Distributed Energy Generation

Benefits, Barriers, and Best Practices

Report to the 60th Legislature
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Energy and Telecommunications Interim Committee

Legislative Services Division

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2005-06 Interim

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≈ Introduction ≈

Distributed energy, distributed generation, or self-generation, referred to hereafter as DEG, is the concept by which many low-capacity to mid-capacity power generation sites provide electrical supplies to a district. By definition, distributed energy resources are relatively small when compared to the central station model ranging to 1,000 megawatts and more. This means that individually, their contributions to energy management and ancillary services on the grid are often small. However, if many distributed energy resources are aggregated and controlled as a single unit, then their effect--and their potential--grows immensely. The fuel or power sources most often associated with DEG are wind, solar, fuel cells, biomass, natural gas, petroleum, and even geothermal and micro hydro energy sources. DEG also includes processes such as co-generation or combined heat and power or CHP. CHP is the simultaneous generation of both power and thermal energy (heat) using the same fuel.

Senate Joint Resolution No. 36 (SJR 36)

The Energy and Telecommunications Interim Committee was assigned to study the appropriateness of DEG for Montana through the following joint resolution:

SENATE JOINT RESOLUTION NO. 36
INTRODUCED BY TOOLE, ESSMANN

A JOINT RESOLUTION OF THE SENATE AND THE HOUSE OF REPRESENTATIVES OF THE STATE OF MONTANA REQUESTING AN INTERIM STUDY TO INVESTIGATE THE POTENTIAL BENEFITS OF, AND OBSTACLES TO, EXPANDING DISTRIBUTED ENERGY GENERATION IN MONTANA.

WHEREAS, Montana citizens and lawmakers have become very interested in renewable and other small-scale distributed generation systems since the electrical energy crisis in the summer of 2001; and

WHEREAS, distributed energy generation complements the central-station model of electricity generation and offers potential solutions to many of today's pressing energy and electric power problems, including energy price spikes, energy security concerns, power quality issues, rising energy costs, tighter emissions standards, transmission bottlenecks, and the desire for greater control over energy costs; and

WHEREAS, distributed generation might provide a more affordable alternative for adding future load to remote Montana locations than adding parallel lines over long distances; and

WHEREAS, distributed energy technologies may be used to meet baseload power, peaking power, backup power, remote power, power quality, and cooling and heating needs; and

WHEREAS, several of the emerging technologies currently being promoted and developed in Montana, such as rooftop solar arrays, small wind turbines, and fuel cells, are ideal for distributed generation; and

WHEREAS, permitting and construction of large, central power plants takes years, while small generating units can be brought online quickly; and

WHEREAS, homeowners and entrepreneurs generating more electricity than they need can net meter and sell their surplus to the grid; and

WHEREAS, an in-depth study is needed to explore any technical, market, and regulatory challenges to developing distributed generation that might exist and to inform the Legislature how these barriers might be overcome.

NOW, THEREFORE, BE IT RESOLVED BY THE SENATE AND THE HOUSE OF REPRESENTATIVES OF THE STATE OF MONTANA:

That the Legislative Council be requested to designate an appropriate interim committee, pursuant to section 5-5-217, MCA, or direct sufficient staff resources to explore any technical, market, and regulatory challenges to developing distributed generation that might exist and to inform the Legislature how these barriers might be overcome.

BE IT FURTHER RESOLVED, that if the study is assigned to staff, any findings or conclusions be presented to and reviewed by an appropriate committee designated by the Legislative Council.

BE IT FURTHER RESOLVED, that all aspects of the study, including presentation and review requirements, be concluded prior to September 15, 2006.

BE IT FURTHER RESOLVED, that the final results of the study, including any findings, conclusions, comments, or recommendations of the appropriate committee, be reported to the 60th Legislature.

Policies and Incentives Thus Far

The State of Montana established a significant incentive for DEG in 1999 with the enactment of a net metering policy (69-8-601, MCA). This policy requires interconnected facilities to comply with all national safety, equipment, and power-quality standards as set by the National Electrical Code (NEC), Institute of Electrical and Electronics Engineers (IEEE), National Electrical Safety Code (NESC), and Underwriters Laboratories (UL). This applies to customers generating up to 50 kilowatts with hydroelectric, wind, or solar energy systems. The law does not specify how many customers may interconnect to each utility. Twenty-five states now have net metering policies. There are also other policies and incentives on the books in Montana regarding *renewable energy* (as opposed to fossil fuel), which of course drives most DEG. The most recent of these is Senate Bill No. 415 passed by the 2005 Montana Legislature. This law requires public utilities by 2008 to buy at least 5% of their electricity from "renewable resources", such as wind, solar, geothermal, or new, small hydroelectric projects. The minimum increases to 10% by 2010 and to 15% by 2015.

This report's appendices include the "rules, regulations & policies" as well the "financial incentives" related to renewable energies that have been adopted in Montana. These measures have been conceived in the private, utility, and/or state sectors. The appendices also compare Montana to all the other states in terms of the measures taken.

DEG at the Crossroads

Few would disagree that Montana's energy future is in uncharted territory. SJR 36 speaks of an "electrical energy crisis in the summer of 2001". This, of course, has been followed by unprecedented increases in the prices that Montanans now pay for their energy. Other forces are also converging that make DEG a timely topic. Various technologies are poised--others would say are proved--to be viable ways to harness renewable energy. So too, the energy transmission infrastructure for Montana and the region is aging, struggling under growing load, and facing questions about how to grow. The questions are growing faster than the answers. In addition to citing the potential benefits of DEG, SJR 36 also anticipates that there will be barriers—as well as possible solutions to those barriers. That fairly well describes the themes that can also be found in literature and heard in discussions with experts on DEG.

<u>ETIC review thus far.</u> At their January 19, 2006, meeting, members of the Energy and Telecommunications Interim Committee (ETIC) discussed a staff-prepared overview of the regulatory, market, and technology issues that stakeholders very often refer to when discussing DEG. (That overview, intended to cite issues identified by the research rather than make findings or conclusions per se, is attached to this draft report as Appendix H.)
During this meeting, ETIC members raised numerous possible topics for further investigation. Staff agreed to distill the various proposals down to common themes of interest to the members and then seek their consensus on these matters for further research. This was done in February. Their consolidated focus was as follows:

Safety and Interconnection Issues

<u>Part A:</u>
Does research persuasively suggest that there are solutions for the safety and interconnection concerns attached to distributed generation?

<u>Part B:</u>
Legislative proposal to provide state money for university-based research and development pilot of DEG.

Distributed Energy Generation in Other States

Assess:
- How short-term costs/benefits compared to long-term costs/benefits
- How they handled safety and interconnection concerns

II.≈ Crossing the Road ≈

Executive Summary

The interconnection of distributed generation to existing power systems is being addressed in multiple ways. Great strides are being made at the federal, regional, state, and utility levels to smooth out the technical challenges, including safety. The most obvious manifestation of this has been a broad move *toward* standardization. Yet, though standards clearly pose many benefits for all stakeholders involved, they also have their limits. They do not remove every decision point from every new instance of interconnection. Therein lies some of the confusion, tension, and hard work in connecting distributed generation to a grid. Standardization efforts thus far still leave significant local prerogative over the countless technical and nontechnical issues that interconnection raises.

One such technical issue of particular interest to the ETIC is safety. Though national consensus standards on the safety aspects of interconnection have been promulgated, utilities still note that standards reduce but never fully erase risk, and the price of a single error is high. They state that the safety-related measures and components that they require are absolutely necessary. Data indicating whether Montana-based safety incidents related to interconnection are up or down is not available. At the same time, no conclusive information (for example, in the form of state legal or regulatory findings) about the actual necessity of requirements that Montana utilities identify as safety-related has been identified. One thing that utilities, manufacturers, producers, and others do agree on, however, is that all involved could benefit from more education and face-to-face discussion.

As noted above, many states are pursuing the interconnection of distributed generation. The ETIC was interested to learn whether any of those states have yet analyzed the short- versus long-term economic impacts of their distributed generation efforts. The answer is that they have not. One reason for the lack of studies appears to be that their initiatives have not matured to the point at which they can speak of *long-term* results. Another is that there is disagreement over how to even define economic impact in DEG terms. Finally, if and when such studies do become available, they might be of limited transferability to Montana and of narrow value to its legislators. They would at least be useful for helping Montana decisionmakers appreciate the economic dynamics that have accompanied the growth of distributed generation elsewhere. That would, at a minimum, strengthen the basis for charting any economic assumptions about distributed generation in Montana.

Another dynamic at work in the efforts of various states and regional organizations has been a spirit of consultation and collaboration. This is one attribute of all successful interconnection initiatives that might be fully transferable.

While keeping this report descriptive rather than prescriptive, it is reasonable to suggest that a heightened effort at outreach--be it through education, collaboration, or both--is a vital lesson to take away at this time.

Interconnection

The ETIC asked for more information about "the technical challenges of interconnection". A great many of the technical concerns that one might have about distributed generation are physically addressed at the point where the renewable or combined cycle generation interconnects with local power distribution lines. A great many of the questions about interconnection, including safety, are today being addressed in both regional and national standards.

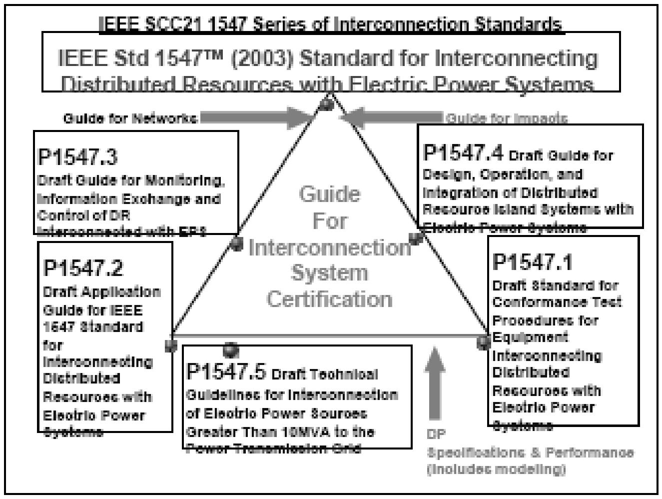
Why standardization? The technologies and operational concepts for properly integrating DEG into existing power systems must be fully developed "in order to realize its benefits and avoid negative effects on reliability and safety". [Doc16-p1] (Note: Bracketed references refer to the bibliography.) Standards help define the safeguards against hazards to personnel or equipment. They improve quality design and quality assurance. They also expand the market for DEG-related technologies. "Uniformity across states is ultimately very important. For manufacturers . . . it is crucial to be able to build a single unit that can be sold in every state in the country without modification." When a consensus standard exists, DEG generators hoping to interconnect are less likely to face redundant testing or unnecessary requirements. They will likely either modify products and components to meet nonstandard requirements, passing the added cost on to consumers, or "will abandon the nonconforming state or utility as a potential market for their products". [Doc14-p1] Finally, standardization will, as a recent Federal Energy Regulatory Commission (FERC) order notes, help "remedy undue discrimination". [Doc18-p2] The effort to establish national consensus standards has engaged government agencies, national laboratories, utilities, private companies, and equipment manufacturers in collaborative dialogue for several years now.

FERC: Whether the issue is power reliability, safety, insurance, approval procedures, or anything else, there is no shortage of guidance to be had. One of the first big steps opening the way for interconnection was FERC Order #888 on *Open Access Transmission Tariff* established in 1996-97. Evolution of the DEG industry has since caused it to be supplemented and updated. For example, wind generation grew by an average rate of 20% each year from 1996 to 2005. [Doc2-p2] In 2005, FERC passed new rulemaking in *Interconnection for Wind Energy*, which provides standards for wind power facilities larger than 20 megawatts. In that same year, FERC also provided new rulemaking for small generation entitled *Standardization of Small Generator Interconnection Agreements and Procedures*. FERC's jurisdiction does not extend to most small generators. However, one purpose of this rulemaking was to offer a "guidepost" for states as they regulate the small generation under their purview. [Doc18-p134] The two sources of guidance that feature most prominently in FERC's small generation rulemaking are: (1) the National Association of Regulatory Utility Commissioners or NARUC; and (2) the IEEE.

