CIMAP Distributed Energy Resources Workshop

Richmond, Virginia

17 May 2002

Final Workshop Summary

A Distributed Energy Resources workshop, coordinated by the Alexandria Research Institute (ARI) CIMAP staff and co-hosted by the Virginia State Corporation Commission (SCC), was held in Richmond, Virginia on 17 May 2002. The workshop focused on identifying the implications of distributed resources for the various major stakeholders and suggesting a role for the Commonwealth in developing policies to promote, control or otherwise affect their development. In order to accomplish this, presentations were solicited from the Federal, Commonwealth and energy-intensive private sector. The presentations can be viewed online at the CIMAP workshop website: www.cimap.vt.edu/workshop/index.htm

Principal Findings and Conclusions

The workshop underscored the rapidly-changing landscape of energy delivery services under current and proposed deregulation initiatives. With respect to distributed energy systems, this landscape can be characterized by the following concerns:

- Distributed energy resources offer a potential additional source of electrical energy supply over the next several years, with estimates ranging from 20 percent to 40 percent of installed capacity available from central power stations;
- There is no agreed-upon protocol for evaluating operational and emissions characteristics of late-generation distributed resource units, including a suitable mechanism to collect up-to-date data and scale up from bench test to on-line operation;
- There is a similar absence of an appropriate methodology for incorporating distributed generation technical and human risk factors into distribution system operations;
- New business models are needed based on new technologies and a changing regulatory environment;
- A revised tariff structure, philosophy and payment allocation to incorporate distributed generation will be required;
- Integrated resource planning for a distribution feeder in a deregulated market based on probabilistic planning criteria will be necessary;
- Standards and restrictions for gas-fired distributed resource units should be re-assessed, based on state-of-the-art pollution control abatement technologies permitting greater hours of operation, including possible operation in a peak-shaving mode; and
- The availability and reliability of the gas distribution system, particularly as it relates to new distributed generation units, may be a greater liability than the electrical transmission grid.

The following two sections include a detailed review of the morning presentations as well as a summary of key issues discussed during the afternoon plenary session. These issues will be examined to help structure CIMAP research and workshops during the next two years.

Summary of Workshop Presentations

The one-day workshop, which attracted some twenty-eight (28) participants, was briefly addressed by SCC Commissioner Hullie W. Moore, who emphasized the need to make market-based competition work in Virginia. Judge Moore noted that distributed power may be the way to bring competition into Virginia first, and pointed out that the SCC mandate was to "develop interconnection standards to ensure safety and reliability. Such standards cannot be inconsistent with nationally recognized standards. . . ."

The first presenter was **Mr. Joseph Galdo** from the DOE Office of Distributed Resources, who provided a Federal overview of Distributed Power Resources. He pointed out that, although distributed power and distributed generation are not new ideas, they provide a new option for both consumers and utilities by providing premium value, such as power quality. Other applications include peak power, remote applications, rural areas and providing ancillary services to the grid.

Mr. Galdo cited the high cost of power downtime and voltage fluctuations for industry, and noted that while mobile diesel generator sets have provided power during disasters and catastrophes, future power systems could provide power to a local area as needed via in-place generator sets.

DOE recently undertook studies of the issues surrounding power shortages/outages around the U.S. during the last two summers; a National Transmission Grid Study mapped out congested parts of the transmission system. Although Virginia has not had any severe problems, the study identified two paths in Virginia that may be affected in the future.

Many outage problems result from problems in the distribution system. Data from 124 utilities showed a total average annual investment of $6.4 billion per year for lines, feeders, transformers and substations, although specific utility costs were highly dependent on geographic location.

According to Mr. Galdo, DOE believes that distributed generation can play a critical role in competitive markets by providing the demand side of a supply & demand market. Demand response programs have become popular in areas with power shortages or transmission constraints; a recent EPRI study concluded that for small participation demand response programs, major reductions in peak demand - and accompanying prices - can be achieved.

The National Energy Policy released last year has many recommendations for improving the use of energy systems in the U.S. Major objectives were outlined in the overview. Distributed generation can help achieve these objectives through a variety of approaches: fuel cells; lowered emissions; non-fossil supply; bringing energy closer to the load; improving transmission system operations; and increasing energy efficiency.

