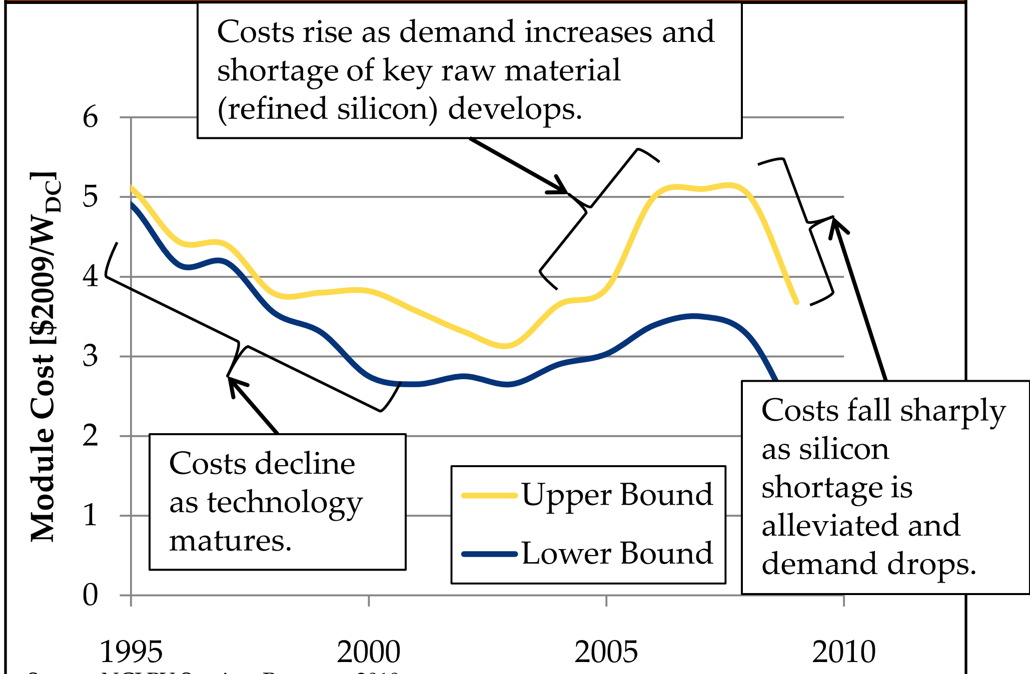
Module costs dominate installed system costs, but have historically seen the most variability in pricing.

2010 Typical Cost Breakout[1,2]



Source: NCI, 2010

Historical Module Costs ($2010/$W_{DC}$)



Costs rise as demand increases and shortage of key raw material (refined silicon) develops.

Costs decline as technology matures.

Costs fall sharply as silicon shortage is alleviated and demand drops.

Source: NCI PV Services Program, 2010

Notes:

1. The data shown is for a typical ground mounted system. The relative proportions will change whether or not tracking is used and with what efficiency modules are used.
2. This pie chart does not includes costs for transmission, interconnection, or substation upgrades.
3. Miscellaneous includes permitting costs, engineering, land, application costs, etc.
4. The Balance of System component can vary depending on whether or not trackers are used
5. Balance of Systems includes: the mounting system, trackers and all electrical components (wires, combiner boxes, conduits, disconnects,…)

Ground-mounted systems can vary in design, cost, and performance.

Ground-Mounted Photovoltaics - Overview

- To capture variability in system design and pricing, Navigant picked three system designs to analyze:
  - A high efficiency system using advanced silicon cells and a single axis tracking system.
  - A high efficiency system using advanced silicon cells without use of a tracking system
  - A lower efficiency system using thin-film cells and a fixed axis tracking system.
- For each system design, two different classes of system size were analyzed:
  - Given the land use patterns in TVA's territory, Navigant assumes most systems will be smaller (~10 MW).
  - However, there might be some locations suitable for larger systems, so Navigant calculated the costs of larger systems (~100 MW). For larger systems, the per unit costs (on a $/kW basis) will likely be lower because of economies of scale (relative to a 10 MW plant) in purchasing and fixed costs being spread over a larger plant.
- Navigant also researched potential regional variations within TVA's service territory.
  - Land: Navigant found land prices can vary from $3,000/Acre to over $5,000/Acre in areas away from population centers[1].
  - Labor: Hourly wages (for plant construction) in TVA's service territory are approximately 30% lower than national U.S. average[2].
  - However, these costs are minor compared to other components, so they do not have a large impact on the overall price.
- The analysis accounted for TVA territory specific wind speed rating (90 mph) and soil conditions.
- Finally, the team benchmarked internal cost data against information from local programs like the TVA Generation Partners Program and the Solar Opportunity Fund.
- Key findings:
  - As shown on the previous slide, module prices have declined significantly in recent years.
  - Navigant expects further system cost reductions as the local and global PV industry matures and as module efficiencies increase.