IEEE and UL: The IEEE is a nonprofit, professional association of 380,000 members in 150 countries that is focused on electronic and information science and technology. Its work is being used in federal legislation and rulemaking in state public utility commission (PUC) deliberations and by more than 3,000 utilities to formulate technical requirements for interconnection agreements. [Doc11-p1 and Doc15-p1]

In 2003, the IEEE established Standard #1547 on Interconnection. This standard, and the series of six subparts that have followed, "address conditions necessary for optimum performance, operation, testing, safety, and maintenance of interconnected distributed resources”. [Doc8-p2]

Table 1 [a]



Of particular importance are subparts .4 (discussed momentarily) and .1 of the standard. Subpart 1547.1 specifies the type, production, and commissioning tests that must be performed to demonstrate that interconnection functions and equipment of DEG conform to IEEE Standard 1547. (Note that the standard is “technology neutral” in that it does not specify particular equipment or type.) These “standardized test procedures are necessary to establish and verify compliance with those requirements”. [Doc1-p20] Most literature references the UL when discussing IEEE. UL 1741 *elaborates* on the testing standards required for inverters, controllers, and other system equipment used in interconnecting DEG. IEEE 1547 and UL 1741 are thus at the forefront in making DEG interconnection safer and more efficient in this country.

Department of Energy (DOE): The DOE’s Office of Energy Efficiency and Renewable Energy is another federal force in the push for standardization that endorses IEEE and UL standards. Its Distributed Energy Program has “focused its research on these two standards. [The program affirms] that development of such national standards will ensure that distributed power products meet minimum requirements for performance, safety, and maintenance, and will significantly advance the commercialization of these technologies.” [Doc23-p7]

Energy Policy Act: Still another federal force in the push for standardization along the lines of IEEE standards is the Energy Policy Act of 2005. Part of this Act amends the Public Utility Regulatory Policies Act by "adding a section standard on interconnection for state commission consideration and determination”. [Doc4-p7]

> *(15) INTERCONNECTION.—Each electric utility* ***shall make available, upon request, interconnection service*** *to any electric consumer that the electric utility serves. For purposes of this paragraph, the term `interconnection service' means service to an*

[a] Thomas Basso, IEEE SCC21* 1547 Series of Interconnection Standards, MADRI workshop, December 8, 2004, PJM Tech Center, Valley Forge, PA.

electric consumer under which an on-site generating facility on the consumer's premises shall be connected to the local distribution facilities. Interconnection ***services shall be offered based upon the standards developed by*** *the Institute of Electrical and Electronics Engineers:* ***IEEE Standard 1547*** *for Interconnecting Distributed Resources with Electric Power Systems, as they may be amended from time to time. In addition, agreements and procedures shall be established whereby the services [that] are offered shall promote current best practices of interconnection for distributed generation, including but not limited to practices stipulated in model codes adopted by associations of state regulatory agencies. All such agreements and procedures shall be just and reasonable, and not unduly discriminatory or preferential.*

(b) COMPLIANCE.— . . . (5)(A) Not later than one year after the enactment of this paragraph, each State regulatory authority (with respect to each electric utility for which it has ratemaking authority) and each nonregulated electric utility shall commence the ***consideration*** *referred to in section 111, or set a hearing date for consideration, with respect to the standard established by paragraph (14) of section 111(d).*

(B) Not later than two years after the date of the enactment of this paragraph, each State regulatory authority (with respect to each electric utility for which it has ratemaking authority), and each nonregulated electric utility, shall complete the consideration, and shall make the determination, referred to in section 111 with respect to the standard established by paragraph (14) of section 111(d). [Emphasis added.]

The Act underscores some of the complexity of this broad move toward standardization. Its rather broad reference to “agreements and procedures” indicates that the aforementioned “standards” are not the only source of guidance to be drawn from. As seen by the Act’s wording about compliance, individual state authorities and utilities are to give all this their “consideration”. That is, *the ultimate mix of standards, agreements, and procedures is not mandated*. The Act does authorize the future creation of an electric reliability organization (ERO) with the statutory authority to enforce compliance with reliability standards among all market participants. It is possible that the North American Electric Reliability Council will become that ERO. [Doc13-p2] However, until that time, guidance becomes compulsory only when a state or public utility commission makes it so.

The Bottom Line on Safety

The IEEE’s subpart 1547.4 will be of particular interest to the ETIC because it addresses one of the safety issues most often cited in relation to DEG: islanding. [b] “Unintentional islanding has the potential to jeopardize safety, disrupt reliability, damage equipment, and reduce power quality.” [Doc25-p1] Subpart 1547.4 is a guide that “provides alternative approaches and good practices for the design, operation, and integration of DEG island systems with electric power systems (EPS). This includes the ability to separate from and reconnect to part of the area EPS while providing power to the islanded local EPSs.” [Doc1-p21]

DEG manufacturers and national laboratories generally say that with the advent of IEEE and UL standards, the risks of islanding have basically been managed. It being understood that one

[b] According to the DOE’s Office of Energy Efficiency and Renewable Energy, circuit protection is the biggest technical challenge of adding generation to distribution circuits. Of particular concern is islanding, in which a distributed generator energizes a portion of a distribution system when the rest of the system is de-energized. This can create safety hazards and damage equipment.

never fully eliminates that chance of failed components and human error in such complex systems, they say safety concerns have been reasonably managed. Utilities, however, tend to hold another view. They are responsible for safety backup, system integrity, and service quality. These responsibilities influence their opinion as to when a risk has been "reasonably managed". In Montana, this question will be greatly clarified if and when data on safety incident trends as they pertain to interconnection is collected.

None of this is meant to imply that utilities claim that a point of reasonable management can never be reached. Montana's public and cooperative utilities all offer procedures and agreements that essentially say, "Here are our requirements for you to safely and effectively interconnect with our distribution systems." It seems, then, that *safety is not the pivotal issue* in matters of interconnection. Montana's utilities all cite and borrow from IEEE's 1547. That standard itself says that it "provides the minimum functional technical requirements that are universally needed to help assure a technically sound interconnection". That is, our utilities are meeting the standard for reliable interconnection that is safe.

However, might they also be exceeding that standard? IEEE 1547 goes on to say, "Any additional local requirements should not be implemented to the detriment of . . . this standard." [Doc15-p3] Additional local requirements, both technical and nontechnical, have the potential to help or harm the advance of interconnected DEG.

Limits on Standardization

As implied above, "standards" tend to cover technical aspects (such as numeric specifications, tolerances, allowable ranges, etc.) while "agreements and procedures" tend to cover everything else (greatly affecting the market and regulatory aspects of DEG interconnection). That being said, the three terms are sometimes used loosely and interchangeably and are all part of the same march toward "standardization".

Finding a Balance

In every aspect of the American economy, one can see an ever-shifting equilibrium between market and regulatory forces and between local, state, and federal prerogatives. The question of interconnecting DEG with the electrical power systems that have dominated our landscape for many decades is, of course, being influenced by this balancing act. (For this reason, the term "standardization" is misleadingly linear and permanent sounding.)

As noted, FERC hopes that its *Standardization of Small Generator Interconnection Agreements and Procedures* will provide states a "guidepost" as they regulate the small generation under their purview. In so doing, FERC says that its aim is to "strike a reasonable balance between the competing goals of uniformity and flexibility while ensuring safety and reliability are protected". [Doc18-p7] Standardization thus lies somewhere between uniformity and flexibility.

The counterpoint to calls for standardization tends to be, "Fine, but with due flexibility." The basic theme is that not all circumstances can be covered by universal standards. Even advocates of interconnecting DEG are inclined to agree with this. The National Renewable Energy Laboratory (NREL) noted that while IEEE 1547 was being crafted, "there arose many specific [issues and obstacles] that were not necessarily appropriate to be stated as universal requirements . . . . [It cited] design-specific, application-specific, and equipment-specific issues." NREL added that there "were also concerns that were broader than simple technical issues. Some concerns seem more appropriately addressed external to a universal, mandatory requirements standards document and are perhaps more appropriate in a guide or special applications document." [Doc16-p4]

Montana's cooperatives echo this when they say of rulemaking that, "One size does not fit all." [Doc30-p1] They add that blanket rules can never be location-specific or size-specific enough. [Doc30-pp1&2] The latter refers to more than the *size* of a given distribution system (and whether smaller ones, like many co-ops, are as able to cope with interconnection as larger ones). It refers also to the *size* of DEG's penetration. Most parties seem to agree that if and when DEG grows significantly beyond today's levels, we will move into rather unknown territory. The question then becomes: will greater saturation by DEG become problematic for some elements of some distribution systems? Should, then, all distribution systems be treated the same?

For all these reasons, utilities are hesitant about being locked into nationally recommended precertification of components across all their systems, or into procedures for all situations, both foreseen and unforeseen. The DOE says the industry concern about interconnection standards that it hears most often is, "Each utility knows its own system best and should be able to set its own interconnection standards." [Doc23-p1]

The "fairness" question has frequently been raised. At a national level, FERC stepped in some years ago with its rulemaking due to what it saw as "unduly discriminatory transmission practices" by utilities. [Doc18-p7] In today's literature one can still find complaints that the requirements which utilities add over and above national standards are unreasonable and unjustifiable. They are said to be anti-competitive measures that defeat the purpose of standardizing and streamlining rules.

In Montana, if such allegations they have been made they have not been formally brought to a state-level legal or regulatory forum. Conversely, some Montana utilities are on record as saying that DEG generators garner unfair "subsidies" under Montana's net metering regulations. [Doc6-p2, Doc30-p3] It might be that neither "side" is focusing enough on the broader public interest the other side might represent.

In defense of both sides, these perceptions might be inevitable. The backdrop, again, is one of ever-shifting equilibrium and ever-present tension between market and regulatory forces; between local state and federal prerogatives. In trying to strike a balance between uniformity and flexibility our national initiatives have left considerable latitude with the states and utilities. Into the breach goes reasonable interpretation (say some) or manipulative barriers (say others). This research proves nothing conclusively about those assumptions or allegations at the Montana state level. But one thing that seems to hold true for all the Montana stakeholders involved is that they could benefit from more education and face-to-face discussion.

<u>Interconnection in Montana</u>

The manner in which DEG gets interconnected in Montana is governed both by our net metering law and by the agreements that utilities draw up with DEG generators.

Net metering: Net metering is a method of crediting customers for electricity that they generate on site in excess of their own electricity consumption. Customers with their own generation offset the electricity they would have purchased from their utility. If such customers generate more than they use in a billing period, their electric meter turns backwards to indicate their net excess generation. Montana's net metering legislation was enacted in 1999. It applies to customers generating up to 50 kW with hydro-electric, wind or solar-energy systems. The law does not specify how many customers may interconnect to each utility. [Doc7 and Doc29-p3] Here are portions of that law. Note that it references some of the entities and standards already described in this report.

69-8-601. Legislative findings. The legislature finds that it is in the public interest to promote net metering because it:

(1) encourages private investment in renewable energy resources;
(2) stimulates Montana's economic growth; and
(3) enhances the continued diversification of the energy resources used in Montana.

69-8-604. Net metering system -- reliability and safety. (1) A net metering system used by a customer-generator must include, at the customer-generator's own expense, all equipment necessary to meet applicable safety, power quality, and interconnection requirements established by the national electrical code, national electrical safety code, institute of electrical and electronic engineers, and underwriters laboratories.

(2) The commission, after appropriate notice and opportunity for comment, may adopt by rule additional safety, power quality, and interconnection requirements for customer-generators that the commission or the local governing body determines are necessary to protect public safety and net metering system reliability.