Although policy and regulations allowing market mechanisms to work to incorporate DER into the power system are very important, Public Utility Commissions and legislators have found that resolving interconnection issues is critical. Two years ago, a study was made of barriers which impact distributed generation. The study (***Making Connections: Case Studies of Interconnection barriers and their Impacts on Distributed Power Projects*, NREL/SR-200-28053, May 2000)** involved 65 case studies of various sizes from 1kw to 25Mw, across several technologies and geographic areas. The study concluded that a variety of business practices and regulatory barriers discourage interconnection of distributed generation. Interconnection requirements vary, compliance is very expensive for small projects, no standard procedures are in place, and the resulting project delays created a real barrier for large projects.

Interconnection issues arise from a need to make sure distributed generation does not affect power system safety, power quality, and other issues. IEEE is working to develop a technical interconnection standard, P1547, to address these and other issues. Since 1999, IEEE has been working with broad industry involvement, to develop this technical standard that will be the basis of a national interconnection standard.

UL1741 has been adopted by several states, an existing standard applying only to inverters, which is being expanded to cover the interconnection of all types of DER. It is also being made to harmonize with IEEE P1547.

Regarding the penetration limits of distributed generation on a feeder system, Mr. Galdo pointed out that Detroit Edison modeled some distributed generation on their system. The results showed that with up to 20% distributed generation, there were no significant impacts of properly connected DG.

Mr. Galdo noted that FERC has admitted that its rules place small distributed generation at a disadvantage and is considering separating small distributed generation cases into a separate set of rules. Jurisdictional issues complicate matters, as the exact boundaries of FERC jurisdiction are an ongoing topic of controversy. Ultimately, the challenges are state and federal implementation of interconnection rules, along with simplified costing methods for distribution systems.

In response to a question whether Virginia should wait until NARUC rules are in place, Mr. Galdo pointed out that good state models are already available, while Federal rules are moving slowly. In his view, the best outcome is that once a national technical standard is in place, states will incorporate it in their regulations.

In response to a question regarding the relative importance of distributed generation in the future, Mr. Galdo replied that DER would play a more important role in the future, whether market penetration is 15%, 20%, or 40%. Of course, a lot of that depends on technologies, making them competitive, and also the regulatory environment that we set up to allow **new business models**. Some companies already are aggregating small distributed generation into virtual power companies, while other project developers are making a business out of installing distributed generation as minute power systems that are more efficient, so that they compete with utility electricity prices.

In response to a question regarding the future role of the natural gas supply infrastructure, Mr. Galdo noted that DOE's Distributed Resources Office has not focused on the issue at the national level. He pointed out that ARI's recent study for the Virginia CIT had visited the near term issues, such as the impact of energy supply on high tech companies.

Mr. Tommy Oliver, Virginia State Corporation Commission presented an overview of the Background and Purpose of SCC Proposed Regulations. He pointed out that the Commonwealth's net metering provision - which became effective 5/25/00 - has received national acclaim, and that five Virginia families now have net metering.

Initially the SCC staff defined a distributed generation facility as an electric generating facility capable of exporting electric energy into the distribution system of a VA public utility. Rules have claimed jurisdiction over everything that FERC leaves behind in its jurisdiction. 56-578A requires the wires company to give equal access to the grid, forbids preferential treatment, and is now using UL-1741 to move forward, while IEEE P1547 is in development. In the interim, the SCC solicited comments on proposed distributed generation rules, which were mailed to 55 persons on 3/20/02; however, only six persons sent comments during the comment period. SCC is now holding meetings with persons who submitted comments.

Mr. Oliver pointed out that existing tariffs were not designed for distributed generation, so tariff structure and philosophy need to be revisited. He summarized three general areas where the SCC is seeking guidance:

- What party should pay for any necessary upgrades to the distribution system to accommodate a DG installation (the DG customer, all customers, the DG customer and any subsequent DG customer that may benefit from the upgrade, or some combination of these)?
- In contrast to the way Staff's proposed DG rules are written, should a utility be allowed to increase the monthly charge to a current customer installing a DG facility to recover the utility's capital cost rather than seek recovery through a back-up rate or some other mechanism? In Texas, for example, the ratepayer was required to pay, because the wire was seen as a benefit to society. In Virginia one distributed generation project was aborted because the utility required a high recovery fee from the DG customer.
- Where is the line between FERC and state jurisdiction when it comes to DG interconnections?

