Interview

An Experienced Perspective

John Berdner, SolarEdge Technologies

Changing the US PV Industry…Again

John Berdner has more than 25 years of experience in the design, manufacture and use of PV equipment and systems. As the founder and president of SMA America, John was integral in launching the first UL-listed grid-direct string inverters with 600 Vdc source circuits, which revolutionized the way utility-interactive PV systems are deployed in North America. In April 2010, after serving as the VP of technology for groSolar, he joined SolarEdge, an Israeli power electronics start-up that offers module-level dc-to-dc optimizers, transformerless fixed-voltage inverters and web-based module-level performance monitoring. As the company's North American general manager, John is once again poised to bring disruptive, next generation PV technology to the North American market.

—Ryan Mayfield, SolarPro *magazine technical editor, recently spoke with John.*

John Berdner, general manager, North America, SolarEdge Technologies In many ways, the modern era of grid-tied PV in the US began with the introduction of SMA Sunny Boy inverters, a revolution that John helped to bring about. He is once again introducing an emerging technology to the North American market with SolarEdge power optimization products.

RM: When did you begin working in the PV industry?

JB: After graduating from UC Davis with a degree in mechanical engineering in 1983, I worked for a small company in West Sacramento called Solarize. After the company wound down along with the tax credits, I went to work for Solarex in its Sacramento office. When I didn't want to move to Washington, DC, for Solarex, I took a position with Photocomm outside of Grass Valley, California. This is where I met Ron Kennedi, Christopher Freitas and Sam Vanderhoof. That position led to Endecon Engineering and Chuck Whitaker. After that, I moved to Ananda Power Technologies, which became Pulse Energy Systems. Eventually, this led me to SMA, where I helped open the US offices.

RM: What sorts of projects were you involved with in those early years?

JB: Right out of school, I started on the Dixon City Hall Project, an approximately 20 kW grid-tied system. It was a third-party–financed system, what we'd call a PPA today. At Solarex, I was doing technical services, engineering and system design. At Endecon, I did some research on PV and batteries. We were looking at PV for utility-owned off-grid systems and as a demand-side management tool. Around 1992, Endecon helped the Trace SW qualify as the first type-tested PV inverter for utility interconnection for Pacific Gas and Electric. Prior to that, you had to have a utility protection engineer come out and run tests on every single system. And then at SMA, I helped bring the German product to the US market.

RM: What was the state of the US grid-tied PV industry and its inverter technology in the US when you incorporated SMA America?

JB: Essentially, the players in the US were Omnion, which had a high-voltage dc product; Advanced Energy, with its GC-1000, which was a 48 V pure grid-tied type; and Trace, with its Trace SW, a 48 V battery-based inverter, and later, the Sun Tie inverter, another 48 V grid-direct inverter. There really wasn't much of a grid-tied market at that time.

California had a $5-per-watt rebate program, but despite that the market really wasn't gaining any traction. The Trace SW was the most reliable inverter of the group, but you had to use batteries with it, which added a lot of significant expense, and the efficiency was pretty low. The other players, AE, Omnion and Trace's Sun Tie, were all suffering from reliability problems.

RM: What were your biggest challenges in bringing the SMA line to market?

JB: The main challenge, internally, was adapting the inverter to US regulatory and UL requirements. Essentially, that meant adding a GFDI circuit. The 2500U is transformer coupled and uses a low-frequency transformer that's typical for older, isolated inverter topologies. In Europe, it runs ungrounded, but in the US, we require grounded arrays. As a result, we had CONTINUED ON PAGE 100

to develop ground-fault–protection circuitry and put that into the 2500U. Getting people to understand that high-voltage dc was allowed by *Code* was probably one of the bigger challenges in getting it into the market.

Installer education was another challenge for SMA when we brought the first inverters to the US market. Most of the existing installers were off-grid folks. We had to do a lot of educating in regard to grid-tie installations, including anti-islanding, string sizing, safety, troubleshooting, ground faults and all the other issues surrounding it.

RM: How did array string sizing evolve with the introduction of the 600 Vdc inverters?
JB: When we started, I manually calculated every job on my HP calculator. It was clear that was not a good long-term solution. Essentially, we had to develop the string-sizing calculator from scratch. They had a string-sizing program in Germany, but it only had one weather data point, which was Freiberg, Germany. It didn't do what installers were asking of a string-sizing program. I worked with Bill Reaugh to develop the string-sizing calculator for the US market. It started as a rudimentary Excel spreadsheet, which Bill refined and then converted to a web application.

RM: You are once again working with an emerging technology. What is it about SolarEdge that convinced you it has a winning solution?
JB: First and foremost, it's the system-level approach. SolarEdge looked at the problems of PV design at a system level and asked, "How can we address all of these problems together?" What intrigued me about the personnel at SolarEdge was that they basically had answers for almost all the questions I asked. They seemed to offer one of the more well-thought-out solutions. They shared some of their reliability philosophy, test data and test protocols. Reliability is paramount when we talk about something that module manufacturers are going to embed on a PV module. We need 25-year reliability, and developing power electronics that are going to live on a module in a high-temperature environment is a significant engineering challenge. SolarEdge seemed to have the most mature solution out there.

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The founders of SolarEdge all came out of the Israeli military, designing hardware for military satellites. They have a background in high-reliability power electronics. Plus I like start-up companies. I like to look for new technology and help bring it to market. And I like to help grow companies.

RM: How do you see power optimization products benefitting the industry?
JB: You can really classify it into four areas of benefits: design freedom, performance, safety and system monitoring.

By allowing designers to essentially get rid of the string constraints and minimize shade issues, you have much greater design freedom.