69-8-605. Applicability. This part does not apply to corporations organized under Title 35, chapter 18. [Author's note: This refers to the exemption of Montana's electric utility cooperatives.]

Utility interconnection agreements in Montana:

Utilities	Features	Sources
Northwestern Energy	• The standard agreement's technical language mirrors state law requirements with respect to national standards but also requires a manual, lockable, external disconnect switch. • It does not require system owners to purchase additional liability insurance, but encourages them to confirm with their insurance provider the limits of coverage applicable to interconnected systems. [Doc7-p1]	• The standard agreement specifically cites IEEE, UL, and the National Electric Code. [Doc27-p7] • [Note: Northwestern most recently revised its standard agreement in January 2006. The IEEE reference it makes is to standard #929, not the newer and broader #1547.]
Montana-Dakota Utilities	• Interconnection parameters (in regard to operating limits, transformers, energization of company equipment by a customer, synchronization, disconnect, metering, grounding, and interruptible rate qualifications) • Protective devices • Testing required for parallel operation	• The guidelines extensively cite IEEE, as well as the National Electrical Safety Code [NESC] and the North American Electric Reliability Council • These guidelines are said to by in sync with the Midwest Independent Transmission System Operator [MISO]
Montana Electric Cooperative's Association	Net metering program (Although the coops are exempt from the state net metering law, they may voluntarily provide this service) • Qualifying Facilities program (either output purchase or output wheeled)	• IEEE • Occupational Safety and Health Administration [OSHA] • NESC • National Rural Utilities Cooperative Finance Corporation [NRUCFC] • National Rural Electric Cooperative Association [NRECA]*

* The final entry above is perhaps emblematic of the rather crowded "flow chart" that many interconnection approvals need to navigate. NRECA's proposed application guide "is intended to supplement, expand and clarify the technical requirements of IEEE 1547." [Doc2-p1] This application guide, over one hundred pages in length, is essentially a guide to a guide.

There are numerous such professional associations which states and utilities around the country tap for guidance. A sampling of these includes the National Association of Regulatory Utility Commissioners (NARUC), the Interstate Renewable Energy Council (IREC), the Regulatory Assistance Project (RAP), and the National Council of State Legislatures (NCSL).

One can also add to this the individual models that state legislatures and regulatory agencies have been adopting.

Status of DEG Interconnection in Other States

The ETIC was interested to learn what the experiences of a few other states might reveal about:
What the longer-term economic impact of fostering DEG was
How they handled safety and interconnection concerns

The first question simply cannot be answered at this time, and the second question cannot be answered within the confines of this report. That having been said, here are some of the research findings.

The Longer-term Economic Impact of Fostering DEG

The experience with interconnected DEG in other states appears to be neither well advanced enough or well analyzed enough to draw conclusions about "short versus long term economic impacts". One reason, as cited at the outset, seems to be that their initiatives have not matured to the point where they can speak of *long-term* results. Another might be a matter of focus. Small residential scale distributed generation is less likely to attract attention for economic study than larger community or utility scale generation. The latter refers to big wind or solar programs—but again, these programs lack the longevity from which to look back and draw retrospective conclusions.

Economic rationale (for example, the postponement or avoidance of transmission infrastructure upgrades or expansions) certainly has been used in the preconstruction justifications for these bigger programs. However, again, perhaps because all these initiatives are still comparatively "young", inquiries about "postinstallation" efforts to revisit (and confirm) those economic arguments have not yielded studies. [Doc32]

Yet another significant reason for the lack of conclusive economic study on interconnected DEG elsewhere is that there is disagreement over how to even *define* economic impact in DEG terms. California, for example, is frequently said to be at the forefront of DEG interconnection in this country. However, as a staff report emerging from the California Energy Commission notes, staff are having significant problems with "the availability and acceptance of data". [Doc28-p12] As they tried to gain "an understanding of available data, methods and models necessary in order to calculate the different DG costs and benefits [it] became evident that reaching agreement and acceptance on methods and the data required for these methods will be a challenge". Not surprisingly, DEG's "costs and benefits vary by stakeholder perspective". As noted before, consensus building among all the parties involved is a key. The report's conclusions and recommendations included the following: [Doc28-pp12 to 15]

- The lack of publicly available data will need to be resolved if California is to reap the benefits of DEG.
- Presently, there is DEG costs and benefits data to consider, but the ability to analyze them varies widely.
- Models are available to analyze the high priority benefits of DEG; however, not all stakeholders accept these models. The Commission needs to develop models that will

have credibility with all stakeholders.

- This may also require more than one analytical method or model.
- Simple approaches, such as project-specific methods, could be implemented first. More sophisticated methods, based on a systemwide approach, are under development and could be implemented when they become available. In the longer-term, a systemwide approach for determining DEG costs and benefits should be adopted. This should occur as better, more readily accepted methods, models, and data are developed that can more accurately determine the locational and time dependent benefits.

If and when those studies are done in other states, their applicability to the energy milieu in Montana might be limited. In the example just given of economic savings through postponing the need for transmission construction, no two transmission systems are the same. Whatever the economic indicator under study might be, it will certainly be affected by a confluence of market, incentive, or regulatory factors unique to the time and place. (Factors can include such incentives, tax subsidies, rates and tariffs, utility contracts, wholesale and retail markets, utility procurement and planning processes, and more.) That is to say, even if there were an abundance of studies available today, they would not necessarily "transfer" or ensure similar outcomes in Montana.

Interconnection and Safety in Other States

The question of how other states have "handled safety and interconnection concerns" is vast, even if limited to just a few case studies. Their adopted standards, procedures, and agreements typically take in hundreds of pages on a wide range of interconnection concerns. The following materials were thus collected.

A. Given the scope of this *White Paper*, two states were selected. California and Texas both have comparatively advanced DEG interconnection initiatives. Those initiatives include significant wind portfolios. The guiding documents drawn up by their respective Public Utility Commissions each gave more attention to the question of safety than other state guidelines reviewed. For these reasons, California and Texas were chosen. This report is not suggesting that these two states offer models that are transferable to Montana per se. The limitations described above apply to them as well: their programs have not yet matured and are situated in market and regulatory milieus all their own. Nevertheless, excerpts of their formal guidance (found in this report's appendices) will show ETIC members what ground those PUCs thought it important to cover.

B. Also included in this report's appendices is the formal guidance of both a Regional Transmission Organization (RTO) and a professional association of regulators. The RTO is called PJM Interconnection. Several research sources suggested that PJM's work with DEG interconnection is quite advanced. This RTO manages the reliability of the largest centrally dispatched control area in North America by coordinating the movement of electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, West Virginia, and the District of Columbia. The model that it is proposing for small generation is initially focused on just Delaware, Maryland, New Jersey, Pennsylvania, and the District of Columbia. PJM claims to have "merged the best practices" of DEG interconnection that exist today.

The professional association that was chosen is the National Association of Regulatory Utility Commissioners or NARUC. NARUC's model was chosen because it is more process-oriented than the others cited here, which have more of a technical focus. It was also incorporated here because the *Energy Policy Act of 2005* explicitly noted (in Sec. 1254. Interconnection) that associations of state regulatory agencies could be a source of "best practices". Thus included in the appendices are excerpts of NARUC's "Model Interconnection Procedures and Agreement for Small Distributed Generation Resources".

≈ Bibliography ≈

Distributed Energy Generation:
Benefits, Barriers, and Best Practices

Doc #

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III.
Appendices

A Montana Interconnection Standards & Incentives

B Montana Financial Incentives for Renewable Energy

C Montana Rules, Regulations & Policies for Renewable Energy

D California PUC Interconnection Standards *(excerpts)*

E Texas PUC Distributed Generation Interconnection Manual *(excerpts)*

F PJM Small Generator Interconnection "Applicable Technical Requirements and Standards"

G NARUC: Model Interconnection Procedures and Agreement for Small Distributed Generation Resources *(excerpts)*

H Initial ETIC Staff Literature Overview (presented 1/19/06)

APPENDIX A

Interconnection Standards / Incentives

Last DSIRE Review: 11/14/2005

Incentive Type:	Interconnection
Eligible Renewable/Other Technologies:	Photovoltaics, Wind, Hydroelectric
Applicable Sectors:	Commercial, Industrial, Residential, Schools, Local Government, State Government
Special Rules for Net-Metered Systems?	Yes
Limit on System Size/Overall Enrollment:	50 kW / none specified
Additional Insurance Requirements?	None specified
External Disconnect Required?	Not specified
Rules for Non-Net-Metered DG?	No
Website:	http://www.deq.state.mt.us/energy/Renewable/NetMeterRenew.asp
Authority 1:	MC § 69-8-604
Date Enacted:	07/01/99

Summary:

Montana's net metering legislation, enacted in 1999, requires interconnected facilities to comply with all national safety, equipment and power-quality standards as set by the National Electrical Code (NEC), Institute of Electrical and Electronic Engineers (IEEE), National Electrical Safety Code (NESC) and Underwriters Laboratories (UL). This applies to customers generating up to 50 kW with hydro-electric, wind or solar-energy systems. The law does not specify how many customers may interconnect to each utility.

NorthWestern Energy (Montana Power) has published a standard interconnection agreement for net-metered facilities; the agreement includes language on the technical requirements for interconnecting. Technical language mirrors the state law requirements with respect to national standards but also requires a manual, lockable, external disconnect switch. NorthWestern does not require system owners to purchase additional liability insurance, but encourages system owners to confirm with their insurance provider the limits of coverage applicable to interconnected systems.

Net metering is also available through Montana-Dakota Utilities (MDU). For information, contact Gary L. Paulsen of MDU at (701) 222-7649.

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Web site: http://www.deq.state.mt.us/ppa/

APPENDIX B DATABASE OF STATE INCENTIVES FOR RENEWABLE ENERGY

Financial Incentives

State/Territory	Personal Tax	Corporate Tax	Sales Tax	Property Tax	Rebates	Grants	Loans	Industry Recruit.	Leasing/ Sales	Production Incentive*
Alabama	1-S					1-S				
Alaska							1-S			
Arizona	2-S		1-S		4-U					
Arkansas										
California	2-S	[illegible]		[illegible]	[illegible]	[illegible]	1-U		[illegible]	[illegible]
Colorado					[illegible]		1-U, 1-L			[illegible]
Connecticut				[illegible]	[illegible]	3-S	3-S			
Delaware					1-S	2-S				
Florida			1-S		2-U					
Georgia										1-U
Hawaii	1-S	1-S			[illegible]		[illegible]	1-S		
Idaho	3-S		1-S			[illegible]	1-S			
Illinois				1-S	[illegible]	[illegible]				
Indiana				1-S		[illegible]				
Iowa	[illegible]	[illegible]	[illegible]	3-S		[illegible]	[illegible]			
Kansas				1-S		[illegible]				
Kentucky							[illegible]			[illegible]
Louisiana				1-S						
Maine					[illegible]	[illegible]				
Maryland	1-S	1-S	1-S	[illegible]	[illegible]		2-S			
Massachusetts	2-S	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]				[illegible]
Michigan				[illegible]	[illegible]	[illegible]	[illegible]	3-S		
Minnesota			2-S	[illegible]	[illegible]	[illegible]	3-S			[illegible]
Mississippi							[illegible]			[illegible]
Missouri		1-S				1-S	1-S			
Montana	2-S	2-S		2-S		2-P, 1-U	1-S			
Nebraska							1-S			
Nevada			[illegible]	3-S	1-S					1-S
New Hampshire				1-S						
New Jersey			1-S		1-S	2-S	1-S			1-S
New Mexico		1-S	1-S			2-S				
New York	1-S		[illegible]	1-S	3-S, 1-U	1-S	1-S			
North Carolina	1-S	1-S		[illegible]			1-S	2-S		1-U, 1-P
North Dakota	1-S	1-S	1-S	[illegible]						
Ohio		1-S	1-S	[illegible]		1-S	1-S			
Oklahoma		1-S						1-S		
Oregon	1-S	1-S		[illegible]	[illegible]	2-P, 1-S	1-S, 4-U			[illegible]
Pennsylvania					[illegible]	[illegible]	[illegible]			[illegible]
Rhode Island	1-S		1-S	1-S	[illegible]	[illegible]				[illegible]
South Carolina					[illegible]					
South Dakota				[illegible]						
Tennessee				[illegible]			1-S			[illegible]
Texas		1-S		1-S	[illegible]			1-S	[illegible]	
Utah	1-S	[illegible]	1-S							
Vermont			1-S		[illegible]	[illegible]				[illegible]
Virginia				1-S		[illegible]		[illegible]		
Washington			1-S		6-U	[illegible]	[illegible]	1-S		2-U, 1-P, 1-S
West Virginia		1-S		1-S						
Wisconsin				[illegible]	[illegible]	[illegible]	[illegible]			
Wyoming			1-S		1-S				1-U	
District of Columbia						1-S				
Palau										
Guam										
Puerto Rico	1-S		1-S							
Virgin Islands										
N. Mariana Islands										
American Samoa										
[illegible]	20	19	10	[illegible]	[illegible]	51	46	9	[illegible]	[illegible]

* In addition to these incentives, some private renewable energy credit (REC) (also know as green tag) marketers provide production-based incentives to renewable energy project owners. See http://www.eere.energy.gov/greenpower/markets/certificates.shtml?page=2 for more information about REC marketers.

