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Reducing Uncertainty in Wind Project Energy Estimates

SECONDWIND by Vaisala

A Cost-Benefit Analysis of Additional Measurement Campaign Methods

Wind project energy production estimates are a key element in determining how a wind project can be externally financed, and the most important input into an energy estimate is the wind resource assessment. The future performance of a planned wind project is commonly evaluated based on historical wind data combined with one or more years of site measurements. Consultants who evaluate the wind resource for project financings quantify the uncertainty that stems from various site conditions and wind resource assessment methods. When other factors are equal, a more thorough resource assessment campaign makes it possible to obtain more favorable financing.

A common situation faced by wind developers occurs when a met mast has been collecting measurements for a period of time. Based on data available at that time, uncertainties in the wind resource assessment may make it difficult to obtain financing; additional data may make financing feasible, or provide better terms. This white paper compares the cost of renting a Triton to the purchase of a met mast for additional measurements, and calculates the increase in project value from each method. The comparison shows that using the Triton for the additional measurement campaign reduces uncertainties and provides a cost-effective way to increase project value.

The Triton® Sonic Wind Profiler is a wind measurement system that can be used cost-effectively to reduce uncertainty in wind project financing. This cost-benefit analysis examines the application of Triton in two areas key to a thorough wind resource assessment: wind shear measurement and site characterization.

Background

Wind Resource Assessment

The classical approach to wind resource assessment uses anemometry: anemometers and wind vanes mounted on met masts to measure wind speed and direction. A new class of wind measurement technology — remote sensing — has recently been introduced to the commercial wind industry on a wide scale. Remote sensing technology includes SoDAR (sonic detection and ranging) and LiDAR (light detection and ranging) — a class of instruments that measure wind characteristics by emitting sound or light waves and using the echoes/reflections of the waves to calculate wind speed and direction at various heights above ground.

Wind project developers are usually not choosing between met masts and remote sensing systems — they are choosing whether to supplement their mast-based campaigns with remote sensing. Unlike met masts, which measure at discrete points, SoDARs and LiDARs typically measure across the turbine rotor area and provide horizontal and vertical wind speeds and wind direction at more heights. This higher data coverage can be a valuable part of the wind resource assessment.

This white paper demonstrates how the Triton Sonic Wind Profiler, a SoDAR commercialized in 2008 by Second Wind (now merged with Vaisala), can be used in combination with an anemometry-based measurement campaign to reduce uncertainty in the project energy estimates and cost-effectively improve the value of the project. While LiDAR can also be used to reduce uncertainty in energy estimates and improve financing terms, LiDARs are more expensive than SoDARs and are not considered in this white paper. Other SoDARs may also be used for the same purposes. The costs and results discussed in this white paper are specific to the Triton.

Wind Project Financing

Wind project financing takes many forms, including direct equity investments, tax-equity investments, and project debt. Most projects have some combination of these. This white paper focuses on project debt and how the change in energy estimate uncertainties impacts the amount of leverage a project may carry. Leveraging a higher level of debt generally allows a project to realize a higher return on the direct equity portion of the project financing.

Wind resource uncertainties drive the probability distribution of expected energy production for a project. Figure 1 shows both one-year and 20-year probability distributions for a typical project. As seen in the blue 20-year curve, the P50 energy production level is the central energy production estimate; the probability of producing more than this amount of energy over the 20-year expected life of the project is 50%. The P99 level represents an energy production value that has a 99% probability of exceedance over the life of the project. The orange one-year curve represents the values for any one year within the 20-year project life. The shape of these distributions is determined by the energy assessment uncertainties and the variability of the wind resource; the wider the spread between the P99 and the P50, the wider the distribution, and the more uncertain the energy estimate. Twenty-year average values are less uncertain than one-year values because the variability inherent in one-year values is averaged out over the long term.

Lenders typically size project debt at a level that can be serviced even at the P99 energy production level. For example, the debt size may be calculated with a debt service coverage ratio (DSCR) of 1.0 times the one-year P99 cash flows. In other words, at a given interest rate, what annual debt payments can be made, or "covered," by the project with the annual cash flow that is generated if the project produced energy at the one-year P99 level? With this common method of debt sizing, the wind resource uncertainties that drive the P99 energy production value have an important role in the project financing.

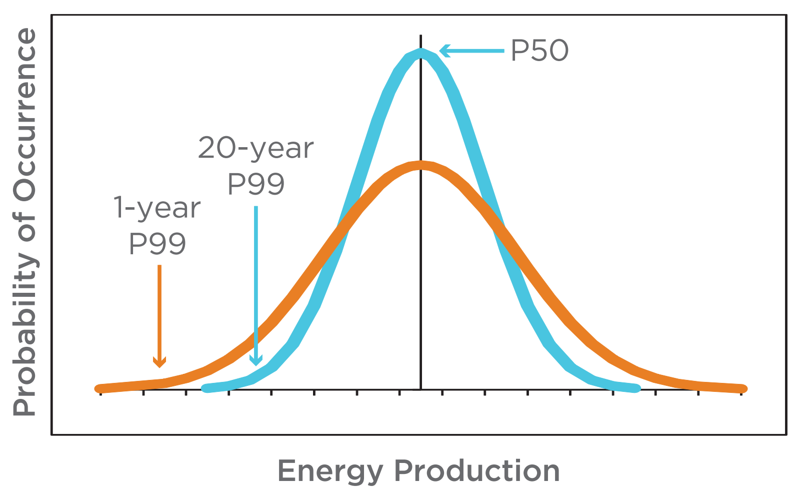


Figure 1: Illustration of the one-year and 20-year energy production probability distribution for a wind power project

Reducing Uncertainty: A Strategic Approach

To make the greatest impact on the financing of a project by reducing wind resource uncertainty, a project developer must evaluate the uncertainties and focus on reducing the largest uncertainty categories. Table 1 summarizes the sources of uncertainty.