Under the propose Virginia approach, a prospective customer must notify the utility of intention to interconnect, and this establishes the timeline for response. Applicants must comply with other applicable rules and laws with respect to siting. The utility is permitted to do an optional study, but there is controversy over who pays for the study. The SCC Staff also proposes a disincentive for utility to require or perform a study for very small system. As there is no operative IEEE standard, the SCC staff is using the Texas statutes as a proxy, in anticipation that IEEE standard will be similar.

Mr. Harold W. Adams, Jr., P.E. Dominion Energy, in his presentation "Distributed Resources: An Investor-Owned Utility Perspective", described the changing world of deregulation and its implication for transmission, distribution, and retail sales. Noting that each side of the meter plays differently in the market, he pointed out that it is conceivable that incumbent utility may in the future only supply one service. The fundamental question for a utility thus becomes: What will drive a utility to be interested in distributed generation?

The energy business is no different from any other: utilities want to take care of customers, and control costs/profitability. How can distributed generation affect these two areas? That is the utility's interest.

When utility service is unbundled, relationships between players change – in fact, a utility may not even sell energy. The utility view of distributed generation thus depends on what market business the utility is in. Each business sells a different product to a different set of customers. Depending on point of view, distributed generation may be an important business option for serving load, or a potential supply source. Use of distributed generation then becomes an economic decision.

With respect to transmission and DG, the RTO (not the utility) controls policies related to this because they set up market rules. The RTO planning process is where distributed generation fits in here.

With respect to distribution and DG, there is potentially strong linkage to distributed generation regarding impact on safety, reliability, cost, and distribution rates. The effects can be either positive or negative. For example, who should pay for incremental upgrade of transmission line that is already fully loaded, when a distributed generation operator proposes to deliver distributed

generation on that line? In order to devise an equitable pricing system, it is necessary to look at the flow of benefits, economic principles.

Distributed generation can affect sales and revenues across the market. The value proposition of distributed generation depends on which part of the business you are in, and – in particular - understanding the relationship between distributed generation and retail supply function (LSE). Distributed generation may be a valuable part of a utility's supply portfolio, especially as part of a broader market. Distributed generation is a potentially valuable and innovative source of energy. It will be important to have consistency between FERC rules and state rules to have effective implementation of the technology.

In reply to a question regarding how energy will be priced, Mr. Adams used the term locational marginal pricing, and stated that RTO policy will govern pricing of energy at each individual node.

Mr. Greg White, Old Dominion Electric Cooperative (ODEC) in his presentation Distributed Resources: A Utility Cooperative Perspective, pointed out that distributed generation is not a new issue for cooperatives. He cited a variety of projects, starting from diesel power for 1980's CD manufacturer who needed distributed generation to obtain power quality and backup generation for its manufacturing process. He also described recent DG projects involving small hydro and fuel cell technology.

Mr. White pointed out that fuel cells are very exciting technology, but very expensive, with costs of $5750/kW and operating cost of $.30 per kWh. Both installed capacity costs and operating costs are significantly higher than central station power plants. Diesel units have costs of $380/kW, with operating cost of $.07 per kWh, which compare well with central station power operating costs of about $.04 per kWh.

ODEC is building 5 diesel sites in 2002 to minimize the impacts of transmission congestion. Two diesel plants in Virginia are needed for reliability purposes. For instance, at the end of a distribution circuit, there are problems that are not easily solved without local generation. Some diesel sites are located at the site of emergency services, so the latter will have a dependable backup power source. Although safety and reliability are the two fundamental interconnection issues, ODEC also doesn't want to promote solutions that are not economically feasible. Ultimately, a successful interconnection must embody three main elements: the "Agreement"; Commission proposed regulations; and Legislative Policy.

In reply to a question about fuel consumption rate for diesel generators, Mr. White stated that ODEC used mobile diesels; however, after the process of interconnection, they don't want to move them. Units come with 8-hour tanks, although ODEC can install 48-hour tanks. ODEC expects the units to run 8-10 hours per day during, for example, to supply summer peak loads, but it is possible to run continuously for 4-5 days – for example, during an ice storm.

Ms. Cliona Robb of Christian & Barton, outlined concerns of DG equipment suppliers. She first noted that as much as 20% of new demand for electricity over the next decade may be accommodated by heavy use of alternative resources, making distributed generation a "big deal." However, many clients have concerns about the high costs of getting small distributed generation online.