Note: This table does not include incentives for renewable fuels and vehicles. For these incentives, go to http://www.eere.energy.gov/afdc/laws/incen_laws.html

APPENDIX C

DATABASE OF STATE INCENTIVES FOR RENEWABLE ENERGY

Rules, Regulations & Policies

State/ Territory	PBF	Disclosure	RPS	Net Metering	Inter-connection	Extension Analysis	Contractor License	Equipment Certification	Access Laws	Construction & Design Standards	Green Power Purchase	Required Green Power
Alabama												
Alaska									1-S			
Arizona		1-S	1-S	2-U	[illegible]	[illegible]	[illegible]	[illegible]	1-S	2-S, 2-L	1-L	
Arkansas				1-S	[illegible]			[illegible]				
California	1-S	1-S	1-S	1-S	[illegible]		[illegible]		2-S, 3-L	1-S, 2-L	5-L	
Colorado		1-S	1-S, 1-L	[illegible]	[illegible]	[illegible]	[illegible]		1-S, 2-L	3-L	2-L	
Connecticut	1-S	1-S	1-S	1-S	[illegible]		[illegible]				1-S	
Delaware	1-S	1-S	1-S	1-S	[illegible]						1-U	
Florida		1-S	1-U	2-U	[illegible]		1-S	1-S	1-S, 1-L	1-S		
Georgia				1-S	1-S				1-S			
Hawaii			1-S	1-S	1-S		1-S		1-S	[illegible]		
Idaho				[illegible]	2-U				1-S			
Illinois	1-S	1-S	1-S	1-U	1-U					[illegible]	[illegible]	
Indiana				1-S	1-S				1-S			
Iowa		1-S	1-S	1-S	1-S				1-S		[illegible]	[illegible]
Kansas					1-S				1-S			
Kentucky				[illegible]	1-U				1-S			
Louisiana				[illegible]	1-S			1-S				
Maine	1-S	1-S	[illegible]	[illegible]				1-S	1-S		1-S	
Maryland		1-S	[illegible]	1-S	1-S				1-S	1-S	[illegible]	
Massachusetts	1-S	1-S	1-S	1-S	1-S				1-S		1-L	
Michigan		1-S		1-S	1-S		1-S					
Minnesota	1-S	1-S	[illegible]	1-S	1-S			1-S	1-S	1-S		[illegible]
Mississippi												
Missouri			[illegible]		1-S				1-S			
Montana	1-S	1-S	1-S	1-S, 1-U	1-S				1-S			[illegible]
Nebraska									1-S			
Nevada		[illegible]	[illegible]	1-S	1-S		1-S		1-S	2-S		
New Hamp.				1-S	1-S				1-S			
New Jersey	1-S	1-S	1-S	1-S	1-S				1-S		1-S	
New Mexico			1-S	1-S	[illegible]	1-S			2-S			[illegible]
New York	1-S	1-S	1-S	1-S	1-S				[illegible]		1-S, 1-L	
N. Carolina					1-S				1-L	1-L		
North Dakota				1-S					1-S			
Ohio	1-S	1-S		1-S, 1-U	1-S				1-S		1-L	
Oklahoma				1-S								
Oregon	1-S	1-S		1-S, 1-L	1-S				[illegible]	2-L	1-L	
Pennsylvania	1-S	1-S	1-S	1-S	1-S						1-S	
Rhode Island	1-S		1-S	1-U	1-S				1-S		1-S	
S. Carolina											5-U	
South Dakota												
Tennessee									[illegible]			
Texas		1-S	1-S, 1-L	1-S, 2-U	1-S	[illegible]				1-S		
Utah				1-S	1-S		[illegible]		1-S		1-L	
Vermont		1-S	1-S	1-S	1-S							
Virginia		1-S		1-S	1-S				1-S, 1-L			
Washington		1-S		1-S, 1-U	1-S				1-S	1-L	2-L	1-S
West Virginia												
Wisconsin	1-S		1-S	1-S	1-S		1-L	1-L	1-S, 1-L	[illegible]	1-L	
Wyoming				1-S	1-S							
D.C	1-S	1-S	1-S	1-S	1-S							
Palau												
Guam										1-S		
Puerto Rico								1-S				
Virgin Is.												
N. Mariana Is.												
Amer. Samoa												
Totals	16	25	22	[illegible]	42	[illegible]	[illegible]	[illegible]	50	[illegible]	[illegible]	[illegible]

APPENDIX D

Mailed 12/21/2000

Decision 00-12-037 December 21, 2000

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Into Distributed Generation.	Rulemaking 99-10-025 (Filed October 21, 1999)

DECISION ADOPTING INTERCONNECTION STANDARDS

1. Summary

This decision approves the Rule 21 language adopted by the California Energy Commission (Energy Commission) on October 25, 2000 in its entirety, as conformed with Decision (D.) 00-11-001. A Model Tariff is set forth in Attachment A that incorporates changes made in D.00-11-001 into the Energy Commission recommendation. A model Interconnection Application Form and agreement are set forth in Attachments B and C.

Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE) are directed to file compliance advice letters to replace their existing Rule 21 with the Model Tariff, Interconnection Application Form and Agreement, within 15 days of the effective date of this order. Within 40 days of the effective date of this order, other respondent utilities (Sierra Pacific Power Company (Sierra), Pacificorp, Mountain Utilities, and Bear Valley Electric) are directed to either file a compliance advice letter adopting the Model Tariff, Interconnection Application Form and Agreement, or a compliance filing in this docket demonstrating compelling reasons why the adopted rules, forms, and agreements should not apply to them.

4.3 Control, protection and safety equipment requirements

4.3.1 **Limits specific to single-phase generators.** For single-phase generators connected to a shared single-phase secondary, the maximum capacity shall be 20 kVA. Distributed Generators applied on a center-tap neutral 240-volt service must be installed such that no more than 6 kVA of imbalance in capacity exists between the two sides of the 240-volt service. For dedicated distribution transformer services, the limit of a single-phase Distributed Generator shall be the transformer nameplate rating.

4.3.2 Technology Specific Requirements

4.3.2.1 **Three-phase synchronous generators.** The Distributed Generator circuit breakers shall be three-phase devices with electronic or electromechanical control. The Electricity Producer shall be responsible for properly synchronizing its Generating Facility with the Distribution System by means of either a manual or automatic synchronizing function. Automatic synchronizing is required for all synchronous generators, which have a Short Circuit Contribution Ratio (SCCR) exceeding 0.05. A Generating Facility whose SCCR exceeds 0.05 shall be equipped with Protective Functions suitable for detecting loss of synchronism and rapidly disconnecting the Generating Facility from the Distribution System. Unless otherwise agreed to between the Electricity Producer and the Electrical Corporation, synchronous generators shall automatically regulate power factor, not voltage, while operating in parallel with the Distribution System. Power system stabilization is specifically not required for Generating Facilities under 10 MW.

Synchronization: At the time of connection, the frequency difference shall be less than 0.2 Hz, the voltage difference shall be less than 10%, and the phase angle difference shall be less than 10 degrees.

4.3.2.2 **Induction Generators.** Induction Generators do not require separate synchronizing equipment. Starting or rapid load fluctuations on induction generators can adversely impact the Distribution System's voltage. Corrective step-switched capacitors or other techniques may be necessary and may cause undesirable ferroresonance. When these counter measures (e.g. additional capacitors) are installed on the Electricity Producer's side of the Point of Common Coupling, the Electrical Corporation must review these measures. Additional equipment may be required to resolve this problem as a result of an Interconnection Study.

4.3.2.3 **Inverter Systems.** Utility-interactive inverters do not require separate synchronizing equipment. Non-utility-interactive stand-alone inverters shall not be used for parallel operation with the Distribution System.

4.3.3 Initial Review process

Appendix A of this Rule defines the Initial Review process. The Initial Review process evaluates the specific characteristics of the Interconnection, including those specific to the location of the Generating Facility, and whether additional requirements are necessary.

4.3.4 Supplemental DG Requirements

4.3.4.1 Unintended Islanding For DG that fail the Export Screen. Generating Facilities must mitigate their potential contribution to an Unintended Island. This can be accomplished by one of the following options:

(1) incorporating certified non-islanding control functions into the Protective Functions, or

(2) verifying that local loads sufficiently exceed the load carrying capability of the Generating Facility, or

(3) transfer trip or equivalent function.

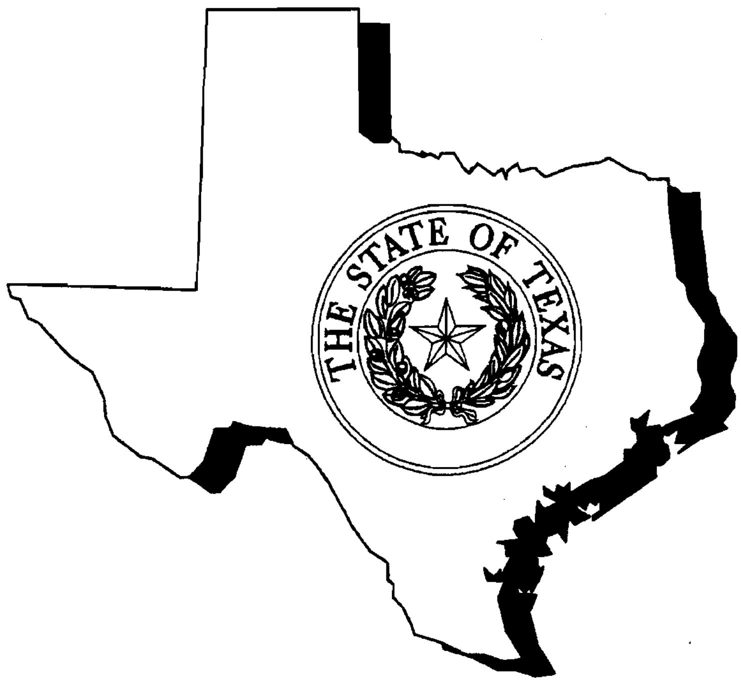
4.3.4.2 Fault Detection. A Generating Facility with an SCCR exceeding 0.1 or that does not meet any one of the options for detecting Unintended Islands in 4.4.4.1 shall be equipped with Protective Functions designed to detect Distribution System faults, both line-to-line and line-to-ground, and promptly remove the Generating Facility from the Distribution System in the event of a fault. For a Generating Facility that cannot detect these faults within two seconds, transfer trip or equivalent function may be required. Reclose-blocking of the Electrical Corporation's affected recloser(s) may also be required by the Electrical Corporation for generators that exceed 15% of the peak load on the Line Section.