Notes:
1. Navigant did not investigate areas very close to population centers because of the likely difficulty of permitting, but land costs could be significantly higher. Data taken from public land auction and realty websites.
2. Data from the R.S. Means Cost Databases.

Navigant projects that while prices may rise in the near term, prices will fall over the long term.

	Polycrystalline PV with Single Axis Tracking - Economic Assumptions for Given Year of Installation (2010$)				
	2010	**2015**	**2020**	**2025**	**2030**
Plant Nameplate Capacity (MW_{DC})[1]	10	10	10	10	10
Project Life (yrs)	25 - 30	25 - 30	25 - 30	25 - 30	25 - 30
Construction Time (yrs)[2]	1	1	1	1	1
Installed Cost ($/$\text{kW}_{\text{DC}}$) [3]	5,900	5,500	4,900	4,300	3,750
Fixed O&M ($/$\text{kW}_{\text{DC}}$-yr)	35	30	26	23	21
Non-Fuel Variable O&M ($/MWh)	0	0	0	0	0
Fuel/Energy Cost ($/MWh)	0	0	0	0	0
Land Requirements (Acres/MW)	6 to 9				

Notes:

1. PV is a modular technology and ground mounted plants can range in size from 1 MW to 500 MW. Some costs scale with size and others do not. The costs presented here are valid for systems between 10 MW and 50 MW in size. Larger systems will have a lower $/kW cost.
2. Installing companies have some level in flexibility in installation time because they can just use more people to install faster. This estimate represents an average.
3. This includes permitting and interest during construction, but does not include interconnection, transmission or substation upgrade costs.

Not having tracking reduces system costs.

	Polycrystalline Silicon PV w/o Tracking – Economic Assumptions for Given Year of Installation (2010$)				
	2010	**2015**	**2020**	**2025**	**2030**
Plant Nameplate Capacity (MW_{DC})[1]	10	10	10	10	10
Project Life (yrs)	25 - 30	25 - 30	25 - 30	25 - 30	25 - 30
Construction Time (yrs)[2]	1	1	1	1	1
Installed Cost ($/$kW_{DC}$) [3]	5,500	4,900	4,300	3,700	3,100
Fixed O&M ($/$kW_{DC}$-yr)	28	24	21	19	17
Non-Fuel Variable O&M ($/MWh)	0	0	0	0	0
Fuel/Energy Cost ($/MWh)	0	0	0	0	0
Land Requirements (Acres/MW)	5 to 8				

Notes:

1. PV is a modular technology and ground mounted plants can range in size from 1 MW to 500 MW. Some costs scale with size and others do not. The costs presented here are valid for systems between 10 MW and 50 MW in size. Larger systems will have a lower $/kW cost.
2. Installing companies have some level in flexibility in installation time because they can just use more people to install faster. This estimate represents an average.
3. This includes permitting and interest during construction, but does not include interconnection, transmission or substation upgrade costs.

As PV systems increase in size price is reduced. However, beyond a certain size, economies of scale do not allow further price reductions.

	Polycrystalline PV w/o Tracking - Economic Assumptions for Given Year of Installation (2010$)				
	2010	**2015**	**2020**	**2025**	**2030**
Plant Nameplate Capacity (MW_{DC})[1]	100	100	100	100	100
Project Life (yrs)	25 - 30	25 - 30	25 - 30	25 - 30	25 - 30
Construction Time (yrs)[2]	2-3	2-3	2-3	2-3	2-3
Installed Cost ($/$kW_{DC}$) [3]	4,800	4,400	3,800	3,400	3,100
Fixed O&M ($/$kW_{DC}$-yr)	28	24	21	19	17
Non-Fuel Variable O&M ($/MWh)	0	0	0	0	0
Fuel/Energy Cost ($/MWh)	0	0	0	0	0
Land Requirements (Acres/MW)	5 to 8				

Notes:

1. PV is a modular technology and ground mounted plants can range in size from 1 MW to 500 MW. Some costs scale with size and others do not. The costs presented here are valid for systems between 100 MW and 300 MW in size.
2. Installing companies have some level in flexibility in installation time because they can just use more people to install faster. This estimate represents an estimate as installers have not installed a single 100MW PV field in the US.
3. This includes permitting and interest during construction, but does not include interconnection, transmission or substation upgrade costs.

The thin film costs are lower for a 10 MW systems because of lower module costs.