She cited Delaware as a state that had encountered many outage problems, with small land mass and too few central station units. In her view, DG may alleviate this problem. A Delaware task force is considering a DG feasibility study, and she recommended that participants follow these developments, as they might have some relevance for Virginia.

From a technology perspective, Ms. Robb identified three advances necessary to successfully combine distributed generation assets with central power stations to optimize power grid:

- Provide distributed generation devices that are able to seamlessly connect, off the shelf, resulting in 2-way power transfer
- Regulatory standards for rapid and safe connection to local power circuits.
- DG devices should be intelligent nodes in the energy network, capable of sensing and responding to a variety of signals. It will be self-healing, part of an advanced logic network. Need a central command/control. Send a signal, for instance, for devices to start producing energy. Sophisticated tracking for devices via digital communications network, allow accounting on the back end (who owes what to whom).

The ultimate question, in Ms. Robb's thinking, is how to do all this? Her recommendation is to survey current resources, keep apprised of programs in other states and at the federal level, and find out what is being done now.

Mr. Rodney Sobin, of the Virginia DEQ, presented some preliminary results from a DEQ study of Administrative and Regulatory Barriers To Distributed Generation. The DEQ study recognizes that DER and CHP have the potential to improve efficiency, enhance reliability, reduce emissions, and reduce generation and transmission limitations. This is of particular relevance, as Virginia is a net importer of electrical energy, with 87.7% from utility and 12.3% from non-utility sources.

The emissions characteristics of technologies employed by distributed energy resources is of great interest to the DEQ, as the northern Virginia and Tidewaters areas currently are in non-attainment for criteria air pollutants, while other areas are expected to be found borderline for non-attainment. In addition to criteria pollutants, other emissions are of concern, such as mercury from coal combustion.

Resources are DOE State Program Special Energy Project, VA DMME, background research, stakeholder interviews, stakeholder workshops (future plan). Focus is administrative regulatory barriers. It is early in the project, so findings are reported from literature, not project.

The DEQ Study of DER and CHP is a DOE State Program Special Energy Project, and is being implemented with support from the Virginia Department of Mines, Minerals and Energy. The basic mandate of the study is to identify and assess administrative and regulatory impediments to distributed energy resources (DER) and combined heat and power (CHP). This is being accomplished by background research and stakeholder discussions, to be followed by stakeholder meetings. The primary issues addressed by the study include:

- Interconnection
- Utility tariffs and procedures
- Air regulations
- Building codes
- Zoning/siting

Mr. Sobin cited the DOE study "Making Connections: Case Studies Of Interconnection Barriers And Their Impacts On Distributed Power Projects," which Mr. Galdo earlier had referenced, as providing a baseline for both issues and recommendations. He pointed out that several logistical problems were identified, including how to find out who to talk to in a utility, and how to get approvals. It appears that standard business procedures may be nonexistent or oriented toward

large merchant plants, and it is likely that new tools are needed to assess the impact of distributed energy resources.

Mr. Sobin also referenced a report by the U.S. Combined Heat and Power Association, National CHP Roadmap, March 2001, which had been undertaken in cooperation with DOE and EPA. The report noted that existing air regulations may ignore benefits of DER/CHP, and found that streamlining of siting and permitting procedures is needed, along with model regulatory principles, standards, tools to assess value and impacts of DER/CHP. Output-based emission standards, pre-certification of certain types of equipment to streamline the permitting process and general permitting for standard small facilities were recommendations that the DEQ team was evaluating.

This in-house study, which is receiving assistance from a private company, should be completed during 2003. Toward that end, the DEQ is looking for more assistance with workshops.

In response to a question about attainment problems, Mr. Sobin noted that cleaner technologies have issues about which standards need to be met. In his view, regulators need to see that clean technologies actually displace coal and diesel, rather than supplement them with accompanying additional emissions. He posed the question: is there a way to provide some sort of emissions credit, or to recognize that CHP achieves greater efficiency, thus lowering emissions overall while increasing them locally?

He pointed out that, at the state level, diesels are subject to permitting regulations, generally forbidding operation in a peak-shaving mode, but he was not aware of any state activity directed at retrofitting to clean up existing sources. It was possible that with abatement technology, perhaps units could be allowed to operate more hours.