4.3.5 Generating Facility types and conditions not identified. In the event that Section 4 of this rule does not address the interconnection requirements of a Generating Facility, the Electrical Corporation and Electricity Producer may interconnect a Generating Facility using mutually agreed upon technical requirements.

APPENDIX E

Distributed Generation Interconnection Manual

Public Utility Commission of Texas



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May 1, 2002

U.S. Department of Energy
Office of Energy Efficiency and Renewable Energy

TABLE OF CONTENTS

1. INTRODUCTION

The Public Utility Commission of Texas (PUCT) has prepared this manual to guide the inclusion of distributed generation into the Texas electric system. It is intended for use by utility engineers processing distributed generation interconnection applications, as well as those persons considering or proposing the interconnection of distributed generation with a transmission and distribution utility (TDU). While every possible eventuality or circumstance cannot be anticipated, the procedures in this manual should cover most important issues or problems, including a process for prompt dispute resolution.

Texas' Public Utility Regulatory Act (PURA) of 1999 included in the list of customer rights and safeguards that "A customer is entitled to have access... to on-site distributed generation..." [§39.101(b)(3)]. This provision led the PUCT in October 1999 to adopt Substantive Rules §25.211 and §25.212 addressing the technical and procedural aspects of interconnecting distributed generation, developed through a collaborative process among the members of the TDU and DG communities. This manual also includes the more recently adopted rules on operational aspects and environmental treatment of distributed resources.

The Public Utility Commission of Texas wants to encourage the use of distributed resources. Distributed resources benefit the state by adding more competitive options, potentially reducing customer energy, improving the asset utilization of TDU distribution systems, firming up reliability, and improving customers' power quality. Texans have the right to use distributed resources for whatever purpose they feel is beneficial and it is the responsibility of the local distribution utilities to accommodate and interconnect distributed generation subject to the rules laid out here.

The philosophy used to develop this manual was that distributed resources will and should be an integral and valued part of the Texas electric supply system. Wherever possible Texas has simplified the process, contractual relationships and hardware required to interconnect distributed resources safely and beneficially for all involved parties.

Joint funding for the preparation of this manual was provided by the U.S. Department of Energy Office of Energy Efficiency and Renewable Energy and the Public Utility Commission of Texas.

2. SAFETY REQUIREMENTS

This section reviews the variety of interconnection-related safety requirements that the DG designer/installer and the utility must take into consideration. The requirements are divided by jurisdiction: State (PUCT), local, and national. These requirements are intended to ensure that DG is designed and installed in a way that

- is not a safety hazard to utility personnel or equipment or to other customers,
- does not disturb other customers or degrade the quality of the distribution system,
- provides reliable service to the DG owner and the utility.

To make certain that these expectations are met, it is critical that the TDU understand the characteristics and requirements of the DG and vice versa.

2.1. PUCT Rules

State regulations regarding the generation, transmission, and distribution of electricity are set by the Public Utility Commission of Texas (PUCT). The PUCT's Web site provides access to all Rules at http://www.puc.state.tx.us under "Rules and Laws". Of technical interest to DG are the following:

Substantive Rules - Chapter 25
Applicable to Electric Service Providers

Subchapter A General Provisions
§25.5 * Definitions

Subchapter C Quality of Service
§25.51 Quality of Service.

Division 2. Transmission and Distribution Applicable to All Electric Utilities
§25.211 * Interconnection of On-Site Distributed Generation
§25.212 * Technical Requirements for Interconnection and Parallel Operation Of On-Site Distributed Generation

The specific requirements of §25.211 and §25.212 are covered in subsequent sections of this manual. These rules detail the operational responsibilities of both the TDU and the applicant.

The PUCT's rules may, in some cases, be superseded by local requirements or modified in the future.

2.2. TNRCC Rules

A distributed generation emissions rulemaking is in progress. This subsection will be updated after a DG emissions rule is adopted by TNRCC.

2.3. Local Codes and Standards

County and city regulations may place additional permit or building code restrictions or requirements on DG systems. These requirements will primarily affect the DG installer, but both the installer and the utility should be aware of local codes and standards that might modify the interconnection requirements specified in the PUCT Rules.

2.4. National Codes and Standards

To address safety and power quality issues, national codes and safety organizations have developed guidelines for equipment manufacture, installation and operation. The major code and safety organizations that apply to distributed generation are the National Fire Protection Association (NFPA), Underwriters Laboratories (UL) and Institute of Electrical and Electronics Engineers (IEEE). Each of these organizations covers different aspects of the DG interconnection in the context of their organizational missions, as explained below.

The national laboratories are also actively involved in issues surrounding DG interconnection. The Department of Energy's National Renewable Energy Laboratory (NREL) in Golden, Colorado and Sandia National Laboratories in Albuquerque, New Mexico work closely with the NFPA, IEEE and UL on code issues and are frequently involved in equipment testing. The labs are not responsible for issuing or enforcing codes, but they do serve as valuable sources of information on DG and interconnection issues. The following subsections discuss each of these standards bodies individually, how the codes interact, and how the documents are being used. A good deal of TDU interconnection work has been done in the renewables arena, primarily PV. Several of the documents listed are PV-specific, but in fact, are relevant to any inverter-based technology and touch on issues that apply to rotating machines as well.

2.4.1. National Fire Protection Association

The National Fire Protection Association publishes NFPA-70, *The National Electrical Code* (NEC), and is the foremost organization in the U.S. dealing with electrical equipment and wiring safety. The scope of the NEC covers all buildings and property except for electric TDU property, i.e., all equipment on the customer's side of the point of common coupling (the meter).

Article 705, Interconnected Electric Power Production Sources, broadly covers DG interconnection. It reinforces many of the topics covered in the PUCT Rule (e.g., "Synchronous generators in a parallel system shall be provided with the necessary equipment to establish and maintain a synchronous condition") and adds some details, for example, related to disconnect switch requirements.

Article 690, Solar Photovoltaic Systems, mentions interconnection to the grid, but focuses more on system wiring and descriptions of components. One key requirement in Article 690 of the NEC is that all equipment interconnecting with the grid must be listed[1]. This requirement is unique both within the code (which primarily encourages rather than requires listed equipment) and within DG. Inverters for a microturbine or fuel cell (which are not explicitly covered by 690) do not have to be listed per the code, though it's nearly always required by electrical inspectors.

The NEC may address fuel cells or utility interconnection issues related to all inverter-based in the future.

Additional relevant standards are found in NFPA-37, the *Standard for the Installation and Use of Stationary Combustion Engines and Gas Turbines*; NFPA-99, the *Standard for Health Care Facilities*; and NFPA-110, the *Standard for Emergency and Standby Power Systems*.

2.4.2. Institute of Electrical and Electronics Engineers (IEEE)

The standards that electric utilities adopt for their equipment often originate from IEEE. Standards balloting rules require that a balanced committee of utilities, manufacturers, users, and general interest groups are involved in the development of new IEEE standards. This diversity ensures that the standards provide a consensus of all interested parties. IEEE standards are voluntary, so utilities are not required to adopt them unless there is a specific Commission or legislative ruling to that effect.

In the 1980s, the Institute of Electrical and Electronics Engineers (IEEE) published ANSI/IEEE Std 1001-1988, *IEEE Guide for Interfacing Dispersed Storage and Generation Facilities with Electric Utility Systems*. This standard addresses the basic issues of power quality, equipment protection, and safety. This document has expired and a new document is under development to take its place. This project, P1547, *Standard for Distributed Resources Interconnected with Electric Power Systems*, was started in 1998 and will be completed 2001.

The recently adopted ANSI/IEEE Std. 929-2000, *IEEE Recommended Practice for Utility Interface of Photovoltaic (PV) Systems*, was developed to meet utility concerns with safety and power quality for PV systems. The intent was that there

[1] As defined in NEC Article 100, listed means "equipment, materials, or services included in a list published by an organization that is acceptable to the authority having jurisdiction and concerned with evaluation of products or services, that maintains periodic inspection of production of listed equipment or materials or periodic evaluation of services, and whose listing states that either the equipment, material, or services meets identified standards or has been tested and found suitable for a specified purpose."

would be no need for *additional* requirements in developing utility-specific guidelines, especially for systems of 10 kW or less. The new Std. 929, replacing a 1988 version, contains a 12-page recommended practice and appendices with detailed background into issues such as how inverters interface with the utility, islanding, and distribution transformers.

Another key standard is IEEE 519-1992, *IEEE Recommended Practices and Requirements for Harmonic Control in Electric Power Systems.* This guide applies to all types of static power converters used in industrial and commercial power systems, and addresses the problems involved in the harmonic control and reactive compensation of such converters. Limits of disturbances to the AC power distribution system that affect other equipment and communications are recommended. Voltage and current harmonics limits—total and single harmonic—as well as the voltage flicker limits of irritation curves are referenced for both utility practice and DG requirements.

IEEE standards covering many aspects of utility interconnection and distribution system design and operation are listed in Appendix A6.

2.4.3. Underwriters Laboratories

Underwriters Laboratories (UL) is a private, not-for-profit organization that has evaluated products, materials and systems in the interest of public safety since 1894. UL has become the leading safety testing and certification organization in the U.S., and its label is found on products ranging from toaster ovens to inverters to some office furniture.

Although UL writes the testing procedures, other organizations may do the actual testing and certification of specific products. In addition to UL, other testing labs such as ETL SEMKO (ETL), and the Canadian Standards Association (CSA) are widely recognized listing agencies for electrical components.

UL Standard 1741, *Static Inverters and Charge Controllers for use in Photovoltaic Power Systems,* deals with design requirements and testing procedures for inverters. UL 1741, published in May 1999, is now being revised comport to IEEE Std 929-2000, to cover inverters used for sources other than PV and to cover controllers that might provide similar capabilities for synchronous and induction machines.

APPENDIX F

PJM Small Generator Interconnection
"Applicable Technical Requirements and Standards"

Scope

The PJM Small Generator Interconnection "Applicable Technical Requirements and Standards" shall apply to all new generator interconnections, within the PJM footprint, with an aggregate size of 2 MW or less at the Point of Interconnection.

Purpose

To align the applicable technical requirements used within PJM with the IEEE Standard 1547 for " Interconnecting Distributed Resources with Electric Power Systems", and to facilitate the pre-certification of manufactured generation equipment and systems for use within the PJM footprint.

Background and Discussion

Developed by the PJM Small Generator Interconnection Working Group (SGIWG), It defines the uniform technical requirements that each Interconnected Transmission Owner (TO) and Electric Distribution Company (EDC) require for interconnecting to their facilities. The requirements defined in this "Applicable Technical Requirements and Standard" will govern for the interconnection of distributed generation, 2MW and below.

Interconnected Transmission Owner and Electric Distribution Companies may elect to waive certain IEEE 1547 requirements and associated exceptions and conditions stated herein but may not add requirements to IEEE 1547 other than the exceptions and conditions contained within this document. For Small Generators qualifying for interconnection under state rules, the state approved technical requirements and procedures shall govern.

PJM Tariff / IEEE 1547 Definition Cross Reference

IEEE Standard 1547	PJM Tariff
PCC (Point of Common Coupling)	POI (Point of Interconnection)
Point of DR Connection	Not Applicable

EPS (Electric Power System)	Interconnected Transmission Owner Facilities
Area EPS Operator	Interconnected Transmission Owner
Not Applicable	Transmission Provider (PJM)
DG (Distributed Generation)	Interconnection Customer Facilities ?
DR (Distributed Resources)	Facility
Interconnection Equipment	Not Applicable
Interconnection System	Interconnection Facilities
Not Applicable	Interconnection Customer Facilities
Point of DR Connection	Not Applicable
Electric Power System, local	Not Applicable
Electric Power System, area	Not Applicable
Cease to Energize (Cessation of energy outflow capability)	Not Applicable

Applicable Technical Requirements and Standards

IEEE Standard 1547 shall constitute the total technical requirements and standards for interconnection of small generators of 2 MW and less with the following noted exceptions, additions, and clarifications.