	Thin-Film PV w/o Tracking - Economic Assumptions for Given Year of Installation (2010$)				
	2010	**2015**	**2020**	**2025**	**2030**
Plant Nameplate Capacity (MW_{DC})[1]	10	10	10	10	10
Project Life (yrs)	25 - 30	25 - 30	25 - 30	25 - 30	25 - 30
Construction Time (yrs)[2]	1	1	1	1	1
Installed Cost ($/$kW_{DC}$) [3]	4,800	4,400	3,800	3,400	3,100
Fixed O&M ($/$kW_{DC}$-yr)	40	34	30	27	25
Non-Fuel Variable O&M ($/MWh)	0	0	0	0	0
Fuel/Energy Cost ($/MWh)	0	0	0	0	0
Land Requirements (Acres/MW)	7 to 10				

Notes:

1. PV is a modular technology and ground mounted plants can range in size from 1 MW to 500 MW. Some costs scale with size and others do not. The costs presented here are valid for systems between 10 MW and 50 MW in size. Larger systems will have a lower $/kW cost.
2. Installing companies have some level in flexibility in installation time because they can just use more people to install faster. This estimate represents an average.
3. This includes permitting and interest during construction, but does not include interconnection, transmission or substation upgrade costs.

Thin film systems will likely see a slight reduction in costs with larger system sizes.

	Thin-Film PV w/o Tracking - Economic Assumptions for Given Year of Installation (2010$)				
	2010	**2015**	**2020**	**2025**	**2030**
Plant Nameplate Capacity (MW_{DC})[1]	100	100	100	100	100
Project Life (yrs)	25 - 30	25 - 30	25 - 30	25 - 30	25 - 30
Construction Time (yrs)[2]	2-3	2-3	2-3	2-3	2-3
Installed Cost ($\$/kW_{DC}$) [3]	4,700	4,300	3,700	3,300	3,000
Fixed O&M ($\$/kW_{DC}$-yr)	40	34	30	27	25
Non-Fuel Variable O&M ($/MWh)	0	0	0	0	0
Fuel/Energy Cost ($/MWh)	0	0	0	0	0
Land Requirements (Acres/MW)	7 to 10				

Notes:

1. PV is a modular technology and ground mounted plants can range in size from 1 MW to 500 MW. Some costs scale with size and others do not. The costs presented here are valid for systems between 100 MW and 300 MW in size.
2. Installing companies have some level in flexibility in installation time because they can just use more people to install faster. This estimate represents an estimate as installers have not installed a single 100MW PV field.
3. This includes permitting and interest during construction, but does not include interconnection, transmission or substation upgrade costs.

Rooftop system prices have declined in recent years.

Rooftop Photovoltaics - Methodology

- A variety of module technologies may be used in Tennessee for rooftop systems, but Navigant used polycrystalline silicon for this analysis to provide average cost and performance data.
- Methodology:
  - Navigant started with internal market data and internal PV system cost model.
  - Navigant benchmarked internal cost data against information form local programs like the TVA Generation Partners Program and the Solar Opportunity Fund.
  - Next, Navigant updated module prices with the data shown in the ground mounted section.
  - Navigant also researched potential labor costs[1].
  - Labor costs are also effected by the maturity of local market and the experience of local installers.
- Navigant accounted for Tennessee-specific requirements for wind speed rating (90 mph).
- Key findings:
  - As discussed in the ground mounted section, module prices have declined significantly since 2008, leading to overall lower system costs.
  - Labor maturity impacts system prices. Due to the relatively small size of the market, installation prices are still higher than more mature markets. However, local incentive programs are over subscribed and even had to turn applications down and revise incentive criteria. This high growth will drive the market and reduce installation price.

Notes:

1. Data from the R.S. Means Cost Databases.

Commercial rooftop system prices will likely fall as the PV industry matures and efficiency increases.

	Polycrystalline PV - Economic Assumptions for Given Year of Installation (2010$)				
	2010	**2015**	**2020**	**2025**	**2030**
Plant Nameplate Capacity (MW$_{DC}$)[1]	0.200	0.200	0.200	0.200	0.200
Project Life (yrs)	25	25	25	25	25
Construction Time (yrs)[2]	0.2-0.3	0.2-0.3	0.2-0.3	0.2-0.3	0.2-0.3
Installed Cost ($/kW$_{DC}$) [3]	5,600	5,000	4,350	3,700	3,100
Fixed O&M ($/kW$_{DC}$-yr)	28	24	21	19	18
Non-Fuel Variable O&M ($/MWh)	0	0	0	0	0
Fuel/Energy Cost ($/MWh)	0	0	0	0	0

Notes:

1. PV is a modular technology, typical commercial rooftop systems can range in size from 10 kW to 2 MW. Navigant picked an average system size.
2. Installing companies have some level in flexibility in installation time because they can just use more people to install faster. This estimate represents an average.
3. This does not include potential increases in property taxes.

Residential systems required more overhead per system than commercial systems and have higher per unit costs.