Sources of Uncertainty*

	Average	Typical Range
Measurement Accuracy: the uncertainty in the accuracy of the measurements. Includes: ▪ Accuracy of instruments ▪ Measurement interference such as SoDAR echoes or tower effects ▪ Data capture and data quality ▪ Quality control and validation	2.4%	1.5–3.5%
Vertical Extrapolation: the uncertainty associated with extrapolating measurements to the turbine hub height and across the turbine rotor.	2.0%	1–3%
Historic Climate: the uncertainty of estimating the long-term wind resource based on a short on-site measurement period (typically 1 to 4 years). Includes: ▪ Uncertainty in Measure Correlate Predict (MCP) analysis ▪ Quality and consistency of long-term data sets	2.3%	1.5–4%
Future Variability: the variability in the wind resource.** Includes: ▪ Interannual variability of wind over the project life ▪ Changes in wind speed frequency distributions ▪ Changes in long-term average wind speeds	2.1%	1–3%
Spatial Variability: the uncertainty associated with estimating the wind resource at each turbine location. Includes: ▪ Uncertainty associated with limited measurement across the site ▪ Uncertainty introduced by wind flow modeling	2.6%	1–4%
Energy Losses: the uncertainty associated with estimating energy losses. Includes: ▪ Turbine availability and performance issues ▪ Wake losses ▪ Environmental and electrical losses	2.0%	1–3%

Table 1

**Uncertainty values are listed as one standard deviation and a percentage on wind speed.*

***The future variability values presented in the table are based on the 20-year variability. The one-year (or year-to-year) variability is typically 4–6%.*

The average and typical uncertainty values presented in Table 1 and Figure 2 are based on a survey of approximately 200 North American pre-construction energy estimates of utility-scale wind farms conducted by DNV KEMA. The largest source of uncertainty is typically spatial variation — there are usually many fewer measurement points than proposed wind turbine locations. However, for any given project the distribution of uncertainties will be different based on the size of the project, the complexity of the terrain, the height of the proposed turbines, the length of the wind measurement campaign, the availability of historical wind data, and many other factors. For example, Figure 3 illustrates the uncertainty breakdown for a project where the variation in wind resource across the project is not well characterized by the on-site measurements.

Large uncertainty categories disproportionately impact the overall uncertainty (and thus the difference between the P50 and the P99 energy estimates) because uncertainty categories are combined in a non-linear manner, by taking the square root of the sum of the individual uncertainties squared. Figure 3 illustrates this effect. It shows the individual uncertainties (on the left) and how these uncertainties contribute to the overall uncertainty (on the right). In this example the largest uncertainty, spatial variation, takes up a larger piece of the pie when its impact on the overall uncertainty is considered. To get the most value out of their investments, developers should focus additional efforts on reducing the largest areas of uncertainty for their projects.