For the last year, DOE has been supporting a regulatory systems project to establish a national model. Industry people have become involved with this since the draft was issued. Some issues brought up in this presentation are being addressed in the draft. Mr. Sobin mentioned that DEQ has seen the draft and is holding internal discussions prior to preparing formal comments.

Afternoon Plenary Session

The afternoon session was devoted to an open-ended discussion of issues. Following is a summary of participant comments:

Mr. Thomas pointed out that the unbundled utility world would create substantial cost and concerns, which raise a number of fairness issues. The costs of incorporating distributed generation should not necessarily all be assigned to utilities, but should be based on fairness concepts that still need to be defined.

Dr. Rahman stressed the historically poor reliability of distributed generation units, although this is increasing. In particular, multiple DGs on a feeder will collectively have a different risk level than a single installation. The utility must still develop strategies for the percent of time the distributed generation installation is down. Since transformers, interconnection equipment, and individual pieces of equipment on both sides of the fence will fail a certain number of hours per year, with potentially disastrous consequences for customers, a proactive approach that incorporates all risk factors is needed.

Mr. Adams pointed out that integrated resource planning for a distribution feeder in a deregulated market is a problem. What are needed are probabilistic planning criteria, as well as the need to examine how the costs are assigned. As an example, he cited the question of when it

is economic to do a feeder upgrade, as well as how distributed generation will play through the market.

Mr. Thomas asked whether the distributed generation community studied this issue. He suggested that this is a classic situation where there may be societal benefits and benefit to a private entity. If so, whose responsibility is it to pay for the feeder upgrade? Does it become everybody's problem? Should everybody pay for it (tax system)?

Dr. Rahman raised a hypothetical situation where a grocery store chain has gone off grid, utilizing mobile sources, due to excessive utility backup charges. Mr. Thomas felt that customers are not willing to accept that level of risk. AEP is a very strong supporter of distributed generation, with significant investments in wind farms in the west. We are interested in a balance in where the costs end up.

With regard to backup supply, Mr. Adams noted that if a supermarket decides to go off-grid or to have backup supply, it's a contractual issue. The utility will have to provide facilities just in case a customer's DG goes down; the customer's option is whether he wants to expose himself to market prices or arrange for a separate backup. Mr. Thomas noted that today's market structure was not intended for the case of distributed generation requiring backup power. It makes a difference whether you implement distributed generation at your existing facility or build a new installation. The rules have to account for both situations.

In Mr. Adams' view, the distribution business is selling the ability to purchase from various sources. This raises the question: how would the scenario of scattered distributed generation along a feeder affect the distribution business' ability to deliver a product?

Dr. Rahman noted that the reaction to accepting DG or not is not always based on the most recent data; there appears to be a time lag with respect to this data.

Mr. Adams said that presumably, a utility would be paying for some avoidance cost, and would give a cost break to a company that is willing to do some self-generation at peak time. However, if it failed to perform, what concerns him most about performance contracts is the liability, if a customer on the circuit lost a large amount of product because the DG was unable to perform. The utility may have a big lawsuit on their hands. Distributed generation adds another element of risk because there is another component that can fail. One aspect is equipment reliability; another is how it is operated and maintained. What if the owner is not an expert in operating DGs? What if it is a grocery store operating a DG? If there are many DG systems, the risk is diversified and consequently smaller. However, what is the risk if there are only a few DGs on the feeder?

Dr. Rahman noted that some facilities have spent millions of dollars on multiple layers of backups because there is 'unreliability' built in to the power service that the utility can provide – prime examples of this are AOL and Dominion Semiconductor.

Mr. Adams noted that this level of service is far higher than that guaranteed through Dominion Virginia's normal contract obligations. Often, customers want higher reliability provided but they want to pay only for the standard contract. Dr. Rahman suggested that this may be a new business model, in which it might be cheaper for a third party to provide premium service, or to provide different levels of service to different groups of customers.

Mr. Adams noted that, unfortunately, all customers on the circuit will get the same level of service. They don't all require the same level, not all are willing to pay for the highest level of service. The real question is how you meet the needs of individual customers with customers in existing geographic sites, along given feeders?