	Polycrystalline PV - Economic Assumptions for Given Year of Installation (2010$)				
	2010	**2015**	**2020**	**2025**	**2030**
Plant Nameplate Capacity (MW_{DC})[1]	0.005	0.005	0.005	0.005	0.005
Project Life (yrs)	25	25	25	25	25
Construction Time (yrs)[2]	0.02 – 0.03	0.02 – 0.03	0.02 – 0.03	0.02 – 0.03	0.02 – 0.03
Installed Cost ($/kW_{DC}$) [3]	7,100	6,400	5,700	5,100	4,400
Fixed O&M ($/kW_{DC}$-yr)[4]	28	24	21	19	18
Non-Fuel Variable O&M ($/MWh)	0	0	0	0	0
Fuel/Energy Cost ($/MWh)	0	0	0	0	0

Notes:

1. PV is a modular technology, typical residential rooftop systems can range in size from 1 kW to 10 kw. Navigant picked an average system size.
2. Installing companies have some level in flexibility in installation time because they can just use more people to install faster. This estimate represents an average.
3. This does not include potential increases in property taxes.

Installing PV requires other costs – some are up front and others are on-going.

Cost	Definition	Typical Values	Discussion
Insurance	Property Insurance	0.5% to 2% of system value	This will vary by state and system type.
Property Tax	Increase in property tax for rooftop systems or annual property tax paid for ground mounted systems	1% to 2%	Property tax amount will vary significantly throughout TVA's territory
Transmission	New transmission that might need to be build to support ground mounted systems	\$500,000/Mile to \$2,000,000/Mile	The amount of transmission required will vary depending on where and how many ground mounted systems are installed.
Substation Upgrades	Potentially required to connect ground mounted systems at substations	Highly Variable	If a substation has access capacity, upgrades will not be required. However, if upgrades are required, the cost will depend on age of the substation, amount of upgrade required, etc.
Integration Costs	Additional ancillary service costs to manage variable PV resources	Unknown for TVA	The only public solar integration study[1] showed costs ranging from \$1.96 to 5.15/MWh as solar penetration increased to 10%.

Notes:

1. Available at http://www.xcelenergy.com/SiteCollectionDocuments/docs/PSCo_SolarIntegration_020909.pdf

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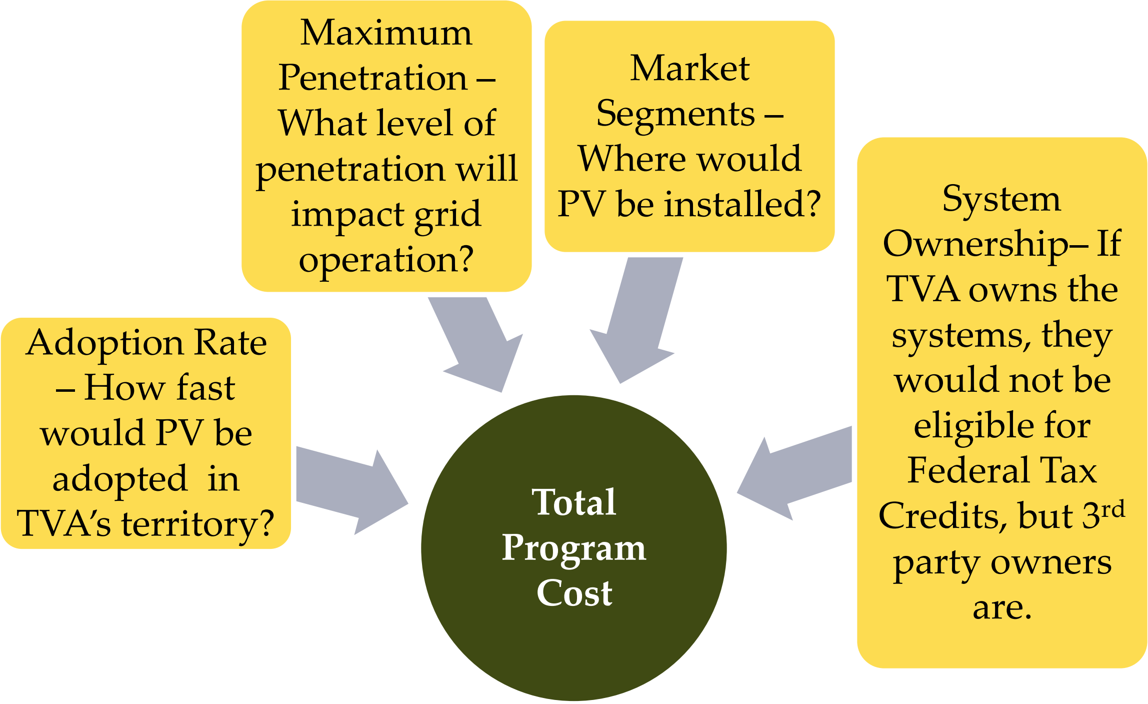
The total program costs will depend on several variables.