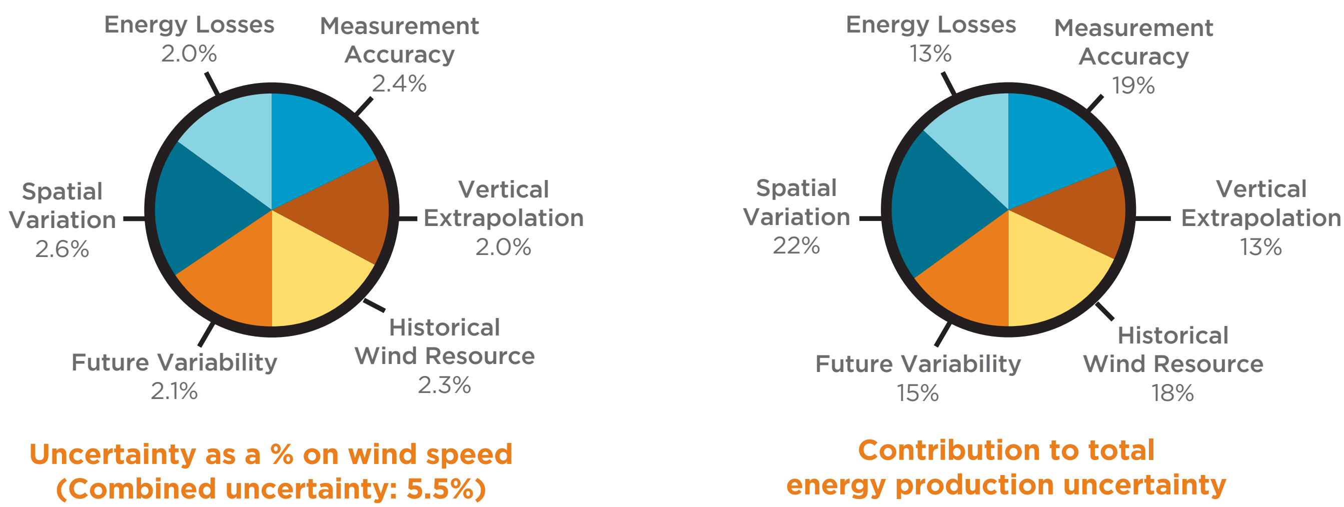


Figure 2: Average of uncertainties from 200 pre-construction energy assessments

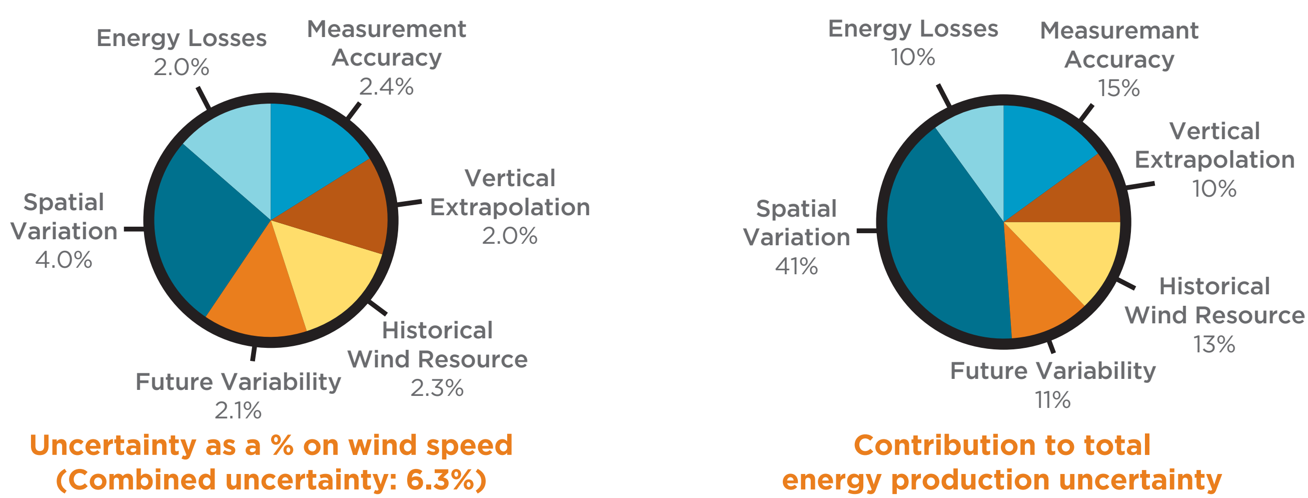


Figure 3: Distribution of energy uncertainties in a scenario with high spatial variation

Reducing Uncertainty through Measurement

Choices of measurement height, location, and duration, as well as the number of measurement locations, affect uncertainty in wind resource assessment. Uncertainty is reduced mainly through additional measurement. For example, the historic climate uncertainty can be reduced by measuring for a longer period. At many locations, measuring the on-site wind resource for only one year comes with the risk that the measured year is roughly 4% to 6% more or less windy than the long-term average. There can be significant uncertainty in adjusting the one year of on-site data to represent the long-term average with off-site reference data or modeled data sets. With more than one year of on-site data, the uncertainty of capturing the long-term wind speed is reduced. Measurement options for reducing vertical extrapolation and spatial variability uncertainties are discussed below.

Reducing Vertical Extrapolation (Shear) Uncertainty

Wind turbines used in new projects are typically taller and have larger rotors than previous turbine models. This typically results in fewer turbines and less land area required to generate a given amount of power. Typical turbine hub heights are 80 m to 100 m, with some reaching to 140 m. Rotor diameters are increasing as well; 80 m to 120 m is common. A 60-m met mast cannot measure winds at heights covered by the blades of modern utility-scale turbines. Within the North American wind market, this is a challenge for wind resource assessment because of the additional permitting required to install a mast taller than 60 m. Taller masts of 70 m and 80 m still fail to capture wind information across the full rotor sweep of the modern turbines as shown in Figure 4, which depicts an 80-m hub height turbine.

To estimate wind speeds at higher heights using met mast data, the wind industry extrapolates using the wind speed measurements at lower heights. Information about the surrounding terrain and vegetation and the atmospheric conditions are often used in the extrapolation. The extrapolation methods are rooted in the assumption that data gathered at lower heights represents the conditions at higher heights. However, this is often not the case, leading to uncertainty in the extrapolated wind speeds. A Second Wind (now Vaisala) study of 111 data sets where measured data were compared to extrapolated data found uncertainties in annual energy production calculations ranging from 3.0% to 4.2%.[1]

The uncertainty associated with vertical extrapolation (wind shear) can be reduced in two ways: 1) by measuring at higher heights, reducing the need to extrapolate and 2) by validating the shear extrapolations made using met mast data with higher-height measurements from SoDARs, LiDARs and taller met masts. For example, if measurements have been made using a 60-m met tower for three years, deploying a SoDAR nearby for an additional year to measure at heights from 40 m to 140 m can yield a better understanding of the wind shear profile. The hub-height SoDAR data can be used directly in an energy assessment without vertical extrapolation and unusual shear patterns across the turbine rotor heights can be identified. Additionally, the SoDAR data can help the analyst identify possible sources of error when data are extrapolated at other locations.