When you do module-level MPPT, shading impacts that module only. When you go to distributed architecture with module-level MPPT, whether it be dc-to-dc or dc-to-ac, it is not unusual to see a 15% improvement in systems with partial shading.

Several of these types of products greatly improve installer and firefighter safety as well. One of the global concerns in the firefighting community is that they essentially have to leave the voltage on the roof. They can't turn it off, and they can't isolate it into safe voltages and currents. In a traditional system design, they still have high-voltage dc on the roof even if they turn off the grid-tied inverter. That's a significant hazard. Many of the distributed module-level power electronic solutions, including SolarEdge's, can help solve this problem. If the inverter is shut down for any reason, the individual SolarEdge Power Box at each module automatically goes to a safe voltage of 1 V per module. Microinverters are similar in the sense that they keep the dc voltages at a safe level when the inverters are turned off. All of these features cost money, and the resulting higher energy yield is what helps pay for all this.

Monitoring at a residential level is certainly interesting; but at the multi-megawatt level, it really is an essential maintenance tool and a way to ensure high-energy production over a long period of time.

RM: Do you feel like optimizers are niche products—say for residential systems or systems smaller than some capacity threshold—or do you see potential for a broader range of applications?
JB: In every system design, there are trade-offs. There are certain approaches that are more appropriate for one size or type of system over another. I believe for very small systems, less than a couple kilowatts, microinverters make a lot of sense. Above that, say at around the 3 kW range, distributed power optimizers start making a lot of sense.

As you start getting up in size, you move into using a distributed architecture with separate inverters, essentially single-phase or larger 3-phase. That makes sense up to the 100 to 500 kW range. People need to start reconsidering some of their misconceptions about smaller inverters, especially the newer transformerless inverters. These topologies make sense up to the several hundreds of CONTINUED ON PAGE 102

kilowatt range. There are still some significant benefits up into the megawatt scale. When you start dealing with large plants, it's purely a decision based on economic analysis. With embedded power electronics—already on the module, as opposed to having something that's mounted on the rail or on the frame—you gain some cost efficiencies. When we have modules from multiple suppliers with embedded power electronics, I think we'll see that the range of application extends into the tens of megawatts, but it's going take a little time.

RM: What do you anticipate will be the biggest barriers to adoption?
JB: Education and track record. People need to get comfortable with the reliability of these products, get some proven track record on increased performance and recognize the benefits of module-level monitoring. I don't think it's a technological barrier. For our Power Boxes, I don't think long-term reliability is truly an issue.

RM: You've been instrumental in helping develop UL standards over the course of your career. What codes and standards issues are on your radar right now?
JB: I would say that arc-fault detection is most significant. It's very likely to be a requirement in the 2011 *Code.* We are just finalizing the answers to questions such as: What is an arc? How fast do you have to detect it and under what conditions? We need to have well-defined test standards that allow us to say, yes, in fact this does meet a written requirement and we can show repeatable testing.

Power quality and grid stability are other areas that I think will increasingly draw attention. Inverters can provide a lot of benefits in this area. All inverters now are microprocessor-controlled and can do things like active power factor correction, where they can dynamically change the power factor. Right now the UL standard requires inverters to maintain a fixed power factor. From a grid-stability standpoint, there may be reasons why we don't want to do that anymore. There may be other benefits that we can bring to the table as well.

One interesting concept is being able to work more closely with utilities on some of these issues where they could send commands to inverters in the field and modify their operating conditions. In the case of anti-islanding, we've been overly cautious about getting all the inverters off line immediately in the event of any kind of grid instability. In Europe, where PV has a higher penetration, utilities are becoming aware that when you bring all inverters off line at once, you likely make the problem worse. If you have a lot of distributed generation online and all of it suddenly dumps off line, it makes the grid stability problems worse and could lead to cascade failures. Now there are discussions about allowing the inverters to ride through a short-term disturbance, so that they would moderate voltage sag instead of immediately jumping off line.

How the West was won From starting SMA America at his living room coffee table, John has come full circle back to the same coffee table to work with a start-up company, SolarEdge, that he does not expect to stay small for long.

RM: Several external 600 Vdc disconnects are currently being marketed specifically for PV applications. Is there a need for dc disconnects listed to UL 1741? If so, how would UL 1741 need to change, and how would these new requirements differ from those in UL 98?
JB: Essentially, UL 1741 applies only to a disconnect sold as part of an inverter or charge controller. UL 98 applies where you have a separate disconnect. UL 98 is a general-purpose disconnect requirement, and it has some tests that are designed around disconnecting motor loads and inductive loads that are extremely severe compared to PV. For example, you have to test at a very high overload, well above your rated current, in order to pass a test that's designed around inductive loads. PV is not inductive, and it is inherently current-limited: It will deliver only a certain amount of current, no matter what. If you look at the input to an inverter, not only is it not inductive, but it's also highly capacitive.

Dissipating the arc energy is the challenge. Most breakers or big switches have arc shoots designed to dissipate arc energy as the switch opens. In the case of PV, we have two conditions: One, we are current-limited; two, a switch is used with an inverter that is disconnecting a capacitive load. There are two normal operating conditions for a dc disconnect that is operating with a grid-tied inverter: Either the inverters are not operating, so no current is flowing; or the array is operating, and the switch needs to only interrupt the current at a voltage that is the difference between open-circuit and maximum power.

UL 98 requires testing at a normal condition, which has been interpreted to be full Voc and full Isc. In reality such a test is extremely harsh, and it is not representative of in-field operating conditions. We could potentially redefine some test criteria for PV-only applications and look at this idea of switching a voltage between Voc and Vmp as being the normal operating condition. That's not a standard yet, but there have been some investigations in this area, and I would expect a standard to be coming soon.