Overview

- The objective of this section is to calculate the total costs over 20 years of achieving the three chosen levels of PV penetration.
- Several variables, such as ramp rate, market segmentation, maximum penetration and system ownership will influence the eventual overall cost of the program.
- Given the number and possible level of variables, Navigant ran all possible scenarios to calculate the range of possible costs.



Maximum Penetration – What level of penetration will impact grid operation?

Market Segments – Where would PV be installed?

Adoption Rate – How fast would PV be adopted in TVA's territory?

System Ownership– If TVA owns the systems, they would not be eligible for Federal Tax Credits, but 3rd party owners are.

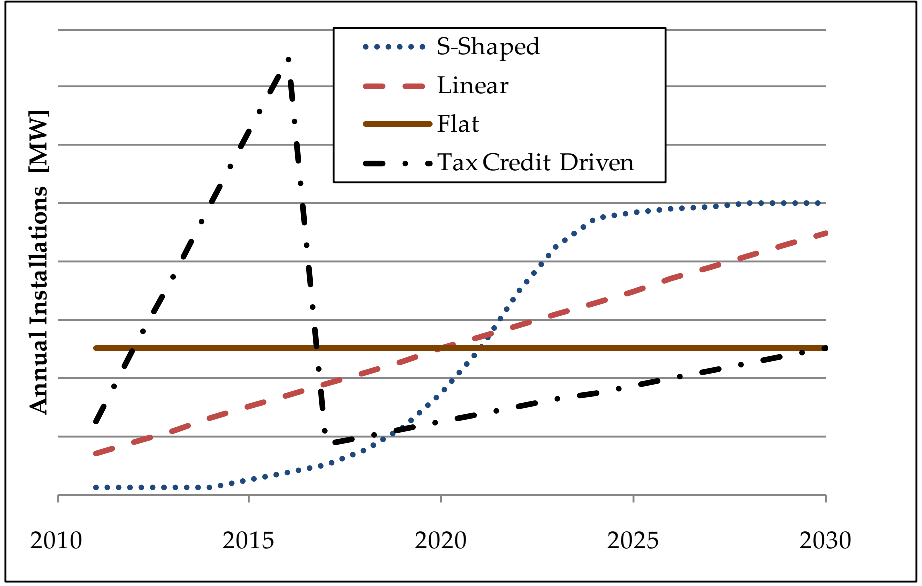
Total Program Cost

How fast systems are adopted will impact overall program costs.

Adoption Rates

- Given the dynamic situation with the costs of adopting PV– costs are expected to fall going forward, but the Federal Investment Tax Credit is expiring at the end of 2016 – when systems are installed will impact the total program cost out to 2030.
- Navigant analyzed four adoption rate scenarios:
  - S-Shaped: This is a typical trend experienced when a new product is introduced into the residential and commercial markets.
  - Linear: This would be experienced if TVA started a program that linearly increased over time or if consumers gradually adopted PV
  - Flat: This could be experienced if TVA started a regular annual procurement of new PV systems.
  - Tax Credit Driven: This scenario could occur if residential and commercial customers purposely install systems in the near-term specifically take advantage of the expiring Tax Credit.

Possible Adoption Rates



TVA is not eligible for the Federal 30% Investment Tax Credit and TVA ownership would result in higher program costs.

System Ownership

- TVA has no Federal tax liability, so it cannot claim the Federal Investment Tax Credit (ITC)[1].
- Residential or commercial customers that would own a system or 3rd party Independent Power Producers that would own a system and sell power to TVA can take the ITC.
- To look at the impact of the ITC impact, Navigant analyzed three system ownership scenarios, taking into account TVA's total debt limit of $30 Billion:
  - TVA owns 10% of the systems
  - TVA owns 20% of the systems
  - TVA owns 30% of the systems

Notes:

1. Note that TVA ownership has other advantages, such as lower cost of capital, but looking at cost of capital is outside the scope of this project.

Navigant calculated the up-front and on-going costs of each combination of variables.