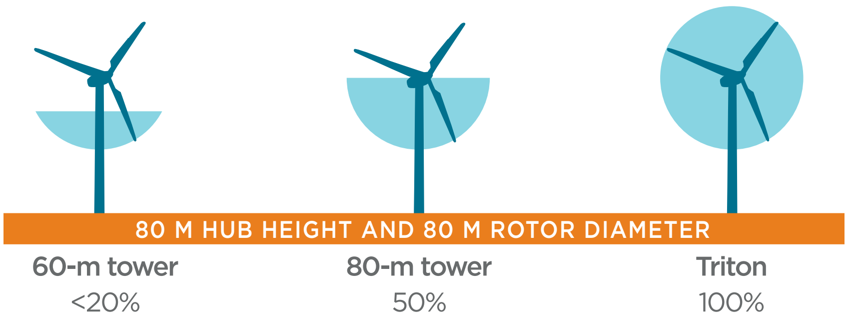


Figure 4: Illustration of data capture for different measurement methods

Reducing Spatial Variation (Wind Flow Modeling) Uncertainty

Spatial variation uncertainty results from the differences in wind characteristics across a site due to terrain, surface roughness, and other elements. Measurements are typically taken at relatively few locations within the project area, but the wind resource must be evaluated at all locations where wind turbines might be deployed. Economically, it is not feasible to measure the wind at every location where a turbine might be installed.

To estimate energy production, the analyst must estimate the wind resource across the site based on data gathered at discrete locations. To accomplish this, the industry relies almost exclusively on wind flow modeling. There are several different types of wind flow models, each based on empirical models or simplifications of physical equations, including linear flow models, non-linear flow or computational fluid dynamics (CFD) models, and dynamic mesoscale atmospheric simulation models.[2] Studies have found significant error and uncertainty in wind flow models.[3,4,5] For most projects, the greatest share of uncertainty in wind resource assessment is the spatial variation (wind flow modeling) category.

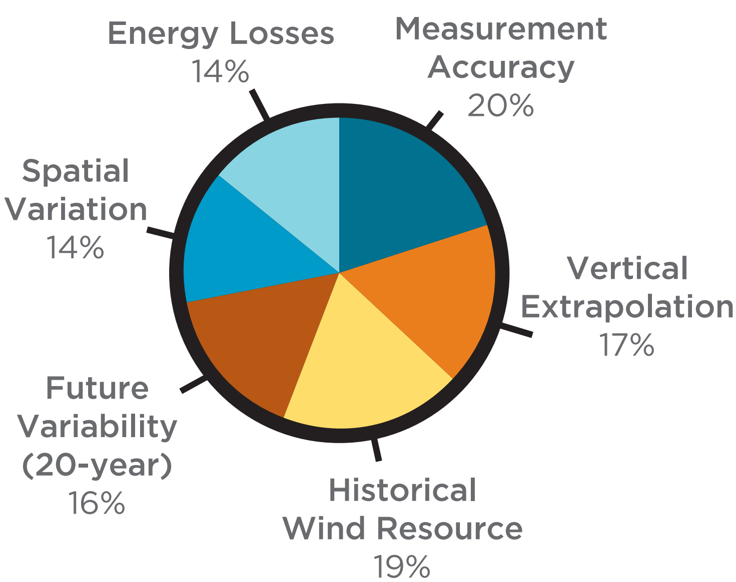
The most effective way to reduce this uncertainty is through additional measurements to better characterize the wind flow across the site.

Cost-Benefit Analysis of Additional Measurement

This white paper evaluates two common project development scenarios, comparing the cost of additional measurement at a pre-construction wind project to the increase in project value. The benefit of the additional measurements is assessed in terms of the change in size of the project debt achieved relative to the incremental cost of the Triton or met mast investment. The cost-benefit analysis for the two project development scenarios is described below, followed by a description of the measurement cost and financial model assumptions.

Scenario 1: Simple Site with 100-m Turbine Hub Height

This scenario represents a 150 MW wind project development in simple terrain with a 100-m proposed turbine hub height. Two 60-m met towers were installed two years ago and an initial evaluation of the energy assessment uncertainties showed that vertical extrapolation is one of the largest contributors to the overall uncertainty, as illustrated in Figure 5.



The following options were evaluated for the purpose of reducing the energy assessment uncertainty:

- Measuring for an additional year with existing measurements; no additional measurements (baseline scenario)
- Adding a one-year hub-height (100-m) met mast measurement
- Adding a one-year SoDAR measurement
- Adding a six-month SoDAR measurement

Figure 5: Baseline uncertainties (contribution to overall uncertainty) in 100-m hub height scenario

For the one-year hub-height (100-m) met mast measurement, the new met mast was located in an area of the project where the wind resource was not well characterized. For the one-year SoDAR measurement the SoDAR was initially located next to one of the existing masts in order to develop a relationship between the met mast and the SoDAR measurements; it was then moved to another location within the project area. For the six-month SoDAR measurement, the SoDAR was located next to the met mast for the full measurement period.