Mr. Thomas pointed out that some tariffs currently allow the customer to choose different levels of risk avoidance for different prices - over time, models will evolve, but "we're just not there yet". Multiple inputs have to come together in an evolutionary process to create fair pricing models. "We (AEP) are starting that process now." Currently, if a customer contracts for less backup capacity than they need, the tariff has penalty provisions as much as 1.5 to 2 times the normal rate.

Mr. Galdo noted the concern that the distributed generation community is not telling "the right story," and pointed out that DOE is looking at standardizing performance assessments. Presently, there is no standard way of measuring various characteristics, so you might get a different answer on a different day. Even with emissions, there are different ways of measuring, so that you are comparing apples to oranges. Dr. Rahman stated that until that happens, utilities would be skeptical about distributed generation claims, with no standard way to evaluate them.

Mr. Thomas noted that the State Corporation Commission, in a recent evaluation of proposed transmission, examined whether strategically placed generation could substitute for transmission lines. In a deregulated market, this would involve two markets: the supply market and wires. Mr. Adams pointed out that the vast majority of capital investments have been in generation; historically, they have been three times the combined T&D investment (75% G 5% T 20% D, according to Mr. Payne) in a vertically integrated utility.

Mr. Thomas cited a growing concern about having to put in transmission or distribution facilities and recovering the cost. What do today's and the future's distribution costs need to be? The notion that distribution is an expensive commodity is already there. We've approached it when we extend service to a customer; you hope that customer's revenue will cover that facility through appropriate tariffs. Distribution revenue should only determine whether it covers distribution-related cost. Now, revenue from the entire bundle determines whether the customer makes a contribution toward distribution expenses. This situation needs to be cleaned up, so that only distribution revenue is a signal for distribution cost recovery from the customer. In a question from Mr. Adams as to whether distribution companies have rights to capacity revenue, Dr. Rahman argued, "Yes, otherwise you are stuck with that expenditure".

Mr. Adams noted that distributed generation as a competitor is a policy question. One can conceive of a distribution entity building a DG to support its distribution needs, and distribution company having no commensurate load obligation. Who is going to pay for it? Having that energy sold into the RTO at the market price is one way to do this, but how to deal with the capacity reserve? A distribution company may have 500 MW -- that is enough to make them a player in the reserve markets. There ought to be a way for a third party to handle this, so that the distribution company will be neutral as to benefits.

Mr. Thomas stated that encouraging legal separation of components of the utility business, and allowing each technology opportunity to stand on its own and compete, would provide better price signals.

Mr. Payne noted that system reinforcements are only a percentage of distribution investments; the majority are line extensions to customers, which you cannot avoid. Incremental capacity is minimal. System improvements are a portion of investment. Some of these deal with reliability improvement. The part related to increasing distribution capacity is small.

Mr. Thomas also felt that environmental costs would be fully internalized in the scenario he described. This would be a desirable goal. So far, AEP has functional unbundling, not legal unbundling. Assets have not yet been transferred out as in other companies such as Southern. According to Mr. Thomas, "we are in infancy of the unbundling process".

Mr. Sobin pointed out that, from an environmental perspective, there has been no significant progress internalizing environmental costs since the 1920s. The question, he stated, is how does one go about trading for NOx among utilities? Right now, there is no mechanism for trading NOx credits. Any such mechanism should include non-utility reduction credits - for example, clean vehicle installations. The proposed NOx trading is narrower than it should be. We'll get there eventually, but we're not there yet.

There was considerable discussion over Virginia's gas supply issues, particularly as the gas and electric infrastructures are related. Some areas of Virginia may have gas supply problems. The question then becomes, how do we decide where gas goes when it is constrained? This is particularly relevant for DGs, with new units primarily gas powered, so one cannot avoid issues related to gas infrastructure. A question yet to be answered conclusively is "has the reliability of gas infrastructure changed"? It doesn't matter whether the resource (state-of-the-art DG units) are dispersed if you cannot get the gas.

Dr. Rahman argued about constrained gas availability in the state, particularly in light of the large number of gas-fired merchant power plants. The power company has an obligation to build new lines to support growth, but gas companies have no similar responsibility. When gas is constrained, consumer prices will rise. Some industrial companies may have to shut down. The question, in brief, is: Where does the gas go? What are we using it for?

Mr. Sobin, who concluded that limited gas availability is potentially a greater liability than transmission lines, reiterated this concern. Dr. Willingham noted that this issue would continue to be a focus of the ARI and the CIMAP program.