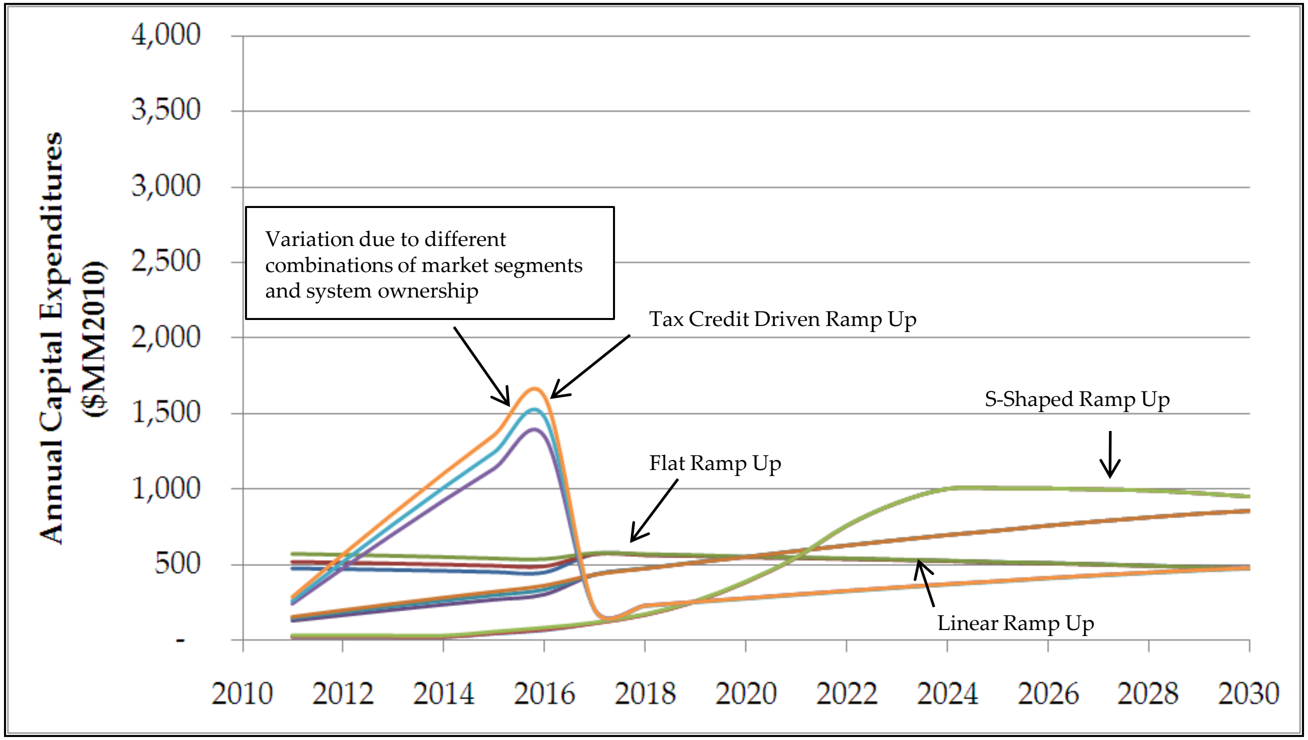
Calculation of Total Costs

- Navigant calculated the up-front and on-going costs of each combination of variables.
- This resulted in 108 different cost scenarios.
- For brevity, this report will show the range of costs for three different combinations of maximum penetration and interconnection point, highlighted below.

Maximum Penetration Level	Minimal Central Station	1/3 Central Station	Majority Central Station
Lower End	2,200	2,600	3,200
Mid Range	3,200	3,600	4,200
Upper End	4,200	4,600	5,200

Case A **Case B** **Case C**

Case A would require between $9,700 and $12,300 Million in capital expenditures.