Adding measurements to the project reduced the vertical extrapolation uncertainty. The spatial variation uncertainty was reduced for the one-year met mast and one-year SoDAR scenarios due to measurements being collected at a new location. The reduction in the measurement accuracy uncertainty was due to the addition of independent measurements. This is particularly true for the hub-height mast measurements. It was assumed that Class 1 anemometers were installed on a goal-post mount above the tower, reducing tower effects. A comparison of the uncertainty reduction, measurement costs, and project financials for each option is presented in Table 2. The cost-benefit analysis is graphically summarized in Figure 6.

100-m Hub Height Turbine Scenario and Results

Uncertainty Category	Baseline	100-m mast 1 yr	Triton 1 year	Triton 6 months
UNCERTAINTY ON WIND SPEED				
Measurement Accuracy	2.4%	2.1%	2.3%	2.4%
Vertical Extrapolation	2.2%	1.0%	0.8%	1.4%
Historical Wind Resource	2.3%	2.3%	2.3%	2.3%
Future Variability (20-year)*	2.1%	2.1%	2.1%	2.1%
Spatial Variation	2.0%	1.7%	1.7%	2.0%
Energy Losses	2.0%	2.0%	2.0%	2.0%
Combined Uncertainty	**5.3%**	**4.7%**	**4.7%**	**5.0%**
ENERGY PRODUCTION				
P50 Production (GWh/year)	460	460	460	460
1-yr P90 Production (GWh/year)	398	402	402	400
1-yr P99 Production (GWh/year)	348	355	355	351
P99 to P50 Ratio	75.6%	77.2%	77.1%	76.3%
Increase in P99 Production (GWh/year)	**NA**	**7**	**7**	**3**
COST-BENEFIT COMPARISON				
Incremental Measurement Cost**	**NA**	**$154,800**	**$54,300**	**$37,900**
Change in Project Debt Size ($millions)	**NA**	**+ $4.9**	**+ $4.5**	**+ $2.2**

Table 2

**The 20-year variability is presented; however, the P99 results are based on the one-year variability which is larger.*

***Costs include equipment, power supply, shipping, installation, relocation (if appropriate), data collection, and monitoring. It is assumed that the SoDAR is rented rather than purchased. Renting the mast is considered impractical.*