IEEE Standard Requirement	**Exceptions, Additions and Clarifications (also see notes)**
4.1.1 Voltage Regulation	**FE Exception**: FE's trip requirement for voltage > 120% is only 6 cycles compared to 10 for IEEE 1547
4.1.2 Integration with EPS Grounding	**PPL and UGI Exception**: PP&L requires a wye-

grounded connection on the T.O. side of the DG step up transformer for all new installations. Other T.O.s within PJM will accept a delta or ungrounded wye connection provided that adequate protection is provided by the DG to detect a ground on the T.O. system. This protection requires voltage monitoring on the high side of the DG transformer using phase to ground connected PTs.

IEEE Standard Requirement	**Exceptions, Additions and Clarifications (also see notes)**
4.1.3 Synchronization	See Note [1] **FE Exception**: No IEEE requirement for slip freq. or phase angle – FE requires slip frequency less than 0.2 Hz and phase angle deviation less than +/- 10 degrees.
4.1.4.1 Distribution Secondary Grid Networks (Under development)	Interconnection to Distribution Secondary Grid Networks only allowed on an exception basis or where state commission regulations specify requirements.
4.1.4.2 Distribution Secondary Spot Networks	Interconnection to Distribution Secondary Grid Networks only allowed on an exception basis or where state commission regulations specify requirements.
4.1.5 Inadvertent Energization	None
4.1.6 Monitoring	Local monitoring provisions are acceptable to meet 4.1.6 requirements except for the following: (1) PJM requires real-time telemetering for Capacity Resources able to set LMP. (2) Pepco and Conectiv require revenue quality metering with dial-up capability for all generators at 2 of the 3 locations as depicted on the single line drawing in Notes item #3. For facilities with multiple supplies and for generators less than 1MW, the requirements for metering will be determined on a case-by-case basis.

	(3) Conectiv may require real-time telemetering for certain interconnections above 1 MW. (4) PSEG may require real-time telemetering for any interconnection depending on location.
4.1.7 Isolation Device	None [2]
4.1.8.1 EMI Withstand	None
4.1.8.2 Surge Withstand	None
4.1.8.3 Paralleling Device Withstand	None

IEEE Standard Requirement	**Exceptions, Additions and Clarifications (also see notes)**
4.2.1 Area EPS Faults	None [3]
4.2.2 Area EPS Reclosing Coordination	None
4.2.3 Voltage Protection	No exceptions. **Clarification**: In cases where the DG interface is via an ungrounded transformer connection at the PCC, the voltage sensing must be done on the T.O. side of the transformer. This voltage sensing must be phase to ground connected and be on all three phases.
4.2.4 Frequency Protection	FE Exception: IEEE requirement for delayed trip> 30kw, FE requirements is >10 kw
4.2.5 Loss of Synchronism	None
4.2.6 Reconnection to Area EPS	
(a) Voltage Requirement	None
(b) Frequency Requirement	None

IEEE Standard Requirement	**Exceptions, Additions and Clarifications (also see notes)**
4.3.1 Limitation of DC Injection	None

4.3.2	Flicker	None [4]
4.3.4	Harmonics	Clarification to IEEE 1547 Requirement [5]
4.4.1	Unintentional Islanding	See below [6]
5.1	Design Test	See Attachment A
5.2	Production Test	See Attachment A
5.3	Interconnection Installation Evaluation	See Attachment A
5.4	Commissioning Test	See Attachement A **<u>FE Exception</u>**: Harmonic Limits (tested at 25% of full load rating or at a level as close to the minimum level of rated output the unit is designed to operate as practical and at a level as close to 100% of full load rating as practical)
5.5	Periodic Tests	**<u>PJM Exception for all</u>**: – Periodic Testing covered by PJM Tariff 55.1, 55.4, and ISA standard T&Cs which include the same PJM Tariff paragraphs.
	ADDITIONAL REQUIREMNTS	**<u>AEP Requirement for Voltage Unbalance</u>** - Voltage unbalance at the point of common coupling caused by the DG equipment under any condition shall not exceed 3% (calculated by dividing the maximum deviation from average voltage by the average voltage, with the result multiplied by 100). In its review of the proposed small generator interconnection request, AEP may determine that a lesser percent unbalance limit is required due to the presence of existing customer loads, such as certain compressor motors and power electronic loads, in the electrical vicinity. **<u>FE</u>**: - Voltage unbalance at the point of common coupling caused by the DG equipment under any condition shall not exceed 3% (calculated by dividing the maximum deviation from average voltage by the average voltage, with the result multiplied by 100).

AEP: For facilities interconnecting at voltages exceeding 480 volts, the Isolating Device required to allow AEP to safely isolate the generator must have a ground grid designed and installed in accordance with specifications to be provided by AEP. This ground grid limits the ground potential rise should a fault occur during switching operations. Operation of this Isolation Device must be restricted to AEP personnel and properly trained operators designated by the Customer.

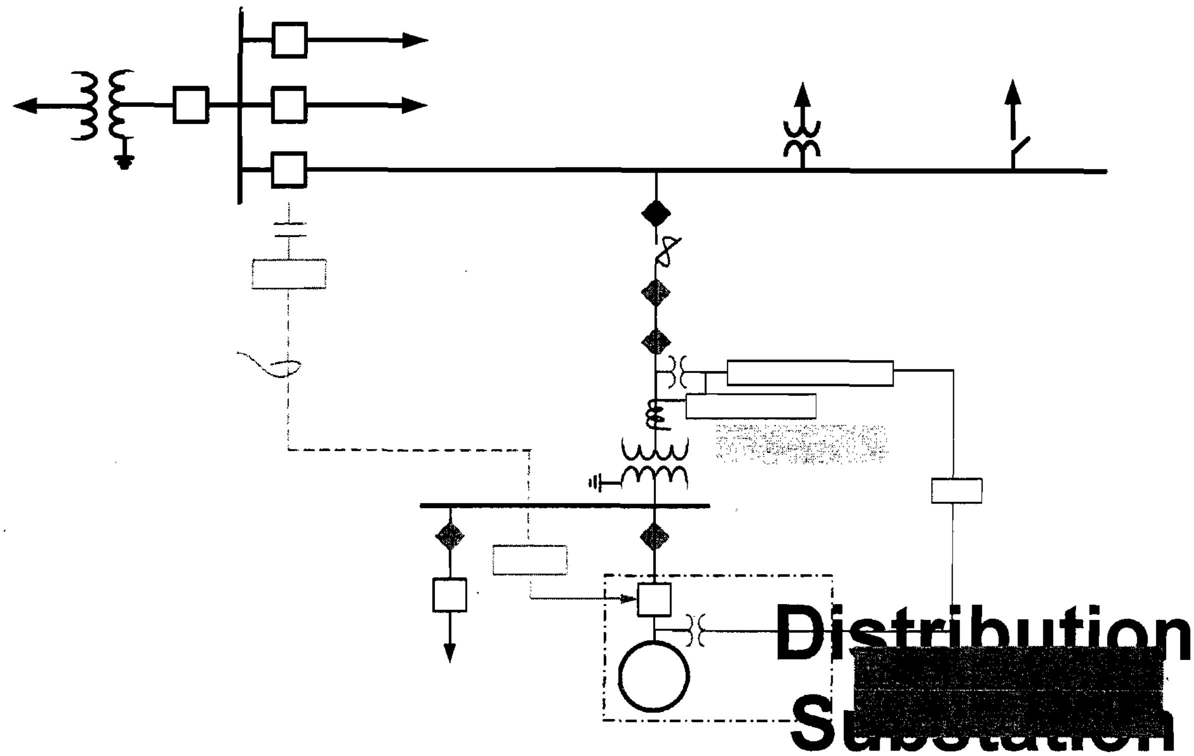
Notes

1 IEEE 1547 Synchronization voltage fluctuation requirement of +/- 5% is applicable as stated. Flicker requirement 4.3.2 guidance is provided by IEEE Standard 519 and IEEE Flicker Task Force P1453. However, the requirement which must be met for 4.3.2 is to not cause voltage and /or frequency disturbances which are objectionable to other EPS customers during actual operation of DR.

2 Discussion of Isolation Device Requirement - The Isolation Device provides a means for the EPS Operator to safely isolate the generator as a potential source of electric energy that could inadvertently energize the Area EPS. To meet the requirement in IEEE 1547 the Isolation Device must be readily accessible to the EPS Operator, lockable in the open position, and provide a visible break in the electrical connection between the generator and the Area EPS. The Isolation Device must be rated for the voltage and current requirements of the installation. The Isolation Device may be electrically located anywhere between the point of common coupling and the generator. However, the customer should consider the impact of the electrical location of the Isolation Device. If the Isolation Device is electrically at or near the generator and the EPS Operator uses the Isolation Device to provide clearance for worker safety, the customer will be unable to operate their generator to maintain electric supply to all or a portion of their load on the Local EPS during an outage of the Area EPS.

AEP Additional Requirement: - For facilities interconnecting at voltages exceeding 480 volts, the Isolating Device required to allow AEP to safely isolate the generator must have a ground grid designed and installed in accordance with specifications to be provided by AEP. This ground grid limits the ground potential rise should a fault occur during switching operations. Operation of this Isolation Device must be restricted to AEP personnel and properly trained operators designated by the Customer.

3 Area EPS Faults ...... Area EPS Fault Protection requirement for typical interconnection:
(Specific requirements will be determined during PJM Feasibility and Impact Studies)



4 Flicker requirement 4.3.2 guidance is provided by IEEE Standard 519 and IEEE Flicker Task Force P1453. However, the requirement which must be met for 4.3.2 is to not cause voltage and /or frequency disturbances which are objectionable to other EPS customers during actual operation of DR.

5 Clarification to the IEEE 1547 Harmonics requirement......

Each individual DG installation must, at their PCC, meet the injected harmonic current distortion limits provided in IEEE 1547 Table 3 (excerpt IEEE 519 Table 10.3). When multiple DG units are operating at different PCCs, each alone may meet the preceding current injection limit. However, the aggregate impart of all the DG units could still cause voltage distortion which would impact other non-DG customers. Therefore, the aggregate voltage distortion at EACH PCC must also not exceed IEEE 519, Table 11.1. If the limits described in IEEE 519, Table 11.1 are exceeded the offending DG is responsible for any appropriate corrective actions taken by the interconnecting transmission owner to mitigate the problem. Studies will be performed to determine if excessive harmonic distortion will occur prior to installation of the DG. However, it may not be possible to predict the net level of voltage distortion before each new DG installation on a given circuit. Voltage distortion in excess of IEEE 519 can be used as a benchmark to trigger corrective action (including disconnection of DG units) if service interference exists.

6 Unintentional Islanding ....

Requirement can be met by the following:

a) Transfer trip.
b) Sensitive Frequency and Voltage relay settings, with a short tripping time delay, where the maximum DR aggregate generation net output to the EPS is considerably less than the expected minimum islanded EPS load. Typically the islanded load must be approximately three times the maximum net islanded DR output.*
c) DR certified to pass an anti-islanding test.
d) Reverse or minimum power flow Relay limited.
e) Other anti-islanding means such as forced frequency or voltage shifting.

* **<u>Exceptions to b) above</u>**:

PSEG – Only applicable to aggregate DR interconnections of 1MW and below.

PEPCO – Generally not applicable for DR interconnections which export energy to the EPS.