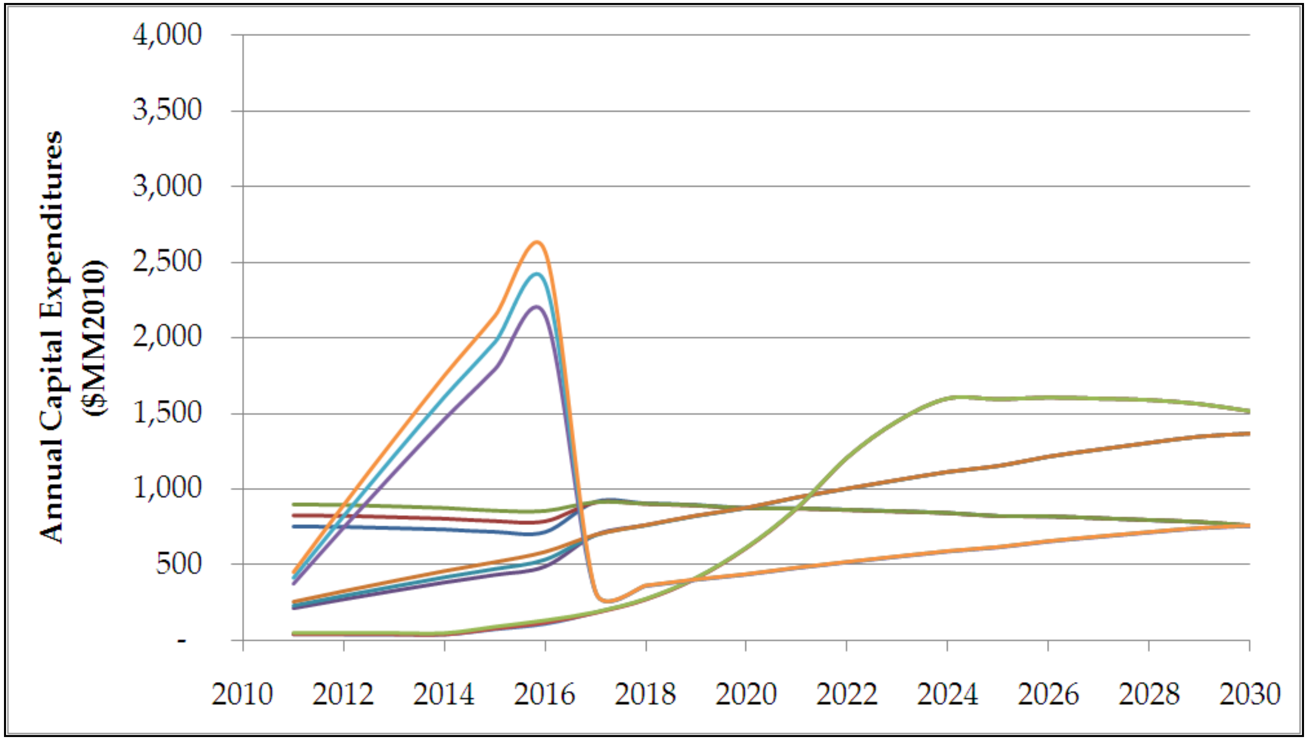


Summary Data – Case A[1]	
Item	**Value**
Total MW Installed (MW_{pDC})	2,200
Total Capital Expenditures[2] ($MM2010)	9,700 to 12,300
Total Operating Expenditures[3] ($MM2010)	1,200 to 2,500
Operating Expenditures in 2018 ($MM2010)	10 to 120

Notes:

1. This includes capital costs (including equipment, installation, permitting, and development fees), It does not include transmission, or substation costs.
2. This includes operation & maintenance costs, insurance costs, and property taxes. It does not include potential integration costs.
3. Note that this is in 2010 dollars and does not account for inflation or the time value of money.

Case B would require between $15,500 and $17,400 Million in capital expenditures.



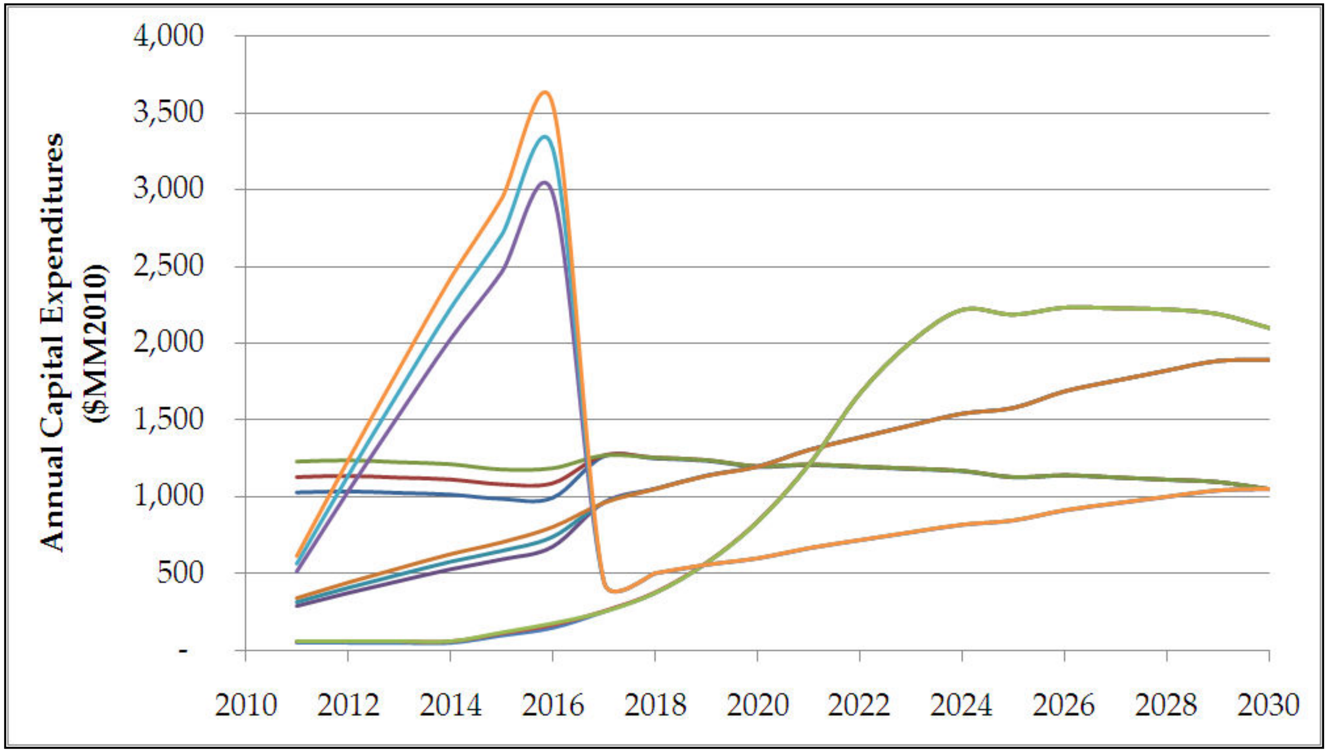
Summary Data – Case B[1]