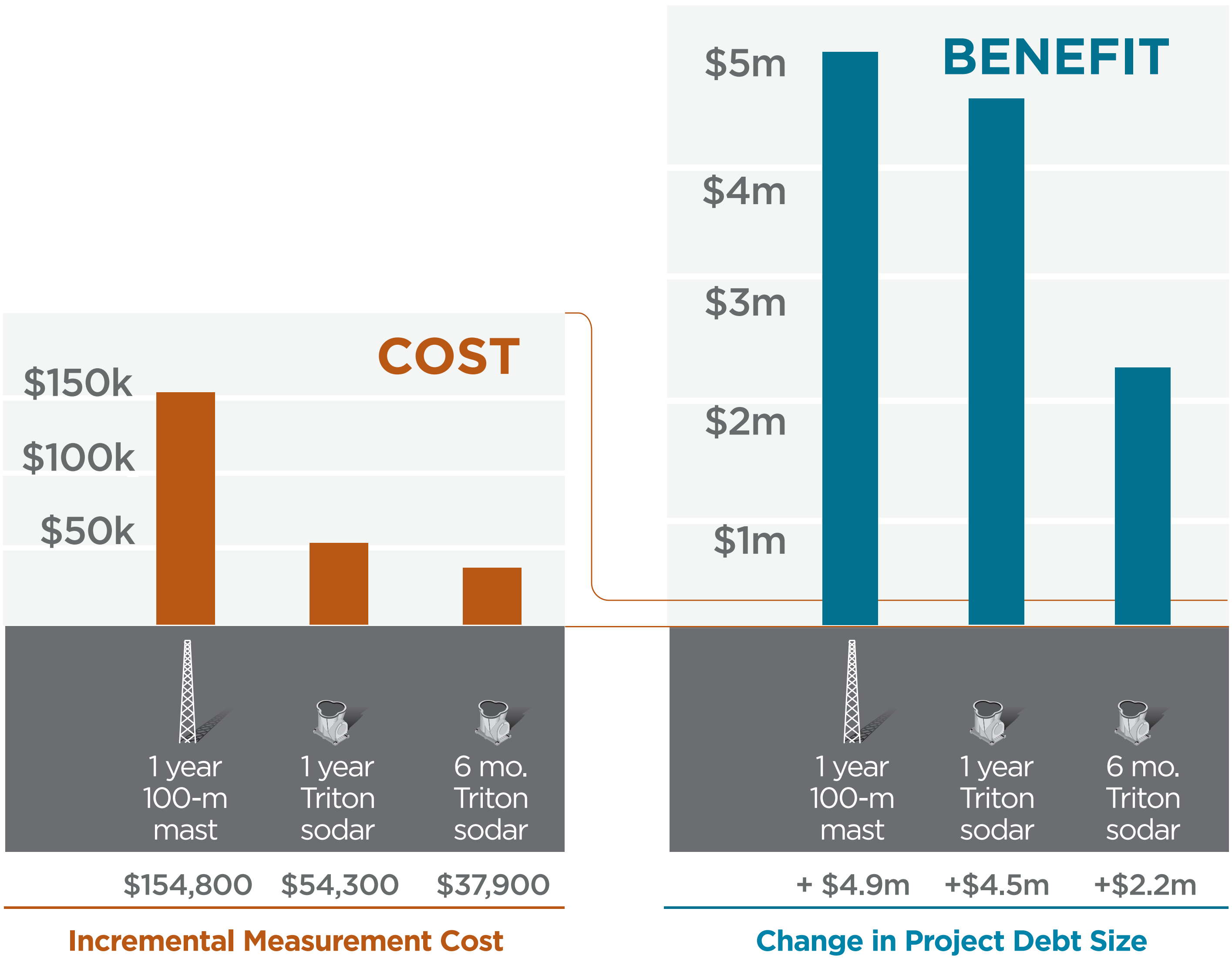
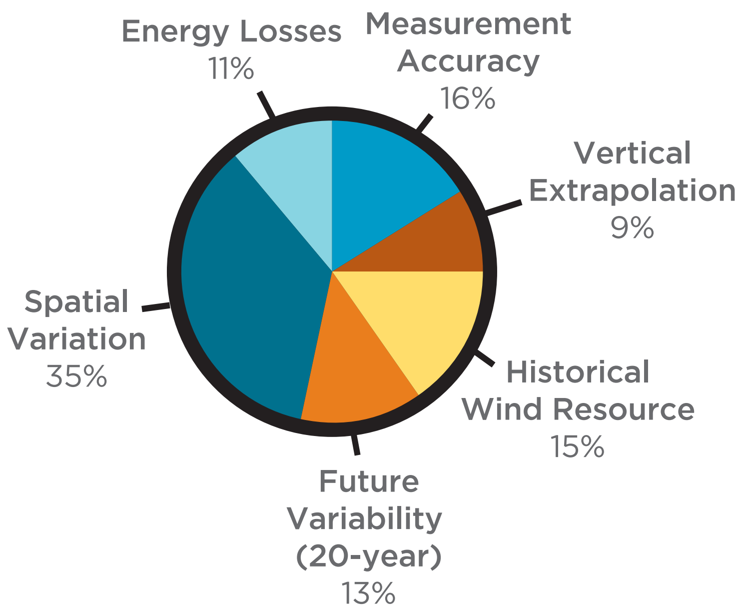


Figure 6: Incremental measurement costs and changes in project debt size, tall turbine scenario

As shown in Table 2, the SoDAR options are less expensive than the hub-height met mast, but the results for the one-year SoDAR measurement option and the met mast are similar in terms of increase in project debt size. The one-year SoDAR option creates a $4.5 million increase in debt size from the $54,300 rental of a Triton. While the six-month SoDAR measurement creates the smallest overall benefit, it allows for a debt level increase with less up-front cost than the met mast option. A higher debt size reduces the amount of equity a developer is required to contribute to a project, so the measurement investments allow the developer to invest this “saved” equity in other projects.

Scenario 2: Complex Terrain Site

This scenario represents a 150 MW wind project development in complex terrain with an 80-m proposed turbine hub-height. Two 60-m met towers were installed two years ago; however, these measurements do not fully characterize the variation of the wind across the site. An initial evaluation of the energy assessment uncertainties showed that the largest contributor to the overall uncertainty is the spatial variation uncertainty, as illustrated in Figure 7.



The following measurements options were evaluated for the purpose of reducing the energy assessment uncertainty:

- Measuring for an additional year with existing measurements; no additional measurements (baseline scenario)
- Adding a one-year 60-m met mast measurement
- Adding a one-year SoDAR measurement
- Adding a one-year 60-m met mast and one-year SoDAR measurement

Figure 7: Baseline uncertainties (contribution to overall uncertainty) in complex terrain scenario

For the SoDAR measurement scenarios, the SoDAR was initially located next to one of the existing towers in order to develop a relationship between the met mast and the SoDAR measurements; it was then moved to another location within the project area of similar terrain complexity. It was assumed that the comparison between the SoDAR and the met mast illustrated that the SoDAR accuracy and uncertainty were similar to those typically observed at simple terrain sites. However, at some complex sites there may be higher uncertainty associated with SoDAR measurements if the flow above the SoDAR is not homogeneous. Adding measurements to the project reduced the spatial variation uncertainty. The vertical extrapolation uncertainty was also reduced for the scenarios with SoDAR due to the measurement of wind speeds above 60 m. The reduction in the measurement accuracy uncertainty was due to the addition of independent measurements.