7 Additional Requirements:

Requirement for Voltage Unbalance – In accordance with <u>ANSI C84.1, Annex D, Section D.2 Recommendation</u>, voltage unbalance at the point of common coupling caused by the DG equipment under any condition shall not exceed 3% (calculated by dividing the maximum deviation from average voltage by the average voltage, with the result multiplied by 100).

AEP - In its review of the proposed small generator interconnection request, AEP may determine that a lesser percent unbalance limit is required due to the presence of existing customer loads, such as certain compressor motors and power electronic loads, in the electrical vicinity.

APPENDIX G

2003

Model Interconnection Procedures and Agreement for Small Distributed Generation Resources

NARUC

October 2003

The National Association of Regulatory Utility Commissioners

Funded by the U.S. Department of Energy's Office of Distributed Energy Resources through the National Renewable Energy Laboratory

National Association of
Regulatory Utility Commissioners

Model Interconnection Procedures and Agreement for Small Distributed Generation Resources

October 2003

Funded by the U.S. Department of Energy's Office of Distributed Energy Resources through the National Renewable Energy Laboratory

Disclaimer: The National Association of Regulatory Utility Commissioners ("NARUC") Model Procedures, Agreement and Application Forms for Small Distributed Generation Resources Interconnection in no way indicates an agreement on the part of NARUC or its member State regulatory authorities to cede jurisdiction over interconnection to or retail transactions on the distribution wires facilities over which the States exercise ratemaking or other regulatory authority as provided by State statute, rules, regulations and regulatory orders.

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INTRODUCTION

July 2002

Dear Colleagues and Distributed Generation Stakeholders:

Over the last few years, several States -- California, Texas, New York, and Ohio -- have completed distributed generation (DG) interconnection procedures and agreements for small generators after extensive stakeholder processes. Other States have begun to consider how to implement DG. The National Association of Regulatory Utility Commissioners (NARUC) has adopted a number of principles, policies, and resolutions recognizing the importance of DG to the nation's energy systems.

On October 25, 2001, the Federal Energy Regulatory Commission (FERC) initiated an Advance Notice of Proposed Rulemaking (ANOPR) aimed at Standardizing Generator Interconnection Agreements and Procedures (Docket No. RM02-1-000) applicable to interconnections subject to FERC jurisdiction. State commission representatives participating in the ANOPR process realized that this would be an opportune time for the States to develop model interconnection agreements and procedures for small generators to parallel the FERC process.

In an effort to harmonize State approaches to DG interconnection, NARUC passed a resolution in February of 2002 supporting the development of two model documents for voluntary adoption or adaptation by the States:

- DG Interconnection Procedures for States; and
- DG Interconnection Agreement for States

How Were These Documents Developed?
With the support of the U.S. Department of Energy and under the direction of a Commissioner Steering Committee, NARUC established a Staff Working Group composed of State interconnection experts including attorneys, engineers, and other State staff. Although numerous States were represented in the Steering Committee and the Staff Working Group, the core of the working group consisted of State staff from the four States with approved DG procedures. Their experience with DG implementation facilitated preparation of the documents. The working group conducted weekly conference calls and one "face-to-face" meeting in order to create draft model interconnection documents. These documents consist for the most part, of provisions that that have been implemented by State commission orders and reflect the "best practices" of existing State procedures and agreements.

Early in this process, the decision was made to defer technical standards issues to existing State technical standards or to the ongoing IEEE process to adopt P1547 for interconnection of distributed generation. The decision was also made to identify policy issues that States would have to decide in implementing DG interconnection procedures and agreements, but not to dictate outcomes to States.

Call for Comments

In June 2002, NARUC released both the draft Interconnection Procedures (IP) and the draft Interconnection Agreement (IA) for broad stakeholder comment. The draft documents were distributed to at least 500 interested parties, including all State commissioners and to the participants in the IEEE P1547 process. Twenty-one sets of comments were received on the draft documents, reflecting a variety of State and industry participant views. The comments were taken under consideration in preparing the final Model DG Interconnection Documents.

The Purpose of These Documents

The documents produced for this DG project are intended to be resources for State commissions and industry stakeholders in their own DG efforts. Our hope is that the Model Interconnection Procedures and Agreement will serve as a catalyst for State DG interconnection proceedings.

As a part of this project, the National Regulatory Research Institute (NRRI) has developed a website with reference materials upon relevant to DG programs (www.nrri.ohio-state.edu/programs/electric/distributedgeneration). This website contains all of the documents produced by this project, as well as the procedures and agreements approved and implemented in California, Texas, New York, and Ohio, the full text of all comments filed on the documents, the responses of State commissions to NRRI's survey of the status of DG processes, and links to current State DG proceedings. In addition to the documents in this package, NARUC is requesting that NRRI prepare a subsequent document that will outline policy issues and discuss those decision points related to State implementation of distributed generation interconnection to further aid States in beginning their DG processes.

How Can States Use These Documents?

None of these documents represent "preferences" regarding the "technical and policy" issues that States have to make. Instead, they are intended to provide information that readers and users of the products can use to understand the issues and the relative merits as if they had been participants. This will be especially useful to commissioners and staff at the beginning of proceedings in their own jurisdictions.

These documents and the information on the NRRI website can be a platform from which to begin workshops, collaboratives, exchanges of technical papers, formal proceedings, or any other type of forums deemed appropriate for considering and implementing DG processes. The hope of the Steering Committee and the Staff Working Group is that these documents and the accompanying website material we have assembled will prove to be valuable tools to all participants in State DG processes.

Respectfully submitted,

Bob Anderson
Co-Chair, Steering Committee
Chair, NARUC Committee on Energy Resources and the Environment

Marsha H. Smith
Co-Chair Steering Committee
Chair, NARUC Committee on Electricity

APPENDIX H

NOTE: The overview was intended to cite issues identified by the research rather than make findings or conclusions per se.

I.
≈ DEG's Potential Benefits ≈

SJR 36 contends that DEG poses numerous benefits. There is a great deal more literature on the subject nationally than there this specific to Montana. But in both can be found arguments made for the benefits of DEG. The "beneficiaries" tend to be grouped as follows:

For consumers:
- DEG provides more consumer choice. [L7]
- Small plants typical of DEG offer communities independence from the wide-area grid.
- Reduced price volatility [U1]
- Greater reliability and power quality [U1]

For the business community:
- DEG stimulates growth and competition in emerging technologies.
- "[Newly] competitive markets favor technologies such as DEG that are low in capitol cost, quick to deploy, and modular, so that they can respond rapidly to changing market conditions. Major new generation projects that take up to 15 years or more to plan site, design, and build (those based on coal or uranium for example) are essentially impossible under today's market conditions." [G2-3]
- "Montana's small, sparsely populated market characteristics with vast, diversified in situ energy resources should be viewed as a strength and turned into economic opportunities through emerging high-tech distributed power technologies."... "Fortunately for Montana, its market characteristics offer a comparative advantage for distributed power over centralized plants. Distributed power technologies, not energy service companies, represent the competitive force to provide low, stable electricity rates in our rural state." [O4]

For utilities:
- DEG gives transmission utilities / suppliers more power sources to chose from (thus less reliance, for example, on PPL).
- DEG may help other utilities as well. [L11]:
    - Relieves line congestion. [U2]
    - Reduces line losses.
    - Lowers exposure to price peaks.
    - Alternative to expensive line extensions. [D1] [N1] [U2]
    - Back-up generation & reliability.
    - Easier emissions permitting.
    - Ancillary services (such as voltage support or stability, VARs, contingency reserves, and black start capability). [U2]

For Montana's environmentally sustainable energy development:

- DEG promotes the **renewable** resources & **clean** technologies emerging in Montana.
- DEG promotes more **efficient** energy transmission architecture.
    - Local generation creates opportunities for local consumption. This reduces wasteful transmission distances. (By one estimate, an estimated 10% is lost over the lines in standard transmission and distribution.) DEG "can be located close to the user and can be installed in small increments to match the load requirements of the customer." [S1]
    - Local sources of energy that might otherwise go undeveloped within the "central power" architecture can be tapped DEG. "Distributed generators can take advantage of locally-produced fuel such as methane... the efficiency of these systems is not an issue, because the fuel is delivered free, on site" [I2]
- DEG promotes more energy **efficient** generation.
    - Encouragement of DEG promotes conservation-minded processes like co-generation ("co-gen") or combined heat and power ("CHP") "CHP is the simultaneous generation of both power and thermal energy (heat) using the same fuel." [M1] These are also referred to as combined cycle processes.
        - By one assessment, coal fired power plants in Montana are at best about 35% efficient. Deducting transmission and distribution loss leaves about 31.5% efficiency of central station fossil fueled electric energy. Combined cycle gas fired plants can be as efficient as 60% - this is as good as central station power gets period, 40% of the energy leaves as heat and is not useable. [I1]

II.
≈ Regulatory Issues ≈

Barriers	Solutions
General	(For "financial incentives" see Market Issues)
Montana has "policies in place that help distributed generation, but they fall short of doing what needs to be done to see widespread adoption." [I-3]	
Fairness	
Rural Cooperatives worry about "non-generating customers having to face rate increases to <u>subsidize</u> [DEG] costs." [N__]	Model <u>policy</u> / <u>agreement</u> to assure that "non-generating customers" do not have to face rate increases to subsidize costs". [N__]
DG manufacturers and *owners* would like to shift the cost "from owners to all users of the grid, much as transmission and distribution companies do today. [G4] To accommodate load growth [under today's central station model] all users share in paying for specific upgrades--a principle not applied to accommodating the growth of DG." [G7-8]	
Cooperatives sometimes reason that The DG consumer-generator "takes high cost energy and pays the kWh back when the value of energy is less." … In this way, "net metering is a subsidy of the DG at the expense of other ratepayers." [N3]	
Interest of other stakeholders	
Utilities and *electric distribution companies* can be motivated, under current regulatory regimes, to seek excessively restrictive interconnection requirements to stifle <u>competition</u> and increase their own profits." [G4 & P2]	
"Electric distribution *utilities* and *cooperatives* have a disincentive under their rate structures to see widespread adoption of DG technologies." [E5&14] Certain Montana utilities "have a disincentive to promote distributed generation due to the loss of distribution revenue through the variable charge." [E13]	
"It may be to the *utility's* advantage to discourage interconnection if it owns central generation, with which DG competes. Even unbundled distribution companies have a direct incentive to discourage distributed generation if their income is based on the flows on the transmission or distribution system, on energy sales to customers, or on the	

value of the installed system (typical rate-of-return regulation)" [G4]	
"The *local utility* is both the guardian of the communal power system and a competitive supplier of energy; it may fear losing money if DG is successful". [G3]	
Rate structures	
"Uncertainty about rates paid to qualifying generators is a barrier, to be addressed by the Federal Energy Regulatory Commission." [I3]	"We need to work with the Public Service Commission to set reasonable utility rates for distributed generation to sell energy." [I3]
"The failure to take societal benefits and environmental externalities into account when determining appropriate rate treatment for renewable generators is a barrier." [I3]	We need to work with the PSC to grant some credit for environmental benefits of distributed generation, including credit for line losses avoided by using DG." [I3 & J14] [J13 also = Ryan]
The Renewable Portfolio Standard "ignores the value of environmental externalities." [J13]	Remove this barrier in the RPS by requiring a "percentage purchase of supply from renewable generators recognizing environmental benefits." [J14]
	The Public Utility Regulatory Policy Act, PURPA, of 1978 requires utilities to purchase power from qualifying facilities. The Montana Renewable Power Production and Rural Economic Development Act requires utilities to purchase renewable energy. [I3]
Rates can provide a disincentive for distributed generation, depending upon the design of the rate structure. If we assume that the goal is to deploy distributed generation resources on a cost-effective basis using a systems approach, then the objective of the rate design is to provide the correct price signals to the market so that the electrical system is maintained and operated at minimal cost." [E-20]	Rate structures for distribution utilities and retailers should include the following three components to be incentive compatible with cost-effective deployment. [E20]: Time-of-use supply rates – Averaged rates across time-of-use mask the true supply cost of electric power during the peak periods of the day. For intermittent distributed generation fueled by solar and wind, the generation may coincide with the time periods when supply costs are higher. Time-of-use rates would de-average prices across time and thus would provide the correct information necessary for performing economic analysis of distributed generation. "Locational" buy-back credit – The cost of distribution service differs by location, but rates are averaged across the entire distribution grid. One method for de-averaging distribution rates to more closely match the true avoided cost is to offer locational buy-back credits. For example, in areas that have low to moderate growth and (a) are capacity constrained, or (b) have aging infrastructure, or (c) require new infrastructure service, a buy-back credit could be offered within