Item	Value
Total MW Installed (MW_{pDC})	3,600
Total Capital Expenditures[2] ($MM2010)	15,500 to 17,400
Total Operating Expenditures[3] ($MM2010)	1,900 to 4,000
Operating Expenditures in 2018 ($MM2010)	16 to 195

Notes:

1. This includes capital costs (including equipment, installation, permitting, and development fees), It does not include transmission, or substation costs.
2. This includes operation & maintenance costs, insurance costs, and property taxes. It does not include potential integration costs.
3. Note that this is in 2010 dollars and does not account for inflation or the time value of money.

Case C would require between $21,400 and $24,100 Million in capital expenditures.



Summary Data – Case C[1]	
Item	**Value**
Total MW Installed (MW_{pDC})	5,200
Total Capital Expenditures[2] ($MM2010)	21,400 to 24,100
Total Operating Expenditures[3] ($MM2010)	2,700 to 5,600
Operating Expenditures in 2018 ($MM2010)	22 to 272

Notes:
1. This includes capital costs (including equipment, installation, permitting, and development fees), It does not include transmission, or substation costs.
2. This includes operation & maintenance costs, insurance costs, and property taxes. It does not include potential integration costs.
3. Note that this is in 2010 dollars and does not account for inflation or the time value of money.

Navigant's analysis found that delaying installations would likely result in overall lower capital costs.

Impact of Each Variable

- Increasing the PV penetration level increases costs.
- The higher the proportion of ground mounted systems, the lower overall program costs (on a real basis) are.
    - Using Case A (Lower End of Penetration) as an example, getting to 2,200 MW with a majority of ground mounted systems (~60%) would cost between $8,700 and $11,000 Million, or ~10% lower than getting to 2,200 MW with mostly rooftop systems.
- The adoption rate had up to a 6% impact in overall program costs (on a real basis)
    - The S-Shaped and Tax Credit Driven adoption rates resulted in ~6% lower capital costs than the Linear rate.
    - The Flat adoption rate was 4% lower the Linear rate.
- Because TVA can not take the ITC, their capital costs will likely be higher. As a result, the lower TVA's ownership, the lower overall capital costs were.
- In summary, a program that was predominantly ground mounted and had mostly 3rd party ownership would likely result in the lowest capital costs. Adoption rate would impacts costs, but to a lesser degree.

Program Costs » Conclusions

Conclusions

- Navigant's has found that between 5% and 15% penetration of PV (on a peak basis) will not likely impact grid operation significantly and is feasible given the technical potential in TVA's territory, but the point of PV interconnection (DG vs. central station) will influence the level, with central station likely being able to handle higher penetration.
- The capital costs will range from $9,700 Million to 24,100 Million (in 2010 dollars) depending on penetration level.
- Given the various dynamics in the PV industry (e.g. federal tax credits, different costs by market segment, etc.), Navigant's analysis found that a program that was predominantly ground mounted and had mostly 3rd party ownership would likely result in the lowest capital costs.

Next Steps

- Navigant's recommended next steps in analyzing PV in TVA's territory would be:
    - Assess the benefits (e.g. avoided costs, potential capacity contribution, employment impacts, etc.) of installing PV in TVA's territory.
    - Conduct a GIS analysis to identify candidate sites for ground mounted systems. Such an analysis was outside of Navigant's scope of work, so Navigant could not develop definitive assumptions on installations by market segment.
    - After this, conduct load flow studies to understand if new or upgraded transmission would be required. Navigant was not able to estimate these costs.
    - Conduct a solar integration study to calculate expected integration costs.

Key Contacts

Lisa Frantzis, Managing Director-in-Charge
Managing Director
Burlington, MA
(781) 270-8314
lfrantzis@navigantconsulting.com

Jay Paidipati, Project Manger
Associate Director
San Francisco, CA
(415) 399-2191
jpaidipati@navigantconsulting.com

Shalom Goffri
Managing Consultant
Burlington, MA
(781) 270-8374
Shalom.Goffri@navigantconsulting.com

Maria Duaime
Consultant
Burlington, MA
(781) 270-8355
Maria.Duaime@navigantconsulting.com

Tucker Moffat
Consultant
Burlington, MA
(781) 270-8367
Tucker.Moffat@navigantconsulting.com

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