A comparison of the uncertainty reduction, measurement costs, and project financials for each option is presented in Table 3, which shows that the 60-m met mast option is the least expensive but results in a smaller increase in debt size relative to the one-year SoDAR option. However, the largest increase in debt size is achieved by deploying both a SoDAR and a met mast. Figure 8 graphically summarizes the costs and benefits of the different measurement campaigns.

Complex Terrain Scenario and Results

Uncertainty Category	Baseline	60-m mast 1 yr	Triton 1 year	Triton & mast 1 yr
UNCERTAINTY ON WIND SPEED				
Measurement Accuracy	2.4%	2.3%	2.4%	2.3%
Vertical Extrapolation	1.8%	1.8%	1.5%	1.5%
Historical Wind Resource	2.3%	2.3%	2.3%	2.3%
Future Variability (20-year)*	2.1%	2.1%	2.1%	2.1%
Spatial Variation	3.5%	3.0%	3.0%	2.6%
Energy Losses	2.0%	2.0%	2.0%	2.0%
Combined Uncertainty	**5.9%**	**5.6%**	**5.5%**	**5.3%**
ENERGY PRODUCTION				
P50 Production (GWh/year)	420	420	420	420
1-yr P90 Production (GWh/year)	360	362	363	364
1-yr P99 Production (GWh/year)	311	315	315	318
P99 to P50 Ratio	74.0%	74.9%	75.0%	75.7%
Increase in P99 Production (GWh/year)	**NA**	**4**	**4**	**7**
COST-BENEFIT COMPARISON				
Incremental Measurement Cost**	**NA**	**$39,800**	**$54,300**	**$94,100**
Change in Project Debt Size ($millions)	**NA**	**+ $2.4**	**+ $2.8**	**+ $4.6**

Table 3

**The 20-year variability is presented; however, the P99 results are based on the one-year variability which is larger.*

***Costs include equipment, power supply, shipping, installation, relocation (if appropriate), data collection, and monitoring. It is assumed that the SoDAR is rented rather than purchased. Renting the mast is considered impractical.*

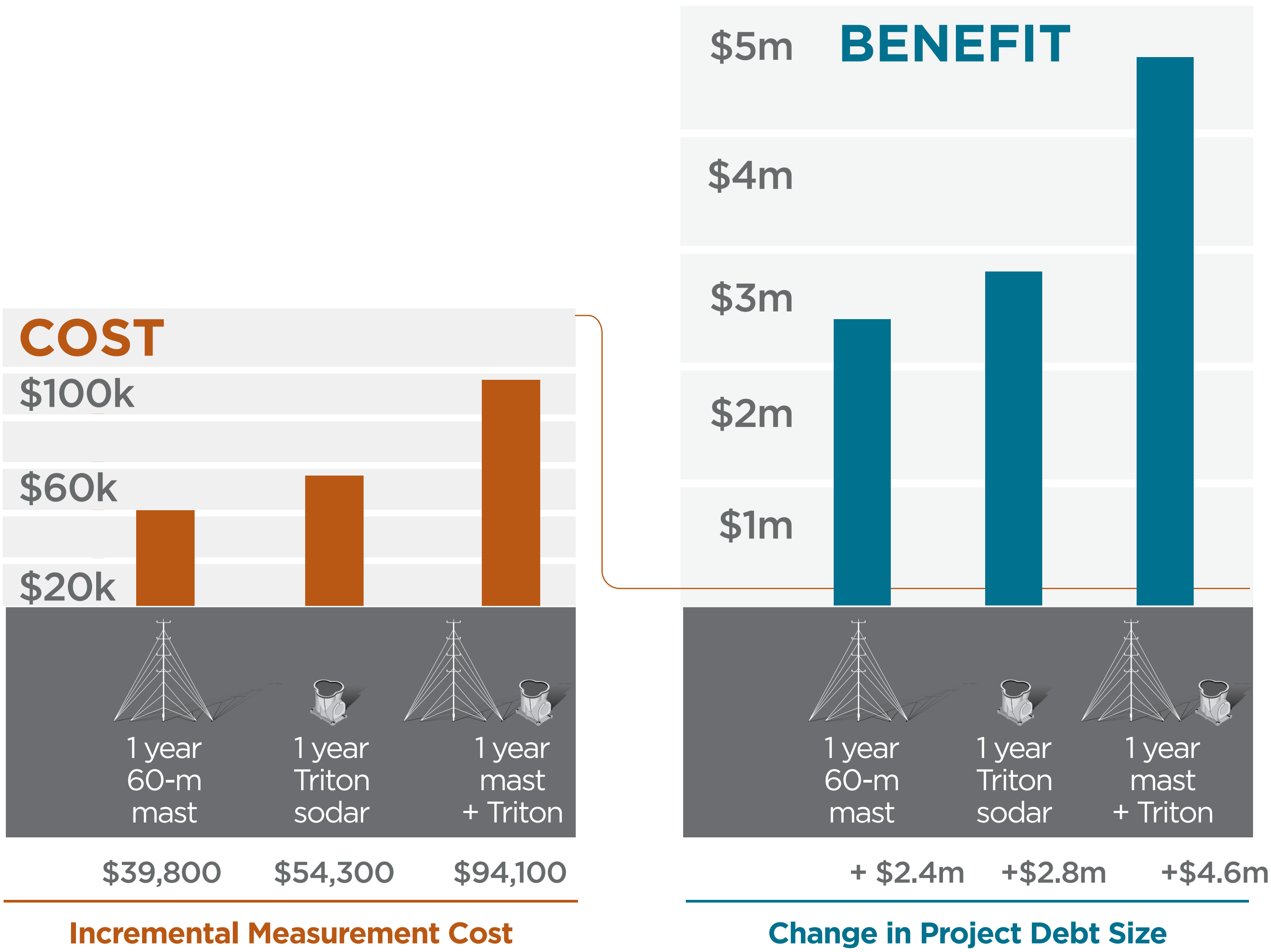


Figure 8: Incremental measurement costs and changes in project debt size, complex terrain scenario