	the load zone at a cost to the utility that is equal to or less than the cost of replacing or building new distribution infrastructure. With the locational buy-back credit, the avoided cost information is provided to decision-makers so that analyses for distributed generation within that location reflect the true distribution cost savings. <u>Revenue cap rates</u> – Utilities charge customers for distribution costs either through a fixed monthly charge or per unit of usage/demand, or some combination of the two. From a distributed generation and energy efficiency standpoint, these different rate structures clearly affect the utility's incentive for promoting and the customer's incentive for making cost-effective investments on the customer side of the meter. Fixed charges promote inefficient consumption since the customer faces zero marginal costs of consumption, resulting in reliability degradation. The utility is indifferent to distributed generation investments on the customer side of the meter under a fixed charge rate. Under a price per unit of usage/demand, the customer has an incentive for cost-effective investment, but the utility has a disincentive to promote such investment since a reduction of throughput over its line reduces its profits. As more states and utilities go to performance-based rates, distribution costs are recovered through charges per unit of electricity supplied under a price or revenue cap rate structure. The price cap rate structure results in a disincentive to utilities to promote customer investments in distributed generation, since profits are still tied to throughput across its wires. The revenue cap rate structure, however, provides no disincentive to the utility and the proper economic incentive to customers to invest in cost-effective distributed generation. Under a revenue cap structure, the utility is essentially operating under a fixed charge per customer, while at the same time the price observed by the customer is a charge per unit of consumption. Thus for the customer, investments in distributed generation reduce their power bill while for the utility, short-term profits remain independent of throughput over its wires.
Net metering (agreement)	
	NCAT: "The most helpful policy for distributed generation is net metering." [13]

	MECA: "Net metering can greatly increase the viability of a DG project." [N3]
	"Fix rates for net metered generators." One such proposed formula [J15]: • "Customer-Generator pays net distribution based upon supply voltage • Utility pays customer-generator supply rates • Utility pays customer-generator for avoided losses • Utility pays customer-generator for renewable energy credits"
Rural Cooperatives worry that any possible new state net metering laws might be passed in a blanket fashion… "One size legislation does not fit all." [K11 & N1]	Any possible new state net metering laws should account for cooperatives diversity and not pursue a one-size-fits-all approach.
Interconnection	
In general, "the interconnection conundrum will have far-reaching consequences for the future of DEG... The economics of interconnecting to the grid will help determine whether distributed generation ends up operating grid-parallel; isolated via an automatic transfer switch; or completely separated from the network of wires, switches, and poles..." [G5]	
Montana's incentive programs require interconnection. [E14] This requirement has been a disincentive. [E5]	Deemphasize interconnection to grid. [E5] … Do not require interconnection for incentive programs; promote grid isolation applications to directly serve end-use loads and plug-n-play building codes for new construction. [E14]
"The cost associated with interconnecting to the electric power system presents a major challenge to commercial deployment." [G1]	
"For small-scale DG, especially household scale in the range of 1-5kW capacity, the amount of electricity that is generated and put back on to the grid is typically trivial, while the fixed cost for interconnecting and metering/billing can be significant." [E18]	
Nationally-speaking, "exhaustive barriers, from pre-certification to extensive testing and planning, often discourage interconnection to the grid." [P2]	
Manufacturers, "having invested hundreds of millions of dollars to develop technologies such as microturbines and fuel cells, are now turning more aggressively toward influencing policy. Current interconnection requirements increase their costs, delay deployment, increase uncertainty, and reduce the available market. Regulations differ among utilities, states, or countries, which raises	

customization costs and makes it harder for these *manufacturers* and their *distributors* to support their products. [G3-4]	
"The approval process for interconnecting can often stretch from months into years." [G8]	[1999, nationally]: "Several governmental bodies are beginning to address DG interconnection issues through legislative or regulatory action. The trend appears to be in the direction of simpler, more uniform interconnection requirements that will be more favorable to small-scale DG." [G1]
Regulators are interested in promoting competition and increasing customer choice. In some regulators' minds, small-scale distributed generation should be part of an open market for generation. [G4]	In 1998, the National Association of Utility Regulatory Commissioners (NARUC) called for a national U.S. standard on interconnection, and some regulators from individual states have started efforts to implement the resolution's intent. [G4]
Awareness	
Customer is not educated - Montana is top tier in financial incentive programs but much lower in educational programs. [E15] "Montana ranks toward the bottom in the number of state and utility educational programs for renewable energy and distributed generation." [E15]	Implement educational programs in Montana that are successful in other states, especially those that work in conjunction with trade allies. [E15]
There can be a "'mindset' barrier, whereby the deployment of DG resources may entail a revolutionary rethinking of how the energy infrastructure could be revamped." [R2]	
There is hesitation to embrace DEG processes like CHP because (1) it is not part of traditional regulatory process and, (2) its costs and benefits are still unclear to many. [M4]	
Other	
Poor routing of incentive programs: "Incentive programs are sometimes offered through electric distribution utilities and cooperatives, which under their current rate structures have a disincentive to see widespread adoption of DG technologies." [E14] Natural market (the dealer, distributor, and energy service company) ally is not incentivized or helped [E14]	Route incentives through a more "natural trade ally – the dealer, distributor, end energy service company that sells" to the DG customer-generator." [E14] "Develop financial incentive programs for allies that can include pass-through money to consumers." [E14]
"Limitations on the size of renewable generators that can be interconnected, and interconnection requirements by utilities, is a continuing barrier." [I3] [Note: 69-8-103 MCA, puts "small customer" criterion at 50 kilowatt or less.]	"We need to go back to the legislature and get the limit to net metering of 50 KW removed. Cooperative members need to let their cooperative boards know that a 10 KW limit to distributed generators is not acceptable." (I3)
Clean technologies fall through the cracks. [E14] "[CHP] uses a single fuel to produce electricity and	Select technologies for incentives based on

heat [thus] can be a more efficient use of fuel. The current efficiency standards [nationally] do not account for this efficiency gain since the standards use input of fuel measurements, not output of energy." [P2]	pollution per unit of output; incentivize clean generation technologies (e.g., fuel cells and Stirling engines) similar to energy efficient technologies. [E14]
There are too many steps for DEG entrepreneur to pass through. This contributes to the dropout rate of interested entrepreneurs.	Streamline the business process for program incentives so that the consumer is dealing with just one entity during the transaction. [E5]

III.
≈ Market Issues ≈

Barriers	Solutions
"Power provided by the electric utility is comparatively dirt cheap… [Thus] the only way that anyone will install distributed power is they have some reason other than economics." [I2] "In some applications, especially where CHP [is used]… the efficiencies can be high enough to result in lower overall cost for the customer. However, customers may also be interested in DG for many other reasons, including greater environmental benefits, more reliable power, or greater control over the quality of power received. In the later examples, the overall benefits may outweigh the costs." [R3]	
"DG only seems to make sense in specialized niche applications… DG capacity costs and operation costs are generally not competitive with grid power for most applications at this time" … "It will move to the mainstream only if its capital and operating costs decrease, or if centralized generation becomes relatively more expensive, unobtainable, or undeliverable." [N1&3]	"Distributed generation, when properly deployed and using appropriate technologies, can reach beyond niche markets to provide customers of all types—residential, commercial, industrial and small business—with more reliable and higher quality electricity." [R2]
"A significant common barrier to overcome for all [DEG technologies] is the high transaction cost relative to the technology itself. ... If these emerging technologies are to penetrate the market, the total transaction cost per unit must be greatly reduced through streamlined business and regulatory processes." [B5 & D6]	Define standard business practices for utility review of interconnections with the grids. [B5] Define standard business terms for interconnection agreements to facilitate multiple distribution channels for distributed techs. [B5] Develop streamlined business process maps for utilities and distributors for sales and service of DG accounts. [B5]
	Education, stronger marketing, standardization, streamlining business & regulatory plans... Coherent & efficient relationships between customers (whether residential or commercial), the dealers & energy service firms, financing companies & government
Financial incentives	
	"A 30% federal income tax credit will be available starting in 2006, and a [Montana] state income tax credit has been in place for some time now. Low interest loans for renewable generators are

	available through the state Department of Environmental Quality." [I3]
In regard to the broader promotion of *renewable energies*, the State of Montana offers personal, corporate, and property tax incentives, as well as loans. Utilities and private sources also offer grants to promote renewable energies. [DSIRE]	
It should be noted, however, that these financial incentives do not extend to CHP activities. "Only a few states have financial incentives for combined heat & power technologies; Montana has none." [E10] & [P21]	
Challenge for fuel cells: cost effectiveness [L3]	Encourage a fuel cell market: [L8&9]: • Prioritize energy security, air quality, power reliability & fuel diversity • Improve investment environment • Include fuel cells in definition of clean technologies & vehicles and in Renewable Portfolio Standards • Support demonstration projects • Fund university R&D • Tax credits

IV.
≈ Technical Issues ≈

Barriers	Solutions
"Concerns fall into three major technical areas—faults, islanding, and power quality--each of which addresses safety, protection of equipment, or power quality/continuity of service, and sometimes all three." [G3-4, 9 & K11]	
"Initially, technical difficulties with interconnection to the utility grid were the largest problems for any small or non-utility generator. These barriers included safety standards, issues regarding grid reliability and power quality, and transmission difficulties regarding capacity. In 2000, the National Renewable Energy Laboratory released a report categorizing the barriers for distributed power projects (NREL 2000). As explained in that report, many of these technical barriers have been reduced or overcome, but utilities have not always updated their rules to keep pace with technological advances, or chosen to respond to developments." [P2]	
Fault current. "Utilities are concerned not just about individual generators but also about the aggregated impact of all of the distributed generators at a single location or on a single feeder. In particular, the total uncontrolled fault current coming from a collection of distributed generators is what complicates the existing systems protection scheme. This is why it is hard to determine if a specific generator can be accommodated at a specific location without adding cost in the form of upgrading the utility's protection scheme. [G8]	"Yet utilities (and their regulators) deal with this problem [of total fault current] all the time. For example, the house most recently added to a distribution feeder is not charged for a new substation transformer if it pushes the aggregated load over the transformers limits." [G8]
Islanding. "DG units can continue to provide power to onsite customers even if the utility's grid goes down... This extra reliability is one of the primary benefits." However, such islanding "has the potential to jeopardize **safety**, disrupt reliability, damage equipment, and reduce power quality." [H1]	According to *NCAT*, the record shows that safety concerns are "unfounded". [I3]
Other technical issues: [N2] • Power quality • Voltage regulation • Grounding and distribution system overvoltage • Network interconnection	

• Isolation of multiple source generation • Cold load pickup	
Administrative complexity	
Utilities and *distribution companies* "are concerned about how to meter and control distributed generation." [G3-4]	
"It's much easier to administer one 50 kW source than 50 1kW sources." [Q1]	
"Metering and billing hassles caused by backward rotation". [J11]	Therefore use (1) electronic meters with dual registers, and (2) two meters. [J11]
Other	
More training on safe installation and maintenance would be helpful.	"Several states have training programs for installation and maintenance of... equipment." [E8]
Power system engineers are conservative. The risk-reward ratio offers little incentive. [G3]	