Analysis Assumptions

This analysis was based on hypothetical cases designed to represent common project development scenarios, measurement options, assessment uncertainties, and financing terms. Actual results will depend on specifics such as project size, terrain, previous measurement campaign and duration, turbine type, capital and O&M costs, interest rate, discount rate, power purchase price and many other factors.

The measurement options considered in the scenarios are not comprehensive. SoDARs, LiDARs and met masts can be used to reduce energy assessment uncertainty and different measurement durations can be pursued. Cost, accuracy, reliability, permitting requirements, deployment time, and other factors should be considered when selecting equipment.

Additionally, it was assumed that the met mast and SoDAR provided quality data at high data recovery rates. However, this can vary based on the site conditions. For example, cup anemometers are affected by the distortion of flow around the tower and can freeze in icy conditions and SoDAR data can be affected by precipitation and echoes from nearby trees or structures. Proper documentation, siting, monitoring, and maintenance are necessary to ensure quality data.

This analysis assumed that the P50 annual energy production did not change due to additional measurements. In practice, additional measurements from the existing data sources, or from additional SoDARs or met masts, will increase or decrease the P50 value because more is known about the wind resource. While the P50 can increase or decrease due to the additional measurements, the P99 will typically increase relative to the P50 because the energy production estimate becomes more certain. In some situations, such as high negative shear or measurements of lower wind speeds across the project, the P50 and P99 values will both decrease but the P99 will move closer to the P50.

Measurement Costs Assumptions

Item	Cost
100-m met mast — equipment and installation*	**$150,000**
60-m met mast — equipment and installation*	**$35,000**
Triton 12-month rental	**$36,000**
Triton six-month rental	**$24,000**
Triton installation and commissioning	**$5,000**
Triton relocation	**$2,000**
SoDAR shipping, decomissioning, fuel costs, etc.	**$4,500**
Data monitoring and analysis (per month per SoDAR or met mast)	**$400**

Table 4

**The residual value of the met mast, which would likely bring value to the developer beyond the first year of measurement, was not considered in the analysis. Actual costs will vary.*

Measurement Cost Estimates

Costs used in this analysis included the equipment, power supply, shipping, installation, relocation (if appropriate), and data collection and monitoring cost, as summarized in Table 4.

Pro Forma Financial Model

DNV KEMA developed a project cash flow model to assess costs, revenues and project debt financing for each case. The model incorporates capital expenditures, energy production revenues, operating expenses, renewable energy tax incentives, corporate income and property taxes, and financing costs. The O&M costs and project capital cost inputs were derived from DNV KEMA's proprietary cost models, which include data from numerous operating projects. The proforma model is used to calculate the project cash flows, achievable debt size, and rates of return based on P50 and P99 energy production levels. The model results were compared to evaluate the change in the overall project value for each measurement scenario and the change in the project debt.

The project benefits from additional data because the increased resource assessment certainty narrows the spread between the P50 and P99 energy production estimates (by increasing the P99 production). This results in higher revenue estimates for the P99 case, which is commonly a driver in setting the loan amount. A higher loan amount allows the project developer to reduce its required equity investment.

Each scenario incorporated the following project financing assumptions:

- Project debt size is determined based on a debt service coverage ratio of 1.0 on the one-year P99 cash flows, and also meets a minimum debt service coverage ratio of 1.4 or more each year on the P50 cash flows
- Interest rate on the project debt is 5.5%, with a term of 17 years
- Project utilizes the Production Tax Credit at 2.2 cents per kWh for the first 10 years of the project life
- Corporate income tax rate of 35%; Annual inflation rate of 2.5%
- Project utilizes an accelerated asset depreciation schedule

Conclusions

Thorough resource assessment campaigns are important for understanding expected energy production and increasing project values. Sources of uncertainty should be evaluated and measurement campaigns should be adapted to reduce the largest uncertainty category in order to have the largest benefit. The above case studies illustrate that deploying a Triton Sonic Wind Profiler can achieve benefits in a cost-competitive manner. Conventional met masts can also provide increased project returns and larger debt size. In order to determine the most appropriate assessment campaign for any particular project, a cost-benefit analysis should be conducted based on the specific circumstances of the project.

This white paper was co-written by DNV KEMA and based on their analysis.

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Through the combined expertise of Vaisala, a global leader in atmospheric observation, and Second Wind, a global leader in remote sensing technology and data services for the wind energy industry, we offer an integrated suite of wind measurement solutions.

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